Fundamentals of Power System Protection[1]

1.1 Overview of Electrical Energy Systems

They may occupy different angular positions, but all machines rotate at the same electrical speed. This close knitting implies an embedded interaction of generators through the transmission network which is governed by the differential and algebraic equations of the apparatus and interconnects. This aspect is referred to as the system behaviour. This system has to be protected from abnormalities which is the task of protection system.

1.2 Why do we need Protection?

Electrical power system operates at various voltage levels from 415 V to 400 kV or even more. Electrical apparatus used may be enclosed (e.g. motors) or placed in open (e.g. transmission lines). All such equipment undergo abnormalities in their life time due to various reasons. For example, a worn out bearing may cause overloading of a motor. A tree falling or touching an overhead line may cause a fault. A lightning strike (classified as an act of God!) can cause insulation failure. Pollution may result in degradation in performance of insulators which may lead to breakdown. Under frequency or over frequency of a generator may result in mechanical damage to it's turbine requiring tripping of an alternator. Even otherwise, low frequency operation will reduce the life of a turbine and hence it should be avoided.

It is necessary to avoid these abnormal operating regions for safety of the equipment. Even more important is safety of the human personnel which may be endangered due to exposure to live parts under fault or abnormal operating conditions. Small current of the order of 50 mA is sufficient to be fatal! Whenever human security is sacrificed or there exists possibility of equipment damage, it is necessary to isolate and de-energize the equipment. Designing electrical equipment from safety perspective is also a crucial design issue which will not be addressed here. To conclude, every electrical equipment has to be monitored to protect it and provide human safety under abnormal operating conditions. This job is assigned to electrical protection systems. It encompasses apparatus protection and system protection.

1.3 Types of Protection

Protection systems can be classified into apparatus protection and system protection.

1.3.1 Apparatus Protection

Apparatus protection deals with detection of a fault in the apparatus and consequent protection. Apparatus protection can be further classified into following:

- Transmission Line Protection and feeder protection
- Transformer Protection
- Generator Protection
- Motor Protection
- Busbar Protection

1.3.2 System Protection

System protection deals with detection of proximity of system to unstable operating region and consequent control actions to restore stable operating point and/or prevent damage to equipments. Loss of system stability can lead to partial or complete system blackouts. Under-frequency relays, out-of-step protection, islanding systems, rate of change of frequency relays, reverse power flow relays, voltage surge relays etc are used for system protection. Wide Area Measurement (WAM) systems are also being deployed for system protection. Control actions associated with system protection may be classified into preventive or emergency control actions. Monitoring of system behaviour, taking corrective measures to maintain synchronous operation and protecting the power system apparatus from harmful operating states is referred as system protection.

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[1] Extract from IIT Bombay NPTEL Online
Electrical Engineering : Power System Protection
Fundamentals of Power System Protection

1.4 What is a Relay?

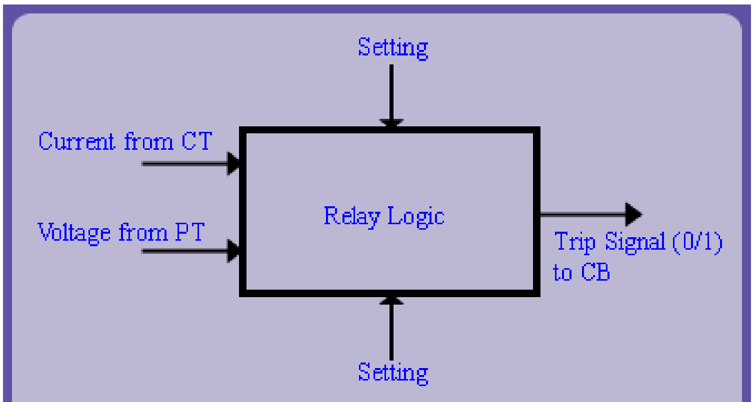

Fig 1.2 Conceptual Diagram of Relay

Formally, a relay is a logical element which processes the inputs (mostly voltages and currents) from the system/apparatus and issues a trip decision if a fault within the relay's jurisdiction is detected. A conceptual diagram of relay is shown in fig 1.2.

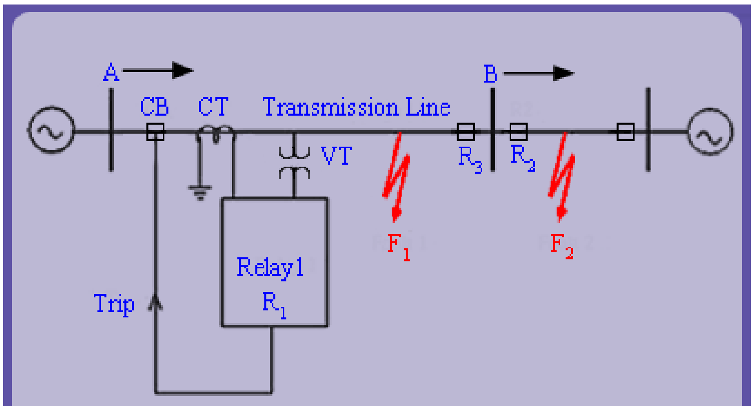

Fig 1.3 Typical Relaying System

In fig 1.3, a relay R_1 is used to protect the transmission line under fault F_1. An identical system is connected at the other end of the transmission line relay R_3 to open circuit from the other ends as well.

To monitor the health of the apparatus, relay senses current through a current transformer (CT), voltage through a voltage transformer (VT). VT is also known as Potential Transformer (PT).

The relay element analyses these inputs and decides whether (a) there is a abnormality or a fault and (b) if yes, whether it is within jurisdiction of the relay. The jurisdiction of relay R_1 is restricted to bus B where the transmission line terminates. If the fault is in it's jurisdiction, relay sends a tripping signal to circuit breaker(CB) which opens the circuit. A real life analogy of the jurisdiction of the relay can be thought by considering transmission lines as highways on which traffic (current/power) flows.

If there is an obstruction to the regular flow due to fault F_1 or F_2, the traffic police (relay R_1) can sense both F_1 and F_2 obstructions because of resulting abnormality in traffic (power flow). If the obstruction is on road AB, it is in the jurisdiction of traffic police at R1; else if it is at F_2, it is in the jurisdiction of R_2. R_1 should act for fault F_2, if and only if, R_2 fails to act. We say that relay R_1 backs up relay R_2. Standard way to obtain backup action is to use time discrimination i.e., delay operation of relay R_1 in case of doubt to provide R_2 first chance to clear the fault.

1.5 Evolution of Relays

If we zoom into a relay, we see three different types of realizations:

- Electromechanical Relays
- Solid State Relays
- Numerical Relays

1.5.1 Electromechanical Relays

When the principle of electromechanical energy conversion is used for decision making, the relay is referred as an electromechanical relay. These relays represent the first generation of relays. Let us consider a simple example of an over current relay, which issues a trip signal if current in the apparatus is above a reference value. By proper geometrical placement of current carrying conductor in the magnetic field, Lorentz force $F=BIL.\sin\theta$ is produced in the operating coil.

This force is used to create the operating torque. If constant 'B' is used (for example by a permanent magnet), then the instantaneous torque produced is proportional to instantaneous value of the current. Since the instantaneous current is sinusoidal, the instantaneous torque is also sinusoidal which has a zero average value. Thus, no net deflection of operating coil is perceived.

On the other hand, if the B is also made proportional to the instantaneous value of the current, then the instantaneous torque will be proportional to square of the instantaneous current (non-negative quantity). The average torque will be proportional to square of the rms current. Movement of the relay contact caused by the operating torque may be restrained by a spring in the overcurrent relay. If the spring has a spring constant 'k', then the deflection is proportional to the operating torque (in this case proportional to I^2_{rms}).

