

IEEE Guide for Protective Relay Applications to Transmission Lines

IEEE Power and Energy Society

Sponsored by the
Power System Relaying Committee

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USA

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IEEE Std C37.113-1999)

IEEE Guide for Protective Relay Applications to Transmission Lines

Sponsor

**Power System Relaying Committee
of the
IEEE Power and Energy Society**

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Abstract: Information on the concepts of protection of ac transmission lines is presented in this guide. Applications of the concepts to accepted transmission line-protection schemes are also presented. Many important issues, such as coordination of settings, operating times, characteristics of relays, mutual coupling of lines, automatic reclosing, and use of communication channels, are examined. Special protection systems, protection of multi-terminal lines, and single-phase tripping and reclosing are also included. The impact of different electrical parameters and system performance considerations on the selection of relays and protection schemes is discussed.

The purpose of this guide is to provide a reference for the selection of relay schemes and to assist less experienced protective relaying engineers in applying protection schemes to transmission lines.

Keywords: distance protection, IEEE C37.113™, pilot protection, protective relaying, relay application, relaying, transmission line protection

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Introduction

This introduction is not part of IEEE Std C37.113-2015, IEEE Guide for Protective Relay Applications to Transmission Lines.

This document is a revision of IEEE Std C37.113-1999 [B65]. This guide is intended to assist protection engineers and technologists in effectively applying relays and protection systems to protect transmission lines.

Several areas have been improved in this revision, most notably the following:

- Several clauses revised for uniformity of style and ease of understanding the issues discussed in them
- Enhanced fundamental discussions
- Better defined technical discussion about length considerations
- Updated relay schemes with current technology
- Added Annex A that describes system studies

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1. Overview

Each component on the electrical power system has protection problems unique to itself, but 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 protection of most components of power systems. A study of transmission line protection leads to a better appreciation of protection-related issues because transmission lines are links to substation buses and/or other equipment connected to the lines. Electrical engineers and technologists working with electric power utilities; consultants and manufacturers in general; and those working in designing, selecting, and maintaining protection systems in particular would benefit from the information provided in this guide.

General specifications of relays are given in IEEE Std 37.90™, IEEE Standard for Relays and Relay Systems Associated with Electric Power Apparatus.¹ While protection of transmission lines is discussed in this guide, protection of distribution lines is addressed in IEEE Std C37.230™, IEEE Guide for Protective Relay Applications to Distribution Lines [B68].²

All interrupting devices are shown in the figures included in this guide. The isolators (disconnects) used in conjunction with the interrupting devices are not shown in all figures. If they are not shown, they are assumed to be provided for proper control and operation of the system.

1.1 Scope

Concepts of transmission line protection are discussed in this guide. Applications of these concepts to various system configurations and line termination arrangements are presented. Many important issues,

¹ Information on references can be found in Clause 2.

² The numbers in brackets correspond to those of the bibliography in Annex B.

such as coordination of settings, operating times, characteristics of relays, impact of mutual coupling of lines on the protection systems, automatic reclosing, and use of communication channels, are examined. Special protection systems, multi-terminal lines, and single-phase tripping and reclosing are also included. The impact that system parameters and system performance have on the selection of relays and relay schemes is discussed as well.

1.2 Purpose

The purpose of this guide is to provide protection engineers with information that helps them to properly apply relays and other devices to protect three-phase high-voltage transmission lines.

2. Normative references

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

IEEE Std C37.2™, IEEE Standard Electrical Power System Device Function Numbers, Acronyms, and Contact Designations.^{3, 4}

IEEE Std C37.90™, IEEE Standard for Relays and Relay Systems Associated with Electric Power Apparatus.

3. Definitions, device numbers, and abbreviations

3.1 Definitions

For the purposes of this document, the following terms and definitions apply. The *IEEE Standards Dictionary Online* should be consulted for terms not defined in this clause.⁵

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

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.

apparent impedance: The impedance from a relay location to a fault as determined by a distance relay from the applied current and voltage. It may be different from the actual impedance because of current infeed or current outfeed at some point between the relay and the fault.

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

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⁵ *IEEE Standards Dictionary Online* is available at: <http://ieeexplore.ieee.org/xpls/dictionary.jsp>.

backup zone: The segment of the power system for which a relay or element within a relay offers protection that is in addition to its primary protection zone. The backup protection zone relays or elements are coordinated with the remote zone relays or elements and usually contain a coordination time delay. The backup zone may disconnect more power system elements than those isolated by the operation of the relays that protect the primary zone.

blocking signal: A logic signal, used in a pilot scheme, which is received from a remote terminal to prevent the instantaneous (pilot time) tripping of the local terminal by the pilot scheme.

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

breaker failure protection: A form of protection that is designed to detect the failure of a circuit breaker to operate or to interrupt a fault. Upon detection of a breaker failure during a fault condition, the scheme is designed to take appropriate action to clear the fault. Upon detection of a breaker failure during a non-fault condition, the scheme may take other appropriate action.

NOTE—Detailed description of this protection function is given in IEEE Std C37.119™, IEEE Guide for Breaker Failure Protection of Power Circuit Breakers [B67].

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).

coordination of protection: The process of choosing current or voltage settings and 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.

cross polarization: The method used by a relay for determining directionality using the voltage(s) from a healthy (unfaulted) phase(s). One example of this is quadrature polarization.

current differential scheme: A protection scheme designed to detect faults by measuring the differences between the currents at the terminals of a transmission line.

dependability: The degree of certainty that a protection system will respond when the fault or abnormal condition the protection system is intended to detect is present.

distance relay: A protective relay in which the response to the input quantities is primarily a function of the impedance or a component of the impedance of the circuit between the relay and the point of fault.

dual polarization: The method used by a relay for determining directionality using both current and voltage sources.

fault impedance: Impedance, resistive or reactive, between phase conductors or the phase conductor and ground during a power system fault.

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

grounding transformer: Delta-wye or zigzag connected transformer(s) installed to establish a system ground that provides a path for zero-sequence current flow assisting in detection of phase-to-ground faults.

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

impedance relay: A distance relay in which the threshold of operation depends on the magnitude and angle of the ratio of the voltage vector to the current vector applied to the relay.

infeed: A flow of fault current from a source that is physically located between a relay location and a fault location.

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

mho unit: A distance relaying unit that has a circular tripping characteristic that passes through or is offset from the origin on an R-X diagram.

multi-terminal line: A transmission line that has more than two terminals to which sources of power are connected. A multi-terminal line can also be considered a line with multiple taps that may not have connected sources.

outfeed: Flow of current out of a terminal of a line when there is a fault on the line.

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.

permissive: Pertaining to a scheme that requires the receipt of a logic signal from the remote terminal(s) before allowing the tripping of the circuit breaker(s) controlling the line.

phase comparison protection: A form of pilot protection that compares the phase angles of currents at the terminals of a transmission line. Data from the relay at the remote terminal is provided to the local relay using a communications channel. This data is utilized by the local relay to develop representations of the phase angles of the currents measured by the remote relay. These representations are then compared with the phase angles of the currents measured by the local relay.

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

pilot scheme: A protection scheme involving relays at two or more line terminals that share data or logic status via a communication channel for improving the tripping speed and/or coordination.

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

primary zone: The segment of the power system for which the relay or element within the relay is principally responsible for protection.

quadrature polarization: A form of cross polarization in which the polarizing voltage is in quadrature with the voltage of the faulted phase(s). Phase A voltage would be used for polarization during a short circuit between phases B and C.

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

redundancy: A design of relaying, equipment, and tripping circuits developed with the goal of avoiding the possibility that a single component failure will prevent the relaying from reliably sensing and isolating a fault in the protected zone.

reliability: The ability of a protection system to operate correctly taking into consideration both dependability and security.

security: The degree of certainty that a protection system will not respond when the fault or abnormal condition the protection system is intended to detect is not present.

segregated phase comparison protection: Similar to phase comparison protection except that the phase angle data of all phase currents (or all phase and ground currents) measured by the remote relay are sent separately to the local relay for individual comparison with the phase angle of the currents measured by the local relay.

self-checking (by a relay): Self-testing by microprocessor-based relays that checks operation of selected modules of processor software as well as selected hardware components.

sequential tripping: A situation where a local relay cannot detect and trip for a line fault until one or more of the remote terminals has opened to remove infeed.

single-phase tripping and reclosing: Opening the interrupters of a circuit breaker in one phase only to isolate the faulted phase in the event of a single-phase-to-ground fault and reclosing them after some time delay.

source impedance: The impedance of the equivalent source behind a terminal of a transmission line used in calculating the source impedance ratio for determining the electrical length of the line. In network applications, this impedance can vary depending on the position of other circuit breakers and switches close to the transmission line terminal.

source of fault current: A terminal that contributes current to a fault on the protected line.

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

step distance: A non-pilot distance relay scheme using multiple reach settings (zones) with time delays associated with some zones to provide coordination of protection.

switch onto fault protection: A protection scheme that trips the line circuit breaker if it is closed into a fault. This protection scheme is to clear a line before the breaker at the remote terminal closes or in cases where there is insufficient voltage for polarizing the directional elements. Also referred to as line pickup protection.

transfer trip: A pilot scheme that receives a logic signal from a remote terminal to trip the local terminal with or without local supervision.

unblocking: Pilot scheme logic that allows a permissive pilot scheme local relay to trip within a time window if a communication signal, such as an audio tone, power-line carrier, or frequency shift keying, is lost from the remote relay. The logic is based on the possibility that the communications signal was interrupted by the occurrence of a line fault.

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.

3.2 Device numbers

The device numbers used in this guide are in accordance with IEEE Std C37.2, IEEE Standard Electrical Power System Device Function Numbers, Acronyms, and Contact Designations.

3.3 Acronyms and abbreviations

ANSI	American National Standards Institute
BCG	phase B to phase C to ground fault
CT	current transformer
CVT	capacitance voltage transformer
DCB	directional comparison blocking
DCUB	directional comparison unblocking
DUTT	direct underreaching transfer trip
EHV	extra-high voltage
FSK	frequency shift keying
GIC	geomagnetically induced currents

HV	high voltage
IOC	instantaneous overcurrent
LOP	loss of potential
MOV	metal oxide varistor
NERC	North American Electric Reliability Corporation
POTT	permissive overreaching transfer trip
PSRC	Power System Relaying Committee
pu	per unit
PUTT	permissive underreaching transfer trip
RO	overreaching (relay element, in figures)
RU	underreaching (relay element, in figures)
R-X	resistance-reactance
SCADA	supervisory control and data acquisition
SCV	voltage at the swing center
SIR	source-to-line impedance ratio
SVC	static var compensator
TOC	time overcurrent
UHV	ultra-high voltage
var	voltampere reactive
VT	voltage transformer

4. Fundamentals

4.1 General

It is necessary to review two terms used in this guide before the fundamentals are discussed; the terms are transmission line and zones of protection.

4.2 Transmission line

Terms such as transmission line, subtransmission line, and distribution line have different connotations among different utilities. Many issues, such as what constitutes a line terminal, may also vary among companies. Clauses of this guide address many line configurations and the effect those configurations may have on the application of systems to protect lines.

