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MODERN DISTANCE PROTECTION

FUNCTIONS and APPLICATIONS

Working Group
B5.15

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WG B5.15

Modern Distance Protection

Functions and Applications

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FOREWORD

The purpose of an electrical power system is to generate and supply electrical energy to consumers. The greatest threat to the security of a supply system is a short circuit, which generates abnormally high current flow and is accompanied by a localized release of a considerable quantity of energy that can cause fire at the fault location, mechanical damage throughout the system, and an interruption in the supply of electrical energy.

It is important that on the occurrence of a fault on any part of the system the faulted section or plant be disconnected as quickly as possible. It is equally important that unfaulted healthy sections remain in service or automatically be returned to service without delay. Protective relays detect system fault conditions and disconnect the faulted equipment from the power system through the operation of the appropriate circuit breakers. This is necessary in order to accomplish the following:

- Keep damage and consequent cost of repairs to the plant to a minimum.
- Reduce the possibility of system disturbance and supply disruption.
- Minimize the risk to personnel from explosion and fire.

Different types of protection relays are applied to protect transmission lines, power transformers, generators, motors, shunt capacitors, shunt reactors, and distribution lines. The most common protection principle used throughout the world for the protection of transmission lines is the distance protection principle applied either as a non-unit distance protection function or as unit protection based on distance teleprotection schemes. Distance protection devices are also applied for the protection of transformers and generators and to separate large networks into smaller ones to maintain their stability during major disturbances that cause out-of-step conditions. Even though the principle of operation of the distance protection function is well documented in literature, tremendous progress has been achieved in the last 25 years, from older electromechanical and solid-state technologies to modern numerical distance protection devices.

Modern numerical distance protection relays offer numerous improvements over previous generations and technologies of distance protection devices. These improvements include the following:

- Increased protection functionality
- Improved protection performance
- Reduced maintenance requirements
- Improved availability
- Increased versatility

Study Committee B5 on “Protection and Automation” and its Advisory Group 02 on “Protection of Main Plants and Circuits” commissioned Working Group 15 to determine the current state of the art of distance relaying, and examine how it may be further improved using new technologies.

In order to meet this scope, the following objectives were defined:

- Identify the state of the art of modern numerical distance protection devices, i.e., technical and functional improvements over previous generations and technologies of distance protection devices.
- Identify the extent of functional integration in modern distance protection devices, and provide examples of functional integration and its advantages in modern distance protection devices.
- Identify adaptive functions in distance protection devices, describe the principles and examples of adaptive functions, and illustrate some of the adaptive concepts used in modern distance devices.
- Identify and report on high-level issues and special considerations that are relevant and important for testing modern distance protection relays.

- Identify and report future trends of distance protection devices.

To that end, this Technical Brochure has been prepared. The following provides a brief synopsis of each of the major sections in the report.

Section 1 – Power System Protection

Section 1 gives the reader a brief overview of the need for power system protection, the principle of protection zones, and a historical perspective of the different technologies used for the protection of power systems. Earlier electromechanical and solid-state technologies are briefly discussed, and emphasis is placed on modern microprocessor-based relay technology. The basic principles of transmission line protection are also covered in this introductory section.

Section 2 – Distance Protection Functions and Applications

This section presents the basic principles of distance protection devices, i.e., measuring principles, impedance calculation methods, and distance relay characteristics. Digital filtering requirements and digital implementation of distance relay characteristics are also covered. Quantities that influence distance measurement accuracy like instrument transformer transients, fault resistance, parallel lines, cable-grounding methods, series-compensated lines, untransposed lines, multiterminal lines, and transformer connections are discussed. This section also presents step-distance non-unit protection schemes as well as communications-aided directional comparison protection schemes. The application of distance protection to overhead transmission lines, high-voltage ac underground cables, composite lines, transformers, generators, and buses and the detection of out-of-step protection are also discussed in this section.

Section 3 – Functional Integration in Distance Relays

The purpose of this section is to present the numerous protection, control, monitoring, and metering functions that relay manufacturers have integrated in modern numerical distance protection devices. These devices provide users the flexibility to design advanced protection and control schemes that could not have been realized with earlier electromechanical and solid-state technologies. This section presents application examples to demonstrate the advantages of functional integration in modern distance protection devices in the areas of protection performance improvements, control, and monitoring.

Section 4 – Adaptive Distance Relay Functions

Adaptive protection is a protection philosophy that permits and seeks to make adjustments in various protection functions automatically in order to make them more attuned to prevailing power system conditions. The realization of adaptive protection functions was nearly impossible with electromechanical and analog solid-state relays. The advent of digital technology and the use of microprocessors in modern numerical distance relay devices, with their inherent programmability, “essentially” unlimited logic, and memory capability, have made the implementation of adaptive concepts more practical and straightforward. Protection, control, and monitoring functions can adjust their performance to match the needs of changing power system conditions and can handle changing system configurations. The main objective of this section is to present the principles of adaptive functions, provide examples of adaptive functions, and illustrate some of the adaptive concepts used in modern distance devices. In addition, this section presents the most important advantages of adaptive protection functions implemented in modern distance protection devices.

Section 5 – Distance Relay Testing

Section 5 provides information on some high-level issues and special considerations that are relevant and important for testing modern distance protection relays. The issues covered refer to the testing of individual relays and not to the testing of complete protection schemes. Due to the large variety of protection equipment available from a number of different manufacturers, the document does not provide detailed testing information. A CIGRE report prepared by Working Group 34.10, “Analysis and Guidelines for Testing Numerical Protection Schemes,” published in 2000, provides a good foundation for testing modern protection relays.

Section 6 – Future Trends

Finally, Section 6 makes an attempt to look at future trends of distance protection devices. This section looks at reduction of engineering costs by standardizing protection application designs, limiting the number of different devices applied at the different power system voltage levels, taking advantage of functional integration, and applying IEC 61850 compliant devices to reduce the costs and improve the efficiency of integrated substation protection and control systems by replacing the hard wiring between intelligent electronic devices (IEDs) with high-speed serial communications. This section also looks at the potential for improving power system reliability and the observability of power system dynamics through the use of intelligent wide area protection, monitoring, and control systems that are based on synchronized phasor measurement technologies available in modern distance protection, control, and automation devices.

The Technical Brochure includes an extensive list of references and several supporting appendices.

Many internationally recognized experts have contributed to the completion of this Technical Brochure to bring the most up to date information on the subject matter. Their aim throughout this work was the production of essential material that will directly benefit electric power utility protection engineers. This information will also interest other professionals interested in modern distance protection devices and their application. As chairman of the Working Group and editor of the Technical Brochure, I would like to take the opportunity to offer my most sincere thanks to the contributing Working Group members. I would also like to thank the WG member organizations for their continued support in ensuring availability of their staff, whose time was in great demand from within their organizations and from national and international organizations. Finally, I would like to offer my sincere thanks to two individuals, Mrs. Barbie Miller, and Mrs. Becky Lagerquist of Schweitzer Engineering Laboratories, Inc. for their invaluable help in editing and producing most of the figures of this Technical Brochure.

It is the hope of all WG members that the report will be of practical value to all protection engineers and other professionals who are interested in the application of modern distance protection devices.

1. POWER SYSTEM PROTECTION

1.1 NEED FOR PROTECTION

The purpose of an electrical power system is to generate and supply electrical energy to consumers. The system should be designed and managed to deliver this energy to the utilization points with both reliability and economy. The purpose of the transmission line is to transfer power over great distances, an obvious requirement where generation site and consumer centers do not coincide.

The greatest threat to the security of a supply system is the short circuit, which imposes a sudden and sometimes violent change on system operation. If allowed to persist, the abnormally high current flow, accompanied by the localized release of a considerable quantity of energy, can cause fire at the fault location, mechanical damage throughout the system, and an interruption in the supply of electric energy.

Every element of an electrical system is liable to faults resulting from:

- Natural hazards (e.g., lightning)
- Plant failure due to unavoidable aging
- Line damage due to birds, falling trees, etc.
- Human error

It is important that on the occurrence of a fault on any part of the system, the faulted section or plant be disconnected as quickly as possible, and it is equally important that unfaulted healthy sections remain in service or automatically be returned to service without delay. This is necessary in order to accomplish the following:

- Keep damage and consequent cost of repairs to the plant to a minimum.
- Reduce the possibility of system disturbance and supply disruption.
- Minimize the risk to personnel from explosion and fire.

Discriminative protection equipment detects system fault conditions and disconnects the faulted element from the power system through the operation of the appropriate circuit breakers.

A power system is not properly designed and managed if it is not adequately protected. This is the measure of the importance of protection systems in modern practice and of the responsibility of the protection engineer.

1.2 PRINCIPLE OF PROTECTION ZONES

Disturbances in a power system are described as faults. The general philosophy to facilitate speedy removal of a disturbance from a power system is to divide the power system into “protection zones.”

Protection relays monitor the system quantities appearing in these zones. If, for example, a fault occurs inside a zone, the relays operate to isolate the zone from the remainder of the power system. The operating characteristic of a relay depends on the input signals fed to it, such as current or voltage or various combinations of these two quantities and also on the manner in which the relay is designed to respond to this information.

The power system is divided into protection zones for generators, transformers, buses, transmission and distribution lines, and motors. A typical power system and its zones of protection are illustrated in Figure 1.1.

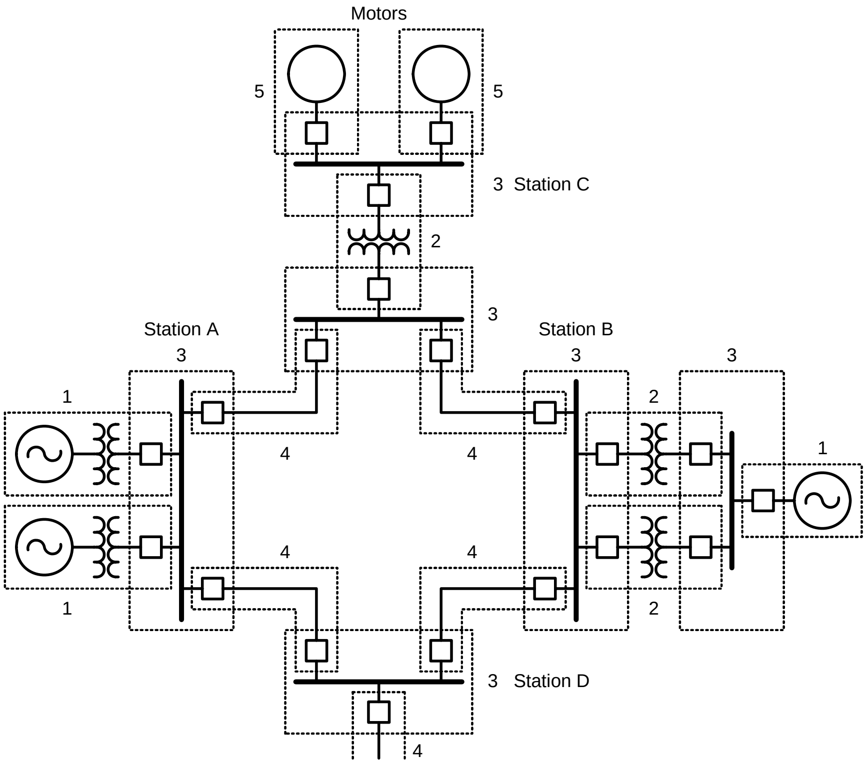


Figure 1.1 Overlapping zones of protection

Each protection zone is controlled by switchgear in association with protective gear. The location of current transformers (CTs) defines the edge of the protection zone. Because failures do occur, some form of backup protection is provided to trip out the adjacent breakers or zones surrounding the trouble area. Ideally, the zones of protection should overlap, with the circuit breaker being included in both zones, to avoid the possibility of unprotected areas.

1.3 HISTORICAL PERSPECTIVE

The relays used to protect electrical equipment have been developed using the following three technologies:

- Electromechanical and electromagnetic technology
- Solid-state (analog electronics) technology
- Microprocessor-based (digital electronics) technology

The use of these technologies for protecting power systems is briefly discussed in this section.

1.3.1 Electromechanical and Electromagnetic Relays

The first technology used for designing relays was the electromechanical and electromagnetic technology. These relays were single-input, dual-input and multi-input types.

Single-Input Relays

Early single-input relays were the plunger, clapper, and balanced-beam-type instantaneous overcurrent relays. The actuating current produced a flux in the air gap; the flux in turn attracted the plunger with a force proportional to the square of the current. When this force exceeded the force of the restraining spring, the relay closed a normally open contact or opened a normally closed contact. Because of the time-varying nature of the ac signals, the force was unidirectional but varied between zero and a maximum value at twice the system frequency. This produced a chatter that was suppressed by using split pole faces.

The development of inverse-time overcurrent relays, which used wattmeter-type structures, followed the plunger-type elements. The structures took two forms: two-magnet form and split pole-face form. The split pole face consisted of a shorted ring placed on one part of the pole face. Several shapes of the inverse-time characteristics were developed for varied application. The current-time characteristics of most relays were asymptotic to the current and time axis, and could be moved by selecting different time-dial settings.

Dual-Input Relays

Several relay types needed two or more inputs. They took the form of amplitude comparators or phase comparators. The amplitude comparators operated if the magnitude of the operating signal exceeded the summation of the magnitudes of the restraining signals. The balance beam structure is an example of a dual-input amplitude comparator. The operation of the phase comparators depends on the phase displacement between the applied signals. The phase comparators were initially like wattmeters. Later, induction cup and loop structures were introduced. Induction cup, usually made of aluminum or copper, worked like induction motors. The operating time of these structures is small; some high-speed induction cup distance relays operate in less than one period of the fundamental frequency.

1.3.2 Solid-State Relays

Analog electronic relays were introduced in the market in the early 1960s. These relays had two drawbacks. The first drawback was due to the use of vacuum tubes with a short mean time to failure, and, therefore, they needed frequent maintenance. The second drawback was that their designers assumed that the voltages and currents of the inputs were sinusoids of the fundamental frequency. This was far from the truth. Because of these drawbacks, solid-state relays were not widely accepted.

Integrated-circuits technology became available in the later half of the 1960s. The relay designers took advantage of this enhancement of technology and, with a better understanding of the signals encountered in power systems, designed a new generation of solid-state relays that performed well during system disturbances.

The major component that was instrumental in the success of this technology was the operational amplifier. Using these amplifiers along with resistances and capacitors, the designers were able to amplify the signals, integrate and differentiate them, and shift the phase of the signals. Using diodes and Zener diodes, the designers were able to rectify the signals and identify the zero crossings of sinusoidal signals. Using these abilities of the solid-state technology, the designers provided phase comparators for directional and distance relays. The technology was also used for amplitude comparison.

This technology had just started to mature when competition from digital electronics technology surfaced. The use of the digital technology is described in the next section.

1.3.3 Microprocessor-Based Relays

The possibility of using computers for protecting elements of power systems was first suggested in 1965. George D. Rockefeller was the first to outline the details of using a computer for protecting all the equipment in a high-voltage substation and the lines emanating from the substation. Several subsequent projects demonstrated the feasibility of implementing the concepts outlined by Mr. Rockefeller. Designers and researchers also developed new approaches for implementing the previously used concepts and developed new concepts. It is a fact that almost all new relays being manufactured in the world today are microprocessor-based relays. This technology has come from the fringes to the mainstream in fifteen years because of the low cost of the components and the ability of this technology to provide solutions that were previously almost impossible to develop.

The major blocks of a typical microprocessor-based relay are:

- Auxiliary transducers
- Signal conditioners
- Analog-to-digital converters
- Multiprocessors
- Relay output modules
- Communications module
- Power supply

Auxiliary voltage transformers (VTs) reduce the levels of voltages so that the inputs do not exceed the rating of the electronic components, typically ±5 volts. The CT outputs are reduced in level and are converted to equivalent voltages; the levels of these voltages should not exceed the rating of the electronic components as well. Low-pass filters remove the high-frequency components, which can appear as low-frequency components due to aliasing. The signals are sampled at rates of up to 8000 samples per second and are then quantized by analog-to-digital converters. The quantized values are transferred to a microprocessor for processing. If a relay makes a decision, the decision is transmitted to another device or devices via output modules. In addition to the processing of analog signals, relays receive information concerning the status of switches, such as isolators and circuit breakers, for implementing logic functions. Communications modules have become essential for the relays to communicate with other relays and substation and remote-control computers.

1.3.4 Numerical Relay Algorithms

Microprocessor relays numerically manipulate the quantized values of the voltage and current samples. These devices use algorithms to convert the quantized values of the acquired signals to useful information. Numerical relay algorithms can be classified in the following three categories:

- Phasor-calculating algorithms
- Model-based algorithms
- Other algorithms

Phasor-based algorithms include Fourier, least squares, trigonometric, and Kalman filtering algorithms. Phasor-based algorithms use the quantized sampled waveform values to calculate the phasors that represent the sampled waveform. The model-based algorithms apply the quantized samples to a model of the equipment being protected, such as a line or a transformer, and compare the output of the model with the performance of the equipment. In the event of a substantial mismatch, it is concluded that there is a fault in the protection zone of the equipment. Other algorithms include neural net, pattern recognition, and wavelet-transform algorithms.

1.4 TRANSMISSION LINE PROTECTION

The following protection principles are used in the protection of electric power transmission and distribution lines:

1. Overcurrent protection (directional and nondirectional)
2. Stand-alone distance protection
3. Distance protection with communications channels
4. Differential protection with pilot-wire circuits or other communications channels
5. Phase comparison protection with communications channels

1.4.1 Protection Without Telecommunications

The following three principles used for protecting power transmission and distribution lines without help from telecommunications facilities are briefly reviewed in this section:

1. Nondirectional and directional overcurrent protection
2. Stand-alone distance protection

1.4.1.1 Nondirectional and Directional Overcurrent Protection

Overcurrent protection was first applied with the help of fuses and then with instantaneous and inverse-time overcurrent relays. These protection modes were suitable for radial circuits that connected energy sources with load centers. Fuses were used mostly in situations that did not require coordination between more than a couple of devices. When a circuit had to be divided into more parts, instantaneous overcurrent relays, in conjunction with timers and circuit breakers for isolating each section, were used. The relays at the remote end were set to operate with minimal delay. The operating times of the relays further up the line were increased gradually to achieve proper coordination.

The disadvantage of this approach was that the time to disconnect a faulted section remained the same, irrespective of the magnitude of the current in the protected circuit. The philosophy of setting the remote end relays to operate with minimal delay and increasing the operating times gradually as the relay location moved up towards the source was also used with these relays. This disadvantage was taken care of by using inverse-time overcurrent relays that operated in lesser times for larger fault currents and faults closer to the relaying point.

It became impossible to coordinate the overcurrent relays for protecting circuits as they developed from radial to looped configurations. Directional overcurrent relays were introduced to achieve proper coordination in those cases. The disadvantage of protecting circuits with overcurrent and directional overcurrent relays is that the relays close to the source operate after longer time delays than the relays at the remote ends.

1.4.1.2 Distance Protection

The philosophy of distance protection was introduced to overcome the disadvantage of large operating times of relays close to the energy source. Distance protection attempted to determine the impedance from the relay location to the fault and operated if the impedance was less than a preselected percentage of the line impedance. Impedance per-unit length of a homogeneous line is constant, and, therefore, these relays were thought to be measuring distance from the relay location to the fault.

The relays used for protecting Zone 1, from the relay location to a location 80–85 percent of the line length, are allowed to open the line circuit breakers instantaneously. Zone 2 relays are set to protect the entire line and a part (40–60 percent) of the shortest line out of the remote bus. However, time delays are incorporated so that they do not open the local circuit breakers when a fault is on a remote line. Similarly, Zone 3 relays are set to operate for faults on the protected line and all of the shortest lines out of the remote bus.

1.4.2 Protection With Telecommunications

Line protection with the aid of telecommunications facilities is applied in four basic forms. These are ac pilot-wire relaying, phase comparison, directional comparison, and current differential. The basics of these forms are described in this section. Initially, these protection systems used communications channels in the form of power-line carrier facilities, but, more recently, microwave and fiber-optic communications channels are also being used.

1.4.2.1 AC Pilot-Wire Relaying

Two types of pilot-wire relays are used for protecting short lines. These are the circulating current types and the balancing voltage types. The circulating current-type protection applied to ac circuits is very similar to differential protection applied to generators, transformers, and buses. A schematic diagram of a circulating current pilot-wire protection system is shown in Error! Reference source not found..

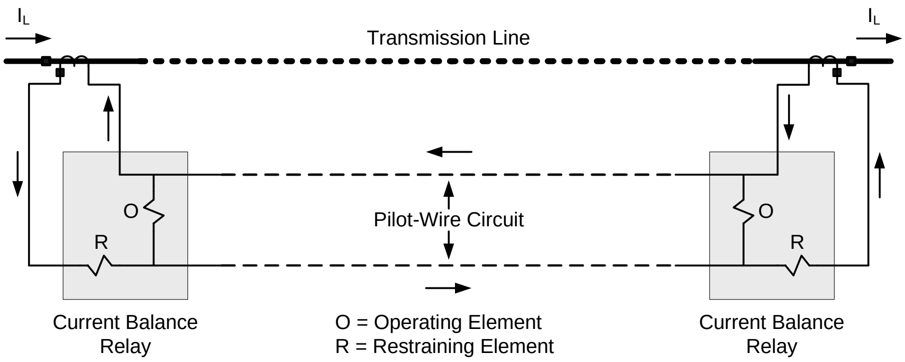


Figure 1.2 Typical circulating current pilot-wire protection system

Summation transformers are used at each terminal to convert the three-phase currents to an equivalent current. For external faults, most of the current flows in the restraining coils. Because of charging currents in the pilot-wire capacitances, the equivalent currents at the two terminals are somewhat different. The difference current shows up in the operating coils of the relays. Current flows in the restraining coils to ensure that the relays are restrained from operating during normal operation and during external faults. However, during internal faults, the currents in the operating coils become substantial, and the relays operate.

A schematic diagram of an opposing-voltage pilot-wire protection system is shown in Figure 1.3. In this case, the currents at each line terminal are converted to equivalent voltages. During external faults and normal power flow, the voltages applied to the pilot-wire circuit are of the polarities shown in the figure. The voltages are of opposing polarities, and, consequently, no current flows in the pilot-wire and the operating coils. When an internal fault occurs, the polarity of the voltage at one terminal reverses, and sufficient current flows through the operating coils, causing the relays to operate.

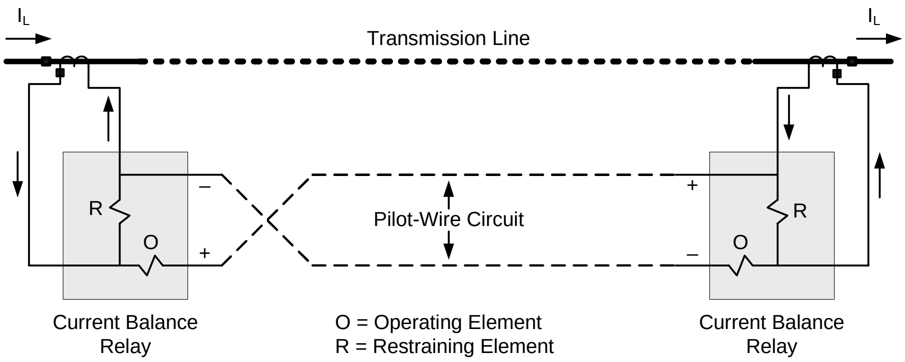


Figure 1.3 Arrangement of a typical opposed-voltage pilot-wire protection scheme

1.4.2.2 Phase Comparison Protection

Phase comparison relaying schemes compare the phase angles between the local and the remote terminal line currents. The phase comparison scheme requires a communications channel to transmit and receive the necessary information to and from the remote line terminal, and, consequently depends on communications channel availability. Phase comparison relaying systems are either of the segregated-phase or the composite type. Phase-angle comparison is performed on a per-phase basis in the segregated-phase comparison system. All other phase comparison systems use a composite signal proportional to the positive-, negative-, and zero-sequence current input to provide protection for all fault types. The composite signal is passed through a squaring amplifier to obtain a square wave signal that contains phase angle information. The relay compares the local squared signal against the remote squared signal; if the coincidence of the two signals is greater than a certain value, 90 for example, the scheme declares an internal fault condition. Figure 1.4 shows a block diagram of a phase comparison protection system.

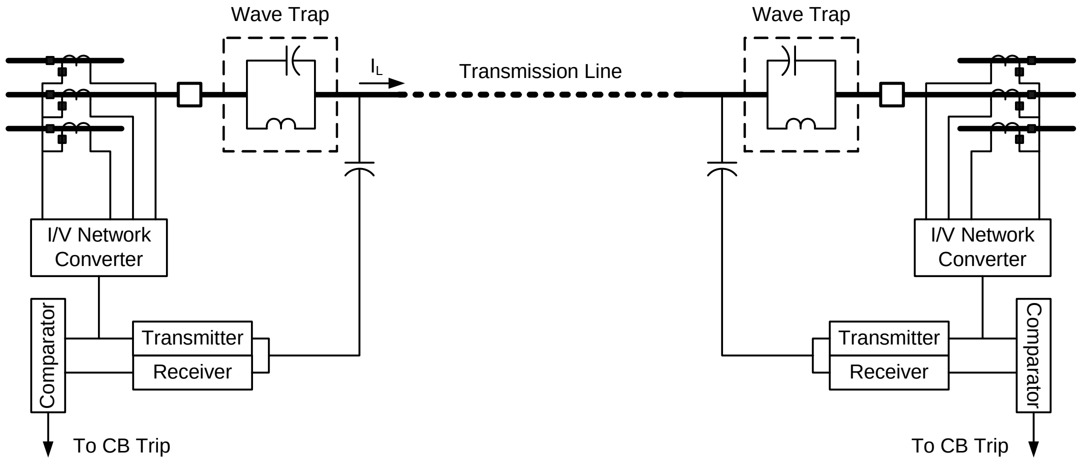


Figure 1.4 Block diagram of a phase comparison protection system

In power-line carrier applications of the composite phase comparison system, the I/V networks convert the fault currents at each terminal into an equivalent voltage, for example a voltage that is proportional to the positive-, negative-, and zero-sequence fault currents. During the positive half-cycle of this equivalent voltage a carrier signal is generated and transmitted to the remote end of the line by a carrier-current channel. The carrier signal generated at the local terminal is compared, in a comparator circuit, with the carrier signal received from the remote terminal to determine whether the fault is internal or external to the protected transmission line.

The voltage provided by the I/V network converters and carrier signals generated at each terminal during an external fault are shown in Figure 1.5. This figure shows that the carrier signal is present in the comparing circuit practically all the time. Because of the presence of the carrier signal, no output is provided to the trip circuit.

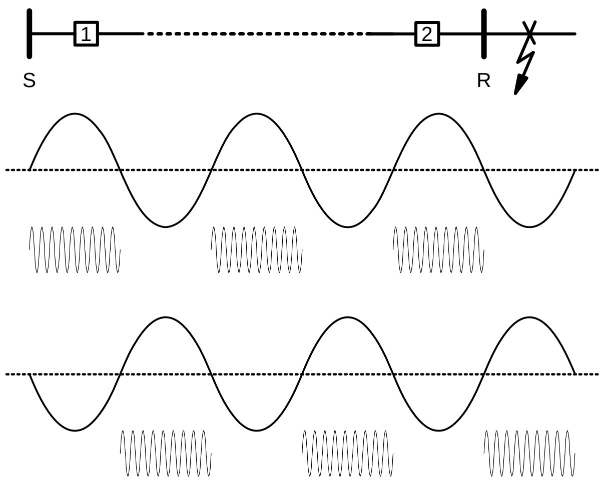


Figure 1.5 Outputs of the I/V converters and carrier-current signals produced during an external fault

The voltage provided by the I/V network converters and carrier signals generated at each terminal during an internal fault are shown in Figure 1.6. This figure shows that the carrier signal is not present in alternate half periods of the output. When the absence of the carrier is detected, an output is provided to the trip circuit at each end.

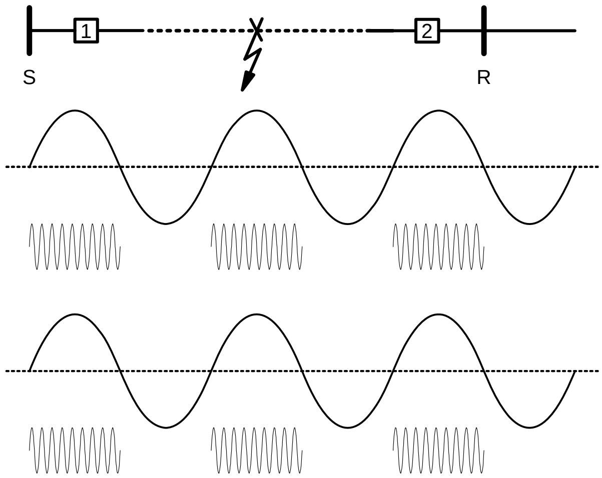


Figure 1.6 Outputs of the I/V converters and carrier-current signals produced during an internal fault

The phase comparison scheme has been very popular in the past because it has minimal communications channel requirements. Because the current signals contain phase-angle information, this scheme is more secure than the current differential scheme for external fault conditions with CT saturation. On the other hand, the sensitivity of the phase comparison relaying system is normally lower than the line differential relaying system.

1.4.2.3 Directional Comparison Protection

Directional comparison schemes compare the fault direction information from both ends of the protected zone to determine whether the fault is internal or external to the zone of protection. Directional comparison schemes use different types of measuring elements, such as distance, directional zero-sequence, or negative-sequence, at each end of the protected circuit. These relaying schemes can be divided into four categories:

1. Directional comparison blocking schemes
2. Directional comparison unblocking schemes
3. Permissive overreaching transfer trip schemes
4. Permissive or non-permissive underreaching transfer trip schemes

Directional comparison schemes require a communications channel for the exchange of directional information between terminals to provide high-speed protection of the protected circuit. Directional comparison schemes have minimum channel requirements, and for this reason they have been very popular in transmission line and cable protection applications. Loss of the communications channel only disables the directional comparison functions but does not disable directional-protection functions for local and remote backup.

Directional comparison schemes require both voltage and current inputs. Frequently, these schemes use phase-distance and ground-distance elements. Modern distance numerical relays have directional zero-sequence and negative-sequence elements that can also be used very effectively for transmission line and cable protection applications. Negative-sequence directional elements provide excellent fault resistance coverage. In underground cable protection applications, using directional comparison schemes, it is a good practice to avoid applying relay elements that depend on the cable characteristics. For example, ground distance element measurement depends on, to a great degree, the cable characteristics and the ground current return path, which makes their application and settings very challenging. Section 2 covers in more detail all aspects of the application of directional comparison schemes including their advantages and disadvantages.

1.4.2.4 Current Differential Protection

The current differential protection scheme compares the amplitude and phase of the local terminal currents with the amplitude and phase of the currents received through a communications channel from the remote terminal to determine whether the fault is inside or outside the zone of protection. The current differential scheme can be either of the segregated-phase or the composite type system. The segregated-current differential system compares the currents on a per-phase basis. The composite-current differential system compares a local and a remote single-phase signal proportional to the positive-, negative-, and zero-sequence current input. The current differential scheme provides instantaneous protection for the entire length of the line or cable circuit.

The current differential scheme requires a communications channel of wide bandwidth to transmit and receive current information to and from the remote terminal. Its availability, therefore, depends on channel availability. The current differential scheme only requires current inputs and cannot provide backup protection by itself. However, modern numerical relay systems have integrated the current differential relaying scheme as part of a full distance protection relay. It requires special security logic to restrain for external faults during CT saturation conditions. The current differential scheme is immune to power swings and current reversal conditions. In general, the relaying settings for current differential schemes are few and easy to compute, however, cable/long transmission line-charging currents and shunt-reactor applications in cables or overhead transmission circuits must be carefully studied.

Current differential protection in the form of generator, transformer, and circulating current pilot-wire protection has been around for a long time. Current differential protection for transmission line protection has been applied in recent years, only after the introduction of microprocessor technology in manufacturing protection relays and advances in digital communications. The currents at each line terminal are sampled and quantized. The actual sampled current values, or computed phasors representing the current waveforms from the numerical values of the samples, are transmitted to the remote end of the protected line for comparison. If the sampling of the current waveforms at the two terminals is synchronized, the phasors are approximately in phase for internal faults and approximately 180 degrees out of phase for external faults, depending on line loading conditions. If the sampling is not synchronized, the phase angles of the computed phasors are adjusted for the sampling skew and communications channel delays before comparison. Normally, the currents at the two terminals are not equal because of the line-charging phenomenon.

1.4.3 Backup Protection

Relays, circuit breakers, and associated equipment do not always operate correctly. It is a general practice to take some remedial measures in case appropriate measures are not successful in isolating a fault or a disturbance. As far as relaying is concerned, backup protection is provided so that the faulted element is isolated even when the primary protection system fails for some reason. The backup protection system operates independently from the primary protection system. To ensure that only the faulted equipment is removed from service, the operation of the backup protection is time-delayed so that the primary protection system has a fair chance to perform its intended function.

An ideal backup protection system would consist of independent CTs, VTs, auxiliary trip relays, dc power supply, circuit-breaker trip coils, etc. This is rarely done in practice. Instead of using separate CTs, separate cores of the CTs are used for primary and backup protection systems. Separate VTs are rarely used because of increased cost. The dc trip supplies are separately fused instead of using separate batteries.

2. DISTANCE PROTECTION FUNCTIONS AND APPLICATIONS

2.1 BASIC PRINCIPLES OF DISTANCE PROTECTION DEVICES

The operating voltage of the lines and equipment protected by distance relays is usually several thousand volts, and the current in the equipment during system faults and disturbances is thousands of amperes. The levels of the primary system voltages and currents are reduced using voltage and current transformers to protect personnel and apparatus from high voltage and to allow reasonable insulation levels for relays, meters, and other instruments. The reduced levels of voltages are 120 V, 230 V, or another similar value. The reduced levels of currents are either 5 A or 1 A when rated current flows in the primary circuit. The voltage and current transformers act as interfaces between the relays and power circuits. Two distinct configurations are used for this purpose. A single-bus 138 kV substation and a double-bus 380 kV substation are used as examples to describe the interfacing structures. These configurations are displayed in the single-line diagrams shown in Figure 2.1 and Figure 2.2.

2.1.1 Type 1 Interface

Figure 2.1 shows a single-line diagram of a three-phase substation where five 138 kV circuits meet. The bus, circuits, circuit breakers, isolators, CTs, VTs, and relays provided to protect the circuits are shown in this figure. A set of three VTs, which are connected to the bus, reduce the primary voltages to 120 V or 230 V rms (line-to-line). The secondary voltages are applied to all relays and indicating instruments. It is also common for each line to have its own VTs or capacitive voltage transformers (CVTs) in subtransmission level substations. A set of three CTs is provided on each circuit. The secondary currents are applied to the relays as well as to the indicating instruments.

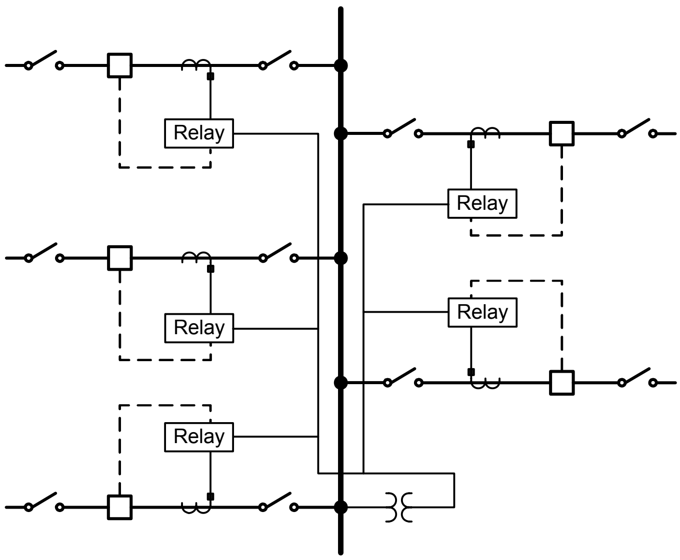


Figure 2.1 A single-bus substation showing the relays and interface with the power system

The bus voltage levels decrease and the currents in the affected circuits increase during system faults and disturbances. Each relay processes the information received from the system to decide if it should open the circuit breaker it controls. If it decides that a circuit breaker should be opened, the relay energizes the trip coil of the circuit breaker.

2.1.2 Type 2 Interface

Figure 2.2 shows a single-line diagram of a three-phase 380 kV double-bus substation. The buses, circuits, circuit breakers, isolators, CTs, and VTs are shown in this figure. The relays used to protect transmission lines, the inputs provided to the relays, and the relay outputs are also shown in the figure. The major difference from the protection concept of Figure 2.1 is that each line has its own set of VTs (one for each phase) that provide the voltages of the line to the relays protecting it.

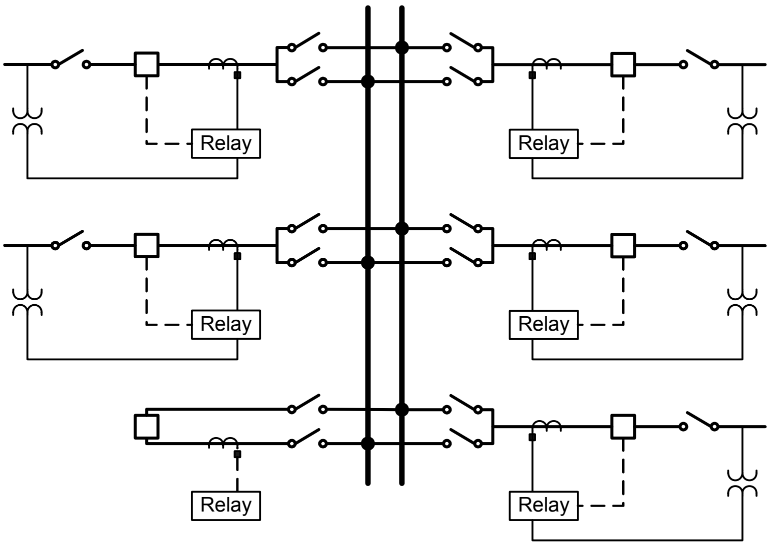


Figure 2.2 A double-bus substation showing the relays and interface with the power system

2.1.3 Interfacing Equipment

Traditionally, two types of VTs have been used for interfacing the relays with the power systems—electromagnetic transformers and capacitive voltage dividers (coupling capacitor voltage transformers). The secondary windings of these transformers are usually wye connected. However, in some applications, they are connected in an open-delta configuration. Electromagnetic CTs are generally used. The secondary windings of the conventional CTs are either connected in a wye or delta configuration, depending on the application. Optoelectronic VTs and current transducers have also been introduced more recently in the marketplace.

2.1.4 Trip Circuit

When a relay operates, a trip contact closes, completing an electrical circuit that energizes an auxiliary relay that keeps the trip circuit energized until the breaker opens. Some solid-state and numerical relays operate a mercury switch that energizes the trip coil of the circuit breaker. In some cases, a thyristor is turned on to energize the trip circuit.

2.1.5 Measuring Principle

The term "impedance locus of a line" is often used and explains the underlying principle used in distance protection systems. Consider a transmission line protected by a relay that is experiencing a three-phase fault, as shown in Figure 2.3. The fault currents are supplied by the source and are usually much more than the currents experienced during normal operation.

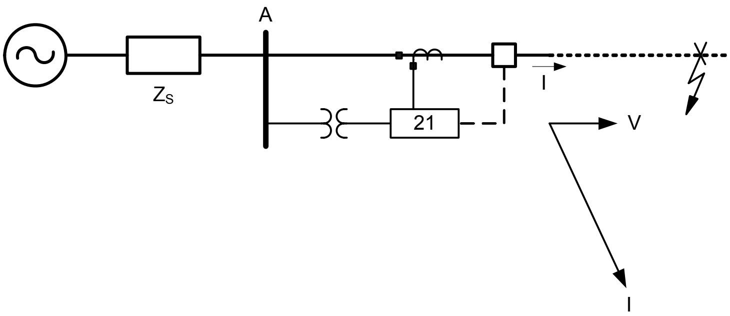


Figure 2.3 Distance relay protecting a transmission line

The voltages and currents applied to the relay are bus voltages and line currents reduced by the ratio of the VTs and CTs. The phase voltages and line currents applied to the relay can be expressed as follows:

$$V_{pr} = \frac{V_{pb}}{N_{vt}} \tag{2.1}$$

$$I_{pr} = \frac{I_{pl}}{N_{ct}} \tag{2.2}$$

Where:

V_{pb}	=	voltage of a phase of the bus
V_{pr}	=	voltage of a phase applied to the relay
N_{vt}	=	turns ratio of the VTs
I_{pl}	=	current in a phase of the line
I_{pr}	=	phase current applied to the relay
N_{ct}	=	turns ratio of the CTs

Now consider that the relay calculates the ratio of the Phase A voltage and the Phase A line current applied to it. This ratio (impedance) is given by the following equation:

$$\frac{V_{pr}}{I_{pr}} = \frac{N_{ct}}{N_{vt}} \bullet \frac{V_{pb}}{I_{pl}} \tag{2.3}$$

$$= N_f \bullet m \bullet Z_l$$

Where:

m	=	distance from the bus to the fault in km
Z_l	=	impedance of the line in ohms/km
N_f	=	ratio of the impedance seen by the relay and the impedance of the line from the bus to the fault

For a relay, N_f is a constant because the CT and VT ratios are determined at the design stage and do not change from day to day. The line impedance, Z_l, is also constant if the protected line is homogeneous. Because N_f and Z_l are constant, the impedance calculated by a relay for faults on the line depends on the distance m. The fault currents usually lag the voltage by 60–85 degrees, depending on the line characteristics. The calculated impedances, therefore, are inductive and lie in the first quadrant of the complex R-X plane. When plotted on this plane, the impedances describe a straight line that is usually referred to as the line impedance locus of the line. This locus for an HV line is shown in Figure 2.4. Note that the impedances seen by the relays when the fault is on the line side of the relay are in the first quadrant.

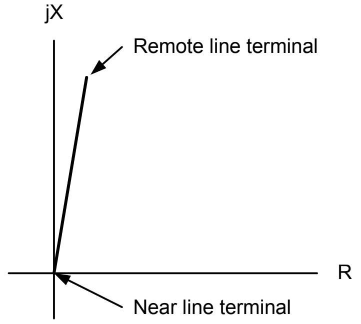


Figure 2.4 Locus of the impedance of a short-circuited line as seen from the protecting relay

2.1.6 Impedance Calculation Methods

The impedance measured by using the voltage and current of a particular phase is the line impedance from the relay location to the fault if it is a three-phase fault. However, if the fault is a single-phase-to-ground fault, the measurement is not equal to the line impedance. To obtain consistent measurements, different voltage and current combinations are used for different types of faults.

2.1.6.1 Phase-to-Phase Faults

Phase-to-phase voltages and the differences between the currents in those phases are used for measuring impedances during phase-to-phase faults. The combinations of voltages and currents used are as shown in Table 2.1.

Table 2.1 Voltage and current combinations used for detecting phase-to-phase faults

	Voltage Applied	Current Applied	Relay Responds to Faults Between
Relay Element 1	$V_a - V_b$	$I_a - I_b$	Phase A to Phase B Phase A to Phase B to Ground
Relay Element 2	$V_b - V_c$	$I_b - I_c$	Phase B to Phase C Phase B to Phase C to Ground
Relay Element 3	$V_c - V_a$	$I_c - I_a$	Phase C to Phase A Phase C to Phase A to Ground

Table 2.1 shows that three distance relay elements are needed to detect phase-to-phase and phase-to-ground faults.

2.1.6.2 Phase-to-Ground Faults

When a single-phase-to-ground fault occurs and the voltage of the faulted phase and current in the faulted phase is used, the measured impedance is not equal to the impedance of the line from the relay's location to the fault. To obtain consistent measurements, the voltage and current combinations listed in Table 2.2 are used.

Table 2.2 Voltage and current combinations used for detecting phase-to-ground faults

	Voltage Applied	Current Applied	Relay Responds to Faults Between
Relay Element 4	V_a	$I_a + k3I_0$	Phase A to Ground
Relay Element 5	V_b	$I_b + k3I_0$	Phase B to Ground
Relay Element 6	V_c	$I_c + k3I_0$	Phase C to Ground

The constant k in these equations is given by:

$$\frac{Z_0 - Z_1}{3Z_1} \tag{2.4}$$

Where:

Z_0 = zero-sequence impedance of the line

Z_1 = positive-sequence impedance of the line

2.1.7 Distance Relay Characteristics

The operating characteristics of many distance relays can be expressed in terms of the impedance or its components. When plotted on a set of rectangular coordinates (resistance R as the abscissa and reactance X as the ordinate), the characteristics form geometric figures. These figures and brief descriptions of the relays are provided in this section.

2.1.7.1 Impedance Relay

The relays that respond to the ratio of the rms voltage at the line terminal and rms current flowing in the line are classified as impedance relays. The magnitude of the ratio of the voltage and current phasors is the magnitude of the measured impedance. In these relays, the magnitude of the measured impedance is compared with a specified magnitude (usually 80–90 percent of the line impedance). If the magnitude of the measured impedance is less than the specified magnitude, the relay indicates that the fault is in the protected zone.

A typical characteristic of an impedance relay is shown in Figure 2.5. This figure shows that the relay operates if the measured impedance lies in any of the four quadrants. The impedances measured during faults on adjacent lines (other lines emanating from the same bus) would be in the third quadrant and the relay would operate if the impedance is in the relay characteristic. The relay characteristic shown below is nondirectional in nature.

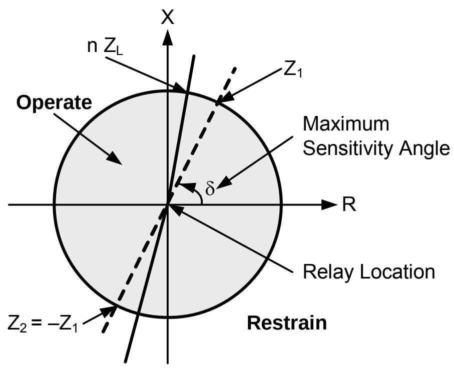


Figure 2.5 Operating characteristic of an impedance relay plotted on the R-X plane

To keep the relay from operating during faults on an adjacent line, a directional relay is used in conjunction with impedance relays. The directional relay determines if the fault is on the line side of the relay or on the bus side of the relay. If the fault is on the line side, the impedance relay is allowed to open the line circuit breaker. If the fault is on the bus side of the relay, the trip signal from the impedance relay is blocked. This is achieved by connecting the trip contacts of the directional relay and the impedance relay in series.

2.1.7.2 Mho (Admittance) Relay

The operating characteristic of a mho distance relay, also known as an admittance relay, is a circle that passes through the origin of the R-X plane, as shown in Figure 2.6. Since the third quadrant of the R-X plane is outside the operating characteristic of the relay, the faults on the bus side are not seen by this relay. Another advantage of using mho relays for transmission line protection is that, when protecting the same line, their reach along the R axis is substantially less than that of impedance relays. Because of these advantages, the use of mho relays is always preferred over the use of impedance relays.

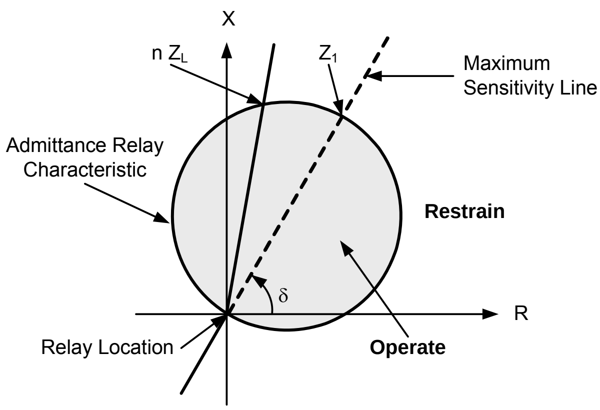


Figure 2.6 Operating characteristic of a mho (admittance) relay

2.1.7.3 Quadrilateral Relay

The circular and straight-line characteristics of distance relays were originally developed using electro-mechanical technology. The circular shape of the relays was a natural outcome of that technology. The straight line is a special type of circle; it is a circle of infinite radius.

When analog electronics technology became acceptable, it became possible to develop relay shape characteristics other than circles. The most important development in this area was the introduction of the quadrilateral characteristic shown in Figure 2.7. Two approaches are used in developing these relays. The first approach is to develop special equations that describe the quadrilateral and implement them. The second approach is to include the design of four blocking characteristics using operational amplifiers based on analog electronic circuits.

An advantage of this characteristic is that the “reach” of the relay in the R and X directions can be controlled somewhat independently.

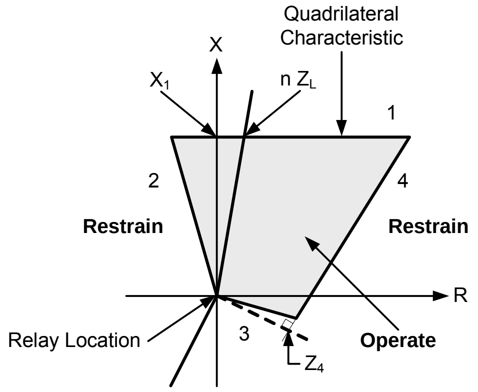


Figure 2.7 Operating characteristic of a generalized quadrilateral characteristic

2.1.7.4 Other Relay Characteristics

Several other relay characteristics have been proposed from time to time. Three of those are worth mentioning—the elliptical characteristic, the peanut characteristic, and the lens characteristic. These characteristics reduce the reach of the relay in the direction of the R axis. The relays, therefore, are used for protecting long transmission lines.

The elliptical characteristic (Figure 2.8) was used in the USSR and Eastern European countries for some time but was not used in North America. The peanut characteristic (Figure 2.9) was used for a short time in Europe. The lens characteristic (Figure 2.10) was also introduced in Europe and is being used to some extent in North America.

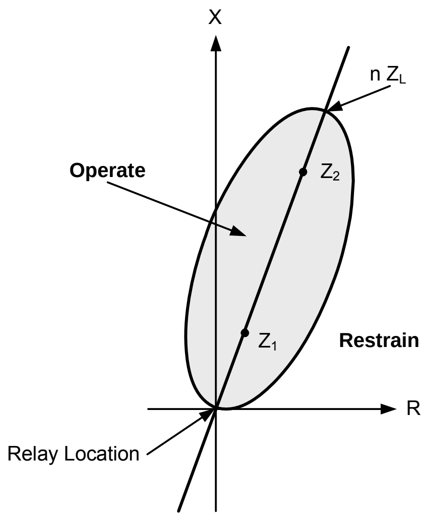


Figure 2.8 Elliptical characteristic

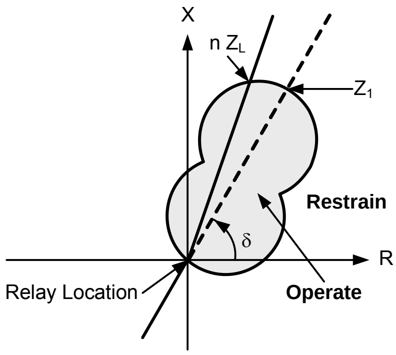


Figure 2.9 Peanut characteristic

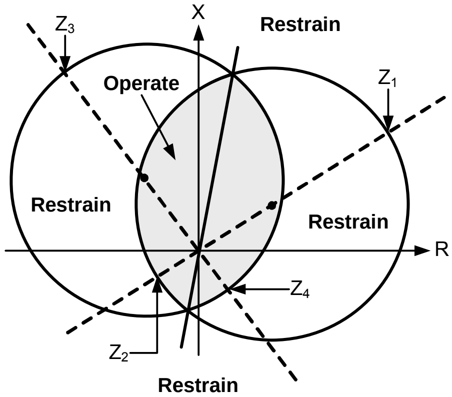


Figure 2.10 Lens characteristic

Another characteristic worth mentioning is the tomato characteristic, which was applied in short lines to improve resistive coverage. The tomato characteristic consists of the combination of two mho characteristics, similar to the ones shown in Figure 2.10, without offset.

2.1.8 Polarization Methods

Need for Polarization

Comparator-based distance elements require a polarizing quantity to provide a reliable angle reference for directional discrimination. When a fault occurs, this angle reference should be stable and last long enough to guarantee that the protection element consistently picks up until the fault is cleared. The following are basic requirements for the polarizing quantity:

- Provide reliable operation for all in-zone faults.
- Be secure for all external faults.
- Provide stable operation during single-pole open conditions.
- Tolerate fault resistance.

Distance functions need robust polarization in order to ensure directional discrimination between close-in forward and close-in reverse faults. Under close-up fault conditions, when the relay voltage falls to zero or near zero, a self-polarized mho distance relay element may fail to operate when it is required to do so or misoperate for a close-in reverse fault. Methods of covering this condition include the use of nondirectional impedance characteristics, such as offset mho, offset lenticular, or cross-polarized and memory-polarized directional impedance characteristics.

Memory Action

In electromechanical and solid-state relays, a series R-C circuit is connected across the secondary winding of each voltage transformer. When the voltage of the system collapses, the R-C and the voltage coil of the relay form a circuit (Figure 2.11) that has a resonance frequency of approximately the nominal power system frequency. The circuits remain energized during normal operation. When a fault occurs and the voltage collapses, a current flow in the voltage coil is maintained that provides a reference voltage to the relay for determining the direction of the fault. The output of the resonant circuit decays with time, and therefore, the memory action is available for a limited period of time.

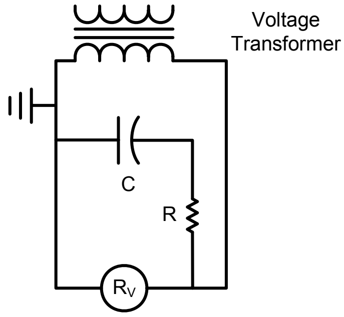


Figure 2.11 R-C circuit to provide memory action

Common types of memory polarizing techniques for microprocessor-based relays are Infinite Impulse Response (IIR) filters or rotating registers. The choice of IIR filter memory time constant or the length of polarizing memory is always a critical design issue. Considerations in choosing the time constant typically include the following:

- The maximum clearance time of both internal and external zero-voltage faults.
- Backup-zone fault clearance time on high SIR systems where the relaying voltage might be very small, even for remote faults.
- Bypass switch operating time of series-compensation capacitors.

On series-capacitor compensated lines, voltage inversion endangers the directional security of the mho distance elements. In such applications, the polarizing memory should be long enough to provide correct and consistent distance element operation until the fault is cleared, the spark-gap protection operates, or the capacitor bypass switch operates to clear the voltage inversion.

Polarization

In phase comparators, operating and polarizing signals are used for detecting a fault in the protected zone. For example, for a b-c fault the operating voltage is $(I_B - I_C)Z_R - (V_B - V_C)$ and the polarizing voltage is $(V_B - V_C)$. This is a self-polarized relay. Traditionally, one of three types of external polarization has been used—cross polarization, leading phase polarization, or lagging phase polarization. Cross polarization is used for phase-fault relays as well as ground-fault relays. Leading and lagging phase polarization are used for single-phase-to-ground fault relays. More recently, positive-sequence voltage polarization has been used in solid-state and numerical distance relays.

Following is a list of polarization methods used in distance protection:

1. Self-polarization uses the faulted phase loop voltage as a polarizing quantity. The resulting mho characteristic is often referred to as a static mho because it does not change with system conditions, fault conditions, or time.
2. Cross polarization uses healthy phase (nonfaulted) loop voltages as the polarizing quantity. The mho characteristic produced is called a variable mho because of its variable shapes for different system and fault conditions. The cross-polarized mho characteristic does not change with time.
3. Memory polarization uses memorized self- or cross-polarizing quantities as a polarizing quantity. The mho characteristic produced by memory polarization is a so-called dynamic mho because the mho characteristic size changes as the memory dies out with time.
4. Combined polarization. The most popular combined polarizing scheme is positive-sequence voltage polarization with memory. The positive-sequence voltage itself provides a combination of self- and cross-polarization.

Self-Polarization

Self-polarization, the oldest and simplest type of polarization, has many disadvantages. Self-polarization does not provide enough fault resistance coverage, is not secure for external faults with certain load flow and fault resistance, and does not work for zero-voltage faults.

Cross Polarization

Cross polarization is used with phase-fault relays. For example, when a fault between Phases B and C is experienced, the operation of the self-polarized Phase B-C distance relay is dictated by the following equation:

$$k_1[(I_B - I_C)Z_R - (V_B - V_C)](V_B - V_C)\cos\phi - k_2 \geq 0 \tag{2.5}$$

The angle ϕ is the phase displacement between the operating and polarizing signals. In cross-polarized distance relays, to detect a Phase B to Phase C fault, a fraction of the Phase A voltage shifted by –90 degrees is used and is added to the polarization voltage used in self-polarized relays. The relay now operates by implementing the following inequality:

$$k_1[(I_B - I_C)Z_R - (V_B - V_C)][(V_B - V_C) + kV_A\angle -90°]\cos\phi - k_2 \geq 0 \tag{2.6}$$

Because the Phase B-C voltage is practically zero for close-in faults, the polarizing voltage assists in determining if the fault is on the line side of the relay or on the bus side of the relay. The operating and polarizing signals during line-side and bus-side faults at the relay location are shown in Figure 2.12. The relay provided for detecting faults between Phase C and Phase A is cross polarized by using a phase-shifted Phase A voltage. Similarly, the relay provided to detect faults between Phase A and Phase B is cross polarized by a phase-shifted Phase C voltage.

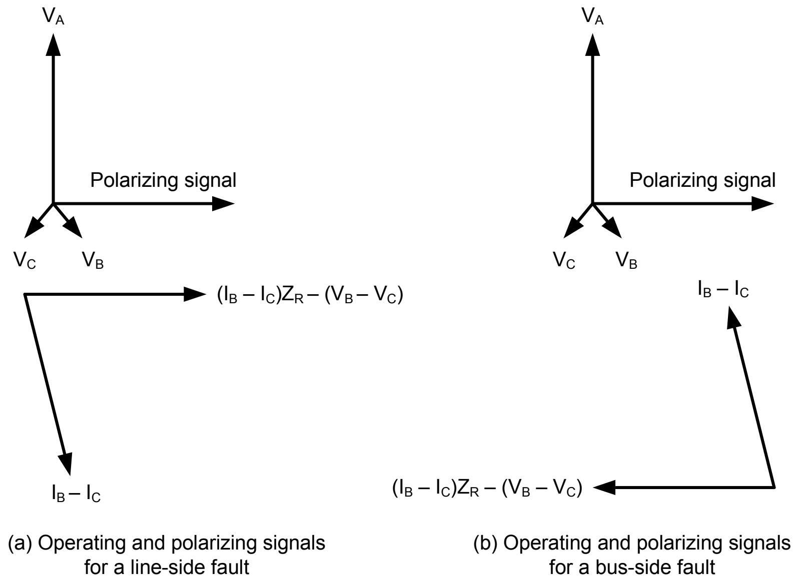


Figure 2.12 Operating and polarizing signals for (a) line-side and (b) bus-side b-c faults

A self-polarized single-phase-to-ground fault relay operates when the following inequality is satisfied:

$$k_1[(I_A + k_0 3I_0)Z_R - (V_A)](V_A)\cos\phi - k_2 \geq 0 \tag{2.7}$$

The relay would not detect a fault if the Phase A voltage collapsed because of the fault being close to the relay location. Voltages of Phase B and Phase C are used to develop torque during close-in faults. The relay would operate when the following inequality is satisfied:

$$k_1[(I_A + k_0 3I_0)Z_R - (V_A)][k_3(-V_B + V_C)\angle -90°]\cos\phi - k_2 \geq 0 \tag{2.8}$$

Because Phase A voltage is practically zero for close-in faults, the polarizing voltage assists in determining if the fault is on the line side or on the bus side of the relay. The operating and polarizing signals during faults on the line side and bus side of the relay are shown in Figure 2.13. The relay provided for detecting a Phase-B-to-ground fault is cross polarized by using a phase-shifted voltage between Phase C and Phase A. Similarly, the relay provided to detect a Phase-C-to-ground fault is cross polarized by the phase-shifted voltage between Phase A and Phase B.

Some references indicate that the polarizing voltage used by relays provided for detecting Phase-A-to-ground faults is $k_3(V_B - V_C)\angle{+90°}$. A signal can be phase advanced by differentiating it. This is not a good practice because differentiating a signal amplifies the noise. On the other hand, the polarizing signal $k_3(-V_B + V_C)\angle{-90°}$ can be implemented by integrating the voltage, which suppresses the noise.

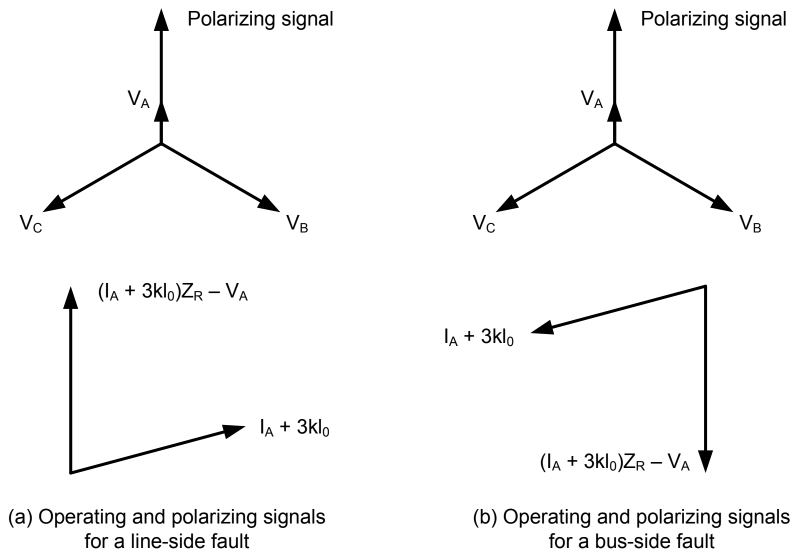


Figure 2.13 Operating and polarizing signals for (a) line-side and (b) bus-side Phase-A-to-ground faults

Lagging Phase Polarization

When a phase-to-ground fault occurs close to the relay location, the voltage of the faulted phase would be reduced to substantially low values. This would cause problems for the relay in determining if the fault is on the line side or bus side. One of the possible approaches is to use the lagging phase voltage as a polarizing signal. For example, if Phase A experiences such a fault, a fraction of the Phase B voltage would be used as the polarizing signal. The relay would operate if the following criterion is satisfied:

$$k_1\left[\left(I_A + k_0 3I_0\right)Z_R - \left(V_A\right)\right]\left[k_3\left(-V_B\right)\angle -60°\right]\cos\phi - k_2 \geq 0 \tag{2.9}$$

Leading Phase Polarization

Leading phase polarization is similar to lagging phase polarization except that the voltage of the phase that leads the faulted phase is used for polarization. For example, if Phase A experiences such a fault, a fraction of the Phase C voltage would be used as the polarizing signal. The relay would operate if the following criterion is satisfied:

$$k_1\left[\left(I_A + k_0 3I_0\right)Z_R - \left(V_A\right)\right]\left[k_3\left(-V_C\right)\angle +60°\right]\cos\phi - k_2 \geq 0 \tag{2.10}$$

Note that lagging and leading phase polarization are not being used at this time by the industry. Also, note that cross polarization during a single-phase-to-ground fault is a combination of the leading and lagging phase polarization.

Positive-Sequence Voltage Polarization

Mho elements compare the angle between (Z • I – V) and V_p. There are many choices for the polarizing voltage, V_p. With the advent of numerical relays, it has become convenient to use positive-sequence voltage polarization. This voltage is substantial for all types of faults except for close-in three-phase faults. For such faults, memory action is used.

Positive-sequence memory-polarized elements are generally preferred for the following reasons:

- They offer the greatest amount of expansion for improved resistive coverage. These elements always expand back to the source.
- They provide memory action for all fault types. This is very important for close-in three-phase faults.
- They offer a common polarizing reference for all six distance-measuring loops. This is important for single-pole tripping during a pole-open period.

Table 2.3 provides a summary of mho element polarization techniques used by the industry at this time.

Table 2.3 Mho element polarizing choices

Operating	**Polarizing**		**Comments**
$Z_R \bullet I_{XY} - V_{XY}$	V_{XY}	XY = AB, BC, CA Z_R = setting Self-polarized	• No expansion • Requires directional element supervision • Unreliable for zero-voltage faults
$Z_R \bullet I_{XY} - V_{XY}$	$-jV_Z$	XY = AB, BC, CA Z = C, A, B Z_R = setting Cross polarized without memory	• Good expansion for phase-to-phase faults • Unreliable for zero-voltage three-phase faults • Requires directional element supervision
$Z_R \bullet I_{XY} - V_{XY}$	$-jV_{Z\_MEM}$	XY = AB, BC, CA Z = C, A, B Z_R = setting Cross-polarized with memory	• Good expansion for phase-to-phase faults • Reliable for zero-voltage three-phase faults until polarizing memory expires • Requires directional element supervision
$Z_R \bullet I_{XY} - V_{XY}$	$-jV_{Z1\_MEM}$	XY = AB, BC, CA Z = C, A, B Z_R = setting Positive-sequence memory polarized	• Greatest characteristic expansion for phase-to-phase and three-phase faults • Reliable for zero-voltage three-phase faults until polarizing memory expires • Requires directional element supervision • Best single-pole trip security
$Z_R \bullet (I_X + kI_R) - V_{XG}$	V_{XG}	X = A, B, C $I_R = I_A + I_B + I_C$ $k = (Z_0 - Z_1)/3Z_1$ Self-polarized	• No expansion • Residual ground ($I_R = 3I_0$) compensation • Unreliable for single-phase-to-ground faults • Requires directional element supervision
$Z_R \bullet (I_X + kI_R) - V_{XG}$	jV_{YZ}	X = A, B, C YZ = BC, CA, AB $I_R = I_A + I_B + I_C$ $k = (Z_0 - Z_1)/3Z_1$ Cross-polarized without memory	• Good expansion • Residual ground ($I_R = 3I_0$) compensation • Reliable operation for zero-voltage single-phase-to-ground faults • Requires directional element supervision
$Z_R \bullet (I_X + kI_R) - V_{XG}$	V_{X1_MEM}	X = A, B, C Z_R = setting Positive-sequence memory polarized	• Greatest expansion • Residual ground ($I_R = 3I_0$) compensation • Reliable operation for zero-voltage single-phase-to-ground faults • Requires directional element supervision • Best single-pole trip security

2.2 DIGITAL RELAY FILTERING REQUIREMENTS

Protective relays must filter their inputs to reject unwanted quantities and retain signal quantities of interest. Distance relays, for example, have critical filtering requirements because they must make precise measurements quickly, even with corruption from dc offsets, CVT transients, traveling wave reflections, and other interference.

Filtering requirements depend on the protection principle and application. In almost all relays, the system frequency components are the information, and everything else represents interfering signals. Among the exceptions are transformer differential relays, using harmonic restraint, and peak-sensitive voltage relays, which may need to detect off-frequency signals. Because distance relays measure impedance and because impedance is defined at a given frequency, distance relay digital filters must calculate the fundamental frequency.

When the resistance-inductance behavior of the power system dominates, the voltages and currents are sinusoids with exponentially decaying dc offsets. Nonlinear loads, power transformers, and instrument transformers can produce harmonics. Series compensation introduces sub-synchronous frequency transients that are very close to the system frequency and present a significant filtering problem. Capacitive coupled voltage transformers also produce low-frequency transients. The overdamped nature of the transients makes them resemble dc offset.

2.2.1 Filter Design Characteristics

Relay filters must have certain characteristics, whether they use analog components, digital implementations, or some combination of the two. The main characteristics are:

- Band-pass response about the system frequency 50 or 60 Hz, because other frequency components may not be of any interest in most protection applications
- Reject dc and ramp to guarantee decaying exponentials are filtered out. However, some distance protection algorithms solve a first order differential equation that requires the dc component information to achieve higher accuracy.
- Attenuate or reject harmonics to limit the effect of nonlinearities
- Have a reasonable bandwidth for fast response
- Good transient response
- Simple to design, build, and manufacture

Ultimately, we wish to build the filter using analog and/or digital electronic techniques. Relay requirements of polarizing memory and system requirements of fault locating and event recording essentially insist on a digital sampled data system design. A digital design provides a choice between finite impulse response (FIR) and IIR filtering, whereas analog filters practically limit us to IIR.

The outputs of FIR filters depend on a finite-time history of the input. On the other hand, the outputs of IIR filters depend on all prior history of the input.

FIR filters subjectively make good sense for protection for two reasons:

- FIR filters quickly forget the prefault condition and work on analyzing the faulted system. Once the filters fill up with fault data, their phasor estimates of the faulted voltage or current are no longer corrupted with prefault data.
- FIR filters naturally have zeros in their frequency responses. It is relatively easy to put them where we want them, e.g., at dc and the harmonics.

FIR filters have advantages over IIR filters. FIR filters have zeros naturally in their frequency response. Arrange these zeros to reject harmonics exactly. An FIR filter uses finite samples of an input for its output. Once the fault inception point propagates through the filtering window, its output is no longer corrupted with prefault data. The outputs of IIR filters, however, rely on the entire history of an input. This is contrary to the basic requirement of protective relays.

2.2.2 How Sampling Rate Affects Relay Operating Time

Sampling faster means slightly shorter operating times, but the improvement is tempered by filter delay. Figure 2.14 plots operating times for a certain fault condition as a function of the sampling rate. For each value of the sampling rates, the digital and analog filter pair are optimized. Increasing the rate from 4–8 samples-per-cycle decreases the operating time by about 1/8 of a cycle, at the cost of double computations. Doubling the sampling rate again yields only a reduction of about 1/16 of a cycle, again with double the computations. Doubling from 16–32 samples-per-cycle speeds up the operation by only 1/32 of a cycle. For remote faults, the operating times are all longer, but the speedup times remain about the same.

The advantage of higher sampling rates on the relay speed diminishes when the filtering window is fixed. The improvement in speed comes from decreasing the analog low-pass filter delay and computational latency.

The shorter the impulse response of a filter, the faster the relay becomes. What happens to other performance features? The longer impulse responses have narrower frequency responses. The one-cycle cosine filter has zeros at dc and at the harmonics of 60 Hz. Rejection of the even harmonics is lost when filter is reduced to half cycle. The time-response graph of the half-cycle cosine filter in Figure 2.15 shows the penalty for increasing speed—poor transient response. The half-cycle filter does not have the double-differentiator property and, therefore, has a poor ability to reject exponentials. The impedance-plane trajectory spirals, indicating severe overreaching.

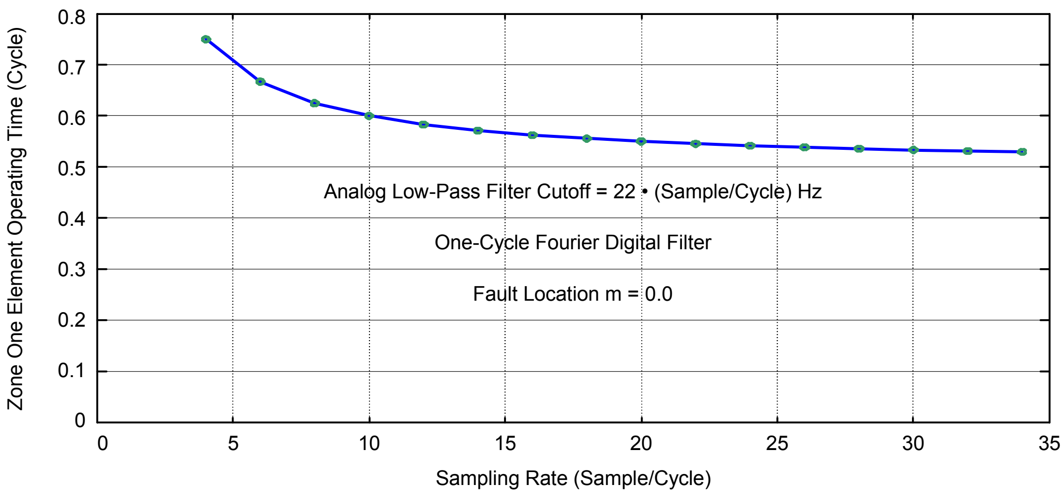


Figure 2.14 Operating time versus sampling rate

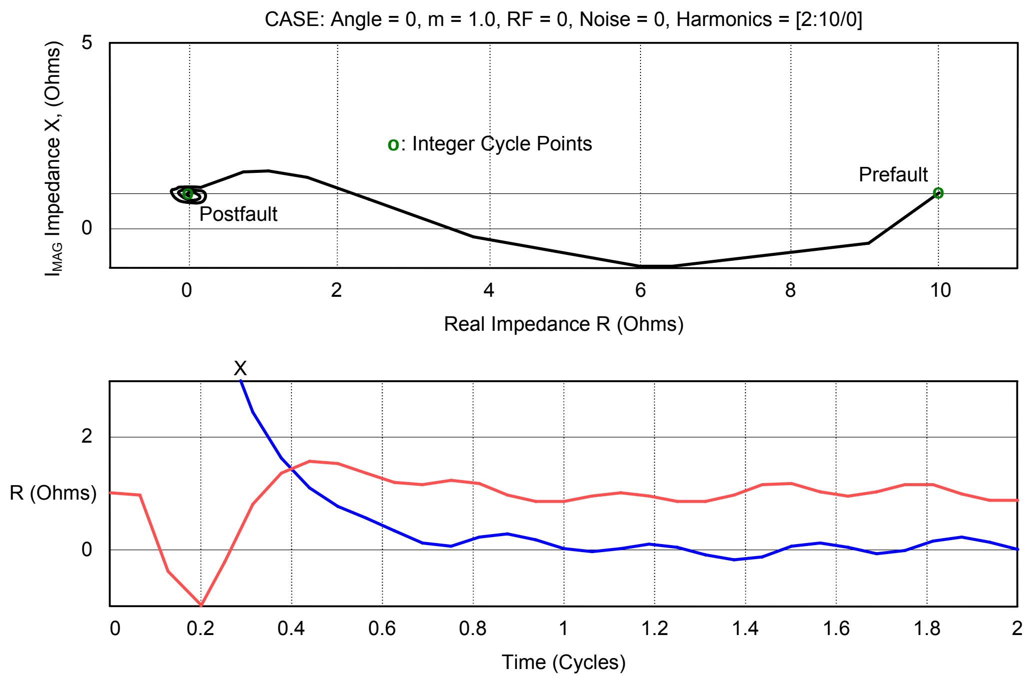


Figure 2.15 Impedance plot of half-cycle cosine filter

2.2.3 Digital Relay Filter Evaluation

Digital relay filters should be evaluated by studying their steady-state and transient performance. The frequency response, or Bode magnitude plot, of a filter is an excellent tool to study the filter's steady-state performance. Visualize the filter's frequency characteristics, e.g., what signal frequencies pass or which ones are blocked. However, the frequency response of a filter represents its steady-state behavior. In addition, only time-invariant filters, whose filter coefficients do not change with time, have frequency response plots.

To investigate the filter transient performance, like overreaching and settling time, and to study time-variant filters, time-domain filter simulations are needed. Filter simulations confirm the filter steady-state properties as well. Filter simulations should be as simple and basic as possible in order to provide useful and clear results efficiently. Also, the simulation environment should be controllable so that different desired filter properties can be unveiled clearly and separated. Simple power system simulations using MATLAB® and EMTP, for example, can provide fault voltages and currents and help us probe the filter's ability to reject exponentially decaying dc offsets, high-frequency transients, and harmonics.

A typical model system used to evaluate digital filters is shown in Figure 2.16. The model includes the analog low-pass filters, the analog-to-digital conversion stage, digital filters, and impedance calculation.

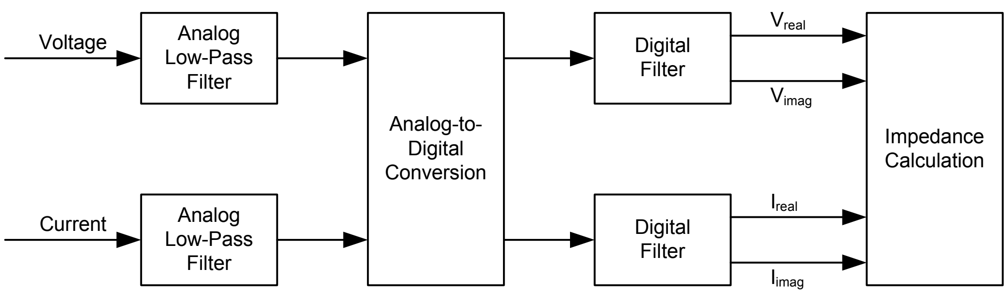


Figure 2.16 Evaluation of analog and digital filters

The impedance is a complex value and its calculation requires the voltage and current phasors or their real and imaginary parts. Phasors can be obtained by two different methods. One is through an orthogonal filter pair, such as the sine and cosine Fourier filter. When filtering a signal, the filter pair simultaneously gives two filtered outputs with a 90 degree phase shift, which constitutes the real and imaginary parts of a phasor. Alternatively, the present and the quarter-cycle earlier outputs of one filter are 90 degrees apart. One filter plus a quarter-cycle delay is, thus, another way to get the voltage and current phasors.

We might expect that the orthogonal filter pair method should be a quarter-cycle faster than the filter plus delay method. However, as we shall see, this is not necessarily true. The orthogonal filter pair method filters a quantity twice to get a phasor and requires twice as many calculations.

FIR filters with less than a one-cycle window cannot reject all harmonics. Even worse, the lower harmonics (second and third) are usually the first ones that are not damped sufficiently when shortening the window. For this reason, we limit our discussions only to one-cycle-window FIR filters. The analog low-pass filter used in the evaluation is a second order Butterworth with a cutoff frequency of 360 Hz. We use a sampling rate of 16 samples-per-cycle, and we evaluate and compare two digital filters—cosine and Fourier filters. The nominal system frequency is assumed to be 60 Hz in this evaluation.

The cosine filter has its coefficients evenly sampled from a cycle of a cosine waveform. The cosine filter is a differentiator, a property that is essential to effectively reject exponentially decaying dc offsets. From the cosine filter's frequency response shown in Figure 2.17, we see that the filter rejects exactly all harmonics and has a band-pass filtering property.

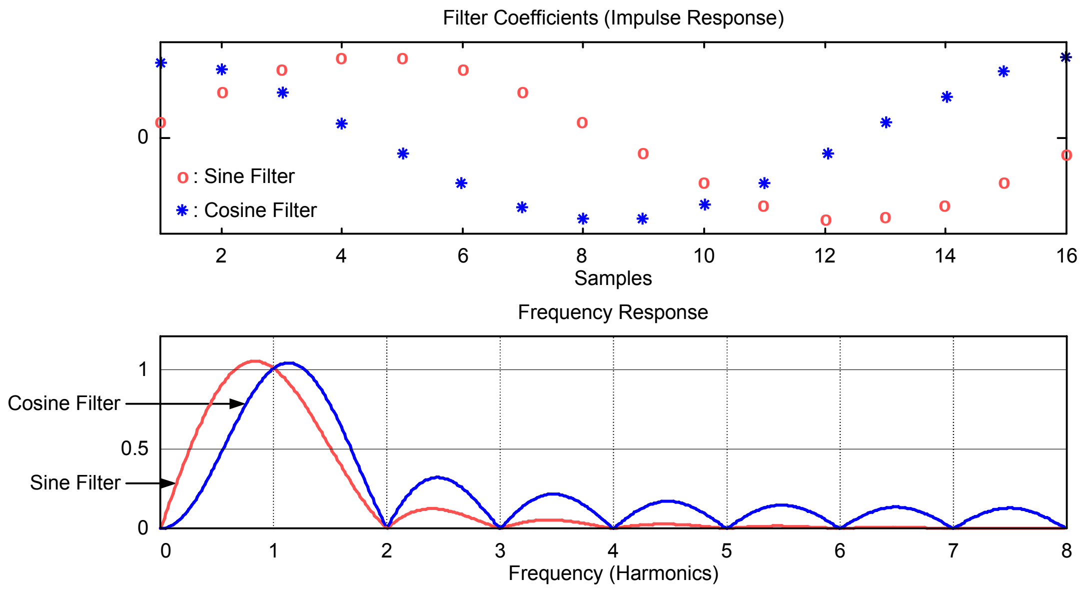


Figure 2.17 Cosine and sine filters

Figure 2.18 shows one impedance plot calculated for a 5 amperes relay with phasors obtained from the cosine filter.

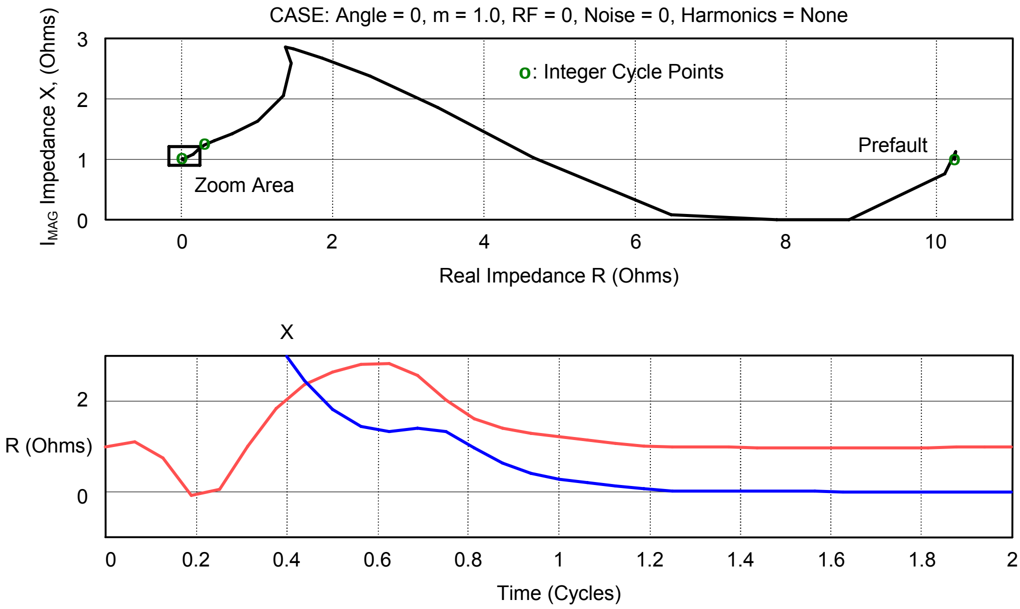


Figure 2.18 Impedance plot of cosine filter

The imaginary part of voltage and current phasors comes from a quarter-cycle delayed filter output. From the start of a fault, it takes one cycle for the fault to fill the filter and another quarter-cycle delay to complete the quadrature component. The worst case filter speed is, thus, one and one-quarter cycles.

2.2.4 Fourier Filter

One natural thought is to eliminate the quarter-cycle delay needed to get the quadrature component. This can be accomplished with a filter orthogonal to the cosine filter, which is the sine filter. The frequency response of the sine filter is shown together with that of the cosine filter in Figure 2.17. The response looks like the cosine filter pushed toward low frequencies. The sine filter has better high-frequency attenuation and the same total harmonic rejection. However, we pay for this better high-frequency attenuation by sacrificing ramp rejection (double differentiation) capability. Because it lacks ramp rejection, the Fourier filter pair has poor transient response.

To determine if the Fourier filter is a quarter-cycle faster than the cosine filter, consider what happens when there are dc offsets in the test signals. Figure 2.19 shows the impedance response of the Fourier filter with full dc offset. The imaginary part of the post-fault impedance is one ohm. The zoomed version of the impedance plot in Figure 2.20 shows that the post-fault impedance circles around the post-fault point and takes a long time to settle. After one and three-quarters cycles, the Fourier filter still has ten percent overreaching and underreaching. The cosine filter, however, gives less than two percent impedance variation after one and one-quarter cycles. Therefore, the cosine filter is faster and more accurate than the Fourier filter whenever dc offsets accompany fault currents.

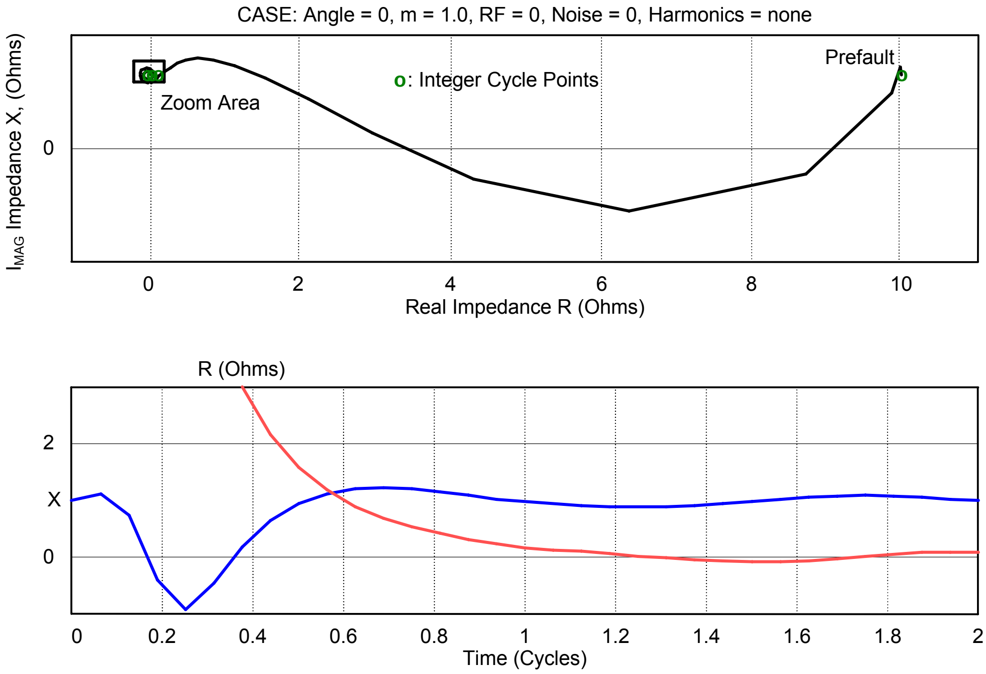


Figure 2.19 Impedance plot of Fourier filter

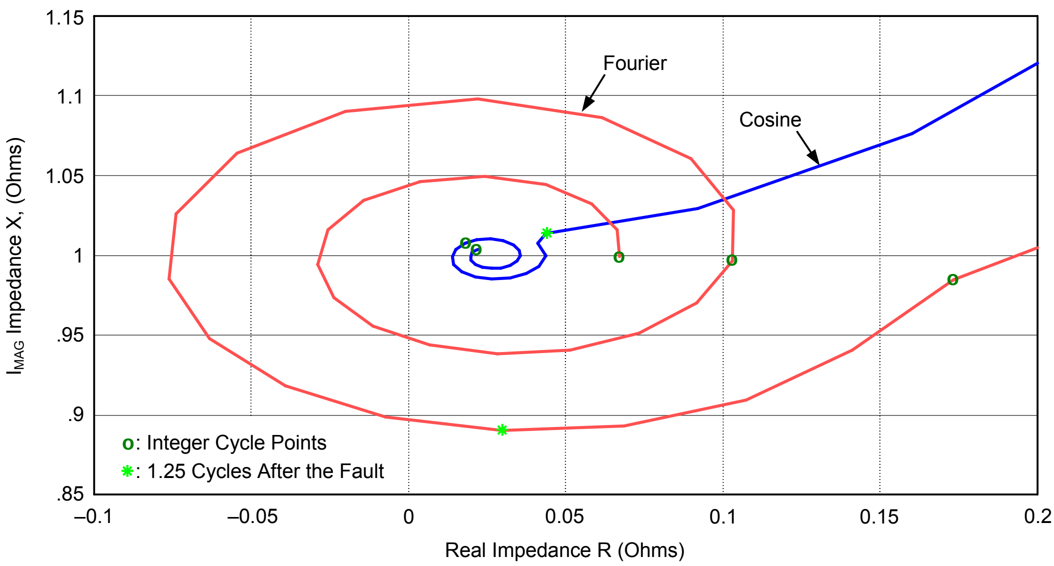


Figure 2.20 Comparison of cosine and Fourier filters

Among all possible fault incident angles from 0–360 degrees, there are exactly two points where a fault does not cause any dc offset. A fault incident angle more than 10 degrees from those two points will cause Fourier filter transient overreaching and underreaching. To remedy this effect, digital relays using a Fourier filter also include a digital mimic filter in order to remove the dc component from the current signals.

