PC37.230™/D2.8 Draft Guide for Protective Relay Applications to Distribution Lines

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Abstract: A review of generally accepted applications and coordination of protection for power system distribution lines is presented. The advantages and disadvantages of schemes presently being used in protecting distribution lines are examined in this guide. Identification of problems with the methods used in distribution line protection and the solutions for those problems is included.

Keywords: coordination, distribution, faults, protection, reclosing, sensitivity

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Introduction

This introduction is not part of PC37.230/D2.8, Draft Guide for Protective Relay Applications to Distribution Lines.

This guide compiles information on the application considerations of protective relays to power distribution lines. This guide presents a review of generally accepted distribution line protection schemes. Its purpose is to describe various schemes to assist relay engineers in selecting the most appropriate scheme for a particular installation. It is intended for engineers who have a basic knowledge of power system protection. This is an application guide and does not cover all of the protective requirements of all distribution line configurations in every situation. Additional reading material is suggested so the reader can evaluate the protection for the individual application.

Contents

Draft Guide for Protective Relay Applications to Distribution Lines

1. Overview

This guide is divided into nine clauses. Clause 1 provides the scope and purpose of this guide. Clause 2 lists referenced documents that are indispensable when applying this guide. Clause 3 provides definitions that are not found in other standards. Clause 4 gives an explanation of distribution fundamentals. Clause 5 discusses system configuration and components. Clause 6 explains the characteristics of protective schemes. Criteria and examples are discussed in Clause 7, including margins and common considerations. Clause 8 has several special applications and considerations for distribution line protection. ~~Clause 9 focuses on emerging technologies.~~

This guide also contains two annexes. Annex A provides the bibliography, and Annex B contains a glossary of terms defined in other IEEE standards.

1.1 Scope

This guide discusses the application and coordination of protection of power-system distribution lines. It includes the descriptions of the fundamentals, line configurations, and schemes. In addition to these, this guide identifies problems with the methods used in distribution line protection and the solutions to those problems.

1.2 Purpose

This guide educates and provides information on distribution protection schemes to utility engineers, consultants, educators, and manufacturers. The guide examines the advantages and disadvantages of schemes presently used in protecting distribution lines. This provides the user with the rationale for determining the best approach for protecting an electric power distribution system.

2. Normative references

The following referenced documents are indispensable for the application of this document (i.e., they must be understood and used, so each referenced document is cited in text and its relationship to this document is explained). For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

There are no references that are indispensable for the application of this document.

3. Definitions, acronyms, and abbreviations

3.1 Definitions

For the purposes of this document, the following terms and definitions apply. The *IEEE Standards Dictionary Online* should be consulted for terms not defined in this clause. [1]

distributed energy resource (DER): Source of electric power that is not directly connected to a bulk power transmission system. DERs include both generators and energy storage technologies.

distribution automation: A technique used to limit the outage duration and restore service to customers through fault location identification and automatic switching.

interrupting medium: The material used to facilitate the interruption of the arc during opening of a switching device.

polarizing voltage: The input voltage to a relay that provides a reference for establishing the direction of the operating current.

sympathetic tripping: The phenomenom where an interrupting device on an unfaulted circuit trips for a fault on a nearby circuit, usually caused by current inrush on the device after the faulted feeder's interrupting device opens and the system voltage returns to normal.

varmetric relays: Relays that respond to the quadrature (imaginary) component current compared to the polarizing voltage.

wattmetric relays: Relays that respond to the in-phase (real) component current as compared to the polarizing voltage.

3.2 Acronyms and abbreviations

AMI	Automated Metering Infrastructure
BIL	basic insulation level
CT	current transformer
CIS	customer information system
DA	distribution automation
DER	distributed energy resource
DMS	distribution management systems
FLISR	fault location, isolation, and service restoration
FDIR	fault detection, isolation, and restoration
GIS	geographic information system
OMS	outage management system
PSAT	Modern powertrain system analysis toolkit
SCADA	supervisory control and data acquisition
SF_6	sulfur hexafluoride

[1] *IEEE Standards Dictionary Online* is available at: http://dictionary.ieee.org

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VT	voltage transformer
Xfmr	transformer
Zf	fault impedance

4. Fundamentals

4.1 Fault characteristics

4.1.1 Type and calculation

Faults commonly occur on overhead and underground electric distribution systems. It is not feasible to design distribution systems to eliminate the possibility of faults from occurring. Faults can be caused by a number of sources including the following

- Equipment failure
- Weather (such as wind, lightning, extreme temperature, and precipitation)
- Public contact (such as vandalism, vehicle accidents and underground dig-ins)
- Vegetation
- Wildlife

Some faults are temporary in nature. Common causes of temporary faults are wildlife, wind, and lightning. Some faults are permanent in nature, such as those caused by equipment failures or dig-ins. When faults occur, they can present hazards to the general public and utility personnel, and can cause damage to distribution facilities. Protective systems are applied to detect short circuit conditions (faults), clear faults in a timely fashion, and limit the effects to the smallest practical portion of the distribution system.

Different types of faults can occur on distribution systems. The design of the grounding configuration of a given distribution system such as a three-wire ungrounded or four-wire effectively grounded system determines the short circuit characteristics associated with different types of faults. Fault types commonly experienced include the following:

- Three-phase
- Phase-to-phase
- Phase-to-ground
- Two-phase-to-ground

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.

An understanding of the type of grounding system and type of fault assists in the modeling and calculating of fault currents, and to application of protective systems that identifies and operates for detectable fault conditions involving ground. There are three classes of grounding systems used. They include ungrounded, impedance (resistance or reactance) grounded, and effectively (or solidly) grounded. Current and voltage characteristics during fault conditions will vary depending on the grounding system utilized.

The consideration of fault impedance helps optimize low level relay settings. Some faults will be solid, such as the case when a broken phase conductor contacts a neutral wire; some will have an arc whose resistance varies with the arc length, such as an insulation flashover; and other faults involve specific fault impedance, such as the case of a tree limb contacting an overhead circuit. Fault impedance is typically more of a consideration for faults involving ground, or at lower distribution voltages. In addition, the types of faults that may occur at a given location on a distribution system are defined by the number of phases (one, two, or three) involved in contributing to the fault current.

Calculations of the system fault currents used to select, apply, and set protective devices for use on distribution systems are typically accomplished through the use of the symmetrical components methodology. Symmetrical components are a mathematical tool used to calculate the effects of balanced and unbalanced fault conditions on three-phase distribution systems. 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 'symmetrical components' for various types of fault conditions. These studies obtain these characteristics at various nodes of the circuit. The currents can then be used to select and apply protective devices such as relays, reclosers, and fuses. In the application of overcurrent protective equipment to distribution systems, it is important to know the minimum as well as the maximum fault current levels. Various cases are typically modeled in order to calculate maximum and minimum fault currents.

For radially designed and operated distribution circuits the maximum available fault current is at the substation bus or feeder source. In some cases, maximum fault current levels are limited by specifying a minimum allowable substation transformer impedance or adding line reactors in order to apply equipment with lower short-circuit interrupting capability. Due to the effects of the impedance of the line conductors, fault currents decrease with distance from the substation source.

For a radial system, maximum fault current levels are influenced by low source impedances at maximum generation conditions and zero fault impedance. Minimum fault-current levels are influenced by high source impedances during times of minimum generation and non-zero fault impedance (Figure 1). These conditions are calculated for three-phase, phase-to-phase, and phase-to-ground faults. Normally, fault current decreases as the fault resistance increases. However, there are some cases where the current magnitude in one phase of a phase-to-phase to ground fault will increase when going from a zero to a non-zero value of fault impedance (see *Electrical Distribution-System Protection* [B8]).

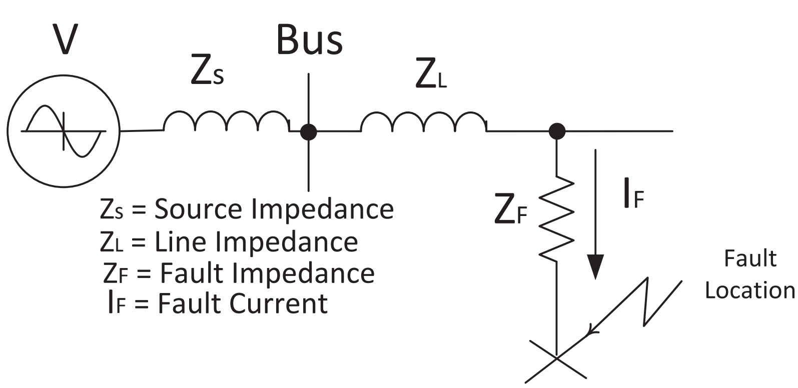


Figure 1—Fault on radial system

It is common in fault studies to use nominal system voltages with no distinction between circuit loading conditions that produce maximum and minimum voltages. Also, it is assumed that loads are not modeled. In most distribution applications, the substation transformer impedance is much larger than the generation-source impedance supplying it. For this reason, the maximum and minimum generation source impedances are often assumed to be equal. In locations served by parallel transformers, minimum fault currents occur with only one transformer in service. In radial systems, the positive-sequence source impedance is the sum of the positive sequence impedances of all system components from the distribution substation low-voltage (LV) bus up to and including the generator. The negative sequence source impedance is defined in a similar fashion. The zero-sequence source impedance is usually not the sum of the component zero-sequence impedances because the typical delta winding of the transformer causes a discontinuity in the zero sequence network.

4.1.2 High-impedance faults

Fault impedance (*Zf*) is the impedance involved in the fault (see *Electrical Distribution-System Protection* [B8]). *Zf* is different than positive- (Z_1) or zero-sequence (Z_0) impedances, which are system characteristics. *Zf* is the complex impedance between the faulted power system phase conductor(s) or between phase conductors and ground. *Zf* is not earth resistivity or the mutual impedance between an overhead conductor and a conducting ground plane. *Zf* depends on the fault type and the environment. A phase-to-phase fault on an overhead circuit caused by a dry tree branch can be a high-impedance fault, and ground is not involved at all. A fallen conductor can cause a low *Zf* value if the conductor drops into a stream or ground water, or it can cause a high *Zf* value if it drops onto a dry pavement.

Zf can vary over time. A fault may begin as a high-impedance fault and progress to a low impedance fault. Conversely, a fault may start out with some fault impedance that increases to infinity if the fault is self-clearing, or if the flow of fault current into the contacted material causes changes in that material which increases its impedance.

A small percentage of ground faults have very large impedance to ground. They are comparable to load impedances and consequently have very little fault current, typically less than 50 Amps. High impedance faults may not pose imminent danger to power system equipment; however, high impedance faults can be a considerable threat to humans and property. The IEEE Power System Relaying Committee working group on High Impedance Fault Detection Technology [B56] defines high impedance faults as those that 'do not produce enough fault current to be detectable by conventional overcurrent relays or fuses'. Protection engineers and researchers have been challenged for a long time to develop a suitable technique for detecting high impedance faults with a reasonable degree of reliability and security.

High impedance faults generally result when an energized primary conductor makes electrical contact with a quasi-insulated object such as a tree, a pole with very high impedance grounding, or a surface in the case of conductor snapping and falling. High impedance faults can also be multiphase faults, for example, a tree limb making contact with two phase conductors. The majority of high impedance faults involve a ground path, such as conductor snapping and falling on a surface, which can pose risks to life. It is difficult to determine the frequency of high impedance fault occurrences because utilities' record-keeping practices do not normally track these events. Some of the statistics from a survey of many utilities in different countries are reported in "High Impedance Faults" [B57].

Generally speaking, in the protection world, a relay detects a fault and trips a circuit breaker. However, high impedance fault detection is a quite different situation. In order to detect any type of fault there needs be a difference in the measurements before and after the fault. Reliability of high impedance fault detection requires both dependability and security. Dependability of detection is the ability of the detection method to detect all high impedance faults. Security reflects the ability of the detection method to not falsely identify a normal situation as a high impedance fault. High dependability forces lower security, and vice versa. Higher dependability is a target but security is also very important as outages that affect critical loads such as traffic control and hospitals can create a public hazard.

The tripping level of conventional ground overcurrent relays are adjusted to values that are above the neutral imbalance on the grid to avoid unwanted trips. The pickup levels may conflict with the values chosen when applying high impedance fault detection methods. Consequently, some high impedance ground faults cannot be detected since they produce low levels of fault current and cannot be differentiated from the load current.

In the 1970s, research began in the USA on the characteristics of the waveforms of arcing faults. In the mid-1990s, one of the first commercially available relays based on the use of the harmonic content of the current waves for detecting arcing faults was developed. Other devices were launched in the mid-2000's that use multiple algorithms, using harmonics and inter-harmonics of the current waveforms. These products have been tested in the field by various utilities for several years. They are being implemented at a slower pace than previously anticipated due to some misoperation [B58][B59][B60][B61][B62][B63].

4.2 Load characteristics

Line protection devices are not typically intended to operate during normal or abnormal loading conditions. An understanding of the load characteristics at various points in the distribution system is beneficial when setting distribution line protection devices to prevent unintended operations on load conditions.

4.3 Harmonics

A harmonic is defined as a sinusoidal component of a periodic wave or quantity having a frequency that is an integral multiple of the fundamental frequency (see IEEE Std 519 [B29]). In other words, a harmonic is a sinusoidal waveform that has a frequency equal to an integer multiple of the fundamental frequency.

The effect of harmonic currents on power system protection can be analyzed using symmetrical components. Assuming a balanced three-phase power system, harmonic quantities can be considered in terms similar to symmetrical components. However, a fundamental difference between the harmonic components and the symmetrical components is the frequency of the signal. Symmetrical components, as commonly used, are of fundamental frequency, while harmonic components have frequencies that are integer multiples of the fundamental frequency. Table 1 lists a few lower order harmonics and their corresponding similarity with a sequence component (see IEEE Std 141-1993 *(IEEE Red Book)* [B27] and "Representation of loads" [B7]).

Table 1—Similarity between a harmonic quantity and a sequence component

Order	Sequence	Order	Sequence	Order	Sequence
1	Positive	6	Zero	11	Negative
2	Negative	7	Positive	12	Zero
3	Zero	8	Negative	13	Positive
4	Positive	9	Zero	14	Negative
5	Negative	10	Positive	15	Zero

The similarity between a sequence component and any harmonic component can be found by further developing Table 1. For example, the 16^{th} harmonic would be similar to the positive sequence; the 17^{th} harmonic would be similar to the negative sequence, and so on.

Thinking of harmonics in terms of symmetrical components can aid the protection engineer in analyzing how harmonics might affect protection devices. For example, all harmonics divisible by three or *triplens* are similar to zero sequence quantities and are thus capable of affecting ground relays if the relays do not operate based on the fundamental frequency. Protective devices such as fuses and traditional electromechanical overcurrent relays monitor an unfiltered current, and thus respond to the *total RMS* value of the current. When high harmonic distortion is present, the effect of harmonics can have an impact on these devices. If harmonic distortion is great, the total RMS current can be significantly greater than the fundamental frequency component alone.

Harmonics associated with the acceptable distortion levels set forth in IEEE Std 519 [B29] do not present a significant threat to the proper operation of protective relays. Furthermore, harmonic currents tend to affect electromechanical relays more severely than modern microprocessor-based relays. Most of these microprocessor relays employ 60 Hz filters in their protection algorithms and are practically immune to the effects of harmonics.

4.4 Interrupting ratings

When circuit breakers, reclosers, and fuses are called upon to interrupt a fault, it is imperative that their interrupt rating is not exceeded. The interrupt rating is the maximum symmetrical current that the device is capable of interrupting and is provided by the manufacturer.

When applied to reclosers and circuit breakers, the interrupting current rating must be greater than the maximum expected symmetrical fault current at the device's point of application or possible damage can occur for a fault. The X/R ratio at that location must be equal to or less than that at which the device is tested, at the maximum interrupting current, during the operating duty test for the same reason. No uprating for symmetrical fault currents occurring at X/R ratios less than these maximums for which the recloser is tested are allowed. The maximum available interrupting ratings for reclosers are typically less than those of circuit breakers and therefore their use may not be suitable for distribution systems with higher maximum available fault currents. [B79]

5. System configuration and components

5.1 System

5.1.1 Neutral treatment

There are three main methods of system grounding used around the world. The methods are solidly grounded, ungrounded, and impedance grounded. 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 not important during normal operation, if all the loads are connected phase-to-phase. However, during single-phase-to-ground faults, operational and safety aspects strongly depend on the grounding method chosen (see "Roundup: System grounding" [B41] and *Electricity Distribution Network Design* [B42]).

5.1.1.1 Multi-grounded system

Multi-grounded systems have a neutral wire that is grounded at multiple locations along the length of the feeder (Figure 2). This is commonly referred to as a four wire system supplied by a wye-grounded source. This is the most widely used method in the U.S. and is also used in some developing countries. It provides power for single-phase and three-phase loads and is cost-effective for rural areas where single-phase loads are widely scattered. Phase-to-ground faults do not excessively affect voltage magnitudes on the other two unfaulted phases because the neutral is solidly grounded, however it shifts slightly since the grounding resistance in real life applications cannot be zero. Ground fault currents may be high, but the majority of fault current returns to the source through the neutral conductor, not through ground, which limits touch and step voltages within acceptable ranges [B65]. Ground fault currents depend on the system voltage, parameters of the feeder on which the fault occurs, and the grounding resistance. A system is considered effectively grounded if the voltage rise on the un-faulted phases does not exceed 35% of nominal voltage (see IEEE Std C62.92.4 [B64]. Ground fault protection is typically provided by ground overcurrent relays set more sensitively than phase overcurrent relays, depending on the load unbalance as explained in Subclause 5.1.3.1.

Advantages of a multi-grounded system include the following:

- Overvoltages during ground faults are low
- Protection is simple and inexpensive.
- The detection and isolation of ground faults can be accomplished with time overcurrent protection devices such as fuses or reclosers.

Disadvantage of multi-grounded systems include the following:

- Shorter interrupting times are needed when ground faults occur to prevent the high fault currents from causing excessive damage to unfaulted circuit components, and to minimize the duration of voltage dip to customers connected to the faulted phase.

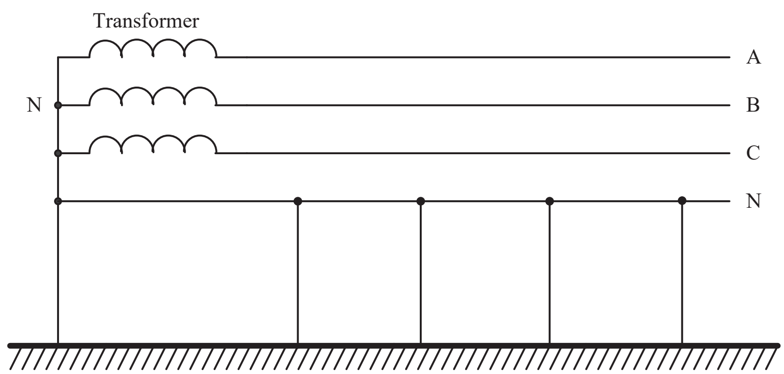


Figure 2 – Four Wire Multi-Grounded System

5.1.1.2 Ungrounded system

Ungrounded systems (Figure 3) are still widely used. Since the neutral is not grounded, it can freely shift. Under normal conditions and balanced loads, phase-to-ground voltages are equal in magnitude and 120° apart. Therefore, there is no voltage difference between neutral and ground. In the case of a phase-to-ground fault (Phase C in Figure 4), the fault current will flow from the source to the fault location and returns through the stray capacitance-to-ground of the two unfaulted phases of that feeder and the unfaulted phases of all other feeders connected to the same power transformer. Therefore, ground fault current magnitudes depend not only on the faulted feeder parameters, but also on the size (i.e., stray capacitance) of the rest of the system.

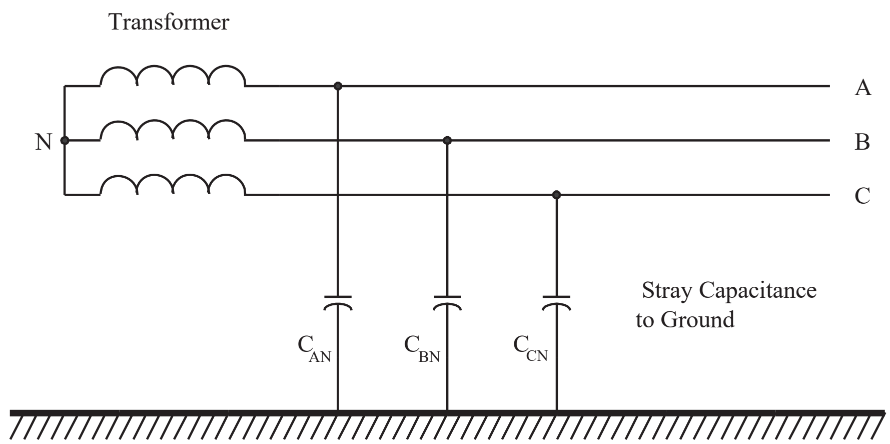


Figure 3—Ungrounded system

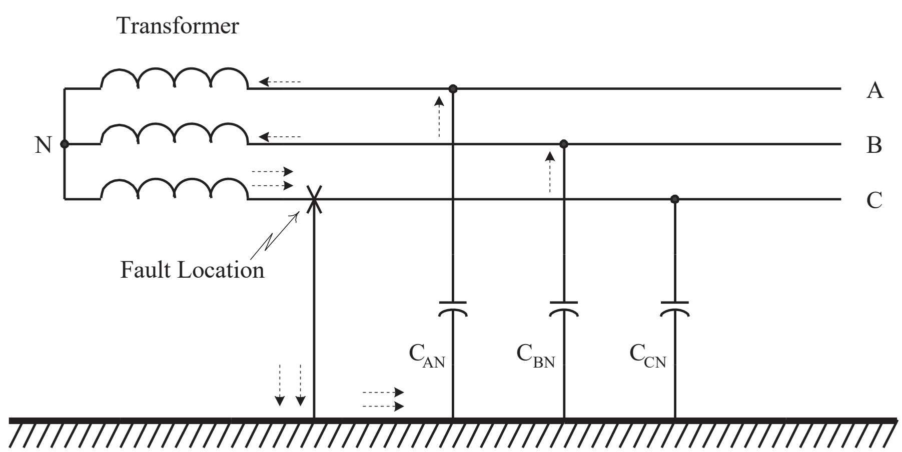


Figure 4—Ground fault in ungrounded system

Ground faults also cause phase-to-ground voltage rise on the unfaulted phases (A and B in Figure 4) approaching $\sqrt{3} \times$ nominal. The insulation level of feeders is designed to accommodate this voltage increase, which can be a disadvantage due to increased investment. However, when system expansion increases the fault current through the stray capacitance, a neutral may be added, converting it to a grounded system. Grounding the system can be accomplished by grounding the neutral of the transformer, either solidly or through an impedance, or by installing a grounding transformer. If the solidly grounded method is used, the same feeders can then transfer more power by increasing the system voltage. For example, feeders of an existing 15 kV system can be energized at 25 kV, since they are already designed for this higher voltage, allowing transfer more power. This has been implemented in some countries in Europe.

Effective ground fault protection for ungrounded systems is provided by directional overcurrent relays that use residual voltage or neutral current for polarization and residual current from the faulted feeder, as described in 8.14. Phase difference between residual voltage and residual current is approximately 90° (Figure 5).

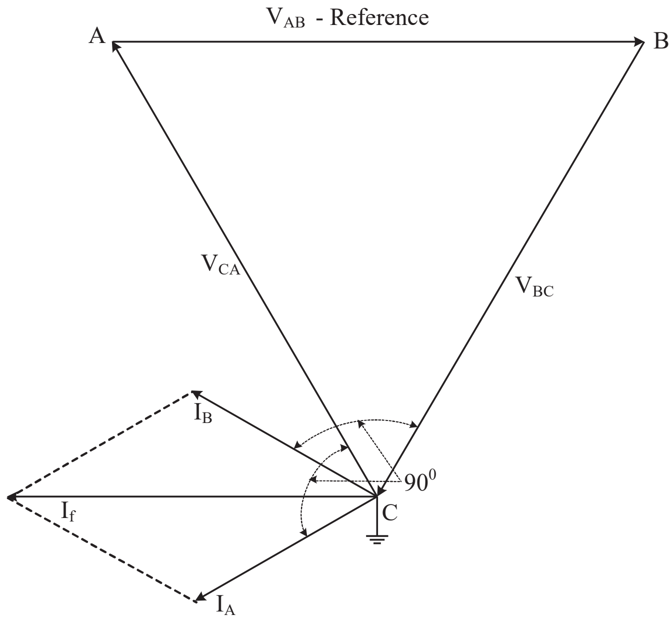


Figure 5—Voltage and ground fault currents in ungrounded system

The ungrounded system can operate for a prolonged time with a ground fault, and the arc can self-extinguish. This is an advantage for reliable operation, but also poses a personnel safety hazard. Relays are applied to detect the condition and alert the operators so that the fault can be located and repaired in a timely manner.

Advantages of ungrounded systems include the following:

- Fault current arcs can often self-extinguish
- System can continue to operate with a single ground fault

Disadvantages of ungrounded systems include the following:

- Fault current arcs cannot self-extinguish when capacitive currents become high
- Intermittent arcing can occur and develop high-frequency oscillations that can cause overvoltage escalation of several times rated voltage.
- Voltage rise occurs on unfaulted phases during phase-to-ground fault
- Single-phase-to-ground faults can develop into phase-phase faults
- Operating with a single-phase-to-ground fault can yield high fault currents similar to solidly uni-grounded systems in the case of a second phase-to-ground fault.

See 8.14 for methods of detecting ground faults on ungrounded systems.

5.1.1.3 Uni-grounded system

Uni-grounded systems are solidly grounded only at the substation. This can be a three-wire system, with no neutral conductor (Figure 6) or a four-wire system with an insulated neutral. Similar to multi-grounded systems, ground-fault currents can be as high as phase-fault currents (or even higher) at the substation but will typically be lower than phase-fault currents further outside the substation. In a uni-grounded system, ground fault currents flow back to the source through earth. A very high voltage between the faulted point and the reference ground can occur. Part of this voltage represents hazardous voltages defined as touch (V_{touch}) and step (V_{step}) voltages that are dangerous for humans and animals. Additional details on step and touch and grounding system design can be found in IEEE Std. 80, IEEE Guide for Safety in AC Substation Grounding [B65].

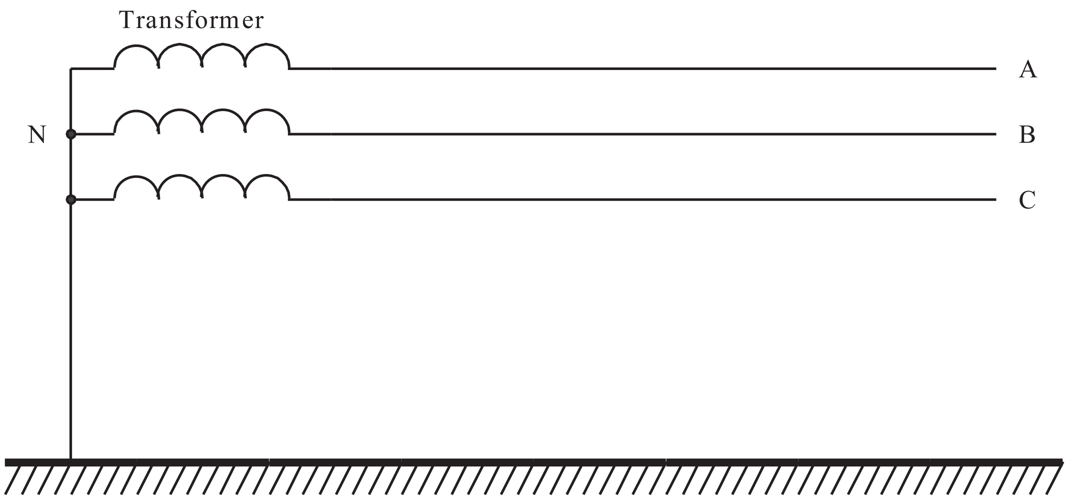


Figure 6—Solidly uni-grounded system

Advantages of uni-grounded systems include the following:

- Overvoltages on unfaulted phases are small, usually below 1.4 p.u.
- Intermittent arc voltages are avoided
- Transformer windings near the neutral do not see high voltages even during ground faults, which permits a less expensive graded insulation of the entire winding

Disadvantages of uni-grounded systems include the following:

- Grounding study is needed to evaluate and address ground and step potentials.

5.1.1.4 Resonant-grounded system

Resonant-grounded systems are most often applied in Europe. In this method, the substation transformer neutral is grounded through a reactance, also known as a Petersen coil (Figure 7). The reactance is resonantly tuned to the fundamental frequency with the stray capacitance of all feeders connected to the same transformer. The value of reactance is approximately determined by Equation (1). In the case of a ground fault (C phase-to-ground fault in Figure 8), if properly tuned the neutral reactor and the system stray capacitance will cause the same amount of fault current to flow in opposite directions through the point of fault, canceling each other. Figures 8 and 9 illustrate fault current contribution by the system stray capacitance (solid-line arrows) and by the neutral reactor (dashed-line arrows). Since it is impossible to entirely match values for the neutral reactor with the system stray capacitance, a small amount of ground fault current will flow through the fault, but the majority of current will return to the source through the reactor. Small mismatches between the reactance and system capacitance (below 25%) will not create protection problems.

Advantages of a resonant-grounded system include the following:

- Ground fault currents are small.
- Arcs are self-extinguished.
- Touch and step voltages are small.
- The need for maintenance of the switches is reduced.
- For a phase-to-ground fault on the system, it is possible to operate for a period of several hours, even when the fault persists – increasing reliability.
- The self-extinguishing effect exerted by the compensation reduces the possibility of a single-phase-to-ground fault developing into a multi-phase fault.Intermittent ground faults are avoided.

Disadvantages of a resonant-grounded system include the following:

- In protection systems using traditional technology, the reliability and sensitivity of the relays is reduced.
- The difficulty of locating faults is increased.
- Arrester protective levels are higher.
- Insulation may need to be increased due to neutral shifting during transients.
- It is not effective in case of arcing cable faults.
- Cables can produce repetitive and harmful restrikes.
- Tuning can be difficult to adjust for varying system configurations such as those associated with distribution systems During a single-phase-to-ground fault, the phase-to-ground voltages of each unfaulted phase increase by a factor approaching $\sqrt{3}$. Due to economic considerations, this limits implementation of this type of grounding to lower voltage systems, since line-to-line voltage rated insulation would be required.
- The increased voltage raises the probability of simultaneous ground faults developing due to increases in weak points in the system.

The first two drawbacks are being overcome with the development of fault detection and protection technologies (see "Detection of resistive single-phase earth faults in a compensated power-distribution system" [B43]). Due to the last two drawbacks, in order to make it possible to adopt the resonant grounding system, 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. To prevent any harmful effects, it will be necessary to ascertain the weak points in the system and also to check that all equipment has been designed to support new voltage demands. See Subclause 8.13 for methods of detecting ground faults on resonant-grounded systems.

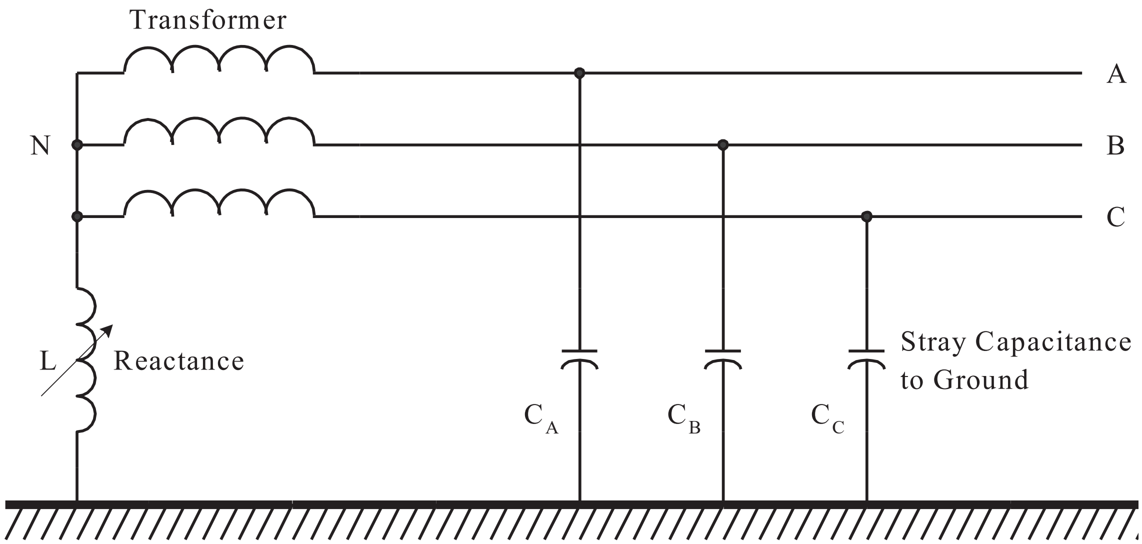


Figure 7—Resonant-grounded system

$$\left|I_L\right| = \left|\vec{I}_A + \vec{I}_B\right|$$

$$I_L = \frac{V_{PH}}{\omega L} = 3\omega C V_{PH}$$

$$L = \frac{1}{3\omega^2 C} \qquad \text{Equation (1)}$$

Where:

L = inductance of the Pederson coil

C = total stray capacitance to ground of the system

ω = 2πf and f is the system nominal frequency

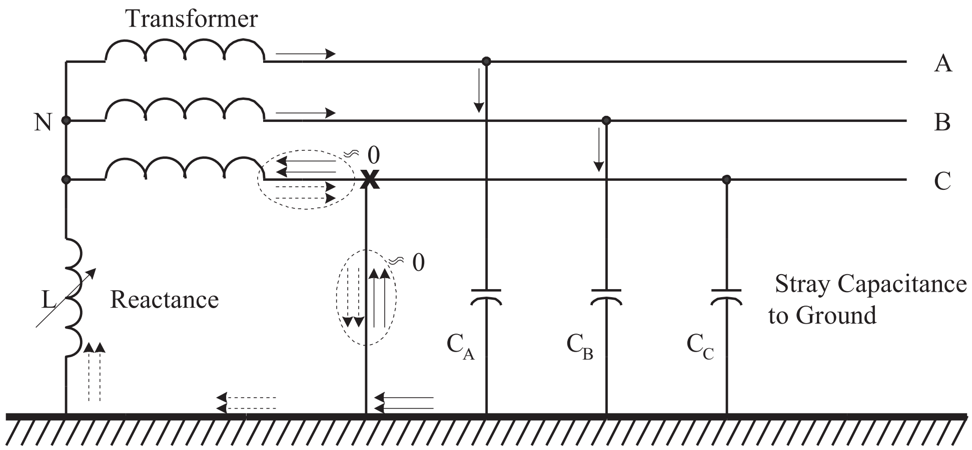


Figure 8—Ground fault in resonant-grounded system

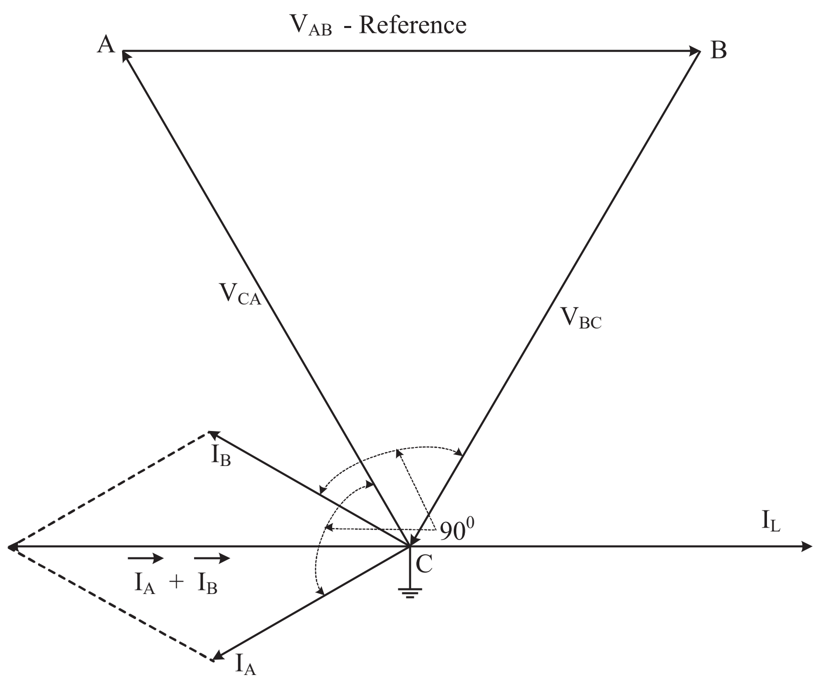


Figure 9—Voltages and ground fault currents in resonant-grounded system

5.1.1.5 Resistive and Reactive grounded system

To limit ground fault currents, and reduce dynamic and thermal stress on equipment (particularly substation transformers), resistors or reactors are installed from the substation transformer's neutral to ground (Figure 10). However, this grounding method causes the neutral voltage to increase during ground faults. For a 40% reduction in ground-fault current using a resistor compared to fault current without a resistor, the neutral voltage increases to 80% of the phase voltage.

