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Power System Protection

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9.1 Transformer Protection

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Types of Transformer Faults

Any number of conditions have been the reason for an electrical transformer failure. Statistics show that winding failures most frequently cause transformer faults (ANSI/IEEE, 1985). Insulation deterioration, often the result of moisture, overheating, vibration, voltage surges, and mechanical stress created during transformer through faults, is the major reason for winding failure.

Voltage regulating load tap changers, when supplied, rank as the second most likely cause of a transformer fault. Tap changer failures can be caused by a malfunction of the mechanical switching mechanism, high resistance load contacts, insulation tracking, overheating, or contamination of the insulating oil.

Transformer bushings are the third most likely cause of failure. General aging, contamination, cracking, internal moisture, and loss of oil can all cause a bushing to fail. Two other possible reasons are vandalism and animals that externally flash over the bushing.

Transformer core problems have been attributed to core insulation failure, an open ground strap, or shorted laminations.

Other miscellaneous failures have been caused by current transformers, oil leakage due to inadequate tank welds, oil contamination from metal particles, overloads, and overvoltage.

Types of Transformer Protection

Electrical

Fuse: Power fuses have been used for many years to provide transformer fault protection. Generally it is recommended that transformers sized larger than 10 MVA be protected with more sensitive devices such as the differential relay discussed later in this section. Fuses provide a low maintenance, economical solution for protection. Protection and control devices, circuit breakers, and station batteries are not required.

There are some drawbacks. Fuses provide limited protection for some internal transformer faults. A fuse is also a single phase device. Certain system faults may only operate one fuse. This will result in single phase service to connected three phase customers.

Fuse selection criteria include: adequate interrupting capability, calculating load currents during peak and emergency conditions, performing coordination studies that include source and low side protection equipment, and expected transformer size and winding configuration (ANSI/IEEE, 1985).

Overcurrent Protection: Overcurrent relays generally provide the same level of protection as power fuses. Higher sensitivity and fault clearing times can be achieved in some instances by using an overcurrent relay connected to measure residual current. This application allows pick up settings to be lower than expected maximum load current. It is also possible to apply an instantaneous overcurrent relay set to respond only to faults within the first 75% of the transformer. This solution, for which careful fault current calculations are needed, does not require coordination with low side protective devices.

Overcurrent relays do not have the same maintenance and cost advantages found with power fuses. Protection and control devices, circuit breakers, and station batteries are required. The overcurrent relays are a small part of the total cost and when this alternative is chosen, differential relays are generally added to enhance transformer protection. In this instance, the overcurrent relays will provide backup protection for the differentials.

Differential: The most widely accepted device for transformer protection is called a restrained differential relay. This relay compares current values flowing into and out of the transformer windings. To assure protection under varying conditions, the main protection element has a multislope restrained characteristic. The initial slope ensures sensitivity for internal faults while allowing for up to 15% mismatch when the power transformer is at the limit of its tap range (if supplied with a load tap changer). At currents above rated transformer capacity, extra errors may be gradually introduced as a result of CT saturation.

However, misoperation of the differential element is possible during transformer energization. High inrush currents may occur, depending on the point on wave of switching as well as the magnetic state of the transformer core. Since the inrush current flows only in the energized winding, differential current results. The use of traditional second harmonic restraint to block the relay during inrush conditions may

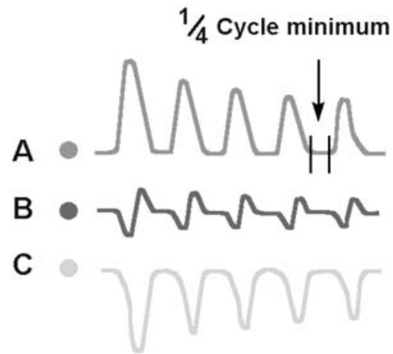

FIGURE 9.1 Transformer inrush current waveforms.

result in a significant slowing of the relay during heavy internal faults due to the possible presence of second harmonics as a result of saturation of the line current transformers. To overcome this, some relays use a waveform recognition technique to detect the inrush condition. The differential current waveform associated with magnetizing inrush is characterized by a period of each cycle where its magnitude is very small, as shown in Fig. 9.1. By measuring the time of this period of low current, an inrush condition can be identified. The detection of inrush current in the differential current is used to inhibit that phase of the low set restrained differential algorithm. Another high-speed method commonly used to detect high-magnitude faults in the unrestrained instantaneous unit is described later in this section.

When a load is suddenly disconnected from a power transformer, the voltage at the input terminals of the transformer may rise by 10–20% of the rated value causing an appreciable increase in transformer steady state excitation current. The resulting excitation current flows in one winding only and hence appears as differential current that may rise to a value high enough to operate the differential protection. A waveform of this type is characterized by the presence of fifth harmonic. A Fourier technique is used to measure the level of fifth harmonic in the differential current. The ratio of fifth harmonic to fundamental is used to detect excitation and inhibits the restrained differential protection function. Detection of overflux conditions in any phase blocks that particular phase of the low set differential function.

Transformer faults of a different nature may result in fault currents within a very wide range of magnitudes. Internal faults with very high fault currents require fast fault clearing to reduce the effect of current transformer saturation and the damage to the protected transformer. An unrestrained instantaneous high set differential element ensures rapid clearance of such faults. Such an element essentially measures the peak value of the input current to ensure fast operation for internal faults with saturated CTs. Restrained units generally calculate an rms current value using more waveform samples. The high set differential function is not blocked under magnetizing inrush or over excitation conditions, hence the setting must be set such that it will not operate for the largest inrush currents expected.

At the other end of the fault spectrum are low current winding faults. Such faults are not cleared by the conventional differential function. Restricted ground fault protection gives greater sensitivity for ground faults and hence protects more of the winding. A separate element based on the high impedance circulating current principle is provided for each winding.

Transformers have many possible winding configurations that may create a voltage and current phase shift between the different windings. To compensate for any phase shift between two windings of a transformer, it is necessary to provide phase correction for the differential relay (see section on Special Considerations).

In addition to compensating for the phase shift of the protected transformer, it is also necessary to consider the distribution of primary zero sequence current in the protection scheme. The necessary filtering of zero sequence current has also been traditionally provided by appropriate connection of auxiliary current transformers or by delta connection of primary CT secondary windings. In microprocessor transformer protection relays, zero sequence current filtering is implemented in software when a delta CT connection would otherwise be required. In situations where a transformer winding can produce zero sequence current caused by an external ground fault, it is essential that some form of zero sequence current filtering is employed. This ensures that ground faults out of the zone of protection will not cause the differential relay to operate in error. As an example, an external ground fault on the wye side of a delta/wye connected power transformer will result in zero sequence current flowing in the current transformers associated with the wye winding but, due to the effect of the delta winding, there will be no corresponding zero sequence current in the current transformers associated with the delta winding, i.e., differential current flow will cause the relay to operate. When the virtual zero sequence current filter is applied within the relay, this undesired trip will not occur.

Some of the most typical substation configurations, especially at the transmission level, are breaker-and-a-half or ring-bus. Not that common, but still used are two-breaker schemes. When a power transformer is connected to a substation using one of these breaker configurations, the transformer protection is connected to three or more sets of current transformers. If it is a three winding transformer or an auto transformer with a tertiary connected to a lower voltage sub transmission system, four or more sets of CTs may be available.

It is highly recommended that separate relay input connections be used for each set used to protect the transformer. Failure to follow this practice may result in incorrect differential relay response. Appropriate testing of a protective relay for such configuration is another challenging task for the relay engineer.

Overexcitation: Overexcitation can also be caused by an increase in system voltage or a reduction in frequency. It follows, therefore, that transformers can withstand an increase in voltage with a corresponding increase in frequency but not an increase in voltage with a decrease in frequency. Operation cannot be sustained when the ratio of voltage to frequency exceeds more than a small amount.

Protection against overflux conditions does not require high-speed tripping. In fact, instantaneous tripping is undesirable, as it would cause tripping for transient system disturbances, which are not damaging to the transformer.

An alarm is triggered at a lower level than the trip setting and is used to initiate corrective action. The alarm has a definite time delay, while the trip characteristic generally has a choice of definite time delay or inverse time characteristic.

Mechanical

There are two generally accepted methods used to detect transformer faults using mechanical methods. These detection methods provide sensitive fault detection and compliment protection provided by differential or overcurrent relays.

Accumulated Gases: The first method accumulates gases created as a by product of insulating oil decomposition created from excessive heating within the transformer. The source of heat comes from either the electrical arcing or a hot area in the core steel. This relay is designed for conservator tank transformers and will capture gas as it rises in the oil. The relay, sometimes referred to as a Buchholz relay, is sensitive enough to detect very small faults.

Pressure Relays: The second method relies on the transformer internal pressure rise that results from a fault. One design is applicable to gas-cushioned transformers and is located in the gas space above the oil. The other design is mounted well below minimum liquid level and responds to changes in oil pressure. Both designs employ an equalizing system that compensates for pressure changes due to temperature (ANSI/IEEE, 1985).

Thermal

Hot Spot-Temperature: In any transformer design, there is a location in the winding that the designer believes to be the *hottest* spot within that transformer (ANSI/IEEE, 1995). The significance of the "hot-spot temperature" measured at this location is an assumed relationship between the temperature level and the rate-of-degradation of the cellulose insulation. An instantaneous alarm or trip setting is often used, set at a judicious level above the full load rated hot-spot temperature (110°C for 65°C rise transformers). [Note that "65°C rise" refers to the full load rated *average* winding temperature rise.] Also, a relay or monitoring system can mathematically integrate the rate-of-degradation, i.e., rate-of-loss-of-life of the insulation for overload assessment purposes.

Heating Due to Overexcitation: Transformer core flux density (B), induced voltage (V), and frequency (f) are related by the following formula.

$$B = k_1 \cdot \frac{V}{f} \tag{9.1}$$

where K_1 is a constant for a particular transformer design. As B rises above about 110% of normal, that is, when saturation starts, significant heating occurs due to stray flux eddy-currents in the nonlaminated structural metal parts, including the tank. Since it is the voltage/hertz quotient in Eq. (9.1) that defines the level of B, a relay sensing this quotient is sometimes called a "volts-per-hertz" relay. The expressions "overexcitation" and "overfluxing" refer to this same condition. Since temperature rise is proportional to the integral of power with respect to time (neglecting cooling processes) it follows that an inverse-time characteristic is useful, that is, *volts-per-hertz* versus *time*. Another approach is to use definite-time-delayed alarm or trip at specific per unit flux levels.

Heating Due to Current Harmonic Content (ANSI/IEEE, 1993): One effect of nonsinusoidal currents is to cause current rms magnitude (I_{RMS}) to be incorrect if the method of measurement is not "true-rms."

$$I_{RMS}^2 = \sum_{n=1}^{N} I_n^2 \tag{9.2}$$

where n is the harmonic order, N is the highest harmonic of significant magnitude, and I_n is the harmonic current rms magnitude. If an overload relay determines the I^2R heating effect using the fundamental component of the current only [I_1], then it will underestimate the heating effect. Bear in mind that "true-rms" is only as good as the pass-band of the antialiasing filters and sampling rate, for numerical relays.

A second effect is heating due to high-frequency eddy-current loss in the copper or aluminum of the windings. The winding eddy-current loss due to each harmonic is proportional to the square of the harmonic amplitude and the square of its frequency as well. Mathematically,

$$P_{EC} = P_{EC-RATED} \cdot \sum_{n=1}^{N} I_n^2 n^2 \tag{9.3}$$

where P_{EC} is the winding eddy-current loss and $P_{EC\text{-}RATED}$ is the rated winding eddy-current loss (pure 60 Hz), and I_n is the n^{th} harmonic current in per-unit based on the fundamental. Notice the fundamental difference between the effect of harmonics in Eq. (9.2) and their effect in Eq. (9.3). In the latter, higher harmonics have a proportionately greater effect because of the n^2 factor. IEEE Standard C57.110-1986 (R1992), *Recommended Practice for Establishing Transformer Capability When Supplying Nonsinusoidal Load Currents* gives two empirically-based methods for calculating the derating factor for a transformer under these conditions.

Heating Due to Solar Induced Currents: Solar magnetic disturbances cause geomagnetically induced currents (GIC) in the earth's surface (EPRI, 1993). These DC currents can be of the order of tens of amperes for tens of minutes, and flow into the neutrals of grounded transformers, biasing the core magnetization. The effect is worst in single-phase units and negligible in three-phase core-type units. The core saturation causes second-harmonic content in the current, resulting in increased *security* in second-harmonic-restrained transformer differential relays, but decreased *sensitivity.* Sudden gas pressure relays could provide the necessary alternative internal fault tripping. Another effect is increased stray heating in the transformer, protection for which can be accomplished using gas accumulation relays for transformers with conservator oil systems. Hot-spot tripping is not sufficient because the commonly used hot-spot simulation model does not account for GIC.

Load Tap-changer Overheating: Damaged current carrying contacts within an underload tap-changer enclosure can create excessive heating. Using this heating symptom, a way of detecting excessive wear is to install magnetically mounted temperature sensors on the tap-changer enclosure and on the main tank. Even though the method does not accurately measure the internal temperature at each location, the *difference* is relatively accurate, since the error is the same for each. Thus, excessive wear is indicated if a relay/monitor detects that the temperature difference has changed significantly over time.

Special Considerations

Current Transformers

Current transformer ratio selection and performance require special attention when applying transformer protection. Unique factors associated with transformers, including its winding ratios, magnetizing inrush current, and the presence of winding taps or load tap changers, are sources of difficulties in engineering a dependable and secure protection scheme for the transformer. Errors resulting from CT saturation and load-tap-changers are particularly critical for differential protection schemes where the currents from more than one set of CTs are compared. To compensate for the saturation/mismatch errors, overcurrent relays must be set to operate above these errors.

CT Current Mismatch: Under normal, non-fault conditions, a transformer differential relay should ideally have identical currents in the secondaries of all current transformers connected to the relay so that no current would flow in its operating coil. It is difficult, however, to match current transformer ratios exactly to the transformer winding ratios. This task becomes impossible with the presence of transformer off-load and on-load taps or load tap changers that change the voltage ratios of the transformer windings depending on system voltage and transformer loading.

The highest secondary current mismatch between all current transformers connected in the differential scheme must be calculated when selecting the relay operating setting. If time delayed overcurrent protection is used, the time delay setting must also be based on the same consideration. The mismatch calculation should be performed for maximum load and through-fault conditions.

CT Saturation: CT saturation could have a negative impact on the ability of the transformer protection to operate for internal faults (dependability) and not to operate for external faults (security).

For internal faults, dependability of the harmonic restraint type relays could be negatively affected if current harmonics generated in the CT secondary circuit due to CT saturation are high enough to restrain the relay. With a saturated CT, 2^{nd} and 3^{rd} harmonics predominate initially, but the even harmonics gradually disappear with the decay of the DC component of the fault current. The relay may then operate eventually when the restraining harmonic component is reduced. These relays usually include an instantaneous overcurrent element that is not restrained by harmonics, but is set very high (typically 20 times transformer rating). This element may operate on severe internal faults.

For external faults, security of the differentially connected transformer protection may be jeopardized if the current transformers' unequal saturation is severe enough to produce error current above the relay setting. Relays equipped with restraint windings in each current transformer circuit would be more secure. The security problem is particularly critical when the current transformers are connected to bus breakers rather than the transformer itself. External faults in this case could be of very high magnitude as they are not limited by the transformer impedance.

Magnetizing Inrush (Initial, Recovery, Sympathetic)

Initial: When a transformer is energized after being de-energized, a transient magnetizing or exciting current that may reach instantaneous peaks of up to 30 times full load current may flow. This can cause operation of overcurrent or differential relays protecting the transformer. The magnetizing current flows in only one winding, thus it will appear to a differentially connected relay as an internal fault.

Techniques used to prevent differential relays from operating on inrush include detection of current harmonics and zero current periods, both being characteristics of the magnetizing inrush current. The former takes advantage of the presence of harmonics, especially the second harmonic, in the magnetizing inrush current to restrain the relay from operation. The latter differentiates between the fault and inrush currents by measuring the zero current periods, which will be much longer for the inrush than for the fault current.

Recovery Inrush: A magnetizing inrush current can also flow if a voltage dip is followed by recovery to normal voltage. Typically, this occurs upon removal of an external fault. The magnetizing inrush is usually less severe in this case than in initial energization as the transformer was not totally de-energized prior to voltage recovery.

Sympathetic Inrush: A magnetizing inrush current can flow in an energized transformer when a nearby transformer is energized. The offset inrush current of the bank being energized will find a parallel path in the energized bank. Again, the magnitude is usually less than the case of initial inrush.

Both the recovery and sympathetic inrush phenomena suggest that restraining the transformer protection on magnetizing inrush current is required at all times, not only when switching the transformer in service after a period of de-energization.

Primary-Secondary Phase-Shift

For transformers with standard delta-wye connections, the currents on the delta and wye sides will have a 30° phase shift relative to each other. Current transformers used for traditional differential relays must be connected in wye-delta (opposite of the transformer winding connections) to compensate for the transformer phase shift.

Phase correction is often internally provided in microprocessor transformer protection relays via software virtual interposing CTs for each transformer winding and, as with the ratio correction, will depend upon the selected configuration for the restrained inputs. This allows the primary current transformers to all be connected in wye.

Turn-to-Turn Faults

Fault currents resulting from a turn-to-turn fault have low magnitudes and are hard to detect. Typically, the fault will have to evolve and affect a good portion of the winding or arc over to other parts of the transformer before being detected by overcurrent or differential protection relays.

For early detection, reliance is usually made on devices that can measure the resulting accumulation of gas or changes in pressure inside the transformer tank.

Through Faults

Through faults could have an impact on both the transformer and its protection scheme. Depending on their severity, frequency, and duration, through fault currents can cause mechanical transformer damage, even though the fault is somewhat limited by the transformer impedance.

For transformer differential protection, current transformer mismatch and saturation could produce operating currents on through faults. This must be taken into consideration when selecting the scheme, current transformer ratio, relay sensitivity, and operating time. Differential protection schemes equipped with restraining windings offer better security for these through faults.

Backup Protection

Backup protection, typically overcurrent or impedance relays applied to one or both sides of the transformer, perform two functions. One function is to backup the primary protection, most likely a differential relay, and operate in event of its failure to trip.

The second function is protection for thermal or mechanical damage to the transformer. Protection that can detect these external faults and operate in time to prevent transformer damage should be considered. The protection must be set to operate before the through-fault withstand capability of the transformer is reached. If, because of its large size or importance, only differential protection is applied to a transformer, clearing of external faults before transformer damage can occur by other protective devices must be ensured.

Special Applications

Shunt Reactors

Shunt reactor protection will vary depending on the type of reactor, size, and system application. Protective relay application will be similar to that used for transformers.

Differential relays are perhaps the most common protection method (Blackburn, 1987). Relays with separate phase inputs will provide protection for three single phase reactors connected together or for a single three phase unit. Current transformers must be available on the phase and neutral end of each winding in the three phase unit.

Phase and ground overcurrent relays can be used to back up the differential relays. In some instances, where the reactor is small and cost is a factor, it may be appropriate to use overcurrent relays as the only protection. The ground overcurrent relay would not be applied on systems where zero sequence current is negligible.

As with transformers, turn-to-turn faults are most difficult to detect since there is little change in current at the reactor terminals. If the reactor is oil filled, a sudden pressure relay will provide good protection. If the reactor is an ungrounded dry type, an overvoltage relay (device 59) applied between the reactor neutral and a set of broken delta connected voltage transformers can be used (ABB, 1994).

Negative sequence and impedance relays have also been used for reactor protection but their application should be carefully researched (ABB, 1994).

Zig-Zag Transformers

The most common protection for zig-zag (or grounding) transformers is three overcurrent relays that are connected to current transformers located on the primary phase bushings. These current transformers must be connected in delta to filter out unwanted zero sequence currents (ANSI/IEEE, 1985).

It is also possible to apply a conventional differential relay for fault protection. Current transformers in the primary phase bushings are paralleled and connected to one input. A neutral CT is used for the other input (Blackburn, 1987).

An overcurrent relay located in the neutral will provide backup ground protection for either of these schemes. It must be coordinated with other ground relays on the system.

Sudden pressure relays provide good protection for turn-to-turn faults.

Phase Angle Regulators and Voltage Regulators

Protection of phase angle and voltage regulators varies with the construction of the unit. Protection should be worked out with the manufacturer at the time of order to insure that current transformers are installed inside the unit in the appropriate locations to support planned protection schemes. Differential, overcurrent, and sudden pressure relays can be used in conjunction to provide adequate protection for faults (Blackburn, 1987; ABB, 1994).

Unit Systems

A unit system consists of a generator and associated step-up transformer. The generator winding is connected in wye with the neutral connected to ground through a high impedance grounding system. The step-up transformer low side winding on the generator side is connected delta to isolate the generator from system contributions to faults involving ground. The transformer high side winding is connected in wye and solidly grounded. Generally there is no breaker installed between the generator and transformer.

It is common practice to protect the transformer and generator with an overall transformer differential that includes both pieces of equipment. It may be appropriate to install an additional differential to protect only the transformer. In this case, the overall differential acts as secondary or backup protection for the transformer differential. There will most likely be another differential relay applied specifically to protect the generator.

A volts-per-hertz relay, whose pickup is a function of the ratio of voltage to frequency, is often recommended for overexcitation protection. The unit transformer may be subjected to overexcitation during generator startup and shutdown when it is operating at reduced frequencies or when there is major loss of load that may cause both overvoltage and overspeed (ANSI/IEEE, 1985).

As with other applications, sudden pressure relays provide sensitive protection for turn-to-turn faults that are typically not initially detected by differential relays.

Backup protection for phase faults can be provided by applying either impedance or voltage controlled overcurrent relays to the generator side of the unit transformer. The impedance relays must be connected to respond to faults located in the transformer (Blackburn, 1987).

Single Phase Transformers

Single phase transformers are sometimes used to make up three phase banks. Standard protection methods described earlier in this section are appropriate for single phase transformer banks as well. If one or both sides of the bank is connected in delta and current transformers located on the transformer bushings are to be used for protection, the standard differential connection cannot be used. To provide proper ground fault protection, current transformers from each of the bushings must be utilized (Blackburn, 1987).

Sustained Voltage Unbalance

During sustained unbalanced voltage conditions, wye-connected core type transformers without a delta-connected tertiary winding may produce damaging heat. In this situation, the transformer case may produce damaging heat from sustained circulating current. It is possible to detect this situation by using either a thermal relay designed to monitor tank temperature or applying an overcurrent relay connected to sense "effective" tertiary current (ANSI/IEEE, 1985).

Restoration

Power transformers have varying degrees of importance to an electrical system depending on their size, cost, and application, which could range from generator step-up to a position in the transmission/distribution system, or perhaps as an auxiliary unit.

When protective relays trip and isolate a transformer from the electric system, there is often an immediate urgency to restore it to service. There should be a procedure in place to gather system data at the time of trip as well as historical information on the individual transformer, so an informed decision can be made concerning the transformer's status. No one should re-energize a transformer when there is evidence of electrical failure.

It is always possible that a transformer could be incorrectly tripped by a defective protective relay or protection scheme, system backup relays, or by an abnormal system condition that had not been considered. Often system operators may try to restore a transformer without gathering sufficient evidence to determine the exact cause of the trip. An operation should always be considered as legitimate until proven otherwise.

The more vital a transformer is to the system, the more sophisticated the protection and monitoring equipment should be. This will facilitate the accumulation of evidence concerning the outage.

History — Daily operation records of individual transformer maintenance, service problems, and relayed outages should be kept to establish a comprehensive history. Information on relayed operations should include information on system conditions prior to the trip out. When no explanation for a trip is found, it is important to note all areas that were investigated. When there is no damage determined, there should still be a conclusion as to whether the operation was correct or incorrect. Periodic gas analysis provides a record of the normal combustible gas value.

Oscillographs, Event Recorder, Gas Monitors — System monitoring equipment that initiates and produces records at the time of the transformer trip usually provide information necessary to determine if there was an electrical short-circuit involving the transformer or if it was a “through-fault” condition.

Date of Manufacture — Transformers manufactured before 1980 were likely not designed or constructed to meet the severe through-fault conditions outlined in ANSI/IEEE C57.109, *IEEE Guide for Transformer Through-Fault Current Duration* (1985). Maximum through-fault values should be calculated and compared to short-circuit values determined for the trip out. Manufacturers should be contacted to obtain documentation for individual transformers in conformance with ANSI/IEEE C57.109.

Magnetizing Inrush — Differential relays with harmonic restraint units are typically used to prevent trip operations upon transformer energizing. However, there are nonharmonic restraint differential relays in service that use time delay and/or percentage restraint to prevent trip on magnetizing inrush. Transformers so protected may have a history of falsely tripping on energizing inrush which may lead system operators to attempt restoration without analysis, inspection, or testing. There is always the possibility that an electrical fault can occur upon energizing which is masked by historical data.

Relay harmonic restraint circuits are either factory set at a threshold percentage of harmonic inrush or the manufacturer provides predetermined settings that should prevent an unwanted operation upon transformer energization. Some transformers have been manufactured in recent years using a grain-oriented steel and a design that results in very low percentages of the restraint harmonics in the inrush current. These values are, in some cases, less than the minimum manufacture recommended threshold settings.

Relay Operations — Transformer protective devices not only trip but prevent reclosing of all sources energizing the transformer. This is generally accomplished using an auxiliary “lockout” relay. The lockout relay requires manual resetting before the transformer can be energized. This circuit encourages manual inspection and testing of the transformer before reenergization decisions are made.

Incorrect trip operations can occur due to relay failure, incorrect settings, or coordination failure. New installations that are in the process of testing and wire-checking are most vulnerable. Backup relays, by design, can cause tripping for upstream or downstream system faults that do not otherwise clear properly.

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9.2 The Protection of Synchronous Generators

Gabriel Benmouyal

In an apparatus protection perspective, generators constitute a special class of power network equipment because faults are very rare but can be highly destructive and therefore very costly when they occur. If for most utilities, generation integrity must be preserved by avoiding erroneous tripping, removing a generator in case of a serious fault is also a primary if not an absolute requirement. Furthermore, protection has to be provided for out-of-range operation normally not found in other types of equipment such as overvoltage, overexcitation, limited frequency or speed range, etc.