2.2.5 Least Squares Filtering

Least error squares (LES) technique [1] can also be used for estimating the phasors of the fundamental and harmonic frequency components of voltages and currents. It is based on minimizing the sum of the squares of the errors between the actual and assumed waveforms. The voltage and/or current waveform can be modeled as a combination of the fundamental frequency component, an exponentially decaying dc component, and harmonics of specified orders (this assumption ignores the presence of high frequencies that are, in most applications, eliminated by the anti-aliasing filters). Annex II explains the least squares algorithm mathematical details.

$$v(t) = V_0 e^{-\frac{t}{\tau}} + \sum_{n=1}^{N} V_n \sin(n\omega_0 t + \theta_n) \tag{2.11}$$

Where:

- $v(t)$ = instantaneous value of the voltage at time t
- τ = time constant of the decaying dc component
- N = highest order of the harmonic component present in the signal
- ω_0 = fundamental frequency of the system
- V_0 = magnitude of the dc offset at t = 0
- V_n = peak value of the n^{th} harmonic component
- θ_n = phase angle of the n^{th} harmonic component

By expanding the decaying dc component using the Taylor series and retaining the first two terms of the series, the following equation is obtained:

$$v(t) = V_0 - \left(\frac{V_0}{\tau}\right) + \sum_{n=1}^{N} V_n \sin(n\omega_0 t + \theta_n) \tag{2.12}$$

This equation can be written as a quantized value of voltage sampled at time t_1 as a function of components of the real and imaginary parts of the phasors and a constant and decaying part of the dc.

$$x(t_1) = a_{11}x_1 + a_{12}x_2 + ... + a_{1(2N+1)}x_{(2N+1)} + a_{1(2N+2)}x_{(2N+2)} \tag{2.13}$$

Each subsequent sample can be expressed as a linear equation. A total of [(2N + 2) + 1] equations, similar to (2.13), can be formed using (2N + 3) consecutive samples. These can be written in the matrix form as:

$$\underset{(2N+3)x(2N+2)}{[A]}\ \underset{(2N+2)x1}{[X]} = \underset{(2N+3)x1}{[v]} \tag{2.14}$$

Where:

- N = (P – 2) / 2
- N = highest order of the harmonic component present in the model of the voltage
- P = number of samples-per-cycle

The LES estimate of [X] is given by the following equation:

$$\begin{aligned}[X] &= \left[[A]^T[A]\right]^{-1}[A]^T[v] \\ &= [A]^{\dagger}[v]\end{aligned} \tag{2.15}$$

Where:

- $[A]^{\dagger}$ = left pseudo-inverse of [A]

Details of the derivation of this equation are given in Annex 2.

The elements of two rows of $[A]^{\dagger}$ are the coefficients of the filter for estimating the real and imaginary components of the phasor of the signal of the frequency of interest. These coefficients can be calculated in the off-line mode and then used to estimate the real and imaginary components of the phasors just like the DFT coefficients are used.

The magnitude responses of the LES technique that uses 13 samples taken at intervals of 30 degrees electrical are as shown in Figure 2.21.

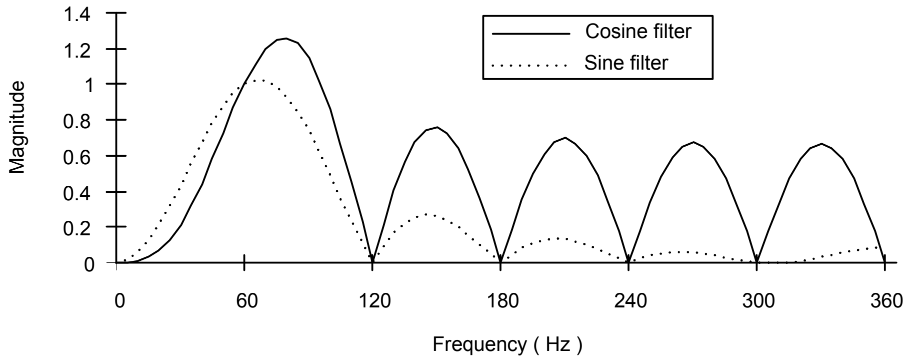


Figure 2.21 Magnitude response of the LES technique

The leakage at off-harmonic frequencies is more in this case than it is for the DFT. Because anti-aliasing filters are used in the relays, the overall frequency response is not much worse.

2.2.6 Frequency Tracking

Numerical relays are designed to measure the fundamental frequency component of their voltage and current inputs. In practice, the frequency of the power system is constantly varying to some degree around the nominal system frequency, 50 or 60 Hz, depending on network conditions or circuit breaker switching. Power systems with weak frequency stability can have wide range shifts in the network frequency. When the fundamental frequency of the power system changes, numerical relays adapt their phasor estimation algorithms to minimize the phasor measurement error. Numerical relays typically either apply frequency-tracking algorithms by estimating the system frequency and changing their sampling interval to obtain a fixed number of samples-per-power-system-cycle, or use a fixed sampling frequency and mathematically compensate the phasors for the difference between the nominal and actual power system frequency.

The errors in phasor estimation are typically small, for small deviations of system frequency from nominal frequency. The rate of change of the frequency is limited by the system inertia. During major disturbances where the system may experience a large rate of change of frequency, different implementations of frequency tracking algorithms may perform differently. Some numerical relays may not be able to track the system frequency in some situations, some can only track the frequency up to plus or minus a few Hz from the nominal system frequency, and there are also a number of numerical relay implementations that may not perform any frequency tracking.

Distance relays may use sophisticated frequency tracking algorithms. This is particularly true for single-pole tripping relays where no single voltage is a good choice for a frequency-tracking signal. During single-pole tripping, particular phases may be de-energized and their voltages may be severely distorted by transients related to shunt reactors.

Several methods can be used for tracking frequency. The object is to estimate frequency and use it in making accurate decisions for protecting lines and other equipment. Out of the many techniques that are available for measuring frequency, zero-crossing and phasor tracking techniques are described in this section. The issue of frequency tracking is then discussed.

2.2.6.1 Frequency Measurement

Zero-Crossing Detection

Zero-crossing frequency estimation is a method that can be implemented either in the hardware or software of a microprocessor-based relay. The method measures the time between two zero crossings and calculates the frequency from that measurement. The time between two consecutive zero crossings is the time of one-half a period, whereas the time between two alternate half cycles is the time of one period of the signal. Other variations of this approach measure the time between a selected number of zero crossings. These methods use the following generic equation:

$$f(t_M) = \frac{M-1}{2} \frac{1}{t_M - t_1} \tag{2.16}$$

Where:

t_M = time of the mth zero crossing

t_1 = time of the first zero crossing

f = estimate of the frequency

Because this method is susceptible to spurious zero crossings, it is necessary that the input waveform be prefiltered using either a low-pass or a band-pass filter. If implemented in software, the method requires that the time of a zero crossing be estimated from the timestamps of the samples in its vicinity as shown in Figure 2.22, except when the samples are taken at the rate of tens of thousands per second.

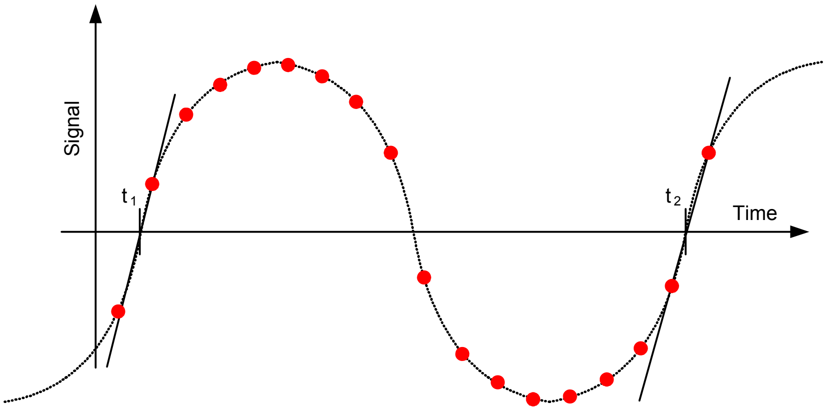


Figure 2.22 Software implementation of the zero-crossing detection

This method usually requires additional post filtering, such as averaging several consecutive measurements, or applying a nonlinear filter, such as the median filter, to cope with the spurious zero crossings. Another solution is to apply validation equations that would reject a measurement if its value differs dramatically from the previous valid frequency estimate.

Another issue that concerns this approach is the interaction between the frequency estimates and frequency tracking mechanisms. If the frequency-tracking mechanism adjusts the sampling frequency, an error may be introduced in a subsequent frequency estimate. The safest solution for the zero-crossing detection algorithm is to use timestamps of the samples instead of the sampling frequency, because it may change between the two zero crossings.

Phasor-Based Methods

The voltage and current phasors, estimated from quantized samples by using the relaying algorithms, rotate at their radian frequency as shown in Figure 2.23. This feature allows for the measurement of frequency from consecutive estimates of the phase angles. The generic equation for this method is as follows:

$$f(t) = \frac{1}{2\pi} \frac{d\varphi}{dt} \tag{2.17}$$

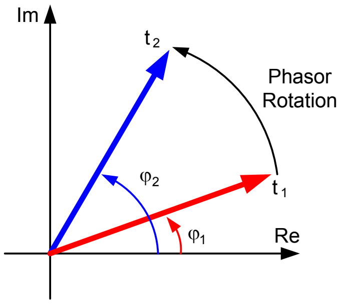


Figure 2.23 Phasor rotation for measuring frequency

This method is applied in different forms. The variations include the use of differences of phase angles over different time spans, use of different phasor estimation techniques, use of different signals such as phase voltage or positive-sequence voltage, and use of different techniques for filtering the calculated estimates.

This method can update the frequency estimate with each new calculation of the phasor of a voltage or current. Theoretically, it can be done several times a cycle by using the voltages and currents and their combinations. The faster the method of estimation, the higher the susceptibility to estimation errors.

The interaction between the changes in sampling frequency and the frequency estimates may create some problems. The Fourier transform and several other techniques assume a constant sampling rate. Should the sampling frequency change from its nominal value, the number of samples in the data window would not span an integer number of periods of the signal. This would cause errors in the phasor estimates that would result in errors in the frequency estimates. Strategies to deal with this problem include a method that adjusts the length of the data window according to the actual frequency so that the window always covers exactly one period. This approach keeps the length of the data window fixed but dynamically adjusts the digital filters to follow the actual frequency, changes the sampling rate so that the data-window is always integer number of periods, and uses a software resampling approach that recalculates the values of the samples before estimating the phasors.

Other Methods

Other algorithms for estimating power system frequency include linear regression with adaptive online readjustment of the input filter, LES technique, a Newton-type algorithm, and a Kalman filter-based approach.

2.2.6.2 Frequency Tracking (Small Deviations)

Algorithms for estimating phasors are tuned to a preselected nominal frequency (50 Hz or 60 Hz). At the selected frequency, the gain of the phasor estimator is one. This means that the magnitude of the input signal is measured accurately if the frequency of the waveform from which the samples are taken is the same as the selected frequency. In case the frequency of the waveform is different from the pre-selected frequency that was used to design the phasor estimator, the calculated value of the phasor will oscillate between the lower and upper envelopes as shown in Figure 2.24.

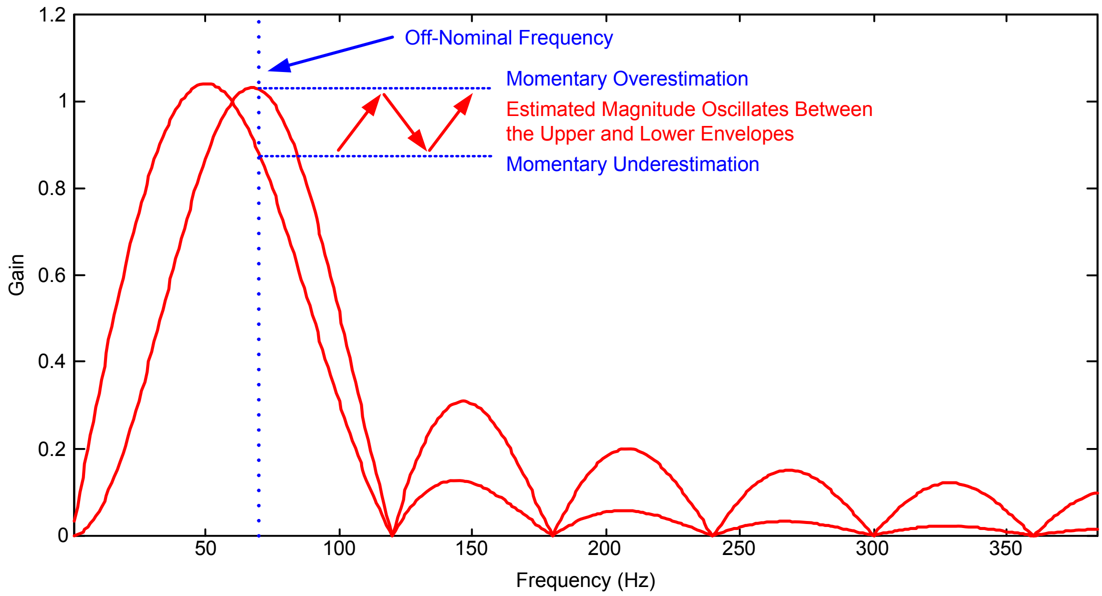


Figure 2.24 Effect of off-nominal frequency on phasor estimation

The goal of frequency tracking is to modify the phasor estimation process in such a manner that the phasor estimates remain correct even if the system frequency deviates from its nominal value. This is done by measuring the frequency and adjusting the sampling clock, algorithm, or values of the quantized samples. A simple correction for the frequency error is not possible because the error changes with time.

Conditions that usually affect the frequency tracking are noise, spurious zero crossings, fast frequency changes, subsynchronous oscillations, and power swings.

Phase Angle Displacement Between Signals

While calculating the phase angle displacement between two signals appears to be a straightforward problem, it might require some thought. Two methods are described in this section. The first method calculates the phase difference from the instantaneous values of the signals, and the second method calculates the phase difference from the calculated phasors.

Instantaneous Values Method

If the instantaneous values of the samples and the time at which they are acquired are available, the zero crossings of the waveforms can be calculated. The time difference between the zero crossings of two waveforms can be converted to a phase angle if the waveforms are of a single frequency. This is not usually true; therefore, it is preferable to calculate the phase angles from the phasors calculated by one of the techniques previously described in this report.

Phasor Method

Three scenarios are examined in this category. Consider the first scenario in which different waveforms are sampled and quantized by a relay, and the quantized values are then used to calculate the phasors representing those waveforms. In this scenario, it is assumed that the same algorithm is used to calculate the phasors. The phase angle displacement is the difference between the calculated phase angles representing the waveforms.

Consider the second scenario in which the phasors are calculated by different relays that are installed in the same substation, and the master clock of the substation triggers the sampling of the waveforms. In this case also, the phase angle displacement between signals is the difference between the angles of the calculated phasors.

Now consider the third scenario in which the relays are installed in one substation, have clocks synchronized with the GPS or a similar time signal, and each relay controls its waveform-sampling process. In this case, the sampling in the relays is not synchronized; therefore, there is a skew between the calculated phasors. Each phasor calculated by the relays is time tagged. The phase displacement between the waveforms is the difference between the angles of the calculated phasors corrected for the angle due to the difference in the time tags of the phasors. This is demonstrated in Figure 2.25.

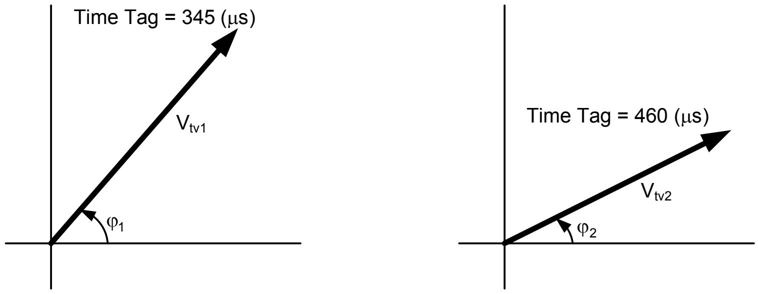


Figure 2.25 Two voltage phasors computed by two different devices

Now consider that the calculated voltage phasors and time tags are as follows:

$$V_{tv1} = 1.05\angle 50.126 \text{ degrees} \qquad V_{tv2} = 0.97\angle 31.043 \text{ degrees} \tag{2.18}$$

$$t_{v1} = 345\ \mu s \qquad t_{v2} = 460\ \mu s$$

The phase difference between the calculated phase angles of the phasors is 19.083 degrees. The time tags indicate that the phasor of voltage V_{tv2} was calculated 115 μs after the phasor of voltage V_{tv1}; this means that V_{tv2} lags by an additional angle of $115 \bullet 10^{-6} \bullet 360 \bullet f$ degrees. If the frequency is 60 Hz, the angle is 2.484 degrees. The phase displacement, therefore, is 21.567 degrees. This is the phase difference between the phasors and not the phase displacement between the zero crossings of the waveforms.

2.3 Digital Implementation of Distance Relay Characteristics

Distance relays compare voltages and currents to create impedance-plane and directional characteristics. Electromechanical relays do so by developing torques. Most static-analog implementations use coincidence-timing techniques.

Numerical techniques are the newest way to implement distance and directional relay elements. These relays use torque-like products and other methods to accomplish their operating characteristics. How do these new techniques relate to the classical electromechanical and static phase-angle comparators?

In this section, we present some basic distance and directional element designs. Emphasis is placed on relating the newer digital and numerical methods to the established electromechanical and static-analog methods of designing relay elements.

2.3.1 Phase-Angle Comparators

Phase-angle comparators test the angle between various voltage and current combinations to produce directional, reactance, mho, and other characteristics.

In this section, we describe two different relay technologies used to compare phasors in relays: induction cylinders and digital multiplication. We also present a method, used in modern distance relays, on how to map a distance relay characteristic (e.g., a mho circle) onto a point on a number line.

2.3.1.1 Induction Cylinder Phase Comparator

Figure 2.26 is a sketch of an induction cylinder comparator. Assume Currents A and B flow in the windings as shown. The cup tends to rotate in the direction of the rotating flux established by the currents. For example, if B leads A, the cup rotates clockwise to close the contacts. If A and B are in phase, the net torque is zero and the cup does not move. This is the only external information available from the relay; either the contacts are open or closed.

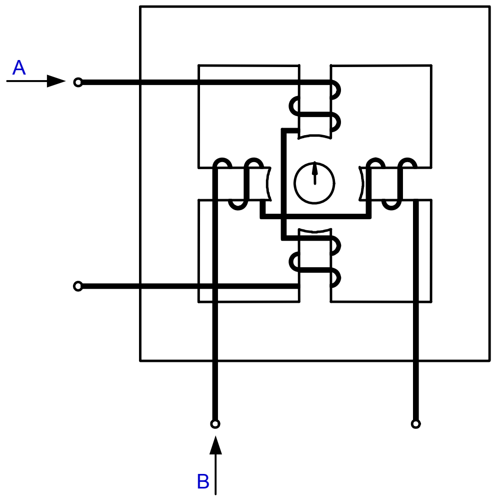


Figure 2.26 Induction cylinder comparator

The equation for the cup torque, T, is:

$$T = k \cdot |A| \cdot |B| \cdot \sin\theta \qquad (2.19)$$

Where:

θ = angle between A and B

External circuitry and the coils themselves can be used to modify the torque equation to test other phase relationships.

2.3.1.2 Digital Product Phase Comparator

We can emulate the behavior of the induction cup element using a computer as part of a digital relay. Given Phasors A and B, consider the following complex product:

$$\begin{aligned} S &= A \cdot B^* \qquad (2.20) \\ &= (A_x + j \cdot A_y) \cdot (B_x - j \cdot B_y) \\ &= A_x \cdot B_x + A_y \cdot B_y + j \cdot (A_y \cdot B_x - A_x \cdot B_y) \end{aligned}$$

Where:

* = complex conjugate

The angle of the product A • B* is the same as the angle of A/B and is the angle by which A leads B.

Without loss of generality, assume our phase reference is B, and Phasor A leads Phasor B by angle θ. In this frame of reference,

$$B_x = |B| \qquad B_y = 0 \qquad (2.21)$$

$$A_x = |A| \cdot \cos\theta \qquad A_y = |A| \cdot \sin\theta$$

and

$$S = |A| \cdot |B| \cdot \cos\theta + j \cdot |A| \cdot |B| \cdot \sin\theta$$

Separate the real and imaginary parts of:

$$S = P + j \cdot Q = A \cdot B^* \qquad (2.22)$$

Where:

P = |A| • |B| • cosθ

Q = |A| • |B| • sinθ

Both P and Q are two-input phase-angle comparators. The P comparator has a maximum "torque" when A and B are in phase. The Q comparator has maximum torque when the two inputs are in quadrature. The Q comparator is essentially the same as the induction cylinder with current inputs.

In digital relays, it is easy to save the torques (P, Q). We can use the sign of the result (analogous to the cup rotation direction) as well as the magnitudes for tests involving fault type, sensitivity, etc.

2.3.1.3 Application of Digital Product Phase Comparator

A mho element tests the angle between a line-drop compensated voltage δV and a polarizing or reference voltage V_p.

$$\delta V = (r \bullet Z \bullet I - V) \tag{2.23}$$

Where:

- δV = line-drop compensated voltage
- Z = replica line impedance
- r = p.u. reach in terms of the replica impedance
- I = measured current
- V = measured voltage
- V_p = polarizing voltage

We need to test the angle between δV and V_p. When the angle is 90 degrees, the relationship between δV and V_p is any point on the circle, as shown in Figure 2.27.

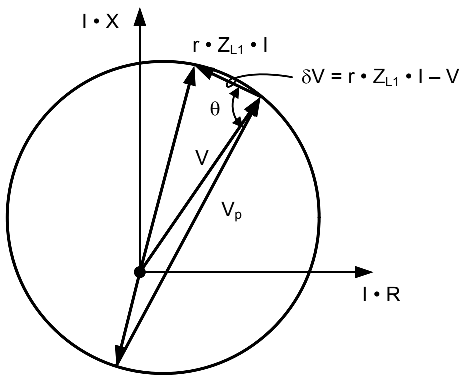


Figure 2.27 Mho element derivation

Let us test δV and V_p using a digital product comparator. Because balance (or zero torque) is at 90 degrees, we need to use the cosine comparator, because cos 90 degrees = 0.

Let:

$$P = \mathrm{Re}[\delta V \bullet V_p^*] \tag{2.24}$$

Where:

- Re = real portion

Then:

- $P > 0$ represents the area inside the circle of reach $r \bullet Z$
- $P = 0$ represents the circle itself
- $P < 0$ represents the area outside the circle of reach $r \bullet Z$

2.3.1.4 Characteristic-Mapping Approach

Traditionally, one comparator is required for each zone and for each voltage and current input combination. We can achieve significant economy in processing with no loss in performance by mapping the points on any mho circle of reach r onto a unique point on a number line.

Recall the mho comparator, P:

$$P = \mathrm{Re}[\delta V \bullet V_p^*]$$
$$= \mathrm{Re}[(r \bullet Z \bullet I - V) \bullet V_p^*]$$

For any V, I, V_p combination on a circle of reach r, P is zero. This condition of balance is:

$$0 = \mathrm{Re}[(r \bullet Z \bullet I - V) \bullet V_p^*]$$

Solving for r yields an equation that is the reach of the mho circle corresponding to the condition of balance:

$$\underline{r} = \frac{\mathrm{Re}(V \bullet V_p^*)}{\mathrm{Re}[Z \bullet I \bullet V_P^*]} \tag{2.25}$$

Observations:

1. Equation (2.25) maps all the points on any mho circle of reach r onto a single point on the number line. If we need four mho circles, we no longer require four comparators. Instead, we simply need four tests of the calculated r.

   For example, a Zone 1 mho circle test might test r against 0.85, which represents a reach of 85 percent. Figure 2.28 illustrates mapping of mho circles into points for a four-zone relay.

2. Because V could be zero, do not rely on the sign of r to reliably indicate direction. Fortunately, the denominator of the r equation is a directional element because it tests the angle between a voltage and a current. The sign of the denominator reliably indicates fault direction.

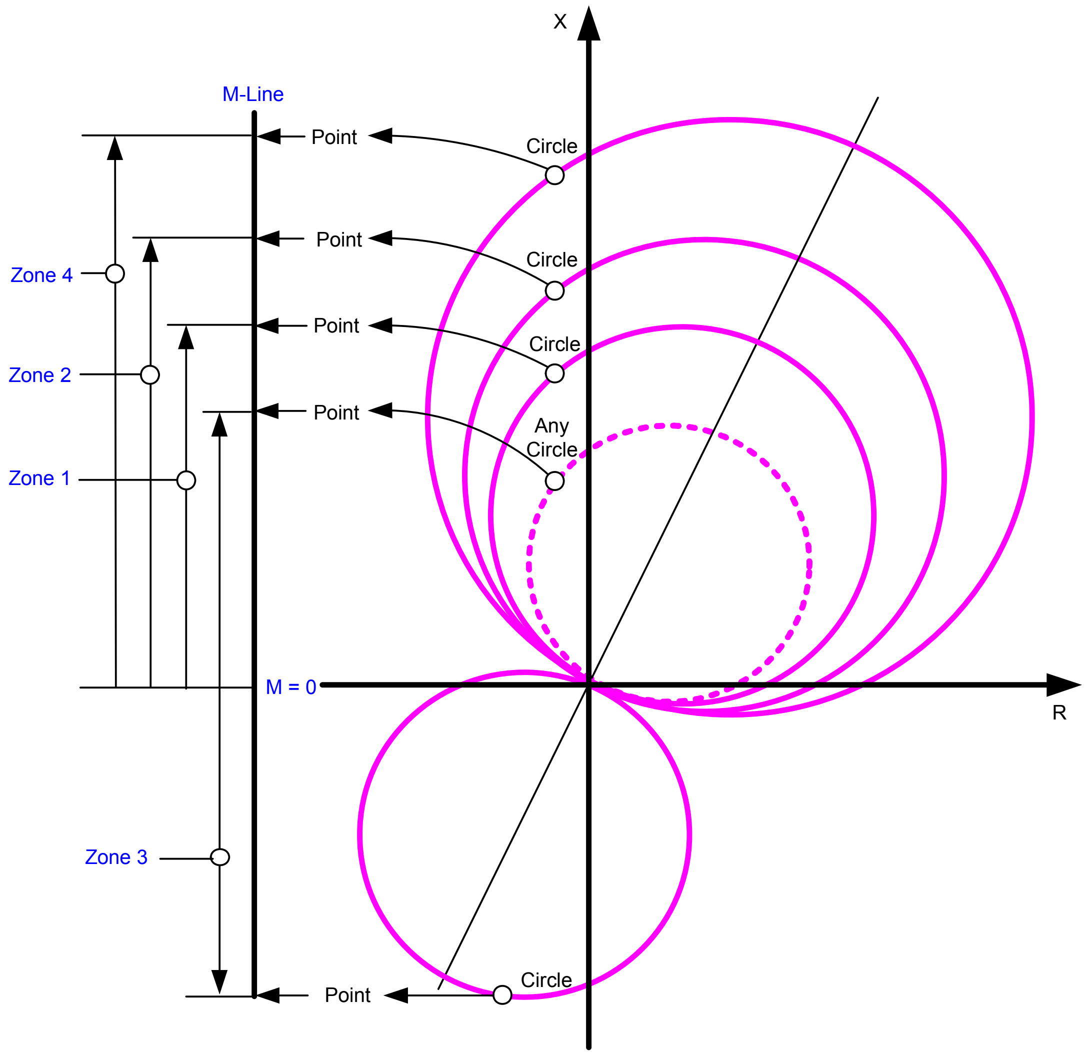


Figure 2.28 Each mho circle maps onto a point on the M line

2.3.2 Digital Implementation of a Quadrilateral Distance Characteristic

The quadrilateral characteristic requires four tests:

- Reactance test (top line)
- Positive-resistance tests (sides)
- Negative-resistance tests (sides)
- Directional test (bottom)

2.3.3 Ground Distance Reactance Comparator

A reactance element tests the angle between the line-drop compensated voltage δV and the polarizing current I_p.

$$\delta V = (r \bullet Z \bullet I - V) \quad (2.26)$$

Where:

δV = line-drop compensated voltage

Z_1 = replica positive-sequence line impedance

Z_0 = replica zero-sequence line impedance

r	=	p.u. reach in terms of the replica impedance
I	=	phase current plus the residual current compensated by $k = (Z_0 - Z_1)/3 \bullet Z_1$
V	=	measured voltage
I_p	=	polarizing current

We need to test the angle between δV and I_p^*. When the angle is 0 degrees, the impedance is on the line, as shown in Figure 2.29.

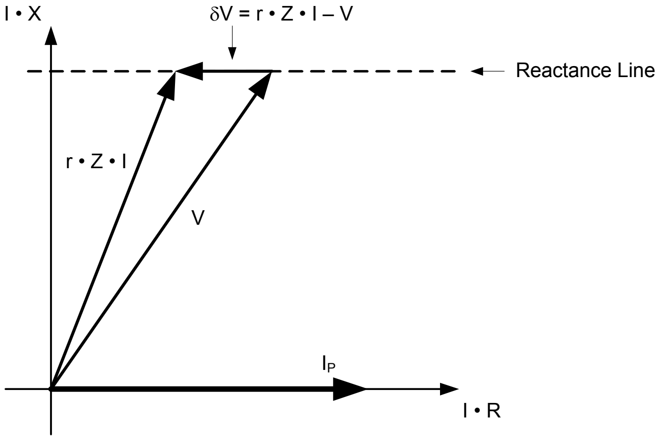


Figure 2.29 Ground distance reactance element derivation

Again, using a digital product comparator, test the angle between δV and I_p. The correct comparator to use is the sine comparator because the balance point is 0 degrees.

$$Q = I_m[\delta V \bullet I_p^*] \tag{2.27}$$

Where:

I_m	=	imaginary portion

Then:

$Q < 0$ represents the area above the line with reach $r \bullet X$

$Q = 0$ represents the line itself

$Q > 0$ represents the area below the line of reach $r \bullet X$

This element must measure line reactance without adverse effects from fault resistance or load flow. Phase currents are poor choices for the polarizing reference, because they make the reactance element severely under- or overreach, depending on the flow of load current. Negative-sequence or residual currents are appropriate polarizing choices.

2.3.4 Maintaining Directional Security

Directional security is paramount in protective relays. At first glance, mho elements appear directional. However, some safeguards are required to ensure security.

The operating quantities for all ground distance elements include residual current. For example, the residual current produced by a reverse A-phase ground fault is also used in the phase-to-ground distance elements for B and C phases. The residual current can cause a forward-reaching B-phase or C-phase ground distance element to operate. We can avoid this problem by supervising the ground distance elements with a directional element, by a phase-selection comparator, or by introducing additional conditions in a multiple-input comparator.

Phase-to-phase distance elements use phase-to-phase currents. For example, a BC phase-to-phase distance element uses I_{BC} or $I_B - I_C$. For a close-in reverse CA fault, the C-phase current can cause operation of the forward-reaching BC element. An easy way to avoid this risk is by supervising the phase-to-phase distance elements with a negative-sequence directional element. (The negative-sequence directional element is ignored for three-phase faults that pick up all three phase-to-phase distance elements.)

Phase distance elements require memory polarization to be secure and reliable for reverse three-phase faults.

The most onerous three-phase fault is one with the following qualifications:

- A small critical amount of fault resistance
- Significant load flow into the bus from a weaker source

Three-phase faults are a concern to phase distance elements only after the memory expires. For bolted faults, each phase voltage is zero. Once the memory expires, the distance elements may be disabled. However, with some resistance, the polarization voltage does not go to zero and could move to an angle permitting tripping. In some implementations, the memory voltage is sealed in until the system voltage recovers or the fault is cleared.

2.3.5 Fault-Type Selection Considerations

For security, distance relay schemes must consider the behavior of the distance elements in all six fault loops (AG, BG, CG, AB, BC, and CA) under very broad and general system, load, and fault conditions.

There are two major concerns:

- Ground distance elements can overreach for line-to-line-to-ground (LLG) faults.
- Phase distance elements can operate for close-in line-to-ground (LG) faults.

The first concern is generally considered a problem in all applications. The second concern is a problem in single-pole tripping schemes and an indication or targeting nuisance in three-pole tripping applications. How can a proper digital relay design reliably prevent unwanted relay elements from interfering with the performance of the overall scheme? One approach is to design a secure fault-type selection algorithm, and if we determine that the fault is an AG fault, then we can block the AB and CA elements in order to avoid a three-pole trip for a LG fault. If we determine that the fault is a BCG fault, then we can block the BG and CG elements, avoiding possible overreach by the BG and CG elements. (The BG element tends to overreach for a BCG fault with resistance to ground. The CG element tends to overreach for a BCG fault with resistance between the phases.)

2.3.6 Load Encroachment Considerations

The impedance of heavy loads can actually be less than the impedance of some faults. Yet, the protection must be made selective enough to discriminate between load and fault conditions. Unbalance aids selectivity for all faults except three-phase faults.

For better load rejection, traditional methods used lenticular or elliptical shape characteristics. Unfortunately, these characteristics reduce the fault-resistance coverage. Alternatively, one can use additional comparators to make blinders parallel to the transmission line characteristic, to limit the impedance-plane coverage, and to exclude load from the tripping characteristic, or to build quadrilateral characteristics that box out load.

All traditional solutions have the same common approach—shape the operating characteristic of the relay to avoid load. The traditional solutions have two major disadvantages:

- Reducing the size of the relay characteristic desensitizes the relay to faults with resistance. Avoiding a small area of load encroachment often requires sacrificing much larger areas of fault coverage.
- From a user’s point of view, the more complex shapes become hard to define, and the relays are harder to set.

Modern digital design approaches do not modify the relay characteristic shape directly. Instead, they define the load regions in the impedance plane and block operation of distance elements if the impedance is in either of the load regions, as shown in Figure 2.30.

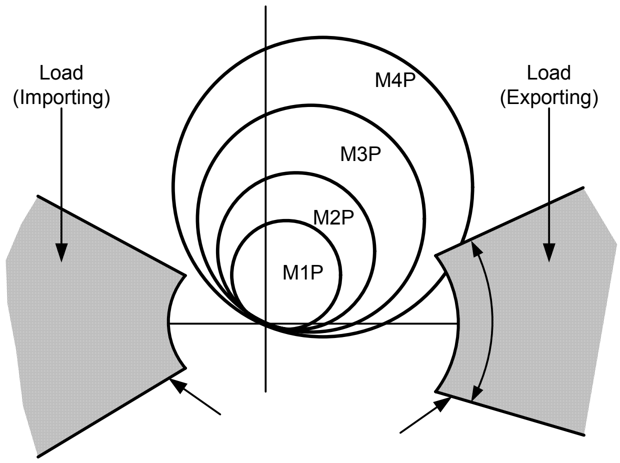


Figure 2.30 Load-encroachment characteristic

2.4 DISTANCE PROTECTION SCHEMES AND APPLICATIONS

Distance protection is a non-unit protection system that is simple to apply for protection of many power system elements, is of the high-speed class of protection systems, and can provide both primary and backup protection of electrical equipment. Distance protection can be modified into a unit system of protection by combining it with a communications channel that makes it suitable for the protection of important transmission lines that require high-speed protection and auto reclosing.

2.4.1 Transmission Line Protection With Distance Relays

The main task of transmission lines is to transmit electrical energy from the generator plants to the load center. The protection of transmission lines is, therefore, a very important task because an outage of a major transmission line can lead to additional line outages, loss of load, and possible network instability. The basic requirements for transmission line protection are that line faults must be cleared selectively and at high speed.

In terms of selectivity, the differential principle is superior to the distance principle. However, the distance protection principle has the advantage that the tripping decision can be determined with local measured quantities and can also respond to external faults by providing a time-delayed backup protection function. Distance protection serves as the main protection function in overhead transmission lines in many countries around the world. The principle of operation of distance protection is well documented and is discussed in great detail in this report.

The improvement from the older electromechanical relays to today's modern numerical devices is enormous. Modern numerical distance relays have brought about many technical and functional improvements when compared to traditional static and electromechanical distance relays. The distance protection zones were limited in electromechanical and static relays mostly because of the physical size and cost of components. Modern digital IC technologies offer advanced processing capabilities, reduced relay size, improved performance, and increased flexibility with respect to functionality and setting possibilities. Numerical technology offers the user a more comprehensive but flexible way of setting the parameters.

2.4.1.1 Stepped Distance Protection Schemes

Stepped distance protection is used for primary and backup protection of subtransmission and transmission lines where high-speed reclosing is not necessary to maintain system stability and where the short time delay associated with the clearing of line end-zone faults can be tolerated. Distance relays are much less affected than overcurrent relays by changes in generation and system configuration. For this reason, distance relays are preferred to overcurrent relays for line protection.

A distance relay is designed to operate for faults occurring between the relay location and a selected reach point, which is a settable parameter, providing discrimination for faults that occur beyond the set reach that are considered external to the distance zone of protection. A distance relay is capable of measuring the impedance of a transmission line up to a preset point, or desired reach, and is applied mostly for the protection of transmission lines because their impedance is proportional to their length.

Phase and ground distance relays measure voltages and currents at one line terminal and calculate the positive-sequence impedance between the relay and the fault location. The following step-distance zones are used for the protection of subtransmission and transmission lines.

Zone 1

A step-distance protection scheme utilizes two or three zones of protection. Proper coordination between distance relays on a power system is achieved by controlling the reach setting of the distance protection relay and the tripping time of the different zones of measurement. Zone 1 is a high-speed, instantaneous zone with no intentional delay and is normally set to provide 80–85 percent coverage of a two-ended line (Figure 2.31). The resulting 15–20 percent margin ensures that there is no risk of overreaching for faults at or beyond the remote end terminal of the protected line, avoiding loss of discrimination with high-speed operating protection devices on adjacent line sections because of instrument transformer errors, inaccuracies of line impedance data, and relay measurement errors. The remaining 15–20 percent of the line length is protected with a time-delayed Zone 2 distance element. Zone 1 should never overreach beyond the remote bus.

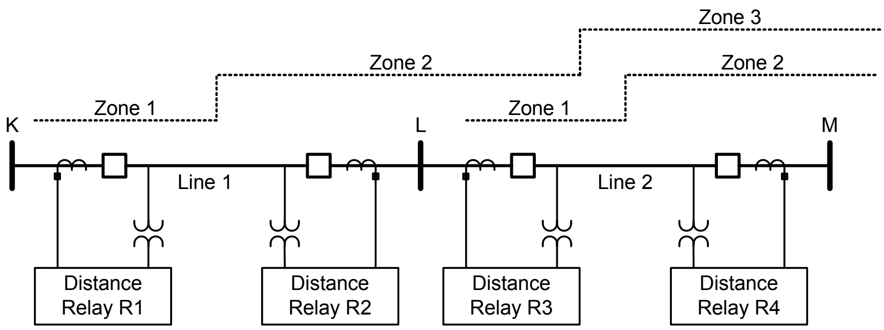


Figure 2.31 Concept of step-distance protection zones

Zone 1 Extension

The Zone 1 extension function is intended for use with an autoreclose function, where no communications channel is available, or where the communications channel has failed. This scheme is typically used on radial distribution feeders, on subtransmission networks, and less often on critical transmission lines.

The Zone 2 elements of the distance relay have two settings. One is set to cover 75–80 percent of the protected line length, as in the basic distance scheme. The other, known as the “Extended Zone 1 or Z1X”, is set to overreach the protected line by 20–30 percent. On occurrence of a fault at any point within the Z1X reach, the relay operates instantaneously (in Zone 1 time), trips the circuit breaker, and initiates autoreclosing. Before the autoreclosing pulse is applied to the breaker closing coil, the Zone 1 reach is reset to the normal Zone 1 value of 80–85 percent. In meshed networks, the Z1X scheme is enabled automatically upon loss of the communications channel by selection of the appropriate relay setting, or a different setting group in modern numerical distance relays. If the fault is transient, the tripped circuit breaker will reclose successfully; otherwise, further tripping during the reclaim time is subject to the discrimination obtained with normal Zone 1 and Zone 2 settings.

The disadvantage of the Zone 1 extension scheme is that external faults within the Z1X reach of the relay result in tripping of circuit breakers external to the faulted section and a potential transient loss of supply to consumers.

Zone 2

Zone 2 is a time-delayed directional protection zone that covers the protected line (Line 1, KL) and part of the next line (Line 2, LM) to the right of Bus L in Figure 2.31. The primary purpose of Zone 2 is to clear faults in the protected Line 1 beyond the reach of Zone 1. Zone 2 also provides backup for a failed Zone 1, both in the protected Line 1 and adjacent Line 2.

The reach and time-delay settings of Zone 2 are dictated by the amount of desired backup protection and coordination considerations with adjacent line sections and their protection schemes. The reach setting of the Zone 2 distance element is set to cover the protected line plus 50 percent of the shortest adjacent line at the remote bus or 120 percent of the protected line, whichever is greater. If there is current infeed at Bus L, it will reduce the reach of Zone 2. However, in all cases, Zone 2 will protect Line 1, which is the primary purpose of Zone 2. It is also very important that the overreaching Zone 2 element does not overreach any of the Zone 1 elements of adjacent line sections at the remote bus to avoid a miscoordination. The Zone 2 time delay is set to coordinate with the operating time of the primary protection of the next line sections, the breaker operating time, and breaker failure operating times. The Zone 2 time delay is typically set at 20–30 cycles of the power system frequency.

Overreaching distance zones (i.e., Zone 2 and Zone 3) are used in both step-distance and high-speed pilot schemes. In the step-distance scheme, they are set with increasing time delays in direct proportion to the remote station zones they overreach. For example, the local Zone 2 relay is time delayed to coordinate with a remote terminal Zone 1 relay to allow the remote terminal to trip before the local Zone 2. Similarly, a Zone 2 at a remote terminal must trip before the Zone 3 at the local terminal.

An example of distance relay element coordination is shown in Figure 2.32. The relay at Breaker A is set to trip instantaneously for faults within its Zone 1. It is assumed that faults downstream of Breaker C are cleared by the operation of that relay and breaker in instantaneous time. If Breaker C fails to clear a fault in its Zone 1, Breaker A is set to clear the fault when its Zone 2 timer times out. Breaker A clears faults that occur between Point 1 and Breaker B in Zone 2 time. The selectivity delay, S, is the sum of the operating time of Breaker C, local breaker failure time when applied at the remote bus, and some small factor-of-safety time.

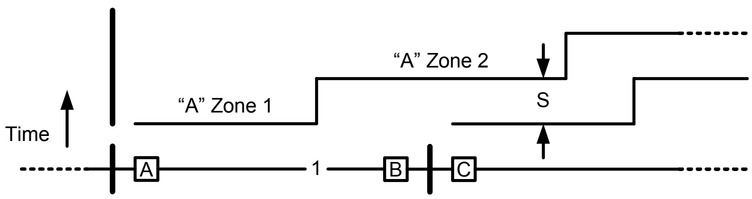


Figure 2.32 Example of time-stepped distance relay settings

Zone 3

Traditionally, the Zone 3 element in a step-distance relay scheme provides time-delayed remote backup protection in case of failure of the primary protection at the remote station. Zones 1 and 2 are applied to prevent loss of life, and to preserve continuity of service and system stability. Zone 3 is applied to prevent damage to the equipment and personnel. Zone 3 is set to cover Line 2 in Figure 2.31 completely. Zones 1 and 2 should never overreach the end of Line 2, and Zone 3 should never underreach. Zones 1 and 2 are set using the actual impedance of Line 1, ignoring current infeed at Bus L, while Zone 3 must be set for a fault at Bus M with maximum infeed conditions at Bus L. On interconnected power systems, the fault current infeed at the remote bus, Bus L in Figure 2.31, will cause the impedance presented to the Zone 3 distance element to be much greater than the sum of the two line impedances, i.e., Line 1 (KL) and Line 2 (LM). This needs to be taken into account when setting the Zone 3 distance element. Variations of remote bus fault current infeed at Bus L in Figure 2.31 can sometimes prevent the application of a remote backup Zone 3 distance element. The

Zone 3 distance element is seldom called on to operate; however, it must not operate during extreme loading conditions, stressed power system conditions, or slow power swings. Overreaching Zone 3 distance relay elements misoperated in the past during stressed system conditions, and this undesirable Zone 3 tripping has often contributed to cascading outages. Adequate measures must be taken to prevent Zone 3 operation for such conditions, using properly shaped distance characteristics or a load encroachment feature and a power-swing blocking feature in the distance relay.

The Zone 3 reach is typically set to 120 percent of the impedance presented to the distance relay for a fault at the remote end of the second line section, Bus M in Figure 2.31. Alternatively, Zone 3 is set at 120 percent of the highest apparent impedance for a remote station line-end fault with the remote terminal breaker open as shown in Figure 2.33. The Zone 3 time delay is typically twice that of Zone 2 (i.e., 40–60 cycles) to achieve time coordination.

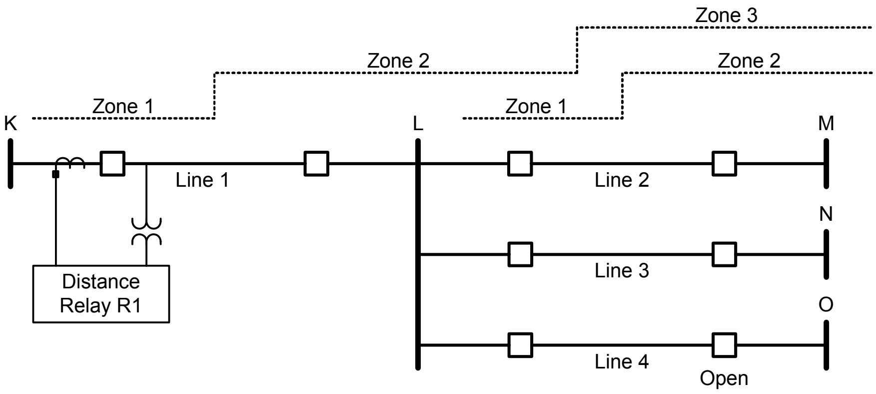


Figure 2.33 Zone 3 at Terminal K set for a Line 4 end fault

Reverse Zone 3

The distance relay at K in Figure 2.31 normally provides the Zone 3 backup protection for Line 2. Distance Relay R2 can also provide this backup protection function by reversing its Zone 3. In other words, reversing all Zone 3 protections to cover the lines behind them instead of the lines in front of them can also provide backup protection. The same level of backup protection is provided, but the reach of the Zone 3 element is shorter, reducing the risk of operating on load or during power swings. One of the drawbacks of the reversed Zone 3 backup protection is that it has the same dc source as the protection it is backing up and may fail for the same reason.

Contingencies Covered by Zone 3

Good engineering practice recognizes possible protection equipment failures and provides the necessary remedies [2]. A backup protection scheme capable of covering failures must always be considered. Remote backup systems, such as Zone 3, provide backup protection for substations or facilities that can be damaged because of catastrophic physical failures, such as earthquakes or storms. Human error, such as incorrect settings or equipment outages during maintenance, is also considered a catastrophic failure. The following are covered by the backup protection systems.

Batteries

If only one battery is available at the substation, a SCADA system alerts the operating department to take corrective action if the battery becomes defective. At higher transmission voltage levels, it is not uncommon to provide two batteries, in which case, providing backup protection for battery failure may not be necessary. However, if only one battery is available, even with a SCADA warning alarm, it may be advisable to set a Zone 3 at the remote station(s) if the failed battery is at a location that is not easily reached and maintenance personnel may not have the time to correct the problem quickly.

Relays

At the lower voltage levels, relays may not be duplicated, and hence, a failure of the local protection scheme may require a Zone 3 remote backup. At the higher voltage levels, two sets of pilot-relay systems are installed, including local breaker failure protection schemes. One may, therefore, conclude that remote backup protection may be unnecessary, but care must be taken to be sure that no common-mode failures exist within the circuitry of multiple relay sets.

Transducers

At lower voltage levels, the transducers are not normally duplicated, and a failure of the voltage or current transformers can go unnoticed and result in a failure to trip. In this instance, a Zone 3 remote backup is desirable. At the higher voltage levels, the CT secondary windings are duplicated, or multiple CTs are available, each serving a separate set of relays. The voltage transformers are typically fused separately to maintain integrity to each set of relays.

Circuit Breakers

Circuit breakers are not duplicated, and failure of a circuit breaker to clear a fault must be considered. Circuit breaker failure tripping schemes are sensitive to system and station configuration. In some cases, it is sufficient to open all local breakers that contribute to the fault upon detecting a breaker failure. This may not be sufficient sometimes, depending on substation configuration, and to clear the fault, a direct transfer trip scheme to remote breakers is required. This involves expenditures for communications equipment, which may not be justified at some locations, and a remote Zone 3 is then required.

Bus Configurations

Figure 2.34(a) is a ring-bus configuration common to EHV (extra-high voltage) stations. Assume that Breaker 1 at Station K fails for the fault shown. The breaker failure protection scheme at Station K will trip Breaker 4 and send a direct transfer trip to the remote breaker at Station L to clear the fault. If the transfer trip scheme cannot be justified for this station, the fault may be outside the reach of the Zone 2 distance relay at L, and a Zone 3 at Station L is required to clear the fault.

Figure 2.34(b) is a breaker-and-a-half station configuration, perhaps the most common EHV bus arrangement. For a fault on Line 1 with a failed Breaker 2, Breaker 3 opens by the local breaker failure scheme, while the remote Line 2 breakers open with a direct transfer trip, which requires a communications channel. Alternatively, a Zone 3 at the remote end of Line 2 must be set to see Line 1 end faults in the absence of a communications channel.

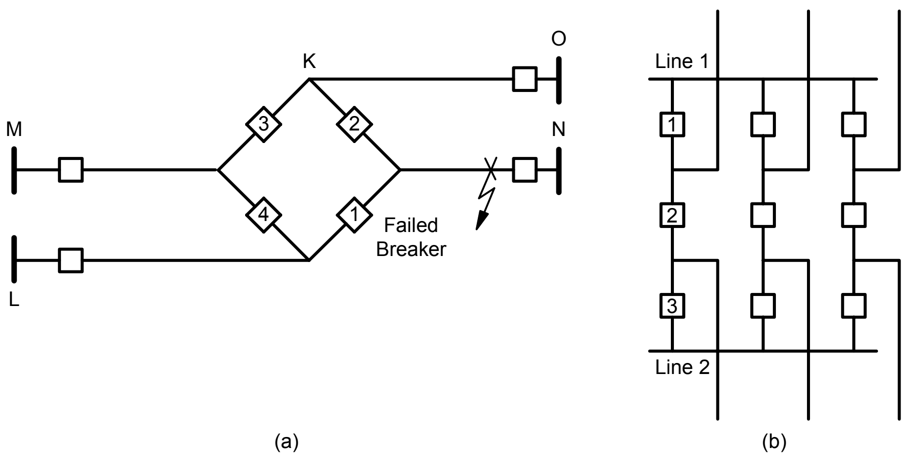


Figure 2.34 Ring-bus (a) and breaker-and-a-half bus (b) configurations

2.4.1.2 Zone Distance Characteristics Impacting Loadability

Overreaching distance relays have historically tripped undesirably in major blackouts. The August 14, 2003 blackout is the most notable, recent event in North America demonstrating undesirable Zone 3 tripping [4]. As far back as 1965, distance relays have been identified as tripping undesirably on line loading during significant system events. A backup distance relay initiated the November 9, 1965 blackout when it tripped on load on one of five 230 kV lines out of the Sir Adam Beck No. 2 Hydroelectric Plant on the Niagara River in Ontario. The remaining four lines loaded up and tripped by their respective backup distance relays immediately thereafter. Those relays were set with a load pickup of 375 MW to provide breaker failure protection for breakers at the remote Burlington, Ontario substation. The distance relay settings were significantly below the loading capability of the protected lines.

As recently as November 4, 2006, distance relays have been identified as tripping on line loading during significant system events. A distance relay on the Wehrendorf end of the Wehrendorf-Landesbergen 380 kV transmission line in North Germany operated on load during one of the most severe and largest disturbances ever to occur in Europe. More than 15 million European households lost service, and the UCTE system was split into three islands. It was concluded that the distance protection operated as designed and might have prevented an even more severe blackout, as their operations resulted in the system separating in desirable islands.

Misoperation of Zone 3 due to load is perhaps the single most obvious protective relay characteristic that has been addressed following the August 14, 2003 blackout in North America [2]. Recent National Electric Reliability Council (NERC) guidelines [4] have specified that third-zone settings should not be encroached by load up to an "extreme" level of thermal overload on all series-connected elements in the transmission line in question. A task force report by protection experts [5] has identified several conditions under which the NERC criteria cannot be met.

Subsequent directives by NERC have acknowledged that under the conditions specified in the task force report, a NERC committee will accept exceptions to the NERC guidelines after review. Ratings of all series-connected elements in a transmission path are known parameters, and loadability limits defined by the NERC guidelines based on these current ratings are easily established. However, it is not just the thermal rating of transmission facilities that should be the deciding criteria for the loadability limit of a transmission facility. The System Protection and Control Task Force Report rightly points out other phenomena that may impose different loading limits on certain facilities. These other considerations are documented as "exceptions" in [5] and are presented as mitigating methods that should be considered.

Specifically, NERC has recommended that all Zone 3 relays on all transmission lines operating at 230 kV and above shall not trip under "extreme" emergency loading conditions. NERC guidelines define "extreme" emergency loading as 150 percent of the emergency current rating of a line, assuming a 0.85 p.u. voltage and a load power factor angle of 30 degrees.

This section describes the vulnerability of distance relays to overload tripping and discusses methods to minimize susceptibility to this tripping [6]. More details on this topic can be found in a report prepared by Working Group D4 of the Line Protection Subcommittee of the Power System Relaying Committee [7].

Variations in Zone Positioning

For distance elements, such as the traditional mho characteristic, the susceptibility of an overreaching zone to pick up on heavy load generally increases as the reach (impedance setting) is increased. The mho characteristic is most likely to respond to system transient load swings but may also detect steady-state load, especially when it is heavy and inductive in nature. Different methods are applied to reduce the susceptibility of a sensitively set distance zone responding undesirably to a load condition. A number of these methods are outlined in the following sections.

Mho Characteristic Angle Adjustment

The simplest adjustment that reduces the mho characteristic's susceptibility to responding to load conditions is to increase the maximum torque (sensitivity) angle. Such an adjustment, however, reduces the fault resistance coverage. It is desirable to have a lower maximum torque angle for the underreaching zone and a higher maximum torque angle for the overreaching zone when both underreaching and overreaching zones are applied. This arrangement optimizes the resistive coverage for close-in faults while maintaining lower susceptibility to false operations under heavy loading conditions or power swings.

Mho Characteristic Offset

Another method to reduce distance relay load susceptibility is by offsetting the mho distance relay characteristic. A forward offsetting moves the mho circle towards the direction of the protected line. A forward offset can be applied to move a sensitively set overreaching zone beyond the anticipated range of steady-state and transient load impedance loci. A shorter reaching distance zone must be relied on to protect the close-in portion of the line left unprotected by a forward offset mho characteristic. Reverse offsetting pulls the steady-state mho characteristic back away from the main forward reach to encompass the relay's location.

Characteristic Shaping

A lenticular-type characteristic is less prone to operate during power swings or steady-state load than a standard mho characteristic. On the other hand, a lenticular-type characteristic has reduced fault-resistance coverage. Other distance relay characteristic shapes have also been implemented (e.g., ice cream cone, blinders) that make a distance relay less prone to operate on heavy loading conditions or power swings. However, all these characteristics have a drawback in that they compromise the ability of the relay system to detect resistive-type faults.

Load-Encroachment Characteristic

Almost always, improved loadability has been paid for with a loss in the coverage for resistive faults. Some modern line protection devices offer a much more optimal method of discerning between load and fault conditions, referred to as load-encroachment. Because load on a transmission system is primarily a balanced three-phase condition, supervision restrictions are placed only on the operation of the three-phase distance elements. The ability to detect phase-to-phase, phase-to-ground, and double-phase-to-ground faults is not in any way compromised by the load-encroachment feature. The user can define custom load regions in both the forward and reverse directions when the feature is enabled. The relay calculates the positive-sequence voltage and current from the measured phase quantities and, from them, calculates the magnitude and phase angle of the positive-sequence impedance. If the calculated positive-sequence impedance lies within the defined load-encroachment region, the three-phase distance element is blocked from operating. Under this supervision, only resistive three-phase faults (a very unlikely occurrence) corresponding to positive-sequence impedance in a load region will not be detected.

2.4.1.3 SIR Considerations

The SIR (source impedance ratio) is the ratio of the source impedance behind the relay terminal to the line impedance [8] and, more accurately, to the distance relay reach setting. The SIR is effectively a measure for the magnitude of the faulted-loop voltage seen by the relay. High fault levels correspond to low SIRs and vice versa. As a general rule, low SIR systems produce high levels of fault current, which require fast clearing times in order to preserve system stability and reduce the possibility of damage to the plant.

The ability of a distance relay to measure accurately for a reach-point fault depends on the minimum voltage at the relay location under this condition being above a certain specified voltage. This voltage typically depends on the relay design and can be quoted in terms of an equivalent maximum Z_S/Z_L or

SIR [8]. Distance relays are designed so that, provided the reach-point voltage criterion is met, any faults closer to the relay will not prevent distance relay operation.

The amount of dynamic expansion of distance relay zone characteristics that employ memory voltage polarization is dependent on the SIR. Relays applied on systems with a low SIR will not exhibit a large increase in the size of the characteristics under dynamic conditions, whereas the converse is true for relays applied to systems with high SIRs.

Distance relays should be tested for a range of SIR conditions that would typically be encountered on the particular network to which the relay is to be applied, because the measurement techniques employed by some relays can have some difficulty in making a correct measurement, particularly when the SIR is very low or very high.

2.4.1.4 Line Length Considerations [9]

Transmission lines can vary in length from less than 1 km to over 450 km. Very short lines are not ideally suited for the application of distance protection, and it is more effective to apply unit-type protection. The main inhibiting factors are as follows:

- The inability to effectively set the relay, particularly the underreaching zone, to the required small impedance value.
- The poor resistive reach coverage obtained on such short lines.
- The difficulty in setting the protective zones without encountering load-encroachment problems.

Short lines are so designated because the SIR ratios are large. Ratios of approximately four or greater generally define a short line. Medium lines are those having SIRs from 4 down to 0.5. Long lines are those having SIRs less than 0.5.

It should be noted that for a given length of line, the p.u. impedance varies much more with the nominal voltage of the line than the ohmic impedance. This factor, together with the different short-circuit impedances at different voltage levels, means that the nominal voltage of a line has a significant effect on the SIR.

For example, a 500 kV line with a positive-sequence reactance of 0.332 ohms/km has a corresponding reactance of 0.0013 p.u./km on a 100 MVA and 500 kV base. If the source impedance behind the relay has a fault level of 10,000 MVA, which corresponds to 0.01 p.u., the following specifications apply:

- Line lengths less than 19 km will result in an SIR greater than four and may be considered short lines.
- Line lengths longer than 150 km will result in an SIR less than 0.5 and may be considered long lines.

On the other hand, a 69 kV line with a positive-sequence reactance of 0.53 ohms/km has a corresponding 0.015 p.u./km on a 100 MVA and 69 kV base. If the source impedance behind the relay has a fault level of 1000 MVA, which corresponds to 0.1 p.u., the following specifications apply:

- Line lengths less than 1.7 km would result in an SIR greater than four and may be considered short lines.
- Line lengths longer than 14 km would result in an SIR less than 0.5 and may be considered long lines.

The above examples demonstrate the importance of source impedances and nominal voltages in the classification of a line as short, medium, or long.

The next section discusses the application of directional comparison distance protection schemes to achieve high-speed protection of transmission lines and permit the application of high-speed auto reclosing to minimize equipment damage, increase system reliability, and maintain system stability.

2.4.2 Directional Comparison Distance Protection Schemes

The importance of transmission system integrity necessitates high-speed fault clearing times and high-speed auto reclosing to avoid system instability and total collapse. A disadvantage of stepped distance protection is that 30–40 percent of the line length is not covered by high-speed instantaneous protection because the Zone 1 distance setting is limited to 80–85 percent of the protected line with the exception of the Z1X scheme and its disadvantages discussed earlier. This is not acceptable for most EHV transmission systems, and a distance unit protection system utilizing a communications channel between distance protection relays at the two line ends is required to speed up the fault detection and clearing time.

One such application where communications schemes are needed is where high-speed auto reclosing is desired at both ends of the transmission line. With time-stepped distance schemes, a fault near one end of the transmission line must be cleared in Zone 2 time from one source. This does not permit high-speed auto reclose. If a communications scheme is employed, the dead period required to be certain both ends have cleared their contributions to the fault is greatly reduced. It is important to remember that the faster faults are cleared from the system, the faster that transmission line can be restored (assuming the fault is transient) and the more likely the entire system is to remain stable.

In networked transmission systems, power system faults on a protected line segment will be seen from both ends of the line. With step-distance protection, line end faults must be cleared from the remote terminal with a coordinating time delay resulting in delayed clearing of the fault from that line terminal. Various communications-aided protection schemes have been developed to provide high-speed tripping from both ends of the line.

High-speed clearing of faults along the entire line segment is required for several reasons.

- When a short circuit exists on a power system, the ability to transfer power across the power system is reduced. Reducing the time that the short circuit exists on the power system reduces the likelihood of the power system going unstable.
- High-speed reclosing is another means to improve power system stability. Power transfer capability is reduced when a line is out of service. Automatically restoring the line with minimal delay, allowing only for arc deionizing time, can also reduce the likelihood of the power system going unstable. However, in order to achieve this, both line terminals must clear the fault instantaneously.
- In step-distance applications where a long line is adjacent to a short line, it may not be possible to coordinate the reach of Zone 2 for the long line with the reach of Zone 1 for the short line. Thus, the entire short line may have to be cleared instantaneously for coordination reasons.

High-speed fault clearing offers the following additional advantages:

- Minimizes the duration of the voltage sag caused by the short circuit that affects power quality.
- Reduces through-fault duty on power transformers, insulator damage due to sustained arcing, etc.

Generally, a pilot protection scheme requires a communications channel between each end of the line. Information regarding the fault direction at each line end is transmitted to the remote end in order for the pilot protection system to determine whether the fault is internal or external to the protected line section.

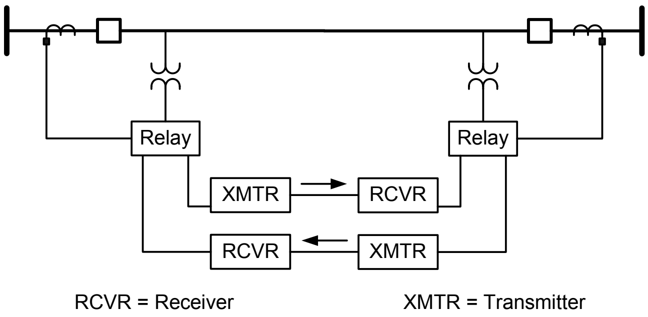


Figure 2.35 Pilot protection scheme

There are many ways to create a communications channel between remote substations.

- Optical fiber communication channels are becoming more available for power system protection applications. A fiber-optic channel can consist of a direct point-to-point fiber connection or a multiplexed fiber link. SONET (Synchronous Optical Network) or SDH (Synchronous Digital Hierarchy) can be part of a wide-area communications network for voice and data traffic. The concern with a nondedicated teleprotection channel is that the channel delays may change as the network reconfigures when a link fails.
- Microwave systems can be either digital or analog. These are often part of a wide-area communications network for voice and data traffic as well. Analog systems generally require audio tone FSK (frequency shift keying) sets to put the teleprotection information into a voice channel. Channel delays for audio tone sets on analog microwave can be 14–20 milliseconds. Digital microwave can provide channel delays in the 3–4 millisecond range.
- Power line carrier (PLC) is used as a reliable point-to-point path for sending teleprotection information from point to point. The equipment to couple the signal to the high voltage power line can be expensive. Also, the teleprotection scheme used must be designed to work if the channel is lost during an internal fault that short circuits the communications channel. PLC channel equipment usually comes in two types, on/off and FSK. The type used is dependent upon the requirements of the teleprotection scheme.
- Private or leased lines are also used for digital and audio tone communications channels.

Pilot protection schemes typically fall into three possible categories.

- Directional comparison schemes use distance or directional relays to determine whether each terminal sees the fault as forward or reverse. By exchanging this information, the fault can be classified as either internal or external to the protected line segment.
- Phase comparison is a form of current only pilot protection. Phase comparison protection systems compare the phase angles of currents entering at one terminal of the line and the currents leaving at the other terminal of the line. If the fault is external, the currents entering and exiting the line should be in phase with each other.
- Current differential schemes send information about the magnitude and angle of the currents entering and exiting the line. This type of pilot protection requires higher bandwidth teleprotection channels, and it is becoming more common with the availability of fiber-optic networks.

In this section, the focus is on directional comparison pilot schemes based on distance relay elements.

Directional comparison pilot protection schemes are designed around sending one bit of data across the teleprotection channel at a very high speed. In some schemes, this one bit tells the other end that it has permission to trip (permissive). In other schemes, the bit represents a signal to tell the other end not to trip (block). There are many variations, but the following are the most prevalent:

- Permissive overreaching transfer trip (POTT)
- Permissive underreaching transfer trip (PUTT)
- Direct underreaching transfer trip (DUTT)

- Directional comparison blocking (DCB)
- Directional comparison unblocking (DCUB)

2.4.2.1 Permissive Overreaching Transfer Trip

At a minimum, a POTT scheme requires a forward-overreaching element at each end of the line. This is typically provided by a Zone 2 element set to reach around 120–150 percent of the line length. If each relay sees the fault in the forward direction, then the fault can be determined to be internal to the protected line.

In Figure 2.36, Relay 3 will key permission if it sees the fault in a forward direction. Then Relay 4 will be allowed to trip if it sees the fault in a forward direction AND it receives permission from Relay 3. A reverse element is required for reasons that will be described shortly. This is typically provided by a Zone 3 element set in the reverse direction. It is important that the reverse Zone 3 element be set to reach such that it always picks up for faults that can be seen by the remote Zone 2 overreaching element. It is important to note that in all of these schemes, an underreaching Zone 1 element is typically used that will trip for non-end-zone faults independent of the pilot protection scheme.

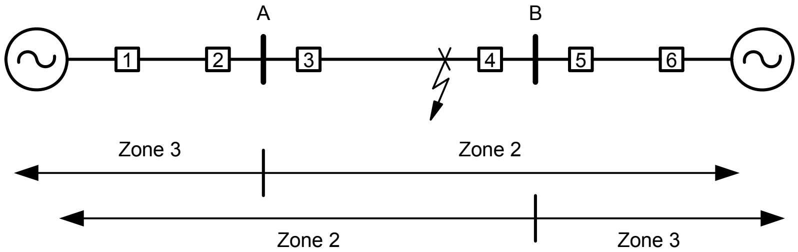


Figure 2.36 Distance zones and their direction as applied in a POTT scheme

The basic logic for a POTT scheme is shown in Figure 2.37. A trip requires Zone 2 overreaching elements to be picked up AND permission received (RCVR) from the remote end. The pickup of Zone 2 overreaching elements keys transmission of a permissive trip signal (Key XMTR) to the remote end.

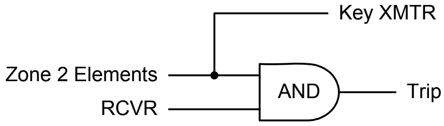


Figure 2.37 Basic POTT logic

There are a number of system conditions and line circuit breaker states during faults that require additional logic to that shown in Figure 2.37 in order for the POTT scheme to work properly. Current reversals during fault clearing in parallel transmission lines can cause the healthy line to trip incorrectly. Below, we outline some of those conditions:

- When the remote terminal is open, the relay at that terminal will not see the fault; therefore, it is unable to send trip permission to the remote end.
- If one terminal is a much weaker source of fault current than the other or its normal source is out of service, it may not produce sufficient current during a fault to allow pickup of the distance elements. In this case, the weak terminal will not send permission to allow tripping at the strong terminal.
- If the channel fails completely, permission to trip cannot be transmitted. To overcome this, the Zone 2 overreaching element typically starts a Zone 2 timer to allow backup tripping after a coordinating time interval to provide backup step-distance mode of operation in case of channel failure.

Current Reversals

In double-circuit line applications, faults near one end of the line may result in a sequential trip operation. This sequential trip happens when the instantaneous relay elements trip the breaker nearest to the fault location (this trip is independent from the communications tripping scheme). The breaker farthest from the fault must wait for a permissive signal. The major problem with this sequential fault current clearance is that it creates a current reversal in the healthy parallel line. If the protection for the healthy line is not equipped to address this reversal, one terminal of the healthy (nonfaulted) line may trip incorrectly.

Figure 2.38 shows the status at the inception of the fault. Relaying at Breaker 3 detects the fault as being within Zones 1 and 2. The instantaneous Zone 1 element issues a trip signal to the breaker independent of the communications-assisted tripping scheme. It is the Zone 2 elements at Breaker 3 that issue a permissive signal to the protection at Breaker 4. The protection at Breaker 4 detects the fault within Zone 2 but must wait for the permissive signal from Breaker 3 before issuing a permissive trip output. In the event that the permissive trip signal never arrives and the fault persists, Breaker 4 is tripped by Zone 2 time-delayed protection.

The Zone 2 element at Breaker 2 also picks up at fault inception and issues a permissive signal to the protection scheme at Breaker 1. At this time, the Zone 3 elements at Breaker 1 also pick up and identify the fault as being reverse (or out of section) to its location.

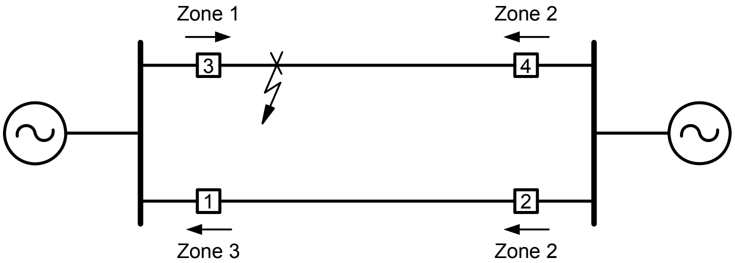


Figure 2.38 Faulted system with all breakers closed

After Breaker 3 opens, the fault currents redistribute. When this redistribution occurs, the Zone 2 element at Breaker 2 and the Zone 3 element at Breaker 1 begin to reset. If the Zone 2 element at Breaker 1 picks up before the received permissive signal resets, Breaker 1 trips as a result of this current reversal. This scenario can easily occur when ground directional overcurrent relay elements are used in a POTT scheme, because they can often see an end-zone fault on an adjacent line. It is less of a factor when ground distance relays are used.

Another factor that contributes to this is the fact that the closing torque of an electromechanical element would be much higher than the opening spring’s torque, resulting in a large disparity in pickup versus dropout times. This disparity is also true with numerical relays but to a much lesser degree.

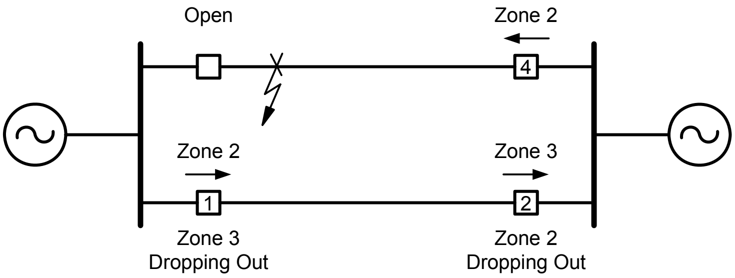


Figure 2.39 Faulted system with Breaker 3 open

Typical current-reversal logic is shown in Figure 2.40. Gate AND 2 represents simple POTT logic. Gate AND 1 is the added logic to prevent tripping on current reversals. The logic of gate AND 1 blocks local tripping and permissive trip keying if the local breaker is closed and the fault is detected by Zone 3 in the reverse direction. The Zone 3 reverse block dropout delay (T1 timer) holds this block for a period of time T1 upon dropout of the Zone 3 reverse element. Factors that influence the T1 timer setting are the remote terminal Zone 2 reset and the channel reset time. To be conservative, some margin should be added to the sum of these times. A safe margin (and known quantity) is the maximum expected operating time of the breaker on the parallel faulted line.

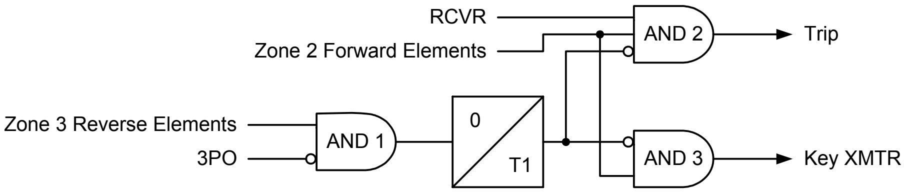


Figure 2.40 Current-reversal logic

POTT schemes require permission from both terminals to achieve accelerated trip times for internal faults along the entire line. When one line terminal is open, as shown in Figure 2.41, the protective relay elements at the open line terminal are unable to detect an internal fault and cannot transmit trip permission to the remote terminal. This is a deficiency of the POTT scheme and usually requires that end-of-line faults be cleared by Zone 2 time-delayed elements, unless additional logic is provided.

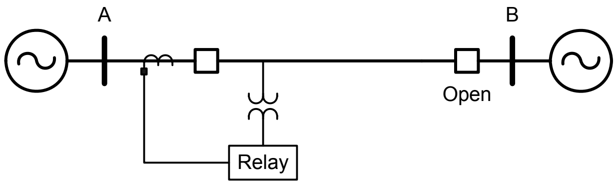


Figure 2.41 Line with remote terminal breaker open

The simplest means of dealing with this is to use a 52b contact of the open breaker to key a constant permissive signal. However, this solution is undesirable for two reasons:

- It results in constant keying of the permissive signal from both terminals after they open to clear an internal fault.
- If the communications equipment requires guard-before-trip for a specified amount of time before accepting the permissive trip signal and if the communications signal fades for whatever reason, the communications-assisted tripping is defeated.

Echo logic is added to the POTT scheme to overcome the deficiency. The echo logic causes the relay at the open breaker terminal to echo back the permissive signal it received from the remote terminal that detected a line fault. Typically, the following conditions must be met before a received permissive signal from the remote terminal is repeated or echoed to the initiating terminal:

- Zone 3 reverse elements did not detect a reverse fault.
- Zone 2 element did not detect a forward fault.
- The permissive trip (PT) input is asserted for a settable length of time.

The first requirement assures that the fault is not behind the relay location before transmitting permission to the remote terminal (assuming the Zone 2 elements at the remote breaker detected a fault and sent a permissive signal). The second requirement prevents the relay from issuing a permissive signal to the remote terminal for communications channel noise. It also allows time for the reverse looking elements to operate. The echo time-delay pickup (T3) timer setting determines the permissive trip signal qualifying time. A typical setting is two cycles.

Once the echoed permissive signal is issued to the remote terminal, its duration must be limited to prevent a scenario where both terminals maintain the permissive signal channel in a continuous “trip keyed” or constantly “on” state. The echo duration (T4) timer limits the echoed permissive trip signal to a settable duration. T4 is typically set greater than the communications channel operation time plus the remote breaker tripping time. It is desirable to maintain the echoed permissive trip signal to the remote breaker until the fault is cleared. Assuming a three-cycle breaker and half-cycle channel operation time, a typical T4 setting would be three and one-half cycles.

The echo logic in Figure 2.42 shows that echo keying will occur if no Zone 3 reverse elements are picked up and a permissive trip signal has been received for a T3 time delay. Logic is also included to block the echo transmit function for a period of time via the echo block dropout delay (T2) timer after a forward fault is detected.

The T2 would typically be set greater than the sum of the following delays:

- Remote Zone 2 pickup equal to one cycle
- Remote breaker trip time equal to three cycles
- Channel reset time equal to one cycle

A typical setting is ten cycles.

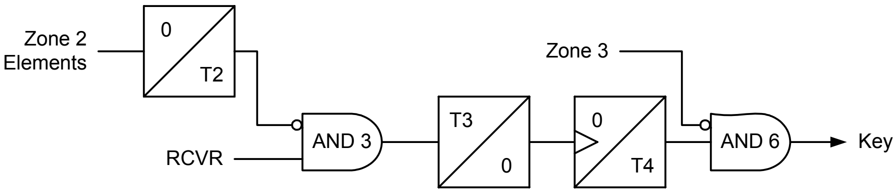


Figure 2.42 Echo logic

In some system configurations, with all sources in, the weak source terminal may not contribute enough fault current to operate its protective relay elements for a fault near the strong terminal. After the strong terminal line breaker opens, the fault current from the weak source terminal may increase sufficiently to permit sequential tripping of the weak source terminal line breaker. If the fault current does not increase sufficiently to operate the protective elements at the weak source terminal, it is still desirable to trip the weak source breaker. This prevents the low-level currents from maintaining the fault arc and allows successful auto reclosure from the strong terminal. When the fault location is near the weak source terminal, the Zone 1 elements of the strong terminal do not pick up, and the fault is not cleared rapidly. This is because the weak terminal protective elements do not operate.

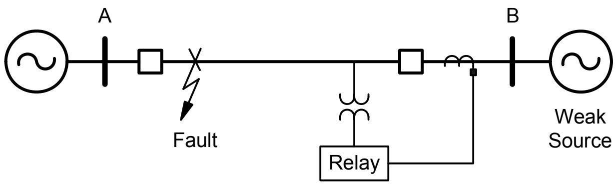


Figure 2.43 Weak-infeed terminal

Even though the weak-infeed terminal contributes low levels of fault current during a fault, the phase voltages are depressed. We can take advantage of the low voltages at the weak source to enable weak-infeed logic tripping. Weak-infeed logic permits rapid tripping of both line terminals for internal faults near the weak terminal. The strong terminal is allowed to trip via the echoed back permissive signal from the weak source terminal. In addition, the weak-infeed logic generates a trip signal at the weak source terminal if all of the following are true:

- A permissive trip (PT) signal is received for T3 time.
- A phase undervoltage or residual overvoltage element is picked up.
- No reverse looking elements are picked up.
- All breaker poles are closed.

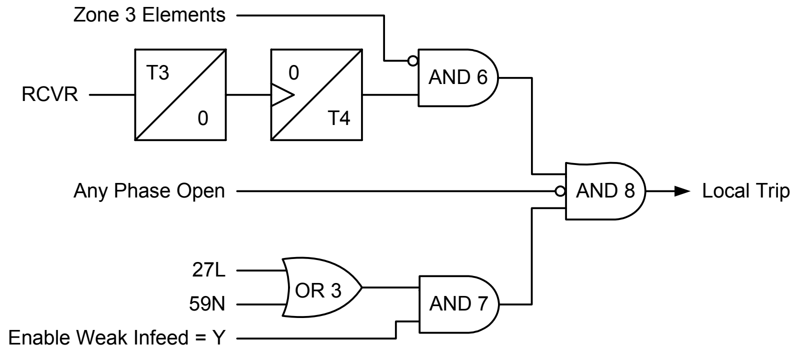


Figure 2.44 Weak-infeed logic

The top half of the logic diagram is from the "breaker open" echo keying logic. If we have a permissive signal to echo transmit AND the breaker is closed AND low voltage is detected at the weak source terminal, the relay will trip the local breaker (echo conversion to trip).

This weak-infeed trip logic is typically enabled only when necessary. A typical phase undervoltage setting is 70–80 percent of the lowest expected system operating voltage. The residual overvoltage setting should be set to approximately twice the expected standing $3V_0$ voltage. With the 59N element set at twice the nominal standing $3V_0$ voltage, the element measures only fault-induced zero-sequence voltage.

2.4.2.2 Permissive Underreaching Transfer Trip

PUTT uses the same basic logic as POTT but can be even more secure. Underreaching elements are used to key permissive trip to the remote terminal. The remote terminal is allowed to trip if it sees the fault as forward with its overreaching element and the remote end sees it with its underreaching element. Because the permissive keying elements can only see faults within the protected line, there is no danger of misoperation on current-reversal situations. Because the tripping elements are not set with as great a reach, the PUTT is slightly slower and provides less fault resistance coverage. This scheme should not be used in applications where weak-infeed conditions exist in one of the line terminals.

2.4.2.3 Direct Underreaching Transfer Trip

DUTT schemes work on the principle that any time an underreaching phase or ground element picks up, a trip signal is issued to the remote end of the transmission line. DUTT schemes require a very secure communications channel because the received trip signal at the remote end is not supervised by a protective element.

Direct transfer trip (DTT) schemes are similar to DUTT schemes with the difference being that the trip signal is issued to the remote end any time the local breaker is called on to trip, except when operating personnel trip the breaker manually.

2.4.2.4 Directional Comparison Blocking

In a DCB scheme, each line terminal has reverse elements (Zone 3) and forward-overreaching elements (Zone 2). Zone 1 underreaching elements are applied for independent, high-speed clearing of non-end-zone faults from each terminal.

In a DCB scheme, the relay transmits a blocking signal to the remote end if it detects the fault in the reverse direction, indicating that the fault is outside of the protected zone. The DCB logic will issue a local trip signal if the fault is in the forward direction and does not receive a blocking signal from the remote end.

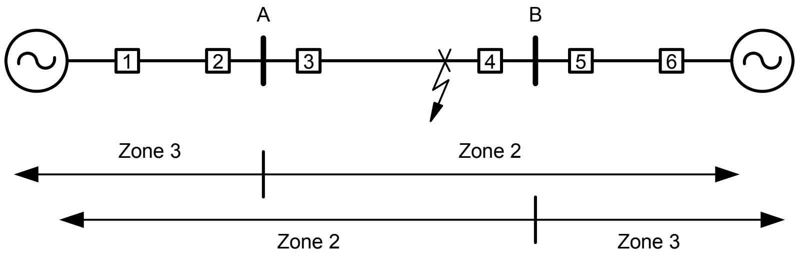


Figure 2.45 Typical zones in a DCB scheme

Figure 2.46 shows the fundamental logic involved in a DCB scheme. Pilot tripping occurs for an internal fault if the local Zone 2 forward-overreaching element operates and no blocking signal has been received from the remote line end within a settable time. This time delay, the channel coordination time delay, is required to allow time for the blocking signal to be received from the remote terminal before the tripping element at the local terminal generates a trip signal. If the blocking signal does not get through or is late, a DCB scheme may overtrip. The DCB scheme uses a PLC channel because the only time that it is necessary to transmit a blocking signal is when the fault is not on the protected line.

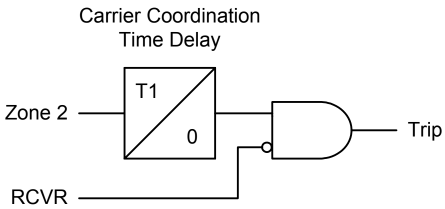


Figure 2.46 Basic DCB logic

There are a number of complications that need to be addressed with DCB schemes. Emphasis is placed on time coordination issues and ways to improve the likelihood of a secure operation of a DCB scheme. Current reversals also have to be addressed.

Loss of channel in DCB schemes can cause a line trip for an external fault, because no blocking signal can be received from the remote terminal. This is complicated by the fact that an on/off carrier set is typically used for the highest possible channel speed. An on/off carrier set is off in the normal state, and it is turned on to block the remote end from tripping. For this reason, it is usually desirable to use an automatic carrier check-back system with on/off carrier sets. An automatic carrier check-back system can be programmed to operate several times a day to check the condition of the channel. There is usually a master check-back unit that keys the local transmitter with a series of carrier pulses. The slave check-back units monitor their local receiver and recognize this code as a check-back transmission instead of a fault transmission. Then they respond by keying their local transmitter with an answer code. If the master receives the slave code on its local receiver, it knows that the channel is healthy. If it does not, it will typically generate an alarm to indicate that the channel has failed. If an internal fault occurs during a check-back transmission, the relay will assert its “carrier stop” output. The carrier sets have “carrier stop” over “carrier start” priority that will turn off the transmitter if the fault is internal.

The channel delay coordination timer blocks the local trip signal, so it is desirable to make this delay as short as possible while maintaining security. The local Zone 2 elements are delayed to coordinate with the blocking signal. This channel coordination time delay is improved by the fact that, for an external fault, the local reverse Zone 3 element will be closer to the fault, and the fault will be at a lower percentage of the element reach than the remote forward-reaching Zone 2 element. Thus, the Zone 3 element that is keying the blocking signal will naturally operate faster than the remote Zone 2 tripping element. This allows the coordination delay to be set close to the channel time with the difference in element operate time making up the security margin.

Figure 2.47 shows a typical DCB scheme with directional element transmitter start logic. In this case, the block signal is only sent when the relay sees the fault in the reverse direction. Nondirectional carrier start can be used to reduce the channel delay coordination time delay and improve the speed of a DCB scheme. The relay turns on the transmitter as soon as a fault is detected by nondirectional elements to send a block signal as soon as possible. Then, if the slower, forward-overreaching elements pick up, indicating that the fault appears to be in the protected zone, the transmitter stop asserts and turns off the carrier allowing a breaker trip.

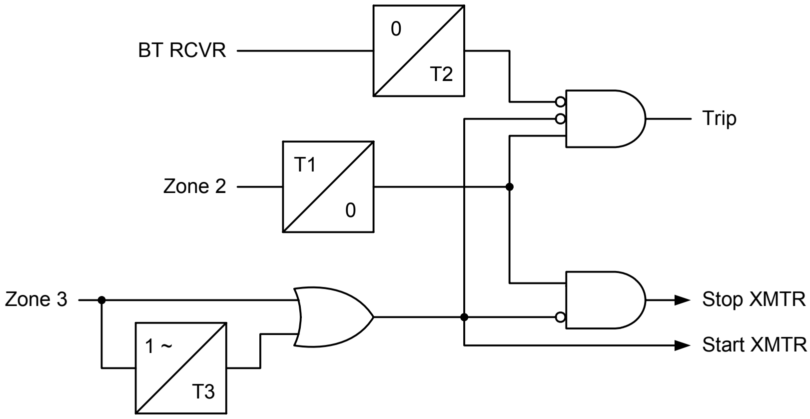


Figure 2.47 Carrier start using directional elements in DCB schemes

Stop preference over start is a feature of on/off teleprotection channel equipment. This feature is required for nondirectional transmitter start because the transmitter is keyed for internal and external faults to reduce the channel coordination delay time. However, for an internal fault, both the transmitter start will be asserted by the nondirectional element and the transmitter stop will be asserted by the forward-overreaching Zone 2 elements. Figure 2.48 shows that numerical and electromechanical nondirectional elements are very close in operating speed. This may not be true for all nondirectional numerical and electromechanical elements.

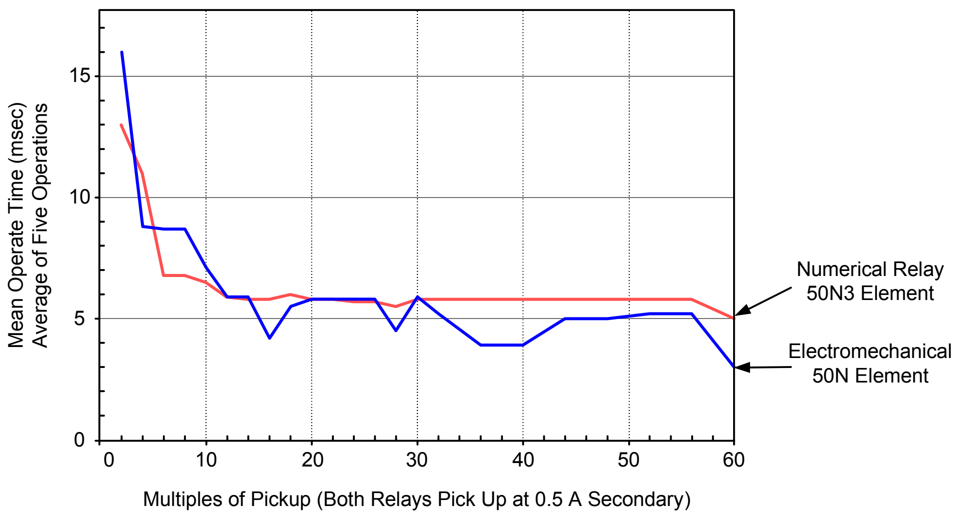


Figure 2.48 Nondirectional overcurrent element (EM vs. µP) speed comparison

Figure 2.49 indicates that a speed improvement can be achieved with nondirectional transmitter start. The nondirectional element is almost a half cycle faster. For an internal fault, approximately a 7–10 millisecond burst of carrier will be present and then it would shut off, allowing the remote end to trip. However, the remote channel delay coordination timer could be set to be 7–10 millisecond less for the same scheme security.

