J. Webster (ed.), *Wiley Encyclopedia of Electrical and Electronics Engineering*

POWER SYSTEM RELAYING

Power system relaying is an art as well as a science. It is an art because judgment is required to maximize effectiveness of protection with available resources. Protective relaying is an essential feature of an electrical system and should be considered concurrently with the system design. It should minimize the damage to the system components and maximize continuity of service. Protecting an inadequately designed system will be more complex and less satisfactory than protecting one that is properly designed. Many utility companies establish standards of quality of service based upon number and duration of outages on a given type of circuit on a yearly basis. In continuous process plants, a single loss of equipment or nuisance trip resulting from relay system performance may be unacceptable.

The two major components of power system protection, whether it is a 120/240 V residential circuit serving an appliance or a 765 kV high-voltage line running across country, are (1) circuit interrupting devices and (2) protective relays that sense and actuate the circuit interrupting devices to isolate the faulty component. A fuse is a sensing and interrupting device. Power circuit breakers are interrupting devices only; though in case of low-voltage molded case circuit breakers, the sensing devices (i.e., thermal and magnetic trips) may be built into the breaker itself. Apart from protection, relays serve a variety of functions which include monitoring, regulating, programming, and performing auxiliary functions associated with fault detection. The input to a relay may be ac current, ac voltage, dc voltage, etc., obtained as a proportional replica of the quantities in the power system through instrument transformers and station batteries.

Protective relaying can be distinctively categorized as *equipment protection and system protection.* Equipment protection narrows down the protection to individual equipment (i.e., generator, transformer, transmission line, bus). System protection takes a broader perspective of how the various protective devices will function and integrate within the operating parameters of a system configuration. Back-up protection against a failure of a relaying scheme, a breaker, or control power supply are important considerations. Relaying for a mesh or ring-connected bus configuration will be different than a radial system, even though each of these systems may interconnect the same size of transformers and generators.

A host of electrical system data is required to properly select and apply protective devices. Three-phase short-circuit currents, fault voltages, load and inrush currents, and system impedances are the primary data. The asymmetrical faults in a three-phase system (i.e., a phase-to-ground or phase-to-phase fault) require calculations using symmetrical sequence components. Electrical system contingency operating conditions, phase relations, transformer winding connections, stability characteristics, and evaluation of transients are required depending upon the specific application. The power system studies of short-circuit, load flow, stability, transients and harmonics are invariably carried out on digital computers.

Design Criteria of Protective Systems

The logic of protective relaying looks at a complex distribution system as an integration of various subsystems. In all cases, some common design criteria are applicable. This consists of five basic elements: (1) selectivity, (2) speed of operation (3) reliability, (4) simplicity, and (5) economics. Sometimes a sixth criterion of maintainability is also added.

Selectivity. A protection system should operate so as to isolate the faulted section only. In a radial system of distribution, using inverse time relays as the primary protection, the desired selectivity is obtained by coordinating upstream relays with the downstream relays in steps, so that an upstream relay is *slower* than the downstream relay. This may increase the fault clearance time toward the source depending upon relay characteristics and the fault current distribution. A separate zone of protection can be established around each system element so that a fault occurring in that zone will be instantaneously cleared without a time delay. Normally, these zones are overlapped by proper location of the current transformers and protective relays so that there are no unprotected areas. This logically divides the system into protective zones for generators, transformers, buses, transmission lines, cables, and motors. These are called unit protection schemes. The faults are cleared fast, with detection times of 1 to 2 cycles. The other relays, such as time overcurrent and directional relays, are still retained as *backup* protection. The desired reliability may increase the system protection complexity and backup protection becomes necessary. Reliability and fast fault clearing dictate these unit protection schemes. In a network of interconnected lines and multiple generators, more than one breaker must be tripped to isolate the fault.

Speed. Fault damage to the system components, the stability between synchronous machines, and auto reclosing to restore power are to be considered in designing the speed of operation of the protective system. The total fault duration is the relay operating time plus the breaker interrupting time. A reduction in power transferred to the loads will occur during a fault condition, the amount depending upon the type of fault. The shorter the fault clearance time, the greater the amount of power that can be transferred without a system separation and shutdown.

Reliability. Dependability and security are the measures of reliability. The protection must be dependable and operate in response to system trouble within its required area and be secure against incorrect trips from all other conditions (i.e., voltage regulation due to load application and rejection, inrush currents, switching surges, and high magnitude of through fault currents). Thus, these two objectives of reliability mutually oppose each other. Designing more flexibility into the system design (i.e., double-ended substation, duplicate feeders, auto-switching, and bus transfer schemes) will increase the complexity and hence reduce security of the protective system. Reliability should be viewed in terms of overall system performance—overprotection and underprotection may both jeopardize it.

Abnormal Conditions

The most severe electrical hazards against which protection is required are short circuits, even though there are many other abnormal conditions (i.e., overloads, undervoltage and overvoltage, underfrequency and overfrequency, unbalanced voltages or currents, direction of power flow, loss of excitation, or synchronism) for which protection is required. In addition, protection against surges of atmospheric origin (i.e., lightning and surges internally generated in the system due to switching, restrikes, and operation of current limiting fuses) is required. Surge protection is not discussed in this article.

Short-Circuit Currents. The short-circuit current data required for relaying can be summarized as follows:

- The first-cycle asymmetrical current is required for instantaneous, differential, and distance relays where the relay operation is fast and asymmetricity in fault currents should be accounted for. The asymmetricity in the first-cycle current also affects current transformer performance.

- The *maximum* symmetrical fault current (a few cycles later depending upon the breaker operating time) is required to establish circuit protection coordination interval. The *minimum* interrupting current is required to ascertain whether circuit protection sensitivity is adequate.
- The 30-cycle short-circuit current is required for application of time-delay relays beyond six cycles. The induction and synchronous motor contributions to the fault currents decay to zero, and the generators are represented by transient or larger impedance related to the magnitude of the decaying short-circuit current at the specified calculation time.
- Generator time-dependent short-circuit decrement curves are needed for application and setting of voltage controlled or voltage restrained generator overcurrent relays. A generator decrement curve can be constructed from the following expression:

$$I_{ac} = (I''_d - I'_d)\epsilon^{-t/T''_d} + (I'_d - I_d)\epsilon^{-t/T'_d} + I_d \tag{1}$$

$$I_{dc} = \sqrt{2}I''_d\epsilon^{-t/T_A} \tag{2}$$

The total rms current is:

$$I_{tot} = \sqrt{(I_{ac})^2 + (I_{dc})^2} \tag{3}$$

where I_{ac} and I_{dc} are the ac and dc components of the decaying short-circuit current; I''_d, I'_d, and I_d are the subtransient, transient, and steady state components of the short-circuit current; T''_d, and T'_d, are the short-circuit subtransient and transient time constants; and T_A is armature short-circuit time constant in seconds.
- Maximum and minimum ground fault currents are required for application of ground fault protective devices. Two-phase-to-ground and phase-to-phase fault currents may also be required.

Symmetrical Components

Symmetrical components are applied to calculations of unbalanced fault currents and voltages and in rotating machine analysis. Theory of symmetrical components can be briefly stated thus: a coplanar vector is defined by the position of its terminal and length and has 2 degrees of freedom. A three-phase balanced system has 2 degrees of freedom because the current or voltage vectors (phasors) are displaced from each other by equal angles of separation of 120° and are of equal length. A three-phase unbalanced system of currents or voltages has 6 degrees of freedom because the vectors are of varying length at varying displacement angles from each other. Such an unbalanced system can be resolved into three symmetrical systems, each system having three vectors with 2 degrees of freedom. *Positive-sequence system* is a set of balanced three-phase components of the same phase sequence as the original unbalanced set. *Negative-sequence system* is a set of three-phase components of opposite phase sequence to the positive sequence system but vectors (phasors) of the same magnitude. *Zero-sequence system* consists of three single-phase components of the same magnitude and cophasial. These are related by the following equations:

$$\begin{bmatrix} V_a \\ V_b \\ V_c \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} \begin{bmatrix} V_a^0 \\ V_a^+ \\ V_a^- \end{bmatrix} \tag{4}$$

and

$$\begin{bmatrix} V_a^0 \\ V_a^+ \\ V_a^- \end{bmatrix} = \frac{1}{3} \begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix} \begin{bmatrix} V_a \\ V_b \\ V_c \end{bmatrix} \tag{5}$$

Where V_a, V_b, and V_c are the original unbalanced voltages; a is a unit vector operator that rotates 120° in the counterclockwise direction; and $V^+{}_a$, $V^-{}_a$, and $V^0{}_a$ are the positive, negative, and zero sequence components of the original unbalanced set.