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

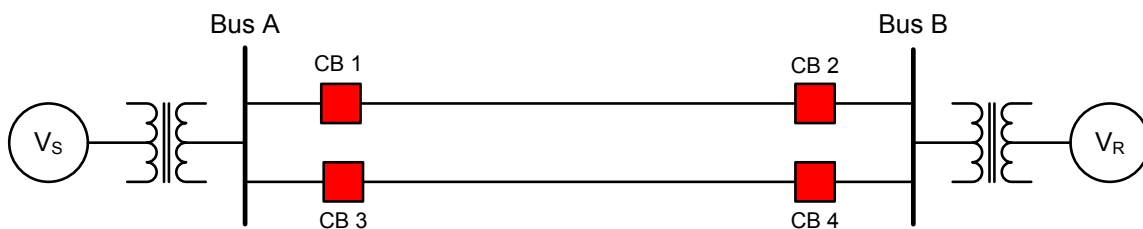


Figure 1—Definition of line

4.3 Single-line representation of lines and equipment

There are many ways to represent electrical systems and the protection schemes applied to them:

- Three-line ac diagrams
- Single-line diagrams
- Single-line diagrams with current transformers (CTs) and voltage transformers (VTs)
- Single-line diagrams with protection, and other related equipment
- DC and ac schematics
- Relay functional diagrams
- Relay logic diagrams
- DC elementary diagrams

Connections of protective relays are shown in their broadest level (minimum detail) in a single-line diagram shown in Figure 2. Connections shown as single lines are actually three-phase circuits. The relays are represented as circles labeled “R” (for relay), connected to CTs and VTs. This type of single-line diagram is useful for understanding the various zones of protection. One of the relays shown in Figure 2 is labeled “21,” which indicates that this device is a distance relay that is provided to protect the line. Function numbers are given in IEEE Std C37.2, as already stated in 3.2.

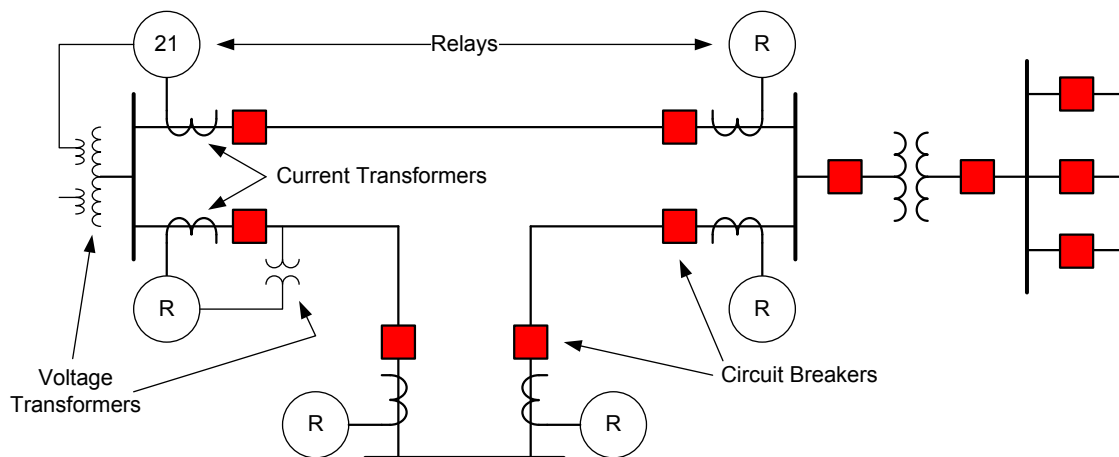


Figure 2—One-line diagram of a sample transmission system

Protection characteristics can be shown on time-current diagrams, $R-X$ diagrams, relay-reach versus operating time diagrams, or distance to fault versus the zone operating time. Figure 3 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 4 shows the method of representing the operating characteristics of a distance relay on an $R-X$ diagram. This characteristic, like that on the current-versus-time diagram, also separates the operate and the non-operate regions. The region of where load plots is illustrated as well on the $R-X$ diagram.

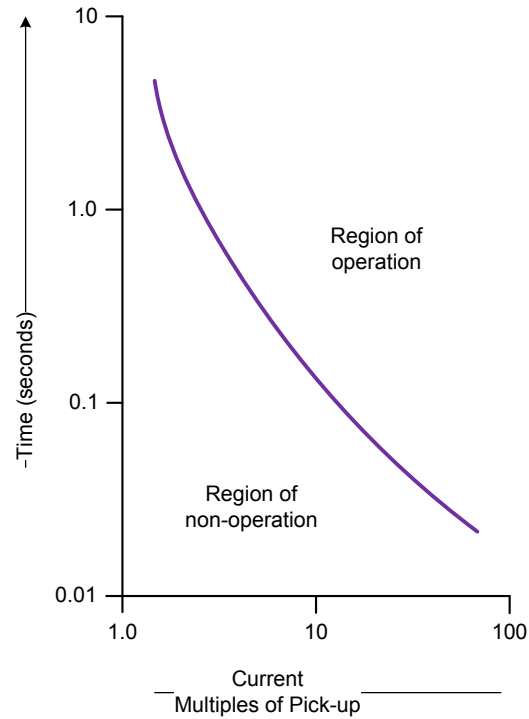


Figure 3—Extremely inverse time overcurrent characteristics

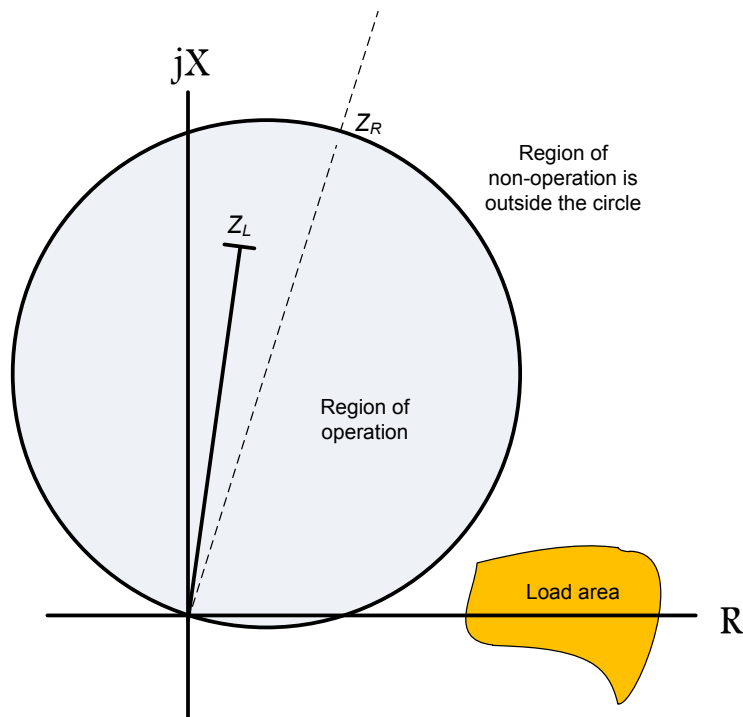


Figure 4—Relay characteristics on the R - X plane

4.4 Zone of protection

There are many types of protection zones; the following basic protection zones are shown in Figure 5:

- Generator protection zone (a)
- Transformer protection zone (b)
- Bus protection zone (c)
- Line protection zone (d)
- Motor protection zone (e)
- Generator-transformer protection zone (f)

The boundaries of a measuring zone of protection, as applied to protective relays, are determined by the locations of the CTs that provide currents to the relay; these currents represent the line currents. Overlapping of zones of protection is an established protection concept whose application is shown in Figure 6. The placement of CTs for part of station B of Figure 5 is shown in Figure 6. The CT connections for the generator zone and bus zone relays are also shown in this figure. Detailed discussion of bus protection is provided in IEEE Std C37.234™ [B69]. Detailed discussion of generator protection is provided in IEEE Std C37.102™ [B60].

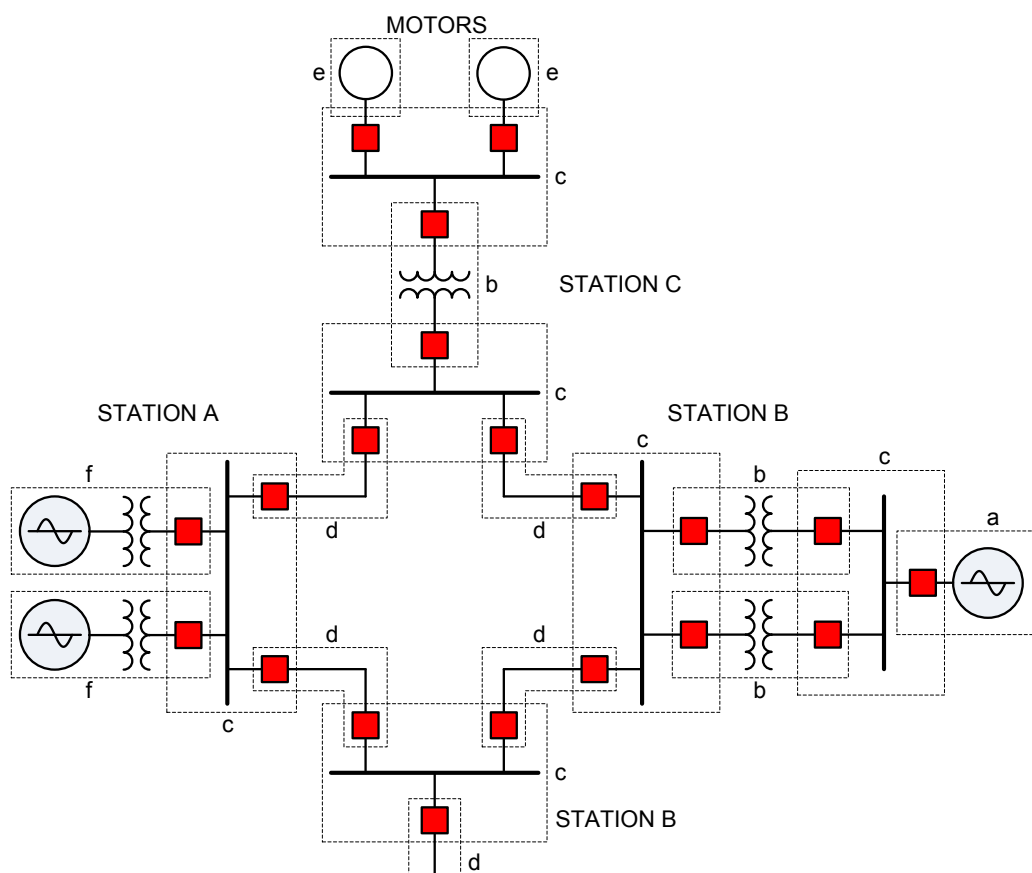


Figure 5—A sample power system and its zones of protection

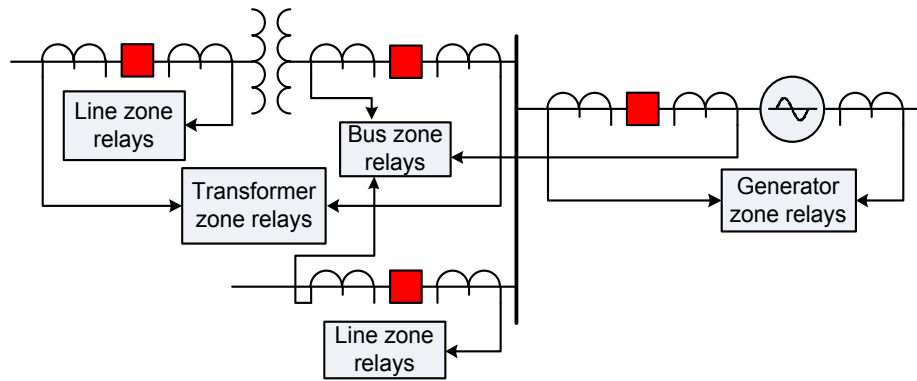


Figure 6—The principle of overlapping protection

The boundaries of the zone of protection of a line-protection scheme that uses pilot communication are clearly defined. However, many line protection practices 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.

