BASIC PRINCIPLES OF DISTANCE PROTECTION DEVICES[1]

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.

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.

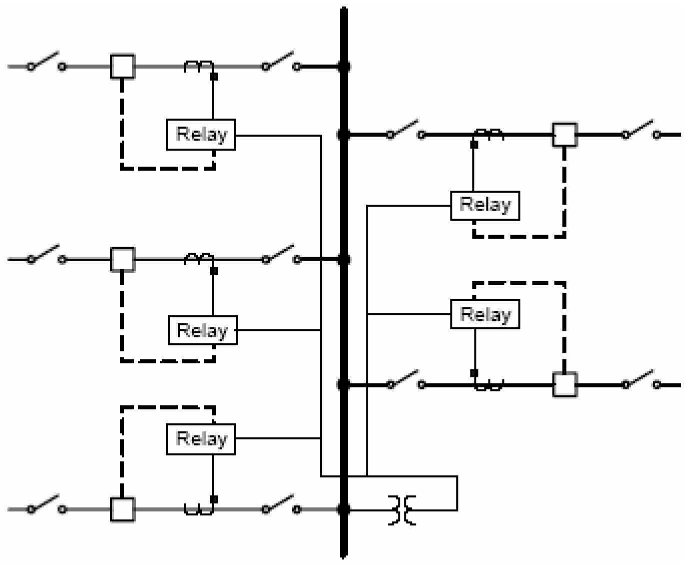

Figure 2.1 A single-bus substation showing the relays and interface with the power system

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.

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

[1] Extract from CIGRE Publication
Modern Distance Protection Functions and Applications
Working Group B5.15
October 2008

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.

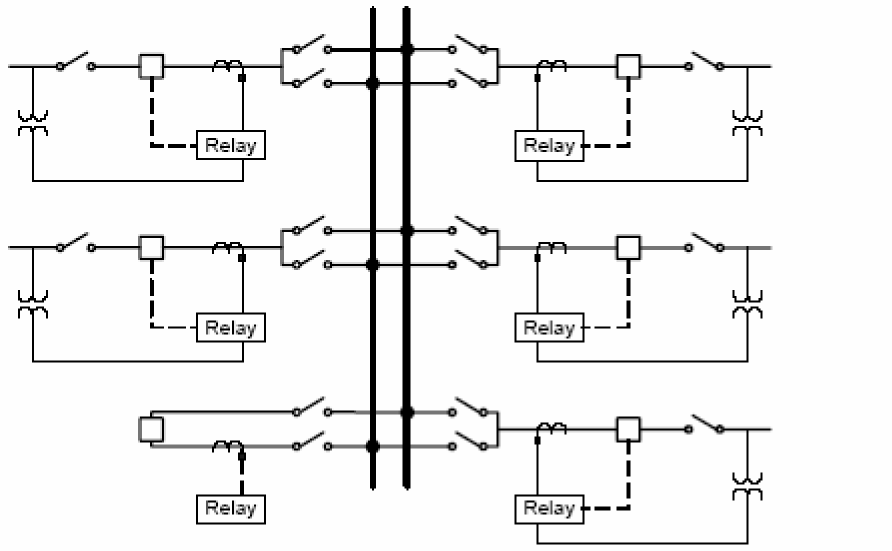

Figure 2.2 A double-bus substation showing the relays and interface with the power system

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.

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.

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.

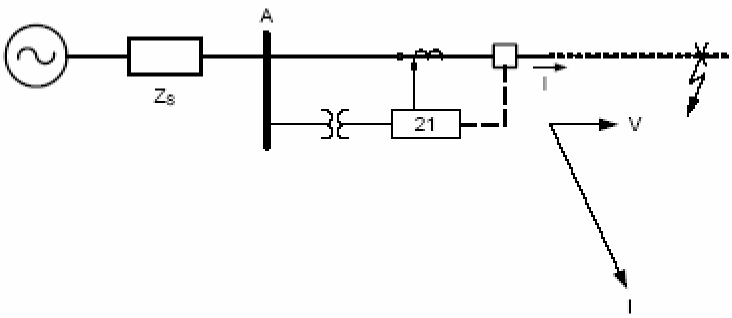

Figure 2.3 Distance relay protecting a transmission line

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:

- Vpb = voltage of a phase of the bus
- Vpr = voltage of a phase applied to the relay
- Nvt = turns ratio of the VTs
- Ipl = current in a phase of the line
- Ipr = phase current applied to the relay
- Nct = 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:

$$\begin{aligned}\frac{V_{pr}}{I_{pr}} &= \frac{N_{ct}}{N_{vt}} \bullet \frac{V_{pb}}{I_{pl}} \\ &= N_f \bullet m \bullet Z_l\end{aligned} \tag{2.3}$$

Where:

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

For a relay, Nf 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, Zl, is also constant if the protected line is homogeneous. Because Nf and Zl 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.