It should be borne in mind that, similar to all protective schmes, there is to a certain extent a "philosophical approach" to generator protection and all utilities and all protective engineers do not have the same approach. For instance, some functions like overexcitation, backup impedance elements, loss-of-synchronism, and even protection against inadvertant energization may not be applied by some organizations and engineers. It should be said, however, that with the digital multifunction generator protective packages presently available, a complete and extensive range of functions exists within the same "relay": and economic reasons for not installing an additional protective element is a tendancy which must disappear.

The nature of the prime mover will have some definite impact on the protective functions implemented into the system. For instance, little or no concern at all will emerge when dealing with the abnormal frequency operation of hydaulic generators. On the contrary, protection against underfrequency operation of steam turbines is a primary concern.

The sensitivity of the motoring protection (the capacity to measure very low levels of negative real power) becomes an issue when dealing with both hydro and steam turbines. Finally, the nature of the prime mover will have an impact on the generator tripping scheme. When delayed tripping has no detrimental effect on the generator, it is common practice to implement sequential tripping with steam turbines as described later.

The purpose of this article is to provide an overview of the basic principles and schemes involved in generator protection. For further information, the reader is invited to refer to additional resources dealing with generator protection. The ANSI/IEEE guides (ANSI/IEEE, C37.106, C37.102, C37.101) are particularly recommended. The *IEEE Tutorial on the Protection of Synchronous Generators* (IEEE, 1995) is a detailed presentation of North American practices for generator protection. All these references have been a source of inspiration in this writing.

Review of Functions

Table 9.1 provides a list of protective relays and their functions most commonly found in generator protection schemes. These relays are implemented as shown on the single-line diagram of Fig. 9.2.

As shown in the Relay Type column, most protective relays found in generator protection schemes are not specific to this type of equipment but are more generic types.

Differential Protection for Stator Faults (87G)

Protection against stator phase faults are normally covered by a high-speed differential relay covering the three phases separately. All types of phase faults (phase-phase) will be covered normally by this type of protection, but the phase-ground fault in a high-impedance grounded generator will not be covered. In this case, the phase current will be very low and therefore below the relay pickup.

Contrary to transformer differential applications, no inrush exists on stator currents and no provision is implemented to take care of overexcitation. Therefore, stator differential relays do not include harmonic restraint (2nd and 5th harmonic). Current transformer saturation is still an issue, however, particularly in generating stations because of the high X/R ratio found near generators.

TABLE 9.1 Most Commonly Found Relays for Generator Protection

Identification Number	Function Description	Relay Type
87G	Generator phase phase windings protection	Differential protection
87T	Step-up transformer differential protection	Differential protection
87U	Combined differential transformer and generator protection	Differential protection
40	Protection against the loss of field voltage or current supply	Offset mho relay
46	Protection against current imbalance. Measurement of phase negative sequence current	Time-overcurrent relay
32	Anti-motoring protection	Reverse-power relay
24	Overexcitation protection	Volt/Hertz relay
59	Phase overvoltage protection	Overvoltage relay
60	Detection of blown voltage transformer fuses	Voltage balance relay
81	Under- and overfrequency protection	Frequency relays
51V	Backup protection against system faults	Voltage controlled or voltage-restrained time overcurrent relay
21	Backup protection against system faults	Distance relay
78	Protection against loss of synchronization	Combination of offset mho and blinders

The most common type of stator differential is the percentage differential, the main characteristics of which are represented in Fig. 9.3.

For a stator winding, as shown in Fig. 9.4, the restraint quantity will very often be the absolute sum of the two incoming and outgoing currents as in:

$$Irestraint = \frac{|IA\_in| + |IA\_out|}{2}, \tag{9.4}$$

whereas the operate quantity will be the absolute value of the difference:

$$Ioperate = |IA\_in - IA\_out| \tag{9.5}$$

The relay will output a fault condition when the following inequality is verified:

$$\mathrm{Irestraint} \geq \mathrm{K} \bullet \mathrm{Ioperate} \tag{9.6}$$

where K is the differential percentage. The dual and variable slope characteristics will intrinsically allow CT saturation for an external fault without the relay picking up.

An alternative to the percentage differential relay is the high-impedance differential relay, which will also naturally surmount any CT saturation. For an internal fault, both currents will be forced into a high-impedance voltage relay. The differential relay will pickup when the tension across the voltage element gets above a high-set threshold. For an external fault with CT saturation, the saturated CT will constitute a low-impedance path in which the current from the other CT will flow, bypassing the high-impedance voltage element which will not pick up.

Backup protection for the stator windings will be provided most of the time by a transformer differential relay with harmonic restraint, the zone of which (as shown in Fig. 9.2) will cover both the generator and the step-up transformer.

An impedance element partially or totally covering the generator zone will also provide backup protection for the stator differential.

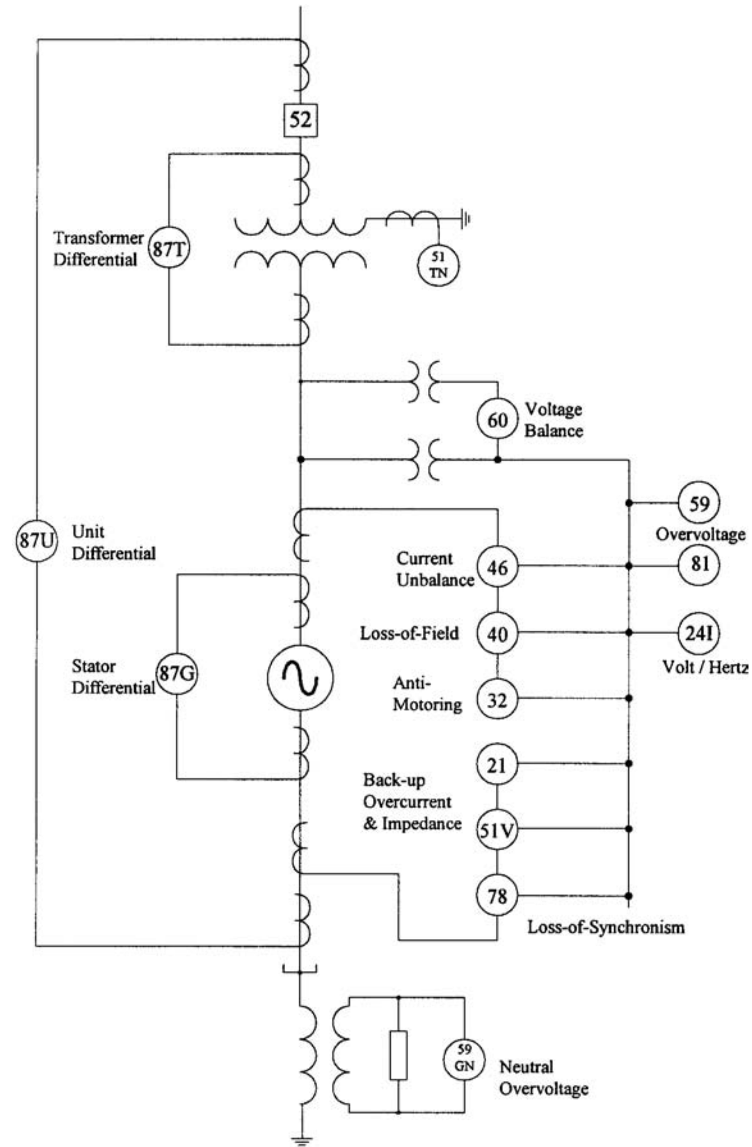

FIGURE 9.2 Typical generator-transformer protection scheme.

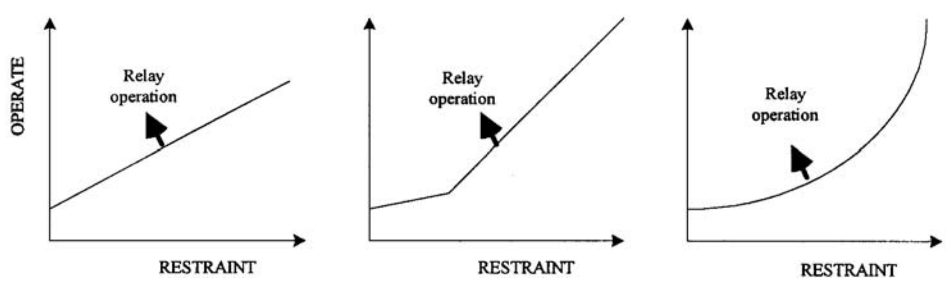

FIGURE 9.3 Single, dual, and variable-slope percentage differential characteristics.

FIGURE 9.4 Stator winding current configuration.

Protection Against Stator Winding Ground Fault

Protection against stator-to-ground fault will depend to a great extent upon the type of generator grounding. Generator grounding is necessary through some impedance in order to reduce the current level of a phase-to-ground fault. With solid generator grounding, this current will reach destructive levels. In order to avoid this, at least low impedance grounding through a resistance or a reactance is required. High-impedance through a distribution transformer with a resistor connected across the secondary winding will limit the current level of a phase-to-ground fault to a few primary amperes.

The most common and minimum protection against a stator-to-ground fault with a high-impedance grounding scheme is an overvoltage element connected across the grounding transformer secondary, as shown in Fig. 9.5.

For faults very close to the generator neutral, the overvoltage element will not pick up because the voltage level will be below the voltage element pick-up level. In order to cover 100% of the stator windings, two techniques are readily available:

1. use of the third harmonic generated at the neutral and generator terminals, and
2. voltage injection technique.

Looking at Fig. 9.6, a small amount of third harmonic voltage will be produced by most generators at their neutral and terminals. The level of these third harmonic voltages depends upon the generator operating point as shown in Fig. 9.6a. Normally they would be higher at full load. If a fault develops near the neutral, the third harmonic neutral voltage will approach zero and the terminal voltage will increase. However, if a fault develops near the terminals, the terminal third harmonic voltage will reach zero and the neutral voltage will increase. Based on this, three possible schemes have been devised. The relays available to cover the three possible choices are:

1. Use of a third harmonic undervoltage at the neutral. It will pick up for a fault at the neutral.
2. Use of a third harmonic overvoltage at the terminals. It will pick up for a fault near the neutral.
3. The most sensitive schemes are based on third harmonic differential relays that monitor the ratio of third harmonic at the neutral and the terminals (Yin et al., 1990).

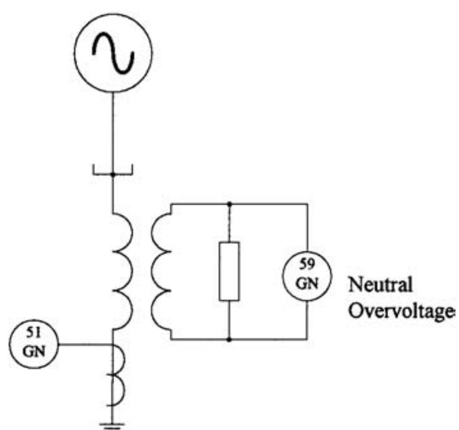

FIGURE 9.5 Stator-to-ground neutral overvoltage scheme.

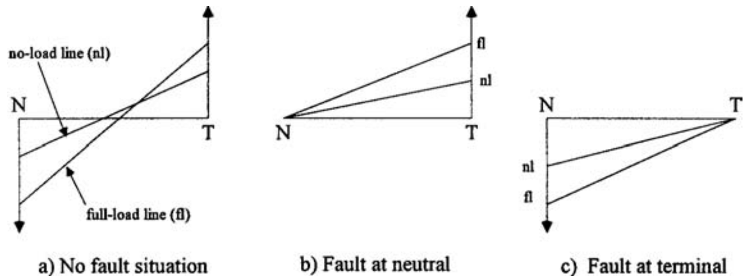

FIGURE 9.6 Third harmonic on neutral and terminals.

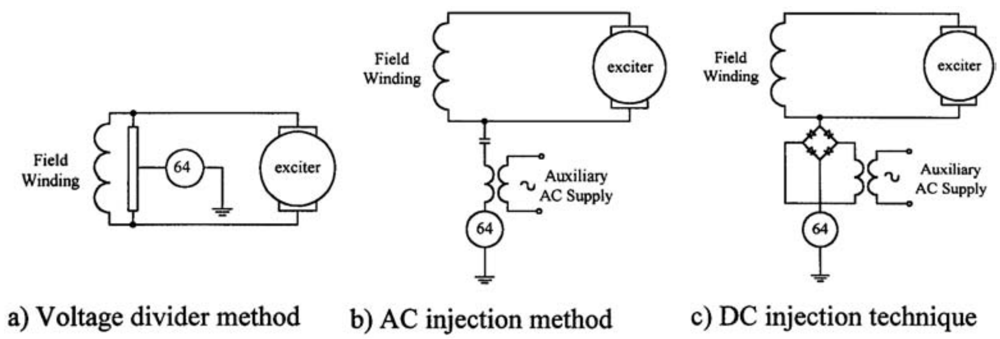

FIGURE 9.7 Various techniques for field-ground protection.

Field Ground Protection

A generator field circuit (field winding, exciter, and field breaker) is a DC circuit that does not need to be grounded. If a first earth fault occurs, no current will flow and the generator operation will not be affected. If a second ground fault at a different location occurs, a current will flow that is high enough to cause damage to the rotor and the exciter. Furthermore, if a large section of the field winding is short-circuited, a strong imbalance due to the abnormal air-gap fluxes could result on the forces acting on the rotor with a possibility of serious mechanical failure. In order to prevent this situation, a number of protecting devices exist. Three principles are depicted in Fig. 9.7.

The first technique (Fig. 9.7a) involves connecting a resistor in parallel with the field winding. The resistor centerpoint is connected the ground through a current sensitive relay. If a field circuit point gets grounded, the relay will pick up by virtue of the current flowing through it. The main shortcoming of this technique is that no fault will be detected if the field winding centerpoint gets grounded.

The second technique (Fig. 9.7b) involves applying an AC voltage across one point of the field winding. If the field winding gets grounded at some location, an AC current will flow into the relay and causes it to pick up.

The third technique (Fig. 9.7c) involves injecting a DC voltage rather than an AC voltage. The consequence remains the same if the field circuit gets grounded at some point.

The best protection against field-ground faults is to move the generator out of service as soon as the first ground fault is detected.

Loss-of-Excitation Protection (40)

A loss-of-excitation on a generator occurs when the field current is no longer supplied. This situation can be triggered by a variety of circumstances and the following situation will then develop:

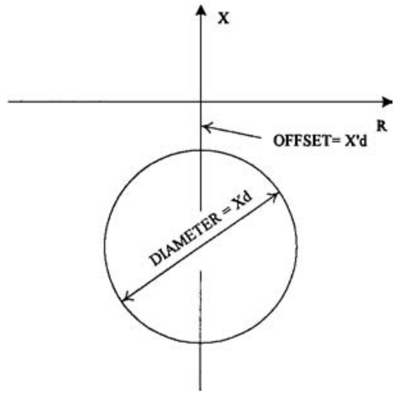

FIGURE 9.8 Loss-of-excitation offset-mho characteristic.

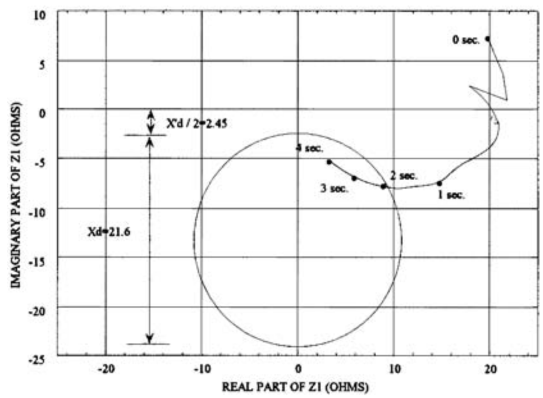

FIGURE 9.9 Loss-of-field positive sequence impedance trajectory.

1. When the field supply is removed, the generator real power will remain almost constant during the next seconds. Because of the drop in the excitation voltage, the generator output voltage drops gradually. To compensate for the drop in voltage, the current increases at about the same rate.
2. The generator then becomes underexcited and it will absorb increasingly negative reactive power.
3. Because the ratio of the generator voltage over the current becomes smaller and smaller with the phase current leading the phase voltage, the generator positive sequence impedance as measured at its terminals will enter the impedance plane in the second quadrant. Experience has shown that the positive sequence impedance will settle to a value between Xd and Xq.

The most popular protection against a loss-of-excitation situation uses an offset-mho relay as shown in Fig. 9.8 (IEEE, 1989). The relay is supplied with generator terminals voltages and currents and is normally associated with a definite time delay. Many modern digital relays will use the positive sequence voltage and current to evaluate the positive sequence impedance as seen at the generator terminal.

Figure 9.9 shows the digitally emulated positive sequence impedance trajectory of a 200 MVA generator connected to an infinite bus through an 8% impedance transformer when the field voltage was removed at 0 second time.

Current Imbalance (46)

Current imbalance in the stator with its subsequent production of negative sequence current will be the cause of double-frequency currents on the surface of the rotor. This, in turn, may cause excessive overheating of the rotor and trigger substantial thermal and mechanical damages (due to temperature effects).

The reasons for temporary or permanent current imbalance are numerous:

- system asymmetries
- unbalanced loads
- unbalanced system faults or open circuits
- single-pole tripping with subsequent reclosing

The energy supplied to the rotor follows a purely thermal law and is proportional to the square of the negative sequence current. Consequently, a thermal limit K is reached when the following integral equation is solved:

$$K = \int_0^t I_2^2 \, dt \tag{9.7}$$

In this equation, we have:

K = constant depending upon the generator design and size
I_2 = RMS value of negative sequence current
t = time

The integral equation can be expressed as an inverse time-current characteristic where the maximum time is given as the negative sequence current variable:

$$t = \frac{K}{I_2^2} \tag{9.8}$$

In this expression the negative sequence current magnitude will be entered most of the time as a percentage of the nominal phase current and integration will take place when the measured negative sequence current becomes greater than a percentage threshold.

Thermal capability constant, K, is determined by experiment by the generator manufacturer. Negative sequence currents are supplied to the machine on which strategically located thermocouples have been installed. The temperature rises are recorded and the thermal capability is inferred.

Forty-six (46) relays can be supplied in all three technologies (electromechanical, static, or digital). Ideally the negative sequence current should be measured in rms magnitude. Various measurement principles can be found. Digital relays could measure the fundamental component of the negative sequence current because this could be the basic principle for phasor measurement. Figure 9.10 represents a typical relay characteristic.

Anti-Motoring Protection (32)

A number of situations exist where a generator could be driven as a motor. Anti-motoring protection will more specifically apply in situations where the prime-mover supply is removed for a generator supplying a network at synchronous speed with the field normally excited. The power system will then drive the generator as a motor.

A motoring condition may develop if a generator is connected improperly to the power system. This will happen if the generator circuit breaker is closed inadvertently at some speed less than synchronous speed. Typical situations are when the generator is on turning gear, slowing down to a standstill, or has reached standstill. This motoring condition occurs during what is called "generator inadvertent energization." The protection schemes that respond to this situation are different and will be addressed later in this article.

Motoring will cause adverse effects, particularly in the case of steam turbines. The basic phenomenon is that the rotation of the turbine rotor and the blades in a steam environment will cause windage losses.

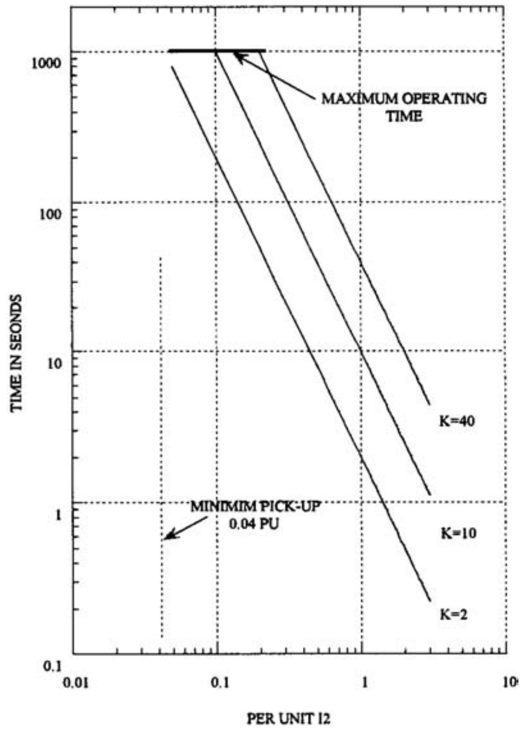

FIGURE 9.10 Typical static or digital time-inverse 46 curve.

Windage losses are a function of rotor diameter, blade length, and are directly proportional to the density of the enclosed steam. Therefore, in any situation where the steam density is high, harmful windage losses could occur. From the preceding discussion, one may conclude that the anti-motoring protection is more of a prime-mover protection than a generator protection.

The most obvious means of detecting motoring is to monitor the flow of real power into the generator. If that flow becomes negative below a preset level, then a motoring condition is detected. Sensitivity and setting of the power relay depends upon the energy drawn by the prime mover considered now as a motor.

With a gas turbine, the large compressor represents a substantial load that could reach as high as 50% of the unit nameplate rating. Sensitivity of the power relay is not an issue and is definitely not critical. With a diesel type engine (with no firing in the cylinders), load could reach as high as 25% of the unit rating and sensitivity, once again, is not critical. With hydroturbines, if the blades are below the tail-race level, the motoring energy is high. If above, the reverse power gets as low as 0.2 to 2% of the rated power and a sensitive reverse power relay is then needed. With steam turbines operating at full vacuum and zero steam input, motoring will draw 0.5 to 3% of unit rating. A sensitive power relay is then required.

Overexcitation Protection (24)

When generator or step-up transformer magnetic core iron becomes saturated beyond rating, stray fluxes will be induced into nonlaminated components. These components are not designed to carry flux and therefore thermal or dielectric damage can occur rapidly.

In dynamic magnetic circuits, voltages are generated by the Lenz Law:

$$V = K\frac{d\phi}{dt} \tag{9.9}$$

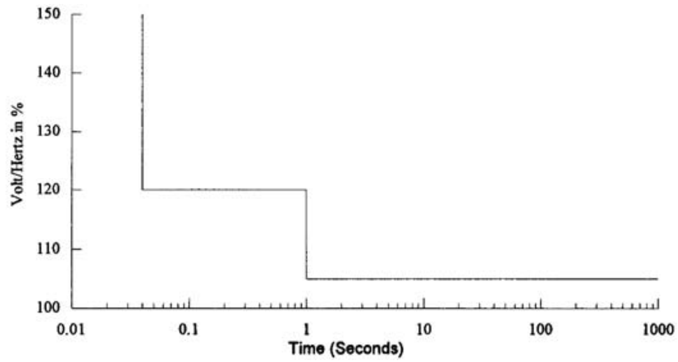

FIGURE 9.11 Dual definite-time characteristic.

Measured voltage can be integrated in order to get an estimate of the flux. Assuming a sinusoidal voltage of magnitude Vp and frequency f, and integrating over a positive or negative half-cycle interval:

$$\phi = \frac{1}{K}\int_0^{T/2} V_p \sin(\omega t + \theta)\,dt = \frac{V_p}{2\pi f K}\left(-\cos \omega t\right)\Big|_0^{T/2} \tag{9.10}$$

one derives an estimate of the flux that is proportional to the value of peak voltage over the frequency. This type of protection is then called volts per hertz.

$$\phi \approx \frac{V_p}{f} \tag{9.11}$$

The estimated value of the flux can then be compared to a maximum value threshold. With static technology, volts per hertz relays would practically integrate the monitored voltage over a positive or negative (or both) half-cycle period of time and develop a value that would be proportional to the flux. With digital relays, since measurement of the frequency together with the magnitudes of phase voltages are continuously available, a direct ratio computation as shown in Eq. (9.11) would be performed.

ANSI/IEEE standard limits are 1.05 pu for generators and 1.05 for transformers (on transformer secondary base, at rated load, 0.8 power factor or greater; 1.1 pu at no-load). It has been traditional to supply either definite time or inverse-time characteristics as recommended by the ANSI/IEEE guides and standards. Fig. 9.11 represents a typical dual definite-time characteristic whereas Fig. 9.12 represents a combined definite and inverse-time characteristic.

One of the primary requirements of a volt/hertz relay is that it should measure both voltage magnitude and frequency over a broad range of frequency.

Overvoltage (59)

An overvoltage condition could be encountered without exceeding the volt/hertz limits. For that reason, an overvoltage relay is recommended. Particularly for hydro-units, C37-102 recommends both an instantaneous and an inverse element. The instantaneous should be set to 130 to 150% of rated voltage and the inverse element should have a pick-up voltage of 110% of the rated voltage. Coordination with the voltage regulator should be verified.

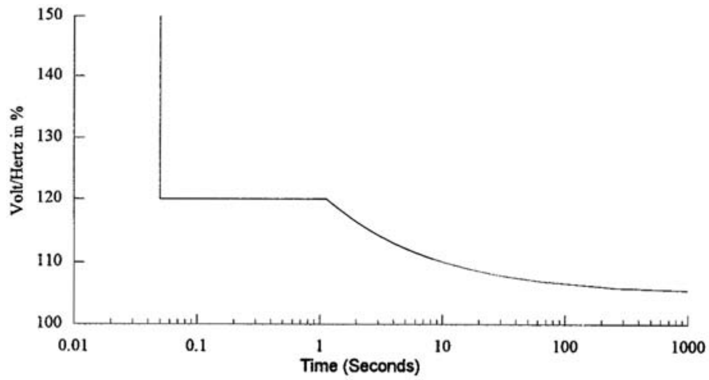

FIGURE 9.12 Combined definite and inverse-time characteristics.

Voltage Imbalance Protection (60)

The loss of a voltage phase signal can be due to a number of causes. The primary cause for this nuisance is a blown-out fuse in the voltage transformer circuit. Other causes can be a wiring error, a voltage transformer failure, a contact opening, a misoperation during maintenance, etc.

Since the purpose of these VTs is to provide voltage signals to the protective relays and the voltage regulator, the immediate effect of a loss of VT signal will be the possible misoperation of some protective relays and the cause for generator overexcitation by the voltage regulator. Among the protective relays to be impacted by the loss of VT signal are:

- Function 21: Distance relay. Backup for system and generator zone phase faults.
- Function 32: Reverse power relay. Anti-motoring function, sequential tripping and inadvertent energization functions.
- Function 40: Loss-of-field protection.
- Function 51V: Voltage-restrained time overcurrent relay.

Normally these functions should be blocked if a condition of fuse failure is detected.

