



IEEE Guide for Protective Relay Applications to Distribution Lines

IEEE Power Engineering Society

Sponsored by the
Power System Relaying Committee

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IEEE Guide for Protective Relay Applications to Distribution Lines

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**Power System Relaying Committee
of the
IEEE Power Engineering Society**

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Abstract: A review of generally accepted applications and coordination of protection for radial 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, protective reach, radial distribution line protection, recloser

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Introduction

This introduction is not part of IEEE Std C37.230-2007, IEEE Guide for Protective Relay Applications to Distribution Lines.

The art and science of the protective relaying of distribution lines has evolved over many years. This newly developed guide is an effort to compile 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 used for different conditions and situations and 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.

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IEEE Guide for Protective Relay Applications to Distribution Lines

1. Overview

This guide is divided into eight 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 normal considerations. Clause 8 has several special applications and considerations for distribution line protection.

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

The scope of this guide is to discuss the application and coordination of protection for radial power-system distribution lines. It includes the descriptions of the fundamentals, line configurations, and schemes. In addition to these, the scope includes identification of problems with the methods used in distribution line protection and the solutions for 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 guide (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.

IEEE Std C57.13™, IEEE Standard Requirements for Instrument Transformers.^{1, 2}

IEEE Std C62.92.4™, IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems, Part IV—Distribution.

3. Definitions

For the purposes of this guide, the following terms and definitions apply. *The Authoritative Dictionary of IEEE Standards Terms* [B29]³ should be referenced for terms not defined in this clause.

3.1 distributed resources (DRs): Power sources such as generators, photovoltaic units, fuel cells, etc., connected on distribution circuits and dispersed throughout the utility distribution system.

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

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

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

3.5 sympathetic tripping: The phenomena where an unfaulted interrupting device 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.

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

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

4. Fundamentals

4.1 Fault characteristics

4.1.1 Type and calculation

Faults occur on overhead and underground electric distribution systems with regularity. 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:

- Weather (such as wind, lightning, extreme temperature, and precipitation)
- Equipment failure
- Forestry contact
- Public contact (including pole and overhead contacts and underground dig-ins)

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³ The numbers in brackets correspond to those of the bibliography in Annex A.

- Animal contact
- Vandalism
- Vehicle accidents

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 sense 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 or single-line-to-ground
- Two-phase-to-ground

Most 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. 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.

The type of grounding system and fault type must be understood in order to model and calculate fault currents, and to apply protective systems that will sense and operate for detectable fault conditions. 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 differ from non-faulted conditions, and will vary depending on the grounding system utilized. Fault impedance should be considered. 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 a 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) in place.

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 'sequence components' for various types of fault conditions. These currents can then be used to select and apply protective devices such as relays, reclosers, and fuses. 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. Due to the effects of the impedance of the line conductors, fault currents decrease with distance from the substation source. In many cases, maximum fault currents are limited in order to apply distribution class equipment on the circuit.

4.1.2 High-impedance faults

In some cases, the fault impedance will limit the fault current to values that are not detectable or that are comparable to load current values. Examples of this condition include a dry tree limb contacting two phase conductors, or the case of a conductor breaking and contacting asphalt or concrete pavement. These conditions, typically referred to as high-impedance faults, present a challenge to the protection specialist in application of protective devices to sense and clear faults. Conventional overcurrent and distance protection cannot reliably detect this type of fault. Special protection is necessary for this type of fault, which is beyond the scope of this guide. In the last decade, there have been technological advancements in the development of protective and monitoring devices specifically designed to sense high-impedance faults. Evaluation of the trade-offs between security and dependability of these devices is continuing.

4.2 Load characteristics

It is important to have the knowledge of load characteristics at various points in a power system for various studies such as load flow, short circuit, stability, and electromagnetic transients as explained in “System load dynamics-simulation effects and determination of load constants” [B30], “Representation of loads” [B11], “Incorporation of load modeling in load flow studies” [B17], and “A fault locator for radial subtransmission and distribution lines” [B14]. Complex models to represent the load exist; however, the main problem to include adequate representation of loads is obtaining proper data for use in a model.

Although frequency-dependant load models have been proposed in various works such as “Representation of loads” [B11], “Incorporation of load modeling in load flow studies” [B17], and “The influence of load characteristics on power system performance—A C.E.G.B. viewpoint” [B63], it is difficult to obtain data from field tests for these models. It is almost impossible to obtain permission from grid control to isolate a part of the system and vary frequency over a wide range to measure load frequency characteristics at various load points. In a large interconnected system, the frequency usually does not vary over a wide range.

4.3 Harmonics and transients

4.3.1 Harmonics and their effect on distribution line protection

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™-1993 [B38]). In other words, a harmonic is a sinusoidal waveform that has a frequency equal to an integer multiple of the fundamental frequency. For 60 Hz power systems, harmonics will be integer multiples of 60 Hz, which can be expressed another way, as follows in Equation (1):

$$h = n \cdot 60 \text{ Hz} \tag{1}$$

where

- h is the harmonic frequency
- n is the harmonic number

A 60 Hz waveform and its second, third, fourth, and fifth harmonics are shown in Figure 4-1.

