9

Fundamentals of Power System Protection

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9.1 Fundamentals of Power System Protection

This chapter defines the power system faults, the role of protective relaying, and the basic concepts of relaying. The discussion is a rather general overview. More specific issues are discussed in several excellent textbooks (Horowitz and Phadke, 1992; Blackburn, 1998; Ungrad *et al.*, 1995).

9.1.1 Power System Faults

Power systems are built to allow continuous generation, transmission, and consumption of energy. Most of the power system operation is based on a three-phase system that operates in a balanced mode, often described with a set of symmetrical phasors of currents and voltages being equal in magnitude and having the phase shifts between phases equal to 120° (Blackburn, 1993). The voltages and current behave according to Kirchhoff's laws of the electrical circuits stating that the sum of all currents entering and leaving a network node is equal to zero, and the sum of all voltage drops and gains in a given loop is also equal to zero. In addition, the voltage and currents generate electric power that integrated over a period of time produce energy. For the three-phase systems, a variety of definitions for the delivered, consumed, or transmitted power may be established as follows: **instantaneous**, **average**, **active**, **reactive**, and **complex**. The power system consists of components that are put together with a goal of matching each other regarding the power ratings, dielectric insulation levels, galvanic isolation, and number of other design goals. In the normal operating conditions, currents, voltages, power, and energy are matched to meet the design constraints.

As such, the system is capable of sustaining a variety of environmental and operating impacts that resemble normal operating conditions.

The abnormal operating conditions that the system may experience are rare but do happen. They include lightning striking the transmission lines during severe weather storms, excessive loading and environmental conditions, deterioration or breakdown of the equipment insulation, and intrusions by humans and/or animals. As a result, power systems may experience occasional faults. The **faults** may be defined as events that have contributed to a violation of the design limits for the power system components regarding insulation, galvanic isolation, voltage and current level, power rating, and other such requirements. The faults occur randomly and may be associated with any component of the power system. As a result, the power component experiences an exceptional stress, and unless disconnected or de-energized, the component may be damaged beyond repair. In general, the longer the duration of a fault, the larger is the damage. The fault conditions may affect the overall power system operation since the faulted component needs to be removed, which in turn may contribute to violation of the stability and/or loading limits. Last, but not least, the faults may present a life threat to humans and animals since the damage caused by the faults may reduce safety limits otherwise satisfied for normal operating conditions. Protective relaying was introduced in practice as early as the first power systems were invented to make sure that faults are detected and damaged components are taken out of service quickly.

To facilitate graphic representation of different types of faults, circuit diagrams shown in Figure 9.1 are used. The example is related to the faults on transmission lines and covers eleven types of most common transmission line ground and/or phase faults. To facilitate the presentation, multiple fault types are shown on the same diagram.

The rest of the discussion in this section describes the basic power system components and how different power system components are used to facilitate implementation of the protection concept. The basic requirements for the protection system solution are outlined pointing out the most critical implementation criteria.

9.1.2 Power System Components

The most basic **power system components** are generators, transformers, transmission lines, busses, and loads. They allow for power to be generated (generators), transformed from one voltage level to another (transformers), transmitted from one location to another (transmission lines), distributed among a number of transmission lines and power transformers (busses), and used by consumers (loads). In the course of doing this, the power system components are being switched or connected in a variety of different configurations using circuit breakers and associated switches (Horowitz and Phadke, 1992; Blackburn, 1998; Ungrad *et al.*, 1995). The circuit breakers are capable of interrupting the flow of power at a high energy level and, hence, may also be used to disconnect the system components on an emergency basis, such as in the case when the component experiences a fault (Flurscheim, 1985). Because the power systems are built to cover a large geographical area, the power system components are scattered across the area and interconnected with transmission lines. The grouping of the components associated with generation, switching, transformation, or consumption are called **power plants** (generation and transformation), **substations** (transformation and switching), and **load centers** (switching, transformation, and consumption). In turn, the related monitoring, control, protection, and communication gear is also located at the mentioned facilities.

To facilitate the description of power systems, a graphical representation of the power system components as shown in Figure 9.2 is used. Such representation is called a **one-line diagram**. It is reducing the presentation complexity of the three-phase connections into a single-line connection. This is sufficiently detailed when the normal system operation is considered since the solutions of voltages and currents are symmetrical and one-line representations resemble very closely the single-phase system representation used to obtain the solution. The solution for the faulted systems requires more detailed three-phase representation, but the one-line diagram is still sufficient to discuss the basic relaying concepts. In that case, a detailed representation of the faults shown in Figure 9.1 is not used, but a single symbol representing all fault types is used instead.

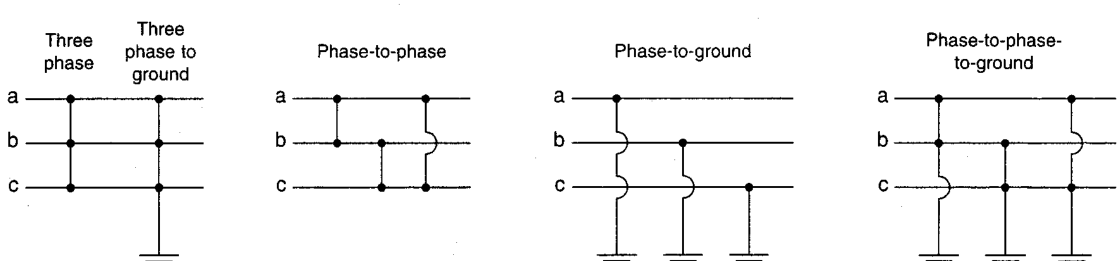


FIGURE 9.1 Eleven Types of Most Common Transmission Line Faults

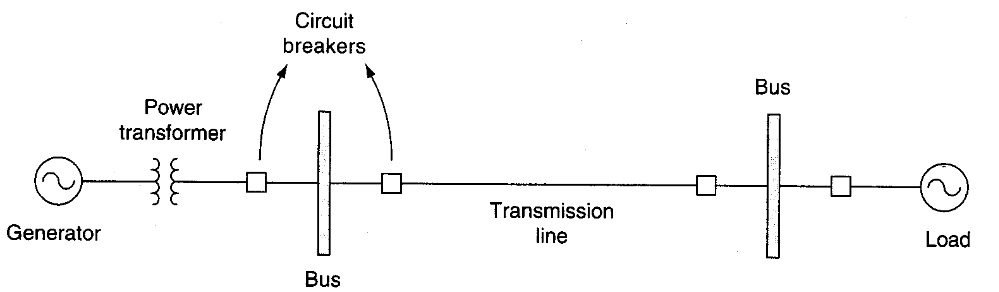


FIGURE 9.2 One-Line Representation of the Power System Components and Connection

The next level of detail is the **representation of the points** where the components merge, shown in Figure 9.2 as busses. A good example of such a point is a substation where a number of lines may come together, and a transformation of the voltage level may also take place. Figure 9.3 shows a one-line representation of a substation.

Substations come in a variety of configurations, and the one selected in Figure 9.3 is called a breaker-and-a-half. This configuration is used in high-voltage substations containing a number of transmission lines and transformers as well as different voltage levels and associated busses. This representation also includes circuit breakers and busses as the principal means of switching and/or connecting the power system components in a substation. The protective relaying role is to disconnect the components located or terminated in the substation when a fault occurs. In the case shown in Figure 9.3, the transmission line is connected to the rest of the system through two breakers marked up as "L," the bus is surrounded with several breakers connected to the bus and marked up as "B," and the power transformer is connected between the two voltage level busses with four breakers marked up as "T." In the common relaying terminology, all the breakers associated with a given relaying function are referred to as a **bay**, hence, the terminology exists of "protection bays" for a transmission line, a bus, and a transformer. It may be observed in the high-voltage substation example, given in Figure 9.3, that each breaker serves at least two protection bays. In Figure 9.3, each breaker box designated as "L" or "T" also acts as the breaker designated with "B." This property will be used later when introducing the concept of overlapping protection zones.

9.1.3 Relay Connections and Zones of Protection

Protective relays are devices that are connected to instrument transformers to receive input signals and to circuit breakers to issue control commands for opening or closing. In some instances, the relays are also connected to the communication channels to exchange information with other relays. The electronic relays always require a power supply, which is commonly provided through a connection to the station dc battery. Often, relays are connected to some auxiliary monitoring and control equipment to allow for coordination with other similar equipment and supervision by the operators. In the high-voltage power systems, relays are located in substations and, most frequently, in a control house. The connections to the instrument transformers and circuit breakers located in the substation switchyard are done through standard wiring originating from the substation switchyard and terminating in the control house.