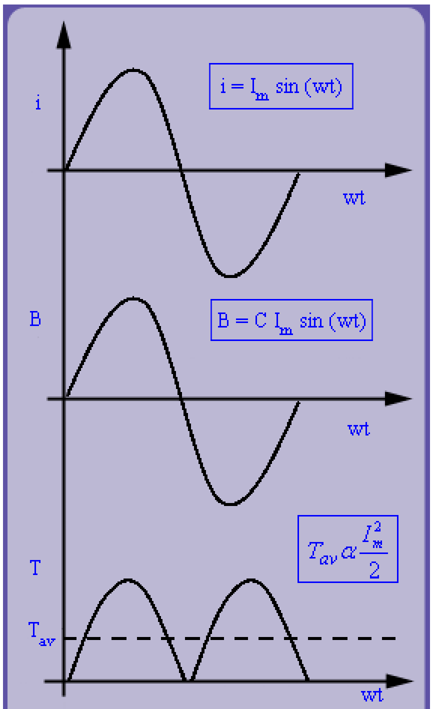

Fig. 1.4 Torque and Current Relationship in Attracted Armature Relay

When the deflection exceeds a preset value, the relay contacts closes and a trip decision is issued. Electromechanical relays are known for their ruggedness and immunity to Electromagnetic Interference (EMI).

1.5.2 Solid State Relays

With the advent of transistors, operational amplifiers etc, solid state relays were developed. They realize the functionality through various operations like comparators etc. They provide more flexibility and have less power consumption than their electromechanical counterpart. A major advantage with the solid state relays is their ability to provide self checking facility i.e. the relays can monitor their own health and raise a flag or alarm if its own component fails. Some of the advantages of solid state relays are low burden, improved dynamic performance characteristics, high seismic withstand capacity and reduced panel space.

Relay burden refers to the amount of volt amperes (VA) consumed by the relay. Higher is this value, more is the corresponding loading on the current and voltage sensors i.e. current transformers (CT) and voltage transformers (VT) which energizes these relays. Higher loading of the sensors lead to deterioration in their performance. A performance of CT or VT is gauged by the quality of the replication of the corresponding primary waveform signal. Higher burden leads to problem of CT saturation and inaccuracies in measurements. Thus it is desirable to keep CT/VT burdens as low as possible.

These relays have been now superseded by the microprocessor based relays or numerical relays.

1.5.3 Numerical Relays

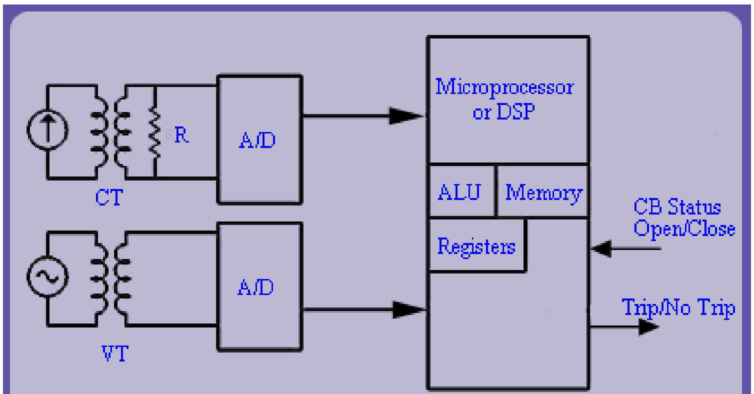

Fig 1.5 Block Diagram of Numerical Relay

The block diagram of a numerical relay is shown in fig 1.5.

It involves analogue to digital (A/D) conversion of analogue voltage and currents obtained from secondary of CTs and VTs. These current and voltage samples are fed to the microprocessor or Digital Signal Processors (DSPs) where the protection algorithms or programs process the signals and decide whether a fault exists in the apparatus under consideration or not. In case, a fault is diagnosed, a trip decision is issued. Numerical relays provide maximum flexibility in defining relaying logic.

The hardware comprising of numerical relay can be made scalable i.e., the maximum number of v and i input signals can be scaled up easily. A generic hardware board can be developed to provide multiple functionality. Changing the relaying functionality is achieved by simply changing the relaying program or software. Also, various relaying functionalities can be multiplexed in a single relay. It has all the advantages of solid state relays like self checking etc. Enabled with communication facility, it can be treated as an Intelligent Electronic Device (IED) which can perform both control and protection functionality. Also, a relay which can communicate can be made adaptive i.e. it can adjust to changing apparatus or system conditions.

For example, a differential protection scheme can adapt to transformer tap changes. An overcurrent relay can adapt to different loading conditions. Numerical relays are both "the present and the future".

1.6 What is a Circuit Breaker?

A Circuit Breaker (CB) is basically a switch used to interrupt the flow of current. It opens on relay command. The relay command initiates mechanical separation of the contacts. It is a complex element because it has to handle large voltages (few to hundreds of kV's) and currents (in kA's). Interrupting capacity of the circuit breaker is therefore expressed in MVA.

Power systems under fault behave more like inductive circuits. X/R ratio of lines is usually much greater than unity. For 400 kV lines, it can be higher than 10 and it increases with voltage rating. From the fundamentals of circuit analysis, we know that current in an inductive circuit (with finite resistance) cannot change instantaneously. The abrupt change in current, if it happens due to switch opening, will result in infinite di/dt and hence will induce infinite voltage. Even with finite di/dt, the induced voltages will be quite high. The high induced voltage developed across the CB will ionize the dielectric between its terminals. This results in arcing. When the current in CB goes through the natural zero, the arc can be extinguished (quenched). However, if the interrupting medium has not regained its dielectric properties then the arc can be restruck. The arcing currents reduce with passage of time and after a few cycles the current is finally interrupted.

Usually CB opening time lies in the 2-6 cycles range. CBs are categorized by the interrupting medium used. Minimum oil, air blast, vacuum arc and SF_6 CBs are some of the common examples. CB opening mechanism requires much larger power input than what logical element relay can provide. Hence, when relay issues a trip command, it closes a switch that energizes the CB opening mechanism powered by a separate dc source (station battery). The arc struck in a CB produces large amount of heat which also has to be dissipated.

2 Protection Paradigms - Apparatus Protection

Objectives : In this section we will introduce the following:

- Principle of overcurrent protection.
- Principle of directional overcurrent protection.
- Principle of distance protection.
- Principle of differential protection.

For simplicity in explaining the key ideas, we consider three phase bolted faults.

2.1 Overcurrent Protection

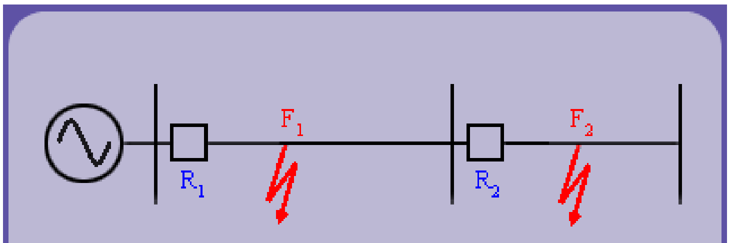

Fig 2.1 Radial Distribution System

This scheme is based on the intuition that, faults typically short circuits, lead to currents much above the load current. We can call them as overcurrents. Over current relaying and fuse protection uses the principle that when the current exceeds a predetermined value, it indicates presence of a fault (short circuit). This protection scheme finds usage in radial distribution systems with a single source. It is quite simple to implement.