4.5 Line-relaying selection

4.5.1 General

The selection of a system for protecting a line requires that several factors, some of which are mutually exclusive, should be considered. For example, knowledge of the most probable modes of failure, recommendations of equipment suppliers, and good practical judgment can assist a protection engineer in determining the emphasis that each factor should be given.

One of the most important considerations for selecting a protection system is reliability. The reliability of protection systems is separated into two aspects: dependability and security. Dependability is relatively easy to obtain in relay design or in the application of a number of relays. Testing using operating conditions and redundancy are methods to ensure dependability. Security is difficult 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 the following:

- Application of redundant relay systems with independence of design.
- Application of redundant relay systems with different operating principles.
- Redundancy within the relay systems.
- Local backup methods.
- Remote backup methods.

Security can be enhanced by various practices, such as the following:

- Application of relays and relay systems that do not cause undesirable trips upon failure.
- Using protection systems that degrade into a fail-safe mode.
- Series-connected protection systems; for example, two-out-of-two protection systems require both relay systems to operate to initiate a trip. While using two-out-of-two increases security, it reduces dependability. Failure of one of the two systems would result in no operation during a fault.

- Using an independent disturbance detector to supervise the protection system.
- Improved monitoring and self-checking.
- Emphasis on high-quality components.
- Two or more protection systems can be used to protect a line, and a voting scheme can be used to achieve a balance between dependability and security; for example, a voting scheme that uses two-out-of-three trip logic.

Another important design consideration is selectivity and coordination of the protection system. Selectivity is the ability of a protection system to cooperate with other protection systems to reduce the outage area when a faulted component of the system is isolated from the system. Coordination refers to the process of applying relays to operate for faults in their primary zone of protection and within their backup zones, which extend beyond the primary zone. Within backup zones, the relay operation may be delayed to coordinate with operation of the relay systems protecting the components in the extended zones. Selectivity and coordination should be achieved to ensure maximum service continuity and security.

Fault-clearing time is an important consideration in the selection of a system for protecting lines. Requirements for the speed of a relay should be carefully determined. If the operating speed is too slow, system instability, excessive equipment damage, and adverse effects on customers' equipment may result. However, a faster operating speed of the protection system may compromise the security, coordination, and selectivity of the protection system. There is a limit to the speed with which a protection system can correctly respond to the occurrence of a fault. The limit is due to the operating principle of the relay, and due to the transients that are present in voltages and currents experienced during faults and applied to the protection system via the CTs and VTs (see 6.11).

The sensitivity of a protection system that refers to the minimum operating quantities required for the system to detect a fault is an important factor. Most solid-state or numerical relays are more sensitive than their electromagnetic and electromechanical predecessors. But certain problems, such as detecting high-impedance ground faults, inherent system voltage unbalances, and high source-to-line impedance ratios (SIRs; see 5.2), still challenge the sensitivity of relays and should be considered when protection systems are selected.

The design of a line-protection system may 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 protection engineers, who are responsible for setting relays, and operations and maintenance personnel. The problems caused by incorrect or incomplete implementation of overly complex protection systems may create more serious consequences than not providing solutions for special situations. Protection engineers should carefully weigh the consequences and probability of each problem to determine if they justify using the complex special solutions that might be available or could be developed.

Protection engineers have long pointed out the relatively low cost and high importance of protection systems compared with the equipment they protect. However, it is important to achieve the required protection at a reasonable cost. In recent years, more importance has been placed on economic analysis that considered more than just the lowest initial cost. The additional factors considered include installation and maintenance costs as well as the cost of unreliable protection. In addition, modern protection systems usually offer many features that were not previously available; those features 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 the available alternatives.

Pilot relaying schemes are used to achieve high-speed tripping for faults at all locations on the line. These schemes require that, during a fault, information be transmitted between the protection systems that are located in different substations to determine if the fault is inside or outside of the line-protection zone. This is accomplished by using several different methods, ranging from direct hardwire communications to fiber optic communication systems (see 6.3). Different protection schemes and communication channels have different degrees of dependability and security. Knowledge of the communication options is necessary to

determine the reliability of the protection schemes being considered. The network configuration and local system-loading requirements may also affect the suitability of pilot protection schemes.

4.5.2 Factors influencing line relaying selection

4.5.2.1 General

A number of factors affect the selection of an adequate protection system for a given application. Some of the factors are described in 4.5.2.2 through 4.5.2.8.

4.5.2.2 Impact of line faults on the power system

4.5.2.2.1 General

One of the significant factors in determining the system for protecting a transmission line is the impact a fault on the line will have on the power system. How the fault is detected and cleared is important to the remaining system, not so much to the faulted line, except that high-speed clearing of line faults will reduce the damage to the line hardware and increases the likelihood of a successful reclose. The greater the impact a fault on the line will have to the power system may justify redundancy in protection, communication, and perhaps even dc auxiliary supply. A fault on a medium-voltage, long, radial transmission line will have minimum effect on the remaining system, so it may be adequately protected with a step-distance or overcurrent system; whereas a high-voltage, short, line that is part of a closely tied network may require a pilot or a current differential system.

The determination of the type of line protection is usually based on factors such as the operating voltage of the line, the length of the line, the proximity of the line to generating stations, power flows, stability studies, regional and federal regulations, and customer service considerations.

Several factors related to the requirements of the power system or to the requirements of the configuration of the line should be weighed in the selection of transmission line protection. These include the factors outlined in 4.5.2.2.2 through 4.5.2.2.6.

Faster clearing of line faults will reduce the damage to the insulators and support hardware caused by the arcing of the fault. This reduction in damage could increase the success rate of the autoreclosing.

4.5.2.2.2 Fault-clearing time requirements

The time in which a protection system should clear a fault is determined by considering issues such as system stability and the effects of the durations of voltage sags on customers' operations. The clearing time consideration not only influences the selection of primary relays, but may also dictate the application of local backup protection and selection of the type of inter-substation communications needed for the application.

4.5.2.2.3 Line length

Very short lines or very long lines may require protection solutions specifically designed for those lines (see 5.2).

4.5.2.2.4 Capacity of sources

Closely related to the line length consideration is the capacity of the sources connected to a transmission line. The source-capacity determines fault current levels and affects the ability of protection systems to provide adequate selectivity. If the capacities of the sources are subject to significant variations due to changes in operating conditions, some protection systems require flexibility for modifying the protection system, or to automatically adapt to accommodate the impact of changes in the power system.

4.5.2.2.5 Line configuration

The number of terminals, effects of tapped loads, and impacts of series capacitors and shunt reactors have considerable influence on the selection of a protection system. This issue is discussed in detail in Clause 5.

4.5.2.2.6 Line loading

The voltage-to-current ratio (impedance), as seen from a line terminal, can be small if the line is heavily loaded. This impedance could lie in the operating characteristic of a distance relay provided to protect the line. Protection systems that include load-blinding features or that are naturally immune to flow of load currents should be used in such cases.

4.5.2.3 Communications

Many transmission-line-protection systems depend on communication between the line terminals. The choice of the communication system is influenced by many factors, including most of the factors that influence the selection of the protective relays.

If the choice of communication is dictated by factors independent of the choice of the protection system, then the communication system will influence the protection to be applied. If the protection is chosen based on factors independent of the communication system, then the communication selected should be compatible with the protection requirements.

It is important to understand the difference between the goals and means of such protection when the need for a communication-based protection system is considered. For example, improved stability is a goal and short-fault clearing time is a means of achieving that goal. Utilities target to reduce the fault-clearing time on transmission lines for technical reasons, such as to improve generator angular stability or to reduce equipment damage that might occur if the flow of fault currents continued for longer periods of time.

There are several reasons for the need of high-speed clearing of faults on an entire line. Generator angular stability is just one of the issues that require consideration to justify the need for communication-based transmission line protection. Some of the other reasons for the need of using communication systems in transmission line protection include the following:

- Limiting fault current damage by reducing fault-clearing times
- Allowing high-speed autoreclosing
- Technically simplifying single-phase tripping and reclosing applications
- Providing protection for remote transformers that do not have interrupting devices
- Adequately protecting multi-terminal and high SIR (short) lines
- Protecting weak infeed terminals and instantaneously clearing low-current faults along the entire transmission line
- Providing breaker failure protection and transfer trip for multiple breaker terminals
- Limiting voltage sag to prevent voltage stability issues and voltage sag to nearby customer loads, thereby improving power quality
- Avoiding fault-induced voltage collapse

Each of these aspects should be studied when determining the need for a communication-based protection system. These considerations may be added to other uses for communication paths [e.g., need for substation SCADA (supervisory control and data acquisition)] that may provide sufficient justification to permit pilot protection to be implemented.

Once the need for a communication-based protection scheme has been established, some additional general requirements that should be determined include the following:

- The number of communication systems required
- Type of communication system, such as analog or digital
- Medium for communication, such as copper wire, fibre optic, or power-line carrier
- Need for alternative communication paths if the normal communication path/paths fail
- How to operate the line if the communication becomes unavailable
- How breaker/relay maintenance affects the protection at each terminal

This type of thorough analysis of the technical justification and operational requirements for pilot protection should be integrated with the economic implications of those requirements in a comprehensive review of the transmission line protection. This practice should be followed for selecting protection systems for new transmission lines and also when protection is replaced on existing lines (PSRC Report [B40]).

A thorough discussion of the commonly applied pilot protection schemes and the interrelationships of protection and communications is included in 6.3.

4.5.2.4 Failure modes

Protective relaying design should consider and reduce the negative 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 protection system. Redundant protection, local backup-protection, remote backup-protection, and duplication of other system components are used to reduce the effects of single-point failures.

“Common-mode failure” is another design consideration. Common-mode failures are failures of multiple functions due to the failure of one component or due to the same root cause. Examples would be failures due to mechanical jolts, such as bumping the panel or earthquake vibrations. Other common-mode failures could be application errors, setting errors, incorrect maintenance or calibration procedures, or inadequate shielding from electromagnetic induction. Independence in the operating principles of the primary and backup protection systems is a technique that may be applied to reduce the chances of common-mode failures. Physical isolation or separation, use of equipment from different manufacturers, 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.