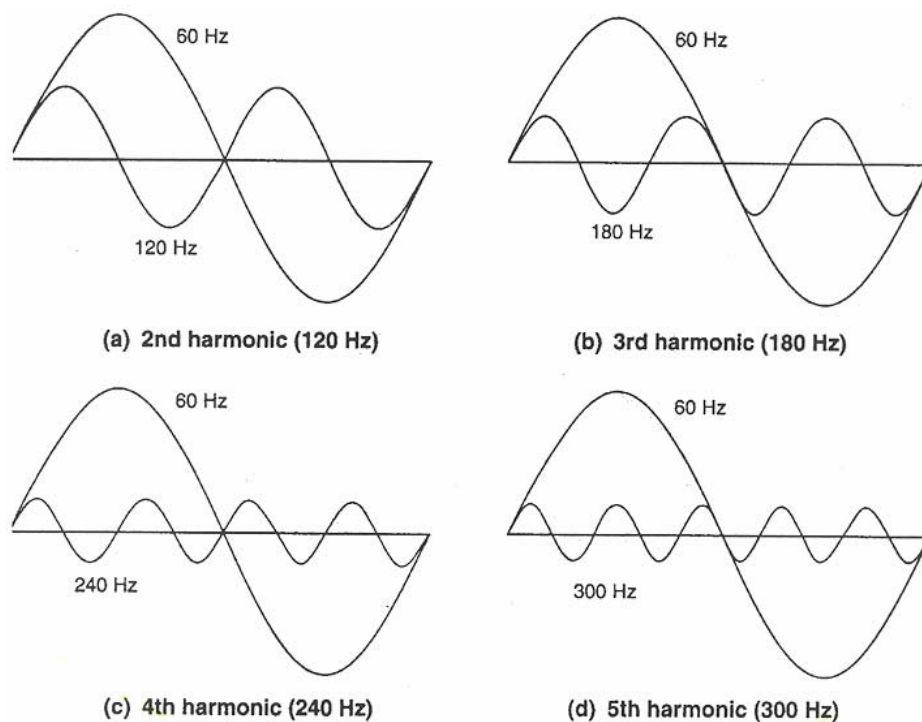


**Figure 4-1—Second, third, fourth, and fifth harmonics with a 60 Hz sinusoid
from IEEE Std 141™-1993 (*IEEE Red Book*™) [B35]**

Nonlinear loads and power electronic devices are the largest source of the harmonics that appear in power systems. Some typical devices that inject harmonics into the power system are identified in *Electric Power Quality* [B27] as follows:

- Single-phase static and rotating ac/dc converters
- Three-phase static ac/dc converters
- High phase order static converters
- Battery chargers
- Electric arc furnaces
- Fluorescent lighting
- Pulse modulated devices
- Adjustable speed motor drives
- Transformers

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

Like fundamental frequency currents, harmonic currents tend to flow towards the path of least impedance. This causes them to show up in the most unexpected places such as power system neutrals. Other problems such as series and parallel resonance can occur, but those problems will not be addressed in this guide.

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 4-1 lists a few lower order harmonics and their corresponding similarity with a sequence component (see IEEE Std 141-1993 (*IEEE Red Book*) [B35] and “Representation of loads” [B11]).

Table 4-1—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 with any harmonic component can be found by further developing Table 4-1. For example, the 16th harmonic would be similar to the positive sequence; the 17th harmonic would be similar to the negative sequence, and so on.

Thinking of harmonics in terms of sequence 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 are not tuned to the fundamental frequency. Negative sequence harmonics may cause erroneous operation of negative sequence responding elements if those elements are not tuned to 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. The effect of harmonics on these devices should be considered when high harmonic distortion is present. If harmonic distortion is great, the total RMS current can be significantly greater than the fundamental frequency component alone. The true RMS current can be found by using Equation (2) as follows:

$$\text{RMS} = \sqrt{\sum_{n=1}^{\infty} i_n^2} \quad (2)$$

where

i is the RMS value of a particular harmonic current

n is the harmonic number

It should be noted that harmonics associated with the acceptable distortion levels set forth in IEEE Std 519-1993 [B38] 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.

4.3.2 Effect of transients on distribution line protection

Distribution line protective relays can be negatively affected by power transients, and their effect should always be evaluated when applying settings. For example, if a large capacitor bank is installed at the

substation bus, “close in” faults can cause large capacitor discharge currents to flow resulting in the possible misoperation of instantaneous over-current relays. Additional examples of transients are transformer energization inrush and system switching. Typically, time over-current relays are not affected by transients since the transient will be dampened out much faster than the relay operating time.

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.

When applied to reclosers and breakers, the interrupt current rating must be greater than the maximum expected symmetrical fault current at the device’s point of application. The X/R ratio at that location must be equal to or less than that at which the recloser is tested, at the maximum interrupting current, during the operating duty test. No uprating for symmetrical fault currents occurring at X/R ratios less than these maximums for which the recloser is tested should be allowed.

Typically, reclosers are rated up to 20 kA. Circuit breakers are rated up to 63 kA for distribution applications.

