

IEEE Guide for Protective Relay Applications to Transmission Lines

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Abstract: This newly developed guide compiles information on the application considerations of protective relays to ac transmission lines. The guide describes accepted transmission line protection schemes and the different electrical system parameters and situations that affect their application. Its purpose is to provide a reference for the selection of relay schemes and to assist less experienced protective relaying engineers in their application.

Keywords: protective relaying, relay application, relaying, transmission line protection

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Introduction

(This introduction is not part of IEEE Std C37.113-1999, IEEE Guide for Protective Relay Applications to Transmission Lines.)

The art and science of the protective relaying of transmission 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 transmission lines. The guide presents a review of generally accepted transmission 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 transmission 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 Transmission Lines

1. Overview

This guide presents a review of the generally accepted transmission line protection schemes. Its purpose is to present the concepts of line protection and to describe the typical means of implementing such concepts. It is intended for engineers who have a working knowledge of power system protection or who have a need to understand the fundamentals of the various schemes. The fundamentals and definitions describing the relay schemes are written in a way intended to be understood by both relay and non-relay engineers. The circuits and operating characteristics of the various schemes are critically examined so the reader can understand and evaluate the advantages and disadvantages of the specific applications and evaluate alternative relays and relaying packages. This is an application guide and does not cover all of the protective requirements of all transmission line configurations in every situation. Additional reading material is suggested so the reader can evaluate the required protection for each application.

1.1 Scope

The study of transmission line protection offers an opportunity to examine many fundamental relaying considerations that apply, in one degree or another, to the protection of other types of power system equipment. Each electrical element, of course, will have protection problems unique to itself; however, the concepts associated with transmission line protection are fundamental to all other electrical devices and provide an excellent starting point to examine and appreciate the implementation of all power system protection. The basic relaying characteristics of reliability, selectivity, local and remote backup, zones of protection, coordination, and speed are present in almost all relaying situations. This guide specifically addresses these concepts for transmission line protection, but the ideas are universally applicable. Since transmission lines are also the links to adjacent lines or connected equipment, the protection provided for transmission lines must be compatible with the protection provided for all of these other elements. This requires coordination of settings, operating times, and characteristics. Individual relays, such as overcurrent, directional, and distance, as well as the total protection package, including the communication channels, are all examined in this guide, with appropriate discussion relating to their application and their particular advantages and disadvantages. Special topics, such as the effects of series capacitors or static volt-ampere reactive (var) systems and consideration for tripping versus blocking during system power swing conditions, are also discussed.

In addition to the protection of the line itself, consideration is given to the various system configurations and bus arrangements, mutually coupled lines, reclosing, and the impact that system performance and parameters have on the selection of relays and relay schemes. Special protection systems, multiterminal lines, and single-phase tripping are among the topics covered.

2. References

This guide shall be used in conjunction with the following publications. When the following standards are superseded by an approved revision, the revision shall apply.

IEEE Std 100 -1996, The IEEE Standard Dictionary of Electrical and Electronics Terms, Sixth Edition.¹

IEEE Std C37.2-1996, IEEE Standard Electrical Power System Device Function Numbers and Contact Designations.

IEEE Std C37.90-1989 (Reaff 1994), IEEE Standard for Relays and Relay Systems Associated with Electric Power Apparatus.

IEEE Std C37.90.1-1989 (Reaff 1994), IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems.

IEEE Std C37.100-1992, IEEE Standard Definitions for Power Switchgear.

IEEE Std C37.109-1988 (Reaff 1999), IEEE Guide for the Protection of Shunt Reactors.

IEEE Std C37.110-1996, IEEE Guide for the Application of Current Transformers Used for Protective Relaying Purposes.

3. Fundamentals

3.1 Terms and definitions

For the purpose of this guide, the following terms and definitions apply. IEEE Std 100-1996 should be referenced for terms and definitions not defined in this subclause.

3.1.1 Transmission line

Terms such as transmission, subtransmission, and distribution lines have different connotations among different companies. Such issues as what constitutes a line terminal may also vary among companies. Clauses of this guide will address the many line configurations and the effect these configurations may have on the protection of these lines.

For purposes of protection, a “line” is defined by the location of the circuit breakers (or other sectionalizing devices) that serve to isolate the line from other parts of the system. The line includes the sections of bus, overhead conductor, underground cable, and other electrical apparatus (including line traps, series capacitors, shunt reactors, and autotransformers) that fall between these circuit breakers. In Figure 1, segments 1 to 2 and 3 to 4 are defined as lines. It would normally be assumed that two or more stations are involved or the circuit breakers are too far apart to allow interconnection of control cables and station ground mats.

¹IEEE publications are available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA (<http://www.standards.ieee.org/>).

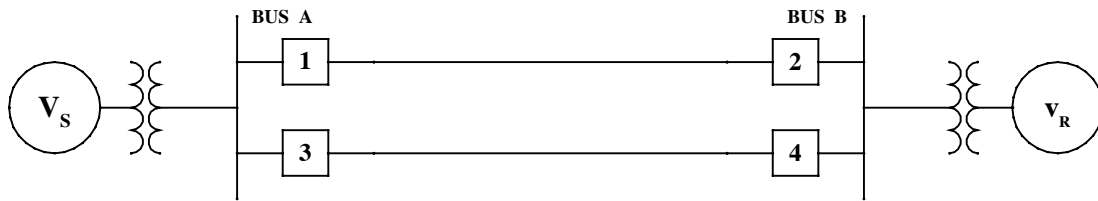


Figure 1—Definition of lines

3.1.2 Zone of protection

There are four basic types of protection zones, as shown in Figure 2. The four types are as follows:

- a) Generator
- b) Transformer
- c) Bus
- d) Lines

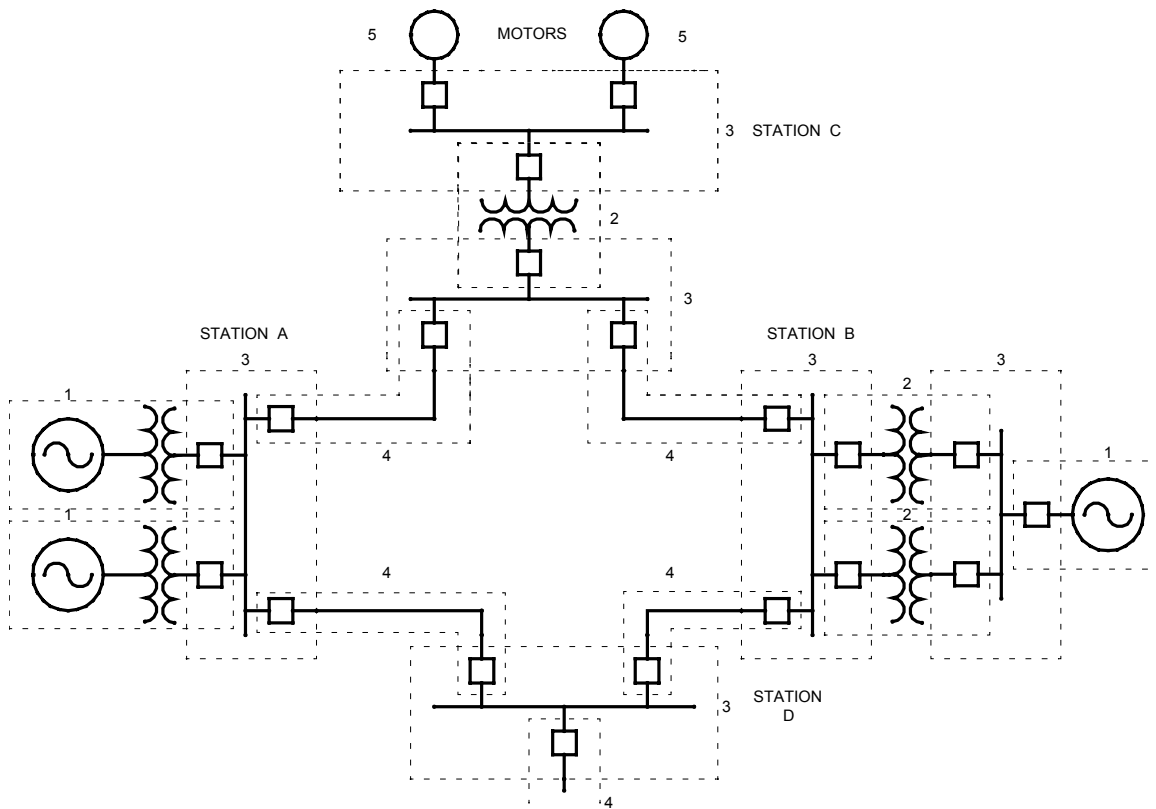


Figure 2—Typical system and its zones of protection

The boundaries of the zone of protection, as it applies to protective relays, are determined by the locations of the current transformers (CTs) that provide the representation of the line currents to the relays. Overlapping zones of protection is an established protection concept represented by Figure 3.