Characteristics of Sequence Components. In a three-phase wye connected and ungrounded system, no zero sequence current flows. If the wye point is grounded, neutral carries the out-of-balance current. In a delta connection, no zero sequence currents can appear in the line currents. In a balanced three-phase system with balanced loads, only positive sequence currents can flow. Negative sequence currents are set up in circuits of unbalanced impedances and voltages. In symmetrical circuits, currents and voltages of different sequence do not affect each other (i.e., the positive sequence currents produce only positive sequence voltage drops and the theorem of superposition applies). Sequence impedance networks must be constructed for unbalanced fault current calculations and data input to digital computers. As an example, the single-line-to-ground fault is given by the expression:

$$I_g = \frac{3E}{Z^+ + Z^- + Z^0} \tag{6}$$

Where I_g is the single-line-to-ground fault current; E is the line-to-neutral voltage; and Z^+, Z^-, and Z^0 are the positive, negative, and zero sequence impedances to the fault point.

Circuit-Interrupting Devices

The circuit interrupting devices are fuses and power circuit breakers. In addition, load break and off load disconnect switches are used for isolation, bypass, and maintenance. Low-voltage and medium-voltage motor-starter contactors are also classed as circuit-interrupting devices. Only a brief description of circuit breakers is provided.

Circuit Breakers.

Low-Voltage Circuit Breakers. Low-voltage circuit breakers up to 1000 V are classified as molded-case circuit breakers (*MCCB*s), insulated case circuit breakers (*ICCB*s), and power circuit breakers (*LVPCB*s). A molded-case circuit breaker is assembled as an integral unit in a supporting and enclosing housing of insulating material. The contacts are not accessible for inspection or maintenance. The interrupting ratings of molded-case circuit breakers with instantaneous trip devices have increased to 100 kA and with integrally mounted fuses have increased to 200 kA symmetrical. A molded-case circuit breaker can be current limiting without integrally mounted fuses, and it is not 100% rated. It is applied at a maximum of 80% of its rating. ICCBs are hybrids between power and molded-case circuit breakers, may use electronic trip devices, but are not current limiting. An ICCB may be 100% rated and have a short-time short-circuit withstand capability of a maximum of 20 cycles. A metal-enclosed power circuit breaker (LVPCB) is maintainable and has a short-time fault-current withstand capability of 30 cycles. The instantaneous trips on these breakers can be omitted for coordination with downstream breakers if the short-time trips are set within the breaker short-time withstand rating.

Medium-Voltage and High-Voltage Circuit Breakers. Medium-voltage indoor oilless circuit breakers can be applied in *drawout metalclad* designs to 38 kV. Each component (i.e., bus bars, cable terminations, relays, and the breaker itself) are enclosed in a grounded metallic partition in one cubical. SF_6 gas and vacuum technologies have replaced air-break designs at medium voltage. Damage to motor insulation was reported in earlier designs of vacuum breakers as a result of *multiple restrikes* causing excessive high-voltage transients. The advances in contact tip materials have overcome these problems. *Outdoor power circuit breakers* for high voltages use oil, SF_6 gas, or pressurized air as the interrupting mediums. 800 kV, SF_6 gas circuit breakers in interrupting ratings of 63 kA symmetrical are available. SF_6 has certain advantages as an arc-interrupting medium. Its octahedral molecule has electronegative characteristic to seize an electron and form an ion which is the reverse of ionization. The breakdown strength can exceed transformer oil at a pressure of approximately 303,975 Pa (3 atm). The earlier designs of two-pressure system SF_6 breakers have been replaced with *puffer-type* breakers, where the impulse of high pressure is generated by contact movement itself. SF_6 has been extensively used in *GIS* (gas insulated substations) at voltages to 765 kV.

Synchronous Breakers. An interruption time of one cycle has been achieved in mechanical breakers by ensuring that the current is interrupted at its natural zero, using a sync pulse to detect zero crossing (two pulses per cycle) when the breaker trip is energized. A trip signal and a zero-crossing pulse must be simultaneously present to initiate the opening sequence. Thus, arcing time as well as arc energy are reduced. A laser guide and electromagnetic repulsion technique are used to introduce quick separation between the breaker contacts and control arc extinction.

Solid-State Breakers. Solid-state breakers (*SSB*s) have been developed for *FACT* (Flexible AC Transmission). A 15 kV class breaker consists of two parallel branches: a solid-state switch composed of *GTO*s (Gate turnoff devices) and a solid-state switch using SCRs in series with a current limiting reactor. The GTO switch is used to clear breaker source-side faults. The breaker remains closed until the fault current reaches a predetermined lower value, at which point it opens in a half cycle.

The Nature and Purpose of Protective Relays

Relays may be classified according to their function (i.e., protection, monitoring, regulating) according to operating principal [i.e., electromechanical, thermal, percentage, static (digital or analog)] and according to performance characteristics (i.e., overcurrent, distance, differential, undervoltage, frequency).

Overcurrent Relays. An inverse-time delay overcurrent and instantaneous relay is the most commonly used protective relay and is applied in every protective zone in an electrical system as primary or backup protection, except high-voltage transmission systems. The overcurrent relays are simply magnitude relays and operate when the overcurrent exceeds the relay set pickup current. For all values of current less than pickup current, the relay remains inoperative. The electromagnetic version of instantaneous overcurrent relays have been historically of solenoid or plunger-type and clapper-type whereas the time delay overcurrent relays use induction disk principal, similar to a watt-hour meter. An instantaneous function can be mounted in the same relay case, and a target and seal-in unit is actuated when the relay operates. The magnet coil is tapped to provide adjustable current settings, whereas the travel of a spring-controlled disk sets the time delay. Figure 1 shows typical time-current curve shapes of the overcurrent relays.

Directional overcurrent relays provide sensitive fault detection in one direction and nontripping for load or fault currents in the other direction. These were developed for applications in a loop or network system. These are also used for detection of noncleared faults in the utility system, which continue to be fed from industrial plant generators or motor loads. Another use is for the sensitive ground fault protection of transformers, lines, and generators and to speed up the fault clearance times on a tie circuit by distinguishing the direction of current flow. A directional relay has a current coil and a polarizing coil, which can be polarized by voltage or current. Some units can be dual polarized by voltage and current. Ground directional units can be polarized by sequence quantities—negative or zero. The maximum directional sensitivity may be produced when the current is at a certain angle with respect to voltage and in current polarized relays the maximum directional

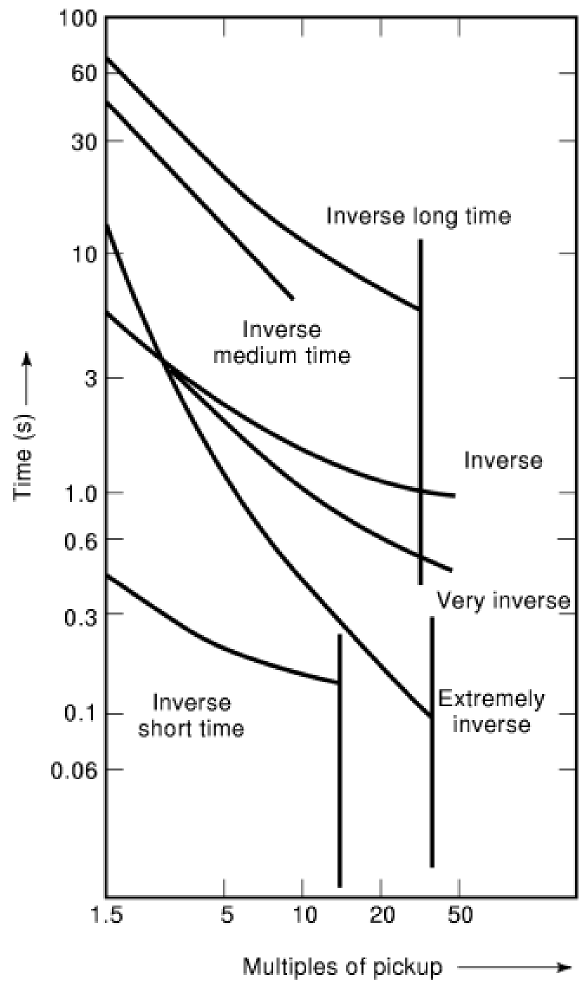

Fig. 1. Typical time-current characteristics of overcurrent relays.

sensitivity usually occurs when the two currents are in phase. A product-type directional relay operates on the product of the current in the operating coil and voltage or current in the polarizing coil. These relays find application in ground fault differential schemes for generators and transformers.

Differential Relays. Differential relays provide high-speed (1 to 2 cycles), sensitive, and inherently selective protection. These will not provide protection for turn-to-turn winding faults in generators, motors, and transformers because of the small increment in the current produced by such faults, which remain below the pickup sensitivity of the relays. An overcurrent relay can be used to provide differential protection when it is so connected that external fault currents through the current transformers balance out and do not give rise to a current in the relay operating coil. A phase or ground fault within the protected zone results in current unbalance and operates the relay. This scheme is limited by current transformer saturation at high magnitudes of external fault currents. *Partial differential protection* of a motor uses core balance transformers, which circle phase and neutral leads so that under an external fault situation the magnetic fluxes in the core of the transformer balance out and current transformer saturation is avoided.