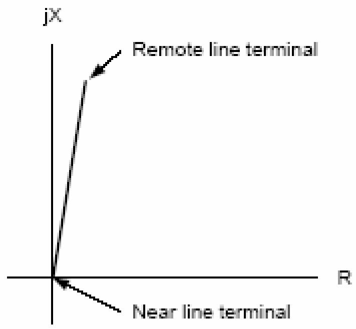

Figure 2.4 Locus of the impedance of a short-circuited line as seen from the protecting relay

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.

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.

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:

$$\frac{Z_0 - Z_1}{3Z_1} \qquad (2.4)$$

Where:

Z0 = zero-sequence impedance of the line

Z1 = positive-sequence impedance of the line

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.

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.

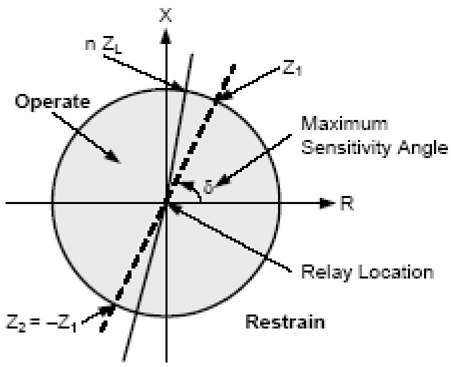

Figure 2.5 Operating characteristic of an impedance relay plotted on the R-X plane

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.

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.

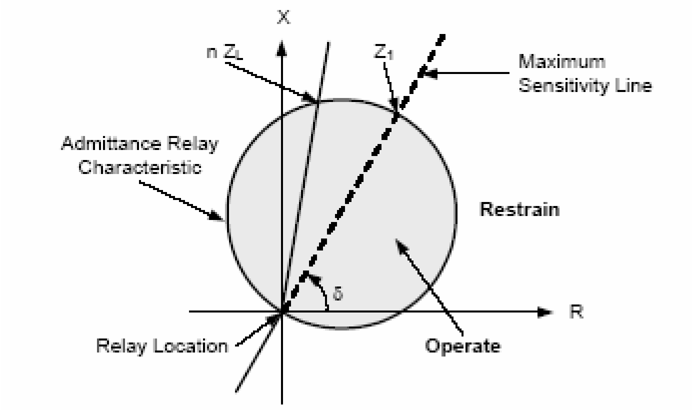

Figure 2.6 Operating characteristic of a mho (admittance) relay

Quadrilateral Relay

The circular and straight-line characteristics of distance relays were originally developed using electromechanical 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.

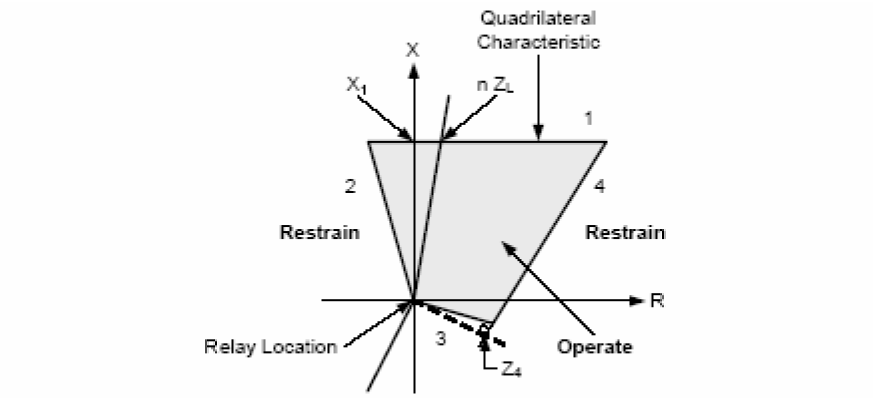

Figure 2.7 Operating characteristic of a generalized quadrilateral characteristic

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.