5. System configuration and components

5.1 System

5.1.1 Neutral treatment

As mentioned in 4.1.1, 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” [B52] and *Electricity Distribution Network Design* [B55]).

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. 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 and 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. 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 unfaulted phases does not exceed 35% of nominal voltage (see IEEE Std C62.92.4).⁴ Ground fault protection is provided by ground overcurrent relays set more sensitively than phase overcurrent relays, depending on the load unbalance as explained in 5.1.1.2.

⁴ Information on references can be found in Clause 2.

Advantages of multi-grounded systems are that the overvoltages during ground faults are low and protection is simple and inexpensive.

Disadvantages of multi-grounded systems are that the circuit should be quickly interrupted when ground faults occur to prevent the high fault currents from causing excessive damage, to prevent damage to unfaulted circuit components, and to minimize the duration of voltage dip to customers connected to the faulted phase.

5.1.1.2 Ungrounded system

Ungrounded systems (Figure 5-1) 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 5-2), 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. Magnitudes can be approximately calculated from Equation (3) (as shown in Figure 5-3).

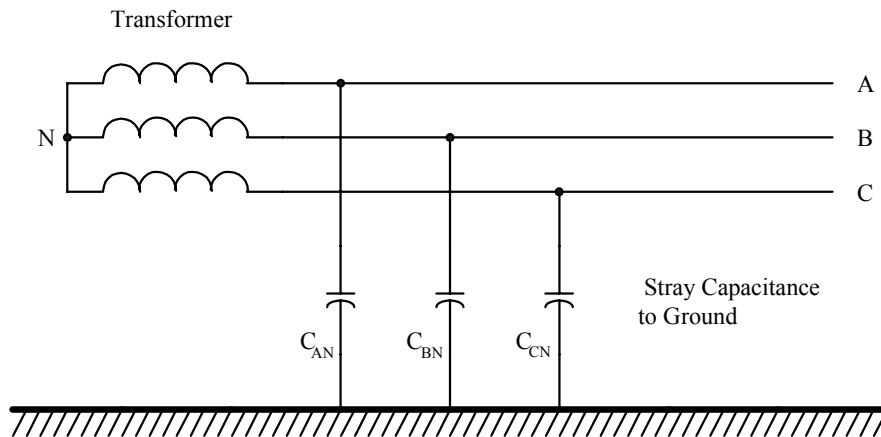


Figure 5-1—Ungrounded system

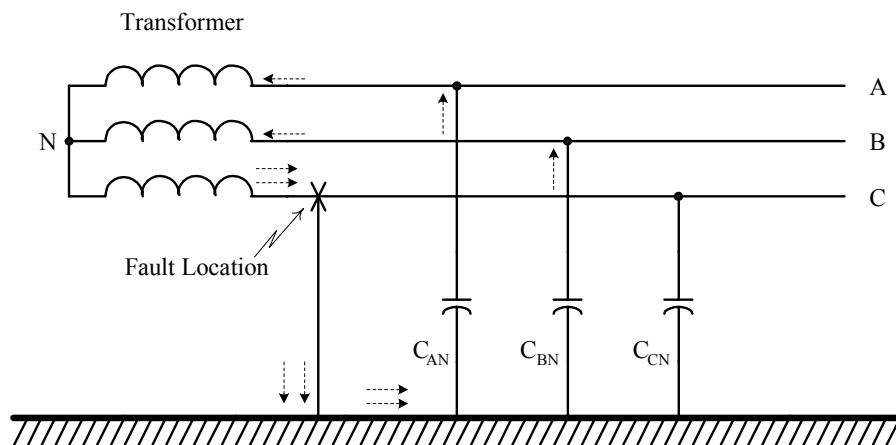


Figure 5-2—Ground fault in ungrounded system

$$C_{AN} = C_{BN} = C_{CN} = C \quad (\text{phase-to-ground capacitance of each phase})$$

$$|V_{AN}| = |V_{BN}| = |V_{CN}| = V_{PH} \quad (\text{phase-to-ground voltages})$$

$$I_A = j\omega CV_{CA}$$

$$I_B = -j\omega CV_{BC}$$

$$I_f = |\vec{I}_A + \vec{I}_B| = 3\omega CV_{PH} \quad (\text{fault current}) \quad (3)$$

where

ω is equal to $2\pi f$ rad/s

Ground faults also cause phase-to-ground voltage rise on the unfaulted phases (A and B in Figure 5-3) approaching $\sqrt{3} \times$ nominal. The insulation level of feeders should be designed to accommodate this voltage increase, which is 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. This 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 10 kV system can be energized at 20 kV, since they are already designed for this higher voltage, allowing transfer of two times 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 8.15. Phase difference between residual voltage and residual current is approximately 90° (Figure 5-3).