Fig 2.1 shows a radial distribution system with a single source. The fault current is fed from only one end of the feeder. For this system it can be observed that:

- To relay R_1, both downstream faults F_1 and F_2 are visible i.e. I_{F1} as well as I_{F2} pass through CT of R_1.
- To relay R_2, fault F_1, an upstream fault is not seen, only F_2 is seen. This is because no component of I_{F1} passes through CT of R_2. Thus, selectivity is achieved naturally. Relaying decision is based solely on the magnitude of fault current. Such a protection scheme is said to be non-directional.

2.2 Directional Overcurrent Protection

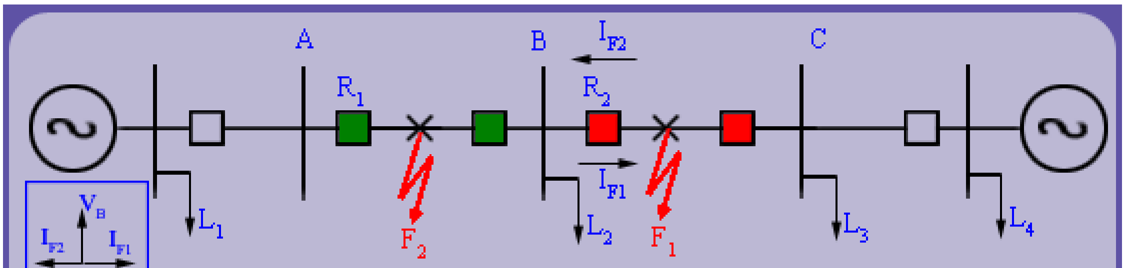

Fig 2.2 A Radial System with Source at Both Ends

In contrast, there can be situations where for the purpose of selectivity, phase angle information (always relative to a reference phasor) may be required. Fig 2.2 shows such a case for a radial system with source at both ends. Consequently, fault is fed from both the ends of the feeder. To interrupt the fault current, relays at both ends of the feeder are required.

In this case, from the magnitude of the current seen by the relay R_2, it is not possible to distinguish whether the fault is in the section AB or BC. Since faults in section AB are not in its jurisdiction, it should not trip. To obtain selectivity, a directional overcurrent relay is required. It uses both magnitude of current and phase angle information for decision making. It is commonly used in subtransmission networks where ring mains are used.

2.3 Distance Protection

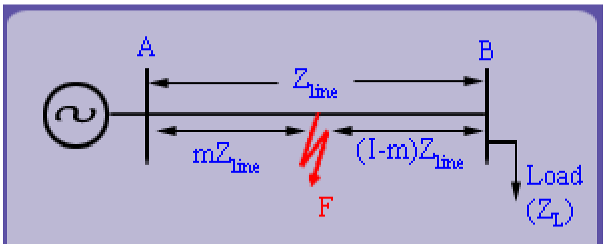

Fig 2.3 Fault in Transmission Line

Consider a simple radial system, which is fed from a single source. Let us measure the apparent impedance (V/I) at the sending end. For the unloaded system, I = 0, and the apparent impedance seen by the relay is infinite. As the system is loaded, the apparent impedance reduces to some finite value (Z_L+Z_{line}) where Z_L is the load impedance and Z_{line} is the line impedance. In presence of a fault at a per-unit distance 'm', the impedance seen by the relay drops to a mZ_{line} as shown in fig 2.3.

The basic principle of distance relay is that the apparent impedance seen by the relay, which is defined as the ratio of phase voltage to line current of a transmission line (Z_{app}), reduces drastically in the presence of a line fault. A distance relay compares this ratio with the positive sequence impedance (Z_1) of the transmission line. If the fraction Z_{app}/Z_1 is less than unity, it indicates a fault. This ratio also indicates the distance of the fault from the relay. Because, impedance is a complex number, the distance protection is inherently directional. The first quadrant is the forward direction i.e. impedance of the transmission line to be protected lies in this quadrant. However, if only magnitude information is used, non-directional impedance relay results. Fig 2.4 and 2.5 shows a characteristic of an impedance relay and 'mho relay' both belonging to this class. The impedance relay trips if the magnitude of the impedance is within the circular region. Since, the circle spans all the quadrants, it leads to non-directional protection scheme. In contrast, the mho relay which covers primarily the first quadrant is directional in nature.

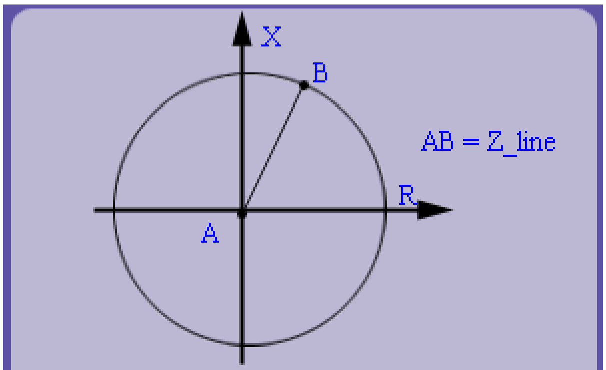

Fig 2.4 Impedance Relay

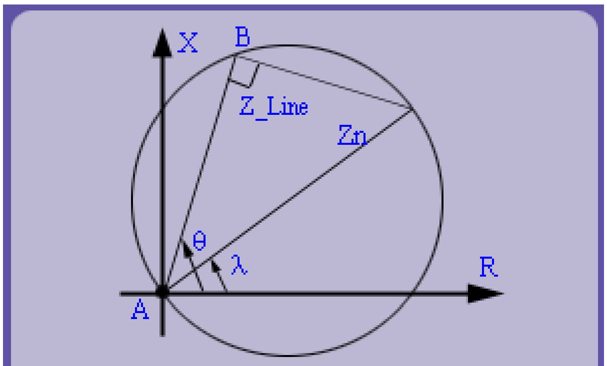

Fig 2.5 Mho Relay

Thus, the trip law for the impedance relay can be written as follows:

$$|Z_{app}| = \frac{|V_R|}{|I_R|} < |Z_{set}|,$$

then trip; else restrain.

While impedance relay has only one design parameter, Z_{set}; 'mho relay' has two design parameters Z_n, λ. The trip law for mho relay is given by if

$$|Z_{app}| < |Z_n| \cos(\theta - \lambda),$$

then trip; else restrain.

As shown in the fig 2.5, θ is the angle of transmission line. Based upon legacy of electromechanical relays λ is also called 'torque angle'.

2.3.1 Example

1. (a) Find out the value of Zn for a mho relay with torque angle 75º which has to give 100% protection to a 50 km long 110kV transmission line with impedance 0.8Ω per km and angle 80º.

Ans: The two design parameters of a mho relay are Zn and λ. Here the torque angle, λ of the relay has been selected as 75º.
The transmission line impedance Z_{Line} as on primary = 0.8 x 50 = 40Ω

$$Z_{Line}\ (\text{secondary}) = Z_{Line}\ (\text{primary}) \times \frac{Rc}{Rv}$$

where Rc, CT ratio = 200
Rv, VT ratio = 1000

$$Z_{Line}\ (Secondary) = 40 \times \frac{200}{1000} = 8\Omega$$

$$Z_{Line} = Zn\,Cos(\theta - \lambda) \text{ where } \theta = \text{ angle of transmission line}$$

$$Zn = \frac{Z_{Line}}{Cos(\theta - \lambda)}$$

$$= \frac{8}{Cos(80 - 75)} = \frac{8}{Cos\,5} = 8.03\Omega$$

This value is to be set on the mho relay.