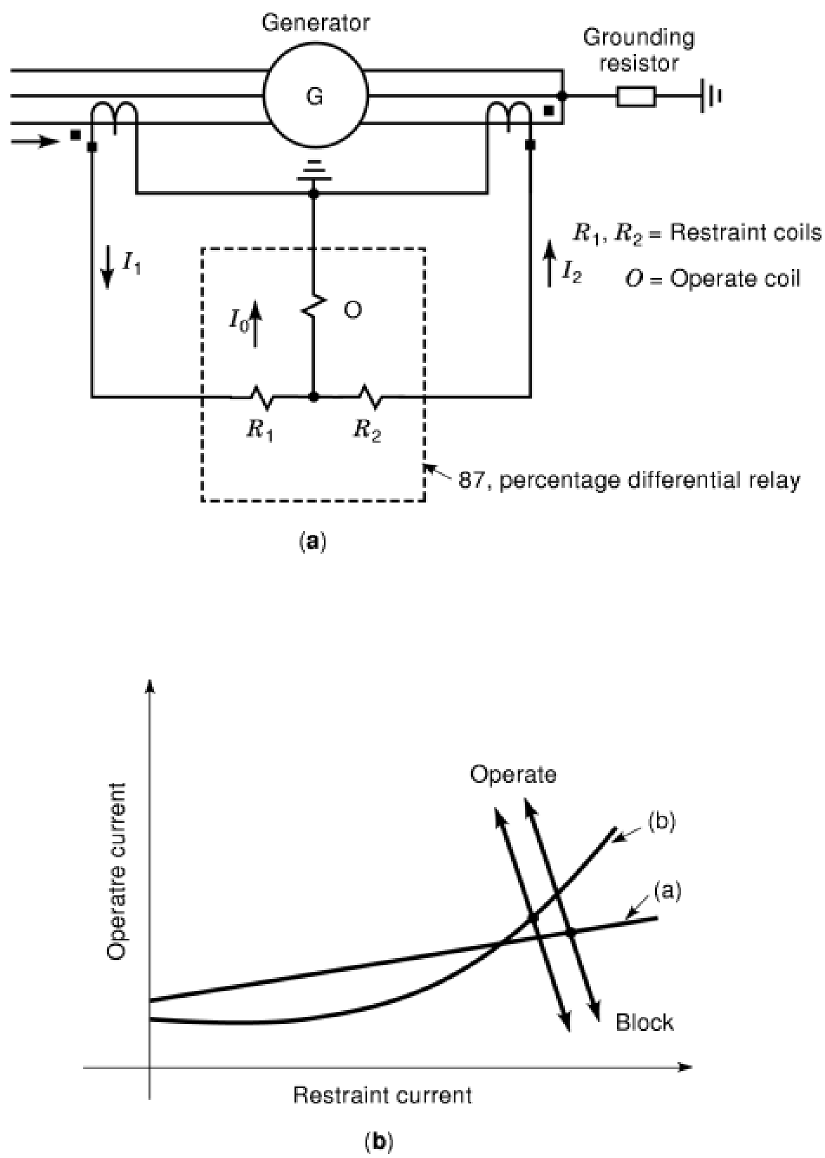

Fig. 2. (a) Connections of percentage restraint differential relay (one phase shown), where R_1 and R_2 are restraint coils, O is an operating coil, I_1 and I_2 are current transformer secondary currents; I_0 is the operating current = $I_2 - I_1$. (b) Characteristics of percentage restraint differential relays where (a) is the fixed restraint and (b) is the variable restraint. Restraint current = $(I_1 + I_2)/2$.

Percentage differential relays are used for protection of transformers, bus, motor or generator. Figure 2 shows the basic connections of a percentage differential relay and its characteristics. Load and external fault current circulates through the restraint coils, and no current flows through the operating coil, except as a result of current transformer errors. For a fault in the protected zone, the difference current flows through the operating coil to actuate the relay. For a fixed restraint relay, the operating current required to overcome restraint is a fixed percentage of the restraint current, whereas in a variable restraint relay the current to operate the relay increases with the magnitude of fault current. The number of relay input restraint elements will vary with the design and application. For transformer differential protection, harmonic restraint may also be applied to make the relay insensitive to transformer inrush currents, which are rich in harmonics. An instantaneous trip unit is included for high-magnitude internal faults.

High-impedance differential relays are primarily used for bus protection. A high-impedance relay is connected across the current transformer secondaries, which are paralleled together with proper polarity. An external fault results in currents circulating between the current transformers and creates a low voltage across the relay, which is set to operate above this value. For an internal fault, the resulting secondary voltage exceeds this set value. The current transformers must be of the same ratio. The system can easily accommodate expansion, when more circuits are added.

Pilot differential relays are applied to short transmission line protection of approximately 40 km (25 mi) length or less, where a metallic, microwave, or fiber-optic communication circuit is available to compare the system conditions at two ends of the transmission line. The protection is analogous to differential protection of transformers and machines. Composite filters are used to convert three-phase currents at each end into a single-phase voltage. These single-phase voltages are compared at each line terminal over the pilot channels to determine whether the fault is inside or outside the protected zone. The pilot channels are continuously monitored for open and short circuits. Transfer trip facilities are usually added with additional relays. The series resistance and shunt capacitance of the pilot wires and the voltages developed under fault conditions are of concern. Drainage reactors, neutralizing and insulating transformers, and surge arresters are needed. These complications can be avoided and security enhanced by using fiber-optic or microwave channels and interfaces, which are not affected by fault-induced voltages.

Distance Relays. There are basically three types of distance relays: (1) an impedance type of relay measures the voltage-to-current ratio on a faulty line, which is the impedance to fault; (2) a reactance type of relay measures a signal proportional to the imaginary component of the voltage-to-current ratio; and (3) an admittance type of relay, also called a mho relay, measures current to voltage and is inherently directional. The relays thus respond to impedance, reactance, or mho, rather than the fault current. Static distance relays may operate within 0.5 cycle of fault inception. External timers and the distance settings are used to provide selectively. The characteristics of a distance relay are plotted on an R–X diagram. Thus, the characteristic of an impedance relay is a circle, and the relay will operate in either direction for an impedance setting within the circle. The characteristic of a reactance relay is a straight line parallel to the R-axis and is nondirectional. A mho relay has a circular characteristic, which passes through the origin and hence is directional. Variations in these basic characteristics are conventional. Consider that a distance relay is applied to a short-line, the arc fault resistance can alter the reach of the relay and result in a no-trip or nuisance trip. Conversely, a reactance relay will remain unaffected by the arc fault resistance but may operate on load currents. It should be used in conjunction with other relays to restrict its reach along the R-axis and in a negative reactance direction. For specific applications, the characteristics of a mho relay can be offset in the forward or reverse direction. Blinder relays have an angle impedance characteristic that can be set parallel to the impedance characteristics of a line. Figure 3(a) shows characteristics of distance relays. The reverse offset mho characteristic is used for loss of excitation protection of a generator. The concentric circles and blinder characteristics, shown in Fig. 3(b) are used for out-of-step protection.

Electromagnetic Versus Static Relays. Static relays can be analog or digital types. A major advantage is programmable characteristics [i.e., a digital microprocessor-based overcurrent relay can duplicate all the ANSI characteristics shown in Fig. 1 and also International Electrochemical Commission (*IEC*) characteristics]. Some other advantages are closer current and time setting ranges and lesser tolerances, 0.5% versus 5% or more on pickup for electromagnetic relays and elimination of overtravel inherent in electromagnetic relays (overtravel is the tendency of the relay disk to continue movement resulting from inertia, once the fault is removed). As overtravel is eliminated, *CTI* (coordinating time interval) between successive levels of protection can be reduced by approximately 0.1 s. Static relays have faster reset time; lower operating burdens; and

