KWAME NKRUMAH UNIVERSITY OF SCIENCE AND TECHNOLOGY

College of Engineering

FACULTY OF ELECTRICAL AND COMPUTER ENGINEERING

Department of Electrical and Electronic Engineering

MPHIL ELECTRICAL POWER SYSTEMS ENGINEERING

EE 559 – Protection of Power Systems (3 2 4)

By:

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COURSE CONTENT

Fault Analysis: Calculation of power system currents and voltages during faults;
Protection Fundamentals.
Instrument transformers and metering devices, Fuses.
Overcurrent protection: relay types, operating characteristics and equations, grading, applications.
Differential protection: voltage balance and circulating current schemes, biased characteristics and high impedance schemes. Applications to the protection of transformers, feeders and busbars.
Distance protection: basic principle, block average comparator, zones of protection, residual compensation, power swing blocking.
Generator and Motor Protection, System grounding;
Digital protection: relay hardware. Digital signal processing in protection relays. Digital distance protection. Digital differential protection.

LEARNING OUTCOMES

After completing this module, students should be able to:

(i) divide a power system network into manageable units suitable for protection;
(ii) design a non-unit protection scheme for distribution feeders and determine appropriate relay settings;
(iii) design unit protection schemes;
(iv) explain the characteristics and limitations of protection primary transducers;
(v) design a distance protection scheme for transmission line circuits;
(vi) explain the design and operation of digital transmission line protection.

READING LIST

1. Paithankar Y.G. and Bhide S.R.: *Fundamentals of Power System Protection*, PHI learning, 2010, ISBN 8120341236, 9788120341234.
2. Ram B. and Vishwakarma D. N.: *Power System Protection and Switchgear*, Tata McGraw-Hill Education, April 2001.
3. Christopoulos C., Wright A.: *Electrical Power System Protection*, Springer 1999, ISBN 10: 0412817608 /13: 9780412817601.
4. Anderson P.M.: *Power System Protection*, Wiley-IEEE Press, 1998, ISBN: 978-0-7803-3427-4.
5. Ibrahim M.A.: *Disturbance Analysis for Power Systems*, Wiley-IEEE, November 2011, ISBN: 978-0-470-91681-0

CHAPTER 1 – FUNDAMENTALS OF PROTECTION

1.1 Introduction

The purpose of electric power systems is to generate and supply electrical energy to consumers. The power system should be designed and managed to deliver this energy to the utilization points in a reliable and economic manner. The capital investment involved in generation, transmission and distribution is so great that the proper precautions must be taken to ensure that equipment not only operate as nearly as possible to peak efficiency, but also must be protected from damage. Equipment damages may result in huge financial losses to utility companies. Some power equipment cost several millions of dollars and their destruction has huge financial implications. Furthermore outage due to failure of power system causes severe damage to economic activities and inconvenience to people's daily life.

Protection of power system equipment is critical in the operation of power systems. All power equipment including generators, transformers, transmission lines, reactors, capacitors, loads, etc need protection. Protection is necessitated by all kinds of contingencies such as insulation deterioration or failure, lightning strike, short-circuits, open-circuits, inappropriate operation of power system and other inadvertent incidences. Any abnormal operating state of a power system is known as fault. Faults can be categorised into short-circuits and open-circuits. Open-circuit faults are less frequent than short-circuit faults. Short circuits are of far greater concern than open-circuits, although some open-circuits present some potential hazards to personnel. The consequences of faults include:

- Damage to the equipment due to abnormally large and unbalanced currents and low voltages produced by the short circuits.
- Explosions in equipment which have insulating oil, particularly during short circuits. This may result in fire and hazardous conditions to personnel and equipment.
- Individual generators with reduced voltage in a power station or a group of generators operating at low voltage may lead to loss of synchronism and possible system collapse.
- Risk of synchronous motors in large industrial premises falling out of step and tripping out.
- Danger to operating personnel

1.2 Basic components of protection systems

Protection systems employ a number of components to ensure effective operation. These include:

(a) *Relays*: They sense faults using signals such as current and voltage magnitudes and initiate tripping action to disconnect faulted equipment or section(s) of the power system.

(b) *Current and Voltage transformers*: The step down the actual high currents and voltages that exist in power systems to levels which can be used by relays.

(c) *Circuit breakers*: They disconnected/reconnect equipment or sections of a system based on instructions from relays.

(d) *Fuses*: These are mostly employed in low voltage and in some medium voltage systems. They interrupt fault currents. Fuses are self-acting; they do not need any instruction to operate.

(e) *Batteries*: The operation of relays and circuit breakers require uninterrupted power supply which cannot be guaranteed by that of the grid which itself is being protected. Such a supply is therefore provided by batteries.

1.3 Zones and types of protection system

Electric power systems are usually divided into several zones of protection. Each zone of protection contains one or more components of a power system in addition to two circuit breakers (one breaker is mostly used for radial systems). The circuit breakers are inserted between the component of the zone and the rest of the power system. Thus, the location of the circuit breaker helps to define the boundaries of the zones of protection. When a fault occurs within the boundary of a particular zone, then the protection system responsible for the protection of the zone acts to isolate (by tripping the circuit breakers) equipment within that zone from the rest of the system.

Different neighbouring zones of protection are made to overlap each other, which ensure that no part of the power system remains without protection. However, occurrence of a fault within an overlapped region will initiate a tripping sequence of different circuit breakers so that the minimum necessary to disconnect the faulty element.

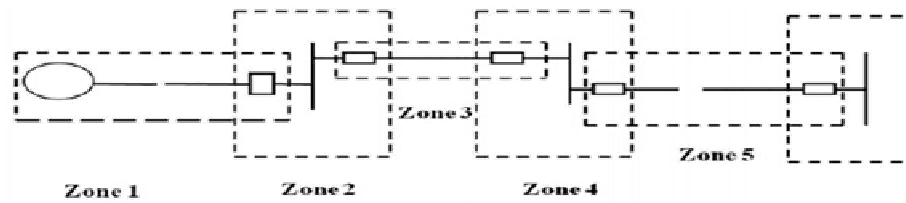


Figure 1.1: Zones of protection

1.3.1 *Types of Protection (Primary and Back-up Protection)*

There is always some possibility of failure of one part of a protection system. For this reason, it is usual to deploy multiple protection schemes for a given protection zone. The protection provided by a protective system can be categorized into two types namely: *Primary protection* and *Secondary or Backup protection*.

(a) *Primary protection*

The primary protection scheme ensures fast and selective clearing of any fault within the boundaries of the zone of protection. Primary Protection as a rule is provided for each section of an electrical installation. However, the primary protection can fail. The primary causes of failure of the Primary Protection system are enumerated below.

- Failure of CTs or PTs operation
- Failure in relay operating current or voltage
- Failure of main protective relay operation
- Failure of DC supply to the tripping Circuit
- Failure in circuit breaker tripping mechanism
- Failure in the wiring of relaying system

(b) *Back-up or Secondary protection*

Back-up or secondary protection is the name given to a scheme that provides the needed protection when the primary protection fails. It is the second line of defence after the primary protection system fails. Back-up protection by definition is slower than the primary protection system. The design of a back-up protection needs to be coordinated with the design of the primary protection.

As a measure of economy, back-up protection is given against short-circuit protection and generally not for other abnormal conditions. The extent to which back-up protection is provided, depends upon economic and technical considerations. The cost of back-up protection is justified on the basis of probability of failure of individual component in protection system, cost of the protected equipment, importance of protected equipment, location of protected equipment, etc.

Advantages of Back-up Protection

Back-up protection is provided for the following reasons:

- If due to some reason, the primary protection fails, the back-up protection serves the purpose of protection.
- When primary protection is made inoperative for the purpose of maintenance, testing, etc. the back-up protection acts like primary protection.

The following are types of back-up protection:

(a) *Relay backup protection*

Same breaker is used by both primary (main) and back-up protection, but the protective systems are different. Separate trip coils may be provided for the same breaker.

(b) *Breaker backup protection*

Different breakers are provided for main and back-up protection, both breakers being in the same station.

(c) *Remote backup protection*

The main and back-up protections are provided at different stations and are completely independent.

(d) *Centrally co-ordinate backup protection*

A system having central control can be provided with centrally controlled back-up. Central control continuously supervises the load flow and frequency in the system. The information about load flow and frequency is assessed continuously. If one of the components in any part of the-system fails, (e.g. a fault on a transformer, in some station) the load flow in the system is affected. The central coordinating station receives information about the abnormal condition through high frequency carrier signals. The stored programme in the digital computer determines the correct switching operation, as regards severity of fault, system stability,

1.4 Fundamental requirements of protection systems

The fundamental requirements for a protection system are as follows:

(a) *Reliability*

It is the ability of the protection system to operate correctly. The reliability feature has two basic elements, which are dependability and security. The dependability feature demands the certainty of a correct operation of the designed system, on occurrence of any fault. Similarly, the security feature can be defined as the ability of the designed system to avoid incorrect operation during faults. A comprehensive statistical method based reliability study is required before the protection system may be commissioned. The factors which affect this feature of any protection system depends on the following:

- quality of components used,
- maintenance schedule,
- the supply and availability of spare parts,
- design principle, and
- the electrical and mechanical stress to which the protected part of the system is subjected to.

(b) *Speed*

Minimum fault clearing is desired to avert the dangers associated with faults. The speed of the protection system consists primarily of two time intervals of interest:

(i) *The Relay Time*

This is the time between the instant of occurrence of the fault to the instant at which the relay contacts close.

(ii) *The Breaker Time*:

This is the time between the instant of closing of relay contacts to the instant of final arc extinction inside the medium, and removal of the fault.

(c) *Selectivity*

This feature aims at maintaining the continuity of a supply system by disconnecting the minimum section of the network necessary to isolate the fault. The property of selective tripping is also known as “discrimination”. This is the reason for which the entire system is divided into several protective zones so that minimum portion of the network is isolated with accuracy. Two examples of utilization of this feature in a relaying scheme are time graded systems and unit systems.

(d) *Sensitivity*

The sensitivity of a relay refers to the smallest value of the actuating quantity at which the relay operates detecting any abnormal condition. In case of an overcurrent relay, mathematically this can be defined as the ratio between the short circuit fault current and the relay operating current. The value of the relay operating current, should not be too small or large so that the relay is either too sensitive or slow in responding.

(e) *Stability*

It is the quality of any protection system to remain in operation within a set of defined operating scenarios and procedures. For example the biased differential scheme of differential protection is more stable towards switching transients compared to the more simple and basic Merz Price scheme in differential protection.

CHAPTER 2 - INSTRUMENT TRANSFORMERS AND METERING DEVICES

2.1 Introduction

Instrument transformers (ITs) are designed to transform voltage or current from the high values in the transmission and distribution systems to the low values that can be utilized by low voltage metering devices. There are three primary applications for which ITs are used: metering (for energy billing and transaction purposes); protection control (for system protection and protective relaying purposes); and load survey (for economic management of industrial loads).

Depending on the requirements for those applications, the IT design and construction can be quite different. Generally, the metering ITs require high accuracy in the range of normal operating voltage and current. Protection ITs require linearity in a wide range of voltages and currents. During a disturbance, such as system fault or overvoltage transients, the output of the IT is used by a protective relay to initiate an appropriate action (*open or close a breaker, reconfigure the system, etc.*) to mitigate the disturbance and protect the rest of the power system. Instrument transformers are the most common and economic way to detect a disturbance. Typical output levels of instrument transformers are 1-5 amperes and 115-120 volts for CTs and VTs, respectively. There are several classes of accuracy for instrument transformers defined by the IEEE, CSA, IEC, and ANSI standards. Grounding of the secondary circuit is most important, but in complicated three-phase connections, the best point to ground is not always easily determined.

A - CURRENT TRANSFORMERS

2.2 CT burden

The burden of a CT is the maximum load (in ohms or VA) that can be applied to the CT secondary. The CT burden equals the sum of the VA's (or ohms) of all the loads (relays, ammeters, wattmeter, transducer, etc.) connected in series to the CT secondary circuit plus the CT secondary circuit cable VA (or ohms). The applied CT secondary circuit burden should not be more than the rated burden. If the load is less than the CT burden, all meters connected to the measuring CT should provide correct readings.

2.2.1 *Resistance of a conductor*

The resistance of a conductor can be calculated from the equation:

$$R = \frac{\rho l}{A} \tag{1}$$

where ρ is resistivity of the conductor material (given typically at +20°C), *l* is length of the conductor, and *A is* cross-sectional area.

If the resistivity is given in $\mu\Omega m$, the length in *m* and the area in mm^2, then (1) will give the resistance directly in ohms. The resistivity and temperature coefficient for copper are given in Table 2.1

Table 2.1 Resistivity and Temperature coefficient of copper

Material	Resistivity at +20°C ($\mu\Omega m$)	Resistivity at +75°C ($\mu\Omega m$)	Temperature coefficient (K^{-1})
Copper	0.0178	0.0216	0.0039

2.2.2 ***Resistance at higher temperatures***

The resistance of conductors is temperature-dependent: when the temperature rises, the resistance will increase. Therefore, the resistance of a conductor should be calculated at the worst-case temperature. Normally, +75°C is used for calculations. For pure metals like copper and aluminium, the dependence is almost linear in quite a wide temperature range (i.e. -50 to +200°C). Resistance R_2, at a new temperature T_2 is calculated as follows:

$$R_2 = R_1 \times [1 + \alpha(T_2 - T_1)] \qquad (2)$$

where R_1 is the resistance at temperature T_1, α is the temperature coefficient of the conductor, and T_1, T_2 are the temperatures in Kelvin (20°C = 293.15K)

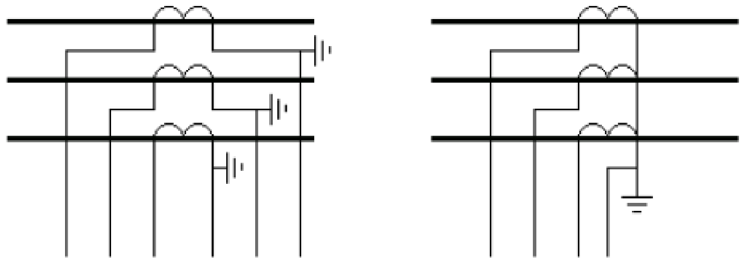
The resistance per cable length at +75°C for copper is given in the Table 2.2

Table 2.2 Resistance per cable length (at +75°C) for copper

Material	2.5mm² (Ω/m)	4mm² (Ω/m)	6mm² (Ω/m)
Copper	0.00865	0.00541	0.00360

2.2.3 ***Cable length for 4-wire and 6-wire connections***

CTs are usually connected in groups of three to form star connections as shown in Figure 2.1.



(a) (b)

Figure 2.1: Six-wire and four-wire connection of CTs

If 6-wire connection is used as in Figure 2.1 (a), the total length of the wire is two times the distance between the CT and the relay. However, in many cases, a common return conductor is used as in Figure 2.1 (b). For the 4-wire connection, instead of multiplying the distance by two, a factor of 1.2 is typically used. For example, if the distance between the CT and the relay is 5 metres, the total length of wire is $2 \times 5 = 10m$ for 6-wire connection, but only $1.2 \times 5 = 6m$ when 4-wire connection is used.

2.2.4 ***Burden of the relay and other devices***

The CT burden impedance decreases as the secondary current increases**,** because of saturation in the magnetic circuits of relays and other devices. Hence, a given burden may apply only for a particular value of secondary current. The burden (or input impedance) of relay and other devices must be checked from the manufacturer's manual (user's manual or technical data). The indicated burdens are input-current specific. In others words, the device burden for a 1A input current is different for a 5A input current. If the rated burden for secondary input current I_1 is Z_1, then the new burden, Z_2 for a new secondary current I_2 is given as:

$$Z_2 = Z_1 \times \left(\frac{I_1}{I_2}\right)^2 \qquad (3)$$

Example 2.1

The rated impedance of a CT at the 1A tap is $(1.47 + j5.34)\Omega$. What is the rated impedance when burdens are to be connected at the 4A tap?

Solution

$$Z_2 = Z_1 \times \left(\frac{I_1}{I_2}\right)^2 = (1.47 + j5.34) \times \left(\frac{1}{4}\right)^2 = 0.0919 + j0.3338$$

Example 2.2

The distance between the CTs and a protection relay is 15 metres. 4 mm^2 Copper conductors in 4-wire connection are used. The burden of the relay input is less than $20m\Omega$ (5A input). Calculate the actual burden of the CT at 75^{o}C.

Solution

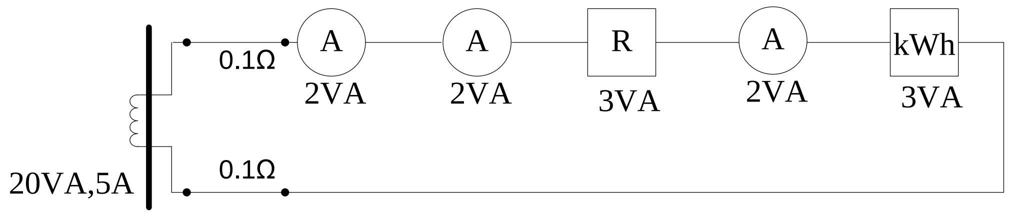
$\rho = 0.0216\mu\Omega m$ (75^{o}C)

$$R = \frac{\rho l}{A} = \frac{0.0216 \times (1.2 \times 15)}{4} = 0.097\Omega$$

Burden of CT $= 0.097 + 0.020 = 0.117\Omega$

Example 2.3

Decide whether 5A, 20VA CT is sufficient for the following circuit.



Solution

Total instrument burden $= 2 + 2 + 3 + 2 + 4 = 13VA$.

Total pilot load resistance $= 2 \times 0.1 = 0.2\Omega$.

With 5A secondary current, volt-drop in leads is $5 \times 0.2 = 1V$.

Burden imposed by both leads $5 \times 1 = 5VA$.

Total burden on CT = 13 + 5 = 18V A.

As the CT is rated 20V A, it has sufficient margin.

2.3 **Errors in Current transformers**

Figure 2.2 shows the equivalent circuit of a current transformer.

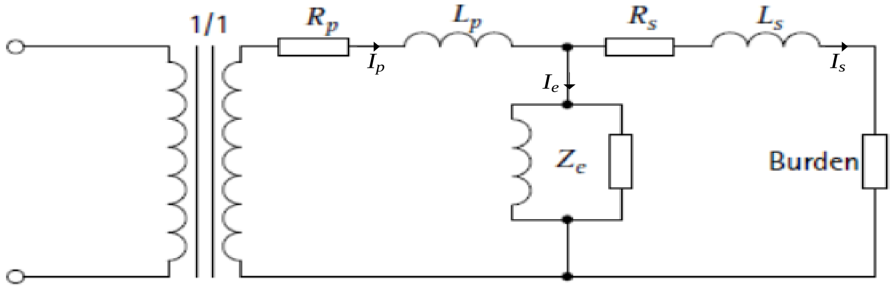


Figure 2.2: Equivalent circuit of CT with all values referred to secondary

It is noted from Figure 2.2 that that secondary current is not equal to the transformed primary current. Errors arise because of the shunting of the burden by the exciting impedance. This uses a small portion of the input current for exciting the core thereby reducing the current passed to the burden. Figure 2.3 shows the vector diagram for a current transformer.

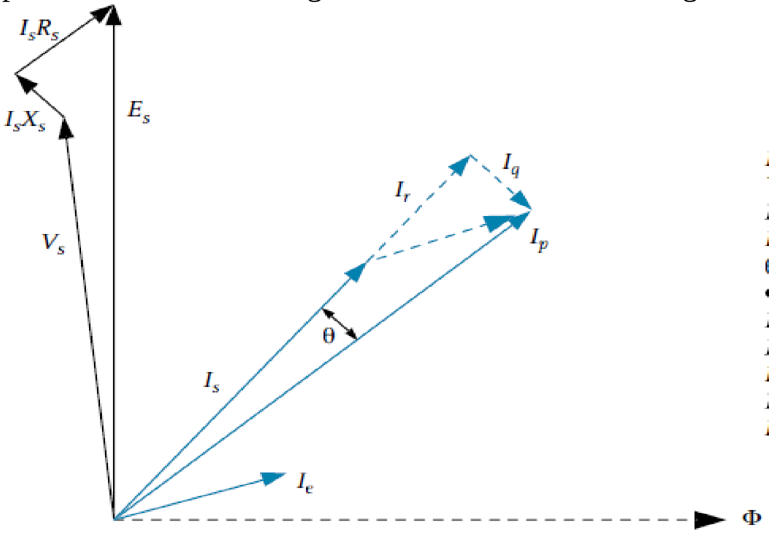


Figure 2.3: CT vector diagram

The following errors exist in current transformers:

(a) *Current or ratio error*

This is the difference in magnitude between I_p and I_S, and is equal to I_r, the component of I_e which is in phase with I_s.

(b) *Phase error*

Phase error is the difference in phase between the primary and secondary current vectors. The phase displacement is said to be positive when the secondary current vector leads the primary current vector. It is usually expressed in minutes. 1 degree equals 60 minutes and is equal to 3600 seconds (i.e. $1^O = 60' = 3600''$).

The values of the current error and phase error depend on the phase displacement between I_s and I_e, but neither current nor phase error can exceed the vectorial error I_e. For a moderately inductive burden which results in I_s and I_e being approximately in phase, there will be little phase error, and the exciting component will result almost entirely in ratio error. A reduction of the secondary winding by one or two turns is often used to compensate for this.

(c) *Composite error*

This is defined in IEC 60044-1 as the *rms* value of the difference between the ideal secondary current and the actual secondary current. It includes current and phase errors and the effects of harmonics in the exciting current.

2.3.1 **Error calculations**

The equivalent diagram in Figure 2.4 comprises all quantities necessary for error calculations. The primary internal voltage drop does not affect the exciting current, and the errors — and therefore the primary internal impedance — are not indicated in the diagram. The secondary internal impedance, however, must be taken into account, but only the winding resistance R_i. The leakage reactance is negligible where continuous ring cores and uniformly distributed secondary windings are concerned. The exciting impedance is represented by an inductive reactance in parallel with a resistance. I_q and I_r are the reactive and loss components of the exiting current, I_e. The reactive component I_q is 90 degrees out of phase with E_s and the loss component I_r is in phase with E_s.

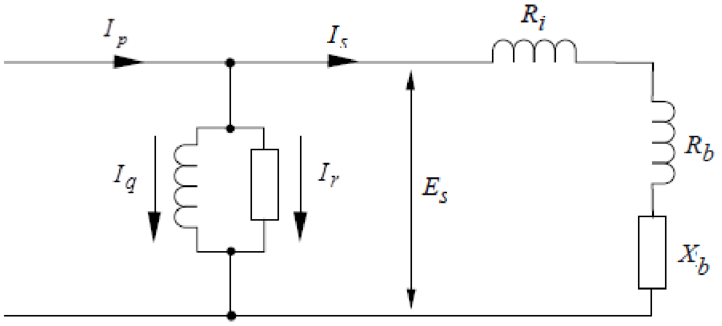


Figure 2.4: Reduced CT circuit diagram for error calculation

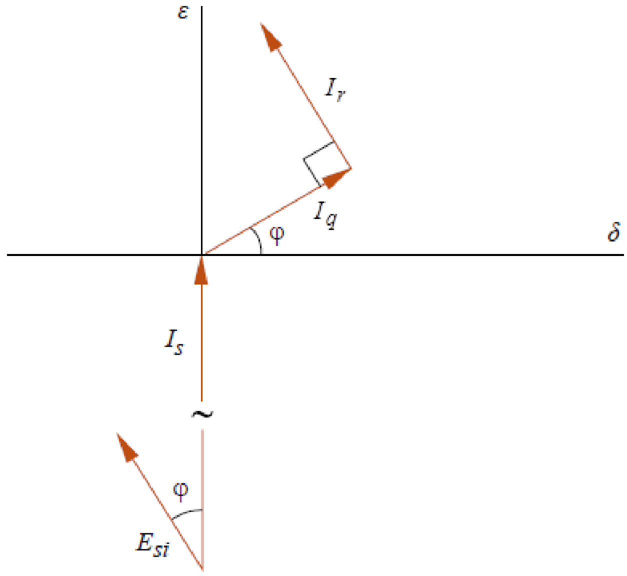


Figure 2.5: Vector diagram for CT error calculation

The error calculation is performed in the following four steps:

1. The secondary induced voltage E_s is calculated from

$$E_s = I_s Z \tag{4}$$

   where Z is the total secondary impedance. $Z = \sqrt{(R_s + R_b)^2 + X_b}$

2. The inductive flux density, B necessary for inducing the voltage E_s is calculated from

$$B = \frac{E_s}{\pi \times \sqrt{2} \times f \times A_j \times N_2} \tag{5}$$

   Where f is frequency in Hz, A_j is core area in mm^2 and N_2 is the number of secondary turns.

3. The exciting currents I_q and I_r are necessary for producing the magnetic flux B. The magnetic data for the core material in question must be known. This information is

obtained from the exciting curve showing the flux density versus the magnetizing force H. Both the reactive component, H_q and the loss component H_r must be given. When H_q and H_r are obtained from the curve, I_q and I_r can be calculated using the following equations:

$$I_q = H_q \times \frac{L_j}{N_2} \tag{6}$$

$$I_r = H_r \times \frac{L_j}{N_2} \tag{7}$$

where L_j is the magnetic path length in cm and N_2 is the number of secondary turns.

4. The vector diagram of Figure 2.5 is then used to determine the errors.

2.3.2 *Variation of errors with current*

If the errors are calculated at two different primary currents and with the same burden, it will appear that the errors are different for the two currents. The reason for this is the non-linear characteristic of the exciting curve. If a linear characteristic is supposed, the errors would remain constant. This is illustrated in Figure 2.6. The dashed lines apply to only the linear case. Figure 2.6(b) shows that the error decreases when the current increases. This goes on until the current and the flux have reached a value (point 3) where the core starts to saturate. A further increase of current will result in a rapid increase of the error. At a certain current I_{ps}(4), the error reaches a limit stated in the current transformer standards.

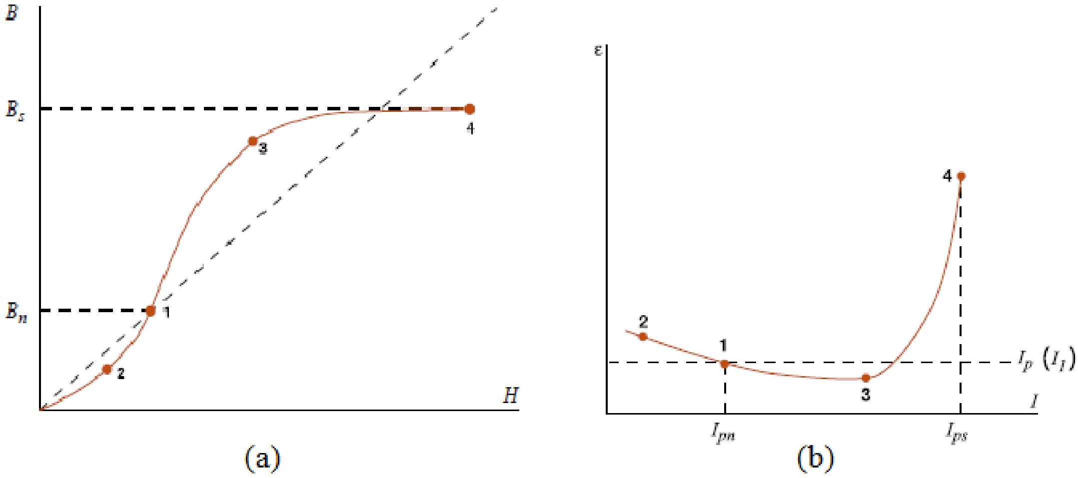


Figure 2.6: Relationship between CT error and current

I_{ps} is called the instrument security current for a measuring transformer and accuracy limit current for a protective transformer. The ratio of I_{ps} to the rated primary current I_{pn} (I_1) is called the Instrument Security Factor (FS) and Accuracy Limit Factor (ALF) for the measuring CT and the protective CT respectively.

2.4 Accuracy limit factor

The rated accuracy limit factor is the ratio of the rated accuracy limit primary current to the rated primary current. A protective current transformer type 5P10 has, for example, the accuracy class 5P and a rated accuracy limit factor 10. For protective current transformers, the accuracy class is determined by the highest permissible percentage composite error at the rated accuracy limit primary current specified for the accuracy class concerned, followed by the letter “P” (referring to protection). The CT accuracy primary limit current defines the highest fault current magnitude at which the CT will meet the specified accuracy. Beyond this level, the secondary current of the CT will be distorted, and this may have severe effects on the performance of the protection relay. In practise, the actual accuracy limit factor differs from the rated accuracy limit factor and is proportional to the ratio of the rated CT burden and the actual CT burden.

For the reliable and correct operation of the protection relays, the current transformer (CT) has to be carefully chosen. The distortion of the secondary current of a saturated CT may endanger the operation, selectivity and co-ordination of the protection. A correctly selected CT, on the other hand, enables fast and reliable protection.

