



**NATIONAL POWER TRAINING INSTITUTE OF NIGERIA
PLOT 21, CADESTRAL ZONE, IDU INDUSTRIAL LAYOUT,
ABUJA**

NAPTIN COURSE MANUAL

ON:

**DISTRIBUTION NETWORK POWER LOSS MANAGEMENT
COMPILED BY:**

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Distribution Network Loss Management Course Concept:

Objectives: At the end of the course, participants should be able to;

- Explain the concept of power loss and its effect as it relates to power system
- Classify power losses and identify the causes and effects of each class
- Evaluate and estimate technical manually and via power system analysis tool
- Evaluate and estimate non-technical losses
- Discuss and analyze energy audit as it relates to power management and loss reduction
- Design action plan for power loss reduction
- Explain and appreciate Power loss reduction technologies and Distribution automation

Designed for:

- Distribution Engineers and technologist
- Senior Distribution Technicians
- Electricity energy audit officers

Duration: A week (5 days)

Course Contents:

- Introduction; Power system fundamentals – Generation, Transmission, Distribution and Consumption
- Overview of Losses in Electricity Industry –
 - Technical and
 - Non-technical
- Power Losses in Developing countries – Case studies and analysis
- Power Loss estimation and evaluation –
 - Technical loss – Manually and using NEPLAN
 - Non-technical loss – From ATC&C losses
- Causes of Losses
- Power loss mitigation strategies –
 - How to reduce technical losses,
 - How to reduce non-technical losses
- Energy Audit and loss reduction

- Power Loss Reduction Technologies – AMR/AMI, CIS/CRM, GIS, PSAT, DMS/OMS/SCADA.
- Strategies for management plan on Power loss reduction

Methodology:

- Class room presentations
- Case studies and exercises
- Site visitations

1.0 INTRODUCTION: POWER SYSTEM FUNDAMENTALS:

A power system is an interconnected network with components converting non-electrical energy continuously into the electrical form and transporting the electrical energy from generating sources to the loads/users. A power system serves one important function and that is to supply customers with electricity as economically and as reliably as possible. The sequence of the electricity power supply system is in the following order:

- Electricity Generation
- Transmission
- Distribution, and
- Consumption

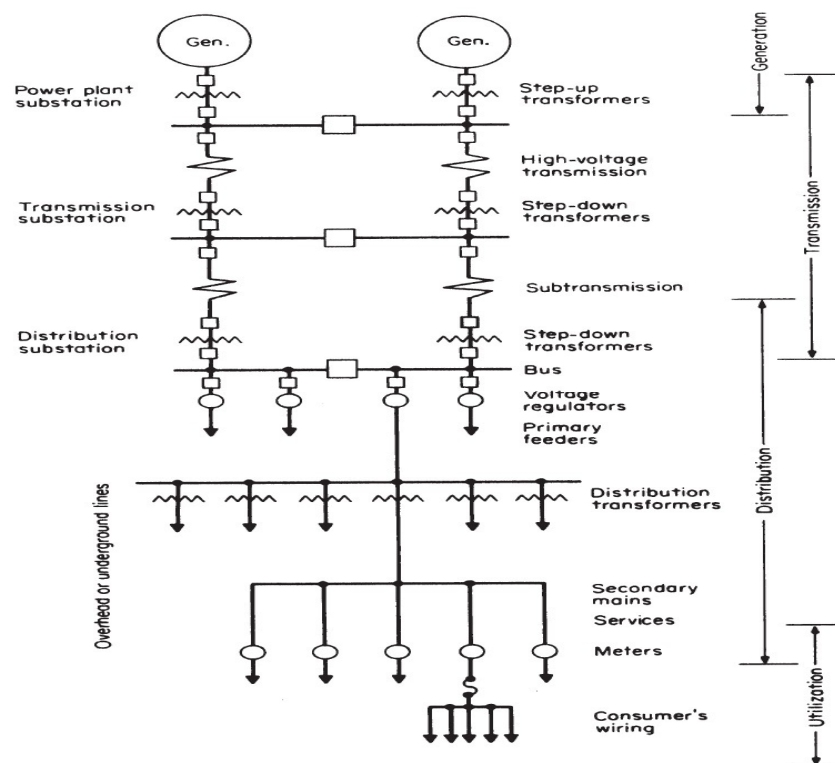


Fig. 1.1: Power System Single Line Diagram Representation

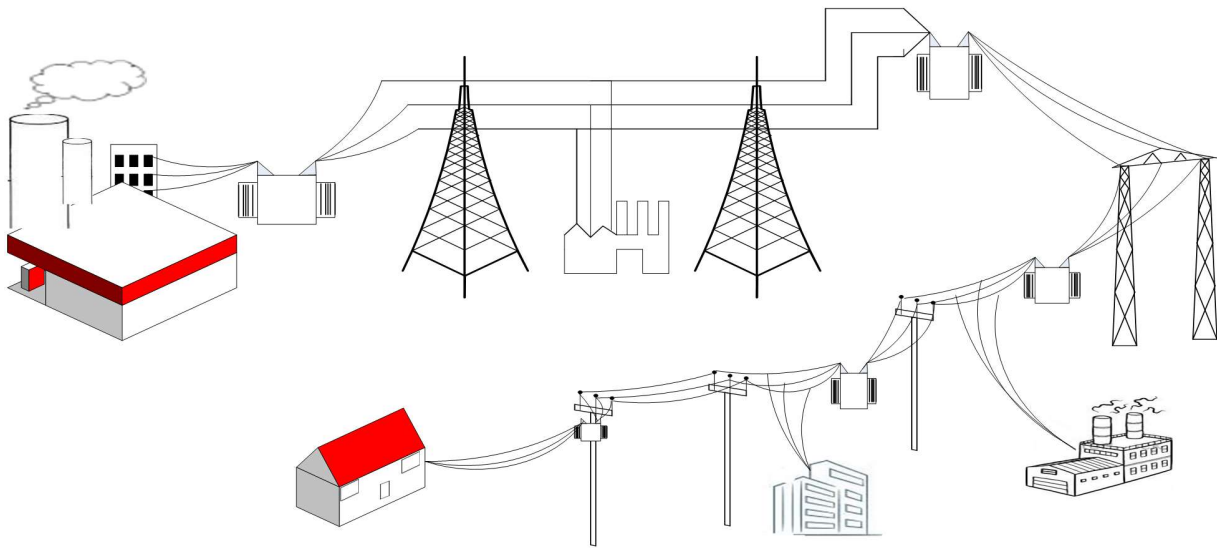


Figure 1.2. Structure of the Electric Power System.

○ Electricity Generation

Electricity is produced by generating units called generators, which convert primary energy into electric energy. The primary energy sources are derived from: the sun, the earth's heat, the wind, water (rivers, lakes, tides and oceans), fossil fuel – coal, oil and natural gas, biomass and radioactive materials. The way and manner these energy sources are used to convert this energy into electric energy depends on the design of the generating units.

- i. Thermal generating unit (Steam) burn fuel to convert chemical energy into thermal energy. Water is heated, turns into high-pressure steam and spins a steam turbine which drives the mechanical shaft of an a.c electric generator that produces electric power at its terminals.



Figure 1.3. Egbin Thermal generating unit.

- ii. Nuclear generating units use an energy conversion process similar to thermal units, except the thermal energy needed to produce steam comes from nuclear reactions.
- iii. Hydro and wind generating units convert the kinetic energy of water and wind, respectively, into rotation of the electric generator's mechanical shaft.



Figure 1.4. Refurbished 1G6 (120MW) at Kainji



Figure 1.5. Kainji Hydro Spill Gate.

- iv. Solar-thermal and geothermal generating units use the sun's radiation and the Earth's warmth respectively, to heat a fluid and then follow a conversion process similar to thermal units. Solar photovoltaic generating units are quite different and convert the energy in solar radiation directly into electrical energy.



Figure 1.6. 10kW Photovoltaic Plant at Kainji



Figure 1.7. 15kW Wind Plant at Kainji

- v. The basic operation of the gas or combustion turbine is similar to that of the steam power plant except that air is used instead of water. These burn a pressurised mixture of natural gas and air in a jet engine that drives the electric generator.



Figure 1.8. Afam VI Gas Power Plant.

- vi. Combined-cycle gas turbine plants have a gas turbine and a steam turbine. They reuse the waste heat from the gas turbine to generate steam for the steam turbine and hence achieve higher energy conversion efficiencies.

The electric power system is classified into three categories from operational perspective, namely: baseload, intermediate and peaking units.

- Baseload plants are the power plants used to meet some or all of a given region's continuous energy demand, and produce energy at a constant rate, usually at a low-cost relative to other production facilities available in the system. Examples of baseload plants using non-renewable fuels include nuclear, coal-fired plants and run-of-the-river hydroelectric plants. Baseload plants typically run at all times through the year except in the case of repairs or scheduled maintenance. These plants are often designed for relatively high efficiency and may be combined cycle plants but may take several days to start up and shut down.
- Intermediate units, also called cycling units, operate for extended periods of time but, unlike baseload units, not at one power continuously. They have the ability to vary their output more quickly than baseload units. Combined-cycle gas turbine plants and older thermal generating units generally are used as intermediate units.
- Peaking units operate only when the system power demand is close to its peak. They must be able to start and stop quickly. Gas turbine and hydroelectric plants with reservoirs are generally used as peaking units. Gas turbines are the least expensive to build but have high operating costs.

The generated power is at the generation voltage level which is usually a few tens of kV. The voltage is increased to a few hundred kV by using step-up power transformers to transmit the power over long distances under the most economical conditions.

○ **Electricity Transmission**

Electric power transmission is the process by which large amounts of electricity produced at power plants is transported over long distances for eventual use by consumers. The transmission network is composed of power lines, transmission towers and stations/substations.



Figure 1.9. Transmission Power Lines.

Conductors are the power lines that carry the electricity to and through the grid to consumers. Generally, several conductors are strung on a tower for each electrical circuit. Conductors are constructed primarily of twisted metal strands, but newer conductors may incorporate ceramic fibers in a matrix of aluminum for added strength with lighter weight.

Transmission towers are the most visible component of the power transmission system. Their function is to keep the high-voltage conductors (power lines) separated from their surroundings and from each other. A variety of tower designs exist that generally employ an open lattice work or a monopole, but generally they are very tall metal structures.

The very high voltages used for electric transmission are converted to lower voltages for consumer use at substations. Substations vary in size and configuration and house transformers, switchgears, measurement instruments and communication equipment.

- Transformers are used to change the level of the transmission voltage.
- Switchgears includes circuit breakers and other types of switches used to disconnect parts of the transmission network for system protection and/or maintenance.
- Measurement instrumentation collects voltage, current and power data for monitoring, control and metering purposes.
- Communication equipment transmits this data to control centers and also allows switchgear to be controlled remotely.

▪ **Transmission Voltages**

Transmission voltage varies from region to region and country to country. In Nigeria, the transmission voltages commonly used are 132kV and 330kV, while a proposed Ultra High Voltage (UHV) of 750kV is in the pipeline. Transmission voltages commonly used (but not exclusively) in the U.S are 138kV, 230kV, 345kV, 500kV and 765kV while in China up to 1000kV has been used on a transmission line.

High-Voltage Direct Current (HVDC) electric power transmission system (also called a power superhighway or an electrical superhighway) uses direct current (dc) for the bulk transmission of electrical power, in contrast with the more common alternating current (ac) system. For long-distance transmission, the HVDC system may be less expensive, requires only two conductors instead of three and suffers lower electrical losses because transmission line presents no reactive impedance to dc. For underwater power cables, HVDC avoids heavy currents required to charge and discharge the cable capacitance for each cycle. However, HVDC transmission line requires expensive converter stations at either end of the line to connect to the rest of the ac system.

The transformer at a transmission substation converts transmission voltages down to lower levels to connect to the sub-transmission network or directly to the distribution network. In Nigeria, the commonly used sub-transmission voltages are 132kV and 33kV.

Topologically, the transmission and sub-transmission line configurations are mesh (ring) networks (as opposed to radial), meaning there are multiple paths between any two points on the network. This redundancy allows the system to provide power to the loads even when a transmission line or a generating unit goes offline.

In Nigeria the transmission grid both at 330kV and 132kV is not yet completely ring (mesh). There are a lot of on-going projects to complete as shown in Figure 1.9. Blue lines indicate 330kV line while orange is 132kV line.

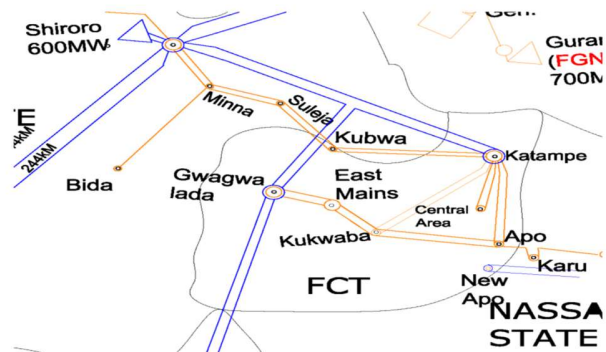


Figure 1.10. Existing Topology in and around Abuja.

▪ **Transmission Line Constraint**

The power that can be transmitted on a transmission line is limited by either thermal, voltage stability or transient stability constraint.

The thermal limit of an overhead transmission line is reached when the electric current flow heats the conductor material up to a temperature above which the conductor material gradually loses mechanical strength and sags due to conductor expansion, thereby decreasing clearance to ground. The maximum allowable conductor temperatures based on annealing considerations are 127°C for conductors with high aluminum content and 150°C for other conductors. However, the maximum permissible conductor temperature is further limited by conductor age, geometry, the heights of the towers and the security standards regarding clearance to ground.

The maximum allowable current-carrying capacity depends on the ambient temperature, wind velocity, solar radiation, surface conditions of the conductor, and altitude above the sea level.

Voltage stability is the ability of the system to maintain steady acceptable voltages at all buses in the system under normal conditions and even after being subjected to disturbance. Instability occurs in the form of a progressive fall or rise of voltages in some buses. A possible outcome of voltage instability is loss of load in an area or outages. Furthermore, loss of synchronism may result from these outages or from operation under field current limit.

The transient stability constraint relates to the ability of the transmission line to deal with rapid changes in the power flowing through it without causing the generators to fall out of synchronism with each other.

Generally, maximum power flow on short transmission lines is limited by thermal constraint, while power flow on longer transmission lines is limited by either voltage or transient stability constraints.

Some very large consumers take electric power directly from the transmission network. However, the majority of consumers get their power from the distribution network.

○ **Electricity Distribution**

Electric power distribution system is the final stage in the delivery of electric power; it carries electricity from the transmission system to individual consumers. Distribution substations connect to the transmission system and lower the transmission voltage to primary distribution level ranging between 2kV and 35kV with the use of transformers.

▪ **Primary Distribution**

These consist of high voltage (33kV and 11kV in Nigeria) networks from primary and sub-primary substations, which are interconnected with HV transmission lines. In most cases, large industrial consumers like cement factories, refineries, breweries, flour mills, steel rolling mills etc. take supply at primary distribution system with associated transformers, circuit breakers and switchgears.

▪ **Secondary Distribution**

These consist of low voltage feeder networks from the secondary distribution transformers usually mounted on a pole or on ground, that are connected along main roads and streets, service connections are made to individual consumers by service cable or wires from these network feeder lines.



Figure 1.11. POLE Mounted Transformer.

The various system of a.c distribution for domestic consumers includes:

- Single phase 2-wire system
- Single phase 3-wire system
- Three phase 3-wire system
- Three phase 4-wire system

Of these, Single phase 2-wire system and three phase 4-wire system are the most widely used in Nigeria at a voltage of 230V and 400V respectively.

Distribution network usually has a radial topology, referred to as a “star network”, with only one power flow path between the distribution substation and a particular load. Distribution network sometimes has a ring (or loop) topology, with two power flow paths between the distribution substation and load. However, this is still operated as a star network by keeping a circuit breaker open. In highly dense urban settings, distribution networks may have a mesh network topology, which may be operated as an active mesh network or a star network. The presence of multiple power flow paths in ring and mesh distribution networks allows a load to be serviced through an alternate path by opening and closing appropriate circuit breakers when there is a problem in the original path. When this process is carried out automatically, it is often referred to as “self-healing.”

- **Electricity Consumption**

Electric energy consumption is a form of consumption that uses electric energy and is the actual energy demand made on existing electricity supply.

Electric and electronic devices consume electric energy to generate the desired output (i.e. light, heat, motion, etc.). These loads can be classified based on their impedance, which can be resistive, reactive or a combination of the two.

In theory, loads can be purely reactive which can either be inductive or capacitive. However, in practice the impedance of most loads is either purely resistive or a combination of resistive and inductive reactance. Heaters and incandescent lamps have purely resistive impedance, while motors have impedance that is resistive and inductive. Only purely resistive loads consume real power. Loads with inductive impedance draw reactive power. Loads with capacitive impedance supply reactive power.

Because of the abundance of motors connected to the network, the power system is dominated by inductive loads. Hence, generating units have to supply both real and reactive power. Since capacitors produce reactive power, they often are connected close to large inductive loads to cancel their reactive power (i.e. increase the effective power factor of the load) and reduce the burden on the network and the generators.

2.0 LOSSES IN ELECTRICITY INDUSTRY:

Electric power is generated in power stations and delivered through the transmission and distribution systems to the customer. Energy losses can occur in each part of the power system until reaching the customer's meter. Power system energy losses are divided into categories based on where the losses happen and the cause of power losses, as indicated below:

- **Power station losses** – energy consumed by the equipment in support of power generation, it is also called power station auxiliary load or power station own usage.
- **System losses** – losses incurred by moving power through the transmission and distribution systems, including transformers, overhead line conductors, aerial cables or underground cables, and low voltage (LV) secondary service wires.

For Electricity Distribution Companies (DISCOs), there are no station losses since they do not own any power plants. DISCOs' system losses occur in the distribution system. Losses in the system losses category consist of both **technical losses** and **non-technical losses**

In electricity supply to final consumers, losses refer to the amounts of electricity injected into the transmission and distribution grids that are not paid for by users. Total losses have two components: technical and non-technical. Technical losses occur naturally and consist mainly of power dissipation in electricity system components such as transmission and distribution lines, transformers, and measurement systems. Non-technical losses are caused by actions external to the power system and consist primarily of electricity theft, non-payment by customers, and errors in accounting and record-keeping. These three categories of losses are respectively sometimes referred to as commercial, non-payment, and administrative losses, although their definitions vary in the literature.

Metering and billing for electricity consumed by users is integral to commercial management of an electricity utility. Another critical task is collection of the billed amounts. Effective performance in both functions is critical to ensure the financial viability of the company. From the operational point of view, metering-billing and collection are separate functions and they require specific management approaches.

Optimization of technical losses in electricity transmission and distribution grids is an engineering issue, involving classic tools of power systems planning and modelling. The driving criterion is minimization of the net present value (sum of costs over the economic life of the system discounted at a representative rate of return for the business) of the total investment cost of the transmission and distribution system plus the total cost of technical losses. Technical losses are valued at generation costs.

Technical losses represent an economic loss for the country, and its optimization should be performed from a country's perspective, regardless of the institutional organization of the sector and ownership of operating electricity utilities. Although each case has its

specific characteristics, depending on the current and future values of generation costs, some general comments can be made. In the last two decades, global prices of primary energy resources (oil and other fossil fuels) had been rising in real terms.

On the investment side, prices of equipment in the electricity sector (generation, transmission and distribution) steadily rose this decade. Against these price trends, the total costs of technical losses tend to exceed investment costs of transmission and distribution equipment required to reduce them to their optimum value, more so where a significant portion of generation is based on fossil fuels. This tendency is accentuated if environmental costs of power generation (harmful local pollutants as well as greenhouse gas emissions) and increasing difficulties in achieving social acceptance of new power plant construction (regardless of fuel type and technology) are considered.

Non-technical losses represent an avoidable financial loss for the utility. Although it is clear that the amounts of electricity involved in non-technical losses are being consumed by users that do not pay for them, experience shows that a significant percentage of those amounts (in some cases more than 50 percent) becomes reduced demand when those users have to pay for that electricity, because they adjust their consumption to their ability to pay for electricity services. That reduction in demand has the same effect as a reduction in technical losses: less electricity needs to be generated. Thus, from the country's perspective, reductions in non-technical losses are also positive.

From a social point of view, non-technical losses have several perverse effects. Customers being billed for accurately measured consumption and regularly paying their bills are subsidizing those users who do not pay for electricity consumption. There is a wide range of situations creating non-technical losses. A classic case is a theft of electricity through an illegal connection to the grid or tampering of a consumption meter. But examples also include unmetered consumption by utility customers who are not accurately metered for a variety of reasons. In all the cases some level of poor management of the utility in execution of its operations is present.

Electricity theft is de facto subsidization of those who steal by customers regularly paying bills according to their consumption. The same usually applies in the case of unmetered customers, unless this situation is explicitly and transparently defined by the competent authorities and reflected in the legal and regulatory framework of the sector—in some countries some categories of consumers (e.g., agriculture users in India and Bangladesh) are unmetered and pay a fixed amount for electricity irrespective of the amounts consumed, which means in practice that they are subsidized by consumers in other categories, tax payers, or both. Depending on the financial situation of the power sector, the savings from reductions in non-technical losses could be channelled to

- a) reduce taxpayers' subsidies or tariffs paid by customers,
- b) achieve an average tariff level allowing recovery of costs reflecting efficient sustainable performance (critical to assure service quality),
- c) subsidize consumption of selected categories of socially sensitive existing users, or

d) extend access to electricity supply to currently un-served population (in general the poorest and socially unprotected).

Power generated in power stations passes through large and complex networks like transformers, overhead lines, cables and other equipment and reaches the end users. It is a fact that the unit of electric energy generated by power stations does not match with the units distributed to the consumers. Some percentages of the units are lost in the distribution network.

This difference in the generated and distributed units is known as Transmission and Distribution (T&D) loss. T&D losses are the amounts that are not paid for by users.

$$T\&D \text{ Losses} = \frac{\text{Energy Input to feeder (Kwh)} - \text{Billed Energy to Consumer(Kwh)}}{\text{Energy Input kwh}} \times 100$$

Distribution Sector considered as the weakest link in the entire power sector. Transmission Losses is approximate 17% while Distribution Losses is approximate 50%.

There are two types of Transmission and Distribution Losses:

1. Technical Losses
2. Non-Technical Losses (Commercial Losses)

2.1 Technical Losses

The technical losses are due to energy dissipated in the conductors, equipment used for transmission line, transformer, sub-transmission line and distribution line and magnetic losses in transformers. Technical losses normally depend on the network characteristics and the mode of operation.

The major amount of losses in a power system is in primary and secondary distribution lines. While transmission and sub-transmission lines account for only about 30% of the total losses. Therefore, the primary and secondary distribution systems must be properly planned to ensure within limits.

- The unexpected load increase was reflected in the increase of technical losses above the normal level
- Losses are inherent to the distribution of electricity and cannot be eliminated.

There are two Type of Technical Losses.

2.1.1 Permanent/Fixed Technical losses

- Fixed losses do not vary according to current. These losses take the form of heat and noise and occur as long as a transformer is energized
- Between 1/4 and 1/3 of technical losses on distribution networks are fixed losses.
- Fixed losses on a network can be influenced in the ways set out below

- Corona Losses
- Leakage Current Losses
- Dielectric Losses
- Open-circuit Losses
- Losses caused by continuous load of measuring elements
- Losses caused by continuous load of control elements

2.1.2 Variable Technical losses

Variable losses vary with the amount of electricity distributed and are, more precisely, proportional to the square of the current. Consequently, a 1% increase in current leads to an increase in losses of more than 1%. Between 2/3 and 3/4 of technical (*or physical*) losses on distribution networks are variable Losses.

By increasing the cross-sectional area of lines and cables for a given load, losses will fall. This leads to a direct trade-off between cost of losses and cost of capital expenditure. It has been suggested that optimal average utilization rate on a distribution network that considers the cost of losses in its design could be as low as 30 per cent. The major categories of losses in power networks are;

- Joule losses in lines in each voltage level
- Impedance losses
- Losses caused by contact resistance.

The figure below shows the possible inputs of energy to the distribution network, which are distributed generation and transmission network. If these sources are metered in conjunction with the output of the distribution network to their loads, the resultant is the constituent of technical and non-technical losses. These are the distribution losses.

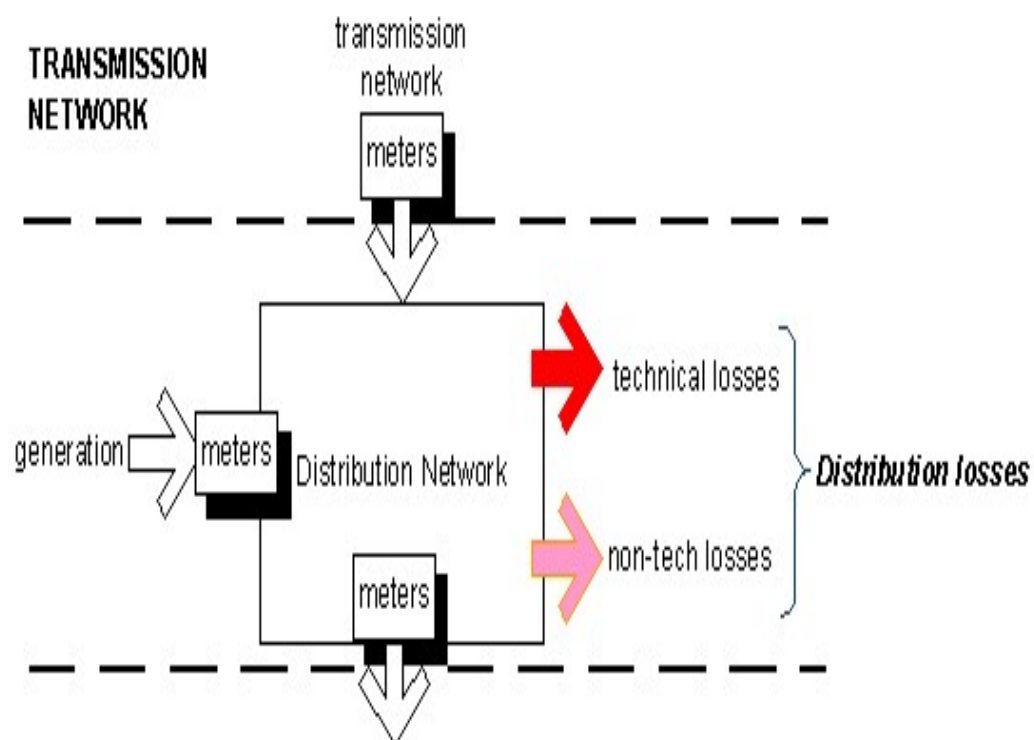


Fig. 1.12; Distribution losses from the input and output concept

3.0 POWER LOSSES IN DEVELOPING NATIONS:

Non-technical losses in the power sector are almost non-existent or negligibly small in developed countries, as most of the population can afford to pay tariffs reflecting costs of supply (even if they are higher than those reflecting optimized performance of the service providers). In contrast, although mixed, the situation tends to be significantly different in developing countries. Many electricity utilities in developing countries succeeded in significantly reducing or eliminating non-technical losses in electricity supply on a sustainable manner, but others continue to show high losses.

In all successful cases, a large share of non-technical losses was concentrated in users able to pay for cost-reflective tariffs. Thus, non-technical losses can be reduced with little loss of welfare, while their continuation jeopardizes the financial sustainability of the power sector and harms well-behaving electricity consumers, taxpayers, socially disadvantaged segments, and the country. Elimination of those losses (with the exception unmetered consumption explicitly and transparently defined in the regulatory framework) should be a matter of high national priority for every country.

3.1 Latin America

High total losses were prevalent in most Latin American countries at the beginning of the 1990s, in a scenario characterized by poor performance of state-owned enterprises (SOEs), poor service quality, and low access rates. Average tariff levels were usually below the cost of supply (exacerbated by inefficiencies in the performance of the utilities, particularly high non-technical losses) and both government subsidies and tariff cross-subsidization (in general from industrial and commercial to residential customers) were the usual practices. A vicious downward circle or “low-level trap” was the norm, as external subsidies were just keeping inefficient utilities afloat while the quality of service to existing customers progressively worsened. Therefore, the willingness of the population to pay for higher tariffs steadily declined over time, reducing the income source for the power sector and deepening the crisis.

From 1985 to 2000, Latin America was the region in the developing world that made the most significant advances in the comprehensive reform of the power sector. In 1982 Chile became the first country to introduce widespread institutional and regulatory reforms in its power sector, aimed at promoting efficiency and sustainability of existing operations and expansion of services. Reforms were initially applied to existing SOEs, but they were fully privatized in the second half of the 1980s as an important means of ensuring efficiency in sector operations within a well-defined regulatory framework which was transparently applied and enforced. The results achieved were impressive and the current performance of some Chilean utilities shows higher efficiency levels than comparable companies in developed countries.

In the first phase of reforms Chile was followed by Argentina in the early 1990s and shortly thereafter by Bolivia and Peru. The second phase of reforms included Colombia and

Brazil by the mid-1990s and several Central American and Caribbean countries (Dominican Republic, El Salvador, Panama, Guatemala, and Nicaragua) by the end of the decade.

The reform of the electricity sectors was limited or almost non-existent in Costa Rica, Honduras, Mexico, Paraguay, Uruguay and Venezuela. In all cases, reform components included unbundling of sector operations, introduction of competition in generation through the creation of electricity wholesale markets (which had mixed results), and privatization of existing companies (predominantly in charge of generation and distribution and retail).

The distribution segment reform of the electricity sector produced largely positive outcomes. Privatized companies achieved substantial increases in overall efficiency (operational and financial) by cutting technical and non-technical losses and improving service quality to existing customers.

The Chileans took advantage of being the pioneers in improving the efficiency of their privatized companies. They participated in the privatization processes of distribution companies in Argentina, Brazil, Peru, and Colombia, and became the new owners and operators of some of the most important utilities in those countries. Immediately after takeover of each company they implemented their in-house approach for improving performance, which was progressively refined and updated, incorporating the operational tools and the know-how they had to develop to overcome the challenges present in each specific environment.

3.2 East Asia

Chinese state-owned provincial electric power companies generally show good operational performance, in terms of service provided to existing customers, losses which are low, and connection of new consumers in rural areas. Performance of some companies in the richest South-Eastern region is excellent and comments made on the Chilean utilities are equally applicable.

In the last 10 years, Vietnam has achieved impressive results in improving operational performance of its state-owned electricity utilities and increasing electrification rates, despite a 15 percent annual growth in demand. Losses have been drastically reduced and service quality improved, particularly in urban areas; rural areas still need further improvement.

The Philippines has reasonably well performing private companies serving the capital and more than 100 small, poorly performing cooperatives in main urban areas characterized by poor operational and financial performance.

3.3 South Asia

State-owned utilities are highly predominant in the region. Quite recently Pakistan privatized the Karachi Electric Supply Company while all the other utilities remain state-

owned. Poor operational and financial performance, with total losses exceeding 30 percent, is typical, including the Karachi Electric Supply Company. State-owned utilities are in the process of being restructured and corporatized in Bangladesh, starting from a poor operational and financial base. Total losses exceed 20 percent in all cases, although figures vary among the different companies.

In India, most of distribution activities are carried out by utilities owned by state governments. The exceptions are Reliance (former BSES) and Tata, two private companies serving Mumbai which have always been private. While both Reliance and Tata show total losses of about 11–12 percent, the performance of state-owned utilities is generally bad, with losses exceeding 30 percent in most cases. Seven states started reform and restructuring of their power sectors in the 1990s, involving unbundling and corporatization of state-owned utilities. Privatization of only six distribution companies has gone forward so far and three of those have failed. The state of Orissa was the first to unbundle its electricity companies in 1996, followed by three failed attempts at privatizing some companies. Privatization of Delhi Electricity Co. in July 2002 was an ambitious undertaking, given its more than 4 million customers and losses greater than 50 percent of all power purchased at the time of takeover by new private owners, Reliance and Tata. The privatized companies have reduced total losses markedly. The case of the North Delhi Power Limited (NDPL), is probably the most recent example of a great success in sustainable loss reduction using state-of-the-art management and information technology tools currently available worldwide.

A successful functional unbundling program from an operational perspective is restructuring of the Andhra Pradesh State Electricity Board (APSEB). This utility has unbundled and corporatized the units in charge of generation, transmission, and distribution, while maintaining state ownership of all entities. One transmission and four distribution companies were created. They managed to reduce transmission and distribution losses from about 38 percent in 1999 to 26 percent in 2003 and less than 20 percent in 2008—in large part through theft control, with the utilities regularizing 2.25 million unauthorized connections.

3.4 Former Soviet Union

In the 1980s, the performance of electricity distribution utilities of the countries in the former Soviet Union was characterized by universal access, reasonably acceptable service quality, but poor financial performance. High total losses and poor collection rates, due to weak metering, billing, and payment collection accounted for the companies' financial distress. Starting in the 1990s, most EU accession countries have successfully privatized their distribution companies. Ukraine and Georgia are moving in the same direction. However, the situation remains almost unchanged, and the commercial performance of distribution companies is poor in Russia and most of the other countries in the former Soviet bloc.

3.5 Sub-Saharan Africa

A draft 2008 World Bank report describes the performance of the utilities in Sub-Saharan countries. The median utility in that region presents huge inefficiencies. Only 50 percent of electricity generated is paid for, due to a combination of low percentages of amounts of electricity injected in distribution networks being billed and low rates of collection of the billed amounts. The variation in performance is enormous, with the highest inefficiencies in Nigeria, where the utility is capturing only 25 percent of the revenues owed. Some recent studies have shown that hidden costs of distribution losses in Sub-Saharan Africa are usually more than 0.5 percent of GDP and may be as large as 1.2 percent of GDP in some countries. The exceptions are the state-owned and operated utilities of Botswana and South Africa. Botswana Power Corporation has long provided reliable, high-quality service. It has expanded the network in both urban and rural areas, covered its costs and posed no burden on the government budget. It has also reduced system losses to 10 percent and earned a decent return on assets. Electricity losses in Botswana are lower than in South Africa, whose power sector is operated by Eskom, one of the largest utilities in the world, with about 15 percent total losses.

4.0 POWER LOSS ESTIMATION AND EVALUATION:

Electricity must be transmitted from large power plants to the consumers via extensive networks. The transmission over long distances creates power losses. A major part of the energy losses comes from the Joule effect in transformers and power lines. The energy is lost as heat in the conductors.

Considering the main parts of a typical Transmission & Distribution network, here are the average values of power losses at the different steps:

- **1-2%** – Step-up transformer from generator to Transmission line
- **2-4%** – Transmission line
- **1-2%** – Step-down transformer from Transmission line to Distribution network
- **4-6%** – Distribution network transformers and cables

The overall losses between the power plant and consumers are then in the range between 8 and 15%.

This must not be mixed up with the efficiency of power plants like nuclear, coal-fired or natural gas turbines. These technologies are based on a thermodynamic cycle; which efficiency is in the order of 35%. This means that the combustion of coal, for example, will produce heat, which will be converted into mechanical energy and then into electricity.

From the energy assessment, it can be concluded that 100 units saved at home can save 300 units saved at the power plant. This should be a real encouragement to save energy for a greener environment.

However, it is important to note that the units saved at the power plant are units of heat, and not units of electrical energy. Each unit saved at home represents one unit of electrical energy saved at the power plant, in addition to the energy saved along the line. As mentioned earlier, this represents between 8 and 15% of the electrical energy produced.

Otherwise, this energy assessment relates to fuel burning power plants, and not to renewable energy like hydroelectricity or wind turbines. These technologies have much better efficiency and do not produce heat for energy conversion. The 100 units saved at home represent much less than 300 units saved at the power plant.

But this is not a good reason for wasting electricity!

To develop a power loss reduction strategy, the utilities first need to have a good knowledge of the level of power losses in their systems. The knowledge comes from monitoring and evaluating power losses on a constant basis. Loss evaluation is not a one-time event but needs to be considered when developing all utility processes; e.g., operational procedures, planning and engineering system expansions, purchasing materials, and defining revenue assurance measures.

As a starting point for the utilities to start estimating losses, DISCOs need to establish strategies for evaluating losses for their utilities. The DISCOs can then start collecting information to use the study. With the evaluation process repeated periodically, more and more data can be accumulated so that the study results become more and more accurate to reflect DISCOs actual level of losses.

New technologies will help DISCOs in improving the availability of information as well as providing support to the power loss monitoring and evaluation program. All DISCOs shall continue the effort of installing revenue meters for those unmetered customers as well as new customers to improve the accuracy of energy consumption measurements. Furthermore, DISCOs shall develop plan to install revenue class meters at strategic locations, such as in 33kV/11kV substations to monitor consumption of each outgoing feeder, as well as locations where a feeder supplies loads belong to neighboring DISCOs (referred as feeder sharing). By collecting and analyzing these meter measurements, DISCOs can improve their capability of reducing power losses and increasing revenue. Technologies will be helpful in DISCO's effort to monitor and evaluate power losses, especially Customer Information System (CIS), Geographic Information System (GIS), Automated Meter Reading (AMR) and Power System Analysis Tools (PSAT). These technologies should have the highest priority in each DISCO's overall technological advancement.

Generally speaking;

$$\text{Percent Losses} = \frac{kWh \text{ Purchases} - kWh \text{ Sales}}{kWh \text{ Purchases}} \times 100$$

The figure below shows the revenue source of the distribution system, as well as the cost incurred because of the losses.

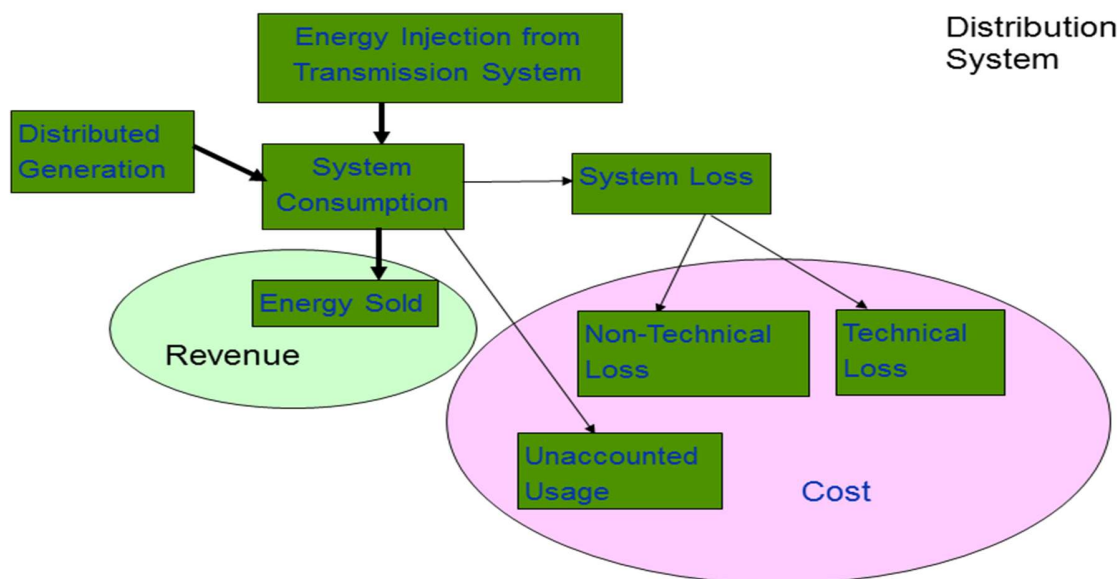


Fig. 4.1; Revenue and Losses cost of Distribution system

Ideally, Technical and Non-technical losses are calculated or estimated or evaluated separately. An example of how to calculate technical loss is as below:

Example

The model distribution line has the following parameters:

Transformer Parameters

Primary Voltage (Ur1) = 220kV

Secondary Voltage (Ur2) = 33kV

Resistive Percentage Impedance (URr(1)) = 1%

Reactive Percentage Impedance (Ukr(1)) = 10%

Iron Loss (IL) = 7.0kW (usually given by the manufacturer or sometimes calculated by using 0.1% at optimal or 0.2% of Transformer capacity), $7,000 \times 0.1\% = 7.0\text{kW}$ or as calculated in the Iron loss later.

Apparent Power (Sn) = 7,000kVA

Line Parameters

Type : 150sqmm_33kV_Wishbone_OHL

Resistance (RL) = 0.2046 Ohms/km

Length (L) = 20 km

Load Parameters

Peak load (PL) = 5,000kW

Power Factor (PF) = 1.0

The Technical Loss has been calculated manually and using NEPLAN software as shown below;

a. Manual Calculation for instantaneous technical loss

Transformer Loss

First, we need to calculate the primary current (I_1) considering the Peak load of 5,000kW (PL) using the formula:

$$I_1 = PL / (\sqrt{3} \times Ur1 \times PF)$$

$$I_1 = 5,000 / (\sqrt{3} \times 220 \times 1.0) = 13.12 \text{ A}$$

The transformer copper power loss (P_{Tc}) can be calculated using the formula:

$$P_{Tc} = (I_1^2 \times R_T) \times 3$$

where R_T is the one phase resistance of the transformer winding.

To calculate R_T , we need to convert the percentage impedance values to actual values:

Primary side percentage impedance formula is

$$\begin{aligned}\%Z (1) &= V_{st} \times 100 / U_{r1} \\ &= (I_1 \times Z \times \sqrt{3}) \times 100 / U_{r1} \\ &= (I_1 \times Z \times \sqrt{3}) \times U_{r1} \times 100 / U_{r1}^2 \\ &= (I_1 \times U_{r1} \times \sqrt{3}) \times Z \times 100 / U_{r1}^2 \\ &= S_n \times Z \times 100 / U_{r1}^2\end{aligned}$$

V_{st} is the primary voltage at secondary short circuit

Z is one phase impedance of the transformer winding

Therefore, Real part is

$$\begin{aligned}URr(1) &= S_n \times R_T \times 100 / U_{r1}^2 \\ R_T &= URr(1) \times U_{r1}^2 / (100 \times S_n) \\ &= 1 \times (220 \times 1,000)^2 / (100 \times 7,000 \times 1,000) = 69.14 \text{ Ohms}\end{aligned}$$

Now we can substitute these values into the formula for P_{Tc} :

$$\begin{aligned}P_{Tc} &= 13.12^2 \times 69.14 \times 3 \\ P_{Tc} &= 35,704.11 \text{ or } \mathbf{35.70kW}\end{aligned}$$

Therefore, the transformer copper power loss is approximately 35.7 kW when a load of 5,000 kW is connected to the transformer.

Transformer [No-Load (Iron)] Loss is calculated as follows;

$\%Z (2) = S_n \times Z \times 100 / U_{r1}^2$ (Quote from previous slide.)

$$X_T = URr (1) \times U_{r1}^2 / (100 \times S_n)$$

$$X_T = 0.1 \times 220^2 / 7,000 = 6.914 \Omega$$

Taking $R = 6.914 \Omega$

$$I = I_1 = PL / (\sqrt{3} \times U_{r1} \times PF)$$

$$I_1 = 7,000 / (\sqrt{3} \times 220 \times 1.0) = 18.4A$$

$$PTi = (I_1^2 \times R_T) \times 3$$

$$P = (18.4^2 \times 6.914) \times 3 = 7.0 \text{ kW (Usually given by the manufacturer or calculated in manual calculation)}$$

Line Loss

The line losses for a single line can be determined using the equation below:

$$P_L = I_2^2 \times R_L \times L$$

Where;

P_L = Line Losses (W)

I_2 = Secondary current of the Transformer at the peak load given by;

$$I_2 = PL / (\text{sqrt}(3) \times U_{r2} \times PF)$$

Considering the load of 5,000kW, the current is found to be

$$I_2 = 5,000 / (\text{sqrt}(3) \times 33 \times 1.0)$$

$$I_2 = 87.48 \text{ A}$$

R_L = Resistance of the line per kilometer = 0.2046 ohms/km, and

L = Length of the distribution line = 20km

Therefore,

$$P_L = 87.48^2 \times 0.2046 \times 20$$

$$P_L = 31,315.05 \text{ W} = 31.32 \text{ kW}$$

The above value is for a single line.

Now, for 3 phase 3 wire system:

$$P_L = 3 \times 31.32 \text{ kW}$$

$$P_L = 93.96 \text{ kW}$$

Therefore, the total power loss = Transformer copper loss + Transformer Iron loss + Line loss

$$P_t = 93.96 \text{ kW} + 7.0 \text{ kW} + 35.70 \text{ kW} = 137 \text{ kW}$$

b. NEPLAN Calculation:

The parameters above were inserted into the software and the loss calculation was run. The screenshots of the procedure and the results is shown below.

[illegible]

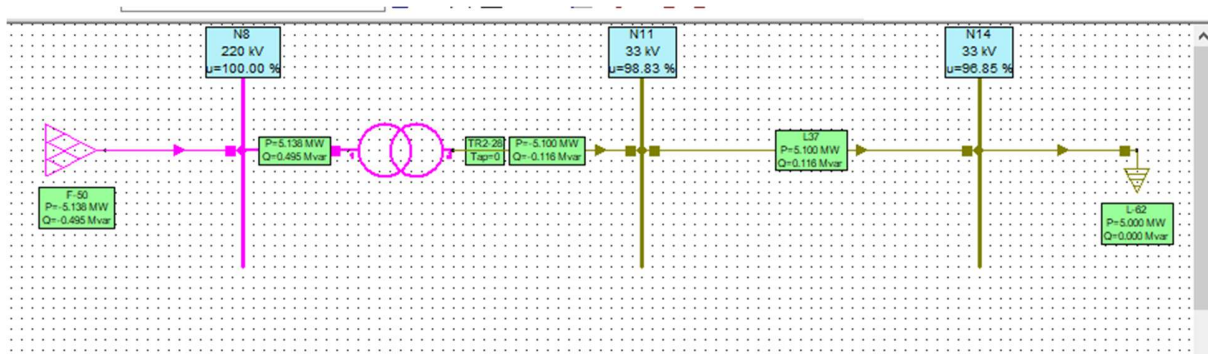
Composite load

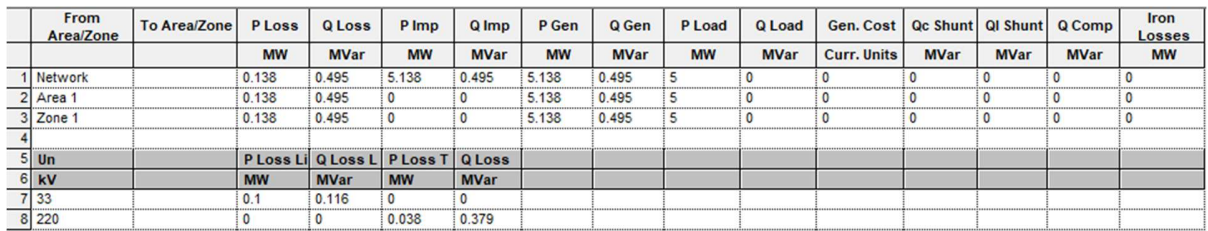
l= 20 km
type: ACSR ANT

Text01 / Diagram 0°

The diagram shows a circuit with a voltage source (represented by a square with an 'X' inside) connected to a switch (represented by two vertical lines with a horizontal bar). The switch is in the open position. The circuit continues through a load (represented by a circle with a dot inside) and then through another switch (also in the open position). The circuit is connected to ground (represented by a triangle with a horizontal line).

The iron loss is usually given by the manufacturer and inputted in to the NEPLAN software or determined automatically by the software based on 1-10% value of the transformer capacity.





DISTRIBUTION TECHNICAL LOSS CALCULATION SPREADSHEET

Transformer Losses:

1. Transformer Copper Loss (P_{cu}): This is calculated based on the formula

$$P_{cu} = I^2 \times R_{Pcu} = I^2 \times R$$

where (I) is the current and (R) is the resistance of the transformer's winding.

2. Transformer Iron Loss (P_i): This is usually given by the manufacturer and is constant, regardless of the load.

Distribution Line Loss:

1. Line Loss (P_{line}): Similar to copper loss, it can be calculated using the formula

$$P_{line} = I^2 \times R_{(line)} \quad P_{line} = I^2 \times R_{line}$$

where (R_(line)) is the resistance of the distribution line.

You would then sum these losses for the total technical loss.

Transformer Rating (kVA)	Load (kW)	Primary Voltage (KV)	Secondary Voltage (Kv)	U _{rl} 1	U _{kl} 1	Conduc. Resist. (Ohms)	Line Length (m)	Power Factor	Sec. Current (IL2)	Load Current (IP)	Winding Resistance *	Copper Loss (P _{cu})	Iron Loss (Pi)	Line Loss	Total Loss
7000	5000	220	33	1%	10%	0.2046	20	1	87.58101244	13.13715187	69.14285714	35.799	7	94.16224458	136.9612546
5000															
1000															

You'll need to fill in the blanks with your specific data. The 'Total Loss' column will be the sum of 'Copper Loss (P_{cu})', 'Iron Loss (P_i)', and 'Line Loss (P_{line})' for each transformer.

4.3. Annual Loss Calculation:

Transformer Parameters

Primary Voltage (U_{r1}) = 220kV

Secondary Voltage (U_{r2}) = 33kV

Resistive Percentage Impedance ($U_{Rr(1)}$) = 1%

Reactive Percentage Impédance ($U_{Kr(1)}$) = 10%

Capacity (S_n) = 7,000kVA

Line Parameters

Type : 150sqmm_33kV_Wishbone_OHL

Resistance (R_L) = 0.2046 Ohms/km

Length (L) = 20 km

Load Parameters

Peak load (PL) = 5,000kW

Annual power supply (APS) at the feeder = 28,470MWh

Power Factor (PF) = 1

Solution:

In order to calculate the actual annual technical loss, it is necessary to calculate the instantaneous technical loss using the value of the load current that changes from moment to moment, and then sum (integrate) this for one year. This is not a realistic method for calculating the annual technical loss, because it requires a large amount of calculation effort, in addition to the need to know all instantaneous load currents.

For this reason, statistical methods are used in general annual technical loss calculations. Each factor used in the statistical method is described below.

Below is an example of how to calculate annual technical losses using statistical methods.

Peak load consumed per annum = Peak load (PL) x 365day x 24hrs = 5,000kW x 8,760hrs
= **43,800,000kWh** = 43,800MWh

Load factor (LF) = APS at the feeder / Peak load consumed per annum
= 28,470 MWh / 43,800 MWh
= **0.65**

Load Factor (LF): Load factor represents the ratio of the average load on a power system to the maximum load it can handle over a given period. It is a measure of how effectively the power system is utilized. The load factor is calculated using the formula:

$$\text{Load Factor} = \text{Average Load} / \text{Peak Load}$$

A higher load factor indicates a more efficient utilization of the power system, resulting in lower losses.

$$\text{Load Loss Factor (LLF)} = (0.8 \times \text{LF}^2) + (0.2 \times \text{LF}) = (0.8 \times 0.65 \times 0.65) + (0.2 \times 0.65) = 0.338 + 0.13 = \mathbf{0.468}$$

The load-loss factor, often known as the loss load factor, LLF, or just the loss factor, is a dimensionless ratio between the average and peak values of the load loss (loss of electrical power throughout the distribution of energy between the source and the consumer). The LLF can be calculated by measuring the square of delivered power over a short period of time (typically half an hour), taking an average of these values over a long period of time (a year), and dividing by the square of the peak power displayed during the same long period of time because losses in the wires are proportional to the square of the current (and thus the square of the power).

Load Loss Factor can also be calculated using the Load factor as follows.

$$\text{LLD} = (0.8 \times \text{LF}^2) + (0.2 \times \text{LF})$$

Load loss factor helps quantify the proportion of power lost during transmission and distribution.

By using statistical methods in the calculation of ever-changing copper losses, Annual power loss (PLA) is calculated by multiplying the instantaneous power loss at the peak load with the Load Loss Factor.

The annual iron loss for Transformers (P_{ATi}) can be calculated as below

$$P_{ATi} = \mathbf{7.0 \text{ kW (usually given by the manufacturer or as calculated earlier)}}$$

The annual copper loss for Transformers (P_{ATc}) can be calculated as below

$$P_{ATc} = P_{Tc} \times \text{LLF} = 35.70 \times 0.468 = \mathbf{16.71 \text{ kW}}$$

P_{Tc} : The transformer copper power loss at peak load

The annual Line copper loss (P_{AL}) can be calculated as below

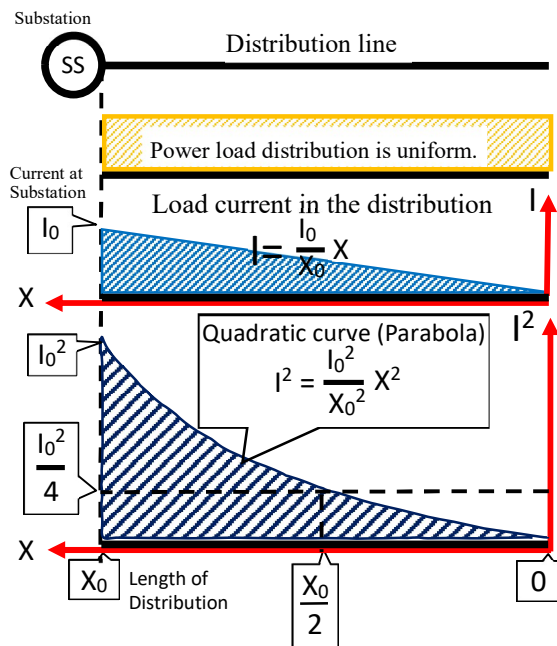
$$P_{AL} = P_L \times \text{LLF} / \text{LDF} = 93.96 \times 0.468 = 43.96 = \mathbf{43.96 \text{ kW}}$$

$$\text{Using LDF of 1.5, } P_{AL} = 43.96 / 1.5 = \mathbf{29.32 \text{ kW}}$$

P_L : Line Losses at peak load

Load Distribution Factor (LDF): Load distribution factor represents the fraction of total load carried by a particular component, such as a transmission line or transformer, in relation to the total load in the system. It helps determine the contribution of each component to the overall power losses.

< Calculation of the power load loss (in case of uniform load) >



Calculation Method of power load loss (L)

$$L = \int_0^{X_0} R I^2 dX$$

Note
 R : Conductor registration per unit
 I : Load current
 X : Distance from end of distribution line

$$= \int_0^{X_0} R \frac{I_0^2}{X_0^2} X^2 dX$$

$$= \left[\frac{1}{3} R \frac{I_0^2}{X_0^2} X^3 \right]_0^{X_0}$$

$$= \frac{1}{3} R I_0^2 X_0$$

Load Distribution factor (LDF)
at uniform load

Additionally, for loads at the end of line alone the LDF is usually 1, at average it is supposed to be 1.5 while for the minimum value it is usually 3 and when load is concentrated near the substation, the value may be higher than 3.

By analysing the load distribution factor, system planners can identify heavily loaded components that may contribute more to losses.

These factors, when considered together, provide insights into the efficiency, losses, and load characteristics of a power system network. By optimizing these factors, power system engineers and planners can design and operate more efficient systems, reduce losses, and ensure reliable power supply.

$$\text{Annual Technical Loss (PLA)} = P_{ATi} + P_{ATc} + P_{AL}$$

$$= 16.71 + 7.02 + 29.32 = \mathbf{53.05kW}$$

Taking 53.05kW loss with LDF of 1.5, Loss annually becomes $53.05 \times 8760 = 464.72\text{MWh}$

CAUSES POWER LOSS AND MITIGATION

5.1 Causes of Technical Losses

Technical Losses are caused by the inefficiencies of electric power flow through conductors and equipment in the distribution system. The condition of conductors and equipment is an important factor impacting technical losses. It was discovered that the following items are some of the major causes of technical losses in distribution system:

- Lengthy distribution lines:
- Overloading of Distribution Transformers:
- Inadequate Size of Conductors of Distribution Lines:
- Low Power Factor of Primary and Secondary Distribution System:
- Wire connector – old and/or loose connections
- Old equipment, such as old switching devices, old transformers, etc.
- Maintenance issues.

Reducing technical losses is an important goal for power distribution companies, as it can lead to increased efficiency and lower costs for both the company and the consumers. The description of the main reasons for technical losses in power distribution systems are:

5.1.1 Lengthy distribution lines:

The primary and secondary distribution lines mostly in rural areas are usually extended over long distances to feed loads scattered over large areas. These lines are typically radial in nature, which results in high line resistance and therefore high I^2R losses in the line.

5.1.2 Overloading of Distribution Transformers:

Proper sizing and selection of transformers are crucial for reducing technical losses. If the transformer is undersized, then it will not be able to handle the load, resulting in power losses. On the other hand, if the transformer is oversized, then it will be inefficient and result in higher commercial losses.

When transformers are overloaded, they become less efficient. Thus, the overloading of distribution transformers due to increased demand or faulty design can result in higher technical losses.

5.1.3 Inadequate Size of Conductors of Distribution Lines:

Conductors are used to transfer power from the source to the load. If the size of the conductor is inadequate, then the power transfer capacity of the conductor will be limited, leading to power losses in the form of heat. This can cause the conductor to overheat and even fail, leading to further losses. The size of the conductors should be selected based on the KVA x KM capacity of the standard conductor for a required voltage regulation

5.1.4 Installation of Distribution Transformers Far Away from Load Centers:

Distribution transformers are used to step down the voltage to a lower level for the distribution of electricity. In most cases, transformers are not located close to consumers. Consequently, the farthest consumers obtain an extremely low voltage even though a good voltage level is maintained at the transformer's secondary. If the distribution transformer is installed far away from the load center, then there will be a voltage drop due to the resistance of the distribution line. This voltage drop results in power losses, which increase as the distance between the transformer and the load center increases.

5.1.5 Low Power Factor of Primary and Secondary Distribution System:

Power factor (PF) is a measure of how efficiently electrical power is being used. A low PF means that the electrical system is not using power efficiently, resulting in power losses in the form of heat. This can cause equipment to overheat and fail, leading to further losses. A low power factor can result in increased technical losses due to higher reactive power consumption in the system.

In most LT distribution circuits, normally the PF ranges from 0.65 to 0.85. A low Power Factor contributes towards high distribution losses. For a given load, if the PF is low, the current drawn is high and the losses proportional to the square of the current will be more.

5.1.6 Feeder Phase Current and Load Imbalance:

If the phase currents are significantly different, the load is considered unbalanced, which can result in increased losses and voltage drop in the system. Similarly, load imbalance among distribution feeders will also increase losses assuming similar conductor resistance.

Feeder phase current and load balancing are essential for reducing technical losses. If there is an imbalance in the current flow between the phases or an imbalance in the load, then power losses will occur due to the increased resistance in the system. Feeder phase balancing also tends to balance voltage drop among phases giving three-phase customers less voltage unbalance.

One of the easiest loss savings of the distribution system is balancing current along three-phase circuits. Feeder phase unbalance may vary during the day and with different seasons. Feeders are usually considered "balanced" when phase current magnitudes are

within 5% of each other. This means that the current flowing through each phase is roughly the same, indicating that the load is evenly distributed across all three phases.

5.1.7 Load Factor Effect on Losses:

if the load factor is low, then the system is not being used efficiently, resulting in higher technical losses.

The power consumption of customers varies throughout the day and over seasons. Load factor is the ratio of the average load over some time to the peak load during that time and it varies from 0 to 1. A high load factor means that the electrical system is being used efficiently, resulting in fewer technical losses.

Residential customers generally draw their highest power demand in the evening hours. The same commercial customer load generally peaks in the early afternoon. Because the current level (hence, load) is the primary driver in distribution power losses, keeping power consumption more level throughout the day will lower peak power loss and overall energy losses.

5.1.8 Loose Terminations and Wire Connectors

Loose connections and terminations refer to the improper fastening or securing of electrical conductors, cables, and components within the distribution system. When connections and terminations are not properly tightened or secured, they can result in various issues that contribute to technical losses. Some of the impacts of loose connections and terminations include Safety Hazards, Increased Resistance, Voltage Drop, Overheating, and Equipment Damage which all have an effect on power loss.

5.1.9 Poor quality of equipment and maintenance:

The use of poor-quality of equipment and materials, such as transformers, switchgear, and conductors can lead to increased technical losses due to inefficient operation and higher maintenance requirements. Lack of maintenance also cause technical losses.

5.1.10 Bad Workmanship:

Bad workmanship during the installation and maintenance of electrical systems can contribute significantly towards increasing distribution technical losses. Improper installation, connection, and maintenance of equipment can lead to power losses, equipment failure, and safety hazards.

5.2 Power Loss Reduction Techniques:

In 2013, DNV KEMA conducted a study on power loss reduction techniques in some selected utility companies in Nigeria. The study aimed to identify the causes of technical losses in the power distribution network and to recommend measures to reduce these losses. As part of their recommendations, they suggested certain processes to be implemented by the DISCOs, in addition to using loss reduction technologies. They are

- Monitor and evaluate losses
- Implement processes and procedures aimed at reducing technical losses
- Implement processes and procedures aimed at reducing non-technical losses

One of the key strategies the DISCOs in their efforts to minimize power losses should prioritize is the continuous monitoring, evaluation, and assessment of these losses as it serves as the foundation for effective power loss reduction. Recognizing that complete elimination of losses is not practically achievable, the success of loss reduction initiatives lies in identifying and prioritizing areas where losses are significantly higher. Consequently, the efficient planning and implementation of loss reduction strategies necessitate a comprehensive understanding of the current status of actual losses.

For this reason, the primary method for reducing losses involves the calculation of technical losses per transformer (and ideally per feeder, if feasible) within the substation. This calculation can be accomplished using either the NEPLAN model or manual calculations, as discussed in the preceding Chapter 4.0. Moreover, beyond its role in quantifying the impact of loss reduction efforts, comprehending these technical losses also aids in grasping the extent of the magnitude of non-technical losses.

Equally important as the availability of technologies is the proficiency of the user of the technologies. The DISCOs should consider workforce development and training as an essential part when implementing the recommended technologies.

Here are some measures that can be taken to mitigate technical losses in distribution systems based on the causes mentioned:

The following table provides a concise overview of the factors contributing to technical losses and suggests corresponding mitigation measures. It is imperative to implement these measures for the primary loss areas that have been identified.

S/ N	Causes of Technical Loss	Mitigation Measures
1	Lengthy Distribution Lines	Optimization of Distribution Network a) Feeder segmentation b) Changing power supply routes

		c) Selection of suitable supply voltage
2	Inadequate Size of Conductors	Using Adequate Conductors for Distribution Lines a) Upgrading existing lines b) Use of compact conductors
3	Overloading Distribution Transformers	Optimization of Transformer Capacity and Location a) Upgrading transformers b) Optimization of LV distribution network
4	Installation of Distribution Transformers away from the Load Centers	Optimization of Transformer Capacity and Location
5	Low Power Factor of Primary and Secondary Distribution Systems	Low power factor improvement a) Power Factor Improvement b) Encouraging consumers to install capacitors that are appropriate for their load facilities
6	Load in-balance across phases	Feeder phase current and load balancing a) Load Distribution b) Phase balancing
7	Loose Terminations and Wire Connections	a) Proper Torque and Fastening b) Regular Inspection and Maintenance c) Use of Proper Tools, Equipment, and Techniques d) Training and Awareness
8	Poor quality of equipment and maintenance	a) Using only high-quality equipment and materials b) Conducting quality control checks on equipment and materials

5.2.1 Optimization of Distribution Network:

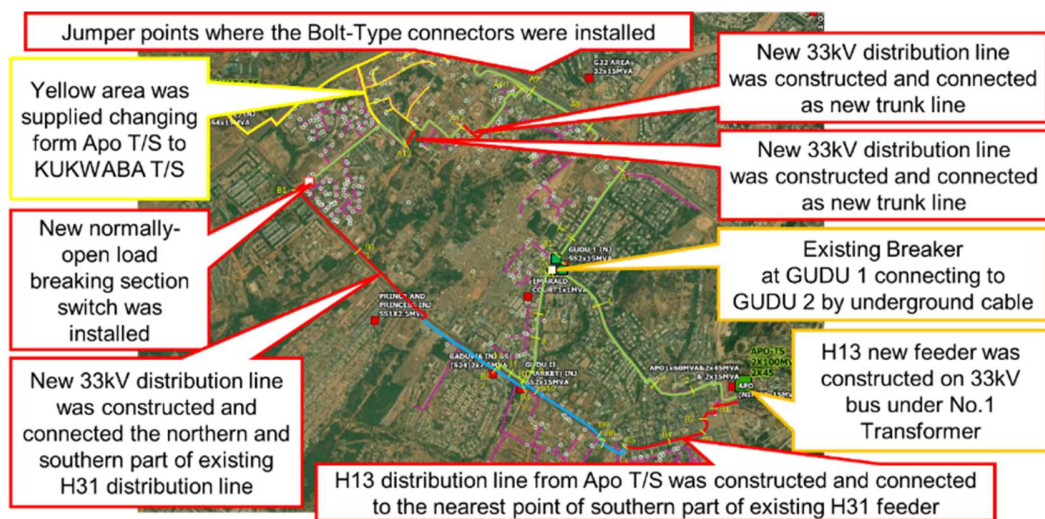
Optimizing the distribution network is a critical strategy in reducing technical losses and enhancing the efficiency of power distribution. This optimization process involves proper network planning and design to ensure that all loads are supplied via the shortest and most efficient route from the nearest power source. If the existing network is no longer efficient and suitable due to changes in power supply and load distribution, the following strategies should be considered:

a) **Feeder Segmentation:** Divide lengthy feeders into smaller segments, especially in areas with dispersed loads and where the primary distribution line is significantly longer. This should be done after evaluating the availability of other feeders.

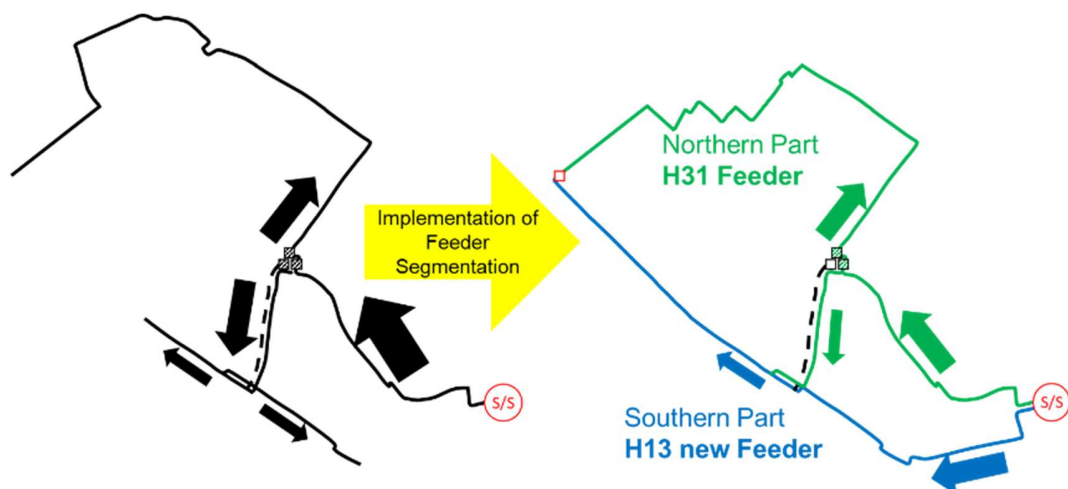
- Examples of Implementation at AEDC through JICA Projects

In the JICA project implemented from 2022 to 2025, separation and looping of the H31 feeder by new construction of the missing distribution lines were conducted as the pilot project. The outline of the pilot project is as follows.