For this type of neutral grounding, resistors or reactors are used to reduce ground fault currents to acceptable levels, but not to entirely (almost zero current) eliminate it as with resonant-tuned systems.

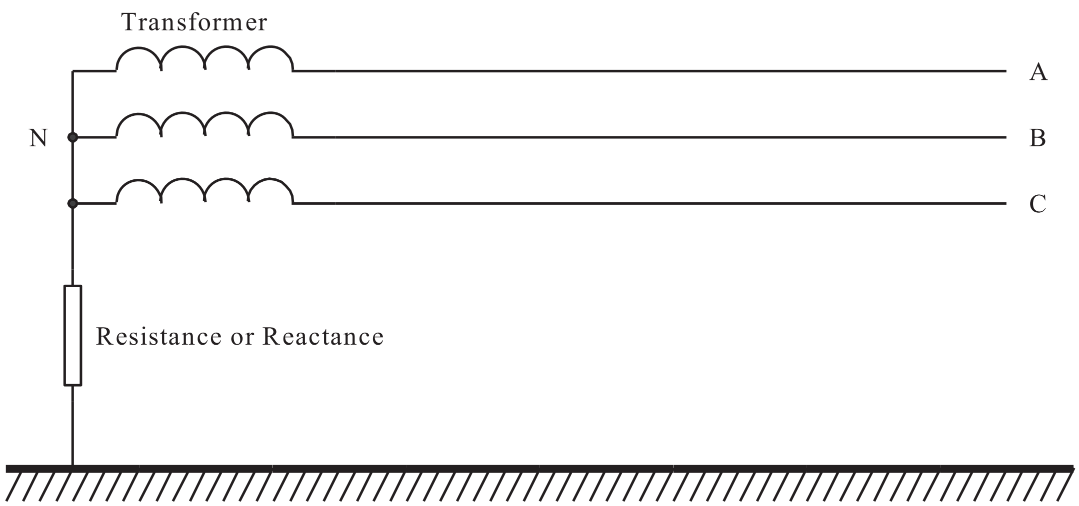


Figure 10—Resistively or reactively grounded system

Advantages of resistive or reactive grounded systems include the following:

- Ground-fault currents, touch, and step voltages are reduced.
- Overvoltages are smaller compared to ungrounded systems depending on the size of the neutral resistor or reactor.
- Intermittent arc voltages are avoided.

Some disadvantages of these systems include the following:

- The use of neutral resistance or reactance increases neutral voltages during ground faults and requires higher insulation of the transformer neutral.
- Overvoltages can be high when higher resistance values are used.

Table 2 presents comparative results of the impact of different transformer neutral treatments on a typical distribution system during phase-to-ground faults. Figure 11 shows a 12.47 kV feeder supplying power to a 5 MVA constant impedance, delta connected load. The source voltage was increased 5% to obtain 0.99 p.u. voltage at the load. A ground fault on phase C, with a fault resistance of 1 Ω, was simulated. For different load types and connections, the results will be different.

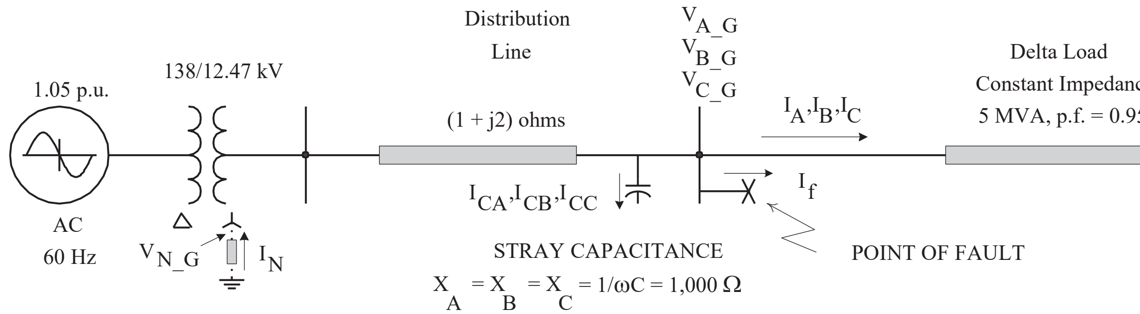


Figure 11—A typical distribution system with a radial feeder

Table 2—System voltages and currents during single-phase-to-ground faults for different neutral treatments (refer to Figure 11)

Voltages and Currents		Normal operation	Single-phase-to-ground fault with neutral impedance				
			Solidly grounded	Ungrounded	Resonant grounded	Resistor grounded	Reactor grounded
			0.1 Ω	10000 Ω	1000/3 Ω	10 Ω	10 Ω
Voltage at fault	V_{AG} [V]	7159	7276	12430	12400	10480	11610
	V_{BG} [V]	7163	7252	12480	12400	11860	10580
	V_{CG} [V]	7161	2062	22	0	578	542
Load currents	I_A [A]	230	114	231	230	212	198
	I_B [A]	230	223	231	230	238	219
	I_C [A]	230	190	230	230	213	226
Xformer neutral	V_{NG} [V]	0	207	7197	7141	5795	5601
	I_N [A]	0	2067	0	21.4	579	560
Fault current	I_f [A]	0	2062	22	0	578	542
Capacitive currents	I_{CA} [A]	7.2	7.3	12.4	12.4	10.5	11.6
	I_{CB} [A]	7.2	7.3	12.5	12.4	11.9	10.6
	I_{CC} [A]	7.2	2.1	0	0	0.6	0.5

5.1.2 Bus configurations

The bus configuration designs take 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 involved duplicate systems.

Bus configurations play an important role in determining adequate settings for feeder breakers. Feeder breakers are set to coordinate with the upstream and downstream relays and devices to improve selectivity of protection tripping. The bus configuration will determine which relays require consideration for coordination. The figures following are some commonly used distribution bus arrangements. For a detailed discussion of the protection schemes for substation buses see IEEE C37.234 Guide for Protective Relay Applications to Power System Buses [B66].

Figure 12 shows a substation with a fused transformer, transformer low side breaker (T), and three feeder breakers (F). The transformer low side breaker provides bus protection and backup for the feeder breakers. The protection on the feeder breakers coordinates with the transformer low side relays and with downstream devices on the feeder to avoid additional tripping. For a detailed discussion on the protection requirements for transformers see IEEE C37.91 Guide for Protecting Power Transformers [B34].

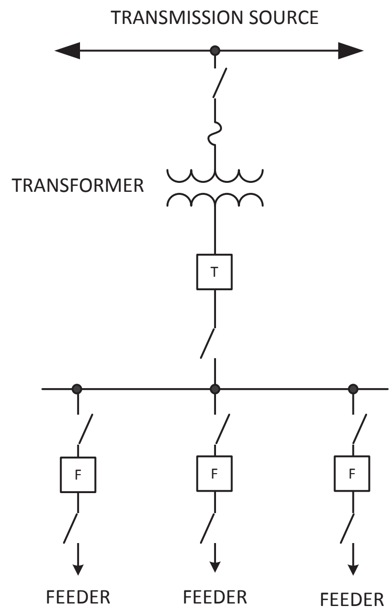


Figure 12—Single transformer distribution bus

Figure 13 shows a similar substation with a second transformer, a bus-tie breaker, and additional feeders. The protection on the feeder breakers coordinates with the bus breaker relays if possible to avoid additional undesired tripping. Sometimes, due to the lack of available coordination interval, the transformer low side relay setting curves will not fit between the transformer fuse and feeder relay setting curves. In these cases the transformer low side breaker provides little additional selectivity for bus faults and the transformer protection will usually clear at approximately the same time as the transformer low side relays.

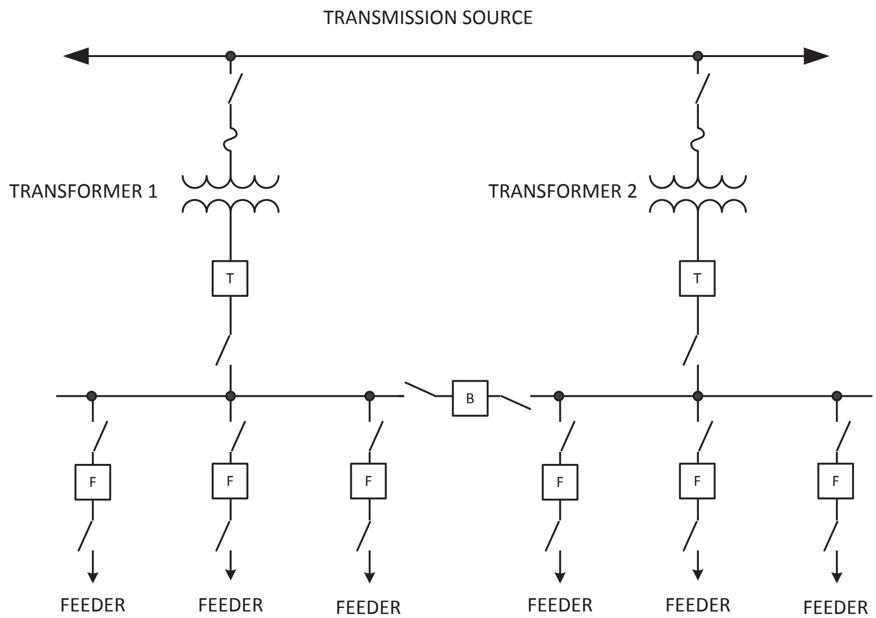


Figure 13—Two-transformer distribution bus

To add a bus tie breaker without introducing an additional set of time overcurrent relays, a fairly common scheme is the 'partial bus differential' scheme shown in Figure 14. This uses one relay (51PB) for each bus, connected to current transformers (CTs) on the transformer low side breaker and on the bus tie breaker. The CTs are connected so each 51PB relay responds only to current on the associated bus.

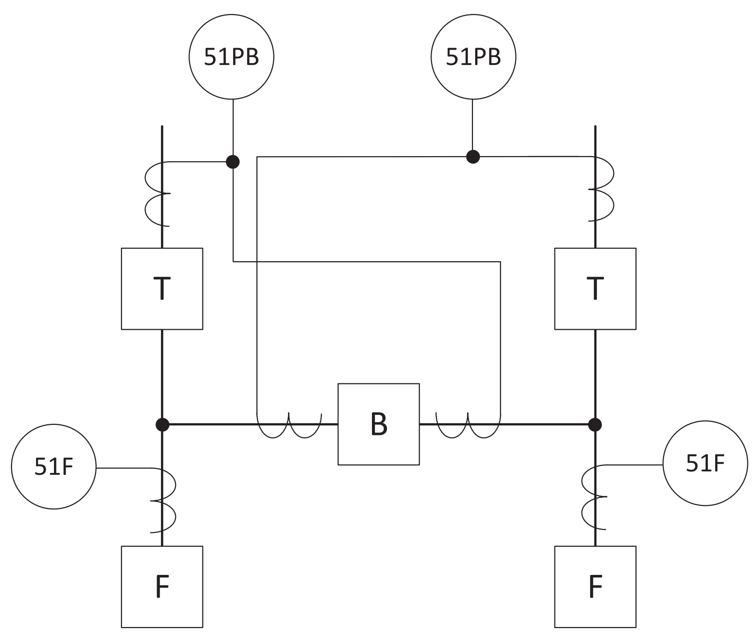


Figure 14—Partial bus differential scheme

Figure 15 shows a main-transfer bus arrangement with high side power fuses for transformer overcurrent protection. Since there is no low side breaker on this transformer, the fuses are also the primary protection for the low side bus. The transformer, all of the feeder breakers (F), and the transfer breaker (T) are normally connected to the main bus. The protection on the feeder breaker coordinates with the transformer fuses for faults on the feeders; otherwise additional customers may be unnecessarily impacted by the fault. The transfer breaker is used to energize the transfer bus and provide a reserve feed to any feeder. The protection on the transfer breaker is configured to protect and coordinate with the devices on any of the different feeders.

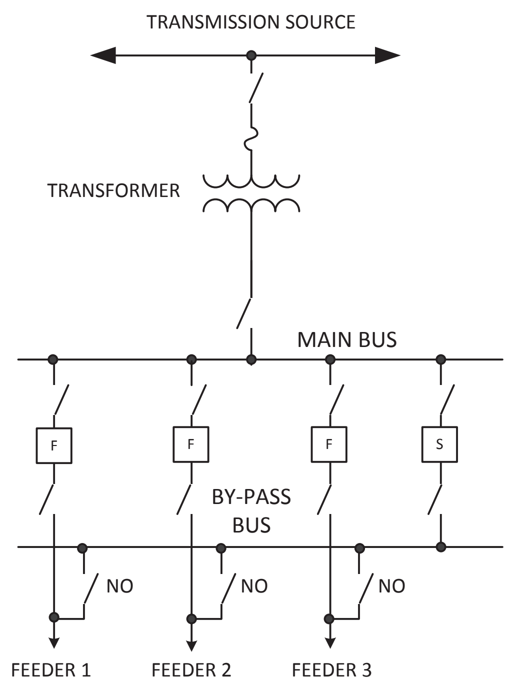


Figure 15—Main-bypass bus with high side interrupter

Figure 16 is of a substation bus arrangement that uses more air break switches but has additional flexibility of operation over the main-transfer bypass bus arrangement. This bus arrangement is sometimes referred to as a dual-operation bus. The transformer and the feeder breakers can be connected to either bus. The B breaker is connected between the buses and is normally called a bus tie breaker. Although the feeder breakers can be fed off either of the buses, only Bus 2 can be used as a transfer bus. To transfer a feeder, the transformer is connected to Bus 1, and the feeder to have the breaker removed from service is connected to Bus 2 through the normally open transfer switch. The feeder load is then carried through the bus tie breaker. The relay settings on the bus tie breaker need to be flexible enough to protect and carry the load of any of the feeders.

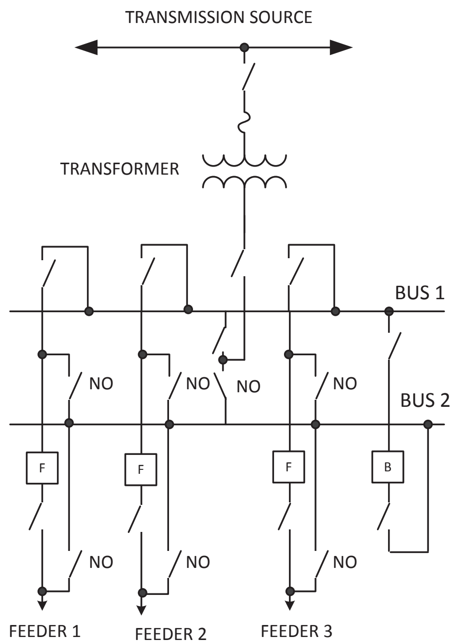


Figure 16—Dual-operation bus

The flexibility of the dual-operation bus is more obvious when there are two transformers to be operated either in split bus or parallel operation as shown in Figure 17. In this case, each transformer is connected to a different bus with some of the feeder breakers connected to each bus. If the transformers are to be operated in parallel, the bus tie is closed-tying the two buses together. The coordination of the transformer high side protection, the bus tie breaker, and the feeder breakers is a little more complex. Depending on which bus the faulted feeder is connected to, the coordination is different. The complexity increases if the two transformers are not the same size, but it can be accomplished. As an example, using the bus configuration in Figure 17 for a fault on Feeder 1, the Feeder 1 relays will need to coordinate with the Transformer 1 fuse based on the current that Transformer 1 contributes to the fault. The Feeder 1 relays also need to coordinate with the bus tie relays for the current that Transformer 2 contributes to the fault. Also, the bus tie relays need to coordinate with the Transformer 2 fuse based on the current that Transformer 2 contributes to the fault.

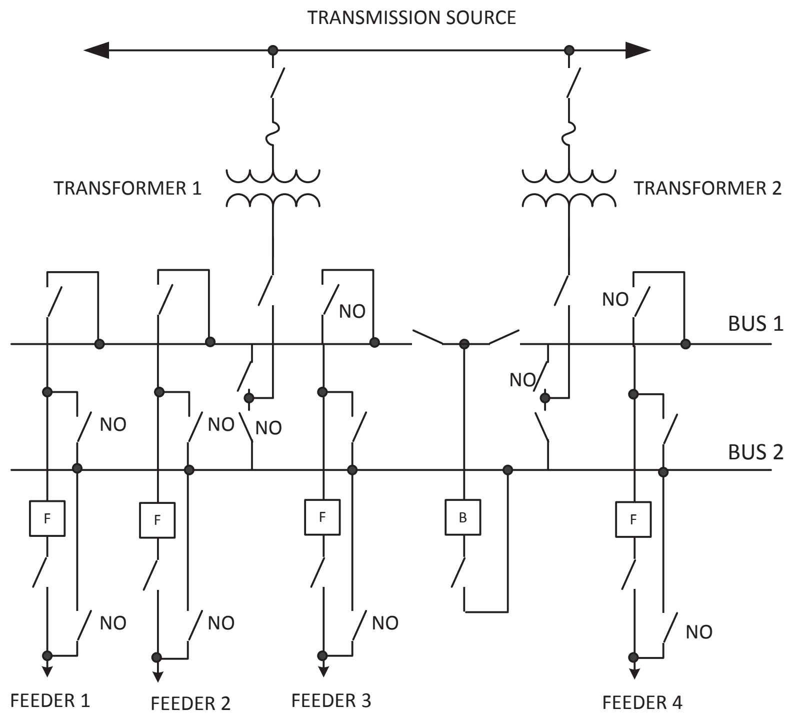


Figure 17—Dual-operation bus with two transformers

With this bus arrangement, if a feeder breaker is to be bypassed, it is best to put the transformers in split bus mode by opening one of the switches on Bus 1. This creates three buses. One transformer is connected to the left Bus 1 and the other to the right Bus 1. The bus tie breaker needs to be connected on the side with the feeder breaker to be bypassed. The feeder breakers are all connected to Bus 1. Bus 2 is then a bypass bus, and the feeder to have the breaker removed from service is connected to Bus 2 through the normally open bypass switch.

With increased interest in distributed energy resources (DERs), it may be desirable to connect one or more generators to a distribution substation bus or feeder. Figure 18 shows one generator directly connected to a common bus with four feeders. However, DERs can also be connected to the bus or feeder through an interface transformer.

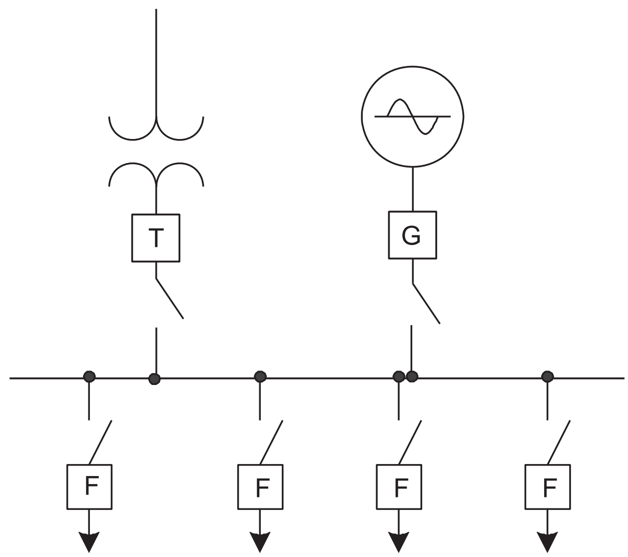


Figure 18—Generator connected to distribution substation bus

When a DER is connected to a bus or feeder, three different scenarios can be considered to estimate fault currents: 1) the utility system alone; 2) the combined utility and DER system; and 3) the DER alone. Although the DER would not normally be connected to the distribution system without the utility source, this can occur due to sequential tripping during a fault. Additional DERs may cause fault current levels to exceed the interrupting rating of distribution system equipment. If DER capacity connected to a bus is large, to limit its current contribution during faults, it may be necessary to use current-limiting reactors in series with each generator. DERs are discussed in further detail in Clause 8.6. Proper protection, operation, and coordination on the utility system could be impacted for some types of DERs. For DER interconnection to distribution systems, see IEEE Std 1547™ [B30].

5.1.3 Neutral / residual ground CTs

5.1.3.1 Ground-fault relaying

In power systems, ground-fault protection can be designed using ground relays. Figure 19 shows typical CT, overcurrent phase relay, and residual ground relay connections.

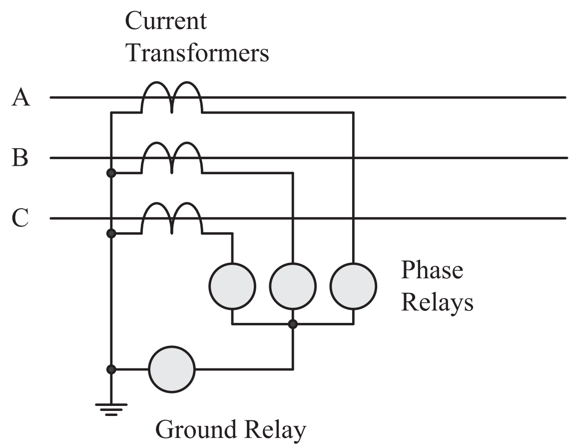


Figure 19—Typical phase and ground relay connections

Overcurrent relays used for ground-fault protection generally are the same as those used for phase-fault protection, except that a more sensitive range of minimum operating current values is needed. The residual ground overcurrent function can either be a directly measured function (from a separate ground relay) or it can be a mathematically derived relay element from the phase relays (Ig = 3I0 = IA + IB + IC) which is an option for most three phase microprocessor relays).

When this method is used on four-wire multi-grounded systems, the residual ground relay setting can allow for the system unbalanced (residual) currents, resulting from the phase-to-neutral connected loads. This is because the residual ground relay will measure unbalanced (residual) current.

Ground relays can be set more sensitively if the relays are not influenced by the load currents and the system unbalance. On four-wire systems with insulated neutral conductor, an additional CT installed in the neutral conductor removes the residual load currents from the ground relay (Figure 20). This application is most common in low-voltage systems.

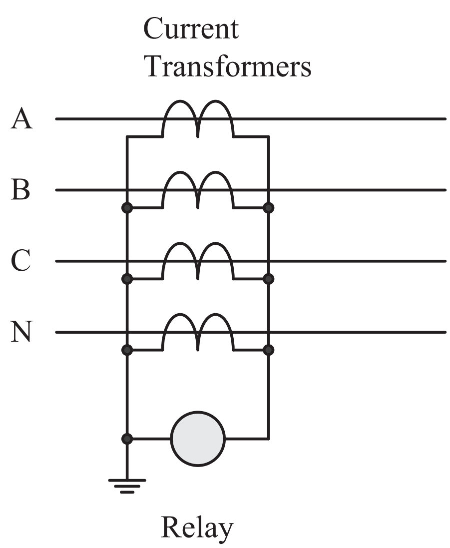


Figure 20—Ground relay and residually connected CTs

When used in ungrounded systems, a polarizing signal (voltage or current) is also required to obtain directionality of protection operation.

Residually connected CTs can cause nuisance operation due to errors arising from CT saturation and unmatched characteristics. Sometimes the optimum relay speed and sensitivity are compromised because of this issue.

5.1.3.2 Zero-sequence CT (core balance)

An improved type of ground-fault protection can be obtained by a zero-sequence relay scheme in which a single window-type CT is mounted to encircle all three-phase conductors, as illustrated in part (a) of Figure 21.

When used on four-wire systems with insulated neutral conductors, the neutral conductor passes through the zero-sequence CT as shown in part (b) of Figure 21. This scheme allows for increased sensitivity for ground fault protection when neutral load is present.

There are several advantages of using zero-sequence CTs instead of residually connected CTs as follows:

a) Only one CT is required for residual current measurements instead of three residually connected CTs.

b) Zero-sequence CTs output is more accurate since it measures true residual current as a result of sums of flux produced by all three phases. Whereas in residually connected CTs any mismatch in the CT characteristics will appear as false residual currents.

c) Zero-sequence CTs can be more compact, having smaller core dimensions than residually connected CTs since they are not influenced by load currents or three-phase fault currents.

d) During multi-phase faults, one or more residually connected CTs can saturate and cause false residual current through the relay. This problem is avoided by using zero-sequence relay scheme.

Zero-sequence CTs are available in various designs, e.g., for mounting over a cable close to the cable termination or for installing around three phases in medium voltage switchgear. Zero-sequence CTs can be of closed-core design when cables can be disconnected for the CT installation or split-core design for easier installation on existing cables.

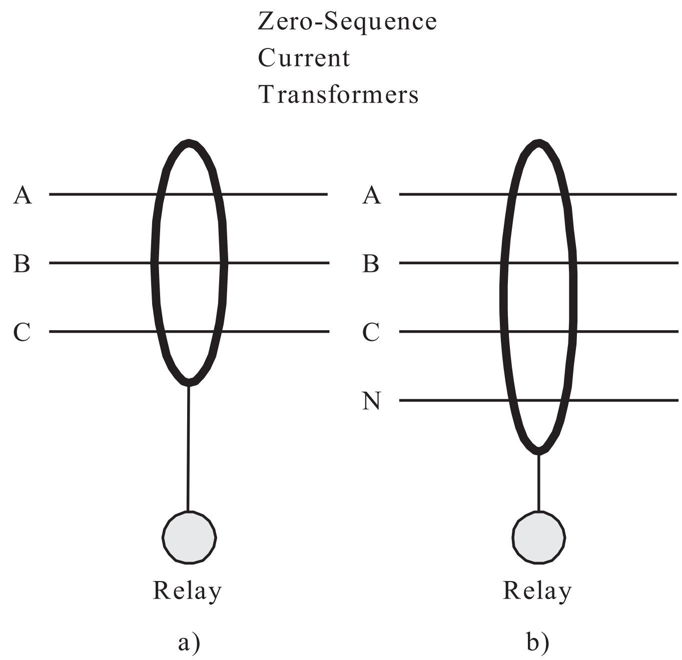


Figure 21—Zero-sequence CT and ground relay, (a) three-wire system and (b) four-wire system

When applied on cables with sheaths, to compensate residual currents that can flow through sheaths, grounding of cable sheaths are done as shown in Figure 22. Any flux caused by residual currents in the cable sheath will be cancelled by the flux from currents through the sheath-grounding conductor.

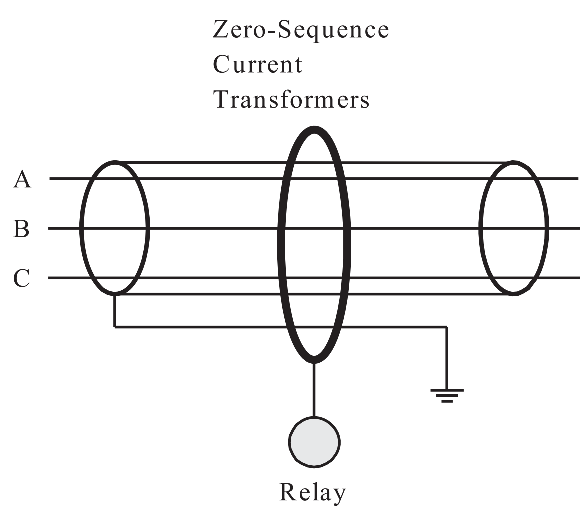


Figure 22—Application of a neutral CT to a cable with sheath

5.1.4 Transformer ground source connections

Additional transformers may be added to provide a ground reference on systems where no ground connection exists. A delta connected transformer is one example of this situation.

Two commonly used transformer arrangements are as follows:

— Grounded-wye with closed delta [part (a) of Figure 23]

— Zigzag [part (b) of Figure 23]

Both connections present a low zero-sequence impedance to the distribution system. The zigzag transformer is more commonly used since it provides more effective use of transformer material. To limit ground-fault currents to a level satisfying the criteria for resistance grounded systems, a resistor between the primary neutral and ground may be installed as shown in Figure 23

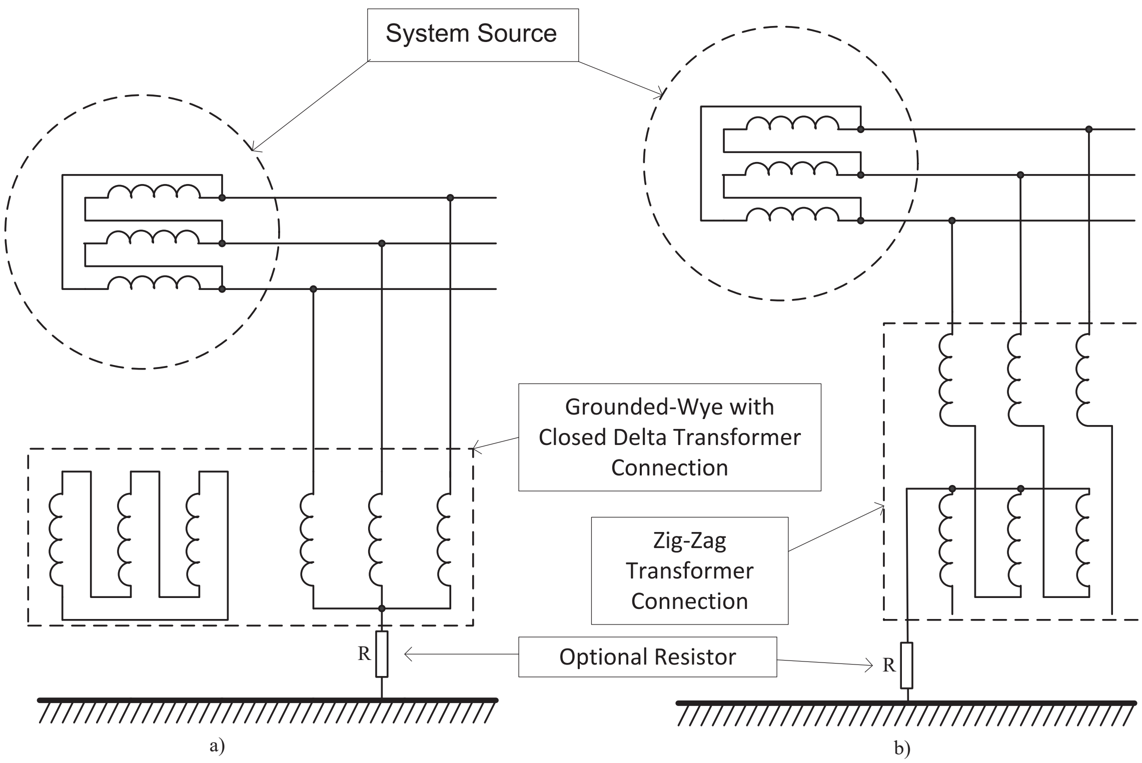


Figure 23—Grounding transformers

5.2 Lines

When coordinating overcurrent protection of the distribution system, the conductor damage curve is one of the components that are considered. Conductor damage curves are available in reference books from the manufacturers of the wire. Overhead conductors can be damaged by annealing, a reaction due to heating that significantly reduces the mechanical strength of the metal where they can sag beyond safety tolerances, or they can melt like a fuse element. Annealed conductors will typically remain in service, but over time the weakened metal can fail due to additional stress from wind and weather. Annealing is normally not a significant issue with steel reinforced conductors unless the core becomes deteriorated. Insulated power cables are also of concern as overheating can result in damage to the dielectric, sheath, extruded jacket, splices, and PVC conduit systems. Since cable systems are direct buried or enclosed in conduit systems, heat dissipation from fault currents takes much longer than for overhead bare conductors. Coordination with the conductor damage or I^2t curve is necessary for those systems that have high available fault currents due to low system equivalent impedances and substation transformers with large megavolt-ampere ratings. This can particularly be an issue for systems where the distribution circuits are aging while the substation and sources are being upgraded, resulting in a much higher fault current than that available when the circuits were designed. Parameters to consider in the evaluation are the available fault current, relay time-current curve, conductor I^2t curve, and effects of reclosing (fast reclose cycles will not allow significant cooling of the conductor between shots).

5.3 Distribution transformers

Distribution line protection takes into consideration the coordination with the transformer damage curves of the substation supply transformer. The substation transformer damage curves are based on I^2t of the windings and on mechanical bracing of the windings for through faults [B39]. Some transformers have both infrequent- and frequent-fault-incidence damage curves. For substations that incorporate a low side substation transformer breaker, the overcurrent protection associated with that breaker considers the infrequent-fault-incidence substation transformer damage curve [B34]. This protection may or may not provide overload protection to the transformer.

The feeder breaker overcurrent protection time-current curves are intended to beset more sensitive and faster than the low side substation transformer breaker protection. For substations that do not incorporate a low side substation transformer breaker, the feeder breaker overcurrent protection time-current curves are set below the substation transformer frequent-fault-incidence t damage curve to allow coordination with the substation transformer high side protection and protect the transformer. The high and low side current ratio is a function of the type of fault and the transformer connection as discussed in more detail in IEEE Std C37.91™ [B34].

Primary fuses on distribution service transformers protect the transformer in the same manner as previously mentioned. It is often advantageous to consider the coordination only with the largest distribution service transformer for each coordination path as all smaller transformers will then coordinate with the upstream feeder protection.

5.3.1 Winding configuration

In general, the common practice in North America is to operate three phase distribution systems in a four-wire multi-grounded wye configuration. This practice dictates that the substation transformer LV or secondary winding is connected in wye and solidly grounded at the common wye connection. It is also common practice that the primary HV winding be connected in delta. This provides advantages for the application of protective relays on the primary supply system.

Transformer banks with a capacity greater than 3000 kVA are generally three-phase units. Smaller banks are often comprised of three single-phase transformers. Figure 24 illustrates these differences.