For pilot communication line protection schemes, the boundaries of the zone of protection are clearly defined. Many line protection practices, however, have unrestricted zones; the start of the zone is defined by the CT location, but the extent of the zone is determined by measurement of system quantities that may vary with generation and system configuration changes.

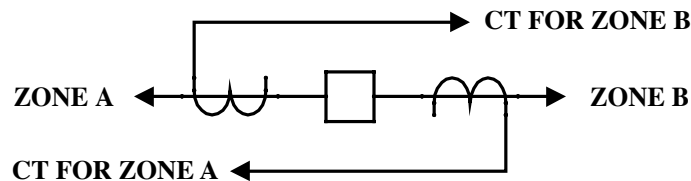


Figure 3—The principle of overlapping protection

3.1.3 Definitions

For the purposes of this standard, the following terms and definitions apply:

3.1.3.1 adaptive relay: A relay that can change its setting and/or relaying logic upon the occurrence of some external signal or event.

3.1.3.2 adaptive relaying: A protection philosophy that permits, and seeks to make adjustments automatically, in various protection functions to make them more attuned to prevailing power conditions.

3.1.3.3 apparent impedance: The impedance to a fault as seen by a distance relay is determined by the applied current and voltage. It may be different from the actual impedance because of current outfeed or current infeed at some point between the relay and the fault (see 5.5.1 and 5.5.2).

3.1.3.4 arc resistance: The impedance of an arc that is resistive by nature; it is a function of the current magnitude and arc length.

3.1.3.5 backup zone: The protected zone of a relay that is not the primary protection. It is usually time delayed (e.g., zones 2 and 3 of a distance relay). In addition, the backup zone will usually remove more of the system elements than required by the operation of the primary zone of protection.

3.1.3.6 blocking signal: A logic signal that is transmitted in a pilot scheme to prevent tripping.

3.1.3.7 breaker failure: The failure of a circuit breaker to operate or to interrupt a fault.

3.1.3.8 circuit switcher: A circuit interrupting device with a limited interrupting rating as compared with a circuit breaker. It is often integrated with a disconnecting switch. Its design usually precludes the integration of current transformers (CTs).

3.1.3.9 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.

3.1.3.10 cross polarization (protective relaying): The polarization of a relay for directionality using some proportion of the voltage from a healthy (unfaulted) phase(s). One example of this is quadrature polarization. In this case, the polarizing voltage is in quadrature to the faulted phase voltage.

3.1.3.11 current differential relay: A relay designed to detect faults by measuring the current magnitude and phase angle difference between relay terminals of a transmission line.

3.1.3.12 distance relay: A protective relay in which the response to the input quantities is primarily a function of the electrical circuit distance between the relay location and the point of fault.

3.1.3.13 dual polarization: The polarization of a relay using current and voltage sources.

3.1.3.14 fault impedance: An impedance, resistive or reactive, between the faulted power system phase conductor(s) or ground.

3.1.3.15 grounding transformer: A transformer(s), delta-wye or zig-zag connected, installed to establish a system ground and thus provide a source of zero-sequence current for ground fault detection.

3.1.3.16 ground distance relay: A distance relay designed to detect phase-to-ground faults.

3.1.3.17 hybrid scheme: A relay scheme (usually a pilot scheme) combining the logic of two or more conventional schemes.

3.1.3.18 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.

3.1.3.19 infeed: A source of fault current between a relay location and a fault location.

3.1.3.20 lenticular characteristic: A distance relay characteristic having a lens shape on a resistance-reactance (R-X) diagram.

3.1.3.21 mho unit: A distance relaying unit having a circular impedance tripping locus that passes through the origin on an R-X diagram

3.1.3.22 multiterminal: A transmission line with more than two terminals having a source of power.

3.1.3.23 outfeed: A current out of a terminal on a faulted line. Outfeed only occurs on multiterminal or series compensated lines.

3.1.3.24 overlapping protection: A situation in which the protected zone of one relay overlaps the protected zone of another relay (usually done to ensure protection of equipment at the border of a protected zone). This is often necessary due to the location of current transformers (CTs) on equipment.

3.1.3.25 permissive: Pertaining to a scheme requiring permission to trip from a remote terminal, usually in the form of a pilot signal.

3.1.3.26 phase comparison protection: A form of pilot protection that compares the relative phase angle position of specified currents at the terminals of a circuit.

3.1.3.27 phase distance relay: A distance relay designed to detect phase-to-phase and three-phase faults.

3.1.3.28 pilot communication scheme: A protection scheme involving relays at two or more substations that share data or logic status via a communication channel to improve tripping speed and/or coordination.

3.1.3.29 primary zone: The part of a relay's protected zone where the relay operates with no intentional time delay.

3.1.3.30 quadrilateral characteristic: A distance relay characteristic on an R-X diagram created by a directional measurement, a reactance measurement, and two resistive measurements.

3.1.3.31 segregated phase comparison: Similar to phase comparison, except data on each phase and ground is sent separately to the remote terminal for comparison with the local phase data at that terminal.

3.1.3.32 self-checking (by a relay): Self-testing by microprocessor-based relays that checks operation of the processor software.

3.1.3.33 sequential tripping: A situation where one or more relay terminals of a line cannot detect an internal line fault, typically because of infeed, until one or more terminals has already opened and removed the infeed.

3.1.3.34 source impedance: The Thevenin equivalent impedance of an electrical system at the terminal of a transmission line. In network applications, this impedance can vary depending on the location of the fault on the transmission line and the status (i.e., opened or closed) of other terminals associated with the transmission line.

3.1.3.35 source of fault current: A terminal that contributes a significant amount of current to a fault on the protected line. Note that it is not necessary for generation to be connected to a terminal for it to be a source of fault current. For instance, large synchronous motor loads can contribute significant amounts of fault current for a few cycles within the duration of fault clearing. Transformers can also be a significant source of zero-sequence currents to unbalanced faults involving ground if they have winding with a grounded neutral connected to the line, and also have a delta or zig-zag winding.

3.1.3.36 source-to-line impedance ratio (SIR): The ratio of the source impedance behind a relay terminal to the line impedance.

3.1.3.37 step distance: A non-pilot distance relay scheme using multiple zones with time delay to differentiate between the zones.

3.1.3.38 swing: A transient power flow due to change in relative angles of generation on the system caused by a change in transmission or generation configuration.

3.1.3.39 switch onto fault protection: This provides tripping in the event that the breaker is closed into a zero voltage bolted fault, such as occurs if the grounding chains were left on the line following maintenance (also called line pickup protection).

3.1.3.40 transfer trip: The sending of a TRIP signal via a communication channel to a remote line terminal.

3.1.3.41 unblocking: Logic that will allow a permissive pilot scheme to trip for an internal fault within a time window, even though the pilot TRIP signal is not present when the signal is lost due to the fault.

3.1.3.42 untransposed: Refers to the physical positions of the phase conductors of a transmission line, which are not interchanged periodically to balance the mutual impedances between phases.

3.1.4 Acronyms and abbreviations

AT	audio tones (pilot-wire)
BCG	phase B to phase C to ground fault
CCVT	capacitance coupled voltage transformer
CT	current transformer
CVT	capacitance voltage transformer
DUTT	direct underreaching transfer trip
EHV	extra high voltage
FO	fiber optic
FSK	frequency shift keying
GIC	geomagnetically induced currents
IOC	instantaneous overcurrent
LOP	loss of potential
MOV	metal oxide varistor
MW	microwave
OS	out-of-step
PLC	power line carrier
POTT	permissive overreaching transfer trip
PUTT	permissive underreaching transfer trip
PW	pilot-wire
R	point-to-point radio
RO	overreaching
RU	underreaching
R-X	resistance-reactance
SIR	source-to-line impedance ratio
SVC	static var compensator
TOC	time overcurrent
UHV	ultra high voltage
var	volt ampere reactive
VT	voltage transformer

3.1.5 Symbols

Symbols used in this document and their meanings are shown in Figure 4.

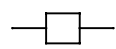
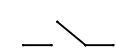
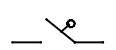
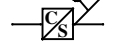
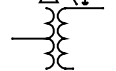
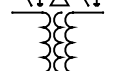
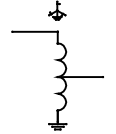
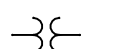
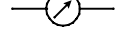
	CIRCUIT BREAKER
	DISCONNECT SWITCH
	MOTOR OPERATED DISCONNECT SWITCH
	CIRCUIT SWITCHER
	TWO WINDING TRANSFORMER
	THREE WINDING TRANSFORMER
	AUTO TRANSFORMER
	CURRENT TRANSFORMER (CT)
	VOLTAGE TRANSFORMER (VT)
	OVERHEAD LINE
	UNDERGROUND CABLE
	PHASE SHIFTING TRANSFORMER
	PROTECTIVE RELAY

Figure 4—Symbols

3.1.6 Graphical representation methods

There are many ways to represent electrical systems and the applied protection. These include three-line ac diagrams; one-line diagrams; one-line diagrams with CTs, voltage transformers (VTs), protection, and other related equipment superimposed; dc and ac schematics; relay functional diagrams; and dc elementary diagrams.