4.5.2.5 Protective scheme design compromises

The design of a protection system may require considerable compromise. Reliability is, by definition, a combination of dependability and security. Increasing dependability usually reduces security; a tradeoff is, therefore, necessary. Other compromises are reliability versus cost, speed versus security, simplicity versus complex features, independence of design and manufacture versus standardization, and old technology versus new technology. All of these, and many more choices, should be considered at the design stage. A prudent relay design engineer would document these choices, particularly the compromises and the reasons behind them. This documentation process provides the operations department with the information necessary to evaluate the protection in less technically-complex terminology. It would provide 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.

4.5.2.6 Past practices

The selection of protection usually takes into consideration past practices and the familiarity of the personnel responsible for those practices. The selection of different protective systems may result in requirements for development of new documentation and for additional training for the staff. Protection solutions can only be effective if designed properly, installed and commissioned correctly, and supported sufficiently by operations and maintenance personnel.

4.5.2.7 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 and VT 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.

4.5.2.8 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 and easy to modify or replace.

4.6 Redundancy and backup considerations

Redundancy is the design of relaying developed with the goal of avoiding the possibility that a single component failure will prevent the relaying from reliably sensing and isolating a fault in the protected zone. Backup protection is a form of protection that operates independently of specified components in the primary protective system. It may duplicate the primary protection or may be intended to operate only if the primary protection fails or is temporarily out of service. Many transmission lines are protected by two protection systems, for example, the line from bus B to bus D shown in Figure 7 is protected by a differential protection system as well as by a permissive overreaching transfer trip (POTT) protection system. Both protection systems operate independently and ensure that the line is disconnected from the rest of the power system in the event a fault occurs in the line-protection zone. The two protection systems are functionally equivalent and do not share any components; therefore, they are deemed to be redundant protection systems.

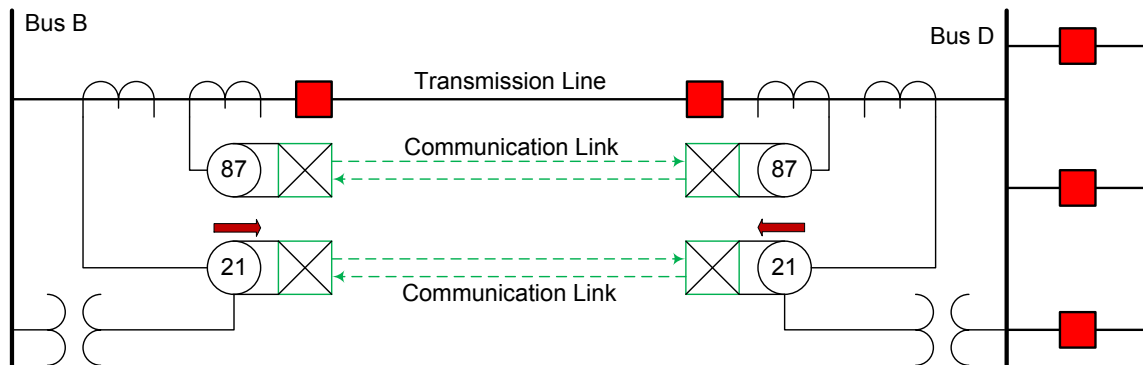


Figure 7—Main 1 and main 2 systems for protecting a transmission line

These redundant protection systems are often referred to as main 1 and main 2, system 1 and system 2, system A and system B, or similar descriptions for these redundant protection systems. The advantage of using redundant protection systems is that the failure of one component of a protection system does not result in losing the ability to isolate the protected circuit if a fault occurs on that circuit. This improves the reliability of the power system.

Redundant CTs, VTs, breaker trip coils, power circuit breakers, dc sources, communication channels, and/or other system components can be used to improve the reliability of the power system.

Backup protection is achieved by using different protection systems or functions. These systems function simultaneously with the primary protection systems, but their operation is delayed long enough to allow the primary protection systems to isolate the fault first. Backup systems perform the tripping function only if the primary protection systems fail to isolate the faulted line.

Redundant and backup protection of ac transmission lines can be provided by different methods, each with varying levels of complexity. The practices in various utilities include the following:

- Using identical relay systems
- Using relays from the same manufacturer but with different models or principles
- Using relays from different manufacturers but with the same principles
- Using relays from different manufacturers with different principles

There are various tradeoffs in complexity, cost, dependability, and security in all of those alternatives. The history in each utility is sometimes the deciding factor. Sometimes, one of the objectives is to lessen the possibility of similar hardware and software design problems affecting both protection systems.

Backup protection can be divided into two types: local backup and remote backup. Local backup protection refers to the protection system located at the substations where line terminals are located. The term “remote backup” refers to detecting faults using protection systems that are located at substations other than the substations where the line terminals are located.

The basic form of local backup protection is the inclusion of redundancy in the protection scheme. Typically, the higher the voltage level, the greater is the redundancy provided in the protection systems. The use of local backup reduces delays and loss of selectivity that occurs with the operation of remote backup protection. The tradeoff occurs in extra cost for the additional equipment required for local backup protection.

A part of a transmission system protected by multiple-zone distance relays is shown in Figure 8. All lines in this transmission system are protected with step-distance protection systems that use separate relay elements for each zone using the setting philosophy detailed in 6.2.4.2. Also, no breaker failure or other protective relays are provided. A fault on line from bus B to bus D would be detected by the distance relays provided on the line at those buses and would isolate the line by opening circuit breakers B3 and D3. Zone 2 elements of those relays provide backup protection for the failure of the zone 1 elements and provide time-delayed protection of the line section from the end of zone 1 to the end of the line. The zone 3 elements of those relays provide local backup protection for the failure of zone 2 elements to clear faults beyond the reach of the zone 1 elements as well as provide backup protection for the zone 1 elements. This is because separate protection elements are used in the distance relays in this example. Zone 2 and/or zone 3 elements of distance relays provided at circuit breakers A1, C2, E1, E2, and F4 would also detect the fault in the forward direction if they are within the reach of the relay. They would open circuit breakers A1, C2, E1, E2, and F4 after the set time delay in case the primary or local backup protection of the faulted line failed to isolate the line from the system before the expiration of the coordination time delays. This illustrates a drawback of remote backup protection in that it results in a complete loss of supply to the affected substations, because all lines into the station have to be tripped to remotely clear the fault.

The operation of the remote backup protection is delayed more than the operating time of the local backup protection to ensure that parts of the power system other than the faulted line are not unnecessarily de-energized.

Where remote protection is required to provide secondary or backup protection, it should be verified that the sensitivity of the remote backup protection would detect all types of faults and for all credible system configurations. The effects of infeed from other lines at the remote terminals should be taken into account to ensure complete coverage of the protected line. In some cases, it may be acceptable for remote backup relays to operate sequentially if the remote backup relays cannot provide complete coverage of the line. Also, remote backup protection should not operate during high system loads and during low levels of system voltage.

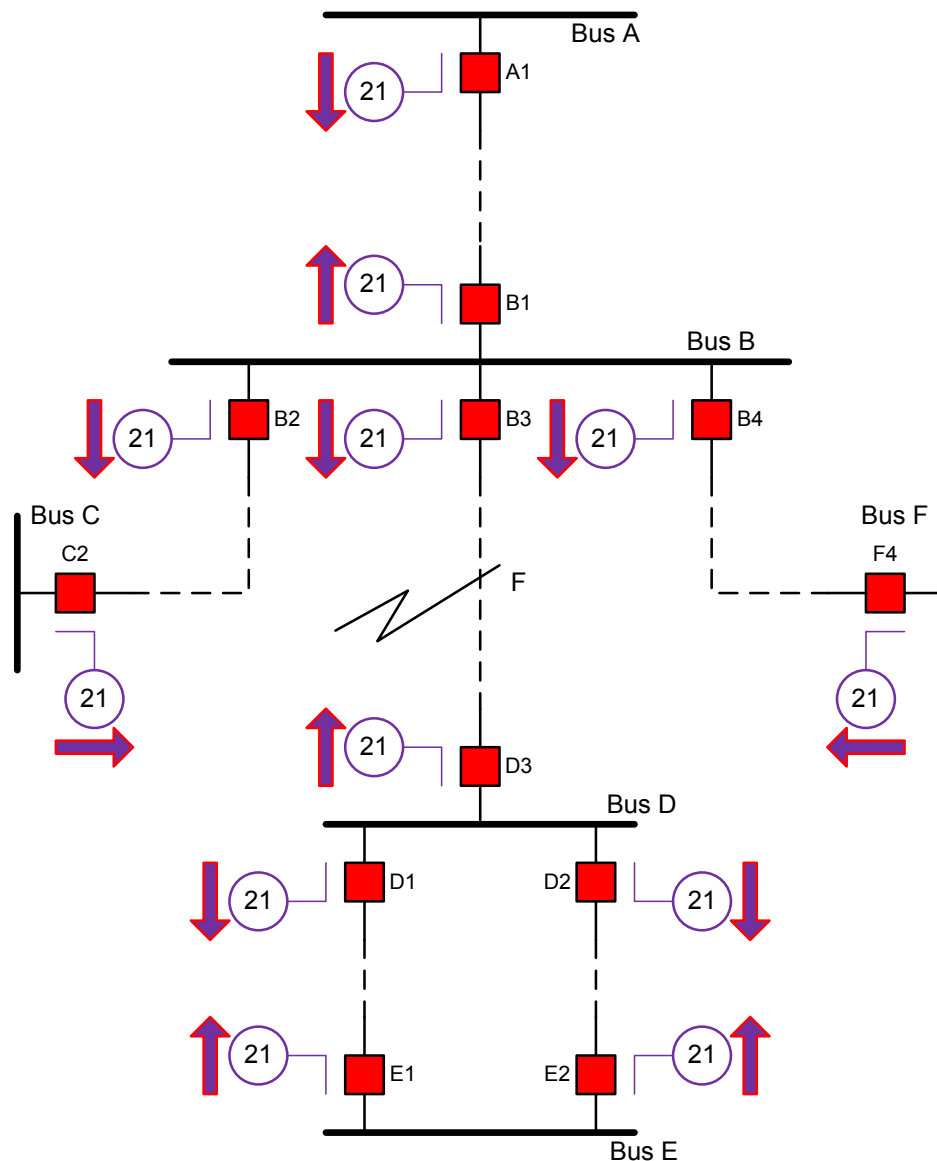


Figure 8—Remote backup protection of a transmission line

It is important to appreciate that one relay can provide local and/or remote backup protection simultaneously to different components of a system, including transmission lines. Also, a transmission line can have a number of different backup protection relays. Some elements within a protection system may back each other up as well as back up the protection in other transmission lines. However, since different elements within a single system may share some common components (such as power supply), completely independent backup cannot be achieved within a single system.

Some protection functions operate only for faults on a transmission line. These functions, such as pilot wire, current differential, and phase comparison protection do not offer remote backup protection and can be used only as primary functions. Other protection functions, such as overcurrent protection and step-distance with overreaching zones, can detect faults on the transmission line they are provided for and parts of adjacent protection zones. These functions offer remote backup and can be used as primary or local backup functions as well.