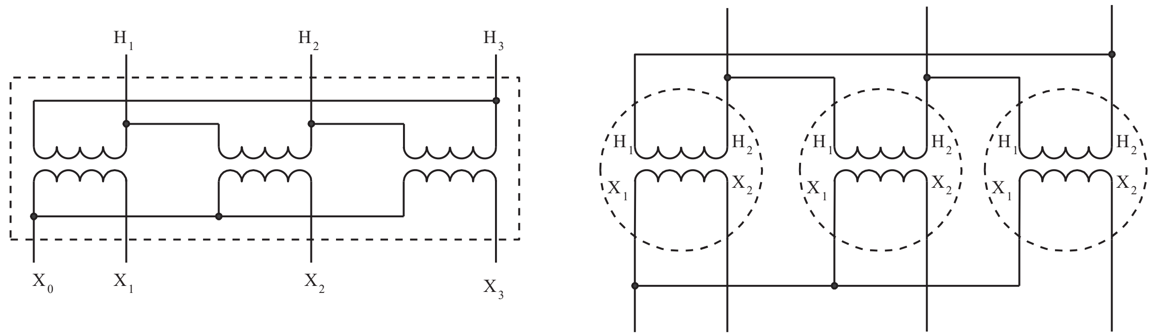


Figure 24—Three-phase and single-phase transformer connections

5.3.2 Impedance

Preferred standard values of transformer impedance are provided in Table 10 of ANSI C57.12.10 [B3], which is shown as Table 3. IEC 60076-5 [B22] specifies minimum values of impedance for two winding transformers. Variation from these values may be required in some applications to limit distribution bus fault magnitudes.

Table 3—BILs and percent impedance at self-cooled (OA) rating

	Without load tap changing		With load tap changing
High-voltage BIL (kV)	**Low voltage 480 V**	**Low voltage 2400 V and above**	**Low voltage 2400 V and above**
60–110	5.75 [a]	5.5 [a]	—
150	6.75	6.5	7.0
200	7.25	7.0	7.5
250	7.75	7.5	8.0
350	—	8.0	8.5
450	—	8.5	9.0
550	—	9.0	9.5
650	—	9.5	10.0
750	—	10.0	10.5

[a] For transformers greater than 5000 kVA self-cooled, these values are the same as those shown for 150 kV HV BIL.

Source: ANSI C57.12.10-1997 [B3].

5.4 Protective devices

5.4.1 Relay

Relays are devices that respond to signals from sensors (voltage, current, temperature, etc.), and operate contacts based upon predetermined criteria. These contacts are usually wired to the trip coil of a circuit breaker or a lockout relay. A relay can also be used as a control device to operate a circuit breaker after a preset time interval [B33].

Next to a fuse, the overcurrent relay is the oldest, least expensive, and simplest form of fault detecting device. The initial designs were single-phase electromechanical relays that measured phase and ground current to provide phase and ground fault protection. Three-phase overcurrent relays were developed that derived sequence currents for use in detecting phase and ground faults. Relays with instantaneous or numerous time delay characteristic shapes are available. Where the systems are not radial, a directional element using a polarizing voltage and/or current for reference is added to supervise the overcurrent element.

While the simple single- and multi-phase overcurrent devices are still applied, the microprocessor-based numerical relays with numerous functions are becoming more common. In these relays, the “overcurrent relay” is often just one of many functions included, and it may use any combination of sequence currents to produce its operating characteristics.

5.4.2 Recloser

A recloser is a device that combines the sensing, relaying, fault-interrupting, and reclosing functions in one integrated unit. Reclosers can be placed in substations or out on the distribution lines. The purpose of the recloser is to detect a fault, clear the fault, and attempt to restore service. If the fault is permanent, the recloser follows a predetermined sequence of open and close operations before locking out in the open position. Reclosers are frequently installed with accompanying isolating and bypass switches to facilitate maintenance and inspection operations. When maintenance or inspection is performed, protection is provided by either: a temporary fuse place in series with the bypass switch, a temporary fuse installed immediately upstream or downstream of the bypassed recloser, or the next upstream overcurrent protection device.

Reclosers may be identified in a number of ways: by their interrupting medium, by their means of control, by their fault-testing method and by their number of phases.

5.4.2.1 Interrupters

Reclosers have fault current interrupting contacts that are under either oil or vacuum for their interrupting medium. In the late 1960s, vacuum was introduced, and it is now the most common interrupting medium being used. The high-voltage dielectric insulating medium for vacuum reclosers can be oil, air, SF_6, or a solid dielectric.

5.4.2.2 Control

Recloser operating characteristics, such as timing, counting, and reclosing, can be controlled by either a hydraulic or an electronic method.

Hydraulic control is associated with series trip coil reclosers. In all hydraulically controlled reclosers, overcurrents are measured by a series solenoid, and timing is controlled by hydraulic action of oil fluid. Since the viscosity of the hydraulic fluid varies with temperature, the timing has been known to increase as the temperature decreases.

Electronic control is associated with shunt trip coil reclosers using either vacuum or hydraulic interrupters. These controls can be electromechanical, solid state, or Microprocessor-based. It uses an integrated or separately mounted electronic control, or set of overcurrent and reclosing relays to provide trip timing, counting, and reclose open interval timing characteristics. These controls are more accurate, repeatable, and flexible than hydraulic controls.

5.4.2.3 Fault-testing method

After tripping in response to an overhead feeder fault, conventional breakers and reclosers test for the continued presence of the fault by automatically reenergizing the phase or phases that were opened. This fault-testing method recloses the opened phases at a random system voltage angle, reapplying the available energy of the system to the downstream circuit. If the fault is still present, the fault is reinitiated and overcurrent protection re-trips the phase or phases that were reclosed.

Alternatively, a fault-testing method can be used to reduce the energy when closing into a fault. Instead of closing randomly at any system voltage angle, a minor-loop or pulse of current is developed by initiating a single-phase, rapid close-open operation at specific system voltage angles. Using conventional vacuum bottle contacts, this rapid close-open operation is initiated after a system voltage peak such that the duration of the resulting minor-loop of current is between approximately ¼ and ½ cycles.

This resulting minor-loop of current is then analyzed to determine if it represents a fault condition. If the analysis indicates a fault is still present, reenergizing the feeder section is suspended until a subsequent fault test operation indicates the absence of the fault, or lockout is reached. The time intervals between subsequent fault testing operations are selectable and typically correlate with the open intervals between conventional reclosing operations.

When this fault testing method is performed in response to a multi-phase fault not involving ground, the voltage point-on-wave, rapid close-open operation is based on phase-to-phase system voltage. Consequently, the resulting minor-loop of current does not indicate a fault condition until fault testing the second phase. While the second phase never recloses under this condition, the first phase has, and is subsequently reopened as a result of the phase-to-phase fault declaration.

In the event fuse saving is practiced, and a fuse has been prevented from operating in response to a downstream fault, this fault testing will continue to detect the presence of this fault without the fuse responding. Since the fault testing energy is incapable of causing fuse operation, one of the fault-testing sequences (prior to reaching lockout) will require a conventional closing operation to permit fuse operation.

5.4.2.4 Number of phases

Reclosers are designed as three-phase and single-phase devices. The three-phase type may operate in one of several modes: single-phase trip single-phase lockout, single-phase trip three-phase lockout, or three-phase trip three-phase lockout. See Clause 8.12 for a discussion on single phase tripping schemes.

Single-phase reclosers are either of the hydraulic or vacuum type with integrated or separately mounted controls that function as previously described. Some designs are self-powered and either protect the fuse from transients or replaces fuse altogether. These can be mounted either in existing/new cutout mountings or are installed immediately ahead of the existing fused cutout.

5.4.3 Fuses

Fuses are the most basic type of devices used for overcurrent protection. There are two fundamental types of fuses in distribution systems: expulsion and current limiting fuses. Before the system is faulted, fuses act as part of the line. However, when the line is faulted, the element, carrying more current than it can handle, heats to its melting point, then breaks apart in different ways depending on the fuse type and the fault current characteristic. Expulsion fuses use gas generation and exhaust to remove conducting particles from the arc column and allow the fuse to interrupt current at current zero [B67].

Because expulsion fuses interrupt currents at the current zero, they will let-through up to a full half-cycle of the full fault current before the current interruption and will not limit the fault current magnitude. Current limiting fuses reduce the magnitude and duration of the fault current by introducing a high resistance into the circuit. This action significantly reduces the let-through I^2t value compared to the I^2t value of expulsion fuses. The lower I^2t reduces stress on the power equipment subjected to this fault current.

Current limiting fuses come in three types: backup, general purpose, and full range. Backup fuses are designed for high fault current interruptions but are limited to how low of a fault current that they can successfully interrupt and therefore rely on other devices for low current interruption. General-purpose fuses can interrupt currents that cause the fuse to operate in one hour or less. Full-range fuses are designed to interrupt any current that causes element melting under normal fusing operations [B68].

5.4.4 Other Protection Devices

In addition to the protective devices described in 5.4.1 through 5.4.3, certain types of pad-mounted or sub-surface overcurrent protective devices can be applied to power distribution systems. These devices are typically self-contained, with the fault sensing and current interrupting components enclosed within the switchgear itself. Switch-fuse units have been used in the industry for decades, with fuses providing the overcurrent protection. In addition, other types of devices falling into the general category of vacuum fault interrupters are often applied to underground portions of the distribution system. Time overcurrent, instantaneous overcurrent, phase, and ground sensing are typically included, and settings can be applied via a programmable control or by setting of discrete components such as dip switches. Interruption is typically accomplished via vacuum interrupters, and can be designed or set for single-phase or three-phase operation. The high-voltage dielectric insulating medium can be oil, SF_6 or a solid dielectric. An advantage to these types of equipment is that they are resettable after an operation occurs. These devices, unlike reclosers, do not typically have reclosing capability, as they are primarily intended to protect underground distribution cables where reclosing into a fault is not desired.

5.4.5 Sectionalizers

Sectionalizers are not fault interrupting devices, but may be used in conjunction with upstream overcurrent devices. A sectionalizer may be set to open when there is no voltage, after sensing fault current one or more times. This provides an additional place to sectionalize the system, with a device that does not have to interrupt fault current. Application of sectionalizers is beyond the scope of this guide.

5.5 Switching

During switching, the resulting system configuration can have a significant impact on application of protective devices. Feeder tie switches are commonly used to isolate sections of the feeder from the normal source and tie it to an adjacent feeder. This facilitates maintenance and outage restoration, and allows feeder loads to be balanced by switching loads between feeders.

If the tie switch consists of a set of three single-phase switches, each phase is operated individually with a hot stick. It may take several seconds to operate all three phases. During this switching time, unbalanced currents will flow. The sensitivity of residual or ground time overcurrent relays may be limited or disabled to prevent misoperation during this switching period. If the tie switches are gang-operated, this is not a limitation.

When the tie switches are used to connect a section of the feeder to an adjacent feeder, a long circuit can be created. This may result in lower short circuit currents due to the impedance of the longer line and higher load currents due to addition of the switched feeder section to the normal feeder load. This makes lower current pickup settings desirable to detect short circuits, but makes higher current pickups necessary to prevent operation on load current.

5.6 Instrument transformers (sensing)

5.6.1 CT/VT

Instrument transformers provide scaled signals for use in the protective relay schemes, stepping the power system currents and voltages down to a manageable level, and providing isolation between the relay system and the primary circuits. Instrument transformer performance can be a significant factor in protective relay scheme performance, since they provide the signals upon which the relays base their responses. In numeric relaying systems, the CT and VT signals may also be used for metering functions.

CTs take the power system currents (primary) and step them down to a lower level (secondary) for relaying. The CT ratio defines this scaling factor, and is specified as the ratio of primary to secondary current (e.g., 1200/5). Multi-ratio CTs are designed with multiple secondary taps, providing more flexibility in setting relay response characteristics, optimizing the relay system performance, and allowing standardized hardware. The CT accuracy class is determined by a letter designation and a secondary voltage terminal rating (see Subclause 5.6.3). IEEE Std C37.110™ [B37] provides guidelines to ensure that CTs are applied correctly for protective relay applications. Reclosers and some switches may have internally mounted CTs encapsulated in solid dielectric. The accuracy and response of these CTs are tested and verified in a switchgear system (recloser, control, and control cable) per the manufacturer's specification. Current measurements are necessary for all forms of overcurrent relaying (time or instantaneous, phase, neutral, or negative sequence)

VTs step the primary power system voltage down to a lower voltage for the relay (secondary) circuits. As with CTs; VTs are specified based on their turns ratio. VTs are necessary for voltage-based relaying, including overvoltage, undervoltage, overfrequency, and underfrequency. VTs can also provide polarizing signals for directional overcurrent schemes.

5.6.2 Location and configuration (wye/delta)

In distribution applications, CTs are required for each protected feeder as shown in Figure 25. The CTs are usually located on the bus side of the feeder circuit breaker, or associated sectionalizing device. This ensures that any fault on the line side of the breaker or the breaker interrupting components will be detected by the connected overcurrent relays (no unprotected area between breaker and CT). CTs are usually connected in wye, with a CT for each phase. This allows direct measurement of the phase and neutral currents (see Figure 26). The residual (zero sequence) and negative sequence currents can also be derived from the phase currents in a microprocessor-based relay.

VTs are usually connected to the power system bus, since a voltage disruption will be equally distributed within the substation. Line side VTs may be required for permissive closing schemes, if the distribution lines are not radial, or if DERs are present on the lines. VT primaries can be connected wye or delta, depending on needs. Three wye-connected VTs provide three phase-to-phase and phase-to-neutral voltages [see part (a) of Figure 27]. The open delta VT connection provides three phase-to-phase voltage measurements using only two VTs [see part (b) of Figure 27]. The VT connection is selected based on the application and relays selected. A more detailed discussion of voltages available from VTs is included in Clause 6.3. VTs are usually connected with primary fuses to isolate failed VTs from the power system.

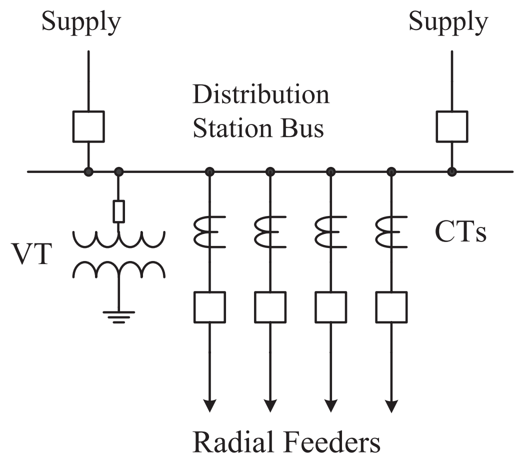


Figure 25—CT and VT location in a distribution station

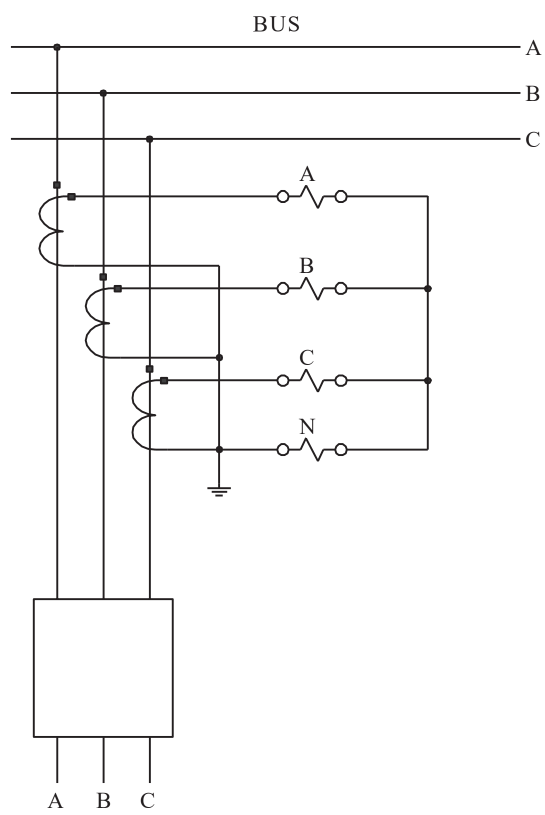
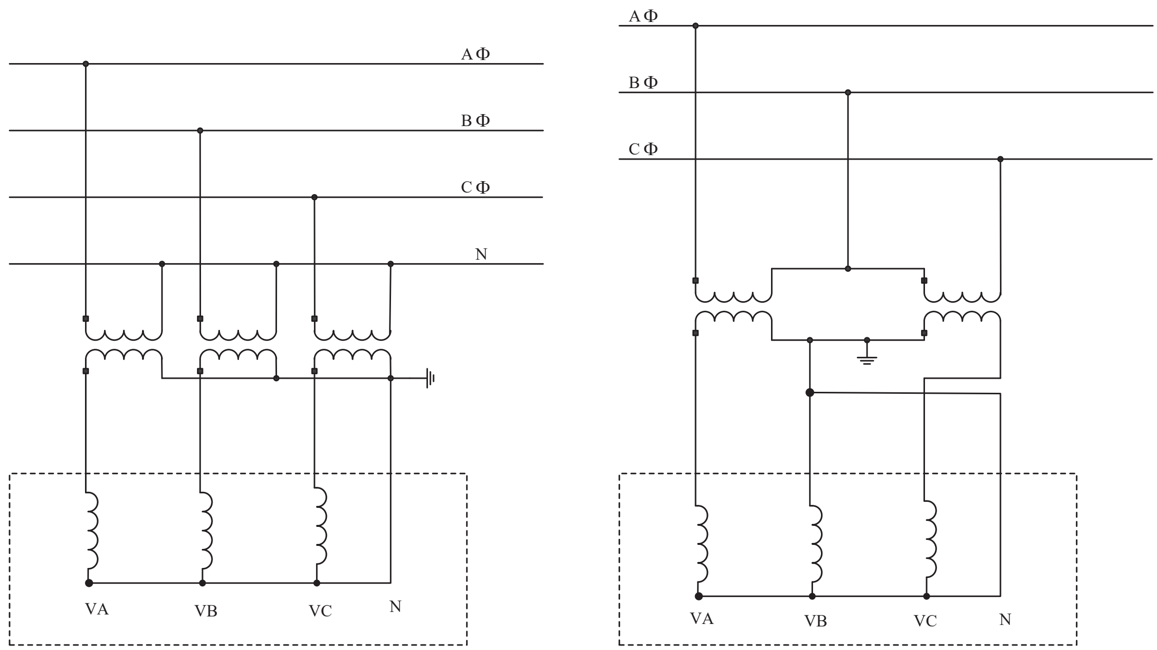


Figure 26—CT connection, 3-wire



a) 3-phase vt, 4-wire connection.

b) 3-phase vt, 3-wire connection.

Figure 27—VT connections

5.6.3 Accuracy and ratings

Relaying CTs are intended to operate reliably over a wide dynamic range, from current levels well below rated current, to many multiples of rated current. Relay class CTs are rated for either 5 A or 1 A nominal secondary current, and are specified to have less than 10% error with up to 20 times rated current while feeding up to a standard burden. For instance, a 5 A secondary rated C100 accuracy class CT is defined to have less than 10% error over a range of up to 100 A (20 times rated) through a burden of up to 1 Ω, without saturating (see IEEE Std C37.110 [B37] and IEEE Std C57.13 [B69]).

VTs are not required to operate over as wide a dynamic range as CTs, since the voltages collapse during faults. Maximum voltages expected should not exceed 3.0 p.u. for ferroresonance, of nominal to avoid stress on insulation. VTs are usually rated 69 V or 120 V phase-to-neutral across the secondary windings. The 69 V tap provides 120 V phase-to-phase voltage.

5.6.4 CT saturation

CT saturation causes distortion in the secondary current waveform and a decrease in CT accuracy. This can be due to abnormally high primary currents, excessive connected burden, or remnant flux. These conditions can create high flux density in the CT's iron core, leading to excessive excitation current, I_e. This results in a secondary current less than would be indicated by an ideal CT. With reference to the CT equivalent circuit shown in Figure 28, as I_e gets large, I_s does not replicate I_p well.

The CT excitation current is indicated by the V-I characteristic curves, as shown in Figure 29. Excitation current is generally low, compared to secondary current, unless the secondary excitation voltage V_e exceeds the knee-point of the curve. At this point, a small increase in excitation voltage results in a very large increase in excitation current.

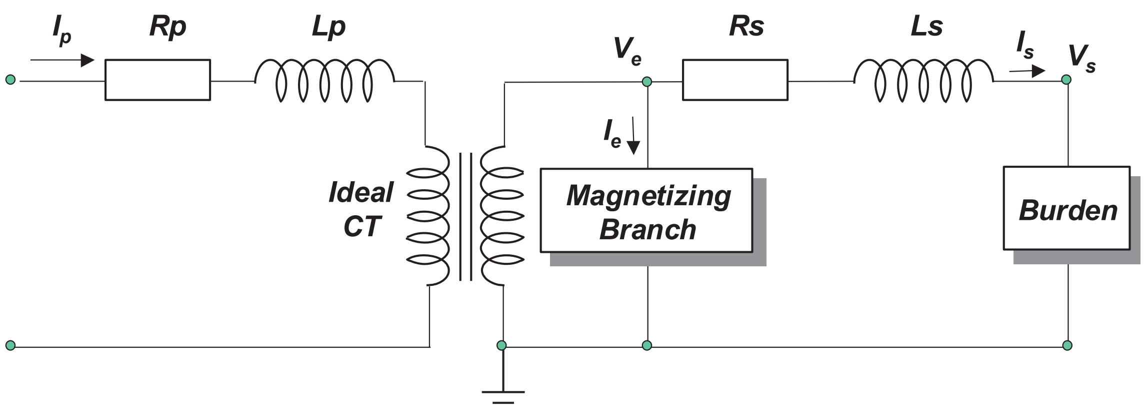


Figure 28—CT equivalent circuit

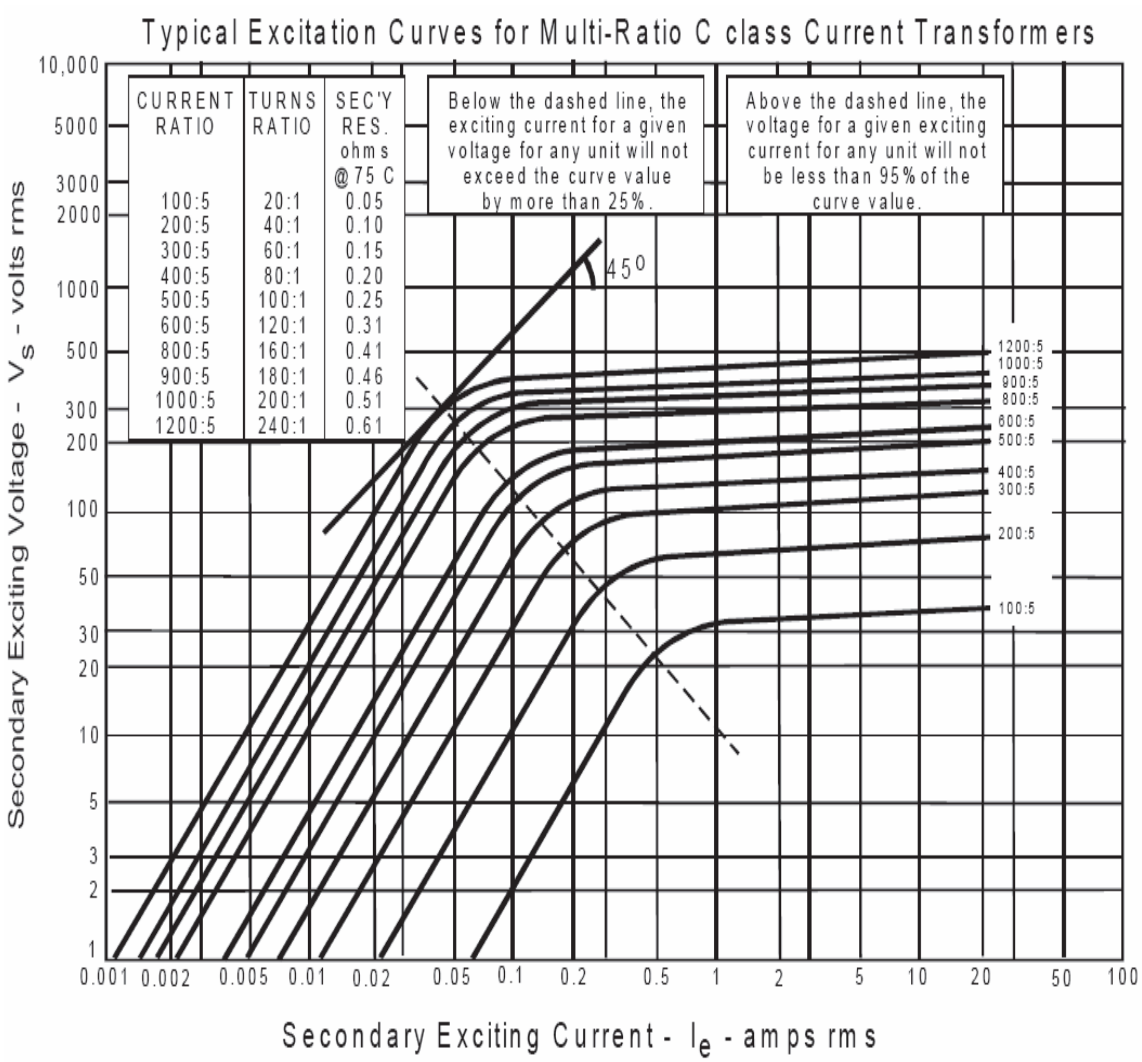


Figure 29—Typical excitation curves for a multi-ratio C class CT

CT saturation (see Figure 30) can decrease the current through the relays and cause under-reaching of the protection scheme. To limit the possibility of saturation, the burden connected to the CTs should be kept as low as possible. This will decrease the required secondary excitation voltage (V_e in Figure 28) and associated excitation current I_e. Figure 30 shows a 1200/5 A, C400 CT performances for two different fault currents and burden. The CT slightly saturates at 20 times CT rated current ($20I_N$) but is within the 10% accuracy error as defined by the IEEE Std C57.13 [B69]. At $40I_N$, the CT heavily saturates with rated burden of 4 Ω. The CT saturation is significantly smaller with reduced burden to 2 Ω, demonstrating the burden impact on the CT saturation.

CT saturation can also be caused by the dc component of an asymmetrical fault current. The effect of dc component on the CT saturation is shown in Figure 31. After saturation occurs, the decay of the dc component will allow the CT to recover. In three-phase systems, the offset will be different on each of the phase CTs, causing different CT saturation in each phase as shown in Figure 32. This will result in residual current I_R and can cause false signals in residually connected protective devices.

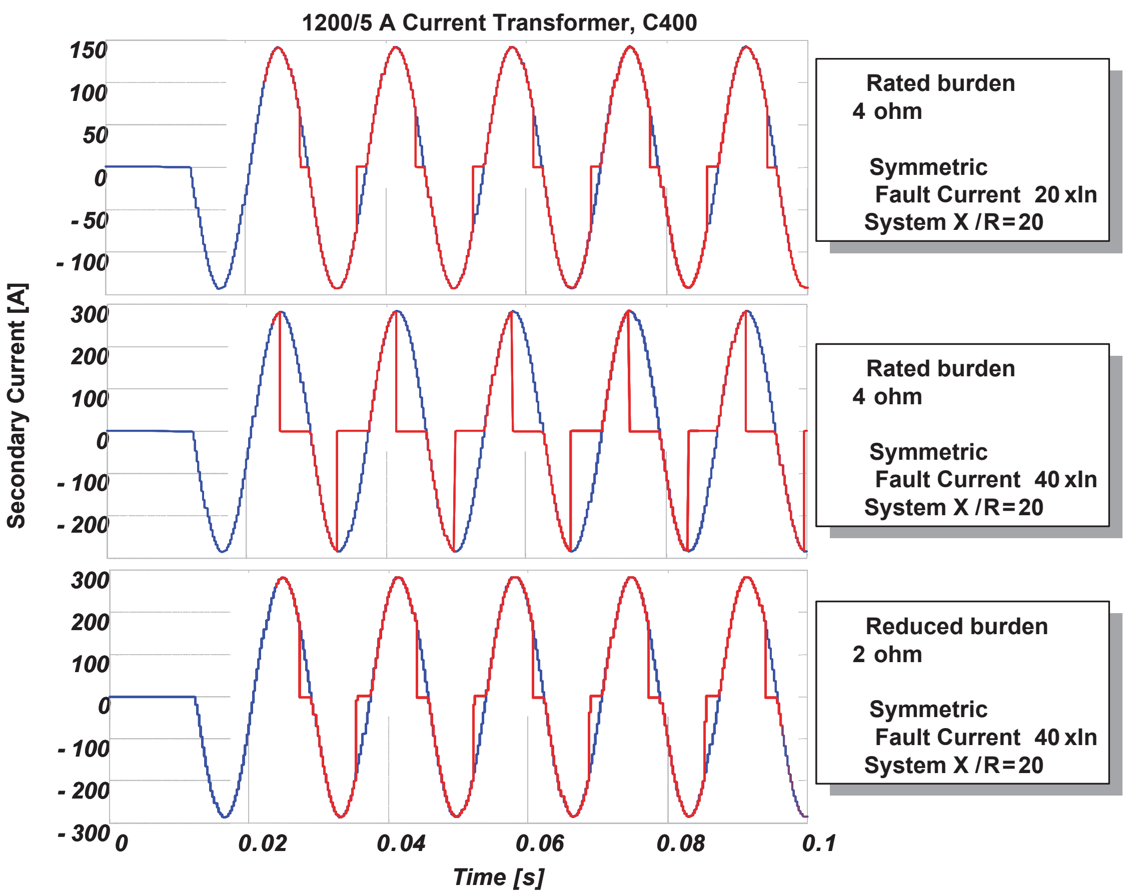


Figure 30—CT saturation at rated burden and reduced burden

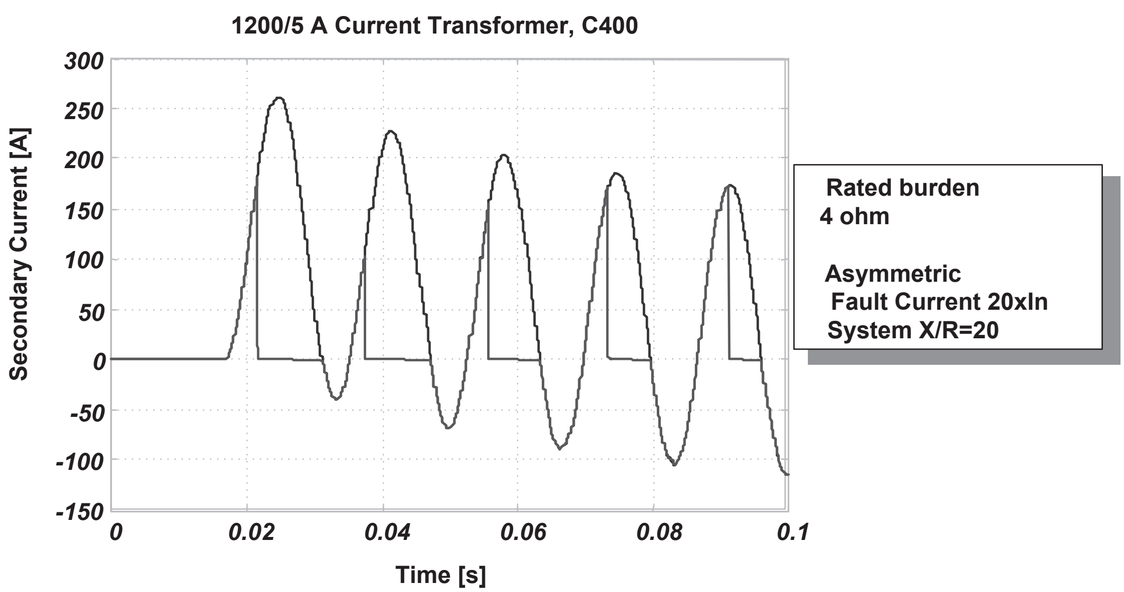


Figure 31—Effect of dc component on CT saturation

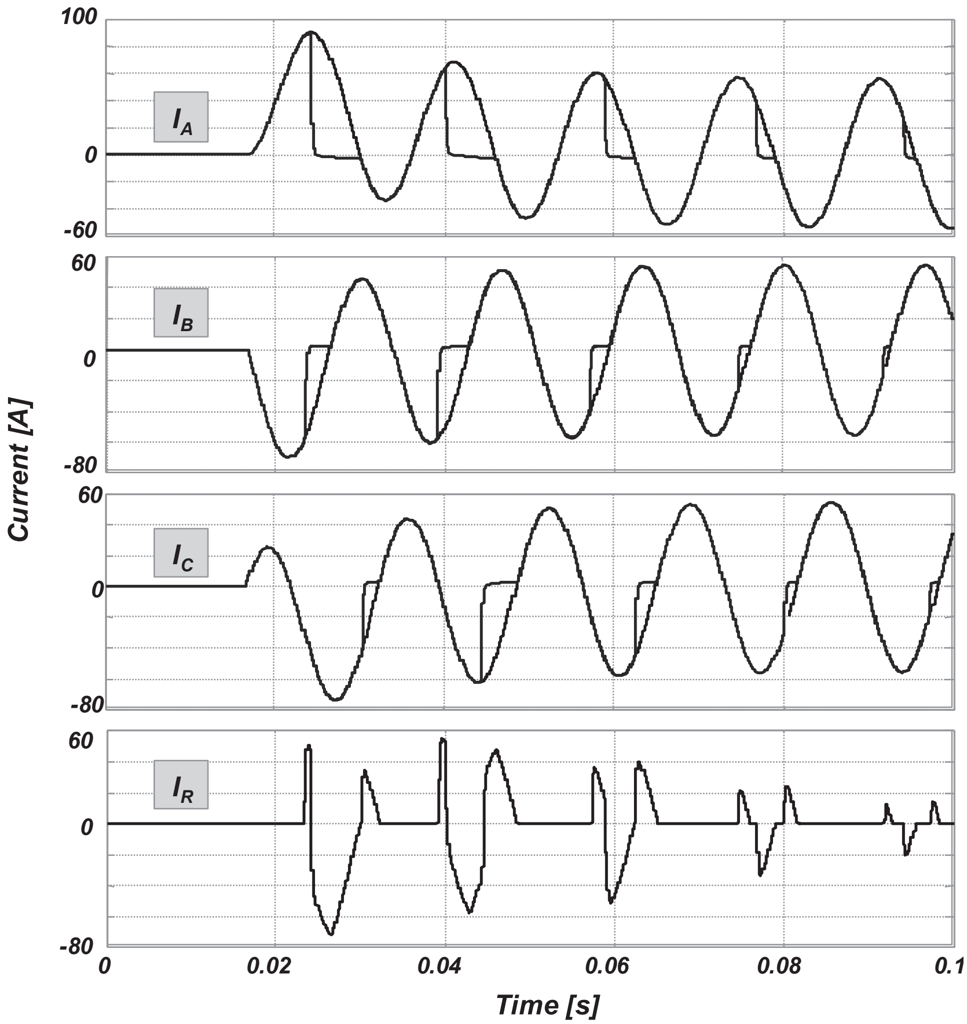


Figure 32—Residual current caused by CT saturation due to dc components

CT saturation will not always impact relay coordination. This depends on the time-current characteristic (TCC) curve used, protection setting, and the fault current relative to CT saturation points. In practice, the load current I_L has been used to determine the minimum pickup for phase and ground (residual) time overcurrent elements for relays and reclosers. When calculating the phase minimum pickup/trip, a safety factor of 1.5 to 3.0 times normal load current I_L may be included to account for load growth, contingency operating conditions, and cold-load inrush currents. With this setting philosophy, CT saturation issues are minimized that may cause overcurrent protection misoperation when using fast TCC curves. Figure 33 shows that at minimum pickup setting of $2I_L$, the CT saturation will not impact protection coordination. However, minimum pickup setting of $4I_L$ could impact protection coordination.