In Figure 5, the connections of protective relays are shown in their broadest level (minimum detail) in a one-line diagram. The relays are represented as circles labeled “R” (for relay), connected by single lines to current and VTs. Connections shown as single lines are actually three-phase circuits. This type of single-line diagram is useful for understanding the various zones of protection. One of the relays shown in Figure 5 is labeled “21,” which indicates the type of protection this device provides. Function numbers are given in IEEE Std C37.2-1996.

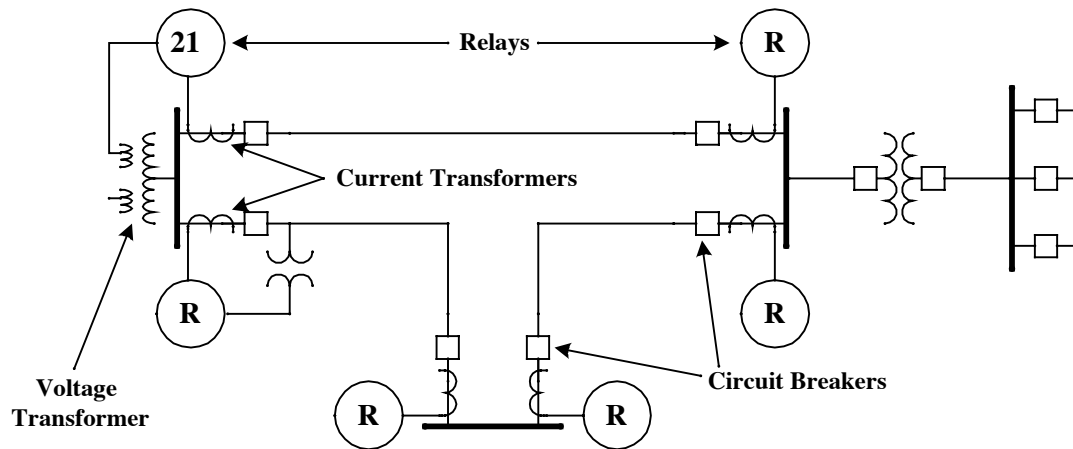


Figure 5—One line diagram

More detailed methods of showing relay connections, such as three-line schematics, dc schematics, and wiring diagrams, are not discussed in this guide.

In addition, protection characteristics can be shown on time-current diagrams, R-X diagrams, and one-line diagrams with zones or time characteristics overlaying the lines. Figure 6 shows one method of representing protective relay characteristics. This particular characteristic is the current versus time characteristic of a time overcurrent relay. The characteristic shows two regions: one in which the relay operates, and the other in which the relay does not operate. The line separating the regions is the characteristic curve of the relay.

Figure 7 shows another method of representing relay operating characteristics using an R-X diagram. Again, the characteristic separates two regions.

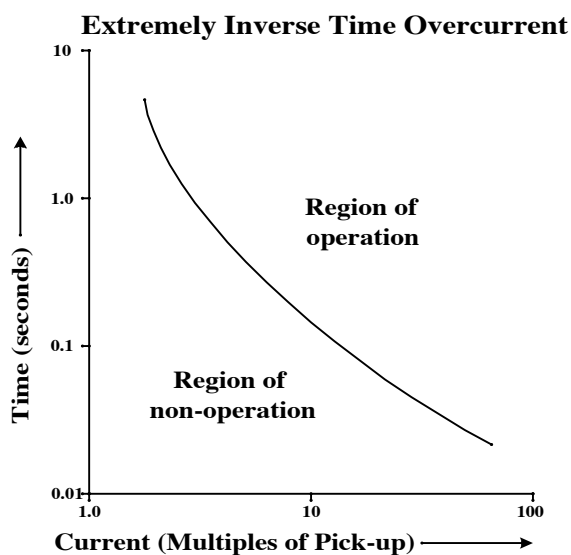


Figure 6—Extremely inverse time overcurrent characteristic

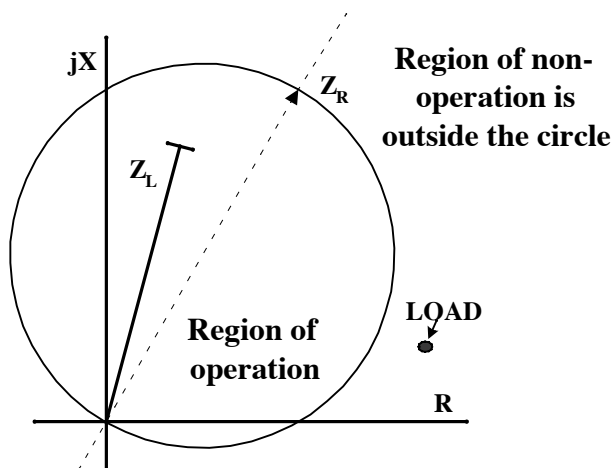


Figure 7—R-X diagram

3.2 Line relaying selection

The selection of line protection requires the consideration of several factors, some of which are mutually exclusive. Knowledge of the most probable failures, recommendations of equipment suppliers, and good practical judgment can assist the protection engineer in determining which of the factors deserve the most emphasis.

One of the most important design considerations of relaying is reliability. Relaying reliability is separated into two aspects: dependability and security. Dependability is defined as “the degree of certainty that a relay or relay system will operate correctly.” Security is defined as “the degree of certainty that a relay or relay system will not operate incorrectly.” In other words, dependability is a measure of the relay’s ability to operate when it is supposed to operate. Security is a measure of the relay’s ability to avoid operation for all other conditions for which tripping is not desired.

Dependability is relatively easy to obtain in relay design or in the application of a number of relays. Testing using operating conditions, fail-safe designs, and redundancy are methods to ensure dependability. Security is harder to attain; an almost infinite variety of tests would be needed to simulate all possible conditions to which a relay may be exposed.

Various engineering practices can enhance dependability. These include independence of design, different operating principles, redundancy within the relay systems, local backup methods, remote backup methods, and application of relays and relay systems that cause undesirable trips upon failure. Security can be enhanced by using relays that fail into a “disarmed” mode, series connected protection, improved monitoring and self-checking, and emphasis on high-quality components.

Another important design consideration is protection selectivity or coordination. Selectivity is the ability of relays and relaying systems to cooperate with each other to minimize the outaged area resulting from a fault. Coordination refers to the process of applying relays to operate as fast as possible for conditions with their primary zone, but to have delayed, or coordinated operations for conditions within an extended backup zone. Selectivity and coordination must be achieved to ensure maximum service continuity.

Fault clearing time is an important consideration in the selection of line relaying. Requirements for relaying speed must be carefully determined. If the relaying is too slow, system instability, excessive equipment damage, and adverse effects on customer service may result. However, faster protection tends to compromise relay system security and selectivity. There is a limit to the speed with which a relay can correctly respond due to the transients present in the power system itself (see 5.10).

Sensitivity of protection refers to the minimum operating quantities that must be available for the relays to detect an abnormal condition. While this factor is still important, most modern relays are using solid state or microprocessor technologies that are many times more sensitive than their electromechanical predecessors. Certain problems, such as high-impedance ground faults, inherent system voltage unbalances, and high source-to-line impedance ratios (SIRs) still challenge the sensitivity of relays and should be considered in relay selection.

The line protection design may often fail to recognize one of the more important design factors—simplicity. The multifunction and programmable capabilities of modern relays have created an abundance of special solutions to possible system problems. The implementation of these solutions challenges the application engineer, those responsible for setting the relays, and operations and maintenance personnel. The problems caused by incorrect or incomplete implementation of overly complex protection may create more serious consequences than not providing special solutions. The protection engineer should carefully weigh the consequences and probability of each problem to determine if it justifies using complex special solutions.

Economic evaluations of protection options will continue to be necessary. Protection engineers have long pointed to the relatively low cost and high importance of relays compared with the equipment they protect. However, it is fundamental to attempt to achieve the required protection at the lowest cost. In recent years, more importance has been placed on economic analysis that considers more than just the lowest initial cost. Installation and maintenance costs, as well as the cost of unreliable protection, are sometimes considered. In addition, modern protection usually offers many features not previously available that may result in improvements in operations, restoration of the system, and post-fault analysis. The value of these improvements should be considered in a complete economic evaluation of alternatives.

Certain transmission system configurations and characteristics require protective relaying with communication systems to provide high-speed clearing for all faults within the zone of protection. Pilot relaying schemes are employed to provide this high-speed fault clearing. These pilot relaying systems require the transmission of information during a fault between relays that are located in different substations to determine if the fault is internal or external to the zone of protection. This is accomplished using several different methods, ranging from direct hardwire communications to fiber optic communications systems (see 4.1). Different protection schemes and communication channels have different degrees of reliability. Knowledge of these different communication options is necessary to determine the reliability of the protection scheme being considered. The network configuration and local system loading requirements may also affect the type of pilot protection scheme chosen.