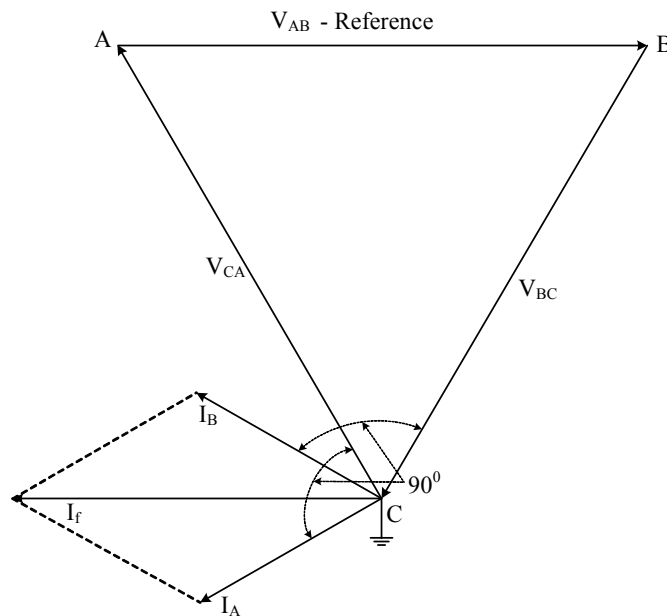


Figure 5-3—Voltage and ground fault currents in ungrounded system

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 should be applied to detect the condition and alert the operators so that the fault can be located and repaired in a timely manner.

A disadvantage of the ungrounded system is that fault current arcs cannot self-extinguish when capacitive currents become high. Also, intermittent arcing can occur and develop high-frequency oscillations that can cause overvoltage escalation of several times rated voltage. There will be fundamental frequency voltage rises on healthy phases; therefore 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.

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 5-4) or a four-wire system with an insulated neutral. Ground-fault currents can be as high as phase-fault currents or even higher, similar to multi-grounded systems. However, ground fault currents flow back to the source through earth. A very high voltage between the faulted point and the reference ground (V_g) 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 (Figure 5-5).

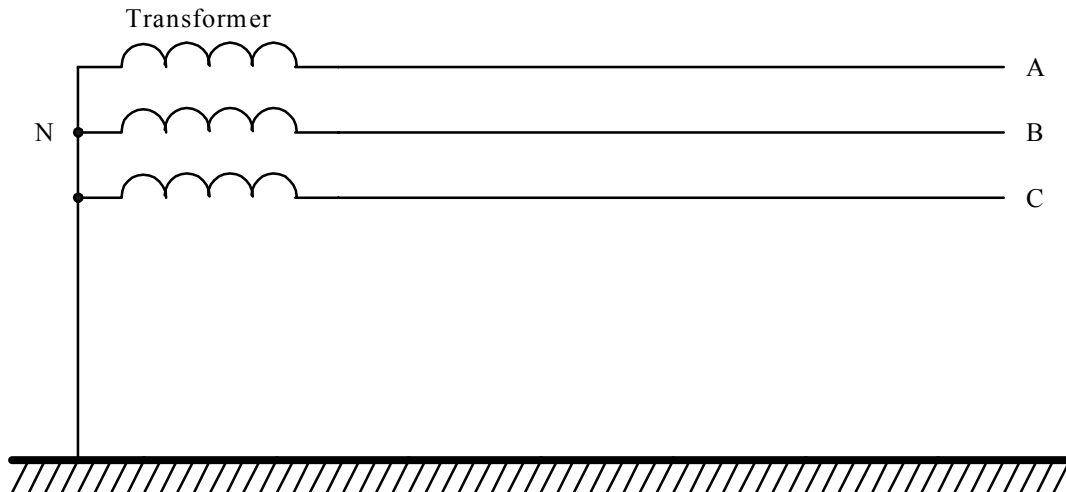


Figure 5-4—Solidly uni-grounded system

Advantages are that overvoltages are small (usually below 1.4 p.u.), and intermittent arc voltages are avoided. Because the transformer windings near the neutral do not see high voltages even during ground faults, this permits a graded insulation of the entire winding, which is less expensive.

A disadvantage is that extensive analysis is needed to design an effective grounding system.