It is common practice for large generators to use two sets of voltage transformers for protection, voltage regulation, and measurement. Therefore, the most common practice for loss of VT signals detection is to use a voltage balance relay as shown in Fig. 9.13 on each pair of secondary phase voltage. When a fuse blows, the voltage relationship becomes imbalanced and the relay operates. Typically, the voltage imbalance will be set at around 15%.

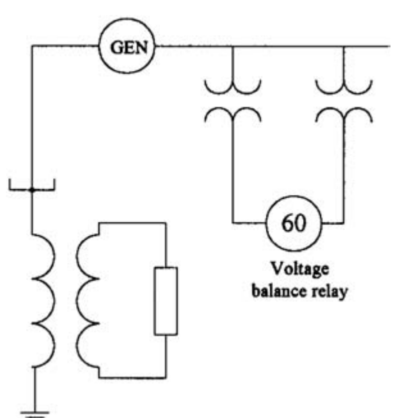

FIGURE 9.13 Example of voltage balance relay.

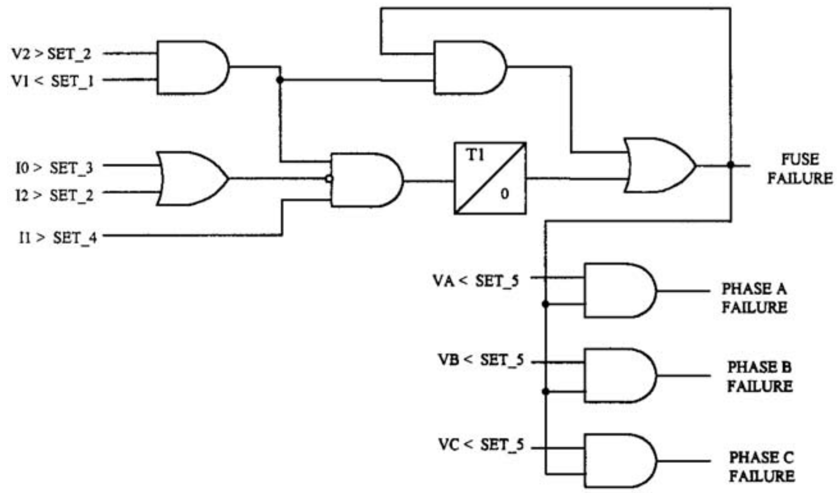

FIGURE 9.14 Symmetrical component implementation of fuse failure detection.

The advent of digital relays has allowed the use of sophisticated algorithms based on symmetrical components to detect the loss of VT signal. When a situation of loss of one or more of the VT signals occurs, the following conditions develop:

- there will be a drop in the positive sequence voltage accompanied by an increase in the negative sequence voltage magnitude. The magnitude of this drop will depend upon the number of phases impacted by a fuse failure.
- in case of a loss of VT signal and contrary to a fault condition, there should not be any change in the current's magnitudes and phases. Therefore, the negative and zero sequence currents should remain below a small tolerance value. A fault condition can be distinguished from a loss of VT signal by monitoring the changes in the positive and negative current levels. In case of a loss of VT signals, these changes should remain below a small tolerance level.

All the above conditions can be incorporated into a complex logic scheme to determine if indeed a there has been a condition of loss of VT signal or a fault. Figure 9.14 represents the logic implementation of a voltage transformer single and double fuse failure based on symmetrical components.

If the following conditions are met in the same time (and condition) during a time delay longer than T1:

- the positive sequence voltage is below a voltage set-value SET_1,
- the negative sequence voltage is above a voltage set-value SET_2,
- there exists a small value of current such that the positive sequence current I1 is above a small set-value SET_4 and the negative and zero sequence currents I2 and I2 do not exceed a small set-value SET_3,

then a fuse failure condition will pick up to one and remain in that state thanks to the latch effect. Fuse failure of a specific phase can be detected by monitoring the level voltage of each phase and comparing it to a set-value SET_5. As soon as the positive sequence voltage returns to a value greater than the set-value SET_1 and the negative sequence voltage disappears, the fuse failure condition returns to a zero state.

System Backup Protection (51V and 21)

Generator backup protection is not applied to generator faults but rather to system faults that have not been cleared in time by the system primary protection, but which require generator removal in order for the fault to be eliminated. By definition, these are time-delayed protective functions that must coordinate with the primary protective system.

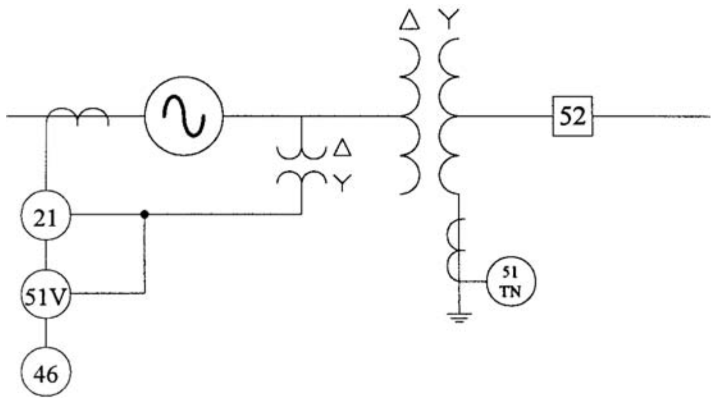

FIGURE 9.15 Backup protection basic scheme.

System backup protection (Fig. 9.15) must provide protection for both phase faults and ground faults. For the purpose of protecting against phase faults, two solutions are most commonly applied: the use of overcurrent relays with either voltage restraint or voltage control, or impedance-type relays.

The basic principle behind the concept of supervising the overcurrent relay by voltage is that a fault external to the generator and on the system will have the effect of reducing the voltage at the generator terminal. This effect is being used in both types of overcurrent applications: the voltage controlled overcurrent relay will block the overcurrent element unless the voltage gets below a pre-set value, and the voltage restraint overcurrent element will have its pick-up current reduced by an amount proportional to the voltage reduction (see Fig. 9.16).

The impedance type backup protection could be applied to the low or high side of the step-up transformer. Normally, three 21 elements will cover all types of phase faults on the system as in a line relay.

As shown in Fig. 9.17, a reverse offset is allowed in the mho element in order for the backup to partially or totally cover the generator windings.

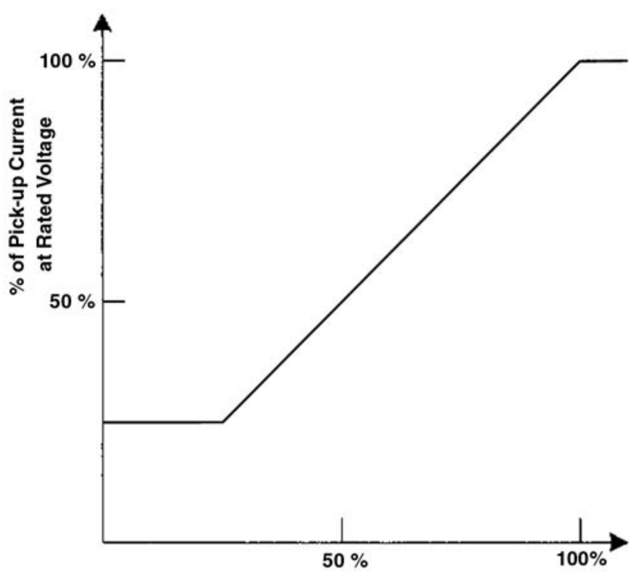

FIGURE 9.16 Voltage restraint overcurrent relay principle.

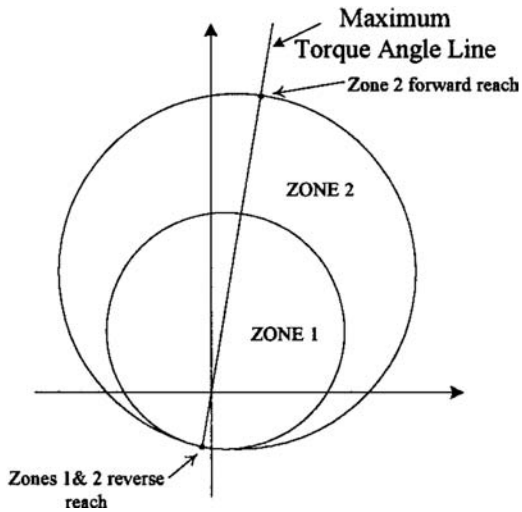

FIGURE 9.17 Typical 21 elements application.

Out-of-Step Protection

When there is an equilibrium between generation and load on an electrical network, the network frequency will be stable and the internal angle of the generators will remain constant with respect to each other. If an imbalance (loss of generation, sudden addition of load, network fault, etc.) occurs, however, the internal angle of a generator will undergo some changes and two situations might develop: a new stable state will be reached after the disturbance has faded away, or the generator internal angle will not stabilize and the generator will run synchronously with respect to the rest of the network (moving internal angle and different frequency). In the latter case, an out-of-step protection is implemented to detect the situation.

That principle can be visualized by considering the two-source network of Fig. 9.18.

If the angle between the two sources is θ and the ratio between the voltage magnitudes is $n = E_G/E_S$, then the positive sequence impedance seen from location will be:

$$Z_R = \frac{n\left(Z_G + Z_T + Z_S\right)\left(n - \cos\theta - j\sin\theta\right)}{\left(n - \cos\theta\right)^2 + \sin^2\theta} - Z_G. \tag{9.12}$$

If n is equal to one, Eq. (9.12) simplifies to:

$$Z_R = \frac{n\left(Z_G + Z_T + Z_S\right)\left(1 - j\,cotg\,\dfrac{\theta}{2}\right)}{2} - Z_G \tag{9.13}$$

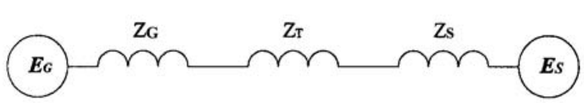

FIGURE 9.18 Elementary two-source network.

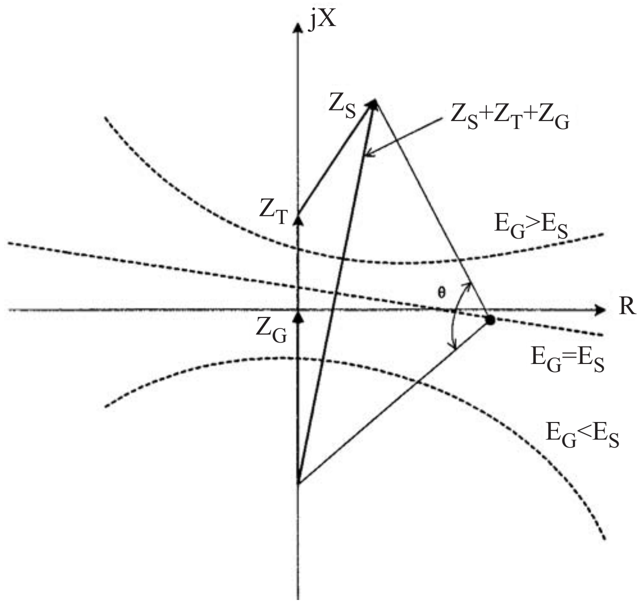

FIGURE 9.19 Impedance locus for different source angles.

The impedance locus represented by this equation is a straight line, perpendicular to and crossing the vector $Z_s + Z_T + Z_G$ at its middle point. If n is different from 1, the loci become circles as shown in Fig. 9.19. The angle θ between the two sources is the angle between the two segments joining Z_R to the base of Z_G and the summit of Z_S. Normally, that angle will take a small value. In an out-of-step condition, it will assume a bigger value and when it reaches 180°, it crosses $Z_s + Z_T + Z_G$ at its middle point.

Normally, because of the machine's inertia, the impedance Z_R moves slowly. The phenomenon can be taken advantage of and an out-of-step condition will very often be detected by the combination a mho relay and two blinders as shown in Fig. 9.20. In this application, an out-of-step condition will be assumed to be detected when the impedance locus enters the mho circle and remains between the two blinders for an interval of time longer than a preset definite time delay. Implicit in this scheme is the fact that the angle between the two sources is assumed to take a large value when Zr crosses the blinders. Implementation of an out-of-step protection will normally require some careful studies and eventually will require some stability simulations in order to determine the nature and the locus of the stable and the unstable swings. One of the paramount requirement of an out-of-step protection is not to trip the generator in case of a stable wing.

Abnormal Frequency Operation of Turbine-Generator

Although it is not a concern for hydraulic generators, the protection against abnormal frequency operation becomes an issue with steam turbine-graters. If the turbine is rotated at a frequency other than synchronous, the blades in the low pressure turbine element could resonate at their natural frequency. Blading mechanical fatigue could result with subsequent damage and failure.

Figure 9.21 (ANSI C37.106) represents a typical steam turbine operating limitation curve. Continuous operation is allowed around 60 Hz. Time-limited zones exist above and below the continuous operation regions. Prohibited operation regions lie beyond.

With the advent of modern generator microprocessor-based relays (IEEE, 1989), there does not seem to be a consensus emerging among the relay and turbine manufacturers, regarding the digital implementation of underfrequency turbine protection. The following points should, however, be taken into account:

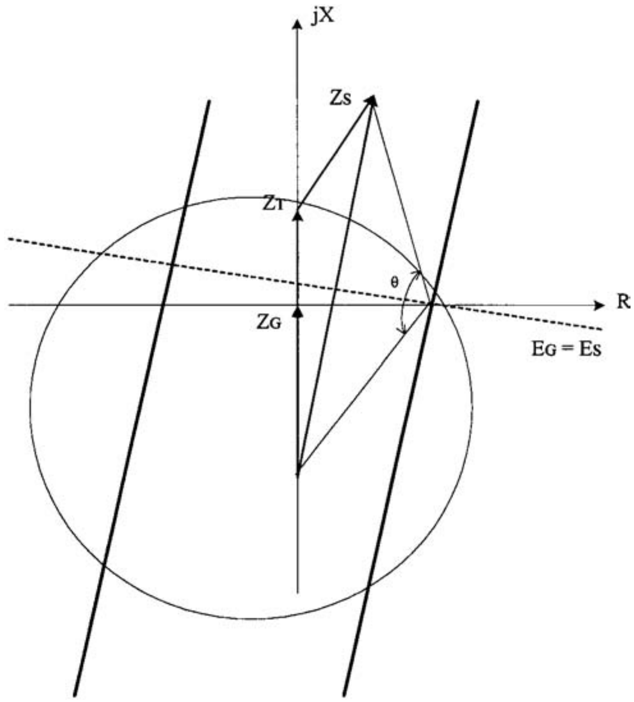

FIGURE 9.20 Out-of-step mho detector with blinders.

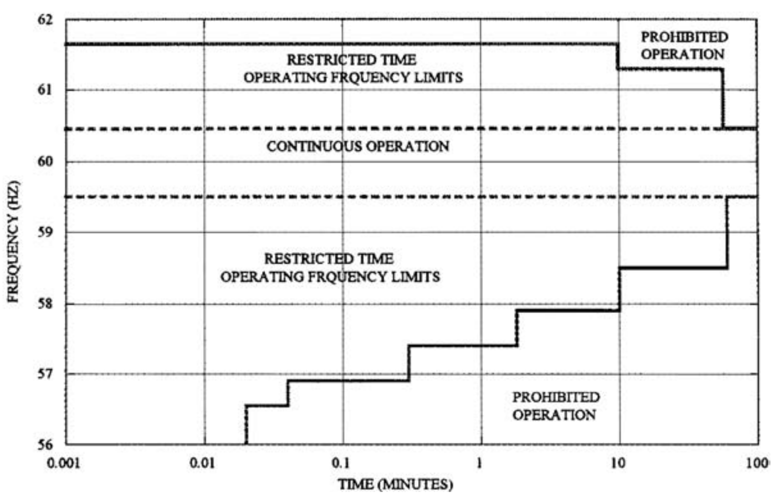

FIGURE 9.21 Typical steam turbine operating characteristic. (Modified from ANSI/IEEE C37.106-1987, Figure 6.)

- Measurement of frequency is normally available on a continuous basis and over a broad frequency range. Precision better than 0.01 Hz in the frequency measurement has been achieved.
- In practically all products, a number of independent over- or under-frequency definite time functions can be combined to form a composite curve.

Therefore, with digital technology, a typical over/underfrequency scheme, as shown in Fig. 9.22, comprising one definite-time over-frequency and two definite-time under-frequency elements is readily implementable.

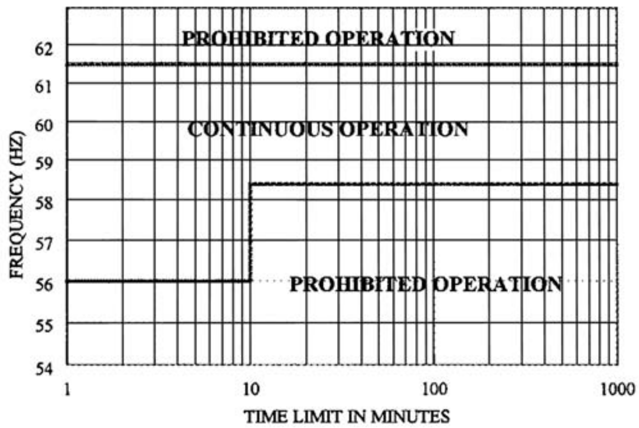

FIGURE 9.22 Typical abnormal frequency protection characteristic.

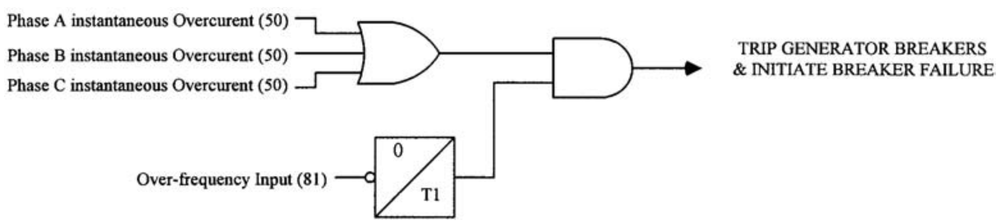

FIGURE 9.23 Frequency supervised overcurrent inadvertent energizing protection.

Protection Against Accidental Energization

A number of catastrophic failures have occurred in the past when synchronous generators have been accidentally energized while at standstill. Among the causes for such incidents were human errors, breaker flashover, or control circuitry malfunction.

A number of protection schemes have been devised to protect the generator against inadvertent energization. The basic principle is to monitor the out-of-service condition and to detect an accidental energizing immediately following that state. As an example, Fig. 9.23 shows an application using an over-frequency relay supervising three single phase instantaneous overcurrent elements. When the generator is put out of service or the over-frequency element drops out, the timer will pick up. If inadvertent energizing occurs, the over-frequency element will pick up, but because of the timer drop-out delay, the instantaneous overcurrent elements will have the time to initiate the generator breakers opening. The supervision could also be implemented using a voltage relay.

Accidental energizing caused by a single or three-phase breaker flashover occurring during the generator synchronizing process will not be detected by the logic of Fig. 9.23. In such an instance, by the time the generator has been closed to the synchronous speed, the overcurrent element outputs would have been blocked.

Generator Breaker Failure

Generator breaker failure follows the general pattern of the same function found in other applications: once a fault has been detected by a protective device, a timer will monitor the removal of the fault. If, after a time delay, the fault is still detected, conclusion is reached that the breaker(s) have not opened and a signal to open the backup breakers will be sent.

Figure 9.24 shows a conventional breaker failure diagram where provision has been added to detect a flashover occurring before the synchronizing of the generator: in addition to the protective relays detecting

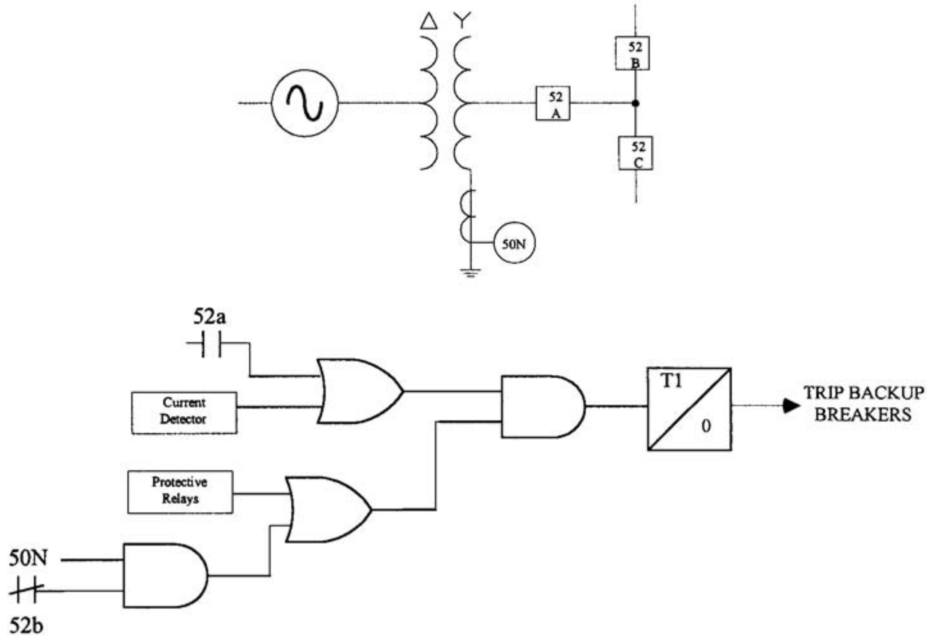

FIGURE 9.24 Breaker failure logic with flashover protection.

a fault, a flashover condition is detected by using an instantaneous overcurrent relay installed on the neutral of the step-up transformer. If this relay picks up and the breaker position contact (52b) is closed (breaker open), then a flashover condition is asserted and breaker failure is initiated.

Generator Tripping Principles

A number of methods for isolating a generator once a fault has been detected are commonly being implemented. They fall into four groups:

- Simultaneous tripping involves simultaneously shutting the prime mover down by closing its valves and opening the field and generator breakers. This technique is highly recommended for severe internal generator faults.
- Generator tripping involves simultaneously opening both the field and generator breakers.
- Unit separation involves opening the generator breaker only.
- Sequential tripping is applicable to steam turbines and involves first tripping the turbine valves in order to prevent any overspeeding of the unit. Then, the field and generator breakers are opened. Figure 9.25 represents a possible logical scheme for the implementation of a sequential tripping function. If the following three conditions are met, (1) the real power is below a negative pre-set threshold SET_1, (2) the steam valve or a differential pressure switch is closed (either condition indicating the removal of the prime-mover), (3) the sequential tripping function is enabled, then a trip signal will be sent to the generator and field breakers.

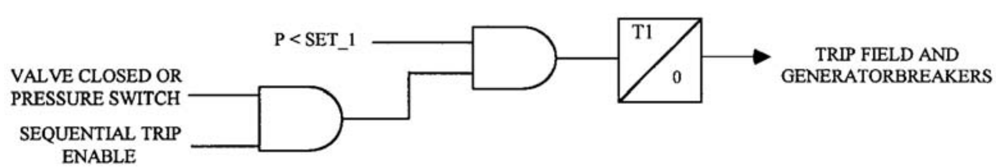

FIGURE 9.25 Implementation of a sequential tripping function.

Impact of Generator Digital Multifunction Relays[1]

The latest technological leap in generator protection has been the release of digital multifunction relays by various manufacturers (Benmouyal, 1988; Yalla, 1992; Benmouyal, 1994; Yip, 1994). With more sophisticated characteristics being available through software algorithms, generator protective function characteristics can be improved. Therefore, multifunction relays have many advantages, most of which stem from the technology on which they are based.

Improvements in Signal Processing

Most multifunction relays use a full-cycle Discrete Fourier Transform (DFT) algorithm for acquisition of the fundamental component of the current and voltage phasors. Consequently, they will benefit from the inherent filtering properties provided by the algorithms, such as:

- immunity from DC component and good suppression of exponentially decaying offset due to the large value of X/R time constants in generators;
- immunity to harmonics;
- nominal response time of one cycle for the protective functions requiring fast response.

Since sequence quantities are computed mathematically from the voltage and current phasors, they will also benefit from the above advantages.

However, it should be kept in mind that fundamental phasors of waveforms are not the only parameters used in digital multifunction relays. Other parameters like peak or rms values of waveforms can be equally acquired through simple algorithms, depending upon the characteristics of a particular algorithm.

A number of techniques have been used to make the measurement of phasor magnitudes independent of frequency, and therefore achieve stable sensitivities over large frequency excursions. One technique is known as frequency tracking and consists of having a number of samples in one cycle that is constant, regardless of the value of the frequency or the generator's speed. A software digital phase-locked loop allows implementation of such a scheme and will inherently provide a direct measurement of the frequency or the speed of the generator (Benmouyal, 1989). A second technique keeps the sampling period fixed, but varies the time length of the data window to follow the period of the generator frequency. This results in a variable number of samples in the cycles (Hart et al., 1997). A third technique consists of measuring the root-mean square value of a current or voltage waveform. The variation of this quantity with frequency is very limited, and therefore, this technique allows measurement of the magnitude of a waveform over a broad frequency range.

A further improvement consists of measuring the generator frequency digitally. Precision, in most cases, will be one hundredth of a hertz or better, and good immunity to harmonics and noise is achievable with modern algorithms.

Improvements in Protective Functions

The following functions will benefit from some inherent advantages of the digital processing capability:

- A number of improvements can be attributed to stator differential protection. The first is the detection of CT saturation in case of external faults that would cause the protection relay to trip. When CT ratios do not match perfectly, the difference can be either automatically or manually introduced into the algorithm in order to suppress the difference.
- It is no longer necessary to provide a Δ-Y conversion for the backup 21 elements in order to cover the phase fault on the high side of the voltage transformer. That conversion can be accomplished mathematically inside the relay.
- In the area of detection of voltage transformer blown fuses, the use of symmetrical components allows identification of the faulted phase. Therefore, complex logic schemes can be implemented where only the protection function impacted by the phase will be blocked. As an example, if a 51V is implemented on all three phases independently, it will be sufficient to block the function only

[1]This section was published previously in a modified form in Working Group J-11 of PSRC, Application of multifunction generator protection systems, *IEEE Trans. on PD,* 14(4), Oct. 1999.

on the phase on which a fuse has been detected as blown. Furthermore, contrary to the conventional voltage balance relay scheme, a single VT will suffice when using this modern algorithm.