To achieve effective protection solutions, the entire relaying problem is built around the concept of **relaying zones.** The zone is defined to include the power system component that

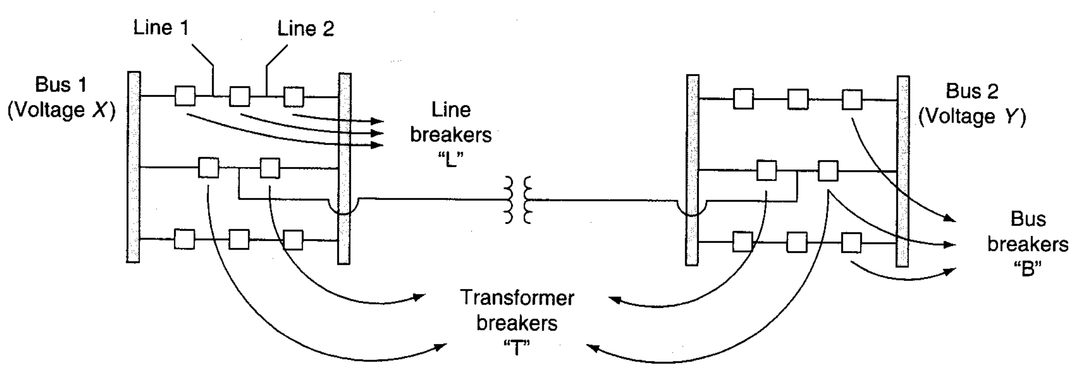


FIGURE 9.3 Breaker-and-a-Half Substation Connection

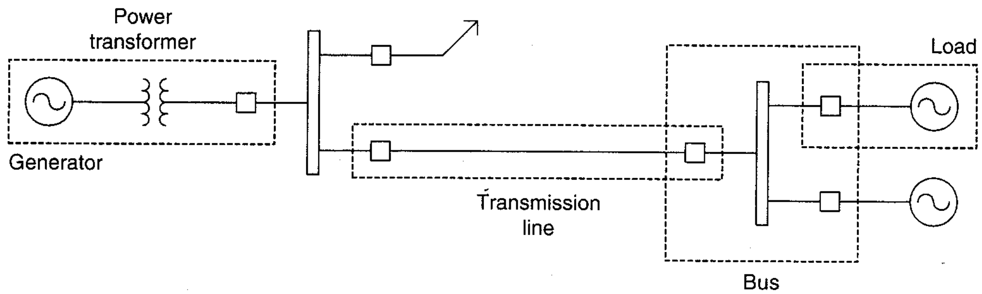


FIGURE 9.4 Allocation of Zones of Protection for Different Power System Components

has to be protected and include the circuit breakers needed to disconnect the component from the rest of the system. A typical allocation of protective relaying zones for the power system shown in Figure 9.2 is outlined in Figure 9.4.

Several points regarding the zone selection and allocation are important. First, the zones are selected to ensure that a multiple usage of the breakers associated with each power system component is achieved. Each circuit breaker may be serving at least two protection functions. This enables separation of the neighboring components in the case either one is faulted. At the same time, the number of breakers used to connect the components is minimized. By overlapping at least two zones of protection around each circuit breaker, it is important to make sure that there is no part of the power system left unprotected. This includes the short connection between circuit breakers or between circuit breakers and busses. Such an overlap is only possible if instrument transformers exist on both sides of the breaker, which is the case with so-called dead-tank breakers that have current transformers located in the breaker bushings.

Another important notion of the zones is to define a **backup coverage.** This is typical for the transmission line protection where multiple zones of protection are used for different sections of the transmission line. Figure 9.5 shows how the zones may be selected in case three zones of protection are used by each relay. The zones of protection are selected by determining the **settings** of the relay reach and the time associated with relay operation.

Each zone of protection is set to cover specific length of the transmission line, which is termed the **relay reach.** Typical selection of the zones in the transmission line protection is to cover 80 to 90% of the line in zone 1, 120–130% in zone 2, and 240–250% in zone 3. This protection is selected by locating a relay at a given line terminal and determining the length corresponding to the relay coverage as a percentage of the line length between the relay terminal and adjacent relay terminals. When doing this, the selected direction is down the transmission line starting from the terminal where the relay is located. The length of the transmission line originating from the location of the relay and ending at the next terminal is assumed to be 100%. The meaning of 120% is that the entire transmission line is covered as well as the additional 20% of the line originating from the adjacent terminal. The **times of operation** associated with zones are different: zone 1 operation is instantaneous, zone 2 is delayed to allow zone 1 relays to operate first, and zone 3 times allow the corresponding relays closer to the fault to operate first in either the zone 1 or zone 2. With this time-step approach selected for different zones of protection, the relays closest to the fault are allowed to operate first. If they fail to operate, the relays located at the remote terminals, that "see" the same fault in zone 2, will still disconnect the failed component. If zone 2 relay operation fails, relays located further away from the faulted line will operate next with the zone 3 settings. The advantage of this approach is a redundant coverage of each line section. They are also covered with multiple relay zones of the relay located on the adjacent lines, ensuring that the faulted component will be eventually removed even if the relay closest to the fault fails. The disadvantage is that each time a backup relay operates, a larger section of the system is removed from service because the relays operating in zone 2 (sometimes) or zone 3 (always) are connected to the circuit breakers that are remote from the ends of the transmission line experiencing the fault. In addition, the time to remove faulted sections from service increases as the

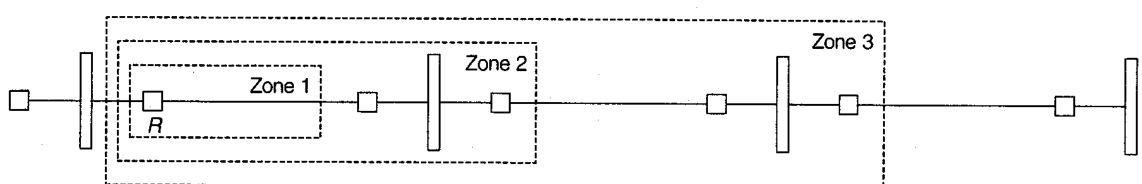


FIGURE 9.5 Selection of the Overlapping Zones for Transmission Line Protection

zone coverage responsible for the relay action increases due to the time delays associated with the zone 2 and zone 3 settings.

9.2 Relaying Systems, Principles, and Criteria of Operation

This section describes elements of a relaying system and defines the basic concept of a relaying scheme. In addition, the basic principles of protective relaying operation are discussed. More detailed discussions of each of the relaying solutions using the mentioned principles aimed at protecting different power system components are outlined in subsequent sections.

9.2.1 Components of a Relaying System

Each **relaying system** consists, as a minimum, of an instrument transformer, relay, and a circuit breaker. A typical connection for protection of high-voltage transmission lines using distance relays is shown in Figure 9.6.

In the case of Figure 9.6, since the relay measures the impedance (which is proportional to distance), both current and voltage instrument transformers are used. The relay is used to protect the transmission line, and it is connected to a circuit breaker at one end of the line. The other end of the line has another relay protecting the same line by operating the breaker at that end. In a case of a fault, both relays need to operate, causing the corresponding breakers to open and resulting in the transmission line being removed from service.

The role of **instrument transformers** is to provide galvanic isolation and transformation of the signal energy levels between the relay connected to the secondary side and the voltages and currents connected to the primary side. The original current and voltage signal levels experienced at the terminals of the power system components are typically much higher than the levels used at the input of a relay. To accommodate the needed transformation, instrument transformers with different ratios are used (IEEE, 1996; Ungrad, 1995). Next, a brief discussion of the options and characteristics of most typical instrument transformer types is given.

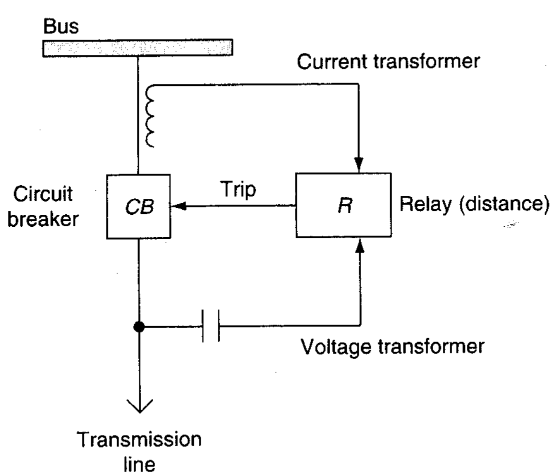


FIGURE 9.6 Protective Relaying System Consisting of Instrument Transformers, a Relay, and a Breaker

Current Transformer

Current transformers (CTs) are used to reduce the current levels from thousands of amperes down to a standard output of either 5 A or 1 A for normal operation. During faults, the current levels at the transformer terminals can go up several orders of magnitude. Most of the current transformers in use today are simple magnetically coupled iron-core transformers. They are input/output devices operating with a hysteresis of the magnetic circuit and, as such, are prone to saturation. The selection of instrument transformers is critical for ensuring a correct protective relaying operation. They need to be sized appropriately to prevent saturation. If there is no saturation, instrument transformers will operate in a linear region, and their basic function may be represented via a simple turns ratio. Even though this is an ideal situation, it can be assumed to be true for computing simple relaying interfacing requirements. If a remanent magnetism is present in an instrument transformer core, then the hysteresis may affect the time needed to saturate next time the transformer gets exposed to excessive fault signals. The current transformers come as free-standing solutions or as a part of the circuit breaker or power transformer design. If they come preinstalled with the power system apparatus, they are located in the bushings of that piece of equipment.