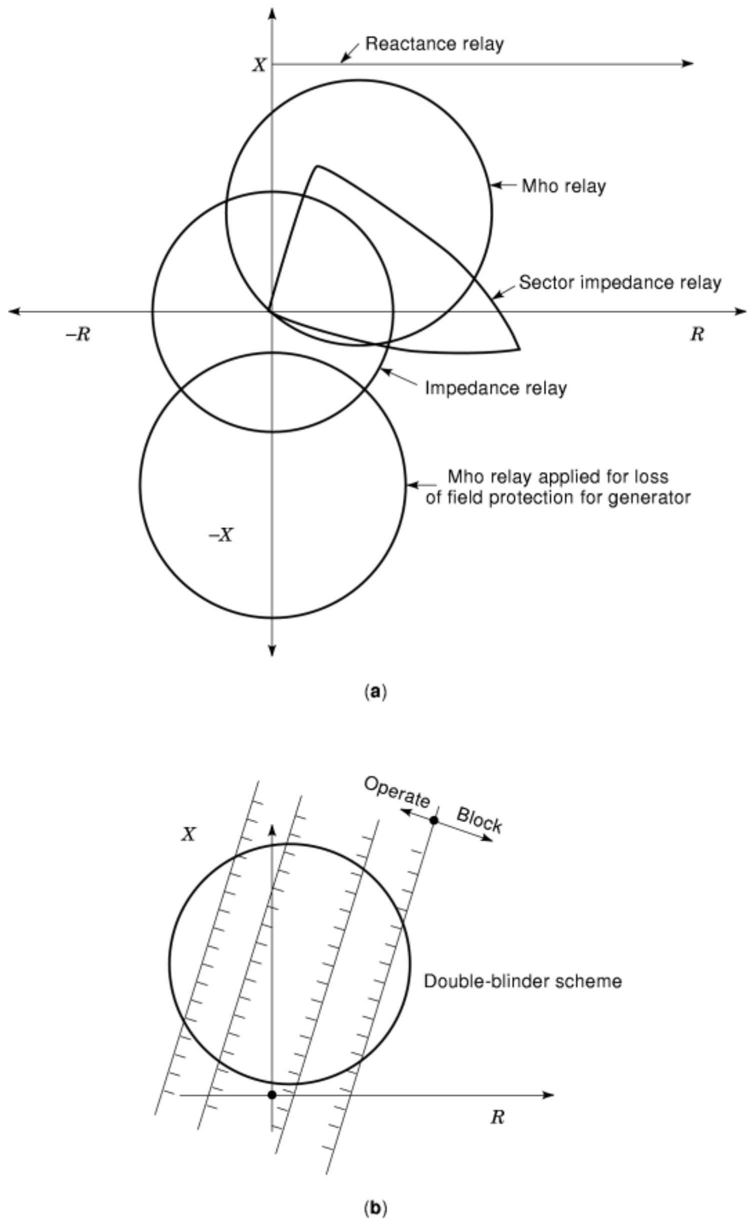

Fig. 3. (a) Characteristics of distance relays. (b) A double blinder distance relay scheme, used for out-of-step relaying.

much smaller dimensions resulting in saving of panel space and external wiring. In addition, metering, remote communication, data logging and self-diagnostic facilities can be included. Figure 4 shows a general schematic of a microprocessor-based digital relay.

Adaptive Relaying. Adaptive relaying is defined as a protection system in which the relay settings can be changed automatically so that its function is consistent with the changing power system conditions. As power system conditions change, the response to various transients will be different. Out-of-step relaying and

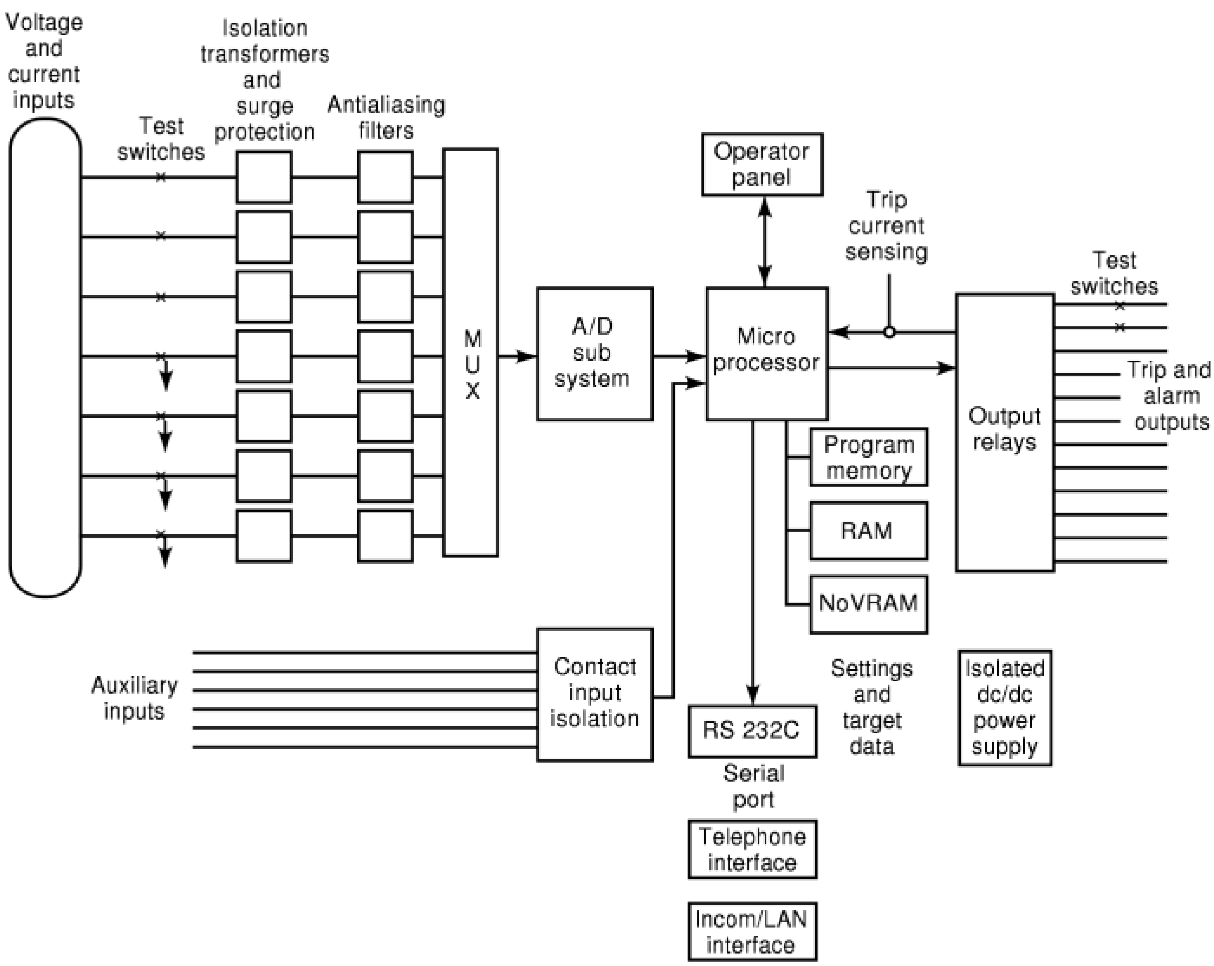

Fig. 4. Block diagram of a microprocessor-based digital relay.

distance relaying, where the system operation and changes introduce errors, are the applicable fields. Digital line protection systems can also employ adaptive relaying methods.

Instrument Transformers

Instrument transformers are interfaces between the power system and protection and metering devices. These serve two purposes: (1) transform the power system high currents and voltages to low values acceptable for relaying and (2) protect personnel and relaying equipment from high voltages by sufficient insulation levels.

Current Transformers.

Accuracy Classification. Accuracy of the current transformers is an important consideration for protective relay performance. A current transformer should faithfully reproduce secondary currents in direct proportion to primary currents, depending upon its ratio, from load currents to high fault currents. The accuracy at high currents is a function of the cross-sectional area of the core and the number of secondary turns. As the cross-sectional area gets larger, the saturation caused by fluxing from short-circuit currents will be less. Accuracy in low-ratio bar-type current transformers is therefore limited by the core size. *ANSI/IEEE* designates accuracy classification by one letter, C or T. C classification covers bushing-type transformers with uniformly distributed secondary windings, and the leakage flux has a negligible effect on the ratio within defined limits. The performance of C-type current transformers can be readily calculated, but the T-type current transformers must be tested. T classification covers wound-type transformers whose core leakage flux appreciably affects the ratio. The standard designated secondary terminal voltages are 10, 20, 50, 100, 200, 400, and 800 V for 5 A secondary current transformers at the specified standard burdens. A transformer with relaying accuracy class C200 means that the percentage ratio correction will not exceed 10% at any current from 1 to 20 times the rated secondary current at a standard burden of 2.0 Ω, which will generate 200 V. If the current transformer is rated at anything other than 5 A secondary, the appropriate voltage rating values may be derived by multiplying the 5 A voltage ratings by 5 and dividing by the actual current transformer secondary amperes rating.

Current transformer burden is the load, including its leads, connected to the secondary terminals of the transformer and expressed in volt-amperes (VA) at a specified power factor and current or as total impedance in ohms with effective resistance and reactive components. For comparing various transformers, ANSI has designated standard burdens.

Current Transformer Performance. Current transformer steady-state performance can be calculated from ANSI accuracy classification for C type or excitation data supplied by the manufacturer for C and T types. The secondary voltage as given by the maximum fault current reflected on the secondary side multiplied by the connected burden should not exceed the assigned C accuracy class. Conversely, the permissible current transformer burden for a given accuracy class can be calculated. Performance using excitation data calculates the excitation current at the secondary voltage, which should be a small percentage of the operating current. For T-type transformers, the manufacturer should supply overcurrent ratio curves from 1 to 22 times normal current and for all standard burdens up to the one that causes a ratio error of 50%.

The transient performance should consider the dc component of the fault current because it has far more effect in producing severe saturation of the current transformer than the ac component. Before a current transformer reaches its saturation flux, it may still accurately reproduce the offset fault current for a short duration. The time to saturate is a function of magnitude of the short-circuit current and its offset, secondary burden, system time constant, and current transformer time constant and its characteristics. The current transformers may saturate within the first half cycle at large fault currents. The remanence in the core is the result of a previous current interruption, at other than current zero. This can force the current transformer into saturation sooner than expected. Figure 5 shows the output of a saturated current transformer. *Time to desaturate* is dependent upon the same parameters as the time to saturate and is on the order of five cycles, largely because of the power system time constant.