Outline of AEDC Pilot Project: Separation of H31 Feeder in Apo T/S



Although this is a rough estimate based on a very simplified network model due to the lack of detailed network data, the loss reduction effect achieved by this pilot project was **approximately 57%**. The image of the loss reduction effect is illustrated in the following figure.



b) Changing Power Supply Routes: Where the existing supply route is not the most direct and contains significant detours that significantly increase the distance power must travel, consider modifying the routing of the distribution lines to minimize losses and optimize efficiency.

c) Selection of Suitable Supply Voltage: In cases where there is a substantial load located far from the power supply source with no other supply sources nearby, opt for higher voltage distribution. If increasing the voltage is not feasible, explore the possibility of implementing a dedicated supply line for that load.

5.2.2 Using Adequate Conductors for Distribution Lines:

Selecting appropriate conductors for distribution lines is essential for reducing technical losses, especially in areas where there is a constant high demand with high current flow. To address this, the following strategies should be considered. Note that priority should be given to replacing existing conductors with those of lower resistance.

a) Upgrading Existing Lines: Evaluate and upgrade the existing distribution lines by replacing smaller conductors with larger ones. In situations where limitations exist in terms of support strength or conductor specifications, it becomes necessary to explore the possibility of voltage upgrades as an alternative solution.

b) Use of Compact Conductors: This refers to the selection of conductors that have a smaller physical size but can carry higher amounts of current. These conductors are engineered to have a higher cross-sectional area, which reduces their resistance per unit length. However, it's important to note that these compact conductors may be more expensive compared to the conventional ones. Therefore, it's essential to conduct a thorough and long-term economic evaluation to determine their feasibility and cost-effectiveness before integrating them into the distribution system.

5.2.3 Optimization of Transformer Capacity and Location:

Efficiently managing transformers' capacity and their strategic location is crucial for reducing technical losses in the distribution network. When the need arises to replace a transformer due to failure or overload, it's essential to consider the following loss reduction measures, taking into account factors such as the current load size, its increasing growth trend, and the associated economic benefits:

a) Upgrading Transformers: Transformer design varies among manufacturers, and losses at rated load can vary as well. Generally, transformers with larger rated capacities tend to have higher losses at their rated load. However, when operated at the same load, larger-rated transformers tend to exhibit lower losses. From a loss reduction perspective, it is better to opt for higher-rated capacity transformers.

However, it's important to note that while higher-rated capacity transformers are more efficient, their initial costs are also higher. Therefore, it's crucial to consider the trade-off between loss reduction and initial cost. Transformer capacity should be determined after conducting a comprehensive evaluation of long-term economic benefits.

b) Optimization of Low Voltage Distribution Network: Evaluate the need for system expansion and reconfiguration to bring distribution transformers closer to the load centers. This may involve installing additional transformers or relocating existing ones to reduce the length of the distribution lines. For example, if a transformer needs replacement due to overload, and it is situated at a considerable distance from the load center, relocating it closer to the load center can be an effective strategy for reducing losses.

5.2.4 Improvement of Low Power Factor:

A low power factor in the distribution network can result in increased technical losses, as losses are inversely proportional to the square of the power factor. When the power factor falls below 0.8, distribution line losses significantly increase, making it imperative to consider corrective measures. The table and figure below demonstrate the effect of the power factor on the technical loss on distribution lines.

Table: Relationship between power factor and technical loss on distribution lines

1

Power factor ($\cos\theta$)	1	0.95	0.9	0.85	0.8	0.75	0.7	0.65
$1/\cos\theta$ (apparent current/active current)	1	1.05	1.11	1.18	1.25	1.33	1.43	1.54
Increase in technical loss ($1/\cos^2\theta - 1$)	0	0.11	0.23	0.38	0.56	0.78	1.04	1.37

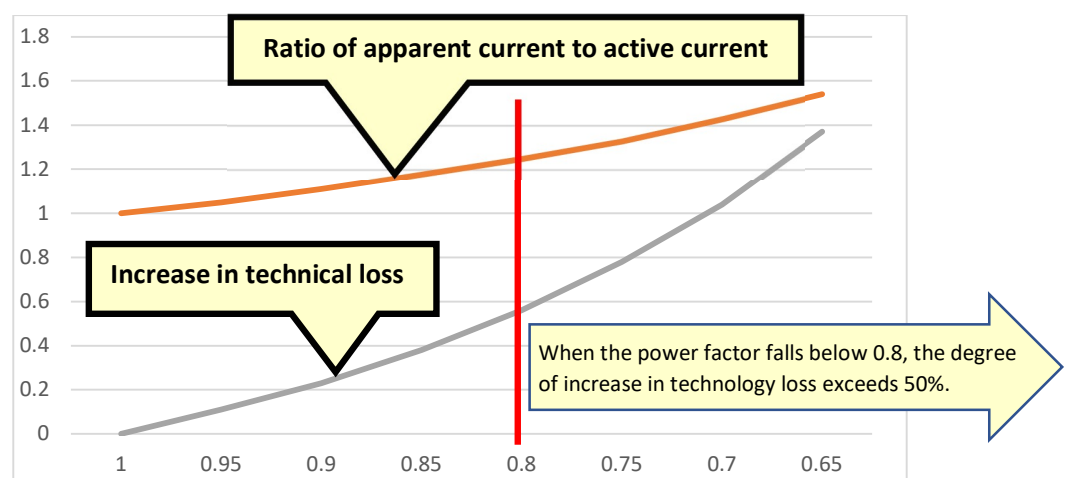


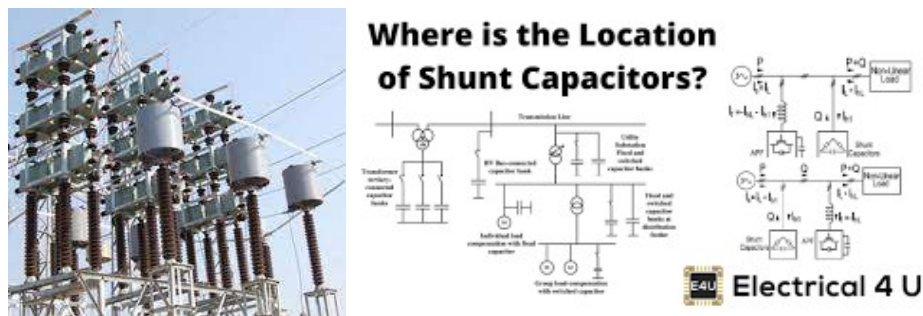
Fig. Relationship between power factor and technical loss of distribution lines

To enhance a low power factor, the following steps can be implemented:

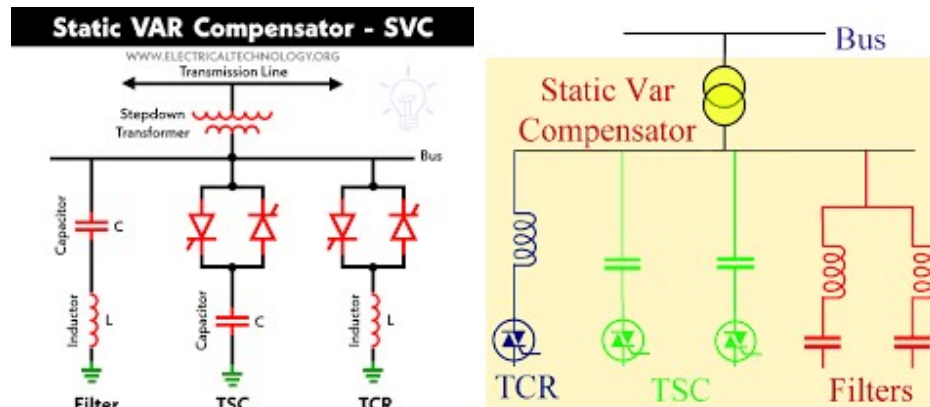
a) Installation of Power Factor Improvement Equipment:

The most common approach to improve the power factor involves installing power factor correction equipment near substations or load centers where the power factor is deteriorating. Common power factor correction facilities include:

1. Shunt Capacitors: These capacitors are connected in parallel with the loads to provide reactive power compensation. They supply the required reactive power locally, offsetting the reactive power demand of inductive loads thereby improving the power factor. Capacitor banks can be installed at distribution substations to compensate for reactive power at the system level, with the ability to switch them on or off as needed to maintain a desired power factor.



Static VAR compensators (SVCs): are devices used to regulate reactive power in an electrical system. They consist of power electronics that can quickly inject or absorb reactive power into the grid depending on the system's requirements. When the power factor is lagging, SVCs supply capacitive reactive power to reduce the phase difference between voltage and current, thereby improving the power factor. Conversely, when the power factor is leading, SVCs provide inductive reactive power. By maintaining a close-to-unity power factor, SVCs help reduce technical losses caused by excessive reactive power flow in the distribution network.



Static Synchronous Compensators (STATCOMs): also called self-excited SVCs, have variable reactive power outputs that can be changed in milliseconds to supply or consume both capacitive and inductive reactive power. While they can be used for voltage support and power factor correction, their primary role is in handling dynamic power system events such as grid support under fault conditions or emergency conditions.

It is worth noting that Although STATCOMs are the best in terms of performance, they are very expensive, and considering that in many cases the cause of low power factor is lagging caused by inductive loads, it is most economical to utilize shunt capacitors for power factor correction.

A comparison between shunt capacitors, SVCs, and STATCOMs is shown in the table below:

	1. Shunt capacitors	2. SVCs	3. STATCOMs
Delayed power improvement	Available	Available	Available
Advance power improvement	Not available	Available	Available
harmonics	Not available	Not available	Available
Response speed	Manual On-Off operation	High speed (About 100msec)	Very high Speed (About 30msec)
Installation Cost	Reasonable	High	Very high
Remarks		Need to be used with capacitors	

b) Encouraging Consumers to Install Capacitors for Load Facilities:

To promote the installation of power factor improvement equipment among consumers, it's essential to communicate the benefits and incentivize them to take action. This can be achieved through government incentives and changes in electricity rate structures. Benefits for consumers from capacitor installation include:

- 1) **More Room for Power Equipment:** Installing low-voltage capacitors creates additional capacities in transformers and power lines, enabling the addition of loads without the need for additional equipment.
- 2) **Reduced Power Loss:** Installing low-voltage capacitors reduces the current flowing through transformers and power lines, resulting in less power loss and more efficient power utilization.
- 3) **Voltage Stabilization:** Capacitors reduce voltage drops and fluctuations within the premises, allowing for the use of high-quality electric power. This improves power quality and overall productivity.

Incentives for Consumers through Rate Structures:

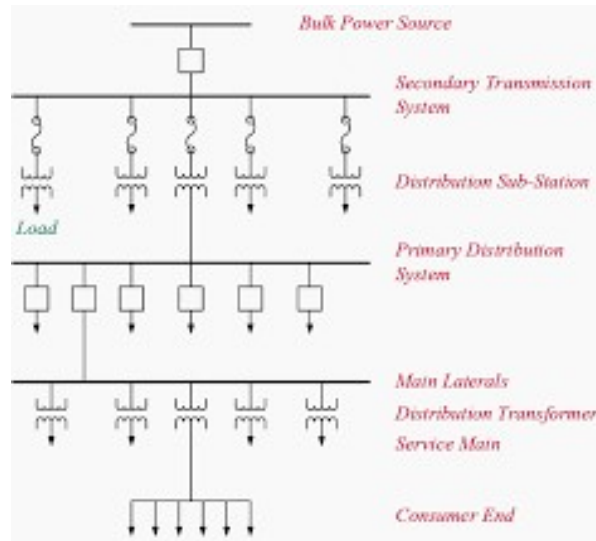
Incentives for consumers can be provided through rate structures. For example, a discount on the base rate could be applied when consumers install capacitors to improve the power factor. The discount would be based on the degree of improvement achieved.

For instance, if the power factor is increased from 0.85 to 0.95, a 10% discount could be applied to the base rate.

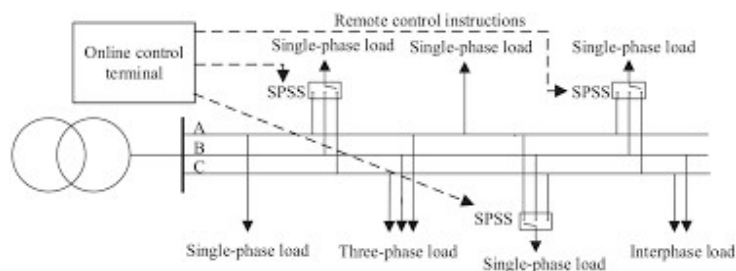
5.2.5 Feeder Phase Current and Load Balancing:

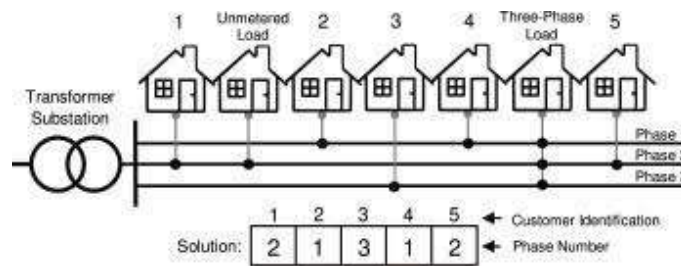
To mitigate against this cause, introduce:

- a) **Load Distribution:** Load distribution involves the equitable balancing of the loads by redistributing from heavily loaded feeders to lightly loaded feeders and ensuring equal distribution of load across all three phases. By ensuring that the loads are balanced among the phases, load distribution reduces the risk of overloading a single phase while others remain underutilized. Balanced load distribution helps prevent uneven stress on distribution lines, transformers, and other equipment, ultimately leading to reduced technical losses by optimizing the utilization of the entire network.



b) Phase Balancing: Also known as phase correction or phase swapping, is a power loss reduction technique used in three-phase electrical systems. It refers to the intentional interchange of the connections of two or more phases in a distribution network. In an ideal three-phase system, the load should be evenly distributed among the three phases to ensure balanced currents and minimize losses. However, due to various factors such as uneven distribution of loads, different power demands, or incorrect wiring, the phases can become imbalanced, leading to higher losses. By swapping phases, the load on each phase can be better distributed, minimizing the potential for overload on any one phase. Phase swapping can be strategically implemented to optimize the utilization of the distribution system, enhance load balance, and subsequently reduce technical losses.





5.2.6 Loose Terminations and Wire Connections

By addressing loose connections and terminations, the distribution system can minimize resistive losses, improve voltage regulation, enhance system reliability, and mitigate safety risks. This results in a more efficient and reliable distribution network with reduced technical losses.

To address the issues related to loose connections and terminations and reduce associated losses, the following measures can be taken:

- a) **Proper Torque and Fastening:** Ensuring that all electrical connections and terminations are properly tightened and secured to the recommended torque levels specified by manufacturers and industry standards.
- b) **Regular Inspection and Maintenance:** Conducting routine inspections of electrical connections and terminations to identify any signs of looseness, corrosion, or degradation. Promptly addressing any identified issues through re-tightening or replacement of faulty components.
- c) **Use of Proper Tools and Techniques:** Utilizing appropriate tools, such as torque wrenches, to achieve accurate and consistent torque values during installation and maintenance. Following recommended procedures and techniques for making connections and terminations.
- d) **Training and certification of technicians:** Providing training and awareness programs for technicians and maintenance personnel on the importance of proper connections and terminations. Educating them about the potential consequences of loose connections and the correct methods for ensuring secure and reliable electrical connections.

Effective connections, joints, and terminations play a crucial role in mitigating power technical losses in power systems by minimizing resistive losses, ensuring reliability, and maintaining system efficiency.

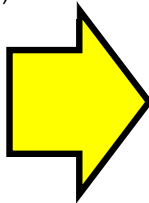
- Reduced Resistive Losses:
 - Properly designed and installed connections, joints, and terminations result in lower resistance at critical points in the power system. Reduced resistance means less power is dissipated as heat,

resulting in lower resistive losses. This is particularly important in high-current areas such as substations, transformers, and distribution lines.

- Improved Reliability:
 - Faulty or poorly constructed connections, joints, and terminations can lead to increased impedance, voltage drops, and hotspots. These issues can result in overheating, arcing, and ultimately, equipment failure or system outages. By ensuring that connections are securely made, joints are properly insulated, and terminations

Connection and disconnection of Jumpers by Bolt-type connector

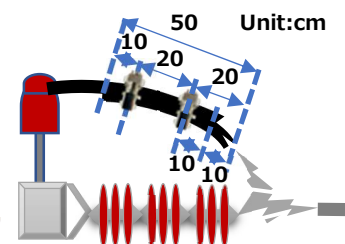
<<Status quo (Binding connection)>>



<<Bolt-type connector>>

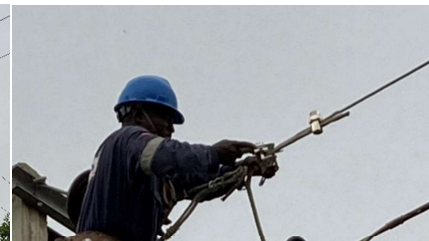


Weight: 693g/piece,
Length: 70mm/piece



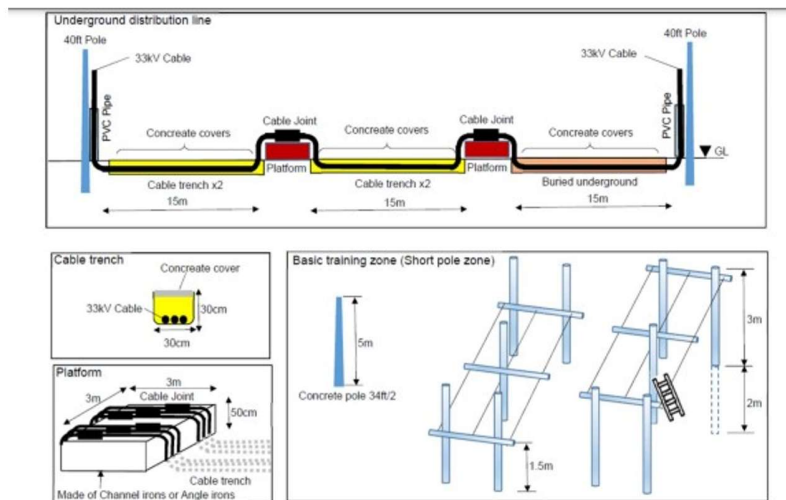
Advantage of Bolt-type connector

- > Repeatedly disconnecting and connecting jumpers is able **without jumper damage**
- > Anyone can do this work (**Skill less**)
- > **Stable the joint quality**



are correctly installed, the risk of faults and failures is minimized, thus improving overall system reliability.

Cable Joints and overhead line stringing for loss mitigation



5.2.7 Poor quality of equipment and maintenance:

- Using only high-quality equipment and materials:** Using only high-quality equipment and materials from reputable manufacturers is an effective strategy for reducing technical losses in the distribution system because by enhancing reliability, improving efficiency, extending equipment lifespan, ensuring compatibility, promoting compliance with standards, and providing access to technical support. It is a proactive approach to minimize technical losses and maintain a robust and efficient distribution system.
- Conducting quality control checks on equipment and materials:** Conducting quality control checks on equipment and materials before installation is crucial for reducing technical losses in the distribution system. This practice ensures that high-quality components are used, which leads to several benefits. This will help to ensure the use of reliable, efficient, and compliant equipment. This reduces technical losses by improving equipment performance, minimizing energy wastage, enhancing safety, reducing long-term costs, complying with standards, and promoting proper installation practices.

DISTRIBUTION TECHNICAL LOSS: EVALUATION, CAUSES AND MITIGATION

NAPTIN PRESENTATION

JUNE 2025



Getting to Know Each Other...

- Full Name
- Profession/Job role
- Years of experience
- What would you like to get out of this Training?



OBJECTIVES

• At the end of the training, participants should be able to:

- 1. Evaluate/calculate Technical losses; manually and using a Power System Analysis Tool (PSAT - NEPLAN)
- 2. Explain the major causes of technical losses in distribution network
- 3. Describe the strategies of mitigating losses
- 4. Apply various methods of mitigating losses in the distribution network



OUTLINE

Module I-
Introduction on
Losses

- **Classification of Losses**

Module II –
Evaluation of
Technical Losses

- **Instant technical loss manual calculation**
- **Instant technical loss calculation via NEPLAN**
- **Annual technical loss calculation**

Module III- Causes of
Technical Losses and
mitigation strategies

- **Causes**
- **Mitigation**





MODULE I: Introduction on Losses

Power Losses

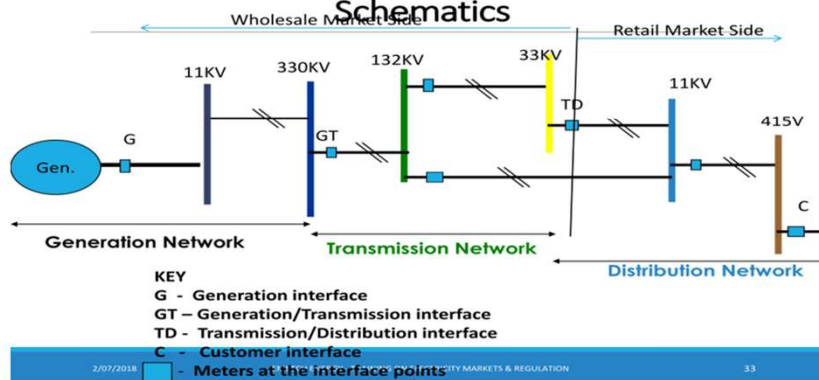
Electric power is generated in power stations and delivered through the transmission and distribution systems to the customer. Energy losses can occur in each part of the power system until reaching the customer's meter. Power system energy losses are divided into categories based on where the losses happen and the cause of power losses, as indicated below:

- **Power station losses** – energy consumed by the equipment in support of power generation, it is also called power station auxiliary load or power station own usage.
- **System losses** – losses incurred by moving power through the transmission and distribution systems, including transformers, overhead line conductors, aerial cables or underground cables, and low voltage (LV) secondary service wires.

Power Losses – Meters at interface points to indicate delivered energy and losses in the electricity market



The Electricity Value Chain - Schematics



Distribution Losses



- Power generated in power stations passes through large and complex networks like transformers, overhead lines, cables and other equipment and reaches the end users. It is a fact that the unit of electric energy generated by power stations does not match with the units distributed to the consumers. Some percentages of the units are lost in the distribution network.
- This difference in the generated and distributed units is known as Distribution (D) loss. D losses are the amounts that are not paid for by users.

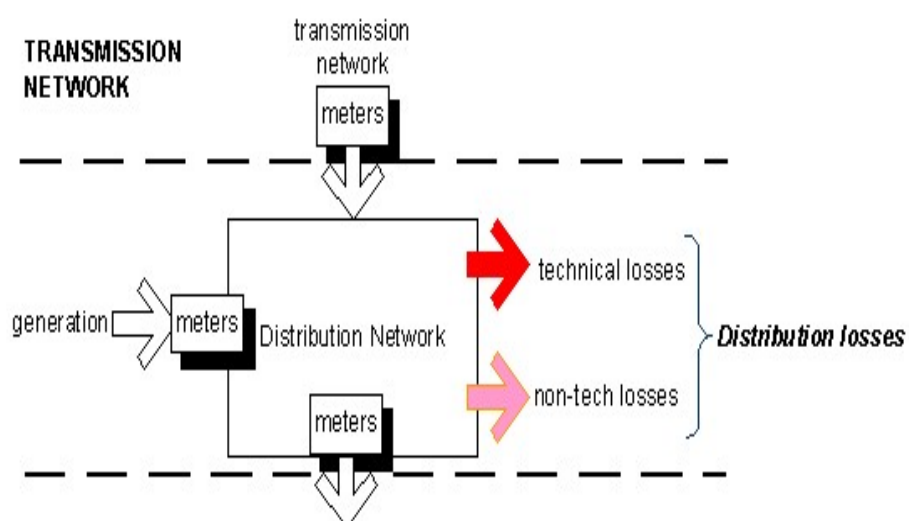
• D Losses =

$$\frac{\text{Energy Input to feeder (kWh)} - \text{Billed Energy to Consumer (kWh)}}{\text{Energy Input (kWh)}} \times 100$$

Distribution Losses

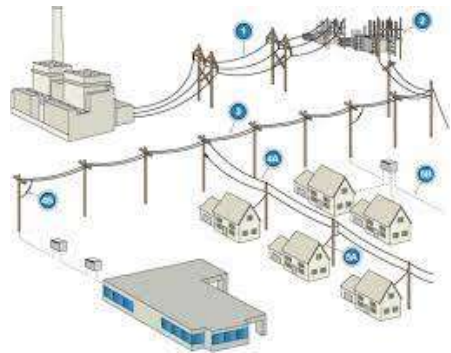


- Distribution Sector considered as the weakest link in the entire power sector.
- Transmission Losses is approximately 17% while Distribution Losses is approximately 45%, on average
- There are two types of Distribution Losses:
 1. Technical Losses
 2. Non-Technical Losses (Commercial/Collection Losses)



Technical Losses

- The technical losses are due to energy dissipated in the conductors, equipment used for lines, and transformers.
- The major amount of losses in a power system is in primary and secondary distribution lines.
- The unexpected load increase was reflected in the increase of technical losses above the normal level
- Technical Losses are inherent to the distribution of electricity and cannot be eliminated but can be minimized



Fixed and Permanent Losses

- Fixed losses do not vary according to current. These losses take the form of heat and noise and occur as long as a transformer is energized
- Between $\frac{1}{4}$ and $\frac{1}{3}$ of technical losses on distribution networks are fixed losses.
- Fixed losses on a network can be influenced in the ways set out below
 - Corona Losses
 - Leakage Current Losses
 - Dielectric Losses
 - Open-circuit Losses
 - Losses caused by continuous load of measuring elements
 - Losses caused by continuous load of control elements



Variable Technical Losses

- Variable losses vary with the amount of electricity distributed and are, more precisely, proportional to the square of the current. Consequently, a 1% increase in current leads to an increase in losses of more than 1%.
- Between $\frac{2}{3}$ and $\frac{3}{4}$ of technical (*or physical*) losses on distribution networks are variable Losses.
- By increasing the cross-sectional area of lines and cables for a given load, losses will fall.
- This leads to a direct trade-off between cost of losses and cost of capital expenditure.



Exercises: 1

- Types and Classes of Losses:
 - Technical Losses: Explain concepts like line losses, transformer losses, corona losses, and metering inaccuracies. Use visuals and real-world examples.
 - Non-Technical Losses: Briefly touch upon commercial losses (billing fraud, meter tampering) and theft.
- Impact of Losses:
 - Highlight the economic and environmental consequences of power losses.





MODULE II: Evaluation of Technical Losses

Introduction

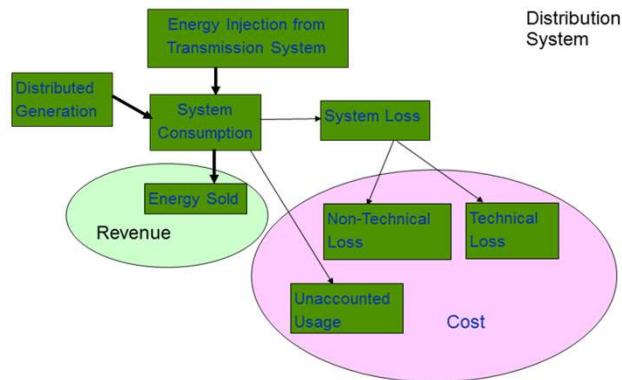
- One of the key strategies the DISCOs in their efforts to minimize power losses should prioritize is the continuous monitoring, evaluation, and assessment of these losses as it serves as the foundation for effective power loss reduction.
- Recognizing that complete elimination of losses is not practically achievable, the success of loss reduction initiatives lies in identifying and prioritizing areas where losses are significantly higher.
- Consequently, the efficient planning and implementation of loss reduction strategies necessitate a comprehensive understanding of the current status of actual losses.
- For this reason, the primary method for reducing losses involves the calculation of technical losses per transformer (and ideally per feeder, if feasible) within the substation.
- This calculation can be accomplished using either the NEPLAN model or manual calculations.



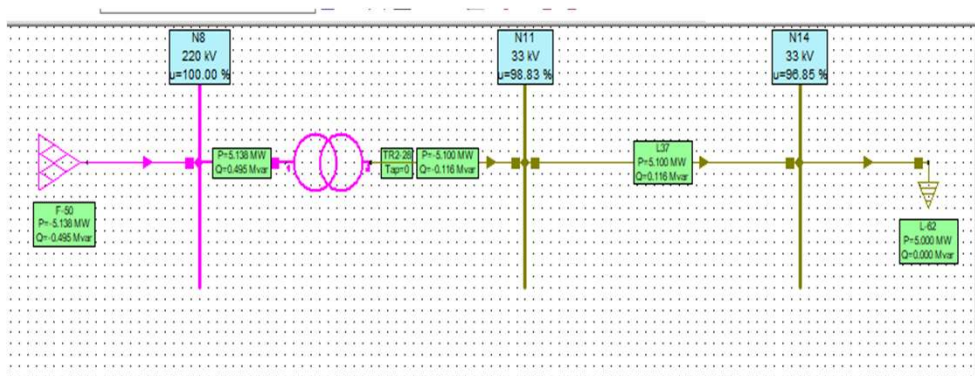
Power Distribution Loss Estimation

- Generally speaking;

$$\text{Percent Losses} = \frac{\text{kWh Purchases} - \text{kWh Sales}}{\text{kWh Purchases}} \times 100$$



Model Distribution Line for Loss Calculation



Example of Technical Loss Calculation

- The model distribution line has the following parameters:

• Transformer Parameters

- Primary Voltage (U_{r1}) = 220kV
- Secondary Voltage (U_{r2}) = 33kV
- Resistive Percentage Impedance ($U_{Rr}(1)$) = 1%
- Reactive Percentage Impedance ($U_{kr}(1)$) = 10%
- Iron Loss (No-load Loss) = 7.0kW (given by the manufacturer, usually)
- Rated Capacity (S_n) = 7,000kVA



Example of Technical Loss Calculation

• Line Parameters

- **Type** : 150sqmm_33kV_Wishbone_OHL

- Resistance (R_L) = 0.2046Ω/km

- Length (L) = 20km

Note: In this case, the technical loss will be calculated using Load Distribution Factor (LDF) = 1 which means all loads at the end of the line alone

• Load Parameters

- Peak Load Power (P_L) = 5,000kW
- Power Factor (PF) = 1.0



Technical Instantaneous Loss calculation procedure

Start by calculating Transformer copper loss. To do this, Calculate the Primary current based on the load connected to the transformer

Using the Resistance of the transformer and calculated current, find the copper loss via $P_{TP} = (I_{1P}^2 \times R_T) \times 3$. If resistance is not known, calculate it from the %z of the transformer

Transformer iron loss is constant and usually given. Add it to the copper loss to give total Transformer loss

Calculate the line losses using $PL_P = (I_{1P}^2 \times R_T) \times L \times 3$, where L is the length of the line

Calculate Total Power loss by adding the cu loss, the Fe loss and the line loss



Manual Calculation for instantaneous technical loss

• Transformer Loss [Load (Copper) Loss]

- First, we need to calculate the primary current (I_1) considering the Peak load of 5,000kW (PL) using the formula:

- $I_{1P} = PL / (\sqrt{3} \times U_{r1} \times PF)$
- $I_{1P} = 5,000 / (\sqrt{3} \times 220 \times 1.0) = 13.12A$

- The transformer copper power loss (P_{TP}) at Peak load (5,000kW) can be calculated using the formula:

- $P_{TP} = (I_{1P}^2 \times R_T) \times 3$

- Where, R_T is the one phase resistance of the transformer winding. To calculate R_T , we need to convert the percentage impedance values to actual values.



Manual Calculation of Instantaneous Technical Loss

- Percentage impedance in a transformer is a measure of the transformer's opposition to the flow of alternating current (AC) within its windings.
- Percentage Impedance = (Impedance Voltage / Rated Voltage) × 100%
- Where:
 - Rated Voltage is the transformer's rated voltage on its primary or secondary side (depending on the reference side).
 - The percentage impedance is typically a small value, ranging from around 2% to 10% for most power transformers.
 - A lower percentage impedance value indicates better voltage regulation and higher efficiency but also higher short-circuit currents in case of a fault. Conversely, a higher percentage impedance value provides better short-circuit protection but poorer voltage regulation and lower efficiency.
 - Percentage impedance is usually found in the name plate of the transformer



Manual Calculation of Instantaneous Technical Loss

- Primary side percentage impedance formula is

$$\begin{aligned}\%Z (1) &= V_{st} \times 100 / U_{r1} \\ &= (I_1 \times Z \times \sqrt{3}) \times 100 / U_{r1} \\ &= (I_1 \times Z \times \sqrt{3}) \times U_{r1} \times 100 / U_{r1}^2 \\ &= (I_1 \times U_{r1} \times \sqrt{3}) \times Z \times 100 / U_{r1}^2 \\ &= S_n \times Z \times 100 / U_{r1}^2\end{aligned}$$

- Where,

V_{st} is the primary voltage at secondary short circuit when the primary current is rated current (I_1)

Z is one phase impedance of the transformer winding



Manual Calculation for instantaneous technical loss



To calculate R_T , we need to convert the percentage impedance values to actual values:

- $\%Z (1) = S_n \times Z \times 100 / U_{r1}^2$ (Quote from previous slide.)
- $R_T = U_{Rr} (1) \times U_{r1}^2 / (100 \times S_n)$
- $R_T = 1 \times 220^2 / 7,000 \times ((1000^2)/(1000 \times 100)) = 69.14 \Omega$
- Now we can substitute these values into the formula for P_{TP} :
 - $P_{TP} = 13.12^2 \times 69.14 \times 3$
 - $P_{TP} = 35,704.11$ or **35.70kW**
- Therefore, the transformer power loss is approximately 35.7kW when a Peak load of 5,000kW is connected to the transformer.

Manual Calculation for instantaneous technical loss



Line Loss

- The line losses for a single line can be determined using the equation below:
 - $P_{LP} = I_{2P}^2 \times R_L \times L$
- Where;
- P_{LP} = Line Losses at peak load (W)
- I_{2P} = Secondary current of the Transformer at the peak load given by;
 $= PL / (\sqrt{3} \times U_{r2} \times PF)$
Considering the Peak load of 5,000kW, the current is found to be
 $I_{2P} = 5,000 / (\sqrt{3} \times 33 \times 1.0) = 87.48A$

Manual Calculation for instantaneous technical loss



- R_L is Resistance of the line per kilometer = $0.2046\Omega/\text{km}$, and
- L is Length of the distribution line = 20km
- Therefore,
- $P_{LP} = 87.48^2 \times 0.2046 \times 20$
- $P_{LP} = 31,315.05\text{W} = 31.32\text{kW}$
- The above value is for a single line.
- Now, for 3 phase 3 wire system:
- $P_{3LP} = 3 \times 31.32\text{kW} = \mathbf{93.96\text{kW}}$

Manual calculation total



- Therefore, the total instantaneous power loss at peak load (P_{IP}) =
Transformer Copper loss (P_{TcP}) + Transformer Iron Loss + Line loss (P_{3LP})
- $P_t = 35.70\text{kW} + 7.0\text{kW} + 93.96\text{kW}$
 $= \mathbf{137\text{kW}}$

NEPLAN Calculation



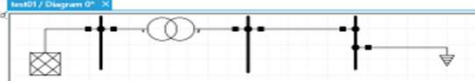
In a similar way add also a load and enter the parameters as shown:

Adding a load of 5000 kW
To be connected later

Transformer
Ur1= 220 kV
Ur2= 33 kV
URr(1)= 1%
Ukr(1) = 10%
Sn= 7000 kVA
Pfe= 7kW

Line
l= 20 km
type: ACSR ANT

Fig. 11-Tutorials. Add a load (drag and drop symbol of external grid)



Exercise 2



- Briefly introduce NEPLAN as a power system analysis software.
- Demonstrate how to model a simple system in NEPLAN and extract loss data for instant level.
- Participants to practice using NEPLAN and compare results with manual calculations.

NEPLAN - General

NEPLAN®

Smarter Tools

Power systems analysis software

Planning
Optimisation
Simulation

Generation
HV transmission networks
MV and LV distribution
networks
Industrial networks



NEPLAN - Advantages

NEPLAN®

Smarter Tools

- Software frequently used in the sector
- Intuitive graphic and tabular programming
- Accessible via cloud
- Several uses (modules)
- Easy data exchange with Excel, Word, SQL...



NEPLAN - Analysis

NEPLAN®

Smarter Tools

- *Load flow*
- *Short circuit analysis*
- *Dynamic simulation*
- Overcurrent protection
- Harmonic analysis
- Reliability analysis
- Small signal stability



NEPLAN – Installation demo

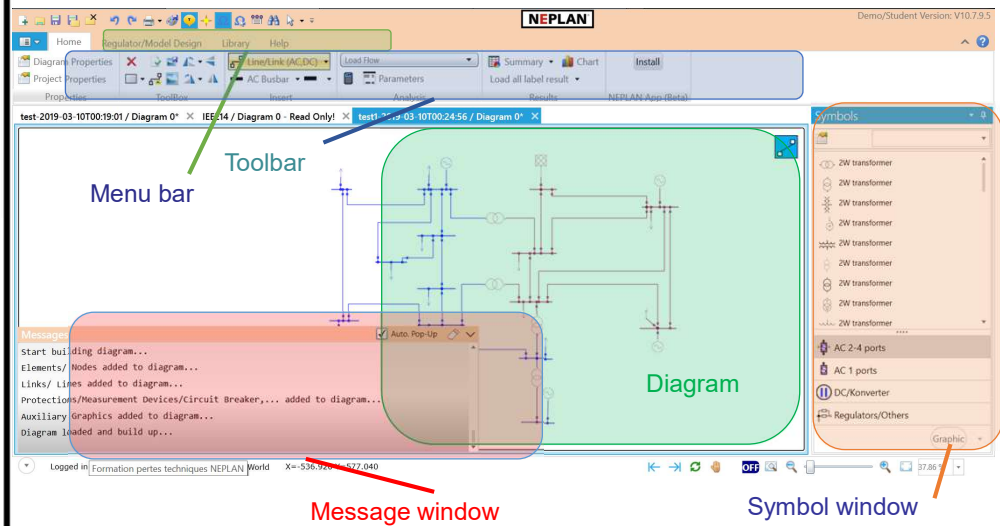
1. Open Internet Explorer
2. Go to www.neplan.ch
3. Click on the Free Demo tab → Demo Link



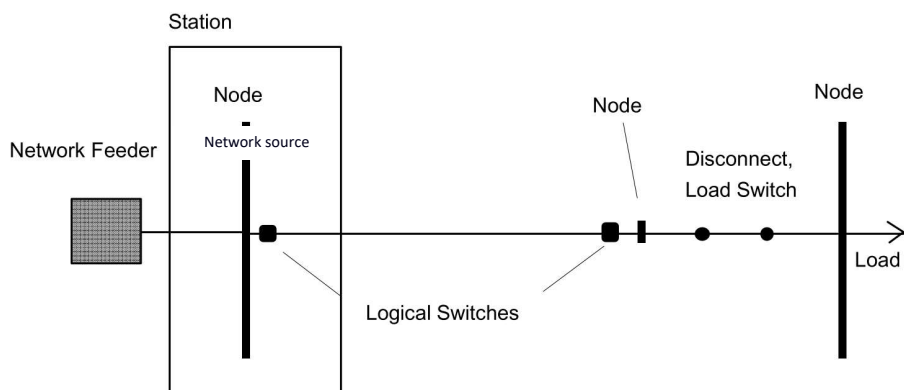
4. Click on Register to create an account (+validate by email)
5. Login to the site, using Internet Explorer (only)



NEPLAN - Interface

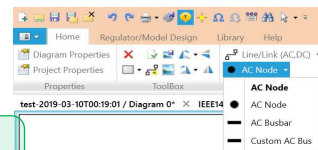


NEPLAN – Basic elements



NEPLAN – Node

- Name and nickname (Alias)
- Node type (main busbar, busbar, junction, special node)
- Rated voltage (U_n) in kV and rated frequency (F_n) in Hz
- Minimum voltage (U_{min}) and maximum voltage (U_{max}) in %
- Grounding resistance in Ω (if applicable)
- Location → Zone and region (Area)



NEPLAN - Elements

- Name and nickname (Alias)
- Nominal characteristics (U_n , I_n , F_n ...)
- Parameters (reactance, losses...)
- Passive elements (lines, transformers, switches, loads...)
- Active elements (Grid source, synchronous and asynchronous machine...)



Creating a project on NEPLAN 360 (web) or 10 (PC)

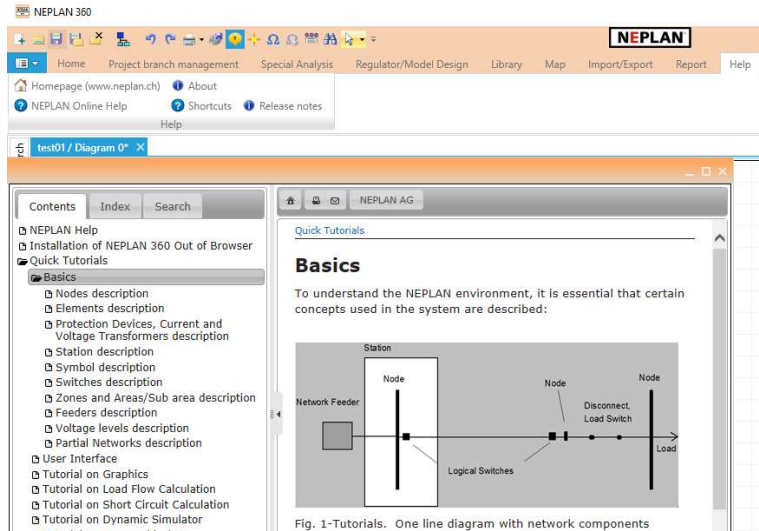


Fig. 1-Tutorials. One line diagram with network components

Creating a project on NEPLAN 360 (web) or 10 (PC)

- NEPLAN Help
- Installation of NEPLAN 360 Out of Browser
- Quick Tutorials
 - Basics
 - Nodes description
 - Elements description
 - Protection Devices, Current and Voltage Transformers description
 - Station description
 - Symbol description
 - Switches description
 - Zones and Areas/Sub area description
 - Feeders description
 - Voltage levels description
 - Partial Networks description
 - User Interface
 - Tutorial on Graphics
 - Tutorial on Load Flow Calculation
 - Tutorial on Short Circuit Calculation
 - Tutorial on Dynamic Simulator
 - Tutorial on Geographical Maps
- Menu and Toolbars
- Element Data Input and Models
- Calculations

Quick Tutorials / Basics

Partial Networks description

Unlike zones and areas, a partial network is an independent network. A partial network has no connections to any other networks. You can make partial networks by opening logical or physical switches. It is possible to color each partial network differently (see below).

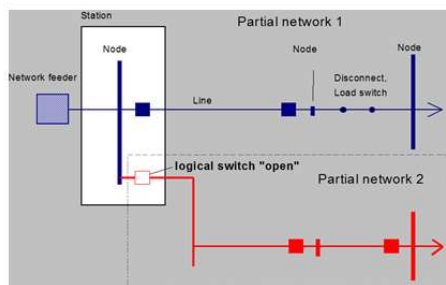
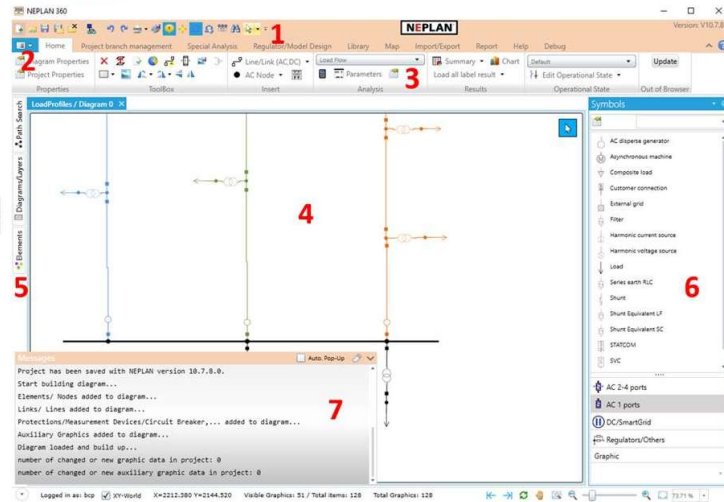


Fig. 2-Tutorials. Partial networks

Creating a project on NEPLAN 360 (web) or 10 (PC)

- Installation of NEPLAN 360 Out of Browser
- Quick Tutorials
 - Basics
 - Nodes description
 - Elements description
 - Protection Devices, Current and Voltage Transformers description
 - Station description
 - Symbol description
 - Switches description
 - Zones and Areas/Sub area description
 - Feeders description
 - Voltage levels description
 - Partial Networks description
 - User Interface
 - Tutorial on Graphics
 - Tutorial on Load Flow Calculation
 - Tutorial on Short Circuit Calculation
 - Tutorial on Dynamic Simulator
 - Tutorial on Geographical Maps
 - Menu and Toolbars
 - Element Data Input and Models
 - Calculations

User Interface



Creating a project on NEPLAN 360 (web) or 10 (PC)

Tutorial on Graphics

Create a new project

To create a new project, after having started the program, go to the following menu as displayed and select "New".



Fig. 4-Tutorials. Menu to create a new project

Type the desired Project name, and select the network medium type project.

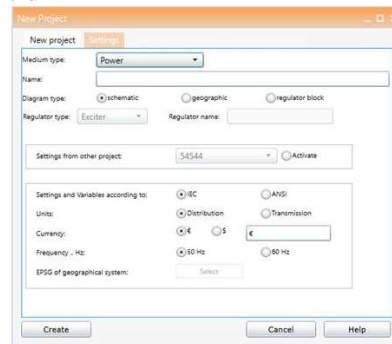


Fig. 5-Tutorials. New project creation

Creating a project on NEPLAN 360 (web) or 10 (PC)

Drawing a small network

As first step, you'll enter nodes and elements to build a small electrical network.

Select the AC Busbar option and also the orientation (vertical or horizontal) and draw it in the diagram with the mouse defining the beginning (clicking) and the end of the busbar (releasing) as shown below:

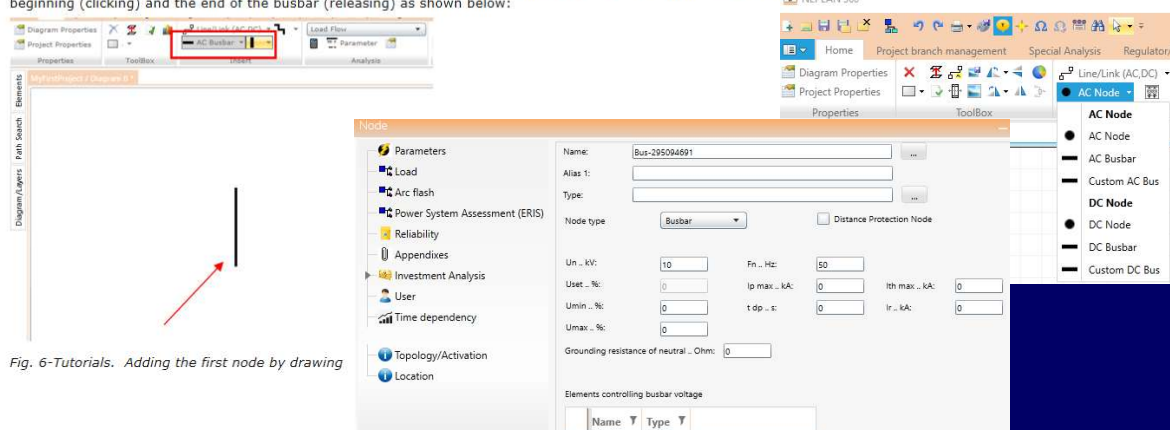


Fig. 6-Tutorials. Adding the first node by drawing

Creating a project on NEPLAN 360 (web) or 10 (PC)

Similarly add two more busbars, Bus-2 and Bus-3 assigning 65 kV to these. You should have a sim drawing as the following:

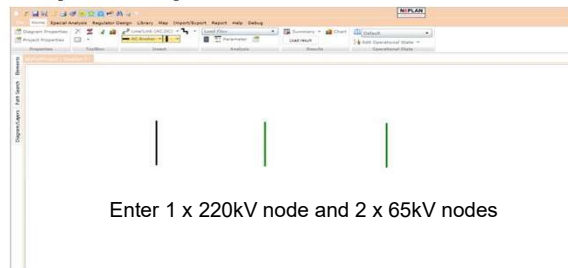


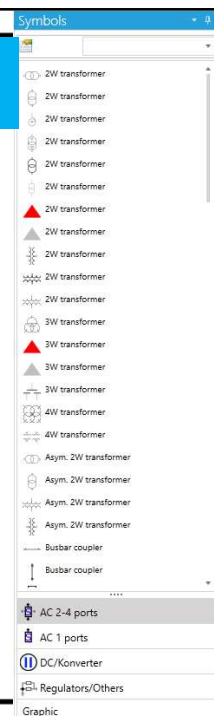
Fig. 8-Tutorials. Network consisting of 3 nodes only

Now its time to add some elements in your network. To see the symbol window click the following



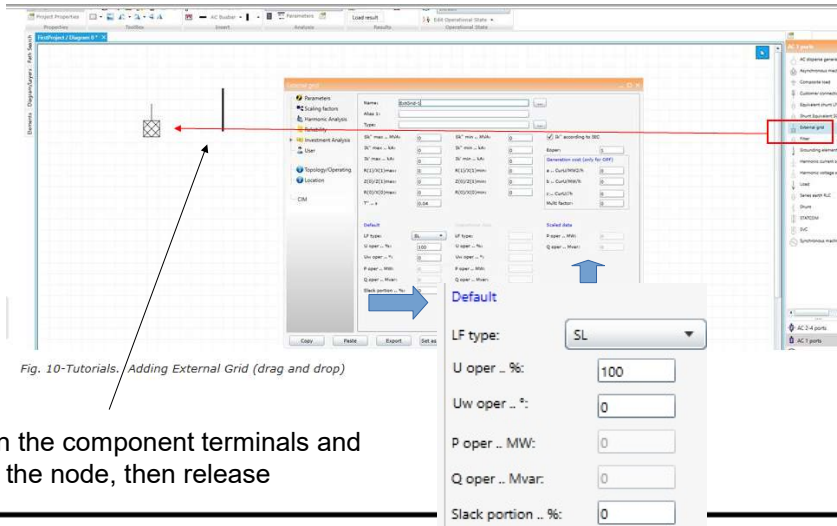
Fig. 9-Tutorials. Making symbols visible

Change the voltage of the two 65kV nodes to 33 kV



Creating a project on NEPLAN 360 (web) or 10 (PC)

Enter an external network (i.e. source: slack node)



Creating a project on NEPLAN 360 (web) or 10 (PC)

Parameters

Name: TR2-109

Type: ☒ 3-phase transformer ☐ 3 x 1-phase transformer

Un1 .. kV: 220 Un2 .. kV: 33 Sr .. MVA: 7

Ur1 .. kV: 220 Ur2 .. kV: 33

URr(1) .. %: 1 kW: 70 URr(0) .. %: 0 kW: 0

Ukr(1) .. %: 10 Ukr(0) .. %: 0

X(1)/R(1): 9.95 ... X(0)/R(0): 0 ...

IO .. %: 0 U01(0) .. %: 0 LMUNS .. pu: 0

P fe .. kW: 7 U02(0) .. %: 0 LMSAT .. pu: 0

☐ has on-load tapchanger capabilities (IEC 60909)

☐ On-load tapchanger active

☐ Switchable

☐ Autotransformer

Vector Group: Yy0

phiresA .. pu: 0

phiresB .. pu: 0

phiresC .. pu: 0

Adding a load of 5000kW
To be connected later

Transformer Line

Ur1= 220 kV

Ur2= 33 kV

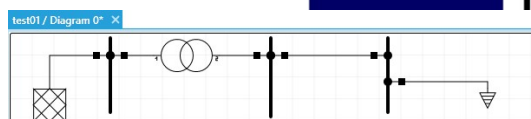
URr(1)= 1% l= 20 km

Ukr(1)= 10% type: ACSR

ANT

Sn= 7000 kVA

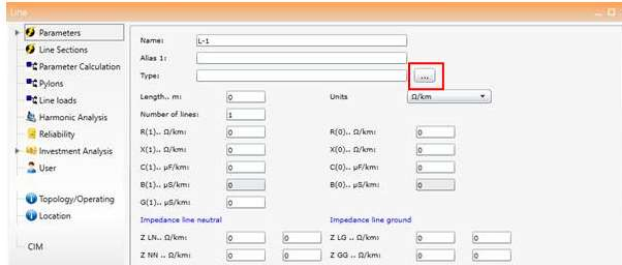
Pfe= Sn x 0.1% = 7.0kW



Creating a project on NEPLAN 360 (web) or 10 (PC)



The user can enter parameters as done previously with other elements, but also can select a line type from a library. This way parameters will be assign automatically. To assign a library type click the button shown below:



The library type selector will show up. You can select the type you desire

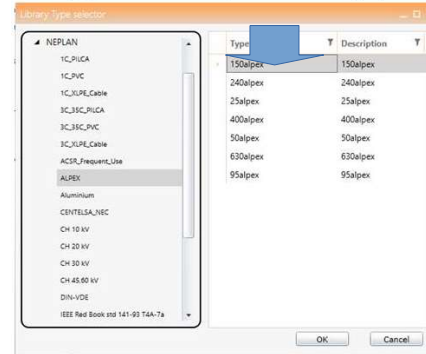


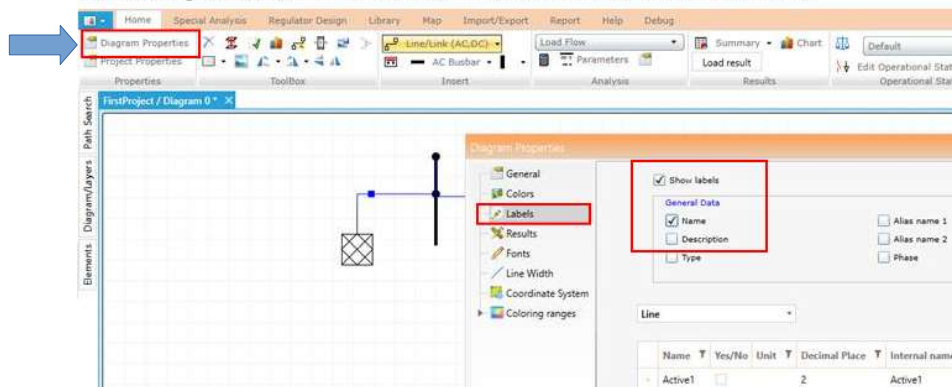
Fig. 18-Tutorials. Selection of line type from library

Creating a project on NEPLAN 360 (web) or 10 (PC)

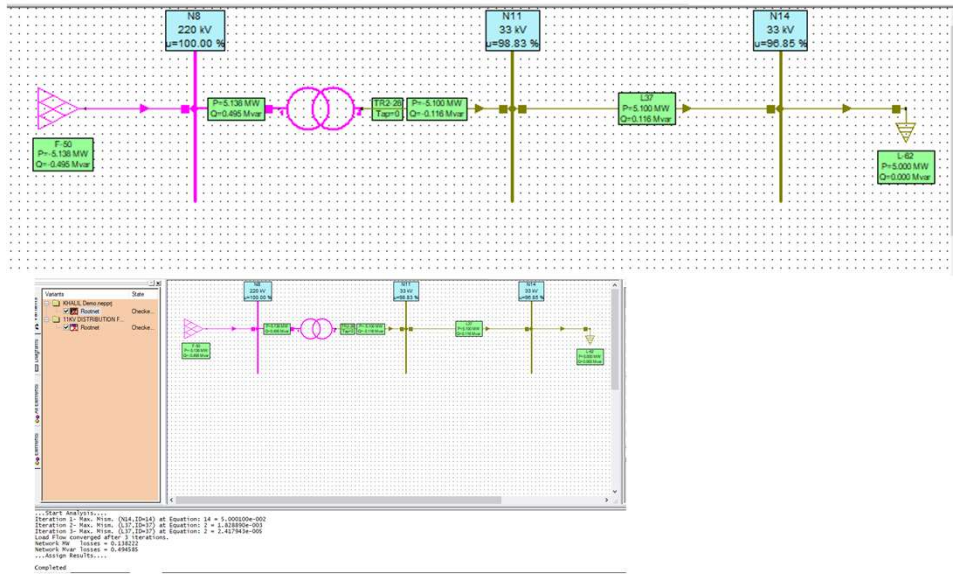


Display the labels (node names...)

You can show information about the network in the single line diagram, by going to *Diagram Properties* and activating the desired info. For this tutorial make the names of the elements visible:



NEPLAN Calculation



Parameters

Name: TR2-100

Type: ☒ 3 phase transformer ☐ 3 x 1-phase transformer

Un1_kV: 220 Un2_kV: 33 Sv_MVA: 7

Un1_kV: 220 Un2_kV: 33

UR(1)_: 1 kW: 70 UR(0)_: 0 kW: 0

UK(1)_: 10 UK(0)_: 0

X(1)/R(1): 9.95 X(0)/R(0): 0

U0_: 0 U0(0)_: 0

P.le_kW: 7

LMUNS_pu: 0

LMSAT_pu: 0

KP_pu: 0

phasesA_pu: 0

phasesB_pu: 0

phasesC_pu: 0

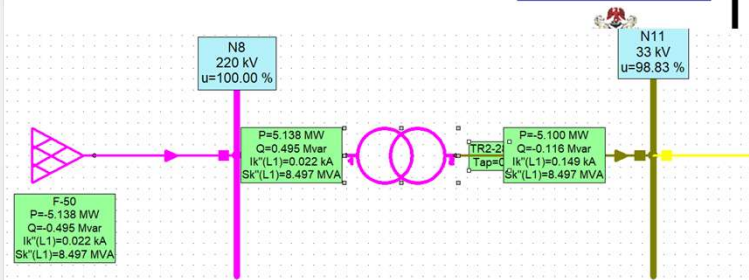
☐ on-load tapchanger capabilities (IEC 60090)

☐ On-load tapchanger active

☐ Switchable

☐ Autotransformer

Vector Group: Yy0



From Area/Zone	To Area/Zone	P Loss	Q Loss	P Imp	Q Imp	P Gen	Q Gen	P Load	Q Load	Gen. Cost	Qc Shunt	Ql Shunt	Q Comp	Iron Losses
		MW	MVar	MW	MVar	MW	MVar	MW	MVar	Curr. Units	MVar	MVar	MVar	MW
1 Network		0.138	0.495	5.138	0.495	5.138	0.495	5	0	0	0	0	0	0
2 Area 1		0.138	0.495	0	0	5.138	0.495	5	0	0	0	0	0	0
3 Zone 1		0.138	0.495	0	0	5.138	0.495	5	0	0	0	0	0	0
4														
5 Un		P Loss Li	Q Loss Li	P Loss Tr	Q Loss T									
6 kV		MW	MVar	MW	MVar									
7 33		0.1	0.116	0	0									
8 220		0	0	0.038	0.379									

NEPLAN Calculation



From Area/Zone	To Area/Zone	P Loss	Q Loss	P Imp	Q Imp	P Gen	Q Gen	P Load	Q Load	Gen. Cost	Qc Shunt	Ql Shunt	Q Comp	Iron Losses
		MW	MVar	MW	MVar	MW	MVar	MW	MVar	Curr. Units	MVar	MVar	MVar	MW
1 Network		0.138	0.495	5.138	0.495	5.138	0.495	5	0	0	0	0	0	0
2 Area 1		0.138	0.495	0	0	5.138	0.495	5	0	0	0	0	0	0
3 Zone 1		0.138	0.495	0	0	5.138	0.495	5	0	0	0	0	0	0
4														
5 Un		P Loss Li	Q Loss L	P Loss T	Q Loss									
6 kV		MW	MVar	MW	MVar									
7 33		0.1	0.116	0	0									
8 220		0	0	0.038	0.379									

The calculation results by manual are below

line loss is 93.96 kW, transformer loss is 35.70+7kW, total loss is **137kW**

The results of power system analysis software, **138kW** and manual calculations **137kW** are almost identical.

NEPLAN Calculation



The calculation results by manual are below:

- Line loss is 93.96 kW,
- Transformer loss is 35.70+7.0kW,
- Total loss is **137kW**

The results of power system analysis software, **138kW** and manual calculations **137kW** are almost identical.

Iron Loss in NEPLAN

Parameters

Name: TR2-109

Type: ☒ 3-phase transformer ☐ 3 x 1-phase transformer

Un1 . kV: 220 Un2 . kV: 33 Sr . MVA: 7

Ur1 . kV: 220 Ur2 . kV: 33

UR(1) . %: 1 kW: 70 UR(0) . %: 0 kW: 0

UK(1) . %: 10 UK(0) . %: 0

X(1)/R(1): 9.95 X(0)/R(0): 0

IO . %: 0 U01(0) . %: 0 LMUNS . pu: 0

Pfe . kW: 7 U02(0) . %: 0 LMSAT . pu: 0

☐ has on-load tapchanger capabilities (IEC 60909)

☐ On-load tapchanger active

☐ Switchable

☐ Autotransformer

Vector Group: Yy0

phiresA . pu: 0

phiresB . pu: 0

phiresC . pu: 0

KP . pu: 0

• Note:

- NEPLAN has limit of 10% Iron loss in its computation, irrespective of the value you put.
- Hence, even when I used 7kW iron loss the total loss did not change

Annual Loss Calculation

• Transformer Parameters

- Primary Voltage (Ur1) = 220kV
- Secondary Voltage (Ur2) = 33kV
- Resistive Percentage Impedance (URr(1)) = 1%
- Reactive Percentage Impedance (Ukr(1)) = 10%
- Iron Loss (IL) = 7.0kW (usually given by the manufacturer)
- Rated Capacity (Sn) = 7,000kVA

Annual Loss Calculation

• Line Parameters

- **Type** : 150sqmm_33kV_Wishbone_OHL
- Resistance (R_L) 0.2046 Ω /km
- Length (L) = 20km
- Load Distribution Factor (LDF) = 1

• Load Parameters

- Peak Load Power (PL) = 5,000kW
- Power Factor (PF) = 1.0
- Annual power supply (APS) at the feeder = 28,470MWh



Annual Loss Calculation

- In order to calculate the actual annual technical loss, it is necessary to calculate the instantaneous technical loss using the value of the load current that changes from moment to moment, and then sum (integrate) this for one year.
- This is not a realistic method for calculating the annual technical loss, because it requires a large amount of calculation effort, in addition to the need to know all instantaneous load currents.
- For this reason, statistical methods are used in general annual technical loss calculations.



Technical Annual Loss calculation procedure

Start by calculating Peak load consumed per annum = Peak Load Power (PL) x 24h x 365days

Calculate load factor using Load factor (LF) = APS at the feeder / Peak load consumed per annum

Calculate Load loss factor (LLF) using Load Loss Factor (LLF) = $(0.8 \times LF^2) + (0.2 \times LF)$

Multiply copper and line loss (previously calculated as instantaneous values) with LLF and hours of the year, while multiply iron loss only by the hours of the year, as it is constant

Add all annual calculated values to give you the total Annual technical loss



Annual Loss Calculation

- Below is an example of how to calculate annual technical losses using statistical methods.
- Peak load consumed per annual = Peak Load Power (PL) x 24h x 365days
 $= 5,000\text{kW} \times 8,760\text{h}$
 $= \mathbf{43,800\text{MWh}}$
- Load factor (LF) = APS at the feeder / Peak load consumed per annum
 $= 28,470\text{MWh} / 43,800\text{MWh}$
 $= \mathbf{0.65}$
- Load Loss Factor (LLF) = $(0.8 \times LF^2) + (0.2 \times LF)$
 $= (0.8 \times 0.65 \times 0.65) + (0.2 \times 0.65)$
 $= 0.338 + 0.13$
 $= \mathbf{0.468}$



Annual Loss Calculation



- In a statistical method, Annual power loss is calculated by multiplying the instantaneous power loss with the Load Loss Factor.
- Taking instantaneous technical loss, at peak, as calculated earlier, annual technical loss becomes as follows
- Tr. Iron loss $7.0\text{kW} \times 8,760\text{h} = 61,320\text{kWh} = 61.3\text{MWh}$
- Tr. Cop. loss $35.70\text{kW} \times 0.468(\text{LLF}) \times 8,760 = 146.4\text{MWh}$
- Line loss $93.96\text{kW} \times 0.468(\text{LLF}) \times 8,760 = 385.2\text{MWh}$
- Total Annual Loss = **592.9MWh**

Note: This value is based on considering Distribution load factor of 1.

Factors in Loss Calculation



- 1. Load Factor (LF):** Load factor represents the ratio of the average load on a power system to the maximum load it can handle over a given period. It is a measure of how effectively the power system is utilized.

The load factor is calculated using the formula:

- **Load Factor = Average Load / Maximum Load**
- A higher load factor indicates a more efficient utilization of the power system, resulting in lower losses.

Factors in Loss Calculation



2. Load Loss Factor (LLF): Load loss factor represents the ratio of the power loss in the network to the power supplied to the peak load.”

The load loss factor is calculated using the formula:

- **Load Loss Factor = Load Loss / Power Supplied to Peak Load**

Load Loss Factor can also be approximately calculated using the Load factor as follows by a statistical method

- **$LLF = (0.8 \cdot LF^2) + (0.2 \cdot LF)$**
- Load loss factor helps quantify the proportion of power lost during transmission and distribution.

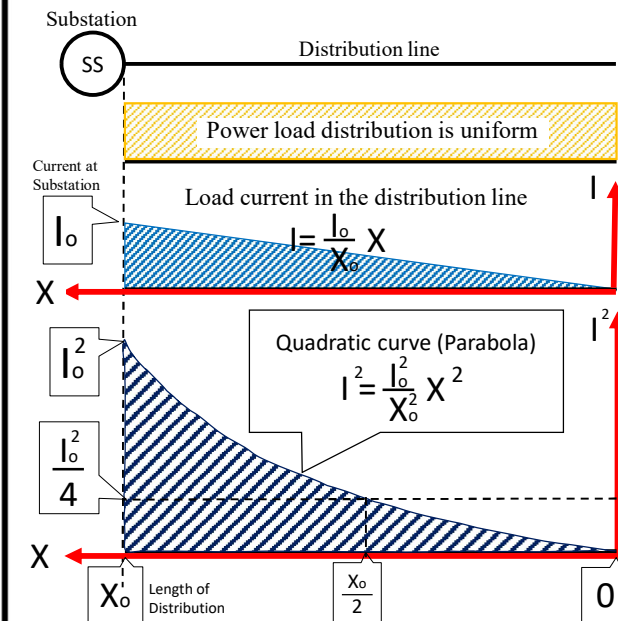
Factors in Loss Calculation



3. Load Distribution Factor (LDF): The load distribution factor represents the ratio of loss in distributed load to the terminal concentrated load (loads at the end of the line alone).