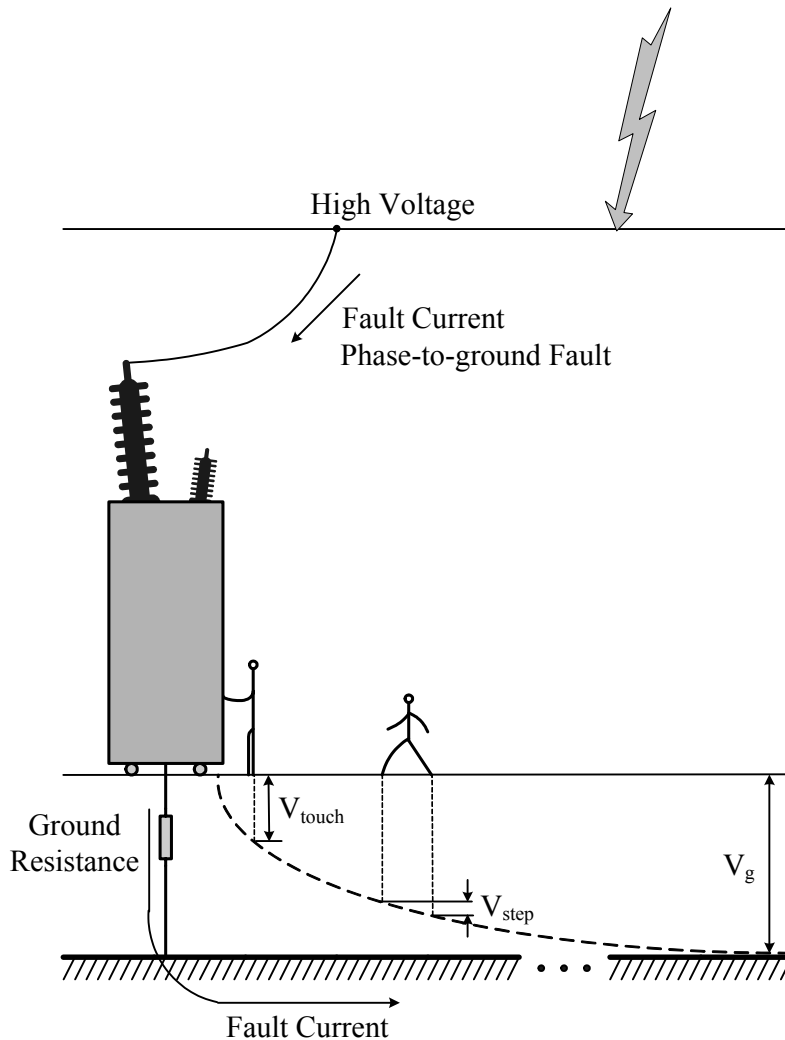


Figure 5-5—Touch and step voltages for a substation transformer

5.1.1.4 Resonant-grounded system

Resonant-grounded systems are most often applied in Europe. In this method, the transformer neutral is grounded through a reactance, also known as a Petersen coil (Figure 5-6). 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 (4). In the case of a ground fault (C phase-to-ground fault in Figure 5-7), 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. Figure 5-7 illustrates 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.
- Intermittent ground faults are avoided.

Disadvantages of a resonant-grounded system include the following:

- Phase-to-ground voltages can be high due to resonance.
- 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.