The protection scheme required will often dictate the type of relaying communications that will be used. On the other hand, the relaying communications may limit the types of relay schemes that can be used. Obviously, the requirements of the relaying scheme must be considered, along with the types of communications available.

3.2.1 Line relaying selection influences

The “proper” relaying for a given application can be influenced by a number of factors, some of which are described in 3.2.2 through 3.2.9.

3.2.2 “Criticality” of the line

One of the more significant determinants in transmission line protection is the criticality of the line to the system. This determination will define such considerations as the desired level of reliability and the role cost will play in the design. A system’s most critical lines may justify redundancy in protection, communication, and perhaps even dc auxiliary supply. Less critical lines may be adequately protected with step distance or overcurrent systems.

The determination of criticality could be based on voltage level, line length, proximity to generation sources, load flows, stability studies, customer service considerations, or other factors.

3.2.3 Other line or system factors

Several factors related to the system’s requirements or to the configuration of the line must be weighed in the selection of transmission line protection. These include the following:

- a) **Fault clearing time requirements.** Issues such as system stability and the effects of voltage dip duration on customer service may influence the selection of the protective systems. The clearing time consideration not only influences the selection of the primary relays, but may also dictate the application of local backup protection and may control the options for interstation communications.
- b) **Line length.** Very short lines or very long lines may require special protection solutions (see 4.1).
- c) **Strength of sources.** Closely related to the line length consideration is the strength of the sources to a transmission line. Source strength determines fault current levels and affects the ability of protection systems to provide adequate selectivity. If the strength of the sources is subject to significant variations due to changes in operating conditions, the protection may require the flexibility to be easily modified, or to automatically adapt, to accommodate the variations.
- d) **Line configuration.** As discussed in detail in Clause 4, the number of terminals, the effects of tapped loads or generation, or such influences as series capacitors or shunt reactors, may require special protection practices.

- e) **Line loading.** Very heavy loading may require special types of protection systems that include load-blinding features or that are naturally immune to load flow.

3.2.4 Communications

Many of the transmission line protection options depend on communications between the line terminals. The choice of communications is influenced by many factors, including most of the factors that influence the selection of the protective relaying. If the choice of communications is dictated by factors independent of the choice of the protective relaying system, then the communication system will influence the protection to be applied. If the protection is chosen based on factors independent of the communications, then the communication selected should be compatible with the protection requirements. See 5.2 for a discussion of the interrelationships of protection and communications.

3.2.5 Past practices

The selection of protection should take into consideration past practices and the familiarity of the responsible personnel with these practices. The selection of different protective systems may result in requirements for development of new documentation and for training. Special protection solutions can only be effective if designed properly, installed and commissioned correctly, and supported sufficiently by operations and maintenance personnel.

3.2.6 Old versus new technologies

Similar to the discussion on past practices is the issue of whether to sustain application of the old “tried and proven” technologies, or take advantage of the many advanced protection features provided by new technologies. Often, the benefits of the new technologies in areas such as reduced maintenance requirements and additional operational information provide the incentives to make the change. Newer relay technologies also provide lower CT burdens, better sensitivities, wider setting ranges, easier setting changes, greater flexibility, and the ability to solve special protection problems. Multifunctional relays also reduce panel wiring and panel space.

3.2.7 The future

While it is not possible to anticipate all changes to the line or to the surrounding system within the foreseeable future, it is often prudent to select protection that is capable of handling changes in line loading, source conditions, or effective line length. Other changes to CT ratios, communications, substation configuration, etc., can be handled if the protection is selected and designed to be flexible, easy to modify, or even easy to replace.

3.2.8 Failure modes

Protective relaying design should minimize the effects of “single-point failures.” A single-point failure is any one failure of a relay, breaker, dc auxiliary supply, communication system, or any other component of the overall protective system. Redundancy or duplication of protection, local backup protection, remote backup protection, and duplication of other system components are used to minimize the effects of single-point failures.

“Common mode failure” is another design consideration. Common mode failures are multiple failures occurring due to a common cause. Examples would be failures due to a dc system transient or to induced currents, or those caused by mechanical jolts, such as bumping the panel or earthquake vibrations. Other common mode failures could be application errors, setting errors, or incorrect maintenance or calibration procedures. Independence in the operating principles of the primary and backup systems is a technique widely applied to minimize common mode failures. Physical isolation or separation, use of different manu-

facturer's equipment, varying maintenance personnel from time to time, and independent checks of settings and designs are other techniques for reducing the possibility of common mode failures.

3.2.9 Protective scheme design compromises

The design of the protective relay system may require considerable compromise. Reliability is, by definition, a combination of dependability and security, which are often mutually exclusive. Other compromises are reliability versus cost, speed versus security, simplicity versus complex features, independence of design and manufacturer versus standardization, and old technology versus new technology. All of these, and many more choices, make up the design decision. The prudent relaying design engineer will document these choices, particularly the compromises and the reasons behind them. This documentation process provides management with the information necessary to evaluate the protection in less technically complex terminology. It also provides continuity and consistency over time so that subsequent generations of protection personnel can better understand the reasons for certain practices.

The very act of documenting the reasons for choices and compromises often reveals other alternatives or options and generally results in a better final design.

3.3 Redundancy and backup considerations

Redundancy for transmission line protection can be provided by a number of methods, each with varying levels of complexity, benefits, and costs. These methods include two or more duplicate protection schemes, local backup, remote backup, and the duplication of dc sources, CTs, VTs, and breaker trip coils.

Different, or perhaps identical, protection systems operating in parallel is a common practice on most transmission lines. Independent operating principles of these different protection systems are often considered important. The degree of duplication in dc sources, CTs, VTs, and the application of interrupting devices is usually determined by the importance of the application and the consequences of single contingency failures.

Local backup schemes may consist of other protective devices with similar protective characteristics for the case of a relay failure-to-detect a fault condition. Control circuit and protection techniques may be designed to protect the faulted line in the case of a power circuit breaker failure-to-trip condition. Local backup can usually provide faster backup fault clearing than remote backup protection.

Remote backup protection provides slower fault clearing and results in more of the system being de-energized. It is widely applied to provide relatively inexpensive, independent backup protection. The sensitivity of remote backup protection may not be adequate for all fault types, fault locations, and system configurations, in which case local backup protection is required.

3.4 Reclosing methods

To maintain the integrity of the overall electrical transmission system, protective relays are installed on the transmission system to isolate faulted segments during system disturbances. Faults caused by lightning, wind, or tree branches could be temporary in nature and may disappear once the circuit is de-energized. Automatic reclosing systems are put into place to re-energize and restore the faulted section of the transmission system once the fault is extinguished (providing it is a temporary fault). For certain transmission systems, reclosing is used to improve system stability by restoring critical transmission paths as soon as possible.

There are several types of reclosing schemes used in the transmission system, as follows:

- a) Unsupervised

- 1) High speed (no intentional delay)
- 2) Delayed
- b) Supervised
 - 1) Synchronism check
 - 2) Undervoltage line/bus
 - 3) Return of voltage

The type of reclosing used is typically dependent on the voltage level, customer requirements, stability considerations, and the proximity of a generator. Higher voltage transmission lines typically reclose on high speed, voltage check, and/or synchronism check. Lower voltage transmission systems may have two or three blind shots from either end of the line. Details of various features that may accompany automatic reclosing schemes are beyond the scope of this guide (see IEEE PSRC Report [B1]).

3.5 Effects of load on line relay applications and settings

One of the principal influences on protective relay settings is load; hence, maximum load current level, in turn, may influence fault detection sensitivity.

3.5.1 Phase overcurrent relays

Phase overcurrent relays must be set to avoid operation on all of those “normal” conditions to which they may be subjected, such as transformer inrush, motor starting current, maximum emergency load conditions, and maximum recoverable swing conditions. This usually entails a time overcurrent pickup setting above a maximum load current level and/or a coordinated instantaneous pickup setting to ensure security of the relays against misoperation. The sensitivity achievable is, therefore, somewhat coarse, but many applications in which they are used do not require extreme sensitivity (see 5.1.1 and 5.1.2).

3.5.2 Ground overcurrent relays

Ground overcurrent relays have the advantage of utilizing a current source that supplies little or no normal current to the relays. The sensitivity achievable is substantially better than that afforded by phase overcurrent relays. Only unbalanced load current and normal system unbalance affect the setting of these devices.

3.5.3 Directional overcurrent relays

Directional overcurrent relays have the same restrictions as phase and ground overcurrent relays for load flow in their tripping direction. Properly selected directional elements block tripping for load flow and faults in the nontripping direction.

3.5.4 Phase distance relays

Phase distance relays have a relatively fixed reach; they operate most sensitively when fault currents are present and less sensitively when only load current exists. Fault currents typically lag voltage by 60° or greater. Load current typically leads or lags voltage by 30° or less. Although less sensitive in the load angle region, phase distance relays may require a setting for adequate fault coverage that may limit line loading (see 5.6.1).