(b) If the maximum load on this line is 1000A at 30º lagging, is there any possibility of relay tripping on load? CT ratio is 1000:5

Ans: Maximum Load current I_{load} = 1000A

$$V_{Line} = 110 \times 10^3 V\text{s}$$

$$Z_{load} = \frac{V_{Line}}{\sqrt{3} \times I_{load}} = \frac{110 \times 10^3}{\sqrt{3} \times 1000} = 63.5\Omega$$

$$Z_{load}\ Secondary = 63.5 \times \frac{Rc}{Rv} = 63.5 \times \frac{200}{1000} = 12.7\Omega$$

Since this value will not fall within the operating circle, the mho relay will not trip for this load.

2.4 Principle of Differential Protection

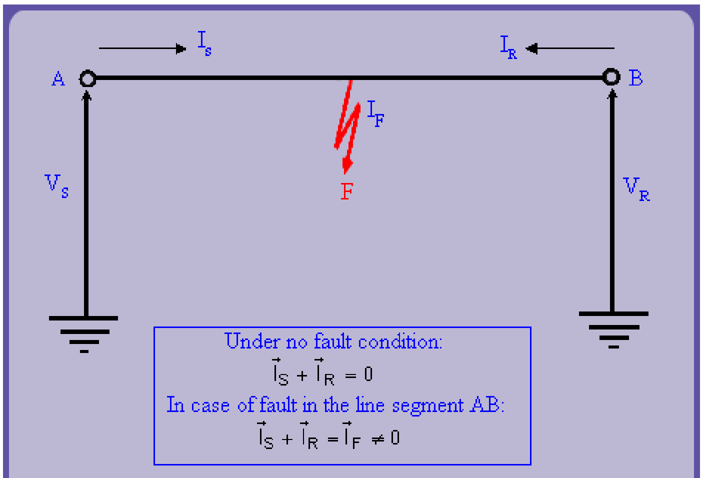

Fig 2.6 Differential Protection of Short Transmission Line

Differential protection is based on the fact that any fault within an electrical equipment would cause the current entering it, to be different, from the current leaving it. Thus by comparing the two currents either in magnitude or in phase or both we can determine a fault and issue a trip decision if the difference exceeds a predetermined set value.

2.4.1 Differential Protection for Transmission Line

Fig 2.6 shows a short transmission line in which shunt charging can be neglected. Then under no fault condition, phasor sum of currents entering the device is zero i.e.

$$\vec{I}_S + \vec{I}_R = 0$$

Thus, we can say that differential current under no fault condition is zero.

However in case of fault in the line segment AB, we get

$$\vec{I}_S + \vec{I}_R - \vec{I}_F \neq 0$$

i.e. differential current in presence of fault is non-zero.

This principle of checking the differential current is known as a differential protection scheme. In case of transmission line, implementation of differential protection requires a communication channel to transmit current values to the other end. It can be used for short feeders and a specific implementation is known as pilot wire protection. Differential protection tends to be extremely accurate. Its zone is clearly demarcated by the CTs which provide the boundary.

Differential protection can be used for tapped lines (multiterminal lines) where boundary conditions are defined as follows:

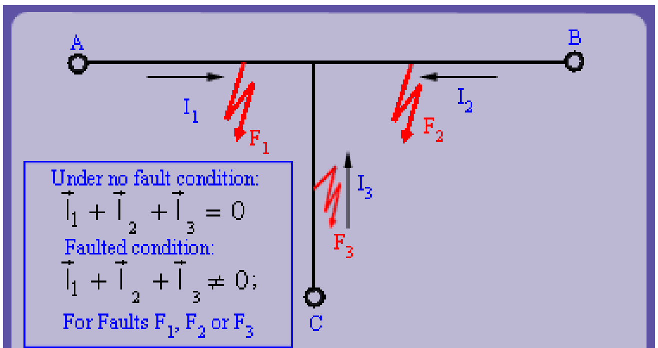

Fig 2.7 Differential Protection for Tapped Transmission Line

Under no fault condition:

$$\bar{I}_1 + \bar{I}_2 + \bar{I}_3 = 0$$

Faulted condition:

$$\bar{I}_1 + \bar{I}_2 + \bar{I}_3 \neq 0$$

2.4.2 Differential Protection for Transformer

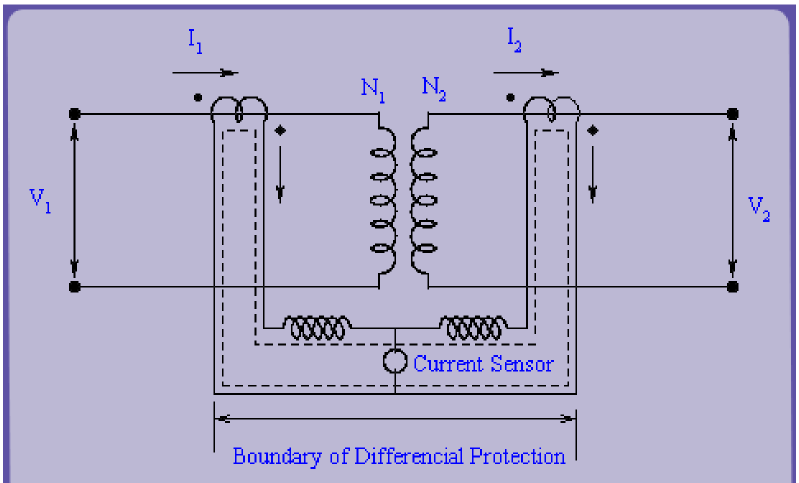

Fig 2.8 Differential Protection for Transformer

Differential protection for detecting faults is an attractive option when both ends of the apparatus are physically located near each other. e.g. on a transformer, a generator or a bus bar.

Consider an ideal transformer with the CT connections, as shown in fig 2.8. To illustrate the principle let us consider that current rating of primary winding is 100A and secondary winding is 1000A. Then if we use 100:5 and 1000:5 CT on the primary and secondary winding, then under normal (no fault) operating conditions the scaled CT currents will match in magnitudes. By connections the primary and secondary CTs with due care to the dots (polarity markings), a circulating current can be set up as shown by dotted line.

No current will flow through the branch having overcurrent current relay because it will result in violation of KCL. Now if an internal fault occurs within the device like interturn short etc., then the normal mmf balance is upset i.e. $N_1I_1 \neq N_2I_2$. Under this condition, the CT secondary currents of primary and secondary side CTs will not match. The resulting differential current will flow through overcurrent relay. If the pick up setting of overcurrent relay is close to zero, it will immediately pick up and initiate the trip decision.

In practice, the transformer is not ideal. Consequently, even if $I_2=0$, $I_1 \neq 0$, it is the magnetization current or (no load) current. Thus, a differential current always flows through the overcurrent relay. Therefore overcurrent relay pick up is adjusted above the no load current value. Consequently, minute faults below no load current value cannot be detected. This compromises sensitivity.