Referring to Figure 2.6(b), if the primary current increases from I_{pn} to I_{ps}, the induced voltage and the flux increase at approximately the same proportion.

$$(FS)ALF = \frac{I_{ps}}{I_{pn}} \approx \frac{B_s}{B_n} \tag{8}$$

Because of the flat shape of the excitation curve in the saturated region, B_s could be looked upon as approximately constant and independent of the burden magnitude. B_n, however, is directly proportional to the burden impedance, which means that the formula above could be written as

$$(FS)ALF \approx \frac{1}{B_n} \approx \frac{1}{Z} \tag{9}$$

The formula states that the saturation factor depends on the magnitude of the burden. This factor must therefore always be related to a certain burden. If the rated saturation factor (the saturation factor at rated burden) is given, the saturation factor for other burdens can be roughly estimated from:

$$ALF \approx ALF_n \times \frac{Z_n}{Z} \tag{10}$$

Where ALF_n is rated saturation factor, Z_n is rated burden including secondary winding resistance and Z is the actual burden including secondary winding resistance.

A more accurate calculation of accuracy limit factor is presented in sub-section 2.4.1.

2.4.1 *Calculation of the actual accuracy limit factor*

The actual accuracy limit factor (*Fa*) is calculated using equation 11.

$$F_a = F_n \times \frac{S_{in} + S_n}{S_{in} + S_a} \tag{11}$$

where F_n is the rated accuracy limit factor, S_{in} is the internal burden of the CT secondary coil, S_n is the rated burden of the CT, S_a is actual burden of the CT.

In equation 11, all burdens must be in VA. VA burden can be calculated from resistance burden using the expression $S = I^2R$ by using the rated secondary current of the CT. The power factor (cosϕ) of CTs is often ignored in burden calculations.

Example 2.4

The internal secondary coil resistance of a CT is 0.07Ω, the secondary burden (including wires and relay) is 0.117 and the CT is rated 300/5, 5P20, 10VA. Calculate the actual accuracy limit factor.

Solution

$F_n = 20$(CT data for 5P20), $S_n = 10VA$(from CT data),

$$S_{in} = I^2 R = 5^2 \times 0.07 = 1.75VA$$

$$S_a = I^2 R = 5^2 \times 0.117 = 2.925VA$$

$$F_a = F_n \times \frac{S_{in} + S_n}{S_{in} + S_a} = 20 \times \frac{1.75 + 10}{1.75 + 2.925} = 50.3$$

Alternative method

There is also an alternative method for calculating F_a, that is, by first calculating the voltage on the CT secondary side, using the rated values:

$$V_{sat} = F_n \times I_n \times (R_{in} + R_n) \tag{12}$$

where F_n *is* rated accuracy limit factor, I_n is the rated secondary current of the CT, R_{in} is the internal resistance of the CT secondary coil, R_n is the rated resistance (burden) of the CT.

This voltage (secondary limiting e.m.f.) is independent of the CT burden. Thus, F_a for the actual burden can be calculated as follows:

$$F_a = \frac{V_{sat}}{I_n (R_{in} + R_a)} \tag{13}$$

where R_a is the actual resistance (burden) of the CT.

By using the values from the previous example, the solution will be:

$$V_{sat} = 20 \times 5 \times \left(0.07 + \frac{10}{5^2} \right) = 47V$$

$$F_a = \frac{47}{5 \times (0.07 + 0.117)} = 50.3$$

2.5 Performance of CTs

The performance of CTs is determined by the highest current that can be reproduced without saturation to cause large errors. Using the CT equivalent circuits and excitation curves, the following procedure can be used to determine CT performance.

Step1: Assume a CT secondary output current I_s.

Step 2: Compute the secondary voltage $E_s = I_s (Z_s + Z_b)$.

Step 3: Using E_s, find I_e from the excitation curve.

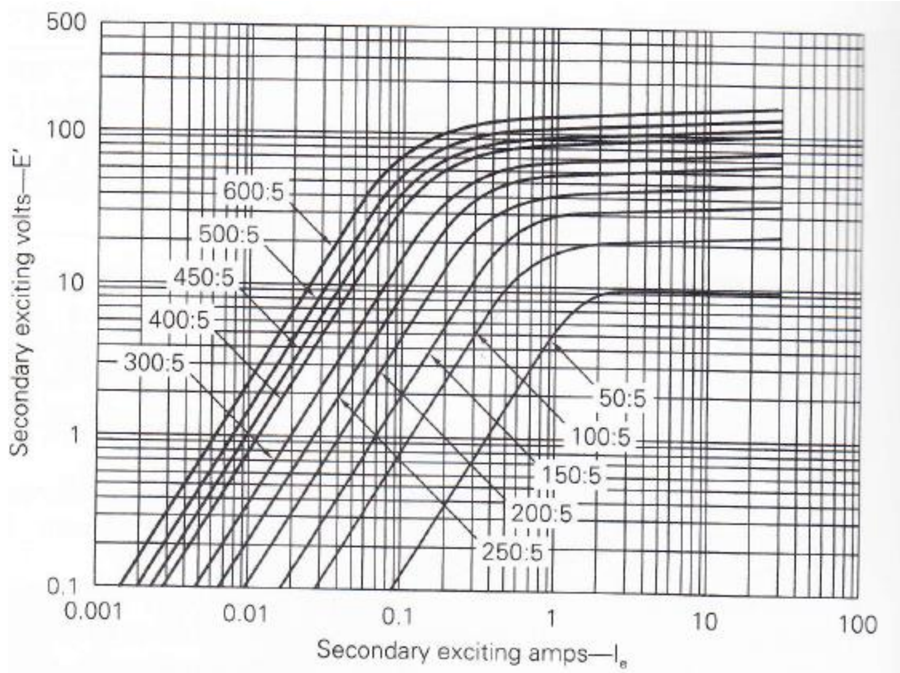
Step 4: Compute $I_p = n(I_s + I_e)$

Step 5: Repeat steps 1-4 for different values of I_s, then plot I_s versus I_p.

For simplicity, approximate computations are made with magnitudes rather than with phasors. Also, CT error is the percentage difference between $(I_s + I_e)$ and I_s, given by:

CT error $= \frac{I_e}{I_s + I_e} \times 100\%$.

Example 2.5
Evaluate the performance of the multi-ratio CT with ratio 100:5, for the following secondary output currents and burdens: (a) $I_s = 5A$ and $Z_b = 0.5\Omega$; (b) $I_s = 8A$ and $Z_b = 0.8\Omega$; and (c) $I_s = 15A$ and $Z_b = 1.5\Omega$. The excitation curve is shown in the figure below.



Solution

(a) $E_s = I_s(Z_s + Z_b) = 5(0.082 + 0.5) = 2.91V$

From the excitation curve, $I_e = 0.25A$

$I_p = n(I_s + I_e) = \frac{100}{5}(5 + 0.25) = 105A$

CT error $= \frac{0.25}{5 + 0.25} \times 100\% = 4.8\%$

(b) $E_s = I_s(Z_s + Z_b) = 8(0.082 + 0.8) = 7.06V$

From the excitation curve, $I_e = 0.4A$

$I_p = n(I_s + I_e) = \frac{100}{5}(8 + 0.4) = 168A$

CT error $= \frac{0.4}{8 + 0.4} \times 100\% = 4.8\%$

(c) $E_s = I_s(Z_s + Z_b) = 15(0.082 + 1.5) = 23.73V$

From the excitation curve, $I_e = 20A$

$I_p = n(I_s + I_e) = \frac{100}{5}(15 + 20) = 700A$

CT error $= \frac{20}{15 + 20} \times 100\% = 57.1\%$

Note that for the 15A secondary current in (c), high CT saturation causes a large CT error of 57.1%. Standard practice is to select a CT ratio to give a little less than 5A secondary current at maximum normal load. From (a), the 100:5 CT ratio and 0.5 ohm burden are suitable for a maximum primary load current of 100A.

Example 2.6

An overcurrent relay set to operate at 8A is connected to a CT with a ratio of 100:5. Will the relay detect a 200A primary fault current if the burden is (a) 0.8Ω and (b) 3.0Ω?

Solution

Primary current corresponding to 8A set relay current $=\frac{100}{5}\times 8 = 160A$.

(a) $E_S = I_S(Z_S + Z_b) = 8(0.082 + 0.8) = 7.06V$

From the excitation curve, $I_e = 0.4A$

$I_p = n(I_S + I_e) = \frac{100}{5}(8 + 0.4) = 168A$

With a 0.8Ω burden, the minimum primary current that causes the relay to operate is 168A. The relay will therefore operate for the 200A fault current.

(b) $E_S = I_S(Z_S + Z_b) = 8(0.082 + 3) = 24.66V$

From the excitation curve, $I_e = 30A$

$I_p = n(I_S + I_e) = \frac{100}{5}(8 + 30) = 760A$

With a 3.0Ω burden, 760A is the lowest primary current that causes the relay to operate. Therefore, the relay will not operate for the 200A fault current.

2.6 **Classification of CTs**

To guarantee correct operation, current transformers (CTs) must be able to correctly reproduce the current for a minimum time before saturation begins. To fulfil the requirement on a specified time to saturation, the CTs must fulfil the requirements of a minimum secondary e.m.f. There are several different ways to specify CTs. Conventional magnetic core CTs are usually specified and manufactured according to some international or national standards, which specify different protection classes as well. There are many different standards and a lot of classes but fundamentally there are three different types of CTs:

(a) *High remanence type CT*

The high remanence type has no limit for the remanent flux. This CT has a magnetic core without any air gap and a remanent flux might remain for almost infinite time. In this type of transformers, the remanence can be up to around 80 % of the saturation flux. Typical examples of high remanence type CT are class P, PX, TPS, TPX according to IEC (*International Electrotechnical Commission*) and non-gapped class C, T and X according to ANSI/IEEE (*American National Standards Institute/Institute of Electrical and Electronic Engineers*).

(b) *Low remanence type CT*

The low remanence type has a specified limit for the remanent flux. This CT is made with a small air gap to reduce the remanence to a level that does not exceed 10% of the saturation flux. The small air gap has only very limited influences on the other properties of the CT. Class PR, TPY according to IEC are low remanence type CTs.

(c) *Non-remanence type CT*

The non-remanence type CT has practically negligible level of remanent flux. This type of CT has relatively big air gaps in order to reduce the remanence to practically zero level. At the same time, these air gaps reduce the influence of the DC-component from the primary fault current. The air gaps will also decrease the measuring accuracy in the non-saturated region of operation. Class TPZ according to IEC is a non-remanence type CT.

2.7 **Selection of CTs**

The key factors considered in the selection of current transformers are:

(a) Standard (IEC, IEEE or National)
(b) Rated insulation level (service voltage)
(c) Altitude above sea level (if >1000 m)
(d) Ambient temperature (daily temperature or average over 24 hours)
(e) Rated primary current
(f) Rating factor (maximum continuous current)
(g) Rated secondary current
(h) Short-time current
(i) Dynamic current
(j) Number of cores
(k) Burdens (outputs) and accuracies for each core
(l) Pollution level (creepage distance)

2.7.1 ***Rated insulation level***

The current transformer must withstand the operational voltage and overvoltages in the network. Test voltages are specified in the standards in relation to the system voltage. These tests shall show the ability of a current transformer to withstand the overvoltages that can occur in the network. The lightning impulse test is performed with a wave shape of 1.2/50 μs and simulates a lightning overvoltage. For current transformers with a system voltage of 300 kV and more, the switching impulse test is performed with a wave shape of 250/2500 μs simulating switching overvoltages. It is performed as a wet test. For voltages below 300 kV, a wet power frequency test is performed instead.

The dielectric strength of air decreases as altitude increases. Consequently, for installation at an altitude higher than 1000 m above sea level, the external insulation (arcing distance) of the transformer has to be adapted to the actual site altitude. It is important to note that as far as the internal insulation is concerned, the dielectric strength is not affected by altitude. According to IEC 61869-1, the arcing distance under the standardized atmospheric conditions is determined by multiplying the withstand voltages required at the service location by a factor *k*.

$$k = e^{m(H-1000)/8150} \qquad (14)$$

where H is the altitude above sea level in meters, m is 1 for power frequency and lightning impulse voltage and 0.75 for switching impulse voltage.

According to IEEE, dielectric strength that depends on air should be multiplied by an altitude correction factor (ACF) to obtain the dielectric strength at the required altitude, according to Table 2.3

Table 2.3: Altitude above sea level (ASL) and Altitude correct factor (ACF)

ASL (m)	1000	1200	1500	1800	2100	2400	2700	3000	3600	4200	4500
ACF	1.00	0.98	0.95	0.92	0.89	0.86	0.83	0.80	0.75	0.70	0.67

Refer to IEC 61869-1 to IEEE C57.13-2008 for rated insulation levels.

2.7.2 ***Rated primary current***

The current transformer must also withstand the rated primary current in continuous operation. Here, the average ambient temperature must be taken into account, if there is a deviation from the standard. Current transformers are normally designed according to IEC 60044-1 and IEEE C57.13 standards, i.e. for 35 ºC (or 30 ºC) average ambient air temperature.

The primary rated current should be selected to be approximately 10% - 40% higher than the estimated operating current, which gives a high resolution on the metering equipment and instruments. The closest standard value, decimal multiples of 10, 12.5, 15, 20, 25, 30, 40, 50, 60 or 75 A, should be chosen.

In order to obtain several current ratios, current transformers can be designed with either primary or secondary reconnection or a combination of both.

Primary reconnection

A usual way to change ratio is to have two separated primary windings, which can be connected, either in series or in parallel. The advantage is that the number of ampere-turns will be identical at all different ratios. Thus, output and class will also be identical at all current ratios. The most usual design is with two different ratios, in relation 2:1, but three current ratios in relation 4:2:1 are also available. However, as the short-time withstand current will be reduced when the primary windings are connected in series compared to the parallel connected winding, the short-circuit capability is reduced for the lower ratios.

Secondary reconnection

For high rated currents and high short-time currents (> 40 kA) normally only one primary turn is used. Reconnection is made with extra secondary terminals (taps) taken out from the secondary winding. In this case, the number of ampere-turns and also the output will be reduced at the taps, but the short-circuit capacity remains constant. The accuracy rating applies to the full secondary winding, unless otherwise specified.

IEC 60044-1, IEEE C57.13

Combinations of reconnections both at the primary and the secondary side are also possible, providing several different ratios with few secondary taps.

Table 2.5: Multiple current ratings and secondary taps for a 600:5 CT (Multi-ratio IEEE C57.13-2008)

Current ratings(A)	50:5	100:5	150:5	200:5	250:5	300:5	400:5	450:5	500:5	600:5
Secondary	X2-	X1-	X1-	X4-	X3-	X2-	X1-	X3-	X2-	X1-

taps	X3	X2	X3	X5	X4	X4	X4	X5	X5	X5

2.7.3 *Rated continuous thermal current*

The continuous rated thermal current is the current which can be permitted to flow continuously in the primary winding without the temperature rise exceeding the values stipulated in the standards. Unless otherwise specified it is equal to the rated primary current, i.e. the rating factor is 1.0.

In applications where the actual currents are higher than the rated current, a rating factor must be specified. With a rating factor of for instance 1.2 the current transformer must withstand a continuous current of 1.2 times the rated current. The accuracy for metering cores must also be fulfilled at this current. In IEC 60044-1, it is called extended current rating and has standard values of 120%, 150% and 200% of the rated primary current.

2.7.4 *Rated secondary current*

The secondary rated current can be 1 or 5 A, but there is a clear trend towards 1 A. As modern protection and metering equipment have relatively low burdens, the burdens in the cables are predominant ones. Considering the fact that the cable burden is I^2R, 1 A circuit has a cable burden 25 times lower in VA compared to a 5 A circuit. The lower burden needed for 1 A reduces the size and the cost of current transformer cores.

2.7.5 *Short-time thermal current (I_{th}) and dynamic current (I_{dyn})*

This is the maximum current, which the transformer can withstand for a period of one second, without reaching a temperature that would be disastrous to the insulation, e.g. 250 ºC for oil immersed transformers. If the short-time thermal current (I_{th}) is not specified, it can be calculated by using the formula:

$$I_{th} = \frac{S_k}{V_n\sqrt{3}} \ [kA] \qquad (14)$$

where S_k is the fault level at the point where current transformer is to be installed and V_n is the rated service voltage (line-to-line) in kV.

A current transformer is connected in series with the network and it is therefore essential to ensure that the current transformer can withstand the fault current, which may arise at its position. If the current transformer should break down, the entire associated equipment would be left unprotected, since no information will then be submitted to the protective relays. The protective equipment will be both “blind” and “deaf”. The short-time current for periods other than one second I_{st} can be calculated by using the following formula:

$$I_{st} = \frac{I_t}{\sqrt{t}} \qquad (15)$$

where t is the actual time in seconds.

The short-time thermal current has a thermal effect upon the primary winding. In the event of a short-circuit, the first current peak can reach approximately 2.5 times I_{th}. This current peak gives rise to electromagnetic forces between the turns of the primary winding and externally between the phases in the primary connections. A check should therefore be made to ensure that the current transformer is capable of withstanding the dynamic current as well as the short-time thermal current.

NOTE: It is very important to adapt requirements imposed on short-time current to a real level. Otherwise, especially at low rated currents, the low number of ampereturns must be compensated for by increasing the core volume. This will result in large and expensive current transformer cores. To increase the number of ampere-turns at lower currents with a given core size, the number of primary turns in the current transformer can be increased. As a consequence, the primary short-circuit current (I_{th}) will be lower for a higher number of primary turns. At high short-time currents and low rated currents, the number of ampere-turns will be very low and the output from the secondary side will thus be limited. Standard rms values of rated short-time thermal current (I_{th}) (expressed in kilo amperes) are: 6.3, 8, 10, 12.5, 16, 20, 25, 31.5, 40, 50, 63, 80 and 100.

Dynamic peak current (I_{dyn}) values are: IEC 50Hz - $2.5I_{th}$; IEC 60Hz - $2.6I_{th}$; ANSI/IEEE 60Hz

2.7.6 *Burden and accuracy*

In practice all current transformer cores should be specially adapted for their application for each station.

(a) Measurement of current

The output required from a current transformer depends on the application and the type of load connected to it:

- Metering equipment or instruments, like kW, kVar, A instruments or kWh or kVArh meters, are to measure under normal load conditions. These metering cores require high accuracy, a low burden (output) and a low saturation voltage. They operate in the range of 5-120% of rated current according to accuracy classes: - 0.2 or 0.5 for IEC, - 0.15 or 0.3 or 0.6 for IEEE
- For protection relays and disturbance recorders, information about a primary disturbance must be transferred to the secondary side. Measurement at fault conditions in the overcurrent range requires lower accuracy, but a high capability to transform high fault currents to allow protection relays to measure and disconnect the fault. Typical relay classes are 5P, 10P, PR, PX or TP (IEC) or C 100-800 (IEEE).

In each current transformer, a number of different cores can be combined. Normally one or two cores are specified for metering purposes and two to four cores for protection purposes.

(a) Metering cores

To protect the instruments and meters from being damaged by high currents during fault conditions, a metering core must be saturated typically between 5 and 20 times the rated current. Normally, energy meters have the lowest withstand capability, typically 5 to 20 times rated current. The rated Instrument Security Factor (*FS*) indicates the overcurrent as a multiple of the rated current at which the metering core will saturate. It is thus limiting the secondary current to *FS* times the rated current. The safety of the metering equipment is greatest when the value of *FS* is small. Typical *FS* factors are 5 or 10. It is a maximum value and only valid at rated burden. At lower burdens than the rated burden, the saturation value increases approximately to *n*:

$$n \approx FS \times \frac{S_n + R_{ct} I_{sn}^{\ 2}}{S + R_{ct} I_{sn}^{\ 2}} \tag{16}$$

Where S_n is the rated burden in VA, S is the actual burden in VA, I_{sn} is the rated secondary current in A, and R_{ct} is the internal resistance at 75ºC in ohms.

To fulfil high accuracy classes (e.g. class 0.2, IEC) the magnetizing current in the core must be kept at a low value. The consequence is a low flux density in the core. High accuracy and a low number of ampere-turns result in a high saturation factor (FS). To fulfil high accuracy with low saturation factor the core is usually made of nickel alloyed steel.

NOTE: The accuracy class will not be guaranteed for burdens above rated burden or below 25% of the rated burden (IEC).

With modern meters and instruments with low consumption the total burden can be lower than 25% of the rated burden (see Figure 2.1). Due to turns correction and core material, the error may increase at lower burdens. To fulfill accuracy requirements the rated burden of the metering core shall thus be relatively well matched to the actual burden connected. The minimum error is typically at 75% of the rated burden. The best way to optimize the core regarding accuracy is consequently to specify a rated burden of 1.5 times the actual burden.
It is also possible to connect an additional burden, a "dummy burden", and in this way adapt the connected burden to the rated burden. However, this method is rather inconvenient. A higher output from a core will also result in a bigger and more expensive core, especially for cores with high accuracy (class 0.2).

How the ampere-turns influence accuracy
The number of ampere-turns influences the accuracy by increasing the error at lower ampere-turns. The error (ε) increases:

$$\varepsilon \approx k \times \frac{1}{(AN)^2} \tag{17}$$

where k is a constant, and AN is ampere-turns.

Also larger core diameter (length of the magnetic path) will also lead to an increase
in the error:

$$\varepsilon \approx k \times L_j \tag{18}$$

where L_j is the length of the magnetic path.

(b) Relay cores
Protective current transformers operate in the current range above rated currents. The main characteristics of these current transformers are:

- Low accuracy (larger errors permitted than for measuring cores)
- High saturation voltage
- Little or no turn correction

The saturation voltage is given by the Accuracy Limit Factor (*ALF*). It indicates the overcurrent as a multiple of the rated primary current up to which the rated accuracy is fulfilled with the rated burden connected. It is given as a minimum value. It can also be defined as the ratio between the saturation voltage and the voltage at rated current. Also the burden on the secondary side influences the *ALF*.

In the same way as for the metering cores, the overcurrent factor n changes for relay cores when the burden is changed.

$$n \approx n_{ALF} \times \frac{S_n + R_{ct} I_{sn}^{\;2}}{S + R_{ct} I_{sn}^{\;2}} \tag{18}$$

where n_{ALF} is the rated accuracy limit factor, S_n is the rated burden in VA, S is the actual burden in VA, R_{ct} is the internal resistance at 75 ºC in ohm, and I_{sn} is the rated secondary current in A.

Note that burdens today are purely resistive and much lower than the burdens several years ago, when electromagnetic relays and instruments were used.

Class PX protective current transformer
A class PX CT is a transformer of low leakage reactance for which knowledge of the transformer's secondary excitation characteristics, secondary winding resistance, secondary burden resistance and turns ratio is sufficient to assess its performance in relation to the protective relay system with which it is to be used.

Rated knee point emf
It is the minimum sinusoidal *emf* (rms) at rated power frequency when applied to the secondary terminals of the transformer, all other terminals being open-circuited, which when increased by 10% causes the rms exciting current to increase by no more than 50%. It is important to note that the actual knee point *emf* will be greater than or equal to the rated knee point *emf.*

Refer to IEC 60044-1 and IEEE C57.13 for CT accuracy class details.

B – VOLTAGE TRANSFORMERS

2.8 **Characteristics of voltage transformers**

Figure 2.7 shows the equivalent circuit and vector diagram of an inductive VT (IVT) while Figure 2.8 shows the equivalent circuit of a Capacitor VT (CVT). If the voltage drops could be neglected, the transformer should reproduce the primary voltage without errors. In reality, however, it is not possible to neglect the voltage drops in the winding resistances and the leakage reactances. The primary voltage is therefore not reproduced exactly.

The error in the reproduction will appear both in amplitude and phase. The error in amplitude is called voltage error or ratio error, and the error in phase is called phase error or phase displacement. The voltage error is positive if the secondary voltage is too high, and the phase error is positive if the secondary voltage is leading the primary.

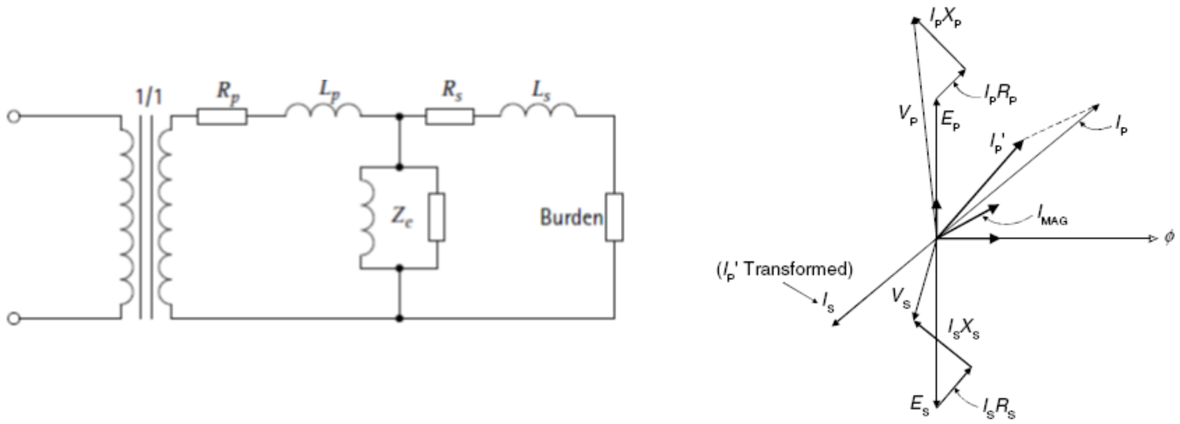


Figure 2.7: Equivalent circuit and phasor diagram of VT

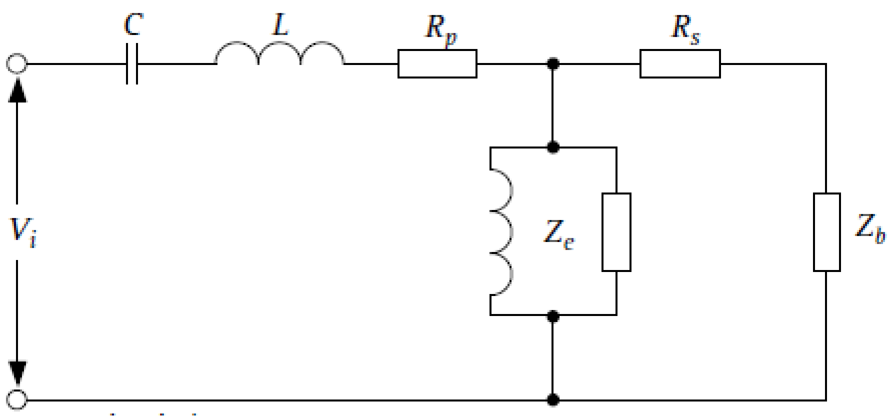


Figure 2.8: Equivalent circuit of a CVT

2.9 **Error calculation**

Figure 2.9 shows an equivalent voltage transformer diagram converted to the secondary side. The impedance Z_p represents the resistance and leakage reactance of the primary, Z_s

represents the corresponding quantities of the secondary. It is practical to look at the total voltage drop as the sum of a no-load voltage drop caused by *Is*. The diagram in Figure 2.7 is therefore divided into a no-load diagram shown by Figure 2.10(a) and a load diagram shown in Figure 2.10(b). The no-load voltage drop is, in general, very small and of a constant magnitude for a given design. For these reasons, the no-load voltage drop is neglected and attention rather focused on the load diagram of Figure 2.10(b) with the magnetising branch neglected.

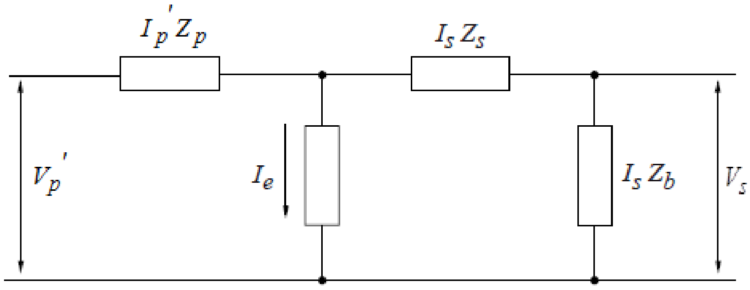


Figure 2.9: Equivalent circuit of VT with all values referred to secondary side

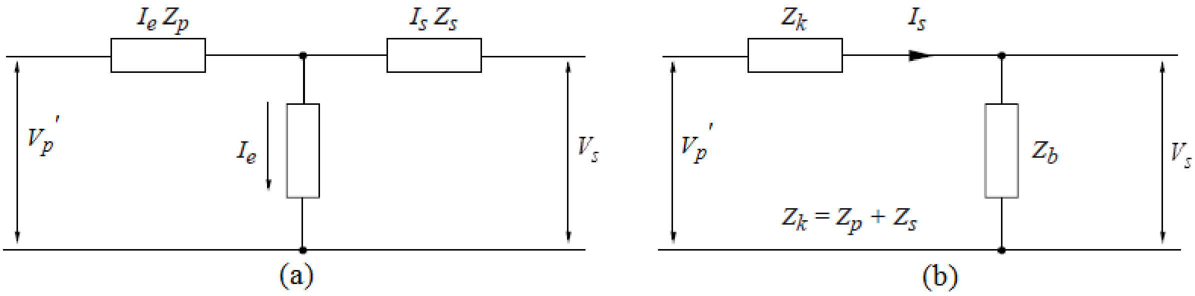


Figure 2.10: No-load and load equivalent circuits of VT at secondary side

From Figure 2.10(b), the voltage error, ΔV can be computed as:

$$\Delta V = \frac{V_p{}'}{Z_k + Z_b} \times Z_k = \frac{N_s}{N_p} V_p \times \frac{Z_k}{Z_k + Z_b} \tag{19}$$

where Z_k, is the combined impedance of the primary and secondary windings, i.e., $Z_k = Z_p + Z_s$.