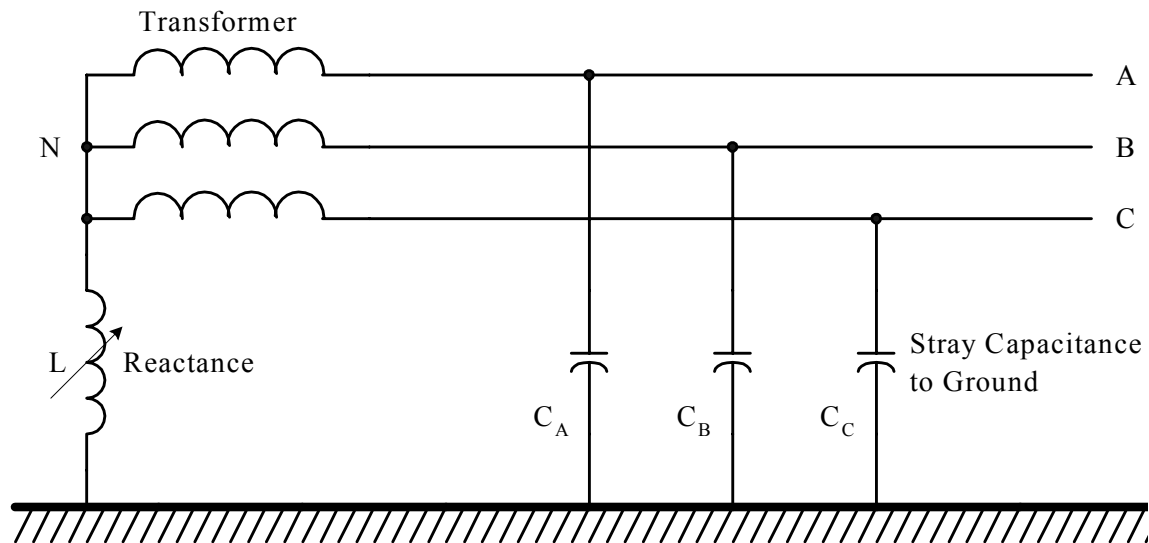


Figure 5-6—Resonant-grounded system

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

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

$$L = \frac{1}{3\omega^2 C} \quad (4)$$

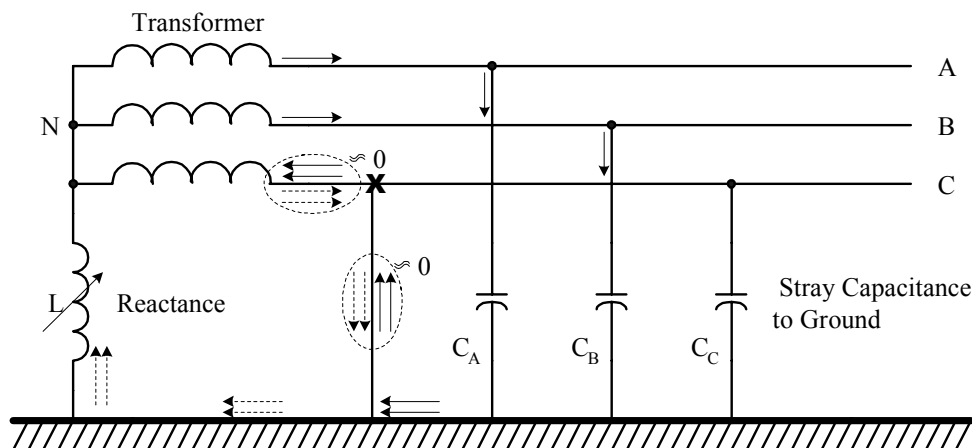


Figure 5-7—Ground fault in resonant-grounded system

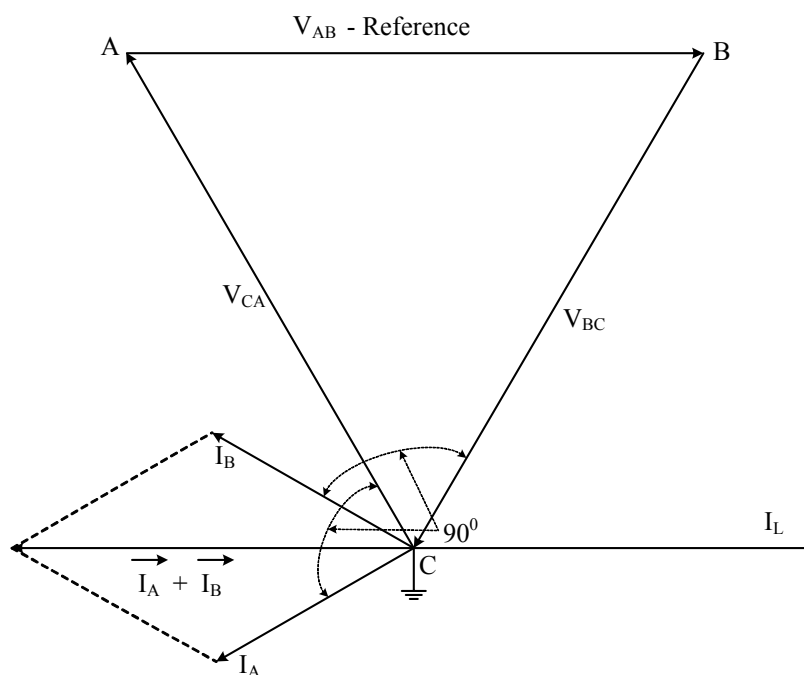


Figure 5-8—Voltages and ground fault currents in resonant-grounded system

5.1.1.5 Resonant-grounded system

To limit ground fault currents and reduce dynamic and thermal stress on equipment (particularly transformers), resistors or reactors are installed from the transformer's neutral to ground (Figure 5-9). 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.

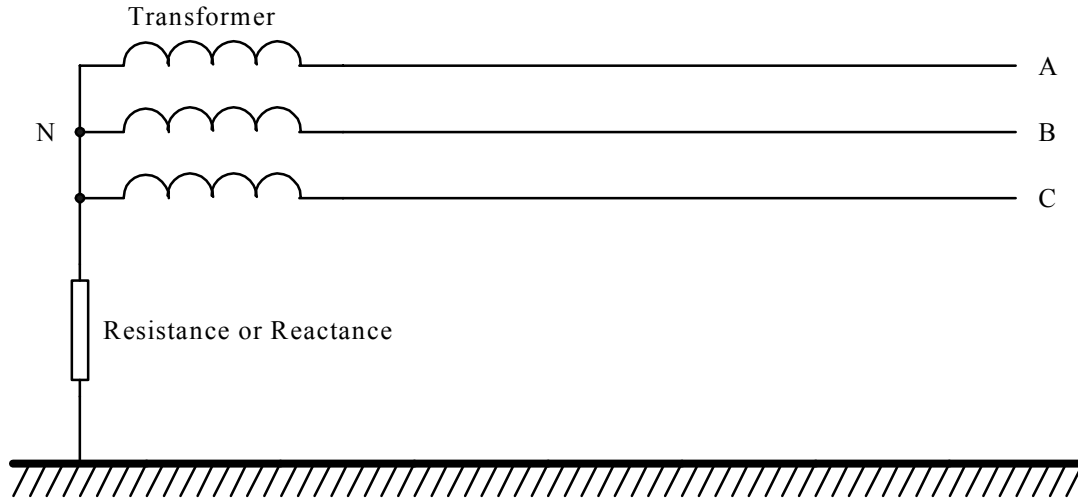


Figure 5-9—Resistively or reactively grounded system

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.
- 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 5-1 presents comparative results of the impact of different transformer neutral treatments on a typical distribution system during phase-to-ground faults. Figure 5-10 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.