- Additionally, LDF have the following values.
 - In case of loads at the end of the line alone : 1
 - In case of urban feeder : assumed to be around 1.5
 - In case of rural feeder : assumed to be around 2
 - In case of uniform load : 3
- Next slide shows the calculation example of LDF for uniform load.

< Calculation of Load Distribution Factor (in case of uniform load) >



Calculation Method of power load loss (L)

$$L = \int_0^{X_0} R I^2 dX$$

Note

R: Conductor registration per unit

I: Load current

X: Distance from end of distribution line

$$\begin{aligned} &= \int_0^{X_0} R \frac{I_0^2}{X_0^2} X^2 dX \\ &= \left[\frac{1}{3} R \frac{I_0^2}{X_0^2} X^3 \right]_0^{X_0} \\ &= \frac{1}{3} R I_0^2 X_0 \end{aligned}$$

Load Distribution factor (LDF) at uniform load

Annual Technical Loss Calculation

- Considering Distribution load factor above, say 1.5 which is applicable to most urban feeders.
- **Line Parameters**
 - **Type** : 150sqmm_33kV_Wishbone_OHL
 - Resistance (R_L) 0.2046Ω/km
 - Length (L) = 20km
 - **Load Distribution Factor (LDF) = 1.5**
- **Load Parameters**
 - Peak Load Power (PL) = 5,000kW
 - Power Factor (PF) = 1.0
 - Annual power supply (APS) at the feeder = 28,470MWh

Annual Technical Loss Calculation

- Since Load Distribution Factor (LDF) must be used for distribution line loss calculations, copper losses in transformers, iron losses in transformers, and distribution line losses must be calculated separately.

- The annual iron loss for Transformers (P_{ATI}) can be calculated as below

$$P_{ATI} = 7.0\text{kW} \times 8,760\text{h} = 61,495\text{kWh} = 61.5\text{MWh (Since Iron loss is constant)}$$

- The annual copper loss for Transformers (P_{ATC}) can be calculated as below

$$P_{ATC} = P_{TCP} \times \text{LLF} = 35.70 \times 0.468 \times 8,760 = 146.4\text{MWh}$$

P_{TCP} : The transformer copper power loss at peak load

- The annual Line copper loss (P_{AL}) can be calculated as below

$$P_{AL} = P_{LP} \times \text{LLF} / \text{LDF} \times 8,760 = 93.96 \times 0.468 / 1.5 \times 8,760 = 385.2 / 1.5 = 256.8\text{MWh}$$

P_{LP} : Line Losses at peak load

- Annual Technical Loss (PL_A) = $P_{ATI} + P_{ATC} + P_{AL} = 61.5 + 146.4 + 256.8 = 464.7\text{MWh}$



DISTRIBUTION TECHNICAL LOSS CALCULATION SPREADSHEET

Transformer Losses:

1. Transformer Copper Loss (P_{Cu}): This is calculated based on the formula

$$P_{Cu} = I^2 \times R$$

where (I) is the current and (R) is the resistance of the transformer's winding.

2. Transformer Iron Loss (P_i): This is usually given by the manufacturer and is constant, regardless of the load.

Distribution Line Loss:

1. Line Loss (P_{line}): Similar to copper loss, it can be calculated using the formula

$$P_{line} = I^2 \times R_{line}$$

where (R_{line}) is the resistance of the distribution line.

You would then sum these losses for the total technical loss.

Annual technical loss calculation

Transformer Rating (kVA)	Peak Load (kW)	Annual power supply APS (MWh)	Primary Voltage (kV)	Secondary Voltage (kV)	Percent Impedance		Iron Loss P_i (kW)	Load Factor LF	Load Loss Factor LLF	Load Distribution Factor LDF	Conduc. Resist. (Ω/km)	Line Length (km)	Power Factor	Prim. Current at Peak I_p (A)	Sec. Current at Peak I_s (A)	Winding Resistance * (Ω)	Peak load instant. Loss (kW)	Annual Copper Loss P_{ATC} (MWh)	Annual Iron Loss P_{ATI} (MWh)	Annual Line Loss P_{AL} (MWh)	Total Loss (MWh)
					Resistive URr 1 (%)	Reactive Ukr 1 (%)															
7,000	5,000	28,470	220	33	1%	10%	7	0.65	0.468				1.0	13.12		69.14	35.71	146.4	61.3		464.5
	5,000	28,470	220	33				0.65	0.468	1.5	0.2046	20	1.0		87.48		93.94		256.7		

You'll need to fill in the blanks with your specific data. The "Total Loss" column will be the sum of "Copper Loss (P_{Cu})", "Iron Loss (P_i)", and "Line Loss (P_{line})" for each transformer.





MODULE III: Causes of Technical Losses and Mitigation Strategies

Introduction

- Technical Losses are caused by the inefficiencies of electric power flow through conductors and equipment in the distribution system.
- The condition of conductors and equipment affects technical losses directly.
- Some of the major causes of technical losses in the distribution system:
 - Lengthy distribution lines
 - Overloading of Distribution Transformers
 - Inadequate Size of Conductors of Distribution Lines:
 - Low Power Factor of Primary and Secondary Distribution Systems
 - Wire connector – old and/or loose connections
 - Old equipment, such as old switching devices, old transformers, etc.
 - Maintenance issues.

Causes and Mitigation: Lengthy Distribution Lines

- Reducing the length of distribution lines through; proper network planning and design, feeder segmentation, network reinforcement, load analysis, and load balancing will mitigate the technical loss effect.
- To reduce the length of distribution lines for technical loss reduction, consider the network reconfiguration which may include the following strategies:



a)Feeder Segmentation: Divide long feeders into smaller segments, particularly in areas with dispersed loads. This helps reduce the length of individual segments, minimizing losses associated with long radial feeders.

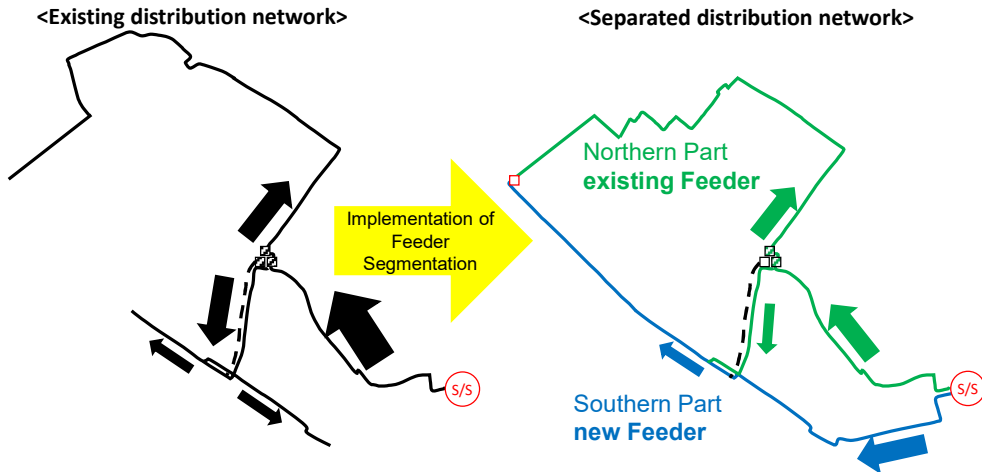
b)Changing supply routes: Where the existing supply route is not the most direct and contains significant detours that significantly increase the distance power must travel, consider modifying the routing of the distribution lines to minimize losses and optimize efficiency.

c)Selection of suitable supply voltage: In cases where there is a substantial load located far from the power supply source with no other supply sources nearby, opt for higher voltage distribution. If increasing the voltage is not feasible, explore the possibility of implementing a dedicated supply line for that load.



Causes and Mitigation: Lengthy Distribution Lines

Implementation Example of Feeder Segmentation



In a very simplified technical loss calculation, the loss reduction effect in the above example was **approximately 57%**.

Causes and Mitigation: Overloading Distribution Transformer

- Overloading a transformer is caused by the additional load [Current(I)] connected to it.
- To counter the effect, always ensure that high-efficiency transformers are installed so that the copper and iron losses are minimized.
- In addition, any of the following measures can be adopted;

a)Upgrading transformers: If the size of the transformer is discovered to be small or the load connected to it is above its size, it should be replaced with a higher-capacity unit.

b)Installing additional transformer: Where necessary, installing additional transformers and deloading the existing ones can equally help in reducing the effect of technical power loss associated with the distribution transformers.

c)Optimization of LV distribution networks: Evaluate the need for system expansion and reconfiguration to bring distribution transformers closer to the load centers. This may involve installing additional transformers or relocating existing ones to reduce the length of the distribution lines. For example, if a transformer needs replacement due to overload, and it is situated at a considerable distance from the load center, relocating it closer to the load center can be an effective strategy for reducing losses



Causes and Mitigation: Inadequate size of conductors

- To address the issue of inadequate conductor size and mitigate its impact on technical losses, the following measures can be taken:

a)Use of compact conductors: These conductors are engineered to have a higher cross-sectional area, which reduces their resistance per unit length. However, it's important to note that these compact conductors may be more expensive compared to the conventional ones.

b)Upgrading Existing Lines: In situations where limitations exist in terms of support strength or conductor specifications, it becomes necessary to explore the possibility of voltage upgrades as an alternative solution.



Causes and Mitigation: Transformers away from load centers



- To address the issue of transformers installed away from the load centers and mitigate its impact on technical losses, the following measures can be taken:

Optimization of Transformer capacity and location:

- Evaluate the need for system expansion and reconfiguration to bring distribution transformers closer to the load centers.
- This may involve installing additional transformers or relocating existing ones to reduce the length of the distribution lines.

Causes and Mitigation: Low Power factor

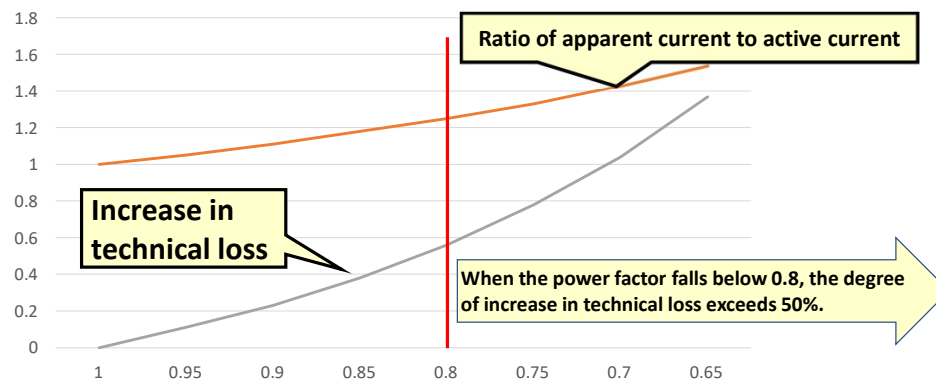


- A low power factor in the distribution network can result in increased technical losses, as losses are inversely proportional to the square of the power factor.
- When the power factor falls below 0.8, distribution line losses significantly increase, making it imperative to consider corrective measures.
- The table and figure below demonstrate the effect of the power factor on the technical loss on distribution lines.

Causes and Mitigation: Low Power factor

Table: Relationship between power factor and technical loss on distribution lines

Power factor ($\cos\theta$)	1	0.95	0.9	0.85	0.8	0.75	0.7	0.65
$1/\cos\theta$ (apparent current/active current)	1	1.05	1.11	1.18	1.25	1.33	1.43	1.54
Increase in technical loss ($1/\cos^2\theta - 1$)	0	0.11	0.23	0.38	0.56	0.78	1.04	1.37



Causes and Mitigation: Low Power factor

- To address the issue of a low power factor, customers (especially industrial) can be encouraged to install power factor improvement devices like capacitor banks

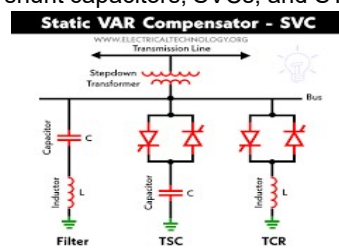
a) Installation of Shunt Capacitors:

- To promote the installation of power factor improvement equipment among consumers, it's essential to communicate the benefits and incentivize them to take action. This can be achieved through government incentives and changes in electricity rate structures. Benefits for consumers from capacitor installation include:
 - 1) More Room for Power Equipment
 - 2) Reduced Power Loss
 - 3) Voltage Stabilization:

Causes and Mitigation: Low Power factor

• Installing Static VAR Compensators (SVCs):

- Also called self-excited SVCs, have variable reactive power outputs that can be changed in milliseconds to supply or consume both capacitive and inductive reactive power. While they can be used for voltage support and power factor correction, their primary role is in handling dynamic power system events such as grid support under fault conditions or emergency conditions.
- It is worth noting that Although STATCOMs are the best in terms of performance, they are very expensive, and considering that in many cases the cause of low power factor is lagging caused by inductive loads, it is most economical to utilize shunt capacitors for power factor correction.
- A comparison between shunt capacitors, SVCs, and STATCOMs is shown in the table below:



Causes and Mitigation: Load Balancing

- To mitigate against this cause, introduce:

a) Load Distribution:

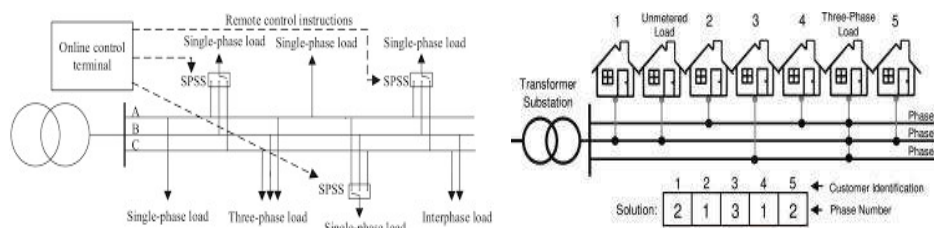
- Involves balancing of the loads by redistributing from heavily loaded feeders to lightly loaded feeders and ensuring equal distribution of load across all three phases.

b) Load Balancing:

- By ensuring that the loads are balanced among the phases, load distribution reduces the risk of overloading a single phase while others remain underutilized. Balanced load distribution helps prevent uneven stress on distribution lines, transformers, and other equipment, ultimately leading to reduced technical losses by optimizing the utilization of the entire network.

Causes and Mitigation: Load Balancing

- phase correction or phase balancing, is a power loss reduction technique used in three-phase electrical systems.
- It refers to the intentional interchange of the connections of two or more phases in a distribution network.
- In an ideal three-phase system, the load should be evenly distributed among the three phases to ensure balanced currents and minimize losses.



Causes and Mitigation: Loose Terminations and Connections

- By addressing loose connections and terminations, the distribution system can minimize resistive losses, improve voltage regulation, enhance system reliability, and mitigate safety risks. This results in a more efficient and reliable distribution network with reduced technical losses.
- To address the issues related to loose connections and terminations and reduce associated losses, the following measures can be taken:
 - **Proper Torque and Fastening**
 - **Regular Inspection and Maintenance**
 - **Use of Proper Tools and Techniques**
 - **Training and certification of technicians**

Causes and Mitigation: Loose Terminations and Connections

- Effective connections, joints, and terminations play a crucial role in mitigating power technical losses in power systems by minimizing resistive losses, ensuring reliability, and maintaining system efficiency.
 - Reduced Resistive Losses:
 - Properly designed and installed connections, joints, and terminations result in lower resistance at critical points in the power system. Reduced resistance means less power is dissipated as heat, resulting in lower resistive losses. This is particularly important in high-current areas such as substations, transformers, and distribution lines.
 - Improved Reliability:
 - Faulty or poorly constructed connections, joints, and terminations can lead to increased impedance, voltage drops, and hotspots. These issues can result in overheating, arcing, and ultimately, equipment failure or system outages. By ensuring that connections are securely made, joints are properly insulated, and terminations are correctly installed, the risk of faults and failures is minimized, thus improving overall system reliability.



Causes and Mitigation: Loose Terminations and Connections

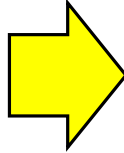
- Enhanced Efficiency:
 - Effective connections and terminations help to maintain the integrity of the electrical circuit, allowing for efficient power transmission and distribution. By minimizing voltage drops and impedance mismatches, energy losses are reduced, and more power can be delivered to end-users without unnecessary waste. This improves the overall efficiency of the power system, leading to cost savings and optimized performance.
- Prevention of Corrosion and Deterioration:
 - Properly designed and maintained connections, joints, and terminations are essential for preventing corrosion, oxidation, and other forms of deterioration over time. Corrosion can increase resistance and impedance, leading to higher losses and decreased system reliability. By using corrosion-resistant materials and implementing effective maintenance practices, the risk of degradation is minimized, ensuring long-term performance and durability.



Causes and Mitigation: Loose Terminations and Connections

Connection and disconnection of Jumpers by Bolt-type connector

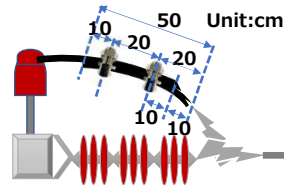
<<Status quo (Binding connection)>>



<<Bolt-type connector>>



Weight: 693g/piece,
Length: 70mm/piece



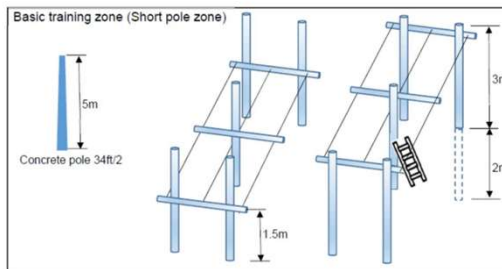
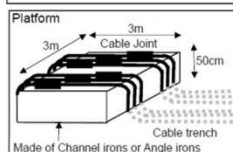
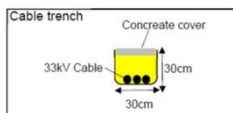
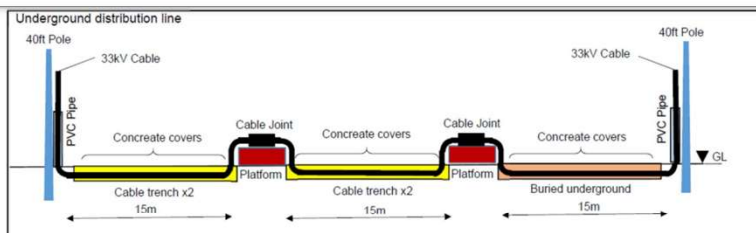
Advantage of Bolt-type connector

- > Repeatedly disconnecting and connecting jumpers is able **without jumper damage**
- > Anyone can do this work (**Skill less**)
- > **Stable the joint quality**
- > No special tools required to work



Causes and Mitigation: Loose Terminations and Connections

Cable Joints and overhead line stringing for loss mitigation



Causes and Mitigation: Poor Quality and Maintenance



- **Using only high-quality equipment and materials:**
 - Using only high-quality equipment and materials from reputable manufacturers is an effective strategy for reducing technical losses in the distribution system
 - It is a proactive approach to minimize technical losses and maintain a robust and efficient distribution system.
- **Conducting quality control checks on equipment and materials:**
 - This will help to ensure the use of reliable, efficient, and compliant equipment.
 - This reduces technical losses by improving equipment performance, minimizing energy wastage, enhancing safety, reducing long-term costs, complying with standards, and promoting proper installation practices.

Exercise 3

Mitigation Strategies for Technical Losses



- **Network Optimization:** Explore strategies like conductor upsizing, reconfiguration, and voltage regulation.
- **Equipment Modernization:** Discuss replacing old transformers and conductors with energy-efficient options.
- **Smart Grid Integration:** Highlight the potential of distributed generation, demand-side management, and advanced metering for loss reduction.
- Forms discussion groups to brainstorm on these issues and others relevant to causes of technical loss and mitigation strategies.

Site Visit and Practical Activities

Visit the demonstration substation

- 1. Determine the structure of the substation and note any issue that can result to technical loss and or issues that are mitigation strategies
- 2. Determine the size of the overhead conductors and the supply voltage levels. Model the system in NEPLAN and determine its instantaneous technical loss value
- 3. Change the conductor size and determine the loss value. Compare the results and see the impact of the conductor size.



NATIONAL POWER TRAINING INSTITUTE OF NIGERIA -NAPTIN

BASIC POWER RELAYING PROTECTION COURSE - P1 (MANUAL)

BY

PROTECTION, CONTROL AND METERING DEPARTMENT

Table of Contents

BASIC POWER RELAYING PROTECTION

COURSE - P1 (MANUAL).....1

Chapter One

PRINCIPLES AND PHILOSOPHY OF RELAYING

PROTECTION32

THE RELAY33

Fault Conditions34

RELAY TYPES AND CLASSIFICATIONS.....35

RELAY PERFORMANCE35

RELAY OPERATING TIME36

ZONES OF PROTECTION36

Generator Protection Zone37

Transformer Protection Zone37

Bus bar Protection Zone39

Lines Protection Zone40

Transmission Line protection Classification.....40

PRIMARY AND SECONDARY RELAYS41

ELECTRICAL POWER SYSTEM DEVICE NUMBERS

AND FUNCTIONS42

Device Definitions and Functions42

DEVICES PERFORMING MORE THAN ONE

FUNCTION57

SUFFIX NUMBERS57

SUFFIX LETTERS.....57

REPRESENTATION OF DEVICE CONTACTS.....58

Chapter Two

CONTROL CIRCUITS60

CONTROL SYMBOLS AND ALPHABETS60

CONTROL CIRCUIT SUPPLIES61

D. C. SUPPLY61

A.C. SUPPLY63

TRIP CIRCUIT64

Chapter Three

FAULT STUDY, ANALYSIS AND SHORT CIRCUIT

CALCULATIONS, FAULT DETECTION.....70

2. Fault Types and Causes	71
Fault Classifications Symmetrical & Unsymmetrical	72
Characteristics of Faults	73
System grounding	75
Types of Faults	76
Necessity for fault calculations	77
Fault Calculations	77
Per Unit and Percentage System formulae	79
Frequent causes of underground cable faults	92
Fault detecting method (overhead/underground)	95
1. Fault detecting by pulse voltage applying (“Hipotronics”)	95
Types of devices	95
Detecting theory	96
2. Fault detecting by insulating resistance (“Megger”)	96
Detecting theory	96
3. Fault detecting by “Murrey loop method”	97
Example of measuring instruments	97
Principle of Wheatstone bridge circuit	98
Detecting theory	98
Example	99
ILLUSTRATION ON MURREY LOOP METHOD OF CABLE FAULT LOCATION	100
4. Important things to remember	101
5. Further Reading	102

Chapter Four

RELAY COORDINATION103

Methods of Relay Co-ordination	103
Co-ordination Procedure	104
Time Graded Systems	105
Current Graded Systems.	107
Time and Current Graded System	108
Circuit breaker interruption time	109
Overshoot	110
Errors	110
Factor of Safety	110

Examples on relay Co-ordination.....	111
Chapter Five	
POWER TRANSFORMERS AND CONNECTIONS ..	128
Theory.....	128
Three-phase unit versus single-phase units:	133
Advantages of 3 phase units	133
Disadvantages of 3 phase units.....	134
Advantages of Single-Phase Units	134
Disadvantages of Single-Phase Units	135
Types of Transformers.....	135
Power Transformers	135
Distribution Transformers	135
Auto Transformers	136
Instrument Transformers	137
Three Phase Transformer connections or Vector group	
Parallel Operation of Transformers.....	139
Phase shift in Delta-Star/Star-Delta Transformations (	
Vector groups 3 and 4)	140
Parallel Operation of DY11 and DY1 Transformers.....	143
Procedures in Parallel Operation.....	144
Using Phasing Sticks	144
Method of an external supply source	146
Voltage Transformers Method	146
Case studies on paralleling of Transformers	149
Paralleling of Transformers of unequal ratings and	
same	
percentage impedances	149
Paralleling of Transformers with unequal %	
Impedances	153
Paralleling of Transformers with unequal secondary	
voltages	153
Three Winding Power Transformers	156
Merits	157
Demerits	158
Cooling of transformers and Cost Comparison of	
the cooling methods.....	160
Requirements and characteristics of insulating oil	163
Tests on Transformers.....	164

Routine tests	164
Type tests	164
Field tests and Commissioning	165
Maintenance of Power Transformers	165
Chapter Six	
INSTRUMENT TRANSFORMERS	167
Classification.....	167
Types of Instrument Transformers.....	167
Current Transformers	168
Theory of Current Transformers	168
Phasor diagram of a C.T.....	169
Equivalent circuit of C.T.: High Reactance and Low Reactance	
Type C.Ts	172
Characteristics of Current Transformers.....	174
Errors in Current Transformers.....	176
Ratio Error	176
Phase Angle Error	176
Composite Error.....	176
Causes of Errors.....	177
Methods to minimize errors	177
Limits of Error	178
Error Limits as per BS 3938.....	178
Error limits as per IEC 185.....	179
Common definition of terms used with Current Transformers	180
Rated Burden.....	180
Rated Output	180
Accuracy Limit Factor (ALF)	181
Instrument Security Factor (ISF).....	182
Rated Insulation Level	183
Highest System Voltage	183
Knee point voltage (V_k)	184
Rated Short Time Thermal Current (I_{th})	185
Rated Dynamic Current (I_{dyn})	187
Rated Primary and Secondary Current.....	187
Selection of the rated output or burden	190
A case study of Estimation of Burden, Knee Point	

Voltage,	
Accuracy Class etc of a Protective CT	193
Recommended Accuracy Class of CT's for Instruments and Relays	
Application	197
Classification of Current Transformers	197
Classification depending upon location	198
Classification depending upon application.....	199
Classification depending upon location in the circuit	199
Classification as per Construction	200
Bar type	200
Wound type.....	201
Ring type.....	202
Split core type	203
Linear C.T	203
Cascade C.T	203
Classification as per insulation	204
Classification depending upon the location of the secondary core	204
Dead tank type.....	204
Inverted type or Live tank C.T	205
Insulator type or Cross connected type	206
Tests on C.T	207
Type tests	207
Routine tests.....	207
Polarity and Markings	208
Field testing and Commissioning tests on Current Transformers	209
Visual checks.....	209
Insulation test.....	209
Polarity test and verification of markings	209
Ratio test	210
Excitation test	211
Oil test.....	213
How to specify a Current Transformer	214
Maintenance of C.Ts in service	215
VOLTAGE OR POTENTIAL TRANSFORMERS (V.Ts OR P.Ts)	216
Types	216

Electromagnetic type	216
Capacitor type	217
Bushing Type Capacitive Voltage Transformer	221
Common definition of terms used with Voltage Transformers	223
Rated Burden.....	223
Rated primary voltage.....	224
Highest system voltage.....	224
Rated secondary voltage	224
Rated Outputs or Burden.....	225
Equivalent circuit of a voltage transformer.....	225
Errors in Voltage Transformers.....	227
Voltage Error or Ratio Error	227
Phase displacement error.....	228
Limits of Error	228
Voltage Factor (V f).....	229
Application of Accuracy Class for various metering and protection purposes	231
Choice between Magnetic Type Voltage Transformers and Capacitive Type Voltage Transformers	231
Purpose	231
Layout	232
Cost	233
Problems associated with C.V.Ts	234
Reference Range of Frequency	234
Use of C.V.Ts as a coupling capacitor for PLCC and Tele-protection.....	234
Factors affecting the choice of the capacitance for C.V .Ts	235
Polarity and Connections of V.Ts	236
VT Testing	240
Type tests	240
For C.V.Ts	240
Routine Tests - for Electromagnetic V.Ts	241
For C.V.Ts	240
Field Commissioning Tests.....	241
Visual Checks	241
Insulation test.....	241

Polarity test	241
Ratio test.....	242
additional testing.....	242
How to specify a Voltage Transformer.....	243
Protection of V.Ts	244
Maintenance of V.Ts in Service	244
Chapter Seven	
BASIC DIFFERENTIAL PROTECTION	245
Basic Differential Relaying	245
Types of Differential Protection or Relaying	246
Current Differential Relaying.....	246
Voltage Differential Relaying	247
Biased Differential Protection or Percentage differential Protection	247
Application	255
Chapter Eight	
GENERATOR PROTECTION	256
TYPES OF GENERATOR FAULTS	256
Stator Faults	256
Rotor faults	256
Miscellaneous faults and or abnormal conditions	257
STATOR PROTECTION.....	257
Resistance Grounding	257
Distribution Transformer Grounding of Large Generators.....	259
Voltage Transformer Grounding	261
Reactance Grounding.....	261
Phase and Ground Faults.....	262
percentage bias of the relay	263
Stator Interturn Faults	263
Short circuit protection of stator windings	267
Stator Overheating.....	267
Stator Open Circuit	268
Over Voltage Protection.....	268
Unbalanced Stator Current	269
ROTOR PROTECTION	271
Rotor Ground Faults	271
Detecting Rotor Earth Faults: Method 1	272

Detecting Rotor Earth Faults: Method 2	273
Field Failure (Loss of Field)	274
MISCELLANEOUS FAULTS AND ABNORMAL CONDITIONS	278
Over-speed	278
Motoring	279
Loss of Synchronism	279
Bearing Overheating	280
Chapter Nine	
PROTECTION OF TRANSFORMERS	281
NATURE OF TRANSFORMER FAULTS.....	281
THROUGH OR EXTERNAL FAULTS.....	281
Overloads	282
External short circuits	283
Terminal faults	283
Over-Voltage and Over-Fluxing	283
INTERNAL FAULTS	283
Electrical Faults	284
Miscellaneous or Incipient Faults.....	284
PROTECTION AGAINST INTERNAL FAULTS	285
Gas Actuated Relays	285
Bucholz relay	285
Sudden Pressure Relay (SPR)	287
Over Current and Unrestricted Earth Fault Protection...	289
Balanced Earth Fault or Restricted Earth Fault Protection (REFP).....	291
Use of Stabilising Resistors	293
Frame Leakage Protection	296
Differential Protection	297
Current Transformer Characteristics	298
Ratio change as a result of change of tappings.....	299
Magnetising Inrush	300
Recovery Inrush.....	301
Sympathetic Inrush	302
Phase Shift Introduced by Delta-Star and Star-Delta	303
Guidelines in the selection of Current Transformers for Differential Protection.....	303
Examples on providing Differential Protection for	

Powejr Transformers	304
To provide differential Protection for a 30MVA, 132/33 KV DY 11 Transformer	304
To provide Differential Protection for a 7.5MVA, 33/11KV DY1 Transformer	306
DIFFERENTIAL PROTECTION FOR A THREE WINDING TRANSFORMER	309
MATCHING C.T. SELECTION	312
THREE WINDING TRANSFORMER DIFFERENTIAL CONNECTION.....	313
To provide Differential Protection for a 80MVA; 330/132/11KV Three Winding Transformer YY0/D1 loaded Tertiary of 25MVA rating	314
To provide Differential Protection for a Unit Generator-Transformer 145MVA; 16/330KV. Generator in Star and Transformer Yd1.....	315
METHODS ADOPTED TO DISTINGUISH BETWEEN A FAULT AND AN INRUSH CURRENT	316
Desensitization of the Transformer bank	317
Differential Relays with Reduced Sensitivity to Inrush...	317
Harmonic Relays	318
Harmonic Cancellation	319
Harmonic Restraint	319
Harmonic Blocking.....	320
D.C. Bias.....	320
Over-voltages and Over-fluxing	321
Sustained Over-voltages	321
Transient Over-voltages	323

Chapter Ten

BASIC LINE PROTECTION	324
TYPES OF PROTECTION	324
OVER CURRENT AND EARTH FAULT PROTECTION	325

DISTANCE PROTECTION	325
PILOT PROTECTION	326
OVER CURRENT AND EARTH FAULT PROTECTION FOR SINGLE LINES	327
SELECTION OF THE INVERSENESS OF A RELAY CHARACTERISTIC	329
APPLICATIONS OF INSTANTANEOUS O.C RELAYS.....	330
PROTECTION FOR PARALLEL LINES	330
ADJUSTMENTS FOR LOOP AND INTERCONNECTED CIRCUITS	332

Chapter Eleven

AUTORECLOSING SCHEMES	335
ADVANTAGES OF RECLOSING	335
DEFINITION OF COMMON TERMS USED IN AUTORECLOSE SCHEMES	337
Operating Time	337
Dead time	338
Closing Impulse time	338
Reclaim time	338
Lock Out	339
Anti-pumping.....	339
Number of shots	339
APPLICATION OF AUTORECLOSE SCHEMES	339
System Stability and Synchronism	340
Synchronous and Induction Motor Loads	340
Reclosing Time	343
RECLOSING SYSTEM CONSIDERATIONS.....	343
One shot Versus Multiple Shot Reclosing relays	343
Three Phase Versus Single Phase Auto reclosing	344
AUTO RECLOSURES	346
LIMITATIONS IN USE OF AUTORECLOSE SCHEMES	347
Sequence of Operations	348

Chapter Twelve

OVERVOLTAGES AND SURGE PROTECTION	353
OVERVOLTAGES	353
Atmospheric Over voltages.....	353
Switching over voltages	355

Temporary Over voltages	356
SIGNIFICANCE OF OVER VOLTAGES IN POWER SYSTEMS.....	356
PROTECTION AGAINST OVER VOLTAGES IN POWER SYSTEMS	357
Protection for Lines.....	357
Protection for Equipment	359
Lightning Arresters.....	359
Classification of Lightning Arresters	359
location in the power system network.....	359
linear or non linear	360
discharge medium	360
modus operandi	360
Expulsion type	360
Valve type	361
Station type.....	362
Line type	362
Ratings and Characteristics of Lightning Arresters.....	363
Rated Voltage	363
Co-efficient of Earthing	364
Effectively earthed system	364
Non-Effectively Earthed System	365
Isolated or Unearthed Neutral Systems	365
Nominal Discharge Current	366
Rated frequency	366
Power Frequency Spark-Over Voltage	366
Maximum Impulse Spark-Over Voltage	367
Residual or Discharge Voltage	367
Maximum Discharge Current	368
Follow Current	368
Cut-off Voltage	368
Impulse Spark-over Volt-time Characteristics.....	369
Front of Wave Spark-over Voltage	370
Front of Wave Steepness	370
Protection Level of a Lightning Arrester.....	370
Protective Margin.....	370
Selection of Lightning Arresters	371
Establishment of Separation Limit	372

An example on selection of a L.A. for a 132 KV system	
Rod Gaps.....	375
Protector tubes	377
Insertion of Linear or Non-Linear Shunt Reactors and	
Insertion of Resistors at Circuit Breakers	378
Tests on L.As	380
Type Tests	380
Sample tests	380
Routine tests.....	380
Chapter Thirteen	
FUSES AND FUSE CO-ORDINATION	382
Types of Fuses	382
Power Fuses.....	383
The Fuse Mounting.....	383
Fuse Holder	383
Fuse Link	384
time required to melt the fusible link	384
Fuse links are divided into two.....	385
Expulsion Fuse	385
FUSE CO-ORDINATION	385
Method of Determining Coordinated Fusing	387
Minimum Melting Time.....	387
Total Clearing Time	387
CHAPTER 14	
REDUCING FORCED OUTAGES	389
LEARNING OUTCOMES.....	389
Reduction of the frequency of outage incidents.....	389
1. Proper recording of the data of outage incidents.....	389
2. Analysis of the accumulated data	390
3. Appropriate countermeasures	391
Here are some typical examples of the countermeasures	
for the combination of the damaged equipment and the	
root cause.	391
4. Verification of the effectiveness of the countermeasure	
.....	392
Reduction of outage duration per one outage incident ..	392
1. Energizing the healthy section as early as possible ..	393
2. Restoring the faulty point as early as possible	394
SUMMARY	394

DESCRIPTIONS	394
Chapter Fifteen	
STABILITY, RECLOSING AND LOAD SHEDDING	
POWER SYSTEM FREQUENCY CONTROL	398
System Instability/Frequency Control	398
Interconnected Power System	399
Illustrations/Case Study	401
Load Shedding and Under Frequency Relay	404
Load Scheduling	406
Chapter Sixteen EARTHING	408
OBJECTIVES OF EARTHING	408
Neutral Earthing	408
General Earthing	409
NEUTRAL EARTHING	409
ISOLATED NEUTRAL SYSTEM	410
SOLID EARTHING	411
The Main Advantages of Solid Earthing	412
Disadvantages of Solid Earthing	413
RESISTANCE EARTHING	413
The main advantages Resistance Earthing	415
The disadvantages of Resistance Earthing	415
REACTANCE EARTHING	416
EARTHING TRANSFORMERS	419
CHOICE OF THE METHOD OF NEUTRAL	
EARTHING	422
SELECTION OF GROUNDING MATERIAL	425
Size of Conductor	426
EARTHING SYSTEM	427
Step Potential, Touch Potential and Transfer Potential	
Definitions	428
GENERAL INSTRUCTIONS FOR LAYING	
EARTHING GRID	432
Chapter Seventeen	
TESTING AND MAINTENANCE OF RELAYSj	434
TESTS ON RELAYS	434
Type Tests	435
Thermal Requirements	435

Accuracy	436
Mechanical Endurance	436
Shock Vibration.....	437
Contact Performance	437
Rated Burden and Rated Impedance	437
Insulation Requirements	437
Di-electric Withstand Capacity	437
Impulse Test	438
High Frequency Disturbance Test	439
D.C. Auxiliary Supply Interruption Test.....	439
Operating Value Test	440
Operating Time Test	440
Reset Value Test	440
Reset Time Test	440
ROUTINE TESTS	441
Visual Inspection Check List.....	440
Verifications with respect to purchase	441
Soldering.....	441
Terminations	441
Wiring.....	442
Varnishing.....	442
Winding.....	442
Indication/Name Plate.....	443
Mechanical Fixing	443
Finish	443
VERIFICATION OF OPERATIONAL CHARACTERISTICS	444
I.D.M.T. O.C. and E.F. Relays	444
Pick up and Drop Off Value	443
Time Delay.....	443
Definite Time O.C. and E.F. Relays	444
Pick Up and Drop Off Value.....	444
Operating Time Test	444
Directional Relays (Voltage Restraint)	444
Quadrature Test.....	444
Sensitivity Test.....	444
Directional Relay (Current Restraint)	445
Voltage Relays (Over Voltage)	445
Pick Up Value	445

Operating Time	445
Voltage Relays (Under Voltage)	445
Pick Up Value	445
Operating Time	445
Transformer Differential Relays	446
Operating Characteristics	446
Operating Time Test	446
Harmonic Restraint Characteristics	446
Stability Test	447
Auxiliary Supply Variation	447
Operation of flag Indicator	447
ACCEPTANCE TESTS.....	448
COMMISSIONING/INSTALLATION TESTS	449
Staged Fault tests.....	449
commissioning tests	449
MAINTENANCE OR FUNCTIONAL TESTS.....	450
REPAIR TESTS.....	452
ACCESSORIES FOR TESTING, PRECAUTIONS DURING TESTING AND MAINTENANCE TESTS.....	453
Typical Secondary Injection tests on several relays	454
O.C. and E.F. Relays.....	454
Directional O.C. and E.F. Relays (Voltage/Current restraint).....	455
Differential Relays:.....	455
Distance Relays.....	455
FAULT INVESTIGATION/RELAY OPERATION.....	456

CHAPTER ONE

PRINCIPLES AND PHILOSOPHY OF RELAYING PROTECTION

INTRODUCTION

Relaying protection is used to prevent or minimize damage to equipment and maintain continuous supply of Electricity at barest minimum cost. The need for relaying protection comes into play in providing the most efficient protection for power system equipment. This can be very expensive. To reduce such cost, a balance needs to be struck between the cost of the protection and the degree of safety to the equipment.

The main purposes of relaying protection are as stated below:

- (i) To ensure uninterrupted power supply.
- (ii) To reduce equipment damage.
- (iii) To maintain quality of service.
- (iv) To guarantee safety of life and property.
- (v) To ensure operation of equipment at peak efficiency.

The earliest method of protection was the fuse. The fuse finds its use primarily in Distribution Circuits due to its cheapness and simplicity. Its use in system protection in NEPA is limited by the following disadvantages:

- (a) The fuse is slow in operation
- (b) Before power supply can be restored the fuse has to be replaced
- (c) The fuse is not selective or discriminative in operation
- (d) It cannot be used for very high voltage protection.

As a result of the above shortcomings, the use of fuses has generally been replaced with the protective relays.

THE RELAY

This is an electrical device that behaves in a prescribed way to an applied input so as to cause, by its contact operation, abrupt changes in associated control circuits.

In protective relaying, there are important parameters required for effective performance. They include:

(a)Sensitivity

A relay must be sensitive to the least fault conditions for which it has been configured.

(b)Reliability

It must be relied upon at all times to respond to any fault by relaying signals that will cause the faulty part to be isolated.

(c)Selectivity

The relay must be able to discriminate between faults and abnormal conditions.

(d)Simple

For a relay to be effectively used, its construction and operation has to be simple in nature.

(e)Speed of Operation

To be able to prevent damage to the associated equipment the relay is protecting, it must act fast before the damage is done.

(f) Cost

The relay should not be so expensive as to outweigh the benefit of using it to protect the associated equipment.

Fault Conditions

In power systems, faults occur as a result of breakdown in equipment insulation.

These faults can be categorized as follows:

- Single phase to ground fault
- Double phase to ground fault
- Three phase to ground fault
- Phase to phase fault
- Three phase fault.

The commonest, in occurrence, of the above fault conditions, is the single phase to ground fault which is about 70%.

Damage to equipment can be caused by other abnormal conditions in a power system. Such conditions are:

- Over heating
- Over voltage (surge)
- Over load
- Fire disaster

- Unbalanced loading
- Loss of synchronism

For the faults and abnormal conditions enumerated above protective relays are designed to isolate and reduce damage to the system equipment.

RELAY TYPES AND CLASSIFICATIONS

Relays are classified according to the following:

- Input - voltage, current, frequency.
- Operating Principle – percentage or restraining.
- Function - Monitoring, Regulating, Auxiliary, Programming or Protection.
- Performance characteristics - Definite time, Inverse time or Distance.
- Structure - Static, Electromechanical or Thermal

Sometimes relays are also classified using a combination of the above terms, e.g. inverse time over current.

RELAY PERFORMANCE

Performance of relays can be classified as:

- (i) Correct
- (ii) Incorrect
- (iii) Inconclusive.

Incorrect Operation

This can be due to the following factors:

- (a) Poor Application

(b) Incorrect Relay Setting

(c) Personnel Error

(d) Equipment Malfunction

Incorrect tripping may be either failure to trip or false tripping.

Failure to trip can be caused by faulty associated instrument transformer, circuit breakers, control cables and wiring and station batteries.

Inconclusive Operation

This is the last resort when no evidence is available either for a correct or incorrect operation. Quite often, this is a personal involvement.

RELAY OPERATING TIME

Relays can be classified in terms of their operating times as follows:

- High Speed Relays - operate in less than three (3) cycles
- Slow speed relays - operate in three (3) cycles or more
- Time delay relays - have built in time delay facility to allow co-ordination with other relays within the power system.
- Instantaneous relays - have no deliberate time delay facility. They operate instantaneously.

ZONES OF PROTECTION

For effective protection of the system with minimum part disconnected during fault, protection zones are mapped out. These zones are created in such a way that each overlap around an isolating device such as a circuit breaker.

This method guarantees total protection of power system sub circuits. These zones follow common logical boundaries to cover such equipment as Lines, Transformers, Buses, Generators, Motors and any combinations of the above equipment.

For such boundaries to be genuine, there must be:

- Measuring devices such as Current Transformer or Voltage Transformer.
- Isolating devices such as breakers.

Generator Protection Zone

Typical faults occur within generators such as - Winding faults, Field Ground fault, A.C.

Over Voltage faults and Field Loss faults. The protective relay, on occurrence of any of these faults must act very fast to isolate the faulty part in order to save both the life of the equipment and the personnel around it.

Transformer Protection Zone

In this zone, the usual faults that can occur are as follows:

Winding faults, Phase to Ground faults, Phase-to-Phase faults and Inter turn faults.

For these faults, differential protection is the major type used for transformer protection. Oil/Winding temperature relays are also provided along with Bucholz gas Alarm/Bucholz surge trip protection.

These four methods are used to protect the transformer against faults within the windings. Over current/Earth fault protection are also provided.

Adequate protection to the transformer is cumbersome due to the following transformer constraints:

- (i) There is phase shift in star connected transformers.
- (ii) There are different voltage levels between the primary, the secondary and or the tertiary side of the transformer.
- (iii) There is a high magnetizing inrush current especially during transformer energization. These currents show harmonic currents of the 2nd order and above.

In order to compensate for the above constraints, transformer differential schemes are designed taking them into account.

As an example:

- (a) To prevent tripping of transformer on high magnetizing inrush currents, a harmonic restraint device is embedded in the differential relay, which prevents it from operating on inrush currents during transformer energization.
- (b) Matching current transformers are used to correct the voltage level differences at both sides of the transformer and also to correct the differences in transformer characteristics of the current transformers on both sides of the transformer.

(c) Phase shift in the Star-Delta windings of transformers are taken care of by connecting star winding CT's in Delta and Delta winding CT's in Star.

In some cases the relay may be unstable as a result of spill current on the Delta side of the transformer due to zero sequence. These currents are filtered out by wiring part of the matching C.T. winding to cancel itself out of the delta side of the transformer.

The vector group of the transformer windings also plays a prominent role when the differential relay is wired. To take care of this, the delta wiring of the matching CT's must be wired according to the vector group of the winding as stipulated by the manufacturer.

Details of transformer differential are discussed fully in Chapter 9 on Power Transformer Protection.

Bus bar Protection Zone

The most common fault within this zone is the phase to ground fault generally caused by flash over on insulators as a result of lightening. Other causes of this flash over are:

- Cracked insulators, birds and reptiles, dirty or broken insulators or animals that may walk close to the bus.

The bus has several lines/feeders tied to it. The current transformers on the bus get easily saturated due to these lines. The usual type of protection for the bus zone is the differential type. This method compares the current entering the bus zone with that leaving it. Current transformers installed on each bus feed are

used to make this comparison. Under a fault condition, the CT's on the faulted circuit get the sum of all the currents from the other circuits.

Lines Protection Zone

The transmission and distribution lines comprise the major means where by electric power is transported from generating source to the points where the energy is to be used. These lines run into thousands of kilometers.

Faults occurring on power transmission lines can be due to the following causes:

- Lightning
- Wind
- Birds
- Bush fire

There are four types of line faults namely: Line to Ground, Line to Line, Double Line to Ground faults.

Transmission Line protection can be classified as follows:

- (a) Instantaneous/inverse time over current (non-directional)
- (b) Instantaneous/inverse time over current (directional)
- (c) Distance protection - directional/inverse or instantaneous
- (d) Pilot wire using communication channels
- (e) Current balance.

For effective line protection, the different protection schemes must be properly coordinated. Distribution lines are adequately protected using over current relays and fuses.

Distance protection is frequently used for voltages of 66KV and above. The scheme functions by comparing the system voltage and current and operates when the voltage-current ratio is less than a pre-set value.

Thus $V = IZ$, where V , I , Z , are system voltage, current and impedance respectively.

In normal operation, the system Z is fixed. This value reduces or increases depending upon an external or internal fault within the zone of protection. Impedance diagrams are usually used to show the characteristics of the distance relay and are usually known as Mho characteristics. Distance relays can be single-phase type or three-phase types.

In modern line distance protection, tripping in remote stations is facilitated through the use of communication channels. This method is called carrier-assisted distance protection scheme.

PRIMARY AND SECONDARY RELAYS

Primary Relays are the first line of defense in the system. They are generally high-speed relays. The primary relay scheme is designed to remove minimum equipment from service.

Secondary Relays also called backup relays are intentionally delayed in their operation so as to give the primary relays a chance to operate first. The backup relays scheme is independent of the primary relay scheme and operates if the primary relay scheme fails to operate. The equipment removed from service by

the backup protection is more of the equipment including the faulty ones. Backup protection comes in overlapping zones.

ELECTRICAL POWER SYSTEM DEVICE NUMBERS AND FUNCTIONS

The devices in switching equipment are referred to by numbers with appropriate suffix letters when necessary, according to the functions they perform.

These numbers are based on a system adopted as standard for automatic switchgear by IEEE.

This system is used in connection diagrams, in instruction books and in specifications.

Device Definitions and Functions

Number

- 1 Master Element** is the initiating device such as a control switch, voltage relay, float switch etc., which serves either directly or through such permissive devices as protective and time delay relays to place equipment in or out of operation.
- 2 Time Delay Starting or Closing Relay** is a device which functions to give a desired amount of time delay before or after any point of operation in a switching sequence or protective relay system except as specifically provided by Device Functions 48, 62 and 79 described later.
- 3 Checking or Interlocking Relay** is a device that operates in response to the position of a number of other devices (or to a number of predetermined conditions) in an equipment, to allow an operating

sequence to proceed to stop, or to provide a check of the position of these devices or of these conditions for any purpose.

4 Master Contactor is a device, generally controlled by Device No. 1 or equivalent and the required permissive and protective devices that serve to make and break the necessary control circuits to place equipment into operation under the desired conditions and to take it out of operation under other or abnormal conditions.

5 Stopping device is a control device used primarily to shut down equipment and hold it out of operation (this device may be manually or electrically actuated but excludes the function of electrical lock out (See Device Function 86 on abnormal conditions).

6 Starting Circuit breaker is a device whose principal function is to connect a machine to its source of starting voltage.

7 Anode Circuit breaker is one used in the anode circuits of power rectifiers for the primary purpose of interrupting the rectifier circuit if an arc back should occur.

8 Control Power Disconnecting Device is a disconnection device such as a knife switch, circuit breaker or pull out fuse block, used for the purpose of connecting and disconnecting the source of control power to and from the control bus or equipment.

Note: Control power is considered to include auxiliary power, which supplies such apparatus as small motors and heaters.

9 Reversing Device is used for the purpose of reversing a machine field or for performing any other reversing functions.

10 Unit Sequence Switch is used to change the sequence in which units may be placed in and out of service in multiple unit equipment.

11 RESERVED FOR FUTURE APPLICATION

12 Over Speed device is usually a directly connected speed switch, which functions on machine over speed.

13 Synchronous Speed device such as a centrifugal speed switch, a slip frequency relay, a voltage relay, an under current relay or any type of device, that operates at an approximate synchronous speed of a machine.

14 Under Speed device functions when the speed of a machine falls below a predetermined value.

15 Speed or frequency matching device functions to match and hold the speed or the frequency of a machine or of a system equal to or approximately equal to that of another machine, source or system.

16 RESERVED FOR FUTURE APPLICATION

17 Shunting or Discharge switch serves to open or to close a shunting circuit around a piece of apparatus (except a resistor) such as a machine field, a machine armature, a capacitor or a reactor.

Note: This excludes devices which perform such shunting operations as may be necessary in the process of starting a machine by Devices 6 or 42

or their equivalent, and also excludes Device 73 which serves for the switching of resistors.

18 Accelerating or Decelerating device is used to close or to cause the closing of circuits, which are used to increase or to decrease the speed of a machine.

19 Starting to Running Transition Contactor is a device, which operates to initiate or cause the automatic transfer of a machine from the starting to the running power connection.

20 Electrically Operated Valve is electrically operated, controlled or monitored valve in a fluid line.

Note: The function of the valve may be indicated by the use of suffixes.

21 Distance Relay is a device which functions when the circuit admittance, impedance or reactance increases or decreases beyond predetermined limits.

22 Equaliser Circuit breaker is a breaker, which serves to control or to make and break the equaliser or the current balancing operations for a machine field, or for regulating equipment in a multiple unit installation.

23 Temperature Control device which functions to raise or lower the temperature of a machine or other apparatus or of any medium, when its temperature falls below, or rises above, a predetermined value.

Note: An example is a thermostat, which switches on a space heater in a switchgear assembly when the temperature falls to a desired value as

distinguished from a device, which is used to provide automatic temperature regulation between close limits and would be designated as 90T.

24 RESERVED FOR FUTURE APPLICATION

25 Synchronizing or Synchronism Check device operates when two A.C circuits are within the desired limits of frequency, phase angle or voltage to permit or to cause the paralleling of these two circuits.

26 Apparatus Thermal device functions when the temperature of the shunt field or the armotisseur windings of a machine or that of a load limiting or load shifting resistor or of a liquid or other medium exceeds a predetermined value; or if the temperature of the protected apparatus, such as a power rectifier, or of any medium decreases below a predetermined value.

27 Under Voltage relay is a device, which functions on a given value of under voltage.

28 Flame Detector is a device that monitors the presence of the pilot or main flame in such apparatus as a gas turbine or a steam boiler.

29 Isolating Contactor is used expressly for disconnecting one circuit from another for the purpose of emergency operation, maintenance or test.

30 Annunciator Relay is a non automatically reset device that gives a number of separate visual indications upon the functioning of protective devices, and which may also be arranged to perform a lock out function.

31 Separate Excitation device connects a circuit such as the shunt field of a synchronous converter, to a source of separate excitation during the starting sequence; or one, which energizes the excitation and ignition circuits of a power rectifier.

32 Directional Power relay is one which functions on a desired value of power flow in a given direction, or upon reverse power resulting from arc back in the anode-cathode circuits of a power rectifier.

33 Position Switch makes or breaks contact when the main device or piece of apparatus, which has no device function, reaches a given position.

34 Master Sequence device is a device such as a Motor operated multi-contact switch, or the equivalent, or a programming device such as a computer that establishes or determines the operating sequence of the major devices in an equipment during starting and stopping or both during other sequential switching operations.

35 Brush Operating or slip ring short circuiting device is used for raising, lowering or shifting the brushes of a machine, or for short-circuiting its slip rings, or for engaging or disengaging the contacts of a mechanical rectifier.

36 Polarity or Polarizing Voltage device operates or permits the operation of another device on a predetermined polarity only or verifies the presence of a polarizing voltage in an equipment.

37 Undercurrent or under power relay functions when the current or power flow decreases below a predetermined value.

38 Bearing Protective device functions on excessive bearing temperature or on other abnormal mechanical conditions, such as undue wear, which may eventually result in excessive bearing temperature.

39 Mechanical Condition monitor is a device that functions upon the occurrence of an abnormal mechanical condition (except that associated with bearings as covered under Device function 38) such as excessive vibration, eccentricity, expansion, shock, tilting or seal failure.

40 Field relay functions on a given or abnormally low value or failure of machine field current, or an excessive value of the reactive component of armature current in an A.C. machine indicating abnormally low field excitation.

41 Field Circuit breaker is a device, which functions to apply, or to remove, the field excitation of a machine.

42 Running Circuit breaker is a device whose principal function is to connect a machine to its source of running or operating voltage. This function may also be used for a device, such as a contactor, that is used in series with a circuit breaker or other fault protecting means, primarily for frequent opening or closing of the circuit.

43 Manual Transfer or Selector device transfers the control circuits so as to modify the plan of operation of the switching equipment or of some of the devices.

44 Unit Sequence starting relay is a device, which functions to start the next available unit in multiple unit equipment on the failure or on the non-availability of the normally preceding unit.

45 Atmospheric Condition monitor is a device that functions upon the occurrence of an abnormal atmospheric condition such as damaging fumes, explosive mixtures, smoke or fire.

46 Reverse phase or Phase balance current relay is a relay which functions when the polyphase currents are of reverse phase sequence, or when the polyphase currents are unbalanced or contain negative phase sequence components above a given amount.

47 Phase sequence Voltage Relay functions upon a predetermined value of polyphase voltage in the desired phase sequence.

48 Incomplete Sequence Relay is a relay that generally returns the equipment to the normal, or off, position and locks it out if the normal starting, operating or stopping sequence is not properly completed within a predetermined time. If the device is used for alarm purposes only, it should preferably be designated as 48A (Alarm).

49 Machine or Transformer Thermal Relay is a relay that functions when the temperature of a machine armature or other load carrying winding or

element of a machine, or the temperature of a power rectifier or power transformer (including a power rectifying transformer) exceeds a predetermined value.

50 Instantaneous over current or rate of rise relay is a relay that functions instantaneously on an excessive value of current, or an excessive rate of current rise, thus indicating a fault in the apparatus or circuit being protected.

51 A.C. Time Over current relay is a relay with either a definite or inverse time characteristic that functions when the current in an A.C. circuit exceeds a predetermined value.

52 A.C. Circuit breaker is a device that is used to close and interrupt an A.C. power circuit under normal conditions or to interrupt this circuit under fault or emergency conditions.

53 Exciter or D.C. generator relay is a relay that forces the D.C. machine field excitation to build up during starting or which functions when the machine voltage has built up to a given value.

54 RESERVED FOR FUTURE APPLICATION

55 Power Factor Relay is a relay that operates when the power factor in an A.C. circuit rises above or drops below a predetermined value.

56 Field Application Relay is a relay that automatically controls the application of the field excitation to an A.C. motor at some predetermined point in the slip cycle.

57 Short circuit or grounding device is a primary circuit switching device that functions to short circuit or to ground a circuit in response to automatic or manual means.

58 Rectification Failure Relay is a device that functions if one or more anodes of a power rectifier fail to fire or to detect an arc back or failure of a diode to conduct or block properly.

59 Over voltage Relay is a relay that functions on a given value of over voltage.

60 Voltage or current balance Relay is a relay that operates on a given difference in voltage, or current input or output of two circuits.

61 RESERVED FOR FUTURE APPLICATION

62 Time Delay stopping or opening relay is a time delay relay that serves in conjunction with the device that initiates the shutdown, stopping or opening operation in an automatic sequence.

63 Pressure switch is a switch, which operates on given values or on a given rate of change of pressure.

64 Ground Protection Relay is a relay that functions on failure of the insulation of a machine, transformer or of other apparatus to ground, or on flash over of a D.C. machine to ground.

Note: This function is assigned only to a relay, which wired to operate the relay in front is always equal to or less than the primary current required to operate the relay behind it.

65 Governor is the assembly of fluid, electrical or mechanical control equipment used for regulating the flow of water, steam or other medium to the prime mover for such purposes as starting, holding speed or load or stopping.

66 Notching or Jogging device functions to allow only a specified number of operations of a given device or equipment or a specified number of successive operations within a given time frame. It also functions to energise a circuit periodically or for fractions of a specified time interval or that used to permit intermittent acceleration or jogging of a machine at low speeds for mechanical positioning.

67 A.C Direction or Over-current Relay is a relay that functions on a desired value of A.C over-current flowing in a predetermined direction.

68 Blocking relay is a relay that initiates a pilot signal for blocking of tripping on external faults in a transmission line or in other apparatus under predetermined conditions or co-operates with other devices to block tripping or to block re-closing on an out of step condition or on power swings.

69 Permissive control device is generally a two position manually operated switch that in one position permits the closing of a circuit breaker or the placing of equipment into operation and in the other position prevents the circuit breaker or the equipment from being operated.

70 Rheostat is a variable resistance device used in an electric circuit, which is electrically operated or has other electrical accessories, such as auxiliary position or limit switches.

71 Level switch is a switch, which operates on given values, or on a given rate of change of level.

72 D.C Circuit breaker is used to close and interrupt a D.C power circuit under normal conditions or to interrupt this circuit under fault or emergency conditions.

73 Load Resistor contactor is used to shunt or insert a step of load limiting, shifting, or indicating resistance in a power circuit or to switch a space heater in circuit or to switch a light, or regenerative load resistor of a power rectifier or other machine in and out of circuit.

74 Alarm relay is a device other than an Annunciator, as covered under Device No. 30, which is used to operate in connection with a visual or audible alarm.

75 Position Changing mechanism is a mechanism that is used for moving a main device from one position to another in an equipment as for example, shifting a removable circuit breaker unit to and from the connected, disconnected and test positions.

76 D.C. Over-current relay is a relay that functions when the current in a D.C circuit exceeds a given value.

77 Pulse Transmitter is used to generate and transmit pulses over a telemetering or pilot wire circuit to the remote indicating or receiving device.

78 Phase angle measuring or out of step protective relay is a relay that functions at a predetermined phase angle between two voltages or between two currents or between voltage and current.

79 A.C. Reclosing relay is a relay that controls the automatic re-closing and locking out of an A.C. circuit interrupter.

80 Flow Switch is a switch, which operates on given values or on a given rate of change of flow.

81 Frequency Relay is a relay that functions on a predetermined value of frequency either under or over or on normal system frequency or rate of change of frequency.

82 D.C. Reclosing relay is a relay that controls the automatic closing and re-closing of a D.C. circuit interrupter, generally in response to load circuit conditions.

83 Automatic Selective control or Transfer relay is a relay that operates to select automatically between certain sources or conditions in an equipment or performs a transfer operation automatically.

84 Operating mechanism is the complete electrical mechanism or servo-mechanism, including the operating motor, solenoids, position switches,

etc., for a tap changer, induction regulator or any similar piece of apparatus which has no device function number.

85 Carrier or Pilot Wire Receiver Relay is a relay that is operated or restrained by a signal used in connection with the carrier current or D.C pilot wire fault directional relaying.

86 Locking out relay is an electrically operated hand or electrically reset relay that functions to shut down and hold an equipment out of service on the occurrence of abnormal conditions.

87 Differential Protective Relay is a protective relay that functions on a percentage or phase angle or other quantitative difference of two currents or of some other electrical quantities.

88 Auxiliary motor or motor generator is one used for operating auxiliary equipment such as pumps, blowers, exciters, rotating magnetic amplifiers etc.

89 Line switch is used as disconnecting load interrupter or isolating switch in an A.C or D.C power circuit when this device is electrically operated or has electrical accessories such as an auxiliary switch, magnetic lock etc.

90 Regulating device functions to regulate a quantity or quantities such as voltage, current, power, speed, frequency, temperature and load at a certain value or between certain (generally close) limits for machines, tie lines or other apparatus.

91 Voltage directional relay is a relay that operates when the voltage across an open circuit breaker or contactor exceeds a given value in a given direction.

92 Voltage and power directional relay is a relay that permits or causes the connection of two circuits when the voltage difference between them exceeds a given value in a predetermined direction and causes these two circuits to be disconnected from each other when the power flowing between them exceeds a given value in the opposite direction.

93 Field changing contactor functions to increase or decrease in one-step the value of field excitation on a machine.

94 Tripping or trip free relay functions to trip a circuit breaker, contactor or equipment or to permit immediate tripping by other devices; or to prevent immediate re-closure of a circuit interrupter, in case it should open automatically even though its closing circuit is maintained closed.

95 USED ONLY FOR SPECIFIED APPLICATIONS ON INDIVIDUAL

96 INSTALLATIONS WHERE NONE OF THE ASSIGNED NUMBERED

97 FUNCTIONS, 1 TO 94, ARE SUITABLE.

DEVICES PERFORMING MORE THAN ONE FUNCTION

If one device performs two relatively important functions in an equipment so that it is desirable to identify both of these functions, this may be done by using a double device function such as: **50/51** - An over-current relay with an instantaneous element and an inverse element.

SUFFIX NUMBERS

If two or more devices with the same function number and suffix letter (if used) are present in the same equipment then these are distinguished as follows 52x-1, 52x-2, 52x-3 etc

SUFFIX LETTERS

Suffix letters are used with device numbers for various purposes. The meaning of each suffix letter or combination of letters should be clearly indicated in the legend on the drawings or publications accompanying the equipment. This is to avoid possible confusion. These letters should be written directly after the device function number to indicate that they are a part of the device.

Commonly used letters are as follows:

R	-	Raising relay or for remote operation
L	-	Lowering relay or for local operation
O	-	Opening relay or contactor
C	-	Closing relay or contactor
CS	-	Control Switch

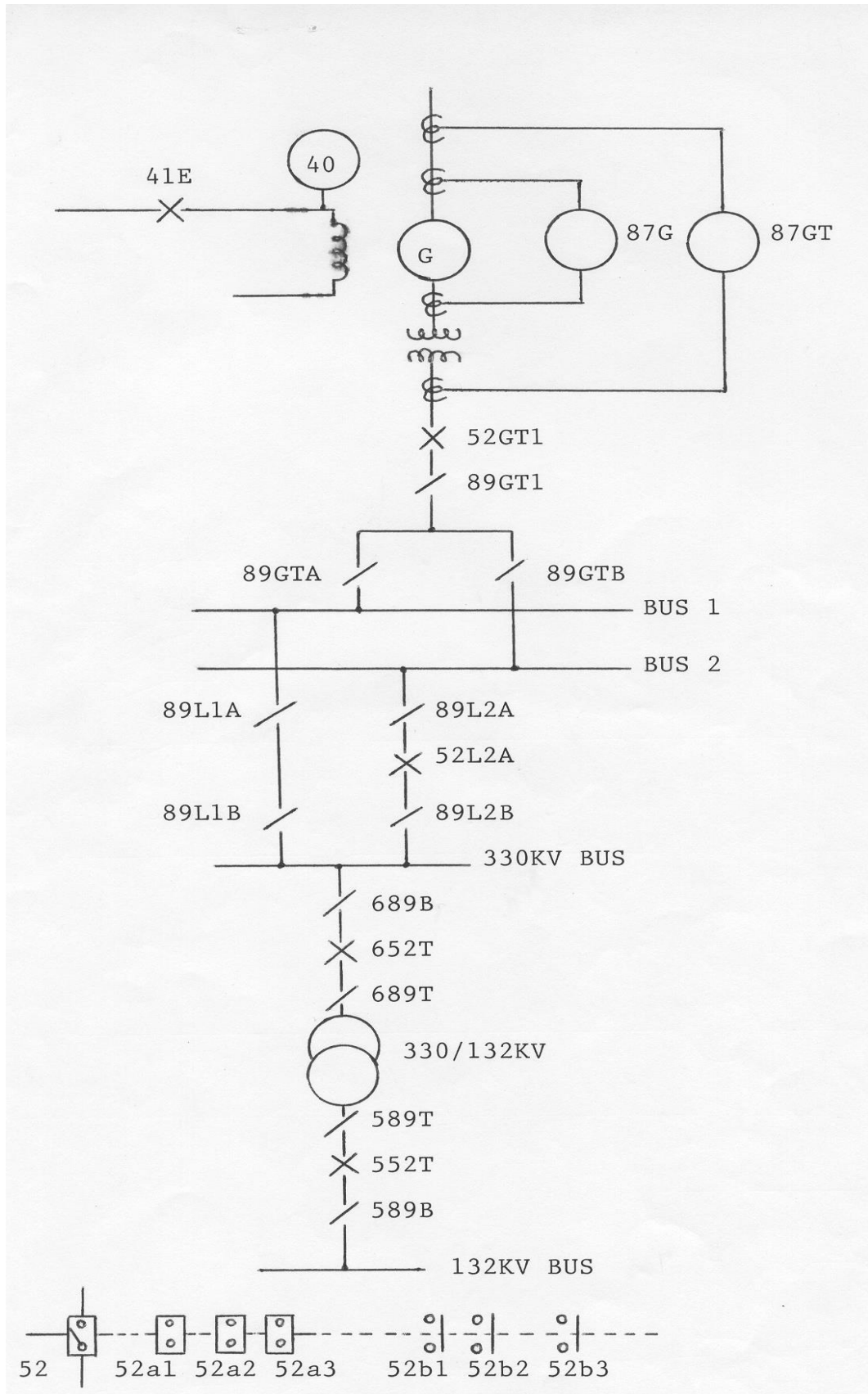
CC	-	Closing Coil
TC	-	Trip Coil
PB	-	Push Button
G	-	Generator
T	-	Transformer
L	-	Line
F	-	Feeder etc

Example: **52 TC** – Tripping coil of the breaker.