- Because of the different functions recording their characteristics over a large frequency interval, it is no longer necessary to monitor the frequency in order to implement start-up or shut-down protection.
- The 100% stator-ground protection can be improved by using third-harmonic voltage measurements both at the phase and neutral.
- The characteristic of an offset mho impedance relay in the R-X plane can be made to be independent of frequency by using one of the following two techniques: the frequency-tracking algorithm previously mentioned, or the use of the positive sequence voltage and current because their ratio is frequency-independent.
- Functions which are inherently three-phase phenomena can be implemented by using the positive sequence voltage and current quantities. The loss-of-field or loss-of-synchronism are examples.
- In the reverse power protection, improved accuracy and sensitivity can be obtained with digital technology.
- Digital technology allows the possibility of tailoring inverse volt/hertz curves to the user's needs. Full programmability of these same curves is readily achievable. From that perspective, volt/hertz protection is improved by a closer match between the implemented curve and the generator or step-up transformer damage curve.

Multifunction generator protection packages have other functions that make use of the inherent capabilities of microprocessor devices. These include: oscillography and event recording, time synchronization, multiple settings, metering, communications, self-monitoring, and diagnostics.

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9.3 Transmission Line Protection

Stanley H. Horowitz

The study of transmission line protection presents many fundamental relaying considerations that apply, in one degree or another, to the protection of other types of power system protection. Each electrical element, of course, will have problems unique to itself, but the concepts of reliability, selectivity, local and remote backup, zones of protection, coordination and speed which may be present in the protection of one or more other electrical apparatus are all present in the considerations surrounding transmission line protection.

Since transmission lines are also the links to adjacent lines or connected equipment, transmission line protection must be compatible with the protection of all of these other elements. This requires coordination of settings, operating times and characteristics.

The purpose of power system protection is to detect faults or abnormal operating conditions and to initiate corrective action. Relays must be able to evaluate a wide variety of parameters to establish that corrective action is required. Obviously, a relay cannot prevent the fault. Its primary purpose is to detect the fault and take the necessary action to minimize the damage to the equipment or to the system. The most common parameters which reflect the presence of a fault are the voltages and currents at the terminals of the protected apparatus or at the appropriate zone boundaries. The fundamental problem in power system protection is to define the quantities that can differentiate between normal and abnormal conditions. This problem is compounded by the fact that "normal" in the present sense means outside the zone of protection. This aspect, which is of the greatest significance in designing a secure relaying system, dominates the design of all protection systems.

The Nature of Relaying

Reliability

Reliability, in system protection parlance, has special definitions which differ from the usual planning or operating usage. A relay can misoperate in two ways: it can fail to operate when it is required to do so, or it can operate when it is not required or desirable for it to do so. To cover both situations, there are two components in defining reliability:

Dependability — which refers to the certainty that a relay will respond correctly for all faults for which it is designed and applied to operate; and

Security — which is the measure that a relay will not operate incorrectly for any fault.

Most relays and relay schemes are designed to be dependable since the system itself is robust enough to withstand an incorrect tripout (loss of security), whereas a failure to trip (loss of dependability) may be catastrophic in terms of system performance.

Zones of Protection

The property of security is defined in terms of regions of a power system — called zones of protection — for which a given relay or protective system is responsible. The relay will be considered secure if it responds only to faults within its zone of protection. Figure 9.26 shows typical zones of protection with transmission lines, buses, and transformers, each residing in its own zone. Also shown are "closed zones" in which all power apparatus entering the zone is monitored, and "open" zones, the limit of which varies with the fault current. Closed zones are also known as "differential," "unit," or absolutely selective," and open zones are "non-unit," "unrestricted," or "relatively selective."

The zone of protection is bounded by the current transformers (CT) which provide the input to the relays. While a CT provides the ability to detect a fault within its zone, the circuit breaker (CB) provides the ability to isolate the fault by disconnecting all of the power equipment inside its zone. When a CT is part of the CB, it becomes a natural zone boundary. When the CT is not an integral part of the CB,

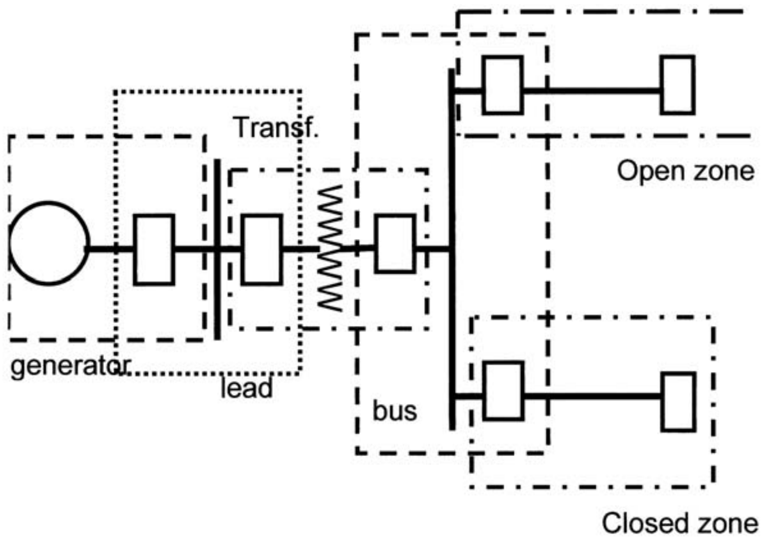

FIGURE 9.26 Closed and open zones of protection. (*Source:* Horowitz, S. H. and Phadke, A. G., *Power System Relaying,* 2nd ed., 1995. Research Studies Press, U.K. With permission.)

special attention must be paid to the fault detection and fault interruption logic. The CTs still define the zone of protection, but a communication channel must be used to implement the tripping function.

Relay Speed

It is, of course, desirable to remove a fault from the power system as quickly as possible. However, the relay must make its decision based upon voltage and current waveforms, which are severely distorted due to transient phenomena that follow the occurrence of a fault. The relay must separate the meaningful and significant information contained in these waveforms upon which a secure relaying decision must be based. These considerations demand that the relay take a certain amount of time to arrive at a decision with the necessary degree of certainty. The relationship between the relay response time and its degree of certainty is an inverse one and is one of the most basic properties of all protection systems.

Although the operating time of relays often varies between wide limits, relays are generally classified by their speed of operation as follows:

1. Instantaneous — These relays operate as soon as a secure decision is made. No intentional time delay is introduced to slow down the relay response.
2. Time-delay — An intentional time delay is inserted between the relay decision time and the initiation of the trip action.
3. High-speed — A relay that operates in less than a specified time. The specified time in present practice is 50 milliseconds (3 cycles on a 60 Hz system).
4. Ultra high-speed — This term is not included in the Relay Standards but is commonly considered to be operation in 4 milliseconds or less.

Primary and Backup Protection

The main protection system for a given zone of protection is called the primary protection system. It operates in the fastest time possible and removes the least amount of equipment from service. On Extra High Voltage (EHV) systems, i.e., 345kV and above, it is common to use duplicate primary protection systems in case a component in one primary protection chain fails to operate. This duplication is therefore intended to cover the failure of the relays themselves. One may use relays from a different manufacturer, or relays based on a different principle of operation to avoid common-mode failures. The operating time and the tripping logic of both the primary and its duplicate system are the same.

It is not always practical to duplicate every element of the protection chain. On High Voltage (HV) and EHV systems, the costs of transducers and circuit breakers are very expensive and the cost of duplicate equipment may not be justified. On lower voltage systems, even the relays themselves may not be duplicated. In such situations, a backup set of relays will be used. Backup relays are slower than the primary relays and may remove more of the system elements than is necessary to clear the fault.

Remote Backup — These relays are located in a separate location and are completely independent of the relays, transducers, batteries, and circuit breakers that they are backing up. There are no common failures that can affect both sets of relays. However, complex system configurations may significantly affect the ability of a remote relay to "see" all faults for which backup is desired. In addition, remote backup may remove more sources of the system than can be allowed.

Local Backup — These relays do not suffer from the same difficulties as remote backup, but they are installed in the same substation and use some of the same elements as the primary protection. They may then fail to operate for the same reasons as the primary protection.

Reclosing

Automatic reclosing infers no manual intervention but probably requires specific interlocking such as a full or check synchronizing, voltage or switching device checks, or other safety or operating constraints. Automatic reclosing can be high speed or delayed. High Speed Reclosing (HSR) allows only enough time for the arc products of a fault to dissipate, generally 15–40 cycles on a 60 Hz base, whereas time delayed reclosings have a specific coordinating time, usually 1 or more seconds. HSR has the possibility of generator shaft torque damage and should be closely examined before applying it.

It is common practice in the U.S. to trip all three phases for all faults and then reclose the three phases simultaneously. In Europe, however, for single line-to-ground faults, it is not uncommon to trip only the faulted phase and then reclose that phase. This practice has some applications in the U.S., but only in rare situations. When one phase of a three-phase system is opened in response to a single phase-to-ground fault, the voltage and current in the two healthy phases tend to maintain the fault arc after the faulted phase is de-energized. Depending on the length of the line, load current, and operating voltage, compensating reactors may be required to extinguish this "secondary arc."

System Configuration

Although the fundamentals of transmission line protection apply in almost all system configurations, there are different applications that are more or less dependent upon specific situations.

Operating Voltages — Transmission lines will be those lines operating at 138 kV and above, subtransmission lines are 34.5 kV to 138 kV, and distribution lines are below 34.5 kV. These are not rigid definitions and are only used to generically identify a transmission system and connote the type of protection usually provided. The higher voltage systems would normally be expected to have more complex, hence more expensive, relay systems. This is so because higher voltages have more expensive equipment associated with them and one would expect that this voltage class is more important to the security of the power system. The higher relay costs, therefore, are more easily justified.

Line Length — The length of a line has a direct effect on the type of protection, the relays applied, and the settings. It is helpful to categorize the line length as "short," "medium," or "long" as this helps establish the general relaying applications although the definition of "short," "medium," and "long" is not precise. A short line is one in which the ratio of the source to the line impedance (SIR) is large (>4 e.g.), the SIR of a long line is 0.5 or less and a medium line's SIR is between 4 and 0.5. It must be noted, however, that the per-unit impedance of a line varies more with the nominal voltage of the line than with its physical length or impedance. So a "short" line at one voltage level may be a "medium" or "long" line at another.

Multiterminal Lines — Occasionally, transmission lines may be tapped to provide intermediate connections to additional sources without the expense of a circuit breaker or other switching device. Such a configuration is known as a multiterminal line and, although it is an inexpensive measure for strengthening the power system, it presents special problems for the protection engineer. The difficulty

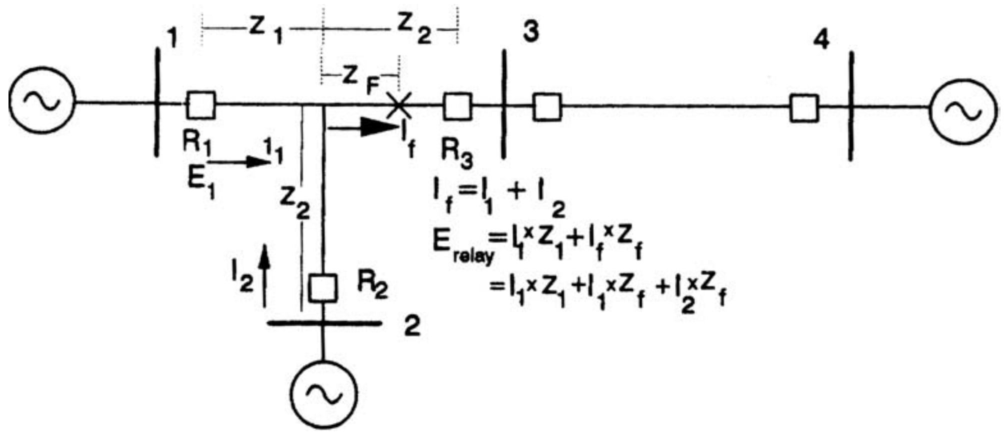

FIGURE 9.27 Effect of infeed on local relays. (*Source:* Horowitz, S. H. and Phadke, A. G., *Power System Relaying,* 2nd ed., 1995. Research Studies Press, U.K. With permission.)

arises from the fact that a relay receives its input from the local transducers, i.e., the current and voltage at the relay location. Referring to Fig. 9.27, the current contribution to a fault from the intermediate source is not monitored. The total fault current is the sum of the local current plus the contribution from the intermediate source, and the voltage at the relay location is the sum of the two voltage drops, one of which is the product of the unmonitored current and the associated line impedance.

Current Actuated Relays

Fuses

The most commonly used protective device in a distribution circuit is the fuse. Fuse characteristics vary considerably from one manufacturer to another and the specifics must be obtained from their appropriate literature. Figure 9.28 shows the time-current characteristics which consist of the minimum melt and total clearing curves.

Minimum melt is the time between initiation of a current large enough to cause the current responsive element to melt and the instant when arcing occurs. Total Clearing Time (TCT) is the total time elapsing from the beginning of an overcurrent to the final circuit interruption; i.e., TCT = minimum melt plus arcing time.

In addition to the different melting curves, fuses have different load-carrying capabilities. Manufacturer's application tables show three load-current values: continuous, hot-load pickup, and cold-load pickup. Continuous load is the maximum current that is expected for three hours or more for which the fuse will not be damaged. Hot-load is the amount that can be carried continuously, interrupted, and immediately reenergized without melting. Cold-load follows a 30-min outage and is the high current that is the result in the loss of diversity when service is restored. Since the fuse will also cool down during this period, the cold-load pickup and the hot-load pickup may approach similar values.

Inverse-Time Delay Overcurrent Relays

The principal application of time-delay overcurrent relays (TDOC) is on a radial system where they provide both phase and ground protection. A basic complement of relays would be two phase and one ground relay. This arrangement will protect the line for all combinations of phase and ground faults using the minimum number of relays. Adding a third phase relay, however, provides complete backup protection, that is two relays for every type of fault, and is the preferred practice. TDOC relays are usually used in industrial systems and on subtransmission lines that cannot justify more expensive protection such as distance or pilot relays.

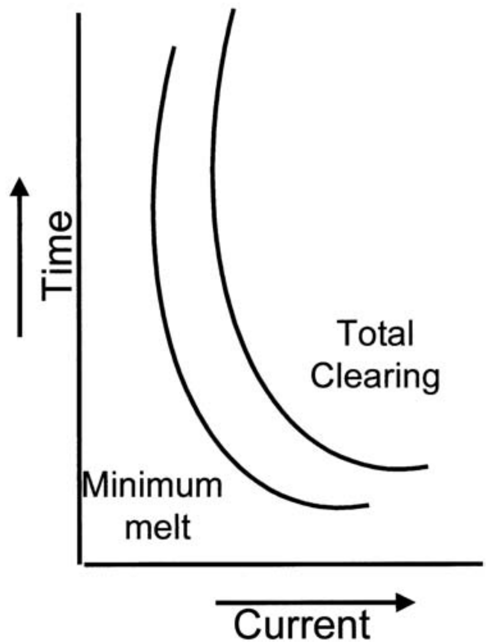

FIGURE 9.28 Fuse time-current characteristic. (*Source:* Horowitz, S. H. and Phadke, A. G., *Power System Relaying*, 2nd ed., 1995. Research Studies Press, U.K. With permission.)

There are two settings that must be applied to all TDOC relays: the pickup and the time delay. The pickup setting is selected so that the relay will operate for all short circuits in the line section for which it is to provide protection. This will require margins above the maximum load current, usually twice the expected value, and below the minimum fault current, usually 1/3 the calculated phase-to-phase or phase-to-ground fault current. If possible, this setting should also provide backup for an adjacent line section or adjoining equipment. The time-delay function is an independent parameter that is obtained in a variety of ways, either the setting of an induction disk lever or an external timer. The purpose of the time-delay is to enable relays to coordinate with each other. Figure 9.29 shows the family of curves of a single TDOC model. The ordinate is time in milliseconds or seconds depending on the relay type; the abscissa is in multiples of pickup to normalize the curve for all fault current values. Figure 9.30 shows how TDOC relays on a radial line coordinate with each other.

Instantaneous Overcurrent Relays

Figure 9.30 also shows why the TDOC relay cannot be used without additional help. The closer the fault is to the source, the greater the fault current magnitude, yet the longer the tripping time. The addition of an instantaneous overcurrent relay makes this system of protection viable. If an instantaneous relay can be set to "see" almost up to, but not including, the next bus, all of the fault clearing times can be lowered as shown in Fig. 9.31. In order to properly apply the instantaneous overcurrent relay, there must be a substantial reduction in short-circuit current as the fault moves from the relay toward the far end of the line. However, there still must be enough of a difference in the fault current between the near and far end faults to allow a setting for the near end faults. This will prevent the relay from operating for faults beyond the end of the line and still provide high-speed protection for an appreciable portion of the line.

Since the instantaneous relay must not see beyond its own line section, the values for which it must be set are very much higher than even emergency loads. It is common to set an instantaneous relay about 125–130% above the maximum value that the relay will see under normal operating situations and about 90% of the minimum value for which the relay should operate.

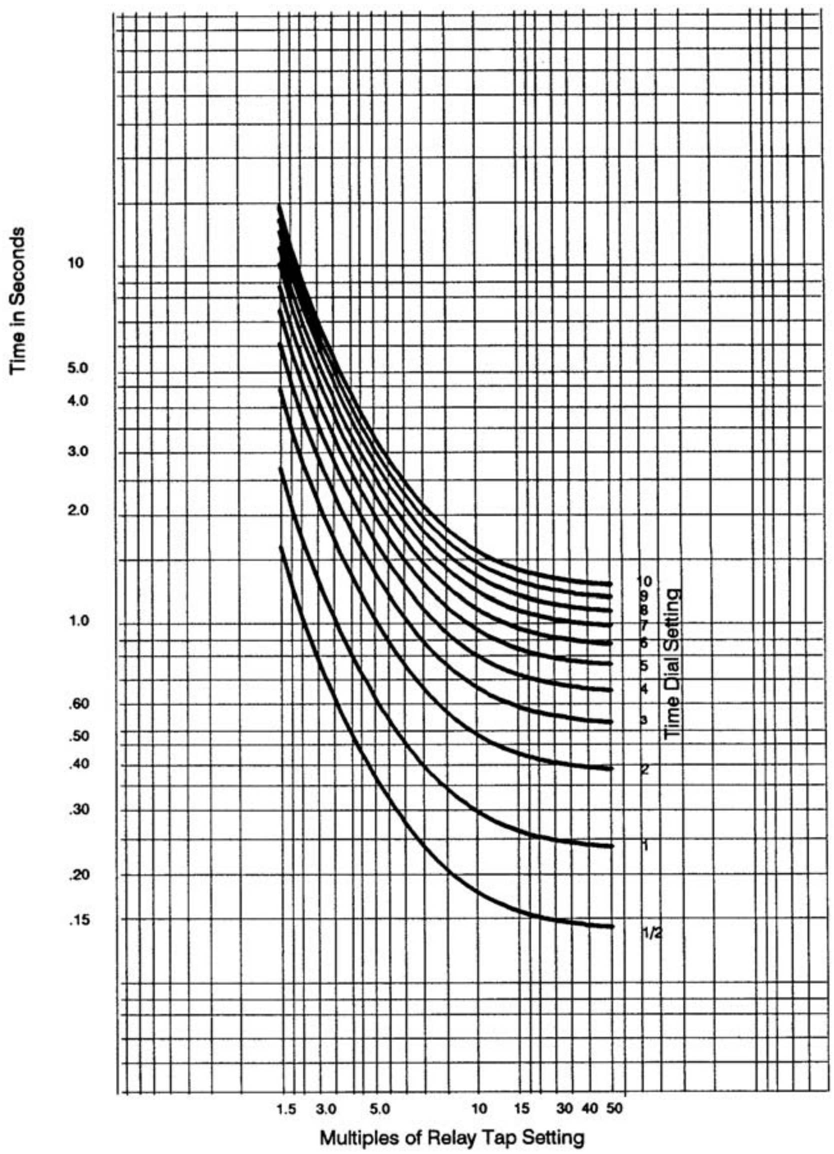

FIGURE 9.29 Family of TDOC time-current characteristics. (*Source:* Horowitz, S. H. and Phadke, A. G., *Power System Relaying,* 2nd ed., 1995. Research Studies Press, U.K. With permission.)

Directional Overcurrent Relays

Directional overcurrent relaying is necessary for multiple source circuits when it is essential to limit tripping for faults in only one direction. If the same magnitude of fault current could flow in either direction at the relay location, coordination cannot be achieved with the relays in front of, and, for the same fault, the relays behind the nondirectional relay, except in very unusual system configurations.

Polarizing Quantities — To achieve directionality, relays require two inputs; the operating current and a reference, or polarizing, quantity that does not change with fault location. For phase relays, the polarizing quantity is almost always the system voltage at the relay location. For ground directional indication, the zero-sequence voltage ($3E_0$) can be used. The magnitude of $3E_0$ varies with the fault

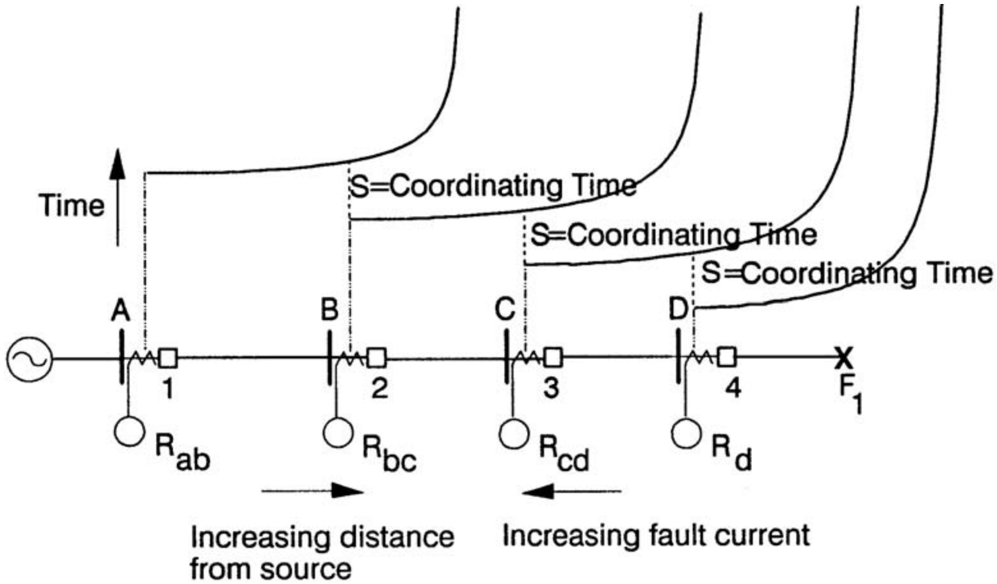

FIGURE 9.30 Coordination of TDOC relays. (*Source:* Horowitz, S. H. and Phadke, A. G., *Power System Relaying,* 2nd ed., 1995. Research Studies Press, U.K. With permission.)

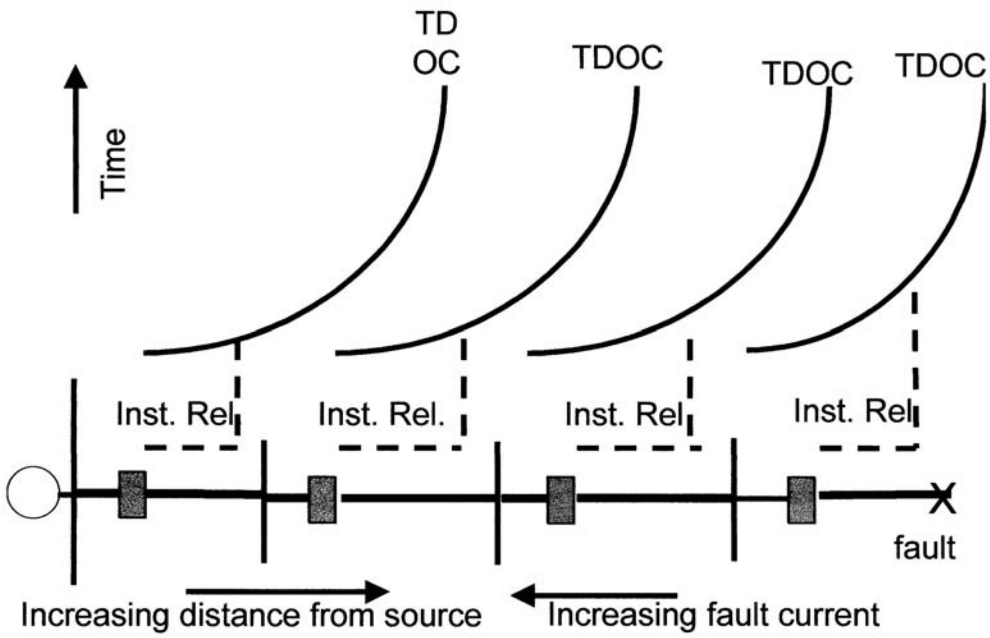

FIGURE 9.31 Effect of instantaneous relays. (*Source:* Horowitz, S. H. and Phadke, A. G., *Power System Relaying,* 2nd ed., 1995. Research Studies Press, U.K. With permission.)

location and may not be adequate in some instances. An alternative and generally preferred method of obtaining a directional reference is to use the current in the neutral of a wye-grounded/delta power transformer.

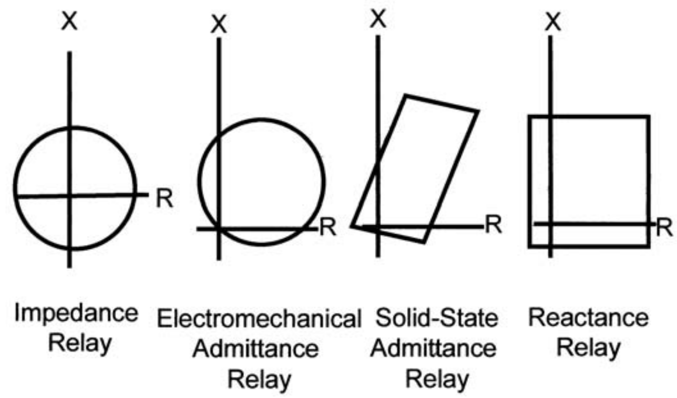

FIGURE 9.32 Distance relay characteristics. (*Source:* Horowitz, S. H. and Phadke, A. G., *Power System Relaying,* 2nd ed., 1995. Research Studies Press, U.K. With permission.)