The operation of some protection functions requires transfer of information between protection systems provided at all the terminals of a line. It is always desirable to provide backup protection functions that do not need communications between the terminals for detecting the fault and isolating the faulted line.

4.7 Autoreclosing methods

Automatic reclosing is discussed in detail in IEEE Std C37.104™ [B61]. Some comments are provided in this subclause for readers' ready reference.

Protective relays are applied to isolate faulted elements and maintain the integrity of electrical transmission systems. The loss of a single line in the transmission system can have a great impact on the economics and reliability of the system. Many system faults, such as those caused by lightning, wind, or tree branches, are temporary in nature and may disappear once the faulted circuit is de-energized. Autoreclosing of line circuit breakers is widely used to reduce the impact of these temporary faults by re-energizing and restoring the faulted section of the transmission system.

Two methods of autoreclosing are typically applied on transmission lines; these are high-speed autoreclosing and time-delayed autoreclosing. High-speed autoreclosing is initiated with high-speed relays and consists of automatic closing of a circuit breaker with no intentional delay beyond an allowance for arc deionization. Some benefits of high-speed autoreclosing include fast restoration of power to customers, improved system stability, and immediate restoration of system capacity and reliability. It should be noted that high-speed tripping of all line terminals needs to be present in order to apply this method of autoreclosing. A time-delayed reclosing is sometimes attempted if high-speed reclosing does not succeed.

Time-delayed autoreclosing is implemented with a definite circuit breaker open interval. A time-delayed autoreclose can be used following an unsuccessful initial high-speed autoreclose or where multiple-shot autoreclosing is desired. The initial autoreclose dead time for a time-delayed autoreclose cycle can be as low as 0.5 s and as high as 60 s.

Single-shot autoreclosing is the automatic closure of a circuit breaker one time only. Multiple-shot autoreclosing is the automatic closure of a circuit breaker more than one time in a predetermined autoreclose sequence. Autoreclosing on extra-high-voltage (EHV) systems is typically of the single-shot type. Multiple-shot reclosing, however, has gained acceptance on lower voltage transmission systems even though the success rate for additional dead-line autoreclose attempts is poor.

Various forms of supervision may be applied to autoreclose schemes. Autoreclose supervision prevents autoreclosing for conditions that might cause undesired affects, such as damage to generators or motors, or re-energizing faulted equipment such as transformers and reactors. Selective and adaptive autoreclosing are other methods utilized to prevent autoreclosing for specific types of faults or system conditions.

Autoreclosing has evolved due to the availability of greater amounts of information through SCADA and modern relaying systems, such as neural network-based devices. This evolution allows for more selective schemes that improve the reclosing success rates and lessen damage to system components that might have been caused by closing into permanent faults. The type of autoreclosing used typically depends on the voltage level, customer requirements, stability considerations, and the proximity of generation.

4.8 Effects of load on line relay applications and settings

4.8.1 General

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

4.8.2 Phase overcurrent relays

Phase overcurrent relays are generally set such that they do not operate when system load is being supplied, as well as during transient operating conditions, such as transformer inrush, motor starting, emergency loads, and recoverable power swings. This usually requires an overcurrent pickup setting above a maximum load level. The sensitivity that can be achieved is, therefore, somewhat coarse, but many applications in which phase overcurrent relays are used do not require high sensitivity (for details, see 6.2.2 and 6.2.3).

4.8.3 Ground overcurrent relays

Ground overcurrent relays have the advantage of using current that is either zero or very small under normal conditions. The sensitivity that can be achieved is substantially better than that afforded by phase overcurrent relays. Only unbalanced load currents and system unbalances affect the setting of these devices. Balanced system load has no impact on the ground overcurrent relay applications on transmission lines.

4.8.4 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 non-tripping direction. For further discussion on directional overcurrent relays, see 6.2.3.

4.8.5 Phase distance relays

Phase distance relays have a relatively fixed reach along the line impedance depending on the shape of their operating characteristics and settings. These relays are applied to operate when fault currents flow on the protected line and to not operate when only load currents flow on the protected line. Phase distance relays may sometimes require a setting for adequate fault coverage that might limit the line loading capability. A detailed discussion of this issue is given in 6.7.2.

4.8.6 Ground distance relays

Ground distance relays are applied on transmission lines using phase currents, residual current, and phase voltages as inputs. In some cases, the residual current is not zero during normal operation of the line because of various reasons, such as unbalance in the loads on the three phases. This makes these relays susceptible to false operation under heavy load conditions if not supervised by directional elements. Sometimes, ground distance relays are supervised by ground fault detectors that are set after considering such things as CT mismatch or load unbalance.

Ground distance relays are also susceptible to errors associated with ground fault resistance in the presence of load-flow-induced source angle differences. The relays may overreach or underreach for leading and lagging phases when phase-to-ground faults occur if some provisions are not included in the relay design to compensate for these factors. Giuliani, McConnell, and Turner [B31] describe these provisions. These problems can be taken care of by using more conservative settings of the relay.

4.8.7 Pilot systems—Two terminal lines

The influence of load on pilot systems depends largely on the nature of the protective relaying scheme. The systems that use overreaching distance measurement, such as directional comparison blocking (DCB), POTT, and directional comparison unblocking (DCUB), have the advantage of limited load sensitivity. These systems are least affected by load currents, typically because the overreaching element does not come near loading values. However, the pilot trip elements may approach loading impedances in very long line applications. In some cases, the relays include blinders, load encroachment, or shaped characteristics that prevent operation of the pilot system during balanced three-phase load conditions. The DCB, POTT, and DCUB schemes are further described in 6.3.5.6, 6.3.5.4, and 6.3.5.7, respectively.

The distance relays are set short of the remote line terminal for direct underreaching transfer trip (DUTT) schemes. This setting makes the scheme less susceptible to tripping under heavy load conditions. However, the reach variation of the distance relay as a result of pre-fault load current is much more critical than for the overreaching schemes for situations in which fault resistance is not zero. It is desirable that load or fault current, or any combination of the two, should never cause operation of the zone 1 elements for any condition other than a fault on the protected line. The DUTT scheme is further described in 6.3.5.2.

Phase comparison and current differential schemes are not normally susceptible to operation for load currents flowing on the line because these schemes use the summation of current from each terminal of the line, which is very low during normal load flow. 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. The use of channel trip inhibit circuits in these schemes prevents them from false tripping even when their current-based fault detectors have operated. But if the channel trip inhibit circuits are not provided or if they fail, this would result in incorrect operation of the protection system during normal operating conditions or during faults external to the protected circuit. Current differential schemes may be sensitive to tapped loads, and settings should be chosen accordingly. Also, high levels of through-load currents may reduce the fault detection sensitivity of both phase comparison and current differential schemes. This can happen because the phase angles of currents may shift beyond the operating region, resulting in restraining the protection system during internal faults (weak-infeed and -outfeed conditions).

Line charging current is substantial in EHV transmission lines (more than 1 MVA reactive per kilometer for a 500 kV line) and high-voltage cables. Special considerations may be required for setting fault detectors used to protect those systems.

4.8.8 Pilot systems—Three terminal

An outfeed condition may occur even without load during an internal fault on a three-terminal line. Depending on the type of protection system, this may result in an undesired delay in clearing the fault. Three-terminal applications occasionally have at least one weak source. Therefore, care should be taken to ensure that either the contribution to an internal fault exceeds the load current outfeed (discussed in 6.6.2), or the relaying system used to protect the line is based on the total internal fault current similar to a differential protection system.

4.8.9 Sensitive ground overcurrent fault protection

Sensitive ground-fault protection is used to reduce hazards for the public and protect equipment. While transmission faults with fault impedance are not as common as faults in distribution systems, the severity and adverse consequences of a transmission-line fault that is not detected can be significantly higher due to the high energy levels that are present. This topic is further covered in a 2014 PSRC report, “Transmission line applications of directional ground overcurrent relays” [B51].

The type of system grounding and specific fault impedance determine the magnitude of ground faults. Faults that contain high impedance pose a challenge to distance relays. Directional ground overcurrent

relays may be set sensitive enough to detect these faults, but they could adversely impact security. The balance between sensitivity and security is based on individual and company preferences. Limits exist on how sensitive a relay is allowed to be set and is truly part of the “art” of protective relaying. In addition, microprocessor relays provide a means to detect higher impedance faults that electro-mechanical relays cannot. This allows the protection engineer to use a more sensitive ground protection setting.

Methods of setting directional ground overcurrent relays vary among companies, locations, etc. One method sets the pickup to a small portion of a minimum expected fault current. This method inherently allows for different system conditions and contingencies as well as for faults with impedance. However, it may not encompass the desired sensitivity. Another method may set the ground relay for a fault with a set value of impedance. Regardless of the method, setting the ground relay sensitive enough to detect faults that ground impedance elements do not detect is desirable.

Due to an increased focus on sensitivity, factors that were previously discounted and were accounted for in general tolerances have now become more important, and consideration for such factors is required. These factors include maximum ground current (due to system imbalance) during heavy loads, the system model, mutual coupling, instrument transformer inaccuracies, single-phase tripping, and contingencies.

The system model should be as accurate as needed to support the sensitivity of relay settings. Transmission lines need to be correctly modeled; the models should include factors, such as specific cable types, series compensation, structure type, earth resistivity, etc. Mutual coupling should be accurately modeled with the correct orientation between line segments and the correct mutual coupling effects. Under-built distribution lines may also need to be considered. Data recorded from system faults may be used to validate and revise the model if it becomes necessary.

The selection of the time delay curve is a matter of preference. However, the ground relay should coordinate with the ground distance relays and other ground overcurrent relays. In order to improve the coordination requirements of the ground distance protection functions, trip times for line-end ground faults should be larger than zone 2 delay times with a margin. Coordination with other similar relays at remote terminals need only be effective for fault current levels defined by the fault impedance expected in an application.

5. Impact of system configuration on selection of protection schemes

5.1 General

This clause addresses the impact of system configuration on the selection of protection schemes: line length, line design, number of line terminals, lines terminated in transformers, weak electrical systems, ground path configurations, distribution taps, power flow control devices, parallel lines, high-impedance return paths, and terminal configurations.

5.2 Length considerations

5.2.1 General

This clause is concerned with the influence of line length on the selection of schemes for protecting transmission lines. Transmission lines may be classified as short, medium, or long.

A line is designated short if the SIR for the line is large. Transmission lines that have SIRs greater than 4 are classified as short lines. The lines that have SIRs of 0.5 to 4 are classified as medium lines. Finally, lines that have SIR of less than 0.5 are classified as long lines.

The per unit (pu) impedance of a line of given length varies much more with the nominal voltage of the line than the impedance of the line in ohms, because the per unit impedance varies with the square of the voltage. 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, which, in turn, influences whether the line is considered “short,” “medium,” or “long.”

For example, consider a 500 kV line whose positive sequence reactance is 0.332 Ω per km (0.5343 Ω per mi). This corresponds to a reactance of 0.000133 pu per km (0.000214 pu per mi) on 100 MVA and 500 kV base values. 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 18.7 km (11.6 mi) would result in an $SIR > 4$ and may be classified as short lines.
- Line lengths greater than about 150.4 km (93.5 mi) would result in an $SIR < 0.5$ and may be classified as long lines.