REPRESENTATION OF DEVICE CONTACTS

There are almost in all electrical devices, particularly in circuit breakers and relays, a set of contacts which are normally open and another set of contacts which are normally closed. When the device operates, the contact position reverses. Those normally open become closed and vice versa. These are generally indicated as 'a' and 'b' contacts. When the device has not operated or de-energized or open contacts, they are designated thus:

Normally Open (NO) contacts – 'a' Normally Closed (NC) contacts – 'b'



CHAPTER TWO

CONTROL CIRCUITS

INTRODUCTION

During power system faults, devices are used for fast isolation of affected equipment to save them from damage. Special circuits called control circuits are used to realize the above objective. Control circuits are used for other functions besides switching on or off of circuit breakers and isolators as enumerated below:

1. Voltage raise or lower in tap changer device of power transformers.
2. Frequency regulation and load control.
3. Power system monitoring such as power factor control.
4. Alarm and indication control.
5. Circuit supervision.
6. Audio/visual annunciation.

B. CONTROL SYMBOLS AND ALPHABETS

In order to make for easy identification, symbols and alphabets are used for various devices in control circuits. This method helps to simplify the control drawings. Control symbols and alphabets generally used are as shown in Table 1. A clear knowledge of these facilitates the understanding of the control drawings.

CONTROL CIRCUIT SUPPLIES

To effect operation of control circuits, external auxiliary power supplies are used. Two major sources of supplies are most common namely:

- D.C. supply
- A.C. supply

D. C. SUPPLY

The major source of D. C. supply is from a storage battery. The storage battery types commonly used are:

- (a) Lead Acid Accumulator type
- (b) Nickel Cadmium type.

Auxiliary D.C. supply has standard voltage ratings of 24V, 30V, 36V, 48V, 50V, 60V, 72V, 110V, 220V and 250V. Generally 110V is used for Trip/Close control. In some cases a combination of 50V and 110V D.C. are used. In this case the relay coil energizes an auxiliary interposing relay whose contacts make to energize an 110V D.C. breaker trip/close coil which in turn opens/closes the contacts of a breaker.

Standard ampere-hour ratings of auxiliary D.C. supply are 45, 60, 100, 250, 500 and 1000AH.

The voltage rating and the Ampere-Hour rating are decided by:

- (i) The size and capacity of the generating station and or substations.
- (ii) The bus bar switching arrangement, which decides the number of circuit breakers and isolators.

- (iii) The location of the control equipment in regard to the location of the controlled apparatus i.e. the distance from the control room to the controlled apparatus.

In most 11KV, 33KV and 132KV substations in NEPA, 110V DC batteries are installed. In 330KV substations, both 50V DC and 110V DC batteries are used for control circuits.

The ampere-hour rating range between 100 and 250 AH.

A D. C. distribution panel is generally associated with a D. C storage battery. The size of the panel depends upon the number of individual circuits it serves. A Non-fused breaker usually protects each sub-circuit of the distribution panel, which trips as soon as a fault exists along the circuit being protected.

To protect the D. C. circuits from ground fault, a ground fault relay is installed which usually flags whenever there is a ground fault within any of the poles of the D.C circuits. For example, if there is a fault within the positive pole of the D. C. circuits, the D.C. ground positive target of the ground fault relay will operate. The relay will not reset except the source of the fault is cleared. In some cases, the fault signal is wired to a visual alarm, which will indicate the actual pole that is faulty. In some installations, a switch is used to monitor the amount of voltage leaking to ground.

Under normal conditions P-E and N-E voltages are equal. But a pole loses the voltages to ground if faulty.

A.C. SUPPLY

The A.C. supply for the control circuits is obtained from a station auxiliary transformer. This, in the case of generating units, may be directly connected to the generator terminals as unit auxiliary transformers.

A standby A.C generator is also used as an alternate source of A.C. supply for control circuits. In stations where A.C. supply is to be reliable, there could be two sources from which auxiliary supply is obtained with an automatic change – over switch. In this case, if supply from one source fails then, supply from the other source is readily available. The alternative source could be another auxiliary transformer from a separate source, D.C. motor, A.C. generator set, or battery inverter circuit.

In control circuits, A.C. supply could serve the following purposes:

- (a) Control panel illumination
- (b) Control panel heater
- (c) Breaker spring operating motor.
- (d) Breaker control panel heater and illumination.
- (e) Control panel indication lamps
- (f) Audio/visual annunciation
- (g) OLTC gear motor operation in power transformers
- (h) Position indication for tap – changer progress.

TRIP CIRCUIT

The control circuit for the opening of switchgear during normal operation or on fault is usually known as Trip Circuit.

To ensure that this circuit does not fail whenever a signal is sent to operate the breaker/disconnect switch, it is being monitored continuously by a relay known as Trip Circuit Supervision relay. The relay is wired in such a way that the relay coil is energized as long as the trip circuit is healthy. If for any reason there is a fault within the trip circuit causing a loss of D.C. supply, this relay de-energises causing the mechanical target to flag, which will indicate, "Trip circuit faulty". This relay is usually a self-reset relay, which resets itself as soon as the D.C. supply is restored. D.C. supply can also be lost if the battery charger is faulty or the D.C. fuse gets ruptured as a result of a short-circuit fault within the D.C. circuit. A control scheme showing the trip circuit supervision wiring is as shown in Figs. 1 and 2.

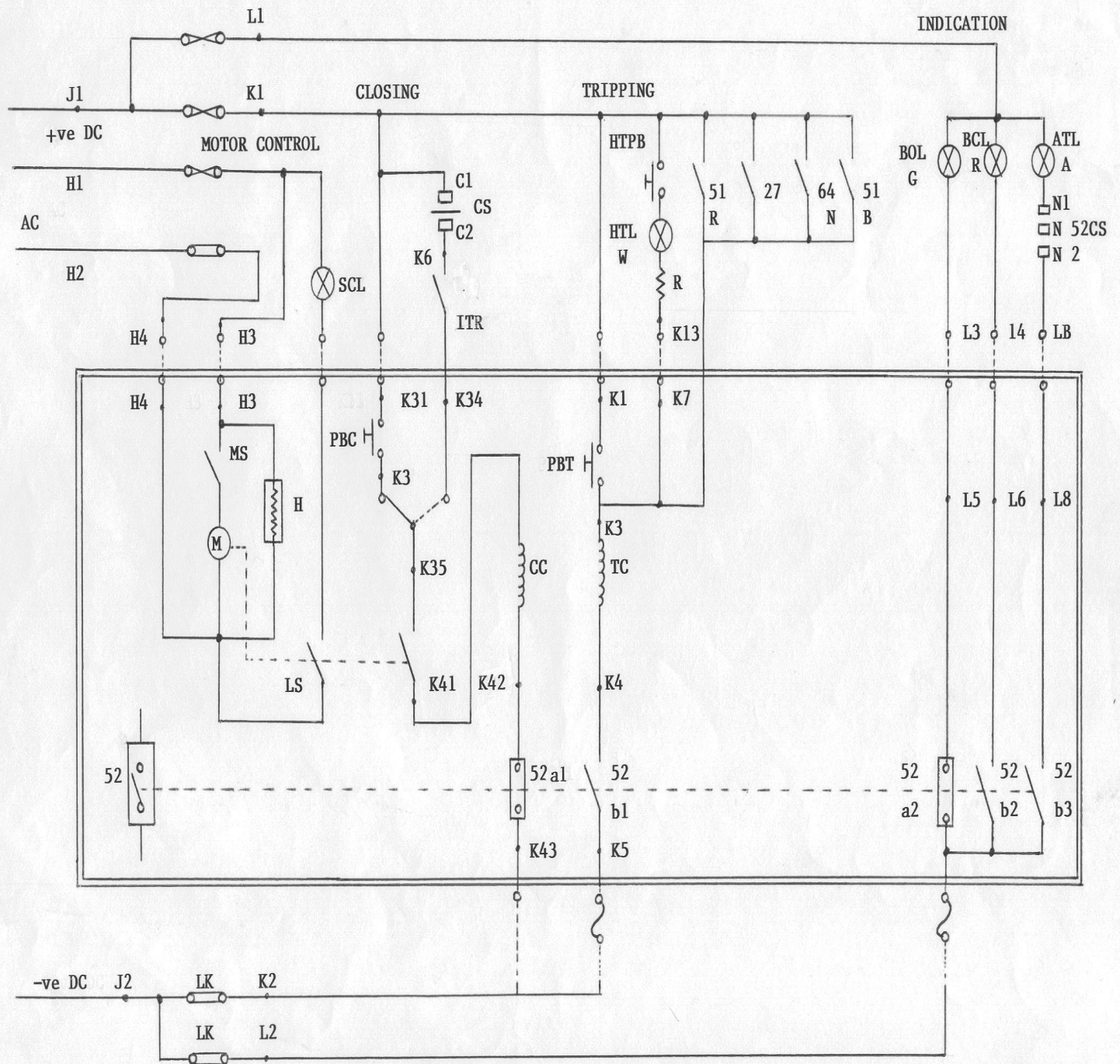
CONTROL SYMBOLS AND ALPHABETS

Table 1

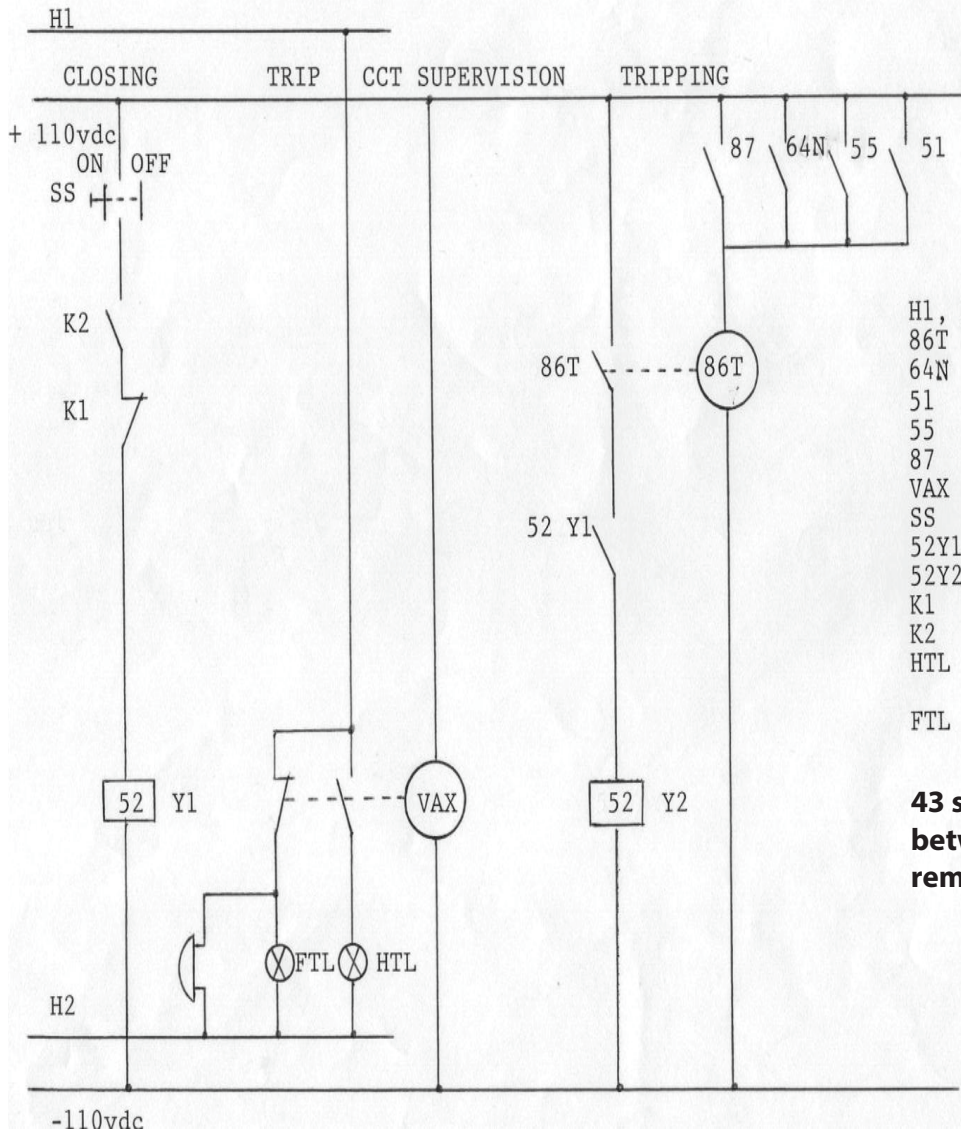
SYMBOL	N A M E	SYMBOL	N A M E	ALPHABET	N A M E
	Normally closed contact		Metrosil voltage dependent	YB;RWB UVW;RST ABC;H1 H2 H3;X1,X2, X3.	Three phase A.C. supply
	Normally open contact		Relay coil		
	Control switch		Transistor	J1,J2	Positive negative of D.C. supply
	Push button		System grounding	L-N	Single phase A.C. Supply
	Circuit breaker		Positive pole		
	Isolator		Negative pole of D.C. voltage	N	A.C neutr-al
	Power and distribution transformer		Hooter	A10-A11-R A30-A31-Y A50-A51-B	Protection C.T sec. of higher accuracy class or major protection C.T. Secondary
	Current transformer		Bell motor		
	Voltage transformer		AC Heater		

SYMBOL	N A M E	SYMBOL	N A M E	ALPHABET	N A M E
	Capacitive Voltage Transformer		Contactor		
	Indicating Lamps		Relay		
	Resistor		Power generator	C10-C11-R C30-C31-Y C50-C51-B	Protection secondary of lower accuracy class or sec. backup protection
	Variable Resistor or Rheostat		DC Voltage		
	Inductor		AC Voltage		
	Variable Inductor		Relay with Timer		
	Capacitor		Tripping/closing coil	D10-D11-R D30-D31-Y D50-D51-B	Metering CT secondary
	Variable Capacitor		Test socket		
	Plug-in contact or draw out contact			E10-E11-R E30-E31-Y E50-E51-B	Voltage Transformer secondary
	Link				
	Fuse				
	Diode				
	Zener Diode				
	Thyristor				

FIG. 2: TYPICAL CONTROL SCHEME FOR CLOSING/TRIPPING OF CIRCUIT BREAKERS



TYPICAL CONTROL SCHEME FOR CLOSING/TRIPPING OF CIRCUIT BREAKER



LEGEND

- H1, H2 - Aux. a.c single phase supply
- 86T - Trip relay
- 64N - Neutral E/F relay
- 51 - O/C relay
- 55 - Distance relay
- 87 - Differential relay
- VAX - Trip circuit supervision relay
- SS - Selector switch
- 52Y1 - Breaker closing coil
- 52Y2 - Breaker tripping coil
- K1 - Anti-pumping device
- K2 - SF6/Air pressure
- HTL - Healthy trip circuit supervision
- FTL - Faulty trip circuit supervision

43 switch that toggles between local trip and remote trip

LEGEND FOR FIG. 2

H ₁ - H ₂	- Auxiliary A.C. Single phase supply
M	- Spring charging motor
MS	- Motor control switch
H	- Heater
PBC, PBT	- Push button (close/open)
52 CS	- Control switch for circuit breaker
LS	- Limit switch
LSS	- Local selector switch
LCS	- Local control switch
RSS	- Remote selector switch
L/R	- Local/remote position
CC / TC	- Closing/Trip coil
ITR	- Inter-tripping Relay (optional)
HTPB	- Healthy trip push button
HTL	- Healthy trip supervision lamp
BOL	- Breaker open lamp
BCL	- Breaker close lamp
ATL	- Auto trip lamp
52a, b	- Circuit breaker auxiliary contacts
51	- Over current relay
64N	- Earth fault relay.

CHAPTER THREE

FAULT STUDY, ANALYSIS AND SHORT CIRCUIT CALCULATIONS, FAULT DETECTION

LEARNING OUTCOMES

- **Know the different fault types and causes**
- **Know the two classes of faults**
- **Know the parameters for characterizing faults**
- **Know how ground faults interact with fault characteristics**
- **Understand the application of manual fault calculations**
- **Perform Manual Fault Calculations**
- **Know the utility and application of Per Unit and Percentage system**
- **Know the different fault detecting Methods for overhead/ underground distribution systems**
- **Know the theory behind some fault detection methods**

1. Introduction

It is highly impossible to design a fault proof power system, as it is neither practical nor economical. Modern power systems, constructed with as high insulation level as is economically practical, have sufficient flexibility so that one or more components may be out of service with a minimum interruption of service. Though faults occur principally due to failure of insulation, yet faults can also result from electrical, mechanical, thermal failures or from any combination of these.

2. Fault Types and Causes

The major types and causes of failures are listed in the table below.S/N	TYPES	CAUSES
1	Insulation	- Design defects or errors - Manufacturing defects or improper methods in manufacture - Improper installation - Ageing and deterioration - Thermal over stressing - Voltage over stressing - Mechanical fracture - Chemical decomposition

S/N	TYPES	CAUSES
2	Electrical	- Lightning surges - Switching surges - Dynamic over voltages
3	Mechanical	- Wind - Snow or ice - Atmospheric pollution and contamination (in industrial areas)
4	Thermal	- Over current - Over voltage
5	Others	- Uprooting of trees (and falling on lines) - Bird faults - Bush fires (shorting of lines together or to ground) - Kite flying - Sabotage

2.1 Electrically, all the above types of faults fall in one or the other of the following categories:

(a) Three phase fault]	Symmetrical faults
(b) Three phase fault to ground	Unsymmetrical faults
(c) Phase to phase	
(d) Two phase fault to ground	

- (e) Single phase fault to ground _____
 - (f) One phase broken wire
 - (g) Two phase broken wire
- } Open conductor faults

2.3 The faults listed in (a) to (e) above are also called short-circuit faults or short-circuit between phases and or to ground as the case may be. These faults cause damage to life, property and equipment and as such have to be cleared as fast as is practically possible.

Faults listed in (f) and (g) are not faults in the strict sense of it as they do not pose a danger to life, property and equipment. They constitute an abnormal operating condition in the system affecting the quality of service and if not taken care of can, over a period of time, affect the equipment resulting in an electrical fault.

3.0 Characteristics of Faults

3.1 A fault is characterized by:

- (a) Magnitude of the fault current
- (b) Power factor or phase angle of the fault current

3.2 The magnitude of the fault current depends upon:

- (a) The capacity and magnitude of the generating sources feeding into the fault
- (b) The system impedance up to the point of fault or source impedance behind the fault
- (c) Type of fault

(d) System grounding, number and size of overhead ground wires

(e) Fault resistance or resistance of the earth in the case of ground faults and arc resistance in the case of both phase and ground faults.

3.3 The phase angle of the fault current is dependent upon:

(a) For phase faults: - the nature of the source and connected circuits up to the fault location and

(b) For ground faults: - the type of system grounding in addition to (a) above.

3.4 The current will have an angle of 80 to 85° lag for a phase fault at or near generator units. The angle will be less out in the system, where lines are involved.

Typical open wire transmission line angles are as follows:

(a) 7.2 to 23KV - 20 to 45° lag

(b) 23 to 69KV - 45 to 75° lag

(c) 69 to 230KV - 60 to 80° lag

(d) 230KV and above - 75 to 85° lag

At these voltages, the currents for phase faults will have the angles shown where the line impedance predominates. If the transformer and generator impedances predominate, the fault angles will be higher. Systems with cables can have lower angles if the cable impedance is a large part of the total impedance to the fault.

However the importance of this phase angle is only in distance relay applications.

3.5 System grounding

This significantly affects both the magnitude and phase angle of ground faults. There are three classes of grounding namely:

- (a) Ungrounded or isolated neutral
- (b) Impedance grounding (resistance or reactance)
- (c) Effectively grounded (neutral solidly grounded)

3.6 Fault resistance

- (a) In phase-to-phase faults, unless the fault is solid, an arc whose resistance varies with the arc length and the magnitude of the fault current is usually drawn through air. Several studies have indicated that for currents in excess of 100 Amps, the voltage across the arc is nearly constant at an average of approximately 440 volts/ft. Arc resistance is seldom an important factor in phase faults except at low system voltages. The arc does not elongate sufficiently for the phase spacing involved in present day line phase-to-phase spacing to decrease the current flow materially. In addition, the arc resistance is at right angles to the line reactance and hence may not greatly increase the system impedance.
- (b) Arc resistance may be an important factor in ground faults. With high tower footing resistance, longer arcs can occur which may appreciably limit the fault current.

- (c) However the importance of the arc resistance arises only in distance relay application and in application of auto reclosing schemes.

3.7 Types of Faults

Except for a few special conditions, the maximum current flows in the case of three-phase, symmetrical faults. The situations under which the fault currents may possibly be greater than under a symmetrical three-phase fault are:

- (a) **Between one line and earth** - Assuming an earthed neutral and no impedance in the earth, the current may be as much as 50% greater than that of 3 phase symmetrical faults depending upon system configuration and machine characteristics. Single line to ground fault currents greater than 3 phase symmetrical faults are come across near generating stations or near large interconnected substations.
- (b) **Between two lines** - This again is dependent upon the system configuration and machine characteristics. It may be about 15% greater than that of a 3 phase symmetrical fault current with zero fault impedance. The worst conditions occur in very high voltage installation near a generating station.
- (c) **Between two lines and earth** - Here again, it is dependent upon the system configuration and machine characteristics. It may

achieve a maximum current value of about 25% greater than the corresponding 3 phase symmetrical value with zero external earth impedance and may achieve a value around 15% of (b) above, if the earth impedance approaches or is near infinity.

4.0 Necessity for fault calculations

Fault calculations are done primarily for the following:

- (a) To determine the maximum fault current at the point of installation of a circuit breaker and to choose a standard rating for the circuit breaker (rupturing)
- (b) To select the type of circuit breaker depending upon the nature and type of fault.
- (c) To determine the type of protection scheme to be deployed.
- (d) To select the appropriate relay settings of the protection scheme.
- (e) To co-ordinate the relay settings in the overall protection scheme of the system.

5.0 Fault Calculations

5.1 The fault calculations are done to meet the requirements in paragraph (4) above not only for the present system requirement but also to meet:

- (a) The future expansion schemes of the system such as addition of new generating units
- (b) Construction of new transmission lines to evacuate power.
- (c) Construction of new lines to meet the load growth and or

(d) Construction of interconnecting tie lines.

5.2 The calculations pertaining to unsymmetrical faults are done using symmetrical components and also taking into consideration the sub transient and transient reactances of rotating machines such as generators and synchronous motors. However for the purpose of this course it is considered not necessary to delve into details of symmetrical components, as this would require a course by itself.

As such, in this course fault calculations are limited to symmetrical faults and under steady state conditions of machine characteristics.

5.3 Nevertheless, it would not be out of place to mention that in a large interconnected power system, such fault calculations are today being handled using a digital computer and a couple of years back, with the aid of a 'Network Analyzer'.

The long hand method is tedious, time consuming and may lead to human errors etc.

5.4 Basically, there are two approaches to fault calculations. These are:

- (a) Actual reactance or impedance method
- (b) Percentage reactance or impedance method or per unit (p.u) reactance or impedance method.

5.5 Accordingly there are certain basic formulae, which one has to be aware of in fault calculations. Besides, machine and transformer impedances or reactances are always noted in percentage values on the nameplate.

Hence the latter method described in 5.4 (b) is in vogue. Again, as already described in paragraph 5.1, fault levels are computed at all the substations for the present system conditions and also for the future conditions as set out in paragraph 5.1.

The approach here is the long hand method, which is practicable only for simple cases.

5.6 Per Unit and Percentage System formulae

5.6.1 Definitions

Z, X, R = Actual impedance, reactance and resistance in ohms

$$\% Z \text{ or } X \text{ or } R = \frac{I_{fl} \times Z \text{ or } X \text{ or } R \times 100}{V_{ph}}$$

$$Z \text{ p.u.} = \frac{\% Z}{100}; \text{ similarly for } X_{p.u} \text{ or } R_{p.u}$$

where p.u = per unit.

(KVA) base = Base KVA (3phase) in kilovolt amps.

(KV) base = Base KV (line to line) in kilovolts.

I base = Base current in amperes

Z base = Base impedance in ohms

Z p.u = Per Unit Impedance

I_{fl} = Full load current in amperes

V_{ph} = Phase voltage in volts.

Basic Formulae

From ohm's law

$$Z = \frac{V}{I}$$

The base impedance is given by

$$Z_{\text{base}} = \frac{V_{\text{ph}}}{I_{\text{fl}}}; \quad Z_{\text{base}} = \frac{V_{\text{base}}}{I_{\text{base}}} \quad - 1$$

$$\frac{Z_{\text{base}}}{Z} = \frac{V_{\text{ph}}}{I_{\text{fl}}} \times \frac{1}{Z}$$

$$\frac{Z}{Z_{\text{base}}} = \frac{I_{\text{fl}} \times Z}{V_{\text{ph}}} = Z_{\text{p.u.}} \quad - 2$$

$$\frac{Z}{Z_{\text{base}}} = Z_{\text{p.u.}} \quad - 3$$

From eqn. 2

$$Z_{\text{p.u.}} = \frac{I_{\text{fl}} \times Z}{V_{\text{ph}}}$$

Recall that:

$$V_{\text{ph}} = \frac{V_{\text{line}}}{\sqrt{3}} = \frac{\text{KV line}}{\sqrt{3} \times 1000} \quad - 4$$

$$I_{\text{fl}} = \frac{\text{KVA}}{\sqrt{3} \times \text{KV}} \quad - 5$$

Substituting eqns. 4 + 5 into 2

$$\begin{aligned} Z_{\text{p.u.}} &= \frac{\frac{\text{KVA}}{\sqrt{3} \times \text{KV}} \times Z}{\frac{\text{KV}}{\sqrt{3} \times 1000}} \\ &= \frac{1000 \text{ KVA} \times Z}{(\text{KV})^2} \end{aligned}$$

$$Z_{p.u} = \frac{Z \text{ (MVA)}}{(KV)^2} \quad - 6$$

From eqns. 4 + 5

$$I_{fl} = \frac{KVA}{\sqrt{3} \times KV} \quad I \text{ base} = \frac{(KVA) \text{ base}}{\sqrt{3} \times (KV) \text{ base}}$$

$$V_{ph} = \frac{KV}{\sqrt{3} \times 1000} \quad V \text{ base} = \frac{(KV) \text{ base}}{\sqrt{3} \times 1000}$$

From eqns 1 + 2

$$Z_{base} = \frac{V \text{ base}}{I \text{ base}}$$

$$\frac{Z}{Z_{base}} = Z_{p.u}$$

Substituting

$$\begin{aligned} Z_{base} &= \frac{\frac{(KV) \text{ base}}{\sqrt{3} \times 1000}}{\frac{(KVA) \text{ base}}{\sqrt{3} \times (KV) \text{ base}}} \\ &= \frac{(KV) \text{ base} \times (KV) \text{ base}}{1000 \times (KVA) \text{ base}} \end{aligned}$$

$$Z_{base} = \frac{(KV)^2 \text{ base}}{(MVA) \text{ base}} \quad - 7$$

$$Z_{p.u} = \frac{Z}{Z_{base}} = \frac{Z}{\frac{(KV)^2 \text{ base}}{(MVA) \text{ base}}}$$

$$Z_{p.u} = \frac{Z \text{ (MVA) base}}{(KV)^2 \text{ base}}$$

Conversions

From eqns (6) + (7)

$$Z_{base} = \frac{(KV)^2 \text{ base}}{(MVA) \text{ base}}$$

$$Z_{base} \propto (KV)^2 \text{ base}$$

$$Z_{p.u} = \frac{Z (MVA)}{(KV)^2}$$

$$Z_{p.u} \propto \frac{1}{(KV)^2} \propto MVA$$

$$Z_{p.u. (base)} = \frac{K}{(KV)^2 \text{ base}} = K (MVA) \text{ base}$$

$$Z_{p.u (base)} \times (KV)^2 \text{ base} = K \quad - 1$$

$$\text{Also } \frac{Z_{p.u (base)}}{MVA \text{ base}} = K \quad - 2$$

Converting to new voltage base in eqn. 1

$$\begin{aligned} Z_{p.u (base2)} \times (KV)^2 (base2) &= Z_{p.u (base1)} \times (KV)^2 (base1) \\ &= K \end{aligned}$$

$$Z_{p.u (base2)} = Z_{p.u (base1)} \times \frac{(KV)^2 \text{ base1}}{(KV)^2 \text{ base2}}$$

Converting $Z_{p.u}$ to new MVA or KVA base in eqn. 2

$$\frac{Z_{p.u (base1)}}{MVA (base1)} = \frac{Z_{p.u (base2)}}{MVA (base2)}$$

$$Z_{p.u (base2)} = Z_{p.u (base1)} \times \frac{MVA (base2)}{MVA (base1)}$$

Similarly,

$$Z_{p.u} (\text{base2}) = Z_{p.u} (\text{base1}) \times \frac{\text{KVA} (\text{base2})}{\text{KVA} (\text{base1})}$$

Converting Z in ohms to new voltage base:

$$Z \text{ base} \propto (KV)^2 \text{ base}$$

$$Z \text{ base} = K (KV)^2 \text{ base}$$

$$\frac{Z (\text{base1})}{(KV)^2 \text{ base1}} = \frac{Z (\text{base2})}{(KV)^2 \text{ base2}} = K$$

$$Z (\text{base2}) = Z (\text{base1}) \times \frac{(KV)^2 \text{ base2}}{(KV)^2 \text{ base1}}$$

MAGNITUDE OF FAULT CURRENT I_F AND FAULT MVA

$$\text{Fault MVA} = \frac{\text{Base MVA}}{Z_{p.u} \text{ up to the point of fault}}$$

$$\text{Fault current } I_F = \frac{\text{Fault MVA} \times (10)^3}{\sqrt{3} \times KV}$$

EXAMPLES ON FAULT CALCULATIONS

- (1) To calculate the p.u impedance and % impedance of a transmission line at

100 MVA base

Line voltage 330 KV

Line length 200 Kms

Line resistance /Km = 0.06 ohms/Km

Line reactance /Km = 0.4 ohms/Km

$$Z = R + jX$$

For the 200kms line length

$$Z = 200 (0.06 + j 0.4)$$

$$= 12 + j 80$$

$$|Z| = \sqrt{[(12)^2 + (80)^2]} = 80.895 \text{ ohms}$$

$$Z_{p.u} = Z \times \frac{\text{MVA base}}{(\text{KV})^2 \text{ base}}$$

$$= \frac{80.895 \times 100}{(330)^2}$$

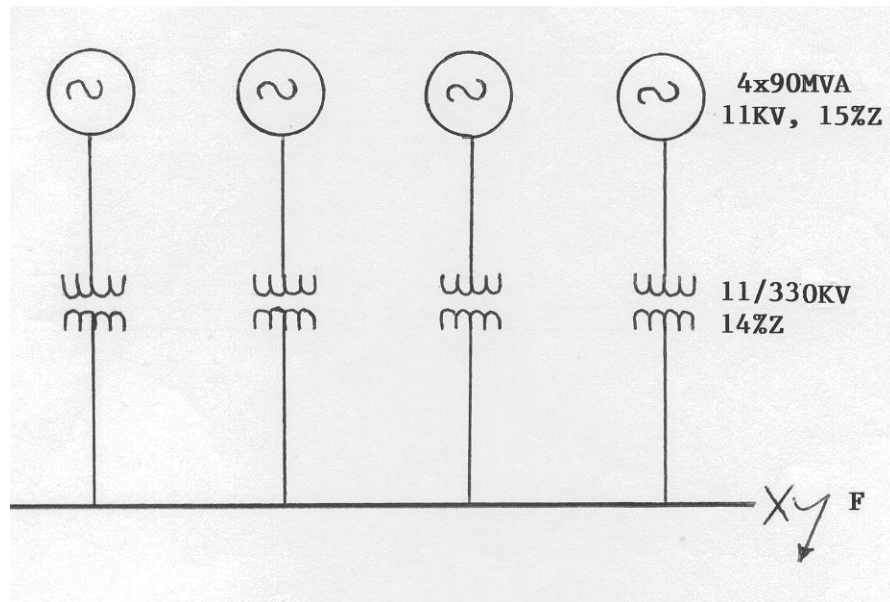
$$= 0.0743 \text{ p.u}$$

$$\%Z = 0.074 \times 100$$

$$= 7.43$$

(2) To calculate the p.u impedance to a 100 MVA base

Given four generators; 90MVA, 11KV of 15% impedance each connected to step up transformers of 90MVA 11KV/330KV of 14% impedance. Calculate the fault current at F.



Assumed MVA = 100

%Z generators = 15 on 90 MVA base

or Z_g p.u = 0.15 on 90 MVA base

Z_g p.u on 100 MVA base will be:

$$(Z_g \text{ p.u})_{\text{base2}} = (Z_g \text{ p.u})_{\text{base1}} \times \frac{\text{MVA base2}}{\text{MVA base1}}$$

$$\begin{aligned} (Z_g \text{ p.u})_{100} &= 0.15 \times \frac{100}{90} \\ &= 0.167 \end{aligned}$$

%Z transformers = 14 on 90 MVA base

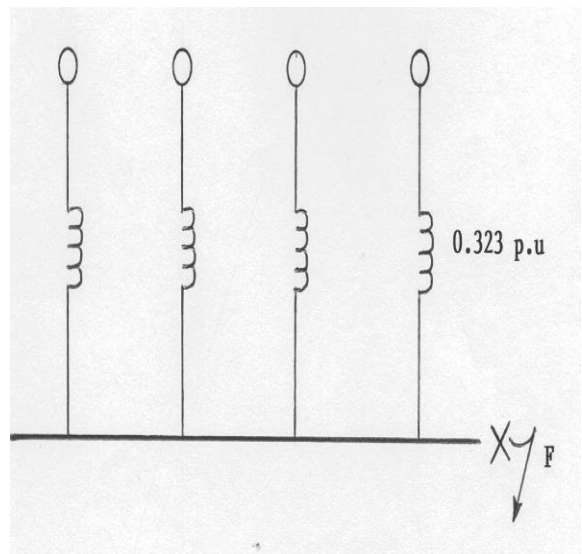
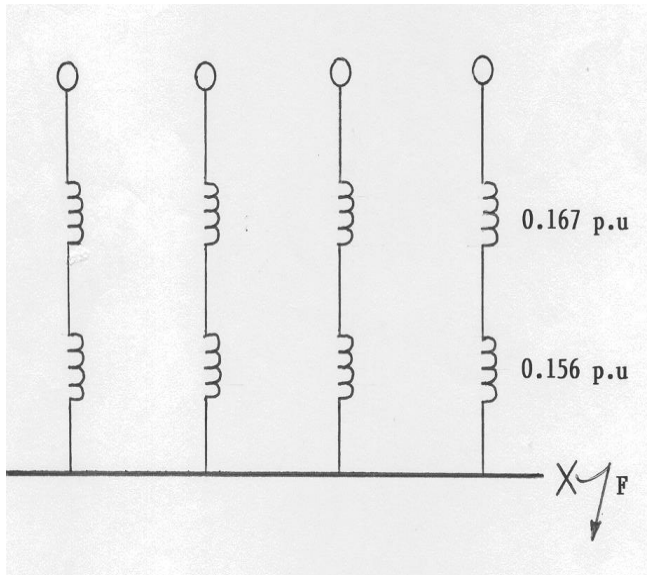
or Z_t p.u = 0.14 on 90 MVA base

Z_t p.u on 100 MVA base will be:

$$(Z_t \text{ p.u})_{\text{base2}} = (Z_t \text{ p.u})_{\text{base1}} \times \frac{\text{MVA base2}}{\text{MVA base1}}$$

$$\begin{aligned} (Z_t \text{ p.u})_{100} &= 0.14 \times \frac{100}{90} \\ &= 0.156 \end{aligned}$$

The system reduces as follows



$$Z_{\text{total}} = \frac{0.323}{4}$$

$$= 0.08075$$

Total p.u impedance at F = 0.08075 = Z_{total}

$$\text{Fault MVA at F} = \frac{\text{Base MVA}}{Z_{\text{total}}}$$

$$= \frac{100}{0.08075} \text{ MVA}$$

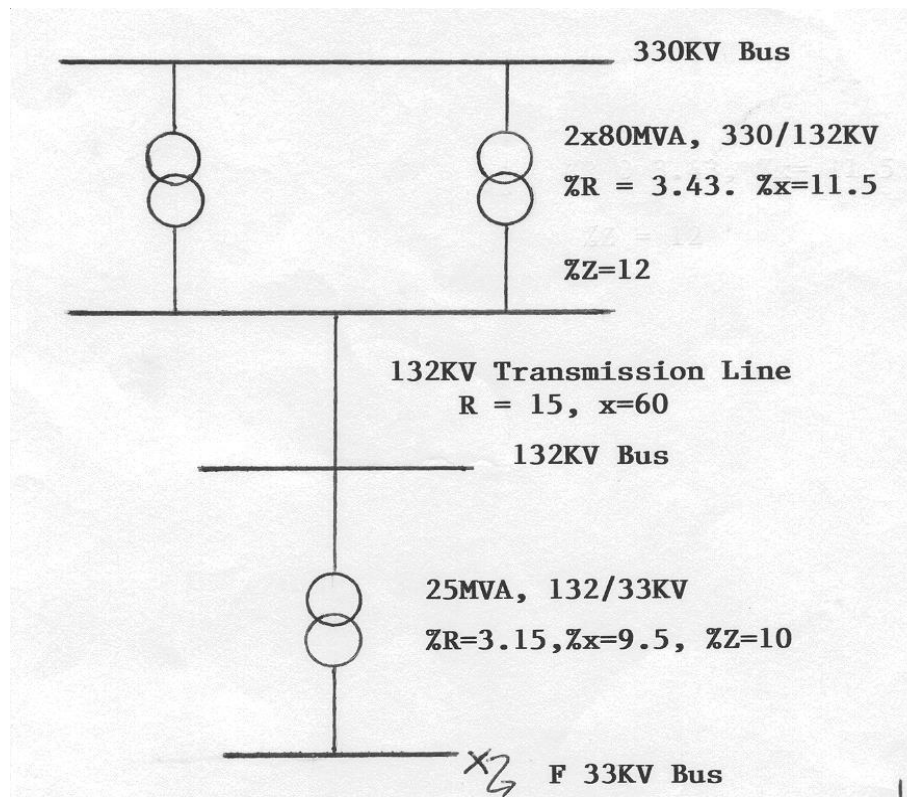
$$= 1238.4 \text{ MVA}$$

$$\text{Current at F} = \frac{\text{Fault MVA} \times (10)^3}{\sqrt{3} \times \text{system voltage (KV) at point of fault}}$$

$$= \frac{1238.4 \times (10)^3}{\sqrt{3} \times 330}$$

$$= 2166.638 \text{ Amps}$$

6.3 To calculate the fault MVA and fault current of a system at 33KV given the fault level at the 330KV bus, as 5000MVA.



Assume 100 MVA base

$$\text{Fault MVA} = \frac{\text{Base (MVA)}}{Z_{p.u}}$$

$$5000 = \frac{100}{Z_{p.u}}$$

$$Z_{p.u} = \frac{100}{5000} = 0.02 \text{ p.u} \quad (\text{source impedance in p.u})$$

Z_{p.u} of each 330/132KV 80MVA Transformer at 100MVA base

$$Z_{p.u} = \frac{12}{100} \times \frac{100}{80} = 0.15$$

$$Z_1 \text{ of 132KV Trans. line} = 15 + j 60 = R + jX$$

$$= \sqrt{[(15)^2 + (60)^2]}$$

$$= 61.85 \text{ Ohms}$$

$$Z_1 \text{ p.u. of this line} = \frac{(Z) \text{ MVA base}}{(\text{KV})^2}$$

$$= \frac{(61.85) \times 100}{(132)^2}$$

$$= 0.355 \text{ p.u}$$

Impedance of 132/33 KV, 25MVA transformer on 100 MVA base at %z =10

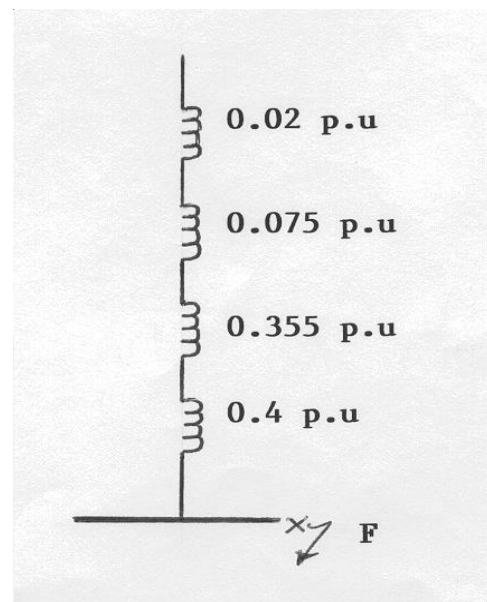
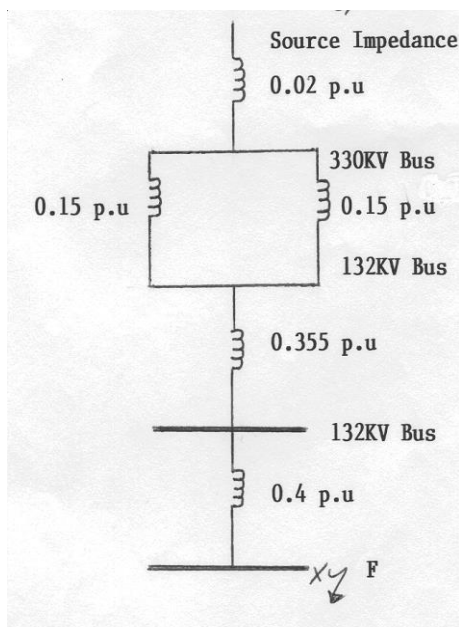
$$Z_{t1} = \frac{100 \times 10\%}{25}$$

$$= 40\%$$

$$\text{or } Z_{t1} = 0.4 \text{ p.u}$$

The system now reduces as follows:

This can be further reduced to:



Total system impedance up to F

$$= 0.85 \text{ p.u}$$

$$\text{Fault MVA at F} = \frac{100}{0.85}$$

$$= 117.6 \text{ MVA}$$

$$\text{Fault current at F} = \frac{117.6 \times 1000}{\sqrt{3} \times 33}$$

$$= 2057.466 \text{ Amps}$$

$$\text{or } 2.058 \text{ KA}$$

6.4 The above calculations are based on taking the total impedance of the equipment into consideration. If the X/R ratio of an equipment is > 3 , no harm is introduced if the fault current is calculated by taking into consideration the value of reactances only and ignoring the resistances for purposes of comparison.

Example 6.3 is worked as follows:

Assume base MVA = 100

System reactance behind 330 KV bus in p.u is:

$$X_s = \frac{100}{5000} = 0.02 \text{ p.u}$$

Reactance of each 330/132 KV transformer on 100 MVA base

$$X_{tr} = \frac{100}{80} \times 11.5$$

$$= 14.375\%$$

$$= 0.14375 \text{ p.u}$$

Reactance of transmission line X_l

$$= \frac{60 \times 100}{(132)^2}$$

$$= 0.344 \text{ p.u}$$

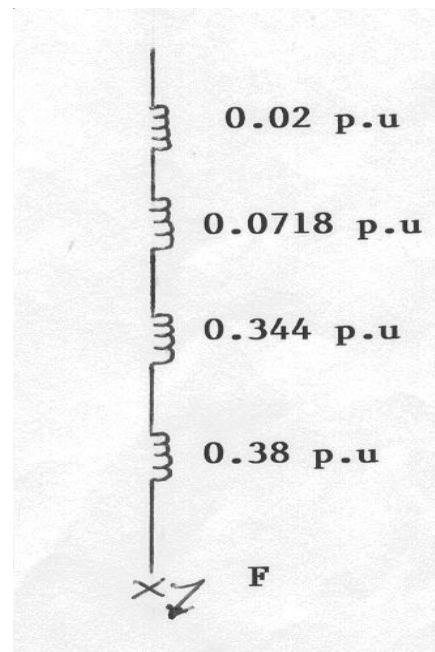
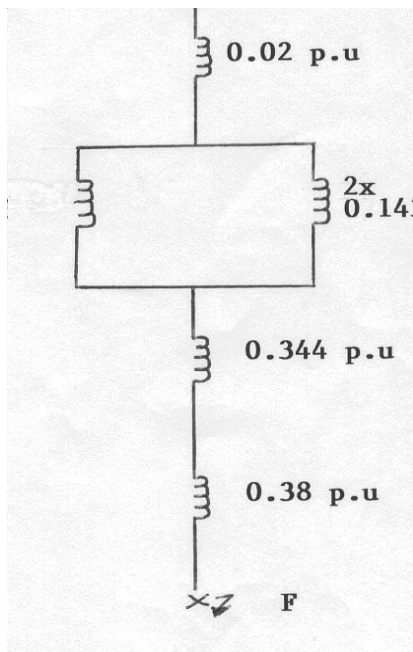
Reactance of 132/33KV transformer on 100 MVA base

$$X_{t1} = \frac{100 \times 9.5}{25}$$

$$= 38\%$$

$$= 0.38 \text{ p.u}$$

The system now reduces as follows:



Total system reactance up to F will be:

$$= 0.02 + \frac{0.14375}{2} + 0.344 + 0.38$$
$$= 0.815875 \text{ p.u}$$

$$\text{Fault MVA at F} = \frac{100}{0.815875}$$

$$= 122.57 \text{ MVA}$$

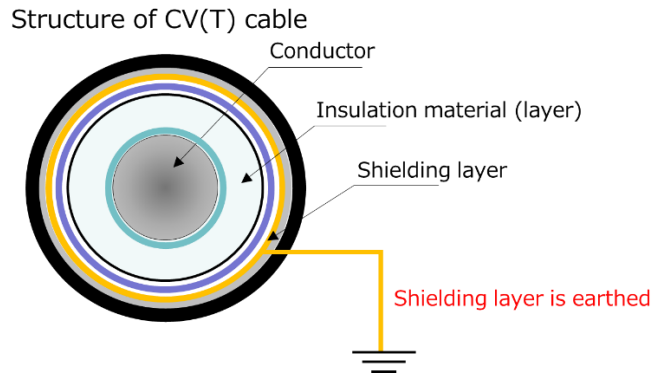
$$\text{Fault current at F} = \frac{122.57 \times 10^3}{\sqrt{3} \times 33}$$

$$= 2.144 \text{ KA}$$

Comparing the above results with that obtained earlier, the values are more or less the same.

Frequent causes of underground cable faults

1. Water tree phenomenon

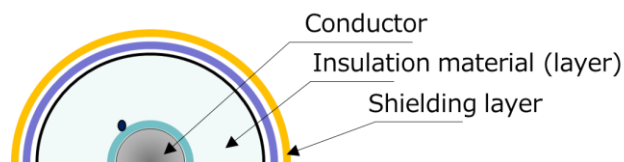


In the insulation layer of CV or CVT cable, insulation degradation grows dendritically (i.e. “tree”-like), penetrates the insulation layer, and finally causes the insulation breakdown. This is called “water tree phenomenon”.

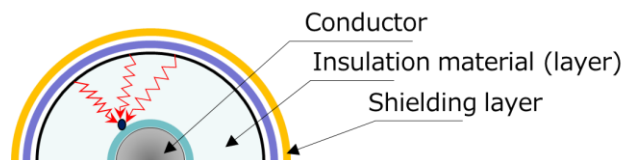
It is known that this tends to happen in the cable exposed all the time to the environment where water is contained, like underground. Cables soaked in water for a long time might grow its insulation degradation and finally lead to the insulation breakdown.

[How does it happen?]

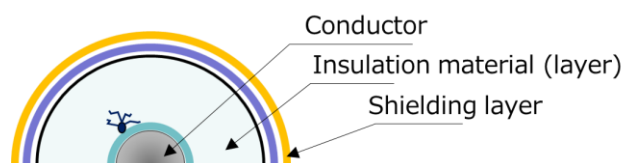
- (1) Due to the manufacturing process or malfunction, foreign substance (such as water) or gap appear in the insulation layer.



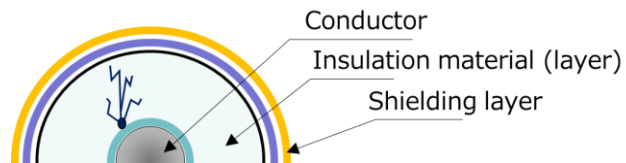
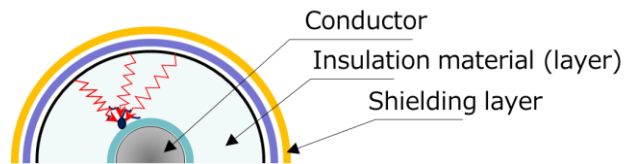
- (2) Electric field concentrates on the foreign substance or gap.



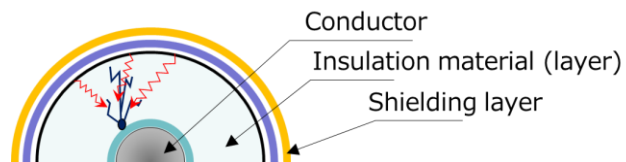
- (3) Concentration of the electric field accelerates the insulation degradation.



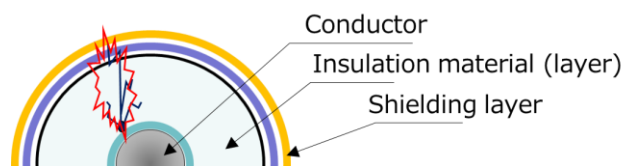
- (4) More electric field concentrates on the foreign substance or gap, more insulation degradation is accelerated.



- (5) Concentration of electric field and insulation degradation are repeated and repeated.



- (6) Finally insulation between the conductor and the shielding layer gets broken down, and the earth fault on the cable occurs.



2. Vandalism

Vandalizers destroy the conduit to steal the cable in order to get money by selling the metal (copper).



3. Excavation, vehicles

In excavation sites, underground cables sometimes unintentionally get damaged by workers or heavy machineries.



Runaway vehicles sometimes crash into the equipment on the road connected to underground cables, and damage cables there.



Fault detecting method (overhead/underground) at distribution voltage level (33kV and 11kV)

1. Fault detecting by pulse voltage applying (“Hipotronics”)

(1) Types of devices

There are several types of pulse voltage applying devices. The appropriate one should be selected and purchased based on the specification, detecting capacity, price, and so on.



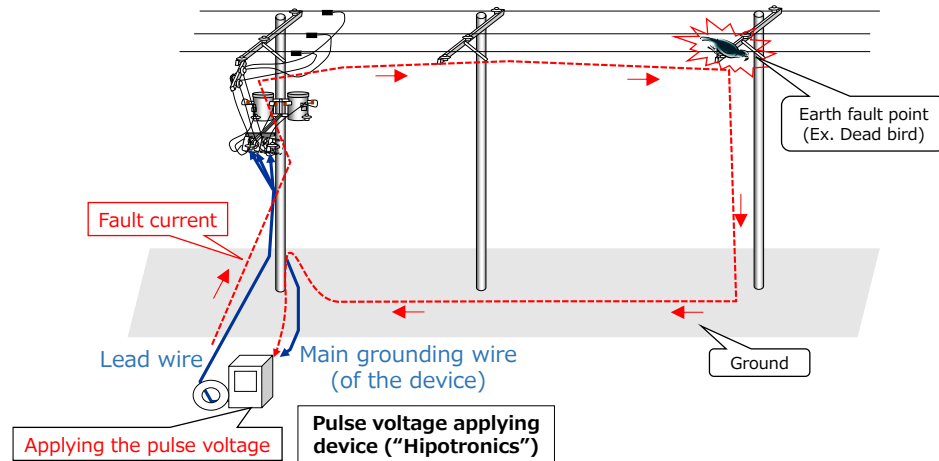
(Fig 1.1) Portable-type pulse voltage applying devices



(Fig 1.2) On-vehicle-type pulse voltage applying devices

(2) Detecting theory

The devices apply the pulse voltage onto the grid. If there is an earth fault point, the fault current will be observed by the devices. (Electric circuit is configured via the device, earth fault point, ground, and the device, as described in Fig. 1.3.) If there is not an earth fault point, the fault current will not be observed because electric circuit is not configured.

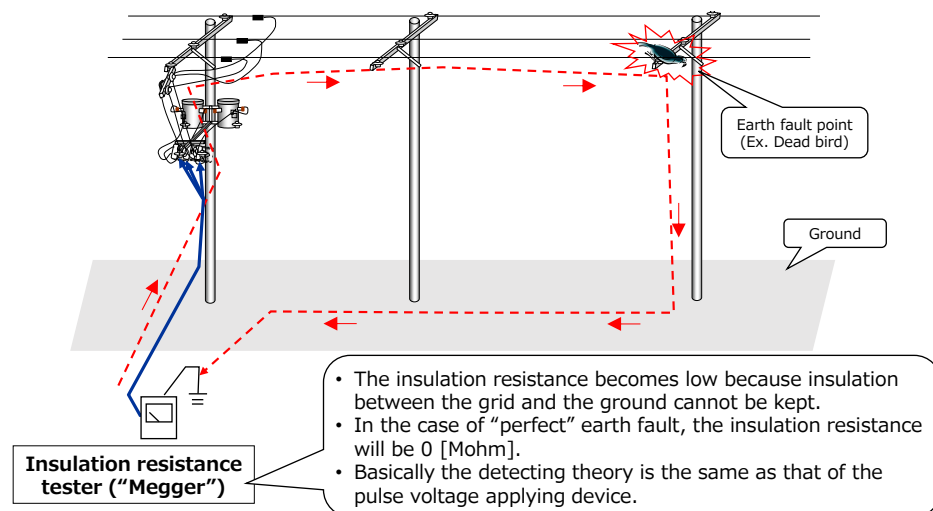


(Fig 1.3) How fault detecting by pulse voltage applying works

2. Fault detecting by insulating resistance ("Megger")

(1) Detecting theory

Measurement of the insulation resistance of the grid is needed. Basically the detecting theory is the same as that of the pulse voltage applying device. If there is an earth fault point, the insulation resistance becomes significantly low, as described in Fig 2.1. If there is not an earth fault point, the insulation resistance is kept normal.



(Fig 2.1) How fault detecting by insulating resistance works

3. Fault detecting by “Murrey loop method”

When fault occurred on the underground cable, the distance to the fault point can be calculated based on the balancing condition of “Wheatstone bridge circuit”.

(1) Example of measuring instruments

Here are some sample pictures of measuring instruments. See Fig 3.1, 3.2, and 3.3.



(Fig 3.1) Power source

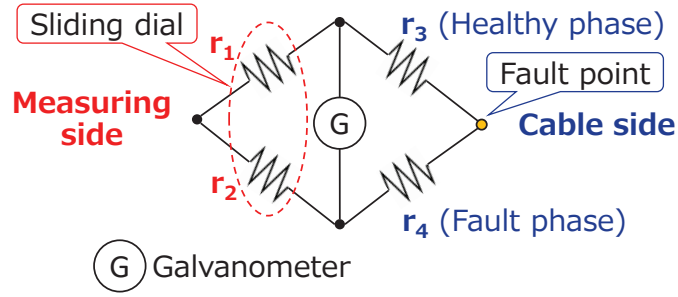


(Fig 3.2) Bridge circuit (analog type)



(Fig 3.3) Bridge circuit (digital type)

(2) Principle of Wheatstone bridge circuit



(Fig 3.4) Wheatstone bridge

When no current flows on the galvanometer, the bridge is balanced. At this time,

$$r_1 r_4 = r_2 r_3 \Leftrightarrow \frac{r_4}{r_3} = \frac{r_1}{r_2}$$

Then the distance to the fault point can be calculated based on r_1 and r_2 .

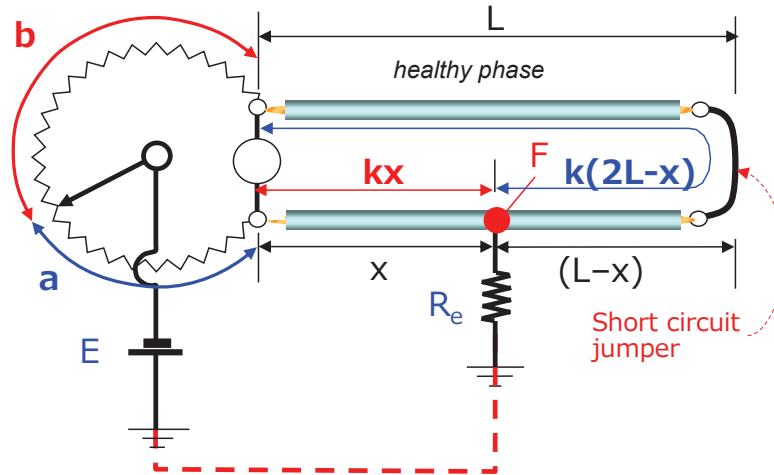
Detecting theory

Assume that

- L : Length of the cable
- F : Fault point
- x : Distance to F
- k : Constant
- R_e : Resistance of the earth

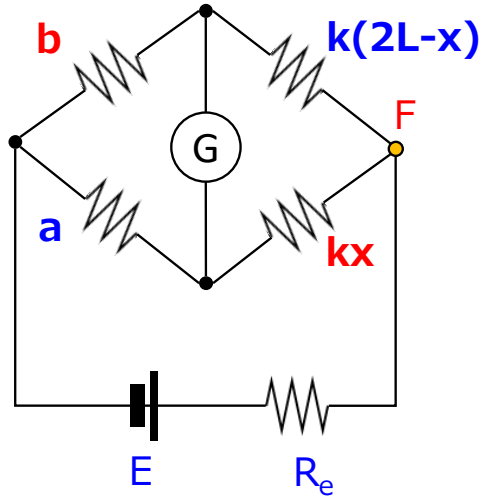
(3)

Then the cable resistance of the **fault phase** and the **healthy phase** can be described as kx and $k(2L - x)$ respectively, as Fig 3.5 shows.



(Fig 3.5) Fault detecting circuit of “Murrey loop method”

The circuit above is equivalent to the circuit below:



(Fig 3.6) Equivalent circuit to the fault detecting circuit of Fig 3.5

From the principle of Wheatstone bridge circuit, when the bridge is balanced,

$$bkx = ak(2L - x)$$

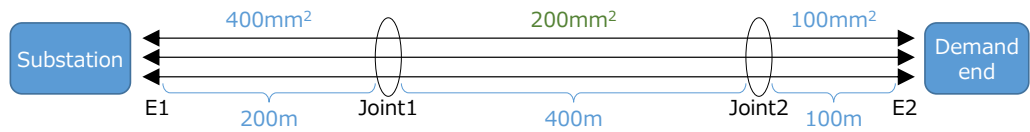
Therefore the distance to F can be calculated as

$$x = \frac{2a}{a + b} L$$

Note: if the grid is composed of several sizes of cables, equivalent conversion has to be done.

(4) Example

Assume the following grid described below in Fig 3.7.



(Fig 3.7) Example grid

Here is the equivalent conversion of cable size (for example conversion into 200sq). Converted length of the cable can be described as

$$L = \frac{200[\text{mm}^2]}{400[\text{mm}^2]} \times 200[\text{m}] + \frac{200[\text{mm}^2]}{200[\text{mm}^2]} \times 400[\text{m}] + \frac{200[\text{mm}^2]}{100[\text{mm}^2]} \times 100[\text{m}] = 700[\text{m}]$$

By measurement, if $\frac{2a}{a + b} = 0.9$ (= 90%), **converted distance to the fault point from substation is**

$$x' = 90\% \times 700[\text{m}] = 630[\text{m}]$$

From converted length, the fault point obviously exists between Joint2 and E2.

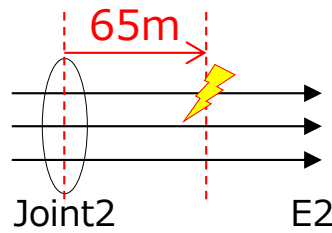
Converted distance to the fault point from Joint2 is

$$x'' = 630[\text{m}] - 100[\text{m}] - 400[\text{m}] = 130[\text{m}]$$

x'' is still converted value, therefore it has to be converted again inversely.

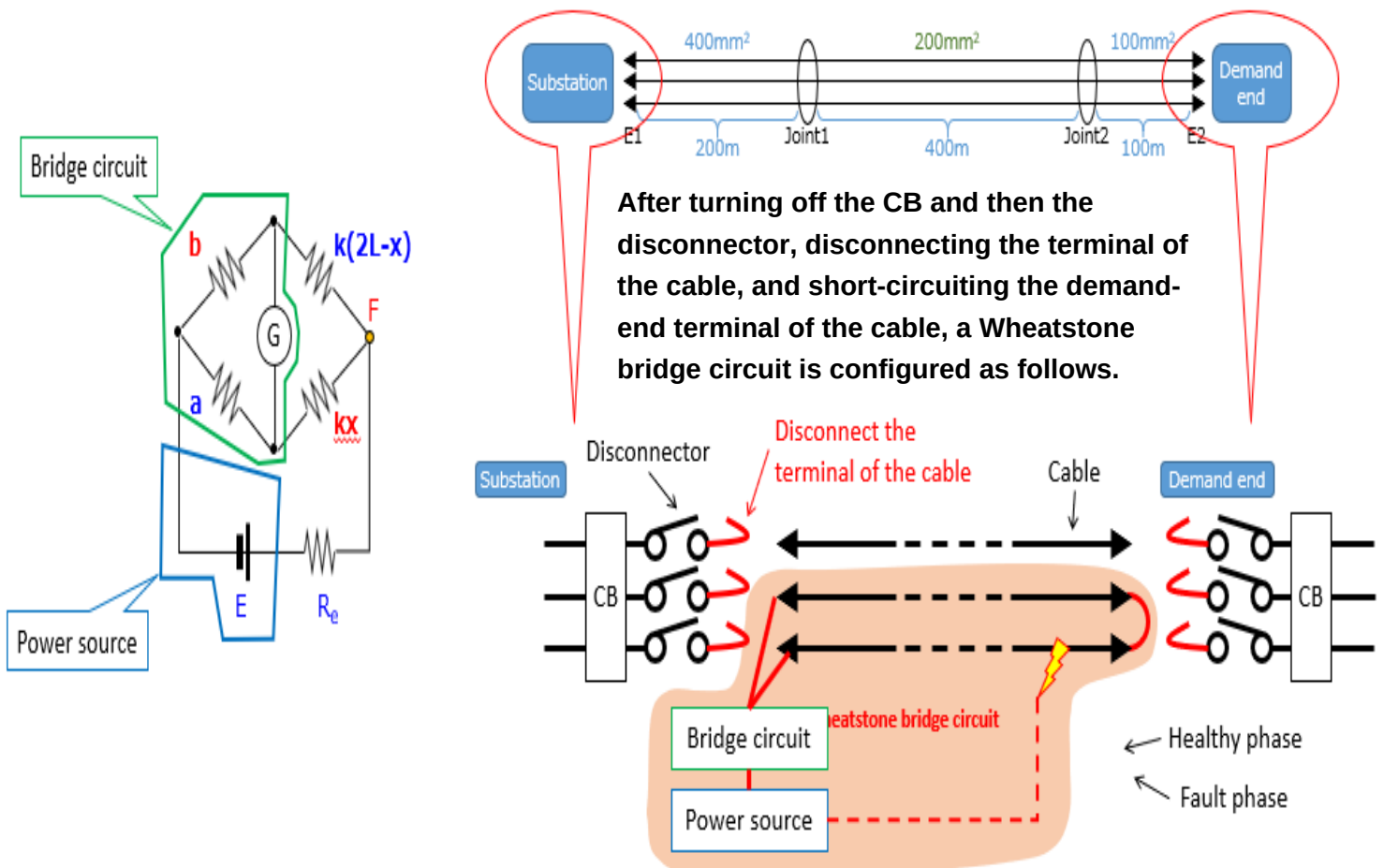
$$x = \frac{100[\text{mm}^2]}{200[\text{mm}^2]} \times 130[\text{m}] = 65[\text{m}]$$

This means the distance from Joint2 described in Fig 3.8 below.



(Fig 3.8) Distance to the fault point from Joint2.

ILLUSTRATION ON MURREY LOOP METHOD OF CABLE FAULT LOCATION



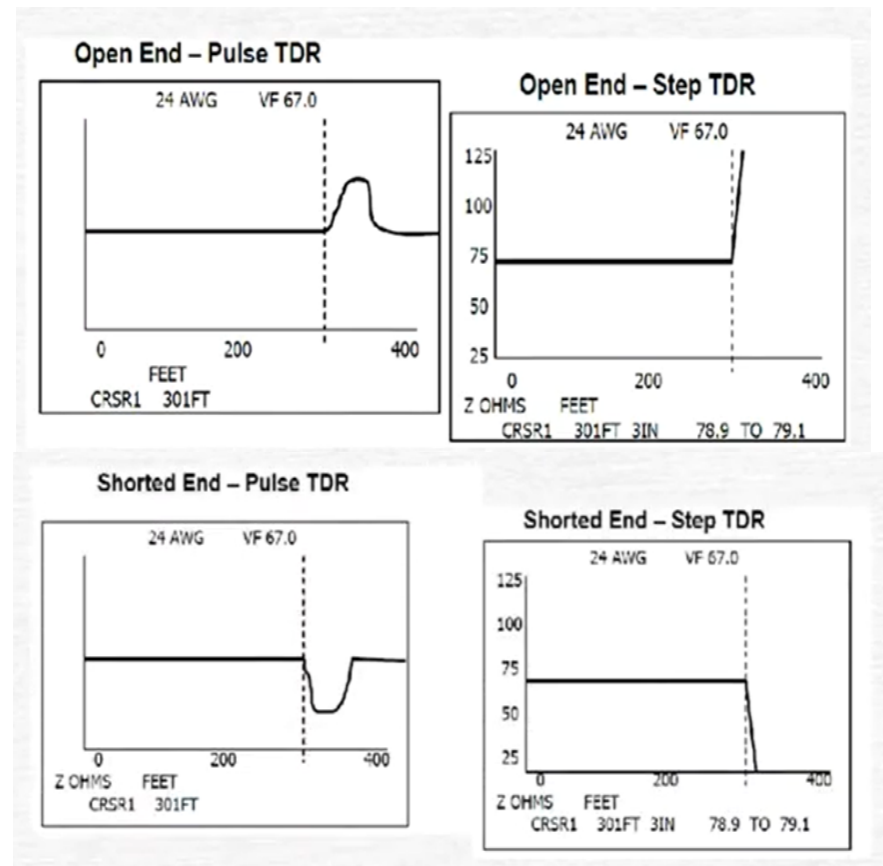
4. Important things to remember

- (1) When detecting the fault point, you have to pay attention to...
 - The length that the devices can detect the fault point
 - The threshold of fault current
- (2) These values depend on the specifications of the device, so follow the instruction from the manufacturer carefully before use.
 - Otherwise you might make an incorrect detection, which will delay the restoration of the outage incident.
- (3) After the restoration work, you should use the detecting device again and check that there is no fault current (which means there is no fault point any more).
- (4) Because Murrey loop method needs a loop circuit at the fault point, this method cannot be applied if
 - There is no healthy phase,
 - Cable is breaking down
- (5) Murrey Loop method is for underground cable faults

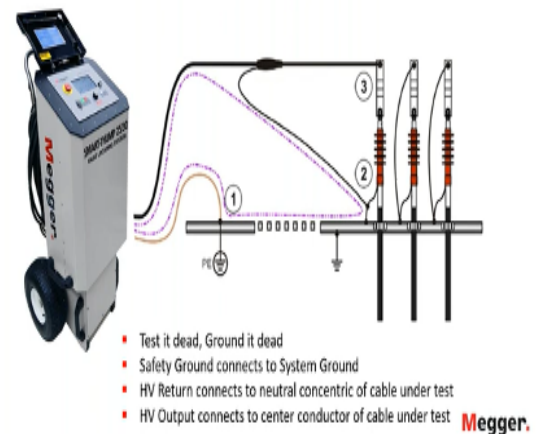
5. Further Reading

According to (Institute Of Electrical And Electronics Engineers, 2000, p. 1183) faults on a transmission system can also be detected by an instrument designed to indicate and to measure reflection characteristics of the transmission system connected to the instrument. This instrument uses a technique called Time Domain Reflectometry (TDR)

The TDR instrument monitors the step-formed signals entering the test object (transmission system e.g. cable or conductor) and the superimposed reflected transient signals on an oscilloscope that is equipped with a suitable timebased sweep. The measuring system basically consists of a fast-rise function generator, a tee coupler, and an oscilloscope connected to the probing branch of the coupler.