Voltage Transformer

Voltage transformers come in two basic solutions: **potential transformer** (PT) with iron-core construction and **capacitor coupling** voltage transformers (CVTs) that use a capacitor coupling principle to lower the voltage level first and then use the iron-core transformer to get further reduction in voltage. Both transformer types are typically free-standing. PTs are used frequently to measure voltages at substation busses, whereas CVTs may be used for the same measurement purpose on individual transmission lines. Since the voltage levels in the power system range well beyond kilovolt values, the transformers are used to bring the voltages down to an acceptable level used by protective relays. They come in standard solutions regarding the secondary voltage, typically 69.3 V or 120 V, depending if either the line-to-ground or line-to-line quantity is measured respectively. In an ideal case, both types of instrument transformers are assumed to be operating as voltage dividers, and the transformation is proportional to their turns ratio. In practice, both designs may experience specific deviations from the ideal case. In PTs, this may manifest as a nonlinear behavior caused by the effects of the hysteresis. In CVTs, the abnormalities include various ringing effects at the output when a voltage is collapsed at the input due to a close-in fault as well as impacts of the stray capacitances in the inductive transformer, which may affect the frequency response.

Relays

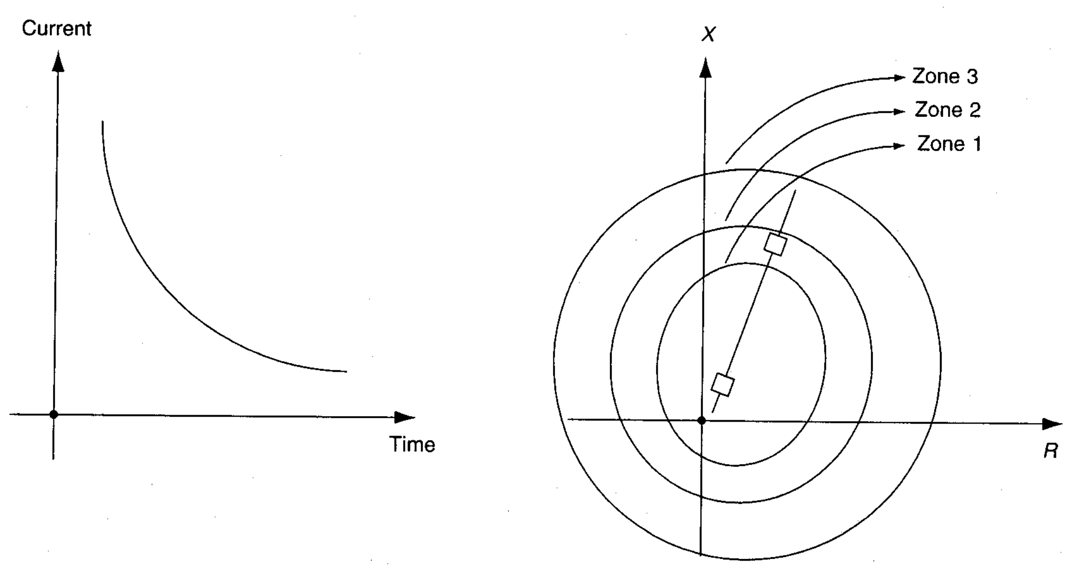
Another component shown in Figure 9.6 is the **relay** itself. Relays are controllers that measure input quantities and compare them to thresholds, commonly called relay settings, which in turn define operating characteristics. The relay characteristics may be quite different depending on the relaying quantity used and the relaying principle employed. A few different **operating characteristics** of various relays are shown in Figure 9.7. The first one is for the relay operating using an overcurrent principle with an inverse time-delay applied for different levels of input current. The second one is used by transmission line relays that operate using an impedance (distance) principle with the time-step zone implementation.

Further discussion of the specific relaying principles will be given later. In general, the relay action is based on a comparison between the measured quantity and the operating characteristic. Once the characteristic thresholds (**settings**) are exceeded, the relay assumes that this is caused by the faults affecting the measuring quantity, and it issues a command to operate associated circuit breaker(s). This action is commonly termed as a **relay tripping**, meaning opening a circuit breaker.

The relays may come in different designs and implementation technologies. The number of different designs at the early days when the relaying was invented was rather small, and the main technology was the electromechanical one. Today's design options are much wider with a number of different relay implementation approaches being possible. This is all due to a great flexibility of the microprocessor-based technology almost exclusively used to build relays today. Since the microprocessor-based relays use very low-level voltage signal at inputs to the signal measurement circuitry, all these relays have **auxiliary transformers** at the front-end to scale down the input signal levels even further from what is available at the secondary of an instrument transformer. To accommodate specific needs and provide different levels of the relay input quantities, some of the relay designs come with multiple connections of the auxiliary transformers called **taps**. Selecting appropriate tap determines a specific turns ratio for the auxiliary transformer that allows more precise selection of the specific level of the relay input signal. Besides the voltage and/or current signals as inputs and trip signals as outputs, the relays have a number of input/output connections aimed at other functions: coordination with other relays, communication with relays and operators, and monitoring. For an electronic relay, a connection to the power supply also exists.

Circuit Breaker

The last component in the basic relaying system is the **circuit breaker**. The breakers allow interruption of the current flow, which is needed if the fault is detected and a tripping command is issued by the relay. Circuit breakers operate based on different principles associated with physical means of interrupting the flow of power (Flurscheim, 1985). As a result, vacuum, air-blast, and oil-field breakers are commonly used depending on the voltage level and required speed of operation. All breakers try to detect the zero crossing of the current and interrupt the flow at that time since the energy level to be



(A) Overcurrent for Inverse-Time Relay

(B) Distance (Impedance) for Three Zone MHO Relay

FIGURE 9.7 Typical Relay-Operating Characteristic interrupted is at a minimum. The breakers often do not succeed in making the interruption during the first attempt and, as a result, several cycles of the fundamental frequency current signal may be needed to completely interrupt the current flow. This affects the **speed of the breaker operation.** The fastest breakers used at the high-voltage levels are one-cycle breakers, whereas a typical breaker used at the lower voltage levels may take 20 to 50 cycles to open. Circuit breakers are initiated by the relays to disconnect the power system component in the case a fault is present on the component. In the case of the transmission line faults, many faults are temporary in nature. To distinguish between permanent and temporary faults on transmission lines, the concept of **breaker autoreclosing** is used. It assumes that once the breaker is tripped (opened) by the relay, it will stay open for a while, and then it will automatically reclose. This action allows the relays to verify if the fault is still present and, if so, to trip the breaker again. In the case the fault has disappeared, the relays will not act, and the transmission line will stay in service. The autoreclosing function may be implemented quite differently depending on the particular needs. The main options are to have a single or multiple reclosing attempts and to operate either a single pole or all three poles of the breaker. Circuit breakers are also quite often equipped with auxiliary relays called **breaker failure** (BF) relays. If the breaker fails to open when called upon, the BF relay will initiate operation of other circuit breakers that will disconnect the faulted element, quite often at the expense of disconnecting some additional healthy components. This may be observed in Figure 9.3: once a transmission line relay operates the two breakers in the transmission line bay and one of the breakers fails to operate, the BF relay will disconnect all the breakers on the bus side where the failed breaker is connected, making sure the faulted line is disconnected from the bus.

9.2.2 Basic Relaying Principles

When considering protection of the most common power system components, namely generators, power transformers, transmission lines, busses, and motors, only a few basic relaying principles are used. They include **overcurrent, distance, directional,** and **differential.** In the case of transmission line relaying, communication channels may also be used to provide exchange of information between relays located at two ends of the line. The following discussion is aimed at explaining the generic properties of the above-mentioned relaying principles. Many other relaying principles are also in use today. The details may be found in a number of excellent references on the subject (Horowitz and Phadke, 1992; Blackburn, 1998; Ungrad *et al.*, 1995; Blackburn, 1993).