Distance Relays

Distance relays respond to the voltage and current, i.e., the impedance, at the relay location. The impedance per mile is fairly constant so these relays respond to the distance between the relay location and the fault location. As the power systems become more complex and the fault current varies with changes in generation and system configuration, directional overcurrent relays become difficult to apply and to set for all contingencies, whereas the distance relay setting is constant for a wide variety of changes external to the protected line.

There are three general distance relay types as shown in Fig. 9.32. Each is distinguished by its application and its operating characteristic.

Impedance Relay

The impedance relay has a circular characteristic centered at the origin of the R-X diagram. It is nondirectional and is used primarily as a fault detector.

Admittance Relay

The admittance relay is the most commonly used distance relay. It is the tripping relay in pilot schemes and as the backup relay in step distance schemes. Its characteristic passes through the origin of the R-X diagram and is therefore directional. In the electromechanical design it is circular, and in the solid state design, it can be shaped to correspond to the transmission line impedance.

Reactance Relay

The reactance relay is a straight-line characteristic that responds only to the reactance of the protected line. It is nondirectional and is used to supplement the admittance relay as a tripping relay to make the overall protection independent of resistance. It is particularly useful on short lines where the fault arc resistance is the same order of magnitude as the line length.

Figure 9.33 shows a three-zone step distance relaying scheme that provides instantaneous protection over 80–90% of the protected line section (Zone 1) and time-delayed protection over the remainder of the line (Zone 2) plus backup protection over the adjacent line section. Zone 3 also provides backup protection for adjacent lines sections.

In a three-phase power system, 10 types of faults are possible: three single phase-to-ground, three phase-to-phase, three double phase-to-ground, and one three-phase fault. It is essential that the relays provided have the same setting regardless of the type of fault. This is possible if the relays are connected to respond to delta voltages and currents. The delta quantities are defined as the difference between any two phase quantities, for example, $E_a - E_b$ is the delta quantity between phases a and b. In general, for a multiphase fault between phases x and y,

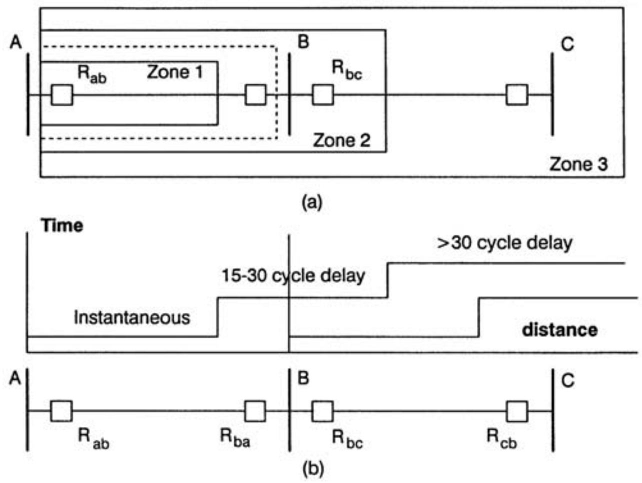

FIGURE 9.33 Three-zone step distance relaying to protect 100% of a line and backup the neighboring line. (*Source:* Horowitz, S. H. and Phadke, A. G., *Power System Relaying,* 2nd ed., 1995. Research Studies Press, U.K. With permission.)

$$\frac{Ex - Ey}{Ix - Iy} = Z1 \tag{9.14}$$

where x and y can be a, b, or c and Z_1 is the positive sequence impedance between the relay location and the fault. For ground distance relays, the faulted phase voltage, and a compensated faulted phase current must be used.

$$\frac{Ex}{Ix + mI_0} = Z_1 \tag{9.15}$$

where m is a constant depending on the line impedances, and I_0 is the zero sequence current in the transmission line. A full complement of relays consists of three phase distance relays and three ground distance relays. This is the preferred protective scheme for high voltage and extra high voltage systems.

Pilot Protection

As can be seen from Fig. 9.33, step distance protection does not offer instantaneous clearing of faults over 100% of the line segment. In most cases this is unacceptable due to system stability considerations. To cover the 10–20% of the line not covered by Zone 1, the information regarding the location of the fault is transmitted from each terminal to the other terminal(s). A communication channel is used for this transmission. These pilot channels can be over power line carrier, microwave, fiberoptic, or wire pilot. Although the underlying principles are the same regardless of the pilot channel, there are specific design details that are imposed by this choice.

Power line carrier uses the protected line itself as the channel, superimposing a high frequency signal on top of the 60 Hz power frequency. Since the line being protected is also the medium used to actuate the protective devices, a blocking signal is used. This means that a trip will occur at both ends of the line unless a signal is received from the remote end.

Microwave or fiberoptic channels are independent of the transmission line being protected so a tripping signal can be used.

Wire pilot channels are limited by the impedance of the copper wire and are used at lower voltages where the distance between the terminals is not great, usually less than 10 miles.

Directional Comparison

The most common pilot relaying scheme in the U.S. is the directional comparison blocking scheme, using power line carrier. The fundamental principle upon which this scheme is based utilizes the fact that, at a given terminal, the direction of a fault either forward or backward is easily determined by a directional relay. By transmitting this information to the remote end, and by applying appropriate logic, both ends can determine whether a fault is within the protected line or external to it. Since the power line itself is used as the communication medium, a blocking signal is used.

Transfer Tripping

If the communication channel is independent of the power line, a tripping scheme is a viable protection scheme. Using the same directional relay logic to determine the location of a fault, a tripping signal is sent to the remote end. To increase security, there are several variations possible. A direct tripping signal can be sent, or additional underreaching or overreaching directional relays can be used to supervise the tripping function and increase security. An underreaching relay sees less than 100% of the protected line, i.e., Zone 1. An overreaching relay sees beyond the protected line such as Zone 2 or 3.

Phase Comparison

Phase comparison is a differential scheme that compares the phase angle between the currents at the ends of the line. If the currents are essentially in phase, there is no fault in the protected section. If these currents are essentially 180° out of phase, there is a fault within the line section. Any communication link can be used.

Pilot Wire

Pilot wire relaying is a form of differential line protection similar to phase comparison, except that the phase currents are compared over a pair of metallic wires. The pilot channel is often a rented circuit from the local telephone company. However, as the telephone companies are replacing their wired facilities with microwave or fiberoptics, this protection must be closely monitored.

9.4 System Protection

Miroslav Begovic

While most of the protective system designs are centered around individual components, system-wide disturbances in power systems are becoming a frequent and challenging problem for electric utilities. The occurrence of major disturbances in power systems requires coordinated protection and control actions to stop the system degradation, restore the normal state, and minimize the impact of the disturbance. Local protection systems are often not capable of protecting the overall system, which may be affected by the disturbance. Among the phenomena that create the power system disturbances are various types of system instability, overloads, and power system cascading (Horowitz and Phadke, 1992; Elmore, 1994; Blackburn, 1987; Phadke and Thorp, 1988; Anderson, 1999).

Power system planning has to account for tight operating margins with less redundancy, because of new constraints placed by restructuring of the entire industry. The advanced measurement and communication technology in wide area monitoring and control are expected to provide new, faster, and better ways to detect and control an emergency (Begovic et al., 1999).

Transient Stability and Out-of-Step Protection

Every time a fault or a topological change affects the power balance in the system, the instantaneous power imbalance creates oscillations between the machines. Stable oscillations lead to transition from one (pre-fault) to another (post-fault) equilibrium point, whereas unstable ones allow machines to oscillate beyond the acceptable range. If the oscillations are large, the stations' auxiliary supplies may undergo severe voltage fluctuations, and eventually trip (Horowitz and Phadke, 1992). Should that

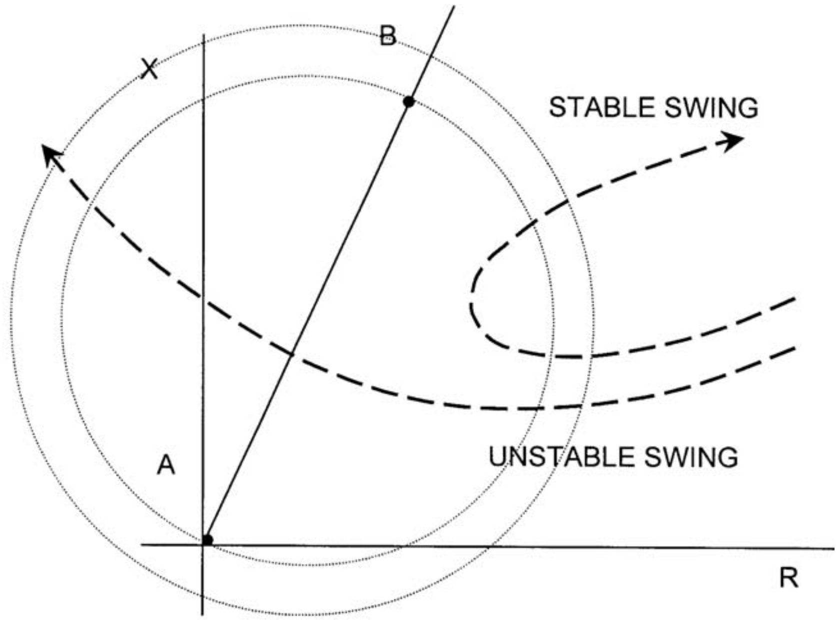

FIGURE 9.34 Trajectories of stable and unstable swings in the impedance plane.

happen, the subsequent resynchronization of the machines might take a long time. It is, therefore, desirable to trip the machine(s) exposed to transient unstable oscillations while the plant auxiliaries remain energized.

The frequency of the transient oscillations is usually between 0.5 and 2 Hz. Since the fault imposes almost instantaneous changes on the system, the slow speed of the transient disturbances can be used to distinguish between the two. For the sake of illustration, let us assume that a power system consists of two machines, A and B, connected by a transmission line. Figure 9.34 represents the trajectories of the stable and unstable swings between the machines, as well as a characteristic of the mho relay covering the line between them, shown in the impedance plane. The stable swing moves from the distant stable operating point towards the trip zone of the relay, and may even encroach on it, then leave again. The unstable trajectory may pass through the entire trip zone of the relay. The relaying tasks are to detect, and then trip (or block) the relay, depending on the situation. Detection is accomplished by out-of-step relays, which have multiple characteristics. When the trajectory of the impedance seen by the relays enters the outer zone (a circle with a larger radius), the timer is activated, and depending on the speed at which the impedance trajectory moves into the inner zone (a circle with a smaller radius), or leaves the outer zone, a tripping (or blocking) decision can be made. The relay characteristic may be chosen to be straight lines, known as "blinders," which prevent the heavy load from being misrepresented as a fault or instability. Another piece of information that can be used in detection of transient swings is that they are symmetrical, and do not create any zero or negative sequence currents.

In the case when power system separation is imminent, out-of-step protection should take place along boundaries that will form islands with matching load and generation. Distance relays are often used to provide an out-of-step protection function, whereby they are called upon to provide blocking or tripping signals upon detecting an out-of-step condition. The most common predictive scheme to combat loss of synchronism is the Equal-Area Criterion and its variations. This method assumes that the power system behaves like a two-machine model where one area oscillates against the rest of the system. Whenever the underlying assumption holds true, the method has potential for fast detection.

Overload and Underfrequency Load Shedding

Outage of one or more power system components due to the overload may result in overload of other elements in the system. If the overload is not alleviated in time, the process of power system cascading may start, leading to power system separation. When a power system separates, islands with an imbalance between generation and load are formed. One consequence of the imbalance is deviation of frequency from the nominal value. If the generators cannot handle the imbalance, load or generation shedding is necessary. A special protection system or out-of-step relaying can also start the separation.

A quick, simple, and reliable way to reestablish active power balance is to shed load by underfrequency relays. The load shedding is often designed as a multistep action, and the frequency settings and blocks of load to be shed are carefully selected to maximize the reliability and dependability of the action. There are a large variety of practices in designing load shedding schemes based on the characteristics of a particular system and the utility practices. While the system frequency is a final result of the power deficiency, the rate of change of frequency is an instantaneous indicator of power deficiency and can enable incipient recognition of the power imbalance. However, change of the machine speed is oscillatory by nature due to the interaction among generators. These oscillations depend on location of the sensors in the island and the response of the generators. The problems regarding the rate-of-change of frequency function are:

- Systems having small inertia may cause larger oscillations. Thus, enough time must be allowed for the relay to calculate the actual rate-of-change of frequency reliably. Measurements at load buses close to the electrical center of the system are less susceptible to oscillations (smaller peak-to-peak values) and can be used in practical applications. Smaller system inertia causes a higher frequency of oscillations, which enables faster calculation of the actual rate-of-change of frequency. However, it causes faster rate-of-change of frequency, and, consequently, a larger frequency drop.
- Even if rate-of-change of frequency relays measure the average value throughout the network, it is difficult to set them properly unless typical system boundaries and imbalance can be predicted. If this is the case (e.g., industrial and urban systems), the rate of change of frequency relays may improve a load shedding scheme (scheme can be more selective and/or faster).

Voltage Stability and Undervoltage Load Shedding

Voltage stability is defined by the System Dynamic Performance Subcommittee of the IEEE Power System Engineering Committee as being the ability of a system to maintain voltage such that when load admittance is increased, load power will increase, and so that both power and voltage are controllable. Also, voltage collapse is defined as being the process by which voltage instability leads to a very low voltage profile in a significant part of the system. It is accepted that this instability is caused by the load characteristics, as opposed to the angular instability that is caused by the rotor dynamics of generators.

The risk of voltage instability increases as the transmission system becomes more heavily loaded. The typical scenario of these instabilities starts with a high system loading, followed by a relay action due to either a fault, a line overload, or hitting an excitation limit.

Voltage instability can be alleviated by a combination of the following remedial measures: adding reactive compensation near load centers, strengthening the transmission lines, varying the operating conditions such as voltage profile and generation dispatch, coordinating relays and controls, and load shedding. Most utilities rely on planning and operation studies to guard against voltage instability. Many utilities utilize localized voltage measurements in order to achieve load shedding as a measure against incipient voltage instability. The efficiency of the load shedding depends on the selected voltage thresholds, locations of pilot points in which the voltages are monitored, locations and sizes of the blocks of load to be shed, as well as the operating conditions that may activate the shedding. The wide variety of conditions that may lead to voltage instability suggests that the most accurate decisions should imply the adaptive relay settings, but such applications are still in the stage of early development.

Special Protection Schemes (SPS)

Increasingly popular over the past several years are the so-called special protection systems, sometimes also referred to as remedial action schemes (Anderson and LeReverend, 1996; McCalley and Fu, 1998). Depending on the power system in question, it is sometimes possible to identify the contingencies or combinations of operating conditions that may lead to transients with extremely disastrous consequences (Tamronglak et al., 1996). Such problems include, but are not limited to, transmission line faults, the outages of lines and possible cascading that such an initial contingency may cause, outages of the generators, rapid changes of the load level, problems with HVDC or FACTS equipment, or any combination of those events.

Among the many varieties of special protection schemes, several names have been used to describe the general category (Elmore, 1994): special stability controls, dynamic security controls, contingency arming schemes, remedial action schemes, adaptive protection schemes, corrective action schemes, security enhancement schemes, etc. In the strict sense of protective relaying, we do not consider any control schemes to be SPS, but only those protective relaying systems that possess the following properties (McCalley and Fu, 1998):

- SPS can be operational ("armed"), or out of service ("disarmed"), in conjunction with the system conditions.
- SPS are responding to very low probability events; hence they are active rarely more than once a year.
- SPS operate on simple, predetermined control laws, often calculated based on extensive offline studies.
- Oftentimes, SPS involve communication of remotely acquired measurement data (SCADA) from more than one location in order to make a decision and invoke a control law.

The SPS design procedure is based on the following (Elmore, 1994):

- **Identification of critical conditions:** On the grounds of extensive offline steady state studies on the system under consideration, a variety of operating conditions and contingencies are identified as potentially dangerous, and those among them that are deemed the most harmful are recognized as the critical conditions. The issue of their continuous monitoring, detection, and mitigation is resolved through offline studies.
- **Recognition triggers:** These are the measurable signals that can be used for detection of critical conditions. Oftentimes, such detection is accomplished through a complicated heuristic logical reasoning, using the logic circuits to accomplish the task: "**If** event A **and** event B occur together, **or** event C occurs, **then**…" Inputs for the decision making logic are called recognition triggers, and can be the status of various relays in the system, sometimes combined with a number of (SCADA) measurements.
- **Operator control:** In spite of extensive simulations and studies done in the process of SPS design, it is often necessary to include human intervention, i.e., to include human interaction in the feedback loop. This is necessary because SPS are not needed all the time, and the decision to arm, or disarm them remains in the hands of an operator.

Among the SPS schemes reported in the literature (Anderson and LeReverend, 1996; McCalley and Fu, 1998), the following are represented:

- Generator Rejection
- Load Rejection
- Underfrequency Load Shedding
- System Separation
- Turbine Valve Control
- Stabilizers
- HVDC Controls

- Out-of-step Relaying
- Dynamic Braking
- Generator Runback
- VAR Compensation
- Combination of schemes

Some of them have already been described in the above text. A general trend continues toward more complex schemes, capable of outperforming the present solutions and taking advantage of the most recent technological developments and advances in systems analysis. Some of the trends are described in the following text (Begovic et al., 1999).

Future Improvements in Control and Protection

Existing protection/control systems may be improved and new protection/control systems may be developed to better adapt to prevailing system conditions during system-wide disturbance. While improvements in the existing systems are mostly achieved through advancement in local measurements and development of better algorithms, improvements in new systems are based on remote communications. However, even if communication links exist, conventional systems that utilize only local information may still need improvement since they are supposed to serve as fallback positions. The increased functions and communication ability in today's SCADA systems provide the opportunity for an intelligent and adaptive control and protection system for system-wide disturbance. This, in turn, can make possible full utilization of the network, which will be less vulnerable to a major disturbance.

Out-of-step relays have to be fast and reliable. The present technology of out-of-step tripping or blocking distance relays is not capable of fully dealing with the control and protection requirements of power systems. Central to the development effort of an out-of-step protection system is the investigation of the multiarea out-of-step situation. The new generation of out-of-step relays has to utilize more measurements, both local and remote, and has to produce more outputs. The structure of the overall relaying system has to be distributed and coordinated through a central control. In order for the relaying system to manage complexity, most of the decisions have to be made locally. Preferably, the relay system is adaptive, in order to cope with system changes. To deal with out-of-step prediction, it is necessary to start with a system-wide approach, find out what sets of information are crucial and how to the process information with acceptable speed and accuracy.

Protection against voltage instability should also be addressed as a part of hierarchical structure. The sound approach for designing the new generation of voltage instability protection is to first design a voltage instability relay with only local signals. The limitations of local signals should be identified in order to be in a position to select appropriate communicated signals. However, a minimum set of communicated signals should always be known in order to design reliable protection, which requires the following: (a) determining the algorithm for gradual reduction of the number of necessary measurement sites with minimum loss of information necessary for voltage stability monitoring, analysis, and control; (b) development of methods (i.e., sensitivity analysis), which should operate *concurrent* with any existing local protection techniques, and possessing superior performance, both in terms of security and dependability.

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9.5 Digital Relaying

James S. Thorp

Digital relaying had its origins in the late 1960s and early 1970s with pioneering papers by Rockefeller (1969), Mann and Morrison (1971), and Poncelet (1972) and an early field experiment (Gilcrest et al., 1972; Rockefeller and Udren, 1972). Because of the cost of the computers in those times, a single high-cost minicomputer was proposed by Rockefeller (1969) to perform multiple relaying calculations in the substation. In addition to having high cost and high power requirements, early minicomputer systems were slow in comparison with modern systems and could only perform simple calculations. The well-founded belief that computers would get smaller, faster, and cheaper combined with expectations of benefits of computer relaying kept the field moving. The third IEEE tutorial on microprocessor protection (Sachdev, 1997) lists more then 1100 publications in the area since 1970. Nearly two thirds of the papers are devoted to developing and comparing algorithms. It is not clear this trend should continue. Issues beyond algorithms should receive more attention in the future.

The expected benefits of microprocessor protection have largely been realized. The ability of a digital relay to perform self-monitoring and checking is a clear advantage over the previous technology. Many relays are called upon to function only a few cycles in a year. A large percentage of major disturbances can be traced to "hidden failures" in relays that were undetected until the relay was exposed to certain system conditions (Tamronglak et al., 1996). The ability of a digital relay to detect a failure within itself and remove itself from service before an incorrect operation occurs is one of the most important advantages of digital protection.

The microprocessor revolution has created a situation in which digital relays are the relays of choice because of economic reasons. The cost of conventional (analog) relays has increased while the hardware cost of the most sophisticated digital relays has decreased dramatically. Even including substantial software costs, digital relays are the economic choice and have the additional advantage of having lower wiring costs. Prior to the introduction of microprocessor-based systems, several panels of space and considerable wiring was required to provide all the functions needed for each zone of transmission line protection. For example, an installation requiring phase distance protection for phase-to-phase and three-phase faults, ground distance, ground-overcurrent, a pilot scheme, breaker failure, and reclosing logic demanded redundant wiring, several hundred watts of power, and a lot of panel space. A single microprocessor system is a single box, with a ten-watt power requirement and with only direct wiring, has replaced the old system.

Modern digital relays can provide SCADA, metering, and oscillographic records. Line relays can also provide fault location information. All of this data can be available by modem or on a WAN. A LAN in the substation connecting the protection modules to a local host is also a possibility. Complex multi-function relays can have an almost bewildering number of settings. Techniques for dealing with setting management are being developed. With improved communication technology, the possibility of involving microprocessor protection in wide-area protection and control is being considered.

Sampling

The sampling process is essential for microprocessor protection to produce the numbers required by the processing unit to perform calculations and reach relaying decisions. Both 12 and 16 bit A/D converters

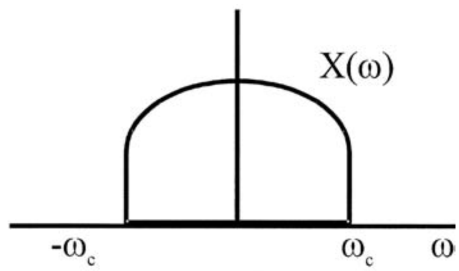

FIGURE 9.35 The Fourier Transform of a band-limited function.

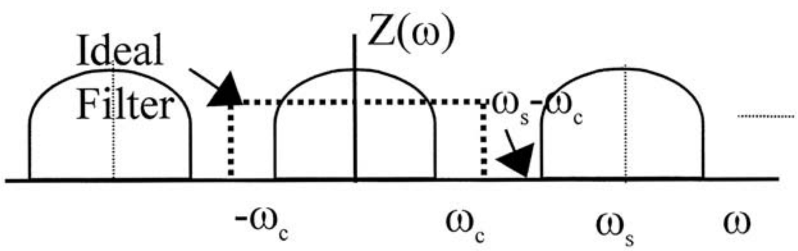

FIGURE 9.36 The Fourier Transform of a sampled version of the signal x(t).

are in use. The large difference between load and fault current is a driving force behind the need for more precision in the A/D conversion. It is difficult to measure load current accurately while not saturating for fault current with only 12 bits. It should be noted that most protection functions do not require such precise load current measurement. Although there are applications, such as hydro generator protection, where the sampling rate is derived from the actual power system frequency, most relay applications involve sampling at a fixed rate that is a multiple of the *nominal* power system frequency.

Antialiasing Filters

ANSI/IEEE Standard C37.90, provides the standard for the Surge Withstand Capability (SWC) to be built into protective relay equipment. The standard consists of both an oscillatory and transient test. Typically the surge filter is followed by an antialiasing filter before the A/D converter. Ideally the signal x(t) presented to the A/D converter x(t) is band-limited to some frequency ω_c, i.e., the Fourier transform of x(t) is confined to a low-pass band less that ω_c such as shown in Fig. 9.35. Sampling the low-pass signal at a frequency of ω_s produces a signal with a transform made up of shifted replicas of the low-pass transform as shown in Fig. 9.36. If $\omega_s - \omega_c > \omega_c$, i.e., $\omega_s > 2\omega_c$ as shown, then an ideal low-pass filter applied to z(t) can recover the original signal x(t). The frequency of twice the highest frequency present in the signal to be sampled is the Nyquist sampling rate. If $\omega_s < 2\omega_c$ the sampled signal is said to be "aliased" and the output of the low-pass filter is not the original signal. In some applications the frequency content of the signal is known and the sampling frequency is chosen to avoid aliasing (music CDs), while in digital relaying applications the sampling frequency is specified and the frequency content of the signal is controlled by filtering the signal before sampling to insure its highest frequency is less than half the sampling frequency. The filter used is referred to as an antialising filter.

Aliasing also occurs when discrete sequences are sampled or decimated. For example, if a high sampling rate such as 7200 Hz is used to provide data for oscillography, then taking every tenth sample provides data at 720 Hz to be used for relaying. The process of taking every tenth sample (decimation) will produce aliasing unless a digital antialiasing filter with a cut-off frequency of 360 Hz is provided.

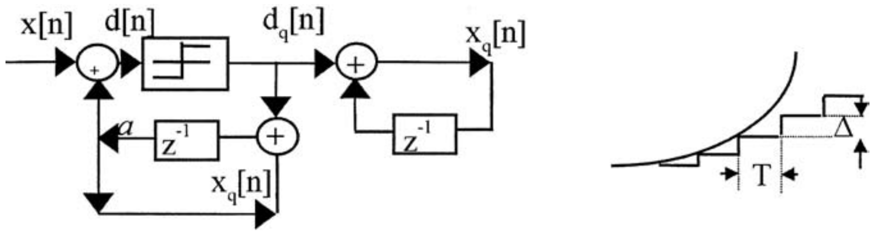

FIGURE 9.37 Delta modulator and error.