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This radar-like technique reveals at a glance the characteristic impedance of the line, and it shows the position of each discontinuity (including Cable Joints/Splices) along the line. TDR also demonstrates whether losses in a transmission system are series losses or shunt losses (like illegal taps). All of this information is immediately available from the oscilloscope's display. According to Gil (2009) TDR is used in Cable Fault Location, Partial Discharge Testing, and Cable Condition Monitoring.

CHAPTER FOUR

RELAY COODINATION

1.0 INTRODUCTION

Co-ordination of relays is an integral part of the overall system protection and is absolutely necessary to:

- (a) Isolate only the faulty circuit or apparatus from the system.
- (b) Prevent tripping of healthy circuits or apparatus adjoining the faulted circuit or apparatus.
- (c) Prevent undesirable tripping of other healthy circuits or apparatus elsewhere in the system when a fault occurs somewhere else in the system.
- (d) Protect other healthy circuits and apparatus in the adjoining system when a faulted circuit or apparatus is not cleared by its own protection system.

2.0 Methods of Relay Co-ordination

A correct relay co-ordination can be achieved by one or other or all of the following methods:

- Current graded systems
- Time graded systems or Discriminative fault protection
- Operate in a time relation in some degree to the thermal capability of the equipment to be protected.

- A combination of time and current grading.

A common aim of all these methods is to give correct discrimination or selectivity of operation. That is to say that each protective system must select and isolate only the faulty section of the power system network, leaving the rest of the healthy system undisturbed. This selectivity and coordination aims at choosing the correct current and time settings or time delay settings of each of the relays in the system network.

3.0 Co-ordination Procedure

3.1 The correct application and setting of a relay requires knowledge of the fault current at each part of the power system network. The following is the basic data required for finding out the settings of a relay.

- (a) A single line diagram of the power system.
- (b) The impedance of transformers, feeders, motors etc. in ohms, or in p.u. or % ohms.
- (c) The maximum peak load current in feeders and full load current of transformers etc, with permissible overloads.
- (d) The maximum and minimum values of short circuit currents that are expected to flow.
- (e) The type and rating of the protective devices and their associated protective transformers.

- (f) Performance curves or characteristic curves of relays and associated protective transformers.

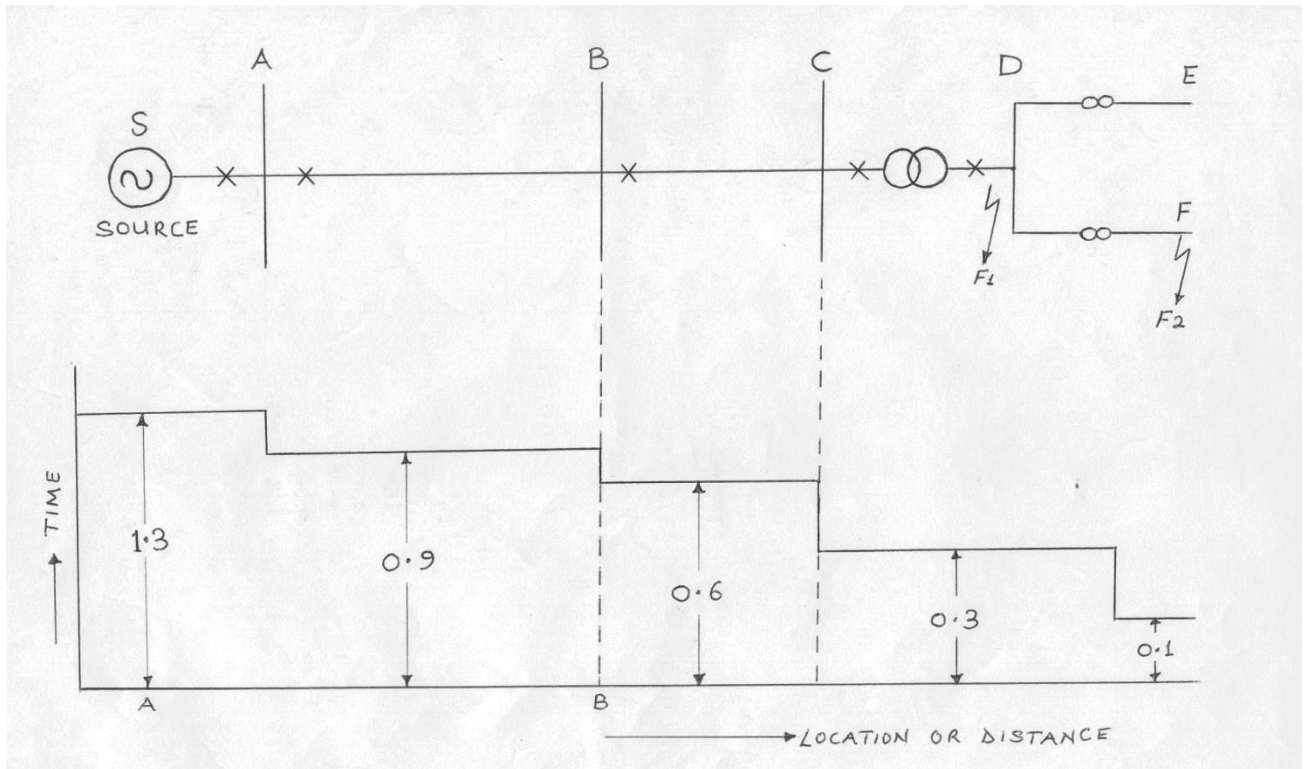
3.2 The following are the guidelines for correct relay co-ordination:

- (a) Whenever and wherever possible, use relays with the same characteristics in series with each other.
- (b) Set the relay farthest from the source at the minimum current settings.
- (c) For succeeding relays approaching the source, increase the current setting or retain the same current setting. That is 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.

3.3 Time Graded Systems

3.3.1 In this method, selectivity is achieved by introducing time intervals for the relays. The operating time of the relay is increased from the farthest side to the source towards the generating source. This is achieved with the help of definite time delay over current relays. When the number of relays in series increases, the operating time increases towards the source. Thus the heavier faults near the generating source are cleared after a long interval of time, which is definitely a draw back of this system of co-ordination. However, its main application is in systems where the fault levels at successive locations do not vary greatly.

3.3.2 The diagram below represents the principle of a time graded over current system of protection for a radial feeder.



Protection is provided at sections A, B, and C. The relay at C is set at the shortest time delay in order to allow the fuse to blow out for a fault in the secondary of the distribution Transformer D. If 0.3 secs is the time delay for relay at C, then for a fault at F1, the relay will operate in 0.3 secs.

Relays at A, B and S do not operate, but these relays only act as back up Protection relays. For a fault at F2, the fuses blow out in say 0.1 secs and if they fail to blow out then the relay at C operates to clear the fault in 0.3 secs. It may be noted that between successive relays at C, B, and A etc

there is an interval of time difference. This is known as 'Time Delay Step', which varies from 0.3 to 0.8 secs.

3.4 Current Graded Systems.

3.4.1 This principle is based 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. The relays are set to pick up at progressively higher currents towards the source. This current grading is achieved by high set over current relays and with different current tap positions in the over current relays. Since their selectivity is based solely on the magnitude of the current, there must be a substantial difference (preferably a ratio of 3:1) in the short circuit currents between two relay points to make them selective.

3.4.2 A simple current graded scheme applied to the system as shown in fig 1 above will consist of high set over current relays at S, A, B and C such that the relay at S would operate for faults between S and A; the relay at A would operate for faults between A and B and so on.

3.4.3 In practice the following difficulties are experienced with the application of purely current graded systems:

- (a) The relay cannot differentiate between faults that are very close to, but are on each side of B, since the difference in current would be very small.
- (b) The magnitude of the fault current cannot be accurately determined since all the circuit parameters may not be known exactly and accurately.

(c) There may be variations in the fault level depending upon the source generation, thereby necessitating the frequent change in the settings of the relay.

3.4.4 Thus discriminating by current grading alone is not a practical proposition for exact grading. As such current grading alone is not used, but may be used to advantage along with a Time Graded System.

3.5 Time and Current Graded System

3.5.1 The limitations imposed by the independent use of either time or current graded systems are avoided by using a combination of time and current graded systems.

3.5.2 It is for this purpose that over current relays with inverse time characteristics are used. In such relays the time of operation is inversely proportional to the fault current level and the actual characteristics is a function of both time and current settings. The most widely used is the IDMT characteristic where grading is possible over a wide range of currents and the relay can be set to any value of definite minimum time required. There are other inverse relay characteristics such as very inverse and extremely inverse, which are also sometimes employed. If the fault current reduces substantially as the fault position moves away from the source, very inverse or extremely inverse type relays are used instead of IDMT relays.

3.5.3 There are two basic adjustable settings on all inverse time (IDMT) relays.

One is the TMS (Time Multiplier Setting) and the other is the current setting, which is usually called the PSM (Current Plug Setting Multiplier)

$$\text{Time Multiplier Setting (TMS)} = \frac{T}{T_M}$$

Where T = required time of operation

T_M = time obtained from the standard IDMT curve at $MS=1$.

$$\text{Plug Setting Multiplier (PSM)} = \frac{\text{Primary Current}}{\text{Relay operating current} \times \text{C.T.R}}$$

3.5.4 As per B.S., there are two types of IDMT relays, namely 3.0 secs and 1.3 secs relays. This only means that with $TMS = 1.0$ and $PSM = 10$, the relay operates at the time of 3.0 secs or 1.3 secs as the case may be.

3.5.5 The time interval of operation between two adjacent relays depends upon a number of factors. These are:

- (a) The fault current interrupting time of the circuit breaker.
- (b) The overshoot time of the relay.
- (c) Variation in measuring devices - Errors.
- (d) Factor of Safety.

3.5.6 Circuit breaker interruption time

It is the total time taken by the circuit breaker from the opening of the contacts to the final extinction of the arc and energization of the relay.

Modern circuit breakers have an operating time or tripping time of 3 to 5 cycles in the EHV ranges and up to 8 cycles in the H.V and M.V ranges.

3.5.7 Overshoot

When the relay is de-energised, operation may continue for a little longer until any stored energy has been dissipated. This is predominant only in electromagnetic relays but not in static relays.

3.5.8 Errors

All devices such as relays, CT's etc are subject to some degree of error. Relay grading is carried out by assuming the accuracy of the measuring device or by allowing a margin for errors.

3.5.9 Factor of Safety

Some safety margin is intentionally introduced to account for errors and delays in breaker operating time.

The Phase-to-Phase fault current should be considered for phase fault relays and the phase to earth fault current for earth fault relays.

The setting for phase fault element (OCR) may be kept as high as 150 to 200% of full load current. Normally the minimum operating current is set not to exceed 130% of the setting i.e.

$$I \text{ setting} = \frac{\text{Minimum short circuit current}}{1.3}$$

The setting also depends upon the practices followed by a Power Authority and may be limited to 100% as in PHCN. In the examples that

follow, we shall limit ourselves to 100% setting and it is advisable that we don't exceed this value most especially for transformer protection.

4.0 Examples on relay Co-ordination

4.1 Data: Required to calculate relay settings of an IDMT 3 secs relay to operate in 2 secs on a short circuit current of 8000A. Connected C.T. ratio is 400/5A.

Normal full load current is 400A.

Relay Plug settings available 2.5, 3.75, 5, 6.25, 7.5, 8.75, 10

TMS: 0.1 to 1.0 in multiples of 0.1.

SOLUTION

$$\text{Secondary value of short circuit current} = \frac{8000 \times 5}{400}$$

$$= 100 \text{ A}$$

Full load current = 400A

$$\text{Secondary value of full load current} = \frac{400 \times 5}{400}$$

$$= 5\text{A}$$

$$\text{With 100\% current setting } I_R = 5\text{A}$$

$$\text{Therefore Plug setting} = 5.0$$

Fault current of 100 A corresponds to 20 times I_R i.e.

$$\text{MPS} = \frac{100}{5} = 20$$

Looking into the relay characteristic curve, the time of operation for this value is 2.2 seconds at Unity TMS. If the relay is to operate in 2.0 sec., then

$$\text{TMS} = \frac{2.0}{2.2} = 0.9$$

i.e. from formulae $T_u = \frac{T_o}{\text{TMS}}$

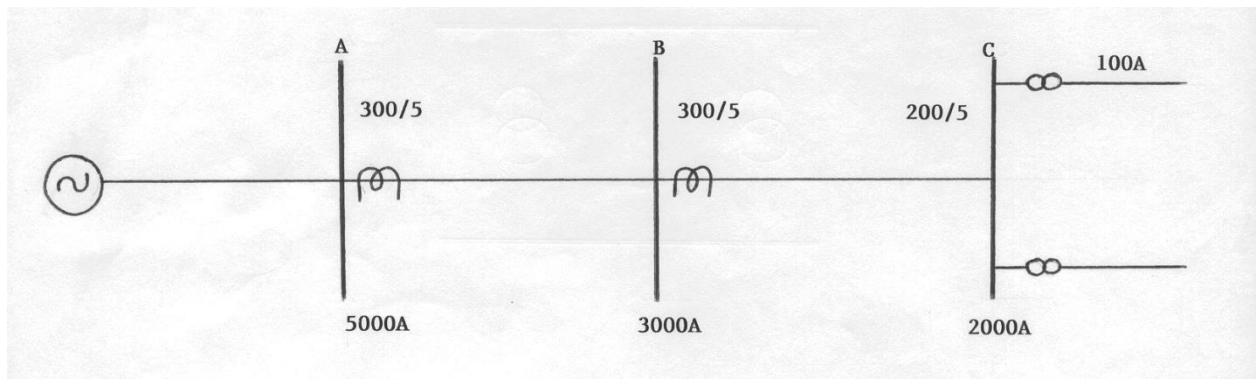
$$\text{Or } T_o = T_u \times \text{TMS}$$

Alternatively: $T_o = \frac{0.14}{\text{MPS}^{0.02} - 1} \quad \text{TMS} = 1 \text{ for 3 secs relays}$

4.2 Data: Given a radial feeder with fault current and C.T. ratios at substations A, B, and C as indicated. Full load current at C = 100A.

Available relay is 1DMT 3 secs. Relay.

Find out the current setting P.S and TMS at each substation.



SOLUTION

We proceed from the farthest station towards the source.

Substation C

$$\text{Secondary value of fault current} = 2000 \times \frac{5}{200} = 50\text{A}$$

$$\text{Full load current} = 100\text{A}$$

$$\text{Secondary value of full load current} = 100 \times \frac{5}{200} = 2.5\text{A}$$

$$\text{For 100\% setting our Plug set} = 2.5\text{A} = I_R$$

$$\text{Fault current of 50 A corresponds to: } \frac{50}{2.5} = 20 \text{ times } I_R$$

Time of operation of the relay at 20 times I_R with TMS = 1 is 2.2 secs

(from relay characteristic curve)

Now the time of operation of relay at C has to be the lowest.

We assume this time equal to the sum of operating time of the fuse say

0.1 sec. and a time delay (of 0.16sec.) to allow the fuse to blow.

Actual time of operation of the relay at C is

$$= 0.1 + 0.16 = 0.26 \text{ secs}$$

$$\text{TMS} = \frac{0.26}{2.2} = 0.12$$

$$\text{At C: P.S} = 2.5$$

$$\text{TMS} = 0.12$$

Substation B

The relays at B must act at a time grading higher than that of relays at C.

Therefore we assume a time grading of 0.35 secs. (in our own case)

Relay operating time at B for a fault at C (i.e. a fault current of 2000A) is

$$= 0.26 + 0.35 = 0.61 \text{ secs}$$

The current setting at B must be increased when compared to that at C.

We shall set this at 130% of that at C. This is in order to allow for load increases.

Current setting of the relay at B = 1.3 times current setting at C

$$= 1.3 \times 2.5 = 3.25\text{A}$$

We choose a plug setting of 3.75A

Secondary value of short circuit current at B is

$$= 2000 \times \frac{5}{300} = 33.33\text{A}$$

$$\text{Multiples of plug setting} = \frac{33.33}{3.75} = 8.88$$

The time of operation of the relay at MPS = 8.88 with TMS = 1 is 3.2 secs

(from the relay characteristic curve)

$$\text{TMS at 0.61 secs.} = \frac{0.61}{3.2} = 0.19$$

Secondary value of fault current at B

$$= 3000 \times \frac{5}{300}$$

$$= 50A$$

$$\text{But our Plug Setting PS} = 3.75A$$

$$\text{MPS} = \frac{50}{3.75} = 13.33$$

The time of operation of the relay at MPS = 13.33 with TMS = 1 is 2.6 secs (from the relay characteristic curve)

But TMS chosen for the relay at B is 0.19

Actual operating time of the relay at B for a fault current of 3000A (a fault very close to B) is equal to:

$$\begin{aligned} T_o &= T_u \times \text{TMS} \\ &= 0.19 \times 2.6 \\ &= 0.49 \text{ secs.} \end{aligned}$$

Substation at A

Required operating time for relay at A for a fault current at B is:

$$= 0.49 + 0.35 = 0.84\text{sec}$$

Assume that PS at A = PS at B i.e. 3.75

Secondary value of fault current at B for relay at A:

$$\begin{aligned} &= 3000 \times \frac{5}{300} \\ &= 50A \end{aligned}$$

$$\begin{aligned} \text{Multiples of Plug Setting} &= \frac{50}{3.75} \\ &= 13.33 \end{aligned}$$

With TMS = 1, operating time for this value of MPS = 13.33 is given as 2.6 sec.

TMS for the operating time of 0.84 secs

$$= \frac{0.84}{2.6} = 0.32$$

$$\text{TMS at A} = 0.32$$

For a fault close to A, secondary value of fault current

$$= \frac{5000 \times 5}{300} = 83.33\text{A}$$

$$\text{MPS} = \frac{83.33}{3.75}$$

$$= 22.22$$

Time of operation of relay at 22.22 times I_R at TMS = 1.0 is 2.2 secs

(using 20 MPS available on the graph)

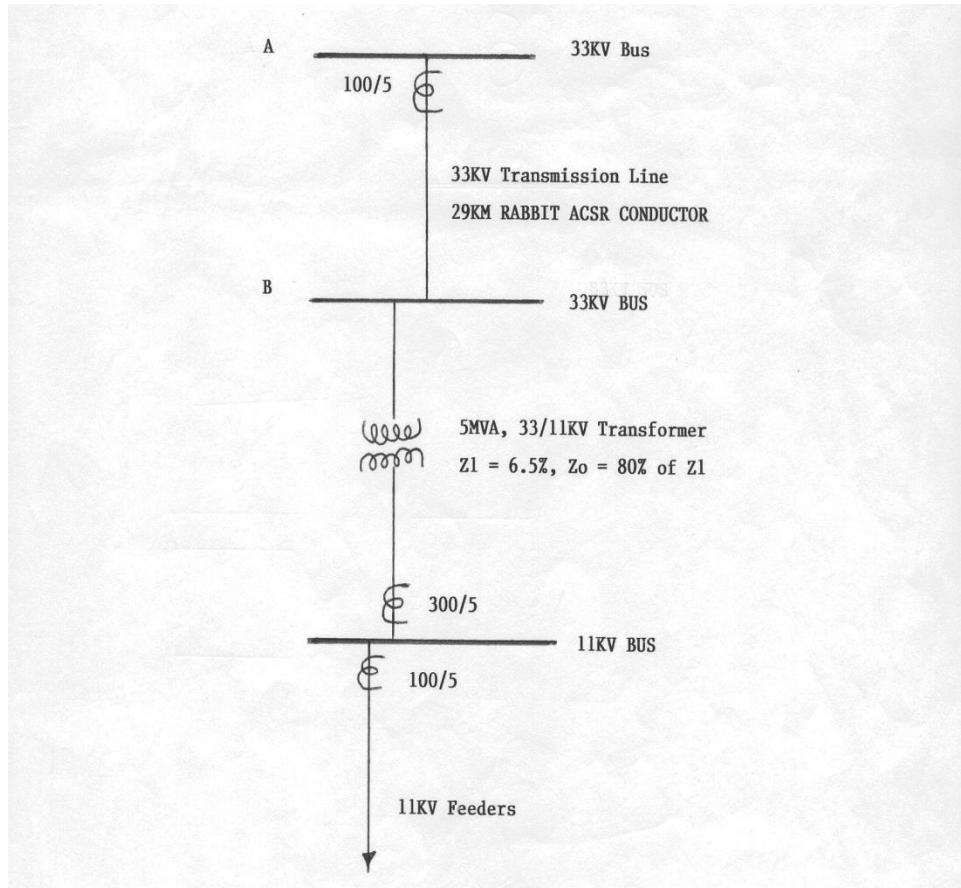
Actual time of operation of the relay at A is

$$= 0.32 \times 2.2 \text{ secs}$$

$$= 0.7 \text{ secs}$$

SUBSTATION	CTR	P.S	Actual Operating time of relays
A	300/5	3.75	0.7 secs
B	300/3	3.75	0.49 secs
C	200/5	2.50	0.26 secs

- 4.3** Given data on a 33 KV transmission line and substation as shown below.
Determine the relay settings at the substations.



Fault level at station A = 37.17MVA

Transmission Line constants for 29Kms:

$$Z_1 = 19.58 + j12.86 \text{ ohms}$$

$$Z_0 = 23.89 + j38.37 \text{ ohms}$$

SOLUTION

Assume base MVA = 100

$$\text{Source impedance at station A} = \frac{\text{Base MVA}}{\text{Fault MVA}}$$

$$\begin{aligned} Z_s &= \frac{100}{37.17} \\ &= 2.69 \text{ p.u} \end{aligned}$$

Transmission line constants on base MVA in p.u

$$\begin{aligned} Z_1 &= \sqrt{[(19.58)^2 + (12.86)^2]} \\ &= 23.43 \text{ ohms} \end{aligned}$$

$$\begin{aligned} Z_{p.u} &= \frac{Z_1 \times \text{MVA}}{(\text{KV})^2} \\ &= \frac{23.43 \times 100}{(33)^2} \end{aligned}$$

$$= 2.15 \text{ p.u}$$

$$\begin{aligned} Z_0 &= \sqrt{[(23.89)^2 + (38.37)^2]} \\ &= 45.19 \text{ ohms} \end{aligned}$$

$$Z_{p.u} = \frac{45.19 \times 100}{33^2}$$

$$= 4.15 \text{ p.u}$$

Impedance of transformer at station B on 100 MVA base

$$Z_{p.u} = \%Z \times \frac{\text{base MVA}}{\text{Transformer MVA}}$$

$$= \frac{6.5 \times 100}{100 \times 5}$$

$$Z_t = 1.3 \text{ p.u}$$

Total fault impedance at station B in p.u is:

$$\begin{aligned}
 Z_f &= Z_s + Z_1 + Z_t \\
 &= 2.69 + 2.15 + 1.3 \\
 &= 6.14 \text{ p.u.}
 \end{aligned}$$

Assuming a 3-phase fault on 11KV at station B

$$\begin{aligned}
 \text{Fault MVA} &= \frac{\text{Base MVA}}{Z_f} \\
 &= \frac{100}{6.14} \\
 &= 16.29 \text{ MVA} \\
 \text{Fault current} &= \frac{16.29 \times 10^6}{\sqrt{3} \times 11 \times 10^3} \\
 &= 855 \text{ A}
 \end{aligned}$$

RELAY CO-ORDINATION FOR 11KV FEEDER BREAKER OVER CURRENT

RELAY

$$\text{Feeder CT ratio} = 100/5$$

Secondary value of fault current

$$\begin{aligned}
 &= 855 \times \frac{5}{100} \\
 &= 42.75 \text{ A}
 \end{aligned}$$

Assuming a full load current of 100A on the feeder

We have secondary value of full load current

$$= 100 \times \frac{5}{100}$$

$$I_R = 5A$$

Hence we choose a P.S of 5.0

Fault current of 42.75A corresponds to $\frac{42.75}{5} = 8.55$ MPS

Time of operation for 8.55 times I_R with TMS = 1 is given as 3.25 secs.

Now the time of operation of the feeder has to be the lowest.

$$\text{Time of operation of relay} = 0.1 + 0.16 = 0.26 \text{ secs.}$$

Where 0.1sec = Fuse operation time on 11KV side

0.16sec = Time delay to allow fuse to blow

$$\text{TMS} = \frac{0.26}{3.25}$$

$$= 0.08$$

For 11 KV feeder: P.S = 5.0

TMS = 0.08

RELAY CO-ORDINATION FOR 11 KV TRANSFORMER BREAKER OVER

CURRENT RELAY (OCR)

Transformer bank C.T. ratio = 300/5

Secondary value of fault current

$$= 855 \times \frac{5}{300}$$

$$= 14.25A$$

Transformer secondary full load current

$$= \frac{5 \times 10^6}{\sqrt{3} \times 11 \times 10^3}$$

$$= 262.5A$$

Secondary value of full load current

$$= 262.5 \times \frac{5}{300}$$

$$= 4.375A$$

Choose a P.S = 5.0

Fault current of 14.25A corresponds to $\frac{14.25}{5} = 2.85MPS$

and with TMS = 1, the time of operation = 6.29 secs.

Operating time required for the transformer breaker= Relay operating

time of feeder + time step delay

$$= 0.26 + 0.35 = 0.61 \text{ secs}$$

$$TMS = \frac{0.61}{6.29}$$

$$= 0.096 = 0.10$$

For 11 KV Transformer breaker:

$$P.S = 5.0$$

$$TMS = 0.1$$

33KV Line breaker relay co-ordination at station A (OCR)

$$\text{Fault current on 33KV} = \frac{855}{3} \text{ A (by transformer ratio)}$$

$$= 285 \text{ A}$$

$$\text{CTR} = 100/5$$

Secondary value of fault current

$$= \frac{285 \times 5}{100}$$

$$= 14.25 \text{ A}$$

33KV Transformer full load current

$$= \frac{5 \times 10^6}{\sqrt{3} \times 33 \times 10^3}$$

$$= 87.5 \text{ A}$$

Secondary value of full load current

$$= \frac{87.5 \times 5}{100}$$

$$= 4.375 \text{ A}$$

We choose a P.S = 5A

$$\text{MPS} = \frac{14.25}{5}$$

$$= 2.85$$

With Unity TMS, operation time = 6.29 secs

The operating time required is:

= Relay operating time of 11KV transformer breaker + step delay

$$= 0.61 + 0.3$$

$$= 0.91 \text{ secs.}$$

$$\text{TMS} = \frac{0.91}{6.29}$$

$$= 0.1446 = 0.15$$

For 33KV breaker at station A:

$$\text{P.S} = 5.0$$

$$\text{TMS} = 0.15$$

STATION B	P.S	TMS	CTR	RELAY
11KV main breaker	5.0	0.10	300/5	OCR
25 11KV feeder breaker	5.0	0.08	100/5	OCR
26 STATION A 33KV line breaker	5.0	0.15	100/5	OCR

27 Earth Fault Relay Co-ordination

For transmission line and transformer $Z_1 = Z_2$

$$Z_0 \text{ of transmission line} = 4.15 \text{ p.u}$$

$$Z_1 = 2.15 + 1.3 = 3.45 = Z_2$$

$$Z_0 \text{ of transformer} = 80\% \text{ of } Z_t$$

$$= 0.8 \times 1.3 = 1.04 \text{ p.u}$$

$$Z_0 = 4.15 + 1.04 = 5.19 \text{ p.u}$$

Assume a single line to ground fault then:

$$\text{Earth fault impedance} = Z_s + \frac{Z_1 + Z_2 + Z_0}{3}$$

$$= 2.69 + \frac{3.45 + 3.45 + 5.19}{3}$$

$$= 2.69 + \frac{12.09}{3}$$

$$= 6.72 \text{ p.u}$$

Earth fault MVA on 11KV at station B

$$= \frac{\text{Base MVA}}{Z_f}$$

$$= \frac{100}{6.72}$$

$$= 14.88 \text{ MVA}$$

$$\text{Earth fault current} = \frac{14.88 \times 10^6}{\sqrt{3} \times 11 \times 10^3}$$

$$= 781 \text{ A}$$

Feeder CTR = 100/5

Secondary value of Earth fault current

$$= \frac{781 \times 5}{100}$$

$$= 39.05A$$

For earth fault the P.S is kept at the lowest setting for the feeder and so also the operating time at the minimum say, 0.1 sec.

Therefore, P.S = 1.0

A fault current of 39.05 A corresponds to an MPS of $\frac{39.05}{1.0} = 39.05$ which operating time at Unity TMS is given as 1.84 secs.

$$TMS = \frac{0.1}{1.84}$$

$$= 0.05$$

Earth Fault Relay setting for the 11KV feeder is given as:

$$P.S = 1.0$$

$$TMS = 0.05$$

$$\text{Transformer breaker CTR} = 300/5$$

Secondary value of fault current is:

$$= \frac{781 \times 5}{300}$$

$$= 13.02 A$$

P.S is again kept at the lowest value of 1.0 (I_R)

The relay operating time will be= EFR operating time of feeder + Time step delay = 0.1 + 0.3 = 0.4 secs

Fault current of 13.02 A will give an MPS of $\frac{13.02}{1.0} = 13.02$

With Unity TMS, Operating time = 2.66 secs.

$$\begin{aligned} \text{TMS} &= \frac{0.4}{2.66} \\ &= 0.15 \end{aligned}$$

Earth Fault Relay setting for 11KV Transformer breaker is:

$$\begin{aligned} \text{P.S} &= 1.0 \\ \text{TMS} &= 0.15 \end{aligned}$$

On 33KV bus at station A, 33KV line breaker CTR = 100/5

Secondary value of earth fault current

$$\begin{aligned} &= 781 \times \frac{5}{100} \\ &= 39.05 \text{ A} \end{aligned}$$

$$\begin{aligned} \text{Fault current on 33KV} &= \frac{39.05}{3} \\ &= 13.02 \text{ A (by transformation ratio)} \end{aligned}$$

With P.S = 1.0, MPS = $\frac{13.02}{1} = 13.02$ and at Unity TMS,

Operating time = 2.66secs

Relay operation time will be:

$$\begin{aligned} &= \text{EFR operating time} + \text{time step delay for transformer} \\ &\quad \text{breaker} \\ &= 0.4 + 0.3 = 0.7 \text{ sec.} \end{aligned}$$

$$\text{TMS} = \frac{0.7}{2.66}$$

$$= 0.26$$

Therefore Earth Fault Relay setting of 33KV line panel at station A is:

$$\text{P.S} = 1.0$$

$$\text{TMS} = 0.26$$

STATION B	P.S	TMS	CTR	RELAY
11KV Feeder	1.0	0.05	100/5	EFR
11KV Transformer breaker	1.0	0.15	300/5	EFR
STATION A				
33KV Line breaker	1.0	0.26	100/5	EFR

CHAPTER FIVE

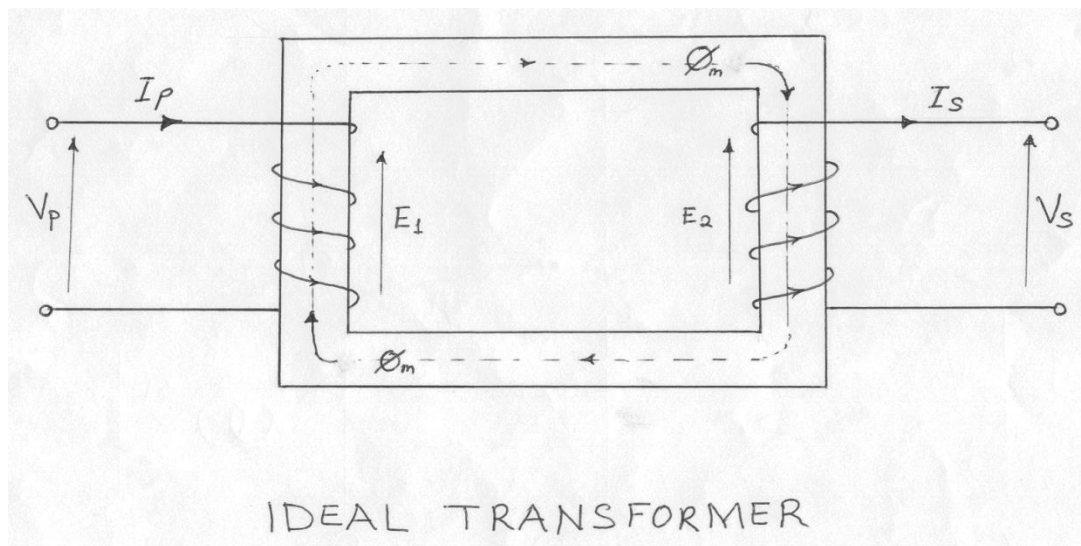
POWER TRANSFORMERS AND CONNECTIONS

1.0 Introduction

The transformer is an electro-magnetically coupled circuit, which transforms power from one level of voltage and current to another. It is a vital link in a power system, which has made possible the power generated at lower voltages (11KV) to be transmitted over long distances at higher voltages (330KV, 132KV, etc.)

2.0 Theory

In its simplest form, a transformer consists of a laminated core about which are wound two sets of windings; one called the primary and the



other the secondary.

When a voltage is applied to the primary, it produces a magnetic flux in the core and the relationship between flux and voltage is given by:

$$e = -n \frac{d\phi}{dt} \quad 1$$

where e and ϕ are the instantaneous values of voltage and flux and n the number of turns.

This flux lags behind applied voltage by 90°

Thus if

$$e = E_m \sin \omega t$$

$$\phi = \phi_m \cos \omega t$$

Substituting in eqn. 1 we have:

$$E_m \sin \omega t = -n \frac{d(\phi_m \cos \omega t)}{dt}$$

$$E_m \sin \omega t = n \omega \phi_m \sin \omega t$$

$$E_m = 2\pi f n \phi_m \quad (\text{where } \omega = 2\pi f)$$

$$\sqrt{2} E = 2\pi f n \phi_m$$

$$(\text{where } E = \text{rms value} = \frac{1}{\sqrt{2}} E_m)$$

$$E = \frac{2 \times 3.14 f n \phi_m}{\sqrt{2}}$$

$$= 4.44 \phi_m n f \text{ volts}$$

$$= 4.44 B_m A n f$$

(where $B_m A$ = maximum flux density)

Thus if E_p is the voltage applied to the primary, n_p the number of the turns in the primary winding, then:

$$E_p = 4.44 B_m A n_p f \quad 2$$

This flux produced by voltage E_p links with the secondary winding of n_s turns and similarly produces a voltage, i.e.

$$E_s = 4.44 B_m A n_s f \quad 3$$

Dividing eqn. 2 by 3 we have:

$$\frac{E_p}{E_s} = \frac{4.44 B_m A n_p f}{4.44 B_m A n_s f}$$

$$\frac{E_p}{E_s} = \frac{n_p}{n_s} \quad 4$$

There is also a relationship between current and the flux, which is given by:

$$\phi \propto \frac{nI}{l}$$

where n = number of turns

l = the length of the magnetic circuit

Thus if the secondary winding delivers a current I_s to the load, then a flux ϕ_s is produced which is given by:

$$\phi_s \propto \frac{n_s I_s}{l} \quad 5$$

Thus flux ϕ links with the primary winding and causes a primary current

I_p to be drawn from the source such that:

$$\phi_p = \frac{n_p I_p}{l} \quad 6$$

Equating 6 and 5 we have:

$$\frac{n_p I_p}{l} = \frac{n_s I_s}{l}$$

or $n_p I_p = n_s I_s$

$$\frac{I_p}{I_s} = \frac{n_s}{n_p}$$

$$\text{or } \frac{I_s}{I_p} = \frac{n_p}{n_s} \quad 7$$

Thus combining eqns. 4 and 7 we have:

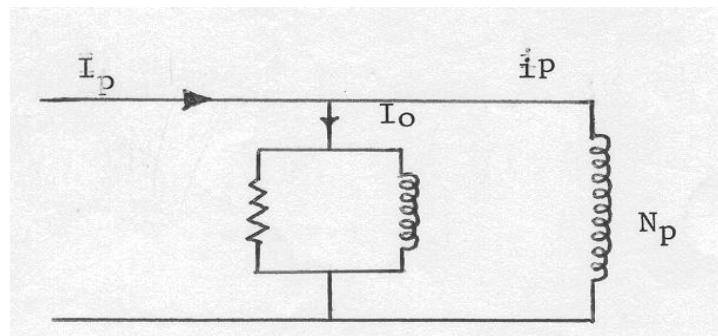
$$\frac{E_p}{E_s} = \frac{n_p}{n_s} = \frac{I_s}{I_p}$$

This is the equation of an Ideal Transformer.

But in practice if I_p' is the primary current then

$$I_p = I_p' \text{ (primary load current) } - I_o$$

where I_o is the primary no load current



So that $I_p N_p = I_s N_s$

$$\text{or } \frac{N_p}{N_s} = \frac{I_s}{I_p}$$

Similarly the secondary load voltage V_s is given by:

$$V_s = E_s - (I_s R_s + I_s X_s)$$

where E_s = secondary induced e.m.f

$(I_s R_s + I_s X_s)$ = voltage drop due to secondary load current in secondary windings.

The voltage E_s is transformed by primary voltage E_p and

$$\frac{E_p}{E_s} = \frac{N_p}{N_s}$$

But the primary applied voltage V_p is given by:

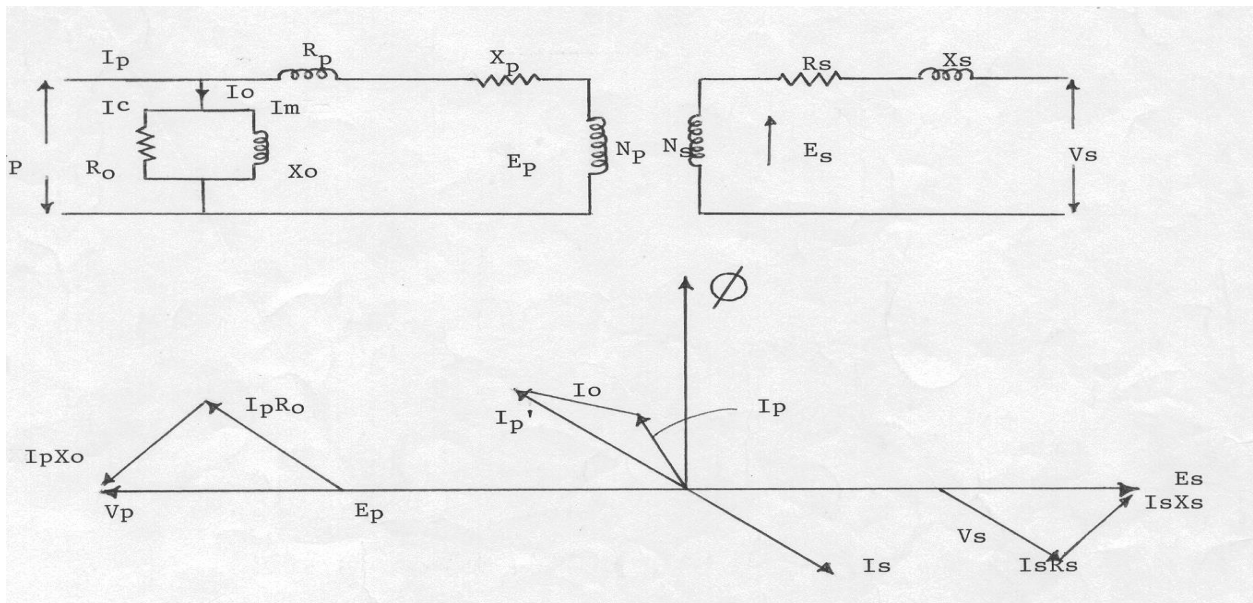
$$V_p = E_p + (I_p R_p + I_p X_p)$$

where $I_p R_p + I_p X_p$ = voltage drop due to primary load current in primary windings

$$\text{Hence } \frac{V_p}{V_s} = \frac{E_p}{E_s}$$

$$\text{And } \frac{V_p}{V_s} = \frac{N_p}{N_s}$$

The above relationships are explained by the phasor and circuit diagrams shown below



3.0 Three-phase unit versus single-phase units:

Since the transmission system is 3-phase, transformers may be built as 3-phase single units or as three single-phase units into delta and star combinations or groups.

3.1 Advantages of 3 phase units

- They occupy less space
- No extra support equipment is required to form a 3-phase Delta or Star connection.
- They are cheaper
- They can be transported from factory as a compact unit, erected and commissioned at site quickly

- Compact on-load tap changing (OLTC) gear can be provided as a built in unit.

3.2 Disadvantages of 3 phase units

- Problem of transportation in case of large capacity units weighing more than 100 tons.
- Takes time in assembling, erecting and commissioning if parts are dismantled and sent to site.
- The cost of one spare 3-phase transformer is more.
- Change of connections from star to delta or vice-versa cannot be done.
- If reconditioning is undertaken then the complete unit has to be taken out of service and this becomes a problem if no spare capacity is available.

3.3 Advantages of Single-Phase Units

- The cost of a spare transformer is the cost of a single-phase unit, which is comparatively very much less than the cost of a complete spare 3-phase unit.
- They can be transported to site as completely assembled units and commissioned quickly.
- Reconditioning can be undertaken on individual units with a minimum outage time.
- It is possible to obtain different possible pairs of connections between the primary and secondary.

3.4 Disadvantages of Single-Phase Units

- They occupy more space
- They require additional support structure to form 3-phase connections.
- Expenditure on civil engineering works is more
- The problem of providing on-load tap changing gear and even if provided the cost of providing tap changing gear on each unit works out costlier by at least 50% when compared to a compact unit in a 3-phase transformer.

3.5 Considering all the above, there is little argument in favour of the adoption of single-phase units as compared to 3-phase units. Single-phase units are the only choice where 3-phase units cannot be transported because of their weight and dimensions and also if there are no facilities at site for the assembly, preparation and commissioning of the 3-phase units.

4.0 Types of Transformers

This is dealt with in reference to units normally installed in a power utility like NEPA.

4.1 Power Transformers

These are transformers of high rating of generally not less than 5MVA and 33KV and the rating also increases with the voltage rating. They may be of the step-up type installed at generating stations or of the step-down type installed at substations. They have a high utilisation factor, which means that they are arranged to work at a constant load equal to their

rating. Hence their maximum efficiency is designed to be at or near full load. Such power transformers installed in substations are provided with OLTC gear to regulate the voltage to be within permissible limits during peak load and off peak load hours. However, generator step-up power transformers are provided with only off circuit taps.

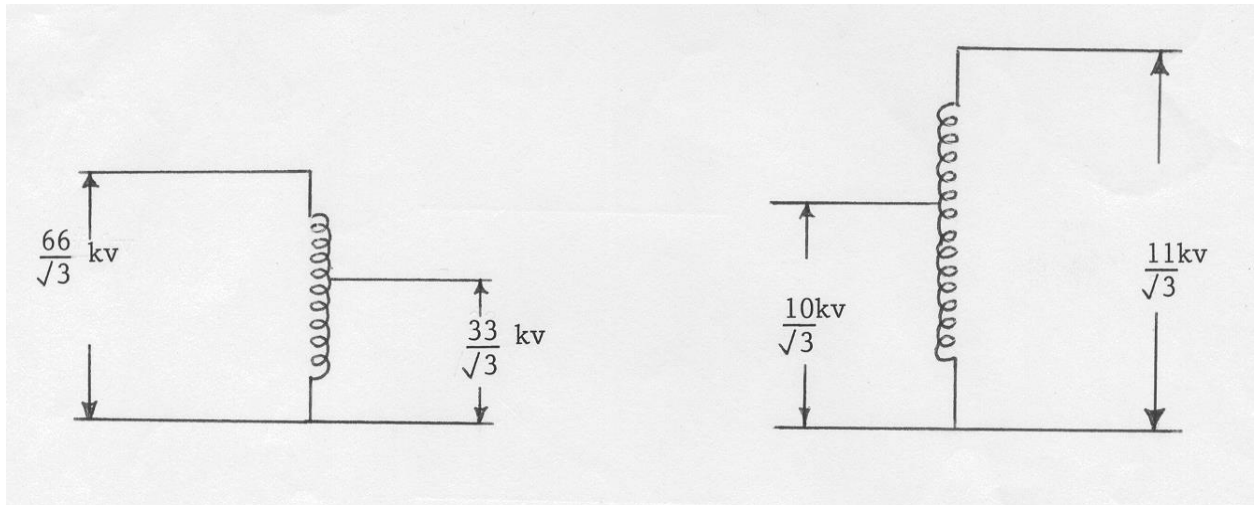
4.2 Distribution Transformers

These are transformers installed in H.V. distribution feeders to meet consumer voltage requirements. These are generally rated at 11KV and have a rating not exceeding 1000KVA. These transformers are characterised by an intermittent variable load, which is usually considerably less than the full load rating. They are therefore designed to have their maximum efficiency at between half and three quarter of full load. These transformers are not provided with any OLTC gear but with only off circuit taps.

4.3 Auto Transformers

An Auto Transformer is a transformer with a common winding for both primary and secondary. They are used in place of two winding power transformers where the ratio of transformation does not exceed 2 as they are cheaper than two winding transformers such as in a 132KV/66KV system or 66KV/33KV system.

They are used in distribution systems for improvement of voltage by boosting or bucking of supply voltage by a small amount. Typical connections of their use are shown below:



4.4 Instrument Transformers

This is dealt with exhaustively in a separate chapter.

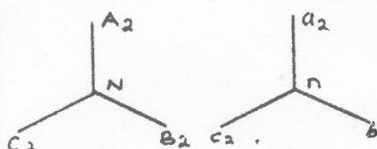
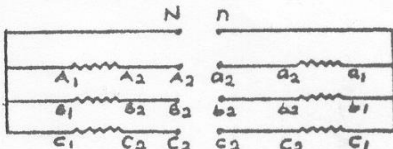
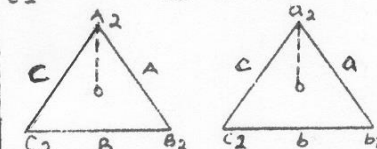
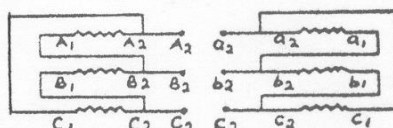
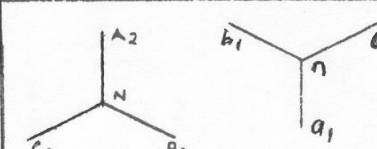
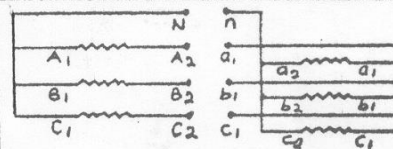
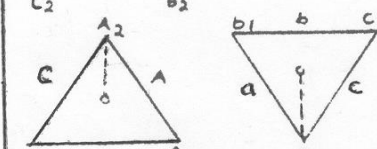
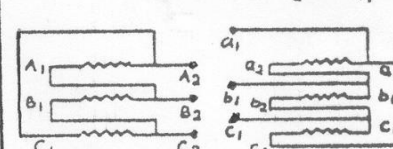
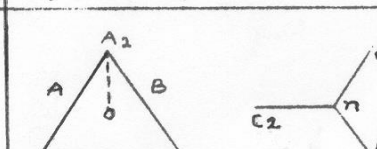
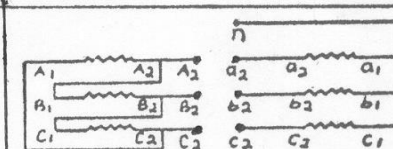
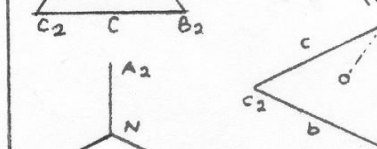
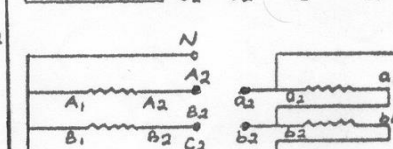
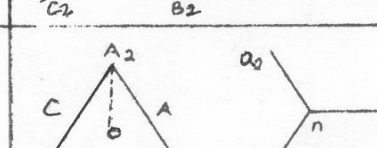
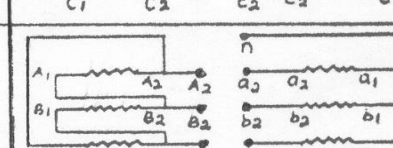
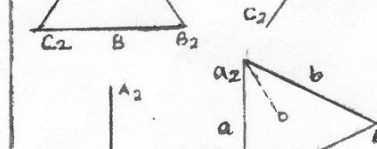
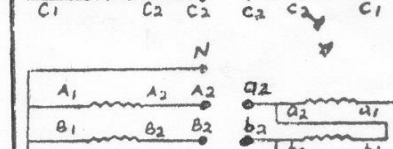
5.0 Three Phase Transformer connections or Vector group

Three phase transformers are divided into four groups depending upon the phase displacement between the primary and secondary terminals.

These groups are:

1. No phase displacement (0°)
2. 180° phase displacement
3. -30° phase displacement
4. $+30^\circ$ phase displacement

These vector groups; their symbols and connections are shown in the next page

Phase Group No. and Phase Displ.	Vector Symbols	Phasor Diagram of Induced Voltages (Phasor Rotation is Counter-Clockwise)		Winding Connections
		H.V Winding	L.V Winding	
Group 1 0°	Yy0			
	Dd0			
Group 2 180°	Yy6			
	Dd6			
Group 3 -30°	Dy1			
	Yd1			
Group 4 +30°	Dy11			
	Yd11			

6.0 Parallel Operation of Transformers

6.1 The following conditions must be strictly observed in order that 3-phase transformers may operate in parallel.

- (a) The secondaries must have the same phase sequence or the same phase rotation.
- (b) All corresponding secondary line voltages must be in phase.
- (c) The same inherent phase angle difference between primary and secondary terminals.
- (d) Same polarity.
- (e) The secondaries must give the same magnitude of line voltages.

In addition, it is desirable that:

- (f) The impedances of each transformer, referred to its own rating should be the same, i.e. each transformer should have the same percentage or per unit resistance and reactance.

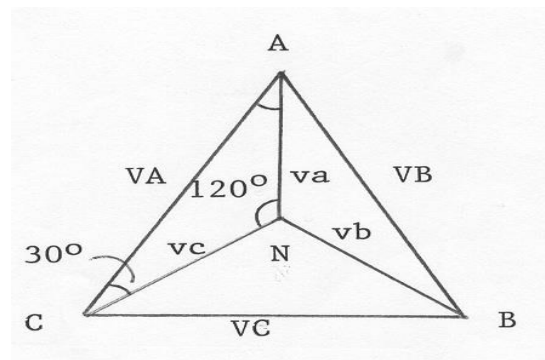
6.2 If conditions (a) to (e) are not complied with, the secondaries will simply short-circuit one another and no output will be possible.

6.3 If condition (f) is not complied with, the transformers will not share the total load in proportion to their ratings and one transformer will become over-loaded before the total output reaches the sum of the individual ratings. It is difficult to ensure that transformers in parallel have identical per unit impedance and this affects the load sharing.

6.4 It follows from the vector group connections indicated in paragraph 5.0, that if a pair of 3-phase transformers belong to the same group provided conditions (a) to (e) are fulfilled, then they can be paralleled with each other by connecting together terminals which correspond both physically and alphabetically. Thus, taking the case of two, 3-phase transformers belonging to vector group 1 with vector symbols Yy 0 and Dd 0, then these can be operated in parallel by connecting the terminals A21, B21 and C21 of the first transformer with terminals A21, B21 and C21 of the second transformer and similarly by connecting terminals a21, b21 and c21 of the first transformer with the second.

6.5 Sometimes it may be required to operate a 3-phase transformer belonging to one group with another 3-phase transformer belonging to another group. This is only possible with groups 3 and 4 by interchanging the external connections. The -30° phase shift can be corrected to $+30^\circ$ and vice-versa by interchanging the external primary connection of any one of the two transformers. However, this is not possible with groups 1 and 2 or with groups 1 or 2 with 3 and 4.

6.6 Phase shift in Delta-Star/Star-Delta Transformations (Vector groups 3 and 4)



From triangle ANC, we have:

$$\frac{V_A}{\sin 120^\circ} = \frac{V_a}{\sin 30^\circ}$$

$$V_A = V_a \frac{\sin 120^\circ}{\sin 30^\circ}$$

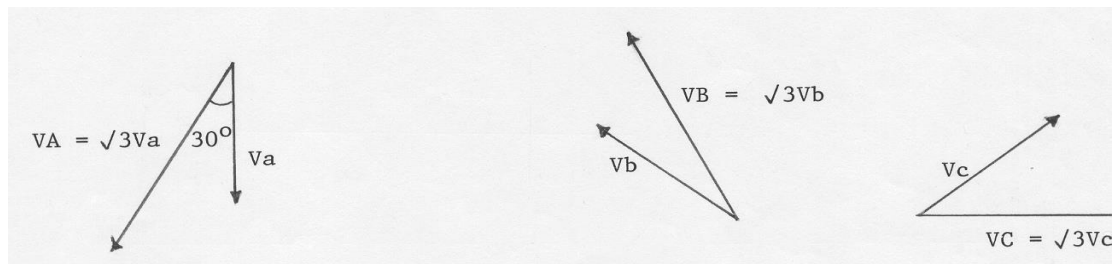
$$= V_a \frac{\cos 30^\circ}{\sin 30^\circ}$$

$$= \frac{V_a}{\tan 30^\circ} = \frac{V_a}{\frac{1}{\sqrt{3}}}$$

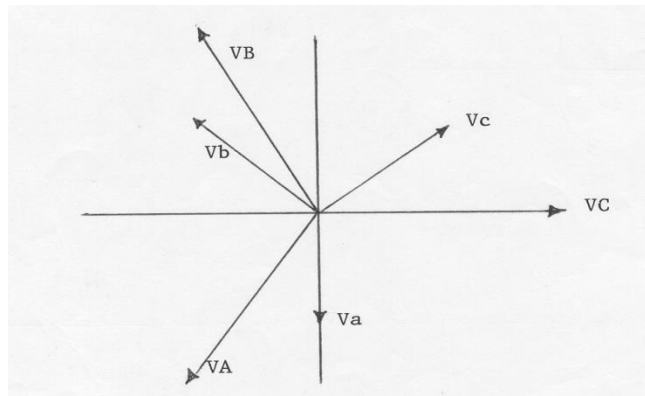
$$V_A = \sqrt{3} V_a$$

Also V_A is displaced from V_a by 30° as shown

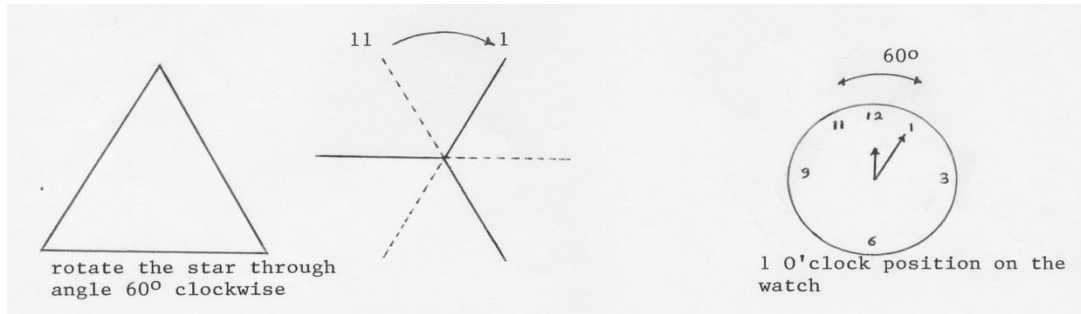
Similarly for the other three phases as follows:



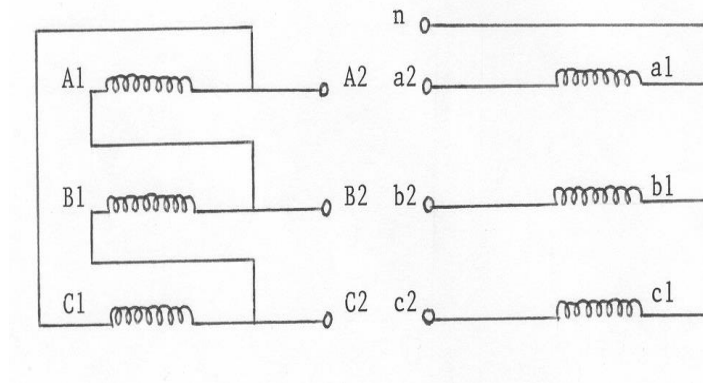
Combining the three phasor diagrams 1, 2 and 3 we have:



Similarly it can be shown for DY 1 group as follows:



The above phase shift can also be explained as follows with reference to



DY 11

Delta voltage V_A transformed to secondary star voltage V_a is given by:

$$V_A = V_{AB} - V_{CA} = \sqrt{3} V_a$$

$$V_a = \frac{V_{AB} - V_{CA}}{\sqrt{3}}$$

$$= \frac{1}{\sqrt{3}} [V_{AB} - V_{AB} \angle(240^\circ)]$$

$$= \frac{1}{\sqrt{3}} [V_{AB} - V_{AB} (-\frac{1}{2} - j\frac{\sqrt{3}}{2})]$$

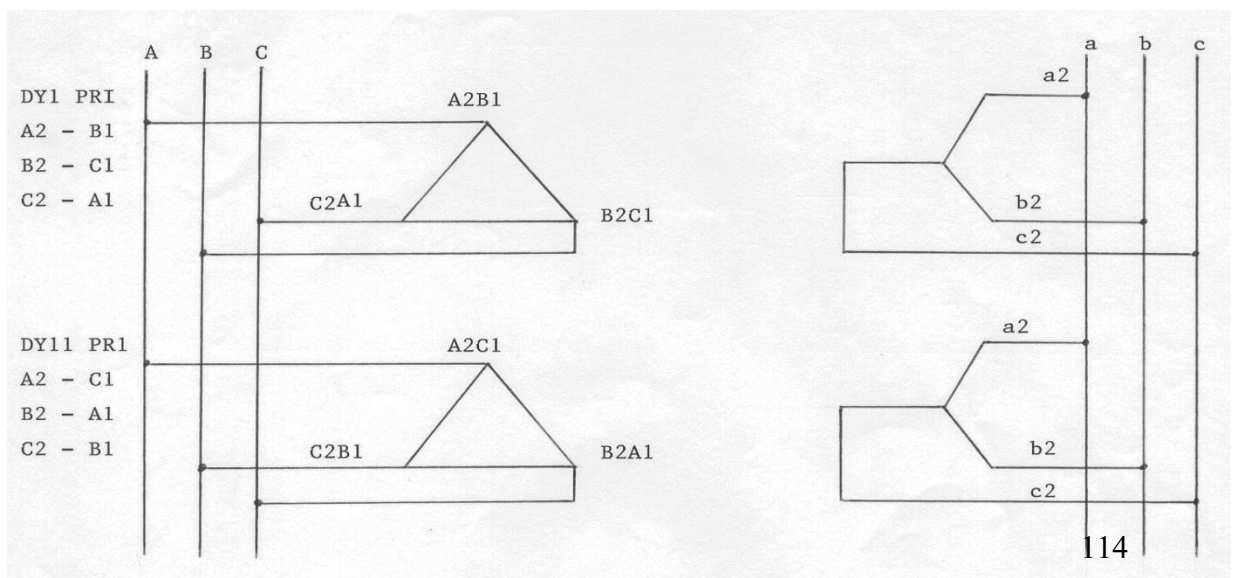
$$= \frac{1}{\sqrt{3}} [V_{AB} (1 + \frac{1}{2} + j\frac{\sqrt{3}}{2})]$$

$$\begin{aligned}
 & \frac{\sqrt{3}}{2} \\
 & = \frac{1}{\sqrt{3}} V_{AB} \left(1 + \frac{1}{2} + j \frac{\sqrt{3}}{2} \right) \\
 & = \frac{1}{\sqrt{3}} V_{AB} \left(\frac{3}{2} + j \frac{\sqrt{3}}{2} \right) \\
 & = \frac{\sqrt{3}}{3} V_{AB} \left(\frac{3}{2} + j \frac{\sqrt{3}}{2} \right) \\
 & = \frac{1}{3} V_{AB} \left[\frac{3\sqrt{3}}{2} + j \frac{3}{2} \right] \\
 & = V_{AB} \left(\frac{\sqrt{3}}{2} + j \frac{1}{2} \right) \\
 & = V_{AB} \angle 30^\circ
 \end{aligned}$$

Similarly it can be shown for the other phases and vector group DY 1.

6.7 Parallel Operation of DY 11 and DY 1 Transformers

The parallel operation of these transformers is done by changing the primary connections to any one of the two transformers as shown.



7.0 Procedures in Parallel Operation

7.1 While paralleling two transformers the following checks are to be conducted:

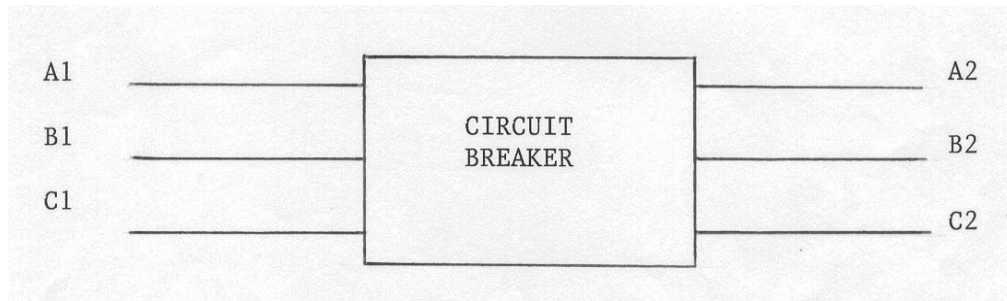
- (a) Measurement of terminal voltages of each transformer - done individually.
- (b) Checking the phase sequence of each transformer individually.
- (c) Phasing out the terminal voltage between each of the phases of the two transformers.

7.2 The following methods are employed for carrying out the above checks

- (a) By the use of phasing sticks.
- (b) By the use of an external low voltage supply.
- (c) By the use of voltage transformers.

7.3 Using Phasing Sticks

- (a) Phasing sticks are high voltage insulated sticks with built in condensers to reduce the voltage to an acceptable value as can be measured by normal indicating instruments.
- (b) These sticks are available in ratings of 5 to 33KV. They are also used to indicate if a line is alive or not.
- (c) In the diagram shown below A1, B1, C1 and A2, B2, C2 are the three phase secondaries of two transformers 1 and 2 to be paralleled. From the same supply both the transformers are energised keeping the CB or switch open



(d) Three sticks are used to determine the phase sequence. These sticks are labelled (1), (2) and (3) if no colour or other distinguishing marks are available. Two sticks are used to measure the voltages.

(e) The individual voltages are measured and recorded as follows by connecting a voltmeter to the low voltage end of the two phasing sticks (1) and (2).

Phasing Stick connection line end		Terminal at which voltage is measured	Magnitude of voltage measured
28 Stick 1	29 Stick 2		
A1	B1	A1 – B1	Say 110V
B1	C1	B1 – C1	110V
C1	A1	C1 – A1	110V
A2	B2	A2 – B2	110V
B2	C2	B2 – C2	110V
C2	A2	C2 – A2	110V

Adjust the voltage taps of any one of the two transformers if the voltages of transformer (1) are different from those of transformer (2).

(f) The next step is to determine the phase sequence. A phase sequence meter is connected to the low voltage end of the three phasing sticks such that terminals R, Y, B of phase sequence meter are connected to

sticks (1), (2) and (3) respectively. The line ends of sticks (1), (2) and (3) are held to terminals A1, B1, and C1 and the phase rotation observed and recorded as positive if anticlockwise and negative if clockwise. Similarly, the phase rotation is observed by holding sticks (1), (2) and (3) to terminals A2, B2 and C2. The phase sequence should be the same in both cases and if not; change any two of the primary connections of any one of the two transformers. Repeat the check and observe phase sequence to be the same.