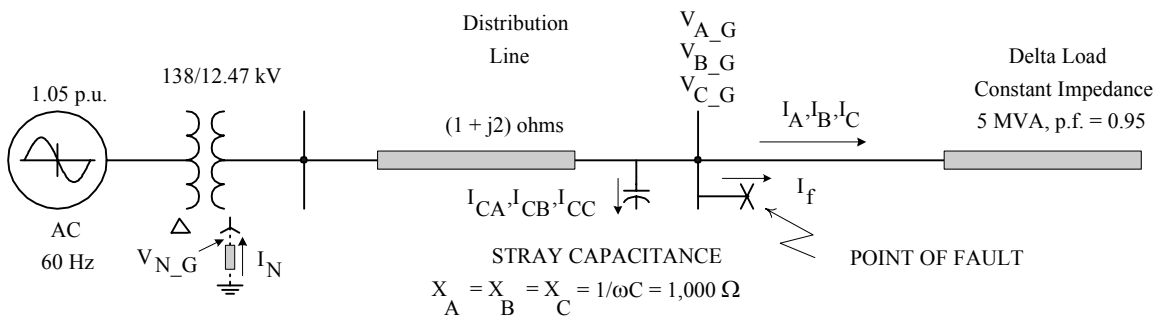


Figure 5-10—A typical distribution system with a radial feeder

Table 5-1—System voltages and currents during single-phase-to-ground faults for different neutral treatments

Neutral impedance (Ω)		Normal operation	Single-phase-to-ground fault (refer to Figure 5-10)				
			Solidly grounded	Ungrounded	Resonant grounded	Resistor grounded	Reactor grounded
			0.1 Ω	10 000 Ω	1 000/3 Ω	10 Ω	10 Ω
Voltage at fault	V_{AG} [V]	7 159	7 276	12 430	12 400	10 480	11 610
	V_{BG} [V]	7 163	7 252	12 480	12 400	11 860	10 580
	V_{CG} [V]	7 161	2 062	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	7 197	7 141	5 795	5 601
	I_N [A]	0	2 067	0	21.4	579	560
Fault current	I_f [A]	0	2 062	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 Fault studies

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. A fault study should be performed to obtain these levels at each node of the circuit.

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 5-11). These conditions are calculated for three-phase, line-to-line, and line-to-ground faults. Normally, fault current decreases as the fault resistance increases. However, there are actual circuits where the current magnitude in one phase of a double-line-to-ground fault will increase when going from a zero to a non-zero value of fault impedance (see *Electrical Distribution-System Protection* [B12]).

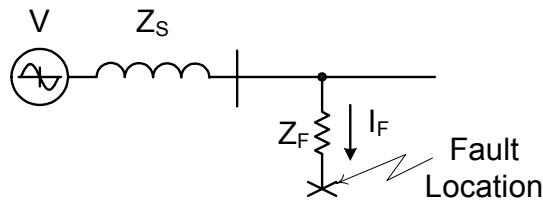


Figure 5-11—Fault on radial system

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.

5.1.2.1 Methods for calculating source impedance

Depending on the information available, several methods for calculating source impedance may be used.

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 of the effect of the transformer connections.

If a short-circuit study was performed and the per-unit values of fault current for a three-phase fault ($I_{f_{3ph}}$), line-to-line fault ($I_{f_{ph-ph}}$), and line-to-ground fault ($I_{f_{ph-G}}$) at the high-voltage (HV) bus of the distribution substation were determined, symmetrical components Z_{s1} , Z_{s2} , and Z_{s0} of source impedances at the HV bus can be found from Equation (5), Equation (6), and Equation (7), as follows:

$$Z_{s1} = \frac{V_{l-n}}{I_{f_{3ph}}} - Z_f \quad (5)$$

$$Z_{s2} = \frac{j\sqrt{3}V_{l-n}}{I_{f_{ph-ph}}} - Z_{s1} - Z_f \quad (6)$$

$$Z_{s0} = \frac{3V_{l-n}}{I_{f_{ph-G}}} - Z_{s1} - Z_{s2} - 3Z_f \quad (7)$$

Knowing that transmission lines and transformers have $Z_1 = Z_2$ and assuming $Z_f = 0$, then for single- and three-phase faults, the source impedances Z_{s1} , Z_{s2} , and Z_{s0} can be calculated using Equation (8), Equation (9), and Equation (10) as follows:

$$Z_{s1} = \frac{V_{l-n}}{I_{f_{3ph}}} \quad (8)$$

$$Z_{s2} = Z_{s1} \quad (9)$$

$$Z_{s0} = \frac{3V_{l-n}}{I_{f_{ph-G}}} - 2Z_{s1} \quad (10)$$

The Z_{s1} , Z_{s2} , and Z_{s0} values obtained from the Equation (8), Equation (9), and Equation (10) are HV bus values and have to be appropriately combined with the per-unit symmetrical components of the substation transformer to obtain the source symmetrical components at the LV side of the substation.