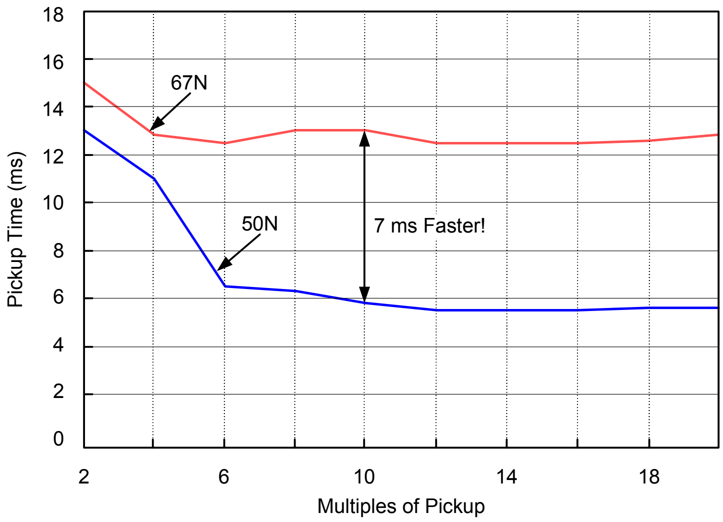


Figure 2.49 Directional and nondirectional overcurrent speed comparison

Figure 2.50 shows typical carrier stop logic that asserts if any of the forward-reaching elements pick up and the reverse elements do not pick up, indicating a possible current-reversal situation.

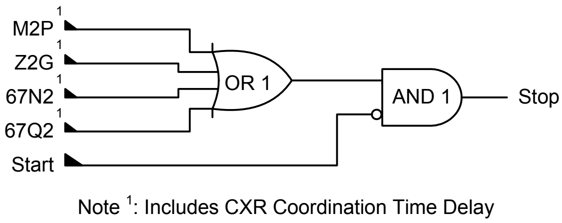


Figure 2.50 Carrier stop logic in DCB schemes

A DCB scheme may lack security during current reversals as well. Figure 2.51 shows the status of the circuit breakers and fault current direction at the inception of the fault.

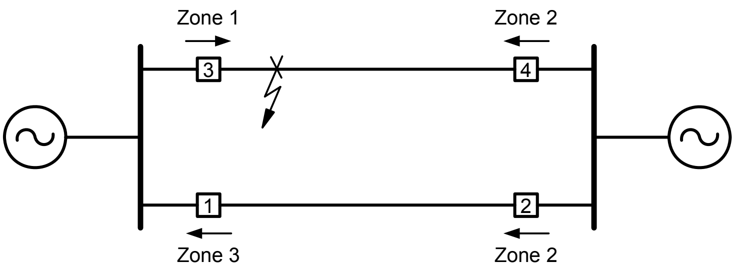


Figure 2.51 In-section line fault with all breakers closed

The distance relay at Breaker 3 detects the fault as being within Zone 1 and issues a trip signal to the breaker independent of the communications-assisted tripping scheme. This trip condition also stops the transmit of a blocking signal. The relay at Breaker 4 detects the fault within Zone 2; however, it has to wait for its channel coordination timer to expire before tripping.

The reverse-reaching Zone 3 element at Breaker 1 is picked up, indicating the fault is initially in the reverse direction. The assertion of the Zone 3 element starts transmission of a blocking signal to block Breaker 2 from operating. At the same time, the Zone 2 element at Breaker 2 is picked up. Because the typical carrier coordination timer setting is less than the breaker operation time, the Zone 2 element will be ready to trip but is being blocked by the signal from Breaker 1. After Breaker 3 opens, the fault currents redistribute so the forward-overreaching Zone 2 elements at Breaker 2 and the reverse Zone 3 element at Breaker 1 begin to drop out. If the Zone 3 element at Breaker 1 drops out and the channel resets before the Zone 2 element at Breaker 2 drops out, Breaker 2 will perform an unwanted trip.

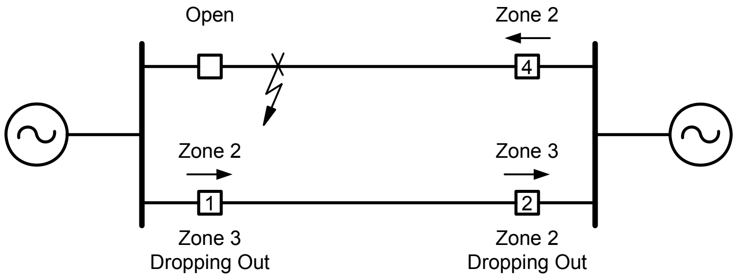


Figure 2.52 Current reversal when Breaker 3 opens

The T3 timer holds the block signal up for a period of time to allow the remote Zone 2 elements to drop out before turning off the blocking signal, as shown in Figure 2.53.

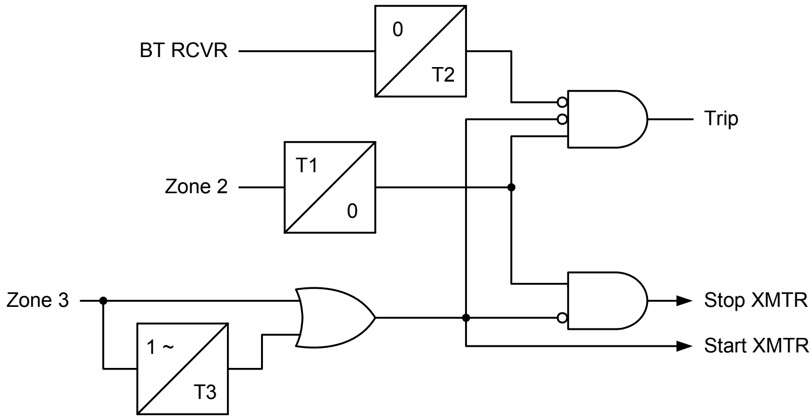


Figure 2.53 Typical current-reversal logic in a DCB scheme

The diagram in Figure 2.54 shows the timing sequence for the scenario just described. For Breaker 2, notice the timing between Zone 2 pickup and receipt of block from Breaker 1. The shaded area represents the carrier coordination timer. Notice that the T3 timer for Breaker 1 starts two cycles after the reverse Zone 3 element picks up, indicating that an out-of-zone fault has been detected. This element then starts timing down upon dropout of the Zone 3 element. Notice also that the block trip (BT) signal at Breaker 2 is maintained until the T3 timer expires at Breaker 1. The result is that there is no race with dropout of Zone 2 elements at Breaker 2.

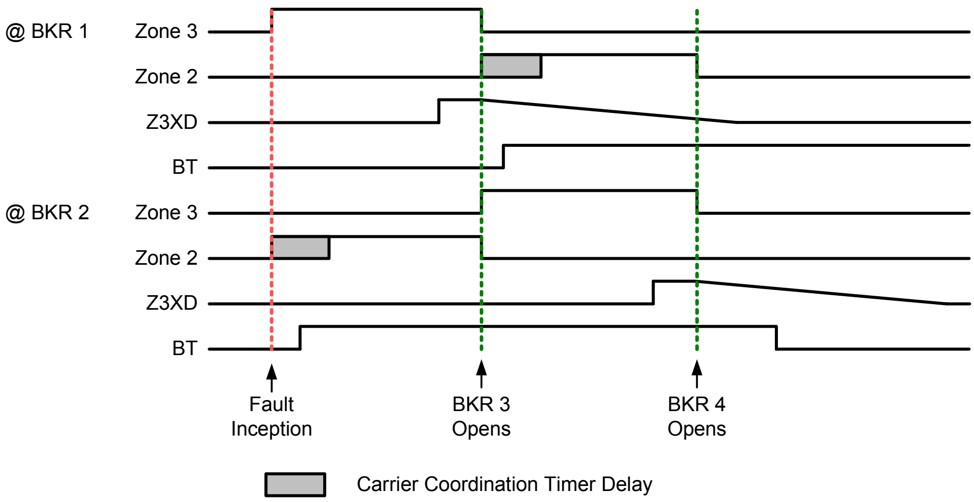


Figure 2.54 Current-reversal timing sequence

2.4.2.5 Directional Comparison Unblocking Scheme Logic

The basic POTT scheme requires that relays at both ends of the line see the in-section fault and transmit a trip signal to each other by use of a communications channel. Overreaching Zone 2 elements are then allowed to trip with receipt of the permissive signal. Typically, faults within Zone 1 reach are cleared by instantaneous elements without regard for the receipt of the trip signal from the other end. Faults outside Zone 1 but within Zone 2 must receive a permissive signal from the remote relay to trip fast or must wait for the Zone 2 timer to time out.

The communications medium for transmitting the trip signal to the other end may be fiber-optic channels, company owned or leased telephone lines, or PLC. When using PLC in a permissive scheme, getting the trip signal through to the remote end can be difficult. In many instances, the signal is transmitted on the same line that has the fault. This may reduce the signal to the point of not having it received by the remote end. It is these cases where a DCUB scheme can provide the means for fast clearing of the fault.

In a DCUB scheme, FSK carrier equipment is typically used to provide communications between the two ends of the line. This equipment continuously transmits a guard signal on one frequency. When a fault occurs, the protective relay signals the carrier equipment to shift from the guard frequency to the permissive frequency. The receiver at the other end of the line monitors these signals. There is a short transition period in which there is no guard signal and no permissive trip signal received. If the permissive trip signal arrives momentarily, then a normal trip occurs.

Unblocking schemes employ logic whereby if the guard signal is lost and no permissive trip signal is received (because of signal attenuation during a line fault), the requirement for a permissive trip signal is bypassed for 150 milliseconds to allow tripping if a permissive Zone 2 element picks up. After the 150 millisecond time window expires and no trip is issued by the protective relaying, the permissive signal channel is assumed to be faulty and the permissive signal criteria for tripping is not bypassed any longer.

DCUB allows the security of a POTT scheme to be used in situations where the channel is susceptible to failing at the same time as a fault on the power line. It does this by allowing an unsupervised trip for a short time upon failure of the channel. This scheme is appropriate when using PLC, fiber-optic cable in the ground, sometimes wire, or otherwise using a channel strung in the same right-of-way or on the same towers as the protected line. In a DCUB scheme, if the communications equipment at the remote terminal fails at the same time an out-of-section fault occurs that is within the reach of the forward-overreaching elements at the local end, then an incorrect single-ended trip can occur.

In summary, DCB schemes are not secure and will overtrip if the channel fails or if the channel delay increases. POTT schemes can be less dependable because they will fail to trip for a channel failure. DCUB schemes combine the security of POTT schemes and also allow tripping for a window of time to accommodate channel failure during a fault. FSK channel equipment provides continuous monitoring of the channel by continuously transmitting the guard (block) signal. DCB schemes should not be used with networked communications channels such as SONET where the channel delay can change. A high-speed channel such as a PLC on/off channel is required.

POTT and DCUB schemes will not trip until the permission (unblock) signal arrives, so there are no concerns about channel delay for security. Channel delay does affect ultimate tripping time.

2.4.3 Protection of Composite Lines

In some power systems, transformers and overhead lines or cables are sometimes connected together without intermediate circuit breakers. In some other cases, the lack of CTs or VTs necessitates the inclusion of power transformers in the zones of distance relays. Under these situations, fault magnitudes and phase angle transformations as seen by the distance protection need to be carefully evaluated.

2.4.3.1 Protection of Power Transformers Connected to Transmission Lines

In the example shown in Figure 2.55, the primary protection scheme for the transformer is an instantaneous differential relay with the provision of mechanical and thermal transformer protection.

Alternatively, when the distance protection includes the transformer zone because of the physical connection of CTs or VTs on the bus side of the transformer, a selective underreaching setting can be accomplished if the line reactance is equal to or greater than twice the transformer reactance. Setting Zone 1 distance protection should take into account the normal voltage variation caused by the transformer tap changer mechanism.

Typically, the reach settings of the underreaching and overreaching zones on the HV side are as follows:

$$Z1 = Z_{TR} + 0.9 \bullet \left(\frac{V_H}{V_L} \right)^2_{min} \bullet Z_L \tag{2.28}$$

$$Z2 > Z_{TR} + \left(\frac{V_H}{V_L} \right)^2_{max} \bullet Z_L \tag{2.29}$$

Where:

V_H = line-to-line voltage on the HV side

V_L = line-to-line voltage on the LV side

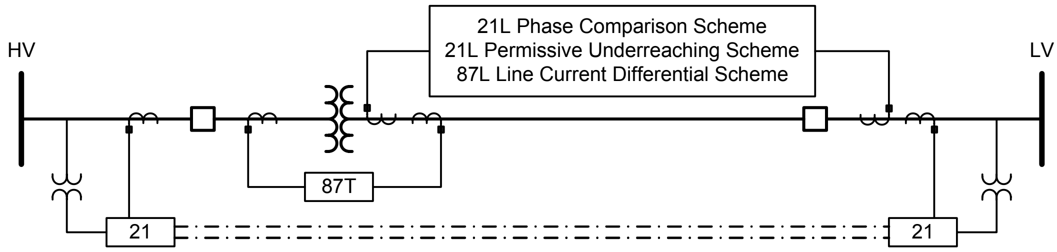


Figure 2.55 Mixed overhead line and transformer

2.4.3.2 Starting Element Impedance Set to Not Be Affected by Transformer Inrush Current

It should be noted that fault measurements as seen by the distance relay are influenced by the connection of the transformer windings (e.g., Y-Y, Y-D) and the earthing star-point reference of the transformer. In this case, an underreaching effect may result for ground faults on the line causing additional delays for fault clearance. A good practice is to include telecommunication channels with the distance protection schemes.

Modern distance protection sometimes includes a line differential protection scheme integrated into the distance relay device. It is possible to use this modern technology to protect the line and the transformer adequately and, using intertripping outputs, to enable or inhibit circuit breaker auto reclosing.

2.4.3.3 Composite Overhead and Underground Cable Lines

Usually, the underground cable is a small amount of the total line length that still preserves a minimum impedance value to allow correct operation of the distance protection. Therefore, utilities that attempt to obtain a basically uniform philosophy generally apply distance protection to lines that are partially cable and partially overhead, even if the application requires critical aspects to be considered.

Underreaching misoperation can occur because of the overlap of the fault and charging current due to the cable section capacitance. Depending on the capacitance and reactance of the cable and overhead sections, measurement error may reach 20 percent in 400 kV lines.

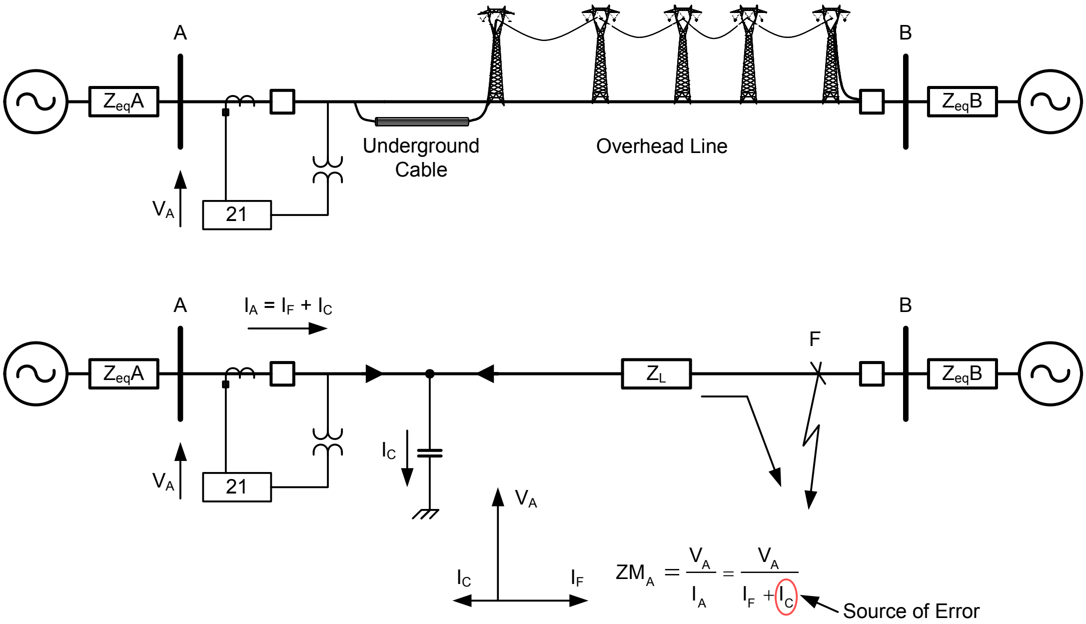


Figure 2.56 Mixed overhead line and underground cable

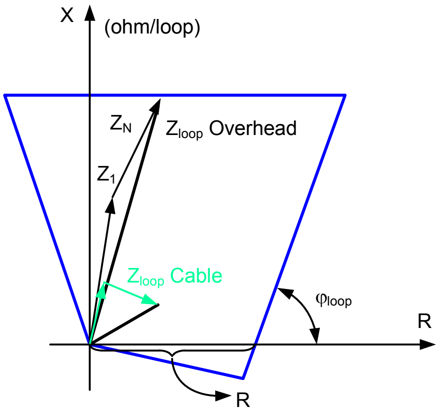
Furthermore, the presence of attached hybrid sections of overhead line and cable causes a nonhomogeneous Z_0/Z_1 ratio along the line that has a large influence on the distance measurement in the case of single-phase-to-ground faults.

Table 2.4 Typical 132–150 kV overhead line and UG cable impedances

132–150 kV	Cable XLPE Al 1 • 1600 mm^2 (trefoil and cross-bonded) [ohm/km]	Overhead AA 1 • 585 mm^2 [ohm/km]
Z_1	0.03 + j0.11	0.055 + j0.38
Z_0	0.13 + j0.055	0.208 + j1.25
$X_{1\_Overhead} / X_{1\_Cable} = 3.5$		
$X_{0\_Overhead} / X_{0\_Cable} = 22.7$		

Table 2.5 Typical 380 kV overhead line and UG cable impedances

380 kV	Cable XLPE Cu 1 • 2500 mm^2 (trefoil and cross-bonded) [ohm/km]	Overhead AA 3 • 585 mm^2 [ohm/km]
Z_1	0.02 + j0.11	0.02 + j0.27
Z_0	0.07 + j0.06	0.28 + j1.06
$X_{1\_Overhead} / X_{1\_Cable} = 2.5$		
$X_{0\_Overhead} / X_{0\_Cable} = 17.7$		



$Z_m = Z_{loop} = Z_1 + Z_N = Z_1 + 1/3\ (Z_0 - Z_1)$

Figure 2.57 Loop impedance for the composite line of Figure 2.56

A distance relay with a flexible algorithm is strongly recommended in order to provide independent settings for each zone, the X/R ratio, and all other parameters related to zero-sequence compensation for line-to-ground faults. The availability of independent settings for Zone 1 and overreaching Zone 2 that represent the main protection at the end of the line with the faster clearing time is of utmost importance. A wide range of zero-sequence current compensation factor amplitude and phase, $k_0 = (Z_0 - Z_1) / 3 \bullet Z_1$, is needed. Modern distance relays offer a k_0 amplitude of 0.0–10.0 and a k_0 phase between –180 degrees to 180 degrees.

Transmission lines that use cable for a portion of their total length present a special concern for utilities as to whether to incorporate auto reclosing or not. Faults inside cables are permanent and auto reclosing should not be enabled. If the line consists of underground cable completely, then auto reclosing should not be enabled since a cable fault is permanent and auto reclosing, if allowed, will cause more damage and increase the stress to adjacent portions of the power system. Therefore, the use of auto reclosing on transmission lines entirely made of cable is not recommended. If the line is partially cable and partially overhead, depending on the location and length of the cable section relative to the total transmission line, some utilities may be willing to risk additional damage to the cable and consider this type of feeder as "totally overhead" and apply their standard auto reclosing practice.

Lines that experience a temporary fault on the overhead section that may be successfully cleared benefit from the use of auto reclosing. If the fault were to occur in the cable portion, then the substation equipment and line sustain further damage as a result of the auto reclose attempt. Installing additional relays on the cable portion to determine if the fault is in the cable and inhibit auto reclosing for such conditions is possible but could be costly. By using a pilot relay scheme, faults in the cable section can be identified. Should a fault occur within the cable, then auto reclosing would be blocked. Pilot schemes, such as current differential, phase comparison, or pilot wire, are suited to this approach.

This approach would be expensive, because there would be a need for a communications channel for transfer trip/auto reclose inhibit and additional freestanding CTs at the overhead/cable terminals. Therefore, some utilities employ a current differential scheme with fiber-optic communications to trip and block auto reclosing for cable faults on a 400 kV composite line.

It is also important to keep in mind which end of a composite line will perform an auto reclosing attempt first. Transient overvoltage studies using a transient network analyzer may need to be performed to identify any problems that may occur if the line is auto reclosed. These studies are especially important if a shunt reactor is added to the line as a means to control the voltage boost effect due to the cable capacitance.

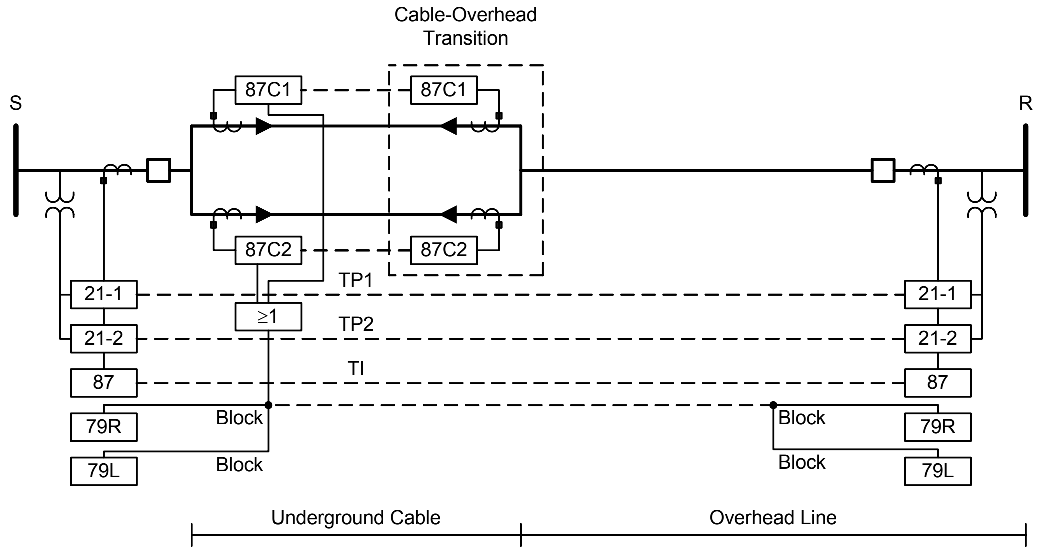


Figure 2.58 Protection of mixed overhead and underground cable

Successful auto reclosing for a temporary fault is conditional upon extinguishing the secondary arc and attaining a favorable recovery voltage. With one phase open to clear a single-line-to-ground fault, voltage is induced in the isolated phase because of capacitive coupling and, to a lesser extent, by inductive coupling. This coupling has the effect of prolonging the arc deionization time, referred to as maintaining the secondary arc current. This secondary arc current is proportional to the circuit voltage and the length of the overhead transmission circuit. Cable sections have no mutual capacitive coupling; therefore, they reduce the secondary arc current and the recovery voltage magnitude in the open phase, providing a positive effect to successful reenergization. The minimum dead time before allowing auto reclosing is a function of the duration of secondary arc current. If this time is longer than that allowed to maintain system stability, the line capacitance needs to be compensated. Additional applications of composite line protection, including relay settings and auto reclosing considerations, are discussed in [10].

2.4.3.4 Overhead Lines and Submarine Cables

In countries where islands are located relatively close to the mainland, the island's network can be connected to the country's power system network either on a distribution level or on a transmission level, depending on the island's load size. Figure 2.59 shows a composite one-line diagram of a transmission line where the utility design engineer faces the challenge of allowing automatic reclosing only for faults occurring on overhead Sections A–B and C–D.

With conventional relays, the above problem can be solved by setting the distance relay zone reach in such a way so that Section A–B is covered by Zone 1 allowing automatic reclosing, Section B–C is covered by Zone 2 without automatic reclosing, and Section C–E is covered by Zone 3 allowing automatic reclosing. In such a scheme, it is understood that there is no remote backup protection for faults on the adjacent lines, assuming the distance relay has only three forward reaching zones.

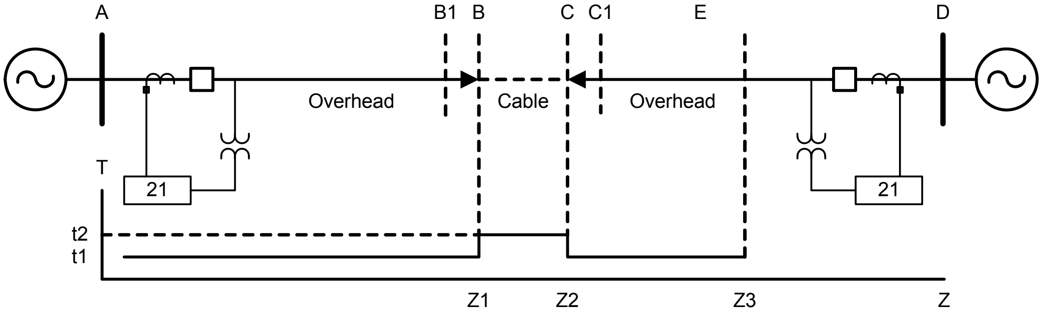


Figure 2.59 Example of mixed overhead and submarine cables

With modern numerical technology relays, the protection engineer can set the distance relay zone reach in the usual manner, as if the line is homogeneous. For example, set Zone 1 at 80 percent of line length (A–E), and make use of the distance relay logic shown in Figure 2.60 to block auto reclosing for submarine cable faults. For security reasons, the fault locator measurement boundaries may be shifted to points B1 and C1 instead of B and C.

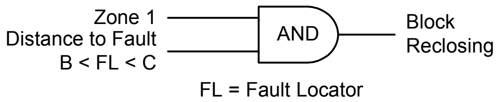


Figure 2.60 Distance relay logic to block reclosing for submarine cable faults

2.4.4 Distance Protection Considerations for Lines With FACTS Devices

The IEEE defines Flexible AC Transmission Systems (FACTS) as “alternating current transmission systems incorporating power electronic-based and other static controllers to enhance controllability and increase power transfer capability.” FACTS controllers include devices that mainly use semiconductor components that are installed in the power network to control power flow, increase system stability, increase transfer capability, and provide access between different areas in the power system. Below is a list of FACTS devices:

SVC	Static Var Compensator
TSSC	Thyristor Switched Series Capacitor
TCSC	Thyristor Controlled Series Capacitor
TCPST	Thyristor Controlled Phase Shifting Transformer
STATCOM	Static Synchronous Compensator
SSSC	Static Synchronous Series Compensator
UPFC	Unified Power Flow Controller
IPC	Interphase Power Controller
CSC	Convertible Static Compensator

A few other power system components (listed below) are not strictly FACTS devices but are applied in the power system for the same reasons as FACTS devices:

MSC	Mechanically Switched Capacitor
MSSC	Mechanically Switched Series Capacitor
PST	Phase Shifting Transformer
SC	Series Capacitor

2.4.4.1 FACTS Controllers

The development of FACTS controllers has followed two distinctly different technical approaches to address targeted transmission problems. The first approach employs reactive impedances or a tap-changing transformer with thyristor switches as controlled elements, while the second approach uses self-commutated static converters as controlled voltage sources.

The first group of FACTS controllers (SVC, TSSC, TCSC, and TCPST) employ conventional thyristors in circuit arrangements similar to breaker-switched capacitors and reactors but with much faster response and are operated by sophisticated controls. Except for the TCPST, all of these absorb or generate reactive power using traditional capacitor and reactor banks with the thyristor switches used only for control of the combined reactive impedance these banks present to the ac power system. The first group of controllers presents a variable reactive admittance to the transmission network and generally changes the character of the system impedance.

The second group of FACTS controllers employs self-commutated voltage source switching converters to realize fast, controllable static synchronous ac voltage or current sources. This approach provides superior performance characteristics when compared to the first group for transmission voltage, effective line impedance, and angle control. The second group of FACTS controllers is analogous to an ideal rotating synchronous machine with controllable amplitude and phase angle, no inertia, and practically an instantaneous response. This group of FACTS controllers does not significantly alter the existing system impedance, but it can internally generate both capacitive and inductive power. Furthermore, it can exchange real power with the ac system if it is coupled to an appropriate source that can supply or absorb the power it supplies to or absorbs from the ac power system.

2.4.4.2 Distance Protection of EHV Lines With FACTS Devices

The employment of FACTS devices can have an adverse impact on the operation of distance relays. For example, controllable series compensation has the ability to direct and control power flow by changing the firing angle of thyristor switches. This causes problems for conventional distance protection schemes because of rapid apparent impedance changes [11].

In recent years, numerous researchers have studied the performance of distance relays on transmission lines with FACTS devices [12]–[19]. In this section, we summarize the results and conclusions of some of those studies and provide a list of references to aid in the application of distance protection of EHV lines with FACTS devices.

The effects of midpoint shunt FACTS compensation on distance relays can be inferred as follows in the text below [12] [13] [14].

An SVC can cause a stand-alone distance relay to underreach. However, channel-aided distance schemes employing either permissive or blocking schemes can overcome this problem. Nevertheless, serious consideration should be given to the underreaching effect caused by SVC while setting the distance relay. Another effect of an SVC presence is to cause incorrect phase selection if a single-pole tripping scheme is enabled.

The presence of midline STATCOM causes underreaching of distance relays. STATCOM operation during faults causes distance relay underreaching because it tries to maintain the midline voltage to its nominal level. During faults, the voltage dips, requiring the STATCOM to produce more reactive current to boost the midline voltage, thus, increasing the apparent impedance seen by a distance relay. Underreaching phenomena can lead to no operation of a distance relay for faults in the protected line. The degree of underreaching depends on load angle variations—the higher the load angle the higher the degree of underreaching [14]. Communications-aided distance schemes with proper settings can solve this problem. STATCOM operation can also cause overreaching of distance relays [12], [13]. A Zone 1 distance element may overreach and misoperate for faults beyond the protected line in the presence of STATCOM. Incorrect phase selection for single-phase faults is also a problem in EHV lines with STATCOM, which cannot be solved by communications-aided schemes [12]. In addition, failure of the communications channel will set the distance protection to stand-alone mode. When a distance relay underreaches in this situation, faults on a considerable portion of the line may not be detected if, for example, Zone 2 is not set properly, or the faults may be cleared with time delay.

Series-connected FACTS devices, using self-commutated static converters as controlled voltage sources, can also cause adverse effects on distance protection if they are part of the fault loop; however, their impact is less severe than midline shunt-connected FACTS devices [16], [17]. On the other hand, lines with TCSC can have a significant impact on power system protection [18]. TCSC dynamic transitions from one mode to another can create serious problems for conventional distance relays like forward overreach, reverse overreach, and miscoordination of primary and backup protection.

The issues brought out so far are all related to particular studied systems. The rating of FACTS devices and system configuration can vary widely. Though the general issues discussed above are still valid, their degree of severity may be higher or lower in a different system. It is imperative, therefore, that a thorough study be conducted whenever a new FACTS device is being installed. The study will provide information on the suitability of distance relaying and, if suitable, the type of scheme to be employed and the required distance relay settings.

2.4.5 Distance Protection of Isolated and Compensated Systems

Isolated and compensated networks are utilized only in subtransmission systems. The distance protection applied in these networks has to consider the effects of the star-point grounding for all ground faults.

A single-phase-to-ground fault does not cause a fault current. Only a small capacitive or compensated current is flowing. The voltage of the involved phase becomes zero in the entire galvanically connected network. The distance element must be set to not operate for this situation, otherwise it would misoperate on the impedance calculation performed with load current. The overcurrent pickup setting for the ground element must be high enough as to not pick up because of the capacitive current. This is a challenge especially in large networks because the capacitive current is proportional to the size of the network. The transient fault current caused by fault initiation can be multiples of the steady-state ground current. This transient oscillation will disappear after approximately two cycles. A special logic is required in the distance relay pickup logic to prevent an operation by this transient current.

The advantage of the isolated and compensated networks is that the probability that an arc fault will self extinguish, because of the small fault current, is very high. However, no load has to be disconnected if the fault does not self extinguish. The operator can search for the fault location and remove only the faulted feeder. The location of the fault may require a considerable length of time during which the voltage on the unfaulted phases has a higher amplitude equal to the phase-to-phase network voltage. This overvoltage stresses the insulation and eventually could develop into a second ground fault at a different network location, as shown in Figure 2.61. The fault current is a function of the distance between the two fault locations. The closer the fault locations are together, the higher the fault current will be and will appear to the distance protection as a typical two-phase-to-ground fault. As the distance between the two faults increases, the fault current decreases.

In isolated and compensated networks, only one fault has to be removed for a two-phase-to-ground fault to interrupt the fault current. For this reason, all distance relays in the galvanically connected network have a feature called double-ground (or cross-country) fault phase preference. Then, in all the relays that are located between the two faults, only the leading or the lagging phase-to-ground impedance loop is calculated depending on the used preference. This results in clearing only one of the ground faults.

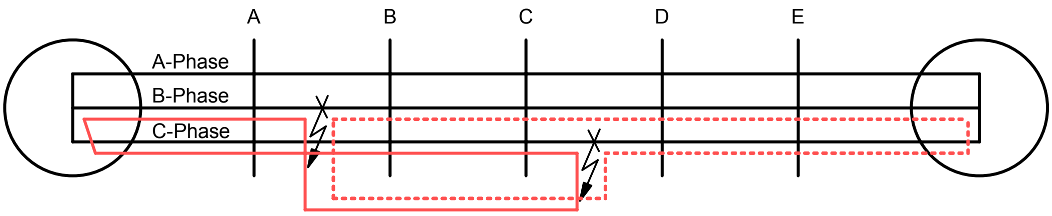


Figure 2.61 Two ground faults in an isolated network

In Figure 2.61, the relays on Buses B and C see a two-phase-to-ground fault in BC to ground. If the selection is to process the leading phase, both relays would calculate the B-ground loop and Relay B would operate. All other relays outside of this double-ground fault only see a phase-to-phase fault and trip accordingly. The calculated impedance tends to underreach, and a time-delayed tripping must be accepted. Relay A will clear the fault after a certain time delay.

2.4.6 Cable Protection Considerations

Underground cables must be protected against excessive overheating caused by fault currents flowing in the cable conductor. High fault currents lasting for a long time generate excessive heating because of I^2R losses. Excessive heating could damage the cable insulation and the cable itself, requiring lengthy and costly repairs. Faults in pipe-type cables may burn partially into the steel pipe even if high-speed relaying systems are applied. If the fault is not cleared quickly enough, the arc resulting from an internal pipe-type cable fault tends to burn through the steel pipe. In addition, the radially directed forces on the pipe during prolonged faults can cause weld seam ruptures. These ruptures could have additional environmental implications, because thousands of gallons of insulating oil fluid could leak into the ground. Such a situation could also require longer repair times, especially if water enters the steel pipe. Most faults in a cable circuit are permanent, regardless of relay operating speed. Therefore, reclosing is prohibited because it will only cause additional damage.

For these reasons, cable protection must be high-speed and typically requires some form of a communications channel between the two ends of the cable circuit. Because most cable faults involve ground initially, ground-fault sensitivity is of utmost importance. The protection principles applied to underground cables are similar to the ones applied in EHV overhead transmission circuits. However, the differences in the electrical characteristics of underground cables and their method of grounding present challenges to protective relaying, especially to ground distance relay elements. Applications of ground distance relays on underground cables can be very challenging, because the effective zero-sequence impedance of the cable depends on the return paths of the fault current. These paths vary over a wide range, depending on fault location, bonding and grounding methods of the sheath or shields, the resistivity of the cable trench backfilling, and the presence of parallel cable circuits, gas pipes, and water pipes.

2.4.6.1 Electrical Characteristics of Cables

Underground cables have quite different electrical characteristics from overhead transmission lines. Underground ac transmission cables have sheaths or shields that are grounded in one or in several locations along the cable length. The ground fault current can return through the sheath or the ground alone, through the sheath and the ground in parallel, or through the ground and the sheath of adjacent cables. Cable design features (e.g., the solid dielectric insulation, the sheath, and in some cases, the armor) and the close spacing of the phase conductors cause these differences. The result is very high charging current and low series inductances. Table 2.6 lists the series sequence impedances in Ω/km and the charging current in A/km for two 230 kV cables and an overhead transmission line [10].

Table 2.6 Typical series impedance and charging currents

Circuit Type	Z_1 and Z_2 in Ω/km	Z_0 in Ω/km	Charging Current in A/km
230 kV SC cable	0.039 + j 0.127	0.172 + j 0.084	9.37
230 kV HPOF pipe-type cable	0.034 + j 0.152	0.449 + j 0.398 at 5000 A	18.00
230 kV OH line	0.060 + j 0.472	0.230 + j 1.590	0.47

The series inductance of cable circuits is typically 30–50 percent lower than overhead lines because of close spacing of cable conductors. The difference in the cable shunt capacitance is even more pronounced and can be 30–40 times higher than that of overhead lines. The closer proximity of the cable conductor to ground potential, surrounded by the cable grounded sheath, and the dielectric constant of the insulation, which is several times that of air, cause this difference.

The zero-sequence impedance of the cable depends on many parameters and is often difficult to determine precisely. The presence of water pipes, gas pipes, railways, and other parallel cables makes the zero-sequence current return path rather complex. All of the above factors make the zero-sequence impedance calculations difficult and, in many cases, questionable, even with the use of modern-day computers. Therefore, many utilities perform field tests during cable commissioning to measure the zero-sequence impedance value of single-conductor cables.

Pipe-type cables are the most common type of transmission cables installed in the United States. Unfortunately, the impedance calculation methods for pipe-type cables are the least refined. The nonlinear permeability and losses in the steel pipe make it very difficult to calculate the flux linkage within the wall of the pipe and external to the pipe. Electromagnetic effects in the steel pipe make determining zero-sequence impedance for pipe-type cables more complex than for single-conductor cables. This compounds the normal issues of ground-current return paths mentioned previously. Another problem with calculating the zero-sequence impedance of pipe-type cables is that the zero-sequence impedance varies with the effective permeability of the steel pipe, and the permeability of the steel pipe varies with the magnitude of the zero-sequence current. Under unbalanced fault conditions, a pipe made of magnetic material, such as steel, can be driven into saturation. Since the pipe forms part of the return path for ground currents, changes in its effective resistance and reactance alter the cable zero-sequence impedance.

Figure 2.62 illustrates the variation of the zero-sequence impedance with ground fault current for a 230 kV, 3500 kcmil HPOF pipe-type cable in a 10.75-inch pipe. The variation of the zero-sequence impedance shown in Figure 2.62 is for currents greater than 5 kiloamperes and is applicable for fault current calculations.

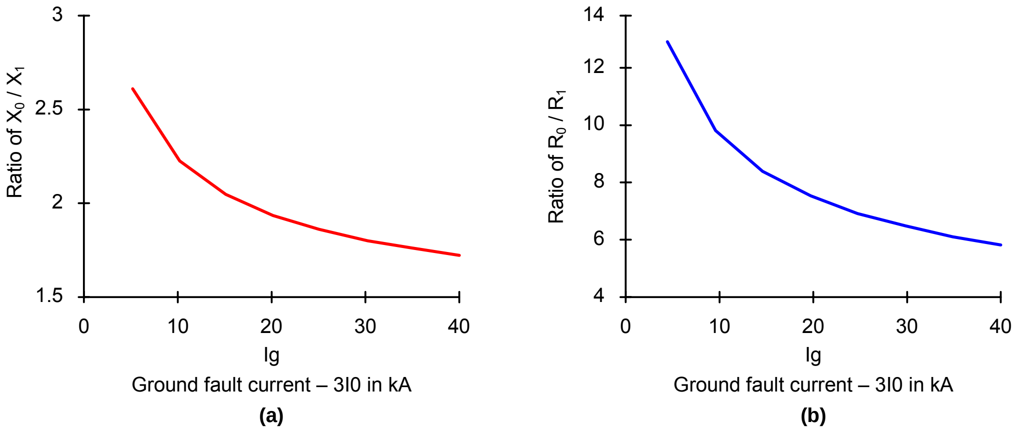


Figure 2.62 Variation of zero-sequence resistance and reactance in a 230 kV pipe-type cable as a function of ground-fault current

The nonlinearity of the zero-sequence impedance for currents below 5 kiloamperes is more pronounced. Reference [21] provides more detailed data about the variation of zero-sequence impedance of pipe-type cables for ground currents below 5 kiloamperes. Short-circuit programs cannot handle nonlinearities such as the variation that steel pipe saturation causes in zero-sequence impedance of pipe-type cables. For that reason, short-circuit studies near pipe-type cables will probably require an iterative process for better accuracy. Using a linear short-circuit model and a few discrete zero-sequence impedance data for different levels of pipe saturation, e.g., low currents (unsaturated), medium currents, and high currents (saturated), with a couple of iterations is adequate.

2.4.6.2 Distance Relay Application Considerations

Frequently, protection engineers use phase distance and ground distance elements in directional comparison schemes for cable protection. They also use distance elements for Zone 1 instantaneous tripping and for backup cable protection using Zone 2 and higher zone time-delayed tripping. Distance relay element application for cable protection requires a good knowledge of cable electrical parameters and a good understanding of the relay technology and any potential limitations.

The cable series impedance of underground cables differs considerably from that of overhead lines. In general, the power cable impedance is less than the overhead line impedance because the phase conductor spacing in cables is less than the spacing in overhead lines. In some cases, the impedance may be less than the minimum distance relay setting value. The cable zero-sequence impedance angle is less than the zero-sequence impedance angle for overhead lines. The zero-sequence angle compensation requires a large setting range that accommodates all possible cable angles.

The current return path for an underground cable depends upon many factors: sheath bonding methods, sheath grounding, and any conducting path in parallel with the cable. All of these factors affect the underground cable sequence impedances, especially the zero-sequence impedance of the cable. Therefore, the computed zero-sequence impedance value is questionable. In pipe-type cables, the zero-sequence impedance varies as a function of the ground-fault current level. Most faults in underground single-conductor cables involve ground. It is therefore important to concentrate on the impedances seen by ground distance relays for faults in the underground cable and faults external to the cable zone of protection. Equation (2.30) gives the compensated ground loop impedance.

$$Z_c = \frac{V_a}{I_a + k_0 \bullet I_r} \tag{2.30}$$

Where:

V_a = line-to-neutral voltage

I_r = residual current ($I_r = I_a + I_b + I_c$)

k_0 = zero-sequence current compensation factor

Choosing the correct zero-sequence current compensation factor, k_0, produces the correct distance measurement in terms of positive-sequence impedance. Equation (2.31) gives the proper zero-sequence current compensation factor for overhead transmission lines.

$$k_0 = \frac{Z_{0L} - Z_{1L}}{3 \bullet Z_{1L}} \tag{2.31}$$

Where:

Z_{0L} = zero-sequence impedance of the line

Z_{1L} = positive-sequence impedance of the line

Note that in overhead transmission lines, Z_{1L} and Z_{0L} are proportional to the distance. However, this is not true for underground cables where the zero-sequence impedance may be nonlinear with respect to distance [22]. The zero-sequence compensation factor, k_0, for solid-bonded and cross-bonded cables is not constant for internal cable faults, and it depends on the location of the fault along the cable circuit. Because ground distance relays use a single value of k_0, the compensated loop impedance displays a nonlinear behavior. Annex 3 provides an example on how to calculate the zero-sequence current compensation factor for an underground cable.

Single-Point Bonded Cable Sheath

Let us look at the compensated loop impedance for different types of cable grounding arrangements. We will look at a cable with the sheaths grounded at one end only, with a ground continuity conductor installed along the cable run and grounded at both ends of the cable. Figure 2.63 shows the system used to calculate the compensated loop impedances at the two ends of the cable.

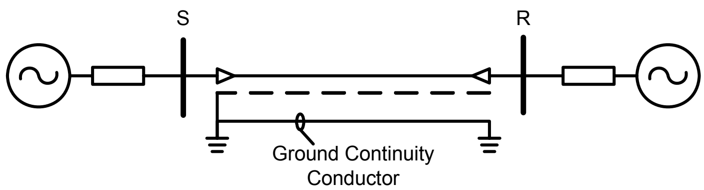


Figure 2.63 Single-point bonded cable at Terminal S

The cable in this example is a 1000-meter, 230 kV, single-conductor 1200 mm^2 copper cable. The positive-sequence impedance of the cable is $Z_{1c} = 0.018 + j\ 0.135\ \Omega$, and the zero-sequence impedance is $Z_{0c} = 0.131 + j\ 0.551\ \Omega$. Figure 2.64 and Figure 2.65 show the compensated loop impedances seen by the ground distance relays at the two ends of the cable. The zero-sequence current compensation factor calculated using (2.31) is $k_0 = 1.048 - j\ 0.139\ \Omega$. There is a major difference in the impedance seen by the relay at Terminal S for a core-to-sheath fault and a core-to-ground fault at Terminal R. For a core-to-sheath fault at Terminal R, the impedance seen from Terminal S is $0.138 + j\ 0.043\ \Omega$, but for a core-to-ground fault, the impedance is $0.018 + j\ 0.135\ \Omega$. For a core-to-sheath fault at Terminal R with a zero-sequence compensation factor of 0.79, the compensated impedance seen from Terminal S is 0.155 + j 0.036 Ω.

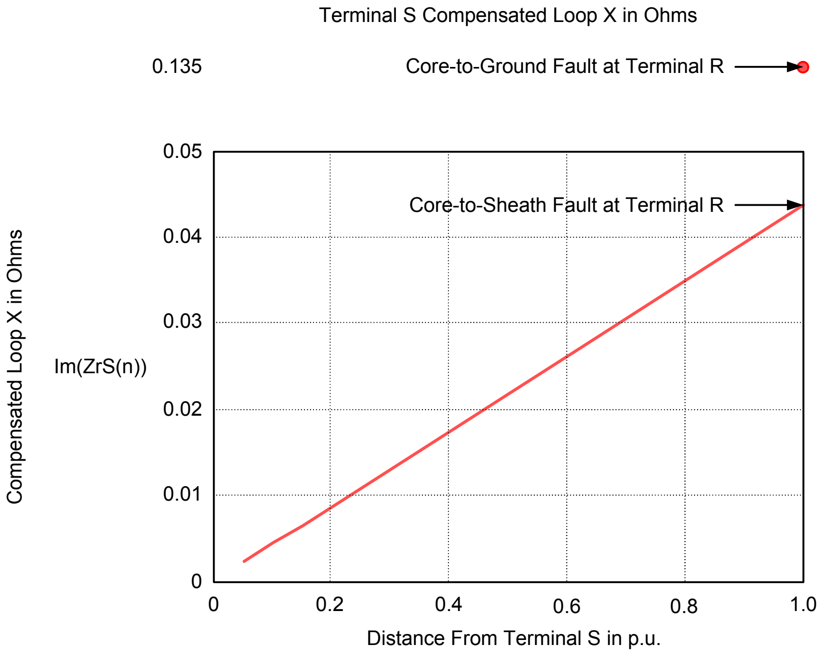


Figure 2.64 Terminal S compensated loop reactance in ohms for a single-phase-to-sheath fault on a single-point bonded cable

Note the following:

- The compensated impedance depends on the source impedance.
- The imaginary component of the measured impedance is very low compared to the positive-sequence impedance of the cable, even if the length of the cable is increased by ten times (10 km).
- The imaginary part of the loci of the measured impedance for faults along the cable remains well below the imaginary part of the impedance measured for a core-to-ground fault at the opposite cable end (Terminal R).

Note also that the compensated loop impedance for a cable, with sheaths grounded at Terminal S only, has a linear characteristic similar to an overhead line. This linear characteristic is not like the compensated loop impedances of cables whose sheaths are cross-bonded or solidly bonded and grounded at both ends of the cable. Note also that the compensated loop impedances are not the same at the two ends of the cable because of sheath-grounding asymmetry.

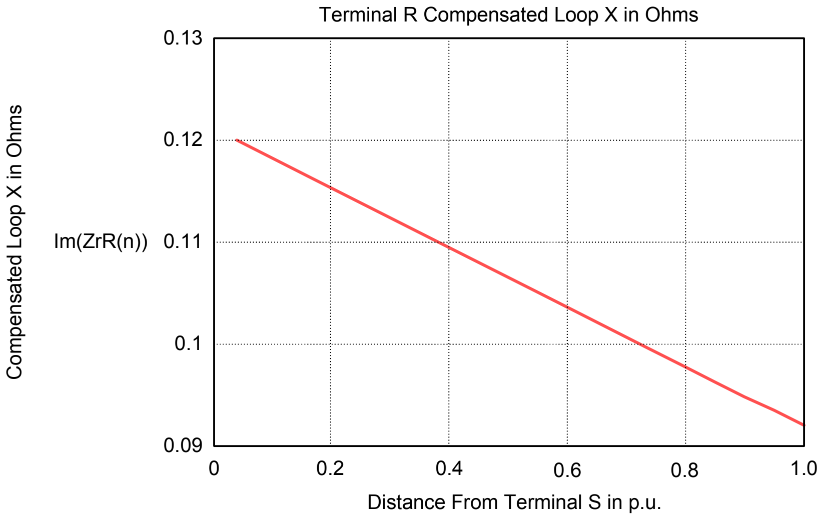


Figure 2.65 Terminal R compensated loop reactance in ohms for a single-phase-to-sheath fault on a single-point bonded cable

Figure 2.66 shows variation of the compensated loop impedance caused by a change in the zero-sequence source impedance.

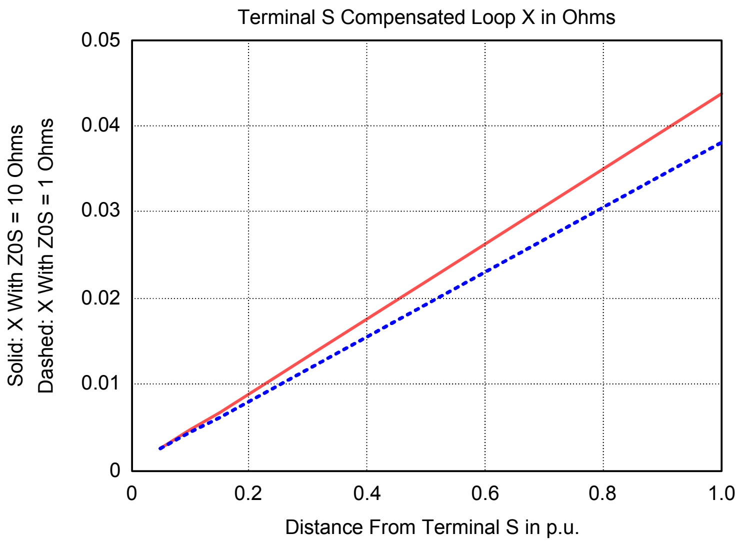


Figure 2.66 Variation of the compensated loop reactance at Terminal S caused by a change of the zero-sequence source impedance magnitude

For a core-to-sheath ground fault right in front of Terminal R, the compensated loop impedance at Terminal R is not zero and takes on a large value, 0.189 + j 0.092 Ω.

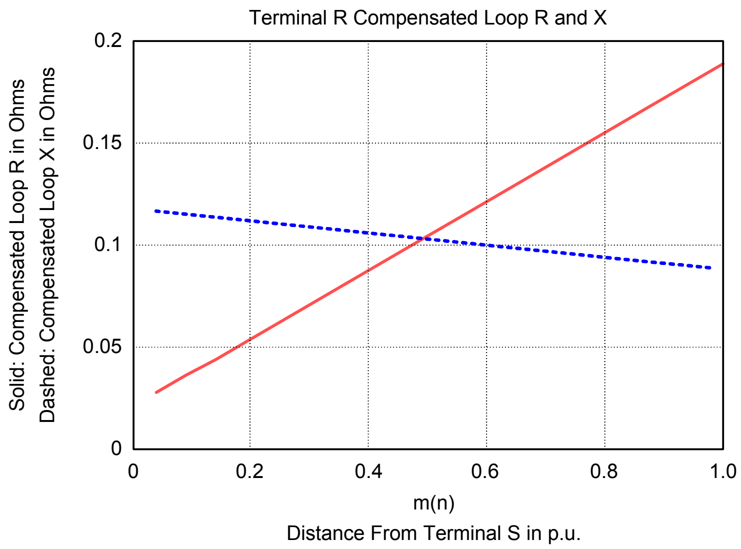


Figure 2.67 Terminal R compensated loop X and R in ohms for a single-phase-to-sheath fault on a single-point bonded cable

In addition, the compensated loop resistance at Terminal R decreases as the fault is moved away from Terminal R, as shown in Figure 2.67. Note that a fault at Terminal R is represented at one p.u. throughout this section. In other words, fault distance is increasing as the fault moves from Terminal S toward Terminal R.

The compensated reactance measured at Terminal S for a fault at the end of the cable involving sheath return current is only 30 percent of the reactance measured for an external fault at Terminal R. From this analysis, we can conclude that a Zone 1 ground distance relay setting at Terminal S, the terminal where the sheaths are grounded, can be very selective and cover the whole length of the cable. However, relay settings at this terminal for overreaching backup zones must be carefully chosen. In contrast, we cannot successfully apply a Zone 1 ground distance relay at Terminal R. The relay at Terminal R sees a compensated loop impedance discontinuity between a core-to-sheath and a core-to-ground fault at Terminal R but does not see any impedance discontinuity between a core-to-sheath and a core-to-ground fault at the remote terminal.

Solid-Bonded Cable Sheaths (Grounded at Both Ends of the Cable)

Next, we look at the compensated loop impedances for the same cable but with the sheaths grounded at both ends of the cable, as shown in Figure 2.68. Note that a ground continuity conductor is present and grounded at both ends of the cable run. Since the sheaths are grounded at both ends of the cable, the compensated loop impedance varies continuously without any discontinuities present between internal and external cable faults.

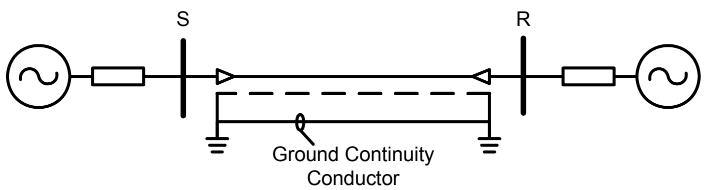


Figure 2.68 Solid-bonded cable with sheaths grounded at both ends of the cable

There are two ground fault current return paths for faults that involve the cable core with its own sheath. The first path is directly in the faulted cable sheath. The second path is the faulted cable sheath, the sheaths of the other two cables, the ground, and the ground continuity conductor via the grounding of the sheaths at the cable ends, as shown in Figure 2.69.

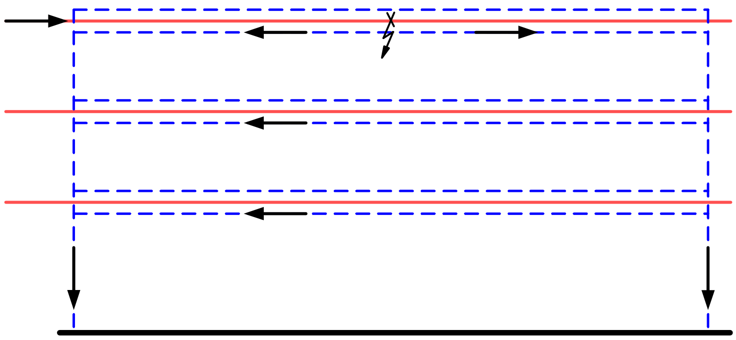


Figure 2.69 Paths for ground current return for a core-to-sheath fault in single-conductor solid-bonded cables

The amount of fault current flowing in each of the return paths varies continuously depending on the resistance of each path as the location of the fault changes along the cable circuit. The continuous variation of the ground current return path causes a nonlinear relation between the fault point and the compensated loop impedance. Figure 2.70 shows the compensated loop impedance nonlinear behavior for ground faults along the cable.

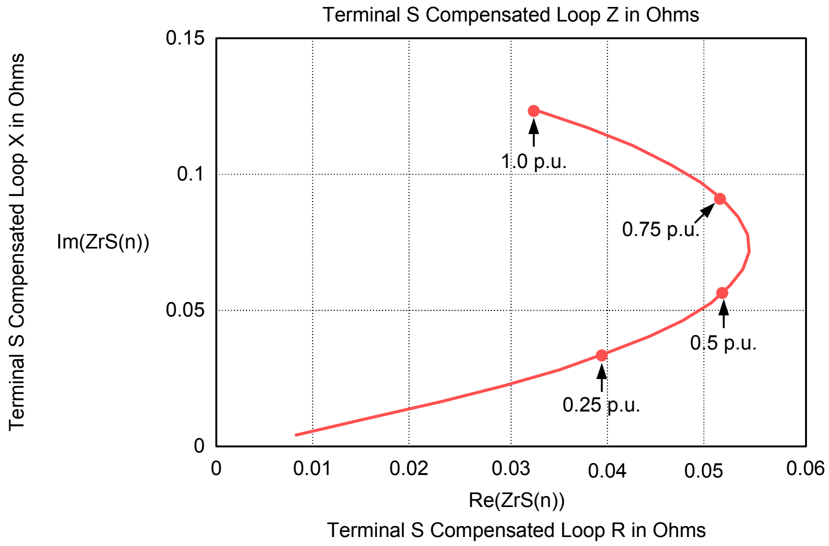


Figure 2.70 Nonlinear behavior of compensated loop impedance in solid-bonded cables

Note the following:

- The measured impedance for a fault at the end of the cable is the positive-sequence impedance of the cable, using the cable's complex compensation factor.
- The measured impedance loci at Terminal R and Terminal S are not the same because of nonidentical source impedances at Terminal R and Terminal S.
- A nonlinear relationship exists between the measured reactance and the fault location.

Figure 2.71 shows the compensated loop reactance obtained with two different compensation factors. The solid line is for a zero-sequence current compensation factor, $k_0 = 0.79$, that is used on a typical 230 kV overhead transmission line. The dashed line is for the actual complex zero-sequence current compensation factor, $k_0 = 0.052 - j\,0.287$, calculated for an external fault for the cable in Figure 2.68.

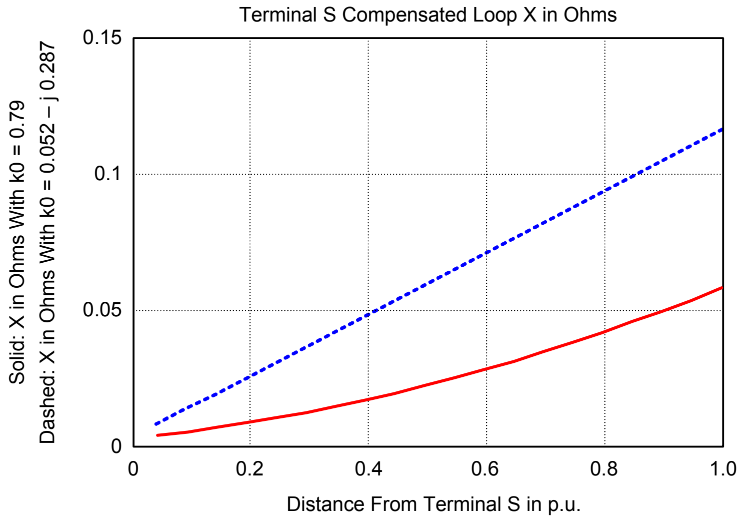


Figure 2.71 Compensated loop reactance for different values of zero-sequence current compensation factors

Note that the slopes of the two curves are different, depending on the zero-sequence current compensation factor one chooses. The variation of the slope depends on the particular cable and system studied and cannot be generalized for all single-conductor solid-bonded cables. A steeper slope of the compensated reactance for faults at the remote end of the cable would offer some advantage in setting a Zone 1 ground distance relay, in spite of the small impedance characteristics of single-conductor cables.

Figure 2.72 shows the nonlinear behavior of the compensated loop resistance at Terminal S as a function of fault distance in p.u. along the cable.

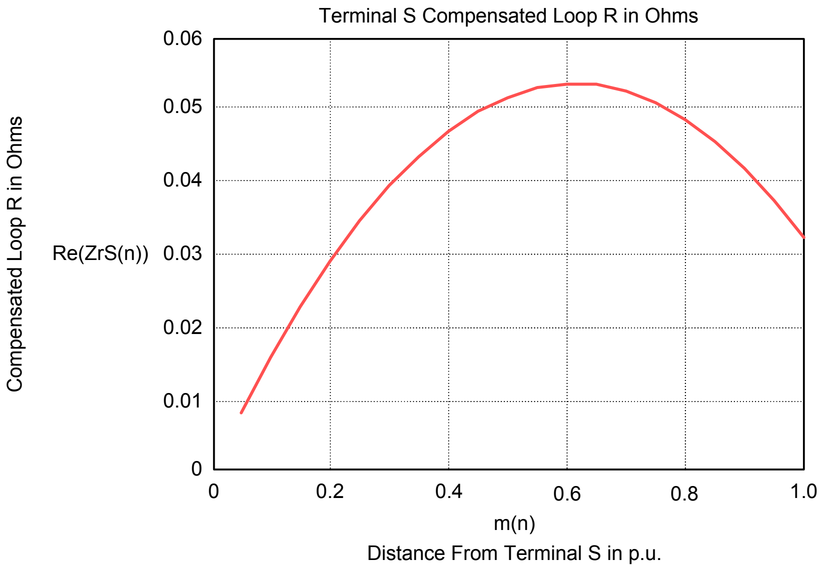


Figure 2.72 Compensated loop resistance at Terminal S

Note that in solid-bonded and cross-bonded cables, the compensated loop resistance is not maximum for a fault at the remote end.

Cross-Bonded Cable Sheaths

Cross-bonded sheaths are used more often in longer cable runs where the induced voltage in the sheaths is unacceptable. Longer cable circuits can consist of more than one major section. The voltage induced on the cable sheaths after three minor sections (i.e., one major section) during load is close to zero. The ground return path in cross-bonded cables changes depending on the fault point in the cable circuit. In addition, moving the fault from the end of a minor section to the beginning of the next minor section causes a different return path for the ground fault current and, consequently, causes a discontinuity in the compensated loop impedance. This discontinuity, shown in Figure 2.73, offers some advantage in obtaining selectivity for a Zone 1 setting distance element for faults in the last minor section.

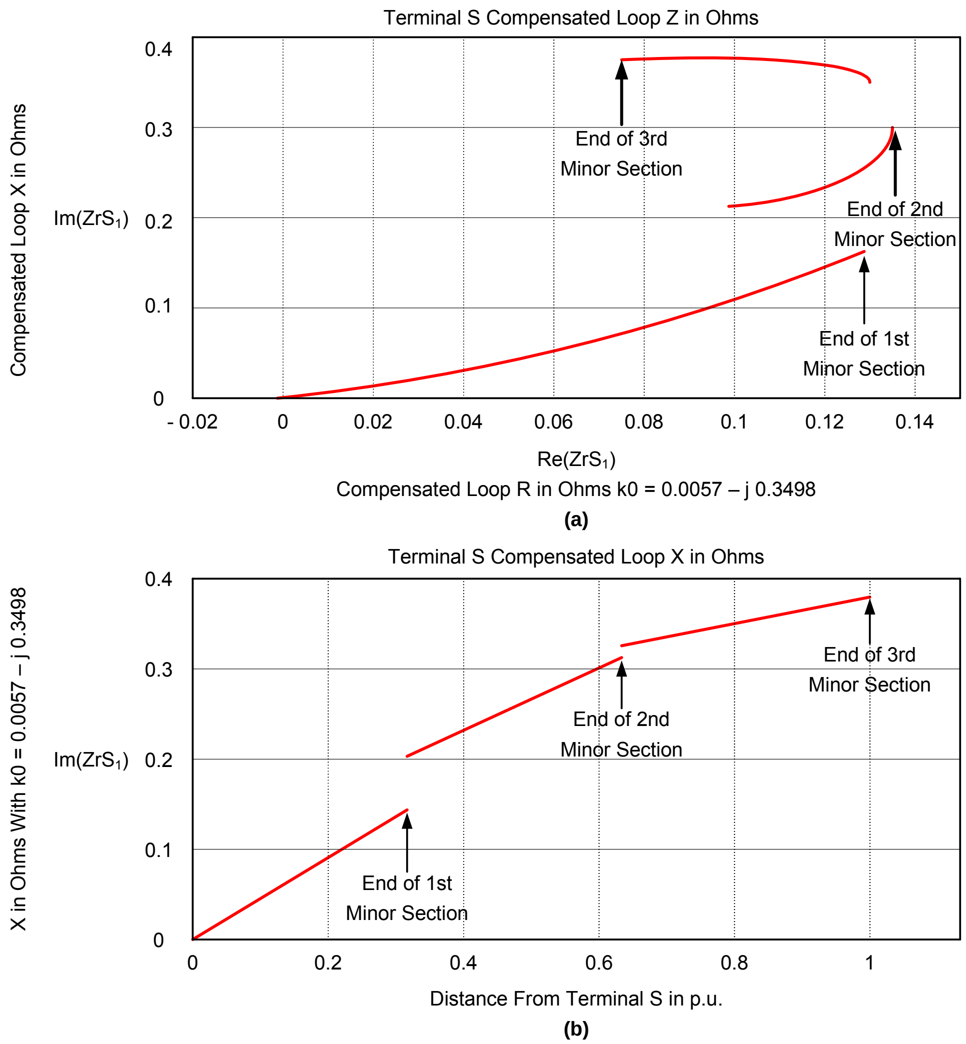


Figure 2.73 Compensated loop impedance (a) and reactance (b) for cross-bonded cables

Note that the discontinuity is more pronounced when the fault is moved from the first to the second minor section. The cable modeled to generate the data for Figure 2.73 consists of three minor sections (i.e., only one major section). However, for longer cable circuits with two or more major sections, the discontinuity tends to be less pronounced as the fault moves to the last minor section.

Note the following:

- The measured impedance loci at Terminal R and Terminal S are not the same because of nonidentical source impedances at Terminal R and Terminal S.
- A nonlinear relationship exists between the measured reactance and the fault location.
- A nonlinear relation exists between the measured resistance and the fault location.

2.4.6.3 Distance Protection Setting Considerations

The basic philosophy in setting under- and overreaching distance relays for underground cable protection is the same as that for setting them for overhead transmission lines. The Zone 1 element should not overreach for faults at the remote terminal, and the overreaching zones should provide protection for the whole cable circuit.

Ground distance elements should measure fault impedance in terms of positive-sequence impedance only. Set the zero-sequence current compensation factor so that the Zone 1 ground distance elements do not see faults external to the protected cable, while the Zone 2 and Zone 3 forward ground distance elements must see all cable internal faults and coordinate with distance relays on adjacent line or cable circuits.

The choice of zero-sequence current compensation factor can influence the reach and the performance of ground distance relays. The zero-sequence current compensation factor has to be chosen such that the compensated loop impedance corresponds to the positive-sequence impedance measured for external faults. This can be achieved by either setting the correct complex zero-sequence current compensation factor or by setting a real zero-sequence current compensation factor calculated to compensate correctly for faults at the opposite cable terminal. If there are downstream overhead lines, the zero-sequence current compensation factor of Zone 2 should be set to that of the overhead lines. In general, choose a zero-sequence current compensation factor that obtains a constant or increasing slope of the compensated loop reactance for faults at the end of the cable. Do this by choosing a complex zero-sequence current compensation factor corresponding to the cable under consideration or by selecting a fictitious scalar ground zero-sequence current compensation factor that would compensate correctly for faults at the end of the cable. Annex 3 of this report shows how to calculate the zero-sequence current compensation factor for a homogeneous cable and for an external fault.

The measured compensated loop resistance does not have its maximum value for faults at the end of the cable in solid-bonded and cross-bonded cables depending on the zero-sequence ground compensation factor. The resistive reach, which determines the R/X ratio of the setting characteristic, often presents a problem in underground cable protection. Because the cable has a low characteristic angle, the R/X ratio is critical and often leads to pilot schemes because the minimum requirements cannot be met. In most cases, distance relays must be applied in an overreaching pilot protection scheme to properly protect underground cables.

Network topology plays an important role in selecting settings for underground cable applications. In some applications, parallel cables are installed between two substations. In others, there are mixed overhead and underground sections, and adjacent line sections may consist of either cables or overhead lines.

For example, in the case of parallel cables, select the proper zero-sequence current compensation factor for Zone 1 by placing a phase-to-ground fault at the remote terminal with the parallel cable out of service. Find the ground distance reactance measurement that does not overreach for that fault using the two zero-sequence current compensation factors that correspond to two different return paths, sheath return only and sheath and ground return. Use all three different cable zero-sequence impedances in the fault study. Select the zero-sequence compensation factor that does not provide any overreach for sheath return alone or for sheath and ground return path.

For the overreaching zones, select the zero-sequence compensation factor so that the ground distance overreaching zones do not underreach for any internal ground faults. Select the zero-sequence current compensation factor that corresponds to the zero-sequence impedance of the cable with ground return only. Place both parallel cables in service, simulate a line-to-ground fault at the remote terminal, and calculate the distance reactance measurement for each of the three possible zero-sequence cable impedances.

Modern digital ground distance relay elements offer the user more options in achieving a better performance of ground distance element measurement than do older electromechanical and static counterparts. They offer more than one complex zero-sequence current compensation factor with a wide range of magnitude and angle settings, as well as a choice of the ground distance relay polarizing quantity, such as either zero-sequence or negative-sequence current. In general, negative-sequence current polarizing is the preferred choice for cable applications because the negative-sequence network is more homogeneous than the zero-sequence network. In addition, modern digital relays offer a nonhomogeneous correction angle setting to help prevent overreach or underreach for ground faults at a specific fault point by compensating the angle of the reactance line. Although most of the discussion above was on the ground distance element, large capacitive charging currents could also affect phase distance elements. The large charging currents could result in an overreaching effect of a Zone 1 phase distance relay.

Protecting underground cables with distance relays can be quite challenging and difficult to achieve because of cable electrical characteristics, the influence of grounding methods and return currents in the zero-sequence impedance of the cable, the nonlinear behavior of the compensated loop impedance, and the short cable length in many applications. For all these reasons and the complexities involved in making the proper settings, most users prefer to protect HV underground cables using line current differential protection systems or phase comparison relaying systems. Distance relays are typically applied in a directional comparison blocking or unblocking scheme and for backup protection.

Modern digital relays have a complete line differential relaying scheme with full distance-protection elements that include communications-assisted protection logic, negative-sequence directional elements, zero-sequence directional elements, and a plethora of other overcurrent elements integrated into one device. With modern digital relays, the user now has a choice of many different relay elements for the protection of underground cables, some of which may be better suited than others. Supplementing ground distance elements with negative-sequence directional elements in a communications-assisted tripping scheme provides an excellent resistive coverage for high-resistance ground faults, e.g., during a flashover of a contaminated pothead. Use of negative-sequence directional elements has also been successful in a directional comparison scheme for the protection of submarine cables [23].

2.4.7 Single-Pole Tripping Considerations

Increasing electricity supply demands from society and industry, together with network capacity optimization and power system growth limitations, challenge power system reliability. Because of these system demands, the power system is operated closer to its stability limits. In recent years, increasing construction and operating costs have imposed economic restrictions on many electric power companies, forcing them to intensify their search for capital investment and operating expense reductions. Faced with continuing demand for more and more power in an environmentalist era, many operating companies are seeking, among other things, a means for supplying reliable power with fewer transmission lines and, hence, reduced capital investment. Series capacitor compensation and single-pole tripping on transmission lines with and without series compensation have increased power transfer capability, power system stability, and overall reliability of power system networks.

A relay protection system that provides single-pole tripping and reclosing is a system that, after it detects a fault in a transmission line, will trip only the faulted phase on single-line-to-ground faults and all three phases on all multiphase faults. In single-phase tripping schemes, automatic reclosing is always employed to reclose the open phase in the event of a single-pole trip. In general, single-pole tripping schemes operate as follows:

- When a single-phase-to-ground fault occurs on a transmission line, the faulted phase is tripped and automatically reclosed after a suitable dead time. If the fault is cleared and of transient nature, everything resets. If the fault is still on the line when the pole is reclosed, all three poles are tripped and no further reclosing takes place.
- When a multiphase fault occurs on a transmission line, all three poles are tripped. At this point, depending on how the relay system is set, the line breakers could be locked out or, after a suitable dead time, reclosed into the line. In the latter case, if the fault is gone, everything resets. If the fault is still present, all three poles trip and no further reclosing takes place.

A single-pole tripping scheme must make two basic determinations:

(a) Whether or not the fault is in the protection trip zone

(b) Which phase or phases are faulted

In the case of (a), a single-pole tripping scheme needs to determine whether it is a multiphase fault or a single-phase fault, and in the event of a single-phase-to-ground fault, it must establish which phase is faulted.

A single-pole tripping scheme may utilize the same measuring functions to perform both (a) and (b) functions above, or it may utilize one set of functions to establish (a) and a separate set to determine (b). Regardless of how the relay system is designed, it must be able to distinguish between multiphase faults and single-phase-to-ground faults and, in the latter case, needs to ascertain which phase is faulted and produce the associated tripping outputs. The logic is such that for any fault other than a single-phase-to-ground fault the relay system would produce a three-phase output. For a single-phase-to-ground fault, it would produce a single-phase tripping output associated with the faulted phase.

There are a number of application considerations and significant details in the proper design of single-phase tripping schemes. Some of these are discussed below.

2.4.7.1 Line-Side vs. Bus-Side Potentials

Because single-pole tripping schemes must perform properly and detect faults that occur or evolve during the time that one or more poles are open, the location of the relay voltage supply is very important. When the voltage transducers are located on the bus side of the circuit breaker, the three-phase voltages tend to stay relatively well balanced when one phase is open. However, if the voltage transducers are located on the line side of the breaker, the voltage present on the "open" phase can have a major influence on the distance protection measurement. When one phase of a transmission line is open at both ends while the other two phases are energized, the "open" phase voltage does not go to zero. The voltage on this open phase has some magnitude and angle that depends on the following:

- Whether a secondary arc still exists on the open phase
- Whether line shunt reactors are present
- Load flow in the two healthy phases
- Line electrical characteristics and whether the line is transposed, and if the line is not transposed, which phase is open

Therefore, single-phase tripping relaying systems that utilize distance protection functions must be designed to mitigate the effects of any possible misoperation during the time that one pole is open. This requirement tends to make distance relaying scheme logic utilizing line-side voltages somewhat more complex than those that employ bus-side potentials.

2.4.7.2 Open-Pole Operation

When a transmission line pole is open, an asymmetrical condition exists on the system that results in negative- and zero-sequence current flow throughout the system, which in turn produces negative- and zero-sequence voltages throughout the system. Negative- and zero-sequence directional relays located at the terminals of a transmission line operating with one open phase will receive voltages and currents that indicate to the relays at both terminals the impression that an internal fault exists. If sufficient current is flowing, such devices could produce continuous trip outputs during the time that one pole is open. To similar relays located at both ends of a parallel line, the condition resembles an external fault. Other similar relays located elsewhere on the system may see the condition as either an internal or an external fault. In any case, schemes that employ zero- or negative-sequence relays must be designed with these points in mind because the continuous output of a tripping relay can activate the circuit breaker backup protection during the time that one pole is open and can result in a retrip when the open pole is reclosed.

Another major concern during pole-open conditions is proper estimation of distance measurements because of frequency excursions. Power systems are prone to instability during pole-open conditions.

The frequency changes when one phase is open because of the sudden increase in the impedance between the two line terminals, particularly in weak source systems. The distance relay needs to track this frequency in order to minimize distance element overreach. Figure 2.74 shows a 600 MVA generator connected to a 275 kV network through two transmission lines. As illustrated in Figure 2.75, the frequency changes when Line 2 opens one phase to clear a phase-to-ground fault while Line 1 is open. The frequency varies from 60.2–59.8 Hz during the pole-open condition.

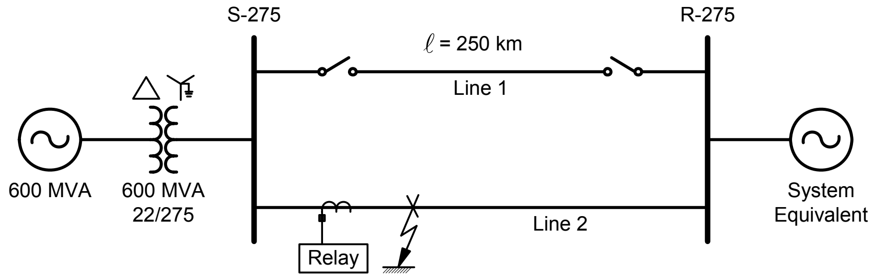


Figure 2.74 275 kV network with 600 MVA generator

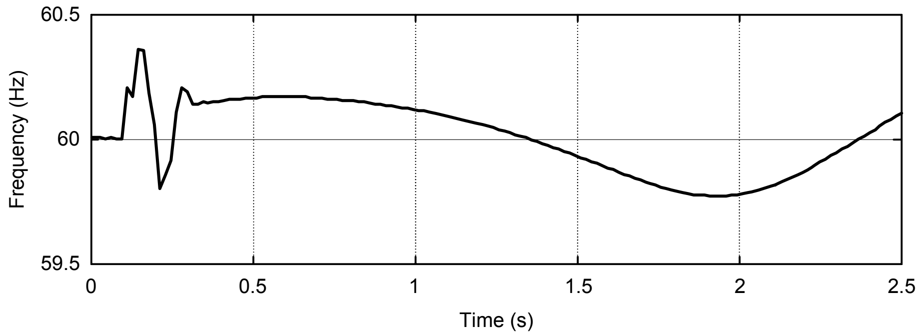


Figure 2.75 Frequency at the terminal close to the 600 MVA generator

If the relay in Figure 2.74 does not track the system frequency, the apparent impedance begins to appear as a fault condition, as shown in Figure 2.76. The relay must use voltage information from the unfaulted phases to track the system frequency and minimize distance element overreach.

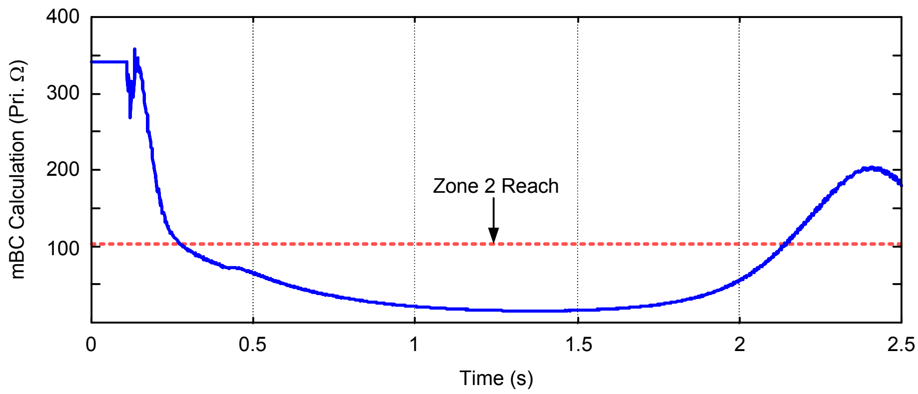


Figure 2.76 Distance element apparent impedance during pole-open conditions

Eventual corruption of the polarizing quantity can occur during pole-open conditions in applications with line-side potentials if the input voltage to the memory circuit is corrupted. Invalid memory polarization may cause distance element misoperation.

Shunt-reactor switching generates damped oscillations with signals that have different frequencies than the actual system frequency. Shunt reactors located on the line side of the circuit breakers compensate the line charging currents and reduce overvoltages in long transmission lines. After the circuit breakers open at both line ends, the remaining circuit is basically an RLC circuit with stored energy in the reactor and line capacitance. The shunt reactors interact with the line capacitance and maintain ringing line voltages for several cycles. These ringing voltages corrupt the distance protection polarization and frequency estimation. Figure 2.77 shows the A-phase voltage at the relay location after de-energization of the line.

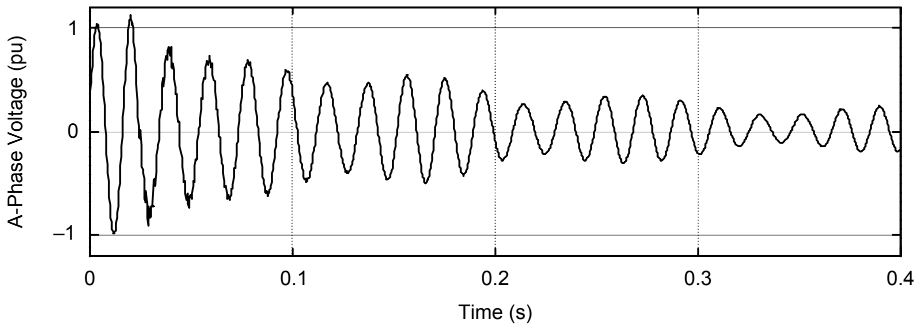


Figure 2.77 A-phase line voltage after line de-energization

The most popular polarizing quantity for distance protection is positive-sequence voltage with memory. The frequency of the voltage signal oscillates between 44.6 and 54.4 Hz after line de-energization. These corrupted voltages must be removed from the frequency estimation logic to prevent distance estimation errors. Modern distance relays detect the ringing condition and eliminate the corrupted voltage from the memory filter input to prevent distance element misoperation.

2.4.7.3 High Fault Resistance

In general, it is important to recognize that ground distance relays have high fault resistance detection limitations. Such relay systems tend to have difficulties with single-phase-to-ground faults initiated by trees or brush fires. However, because most single-pole tripping schemes are used on long or medium length lines, this problem is somewhat mitigated by the large reach settings that are required to protect them. Where such conditions can exist or where line construction is such that no ground or shield wires exist and high tower footing resistance to ground is prevalent, careful consideration must be given when ground distance relays are applied. The application of zero-sequence directional ground elements in modern multifunction distance relay systems should be considered in order to supplement ground distance elements and assure clearance of high resistance ground faults. High ground fault resistance, in combination with heavy load transfer, can make it difficult for the segregated phase comparison or line differential relay systems to detect single-phase-to-ground faults.

2.4.7.4 Circuit Breaker Failure Backup Protection

In single-pole tripping schemes, it is necessary to consider circuit breaker failure backup protection factors that are somewhat different from those involved in three-pole tripping schemes.

If a circuit breaker pole fails to interrupt when attempting a single-pole operation, it is necessary to trip all three poles of the failed breaker plus all the backup circuit breakers. In this regard, the operation is no different than any three-pole scheme. However, if a circuit breaker affects a successful single-pole trip during the dead time of the faulted phase, the two good phases still carry current. Thus, single-pole tripping schemes must utilize segregated pole current detectors and associated timers that must, in the logic of the overall scheme, be associated individually with the devices that determine which phase is faulted. With such an arrangement, the scheme will not operate incorrectly as a result of the current continuing to flow in the healthy phases of a line while one pole is open.

The current breaker failure backup protection scheme must be coordinated with the selected basic line-protection scheme.

2.4.7.5 Evolving Faults

An evolving fault is one that starts as a single-phase-to-ground internal or external fault but then involves additional phases (internal or external) while the initial fault is being cleared or during the dead time of the original faulted phase. Single-pole schemes should provide some means for detecting and clearing evolving faults. Segregated line differential and phase comparison schemes are able to detect evolving faults naturally, because each phase is protected on an individual basis. On the other hand, in single-phase relaying schemes that utilize functions requiring voltages such as distance protection functions, it is necessary in the design of the logic to consider the types of measuring functions employed and whether or not line-side voltage sources are used in order to ensure the desired performance.

2.4.7.6 Blocking vs. Tripping Schemes

In traditional blocking-type schemes, no blocking signal is sent in the quiescent state. On the other hand, in permissive tripping and unblocking schemes, the blocking signal is normally sent in the quiescent state. In these latter types of schemes, it is usually necessary to provide some means for tripping a circuit breaker when picking up a faulted dead line. Traditionally, in three-pole schemes, this is accomplished with circuit breaker auxiliary switches or sensitive current detectors that key the transmitters to the unblock or trip frequency when the associated circuit breaker is open. Another approach is to utilize a switch-onto-fault scheme that permits tripping on the operation of a fault detector alone, when a circuit breaker is closed or reclosed, to pick up a dead line.

In general, this same situation exists when single-pole schemes are used in unblocking or permissive modes. However, when only a single channel is used, more detailed consideration must be given to this aspect of the design, because opening any one pole would key the transmitter while the other two poles are closed and carrying load. Unless provisions are included to mitigate this situation, this could result in a false trip if a nearby external fault were to occur during the time that one pole was open. This is not generally a consideration in the segregated phase comparison or line differential schemes because they utilize one communications channel per phase. It is also not a consideration in blocking schemes because no blocking signal is sent in the quiescent state.

2.4.8 Generator Protection

The core of an electric power system is the generation. Generators based on steam, gas, water, or wind turbines are all in use, with steam units exceeding 1200 MVA ratings. Numerous protection functions are used for complete generator protection. Distance relay elements are typically used to provide loss-of-field generator protection, loss-of-synchronism protection, and generator backup protection. More details on generator protection, including distance relay element application and settings considerations, can be found in [24] and [25].

2.4.8.1 Loss-of-Field Protection

Synchronous generators require field-winding dc voltage and current to maintain synchronism with a power system. Loss of field of a synchronous generator is an abnormal condition for both the generator and the system, which must be quickly detected, leading to isolation of the generator from the system. Loss of field of large generators means that the generator will run at higher than synchronous speed and operate as an induction generator delivering power to the system but, at the same time, obtaining reactive power from the system. This condition affects system voltage stability.

The most widely applied scheme for detecting a generator loss of field is the use of distance relays to sense the variation of impedance as viewed from the generator terminals. There are two types of distance relaying protection schemes used to detect the impedance seen during a loss of field. The two schemes differ mainly in that the first scheme uses a negative-offset mho distance element, and the second scheme uses a positive-offset mho distance element with directional unit supervision.

The first scheme is shown in Figure 2.78 where one or two negative-offset mho distance elements are used to protect the generator. These distance relay elements are applied to the generator terminals and set to look into the machine. On small or less important generator units, only a single relay is typically used, with the diameter of its circular characteristic set equal to the synchronous reactance of the machine (X_d) and with an offset equal to one half of the direct axis transient reactance (X'_d). A time delay of 0.5–0.6 seconds is typically used with this unit in order to prevent possible incorrect operations on stable swings. Transient stability studies are used to determine the proper time-delay setting.

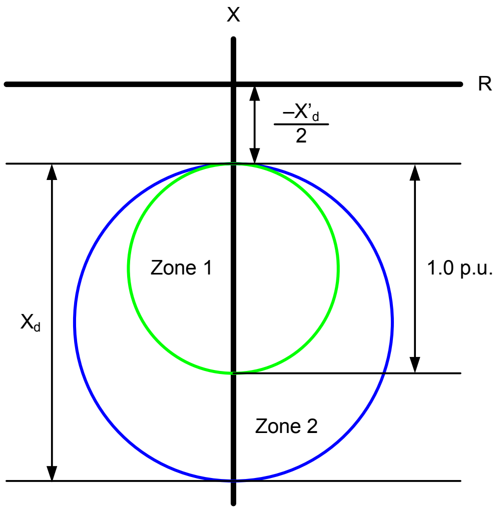


Figure 2.78 First scheme – Generator protection using two loss-of-excitation distance relay elements

Depending upon machine and system parameters, two distance relay zones are sometimes used, as shown in Figure 2.78. The use of two zones is becoming more prevalent with the application of multifunction generator protection systems. The relay element with 1.0 p.u. (generator base) impedance diameter detects a loss of field from full load to about 30 percent load. A small time delay of about 0.1 seconds is recommended for security against transients. The function of this protection zone is to provide fast protection for more severe conditions in terms of machine damage and adverse affects on the system. The second relay is set with a diameter equal to X_d and a time delay of 0.5–0.6 seconds. Both zones are set with an offset equal to one half of the generator transient reactance.