Overcurrent protection is based on a very simple premise that in most instances of a fault, the level of fault current dramatically increases from the prefault value. If one establishes a threshold well above the nominal load current, as soon as the current exceeds the threshold, it may be assumed that a fault has occurred and a trip signal may be issued. The relay based on this principle is called an **instantaneous overcurrent relay**, and it is in wide use for protection of radial low-voltage distribution lines, ground protection of high-voltage transmission lines, and protection of machines (motors and generators). The main issue in applying this relaying principle is to understand the behavior of the fault current well, in particular when compared to the variation in the load current caused by significant changes in the connected load. A typical example where it may become difficult to distinguish the fault levels from the normal operating levels is the overcurrent protection of distribution lines with heavy fluctuations of the load. To accommodate the mentioned difficulty, a variety of overcurrent protection applications are developed using the basic principle as described previously combined with a **time delay**. One approach is to provide a fixed time delay, and in some instances, the time delay is proportional to the current level. One possible relationship is an inverse one where the time delay is small for high currents and long for smaller ones. The example shown earlier in Figure 9.7 describes an inverse time characteristic, which may also be a very or extremely inverse type. Further variations of the overcurrent relay are associated with the use of the **directional element**, which is discussed later. The issues of coordinating overcurrent relays and protecting various segments of a distribution line are also discussed later.

Distance relaying belongs to the principle of **ratio comparison**. The ratio is between the voltage and current, which in turn produces **impedance.** The impedance is proportional to the distance in transmission lines, hence the "distance relaying" designation for the principle. This principle is primarily used for protection of high-voltage transmission lines. In this case, the overcurrent principle cannot easily cope with the change in the direction of the flow of power, simultaneous with variations in the level of the current flow, which is common in the transmission but not so common in the radial distribution lines. Computing the impedance in a three-phase system is a bit involved because each type of fault produces a different impedance expression (Lewis, 1947). Because of these differences the settings of a distance relay need to be selected to distinguish between the ground and phase faults. In addition, fault resistance may create problems for distance measurements because the value of the fault resistance may be difficult to predict. It is particularly challenging for distance relays to measure correct fault impedance when a current in-feed from the other end of the line creates an unknown voltage drop on the fault resistance. This may contribute to erroneous computation of the impedance, called apparent impedence, "seen" by the relay located at one end of the line and using the current and voltage measurement just from that end. Once the impedance is computed, it is compared to the settings that define the operating characteristic of a relay. Based on the comparison, a decision is made if a fault has occurred and, if so, in what **zone**. As mentioned earlier, the

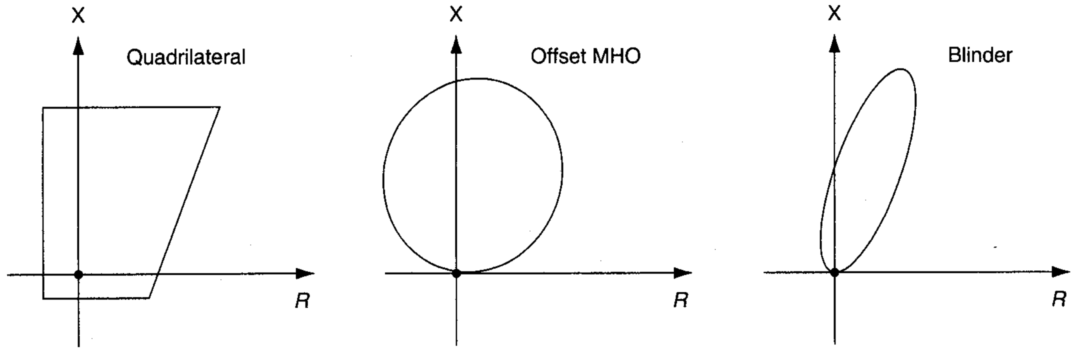


FIGURE 9.8 Operating Characteristics of a Distance Relay

impedance relay may be set to recognize multiple zones of protection. Due to variety of application reasons, the operating characteristics of a distance relay may have different shapes, the quadrilateral and MHO being the most common. The different operating characteristic shapes are shown in Figure 9.8 (Blackburn, 1998). The characteristics dictate relay performance for specific application conditions, such as the changes in the loading levels, different values of fault resistance, effects of power swings, presence of mutual coupling, and reversals of fault direction.

Distance relays may be used to protect a transmission line by taking the input measurements from only one end of the line. Another approach is to connect two distance relays to perform the relaying as a system by exchanging the data between the relays from two ends through a communication link. In this case, it is important to decide what information gets exchanged and how is it used. The logic that describes the approach is called a **relaying scheme.** Most common relaying schemes are based on the signals sent by the relay from one end causing either blocking and unblocking or facilitating and accelerating of the trip from the relay at the other end. In all of the mentioned applications, **directionality** of a distance relay is an important feature. It will be discussed in more detail later on.

As an example of the relaying scheme operation, Figure 9.9 shows relaying zones used for implementation of a blocking scheme. The zones for each relay are **forward overreaching** (FO) and **backward reverse** (BR). The FO setting is selected so that the relay can "see" the faults occurring in a forward direction, looking from the relay position toward the adjacent line terminal and beyond. The BR setting is selected so that the relay can "see" the faults occurring in the backward direction, causing a reversal of the power flow. If the relay *R*1 (at location A) has "seen" the fault (at location *X*1) in zone FO behind the relay *R*2 positioned at the other end (at location B) of the line, the relay is blocked by relay *R*2 from operating. Relay *R*2 has "seen" the fault at location *X*1 in a BR zone and, hence, can "tell" the relay *R*1 not to trip by sending a blocking signal. Should a fault occur in between the two relays (location *X*2), the blocking signal is not sent, and both relays operate instantaneously since both relays "see" the fault in zone FO and neither in zone BR.

A relaying concept widely used for protection of busses, generators, power transformers, and transmission lines is the **current differential.** It assumes that the currents entering and leaving the power system component are measured and compared to each other. If the input and output currents are the same, then it means that the protected component is "healthy," and no relaying action is taken. If the current comparison indicates that there is a deference, which means that a difference is caused by a fault, the relay action is called upon. The difference has to be significant enough to be attributed to a fault since some normal operating conditions and inaccuracies in the instrument transformers may also indicate a difference that is not attributed to a fault. More discussion about the

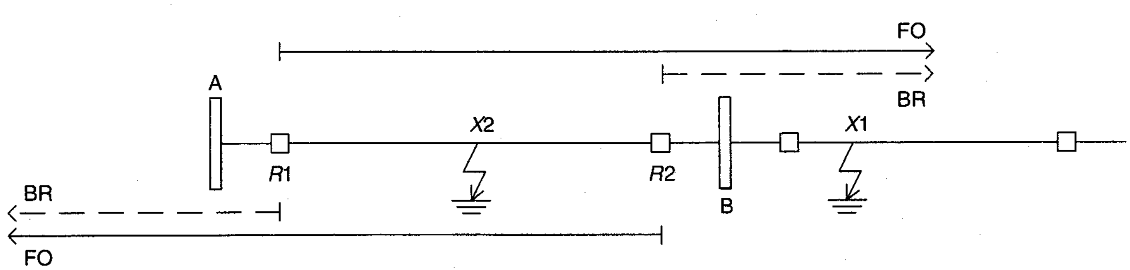


FIGURE 9.9 The Blocking Principle of Relaying with Fault Directionality Discrimination

criteria for establishing the type and level of the difference that are typical for a fault event are presented at a later time when this relaying principle is discussed in more detail. In the case of a differential protection of transmission lines, the measured quantities need to be sent over a communication channel to compute the difference. Since the speed and reliability of communication channels may play a role in the overall performance of the concept, slightly different philosophy is established regarding the type of measurements taken and the comparison criteria for the transmission lines versus other, more local, applications.

Directionality of a relay operation is quite important in many applications. It is established based on the angle of the fault current with the respect to the line voltage. It can be established for current alone or for impedance. In the latter case, the directionality is detected by looking at the angle between the reference voltages and fault current. In the impedance plane, the directionality is detected by the quadrant where the impedance falls. Whether the calculated fault impedance is in a forward (first-quadrant) or reverse (third-quadrant) zone determines the directions of the fault. Typically, the zone associated with the reverse direction is called a **reverse zone** and is numbered in a sequence after the **forward zones** are numbered first. The directionality may also be based on the power calculation, which in turn determines the direction of the power flow to/from a given power system component. Besides being used for implementation of the transmission line relaying schemes, directionality is quite important when applying overcurrent principle and is often used when implementing various approaches to ground protection.