If a current transformer is chosen based upon steady-state performance, current transformer saturation due to dc offset will not cause problems on the operation of time overcurrent relays, as long as the dc component decays to zero in the time the relay is expected to operate. For high-speed relays, such as instantaneous relays, differential and distance relays, and other relay types operating in less than two cycles, the current transformers should be selected so as not to saturate in less than 2 cycles. The rms value of the distorted output current of a current transformer can be calculated. Relays that respond to only the fundamental may be more seriously affected than what the rms value indicates. Selecting as high a ratio as an application will permit and series and parallel connections of current transformers are some of the means to reduce saturation. Current transformers with an air gap have a fairly high exciting current and low residual flux and can be used in some differential schemes; however, their use is limited in the modern protective schemes.

Voltage Transformers. Most protective relays have standard voltage ratings of 120 V or 69 V depending on whether these are connected phase-to-phase or phase-to-ground. Voltage transformers transform from system voltage level to the relaying quantities, and for high-voltage applications voltage transformers will consist of single-phase units connected line-to-ground and protected for the basic impulse insulation level

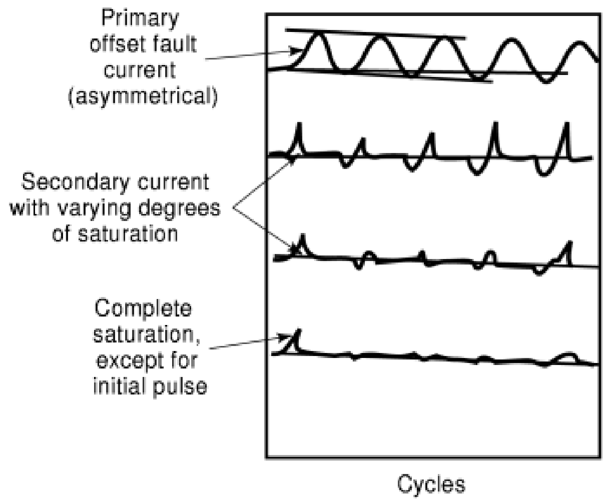

Fig. 5. Current transformer saturation, waveform of secondary current output for various degrees of saturation.

(*BIL*) of the system. These are connected in wye–wye connections and may have multiple secondary windings (i.e., one set of windings may be connected in open corner delta to sense zero sequence voltages). In medium-voltage switchgear, when the zero sequence voltage is not needed, an open delta connection of two voltage transformers is often used. Typical rated maximum errors for these devices are 0.3, 0.6, and 1.2%.

Coupling capacitance voltage transformers (*CCVTs*) provide an economical method of stepping down the high voltage by using a capacitance tap on a condenser bushing. Surge suppression, tuning reactor, isolation transformer, and ferroresonance suppressor circuits are included. These are inferior to voltage transformers in transient performance. After a sudden collapse of terminal voltage, say as a result of a fault, the stored energy in the capacitance and inductance of CCVT is dissipated in damped oscillations. CCVTs can be designed for metering and relaying applications. Generally, these are not used for revenue metering.

Transient Stability and Load Shedding

The response of an electrical system to sudden impacts is oscillatory in nature. *Transient stability studies* are limited to relatively short time intervals, typically 1 s or less, and are used to determine the stability of a single unit or plant during the initial period of high stress immediately following a nearby fault. *Dynamic stability studies* cover longer periods, occasionally up to 30 s. Attention may be focused on a single unit or plant, but frequently these studies are made to obtain large system response, say under a breakup or an isolated system having excess load or generation.

In the *classical stability* model of a synchronous machine on infinite bus, the mechanical power input is considered constant during the transient, damping is neglected, the synchronous machine is represented by a constant voltage source behind a transient reactance, and the mechanical angle of the rotor is considered coincident with the electrical phase angle of the voltage behind the transient reactance. These concepts have undergone much change, and more elaborate models of synchronous machines in direct and quadrature axis, saturation characteristics, excitation systems, and prime movers are used in a transient stability study, invariably carried out on a digital computer. The swing equation of a synchronous machine on an infinite bus can be

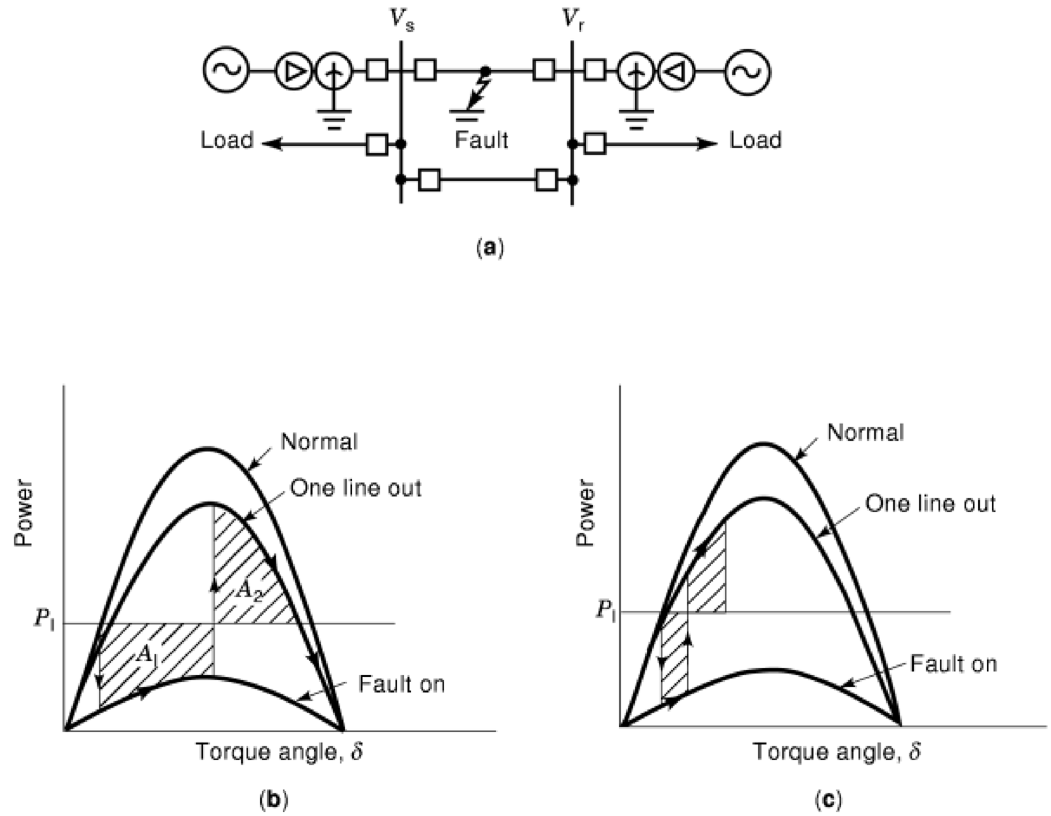

Fig. 6. (a) An electrical distribution system interconnected with duplicate feeders, loads and generation at each end, and a fault on one of the paralleled feeders. (b) Instability caused by delayed fault clearing. Applying equal area criterion of stability, area A_2 is less than area A_1. (c) Stability caused by fast fault clearance.

written as

$$\frac{2H}{\omega_s}\frac{d^2\delta}{dt^2} + \frac{D}{\omega_s}\frac{d\delta}{dt} + K_1\Delta\delta + K_2\Delta E'_q = 0 \tag{7}$$

where H is the inertia constant, ω_s is the synchronous frequency, D is the damping coefficient, K_1 is the synchronizing coefficient, $K_2\ \Delta E'_q$ is determined mainly by changes in the excitation level, and $\Delta E'_q$ represents changes in the machine flux and δ is the torque angle. This equation is nonlinear and requires numerical step-by-step methods for solution.

Factors Affecting Stability. Some of the factors affecting stability are high-speed fault clearance, generator dropping, series capacitor insertion, fast valving, fast excitation systems, auto reclosing, reserve capacity in the system, and system impedance.

Figure 6 illustrates the effect of fast fault clearance on transient stability, using *equal area criterion.* Simply stated, the equal area criterion means that the integral of decelerating power with respect to torque angle must not exceed the integral of accelerating power with respect to torque angle for transient stability to be retained. Referring to Figs. 6(b) and 6(c), P_1 is the steady-state power of the generators supplied to the load, ignoring line losses, and δ_1 is the initial torque angle before the fault occurs. On a simplistic basis, the power supplied is given by

$$P = (V_s \cdot V_r \cdot \sin\delta)/X \tag{8}$$

where X is the system reactance, and V_s and V_r are the sending end and receiving end voltages. The theoretical steady-state maximum power transfer is achieved at $\delta = 90°$. Area A_1 represents the energy gained by the generators in accelerating, whereas area A_2 represents the energy lost. The maximum swing in torque angle is fixed by the condition that $A_1 = A_2$. Thus, for any power transfer there is a *critical clearing angle,* and unless the fault is cleared before the torque angle equals the critical clearing angle, the stability will be lost.