ΔV can also be written as

$$\Delta V = \frac{V_s}{Z_b} \times Z_k \tag{20}$$

The voltage drop expressed as a percent V_s of is:

$$\Delta V = \frac{Z_k}{Z_b} \times 100\% \tag{21}$$

Two vectors ΔV_a and ΔV_r can be constructed from ΔV as shown in the vector diagram in Figure 2.11. The direction of the two vectors is given by the phase angle between the load current vector I_s and the reference vector V_s.

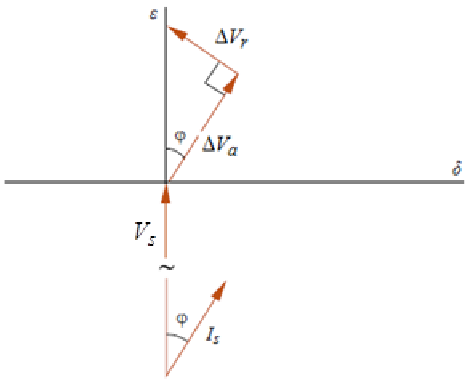


Figure 2.11: Vector diagram of VT

The resistive component ΔV_a is in phase with I_s and the reactive component ΔV_r is 90º out of phase with I_s.

$$\Delta V_a = \frac{R_k}{Z_b} \times 100\% \qquad (22)$$

and

$$\Delta V_r = \frac{X_k}{Z_b} \times 100\% \qquad (23)$$

2.9.1 *Variation of errors with voltage*

The errors vary if the voltage is changed. This variation depends on the non-linear characteristic of the exciting curve which means that the variation will appear in the no-load errors. The error contribution from the load current will not be affected at all by a voltage change. The variation of errors is small even if the voltage varies with wide limits. Figure 2.12 show typical error curves

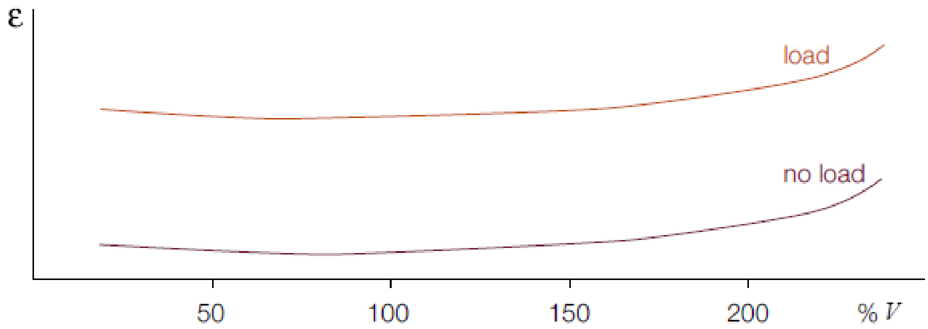


Figure 2.12: Typical VT error curves

2.10 Capacitor Voltage Transformer (CVT)

The capacitor voltage transformer (CVT) is the most used voltage transformer for high voltages greater than 100 kV. There are two types of capacitor voltage transformers on the market: high and low capacitance types. With requirements on accuracy at different operation conditions, such as pollution, disturbances, variations of frequency, temperature and transient response, the high capacitance type is the best choice. The application of capacitor voltage transformers is the same as for inductive voltage transformers. A capacitor voltage transformer can also be combined with Power Line Carrier (PLC) equipment for communication over the high-voltage transmission line.

The dual function - voltage transformer and coupling capacitor - makes the CVT an economic alternative to inductive type VTs. The CVT consists of two parts, the capacitive voltage divider and an electromagnetic unit. The size of the capacitances determines the voltage ratio of the voltage divider.

2.10.1 *Characteristics of a CVT*

The capacitor voltage transformer comprises a Capacitor Voltage Divider (CVD) and an Electromagnetic Unit (EMU). The CVD contains two series connected capacitors. The voltage divider is loaded by an electromagnetic unit, which contains sufficient inductance for compensation of the capacitance in the CVD. The EMU contains an inductive voltage transformer, a tuning reactance and a protection against ferro-resonance. The basic theory regarding accuracy classes, ratio and phase errors for CVTs is the same as for inductive voltage transformers.
The compensation inductance is obtained from the transformer windings and from a specially designed tuning reactor.

The complete circuit diagram is shown in Figure 2.13, where the EMU is represented by the primary resistance R_1 and inductance L_1. Corresponding on the secondary side is R_2 and L_2. R_t and L_t are resistance and inductance of the tuning reactor. The magnetizing impedance is represented by the resistance R_m in parallel with inductance L_m. The losses of the capacitor section are represented by R_{c1} and R_{c2}. The total series-inductance includes the leakage inductance $L_1 + L_2$ and the tuning inductance L_t. The impedance Z_b represents the load connected to the secondary terminals. Figure 2.13 can be converted to an equivalent circuit according to Figure 2.14. Since the magnetizing impedance Z_m is 500 - 1000 times the impedance $(Z_e + Z_1)$, it can be disregarded and the simplified equivalent circuit according to Figure 2.16 can be used for calculations.

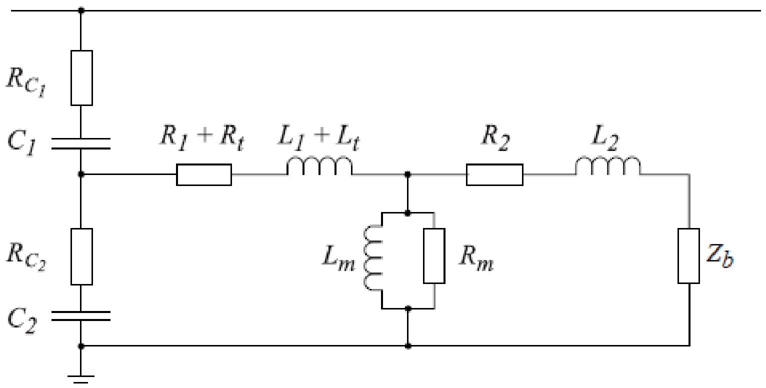


Figure 2.14: Equivalent circuit CVT

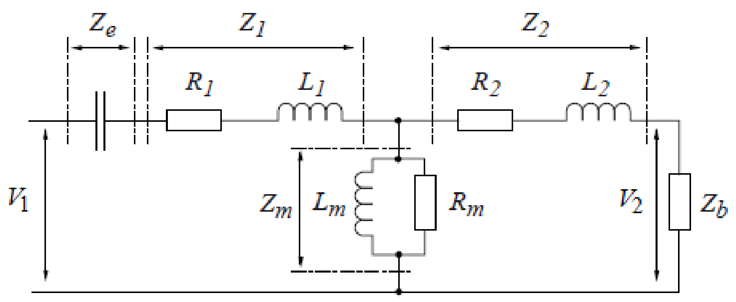


Figure 2.15: Reduced CVT equivalent circuit

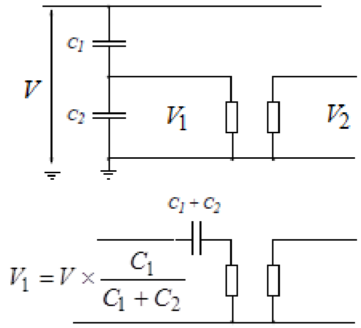


Figure 2.16: Simplified equivalent circuit

The two capacitors C_1 and C_2 are built from identical capacitor elements and their phase displacement can be regarded as being the same. The loss angle for modern capacitors is very low, <0.2%, that is why the losses (resistances) can be neglected. Seen from the EMU,

$$Z_e = \frac{X_{c1}X_{c2}}{X_{c1}+X_{c2}} = \frac{\frac{1}{j\omega C_1}\times\frac{1}{j\omega C_2}}{\frac{1}{j\omega C_1}+\frac{1}{j\omega C_2}} = \frac{1}{j\omega(C_1+C_2)} = \frac{1}{j\omega C_e}. \quad (26)$$

$C_e = C_1 + C_2$ is called the equivalent capacitance.

The intermediate voltage, i.e. the voltage for the EMU is:

$$V_1 = \frac{\frac{1}{j\omega C_2}}{\frac{1}{j\omega C_1}+\frac{1}{j\omega C_2}} \times V = \frac{C_1}{C_1+C_2}\times V \quad (27)$$

$n_c = \frac{C_1+C_2}{C_1}$ is the voltage ratio of the capacitor voltage divider.

The ratio of the EMU is defined according to the same rules as for inductive voltage transformers, i.e. $n_t = \frac{N_1}{N_2} = \frac{V_1}{V_2}$.

The total ratio, from the high voltage side of the CVD to the secondary side of the EMU is:

$$n_{tot} = n_c . n_t = \frac{V_1}{V_2} = \frac{C_1+C_2}{C_1}. \quad (28)$$

This is the same as for inductive voltage transformers. The only difference is the capacitance $C_1 + C_2$ in series with the primary winding.

2.11 Selection of VTs

Key factors in the selection of voltage transformers are:

(a) Standard (IEC, IEEE or national)
(b) Inductive or capacitor voltage transformers
(c) Insulation level (service voltage)
(d) Altitude above sea level (if >1000 m)
(e) Rated primary voltage
(f) Rated secondary voltage
(g) Ratio
(h) Rated voltage factor
(i) Burdens (outputs) and accuracy for each winding
(j) Pollution levels (creepage distance)

2.11.1 *Rated primary and secondary voltage*

The performance of the transformer is based on its rated primary and secondary voltage. Voltage transformers for outdoor applications are normally connected between phase and ground. The standard values of rated primary voltage are $1/\sqrt{3}$ times of the value of the rated system voltage. The rated secondary voltage is chosen according to local practice.

Wherever possible, the chosen voltage ratio shall be one of those stated in the standards. If, for some reason, a special ratio must be chosen, the ratio factor should be of a simple value (100, 200, 300, 400, 500, 600, 1000, 2000 and their multiples). As can be seen from Figure 2.10 the variation of accuracy within a wide range of voltages is very small. The transformers will therefore supply a secondary voltage at good accuracy even when the primary voltage varies considerably from the rated voltage. A check must, however, be made for the connected metering and relaying equipment, to ensure that they operate satisfactorily at the different voltages. The normal measuring range of a voltage transformer for the metering winding is 80-120% of the rated voltage. The protection winding has a voltage range from 0.05 to 1.5 or 1.9 of the rated voltage.

2.11.2 ***Rated voltage factor***

Voltage factor, V_f, is an upper limit of operating voltage, expressed in per unit of rated voltage. Voltage transformers, both inductive and capacitor types are usually connected phase to earth. In the event of a disturbance in a three-phase network, the voltage across the voltage transformer may sometimes be increased even up to V_f times the nominal rated performance voltage.

The IEC specifies a voltage factor of 1.5 for solidly earthed systems and 1.9 for impedance earthed or unearthed systems. The duration is specified to be 30 seconds if automatic fault tripping is used during earth faults, and 8 hours in other cases. Because of the above-mentioned requirement, voltage transformers operate with low flux density at rated voltage. The voltage transformer core must not be saturated at the voltage factor.

2.11.3 ***Burden and accuracy classes***

Voltage transformers, like CTs are divided into classes for measuring and protection purposes.

For revenue metering, it is important that the transformer is measuring correctly at different temperatures. An inductive voltage transformer has negligible deviations at different temperatures, while capacitor voltage transformers with a dielectric consisting only of paper or polypropylene film show large variations due to changes in capacitance. In a modern capacitor voltage transformer, the dielectric consists of two different types of material, paper and polypropylene, which have opposite temperature characteristics and thus combine to give minimum voltage deviation. The deviation is about the same magnitude as that of an inductive voltage transformer.

Like CTs, VTs are provided with more than one secondary winding. However, these windings are not independent of each other, as is the case of a current transformer with several secondary windings each on their own core. *The voltage drop in the primary winding of a voltage transformer is proportional to the total load current in all secondary windings.* Measuring and protective circuits can therefore not be selected independently of each other. It is important to note that different secondary windings of a voltage transformer are dependent on each other.

The accuracy class and rated burden are normally selected as follows:

- When the burden consists of metering and relaying components, the higher accuracy class required for metering must be selected.
- The burden requirements must be equivalent to the total burden of all the equipment connected to the voltage transformer.

For example, if the following are requirements of a VT: Metering equipment 25 VA, Accuracy class 0.5; Relays 100 VA, and Accuracy class 3P, the voltage transformer selected should then be able to supply 125 VA at an accuracy corresponding to class 0.5. The above is valid provided that the relays consume the 100 VA connected continuously in regular service. If the relay circuits are loaded only under emergency conditions, their influence on the metering circuits can be neglected.

Refer to Accuracy classes according to IEC 60044-2.

C - METERING DEVICES

2.12 Introduction

Metering is defined as the act of electrical energy. Meter is done to determine and record the amount of energy consumption by a customer over a period of time. Generally, meter readings are done on a monthly basis.

The demand pull created by the ever-increasing deregulation and restructuring of electricity supply, coupled with the supply push created by modern day electronic and computation technologies, have resulted in an increasing emphasis on high precision metering.

In the modern electricity supply regime, bulk power exchanges take place from the generating company to the transmitting and distributing companies. Metering assumes great significance at each of these bulk transfer points. In addition to being highly accurate and reliable, these metering systems must collect, compute, collate, communicate and present data in a form suitable for analysis and usage. Independent power producers, generating and transmitting companies should take great care when selecting, installing, commissioning and maintaining their metering systems. The following are key features that must be considered when selecting meters or metering systems.

- System accuracy
- Four quadrant metering and high reactive accuracy
- Serviceability
- Auxiliary power
- Data communication and security
- Configurability
- Self-diagnosis and testing
- Low cubicle space

2.12.1 *System accuracy*

One of the crucial requirements for metering at bulk power points is the accuracy of measurement. Since the revenue involved is enormous, even small measurement errors can contribute to significant differences in billing. Class 0.2s meters with Class 0.2s potential transformers and Class 0.2s current transformers are traditionally used for these applications. The meter and instrument transformer inaccuracies, together with the losses on the potential transformer cables, result in overall system inaccuracy of about 0.5% at full load. In many poorly selected and installed metering systems, the total inaccuracy can be as bad as 1%.

While it is not economically feasible at the present level of technology to use CTs of higher accuracy for commercial applications in the field, advanced metering technologies can offer a cost-effective solution. Present day meters can offer compensation for the errors of the external instrument transformers (CT and VT) thereby significantly enhancing the system accuracy. Such meters actually store and compensate for the linear and non-linear error characteristics of the external current transformers.

Many installations have the meter located far from the actual VT measurement points. This results in voltage drops on the VT cables. It also introduces significant errors in the voltage measurement, particularly when the voltage circuit burden (VA rating) is high. It is recommended that meters are installed as close to the measurement points as practicable. Meters with low voltage circuit VA burdens are always useful in this respect.

2.12.2 *Four quadrant metering and high reactive accuracy*

It is important to carry out full four quadrant metering for bulk power exchange points. In many inter-utility bulk power tie lines, conditions of line float are encountered when the active power transfer (import or export) is very low and yet the reactive power transfer (lag or lead) is significantly high. New tariffs based on reactive draws are becoming common.

A metering system should be able to measure accurately in all four quadrants, so that a just tariff regime can be agreed and applied. Conventional static metering technologies were only able to measure reactive energies with a limited degree of accuracy. Today, however, state-of-the-art technologies allow a great degree of accuracy to be achieved in both active and reactive measurements.

2.12.3 *Serviceability*

The need to have a high up time for grid metering systems cannot be over-emphasised. The equipment used for such applications is exposed to the harshest environments in the electricity industry, and must be designed to withstand the high levels of surge and switching transients that will probably occur.

Despite all the reliability considerations in the design of such meters, dual redundancy is almost always provided by means of a check metering arrangement. In the event of an incident it should be easy to remove and replace the meters; a module construction with 'hot plugability' is the order of the day. Such meters are capable of being pulled out and replaced without interrupting the power. Arrangements are provided to short the external CTs automatically by means of a 'make-before-break' type contact.

2.12.4 *Auxiliary power*

The use of auxiliary power for grid metering equipment is highly recommended. This has at least two distinct advantages over powering up the metering system from the voltage transformers. First it reduces the VA burden, thereby improving accuracy and allowing usage of cheaper VTs. Secondly it allows meter reading and verification even under conditions of feeder shutdown. A reliable metering system should employ at least two auxiliaries, one AC and the other from the station back-up DC supply. The system should be capable of monitoring the status of these lines and automatically switch to the back-up system whenever necessary.

2.12.5 *Data communication and security*

Reliable data storage is a must for managing complex energy flows across power networks. All data pertaining to metering, tariff, billing, demand and load profiling should be passed on for further analysis and use. The new trend is towards storing all this data on the memory available within the meter, rather than the complex pulsing data loggers used up to now. The choice of the right medium for communication is almost always specific to a particular application. In addition to local ports for data communication, remote meter reading is very important. Central and local load dispatch centres require access to this data, either directly or through the Internet.

While data transfer, assimilation and analysis have become popular in metering systems, the more important issues of data integrity and data security are often ignored. Insecure methods of time synchronisation, energy pulse accumulation and so on must be avoided altogether; all control and data transfer functions should be handled through reliable digital data communication methods. Present day systems employ several levels of security keys for controlling data access, and use some form of authentication algorithms to ensure data integrity. With the advent of the information age the significance of data security can hardly be ignored, particularly for high revenue applications like bulk power transfer.

2.13 ***Configurability***

Metering systems today are highly customised applications. Different utilities and power producers have different power purchase agreements and tariff structures. As the process of deregulation is in a fluid state in most parts of the world, the application of tariffs and use of meters is evolving over time. The metering system chosen must be amenable to configuration of the definitions of the energy register types – time-of-day (TOD) registers, rate registers, billing parameters, load surveys, event logging, alarm annunciation and many more.

2.14 ***Self diagnosis and testing***

Because it is the utility's cash register, the metering equipment needs continuous monitoring. Self diagnostic alarm annunciation should be employed. Such alarms can include watchdogs, auxiliary power failure, phase imbalance and so on. A good technique to check overall system accuracy is to monitor the instantaneous summation of energy registers of all the incoming and outgoing feeder meters, configured to give an ideal summation of zero if all registers are being measured accurately.

The meters should allow for testing *in situ*. The most commonly employed technique is the use of pulsing LEDs. However, more advanced systems provide a means of testing all the energy registers simultaneously using digital data transfer techniques from the local ports. This is substantially easier to use, as well as being time efficient, particularly with large numbers of energy registers used with bulk power transfer applications.

2.15 ***Low cubicle space***

Retrofitting high accuracy metering equipment requires cost effective use of space and should also reduce new cubicle costs. The metering equipment for present day systems should be compact and easy to handle. Nineteen-inch rack mounted products with removable metering modules are frequently used.

Bulk power transfer metering has reached a new level of sophistication and maturity, giving independent power producers, generating and transmission companies unsurpassed accuracy and functionality in a single product.

3. **OVERCURRENT PROTECTION**

3.1 **INTRODUCTION**

An overcurrent exists when current exceeds the rating of conductors or equipment mainly due to fault conditions such as short circuits. Failure to protect equipment and conductors from overcurrent may lead to irreparable damages. Overcurrent protective devices protect devices or circuits by opening them when currents reach values that pose danger to the devices, conductors or circuits. There are essentially two types of overcurrent protective devices. These are fuses and overcurrent relays.

3.2 **FUSES**

A fuse is an overcurrent protection device; it possesses an element (fuse link) that is directly heated by the passage of current and is destroyed (through melting) when the current exceeds a predetermined value. A suitably selected fuse should open the circuit by the destruction of the fuse element, extinguish the arc established during the destruction of the element and then maintain circuit conditions open with nominal voltage applied to its terminals. Fuses are mainly used in distribution systems.

The majority of fuses used in distribution systems operate on the expulsion principle, i.e. they have a tube to confine the arc, with the interior covered with de-ionising fibre, and a fusible element. In the presence of a fault, the interior fibre is heated up when the fusible element melts and produces de-ionising gases which accumulate in the tube. The arc is compressed and expelled out of the tube. In addition, the escape of gas from the ends of the tube causes the particles that sustain the arc to be expelled. In this way, the arc is extinguished when current zero is reached. The presence of de-ionising gases, and the turbulence within the tube, ensures that the fault current is not re-established after the current passes through zero point. The zone of operation is limited by two factors; the lower limit based on the minimum time required for the fusing of the element (minimum melting time) with the upper limit determined by the maximum total time that the fuse takes to clear the fault.

There are a number of standards to classify fuses according to the rated voltages, rated currents, time/current characteristics, manufacturing features and other considerations. For example, there are several sections of ANSI/UL 198-1982 standards that cover low voltage fuses of 600 V or less. For medium and high voltage fuses within the range 2.3-138 kV, standards such as ANSI/IEEE C37.40, 41, 42, 46, 47 and 48 apply. Other organisations and countries have their own standards. In addition, fuse manufacturers have their own classifications and designations.

In distribution systems, the use of fuse links designated K and T for fast and slow types respectively, depending on the speed ratio, is very popular. The speed ratio (SR) is the ratio of minimum melt current that causes fuse operation at 0.1 *s* to the minimum melt current for 300*s* operation. For the K link, a speed ratio of 6-8 is defined and for a T link, 10-13.

The following information is required in order to select a suitable fuse for use on the distribution system:

(i) Voltage and insulation level
(ii) Type of system
(iii) Maximum short-circuit level
(iv) Load current

The above four factors determine the fuse nominal current, voltage and short circuit capability characteristics.

3.2.2 **Criteria for coordination of fuses in distribution systems**

The following basic criteria should be employed when coordinating fuses in distribution systems:

(a) The fuse should clear a permanent or temporary fault before the backup protection operates, or continue to operate until the circuit is disconnected. However, if the main protection is a fuse and the back-up protection is a recloser, it is normally acceptable to coordinate the fast operating curve or curves of the recloser to operate first, followed by the fuse, if the fault is not cleared.
(b) Loss of supply caused by permanent faults should be restricted to the smallest part of the system for the shortest time possible.

3.2.3 **Fuse-fuse coordination**

The essential criterion when using fuses is that the maximum clearance time for a main fuse should not exceed 75 per cent of the minimum melting time of the backup fuse, for the same current level. This ensures that the main fuse interrupts and clears the fault before the back-up fuse is affected in any way. The factor of 75 per cent compensates for effects such as load current and ambient temperature, or fatigue in the fuse element caused by the heating effect of fault currents that have passed through the fuse to a fault downstream but were not sufficiently large enough to melt the fuse.

The coordination between two or more consecutive fuses can be achieved by drawing their time/current characteristics, normally on log-log paper as for overcurrent relays. In the past, coordination tables with data of the available fuses were also used, which proved to be an easy and accurate method. However, the graphic method is still popular not only because it gives more information but also because computer-assisted design tools make it much easier to draw out the various characteristics.

3.3 OVERCURRENT RELAYS

Overcurrent relays are used for both short-circuit and earth-fault protection. They can be instantaneous or delayed, definite- or inverse time. Their operations largely depend on current transformer outputs. There are three types of operating characteristics of overcurrent relays. These are:

- Definite(Instantaneous)-current protection,
- Definite-time protection and
- Inverse-time protection.

The ANSI device number is 50 for an instantaneous overcurrent (IOC) or a definite time overcurrent (DTOC) and 51 for the inverse definite minimum time relay.

3.3.2 Definite(instantaneous)-current protection

The definite-current overcurrent relay operates as soon as current gets higher than a pre-set value. There is no intentional time delay set. However, there is always an inherent time delay of the order of a few milliseconds.

The relay setting is adjusted based on its location in the network. The relay located furthest from the source, operates for a low current value. For example, when an overcurrent relay is connected to the end of distribution feeder, it will operate for a current lower than that connected in beginning of the feeder, especially when the feeder impedance is large. In a feeder with small impedance, distinguishing between the fault currents at both ends is difficult and leads to poor discrimination and little selectivity at high levels of short-circuit currents. While, when the impedance of feeder is high, the instantaneous protection has advantages of reducing the relay's operating time for severe faults and avoiding the loss of selectivity.

3.3.3 Definite-time protection

In this type, two conditions must be satisfied for operation (tripping). They are: (a) current must exceed the setting value, and (b) the fault must be continuous for at least a time equal to the time setting of the relay. This relay is created by applying intentional time delay after crossing pick up value of the current. A definite time overcurrent relay can be adjusted to issue a trip output at definite amount of time after it picks up. Thus, is has a time setting and pick up setting. Modern relays may contain more than one stage of protection with each stage having its own current and time setting. The settings of this kind of relay at different locations in the network can be adjusted in such a way that the breaker closest to the fault is tripped in the shortest time and then the other breakers in the direction toward the upstream network are tripped successively with longer time delay.

The disadvantage of this type of protection is that it is difficult to coordinate and also requires changes with the addition of load and that the short-circuit fault close to the source may be cleared in a relatively long time in spite of its highest current value. Definite time overcurrent relay is usually used as a backup protection to distance protection for transmission lines, differential protection of power transformers with time delay and main protection to outgoing feeders and bus couplers with adjustable time delay setting.

3.3.4 Inverse-time overcurrent relays

In this type of relays, operating time is inversely changed with the current such that high current will operate the relay faster than low ones. They are available with standard inverse, very inverse and extremely inverse characteristics. Inverse time relays are also referred to as inverse definite minimum time (IDMT) relays. The operating time of both overcurrent definite-time relays and overcurrent inverse-time relays must be adjusted in such a way that the relay closer to the fault trips before any other protection. This is known as time grading. The difference in operating time of these two relays for the same fault is defined as discrimination margin.

The adjustment of definite-time and inverse-time relays can be carried out by determining two settings: time dial setting and pickup setting. The time dial setting adjusts the time delay before the relay operates whenever the fault current reaches a value equal to, or greater than, the relay current setting. The time dial setting is also referred to as the time multiplier setting. The tripping characteristics for different TMS settings using the IEC 60225 are shown in Table 3.1.

Table 3.1 Operating time for different relay characteristics

Relay characteristic	Equation (IEC 60225)
Standard Inverse (SI)	$t = TMS \times \dfrac{0.14}{I_r^{0.02} - 1}$
Very Inverse (SI)	$t = TMS \times \dfrac{13.5}{I_r - 1}$
Extremely Inverse (EI)	$t = TMS \times \dfrac{80}{I_r^{2} - 1}$

Time multiplier settings are multipliers used to convert times derived from time/psm curves into actual operating times. Actual times of operation are calculated by multiplying time setting multiplier with time obtained from time/psm curves of relays. Pickup setting is used to define the pickup current of the relay by which the fault current exceeds its value. It is determined by:

$$Pickup\ setting = \frac{K_{ld} \times I_{norm}}{CT} \qquad 3.1$$

where K_{ld} is the overload factor, I_{norm} is the nominal rated current, and CT is the current transformer ratio.

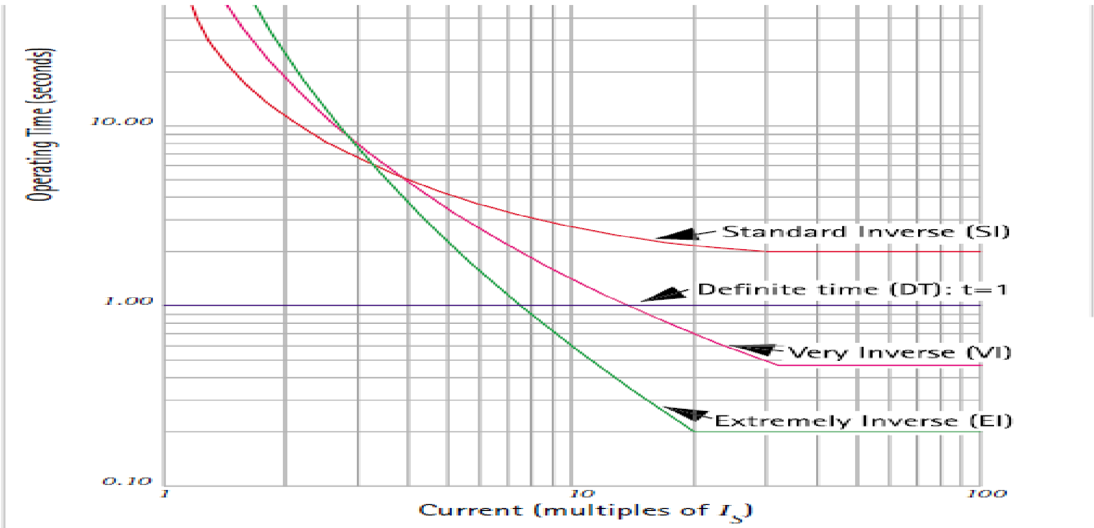


Figure 3.2: IDMT relay characteristics

Figure 3.1 shows typical curves for the various inverse characteristics. It can be seen from the figure that the very inverse curve is much steeper and therefore the operation increases much faster for the same reduction in current compared to the standard inverse (SI) curve. Very inverse overcurrent relays are particularly suitable if there is a substantial reduction of fault current as the distance from the power source increases. With the extremely inverse (EI) characteristic, the operating time is approximately inversely proportional to the square of the applied current. This makes it suitable for the protection of distribution feeder circuits in which the feeder is subjected to peak currents on switching in.