The second protection scheme is illustrated in Figure 2.79. This scheme uses a combination of an impedance unit, a directional unit, and an undervoltage unit applied at the generator terminals and set to look into the machine. The Zone 2 impedance unit is set to coordinate with the steady-state stability limit and the minimum excitation limiter. The machine capability curve and the minimum excitation limiter can be plotted on the RX plane by taking points from the machine capability curve in the PQ plane and converting them to impedance values.

The distance relay element settings are shown in Figure 2.79. Zone 1 is set with a negative offset equal to $X'_d/2$ and with the long reach intercept equal to $1.1 \cdot X_d$. In this case, the Zone 1 element should trip with a time delay of 0.2–0.3 seconds to ride through stable swings and system transients. Because the Zone 2 impedance unit has a positive offset, it is supervised by a directional element to prevent pickup for close-in faults on the system. During abnormally low excitation conditions, such as might occur following a failure of the minimum excitation limiter, both the directional and impedance units operate and sound an alarm, allowing a station operator to correct the condition. In many cases, this also starts a timer to trip the unit if the condition cannot be corrected before the unit goes unstable or is damaged. This timer is typically set at 1 minute.

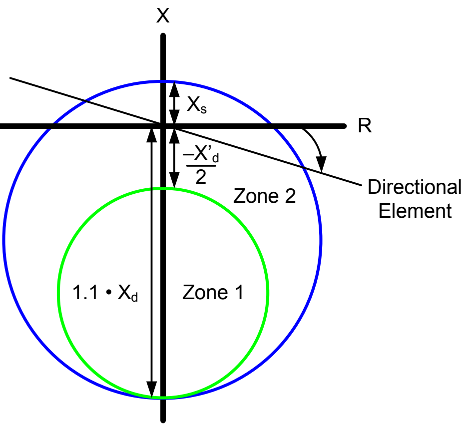


Figure 2.79 Second scheme – Generator protection using two loss-of-excitation distance relay elements

2.4.8.2 Generator Backup Protection

System backup time-delayed protection, as applied to generator protection, is used to protect against failure of the primary system protective relaying and subsequent long clearing system faults. Two types of relays are commonly used for system phase fault backup: a distance relay or a voltage-restrained or voltage-controlled time overcurrent relay. The choice of relay in any application is usually a function of the type of relaying used on the generating station transmission lines. To simplify coordination, a distance backup relay is used where distance relaying is used for line protection, while the overcurrent type of backup relay is used where overcurrent relaying is used for line protection. Connection of system backup protection (overcurrent or distance) is shown in Figure 2.80. These relays are usually connected to receive currents from current transformers in the neutral ends of the generator phase windings and voltage from the generator terminals.

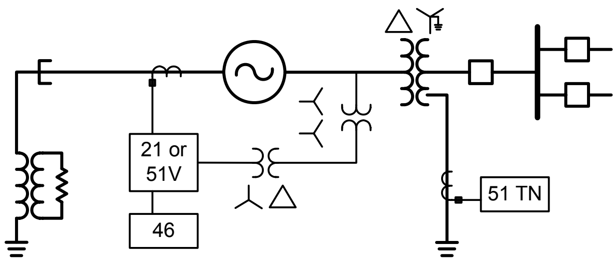


Figure 2.80 Application of system backup relay with generator connected directly to the system

If the step-up transformer between the generator and the system is a delta-grounded-wye, special care must be taken in selecting the distance relay and in applying the proper currents and voltages so that these relays see correct impedances for system faults. With some relay designs, the phase angle of the voltages applied to the relay have to be shifted so that they are in phase with the system voltages in order for the relay to detect system faults correctly. If required, this phase shift is accomplished by using auxiliary VTs connected in delta-wye, as shown in Figure 2.80. Note that the auxiliary VT is only a phase shifting transformer and its turns ratio is chosen so that the line-to-line voltages on either side of the auxiliary VTs are 1:1.

In some cases, the backup distance relay is connected looking toward the system, receiving both currents and voltages from the terminals of the generator. In this approach, an offset mho characteristic is used to provide backup protection for system faults and for some generator and generator-zone faults when the generator is connected to the system. However, this connection will not provide backup for the generator or generator zone when the generator is disconnected from the system.

Generator backup distance relay settings must be sensitive enough to detect system phase faults and to cover failure of the line relaying going out of the power station. Infeed effects, as well as different line lengths connected to the station bus, complicate this setting. Coordination with line protection devices is usually achieved by applying a time delay that is longer than a second zone clearing time for the line fault. In addition, the setting must remain conservatively above the machine rating to prevent undesired trips on generator swings and severe voltage disturbances. This criterion normally requires compromises in the desired protection to maintain generator security.

The backup distance relay is applied to isolate the generator from the power system for a fault that is not cleared by the transmission line breakers. In some cases, this relay is set with a very long reach. A system condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristic of the backup distance relay. Generally, a backup distance relay setting of 150–200 percent of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving infeed, and normal loading conditions. The tripping time delay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.

Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders can prevent misoperation for these conditions.

With the advent of multifunction generator protection relays, it is becoming more common to use two phase-distance zones. The Zone 1 element can be used to provide high-speed protection for phase faults in the generator and iso-phase bus with partial coverage of the generator step-up transformer. For this application, the Zone 1 element is typically set to 50 percent of the transformer impedance with little or no intentional time delay. Caution should be exercised with such an application because it is possible for a Zone 1 element to operate on a loss-of-synchronism condition and cause uncontrolled generator tripping in addition to providing misleading targeting information.

The operation of the generator backup distance relay is more predictable than the voltage-controlled or voltage-restraint generator backup relays and should be preferred [6]. However, generator distance backup relays have also operated during stressed conditions, depending on their settings. The safest solution to avoid misoperations by the generator phase backup protection relays is to apply local breaker failure protection at the high-voltage switchyard, including direct transfer trip to remote line terminals if it is necessary, and set the relays to provide backup only for faults up to the switchyard. Note that you may still have to set the relays to detect faults at the remote end of the line if the high-voltage bus is of a ring or a breaker-and-a-half configuration. However, the generator backup relay settings will not be as sensitive, because you do not have to consider the infeed from the other sources on the high-voltage bus. Reference [24] offers a more complete discussion on the application of generator backup protection, recommended settings, and trade-offs between sensitivity and security.

2.4.8.3 Loss of Synchronism

As machine sizes have increased, generator p.u. reactances have increased and inertia constants have decreased. The culmination of these factors has resulted in reduced critical clearing times required to isolate a system fault near a generating plant before the generator loses synchronism with the power system. In addition to prolonged fault-clearing times, generator loss of synchronism may also be caused by low system voltage, low machine excitation, high impedance between the generator and the system, or some line-switching operations. When a generator loses synchronism, the resulting high peak currents and off-frequency operation cause winding stresses, pulsating torques, and mechanical resonances that are potentially damaging to the generator and turbine generator shaft. To minimize the possibility of damage, the generator should be tripped without delay, preferably during the first half-slip cycle of a loss-of-synchronism condition.

The conventional relaying approach for detecting a loss-of-synchronism condition is to monitor the variation in apparent impedance as viewed from the generator terminals. During a loss of synchronism between a generator and the system, the apparent impedance as viewed from the generator terminals will vary as a function of the generator and system impedance, the system voltages, and the angular separation between the generator and the system. The impedance variation is typically detected by impedance relaying, and in most instances, the generator may be separated before the completion of one slip cycle. For specific cases, stability studies may determine the loci of an unstable swing so that the best selection of a loss-of-synchronism relay or relay scheme may be made. A number of different schemes have been used to detect generator instability, such as the single blinder, double blinder, double lens, and double mho. In this section, the single- and double-blinder schemes are discussed.

Single-Blinder Scheme

A basic scheme used for generator loss-of-synchronism protection is the single-blinder scheme shown in Figure 2.81.

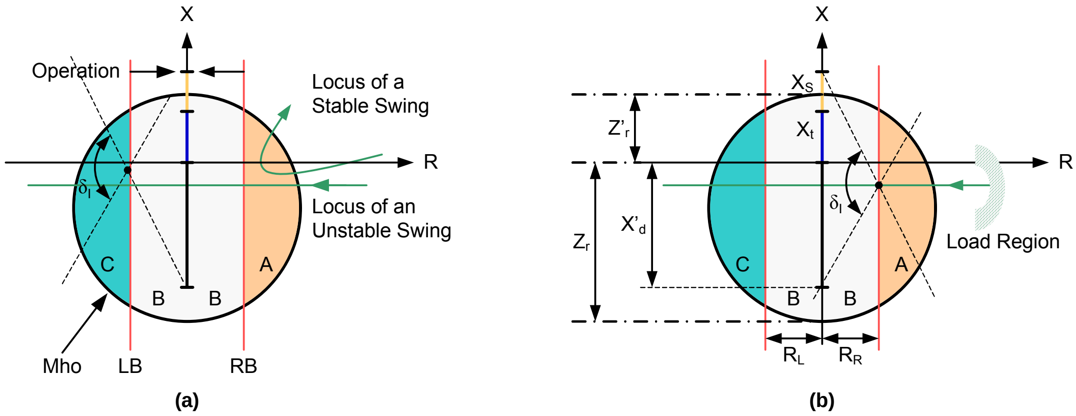


Figure 2.81 Single-blinder loss-of-synchronism scheme

The single-blinder scheme consists of the following:

- A mho element
- An ohm element, called the left blinder (LB), whose operating zone is the semiplane located at the right of the blinder
- An ohm element, called the right blinder (RB), whose operation zone is the semiplane located at the left of the blinder

This scheme detects a loss-of-synchronism condition by tracking the trajectory of the positive-sequence apparent impedance passing through the three regions in the complex impedance plane. The mho element ensures that the scheme works only for the case of swings occurring within the generator transformer zone. Swings with electrical centers well inside the system should not produce a trip condition by the loss-of-synchronism generator protection. The blinders, mho unit, and associated logic evaluate the progressive change in impedance as it moves through the three regions in the complex plane.

The supervising mho element must detect all apparent impedances that can produce a loss-of-synchronism condition for the generator. This can be accomplished by setting the mho element to encompass both the generator and the transformer. Therefore, Z_r must be larger than the generator impedance, typically 150 percent of X'_d, and Z'_r must be set larger than the transformer impedance, typically 150 percent of X_t. In addition, the mho element must not operate for the minimum apparent impedance, Z_{min}, produced by the generator maximum load. The blinder settings, R_R and R_L, are calculated for an angle, $\delta_I = 120$ degrees, that represents a possible loss-of-synchronism condition that would prevent the generator from returning to a stable state of equilibrium.

Double-Blinder Scheme

The double-blinder scheme, shown in Figure 2.82, is similar to the single-blinder scheme. The mho element and the inner blinders, ILB and IRB, work in the same way as in the single-blinder scheme. The relay trips if the apparent impedance trajectory moves from right to left crossing regions A-B-C, or if the apparent impedance trajectory moving from left to right crosses regions C-B-A.

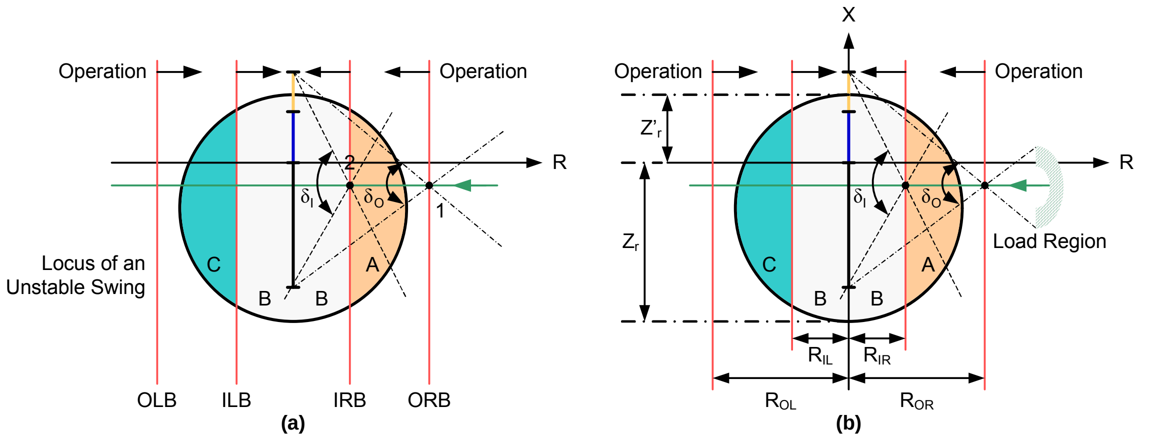


Figure 2.82 Double-blinder loss-of-synchronism scheme

The only fundamental difference of this scheme, when compared to the single-blinder scheme, is that the additional outer blinders, OLB and ORB, can differentiate internal short circuits from power swings. This differentiation occurs through indirect measurement of the rate of change of the apparent impedance.

If the apparent impedance penetrates Region B quickly, a fault is declared. If the apparent impedance moves into Region B in a relatively slow manner, the scheme would declare a swing. The time difference between when the apparent impedance crosses ORB and when it crosses IRB is represented by Points 1 and 2, consecutively, in Figure 2.82.

The criteria used to calculate the settings of the inner ohm elements, R_{IR} and R_{IL}, shown in Figure 2.82(b), are the same as those for the two-ohm elements of the single-blinder scheme. Calculations of the outer-blinder settings and the mho element should follow these recommendations:

- The outer blinder should not assert for the maximum load impedance.
- The outer blinder should lie outside the mho circle to satisfy the relay logic. This means that the mho element is set in the same way as it is for the single-blinder scheme. In addition, the following constraint must be verified: $(|Z_r+Z'_r|/2) < R_{OR}$.
- The outer blinder should separate from the inner blinder far enough to ensure that, given a time setting, T_L, the loss-of-synchronism element can detect swings with a frequency slip equal to or smaller than the fastest swing you want to detect.

The loss-of-synchronism protection may be connected to trip only the main generator breaker(s) and, thereby, isolate the generator with its auxiliaries if the unit has full load-rejection capabilities. In this way, when system conditions have stabilized, the unit may be readily resynchronized to the system. If the unit does not have full load-rejection capability, this protection should be converted to trip and shut down the generator and prime mover.

2.4.9 Transformer Protection With Distance Relays

Distance relays are used for primary or backup transformer protection. They typically consist of multizone impedance relays on the high-voltage (HV) and low-voltage (LV) side of the transformer. They are connected to look into the transformer from the HV and LV sides as shown in Figure 2.83. The Zone 1 distance elements from the HV and LV sides are set to see up to 70 percent of the transformer impedance with a small time delay providing 100 percent coverage. The other distance relay zones are applied as system backup protection and for uncleared HV and LV side bus faults. In some countries, the HV and LV side distance relays are applied in a directional comparison scheme for transformer backup protection. The transformer impedance relays offer an additional benefit because they provide overlapping protection of the bus protection zones. However, they must coordinate with transmission line relays, causing them to be slower than the differential relay. Distance relays applied for transformer protection must be set to not operate on the transformer energization inrush current.

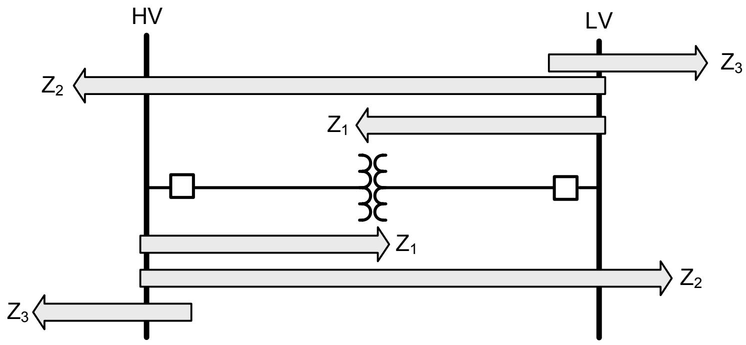


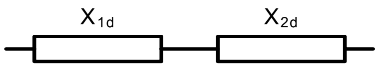
Figure 2.83 Distance protection of a transformer bank

2.4.9.1 Transformer Models

To introduce how to apply distance protection to protect power transformers, some common transformer models are given below.

Positive-Sequence Impedance

$$X_{1d} + X_{2d} = X_T \tag{2.32}$$



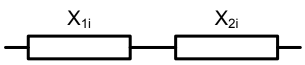
Where:

Subscript d = positive sequence

Negative-Sequence Impedance

Assuming that negative-sequence impedances are equal to positive-sequence impedances,

$$X_{1i} + X_{2i} = X_{1d} + X_{2d} = X_T \tag{2.33}$$

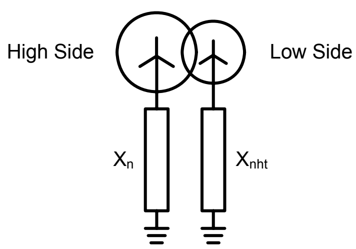


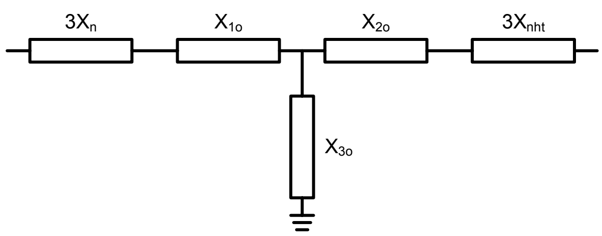
Where:

Subscript i = negative sequence

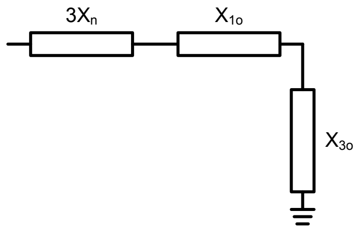
Zero-Sequence Impedance

<u>Yy or Yyd Transformer</u>

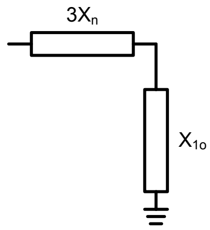




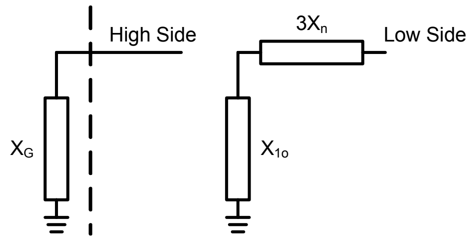
If we assume that $X_{2o} + 3X_{nht} > X_{3o}$, then $Io_{TR} = 0$ on the LV side. The previous model then simplifies to:



<u>Dy Transformer on Star Side</u>



For Dy transformer, we assume the following scheme:



Where:

X_G = value of the external zero-sequence impedance on delta HV side

2.4.9.2 Settings of Impedance Relays

To facilitate the discussion of points regarding the distance protection measurements on a transformer bank, consider an example in which the relay, located on the LV side of the transformer, sends a trip command to the circuit breakers on both sides of the transformer.

The purpose of this relay is as follows:

- Back up the main relays on the power transformer (Buchholz, current differential relay).
- Clear the fault current from the LV side for an HV-side bus fault in case of a failure of the HV-side bus differential relay or in case of an HV-side bus fault without a differential relay.
- Clear the fault current from the HV side for an LV-side bus fault in case of a failure of the LV-side bus differential relay or in case of an LV-side bus fault without differential relay.

The following points are also to be considered:

- Power transformers can be overloaded, and the backup relay must not trip for a nonfault condition. Shifted characteristics must be used to preserve a sufficient capability of fault detection.
- Faults on the HV side of the transformer are difficult to detect for the LV-side impedance relay (especially if accuracy measurement is needed). The correct measurements are given below, depending on transformer connections.

Y-D Transformer

Table 2.7 Proper measurements depending on transformer connections

Fault	Measure	Comment
Single phase to ground	Between two phases	
Two phase	Between one phase and ground	
Two phase to ground	Between one phase and ground	
Three phase	Between two phases or between one phase and ground	Both measures are possible

Y-Y Transformer

Table 2.8 Proper measurements depending on transformer connections

Fault	Measure	Comment
Single phase to ground	Between one phase and ground	
Two phase	Between two phases	
Two phase to ground	Between two phases	
Three phase	Between two phases or between one phase and ground	Both measures possible

When using a distance protection relay with only one measuring element, some difficulties might arise with zero-sequence current. According to the properties of the transformer (impedances, third winding, etc.), it is not certain that the fault on the HV side provides sufficient zero-sequence current to the monitoring logic of the protection, and thus, incorrect voltages or currents might be applied on the measuring element or might be computed in a numerical relay (possible misoperation or failure to trip). These points must be checked for each particular case regarding the transformer model.

A better way to detect faults on the HV side of the transformer is to measure the impedance simultaneously on the three two-phase loops and on the three single-phase-to-ground loops. This system can be made without any zero-sequence current monitoring logic, but with:

- Three impedance-delayed relays with shifted characteristics, which measure:

$$\frac{V_a - V_b}{I_a - I_b}, \frac{V_b - V_c}{I_b - I_c}, \frac{V_c - V_a}{I_c - I_a} \tag{2.34}$$

- Three impedance-delayed elements with shifted characteristics, which measure:

$$\frac{V_a}{I_a}, \frac{V_b}{I_b}, \frac{V_c}{I_c} \tag{2.35}$$

Computing the measurements of all six loops for all type of faults provides a useful check.

Guide for Impedance Relay Settings

Assuming that the impedance relay or distance protection is located on the LV side, the goal is to measure all fault types on the HV side near the transformer. Table 2.9 and Table 2.10 summarize the relevant formulas for different transformer types.

Table 2.9 Relevant formulas for different transformer types

	Yyd Transformer Assuming $Io_{TR} = 0$ on LV Side	Yd11 Transformer
Phase-to-ground fault (A)	$\frac{VA}{IA_{TR}} = X_{1d} + X_{2d} + \frac{(X_{1o} + X_{3o} + 3X_n)}{2}$	$\frac{VA - VC}{IA_{TR} - IC_{TR}} = X_{1d} + X_{2d} + \frac{(X_{1o} + 3X_n)}{2}$
Three-phase fault	$\frac{VA}{IA_{TR}} = X_{1d} + X_{2d}$ or $\frac{VA - VB}{IA_{TR} - IB_{TR}} = X_{1d} + X_{2d}$	$\frac{VA}{IA_{TR}} = X_{1d} + X_{2d}$ or $\frac{VA - VB}{IA_{TR} - IB_{TR}} = X_{1d} + X_{2d}$
Phase-to-phase fault (BC)	$\frac{VB - VC}{IB_{TR} - IC_{TR}} = X_{1d} + X_{2d}$	$\frac{VB}{IB_{TR}} = X_{1d} + X_{2d}$
Phase-to-phase-to-ground fault (BC to ground)	$\frac{VB - VC}{IB_{TR} - IC_{TR}} = X_{1d} + X_{2d}$	$\frac{VB}{IB_{TR}} = X_{1d} + X_{2d}$

Table 2.10 Relevant formulas for different transformer types

	Yyd Transformer (General Case)	Dy1 Transformer
Phase-to-ground fault (A)	See below*	$\frac{VA - VB}{IA_{TR} - IB_{TR}} = X_{1d} + X_{2d} + \frac{X_G}{2}$ Where: $X_G =$ Value of the zero-sequence impedance on delta HV side
Three-phase fault	$\frac{VA}{IA_{TR}} = X_{1d} + X_{2d}$ or $\frac{VA - VB}{IA_{TR} - IB_{TR}} = X_{1d} + X_{2d}$	$\frac{VA}{IA_{TR}} = X_{1d} + X_{2d}$ or $\frac{VA - VB}{IA_{TR} - IB_{TR}} = X_{1d} + X_{2d}$
Phase-to-phase fault (BC)	$\frac{VB - VC}{IB_{TR} - IC_{TR}} = X_{1d} + X_{2d}$	$\frac{VC}{IC_{TR}} = X_{1d} + X_{2d}$
Phase-to-phase-to ground fault (BC to ground)	$\frac{VB - VC}{IB_{TR} - IC_{TR}} = X_{1d} + X_{2d}$	$\frac{VC}{IC_{TR}} = X_{1d} + X_{2d}$

*Phase-to-Ground Fault for Yyd Transformer

Suppose that X_{Sd} is the positive-sequence impedance value of the LV-side source, and X_{So} is the zero-sequence impedance value of the same source. Note that:

$$X_d = X_{1d} + X_{2d} + X_{Sd} \tag{2.36}$$

$$X_o = 3X_n + X_{1o} + \frac{X_{3o}(X_{2o} + 3X_{nht} + X_{So})}{X_{3o} + X_{2o} + 3X_{nht} + X_{So}} \tag{2.37}$$

If we can not assume that $X_{2o} + 3X_{nht} > X_{3o}$, then:

$$IA_{TR} = Id_{TR} + Ii_{TR} + Io_{TR} = \frac{2Vn}{(2X_d + X_o)}\left(1 + \frac{1}{2}\frac{X_{3o}}{X_{3o} + X_{2o} + 3X_{nht} + X_{So}}\right) \quad (2.38)$$

$$VA = Vd + Vi + Vo = Vn \cdot \left(1 - \frac{2X_{Sd}}{2X_d + X_o} - \frac{X_{So}}{(2X_d + X_o)}\frac{X_{3o}}{(X_{3o} + X_{2o} + 3X_{nht} + X_{So})}\right) \quad (2.39)$$

If we assume that $X_{2o} + 3X_{nht} > X_{3o}$, then:

$$IA_{TR} = Id_{TR} + Ii_{TR} = \frac{2Vn}{(2Z_d + Z_o)} \quad (2.40)$$

$$VA = Vd + Vi = Vn \cdot \left(1 - \frac{2X_{Sd}}{2X_d + X_o}\right) \quad (2.41)$$

and

$$\frac{VA}{IA_{TR}} = X_{1d} + X_{2d} + \frac{(X_{1o} + X_{3o} + 3X_n)}{2} \quad (2.42)$$

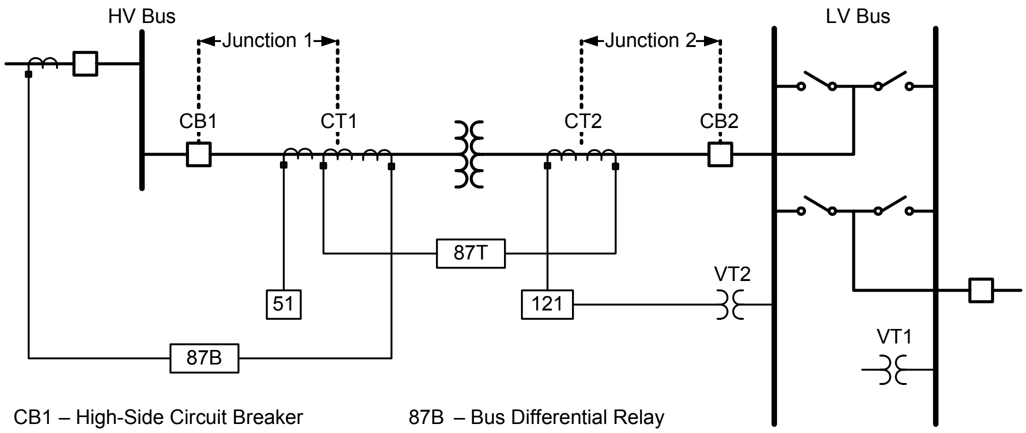
The following functions are usually provided to protect a transformer from internal faults:

- Buchholz relay (97)
- Transformer differential relay (87T)
- Ground tank relay (instead of current differential relay) ($87I_0$ or $51I_0$)

The following functions are usually provided to protect a transformer from external faults:

- Bus differential relay (HV side) (87B)
- Nondirectional overcurrent relay (HV side) (51)
- Distance relay (LV side) (121)

Figure 2.84 shows a possible arrangement of these devices.



CB1 – High-Side Circuit Breaker
CB2 – Low-Side Circuit Breaker
CT1 – High-Side Freestanding CT
CT2 – Low-Side Freestanding CT
VT – Voltage Transformers

87B – Bus Differential Relay
87T – Transformer Differential Relay
51 – Overcurrent Relay
121 – Distance Relay

Figure 2.84 Transformer bay protection

The distance relay is connected to the LV current transformer, CT2, and to the bus voltage transformer, VT2. This protection requires a set of three VTs for every LV bus to which the transformer is connected.

For the HV side, a more economical nondirectional overcurrent relay is usually preferred. This protection operates adequately as a backup for the distance relays of the HV transmission lines and for the bus differential relay. Furthermore, if a fault occurs in the HV network, the fault current from the LV could be too low to start distance protection.

However, on the LV side, the use of a distance relay is largely justified. This device operates as the main protection for:

1. The LV bus (Zone 1)
2. The HV between CB1 and CT1, shown in Figure 2.84 as Junction 1 (reverse zone)
3. The HV bus without bus differential relay (reverse zone)

This device operates as backup protection for:

4. The LV distance line relays (Zones 2 and more)
5. The HV bus differential relay (reverse zone)
6. The main (Buchholz, differential relay) transformer protection (reverse zone)

Previous points 1, 2, and 4 are discussed below.

- If a fault occurs in the LV bus, the heavy fault current should be extinguished as soon as possible in order to preserve the transformer. The Zone 1 distance element can operate with a delay time of 0.15–0.30 seconds (adequate to guarantee the necessary selectivity with the distance relays in the LV transmission lines). This is by far superior to the clearing time of an overcurrent relay (normally longer than 1 s). Undoubtedly in this case, the best solution is to provide the LV bus with a differential relay, but this arrangement is usually not feasible either from a technical or economical point of view.
- If a fault occurs in the HV Junction 1 shown in Figure 2.84 between CB1 and CT1, the bus differential relay trips CB1 while the transformer differential relay is not affected by the fault and does not operate. The fault current from the LV side is cleared by the distance protection that, with its reverse zone and with a certain delay, trips CB2.
- If a distance relay of an LV line fails, the transformer distance relay provides a backup with its overreaching zone(s).

Correct protection system operation requires that the zones of the transformer distance relay be coordinated in time and impedance with the corresponding zones of the LV line distance relay. A delayed reverse zone that overreaches the transformer impedance is also needed.

The following table summarizes the transformer distance relay operation according to the different fault positions.

Table 2.11 Transformer distance relay operation according to different fault positions

Fault Position		Distance Protection Function	Operative Zone
HV	Between CB1 and CT1	Main	Reverse
	Bus	Backup – the bus differential relay and the overcurrent relay Main without the bus differential relay	Reverse
	Line	No function	No operation
LV	Between CT2 and CB2	Main	1
	Bus	Main	1
	Line	Backup – the LV distance line relays	2 or more
Transformer		Backup – the power transformer main relays	Reverse

In this example, accuracy is required especially for forward zones, whereas the reverse zone is mainly a backup zone. The distance protection is used with its common measurement loops. It is necessary to check that all faults on the HV side can be detected by the reverse zone, keeping in mind the transformer type and the grounding on LV and HV sides.

2.4.9.3 Distance Relay Response to Transformer Energization

This section highlights two common distance relay applications that can be subject to transformer inrush.

- Dedicated transformer
- Multiple tapped transformers on a transmission line

The first application illustrates the distance element response to transformer energization when the relay is applied on the terminals of a 230/23 kV, 240 MVA, three-phase transformer. Figure 2.85 shows the one-line diagram for this application [26].

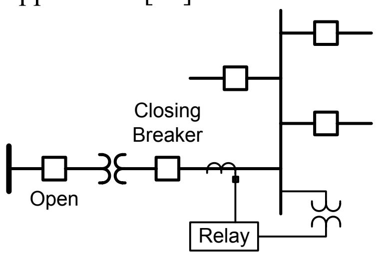


Figure 2.85 Single transformer line diagram

The transformer is delta-connected on the 230 kV side and grounded-wye on the 23 kV side. The transformer impedance is 7 percent. Figure 2.86 shows the phase current magnitudes from the digital relay filter output. The fundamental frequency component (digital filter output) magnitude is close to 15 amperes secondary, about 40 percent of the peak inrush value.

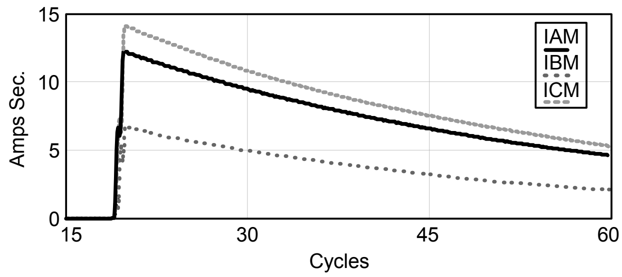


Figure 2.86 Fundamental magnitudes of single transformer inrush current

Figure 2.87 shows the impedance plot of the phase-to-phase distance elements. The lower line (M1P) is the transformer impedance, while the other line (M2P) is 200 percent of the transformer impedance. Setting philosophies vary in these applications, so the figure shows these thresholds for illustrative purposes. One can observe from Figure 2.87 that the distance element measures a transient impedance value that is close to the transformer impedance. Overreaching Zone 2 elements can pick up on the inrush currents and trip on time delay or switch-onto-fault.

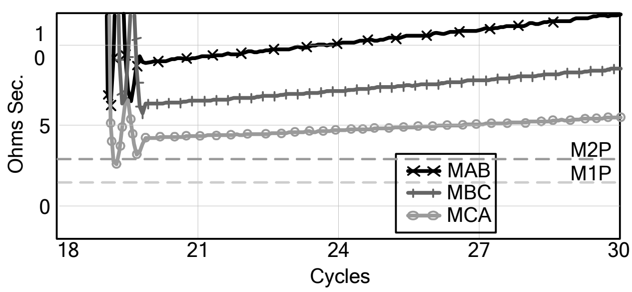


Figure 2.87 Impedance plot for single transformer inrush

The following example illustrates the distance element response to energizing a line with multiple tapped transformers. This example is similar to the previous example except that load is connected to the transformers and the impedance elements typically have a greater reach setting to accommodate the effects of infeed (Zone 2 elements are set typically to "see" through the transformer). The line is a 60-mile, 115 kV transmission line. A total of four 30 MVA, 115 kV/12.47 kV delta-grounded-wye transformers are connected to the line in two locations (two transformers at each location). Each transformer feeds 10 MW of load at a 0.9 power factor; the load is connected during line energization.

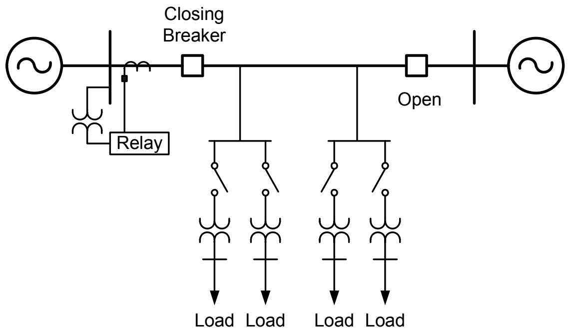


Figure 2.88 Tapped transformer single-line diagram

Figure 2.89 shows the phase current magnitudes from the digital filter output. In this example, the fundamental frequency component (digital filter output) is close to 4.2 amperes secondary, about 34 percent of the peak inrush value.

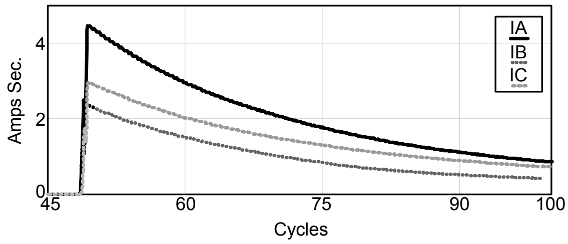


Figure 2.89 Fundamental magnitudes of tapped transformer inrush current

Figure 2.90 shows the impedance plot of the phase-to-phase distance elements. The plot shows line M1P, which is the sum of the line impedance to the farthest connected transformer and the transformer impedance at that location. The upper line, M2P, is a typical Zone 2 distance element reach setting. The Zone 2 distance element is set to reach through the farthest transformer and include the effect of infeed from the remote terminal. The overreaching Zone 2 element is picked up for a relatively long period of time; the CA phase pair picks up for almost 20 cycles. A time-delay backup element could operate for this inrush condition.

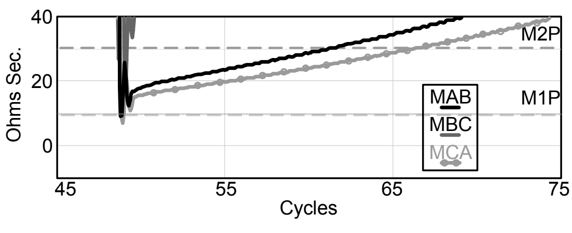


Figure 2.90 Impedance plot for tapped transformer inrush

Many differing methods and guidelines exist for setting distance elements in applications involving transformers. The following recommendations serve as general guidelines and cautions for most distance element applications with transformers.

Take extra caution in setting and applying Zone 1 distance elements. There are two approaches to making a Zone 1 distance element secure in transformer applications: reduce the Zone 1 reach or apply overcurrent fault detectors. Reducing Zone 1 reach may be prohibitive in some cases, such as those applications with tapped transformers. However, in dedicated transformer applications, such reduction does not significantly impact the speed or dependability of the scheme. In other applications, set an overcurrent fault detector higher than the maximum inrush current. The above examples show that the fundamental frequency component magnitude can be as high as 40 percent of the maximum peak inrush current. Ensure secure Zone 1 operation by setting the overcurrent fault detector greater than this value.

It is more likely that the Zone 2 distance element can operate on inrush as a result of the increased reach setting on these overreaching elements. The Zone 2 element can cause two types of unwanted operations: switch-onto-fault or time-delayed backup. For switch-onto-fault, supervise the Zone 2 distance element (and possibly all distance elements) with an undervoltage element. Typically, setting the undervoltage element to 75–80 percent of the nominal system voltage covers the majority of cases. In some applications, however, different thresholds may be necessary as a result of system conditions. For time-delayed backup applications, longer time delays may be necessary. Predicting the necessary delay can be difficult, but 0.5–0.75 seconds should be adequate in most cases.

2.4.9.4 Reach of Distance Relays in Delta-Wye Transformers

This section discusses the performance of two distance elements, with different polarization methods, applied for transformer and line protection when the instrument transformers (CTs and VTs) are located on the low side of a delta-wye power transformer [27]. The two types of phase distance elements are as follows:

- Phase distance elements using positive-sequence voltage memory polarization
- Compensator distance elements

The theory of operation to evaluate the elements can be found in [28] and [29]. Reference [28] provides the background for the compensator distance element principle, which has a three-phase and a phase-to-phase element. The mathematical model used to evaluate its performance for phase-to-phase and phase-to-phase-to-ground faults is expressed in (2.43), (2.44), and (2.45). The compensator distance element torque is the imaginary part of the product between Phasor A and the complex conjugate of Phasor B. The complex conjugate is indicated by an asterisk (*) above the expression.

$$T := I_m\left[A \bullet (B)^*\right] \tag{2.43}$$

$$\begin{aligned} A &:= V_{ab} - Z_{1R} \bullet I_{ab} \\ B &:= V_{bc} - Z_{1R} \bullet I_{bc} \end{aligned} \tag{2.44}$$

$$Z_{1R} := r \bullet Z_1 \angle \theta 1 \tag{2.45}$$

Equation (2.46) shows the phase-pair positive-sequence voltage memory polarized mho element for the B-C phase-to-phase element (repeated for A-B and C-A). The value of MBC indicates the per-unit reach that is required for the element to operate for given system fault quantities (V_{bc}, I_{bc}). Z_1 is the positive-sequence impedance of the protected line, and VB_1 and VC_1 are "healthy" prefault positive-sequence voltages referenced to B-phase and C-phase, respectively.

$$MBC := \frac{\mathrm{Re}\left[(V_{bc}) \bullet (VB_1 - VC_1)^*\right]}{\mathrm{Re}\left[Z_1 \bullet (I_{bc}) \bullet (VB_1 - VC_1)^*\right]} \tag{2.46}$$

Figure 2.91 shows an example system where the distance relays are applied to protect the transformer and the 138 kilovolt line, using inputs from the 34.5 kilovolt system.

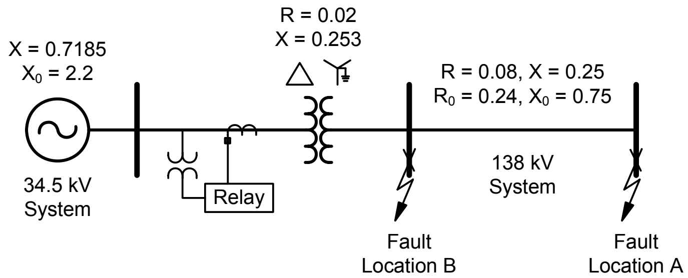


Figure 2.91 138 kV grounded-wye, 34.5 kV delta system diagram

In Table 2.12, MAB, MBC, and MCA are the respective reaches required for the phase-to-phase mho elements to operate. The required reach for the compensator distance element is r. For simplicity, we initially modeled the transformer and line impedance at approximately the same magnitudes. The reaches (MAB, MBC, MCA, and r) in Table 2.12 and Table 2.13 are shown in per unit of the line impedance. Thus, a fault should yield an impedance of 1 per unit at the transformer HV side and of 2 per unit at the remote bus. Table 2.12 shows the phase-pair elements (MAB, MBC, and MCA) reach correctly only for the three-phase faults. The compensator distance element, r, provides an accurate reach for all fault types.

Table 2.12 Required reach of phase-pair and compensator distance elements to detect faults on 138 kV system through high-side delta-grounded-wye transformer bank

Fault Type	Fault Location	MAB	MBC	MCA	r	Fault Type
B-C	B, high-side transformer	*	1.97	2.76	1.01	B-C
B-C-G	B, high-side transformer	2.99	1.29	1.47	1.04	B-C-G
3LG	"B, high-side transformer	1.01	1.01	1.01	1.01	3LG
B-C	A, remote bus	*	3.29	3.97	1.99	B-C
B-C-G	A, remote bus	9.99	2.66	3.15	1.99	B-C-G
3LG	A, remote bus	1.99	1.99	1.99	2	3LG

Sometimes distance relays are used to protect lines, but only the currents are available from the high-voltage line; the voltage inputs must be taken from the medium-voltage system. Figure 2.92 shows such a system.

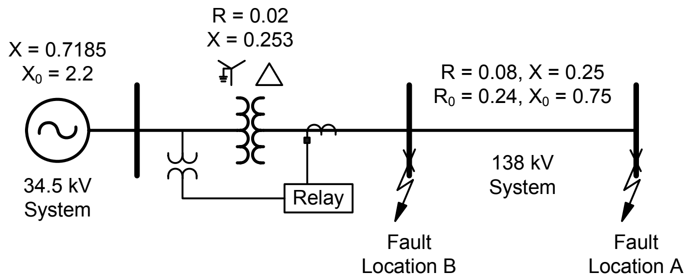


Figure 2.92 138 kV delta, 34.5 kV grounded-wye system diagram with 138 kV CTs, 34.5 kV VTs

The difference of this connection to the system in Figure 2.91 is that the relay currents and voltages are out of phase by 30 degrees. Table 2.13 shows the distance element performance for this system. The values in parentheses show the reach calculated with the VT connections in delta-wye to simulate the power transformer phase shift. That is, if the transformer connection is high-side delta-grounded-wye, we connect the VTs on the low side as grounded-wye-delta to “undo” the phase shift effect of the power transformer.

Table 2.13 Performance of distance elements with 34.5 kV VT connection

Fault Type	Fault Location	MAB	MBC	MCA	r	Fault Type
B-C	B, high-side transformer	25.70	1.71 (0.84)	4.77	1.12 (1.02)	B-C
B-C-G	B, high-side transformer	25.70	1.71 (0.84)	4.77	1.12 (1.02)	B-C-G
3LG	“B, high-side transformer	0.99	0.99	0.99	1.0	3LG
B-C	A, remote bus	42.29	2.84 (1.87)	6.87	2.24 (2.0)	B-C
B-C-G	A, remote bus	42.29	2.84 (1.87)	6.87	2.24 (2.0)	B-C-G
3LG	A, remote bus	2.03	2.03	2.03	2.02	3LG

The compensator distance element displays about a 10 percent error if no correction is performed on the VT connections. When the VT connections are modified to delta-wye to simulate the transformer connection, the compensator distance element performs with precision. The performance of the phase-pair element is very erratic and should be tested or modeled if used on this type of system. The compensator distance element principle is a superior design for properly applying distance relays through transformers. It is unaffected by common delta-wye transformer connections and basically measures positive-sequence impedance. Compensator distance elements can be affected by load, causing the relay to over- or underreach, and this should be taken into consideration when making relay settings. More data are available in [27] comparing the performance of the two distance relay elements. References [30] [31] [32] and [33] provide additional information for transformer protection with distance relays.

2.4.10 Bus Protection With Distance Relays

Distance relays can be used for protecting buses. In the example shown in Figure 2.93, the four relays are mho relays. Each relay is connected to see faults on the bus side of the relay. The outputs of the relays are connected to a logic circuit consisting of a four-input AND gate that provides a “high” output when all the inputs are “high.” This output is used to trip all the circuit breakers connected to the bus.

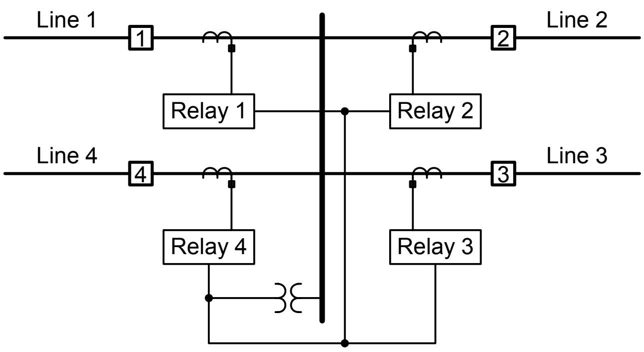


Figure 2.93 A bus with four circuits connected to it

Another approach is to use incremental voltages and currents. In this case, each relay is connected to work with the voltages at the bus and with the currents flowing from the bus to the line. Consider a transmission line that connects Bus A with Bus B, as shown in Figure 2.94. In this figure, Systems 1 and 2 are interconnected by a transmission line. The source impedances are Z_{S1} and Z_{S2}, and the induced voltages of the two systems are E_1 and E_2. Before a fault occurs at F, the voltage at the fault location is V_F.

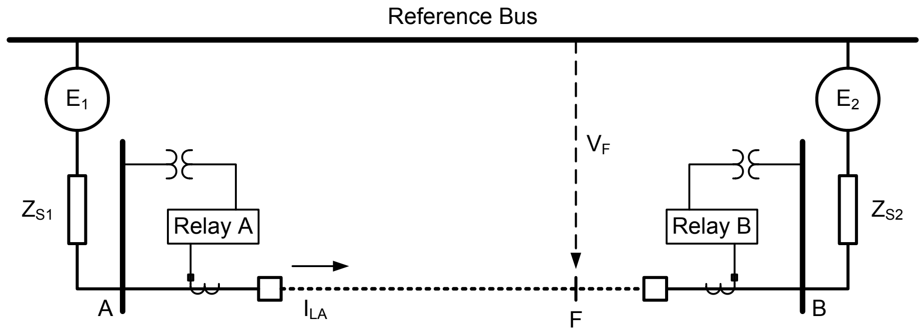


Figure 2.94 Voltages and currents during normal operation

When a fault occurs, the system can be represented by Figure 2.95. The impedance Z_F represents the fault resistance and a combination of the negative-sequence and zero-sequence networks depending on the type of the fault. The voltages and currents during the fault are composed of the load-flow components and the fault current components.

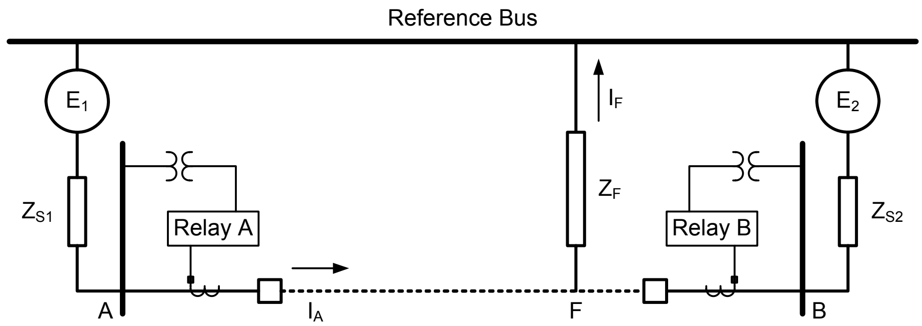


Figure 2.95 Voltages and currents during a fault at F

The fault current components, given by the Thevenin's theorem, are shown in Figure 2.96. This figure shows that the voltage at Bus A is given by:

$$V_{AF} = -I_{FA} Z_{S1} \tag{2.47}$$

The impedance measured by Relay A would be $-Z_{S1}$, which lies in the third quadrant. The phasors of the incremental voltages are the phasors of the voltages experienced during the fault less the phasors of the voltages that existed before the occurrence of the fault.

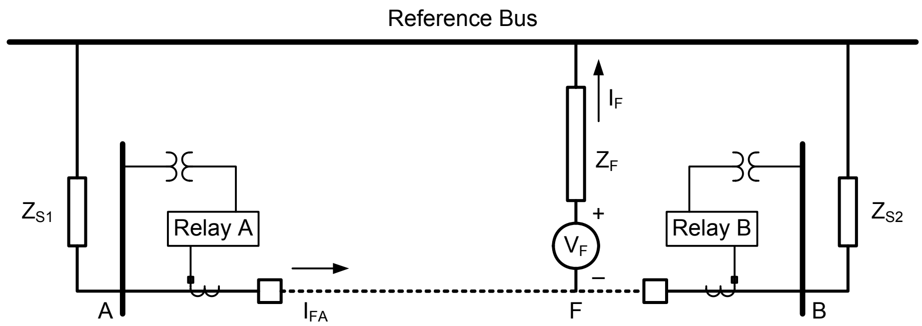


Figure 2.96 Voltages and currents only because of the fault at F

Similarly, Figure 2.98 represents a fault that occurs on the bus side of Relay A. The impedance seen by Relay A is $Z_L + Z_{S2}$, which lies in the first quadrant. This relay looks towards the bus. If these relays are installed on all the outgoing circuits connected to a bus, they will all operate for faults on the bus. If a fault is on a circuit, all relays except the one provided on that circuit would operate. In the four-bus system, the outputs of the relays would be provided to a four-input AND logic. The AND gate would provide an output for faults on the bus. The major advantage of using the incremental signals is that the relay operation is not affected by the prefault power flows on the line.

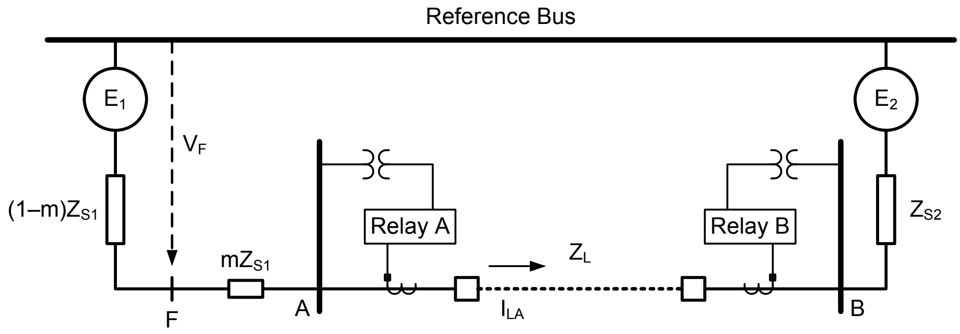


Figure 2.97 Voltages and currents during normal operation

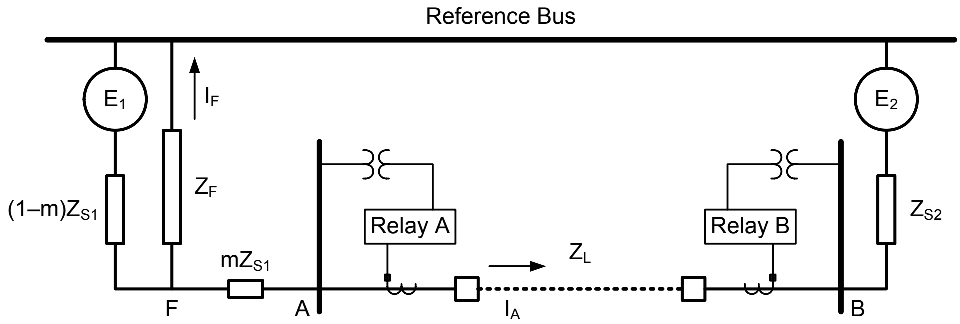


Figure 2.98 Voltages and currents during a fault at F

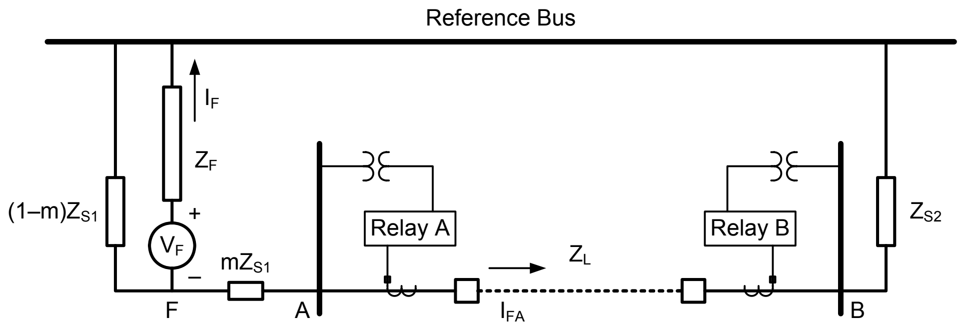


Figure 2.99 Voltages and currents only because of the fault at F

2.4.11 Impedance-Based Shunt Capacitor Protection

The impedance-based measurement for the protection of a fuseless capacitor bank incorporates a temperature sensor to compensate for the change of capacitor impedance as a function of ambient temperature. The ambient temperature compensation allows the impedance-based protection to have a much higher sensitivity (the radius of the mho element will be smaller). The characteristic of the offset mho element shown in Figure 2.100 measures a purely negative reactive impedance (–x), and the relay operates when the capacitor impedance falls outside of a given mho circle characteristic. The ambient temperature compensation feature enables the center of the offset mho characteristic to be shifted based on the actual ambient temperature. Figure 2.100 shows the impedance-based protection characteristics for shunt capacitor bank protection with its trip and alarm zones plotted in the R-X impedance plane.

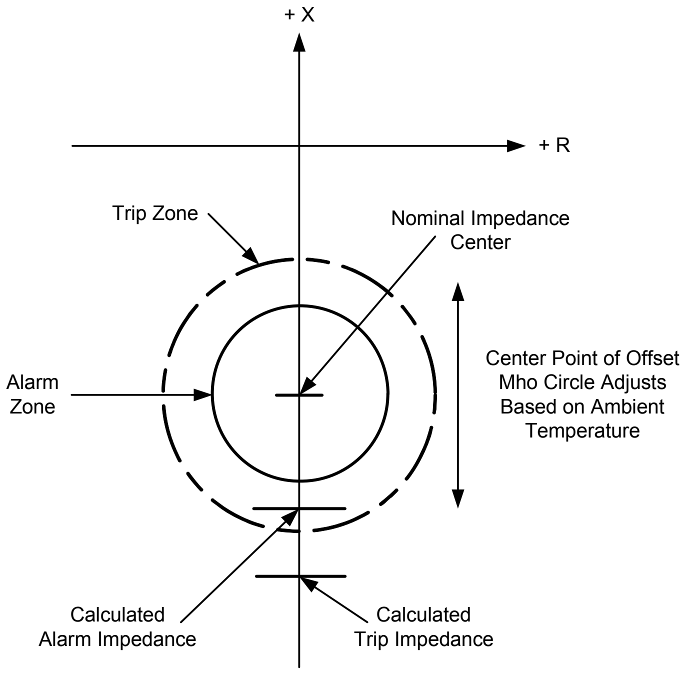


Figure 2.100 Example of impedance-based shunt capacitor protection

The impedance method used for the protection of capacitor banks is based on measuring the current in each string with a protection sensitivity to enable the detection and alarm for a single shorted series section. If the numbers of shorted series sections are large enough to cause an impedance change shift to the trip region, then the failed capacitor string is identified.

Figure 2.101 illustrates the capacitor bank configuration and the functionality of the multifunction distance protection device. A large number of analog input channels are required to accommodate the string current inputs and backup phase and ground overcurrent elements in addition to the voltage inputs from the bus. Depending on the capacitor bank configuration and the number of strings in the capacitor bank, it may be necessary to protect the bank with two or more relays because of a limited number of relay analog channels.

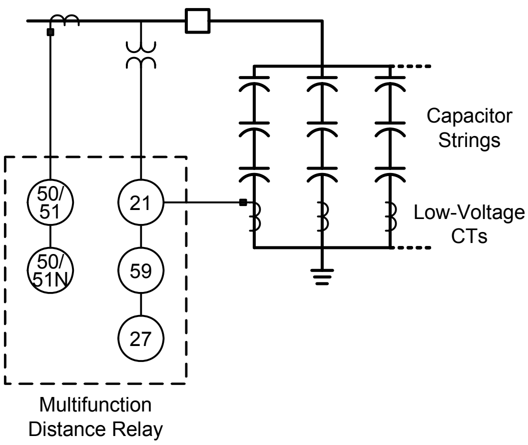


Figure 2.101 Shunt capacitor bank protection

2.4.12 Out-of-Step (OOS) Protection

Power systems are subjected to a wide range of disturbances, small or large, during operating conditions. Small changes in loading conditions occur continually. The system must be able to adjust to these changing conditions and continue to operate satisfactorily and within desired bounds of voltage and frequency. The power system must also be able to survive larger disturbances, such as faults, loss of a large generator, or line switching.

Power system stability is the ability of an electric power system to regain a state of operating equilibrium after being subjected to disturbances such as faults, load rejection, line switching, and loss of excitation. Power system integrity is preserved when nearly the entire system remains intact with no tripping of generators or loads, except for those disconnected by the isolation of the faulted elements or intentionally tripped to preserve the continuity of operation of the rest of the system.

Certain power system disturbances may cause the loss of synchronism between a generator and the rest of the utility system or between neighboring utility interconnected power systems. If such loss of synchronism occurs, it is imperative that the generator or system areas operating asynchronously are separated immediately to avoid widespread outages and equipment damage. One way of containing such a disturbance is through system separation based on the OOS tripping (OST) protection philosophy at preselected network locations. OST must be complemented with power swing blocking (PSB) of distance relay or other relay elements prone to operate during unstable power swings at all other locations and prevent system separation at any locations other than preselected ones. The philosophy and application of OST and PSB schemes are discussed in the following sections.

2.4.12.1 Loss-of-Synchronism Characteristics

The response of the power system to a disturbance depends on both the initial operating state of the system and the severity of the disturbance. A fault on a critical element of the power system followed by its isolation by protective relays will cause variations in power flows, network bus voltages, and machine rotor speeds. Voltage variations will actuate generator voltage regulators, and generator speed variations will actuate prime mover governors.

Depending on the severity of the disturbance and the actions of protective relays and other power system controls, the system may remain stable and return to a new equilibrium state experiencing what is referred to as a stable power swing. On the other hand, if the system is transiently unstable, it will cause large separation of generator rotor angles, large swings of power flows, and large fluctuations of voltages and currents and will eventually lead to a loss of synchronism between groups of generators or between neighboring utility systems. When two areas of an interconnected power system lose synchronism, there is a large variation of voltages and currents throughout the power system. When the two areas are in phase, the voltages are at a maximum and the currents are at a minimum. Conversely, when the two areas are 180 degrees out of phase, the voltages are at a minimum and the currents are at a maximum. The large variation of voltages and currents is shown in Figure 2.102.

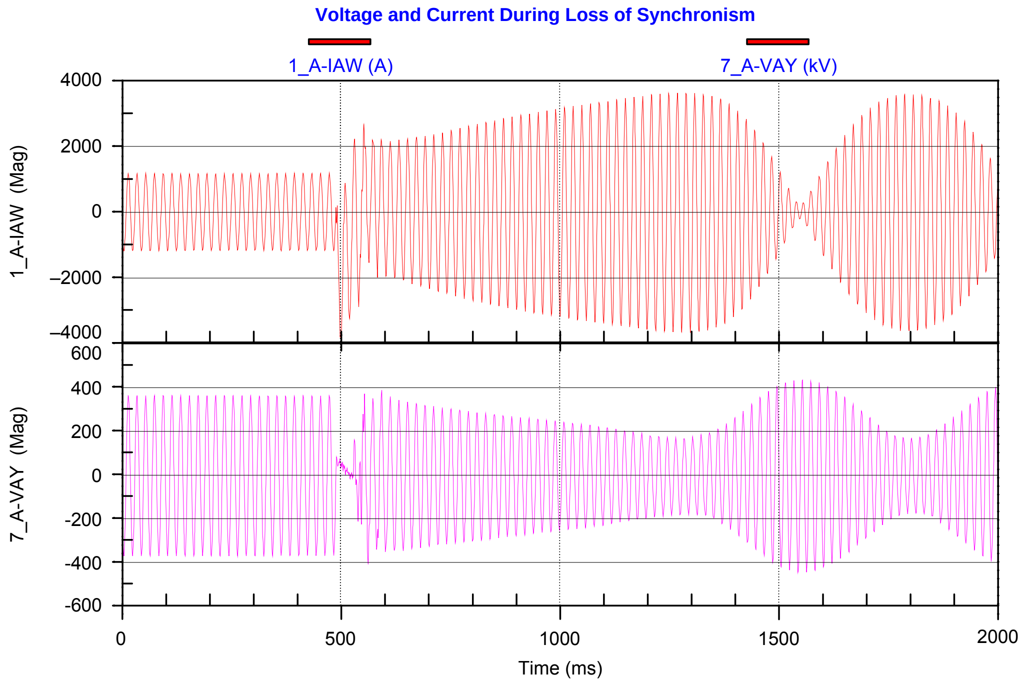


Figure 2.102 Voltage and current during loss of synchronism

2.4.12.2 Impedances Measured by Distance Relays During Power Swings

During a system OOS event, a distance relay may detect the OOS as a phase fault if the OOS trajectory enters the operating characteristic of the relay. To demonstrate this, let us look at the impedance that a distance relay measures during an OOS condition for a simple two-source system.

Using the receiving-end source R as a reference, we can express the sending-end source as $E_S\angle\delta$. The current flowing on the line is:

$$I = \frac{E_S\angle\delta - E_R}{X} \tag{2.48}$$

The voltage measured at the sending-end bus can be found as:

$$V = E_S\angle\delta - X_S \bullet I \tag{2.49}$$

The measured impedance can then be expressed as:

$$Z1 = \frac{V}{I} = -X_S + X\frac{E_S\angle\delta}{E_S\angle\delta - E_R} \tag{2.50}$$

Assume $E_S = E_R$ for a special case, then:

$$\begin{aligned} Z1 &= -X_S + X\frac{1}{1-\angle-\delta} \\ &= -X_S + X\frac{1+\angle\delta}{(1-\angle-\delta)(1+\angle\delta)} \\ &= -X_S + X\frac{1+\cos\delta + j\sin\delta}{2j\sin\delta} \\ &= -X_S + X\left[\frac{1}{2} - j\left(\frac{1+\cos\delta}{2\sin\delta}\right)\right] \\ &= \left(\frac{X}{2} - X_S\right) - j\left(\frac{X}{2}\cot\frac{\delta}{2}\right) \end{aligned} \tag{2.51}$$

This result shows that when δ changes from 0–360 degrees during an OOS, the impedance trajectory of Z_1 follows a straight line that offsets from the origin by $X / 2 - X_S$ and is perpendicular to the total reactance X. This Z_1 trajectory is shown in Figure 2.103 for a pure reactance system. When $E_S \neq E_R$, the Z_1 trajectory follows a group of circles, as shown in the same figure.

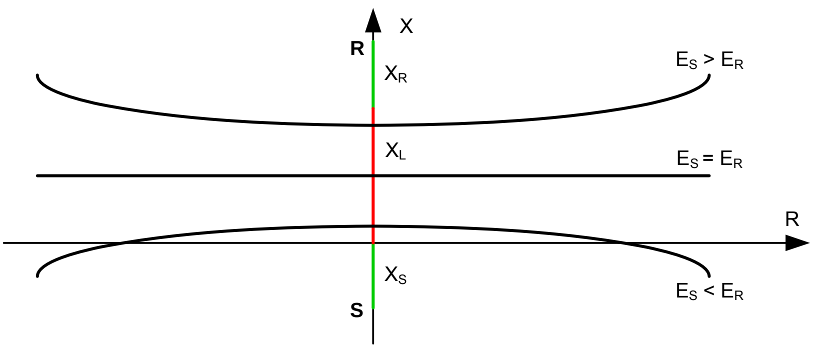


Figure 2.103 Z_1 trajectory of OOS for different E_S and E_R ratios

Effect of Instability on Distance Relaying Systems

The loss of synchronism between power systems or a generator and the power system affects transmission line relays and systems in various ways. Some relay systems, such as segregated-line differential relay systems, will not respond to an OOS condition. Other relays, such as overcurrent, directional overcurrent, and distance relays, may respond to the variations of voltage and currents and their phase-angle relationship. In fact, some of the above relays may even operate for stable power swings for which the system should recover and remain stable.

Phase distance relays measure the positive-sequence impedance for three-phase and two-phase faults. It has been shown earlier that the positive-sequence impedance measured at a line terminal during an OOS condition varies as a function of the phase-angle separation δ between the two equivalent system source voltages. Distance relay elements will operate during a power swing, stable or unstable, if the swing locus enters the distance relay operating characteristic. Keep in mind that the Zone 1 distance relay elements with no intentional time delay are the distance relay elements most prone to operate during a power swing. Zone 2 distance relay elements used in pilot relaying systems (e.g., blocking or permissive type relay systems) are also very prone to operate during swings. Backup zone step-distance relay elements will not typically operate during a swing, depending on their time-delay setting and the time it takes for the swing impedance locus to traverse through the relay characteristic. Figure 2.104(a) shows the operation of a Zone 1 distance relay when the swing locus goes through its operating characteristic, and Figure 2.104(b) shows a directional comparison blocking scheme characteristic and how it may be impacted by the swing locus.

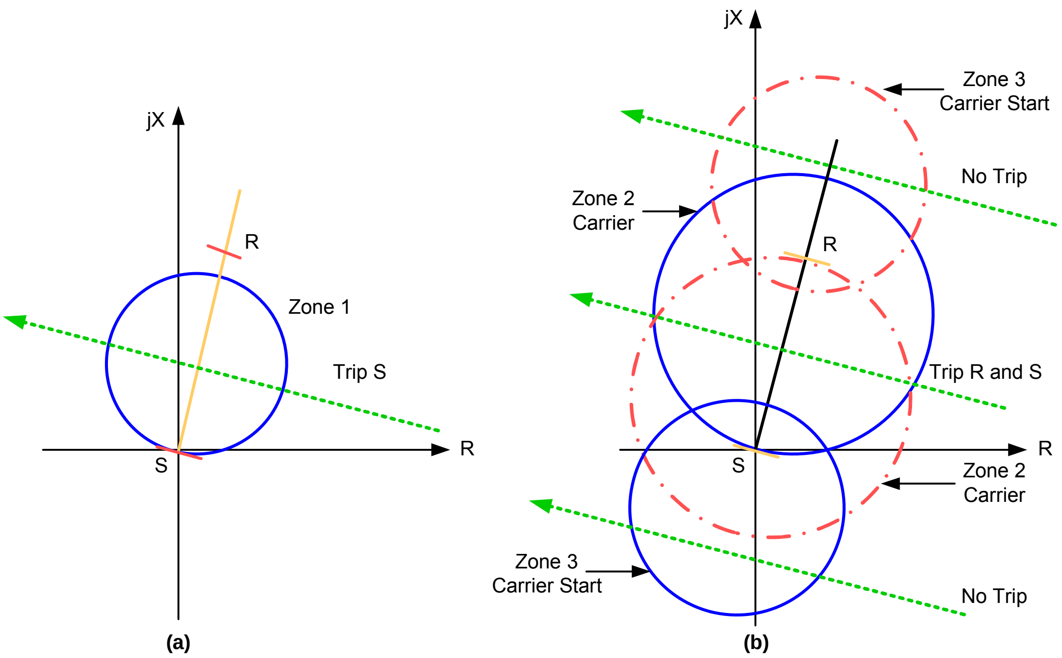


Figure 2.104 Zone 1 distance relay (a) and directional comparison blocking scheme (b) characteristics

It is important to recognize that the relationship between the distance relay polarizing memory and the measured voltages and currents plays the most critical role in whether a distance relay will operate during a power swing. Another important factor in modern microprocessor-based distance relays is whether the distance relay has a frequency-tracking algorithm to track system frequency. Relays without frequency tracking will experience voltage polarization memory rotation with respect to the measured voltages and currents. Furthermore, the relative impedance magnitude of the protected line and the equivalent system source impedances are important factors in the performance of distance relays during power swings. If the line positive-sequence impedance is large when compared with the system impedances, the distance relay elements may not only operate during unstable swings but may also operate during swings from which the power system may recover and remain stable.

2.4.12.3 Power-Swing Detection Methods With Distance Relay Characteristics

The fact that the voltage/current variation during a power swing is gradual, while it is virtually a step change during a fault, allows OOS protection functions to detect stable power swings and OOS conditions. Both faults and power swings may cause the measured apparent positive-sequence impedance to enter into the operating characteristic of a distance relay element. A short circuit is an electromagnetic transient process with a short time constant. The apparent impedance moves from the prefault value to a fault value in a few milliseconds. On the other hand, a power swing is an electromechanical transient process with a time constant much longer than that of a fault. The rate of change of the positive-sequence impedance is much slower during a power swing or OOS condition than during a fault and depends on the slip frequency of the OOS. For example, if the frequency of the electromechanical oscillation is about 1 Hz and the impedance excursion required to penetrate the relay characteristic takes about half a period (a change in δ of 180 degrees), the impedance change occurs in about 0.5 seconds. When δ approaches 180 degrees during an OOS, the measured impedance falls into the operating characteristic of a distance relay for a particular transmission line. The impedance measurement by itself cannot be used to distinguish an OOS condition from a phase fault. The fundamental method for discriminating between faults and power swings is to track the rate of change of measured apparent impedance.

The difference in the rate of change of the impedance has been traditionally used to detect an OOS condition and then block the operation of distance protection elements before the impedance enters the protective relay operating characteristics. Actual implementation of measuring the impedance rate of change is normally performed though the use of two impedance measurement elements together with a timing device. If the measured impedance stays between the two impedance measurement elements for a predetermined time, then an OOS is declared and a PSB signal is issued to block the distance relay element operation. Impedance measurement elements with different shapes have been used over time. These shapes include double blinders, concentric polygons, and concentric circles, as shown in Figure 2.105.

To guarantee that there is enough time to carry out blocking of the distance elements after an OOS is detected, the inner impedance measurement element of the OOS detection logic must be placed outside the largest distance protection region that is to be blocked. The outer impedance measurement element for the OOS detection has to be placed away from the load region to prevent inadvertent PSB logic operation caused by heavy loads. These relationships among the impedance measurement elements, as shown in Figure 2.105(b), use concentric polygons as OOS detection elements. Note that some modern power-swing detection algorithms are not based on timing of the impedance trajectory movement through set impedance boundaries. These new algorithms depend on a continuous monitoring of the rate of change of the swing center voltage [35] or of the impedance trajectory [66].

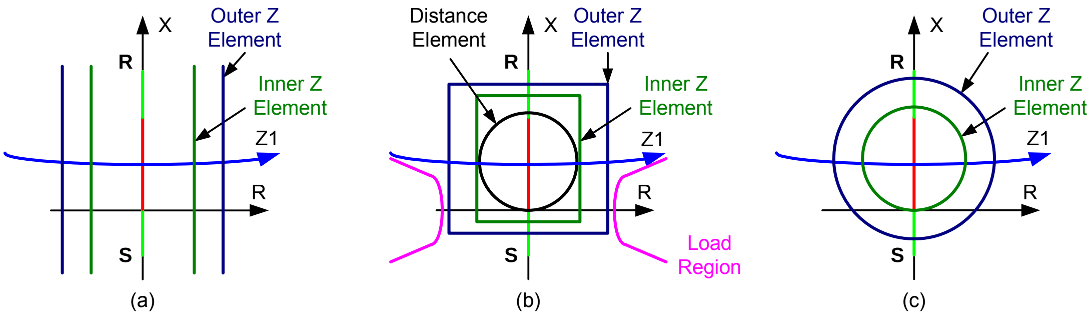


Figure 2.105 Different PSB characteristics

2.4.12.4 OOS Protection Functions

There are basically two functions related to OOS detection. The OST protection function discriminates between stable and unstable power swings and initiates network sectionalizing or islanding during loss of synchronism. The PSB protection function discriminates between faults and stable or unstable power swings. The PSB function must block relay elements prone to operate during stable and/or unstable power swings. In addition, the PSB function must allow relay elements to operate during faults or faults that evolve during an OOS condition.

OST schemes are designed to protect the power system during unstable conditions by isolating unstable generators or larger power system areas from each other with the formation of system islands. Stability within each island is maintained by balancing the generation resources with the area load.

To accomplish this, OST systems must be applied at preselected network locations, typically near the network electrical center, and network separation must take place at such points to preserve a close balance between load and generation. However, as discussed earlier, many relay systems are prone to operate at different locations in the power system during an OOS condition and cause undesired tripping. Therefore, OST systems must be complemented with PSB functions to prevent undesired relay system operations, prevent equipment damage and shutdown of major portions of the power system, and achieve a controlled system separation.

In addition, PSB must be used at other locations in the network to prevent system separation in an indiscriminate manner. Where a load-generation balance cannot be achieved, some means of shedding nonessential load or generation will have to take place to avoid a complete shutdown of the area.

Typically, the location of OST relay systems determines the location where system islanding takes place during loss of synchronism. However, in some systems, it may be necessary to separate the network at a location other than the one where OST is installed. This is accomplished with the application of a transfer tripping type of scheme. Another important aspect of OST is to avoid tripping a line when the angle between systems is near 180 degrees. Tripping during this condition imposes high stresses on the breaker and can cause restrikes and breaker damage.

While the OOS relaying philosophy is simple, it is often difficult to implement it in a large power system because of the complexity of the system and the different operating conditions that must be studied. The selection of network locations for placement of OST systems can best be obtained through transient stability studies covering many possible operating conditions. The maximum rate of slip is typically estimated from angular change versus time plots from stability studies. With the above information at hand, reasonable settings can be calculated for well designed OST relaying schemes.

The recommended approach for OOS relaying application is summarized below [34] [35]:

- Perform system transient stability studies to identify system stability constraints based on many operating conditions and stressed system operating scenarios. The stability studies will help identify the parts of the power system that impose limits to angular stability, generators that are prone to go out of step during system disturbances and those that remain stable, and groups of generators that tend to behave similarly during a disturbance. The results of stability studies are also used to identify the optimal location of OST and PSB protection relay systems because the apparent impedance measured by OOS relays is a function of the MW and MVAR flows in the transmission lines.
- Determine the locations of the swing loci during various system conditions, and identify the optimal locations to implement the OST protection function. The optimal location for the detection of the OOS condition is near the electrical center of the power system. However, we must determine that the behavior of the impedance locus near the electrical center would facilitate the successful detection of OOS. There are a number of methods to determine the system electrical center or whether the swing locus would go through a particular transmission line. Some of the methods are discussed in the Appendix.
- Determine the optimal location for system separation during an OOS condition. This will typically depend on the impedance between islands, the potential to attain a good load/generation balance, and the ability to establish stable operating areas after separation. To limit the amount of generation and load shed in a particular island, it is essential that each island have reasonable generation capacity to balance the load demand. High-impedance paths between system areas typically represent appropriate locations for network separation.
- Establish the maximum rate of slip between systems for OOS timer setting requirements as well as the minimum forward and reverse reach settings required for successful detection of OOS conditions. The swing frequency of a particular power system area or group of generators relative to another power system area or group of generators does not remain

constant. The dynamic response of generator control systems, such as automatic voltage regulators, and the dynamic behavior of loads or other power system devices, such as SVCs and FACTS, can influence the rate of change of the impedance measured by OOS protection devices.

- For PSB schemes, the OOS logic uses two concentric polygons, an outer zone and an inner zone. Two factors affect the OOS outer and inner zones impedance settings: the outermost overreaching zone of phase distance element you want to block and the load impedance the relay measures during the maximum anticipated load. The inner zone must be set to encompass the outermost overreaching zone of the phase distance element you have selected for PSB. Set the outermost zone such that the minimum anticipated load impedance locus is outside the outermost zone. The OOS block time delay is set based on the settings of the inner and outer resistance blinders and the fastest stable swing frequency.
- For OST schemes, set the OST inner zone at a point along the OOS swing trajectory where the power system cannot regain stability. Set the OST outer zone such that the minimum anticipated load impedance locus is outside the outermost zone. The OST time delay is set based on the settings of the inner and outer zone resistance blinders and the fastest OOS swing frequency expected or determined from transient stability studies. When the swing impedance locus enters the outermost OOS zone, two timers are started: one detects PSB conditions (PSBD) and the other detects OST conditions (OSTD). The logic detects an OST condition if the OSTD timer expires and the positive-sequence swing impedance locus enters the OOS inner zone before the PSBD timer expires. The OST logic allows one to trip on the way in (TOWI) or trip on the way out (TOWO). TOWI is selected if one desires to trip when the OSTD timer expires and the swing positive-sequence impedance enters the OST inner zone. TOWO is selected when one desires to trip when the OSTD timer expires and the swing positive-sequence impedance enters and then exits the OST inner zone. TOWO is the most common way to apply OST because the breakers will be given a tripping command when the two equivalent voltage sources will be close to an in-phase condition. In rare occasions, system stability requirements are such that a TOWI is desired. Care should be exercised in such cases because the tripping command to circuit breakers will be issued when the two equivalent voltage sources will be close to an out-of-phase condition. Therefore, to avoid breaker damage and ensure personnel safety, the user needs to verify with the circuit breaker manufacturer that the circuit breakers are capable of tripping for such a system condition.

2.4.12.5 Distance Protection Requirements During Power Swings

Ideally, the performance requirements of protective relays under system OOS condition should be identical to those under normal system operations in terms of speed, selectivity, reliability, and sensitivity. However, due to the nature of the distance relay elements under system OOS, it is almost impossible to demand the same performance of the distance elements as those under normal system fault conditions.

When a distance relay detects a swing or OOS condition, it sets a PSB Relay Word bit that may be used to block the distance element operations. These distance elements are operative again in case of unbalanced faults only if fault detection elements asserted during these faults reset the PSB. Traditionally, negative-sequence currents with some time delay reset the PSB condition. This time delay is necessary to coordinate with other protective devices in the event that the fault is external to the protected line section. A simple time delay does not guarantee coordination between relay systems when the OOS center moves from one transmission line to another one on the system. A simple time delay is also not applicable on parallel-line systems to restrain the distance relay from tripping for external faults. On parallel-line systems, a fault is internal to the pair of relays on one line but external to the pair of relays on the other line. In Figure 2.106, for example, the OOS center cuts through the parallel lines and an unbalanced fault occurs on Line 2.

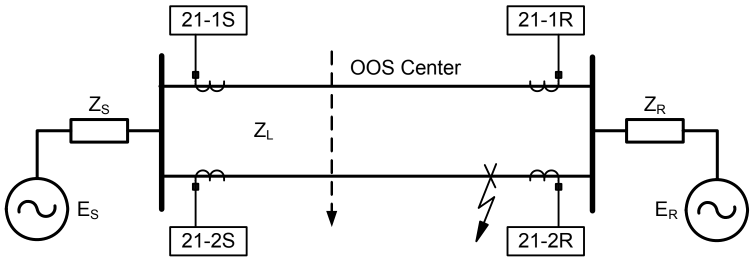


Figure 2.106 Parallel-line systems

To achieve the security for external faults during system OOS, one possible solution is to not reset the PSB of Zone 1 distance elements because of the instantaneous overreach danger of these elements. Instead, we could rely on the Zone 2 elements, together with a Permissive Overreaching Transfer Trip (POTT) scheme, to gain the security.

Figure 2.107 shows how such a scheme works for the given fault during a system OOS situation. For relays on Line 2, on which the fault occurs, both relays detect the fault within their Zone 2 reach after, for example, the forward negative-sequence overcurrent element resets the PSB. In the POTT scheme, Zone 2 elements send out a permissive transfer trip to the other end and issue a trip locally if a permissive signal is received. Therefore, the relays on Line 2 will correctly operate and isolate the fault that is internal to them. For the relays on Line 1, the relay at Terminal S sees the fault within its forward Zone 2 region and keys the permissive signal to the relay at Terminal R. The relay at Terminal R, however, detects the fault in its reverse direction, does not send a permissive signal, and disregards the received permissive signal from the relay at Terminal S. Therefore, the relays on Line 1 are secure for this external fault on Line 2.

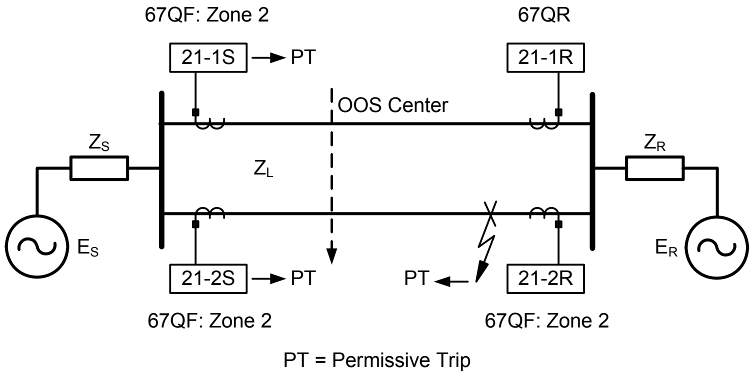


Figure 2.107 Use POTT scheme to gain protection security during system OOS

Implementing such a POTT scheme during system OOS requires that the distance relay have two directional negative-sequence overcurrent elements to reset PSB for Zone 1 and Zone 2 distance elements separately. The directional negative-sequence overcurrent element that is used to reset PSB for the Zone 1 element must have torque control capability to allow users to disable resetting the PSB bit for the Zone 1 elements as their application requires.

Single-pole tripping is an important method to minimize the impacts to the power system after it is disturbed by SLG faults. To ensure that the power system can be separated in a controlled manner and balanced regional operations can be achieved during system OOS, it is especially important that the distance relays retain the single-pole tripping capability during system OOS. However, as we shall see below, it is quite difficult for the distance elements to discern the faulted phase during system OOS.

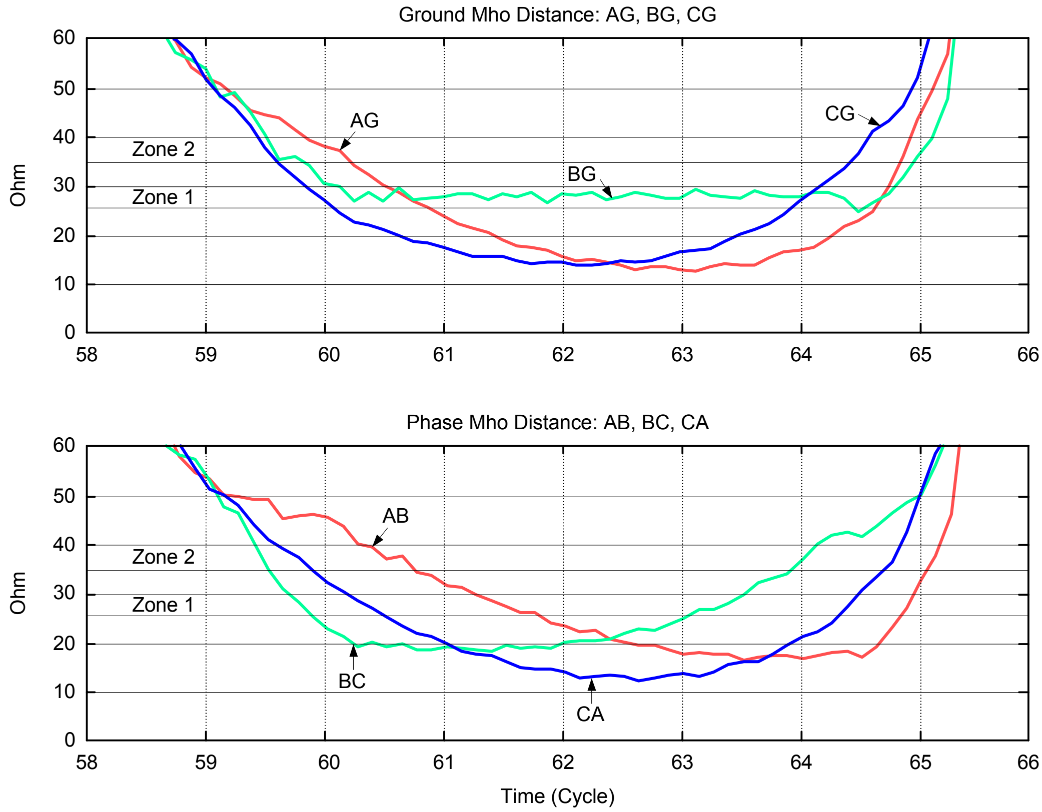


Figure 2.108 Distance calculations for a BG fault during system OOS

For a B-phase ground fault at the end of a line, the upper plot of Figure 2.108 shows the distance calculations for A-phase, B-phase, and C-phase elements. The faulted B-phase distance calculation provides the correct fault impedance. The distance calculations of unfaulted phases move into protection Zone 2 and Zone 1 regions as the machine δ approaches 180 degrees. The lower plot of Figure 2.108 shows the distance calculations of phase elements. All phase distance calculations move into protection regions as the machine δ approaches 180 degrees during system OOS.

It is not always possible for a distance relay to perform single-pole tripping for SLG faults during system OOS. This is because all distance fault measurement loops will overreach protection zones simultaneously when the OOS center falls on the protected line and when the fault occurs at a large machine δ angle, unless the distance relay has special algorithms designed to cope with such a problem.

2.4.12.6 Transient Stability Studies

The requirement for OOS protection (blocking and tripping) on a power system depends on whether a large disturbance rotor angle stability constraint exists. This is usually determined from transient stability studies involving numerous contingencies. These stability studies identify the following:

- The stability limits of the system for the different contingencies
- Those parts of the system that impose limits on system stability, for example, the high impedance paths created during loss of lines or generators
- Generators that are likely to go out of step during system disturbances
- Machines that tend to remain stable during system disturbances
- Generators that tend to swing together as a group during disturbances
- The maximum rate of slip between systems
- Whether the islands created after separation will maintain synchronism

2.5 QUANTITIES INFLUENCING DISTANCE MEASUREMENTS

2.5.1 Multiterminal and Tapped Lines

Multiterminal lines are lines that have three or more terminals, each with substantial generation. Applying distance relays for the protection of three-terminal lines is more complex than the application for two-terminal lines because of the infinite variety of tap locations, line impedances, source impedances, system loading requirements, and system operating conditions involved. In this section, we will discuss the effects of the three-terminal line configuration on the distance elements and the application considerations and settings for various communications-assisted pilot protection schemes.