Reclosing. A fault on a transmission line interrupts or reduces the flow of synchronizing power between the systems it interconnects, and thus power swings and overloads are thrown on other lines. The torque angles between the systems may swing beyond critical value, and synchronism may be lost. Some synchronizing power is transmitted through the unfaulted phases during the faults, except for three-phase faults. The flow of synchronizing power is completely interrupted on the faulted line when the breaker opens. When a single-phase tripping is employed, some synchronizing power flows through two unfaulted phases. This improves the stability limit. The need for high-speed reclosing is thus minimized, although additional gear is needed to quench the arcing fault caused by coupling of the operating energized phases. Figures 7(a) and 7(b) show the equal-area criterion applied to high-speed single phase reclosing. $\delta_3 - \delta_2$ is called the dead time.

Load Shedding. Under a steady-state condition, the active power generated in the electrical system equals the summation of loads plus losses. Any unbalance in this identity will cause a speed change in the turbine-generators and a corresponding frequency change. Thus for a sudden load increase, the rotors slow down, supplying energy to the system. The rate of frequency decay is a function of load unbalance and the inertia constant H of the system.

For gradual load changes and mild overloads, the generator governors will sense the speed change and change the power input to the generator. For rapid frequency plunges that accompany severe overloads, such as when the tie line is lost or one of the generators trips, the governor response cannot arrest the frequency decay. Initially a load *slightly larger than the overload* is shed; otherwise, the frequency will remain bottomed and will not recover to the normal. Frequency relays are used throughout the electrical system and are set to shed a certain amount of load, with a preset time delay, at specific low frequencies. After the frequency decay is arrested, and the frequency returns to normal (generally, it will have an overshoot above the normal frequency), the load is restored in increments to the extent permitted by the spinning reserve. Additional generators may then be brought on line, when the frequency is stable enough to permit their synchronization.

Protective Relaying Schemes

Generator Protection. The selection and protection arrangements of a generator are influenced by the method in which it is connected to the system (i.e., unit generator-transformer configuration, cross-compounded generator, generator sharing a unit transformer, and generator directly connected to a distribution system). Further, the grounding methods; high-resistance grounding, low-resistance grounding, and reactance grounding; generator excitation systems; stator winding arrangements; and the size of the generator are also of consideration.

Generator stator thermal protection is provided by a number of resistance temperature detectors (*RTD*s) in the stator windings. RTDs are also used for failure of cooling systems and bearing overtemperatures. In hydrogen-cooled machines, core hot spot temperatures can be detected by an ion particle detector, which monitors submicron-size particles as a result of thermal decomposition. Voltage regulator systems incorporate overexcitation and volts per hertz protection and indirectly provide thermal protection of the field windings.

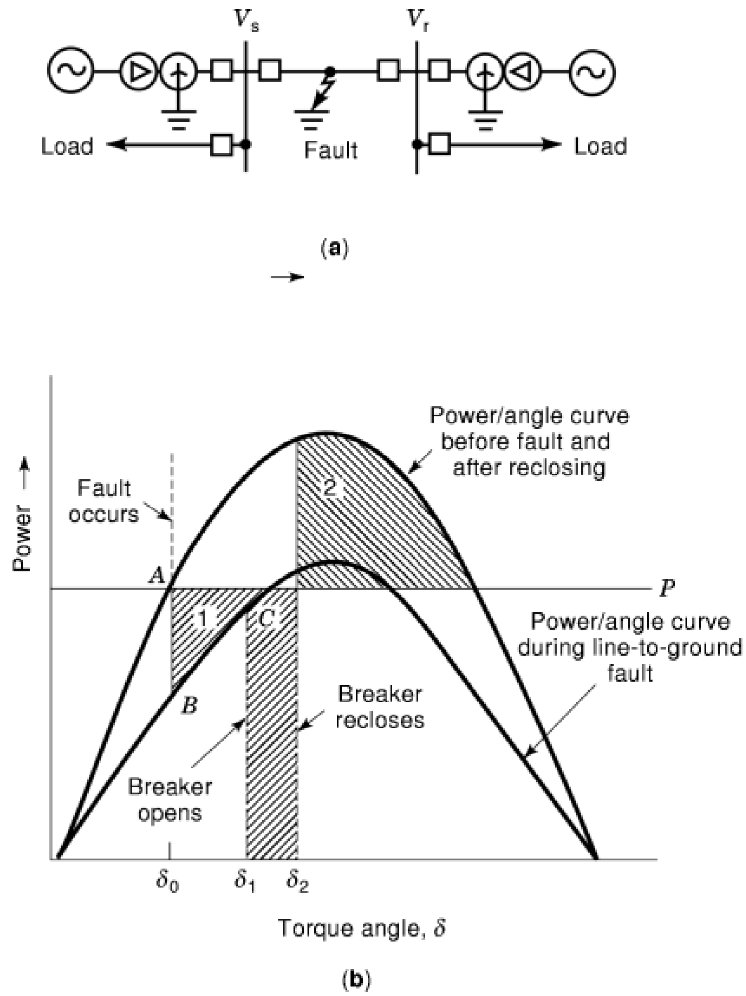

Fig. 7. (a) Electrical distribution system, with a fault on the single interconnecting feeder. (b) Transient stability with autoclosing on a transient fault. No power is supplied during the dead time (see text).

Stator-phase fault protection is provided by variable slope percentage differential relays; however, differential protection will not provide protection for turn-to-turn faults for single-stator windings. If a generator has multiturn coils with two or more circuits per phase, the split-phase relaying scheme can be used. Distance relays or voltage-controlled or voltage-restrained overcurrent relays are used for backup overcurrent system protection.

The percentage of the stator windings protected by a phase fault differential relay depends upon the ratio of the ground fault current to generator rated load. For low-resistance grounding, a product type of ground fault differential relay is used to supplement a time delay overcurrent relay on the neutral. For high-resistance grounded generators, a time delay overvoltage relay is connected across the grounding impedance. A protection scheme with third harmonic relay supervised by a relay to prevent operation when excitation is removed from the generator can be used to provide 100% winding protection against phase-to-ground fault. Other methods used are a third harmonic differential scheme and a subharmonic voltage injection scheme. Rotor ground fault

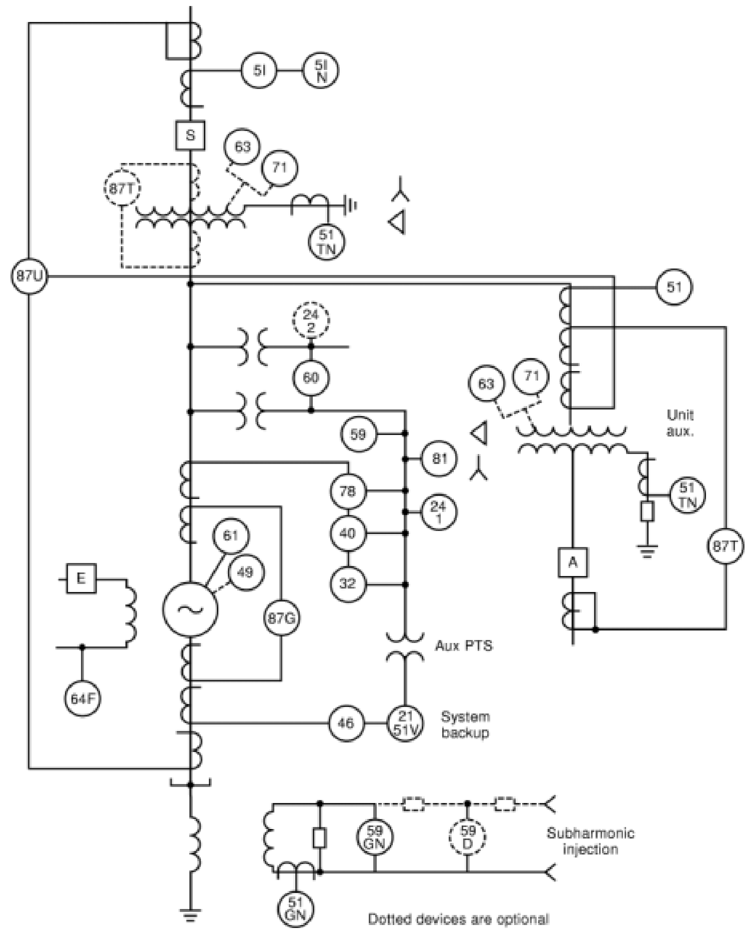

Fig. 8. Protection of a unit generator-transformer configuration. The numbers indicate ANSI/IEEE protective device function numbers. 51: phase overcurrent inverse time relays; 51N: residually connected ground overcurrent inverse time relay; 51TN: transformer neutral connected ground overcurrent inverse time relay; 51GN: generator neutral connected ground overcurrent inverse time relay; 87T, 87U, 87G: transformer, unit, and generator phase differential relays; 64F: generator field ground detector relay operating on failure of field insulation to ground; 32: reverse power or generator antimotoring relay; 49: generator stator winding thermal overload relay; 61: generator winding interturn fault detection relay; 40: generator loss of excitation relay; 78: generator out-of-step relay; 59: overvoltage relay; 59GN, generator neutral overvoltage relay; 59D: instantaneous third-harmonic voltage differential relay; 81: over- or underfrequency relay; 24: volts per hertz relay; 60: voltage balance relay; 63: transformer fault pressure relay; 71: transformer low oil level detector relay; 51V: voltage-controlled or voltage-restrained overcurrent relay; 21: distance relay. Devices 51V or 21 provide system backup protection.

protection can be provided through optical transmitters mounted on the rotor with brushless exciters, an optic coupler, and a receiver.