3.3.5 **Coordination of overcurrent relays**

Correct overcurrent relay application requires knowledge of the fault current that can flow in each part of the network. Since large-scale tests are normally impracticable, system analysis must be used. The data required for a relay setting study are:

i. a one-line diagram of the power system involved, showing the type and rating of the protection devices and their associated current transformers
ii. the impedances in ohms, per cent or per unit, of all power transformers, rotating machines and feeder circuits
iii. the maximum and minimum values of short circuit currents that are expected to flow through each protection device
iv. the maximum load current through protection devices
v. the starting current requirements of motors and the starting and locked rotor/stalling times of induction motors
vi. the transformer inrush, thermal withstand and damage characteristics
vii. decrement curves showing the rate of decay of the fault current supplied by the generators
viii. performance curves of the current transformers

Relay settings are first determined to give the shortest operating times at maximum fault levels and then checked to see if the operation will also be satisfactory at the minimum fault current expected. The basic rules for correct relay co-ordination can generally be stated as follows:

i. Whenever possible, use relays with the same operating characteristic in series with each other.
ii. Make sure that the relay farthest from the source has current settings equal to or less than the relays behind it, that is, that the primary current required to operate the relay in front is always equal to or less than the primary current required to operate the relay behind it.

Among the various possible methods used to achieve correct relay co-ordination are those using either time or overcurrent, or logic coordination. The common aim of all three methods is to give correct coordination. There are three basic coordination (grading) schemes. These are: time-based coordination, current-based coordination and (logic) coordination.

(a) ***Time-based coordination***

In this method, an appropriate time setting is given to each of the relays controlling the circuit breakers in a power system to ensure that the breaker nearest to a fault opens first. The closer the relay is to the source, the longer the time delay. A simple radial distribution system is shown in Figure 3.2 to illustrate the principle.

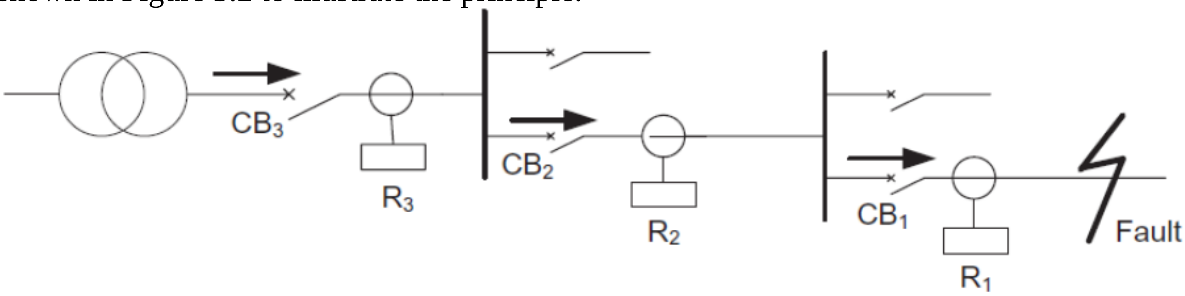


Figure 3.2: A simple radial distribution system

As seen from Figure 3.2, the fault is detected by protection relays R_1, R_2 and R_3. The relay R_1 operates faster than R_2, which operates faster than relay R_3. When CB_1 is tripped and the fault is cleared, relays R_2 and R_3 reset.

The advantage of this coordination system is simplicity and providing its own backup, for example, if relay R_1 fails, relay R_2 is activated for Δt later. The main disadvantage of this method of coordination is that the longest fault clearance time occurs for faults in the section closest to the power source, where the fault level (MVA) is highest. The principle of time-based coordination is applied to radial distribution systems. The time delays set are activated when the current exceeds the relay settings

The coordination interval is the difference in operating time Δt between two successive protection units.

(b) ***Current-based coordination***

Discrimination by current relies on the fact that the fault current varies with the position of the fault because of the difference in impedance values between the source and the fault. Hence, typically, the relays controlling the various circuit breakers are set to operate at suitably tapered values of current such that only the relay nearest to the fault trips its breaker. It is installed at the starting point of each section. The threshold is set at a value lower than the minimum short - circuit current caused by a fault downstream (outside the monitored area). This system can be used advantageously for two line sections separated by a transformer as in Figure 3.2 since it is simple, economical, and tripping without time delay. To ensure coordination between the two protection units R_1 and R_2, the current setting of R_2, I_{set,R_2}, must satisfy the relation 1.25 (max I_{sc,R_1})< I_{set,R_2} <0.8 (min I_{sc,R_2}), where max max I_{sc,R_1} represents the maximum short-circuit current at relay R_1 referred to the upstream voltage level, and min I_{sc,R_2} is the minimum short - circuit current at R_2.

Current-based coordination has drawbacks where the upstream protection unit R_2 does not provide backup for the downstream protection unit R_1. In addition, practically, in the case of MV systems, except for sections with transformers, there is no notable decrease in current between two adjacent areas. Therefore, to define the settings for two cascading protection units and ensuring coordination is difficult.

(c) ***Logic coordination***

Each of the two methods described so far has a fundamental disadvantage. Logic coordination is designed and developed to solve the drawbacks of both time-based and current-based coordination. With this system, coordination intervals between two successive protection units are not needed. Furthermore, the tripping time delay of the CB closest to the source is considerably reduced.

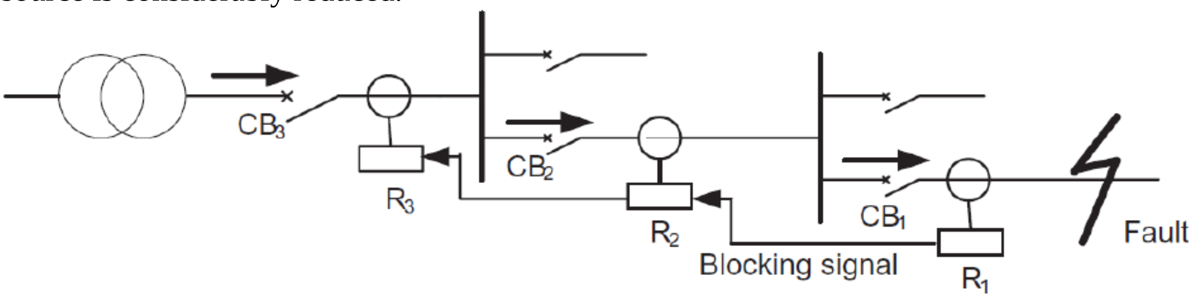
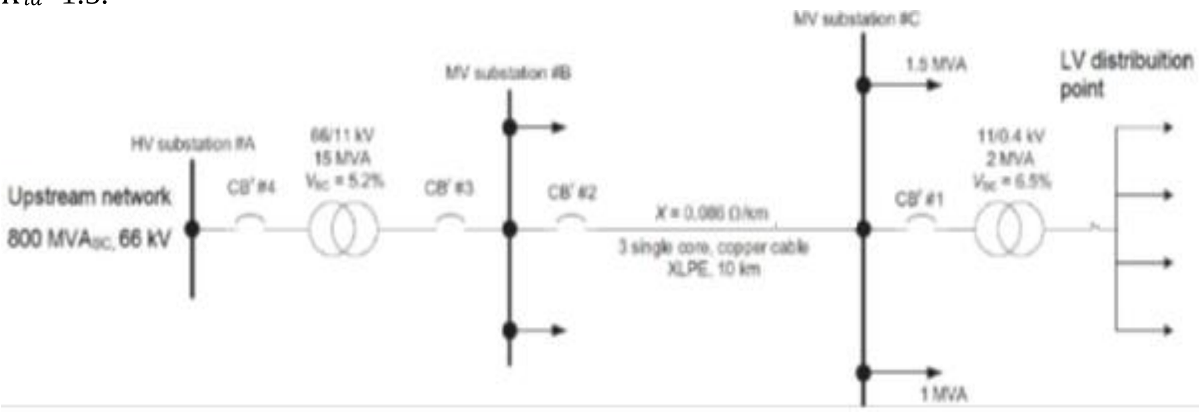


Figure 3.3: Logic controller principles

When a fault occurs on the system as shown in Figure 3.3, the relays that are in an upstream way from the fault (R_1, R_2, R_3) are activated, while the relays on downstream (after the fault) way are not. Each relay that is activated by the fault sends a blocking signal to the relay which is in an upper level as an order to increase the upstream relay time delay. In this case, the circuit breaker CB_1 is tripped since the relay R_1 has not received a blocking signal from the downstream level. Therefore, the relay R_1 will send a blocking signal to relay R_2, which in turn sends a blocking signal to R_3. This tripping order given by R_1 is provided after a delay time t_{R1} and the duration of blocking signal to R_2 is limited to $t_{R1} + t_1$, where t_1 is the sum of opening and arc extinction time of CB_1. In this way if CB_1, fails to trip, the relay R_2 gives the tripping order at $t_{R1} + t_1$, as a backup protection. If there is fault between CB_2 and CB_1, the relay R_2 will operate after a time delay t_{R2}.

A disadvantage of logic coordination is that its implement requires extra wiring for transmitting the blocking signal between the protection units, which causes difficulties for long links as the protection units are far apart from each other.

Example 3.1
For the given system, calculate the nominal rated current, short-circuit level and pickup setting, for the coordination of the overcurrent protection at positions C, B and A. Current transformers ratios are: CT_1=300/5, CT_2=600/5, CT_3=800/5, CT_4=400/5 and overload factor, K_{ld}=1.5.



Solution
Nominal current calculation for CBs:

$$I_{nom,1} = \frac{S}{\sqrt{3} \times V_L} = \frac{2 \times 10^6}{\sqrt{3} \times 11 \times 10^3} = 105A$$

$$I_{nom,2} = \frac{(1.5 + 2 + 1) \times 10^6}{\sqrt{3} \times 11 \times 10^3} = 236.2A$$

$$I_{nom,3} = \frac{15 \times 10^6}{\sqrt{3} \times 11 \times 10^3} = 787.3A$$

$$I_{nom,4} = I_{nom,3} \times \frac{11 \times 10^3}{66 \times 10^3} = \frac{15 \times 10^6}{\sqrt{3} \times 66 \times 10^3} = 131.2A$$

Short circuit current at each CB:

$$\text{Source impedance, } Z_{upstream} = \frac{{V_L}^2}{S} = \frac{(66 \times 10^3)^2}{800 \times 10^6} = 5.44\Omega$$

Transformer impedance, $Z_T = Vsc \times \frac{{V_L}^2}{S} = \frac{5.2}{100} \times \frac{\left(66 \times 10^3\right)^2}{15 \times 10^6} = 15.1\Omega$

$$Z_{BC} = 0.086 \times 10 \times \left(\frac{66 \times 10^3}{11 \times 10^3} \right)^2 = 30.96\Omega$$

Then,

$$I_{FC} = \frac{66 \times 10^6}{\sqrt{3} \times (30.96 + 15.1 + 5.44)} = 739.9A$$

$$I_{FB} = \frac{66 \times 10^6}{\sqrt{3} \times (15.1 + 5.44)} = 1855.2A$$

$$I_{FA} = \frac{66 \times 10^6}{\sqrt{3} \times 5.44} = 7004.6A$$

So, for each relay the pickup setting is computed using (3.1) as:

- Relay 1: *Pickup setting* = $1.5 \times 105 \times \frac{5}{300} = 2.625A$. Thus, pickup current is set at 3A.
- Relay 2: *Pickup setting* = $1.5 \times 236.2 \times \frac{5}{600} = 2.95A$. Thus, pickup current is set at 3A.
- Relay 3: *Pickup setting* = $1.5 \times 787.3 \times \frac{5}{800} = 7.38A$. Thus, pickup current is set at 8A.
- Relay 4: *Pickup setting* = $1.5 \times 131.2 \times \frac{5}{400} = 2.46A$. Thus, pickup current is set at 3A.

3.3.6 **Relay time grading margin**

The time interval that must be allowed between the operation of two adjacent relays in order to achieve correct discrimination between them is called the *grading margin*. If a grading margin is not provided, or is insufficient, more than one relay will operate for a fault, leading to difficulties in determining the location of the fault and unnecessary loss of supply to some consumers. The grading margin depends on a number of factors:

(i) the fault current interrupting time of the circuit breaker
(ii) relay timing errors
(iii) the overshoot time of the relay
(iv) CT errors
(v) Safety margin (final margin on completion of operation)

Factors (ii) and (iii) above depend to a certain extent on the relay technology used – an electromechanical relay, for instance, will have a larger overshoot time than a numerical relay.

Grading is initially carried out for the maximum fault level at the relaying point under consideration, but a check is also made that the required grading margin exists for all current levels between relay pick-up current and maximum fault level.

(a) *Circuit breaker interrupting time*

The circuit breaker interrupting the fault must have completely interrupted the current before the discriminating relay ceases to be energised. The time taken is dependent on the type of circuit breaker used and the fault current to be interrupted. Manufacturers normally provide the fault interrupting time at rated interrupting capacity and this value is invariably used in the calculation of grading margin.

(b) *Relay timing error*
All relays have errors in their timing compared to the ideal characteristic as defined in IEC 60255. For a relay specified to IEC 60255, a relay error index is quoted that determines the maximum timing error of the relay.

(c) *Overshoot*
When a relay is de-energised, operation may continue for a little longer until any stored energy has been dissipated. For example, an induction disc relay will have stored kinetic energy in the motion of the disc; static relay circuits may have energy stored in capacitors. Relay design is directed to minimising and absorbing these energies, but some allowance is usually necessary. The overshoot time is defined as the difference between the operating time of a relay at a specified value of input current and the maximum duration of input current, which when suddenly reduced below the relay operating level, is insufficient to cause relay operation.

(d) *CT errors*
Current transformers have phase and ratio errors due to the exciting current required to magnetise their cores. The result is that the CT secondary current is not an identical scaled replica of the primary current. This leads to errors in the operation of relays, especially in the time of operation. CT errors are not relevant when independent definite-time delay overcurrent relays are being considered.

(e) *Final Margin*
After the above allowances have been made, the discriminating relay should not complete its operation before the margin elapses. However, this may not be realised. To ensure desired performance, some extra allowance, or safety margin, is required to ensure that relay operation does not occur.

In some systems, a fixed grading margin is used. However, the use of a fixed grading margin is only appropriate at high fault levels that lead to short relay operating times. At lower fault current levels, with longer operating times, the permitted error specified in IEC 60255 (7.5% of operating time) may exceed the fixed grading margin, resulting in the possibility that the relay fails to grade correctly while remaining within specification. A suitable minimum grading time interval, Δt, may be calculated using (3.2):

$$\Delta t = \left(\frac{2E_r + E_{ct}}{100}\right)t + t_{cb} + t_o + t_s \qquad (3.2)$$

where:
Er = relay timing error (IEC 60255-4)
Ect = allowance for CT ratio error (%)
t = operating time of relay nearer fault (s)
tCB = CB interrupting time (s)
to = relay overshoot time (s)
ts = safety margin (s)

When the overcurrent relays have independent definite time delay characteristics, it is not necessary to include the allowance for CT error. Hence,

$$\Delta t = \left(\frac{2E_r}{100}\right)t + t_{cb} + t_o + t_s \quad (3.3)$$

Calculation of specific grading times for each relay can often be tedious when performing a protection grading calculation on a power system. Table 3.1 gives practical grading times at high fault current levels between overcurrent relays for different technologies. Where relays of different technologies are used, the time appropriate to the technology of the downstream relay should be used.

Table 3.1: Typical timing errors for IDMT relays

	Relay technology			
	Electromechanical	Static	Digital	Numerical
Basic timing error (%)	7.5	5	5	5
Overshoot (s)	0.05	0.03	0.02	0.02
Safety margin (s)	0.1	0.05	0.03	0.03
Typical overall grading margin (s)	0.4	0.35	0.3	0.3

Example 3.2

Determine the setting of an IDMT overcurrent relay for a network with the following feeder and CT data:

Feeder data:

Feeder load current $= 384A$

Feeder fault current $= 11kA$

CT detail:

CT installed on feeder is 600/1 Amp. Relay Error 7.5%, CT Error 10.0%, relay over shoot time is 0.05s, CB interrupting time is 0.17s, and Safety margin is 0.33s.

IDMT relay current setting:

Overload current setting is 125% and time delay (TMS) is 0.125 Sec, relay curve is selected as standard (normal) inverse type.

Solution

Pick-up current = Feeder load current × Relay setting

$= 384 \times 125\% = 480A$

Plug multiplier setting $= \frac{Pick-up\,current}{Rated\,current} = \frac{480}{600} = 0.8$

Plug setting multiplier (PSM) $= \frac{fault\,current}{pick-up\,current} = \frac{11000}{40} = 22.92$

Actual operating time of relay for standard inverse curve, $t = TMS \times \frac{0.14}{I_r^{0.02} - 1}$

$$= 0.125 \times \frac{0.14}{22.92^{0.02} - 1}$$

$$= 0.125 \times 2.17 = 0.271s$$

Grading Time of Relay $\Delta t = \left(\frac{2E_r + E_{ct}}{100}\right)t + t_{cb} + t_o + t_s$

$$= \left(\frac{2 \times 7.5 + 10}{100} \right) \times 0.271 + 0.05 + 0.17 + 0.33$$
$$= 0.618$$

Operating time of upstream relay $=$ *actual operating time of relay* + *total grading time*

$$= 0.271 + 0.618 = 0.889s$$

3.3.7 Calculation of phase fault overcurrent relay settings

The correct co-ordination of overcurrent relays in a power system requires the calculation of the estimated relay settings in terms of both current and time. The resultant settings are then traditionally plotted in suitable log/log format to show pictorially that a suitable grading margin exists between the relays at adjacent substations. Plotting may be done by hand, but nowadays is more commonly achieved using suitable software.

It is usual to plot all time/current characteristics to a common voltage/MVA base on log/log scales. The plot includes all relays in a single path, starting with the relay nearest the load and finishing with the relay nearest the source of supply. A separate plot is required for each independent path, and the settings of any relays that lie on multiple paths must be carefully considered to ensure that the final setting is appropriate for all conditions. Earth faults are considered separately from phase faults and require separate plots. After relay settings have been finalised, they are entered in a table. One such table is shown in Table 3.2. This also assists in record keeping and during commissioning of the relays at site.

Table 3.2: Typical relay data table

Location	Fault Current (A)		Maximun Load Current (A)	CT Ratio	Relay Current Setting		Relay Time Multiplier Setting
	Maximun	Minimun			Per Cent	Primary Current (A)	

4. **DIFFERENTIAL PROTECTION**

4.1. **Introduction**

Differential protection is one of the most prevalent and successful methods of protecting power system equipment. Differential protection, as its name implies, compares the currents entering and leaving a protected zone and operates when the differential between these currents exceeds a pre-determined magnitude. Differential relays generally fall within one of three broad categories. These are current differential relays, high impedance differential relays and voltage-differential relays.

4.2 **Current-differential relays**

Current-differential relays (also known as Merze Price relays) are typically used to protect large transformers, generators and motors. For these devices, detection of low-level winding-faults is essential to avoid equipment damage.

The principle is illustrated in figure 4.1. The CTs are connected in series and the secondary current circulates between them. The relay is connected across the midpoint. Thus the voltage across the relay is theoretically nil, therefore no current flows through the relay and hence no operation for faults outside the protected zone. Similarly, under normal conditions, the currents, leaving zone A and B are equal, making the relay inactive due to the current balance. Under internal fault conditions (i.e. between the CTs at ends A and B), the relay operates as portrayed in figure 4.2. This is basically due to the direction of current reversing at end B (as is the can in non-radial lines) making the fault current to flow from B to A instead of the normal A to B condition shown in figure 4.1. In power system equipment such as transformers, the differential current arises due to diversion of current through the fault path.

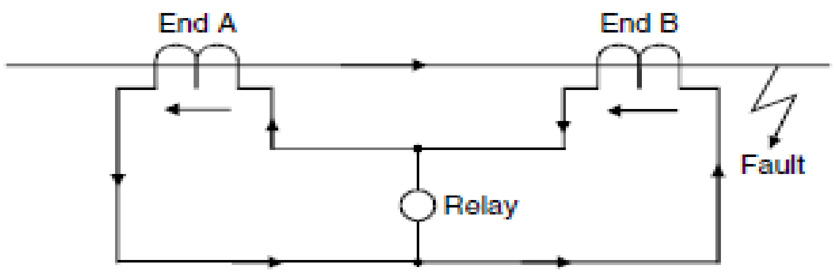


Figure 4.1: Balanced circulating current scheme, external fault (stable)

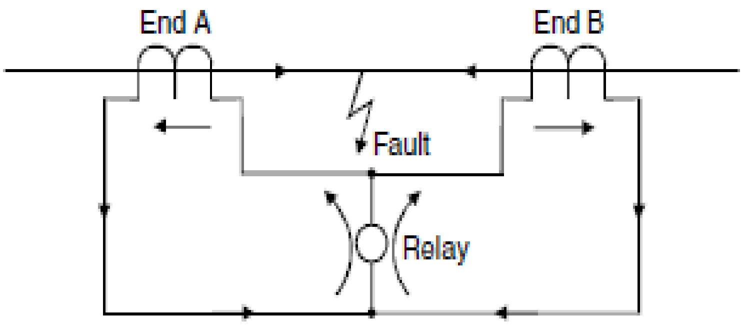


Figure 4.2: Balanced circulating current scheme, internal fault (operate)

Current differential relays typically are equipped with restraint windings to which the CT inputs are connected. For electromechanical current differential relays, the current through the restraint windings for each phase is summed and the sum is directed through an operating winding. The current through the operating winding must be above a certain percentage, (typically 15%-50%) of the current through restraint windings for the relay to operate. For solid-state electronic or microprocessor-based current differential relays, the operating windings exist only in logic and not as a physical winding.

In figure 4.3, the restraint windings are labelled as “R” and the operating windings are labelled as “O.” Because the delta-wye transformer connection produces a phase shift, the secondary CT’s are connected in delta to counteract this phase shift for the connections to the relays.

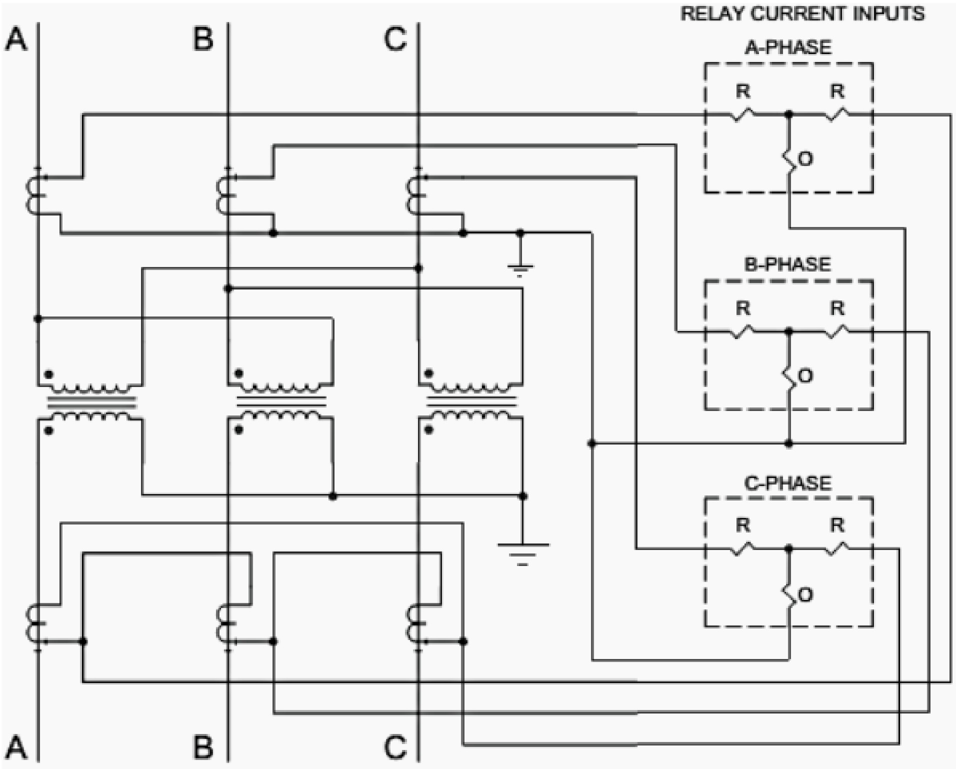


Figure 4.3: Current differential relays with restraint coils

4.2.1 ***Setbacks in current-differential protection***

Current-differential relays suffer a number of setbacks. These are discussed below:

(a) *Unmatched characteristics of CTs*

Current transformers used are generally considered to be identical. However, it is not always possible to have identical CTs. Although the saturation is avoided, there exist differences in CT characteristics due to ratio error at high values of short circuit currents. This causes an appreciable difference in the secondary currents which can operate the relay. The issue of un-identical CT characteristics is overcome by using percentage differential relays. In this relay, the difference in current due to the ratio error exists and flows through relay coil. But at the same time the average current ($(I_1 + I_2)/2$) flows through a restraining coil which produces enough restraining torque to prevent relay operation under healthy conditions.

(b) *Ratio change due to tap change*

To alter the voltage and current ratios between high voltage and low voltage sides of a power transformer, a tap changing equipment is used. This is an important feature of a power transformer. This equipment effectively alters the turns ratio. Variations in turns ratio causes unbalance on both sides. To compensate for this effect, tappings can be provided on CTs and varied in a similar manner as the main power transformer. However, this method is not practicable. The percentage differential relays ensure stability with respect to the amount of unbalance occurring due to tap variations.

(c) *Difference in lengths of pilot wires*

CTs are assumed to share burdens equally between. Due to the difference in lengths of the pilot wires on both sides, an unbalance condition may result. The difficulty is overcome by connecting adjustable resistors in pilot wires at one end or on both sides. These resistors are called balancing or stabilizing resistors. With the help of these resistors, equipotential points on the pilot wires can be adjusted.

(d) *Magnetizing current inrush*

When a transformer is energized, the condition initially is of zero induced emf. A transient inflow of magnetizing current occurs in the transformer. This current is called magnetizing inrush current. This current may be as high as 10-20 times the full load current of the transformer. This current decays very slowly and is bound to operate the differential protection of a transformer falsely, because of the temporary difference in magnitude of the primary and secondary currents. Magnetizing inrush current is affected by the following:

(i) Size of the transformer
(ii) Size of the power system
(iii) Type of magnetic material used for the core
(iv) The amount of residual flux existing before energizing the transformer
(v) The method by which transformer is energized

4.3 **High-impedance differential relay**

A high-impedance differential relay has a high-impedance operating element, across which a voltage relay is connected. CTs are connected such that during normal load or external fault, the current through the impedance is essentially zero. However, for a fault inside the differential zone of protection, the current through the high-impedance input is non-zero and causes a rapid rise in the voltage across the input, resulting in relay operation. High-impedance differential relays are typically used for bus protection.

Figure 4.4 illustrates the concept. In Figure 4.4 the relay has only one set of input. This is done to for the purpose of illustrating the concept. Any number of CTs may be connected to the relay as needed to extend the zone of protection so long as the CT currents sum to zero during normal conditions.

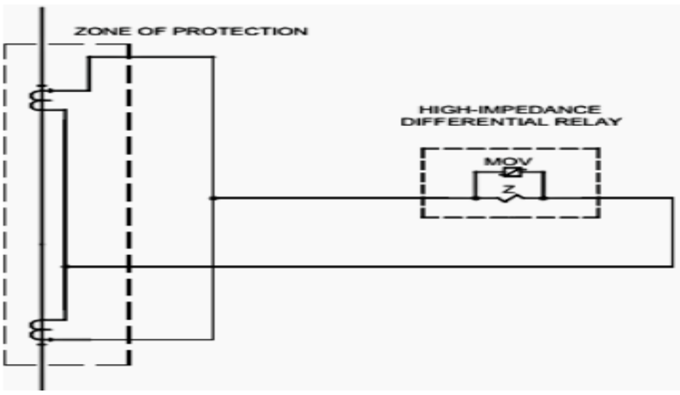


Figure 4.4: High-impedance differential relay

4.4 **Balanced voltage differential relay**

Balanced voltage differential relays are also referred to as pilot differential relay. As the name implies, it is necessary to create a balanced voltage across the relays in end A and end B under healthy and out-of-zone fault conditions. In this arrangement, the CTs are connected to oppose each other (see figure 4.5). Voltages produced by the secondary currents are equal and opposite; thus no currents flow in the pilots or relays, hence stable on through-fault (external fault) conditions. Under internal fault conditions, the relays will operate (see figure 4.6).