(g) The last step is to phase out the two supply voltages. Stick (1) is held to source A1 and stick (2) is held to source terminals A2, B2, and C2 in succession and the voltages are recorded as follows:

Phasing Stick connection		Terminal at which voltage is measured	Magnitude of voltage measured
Stick 1	Stick 2		
A1	A2	A1 – A2	0
	B2	A1 – B1	190
	C2	A1 – C2	190
B1	A2	B1 – A2	190
	B2	B1 – B2	0
	C2	B1 – C2	190
C1	A2	C1 – A2	190
	B2	C1 – B2	190
	C2	C1 – C2	0

From the above it indicates that terminals A1, B1 and C1 correspond to terminals A2, B2, C2 and the CB or switch can now be safely closed to

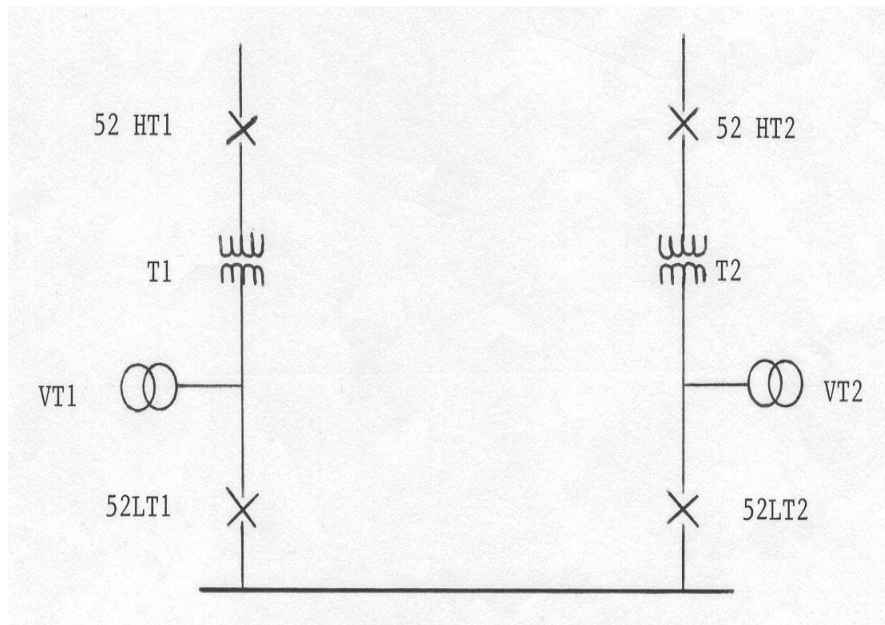
parallel the two sources. However, during the above test, if A1 - B2, B1 - C2 and C1 - A2 show zero voltages as against A1 - A2, B1 - B2 and C1 - C2 respectively then, the phases B2, C2, and A2 must be paralleled with A1, B1, and C1 respectively by interchanging the secondary terminals.

7.4 By the method of an external supply source

- (a) This method is employed where phasing sticks are not available and also if V.T.'s are not available.
- (b) The supply used is generally 400 volts, 3-phase supply from which both the transformers are energised keeping the CB or paralleling switch open.
- (c) Checks as mentioned in paragraph.7.3 (e), (f) and (g) are conducted for paralleling.

7.5 By the use of Voltage Transformers

- (a) This is by far the method always employed in 330KV, 132KV and other substations for paralleling of transformers and for paralleling of two different sources of supply.
- (b) Two sets of V.T.'s are essentially required for this method. The checks are explained with reference to the diagram appended below.



(c) Transformer 1 is energised by closing breaker 52HT1 and keeping 52LT1, 52LT2 and 52HT2 open. The phase sequence and voltages at the secondary of VT1 are measured and recorded as stated in paragraph 7.3 (e) and (f). Next 52LT2 is closed to energise VT2. The phase sequence and voltages at secondary of VT2 are measured and recorded as per paragraph 7.3 (e) and (f). The V.T. secondaries of VT1 and VT2 are also phased out as per paragraph 7.3 (g).

This test is to ensure that both the V.T.'s have the same polarity, connecting secondary voltages, ratio and phase sequence. Breakers 52LT2, 52LT1 and 52HT1 are now opened out.

(d) The test as per paragraph (c) above is repeated for transformer (2) by closing 52HT2 and keeping 52LT2, 52LT1 and 52HT1 open. This test is to

ensure again that both the V.T.'s have the same polarity, connecti

ons,

secondary voltages, ratio and phase sequence.

- (e) If the V.T.'s have a difference in phase sequence, polarity etc., then these have to be suitably corrected and tests (c) and (d) repeated.
- (f) The last step is phasing out the two secondary voltages. For this test, breakers 52LT1 and 52LT2 are kept open. Both the transformers are energised through breakers 52HT1 and 52HT2 and the voltages phased out through the secondaries of the two VT's as enumerated in paragraph 7.3 (g).
- (g) If there is a duplicate bus system provided with bus V.T.'s for each bus, then each bus is charged from the secondary of each transformer with the bus coupler breaker open for conducting the necessary checks before paralleling.

8.0 Case studies on paralleling of Transformers

8.1 Paralleling of Transformers of unequal ratings and same percentage impedances

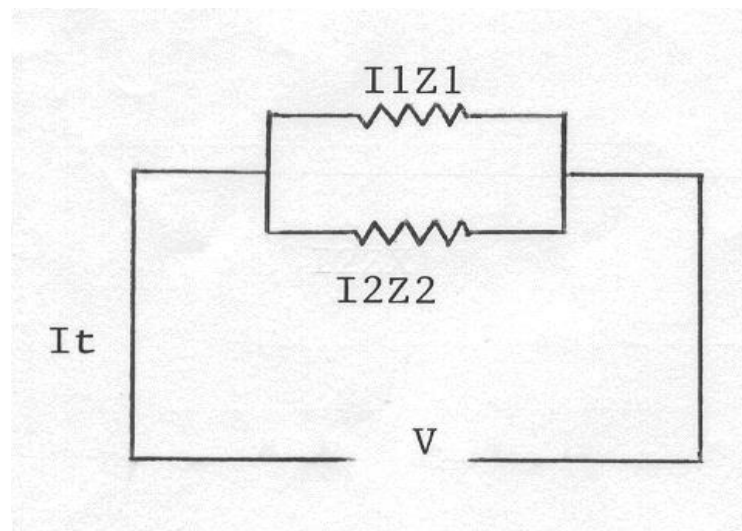
Data	$(KVA)_1$	-	Rating of Transformer No.1
	$(KVA)_2$	-	Rating of Transformer No.2
	Z_1	-	% impedance of Transformer No.1
	Z_2	-	% impedance of Transformer No.2
	I_t	-	Total load current

I_1 - Load current shared by Transformer

No.1

I_2 - Load current shared by Transformer

No.2



Basically the problem is one of two impedance connected in parallel as shown.

$$\text{Here: } V = I_1 Z_1 = I_2 Z_2 \quad 1$$

$$\text{And: } I_t = I_1 + I_2$$

From eqn. (1)

$$I_1 = I_2 \frac{Z_2}{Z_1}$$

$$I_t = I_2 \frac{Z_2}{Z_1} + I_2$$

$$= \frac{I_2 (Z_2 + Z_1)}{Z_1}$$

$$\text{Or } I_2 = \frac{I_t (Z_1)}{(Z_1 + Z_2)} \quad 2$$

$$\text{Similarly } I_1 = \frac{I_t (Z_2)}{(Z_1 + Z_2)} \quad 3$$

Multiply eqn. (2) on both sides by V the secondary load voltage

We now have

$$VI_2 = \frac{VI_t (Z_1)}{(Z_1 + Z_2)}$$

$$\text{Or } \frac{VI_2}{1000} = \frac{VI_t}{1000} \frac{(Z_1)}{(Z_1 + Z_2)}$$

$$(KVA)_2 = (KVA)_t \frac{(Z_1)}{(Z_1 + Z_2)}$$

$$\text{Similarly } (KVA)_1 = (KVA)_t \frac{(Z_2)}{(Z_1 + Z_2)}$$

8.2 Problem: To find the load shared by 2Nos. of 132/33KV Transformers of rating 15 MVA and 25 MVA with % impedances of 10% and 6% respectively.

Total load current = 700 A

Transformer No.1 - 15MVA, 132/33KV; 10% impedance

$$I_{fl} = \frac{15 \times 10^3}{\sqrt{3} \times 33} = 262.5 \text{ A}$$

Transformer No.2 - 25MVA, 132/33KV; 6% Impedance

$$I_{fl} = \frac{25 \times 10^3}{\sqrt{3} \times 33} = 437.5 \text{ A}$$

Assume MVA base = 100.

The per unit impedances of the transformers is given by:

$$Z_{pu} (1) = \frac{0.1 \times 100}{15}$$

$$= 0.67 \text{ p.u}$$

$$Z_{pu} (2) = \frac{0.06 \times 100}{25}$$

$$= 0.24 \text{ p.u}$$

Load current shared by Transformer No.1

$$I_1 = I_t \frac{(Z_2)}{(Z_1 + Z_2)}$$

$$= 700 \frac{(0.24)}{0.67 + 0.24}$$

$$= 700 \times \frac{0.24}{0.91}$$

$$= 184.6 \text{ A}$$

Load current shared by Transformer No.2

$$\begin{aligned}
 I_2 &= I_t \frac{(Z_1)}{(Z_1 + Z_2)} \\
 &= 700 \frac{(0.67)}{0.91} \\
 &= 515.4\text{A}
 \end{aligned}$$

It can be observed that transformer No.2 is already overloaded while transformer No.1 is lightly loaded.

This shows that with unequal % impedances, the load will not be shared in proportion to their ratings.

8.3 Paralleling of Transformers with unequal % Impedances

Problem: To find the load shared by 2 Nos. of 132/33KV 15 MVA Transformer of equal rating but with unequal % impedances of 10% and 10.2%.

Total load current = 500 A

Load current shared by Transformer No.1 (Impedance 10%)

$$\begin{aligned}
 &= 500 \times \frac{(10.2)}{(10 + 10.2)} \\
 &= 500 \times \frac{10.2}{20.2} \\
 &= 252.5 \text{ A}
 \end{aligned}$$

Load current shared by Transformer No.2 (Impedance 10.2%)

$$\begin{aligned}
 &= 500 \times \frac{10.0}{20.2} \\
 &= 247.5 \text{ A}
 \end{aligned}$$

This shows that the transformer with higher impedance shares less load than the transformer with lower impedance. In such a case, the loading should be such as not to exceed the full load current.

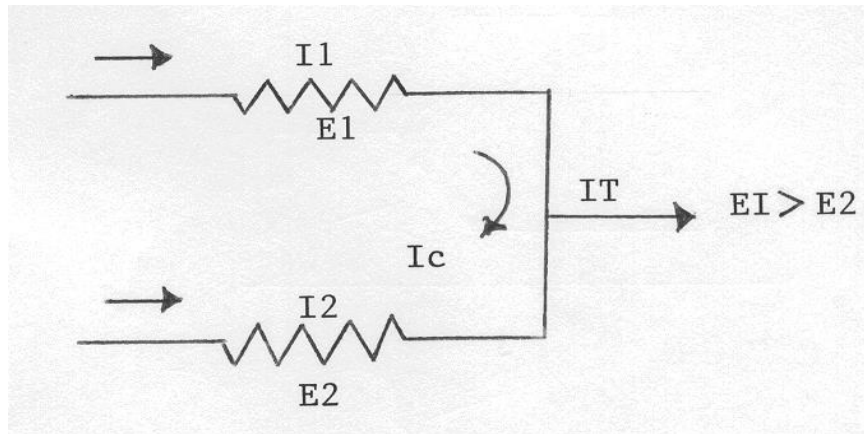
8.4 Paralleling of Transformers with unequal secondary voltages

Let E_1 = secondary phase voltage of Transformer No. (1)

E_2 = secondary phase voltage of Transformer No. (2)

Z_1 = impedance of Transformer No. (1)

Z_2 = impedance of Transformer No. (2)



The unequal secondary voltages will cause a circulating current I_c to flow.

The magnitude of this current is given by the equation:

$$I_c = \frac{E_1 - E_2}{Z_1 + Z_2} \quad (E_1 > E_2)$$

The current in transformer (1) will be $(I_1 + I_c)$ and that in transformer (2) will be $(I_2 - I_c)$. Since Z_1, Z_2 are small in magnitude, the difference $(E_1 -$

E2) must also be small as otherwise a large circulating current will flow overloading the transformers.

Problem - To find the load shared by 2 Nos. of 5MVA; 33/11KV transformers of equal % impedance of 6% but with unequal secondary voltages of 11.2KV and 11.0KV. Total load current = 500 A

Secondary full load current of each transformer will be:

$$= \frac{5 \times 10^6}{\sqrt{3} \times 11 \times 10^3}$$

$$I_{fl} = 262.5 \text{ A}$$

Impedance Z of each transformer will be:

$$= \frac{V_{ph} \times \% Z}{I_{fl} \times 100}$$

$$= \frac{11000 \times 6}{\sqrt{3} \times 262.5 \times 100}$$

$$Z1 = Z2 = 1.45 \text{ ohms}$$

$$I_c = \frac{E1 - E2}{Z1 + Z2}$$

$$= \frac{(11.2 - 11.0) \times \frac{10^3}{\sqrt{3}}}{1.45 + 1.45}$$

$$= 39.8 \text{ A}$$

$$\text{Current in transformer 1} = I_1 + I_c$$

$$\begin{aligned}
&= \frac{I_t (Z_2)}{(Z_1 + Z_2)} + I_c \\
&= \frac{500 (6)}{12} + 39.8 \\
&= 250 + 39.8 \\
&= 289.8 \text{ A}
\end{aligned}$$

This is greater than the full load current of 262.5 A. Hence it is not safe to operate the two transformers in parallel with unequal secondary voltages. But the transformers may be operated in parallel provided that the current in each transformer does not exceed the full load current.

9.0 Three Winding Power Transformers

9.1 In a large EHV substation there will be at least three high voltage systems from the low-tension auxiliary supplies. In some substations there may be even four or five high voltage systems. Although transformers with four high voltage windings are being manufactured, such transformers are not extensively used, because there is no advantage in having four different voltage systems in the same tank as the risk of a fault on any one voltage system involves all the voltage systems.

9.2 An example of an EHV substation having three different voltages is a 330KV substation with voltages at 330KV, 132KV and 11KV.

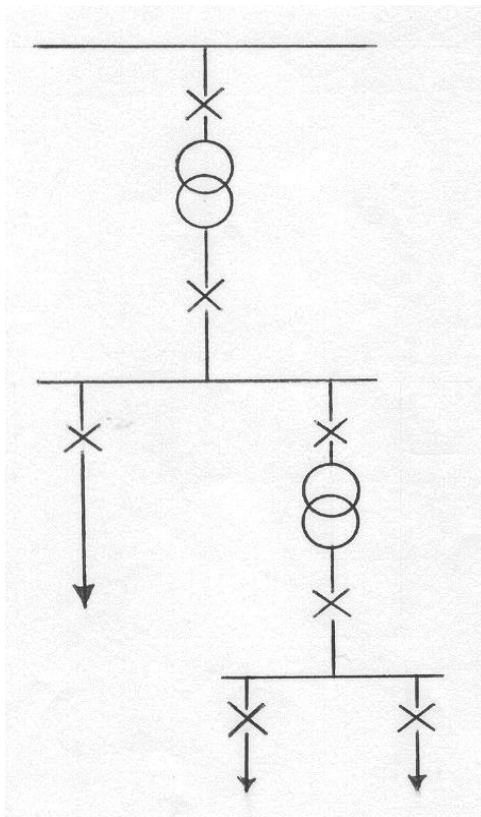
9.3 A comparison is now made as whether to have two winding transformers of 330/132KV and 132/11KV or three winding transformers of 330/132/11KV in an EHV substation with three voltages. The 11KV load in

such a substation is to meet the local loads around the substation and also for the requirements of the station auxiliary supplies. This load may be around 10 to 15MVA.

The two schemes are shown by single line diagrams as follows:

Scheme (A)

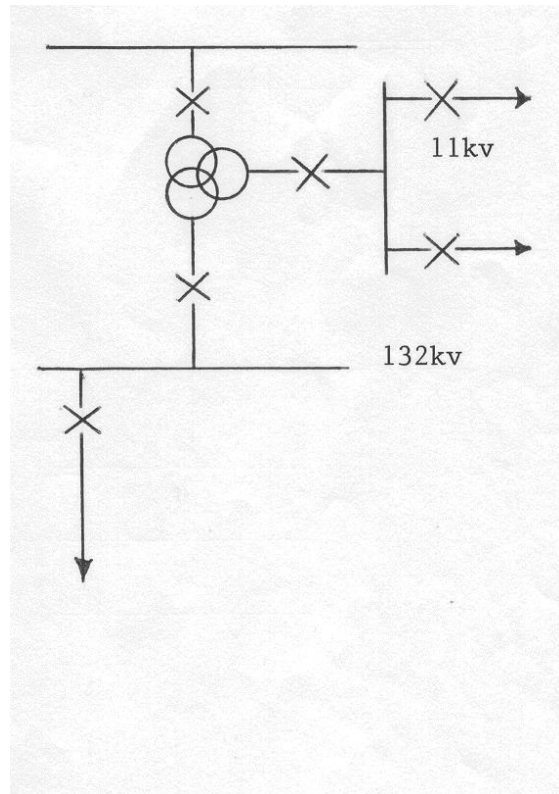
Two winding transformers



transformers

Scheme (B)

Three winding



9.4 Comparing scheme (B) with scheme (A) we have the following merits and demerits

Merits

- (a) The number of transformers, circuit breakers, CT's, isolators and control panels is reduced to a minimum. There is therefore a considerable saving in the cost of equipment required.
- (b) There is considerable saving in the cost of civil engineering and structural works because of the fewer equipment.
- (c) The layout is simple and occupies less space because of the fewer equipment and operation is also simple.
- (d) There is saving in energy because of the reduced transformation losses.
- (e) Besides, it is inevitable to provide a third winding in a star-star connected power transformer. This third winding in such transformers is also called a 'Stabilizing Winding' or 'Tertiary Winding'. This winding is connected in a closed delta to provide a circulating path for the third harmonic voltages and zero sequence currents or ground fault currents.

It is pertinent to note here that a star-star connection is almost always resorted to in the case of EHV transformers of 132KV and above such as in 330/132KV transformers. The reason being that the cost of such a transformer is cheaper because the windings need be insulated for only $1/\sqrt{3}$ times of the line voltage instead of for the full line voltage of $\sqrt{3}$ times the

star voltage with a delta winding. Such a closed delta winding can be made use of for the third voltage, without the necessity of having a separate transformer.

Demerits

(a) The main disadvantage is the increased fault level at 11KV because the voltage is directly transformed from 330 to 11KV. Hence 11KV switchgear of adequately higher rupturing capacity will have to be installed.

The cost of such switchgear may be much more than that of such switchgear installed in the secondary of a 132/11KV transformer.

(b) Since the third winding is a closed delta, an artificial neutral has to be necessarily created by the use of earthing transformers. This is a disadvantage as it adds to the initial cost.

(c) The other disadvantage is that the units are exposed directly to the short circuit stresses because of faults on 11KV lines. The 11KV overhead networks, particularly if carried into rural areas are quite long and extensive. These lines are carried on pin insulators and are therefore susceptible to frequent faults. Such frequent faults, stress the windings and reduces the life of the transformer. If the 11KV winding feeds an urban network through an underground cable system, then this arrangement would prove to be the best and the fear of the transformer being exposed to short circuit stresses is not there.

(d) The capacity of the third winding is generally limited to $1/3^{\text{rd}}$ of the capacity of the main transformer. Hence if there is a rapid increase in the growth of the 11KV load, augmentation of the 11KV capacity to meet this load becomes a problem unless another two winding 132/11KV transformer is added at the substation. This creates problems in load sharing and parallel operation because the impedance of the third delta winding is very much low when compared to the impedance of a similar voltage in a two winding transformer.

10.0 Cooling of transformers and Cost Comparison of the cooling methods

10.1 The B.S.S. recognises three cooling methods for transformers namely Air, Mineral oil and Synthetic liquid. Since almost all of the power transformers are mineral oil cooled, the method of cooling by mineral oil is only dealt with here. The methods of cooling with oil immersed transformer is classified as follows:

10.2 Oil Immersed Natural Cooled - Type ON

Cooling is by circulation of oil under natural thermal heat only. In large transformers the surface area is not sufficient for dissipation of heat by radiation. As such additional surface area is provided for the cooling fins; also called radiators.

10.3 Oil Immersed Air Blast - Type OB

Cooling is similar to type ON except that air circulation is done by external fans mounted below the radiators.

The advantage is the reduction in the size of the transformer for the same rating and consequently a saving in the cost.

10.4 Oil Immersed Water Cooled - Type OW

An internal cooling coil or tubing is mounted through which water is circulated. This requires a free and abundant supply of water. Cooling is by convection.

10.5 Forced Oil Natural Air Cooled - Type OFN

It is similar to type ON except that a cooling pump is installed in the oil circuit for better circulation of oil.

10.6 Forced Oil Air Blast Cooled - Type OFB

It is a combination of type OB and type OFN.

10.7 Forced Oil Water Cooled - Type OFW

It is similar to type OW except that a cooling pump is added in the oil circuit for forced oil circulation into a heat exchanger in which water is allowed to flow.

10.8 It must be noted here that transformers with type OFB and type OFW cooling will carry no load if air or water supply is cut off.

109 It is quite common to select large power transformers of 15MVA and above with two or more systems of cooling namely ON/OFB or ON/OB or

ON/OB/OFB. These determine the type of cooling and permissible loading and as soon as the loading exceeds a preset value, fans/pumps are switched on automatically. An indication of the operation of the fans/pumps is given in the Transformer control panel. The rating of such a transformer with ON/OB cooling will be written as for example 45/60MVA, which means that up to 45 MVA load, the fans will not be working. The fans will be switched on automatically when the load exceeds 45MVA.

10.10 The type of cooling has a bearing on the cost of the Transformer. The approximate relationship on the cost with different methods of cooling is mentioned below.

Type of cooling	ON	OFN	ON/OB	ON/OFB	OFB	OFW
% Cost	100	95	90	85	80	75

10.11 The ON cooling is the simplest method of cooling with no fans or pumps or auxiliary motors. It is used in all distribution transformers and in power transformers up to 15MVA. The saving in cost in power transformers of up to 15MVA in changing the cooling from ON to other types is negligible.

10.12 The OFW cooling is only employed in transformers installed at hydroelectric power stations where an abundant supply of cooling water is assured. But at other stations, special arrangements have to be made for water supply and disposal of hot water, which may increase the cost of the transformer.

11.0 Requirements and characteristics of insulating oil

11.1 The mineral oil in transformers is used not only as an insulating medium but also as a heat-transferring medium to dissipate the heat produced in the windings and the core. The life of a transformer is dependent on the quality of the insulating oil and as such it is very necessary to use insulating oil of a high quality or standard.

11.2 The essential qualities required of the insulating oil are:

- (a) High dielectric strength
- (b) Permits good transfer of heat
- (c) Low specific gravity - suspended particles settle at bottom of tank rapidly.
- (d) Low viscosity - better cooling rate
- (e) Low pour point
- (f) High flash point - prevents vaporisation of oil
- (g) Chemical stability

11.3 There are various national and international standards on characteristics of oil. These are characterised by:

- (a) Sludge value (Max) - %
- (b) Acidity after oxidation - mg KOH/g
- (c) Flash point (min) - °F or °C
- (d) Viscosity at 70 °F or 21.1°C (Max) centistokes or ... secs.Redwood
- (e) Pour point - °F or °C
- (f) Electric strength - KV rms for 1 minute

(g) Acidity Neutralisation value

- Total - mg KOH/g
- Inorganic

(h) Saponification value (max) - mg KOH/g

(i) Copper discoloration - +ve or –ve

(j) Specific Gravity

(k) Volume resistivity - ohms/cm³

(l) Water content – ppm

(m) Tan delta or loss angle

12.0 Tests on Transformers

These are governed by various national and international standards. Most of these standards recommend the following tests.

12.1 Routine tests

(a) Measurement of winding resistance

(b) Ratio, polarity and phase relationship

(c) Impedance voltage

(d) No load losses and no load current.

(e) Load losses

(f) Insulation resistance

(g) Separate source voltage withstand test

12.2 Type tests

- (a) Impulse voltage withstand test
- (b) Temperature rise test

13.0 Field tests and Commissioning

These tests are conducted at the time of commissioning on a completely assembled transformer after necessary drying out of the winding core and filtering of oil.

- (a) Measurement of insulation resistance and Polarisation Index
- (b) Ratio test on all the tap positions
- (c) Open circuit test, no load current and no load losses
- (d) Short circuit test and load losses
- (e) Oil test
- (f) Operation of tap changer manually and electrically on local and remote
- (g) Operation of cooling fans/pumps and motors
- (h) Measurement of earth resistance of transformer grounds namely; neutral and body
- (i) Operation of Bucholtz relay for alarm/tripping
- (j) Measurement of loss angle of EHV bushings

14.0 Maintenance of Power Transformers

Normally, every manufacturer lists out the maintenance procedures to be followed during the lifetime of a transformer in service. However, the

commonly recommended measures in almost all power transformers are the following:

- Hourly: Recording readings of:
 - (i) Load current
 - (ii) Load KW
 - (iii) Temperature
 - (iv) Voltage
- Half Yearly/Yearly:
 - (i) Insulation resistance
 - (ii) Oil test for breakdown voltage, water content and acidity.
- Periodically: Changing the silica gel when the colour has changed from blue to pink.

CHAPTER SIX

INSTRUMENT TRANSFORMERS

1.0 INTRODUCTION

Instrument Transformers are used in power system to:

- (a) Protect personnel and apparatus from high voltages and large currents.
- (b) Allow for reasonable insulation level and current carrying capacity in protective relays, meters and other instruments.

2.0 Classification:

2.1 They are classified as:

- (a) Protective Transformers
- (b) Metering transformers.

2.2 Normally both the above functions are combined in one unit in such apparatus used in power systems. Hence the general term Instrument Transformers.

2.3 There are occasions where these are used exclusively for commercial metering and in which case they are called Metering Transformers.

3.0 Types of Instrument Transformers

There are only two main types namely:

- (a) Current Transformers
- (b) Voltage Transformers.

4.0 Current Transformers

4.1 Current Transformers are used whenever the magnitude of the operating current has to be reduced to the value for which instruments, meters and protective devices are designed. At the same time current transformers isolate metering and protective devices from the system voltage.

4.2 The essential requirement of a current transformer is to deliver on its secondary a quantity, which truly represents the applied quantity on its primary.

The failure of protective system to perform its function correctly is due to incorrect application of these transformers. Hence current and voltage transformers must be regarded as constituting part of the protective system and be carefully matched with the relays to fulfill the requirements of the system.

4.3 The requirements of a protective current transformer are quite different from that of a metering C.T. The metering C.T. is only required to perform its function over the normal range of load current, while the protective C.T. is required to give satisfactory protection over a wide range of fault conditions.

4.4 Theory of Current Transformers

The current transformer operates like any other transformer in that the voltage ratio and the reciprocal of the current ratio are proportional to the turns ratio i.e.

$$\frac{E_p}{E_s} = \frac{N_p}{N_s}$$

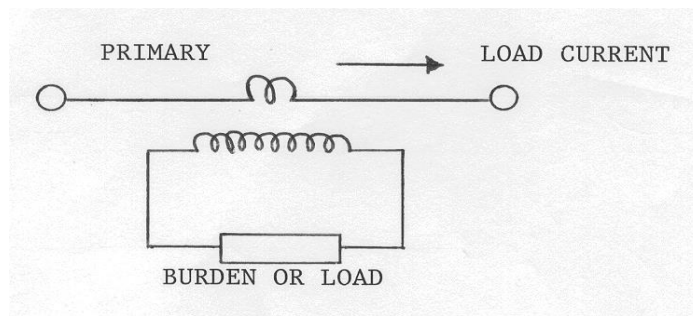
Where: p and s denote primary and secondary

E – Voltage

I – Current

N - number of turns.

- 4.5** The primary winding is connected in series with the load and it is the latter which determines the current induced in the secondary winding.

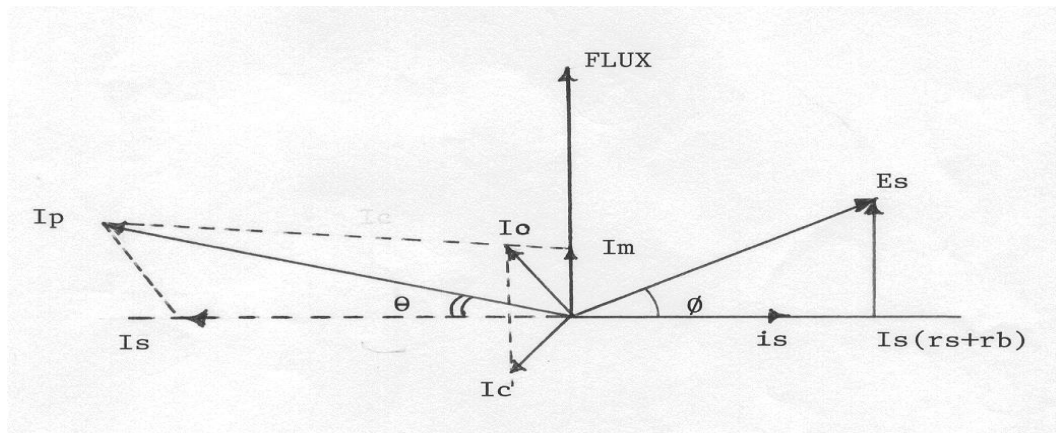


The secondary is connected to a burden, which does not vary, and the primary current is not influenced by the magnitude of the secondary burden. The current in the secondary is determined by the current in the

primary winding. The magnitude of this flux is not determined by the connected secondary burdens.

The flux density in the core is a small fraction of that usually employed in power transformers.

4.6 Phasor diagram of a C.T.



- (a) The secondary current I_s lags behind the secondary induced voltage, E_s by an angle ϕ . This angle is determined by the impedance of the external burden and the impedance of the secondary winding.
- (b) The primary current I_p is the resultant of $-I_s$ and I_o the exciting current. The exciting current I_o consists of two components namely I_c the core-loss component and I_m the magnetising component.
- (c) The angle θ between I_p and $(-I_s)$ is the phase displacement error between the primary and secondary currents. This angle is expressed in minutes of arc and is referred to as the Phase Displacement Error.

(d) The difference in lengths between I_p and $(-I_s)$ is called the Ratio Error.

When this ratio error is expressed as a percentage of the primary current I_p , it is called Percentage Ratio Error.

(e) The secondary voltage E_s is controlled by the burden on the secondary circuit and the impedance of the secondary winding itself i.e.

$$\text{Burden } Z_b = r_b + jX_b$$

$$\text{Secondary winding impedance } Z_s = r_s + jX_s$$

$$\text{Total secondary impedance } Z_t = Z_b + Z_s$$

$$= (r_b + r_s) + j(X_b + X_s)$$

$$E_s = I_s (Z_b + Z_s)$$

1

The e.m.f induced in any transformer winding is given by the equation:

$$E = 4.44 \phi n f$$

Where ϕ is the flux in Weber

n the number of turns in the winding

f the supply frequency.

The number of turns n and f the supply frequency are constant

$$E \propto \phi$$

$$\text{Also } \phi = B A$$

Where B is flux density

A is cross sectional area

We can now write eqn. 1 as follows:

$$\phi \propto E_s \text{ or } I_s (Z_b + Z_s)$$

This shows that:

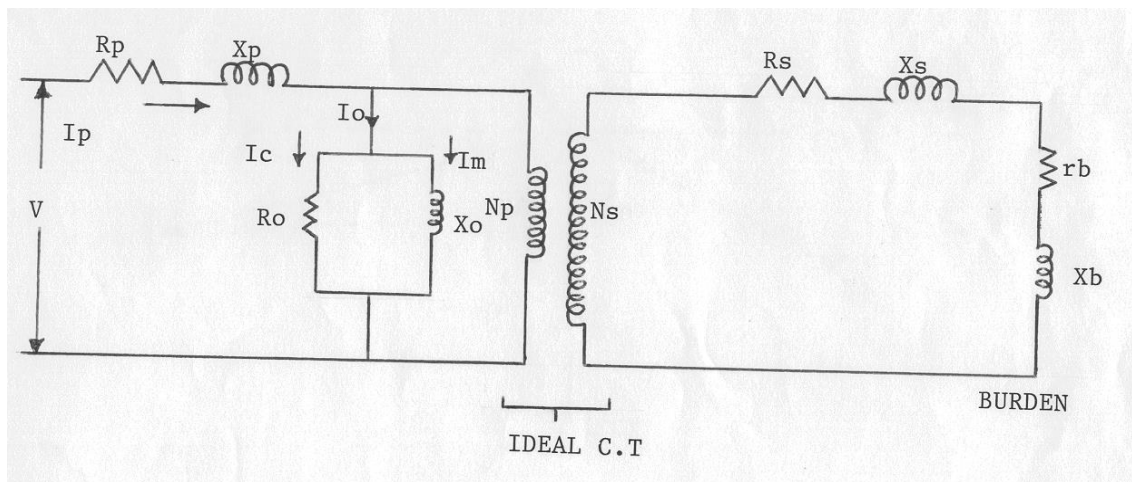
- (i) The magnetic flux depends upon the secondary voltage E_s or secondary current I_s since burden Z_b and internal impedance Z_s are fixed.
- (ii) The flux of the current transformer and also the flux density are variable and they depend upon the primary current I_p because:

$$I_p N_p = I_s N_s \text{ or } I_s = \frac{I_p N_p}{N_s}$$

4.7 Equivalent circuit of C.T.: High Reactance and Low Reactance

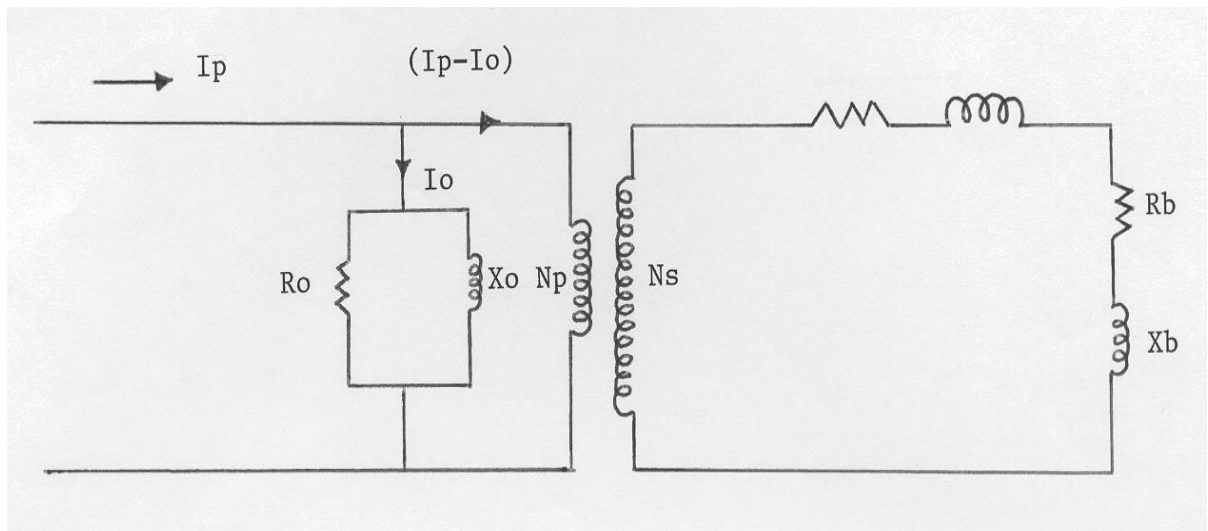
Type C.Ts

The equivalent circuit of an ideal C.T. is as follows:



- (a) The primary winding impedance along with the exciting impedance is shown to the left and the secondary winding impedance along with the burden impedance is shown to the right.

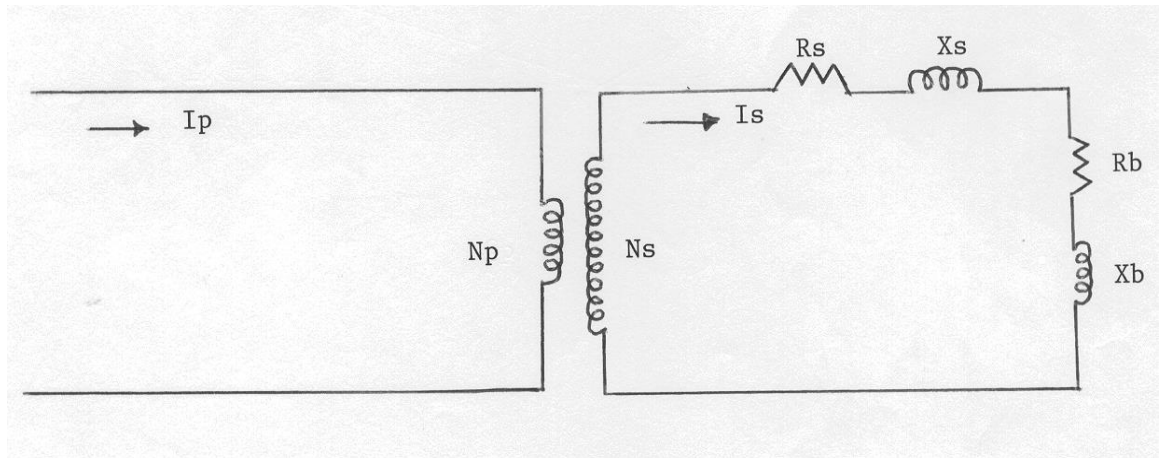
- (b) In a C.T., the primary current I_p is independent of any voltage applied to drive the current. Hence the impedance of the primary winding is of no significance and can be safely omitted.
- (c) However, there are two types of CT's namely the High Reactance type and Low Reactance type.
- (d) The High Reactance type C.T. is usually a wound primary C.T. having considerable magnetic separation between the primary and secondary windings. In such a C.T. the primary exciting impedance is of importance. The equivalent circuit of such a C.T. is as follows:



- (e) The second type of C.T. of the Low Reactance Type has no primary winding. The primary winding is just a bar called the bar primary. A bushing type C.T. is

an example of this type. There is no magnetic separation between the primary winding and secondary winding. As such the primary exciting impedance is only fictitious and can be safely omitted.

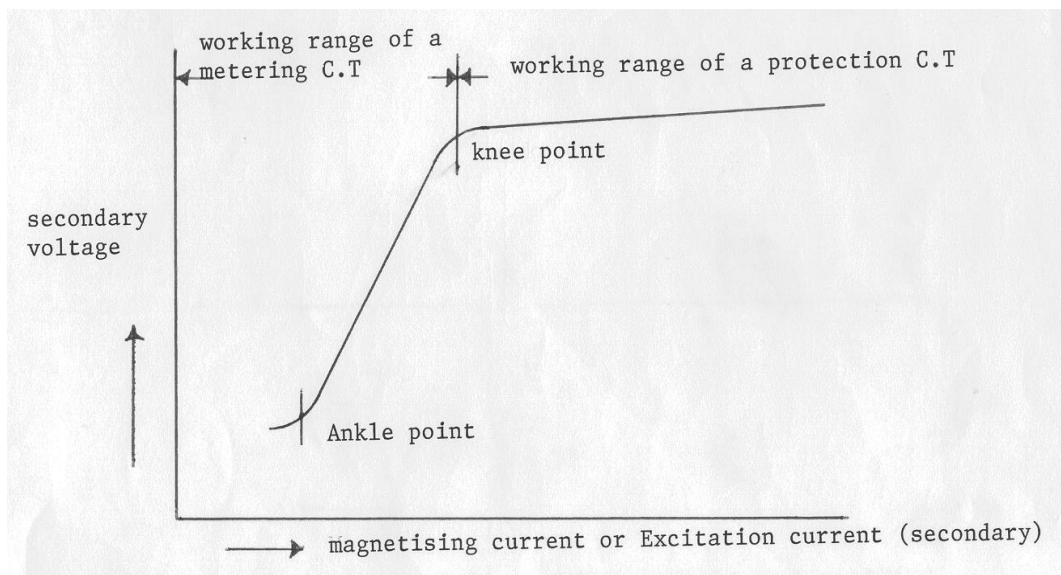
The equivalent circuit of such a C.T is as follows:



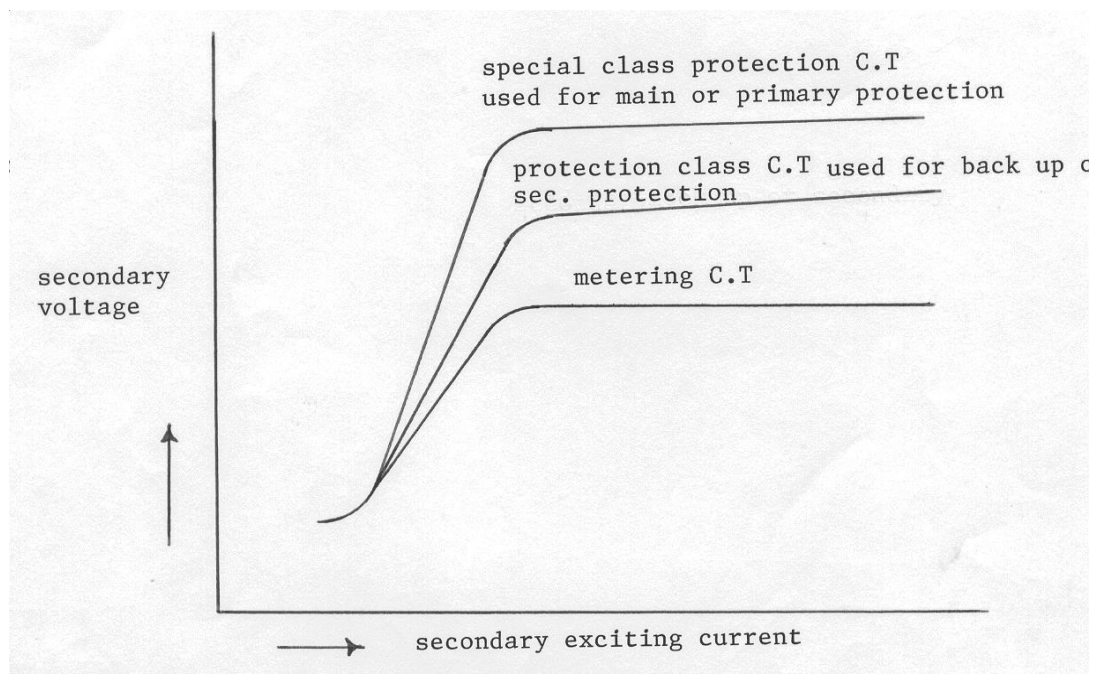
- (f) In ANSI accuracy classification, these high reactance and low reactance CT's are denoted by letters T and C respectively, and were also formerly called Type H and L respectively.

5.0 Characteristics of Current Transformers

- (a) The general form of a C.T. excitation characteristic is as follows:



- (b) The characteristic as can be seen is divided into three regions namely:
- (i) Ankle point
 - (ii) Linear or straight line region
 - (iii) Knee point
- (c) The working range of a metering C.T., is from the Ankle point to the Knee point and slightly beyond it.
- (d) Thus the metering C.T., operates between 10% and 120% of the rated current and saturates beyond this in order to protect the metering instruments.
- (e) The working range of a protective C.T. extends over the full range from the ankle point and beyond. Generally the operating region of a protective C.T. is beyond the knee point as it is required to operate at fault currents, which is several times the full load or rated current.
- (f) The excitation voltages of metering and protective C.T's is as follows:



(g) The knee point voltage of a metering C.T. is generally around 60 to 120V and is kept low so as to protect meters.

(h) The knee point voltages of protective C.T.'s are generally quite high varying from 200V to 1900V depending upon the requirements of the relay. The upper limit of 1900V is specified because the secondary cables from a C.T. are generally rated to withstand 2KV for about 1 or 3 minutes and 660 volts or 1100 volts continuously.

6.0 Errors in Current Transformers

6.1 Ratio Error

This is the amount by which the secondary current differs from the exact proportionality of the primary current. It is generally expressed as a percentage of the rated secondary current or rated primary current.

Thus if I_p is the primary current and I_s the secondary current and

$$K_n = \frac{I_p}{I_s} \quad \text{the transformation ratio.}$$

$$\% \text{ Ratio Error} = \frac{\frac{I_p}{K_n} - I_s}{I_s} \times 100$$

$$\begin{aligned} \% \text{ Ratio Error} &= \frac{\frac{K_n I_s - I_p}{K_n}}{\frac{I_p}{K_n}} \times 100 \\ &= \frac{K_n I_s - I_p}{I_p} \times 100 \end{aligned}$$

The ratio error is also called Current Error

6.2 Phase Angle Error

It is the angle by which the secondary current differs in phase from the primary current and is also called the Phase Difference Error. It is expressed in minutes of arc.

6.3 Composite Error

The composite error takes into account both the ratio and phase angle errors. It is the percentage rms value of the difference between the instantaneous values of the secondary current I_s multiplied by the rated transformation ratio and the instantaneous values of the primary current I_p to the rms value of the primary current I_p .

$$\text{Thus} \quad E_c = \frac{100}{I_p} \sqrt{\frac{1}{T} \int (K_n I_s - i_p)^2 dt}$$

Where E_c is the composite error

T the time of one period

I_p the rms value of the primary current in Amps

i_p the instantaneous value of the primary current in Amps.

I_s is the instantaneous value of the secondary current in Amps.

K_n the transformation ratio = $\frac{I_p}{I_s}$

The composite error takes into account the presence of higher harmonics in the magnetising and secondary currents and as such the usual vectorial representation is no longer valid.

6.4 Causes of Errors

Errors are caused by the secondary burdens. The greater the burden, the larger will be the secondary voltage required to overcome its impedance and hence greater will be the core flux exciting current. Therefore, the error becomes more.

6.5 Methods to minimize errors

- (i) The exciting current must be low
- (ii) The magnetic circuit should be as short as possible to reduce its reluctance and hence the exciting current.
- (iii) The secondary winding must be in close proximity to the primary in order to reduce magnetic leakage.
- (iv) The secondary winding must be safely separated with adequate insulation and the length of the core should be just enough to accommodate the windings.
- (v) Additional turns or compensating windings are provided to reduce the ratio error.

6.6 Limits of Error

The limits of error are prescribed by the national specifications prepared by different countries like the BSS, NEMA, ANSI, ISS, etc, and also by IEC adopted by all countries. However, error limits prescribed by BS 3938 are appended below:

Error Limits as per BS 3938

For Metering Transformers at rated frequency, unity power factor and rated output.

Class	30 Absolute Errors				Variation in Error			
	125% to 20% of rated current		20% to 10% of rated current		10% to 5% of rated current		125% to 5% of rated current	
	Current Error %+/-	Phase Error Mins %+/-	Current Error %+/-	Phase Error Mins %+/-	Current Error %+/-	Phase Error Mins %+/-	Current Error %+/-	Phase Error Mins %+/-
AL	-	-	-	-	0.20	10	-	-
AM	-	-	-	-	0.75	40	0.5	20
BM	-	-	-	-	1.50	60	1.0	30
CM	-	-	-	-	2.0	120	1.5	75
C	1.0	120	2.0	180	-	-	-	-
P	5.0	-	-	-	-	-	-	-

For Protective Transformers

31 Class	Current Error at rated primary current %	Limits of Composite Error at accuracy limit primary current %
S	± 3	5
T	± 5	10
U	± 10	15
X	± 0.25	0.25

Error limits as per IEC 185

For metering transformers at rated frequency, rated output and p.f of 0.8.

Accuracy Class	Primary Current								
	Up to 5%			5% to 20%			20% to 12%		
	Ratio Error $\pm\%$	P/angle Error $\pm\text{mins}$	Total Error $\pm\%$	Ratio Error $\pm\%$	P/angle Error $\pm\text{mins}$	Total Error $\pm\%$	Ratio Error $\pm\%$	P/angle Error $\pm\text{mins}$	Total Error $\pm\%$
0.1	0.4	15	-	0.2	8	-	0.1	5	-
0.2	0.75	30	-	0.35	15	-	0.2	10	-
0.5	1.5	90	-	0.75	45	-	0.5	30	-
1.0	3	80	-	1.5	90	-	1.0	60	-
3.0									

For Protection Transformers

n – ALF (Accuracy Limit Factor which is defined later in paragraph 7.3)

Accuracy Class	Primary Current	Ratio Error %	Phase Angle Error mins $\pm$	Total Error %
5 p n	100%	1	60	-
	N	-	-	5
10 p n	100%	3	-	-
	N	-	-	10

7.0 Common definition of terms used with Current Transformers

7.1 Rated Burden

This is the apparent resistance of the secondary circuit expressed in ohms together with the power factor for which the specified accuracy limits are valid.

7.2 Rated Output

7.2.1 The rated output of a current transformer is the apparent power expressed in VA together with the power factor, which the C.T. can deliver to the secondary circuit at rated current and burden while still maintaining its accuracy in the specified class.

7.2.2 The rated output is equal to the product of the rated secondary current and the voltage drop in the external secondary circuit due to this current.

7.2.3 The standardised values of rated outputs are 2.5, 5, 7.5, 10, 15, 30, 45, 60, 90, & 120 in VA.

7.2.4 In BSS, the VA output is specified along with the accuracy class. For example 30 s 10 means a protection C.T. of accuracy class s having a total error of 5% with a VA of 30. The number 10 is the ALF defined later in paragraph 7.3. However in IEC, the VA is specified separately.

7.3 Accuracy Limit Factor (ALF)

7.3.1 The accuracy limit current is the highest primary current at which a current transformer still meets the specified requirements as regards total error. The accuracy limit factor is the ratio of the accuracy limit current to the rated primary current.

7.3.2 The standardised accuracy limit factors are 5, 10, 15, 20 and 30.

7.3.3 The ALF for metering C.T's is at a minimum value. A current transformer for protection purposes is specified by stating its accuracy class followed by the required ALF. For example, as per IEC 5 p 20 means a C.T. for protection having maximum total error of 5% at 20 times the rated current.

Similarly as per BSS 30 S 10 means a protection C.T. of accuracy class S having a maximum total error of 5% at 10 times the rated current. In BSS, the ALF is also called the Saturation Factor. In ANSI accuracy classification, the ALF is fixed at 20. Thus 2.5 T 800 means a High Reactance C.T with total error of 2.5% and $ALF \times VA = 800$ and $VA = 40$.

7.4 Instrument Security Factor (ISF)

7.4.1 The rated instrument security factor is the smallest primary current at which an instrumentation core exhibits a current error of 10%.

7.4.2 The Instrument Security Factor ISF or FS is the ratio of the rated instrument safety current to rated primary current.

7.4.3 The instrument security factor defines the behavior of a metering C.T. core under over-current conditions. The ISF is specified to protect instruments connected to the metering C.T. core from system short circuit currents. The ISF to be chosen should be as low as possible.

7.4.4 It is expressed as a number ' n ' ≤ 5 or $n \geq 10$.

The table appended below gives a guide on the selection of this ' n '

Application	n	Accuracy Class
Precision measuring instruments, precision industrial metering of power and energy	≤ 5	AL, AM (BSS) 0.1, 0.2, 0.5 (IEC)
Industrial measuring instruments and meters	≤ 10	BM, CM, C, D (BSS) 1.0, 3.0, 5.0 (IEC)

7.5 Rated Insulation Level

It is the nominal system voltage in which the C.T. is installed.

7.6 Highest System Voltage

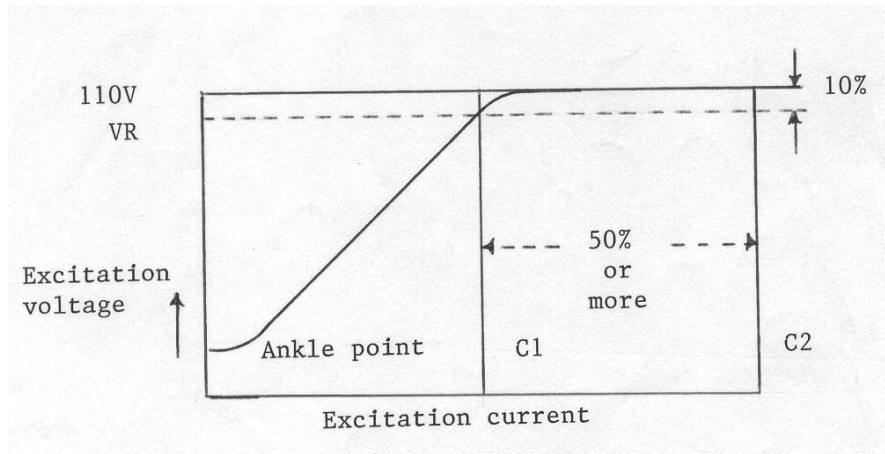
It is the highest rms line-to-line voltage, which can be sustained by the C.T. under normal operating conditions at any time and at any point in the system. It excludes temporary voltage variations due to fault conditions and the sudden disconnection of large loads.

A table below gives the highest system voltages for standard nominal voltages.

Nominal Rated Voltages (KV)	Highest System Voltage (KV)
3.3	3.6
6.6	7.2
11.0	12.0
33.0	36.0
66.0	72.5
132.0	145.0
330.0	363.0

7.7 Knee point voltage (V_k)

7.7.1 This is the sinusoidal e.m.f of rated frequency applied to the secondary terminals of the C.T., with all other windings being open circuited, which when increased by 10% causes the exciting current to increase by 50% or more. This is illustrated below:



Example $V_1 = 100 \text{ V}$

$V_2 = 110 \text{ V}$

Percentage Increase = 10%

Corresponding currents $C_1 = 0.35\text{A}$

$C_2 = 0.7\text{A}$

Percentage increase = 50%

V is the knee point voltage V_k .

7.7.2 The knee point voltage indicates the voltage above which the C.T. enters into saturation and exciting current increases rapidly with a very little increase in voltage.

7.7.3 The exciting current as already indicated in 6.4 and 6.5 is mostly responsible for the introduction of errors in the C.T. The errors of a C.T. above V_k are very high.

7.7.4 The magnitude of V_k has already been dealt with in paragraphs.5 (f), (g) and (h).

7.7.5 The V_k is also limited by practical design and manufacturing consideration as:

$$V_k = \frac{\text{Rated output in VA} \times \text{ALF}}{\text{Secondary rated current}}$$

7.8 Rated Short Time Thermal Current (I_{th})

7.8.1 This is the rms value of the primary current, which the C.T. will withstand for one second without suffering any internal damage or other harmful effects with the secondary being short-circuited.

7.8.2 This rating is for a very short time and it is usually assumed that the entire heat generated is stored in the primary winding itself.

7.8.3 Rated short time thermal current is expressed in KA. It is related to the maximum short circuit current at the point of installation of the C.T., and also on the duration of the breaking time of the short circuit current.

7.8.4 The following condition should be met with

$$I_{th} \geq I_{sc} \times \sqrt{\frac{t + 0.05 \times \frac{50}{f}}{f}} \text{ KA rms.}$$

Where I_{th} - Rated short time thermal current for 1 sec.

I_{sc} - Short circuit current at C.T. location in KA rms

t - short circuit duration in sec.

f - Rated system frequency.

For system frequency of 50 Hertz

$$I_{th} \geq I_{sc} \sqrt{t + 0.05} \text{ KA rms.}$$

The short circuit duration is considered with respect to the short time rating of the switchgear or to the fault clearing time.

The American/Canadian/German practice is to use the short time rating of the switchgear, which is 4 sec. Similarly the British practice is also to use the short time rating of the switchgear, which is 3 sec. However the Russian practice is to use the fault clearing time, which is around 0.2 sec. and this value being too low, a realistic time of 1 sec, is considered. Today with fast operating relays and breakers, a 1 sec time is considered more than adequate and a higher time will make the C.T. expensive.

7.8.5 Standard Thermal ratings are as follows:

	Range
CT's up to 660 V	(60 to 120) I_p
CT's from 1 KV to 46 KV	(100 to 120) I_p
CT's above 46 KV	(120 to 150) I_p

Where I_p is the primary current

7.8.6 While considering the short circuit current, attention must be paid to the maximum expected fault current taking into consideration future expansion of generating capacity and interconnecting lines.

7.9 Rated Dynamic Current (I_{dyn})

It is the peak value of the primary current, which the transformer will withstand without being damaged electrically or mechanically by the

resulting electromagnetic forces, the secondary winding being short-circuited.

The maximum value of this current can be 2.5 times the rated short time thermal current (I_{th})

$$I_{dyn} = 2.5 I_{th}$$

7.10 Rated Primary and Secondary Current

7.11 These are the values of the primary and secondary current on which the performance of the current transformer is based.

7.12 Standard values of primary currents are:

5, 10, 15, 20, 30, 60, 75, 50, 100, 150, 200, 300, 400, 600, 800, 1000, 1500, 2000, 3000, 4000 and above.

7.13 Standard values of secondary currents as per BS 3938 are 5A, 2A and 1A and as per IEC, 5A or 1A. However there are cases where occasionally ratings of 0.577A, 0.866A or 2.87A have been used.

7.14 The selection of the primary current of a C.T. shall always be adopted as closely as possible to the full load or rated current of the installation by rounding off to the next higher standard. However the C.T must be capable of continuously carrying the maximum expected current in service. It is advisable to consider a permitted overload of 20% of the full load current while deciding the rated current.

Another factor to be considered is also the load growth and the increase in capacity of an installation. It is for this reason that multi ratio primary currents are adopted like 800 - 400 - 200 - 100 A.

7.15 The selection of the secondary current depends upon the secondary current of the equipment already in service where interchangeability is a consideration.

7.16 The following are the advantages and disadvantages of CT's with 5A and 1A secondary currents.

- (a) The number of turns required on the secondary side is less for a 5A C.T. than for a 1A C.T. for a given primary current.
- (b) A thicker gauge wire is required for a 5A C.T than for a 1A C.T.
- (c) Both the above factors contribute to the cost reduction of a 5A C.T. when compared to a 1A C.T.
- (d) Since the number of turns is less for a 5A C.T, the voltage induced on the secondary side during secondary saturation or secondary open circuit is less when compared to a 1A C.T.
- (e) The lead burden, however, becomes excessive for a 5A C.T since the same is proportional to the product of the square of the current and resistance of the lead wire. The lead burden in a 1A CT. will be very low.
- (f) In view of the reduced number of secondary turns in a 5A C.T., it is difficult to provide for turns compensation to design and manufacture low

current higher accuracy class CT's. However in a 1A C.T. it is possible to achieve the desired accuracy class because of the increased number of turns and by providing compensating turns.

(g) The internal resistance of a 5A C.T. is comparatively less ($< 1 \text{ ohm}$) when compared to that of 1A C.T. (Generally 3 to 12 ohms)

8.0 Selection of the rated output or burden

8.1 While selecting the rated output of a C.T., it is necessary to calculate the burden imposed on the C.T by the interconnecting leads and other equipment connected in series with it.

8.2 Many times the burden is overestimated. A high burden results in the following disadvantages:

(a) The higher the burden, the higher will be the cross section of the core and hence the C.T. will be bulky and expensive.

(b) The higher the burden, the higher the cross section of the core resulting in higher voltage across the secondary in case of secondary open circuit and saturation which may require additional means to limit such voltage to be within acceptable values.

(c) The ISF and ALF have a direct relationship with the connected burden. Both of these are guaranteed at or near the rated burden. If the connected burden is different from the rated burden then:

$$\text{ISF} = \text{Designed ISF} \times \frac{\text{Rated burden}}{\text{Connected burden}}$$

$$\text{ALF} = \frac{\text{Designed ALF} \times \text{Rated burden}}{\text{Connected burden}}$$

(d) If the burden connected to a C.T. is low, compared to the high burden say less than 25% then the accuracy guaranteed for the C.T. will no longer be valid and the C.T. will be inaccurate.

8.3 The typical VA ratings or power consumption of instruments and relays is appended below to facilitate calculation of the burden imposed on C.T. secondary windings.

Apparatus	Power Consumption VA per phase
(a) Ammeters	
Moving iron up to 4" (100mm) diameter	
Moving iron above 4" (100mm) diameter	0.7 to 1.2
Recording type	1.2 to 3.0
(b) Watt meters - General	5.0 to 10.0
- Recording	1 to 3.0
(c) Power factor meters - General	1.5 to 10.0
-	1.5 to 6.0
Recording	6.0 to 16.0
(d) KWh meter	2.0 to 6.0
(e) Relays	
Overcurrent relay	0.2 to 10.0
Overcurrent inverse time relay	1.5 to 8.0
Directional over current relay	2.5 to 10.0
Directional Earth fault relay	2.5 to 10.0
Reverse Power relay	0.7 to 12.0
Earth fault relay	0.5 to 22.0
Differential relay (Electromagnetic)	1.0 to 2.0
Differential relay (Static)	0.10 to 2.0
Distance relay (Electromagnetic)	3.0 to 30.0
Distance relay (Static)	0.3 to 1.5
Negative Phase Sequence relay	5.0 to 40.0
(f) Current Regulators	55.0 to 100.0
(g) A.C. series trip (C.T. current trip)	2.5 to 5.0

8.3.2 Burden of copper control cables at 50 cycles

Nominal area of conductor (sq.mm)	No and diameter of wires	VA Burden for single length of 100 metres	
		At 5 Amps	At 1 Amp
1.5	1/1.40	28	1.12
2.5	1/1.30	17	0.6775
4.0	1/2.24	11	0.4375
6.0	1/2.80	7	0.28
10.0	7/1.4	4	0.1627
16.0	7/1.7	2.76	0.1104
25.0	7/2.4	1.59	0.0636

Nominal area in sq.inch or Gauge	VA Burden for single length of 100 ft	
	At 5 Amps	At 1 Amp
0.01 sq.in	2.125	0.085
0.02 sq.in	1.06	0.045
No. 14 AWG	6.5	0.26
No. 12 AWG	4.125	0.165
No. 10 AWG	2.508	0.105
No. 8 AWG	1.63	0.065
No. 6 AWG	1.03	0.04

8.4 A case study of Estimation of Burden, Knee Point Voltage, Accuracy Class etc of a Protective Current Transformer

Requirement of a C.T. to protect a 15 MVA, 132/33 KV Delta/Star connected transformer.

Data available

% Impedance of Transformer = 10

Fault level at 132KV side = 1400 MVA

Transformer full load current per phase

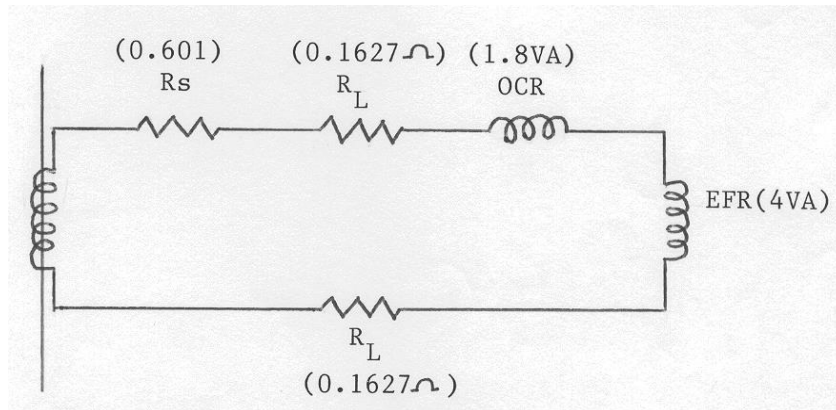
$$\begin{aligned} &= \frac{15 \times 10^6}{\sqrt{3} \times 132 \times 10^3} \\ &= 65.61 \text{ A} \end{aligned}$$

Hence select primary current = 100 A

(a) i.e. $I_p = 100 \text{ A}$

(b) Select secondary current I_s as 5A. A 5A C.T secondary has a winding resistant of less than 1.0 ohm. A typical value may be chosen as 0.601 ohms. Assume

- (i) Distance from C.T to Relay control panel as 100 metres and C.T. secondary leads of 10 sq mm. ($R_L = 0.1627$ ohms for 100 metres)
- (ii) Connected relays are GEC CDG 11 over-current and earth fault relays with VA burden of 1.8 and 4 respectively.



$$\begin{aligned}
 \text{Relay burden} &= I_S^2 R_S + 2I_S^2 R_L + \text{VA of (OCR + EFR)} \\
 &= (5)^2 0.601 + 2(5)^2 0.1627 + (1.8 + 4) \\
 &= 15.0 + 8.135 + 5.8 \\
 &= 28.935 \text{ VA}
 \end{aligned}$$

(c) Hence select relay burden or output as 30 VA

Select Accuracy class 5 P 20

$$\text{(d) Knee point voltage } V_k = \frac{\text{VA} \times \text{ALF}}{\text{Sec. current}}$$

$$= \frac{30 \times 20}{5}$$

$$= \frac{600}{5}$$

$$= 120 \text{ V}$$

$$\text{Fault current at C.T. installation} = \frac{1400 \times 10^6}{\sqrt{3} \times 132 \times 10^3}$$

$$= 6123.6 \text{ A}$$

$$\text{or } 6.124 \text{ KA} = I_{sc}$$

$$I_{th} \geq I_{sc} \sqrt{[t + 0.05]} \text{ KA rms for 1 sec}$$

Assume operating time of breakers, relays etc = 1 sec

$$I_{th} \geq 6.124 \sqrt{[1.05]}$$

$$\geq 6.275 \text{ KA rms}$$

Select I_{th} as 10 KA rms for 1 sec

(e) I_{th} short time rating = 10 KA rms for 1 sec.

$$(f) I_{dyn} = 2.5 I_{th} = 2.5 \times 10 = 25 \text{ KA for 1 sec.}$$

(g) Hence complete specifications for this protection C T will be:

Voltage class: 132 KV

Primary current: 100 A

Highest System Voltage: 145 KV

Secondary current: 5 A

Accuracy class: 5 P 20

V_k : 120 V.

I_{th} : 10 KA rms for 1 sec.

I_{dyn} : 25 KA for 1 sec.

9.0 Recommended Accuracy Class of CT's for Instruments and Relays

Application	Accuracy Class
(a) Precision and calibrating Instruments, very accurate measurements in laboratories and testing stations.	0.1 or AL
(b) Meters of precision grade Accurate power measurements	0.2 or AM
(c) Meters of commercial grade CM Normal commercial metering	0.5 or BM or
(d) General Industrial Measurements	1.0 or C
(e) Approximate measurements	3.0 or D
(f) Overcurrent, Earth fault P 5 Relays instantaneous type	Class T or 5 ALF 5
(g) Overcurrent, Earth fault Relays, Inverse type, Directional relays	Class T/S ALF 10 or 5 P 10
(h) Differential relays Distance relays	Class S or 5 P 10 ALF 10 or 5 P 20 or ALF 20

10.0 Classification of Current Transformers

10.1 C.T's can be classified in a variety of ways. The following are the major classifications:

(a) Depending on the location of installation

- Indoor
- Outdoor

(b) Depending on the application

- Metering
- Protection

(c) Depending on the location in the circuit

- Main C.T.
- Auxiliary C.T.

(d) Depending upon the type of construction

- Bar
- Ring
- Wound
- Split core
- Linear
- Cascade

(e) Depending upon the type of insulation

- Dry type
- Oil impregnated paper

- Epoxy
- SF₆

(f) Depending upon the location of the secondary core and winding.

- Tank type or dead tank
- Inverted type or live tank
- Insulator type or cross connected type

10.2 Classification depending upon location

(a) **Indoor:** C.T's meant for indoor installations are provided with suitable enclosure to protect them from environmental factors such as dust, pollution and humidity. They are usually of the dry type or cast epoxy resin.

(b) **Outdoor:** C.T's meant for outdoor installation are provided with protection against atmospheric and environmental factors. The protection is with porcelain insulators with sealed tanks for the windings and terminals to prevent ingress of moisture. The porcelain insulator has to meet the following:

- Wet power frequency high voltage withstand test
- Lighting impulse withstand test

10.3 Classification depending upon application

This has been dealt with exhaustively in the preceding paragraphs.