On loss of excitation, a generator will overspeed and operate as an induction generator. A hydrogenerator may carry 20% of load as a result of saliency and still remain in synchronism. The most widely used protection system uses one or two offset mho relays. The trace of the impedance locus as viewed from the machine terminals under normal operation and loss of excitation conditions forms the basis of loss of excitation protection.

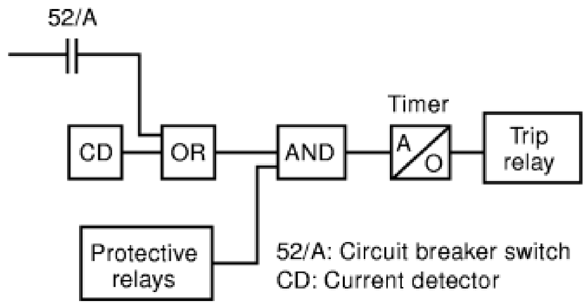

Fig. 9. Functional diagram of a breaker failure scheme.

The system asymmetries, unbalanced loads, and system faults produce negative-phase sequence components of current that induce a double-frequency current in the rotor. The ability of a generator to accommodate unbalanced currents is specified in standards as $I^2{}_2t$ capability, where I_2 denotes the rms value of all the negative sequence currents in per unit (i.e., harmonics 5th, 11th, 17th) and t is the time in seconds. This value is usually between 30 and 90. A static relay is often applied and is more sensitive than an inverse time electromagnetic relay.

After a generator has pulled out of step, the resulting high peak currents and off frequency operation cause winding stresses, pulsating torques, and mechanical resonances that are potentially damaging to the generator. Out-of-step protection is provided by an offset mho relay and a single blinder scheme.

A complete generator protection should include other protective functions such as under/overvoltage, volts per hertz protection, over and underfrequency protection for the turbine, antimotoring protection through reverse power relays, and system backup protection using distance- or voltage-controlled or voltage-restrained overcurrent relays. Breaker failure schemes are often provided for large installations. Figure 8 shows a protection scheme applied to a generator directly connected to a step-up transformer.

Breaker Failure Schemes. Figure 9 shows a functional diagram of a breaker failure scheme. If the breaker does not clear a fault in response to the actuation of a protective relay in a certain time, a timer trips the other breakers in the system to remove the fault from the system. To actuate the timer, a protective relay must operate, and a current detector or breaker “a” switch must indicate that the breaker has failed to open. Other backup schemes include dual-sensing relays, which may be of a different type from the primary protection.

Transformer Protection. Statistically, winding failures in transformers account for approximately 50% of the total failures. Another 19% of the total failures are attributed to tap changer failures. The most difficult transformer winding fault to protect is a turn-to-turn internal fault. Possibly 10% of the winding has to be short-circuited to cause full load current to flow. Sudden rate of rise pressure relays and winding temperature relays may provide some measure of protection against such faults.

Transformer through fault withstand capabilities are described in ANSI/IEEE standards, and the transformers are classified into four categories with respect to their ratings. For unbalanced secondary faults, the currents reflected on the primary windings are a function of the winding connection and are accounted for in selecting and setting overcurrent devices to protect the transformers within their through-fault current limits. When selecting fuses or instantaneous relays, the magnetizing inrush currents are always of consideration—these should be set high so as not to cause nuisance operation and within the guidelines established in the National Electric Code (*NEC*).

For transformers above 10 MVA (in industrial installations) and 20 MVA in consumer utility ties, harmonic restraint differential relays are generally applied. These have restraint on inrush currents, which are rich in harmonics, to prevent false trips on transformer energizing. Compared with percentage differential relays,

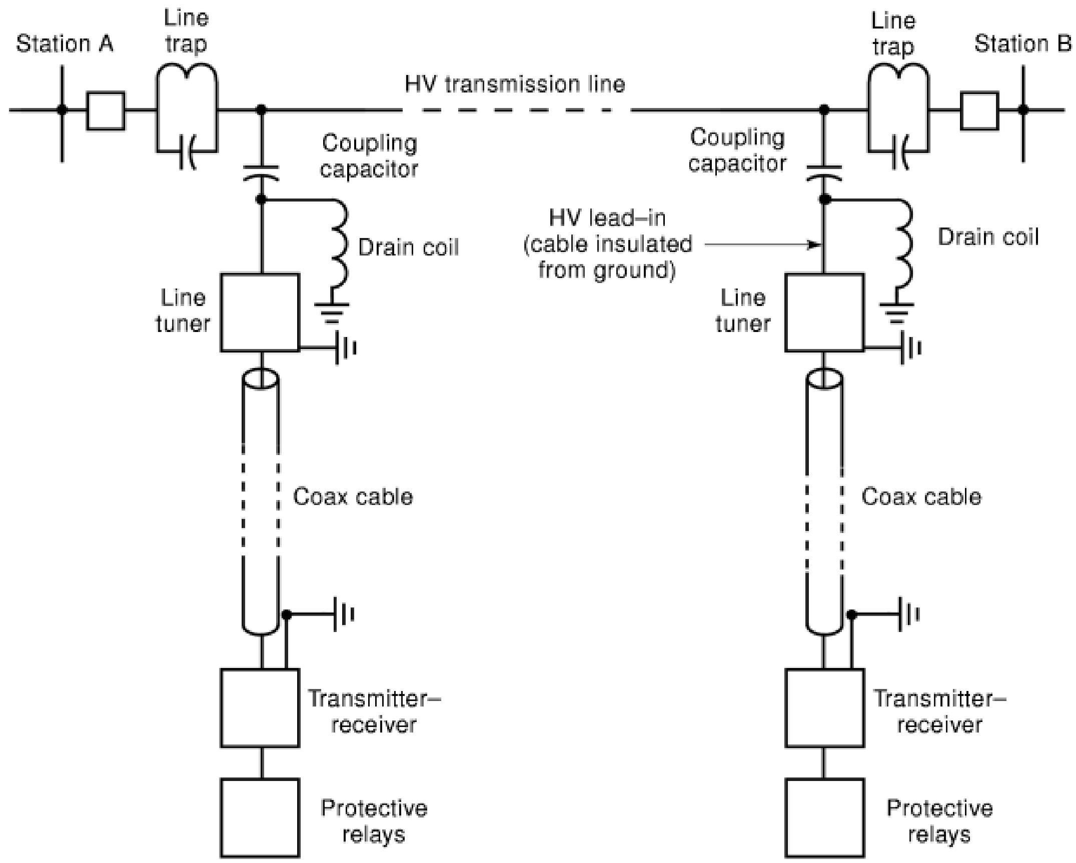

Fig. 10. Basic elements of a PLC system for HV transmission line protection.

harmonic restraint differential relays have lower pickups and faster operating times, typically 0.03 s to 0.05 s versus 0.1 s to 0.2 s for percentage differential relays. Current transformer connections for differential relays should consider the phase shifts introduced in the primary and secondary voltages by their winding connections. In some static relays, the current and power transformer connections can be programmed to account for phase shifts and secondary currents.

High-Voltage (*HV*) Transmission Line Protection. Most transmission lines are protected by directional distance relays. These may serve as backup protection to other schemes in service, or these may be the sensing components in various forms of differential protection.

Figure 10 shows the basic elements of a *PLC* (power line carrier) system extensively used for protection of HV transmission lines. An HV transmission line is capable of simultaneous functions of communications and electrical energy transmission. PLC equipment consists of three distinct parts: terminal assemblies consisting of transmitters, receivers, and protective relays; the coupling and tuning equipment, which connects the terminals to selected points on the transmission line; and the transmission line itself, which provides a suitable channel for the transmission of carrier energy in PLC bands of frequencies between terminals. Coupling to lines is accomplished by means of high-voltage capacitors, which provide a low-loss path to carrier signals and block 60 Hz power frequency energy from the carrier equipment. Line traps minimize the loss of carrier power into adjacent lines and prevent external ground fault currents from short-circuiting the carrier signal of the unfaulted line.