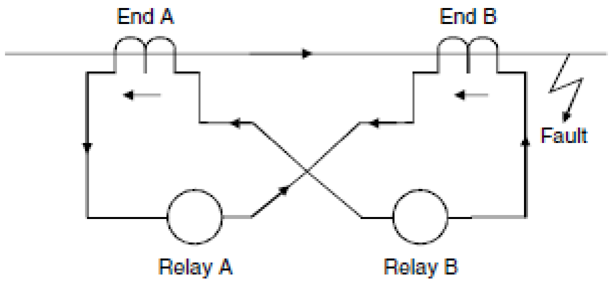


Figure 1: Balanced voltage scheme, external fault (stable)

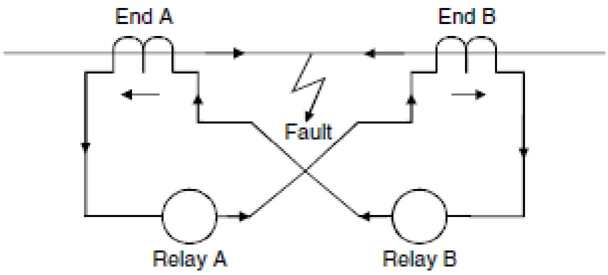


Figure 2: Balanced voltage scheme, internal fault (operate)

Balanced voltage systems are used mainly for line protection where the CTs are mounted in different substations, which are some distance apart. As there are two relays involved, one at each end, they can each be mounted in their respective substation.

4.5 **Differential protection of transformers**

Let the transformer turns ratio given by $N_1 : N_2$ and the corresponding CT ratio be given by $1 : n_1$ and $1 : n_2$. Then,

current in CT - 1 primary $= I_1$,

current in CT - 1 secondary, $i_1 = \dfrac{I_1}{n_1}$,

current in CT - 2 primary, $I_2 = \dfrac{N_1 I_1}{N_2}$ and

current in CT - 2 secondary $i_2 = \dfrac{N_1 I_1}{N_2 n_2}$.

If there is no fault, then with proper connections account for the CT polarity, circulatory current through CT secondary should be obtained.

Hence $i_1 = i_2$. i.e. $\dfrac{I_1}{n_1} = \dfrac{N_1 I_1}{N_2 n_2}$ or

$$N_1 n_1 = N_2 n_2 . \tag{1}$$

If the transformer to be protected is working on tap T, then the above equality is modified as follows:

$$N_1 n_1 = N_2 n_2 T \tag{2}$$

Example 4.1

The primary winding of a transformer has 1000 turns while secondary has 500 turns. If the primary CT ratio is 100:5, find the CT ratio required in the secondary side to establish a circulatory current scheme.

Solution

$N_1 = 1000; N_2 = 500$ and $n_1 = 20$

$$I_2 = \frac{N_1 I_1}{N_2} = \frac{1000 \times 100}{500} = 200A$$

From (1), $n_2 = \frac{N_1 n_1}{N_2} = \frac{1000 \times 20}{500} = 40$

$$i_2 = \frac{I_2}{n_2} = \frac{200}{40} = 5.$$

Thus, a suitable secondary CT ratio would be 200:5.

Remarks 1: Sometimes due to 'odd turns ratio' involved in primary, it may not be possible to obtain matching CTs on the secondary. In such situations, 'auxiliary CTs' are used either on primary or secondary (or both sides) to obtain circulatory currents in absence of internal faults. Primary of the auxilliary CT is connected in series with secondary of main CT. Secondary of auxilliary CT participates in the circulating current scheme.

Remark 2: The circulating current scheme described above has been traditionally used with electromechanical and solid state relays. However, in the case of numerical relays, such physical connections are no more required. Given turns ratio $N_1 : N_2$ and CTs ratio $1 : n_1$ and $1 : n_2$, one can work out the expected current in secondary of transformer (in absence of internal fault). Hence, auxiliary CTs become redundant and the transformer connections are simplified drastically. Thus, with numerical relaying most of the hardware connections and circulatory currents can be easily accounted in software.

Remark 3: When dealing with three-phase transformers, the transformer connections like *Y-Y* or $Y - \Delta$ also play a role in determining CT secondary interconnections to establish circulating current scheme. This is because of the phase shifts typically of the order of $\pm 30^o$ that result from the line currents moving from the primary to secondary sides of the transformer. Figure 4.7 shows typical connections for a star-delta transformer bank for establishing the circulatory currents. The study of the circuit brings out the following important rule for interconnection of CT secondary for Δ / Y transformers: "If the power transformer windings are connected in Y configuration, use Δ configuration for corresponding CT secondary interconnections" (and vice-versa).

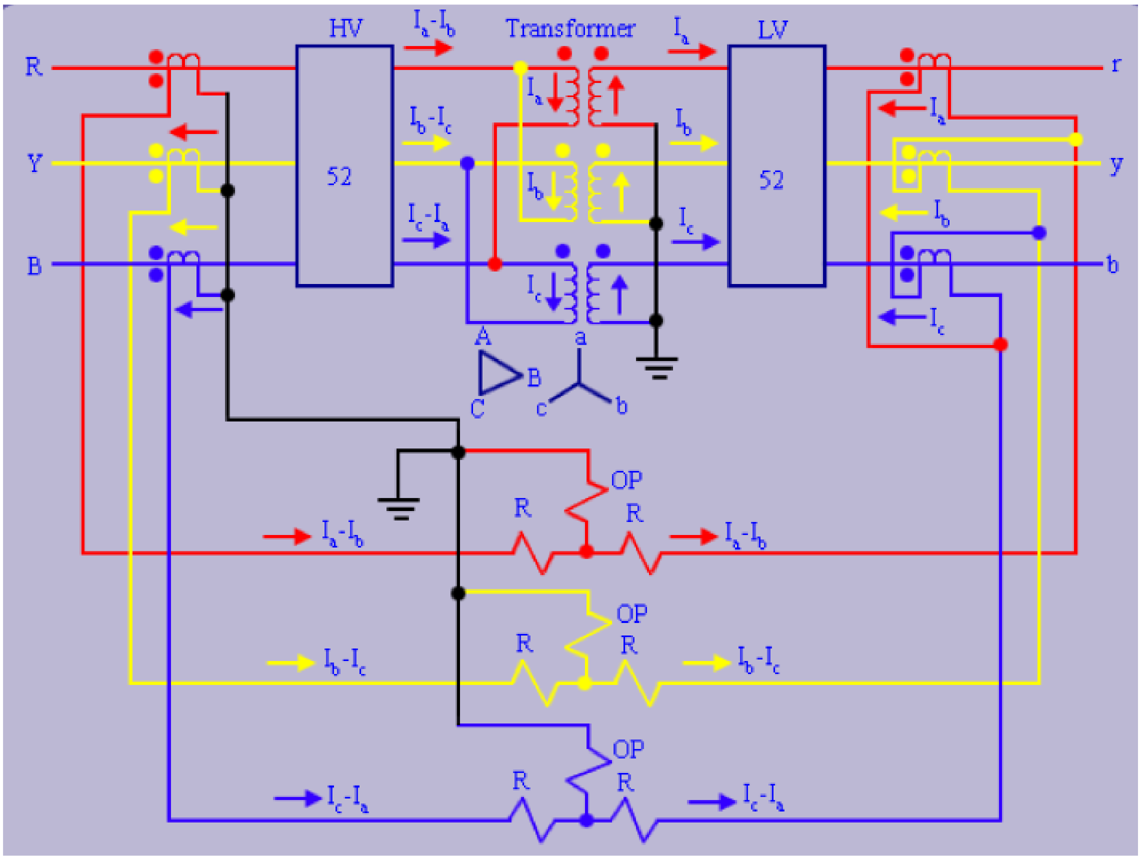


Figure 4.7: Differential protection of Δ / Y *transformer*

Remark 4: With numerical relays such interconnection complexity can be easily handled in software. After specifying the turns ratio and the phase shift from primary to secondary, it should be possible to work out the expected secondary differential current by simple calculation.

4.5.1 *Percentage differential protection scheme*

So far, an ideal transformer with fixed tap has been considered. However, practical transformers and CTs pose additional challenges to protection.

(i) The primary of transformer will carry no-load current even when the secondary is open-circuited. This will lead to differential current on which the protection scheme should not operate.

(ii) It is not possible to exactly match the CT ratio. This would also lead to differential currents under healthy conditions.

(iii)If the transformer is used with an off nominal tap, then differential currents will arise as equation (2) is not satisfied even under healthy conditions. However, tap position can be read in numerical protection schemes and accounted by equation (2). This would make the numerical protection scheme adaptive.

To prevent the differential protection scheme from picking up under such conditions, a percentage differential protection scheme is used. It improves security at the cost of sensitivity. Notice an offset to account for the no-load current (See figure 4.8). The current on the x-axis is the average current of primary and secondary winding referred to primary. It indicates the restraining current while the corresponding difference on Y-axis represents the differential current. The differential protection will pick up if magnitude of differential current is more than a fixed percentage of the restraining current.

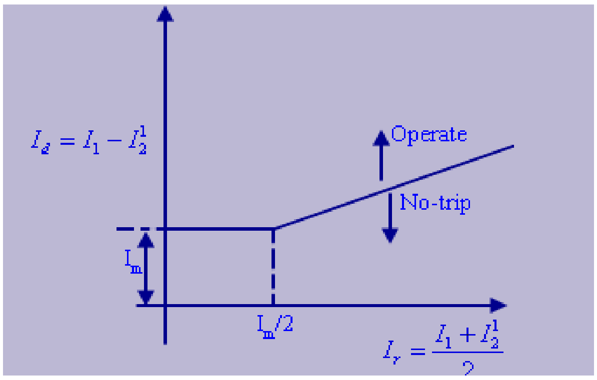


Figure 4.8: Percentage differential protection scheme

4.6 Generator differential protection

As with transformer differential protection, two sets of current transformers are used in generator differential protection schemes. One CT is connected to the line side of the generator and other is connected to the neutral side of the generator in each phase. Typical interconnections of CTs for differential protection of generators are shown in figures 4.9 and 4.10. It is important to choose CTs from the same manufacturer with identical turns ratio to minimize CT mismatch. To improve security, percentage differential protection is preferred. The accuracy of the differential protection for generators is expected to be better than that of differential protection for transformers, as issues like over fluxing, magnetizing inrush, no-load current and different voltage ratings for the same plant does not exist.

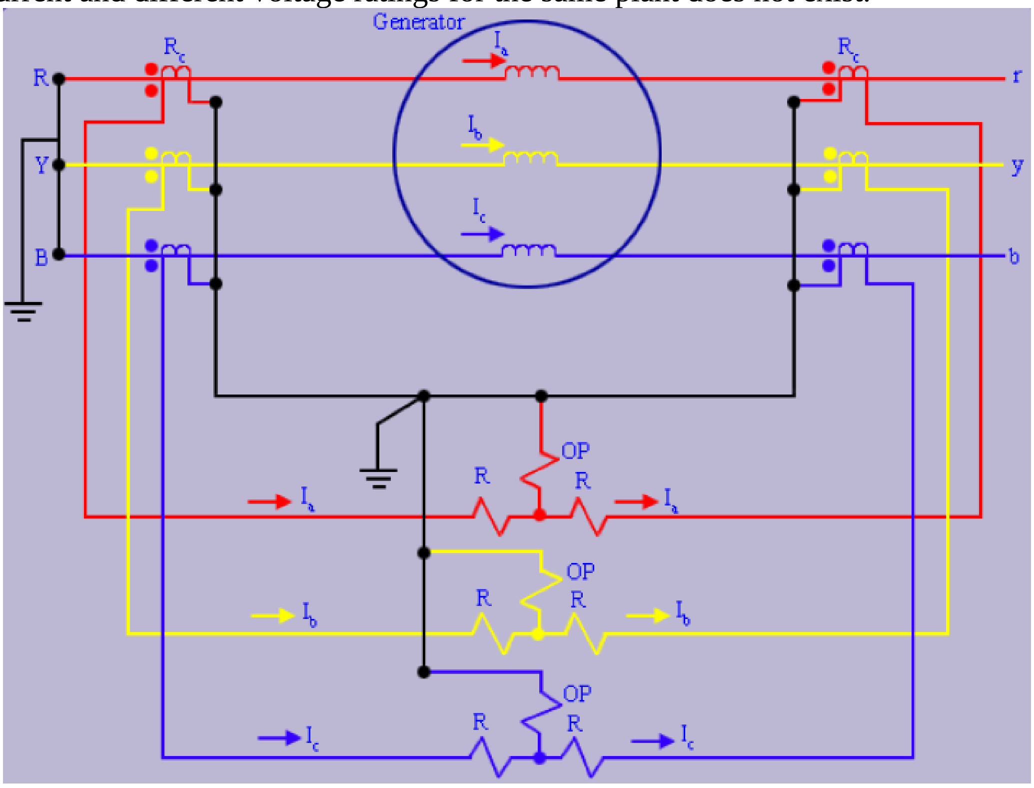


Figure 4.9: Differential protection of star-connected generator

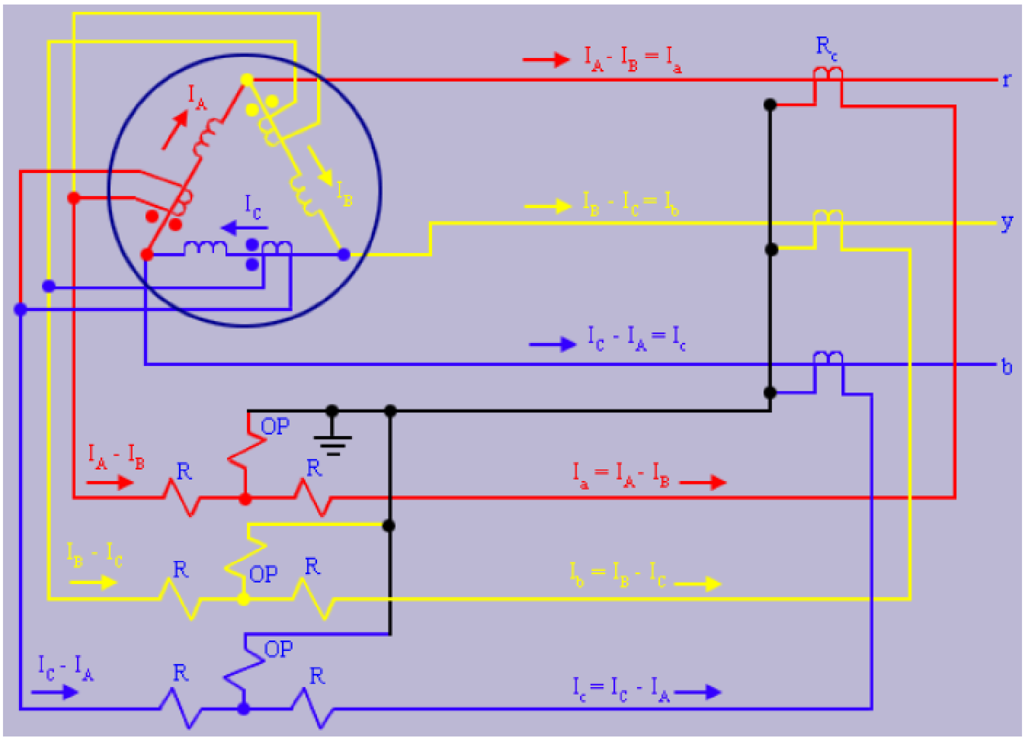


Figure 4.10: Differential protection of delta-connected generator

4.7 **Busbar differential protection**

The most common bus differential relays use either high-impedance or low-impedance differential elements. A high-impedance differential relay forms an operating quantity by connecting zone CTs in parallel with a resistive element. A high-impedance differential relay can be microprocessor-based or electromechanical. A low-impedance differential relay presents a small burden to a CT, and there are several ways to configure low-impedance differential elements.

Figure 4.11 depicts a high-impedance differential element. In high-impedance applications, all CT ratios should be the same because the secondary operating quantity is the result of a physical summation of CT currents. It is also important for the CTs to have similar excitation characteristics, so as not to produce a false operating current for a given burden voltage. Under normal conditions, the sum of the CT currents is zero and no current flows through the resistive element. During a bus fault, the secondary operating current flows through the high-impedance element, resulting in a substantial voltage rise across the resistor. The relay senses this voltage rise and issues a trip signal. A metal oxide varistor (MOV) is used to limit the voltage applied to the resistor to tolerable levels.

Figure 4.12 shows a high impedance differential scheme for a non-sectioned bus. For this scheme, the CTs are connected in parallel. All S1 CT terminals are connected together and form a bus wire. Similarly S2 terminals are connected together to form another bus wire. A tripping relay is connected across these two bus wires as shown in figure 4.11. The current in the tripping relay is the vector sum of the individual line currents applying Kirchoff's current law.

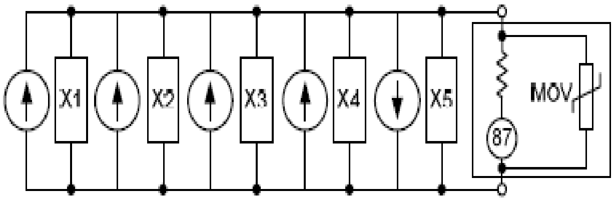


Figure 4.11 : High-impedance differential element

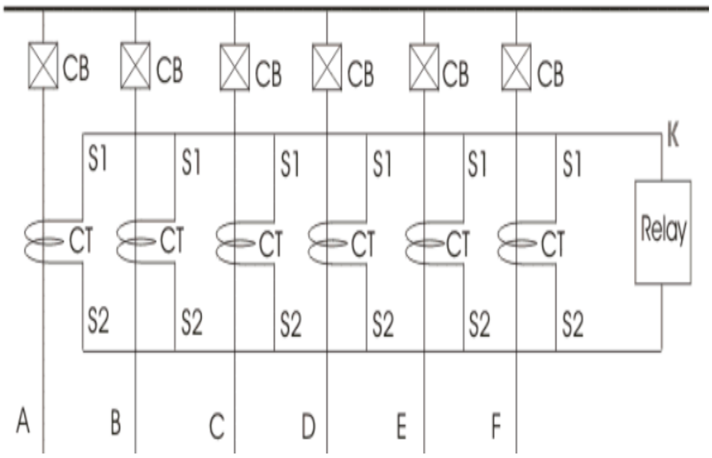


Figure 4.12: Arrangement of CTs in busbar differential protection

In figure 4.12, if it is assumed that lines A, B, C, D, E and F carry currents I_A, I_B, I_C, I_D, I_E and I_F respectively. Applying Kirchoff's current law, the relay current, I_R is given as:

$$I_R = I_A + I_B + I_C + I_D + I_E + I_F \tag{3}$$

The relay current I_R, is zero under normal or external fault conditions.

Now consider a situation when a fault occurs on the bus. For this condition, the sum of all CT secondary currents is no longer zero. Thus I_R will have a non-zero value resulting in the tripping of all line breakers connected to the bus.

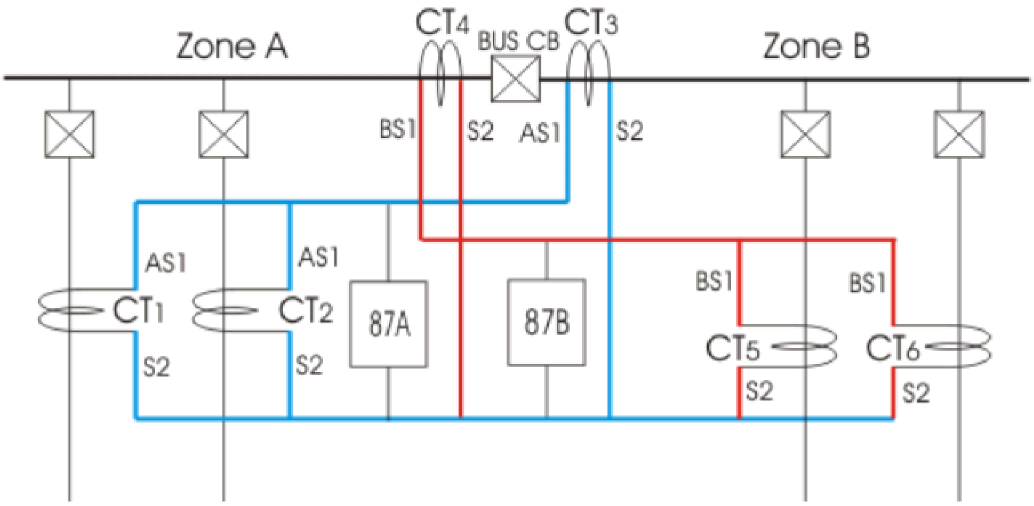


Figure 4.13: Differential protection for a sectioned bus

Figure 4.13 shows a scheme for a sectioned bus. Here, bus section A or zone A is bounded by CT_1, CT_2 and CT_3 where CT_1 and CT_2 are line CTs and CT_3 is bus CT. Similarly, bus section

B or zone B is bounded by CT_4, CT_5 and CT_6. Therefore, zone A and B made to overlapped to ensure full protection of bus. ASI terminals of CTs 1, 2 and 3 are connected together to form secondary bus ASI; BSI terminals of CT_4, 5 and 6 are connected together to form secondary bus BSI. S_2 terminals of all CTs are connected together to form a common bus S_2. Now, busbar protection relay 87A for zone A is connected across bus ASI and S_2. Relay 87B for zone B is connected across bus BSI and S_2. Any fault in zone A, with trip only CB_1, CB_2 and bus C_B. Any fault in zone B, will trip only CB_5, CB_6 and bus CB. Hence, fault in any section of bus will isolate only that portion.

5. DISTANCE PROTECTION

5.1 Introduction

Distance relays can be classified into phase relay and ground relays. Phase relays are used to protect the transmission line against phase faults (three phase, L-L) and ground relays are used to protect against ground faults (S-L-G, L-L-G). Just like an overcurrent relay, a distance relay also has to perform the dual task of primary and back up protection. For example, in fig. 5.1, the distance relay R1 has to provide primary protection to line AB and back up protection to lines BC, BD and BE.

The primary protection should be fast and hence preferably it should be done without any intentional time delay, while back up protection should operate if and only if corresponding primary relay fails. In figure 5.1, R_1 backs operation of relays R_3, R_5 and R_7.

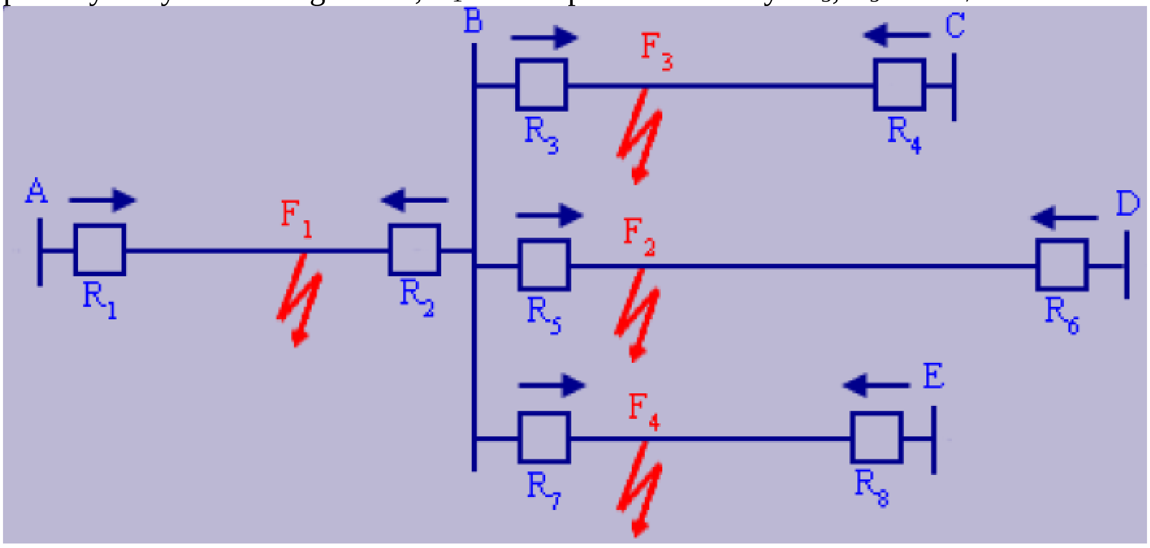


Figure 5.1: Primary and Backup protection

5.2 Zones of Protection

Typically, distance relays are provided with multiple zones of protection to meet the stringent selectivity and sensitivity requirements. At least three zones of protection are provided for distance relays. Digital and numerical distance relays may have up to five zones, some set to measure in the reverse direction.

5.2.1 *Zone 1 protection*

Zone 1 is designated by Z_1 and zones 2 and 3 by Z_2 and Z_3 respectively. Zone 1 is meant for protection of the primary line. Typically, it is set to cover 80% of the line length. Zone 1 provides fastest protection because there is no intentional time delay associated with it. Operating time of Z1 can be of the order of 1 cycle. Zone 1 does not cover the entire length of the primary line because it is difficult to distinguish between faults at F_1 and $F_2/F_3/F_4$ all of which are close to bus B. In other words, if a fault is close to bus, one cannot ascertain if it is on the primary line, bus or on back up line. This is because of the following reasons:

(a) CTs and PTs have limited accuracy. During fault, a CT may undergo partial or complete saturation. The resulting errors in measurement of apparent impedance seen by relay, makes it difficult to determine fault location at the boundary of lines very accurately.

(b) Derivations for equations of distance relays made some assumptions like neglecting capacitance of line, unloaded system transposed lines and bolted faults. In practice none of these assumptions are valid. Fault on a line will also destroy effect of transposing. Such factors affect accuracy of distance relaying. Further, algorithms for numerical relays may use a specific transmission line model. For example, a transmission line may be modelled as a series R – L circuit and the contribution of distributed shunt capacitance may be neglected. Due to model limitation and because of transients accompanied with the fault, working of numerical algorithm is prone to errors.

(c) With only local measurements, and a small time window, it is difficult to determine fault impedance accurately. For example, if the fault has an impedance (i.e. $Z_f \neq 0$), then the derivations of previous lectures are no more exact. The impedance seen by the relay R1 (figure 5.2) for fault *F* also depends upon the current contribution from the remote end, thus

$$Z_R = xZ_l + Z_F + Z_F \frac{I_{BF}}{I_{AF}}. \tag{5.1}$$

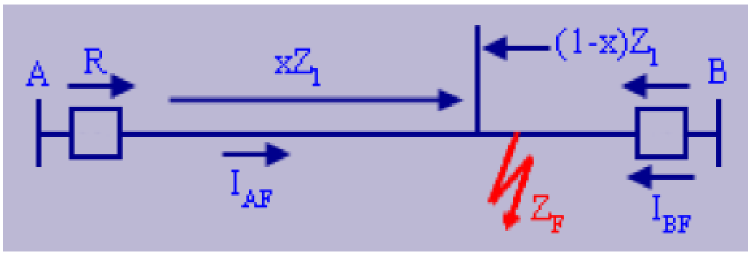


Figure 5.2: A fault with path impedance

(d) There are infeed and outfeed effects associated with working of distance relays. Recall that a distance relaying scheme uses only local voltage and current measurements for a bus and transmission line. Hence, it cannot model infeed or outfeed properly.

5.2.2 *Zone 2 and Zone 3 Protection*

Usually zone 2 is set to 120% of primary line impedance Z_1. This provides sufficient margin to account for non-zero fault impedance and other errors in relaying. Also one should note that Z_2 also provides back up protection to a part of the adjacent line. Therefore, one would desire that Z_2 should be extended to cover as large a portion of adjacent line as possible.

Typically, Z_2 is set to reach 50% of the shortest back up line provided that $Z_p + 1.5Z_b > 1.2Z_p$ where Z_p and Z_b are the positive sequence impedance of primary and the shortest back up line respectively. If the shortest back up line is too short then, it is likely that $Z_p + 1.5Z_b$ will be less than $1.2Z_p$. In such a case, Z_2 is set to $1.2Z_p$.

Since, back-up protection has to be provided for the entire length of remote line, a third zone of protection, Z_3 is used. It is set to cover the farthest (longest) remote lines (BD in figure 5.3(a) for relay R_1 acting as a back-up relay). Since its operation should not interfere with Z_2 operation of relays R_1, R_3 ,R_5 and R_7, it is set up to operate with a time delay of $2\Delta t$ where Δt is the coordination time interval. The settings of relay R_1 on an R-X plane is visualized in figure 5.2(b). The timing diagrams are shown in figure 5.2(c).

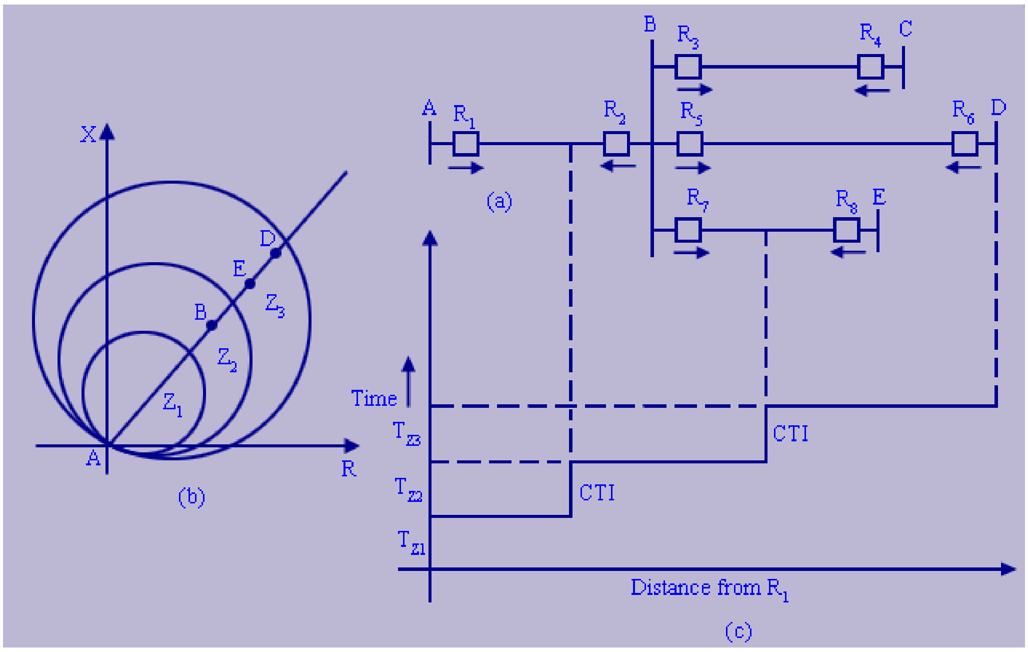


Figure 5.3: Three zones of protection

There is a specific reason as to why Z_2 is not set to reach beyond 50% of the shortest remote line. As shown in figure 5.4(a), if the reach of Z_2 of a relay R_1 is extended too much, then it can overlap with the Z_2 of the relay R_3. Under such a situation, there exists following conflict. If the fault is on line BC (and in Z_2 of R_3), relay R_3 should get the first opportunity to clear the fault. Unfortunately, now both R_1 and R_3 compete to clear the fault. This means that Z_2 of the relay R_1 has to be further slowed down by Δt. This leads to timing diagram (figure 5.4 (b)).