2.5.1.1 Apparent Impedance

The apparent impedance seen by a distance relay for various system and fault conditions is an important concept when determining the settings of the distance functions. The impedance "seen" by a distance relay is not always the actual line impedance from a relay terminal to the point of fault. This is because the relay measures impedance based on the voltage drop between its location and the fault and the line current at its location. Thus, the impedance "seen" by the relay will depend on the current contributions from the other terminals. Consider the system shown in Figure 2.109. Due to the infeed current at Terminal T, the distance relay at Terminal R will see an apparent impedance of 3 ohms, which is greater than the actual impedance to the fault.

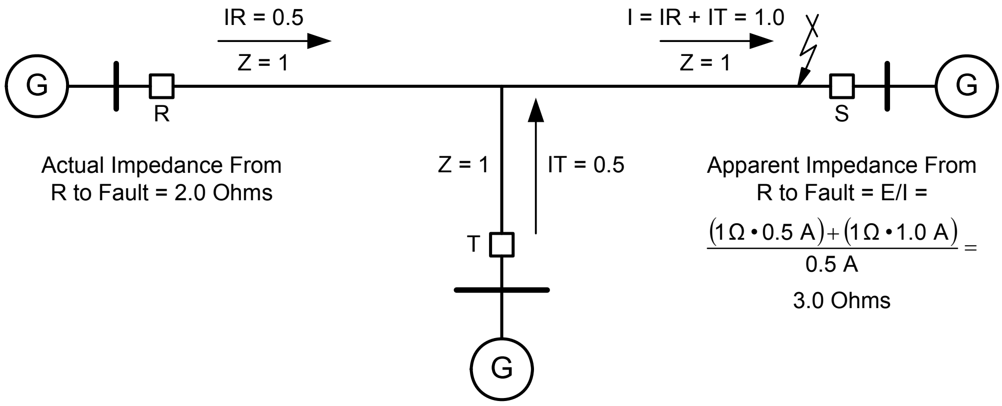


Figure 2.109 Apparent impedance due to infeed

The system shown in Figure 2.110 has an outfeed current at Terminal T rather than an infeed current. In this case, the apparent impedance seen by the relay at Terminal R for a fault at Terminal S is 1.5 ohms, which is less than the actual impedance to the fault. An additional problem is also introduced by the current outfeed at Terminal T; because the current flows out of the line at T, a forward looking distance relay will not see this internal fault. In fact, if there is a blocking unit at T, it may "see" the internal fault as an external fault and, thus, prevent communications-assisted tripping.

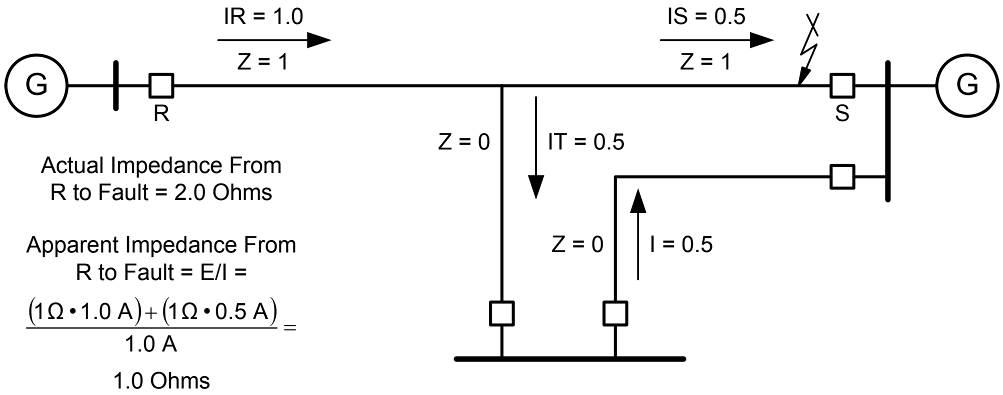


Figure 2.110 Apparent impedance due to outfeed

In many three-terminal line applications, the third terminal may be a transformer-terminated load tap, as shown in Figure 2.111. In this application, there may be no positive- or negative-sequence current source at the tap. However, if the line side of the transformer is grounded-wye, there will be a significant source of zero-sequence current. In this application, the infeed current does not affect the phase-distance elements; however, the ground distance elements will be affected.

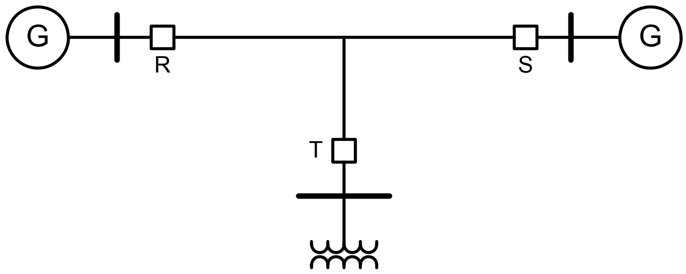


Figure 2.111 Transformer tap

It is evident from these simple examples that the apparent impedance measured by the distance relay will be affected by the current contributions at the various line terminals. The reach of the Zone 1 instantaneous-tripping elements and the Zone 2 permissive-overreaching elements must be determined based on system conditions to ensure that they provide the desired performance.

2.5.1.2 Zone 1 Element Reach Setting

The Zone 1 distance elements must be set so that they do not overreach the nearest remote line terminal for any system operating condition. A typical setting would be 80–90 percent of the positive-sequence line impedance to the nearest terminal. In systems subject to current infeed, the impedance is based on the actual line impedance, rather than on the apparent impedance. If the reach was set based on the apparent impedance due to the infeed, the Zone 1 element could overreach if the breaker at the terminal that is contributing the infeed is open. If the system can experience current outfeed, however, then the reach of the Zone 1 elements may need to be reduced in order to prevent misoperation because the apparent impedance to the fault will be less than the actual impedance to the fault.

2.5.1.3 Zone 2 Element Reach Setting

In communications-assisted tripping scheme applications, the Zone 2 distance elements are used as the permissive tripping elements. In general, it is desirable that the permissive distance elements at every terminal assert for all internal faults. In two-terminal line applications, a reach setting of 125 percent of the line impedance typically meets this requirement. In three-terminal line applications, the reach may need to be extended to at least 125 percent of the apparent impedance for a remote-end fault. When DCB or POTT with echo schemes are used, it is also possible to have “sequential” high-speed tripping of the circuit breakers at every terminal. When the line is protected with a DCB scheme, high-speed pilot tripping may be initiated at any terminal where the overreaching functions assert, provided that no blocking functions assert at any terminal. Therefore, even if the overreaching function at only one terminal sees the fault, the relay at that terminal can operate. Once its associated circuit breaker has opened, any infeed from that terminal is eliminated and the overreaching functions at the other two terminals may see the fault and issue a pilot trip. Thus, while all three breakers do not operate simultaneously, there is no intentional time delay added to clear the fault, such as is needed for a time-delayed backup trip. The POTT scheme with Echo can operate in a similar manner as the DCB scheme; however, with the weak infeed trip option, the POTT scheme can initiate high-speed tripping at every terminal if an overreaching function from at least one terminal sees the fault.

The sensitivity of the Zone 2 permissive overreaching elements may be improved by including a ground directional overcurrent element in the communications-assisted scheme design using logic control equations.

2.5.1.4 Communications-Assisted Tripping Schemes

Modern distance relays include communications-assisted tripping schemes that provide unit-protection for transmission lines with the help of pilot communications. No external coordination devices are required. Typical communications-assisted tripping schemes considered in Section 2.4.2 of this report are listed below:

- Permissive underreaching transfer trip (PUTT)
- Permissive overreaching transfer trip (POTT)
- Directional comparison unblocking (DCUB)
- Directional comparison blocking (DCB)

2.5.1.5 Effects on Fault Locating

Most modern distance relays include a single-ended fault-locating algorithm that uses local currents and voltages to derive an estimated fault location. The fault-locating algorithm on three-terminal line applications is affected by the current infeed or outfeed, just as the distance elements. In some applications, the line constants may not be the same for each of the line sections from the tap point to the relay locations. This will introduce additional errors in the fault-location estimation. In general, the fault-location estimation will be correct for faults between the relay location and the tap point. Thus, one of the three fault-location estimates should always be correct.

Multiterminal fault-locating algorithms can provide a correct fault-location estimate, even in three-terminal applications, if one has access to all the event report data captured by numerical relays at all line terminals [36].

2.5.2 Parallel Lines

Parallel lines are widely employed, particularly in industrialized areas, to transport large amounts of power through narrow line corridors. It is generally less expensive to construct a parallel line using the same right-of-way than building a separate line. In many cases, two or more circuits of different or equal voltage levels are constructed in the same right-of-way, or they utilize the same transmission towers. Parallel lines, even though they provide many economical benefits, bring about particular protection challenges.

When two or more lines are parallel on the same right-of-way, the sum of the conductor currents during ground faults in one of the parallel lines is unbalanced. This causes an induced longitudinal voltage in each of the parallel lines because of zero-sequence mutual coupling. Typical self and mutual sequence impedances of a double-circuit 230 kV line are listed in Table 2.14.

Table 2.14 Sequence impedances of a double-circuit 230 kV line

	Ohms/mi	Magnitude	Angle
Z_{1L}	0.0955 + j 0.760	0.766	82.8 degrees

Z_{0L}	0.3627 + j 2.438	2.465	81.5 degrees
Z_{0M}	0.2672 + j 1.501	1.525	79.9 degrees

The zero-sequence mutual impedance between circuits is about 62 percent of the zero-sequence self impedance. The positive- and negative-sequence mutual impedances between the circuits are very low and can usually be ignored in the application of distance relays. On the other hand, the zero-sequence mutual impedance is significant, and its effect on ground distance relays must be considered.

The presence of mutual coupling in the zero-sequence network causes an underreach or overreach in ground distance relay measurement depending on the power system configuration in the vicinity of the relay location. Zero-sequence mutual coupling can cause under- and overreaching problems on both the faulted line and nonfaulted line relaying terminals for parallel line applications employing ground distance elements or fault location. Ground distance relays can also overreach when the parallel line is out-of-service for maintenance and is grounded at both ends. Ground distance element underreach is synonymous to calculating "larger" impedance, and overreach is synonymous to calculating "smaller" impedance. In general, the following apply:

1. The ground distance element underreaches when the residual currents flow in the same direction on the parallel lines.
2. The ground distance element overreaches when the residual current flow in the offending parallel line is in the opposite direction to the residual current in the line where the measurement is performed.

Figure 2.112 and Figure 2.113 show two cases of a typical system having mutual coupled parallel lines that cause a ground distance relay at Breaker 3 to overreach [37]:

1. Line-to-ground fault at Bus R with the bus-tie breaker open and with the zero-sequence current in Line 2 being a large percentage of the zero-sequence current in Line 1.
2. Line-to-ground fault at Bus R with Breakers 1 and 2 open, and Line 2 has grounding chains on all phase conductors at both line ends.

Both conditions cause an increase of zero-sequence current in Line 1, because of zero-sequence mutual coupling, over the expected zero-sequence current magnitude without mutual induction. The increase in the zero-sequence current in Line 1 for the above two conditions causes the ground distance element at Breaker 3 to overreach because of the reduction in the measured apparent impedance. This is of concern in the application of Zone 1 ground distance relays because they should not operate for these conditions. It is typically necessary to modify the Zone 1 ground distance relay setting to prevent an undesirable operation.

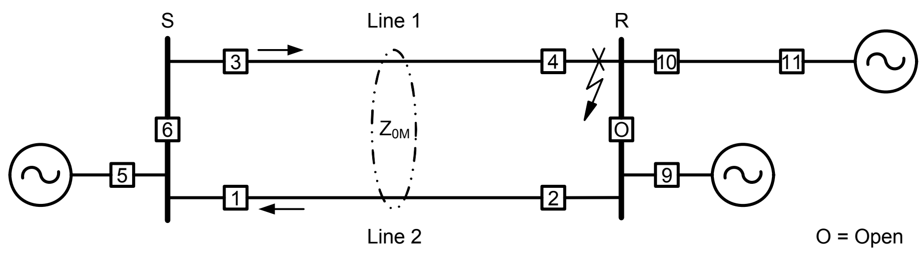


Figure 2.112 Breaker 3 Zone 1 ground distance relay potential overreach for a fault at Bus R with Bus R tie breaker open

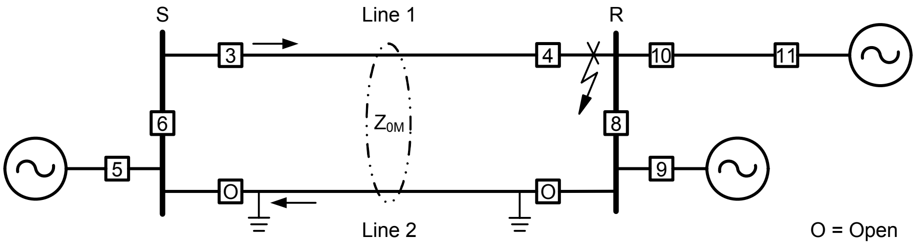


Figure 2.113 Breaker 3 Zone 1 ground distance relay potential overreach for a fault at Bus R with Line 1 open and grounded

The zero-sequence fault current in both Lines 1 and 2 will flow in the same direction, as shown in Figure 2.112, for a fault at Bus R when the bus-tie breaker at Bus R is closed. This condition causes a larger apparent impedance measurement than it actually is for both ground distance relays at Breakers 1 and 3 at Bus S. This fault condition causes an underreach of ground distance elements, and the important consideration here is to make certain that overreaching distance elements used in a stepped distance or pilot-relaying scheme will operate for this remote bus fault with adequate margin.

In applications where parallel lines are served from a single zero-sequence source (Figure 2.114), the percentage of under- and overreach is more pronounced than that of parallel lines where zero-sequence sources exist at both line ends. This switching arrangement arises when only load is served at the remote Bus R or when lines to the right of this remote bus are open for maintenance.

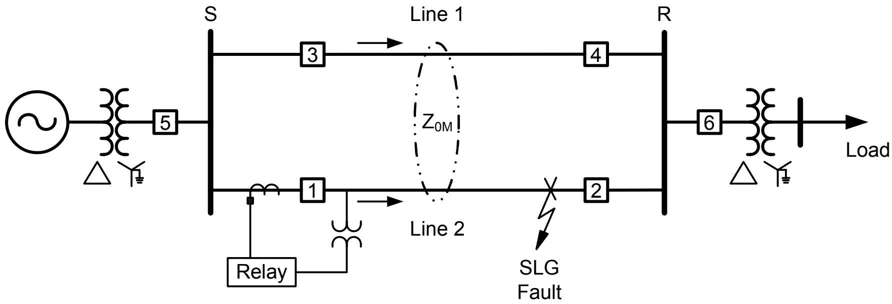


Figure 2.114 Mutually coupled parallel lines with a single zero-sequence source

To overcome the overreaching and underreaching problems mentioned above, protection engineers can choose between different methods:

1. In the ground distance relay of the protected line, introduce the residual current from the offending parallel line, and apply a compensation algorithm in the apparent impedance calculation.
2. Assign and adapt individual settings groups to different operating conditions (parallel line in service, out of service, or out of service and grounded) by considering the effective mutual coupling of the different operating conditions.

2.5.2.1 Zero-Sequence Mutual Compensation Methods

It is theoretically possible to compensate a ground distance relay such that the effect of the zero-sequence mutual coupling on its reach is minimal. This is typically accomplished by bringing the current from the offending parallel line, I_{RM}, into the ground distance relay of the protected line and applying a zero-sequence mutual compensation factor, k_{0M}, to offset the increase or decrease of the zero-sequence voltage induced in the protected line.

The different mutual compensation methods to consider are discussed in more details in [38]. Some of these methods often lead to misoperation of relays connected to the parallel nonfaulted line unless the user is extremely careful with the ground distance relay settings. As the system complexity grows with an increasing number of lines, the user must take extreme care in using ground distance mutual compensation. Application of zero-sequence mutual compensation requires many contingency evaluations and extensive review of the power system under faulted conditions. The application of zero-sequence mutual compensation may be undesirable for a number of reasons listed below, and many relay manufacturers discourage its use or do not provide such compensation in their ground distance relays:

- It is not possible to obtain the zero-sequence current from the parallel line when the lines run in parallel for only a portion of their total length and do not terminate at the same substation at one or both ends.
- It is not possible to obtain the zero-sequence current from the parallel line when the line is out of service for maintenance and is grounded at both line ends, because the application of grounding points are away from the CT locations and the line is isolated from the line breakers with line disconnect switches.
- It is not possible to use mutual compensation when several lines share the same right of way, or more than two circuits share the same transmission tower.
- Application of zero-sequence mutual compensation may cause the ground distance relay of the unfaulted line to loose directionality for a close-in reverse line-to-ground fault on the parallel line, because the zero-sequence compensation current may overpower the actual line currents and allow the ground distance relay to operate.
- Protection engineers do not prefer to mix currents from different line terminals into one relay panel because of the possibility of incorrect installation, for safety considerations, and to avoid testing mistakes.

The residual current from the offending parallel line, $I_{RM,}$ can be routed to the relay shown in Figure 2.115 in order to compensate for the zero-sequence mutual coupling. The voltage measured at the relay location is represented by the following expression (ignoring fault resistance):

$$V_A = m \bullet Z_{1L} \bullet (I_A + k_0 \bullet 3I_0 + k_{0M} \bullet I_{RM}) \tag{2.52}$$

Where:

m = p.u. distance to the fault

Z_{1L} = positive-sequence line impedance

I_A = A-phase current measured by the relay

$3I_0$ = residual current measured by the relay ($3I_0 = I_A + I_B + I_C$)

k_0 = $\dfrac{Z_{0L} - Z_{1L}}{3Z_{1L}}$

k_{0M} = $\dfrac{Z_{0M}}{3Z_{1L}}$

Z_{0L} = zero-sequence line impedance

Z_{0M} = zero-sequence mutual coupling impedance

I_{RM} = residual current from offending line

Rearranging (2.52) in the form of an apparent impedance measured by the relay in p.u.:

$$Z_{APP} = \frac{V_A}{Z_{1L} \bullet (I_A + 3I_0 + k_{0M} \bullet I_{RM})} \tag{2.53}$$

Where:

V_A = Phase-A voltage measured by the relay

Z_{APP} = apparent impedance measured by the relay

The term $k_{0M} \bullet I_{RM}$ in the denominator of (2.53) is the error term if we do not make any corrections using a zero-sequence mutual compensation method.

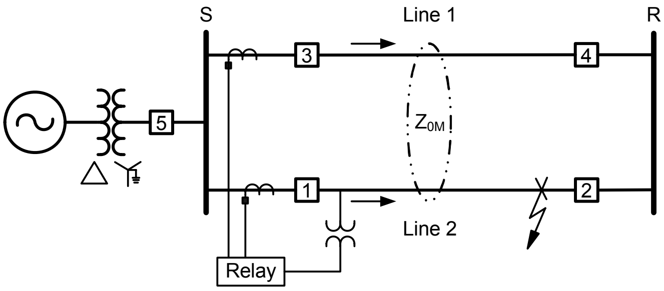


Figure 2.115 Mutual compensation using the zero-sequence current from Line 1 into the ground distance relay in Line 2

Method 1

Measure I_{RM} and use $\dfrac{I_{RM} \bullet Z_{0M}}{3 \bullet Z_{1L}}$ in the denominator of ground fault location calculations.

This method is fraught with difficulties for the sound (or nonfaulted) line relaying system. The residual current, I_{RM}, of the offending line can be much larger than the residual current measured on the healthy line when a close-in fault occurs on the offending line, and a single zero-sequence source is located behind the relaying terminal. I_{RM} equals $3I_0$ for both relaying terminals at the opposite end. The resulting apparent impedance is greatly reduced and positive at the terminal where I_{RM} is less than $3I_0$ (assuming $3I_0$ and I_{RM} are in phase) because I_{RM} is used in the denominator. If I_{RM} and $3I_0$ are in antiphase, the sign of the apparent impedance measured is correctly negative but errant in magnitude.

Method 2

Measure I_{RM} and use a k_0 factor, which is dependent upon the ratio of $I_{RM} / 3I_0$. This k_0 factor is then used in the ground fault distance algorithms. This method simply uses the ratio of $I_{RM} / 3I_0$ to determine which k_0 factor is appropriate. Switch the compensation factor, k_0, used in the ground distance calculations depending on the magnitude of I_{RM}. If $I_{RM} / 3I_0 \leq 1$ (± margin), the ground distance calculations use one k_0 factor. If $I_{RM} / 3I_0 > 1$, the ground distance element uses an alternate k_0 factor. I_{RM} is not used in the ground distance calculations but is used as a simple switching indicator for the k_0 factor.

A weakness of this method is that it does not take into consideration the direction of I_{RM}. Therefore, undesirable overcompensation occurs when the parallel faulted line experiences sequential tripping.

Method 3

Measure I_{RM} and use a k_0 factor, which is dependent upon the ratio of $I_{RM} / 3I_0$ and the direction of I_{RM} relative to $3I_0$. This k_0 factor is then used in the ground fault distance algorithms. This method requires that the relay perform a directional decision independent of the apparent impedance calculation.

This method is the most secure and can work for some applications if implemented appropriately. The difficulties with this method come with changing switching arrangements or the isolation of zero-sequence sources.

Method 4

Ignore the residual current from the offending line. Compensate for the known under- and overreach with appropriate Zone 1 and Zone 2 distance relay reach settings or with different zero-sequence current compensation factors for Zone 1 and overreaching zones.

There are actually few problems associated with this method. Later in this section, we make simple recommendations for calculating the appropriate Zone 1 and Zone 2 distance reach or the different zero-sequence current compensation factors for Zone 1 and overreaching zones. Alternate settings groups are necessary for different system switching configurations.

Table 2.15 shows the different switching states of the parallel line and the measured impedances in each case for a fault at the end of the parallel line, as shown in Figure 2.114, with the following assumptions:

- The phase current and zero-sequence current of the protected line are equal ($I_A = 3I_0$).
- The offending line residual current, I_{RM}, is equal to the residual current of the protected line.

Table 2.15 Calculated impedances for different switching arrangements depending on the state of the parallel line

State of Parallel Line	Calculated Impedance
In service	$Z_{App} = Z_{1L} + \frac{Z_{0M}}{3(1+k_0)}$
Out of service and grounded at one point only or not grounded	$Z_{App} = Z_{1L}$
Out of service and grounded at both line ends	$Z_{App} = Z_{1L} - \frac{Z_{0M}^2}{3Z_{0L} \bullet (1+k_0)}$

The state of the offending parallel line can change dynamically from in service to switched off and not grounded because of a circuit breaker opening at one or both line ends. Ground distance relay settings of the protected line may be too slow to adapt in real time, and for this reason, a user needs to find a common settings parameter group that would serve both situations (e.g., offending parallel line in service or out of service and ungrounded). We refer to this as parameter Settings Group A in this section of the report.

The third condition, during which the offending parallel line is out of service and grounded at both line terminals, is a typical maintenance scenario and can use a different relay settings group that is activated during line maintenance conditions. We refer to this as parameter Settings Group B in this section of the report. Note that some electric utilities apply single-point grounding methods during line maintenance conditions. In such cases, the user may want to introduce an additional Settings Group C that is not compromised due to mutual coupling considerations.

Consequently, this kind of compensation of the mutual coupling effect requires at least two independent parameter sets (A and B) in the relay. In addition to that, we need two different zero-sequence current compensation factors, one for the underreaching zone (Zone 1) and one for the overreaching zones (Zone 2, etc.). Alternatively, different settings can be applied for the phase-to-ground and phase-to-phase fault reach of the overreaching zones.

2.5.2.2 Considerations for Parameter Settings Group A

The requirement for the Zone 1 ground distance relay is to detect ground faults at least up to 60 percent of the line length. Theoretically, 50 percent line coverage would be enough, but then we would have no safety margin. With 60 percent line coverage, ground faults on 20 percent of the line (middle part between 40 and 60 percent) can be cleared from both line terminals simultaneously. The remaining 80 percent of the line (0–40 and 60–100 percent) will normally be cleared sequentially.

For example, a close-in fault in front of Breaker 4 in Figure 2.116(a) will cause an instantaneous Zone 1 trip of Relay 4 and trip Breaker 4, while Relay 3 at Breaker 3 will underreach and see the fault at approximately 130 percent. After circuit Breaker 4 opens, as shown in Figure 2.116(b), the ground current on Line 2 changes its direction and is now opposite the direction of the faulted line ground current. This condition causes an overreach of Zone 1 ground distance relay at Breaker 3, which sees the fault at approximately 80 percent of the line by assuming equal infeed. Therefore, the Zone 1 ground distance relay will clear the line-end fault sequentially if it was set to reach at 85 percent of the protected line.

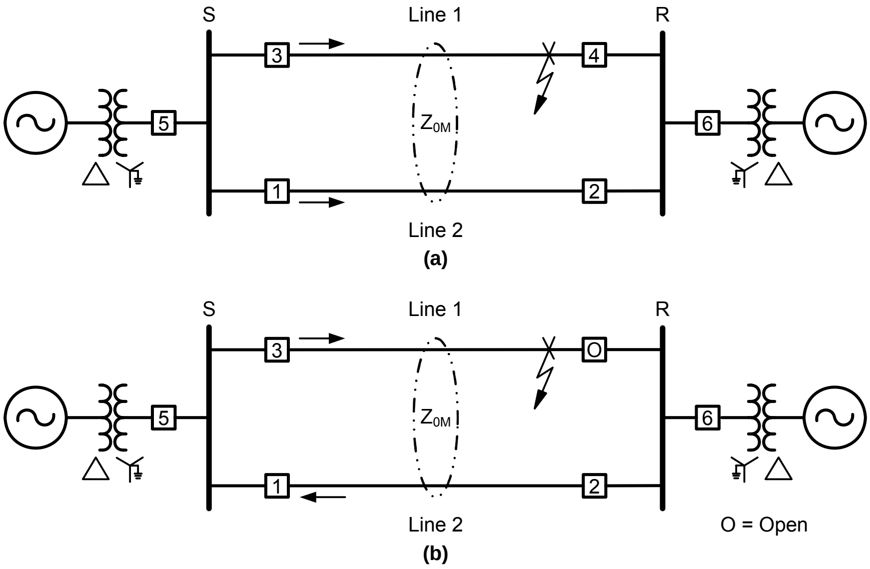


Figure 2.116 Sequential clearing of Line 1 causes current reversal on Line 2 and overreaching of Zone 1 ground distance relay at Breaker 3

The Relay 3 overreach depends on the infeed conditions from both sides. Without infeed from the remote end, assume Breaker 6 is open too in Figure 2.116(b), the Zone 1 relay at Breaker 3 will not operate for the line-end fault. In this case, a pilot scheme is required to guarantee instantaneous tripping of both line terminals, as in the case of a single line.

Because the Zone 1 ground distance relay must cover for ground faults up to 60 percent of the line length and not 60 percent of the line impedance, we must take into account the mutual coupling effect of the parallel line. The above condition is fulfilled if the following relation is true:

$$\frac{SMF \bullet Z_{1L}}{Z_{1L} + \dfrac{Z_{0M}}{3(1+k_0)}} > 0.6 \tag{2.54}$$

Where:

SMF = safety margin factor

Equation (2.54) is valid on the following two assumptions:

1. The relation between the measured impedance and the fault location is linear. This is not true, but we are on the safe side.
2. There is no infeed from the remote side, which represents the worst case.

For the line data in Table 2.14, using magnitudes and ignoring the angle, we have:

Z_{1L} = 0.766 ohms/mile

Z_{0L} = 2.465 ohms/mile

Z_{0M} = 1.525 ohms/mile

k_0 = 0.74

Evaluating the left side of (2.54) with SMF equal to 0.85 gives a value of 0.62, which is greater than 0.6 and the condition of (2.54) is fulfilled. For this line example, an 85 percent safety margin fulfills the requirement that the Zone 1 ground distance relay will detect faults up to 60 percent of the line length. When both lines are in service, a reach of 61.5 percent of line length results. When the parallel line is out of service and ungrounded, the Zone 1 ground distance element reaches 85 percent of line length, which is the desired safety margin for the underreaching Zone 1 setting.

The overreaching zone must cover faults occurring anywhere along the length of the line with a safety margin of at least 120 percent. To fulfill this criteria, it is necessary that a line-to-ground fault at the remote bus be detected by the overreaching zone with the parallel line in service. Ground distance elements at the local line terminals underreach during line-to-ground faults at the remote bus and beyond it when the parallel line is in service. Two possible solutions are available to deal with the underreaching effect. The first solution is to make an overreaching ground distance zone setting based on the apparent impedance measured for a line-to-ground fault at the remote bus with the parallel line in service, and apply a safety factor of at least 120 percent. This guarantees that the overreaching zone sees all line-to-ground faults on the line. This also assumes that the distance relay applied offers separate reach settings for the measuring elements of the phase and ground overreaching zones.

A fault on the parallel line may cause coordination problems in pilot schemes because the direction and magnitude of the residual current in the healthy line will change during the course of sequential fault clearing. The ground distance relay at Breaker 2 in Figure 2.116(b) will overreach and see line-to-ground faults throughout the whole length of the parallel line, especially if the source behind Bus S is weaker than the source behind Bus R. This overreaching effect should also be considered for the reverse looking zones of the relays at Breaker 1 in Figure 2.116(b) when a POTT or a DCB scheme is applied. The reverse looking zone of the ground distance relays at Breaker 1 must reach further that the forward pilot overreaching zone of the ground distance relays at Breaker 2 for all line-to-ground faults in Line 1 in order to avoid a misoperation of the healthy Line 2.

The second solution is to use a modified zero-sequence current compensation factor defined as k_0* and given by (2.58). This is possible only if the distance relay offers different zero-sequence current compensation factors for under- and overreaching zones. A line-to-ground fault at the end of the line is measured as 100 percent when the parallel line is in service. The ground distance relay, using the modified zero-sequence current compensation factor, will overreach when the parallel line is switched off and is not grounded. This overreaching effect is acceptable for pilot relaying schemes; however, additional setting considerations may be necessary for backup time-delayed overreaching zones.

The third condition, when the parallel line is out of service and grounded at both ends, is considered a maintenance condition and can use a separate parameter settings group (Set B), as discussed below.

2.5.2.3 Considerations for Parameter Settings Group B

The ground distance relay at Breaker 3, as shown in Figure 2.117, overreaches for a fault at Bus R with Breakers 1 and 2 open and the parallel line grounded at both ends of the line. The Zone 1 ground distance relay should not overreach for this condition.

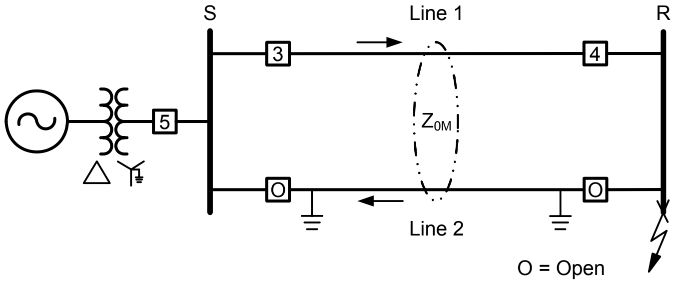


Figure 2.117 Parallel line open and grounded at both line ends

To fulfill this requirement, Zone 1 should be set at 80 percent of the apparent impedance measured for a fault at the end of the line with the parallel line grounded. Therefore, the Zone 1 ground distance element is set using (2.55) with a zero-sequence current compensation based on a single-circuit line.

$$Z_{1G} = 0.8 \cdot \left[Z_{1L} - \frac{Z_{0M}^2}{3Z_{0L} \cdot (1 + k_0)} \right] \quad (2.55)$$

The zero-sequence current compensation factors for the overreaching zones can be set to account for the effect of mutual coupling. The worst case of underreach due to mutual coupling occurs when the only source is located behind the distance relay and the ground fault is at the remote bus. The zero-sequence currents flowing in the parallel lines are equal when the ground fault is located at the remote bus. The compensated residual current used by the distance relay is expressed as:

$$I_a^{CR} = I_A + k_0 \bullet 3I_0 \tag{2.56}$$

The ground distance relay will measure the proper impedance if the compensated current is expressed as:

$$I_a^{CR} = I_A + \frac{Z_{0L} - Z_{1L}}{3Z_{1L}} \bullet 3I_0 + \frac{Z_{0M} \bullet I_{RM}}{3Z_{1L}} \tag{2.57}$$

Calculate a modified zero-sequence current compensation factor by equating (2.56) and (2.57) and solving for k_0, and define it as k_0*. Solving for k_0 gives the correct zero-sequence current compensation that should be applied to the overreaching ground distance zones, which is given as:

$$k_0^* = \frac{Z_{0L} - Z_{1L} + Z_{0M}}{3Z_{1L}} \tag{2.58}$$

The above modified zero-sequence current compensation factor does not correspond to the proper one when the parallel line is switched off and is not grounded at both line ends. During this condition, the overreaching zones will be further overreaching, but this is acceptable because they are typically applied in a directional comparison pilot scheme.

If the line impedance is used as the basis for the overreaching zone setting, it must be recognized that its reach is expanded more than the assumed safety margin because of the overreaching effect caused by this parallel line condition. This is very important for a reverse relay-reaching zone because a reverse external fault must be detected by the relay to avoid a false echo or a missing blocking signal. A POTT scheme would, for example, behave in the following way: If a fault behind Bus R is seen by a forward looking overreaching zone of the relay at Breaker 3, this relay will send a permissive tripping signal to the relay at Breaker 4. If the relay at Breaker 4 does not see the fault by a reverse looking zone, it will echo the received signal back, and the relay in Breaker 3 will trip the line. A blocking scheme would behave similarly. If the relay in Breaker 4 does not see the fault by the reverse looking zone, no blocking signal will be sent and the relay in Breaker 3 will likewise trip the line.

2.5.3 Untransposed Lines

Complete line transposition is achieved by changing the position of the phase conductors so that each of the conductors occupy each of the respective phase conductor positions for the same line length (i.e., for each one third of the total line length). Line transposition is not common practice today because it requires special transposition towers, which make line construction more costly. Eliminating transpositions also means fewer faults. Gross [44] and Lawrence [45] both cited studies that showed that 25 percent of all transmission line outages were associated with faults at transpositions.

Models of overhead lines for fault calculations and for setting distance protection devices are often based on symmetrical components, especially positive-sequence and zero-sequence components (Z_1 and Z_0). This approach assumes that the line is completely transposed. Because it is not possible to build a transmission line where the phase conductors are symmetrically located with respect to each other and with respect to earth and possible ground wires, neither the self impedances (Z_{aa}, Z_{bb}, Z_{cc}) nor the mutual impedances (Z_{ab}, Z_{ba}, Z_{ac}, Z_{ca}, Z_{bc}, Z_{cb}) are the same. Because of this, the transformation of the line impedance matrix from the phase domain to the symmetrical component domain does not yield a diagonalized symmetrical component impedance matrix. Therefore, the sequence networks, which we normally assume are independent, are in fact not independent, but are coupled by mutual impedances between them.

While reducing fault exposure, untransposed lines cause negative-sequence and zero-sequence current flow during normal load conditions and balanced three-phase faults. Some of the undesirable effects of untransposed lines are:

- Negative- and zero-sequence currents can be introduced into the power system.
- Negative-sequence current is troublesome for generator rotor heating.
- Zero- and negative-sequence currents during normal loads and balanced three-phase faults can cause sensitively set negative- and zero-sequence relay elements to pick up.
- Unequal self and mutual line impedances must be accounted for when setting impedance-type relays.

One source of error that influences the measurement of fault location on a line is due to the line characteristics, regardless of the distance protection used. The positive-sequence (Z_1) and zero-sequence impedance (Z_0) of a line are often obtained using the mean geometric spacing approach. It is an approach to compute an equal mutual impedance value between all phase conductors even though the spacing between phase conductors could be different. The real line model is basically transformed into a symmetrical model using this approach. The settings of the distance relay are calculated using the symmetrical model parameters, which introduce an error between the symmetrical model and the untransposed real line.

The following example explains the previous concepts. Let us consider a 225 kV untransposed line with 570 mm^2 phase conductors, without earth wire. The phase conductors are laid out in the flat configuration shown below:

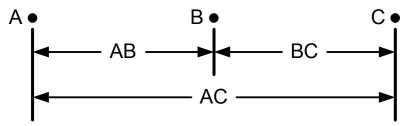


Figure 2.118 Horizontal construction 225 kV line

D_{AB} = 8 m is defined as the distance between Phases Conductors A and B and is equal to D_{BC}. D_{AC} = 16 m is defined as the distance between Phases Conductors A and C. The line impedance matrix of this line (Ohm/km) is:

$$Z = \begin{pmatrix} Z_{aa} & Z_{ab} & Z_{ac} \\ Z_{ba} & Z_{bb} & Z_{bc} \\ Z_{ca} & Z_{cb} & Z_{cc} \end{pmatrix} \tag{2.59}$$

$$Z = \begin{pmatrix} 0.1+0.699i & 0.05+0.298i & 0.05+0.255i \\ 0.05+0.298i & 0.1+0.699i & 0.05+0.298i \\ 0.05+0.255i & 0.05+0.298i & 0.1+0.699i \end{pmatrix} \tag{2.60}$$

The mean geometric distance between phase conductors is defined as $D_{geo} = (D_{AB} \bullet D_{BC} \bullet D_{CA})^{1/3}$. Therefore, D_{geo} = 10.08 m. The sequence impedance matrix of an assumed completely transposed line is:

$$Z_{sym} = \begin{pmatrix} 0.2+1.266i & 0 & 0 \\ 0 & 0.05+0.415i & 0 \\ 0 & 0 & 0.05+0.415i \end{pmatrix} \tag{2.61}$$

The positive-sequence (Z_1) and zero-sequence (Z_0) line impedances of the transposed line are:

$Z_1 = 0.05 + 0.415j$ ohm/km $\qquad$ $Z_0 = 0.2 + 1.267j$ ohm/km

$k_0 = [(Z_1 - Z_0) / 3 \bullet Z_1] = 0.688 - 0.038j$

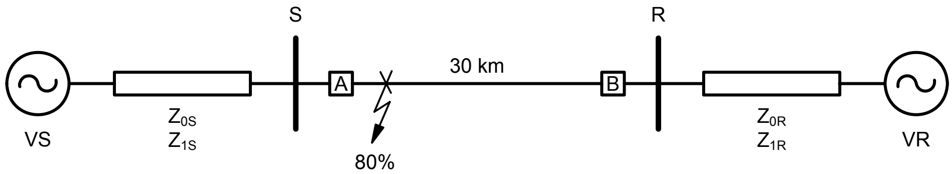


Figure 2.119 Phase-to-ground and phase-to-phase faults simulated at 80 percent of line length from Substation R

The system source impedance data are:

$Z_{0S} = Z_{1S} = Z_{0R} = Z_{1R} = 0.1 + 10j$ ohms

and

VS = VR = 130 kV

Phase-to-ground faults on Phases A, B, and C and phase-to-phase faults on Phase Pairs AB, BC, and CA are simulated at 80 percent of the line length from Substation R with no prefault power flow on the line. The distance protection measurement at Breaker B is simulated using the following equations.

Phase-to-ground loop (e.g., Phase A):

$$Z_{ph\_g} = \frac{V_a}{I_a + k_0 \bullet I_r} \tag{2.62}$$

Where:

V_a = line-to-neutral voltage

I_r = residual current

k_0 = zero-sequence current compensation factor

Where:

$$k_0 = \frac{Z_{0L} - Z_{1L}}{3 \bullet Z_{1L}}$$

Where:

Z_{0L} = zero-sequence impedance of the line

Z_{1L} = positive-sequence impedance of the line

$$k_0 = 0.688 - 0.038j$$

Phase-to-phase loop (e.g., Phase AB):

$$Z_{ph\_ph} = \frac{V_a - V_b}{I_a - I_b} \tag{2.63}$$

The imaginary part of the calculated impedance, Z_{ph_g} or Z_{ph_ph}, is compared with the imaginary part of the line impedance, which is defined as $Z_L = 30 \bullet (0.05 + 0.415j)$ ohms.

Table 2.16 Measured impedances at Substation R for phase-to-ground and phase-to-phase faults

Faults	$Im(Z_{ph\_g})$ Ohm	$Im(Z_{ph\_g})/I_m(Z_L)$ in %
Ph_g Phase A	9.978	80.083
Ph_g Phase B	9.931	79.708
Ph_g Phase C	9.978	80.083
Faults	**$Im(Z_{ph\_p}h)$ Ohm**	**$Im(Z_{ph\_ph})/I_m(Z_L)$ in %**
Ph_ph Phases AB	9.611	77.138
Ph_ph Phases BC	9.611	77.138
Ph_ph Phases CA (if it occurs)	10.663	85.586

The observed simulated error is about 3–5 percent for phase-to-phase loops. This high-value error is due to the flat arrangement of the line conductors. The errors of the phase-to-ground loop measurements are low, but they may be higher if a prefault power flow exists (almost 2 percent error for 2000 amperes power flow current).

Another method to calculate the phase-to-phase loop errors in distance measurement is illustrated below.

Figure 2.120 shows a flat 525 kV line construction with two conductors per phase. The distance AB is the same as BC, and we can expect the mutual impedances Z_{ab} and Z_{bc} to be equal. However, because of the wider spacing of AC, Z_{ac} will not have the same value. The impedance matrix for a 100-mile nontransposed 500 kV line with flat construction is given in (2.64). The impedance is given in per unit on a 500 kV, 1000 MVA base.

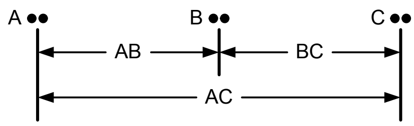


Figure 2.120 Horizontal construction 525 kV line

$$Z = \begin{pmatrix} 0.048+0.432i & 0.036+0.181i & 0.036+0.147i \\ 0.036+0.181i & 0.048+0.432i & 0.036+0.181i \\ 0.036+0.147i & 0.036+0.181i & 0.048+0.432i \end{pmatrix} \tag{2.64}$$

The symmetrical component matrix in this case is:

$$Z_{sym} = \begin{pmatrix} 0.12+0.771i & 0.01-0.006i & -0.01-0.006i \\ -0.01-0.006i & 0.012+0.262i & -0.02+0.011i \\ 0.01-0.006i & 0.02+0.011i & 0.012+0.262i \end{pmatrix} \tag{2.65}$$

We observe, in this case, that the off-diagonal terms are not zero, indicating that there is coupling between the sequence networks for all types of faults. The calculation of a three-phase fault shows the effect of nontransposition on distance relay reach.

$$\begin{pmatrix} V_a \\ V_b \\ V_c \end{pmatrix} = \begin{pmatrix} 1 \\ a^2 \\ a \end{pmatrix} \qquad \begin{pmatrix} I_a \\ I_b \\ I_c \end{pmatrix} = Z^{-1} \bullet \begin{pmatrix} V_a \\ V_b \\ V_c \end{pmatrix} \qquad \begin{pmatrix} I_a \\ I_b \\ I_c \end{pmatrix} = \begin{pmatrix} 0.509-3.661i \\ -3.657+1.883i \\ 3.321+1.721i \end{pmatrix}$$

$$Z_{ab} = \frac{V_a - V_b}{I_a - I_b} \qquad Z_{ab} = 0.03 + 0.248i$$

$$Z_{bc} = \frac{V_b - V_c}{I_b - I_c} \qquad Z_{bc} = -0.006 + 0.248i$$

$$Z_{ca} = \frac{V_c - V_a}{I_c - I_a} \qquad Z_{ca} = 0.012 + 0.285i$$

The reach of mho-distance elements in percent of the symmetrically transposed positive-sequence impedance are:

$$Z_{ab\_e} = \frac{|Z_{ab}|}{|Z_1|}100 \qquad Z_{ab\_e} = 95.1$$

$$Z_{bc\_e} = \frac{|Z_{bc}|}{|Z_1|}100 \qquad Z_{bc\_e} = 94.5$$

$$Z_{ca\_e} = \frac{|Z_{ca}|}{|Z_1|}100 \qquad Z_{ca\_e} = 108.6$$

The calculation shows that the Phase AB and Phase BC mho elements underreach by 4.9 percent and 5.5 percent, respectively, while the Phase CA mho element overreaches by 8.6 percent. Consequently, the relay settings must take into account the effect of nontransposition.

2.5.3.1 Compensation in the Relay Measurement

Compensation techniques are applied in some modern distance protection devices to correct the asymmetrical line impedance measurement. Compensation techniques include residual current compensation, phase current compensation, and combined current compensation. These compensation methods are described in [48]. The paper describes test results of the combined current compensation method to correct asymmetrical line impedance measurement in a multisystem distance protection device. The device monitors the phase currents and the phase-to-ground voltages and calculates the "symmetrized" phase currents. The measured and compensated phase currents are then available to be used by all protection functions implemented in the device. The test results for an asymmetrical single-circuit line indicated that with compensation, the fault location for each of the three phases is balanced. This is compared to the results without compensation in which the one phase overreached by approximately 10 percent. Similar results were observed for a double-circuit line (without measurement of the residual current of the parallel line). The combined current compensation method can provide an improvement of the accuracy and selectivity of distance protection.

2.5.4 Fault Resistance

Resistance in the ground fault path causes ground distance relay measurement errors because of a phase displacement between the total current in the fault path and the fault current measured at the relay location. Load flow in the line, system nonhomogeneity (sources of supply having different X/R ratios), and remote infeed will modify the effect of the resistance on distance relay performance. The effect of the fault resistance on the distance relay measurement error depends on the type of ground distance characteristic and the polarization method used.

The fault type influences whether the fault resistance is nonlinear because of a fault arc, as in the case of phase-to-phase faults that do not involve ground, or whether the fault resistance includes a linear component in addition to the nonlinear arc resistance for faults involving ground. Tower footing resistance, ground wire resistance, or trees that grow in the line that could make contact with a phase conductor introduce the linear component of resistance for faults that involve ground. It is difficult to evaluate the fault arc resistance. However, it is well known that the resistance of an arc increases with the length of the arc and has an inverse relationship to the arc current magnitude [49].

When overhead ground wires are not used, or when they are insulated from the towers or poles, the ground resistance is the tower or pole footing resistance at the location where the ground fault has occurred plus the resistance of the earth back to the source. When overhead ground wires are connected to steel towers or to grounding connections on wood poles, the effect is somewhat as though all footing resistances were connected in parallel, which makes the resulting footing resistance negligible. Published zero-phase-sequence impedance data do not include the effect of tower footing resistance.

Occasionally, a conductor breaks and falls to the ground. The ground-contact resistance of such a fault may be much higher than tower footing resistance, where relatively low resistance is usually obtained with ground rods or counterpoise. The contact resistance depends on the geology of a given location, whether the ground is wet or dry, and if dry, how high the voltage is. It takes a certain amount of voltage to break down the surface insulation.

2.5.4.1 Single-End Feed

A phase distance element measures an impedance given by (2.66) for phase-to-phase faults with fault resistance R_F. The distance to fault is measured correctly as X_{1L}, and the fault resistance R_F is seen as one-half of its value. Phase distance functions will be most affected by arc fault resistance for conditions of high-source-to-line impedance ratios for which the resistance can appear to be large relative to the line impedance.

$$Z_{pp} = R_{1L} + \frac{R_F}{2} + jX_{1L} \tag{2.66}$$

A ground distance element will measure an impedance given by (2.64) for a line-to-ground fault with fault resistance R_F. The fault reactance is measured correctly regardless of the magnitude of the fault resistance. The resistance measurement depends on the ground distance relay zero-sequence compensation factor k_0.

$$Z_{pg} = R_{1L} + \frac{R_F}{1+k_0} + jX_{1L} \tag{2.67}$$

Numerical measurement techniques, utilizing complex arithmetic and separate measurements for the real and imaginary part of the ground fault loop impedance in a single-end feed radial system, have the advantage that line-to-ground faults with fault resistance are measured correctly even if the positive- and zero-sequence system X/R ratios are different. On the other hand, in conventional static and electromechanical measurement techniques, residual compensation causes a phase rotation of the residual current, which introduces an inductive component of the fault resistance that leads to an error of the ground distance measurement [40].

2.5.4.2 Two-Source Infeed

If Breaker B in Figure 2.121 is open, the system is radial, and the relay current, I_R, is equal to and in phase with the current in the fault resistance, I_F. The fault resistance appears to be purely resistive, and it adds directly to the line impedance, as shown in Figure 2.121(b).

If Breaker B is closed, the current in the fault resistance, I_F, is greater than the relay current, I_R, which causes the resistance to appear larger than it actually is (by the ratio of I_F/I_R). With no load flow and a homogeneous system, I_R and I_F will be in phase and the resistance will be magnified but not shifted in phase, as in Figure 2.121(c). Load flow or system nonhomogeneity causes I_F and I_R to be at different angles, which introduces an apparent reactive component to the magnified resistance, as in Figure 2.121(d) and Figure 2.121(e). Exactly how a ground distance relay function responds to resistive faults depends on the type of function (reactance versus mho) and the function polarization method.

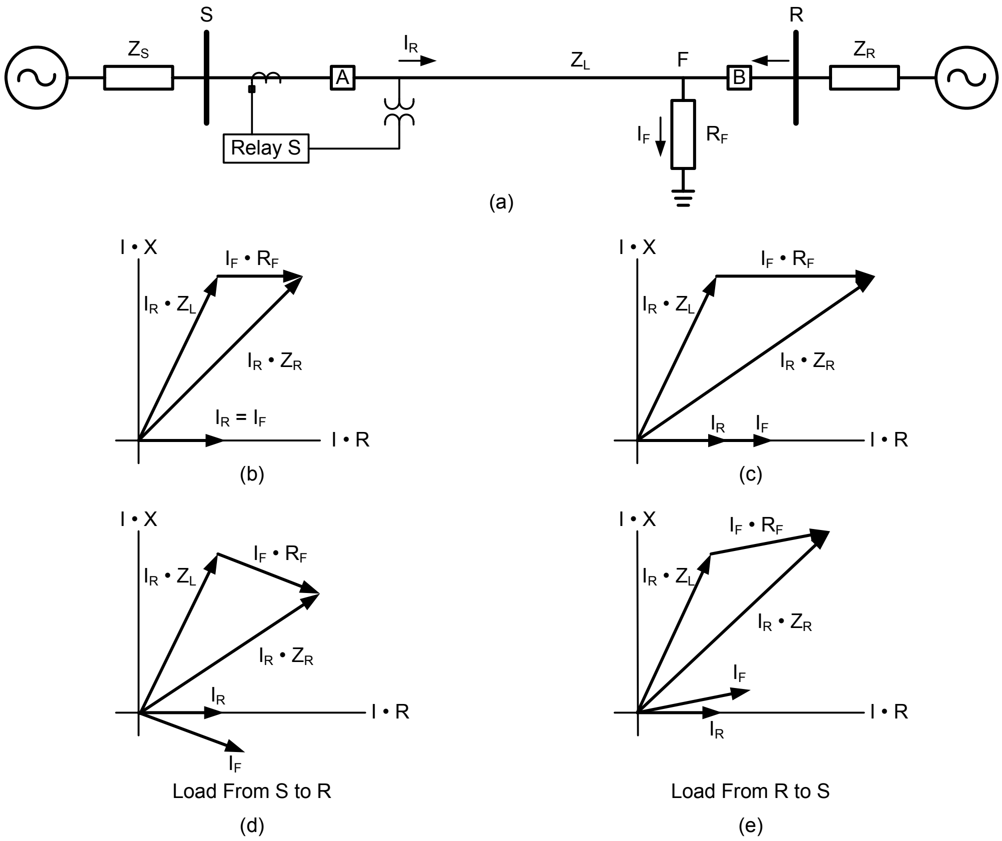


Figure 2.121 Effect of load flow and system nonhomogeneity on fault resistance

Mho ground distance relays have dynamic and/or variable characteristics that depend upon the polarizing quantity, fault type, and system parameters [29] [50] [51] [52]. The mho ground distance relay offers a desirable balance between internal fault resistance accommodation and security against misoperation on external faults. For example, a mho ground distance function that is polarized with healthy phase voltages produces an expanded characteristic that depends on the source behind the function. Load flow shifts the characteristic, as shown in Figure 2.122.

A polarized mho ground distance relay characteristic will rotate depending on the direction of load flow. If the relay is measuring load export, the characteristic becomes desensitized in the R direction and becomes less affected by the load influence on the reactance measurement. If the relay measures load import, the characteristic rotates in such a way that the reach in the R direction increases. Note that the characteristic shifts in the same direction as the shift in the fault resistance. For the external fault, there is no tendency by the mho function to either underreach or overreach regardless of the direction of the load flow. For internal faults, the shift is in the proper direction to provide optimum protection for resistive faults.

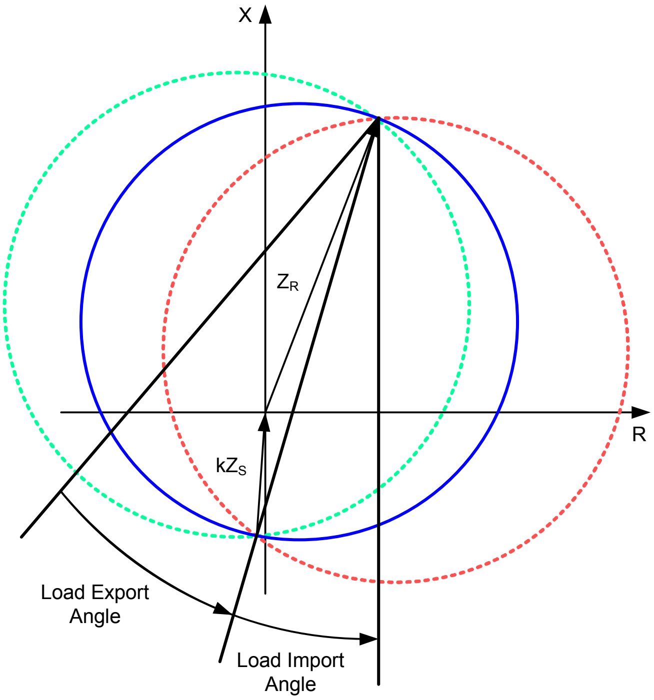


Figure 2.122 Load flow direction causes a shift on a polarized mho ground distance characteristic

Reactance functions can be affected similarly. The performance of a phase-current polarized and a negative-sequence current polarized reactance function will be different. A phase-current polarized function can overreach because the fault current is shifted with respect to the phase current that polarizes the function.

The response of a negative-sequence current polarized reactance function shifts in the same direction as the fault resistance and has no tendency to overreach, such as displayed by the phase-current polarized function. The shift in the characteristic is always in the direction to provide optimum coverage for internal faults with resistance. The overreach is eliminated because the phase relationship between the negative-sequence current polarizing quantity and the total fault current is not affected by load flow. If the system is not homogeneous, the negative-sequence fault current will be shifted relative to the total fault current, which will in turn cause a tendency for the function to either overreach or underreach depending on the impedance relationships. The shift in the fault resistance is not as severe as that caused by load, and the functions can be designed to eliminate overreaching.

By comparison, the quadrilateral relay provides good fault resistance coverage but experiences reduced security on remote faults due to unequal source and line impedance angles for resistive faults [29], [51], [53]. The effect of unequal source and line angles on a quadrilateral element is discussed later in this section.

Decreased sensitivity of the quadrilateral characteristic, for resistive faults at the end of the zone, can be achieved by introducing a fixed slope angle in the upper characteristic border, as shown in Figure 2.123. The application of a teleprotection scheme can solve the overreach problem because of load flow effects on ground distance quadrilateral elements. In cases where a teleprotection scheme is used to advance the distance principal, a conservative setting for the instantaneous Zone 1 is applied to achieve security. Reliability is then achieved with the overreach Zone 2 in combination with the teleprotection scheme. In the future, when communication between devices from two line terminals is more advanced and voltages and currents from the remote end are available in real time at the local end, the load effects can be eliminated.

Modern numerical relays offer mathematical solutions to compensate the load influence based on additional information available at the local relay. This load-compensation method can only minimize the effect from load on the distance measurement but does not solve the problem totally. Only the additional information from the measured voltages and currents from the remote line terminal allow calculating the fault impedance mathematically correct for all situations.

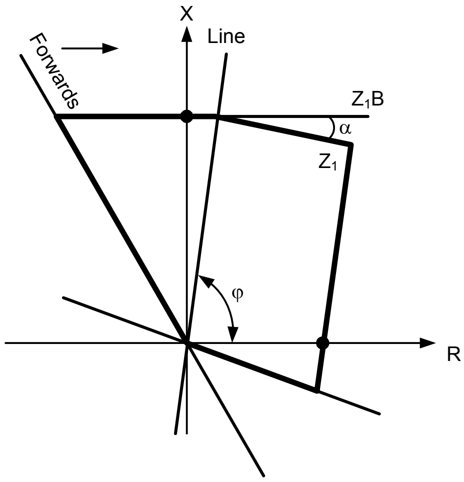


Figure 2.123 Example for a quadrilateral characteristic with fixed slope angle α

Load-Compensation Method

The load-compensation method described below is applicable for single-phase-to-ground faults. It is based on a zero-sequence compensation with the assumption that the phase angle of the zero-sequence impedance is equal on both sides of the fault point and is performed separately for the resistance and reactance part.

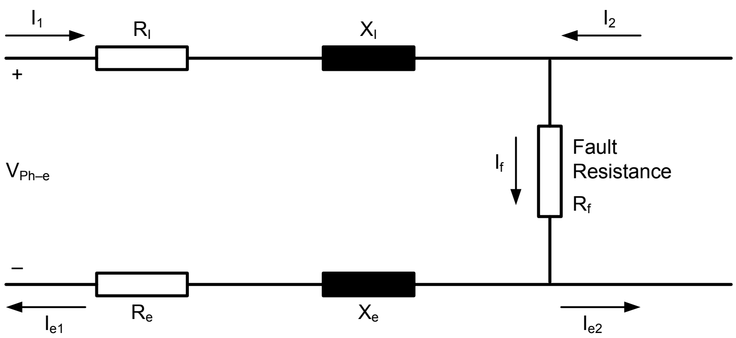


Figure 2.124 Circuit for phase-to-ground loop impedance measurement

The following equation describes the ground fault loop measured from one end:

$$V_{Ph-e} = I_{e1} \bullet (R_e + jX_e) + I_1 \bullet (R_1 + jX_1) + I_f \bullet R_f \tag{2.68}$$

Using two separate zero-sequence compensation factors, RE/RL for the resistive part and XE/XL for the reactive part, (2.68) becomes:

$$V_{Ph-e} = I_{e1} \bullet \left(\frac{RE}{RL} R_1 + j \frac{XE}{XL} X_1 \right) + I_1 \bullet (R_1 + jX_1) + I_f \bullet R_f \tag{2.69}$$

In (2.69), there are three unknown values (X_l, R_l, and R_f) and fault current (I_f) that cannot be measured by the relay. To calculate the two values of interest (X_1 and R_1), more information is needed.

One unknown value in (2.69) can be eliminated by considering the reactance per km (or mile), X_{SEC}, and the resistance per km (or mile), R_{SEC}, of the line.

$$V_{Ph-e} = m \left[I_{e1} \left(\frac{RE}{RL} R_{SEC} + j \frac{XE}{XL} X_{SEC} \right) + I_1 \bullet (R_{SEC} + jX_{SEC}) \right] + I_f \bullet R_f \tag{2.70}$$

The two unknown values, X_1 and R_1, are now summed up by m, which is the distance to the fault. The above equation can be solved if we make an additional assumption that the phase angle of I_{e1} and I_{e2} are nearly equal. The phase angles of the earth currents are determined be the zero-sequence impedances on both sides of the fault. Using this assumption, I_f is then expressed as $k \bullet I_{e1}$, in which k is a real number.

$$V_{Ph-e} = m\left[I_{e1} \bullet \left(\frac{RE}{RL} R_{SEC} + j\frac{XE}{XL} X_{SEC}\right) + I_1 \bullet \left(R_{SEC} + jX_{SEC}\right)\right] + I_{e1} \bullet k \bullet R_f \tag{2.71}$$

The above equation is now one complex equation with two unknown values, which is solved by separating the real and imaginary parts.

$$V_{Ph-e} = m[e + jf] + I_{e1} \bullet k \bullet R_f \tag{2.72}$$

Where:

$$e = \mathrm{Re}\left[I_{e1} \bullet \left(\frac{RE}{RL} R_{SEC} + j\frac{XE}{XL} X_{SEC}\right) + I_1 \bullet \left(R_{SEC} + jX_{SEC}\right)\right] \tag{2.73}$$

$$f = \mathrm{Im}\left[I_{e1} \bullet \left(\frac{RE}{RL} R_{SEC} + j\frac{XE}{XL} X_{SEC}\right) + I_1 \bullet \left(R_{SEC} + jX_{SEC}\right)\right] \tag{2.74}$$

The resulting system of equations is:

$$\mathrm{Re}\left(V_{Ph-e}\right) = m \bullet e + \mathrm{Re}\left(I_{e1}\right) \bullet k \bullet R_f \tag{2.75}$$

$$\mathrm{Im}\left(V_{Ph-e}\right) = m \bullet f + \mathrm{Im}\left(I_{e1}\right) \bullet k \bullet R_f \tag{2.76}$$

The distance m to the fault is determined from (2.77):

$$m = \frac{\mathrm{Im}\left(I_{e1}\right) \bullet \mathrm{Re}\left(V_{Ph-e}\right) - \mathrm{Re}\left(I_{e1}\right) \bullet \mathrm{Im}\left(V_{Ph-e}\right)}{e \bullet \mathrm{Im}\left(I_{e1}\right) - f \bullet \mathrm{Re}\left(I_{e1}\right)} \tag{2.77}$$

The distance to the fault, m, is correct for all load conditions if the assumption is true. The grid conditions and the zero-sequence impedance angles must be known before this kind of load compensation is applied.

Nonhomogeneous System-Compensation Method

A system is nonhomogeneous when the source and line impedance angles associated with the sequence current used by the reactance element as the polarizing reference are not the same. In a non-homogeneous system, the angle of the total current in the fault is different than the angle of current measured at the relay. For a bolted fault (a condition that assumes no resistance in the fault), a difference between the fault current angle and the current angle measured at the relay is not a problem. However, if there is fault resistance, the difference between the fault and relay current angles can cause a ground distance relay to severely underreach or overreach. The effect of system nonhomogeneity has been briefly covered in previous papers [50], [51], [53], [54]. The effects of unequal source and line impedance X/R ratios on a reactance element used in a quadrilateral ground distance characteristic are described in more detail below [55].

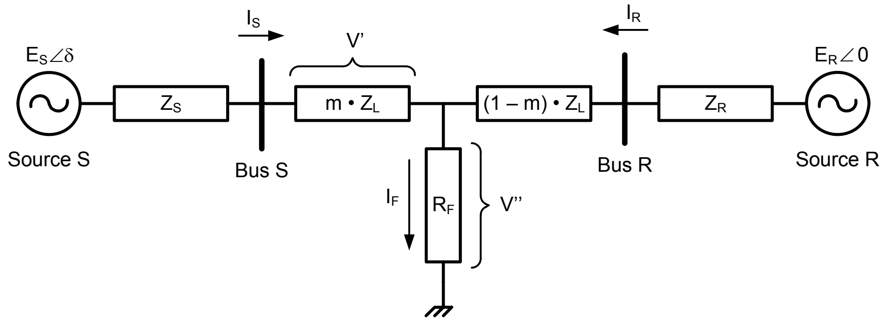


Figure 2.125 Simple two-source system single line diagram

Referring to Figure 2.125, the phase voltage measured by a relay at Bus S can be represented as the sum of two voltage drops: the voltage drop across the transmission line ground loop impedance and the voltage drop across the fault resistance. The sum and definitions of these two voltage drops is given by (2.78):

$$V_\phi = V' + V'' \tag{2.78}$$

Where:

V'	=	$m \bullet Z_{1L} \bullet (I_\phi + k_0 \bullet I_R)$
V''	=	$I_F \bullet R_F$
m	=	p.u. distance to the fault
Z_{1L}	=	positive-sequence line impedance
I_Φ	=	phase current associated with faulted phase voltage
k_0	=	ground distance relay zero-sequence compensation factor $\frac{Z_{0L} - Z_{1L}}{3 \bullet Z_{1L}}$
I_R	=	ground current measured by the relay ($3I_0$)

An error term, V'', which is caused by the voltage drop across the fault resistance, is introduced into the reactance element measurement. When the system is homogeneous or radial, the voltage drop across the fault resistance is purely resistive and in phase with the polarizing current, I_R. The $R_F \bullet I_F$ term is effectively removed from the reactance element measurement. Figure 2.126 shows a voltage diagram for a resistive fault on a homogenous or radial system.

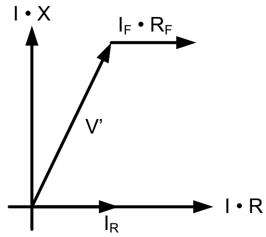


Figure 2.126 Voltage vector diagram for a resistive fault in a radial and homogeneous system

When the system is nonhomogeneous, the voltage drop across the fault resistance is no longer in phase with the polarizing quantity (in this case, the zero-sequence current at Terminal S in Figure 2.125). In a nonhomogeneous system, the voltage drop across the fault resistance includes both real and imaginary terms. The imaginary part can cause the reactance element to overreach or underreach. The reactance element error is defined as $A\angle T°$. Figure 2.127 illustrates the voltage vectors for a resistive fault in a nonhomogeneous system. The reactance element will overreach if I_F lags I_R and will underreach if I_F leads I_R. Current I_R is the polarizing quantity for the reactance element.

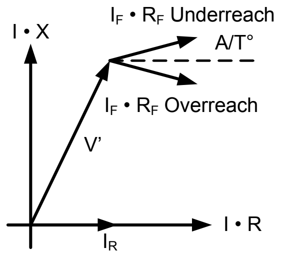


Figure 2.127 Voltage vector diagram of a resistive fault in a nonhomogeneous system

Referring to Figure 2.128, the total zero-sequence current in the fault is a function of the contributions from the source behind Bus S, the source behind Bus R, and the location of the fault on the line. Figure 2.127 shows that the tilt in the voltage drop across the fault resistance causes an error in the reactance element measurement. The degree to which the voltage across the fault resistance tilts is determined by the difference of the fault current angle and reactance element polarizing referencing angle. The reactance element measurement error is then a function of the ratio of the total zero-sequence fault current to the zero-sequence current measured in the relay. Two different methods for calculating the error term shown in Figure 2.127 are given by (2.79) and (2.80). The error terms given by (2.79) and (2.80) are with respect to a relay at Bus S.

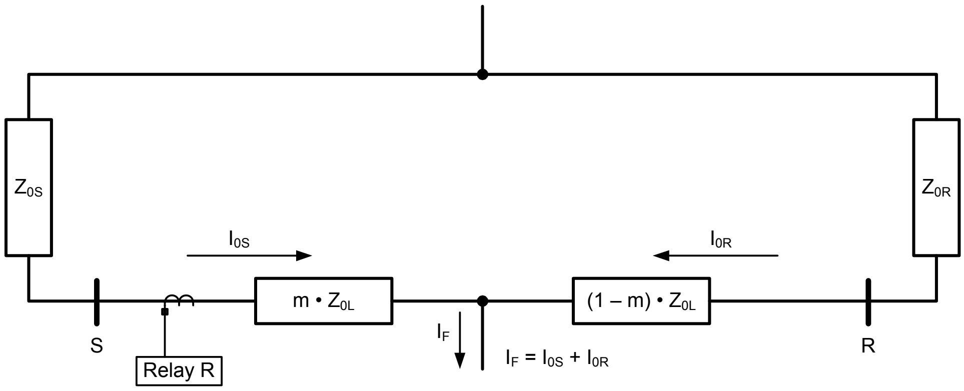


Figure 2.128 Zero-sequence network for a line-to-ground fault

A theoretical approach to calculating $A\angle T°$ is to use (2.79). This method is more complex and requires calculating the zero-sequence source impedance at each end of the line.

$$A\angle T^\circ = \left[\frac{Z_{0S} + Z_{0L} + Z_{0R}}{(1-m)\bullet Z_{0L} + Z_{0R}}\right] \tag{2.79}$$

A more practical and simpler approach is to divide the total zero-sequence fault current by the zero-sequence current seen by the relay.

$$A\angle T^\circ = \frac{I_{0F}}{I_{0S}} \tag{2.80}$$

The term shown in (2.80) can easily be calculated from data available in fault studies. In some fault studies, the zero-sequence current is expressed in terms of $3I_0$. The error term shown in (2.80) can be calculated using the $3I_0$ current if the numerator and denominator terms are consistent.

The effective reactance measurement can be determined by including the voltage drop across the fault resistance shown in (2.81) in the reactance calculation shown in [29].

$$\frac{\mathrm{Im}\left(V_\Phi \bullet {I_R}^*\right)}{\mathrm{Im}\left[1\angle Z_{1L} \bullet \left(I_\Phi + k_0 \bullet I_R\right)\bullet {I_R}^*\right]} = m \bullet \left|Z_{1L}\right| + R_F \bullet \frac{\left|I_R\right|^2 \bullet |A| \bullet \sin(T)}{\mathrm{Im}\left[1\angle Z_{1L} \bullet \left(I_\Phi + k_0 \bullet I_R\right)\bullet {I_R}^*\right]} \tag{2.81}$$

The second term, on the right side of (2.81), is the error caused by the voltage drop across the fault resistance. The fault-resistance induced error can be defined as:

$$\Delta X = R_F \bullet \left[\frac{|I_R| \bullet |A| \bullet \sin(T)}{|I_\Phi| \bullet \sin(\angle Z_{1L} + \angle I_\Phi - \angle I_R) + |k_0| \bullet |I_R| \bullet \sin(\angle Z_{1L} + \angle k_0)} \right] \tag{2.82}$$

Where:

R_F = actual fault resistance at the fault

A = magnitude of the result of (2.79) or (2.80)

T = angle of the result of (2.79) or (2.80)

Z_{1L} = positive-sequence line impedance

I_Φ = phase current measured by the relay for a bolted fault

k_0 = ground distance relay zero-sequence compensation factor $\dfrac{Z_{0L} - Z_{1L}}{3 \bullet Z_{1L}}$

I_R = ground current measured by the relay ($3I_0$) for a bolted fault

Calculating the reactance measurement error is easily accomplished by using data available in fault studies and relay settings. Knowing the reactance measurement error caused by fault resistance allows the protection engineer to properly set the reach on a quadrilateral reactance element to prevent overreaching and underreaching.

Correcting the polarizing reference in the ground reactance calculation by the angle calculated in (2.79) or (2.80) can prevent overreach of Zone 1 elements [29]. Adjusting the polarizing reference is equivalent to setting the variable “T” in (2.81) and (2.82) to zero, thus removing the error introduced by the fault resistance voltage drop. Most relays with a quadrilateral element have a fixed angle; however, some relays provide an angle setting “T” to adjust the polarizing reference angle with respect to the system.

Reducing the Zone 1 reactance reach by the fault-resistance induced error calculated in (2.82) can also prevent overreach on external faults. The fault-resistance induced error is a function of the magnitude of fault resistance in the fault. The worst-case fault-resistance induced error can be calculated using the Zone 1 resistance reach setting. The amount of reactance element overreach, caused by fault resistance, is reduced by limiting the Zone 1 resistive reach. Conversely, increasing the resistive reach allows the Zone 1 element to detect higher resistance faults and increases the potential of reactance element overreach for external faults.

2.5.5 Series-Compensated Transmission Lines

Series capacitors are used on transmission systems to increase power transfer capability, improve system stability, improve load division on parallel paths, and reduce losses. While series capacitors have a beneficial effect on system performance, they introduce additional problems that must be correctly handled by protective relays. Typical problems faced by the relays have been addressed in many publications [56] [57] [58] [59]. CIGRE Study Committee B5 currently has a Working Group (WG B5.10) compiling a comprehensive report dealing with the “Protection, Control, and Monitoring of Series-Compensated Networks.” The report will cover protection of both the series capacitor banks and series-compensated and adjacent lines. In addition, the report will provide information relating to auto reclosing, fault location, modeling, and case studies.

Over the last 40 years, applying protective relays to series-compensated transmission lines has presented the greatest challenge for the manufacturers and utility engineers responsible for the design, selection, and application of such systems. Proper application of high-speed relay systems with secure directional decisions is required for series-compensated transmission lines.

Series capacitors may be installed at one end of the line, both ends of the line, or in some cases in the middle of the transmission line. The level of compensation is typically 25–80 percent of the transmission line impedance. To be able to adapt the system to current load conditions, controlled series compensation systems such as “advanced series compensation” (ASC) and “controlled series compensation” (CSC) are used to allow variation in the line compensation degree. Series capacitors are mainly employed in extra-high-voltage grids, which carry high power over long distances. These networks play a key role in areas with bulk power transmission over long distances, where power generation plants are often situated long distances from load centers.

Transmission lines are inherently inductive. In a power system network without series capacitors, faults are inductive and the current always lags the voltage by some angle. This is a basic assumption in conventional protection schemes. Transmission line protection schemes, such as directional comparison, phase comparison, and current differential, are generally designed for inductive networks. Series capacitors introduce a capacitive reactance to the network and the inductive nature of the fault current can not be assured for all types of faults or fault locations. Therefore, the introduction of capacitive elements could affect the security and dependability of conventional protection schemes. Line protection may fail to operate or may operate incorrectly because of capacitive reactance in the network. This can occur on the compensated line as well as on adjacent transmission lines.

Series compensation is typically applied in EHV transmission systems. These lines demand sub-cycle operating times and reliable directional decisions. Directional decisions are used in conjunction with communications-aided protection schemes to determine whether faults are internal or external. A secure decision is needed in order to ensure fast fault clearing, preserve system stability, and minimize equipment damage. Misoperation of protective relays in such applications can result in a degraded power system condition and can eventually lead to a major power system disturbance. Therefore, advanced testing of the protection system during the design and commissioning stages of a project is critical.

A series capacitor consists of several single capacitors that are interconnected in both parallel and series, thereby providing the required capacitance and dielectric strength. The short time current carrying capacity normally corresponds to two or three times the rated line current. To protect the capacitor during high levels of short-circuit currents, the series capacitor is protected with air gaps, metal oxide varistors (MOVs), current-limiting devices, and bypass switches. The operation of air gaps and the conduction of MOVs introduce transients and unbalances that must be taken into consideration to ensure that the integrity of the protection scheme will not be adversely affected.

Series capacitor banks with air-gap overvoltage protection are typically set to flash over at a voltage level of 2.5–3.5 times the nominal rated voltage of the capacitor bank. The air gaps do not flash instantaneously following the occurrence of a fault and do not flash at all under some fault conditions. The time-to-gap flashing is sometimes longer than the operating time of high-speed line protection. Gap operation and subsequent series capacitor reinsertion generates high-frequency transients that could impact the performance of line protection. Even though gap flashing restores the inductive nature to the network, based on the above observations, protection complications are still present and must be evaluated using advanced transient testing that models, as closely as possible, the network behavior after the real power system.

MOV overvoltage protection of series capacitors, on the other hand, introduces a different set of problems for line protection. These devices are always in service and are not bypassed during faults unless the energy they absorb exceeds their design ratings. The MOVs present a nonlinear behavior by design. MOVs do not conduct during normal load-flow conditions, and they present a very high impedance in parallel with the series capacitor bank. The protective level of MOVs is 2.0–2.5 times the rated peak voltage of the capacitor bank. During faults, the voltage across the MOV can exceed its conduction level, thus considerably reducing the impedance of the MOV. This allows current to flow through the MOV and protect the series capacitor from overvoltages. When the voltage is below the conduction level, the MOV stops conducting and the capacitor bank is effectively reinserted. The conduction and nonconduction periods during a power system cycle generate transients of a different type in the network, which are softer in nature than those caused by air-gap flashing. Relay systems must be able to cope with air-gap flashing as well as with MOV conduction transients. MOVs can be bypassed by parallel gaps designed to protect them during heavy close-in internal faults, which could generate energy levels much higher than the MOV can absorb without damage.

Typically, the series capacitor is short circuited by the MOV or air-gap flashing in the event of a fault, and no serious measurement-related problems are encountered with respect to the distance protection. A quite different situation arises, however, in cases where, as the result of a week infeed or a high-resistive fault, the capacitor remains operative because the gap or MOV fails to respond. In such a case, static and/or dynamic effects will cause distance calculation measuring problems.

2.5.5.1 Protection Issues Related to Series-Compensated Lines

The effect of series compensation on transmission line distance protection depends on the location of the series capacitors, the degree of compensation, the network configuration, and the line parameters. Voltage inversion or voltage inversion is the most common effect of series capacitors. Voltage inversion occurs at the bus if the capacitive reactance of the series capacitor is larger than the inductive reactance of the line section to the fault location. Figure 2.129 shows a typical voltage inversion at Bus S assuming a three-phase fault with $X_C < X_S$.

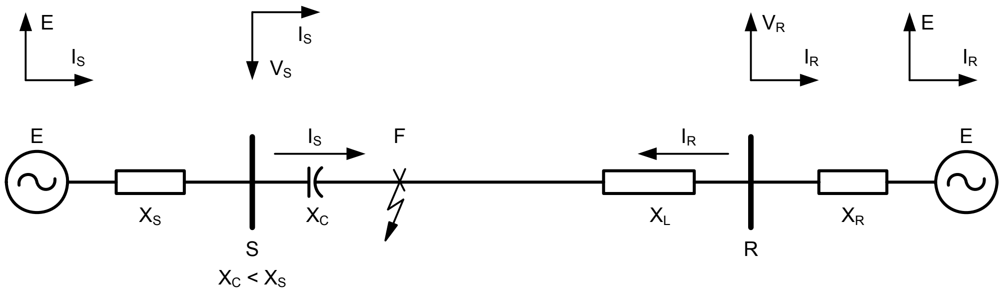


Figure 2.129 Voltage inversion at Terminal S

In Figure 2.129, the voltage applied to the relay at Terminal S is 180 degrees out from what would be considered the “normal” phase position. In addition, a point further back into the system will experience a zero voltage point and could impact the operation of relay systems on nearby transmission lines, even though these lines may not be series compensated.

Figure 2.130 shows a typical waveform with voltage inversion during a line-to-ground bus fault with line-side capacitive coupled voltage transformers. The fault is applied at a voltage peak point.

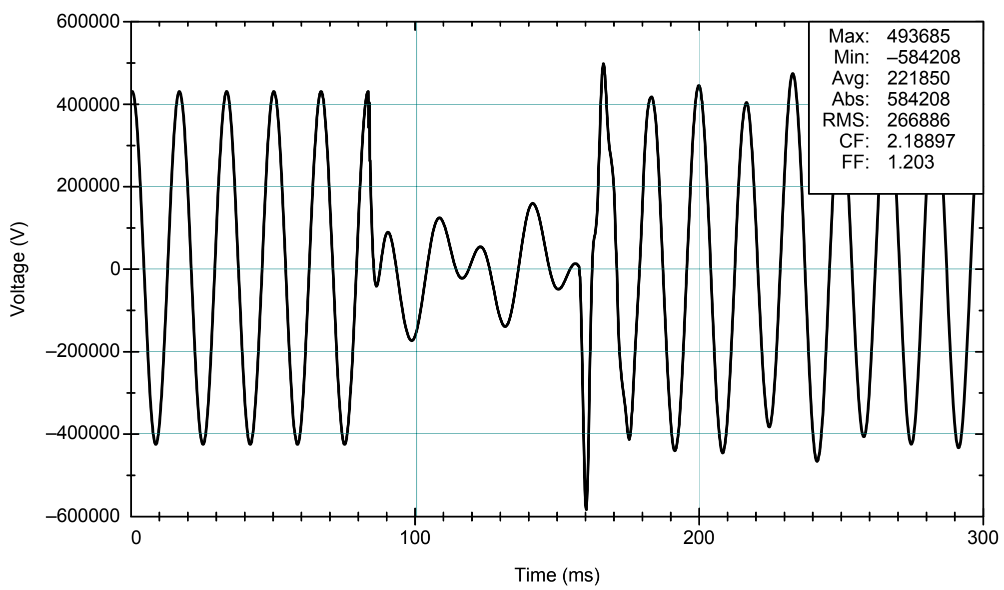


Figure 2.130 Voltage inversion at the relay location

Figure 2.131 shows the voltage across the capacitor bank for the same fault. The series capacitor is rated 1,800 amperes, 24.96 ohms, with a protective level of 4,800 amperes. This is equivalent to a gap-flashing voltage of 169,434 volts peak. Note that the peak voltage never reaches the gap-flashing level.

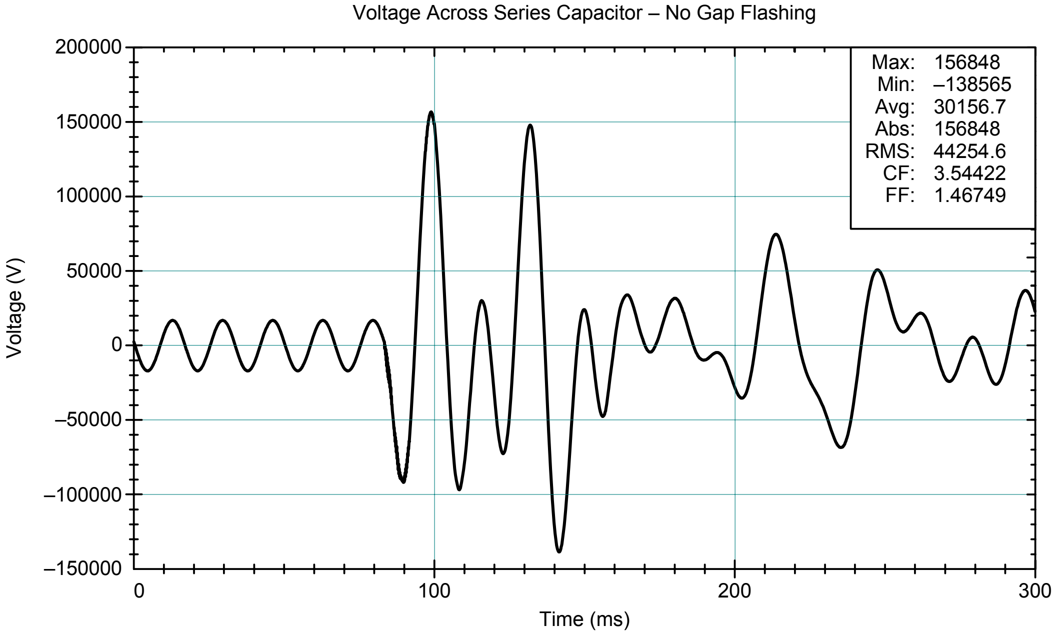


Figure 2.131 Voltage across the A-phase series capacitor

The transients generated for the same A-phase line-to-ground fault with the fault initiated at a different point on the wave could be drastically different. Figure 2.132 demonstrates the voltage reversal at the relay location for a short period of time and a subsequent gap flashing of the A-phase series capacitor bank. In Figure 2.133, the voltage across the series capacitor bank is plotted, and it clearly demonstrates that a totally different set of input signals would be seen by the protection system.

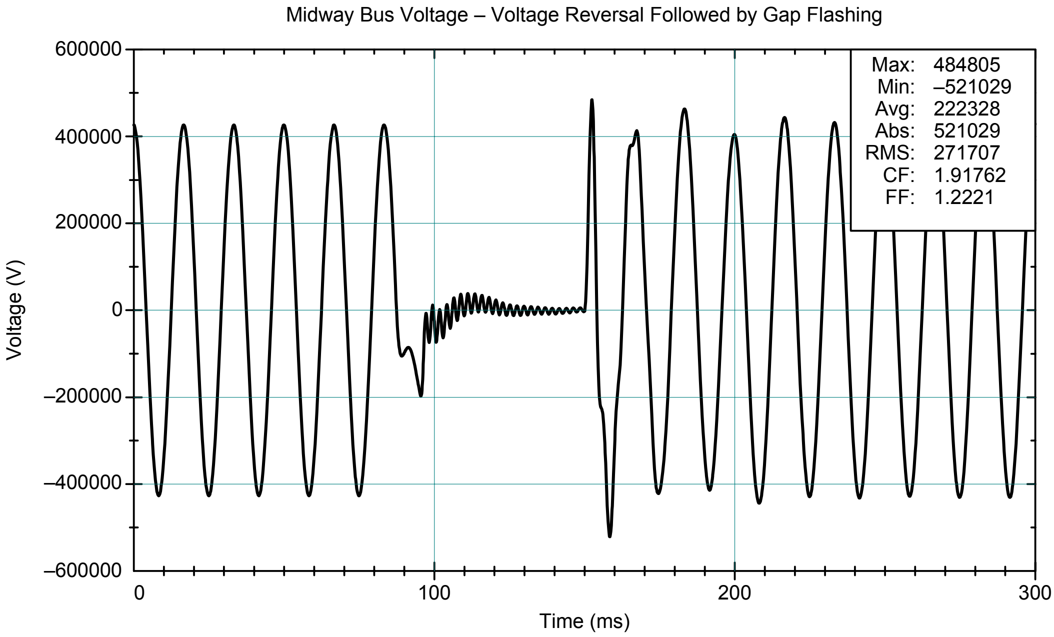


Figure 2.132 Voltage inversion at relay location and subsequent air-gap flashing

Figure 2.133 shows the voltage across the series capacitor and the associated high-frequency transients due to gap flashing. The peak voltage across the series capacitor reached just above the gap-flashing level and triggered series capacitor bank shunting through the air gap.

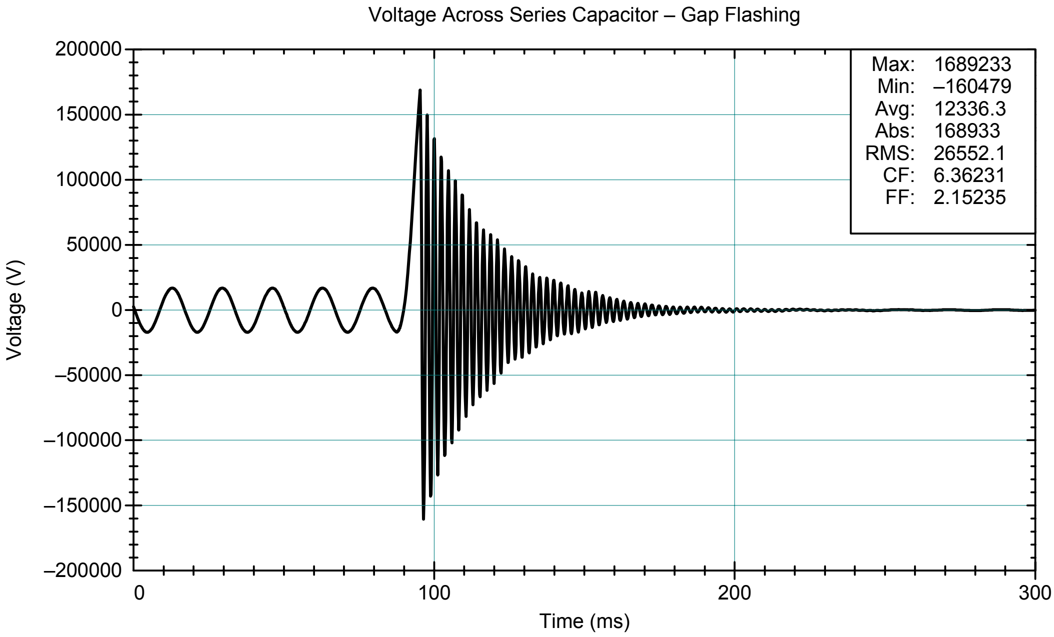


Figure 2.133 Voltage across the A-phase series capacitor with gap-flashing transients

Figure 2.134 and Figure 2.135 show the fault current through the series capacitor bank for the two faults described above, one at voltage peak and the other at a voltage zero.