9.2.3 Criteria for Operation

A number of different criteria for operation may be established, but the three most common ones are **speed**, **dependability/security**, and **selectivity** (WD G5, 1997a, b). All the criteria need to be combined in a sound engineering solution to produce the desirable performance, but for the sake of clarity, each of the criteria is now discussed separately.

Speed

The **speed** of operation is the most critical protective relay operating criterion. The relays have to be fast enough to allow clearing of a fault in the minimum time needed to ensure reliable and safe power system operation. The minimum operating time of a relay is achieved when the relay operates without any intentional time delay settings. Such an example is the time of operation of a distance relay in a direct (instantaneous) trip in Zone 1. The operating time may vary from the theoretical minimum possible to the time that a practical solution of a relaying algorithm may take to produce a decision. The operating time is dependent on the algorithm and technology used to implement the relay design. Because the relays respond to the fault transients, the relay operating time may vary slightly for the same relay if subjected to the transients coming from different types of fault. The minimum acceptable operating time is often established to make sure that the relay will operate fast enough to meet other time-critical criteria. For the transmission line protection example, the overall time budget for clearing faults in a system is expressed based on the number of cycles of the fundamental frequency voltage and current signals. This time is computed from the worst-case fault type persisting and potentially causing an instability in the overall power system. To prevent the instability from occurring, the fault needs to be cleared well before this critical time is reached, hence the definition of the minimum **fault clearance** time. The relay operating time is only a portion of this time-budget allocation. The rest is related to the operation of circuit breakers and a possible multiple reclosing action that needs to be taken. The consideration also includes the breaker failure action taken in the case a breaker fails to open and other breakers get involved in clearing the fault. The relay operating time is a pretty critical criterion even though it is allocated a very small portion of the mentioned fault-clearing time-budget criteria. As an example, the expected average operating time of transmission line relays in zone 1 is around one to two fundamental frequency cycles, where one cycle duration is 16.666 ms.

Dependability/Security

Another important operating criterion for protective relays is dependability/security. It is often mentioned as a pair since dependability and security are selected in a trade-off mode. **Dependability** is defined as the relay ability to respond to a fault by recognizing it each time it occurs. **Security** is defined as an ability of a relay not to act if a disturbance is not a fault. In almost all the relay approaches used today, the relays are selected with a bias toward dependability or security in such a way that one affects the other. A more dependable approach will cause the relays to **overtrip**, the term used to designate that the relay *will* operate whenever there is a fault but at the expense of possibly tripping even for nonfault events. The security emphasis will cause relays ***not*** **to trip** for nofault conditions but at a risk of not operating correctly when the fault occurs. The mentioned trade-off when selecting the relaying approach is made by choosing different types of relaying schemes and related settings to support one or the other aspect of the relay operation.

Selectivity

One criterion often used to describe how reliable a relaying scheme is relates to the relay ability to differentiate between a variety of operating options it is designed for. This criterion is called relay selectivity. It may be attributed to the relay accuracy, relay settings, or, in some instances, the measuring capabilities of the relay. In all cases, it designates how well the relay has recognized the fault conditions that it is designed or set to operate for. An example of the selectivity problem is an inability of a relay to correctly decide if it should operate in zone 1 or zone 2 for a fault that occurs in the region close to the set point between the zones. In this case, the relay operation may be termed as "overreaching" or "underreaching," depending if the relay has mistaken that the fault was inside of the selected zone while it was actually outside and vice versa.

9.3 Protection of Transmission Lines

The protection of transmission lines varies in the principle used and the implementation approaches taken, depending on the voltage level. The main principles and associated implementation issues are discussed for the following most frequent transmission line protective relaying cases: overcurrent protection of distribution radial feeders, distance protection of transmission lines and associated relaying schemes, and differential protection of transmission lines. Detailed treatment of the subject may be found in an excellent recent IEEE survey of the subject (IEEE, 1999).

9.3.1 Overcurrent Protection of Distribution Feeders

Protection of distribution feeders is most adequately accomplished using the overcurrent relaying principle. In a radial configuration of the feeder, shown in Figure 9.10, the fault current distribution is such that the fault currents are the highest for the faults closest to the source and the current decays as the fault gets farther away from the source. This property allows the use of the fault current magnitudes as the main criterion for the relaying action. The **overcurrent relaying** principle is combined with the inverse-time operating characteristic, as shown in Figure 9.11, and this represents the relaying solution for radial distribution feeders in most cases. The **inverse-time property** designates the relationship between the current magnitude and the relay operating time (the higher the fault current magnitude, the shorter the relay operation time). Further discussion is related to the setting procedures for the overcurrent relays with inverse-time characteristics.

To embark on determination of **relay settings**, the following data have to be made available for an overcurrent relay either through a calculation or through simple selection of design options: time dial, tap (pick-up setting), and operating characteristic type; current transformer ratio for each relay location; and extreme (minimum and maximum) short circuit values for fault currents. The mentioned data applied to the relaying system shown in Figure 9.10 are provided in Table 9.1. The values are determined only for relays *R*2 and *R*3 as an example. Similar approaches will yield corresponding values for relay *R*1.

The next step is to establish the criteria for **setting coordination.** The criteria selected as examples for relays *R*3 and *R*2 shown in Figure 9.10 are as these rules state:

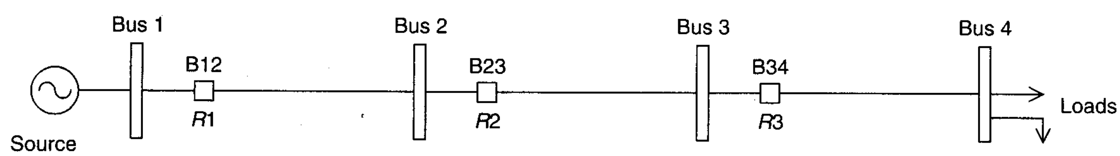


FIGURE 9.10 Protection of a Radial Distribution Feeder

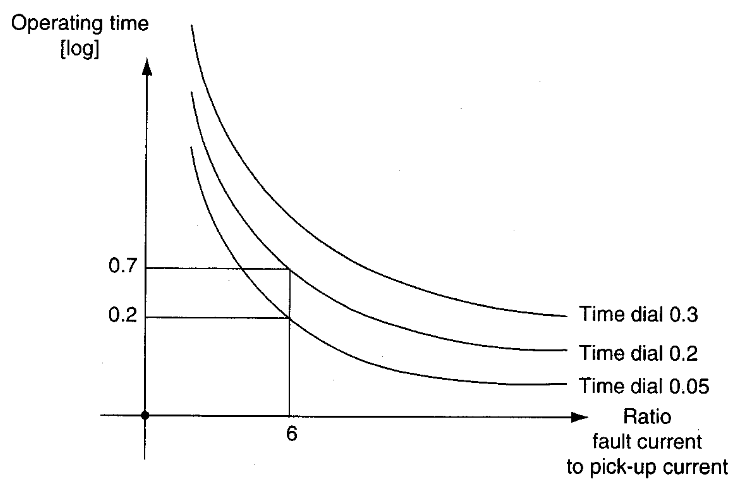


FIGURE 9.11 Inverse-Time Operating Characteristic of an Overcurrent Relay

TABLE 9.1 Data Needed for Setting Determination for the Case in Figure 9.10

Max and min fault current [A]	Bus/relay	
	R2	*R3*
Max fault current	306	200
Min fault current	250	156
CT ratio	50:5	50:5
Pick-up setting	5	5
Time-dial setting	0.2	0.05

1. *R2* must pick up for a value exceeding one-third of the minimum fault current (rule of thumb) seen by relay *R3* (assuming this value will never be below the maximum load current)
2. *R2* must pick up for the maximum fault current seen by *R3* but no sooner than 0.5 sec (rule of thumb) after *R3* should have picked up for that current.

Based on the mentioned criteria and data provided in Table 9.1, the following are the setting calculation steps.

Step 1: Settings for Relay *R3*

The relay has to operate for all currents above 156 A. For reliability, one-third of the minimum fault current is selected. This yields a primary fault current of $156/3 = 52$ A. Based on this, a CT ratio of $50/5 = 10$ is selected. This yields a secondary current of $52/10 = 5.2$ A. To match this, the relay tap (pick-up value) is selected to be 5.0 A. To ensure the fastest tripping for faults downstream from relay *R3*, the time dial of 0.05 is selected (see Figure 9.11).