Carrier Frequencies. Frequencies in the range of 30 kHz to 500 kHz have been employed for PLC relaying and other communication purposes. The range is high enough to be isolated from the transmission line and the noise it creates and yet not so high as to give rise to excessive attenuation. There are two basic types of signals used for teleprotection channels. Keyed carriers are sometimes referred to as *AM*, amplitude modulation: It is normally off and intelligence is transmitted by turning the carrier on and off. This type of signal is normally used in blocking-type relaying systems. The frequency may be in range from 29 kHz to 31 kHz, and the signal could be applied to a single sideband (*SSB*) PLC channel.

Frequency Shift Keyed Carrier. This signal is always on, which provides a means of continuously monitoring the channel. The frequency shift keyed (*FSK*) carrier is less susceptible to noise and has a greater operating range. FSK channels have been available with two-frequency operations, high and low shift frequencies for additional security.

Blocking Schemes. Transmission line faults are detected using either high-speed phase comparison, in which the phase of the currents at the two terminals are compared, or direction comparison relaying. The scheme operates in a trip permissive mode. A received signal is used to block tripping of the protected line for external faults. The blocking scheme is biased toward dependability because channel or remote relay failure will result in operation of the local blocking relay.

Tripping Schemes. A phase comparison tripping scheme channel is keyed to the trip condition every half cycle during the fault. The scheme is biased toward security so that a failure of the channels or relays would result in nonoperation of the local relay for external and internal faults. Directional distance relays can be used both for phase as well as ground fault conditions.

Relay Coordination

Coordination is a systematic application of current actuated devices in a power system, which in response to a fault or overload will remove only a minimum amount of equipment from service. The objective is to minimize the equipment damage. A coordination study provides data useful for selection of instrument transformers, protective relay characteristics and settings, fuse ratings, and other information pertinent to provision of optimum protection and selectivity in coordinating these devices.

Planning and Data Collection. The following data and initial planning steps are required before a coordination study is started:

- Single-line diagram of the electrical system with details of equipment ratings.
- Load flow data and short-circuit data. The maximum and minimum available short-circuit currents, both for phase and ground faults at each relay location in the system.
- Time-current curves, setting ranges, type of characteristics of the protective devices, instrument transformer connections and ratios.
- Power and voltage ratings and winding connections of all power transformers.
- Normal and emergency switching conditions.
- Transformer impedance data, generator fault decrement curves, equivalent impedances of the interconnected networks, conductor sizes, type and configurations and method of installations.

Coordinating Time Intervals. When plotting coordination curves, certain time intervals must be maintained between curves of various protective devices in order to ensure the desired selectivity. These intervals take into account the circuit breaker interrupting time, relay overtravel and an arbitrary safety factor to take into account current transformer errors and tolerances in the relay characteristics. For relayed

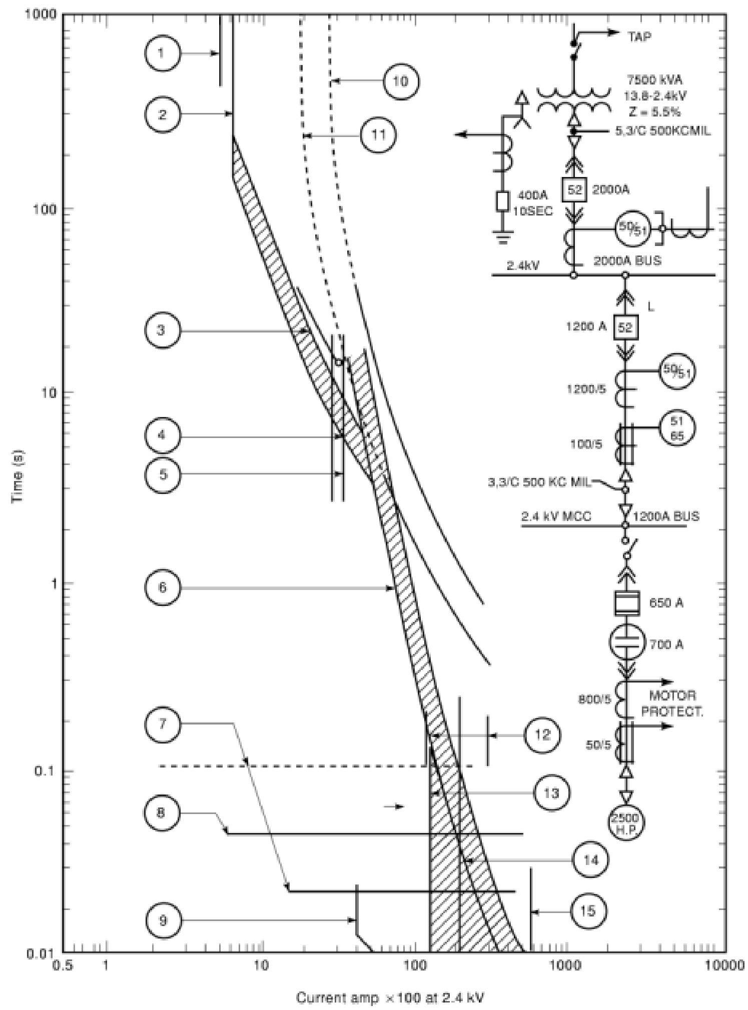

Fig. 11. Phase overcurrent device coordination: 1862.5 kW (2500 hp) motor, 2.4 kV main and feeder breakers, and fused motor contactor. 1: Motor full load current = 545 A; 2: Motor relay pickup = 646 A; 3: Motor thermal damage curve; 4: Motor locked rotor current; 5: Motor adjusted locked rotor current; 6: 650 A motor fuse characteristics; 7: dropout time variations, vacuum contactors; 8: dropout time air-break contactors; 9: Inrush current of the motor control center (largest motor); 10: breaker K overcurrent relays pickup = 2800 A; 11: breaker L overcurrent relays pickup = 1920 A; 12: three-phase sym. short-circuit current after 6 cycles = 27.27 kA, with in-plant generator only in service = 11.74 kA; 13: Interrupting kiloampere vacuum contactor, 14: Interrupting kiloampere air-break contactor; 15: transformer let-through current = 57.20 kA asym.

medium-voltage circuit breakers, interrupting time five cycles, and very inverse and extremely inverse electromagnetic relays, a CTI of 0.4 s is adequate. For solid static relays this can be reduced to 0.3 s because relay overtravel is eliminated. Relayed circuit breakers with electromagnetic relays can be coordinated with downstream fuses with 0.2 s CTI, which can be reduced to 0.1s with static relays. Coordination between fuses for a time duration of less than 0.01s should not be evaluated on a time-current basis. Two series connected instantaneous devices will coordinate if the maximum let-through I^2t of the downstream device is less than minimum I^2t let-through of the upstream devices. Coordination between instantaneous relays without an intervening impedance is generally not possible.

An Example of Protection and Coordination in an Industrial Distribution System. Figure 11 shows the phase overcurrent coordination of the protective devices for 1862.5 kW (2500 hp) motor, 2.4 kV main and feeder breakers, and motor contactor interrupting ratings. The 1862.5 kW (2500 hp) motor is controlled by NEMA 2 motor starter, consisting of a 700 A vacuum contactor and a 650 A type R fuse. The selected fuse should be the smallest whose minimum melting time characteristics does not cross the motor overload relay for currents less than the adjusted locked rotor current of the motor. The adjusted locked rotor current is taken 10% higher than the actual locked rotor current to account for system voltage variations and manufacturing tolerances. In order to coordinate with the selected motor fuse, the pick-up settings on overload relays of feeder breaker L serving 2.4 kV control center are set at 1920 A. This exposes the circuit breaker to 160% of its continuous current rating; however, this compromise is acceptable because practically low level of short-circuit currents will not be sustained and each load at the control center has its own overcurrent protection. The coordination between fuse and 50 MVA interrupting rating of the vacuum contactor for a drop out time of 0.02 cycles is not achieved, and there is a possibility of the contactor clearing a fault current exceeding its interrupting rating. The remedial measures for this situation can be (1) delaying the opening of the motor contactor, (2) connecting the 1862.5 kW (2500 hp) motor to 4.16 kV system, or (3) devising a special design of the 1862.5 kW (2500 hp) motor to reduce the locked rotor current permitting a lower fuse size. The example illustrates the judgment that a protection engineer should make in accepting compromises in a given situation for arriving at an acceptable engineering solution.

Recent Trends

Recent trends in protective relaying are being dictated by advancements in electronics, microprocessor technology, programming, and packaging. It would have been impossible to detect an impeding bearing failure in a motor using electromagnetic devices; however, neural network techniques to characterize the current spectra associated with a normal state of a motor and load makes the detection possible by monitoring the changes in the bearing frequencies as reflected in the current spectra. Developments in high-impedance fault detection (*HIFD*s) fault localization systems, charge-comparison type of current deferential relaying and adaptive relaying are further examples. More knowledge-based systems and new algorithms will be applied to protective relaying, coordination, service restoration, and remedial control actions. Multifunction microprocessor-based relays make it possible to integrate a number of protective functions, metering data, fault location, remote communication, and data logging in a single modular package unit. As an example, most of the generator protective functions shown in Fig. 8 are available in a single unit with added facilities of self-diagnostics, communications, and fault data capture.

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