3.5.5 Ground distance relays

Ground distance relays may also be susceptible to the error associated with ground fault resistance and out-of-phase sources. Further, they may have overreach and underreach characteristics for the “leading” and “lagging” phases in responding to phase-to-phase-to-ground faults, unless provision is included to compen-

sate for these factors. Many ground distance relays operate on phase current and voltage inputs, making them susceptible to operate under heavy load conditions. For this reason, ground distance relays are usually supervised by ground overcurrent elements, which must be set to avoid operation for heavy unbalanced loads. Load current will also influence the “reach” of these devices where fault resistance is involved (Giuliante, McConnell, and Turner [B13]).

3.5.6 Pilot systems—two terminal

The influence of load on pilot systems is highly dependent on the nature of the protective relaying scheme. Those systems using overreaching distance measurement, such as directional comparison blocking, permissive overreaching transfer trip (POTT), and directional comparison unblocking, have the advantage of limited load angle sensitivity and have the absence of a critical reach due to the nature of the relaying system. These relays have very little influence from load except in very long line applications, and this is often accommodated by blinders that prevent operation of the protective relaying system under balanced, three-phase load conditions.

For direct underreaching transfer trip (DUTT) schemes, the pilot distance relays are set short of the remote line terminal. This setting makes the scheme less susceptible to tripping under heavy loading conditions. However, the reach variation of the distance relay as a result of prefault load current is much more critical than for the overreaching schemes. It is imperative that load or fault current, or any combination of the two, never be able to cause operation of the Zone 1 relay for any condition other than a fault on the protected line.

Phase comparison and current differential schemes are not normally susceptible to operation under load condition because of their inherent nature of comparing current into the line at one terminal with current out of the line at the other. However, load does influence the setting of fault detectors in phase comparison blocking schemes and in current differential schemes when operation following channel failure is allowed. Current differential schemes may be sensitive to tapped loads, and settings should be chosen accordingly. Also, high levels of through load current may reduce the fault detection sensitivity of both phase comparison and current differential schemes. When transmission cables are used, special considerations may be required for the fault detector settings because of the capacitance of the cables.

3.5.7 Pilot systems—three terminal

In addition to its significance, which is outlined in 3.5.1 through 3.5.6, load in a three-terminal line application may represent an outfeed condition for an internal fault. Depending on the particular type of relaying system, this may produce an undesired blocking effect. Three-terminal applications generally have at least one weak source and, consequently, care must be exercised to ensure that either the contribution to an internal fault exceeds this load current outfeed, or the relaying system bases its response on the total internal fault current.

4. System configuration

4.1 Length considerations

This clause is concerned with the influence of line length on the selection of the line protection scheme to be applied. Transmission lines may be defined or classified as short, medium, or long.

Short lines are so designated because the SIRs are large. Ratios of approximately four or greater generally define a short line. Medium lines are those having SIRs from four down to 0.5. Long lines are those having SIRs that are very small, meaning ratios of 0.5 or less.

It should be noted that for a given length of line, the per unit impedance varies much more with the nominal voltage of the line than the ohmic impedance. This factor, together with the different short-circuit impedances at different voltage levels, means that the nominal voltage of a line has a significant effect on the SIR and, thus, whether it would be considered “short,” “medium,” or “long.”

For instance, consider a 500 kV line with a positive sequence reactance of $0.332 \Omega/\text{km}$. This corresponds to a reactance of 0.00013 pu per km on a 100 MVA base, at 500 kV. If the source impedance behind a relay terminal is 0.01 pu (corresponding to a fault level of 10 000 MVA), the following classifications apply:

- Line lengths less than about 19 km would result in an $\text{SIR} > 4$ and might be considered short.
- Line lengths greater than about 150 km would result in an $\text{SIR} < 0.5$, and might be considered long.

On the other hand, a 69 kV line, with a positive sequence reactance of $0.53 \Omega/\text{km}$, might have very different length classifications. For such a line, the reactance is 0.015 pu per km on a 100 MVA base, at 69 kV. If the source impedance behind a relay terminal is 0.1 pu (corresponding to a fault level of 1000 MVA), the following classifications apply:

- Lines lengths less than about 1.7 km would result in an $\text{SIR} > 4$ and might be considered short.
- Line lengths greater than about 14 km would result in an $\text{SIR} < 0.5$ and might be considered long.

These examples demonstrate the importance of source impedances and nominal voltages in classifications of a line as “short,” “medium,” or “long.”

Although the physical length of lines is a factor in the SIR, it is inappropriate to describe the line as long, medium, or short based on this characteristic alone. However, the distance between the terminals of a given line may be a factor in determining the type of relay communication system to be used.

The types of communication systems typically used for transmission line protective relaying include the following (abbreviations are shown):

- Fiber optic (FO)
- Pilot-wire 50, 60 Hz (PW)
- Pilot-wire audio tones (AT)
- Power line carrier (PLC)
- Microwave (MW)
- Point-to-point radio (R)

4.1.1 Short lines (SIRs > 4)

Typical protection schemes and communication channels used are as follows:

- Current differential (FO, PW, AT, MW)
- Phase comparison (FO, PW, AT, PLC, MW, R)
- POTT (FO, PW, AT, PLC, MW, R)
- Directional comparison blocking (FO, PW, AT, PLC, MW, R)

Short lines result in a small current magnitude difference and minimal voltage drop difference between close-in and remote faults. Non-pilot overcurrent relays usually cannot be set to discriminate between internal and external line faults. Non-pilot distance relays may be able to discriminate between internal and external line faults for lines with an SIR as high as 20. (See 5.9 for additional information on short line protection.) However, it may not be possible to coordinate non-pilot distance relays on adjacent long lines with

the short line distance relay zones. Therefore, pilot relay schemes utilizing communication channels are used.

The most effective forms of pilot protection for short lines include current differential, phase comparison, POTT, and directional comparison blocking schemes. None of these schemes require distance elements to be set for less than the line impedance. Schemes utilizing Zone 1 distance elements should provide the capability to handle arc resistance or fault impedance, which can be significant compared to the line impedance. Current differential and phase comparison systems do not provide remote backup for adjacent system elements. However, non-pilot overcurrent and distance relay schemes can be applied as backup protection, provided time delays are adjusted to provide coordination.

4.1.2 Medium lines (SIRs < 4, but > 0.5)

Typical protection schemes used are as follows:

- Phase comparison (AT, PLC, MW)
- Directional comparison blocking (AT, PLC, MW)
- Permissive underreaching transfer trip (FO, MW)
- POTT or unblocking (FO, MW, PLC)
- Step distance
- Step or coordinated overcurrent
- Inverse time overcurrent
- Current differential

NOTE—Permissive underreaching transfer trip (PUTT) is discussed in 5.2.4.2; POTT is discussed in 5.2.4.3.

Lines with SIRs less than four allow more effective relay discrimination. Relay schemes utilizing underreaching elements can now be set. Zone 1 can be set to underreach the remote end and still protect 80–90% of the line. The last 10–20% of the line can be protected by a Zone 2 overreaching element. Since selectivity and sensitivity can usually be met, the speed with which a fault needs to be cleared may require the application of pilot relaying. If slow fault clearing is acceptable, simple step distance or overcurrent relays can be applied.

4.1.3 Long lines (SIRs < 0.5)

Typical protection schemes used are as follows:

- Phase comparison (PLC, MW)
- Directional comparison blocking (PLC, MW)
- PUTT, POTT, or unblock (AT, PLC, MW)
- Step distance
- Step or coordinated overcurrent

Long lines have small SIRs, and most long lines are extra high voltage (EHV) or ultra high voltage (UHV) lines. EHV and UHV lines almost always require high-speed tripping of all terminals for stability purposes and to minimize damage caused by the fault. Long lines can also have other system elements included in the line, such as series capacitors. This makes the total line impedance variable under certain conditions and introduces transient behavior that makes selectivity difficult. Phase and directional comparison protection schemes over PLC or MW are well suited to this type of application.

Schemes utilizing distance functions should be applied ensuring that the long reach settings do not restrict load transfer. Also, long communication channels require some attention to ensure that signal attenuation or time delay is not excessive.

4.2 Line design

Transmission lines may be overhead air-insulated lines, insulated cable systems or, in some cases, combinations of both. The electrical characteristics are significantly different.

4.2.1 High-voltage cables

The series inductance of cable circuits is typically one-half to one-third that of comparable overhead lines. The reactance to a fault will, accordingly, be lower for cable systems and becomes a consideration in the application of distance relays. As a practical consideration, cable systems find frequent use in urban or metropolitan areas where short lines are typical. Cables are, therefore, frequently protected using those techniques most suitable to circuits with low total impedance (IEEE PSRC Report [B25]).

4.2.2 Electrically connected double circuit transmission lines

At times, the phase conductors of parallel transmission lines are jumpered together to form a single transmission line. Generally the line is modeled by assuming the phases to be two conductors of a single bundle. The calculations of line impedance are simplified by assuming the lines are fully transposed, even though they most likely are not. Since the lines configured in this manner are generally not very long, the effect of transposition will be negligible.