Step 2: Settings for Relay *R2*

- Selection of CT ratio and relay tap
  The relay *R2* must act as a backup for relay *R3*, and, hence, it has to operate for the smallest fault current seen by relay *R3*, which is 156 A. Therefore, the selection of the CT ratio and relay tap is the same for relay *R2* as it was for relay *R3*.
- Time dial selection
  Based on the rule 2, relay *R2* acting as a backup for relay *R3* has to operate 0.5 sec after relay *R3* should have operated. This means that relay *R2* has to have a delay of 0.5 sec for the highest fault current seen by relay *R3* to meet the above mentioned criteria. Let us assume that the highest fault current seen by relay *R3* is at location next to breaker B34 looking downstream from breaker B34, and this current is equal to 306 A. In that case, the primary fault current is equal to $306/10 = 30.6$ A. The selected relay tap setting will produce a pick-up current of $30.6/5 = 6.12$ A. From Figure 9.11, the time delay corresponding to this pick-up value is 0.2 sec. Hence, if relay *R3* fails to operate, the relay *R2* will operate as a backup with a time delay of $0.2\text{ sec} + 0.5\text{ sec} = 0.7$ sec. According to Figure 9.11, the time delay of 0.7 sec requires the selection of time dial of 0.2. It also becomes obvious that selection of a smaller current for calculation of the time delay of relay *R3* will not allow the criteria in rule 2 to be met.

The overcurrent relaying of distribution feeders is a very reliable relaying principle as long as the time coordination can be achieved for the selected levels of fault current as well as the given circuit breaker operating times and instrument transformer ratios. The problems start occurring if the feeder loading changes significantly during a given period of time and/or the level of fault currents are rather small. This may affect a proper selection of settings that will accommodate a wide-range fluctuation in the load and fault currents. Some other, less likely, phenomena that may affect the relaying performance are as follows: current transformer saturation, selection of inadequate auxiliary transformer taps, and large variation in the circuit breaker opening times.

9.3.2 Distance Protection of Transmission Lines

As explained earlier, the distance protection principle is based on calculation of the impedance "seen" by the relay. This impedance is defined as the **apparent impedance** of the protected line calculated using the voltages and currents measured at the relaying point. Once the impedance is calculated, it is compared to the relay **operating characteristic**. If identified as falling into one of the zones, the impedance is considered as corresponding to a fault; as a result, the relay issues a **trip**. The concept of the impedance being proportional to the length of the transmission line and the idea of using the relay settings to correspond to the line length lead to the reason for calling this relaying principle **distance relaying**.

To illustrate the process of selecting distance relay **settings**, a simple network configuration, with data given in Table 9.2, is considered in Figure 9.12. Table 9.2 also contains additional information about the instrument transformer ratios.

The setting selection and coordination for the example given in Figure 9.12 can be formulated as follows.

Step 1: Determination of Maximum Load Current and Selection of CT and CVT Ratios

From the data given in Table 9.2, the maximum load current is computed as:

TABLE 9.2 Data Needed for Calculation of Settings for a Distance Relay

Data	Line impedance	
	Line 1–2	Line 2–3
Line impedance	$1.0 + j1.0$	$1.0 + j1.0$
Max load current	50 MVA	50 MVA
Line length	50 miles	50 miles
Line voltages	138 kV	138 kV

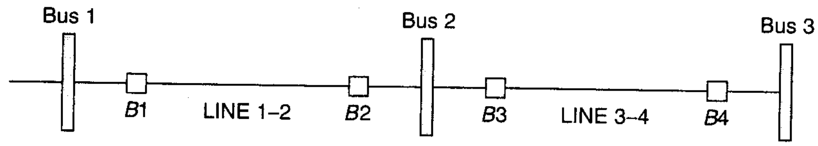


FIGURE 9.12 A Sample System for Distance Relaying Application

$$\frac{50(10^6)}{(\sqrt{3})(138)(10^3)} = 418.4 \text{ A} \qquad (9.1)$$

The CT ratio is $400/5 = 80$, which produces about 5 A in the secondary winding. If one assumes that the CVT secondary phase-to-ground voltage needs to be close to 69 V, then computing the actual primary voltage and selecting the ratio to produce the secondary voltage close to 69 V allows one to calculate the CVT ratio. The primary phase-to-ground voltage is equal to $138\sqrt{3}(10,000) = 79.67(10,000)$ V. If we allow the secondary voltage to be 69.3 V, then the CVT ratio can be selected as $79.67(10,000)/69.3 = 1150/1$.

Step 2: Determination of the Secondary Impedance "Seen" by the Relay

The CT and CVT ratios are used to compute the impedance as follows:

$$\frac{V_p/1150}{I_p/80} = \frac{V_p}{I_p}(0.07) = Z_{\text{line}}(0.07). \qquad (9.2)$$

Therefore, the secondary impedance "seen" by the relay is for both lines equal to $0.07 + j0.07$.

Step 3: Computation of Apparent Impedance

Apparent impedance is the impedance of the relay seen under specific loading conditions. If we select the power factor of 0.8 lagging for the selected CT and CVT ratios as well as the selected fault current, the apparent impedance is equal to:

$$Z_{\text{load}} = \frac{69.3}{418.4\left(\frac{5}{400}\right)}(0.8 + j0.6) = 10.6 + 8.0. \qquad (9.3)$$

Step 4: Selection of Zone Settings

Finally, the zone settings can now be selected by multiplying each zone's impedance by a safety factor. This factor is arbitrarily determined to be 0.8 for zone 1 and 1.2 for zone 2. As a result, the following settings for zone 1 and zone 2, respectively, are calculated as:

$$\begin{aligned} &\text{Zone 1} \quad 0.8(0.007 + j0.7) = (0.056 + 0.56)\Omega \\ &\text{Zone 2} \quad 1.2(0.007 + j0.7) = (0.084 + 0.84)\Omega. \end{aligned} \qquad (9.4)$$

Distance relaying of transmission lines is not free from inherent limitations and application ambiguities. The most relevant inherent limitation is the influence of the current in-feed from the other end as described earlier. The other source of possible error is the fault resistance, which cannot be measured online. Therefore, it has to be assumed at the time of the relay setting computation, when a value different from what is actually present during the fault may be picked up. The anticipated value of the fault resistance is selected arbitrarily and may be a cause for a gross error when computing the impedance for a ground fault. Yet another source of error is the mutual coupling between adjacent transmission line or phases, which if significant, can adversely affect relay operation if not taken adequately into account when computing the fault impedance. The distance relaying becomes particularly difficult and sometimes unreliable if applied to some special protection case, such as multiterminal lines, lines with series compensation, very short lines, and parallel lines. In all of the cases, selecting relay settings is quite involved and prone to errors due to some arbitrary assumptions about the value of the fault impedance.

9.3.3 Directional Relaying Schemes for High-Voltage Transmission Lines

Due to the inherent shortcoming of distance relays not being able to recognize the effect of the current in-feed from the other end of the line and because of this possibly leading to a wrong decision, the concept of a relaying scheme is developed. The concept assumes that the relays at the two ends of a transmission line will coordinate their actions by exchanging the information that they detect for the same fault. To be able to perform the coordination, the relays have to use a **communication channel** to exchange the information. In an earlier discussion, illustrated in Figure 9.9, one of the principles for scheme protection of transmission lines was explained. A more comprehensive summary is given now.

The choices among basic relaying scheme principles are influenced by two factors: the **approach** in using the communication channels and the **type** of information sent over the channel. Regarding the approach for using the channels, one option is for the channels to be active during a fault, which means sending the information all the time and making sure that the communication did not fail. The other option is for the communication channels to be activated only when a command is to be transmitted and not being activated during other intervals or cases related to the fault. Regarding the type of information sent, the channels are used for issuing either a

TABLE 9.3 Summary of Basic Characteristics of Most Common Relaying Schemes

Scheme type (Directional Comparison)	The use of communication channel	Type of signal sent
Blocking	Blocking a signal (use of power line carrier)	Block
Unblocking	Sending either block or unblock signal all the time (use of frequency shift keying channel)	Block/unblock
Overreaching transfer trip Underreaching transfer trip	Sending a trip signal (use of audio tones)	Trip/guard

blocking or a tripping signal. In the case a **blocking signal** is issued, the relay from one end, after making a decision about a fault, sends a blocking signal to the other relay. If a **trip signal** is used, the relay that first detects the fault sends a signal to the other end. This will make the other relay perform a trip action immediately after it has detected a fault as well. Additional consideration in selecting the scheme relates to the type of **detectors** used in the relays for making the decisions about the existence of a fault and the location of the fault with the respect to the zones. Specific choices in setting up the zones are made for each scheme operation. Typical choices for the detector types are overcurrent and/or directional, with the zone I and / or zone II settings being involved in the decision making. A summary of the above considerations is given in Table 9.3.