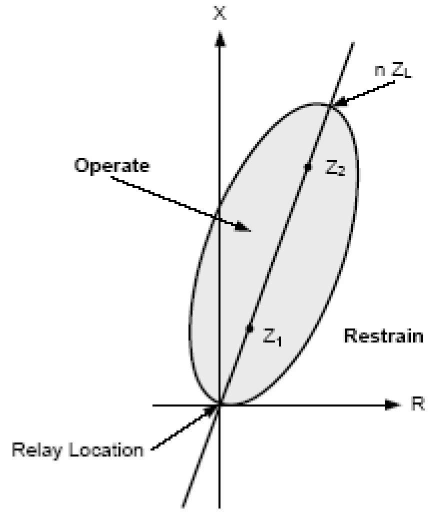

Figure 2.8 Elliptical characteristic

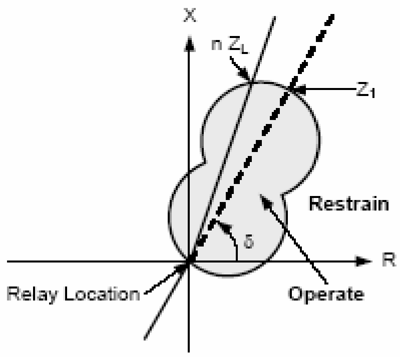

Figure 2.9 Peanut characteristic

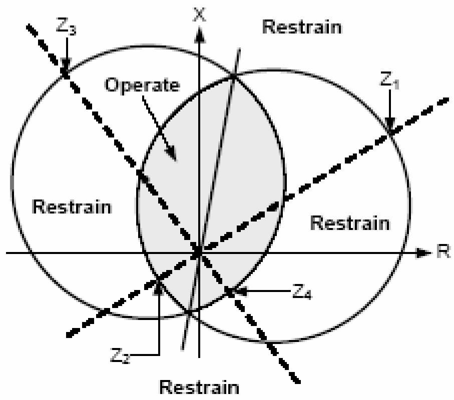

Figure 2.10 Lens characteristic

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.

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.

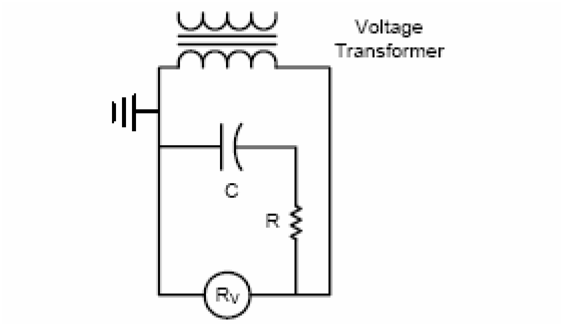

Figure 2.11 R-C circuit to provide memory action

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 (IB – IC)ZR – (VB – VC) and the polarizing voltage is (VB – VC). 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:

$$k_1\left[(I_B - I_C)Z_R - (V_B - V_C)\right](V_B - V_C)\cos\phi - k_2 \geq 0 \qquad (2.5)$$

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:

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

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.