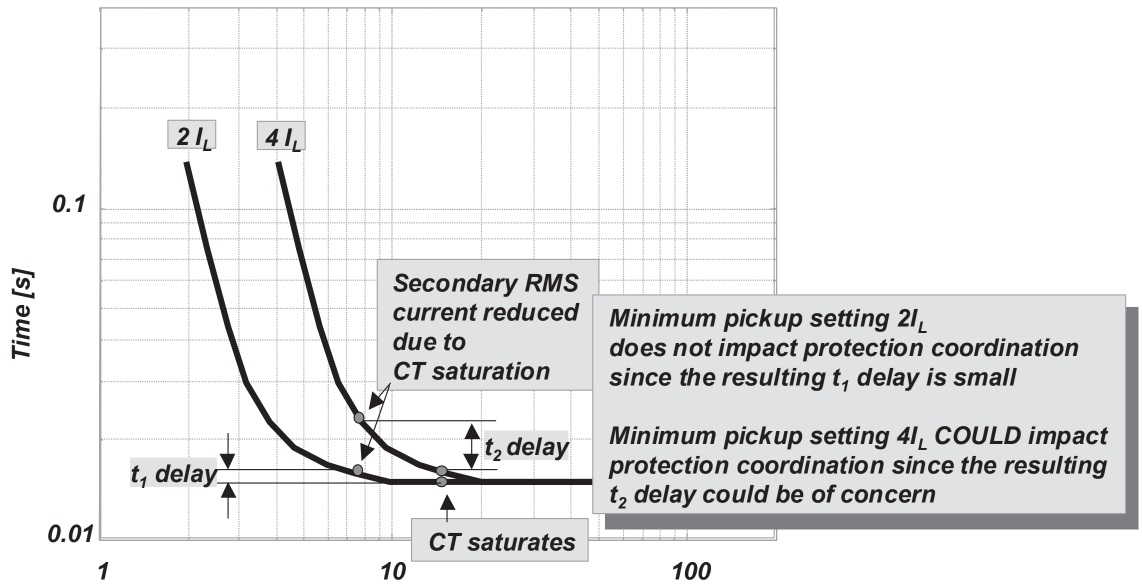


Figure 33—A fast time-current characteristic curve

For more information on the impacts of CT saturation on relay operation, refer to IEEE Std C37.110 [B37].

6. Protective schemes

6.1 Overcurrent scheme

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

a) Phase overcurrent
b) Ground overcurrent
c) 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 applied; while for network or looped systems, directional overcurrent relays are more appropriate. See Clause 8.9 for the application of directional overcurrent relays. In almost all cases, the distribution feeder protection begins at the substation with a feeder breaker or recloser. This device is intended to be coordinated upstream with the main bus breaker or transformer high side protection depending upon the substation design and with downstream devices. Downstream devices are generally reclosers or fuses. These may be located on the main feeder or tap sections. Setting criteria for these devices is discussed in Clause 7.

6.2 Fuse saving/blowing schemes

Overcurrent protection schemes for distribution feeders generally fall in three types as follows:

a) Fuse saving schemes
b) Partial-range fuse saving schemes
c) Fuse blowing schemes

6.2.1 Fuse saving scheme

Distribution fuses require physical replacement after a fault clearing operation. This results in extended outage time to the customer and added expense to replace the fuse. 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. Figure 34 is a time-current coordination graph for a fuse saving scheme. Fuse saving for this scheme requires that a recloser fast clearing curve as shown in Figure 34 (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 the fuse will operate first to clear the persistent fault before the breaker or recloser trips again, as shown by the recloser slow curve in Figure 34. This provides one or two opportunities for a temporary fault to be cleared before the fuse is allowed to operate. Permanent faults typically 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 normally only applied to in-line or tap fuses. Effective operation of fuse savings schemes depends on factors such as the fuse size, the range of fault currents available at the location of the fuse, and the fast clearing curve characteristics of the "upstream" recloser.

Conventional fuse saving does not work in every situation. When fault current is high, a fuse will operate faster than either the fast curve on a recloser or the tripping time for typical distribution substation feeder circuit breaker. This means that if fuse saving were attempted to be applied at high fault currents, not only would the fuse still operate to clear the fault, there is a good chance that the upstream device would also operate. This means attempting to apply fuse saving at high fault currents will make reliability worse by increasing customer momentary outages while not reducing any customer sustained outages.

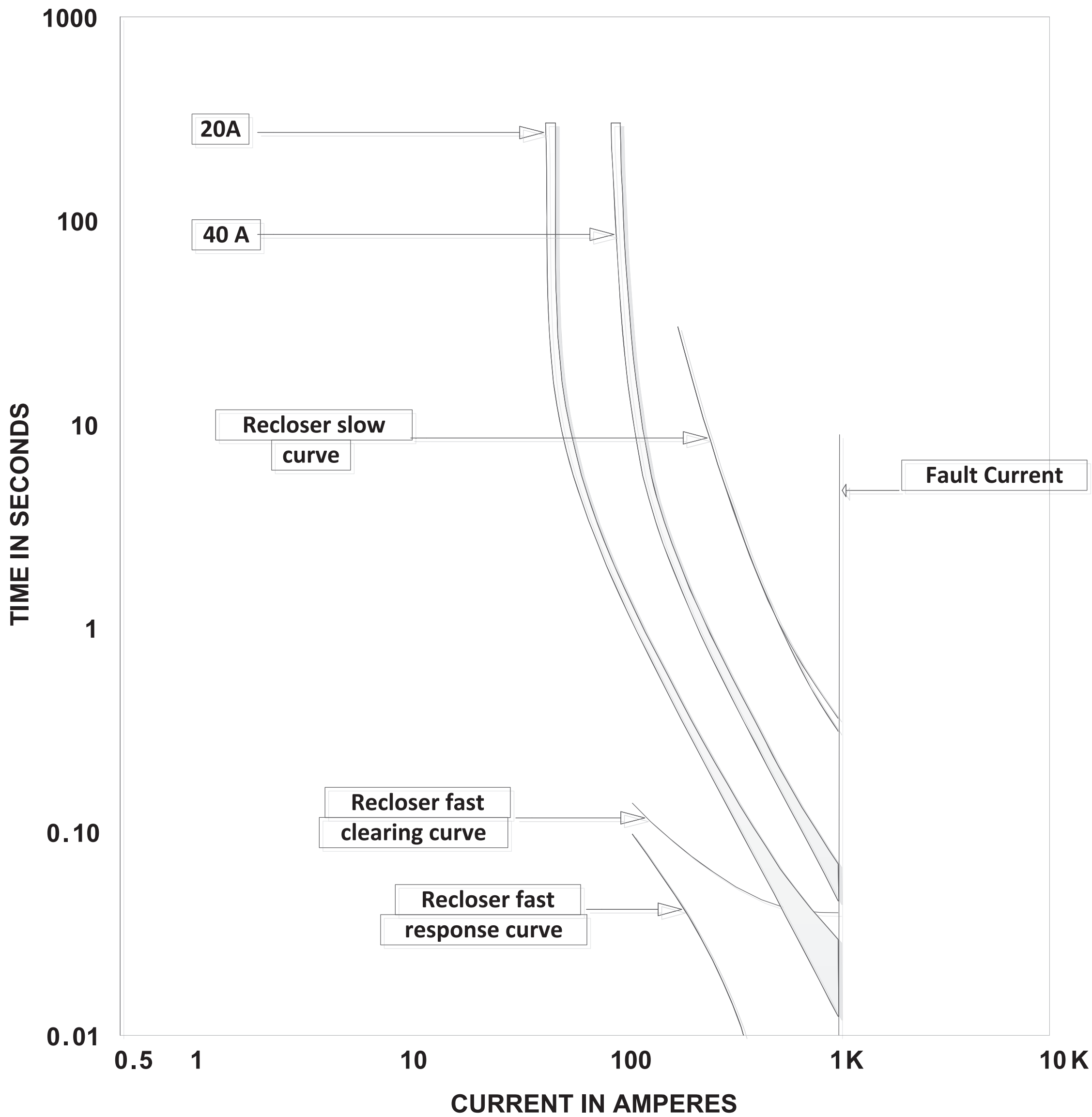


Figure 34—Time-current curve showing fuse saving scheme

6.2.2 Partial-range fuse saving schemes

Conventional fuse saving schemes, as described previously, are occasionally unable to save the fuse due to the level of fault current experienced by both the upstream recloser and the fuse. As an example, and referring to Figure 34, if a fault downstream of the 20 A fuse results in a current of greater than approximately 500 A, the fuse and the upstream recloser both operate. In these instances, the fuse isn't saved, and all customers served by the upstream recloser or circuit-breaker experience an unnecessary momentary interruption.

This combined operation of the upstream recloser and downstream fuse for fault levels above the intersection of the recloser's fast clearing curve and the minimum-melt of the fuse can be avoided by limiting the response of the fast clearing curve to approximately 500 A in the example shown in Figure 34. This current limiting function can be accomplished by developing protection logic using today's modern microprocessor-based protection relays or controls. Microprocessor-based relays allow one to design a fuse saving TCC that mimics a fuse's minimum-melt curve with time and current offsets for coordination with that fuse.

Referring to Figure 35, a fuse saving TCC can be developed specifically for each of the downstream fuse sizes and types. This TCC curve can be placed just below the fuse's minimum-melting curve, with appropriate allowances for such items as the protection response and mechanical interrupting time with tolerances, fuse pre-loading, ambient temperature, and fault-current asymmetry.

The shape of the fast fuse saving curve is designed to conform to the specified fuse curve as closely as possible, thus minimizing interference with smaller downstream transformer fuses.

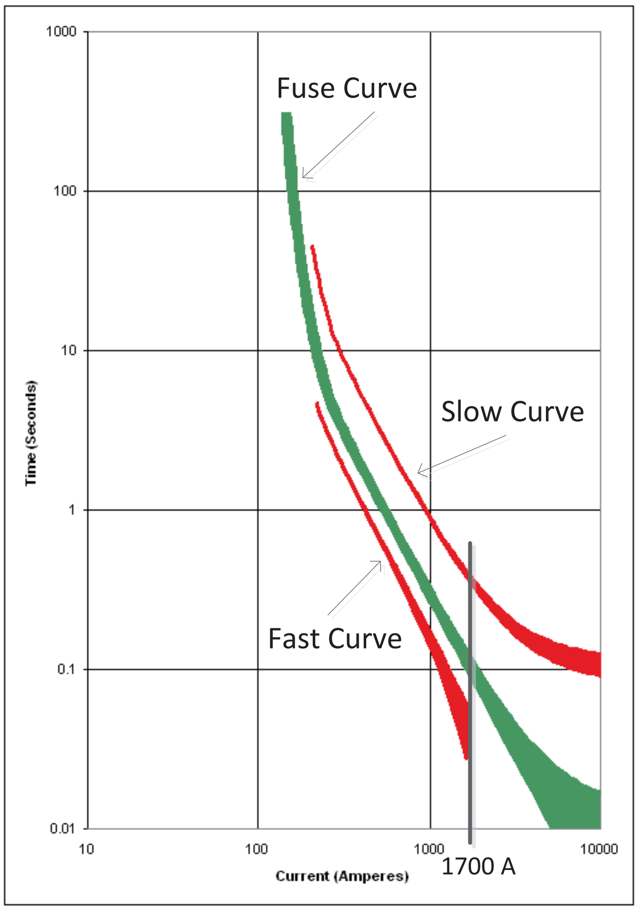


Figure 35—Time-current curve showing partial-range fuse saving scheme

An optimized fuse saving curve is developed by establishing a response-band consisting of a minimum response and a maximum clear TCC with all tolerances accounted for. Since the fast fuse saving curve is created based on the fuse minimum-melt characteristic with which it coordinates, the same curve shape applies for both phase- and ground-fault applications. The only differences between the ground and phase fast fuse saving curves are their pickup currents which are established by the respective phase and ground slow curve pick-up thresholds.

Ideally, a fast fuse saving tripping response occurs when the fault can actually be cleared before the downstream fuse begins to melt. If the fuse cannot be saved, then tripping using the slow curve rather than the fast fuse saving protection is desirable. This selective response of the fast fuse saving curve and slow curve allows the fuse to operate when it cannot be saved and before the recloser trips. In Figure 35, this occurs at 1700 A, so faults above 1700 A are cleared by the fuse and not the upstream fault-interrupter. This technique garners all the benefits of successful fuse saving without the nuisance trips resulting from miscoordination at higher fault currents.

Another partial range fuse blowing scheme involves the installation of remote fault sensors on fused protected underground sections of distribution lines. These fault sensors communicate with the upstream relay or recloser and send a signal to block its fast fuse saving tripping response for faults on underground lines (since faults on underground lines are normally permanent). Details on how these fault sensors communicate with the upstream relay or recloser is outside the scope of this guide.

6.2.3 Fuse blowing schemes

For distribution feeders where loads are sensitive to momentary outages and significant disruption occurs if the line is momentarily deenergized, a fuse blowing scheme is used to limit the number of main feeder trip-reclose cycles. 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 and the substation device serves as a backup in case the fuse fails, in addition to its function of operating for faults on the main feeder trunk.

Most underground cable faults are permanent and do not self-clear. Typically, cable insulation has been breached or termination/switching equipment has failed, resulting in a permanent fault. Underground cable is almost always protected using a fuse blowing scheme for the riser pole fuses. Compromises may be made on an individual basis for circuits that are primarily overhead with short underground sections connecting significant overhead sections, such as at a road crossing. Fuse blowing schemes may result in longer clearing times for momentary faults since all operations will be on a delayed curve. As discussed in Clause 7.3, this may adversely impact the power quality of the customers whose services are electrically close to the fault location, but are not actually interrupted.

Figure 36 is a time-current curve for a fuse blowing scheme. Here only a slow recloser curve is used that allows sufficient time for fuse operation to occur prior to response by the main feeder recloser or breaker.

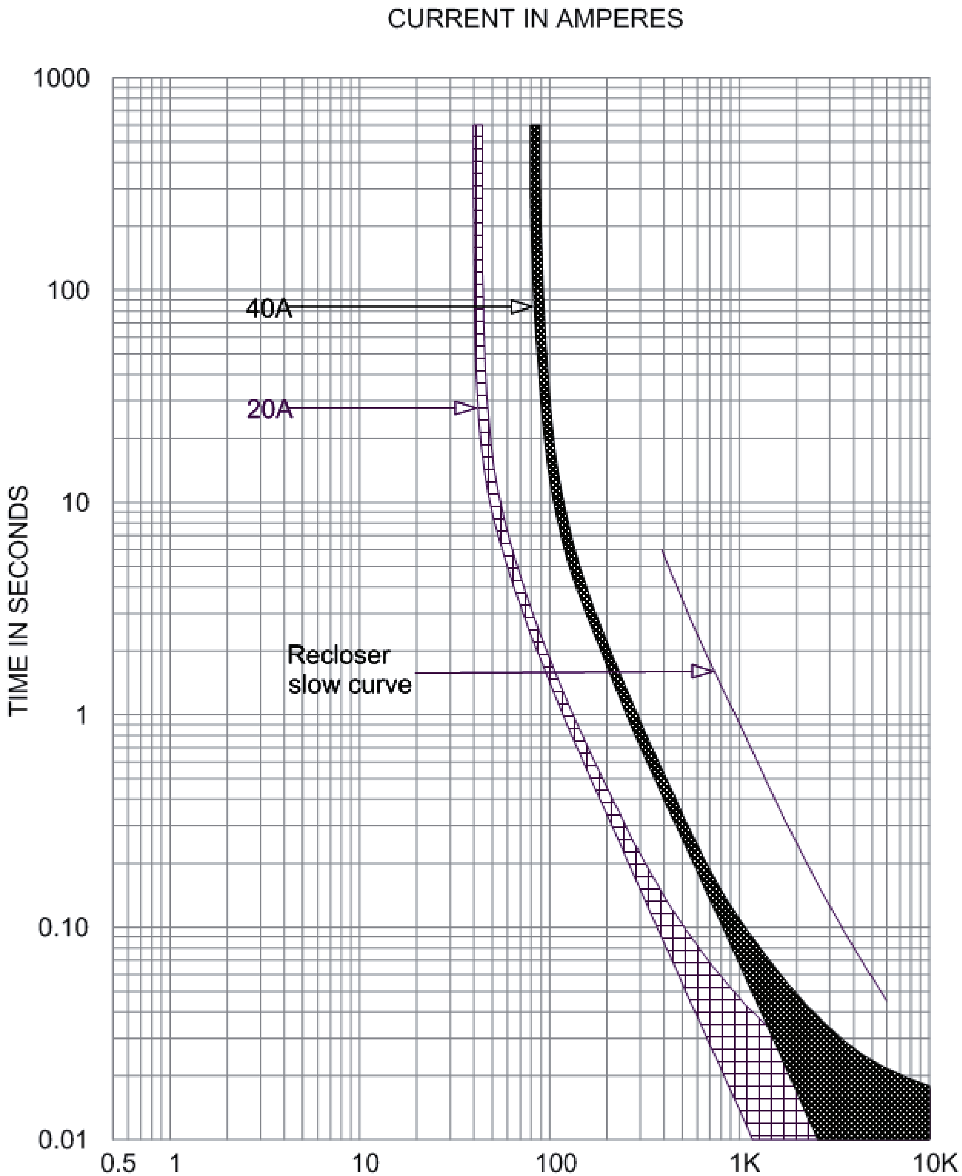


Figure 36—Time-current curve showing fuse blowing scheme

6.3 Voltage scheme

Voltage sensing relays are used in a wide variety of applications. Some of these applications 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, high resistance grounded, and resonance grounded 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; and to supervise or restrain overcurrent elements for fault detection near generation sources.

The voltage elements can be overvoltage or undervoltage 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.

6.3.1 Overvoltage and undervoltage

Overvoltage elements assert when the measured voltage goes above a predetermined threshold. Conversely, undervoltage elements assert when the measured voltage drops below a predetermined threshold.

6.3.2 Phase-to-phase and phase-to-ground voltage elements

Voltage elements can be connected or programmed to measure either phase-to-phase or phase-to-ground voltage. Phase-to-ground connections (see Figure 37) are usually preferred since phase-to-phase quantities can then be calculated. If only one or two VTs are to be used then phase-to-phase connections are generally preferred (See Subclause 5.6.2). It is important to verify that the VTs are rated for phase-to-phase operation (see Figure 38). Note that with the phase-to-phase connections shown in Figure 38, zero sequence voltage (V_0) cannot be measured since it does not exist in the 3-wire system formed by the open delta connection. VT connections are typically considered during initial protection system design.

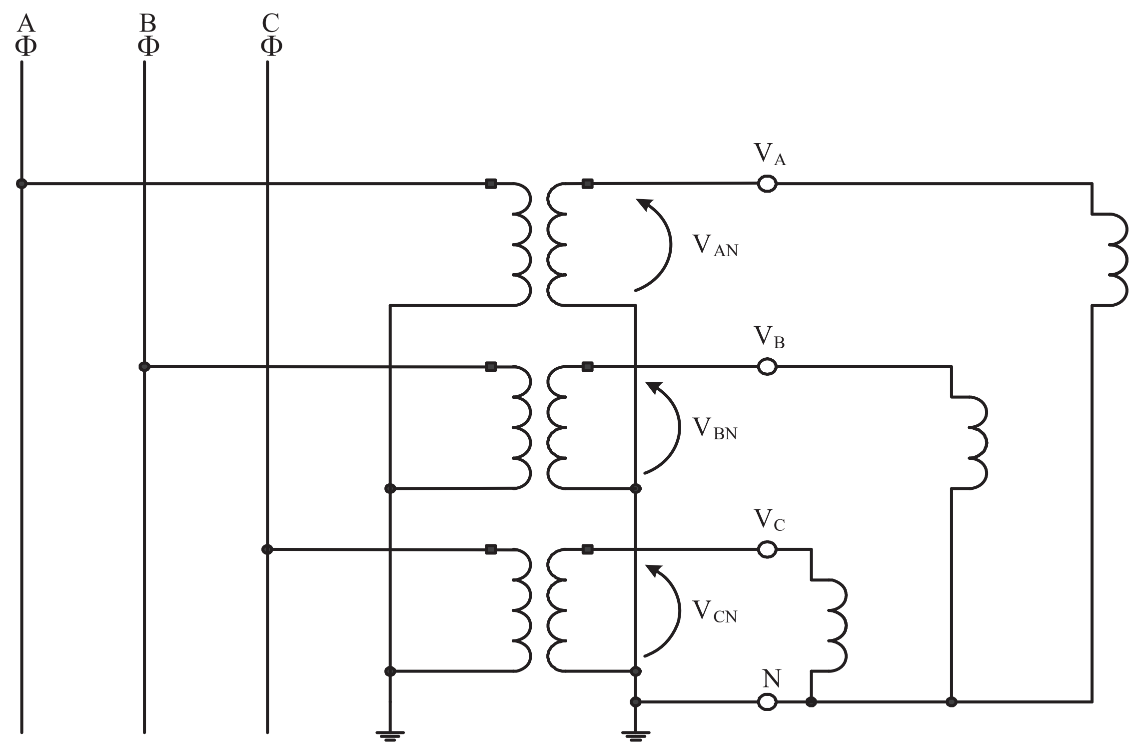


Figure 37—Three-phase, four-wire connected VTs

Assuming ABC phase sequence, the sequence voltages can be derived using below equations

$V_0 = 1/3\ (V_{AN} + V_{BN} + V_{CN})$ Equation 6.3.2.a$V_1 = 1/3\ (V_{AN} + aV_{BN} + a^2V_{CN})$ Equa

$V_2 = 1/3\ (V_{AN} + a^2V_{BN} + aV_{CN})$ Equation 6.3.2.c

Where V_0, V_1, V_2 *are zero, positive and negative sequence voltages respectively;* $a = 1 \angle 120°$

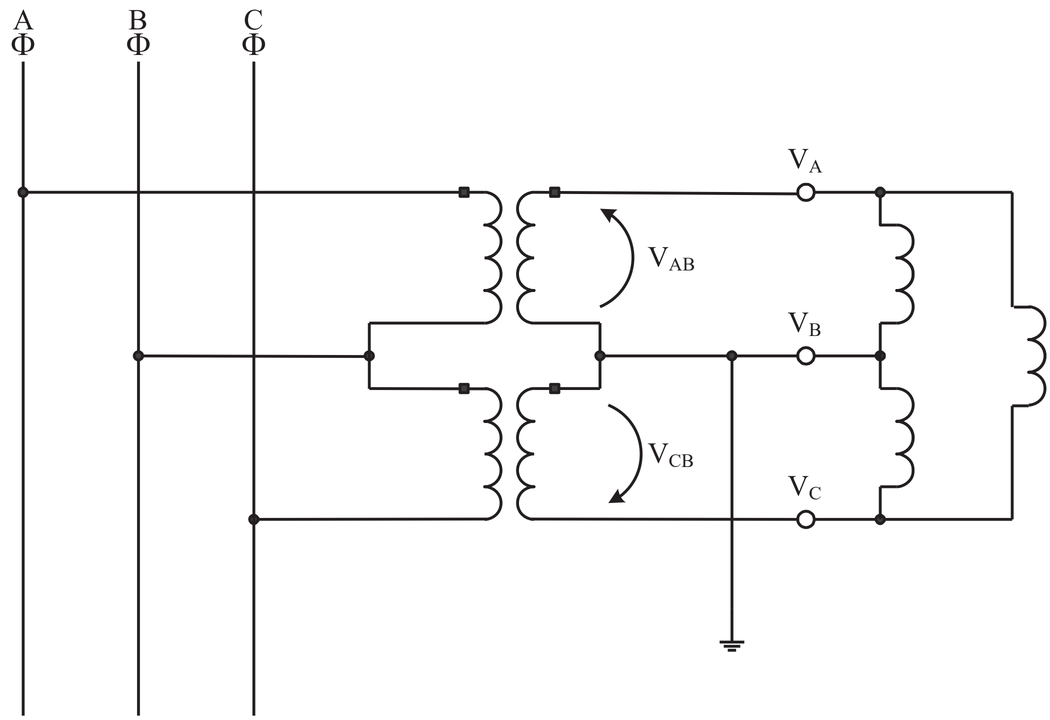


Figure 38—Three-phase, three-wire (open delta) connected VTs

$V_1 = 1/3\ (V_{AB} + a^2 V_{CB})$

$V_2 = 1/3\ (V_{AB} + aV_{CB})$

V_0 is not available

where

$a = 1 \angle 120°$

6.3.3 Positive-, negative-, and zero-sequence voltage quantities

Positive-, negative-, and zero-sequence voltage quantities are frequently used for protection and control purposes. Positive-sequence voltage provides three-phase voltage measurement information under balanced system conditions. Negative-sequence voltage has been widely used for detection of a loss of phase, or to detect a blown fuse. Zero-sequence voltage is used for ground fault detection. Zero-sequence voltage can be calculated from three-phase, four-wire connected VTs or measured directly from the wye-broken delta connection shown in Figure 39.

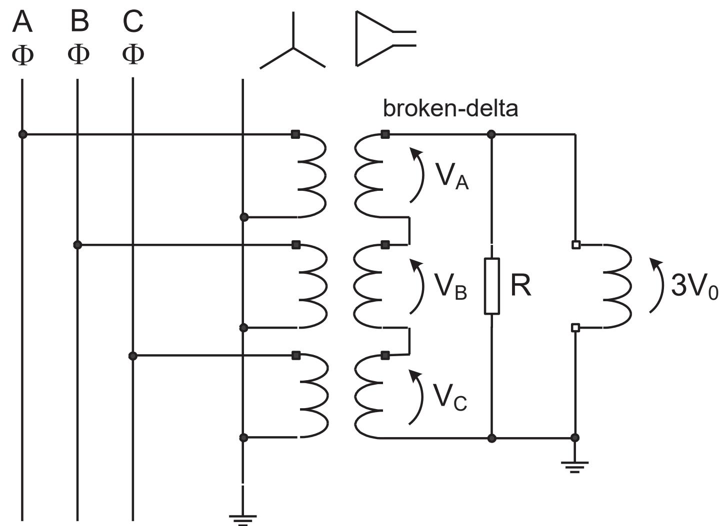


Figure 39—Wye-broken delta connected VTs for zero-sequence voltage sensing

$$V_A + V_B + V_C - V_R = 0$$

$$\begin{aligned} V_R &= (V_1 + V_2 + V_0) + (a^2V_1 + aV_2 + V_0) + (aV_1 + a^2V_2 + V_0) \\ &= V_1(1 + a + a^2) + V_2(1 + a + a^2) + V_0(1 + 1 + 1) \\ &= 3V_0 \end{aligned}$$

V_0 is available

V_1, V_2 are not available

where

$a = 1 \angle 120°$

6.4 Impedance and communications assisted schemes

Impedance based protection and communications assisted protection schemes can be applied to distribution systems but have been historically less common due to the differences in system configurations, system cost, complexity, and other reasons. Situations that may arise that require the use of communication assisted protection schemes are discussed in Clause 8.7 of this guide.

7. Criteria and examples

The goal of the utility is to deliver electric energy to the customers in a safe, reliable, and economical manner. Protective relaying is applied to distribution lines to strive and achieve this goal. The goals in applying protective relays 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.

7.1 Reach/sensitivity

7.1.1 Phase faults

In order to optimize coverage, at least one fault detecting device operates for both phase-to-phase and 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 and fault impedance.

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. Factors to consider when calculating the pickup setting are the line capacity, maximum line loading, cold load characteristics of the feeder’s connected loads, and system transients. Cold load pickup is discussed in Clause 7.5. To avoid misoperation, a phase time overcurrent relay pickup setting of 1.25 to 3.0 times the maximum steady-state load current is commonly used.

Selection of the pickup setting of an instantaneous phase overcurrent relay can range from a setting based on some multiple of the maximum steady-state load current to a setting based on the location of other protective devices on the distribution line. While time overcurrent elements are typically not affected by transients, instantaneous overcurrent elements can be very susceptible to misoperation if set too sensitively. On the distribution system, sources of transient currents include system switching, transformer magnetizing inrush (discussed in Subclause 7.1.3), and capacitor discharge current.

The conflict between setting the phase overcurrent relays above load current and below the minimum fault current is often a concern. . A feeder with the majority of the load located close to the substation but with small loads at significant distances away from the substation and small conductor being used to carry the remote loads can create situations where the maximum load current at the substation could be close to the fault current at the end of the line. Fault-interrupting devices like fuses or reclosers may need to be installed remote from the substation on the feeds to the remote loads. With these remote devices, the substation relay only needs to be able to detect faults as far away as the remote fault-interrupting devices (unless the upstream protection device is being relied on to save that remote fuse). The installation of those devices also can contribute to improving the quality of service to the majority of the customers on the feeder.

If setting the phase time overcurrent relay 1.25 to 3.0 times greater than the maximum steady-state load current cannot be achieved without compromising the desired sensitivity, then either installation of a downstream line recloser or supervising the phase overcurrent relays with a distance or load encroachment device may be considered. Installation of a line recloser will shorten the protection zone of the upstream phase relays which would allow for a higher phase time overcurrent pickup setting while still maintaining the desired sensitivity to faults. Supervising the phase time overcurrent relay with a distance or load encroachment device will block the phase time overcurrent relay from picking up for non-fault conditions even if current is above the phase time overcurrent relay’s pickup setting. When a fault occurs, the phase overcurrent element would be unblocked and its time overcurrent characteristic will still allow for coordination with downstream time overcurrent devices.

Still another alternative in dealing with the conflict of high load currents and low fault currents is to apply negative sequence relays in addition to the phase overcurrent relays. The phase time overcurrent relays can be set to pick up for three-phase faults and the negative sequence time overcurrent relays can be set lower than the phase relay pickup to detect low magnitude phase-to-phase faults. While negative sequence time overcurrent relays are set above the maximum steady-state unbalance current such as load unbalance or loss of a single-phase lateral (or tap), the negative sequence relay pickup can be set below maximum three phase balance loading and therefore can be set substantially lower than the phase overcurrent relay setting. For proper coordination, unbalanced phase currents resulting from transformer magnetizing inrush is considered when setting the instantaneous negative sequence overcurrent pickup.

Negative sequence relays can also be applied to detect open phase conditions and low side phase-to-ground faults on delta-grounded wye or wye-wye transformers. “Negative-sequence overcurrent element application and coordination in distribution protection” [B13] provides an analysis of the effect of an open phase conductor for both three-wire and four-wire distribution systems. 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 relay provides backup at the distribution substation for failure of the local protection.

7.1.2 Ground faults

It is desirable to have at least one fault detecting device operate for any phase-to-ground fault on the distribution line. However, it is not always possible to accomplish this because the amount of resistance in the fault can range from zero to infinity as discussed in Subclause 4.1.2 (High Impedance Faults).

Ground fault detection practices will vary depending on the type of distribution system ground method that is being used. This section discusses ground fault detection on multi-grounded, uni-grounded, impedance-grounded, and reactive-grounded distribution systems. Ground fault detection on resonant grounded and ungrounded systems is discussed in Clause 8.13 and Clause 8.14, respectively. See Subclause 5.1.1 for a discussion on distribution system grounding methods.

On these grounded systems, ground fault protection is provided by overcurrent relays which are connected to measure ground fault current. On wye systems the residual of the current in the neutral and/or phase conductors can be monitored. See Subclause 5.1.3 for a discussion of the various types of neutral and residual relay CT connections used for measuring ground current.

On single point grounded wye systems the earth return for the ground fault current will significantly attenuate the fault current if the fault is any significant distance away from the ground reference. On single point grounded systems with loads connected phase–to-phase or phase-to-insulated neutral, overcurrent relays monitoring the ground fault current can be set rather sensitively.

On multi-grounded wye systems, which are most common in North America, a neutral wire is run along with the phase wires and the neutral is connected to ground at multiple locations along the line as well as at the wye neutral reference at the source. With this type of grounded system, the magnitude of the ground fault currents can be greater but load can still be connected between phases or between the phases and neutral. However any unbalance in the loading of the three phases will appear in the neutral even if the loading on the three phases were balanced, due to hourly and seasonal variations in the load. So, there will be some unbalance load current. Therefore the neutral overcurrent relay is normally set above the maximum unbalance load current including unbalanced cold load pickup current or unbalance following the operation of a downstream single phase overcurrent protection device.

Sometimes it is difficult to set the ground overcurrent relay low enough to detect all ground faults (in particular high impedance faults) while also being high enough to prevent tripping on unbalance load currents. Ground overcurrent protection is set to at detect all zero fault resistance phase-to-ground faults with additional margin added to account for fault impedances. A number of different practices are used to determine minimum ground fault settings that will allow for fault impedance. Some of these practices are noted as follows:

— Select a percent value of the bolted single phase-to-ground fault at the end of the protected area.
— Use an established value for Zf (fault impedance) added at the end of the protected area.
— Use a Zf value that provides a minimum fault current equal to the continuous current carrying capability of the conductor. However, fault currents below the thermal limit of the conductor may not be detected.
— Use a percent of three-phase fault currents.

The establishment of a maximum clearing time for ground faults with zero fault resistance (bolted faults) is desirable. Since the protective devices used on most distribution lines have an inverse time-type characteristic, the operating time for a fault with current near the pickup of the device will be very long. By establishing a maximum time for clearing the most remote bolted fault, coverage is enhanced for some higher resistance faults.

7.1.3 Transformer magnetizing inrush

The effects of transformer magnetizing inrush current are considered when applying phase and ground inverse time and instantaneous overcurrent protection [B70] [B71]. The magnitude of this current is dependent on several factors such as the rating of the transformer, the strength of the source at the transformer location, transformer residual magnetism or remnant flux, transformer core characteristics and the energizing voltage phase angle – energizing a transformer with maximum remnant flux at a zero-degree voltage phase angle induces the highest inrush current.

Magnetizing inrush current is not a symmetrical phenomenon and the inrush waveforms for each phase of a three-phase transformer are very different when energized three-phase. When this occurs, it is likely that a single-phase (wye primary) or phase-to-phase (delta primary) voltage will be near a zero crossing when the transformer is energized potentially causing a large inrush current on one (wye primary) or two phases (delta primary).

Transformer inrush current contains several harmonics with the second harmonic the highest. The duration of this inrush is dependent on the system and the transformer size with high-efficiency transformers having higher inrush currents. The manufacturer of a high-efficiency transformer is a great source of information related to their inrush current values.

Magnetizing inrush current does not generally present a problem when coordinating slower inverse time-overcurrent relays with transformer fuses. However, the minimum response times of fast curves (fuse savings) and instantaneous overcurrent TCCs can be quick enough to be triggered by transformer inrush current. Therefore when analyzing feeder coordination, transformer inrush is considered and plotted as points at 0.1 and 0.01 seconds on TCC coordination plots. Most modern coordination software allows these inrush points to be added to the TCC coordination plots for analysis.

Conservative factors of 12 times (0.1 seconds) and 25 times (0.01 seconds) transformer rated current are often used to approximate the maximum RMS equivalent magnetizing inrush current points for small single-phase transformers (≤ 200 kVA). Conservative factors of <9 times (0.1 seconds) and ≤12 times (0.01 seconds) transformer rated current are frequently used for larger three-phase transformers (≥ 4 MVA). Because of the voltage drop across the source impedance during inrush periods, inrush current factors can be reduced when a transformer is supplied from a weak source versus a strong source [B71].

For proper coordination the overcurrent protection minimum response times plot above or to the right of these 0.1 and 0.01 second inrush factor points. To illustrate this principle a sample feeder is shown in Figure 40 with a single three-phase, wye-wye, 2 MVA load transformer connected to a 12.47 kV line that has an aggregate distributed load of 5 MVA produced by small single-phase transformers.

The substation recloser "R" control is set to pick up for phase faults above 650 A which is about twice the rated full load current of the feeder. The 2 MVA three-phase transformer is located near a strong source (the substation) and will use RMS equivalent magnetizing inrush current factors of 12 times (1111 A) and 25 times (2315 A) full load current at 0.1 seconds 0.01 seconds respectively.