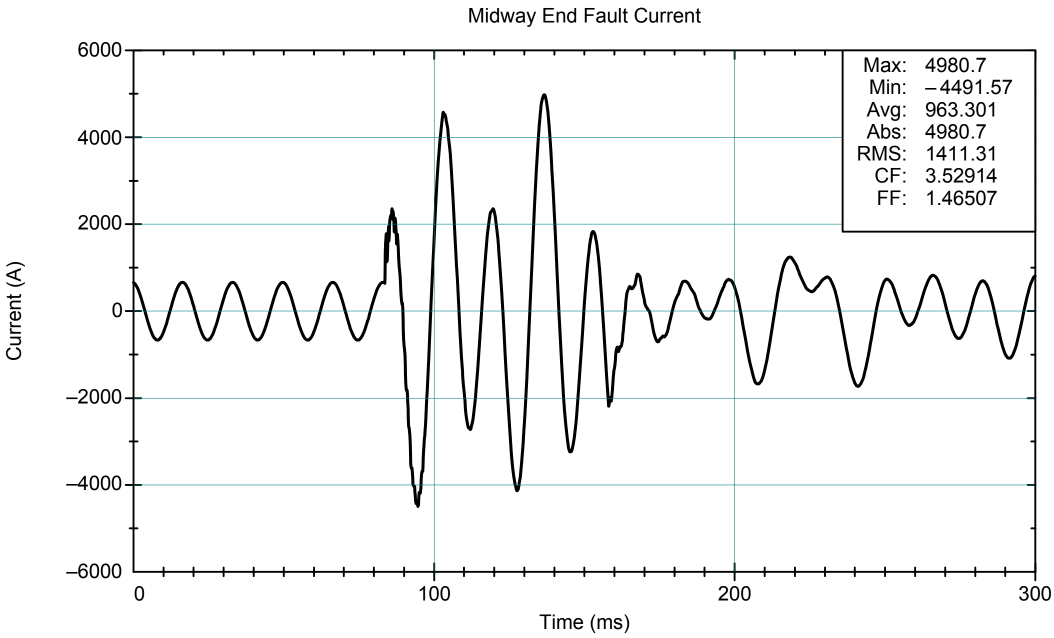


Figure 2.134 Current waveform when fault is applied at voltage peak

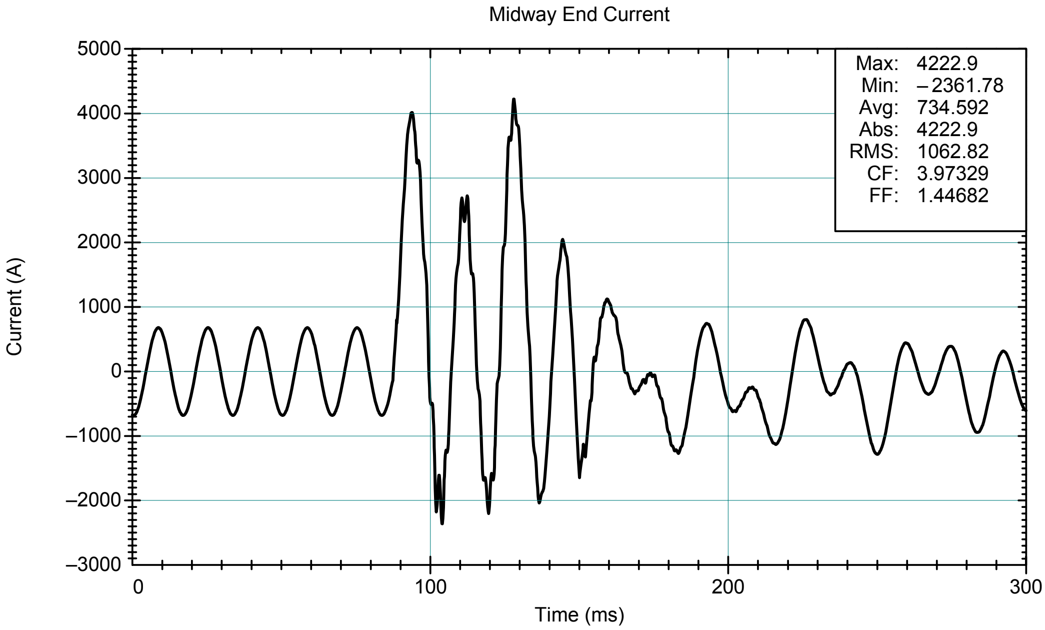


Figure 2.135 Current waveform when fault is applied at voltage zero

The fault current through this capacitor bank never reached the peak protective level of 6,788 amperes. The gap flashing was due to the initial charge present in the capacitor bank prior to fault initiation.

Current inversion could also take place in a series-compensated network. Current inversion can occur when the fault current flowing into the line for an internal fault is capacitive rather than inductive. This is the case when the reactance from the fault point up to and including the source reactance is net capacitive. Figure 2.136 shows a simple network in which X_C is larger than X_S, and a three-phase fault right in front of the series capacitor will present a net capacitive reactance and cause a current inversion at Terminal S.

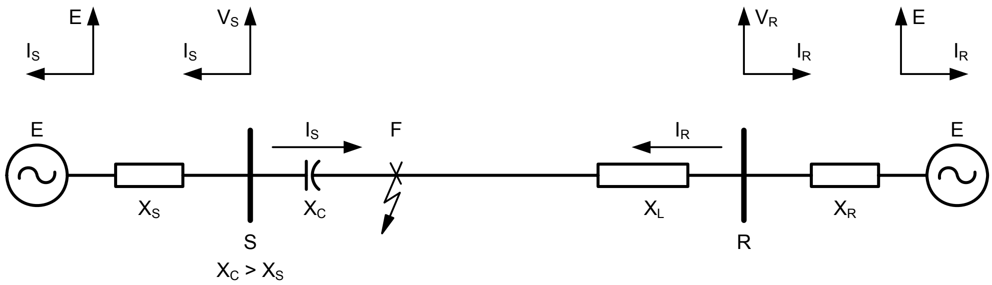


Figure 2.136 Current inversion at Terminal S

Conventional distance-based directional comparison schemes would not operate for this internal fault because the relay at Terminal S would detect a reverse fault. It makes no difference whether line-side or bus voltages are used for distance relays in establishing the direction of this fault. Phase comparison and current differential schemes also will not operate for this internal fault. To protect for such faults, relay manufacturers have included modifications in their designs so that relay systems can cope with voltage and current inversion problems. Current inversion is rare and can be avoided with proper location of the series capacitor bank. However, this may not be feasible for economical reasons.

2.5.5.2 Static Problems on Series-Compensated Lines

The measured reactance to the fault depends on whether the series capacitor remains in service or not. During a short circuit, the measured impedance depends on the method employed for series capacitor protection. If, for example, series capacitor protection is employed by a gap, the line impedance is measured similar to a single line without series capacitors. If only a MOV is installed, a resistive and a reactive component, dependent on the fault current, is added to the fault impedance. To prevent overreach, the underreaching Zone 1 must be set such that the capacitor is assumed to be active, i.e. in case of a fault at the end of the line the measured reactance can become $X_{measured} = X_l - X_C$. Thereby, the instantaneous Zone 1 loses its significance because it can only protect a small line section instantaneously. Furthermore, dynamic effects, such as subsynchronous frequency components, influence the setting of Zone 1.

The measured direction of the fault largely depends on the degree of compensation, infeed conditions, and fault location. Where the fault occurs directly behind the capacitor at the beginning of the line, the distance protection measures a negative reactance. The fault direction would also be reverse for this forward fault if the faulty voltage was used for the direction calculation. For this reason, it is absolutely essential that the distance protection use the polarized or memorized voltage to determine the fault direction on series-compensated lines.

2.5.5.3 Dynamic Problems on Series-Compensated Lines

The effects of the series capacitors are not limited just to the power system frequency phenomena. Series capacitors and their associated protective devices, such as parallel spark gaps, current-limiting devices, and MOVs, are serious transient generators that produce an exchange of high-frequency current through various parts of the power system when the gaps flash or the MOVs conduct. Other issues arise from asymmetrical gap flashing, which creates unequal impedances between phases, i.e., when only one phase of the capacitor bank is bypassed during a line-to-ground fault.

Where series capacitors are used, the power system and line behave like an RLC series resonant circuit. Depending on the system impedance, degree of compensation, and distance of the short circuit, the quantities measured by the relay are disturbed by various dynamic influences. Short-circuit currents are particularly disturbed, depending on the protection of the series capacitor, e.g., by means of a varistor, an air gap, or a combination of both.

The risk of interharmonics is particularly high in case of two- and three-phase faults directly behind the capacitor. Interharmonics have frequencies that are higher than the fundamental component but are not integer multiples. While digital filter algorithms, such as Fourier Filter, can eliminate harmonics, they only dampen interharmonics slightly. With very specific power system conditions, the resonant frequency might even correspond to the fundamental frequency, resulting in the series resonant circuit being excited at its natural frequency, thus reaching resonance. Resonance states of this type cause such high short-circuit currents that the capacitor protection circuit responds reliably, using the varistor or air gap to bypass the capacitor, and thereby avoiding the resonance altogether.

Single-line-to-ground faults at a long distance with correspondingly low short-circuit currents are especially critical with respect to protecting series-compensated lines. Faults of this type may involve subsynchronous oscillations with frequencies between dc and the fundamental but with an amplitude that is too low to trip the capacitor protection element. With some exceptions, these subsynchronous oscillations are only encountered in primary systems when series compensation is employed and are the cause of subsynchronous resonance. The risk here is of torsional vibration developing in the turbine shaft generator systems of power stations. If subsynchronous oscillations cannot be precluded, the reach of the underreaching Zone 1 on the distance relay must be reduced in order to avoid an overreach.

2.5.5.4 Zone 1 Distance Relay Overreaching Problems

The series connection of the capacitor, transmission line, and system source create a resonant RLC circuit. The natural frequency of the circuit is a function of the level of compensation and the equivalent power system source. The level of compensation can change according to the switching of series capacitor "segments." The source impedance can change because of external switching operations of the protected line section.

Figure 2.137 illustrates a transmission line with a 50 percent series-compensated system (i.e., the series capacitor reactance equals 50 percent of the positive-sequence line reactance). For the fault location shown, the underreaching distance element at the remote terminal (Station S) should not operate. Intuitively, we would expect that 80 percent of the compensated impedance ($Z_L - jX_C$) would be an appropriate reach setting. However, the series capacitor and the system inductance generate subharmonic oscillations that can cause severe overreach of the distance element.

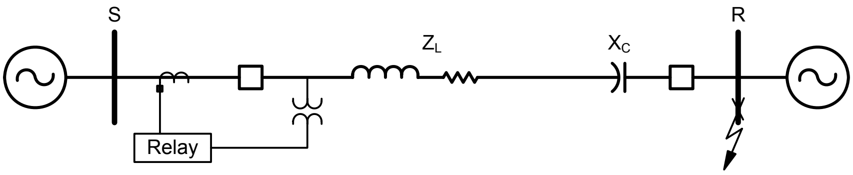


Figure 2.137 Series-compensated line with a fault at the remote bus

Figure 2.138 shows the impedance plane plot for the fault location shown in Figure 2.137 (where the series capacitor remains in service). As we can see from the impedance plot, the apparent impedance magnitude decreases to a value as low as 2 ohms secondary. This value is close to half of the compensated line impedance! Note that the capacitor is modeled with no overvoltage protection. This condition is common for most external faults because the overvoltage protection is typically sized to accommodate external faults (i.e., the overvoltage protection does not operate for external faults).

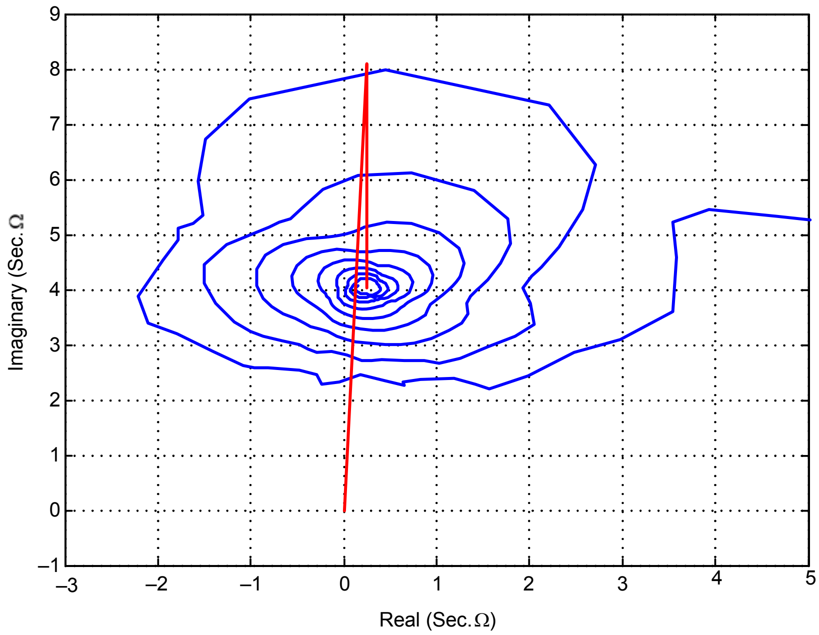


Figure 2.138 Apparent impedance for a fault at the end of the line

2.5.5.5 A Method to Prevent Distance Element Overreach

One method of preventing Zone 1 distance relay element overreach is presented in this section. From Figure 2.137, we can calculate the voltage drop for a bolted A-phase-to-ground fault at the line end as follows:

$$V_{CALC} = \left| \left[(I_A + k_0 \cdot I_G) \cdot Z_{1L} \right] + \left[I_A \cdot (-jX_C) \right] \right| \tag{2.83}$$

Where:

I_A = A-phase current at the relay location

I_G = residual or ground current at the relay location

k_0 = zero-sequence compensation factor

Z_{1L} = positive-sequence line impedance

X_C = capacitive reactance that the relay "sees"

Ignoring variables such as mutual coupling and fault resistance, we can see that the calculated voltage equals the measured voltage. Determining the ratio of the measured voltage to the calculated voltage would result in unity, or one.

When the fault moves to the other side of the series capacitor (line side), the measured voltage increases and the calculated voltage decreases. The measured voltage increases because the series capacitor is no longer between the relay and the fault, and the line appears to be electrically longer. The calculated voltage decreases because it always includes the series capacitor. The ratio of measured voltage to calculated voltage is greater than one for a fault at this location.

As the fault nears the relay location, the measured voltage decreases and the calculated voltage increases. The ratio of measured voltage to calculated voltage approaches zero as the fault location nears the relay location. Figure 2.139 shows a plot of the measured voltage (V_{MEAS}), calculated voltage (V_{CALC}), and the ratio of the measured voltage to calculated voltage. Note that the scale is arbitrary; the purpose of this figure is to illustrate how the voltage magnitudes and the voltage ratio change with respect to fault location.

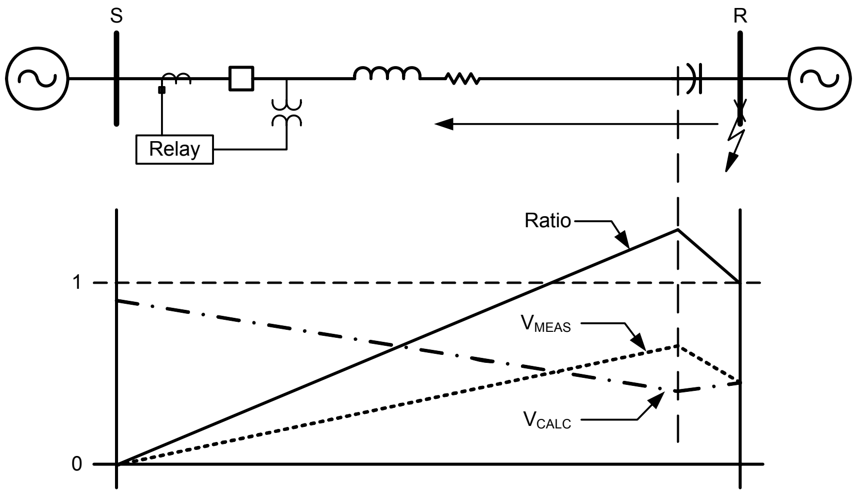


Figure 2.139 Measured and calculated voltages and voltage ratio for faults along the line

We can use the ratio described earlier to supervise underreaching Zone 1 distance elements and prevent overreach for external faults. When the ratio of measured voltage to calculated voltage is less than a predefined threshold, the Zone 1 distance element can operate. Otherwise, the Zone 1 element is blocked. The only additional information the relay needs to calculate this ratio is the capacitive reactance that the relay "sees." With the ratio supervision, you can set the Zone 1 reach based on the uncompensated line impedance.

2.5.5.6 Zone 1 Setting Considerations

When a Zone 1 distance element is applied on a series-compensated system, it is critical to the overall security of the protection that the Zone 1 distance element does not operate for any faults outside the protected line. As noted previously, the low-frequency transients that may occur on series-compensated systems cause an overreach of the Zone 1 elements. Proper setting of the Zone 1 elements includes not only the reach setting of the elements, but also the pickup setting of any overcurrent supervision elements that may be used to supervise the distance element.

The settings required for the Zone 1 distance elements are determined by the factors listed below:

- Series capacitor location
- Capacitor and line impedances
- Type of capacitor protection
- Protective level of the capacitor protection

The settings proposed in this section for series-compensated lines are only to be used as a starting point and not to be applied in an actual series-compensated line application. Proper distance relay settings in actual series-compensated line applications must be verified using transient testing with data obtained from an Electromagnetic Transients Program (EMTP/ATP) or verified in a Real-Time Digital Simulator environment.

Mid-Line Series Compensation

Consider the system shown in Figure 2.140. The series capacitor is considered to be “in front of the relay” when it is between the relay potential location and the remote source. Thus, the Zone 1 elements at both R and S must be set to accommodate a series capacitor.

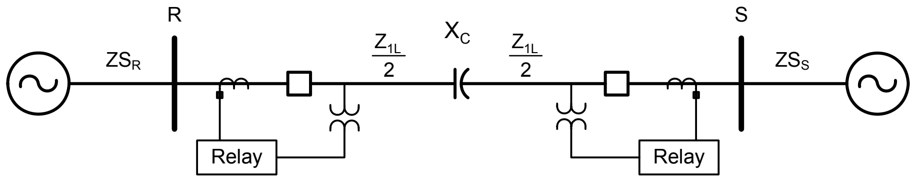


Figure 2.140 Mid-line series capacitor

When the series capacitor is protected by a triggered spark gap, the following settings are suggested:

$$Z1 = 0.80 \bullet (Z_{1L} - X_C) \tag{2.84}$$

When the series capacitor is protected by an MOV, the following settings are suggested:

$$Z1 = 0.50 \bullet (Z_{1L} - X_C) \tag{2.85}$$

Series Compensation at One Line End

Bus-Side Potential

Consider the system depicted in Figure 2.141. The series capacitor is “in front of” both relays. The distance element settings will be the same as those for the mid-line series capacitor from the previous example.

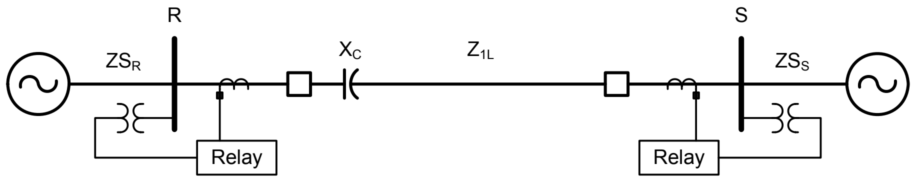


Figure 2.141 Series capacitor at one end – distance relay receives bus-side voltage

Line-Side Potential

Consider the system depicted in Figure 2.142. The potential for the relay at R is supplied from the line side of the series capacitor. For this case, the series capacitor impedance does not affect the reach setting for the Zone 1 distance elements at R. The following settings are suggested for the relay at R:

$$Z1 = 0.80 \bullet Z_{1L} \tag{2.86}$$

The settings for the distance elements at S will be the same as those for the mid-line capacitor location.

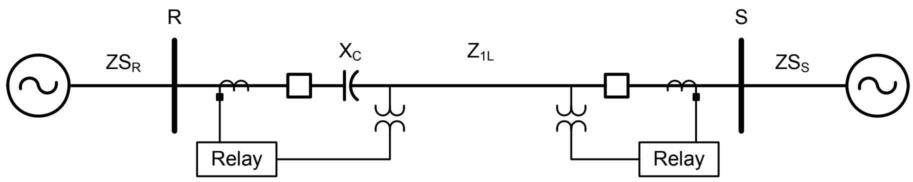


Figure 2.142 Series capacitor at one end – distance relay receives line-side voltage

Series Compensation at Both Line Ends

Bus-Side Potential

Consider the system shown in Figure 2.143. The Zone 1 distance elements at both R and S must be set to accommodate these two series capacitors.

- Spark-gap protection—when the series capacitor is protected by a triggered spark gap, the following settings are suggested:

$$Z1 = 0.80 \cdot \left[Z_{1L} - \left(X_{CR} + X_{CS}\right)\right] \tag{2.87}$$

- MOV protection—when the series capacitor is protected by an MOV, the following settings are suggested:

$$Z1 = 0.50 \cdot \left[Z_{1L} - \left(X_{CR} + X_{CS}\right)\right] \tag{2.88}$$

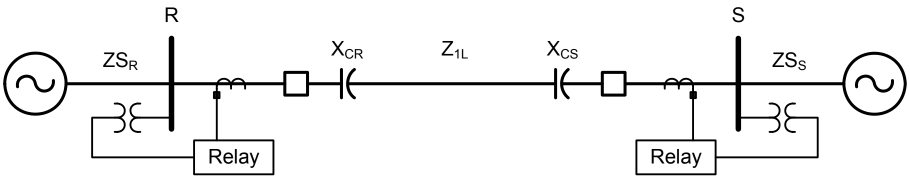


Figure 2.143 Series capacitors at both line ends – distance relays with bus-side voltages

Line-Side Potential

Consider the system shown in Figure 2.144. The Zone 1 distance elements at both R and S must be set to accommodate one series capacitor. Thus, the settings for this case are the same as those for when the capacitor is in the middle of the line.

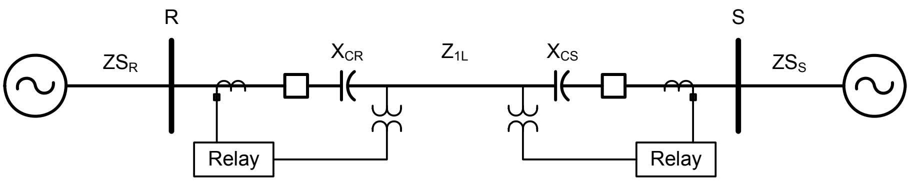


Figure 2.144 Series capacitors at both line ends – distance relays with line-side voltages

Capacitors External to the Protected Line

Consider the system of Figure 2.145. There are no series capacitors in front of the distance elements in the relay at R. Therefore, the Zone 1 distance elements at R will be set as described for compensation at one line end with line-side potential. However, there are two capacitors, C1 and C2, in front of the distance elements in the relay at S.

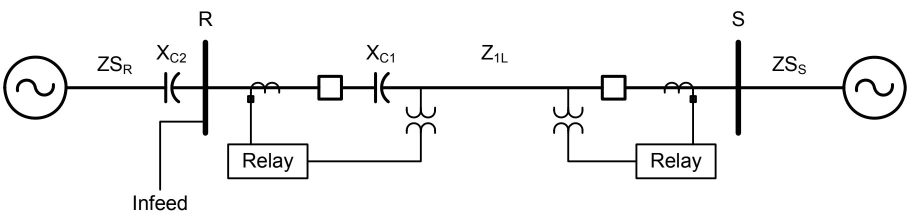


Figure 2.145 Series capacitors external to the protected line

If the infeed at R is sufficient to ensure that the capacitor current through C2 will always be greater than its protective current, then the Zone 1 distance elements at S may be set as if there were only the internal series capacitor, C1. However, if there is not enough infeed, then the settings for the Zone 1 distance elements at S must be set on the basis of two series capacitors.

- Spark-gap protection—when the series capacitor is protected by a triggered spark gap, the following settings are suggested:

$$Z1 = 0.80 \bullet \left[Z_{1L} - \left(X_{C1} + X_{C2} \right) \right] \quad (2.89)$$

- MOV protection—when the series capacitor is protected by an MOV, the following settings are suggested:

$$Z1 = 0.50 \bullet \left[Z_{1L} - \left(X_{C1} + X_{C2} \right) \right] \quad (2.90)$$

2.5.5.7 Pilot Distance Elements

In general, the series capacitors have little effect on the settings used for the overreaching pilot distance elements. In some cases, the low-frequency transients introduced through the addition of the series capacitors may cause the overreaching elements to momentarily drop out. This could delay tripping but will not cause a misoperation. If MOV protection is used on the series capacitor, conduction of the MOVs may cause the fault to appear more resistive than if triggered gaps are used to protect the series capacitor. For these reasons, it is suggested that the reach of the pilot zone distance elements be increased beyond that normally used on uncompensated systems. A minimum reach of 150 percent of the positive-sequence line impedance is suggested.

2.5.5.8 Reverse Zone 3 Elements

It is suggested that reversed Zone 3 distance elements be used for all applications on series-compensated systems. This permits the use of transient blocking within the relay logic to prevent misoperations caused by voltage inversions that might occur on some external faults. The reach of the reverse Zone 3 must coordinate with the reach of the pilot Zone 2 at the remote end of the line.

The suggested reach for bus-side potential location is:

$$Z3 = 1.25 \bullet \left[Z2 - \left(Z_{1L} - X_{CT} \right) \right] \quad (2.91)$$

Where:

$Z2$ = Zone 2 reach setting at the remote line terminal

Z_{1L} = positive-sequence line impedance

X_{CT} = total series capacitor impedance

The suggested reach for line-side potential location is:

$$Z3 = 1.25 \bullet \left[Z2 - \left(Z_{1L} - X_{C1} \right) \right] \quad (2.92)$$

Where:

X_{C1} = impedance of the series capacitor at the remote line end

When distance relays are applied on series-compensated systems, the Zone 3 elements should be set as reverse blocking elements. The particular scheme logic used will depend on the type of channel available as well as on the protection philosophy of the particular utility implementing the scheme. The Permissive Overreaching Transfer Trip (POTT) and Directional Comparison Unblocking (DCUB) schemes are well suited for use on series-compensated systems.

Additional logic can be implemented in modern distance relays to improve the security of the relay against misoperations caused by any voltage inversions that might occur on a series-compensated system. Voltage inversions typically do not affect the performance of distance relays for normal faults because of the design of the polarizing voltage. However, on faults that are cleared very slowly, such as for a breaker failure or a time-delayed trip, the fault may last longer than the polarizing circuit memory.

2.5.6 Cable Grounding Methods

Applications of ground distance relays on underground cables can be very challenging because the effective zero-sequence impedance of the cable depends on the return paths of the ground fault current. The zero-sequence impedance of underground cables is often difficult to determine precisely. The ground current return paths can be rather complex and vary over a wide range, depending on fault location, bonding and grounding methods of the sheath or shields, the resistivity of the cable trench backfilling, and the presence of parallel cable circuits, gas pipes, and water pipes. All of the above factors make the zero-sequence impedance calculations difficult, and in many cases questionable, even with the use of modern-day computers.

Note that in overhead transmission lines, the positive- and zero-sequence line impedances are proportional to the fault distance. However, this is not true for underground cables where the zero-sequence impedance may be nonlinear with respect to distance. The zero-sequence compensation factor, k_0, for solid-bonded and cross-bonded cables is not constant for internal cable faults, and it depends on the location of the fault along the cable circuit. Because ground distance relays use a single value of k_0, the compensated loop impedance displays a nonlinear behavior.

To ensure correct distance protection settings, we must take into consideration the cable grounding technique used in each application. This work requires extensive numerical computations. For more details on this topic, see Section 2.4.6, Cable Protection Considerations, and Annex 3, Cable Zero-Sequence Current Compensation Factor.

2.5.7 Transformer Winding Connections

Power transformer winding connections can influence the reach of distance protection relays. In addition, the location of CTs and VTs can influence distance measurement (whether they are both located on the same side of the transformer, or the CTs are located on the low-side terminals of the transformer and the VTs on the high-side terminals of the transformer). Power transformer protection using distance relays is covered in more detail in Section 2.4.9 of this report. The following peculiarities must be kept in mind when applying distance relays for the protection of transformer banks or through transformer banks [40]:

1. Impedances from one side to the other side of the transformer are transformed with the square of the turns ratio of the transformer windings, which corresponds to the square of the VT ratio.
2. The transformation ratio changes on transformers with load tap changers, depending on the position of the load tap changer.
3. Positive- and negative-sequence components rotate in opposite directions when they are transformed through a grounded-wye-delta transformer bank.
4. Zero-sequence components are not transformed through a grounded-wye-delta transformer bank. Therefore, line-to-ground faults cannot be measured properly with distance relays through grounded-wye-delta transformer banks.
5. Phase-to-phase faults on the wye side of a grounded-wye-delta transformer bank appear as three-phase faults on the delta side. Line-to-ground faults on the wye side of a grounded-wye-delta transformer bank appear as phase-to-phase faults on the delta side.

Figure 2.146 shows two possible locations of instrument transformer connections to a distance relay for transformer protection. Typically, the instrument transformers are connected on the same side of the power transformer. However, other combinations are possible, and the user should treat them as special applications. In addition, phase-shifted voltages (using auxiliary VTs) or delta-connected CTs may be required for some of these special applications.

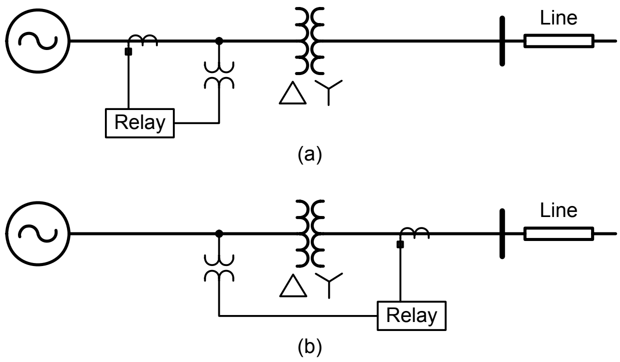


Figure 2.146 Location of instrument transformers

Figure 2.147 shows the fault current distribution (in p.u.) in the windings of a grounded-wye-delta transformer bank for three-phase, phase-to-phase, and phase-to-ground faults on the wye side of the transformer, assuming equal positive-, negative-, and zero-sequence impedances (1.0 p.u.). The transformer is connected per IEEE standards with the low-voltage delta lagging the high-voltage wye by 30 degrees.

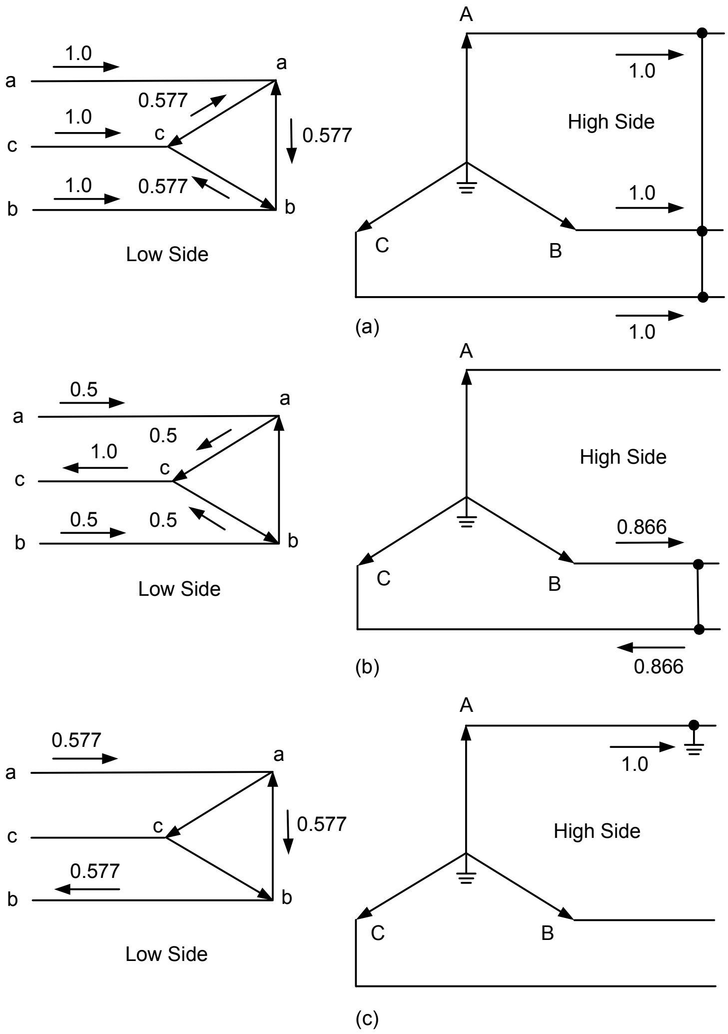


Figure 2.147 Faults through grounded-wye-delta bank (current shown in p.u.)

2.5.8 Instrument Transformer Transients

Current and voltage transducers provide instrument level signals to protective relays. Protective relay accuracy and performance is directly related to the steady state and transient performance of the instrument transformers. Protective relays are designed to operate in a shorter time period than that of the transient disturbance during a system fault. Large instrument transformer transient errors may delay or prevent relay operation. In this section, we discuss the effect of conventional instrument transformer transients on distance relay elements.

2.5.8.1 Current Transformer (CT) Transients

CTs are equipped with iron that can saturate symmetrically due to large symmetrical fault currents or asymmetrically because of prolonged presence of a dc component in the primary fault current. Upon saturation, the CT instantaneous current delivered to the relays and other instruments deviates in both magnitude and shape from the current that actually flows in the power system. During saturation, the CT operates in the nonlinear region of its excitation characteristic [29]. Operation in this region is typically initiated by the following:

- Large, asymmetrical primary fault currents with a decaying dc component
- Large, connected burden combined with high magnitudes of primary fault currents
- Residual magnetism left in the core from an earlier asymmetrical fault or field-testing if the CT has not been demagnetized properly

The dc component can cause CT saturation in the first few cycles of the fault, and long dc time constant offset fault currents can cause CTs to saturate even many cycles after a fault. The fidelity of the CT transformation is reasonably good until saturation takes place. High-speed distance relays may operate before CT saturation occurs. Figure 2.148 shows a simplified CT-equivalent circuit that can be used for a simplified transient analysis.

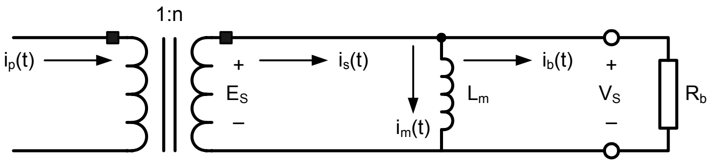


Figure 2.148 Simplified CT-equivalent circuit

Equation (2.93) gives the instantaneous CT secondary current, $i_s(t)$, as the sum of the instantaneous burden, $i_b(t)$, and the magnetizing currents, $i_m(t)$.

$$i_s(t) = i_m(t) + i_b(t) \tag{2.93}$$

The CT steady-state magnetizing current is very small as long as the CT operates in its linear region. If we assume that the exciting current is negligible, then the burden current, $i_b(t)$, is a replica of the primary current adjusted by the CT ratio. When the CT is forced to operate in its nonlinear region, the magnetizing current can be very large due to a significant reduction of the value of the saturable magnetizing inductance. The magnetizing current, which can be considered as an error current, subtracts from $i_s(t)$ and drastically affects the current seen by the connected burden on the CT secondary winding.

Effect of CT Saturation on Distance Relay Element Performance

Numerical mho-type distance element operating and polarizing vector quantities have been implemented as discussed in [29].

$$S_{OP} = r \bullet Z_1 \bullet I_R - V_R \tag{2.94}$$

$$S_{POL} = V_{POL}$$

V_R and I_R are the voltage and current corresponding to a particular impedance loop (six loops are required to detect all phase-to-phase and phase-to-ground faults), Z_1 is the positive-sequence line impedance, r is the per-unit mho element reach (0.8 means 80 percent of the line), and V_{POL} is the polarizing voltage, consisting of the memorized positive-sequence phasor. A relay detects the fault inside the mho element with reach r when the scalar product between the two vectors is positive (i.e., the angle difference between S_{OP} and S_{POL} is less than 90 degrees), as in Equation (2.95):

$$\text{real}\left(\left(r \bullet Z_1 \bullet I_R - V_R\right) \bullet V_{POL}^{\ *}\right) \geq 0 \qquad (2.95)$$

For a forward fault, this is equivalent to the reach r being greater than a distance m, as in the following:

$$r \geq m = \frac{\text{real}\left(V_R \bullet V_{POL}^{\ *}\right)}{\text{real}\left(Z_1 \bullet I_R \bullet V_{POL}^{\ *}\right)} \qquad (2.96)$$

If CT saturation occurs in one of the currents involved in the impedance loop, the magnitude of I_R reduces, and m has a higher value than ideal. From this, we can infer that a mho element underreaches during CT saturation [63].

Consider an A-phase fault on a 500 kV line ($Z_1 = 75 \angle 86°$ and $Z_0 = 300 \angle 75°$ ohms). The fault occurs at 0.1 seconds at a distance from the relay equal to 33 percent of the line length. As shown in Figure 2.150, m corresponding to a normal fault current settles to 0.33 as expected. For a saturated A-phase current (solid line in Figure 2.149), the calculated distance m value crosses the unity line with a half-cycle delay and settles around 0.45 because the current remains in a saturated state.

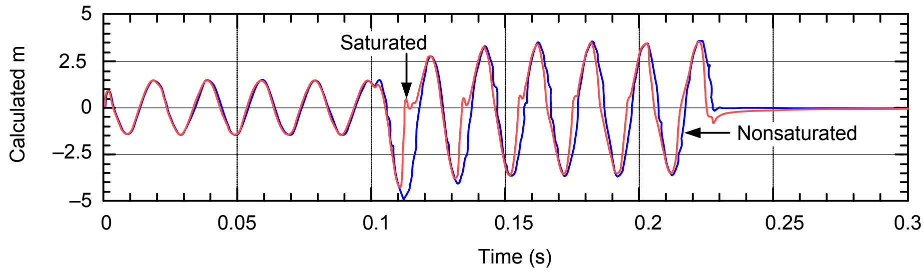


Figure 2.149 Saturated and normal currents

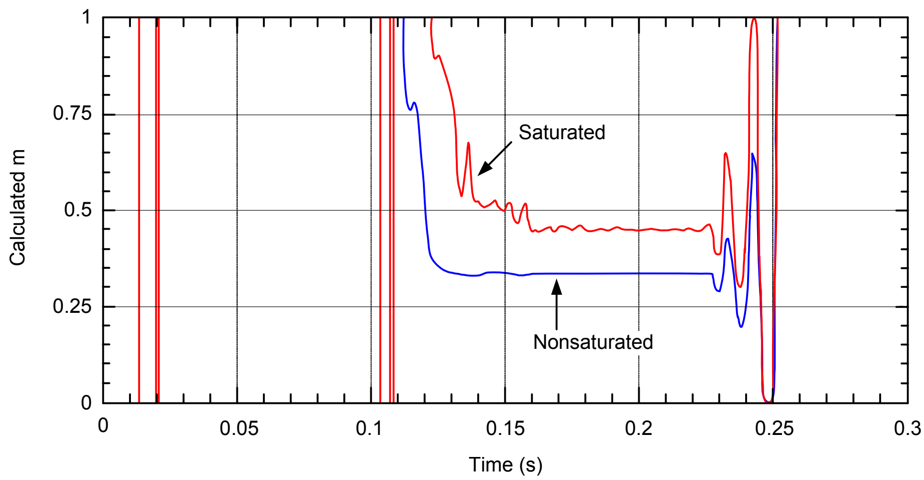


Figure 2.150 Calculated distance m values with normal and saturated currents

Figure 2.151 shows another method of visualizing distance relay element underreach because of CT saturation. Figure 2.151 shows the phasor diagram of the operating and polarizing vector quantities for a fault on the boundary of a self-polarizing mho distance element with reach r. As the CT saturates, the magnitude of I_R decreases and its angle advances (this effect is shown as dashed lines in Figure 2.151). This causes the dV phasor to rotate counterclockwise, which creates an element underreach.

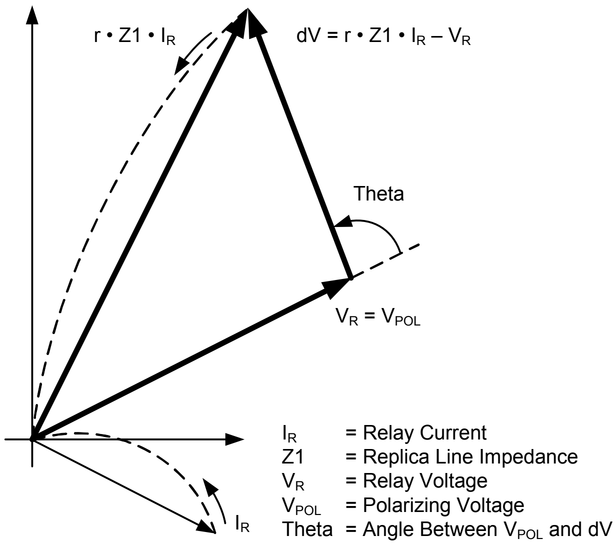


Figure 2.151 Mho element phasor diagram showing how CT saturation causes underreach

The possible impact of CT saturation on distance elements is a minor delay of the corresponding Zone 1 element (assuming the CT does not remain in saturation). Zone 1 element underreach risk increases for fault locations near the relay reach. However, with moderate length lines as the fault location approaches the relay reach, the fault current magnitude decreases and reduces the chances of CT saturation. For larger reach Zone 2 or Zone 3 elements, particularly in communications-assisted schemes (POTT, DCB, etc.), CT saturation has a limited impact on the final result, aside from a slight tripping delay.

2.5.8.2 Capacitor Voltage Transformer Transients

CVTs are widely used in high-voltage power systems. Figure 2.152 shows a typical circuit diagram of a CVT. Capacitors C_1 and C_2 are used as a voltage divider to step down the line voltage before it is applied to a wound step-down voltage transformer (SDT) via a tuning reactor, L_{TR}.

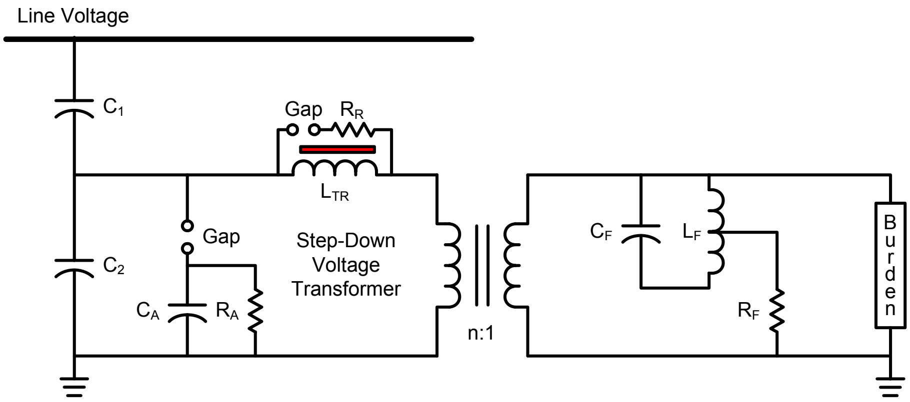


Figure 2.152 CVT circuit

Ferroresonance is possible in any system composed of capacitors and iron-core inductances. In a CVT, the interaction of the source capacitance with the tuning reactor inductance and the SDT magnetizing inductance can lead to a ferroresonance oscillation.

CVT manufacturers use ferroresonance-suppression circuits (FSCs) to reduce or eliminate ferroresonance conditions. One such FSC device is shown connected at the secondary winding of the SDT in Figure 2.152. Capacitor C_F in parallel with L_F forms a high-impedance parallel resonant circuit tuned at the fundamental frequency. At harmonic or subharmonic frequencies, the FSC impedance drops off sharply, leaving only the damping resistor, R_F, in the circuit. This is an active type of FSC. A passive FSC design uses passive elements to suppress the ferroresonance oscillations. The passive FSC design has a permanently connected resistor, R_F, in series with a saturable inductor, L_F, and an air-gap loading resistor. Under normal operating conditions, the secondary voltage is not high enough to flash the air gap, and the loading resistor, R, has no effect on the CVT output.

Many CVT components and system conditions affect the CVT transient performance [64].

- High or extra-high capacitance CVTs, higher STD ratios, and CVTs with passive FSCs display a better transient response.
- Small resistive burden, found in microprocessor-based relays, further improves the CVT transient response.
- A higher system impedance ratio (SIR) results in more severe CVT transients for faults at the same location.
- Fault initiation angle influences the shape of CVT transients. The CVT transient is more severe for faults at a voltage zero crossing.

Effect of CVT Transients on Distance Relay Element Performance

CVT transients reduce the fundamental component of the fault voltage and cause distance relays to calculate a smaller than actual apparent impedance to the fault. Figure 2.153 shows the fundamental frequency magnitude of a CVT secondary voltage as compared with the ideal ratio voltage. Figure 2.154 shows two apparent impedance loci of an end-of-line fault calculated from the ideal ratio voltage and the CVT secondary voltage.

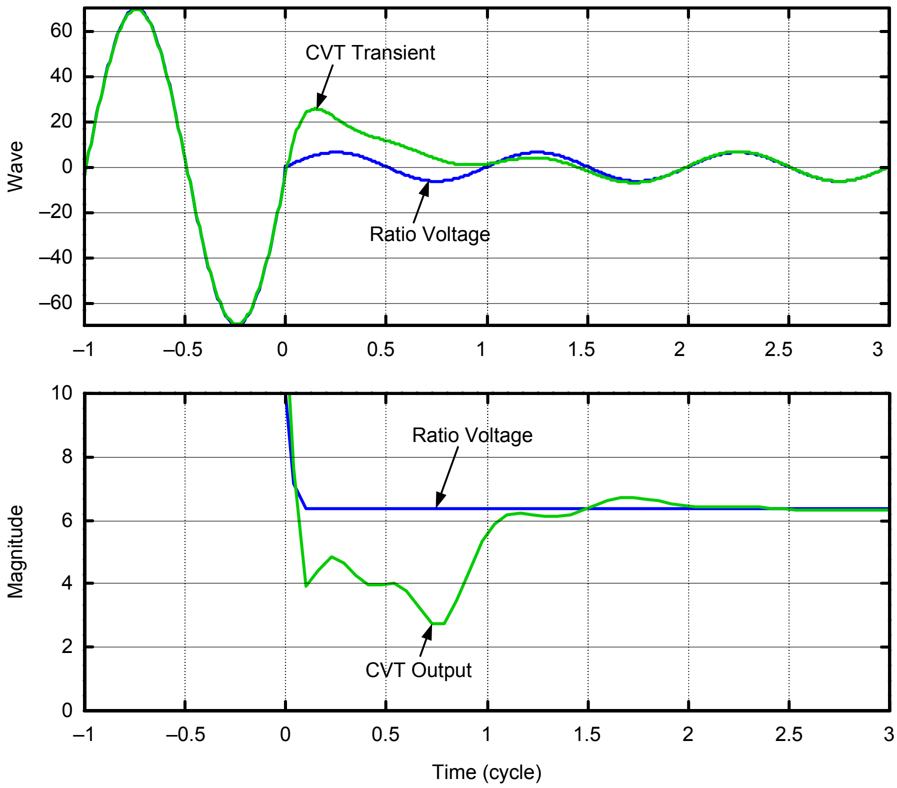


Figure 2.153 CVT transients reduce the fundamental voltage magnitude

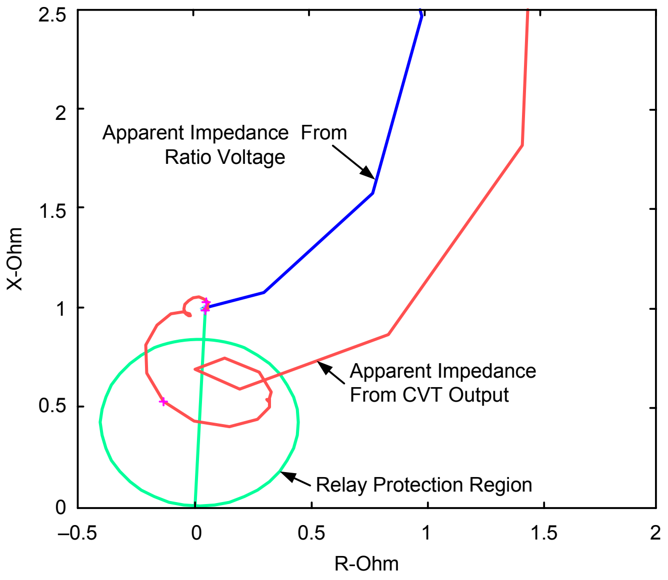


Figure 2.154 Overreach due to CVT transients

2.5.8.3 Bushing Potential Device Transients

Bushing potential devices (BPD) are another voltage input source for protective relays. The BPD uses the capacitance coupling of a specially constructed bushing of a circuit breaker or a transformer to reduce the primary system voltage to a medium voltage level (e.g., 4 kV), which is applied to a SDT to produce the secondary voltages that are applied to protective relays.

BPDs produce a similar transient response to that of a CVT during a system fault. However, the BPD transient response is more dependent on the secondary connected burden because BPDs employ a low SDT ratio. A high inductive burden significantly increases the amount and duration of the transient error [65].

The parameters that affect the BPD transient response are:

- Burden – inductive burdens result in worst transient performance.
- Transformer ratio – a low step-down transformer ratio results in a larger burden effect and produces greater transient error.
- Power factor adjustment – compensating for any lagging power factor burden improves the transient performance.
- Bus voltage dip – the transient error is proportional to the change in bus voltage caused by a fault. Therefore, high source-to-line-impedance ratios result in large voltage changes and transient error at Zone 1 boundary faults.

Distance relay underreaching and overreaching can be expected because of BPD transient response depending on the connected burden. Figure 2.155 and Figure 2.156 illustrate an underreaching effect when the connected BPD burden consists of both electromechanical and numerical relays (10 ohms at 65 percent power factor). The protected line is 40 miles long with a source-to-line-impedance ratio of 5.8. A ground fault occurred at 64 percent of the line from the relay location. The large and slow decaying transient causes a distance relay underreach as shown in Figure 2.156 [65].

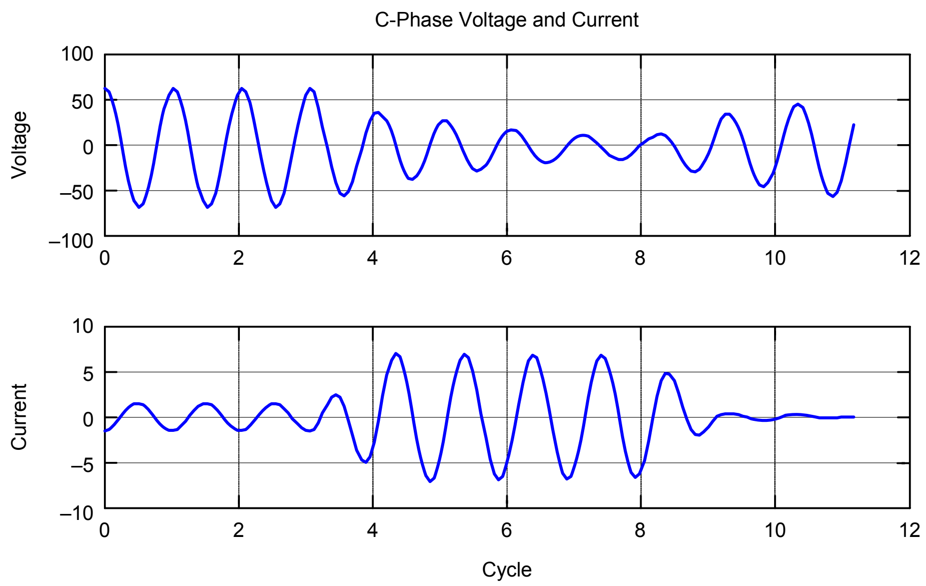


Figure 2.155 Voltage and current for a C-phase fault at 64 percent of line length

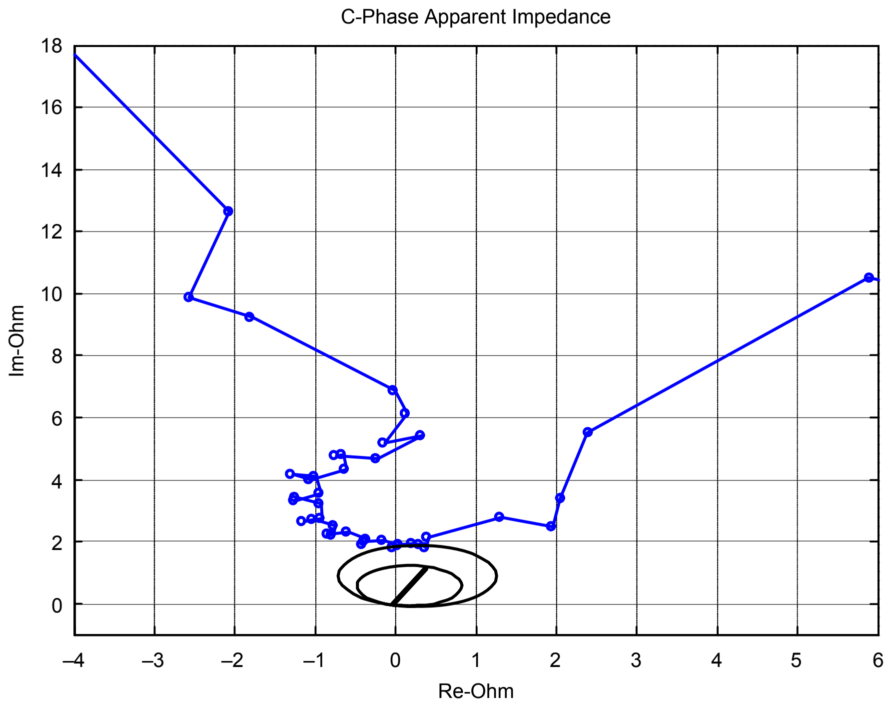


Figure 2.156 Apparent impedance seen by the distance relay for the fault at 64 percent of the line length

Mitigation of CVT and BPD Subsidence Transient

CVT and BPD subsidence transients result in a reduction of the fundamental voltage for a few cycles. This reduction will result in a Zone 1 distance relay overreach for remote terminal faults. The preferred mitigation depends on the fault clearing requirements of the transmission system. If the system can tolerate a few cycles for fault detection, then time delay the Zone 1 output by up to two cycles. However, for systems with stringent fault clearing times, the Zone 1 relay reach should be reduced based on the chart shown in Figure 2.157. Figure 2.157 is obtained using typical passive and active CVTs with a resistive burden of 5 kΩ, representative of the load of several modern microprocessor-relays and meters.

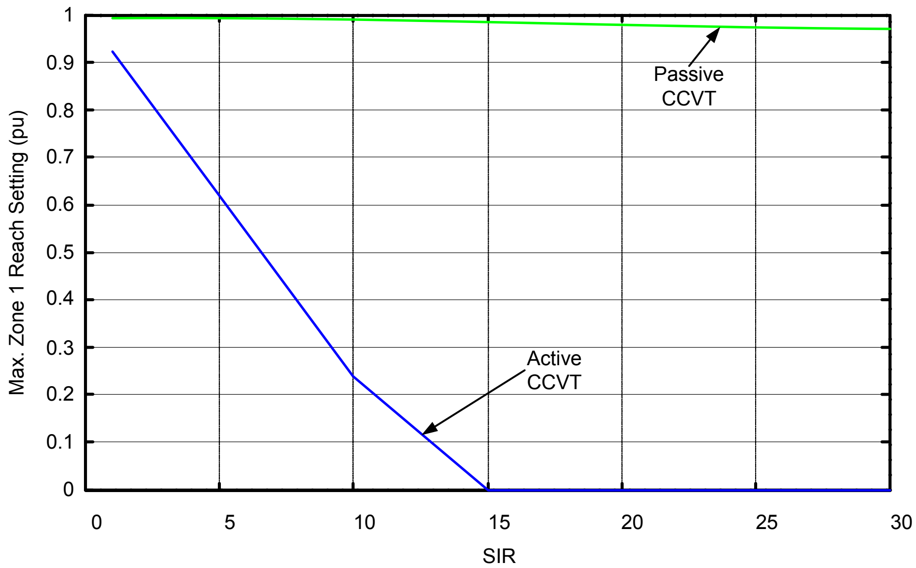


Figure 2.157 Distance element performance as a function of source impedance ratio

CVT Transient Detection Methods

Relay manufacturers have invented many solutions to cope with the CVT transient problem. These solutions include narrow band-pass filtering the voltage (which effectively adds delay via filtering), reducing distance relay reach, and directly delaying the distance relay tripping decision when a CVT transient condition is detected. All of these solutions have their inherent disadvantages. Reference [64] describes a solution that prevents distance relay CVT transient overreach. CVT transient detection logic has been developed to deal with the transient overreach concerns from CVT transients. The system impedance ratio is estimated from the fault voltage and current, and when this value is high, which causes a concern of Zone 1 distance element overreach, a time delay is added to the instantaneous tripping distance elements. The smoothness of the apparent fault impedance is then closely monitored to detect any CVT transient signatures. Therefore, on the detection of a high SIR, the relay applies the Zone 1 delay and monitors the voltage transient. If the transient signature is small and does not indicate overreach, the time delay is quickly removed to allow a quicker operation of the elements. The logic adapts to the quality of the CVT used and only adds time delay when necessary.

Figure 2.158 shows an end-of-line BC phase-to-phase fault. A Zone 1 instantaneous protection element is set at 85 percent of line length. The digital element plot shows that the Zone 1 element would pick up because of the CVT transients; however, the CVT transient detection logic successfully detects the overreach condition and blocks the Zone 1 element. This logic overcomes the undesirable delay aspect by detecting when the CVT transient is complete and removes the Zone 1 element block.

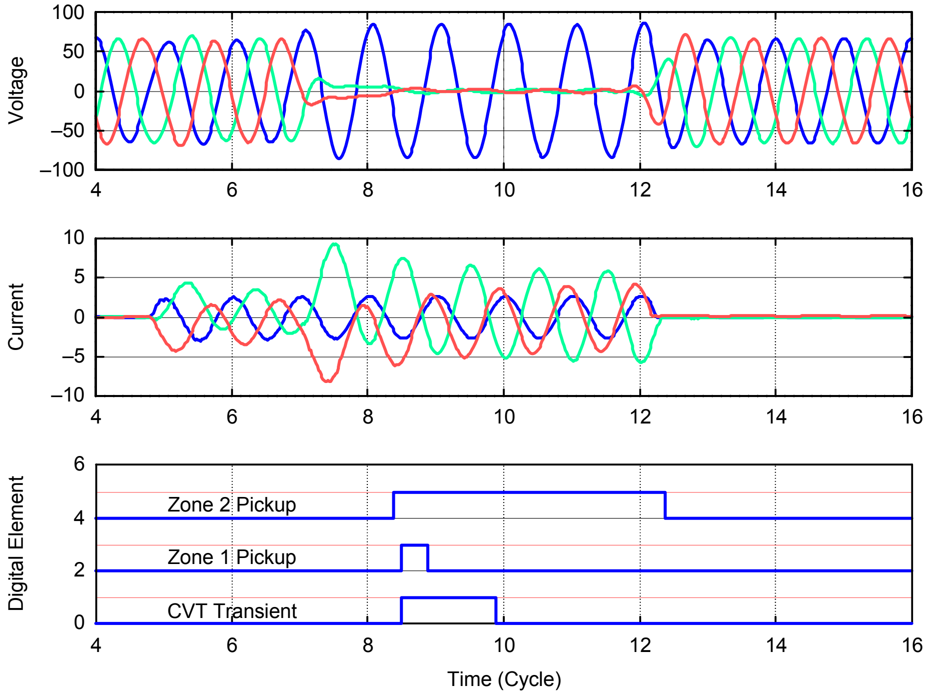


Figure 2.158 CVT transient detection logic prevents Zone 1 element from overreaching

In conclusion, distance relay Zone 1 elements exhibit a minor tripping delay and a potential underreach for faults near the relay reach point due to CT saturation. In general, faults near the relay reach point display a reduced current magnitude if the CT saturates. However, the chance of CT saturation near the relay reach point is much smaller than for faults occurring near the relay location. CT saturation has a limited impact, aside from a slight tripping delay, on longer set Zone 2 and Zone 3 distance elements. However, Zone 2 distance relay settings may have to be adjusted for this potential underreach.

CVT and BPD transients reduce the fundamental component of fault voltage and can cause overreach of Zone 1 distance relay elements. High BPD electromechanical relay burdens can cause large magnitude and slow decaying BPD transients that result in distance relay element underreaching. Relay elements fitted with CVT transient detection logic may introduce a slight (and necessary) tripping delay; however, they exhibit greater security for faults near the relay reach point.

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3. FUNCTIONAL INTEGRATION IN DISTANCE RELAYS

Increased transmission system loading and reduced stability margins demand increased protective relay speeds while maintaining secure and dependable relay operations. Relay manufacturers have integrated in modern numerical distance protection relays a large number of protection, control, monitoring, and metering elements that provide the users the flexibility to design advanced protection and control schemes that could not have been realized with earlier electromechanical and solid-state technologies.

Modern numerical distance relays have a large number of protection functions such as overcurrent, overvoltage, undervoltage, underfrequency, overfrequency, breaker failure, synchronism check, power swing blocking and tripping, pilot protection schemes, digital relay-to-relay communications capability, logic programmability, and advanced math functionality. Functional integration in modern numerical distance-type relays provides protection engineers with the tools and flexibility to design more secure and dependable protection and control schemes to improve the reliability and security of electric power systems. The increased number of relay settings, functionality, design flexibility, and programmability in modern distance relays has also introduced a higher level of complexity for the user and an increased risk of making application and settings errors. Proper user training and appropriate testing of the designed schemes helps in taking full advantage of functional integration offered by modern distance relays and reduces any potential risks of misapplications.

Microprocessor-based relays, applied for transmission line protection, require a complete philosophical protection review. While older types of electromechanical and solid-state relays provided adequate protection schemes, new state-of-the-art numerical protection, with its multifunctional integrated capability, offers unprecedented flexibility and improvements in protection, control, and monitoring principles. These sophisticated devices are designed to ensure stability of modern power systems under all types of conditions.

Some benefits from multifunctional protection intelligent electronic devices (IEDs) are related to protection performance improvements in selectivity, security, backup protection, etc. Other benefits are directly related to reduced costs due to substantial reduction of equipment assemblies, wiring, and maintenance. At the same time, these devices also include other beneficial functions such as disturbance and event recording, programmable scheme logic capabilities, and metering, as well as built-in fault analysis tools and self-monitoring capability.

Multifunctional distance relays are now used in new or upgraded integrated substation protection, monitoring, and control systems and are becoming the main data sources for measurements needed by the local substation HMI or SCADA master.

In this section, we discuss the advantages of functional integration in modern distance protection IEDs in the areas of protection performance improvements, control, and metering, and we include a few application examples to demonstrate those advantages. In addition, the working group (WG) conducted a survey of a number of manufacturers of numerical relays to determine the level of integration in modern distance protection relays. The results of the survey are summarized in Table 3.2.

3.1 FUNCTIONAL INTEGRATION IN NUMERICAL DISTANCE RELAYS IMPROVES SYSTEM RELIABILITY

Protection engineers strive to achieve high-speed tripping for all transmission line faults through the use of communications-assisted protective relaying. In traditional pilot relaying schemes, the relay systems send and receive logic-based information between line terminals to determine whether the fault is internal or external to the protected line section. Traditional pilot relaying schemes require costly external communications equipment. Modern numerical relays integrate the communications functionality within the same distance relay hardware and provide relay-to-relay digital communications for high-speed line protection, monitoring, and control. Novel, more secure, and dependable applications are now possible with the relay-to-relay communications capability. Later in this report, we discuss applications of relay-to-relay digital communications in single-phase tripping and reclosing applications to aid the phase selection function of distance-type relays and avoid three-phase tripping during simultaneous single-phase-to-ground faults near one terminal of a double-circuit transmission line. In three-terminal line protection applications where high-speed tripping is essential, loss of a communications channel between any two of the three terminals renders the high-speed pilot protection scheme inoperable. Relay-to-relay communications and relay programmable logic can maintain high-speed protection even in the event of the loss of one channel between any two of the three terminals.

Protective relay sampling synchronization within 1 microsecond is possible with the advent of satellite-based time-keeping systems and advances in computer technology. Now, modern distance relays are available with synchronized phasor measurement capabilities. The relay measures absolute phase as well as voltage, current, power, and reactive power. Therefore, the distance relay measures the power system state variables in addition to other protective relay-related information. Present methods for control and protection of power systems rely mostly on local measurements. Local measurements impose limitations on the control and protection functions due to lack of adequate knowledge of the power system state at remote locations. The availability and use of synchronized phasor measurements will permit advanced power system protection and control strategies. The addition of synchrophasor measurement in a protective relay results in increased power system reliability and provides better disturbance analysis, protection, and control capabilities than the approaches with different information sources.

Modern microprocessor-based distance relays offer significant potential to cope with the technical and economical challenges facing protection engineers. Multifunctional protection devices address a wide area of protection applications including integrated communications, control, metering, and fault location features. The principal protection functions that are provided in numerical distance devices include distance and line differential protection functions or distance and $\Delta V/\Delta I$ protection functions together with many additional protection features that include undervoltage elements, overvoltage elements, and synchronism-check elements to verify the phase angle between the line and bus voltage for breaker reclosing purposes. Additional integrated protection features, such as phase overcurrent elements, negative-sequence elements, residual-ground elements, and neutral-ground overcurrent elements, provide sensitive directional or nondirectional backup functions for line protection.

The combination of voltage and current elements provided in distance relays can be used to accomplish numerous protection functions. For example, undervoltage and current elements can be used to accomplish the dead-line pickup function enabling the detection of faults when the transmission line is first energized. The inrush stabilization function using second-harmonic restraint logic is provided to detect inrush if the line is energized with an online transformer or shunt reactor, and a high-set overcurrent element is used to block the inrush restraint logic from operation if the line is energized during a fault condition. Other protection features include loss of potential, out-of-step blocking or tripping functions depending on the topology of the system, under- and overfrequency elements, integrated relay-to-relay communications logic, and breaker failure protection. Control, metering, fault location, and disturbance and event recording are some of the many additional functions that are also provided in the same numerical protection device.

In an attempt to answer the question of how much integration in the same distance relay can be justified or how many of those integrated control and protection functions can be used with the main distance protection scheme, protection engineers should evaluate these important issues from the point of view of reliability and availability. Reliability is one of the most determinant issues and is the basic requirement in relay design.

As modern numerical distance protection offers a significant number of improvements over previous generations and technologies, the new state-of-the-art numerical distance protection, with its multifunctional integrated capability, provides an unprecedented flexibility in line protection principles, control, and monitoring schemes including fault location techniques. The improvements in line protection performance are viewed in terms of fault discrimination techniques and fast fault elimination time, protection selectivity, increased backup principles, etc. These enhanced features are considered from the technical perspective, but other benefits are directly related to cost due to substantial reduction of equipment assemblies, wiring, and maintenance.

As more economic pressures are imposed on utilities to maximize equipment use to near the design limits, more constraints on system stability, security, and availability are imposed. Functional integration provided in the same distance protection device allows for a better level of protection performance. The only question that needs to be addressed is related to backup distance protection principles that are used in the same relay and how they should be considered in a nondiscrete protection environment. The incorporation of all protection functions into one device carries a risk of common-mode failure and may result in the removal of all protection and control algorithms from service. For this reason, many utilities are revising their entire protection and control philosophy by retaining two discrete main distance protection devices with backup protection fitted in both Main 1 and Main 2 devices, including breaker failure protection.

In this regard, a common mode failure in one distance protection device will not affect the backup functions as they are duplicated in both main devices. Similarly, breaker failure protection in each device will always respond correctly even during the unavailability of one of the two main devices.

The increased functionality in distance protection from integrating relay-to-relay communications features into the same device has also changed the traditional boundaries between protection and control functions. The first and most obvious one is related to the circuit breaker reclosure function incorporated in the same distance protection device. In this regard, utility engineers have to evaluate the performance benefits from utilizing the auto reclose function in both main distance protection devices. Some utilities would enable the auto reclose function in one main distance device if the lines are not loaded to their maximum thermal rating and accept the risk of not reclosing in case of transient faults or unavailability of the main distance protection device.

On the other hand, it is desirable to enable the auto reclose functions in both main protection devices to provide high-speed reclosing for weakly interconnected systems in order to maintain synchronism and ensure normal load flow in individual lines. Communications links between Main 1 and Main 2 devices and the implementation of programmable relay logic will allow both devices to initiate circuit breaker reclosing functions. Moreover, with the already integrated communications features within the same distance protection device, the remote line end circuit breaker auto reclosure can be enabled or blocked depending on the condition and implemented philosophy. Some utilities still prefer to utilize a separate auto reclose device that could be functionally combined with bay control functions. This simplified approach generally matches the two-trip/one-close coil of circuit breakers.

3.2 INTEGRATED FUNCTIONS IN MODERN DISTANCE RELAYS

A large number of protection and control functions are integrated in microprocessor-based distance relays. Table 3.1 lists most of these protection, control, monitoring, and metering functions that are integrated in modern distance relays.

Table 3.1 Protection, control, and metering functions integrated in modern distance relays

ANSI No.	Protection Functions Integrated in Modern Distance Relays
27	Undervoltage
49	Thermal
50N/G	Ground overcurrent
50P	Phase overcurrent
50Q	Negative-sequence overcurrent
51N/G	Ground time overcurrent
51	Phase time overcurrent
51Q	Negative-sequence time overcurrent

ANSI No.	Protection Functions Integrated in Modern Distance Relays
59	Overvoltage
67N/G	Ground directional overcurrent
67P	Phase directional overcurrent
67Q	Negative-sequence directional overcurrent
78	Out-of-step block and trip
81U/O	Multistage under- and overfrequency
85	Multiple communications-assisted (pilot protection) schemes
87L	Line current differential
	Load-encroachment supervision
	Relay-to-relay communications
	Switch-onto-fault
	Single-pole trip
	Zone level timers
	Programmable analog math

ANSI No.	Control and Metering Functions
25	Synchronism check
50BF	Breaker failure
79	Reclosing
81U/O	Under- and overfrequency
	Fault locating
	Multiple settings groups
	Programmable logic control
	Advanced relay-to-relay communications
	Voltage check on closing
	Selective overcurrent logic
	Current transformer supervision
	Voltage transformer supervision
	Local control switches
	Remote control switches
	Nonvolatile latch control switches
	Display points
	Event, fault, and disturbance report (programmable multicycle data)
	Sequential events recorder
	Circuit breaker control
	Breaker wear monitor
	Trip coil monitor

ANSI No.	Control and Metering Functions
	Substation battery monitor
	Instantaneous meter
	Demand meter
	True rms measurement
	Synchrophasors
	Binary inputs
	Relay outputs

3.2.1 Functional Integration Survey

The CIGRE WG B5.15 initiated a survey to four different relay manufacturers. The objective of the survey was to determine the improvements that were achieved with numerical technology. The survey specified that manufacturers list the additional protection, control, and monitoring functions in modern numerical distance protection devices. Figure 3.1 illustrates schematically the objective of the survey.

Legend

F1 – Function not integrated in the distance protection device before digital technology, but was improved due to its integration into the numerical distance relay

F1+ – Corresponds to an improved function due to the numerical technology

F2 – New nondistance function integrated in the numerical distance protection device

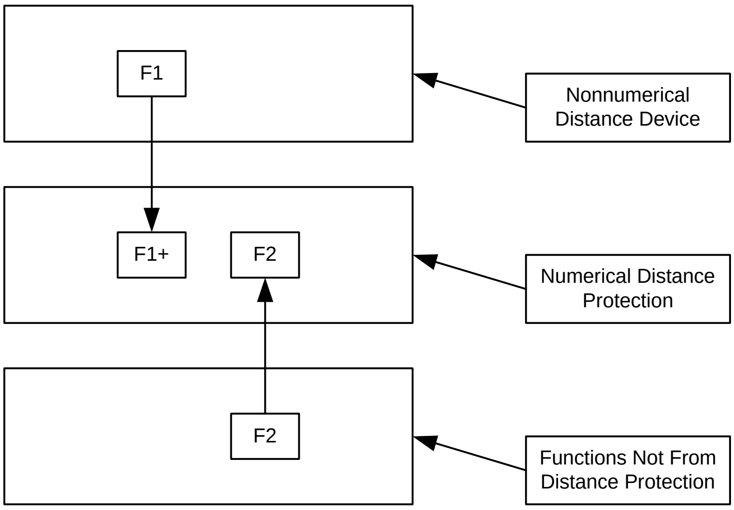

Figure 3.1 Schematic diagram of integrated functions in numerical distance relays

The manufacturer survey indicated that a wide range of advanced integrated protection, control, and monitoring functions are part of distance relays to enhance the reliability of modern power systems under all operating conditions.

Table 3.2 shows the protection, control, monitoring, and metering of functions that are integrated into modern distance protection devices. It indicates which functions were integrated after the introduction of numerical technology from other discrete protection devices. It also indicates which functions may have existed in solid-state distance protection devices and were improved due to advancements in numerical algorithms and the ability to offer adaptive functionality in numerical relays.

Table 3.2 Protection, control, monitoring, and metering functions in numerical distance relays

Protection Functions	F1+	F2
Under- and overfrequency	X	X
Under- and overvoltage	X	X
Overcurrent ([non]directional, phase, ground)	X	X
Negative-sequence protection ([non]directional, voltage, current)	X	X
Breaker failure protection (for two breakers)	X	X
Sudden loss of load	X	X
Power swing protection (blocking, unblocking)	X	
Load encroachment (load blinders)	X	
Fuse failure	X	
CVT transient detection	X	
Multiprinciple protection	X	X
Distance + line differential	X	X
Distance + $\Delta V/\Delta I$	X	X
Multiple settings groups		X
Series compensation logic	X	X
Pilot protection logic		X
Relay-to-relay communications		X
Switch-onto-fault logic	X	
Programmable logic		X
Load shedding (UF or UV)		X
Zone 1 extension	X	
Single-phase tripping	X	
Best choice directional control	X	X
Frequency tracking	X	X
Scheme communications alternatives	X	
Dynamic compensation for under- and overreach	X	
CT saturation detection compensation		X

Control Functions	F1+	F2
Interlocking equations/logic	X	X
Auto reclosing	X	X
Synchronism check	X	X
Synchronizing	X	
Local control switches		X
Remote control switches		X
Nonvolatile latch control switches		X
Display points		X

Control Functions	F1+	F2
Multiple breaker control		X
Control logic equations	X	X
Pole open logic	X	X
Analog level logic comparison equations		X
Voltage check on closing	X	X
Voltage selection	X	

Monitoring and Metering Functions	F1	F2
Substation battery condition	X	X
Load profiling	X	X
Self-test function		X
Signaling	X	X
Disturbance recording		X
Event recording (short circuit, overload, ground faults, etc.)		X
Fault location	X	X
Measurement data	X	
Trip circuit supervision	X	X
Calculation of power, energy, etc.	X	X
Circuit breaker contact wear	X	X
Time synchronization via IRIG-B	X	X
Protection quality		X
True disturbance recording (raw data with fixed sampling rate)		X
Time-synchronized measurements		X
Direct network communications (through serial ports, Ethernet cards, etc.)		X

3.2.2 Protection Functions

Numerical distance relays include the following integrated protection elements:

- Numerical full-scheme distance protection with multiple phase and ground forward and reverse reach; the distance scheme provides multiple mutual-compensation parameters and load blinders
- Multilevel high-sensitivity directional ground fault protection
- Multiple choice characteristics curves for phase and ground directional and nondirectional overcurrent functions, negative-sequence current directional or nondirectional functions, under- or overvoltage elements, etc.
- Thermal overload protection
- Switch-onto-fault protection
- Circuit breaker failure protection
- Overreaching distance elements and time-delayed overcurrent

- Communications-assisted distance schemes such as:
  - Permissive overreaching transfer trip (POTT)
  - Permissive underreaching transfer trip (PUTT)
  - Directional comparison blocking scheme
  - Directional comparison unblocking scheme
  - Weak infeed
  - Echo
- Sudden loss-of-load
- Combined multiprinciple line protection functions such as distance/line differential or distance/phase comparison protection

High-speed line protection is a desirable feature on critical lines with narrow stability margins. Previous limitations in relation to distorted input signals from CTs, VTs, or CVTs due to cables and high levels of saturated current inputs due to severe short-circuit levels were recognized. Digital line protection technology implements accurate digital signal processing and application of waveform recognition techniques in software filtering to ensure fast, desirable tripping of the relay and all its integrated multifunctional protection elements.

Other benefits to functional protection integration in digital distance relays over the previous conventional types are listed below:

- Application flexibility
- Adaptive solutions
- Wide settings range
- Better sensitivity
- Lower CT burdens
- Easy settings changes (local or remote)
- Multiple settings groups
- Reduced intermodule wiring
- Reduced maintenance criteria
- Reduced external components and physical size of the overall line protection system
- High processing capabilities and a greater degree of redundancy with the hardware architecture
- Increased line protection functionality and reliability
- Increased line protection security
- Increased protection availability

3.2.3 Control, Monitoring, and Metering Functions

Integrated control elements include timers, digital counters, advanced logic, math functions, and binary inputs that detect the change of state from external contacts (e.g., breaker control). Control logic is easily developed and custom created using programmable logic or Windows-based software that has a user-friendly interface with programming tools selected from drag-off toolboxes. Multiple control functions integrated into numerical distance relays aid in adapting the different protection functions to changing power system conditions and substation configurations. Control functions are integrated in the IED devices to ensure optimal performance for fault duration and system restoration.

Typical control functions integrated in modern distance relays are listed below:

- Interlocking equations to enable/disable or block/unblock different protection elements
- Single-/multiple-shot one-/three-phase auto reclose with/without synchronism-check features
- Adaptive line CB reclosing

- CB control
- Programmable scheme logic
- Programmable allocation of optoisolated inputs and relay outputs
- Programmable control functions for load shedding and restoration
- Multiple settings groups for adaptive protection

Supplementary functions and benefits in state-of-the-art distance relays are related to their ability to perform post-fault analysis, such as:

- Time-tagged event and fault recording
- Disturbance recording
- Fault location
- Self-monitoring and diagnostics

Monitoring features play an important role for maintenance. The processing power and functionality of line relays allow continuous monitoring functions such as:

- Trip circuit supervision
- VT and CT supervision
- Station battery supervision
- Breaker state monitoring
- Breaker condition monitoring (breaker contact wear)
- Communications monitoring (time synchronization via IRIG-B)

Numerical distance relay advantages listed below provide vital monitoring and metering benefits:

- Self-diagnostic functions monitoring the state of various protection functions, logic inputs, and output circuits
- Event and fault recording
- Measurement of load quantities
- Storage and easy information access
- Interactive oscillography
- Communication with a control hierarchy
- Alarm indication
- Local access of relay database records from a PC via a serial port located at the front of the relay
- Relay database records access via a remote computer
- Relay replay

Relay replay allows the user to make a different number of settings changes and replay an existing event with the modified settings without the need for an actual relay or expensive test equipment. Some newer relays offer the possibility of creating an event record for a given fault setup without the need to connect a test set to the digital line relay. The setup includes:

- Pre-fault and post-fault voltages and currents
- Selection of any fault type and its duration
- Selection of the dc time constant
- Control over fault dynamics to verify reclosing sequences and coordination
- Control of frequency change and rate of change of acceleration during faults
- Control over simulated breaker open/close times
- Manual mode for entry of discrete fault phasors

3.2.4 Communications Interfaces and Functions in Modern Distance Relays

Modern digital relays have integrated communications functions that are valuable in many areas related to protection and to the exchange of operational data needed for control, monitoring, and event fault disturbance recording. A discussion of communications functions integrated in numerical distance relays follows.

3.2.4.1 Communications Interfaces in Distance Relays

Earlier microprocessor distance relays offered a keypad in the front of the relay for viewing and changing relay settings. In addition, they included a front RS-232 serial port to communicate with the relay to change protection settings and to retrieve fault event records. A number of relays offered a parallel printer port to print quick summaries of event reports including fault location information.

Modern distance relays include a number of front and back serial RS-232 communications ports for the user to extract event reports and accomplish relay settings changes either locally at the substation or remotely via a modem. Modern numerical relays record analog current and voltage inputs and the state of optoisolated inputs that monitor the status of substation equipment. They also receive control and relay-to-relay communications signals, relay outputs, and logic element states within the relays. All of this information is available in event reports that can be viewed locally at the substation or can be sent automatically to an engineering workstation for further analysis.

Modern distance protection devices offer direct communications interfacing between relays and communications equipment, thus eliminating additional wiring and reducing cost. Redundant communications channels can be used in multifunctional distance relays to improve the overall reliability of the protection. For example, a directional negative-sequence overcurrent channel can be used independently in parallel with a distance-based protection scheme to enhance the overall performance of the protection. Usually, a single-fiber interface is provided on the protection device, and, in some newer distance protection devices, additional serial ports on the back of the relay are provided for measurement and control functions. In addition, a parallel port on the front of the relay is provided for maintenance and an IRIG-B communications port is provided for time synchronization needs. Figure 3.2 illustrates the communications interface of a numerical distance protection device.

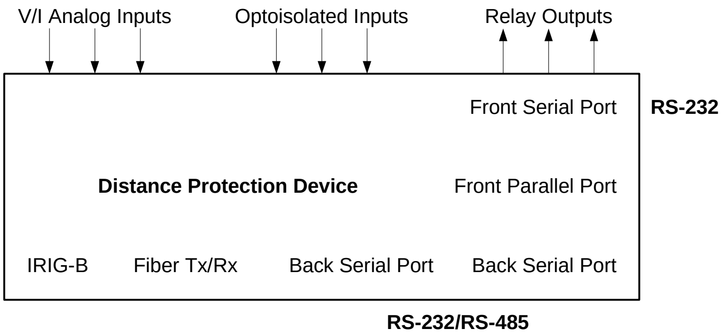

Figure 3.2. Numerical distance protection communications interface

Due to flexibility of modern digital distance relays, fully programmable communications functions are provided to broadcast any measured or calculated quantity by many available protocols. Modern digital relays provide different communications protocols, customize communications maps, and create new control or protection functions to be used through the relay communications ports (RS-232, RS-485).

3.2.4.2 Relay-to-Relay Communications Function

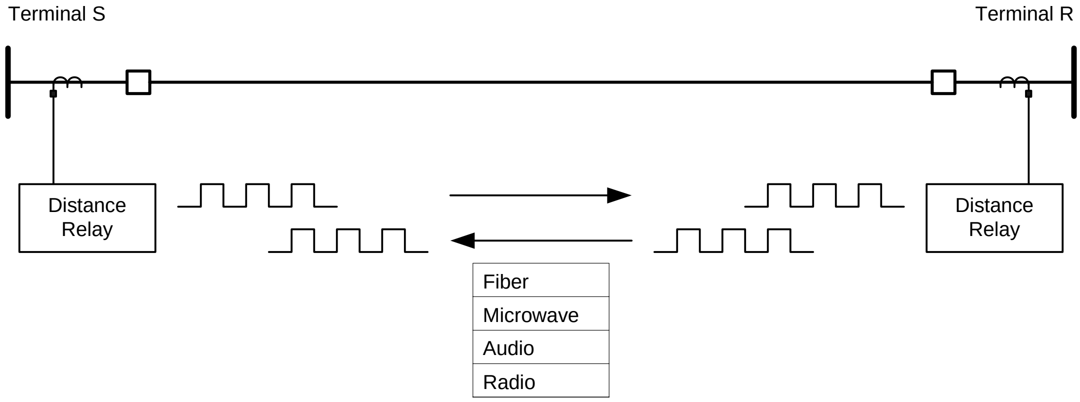

Figure 3.3 Relay-to-relay communications

Relay-to-relay communications is basically a system that sends and receives logic bits encoded in digital messages from one relay to the other to perform many pilot protection applications including control and monitoring functions. Modern digital communication techniques and communication channels provide many opportunities to advance the speed, security, dependability, and sensitivity of protection [1]. Direct digital communication, integrated in distance-type or other types of numerical relays, provides multiple bits in each direction that lead to simpler, more flexible, and economical protection design schemes. Sharing digital information directly from one relay to another adds new possibilities for pilot protection, adaptive relaying, monitoring, and breaker failure, among others. Modern fiber-optic networks or other types of communication links are excellent channels to consider for direct digital-to-digital applications.

Relay-to-relay communications has been incorporated in some modern numerical distance protection devices to accomplish the same pilot protection schemes, such as permissive overreaching transfer trip, permissive underreaching transfer trip, directional comparison unblocking, direct underreaching transfer trip (DUTT), direct transfer trip (DTT), and directional comparison blocking. The new relay-to-relay communications integrated in distance relays offers many beneficial functions related to speed and security with tremendous economical benefits and opens the door to other control and monitoring functions that would otherwise require more expensive external communication equipment and hardware.

Various communication channels can be utilized for relay-to-relay communications such as:

- Dedicated fiber between distance relays
- Multiplexed fiber
- Multiplexed digital microwave
- Leased digital telephone communication circuits
- Direct metallic connection

Communication interface devices such as modems and transceivers impose additional time delay in relay-to-relay communications. However, the transmission delay through a pair of fiber-optic transceivers and optical cable is typically less than 100 microseconds. The speed may play an important role in the distance protection especially when the dynamic stability margin of the network is critical.

Relay-to-relay communications is used in all pilot protection schemes. A typical example used on transmission circuits would be to initiate direct tripping or permissive transfer tripping of line circuit breakers. Other examples are related to blocking the reclosure of circuit breakers, initiating single-pole reclosing, changing relay settings groups, monitoring remote breaker status, retrieving event reports from remote stations, etc.

3.2.4.3 IEC 61850 Communications in a Substation LAN

The use of numerical technology in protection and automation has provided multifunctional devices with serial communications. The introduction of serial communications a couple decades ago resulted in the use of proprietary protocols for the communication and control of protection IEDs. This resulted in the inability of IEDs to communicate together and provided additional burden for users to learn and apply the different protocols. This practice also created additional burden for IED manufacturers because they were pressured by users to offer different types of protocols for their IEDs.

Users requested an open protocol, at least inside the substation, for all protection, control and monitoring functions. An open protocol offers the possibility of third-party equipment to be easily integrated in the system offered by another IED manufacturer. In addition, it offers the possibility to make future extensions without being dependent on the IED manufacturer that delivered previous IEDs of substation automation equipment. The requested protocol must have the following features:

- Cover all communication needs inside the substation
- Assure interoperability between existing functions inside the substation
- Support all types of substation automation architectures (e.g., centralized and decentralized)
- Be future proof (i.e., cope with the fast development in future communications technology)

The developments of IEC 61850 are targeted at reducing the costs and improving the efficiency of integrated substation protection and control systems by replacing the hard wiring between the IEDs with high-speed serial communications. The resulting standard IEC 61850 is now finalized and is based on the above requirements. A joint working group of users, editors, and IEC working group members are collecting experiences from the use of the standard and identifying areas where clarification is needed and areas where future extensions are required.

Figure 3.4 shows a substation automation system with serial communications using IEC 61850 that supports both vertical and horizontal communications as will be explained in the next few paragraphs.

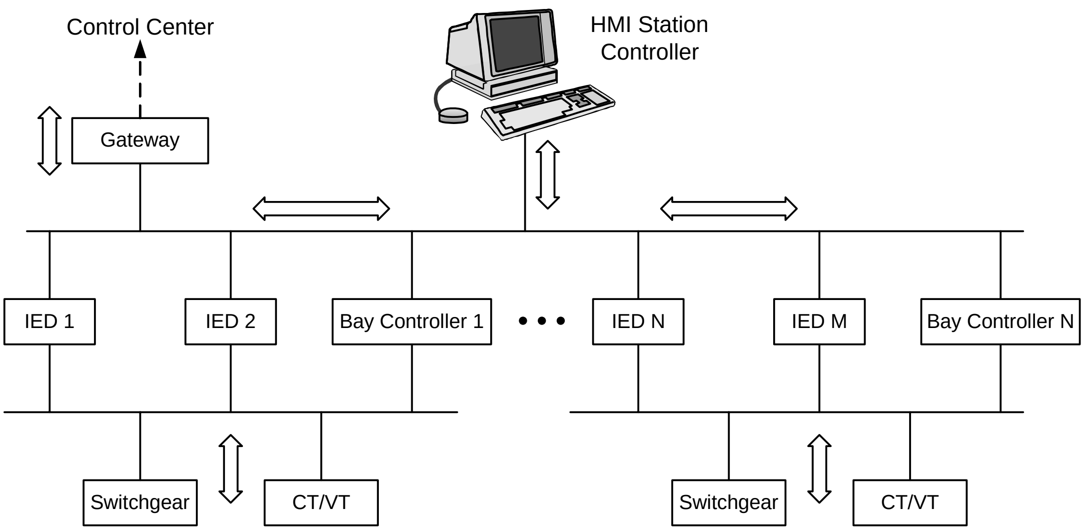

Figure 3.4 Substation automation system with serial communications

Multifunctional IEDs have significant processing power to perform primary and backup protection, control, and monitoring functions. These IEDs provide a valuable interface with the substation environment and, at the same time, provide protection and control functions at the bay level in the substation. The substation computer is a higher level in the hierarchy and performs substation-level functions such as load shedding and restoration. Finally, a PC provides the human-machine interface (HMI) with the different IEDs in the substation including alarms and event reporting.