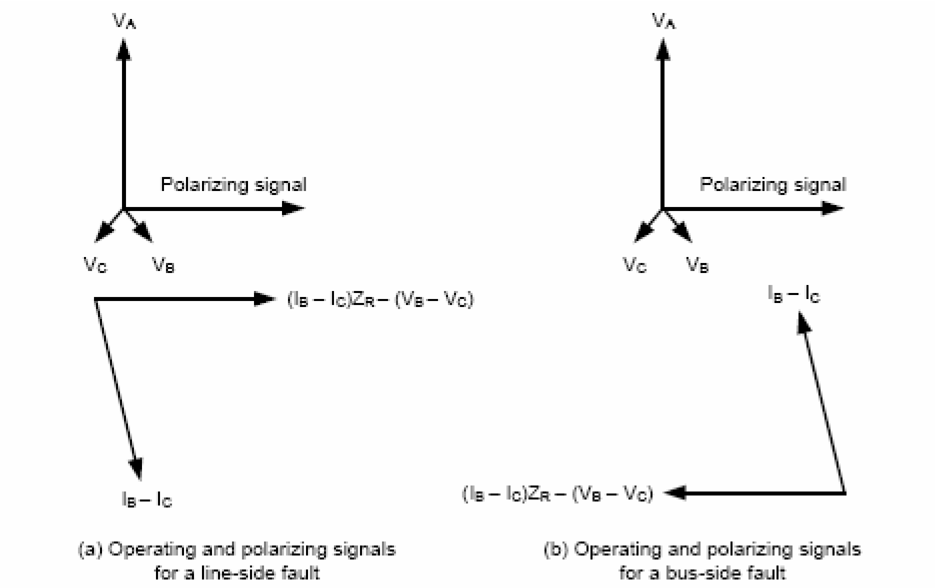

Figure 2.12 Operating and polarizing signals for (a) line-side and (b) bus-side b-c faults

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

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

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:

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

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 k3(VB – VC) +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 k3(–VB + VC) –90° can be implemented by integrating the voltage, which suppresses the noise.

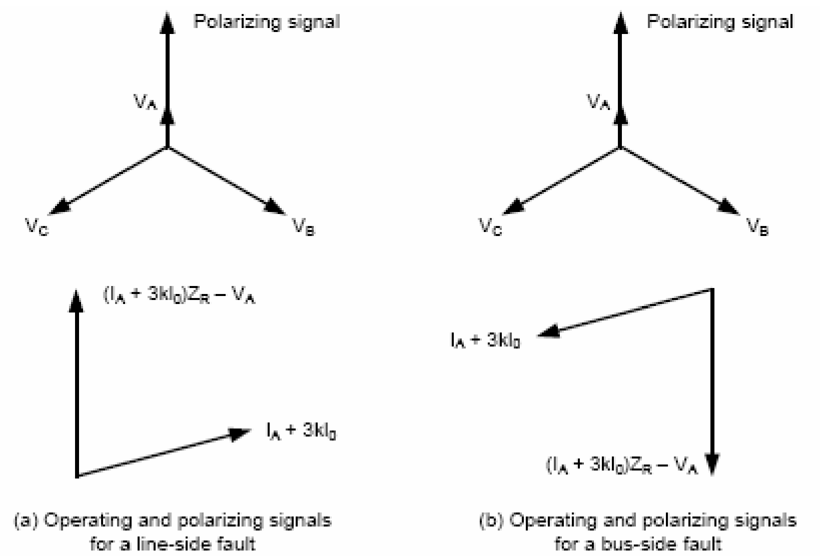

Figure 2.13 Operating and polarizing signals for (a) line-side and (b) bus-side Phase-A-to-ground faults

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 Vp. There are many choices for the polarizing voltage, Vp. 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 • phase-to-phase and three-phase • 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 (IR = 3I0) 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 (IR = 3I0) 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 (IR = 3I0) compensation • Reliable operation for zero-voltage single phase-to-ground faults • Requires directional element supervision • Best single-pole trip security

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.)

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.

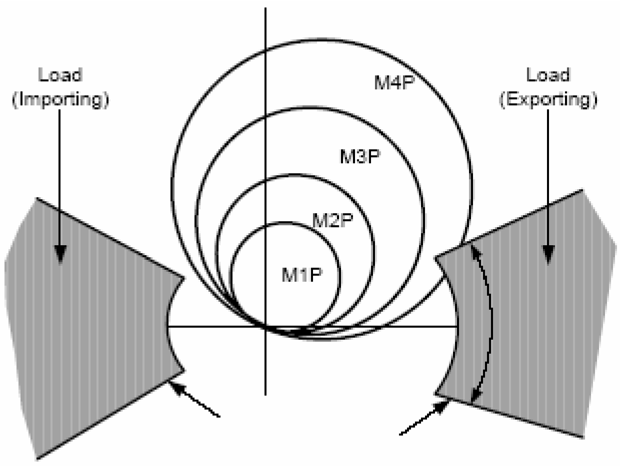

Figure 2.30 Load-encroachment characteristic

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.

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.

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.