Fault currents and apparent impedances, as seen by relays, are affected by a fault on one conductor of a phase. The effect of the fault is isolated between the adjacent jumpers. The current on the unfaulted conductor will flow past the fault location to the next jumper before crossing over, causing an increase in the apparent impedance. This will cause impedance relays to underreach. The worst case occurs where the lines are jumpered only at the ends. This problem can be reduced by adding more jumpers at intermediate locations along the line length. An adequate number will negate the effect, since all single-conductor faults will then be near a jumper.

The effects can be studied if the jumpers near a point of interest (such as a fault near the far end) are modeled as bus points and the conductors in between are treated as mutually coupled parallel lines.

4.3 Number of line terminals

The number of terminals on a transmission line is a basic and important factor when selecting a protective system. A particular terminal becomes significant to the selection of the protective system if it supplies current to faults on the transmission line. The main terminal(s) that can supply fault current must have a protective system that does not operate for normal power flow, but does operate when fault current is detected on the line.

4.3.1 One terminal (radial lines)

A radial transmission line is one that has a source of current at only one terminal, even though the line may split into multiple sections. Quite often, the protection need only measure short-circuit quantities at the source terminal. For radial line faults, it is usually not necessary to determine the direction of the fault current because the fault current can flow in only one direction. Some exceptions occur when the line supplies significant motor load and zero-sequence current sources. Examples of zero-sequence current sources include the following:

- Grounded wye/delta three-phase transformers
- Grounding transformers
- Autotransformers with delta tertiary

When the magnitude of ground fault current from these sources is sufficient to be detected by the protection system, the line protection system must be able to distinguish whether the ground fault current is flowing out to a fault on the line, or the fault current is flowing into a fault “behind” the terminal.

The protection system needs to detect a range of short-circuit currents, from large-magnitude, close-in faults to what can be very small-magnitude remote faults for long lines. Remote faults can be difficult to detect on long lines due to large line impedances, arc resistance, and high-resistance ground return paths.

When the magnitude of remote fault current falls below the detection sensitivity of the relays at the terminal, an additional, more sensitive protective system could be required in series with the line at a point where detection from the terminal is not possible. Additional fault detection and clearing devices are used in series with the line protective system on radial lines when

- The fault magnitude for remote faults cannot be detected at the source terminal.
- It is desired to avoid tripping the entire line for faults at the remote end of the line or along tapped radial line sections.

The magnitude of short-circuit current supplied from the source terminal can vary, depending on system elements being either in or out of service. This factor also needs to be considered when selecting the protective system.

4.3.2 Two terminals

The most common type of transmission line is one that has two terminals, either of which can supply current to faults along the line. When a fault occurs, a method must be used to determine whether the short-circuit quantities measured at the terminals indicate that the fault is on the line between the terminals, or the fault current is merely flowing through this particular line to a fault elsewhere in the transmission system.

A common method used to determine where the fault exists is the direction of fault current flow. Direction of ac current flow, which alternates every half-cycle, must be determined with respect to a reference. The line terminal voltage is typically chosen as the directional reference. Current flowing into the terminal from the line indicates that the fault is not on the line. Current flowing out of the terminal indicates that the fault is on the line or beyond the remote end terminal.

Another useful characteristic of the short-circuit quantities used to determine where the fault is located is current magnitude and phase angle. This characteristic is ineffective on short lines because the close-in and remote faults appear similar. However, a long line will have a wide range of fault current magnitudes when comparing close-in faults to remote faults.

4.3.3 Multiterminal lines

Transmission lines with more than two main terminals offer additional challenges for correctly detecting faults on the line, primarily because of radical changes in fault current levels and apparent impedances as one or more terminals are opened. The system configuration may result in sequential tripping to protect these lines. If sequential tripping results, care should be taken concerning the redundancy of the relay design, because failure of a relay at one terminal may prevent detection of the fault at another terminal. Sequential tripping also delays fault clearing. Pilot schemes may eliminate sequential tripping. Lines with more than three main terminals (i.e., sources of positive sequence currents) are not recommended (see 5.5).

4.4 Lines terminated into transformers

The typical line terminated into a transformer is shown in Figure 8.



Figure 8—Line terminated into a transformer

The additional protection considerations in this application are as described below.

Some transformer faults will not be detected by the line protection and, thus, will require supplementary protection. One method of supplementing the ability to detect certain faults is the addition of a grounding switch, to place a solid fault on the line if a transformer fault or breaker failure occurs at the transformer end. Another common method is to provide a transfer trip scheme that will trip the remote terminal when a transformer fault is detected.

If line protection can operate simultaneously with, or faster than, dedicated transformer protection for transformer terminated lines, the effect of automatic or manual reclosing should be considered. Many transmission line faults are temporary in nature, and the line may be successfully reclosed a short time after the fault has been cleared. This means that it is often desirable to automatically or manually re-energize a line after the line protection has operated. On the other hand, it is not usually desirable to re-energize a faulted transformer. Therefore, even if the line protection will detect some or all faults in the transformer, it is usually desirable to provide protection equipment dedicated to the transformer that operates at least as fast as the line protection for transformer faults. The transformer protection may block reclosing of the line and/or automatically isolate the transformer.

The transformer impedance limits the fault current contribution for faults on the line and beyond. In some cases, the available fault current may not be sufficient to operate the line relays.

Consideration must be given to the placement of VTs and CTs. There may be a temptation to place the CTs and VTs on the source side of the transformer rather than the line side of the transformer due to cost savings associated with lower-voltage equipment. If the transformer impedance is included in the line protection zone, it will add to the total impedance to be measured by the line protection system and reduce the accuracy of the line protection. Also, if the transformer is not a wye-wye, the distance relay settings can be in error due to phase shift. Depending on transformer connections, the ground relay directional sensing and current magnitude can be erroneous. Figure 9 shows an example in which ground directionality changes from the high side to the low side of the transformer.

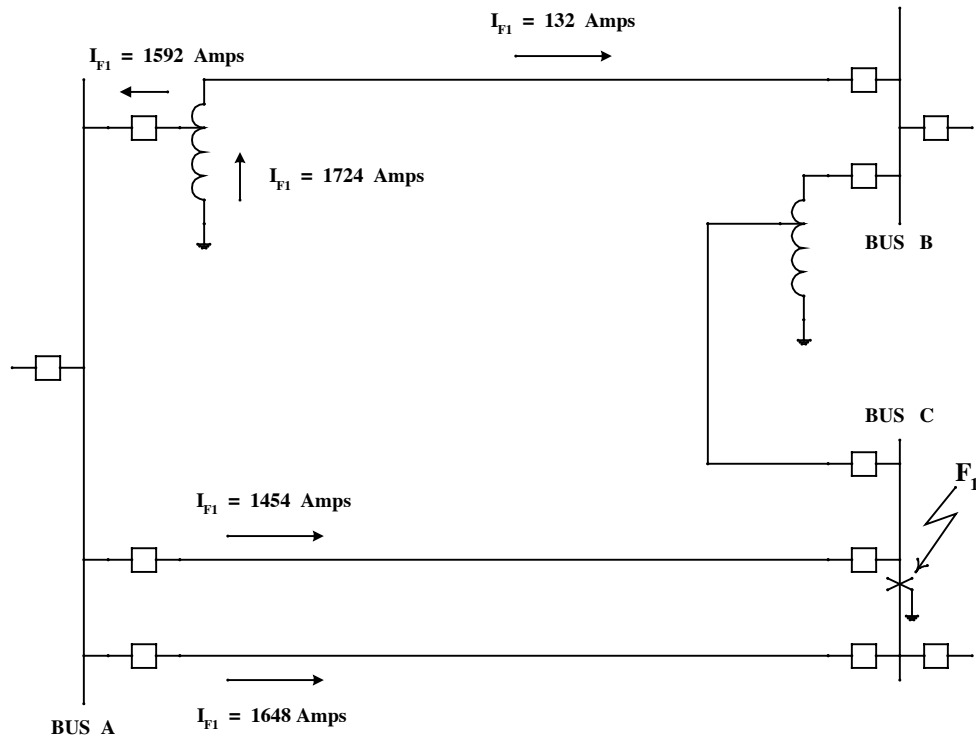


Figure 9—Changes in directional sensing for ground fault

4.5 Weak electrical systems

A system may be considered weak when the source impedance is high. Weak systems often have the following characteristics:

- Relatively low values of fault current availability.
- A fault anywhere on the line causes a relatively flat voltage profile along the line back to the relay location.
- Poor voltage regulation on the line.
- Possible stability problems on the line due to the distance from its power sources.
- Polarizing current sources provide relatively low values of polarizing current.