The 0.1- and 0.01-second inrush factors for the 5 MVA aggregate of small single-phase transformer load will use 5 times (1157 A) and 10 times (2315 A) full load current respectively. These reduced inrush factors of 5 and 10 times full load current are chosen because the small single-phase transformers are uniformly distributed along the length of the feeder – shorter feeders would have higher inrush factors and longer feeders would have lower inrush factors.

The sum of the 2 MVA three-phase transformer and 5 MVA of aggregate small single-phase transformer inrush current factors are plotted at 0.1 seconds (2268 A) and 0.01 seconds (4630 A) on a TCC coordination plot. The recloser overcurrent protection minimum responses are then plotted to determine if their operation is likely during transformer inrush conditions.

Referring to the coordination curve plot in Figure 41, the sum of the 2 MVA and 5 MVA full load current factor point at 0.1 seconds indicates the recloser "FAST CURVE 1" will trip on transformer inrush. This is likely to occur if one phase of recloser "R" closed near a voltage zero and the transformer cores on that phase had appreciable remnant flux. Figure 42 shows the minimum response of a "FAST CURVE 2" plots above the inrush points at both 0.1 and 0.01 seconds preventing the recloser from tripping on transformer inrush.

The use of second harmonic current restraint can help prevent protection responses when their minimum response TCC plots below or to the left of these inrush points. Another method to avoid tripping on transformer inrush while maintaining sensitive coordination is to momentarily block the use of fast or instantaneous TCCs prior to energizing transformers and rely on slower TCCs during this blocking interval.

With the increased use of numerical relays and recloser controls, the response to magnetizing inrush harmonic current can vary between devices due to current signal filtering, percent harmonic restraint and internal processing of the fundamental and harmonic current components. Ensuring that overcurrent protection minimum responses plot above or to the right of conservative RMS equivalent magnetizing inrush factors at 0.1 and 0.01 seconds help prevent unintended relay operation on transformer inrush regardless of the relay or recloser control design.

Feeder full load current $= 7000\ \text{kVA} \div \left(\sqrt{3} \times 12.47\text{kV}\right) = 324\text{A}$

Set "R" phase pickup to 2 × full load current = 2 × 324 A ≈ 650 A.

$$\text{5 MVA aggregate inrush } (0.1\ \text{s}) = 5000\ \text{kVA} \div \left(\sqrt{3} \times 12.47\text{kV}\right) \times 5 = 1157\text{A}$$

$$\text{5 MVA aggregate inrush } (0.01\ \text{s}) = 5000\ \text{kVA} \div \left(\sqrt{3} \times 12.47\text{kV}\right) \times 10 = 2315\text{A}$$

$$\text{2 MVA inrush } (0.1\ \text{s}) = 2000\ \text{kVA} \div \left(\sqrt{3} \times 12.47\text{kV}\right) \times 12 = 1111\text{A}$$

$$\text{2 MVA inrush } (0.01\ \text{s}) = 2000\ \text{kVA} \div \left(\sqrt{3} \times 12.47\text{kV}\right) \times 25 = 2315\text{A}$$

$$\text{Total inrush at 0.1 seconds} = 1157\text{A} + 1111\text{A} = 2268\text{A}$$

$$\text{Total inrush at 0.01 seconds} = 2315\text{A} + 2315\text{A} = 4630\text{A}$$

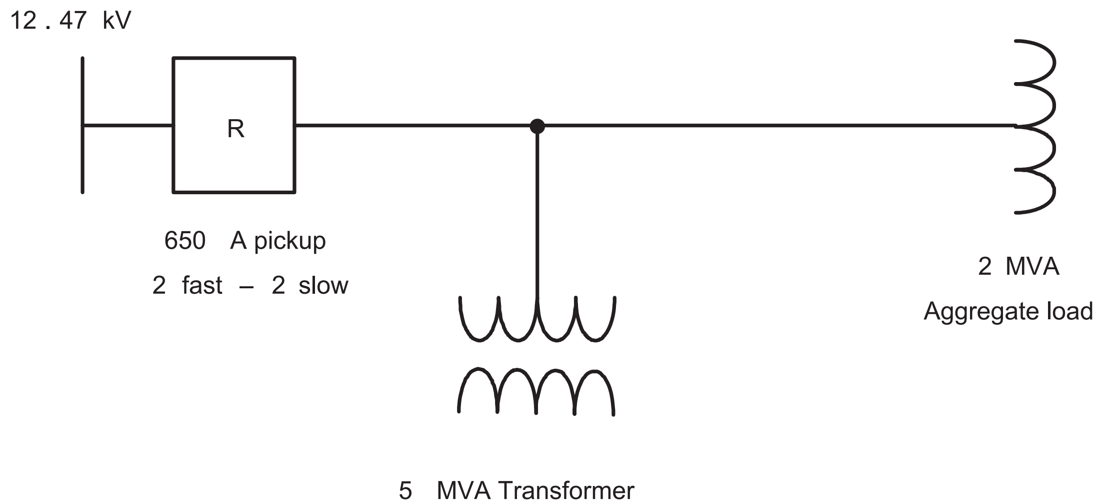


Figure 40—Sample distribution feeder with large transformer

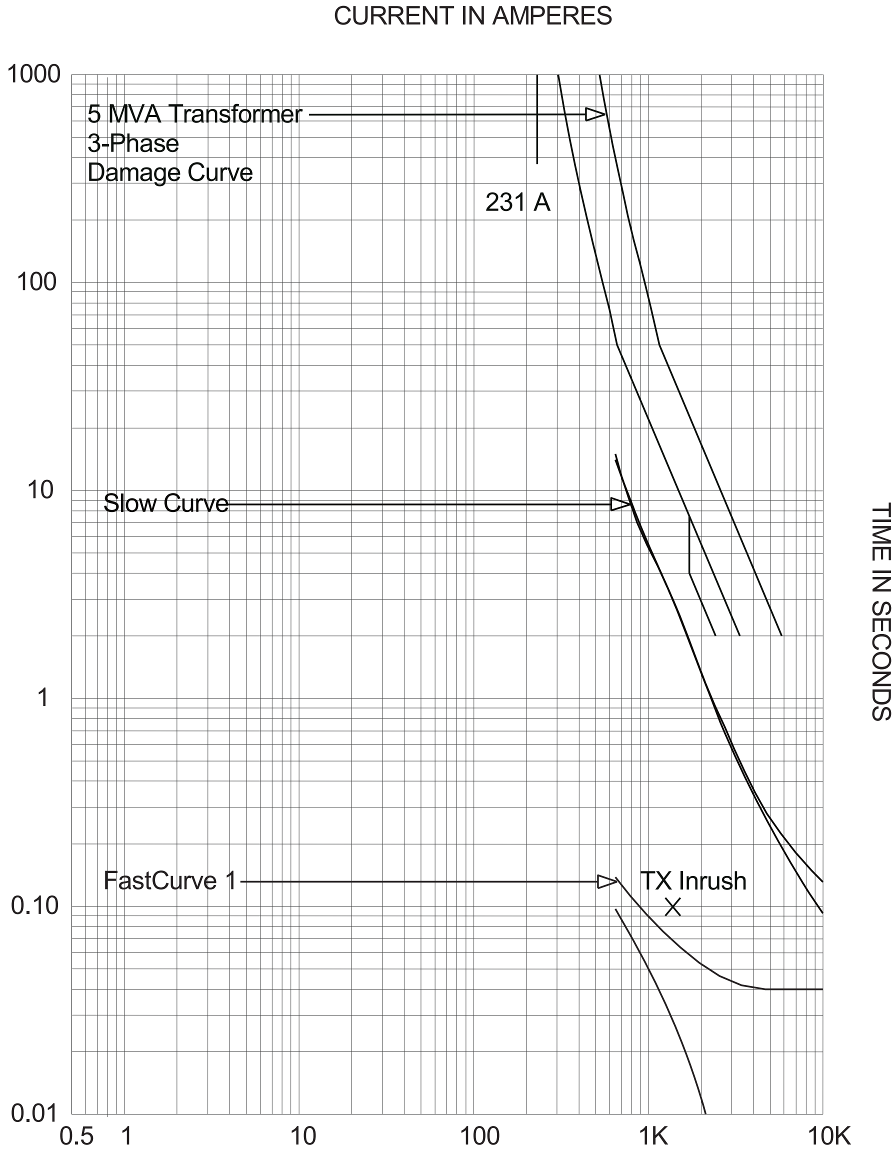
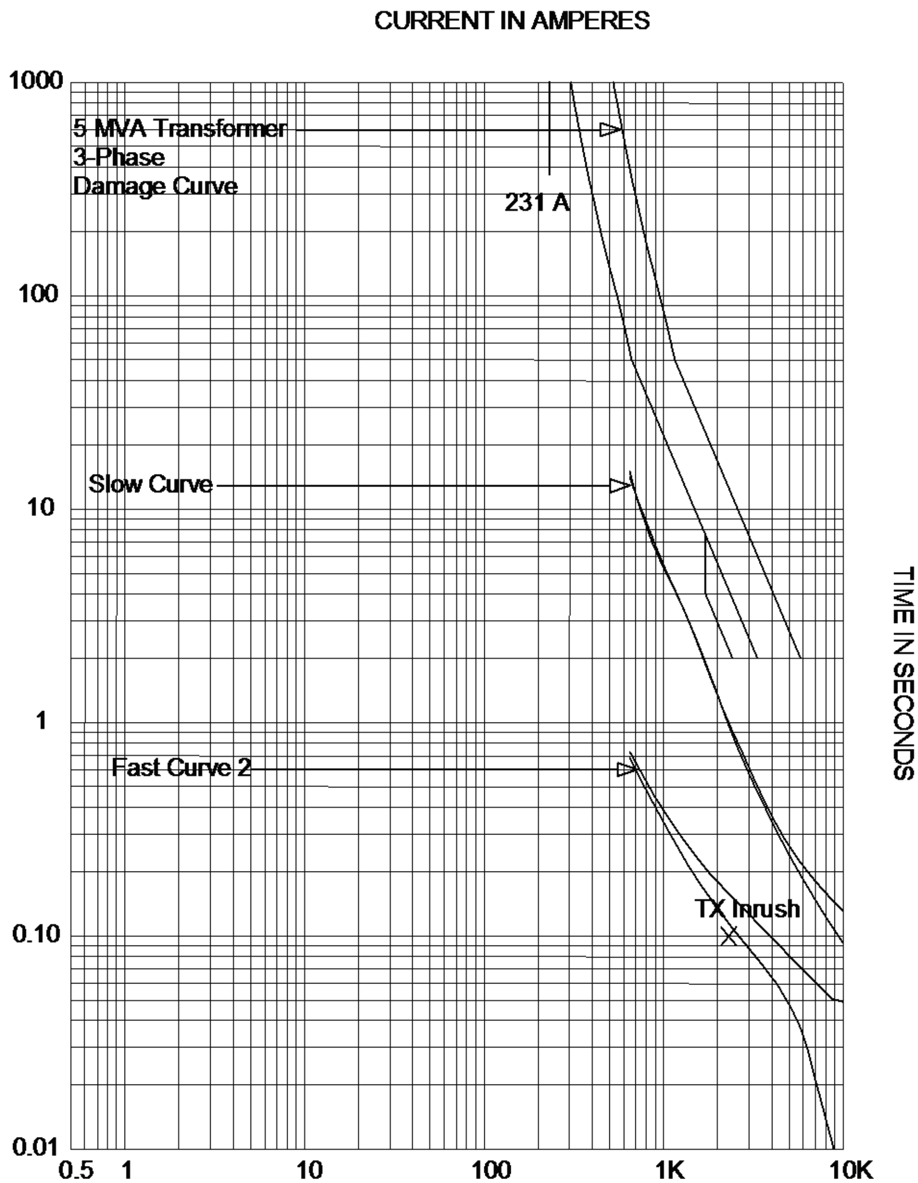


Figure 41—Coordination with large transformer with possible trip on inrush point at 1389 A



1
2 **Figure 42—Coordination with large transformer with minimal possibility**
3 **of trip on inrush point at 2315 A**
4
5
6
7
8

7.2 Coordination

Time-current coordination allows the closest overcurrent protective device(s) to the faulted component to isolate the fault. This ensures that the faulted component is isolated and minimizes the effect of the outage.

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 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 substation feeder protection device. The distribution system most often will not be a single line but a series of line branches that has a structure resembling a tree. Because of this structure, it is typical that the same size conductors will not be used throughout the distribution system. To minimize the amount of customers disconnected for a fault, fault-interrupting devices can be installed at the branching locations.

Often one or more in series protection devices will have sufficient sensitivity to detect each fault. By delaying the device closer to the source, the more remote device closest to the fault can time out and clear the fault before the upstream device operates. In this type of arrangement, the device closer to the source will function as back up in the event of failure of the remote device.

Most of the devices applied to protect distribution lines have inverse time-current characteristics. The larger the magnitude of current above the pickup value of the device, the sooner the device will time out and trigger the interruption of the current. 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 devices during a fault condition. By comparing the response of the devices for the same fault condition, one can determine if the desired coordination will occur. For proper coordination, the remote device detects and clears 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.

One method of coordinating inverse time-current protection elements relies upon plotting the single, nominal, time-current characteristic (TCC) curves of series devices and ensuring they are minimally separated by a Coordinating Time Interval (CTI) time-value. CTI values are frequently based on historical coordination experiences and will often be uniform when coordinating protection elements of like manufacture, i.e., electromechanical vs microprocessor.

CTI time-values are traditionally determined by first accounting for the time-response effects resulting from the sum of the maximum current sensing, current measurement and time-response tolerances of the downstream device plus its maximum total fault clearing time. The time-response effects of the upstream device's minimum current sensing, current measurement and time-response tolerances are then added to the maximum time-response tolerances of the downstream device. Occasionally, some users will add additional time margin to the maximum (downstream) and minimum (upstream) time-response tolerances for additional coordination security.

Figure 43 shows the coordination between three devices using the CTI method where 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. A CTI is maintained between the total clear of the line fuse and the line recloser's nominal TCC for a fault at location 1 and a CTI is maintained between the line recloser's nominal TCC and the relay's nominal TCC for a fault at location 2.

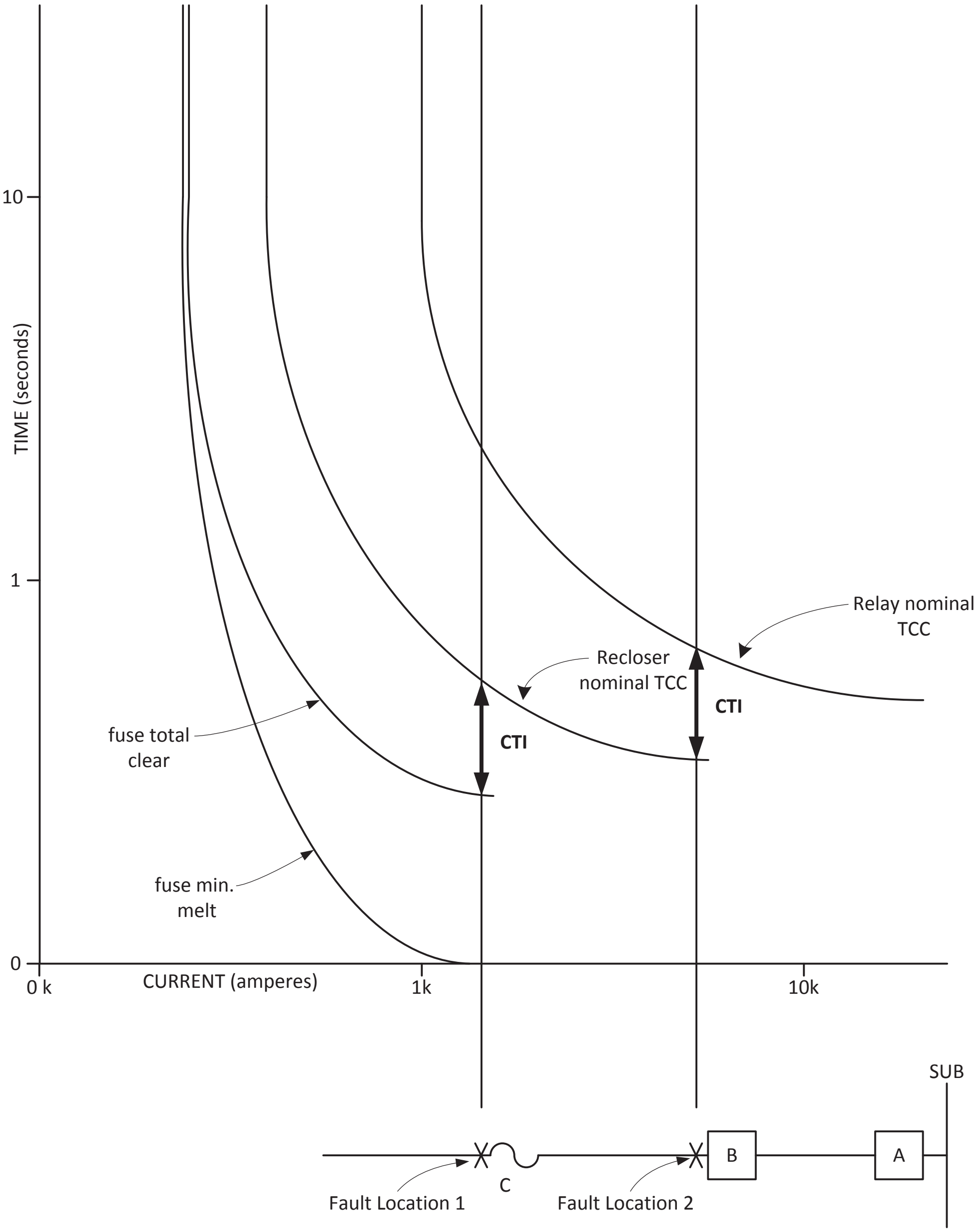


Figure 43—Coordination using a Coordination Time Interval (CTI)

Another approach to coordinating series inverse time-current protection elements is to develop minimum and maximum time-current response curves or bands for each series device. Much like the CTI method, these time-response bands account for the effects of the minimum and maximum primary current sensing (CT) error, the overcurrent element's minimum and maximum current measurement and time-response tolerances, and includes the total fault-clearing time of the associated fault-interrupter. After these time-current tolerance-response bands are developed for each series device, coordination is achieved by simply ensuring these bands don't touch one another for an appropriate level of fault current.

Figure 44 shows the coordination between three devices using minimum and maximum time-current response curves where 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. Coordination is achieved as long as the maximum response curve of the downstream device does not cross the minimum response curve of the upstream device. An additional time margin between the bands may also be considered for additional coordination security.

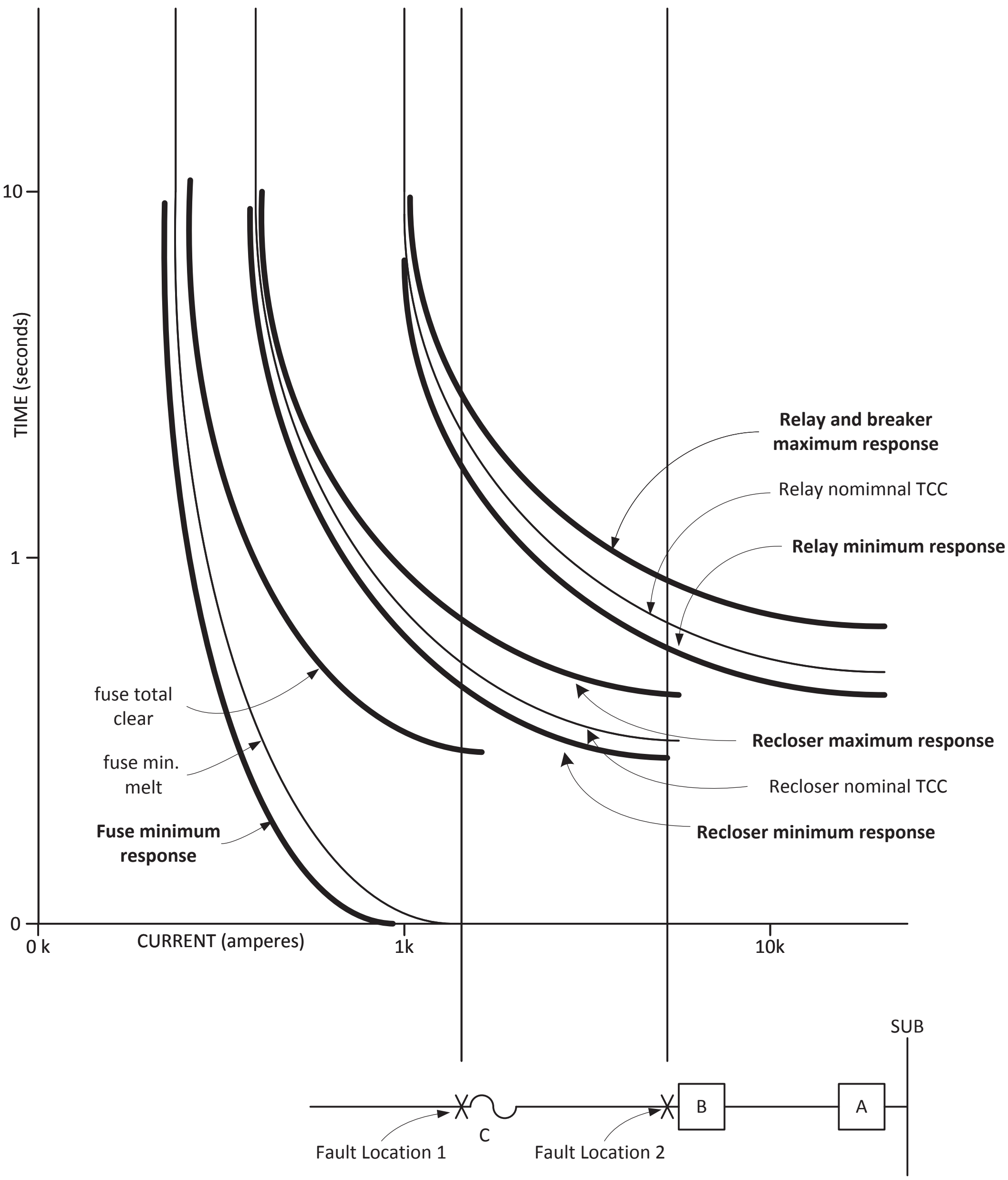


Figure 44—Coordination using Coordination response bands

If a device with an extremely inverse characteristic is being coordinated with a device with an inverse characteristic, it is possible that the time-current response curves will cross at some current value. This type of coordination is shown on Figure 45. The area circled appears to be a miscoordination between the fuse and the recloser. If this area of apparent miscoordination occurs at a fault current that is below the minimum expected fault current (i.e. the minimum fault current required to obtain the desired fault sensitivity) the apparent miscoordination is tolerated.

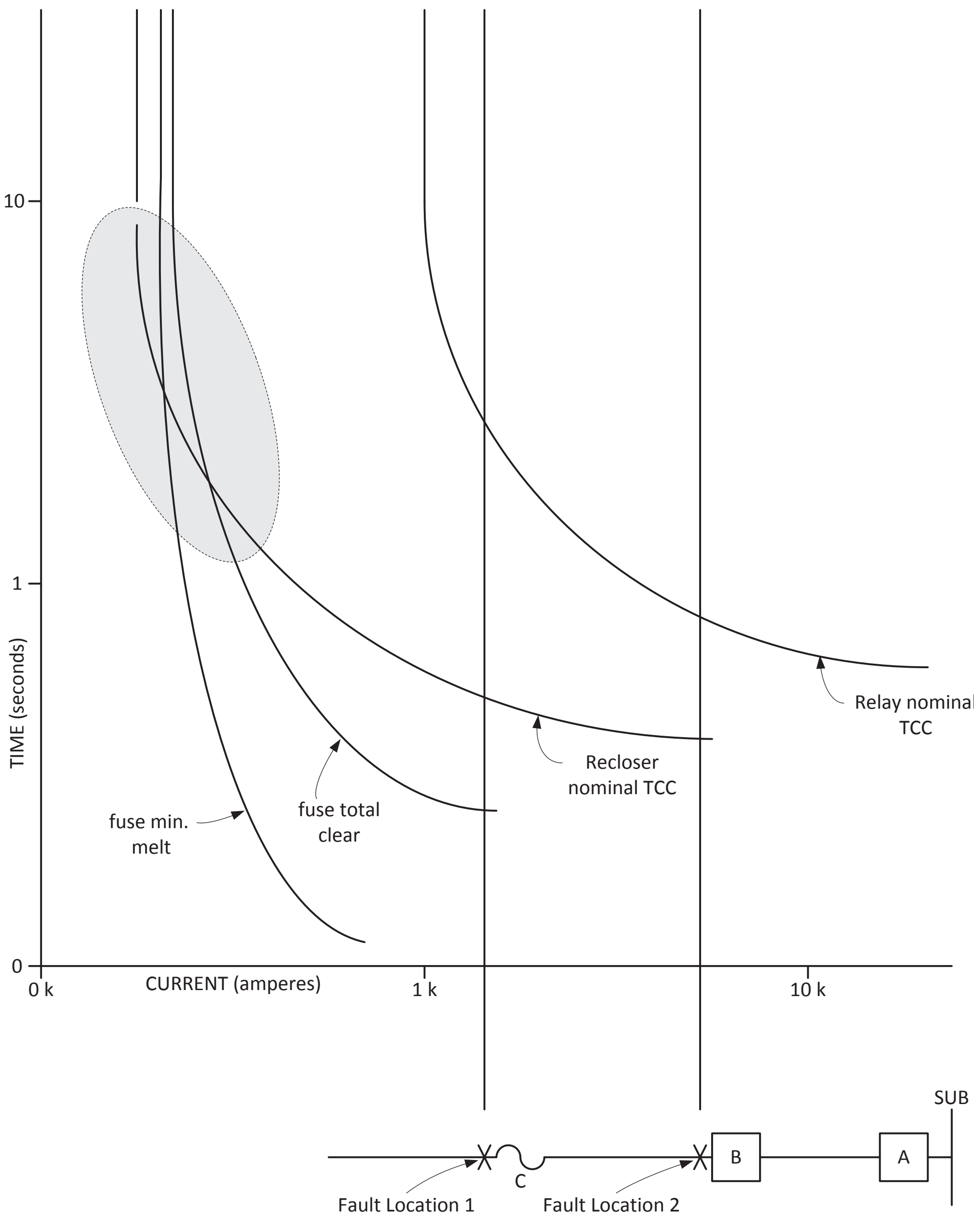


Figure 45—Coordination between an inverse and extremely inverse device

When coordinating overcurrent devices for phase-to-ground faults, both the phase and the ground elements of the protection device are included in the coordination as both elements detect and respond to the currents. 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 characteristic is the faster of the two responses at each current level. Figure 46 demonstrates how both phase and ground elements are involved in the total response for both the relay and the recloser. The composite responses for both the relay and the recloser are marked on the diagram. All three phase elements and the ground element are be used when considering a composite response characteristic curve.

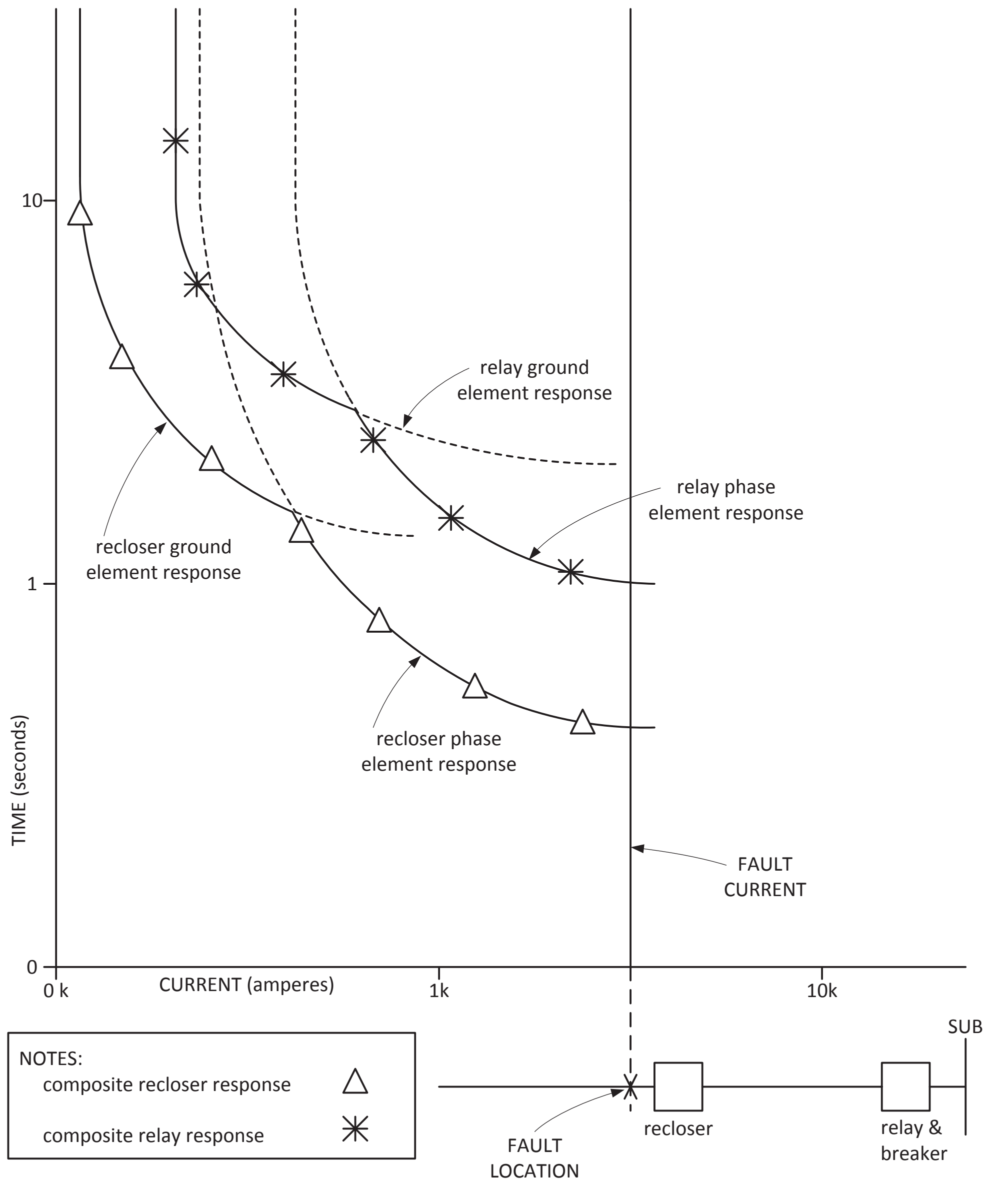


Figure 46—Coordination for phase-to-ground faults

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 detect 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 overcurrent protection will detect only the positive- and negative-sequence current for a phase-to-ground fault on the feeder. For the same phase-to-ground fault, the feeder relay will detect the total of the positive-, negative-, and zero-sequence current on the bases of the low side voltage. To coordinate these two overcurrent protection devices for ground faults requires comparing response times of the two devices for the magnitude of current each will detect for the same fault case. It is a common practice to draw the response characteristic of both devices on the same voltage base, normally the feeder relay's base. This makes it easier to visualize the coordination. The transformer overcurrent device's response is shifted by the ratio of the amounts of current the two devices detect for the same fault.

For example, for a 138 kV delta − 12.5 kV neutral grounded-wye transformer, for a single phase-to-ground fault on the 12.5 kV feeder, $I_a = 9000$ A.

The sequence currents on the 12.5 kV side are $I_1 = I_2 = I_0 = 3000$ A.

The sequence currents on the 138 kV side are:

$I_1 = 12.5\ (3000)\ /\ 138 \angle 30°$

$I_1 = 271.7 \angle 30°$

$I_2 = 12.5\ (3000)\ /\ 138 \angle -30°$

$I_2 = 271.7 \angle -30°$

$I_0 = 0$

$I_a = 2\ (\cos 30°)\ 271.7$

$I_a = 470.6$ A

The ratio between the 12.5 kV phase current to the 138 kV phase current is 9000/470.6 or 19.12. A relay with a pickup of 100 A on the 138 kV side would have the equivalent pickup as phase overcurrent relay on the 12.5 kV side with a 1912 A pickup.

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 detect compared to the current the transformer high side phase overcurrent device will detect is smallest for this fault condition. For the phase-to-phase fault, two phases on the 12.5 kV side will detect 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 detect the same magnitude current as for the three-phase fault [B34]. This is accounted for by shifting the transformer's high side overcurrent device's TCC by 87% of the transformer's turns ratio. If the phase overcurrent relays coordinate for the phase-to-phase fault on the feeder, the relays will coordinate for all fault conditions.

7.2.1 Different reset characteristics

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 current is increased above the pickup value before the relay has reset or the fuse has cooled to the initial state, the overcurrent devices have a precondition 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.

Other overcurrent devices such as electronic and microprocessor relays have the option of an instantaneous reset. Once the current has dropped below the pickup level, they will reset, regardless of how long the overcurrent device has been timing. Microprocessor relays also have the option of having different reset times which can simulate the reset timing characteristics of the EM relay. This is important for nuisance intermittent faults and can also provide additional tools to the relay setter.

A difference in reset characteristics can help some coordination situations and cause problems for others. For two overcurrent devices operating in series on a system, if the device closest to the fault location has a time delay reset and the device closest to the source has an instantaneous reset, the difference in the reset methods will not affect the coordination between the two devices. If the reclosing device closer to the source has a time delay reset and the device closer to the fault has an instantaneous reset, the reclosing sequence may result in unnecessary lockout of the reclosing device closer to the source. For this condition, any of the following may be done: 1) change the reset characteristic of the device closest to the fault to match the reset characteristic of the backup device; 2) increase the coordination time between the devices to compensate for the ratcheting action of the backup device; 3) increase the dead time between reclose attempts to allow the overcurrent devices to fully reset.

7.2.2 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 faulted phases' voltages are depressed at the source substation bus. In addition to this magnitude change, the faulted phases' voltage phasors swing to a different phase angle relationship compared to the pre-fault voltage phasors.

As the bus voltages are restored to nominal magnitudes and expected phase angles after the fault is cleared, 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.

7.2.3 Automatic recovery from intentional miscoordination

The fault testing method described in Subclause 5.4.2.3 and could be used to increase feeder fault-sectionalizing by allowing the addition of more series fault-interrupters. Historically, the number of conventional fault-interrupters or reclosers connected in series on a feeder is limited by their response times (minimum pick-up and total-fault-clear) plus the Coordinating Time Interval (CTI). By accounting for response times and choosing an appropriate CTI, a fault at the end of the feeder results in the fault-interrupter or recloser closest to the fault clearing the fault before any upstream devices begins to respond. As the number of series fault-interrupters increases, the time available to ensure the furthest downstream fault-interrupting device detects and clears the fault before the next upstream device begins to respond, diminishes to the point conventional coordination cannot be achieved.

If miscoordination occurs between or among conventional series reclosers, multiple reclosers trip in response to the fault and subsequently reclose sequentially. If the fault is permanent, eventually, the miscoordinated recloser closest to the source locks out, and all downstream reclosers and loads remain de-energized.

Fault testing allows for intentional miscoordination between series fault interrupters since fault testing operations for permanent or temporary faults are undetected by upstream protection. Therefore the protection in any number of series fault-interrupters can be set the same or marginally faster than their upstream neighbor.

This results in multiple series fault-interrupters responding to a fault and tripping or opening. Once tripped, the fault-interrupter closest to the source has power and three-phase voltage; fault testing detects no fault, as the downstream devices are open, and recloses. The next downstream and open device repeats this process with the same success, until the fault-interrupter closest to the fault senses the fault and remains open.