2.4.3 Differential Protection for Busbar

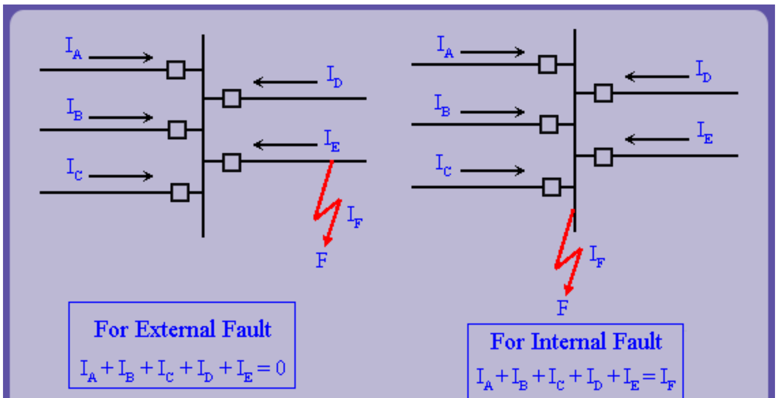

Fig 2.9 Differential Protection for Busbar

Ideally, differential protection is the solution for the bus-bar protection.

Figure 2.8 illustrates the basic idea. If the fault is external to the bus, it can be seen that algebraic sum of the currents entering the bus is zero.

$$\vec{I}_A + \vec{I}_B + \vec{I}_C + \vec{I}_D + \vec{I}_E = 0$$

On the other hand, if fault is on the bus (internal fault), this sum is not zero.

$$\vec{I}_A + \vec{I}_B + \vec{I}_C + \vec{I}_D + \vec{I}_E = \vec{I}_F$$

Thus, differential protection can be used to protect a bus.

3 Protection Paradigms - System Protection

3.1 Overview of Power System Dynamics

Usually, system protection requires study of the system dynamics and control. To understand issues in system protection, we overview dynamical nature of the power system. Power system behaviour can be described in terms of differential and algebraic system of equations. Differential equations can be written to describe behaviour of generators, transmission lines, motors, transformers etc. The detailing depends upon the time scale of investigation.

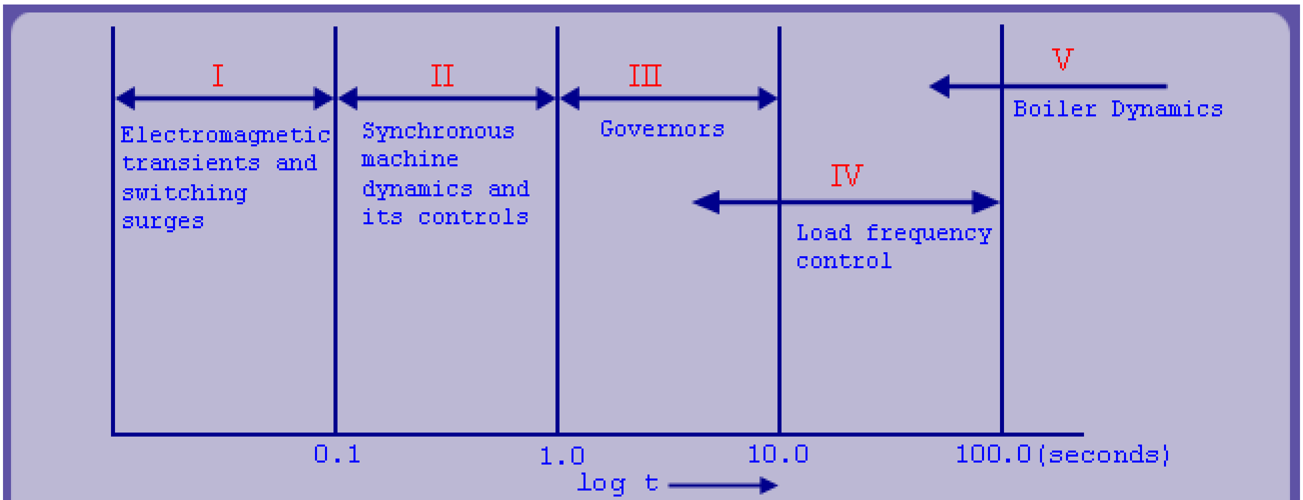

Fig 3.1 Transient Spectrum

Figure 3.1 shows the various time scales involved in modelling system dynamics. The dynamics involved in switching, lightening, load rejection etc have a high frequency component which die down quickly. In analysis of such dynamics, differential equations associated with inductances and capacitances of transmission lines have to be modelled. Such analysis is restricted to a few cycles. It is done by Electromagnetic Transient Program (EMTP).

At a larger time scale (order of seconds), response of the electromechanical elements is perceived. These transients are typically excited by faults which disturb the system equilibrium by upsetting the generator-load balance in the system. As a consequence of fault, electrical power output reduces instantaneously while the mechanical input does not change instantaneously. The resulting imbalance in power (and torque) excites the electromechanical transients which are essentially slow because of the inertia of the mechanical elements (rotor etc).

Detection and removal of fault is the task of the protection system (apparatus protection). Post-fault, the system may or may not return to an equilibrium position. Transient stability studies are required to determine the post fault system stability. In practice, out-of-step relaying, under frequency load shedding, islanding etc are the measures used to enhance system stability and prevent blackouts. The distinction between system protection and control (e.g. damping of power swings) is a finer one. In the today's world of Integrated Control and Protection Systems (ICPS), this distinction does not make much sense.

3.2 System Protection Relays

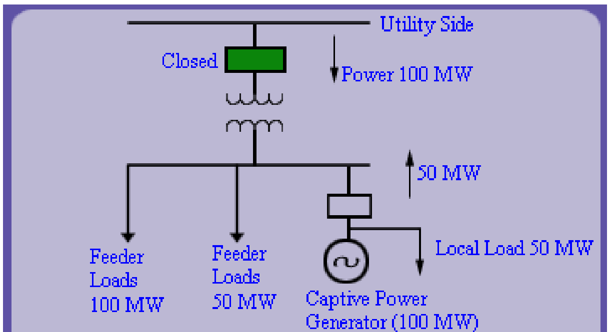

Fig 3.2 Captive Generator that Exports Power and meets Local Demand

Consider a medium voltage distribution system having local generation (e.g., captive power generation) as shown in fig 3.2 which is also synchronized with the grid. During grid disturbance, if plant generators are not successfully isolated from the grid, they also sink with the grid, resulting in significant loss in production and damage to process equipments. The following relays are used to detect such disturbances, its severity and isolate the inplant system from the grid.

- Underfrequency and over frequency relays.
- Rate of change of frequency relays.
- Under voltage relays.
- Reverse power flow relays.
- Vector shift relays.

3.2.1 Underfrequency Relay and Rate of Change of Frequency Relay

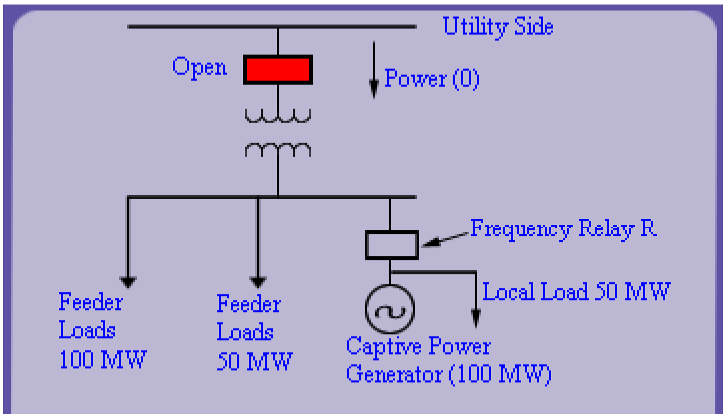

Fig 3.3 Loss of Utility and Over Loading of Captive Plant

In case of a grid failure (fig. 3.3), captive generators tend to supply power to other consumers connected to the substation. The load-generation imbalance leads to fall in frequency. The underfrequency relay R detects this drop and isolates local generation from the grid by tripping breaker at the point of common coupling. After disconnection from the grid, it has to be ascertained that there is load-generation balance in the islanded system. Because of the inertia of the machines, frequency drops gradually. To speed up the islanding decision, rate of change of frequency relays are used.