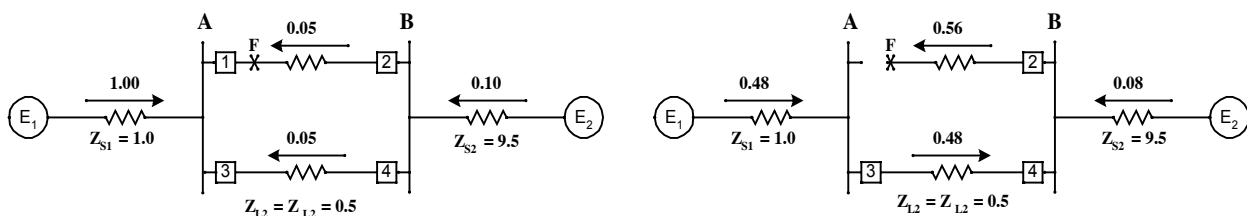
Weak system characteristics may be found at any voltage level, but are more prevalent at lower transmission voltages. Long line transmission systems with remote generation may also have these characteristics. When small generators, or single unit generators, are installed by independent power producers and connected to the system, weak system characteristics could be created because these units are small or because they are occasionally off line. The latter case is particularly challenging to the application of effective protection.

All weak systems present several challenges to the protection engineer. Some of these are as follows:

- a) **Contingency outage considerations.** Different system configurations that occur as a result of system outages may result in substantial changes in line length and load. Backup sources may be connected to a system on a contingency basis, which will change protection considerations. If additional

protective equipment is needed to handle the contingency, proper coordination between the schemes must be considered. Additional relays, modified relay settings, or compromised protection/coordination (in some circumstances) may be required.

- b) **Sequential tripping.** It is possible that all of the line terminals on a line in a weak system will not be able to see the fault on the line at the initial inception of the fault (see Figure 10). With a fault as indicated, and the apparent impedances as indicated, the current initially supplied through Breaker 2 will be significantly less than that through Breaker 1. Therefore, at the onset of the fault, the relays at Breaker 2 may not be able to sense the fault. After Breaker 1 opens, the current through Breaker 2 increases by a factor of more than 10, and the relays sense the fault and open Breaker 2 sequentially.
- c) **Fault detection.** When a source is weak, there may be insufficient current contribution to a fault on the protected line for a relay to reliably detect a fault. Special logic in pilot systems may be required. The logic, known as weak infeed echo and weak infeed trip, is described in 5.3.5.
- d) **Weak source becoming a strong source.** Varying system configurations may cause a system to be, at times, weak or strong. Due to contingencies, some system changes may be made. A power generation source may be added at a location on the system. If the generation units have been designated for peaking only, the time period of unit operation may cause a weak system to become strong.
- e) **Fault clearing times.** On a weak system, the fault currents on one end of a line may be nearly the same magnitude as the currents on the other end of the line. At such locations, if non-pilot systems are used, the only possible differentiating element in the determination of fault location may be time (see Figure 11). If Z_{S1} is much larger than the impedances of line segments Z_{L1} , Z_{L2} , and Z_{L3} , the fault current that is seen in any of the three line segments will be approximately the same value. The pickup settings at V_1 , V_2 , and V_3 may be approximately the same. In order to coordinate the tripping of the lines, time delay may be used to allow the relays at V_3 to trip before the relays at V_2 , and the relays at V_2 to trip before the relays at V_1 .
- f) **Multiterminal lines.** A multiterminal line with a weak source as compared to the other terminals will not detect faults beyond the tap as adequately as relays at a strong source. Thus, the strong source may have to open before the weak source relays can detect the fault. This will result in sequential tripping and, therefore, slower fault clearing than would otherwise occur. The worst case would be a combination of source impedances and line lengths that would require sequential time delay clearing of two of the terminals for phase and/or ground faults.



NOTE—All indicated values are pu values

Figure 10—Example of sequential tripping

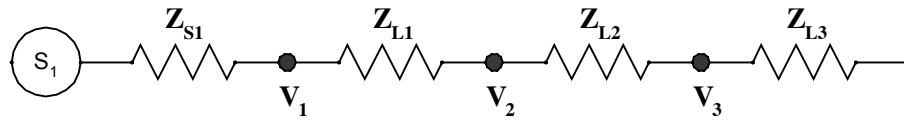


Figure 11—Example of a weak system

4.6 Ground source configurations

Most transmission systems are solidly grounded, with all ground sources tied physically to the station ground mat.

However, some older transmission systems are resistance grounded to reduce single-phase-to-ground fault current. Resistance-grounded systems are sometimes difficult to protect. One problem that can occur is that fault current magnitude can be lower than load current. This diminishes the capability of current-only schemes. Another problem occurs because the fault current is substantially in phase with load current, thereby making it difficult to distinguish between the two. This condition reduces the possibility of using only impedance-based relay schemes on resistance-grounded transmission systems. Directional ground overcurrent relays applied to resistance-grounded systems generally will provide adequate protection.

4.7 Transmission lines with distribution substation taps

It is common utility practice to tap transmission lines to serve distribution load. Figure 12 shows a typical electrical system with Buses 1, 2, 4, and 5 being transmission buses and Bus 3 being the distribution bus. The impedances of segments is shown as Z_A , Z_B , Z_C , Z_D , and Z_E . Z_{Capp1} and Z_{Capp2} represent the apparent impedance of line segment C, as seen by distance type relays at circuit breakers CB1 and CB2, respectively (see 5.5.2). Z_{Eapp1} is the apparent impedance of line section E as seen by CB1.

It should be noted that the “apparent impedance,” such as Z_{Capp1} and Z_{Capp2} , mentioned above, is not the actual impedance of the line section, but some larger impedance that depends on the current infeed from some other source part of the way along the protected circuit. Distance type relays calculate impedance to a fault based on the voltage and current as seen at the relay location. On a three-terminal line, the impedance “seen” by each relay will depend, in part, on the current contributions from the other terminals. The actual line impedance from a relay terminal to the point of fault is not always the impedance “seen” by a distance relay. This clause discusses the relay considerations surrounding the relay design of the line between CB1, CB2, and Bus 3.

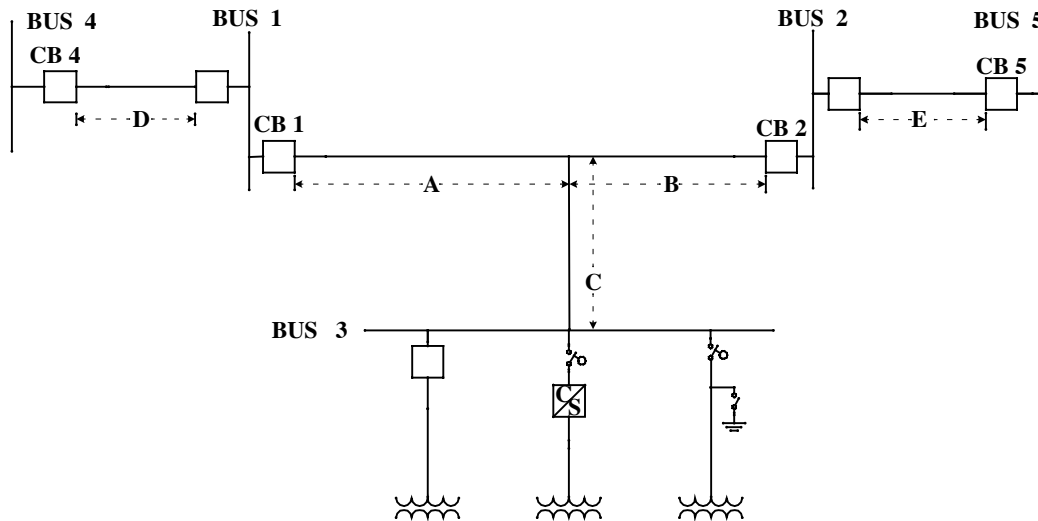


Figure 12—Transmission line with a distribution substation tap

4.7.1 Length and location of tap line

As long as the apparent impedance of C is less than Z_A and Z_B , no significant relaying problems occur because of the tap line. If, however, $Z_{Capp2} > Z_A$, relay setting compromises will be required at CB2. The same holds true for setting relays at circuit breaker CB1, if $Z_{Capp1} > Z_B$. This configuration is further complicated if Z_C is greater than both Z_A and Z_B .

4.7.2 Length of lines on adjoining buses

Whenever line relay settings are extended because of tap lines, the primary, backup, or both relaying schemes may need to be slowed to allow relaying on adjacent lines to coordinate. For instance, when setting relays at circuit breaker CB1 for faults at Bus 3, if $Z_{Capp1} > Z_B$ and $Z_A + Z_{Capp1} > Z_A + Z_B + Z_{Eapp1}$, then time delay must be added to allow coordination for faults at Bus 5 and beyond.

4.7.3 Relay settings limiting line loading

Whenever line relay settings are extended because of tap lines, precautions should be taken to ensure the relay settings are not limiting power transfer or line load carrying capabilities below acceptable values and still properly detect line faults.

4.7.4 Substation considerations that affect transmission line relaying

Generally, transmission line relaying is not designed to see internal transformer faults or low-voltage bus faults. The sensing of these two types of faults is done at the distribution station.