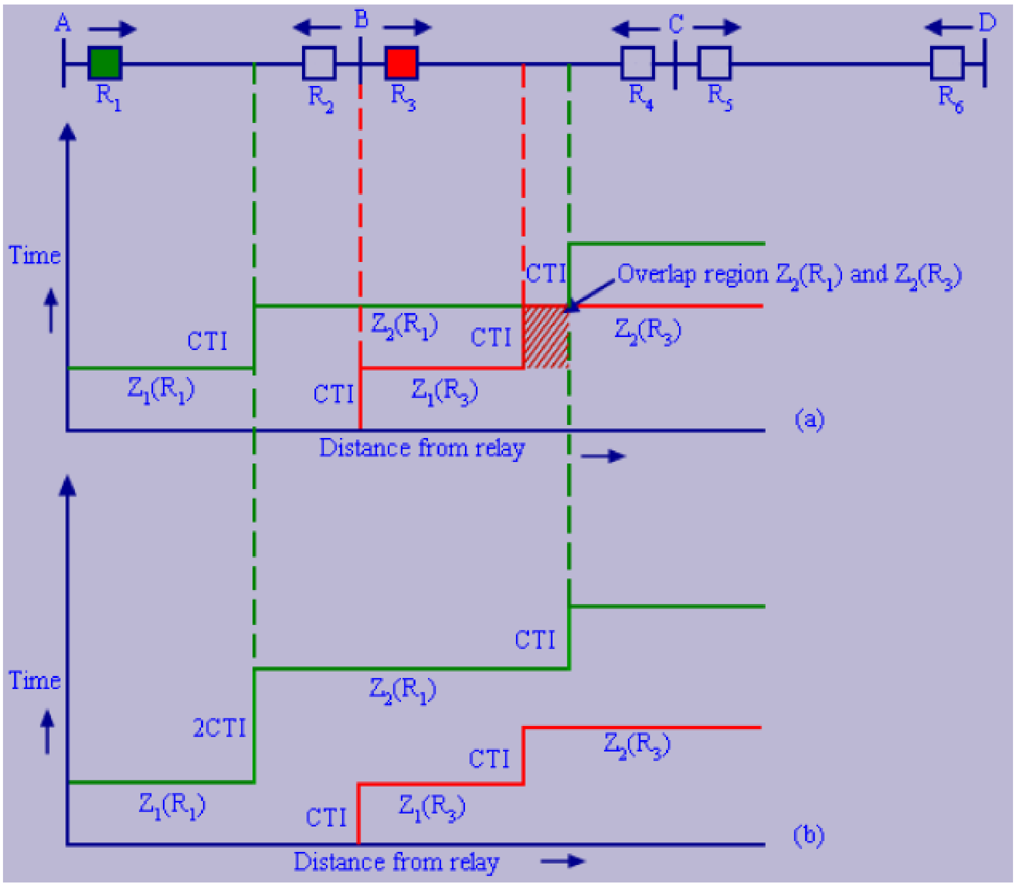
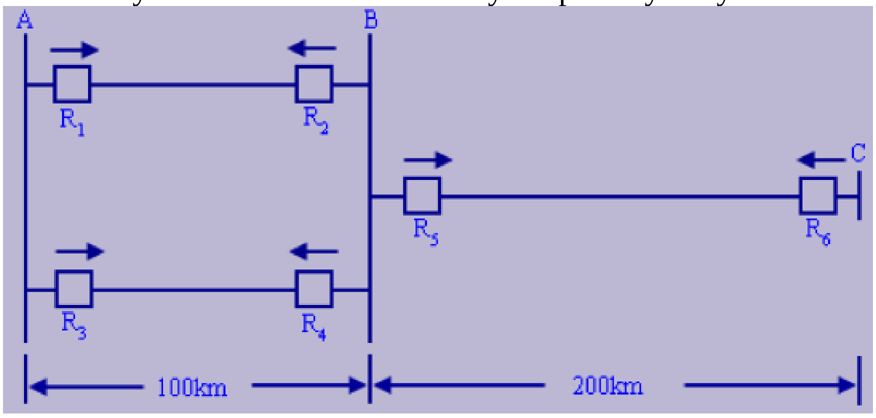


Figure 5.4: Overload problem of Z_2

Thus, it is clear that fault clearing time in 20% region of line AB is delayed a bit too much, thereby degrading performance of Z_2 of relay R_1. Hence, a conscious effort is made to avoid overlaps of Z_2 of relay R_1 and R_3. Setting back zone Z_2 of R_1 to maximum of 120% of primary line impedance or primary line impedance plus 50% of smallest back up impedance usually works out as a good compromise to reach as much of back up lines by Z_2 without getting into Z_2 overlap problem. However, under certain conditions, when the shortest line to be backed up is too short, it may not be possible to avoid Z_2 overlap. Similarly, one may even encounter Z_3 overlap problem. On such small line segments, alternative way to improve speed characteristic of relay is to use pilot relaying.

Example 5.1

Consider a protection system shown below. Identify the primary relays for back up relay R_1.



Solution

Relay R_1 not only backs up line BC but also parallel line AB. Therefore, for relay R1 acting as back up, the primary relays are R_5 and R_4.

Example 5.2

Assuming that the impedance of all transmission lines in the figure of example 5.1 is $0.1 pu/km$, determine the setting of zone 1, zone 2 and zone 3 elements of relay 1.

Solution

$Z_1 = 80\% \times 100 \times 0.1 = 8 pu$

$Z_2 = 100\% \times 100 \times 0.1 + 50\% \times 100 \times 0.1 = 15 pu$ [Because BA is the shortest backup line]

$Z_3 = 100\% \times 100 \times 0.1 + 200\% \times 100 \times 0.1 = 30 pu$ [Because BC is the longest backup line]

This approach for setting of distance relays presented is known as kilometric distance approach because the set values of impedances are proportional to lengths. In doing so, we have neglected effect of load currents and as well as the effect of change in operating condition in the system. More accurate settings can be computed by evaluating fault impedance seen by the relay for a fault by using short circuit analysis programs.

5.3 Outfeed and infeed effect

Consider the operation of distance relay R_1 for a fault F close to remote bus on line BC (figure 5.6). Due to the configuration of generators and loads, $I_{BF} = I_{AB} + I_{ED}$. Hence

$$\begin{aligned} V_{R1} &= I_{AB} Z_1 + x Z_2 I_{BF} \\ &= I_{AB}(Z_1 + x Z_{l2}) + x Z_{l2} I_{ED} \end{aligned}$$

$$\frac{V_{R1}}{I_{AB}} = Z_1 + xZ_{l2} + xZ_{l2}\frac{I_{ED}}{I_{AB}} \tag{5.2}$$

Thus, it is note that the distance relay at R_1 does not measure impedance $(Z_1 + xZ_{l2})$. If there is an equivalent generator source at bus E, then it feeds the fault current. Thus I_{AB} and I_{ED} are approximately in phase. This is known as infeed effect. From (5.2), it is clear that infeeds cause an equivalent increase in apparent impedance seen by the relay R1.

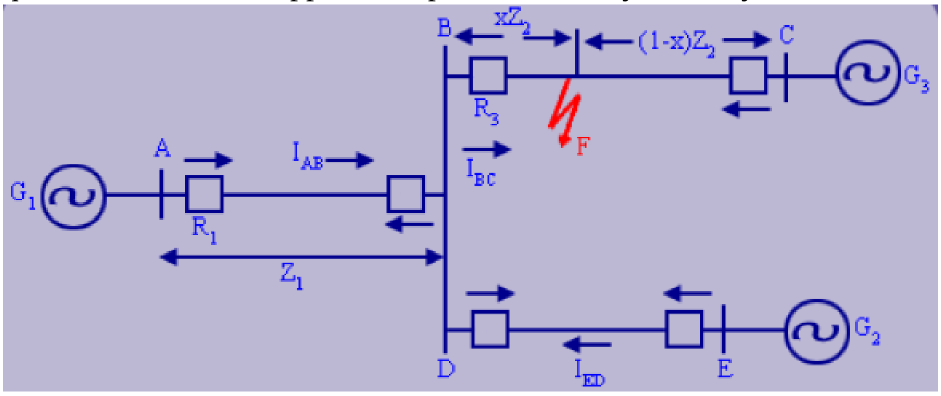


Figure 5.6: Outfeed and infeed effects

From the relay's perspective, the fault is pushed beyond its actual location. Thus, a fault in zone-2 may be pushed into zone-3, thereby compromising selectivity of zone-2. However, infeed effect does not compromise selectivity of zone-1. In other words, relay R_1 perceives fault farther away than its actual location. However, if there is an equivalent load at bus E, then I_{AB} and I_{ED} are in phase opposition. This causes an apparent reduction in the impedance seen by the relay R_1. In other words, the relay R_1 perceives fault to be at a point closer than its actual location. If this perceived point falls well in the section AB, the relay R1 will operate instantaneously for a fault on the back up line, thereby compromising selectivity. Hence, instantaneous primary protection zone (Z_1) of distance relay is always set below 100% line impedance.

Typically, zone 1 is set to cover 0.8 to 0.9 times the primary line length. In other words, it is expected that the errors in measurements of fault impedance will to be within 10-20% accuracy. The remaining portion of the primary line is provided with a time delayed protection known as Z_2. The zone 2 protection is delayed at least by the coordination time interval, Δt to give first opportunity to relays $R_3/R_5/R_7$ to clear a close in fault if it falls into its primary protection zone. Note that, relay R_3 in figure 5.6 is immune to infeed or outfeed effect for fault F.

5.4 Problem of load encroachment

Consider the steady state positive sequence model of a transmission line shown in figure 5.7.

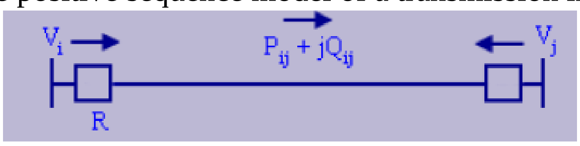


Figure 5.7: Power flow on a transmission line

The apparent impedance seen by relay R is given by,

$$Z_R = \frac{|V_i|^2}{P_{ij} - jQ_{ij}} = \frac{|V_i|^2}{P_{ij}^2 + jQ_{ij}^2}\left(P_{ij} + jQ_{ij}\right) \tag{5.3}$$

Thus from (5.3), the following conclusions can be drawn:

(i) Quadrant of Z_R in the R - X plane correspond to the quadrant of apparent power (S_{ij}) in ($P_{ij} - jQ_{ij}$) plane.

(ii) The apparent impedance seen by the relay is proportional to square of the magnitude of bus voltage. If the bus voltage drops say to 0.9 pu from 1 pu, then Z_R reduces to 81% of its value with nominal voltage. Further, if the bus voltage drops to say 0.8pu, then the apparent impedance seen by the relay will drop to 64% of its value at 1pu.

(iii) The apparent impedance seen by the relay is inversely proportional to the apparent power flowing on the line. If the apparent power doubles up, the impedance seen by relay will reduce by 50%.

During peak load conditions, it is quite likely that combined effect of (ii) and (iii) may reduce the apparent impedance seen by the relay to sufficiently small value so as to fall in Z_2 or Z_3 characteristic. This is quite likely in case of a relay backing up a very long line. In such a case, Z_3 impedance setting can be quite large. If the impedance seen by relay due to large loads falls within the zone, then it will pick up and trip the circuit after its time dial setting requirement are met. Under such circumstances, the relay is said to trip on load encroachment. Tripping on load encroachment compromises security and it can even initiate cascade tripping which in turn can lead to black outs.

Thus, safeguards have to be provided to prevent tripping on load encroachment. A distinguishing feature of load from faults is that typically, loads have large power factor and this leads to Z_{app} with large R/X ratio. In contrast, faults are more or less reactive in nature and the X/R ratio is quite high.

Thus, to prevent tripping on load encroachment, the relay characteristic are modified by excluding an area in R – X plane, which corresponds to high power factor. A typical modified characteristic to account for load encroachment is shown in figure 5.8. The conditions of low value of Z_R discussed in (1) and (2) can also arise due to voltage instability or transients associated with electromechanical oscillations of rotors of synchronous machines after a major disturbance like the faults. This can also induce nuisance tripping. Such tripping is known as “tripping on power swings”.

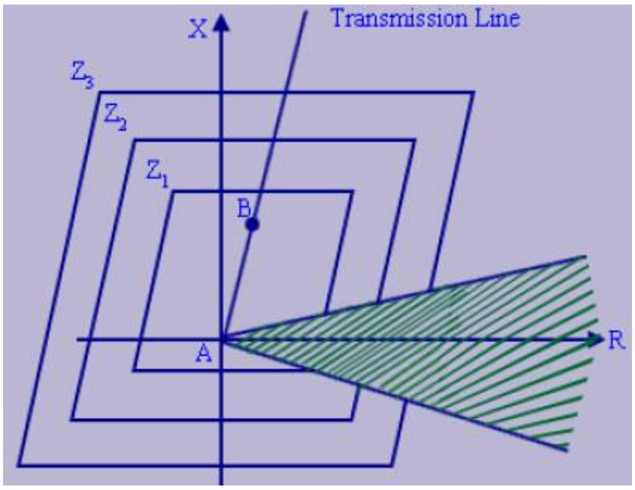


Figure 5.8: Distance relay characteristic modified for load encroachment

5.5 **Pilot protection with distance relays**

As has already been noted, distance relays provide fast protection up to 80% of the primary line length. However, primary protection for the remaining 20% is deliberately slowed down by coordination time interval. Pilot protection is adopted in order to provide high speed simultaneous detection of phase and ground faults for 100% of the primary line. Since distance relays are directional relays, the corresponding schemes are known as directional comparison schemes. The basic idea behind all these schemes is to obtain the response of the distance relay element at other end to speed- up decision making. This requires additional communication signals. The following directional comparison schemes are in use.

(i) Directional comparison blocking
(ii) Directional comparison unblocking
(iii) Overreaching transfer trip
(iv) Under reaching transfer trip: a) non-permissive. b) permissive.

5.5.1 ***Directional Comparison Blocking***

Directional comparison blocking employs directional fault detectors to detect faults in the direction of primary line. Blocking signal from the remote end is utilised in case the fault is not on the primary line.

Consider the requirement of protecting line AB. If the fault is at F_1 (anywhere on the line AB), fast protective action is required from relays R_1 and R_2. To achieve this action, relays $R_1$and R_2 are enabled with two units each called fault detectors (FD_1 and FD_2) and carrier starts S_1 and S_2. Typically, the fault detectors correspond to Z_2 of distance relays at respective locations as shown in figure 5.9. They overreach the primary line. The carrier start relays look for fault in opposite sense to respective FD. They are called carrier starts because the channel signals between A and B are initiated by them.

Imagine a scheme where FD issues a trip signal after identifying a fault unless it is quickly blocked by an external agent (carrier starters). For example, if the fault is in F_1, both FD_1 and FD_2 will pick up. Since neither carrier starts S_1 nor S_2 will pick up, fault F_1 will be cleared quickly. In contrast, suppose that fault is at F_2. Then FD_1 will pick up and so will S_2. The S_2 will initiate channel and send blocking signal to FD_1. The FD_1 will be blocked from tripping action until its timer runs out. In this interval, either the primary relay R_3 will clear the fault or else it is cleared by R_1 as a backup measure. In other words, in this scheme, the relays are set for fast clearing action. They do not care whether the fault is in primary line or the backup line. Blocking from the other end is used to prevent fast tripping for faults on backup line.

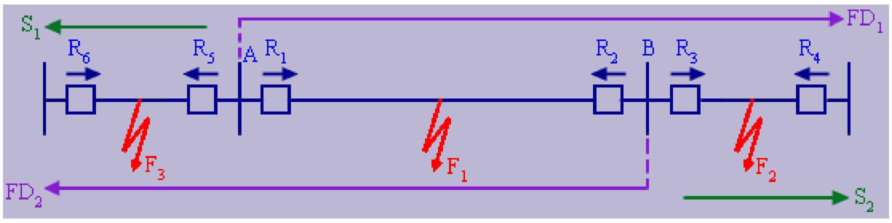


Figure 5.9: Directional comparison blocking

5.5.2 *Directional comparison unblocking pilot system*

The directional comparison unblocking pilot system puts relays in 'block mode' for the coordination time interval, after detecting a fault in the right direction. It also uses unblock signals from the remote end if the fault is on the primary line. In this scheme, as shown in figure 5.10, Z_2 of R_1 and R_2 remain in 'block mode' for a specified time after seeing the fault. Of course, if there is no fault in the system anywhere, neither fault detectors will pick up. In case, relay R_2 observes a fault in the direction of bus A, it sends an unblock signal to relay R_1 (and vice- versa). If the fault is in the primary line AB (F_1), both $R_1$and R_2 detect the fault, and also receive unblock signal from the opposite end. The unblocking signal helps in immediate action of both relays R_1 and R_2 leads to fast tripping of line. In case, the fault is at F_2, then relay R_2 will not send unblock signal to R_1. When relay R_1 sees the fault, its FD also initiates a down counter set to Δt. If the FD detects fault even after counter has run down, then a trip signal is issued by R_1 for back up fault clearing action in the adjacent line.

The advantage of directional comparison unblocking pilot system is that it eliminates need of carrier starts S_1 and S_2. Typically, it is implemented using frequency shift keying (FSK) channels. To summarize, the relays or more appropriately their fault detectors detect fault in the appropriate direction. Unblock signal from the remote end is used to quickly clear the faults on the primary line.

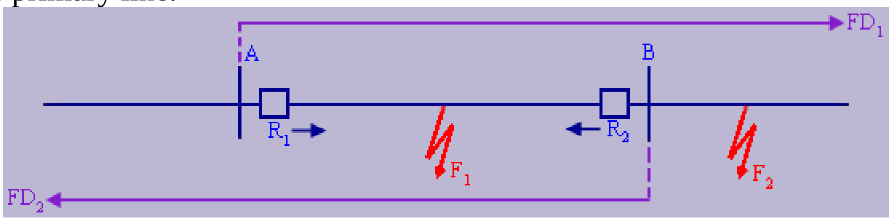


Figure 5.10: Directional comparison unblocking pilot system

5.5.3 *Directional Comparison Overreaching Transfer Trip Pilot System*

The directional comparison overreaching transfer trip pilot system initiate trip only if a fault is detected from both ends of the line.

This scheme is shown in figure 5.11. In this scheme, for internal fault, both FD_1 and FD_2 operate to shift respective transmitters to trip mode. A logical AND-ing of trip of both FD_1 and FD_2 provides the trip output at both ends of the line. In case of external fault either FD_1 or FD_2 will not pick up and hence relays R1and R2 will not operate.

In case there is no fault, neither FD_1 nor FD_2 operate. In case of external fault either FD_1 or FD_2 will pick up depending upon whether fault is on right side of node B or left side of node A. This over reaching initiates a timer. If external fault persists beyond Δt, then a back-up trip decision is initiated by Z_2 of the respective relays.

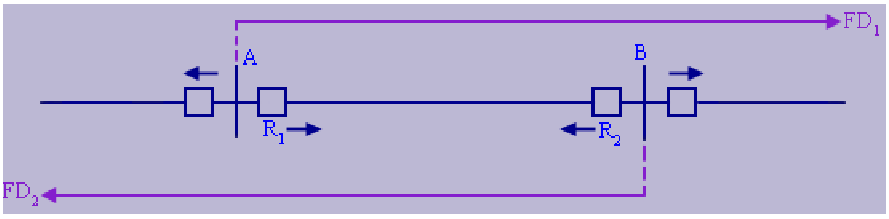


Figure 5.11: Directional comparison overreaching transfer trip pilot system

5.5.4 *Directional comparison under reaching transfer trip pilot system*

The under reaching terminology implies that the FDs are to be set so as always to overlap but not over reach any remote terminal under all operating condition. The schematic diagram of this scheme is given in figure 5.12. Phase directional distance relay zone1 unit meets this requirement. Two types of such implementation exist. They are (i) non permissive, and (ii) permissive. With external faults, neither FD_1 nor FD_2 picks up. For internal faults in the overlap area of FD_1 and FD_2 both FD_1 and FD_2 pick up. To clear internal faults which are not in the overlap region quickly, OR-ing of the trip decision of FD_1 and FD_2 is used at both ends. This system is not very much in use.

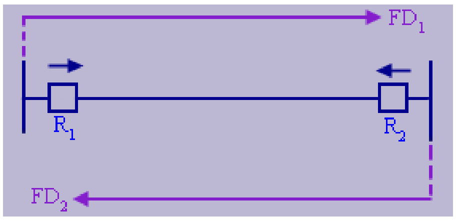


Figure 5.12: Directional comparision under reaching transfer trip pilot system

6. GENERATOR PROTECTION

6.1 Introduction

Generators are designed to run at a high load factor for a large number of years and permit certain incidences of abnormal working conditions. The machine and its auxiliaries are supervised by monitoring devices to keep the incidences of abnormal working conditions down to a minimum. Despite the monitoring, electrical and mechanical faults may occur, and the generators must be provided with protective relays which, in case of a fault, quickly initiate a disconnection of the machine from the system and, if necessary, initiate a complete shutdown of the machine.

A generator has to be protected not only from electrical faults (stator and rotor faults) and mechanical problems (e.g. related to turbine, boilers, etc), but it also has to be protected from adverse system interaction arising like generator going of out-of-step with the rest of system, loss of field winding etc. Under certain situations like internal faults, the generator has to be quickly isolated (shut down), while problems like loss of field problem requires an 'alarm' to alert the operator. Possible generator fault conditions are listed below:

a) Stator faults
b) Rotor faults
c) Thermal overload
d) Overvoltage
e) Unbalanced loading
f) Loss of excitation
g) Over excitation
h) Under-frequency
i) Inadvertent energization
j) Loss of synchronism

6.2 Stator protection

Stator faults result from insulation breakdown that causes an arc to develop, either from phase to phase or from the phase conductor to the grounded magnetic steel laminations of the stator. The cause of the insulation breakdown may be due to overvoltage, overheating, or mechanical damage of the winding insulation due to faults. The overvoltage that may cause an insulation failure might be due to lightning or switching surges, which are usually protected against by surge protective devices. Overheating may be due to prolonged unbalanced loading or to the loss of cooling, either of which may cause insulation deterioration over a period of time. There are many different types of stator protection. Phase fault and ground fault protections schemes have been explained below.

6.2.1 *Phase fault protection*

Phase faults in generators are rare, but they can occur and must be protected against. Phase faults can develop in the winding end turns, where all three phase windings are in close proximity or in slots if there are two coils in the same slot. Phase faults often change to ground faults, but they must be detected in either event. The standard method of protection against phase faults is the differential method, and usually the percentage differential type of relay is used. Most generator manufacturers recommend this type of protection for all units larger than about 1*MVA*.

6.2.2 *Earth fault protection*

Most of the generator stator winding faults are phase-to-earth faults. This is true because the windings are always in close contact with steel slots that are at earth potential and, in some designs, are not close to other phase conductors except for the end turns. Phase-to-phase faults are less severe, in a sense, since the damage due to these faults can sometimes be repaired by carefully taping the damaged insulation. This is not possible for ground faults, which often melt the steel laminations and may cause so much steel damage that the core laminations will have to be rebuilt, resulting in a very long outage.

The neutral point of the generator stator winding is normally earthed so that it can be protected, and impedance is generally used to limit earth fault current. Generators connected direct to the distribution network are usually earthed through a resistor. However, the larger generator–transformer unit (which can be regarded as isolated from the EHV transmission system) is normally earthed through the primary winding of a voltage transformer, the secondary winding being loaded with a low ohmic value resistor. Its reflected resistance is very high (proportional to the squared turns ratio) and it prevents high transient overvoltages being produced as a result of an arcing earth fault.

Earth fault protection can be applied by using a transformer and adopting a relay to measure the earthing transformer secondary current or by connecting a voltage-operated relay in parallel with the loading resistor (see Figure 6.1).

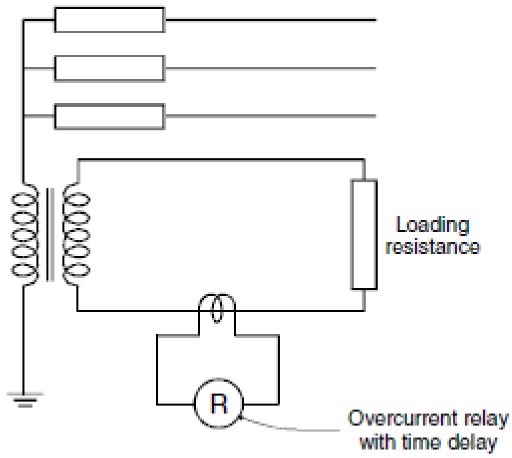


Figure 6.1: Earth fault protection using a relay to measure secondary current

The current operated relay should incorporate third harmonic filter and is normally set for about 5% of the maximum earth fault current. The third harmonic filter is required because of the low current of the earthing system, which may not be much different from the possible third harmonic current under normal conditions. The time delay is essential to avoid trips due to surges (see Figure 6.2).

In the voltage-operated type, a standard induction disk type overvoltage relay is used. It is also to be noted that the relay is connected across the secondary winding of the transformer and the relay shall be suitably rated for the higher continuous operating voltage. Further, the relay is to be insensitive for third harmonic current. Phase-to-phase faults clear of earth are less common. They may occur on the end coils or on adjacent conductors in the same slot. In the latter case, the fault would involve earth in a very short time.

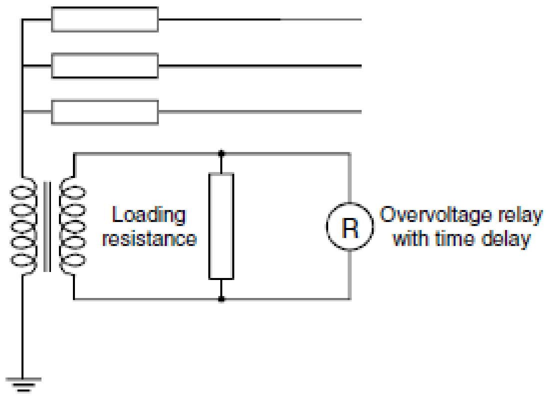


Figure 3: Earth fault protection using a relay in parallel with loading resistor

6.3 **Rotor protection**

The rotor has a DC supply fed onto its winding which sets up a standing flux. When this flux is rotated by the prime mover, it cuts the stator winding to induce current and voltage therein. This DC supply from the exciter need not be earthed. If an earth fault occurs, no fault current will flow and the machine can continue to run indefinitely, however, one would be unaware of this condition. Danger then arises if a second earth fault occurs at another point in the winding, thereby shorting out portion of the winding. This causes the field current to increase and be diverted, burning out conductors.

In addition, the fluxes become distorted resulting in unbalanced mechanical forces on the rotor causing violent vibrations, which may damage the bearings and even displace the rotor by an amount, which would cause it to foul the stator. It is therefore important that rotor earth fault protection be installed.

There are several methods of detecting a rotor circuit ground. The three most common ones are: (i) Potentiometer method, (ii) AC injection method and (ii) DC injection method.

The potentiometer method (refer to figure 6.3) measures the voltage to ground of a center tapped resistor, connected across the exciter output voltage. If some point in the winding becomes grounded, there will be a potential between that point and the point to which the voltage relay is connected. The only problem is that, should a point very close to the center of the winding become grounded, the center tapped potentiometer would not detect it. To check that this has not happened, a manual switch is arranged to move the test point from the center to some other point along the resistor. The operator can check this periodically to ensure that the system is sound.