As with any other relaying approach, the scheme implementations also have different performance criteria established. If one takes the dependability/security criterion (WG D5, 1997; WG, 1981) as the guiding factor in making the decisions, then the property of the various relaying scheme solutions can be classified as follows:

1. **Blocking/unblocking:** The blocking solution tends to provide higher dependability than security. Failure to establish a blocking signal from a remote end can result in overtripping for external faults. The unblocking solution offers a good compromise of both high dependability (channel not required to trip) and high security (blocking is continuous).
2. **Transfer trip (overreaching/underreaching):** The transfer trip solution offers higher security than dependability. A failure to receive the channel signal results in a failure to trip for internal faults. The transfer trip systems require extra logic for internal-trip operation at a local terminal when the remote terminal breaker is open or for a "weak infeed" when the fault contribution is too low to send a trip signal. This is not a problem with blocking and unblocking systems.

The options for scheme protection implementation are much more involved than what has been discussed here. Further details may be found in Blackburn (1993, 1998).

9.3.4 Differential Relaying of High-Voltage Transmission Lines

In the cases when the above-mentioned relaying schemes are not sufficiently effective, a differential scheme may be used to protect high-voltage (HV) transmission lines. In this type of relaying, the measurements from two (or multiple) ends of a transmission line are compared. Transmitting the measurement from one end to the other enables the comparison. The decision to trip is made once the comparison indicates a significant difference between the measurements taken at the transmission line end(s).

The main reason for introducing differential relaying is the ability to provide **100% protection** of transmission lines; at the same time, the influence of the rest of the system is minimal. The scheme has primarily been used for high-voltage transmission lines that have a strategic importance or have some difficult application requirements such as series compensation or multiterminal configuration. The use of a **communication system** is needed for implementation of this approach. This may be considered a disadvantage due to the increased cost and possibility for the channel malfunctioning.

The classification of the existing approaches can be based on two main **design properties**: the type of the communication **media** used and the type of the **measurements** compared. The communication media most commonly used are metallic wire, also known as pilot-wire; leased telephone lines; microwave radio; and fiber-optic cables. The measurements typically used for the scheme are composite values obtained by combining several signal measurements at a given end (IEEE, 1999) and sample-by-sample values of the phase currents (IEEE, 1999). A summary of the most common approaches for the differential relaying principle for transmission lines is given in Table 9.4.

In the past, the most common approach was to use metallic wire to compare the sequence values. The sequence values are a particular representation of the three-phase original values obtained through a symmetrical component transformation (Blackburn, 1993). Due to a number of practical problems caused by the ground potential rise and limited length of the physical wire experienced with the metallic wire use, these schemes have been substituted by other approaches where different media such as fiber-optic or microwave links are used. Most recently, as the wideband communication channels have become more affordable, the differential schemes are being implemented using either dedicated fiber-optic cables or a high-speed leased wideband communication system.

9.4 Protection of Power Transformers

For power transformers, the **current differential** relaying principle is the most common one used. In addition, other types of protection are implemented, such as a sudden pressure relay on the units with large ratings. As much as the current

TABLE 9.4 Summary of Most Common Differential Relaying Principles

Differential principle	Signals used for comparison	Properties
Pilot-wire	Three-phase currents converted into sequence voltage	Use of sequence filters due to direct use of wires prone to transients caused by interference
Phase comparison	Three-phase currents converted into a single current waveform	Composite waveform converted into binary string used for phase comparison
Segregated phase comparison	Phase currents in each phase directly compared at two ends	Currents converted into square waves used for phase comparison
Current differential	Samples of each current transmitted to the other end for comparison	Currents from both ends directly compared
Composite–waveform differential	Each current converted into sequence current and a combined composite signal is transmitted	Composite signals from both ends directly compared

differential relaying has been a powerful approach in the past, it has some inherent limitations that pose difficulties for special applications or practical design considerations. Further discussion concentrates on the mentioned limitations and their impact on the current differential approaches. The other relaying principles applied for protecting power transformers are not discussed here. Further details can be found in references (Horowitz and Phadke, 1992; Blackburn, 1998; Ungrad *et al.*, 1995).

9.4.1 Operating Conditions: Misleading Behavior of Differential Current

Power transformers are energy storage devices that experience transient behavior of the terminal conditions when the stored energy is abruptly changed. Such conditions may be seen during transformer energization, energization of a parallel transformer, removal of a nearby external fault, and a sudden increase in the terminal voltage. The following is a discussion of the mentioned phenomena and the impact they have on the terminal currents.

Energizing a transformer causes a transient behavior of the currents at the transformer primary due to so-called **magnetizing inrush** current. As a voltage is applied on an unloaded transformer, the nonlinear nature of the magnetizing inductance of the transformer causes the magnetizing current to experience an initial value as high as 8–30 times the full-load current, which may appear to the differential scheme as a difference caused by a fault. An example of the harmonic inrush wave shape for the magnetizing current is given in Figure 9.13. Fortunately, the inrush current has a rich harmonic content, which can be used as the basis for distinguishing between the high currents caused by a fault and the ones caused by the inrush. Since the magnetizing inrush is a function of both the prior history of remanent magnetism as well as the type of the transformer connection, selecting the scheme for recognizing proper levels of the harmonics needs to be carried out carefully.

Similar transient behavior of the primary current is seen in a transformer connected in parallel to a transformer that is being energized. The change in the magnetizing current is affecting the primary current of the parallel transformer due to an inrush created on the transformer being energized. This phenomenon is called **sympathetic inrush**. Sudden removal of an external fault and a sudden increase in the transformer voltage also cause the inrush phenomenon, again well recognized by an occurrence of particular harmonics in the primary current.

9.4.2 Implementation Impacts Causing Misleading Behavior of Differential Currents

The current differential relayed for power transformer applications may be affected by practical implementation constraints.

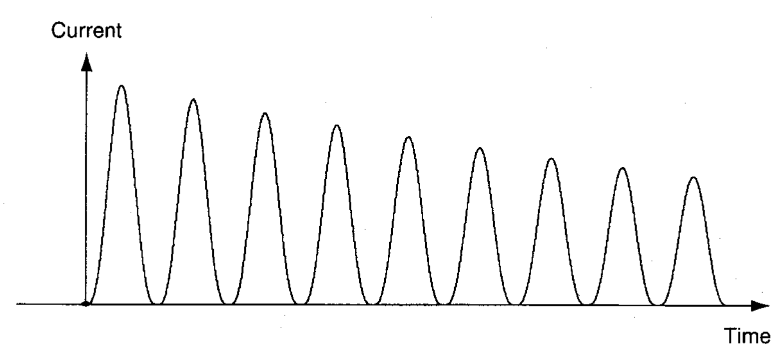


FIGURE 9.13 Magnetizing Inrush Affecting Primary Current

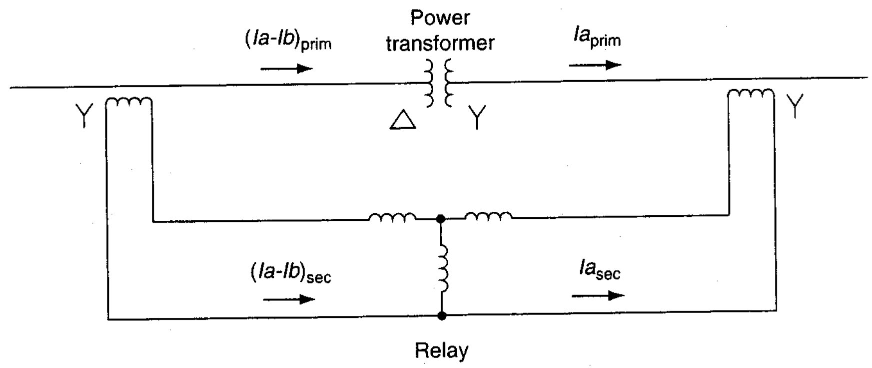


FIGURE 9.14 Phase Mismatch

One of the common problems is to have a mismatch between ratios of the instrument transformers located at the two power transformer terminals. This is called a **ratio mismatch**, and it is corrected by selecting appropriate taps on the auxiliary transformers located at the inputs of the transformer differential relay. Yet another obstacle may be a **phase mismatch**, where the instrument transformer connection may cause a phase shift between the two currents seen at the transformer terminals. This is because the connection of the power transformer may introduce a phase shift, and if the instrument transformer does not correct for this, a phase mismatch will occur at the terminals of the instrument transformer. The phase mismatch is illustrated in Figure 9.14, where the currents in the relaying circuit are not correctly selected. The mismatch can be avoided if the instrument transformer at the Y side of the power transformer is of a Δ type.

Besides the mentioned constraints, other constraints include the mismatch due to a changing tap position on the load tap changer as well as the mismatch caused by the errors in current transformers located at two terminals.