The relays at the distribution station trip the interrupting device associated with the transformer. Where breakers or circuit switchers are not used as high-side interrupting devices, the relays initiate a transfer TRIP signal to the remote breakers or close a ground switch on the high-voltage side of the distribution station transformer. Since transmission relaying is usually not set to see transformer or low-voltage bus faults, if a breaker or circuit switcher fails to trip, local backup should be provided at the distribution station. This local backup can be in the form of transfer trips, ground switches, or air switches. When a ground switch is used,

a motor-operated air switch is often connected ahead of the ground switch and transformer to allow reclosing of the transmission line after the transformer has been isolated.

4.7.5 Use of circuit switchers for transformer protection

It is a utility practice to apply circuit switchers rated below the high-voltage bus fault duty for high-VT protection. The circuit switcher may be blocked from tripping for high-current faults by the use of an instantaneous overcurrent relay. The remote transmission line relaying must sense this particular fault and initiate tripping. If the circuit switcher is not blocked for faults above its rating, it is either allowed to trip or the remote transmission line relaying may be set to trip first.

4.7.6 Transformers as load taps on a transmission line

Transformers can be tapped off any point on the transmission line. Figure 13 and Figure 14 show typical configurations.

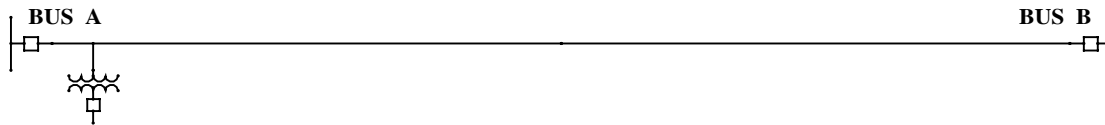


Figure 13—Transformer load tap near one terminal

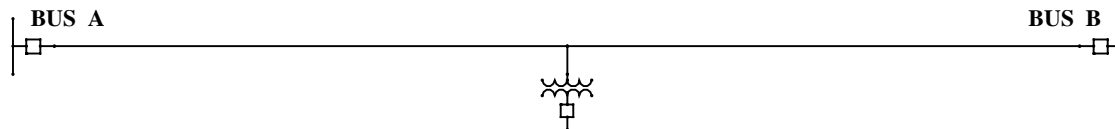


Figure 14—Transformer load tap near center of line

The key protection challenges indicated in these situations, in addition to those provided above, are described below.

A transformer that is not a source of phase or ground fault current requires no special attention. See 4.7.7 if the transformer is a source of phase or ground fault current.

All tapped transformers should be provided with their own dedicated protection systems that operate faster, or at least as fast as, the line protection for faults in the transformer. These dedicated systems will either clear the faulted transformer or, if HV fault-clearing facilities are not available at the tapped station, will initiate tripping of the breakers at the remote terminals of the line and, hence, automatic isolation of the transformer by a motor-operated disconnect switch. Isolating the transformer automatically will ensure that if the transmission line is re-energized, the faulted transformer will not also be re-energized with the line.

If transformers are connected to the lines as shown in Figure 15, closing the N.O. switch will result in a multiterminal line. Further complications will result if the lines are mutually coupled.

NOTE—See 5.5 for problems with multiterminal lines.

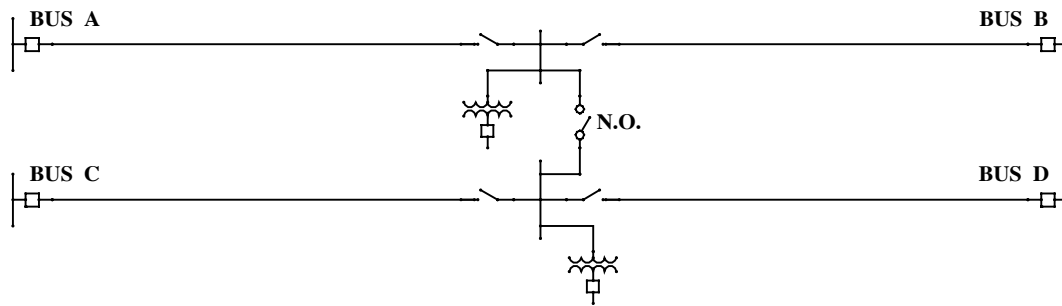


Figure 15—Switch creates the potential for multiterminal lines

Figure 16 is similar to Figure 15, except the line ends terminate in common buses.

It is usually difficult to provide instantaneous line protection that will not trip for at least high side faults within the tapped station. In view of the infrequency of such faults, it may be considered acceptable to allow the line to trip simultaneously with the high side interrupting device at the tapped station for such faults. The line could then be automatically or manually reclosed, restoring the transmission system with the tapped station (with the fault) isolated.

It is important that transmission line protection coordinate with low side protection at the tapped station. Low side equipment (such as distribution feeders) is usually exposed to more frequent faults than occur on the high-voltage side of the station. Thus, it is important that the instantaneous transmission line protection not be able to sense faults on the low side of the tapped station. The most critical case is when the line terminal nearest the tapped station is strong, and the remote terminal is weak, and infeed from the remote terminal does not significantly desensitize the near terminal to faults in the tapped station.

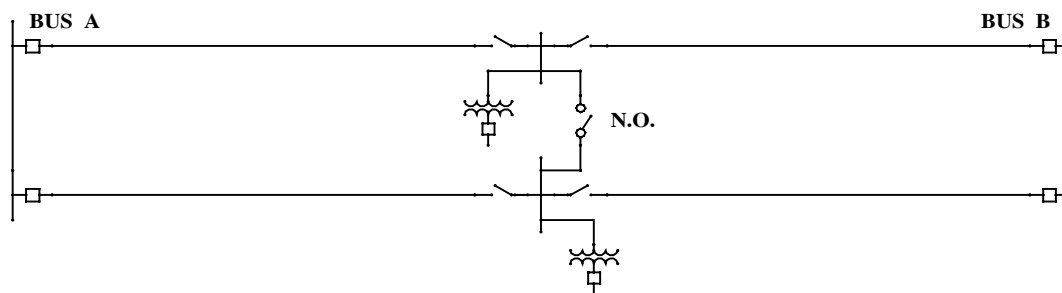


Figure 16—Switch creates the potential for parallel multiterminal lines

4.7.7 Transformer as a source to the transmission system

In some instances, it is possible that the distribution station transformer can be a source to a transmission line fault and must be considered in the relay design. The resulting infeed can cause line distance relays to underreach. This potential exists whenever generation is connected to the distribution bus, or whenever the distribution bus is connected to another distribution circuit served from a different transmission line. If a positive sequence source capable of supplying sustained current to a transmission fault is available from the distribution system, then provision to trip the source, or its feed to the transmission system, is required. Also,

if the transformer has a delta winding, and the high-voltage winding is connected grounded wye, the transformer will be a ground source for zero-sequence currents, causing a similar underreaching of the line ground relays.

If the transformer is a zero-sequence source, the resulting zero-sequence current infeed must be considered when setting the remote ground distance relays or overcurrent relays. The zero-sequence current infeed will desensitize both ground distance and ground overcurrent relays at the main terminals. Since the presence of a zero-sequence source will also tend to reduce the zero-sequence voltage at the line terminals, the performance of zero-sequence directional units must also be evaluated.

A transformer source to a transmission line may be delta connected on the line side and be a source of positive and negative-sequence current to a single-phase-to-ground fault until the last ground source is removed from the line. Then, the line will still be energized by this source; however, no appreciable current can flow due to the delta transformer winding. The delta will remain a source of positive and negative-sequence current flow if the ground source remains on the line (such as a wye grounded/delta transformer tapped to the line) after the main transmission line terminals open. The positive and negative-sequence source of back-feed must be eliminated for multiphase faults and for single line-to-ground faults to ensure arc extinction.

4.8 Lines with devices for var and flow control

For many reasons, control devices can be installed on transmission lines that may affect protection applications. These devices make the transmission system more efficient and controllable. Some of the most common devices installed are:

- Shunt reactors
- Shunt capacitors
- Series capacitors
- Series reactors
- Phase shifting transformers
- Static var compensators (SVCs)

In this subclause, the application of these devices and possible problems they might create for line protection relays are briefly discussed.

4.8.1 Shunt reactors

Shunt reactors are applied on transmission lines to compensate for large capacitive reactance or to suppress secondary arc currents on single-phase tripping schemes. Shunt reactors, whether connected to the line or the bus, should have dedicated protective relays. The reactor may be switched as a unit with the transmission line, or may be connected to the bus behind the line terminal. The reactor current may or may not be included in the current measured by the line protection system. When the reactors are located within the zones of protection of the line relays, the shunt reactors may affect the line relay performance. If the reactor is connected to the bus behind the line protection system, it will generally not have a direct effect on the line protection.

If the shunt reactor is included as part of the zone of protection of the line protection system, the reactor will compensate for some of the effects of line capacitance that can adversely affect a line protection system. The line protection system must be designed to be reliable in the event that the shunt reactor is out of service.

If the reactor is connected directly to the protected line, it will allow the flow of “ring down” currents (which are oscillation currents caused by the line impedance, the shunt capacitance, and the reactor upon line de-energization). These ring down currents will result in a gradually decaying line terminal voltage that may