At this point, if the fault is still present, this last device remains open as fault testing has determined the fault is still present without initiating the previous miscoordination caused by the initial fault. Subsequent fault-testing by this last device, and closest to the fault, results in the same outcome as the initial restorative reclosing operations – all upstream devices remain closed serving their respective loads.

Intentionally miscoordinating series fault-interrupters will cause more temporary outages than fully coordinating series fault interrupters

7.3 Clearing time

Fault-interrupting devices located in the substation and out along the distribution line generally are coordinated to minimize the number of customers that will be disconnected due to faults occurring on the line. The coordination process frequently entails adjusting the fault clearing times of 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.

7.4 Reclosing

After tripping in response to a fault, a reclosing relay or controller automatically closes the interrupting device based on a predetermined sequence. 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 deenergizing the faults long enough to allow the fault arc to deionize. Reclosing elements automatically reclose the feeder breakers to attempt to restore the feeder after these temporary faults.

Reclosing is almost universally applied on overhead distribution feeder breakers, and often applied on circuits with some underground sections. Reclosing is generally not applied on feeders with no overhead exposure, because faults on underground feeders are generally permanent. The reclosing function may be implemented as part of a numeric relay system, or as a separate relay with inputs from the fault detecting/tripping relays.

Reclosing relays (or relay elements) will initiate a sequence of between one and four close attempts with settable time delays between operations. If the fault remains throughout the reclosing sequence, the reclosing relay will go to the lockout state, and block further closing attempts. If, however, any reclose attempt is successful (temporary fault is cleared), the reclosing relay will return to its initial state, after a reset time.

Issues relating to autoreclosing are discussed below. A more detailed discussion of autoreclosing issues can be found in IEEE Std C37.104™ [B36].

7.4.1 Reclosing initiation

A reclosing attempt is generally initiated when the breaker or recloser has opened due to a fault on the protected feeder by either using: an open breaker status or a Reclose Initiate signal from the fault tripping relay or element. If using a Reclose Initiate signal, the reclosing relay or element will look for an open breaker status (often detected with a breaker status contact, such as 52b) in concert with the Reclose Initiate signal. Manual trips, either local or remote, are purposeful and thus, do not typically initiate reclosing attempts. When using breaker status to initiate reclose, contacts from the control switch or remote supervisory control can be used in the reclose path to prevent reclose attempts after manual or supervisory trips. More complex protective schemes may prevent reclosing for certain tripping conditions, such as a high-set instantaneous overcurrent trip, an underfrequency load shedding trip, a multi-phase fault trip, or a trip on an underground cable circuit.

7.4.2 Open interval and number of attempts

Reclosing schemes will usually incorporate several reclosing attempts, with time delays between attempts. The speed and number of reclosers is determined by individual utilities. Some utilities may use one fast and one or two time delayed attempts. The first reclose attempt may have no intentional time delay or have a small (<5 s) time delay. The first reclose open time, combined with the device operating time allows enough time for the arc to deionize. If there is DER downstream of the reclosing device, then having the first open interval long enough to allow the DERs to disconnect from the system allows the feeder reclosing to restore the line. Subsequent reclosing attempts may have longer delays, perhaps 15 s to 30 s.

7.4.3 Reclosing with low magnitude faults

Low magnitude faults may have fault clearing times longer than the reset time of the reclosing relay. This can lead to unlimited reclose attempts for a permanent fault, as the reclosing relay never reaches lockout. This situation can be addressed by applying a reset wait function. The reset wait function will stop the reset timer when a protective element is picked-up and timing towards trip. This will prevent the undesired reset during a fault sequence, without forcing unreasonably long reset times. Another method is to enable the fast tripping overcurrent functions, in a fuse saving scheme, just before resetting of the reclosing function.

7.4.4 Sequence Coordination

Where two or more reclosing devices are applied in series on a distribution feeder, the upstream device's overcurrent elements may overreach for faults beyond the downstream device. This is particularly true when both devices have fuse savings applied since the upstream devices fast (fuse savings) TCC curve will typically not coordinate with the downstream devices delayed TCC curve. Sequence coordination in the upstream device moves the autoreclosing sequence forward whenever a fault is detected by protective element pickup followed by its dropout before reaching its response characteristic. This operation signifies that a downstream device has operated to clear the fault. The upstream device does not trip but instead advances its sequence to remain in step with the downstream device. Sequence coordination will continue to advance the sequence up to the programmed limit if the reset time delay has not expired.

7.4.5 Adaptive reclosing

A majority of distribution line faults are temporary in nature. Adaptive reclosing methods only attempt reclosing in the absence of a fault or when there is a high probability of success. Adaptive reclosing methods also minimize stress on the distribution system by not reclosing on to a fault.

One adaptive reclosing is the fault-testing methodology described in Subclause 5.4.2.3. Unlike conventional reclosing, which relies on the available energy of the system to test for the continued presence of faults after the initial fault-detection and tripping, fault testing produces ¼ to ½ cycle minor-loops of current which are analyzed to determine if the fault is still present or not.

When the fault is still present, reclosing depends upon subsequent fault-detection and single-phase or three-phase tripping to reopen the fault-interrupter after it is automatically reclosed. Alternatively, fault testing is first performed on the phase with the highest recorded fault-current associated with the initial fault-detection and tripping. If the first phase is fault tested and the results indicate the fault is still present, reclosing is suspended and a subsequent fault testing is performed after a predetermined time interval has elapsed just as with conventional reclosing.

If the first phase is fault tested and no fault is detected, this phase is reclosed and the phase with the next highest recorded fault current is fault tested. In the event the initial fault was phase-to-phase, fault testing of the second phase would return a fault result, remain open, and the first phase that was reclosed would be reopened.

A temporary fault that subsequently clears, results in all phases closing phase-by-phase. Reclosing each phase after a no-fault declaration occurs before fault testing the subsequent phase.

In the event fuse saving is practiced, and a fuse has been prevented from operating in response to a downstream fault, fault testing will continue to detect the presence of this fault without the fuse responding. Consequently, as the resulting fault testing energy is incapable of causing fuse operation, one of the fault-testing sequences (prior to reaching lockout) will require a conventional closing operation to permit fuse operation.

Another adaptive reclosing technique involves the installation of remote fault sensors on underground sections of distribution lines which communicate with the upstream relay or recloser. These remote sensors send a signal to the upstream relay or recloser to block automatic reclosing for faults on underground lines (since faults on underground lines are normally permanent). As discussed in Subclause 6.2.2, the fast fuse saving tripping response is blocked (if used) if that underground section is also protected by fuses. Details on how the fault sensors communicate with the upstream relay or recloser is outside the scope of this guide.

7.5 Cold load pickup

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 reenergized, all (or most) of these loads will be switched on. This can cause a significant surge in load current, which may be in excess of time overcurrent pickup levels. This condition is known as cold load pickup. The additional load will decay over a comparatively long time (by relaying standards), perhaps 30 min or more.

Figure 47 shows a generic representation on a cold load pickup event. The pre-outage load current on the feeder is around 30% of the pickup level of the associated overcurrent relay. At 15 min into the chart, a load interruption occurs, and the load current drops to zero. In this example, the outage lasts 25 min, during which some degree of load diversity is lost. When the circuit is restored, at 40 min into the chart, there will be a current surge. The initial inrush current will include the starting current for all of the connected motors. This initial inrush may only last a few seconds, and is not visible in Figure 47. After the initial inrush period, the feeder will be more heavily loaded, as a larger than normal percentage of the cyclical loads will be on. Over some time period, the load diversity is regained, and the load will decline back towards the normal load level. The rate at which load diversity is lost, and regained, depends on a variety of factors, including ambient temperature and insulation ratings of buildings with heating or cooling loads.

Distribution relay schemes take cold load surges into consideration in order to prevent tripping due to load. The simplest method would be to set overcurrent pickups above the worst case cold load current, to ensure security. However, this decreases sensitivity and may limit the ability to detect end-of-zone faults. Alternately, the feeder can be segmented, to pick up load in portions. This allows the overcurrent relays to be set sensitively, but extends outages.

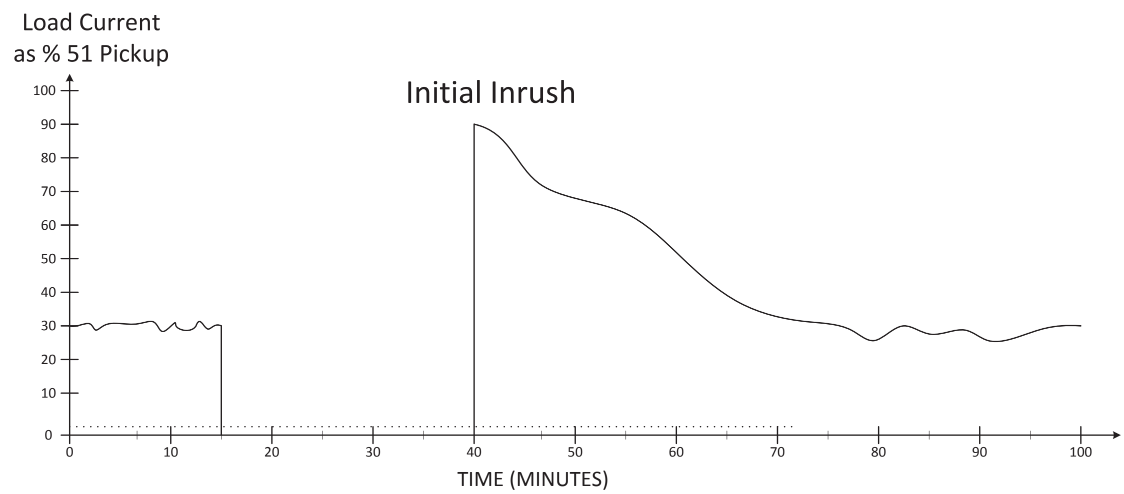


Figure 47—Cold load pickup

Microprocessor-based relay schemes can use adaptive capabilities to prevent unnecessary trips as the result of cold load surges. The dropout, or de-assertion, of a load detecting overcurrent element in the relaying scheme in conjunction with the substation breaker, can be used to signal the absence of load current in a distribution feeder's circuit breaker. The loss of load condition could be used to insert, or lengthen, a time delay to operation of the sensitive overcurrent element. It may be preferable to have the adaptive scheme execute a settings change that will decrease the sensitivity of the element of concern. This allows more sensitive overcurrent settings during low load conditions, while allowing security for cold load situations.

An IEEE report on cold load pickup Issues [B55] provides additional discussion on cold load pickup causes, levels, durations, and protection system application considerations.

8. Special applications

8.1 Simultaneous or Inter-circuit Feeder Faults

System configurations are such that multiple feeder breakers are served from a single point source. In some instances, the distribution circuits are on the same structure and/or in close proximity with each other due to normally opened connecting air switches. When the actual facilities are configured in this manner, the probability of multiple circuits being involved in a single event can be relatively high. This is especially true if instantaneous relaying is not applied. In addition, the probability of multiple circuits being involved in nearly simultaneous events increases during major wind, lightning, or ice storms.

In these situations the fault may begin on one circuit and evolve to the other circuit or it may simultaneously involve both circuits. The single point source detects the entire fault current for the entire duration. Each feeder breaker only detects a portion of the fault current only for the time that the particular feeder breaker is closed. Figure 48 illustrates this type of situation. The entire fault current (I_f) is detected by Circuit Breaker 1 (CB1) while only a portion of the current is detected by each feeder. To ensure proper coordination, either a sufficient coordination margin is obtained or a protection scheme integrating the bus and feeder relays is employed.

One method to accomplish proper coordination is to design the relay system such that the single point source relaying is integrated with the feeder breaker relaying. For instance, any time more than one feeder breaker relay is above a pickup current level, enabling or disabling of certain selected source relay elements can be employed or the source relaying could be prevented from operating.

Additionally, it is important that the reset characteristics of the relays associated with CB1 be quicker than that of the relays associated with the other breakers shown on the one-line. This is true of both electromechanical and solid state relays. If the reset characteristic of the relays associated with CB1 is slower than that of the relays associated with the other breakers on the one-line, there is a higher probability of miscoordination due to multiple faults.

Another method to reduce the likelihood of the CB1 relay misoperation due to multiple faults is to delay the automatic reclosing on breakers FDR1, FDR2, FDR3, and FDR4. This delayed reclose often will allow the relays associated with CB1 an opportunity to reset prior to the feeder breaker closing into a fault.

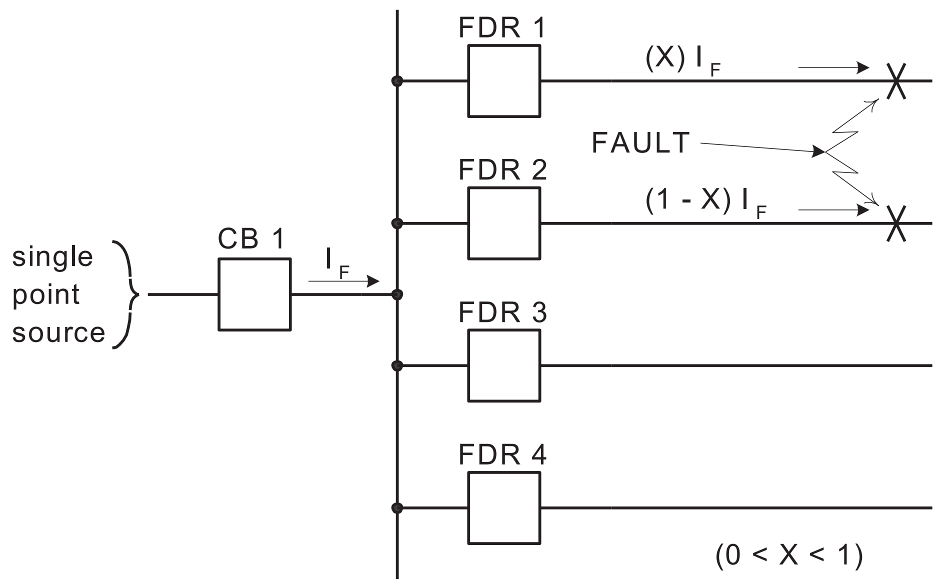


Figure 48—Faults involving two circuits

8.2 Loop Schemes

A loop scheme is a method that is used by utilities to improve system reliability. A loop scheme is applied on two distribution circuits by installing normally closed sectionalizing reclosers (LS) on each circuit and a normally open tie recloser (TS) at a tie point between the two circuits as shown in Figure 49.

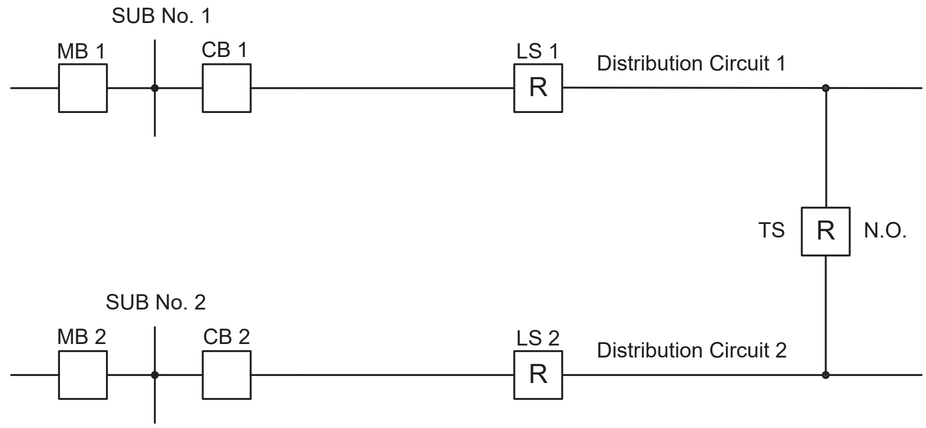


Figure 49—Loop scheme

A simple description of how the loop scheme works is as follows. Assume circuit breaker CB1 opens and locks out for a permanent fault between CB1 and the sectionalizing recloser LS1. The LS1 recloser will detect a loss of three-phase voltage and will open after a time interval greater than the longest CB1 reclose open interval. The tie recloser TS will also detect the loss of voltage on Distribution Circuit 1 and will close after the recloser LS1 open interval and longest LS1 reclose open interval, if Distribution Circuit 2 is energized. This action will automatically restore a portion of Distribution Circuit 1. Note that the protection settings for LS2, CB2, and substation Main Breaker MB2 (if applied) are set to account for the maximum load added when the tie recloser TS closes. Loop schemes can restore even more customers if they are operated in conjunction with sectionalizing switches (SW) as shown in Figure 50.

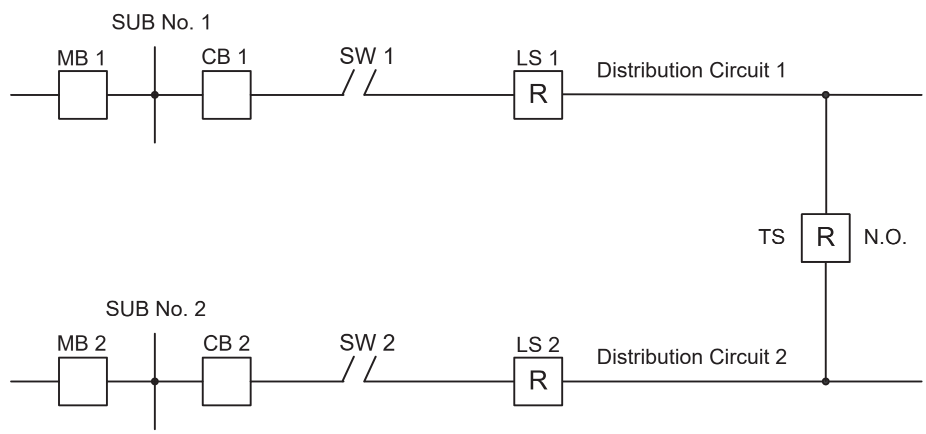


Figure 50—Loop scheme with sectionalizing switches

Loop schemes can be further enhanced for faster operation and more security by adding communications between devices as identified in Section 8.7.3.

8.3 Underfrequency Load shedding

The objective of underfrequency load shedding is to arrest system wide frequency decay after a disturbance to the system such as a loss of a transmission line or generation source. The load shedding is accomplished by applying underfrequency relays at distribution or transmission stations where major load feeders can be controlled by tripping breakers automatically when frequency relays reach the setting threshold.

The predominant system condition addressed here involves the use of protective relays for underfrequency shedding of connected load in the event of insufficient generation or transmission capacity within a power system. When load and supply for an isolated portion of the power system are unequal, the generators in that area will speed up if there is a surplus of generation or slow down if there is a deficit. When the load in a power system significantly exceeds generation, the system can survive only if enough loads are disconnected from the system with a shortage in generation to cause generator output to be equal to or slightly above the connected load. The generation deficiency most often results from the loss of a major transmission line or transformer that is involved in a large transfer of power within the power system or between interconnected systems. Unplanned loss of a major generation source may also cause the deficiency. Frequency is a reliable indicator that such a deficiency condition exists on the power system.

Underfrequency relaying can also be utilized to detect disturbances and separate power systems by opening system ties. This operation requires close coordination between interconnected power systems or undesired system impacts can occur. Similar relaying can be utilized to separate non-utility generation from the utility power system during system disturbances, but is generally used in conjunction with the underfrequency load shedding schemes utilized on the host system.

Manually initiated underfrequency load shedding generally cannot be accomplished fast enough to prevent partial or complete system collapse. Automatic schemes, employing frequency-sensing relays, are therefore employed to shed individual loads or blocks of load at discrete underfrequency set points or at specific frequency rates of decline. In North America, these set points are predetermined based on requirements in NERC's continent-wide and applicable regional reliability standards.

8.3.1 Frequency relays, measuring principles and characteristics

There are three basic types of underfrequency relays available for application in load shedding schemes. They are electromechanical relays, solid-state (or static) relays, and digital (microprocessor) relays.

8.3.1.1.1 Electromechanical relays

Electromechanical underfrequency relays are typically high-speed, induction cup relays. The basic principle of operation is the use of two separate coil circuits that provide increasing phase displacement of the fluxes as the frequency decreases. This flux phase displacement causes torque to be developed in the cup unit, closing the tripping contacts. As the frequency decays, the angular displacement increases, and torque is produced. The strength of the torque produced is proportional to the sine of the angle between the fluxes. Electromechanical relays contain a settable time delay to prevent misoperation when ac input voltage is suddenly applied or removed. A typical minimum delay would be six cycles. Electromechanical underfrequency relays typically contain no intentional undervoltage supervision and will operate at voltages as low as 50% of nominal. Because of the measuring principal employed, the operating time of an electromechanical relay is a function of the rate of change in the measured frequency. As an example, at a −1 Hz/s rate of change the operating time of one manufacturer's relay is 0.65 s, while the operating time at a −2 Hz/s rate of change is 0.40 s.

8.3.1.1.2 Solid-state (static) relays

Like their electromechanical counterparts, solid state over or underfrequency relays are single-phase devices designed to detect underfrequency conditions and, after a preset time delay, provide an output to actuate external control circuits and/or alarms. Major advantages of the solid-state design include the ability to provide multiple over or underfrequency set points, and the incorporation of undervoltage inhibit circuits, which improves overall security of underfrequency load shedding schemes. Also, multiple definite-time delays and/or an inverse-time delay are possible with solid-state designs.

8.3.1.1.3 Microprocessor (digital) relays

The typical digital relay approach is to utilize a microprocessor to measure the period of the measured voltage input. The frequency derived from that period is compared to the frequency limit, and the decision is made to trip when the frequency exceeds the limit for a minimum number of cycles, typically three to six. These relays also provide an undervoltage setting below which the relay will not trip. Redundant measurements may be utilized in certain designs to obtain added security. Because of the measuring principal employed, the operate time of the relay is independent of the rate of change in system frequency.

8.3.2 Operating Principles

8.3.2.1.1 Fixed frequency

Load shedding uses underfrequency relays, designed to operate on the instantaneous value of system frequency. These relays operate any time the frequency drops below the set point of the relay. Operating times of less than six cycles are typically achieved in underfrequency relays. Time delays used in these load shedding schemes may be internal to the relay, or may be an external timer in the control circuit. There are several factors to consider when applying underfrequency relays. The system frequency may already be low before the relay operates. This can delay load shedding and the frequency recovery of the system. Also, voltage waveform distortion may obscure the zero crossings of the waveform, impacting underfrequency relays that operate by measuring the time between zero crossings.

8.3.2.1.2 Rate of change of frequency df/dt

The rate of change of frequency (df/dt) is an instantaneous indicator of power imbalance and is presently used with the frequency function to provide a more selective and/or faster operation. To rely on the rate of change of frequency to detect the megawatt imbalance, additional information (voltage, spinning reserve, total system inertia, load, etc.) about the system is required. Such information may be communicated to the relay or may be available if system separation can be predicted. It is easier to determine system separation for industrial and urban areas where it is simpler to predict development of a disturbance. While the system frequency is a final result of the power deficiency, its rate of change (df/dt) is an instantaneous indicator of power deficiency and can enable incipient recognition of MW imbalance. However, the change in machine speed is oscillatory by nature. These oscillations depend on the response of the generators and differ by location. While load shedding initiated by the frequency drop has a robust response to oscillations, the df/dt function is very sensitive to oscillations.

8.3.3 Setting guidelines for abnormal frequency load shedding

In order to minimize the effects of an underfrequency disturbance on a system, a multi-stage load shedding scheme may be used. To implement a multi-stage underfrequency load shedding scheme, the substation loads can be prioritized and grouped according to their importance and type. Frequency relays can control a single group or multiple groups of loads. During an underfrequency condition, the load groups are disconnected sequentially, depending on the level of underfrequency. The highest priority group is the last one disconnected.

Time delays for load shedding stages should be based on the recommendations of the area coordination council and sufficient to ride-through any transient dips in frequency, as well as to provide time for the load/frequency controls in the system to respond. This requirement should be balanced against the system survival requirement; if the loads are shed with long delays, then system stability may be in jeopardy. Time delay settings range from a few cycles to several seconds, even tens of seconds, depending on the number of load-shedding stages, and the expected rate of frequency decline. The relatively long time delays are intended to provide time for the system controls to respond. This will work well in a situation where the decline of system frequency is slow. For contingencies where rapid decline of frequency is expected, the load shedding scheme mentioned previously could be supplemented by rate of change of frequency monitoring elements or use shorter delay times for each stage. When using rate of change of frequency elements for supervision, the (f + df/dt, frequency with rate of frequency change) element can be used in conjunction with the (f + t, frequency with time delay) element of the stage. An independent frequency setting can be variable for the (f + df/dt) element. This feature can be used to speed up the load shedding even further in severe cases.

In the previously mentioned scheme, the frequency pickup of the (f + df/dt) elements is set a little higher than the frequency pickup of the (f + t) elements. The difference between these pickup frequencies approximately accounts for the measuring time of the relay, assuming a rate of frequency decline equal to that used in the settings. Thus, the stage load may be shed at or just above the frequency pickup setting for the (f + t) element. In this scheme, the slow-decline contingencies and the fast-decline contingencies are independently monitored, and the tripping logic is optimized for each. Since the frequency pickups are independent, it is possible to set the pickup of the (f + t) element somewhat lower, without sacrificing system security.

The (f + df/dt) element may be used in conjunction with the (f + t) element of the stage. The element can be set to measure the rate of change over a short period (as low as one cycle) or a relatively long period (up to 100 cycles). At the lower end, the combined element becomes similar to a rate-of-change monitoring function with a fixed time delay. The fast load shedding decisions in the scheme mentioned previously can be made by monitoring the frequency change over a period of 500 ms. Hence tripping takes place more slowly than in schemes employing the (f+df/dt) element, but the difference is not significant at this setting. If the previously mentioned delay is unacceptable for system stability, then the scheme can be accelerated by using the independent "f" setting of the element.

One of the most common ways of preventing undesirable operation of an underfrequency relay for the loss of the source to the substation where the underfrequency relay is installed is to use an undervoltage inhibit function in the relay. The theory is that when the primary source is lost the voltage will decay below the undervoltage inhibit level before the frequency decays below the underfrequency trip level and the time delay has expired for the trip. With the typical time delays used and a reasonable mixture of resistive and motor loads this solution can work. The higher the setting on the undervoltage element the more secure the underfrequency load shedding relay becomes against undesirable tripping for loss of source. Unfortunately, during system wide disturbances when underfrequency load shedding relays are expected to operate, the system voltage could also be reduced. To prevent blocking of the underfrequency load shedding during system wide disturbances a compromise setting is needed. This is usually possible if a large part of the load connected to the substation is not comprised of motors and that there are no distributed resources connected to lines fed out of the substation. On a system with large motors or distributed resources the voltage may not decay fast enough to block the underfrequency load shedding for the loss of the primary source to the substation. Raising the undervoltage inhibit level could be done in these cases but the functionally of the underfrequency load shedding might be lost by doing so. The guidelines for underfrequency load shedding in some regions specify the maximum level that the undervoltage inhibits functions can be set. A maximum level of 80% of the normal voltage is used in some areas.

8.3.4 Load Restoration

After an underfrequency load shedding event, load may be restored only as rapidly as generation is available to support it, including reactive support for system voltage control. Restoration of loads may be performed manually, in coordination with regional operators, or automatically based on local frequency and a predetermined sequence. Frequency relays may be utilized to automatically restore or supervise the restoration of load to a power system. In restoration schemes, these relays are used to add small blocks of load to the system, trying to increase load to match additional generating capacity as frequency stabilizes to normal levels. Sufficient time delay is used with the overfrequency settings for initiating load restoration to minimize impact to the system. Minimum voltage limits may also be used to supervise automatic restoration.

Automatic restoration is not generally permitted unless the relay tripped on underfrequency, there are no overcurrent fault targets, automatic reclosing is active, and maintenance or hot line tag is not active. Restoration procedures may limit the amount and rate of restored load increments. The load restoration scheme resets any lockouts operated by the load shedding scheme, or otherwise create a permissive condition to allow local or remote manual breaker closing.

While underfrequency load shedding schemes endeavor to match the connected load with available generation, changes in transmission configuration and generation dispatch during the course of an event, can make this difficult. If too much load is shed, the excess generation may cause frequency to abruptly rise, exceeding the safe operating range of the system. Frequency overshoot protection may be employed to quickly restore blocks of load if frequency rises above a selected threshold following underfrequency load shedding. The overshoot protection is generally not needed when normal load restoration is undertaken as the restoration is more gradual in nature.

8.4 Undervoltage Load shedding

The objective of undervoltage load shedding is to unload a system that is on the verge of collapse due to a shortage of reactive power supply.

In the "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations [B52]," the following description of undervoltage load shedding is given, "Automatic undervoltage load-shedding (UVLS) responds directly to voltage conditions in a local area. UVLS drops several hundred MW of load in pre-selected blocks within urban load centers, triggered in stages when local voltage drops to a designated level—likely 89 to 92% or even higher—with a several second delay. The goal of a UVLS scheme is to eliminate load in order to restore reactive power relative to demand, to prevent voltage collapse and contain a voltage problem within a local area rather than allowing it to spread in geography and magnitude. If the first load-shed step does not allow the system to rebalance, and voltage continues to deteriorate, then the next block of UVLS is dropped. Use of UVLS is not mandatory, but is done at the option of the control area and/or reliability council. UVLS schemes and trigger points should be designed to respect the local area's system vulnerabilities, based on voltage collapse studies." The report also stated the 2003 blackout may have been prevented if UVLS would have been in service. PRC-010 [B46] was developed to address issues with UVLS. As part of the standard, the Planning Coordinator or Transmission Planner will develop the UVLS program that includes specifications and implementation schedule. The specifications may include voltage set points, time delays, amount of load to be shed, the location at which loads need to be shed, etc. Based upon these specifications, the protection engineer can develop the protection to accomplish these requirements. In addition to UVLS developed under PRC-010 designed to protect the bulk electric system, system planners may also develop UVLS programs to protect localized issues.

Fault Induced Delayed Voltage Recovery (FIDVR) is a point of focus for some power system stability studies. FIDVR happens when a persistent low fault voltage occurs and causes area induction motors to possibly stall. FIDVR is undesirable because of the potential for insufficient reactive resources, large load loss, and cascading events. A severe event can result in fast voltage collapse. In a technical reference [B45], NERC characterizes FIDVR by:

- Stalling of induction motors
- Initial voltage recover after the clearing of a fault to less than 90% of pre-contingency voltage
- Slow voltage recover of more than 2 second to expected post-contingency steady state voltage levels

One possible solution is to use a UVLS system using a slope permissive undervoltage load shedding scheme (SPUVLS). As compared to UVLS system that uses a constant setpoint for voltage, the SPUVLS measures the slope of voltage recovery to determine if the rate of recovery is sufficient or if load needs to be tripped to assist with voltage recovery. Additional references are available on SPUVLS to explain the algorithm and discuss one utility's use of SPUVLS. [B20][B17]

8.5 Adaptive relaying schemes

Adaptive relaying is making automatic real-time adjustments to power system protection schemes to achieve the most dependable and secure distribution system protection for the system conditions at that time. In addition to adaptive relaying schemes, often supervisory control signals are used to remotely change the protective scheme or relay / recloser control settings based on the desires of the system operator.

8.5.1 Traditional adaptive schemes

Traditional distribution protective schemes have used fairly basic adaptive relaying. For example, one of the oldest methods of adaptive relaying was to alter the tripping time on a protective relay or service restorer based on when the trip operation occurs in relation to the reclose sequence. For instance, the first two circuit trips might operate relatively fast, and if the breaker reclosed into a fault, the tripping curve could be altered to allow the device to operate more slowly. This would allow downstream fuses to ride through the first operations but to blow if the fault was still on the system. This type of scheme is often defined as a fuse saving scheme because for most transient faults, fuses are not required to operate. See Clause 6.2 for additional discussion on fuse saving schemes.

8.5.2 Adaptive relaying using microprocessor relays

Microprocessor protection relays with multiple settings groups provide the capability to adapt protection settings, reclosing schemes, and protection elements by changing settings groups and tripping matrixes. The relays adapt based on decisions made by internal logic, by analog quantities that it measures, and/or by monitoring the status of switches and/or circuit breakers. Microprocessor protection relays with communication can obtain this data from other IEDs; how this is accomplished is outside the scope of this guide.

While most distribution circuits do not require this form of adaptation, present protective relaying capability allows tremendous flexibility to adapt the operation of the relay for changing load, load unbalance, cold load pickup, fault type, and/or system configuration changes.

8.6 Distributed Energy Resources

Distributed energy resources are typically sources of non-utility generation operating in parallel with the Area Electric Power System (Area EPS). There are also utility owned sources of DER for special applications. Both utility distribution companies and utility customers may use DER to improve utility operations, meet regulatory issued or LEED (Leadership in Energy and Environmental Design) goals or implement demand response programs to improve customer service. However; when DERs are integrated on radial or networked power systems originally designed to only serve load, feeder protection schemes may require changes or modifications. The requirements for interconnecting these DERs are determined during their project planning stages. See IEEE STD 1547 [B30] and IEEE 1547.7 [B72] which address consensus methods used for performing impact studies, and mitigating limitations of the utility distribution system. The main concerns for DER and utility distribution system protective relaying are as follows:

- Protective device coordination
- Auto-reclosing
- Issues of islanding DER with local loads
- Grounding

These major concerns have an impact in issues such as safety, procedures, equipment ratings, training, and power quality and may have an impact on other customers.

DER sources have evolved from rotating machinery to include inverter based systems as part of the renewable energy movement. In the years following legislation that opened distribution and transmission system facilities for connection of non-utility generation in many areas of the country, penetration levels of synchronous generators have given way to wind and solar inverter based generation. Recently photovoltaic (PV) solar has been a leading primary source of DER being installed because of incentives and relatively low cost of installation. Some wind is being applied, but most wind of any large capacity has been connected to the transmission system. In many locations there are large amounts of inverter based PV solar power being connected to Area EPS, with mandates to have significant amounts of the power source from renewables. At these locations wind farms have been installed as well as large PV solar farms. Other locations have pockets of activity with PV solar connected to radial distribution feeders.

Areas with very high penetrations of solar have actually had to operate what was once a radial distribution feeder as a network, following transmission operating guidelines. IEEE 1547 [B30] provides capability, upon agreement of the utility, for the utility and the inverter based PV solar to “ride through” voltage and frequency variations caused by remote system faults.

8.6.1 Protective device coordination

The presence of DER will affect protective device coordination in different ways depending on the locations of the protective devices and the DER. The most obvious concern is for the coordination of upstream devices on the radial circuits containing the DER. The coordination of downstream devices, coordination on adjacent circuits, and substation transformer backup protection are all areas that require attention. The type of connection used to connect the DER to the system will determine whether the distribution coordination is affected. For example, if the DER transformer has an ungrounded wye or a delta connection to the feeder, then there will not be any contribution to system ground faults and coordination will not be affected. However, this arrangement will make it difficult to detect single phase-to-ground faults on the system at the DER and can cause other problems such as transient overvoltage not related to protective relay coordination (see IEEE Std 1547[B30] and “Impact of distributed resources on distribution relay protection” [B26]). For the purposes of discussion on coordination effects, it can be assumed that the connection and fault type are such that the DER will contribute.

Consider the system of Figure 51. For protective devices on the circuit beyond the DER it can be expected that the available current for faults at F_1 will be greater. This will result in more circuit coverage from the protective device, which may or may not be desirable. The device coverage may extend through additional lateral circuits and possibly require greater operating times to coordinate. Coordinating devices on the upstream side of the DER connection will be subject to infeed effect, which will result in a larger coordination interval.