Supervisory and data acquisition (SCADA) is a basic task of a substation automation system. The SCADA application relates to human operation of the power system and is performed locally or remotely by a system operator. The data communication for this application is directed vertically from a higher hierarchical control level down to a lower one (operator commands to open or close a breaker) or directed from a lower level up to a higher one (status of breakers or disconnects, alarms, events, and measurements from instrument transformers). For this vertical communication, IEC 61850 uses the client-server model. The server is the process or bay level IED, which provides the data to the client at the substation or any remote location. The data are provided on request by the server or automatically by report from the server issued if certain conditions are fulfilled. The client can send commands to the server in order to:

- Operate the switchgear
- Modify the behavior of the server through the change of internal data (e.g., change of settings, enabling or disabling functions)

In a client-server communication, the client controls the data exchange, and, for this reason, the data exchange and transmission are very flexible. This communication is very reliable but time consuming. For this reason, the client-server communication is not suited for time-critical data transmission. On the other hand, it is well suited for operator communication offering a response time on the order of one second.

There are several automated functions in a substation that require time-critical exchange of binary information between functions located in the same bay or in different bays as listed below:

- Distance protection and auto reclose
- Binary information exchange between bays for breaker failure protection
- Binary information exchange between bays for station interlocking

Typically, these functions do not require human intervention and are safety and time critical. The maximum accepted communications delay is around several milliseconds. The functions exchanging the above information are typically located in different IEDs. The information exchange may be performed using serial communications or copper wires with contacts and auxiliary relays. This exchange of binary information is between devices at the same hierarchical level and is called horizontal communication.

Due to time-critical information exchange, the client-server communication is not appropriate because of its slow response time. A more appropriate communication used for this time-critical information exchange is the publisher-subscriber concept. The publisher is distributing the information over the communications network and the subscriber may receive this information on an as-needed basis. In IEC 61850, the publisher-subscriber communication is not using confirmed services and is, therefore, transmitted over a reduced communications stack resulting in a very short transmission time.

IEC 61850 not only defines the method of the data transfer, it also defines the process of receiving data from the servers. For this purpose, IEC 61850 uses an object-oriented approach with Logical Nodes (LN) as core objects. A LN is a functional grouping of data and represents the smallest function that can be implemented independently in a device. Examples are all the data of a circuit breaker contained in the LN XCBR or all the data of a time overcurrent protection function contained in the LN PTOC. With this approach, the protection engineer can easily identify the objects used in daily work.

For the exchange of information between LNs using serial communications, IEC 61850 introduces a specific information exchange service called GOOSE (generic object oriented substation event) based on the publisher-subscriber concept. The content of the GOOSE message is defined with a dataset. The GOOSE message is sent as a multicast message over the communications network. That means that multiple devices can receive the message and retrieve the information required from the message. Receipt of the communications message by subscriber IEDs is not confirmed; instead, the GOOSE message is repeated several times. Because these messages are used to replace the hard-wired control signal exchange between IEDs for interlocking and protection purposes, they are mission sensitive, time critical, and must be highly reliable.

To achieve a high level of reliability, GOOSE messages are repeated as long as the state persists. To maximize dependability and security, a message has a time to “live,” which is known as “hold time.”

After the hold time expires, the status message will expire unless the same message is repeated or a new message is received prior to the expiration of the hold time.

The repeat time for the initial GOOSE message is short, and subsequent messages have an increase in repeat and hold times until a maximum is reached. The GOOSE message contains information that will allow the receiving IED to know the time since the last status change and that a message has been missed or a status has changed.

In order to achieve high-speed performance and at the same time reduce the network traffic during severe fault conditions, the GOOSE message was designed based on the idea to have a single message that conveys all required protection scheme information regarding an individual protection IED. It represents a state machine that reports the status of the devices in the IED to its peers. To allow further customization of the GOOSE messages, individual applications can map other status points to the user-defined bit pairs.

IEC 61850 also provides a service for the information exchange between the process, high-voltage equipment, and the substation automation system. This includes:

- Voltage and current sampled values
- Position and other status information of high-voltage switchgear
- Open, close, and other control signals to the high-voltage switchgear

IEC 61850 defines a service for sampled value transmission of voltage and currents using standardized serial communications. All other information exchange is using either the client-server model or the publisher-subscriber (GOOSE message) model for time-critical applications.

Substation automation design is a series of steps from specification up to the commissioning of a specific project. For this process, IEC 61850 provides the substation configuration language (SCL). The SCL provides a comprehensive description of the complete substation automation system, supporting the goal of interoperability. SCL allows description of the following:

- Substation single-line diagram (SLD)
- Function allocation to the SLD
- Device function allocation
- Connection of the communication system
- Data as being mandatory or optional
- Setting of all configuration parameters as defined in IEC 61850
- Setting of default values as defined in IEC 61850

The goal of SCL is to have a formal description of the substation automation at the engineering level (i.e., files that can be exchanged between proprietary tools of different suppliers).

IEC 61850 covers all communications-related aspects inside the substation. It is a comprehensive approach to the design of modern protection and substation automation systems using serial communications. It does not, however, mean that all delivered systems will have the same quality irrespective of the supplier. There is freedom in the standard for the communications architecture as well as for the allocation of protection and control functions in different physical devices. Users should also be aware that the quality of the protection and control functions still remains with the supplier of the IEDs and is not part of the IEC 61850 standard.

3.3 Functional Integration Examples

In this section, we provide a number of examples to illustrate the use and the benefits of functional integration in modern numerical distance relays.

3.3.1 Breaker Failure Protection Applications

3.3.1.1 Communication in Conventional Breaker Failure Protection

Communication is used for breaker failure protection in conventional systems in the case of a bus fault when one of the transmission line breakers fails to trip. The fault can be cleared using remote-end backup protection (Zone 2 trip). However, if high-speed fault clearing is required for dynamic stability or power quality reasons, the breaker failure protection will send a direct or permissive intertrip signal to the remote end using a dedicated signaling device or use the available binary signals in the data message of a multifunctional line protection IED.

When the signal is received, the IED will trip the local line breaker (or breakers in the case of a breaker-and-a-half or ring-bus) to clear the fault, thus achieving faster fault clearing compared to a Zone 2 or time-overcurrent remote backup trip.

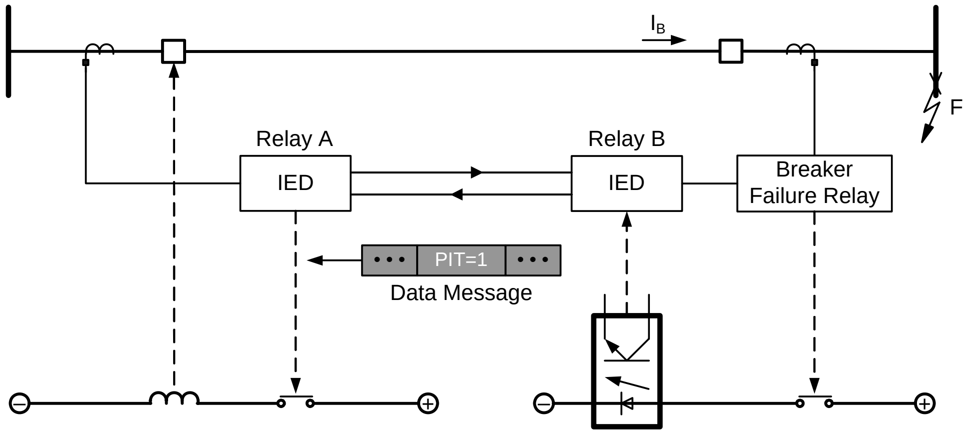

Figure 3.5 Breaker failure protection

3.3.1.2 Distributed Breaker Failure Protection Application

Figure 3.6 shows an example of a distributed breaker failure protection scheme. When the relay detects a fault condition on the protected line, it issues a trip signal in order to clear the fault. This can be a GOOSE message with the trip bit pair indicating the operation of the trip output function of the IED. The bay controller that implements the distributed breaker failure function subscribes to this message, and, as soon as the GOOSE message is received, the bay controller starts the breaker failure timer. If the breaker fails to trip, the breaker failure relay (BFR) indicates a breaker failure and sends a GOOSE message to the substation LAN to trip adjacent breakers in order to clear the fault.

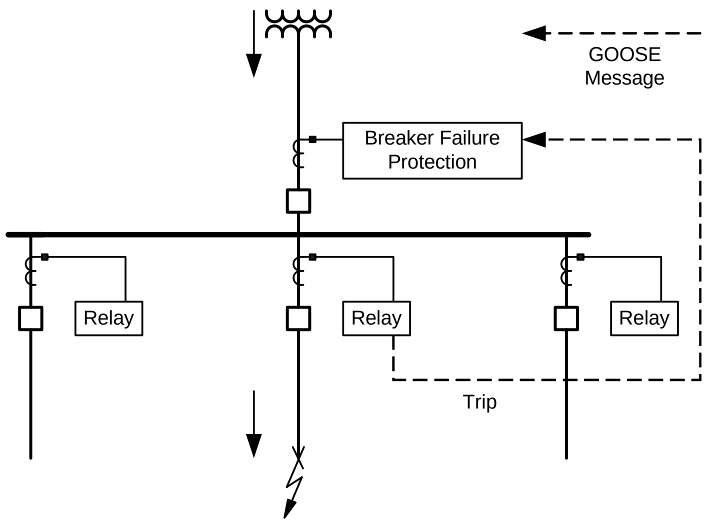

Figure 3.6 Distributed breaker failure protection

In some cases, the BFR function in the bay controller can also send a trip GOOSE message to the network that will attempt to retrip the faulted line breaker through a different physical connection or another breaker IED connected to the substation LAN.

When the breaker failure protection function is built into the distance relay that detects the fault condition, it detects a failure of the breaker and issues a GOOSE message with a bit pair set to indicate the breaker failure condition. All IEDs that are associated with breakers adjacent to the failed breaker will have to be set to subscribe to such a GOOSE message and issue the signal to trip their associated breakers.

Distributed communications-based breaker failure protection can be designed in two different ways:

- As a function in an IED that initiates the breaker failure protection when it sees the trip signal from the relay protecting the faulted power system device
- As a built-in function in the protection IED that detects the fault and issues the trip signal

The breaker failure protection (BFP) element can be configured to operate for trips triggered by protection elements within the relay or via an external protection trip. The latter is achieved by allocating one of the relay optoisolated inputs or virtual inputs to "external trip."

3.3.2 Application of Integrated Sensitive Negative- and Zero-Sequence Overcurrent Functions in Distance Protection

In Figure 3.7, Line 1 in Substation A is protected with an electromechanical distance relay scheme in a permissive underreach mode and with discrete phase and ground electromechanical directional overcurrent relays for backup protection. For the same line in Substations B and C, static type distance relays are used in a permissive underreaching mode and directional ground overcurrent relays are provided for the backup protection function.

According to the topology of the network shown in Figure 3.7 and the short-circuit current contributions at the faulted locations, the quadrilateral distance relay at Substation C may not be able to detect a resistive ground fault (30 ohms) at Location F1. This is due to the limited resistive reach of the distance relay and the load impedance of the system. In this case, only the time-delayed ground directional protection is able to detect and trip the circuit breaker of the faulted line at Substation C. Unselective tripping can easily result upon failure to fast trip the faulted line by the distance protection at both Substations A and B. For instance, if the distance relay at Substation A fails to receive the remote line end permissive trip (PT) signal to allow Zone 2 to trip, then additional fault clearing delays will be imposed by the starting distance element and may consequently affect the selectivity of the healthy line upon the reversal of current at Substation C. Note that the directional ground overcurrent relays may be impacted at all tapped substations if not set long enough to override the longest fault clearing time of the distance devices at Substations A and B.

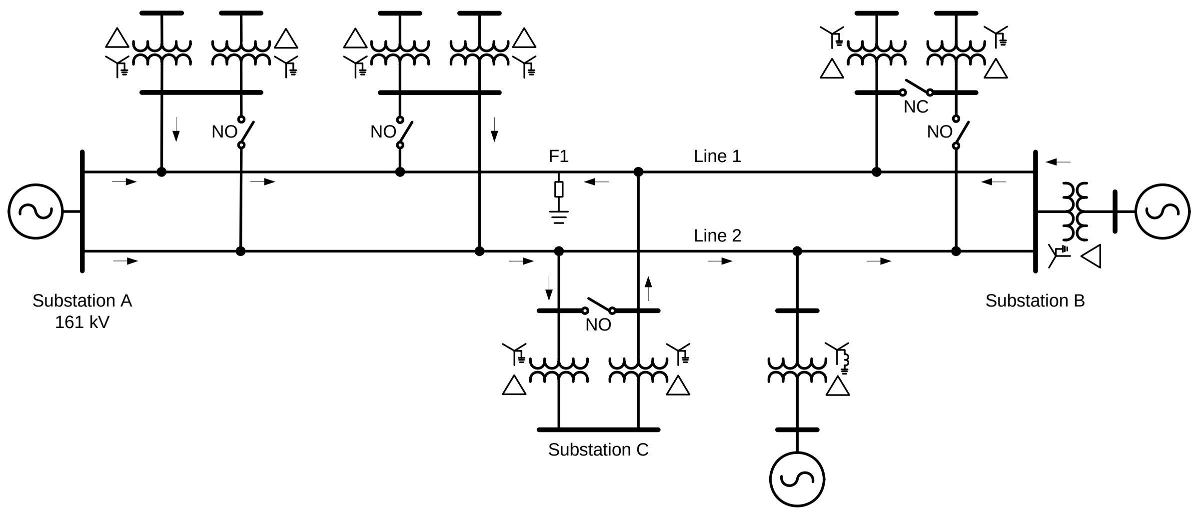

Figure 3.7 System single-line diagram

In order to improve the reliability and the security of the discussed power network, modern numerical distance multifunctional relays can be employed. A definite improvement in protection performance is achieved by enabling sensitive directional negative- and zero-sequence current elements in conjunction with the flexible distance protection application provided in the same device. The desired high-speed operation of the line protection by means of relay-to-relay communications and programmable logic is assured even in the event of one-channel loss between any two terminals. The exchange of various protection elements data in Substations A, B, and C, with the use of the relay DTT programmable features, will result in secure and dependable fast protection operation. Finally, adaptive techniques can be considered as an alternative solution by changing relay settings groups according to the prevailing system and load conditions. The approach to adapt new resistive reach settings is possible in today's modern distance protection devices.

3.3.3 Numerical Distance Relay Settings Group Change

Protection engineers can use innovative and creative applications in both protection and control areas due to the flexibility of multiple inputs and outputs provided in numerical relays. The use of multifunctional distance relays with relay-to-relay communications offers numerous opportunities to enhance control functions and, at the same time, automatically improve the protection performance through a change of settings groups to accommodate the change in network configurations.

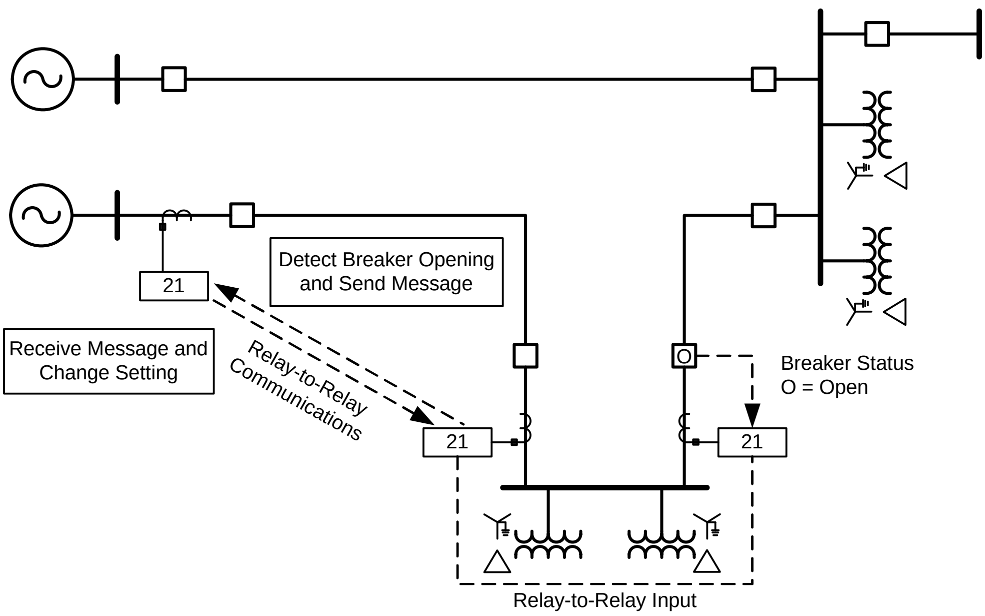

Figure 3.8 Relay settings group change

In Figure 3.8, if the circuit breaker is taken out from service for maintenance reasons, then it is possible to automatically change the remote line end protection settings using relay-to-relay communications. The protection is enhanced without any human intervention. Change of settings groups is possible for various conditions listed below:

- Change the integrated protection functions and settings based on load and breaker status in order to enhance sensitivity and to improve protection coordination
- Change in relay settings based on source conditions that affect sequence current and/or voltage contributions to the fault location
- Change in remote distance protection settings based on system configuration
- Change in settings for adaptive circuit breaker reclosing schemes
- Condition the remote line end circuit breaker reclosing

3.3.4 Application of Directional Ground Current Elements (67N) and Directional Negative-Sequence Current Elements (67Q) With Distance Protection

Conventional distance relays can be ineffective in some cases due to strong zero-sequence current infeed from tapped loads. Depending on the network topology, phase-to-ground faults in some locations on the line may remain undetected for a long time until tripping of the breakers takes place at the tapped station as illustrated in the figures below.

A phase-to-ground fault near the strong terminal source in Figure 3.9 can make the distance relays at the weak terminal end ineffective due to the relatively low zero-sequence current contribution to the fault. In this case, tripping the line circuit breakers at the strong source terminal does not considerably increase the zero-sequence current contribution from the weak source until the tapped load at Substation C is tripped from the line. Tripping the load at Substation C is undesirable because this affects the customers and prevents the normal circuit breaker permutation on the healthy line. Note that sufficient negative-sequence current is available at the weak terminal source and could be used to supervise the distance elements in order to achieve selective tripping before the removal of the tapped load at Substation C.

Figures 3.10a, b, and c indicate the fault points and the fault current contributions for the system shown in Figure 3.9.

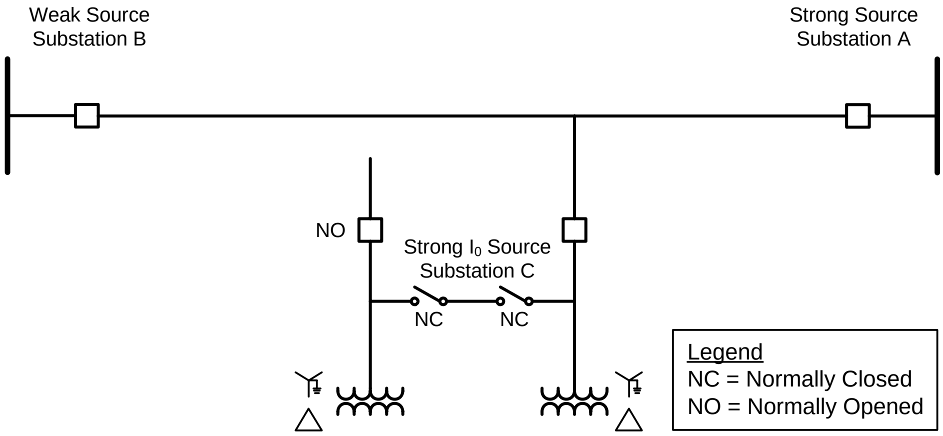

Figure 3.9 System single-line diagram

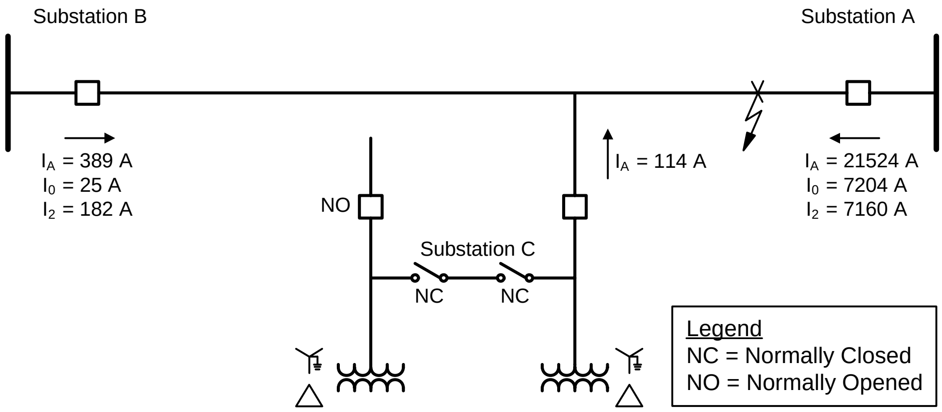

Figure 3.10a Fault current contributions for a fault at Substation A—note status of breakers at Substations A and C

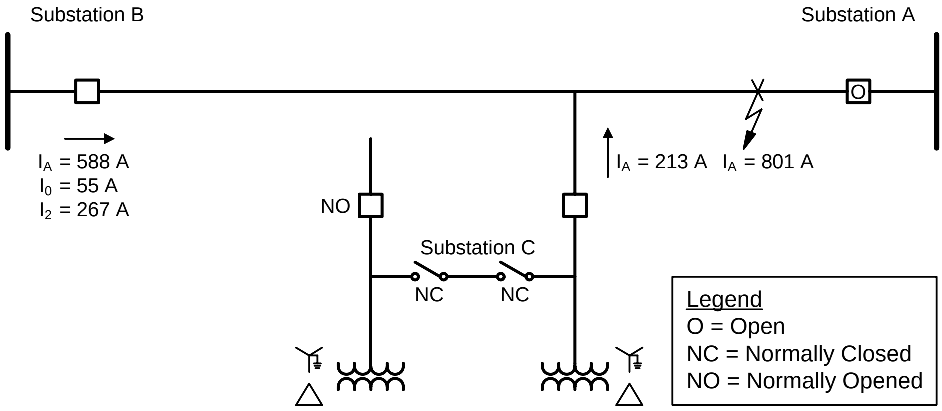

Figure 3.10b Fault current contributions for a fault at Substation A—note status of breakers at Substations A and C

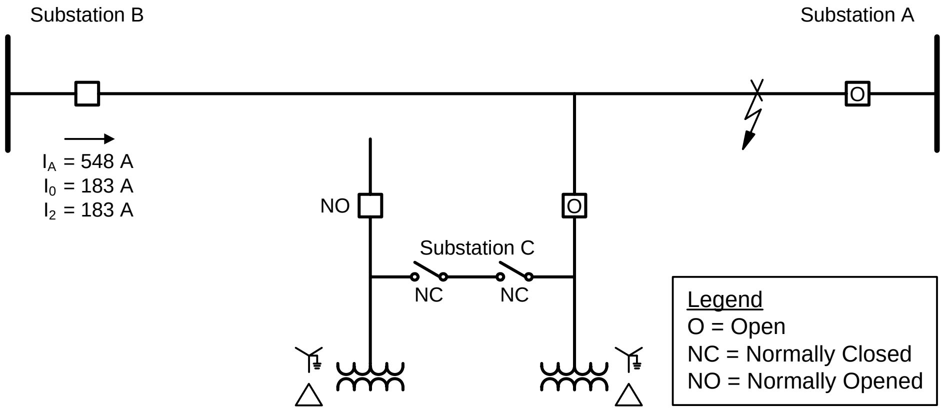

Figure 3.10c Fault current contributions for a fault at Substation A—note status of breakers at Substations A and C

For phase-to-ground faults near the weak terminal source, as illustrated in Figure 3.11, very little zero-sequence current contribution is available at the strong terminal source, which makes the distance relays unable to operate at that end.

If sensitive distance protection is employed at the strong terminal source, sequential tripping will result once the weak source terminal is opened. Integrated very sensitive directional ground current element (67N) and directional negative-sequence current element (67Q) can be used in the directional distance protection logic to enhance the reliability of the protection scheme.

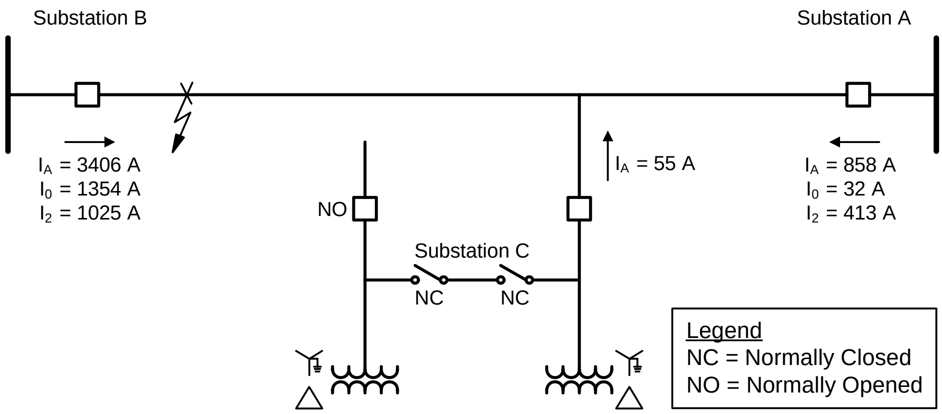

Figure 3.11 Fault current contributions for a fault at substation B

3.3.5 Single-Phase Tripping and Reclosing

Today, many electric power utilities are faced with the need to supply more reliable power without the addition of new transmission lines. Increased use of transmission line single-phase tripping and reclosing design is one of the means to achieve this goal. In a single-phase tripping scheme, only the faulted phase of the transmission line is interrupted for single line-to-ground faults. This allows power to be transmitted over the line on the two remaining healthy phases while the fault is cleared. This improves both the reliability of power transmission and the stability of the system against power swings.

The term cross-country fault is applied when multiple faults occur on the system at the same time and at different locations. For example, an A-phase-to-ground fault may occur on the protected line at the same time that a B-phase-to-ground fault occurs on an adjacent or parallel line. A cross-country fault may have a minimal effect on a three-phase tripping application but may present a major problem to a single-phase tripping application.

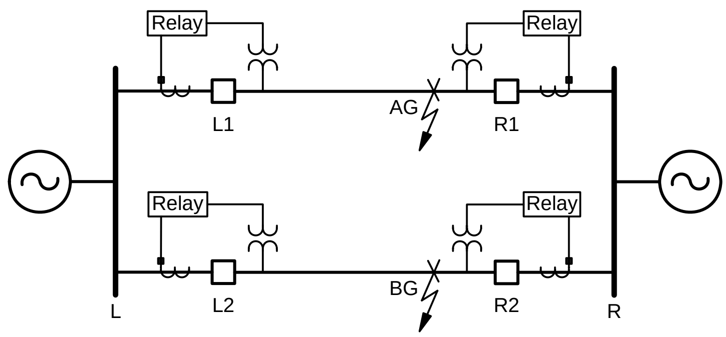

Figure 3.12 Cross-country fault

Consider the system in Figure 3.12 with line-to-ground faults as shown near Bus R. The relay at R1 correctly identifies the fault as an A-phase-to-ground fault, and the relay at R2 correctly identifies the fault as a B-phase-to-ground fault. Relays L1 and L2 sense the fault as a double-line-to-ground fault because the two single-phase-to-ground faults are at essentially the same electrical point on the system. In a simple pilot scheme, the faults depicted in Figure 3.12 may result in correct single-phase tripping by the relays at R1 and R2 but incorrect three-phase tripping by the relays at L1 and L2. This is because the pilot channel information is two-state only—either the relays see a fault or they do not see a fault. The faulted phase selection is performed by the local relays. In this example, the relays at L1 and L2 select an ABG fault type resulting in a three-phase trip for a single-line-to-ground fault. Several approaches may be employed to avoid this misoperation:

- The pilot tripping can be delayed long enough to allow the Zone 1 elements at Bus R to initiate single-phase tripping. After the breakers at Bus R open the proper faulted phases, the relays at L1 and L2 also select the correct phases to trip.
- Multiple two-state pilot communication channels can be used to transmit phase identification in addition to trip permission.
- A digital relay-to-relay communications channel can be used to transmit multiple bits of the actual faulted phase selection in addition to the permissive signal.

The first solution introduces time delay and requires that the protection on the parallel line operates to clear the fault on that line. The second solution improves upon the first; however, the scheme requires multiple communications equipment and additional channel bandwidth, which makes it very expensive and less reliable. The third solution requires the transmission of faulted phase selection information and the PT signal. The relay at the remote station checks the received phase selection information, its own logic, and trips the proper faulted phase. The inclusion of a DTT bit and a reclose-blocking bit in the same digital message improves the breaker failure function and prevents reclosing into a faulted breaker. The pilot digital communications channel provides superior performance when compared to traditional communication channels regarding security, availability, and speed. Availability can be improved more than 20% by adding a simple digital relay-to-relay communications channel in existing installations that use tone equipment to key PTs.

3.3.6 Three-Terminal Line Protection Application

Consider the system in Figure 3.13 in which a POTT scheme is applied using traditional frequency shift audio tone communication equipment and independent communication paths between Terminals R, S, and T. Tripping is initiated if the local relay detects a fault, and a PT signal is received from each remote terminal. In three-terminal line pilot protection applications, where high-speed tripping is essential, loss of a communication channel between any two of the three terminals renders the high-speed pilot protection inoperable, and tripping occurs by time-delayed Zone 2 elements.

Relay-to-relay communications and relay programmable logic can maintain high-speed protection even in the event of one-channel loss between any two of the three line terminals. The ability to send a DTT bit as part of the digital message allows the relay system to clear internal faults in high-speed, not in Zone 2 backup time. For example, if communication is lost between Terminals S and T during an internal fault, Terminal R will high-speed trip and send a DTT to Terminals S and T to clear the fault.

Echo keying logic is included in a POTT scheme at a weak terminal to allow high-speed tripping at a strong terminal if forward tripping elements do not operate at the weak terminal for an internal fault or as an alternative to an open breaker keying signal. Echo keying logic will only repeat the received PT signal when the PT bit is asserted. In a three-terminal line application, PT is asserted only if the local relay receives a PT signal from both of the remote relays. In other words, at least two relays must see the fault in order for the PT signal to be repeated. If there is only one weak terminal, the echo keying logic will function as desired. However, if there are two weak terminals, then the echo keying logic will not function if the overreaching PT elements operate only at the strong terminal. When there are two weak terminals on the line, one can use logic control equations to implement an echo keying logic that also functions when only one PT signal is received.

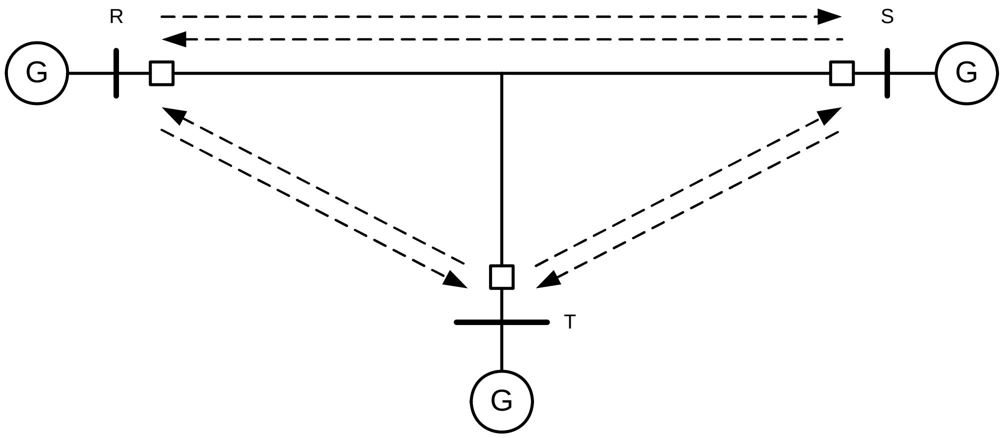

Figure 3.13 Three-terminal system with independent communication paths for protection

3.3.7 Relay-to-Relay Communications Application

Consider Figure 3.14 in which a fault occurs inside Transformer T1 and Breaker 2 fails to trip at Station T.

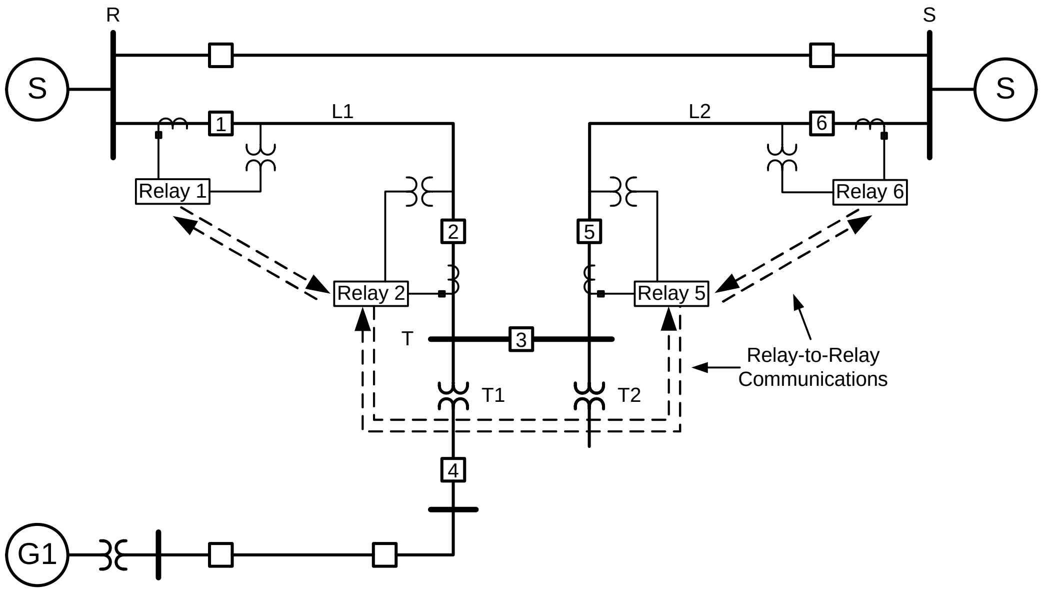

Figure 3.14 Relay-to-relay communications application

For this fault, Breaker 1 at Station R must open due to the breaker failure condition of Breaker 2 at Station T and not be allowed to reclose. In a traditional protection scheme, a separate DTT is applied between Stations R and T to perform the above function. Relay-to-relay communications between relays of L1 and L2, in conjunction with relay programmable logic, can be used to send a DTT from Station T to Stations R and S during breaker failure conditions at Station T and block reclosing at the remote stations.

Let us now consider a fault on L1 for which Breaker 1 at Station R and Breaker 2 at Station T open to clear the line fault, and at the same time a misoperation occurs at Station S, which opens Breaker 6. If high-speed reclosing is applied on both breakers of L1 without any other considerations, there is a possibility to reclose out of synchronism with Generator G1 and cause considerable damage to the generator. For this scenario, using relay-to-relay communications and programmable logic, we can design a protection scheme at Station T to detect L2 tripping at the remote Terminal S, block high-speed reclosing of Breaker 2 at Station T, and transmit a reclose blocking bit to block high-speed reclosing of Breaker 1 at Station R. Slow-speed reclosing from Station R followed by Breaker 2 closing at Station T with synchronism check and slip-frequency supervision allows the two systems to parallel and improves system reliability.

Other applications of relay-to-relay communications include:

- Automated relay settings group changes that adjust the distance reach to better handle the mutual coupling effect of parallel lines in the event one circuit is taken out of service for maintenance, and safety grounds have been applied at both line ends
- Settings group changes to adjust the distance protection reach in the event a breaker is opened for maintenance on a three-terminal line protection application that removes the infeed from that terminal
- Automatic station restoration schemes that can be implemented using the ability to exchange eight bits of information between relays without the need to utilize additional equipment such as programmable logic controllers

3.4 ADDITIONAL BENEFITS OF FUNCTIONAL INTEGRATION

3.4.1 Fault Location

Accurate fault location information helps operators and other utility personnel to expedite service restoration and reduce outage time, operating costs, and customer complaints. Fault location has been quite successful using phasor measurement data from one end of a transmission line and is implemented by most numerical relays. However, this method has some accuracy limitations due to load flow, mutual coupling, fault resistance, and system nonhomogeneity. Multiended methods have been developed to improve the fault location estimate [2]. A number of these methods typically require offline processing of the relay event data using multiended fault location algorithms. Modern distance relays have integrated digital communication channels with the ability to exchange analog data information between devices in addition to logic-based status information. Additionally, modern distance relays include expanded logic control equation programming with math and comparison functions. The functional integration of digital communication with analog data transmission and math functionality can provide more accurate fault location to operators in almost real time.

3.4.2 Synchronized Phasor Measurements

Protective relay sampling synchronization within 1 microsecond has been made possible with the advent of satellite-based time-keeping systems and advances in computer technology. For some time now, stand-alone synchronized phasor measuring devices have been available. They are not in widespread use because they are relatively expensive and useful only on critical systems. A line distance protection relay is available that includes synchronized phasor measurement capabilities [3]. These relays can provide synchronized phasor measurements that eliminate the need to have different devices for protection, control, and electric power system analysis for system-wide applications and traditional protection applications. As these relays are applied widely, especially on extra-high voltage systems, the phasor measurement function will proliferate, and it will no longer be necessary to justify a separate phasor measurement device because synchronized phasor measurement capabilities are functionally integrated, at no additional cost, with the line distance protection relay.

Over the last few years, several utilities in the U.S. and abroad installed synchrophasor measurement devices in their systems to measure voltage, current, power flow, and the relative phase angle between various substation buses. Interest in this technology is based on the potential benefits derived from the use of synchrophasor measurements in a number of power system applications [4]. The addition of synchrophasor measurement in a distance relay results in increased power system reliability and provides easier disturbance analysis, protection, and control capabilities than approaches using different information sources.

3.4.2.1 State Estimation

State estimation plays a key part in real-time monitoring and control of power systems. Traditional measurement sets normally include line real and reactive flow, bus voltage magnitudes, and bus real and reactive injections. The output of the state estimation is the calculation of the system state (i.e., the voltage magnitude and relative phase angle). It provides estimated data for network analysis security, optimization applications, and power system dispatchers. Contingency analysis is intended to perform a number of power flow solutions initialized from the state estimator, which evaluates current system conditions and alerts system operators of possible system violations (e.g., system overloads, overvoltage, or undervoltage).

The prospects of using direct measurements of system state variables in state estimation and using synchrophasor measurements, including the analysis of their impact on solution algorithms, have been discussed in literature since 1985 [5]. Direct measurement of the system state offers a potential for substantial savings in installed communication capacity and improvements in the convergence of the state estimation solution. Synchrophasor measurements can complement other measurements in present state estimators. Direct state measurements can be used to augment state estimators that use line flow and injections or to substitute for certain line flow and injection measurements.

3.4.2.2 System Model Verification

Data captured from actual system events with devices that have synchrophasor measurement capability can be used to verify the system models used in load flow, short circuit, and stability programs. The power system response to a particular disturbance can be analyzed with computer simulations and compared with synchronized data from various locations. Discrepancies between actual recorded event data and simulations can aid in the model validation process and lead to better modeling of the power system. Improvements in system models can help in the efficient utilization of the power system and defer capital expenditures.

One application of system model verification is line parameter estimation using synchronized phasors from the two ends of a transmission line. The electrical parameters of transmission lines are typically calculated using handbook formulas or transmission line parameter calculation programs. The programs produce line parameters that may be accurate enough for some applications; however, higher accuracy of line parameters, derived from synchronized phasor measurements, can improve protection, fault location estimation, load flow, stability, and state estimation applications.

3.4.2.3 Control Applications

Present methods for control and protection of power systems rely mostly on local measurements. Typically, these measurements are used to stabilize and enhance the dynamic performance of the power system via supplementary controls on generator excitation systems, static var compensators (SVC), thyristor-controlled series capacitors (TCSC), static synchronous compensators (STATCOM), unified power flow controllers (UPFC), and high-voltage direct current (HVDC) controls. Local measurements impose limitations on the control and protection functions due to lack of adequate knowledge of the power system state at remote locations. The availability and use of synchronized phasor measurements will permit advanced power system protection and control strategies.

3.4.2.4 Additional Use of Synchronized Phasor Measurements

Synchronized phasor measurements can be used for the following additional power system applications:

- Transient and dynamic instability prediction
- Special protection schemes
- Disturbance analysis and power system monitoring
- Adaptive direct and underfrequency load shedding
- Wide area protection and control
- Adaptive relaying

The list of applications above is by no means complete. It is only included to generate interest in the application of synchrophasor measurements. We did not expand further due to space limitations.

3.5 Disadvantages of Functional Integration

Several hundred settings parameters are required in modern digital line protection. The complexity depends on the protection scheme that is used including the applied integrated protection elements and control functions. Reliability and security should always be of concern. Adequate settings maximize the availability of the protection and minimize the risk of misoperation. Inadequate settings may cause the relay to false trip, prevent the relay from tripping for a fault, or alter the relay operating characteristics. Simplicity in custom or typical protection schemes and adequate relay testing minimize the risk of inadequate settings.

Logical variables are used to develop control equations (similar to a real-life dc control scheme) for relay tripping elements, input logic states, auxiliary relays, and timers. Multifunctional line relays incorporate many pieces of equipment—including breaker failure and other backup overcurrent relays, reclosers, and ammeters—and, thus, substantially reduce material cost and maintenance. However, the logical variables, to be defined by protection engineers and used to perform the desired protection functions, are increased. Logical variables are increased further when programmable inputs and outputs are used for relay-to-relay communications.

Performing careful testing and selecting optimized protection schemes limit the disadvantages related to the increase of logical variables and equations to perform protection, control, and adaptive functions.

3.6 LEVELS OF REDUNDANCY VERSUS TRUE BACKUP

For electromechanical and static relays, incorporation of additional backup functions meant additions to the relay hardware. This might have required an additional electromechanical element or relay card. The hardware addition was accompanied by an increase in price of the relay, thus offering only a marginal savings compared to the function being provided in a separate relay. By its nature, backup protection was generally completely discrete, affording the highest level of reliability.

Modern numerical relays sample power system analog data, typically CT and VT inputs, using the digitized currents, voltage, and phase information as inputs to the protection and control algorithms. Provided that the processor used has sufficient processing power, the convenient approach is to integrate the backup protection functions in the same device as the main protection, as both sets of algorithms can share the same digitized analog-to-digital converter (ADC) values. For all systems above the distribution voltage, the approach of having dual main protection (Main 1 and Main 2) tends to be retained, although the temptation to remove the discrete backup protection is high. The following paragraphs examine the relative advantages and disadvantages of approaches to backup protection.

Few protection engineers would be brave enough to advocate abolition of the Main 1 and Main 2 protection approach for a number of reasons. For example, incorporating all main protection in one device carries a risk that a device failure will remove all algorithms from service. The question, then, would be whether testing to IEC norms, for example, is sufficient to prove every aspect of the relay and eliminate every possible hardware and software failure. The answer is, evidently, “no.” No amount of testing can cover every power system and substation condition. Also, although customers may wish it, no manufacturer can guarantee that zero failures will occur in service. As with any device, the failure rate can approach zero, but zero by itself is unattainable. Should a single main protection device fail, the only safe approach would be to trip the circuit breaker. However, this would disrupt the load flow on the system, and even relay self-monitoring can detect only 90% of failures, so the failsafe tripping is not guaranteed.

Some utilities still favor the use of separate principles if possible for Main 1 and Main 2 protection devices (e.g., distance/current differential, distance/phase comparison). This approach may lessen the risk of common-mode failure to trip. However, where two distance relays are used, the request is generally to have different algorithm principles (such as one with phase comparators and one with numerical approximation), different hardware if possible, and sometimes devices from different manufacturers. On the other hand, a number of utilities apply the same protection device or different devices from the same manufacturer for Main 1 and Main 2 protection systems because they believe that by selecting highly reliable devices, they can benefit from reduced engineering and maintenance costs.

The question that arises, then, is in which devices Main 1 and Main 2 reside and where the backup protection is implemented (e.g., phase and earth overcurrent protection, breaker failure, etc.). Options include the following:

1. Use Main 1 protection as a discrete device and Main 2 protection as a discrete device, with discrete breaker failure and backup protection
2. Same as above but with Main 2 protection sited in a control system bay module or bus protection feeder unit
3. Same as 1 and 2 but with backup protection fitted in both Main 1 and Main 2 devices
4. Same as 1 and 2 but with backup protection split between Main 1 and Main 2 or provided in one main protection only

These approaches have been listed in a subjective order of reliability, with the cost following the same ranking. Option 1 has the highest reliability. This can be seen from the fact that a single failure of one device has no detrimental effect on the task of any other. Only common-mode failures, such as reliance on a single substation battery or fused dc auxiliary input remain. Option 2 is as secure as 1, provided that the additional tasks provided by the Main 2 device don't interfere with its protection duties. However, by introducing more functions within the Main 2 device it can be argued that the testing of satisfactory interaction of all permutations of elements plus correct application of settings is harder (e.g., the greater the number of settings, the greater the chances of a settings error, and the less chance that the manufacturer has tested for all possible ways in which the customer will actually apply the devices). Thus, more and more, conjunctive testing using the customer's service settings will be demanded.

Option 3 is the first apparent major change in the level of protection afforded. A common mode failure, such as a DSP or auxiliary supply board, exists between main and backup protection in any one device. But, as the backup functions are duplicated in both main devices, backup still remains. There would be the requirement to demonstrate that the breaker failure protection in each device will always respond correctly once initiated, such that during unavailability of one of the main protections, the breaker failure in the other device is not a weak link.

Option 4 is generally no cheaper than Option 3 and does not seem beneficial. Thus, why not apply the backup in both devices to avoid such cases of misapplication of settings?

Along with main protection, there is an argument that backup protection should be set in a slightly different way in the two devices to avoid misapplication/misinterpretation being crossfertilized between devices. The increased functionality, and thus complexity of devices, means that bad settings are a very real problem, possibly accounting for half of all IED failures to correctly trip for a fault.

Auto reclosing is a final consideration. For an interconnected power system where lines are not loaded close to their maximum thermal ratings, it is acceptable to set the auto reclose function in one main protection device only. There would need to be a clean contact or another communication method to allow the second main device to initiate auto reclose too. The utility would accept that, in cases of unavailability of the main device with auto reclose, a trip would result in failure to reclose, even for a transient fault.

For weakly interconnected systems, it is essential that high-speed auto reclose occurs to maintain synchronism on the system and maintain the load flow without prolonged overloading of individual lines. In such cases it may be desirable to enable the auto reclose function in both main protection devices or to use a discrete relay. Again, there is an argument that segregating the function makes application mistakes less likely because it is easier to test and commission devices that are assigned similar tasks as legacy protection.

3.7 References

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4. ADAPTIVE DISTANCE RELAY FUNCTIONS

4.1 OVERVIEW

The main objective of this chapter is to describe methods to optimize the usage of modern distance protection devices in electrical networks using adaptive functions.

Modern distance protection devices are multifunctional and sometimes referred to as intelligent electronic devices (IEDs). Protection functions are realized using software stored in ROM and executed on a microprocessor-based main board. Only the size of the main board ROM and the computing power of the digital signal processor and microprocessor chips used restrict the number of functions that can be implemented in one IED. Additional ROM can be added without any technical problems, if necessary. It can be safely stated, to a large extent, that the amount of protection functions that can be implemented in one protection device are not limited within the processing capability of the CPU.

4.2 ADAPTIVE PROTECTION

Adaptive relaying accepts that protective relays may need to change their characteristics to suit the prevailing power system conditions. Typically, a protection system responds to faults or other abnormal events in a fixed, predetermined manner. Adaptive protection has been defined as:

> *Adaptive protection is a protection philosophy, which permits and seeks to make adjustments in various protection functions automatically in order to make them more attuned to prevailing power system conditions.*
>
> *An adaptive protection relay is a protection system in which lower-level set points, relay logic, and relay action set points are adjusted based on data either locally acquired, provided by the neighboring device on the same level locally or remotely, or sent down from a higher level [1].*

4.2.1 Implementation of Time-Unlimited Memories

Protection functions in an IED are realized using software technologies. One important element of software technologies is the possibility to store information in a RAM or NOVRAM area, where information is acquired or determined by the IED. Information can be read from the RAM or NOVRAM area and used to create new information at each IED processing interval, as long as the power supply is not interrupted.

4.2.2 Implementation of Mathematical Methods

It was not possible to implement complex mathematical models in earlier electromechanical and analog solid-state relays. Earlier solid-state technology, based on transistors or logical gates, attempted to implement, as close as possible, the correct mathematical solution. Current advanced numerical protection devices are able to implement highly sophisticated and complex algorithms. The calculation of complex phasors of currents and voltages using a DFT (Discrete Fourier Transform) as well as the realization of a polygon (quadrilateral) tripping characteristic, for example, are now possible with high accuracy.

The availability of time-unlimited memories in combination with the possibility to implement mathematical methods is the basic prerequisite to realize adaptive functions. Adaptive functions take older existing information, as well as new calculated information, into account and generate new information. The new information can be used to decide if the protection device has adapted to the current situation. Figure 4.1 shows this concept in a graphical view.

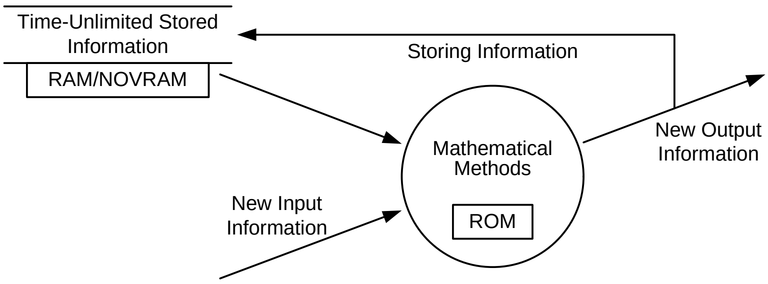

Figure 4.1 Creating new information using time-unlimited memories

4.3 PROTECTION DEVICES WITH ADAPTIVE FUNCTIONS

It was stated that the number of protection functions that can be implemented in the firmware of a protection device is only limited by the available ROM size of the main board and the computing power of the microprocessor and digital signal processor used. The protection functions can be enabled or disabled independently from each other. Assuming that the microprocessor has enough computing power to execute the activated protection functions in real time, different strategies to solve protection problems can be realized, as discussed below.

4.3.1 1-Out-of-N Strategy

The 1-Out-of-N strategy implements "N" different methods, but only "1" method is active at any one time.

Example

The distance protection function can be realized by different impedance-measuring algorithms (e.g., a DFT algorithm or a first-order differential equation algorithm). Only one of the impedance-measuring algorithms will be enabled at the same time.

Figure 4.2 shows the 1-Out-of-N strategy as a state transition diagram. In this example, Impedance-Measuring Algorithms 1, 2, and 3 are implemented as part of the firmware. Only one of the algorithms can be active at any one time dependent on whether Conditions 12, 13, and 23 are true or false.

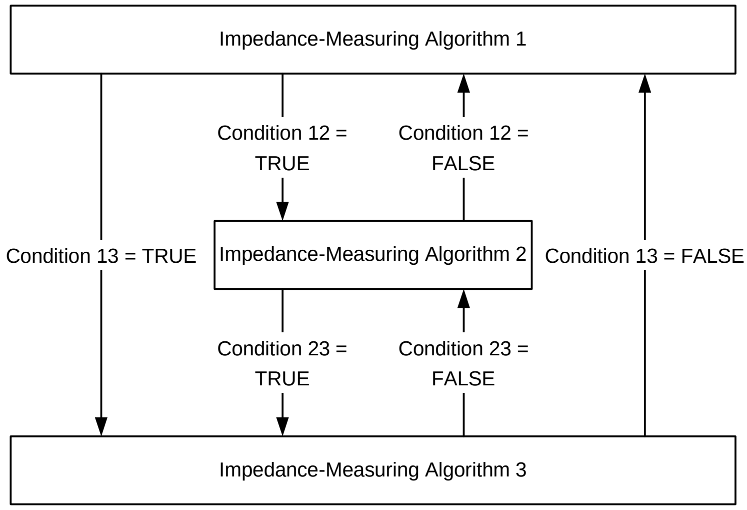

Figure 4.2 1-Out-of-N strategy

4.3.2 M-Out-of-N Strategy

The M-Out-of-N strategy implements "N" different methods, with "M" methods active in parallel at any one time.

Example

The teleprotection function can be enabled in parallel with the distance protection function as the main function (e.g., to protect the line section between the end of Zone 1 and the remote end of the line instantaneously).

Figure 4.3 shows the M-Out-of-N strategy. In this example, Protection Functions 1, 2, 3, and 4 are implemented as part of the firmware. Protection Function 1 and Protection Function 3 can be executed or bypassed dependent on Conditions 1 and 2.

Protection Function 2 is the distance measuring function, and Protection Function 4 is the power-swing blocking function. Both protection functions will be executed continuously. Protection Function 2 (e.g., the teleprotection function) and Protection Function 3 (e.g., Zone 1 extension) will be executed dependent on Conditions 1 and 2.

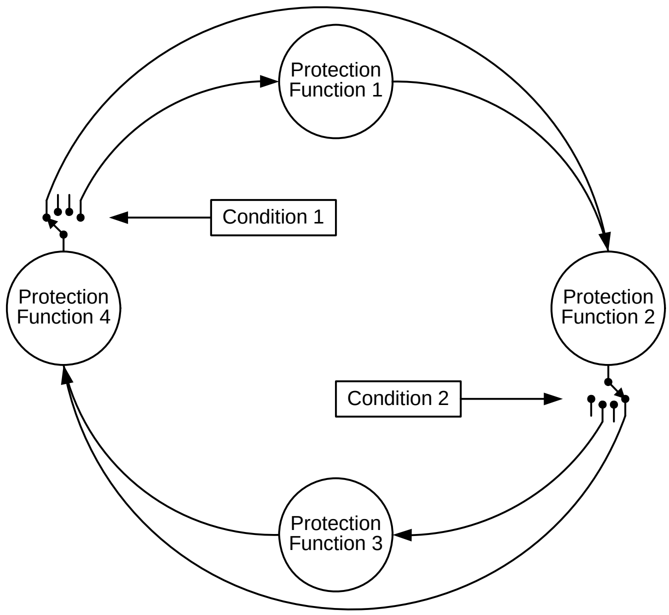

Figure 4.3 M-Out-of-N strategy

4.3.3 Types of Conditions to Enable or Disable Protection Functions

Conditions to enable or disable protection functions can be divided into two different groups—static conditions and dynamic conditions. Both types of conditions take binary and analog input signals into account and calculate one binary output signal that can be used to control a protection function.

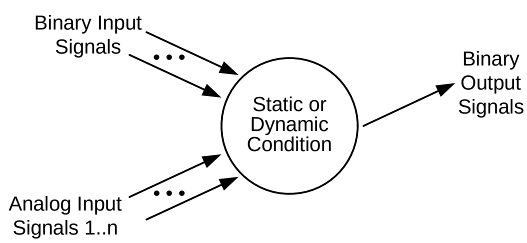

Figure 4.4 Static and dynamic conditions

The binary output signal of a static or dynamic condition can take only two different states:

- True—protection function is enabled
- False—protection function is disabled

The inverse definition of the output signal can be used too.

The input signals for static and dynamic conditions can consist of a various set of analog and binary signals:

- Analog measured signals (e.g., phase currents and voltages)
- Analog calculated signals
- External binary signals (e.g., an auto reclosing command from an external protection device)
- Internal binary signals generated by protection functions

The difference of the two groups is caused by the time-dependent behavior, which will be explained in the following sections.

4.3.3.1 Static Conditions

Static conditions are conditions that change the state of the output signal slowly compared to the real-time behavior of the protection functions. As explained in Section 4.3.3, static conditions can be realized using binary and analog input signals. The list below shows some examples of input signals to realize static conditions.

Binary Signals

- Status of circuit breakers (open, closed, etc.) connected to binary input channels
- Settings to disable or enable protection functions that can be changed via HMI or any other communications links (i.e., manually or via settings software or SCADA system)
- Status signals received via teleprotection channels
- Output status signals of other protection devices

Analog Signals

- 20 milliamps input signal (e.g., temperature measurement)
- Input signals to compensate for the change of line length caused by temperature differences, for example, winter (–40°) versus summer (+45°)
- Long-term calculation of mean values of currents and voltages to suppress signal offset

It can be stated that analog input signals are not as important for static conditions as binary signals.

4.4 CIGRE WG 34.02 "Adaptive Protection and Control"

Some of the most important explanations and definitions from the CIGRE WG 34.02 report, "Adaptive Protections and Control," are copied below.

> *The concept of adaptive protection and local control recognizes the possibility that quite often the settings of various protection and control devices as determined by extensive simulations of power system contingencies, are dependent upon certain assumptions about the nature of prevailing power system loading, generation, and status of various transmission facilities. Consequently, the settings of these devices, although appropriate for conditions which were assumed to exist when the simulations were made, may no longer be appropriate, or even correct. Also, there is the possibility that in order to meet the requirements imposed by several foreseeable contingencies, the actual settings used are not optimum for the prevailing system conditions. The concept of adaptive protection and control recognizes these possible shortcomings of the settings and explores methods by which the settings in question could be altered to match the prevailing conditions of the power system. Clearly, adaptive protection and control pre-supposes computer based relays and control systems. Computer based systems could accept inputs from external sources over communication lines, and act on these inputs to alter and improve their settings. Truly adaptive capabilities would be difficult to realize in electromechanical or analog solid-state systems. …*

> *The concept of adaptive protection evolved during the 1980s. By then, digital computer-based relaying was well accepted. Most relaying functions have been shown to be amenable to digital computer implementation, and the satisfactory field experience with these devices has allayed the fears of protection engineers about the survivability of computer relays in the*

harsh environment of electric utility substations. From the very beginning when earliest experiments with computer relays were being carried out, the possibility of being able to change the relay characteristics under external control has intrigued relay engineers. The field of adaptive relaying is the culmination of efforts in that direction. …

Formally, adaptive relaying has been defined as follows: "Adaptive protection is a protection philosophy which permits and seeks to make adjustments in various protection functions automatically in order to make them more attuned to prevailing power System conditions." This definition has been accepted by an IEEE working group on adaptive protection. A number of other publications have also accepted this definition. …

In a given adaptive protection implementation, we may see different approaches depending upon which part of the protection system is affected, and which signals are used as inputs. However, basically the adaptive system has to recognize a certain set of input data and then produce some output, which can be used to effect a change in the protection system. …

Clearly, the ability of computer relays to communicate with external systems is a key element of adaptive protection systems. The role of communication systems will be emphasized repeatedly in this report. It will become clear that communicating over wide ranges of channel speeds and over varying distances provide adaptability of different kinds and degrees. Even rudimentary communication links can provide significant adaptive capability, and systems can be designed so that the loss of communication links will not degrade the normally available non-adaptive protection functions [2].

4.5 ADAPTIVE FUNCTIONS

Electromechanical and analog static relays protected electrical networks until the 1980s. The realization of adaptive protection functions was nearly impossible on these classical relays. The availability of microprocessor and software technologies at the beginning of the 1970s was the prerequisite to introduce new technologies and methods. Protection functions could be realized based on software techniques independent of the necessary hardware.

Modern software technologies in combination with a continuous increase of available microprocessor power makes it possible to implement more and more complex adaptive protection functions in modern protection devices. The clear decrease of the hardware costs of microprocessor-based protection devices compared with electromechanical and analog static relays gives an additional important reason to use modern numerical protection devices.

The list below shows some important advantages of adaptive functions implemented in modern protection devices.

- The same type of protection device can be used independent of the specific properties of the electrical network (e.g., isolated, compensated, and solidly grounded networks).
- The protection device behavior (e.g., tripping time) is mostly independent of the specific location of the fault along the transmission line.

Additional commercial advantages can be achieved through reduction of the following:

- Protection device models to commission and maintain
- Protection devices in stock to exchange damaged devices
- Cost by using the same model for different applications

It can be stated that the use of modern protection devices containing adaptive protection functions increases the benefit and decreases the cost compared to electromechanical and analog static relays. Therefore, the necessary investments are justified.

4.5.1 Principle of Adaptive Functions

Adaptive techniques in protection devices are based on three basic components:

- Sources that supervise the system conditions
- Adaptive algorithms that analyze the sources, detect changes in system conditions, and select the adaptive methods
- Methods that adapt the protection functions to new system conditions

Figure 4.5 gives an overview of adaptive techniques in protection devices.

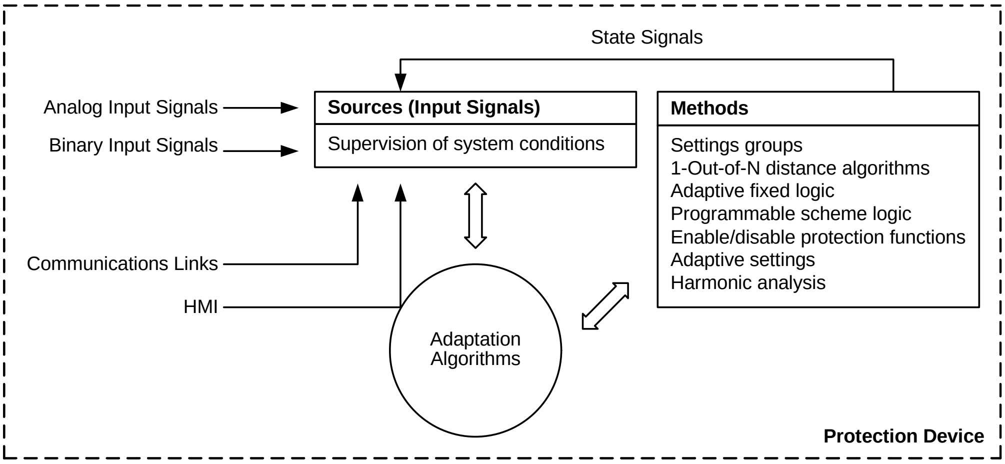

Figure 4.5 Adaptive algorithms with sources and methods

4.5.2 Sources of Adaptive Functions

Modern protection devices are designed to use different types of sources as input signals for implemented protection functions. The protection device can adapt continuously to the state of the electrical power network by analyzing the available input signals.

Two different groups of sources or input signals can be defined—measured and derived sources. Measured sources can be measured directly by the protection device without using additional mathematical algorithms (e.g., phase-to-ground voltages). In contrast with measured sources, derived sources cannot be directly measured by the protection device but can be calculated based on the measured sources. Protection devices calculate several derived sources based on physical models of electrical power networks and the corresponding mathematical equations. Derived sources are, for example, phase-to-phase currents or impedances.

The number of the measured and derived sources that are available as sources for adaptive algorithms depends on the realization of the protection device. In other words, it depends on the existing hardware components of the protection device and the algorithms implemented as part of the device software. For example, voltage supervision protection devices normally utilize as analog inputs voltage transformers (VTs) only. Current transformers (CTs) are not part of the device hardware. Because the protection device is not designed to measure currents, the number of available sources for adaptive protection functions is limited.

- Due to the technical realization of existing modern protection devices, the different types of sources are limited to analog and binary input signals and communications links.

4.5.2.1 Analog Input Signals

Two different types of analog input signals can be defined:

- Measured sources—measured analog input signals (e.g., phase-to-ground voltages)
- Derived sources—derived analog input signals (e.g., impedances)

Analog signals can take all values between 0 (analog signal can not be measured) and the maximum value that is defined by physical and technical aspects.

The analog input signals listed below are normally measured in modern protection devices:

- Phase-to-ground voltages V_{AG}, V_{BG}, and V_{CG}
- Phase currents I_A, I_B, and I_C
- Neutral-displacement voltage V_{NG}
- Residual current I_G
- Fundamental network frequency
- Direct current input
- Input to measure the resistance of a thermocouple element

Measured values can be taken into account as per-unit values referred to the nominal values or as primary values. Normally, the protection device based on mathematical equations will calculate the derived analog signals such as the following:

- Phase-to-phase voltages V_{AB}, V_{BC}, and V_{CA}
- Phase-to-phase currents I_{AB}, I_{BC}, and I_{CA}
- Apparent power
- Active power
- Active power factor
- Reactive power
- Active energy
- Reactive energy
- Load angle
- Positive-sequence voltage V_{pos} or V_1
- Positive-sequence current I_{pos} or I_1
- Negative-sequence voltage V_{neg} or V_2
- Negative-sequence current I_{neg} or I_2
- Zero-sequence voltage V_0
- Zero-sequence current I_0
- Neutral-displacement voltage V_{NG}
- Residual current I_G
- Voltages and currents calculated for harmonic frequencies
- Maximum phase current I_{max}
- Minimum phase current I_{min}

The active and reactive power, the power factor, and the active and reactive energy are calculated based on the measured currents and measured voltages of all three phases.

Direct Current Input

Modern protection devices have one or more direct current input channels to measure various physical quantities, i.e., the resistance of a thermocouple element R = f(T). The measured input current can be used as an input to other protection functions to adapt these functions to physical processes. For example, the direct current input can be used to measure the ambient temperature and adapt the thermal overload protection.

Externally measuring transducers normally supply an output current of 0–20 milliamps that is directly proportional to the physical quantity being measured. If the output current of the measuring transducer is directly proportional to the measured quantity only in certain ranges, then linearization can be applied. Furthermore, it may be necessary for certain applications to limit the monitored range or to monitor certain parts of the range that have a higher or lower sensitivity.

4.5.2.2 Binary Input Signals

External Binary Input Signals

The classical method to couple protection devices with other devices in electrical power networks is to connect the binary input channels of the protection device to the binary output channels of other devices via copper wires. These types of binary input signals are called external binary input signals. Binary input signals can take only two different states. Protection functions, which are assigned to the binary input channels, will be enabled or disabled by triggering these binary input channels.

In addition, the operation mode for binary inputs can be defined. The user can specify whether the presence (active "high" mode) or the absence (active "low" mode) of a voltage should be interpreted as the logic 1 signal. The trigger signal can be defined for an impulse or continuous signal level.

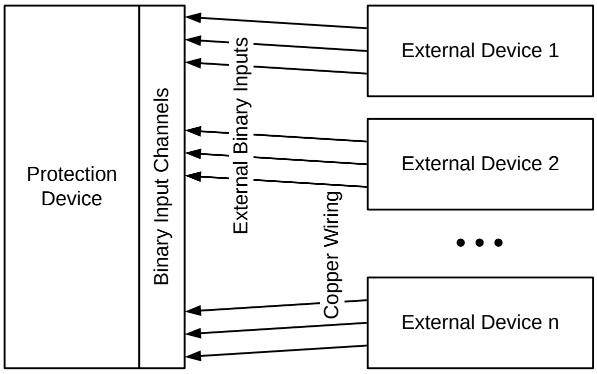

Figure 4.6 External binary input signals

Internal Binary Input Signals

The classical method of external binary input signals can be complemented with internal binary input signals. The use of internal binary inputs is identical to external binary inputs. In contrast, internal binary inputs are realized as a virtual software interface inside the protection device; external copper wiring is not required.

Internal binary inputs increase the capability of protection devices regarding adaptive protection functions.

Because internal binary inputs are realized as part of the firmware of the protection device, the number of internal binary input signals is limited only by the maximum size of the firmware ROM. External binary input signals are always limited because of the limited hardware components of the protection device.

The detection of external binary input signals is delayed by a few milliseconds due to the sampling and debouncing of the binary input signals. Internal binary signals are not delayed, and, therefore, the response of protection functions is sped up.

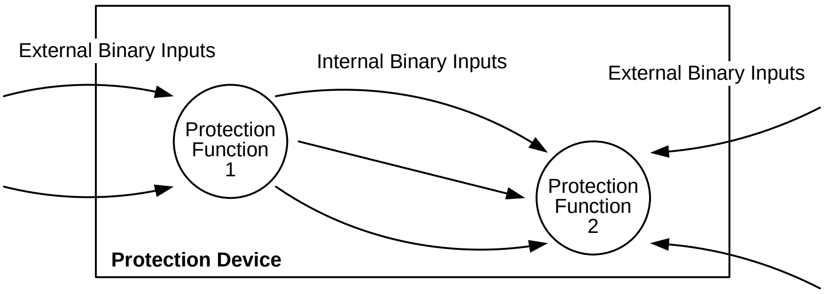

Figure 4.7 Internal binary input signals

4.5.2.3 Communications Links

Communications links can be used to realize binary input signals and analog input signals. The transmission of the data is realized based on a communications protocol. Different types of communications links can be used:

- Communications links to SCADA systems
- Communications links to substation control systems
- Communications links to other protection devices

Example

Substation control systems control and monitor the current state of the electrical network. The substation control system can enable a new parameter subset (e.g., disable reclosing at the local end) if the remote-end protection system detects a breaker failure condition.

Relay-to-Relay Communications

Communications links can also be used to exchange data directly between protection functions of two or more protection devices. This function is called relay-to-relay communications. Binary and analog data can be exchanged between modern IEDs to adapt the remote-end protection device if network conditions change.

Relay-to-relay communications between protection functions can also be used to replace classical protection schemes (e.g., teleprotection-aided schemes). The capability to exchange analog data increases the possibilities to design new adaptive algorithms for distance protection devices, which cannot be realized based on the classical methods that only exchange binary data.

4.5.3 Adaptive Algorithms

Adaptive functions are realized with adaptive algorithms that are based on the physics of the electrical network and the parameters of power system components. Adaptive algorithms sample the analog and binary input signals, analyze the data using mathematical equations, and create new output data that are used to adapt the protection device to the network conditions. The output signals of adaptive algorithms can be both binary and analog.

The use of numerical protection devices has allowed the protection algorithms to become more and more adaptive to the conditions of power systems, which are continuously changing. The use of such adaptive algorithms can increase security and dependability of numerical protection devices compared to classical electromechanical and analog static relays.

Adaptive algorithms can be realized based on one or a combination of several analyzing methods. The partial list below gives an overview of analyzing methods used in modern protection devices.

4.5.3.1 Discrete Fourier Transformation (DFT)

The DFT algorithm has the capability to calculate the phasors using different sized “windows,” full-cycle or half-cycle. The half-cycle window uses the sampling data from the last half cycle, while the full-cycle window uses data from the last full cycle. The half-cycle DFT allows a faster trip when compared with the full-cycle window DFT, but the full-cycle DFT suppresses better, higher harmonics than the half-cycle window DFT. Therefore, the half-cycle DFT causes higher errors in calculating the phasors compared to the full-cycle DFT.

4.5.3.2 Variable-Size Window

The classical approach of the DFT algorithm is a “sliding data window.” When a fault occurs, the sliding data window also contains prefault samples of voltages and currents, which cause phasor calculation errors. This method of phasor estimation has an inherent transient time delay as a function of the window size. The variable-size window algorithm first uses a half-cycle window after the fault has occurred to speed up the relay tripping time while accepting higher errors in calculating the fault distance. If the fault exists more then one cycle, the window size automatically switches to a full-cycle window.

4.5.3.3 Integration of First-Order Differential Equation

Algorithms based on a first-order differential equation take into account the dc component caused by the ratio between the reactance and resistance of the complete electrical power system.

4.5.3.4 Frequency Detection and Tracking

Continuous measurement of network frequency can be used to adapt the sampling interval to the floating network frequency calculation (e.g., take a fixed number of samples-per-power-system-frequency-cycle for use by a DFT algorithm). This method can be used in power systems where the network frequency is continuously floating in a wider range than the nominal frequency.

4.5.3.5 Windowing and Other Filtering Techniques

Windowing techniques can be used to suppress the influence of dc components to DFT algorithms (e.g., in case of series-compensated lines or subharmonics caused by the use of capacitive voltage transformers). Additional prefiltering of the sampled signals can improve the suppression or elimination of frequency components, which are different from the fundamental network frequency.

4.5.3.6 Direct Control Using Logical Equations

The output signal of the adaptive algorithm can be used to enable/disable protection functions or to modify settings for protection functions.

4.5.4 Methods

The third component to realize adaptive techniques is the methods. Acting as the “glue“ between the sources and the adaptive algorithms, the methods are used to adapt the protection function to the new system conditions. The methods continuously use the output data of the adaptive algorithms and control the available sources (measured and derived) and the mathematical algorithms executed as part of the distance protection device software.

4.5.4.1 Harmonic Analysis

The method of harmonic analysis is used to calculate the phasors of higher harmonic frequency components compared to the network frequency. The distance protection device continuously compares the amount of the harmonic phasors with fixed or settable thresholds to determine CT saturation, CVT transients, or transients generated by series compensation). Depending on the harmonic analysis, additional stabilization methods can be enabled to avoid protection device misoperation.

4.5.4.2 Adaptive Settings

Improvements in the response or behavior of a protection device are realized by adapting internal device settings depending on measured sources. For example, a distance protection device could adapt to a different time window memory voltage or adapt the measuring range of the analog input circuit to increase its measuring accuracy and sensitivity.

4.5.4.3 Switching Between Parameter Subsets (Settings Groups)

Modern distance protection devices usually contain up to six parameter subsets (settings groups). Each settings group consists of the same number of settings with identical meaning, but the settings will be stored at different locations in the RAM of the device. Therefore, settings with identical meaning but contained in different settings groups can be set to different values.

The settings group management of modern protection devices guarantees that only one of the settings groups can be enabled by the user via different sources (e.g., optoisolated inputs). The protection functions of the device are only using the settings of the enabled settings group.

Example

The example below describes the use of settings group switching in case of double-circuit line protection. The setting “Zone 1 Reach X1” is part of each settings group but is represented by another RAM location in each settings group. Therefore, the settings exist up to six times from the device software point of view. The protection functions are using only the setting “Zone 1 Reach X1” of the enabled settings group.

The setting “Zone 1 Reach X1” can be set to different values inside each settings group dependent on the state of the double-circuit line. In the example below, the double-circuit line will be used in three possible operating modes. For each of the three operating modes, different settings for “Zone 1 Reach X1” must be set. A possible solution is to use different settings groups:

- Both lines of the double-circuit line are energized → Settings Group 1
- Line 1 is energized and Line 2 is disconnected but not grounded → Settings Group 2
- Line 1 is energized and Line 2 is solidly grounded → Settings Group 3

The switching between Settings Groups 1, 2, and 3 can be realized (e.g., using the state of all four circuit breakers that are connected to the four terminals of the double-circuit line). An example of such logic is shown in Figure 4.8.

Protection of Double-Circuit Lines

```
if (    (Circuit Breaker 1 is CLOSED) AND
        (Circuit Breaker 2 is CLOSED) AND
        (Circuit Breaker 3 is CLOSED) AND
        (Circuit Breaker 4 is CLOSED)    )
then
    Activate Parameter Subset 1:
    ---------------------------
    Both lines in parallel and energized
else
    if (    (Circuit Breaker 1 is CLOSED) AND
            (Circuit Breaker 2 is CLOSED) AND
            (Circuit Breaker 3 is OPEN)   AND
            (Circuit Breaker 4 is OPEN)      )
    then
        Activate Parameter Subset 2:
        ---------------------------
        Line 1 energized
        Line 2 disconnected, but not grounded
    else
        if (    (Circuit Breaker 1 is CLOSED)   AND
                (Circuit Breaker 2 is CLOSED)   AND
                (Circuit Breaker 3 is GROUNDED) AND
                (Circuit Breaker 4 is GROUNDED)    )
        then
            Activate Parameter Subset 2:
            ---------------------------
            Line 1 energized
            Line 2 solidly grounded
        else
```

Figure 4.8 Example of selecting settings groups based on circuit breaker status

4.5.4.4 Programmable Scheme Logic (PSL)

Modern distance protection devices contain programmable scheme logic that can be defined by the user. PSL editor software allows the user to define the required Boolean equations. PSL editors can be based on simple settings or on highly sophisticated graphical user interfaces.

4.6 EXAMPLES OF ADAPTIVE FUNCTIONS

The advent of digital technology and the use of microprocessors in modern numerical distance devices, with their inherent programmability, essentially unlimited logic, and memory capability, have made the implementation of adaptive concepts more practical and straightforward. Protection, control, and monitoring functions can adjust their performance to match the needs of changing power system conditions and can handle changing system configurations. Below, we offer a few examples to illustrate some of the adaptive concepts used in modern distance devices. This list is not complete and the working group does not claim that these examples represent best practices in the relaying industry.

4.6.1 Adaptive Polarizing Voltage Memory

Comparator-based Mho elements require a polarizing quantity to provide a reliable angle reference. When a fault occurs, this angle reference should be stable and last long enough to guarantee that the protection element consistently picks up until the fault is cleared. The following are basic requirements for the polarizing quantity:

- Provide reliable operation for all in-zone faults
- Be secure for all external faults
- Provide stable operation during single-pole open conditions
- Tolerate fault resistance

The memory voltage supports several functions of the distance protection device:

- Allows the distance protection relays to operate for zero voltage three-phase faults in front of the relay
- Prevents the relay from operating for zero voltage three-phase faults behind the relay
- Allows the relay to maintain directionality during voltage inversion in series-compensated lines

The choice of memory time constant or the length of polarizing memory is always a critical design issue. Considerations in choosing the time constant should include the following:

- The maximum clearance time of both internal and external zero-voltage faults
- Backup-zone fault clearance time on high system impedance ratio (SIR) systems where the relaying voltage might be very small, even for remote faults
- Bypass-switch operating time of series-compensation capacitors

The maximum duration of the memory voltage can be fixed (e.g., hard-wired in the source code of the device software), user settable, or adaptive. One possible problem with fixed memory time involves faults beyond the reach of the Zone 1 function. On lines with high source-to-line ratios, the magnitude of the steady-state fault voltage at the relay location for three-phase faults at the remote end of the line may be less than the voltage required for the relay to operate. For these conditions, the overreaching step distance backup functions may not operate if the time delay is greater than the fixed memory time.

Voltage inversion in series-compensated lines endangers the directional security of the Mho distance elements. In such applications, the polarizing memory should be long enough to provide correct and consistent distance element operation until the fault is cleared, the spark-gap protection operates, or the capacitor bypass switch operates to clear the voltage inversion. A typical polarizing memory time is between 3 and 20 cycles.

Figure 4.9 Polarizing quantity slips away from the voltage inputs

Longer polarizing memory helps to detect faults in difficult system and fault conditions like those mentioned above. However, longer memory also comes with a serious security drawback when there is a system frequency excursion. When a frequency excursion occurs, the Mho distance relay tracks to the new frequency. Due to the memory effect, the polarizing voltage phase angle starts to slip away from the input voltage phase angle, resulting in a phase angle difference as shown in Figure 4.9. If this frequency excursion persists long enough, the angle difference between the operating and polarizing signals becomes less than 90 degrees and the relay inadvertently trips due to the frequency excursion and the use of a long polarizing memory.

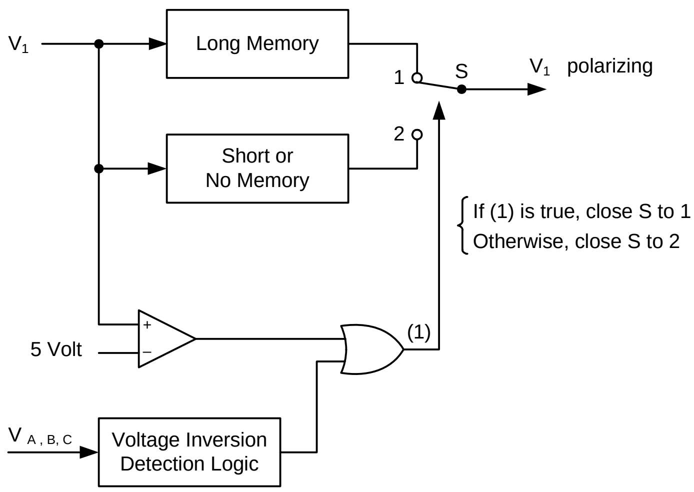

Figure 4.10 Adaptive polarizing memory logic

To overcome the long polarizing memory problem and at the same time provide a reliable polarizing quantity for zero-voltage faults and faults with a voltage inversion, modern distance relays use an adaptive polarizing scheme as shown in Figure 4.10. The relay normally uses the positive-sequence voltage V_1 with little or no memory for the polarizing quantity. This polarization is satisfactory for all faults other than zero-voltage three-phase faults and faults with a voltage inversion. When the relay detects that V_1 magnitude is less than a predetermined value or the relay detects a voltage inversion, it switches to a long-memory V_1 polarizing quantity.

4.6.2 Distance Element Polarization During Pole-Open Conditions

During pole-open conditions, where line-side voltages supply the distance relays, eventual corruption of the polarizing quantity can occur if the input voltage to the memory circuit is corrupted. Invalid memory polarization may cause distance element misoperation. Shunt reactor switching generates damped oscillations with signals that have frequencies that differ from the actual system frequency. Let us look at an adaptive method used by a modern numerical distance relay to prevent the memory polarization from using unhealthy voltages.

Shunt reactors compensate the line charging currents and reduce overvoltage in long transmission lines. After the circuit breakers open at both line ends during a fault, the remaining circuit of the open phase is basically an RLC circuit with stored energy in the reactor and in the line capacitance. The natural frequency of the circuit is close to the nominal system frequency of 50 or 60 hertz. After the three poles of each line breaker open, the shunt reactors interact with the line capacitance and maintain line voltages for several cycles. The circuit applies these voltages to the VTs or capacitive voltage transformers (CVTs). These voltages corrupt the distance protection polarization and frequency estimation. These distorted voltages should be removed from the distance protection polarization and frequency estimation algorithms. The distance relay detects the ringing condition caused by the RLC circuit and pole-open conditions and eliminates the corrupted voltage from the memory filter input. On a phase-by-phase basis, the relay inputs zero to the memory filter during pole-open conditions to prevent distance element misoperation. Figure 4.11 shows the logic for inputting zeros to the memory filter after the relay detects voltage ringing or undervoltage conditions.

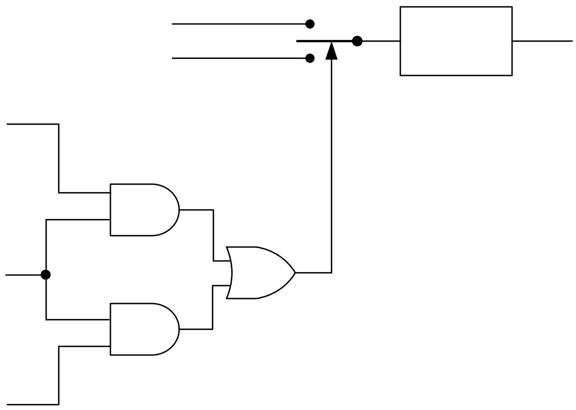

Figure 4.11 The distance relay inputs zeros to the memory filter when input voltages are corrupted

4.6.3 Capacitive Voltage Transformers

CVTs are used to transform the primary-phase-to-ground voltages to the nominal relay voltage V_{nom}. Utilities apply CVTs in EHV systems because the cost is much lower than inductive VTs. However, CVTs can produce low-frequency signal components during system faults that can cause overreaching of the Zone 1 distance protection function and impact the security of the power system.

Distance protection devices measure the faulted phase-to-ground voltages and calculate the fault impedance based on the faulted voltage signals. Therefore, inaccuracy of the calculated fault impedance can increase up to 20 percent or more. Figure 4.12 shows as an example of the phase-to-ground voltage V_{AG} in case of a fault close to the monitoring point of the protection device. The CVT causes a low-frequency signal component about 15 percent of V_{nom} maximum value. The signal component disappears 140 milliseconds after fault occurrence.

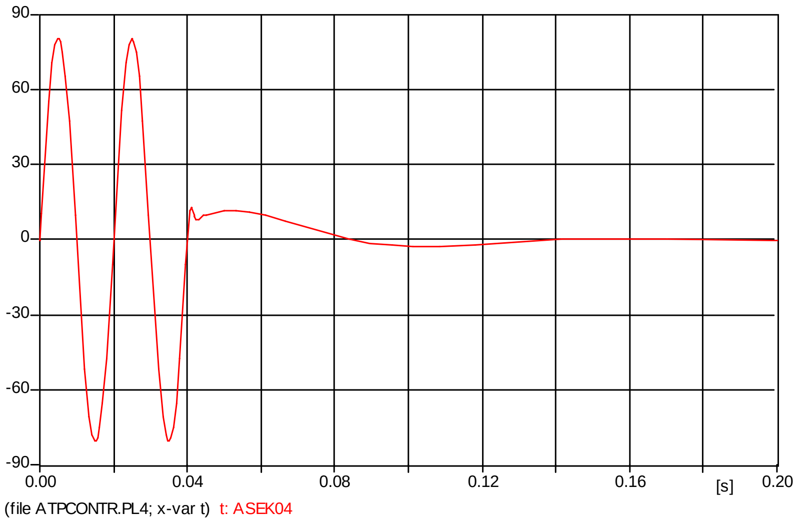

Figure 4.12 CVT phase-to-ground voltage due to a line-to-ground fault

Modern protection devices can detect and suppress the low-frequency signal component using filtering methods (e.g., a high-pass filter). However, it is possible that this additional filtering method could increase the relay tripping time. Therefore, CVT-suppressing filtering methods can be enabled or disabled based on static or dynamic conditions.

- Static condition—realized as an on/off setting to enable or disable the CVT filtering method
- Dynamic condition—can be realized based on frequency analysis of the phase-to-ground voltages, but it has to take into consideration that low-frequency signal components can be caused by other physical effects

Modern distance relays offer a variety of CVT transient detection solutions such as narrow band-pass filtering of the voltages (which effectively adds some delay due to filtering), reduction of the distance relay reach, and directly delaying the distance relay tripping decision when a CVT transient condition is detected. Another CVT transient solution method detects high SIR conditions that exhibit severe CVT transients and adds a time delay to the tripping decision. However, if the logic determines that the fault is close to the relay location, based on the smoothness of the apparent fault impedance calculation, it overrides the time delay to permit rapid tripping for internal faults [3].

4.6.4 Mutual Compensation in Double-Circuit Lines

Three operating modes of double-circuit lines are shown below.

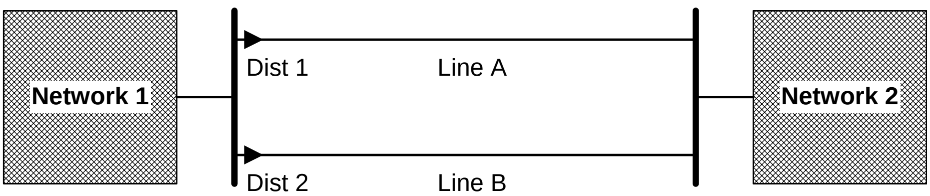

Figure 4.13 Double-circuit lines with Lines A and B operated in parallel

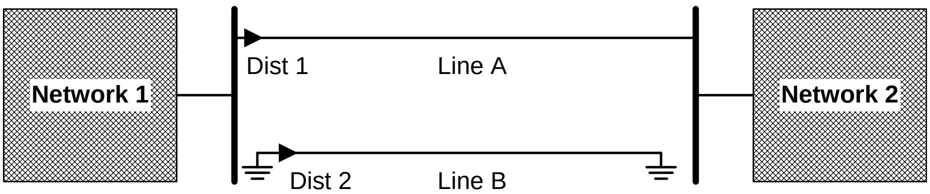

Figure 4.14 Double-circuit lines with Line B switched off and grounded at both ends

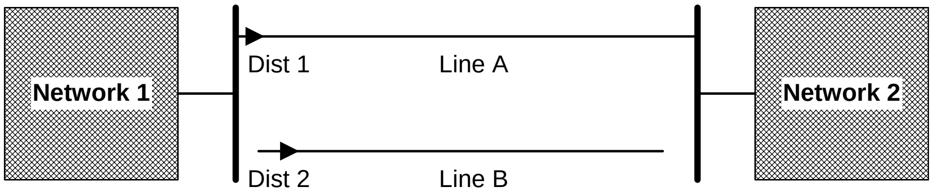

Figure 4.15 Double-circuit lines with Line B not energized (one or both ends isolated)

In the case of ground faults on the parallel line, the residual current of the parallel line is measured from both distance protection devices (Dist 1 and Dist 2 in the figures above). The residual current has a big influence in the calculation of the fault impedances and the fault distance due to the zero-sequence mutual coupling effects of the parallel Lines A and B.