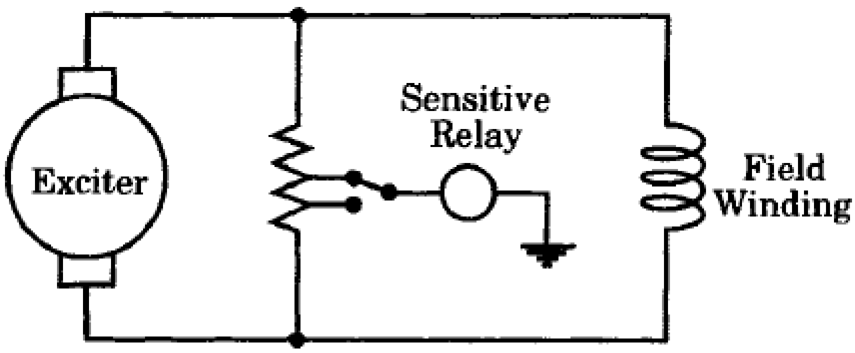


Figure 6.3: Potentiometer method of detecting rotor circuit ground

A better method is the ac injection method (refer to figure 6.4), which connects an ac voltage to the field winding through a capacitor. Should any point on the field winding become grounded, the circuit will be complete and the relay will trip. This system has no blind point. There is a disadvantage, however, in that some current will flow through the capacitance from the field winding to the rotor body, through the rotor body, the bearings, and to ground. This has the potential of causing erosion of the metal in the bearings.

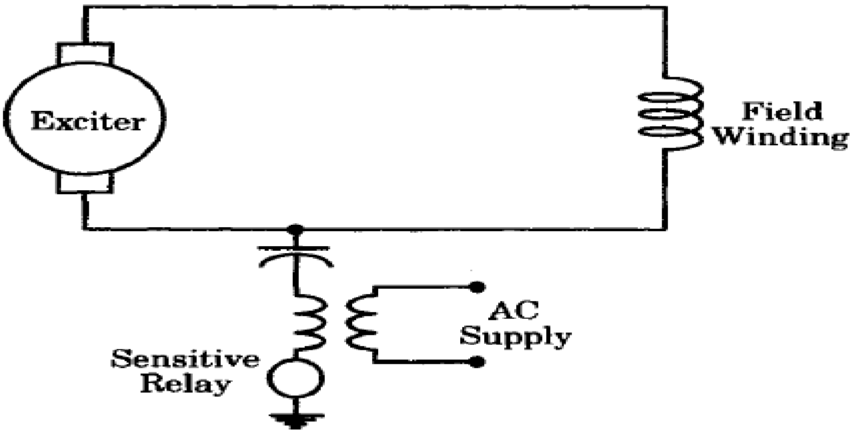


Figure 6.4: AC injection method of detecting rotor circuit ground

A still better method is the dc injection method. The dc output of the transformer-rectifier unit is connected to bias the positive side of the field circuit to a negative voltage relative to ground. A ground at any point on the field winding will complete the circuit to the grounded side of the relay (see figure 6.5). The relay is a sensitive current relay in this case, but must not be so sensitive that it will trip due to normal insulation leakage current. The current through the relay is limited by the high impedance of the rectifier.

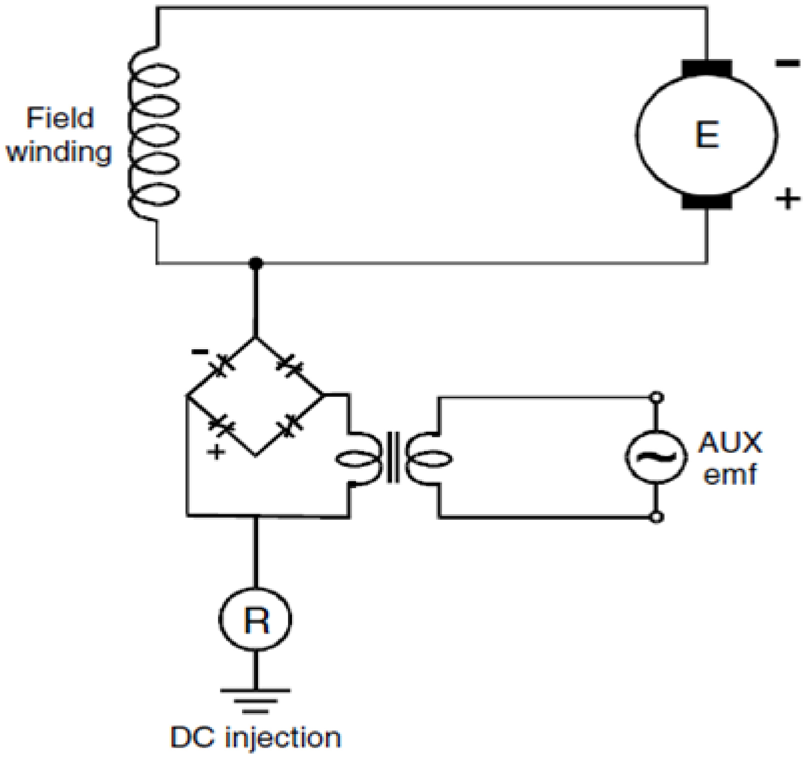


Figure 6.5: DC injection method of detecting rotor circuit ground

6.4 **Unbalance loading**

A three-phase balanced load produces a reaction field, which is approximately constant, rotating synchronously with the rotor field system. Any unbalanced condition can be broken down into positive, negative and zero sequence components. The positive component behaves similar to the balanced load. The zero components produce no main armature reaction. However, the negative component creates a reaction field, which rotates counter to the DC field, and hence produces a flux, which cuts the rotor at twice the rotational velocity. This induces double frequency currents in the field system and rotor body.

The resulting eddy currents are very large, so severe that excessive heating occurs, quickly heating the brass rotor slot wedges to the softening point where they are susceptible to being extruded under centrifugal force until they stand above the rotor surface, in danger of striking the stator iron.

Transmission line dissymmetries due to non-transposed phase wires and open-conductors (for example due to circuit-breaker pole failure) also give rise to considerable negative-sequence currents, as a maximum of more than 50 % of rated machine current. Single-phase and, especially, two-phase short circuits give rise to large negative sequence currents. The combination of two or more of conditions that create unbalance can give rise to harmful negative phase sequence currents, even if each of them gives rise to a relatively small unbalance. It is therefore very important that negative phase sequence protection be installed, to protect against unbalanced loading and its consequences.

6.5 **Loss of excitation**

A complete loss-of-excitation may occur as a result of:

- unintentional opening of the field breaker,
- an open circuit or a short circuit of the main field, or
- a fault in the automatic voltage regulator (AVR), with the result that the field current is reduced to zero.

When a generator with sufficient active load loses the field current, it goes out of synchronism and starts to run asynchronously at a speed higher than the system, absorbing reactive power (var) for its excitation from the system. The loss of excitation represents a threat mainly from the following reasons:

- Stator overloading as result of significant supply of reactive power from the grid.
- Warming up of rotor winding influenced by induced currents,
- extensive swings of active power, which are typical for asynchronous operation.

The loss of excitation can have adverse effect not only on the generator itself, but also on the whole grid and adjacent generators — mainly if they are connected to common point with the generator that lost excitation (i.e. generators in one power plant). If a generator that loses excitation is not shut down, the adjacent generators start increasing the production of reactive power up to the limit when their limiters of rotor and stator currents act.

If even the grid can cope with increased supply of reactive power, it can cause overloading and subsequent the transmission lines outages in cascades. Significant decrease of voltage in individual nodes of the grid and the resultant threat of voltage collapse could have another adverse effect.

6.6 **Thermal overload**

Generators are very rarely troubled by overload, as the amount of power they can deliver is a function of the prime mover, which is being continuously monitored by its governors and regulator. Where overload protection is provided, it usually takes the form of a thermocouple or thermistor embedded in the stator winding.

6.7 **Loss of synchronism**

A generator could lose synchronism with the power system because of a severe system fault disturbance, or operation at a high load with a leading power factor. This shock may cause the rotor to oscillate, with consequent variations of current, voltage and power factor. If the angular displacement of the rotor exceeds the stable limit, the rotor will slip a pole pitch. If the disturbance has passed, by the time this pole slip occurs, then the machine may regain synchronism otherwise it must be isolated from the system. Alternatively, the field switch is tripped for the machine to run as an asynchronous generator, the field excitation and load are reduced, and finally, the field switch is reclosed to resynchronize smoothly.

6.8 **Reverse power**

In modern power systems where several generators run in synchronism with each other, if one generator's prime mover fails, it operates in the motoring mode, thereby drawing power from the grid to run at synchronous speed. This causes unnecessary overburden on the healthy generators and could aggravate the failure of the mechanical drive of the faulted generator. To prevent this, reverse power relays are installed for each generator to detect any abnormal power flow and thereby isolate the generator from the circuit.

6.9 **Overvoltage**

Overvoltages on a generator may occur due to transient surges on the network, or prolonged power frequency overvoltages may arise from a variety of conditions. Surge arrestors may be required to protect against transient overvoltages, but relay protection may be used to protect against power frequency overvoltages. A sustained overvoltage condition should not occur for a machine with a healthy voltage regulator, but it may be caused by the following contingencies:

- defective operation of the automatic voltage regulator when the machine is in isolated operation
- operation under manual control with the voltage regulator out of service. A sudden variation of the load, in particular the reactive power component, will give rise to a substantial change in voltage because of the large voltage regulation inherent in a typical alternator
- sudden loss of load (due to tripping of outgoing feeders, leaving the set isolated or feeding a very small load) may cause a sudden rise in terminal voltage due to the trapped field flux and/or overspeed.

Sudden loss of load should only cause a transient overvoltage while the voltage regulator and governor act to correct the situation. A maladjusted voltage regulator may trip to manual, maintaining excitation at the value prior to load loss while the generator supplies little or no load. The terminal voltage will increase substantially, and in severe cases it would be limited only by the saturation characteristic of the generator. A rise in speed simply compounds the problem. If load that is sensitive to overvoltages remains connected, the consequences in terms of equipment damage and lost revenue can be severe. Prolonged overvoltages may also occur on isolated networks, or ones with weak interconnections, due to the fault conditions listed earlier. For these reasons, it is prudent to provide power frequency overvoltage protection, in the form of a time-delayed element, either IDMT or definite time. The time delay should be long enough to prevent operation during normal regulator action, and therefore should take account of the type of AVR fitted and its transient response. Sometimes a high-set element is provided as well, with a very short definite-time delay or instantaneous setting to provide a rapid trip in extreme circumstances. The usefulness of this is questionable for generators fitted with an excitation system other than a static type, because the excitation will decay in accordance with the open-circuit time constant of the field winding. This decay can last several seconds. The relay element is arranged to trip both the main circuit breaker (if not already open) and the excitation; tripping the main circuit breaker alone is not sufficient.

7. MOTOR PROTECTION

7.1 Introduction

There are a wide range of ac motors and motor characteristics in existence, because of the numerous duties for which they are used. It could be assumed that properly planned, dimensioned, installed, operated and maintained drives should not break down. In real life, however, these conditions are hardly ever ideal. The frequency of different motor damage differs since it depends on different specific operating conditions. All motors need protection; fortunately, the more fundamental problems affecting the choice of protection are independent of the type of motor and the type of load to which it is connected. However, there are some important differences between the protection of induction motors and synchronous motors (explained later). Motor characteristics must be carefully considered when applying protection. For example, the starting and stalling currents/times must be known when applying overload protection, and furthermore the thermal withstand of the machine under balanced and unbalanced loading must be clearly defined.

The conditions for which motor protection is required can be divided into two broad categories: imposed external conditions and internal faults (refer to table 7). Most breakdowns are caused by an overload. Insulation faults leading to earth faults, turn-to-turn or winding short circuits are caused by excess voltage or contamination by dampness, oil, grease, dust or chemicals.

Table 1.1: Motor faults

EXTERNAL FAULTS	INTERNAL FAULTS
Unbalanced supplies	Bearing failure
Undervoltage	Winding faults
Single phasing	Overloads
Reverse phase sequence	

7.2 Protection schemes for induction motors

The sub-sections the follow discuss the protection schemes applied to induction motors

7.2.1 *Overcurrent*

Overcurrent protection interrupts the electrical circuit to the motor upon excessive current demand on the supply system as a result of either short circuits or ground faults in the motor. Overcurrent protection is required to protect personnel, the motor branch circuit conductors, control equipment, and motor from these high currents.

Overcurrent protection is usually provided by overcurrent relays (together with circuit breakers) and fuses. These devices operate when a short circuit, ground fault or an extremely heavy overload occurs. Most overcurrent sources produce extremely large currents very quickly.

7.2.2 *Overload*

One of the most important relays for the detection of abnormal conditions is the overload relay which is applied to the protection of motors. Overload is a condition caused by an increase in the mechanical load to the motor. The overload relay differs from the overcurrent relay in the following ways. Whereas overcurrent relay must operate quickly in times of around or less than 1s, the overload relay is associated with times of tens of seconds to several minutes. However, the overload relay must be capable of measuring accurately current which is only slightly greater than the nominal full-load current, compared to the overcurrent relay, which under fault conditions is required to detect a current which is many times the normal current.

The function of the overload relay is to prevent the overheating of motor. The operation of a typical motor overload relay is of the order of two minutes at twice full-load current. This long time delay can be achieved using thermal relays. Thermal operation is based on the deflection of a bimetallic strip which is made from two metals with differing rates of linear expansion with heat. The circuit is arranged so that the current heats the bimetallic strip which deflects and after a time closes a contact.
The essential settings of a motor overload relay are:

- A current setting slightly higher than the motor full-load current
- A time setting longer than the starting time at the starting current

7.2.3 ***Phase unbalance***

For three-phase motors, unbalanced phase currents result in a negative phase sequence component which produces a rotating field in the opposite direction to the rotating field produced by the applied system voltage. This counter-rotating field will cause induced currents in the rotor of almost twice normal system frequency, resulting in overheating and possible damage.

Apart from the conditions where one phase of the supply is missing completely, for example, owing to a blown fuse it may be thought that any unbalance in the system is small. This may be true in terms of voltage but as the negative sequence voltage will be applied to the short-circuit impedance of the motor, the current will be substantial. Other conditions which cause unbalanced voltages are heavy single-phase loading or a blown fuse in a power factor correction capacitor circuit. Unbalance relays are employed to curtail the problem associated with phase unbalance.

7.2.4 ***Stalling***

Stalling of the motor refers to a condition, where the motor is unable to rotate. This condition can be caused either due to any obstruction in the load or due to any problem with the motor such as bearing seizure, etc. This condition is also known as locked rotor. When a motor stalls, its slip increases. This causes higher voltage and consequently higher current to be induced in the rotor windings. The stator currents also increase. The equivalent of a motor stalled condition is that of a transformer whose secondary is short circuited. The high current drawn will cause damage to the windings and cause the rotor to heat up. Stall protection devices work by monitoring the motor current and the speed. If the motor draws higher current at a preset low speed, the relay is activated.

The starting current of a direct-on-line motor is practically constant at short-circuit level during most of the run-up period and there is therefore no means of detecting a stalled condition by current level alone. The thermal relay will trip the motor eventually, but because the time is long, it may be too slow to prevent damage. In this case, a single element stalling relay is used. This relay has a directly heated bimetal which gives a low overrun and therefore the operating time can be set close to the maximum run-up time. In some cases, the run-up time is greater than the allowable stall time – which means that the condition can only be resolved by the addition of a speed-measuring relay.

7.2.5 **Insulation failure**

In the great majority of cases, motors are switched by means of contactors; air-break contactors at 415V and vacuum contactors at 3.3kV. At 11kV and sometimes at 6.6kV motors are switched by circuit-breakers. Circuit breakers make and break fault current whereas contactors make but not break fault current. This means that tripping by a contactor must only be undertaken when the current is less than the contactor capability. That is when the condition detected is overload, unbalance or stalling. Fault current caused by insulation failure must not be cleared by a contactor. The usual method is to clear the fault with fuses which protect not only the motor and the cable but also the contactor. An earth-fault relay can be used as it will detect low level earth faults and trip the contactor, but at high fault levels, the fuse would operate before the relay. Sometimes the earth-fault relay has a time delay to ensure that the fuse is faster.

7.2.6 **Differential protection**

11kV and 6.6kV motors are generally star connected which means that a normal overcurrent relay which has a setting higher than the short-circuit current of the motor will not detect faults over a large part of the stator winding. To effect an improvement, a more sensitive relay is needed. This can be provided by differential protection. A possible problem with the differential protection is that the leads between the current transformers in the motor neutral terminal box and the relay which is mounted on the switchgear may be long and therefore could have a high resistance. However, as the most onerous condition under which stability is required is the motor starting current, a fairly low relay setting and reasonable small current transformers can be used. The other set of CTs are mounted close to the relay in the switchgear and therefore the lead length is short.

7.2.7 **Loss of supply**

When supply is removed from an induction motor its back emf will decay exponentially and virtually disappear in a few seconds. During that time there will also be a slight decrease in speed so that the phase of the back emf moves away from the position which it occupied before the removal of the supply. If the voltage was restored before 0.4s, then the voltage applied to the motor would be less than system voltage because of the back emf, and the current would be less than short-circuit current. After 0.4s, the voltage between the applied voltage and the back emf is greater than the applied voltage and the short-circuit current would be correspondingly greater. If the voltage was restored after 0.8s, the short-circuit current would be 1.5 times the normal. This means that the mechanical forces exerted on the rotor would be over twice the normal starting forces and could cause damage to the rotor structure.

For this reason, undervoltage relays are used on large machines to ensure that the machines are disconnected if the loss of voltage exceeds, say, 0.3s. The relay used is either an attracted armature relay with a time-delay relay or an induction relay.

7.3 Protection schemes for synchronous motors

The protection for synchronous motors is the same as that for induction motors but with the addition of a relay to detect loss of synchronism and loss of supply.

For loss of synchronism, an out-of-step relay is applied to motors which could be subjected to sudden overloads. The motor could pull out of step because of an increase in mechanical load or if there is a reduction in supply voltage. When pole slipping occurs, the stator current increases and the power factor changes to a very low value and it is this condition that out-of-step relay detects and trips out the motor during the first slip cycle.

If the supply to a synchronous motor is interrupted for more than say 0.3s, then there is a danger that if the supply is restored the motor may be out of step and therefore an undervoltage relay is required to trip the machine. This relay will also prevent starting and running under abnormally low voltage conditions.

Other protection devices are underpower or reverse power relays which are usually induction relays and are identical except that the former closes its contacts when the forward power is less that say, 3% and the latter closes its contacts when the reverse power exceeds 3%. The reverse power relay should always be preferred as it is more stable to momentary swings of power but it depends for operation on the protected motor generating to other loads connected to the same busbar. If there are no other loads then an underpower relay must be used.

8. SYSTEM GROUNDING

8.1 Introduction

System grounding is extremely important, as it affects the susceptibility of a system to voltage transients, determines the types of loads the system can accommodate, and helps to determine system protection requirements. System grounding arrangement is determined by the grounding of the power source. For commercial and industrial systems, the types of power sources generally fall into the following four broad categories:

(a) Utility Service – The system grounding is usually determined by the secondary winding configuration of the upstream utility substation transformer.
(b) Generator – The system grounding is determined by the stator winding configuration.
(c) Transformer – The system grounding of the system fed by the transformer is determined by the transformer secondary winding configuration.
(d) Static power converter – For devices such as rectifiers and inverters, the system grounding is determined by the grounding of the output stage of the converter.

To understand the system voltage relationships with respect to system grounding, it must be recognized that there are two common ways of connecting device windings: wye and delta. Neither of these arrangements is inherently associated with any particular system grounding arrangement, although some arrangements more commonly use one arrangement or the other for reasons that will be explained later.

8.2 Solidly-grounded system

The solidly-grounded system is the most common system arrangement, and one of the most versatile. The most commonly-used configuration is the solidly-grounded wye, because it will support single-phase loads.

The solidly-grounded wye system arrangement is as shown in figure 8.1.

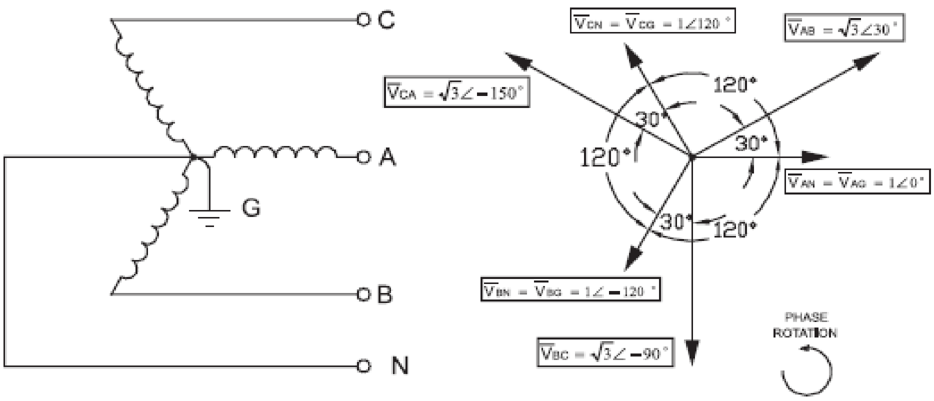


Figure 8.1: Solidly-grounded wye system arrangement and voltage relationships

Several points regarding figure 8.1 can be noted.

First, the system voltage with respect to ground is fixed by the phase-to-neutral winding voltage. Because parts of the power system, such as equipment frames, are grounded, and the rest of the environment essentially is at ground potential also, this has big implications for the system. It means that the line-to-ground insulation level of equipment need only be as large as the phase-to-neutral voltage, which is 57.7% of the phase-to-phase voltage. It also means that the system is less susceptible to phase-to-ground voltage transients.

Second, the system is suitable for supplying line-to-neutral loads. The operation of a single-phase load connected between one phase and neutral will be the same on any phase since the phase voltage magnitudes are equal. This system arrangement is very common.

While the solidly-grounded wye system is by far the most common solidly-grounded system, the wye arrangement is not the only arrangement that can be configured as a solidly grounded system. The delta system can also be grounded, as shown in figure 8.2. Compared with the solidly-grounded wye system, this system grounding arrangement has a number of disadvantages. The phase-to-ground voltages are not equal, and therefore the system is not suitable for single-phase loads. Also, without proper identification of the phases, there is the risk of shock since one conductor, the B-phase (in this case), is grounded and could be misidentified. This arrangement is no longer in common use, although a few facilities where this arrangement is used still exist.

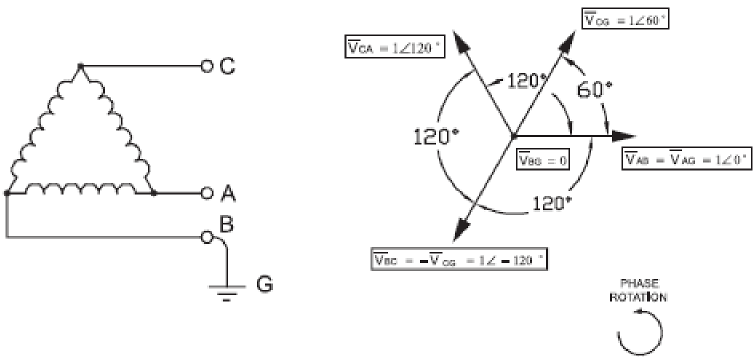


Figure 8.2: Corner-grounded delta system arrangement and voltage relationships

The delta arrangement can be configured in another manner that has merits as a solidly grounded system. This arrangement is shown in figure 8.3. While the arrangement of figure 8.3 may not appear at first glance to have merit, it is suitable both for three-phase and single-phase loads, so long as the single-phase and three-phase load cables are kept separate from each other. This is commonly used for small services which require both 208/415V three-phase and 120/240V single-phase. Note that the phase A voltage to ground is 173% of the phase B and C voltages to ground. This arrangement requires the BC winding to have a center tap.

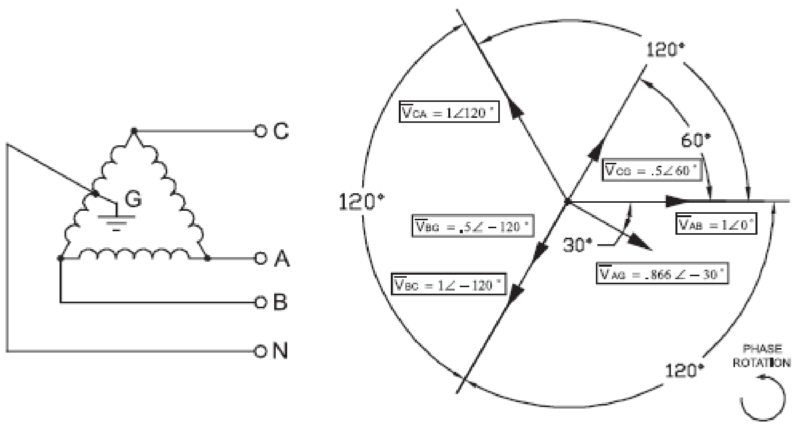


Figure 8.3: Centre-tapped-delta grounded system arrangement and voltage relationships

A common characteristic of all three solidly-grounded systems shown here, and of solidly-grounded systems in general, is that a short-circuit to ground will cause a large amount of short-circuit current to flow. This is illustrated in figure 8.4. As can be seen from figure 8.4, the voltage on the faulted phase is depressed, and large current flows in the faulted phase since the phase and fault impedance are small. The voltage and current on the other two phases are not affected. The fact that a solidly-grounded system will support a large ground fault current is an important characteristic of this type of system grounding and does affect the system design. Statistically, 90-95% of all system short-circuits are ground faults which makes solid grounding important.

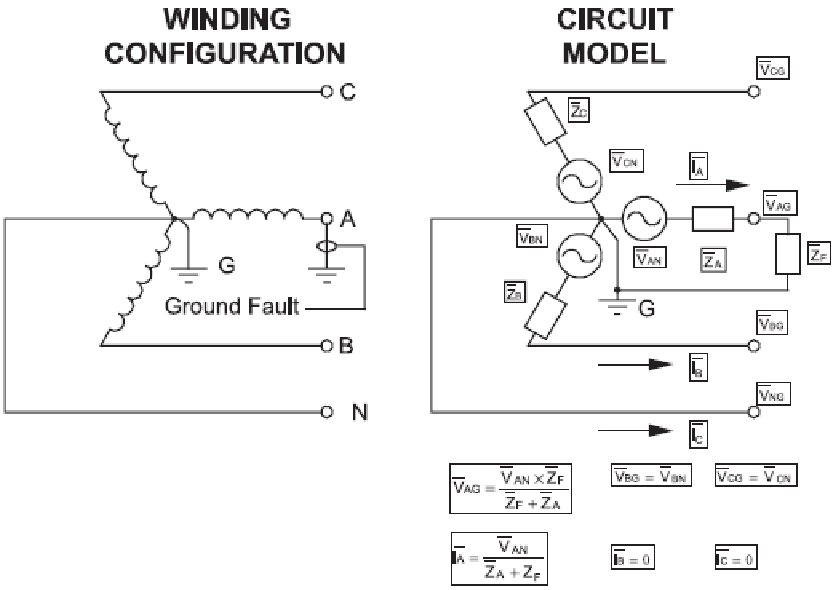


Figure 8.4: Solidly-grounded system with a ground fault on phase A

The occurrence of a ground fault on a solidly-grounded system necessitates the removal of the fault as quickly as possible. This is the major disadvantage of the solidly-grounded system as compared to other types of system grounding. A solidly-grounded system is very effective at reducing the possibility of line-to-ground voltage transients. However, to do this, the system must be effectively grounded. One measure of the effectiveness of system grounding is the ratio of the available ground-fault current to the available three-phase fault current. For effectively-grounded systems, this ratio is usually at least 60%. Most utility systems which supply service for commercial and industrial systems are solidly grounded. Typical utility practice is to ground the neutral at many points, usually at every line pole, creating a multi-grounded neutral system. Because a separate grounding conductor is not run with the utility line, the resistance of the earth limits the circulating ground currents that can be caused by this type of grounding. Because separate grounding conductors are used inside a commercial or industrial facility, multi-grounded neutrals are not preferred in such facilities due to the possibility of circulating ground currents.

In general, the solidly-grounded system is the most popular, and is required where single-phase loads must be supplied, and has the most stable phase-to-ground voltage characteristics. However, the large ground fault currents this type of system gives rise to, and the protective equipment that it necessitates, are a disadvantage and can be hindrance to system reliability.

The advantages and disadvantages of solidly-grounded systems are outlined below:
Advantages:

(i) Controls transient over voltage from neutral to ground.
(ii) Not difficult to locate the fault.
(iii) Can be used to supply line-neutral loads

Disadvantages:

(i) Severe flash hazard
(ii) Main breaker required
(iii) Loss of production
(iv) Equipment damage
(v) High values of fault current
(vi) Single-phase fault escalation into 3 phase fault is likely
(vii) Creates problems on the primary system

8.3 Ungrounded Systems

An ungrounded system is a system where there is no intentional connection of the system to ground. The term "ungrounded system" is actually a misnomer, since every system is grounded through its inherent charging capacitance to ground. To illustrate this point and its effect on the system voltages to ground, the delta winding configuration introduced in figure 8.2 is re-drawn in figure 8.5 to show these system capacitances. If all of the system voltages in figure 8.5 are multiplied by √3 and all of the phase angles are shifted by 30° (both are reasonable operations since the voltage magnitudes and phase angles for the phase-to-phase voltage were arbitrarily chosen), the results are the same voltage relationships as shown in figure 8.3 for the solidly-grounded wye system. The differences between the ungrounded delta system and the solidly-grounded wye system are that there is no intentional connection to ground, and that there is no phase-to-neutral driving voltage on the ungrounded delta system. This becomes important when the effects of a ground fault are considered. The lack of a grounded system neutral also makes this type of system unsuitable for single-phase, phase-to-neutral loads.