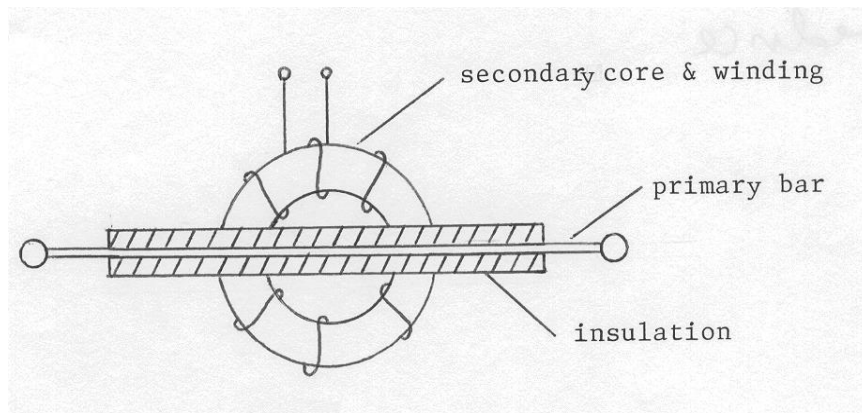
10.3 Classification depending upon location in the circuit

- (a) **Main C.T.:** These C T's are installed in the main circuit and are used for transforming the current flowing in the main circuit to an acceptable value for feeding instruments, relays and other equipment.
- (c) **Auxiliary C.T.:** These are generally fed from the secondary of the main C.T. and are used for one or the other of the following purposes:
- They are also called Interposing Current Transformers (I.CT's) or Matching CT's.
- (i) If secondary current of main C.T. is not the same as that of the device to which it is expected to feed.
 - (ii) For summation of currents like in case of busbar protection.
 - (iii) Where two circuits have to be insulated from each other and where a galvanic separation is required as in a case where a static relay is used.
 - (iv) For displacing current vectors to provide for phase shift as in the case of differential protection for power transformers.
 - (v) To obtain an acceptable ISF if the ISF of the main C.T. is high.
 - (vi) For filtering out the zero sequence currents when the transformer neutral is earthed.
 - (vii) For equalising the transient response of two circuits when an interposing CT is used for static relays.

10.5 Classification as per Construction

(a) Bar type

This type of C.T. essentially consists of a conductor insulated with condenser type of bushing or resin cast. Over this bushing one or several wound cores are assembled.

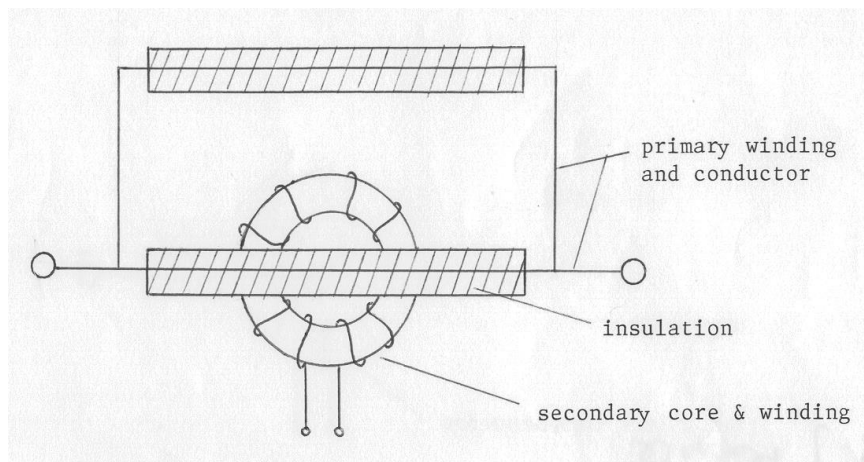


The secondary core is given a protective covering made of non-magnetic material and in case of outdoor type a porcelain insulator is provided over the condenser bushing. The advantages of bar type CT's are:

- (i) It serves the purpose of a C.T. as well as a bushing terminal support.
- (ii) The bar has a very high dynamic current rating and is therefore ideally suited when the primary current rating is very high. The only restriction is because of the single turn winding. There may be accuracy limitation when the current rating is low.

(b) Wound type

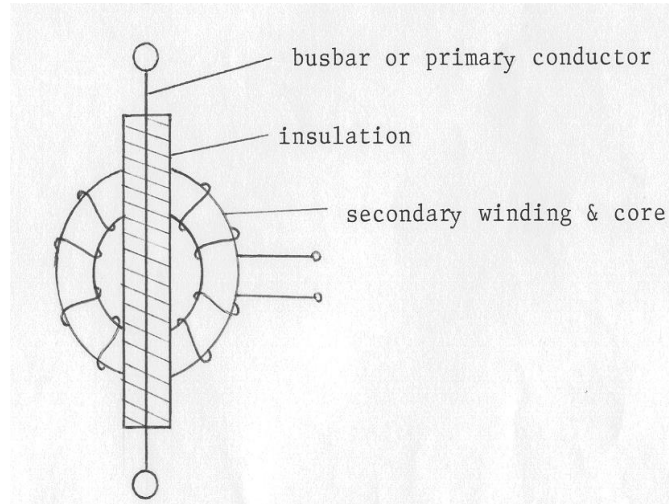
In this type the primary winding consists of several turns wound around the secondary cores.



The primary winding has to be strengthened to make it suitable for high fault currents and short time current ratings. The burden and accuracy are guaranteed even with low primary currents. They are normally used in indoor type switchgear.

(c) Ring type

This C.T. consists of a toroidal secondary winding with a window opening in the middle through which the busbar is slipped.



The C.T. is designed with sufficient air clearance between busbar and C.T. for full insulation level. A thin layer of resin is covered over the secondary core for mechanical protection. If the air clearance is not sufficient for the full insulation level, then adequate insulation is provided over the secondary core for full voltage insulation. This type of C.T. is independent of the current carrying capacity of the busbar and as such, it is ideally suited where high rated currents and fault currents are involved.

(d) Split core type

The split core type consists of a magnetic core in two or more sections with secondary winding installed around the busbar, connected electrically and coupled magnetically.

A Tong tester ammeter is a C.T. of this type.

(e) Linear C.T.

In this type an air gap is provided in the magnetic path such that linear characteristics are obtained between primary and secondary currents over a wide range of fault currents. These are generally used where static relays are employed.

(f) Cascade C.T.

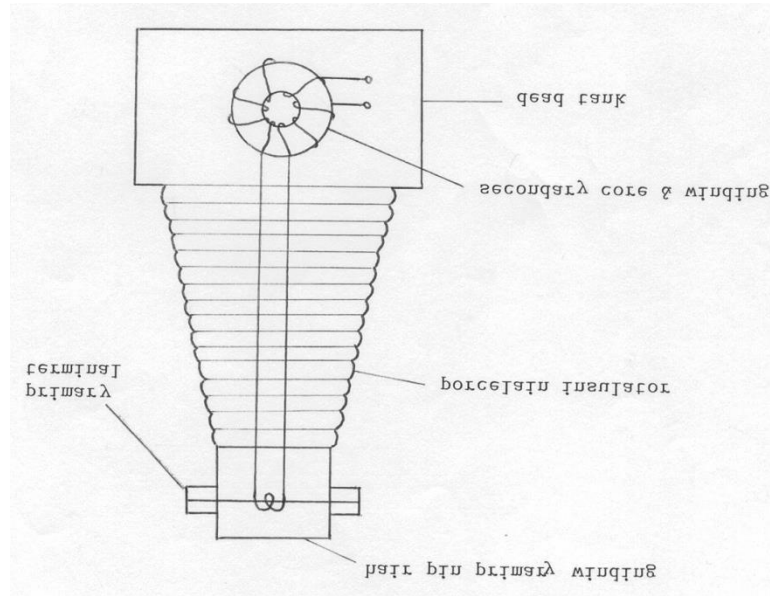
It is sometimes difficult to accommodate a large number of C.T's in the limited space available at large generator bushings. In such a case a single core C.T. rated for a very high burden and ALF is installed with a secondary winding of several amps. The secondary of this C.T. is used to feed a group of CT's depending upon the protection and metering requirements. These groups of CT's installed in separate cubicles are called Cascade CT's.

10.6 Classification as per insulation

- (a) Dry type insulation is used in low and medium voltage type CT's
- (b) Oil impregnated paper type is used in high voltage and extra high voltage CT's along with porcelain support insulators.
- (c) Epoxy type insulation is used in indoor type for low and medium voltages, and high voltage CT's up to 33 KV
- (d) SF₆ gas insulation is used in extra high voltage CT's with porcelain support insulators.

10.7 Classification depending upon the location of the secondary core and winding

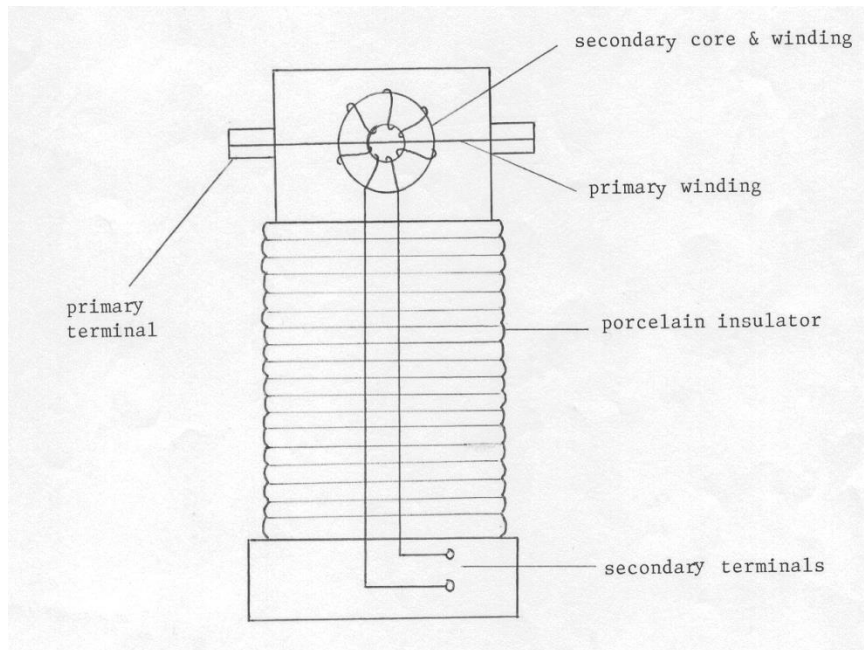
(a) Dead tank type



The secondary core and winding are housed in the tank at the base of the C.T. The primary winding is in the form of a toroidal coil or hairpin passing through the secondary winding. This design has the following advantages:

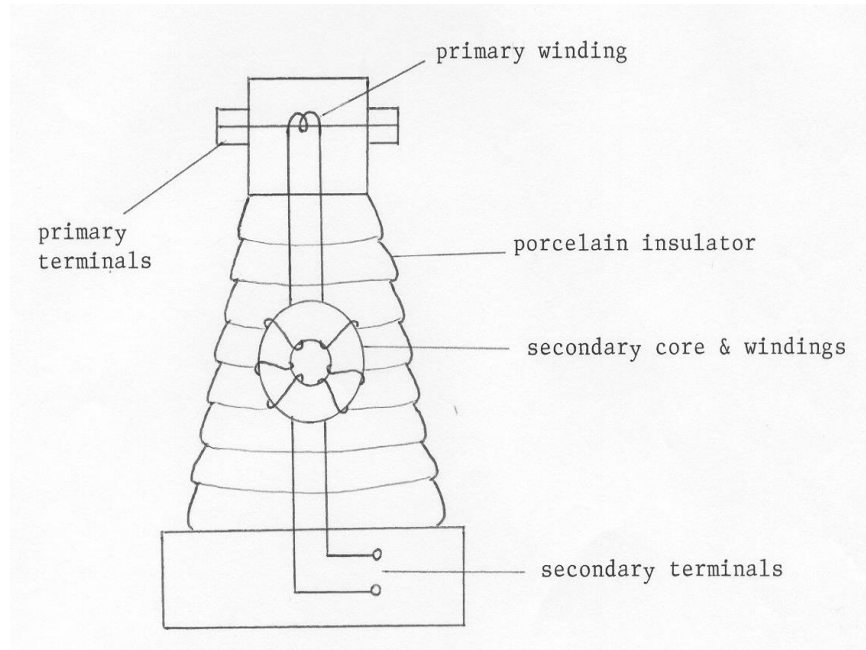
- (i) The core and winding at the bottom render the design more stable and insulators need not have a very high bending strength.
- (ii) It is possible to accommodate bigger cores and more number of cores since they are located at the base.
- (iii) Primary re-connection can be provided at the top for obtaining different ratios.

(b) Inverted type or Live tank C.T.



In this design, the secondary winding and the primary windings are located at the top supported on a hollow insulator filled with oil. Primary re-connection to obtain different ratios and by secondary tapping is possible. Full insulation is provided for both primary and secondary windings. Insulators should have higher bending strength in view of the large head. In view of the small oil volume, any oil leakage will expose the windings causing damage and failure of the C.T.

(c) Insulator type or Cross connected type



In this design, the primary and secondary windings are provided inside an insulator.

Insulation is equally distributed between primary and secondary windings. Both primary re-connection and secondary tapping are possible to obtain different ratios. This type of construction is economical for 220 KV and above where it would be very uneconomical to provide for full insulation for both primary and secondary. A broader insulator is required which adds to the strength and stability.

11.0 Tests on C.T

These are prescribed by various specifications. However commonly recommended tests are as follows:

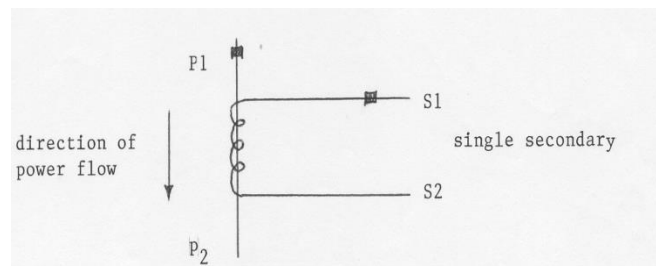
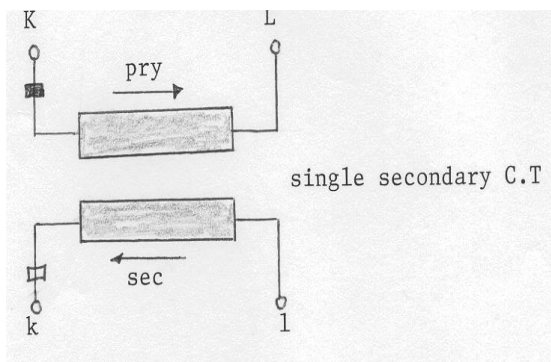
(a) Type tests

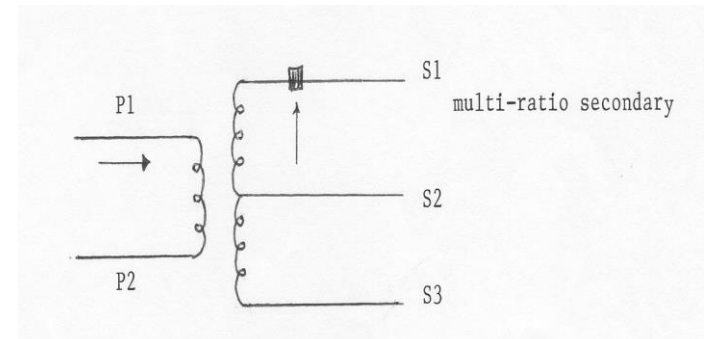
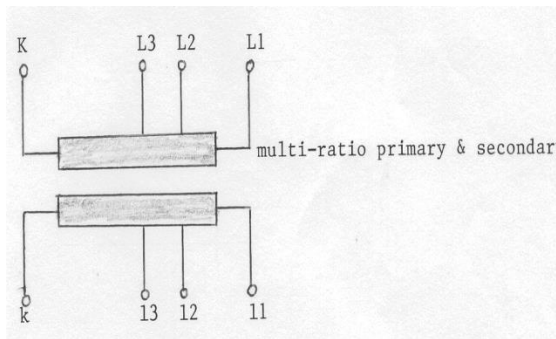
- (i) High voltage power frequency test on primary windings.
- (ii) Impulse voltage withstand test.
- (iii) Short time current test.
- (iv) Temperature rise test

(b) Routine tests

- (i) High voltage power frequency test on primary and secondary.
- (ii) Verification of terminal markings and polarity.
- (iii) Over voltage inter-turn insulation test
- (iv) Determination of errors according to the requirement of the accuracy class.

12.0 Polarity and Markings





13.0 Field testing and Commissioning tests on Current Transformers

(a) Visual checks

Inspect for physical damages such as cracks in porcelain, oil leakages, oil level, etc.

(b) Insulation test

(i) Test with a 1KV, 2.5KV or 5KV Megger between H.V. terminals and earth.

(ii) H.V. terminal and secondary terminal (L.V.)

Insulation values should be around 2 Megohms/KV at 60°C

or 4 Megohms/KV at 50°C

or 8 Megohms/KV at 40°C

or 16 Megohms/KV at 30°C

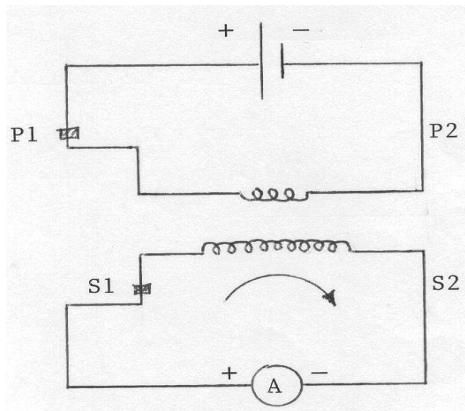
Test with 500V Megger between L.V. terminal and earth.

Insulation values should be infinity.

Precaution: Do not use 1 KV or 2.5 KV Megger for test on L.V or secondary windings as the secondary windings are insulated for only 660 volts or 1100 volts.

(c) **Polarity test and verification of markings**

The test is conducted with a battery cell and a low range D.C.



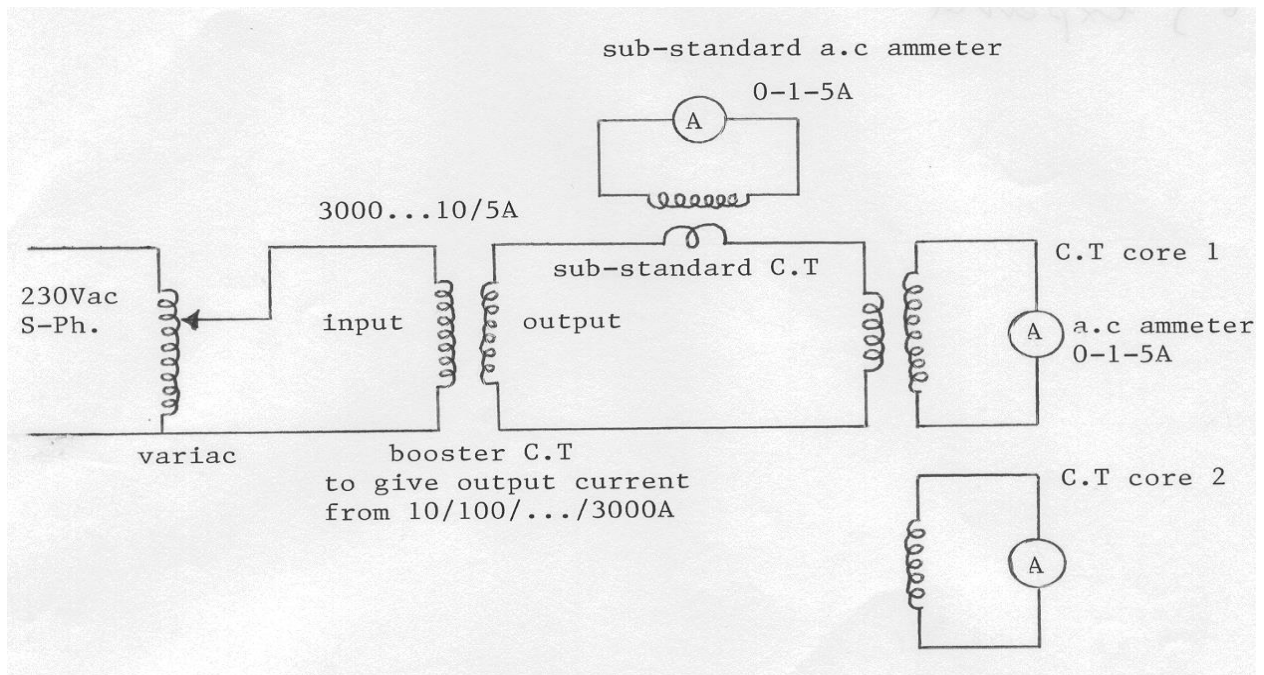
ammeter.

Connect a low range D.C. Ammeter to the secondary windings with S_1 to + ve and S_2 to - ve

Connect the + ve of a battery cell to P_1 and just touch the negative to P_2 .

Observe the kick of the ammeter needle. If it is in the forward direction then terminal P_1 corresponds to S_1 .

(d) Ratio test



The test is conducted on all the cores and for different ratios. The rated primary current of the test C.T is applied from a booster C.T output. This current is measured from a substandard C.T. and ammeter and is recorded as current "to be".

The secondary current in the test C.T is recorded as current "As Found".

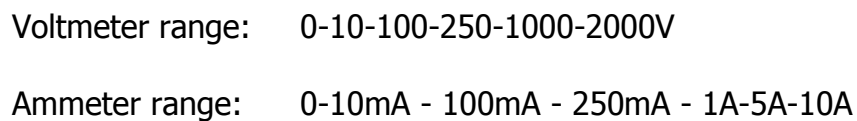
Results are tabulated as follows:

Example: Test C.T. nominal or rated ratio = 100/5

S.S. (1) CT Current	S.S. (2) CT Ratio	1 ^o Current = (1) x (2)	Test C.T Current = As Found	Sec. To be	% Error 65 To be – As Found To be
5	100/5 = 20	20 x 5 = 100	4.96	5.0	$\frac{(5.0 - 4.96) \times 100}{5.0}$ = 0.8 %

Precaution: When large currents of 500 A and above are applied, the leads from the booster C.T to the test C.T should be capable of withstanding this current and the test must be conducted quickly to prevent overheating of the leads.

This test is conducted to determine the knee point voltage and the applicability of the different cores for metering and protection.



The test is conducted with primary windings open and individually on each of the secondary windings. A voltage is applied gradually to the test C.T. secondary full windings and the excitation current is noted, with all the other secondary winding cores being open circuited. The exciting current is increased to twice the rated secondary current. The results are tabulated as follows:

Core No	Accuracy class
Secondary current	Secondary voltage
-	-
0	-
-	-
100mA	-
-	-
1 A	-
-	-
5 A	-
-	-
10 A	-

The results are plotted on a graph with exciting current along abscissa (x-axis) and voltage as ordinates (along y-axis). The graph gives the knee point voltage and enables us to decide:

- (i) The applicability of the core for the purpose it is meant for; namely V_k of metering C.T is low generally (60 - 120V); V_k of back up protection C.T is higher and that of main protection involving differential and distance protection is still higher.

- (ii) To verify whether the V_k meets with the requirements as specified by the relay manufacturer.

(f) Oil test

This is carried out only on oil filled C.Ts where an oil test plug is provided. The oil is tested for Breakdown voltage (B.d.v) only and should withstand 40KV for 1 min with 4mm gap or 25 KV for 1 min with 2.5mm sphere gap spacing.

14.0 How to specify a Current Transformer

- (a) Choose the rated primary current from:

- (i) Full load current of equipment
- (ii) Future expansion
- (iii) Interchangeability within the system.

E.g.: The C.T required from full load requirements is 100A. That required for future expansion is around 200A and C.T existing in the system is 400 - 200 - 100/5A.

Therefore select 400 - 200 - 100A primary current C.T.

- (b) Choose the rated secondary current from:

- (i) Distance of C.T. to control panel
- (ii) Interchangeability within the system.

E.g.: If distance is less than 50 metres, a 5A C.T. may be chosen and 1A if greater. Also existing similar CT's in the system would decide this factor.

- (c) Choose number of cores either 2 or 3. Chose two cores where only metering and primary protection is involved and three cores if metering, primary and back up secondary protection are involved.
- (d) Choose rated VA for each core from:
 - (i) Burden of instrument and leads for metering core
 - (ii) Burden of relays, leads, V_k requirements of relays and ALF.

Note that cost increases with increase in VA rating.
- (e) Choose accuracy class for each core
- (f) Choose C.T. thermal and dynamic current from:
 - (i) Expected system maximum fault level including fault level due to future expansion programmes.
 - (ii) Switchgear short circuit rating.
- (g) Choose indoor or outdoor type with specific reference to ambient temperature, humidity, atmospheric pollution, rainfall and other environmental factors at point of installation.

15.0 Maintenance of C.Ts in service

Generally no maintenance regarding tests is required after commissioning.

However, routine maintenance would involve: -

- (a) Inspection of the porcelain insulator and cleaning thereof.
- (b) Painting of metal surfaces if paint has worn off or badly rusted.
- (c) Periodical logging of the insulation resistance (say once in six months)

- (d) Inspection, cleaning and tightening the primary connections and also the secondary connections
- (e) Testing the insulation oil for b.d.v (say once in six months) and topping up of the oil, if found necessary.

16.0 VOLTAGE OR POTENTIAL TRANSFORMERS (V.Ts OR P.Ts)

16.1 General

Although voltage transformers may be classified as protective voltage transformers and measuring voltage transformers, yet essentially there is no difference between them as in the case of current transformers. The requirements of both measuring and protective transformers are more or less the same, as both have to produce on the secondary side a reasonably accurate representation of the voltage applied to its primary side.

16.2 Types

There are two main types of voltage transformers:

- (a) Electromagnetic type
- (b) Capacitor type also called Capacitive Voltage Transformer (CVT)

16.3 Electromagnetic type

The electromagnetic type of voltage transformer operates in a similar way like any other power or distribution transformer except for the power handled which is a few hundreds of volt amperes (VA). Thus the

fundamental relation of a power transformer of the voltage ratios being proportional to the turns ratio holds good.

$$\text{Thus } \frac{E_p}{E_s} = \frac{N_p}{N_s}$$

Where E_p and E_s are the primary and secondary voltages.

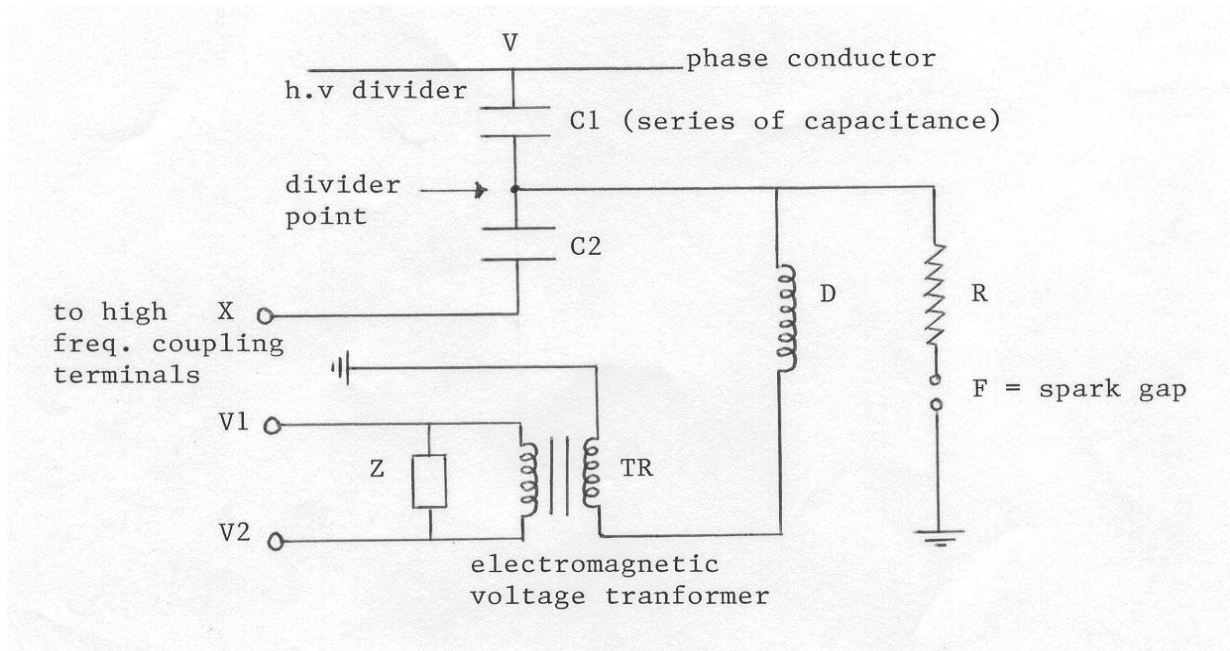
N_p and N_s are the primary and secondary turns.

16.4 Capacitor type

- (a) The capacitor type of voltage transformer is not in fact a transformer as such, but essentially a capacitance potential divider with a compensating device connected between the divider tap and secondary burden to minimise the voltage drop.
- (b) Capacitor type voltage transformers are now being used more and more in high voltage system networks particularly at voltages of 132KV and above where it becomes increasingly economical. It also enables simultaneous measurement of voltage and also for carrier frequency coupling which is used for Telephone communication (PLC, Telemetry, Teleprotection, and remote control).
- (c) Capacitor type voltage transformer are of two types:
 - (1) Coupling capacitor type
 - (2) Bushing type.

Coupling Capacitor type

A line diagram of coupling capacitor type voltage transformer (c.c.v.t.) is shown below



Where	V	Primary Terminal
	C ₁	Primary capacitance or H.V. DIVIDER
	C ₂	Secondary capacitance
	D	Compensating Inductance coil or Reactor
	TR	Intermediate Transformer
	Z	Damping Impedance
	F	Spark gap
	R	Resistor
	X	High frequency coupling terminal
	V1,V2	Secondary potential terminals

Note: If the high frequency coupling terminal is not used it has to be shorted to the earth.

The capacitors C1 and C2 are made of oil impregnated paper and aluminium foil. Each capacitor is composed of a multitude of elements. A tap is taken in between these series capacitor elements and to an electromagnetic voltage Transformer (TR) across the capacitor and the earth.

The location of this tapping point is decided by: -

- (i) System voltage between line and earth.
- (ii) Rating of the primary of the electromagnetic voltage transformer.
Standard ratings are 5, 10, 15 and 20KV depending upon burden and accuracy.

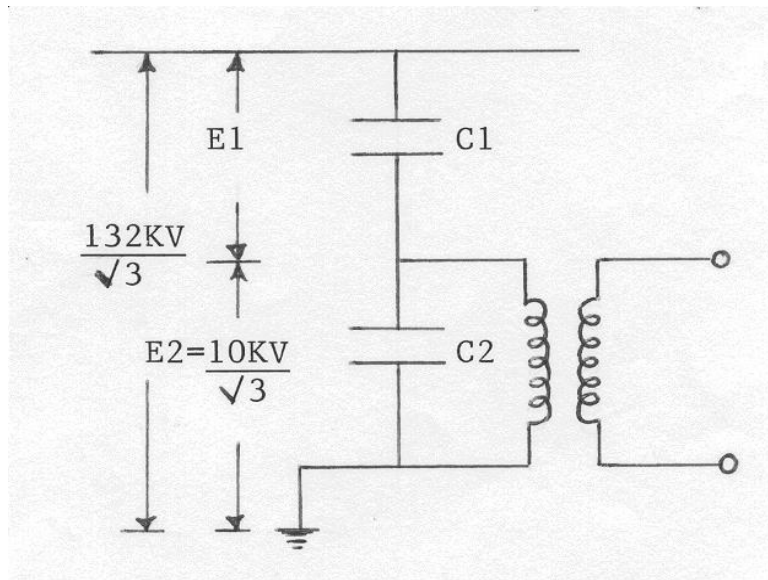
The auxiliary circuit elements are:

- (i) Compensating Inductance coil (D) or Reactor which is placed in series with the primary of the electromagnetic voltage transformer to compensate for any increase on the capacitive voltage divider.
- (ii) Damping Impedance Z that is placed across the secondary winding of the electromagnetic voltage transformer is to avoid ferro-resonance.
- (iii) The resistor R and spark gap 'F' are installed to provide necessary protection against over voltages.

Example: To calculate the capacitance requirements for a CVT to be used on a 132KV system.

- Let (1) Total capacitance of capacitor be 20,000pF
 (2) Burden requirement 100 VA
 (3) Magnetic transformer designed for a standard primary voltage of

$10/\sqrt{3}$ KV



$$\frac{C1}{C2} = \frac{E2}{E1}$$

$$= \frac{10/\sqrt{3}}{132/\sqrt{3} - 10/\sqrt{3}}$$

$$C1 = \frac{10}{132 - 10} \times C2$$

$$= \frac{10}{122} \times C2$$

$$\text{or } C_2 = \frac{122}{10} C_1$$

$$\text{Also } \frac{1}{C_1} + \frac{1}{C_2} = \frac{1}{C}$$

$$\text{or } C = \frac{C_1 C_2}{C_1 + C_2}$$

Substituting for C_2 in the above eqn.

$$C = \frac{C_1 \times \frac{122}{10} C_1}{C_1 + \frac{122}{10} C_1}$$

$$= \frac{C_1^2 \times \frac{122}{10}}{\frac{10C_1 + 122C_1}{10}}$$

$$= \frac{122}{132} C_1$$

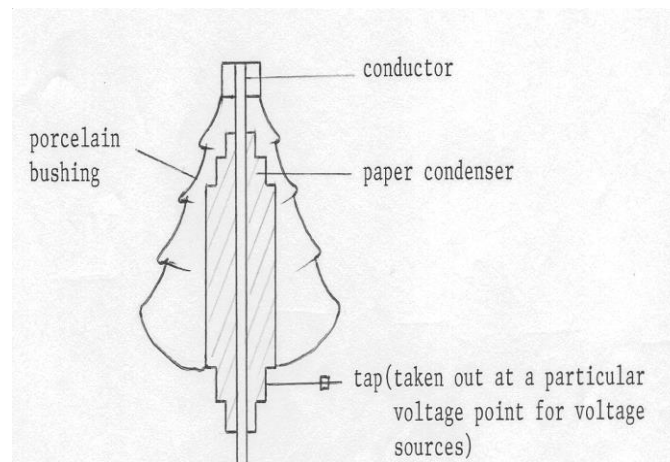
$$C_1 = \frac{132}{122} C$$

$$= \frac{132}{122} \times 20000 = 21639.34 \text{ pF}$$

$$C_2 = \frac{122}{10} \times 21639.34 = 264000 \text{ pF}$$

Bushing Type Capacitive Voltage Transformer

Condenser types of bushings are essentially rolls of vanished impregnated paper with metal sheath made of Aluminium foil. The voltage distribution between the various layers is properly designed and predetermined. A tapping across this by proper calibration can give a replica of the supply



voltage.

The low capacitance imposes severe restrictions on the output power of such CVT's. Hence its application is limited to synchronising, voltage indication and line alive lamp indication. The table below shows the maximum output obtainable with typical bushings for various system voltages.

System Voltage	Output in Watts
66	5
132	15
330	35

However in a substation, there are other apparatus, which need a greater burden and as such these types of CVT's are not commonly used.

17.0 Common definition of terms used with Voltage Transformers

17.1 Rated Burden

- (a) The rated burden of a voltage transformer is usually expressed as the apparent power in volt-amperes absorbed at rated secondary voltage.

The burden is composed of the individual burdens of the associated voltage coils of the instruments, relays and sometimes of the trip coils to which the voltage transformer is connected.

- (b) Normally the standard VA rating nearest to the burden computed should be used. It is not desirable to specify a VA rating much higher than the computed value as to do so would result not only in inaccuracies but also would prove uneconomical by way of cost and unduly large dimensions. The cost of a V.T. directly increases with the burden and voltage rating.

- (c) The typical burden values imposed by different meters and relays are as follows:

Instruments	VA Burden
<i>Voltmeters</i>	
Moving Iron	3.5 to 7VA
Moving Coil with Rectifier	0.1
Recording	4.5 to 20VA
Wattmeters	
Indicating	1 to 5VA
Recording	4 to 9VA

Power Factor Meter

Indicating	3.5 to 7.0VA
Recording	7.5 to 15.0VA
Frequency Meter	1 to 8.0VA
Synchoscope	10 to 20VA
KWH and KVARh Meters	2 to 7.5VA

Relays

Directional OCR Voltage polarized	8 to 15VA
Neutral Displacement Relay	
Definite Time	35VA
Inverse Time	17 to 125VA
Over Voltage	2 to 10VA
Under Voltage - Inverse Time	5 to 15VA
Definite Time	5 to 35VA
Distance relays	8 to 70VA
Reverse Power	14 to 50VA
Auto Reclosing	1.0 to 50VA

Tripping devices

Shunt trip coil	75 to 120VA
Series trip coil	50 to 70VA
Circuit breaker spring closing Motor	140 to 500VA
Circuit breaker closing solenoid	400 to 1800VA
Voltage Regulators	50 to 100VA

17.2 Rated primary voltage

It is the nominal system voltage to which the voltage transformer is connected.

17.3 Highest system voltage

Already dealt with in paragraph 7.6.

17.4 Rated secondary voltage

It is the voltage across an open circuited secondary with rated voltage applied to the primary.

In BSS 3941, the rated secondary voltages are specified as 110V, 220V line-to-line and $110/\sqrt{3}$, $220/\sqrt{3}$ for single phase earthed transformers.

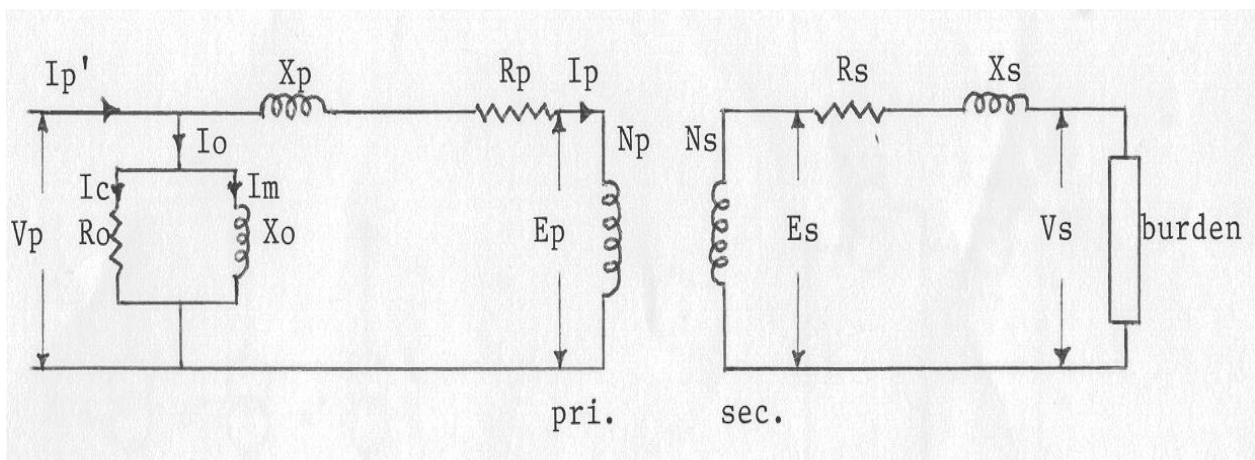
In ANSI, two nominal voltages are allowed for the secondary 115V and 120V line to line and the corresponding neutral voltages being $115/\sqrt{3}$ and $120/\sqrt{3}$. For C.V.T's, voltages are 115 and $115/\sqrt{3} = 66.4$ V

17.5 Rated Outputs or Burden

The preferred rated outputs as per BSS 3941 are 10, 25, 50, 100, 200, 250, 500 VA per phase.

18.0 Equivalent circuit of a voltage transformer

The equivalent circuit of a voltage transformer is as shown below:

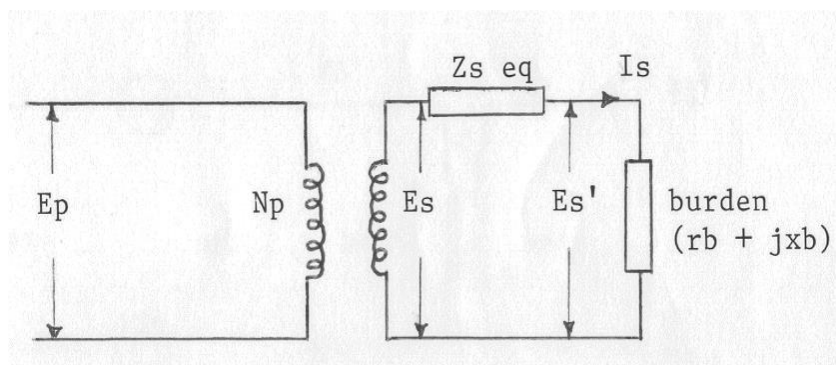


$$\frac{E_p}{E_s} = \frac{N_p}{N_s} = K_n \text{ (Transformation Ratio)}$$

$$\frac{V_p}{V_s} = \frac{N_p}{N_s}$$

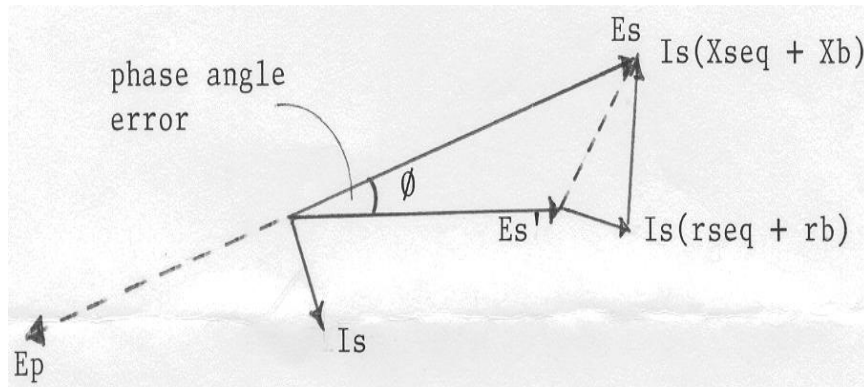
$$\text{But } \frac{V_p}{V_s} = \frac{N_p}{N_s} = K_n$$

The above equivalent circuit can be further reduced as follows. Converting all primary impedance to the secondary side and neglecting the core loss component R_o , magnetising component X_o which are very small.



$$\begin{aligned} \text{Here } Z_{s\ eq} &= Z_s \left(\frac{N_s}{N_p} \right)^2 \\ &= (r_s + jX_s) + \left(\frac{N_s}{N_p} \right)^2 (r_p + jX_p) \\ &= \left(r_s + \left(\frac{N_s}{N_p} \right)^2 r_p \right) + j \left(X_s + \left(\frac{N_s}{N_p} \right)^2 X_p \right) \\ &= r_{s\ eq} + jX_{s\ eq} \end{aligned}$$

The corresponding phasor diagram is as follows:



19.0 Errors in Voltage Transformers

It can be seen from the above phasor diagram that E_s the voltage at the burden is not the same as the voltage E_s transformed by an ideal transformer. It differs both in magnitude and phase angle. This difference constitutes errors in the V.T. Thus we have two main types of errors namely:

- (a) Ratio Error also called Voltage Error
- (b) Phase Displacement Error or Phase Angle Error.

19.1 Voltage Error or Ratio Error

This is the error introduced into the measurement of voltage between primary and secondary and is generally expressed as a percentage of the primary voltage.

Thus from the phasor diagram:

$$\% \text{ error} = \frac{E_s - E_s'}{E_s} \times 100$$

$$\text{But } \frac{E_p}{E_s} = K_n \text{ and } E_s = \frac{E_p}{K_n}$$

$$\begin{aligned}\% \text{ error} &= \frac{\frac{E_p}{K_n} - E_s'}{\frac{E_p}{K_n}} \times 100 \\ &= \frac{E_p - K_n E_s'}{E_p} \times 100\end{aligned}$$

19.2 Phase displacement error

It is the difference in phase angle between the primary voltage and secondary voltage vectors; the direction of the vectors being so chosen that the angle is zero for perfect transformers.

Accordingly in the vector diagram, the phase angle ϕ between E_s and E_s' is the phase displacement error. It is expressed in minutes of an arc.

19.3 Limits of Error

As already stated in paragraph 6.6 the error limits are prescribed by various national standards. These are as follows:

32 BSS 3941

Accuracy Class	90% to 110% of rated Primary voltage: 25% to 100% of rated output at unity power factor	80% to 120% of rated primary voltage at any output not exceeding rated output and power factor
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	Voltage Error ± %	Phase Error ± mins	Voltage Error ± %	Phase Error ± mins
AL	-	-	0.25	10
A	0.5	20	-	-
B	1.0	30	-	-
C	2.0	60	-	-
D	5.0	-	-	-

33 IEC/VDE

Power factor 0.8 lag. Burden 25 to 100% of rated burden

34 Accuracy Class	Primary Voltage	Ratio Error	Phase Angle Error
0.1	80 to 120%	± 0.1%	± 5 mins
0.2	80 to 120%	± 0.2	± 10 mins
0.5	80 to 120%	± 0.5	± 20 mins
1.0	80 to 120%	± 1.0	± 40 mins
3.0	90 to 110%	± 3.0	± 120 mins
5.0	90 to 110%	± 5.0	± 300 mins

20.0 Voltage Factor (V_f)

Voltage Factor is the maximum operating voltage, which in turn is dependent upon earthing conditions of the system and the transformer winding. The voltage factors approximate to different earthing conditions

together with the permissible duration of the maximum operating voltage is appended in the table below

V_f = number = Highest voltage for specified time rated voltage

35 Voltage Factor	36 Duration	Earthing Conditions	
		V.T Primary Winding	System
1.1	Not Limited	Non-earthed	Effectively and non effectively earthed
1.5	30 secs	Earthed	Effectively earthed
1.9	30 secs	Earthed	Non effectively earthed

This voltage factor is introduced only in the BSS Accuracy class as follows:

37 Class	25% to 100% rated output at unity power factor			
	50% to 90% of rated voltage		110% to V_f of rated voltage	
	Voltage Error $\pm$ %	Phase Error $\pm$ mins	Voltage Error $\pm$ %	Phase Error $\pm$ mins
E	3	120	3	120
F	6	250	10	300

In addition as per BS, where transformers are used for the dual purpose of measurement (metering) and protection; should also comply with the accuracy limits class of one of the class E or F as per above table and bear

designation letters of the appropriate two classes as follows: i.e. AE, AF, BE, BF, etc.

21.0 Application of Accuracy Class for various metering and protection purposes

Application	Class of Accuracy
(1) Precision testing or where a standard is required for testing	AL or 0.1
(2) Precision Indicating Instruments	A or 0.2 or 0.5
(3) Commercial grade Meters, Industrial Meters, Portable Meters	B or 1.0
(4) Voltmeters, Recording Instruments, Synchronoscopes	C or 3.0
(5) KWH Meters	0.5, 0.2 or 0.1 or B, A or AL.
(6) Relays	3 or 1, BE or BF, AE or AF.

22.0 Choice between Magnetic Type Voltage Transformers and Capacitive Type Voltage Transformers

There are many factors to be considered before a choice can be made between magnetic type voltage and capacitive type voltage transformers.

The important amongst them are:

- (i) Purpose
- (ii) Layout
- (iii) Cost

(a) Purpose:

This indicates the purpose for which a V.T is required. If the V.T. supply is merely meant for indicating a voltage through a voltmeter or for synchronizing or to indicate that a line is alive (line alive lamp indication), C.V.Ts serve the purpose. But however, if the supply is required for fairly accurate metering and protection then magnetic voltage transformers alone are required. Again, if it is required to adopt tele-protection through carrier channel, it is then necessary that coupling capacitors be used on each phase along with voltage transformers. In such a case we can use CVTs for tele-protection and the less important functions of voltage indication, synchronizing etc. along with magnetic voltage transformers for the other important functions of protection, metering etc. We may also use CVTs for these dual purposes. The choice will then depend upon the layout and price.

(b) Layout

Generally lines below 132KV i.e. 66KV, 33KV are not interconnected and are mostly radial lines. As such for such lines there is no justification for providing tele-protection. Similar is the case with 132KV radial lines. But if the 132KV lines are interconnected then it may be desirable to have tele-protection. Hence in such cases the layout decides whether to use

CVTs or magnetic voltage transformers. The layout could be one or other of the following alternatives:

- (a) To use CVT's for all incoming and outgoing lines for tele-protection, metering and relaying functions with no centralised bus V.T.'s.
- (b) To use CVT's on two phases of each incoming and outgoing lines for telephone communication, tele-protection, and centralised bus CVT's for metering and protection.
- (c) As in (b) above but with electromagnetic type bus V T's for metering and protection.

In the case of 330KV lines, tele protection is a must whether the lines are interconnected or radial. The above alternatives (a), (b) and (c) would equally apply for 330KV lines. In all the above alternatives the layout is decided by the cost.

(c) Cost

The cost is, by far, the most important factor in determining the type of V.T.'s to be used.

In substations of below 132KV rating there is no choice but to use

Electromagnetic voltage transformers because:

- (1) Teleprotection is not used
- (2) The cost of an electromagnetic transformer compares favourably with that of a C.V.T. if not cheaper.

- (3) The errors introduced by a C.V.T. are much higher than that of an electromagnetic V.T at voltages lower than 132KV.

However, in substations of 132KV and above the cost of a C.V.T. compares favourably with that of an electromagnetic type V.T. A judicious choice is therefore required in 132KV substations taking into consideration the layout. But at 330KV voltages, C.V.Ts are definitely cheaper than Electromagnetic V.Ts. As such it is advisable to use CVTs at 330KV voltages unless there are overriding factors such as suppression of over-voltages due to unloaded line switching.

23.0 Problems associated with C.V.Ts

(a) Reference Range of Frequency

The variation in the operating range of frequency has significant influence on the accuracy of a C.V.T. Normally a C.V.T is tuned to yield the best accuracy at the rated frequency of 50Hz. However the accuracy limits will be maintained when the frequency departs from its rated value, within prescribed limits of frequency variation of $\pm 3\%$. This is termed the Reference Range of Frequency. When the operating frequency deviates beyond the reference range of frequency, the accuracy limits are likely to be exceeded. The coincident influential factors affecting the accuracy are the power factor and magnitude of the burden. Hence it is always desirable to obtain the accuracy curves for various power factors and burden when C.V.Ts are used for protection and for high-tension

consumer metering. This is because of the low p.f during faults and also low p.f of the consumer, if any.

(b) **Use of C.V.Ts as a coupling capacitor for PLCC and Tele-protection**

For carrier current application, any element connected between the earth and the potential divider point should have negligible impedance in comparison to the impedance of the intermediate V.T at rated frequency. This is desirable to prevent attenuation of the signal being transmitted. This is achieved by inserting a carrier frequency choke in series with the electromagnetic unit to prevent loss of carrier frequency in the transformer winding itself. However practical experience has shown that even if the impedance of the intermediate voltage transformer is 1000 times that of the impedance of the carrier frequency-coupling device, the influence on the operation of the C.V.T is negligible:

(c) **Factors affecting the choice of the capacitance for C.V.Ts**

The maximum output from a C.V.T is governed by the range of frequency over which the accuracy has to be maintained. The permissible rated output is derived from the following empirical relation

$$W = K (C_1 + C_2) V_1^2 \phi$$

Where W = output in VA

C_1 = capacitance of primary voltage in Farads

C_2 = capacitance of intermediate voltage in Farads

V_1 = intermediate tapping voltage in Volts

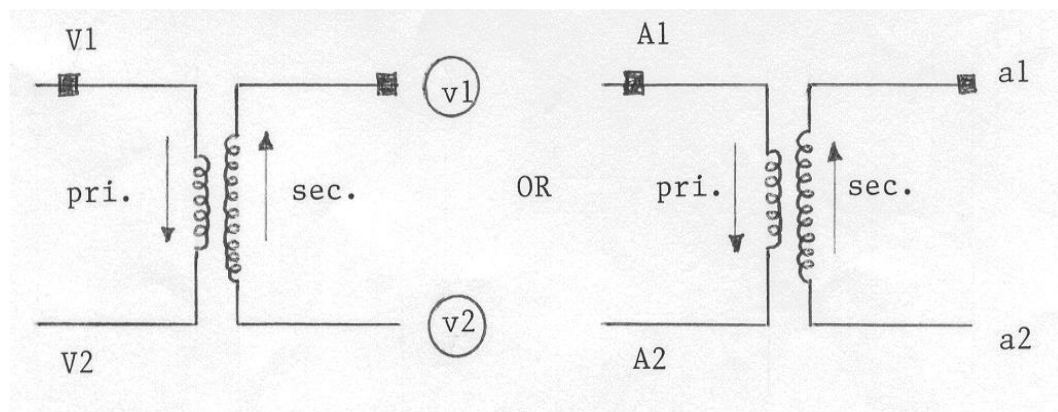
ϕ = Phase angle error change in mins per frequency (Hz)

K = factor depending on frequency, losses etc.

It is apparent from the above equation that for a given accuracy over a given frequency range, the rated output is proportional to the capacitance, and also to the intermediate voltage. An economic limit has to be prescribed for the intermediate voltage and the capacitance for a given output. However if the capacitance is fixed by other considerations such as carrier frequency, then the output is purely decided by the permissible phase angle error change per frequency (Hz).

24.0 Polarity and Connections of V.Ts

24.1 Polarity V_1



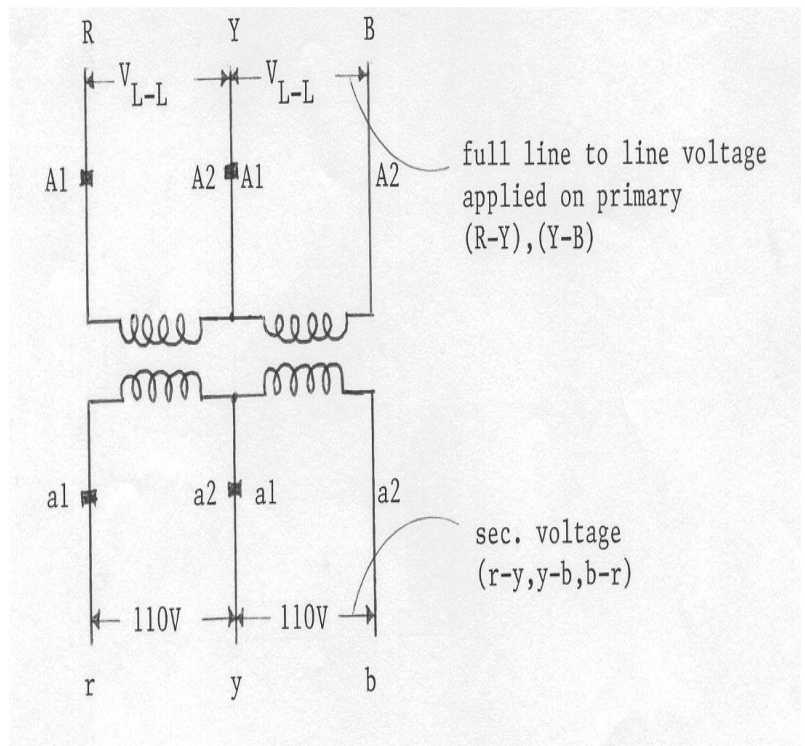
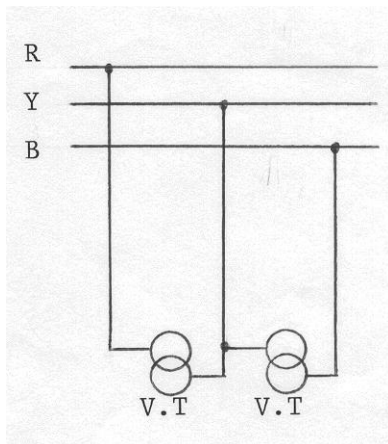
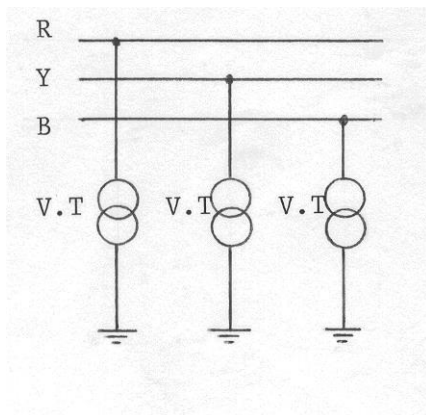
24.2 Connections

- (a) Both single-phase and 3-phase V.Ts are used
- (b) 3-phase V.Ts are used in indoor type switchgear of ratings up to 33KV

(c) Single-phase V.Ts are generally used for voltage ratings of 33KV and above.

(d) Where single-phase V.Ts are used, they are generally star-connected and where 3-phase V.Ts are used they are connected in open delta or V connection.

3-Phase Connection



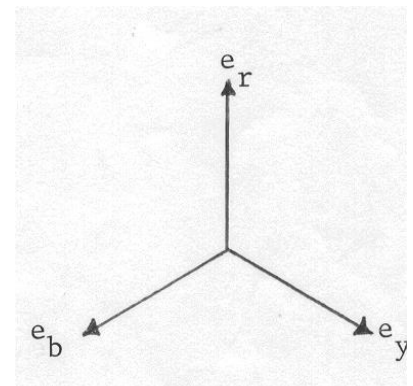
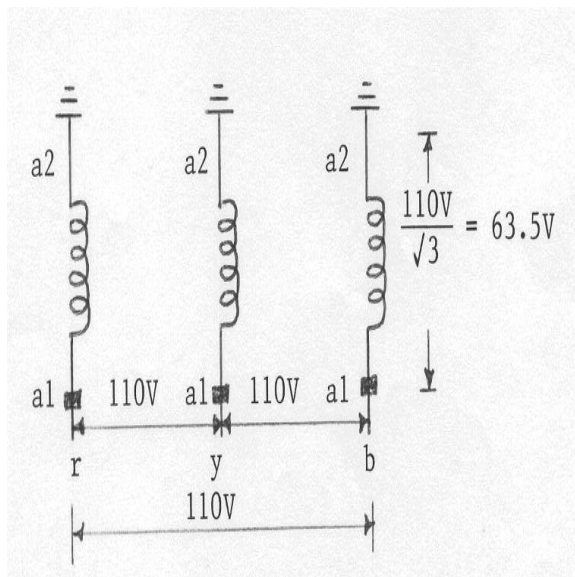
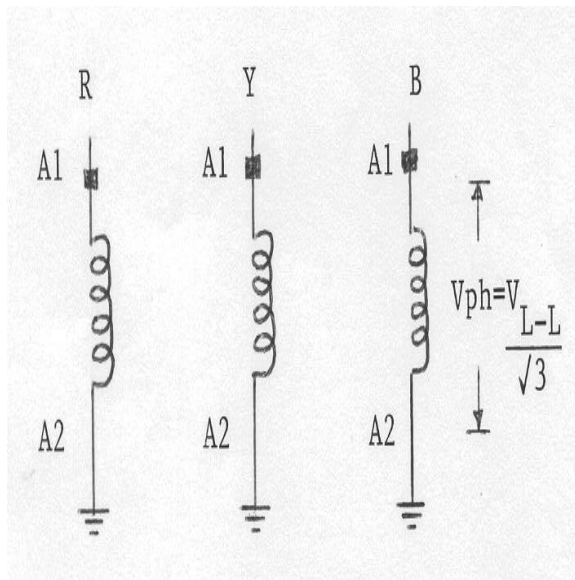
Primary voltage = Full line to line voltage

(R-Y, Y-B, B-R)

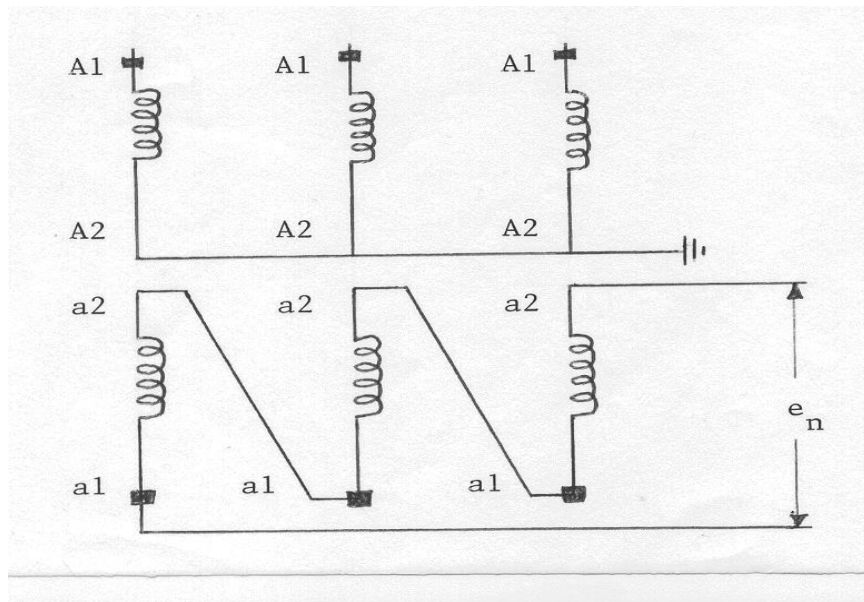
Secondary Voltage = 110V

(r-y, y-b, b-r)

38 Single Phase Connection



(e) There is one more connection commonly called the residual voltage connection. This residual voltage is used for directional earth fault protection. The primary windings are connected in star and the secondary in broken delta as shown.



Under balanced conditions: $e_n = 0$.

$$\begin{aligned}
 e_n &= e_r + e_y + e_b \\
 &= e_r + e_r \angle -120^\circ + e_r \angle 120^\circ \\
 &= e_r [1 + \cos(-120^\circ) + j \sin(120^\circ)] \\
 &= e_r [1 + \cos 120^\circ + j \sin 120^\circ] \\
 &= e_r \left[1 - \frac{1}{2} - j\frac{\sqrt{3}}{2} - \frac{1}{2} + j\frac{\sqrt{3}}{2} \right] \\
 &= e_r (1 - \frac{1}{2} - \frac{1}{2}) = 0
 \end{aligned}$$

Under fault conditions, say fault on Red phase, then

$$\begin{aligned}
 e_r = 0 \text{ and } e_n &= e_y + e_b \\
 &= e_r \angle -120^\circ + e_r \angle 120^\circ \\
 &= e_r \left[-\frac{1}{2} - j\frac{\sqrt{3}}{2} - \frac{1}{2} + j\frac{\sqrt{3}}{2} \right] \\
 &= e_r (-1) \\
 |e_n| &= e_r = \frac{110}{\sqrt{3}}
 \end{aligned}$$

Similarly, under two phase fault condition

$$|e_n| = \frac{110}{\sqrt{3}}$$

25.0 Tests

The following type and routine tests are stipulated in most of the specifications.

25.1 Type tests: - for Electromagnetic V.Ts

- (a) High voltage power frequency withstand voltage test
- (b) Impulse voltage withstand test
- (c) Temperature rise test

For C.V.Ts

- (a) High voltage power frequency withstand voltage test on primary capacitors
- (b) Impulse voltage withstand test

- (c) Test for Ferro resonance
- (d) Test for transient response

25.2 Routine Tests - for Electromagnetic V.Ts

- (a) Induced high voltage power frequency withstand test
- (b) Applied high voltage power frequency test on secondary windings
- (c) Verification of terminal markings
- (d) Test for Accuracy

For C.V.Ts

- (a) Applied high voltage power frequency withstand test on intermediate voltage capacitor and transformer
- (b) Applied high voltage power frequency test on secondary circuit
- (c) Verification of terminal markings
- (d) Tests for accuracy at the limits of frequency range
- (e) Setting of protective gap.

25.3 Field Commissioning Tests

(a) Visual Checks

Inspection as is done for C.T's outlined in paragraph 13 (a)

(b) Insulation test

As per paragraph 13 (b) except that the ground links have to be opened out.

(c) Polarity test

As per paragraph 13 (c) except that a milli-voltmeter is connected in the secondary circuit. Sometimes this test is conducted by connecting a voltmeter across the primary circuit with the battery on the secondary circuit. This is generally done in H.V. Transformers of 66KV and above where a 1.5V battery voltage on the primary may not produce sufficient voltage to cause a kick in the secondary milli-voltmeter because of the large transformation ratio.

(d) **Ratio test**

This test is conducted by applying a single-phase A.C. voltage supply on the primary and noting the primary and secondary voltages with sub- standard voltmeters. The % error is calculated and the same should be within specified limits of accuracy.

- (e) An additional test is done in the case of C.V.Ts. This is to ensure the condition of the capacitors.

A known voltage E of say 230V single phase A.C. is applied to the primary terminal and the divider point. The current I drawn is noted, then.

$$X_c = \frac{E}{I}$$

$$\text{Also } X_c = \frac{1}{2\pi f C}$$

$$\begin{aligned}
 \text{Or } C &= \frac{1}{2\pi f X_c} \\
 &= \frac{1}{2\pi f \frac{E}{I}} \\
 &= \frac{I}{2\pi f E}
 \end{aligned}$$

The value of capacitance C, thus calculated is compared with the nameplate value.

26.0 How to specify a Voltage Transformer

- (a) Choose rated primary voltage: - The accuracy class is met from 80% to 120% of rated voltage.
- (b) Choose type of V.T: - Single phase to earth or three phase V.T. Three V.Ts are required for single phase to earth and are normally used in all installations of outdoor type at 33KV and above.
- (c) Choose rated secondary voltage: - This is normally $110/\sqrt{3}$ for single phase V.Ts and 110V phase to phase for 3 - phase V.Ts.
- (d) Choose number of secondary windings: - This normally is 2 or 3. With 2 windings, one is for metering and the other for protection. With 3 windings, one is for metering, one for protection and the other for connecting residual V.Ts for directional protection relays.

- (e) Choose rated VA for each winding by calculating the VA absorbed by each connected apparatus.
- (f) Choose accuracy class for each winding.
- (g) Choose type of V.T namely; Electromagnetic or C.V.T. Normally C.V.Ts are used for voltages of 132KV and above depending upon the cost.

27.0 Protection of V.Ts.

The primary and secondary windings are generally protected by fuses: -
Expulsion type on the primary side and HRC cartridge fuses or HRC bottle fuses on the secondary side. Though in earlier days, expulsion type fuses protected the primary windings, the practice today is not to use any protection on the primary side.

28.0 Maintenance of V.Ts in Service

This is similar to C.T's vide paragraph (15).