3.2.2 Undervoltage Relay

Whenever there is an uncleared fault on the grid close to the plant, the plant generators tend to feed the fault, and the voltages at the supply point drops. This can be used as a signal for isolating from the grid.

3.2.3 Reverse Power Relay

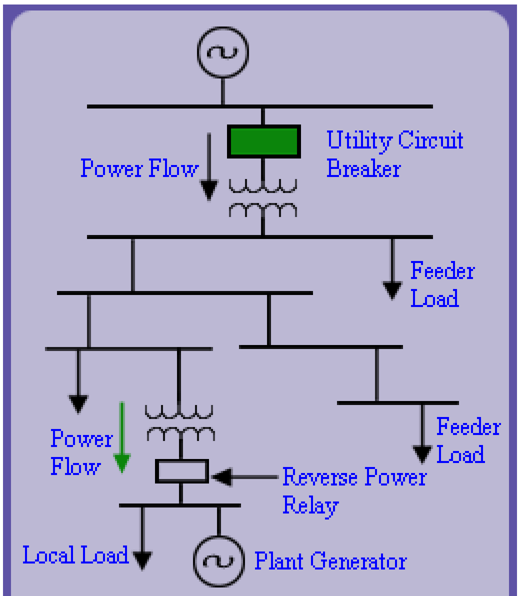

Fig 3.4 Utility and Plant Generator in Parallel

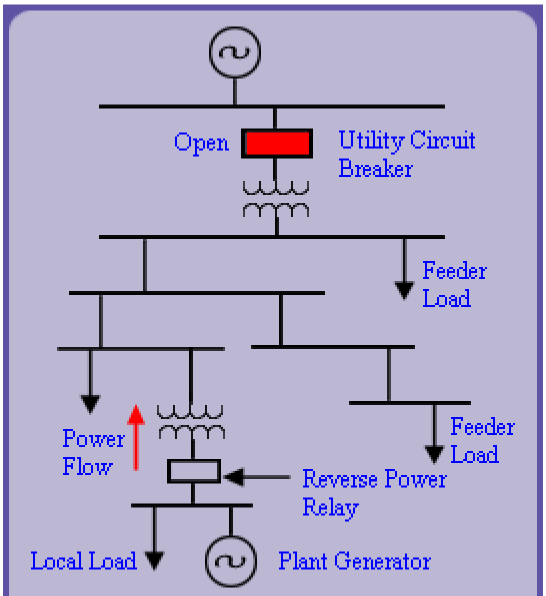

Fig 3.5 Isolation of Grid and Reversal of Power Flow

Distribution systems are radial in nature. This holds true for both utility and plant distribution systems. If there is a fault on the utility's distribution system, it may trip a breaker thereby isolating plant from the grid. This plant may still remain connected with downstream loads as shown in fig 3.4 and 3.5. Consequently, power will flow from the plant generator to these loads.

If in the prefault state, power was being fed to the plant, then this reversal of power flow can be used to island the plant generation and load from the remaining system. This approach is useful to detect loss of grid supply whenever the difference between load and available generation is not sufficient to obtain an appreciable rate of change of frequency but the active power continues to flow into the grid to feed the external loads.

Example

In fig 3.4, consider that the plant imports at all times a minimum power of 5 MW. Studies indicate that for various faults in utility side, minimum power export from the plant generator is 0.5 MW. Deduce the setting of reverse power relay. If the plant generator is of 50 MW capacity, what is likelihood of underfrequency or rate of change of frequency relay picking up on such faults?

Ans: Reverse power flow relay can be set to 0.4 MW. Since minimum reverse power flow is 1% of plant capacity, it is quite likely, that utility disconnection may not be noticed by underfrequency or the rate of change of frequency relays.

3.3 Lightning Protection


Fig 3.6 Lightning Discharge

Many line outages result from lightning strokes that hit overhead transmission lines. Lightning discharges normally produce overvoltage surges which may last for a fraction of second and are extremely harmful. The line outages can be reduced to an acceptable level by protection schemes like installation of earth wires and earthing of the towers.
Lightning overvoltages can be classified as follows:

- Induced overvoltages which occur when lightning strokes reach the ground near the line.
- Overvoltages due to shielding failures that occur when lightning strokes reach the phase conductors.
- Overvoltages by back flashovers that occur when lightning stroke reaches the tower or the shield wire.

The most commonly used devices for protection against lightning surges are the following:

- Shielding by earth wires: Normally, transmission lines are equipped with earth wires to shield against lightning discharges. The earthwires are placed above the line conductor at such a position that the lightning strokes are intercepted by them. In addition to this, earthing of tower is also essential.
- Lightning Arrestors: An alternative to the use of earthwire for protection of conductors against direct lightning strokes is to use lightning arrestors in parallel to insulator strings. Use of lightning arrestors is more economical also.

ZnO varistor is commonly used as lightning arrestor because of its peculiar resistance characteristic. Its resistance varies with applied voltage, i.e, its resistance is a nonlinear inverse function of applied voltage. At normal voltage its resistance is high. But when high voltage surges like lightning strokes appear across the varistor, its resistance decreases drastically to a very low value and the energy is dissipated in it, giving protection against lightning.

4 Desirable Attributes of Protection

A protection system is characterized by following two important parameters:

- Dependability
- Security

4.1 Dependability

A relay is said to be dependable if it trips only when it is expected to trip. This happens either when the fault is in it's primary jurisdiction or when it is called upon to provide the back-up protection. However, false tripping of relays or tripping for faults that is either not within it's jurisdiction, or within it's purview, compromises system operation. Power system may get unnecessarily stressed or else there can be loss of service. Dependability is the degree of certainty that the relay will operate correctly:

$$\%\ Dependability = \frac{Number\ of\ correct\ trips}{Number\ of\ desired\ trips} \times 100$$

Dependability can be improved by increasing the sensitivity of the relaying system.

4.1.1 Sensitivity

For simplicity, consider the case of overcurrent protection. The protective system must have ability to detect the smallest possible fault current. The smaller the current that it can detect, the more sensitive it is. One way to improve sensitivity is to determine characteristic signature of a fault. It is unique to the fault type and it does not occur in the normal operation. For example, earth faults involve zero sequence current. This provide a very sensitive method to detect earth faults. Once, this signature is seen, abnormality is rightly classified and hence appropriate action is initialized.

4.2 Security

On the other hand, security is a property used to characterize false tripping on the relays. A relay is said to be secure if it does not trip when it is not expected to trip. It is the degree of certainty that the relay will not operate incorrectly:

$$\%\ Security = \frac{Number\ of\ correct\ trips}{Total\ number\ of\ trips} \times 100$$

False trips do not just create nuisance. They can even compromise system security. For example, tripping of a tie-line in a two area system can result in load-generation imbalance in each area which can be dangerous. Even when multiple paths for power flow are available, under peak load conditions, overloads or congestion in the system may result. Dependability and security are contrasting requirements. Typically, a relay engineer biases his setting towards dependability. This may cause some nuisance tripping, which can in the worst case, trigger partial or complete blackout! Security of the relaying system can be improved by improving selectivity of the relaying system.