9.4.3 Current Differential Relaying Solutions

The straightforward solution for differential relaying is to take a difference of currents I_1 and I_2 at two ends and compare it to a threshold I_T as shown in equation:

$$|(I_1 - I_2)| \geq I_T. \tag{9.5}$$

This solution will have a problem to accommodate an error due to a mismatch discussed earlier. Hence, a different equation may be used to make sure that a higher error is allowed for higher current levels:

$$|(I_1 - I_2)| \geq \frac{|(I_1 - I_2)|}{2}. \tag{9.6}$$

Finally, to distinguish the case of the inrush condition mentioned earlier, a harmonic restraint scheme is used as represented by equation:

$$|(I_1 - I_2)| \geq k \cdot \frac{|(I_1 - I_2)|}{2}. \tag{9.7}$$

This type of operating characteristic will recognize that the current difference is caused by an event that is not an internal fault, and it will block the relay from operating. The criterion for recognizing a nonfault event is the presence of a particular harmonic content in the differential current. This knowledge is used to restrain the relay operation by relating the factor k to the presence of the harmonic content, hence the "harmonic restraint" terminology.

9.5 Protection of Synchronous Generators

Synchronous generators are commonly used in high-voltage power systems to generate electric power. They are also protected using the **current differential** relaying principle. In addition, the generators require a number of other special operating conditions to be met. This leads to the use of a score of other relaying principles. This section reviews some basic requirements for generator protection and discusses the basic relaying principles used. A much more comprehensive coverage of the subject may be found in an IEEE Tutorial (1995).

9.5.1 Requirements for Synchronous Generator Protection

Generators need to be protected from the **internal faults** as well as the abnormal operating conditions. Since generators consist of two parts, namely the **stator** and the **rotor**, protection of both is required. The stator is protected from both phase and ground faults, while the rotor is protected against ground faults and loss of field excitation. Due to the particular conditions required for the synchronous machine to operate, a number of operating conditions that represent either a power system disturbance or operational hazard need to be avoided. The conditions associated with **network disturbances** are overvoltage or undervoltage, unbalanced currents, network frequency deviation, and subsynchronous oscillations. The conditions of **hazardous operation** are loss of prime mover (better known as generator motoring), inadvertent energization causing a nonsynchronized connection, overload, out-of-step or loss of synchronism, and operation at unallowed frequencies.

9.5.2 Protection Principles Used for Synchronous Generators

The **current differential** protection principle is most commonly used to protect against phase faults on the **stator,** which are the most common faults. Other conditions require other principles to be used. The loss of field and the ground protection of the rotor are quite complex and depend on the type of the grounding and current sensing arrangement used. This subject is well beyond the basic considerations and is treated in a variety of specialized literature (IEEE, 1995). Protection from the **abnormal** generator operating **condition** requires the use of relaying principles based on detection of the changes in voltage, current, power, or frequency. A reverse power relay is used to protect against loss of a prime mover known as generator motoring, which is a dangerous condition since it can cause damage of the turbine and turbine blades. In addition, synchronous generators should not be subjected to an overvoltage. With normal operation near the knee of the iron saturation curve, small overvoltages result in excessive flux densities and abnormal flux patterns, which can cause extensive structural damage in the machine. A relaying principle based on the ratio between voltage and frequency, called a volt-per-hertz principle, is used to detect this condition. An inadvertent connection of the generator to the power system not meeting the synchronization requirements can also cause damage. The overcurrent relaying principle in combination with the reverse power principle are used to detect such conditions. The overload conditions as well as over- and under-frequency operations can cause damage from overheating, and thermal relays in combination with frequency relays are used. Undervoltage and overvoltage protections are used for detecting loss of synchronism and overvoltage conditions.

9.6 Bus Protection

Protecting **substation busses** is a very important task because operation of the entire substation depends on availability of the busses. The bus faults are rare, but in the open-air substations, they occasionally happen. They have to be cleared very fast due to high-fault current flow that can damage the bus. This section briefly discusses the requirements and basic principles used for bus protection. Detailed treatment of the subject is given in several classical references (Horowitz and Phadke, 1992; Blackburn, 1998; Ungrad *et al.*, 1995).

9.6.1 Requirements for Bus Protection

High-voltage substations typically have at least two busses: one at one voltage level and the other at a different voltage level with power transformer(s) connecting them. In high-voltage substations, the breaker-and-a-half arrangement, shown earlier in Figure 9.3, is used to provide a redundant bus connection at each voltage level. In addition, in some substation arrangements, there is a provision for separating one portion of the bus from another, allowing for independent operation of the two segments. All of those configurations are important when defining the bus protection requirements (Blackburn, 1998).

The first and foremost requirement for bus protection is **the speed of relay operation**. There are several important reasons for that all relate to the fact that the fault currents are pretty high. First, the **current transformers** used to measure the currents may get **saturated**; hence, a fast operation will allow for the relaying decision to be made before this happens. Next, due to the high currents, the equipment damage caused by a sustained fault may be pretty severe. Hence, the need to accomplish an isolation of the faulted bus from the rest of the system in the shortest time possible is paramount. Last, but not least, due to the various possibilities in reconfiguring busses, it is very important that the bus protection scheme is developed and implemented in a flexible way. It needs to allow for various parts of the bus to be isolated for maintenance purposes related to the breakers on the connected lines, and yet the protection for the rest of the bus needs to stay intact.

9.6.2 Protection Principles Used for Bus Protection

The most common bus protection principle is the **current differential approach**. All connections to the bus are monitored through current transformers to detect current imbalance. If an internal bus fault occurs, the balance between incoming and outgoing currents is drastically disturbed, and that becomes a criterion for tripping the bus breakers and isolating the bus from the rest of the system. This relaying principle would be very simple to implement if there were no problems with **CT saturation**. Due to high-fault currents, one of the CTs may see extraordinary high currents during a close-in external fault. This may cause the CT to saturate, making it very difficult to distinguish if the CT was saturated due to high currents from an internal or external fault. If **air-gap** or **air-core** CTs are used, the saturation may not be an issue, and the current differential relaying is easily applied. This solution is more costly and is used far less frequently than the solution using standard iron-core CTs.

To cope with the CT saturation, two types of relaying solutions are most commonly used (Blackburn, 1998). The first one is a **multirestraint current differential**, and the other one is a **high-impedance voltage differential**. The multirestraint current differential scheme provides the restraint winding connection to each circuit that is a major source of the fault current. These schemes are designed to restrain correctly for heavy faults just outside the differential zone, with maximum offset current, as long as the CTs do not saturate for the maximum symmetrical current. These schemes are more difficult to apply and require use of auxiliary CTs to match the current transformer ratios. The high-impedance voltage differential principle uses a property that CTs, when loaded with high impedance, will be forced to take the error differential current, and, hence, this current will not flow through the relay operating coil. This principle translates the current differential sensitivity problem is to the voltage differential sensitivity probem for distinguishing the close-in faults from the bus faults. The voltage differential scheme is easier to implement since the worst case voltage for external faults can be determined much more precisely knowing the open voltage of the CT.

9.7 Protection of Induction Motors

Induction motors are a very common type of load. The main behavioral patterns of the induction motor are representative of the patterns of many loads; their operation depends on the conditions of the network that is supplying the power as well as the **loading conditions**. This section gives a brief discussion on the most important relaying requirements as well as the most common relaying principles that apply to the induction motor protection. Further details can be found in (Horowitz and Phadke, 1992; Blackburn, 1998; Ungrad *et al.*, 1995).

9.7.1 Requirements for Induction Motor Protection

The requirements may be divided in three categories: **protecting the motor from faults**, **avoiding thermal damage**, and **sustaining abnormal operating conditions**. The protection from faults has to detect both phase and ground faults. The thermal damage may come from an overload or locked rotor and has to be detected by correlating the rise in the temperature to the occurrence of the excessive currents. The abnormal operating conditions that need to be detected are unbalanced operation, under voltage or overvoltage, reversed phases, high-speed reclosing, unusual ambient temperature, voltage and incomplete starting sequence.

The protection principle used has to differentiate the causes of problems that may result in a damage to the motor. Once the causes are detected and linked to potential problems, the motor needs to be quickly disconnected to avoid any damage.

9.7.2 Protection Principles Used for Induction Motor Protection

The most common relaying principles used for induction motor protection are the **overcurrent protection** and **thermal protection**. The overcurrent protection needs to be properly set to differentiate between various changes in the currents caused either by faults or excessive starting conditions. A variety of current-based principles can be used to implement different protection tasks that fit the motor design properties. Both the phase and ground overcurrents, as well as the differential current relays, are commonly used for detecting the phase and ground faults. The thermal relays are available in several forms: a "**replica**" **type**, where the motor-heating characteristics are approximated closely with a bimetallic element behavior; resistance temperature detectors embedded in the motor winding; and relays that operate on a combination of current and temperature changes.

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