The most common problems concerning distance protection of parallel lines ending at the same bus without mutual compensation can be summarized as follows:

- Tendency to underreach when both Lines A and B are energized
- Tendency to overreach when one of the lines is switched off and grounded at both ends

Modern distance protection devices often include an adaptive function to compensate the mutual influence of parallel lines in case of ground faults. If the parallel line compensation function has been enabled, then the residual current of the parallel line will be included in distance and directional measurement. The function can be enabled or disabled by static or dynamic conditions.

- Static condition—realized as an on/off setting to enable or disable the parallel line compensation
- Dynamic condition—can be realized if the current states of the circuit breakers at the four ends of the line are known by the protection relay; the settings for the three different network configurations shown above can be stored in settings groups, and one of the three settings groups can be selected depending on the status of the circuit breakers

A careful application of mutual compensation for zero-sequence can solve this problem. The zero-sequence current of Line B in case of a ground fault on Line A can be used to compensate the influence of the zero-sequence mutual coupling. This application scheme is often called zero-sequence current balance. The compensation method increases the accuracy of the measured fault reactance in case of phase-to-ground faults of Line A. The equation to calculate the fault impedance for ground faults is defined as follows:

$$Z_{AG} = \frac{V_{AG}}{I_A + k_0 \bullet I_R + k_{0M} \bullet I_{R\_par}} \quad (4.1)$$

Where:

V_{AG} = Phase-to-ground voltage of Line A (Monitoring Point 1)

I_A = Phase current of Line A (Monitoring Point 1)

I_R = Residual current of Line A (Monitoring Point 1)

I_{R_par} = Residual current of the parallel Line B (Monitoring Point 2)

k_0 = Zero-sequence compensation factor of the monitored Line A

k_{0Mr} = Mutual coupling zero-sequence compensation factor

The setting k_{0M} represents the mutual coupling between the two lines of the double-circuit line. If the parallel Line B is out of service, then $k_{0M} = 0$. In this case, the normal equation for fault impedance calculation will be used:

$$Z_{AG} = \frac{V_{AG}}{I_A + k_0 \bullet I_R} \quad (4.2)$$

On the other end, mutual compensation for zero-sequence current in the parallel line is not often used, mainly because of two problems.

- Problem 1—tendency of the healthy line to false trip during earth faults in the parallel line
- Problem 2—tendency to overreach when the parallel line is switched off and grounded at both terminals because, in this case, the parallel line current is not available

The adaptive approach consists mainly of informing each mutually compensated relay about the status (e.g., in service, switched off, terminals grounded) of the parallel lines. Techniques that could allow a more widespread use of mutually compensated distance relays follow.

- Problem 1 can usually be overcome by comparing the magnitude of the zero-sequence currents in both lines and performing the compensation only in the line where the zero-sequence current is higher than that of the parallel line by a certain amount. Another possibility is to block the output of the mutually compensated unit by the instantaneous output of a noncompensated overreaching unit. Preferably, the underreaching and overreaching units should use the same input signals and algorithm in order to ensure faster operation of the overreaching unit.
- Problem 2 can be overcome using an adaptive approach. If the relay is informed that the parallel line is earthed at both terminals, its ground or earth compensation factor can be switched to another value (e.g., stored in another settings group that would take into account the new situation).

4.6.5 Inrush Detection and Stabilization

Inrush currents are transient phenomena, which occur on energization of a transformer. Harmonics are typically produced in the phase currents. The amplitude of the inrush current depends on the physical data of the transformer, especially on the magnetization characteristic. The significant frequency component of the inrush current is the second harmonic (i.e., 100 hertz at nominal frequency of 50 hertz). Inrush currents are not a fault condition and, therefore, the protection device must not trip. In order to achieve this, the protection algorithms have to be stabilized against inrush currents. Figure 4.16 shows the currents during inrush calculated with a network simulation system.

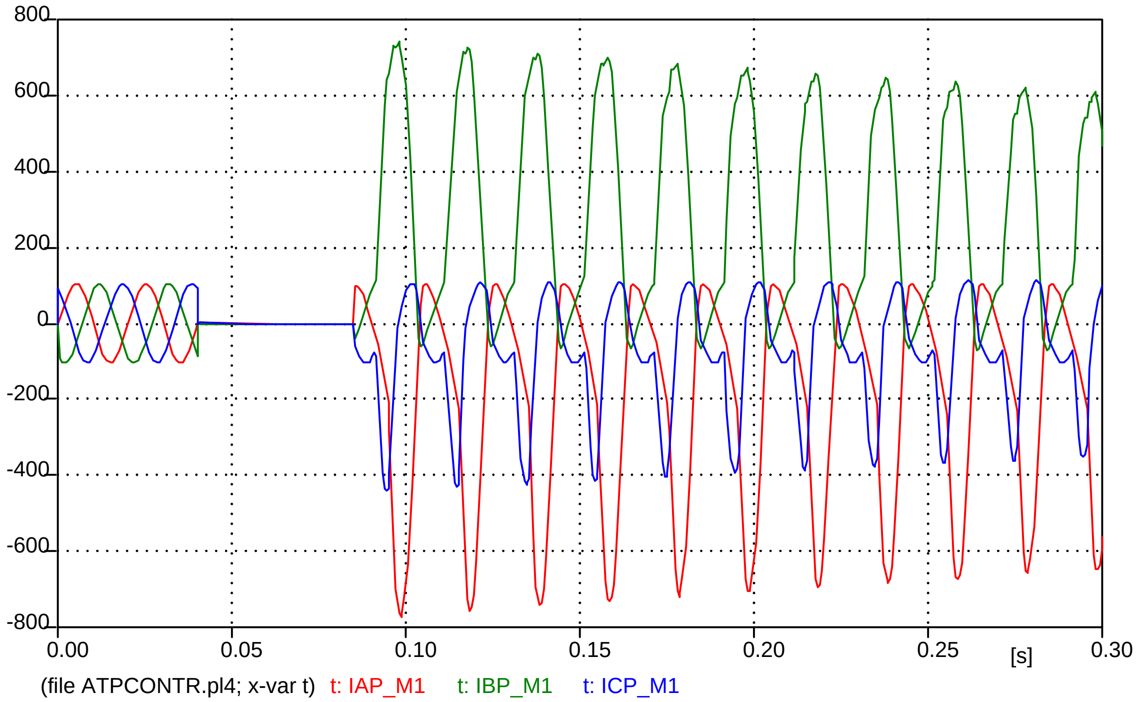

Figure 4.16 Inrush current waveform

The inrush stabilization function is designed to detect inrush current flowing on energization of transformers. On operation, it will block the following protection functions:

- Overcurrent fault detection logic of distance protection
- Underimpedance fault detection logic of distance protection
- Instantaneous-time overcurrent protection
- Definite-time overcurrent protection
- Inverse-time overcurrent protection

The inrush stabilization function detects an inrush current by evaluating the ratio of the second harmonic current component to the fundamental. If this ratio exceeds the set threshold, then the inrush stabilization function operates. A high-set current trigger blocks inrush stabilization if the current exceeds this trigger that is set above the maximum anticipated inrush current level. By setting the operating mode, the user determines whether inrush stabilization will operate phase-selectively or across all phases.

The detection of the inrush current is based on a full-cycle DFT shown in Equation 4.3 below. Using a sampling rate of 1000 hertz, one cycle of the nominal frequency is represented by 20 sampling values.

The DFT algorithm can also be used to calculate harmonic frequency components of higher orders of the sampled phase current. The results of the DFT algorithm are the complex phasors of the phase currents I_A, $I_{B,}$ and I_C.

$$I_{RE} = \frac{2}{m} \bullet \sum_{k=1}^{m} i_k \bullet \sin\left(\frac{2 \bullet \pi \bullet k}{m}\right) \qquad I_{IM} = \frac{2}{m} \bullet \sum_{k=1}^{m} i_k \bullet \sin\left(\frac{2 \bullet \pi \bullet k}{m}\right) \tag{4.3}$$

Where:

i_k = Sampling values of phase current

I_{RE} = Real part of the phase current phasor

I_{IM} = Imaginary part of the phase current phasor

m = Number of samples-per-cycle

k = Number of the sampling value of the cycle

4.6.6 Distance Relay at the Transfer Bus

The text below is copied from the CIGRE WG 34.02 report on “Adaptive Protections and Control”:

> *The transfer bus is used to bypass the switchgear of any feeder to make maintenance possible without interrupting the power supply. The distance relay allocated to the circuit breaker at a transfer bus has to protect different lines. If the distance relay offers facility to pre-store different sets of settings, the selection of settings can be done automatically in connection with the closing of the feeder isolator connected. The adaptation can be done while the protection equipment is disconnected so that no requirement on speed is needed [2].*

The settings for the different power system states, depending on the use of the transfer bus, can be stored in different settings groups. The settings group that has to be used for a certain state can be selected via input signals coming from the circuit breakers of the substation bus and the transfer bus.

- Static condition—the selection of the corresponding settings group can be done at the HMI manually
- Dynamic condition—can be realized if the status of the circuit breakers of the substation bus and the transfer bus are known by the distance protection device (e.g., connecting the output state signals of the circuit breakers to the optoisolated inputs of the device)

4.6.7 Power-Swing Detection

The text below is copied from the CIGRE WG 34.02 report on “Adaptive Protections and Control”:

> *Power-swing detection and control by means of out-of-step relays in distance protection is an important task in high-voltage network control. Distance protection should be able to distinguish between stable and unstable swings. The features required for distance protection schemes to operate in adaptive modes are:*
>
> - *To block or trip following the detection of stable or unstable swing*
> - *To accept a remote signal for coordination sent during normal service conditions; high-speed communication is not required [2].*

Operational switching and short circuits may result in sudden power changes, which consequently lead to transient power swings. Voltages, currents, and the derived quantities (e.g., power or impedance) are oscillating periodically during these swings. The natural frequency is typically in the range of 0.5–2 hertz for stable swings and 4–10 hertz for unstable swings. Frequency, amplitude, and duration of power swings are determined by the parameters of the power system and generators as well as by the swing trigger conditions, especially the short-circuit duration. The higher the short-circuit power of the system (stiff system) and the faster the fault clearance takes place, the smaller the observed power swing. Therefore, power swings are less likely to be observed in meshed medium- and high-voltage systems with relatively high short-circuit power. They will occur on extra-high voltage transmission systems, especially for faults close to big generating plants or on tie lines between subnetworks.

Modern distance relays have integrated numerous protection functions including power-swing blocking and out-of-step or pole-slip tripping functions. The main purpose of the power-swing blocking function is to differentiate faults from power swings and block distance or other relay elements from operating during stable or unstable power swings. Therefore, the first task of distance protection devices is to detect power swings and restrain from tripping even if the measured impedance during the swing enters its distance element characteristics. An additional task may be to allow power-swing tripping during unstable or long-duration swings in order to island the power system at predetermined system locations to prevent a catastrophic failure or a major blackout. This feature is only used at a few locations that need to be determined by power system stability studies.

Most power-swing blocking elements are based on traditional methods that monitor the rate of change of the positive-sequence impedance as was discussed in Section 2.6.7 of this report. Various other algorithms and methods are used for power swing detection besides monitoring the rate of change of the positive-sequence impedance. These algorithms are not covered in this report since they do not base their detection on impedance or rate-of-change of impedance methods.

4.6.8 Series-Compensated Lines

Series-compensated lines can be used to optimize the power load flow through overhead lines if these lines are built over extremely long distances. Series-compensated lines introduce a series-connected capacitor, which has the net result of reducing the overall inductive impedance of the line.

The series connection of the capacitor, the transmission line, and the system source create a resonant RLC circuit. The natural frequency of the circuit is a function of the level of compensation and the equivalent power system source. The level of compensation can change according to the switching in and out of series capacitor segments. The source impedance can change because of switching operations external to the protected line section.

The series capacitor causes a low-frequency signal component during faults, which is superimposed on the fundamental frequency and could cause severe overreach of the Zone 1 distance element. Figure 4.17 shows the phase current measured at one terminal of a series-compensated line in case of a single-line-to-ground fault at the end of the line.

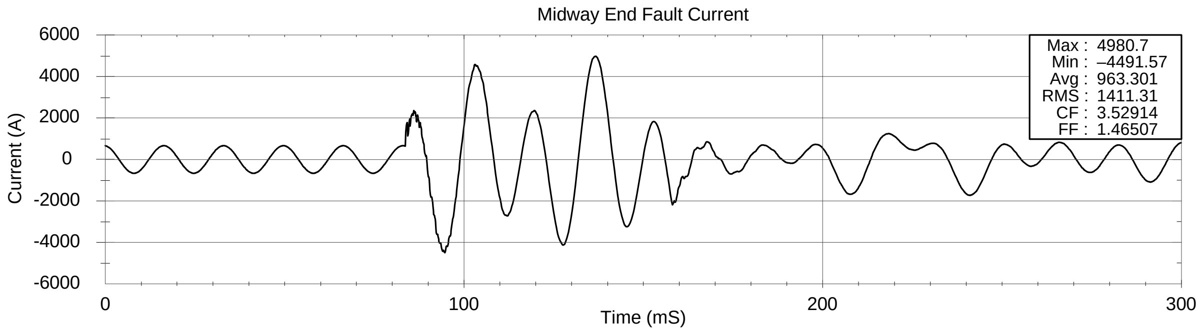

Figure 4.17 Phase fault current in a series-compensated line

Modern distance protection devices can be adapted to suppress the low-frequency signal component using filtering methods as described for CVTs or by using special algorithms as we discussed in Section 2.4.5, Series-Compensated Transmission Lines.

4.6.9 Isolated and Petersen Coil Grounded Networks

Isolated and Petersen Coil grounded networks are used worldwide in networks up to 110 kilovolts. Figure 4.18 shows the neutral-point treatment of isolated networks (left side) and Petersen Coil grounded networks (right side).

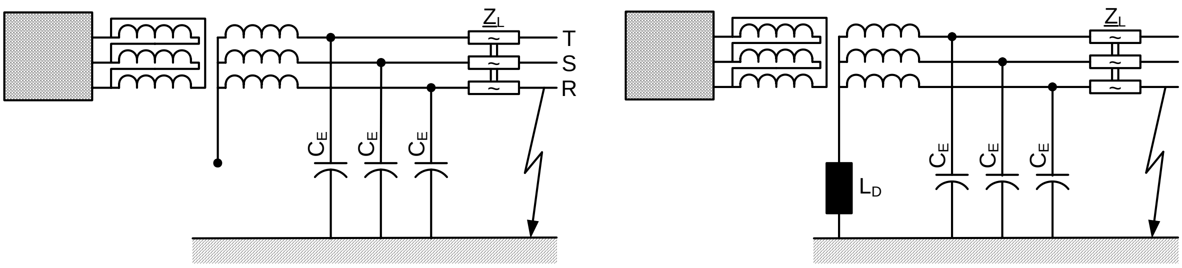

Figure 4.18 Neutral-point treatment in isolated and Petersen Coil grounded networks

The fault current, which is measured in case of a single-phase-to-ground fault, is very small because the resulting zero-sequence impedance of the power system limits the residual current. The zero-sequence impedance is mainly determined for:

- Isolated networks—by the phase-to-ground capacitances
- Petersen Coil grounded networks—by the phase-to-ground capacitances in parallel with the inductance of the Petersen Coil

These represent high impedance in the zero-sequence system in both cases. In addition, a medium-frequency signal component is superimposed to the fundamental frequency in case of a single-phase-to-ground fault. The advantage of both neutral-point treatments is a self-extinction of the fault in most cases. The network elements (e.g., transformers or cables) will not be stressed as in the case of solid-grounded networks, where the short-circuit currents can cause damage to the power system. The power system can further operate in case of a single-phase-to-ground fault for minutes up to several hours because the load flow is not interrupted or disturbed.

Figure 4.19 shows the phase current measured from a distance protection device in case of a single-phase-to-ground fault in a 110 kilovolt network.

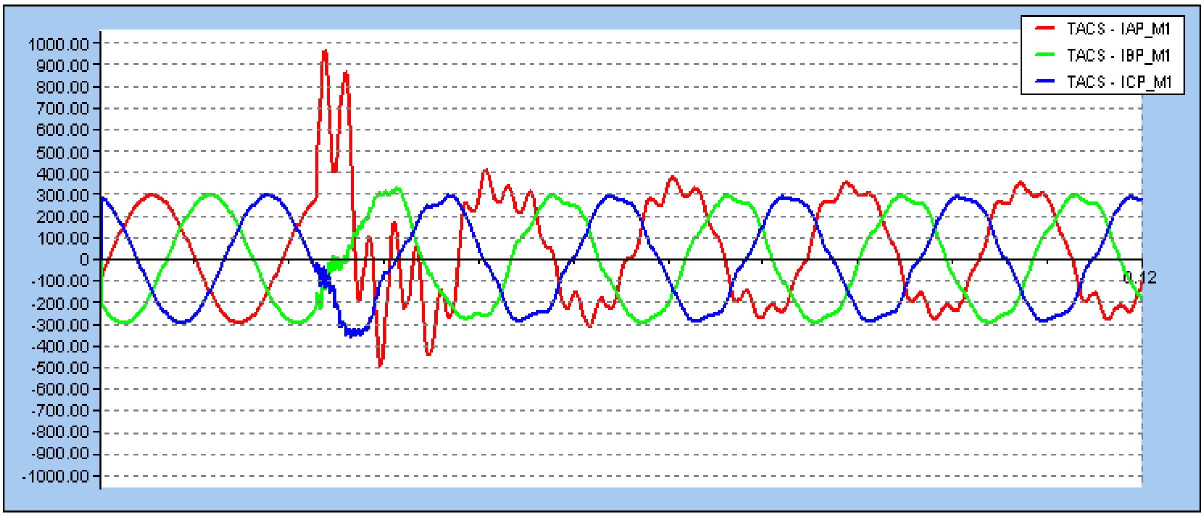

Figure 4.19 Phase currents during a single-line-to-ground fault on a 110 kilovolt network

The medium-frequency signal component can be suppressed using adaptive filtering methods in order to eliminate the errors in the determination of the fundamental frequency phasors. Based on this filtering method, the distance protection device can properly detect single-phase-to-ground faults using ground-fault detection logic. The detection of a ground fault is based on the continuous measurement and supervision of the residual current I_N and the neutral-placement voltage V_{NG}. The distance protection device must not trip in case of a single-phase-to-ground fault.

4.6.10 Protection Signaling (Teleprotection Schemes)

Unit protection schemes, formed by a number of relays located remotely from each other, and some distance protection schemes require some form of communication between each location in order to achieve a unit protection function. This form of communication is known as protection signaling or teleprotection schemes.

Additionally, communications facilities are required when remote operation of a circuit breaker is required as a result of a local event. This form of communication is known as intertripping or transfer trip.

The communications messages involved may quite simply involve instructions for the receiving device to take some defined action (trip, block, etc.), or it may be the passing of measured data in some form from one device to another (as in a unit protection scheme).

Various types of communications links are available for protection signaling such as the following:

- Private pilot-wires installed by the power authority
- Pilot-wires or channels rented from a communications company
- Carrier channels at high frequencies over the power lines
- Radio channels at very high or ultra high frequencies
- Optical fibers

Protection signaling is used to implement unit protection schemes, provide teleprotection commands, or implement intertripping between circuit breakers. Figure 4.20 presents some protection signaling schemes as an example.

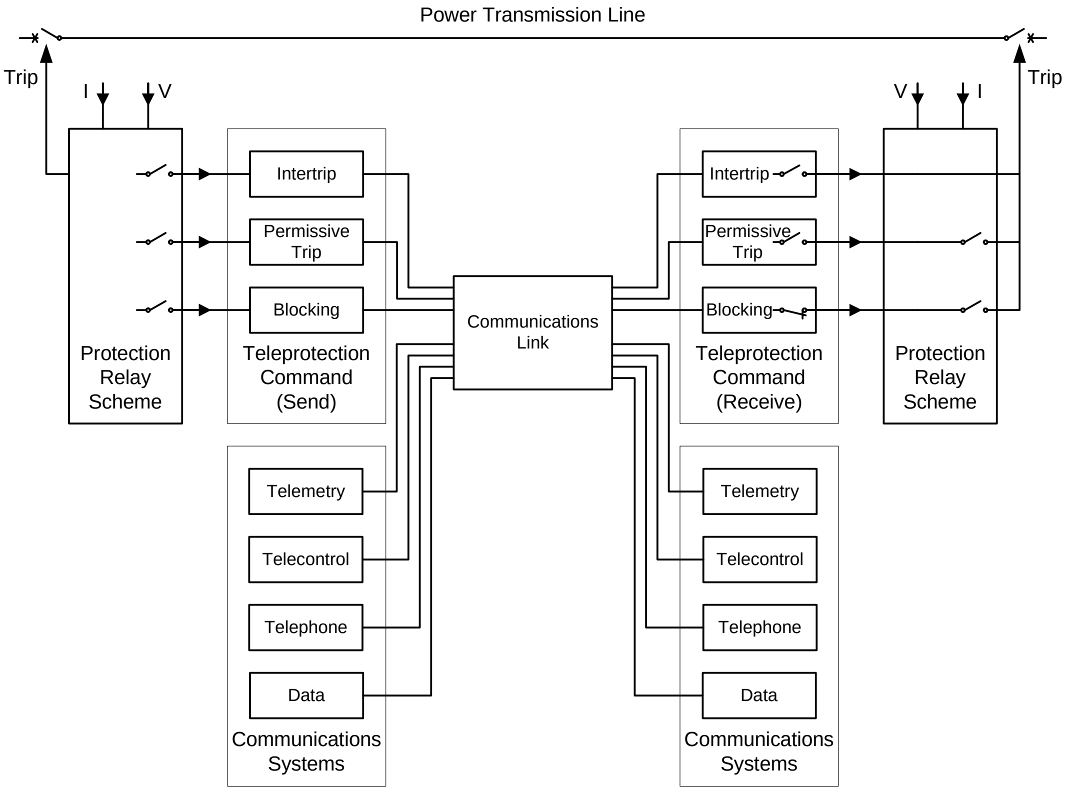

Figure 4.20 Application of protection signaling

The main use of such schemes is to ensure that protection at both ends of a faulted circuit will operate to isolate the equipment concerned. Their basic aim is to instanteneously protect 100 percent of the line length instead of about 80 percent of the line length without protection signaling. Protective signaling can operate in the different modes listed below to adapt the protection device to the local network needs. These communications-aided protection schemes are discussed in more detail in Section 2.4.2 of this report.

- Direct underreaching transfer trip (DUTT)
- Permissive underreaching transfer trip (PUTT)
- Directional comparison blocking (DCB)
- Directional comparison unblocking (DCUB)
- Direct transfer trip (DTT)

The following examples illustrate the use of signaling to achieve fast and selective protection.

Zone 1 Extension

When there is a distance protection trip in Zone 1, a signal is sent to the distance protection device at the remote end of the line. Upon receipt of the transmitted signal, the measuring range of Zone 1 in the remote-end distance protection device is extended by a settable zone extension factor. The response of the remote-end protection device depends on the operating mode.

- Direction-dependent trip—the remote-end protection device trips if a signal is received and the fault direction "forward" is detected
- Distance-dependent trip—the remote-end protection device trips if a signal is received, a fault is detected in the Zone 1 extension, and the additional protective signaling tripping timer has elapsed

Figure 4.21 shows the Zone 1 and the Zone 1 extension of two distance protection devices, looking from both ends of a line to the remote end. Zone 1 of the distance protection device is set to 80 percent of the line length, in which the protection device trips as fast as possible in case of a Zone 1 fault. The "security" zone, 80–100 percent of the line, takes several physical and technical aspects into consideration to avoid wrong trip commands if the fault is outside the protected line. Below are some considerations:

- Use of different tower schemes of overhead lines and/or underground cables
- Limited measuring accuracy of the used distance protection device
- Limited measuring accuracy of the voltage and current transformers in the substations

It can be seen that it is possible to protect 100 percent of the line using this protective signaling scheme. The distance between 80 and 100 percent of the line will be protected using the Zone 1 extension mode but with an increased tripping time compared to the Zone 1 tripping times. The increased tripping time depends on the protective signaling scheme (e.g., the time to send/receive signals via the communications channels).

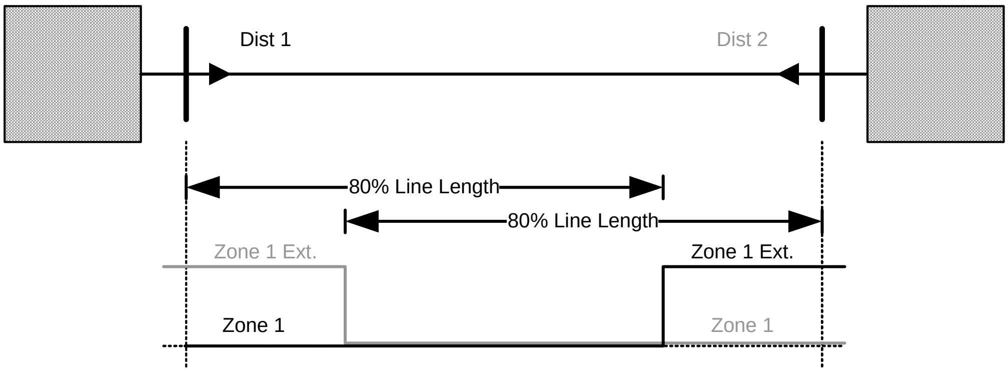

Figure 4.21 Zone 1 extension

Signal Comparison Release Scheme

Signal comparison schemes are used to coordinate the trip logic between the two distance protection devices at both ends of the line. The signals are transmitted through one, three-pole signal comparison information channel or through three, one-pole signal comparison information channels. Therefore, one-pole and three-pole tripping of the distance protection device can be realized. Different technologies can be used to transmit these signals.

- Conventional copper wiring
- Peer-to-peer communications links
- Multicast communications (e.g., Ethernet-based networks)

The distance protection devices at one end send a signal to the distance protection device at the remote end of the line depending on its operating mode.

- Direction-dependent sending—if the distance protection device detects a fault in the forward direction, the device sends a signal to the remote-end device
- Distance-dependent sending—if the distance protection device detects a fault in the Zone 1 extension, the device sends a signal to the remote-end device

The distance protection device at the remote end receives the signal and operates depending on its operating mode.

- Direction-dependent tripping—if the distance protection device has received a signal, it trips in the phase(s) in which the distance elements have detected a fault in the forward direction and signal(s) were received; this operating mode is independent of the Zone 1 extension
- Distance-dependent tripping—the remote-end distance protection device enables Zone 1 extension if a signal has been received; a trip command will be generated if the fault was detected in the Zone 1 extension.

The Zone 1 distance protection function operates instantaneously for faults detected in its zone of protection, independently of any signal received from the remote end.

Figure 4.22 shows an example for distance protection of short underground cables with signal comparison. The aim is to protect the cable but to avoid wrong trip commands if the fault is located outside the cable. Zone 1 is set to 35 percent of the line length to avoid an incorrect trip caused by measuring accuracy problems that are typical in short cable protection applications using distance protection functions. If the fault occurs outside Zone 1 of Dist 1 but in the forward direction, Dist 1 receives a signal from Dist 2. Dist 1 trips immediately but is delayed by the time required to receive the signal from the remote-end distance protection device. The time delay depends on the technology that is used to transmit the signals.

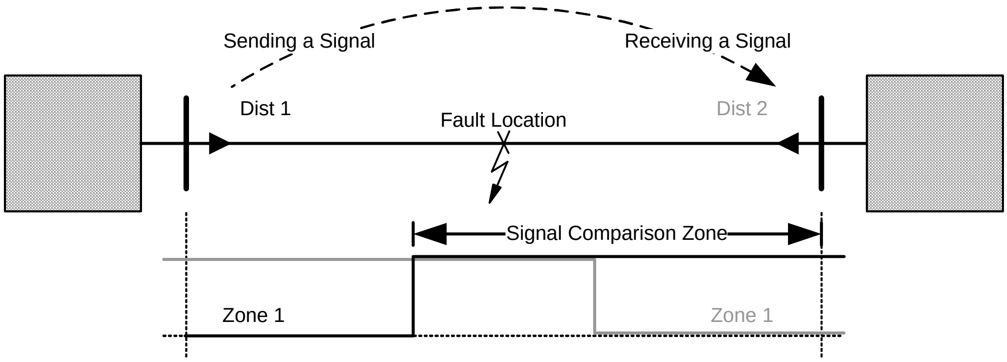

Figure 4.22 Distance protection with signal comparison

4.6.11 Adaptive Fuse Failure Detection

To monitor the voltage-measuring circuits, distance protection devices are designed to detect fuse failures. The protection device monitors several signals (e.g., voltages and currents) to detect a fuse failure and adapts its algorithms to the changed network conditions. The description below gives an example of an adaptive fuse failure distance protection function.

The fuse failure monitoring function must distinguish between a short circuit in the three-phase current system and a lack of measuring voltage due to a short circuit or open circuit (broken wire) in the secondary circuit of the VT. A short circuit exists in the three-phase current system being monitored if one of the following conditions is satisfied:

- Distance protection element started
- Major current variations occur in at least one phase current and in the positive-sequence current system

Distance protection devices use different methods to detect single- or two-phase faults or three-phase faults in the secondary circuit of the VT. The negative- and zero-sequence components are used to detect a fuse failure.

A single- or two-phase fault is present in the secondary circuit of the VT if the following conditions are satisfied simultaneously:

- The base point enable of distance protection has not operated in any of the three phases or has operated in all three phases
- A current rise $\Delta I/\Delta t > 10$ percent does not occur in any one phase
- The negative-sequence current has not exceeded the set threshold
- The negative-sequence voltage has exceeded the set threshold

A three-phase fault is present in the secondary circuit of the VT if the following conditions are satisfied simultaneously:

- The zero-sequence starting of distance protection has operated in at least one phase
- The positive-sequence voltage has fallen below the set threshold V_{pos}
- The positive-sequence current has only varied less than –10 percent or +5 percent within 50 milliseconds after the positive-sequence voltage has fallen below the set threshold $V_{pos}<$

If the above conditions are satisfied, a memory is set. It is reset when the positive-sequence voltage exceeds the fixed threshold (e.g., about 0.5 V_{nom}) and the negative-sequence voltage falls below the set threshold V_{neg}<.

If the buffer has been initiated and the base point enable of distance protection has operated in at least one phase, or if the set threshold of the negative-sequence voltage has been exceeded, then the distance protection device decides that the secondary circuit of the VT is disturbed. In this case, distance protection is blocked, and the device switches to backup overcurrent time.

4.6.12 Frequency Tracking

A frequency tracking algorithm adjusts the sampling frequency of a microprocessor-based relay to the actual power system frequency in order to keep the number of samples-per-power-cycle constant and, by doing so, ensure accurate digital estimation of current and voltage phasors. Modern distance protection devices have settings to select the nominal frequency, 50 or 60 hertz, of the power systems.

In practice, the frequency of the power system is constantly varying to some degree around the nominal system frequency depending on several network conditions (e.g., balance of load and generation) or circuit breaker switching. Power systems, which have "weak" frequency stability, can have wide range shifts of the network frequency. The accuracy of the calculated fault reactance depends on the difference between the actual network frequency and the nominal network frequency. Frequency tracking is discussed in more detail in Section 2.2.6 of this report.

4.6.12.1 Varying Line Reactance

The actual reactance X of the protected line or transformer is floating according to the floating network frequency.

$$X = \omega L = (\omega_{nom} + \omega_{\Delta})L = \omega_{nom} L + \omega_{\Delta} L = X_{nom} + X_{\Delta} \tag{4.4}$$

$$X = X_{nom}\left(1 + \frac{\omega_{\Delta}}{\omega_{nom}}\right) = X_{nom}\left(1 + \frac{f_{\Delta}}{f_{nom}}\right) \tag{4.5}$$

If the nominal frequency of the power system is f_{nom} = 50 hertz, a deviation of the actual network frequency of f_{Δ} = 5 Hz causes a deviation of 10 percent of the actual line reactance compared to the line reactance in case of the nominal network frequency. The distance protection device measures the impedances continuously and compares the calculated impedances with the tripping characteristic, but the tripping characteristic is usually calculated for the nominal network frequency only.

The continuous measurement of the network frequency can be used to adapt the reactive reach means to adapt the settings of the device to the actual measured network frequency to avoid wrong trip commands or wrong blocking commands caused by the floating network frequency.

4.6.12.2 Adaptive DFT Window

DFT algorithms calculate the phasors of voltages and currents using a fixed number of samples-per-cycle based on a fixed fundamental frequency. The number of samples will be determined based on the nominal network frequency and the used sampling rate.

A changing network frequency will cause a changing number of samples-per-cycle if the protection device uses a fixed sampling rate.

f_{nom} = 50 Hz, fs = 1000 Hz → 20 samples-per-cycle

f_{act} = 55 Hz, fs = 1000 Hz → 18 samples-per-cycle

Modern numerical distance relays have frequency-tracking algorithms that continuously determine the actual power system frequency and adapt their sampling interval to take the same number of samples-per-cycle irrespective of the system frequency. Therefore, deviations of the calculated phasors are minimized and the numerical distance relays can accurately calculate the fault impedance, even during network frequency deviations from the nominal frequency.

4.6.13 Adaptive Frequency Estimation

Traditionally, relays that calculate frequency must have circuitry that detects zero-crossings of the voltage signals to determine the signal period. The inverse of the signal period is the frequency. Normally, this circuitry monitors a single-phase voltage; the relay cannot measure frequency if the monitored phase is de-energized during the pole-open condition. Some numerical relays use zero-crossing detection or rate-of-change of angle algorithms to calculate frequency. Distance relay elements can misoperate during frequency excursions and single-pole-open conditions if the relay does not track the system frequency correctly. To prevent relay misoperation, the distance element needs a reliable frequency-estimation algorithm for proper frequency tracking during breaker pole-open conditions. Parallel line mutual coupling or line resonance because of shunt reactor compensation can cause voltage distortion during pole-open conditions. These distortions introduce frequency estimation errors.

Figure 4.23 shows an adaptive logic used by a modern distance relay for frequency estimation to increase distance element reliability. The figure also shows alternate methods for determining the power system frequency (FREQ) for normal system operating, pole-open, and unhealthy voltage conditions. The relay uses FREQ to obtain the relay tracking frequency and to adapt the line protection to power system changes.

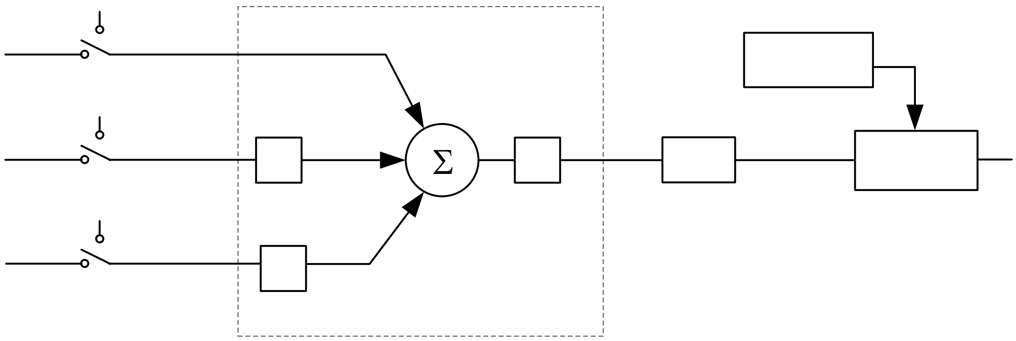

Figure 4.23 Adaptive frequency estimation logic in a distance relay

The frequency estimation logic removes the voltage signal from the open phase to prevent using corrupted signals during pole-open or loss-of-potential (LOP) conditions. The composite signal V_α allows the relay to combine information from three phases without additional signal manipulation with the "α" operator, as in the case of positive-sequence voltage (V_1). This composite signal does not require additional filtering for implementation and has improved transient response. The distance relay uses V_α to track the system frequency during pole-open conditions. The constant K modifies the gain of V_α to provide constant signal amplitude to the frequency estimator for different line operating conditions. The digital band-pass filter (DBPF) extracts the fundamental component signal (60 or 50 hertz) from V_α to obtain the fundamental quantity V_{α_FUND}. The relay uses V_{α_FUND} to calculate FREQ. The frequency estimation algorithm uses the zero-crossing detection method. To prevent erroneous frequency estimation during power system transients (faults), the relay freezes the output of the frequency estimator if the relay detects a transient or a tripping condition. The relay uses the output of the logic FREQ to determine the tracking frequency.

4.6.14 CT Saturation Stabilization

Distance relay accuracy and performance are directly related to the steady state and transient performance of the instrument transformers. CT saturation can cause underreaching in distance relays due to a reduction in magnitude and phase advance of the saturated phase current phasors.

A correction of the saturated phase currents can be performed if all parameters of the CT are exactly known, in particular, the characteristic of the core material. The main problem in practice is that the parameters of the CTs are not exactly known. In addition, the variation of the CT parameters during the life cycle of the CT is also not known in practice. Therefore, because of these difficulties, correction of CT saturated currents based on the physical behavior of the CT using a mathematical model has not been implemented in distance protection devices until now.

4.6.14.1 Detection of CT Saturation and Blocking of Trip Commands

Some distance protection devices employ algorithms, which are designed to detect CT saturation (e.g., based on frequency analysis of the measured phase currents). Compensation of the saturation effects are not part of those algorithms. The distance protection device calculates higher-order odd harmonic phasors (e.g., third, fifth, and seventh) and compares them with predefined thresholds. Other algorithms (e.g., based on the calculation and analysis of the magnetic flux) are also used in practice. Trip commands are blocked as long as the CT saturation has been detected. The definition of these blocking thresholds depends on the filtering algorithm that is used to calculate the phasors of the fundamental frequency.

4.6.14.2 Improvement of Phasor Calculation in Case of CT Saturation

The stability of distance protection devices during CT saturation depends on the characteristics of the relay digital filter, which is used to calculate the phase current phasors. The main goal is to design optimized narrow band-pass filters, which extract only the fundamental frequency component out of the measured phase currents. Such adapted filtering techniques can sometimes cause problems in the case of short circuits currents without saturation. Therefore, it is prudent to switch between two algorithms, one for nonsaturated and one for saturated CT currents, depending on the detection of CT saturation.

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5. DISTANCE RELAY TESTING

5.1 INTRODUCTION

Modern numerical protection relays offer a number of improvements over previous generations and technologies of protection equipment. These include:

- Increased protection functionality
- Improved protection performance
- Reduced maintenance requirements
- Improved availability
- Increased versatility

As a result of these improvements and how different relay manufacturers achieve them, modern relays necessitate a different approach to testing. A CIGRE report prepared by Working Group 34.10, "Analysis and Guidelines for Testing Numerical Protection Schemes," published in 2000, provides a good foundation for testing modern protection relays [1]. The document covers an analysis of specific items in numerical protection that influence testing, guidelines for testing numerical protection, and approaches for determining the interval and content of periodic testing. Due to the large variety of protection equipment available from a number of different manufacturers, the document does not provide detailed testing information.

For the purpose of this document that specifically considers distance protection functions for modern applications, the following information aims at providing some high-level issues and special considerations that are relevant and considered important for testing modern distance protection relays. The issues covered refer to the testing of individual relays and not to the testing of complete protection schemes.

5.2 TYPES OF TESTS AND RESPONSIBILITIES

Table 5.1 proposes the common types of tests that are generally performed on numerical protection equipment. In some instances, the tests are at the discretion of the purchaser or appointed consultant.

Table 5.1 Common types of tests generally performed on numerical protection equipment

No.	Type of Test	Commissioned By	When Applied	Notes
1	Equipment type test	Manufacturer	Before commercial product release	Test device for EMC, detailed performance, software/firmware integrity, etc.
2	Electrical environmental tests	Manufacturer and/or purchaser	Either prior to or immediately after purchase	Verify EMC
3	MPS simulator test	Manufacturer and/or purchaser	Either prior to or immediately after purchase	Test device against required specifications
4	Field trial tests	Purchaser in conjunction with manufacturer	Typically prior to purchase	Test equipment ability to withstand site conditions as well as general performance and functionality
5	Functional test[1]	Purchaser	Either prior to or immediately after purchase	Test device functionality against requirements

No.	Type of Test	Commissioned By	When Applied	Notes
6	Upgrade type test	Manufacturer and/or purchaser	Before accepting firmware upgrade version	Could include functional tests and, in some cases, repeat of MPS tests
7	Commissioning tests	Purchaser	Commissioning of equipment	Can be separated into steady-state, dynamic, transient, scheme, and functional tests
8	Maintenance tests	Purchaser	At predetermined maintenance intervals	Sometimes alternated between full commissioning tests and spot checks

[1] Repeat functional testing may be required if the protection scheme functionality changes.

5.3 RELAY CONFIGURATION

Because modern numerical distance protection relays generally provide users with a considerable level of application versatility, the responsibility of the user in terms of implementing a complete protection scheme is shifted from implementation using a number of hardware components interwired in a scheme panel to implementation of the majority of the scheme logic inside a single multifunction relay device by means of configuration. This impacts the approach to testing the complete protection functionality. Verification that this implemented functionality performs as required is of utmost importance. A good understanding of the relay configuration in terms of how it operates and functions is important for devising tests which will check as many aspects as possible of the configuration. This could include, for example, the impact of logic gate sequencing on the overall timing in the logic circuitry.

The manner in which a utility handles this relay configuration also affects the required testing. In some instances, a utility will adopt a standard configuration as supplied by the relay manufacturer. In this case, the utility will consider the configuration to have been fully tested and verified by the manufacturer. Other utilities will purchase relays on an ad hoc basis with the possibility that each application require a different configuration. The configuration will then have to be tested and verified separately for each application. A third option is for a utility to purchase a particular relay type and set up a customized standard configuration that is applied to each subsequent relay of that particular type purchased by the utility. In this instance, the customized standard configuration is tested and verified once up front, and then the particular relay is certified for further purchase and application.

5.3.1 Interaction Between Functions

With multifunction relays, it is also important to test the interaction between the various functions to ensure that the required level of functional independence is maintained. In general, the protection philosophies previously adopted by utilities, which required each so-called backup protection function to be supplied in a separate hardware device, have been reviewed and revised such that the integration of such functions within a single hardware device is now acceptable. The autonomy of functions, however, still remains an important issue. With the exception of common-mode failures (e.g., input transformers, etc.), the functions should not be interdependent for their respective operation. This factor should be thoroughly tested as part of the equipment type tests.

Any impact on the operation speed of particular protection functions caused by the number of functions enabled should also be tested and measured. Depending on the relay operating system architecture, some devices operate more slowly when more functions are enabled. While this may be acceptable for low-voltage level applications, this is certainly not desirable on extra high-voltage level applications.

5.3.2 Adaptive Functionality

Another aspect to be considered when testing relays is the time the protection functionality is unavailable when switching between settings groups. This is particularly important in adaptive protection applications when it is necessary to change the required adapted parameters dependent on system or surrounding protection conditions. The unavailability of the protection during a change in settings groups should be assessed in terms of the risk should the protection be called upon to operate during this changeover period. Some of these issues can be managed in duplicated protection arrangements by not permitting the settings group change to occur simultaneously in both devices.

5.3.3 Communications Interfaces

Modern numerical protection relays have extensive communications capabilities. This adds to the testing requirements in that the relay communications aspects also need to be tested and verified. This applies not only to individual relays but also to relays working together as a unit protection system.

5.3.4 New Technologies

New technologies, such as digital instrument transformers, the substation process bus, and non-linear FACTS devices, are going to change the way in which modern distance relays are designed and built. Hence, the tests required to check and verify the integrity of the protection equipment will also need to evolve and adapt to accommodate the technological advances. Therefore, a regular review of tests and testing methods is strongly recommended.

5.3.5 Special Testing Considerations

Due to the inherent complexity of measurement techniques built into modern numerical distance relays, testing of the functionality is no longer as simple as it was in previous technology devices. Because of this, special testing considerations need to be taken when testing various aspects of the relay's functionality. The following are some examples of such issues [2]:

5.3.5.1 Directional Supervision of Quadrilateral Characteristics

When testing relays with quadrilateral characteristics that have additional directional supervision functions, the following factors must be taken into consideration:

- The zero-sequence supervision is defaulted to permission if the zero-sequence voltage is low. Consequently, the element would operate even if the zero-sequence voltage is reversed as long as its magnitude is low.
- The zero-sequence directional supervision is dynamically removed if a single-pole open condition is declared during single-pole tripping.
- The zero-sequence supervision circuit has built-in current-reversal logic.

In order to overcome some of the problems, the following should be considered:

- Apply sufficient current so that the operating voltage is safely below nominal and the zero-sequence voltage is not reversed. One way of increasing the effective current while keeping the individual currents below the continuous rating of the relay is to apply three-phase zero-sequence injection. This should be approached with caution because the relay may be expecting the negative- and/or positive-sequence currents and may not respond correctly.
- Increase voltages in healthy phases in order to ensure that the zero-sequence voltage is not reversed when increasing the faulty phase voltage.
- Remove the zero-sequence directional supervision by forcing open pole conditions.

5.3.5.2 Memory and Cross-Phase Polarization

Distance functions need robust polarization in order to ensure directional discrimination between close-in forward and close-in reverse faults. Typically, memory and/or cross-phase polarization is used to solve the problem. However, memory polarization, if kept in effect for too long, may cause a relay to misoperate. A classical example is a power swing when the signals rotate slowly due to the swing while the memorized polarizing quantity remains static. The distance memory circuit must be clearly understood before testing the relay for memory action.

5.3.5.3 Reactance Characteristic

The reactance line constitutes the reach-discriminating boundary of the quadrilateral characteristic. Also, it may be used as an extra supervising line for the mho distance function. The latter is beneficial when using an adaptive reactance characteristic.

It is a well-known phenomenon that a significant fault resistance combined with a heavy pre-fault load may not appear as a pure resistance but may be tilted clockwise (making distance functions overreach) or counterclockwise (making distance functions underreach). Using the reactance comparator polarized from the zero- and/or negative-sequence current, not from the compensated current, may considerably reduce this undesirable effect.

These issues must be properly understood and the necessary changes made to the testing methodology to compensate for the possible effects.

5.3.5.4 Multicomparator Approaches

Distance functions use several conditions in order to establish their pickup/dropout state. Therefore, when testing distance functions that use multicomparator approaches, attention must be paid to all the comparators when testing the function.

5.3.5.5 Ground Directional Overcurrent Functions

Ground directional overcurrent functions are typically used in conjunction with pilot-aided schemes. The negative-sequence or neutral directional functions are fast and sensitive. They do not respond to load currents and enhance resistive coverage of unit protection.

For better performance, ground directional functions often are not implemented as straight angle comparators but use more sophisticated techniques. Concepts of a positive-sequence restraint and an offset impedance are the cause of most issues associated with testing.

Ground directional overcurrent functions, when used in conjunction with pilot-aided schemes, are meant to increase resistive coverage of the protection and, therefore, are typically set very low. If set very sensitive, these elements may respond to spurious zero- or negative-sequence currents due to natural system unbalances or CT saturation.

An offset impedance ensures faster and more reliable operation under low-polarizing voltages (i.e., when the local system is very strong). It also facilitates reliable directional discrimination in series-compensated lines. The offset impedance must not exceed the line impedance and is typically set to a small fraction of the latter.

The concepts of positive-sequence restraint and offset impedance must be clearly understood for the relay being tested such that the necessary testing approach can be adjusted to take these issues into consideration.

5.3.5.6 Off-Nominal Frequencies

A frequency tracking algorithm, or alternative frequency compensation, adjusts the sampling frequency of a microprocessor-based relay to the actual power system frequency in order to keep the number of samples-per-power-cycle constant and, by doing so, ensure accurate digital estimation of currents and voltages.

Distance relays may use sophisticated frequency tracking algorithms. This is particularly true for single-pole tripping relays where no single voltage is a good choice of a frequency- tracking signal. During single-pole tripping, particular phases may get de-energized and their voltages may get severely distorted by transients related to shunt reactors. Under pure zero-sequence injection, the frequency signal can zero out, thereby preventing the relay from measuring and tracking the frequency.

5.4 TRANSIENT TESTING

Modern testing equipment is capable of waveform playback. Microprocessor-based relays are capable of recording faults and other disturbances. More and more often, actual fault records are played back in order to verify relay design and/or settings.

The available fault records, playback equipment, and relay under test must be used appropriately in order to yield meaningful test results.

For example, typical playback equipment accepts waveforms that are evenly spaced in time (constant sampling frequency). A typical microprocessor-based relay uses frequency tracking to compensate for off-nominal frequencies. As such, the relay would produce a record of variable sampling frequency. When played back, such a record will not represent the event correctly. Prior to the playback, the record should be resampled to a constant sampling rate to suit the playback equipment.

Care must be taken to make sure that the playback equipment does not alter the record in a way that invalidates the test.

Modern distance relays are designed to ensure best possible performance under actual power system conditions and not necessarily to follow any standard operating characteristics. New concepts are being introduced in order to improve response to system faults and other abnormal conditions. Even simple and well-known protection functions may follow more sophisticated design philosophies than indicated by their verbal designations.

Too often, functions of advanced relays are tested for operating characteristics extrapolated from their names or ANSI numbers that disregard their actual design equations.

Advances in protective relaying techniques and relays call for testing procedures that are either closer to actual power system conditions or follow design philosophies of relays under test. Ultimately, advanced relays will have to be tested either using detailed power system models (steady-state or transient) or based on the relay's design equations.

5.5 REFERENCES

[1] CIGRE WG 34.10, "Analysis and Guidelines for Testing Numerical Protection Schemes," 2000.

[2] B. Kasztenny, "Testing Considerations for Modern Distance Relays," 57th Annual Georgia Tech Protective Relaying Conference, 2004.

[3] Zexin Zhou et al, "Analog Simulator Tests Qualify Distance Relay Designs to Today's Stingent Protection Requirements," 32nd Annual Western Protective Relay Conference, October 25–27, 2005.

6. FUTURE TRENDS

6.1 INTRODUCTION

In this section, we make an attempt to look at future trends of modern distance protection devices applied for protection, control, and instrumentation of power system elements. The life of a modern distance protection IED starts when a product is conceived and designed at a manufacturer's plant. Later on, this device is sold to customers, installed, commissioned, placed in operation for a number of years, and, finally, after its useful life, the device is removed from service and disposed of.

6.2 GENERAL TRENDS

6.2.1 Engineering

Engineering costs during the design of a substation protection and automation project make up a significant portion of the total project cost. These costs are due to complex and extensive engineering work that is required to perform acceptance tests, protection and control scheme design, calculations of settings, verification of proper device I/O connections during installation, and commissioning.

Standardizing protection application designs and limiting the number of different devices applied at the different power system voltage levels can tremendously reduce the engineering costs associated with future protection, control, and substation automation projects. Performing acceptance tests at the manufacturer's facility and taking advantage of complete turnkey packages offered by suppliers (e.g., drop-in control houses) can reduce engineering costs a great degree. During the design stage, savings can be achieved by application of modern IEDs. Numerous protection functions are integrated in modern distance protection IEDs so that only one device needs to be connected to one set of CTs and CVTs per line end, instead of multiple protection devices. Furthermore, the cost of producing the design documentation that details the connections to the primary switchgear equipment is reduced because the CT, trip circuit, etc., only have to be provided once. The simple and straightforward protection relay application connection reduces the possibilities for incorrect terminations and has a positive influence on the cabling and testing costs in the substation.

The concept of multifunction principles in a single protection IED provides a large contribution in optimizing and reducing the engineering, wiring, testing, and commissioning time. Examples of these IEDs are the combination of line differential and distance protection schemes or phase comparison and distance protection functions in a single device. Another example is the inclusion of object-oriented protection functions in the bay units of a decentralized bus protection system. Due to continued cost pressure, this type of development will continue in the future. The tendency to integrate more and more functions into one device will increase. This results in a positive influence on the cost for system engineering, cabling, and testing. In addition, IEDs with a reduced number of settings or IED complex functions with zero-settings will become available in order to reduce the engineering work and the necessary studies required to set a complex function. One example is the power-swing blocking and tripping functions integrated in a modern distance relay [1].

Taking advantage of the high level of functional integration available in today's and future modern distance protection IEDs can also reduce engineering costs. Section 3 of this report, "Functional Integration at the Bay Level," discusses some of the advantages and benefits that can be obtained by utilizing the high level of integrated functions offered in modern distance IEDs or any other IED in general.

The basic protection principles used in today's modern distance protection devices have a long history and are based on well-known physical laws, mathematical models, and algorithms. During the course of time, a high level of perfection has been achieved. The advent of digital technology and the use of microprocessors in modern numerical distance relays, with their inherent programmability, essentially unlimited logic, and memory capability, have made the implementation of adaptive concepts more practical and straightforward. Protection, control, and monitoring functions can adjust their performance to match the needs of changing power system conditions and can handle changing system configurations. In the future, further refinements can be expected in this area. The exchange of complex information will become an increasingly necessary feature for modern distance protection IEDs due to the availability of fast and wide bandwidth communications links between substations. The importance, however, of the distance protection device to make a local and possibly high-speed trip decision will remain high because the loss of communication to the remote substation will always be a possibility.

Protective relay sampling synchronization within 1 microsecond has been made possible with the advent of satellite-based time-keeping systems and advances in computer technology. Modern distance protection IEDs are available that include synchronized phasor measurement capabilities. These IEDs can provide synchronized phasor measurements for protection, control, and electric power system analysis for wide area protection and control applications and traditional protection applications. As these relays are applied widely, especially on extra-high voltage systems, the phasor measurement function will proliferate, bringing along all the benefits discussed in Section 3.4.2 of this report.

The use of numerical technology in protection and automation has provided multifunctional devices with serial communications. The introduction of serial communications a couple decades ago resulted in the use of proprietary protocols for the communication and control of protection IEDs. This resulted in the inability of IEDs to communicate together and provided additional burden for users to learn and apply the different protocols. This practice also created additional burden for IED manufacturers because they were pressured by users to offer different types of protocols for their IEDs.

Users requested an open protocol, at least inside the substation, for all protection, control and monitoring functions [2]. An open protocol offers the possibility of third-party equipment to be easily integrated in the system offered by another IED manufacturer. The developments of IEC 61850 are targeted at reducing the costs and improving the efficiency of integrated substation protection and control systems by replacing the hard wiring between the IEDs with high-speed serial communications. The resulting standard IEC 61850 is now finalized and offers the following features:

- Covers all communications needs inside the substation
- Assures interoperability between existing functions inside the substation
- Supports all types of substation automation architectures (e.g., centralized and decentralized)
- Copes with the fast development in future communications technology

Substation automation design is a series of steps from specification up to the commissioning of a specific project. For this process, IEC 61850 provides the substation configuration language (SCL). The SCL provides a comprehensive description of the complete substation automation system, supporting the goal of interoperability. SCL allows description of:

- Substation single-line diagram (SLD)
- Function allocation to the SLD
- Device function allocation
- Connection of the communications system
- Data as being mandatory or optional
- Setting of all configuration parameters as defined in IEC 61850
- Setting of default values as defined in IEC 61850

The goal of SCL is to have a formal description of the substation automation at the engineering level (i.e., files that can be exchanged between proprietary tools of different suppliers).

Besides the large number of communications protocols in use already, a surprisingly wide acceptance of the IEC 61850 standard is apparent. It can be expected that this protocol will play a major role in all areas of substation communication and automation and will be part of all future protection IEDs.

6.2.2 Software and Hardware

The complexity of future devices for protection will continue to grow significantly. Because all protection, control, and instrumentation functions in a modern distance protection IED are based on software algorithms, it will become increasingly difficult to test all possible combinations to 100 percent. Software and algorithm development, real-time transient fault simulation testing in the laboratory, and type testing will, therefore, be highly important for critical protection functions and IEDs. This will have a negative impact on total project costs. Testing to IEC norms may not be sufficient to prove every aspect of a modern distance protection IED and eliminate every possible hardware and software failure. No amount of testing can cover every possible power system fault, disturbance condition, and network configuration. Also, although customers may wish it, no manufacturer can guarantee that zero IED failures will occur in service. As with any device, the failure rate can approach zero, but zero by itself is unattainable.

The physical design of different protection IED devices is already very similar. This tendency will increase in the future, thereby allowing the suppliers of protection IEDs to keep costs to a reasonable level. For the end user, the standardization will simplify supply management for spare parts, and it will considerably save time and expense when training maintenance, commissioning, and operation personnel. Modern protection IEDs are realized using the same hardware components, boards, and identical relay cases with the same I/O capability. Compared to conventional relays, in which the individual protection functions are implemented with separate devices or in analog electronic relays with different modules, the advantage of reduced spare parts is immediately evident.

The supervision methods of today's modern distance IEDs cover about 90 percent of the hardware and software of a protection device. Although technically possible, it cannot be justified commercially to increase this number to almost 100 percent. The degree of supervision of external wiring and externally connected devices will also be increased. However, there will still be some cases where it will not be possible to distinguish between a wiring defect and a real fault condition on the power system.

6.2.3 Communications

By utilizing various communications media, new protection principles can also be applied to long transmission lines. Travel of operating personnel is significantly reduced because the IEDs can be remotely controlled via the integrated communications interfaces of the IEDs (e.g., modem or WAN). The communications data interface allows the remote transfer of operational measured values, event records, and the status of circuit breakers and isolators. This also applies to the condition of the protection data interfaces, which are automatically monitored and indicate their status at all line ends.

The IEC 61850 standard protocol covers all communications-related aspects inside the substation. It is a comprehensive approach to the design of modern protection and substation automation systems using serial communications. There is freedom in the standard for the communications architecture as well as for the allocation of protection and control functions in different physical devices. It is expected that the IEC 61850 standard protocol will play a major role in peer-to-peer communications, substation automation, and will be incorporated in all future protection IEDs.

Modern digital communications techniques and communications channels provide many opportunities to advance the speed, security, dependability, and sensitivity of protection. Direct digital communication integrated in distance-type or other types of numerical relays provides multiple bits in each direction that lead to simpler, more flexible, and economical protection design schemes. Sharing digital information directly from one relay to another adds new possibilities for pilot protection, adaptive relaying, monitoring, and breaker failure, among others. Relay-to-relay communications integrated in modern numerical distance protection IEDs offers many beneficial functions related to speed and security with tremendous economical benefits and opens the door for additional control and monitoring functions that would otherwise require more expensive external communications equipment and hardware.

Modern fiber-optic networks or other types of digital communications links are excellent channels for direct relay-to-relay communications. Fiber-optic cables and networks as communications media have been well accepted and will continue to be applied in the future.

6.2.4 Settings Procedures

Many parameters must be determined and set in a modern distance protection IED due to its high integration functionality. The chance of making errors during the settings procedure will, therefore, increase. It can be expected that more interactive help functions will be integrated in the software used to load the parameter set files and into software used for logic scheme design. Integrated commissioning aids, with graphic and browser support on the PC, allow for fast detection of settings and connection mistakes. Although a very desirable feature, it cannot be expected that protection devices from different manufacturers can be configured with the same software.

Adaptive protection techniques will allow distance protection devices to dynamically adjust settings to accommodate for changing network conditions. For example, the characteristic of a longitudinal line differential protection does not have to be set; the protection sets up its own characteristic.

6.2.5 Wide Area Protection

Wide area protection systems (WAMS) are designed to improve power system reliability, mitigate large disturbances, and/or increase power system transmission capacity [3]. These systems will be based on extremely flexible and adaptive protection devices as well as reliable high-speed communications technologies. There is great potential for improving power system reliability through the use of intelligent WAMS and controls based on existing technologies. The introduction of phasor measurements in protection, control, and automation devices has greatly improved the observability of power system dynamics. Synchronized phasor measurement-based design could lead to new kinds of adaptive wide area protection, emergency control, and optimization systems. Application of system time-synchronized measurements will provide a better assessment of actual power system dynamic response. Synchronized measurements can be used effectively in control and remedial protection schemes to increase the reliability of the power system and to reduce the extent of large disturbances. Current trends indicate that these systems will become more common in the future.

6.2.6 Commissioning and Life Cycle

Maintenance and operation personnel will be trained in only a few protection IEDs because the HMI will be the same for almost all products offered by a particular supplier, and future IEDs will be designed using the same hardware. Therefore, in the near future, operating personnel will only be trained on one hardware and one operating software per supplier. Furthermore, the connection between test equipment and the device under test only has to be done once, and the testing of the various protection functions is then done with an automatic test sequence. Modern test equipment can check the integrated protection functions in a single device without additional effort or equipment. In general, a single commissioning engineer is sufficient for completion of this task. In combination with short delivery times, the project completion time can be significantly shortened.

The product life cycle for today’s protection equipment is getting shorter. This is due to the use of commercially available components and processing software. Such products are only being produced as long as there is a reasonable demand on the market. This means that the manufacturer of protection IEDs must make careful planning and stocking rules in order to guarantee the serviceability of the products for the expected operational lifetime of 15–20 years.

6.3 REFERENCES

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[2] K. P. Brand et al., "How to Use IEC 61850 in Protection and Automation," Electra, No. 222, October 2005.

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A1. OUT-OF-STEP FUNDAMENTALS

A1.1 POWER SYSTEM STABILITY

Power systems under steady-state conditions operate very near their nominal frequency. Under steady-state conditions, there is equilibrium between the input mechanical torque and the output electrical torque of each generator. All synchronous machines connected to the power system operate at the same constant speed. The generator speed governors maintain the machine speed close to its nominal value. If the system is disturbed, this equilibrium is upset, resulting in acceleration or deceleration of the rotors of the synchronous machines according to the laws of motion of a rotating body. If one generator runs faster than another, the angular position of its rotor relative to that of the slower machine will advance. The resulting angular difference transfers part of the load from the slow machine to the faster machine, depending on the power angle relationship. This tends to reduce the speed difference and, hence, the angular separation. Beyond a certain limit, an increase in angular separation is accompanied by a decrease in power transfer. This results in further angular separation that leads to instability caused by sustained torque imbalance.

Typically there is a balance between generated and consumed active power under steady-state power system operating conditions. Changes in load and system configuration take place constantly and cause small disruptions to the power system. The ability of the power system to maintain stability under these small, slow changes of system loading is what we refer to as steady-state stability or small disturbance rotor-angle stability. Small disturbance rotor-angle stability is typically associated with insufficient damping of oscillations. The time frame of interest in small disturbance stability studies is on the order of 10 to 20 seconds.

Power system faults, line switching, generator disconnection, and the loss and application of large blocks of load result in sudden changes of the electrical power, whereas the mechanical power input to generators remains relatively constant. These major system disturbances cause severe oscillations in machine rotor angles and severe swings in power flows. Transient stability, or large disturbance rotor-angle stability, is concerned with the ability of the power system to maintain synchronism when subjected to large transient disturbances, such as power system faults. The time frame of interest in transient stability is on the order of 3 to 5 seconds following a disturbance. Loss of synchronism can occur between one generator and the rest of the system or between groups of generators. Synchronism could be maintained within each group of generators, assuming a timely separation occurs, and at other points in the power system where a good balance of generation and load exists.

A1.2 POWER TRANSFER BETWEEN TWO SOURCES

For a simple lossless transmission line connecting two equivalent generators as shown in Figure A1.1, it is well known that the active power (P) transferred between two generators can be expressed as:

$$P = \frac{E_S \bullet E_R}{X} \bullet \sin\delta \qquad \text{(A1.1)}$$

In this equation:

E_S = sending-end source voltage magnitude

E_R = receiving-end source voltage magnitude

δ = angle difference between the two sources ES and ER

X = total reactance of the transmission line and the two sources given by:

$$X = X_S + X_L + X_R \qquad \text{(A1.2)}$$

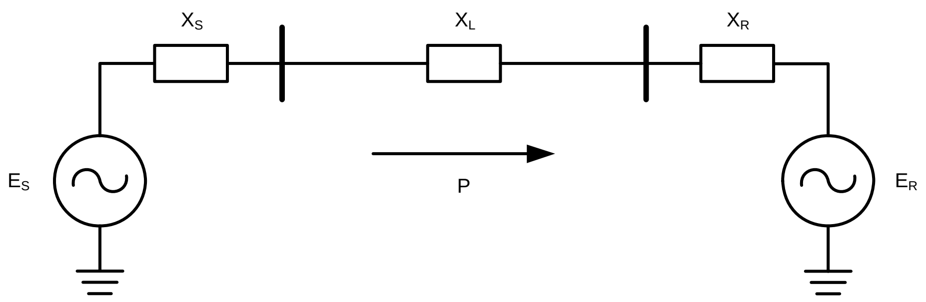

Figure A1.1 A two-source system

A1.3 Power Angle Curve

With fixed E_S, E_R, and X values, the relationship between P and δ can be described in a power angle curve as shown in Figure A1.2. Starting from $\delta = 0$, the power transferred increases as δ increases. The power transferred between two sources reaches the maximum value (P_{MAX}) when δ is 90 degrees. After that point, a further increase in δ will result in a decrease of power transfer. During normal operations of a generation system without losses, the mechanical power (P_0) from a prime mover is converted into the same amount of electrical power and transferred over the transmission line. The angle difference under this balanced normal operation is δ_0.

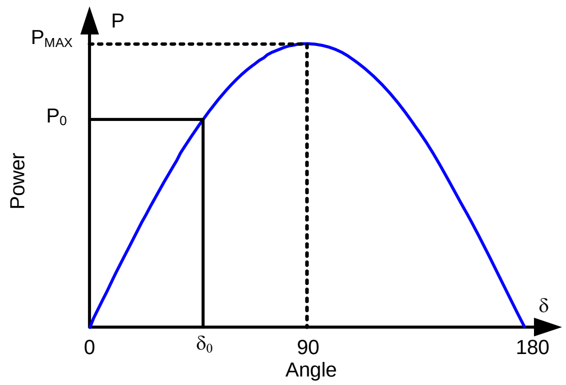

Figure A1.2 The power angle curve

A1.4 Effective Impedance During Faults

When a fault occurs on the transmission line at *m* per-unit distance from the sending-end source E_S, the effective transmission reactance between the two sources will increase according to the type of faults in the system. In general, the fault is modeled as a shunt reactance X_F between the faulted point and the ground, as shown in Figure A1.3.

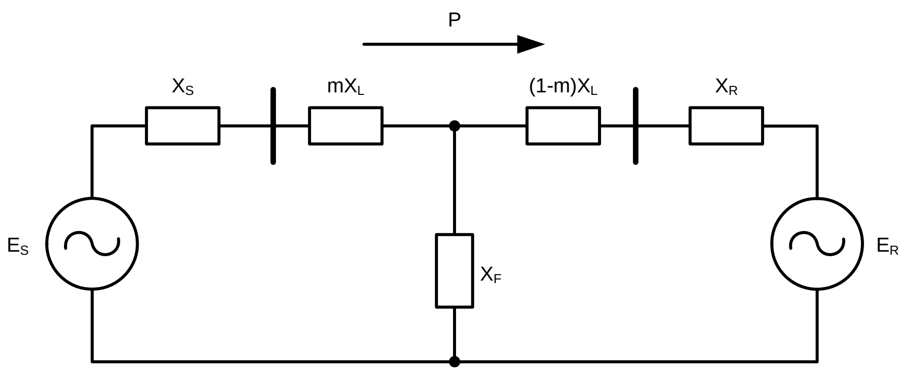

Figure A1.3 Two-source system with a fault at location *m*

For single-line-to-ground (SLG), line-to-line, double-line-to-ground and three-phase faults, the reactance X_F can be found from the interconnection of the sequence networks for each type of fault as shown in Figure A1.4, assuming no fault resistance is involved. In Figure A1.4, the subscripts 0, 1, and 2 are used to represent the zero-, positive-, and negative-sequence impedance of the transmission line and sources.

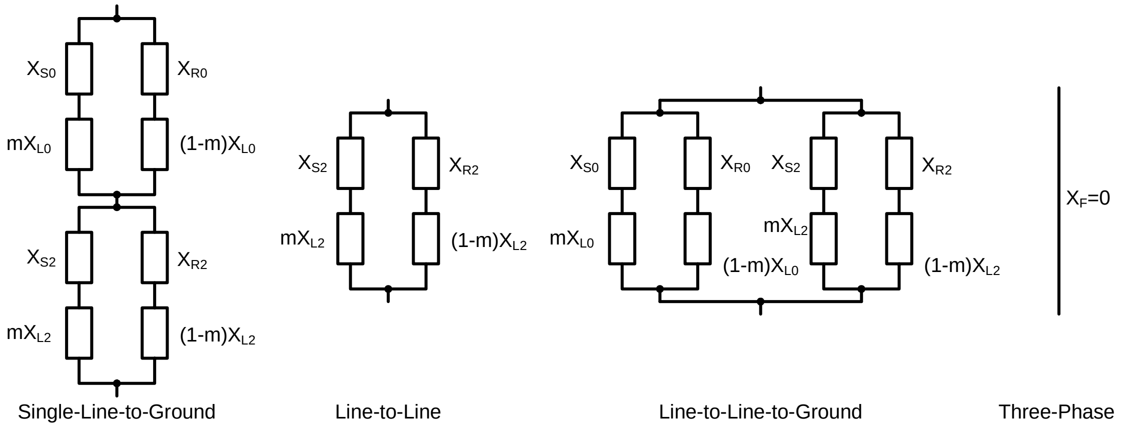

Figure A1.4 X_F for different types of faults

The system in Figure A1.3 can be transformed to single out the effective transmission reactance using the delta-wye equivalent as shown in Figure A1.5. Note that SLG faults in general have the minimum impact on the equivalent transmission reactance among all types of faults, while a three-phase fault blocks all power transmission between the two sources in the simple two-source system considered in Figure A1.5.

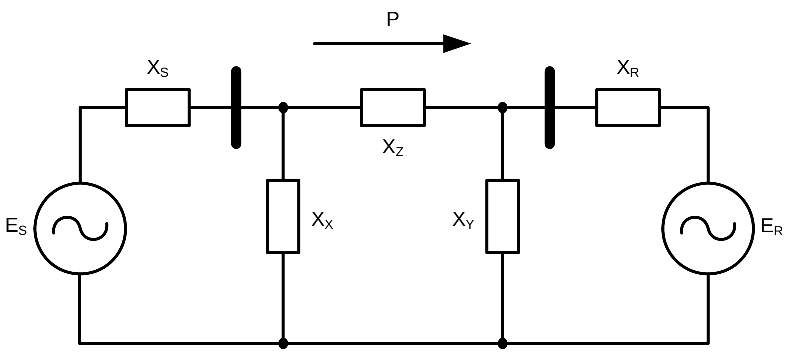

Figure A1.5 Delta-wye equivalent of the faulted system

Assume that the fault is a transient fault, so the transmission line goes back into service after a trip and reclose sequence of a protection relay. The effect of the equivalent transmission reactance on the power angle curve for the prefault, fault, and post-fault states are shown in Figure A1.6 for different types of faults.

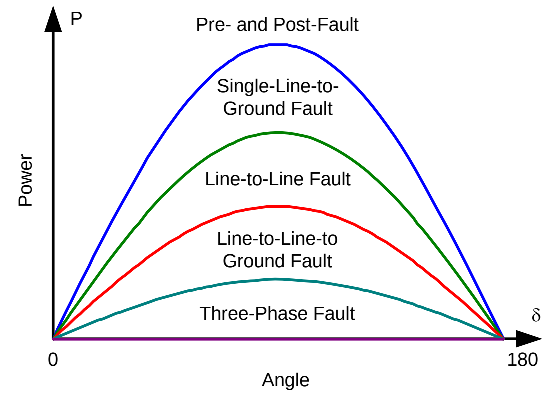

Figure A1.6 Power transmission capability of the normal system and with different types of faults

A1.5 TRANSIENTLY STABLE AND UNSTABLE SYSTEMS

During normal operations of a generator, the output of electric power from the generator produces an electric torque that balances the mechanical torque applied to the generator rotor shaft. The generator rotor, therefore, runs at a constant speed with this balance of electric and mechanical torques. When a fault reduces the amount of power transmission, the electric torque that counters the mechanical torque is also decreased. If the mechanical power is not reduced during the period of the fault, the generator rotor will accelerate with a net surplus of torque input.

Assume that the two-source power system in Figure A1.1 initially operates at a balance point of δ_0, transferring electric power P_0. After a fault, the power output is reduced to P_F. The generator rotor, therefore, starts to accelerate and δ starts to increase. At the time that the fault is cleared when the angle difference reaches δ_C, there is decelerating torque acting on the rotor because the electric power output P_C at the angle δ_C is larger than the mechanical power input P_0. However, because of the inertia of the rotor system, the angle does not start to go back to δ_0 immediately. Rather, the angle continues to increase to δ_F when the energy lost during deceleration in Area 2 is equal to the energy gained during acceleration in Area 1. This is the so-called equal-area criterion.

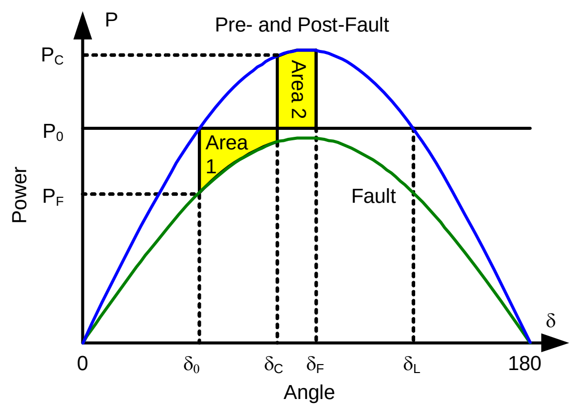

Figure A1.7 A transiently stable system

If δ_F is smaller than δ_L, then the system is transiently stable as shown in Figure A1.7. With sufficient damping, the angle difference of the two sources eventually goes back to the original balance point δ_0. However, if Area 2 is smaller than Area 1 at the time the angle reaches δ_L, then further increase in angle δ will result in an electric power output that is smaller than the mechanical power input. Therefore, the rotor will accelerate again and δ will increase beyond recovery. This is a transiently unstable scenario, as shown in Figure A1.8. When an unstable condition exists in the power system, one equivalent generator rotates at a speed that is different from the other equivalent generator of the system. We refer to such an event as a loss of synchronism or an out-of-step condition of the power system.

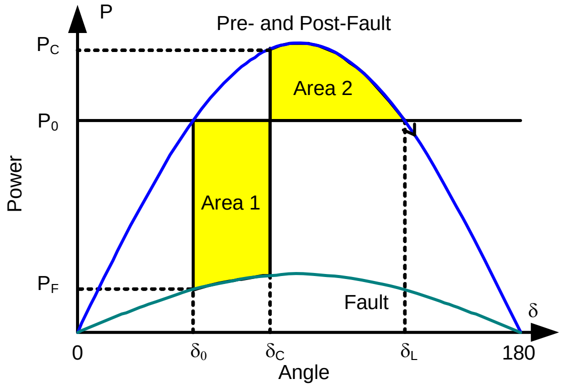

Figure A1.8 A transiently unstable system

A2. LEAST SQUARES FILTERS

The voltage and/or current waveform can be modeled as a combination of the fundamental frequency component, an exponentially decaying dc component, and harmonics of specified orders (this assumption ignores the presence of high frequencies that are, in most applications, eliminated by the anti-aliasing filters). This can be mathematically expressed as:

$$v(t) = V_0 e^{-\frac{t}{\tau}} + \sum_{n=1}^{N} V_n \sin(n\omega_0 t + \theta_n) \tag{A2.1}$$

Where:

V(t)	=	instantaneous value of the voltage at time t
τ	=	time constant of the decaying dc component
N	=	highest order of the harmonic component present in the signal
ω_0	=	fundamental frequency of the system
V_0	=	magnitude of the dc offset at t = 0
V_n	=	peak value of the n^{th} harmonic component
θ_n	=	phase angle of the n^{th} harmonic component

By expanding the decaying dc component using the Taylor series and retaining the first two terms of the series, the following equation is obtained.

$$v(t) = V_0 - \left(\frac{V_0}{\tau}\right) + \sum_{n=1}^{N} V_n \sin(n\omega_0 t + \theta_n) \tag{A2.2}$$

Assume that the voltage is composed of an exponentially decaying dc component, the fundamental frequency component, and components of the second, third, fourth, and fifth harmonics. At time $t = t_1$, Equation A2.2 becomes:

$$\begin{aligned} v(t_1) = V_0 - \left(\frac{V_0}{\tau}\right) t_1 + V_1 \sin(\omega_0 t_1 + \theta_1) + V_2 \sin(2\omega_0 t_1 + \theta_2) \\ + V_3 \sin(3\omega_0 t_1 + \theta_3) + V_4 \sin(4\omega_0 t_1 + \theta_4) + V_5 \sin(5\omega_0 t_1 + \theta_5) \end{aligned} \tag{A2.3}$$

Using trigonometric identities, Equation A2.3 expands to the following form.

$$\begin{aligned} v(t_1) = V_0 - \left(\frac{V_0}{\tau}\right) t_1 + (V_1 \cos\theta_1)\sin(\omega_0 t_1) + (V_1 \sin\theta_1)\cos(\omega_0 t_1) \\ + (V_2 \cos\theta_2)\sin(2\omega_0 t_1) + (V_2 \sin\theta_2)\cos(2\omega_0 t_1) \\ + \dots\dots\dots \\ + (V_5 \cos\theta_5)\sin(5\omega_0 t_1) + (V_5 \sin\theta_5)\cos(5\omega_0 t_1) \end{aligned} \tag{A2.4}$$

This is an algebraic equation that can be expressed as:

$$v(t_1) = a_{11}x_1 + a_{12}x_2 + \dots\dots + a_{1(2N+1)}x_{(2N+1)} + a_{1(2N+2)}x_{(2N+2)} \tag{A2.5}$$

Where:

$x_1 = V_0$ $\quad x_2 = -\dfrac{V_0}{\tau}$ $\quad x_3 = V_1\cos\theta_1$ $\quad x_4 = V_1\sin\theta_1$

$x_5 = V_2\cos\theta_2$ $\quad x_6 = V_2\sin\theta_2$ $\quad \dots\dots\dots$

$$x_{(2N+1)} = V_N \cos\theta_N \qquad x_{(2N+2)} = V_N \sin\theta_N$$

$$a_{11} = 1 \qquad a_{12} = t_1 \qquad a_{13} = \sin(\omega_0 t_1) \qquad a_{14} = \cos(\omega_0 t_1)$$

$$a_{15} = \sin(2\omega_0 t_1) \qquad a_{16} = \cos(2\omega_0 t_1) \qquad \cdots\cdots\cdots\cdots$$

$$a_{1(2N+1)} = \sin(N\omega_0 t_1) \qquad a_{1(2N+2)} = \cos(N\omega_0 t_1)$$

Considering that the signal is sampled at intervals of Δt seconds, Equation A2.6 can be obtained by substituting $t_1 = m\Delta t$ in Equation A2.5.

$$x(m\Delta t) = a_{m1} x_1 + a_{m2} x_2 + \ldots\ldots + a_{m(2N+1)} x_{(2N+1)} + a_{m(2N+2)} x_{(2N+2)} \tag{A2.6}$$

Where:

$\Delta t \quad = \quad \dfrac{1}{f_s}$

fs $\quad = \quad$ sampling frequency

m $\quad = \quad$ sample number

The a-coefficients are now redefined as follows:

$$a_{m1} = 1 \qquad a_{m2} = m\Delta t \qquad a_{m3} = \sin(\omega_o m\Delta t) \qquad a_{m4} = \cos(\omega_o m\Delta t)$$

$$a_{m5} = \sin(2\omega_o m\Delta t) \qquad a_{m6} = \cos(2\omega_o m\Delta t) \qquad \cdots\cdots\cdots\cdots$$

$$a_{m(2N+1)} = \sin(N\omega_o m\Delta t) \qquad a_{m(2N+2)} = \cos(N\omega_o m\Delta t)$$

A total of [(2N + 2) + 1] equations, similar to Equation A2.6, can be formed using (2N + 3) consecutive samples. These can be written as:

$$\underset{(2N+3)x(2N+2)}{[A]} \ \underset{(2N+2)x1}{[X]} = \underset{(2N+3)x1}{[v]} \tag{A2.7}$$

Where:

N $\quad = \quad$ (P – 2) / 2

N $\quad = \quad$ highest order of the harmonic component present in the modeled signal

P $\quad = \quad$ number of samples-per-cycle

The least error squares estimate of [X] is given by the following equation.

$$\begin{aligned}[X] &= \left[[A]^T [A]\right]^{-1} [A]^T [v] \\ &= [A]^\dagger [v]\end{aligned} \tag{A2.8}$$

Where:

$[A]^\dagger \quad = \quad$ left pseudo-inverse of [A]

A3. CABLE ZERO-SEQUENCE CURRENT COMPENSATION FACTOR

Ground distance relays require a zero-sequence current compensation factor, and in some modern relays, there is an option to set several zero-sequence current compensation factors. In cable protection, there are many possible ways to select the zero-sequence current compensation factor, depending on the cable sheath grounding and whether there are other cables or overhead lines in the area. Here we discuss how to calculate the zero-sequence current compensation factor for a homogeneous cable and for an external fault because the zero-sequence current compensation factor is not constant for internal cable faults.

Method

Step 1:

The single-conductor cable data used throughout this report are from [1], with an assumption that the cable sheaths are grounded at both cable ends, and cable conductors are laid in trefoil configuration as shown in Figure A3.1.

Table A3.1 Single-conductor cable data

Cable type	230 kV 1200 mm2 Cu
Cable length	1,000 m
Conductor radius	2.15 E-02 m
Insulation radius	4.52 E-02
Sheath radius	4.98 E-02 m
PVC radius	5.38 E-02 m
Conductor resistivity	1.72 E-08 Ωm at 20°C
Sheath resistivity	2.14 E-07 Ωm at 20°C
Conductor relative permeability	1.0
Sheath relative permeability	1.0
Permittivity of insulation	2.5
Permittivity of PVC	8.0
Earth resistivity	100.0 Ωm

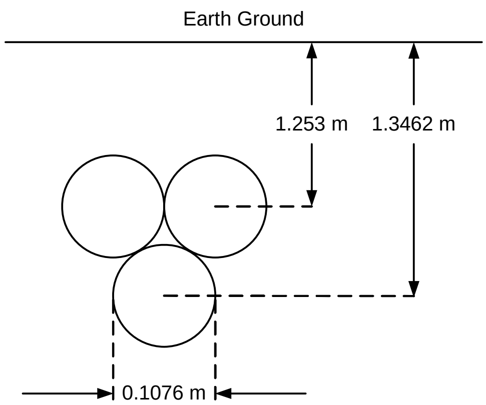

Figure A3.1 Cable trefoil configuration

Compute the self and mutual impedances of all cable conductors including sheath conductors. For a three-phase single-core cable with sheath, we will compute a six by six cable impedance matrix Zcable. For a system frequency of 60 Hz, the cable impedance matrix is:

$$\text{Zcable} = \begin{pmatrix} 0.079+0.8169j & 0.0592+0.6766j & 0.0592+0.6766j & 0.0592+0.7383j & 0.0592+0.6766j & 0.0592+0.6766j \\ 0.0592+0.6766j & 0.079+0.8169j & 0.0592+0.6766j & 0.0592+0.6766j & 0.0592+0.7383j & 0.0592+0.6766j \\ 0.0592+0.6766j & 0.0592+0.6766j & 0.079+0.8169j & 0.0592+0.6766j & 0.0592+0.6766j & 0.0592+0.7383j \\ 0.0592+0.7383j & 0.0592+0.6766j & 0.0592+0.6766j & 0.2151+0.7383j & 0.0592+0.6766j & 0.0592+0.6766j \\ 0.0592+0.6766j & 0.0592+0.7383j & 0.0592+0.6766j & 0.0592+0.6766j & 0.2151+0.7383j & 0.0592+0.6766j \\ 0.0592+0.6766j & 0.0592+0.6766j & 0.0592+0.7383j & 0.0592+0.6766j & 0.0592+0.6766j & 0.2151+0.7383j \end{pmatrix}$$

Step 2:

Because the cable sheaths are grounded at both ends of the cable, we can eliminate them from the above matrix to obtain a three by three matrix, Zred.

Define the following core-to-core, core-to-sheath, and sheath-to-sheath cable impedance submatrices:

Zcc = submatrix (Zcable, 1, 3, 1, 3)

$$\text{Zcc} = \begin{pmatrix} 0.079+0.8169j & 0.0592+0.6766j & 0.0592+0.6766j \\ 0.0592+0.6766j & 0.079+0.8169j & 0.0592+0.6766j \\ 0.0592+0.6766j & 0.0592+0.6766j & 0.079+0.8169j \end{pmatrix}$$

Zcs = submatrix (Zcable, 1, 3, 4, 6)

$$\text{Zcs} = \begin{pmatrix} 0.0592+0.7383j & 0.0592+0.6766j & 0.0592+0.6766j \\ 0.0592+0.6766j & 0.0592+0.7383j & 0.0592+0.6766j \\ 0.0592+0.6766j & 0.0592+0.6766j & 0.0592+0.7383j \end{pmatrix}$$

Zss = submatrix (Zcable, 4, 6, 1, 3)

$$\text{Zss} = \begin{pmatrix} 0.2151+0.7383j & 0.0592+0.6766j & 0.0592+0.6766j \\ 0.0592+0.6766j & 0.2151+0.7383j & 0.0592+0.6766j \\ 0.0592+0.6766j & 0.0592+0.6766j & 0.2151+0.7383j \end{pmatrix}$$

Calculate a reduced impedance matrix using the following matrix equation:

$$\text{Zred} = \text{Zcc} - \text{Zcs} \bullet \text{Zss}^{-1} \bullet \text{ZcsT} \tag{1}$$

$$\text{Zred} = \begin{pmatrix} 0.0852+0.1179j & 0.0443-0.014j & 0.0443-0.014j \\ 0.0443-0.014j & 0.0852+0.1179j & 0.0443-0.014j \\ 0.0443-0.014j & 0.0443-0.014j & 0.0852+0.1179j \end{pmatrix}$$

Step 3:

Using the symmetrical component transformation matrix A below, calculate the cable sequence impedances:

$$\text{Zseq} = \text{A}^{-1} \bullet \text{Zred} \bullet \text{A} \tag{2}$$

Where:

$$\text{A} = \begin{pmatrix} 1 & 1 & 1 \\ 1 & -0.5-0.866j & -0.5+0.866j \\ 1 & -0.5+0.866j & -0.5-0.866j \end{pmatrix}$$

The cable sequence impedances are:

$$\text{Zseq} = \begin{pmatrix} 0.1738+0.0899j & 0 & 0 \\ 0 & 0.0408+0.1319j & 0 \\ 0 & 0 & 0.0408+0.1319j \end{pmatrix}$$

Where:

Zero-sequence impedance is Z_0 = Zseq(1,1) = 0.1738 + j 0.0899 Ohms

Positive-sequence impedance is Z_1 = Zseq(2,2) = 0.0408 + j 0.1319 Ohms

Step 4:

Calculate the zero-sequence current compensation factor using:

$$k_0 = \frac{Z_0 - Z_1}{3 \bullet Z_1} \quad (3)$$

Therefore, k_0 = –0.002 – j 0.337

For more information on how to calculate the zero-sequence cable impedance for different return paths, see Appendix of [1].

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