On the other hand, a 69 kV line, whose positive sequence reactance is 0.53 Ω per km (0.853 Ω per mi), might have very different length classifications. For such a line, the reactance is 0.01113 pu per km (0.0179 pu per mi) on 100 MVA and 69 kV base values. If the source impedance behind a relay terminal is 0.1 pu (corresponding to a fault level of 1000 MVA), the following classifications apply:

- Line lengths less than about 2.2 km (1.39 mi) would result in an $SIR > 4$ and may be classified as short lines.
- Line lengths greater than about 18.0 km (11.2 mi) would result in an $SIR < 0.5$ and may be classified as long lines.

These examples demonstrate the importance of source impedance and nominal voltage on the classification of a line as “short,” “medium,” or “long.” Further, a line can be considered short from one terminal and medium or long from the other depending upon the relative strengths of the sources behind the terminals. To further complicate matters, the positive and zero sequence source impedances can vary considerably such that a line could be short for ground faults and medium or long for phase faults, or vice-versa.

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 consideration only.

5.2.2 Effect of source-to-line impedance ratio on line protection

A short line is a challenge for line protection because it makes it difficult for the relay to differentiate between an in-zone fault and an out-of-zone fault. For a distance element, the higher the SIR (shorter the line), the lower the restraining voltage at the relay for an out-of-zone fault. A very low voltage can be more susceptible to measurement errors and transients, which can result in undesired overreach of an underreaching element. The SIR is a way of quantifying the voltage divider circuit. For an overcurrent relay, when the SIR is high, the faulted system is dominated by the source impedance, and the difference between the fault current magnitude for an in-zone fault and an out-of-zone fault can be smaller than the typical margins used for setting the pickup. More details on short line protection issues are covered in 5.6.6 and 6.10. Thomas and Somani provide additional discussion on SIRs [B101].

5.2.3 Calculating source-to-line impedance ratio for determining line length

A suggested method to calculate the source impedance for the purpose of classifying line length is to place a short circuit at the remote bus (boundary of the line zone) and calculate the source impedance as the voltage drop from the source to the relay location divided by the fault current. For the purpose of illustrating the calculation, Figure 9 shows a transmission system that has been reduced to its two-source

equivalent with the line and transfer impedance branches. The transfer impedance branch that represents the complex transmission system network surrounding the line of interest can have a significant effect on the voltage at the relay for a fault at the zone boundary.

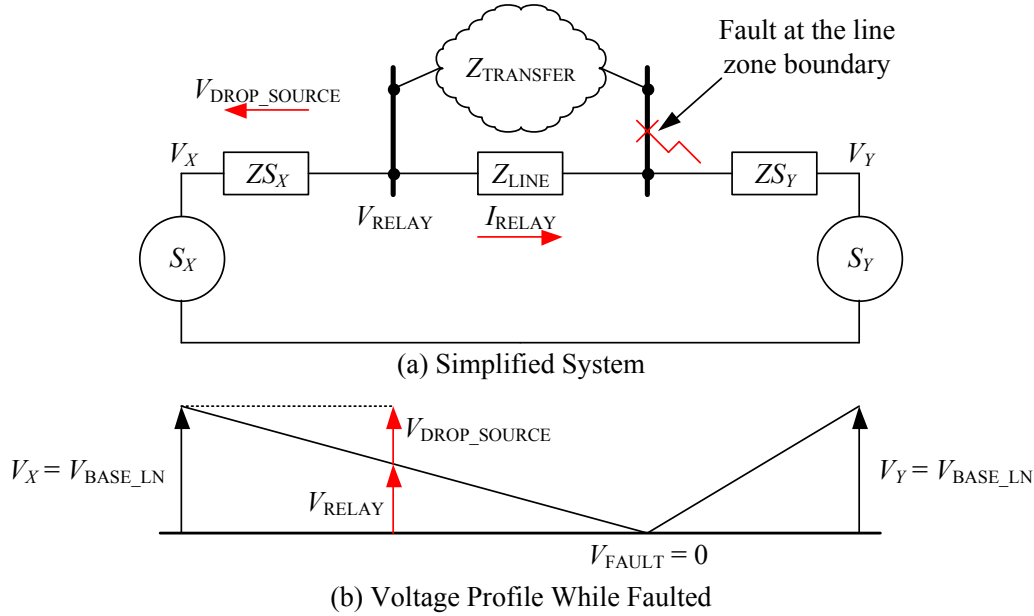


Figure 9—Method to calculate source impedance for use in determining the SIR for classifying line length

Equation (1) and Equation (2) provide the source impedances for the phase and ground fault loops, respectively.

$$Z_{S_{3PH}} = \frac{V_{DROP_SRC}}{I_{RELAY}} = \frac{V_{BASE_LN} - V_{RELAY}}{I_{RELAY}} \quad (1)$$

$$Z_{S_{SLG}} = \frac{V_{DROP_SRC}}{I_{RELAY}} = \frac{V_{BASE_LN} - V_{RELAY}}{I_{RELAY} + (3I_{0_RELAY} \times k_0)} \quad (2)$$

where

- V_{BASE_LN} is the system base voltage, line to neutral, that defines voltage at the infinite bus behind the source impedance in primary units
- V_{RELAY} is the phase-to-ground voltage at the relay for a fault at the remote bus
- I_{RELAY} is the phase current at the relay for a fault at the remote bus
- $3I_{0_RELAY}$ is the zero sequence current at the relay for a fault at the remote bus
- k_0 is the zero sequence compensation factor for the line as defined by Equation (3)

$$k_0 = \frac{Z_{0L} - Z_{1L}}{3 \times Z_{1L}} \quad (3)$$

where

- Z_{1L} is the positive sequence line impedance
- Z_{0L} is the zero sequence line impedance

The source impedances obtained by Equation (1) and Equation (2) are used in Equation (4) to obtain the SIR. Z_{1_LINE} is used in the denominator of the equation to determine the SIR as that defines the zone boundary that should not be overreached. The positive sequence impedance (Z_1) is used for both three-phase and single-line to ground fault because k_0 is used to define ZS_{SLG} .

$$SIR_{3PH} = \frac{ZS_{3PH}}{Z_{1_LINE}} \quad \text{or} \quad SIR_{SLG} = \frac{ZS_{SLG}}{Z_{1_LINE}} \quad (4)$$

It is often desirable to determine the SIR under $N-1$ conditions as well to determine if the line can get short when the strongest source behind the local terminal is out of service.

5.2.4 Example source-to-line impedance ratio calculation

For this example, we have a line between bus W and bus E with the parameters listed in Table 1. The fault values for terminal W are provided in Table 2. The fault values are obtained by placing a three-phase fault at bus E under system normal ($N-0$) and with the strongest source behind the W terminal out ($N-1$). In this case, bus W has one strong source and one weak source connected to the bus behind the relay.

Table 1—Line parameters

Parameter	Value
Voltage	138 kV
Line length	41.53 mi
Z_{1_LINE} primary	34.29 Ω

Table 2—Fault values for determining SIR for terminal W

Parameter	Value
V_{RELAY} for 3PH fault at remote bus E under $N-0$	43.5 kV
I_{RELAY} for 3PH fault at remote bus E under $N-0$	1247 A
V_{RELAY} for 3PH fault at remote bus E under $N-1$	16.3 kV
I_{RELAY} for 3PH fault at remote bus E under $N-1$	484 A

The SIR for the system normal ($N-0$) case for phase protection is calculated as shown in Equation (5) and Equation (6):

$$ZS_{3PH_N-0} = \frac{\frac{138 \text{ kV}}{\sqrt{3}} - 43.5 \text{ kV}}{1247 \text{ A}} = 28.39 \Omega \quad (5)$$

$$SIR_{3PH_N-0} = \frac{28.39 \Omega}{34.29 \Omega} = 0.8 \quad (6)$$

An SIR of 0.8 is greater than 0.5, which indicates that this line should be considered a medium length or borderline long line under $N-0$ conditions.

The SIR for the single contingency ($N-1$) case for phase protection is calculated as shown in Equation (7) and Equation (8):

$$ZS_{3PH_N-1} = \frac{\frac{138 \text{ kV}}{\sqrt{3}} - 16.3 \text{ kV}}{484 \text{ A}} = 130.94 \Omega \quad (7)$$

$$SIR_{3PH_N-1} = \frac{130.94 \Omega}{34.29 \Omega} = 3.8 \quad (8)$$

An SIR of 3.8 is less than 4, which indicates that this line should be considered a medium length or borderline short line under $N-1$ conditions.

Examining this line from terminal E provides the fault values in Table 3. Terminal E is connected to a relatively strong bus with many lines into it.

Table 3—Fault values for determining SIR for terminal E

Parameter	Value
V_{RELAY} for 3PH fault at remote bus W under $N-0$	64.9 kV
I_{RELAY} for 3PH fault at remote bus W under $N-0$	1898 A
V_{RELAY} for 3PH fault at remote bus W under $N-1$	62.0 kV
I_{RELAY} for 3PH fault at remote bus W under $N-1$	1813 A

The SIR for the system normal ($N-0$) case for phase protection is calculated as shown in Equation (9) and Equation (10):

$$ZS_{3PH_N-0} = \frac{\frac{138 \text{ kV}}{\sqrt{3}} - 64.9 \text{ kV}}{1898 \text{ A}} = 7.78 \Omega \quad (9)$$

$$SIR_{3PH_N-0} = \frac{7.78 \Omega}{34.29 \Omega} = 0.2 \quad (10)$$

An SIR of 0.2 is less than 0.5, which indicates that this line should be considered long under $N-0$ conditions.

The SIR for the single contingency ($N-1$) case for phase protection is calculated as shown in Equation (11) and Equation (12):

$$ZS_{3PH_N-1} = \frac{\frac{138 \text{ kV}}{\sqrt{3}} - 62.0 \text{ kV}}{1813 \text{ A}} = 9.75 \Omega \quad (11)$$

$$SIR_{3PH_N-1} = \frac{9.75 \Omega}{34.29 \Omega} = 0.3 \quad (12)$$

An SIR of 0.3 is still less than 0.5, which indicates that under $N-1$ conditions, the line is still long.

The process would be similar for calculating the SIR for ground protection.

5.3 Line design considerations

5.3.1 General

Transmission lines are either overhead air-insulated lines or insulated cable systems and, in some cases, are combinations of air-insulated lines and insulated cables. The electrical characteristics are significantly different for these lines. The characteristics of overhead air-insulated lines are well understood. Key

characteristics of cables are reviewed in this clause. The issues associated with electrically connected double circuit lines are also reviewed in this clause.

5.3.2 High-voltage cables

The series inductance of cable circuits is typically one-half to one-third of the series inductance of comparable overhead lines. The reactance to a fault will, accordingly, be lower for cable systems. This should be considered in the application of distance relays for protecting short lines. As a practical consideration, cable systems are frequently used in urban or metropolitan areas where short lines are typical. Therefore, cables are frequently protected using those techniques that are suitable for protecting short lines and lines that have low total impedance, as discussed in a 1997 PSRC report, “Protective relaying considerations for transmission lines with high voltage ac cables” [B45], and by Tziouvaras [B103].