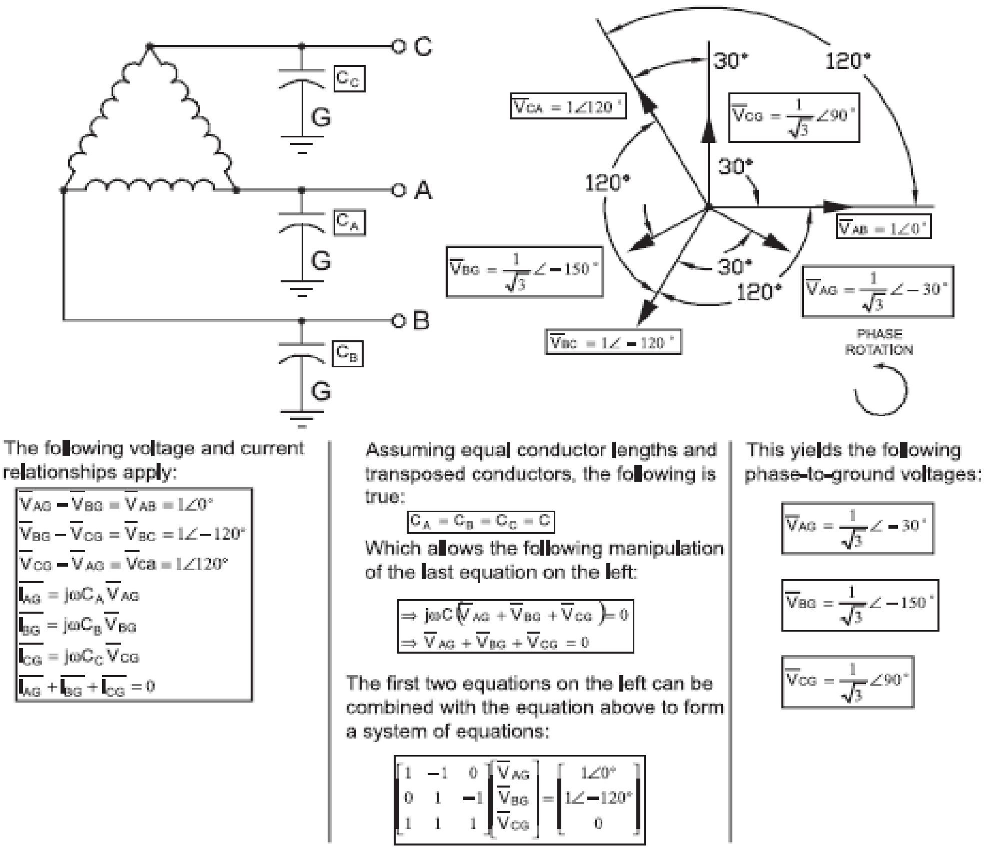
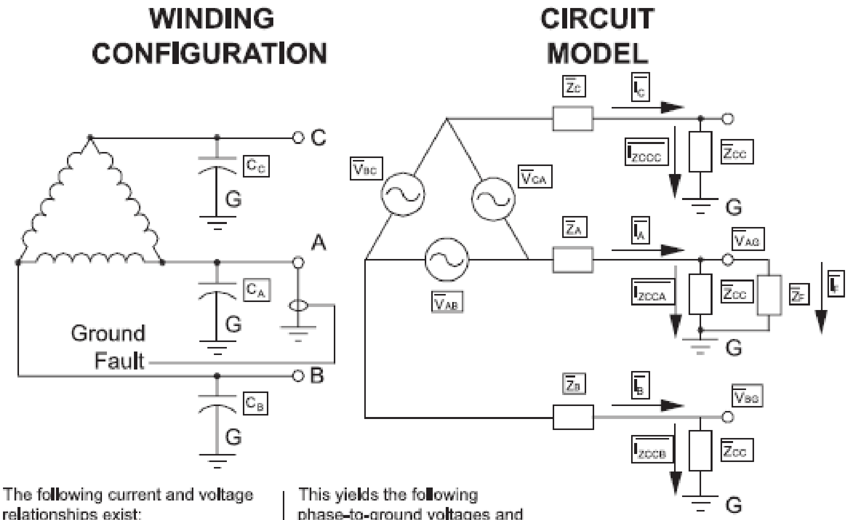


Figure 8.5: Ungrounded delta winding arrangement and voltage relationships

In figure 8.6, the effects of a single phase to ground fault are shown. The equations in figure 8.6 are not immediately practical for use, however if the fault impedance is assumed to be zero and the system capacitive charging impedance is assumed to be much larger than the phase impedances, these equations reduce into a workable form. Figure 8.7 shows the resulting equations, and shows the current and voltage phase relationships. As can be seen from figure 8.7, the net result of a ground fault on one phase of an ungrounded delta system is a change in the system phase-to-ground voltages. The phase-to-ground voltage on the faulted phase is zero, and the phase-to-ground voltage on the unfaulted phases are 173% of their nominal values. This has implications for power equipment – the phase-to-ground voltage rating for equipment on an ungrounded system must be at least equal the phase-to-phase voltage rating. This also has implications for the methods used for ground detection.



The following current and voltage relationships exist:

$$\overline{I_A} = \frac{\overline{V_{AG}}\left(\overline{Z_F} + \overline{Z_{CC}}\right)}{\overline{Z_F} \bullet \overline{Z_{CC}}}$$

$$\overline{I_B} = \overline{I_{ZCCB}} = \frac{\overline{V_{BG}}}{\overline{Z_{CC}}}$$

$$\overline{I_C} = \overline{I_{ZCCC}} = \frac{\overline{V_{CG}}}{\overline{Z_{CC}}}$$

$$\overline{V_{BG}} = \overline{V_{AG}} + \overline{I_A} \bullet \overline{Z_A} + \overline{V_{AB}} - \overline{I_B} \bullet \overline{Z_B}$$

$$V_{CG} = \overline{V_{AG}} + \overline{I_A} \bullet \overline{Z_A} + \overline{V_{AC}} - \overline{I_C} \bullet \overline{Z_C}$$

$$\overline{I_A} + \overline{I_B} + \overline{I_C} = 0$$

This yields the following phase-to-ground voltages and phase currents:

$$\overline{V_{AG}} = \frac{\left[\left(\overline{Z_{CC}} + \overline{Z_C}\right)\overline{V_{AB}} + \left(\overline{Z_{CC}} + \overline{Z_B}\right)\overline{V_{CA}}\right] \bullet \overline{Z_{CC}} \bullet \overline{Z_F}}{-\left(\overline{Z_{CC}} \bullet \overline{Z_F} + \overline{Z_F} \bullet \overline{Z_A} + \overline{Z_C} \bullet \overline{Z_A}\right)\left(2\overline{Z_{CC}} + \overline{Z_B} + \overline{Z_C}\right) - \left(\overline{Z_F} + \overline{Z_C}\right)\left(1 + \overline{Z_C}\right)\left(1 + \overline{Z_B}\right)}$$

$$V_{BG} = \overline{V_{BA}}\left(\frac{\overline{Z_{CC}}}{\overline{Z_{CC}} + \overline{Z_B}}\right) + \left(\frac{\overline{Z_{CC}} \bullet \overline{Z_F} + \overline{Z_F} \bullet \overline{Z_A} + \overline{Z_{CC}} \bullet \overline{Z_A}}{\overline{Z_F} \bullet \overline{Z_{CC}} + \overline{Z_F} \bullet \overline{Z_B}}\right)\overline{V_{AG}}$$

$$\overline{V_{CG}} = \overline{V_{CA}}\left(\frac{\overline{Z_{CC}}}{\overline{Z_{CC}} + \overline{Z_C}}\right) + \left(\frac{\overline{Z_{CC}} \bullet \overline{Z_F} + \overline{Z_F} \bullet \overline{Z_A} + \overline{Z_{CC}} \bullet \overline{Z_A}}{\overline{Z_F} \bullet \overline{Z_{CC}} + \overline{Z_F} \bullet \overline{Z_C}}\right)\overline{V_{AG}}$$

$$\overline{I_A} = \frac{\left[\left(\overline{Z_{CC}} + \overline{Z_C}\right)\overline{V_{AB}} + \left(\overline{Z_{CC}} + \overline{Z_B}\right)\overline{V_{CA}}\right]\left(\overline{Z_{CC}} + \overline{Z_F}\right)}{-\left(\overline{Z_{CC}} \bullet \overline{Z_F} + \overline{Z_F} \bullet \overline{Z_A} + \overline{Z_C} \bullet \overline{Z_A}\right)\left(2\overline{Z_{CC}} + \overline{Z_B} + \overline{Z_C}\right) - \left(\overline{Z_F} + \overline{Z_C}\right)\left(1 + \overline{Z_C}\right)\left(1 + \overline{Z_B}\right)}$$

$$\overline{I_B} = \overline{V_{BA}}\left(\frac{1}{\overline{Z_{CC}} + \overline{Z_B}}\right) + \left(\frac{\overline{Z_{CC}} \bullet \overline{Z_F} + \overline{Z_F} \bullet \overline{Z_A} + \overline{Z_{CC}} \bullet \overline{Z_A}}{\overline{Z_F} \bullet \left(\overline{Z_{CC}}\right)^2 + \overline{Z_F} \bullet \overline{Z_B} \bullet \overline{Z_{CC}}}\right)\overline{V_{AG}}$$

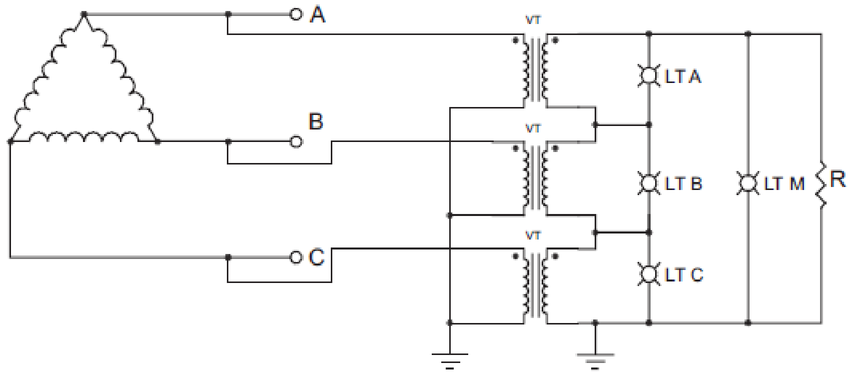
$$\overline{I_C} = \overline{V_{BA}}\left(\frac{1}{\overline{Z_{CC}} + \overline{Z_C}}\right) + \left(\frac{\overline{Z_{CC}} \bullet \overline{Z_F} + \overline{Z_F} \bullet \overline{Z_A} + \overline{Z_{CC}} \bullet \overline{Z_A}}{\overline{Z_F} \bullet \left(\overline{Z_{CC}}\right)^2 + \overline{Z_F} \bullet \overline{Z_C} \bullet \overline{Z_{CC}}}\right)\overline{V_{AG}}$$

Figure 8.6: Ungrounded delta system with a ground fault on one phase

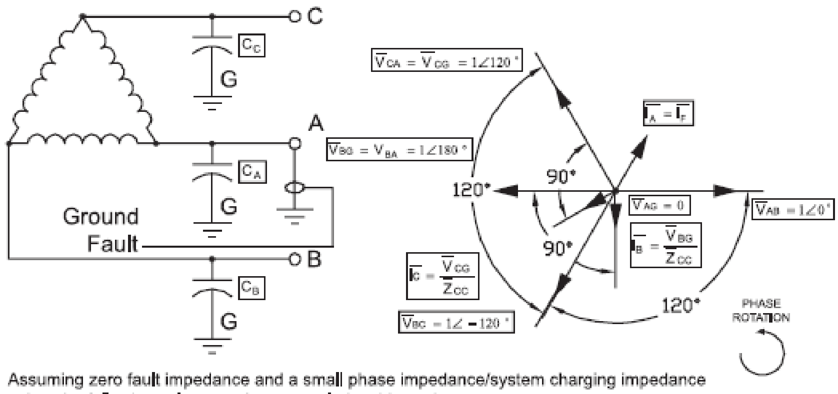
The ground currents with one phase is faulted to ground are essentially negligible. Because of this fact, from an operational standpoint, ungrounded systems have the advantage of being able to remain in service if one phase is faulted to ground. However, suitable ground detection must be provided to alarm this condition. In some older facilities, it has been reported that this type of system has remained in place for 40 years or more with one phase grounded! This condition is not dangerous in and of itself (other than due to the increased phase-to-ground voltage on the unfaulted phases), however if a ground fault occurs on one of the ungrounded phases, the result is a phase-to-phase fault with its characteristic large fault current magnitude.

Another important consideration for an ungrounded system is its susceptibility to large transient overvoltages. These can result from a resonant or near-resonant condition during ground faults, or from arcing. A resonant ground fault condition occurs when the inductive reactance of the ground-fault path approximately equals the system capacitive reactance to ground. Arcing introduces the phenomenon of current-chopping, which can cause excessive overvoltages due to the system capacitance to ground.

The ground detection mentioned above can be accomplished through the use of voltage transformers connected in wye-broken delta, as illustrated in figure 8.7.



GROUND FAULT LOCATION	LTA	LTB	LTC	LTM
NONE	DIM	DIM	DIM	OFF
PHASE A	OFF	BRIGHT	BRIGHT	BRIGHT
PHASE B	BRIGHT	OFF	BRIGHT	BRIGHT
PHASE C	BRIGHT	BRIGHT	DIM	BRIGHT



Assuming zero fault impedance and a small phase impedance/system charging impedance ratios, the following voltage and current relationships exist:

$$\overline{V}_{AG} = 0$$
$$V_{BG} = \overline{V}_{BA}$$
$$\overline{V}_{CG} = \overline{V}_{CA}$$
$$\overline{I}_A = I_F = -\left(\frac{\overline{V}_{BA}}{Z_{CC}} + \frac{\overline{V}_{BA}}{Z_{CC}}\right)$$
$$\overline{I}_B = \frac{\overline{V}_{BA}}{Z_{CC}}$$
$$\overline{I}_C = \frac{\overline{V}_{CA}}{Z_{CC}}$$

Figure 8.7: A ground detection method for ungrounded systems

In figure 8.7, three ground detection lights “LTA,” “LTB” and “LTC” are connected so that they indicate the A, B and C phase-to-ground voltages, respectively. A master ground detection light “LTM” indicates a ground fault on any phase. With no ground fault on the system “LTA,” “LTB” and “LTB” will glow dimly. If a ground fault occurs on one phase, the light for that phase will be extinguished and “LTM” will glow brightly along with the lights for the other two phases. Control relays may be substituted for the lights if necessary. Resistor “R” is connected across the broken-delta voltage transformer secondaries to minimize the possibility of ferroresonance. Most ground detection schemes for ungrounded systems use this system or a variant thereof.

Modern power systems are rarely ungrounded due to the advent of high-resistance grounded systems. However, older ungrounded systems are occasionally encountered.

The advantages and disadvantages of solidly-grounded systems are outlined below:
Advantages:
- (i) Low value of current flow for line to ground fault-5amps or less.
- (ii) No flash hazard to personnel for accidental line to ground fault.
- (iii) Continued operation on the occurrence of first line to ground fault.
- (iv) Probability of line to ground arcing fault escalating to line–line or three phase fault is very small.

Disadvantages:
- (i) Difficult to locate line to ground fault.
- (ii) The ungrounded system does not control transient overvoltages.
- (iii) Cost of system maintenance is higher due to labour in locating ground faults.
- (iv) A second ground fault on another phase will result in a phase-phase short circuit.

8.3.1 ***Creating an artificial neutral in an ungrounded system***
In some cases it is required to create a neutral reference for an ungrounded system. Most instances involve existing ungrounded systems which are being upgraded to high-resistance grounding. The existence of multiple transformers and/or delta-wound generators may make the replacement of this equipment economically unfeasible.

The solution is a grounding transformer. Although several different configurations exist, by far the most popular in commercial and industrial system is the zig-zag transformer arrangement. It uses transformers connected as shown in figure 8.8:

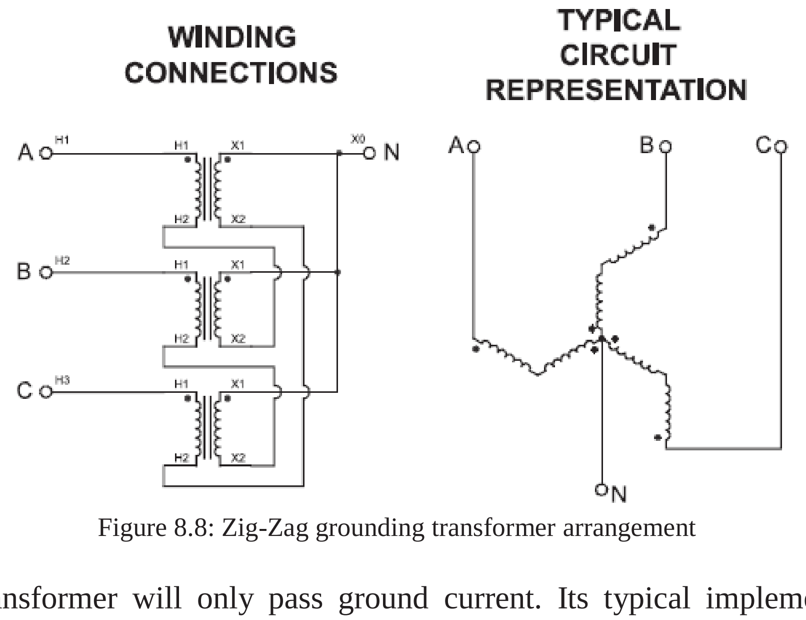


Figure 8.8: Zig-Zag grounding transformer arrangement

The zig-zag transformer will only pass ground current. Its typical implementation on an ungrounded system, in order to convert the system to a high-resistance grounded system, is shown in figure 8.9. The zig-zag transformer distributes the ground current I_G equally between the three phases. For all practical purposes the system, from a grounding standpoint, behaves as a high-resistance grounded system.

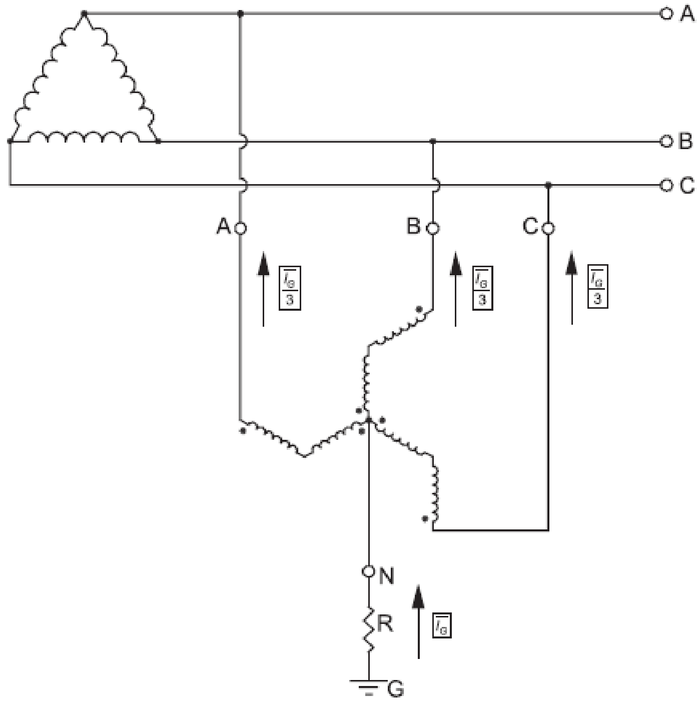


Figure 8.9: Zig-Zag grounding transformer implementation

The solidly-grounded and low-resistance grounded systems can also be implemented by using a grounding transformer, depending upon the amount of impedance connected in the neutral.

8.4 **High resistance ground system**

One ground arrangement that has gained in popularity in recent years is the high-resistance grounding arrangement. For low voltage systems, this arrangement typically consists of a wye winding arrangement with the neutral connected to ground through a resistor. The resistor is sized to allow 1-10 A to flow continuously if a ground fault occurs. This arrangement is illustrated in figure 8.10.

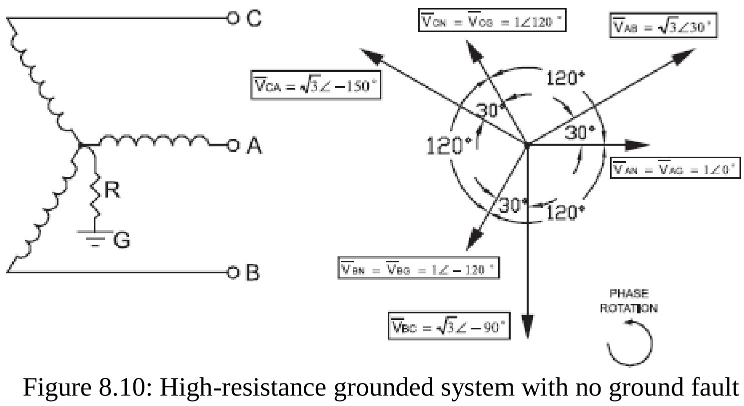
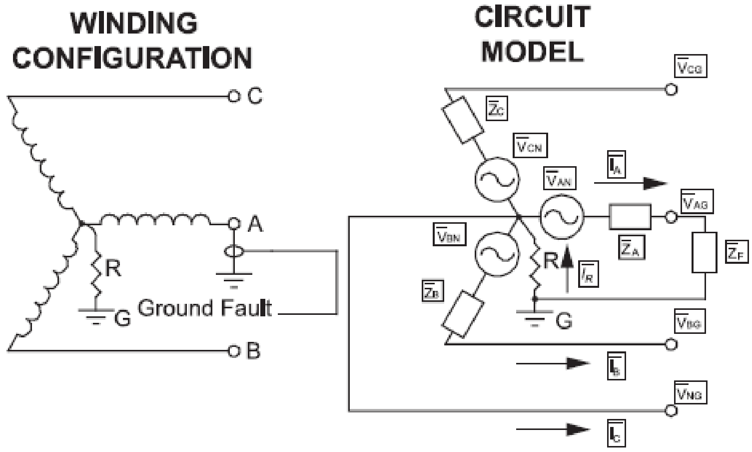


Figure 8.10: High-resistance grounded system with no ground fault present

The resistor is sized to be less than or equal to the magnitude of the system charging capacitance to ground. If the resistor is thus sized, the high-resistance grounded system is usually not susceptible to the large transient overvoltages that an ungrounded system can experience. The ground resistor is usually provided with taps to allow field adjustment of the resistance during commissioning. If no ground fault current is present, the phasor diagram for the system is the same as for a solidly-grounded wye system, as shown in figure 8.10.

However, if a ground fault occurs on one phase, the system response is as shown in figure 8.11, the ground fault current is limited by the grounding resistor.



$$\overline{V}_{AG} = \frac{\overline{V}_{AN} \times \overline{Z}_F}{\overline{Z}_F + \overline{Z}_A + R}$$

$$\overline{V}_{BG} = \overline{V}_{BN} - \overline{I}_R \bullet R$$

$$\overline{V}_{CG} = \overline{V}_{CN} - \overline{I}_R \bullet R$$

$$\overline{I}_A = \overline{I}_R = \frac{\overline{V}_{AN}}{\overline{Z}_A + \overline{Z}_F + R}$$

$\overline{I}_B = 0$ $\overline{I}_C = 0$

Figure 8.11: High-resistance grounded system with a ground fault on one phase

If the approximation is made that Z_A and Z_F are very small compared to the ground resistor resistance value R, which is a good approximation if the fault is a bolted ground fault, then the ground fault current is approximately equal to the phase-to-neutral voltage of the faulted phase divided by R. The faulted phase voltage to ground in that case would be zero and the unfaulted phase voltages to ground would be 173% of their values without a ground fault present. This is the same phenomenon exhibited by the ungrounded system arrangement, except that the ground fault current is larger and approximately in-phase with the phase-to-neutral voltage on the faulted phase. The limitation of the ground fault current to such a low level, along with the absence of a solidly-grounded system neutral, has the effect of making this system ground arrangement unsuitable for single-phase line-neutral loads.

The ground fault current is not large enough to force its removal by taking the system off-line. Therefore, the high-resistance grounded system has the same operational advantage in this respect as the ungrounded system. However, in addition to the improved voltage transient response as discussed above, the high-resistance grounded system has the advantage of allowing the location of a ground fault to be tracked.

A typical ground detection system for a high-resistance grounded system is illustrated in figure 8.12. The ground resistor is shown with a tap between two resistor sections R1 and R2. When a ground fault occurs, relay 59 (the ANSI standard for an overvoltage relay, as discussed later in this guide) detects the increased voltage across the resistor. It sends a signal to the control circuitry to initiate a ground fault alarm by energizing the “alarm” indicator. When the operator turns the pulse control selector to the “ON” position, the control circuit causes pulsing contact P to close and re-open approximately once per second. When P closes R2 is shorted and the “pulse” indicator is energized. R1 and R2 are sized so that approximately 5-7 times the resistor continuous ground fault current flows when R2 is shorted. The result is a pulsing ground fault current that can be detected using a clamp-on ammeter (an analog ammeter is most convenient). By tracing the circuit with the ammeter, the ground fault location can be determined. Once the ground fault has been removed from the system pressing the “alarm reset” button will de-energize the “alarm” indicator.

This type of system is known as *a pulsing ground detection system* and is very effective in locating ground faults, but is generally more expensive than the ungrounded system ground fault indicator in figure 8.7.

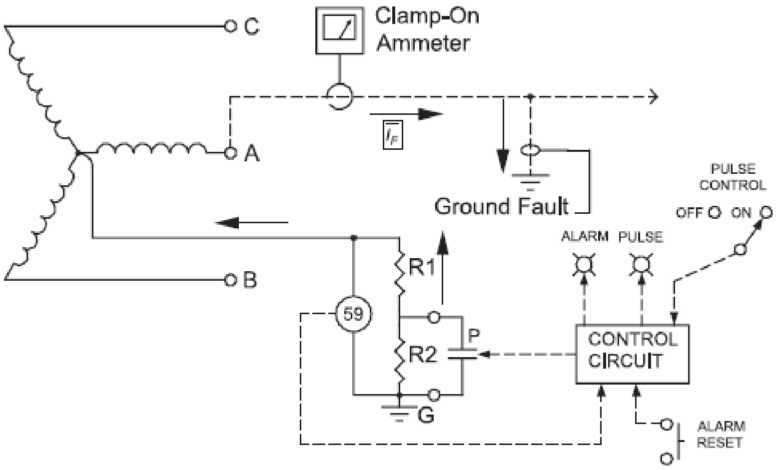


Figure 8.12: Pulsing ground detection system

For medium voltage systems, high-resistance grounding is usually implemented using a low voltage resistor and a neutral transformer, as shown in figure 8.13.

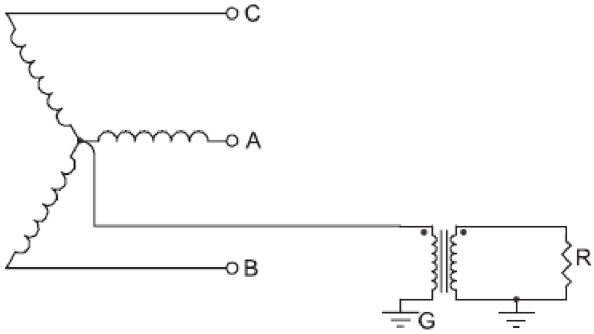


Figure 8.13: Medium voltage implementation of high-resistance grounding

The advantages and disadvantages associated with low-resistance grounding systems are as follows:

Advantages:

(i) Low value of fault current
(ii) No flash hazard
(iii) Controls transient over voltage
(iv) No equipment damage
(v) Service continuity
(vi) No impact on primary system

Disadvantages:

There are no known disadvantages

8.5 **Reactance grounding**

In industrial and commercial facilities, reactance grounding is commonly used in the neutrals of generators. In most generators, solid grounding may permit the level of ground-fault current available from the generator to exceed the three-phase value for which its windings are braced. For these cases, grounding of the generator neutral through an air-core reactance is the standard solution for lowering the ground fault level. This reactance ideally limits the ground-fault current to the three-phase available fault current and will allow the system to operate with phase-to-neutral loads.

8.6 **Low-resistance grounded systems**

By sizing the resistor in figure in 8.11 such that a higher ground fault current, typically 200-800 A, flows during a ground fault a low-resistance grounded system is created. The ground fault current is limited, but is of high enough magnitude to require its removal from the system as quickly as possible. The low-resistance grounding arrangement is typically used in medium voltage systems which have only 3-wire loads, such as motors, where limiting damage to the equipment during a ground fault is important enough to include the resistor but it is acceptable to take the system offline for a ground fault. The low-resistance grounding arrangement is generally less expensive than the high-resistance grounding arrangement but more expensive than a solidly grounded system arrangement.

9. DIGITAL PROTECTION

9.1 Introduction

In recent years, there has been considerable interest in using digital techniques in power systems protection. The main features which have encouraged many researchers to investigate the feasibility of designing digital relays for power system protection are its economy, reliability, flexibility, improved performance over conventional relays and the possibility of integrating a digital relay into the hierarchical computer system. In this chapter, those features are illustrated and the advantages of using digital techniques are pointed out.

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