Sigma-Delta A/D Converters

There is an advantage in sampling at rates many times the Nyquist rate. It is possible to exchange speed of sampling for bits of resolution. So called Sigma-Delta A/D converters are based on one bit sampling at very high rates. Consider a signal x(t) sampled at a high rate T = 1/fs, i.e., x[n] = x(nT) with the difference between the current sample and α times the last sample given by

$$d[n] = x[n] - \alpha\, x[n-1] \tag{9.16}$$

If d[n] is quantized through a one-bit quantizer with a step size of Δ, then

$$x_q[n] = \alpha\, x_q[n-1] + d_q[n] \tag{9.17}$$

The quantization is called delta modulation and is represented in Fig. 9.37. The z^{-1} boxes are unit delays while the one bit quantizer is shown as the box with d[n] as input and $d_q[n]$ as output. The output $x_q[n]$ is a staircase approximation to the signal x(t) with stairs that are spaced at T sec and have height Δ. The delta modulator output has two types of errors: one when the maximum slope Δ/T is too small for rapid changes in the input (shown on Fig. 9.37) and the second, a sort of chattering when the signal x(t) is slowly varying. The feedback loop below the quantizer is a discrete approximation to an integrator with α = 1. Values of α less than one correspond to an imperfect integrator. A continuous form of the delta modulator is also shown in Fig. 9.38. The low pass filter (LPF) is needed because of the high frequency content of the staircase. Shifting the integrator from in front of the LPF to before the delta modulator improves both types of error. In addition, the two integrators can be combined.

The modulator can be thought of as a form of voltage follower circuit. Resolution is increased by oversampling to spread the quantization noise over a large bandwidth. It is possible to shape the quantization noise so it is larger at high frequencies and lower near DC. Combining the shaped noise with a very steep cut-off in the digital low pass filter, it is possible to produce a 16-bit result from the one bit comparator. For example, a 16-bit answer at 20 kHz can be obtained with an original sampling frequency of 400 kHz.

Phasors from Samples

A phasor is a complex number used to represent sinusoidal functions of time such as AC voltages and currents. For convenience in calculating the power in AC circuits from phasors, the phasor magnitude

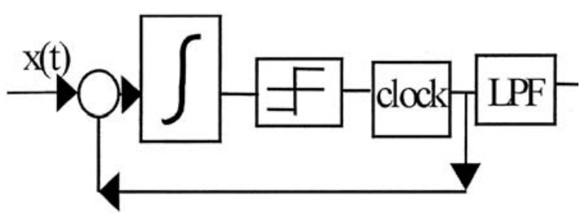

FIGURE 9.38 Signa-Delta modulator.

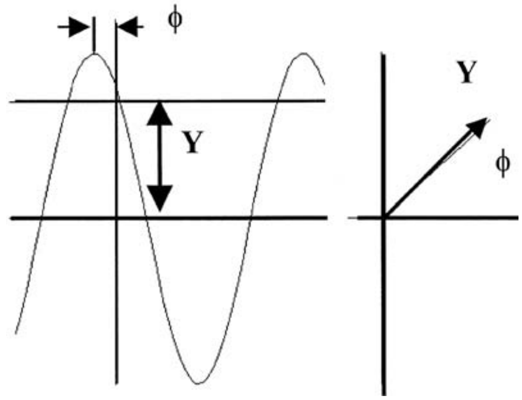

FIGURE 9.39 Phasor representation.

is set equal to the rms value of the sinusoidal waveform. A sinusoidal quantity and its phasor representation are shown in Fig. 9.39, and are defined as follows:

$$\begin{array}{cc} \text{Sinusoidal quantity} & \text{Phasor} \\ y(t) = Y_m \cos(\omega t + \phi) & Y = \dfrac{Y_m}{\sqrt{2}} e^{j\phi} \end{array} \tag{9.18}$$

A phasor represents a single frequency sinusoid and is not directly applicable under transient conditions. However, the idea of a phasor can be used in transient conditions by considering that the phasor represents an estimate of the fundamental frequency component of a waveform observed over a finite window. In case of N samples y_k, obtained from the signal y(t) over a period of the waveform:

$$Y = \frac{1}{\sqrt{2}} \frac{2}{N} \sum_{k=1}^{N} y_k e^{-jk\frac{2\pi}{N}} \tag{9.19}$$

or,

$$Y = \frac{1}{\sqrt{2}} \frac{2}{N} \left\{ \sum_{k=1}^{N} y_k \cos\left(\frac{k2\pi}{N}\right) - j \sum_{k=1}^{N} y_k \sin\left(\frac{k2\pi}{N}\right) \right\} \tag{9.20}$$

Using θ for the sampling angle 2π/N, it follows that

$$Y = \frac{1}{\sqrt{2}} \frac{2}{N} \left(Y_c - jY_s\right) \tag{9.21}$$

where

$$\begin{aligned} Y_c &= \sum_{k=1}^{N} y_k \cos(k\theta) \\ Y_s &= \sum_{k=1}^{N} y_k \sin(k\theta) \end{aligned} \tag{9.22}$$

Note that the input signal y(t) must be band-limited to Nω/2 to avoid aliasing errors. In the presence of white noise, the fundamental frequency component of the Discrete Fourier Transform (DFT) given by Eqs. (9.19)–(9.22) can be shown to be a least-squares estimate of the phasor. If the data window is not a multiple of a half cycle, the least-squares estimate is some other combination of Y_c and Y_s, and is no longer given by Eq. (9.21). Short window (less than one period) phasor computations are of interest in some digital relaying applications. For the present, we will concentrate on data windows that are multiples of a half cycle of the nominal power system frequency.

The data window begins at the instant when sample number 1 is obtained as shown in Fig. 9.39. The sample set y_k is given by

$$y_k = Y_m \cos\left(k\theta + \phi\right) \tag{9.23}$$

Substituting for y_k from Eq. (9.23) in Eq. (9.19),

$$Y = \frac{1}{\sqrt{2}} \frac{2}{N} \sum_{k=1}^{N} Y_m \cos\left(k\theta + \varphi\right) e^{-jk\theta} \tag{9.24}$$

or

$$Y = \frac{1}{\sqrt{2}} Y_m e^{j\phi} \tag{9.25}$$

which is the familiar expression Eq. (9.18), for the phasor representation of the sinusoid in Eq. (9.18). The instant at which the first data sample is obtained defines the orientation of the phasor in the complex plane. The reference axis for the phasor, i.e., the horizontal axis in Fig. 9.39b, is specified by the first sample in the data window.

Equations (9.21)–(9.22) define an algorithm for computing a phasor from an input signal. A recursive form of the algorithm is more useful for real-time measurements. Consider the phasors computed from two adjacent sample sets: y_k {k = 1, 2, ⋯, N} and, y'_k {k = 2, 3, ⋯, N + 1}, and their corresponding phasors Y^1 and $Y^{2'}$ respectively:

$$Y^1 = \frac{1}{\sqrt{2}} \frac{2}{N} \sum_{k=1}^{N} y_k e^{-jk\theta} \tag{9.26}$$

$$Y^{2'} = \frac{1}{\sqrt{2}} \frac{2}{N} \sum_{k=1}^{N} y_{k+1} e^{-jk\theta} \tag{9.27}$$

We may modify Eq. (9.27) to develop a recursive phasor calculation as follows:

$$Y^2 = Y^{2'} e^{-j\theta} = Y^1 + \frac{1}{\sqrt{2}} \frac{2}{N} \left(y_{N+1} - y_1\right) e^{-j\theta} \tag{9.28}$$

Since the angle of the phasor $Y^{2'}$ is greater than the angle of the phasor Y^1 by the sampling angle θ, the phasor Y^2 has the same angle as the phasor Y^1. When the input signal is a constant sinusoid, the phasor calculated from Eq. (9.28) is a constant complex number. In general, the phasor Y, corresponding to the data y_k {k = r, r + 1, r + 2, ⋯, N + r – 1} is recursively modified into Y^{r+1} according to the formula

$$Y^{r+1} = Y^r e^{-j\theta} = Y^r + \frac{1}{\sqrt{2}} \frac{2}{N} \left(y_{N+r} - y_r \right) e^{-j\theta} \tag{9.29}$$

The recursive phasor calculation as given by Eq. (9.28) is very efficient. It regenerates the new phasor from the old one and utilizes most of the computations performed for the phasor with the old data window.

Symmetrical Components

Symmetrical components are linear transformations on voltages and currents of a three phase network. The symmetrical component transformation matrix S transforms the phase quantities, taken here to be voltages E_ϕ, (although they could equally well be currents), into symmetrical components E_S:

$$E_s = \begin{bmatrix} E_0 \\ E_1 \\ E_2 \end{bmatrix} = SE_\phi = \frac{1}{3} \begin{bmatrix} 1 & 1 & 1 \\ 1 & \alpha & \alpha^2 \\ 1 & \alpha^2 & \alpha \end{bmatrix} \begin{bmatrix} E_a \\ E_b \\ E_c \end{bmatrix} \tag{9.30}$$

where $(1,\alpha,\alpha^2)$ are the three cube-roots of unity. The symmetrical component transformation matrix S is a similarity transformation on the impedance matrices of balanced three phase circuits, which diagonalizes these matrices. The symmetrical components, designated by the subscripts (0,1,2) are known as the zero, positive, and negative sequence components of the voltages (or currents). The negative and zero sequence components are of importance in analyzing unbalanced three phase networks. For our present discussion, we will concentrate on the positive sequence component E_1 (or I_1) only. This component measures the balanced, or normal voltages and currents that exist in a power system. Dealing with positive sequence components only allows the use of single-phase circuits to model the three-phase network, and provides a very good approximation for the state of a network in quasi-steady state. All power generators generate positive sequence voltages, and all machines work best when energized by positive sequence currents and voltages. The power system is specifically designed to produce and utilize almost pure positive sequence voltages and currents in the absence of faults or other abnormal imbalances. It follows from Eq. (9.30) that the positive sequence component of the phase quantities is given by

$$Y_1 = \frac{1}{3} \left(Y_a + \alpha Y_b + \alpha^2 Y_c \right) \tag{9.31}$$

Or, using the recursive form of the phasors given by Eq. (9.29),

$$Y_1^{r+1} = Y_1^r + \frac{1}{\sqrt{2}} \frac{2}{N} \left[\left(x_{a,N+r} - x_{a,r} \right) e^{-jr\theta} + \alpha \left(x_{b,N+r} - x_{b,r} \right) e^{-jr\theta} + \alpha^2 \left(x_{c,N+r} - x_{c,r} \right) e^{-jr\theta} \right] \tag{9.32}$$

Recognizing that for a sampling rate of 12 times per cycle, α and α^2 correspond to $\exp(j4\theta)$ and $\exp(j8\theta)$, respectively, it can be seen from Eq. (9.32) that

$$Y_1^{r+1} = Y_1^r + \frac{1}{\sqrt{2}} \frac{2}{N} \left[\left(x_{a,N+r} - x_{a,r} \right) e^{-jr\theta} + \left(x_{b,N+r} - x_{b,r} \right) e^{j(4-r)r\theta} + \left(x_{c,N+r} - x_{c,r} \right) e^{j(8-r)\theta} \right] \tag{9.33}$$

With a carefully chosen sampling rate — such as a multiple of three times the nominal power system frequency — very efficient symmetrical component calculations can be performed in real time. Equations similar to (9.33) hold for negative and zero sequence components also. The sequence quantities can be used to compute a distance to the fault that is independent of fault type. Given the ten possible faults in a three-phase system (three line-ground, three phase-phase, three phase-phase-ground, and three phase), early microprocessor systems were taxed to determine the fault type before computing the distance to the fault. Incorrect fault type identification resulted in a delay in relay operation. The symmetrical component relay solved that problem. With advances in microprocessor speed it is now possible to simultaneously compute the distance to all six phase-ground and phase-phase faults in order to solve the fault classification problem.

The positive sequence calculation is still of interest because of the use of synchronized phasor measurements. Phasors, representing voltages and currents at various buses in a power system, define the state of the power system. If several phasors are to be measured, it is essential that they be measured with a common reference. The reference, as mentioned in the previous section, is determined by the instant at which the samples are taken. In order to achieve a common reference for the phasors, it is essential to achieve synchronization of the sampling pulses. The precision with which the time synchronization must be achieved depends upon the uses one wishes to make of the phasor measurements. For example, one use of the phasor measurements is to estimate, or validate, the state of the power systems so that crucial performance features of the network, such as the power flows in transmission lines could be determined with a degree of confidence. Many other important measures of power system performance, such as contingency evaluation, stability margins, etc., can be expressed in terms of the state of the power system, i.e., the phasors. Accuracy of time synchronization directly translates into the accuracy with which phase angle differences between various phasors can be measured. Phase angles between the ends of transmission lines in a power network may vary between a few degrees, and may approach 180° during particularly violent stability oscillations. Under these circumstances, assuming that one may wish to measure angular differences as little as 1°, one would want the accuracy of measurement to be better than 0.1°. Fortunately, synchronization accuracies of the order of 1 μsec are now achievable from the Global Positioning System (GPS) satellites. One microsecond corresponds to 0.022° for a 60 Hz power system, which more than meets our needs. Real-time phasor measurements have been applied in static state estimation, frequency measurement, and wide area control.

Algorithms

Parameter Estimation

Most relaying algorithms extract information about the waveform from current and voltage waveforms in order to make relaying decisions. Examples include: current and voltage phasors that can be used to compute impedance, the rms value, the current that can be used in an overcurrent relay, and the harmonic content of a current that can be used to form a restraint in transformer protection. An approach that unifies a number of algorithms is that of parameter estimation. The samples are assumed to be of a current or voltage that has a known form with some unknown parameters. The simplest such signal can be written as

$$y(t) = Y_c \cos\omega_0 t + Y_s \sin\omega_0 t + e(t) \tag{9.34}$$

where ω_0 is the nominal power system frequency, Y_c and Y_s are unknown quantities, and e(t) is an error signal (all the things that are not the fundamental frequency signal in this simple model). It should be noted that in this formulation, we assume that the power system frequency is known. If the numbers, Y_c and Y_s were known, we could compute the fundamental frequency phasor. With samples taken at an interval of T seconds,

$$y_n = y(nT) = Y_c \cos n\theta + Y_s \sin n\theta + e(nT) \tag{9.35}$$

where $\theta = \omega_0 T$ is the sampling angle. If signals other than the fundamental frequency signal were present, it would be useful to include them in a formulation similar to Eq. (9.34) so that they would be included in e(t). If, for example, the second harmonic were included, Eq. (9.34) could be modified to

$$y_n = Y_{1c} \cos n\theta + Y_{1s} \sin n\theta + Y_{2c} \cos 2n\theta + Y_{2s} \sin 2n\theta + e(nT) \tag{9.36}$$

It is clear that more samples are needed to estimate the parameters as more terms are included. Equation (9.36) can be generalized to include any number of harmonics (the number is limited by the sampling rate), the exponential offset in a current, or any known signal that is suspected to be included in the post-fault waveform. No matter how detailed the formulation, e(t) will include unpredictable contributions from:

- The transducers (CTs and PTs)
- Fault arc
- Traveling wave effects
- A/D converters
- The exponential offset in the current
- The transient response of the antialising filters
- The power system itself

The current offset is not an error signal for some algorithms and is removed separately for some others. The power system generated signals are transients depending on fault location, the fault incidence angle, and the structure of the power system. The power system transients are low enough in frequency to be present after the antialiasing filter.

We can write a general expression as

$$y_n = \sum_{k=1}^{K} s_k(nT) Y_k + e_n \tag{9.37}$$

If y represents a vector of N samples, and Y a vector of K unknown coefficients, then there are N equations in K unknowns in the form

$$y = SY + e \tag{9.38}$$

The matrix S is made up of samples of the signals s_k.

$$S = \begin{bmatrix} s_1(T) & s_2(T) & \cdots & s_K(T) \\ s_1(2T) & s_2(2T) & \cdots & s_K(2T) \\ \vdots & \vdots & & \vdots \\ s_1(NT) & s_2(NT) & \cdots & s_K(NT) \end{bmatrix} \tag{9.39}$$

The presence of the error e and the fact that the number of equations is larger than the number of unknowns (N > K) makes it necessary to estimate Y.

Least Squares Fitting

One criterion for choosing the estimate $\hat{Y}$ is to minimize the scalar formed as the sum of the squares of the error term in Eq. (9.38), viz.

$$e^T e = \left(y - SY\right)^T \left(y - SY\right) = \sum_{n=1}^{N} e_n^2 \tag{9.40}$$

It can be shown that the minimum least squared error [the minimum value of Eq. (9.40)] occurs when

$$\hat{Y} = \left(S^T S\right)^{-1} S^T y = By \tag{9.41}$$

where $B = (S^TS)^{-1}S^T$. The calculations involving the matrix S can be performed off-line to create an "algorithm," i.e., an estimate of each of the K parameters is obtained by multiplying the N samples by a set of stored numbers. The rows of Eq. (9.41) can represent a number of different algorithms depending on the choice of the signals $s_k(nT)$ and the interval over which the samples are taken.

DFT

The simplest form of Eq. (9.41) is when the matrix S^TS is diagonal. Using a signal alphabet of cosines and sines of the first N harmonics of the fundamental frequency over a window of one cycle of the fundamental frequency, the familiar Discrete Fourier Transform (DFT) is produced. With

$$\begin{aligned}
&s_1\left(t\right) = \cos\left(\omega_0 t\right) \\
&s_2\left(t\right) = \sin\left(\omega_0 t\right) \\
&s_3\left(t\right) = \cos\left(2\omega_0 t\right) \\
&s_4\left(t\right) = \sin\left(2\omega_0 t\right) \\
&\vdots \\
&s_{N-1}\left(t\right) = \cos\left(N\omega_0 t/2\right) \\
&s_N\left(t\right) = \sin\left(N\omega_0 t/2\right)
\end{aligned} \tag{9.42}$$

The estimates are given by:

$$\begin{aligned}
\hat{Y}_{Cp} &= \frac{2}{N}\sum_{n=0}^{N-1} y_n \cos\left(pn\theta\right) \\
\hat{Y}_{Sp} &= \frac{2}{N}\sum_{n=o}^{N-1} y_n \sin\left(pn\theta\right)
\end{aligned} \tag{9.43}$$

Note that the harmonics are also estimated by Eq. (9.43). Harmonics have little role in line relaying but are important in transformer protection. It can be seen that the fundamental frequency phasor can be obtained as

$$Y = \frac{2}{N\sqrt{2}}\left(Y_{C1} - jY_{S1}\right) \tag{9.44}$$

The normalizing factor in Eq. (9.44) is omitted if the ratio of phasors for voltage and current are used to form impedance.

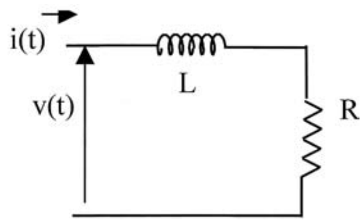

FIGURE 9.40 Model of a faulted line.

Differential Equations

Another kind of algorithm is based on estimating the values of parameters of a physical model of the system. In line protection, the physical model is a series R-L circuit that represents the faulted line. A similar approach in transformer protection uses the magnetic flux circuit with associated inductance and resistance as the model. A differential equation is written for the system in both cases.

Line Protection Algorithms

The series R-L circuit of Fig. 9.40 is the model of a faulted line. The offset in the current is produced by the circuit model and hence will not be an error signal.

$$v(t) = Ri(t) + L\frac{di(t)}{dt} \tag{9.45}$$

Looking at the samples at k, k + 1, k + 2

$$\int_{t_0}^{t_1} v(t)dt = R\int_{t_0}^{t_1} i(t)dt + L\left(i(t_1) - i(t_0)\right) \tag{9.46}$$

$$\int_{t_1}^{t_2} v(t)dt = R\int_{t_1}^{t_2} i(t)dt + L\left(i(t_2) - i(t_1)\right) \tag{9.47}$$

Using trapezoidal integration to evaluate the integrals (assuming t is small)

$$\int_{t_1}^{t_2} v(t)dt = R\int_{t_1}^{t_2} i(t)dt + L\left(i(t_2) - i(t_1)\right) \tag{9.48}$$

$$\int_{t_1}^{t_2} v(t)dt = R\int_{t_1}^{t_2} i(t)dt + L\left(i(t_2) - i(t_1)\right) \tag{9.49}$$

R and L are given by

$$R = \left[\frac{\left(v_{k+1} + v_k\right)\left(i_{k+2} - i_{k+1}\right) - \left(v_{k+2} + v_{k+1}\right)\left(i_{k+1} - i_k\right)}{2\left(i_k i_{k+2} - i_{k+1}^2\right)}\right] \tag{9.50}$$

$$L = \frac{T}{2}\left[\frac{\left(v_{k+2}+v_{k+1}\right)\left(i_{k+1}+i_k\right)-\left(v_{k+1}+v_k\right)\left(i_{k+2}+i_{k+1}\right)}{2\left(i_k i_{k+2}-i_{k+1}^2\right)}\right] \tag{9.51}$$

It should be noted that the sample values occur in both numerator and denominator of Eqs. (9.50) and (9.51). The denominator is not constant but varies in time with local minima at points where both the current and the derivative of the current are small. For a pure sinusoidal current, the current and its derivative are never both small but when an offset is included there is a possibility of both being small once per period.

Error signals for this algorithm include terms that do not satisfy the differential equation such as the currents in the shunt elements in the line model required by long lines. In intervals where the denominator is small, errors in the numerator of Eqs. (9.50) and (9.51) are amplified. The resulting estimates can be quite poor. It is also difficult to make the window longer than three samples. The complexity of solving such equations for a larger number of samples suggests that the short window results be post processed. Simple averaging of the short-window estimates is inappropriate, however.

A counting scheme was used in which the counter was advanced if the estimated R and L were in the zone and the counter was decreased if the estimates lay outside the zone (Chen and Breingan, 1979). By requiring the counter to reach some threshold before tripping, secure operation can be assured with a cost of some delay. For example, if the threshold were set at six with a sampling rate of 16 times a cycle, the fastest trip decision would take a half cycle. Each "bad" estimate would delay the decision by two additional samples. The actual time for a relaying decision is variable and depends on the exact data.

The use of a median filter is an alternate to the counting scheme (Akke and Thorp, 1997). The median operation ranks the input values according to their amplitude and selects the middle value as the output. Median filters have an odd number of inputs. A length five median filter has an input-output relation between input x[n] and output y[n] given by

$$y[n] = \text{median}\left\{x[n-2],\, x[n-1],\, x[n],\, x[n+1],\, x[n+2]\right\} \tag{9.52}$$

Median filters of length five, seven, and nine have been applied to the output of the short window differential equation algorithm (Akke and Thorp, 1997). The median filter preserves the essential features of the input while removing isolated noise spikes. The filter length rather than the counter scheme, fixes the time required for a relaying decision.

Transformer Protection Algorithms

Virtually all algorithms for the protection of power transformers use the principle of percentage differential protection. The difference between algorithms lies in how the algorithm restrains the differential trip for conditions of overexcitation and inrush. Algorithms based on harmonic restraint, which parallel existing analog protection, compute the second and fifth harmonics using Eq. (9.25) (Thorp and Phadke, 1982). These algorithms use current measurements only and cannot be faster than one cycle because of the need to compute the second harmonic. The harmonic calculation provides for secure operation since the transient event produces harmonic content which delays relay operation for about a cycle.

In an integrated substation with other microprocessor relays, it is possible to consider transformer protection algorithms that use voltage information. Shared voltage samples could be a result of multiple protection modules connected in a LAN in the substation. The magnitude of the voltage itself can be used as a restraint in a digital version of a "tripping suppressor" (Harder and Marter, 1948). A physical model similar to the differential equation model for a faulted line can be constructed using the flux in the transformer. The differential equation describing the terminal voltage, v(t), the winding current, i(t), and the flux linkage $\Lambda(t)$ is:

$$v(t) - L\frac{di(t)}{dt} = \frac{d\Lambda(t)}{dt} \tag{9.53}$$

where L is the leakage inductance of the winding.

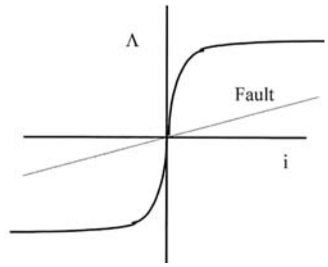

FIGURE 9.41 The flux-current characteristic compared to fault conditions.

Using trapezoidal integration for the integral in Eq. (9.53)

$$\int_{t_1}^{t_2} v(t)\,dt - L\left[i(t_2) - i(t_1)\right] = \Lambda(t_2) - \Lambda(t_1) \tag{9.54}$$

gives

$$\Lambda(t_2) - \Lambda(t_1) = \frac{T}{2}\left[v(t_2) + v(t_1)\right] - L\left[i(t_2) - i(t_1)\right] \tag{9.55}$$

or

$$\Lambda_{k+1} = \Lambda_k + \frac{T}{2}\left[v_{k+1} + v_k\right] - L\left[i_{k+1} - i_k\right] \tag{9.56}$$

Since the initial flux Λ_0 in Eq. (9.56) cannot be known without separate sensing, the slope of the flux current curve is used

$$\left(\frac{d\Lambda}{di}\right)_k = \frac{T}{2}\left[\frac{\left[v_k + v_{k-1}\right]}{i_k - i_{k-1}}\right] - L \tag{9.57}$$

The slope of the flux current characteristic shown in Fig. 9.41 is different depending on whether there is a fault or not. The algorithm must then be able to differentiate between inrush (the slope alternates between large and small values) and a fault (the slope is always small). The counting scheme used for the differential equation algorithm for line protection can be adapted to this application. The counter increases if the slope is less than a threshold and the differential current indicates trip, and the counter decreases if the slope is greater than the threshold or the differential does not indicate trip.