5.3.3 Electrically connected double circuit transmission lines (bifurcated lines)

Phase conductors of parallel transmission lines are sometimes connected together to form a single transmission line. Such a line is modeled either by assuming that each phase is composed of two conductors of a single bundle or, more accurately, by assuming that the two lines are two circuits connected in parallel. The calculations of line impedance are simplified if it is assumed that the lines are fully transposed even though they most likely are not. Since the lines configured in this manner are generally not very long, it may be reasonable to neglect the effect of the lines not being transposed.

Fault currents and apparent impedances, as seen by relays, are affected by a fault on one phase of one of the transmission line circuits. The current on the unfaulted conductor will flow past the fault location to the next jumper before crossing over; this results in an increase in the apparent impedance causing the impedance relays to underreach. The worst case occurs where the lines are connected only at their terminals. This problem can be reduced by adding jumpers at intermediate locations along the line length. An adequate number of jumpers will negate the effect, because 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.

Tziouvaras, Altuve, and Calero [B104] discuss these topics, as well as other topics such as the requirements to cover a fault where the line shorts to the ground with the side closest to the jumper not faulted.

5.4 Number of line terminals

The number of terminals on a transmission line is a basic and important factor when selecting a protection system. A particular terminal becomes significant to the selection of the protection system if it supplies current to faults on the transmission line. All terminals that supply fault current need to be considered for inclusion into the line-protection system.

5.5 Lines terminated into transformers

5.5.1 General

A typical line terminated into a transformer is shown in Figure 10. There are generally two approaches used to protect this line and transformer combination: line current differential schemes described in 6.3.2 and distance relay schemes described in 6.2.4.2. In either case, the implementation of separate transformer differential protection is needed for the transformer, as described in IEEE Std C37.91™ [B56].

This subclause describes examples and protection issues of transmission lines terminated in transformers and protected with instantaneous, underreaching step distance relays (generally zone 1). Additional line differential or piloted distance schemes might be required for a complete protection of the system. The numerical values used for setting relays depend on the practices of utilities and are not intended for use in all applications.

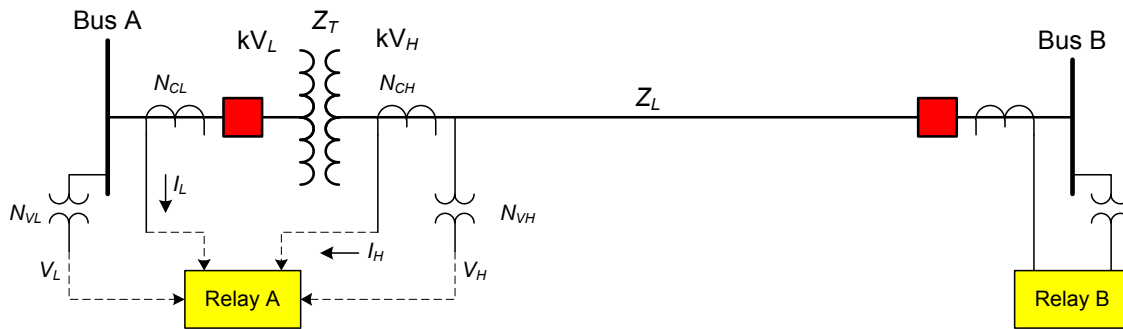


Figure 10—Typical transformer-line combination

Zimmerman and Roth [B108] discuss lines terminated into transformers.

Some issues, such as transformer magnetizing inrush, overexcitation, etc., are not discussed in this clause. IEEE Std C37.91 [B56] discusses additional protection functions that are needed in such cases.

5.5.2 Considerations for line distance applications

The reach of a distance relay is measured from the location of the VTs; the fault direction is sensed by the location and connections of the CTs. In Figure 10, using the VTs and CTs on the line side of the transformer, V_H and I_H , are preferred. In all respects, except for the transfer trip requirement, these applications can be treated as normal line protection applications.

However, economic or other factors may dictate the use of the VTs and CTs measuring the low side (bus A side) quantities V_L and I_L . These factors introduce additional application considerations, which are primarily the effects of the transformer impedance, phase shift introduced by wye-delta transformation, tap changers, secondary impedance calculations, and the availability of ground fault (zero sequence) current. Therefore, careful consideration should be given to the placement of VTs and CTs for these line distance applications. This guide does not provide the mathematical equations needed to compensate for the phase shift in line currents introduced by different power transformers. Microprocessor relays are available that are programmed to cope with this shift.

The key criterion to set any type of instantaneous, step distance relay (non-piloted, zone 1) is not to overreach the remote terminal. This is done to avoid tripping for external faults behind the remote bus. The underreaching margin to apply to distance relays depends of several factors, such as utility practices, errors in the calculation of line parameters, variation of the line ground impedance throughout the year, relay accuracy, and CT/VT errors, among others. In the case of lines terminated in transformers, depending on where the CT/VTs are located, one of the relays may need to measure the combination of the transformer and line impedance. In these cases, the errors of the transformer impedance should be considered while setting the relay, even though transformer impedance errors are much smaller than errors of the line impedance. Guidance for underreaching factors is given in Clause 6.

The following subclauses, 5.5.3 to 5.5.6, provide a discussion of the application considerations for the selected instrument transformer connections.

5.5.3 Preferred protection scheme—Use of V_H and I_H

The preferred method to protect lines terminated in transformers is to utilize, if available, the CTs and VTs located on the line (high-voltage) side. This scheme is shown in Figure 11.

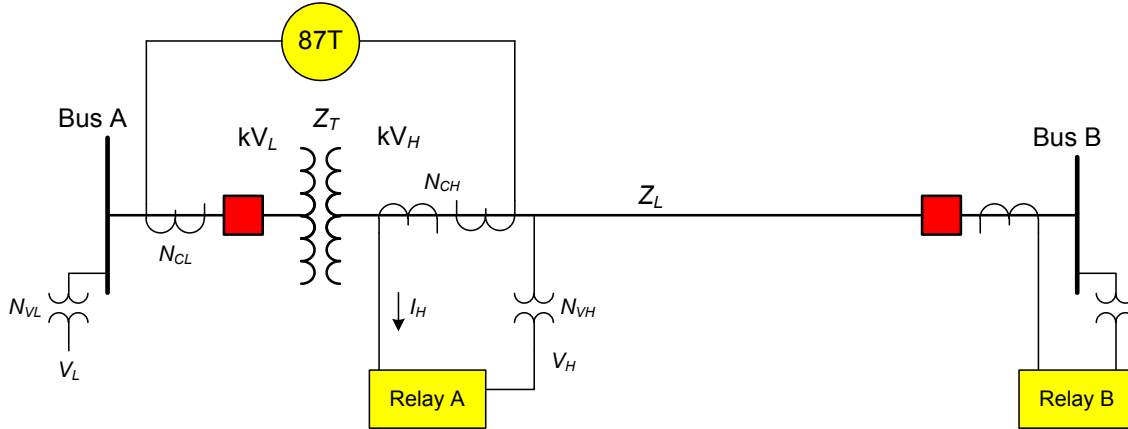


Figure 11—Preferred protection scheme for a line terminated into a transformer

This protection scheme separates the line and transformer into two separate measuring protection zones supervised by separate relays. Both the transformer differential relay and line protection relay are high-speed devices. Relay A and relay B are intended to detect faults on the transmission line and trip the line circuit breakers at bus A and bus B. The transformer differential relay, 87T, is intended to detect faults in the transformer protection zone. An 87T trip initiates the tripping of the line circuit breaker at bus A and initiates a direct transfer trip via a communication channel to the line circuit breaker at bus B.

Line and transformer faults are easily discriminated with this approach. This approach also allows automatic or manual reclosing for trips that result from line faults only. Because it is not desirable to reclose (energize) a faulted transformer, 87T operations should block reclosing at both line terminals. Likewise, it is advisable to autoreclose the remote end first to avoid subjecting the transformer to additional high current.

An alternate method to execute the transfer trip is to have the 87T operate a grounding switch located at the transformer end and within the line's protection zone. This is done to place a solid fault on the line, causing an operation of the line protection and tripping the circuit breakers at both line ends. Drawbacks to this approach are that it applies an additional fault on the system and also delays the clearing of the transformer for the time it takes the grounding switch to close.

The method shown in Figure 11 allows the selection and application of the line-protection scheme independent of the transformer protection scheme. If V_H and I_H are to be used for distance relay A, its setting is not supposed to overreach the remote terminal. Distance relay B can be used to partially protect the transformer (back-up protection); its setting should include the totality of the line plus a good part of the transformer impedance, without overreaching bus A.

5.5.4 Using V_H and I_L

Another option for protecting a line terminated in a transformer is to use, for relay A, the voltage of the high-voltage side of the transformer, V_H , and current from the low-voltage side of the transformer, I_L , as shown in Figure 12.

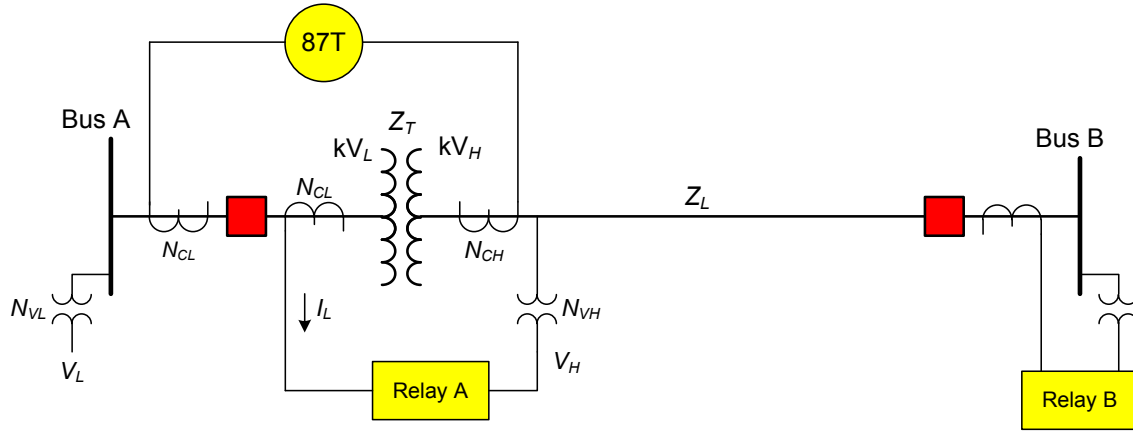


Figure 12—Relay connected to use V_H and I_L

Wye-delta connected transformers introduce a 30° phase shift between V_L and V_H that needs to be taken into consideration. The high-side voltages and currents lead the low-side voltages and currents by 30° for ANSI connected transformers; therefore, 30° should be added to the measured angle of the line current I_L . This may be accomplished by connecting the low-side CTs in delta. This correction is done in the software of some microprocessor relays.