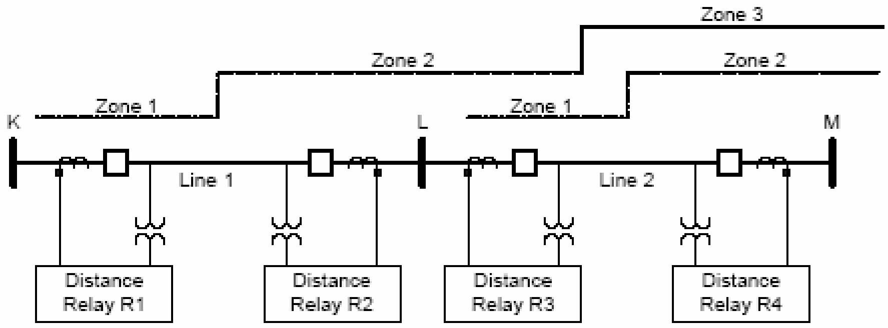

Figure 2.31 Concept of step-distance protection zones

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.

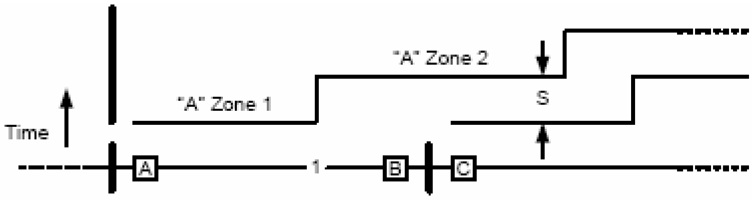

Figure 2.32 Example of time-stepped distance relay settings

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.

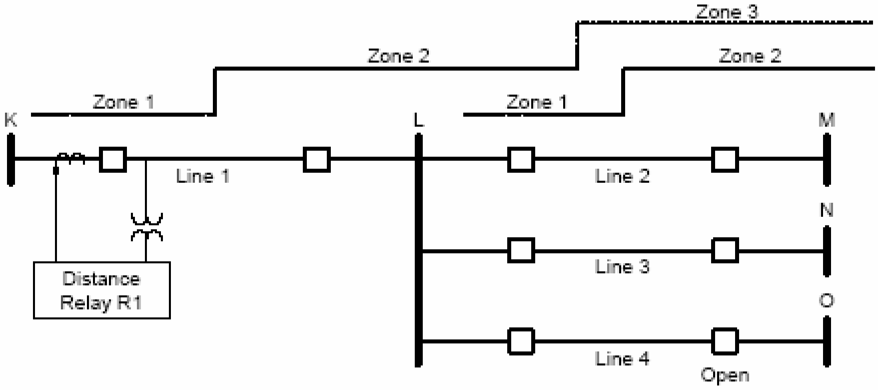

Figure 2.33 Zone 3 at Terminal K set for a Line 4 end fault

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.

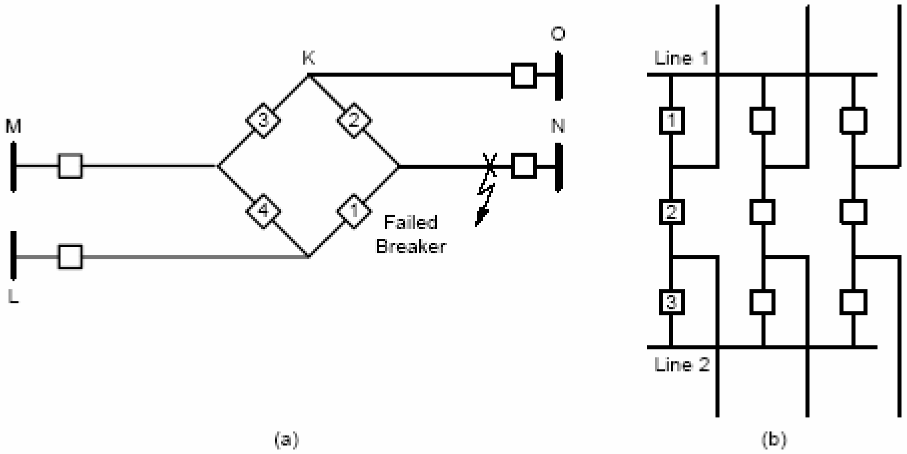

Figure 2.34 Ring-bus (a) and breaker-and-a-half bus (b) configurations

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.

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 ZS/ZL 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.

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.