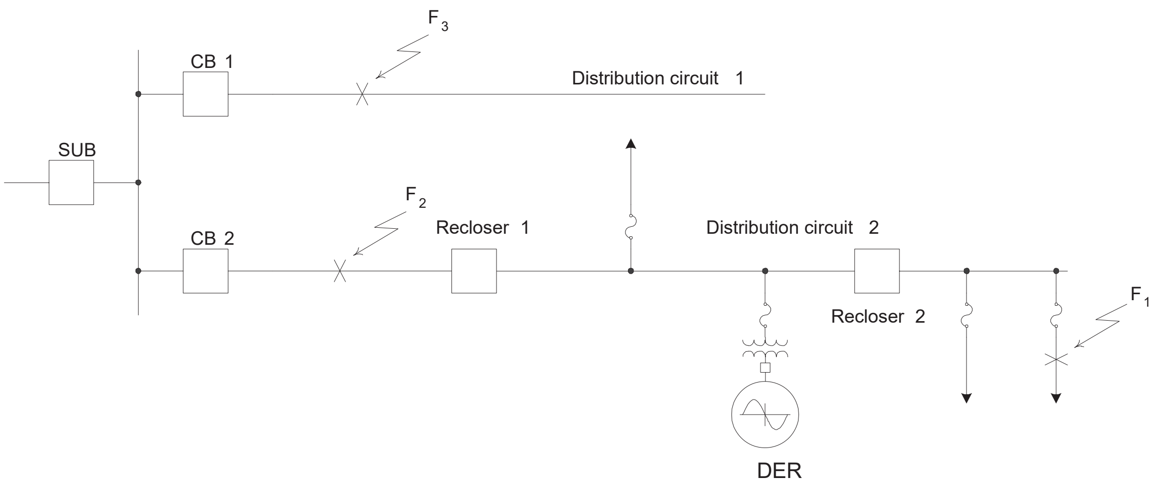


Figure 51—Distribution with DER

Faults such as F_2 that are upstream of the DER will cause reverse current to flow in Recloser 1 in Figure 51. This could cause confusion for sectionalizing schemes if a device downstream of the fault is tripped and delays restoration of customers' loads for temporary faults. Since it is normally not desirable to island the DER with other customers' load, the protection on the DER needs to be coordinated with Recloser 1, or the relay controls for Recloser 1 needs to be made directional to only operate for faults on the DER side of the recloser, so the DER is disconnected before Recloser 1 has a chance to operate.

The fault F_3 located on the adjacent feeder will show effects similar to both of the previous faults. The magnitude of fault current on the circuit will be greater for the entire circuit. The current at breaker CB 2 will be reversed. If the relay protection at breaker CB 2 is not coordinated with breaker CB 1 there could be an unnecessary trip of CB2. This coordination can be further complicated if more than one circuit contains DER. However, adding directionality to CB2 could prevent CB2 from tripping due to reverse current flow from the connected DER.

When the existing line protection is left in place, evaluation of feeder coordination is desirable to review impacts. Changes to the existing protection to accommodate the DER will usually result in longer delays in tripping and reclosing operations and/or the need to add directional relaying. In some cases, sequential operation or miscoordination may have to be considered. Delayed operations, sequential operations and miscoordination represent a degrading of the power quality to other customers on the circuit that could be unacceptable. Consequently, the need to make changes to the line protection systems to accommodate the DER can create additional concerns.

8.6.1.1 DER transfer trip communications

The simplest solution to protection problems arising from the addition of DER to the circuit is to trip the DER any time a fault is detected on the circuit. Sensing for the fault may occur at the DER point of connection; but the primary sensing, for feeder protection, is at the circuit source (breaker CB 2 in Figure 51). This would employ a transfer trip scheme, much the same as applied in transmission protection. Concerns include the reliability of the transfer trip circuit, the future coordination of the maintenance or replacement of that equipment, the loss of flexibility in the operation of the distribution system and the cost of the transfer trip equipment and communication channel. This loss of flexibility is a concern both for future load growth and for abnormal operating situations. If the DER is transferred to another circuit, either temporarily for maintenance or permanently for load growth, the transfer trip equipment would need to be moved or duplicated on that circuit. Refinements can be made to this scheme using the communications to prevent tripping for faults downstream of the DER connection that can be cleared by an appropriate device, such as Recloser 2 in Figure 51. With high penetrations of PV solar power, direct transfer trip is not practical and several alternatives including radio, power line signal injection or use of a 3 phase ground switch located outside the utility substation are alternatives for anti-islanding simultaneous shut down of many DER sources. Specific discussion or details on DER transfer trip and communications schemes is beyond the scope of the guide.

8.6.1.2 Directional relays applied to DER

The use of directional overcurrent relays for both circuit breakers and circuit reclosers are an option for dealing with the coordination problems created by the introduction of a DER to a circuit. This may take the form of impedance-type relays or directionally polarized overcurrent relays or a combination of both. Many microprocessor-based feeder relays have directional overcurrent relay functions as part of the basic relay. With these relays to enable the directional function may only require a change in the relay settings. Although this will solve some of the coordination problems, there are some drawbacks to consider. The directional relays may be more expensive than the existing relays, and they may require the addition of VTs. This type of relaying is different than what is normally used on distribution (non-directional overcurrent) and may require additional training.

8.6.2 Islanding

When a DER is present on a radial distribution system, there may be conditions under which the DER continues to supply power to certain part of the distribution circuit load when the distribution source breaker is opened to clear a fault. Once the breaker opens, the circuit with the DER is considered an island. Unintentional islanding is a concern for DER applications. IEEE Std 1547[B30] provides the unintentional islanding requirements as well as some guidance to meet the requirements. If the power mismatch between the DER output and the load is large enough, the interconnection protection at the DER point of connection will cause the DER to trip. If the power mismatch between the DER output and the load is close to zero, relays at the point of interconnection cannot be relied upon to detect islanding conditions and to trip the DER. Applying multi criteria protection is a potential method to overcome this problem. Voltage vector shift protection combined with rate of change of frequency is one technique that could be considered.

The presence of DER will require a study of reclosing. Consideration of the reclose time allows the DER trip time during islanding conditions. An effective islanding protection is therefore important to trip the DER during the reclose open time. Delayed reclosing is desirable if protection issues cannot be mitigated by other protective relay functions. However, an additional delay on reclosing has a negative effect on the quality of service to the existing customers. Ideally, the DER beyond a reclosing device will disconnect from the distribution circuit to have a successful reclosing and to prevent damage to customers' equipment.

Reclosing may be delayed to account for time required to reliably disconnect DERs via a DTT signal. A direct transfer trip scheme (DTT) may help maintain standard reclosing times. A dead line check control circuit may be added to the current interrupter's controls to delay the reclose until the circuit is dead to cover the cases when the DTT signal is delayed or the DER's equipment fails to respond. 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 DER needs to be coordinated between the DER and the utility, which may help shorten the duration of the circuit reclosing delay. IEEE 1547.4 [B31] addresses intentional islanding. Because of operational and safety issues, intentional islanding is rarely permitted by the utility without extensive analysis. If the DER is planned to remain in service during an islanding condition, the oscillations of the DER in response to a disturbance may result in undesirable voltage flicker. There is no consensus standard for planning DER islanding applications, but guidance is provided in IEEE P1547.4 [B31] and also in IEEE 519 [B29].

8.6.3 Grounding

For most of the protection issues concerning DER already discussed, it was appropriate to consider the grounded wye connection to the system. If the DER connection is ungrounded wye or delta and the utility (grounded) source is opened; then the circuit will become ungrounded. If this occurs during a phase-to-ground fault, then the DER interface may not detect the fault and respond correctly. If islanding occurs on an ungrounded portion of a circuit with an ungrounded DER as the source of power, then serious transient overvoltages may occur that may damage utility and customer equipment and create a safety concern. In this case, direct transfer trip, voltage unbalance detection or neutral overvoltage protection will be required to assure the DER is removed from the circuit.

8.7 Communications assisted protection applications

8.7.1 Introduction

Historically, the use of communication channels with protective relays on distribution circuits has been limited to applications such as direct transfer trip (DTT) or distribution automation applications. As the design of distribution circuits has changed in response to increased reliability and power quality requirements, the use of communication channels to enhance the speed and dependability of the protective relaying schemes has also increased. Relay communication channels for distribution circuit protection have been successfully implemented with direct connections using a variety of media, such as fiber optic cables, leased telephone circuits, and point-to-point radios. Selection of the communication channel and medium considers the speed, security, dependability, and confidentiality requirements of the proposed protection scheme. When different media can support the requirements, other factors such as installation costs and maintenance costs may also be evaluated because they may vary greatly where the protection scheme is physically located. Additional guidance on communication mediums is outside the scope of this guide.

8.7.2 Direct transfer trip

When a DER is connected to a radial distribution system, there may be conditions under which the generator can support the distribution circuit load at full or reduced voltage and frequency if the distribution source breaker is opened which would island the DER. In the case of parallel generation, a DTT scheme can be used to ensure safe isolation of the generator before any attempt is made to reclose the source breaker (see “Myths of Protecting the Distributed Resource To Electric Power System Interconnection” [B9]). In Figure 52, a DER is shown connected to a radial distribution circuit. The protective relays for the 12.5 kV distribution circuit at Substation A are typically non-directional phase and ground overcurrent relays set to coordinate with the downstream devices on the distribution circuit. If the breaker is equipped with automatic reclosing, the reclose interval would be similar to that applied to any other radial overhead distribution circuit except that the first reclose may be delayed or a dead line check control circuit added to delay the reclose for a delayed DTT. This is done to allow time for both the DTT scheme and the high side recloser at the DER to operate and disconnect the generator from the line before any attempt is made to reclose the breaker.

A DTT scheme requires a communications link, such as the one shown in Figure 52. If the 12.5 kV breaker at Substation A trips for a distribution fault or is opened manually, a “52b” contact from the breaker keys the DTT transmitter (DTT Tx) which sends a signal to the DTT receiver (DTT Rx) to open the recloser at the DER.

Another use of the DTT scheme is to trip the DER for a line to ground fault on the 138KV system. Since the DER generator cannot supply fault current through the Substation A delta-wye transformer for ground faults on the 138 kV system, the DER may still be online after the 138 kV line breakers trip. An under/overvoltage (27/59) or zero phase sequence overvoltage (3V0) relay is installed on the 138 kV side of the transformer to detect the phase to neutral voltage change during a 138 kV ground fault condition. The 27/59/3V0 relay keys the DTT Tx to ensure that the generator is disconnected before a138 kV line breaker recloses.

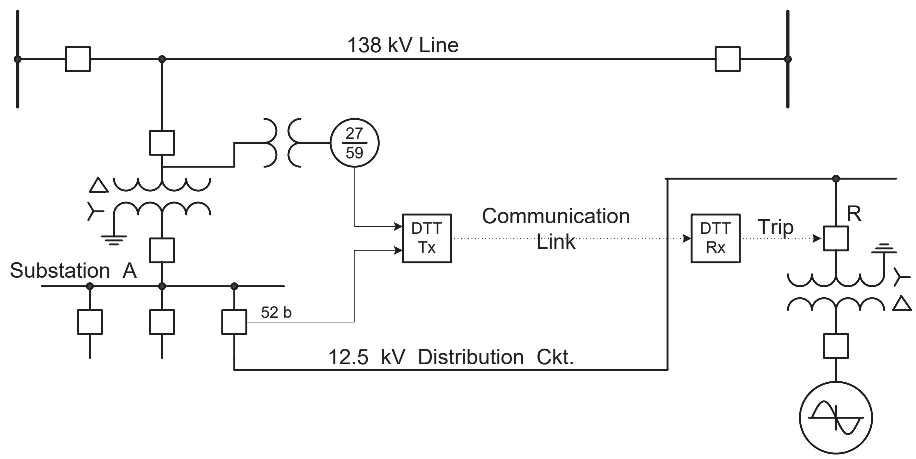


Figure 52—Example of direct transfer trip scheme on a radial distribution circuit

8.7.3 Communications-enhanced trip and restore

A trip and restore protection scheme can be enhanced by using microprocessor-based relays that support a communications link. Adding communications can improve the speed and selectivity of tripping and the continuity of service to customers served from radial or looped-radial distribution circuits. The selection of communication protocol and media is outside the scope of this guide.

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 (see "Trip and Restore Distribution Circuits at Transmission Speeds" [B48]). A simple looped-radial distribution system is shown in Figure 53 consisting of two circuit breakers and three line switches (LS) connecting several sections of distribution line. The line switches typically do not have fault current interrupting capability, and one of the line switches is usually operated normally open (NO). The breakers and line switches are all equipped with relays. The relays are connected together through a communications link supporting the protection requirements to enable them to share system data and breaker or line switch status between them. Logic is then developed in the relays to enable them to determine the location of a line fault and to trip the appropriate breakers and line switches to isolate the fault. Once the fault is isolated, the relays can selectively close the appropriate breaker or line switch based on the equipment status and system condition data received over the communications link to automatically restore all but the faulted line section to service. The ability to communicate using a protocol and media supporting the protection requirements enables the relays to provide faster restoration of service after the line is sectionalized. Automatic restoration times are typically on the order of seconds. Relays that typically support DTT communications may also support additional communication channels for other non-protection related applications, such as SCADA, which are outside the scope of this guide.

Because the entire line could be supplied through one breaker with the other breaker open, the phase and ground overcurrent relays at the breakers are set to coordinate with slowest operating protective device on any of the line sections. The line switch relays are set as overcurrent and undervoltage detectors to provide fault location intelligence. Automatic reclosing for the breakers typically consists of an instantaneous open interval, followed by one or more time-delayed open intervals. If a fault occurs on Line 1 in Figure 53, Relay 1 at Breaker 1 will detect the fault and trip Breaker 1. Breaker 1 will reclose instantaneously. If the fault is still present, Relay 1 will again trip Breaker 1. Relay 2 will detect an undervoltage condition but no overcurrent and will open LS 2 during the second open interval of Breaker 1. Breaker 1 will then reclose. If the fault is still present, Breaker 1 will trip again and lock out (assuming reclosing for the breaker was set for only two open intervals). At this point, the Line 1 fault is isolated, but Line 2 is also deenergized. Restoration of Line 2 can then be accomplished automatically via the relays or remotely via SCADA commands to the relays. If restoration is done via SCADA, the open status of Breaker 1, LS 2, and LS 5 is transmitted to SCADA over the communications link. The fact that both LS 2 and LS 5 saw an undervoltage condition without fault current is also transmitted to SCADA. This information enables the dispatcher to send a close command to LS 5 to restore service to Line 2. If restoration is accomplished automatically via the relays, then Relay 5 "sees" from Relay 2 via the communications link that Relay 1 operated for a fault but that Relay 2 did not see any fault current and that Line Switch 2 is now open. Therefore, Relay 5 automatically closes Line Switch 5 to restore power to the customers on Line 2.

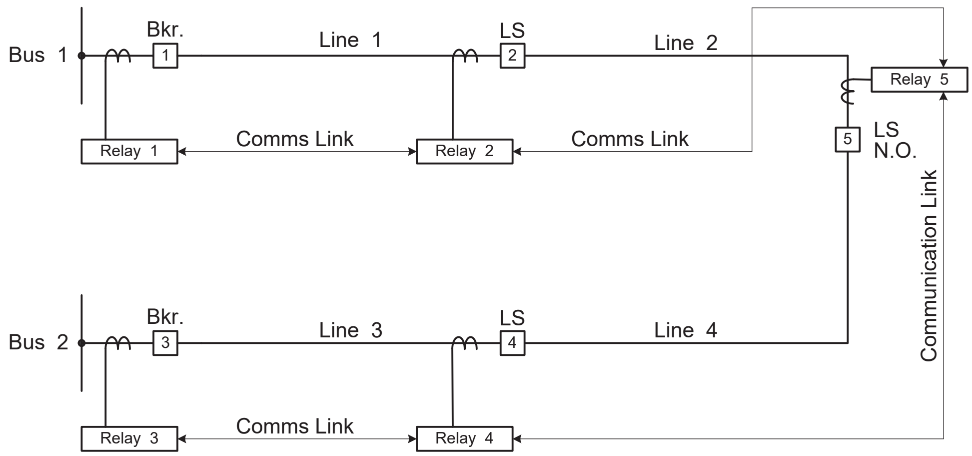


Figure 53—Communications-enhanced trip and restore scheme on a looped-radial distribution system

If the line switches in Figure 53 are replaced by reclosers with fault current interrupting capability, then the communications link can be used in the tripping scheme as well as the restoration scheme. In this case, Relay 1 and Relay 3 would contain a set of phase and ground overcurrent elements set to coordinate with the slowest operating protective device on any line section in order to provide line protection if the communications channel is lost. However, a second set of phase and ground overcurrent elements can also be set in Relay 1 and Relay 3 to coordinate with the slowest operating protective device on its individual line section. Similarly, the phase and ground overcurrent elements in Relays 2, 4, and 5 can be set to coordinate with the slowest operating protective device on its line section. For example, suppose that Relay 1 is set to coordinate with a 40E fuse as the slowest protective device on Line 1 and Relay 2 is set to coordinate with a 100E fuse as the slowest protective device on Line 2, and a fault occurs on Line 2. Both Relay 1 and Relay 2 will see the fault, but the overcurrent detector in Relay 2 will send a signal via the communications link to Relay 1 to momentarily suspend timing in order to allow time for Relay 2 to trip its recloser to clear the fault. If Relay 2 is programmed for automatic reclosing, it can close its recloser at least once to test Line 2. The advantage of this scheme is that only Line 2 is taken out of service for the fault, and the customers on Line 1 are subjected to only a voltage sag, instead of a complete outage.

8.7.4 Communications-aided trip

On a closed loop distribution system, fault-interrupting switchgear can be equipped with directional relays having communications capability to provide automatic clearing of any faulted line section within a few cycles to greatly limit the duration of voltage sags and minimize the number of customers subjected to an interruption in service (see "International Drive Distribution Automation and Protection" [B15]). An example of a looped distribution system equipped with directional relays and fault-interrupting switchgear appears in Figure 54.. Application of directional elements and logic in the relays with the communications links enables the looped system to be protected using the same communications-assisted protection schemes that are in common use on high voltage transmission lines discussed in IEEE C37.113 [B38]. For example, a permissive overreaching transfer trip (POTT) scheme could be implemented in relay logic to provide primary protection for each line section in Figure 54. If a fault occurs on Line 2, the forward-looking directional element in Relay 3 will “see” the fault and send a permissive trip signal to Relay 4. Similarly, the forward-looking directional element in Relay 4 will “see” the fault and send a permissive trip signal to Relay 3. The combination of a forward-looking directional element asserted plus a permissive trip signal from the remote relay causes both Relay 3 and Relay 4 to trip their associated switches to clear the fault.

Note that while the forward-looking directional elements in Relays 1 and 6 may also “see” the fault on Line 2, they will not receive a permissive trip signal from their remote terminals and therefore will not trip their respective fault-interrupting switches. Thus, all customers may see a momentary voltage dip, but only the customers associated with Line 2 will experience an outage.

In addition to the directional elements required for the POTT scheme, backup phase and ground time overcurrent elements in Relays 2 through 7 are generally set to coordinate with the protective device settings on the load feeder switches. Similarly, backup phase and ground time overcurrent elements in Relays 1 and 8 are set to coordinate with the overcurrent settings in Relays 2 and 7, respectively. As in the looped-radial system, the communications link can also provide SCADA system access to the relays for metering and system status data as well as for remote control of the protected equipment.

Details or specifics of the SCADA and communication schemes associated with these relays are outside the scope of this guide.

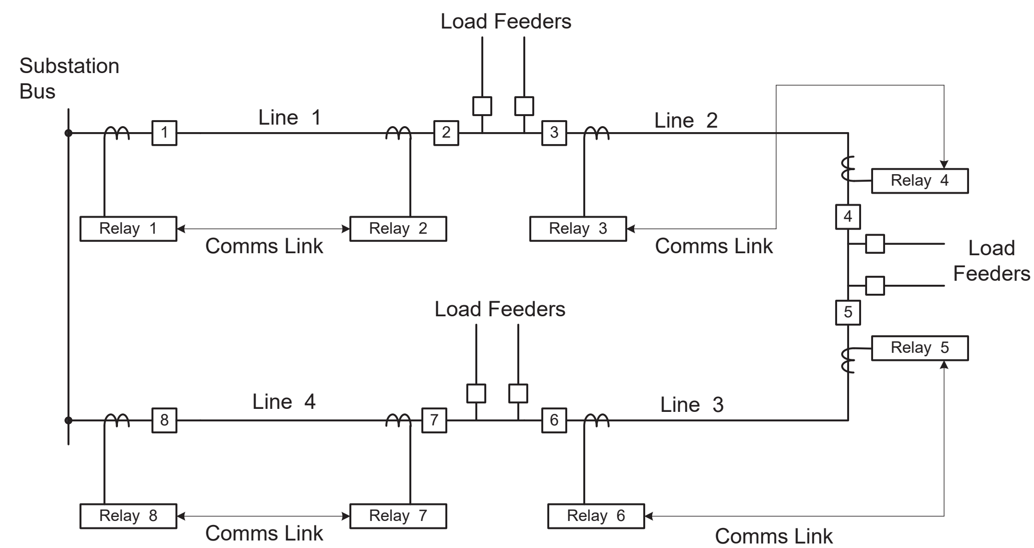


Figure 54—Example of a Communications-aided trip scheme on a closed loop distribution system

8.8 Multiple source configurations

Radial feeders are the most common type 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 DERs, or a line networked with other adjacent stations on the low voltage side; then the protection may be inadequate. Configuration changes also include cases where a line switch may be closed to energize a second line. 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. Note that details or specifics of SCADA schemes are outside the scope of this guide.

Cases with two, three, or more main terminals (this could also include lines with emergency ties) may require directional overcurrent relays. The use of impedance type relays may be considered. A dependable polarizing source at the substation is required and this may not be possible at locations that are "weak" (for example, circuits with a Source Impedance Ratio > 4), especially for ground protection.

Lines that have tie switches can be troublesome to set the overcurrent relays. These settings are based on the farthest location that the relay is set to protect. That could be at the farthest end of the line that is being "picked up" by the good line.

Lines with DERs or other source stations may also require the use of directional overcurrent relays. The ground overcurrent relay settings may be compromised if the DERs or backfeed station is a zero-sequence current source. Negative-sequence overcurrent relays may also have to be incorporated where the normal zero-sequence current protection may be compromised.

Distribution lines that are mostly cable and have substations that can provide backfeed through a line side delta connected transformer warrant review. The use of a primary side VT with an overvoltage/undervoltage relay may be considered to provide protection for primary side faults on the system.

8.9 Directional overcurrent protection

Directional overcurrent relays discern the direction of current flow to a fault, thereby permitting overcurrent relay operation for faults in one direction, and blocking relay operation for faults in the other direction. They are most commonly applied on networked circuits, or distribution circuits that have DERs. Directional phase overcurrent relays have the same restrictions as non-directional phase overcurrent relays for load flow in the tripping direction.

The directionality of the directional element is accomplished by providing the relay with a measured reference quantity. This input can be a voltage, a current, or both. Phase voltage, or positive-sequence voltage, is required to polarize the phase directional element for three-phase faults. Because close-in three-phase faults cause all three-phase voltages to collapse to zero, the phase directional element polarization voltage includes a memory function to provide proper directionality long enough for the time-overcurrent element to operate. Phase voltage, positive-sequence voltage, or negative-sequence voltage can be used to polarize the phase directional element for phase-to-phase faults. Negative-sequence voltage, zero-sequence voltage, or zero-sequence current from a separate zero-sequence current source, can be used to polarize a ground directional element. A combination of two or all three of these can be used to ensure dependable directional element operation under various system configurations and conditions. Negative-sequence polarized directional units are often applied when zero-sequence mutual coupling effects cause zero-sequence directional units to lose directionality, or cause false operation. Negative-sequence voltage polarization has the added advantage that it can be supplied through wye or delta connected potential transformers. Zero-sequence voltage polarization requires three wye-connected potential transformers.

Directional overcurrent protection typically consists of a directional element in combination with an overcurrent element. Ground directional elements are able to detect the direction of a ground fault and are typically combined with a ground overcurrent element that operates on residual ground current, zero-sequence current, or CT neutral ground current. Phase directional elements are able to detect the direction of three-phase and phase-to-phase faults and are typically combined with a phase overcurrent element that operates on phase current. Negative-sequence directional elements, able to detect the direction of phase-to-phase and ground faults, may also be combined with phase and ground overcurrent elements. The directional elements block tripping for load flow and faults in the non-tripping direction.

As with non-directional overcurrent relay schemes, instantaneous and definite-time trip units, which may or may not be directionally controlled, can be added to directional time-overcurrent relay schemes to provide high-speed relay operation for close-in faults. Where the source on one side of the relay terminal is much stronger than the source on the other side, non-directional overcurrent elements which are set to pickup above the maximum current available from the weaker source will be inherently directional because they can only operate for faults driven by the stronger source. Directional overcurrent is used where the relay schemes have different sensitivity or operate time for faults in one direction compared with the other direction.

Input currents to the directional overcurrent relays are provided from CTs located at the line terminal, one for each phase overcurrent unit, and the sum of the three for the residual ground or neutral overcurrent unit. Three-phase devices may have a single-phase overcurrent unit that operates on maximum phase current, or it may have three phase overcurrent elements that operate on their respective phase current. Three-phase devices may also sum the currents internally to produce negative-sequence and residual ground (zero-sequence) operating quantities without the need for additional CT connections.

The time-overcurrent and instantaneous elements used in directional overcurrent schemes are virtually identical in operation and design to those used in non-directional overcurrent relay schemes, with the exception that the operation of one or both units will be controlled or supervised by the directional element.

As with all overcurrent relays, delays for time coordination with other devices is required. Fault coverage and/or operating times may be affected by network changes. The coordinating time delay requirements will often make directional time overcurrent relays unsuitable where extremely high-speed fault clearing is required. However, directional overcurrent relays generally provide adequate operating speed to be used on lower voltage networks, especially as protection for ground faults. Sensitive instantaneous or definite-time directional overcurrent relay elements can be used in pilot scheme applications to where fast fault clearing is required.

There are two different ways to apply the directional element in directional overcurrent relays. In one method, the directional element supervises the output of the overcurrent element. In this method, the overcurrent element is free to operate for any current in excess of its pickup setting, but tripping occurs only if the directional element also asserts. Alternatively, the directional element can control the input to the current measuring portion of the overcurrent element, preventing its operation unless the directional element operates. In an electromechanical relay scheme, for example, a directional element contact can be installed in the shading coil circuit of an overcurrent relay to control the overcurrent relay operation. This is often referred to as “torque control” because the directional element controls the operating torque of the overcurrent relay.

Both directional supervision and directional torque control can be accomplished with electromechanical, solid state, or microprocessor-based relays. One advantage of directionally torque controlling the input to the overcurrent relay is that there is no race between reset of the overcurrent element and operation of the directional element during current reversals due to feeder configuration or DER, i.e., the directional element operates before the overcurrent element can operate.

8.10 Motors (effects of unbalance)

The effect of three-phase motor unbalance on distribution line protection is primarily dependent upon two things: 1) what percentage the unbalanced motor load is of the total load supplied by the circuit the protective device is on and 2) the type of motor and its connection. Typically, the unbalanced three-phase motor load is a small portion of the total load detected by the protective device. Thus, the effect of unbalance operation on protection is minimal and usually can be neglected.

In general, when a three-phase motor is fed by an unbalanced set of phase voltages (either inherently unbalanced or an open-phase condition), the phase currents drawn by the motor will become unbalanced. The most severe operating condition would be that of an open phase. An open phase is usually the result of a blown fuse; however, this can be caused by a bad connector. Figure 55 depicts this typical scenario.

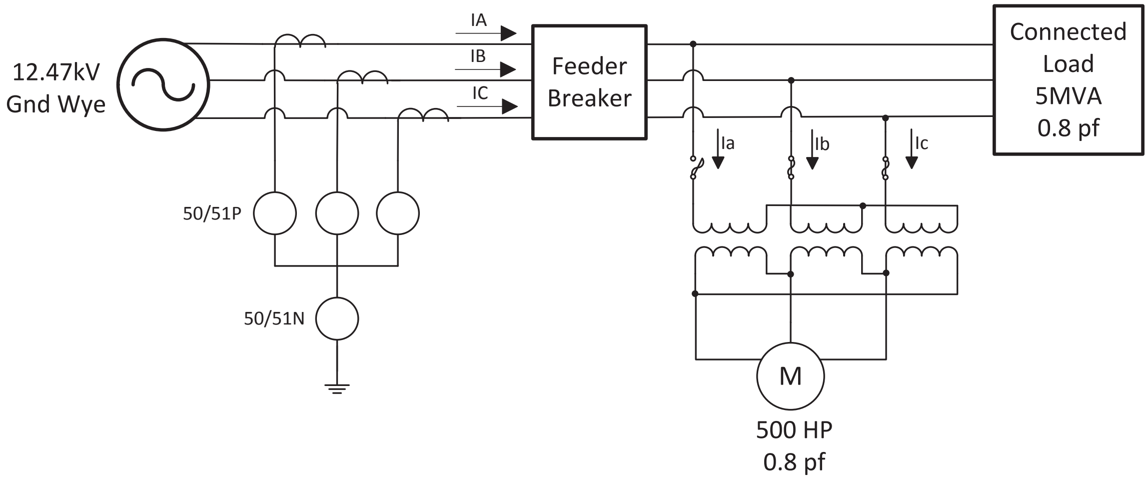


Figure 55—Three-line diagram of a typical open-phase unbalance of a three-phase induction motor

Although synchronous motors can operate with one phase open, they are likely to pull out of step and be disconnected from the system if they are loaded near their ratings. Therefore, only the induction motor will be addressed here.

When an induction motor is operated with an open phase, the phase currents drawn by the motor will theoretically increase to those shown in Table 4 (see also IEEE Std C37.96 [B35] and “Symmetrical Components for Power System Engineering” [B5]). Note that these values are in per unit of the current values prior to the open-phase condition.

Table 4—Theoretical currents for open-phase condition

	Normal condition (p.u.)	Open-phase condition (p.u.)
Phase a	1.0	0.0
Phase b	1.0	1.732
Phase c	1.0	1.732

Although the currents drawn by the motor in phases b and c will increase to a theoretical maximum of 1.732 p.u., the magnitude of the phase currents, IA, IB, IC measured by the protective device will not change very much if the connected load is much larger than the three phase induction motor load. Therefore, for this case, i.e., the connected load is much larger than the unbalanced motor load; the effect on the protective relaying is negligible.

The following scenario shows a situation where the unbalance could potentially become a problem. To illustrate the point, assume that the system shown in Figure 55 is rated at 12.47 kV phase-to-phase and the induction motor is operating at full load and has a rating of 500 HP 0.8 pf lag (assume 1 HP = 1 kVA). The connected load is 5 MVA at 0.8 pf lagging and is connected grounded wye. Neglecting losses (line and transformer), the phase currents measured by the protective relays in Figure 55 can be shown to be equal to the values shown in Table 5.

Table 5—Line current measured by protective device in Figure 55 for normal and open-phase conditions

	Normal condition (A)	Open-phase condition (A)
IA	254.6	231.5
IB	254.6	267.0
IC	254.6	197.8
I_1	254.6	231.8
I_2	0.0	13.4
$3I_0$	0.0	80.1

Once the open-phase condition occurs, approximately 80 A of zero sequence current begins to flow in the ground relays. Note this requires a ground source on both sides of the open phase. Ground relaying would need to be evaluated to insure that it was not set sensitive enough to detect this condition.

There are other rare cases where the connected load to motor load ratio is much smaller. In these instances, the currents resulting from the unbalanced operation of a three-phase induction motor may have an increased impact on the protective relay settings. Phase overcurrent relays are set to carry load current with some margin, and also to detect end of zone phase-to-phase faults. If this cannot be accomplished, load encroachment or negative sequence relays can be used. However, if negative sequence relays are used they are typically set to detect end of zone phase-to-phase faults, but not pick up for the open-phase condition. See C37.96 [B35] for additional discussion on motor protection.

8.11 Breaker failure

Breaker failure relays, applied to distribution feeder circuits, can improve dependability by clearing feeder faults during a breaker failure condition. In particular, multi-function microprocessor 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 to clear a feeder breaker fault.

Alternatively, feeder circuits may 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.

When considering the application of breaker failure protection to distribution feeder circuits, it is important to consider several factors. To develop a dependable and secure breaker failure scheme, understanding how the relay determines circuit breaker position, when the breaker failure timer starts, how breaker failure interacts with reclosing, proper coordination with backup protection, and the operating conditions of the circuit breaker is necessary.

Breaker failure relays, or breaker failure elements, use different criteria to determine the position of the circuit breaker. Relays may determine circuit breaker status by the position of breaker contacts, by the level of measured current flow through the breaker, or a combination of both contact status and current flow. The breaker failure element timer typically starts when a trip command is issued, but in some relays, only starts after the trip command minimum duration time expires. Breaker failure relays may interact with reclosing elements in different fashions. When a breaker failure element trips, it may prevent the issuing of a breaker reclose signal, block reclosing, or drive reclosing to lockout. The breaker failure time delay needs to be long enough to allow a circuit breaker to operate, and account for breaker operating conditions, such as temperature, age and type of the circuit breaker, and general operating experience with circuit breakers.

IEEE Standard C37.119, Guide for Breaker Failure Protection of Power Circuit Breakers [B73], provides a detailed guide on the schemes and considerations for breaker failure protection

8.12 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. For example, suppose a recloser with the single-phase trip option were protecting a feeder. The feeder experiences an "A" phase-to-ground permanent fault. Rather than tripping all three phases for the fault, the recloser trips only the "A" phase. Customers connected to the other two phases, or 67% of the customers in the area assuming balanced loads, do not experience a service interruption due to the fault.

When utilizing a three phase distribution line recloser with the single phase (also called single pole) tripping option, the evaluation of circuit unbalance is generally performed to determine if the unbalanced condition can contribute to an inadvertent ground trip operation on an upstream device or at the substation. One way this could be addressed would be by a microprocessor recloser control with adaptive type settings which would only allow single phase trip and lockout when the anticipated current unbalance is lower than the upstream neutral overcurrent setting. When circuit loads are at unacceptably higher levels, and a single phase trip might cause an upstream neutral overcurrent trip, the recloser control would revert to the three phase trip and lockout mode.

The use of single phase tripping in conjunction with floating wye or delta connected capacitor banks can cause issues. With a single phase open due to a temporary fault, the phase-to-neutral connected loads on the open phase are energized from the other two phases. This can produce overvoltages on the phase-to-neutral connected load on the open phase and cause failure in customer equipment. It is not a good practice to install floating wye or delta capacitor banks beyond the location of the single-phase interrupters in three-phase circuits.

Single-phase tripping can also produce another negative effect if used on a circuit with three-phase motor loads. Single-phasing three-phase motors, as would be done with single-phase tripping, can damage these motors, as the current in the motor increases causes rotor heating due to negative sequence current in the stator. See Clause 8.10 for additional discussion on the effects of imbalance on motors. It is generally accepted that the customer has the responsibility to protect their own three-phase motors against single-phasing; however it may benefit the power supplier to also consider this condition. In circuits with mixed single-phase load and three-phase motor load, the power supplier may weigh the benefits of the increased reliability that can be attained through single-phase tripping against the potential value of helping customers with three-phase motor loads.

When single-phase interrupters are used in three-phase circuits, ferroresonance is possible during ungrounded faults as shown in Figure 56. In this circuit, an ungrounded phase-to-phase fault opens phases A and B protective devices. This establishes a circuit where ferroresonance is possible with the grounded-wye capacitor bank and the floating wye-delta connected transformer bank. Whether ferroresonance will occur depends on the amount of load connected to the floating wye-delta bank, and whether load is connected phase-to-neutral on primary phases A and B on the load side of the single phase interrupters. If this load is large enough it shunts out the capacitor bank, preventing ferroresonance.