4.2.1 Selectivity

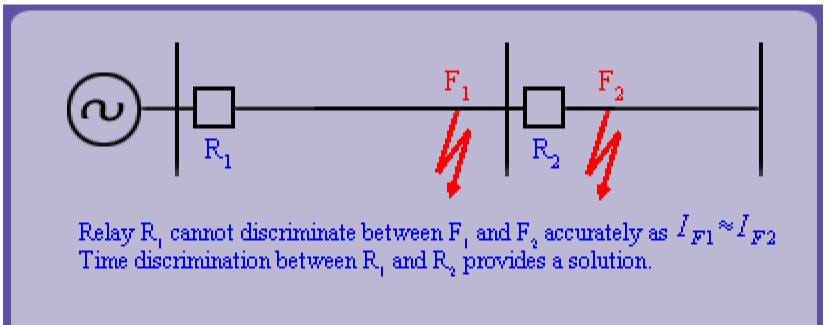

Fig 4.1 Distance or Overcurrent Protection

Like sensitivity, selectivity also implies an ability to discriminate. A relay should not confuse some peculiarities of an apparatus with a fault. For example, transformer when energized can draw up to 20 times rated current (inrush current) which can confuse, both overcurrent and transformer differential protection. Typically, inrush currents are characterized by large second harmonic content.

This discriminant is used to inhibit relay operation during inrush, there by, improving selectivity in transformer protection. Also, a relay should be smart enough, not just to identify a fault but also be able to decide whether fault is in it's jurisdiction or not. For example, a relay for a feeder should be able to discriminate a fault on it's own feeder from faults on adjacent feeders. This implies that it should detect first existence of fault in it's vicinity in the system and then take a decision whether it is in it's jurisdiction. Recall that directional overcurrent relay was introduced to improve selectivity of overcurrent relay.

This jurisdiction of a relay is also called as **zone of protection.** Typically, protection zones are classified into primary and backup zones. In detecting a fault and isolating the faulty element, the protective system must be very selective. Ideally, the protective system should zero-in on the faulty element and only isolate it, thus causing a minimum disruption to the system. Selectivity is usually provided by (1) using time discrimination and (2) applying differential protection principle. With overcurrent and distance relays, such boundaries are not properly demarcated (see fig 4.1). This is a very important consideration in operation of power systems.

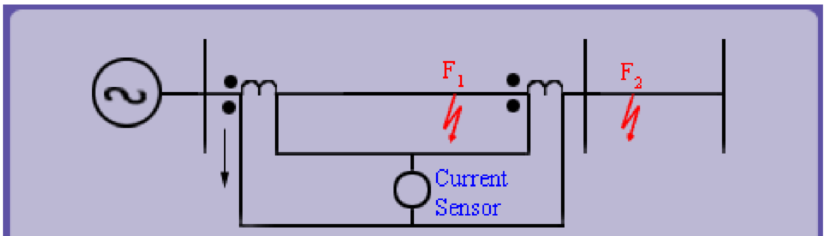

Fig 4.2 Differential Protection Scheme

However with a differential protection the CT location provides 'crisp' demarcation of zone of protection of CT (see fig 4.2). The fault F_1 is in the relay's zone of protection, but fault F_2 is not in its jurisdiction. Because differential protection scheme do not require time discrimination to improve selectivity, they are essentially fast.

4.3 Reliability

A relaying system has to be reliable. Reliability can be achieved by redundancy i.e. duplicating the relaying system. Obviously redundancy can be a costly proposition. Another way to improve reliability is to ask an existing relay say, protecting an apparatus A to backup protection of apparatus B. Both the approaches are used (simultaneously) in practice. However, it is important to realize that back-up protection must be provided for safe operation of relaying system. Redundancy in protection also depends upon the criticality of the power apparatus. For example, a 400 kV transmission line will have independent (duplicated) protection using same or a different philosophy; on the other hand, a distribution system will not have such local back-up. A quantitative measure for reliability is defined as follows:

$$\%\,Reliability = \frac{Number\ of\ correct\ trips}{Number\ of\ desired\ trips + Number\ of\ incorrect\ trips} \times 100$$

Example

The performance of an overcurrent relay was monitored over a period of one year. It was found that the relay operated 14 times, out of which 12 were correct trips. If the relay failed to issue trip decision on 3 occasions, compute dependability, security and reliability of the relay.

Number of correct trips = 12
Number of desired trips = 12 + 3 = 15

$$\%\ Dependability = \frac{Number\ of\ correct\ trips}{Number\ of\ desired\ trips} \times 100 \ = \frac{12}{15} \times 100 = 80\%$$

$$\%\ Security = \frac{Number\ of\ correct\ trips}{Total\ number\ of\ trips} \times 100 \ = \frac{12}{14} \times 100 = 85.71\%$$

$$\%\,Reliability = \frac{Number\ of\ correct\ trips}{Number\ of\ desired\ trips + Number\ of\ incorrect\ trips} \times 100 \ = \frac{12}{15+2} = 70.59\%$$

Note that even though dependability and security are individually above 80%, overall reliability much poor (only 70.55%).

Note that number of desired trips can be greater than or equal to number of correct trips. A desired trip may not happen for various reasons like, the fault level being below the relaying sensitivity, stuck circuit breaker, incorrect setting of relays poor maintenance of circuit breaker etc.

4.3.1 Zone of Protection

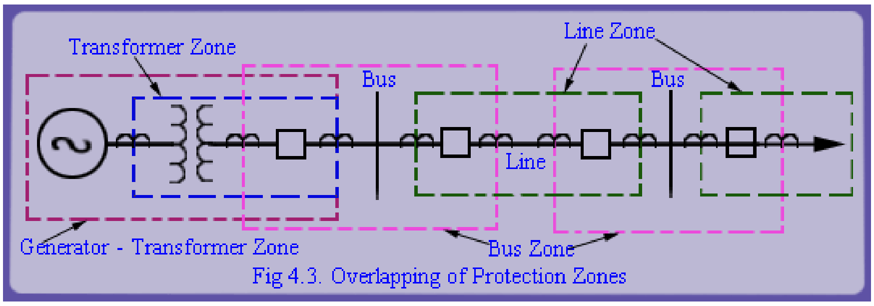

Fig 4.3. Overlapping of Protection Zones

A relay's zone of protection is a region defined by relay's jurisdiction (see fig 4.3). It is shown by demarcating the boundary. This demarcation for differential protection is quite crisp and is defined by CT's location. On the other hand, such boundaries for overcurrent and distance relays are not very crisp. It is essential that primary zones of protection should always overlap to ascertain that no position of the system ever remains unprotected. It can be seen in fig 4.3. This overlap also accounts for faults in the circuit breakers. To provide this overlap additional CTs are required.