Kalman Filters

The Kalman filter provides a solution to the estimation problem in the context of an evolution of the parameters to be estimated according to a state equation. It has been used extensively in estimation problems for dynamic systems. Its use in relaying is motivated by the filter's ability to handle measurements that change in time. To model the problem so that a Kalman filter may be used, it is necessary to write a state equation for the parameters to be estimated in the form

$$x_{k+1} = \Phi_k x_k + \Gamma_k w_k \tag{9.58}$$

$$z_k = H_k x_k + v_k \tag{9.59}$$

where Eq. (9.58) (the state equation) represents the evolution of the parameters in time and Eq. (9.59) represents the measurements. The terms w_k and v_k are discrete time random processes representing state noise, i.e., random inputs in the evolution of the parameters, and measurement errors, respectively. Typically w_k and v_k are assumed to be independent of each other and uncorrelated from sample to sample. If w_k and v_k have zero means, then it is common to assume that

$$\begin{aligned} E\left\{w_k w_j^T\right\} &= Q_k : \; k = j \\ &= 0; \; k \neq j \end{aligned} \tag{9.60}$$

The matrices Q_k and R_k are the covariance matrices of the random processes and are allowed to change as k changes. The matrix Φ_k in Eq. (9.58) is the state transition matrix. If we imagine sampling a pure sinusoid of the form

$$y(t) = Y_c \cos(\omega t) + Y_s \sin(\omega t) \tag{9.61}$$

at equal intervals corresponding to $\omega\Delta\tau = \Psi$, then the state would be

$$x_k = \begin{bmatrix} Y_C \\ Y_S \end{bmatrix} \tag{9.62}$$

and the state transition matrix

$$\Phi_k = \begin{bmatrix} 1 & 0 \\ 0 & 1 \end{bmatrix} \tag{9.63}$$

In this case, H_k, the measurement matrix, would be

$$H_k = \left[\cos(k\Psi) \; \sin(k\Psi)\right] \tag{9.64}$$

Simulations of a 345 kV line connecting a generator and a load (Gurgis and Brown, 1981) led to the conclusion that the covariance of the noise in the voltage and current decayed in time. If the time constant of the decay is comparable to the decision time of the relay, then the Kalman filter formulation is

$$x = \begin{bmatrix} Y_C \\ Y_S \\ Y_0 \end{bmatrix} \qquad \Phi_k = \begin{bmatrix} 1 & 0 & 0 \\ 0 & 1 & 0 \\ 0 & 0 & e^{-\beta t} \end{bmatrix}$$

appropriate for the estimation problem. The voltage was modeled as in Eqs. (9.63) and (9.64). The current was modeled with three states to account for the exponential offset.

and

$$H_k = \left[\cos(k\Psi) \; \sin(k\Psi) \; 1\right] \tag{9.65}$$

The measurement covariance matrix was

$$R_k = Ke^{-k\Delta t/T} \tag{9.66}$$

with T chosen as half the line time constant and different Ks for voltage and current. The Kalman filter estimates phasors for voltage and current as the DFT algorithms. The filter must be started and terminated using some other software. After the calculations begin, the data window continues to grow until the process is halted. This is different from fixed data windows such as a one cycle Fourier calculation. The growing data window has some advantages, but has the limitation that if started incorrectly, it has a hard time recovering if a fault occurs after the calculations have been initiated.

The Kalman filter assumes an initial statistical description of the state x, and recursively updates the estimate of state. The initial assumption about the state is that it is a random vector independent of the processes w_k and v_k and with a known mean and covariance matrix, P_0. The recursive calculation involves computing a gain matrix K_k. The estimate is given by

$$\hat{x}_{k+1} = \Phi_k \hat{x}_k + K_{k+1}\left[z_{k+1} - H_{k+1}\hat{x}_k\right] \tag{9.67}$$

The first term in Eq. (9.67) is an update of the old estimate by the state transition matrix while the second is the gain matrix K_{k+1} multiplying the observation residual. The bracketed term in Eq. (9.67) is the difference between the actual measurement, z_k, and the predicted value of the measurement, i.e., the residual in predicting the measurement. The gain matrix can then be computed recursively. The amount of computation involved depends on the state vector dimension. For the linear problem described here, these calculations can be performed off-line. In the absence of the decaying measurement error, the Kalman filter offers little other than the growing data window. It has been shown that at multiples of a half cycle, the Kalman filter estimate for a constant error covariance is the same as that obtained from the DFT.

Wavelet Transforms

The Wavelet Transform is a signal processing tool that is replacing the Fourier Transform in many applications including data compression, sonar and radar, communications, and biomedical applications. In the signal processing community there is considerable overlap between wavelets and the area of filter banks. In applications in which it is used, the Wavelet Transform is viewed as an improvement over the Fourier Transform because it deals with time-frequency resolution in a different way. The Fourier Transform provides a decomposition of a time function into exponentials, $e^{j\omega t}$, which exist for all time. We should consider the signal that is processed with the DFT calculations in the previous sections as being extended periodically for all time. That is, the data window represents one period of a periodic signal. The sampling rate and the length of the data window determine the frequency resolution of the calculations. While these limitations are well understood and intuitive, they are serious limitations in some applications such as compression. The Wavelet Transform introduces an alternative to these limitations.

The Fourier Transform can be written

$$X(\omega) = \int_{-\infty}^{\infty} x(t) e^{-j\omega t}\, dt \tag{9.68}$$

The effect of a data window can be captured by imagining that the signal x(t) is windowed before the Fourier Transform is computed. The function h(t) represents the windowing function such as a one-cycle rectangle.

$$X(\omega, t) = \int_{-\infty}^{\infty} x(\tau) h(t-\tau) e^{-j\omega\tau}\, d\tau \tag{9.69}$$

The Wavelet Transform is written

$$X(s,t) = \int_{-\infty}^{\infty} x(\tau)\left[\frac{1}{\sqrt{s}}h\left(\frac{\tau - t}{s}\right)\right]d\tau \tag{9.70}$$

where s is a scale parameter and t is a time shift. The scale parameter is an alternative to the frequency parameter of the Fourier Transform. If h(t) has Fourier Transform H(ω), then h(t/s) has Fourier Transform H(sω). Note that for a fixed h(t) that large, s compresses the transform while small s spreads the transform in frequency. There are a few requirements on a signal h(t) to be the "mother wavelet" (essentially that h(t) have finite energy and be a bandpass signal). For example, h(t) could be the output of a bandpass filter. It is also true that it is only necessary to know the Wavelet Transform at discrete values of s and t in order to be able to represent the signal. In particular

$$s = 2^m, \qquad t = n2^m \qquad m = \ldots, -2, 0, 1, 2, 3, \ldots$$

$$n = \ldots, -2, 0, 1, 2, 3, \ldots$$

where lower values of m correspond to smaller values of s or higher frequencies.

If x(t) is limited to a band B Hz, then it can be represented by samples at $T_S = 1/2B$ sec.

$$x(n) = x(nT_s)$$

Using a mother wavelet corresponding to an ideal bandpass filter illustrates a number of ideas. Figure 9.42 shows the filters corresponding to m = 0,1,2, and 3 and Fig. 9.43 shows the corresponding time functions. Since x(t) has no frequencies above B Hz, only positive values of m are necessary. The structure of the process can be seen in Fig. 9.44. The boxes labeled LPF_R and HPF_R are low and high pass

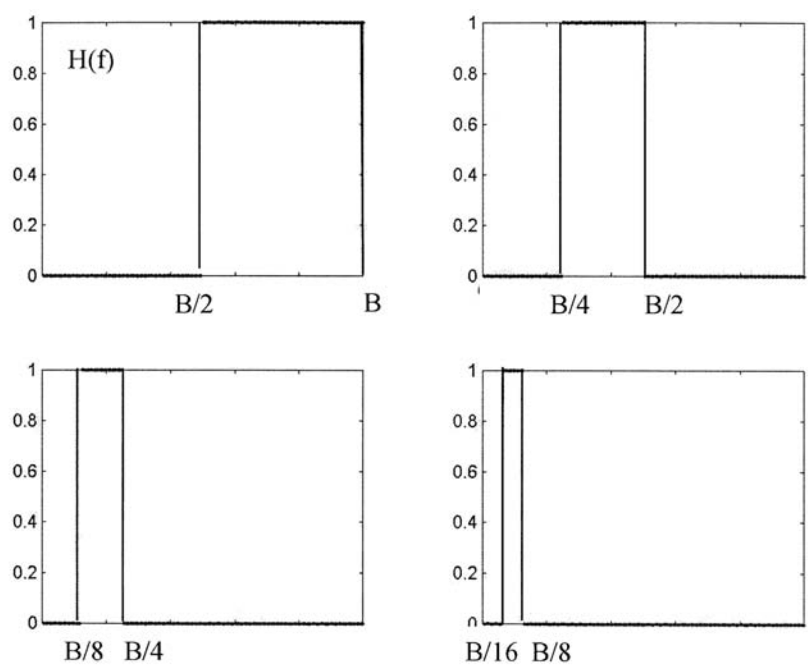

FIGURE 9.42 Ideal bandpass filters corresponding to m = 0, 1, 2, 3.

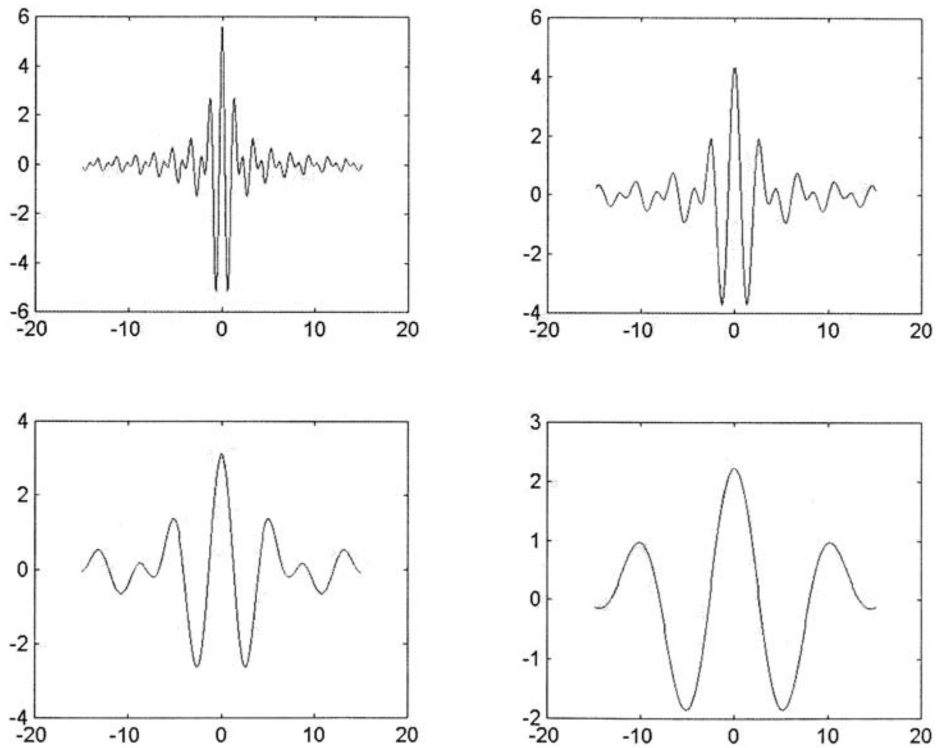

FIGURE 9.43 The impulse responses corresponding to the filters in Fig. 9.42.

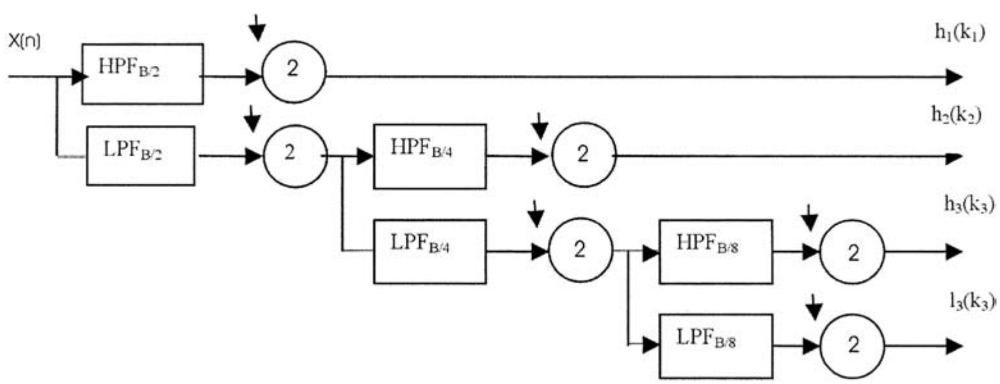

FIGURE 9.44 Cascade filter structure.

filters with cutoff frequencies of R Hz. The circle with the down arrow and a 2 represents the process of taking every other sample. For example, on the first line the output of the bandpass filter only has a bandwidth of B/2 Hz and the samples at T_S sec can be decimated to samples at $2T_S$ sec.

Additional understanding of the compression process is possible if we take a signal made of eight numbers and let the low pass filter be the average of two consecutive samples (x(n) + x(n + 1))/2 and the high pass filter to be the difference (x(n) – x(n + 1))/2 (Gail and Nielsen, 1999). For example, with

$$x(n) = [-2\ -28\ -46\ -44\ -20\ 12\ 32\ 30]$$

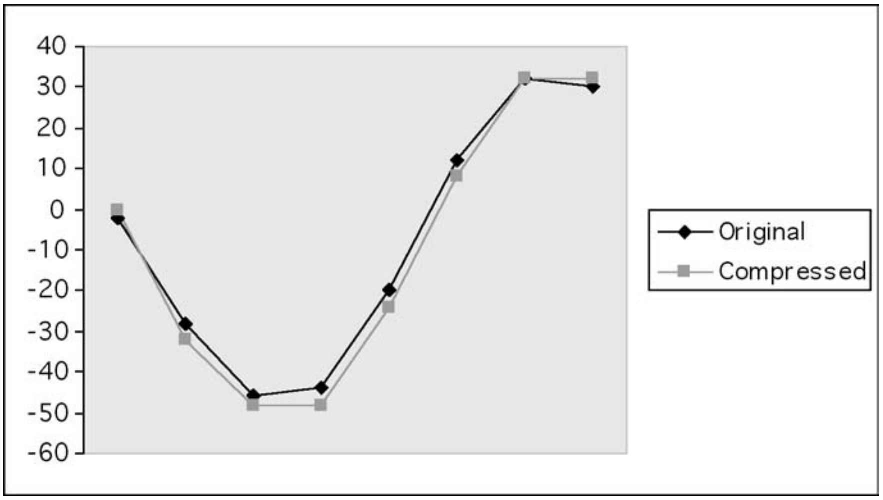

FIGURE 9.45 Original and compressed signals.

we get

$$h_1(k_1) = [13 \;\; -1 \;\; -16 \;\; 1]$$

$$h_2(k_2) = [7 \;\; -8.5]$$

$$h_3(k_3) = [7.75]$$

$$l_3(k_3) = [-0.75]$$

If we truncate to form

$$h_1(k_1) = [16 \;\; 0 \;\; -16 \;\; 0]$$

$$h_2(k_2) = [8 \;\; -8]$$

$$h_3(k_3) = [8]$$

$$l_3(k_3) = [0]$$

and reconstruct the original sequence

$$\tilde{x}(n) = [0 \;\; -32 \;\; -48 \;\; -48 \;\; -24 \;\; 8 \;\; 32 \;\; 32]$$

The original and reconstructed compressed waveform is shown in Fig. 9.45. Wavelets have been applied to relaying for systems grounded through a Peterson coil where the form of the wavelet was chosen to fit unusual waveforms the Peterson coil produces (Chaari et al., 1996).

Neural Networks

Artificial Neural Networks (ANNs) had their beginning in the "perceptron," which was designed to recognize patterns. The number of papers suggesting relay application have soared. The attraction is the use of ANNs as pattern recognition devices that can be trained with data to recognize faults, inrush, or

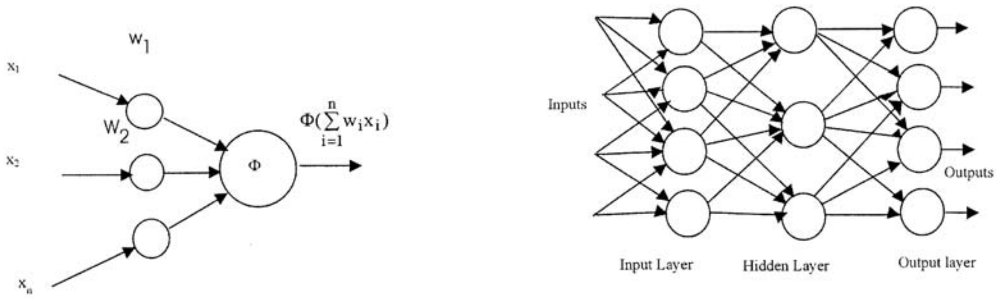

FIGURE 9.46 One neuron and a neural network.

other protection effects. The basic feed forward neural net is composed of layers of neurons as shown in Fig. 9.46.

The function **Φ** is either a threshold function or a saturating function such as a symmetric sigmoid function. The weights w_i are determined by training the network. The training process is the most difficult part of the ANN process. Typically, simulation data such as that obtained from EMTP is used to train the ANN. A set of cases to be executed must be identified along with a proposed structure for the net. The structure is described in terms of the number of inputs, neuron in layers, various layers, and outputs. An example might be a net with 12 inputs, and a 4, 3, 1 layer structure. There would be 4×12 plus 4×3 plus 3×1 or 63 weights to be determined. Clearly, a lot more than 60 training cases are needed to learn 63 weights. In addition, some cases not used for training are needed for testing. Software exists for the training process but judgment in determining the training sequences is vital. Once the weights are learned, the designer is frequently asked how the ANN will perform when some combination of inputs are presented to it. The ability to answer such questions is very much a function of the breadth of the training sequence.

The protective relaying application of ANNs include high-impedance fault detection (Eborn et al., 1990), transformer protection (Perez et al., 1994), fault classification (Dalstein and Kulicke, 1995), fault direction determination, adaptive reclosing (Aggarwal et al., 1994), and rotating machinery protection (Chow and Yee, 1991).

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9.6 Use of Oscillograph Records to Analyze System Performance

John R. Boyle

Protection of present-day power systems is accomplished by a complex system of extremely sensitive relays that function only during a fault in the power system. Because relays are extremely fast, automatic oscillographs installed at appropriate locations can be used to determine the performance of protective relays during abnormal system conditions. Information from oscillographs can be used to detect the:

1. Presence of a fault
2. Severity and duration of a fault
3. Nature of a fault (A phase to ground, A – B phases to ground, etc.)
4. Location of line faults
5. Adequacy of relay performance
6. Effective performance of circuit breakers in circuit interruption
7. Occurrence of repetitive faults
8. Persistency of faults
9. Dead time required to dissipate ionized gases
10. Malfunctioning of equipment
11. Cause and possible resolution of a problem

Another important aspect of analyzing oscillograms is that of collecting data for statistical analysis. This would require a review of all oscillograms for every fault. The benefits would be to detect incipient problems and correct them before they become serious problems causing multiple interruptions or equipment damage.

An analysis of an oscillograph record shown in Fig. 9.47 should consider the nature of the fault. Substation **Y** is comprised of two lines and a transformer. The high side winding is connected to ground. Oscillographic information is available from the bus potential transformers, the line currents from breaker **A** on line 1, and the transformer neutral current. An "A" phase-to-ground fault is depicted on line 1. The

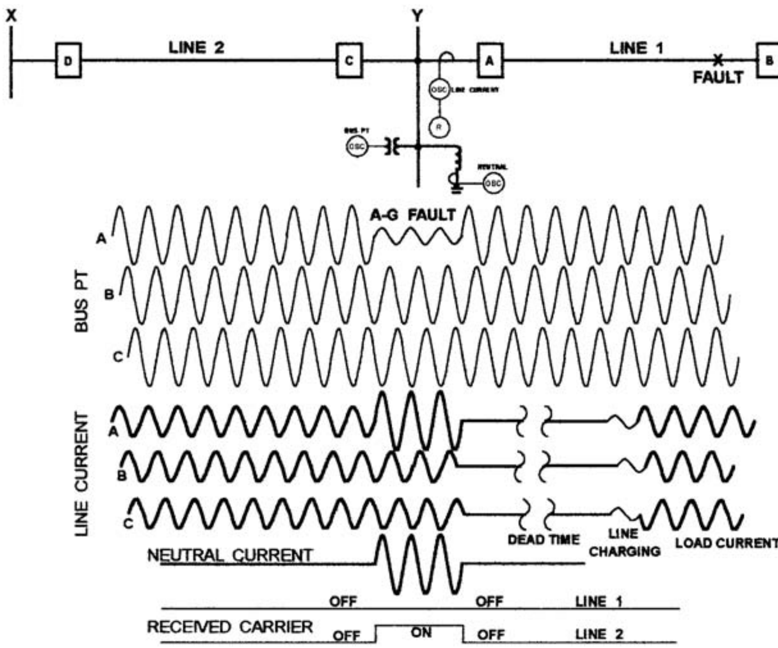

FIGURE 9.47

oscillograph reveals a significant drop in "A" phase voltage accompanied with a rise in "A" phase line 1 current and a similar rise in the transformer neutral current. The "A" phase breaker cleared the fault in 3 cycles (good). The received carrier on line 1 was "off" during the fault (good) permitting high-speed tripping at both terminals (breakers A and B). There is no evidence of AC or DC current transformer (CT) saturation of either the phase CTs or the transformer neutral CT. The received carrier signal on line 2 was "on" all during the fault to block breaker "D" from tripping at terminal "**X**". This would indicate that the carrier ground relays on the number 2 line performed properly. This type of analysis may not be made because of budget and personnel constraints. Oscillographs are still used extensively to analyze known cases of trouble (breaker failure, transformer damage, etc.), but oscillograph analysis can also be used as a maintenance tool to prevent equipment failure.

The use of oscillograms as a maintenance tool can be visualized by classifying operations as good (A) or questionable (B) as shown in Fig. 9.48. The first fault current waveform (upper left) is classified as A because it is sinusoidal in nature and cleared in 3 cycles. This could be a four or five cycle fault clearing time and still be classified as A depending upon the breaker characteristics (4 or 5 cycle breaker, etc.) The DC offset wave form can also be classified as A because it indicates a four cycle fault clearing time and a sinusoidal waveform with no saturation.

An example of a questionable waveform (B) is shown on the right side of Fig. 9.48. The upper right is one of current magnitude which would have to be determined by use of fault studies. Some breakers have marginal interrupting capabilities and should be inspected whenever close-in faults occur that generate currents that approach or exceed their interrupting capabilities. The waveform in the lower right is an example of a breaker restrike that requires a breaker inspection to prevent a possible breaker failure of subsequent operations.

Carrier performance on critical transmission lines is important because it impacts fast fault clearing, successful high-speed reclosing, high-speed tripping upon reclosure, and delayed breaker failure response for permanent faults upon reclosure, and a "stuck" breaker. In Fig. 9.49 two waveforms are shown that depict adequate carrier response for internal and external faults. The first waveform shows a 3 cycle fault and its corresponding carrier response. A momentary burst of carrier is cut off quickly allowing the breaker to trip in 3 cycles. Upon reclosing, load current is restored. The bottom waveform depicts the

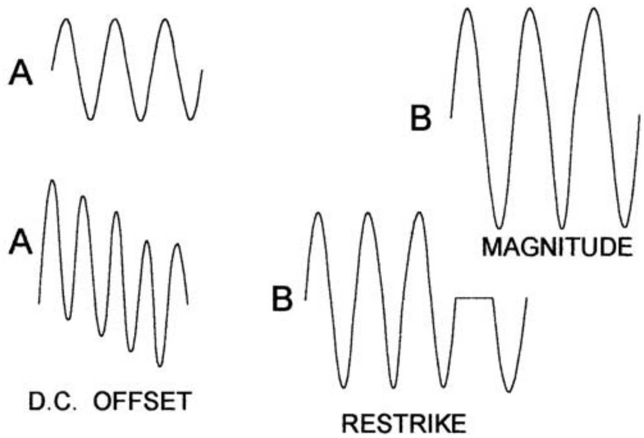

FIGURE 9.48

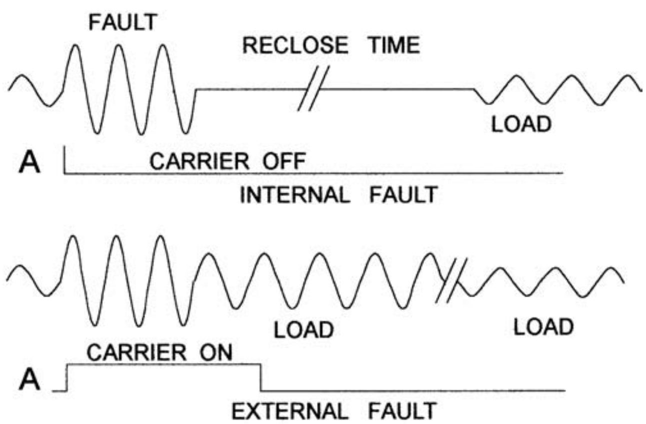

FIGURE 9.49

response of carrier on an adjacent line for the same fault. Note that carrier was "off" initially and cut "on" shortly after fault initiation. It stayed "on" for a few cycles after the fault cleared and stayed "off" all during the reclose "dead" time and after restoration of load current. Both of these waveforms would be classified as "good" and would not need further analysis.

An example of a questionable carrier response for an internal fault is shown in Fig. 9.50. Note that the carrier response was good for the initial 3 cycle fault, but during the reclose dead time, carrier came back "on" and was "on" upon reclosing. This delayed tripping an additional 2 cycles. Of even greater concern is a delay in the response of breaker-failure clearing time for a stuck breaker. Breaker failure initiation is predicated upon relay initiation which, in the case shown, is delayed 2 cycles. This type of "bad" carrier response may go undetected if oscillograms are not reviewed. In a similar manner, a delayed carrier response for an internal fault can result in delayed tripping for the initial fault as shown in Fig. 9.51. However, a delayed carrier response on an adjacent line can be more serious because it will result in two or more line interruptions. This is shown in Fig. 9.52. A fault on line 1 in Fig. 9.47 should be accompanied by acceptable carrier blocking signals on all external lines that receive a strong enough signal to trip if not accompanied by an appropriate carrier blocking signal. Two conditions are shown. A good ("A") block signal and questionable ("B") block signal. The good block signal is shown as one that blocks (comes "on") within a fraction of a cycle after the fault is detected and unblocks (goes "off") a few cycles after the fault is cleared. The questionable block signal shown at the bottom of the waveform in Fig. 9.52

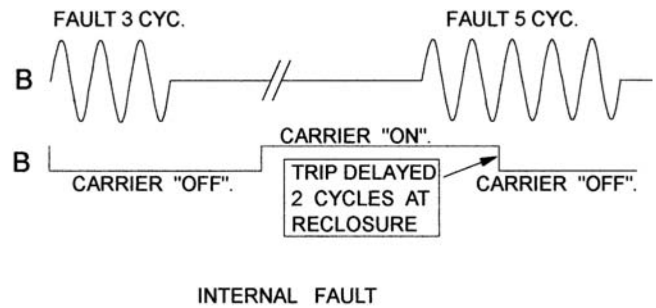

FIGURE 9.50

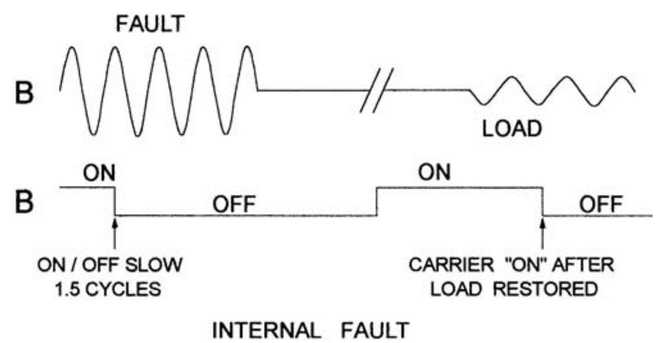

FIGURE 9.51

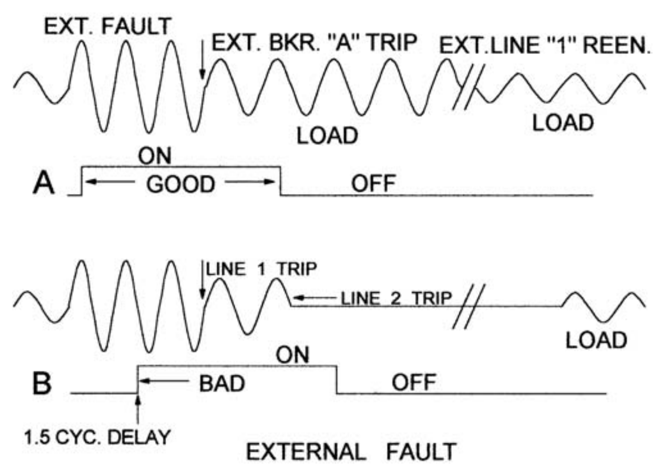

FIGURE 9.52

is late in going from "off" to "on" (1.5 cycles). The race between the trip element and the block element is such that a trip signal was initiated first and breaker "D" tripped 1.5 cycles after the fault was cleared by breaker A in 3 cycles. This would result in a complete station interruption at station "Y."