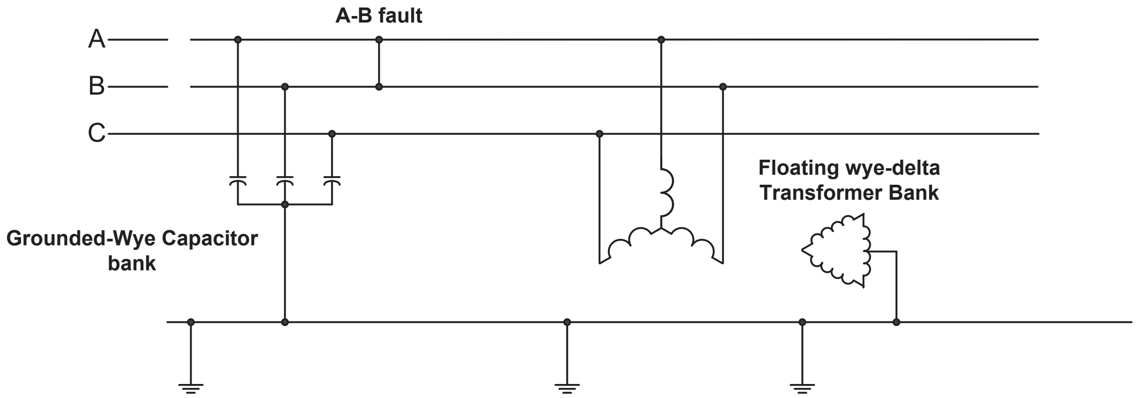


Figure 56—Ungrounded system where ferroresonance could occur

8.13 Methods of detecting ground faults in resonant-grounded systems

Resonant grounded systems are discussed in Subclause 5.1.1.4. The high magnitude of the zero-sequence impedance makes the much smaller positive- and negative-sequence network impedances negligible, and can be ignored without much loss of accuracy when evaluating single-phase-to-ground faults on resonantly grounded power systems. The zero-sequence used for forward and reverse single-phase-to-ground faults in resonant-grounded systems is shown in Figure 57 and Figure 58. For this analysis, the assumption is that the conductance of the power system is infinite (i.e. the source impedance is zero). Stated another way, the insulators are perfect, and the system is perfectly balanced beforehand. This means that the driving voltage of the fault is the pre-fault phase-to-neutral voltage.

Examining the zero-sequence network for a forward fault, the zero-sequence current, I_0, for a perfectly tuned system is 180° out of phase with the zero-sequence voltage, V_0. However, most systems are generally over- or under-tuned, which simply causes the zero-sequence current to either lead the zero-sequence voltage by more than 90° or lag the zero-sequence voltage by more than −90°. Calculating the torque/real power in all the above cases provides a negative result.

Examining the zero-sequence networks for a reverse fault shows that the zero-sequence current for a perfectly tuned system is in phase with the zero-sequence voltage. The zero-sequence current for a reverse fault on an over- or under-tuned system causes the zero-sequence current to either lead the zero-sequence voltage by less than 90°, or lag it by less than −90°. In all cases the torque, or real power, developed is positive.

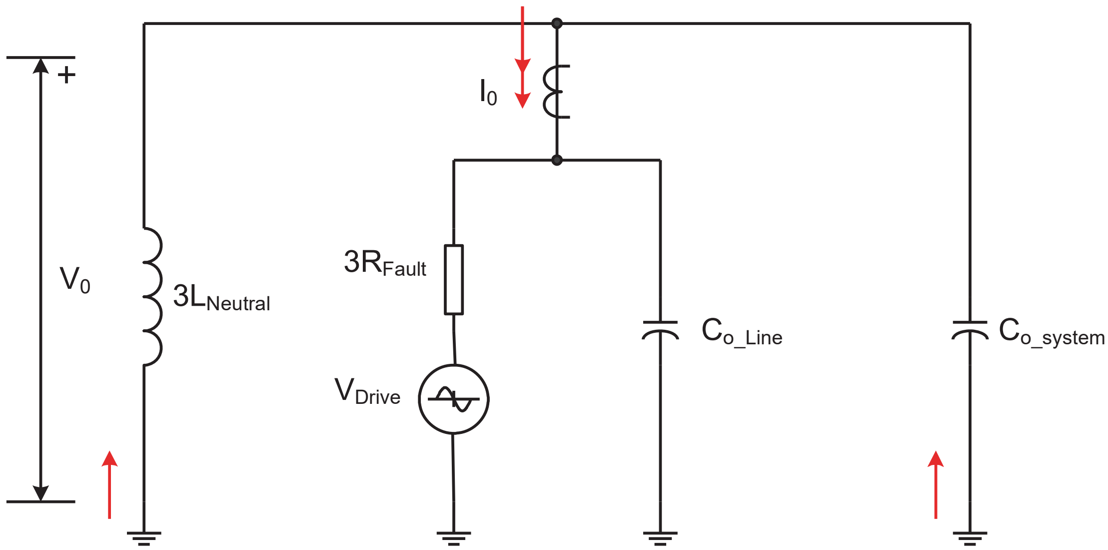


Figure 57—Zero-sequence network diagram for a forward fault

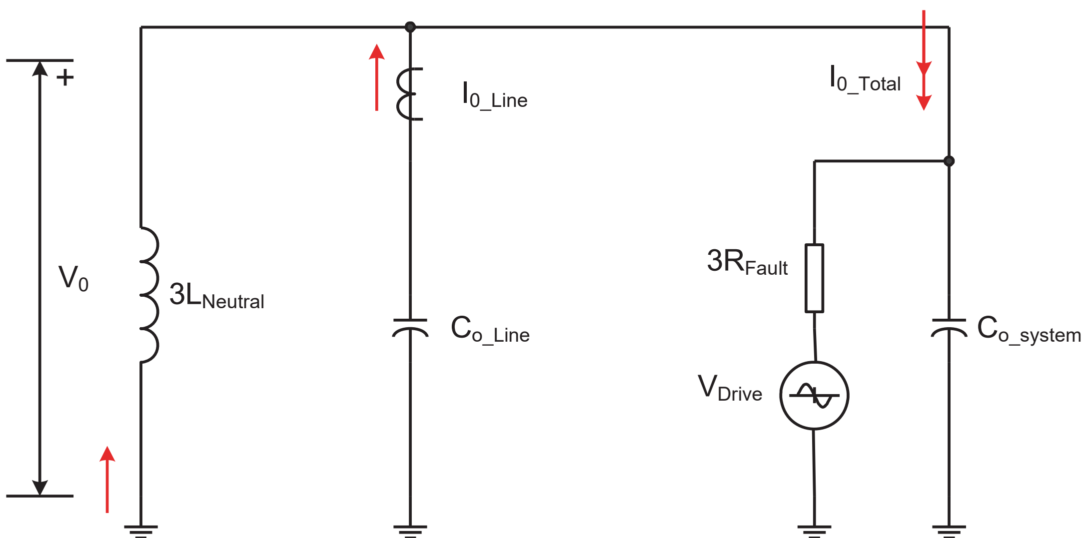


Figure 58—Zero-sequence network diagram for a reverse fault

Therefore, using this information, a negative power is developed for a forward fault, and a positive power is developed for a reverse fault. A wattmetric element (an element that calculates real power) can be used with the following logic:

— If the power developed is less than a set negative threshold, the fault is forward.

— If the power developed is greater than a set positive threshold, the fault is reverse.

Figure 59 shows the phasor diagram for the wattmetric element.

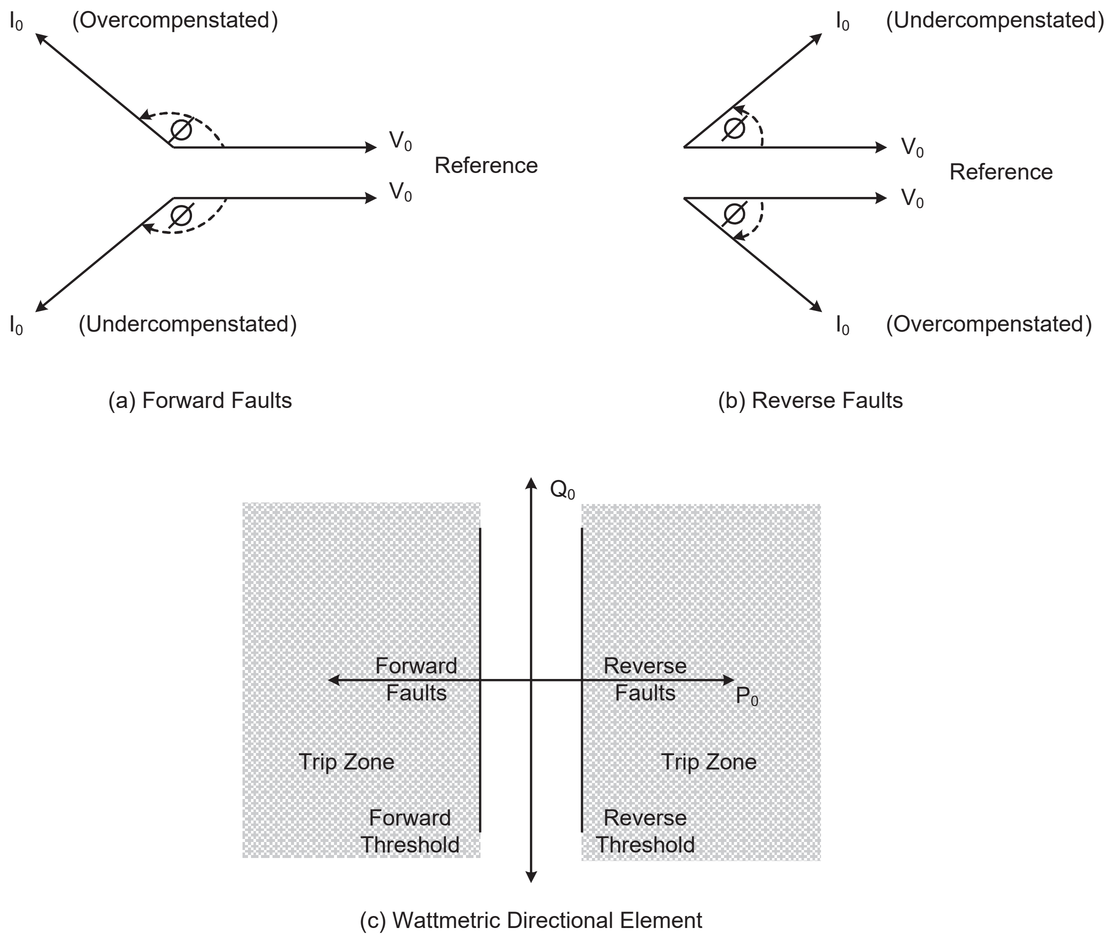


Figure 59—Phasor diagram for the wattmetric element

The sensitivity of the wattmetric element is inhibited by the standing unbalance of the power system. However, where utilities require fault detection for faults that may generate voltages or currents that are less than the standing unbalance of the power system, the incremental conductance method is used. This method calculates the incremental change in the conductance of the power system. To calculate the incremental conductance, the incremental change in current is divided by the incremental change in voltage, where the incremental change in current is the difference between the pre-fault current and the fault current, and the incremental change in voltage is the difference between the pre-fault voltage and the fault voltage. If the calculated change in conductance is positive, the fault is forward. If the calculated change in conductance is negative, the fault is reverse. See "Methods for detecting ground faults in medium voltage distribution power systems" [B16].

8.14 Selective ground fault protection of an ungrounded system

Ungrounded systems are discussed in Section 5.1.1.2. Ground faults on either delta connected systems or systems with isolated neutral can be detected by highly sensitive residual overcurrent relays directionalized by residual voltage. The existing applications involve detection of a ground fault condition by a residual voltage element, but the individual feeder with the fault can only be determined by a trial-and-error method based on sequentially opening of each feeder one by one until the residual voltage disappears.

During ground faults, as shown in Figure 60, ground becomes identified with the voltage of the faulted phase. Therefore, capacitive charging currents flow between the healthy phases and ground. These currents appear as a residual current at the relay location, in the opposite direction of the current flowing to the fault. 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.

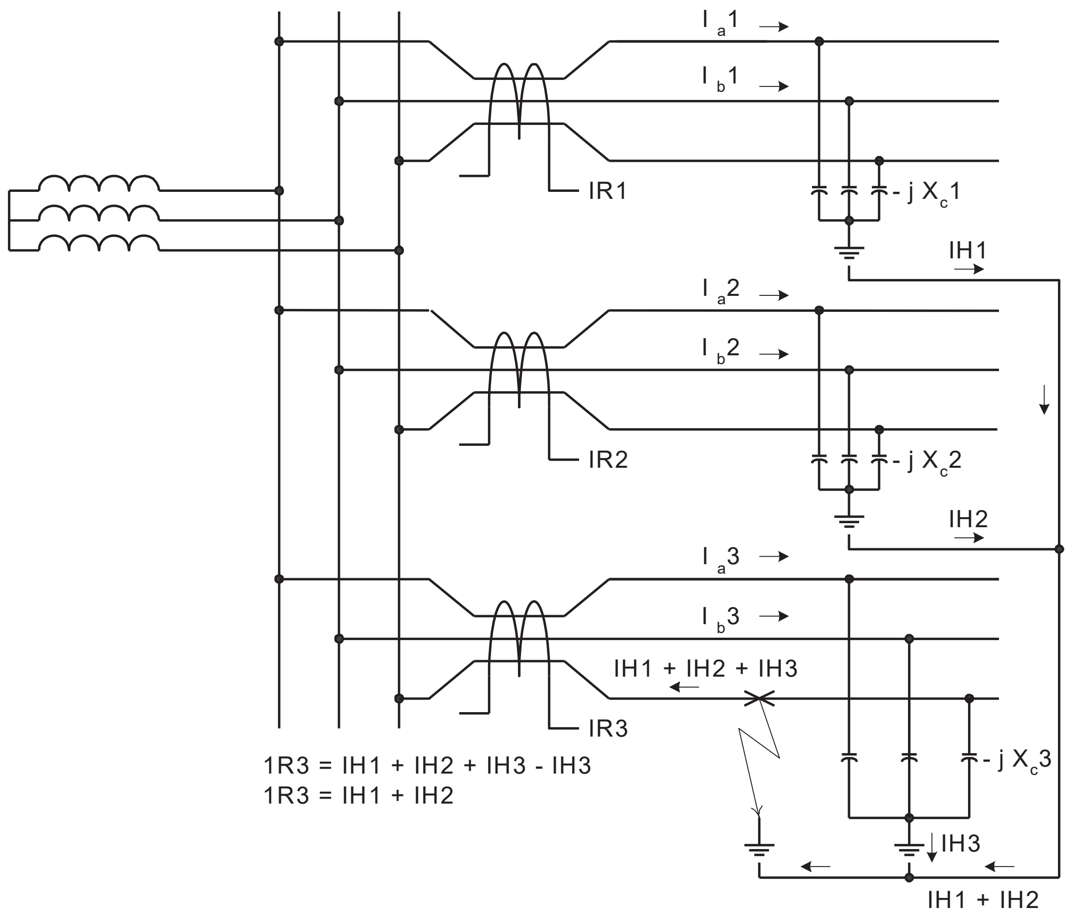


Figure 60—Current distribution in an ungrounded system with C-phase fault

8.14.1 Ground fault detection techniques

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 compensated 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 VTs to provide displacement voltage to the relay.

8.14.1.1 Varmetric relays

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.

8.14.1.2 Wattmetric relays

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.

8.14.2 Setting guidelines

Both varmetric and wattmetric relays typically have a pickup setting based on the minimum available residual current. In addition, some relays also use the magnitude of displacement voltage as an additional pickup criterion. For an isolated neutral system, the current pickup criterion is based on the total capacitive ground current of the connected system flowing through the relay. A pickup setting of about half the capacitive current value of ground current is typical.

During a ground fault, the entire displacement voltage typically appears at the relay. Therefore, when pickup settings for voltage displacement are required, the settings can be quite large, in the range of 30 V to 60 V secondary.

8.15 Arc Flash Hazards

An Arc Flash Hazard may exist when employees are working on or near exposed energized equipment. For distribution lines, this includes work on overhead primary distribution lines and equipment, pad-mounted equipment, and underground lines. The National Electric Safety Code [B74] and OSHA 1910.269, and OSHA 1926.960 [B75], which are applicable to many utilities, require that utilities perform an assessment to determine the potential exposure to an electric arc for employees who work on or near energized lines, parts, or equipment.

If that assessment determines a potential employee exposure greater than a certain level (typically 2 cal/cm^2), the utility may be required to:

- Perform a detailed arc hazard analysis to determine the effective arc rating of clothing or clothing systems to be worn by employees working on or near energized lines, parts, or equipment. The arc hazard analysis includes a calculation of the estimated arc energy based on the available fault current, the duration of the arc (cycles), and the distance from the arc to the employee.

- Require employees to wear clothing or a clothing system with an effective arc rating not less than the anticipated level of arc energy.

8.15.1 Arc Flash Hazard Incident Energy Calculations

The arc flash hazard analysis consists of calculating the incident energy level for the specific work being performed. Various methods can be used to calculate the incident energy for faults on distribution equipment. Appendix E of OSHA 29 CFR 1910.269 and 1926.960 [B75] provide a summary of some of the methods which may be used for this analysis. Each of these methods has limitations that are documented in the referenced material. Other methods may be used providing they can be technically justified. Incident energy calculation typically requires at least the following inputs:

- Working Distances: Based on work practices
- Arc Gaps: Based on equipment construction and voltage level
- Fault Clearing Time: Based on protection device settings and/or employee egress time

- Short Circuit Current: Based on system design and fault characteristics

An arc flash hazard analysis can be used to determine the distribution line protective relays and devices settings that will limit incident energies to acceptable levels. The acceptable incident energy level may be based on a company's safety policies that outline the minimum Personal Protective Equipment (PPE) its employees are required to wear when performing work on or near energized equipment. For example, if a company's practice is to require employees to wear PPE with a minimum rating of 8 cal/cm^2; then the arc flash hazard analysis can determine the distribution line protection settings that will limit the incident energy to less than or equal to 8 cal/cm^2.

Working distances and arc gaps are often fixed based on a company's specific work practices, equipment design, and system voltages. IEEE 1584 [B76], OSHA 1910.269, OSHA 1926.960 [B75], and the NESC [B74] may also be used to obtain typical industry reference values for these inputs. Once these fixed inputs are determined, the incident energy calculation will only be dependent on fault clearing time and short circuit current. Therefore clearing times can be calculated that will limit the incident energy level to a specific level across the spectrum of expected fault current levels.

8.15.2 Arc Flash Incident Energy TCCs

As discussed above, for a given incident energy level, arc gap, and working distance; the fault current vs fault clearing time values can be determined that will limit the incident energy level to the predefined value. This allows one to plot various arc flash incident energy level lines on TCC plots. The protection device TCCs can be plotted on these Arc Flash Incident Energy TCCs to determine the protection device settings that will ensure that the maximum incident energy level is not exceeded. In order for the protection device's TCC to represent the total clearing time, circuit breaker operating time and other tolerances that may affect how long that device will take to clear a fault are included. The entire incident energy TCC does not need to be evaluated if there is a maximum design fault current which will provide an upper limit and a maximum "self-extraction time" or employee egress time which will provide a lower limit for the fault current levels evaluated.

Figure 61 shows a typical TCC for an incident energy level of 8 cal/cm^2 for a phase-to-ground fault in open air with an arc gap of 4" and working distance of 15". The circuit being evaluated has a maximum fault current of 10,000 Amps and the work being performed has a maximum self-extraction time of 2.0 seconds. This graph also shows a TCC for a relay which is protecting this line (the circuit breaker operate time and relay setting tolerances are added to this TCC). This shows that the relay settings are expected to limit incident energy below 8 cal/cm^2 for all design fault levels.

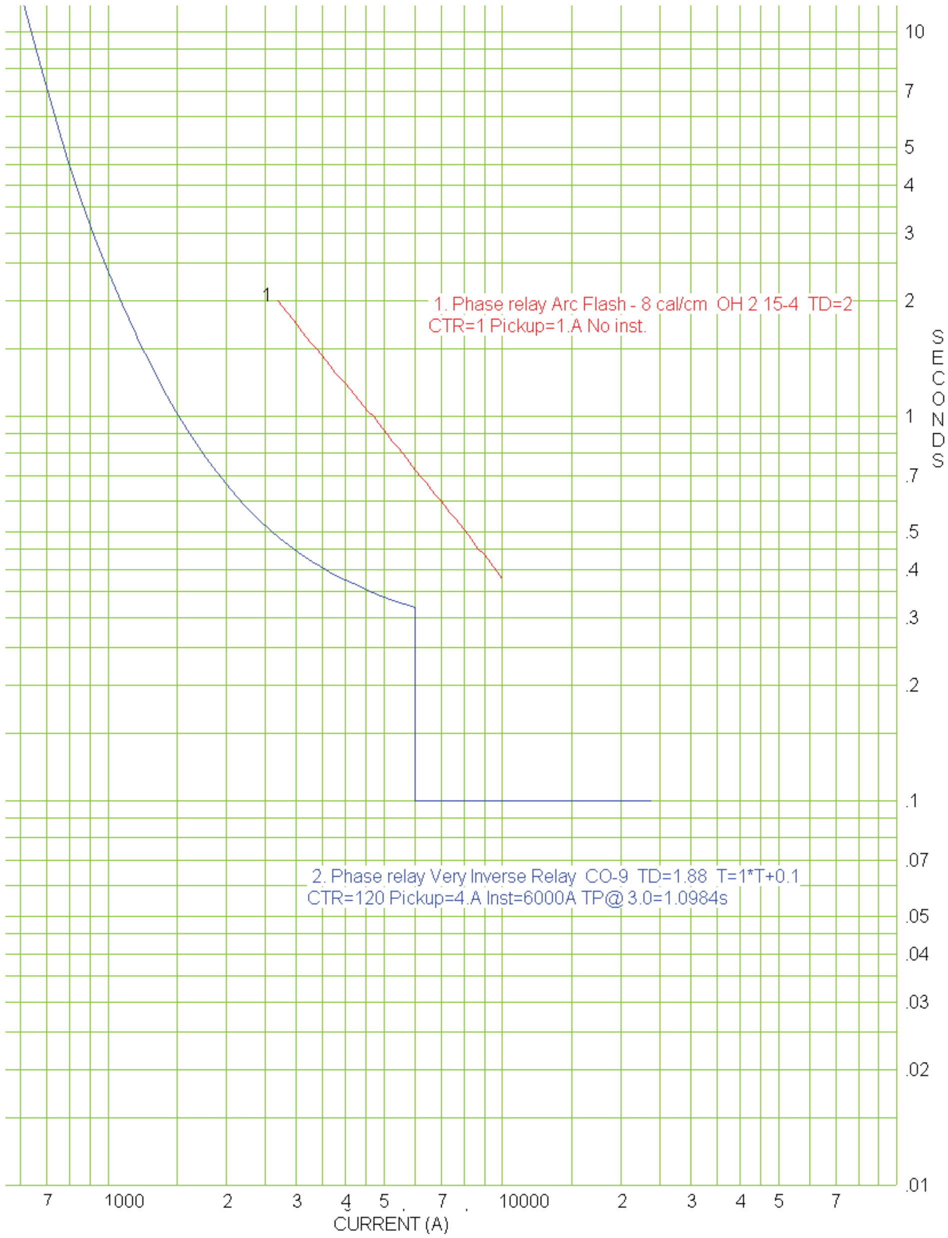


Figure 61—Example Arc Flash TCC

8.16 Locating Faults on Distribution Lines

Determining the location of a fault on a distribution line is challenging because of the unique topology of each system and several other factors. For example, system grounding (solidly, ungrounded, Peterson coil, resistance grounded) impacts fault currents. Each line is likely to have multiple laterals as well as impedance discontinuities. C37.114, Guide for Determining Fault Location on AC Transmission and Distribution Lines [B77], provides a detailed guide on many of the challenges, techniques and application considerations for fault location.

Most distribution lines have multiple laterals at varying locations off a three-phase feeder mainline. Figure 62 shows an example of a distribution feeder structure.

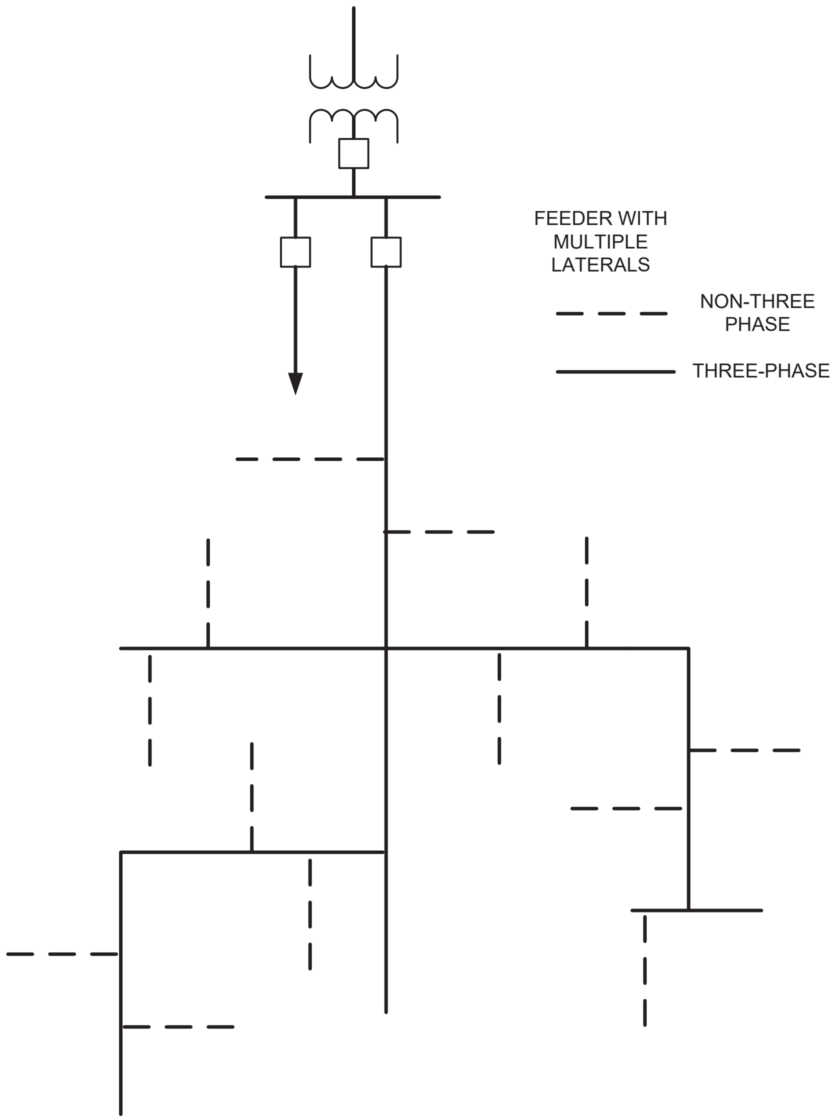


Figure 62: Example of a Distribution Feeder Structure

In practice, fault location has been performed by traditional technologies (restoration through switching, reclosing, fuse operations, customer calls, downed wires, relay targets, dc thumping of underground circuits); observant technologies (local detection with communications feedback, intelligent metering with communications, faulted circuit indicators or FCIs, fault recorders, etc.); and advanced technologies (protective devices, distributed intelligent devices with communications); or some combination of these where the latter two typically include the capability to support SCADA communication that is outside the scope of this guide.

Each method has some challenges in practice. Protective devices, for example, produce a fault location estimate on solidly grounded systems using voltage and current phasors. These devices use various techniques to minimize error. However, conductor sizes may change, making impedance calculations nonlinear, so a good model of the feeder may be required for better accuracy. The fault location estimate at the substation may produce multiple possible fault locations, depending on the feeder topology, so additional information such as an FCI operation may be required. Feeders are more difficult to model than transmission lines, so feeder models may have to be validated with actual results. There is often less energy to establish clean arcs and faults are more likely to evolve, so these factors may require evaluation as well.

~~9. Emerging Trends~~

~~Modern power system characteristics are changing due to the recent focus on improving the reliability and effectiveness of the power system through various smart grid objectives. These changes are visible in distribution systems with the implementation of distributed energy resources, energy storage, demand response, electric vehicles, feeder reconfiguration, volt/var control, power electronics based lighting and drives, and microgrid integration. These trends are adding complexities to the design, operation, protection and maintenance of the distribution system. The confluence of all these activities requires comprehensive distribution automation (DA) strategies that take advantage of available technologies, while also utilizing newer ones [B55]. Improvements in protection and control practices in distribution systems have become imperative and something that can no longer be ignored.~~

~~The integration of distributed resources has been changing the distribution system characteristics over the last few years. The major distinction between traditional generation (both central and distributed) and renewable resources generation is the variable and intermittent nature of the latter, along with their significantly reduced fault current contributions. Intermittent resources impact network frequency/voltage control and stability. The uncertainty and intermittency of renewable generation units reduce security margins and force operators to utilize more effective monitoring and control algorithms enabled by DA systems. As hundreds of such units would be dispersed in networks, their control and monitoring is typically designed in a decentralized manner for efficiency reasons. A high penetration of distributed, intermittent generation units can lead to bi-directional power flows, which in turn require more advanced protection systems.~~

~~Historically, distribution systems have been operated in a radial mode due to the simplicity of operation, ease of coordinating the protecting devices, and overall economics. The need for greater reliability has driven a transition to a "mesh" or "loop" design – in reality, a hybrid of existing radial lines and new ties between substations and feeders – that can carry out the work of advanced distribution system applications. Circuits are generally designed with a peak expected load in mind. As areas grow within the load boundaries of a particular circuit, the peak loads may exceed the load limitations of the circuit. This affects the system flexibility to tie, separate, or transfer load remotely or by local control. DA then becomes a tool for the operator to control the system configuration with greater speed and ease [B56].~~

~~It is the duty of a protection and control engineer to attempt to cover all the possible scenarios, within reason, of a given configuration. The practice of these emerging trends are now impacting protection and controls in ways that historical practices may not have taken into consideration. For example, when feeders are reconfigured, for whatever reason, coordination and the load profile of that feeder may change dramatically. These new conditions may call for drastic and immediate changes in the protection and control settings. Traditional feeder protection and control practices using static settings based on a static feeder would not necessarily cover all configuration capabilities of these new trends in feeder applications.~~

~~Dynamic feeder configurations require more thought and consideration in terms of the switching sequence of the reconfiguration, automatic or manual reconfiguration, multiple different loading profiles of each configuration, dynamic protection and control coordination, and dynamic protection and control sensing levels. The desired capability of transitioning to multiple configurations requires protection and control schemes that have to adapt to their new environment after a transition. Add to that, the ability to manually or automatically transition to these new configurations and one can find oneself with a quite complex P&C problem in a hurry. In order to achieve this, microprocessor relays have been designed with multiple setting groups. It is common to see relays with up to eight setting groups. Those should be enough to consider all possibilities of new topologies or system changes. A good handling of the internal logic of the relays is required to make sure that the relays switch to the appropriate setting groups.~~

~~Not only do these trends require more thought when it comes to protection, but these new trends require more thought from a distribution planning perspective as well. Particularly, different allowable system configurations will impact how protection and control schemes are implemented.~~

~~Protection and control efforts can be optimized with the help of careful planning practices that put appropriate boundaries and standards in place to minimize possible configurations while optimizing the versatility of the distribution system. This symbiotic engineering relationship will certainly help to optimize the reliability and integrity of the distribution system.~~

~~The introduction of distribution system communication technologies and the installation of automated circuit interruption devices are enabling faster automated identification and isolation of faulted feeder segments. One of the major benefits of the smart grid is the functionality that enables the implementation of FLISR (fault location, isolation, and service restoration) or FDIR (fault detection, isolation, and restoration). These trending applications allow protective functions to intelligently isolate a faulted segment and control functions to automatically reconfigure feeders with unprecedented precision and speed when faults occur. Now healthy sections of a faulted feeder can be moved, with the connected loads, to adjacent feeders to avoid the impact on the reliability indices and in particular SAIDI, SAIFI and CAIDI. After the faulted feeder segment has been isolated, automated restoration of un-faulted loads follows using the spare power capacity of adjacent feeders. These automated systems can be centralized at the distribution management systems (DMS) center or distributed using substation-based or peer-to-peer communicating interim feeder relays and controls.~~

~~A comprehensive DA system contains many components: a DMS, an outage management system (OMS), a geographic information system (GIS), a customer information system (CIS), AMI (Automated Metering Infrastructure), and others. A suite of applications is run on the DMS for system protection and control including service restoration following a disturbance. Modern powertrain system analysis toolkit (PSAT) tools (Software packages) should handle as far as possible computer integrated manufacturing (CIM) applications so that the new states reported by the GIS can be quickly processed to determine the best possible relay settings. An OMS hosts the network model (populated by GIS data on utility assets) that provides insights on affected customers. A DMS can manage voltage with VAR control. DMS, integrated on a SCADA platform, can support advanced applications. The OMS can have three sources of input: first, phone calls from customers, second, status changes from the DMS, and third, social media driven by customers. The third input, for example, might be a tweet from customers with a geo-tagged photo of the disturbance, which can significantly speed up the restoration of the service. Specific details on DMS integration with SCADA is outside the scope of this guide.~~

~~Advanced applications are supported by the DMS in coordination with a substation protection and automation system. FLISR/FDIR, volt/var optimization/control, and distribution power flow are the commonly used advanced applications. Volt/var optimization reduces network losses, maintains an optimal voltage profile on feeders, and reduces peak load via feeder voltage reduction. Distribution power flow enables the operator to simulate the results of switching strategies, which contributes to energy efficiency by controlling losses and optimizing loading on feeders. A number of other applications are also run on the DMS.~~

~~The IEDs and other data-generating sensors provide data for the DMS applications. Some utilities have already implemented DA from the DMS center to each customer. This will require gathering and storing large amounts of data. Such an approach poses a real challenge for operators to monitor, control, and protect the system in a centralized manner. If a simple fault occurs downstream, intelligence embedded at the substation or out on the feeder can respond swiftly and automatically and report upstream after the fact. If a fault has more complicated consequences, and operators need to assess conditions on several substations before taking action, then centralized intelligence can be used. A hybrid of centralized and distributed intelligence provides the most flexibility in responding to a wide range of potential issues on the distribution system. Operators can rely on downstream intelligence as much as possible for speed and to avoid overburdening data networks and servers, but can select centralized intelligence when a wider view of the system is needed.~~

~~The evolving distribution system landscape introduces many new challenges in policies, operation, maintenance, protection, and control from inception to life-cycle support. The success of smart grid and distribution automation relies heavily on integration, standards, interoperability, and open data exchange interfaces.~~

Annex A

(informative)

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Annex B

(informative)

Glossary

coordination of protection: The process of choosing settings or time delay characteristics of protective devices such that operation of the devices will occur in a specified order to minimize customer service interruption and power system isolation due to a power system disturbance.

fault impedance: An impedance between the faulted power system phase conductor(s) or between phase conductors and ground.

impedance relay: A distance relay in which the threshold value of operation depends only on the magnitude of the ratio of voltage to current applied to the relay, and is substantially independent of the phase angle between the applied voltage and current.

inverse-time relay: A relay in which the input quantity and operating time are inversely related throughout at least a substantial portion of the performance range.

recloser: A protective device that combines the sensing, relaying, fault-interrupting, and reclosing functions in one integrated unit.

recloser relay: A control device that initiates the reclosing of a circuit after it has been opened by a protective relay (or device).

source impedance (radial system): The Thevenin equivalent impedance of an electrical system for maximum system short-circuit conditions at the point of interest.