4.4 Necessity of Speed in Relaying

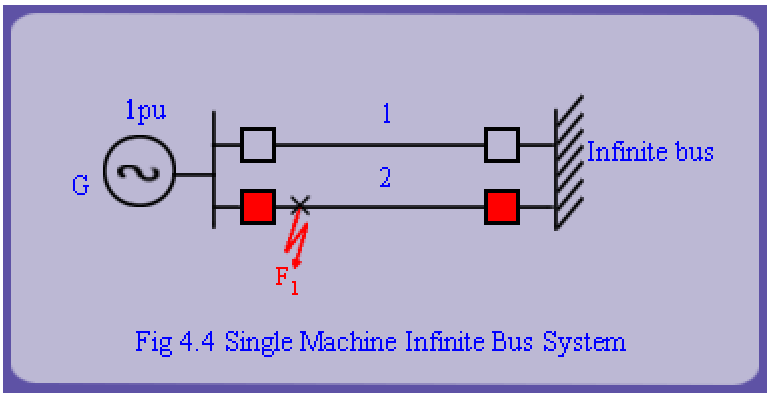

Fig 4.4 Single Machine Infinite Bus System

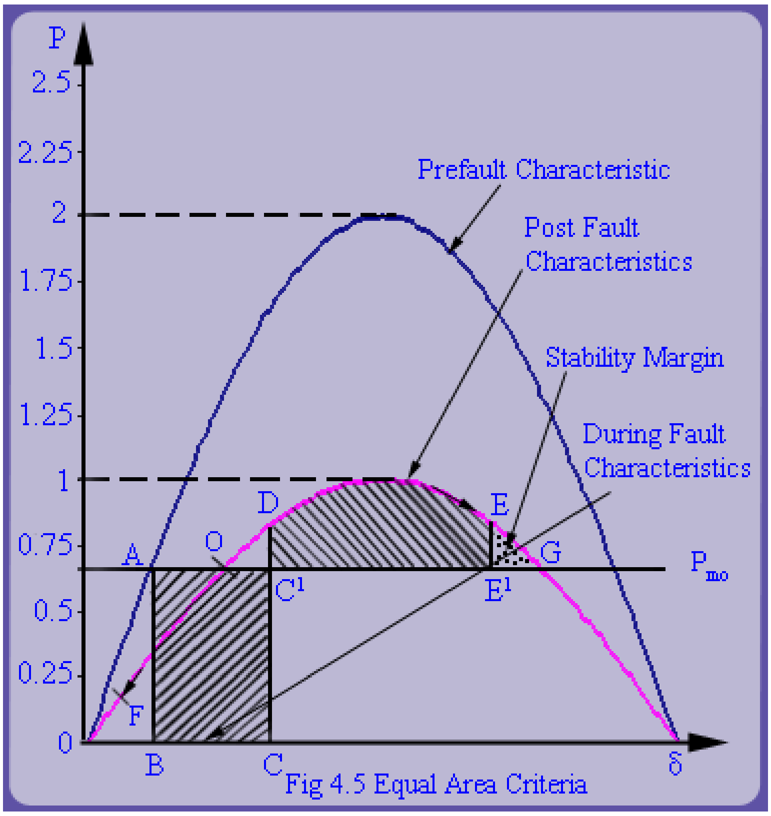

Fig 4.5 Equal Area Criteria

To maximize safety, and minimize equipment damage and system instability, a fault should be cleared as quickly as possible. This implies that relay should quickly arrive at a decision and circuit breaker operation should be fast enough. Typically, a fast circuit breaker would operate in about two cycles. A reasonable time estimate for ascertaining presence of fault is one cycle. This implies approximately three cycle fault clearing time for primary protection. On the other hand, if five cycle circuit breaker is used, fault clearing time increases to six cycles. So long as short circuit fault exist in a transmission system, the electrical output of generator remains below the mechanical input. If a bolted three phase fault occurs close to generator terminal (fig 4.4), $P_e = 0$. Thus, as per equation (1) with input P_m; the generator accelerates.

$$2H\frac{d^2\delta}{dt^2} - P_m - P_e \qquad \text{--- (1)}$$

Fig 4.5 shows the pre and post fault characteristics for the single machine infinite bus system shown in fig 4.4. Initial operating point A is on the pre fault characteristic. Occurrence of fault reduces P_e to 0. The power generation imbalance accelerates generator and hence its δ (power angle) increases. At point C the fault is cleared by tripping the faulted line and the system moves to post fault characteristics. The power output jumps to point D. Now $P_e > P_m$ and the machine decelerates.

At point E, $\Delta w=w-w_0$ is equal to zero and the extreme point of swing is reached. As $P_e > P_m$, the deceleration continues and hence the rotor starts retarding. At point O, $P_e = P_m$ the acceleration is zero, but machine speed is lower than nominal speed $w_0(2\pi f_0)$. Consequently, the angle δ continues to fall back.

However, as δ reduces further, P_e also reduces, therefore $P_m - P_e > 0$ and the generator starts accelerating. This arrests the drop in δ at point F and the swing reverses, again a consequence of acceleration. In absence of damping, these oscillations will recur just like oscillation of a simple pendulum. However, because of damping provided by generator, the oscillations reduce in magnitude and finally system settles to equilibrium at point O.

It should be obvious that interval BC is dependent on fault clearing time of the protection system. The shaded area ABCC^1 is the acceleration area and area C^{1}DEE^1 the deceleration area. As per equal area criteria, the post fault system reaches stable equilibrium if accelerating area equals to the decelerating area. The limit point for deceleration is defined by point G the intersection point of P_{m0} and the post fault characteristic.

If the swing of generator exceeds beyond point G, the generator moves from deceleration to acceleration region. Then, its angle δ continues to rise indefinitely, and the machine is said to go out-of-step. If any machine goes out-of-step with rest of system it has to be islanded. Out-of-step condition in a multi machine system can be simulated by transient stability program. Detection in real-time is a much more challenging task and it is dealt by 'out-of-step relaying' schemes. When a multi machine system is islanded in to different sub-systems, then for stable operation of each sub-system, it is necessary that each sub-system should have generation load balance (Fig 4.6).

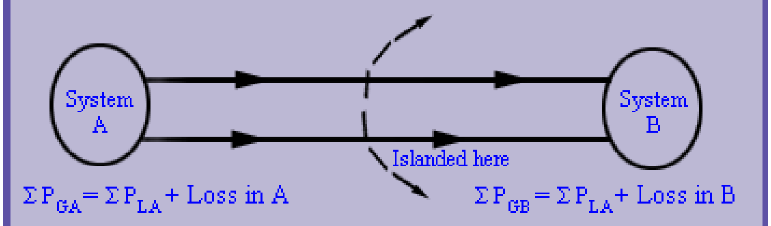

Fig 4.6 System Islanding

However it should be obvious by now that from the stability perspective, transmission system protection should be made as fast as possible. As the fault clearing time increases, the stability margin (area EE^{1}G) reduces. The fault clearing time at which the stability margin reduces to zero is called the critical clearing time.

4.4.1 Speed Vs. Accuracy Conflict

Intuition tells us that quickness is an invitation to disaster. The possible consequences of quick tripping decisions are:

- Nuisance Tripping
- Tripping for faults outside the relay jurisdiction.

Nuisance tripping is the tripping when there is no fault, e.g. an overcurrent relay tripping on load. It compromises faith in the relaying system due to unnecessary loss of service. On the other hand, tripping on faults that are outside the relay's jurisdiction also cause an unwarranted loss of service in the healthy parts of the system.

It has to be mentioned that speed and accuracy bear an inverse relationship. The high-speed systems tend to be less accurate for the simple reason that a high speed system has lesser amount of information available at it's disposal for making decision.

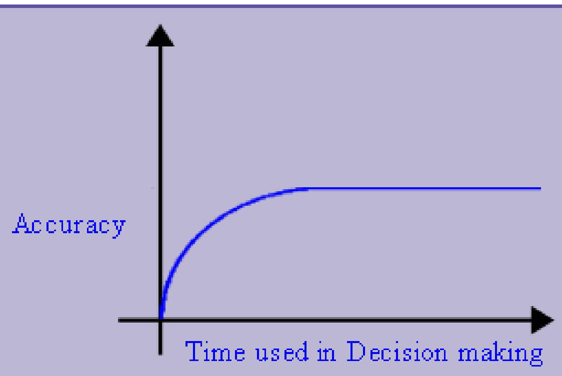

Fig 4.7 Conceptual illustration of Speed Vs. Accuracy Conflict

Thus, the protection engineer has to strike a balance between these two incompatible requirements. Innovations in protection are essentially driven by such requirements.