If only the three-phase fault kVA available at the HV bus is given, then the value for Z_{s1} magnitude is calculated by converting the fault kVA to a per-unit fault current magnitude, using Equation (11) and assuming a nominal system voltage if the actual line-to-line value of V at the HV bus is unknown. The per-unit magnitude of Z_{s1} can also be found from Equation (11) as follows:

$$|Z_{s1}| = \frac{V^2}{\frac{kVA_{3ph(FAULT)}}{kVA_B}} = \frac{V^2}{kVA_{3ph(FAULT_{pu})}} \quad (11)$$

where

$ Z_{S1} $	is the magnitude of positive-sequence source impedance (per unit)
V	is the line-to-line voltage at the substation HV bus (per unit)
$kVA_{3ph (FAULT)}$	is the available three-phase fault kilovolt-ampere
kVA_B	is the base kilovolt-ampere
$kVA_{3ph (FAULT)pu}$	is the three-phase fault kilovolt-ampere (per unit)

5.1.3 Fault impedance

Fault impedance (Z_f) is the impedance involved in the fault (see *Electrical Distribution-System Protection* [B12]). Z_f is different than positive- (Z_1) or zero-sequence (Z_0) impedances, which are system characteristics. Z_f is an impedance, resistive or reactive, between the faulted power system phase conductor(s) or between phase conductors and ground. Z_f is not earth resistivity or the mutual impedance between an overhead conductor and a conducting ground plane. Z_f depends on the fault type and the environment. A line-to-line 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 Z_f value if the conductor drops into a stream or ground water, or it can cause a high Z_f value if it drops onto a dry pavement.

Z_f is also a time variable. 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.

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 Z_f added at the end of the protected area. Frequently used values range from 0 Ω to 40 Ω .
- Set Z_f to a value that provides a minimum fault current equal to the continuous current carrying capability of the conductor. Fault currents below the thermal limit of the conductor may not be detected.
- Use a percent of three-phase fault currents.

5.1.4 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 the involved duplicate systems installed for metropolitan service where the importance of maintaining continuity of service justifies a high capital expenditure.

Bus configuration for distribution buses may differ radically from the layout of transmission buses. In some metropolitan developments supplying underground cable systems, segregated-phase layouts are employed to secure the maximum of reliability in operation (see *Electrical Transmission and Distribution Reference Book* [B2]).

The following are some commonly used distribution substation bus arrangements and a description of the protective relay issues that these bus arrangements create.

Figure 5-12 shows a substation with a fused transformer, transformer secondary breaker (T), and three feeder breakers (F). The transformer secondary breaker provides bus protection and backup for the feeder breakers. Overcurrent relays on the transformer secondary breaker should be set below the transformer damage curve. Overcurrent relays on the feeder breakers should be set to coordinate with the transformer secondary relays and with downstream devices on the feeder. In this substation, there are two sets of relay curves to coordinate between the primary fuse and devices on the feeder. In some installations, the secondary breaker is omitted; then bus protection and feeder backup protection should be provided by the transformer fuse.

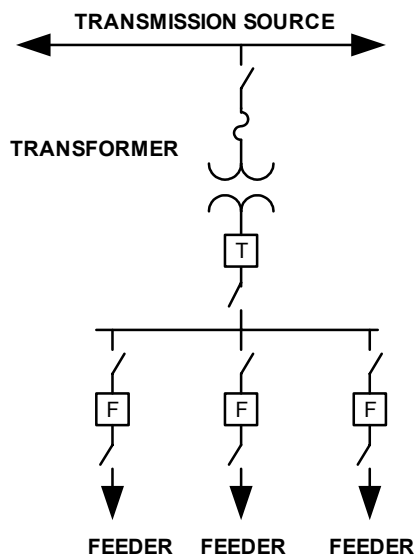


Figure 5-12—Single transformer distribution bus

Figure 5-13 shows a similar substation with a second transformer, a bus tie breaker (B), and additional feeders. Time overcurrent relays on the bus tie breaker should be coordinated with relays on the transformer secondary breakers and the feeder relays. This means there are three sets of relay curves to coordinate between the primary fuse and devices on the feeder.

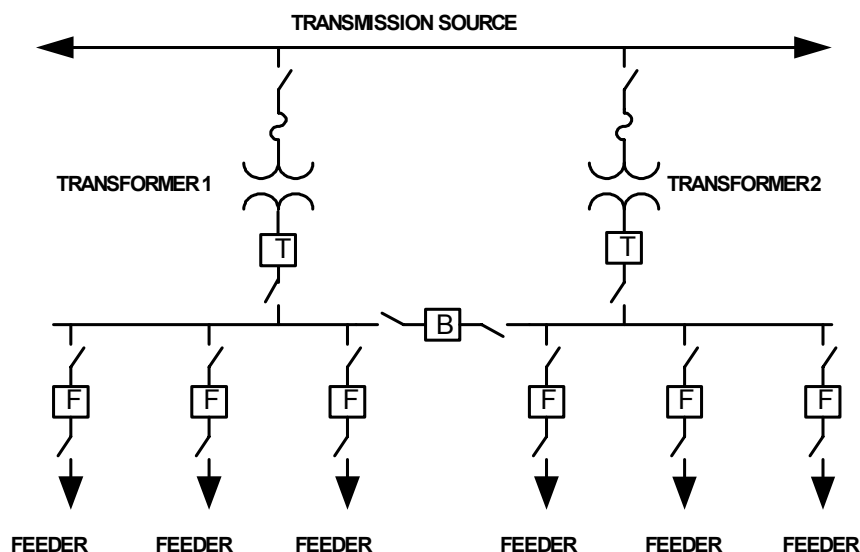


Figure 5-13—Two-transformer distribution bus