The impedance reach is measured from the high- or line-side VTs providing V_H , and the distance relay zone 1 setting should not reach bus B. As shown in Equation (13), the low- or bus-side CT ratio and the power transformer ratio should be taken into account for determining the impedance relay setting.

$$Z_{SEC} = \frac{N_{CL} \frac{kV_L}{kV_H}}{N_{VH}} Z_{PRI} \quad (13)$$

where

- kV_H is the voltage on the high-voltage side of the transformer
- kV_L is the voltage on the low-voltage side of the transformer
- N_{CL} is the turns ratio of the CTs on the low-voltage side of the transformer
- N_{VH} is the turns ratio of the VTs on the high-voltage side of the transformer
- Z_{PRI} is the impedance seen from the high-voltage side of the transformer
- Z_{SEC} is the impedance seen by the relay

For wye-delta transformer windings, zero-sequence current in the transmission line cannot be measured for line-side faults when low-side current, I_L , is used for protection. Therefore, ground distance units using zero-sequence compensation should not be used. Also, zero-sequence directional relays and zero-sequence (ground) overcurrent relays cannot be relied upon.

Negative-sequence current flowing through the transformer is not blocked by the wye-delta transformation as zero-sequence current is. However, the negative-sequence current, I_{H2} , lags I_{L2} by 30° for the ANSI standard transformer connection. If the CTs are connected delta on the low side to provide the $+30^\circ$ phase shift in phase currents, then the -30° phase shift in negative sequence current is accounted for. Negative sequence directional and overcurrent units will accurately perform. For using compensation factors in a microprocessor relay, the relay's manufacturer may be consulted for correct implementation to assure proper operation of negative-sequence elements.

If the transformer has a tap changer, its effect on the power transformation ratio may be included in Equation (13). There are no further considerations if the transformer windings are wye-wye connected and there

is no delta winding. When the transformer is wye-wye connected or is an autotransformer with delta-tertiary winding, the ground distance elements would underreach during single-phase- or two-phase-to-ground faults.

5.5.5 Using V_L and I_L

The third option for protecting a line terminated in a transformer is to use the voltage of the low-voltage side of the transformer, V_L , and current from the low-voltage side of the transformer, I_L , as shown in Figure 13. This is generally the more practical connection when both line-side VTs and CTs are not available. The impedance reach is measured from the bus side VT providing V_L , and the impedance setting should include the entire transformer impedance Z_T . Transformer impedances should be calculated very accurately using transformer test reports or should be obtained from the transformer manufacturer. The zone 1 reach should be set at less than Z_T plus line impedance Z_L , so as not to overreach bus B.

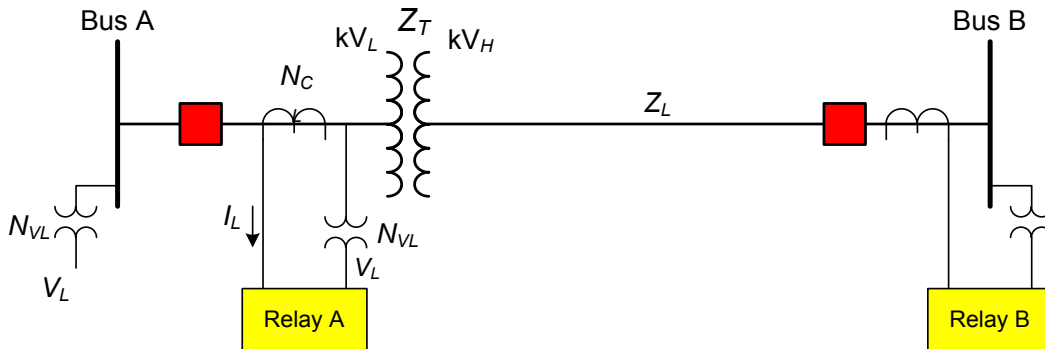


Figure 13—Relay connected to use V_L and I_L

This connection method has a disadvantage of limiting the reach of line protection when Z_T is large compared to Z_L . For example, set the zone 1 reach of relay A to $0.99 Z_T + 0.9 Z_L$ (pu). The multiplier 0.99 is used to allow for 1% positive error in the Z_T measurement (actual impedance is $Z_T/0.99$, but Z_T is measured). If the measured Z_T had no error, the effective line reach from the transformer high side will be $0.9 Z_L - 0.01 Z_T$. For a Z_T/Z_L ratio of 10, the effective line reach will be $0.8 Z_L$. If the error in the measured Z_T is subtractive (actual impedance is $0.99 Z_T$), the effective reach will be even less. As discussed in 5.5.4, the transformer taps should also be taken into account. However, the effect of the tap changer for this case is even more pronounced because it not only changes the value of Z_L as seen from the low side but also changes the value of Z_T (actual impedance is $Z_T/0.99$, but Z_T is measured).

Consideration should be given to transformer inrush currents that would include real-time simulation tests, verification of relay settings, and countermeasures that cope with the phenomenon.

There are no further considerations if the transformer windings are wye-wye connected and there are no limitations on phase or ground protection. However, for wye-delta transformer connections, the limitations on ground protection with zero sequence quantities apply as discussed in 5.5.4. There is also no requirement for phase shift correction with three-phase distance relays that compute phase distance using line current and phase-to-phase voltages.

If the transformer is wye-wye with a delta tertiary winding, a part of the zero-sequence current in the event of ground faults on the line will flow in the tertiary winding, and current seen by relay A will be less than the zero-sequence current in the line. The relay would underreach if the zero-sequence current in the delta winding is not measured and used by the relay.

Issues are similar at relay B, with reaching through the transformer impedance to cover all of the zone. This can be a significant issue depending on the type of relays applied. Zimmerman and Roth [B108] provide further discussion on this topic.

5.5.6 Using V_L and I_H

The fourth option for protecting a line terminated in a transformer is to use the voltage of the low-voltage side of the transformer, V_L , and current from the high-voltage side of the transformer, I_H , as shown in Figure 14.

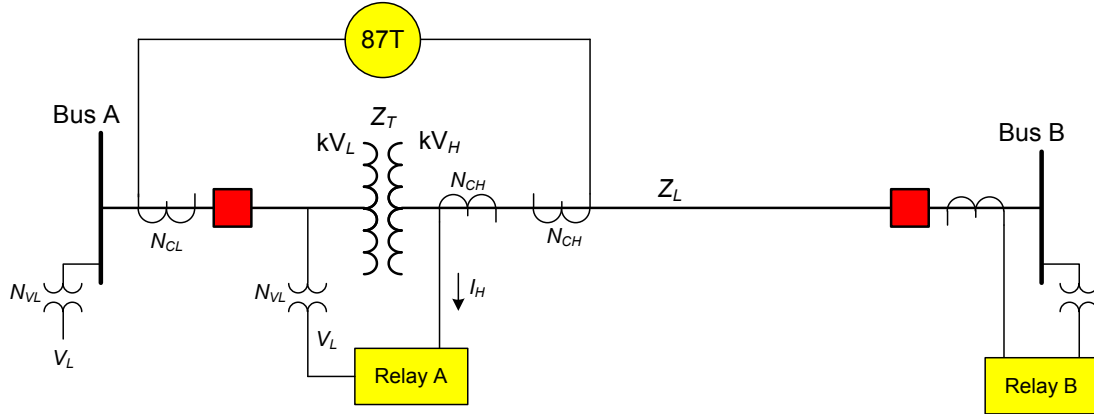


Figure 14—Relay connected to use V_L and I_H

Using these connections, the impedance reach is measured from the low or bus side VT that provides V_L , and the impedance setting should include the transformer impedance, Z_T , plus line impedance Z_L . Zone 1 should not reach bus B.

The disadvantages of having the transformer impedance in the zone 1 setting discussed in 5.5.4 apply in this case as well. Also, the high- or line-side CT ratio should include the power transformer ratio to compute the correct secondary impedance on the low side base. Equation (14) can be used for this purpose.

$$Z_{SEC} = \frac{N_{CH} \frac{kV_H}{kV_L}}{N_{VL}} Z_{PRI} \quad (14)$$

where

- kV_H is the voltage on the high-voltage side of the transformer
- kV_L is the voltage on the low-voltage side of the transformer
- N_{CH} is the turns ratio of the CTs on the high-voltage side of the transformer
- N_{VL} is the turns ratio of the VTs on the low-voltage side of the transformer
- Z_{PRI} is the impedance seen from the low-voltage side of the transformer
- Z_{SEC} is the impedance seen by the relay

If the transformer has a tap changer, its effect on the power transformer ratio should be included as discussed in 5.5.4.

Fault direction is determined from the CT location; therefore, faults in the transformer cannot be detected. For wye-delta transformer connections, there is a 30° phase shift between I_H and I_L that should be corrected. Since primary ohms are computed on the low-side base voltage V_L , I_H should be shifted by -30°

if an ANSI standard connected transformer is used. The correction may be done by connecting the high-side CTs in delta for subtracting 30° from the angle of the high-side phase currents. This correction is done with compensation factors in some microprocessor relays.

The zero-sequence voltage at the line terminal cannot be measured for line faults if the transformer is wye-delta connected. Therefore, ground distance units and zero-sequence directional units that require zero sequence voltage polarization should not be applied. Transformer neutral current or zero-sequence current (derived from phase currents) can be used to identify a ground fault on the line or beyond bus B if the bus-side transformer winding is delta connected and the line-side winding is wye connected, with neutral connected to ground and the CTs are wye connected.

Negative-sequence voltage appears on both sides of a wye-delta transformer; however, V_{H2} lags V_{L2} by 30° for the ANSI standard transformer connection. If the phase angle correction for phase currents with high-side delta-connected CTs is applied as discussed above, then the negative sequence phase angle is accounted for. The correction may also be done with compensation factors available in microprocessor relays.

5.5.7 Application summary at transformer end

A summary of the application considerations for the available CT and VT connections discussed in 5.5.3 through 5.5.6 is given in Table 4.

Table 4—Application considerations for CT and VT connections for distance relays

Connections		$Z_{SEC} = R \times Z_{PRI}$	Comments
V_H	I_H	$R = N_{CH} / N_{VH}$	— Preferred connection — Distance is measured from V_H — Will detect only line faults
V_H	I_L	$R = N_{CL} \times R_T / N_{VH}$ $R_T = kV_L / kV_H$; varies with tap changer	— Set Z_1 with minimum R_T – transformer tap — Set Z_2 with maximum R_T – transformer tap — Distance is measured from V_H — Will detect transformer and line faults — Delta-wye winding phase angle corrections — No zero-sequence relaying
V_L	I_H	$R = N_{CH} \times R_T / N_{VL}$ $R_T = kV_H / kV_L$; varies with tap changer	— Set Z_1 with minimum R_T – transformer tap — Set Z_2 with maximum R_T – transformer tap — Distance is measured from V_L — Will detect only line faults — Delta-wye winding phase angle corrections — No zero-sequence relaying — Accuracy issues when $Z_T \gg Z_L$
V_L	I_L	$R = N_{CL} \times T / N_{VH}$ $T = 0.95$ to 1.05 (assumed); varies with tap changer	— Set Z_1 with minimum R_T – transformer tap — Set Z_2 with maximum R_T – transformer tap — Distance is measured from V_L — Will detect transformer and line faults — Delta-wye winding phase angle corrections — No zero-sequence relaying — Accuracy issues when $Z_T \gg Z_L$