Impedance relays receive restraint from either bus or line potentials. These two potentials behave differently after a fault has been cleared. This is shown in Fig. 9.53. After breakers "A" and "B" open and the line is deenergized, the bus potential restores to its full value thereby applying full restraint to all

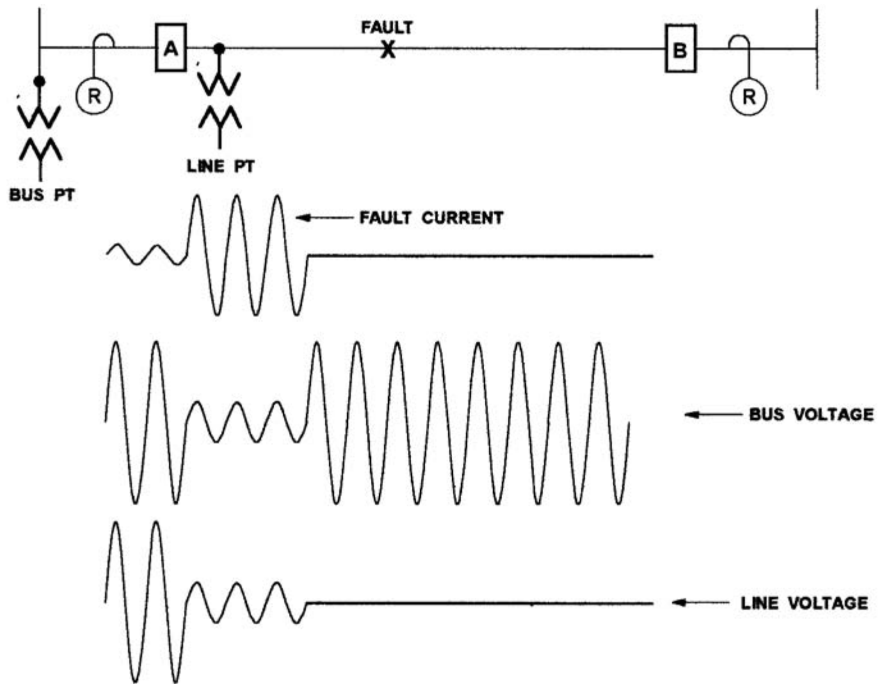

FIGURE 9.53

impedance relays connected to the bus. The line voltage goes to zero after the line is deenergized. Normally this is not a problem because relays are designed to accommodate this condition. However, there are occasions when the line potential restraint voltage can cause a relay to trip when a breaker recloses. This condition usually manifests itself when shunt reactors are connected on the line. Under these conditions an oscillatory voltage will exist on the terminals of the line side potential devices after both breakers "A" and "B" have opened. A waveform example is shown in Fig. 9.54. Note that the voltage is not a 60 Hz wave shape. Normally it is less than 60 Hz depending on the degree of compensation. This oscillatory voltage is more pronounced at high voltages because of the higher capacitance charge on the line. On lines that have flat spacing, the two outside voltages transfer energy between each other that results in oscillations that are mirror images of each other. The voltage on the center phase is usually a constant decaying decrement. These oscillations can last up to 400 cycles or more. This abnormal voltage is applied to the relays at the instant of reclosure and has been known to cause a breaker (for example, "A") to trip because of the lack of coordination between the voltage restraint circuit and the overcurrent monitoring element. Another more prevalent problem is multiple restrikes across an insulator during the oscillatory voltage on the line. These restrikes prevent the ionized gasses from dissipating sufficiently at the time of reclosure. Thus a fault is reestablished when breaker "A" and/or "B" recloses. This phenomena can readily be seen on oscillograms. Action taken might be to look for defective insulators or lengthen the reclose cycle.

The amount of "dead time" is critical to successful reclosures. For example, at 161 kV a study was made to determine the amount of dead time required to dissipate ionized gasses to achieve a 90% reclose success rate. In general, on a good line (clean insulators), at least 13 cycles of dead time are required. Contrast this to 10 cycles dead time where the reclose success rate went down to approximately 50%. Oscillograms can help determine the dead time and the cause of unsuccessful reclosures. Note the dead time is a function of the performance of the breakers at both ends of the line. Figure 9.55 depicts the performance of good breaker operations (top waveform). Here, both breakers trip in 3 cycles and reclose successfully in 13 cycles. The top waveform depicts a slow breaker "A" tripping in 6 cycles. This results in an unsuccessful reclosure because the overall dead time is reduced to 10 cycles. Note, the oscillogram

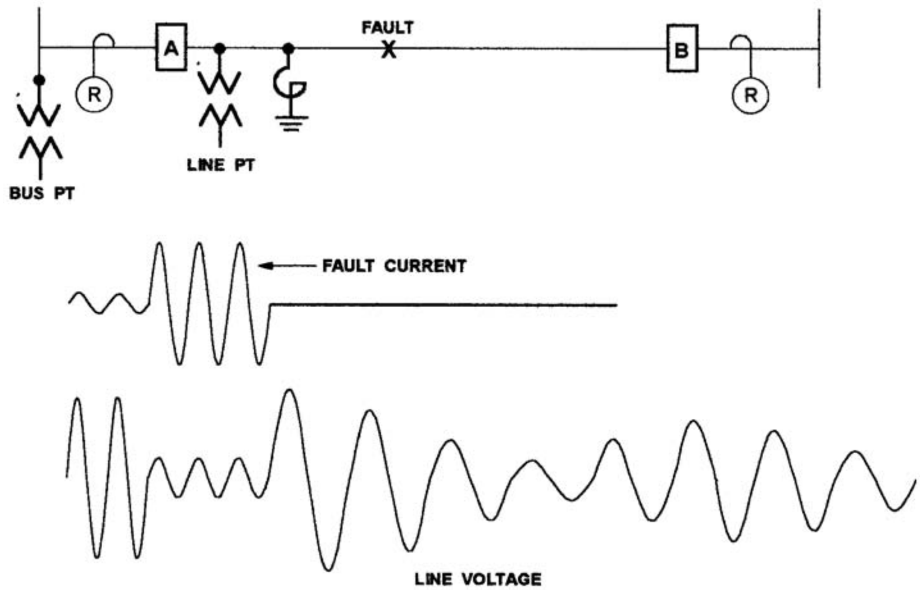

FIGURE 9.54

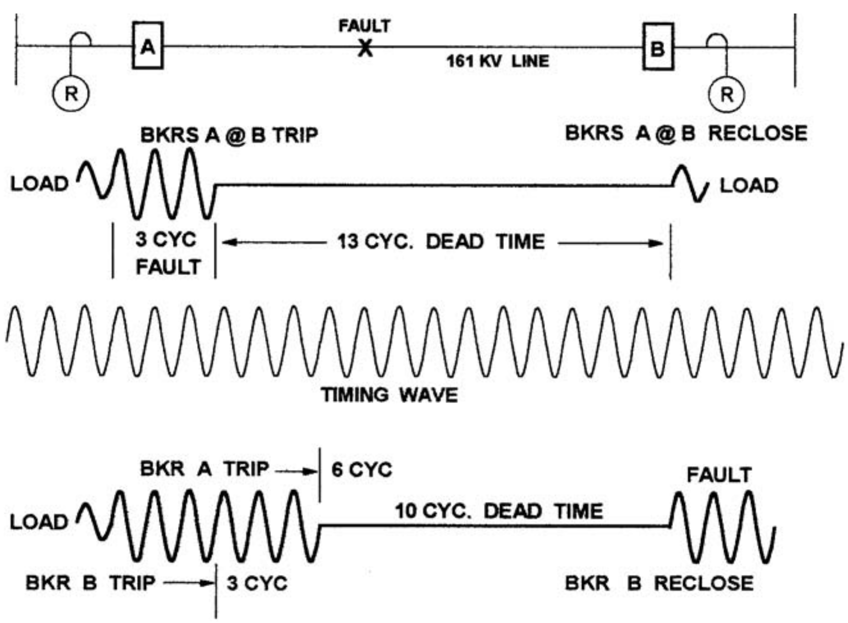

FIGURE 9.55

readily displays the problem. The analysis would point to possible relay or breaker trouble associated with breaker "A."

Figure 9.56 depicts current transformer (CT) saturation. This phenomenon is prevalent in current circuits and can cause problems in differential and polarizing circuits. The top waveform is an example of a direct current (DC) offset waveform with no evidence of saturation. That is to say that the secondary waveform replicates the primary waveform. Contrast this with a DC offset waveform (lower) that clearly indicates saturation. If two sets of CTs are connected differentially around a transformer and the high

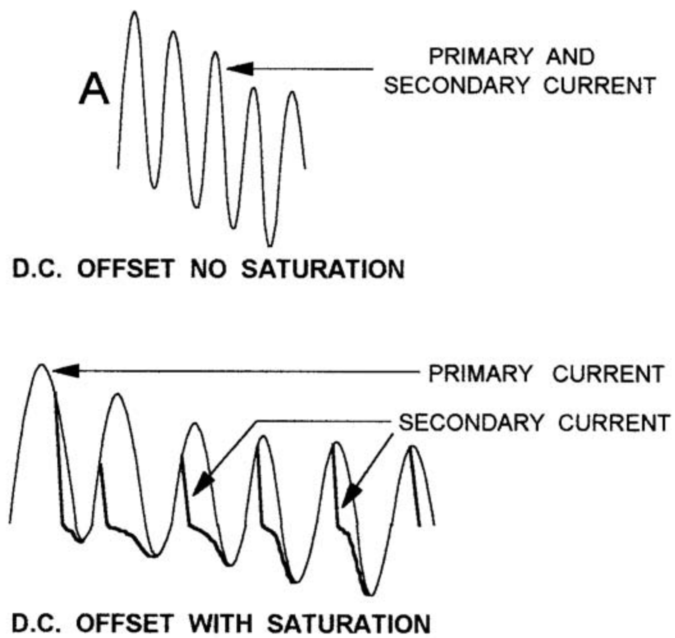

FIGURE 9.56

side CTs do not saturate (upper waveform) and the low side CTs do saturate (lower waveform), the difference current will flow through the operate coil of the relay which may result in deenergizing the transformer when no trouble exists in the transformer. The solution may be the replacement of the offending low side CT with one that has a higher "C" classification, desensitizing the relay or reducing the magnitude of the fault current. Polarizing circuits are also adversely affected by CTs that saturate. This occurs where a residual circuit is compared with a neutral polarizing circuit to obtain directional characteristics and the apparent shift in the polarizing current results in an unwanted trip.

Current reversals can result in an unwanted two-line trip if carrier transmission from one terminal to another does not respond quickly to provide the desired block function of a trip element. This is shown in a step-by-step sequence in Figs. 9.57 through 9.60. Consider a line 1 fault at the terminals of breaker

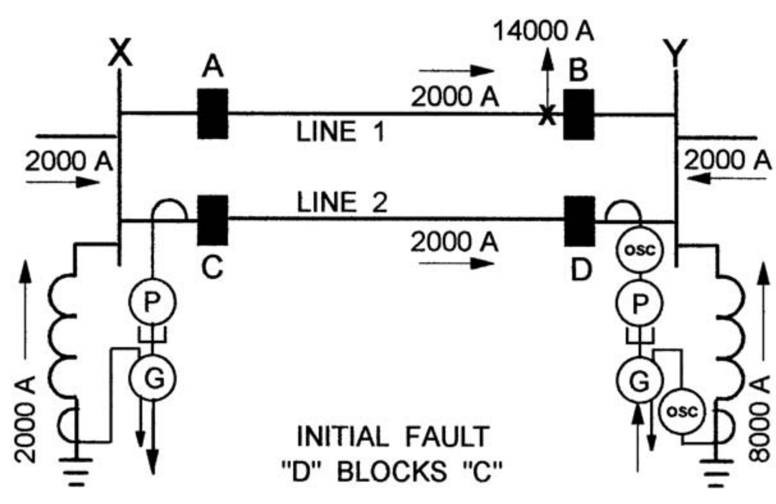

FIGURE 9.57

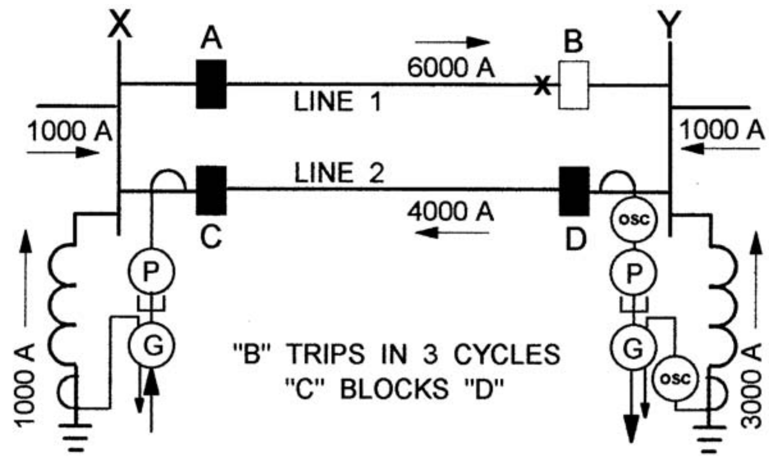

FIGURE 9.58

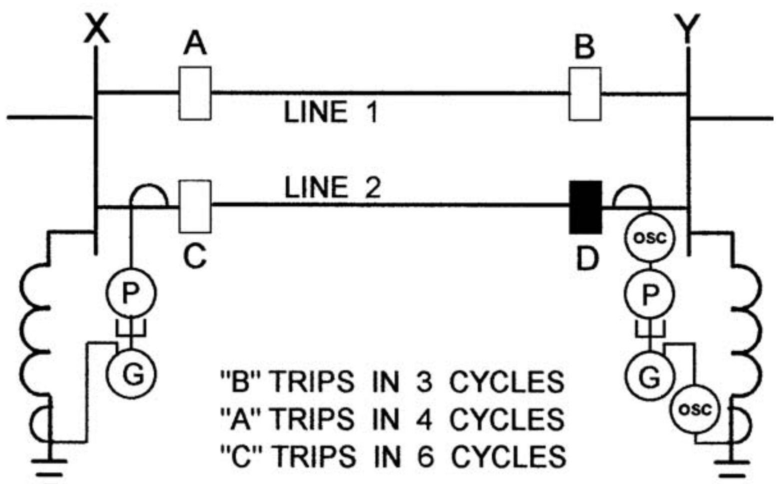

FIGURE 9.59

"B" (Fig. 9.57). For this condition, 2000 amperes of ground fault current is shown to flow on each line from terminal "X" to terminal "Y." Since fault current flow is towards the fault at breakers "A" and "B", **neither** will receive a signal (carrier "off") to initiate tripping. However, it is assumed that both breakers do not open at the same time (breaker "B" opens in 3 cycles and breaker "A" opens in 4 cycles). The response of the relays on line 2 is of prime concern. During the initial fault when breakers "A" and "B" are both closed, a block carrier signal must be sent from breaker "D" to breaker "C" to prevent the tripping of breaker "C." This is shown as a correct "on" carrier signal for 3 cycles in the bottom oscillogram trace in Fig. 9.60. However, when breaker "B" trips in 3 cycles, the fault current in line 2 increases to 4000 amperes and, more importantly, it reverses direction to flow from terminal "Y" to terminal "X." This instantaneous current reversal requires that the directional relays on breaker "C" pickup to initiate a carrier block signal to breaker "D." Failure to accomplish this may result in a trip of breaker "C" if its own carrier signal does not rise rapidly to prevent tripping through its previously made up trip directional elements. This is shown in Fig. 9.59 and oscillogram record Fig. 9.60. An alternate undesirable operation would be the tripping of breaker "D" if its trip directional elements make up before the carrier block signal from breaker "C" is received at breaker "D." The end result is the same (tripping line 2 for a fault on line 1).

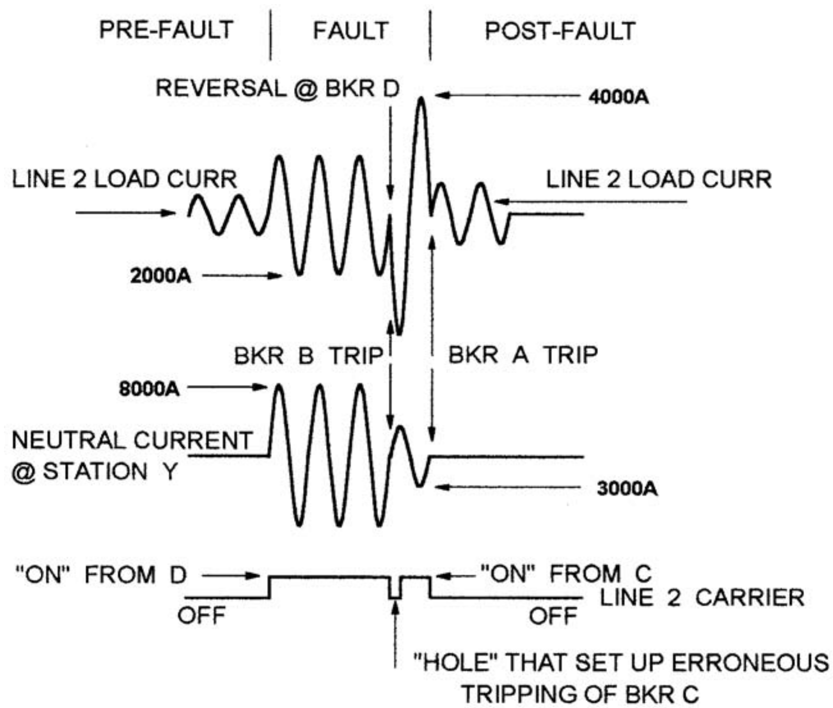

FIGURE 9.60

Restrikes in breakers can result in an explosive failure of the breaker. Oscillogams can be used to prevent breaker failures if the first restrike within the interrupter can be detected before a subsequent restrike around the interrupter results in the destruction of the breaker. This is shown diagrammatically in Fig. 9.61. The upper waveform restrike sequence depicts a 1/2 cycle restrike that is successfully extinguished within the interrupter. The lower waveform depicts a restrike that goes around the interrupter. This restrike cannot be extinguished and will last until the oil becomes badly carbonized and a subsequent fault occurs between the bus breaker terminal and the breaker tank (ground). In Fig. 9.61 the interrupter bypass fault lasted 18 cycles. Depending upon the rate of carbonization, the arc time could last longer or less before the flashover to the tank. The result would be the same. A bus fault that could have devastating affects. One example resulted in the loss of eight generators, thirteen 161 kV lines, and three 500-kV lines. The reason for the extensive loss was the result of burning oil that drifted up into adjacent busses steel causing multiple bus and line faults that deenergized all connected equipment in the station. The restrike phenomena is a result of a subsequent lightning strikes across the initial fault (insulator). In the example given above, lightning arresters were installed on the line side of each breaker and no additional restrikes or breaker failures occurred after the initial distructive failures.

Oscillography in microprocessor relays can also be used to analyze system problems. The problem in Fig. 9.62 involves a microprocessor differential relay installation that depicts the failure to energize a large motor. The CTs on both sides of the transformer were connected wye-wye but the low side CTs were rolled. The 30° shift was corrected in the relay and was accurately portrayed by oscillography in the microprocessor relay but the rolled CTs produced current in the operate circuit that resulted in an erroneous trip. Note that with the low side CTs rolled, the high and low side currents W1 and W2 are in phase (incorrect). The oscillography output clearly pin-pointed the problem. The corrected connection is shown in Fig. 9.63 together with the correct oscillography (W1 and W2 180° out of phase).

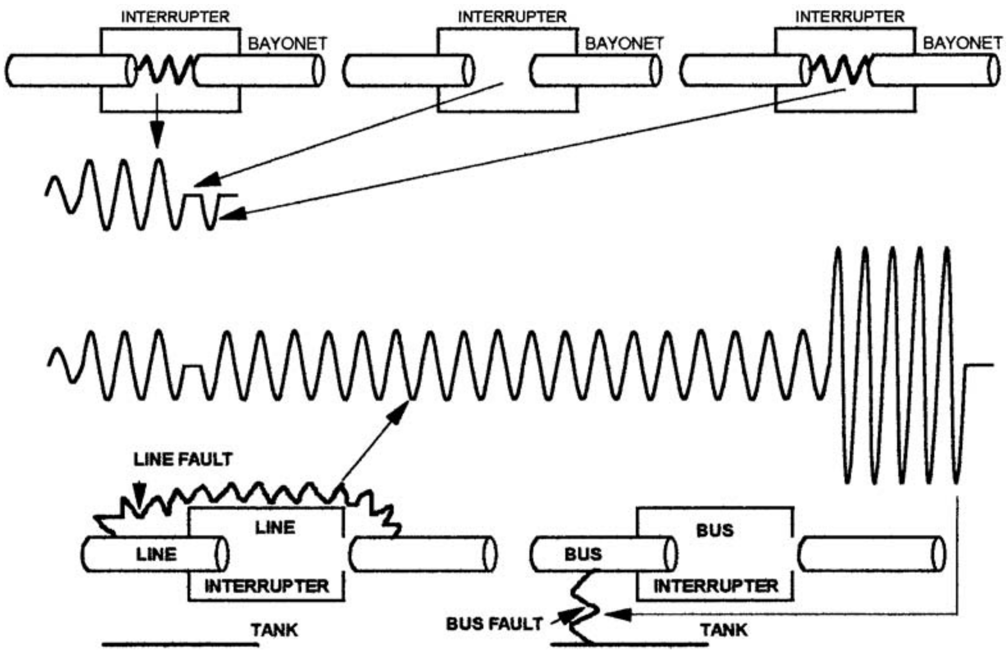

FIGURE 9.61

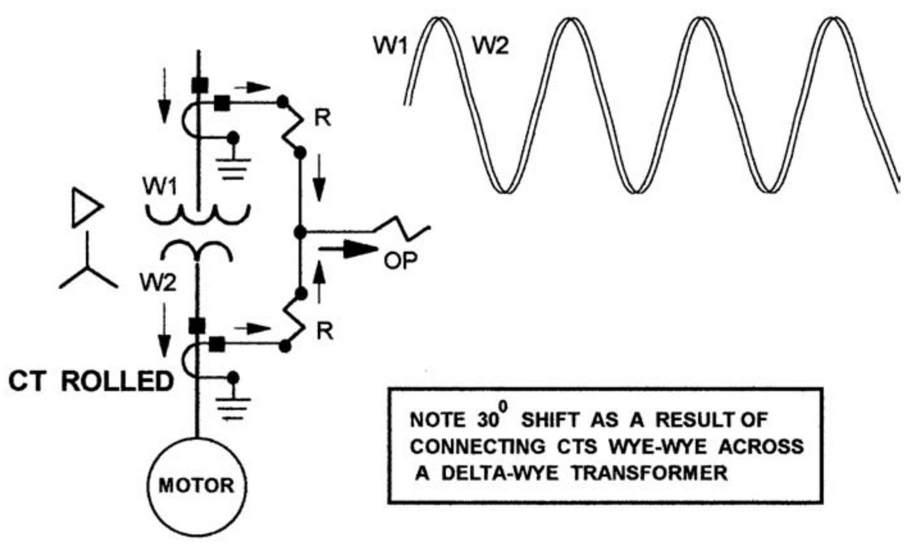

FIGURE 9.62

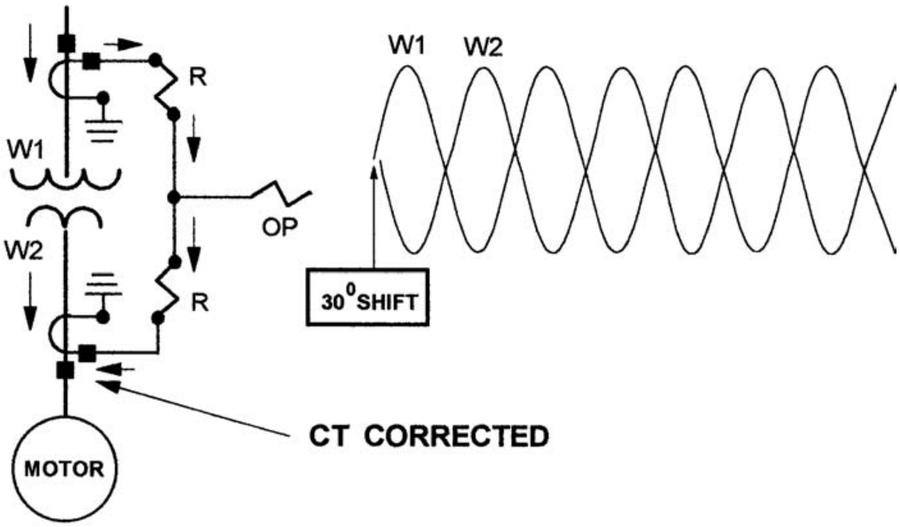

FIGURE 9.63