CHAPTER SEVEN

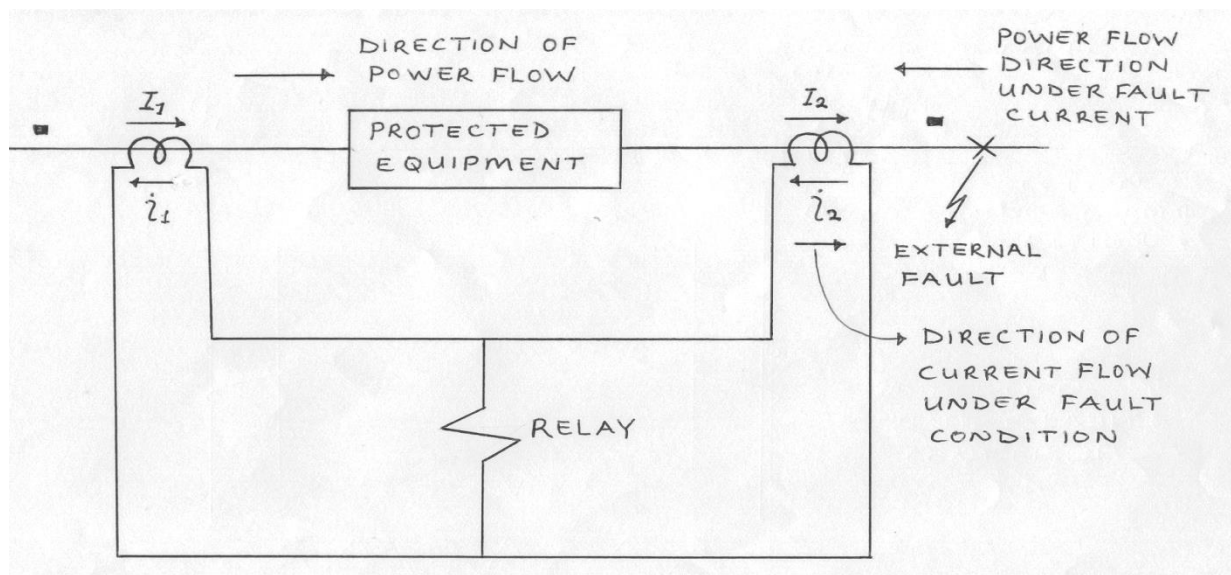
BASIC DIFFERENTIAL PROTECTION

1.0 Introduction

- 1.1** Differential Protection is a form of protection whereby a relay operates when the vector difference of two or more similar electrical quantities exceeds a predetermined amount.
- 1.2** This relay is called a Differential Relay and may take on a variety of forms depending upon the equipment being protected.
- 1.3** Almost any type of relay when connected in a certain way can be made to operate as a Differential relay. In other words it is not so much as the construction of the relay, but the manner in which the relay is connected in a circuit that makes it a differential relay.

2.0 Basic Differential Relaying

- 2.1** The basic scheme of differential relaying is explained with reference to the diagram below:-



- 2.2** The protected equipment may be a length of a circuit or a winding of a generator, or a portion of the bus etc. A C.T is connected at either end of the protected equipment. The secondaries of the C.Ts are interconnected as shown with a relay which may be an over-current relay.
- 2.3** Now suppose current flows through the protected equipment to an external load or to a fault at X. If the two C.Ts have an identical ratio, and are properly connected with respect to polarity, then the secondary induced currents i_1 and i_2 will merely circulate between the two C.Ts and no current flows through the relay.
- 2.4** However if an internal fault should develop in the protected equipment or between the primaries of the two C.Ts then the currents I_1 and I_2 will be different. The current I_1 will be the sum of current I_2 and fault current I_f . Accordingly the C.T secondary currents will be different and the difference in the $(i_1 - i_2)$ flows through the relay causing the relay to operate.
- 2.5** This relay which operates on the vector difference of the current entering and leaving protected equipment is called a differential relay and the scheme of protection as Differential Protection.

3.0 Types of Differential Protection or Relaying

There are two basic types of Differential Relaying namely:-

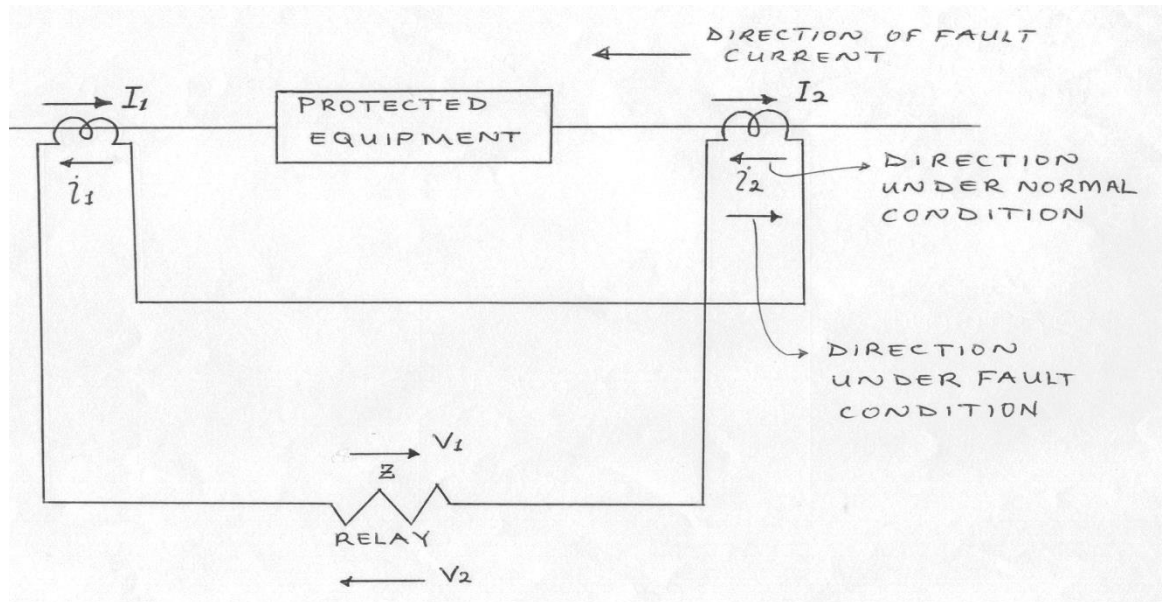
- a) Current Differential Relaying
- b) Voltage Differential Relaying

3.1 Current Differential Relaying

This is also called the current balance method or circulating current method of Differential Relaying. The principle of this method has already been described in paragraph 2.0 above. Most differential relay applications are of the "Current Differential Method" and the method is applied for the protection of Generators, Transformers, Motors and Bus bars.

3.2 Voltage Differential Relaying

This is called voltage balance method or opposed voltage relaying. The two C.Ts at either end of the protected equipment are cross connected with the relay in series as shown below:



Let Z be the impedance of the relay coil.

Then voltage drop produced due to secondary current i_1 in Z :

$$V_1 = i_1 Z.$$

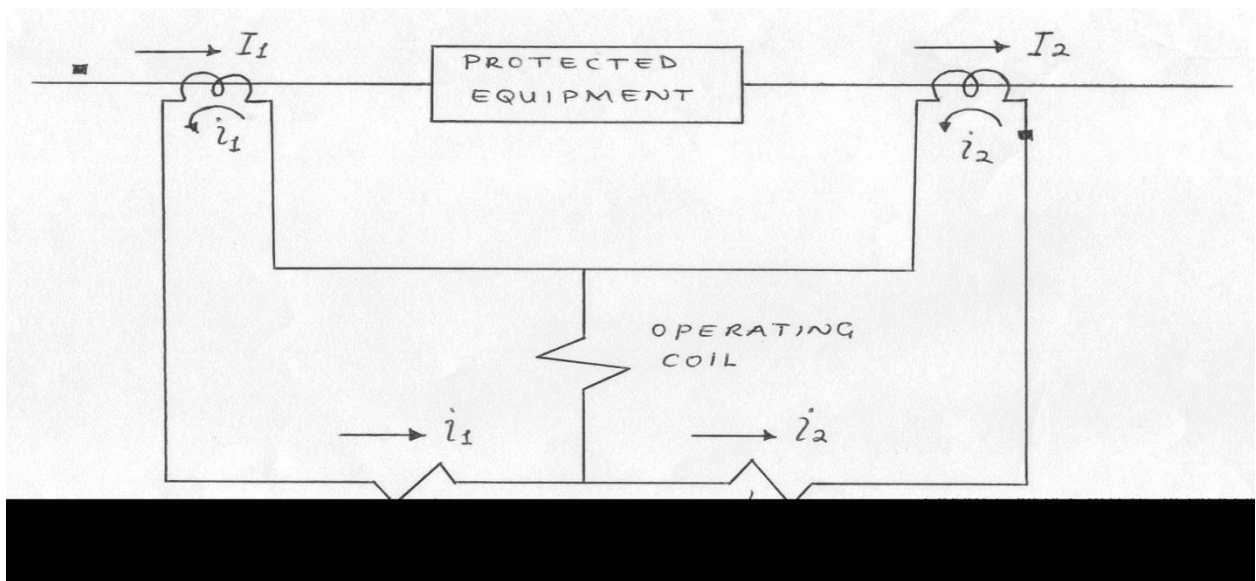
Similarly the voltage drop $V_2 = i_2 Z$

When current i_1 and i_2 are equal the voltage drop V_1 and V_2 are equal and opposed and the relay does not operate.

The relay operates when the vector difference in the voltage drop exceeds the pick up value of the relay. Opposed voltage method of Differential Relaying is generally employed for the protection of transmission lines and feeders in A.C. wire Pilot Relaying.

4.0 Biased Differential Protection or Percentage differential Protection

4.1 This is the most extensively used form of differential protection. It is essentially the same scheme as described in paragraph 2.0 above except that restraining coils are introduced in the C.T secondary circuit as shown

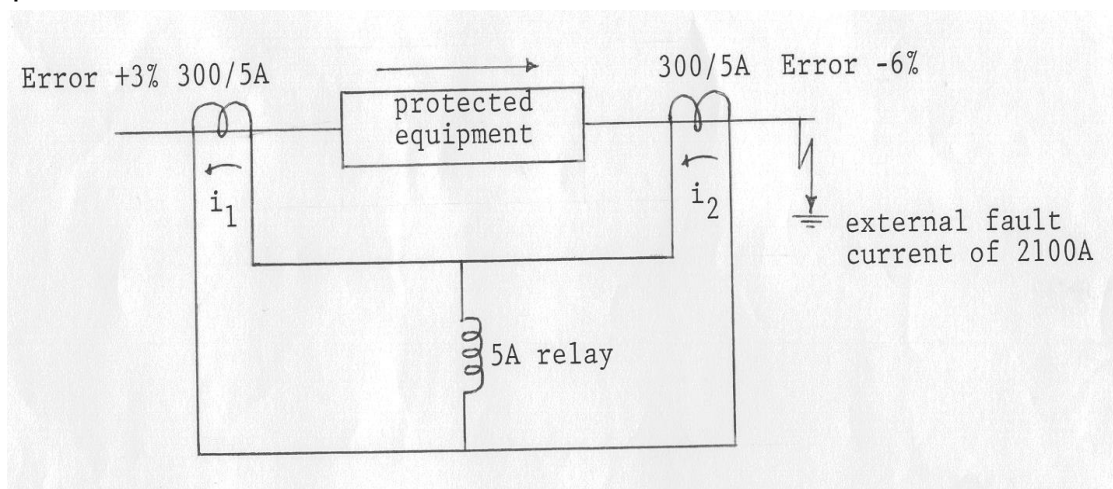


The differential current to operate this relay is a variable quantity owing to the effect of the restraining coil. The differential current in the operating coil is proportional to $(I_1 - I_2)$.

4.2 The development of the percentage differential relay was necessitated to take care of the following:-

- a) Although C.Ts of identical ratios are used, their performance during through faults when the C.Ts are saturated cannot be ensured to be the same. The errors introduced may be different with the result an operating current will flow.

Example:



$$I_1 = I_2 = 2100 \text{ A}$$

$$i_1 = \frac{2100 \times 5}{300} - \left(\frac{3}{100} \times \frac{2100 \times 5}{300} \right)$$

$$= 35 - 1.05$$

$$= 33.95 \text{ A}$$

$$i_2 = \frac{2100 \times 5}{300} + \left(\frac{6}{100} \times \frac{2100 \times 5}{300} \right)$$

$$= 35 + 2.1$$

$$= 37.1 \text{ A}$$

$$\text{Difference in currents} = i_2 - i_1$$

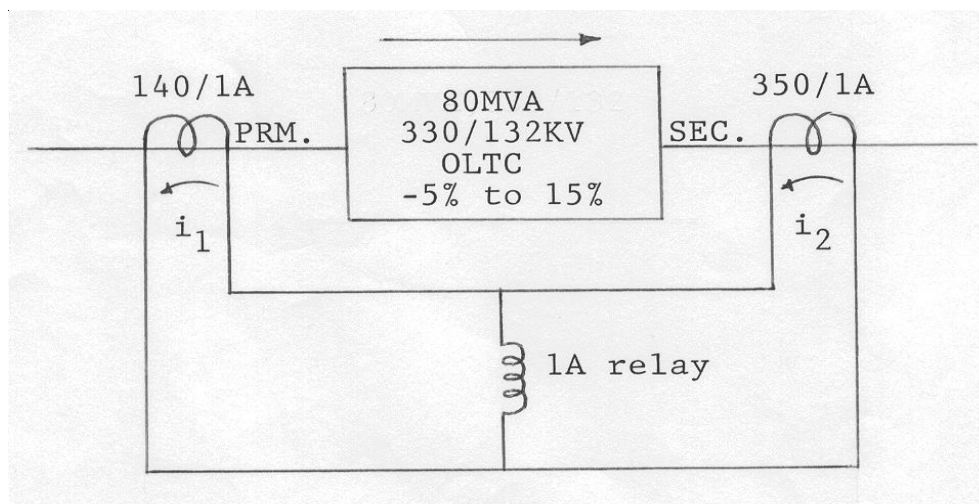
$$= 37.1 - 33.95$$

$$= 3.15 \text{ A}$$

This difference in current may be sufficient to cause operation in the 5A relay unless the pick up value is greater than 3.15 A.

It should also be noted that no two C.Ts however identical they may be in so far as their secondary currents are concerned will give exactly the same secondary current for the same primary current. These discrepancies may be traced to manufacturing variations and to differences in secondary loading caused by unequal length of leads between C.T and relay, unequal burden of meters and instruments connected in one or both secondaries.

- b) Another example of an on load tap changing Transformer is taken to study the effects on the differential circuit.



At normal tap of 330KV/132KV

$$\text{Primary full load current} = \frac{80 \times 10^6}{\sqrt{3} \times 330 \times 10^3}$$

$$= 140 \text{ A}$$

$$\text{Primary C.T. Ratio} = 140/1$$

C.T. secondary current of primary

$$i_1 = 140 \times \frac{1}{140}$$

$$= 1.0 \text{ A}$$

Secondary full load current

$$= \frac{80 \times 10^6}{\sqrt{3} \times 132 \times 10^3}$$

$$= 350 \text{ A}$$

$$\text{Secondary C.T. Ratio} = 350/1$$

C.T. secondary current of secondary

$$i_2 = 350 \times \frac{1}{350}$$

$$= 1.0\text{A}$$

Since $i_1 = i_2$ no current flows in the differential relay and therefore the relay does not operate. Let us now assume that the primary incoming voltage is 310 KV and the OLTC gear is operated to raise the secondary voltage to say 140 KV.

Then primary full load current

$$= \frac{80 \times 10^6}{\sqrt{3} \times 310 \times 10^3}$$

$$= 149 \text{ A}$$

C.T secondary current of primary i_1

$$= 149.00 \times \frac{1}{140}$$

$$i_1 = 1.06 \text{ A}$$

Secondary full load current

$$= \frac{80 \times 10^6}{\sqrt{3} \times 140 \times 10^3}$$

$$= 330 \text{ A}$$

C.T secondary current of secondary

$$i_2 = 330 \times \frac{1}{350}$$

$$= 0.94 \text{ A}$$

Now the difference in the currents between (i_1 and i_2)

$$= (1.06 - 0.94) \text{ A}$$

$$= 0.120 \text{ A}$$

This current of 0.120A flowing in a 1 A relay may cause operation of the differential relay unless the pick up value of the relay is raised to be

beyond 0.120 Amps. It is also not practical to keep on raising the pick up value whenever a tap changing operation is carried out.

4.3 Thus to obviate all these practical difficulties, the percentage differential relay was developed. The current flowing through the restraining coil or windings is called the "Through Current" and the current flowing through the operating winding is called the "Spill Current".

4.4 This spill current necessary to operate the relay expressed as a percentage of the through current is called the percentage bias.

$$\% \text{ bias} = \frac{\text{Spill current for relay operation} \times 100}{\text{Through fault current causing it}}$$

4.5 Bias is provided on both the restraining windings by a plug setting bridge in electromagnetic relays and in static relays by a rotary switch. Bias settings are usually from 10% to 80% in multiples of 10% or 20% to 80% in multiples of 20% or sometimes in multiples of 15%.

4.6 The number of turns on both the restraining windings are always the same so that in effect it can be considered as one winding, with the operating coil or winding connected at its mid point.

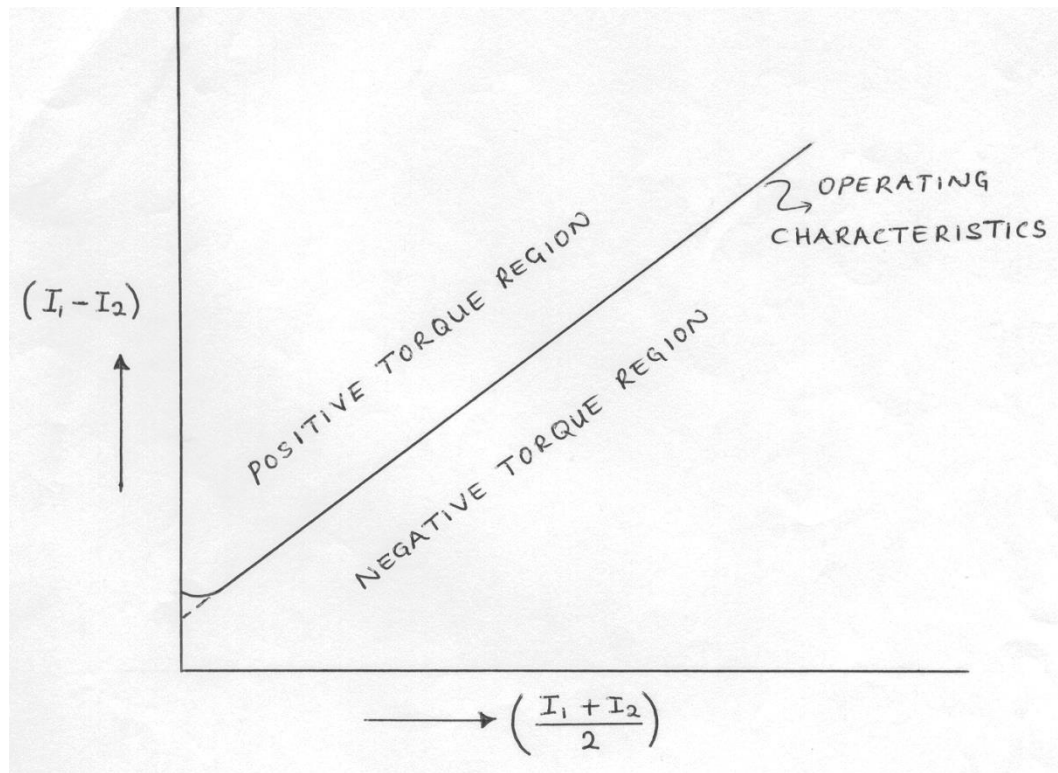
Let N be the turns in the restraining winding.

Then the restraining torque produced is:

$$\begin{aligned} &= \frac{I_1 N}{2} + \frac{I_2 N}{2} \\ &= \frac{(I_1 + I_2) N}{2} \end{aligned}$$

Or Restraining Torque is $\propto \frac{I_1 + I_2}{2}$

4.7 The operating characteristic of such a relay is as shown below:



4.8 It can be seen that $(I_1 + I_2)/2$ is the average of the two currents I_1 and I_2 . Specifically the term “through current” is used to designate I_2 as it is this current which flows in the circuit from one end to the other and also causes the relay operation. Hence the characteristic is also plotted with I_2 as abscissa instead of $(I_1 + I_2)/2$.

4.9 The operating characteristic is a straight line indicating that the spill or operating current is a fixed percentage of the through current. Hence the name “Percentage Differential”

5.0 Application

Percentage Differential relays are almost always used as the primary protection device for generators, transformers, motors and other costly electrical apparatus in industry.

CHAPTER EIGHT

GENERATOR PROTECTION

1.0 INTRODUCTION

The modern practice is to install in a power house a small number of large capacity generators. These generators are to be in service continuously as long as they are sound and independent of load conditions in the network and ignoring other considerations such as availability of water, fuel etc. Thus any internal fault developed within the generator must be cleared completely and instantaneously.

2.0 TYPES OF GENERATOR FAULTS

2.1 These may be broadly classified as:

- a) Stator faults
- b) Rotor faults
- c) Miscellaneous faults and or abnormal conditions.

2.2 Stator Faults – This may be further subdivided into:

- a) Short circuit fault between phases or between phase and ground.
- b) Interturn fault
- c) Unbalanced operation
- d) Over-voltage
- e) Abnormal temperature

2.3 Rotor faults – This similarly can be subdivided into:

- a) Field earth fault
- b) Field failure

2.4 Miscellaneous faults and or abnormal conditions – These are:

- a) Over-speed
- b) Motoring action
- c) Loss of synchronism

3.0 STATOR PROTECTION

3.1 Stator faults are due to the breakdown of insulation between conductors or between conductor and the magnetic core. This breakdown may be caused by:

- a) Over-voltage
- b) Overheating created by unbalanced currents, ineffective ventilation and cooling.

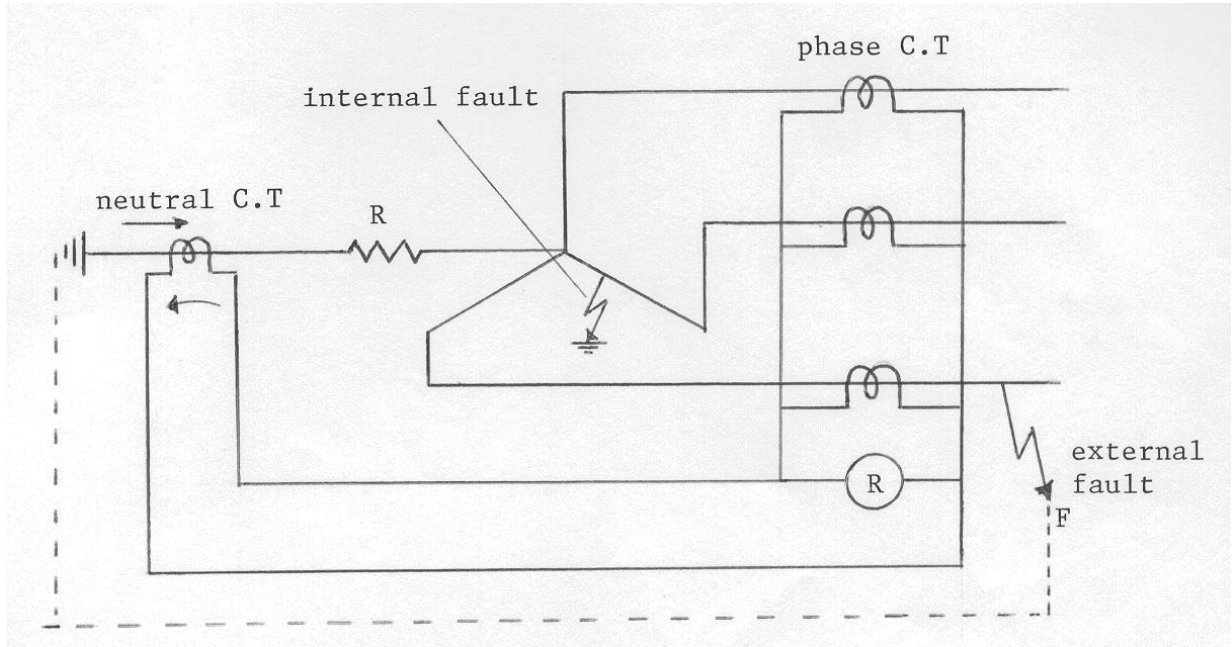
3.2 The ground fault has a destructive effect due to the high temperature of the arc and damages not only conductor but also the core. The ground fault current is limited by the type of grounding and the impedance in the neutral of the generator.

3.3 The common types of grounding employed are:

- a) Resistance grounding
- b) A distribution transformer with resistance loading
- c) Potential Transformer or V.T Grounding

d) Reactance grounding.

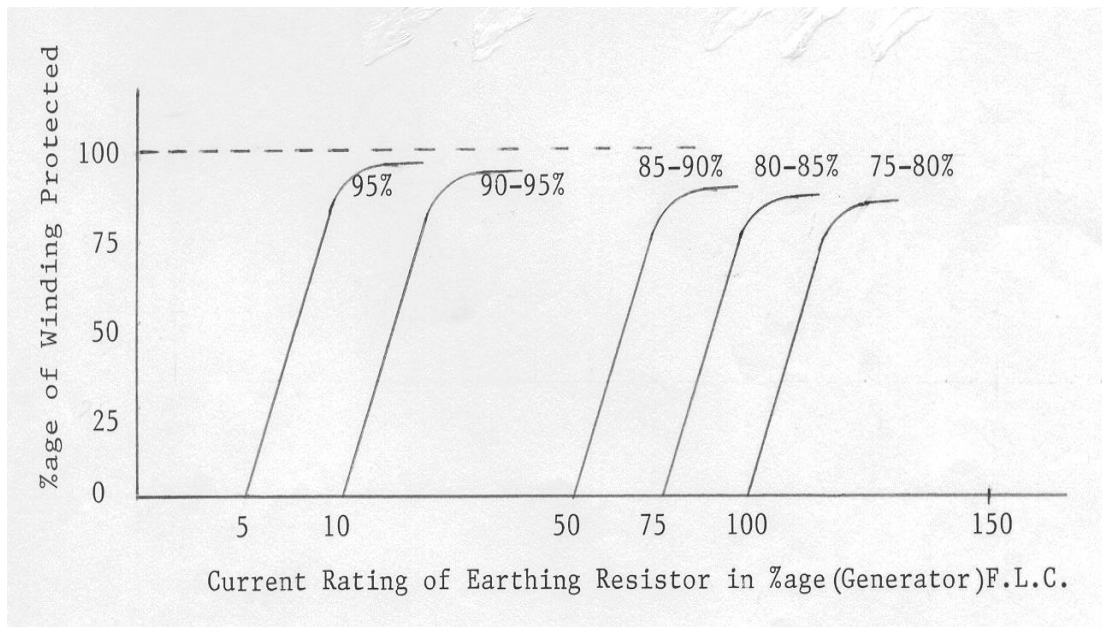
3.4 Resistance Grounding



The resistance is chosen such that the magnitude of the fault current is limited to the full load current in the case of small capacity generators and to a current of 200 to 300 Amps in the case of large generators. A C.T is connected in series with the neutral grounding lead and resistor. The C.T secondary is connected to a sensitive earth fault relay. This method is rarely employed for large capacity generators. The relay is generally a current polarised directional relay with the current directional feature obtained from the phase current C.Ts as shown.

With resistance type of grounding, it is impossible to protect 100% of the stator winding. The percentage of the winding protected depends upon

the value of the earthing resistance. The graph below shows the relationship between the current rating of the earthing resistor expressed as a percentage of the generator full load current and the percentage of the stator winding protected.



- 3.5** The relationship indicates that reducing the fault current setting or increasing the current rating of the resistor does not cause proportional improvements in the amount of winding protected. For example with a 100% full load resistor and 20% relay current setting only 80% of the winding may be protected. Doubling the resistor rating or halving the relay current setting may only increase the percentage of the winding protected by another 10%.

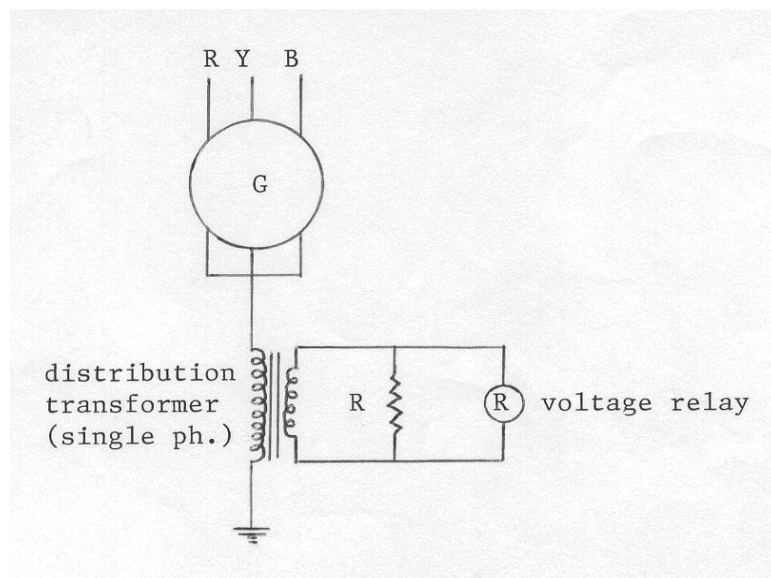
3.6 Distribution Transformer Grounding

This is the most commonly employed method for large generators. The generator neutral is grounded through the H.V winding of a distribution transformer. A resistor and an over voltage relay are connected across the L.V winding. The value of the resistor is so chosen to limit the fault current to approximately 15 Amps and the value of R is generally calculated by the equation:

$$R = \frac{10^3 V}{15 \times \sqrt{3} N^2} \text{ ohms}$$

Where V = phase to phase generator voltage

N = turns ratio of the Distribution Transformer.



It is also suggested that, to avoid large magnetising current flow to the distribution transformer when a ground fault occurs, the high voltage

rating of the distribution transformer should be at least 1.5 times the phase to neutral voltage of the generator. The low voltage rating may be 110, 120, 220, 240 Volts depending on the voltage rating of the protective relay. The over voltage relay is either connected to sound an alarm or to trip the generator main and field breakers. The continuous rating of the transformer should be:

$$\text{KVA} = \frac{10^3 V (V_T)}{\sqrt{3} N^2 R}$$

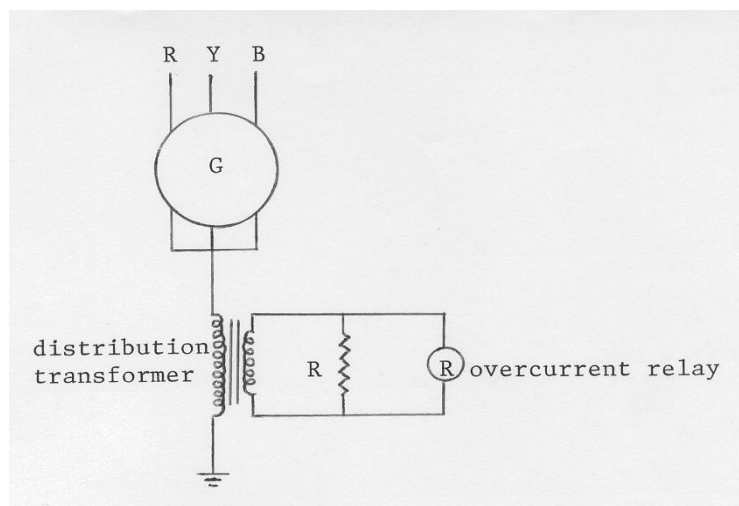
Where V_T is the high voltage rating of the Distribution Transformer.

Similarly the continuous rating of the resistor should be

$$\text{KW} = \frac{10^3 V^2}{\sqrt{3} N^2 R.}$$

The continuous rating is required only if the relay is to sound an alarm.

Otherwise a 10 minute or 1 minute rating can be used in which these values will be 40% and 21% of the continuous rating. Sometimes an over current relay is also connected instead of an over-voltage relay as shown.



3.7 Voltage Transformer Grounding

This is similar to Distribution Transformer Grounding except that the over-voltage relay is connected to trip the generator main and field breakers.

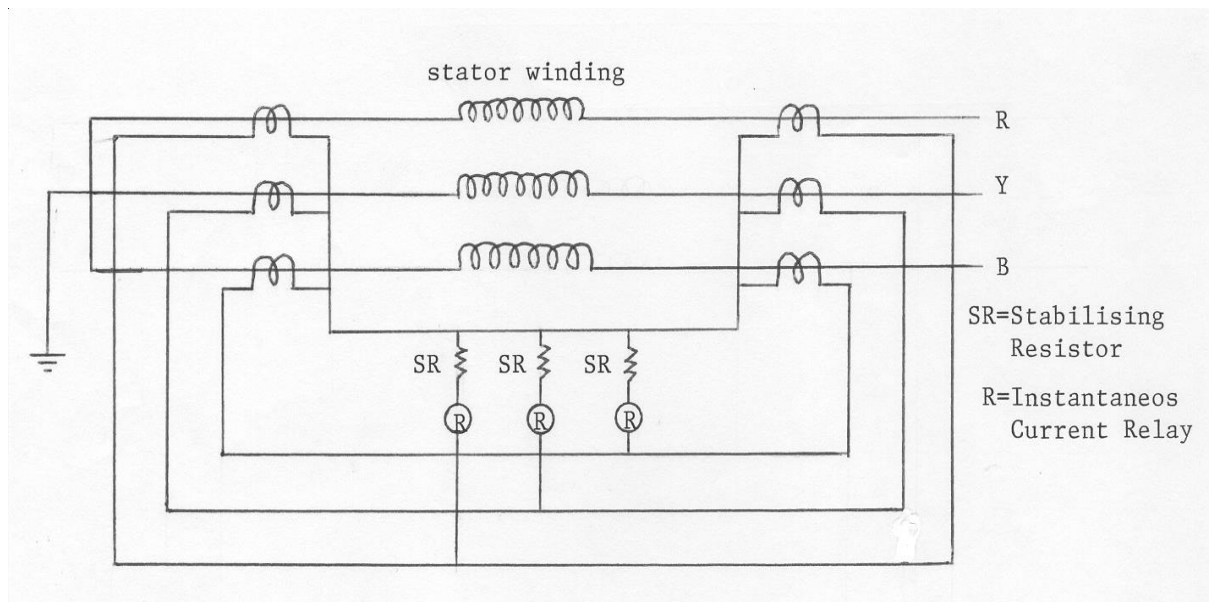
This is in view of the fact that the rating of a V.T cannot be as large as that of a Distribution Transformer.

3.8 Reactance Grounding

This is similar to resistance grounding.

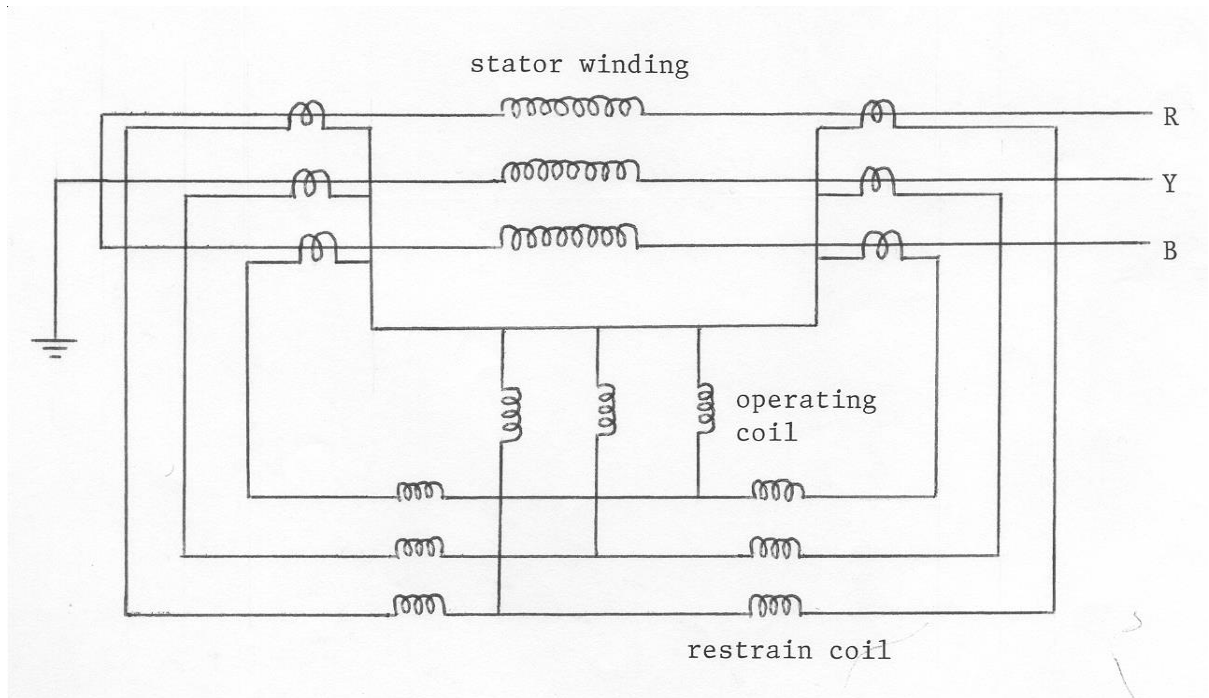
3.9 Phase and Ground Faults

The main protection for the stator winding against phase to phase and phase to earth faults is provided for by the longitudinal differential relay



The relays are of the instantaneous attracted armature type. A setting of 10% to 40% is recommended for all sizes of machines provided the C.Ts are reasonably matched. A stabilising resistor is inserted in series with

the operating coil to ensure that the relay does not operate for faults external to the protected zone. The value of the stabilising resistance is so chosen that even if one set of C.Ts saturate during an external fault, there will be no possibility of the relay mal-operating. However if the C.Ts are not matched then a percentage differential relay is used as shown:



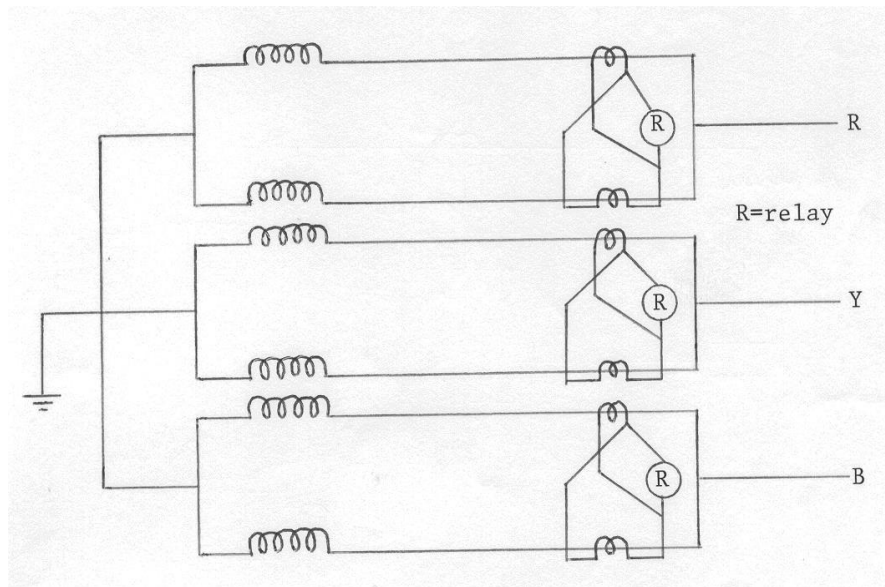
There are two restraining coils per phase with one operating coil. The operating coil produces a pick up torque and the same is restrained by the torque produced by the restraining coils. The current in the operating coil referred to as the Spill Current is reduced during external faults and this increases the setting of the relay. The current in the restraining winding is called the Through Current or through fault current. The spill current level for the relay to just operate is expressed as a percentage of the

through fault current causing it to operate. This is defined as the percentage bias of the relay.

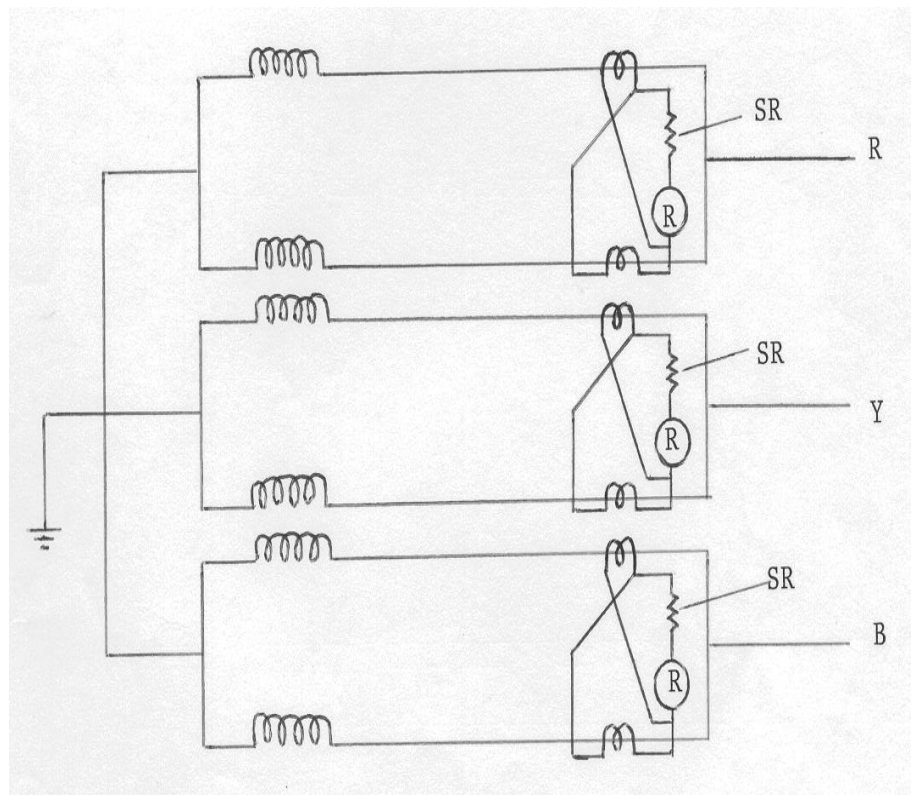
$$\frac{\% \text{ Bias}}{100} = \frac{\text{Spill current for relay operation}}{\text{Through fault current causing it}} \times$$

3.10 Stator Interturn Faults

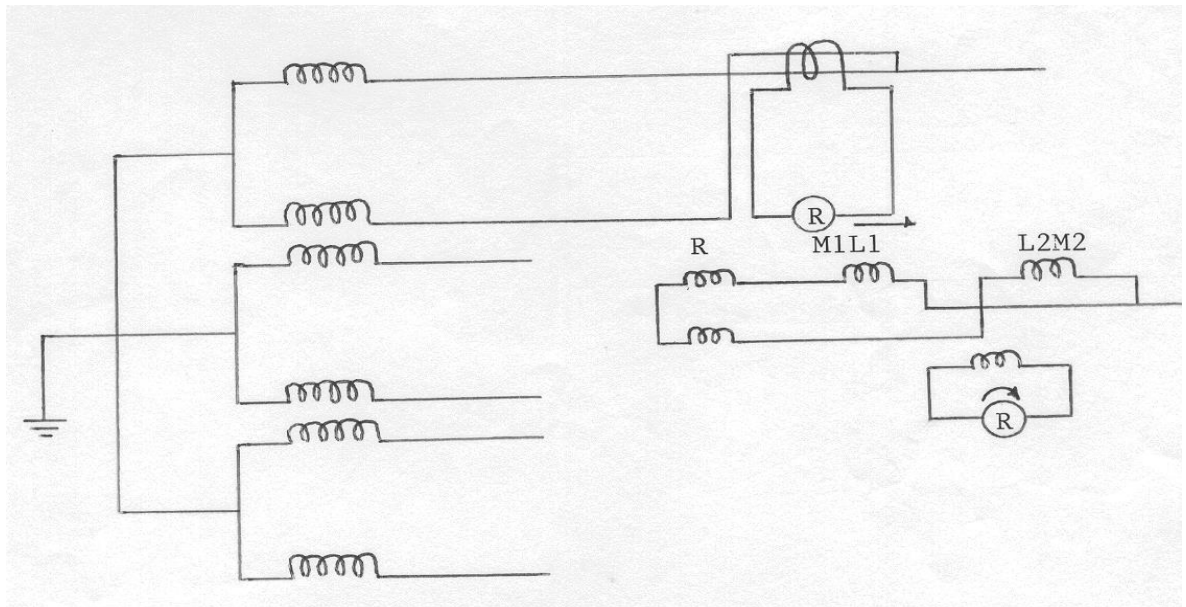
This type of protection was earlier considered not necessary because the breakdown of insulation between points in the same slot and between which a potential difference exists, will very rapidly change into an earth fault. It will then be detected by the stator earth fault protection or by the stator differential protection. Thus unless this fault burns itself through the major insulation into the ground, it will not be detected by the differential or earth fault protection. An exception is a generator designed to provide a relatively high voltage in comparison to its output. Such a generator will have a large number of conductors per slot. With the present day practice of having large sized generators with higher voltage, protection for stator inter-turn faults is realised to be essential. This is achieved only in the case of split or divided phases; that is each phase of generator winding will have two or more parallel windings. The method of protection is called "Split-Phase" relaying or "Cross Differential" relaying as shown in the next page:



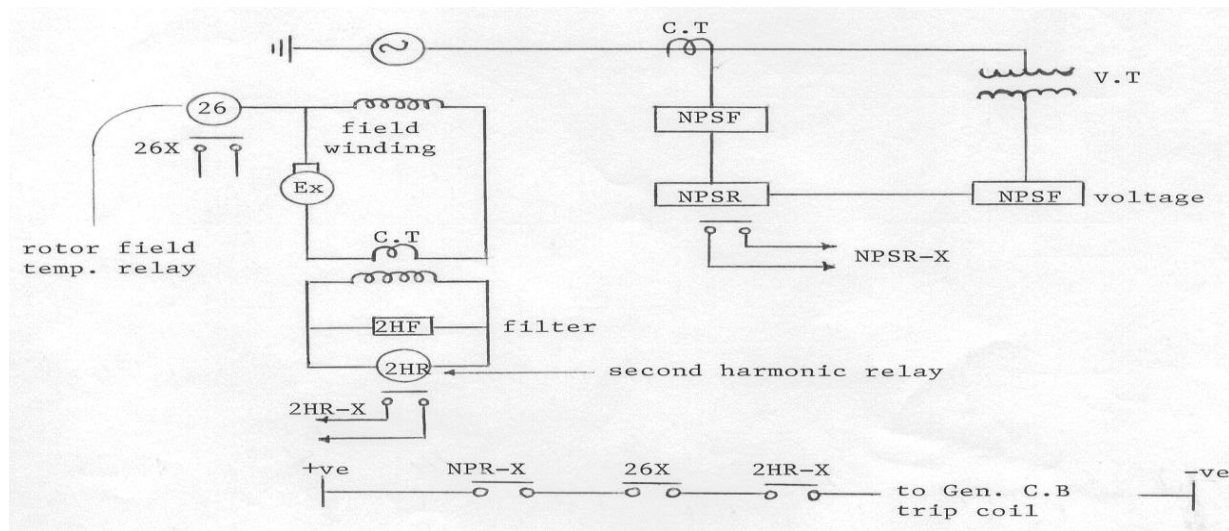
Sometimes a stabilising resistor is introduced in the relay circuit to prevent the relay from picking up on through or external faults as shown:



The relay is of an attracted armature type and the scheme is extremely sensitive. However modern large steam turbine generators which usually have only one turn does not need such a protection as a fault cannot occur without involving ground. As already stated the scheme is applicable to only split or divided phases. A modified version of this scheme is to use double wound primary C.Ts with single secondary as shown below:

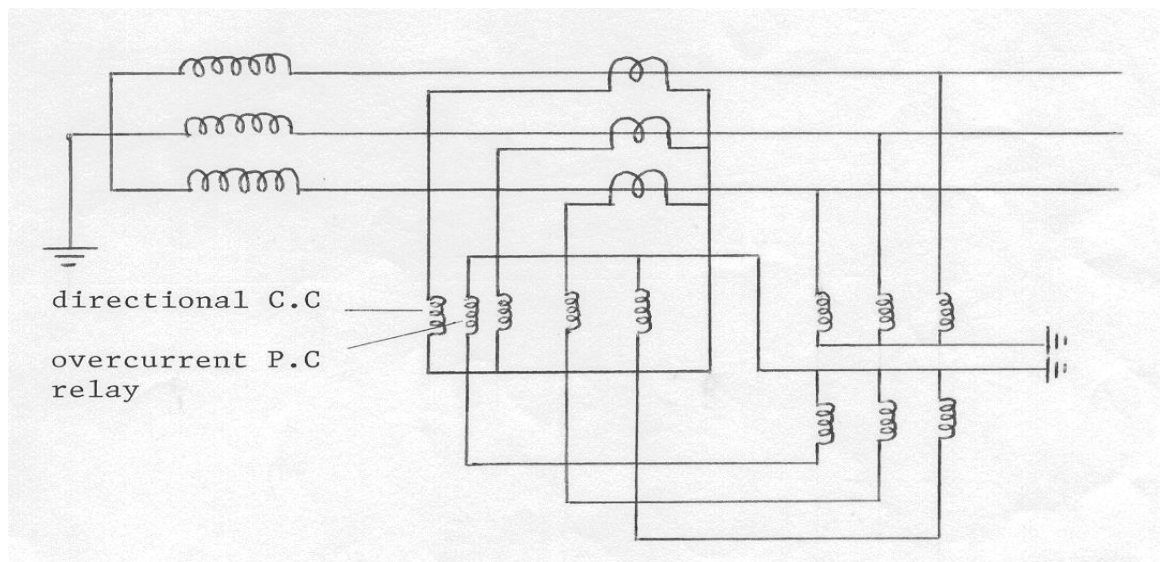


3.11 An alternative scheme which provides complete protection against internal faults for all generators irrespective of the type of winding or method of connection is shown below:



This scheme makes use of the fact that an inter-turn fault in the winding results in second harmonic currents being induced in the field windings. This current is applied to a sensitive relay from a C.T and filter circuit. The operation of the scheme is controlled by a directional Negative phase sequence relay in order to prevent operations during external unbalanced faults or asymmetrical or unbalanced load conditions and allows the generator circuit breaker to be tripped to prevent rotor damage due to overheating effects of second harmonic currents.

3.12 Short circuit protection of stator windings

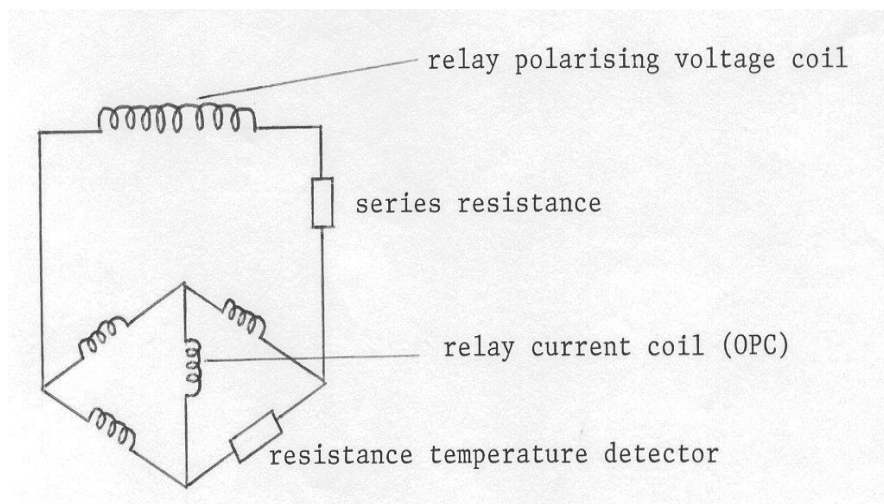


3.13 Stator Overheating

Overheating is caused by overloading or by the failure of the cooling system, or by the stator core lamination having been short circuited. Overheating caused by short circuited lamination is localised.

There are two methods employed to detect such faults.

- a) To compare the inlet and outlet temperatures of the cooling or ventilating system.
- b) To use temperature indicating devices embedded in the stator slots such as thermocouples, thermistor and resistor temperature detectors. A sufficient number of these detectors are located at different places in the winding or in all the stator slots so that an indication can be obtained of the temperature condition throughout the stator. The detector that gives the highest temperature indication is selected for use with a temperature indicator or recorder having alarm contacts to sound an alarm. A scheme of a detector operated relay equipment using a Wheatstone bridge circuit and a directional relay is shown:



3.14 Stator Open Circuit

An open circuit or a high resistance joint in a stator winding is rather difficult to detect until it has caused sufficient damage. This is generally detected by "Split Phase Relaying" described in paragraph 3.10 or by Negative phase sequence relaying described later in paragraph 3.16. However it is not the practice to provide protective equipment for stator open circuits as such faults are rarely encountered in modern, well constructed machines of proven design and reputed makes.

3.15 Over Voltage Protection

Over voltage is generally due to over speed caused by a sudden loss of load. This protection is not provided in turbo-generator sets as it is taken care of by the A.V.R and governor. But in the case of hydro-generators this protection is provided for by an over voltage relay with a setting of 110% to 150% of rated voltage. A time delay unit is sometimes provided with this relay for pick up at 110% to sound an alarm and an instantaneous unit at about 130% to 150% of rated voltage to trip. The relay has to be compensated against the effects of frequency variations. The relay should be energized from a separate V.T other than the one used for the A.V.R.

3.16 Unbalanced Stator Current

Unbalanced stator currents are either due to unbalanced loading or due to external faults. Under balanced conditions, only positive sequence currents flow and these produce a field of armature reaction rotating at synchronous speed in the same direction as the rotor. But during unbalanced operation, negative sequence currents are produced. These negative sequence currents produce a field which rotates at synchronous speed but in a direction opposite to the rotation of the rotor. This field induces double frequency currents in the rotor, causing overheating of the rotor. The severity and rapidity of overheating depends upon the degree of unbalance. The time for which the rotor can withstand this condition is inversely proportional to the square of the negative sequence current.

$$\text{i.e. } I_2^2 t = K$$

Where I_2 - is the negative sequence current

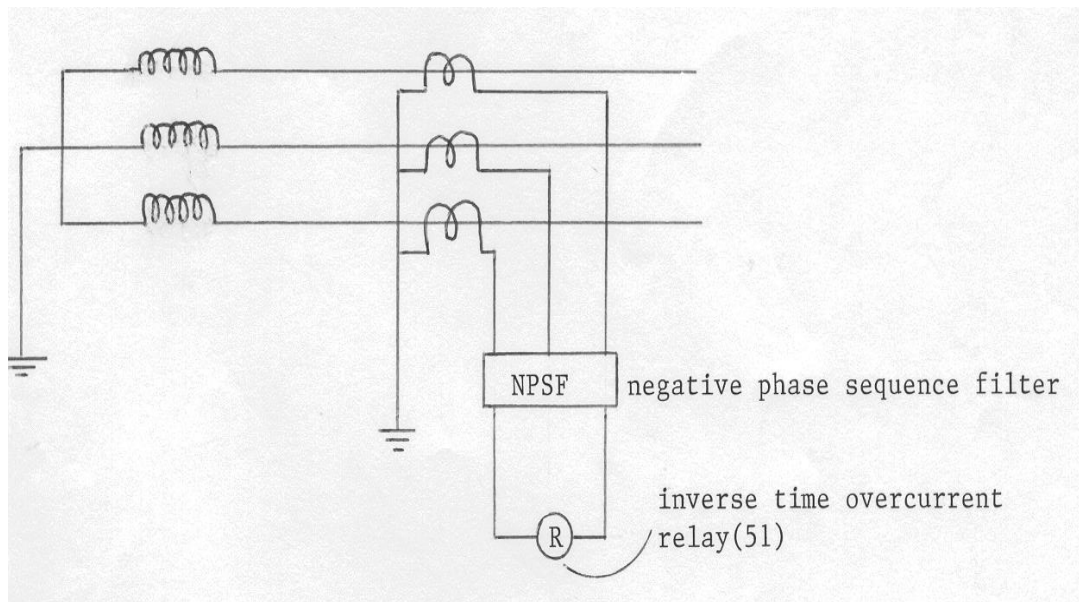
t - is the time

K - Constant (About 30 for turbo-generators and 40 for hydro generators)

Hence any protective relay that is used should have a time current characteristic given by this equation.

$$I_2^2 t = K$$

The protection scheme consists of a negative sequence filter network which filters out only the negative sequence currents to feed to this relay which is a time over-current unit. The time unit is adjustable from 0 to 40% of negative sequence current. The upper limit of 40% is imposed because of the restrictions imposed by the generator cooling system. The scheme is as shown below:



4.0 ROTOR PROTECTION

4.1 Rotor Ground Faults

If the rotor winding is ungrounded, a single fault to the earth has no effect. But a second fault to the earth will increase the current in a part of the rotor winding. This increase in current will produce unbalanced fluxes in the air gap causing serious vibrations which may eventually lead

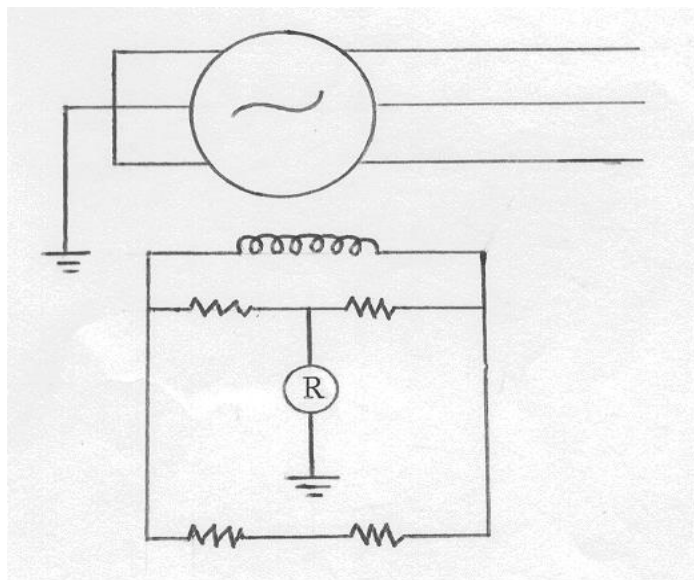
to severe damage. Besides, a single rotor fault to earth raises the potential of the whole field and exciter system. If under these circumstances, the field breaker or the main breaker is opened, it may cause a second fault to the earth.

The second fault to the earth may cause local heating, distortion of the rotor, air gap eccentricity leading to severe vibrations and damage to the shaft.

Apart from these, a rotor earth fault also causes current to flow in the shaft. These shaft currents induce currents in the bearing lines causing damage to the bearings, and pitting of the shaft at these points. There are two methods commonly employed for detecting rotor earth faults.

4.2 Method 1

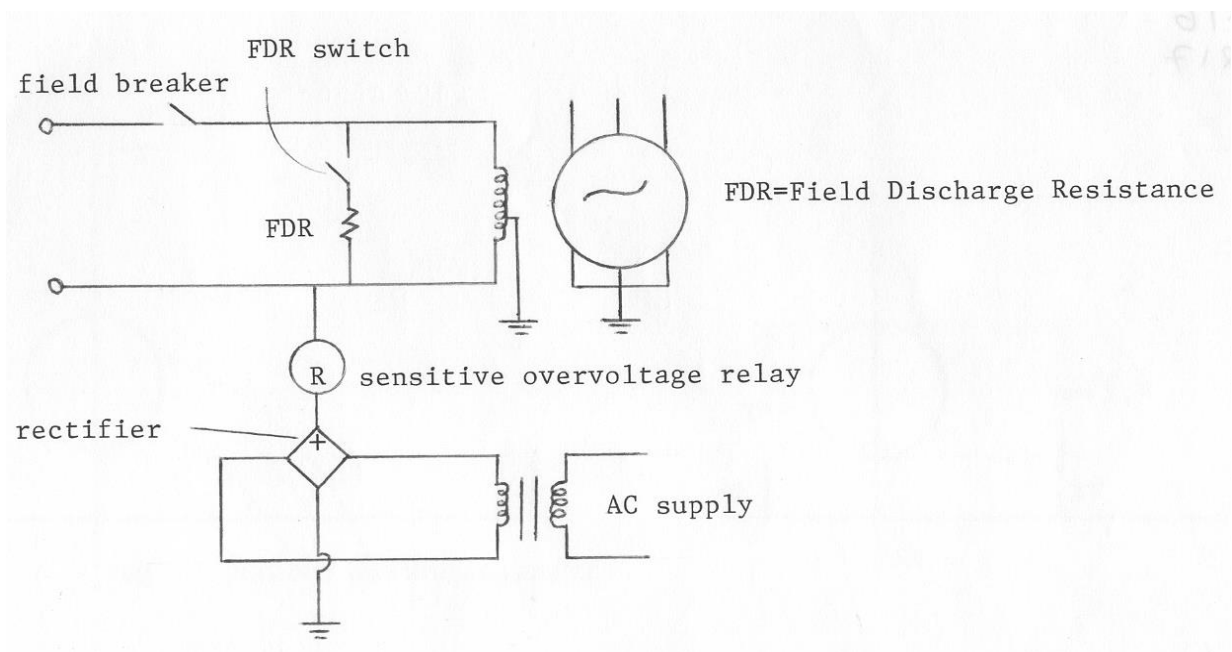
A high resistance is connected in parallel to the field winding. The mid-point of this resistance is earthed through a relay as shown:



When an earth fault occurs at the mid-point, no current flows through the relay as the bridge circuit is balanced. Similarly for a certain portion of field winding on either side of the mid-point, the current may be insufficient to cause the operation of the relay. There is therefore, a dead zone where the faults cannot be detected. To overcome this difficulty the relay location should keep on changing, that is to say the tapping point must be varied by a motor operated device. This is achieved by a brush mounted on the rotor shaft and connected to the earth through the relay.

4.3 Method 2

In this method, the field circuit is biased by a D.C voltage which causes current to flow through the relay if a ground occurs.



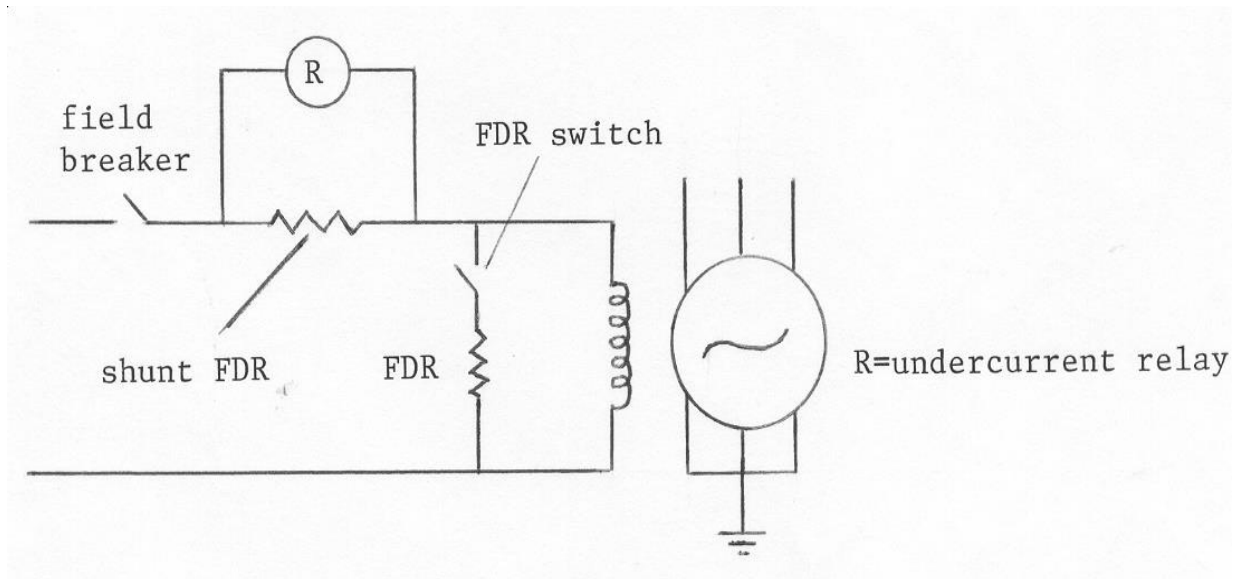
The relay is a polarised moving iron type which will pick up at 1.5% of the field voltage and yet stand full exciter voltage continuously. This method is superior as it has no null point.

4.4 Field Failure (Loss of Field)

When a generator loses its field, it speeds up slightly and acts as an induction generator. In case of generators having amotisseur windings (hydro-generators), this is not of much consequence. In the case of turbo alternators, the rotor gets overheated because of heavy currents induced, as there are no amotisseur windings. Again the stator windings of any type of generator may overheat owing to the currents in the stator windings when running as an induction generator and this current may be as high as 2 to 4 times the full load stator current depending upon the slip.

When a large generator loses its excitation, it draws reactive power from the system which may be 2 to 4 times the generator rating. This large reactive load suddenly thrown on the system may cause wide spread voltage fluctuations and system instability unless the other generators in the system can meet the additional reactive load immediately. On the other hand, a machine with a very fast acting voltage regulator and connected to a rigid system i.e. a system with a large amount of stored rotational energy and capable of supplying reactive load, may run as an induction generator for several minutes without any harm.

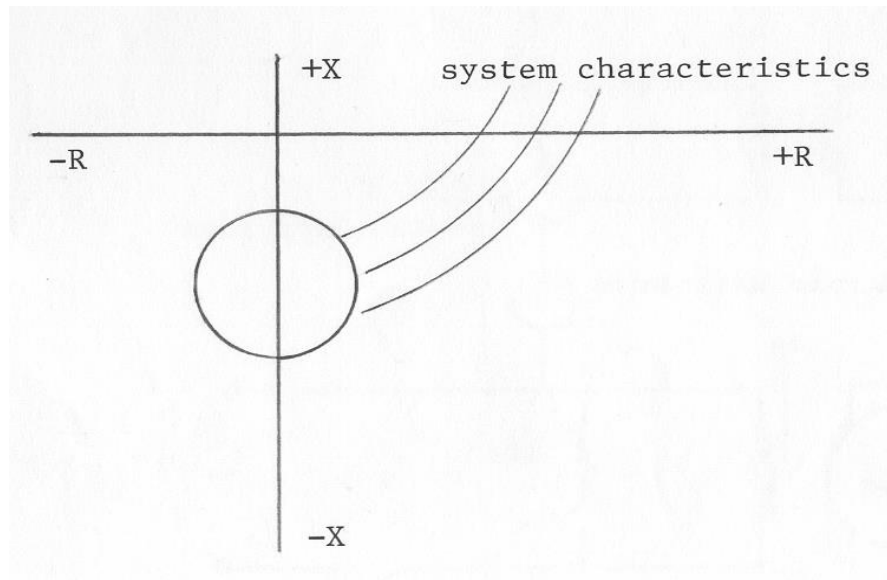
Field failure may be caused by a faulty field breaker or by the failure of the exciter. It can be detected by an undercurrent D.C relay in the field circuit as shown:



However, the field failure due to failure of the exciter may not be detected because the under current relay may be held in by an A.C induced by the stator currents. Besides, modern generators operate over a wide range of field current and as such the presence of this relay is embarrassing and undesirable.

The most reliable and widely used method of field failure is by the use of an offset mho relay or a directional impedance relay with its characteristic in the negative reactance area as shown. This is because the characteristic is affected only by the loss of field and not by any other

condition such as loss of synchronism which may result from the loss of field.



Irrespective of the initial conditions, the loss or severe reduction of excitation is characterised by a swing of the impedance measured at the generator terminals into a particular region near the $(-x)$ axis i.e. a swing from the 1st quadrant to the 4th quadrant. By encompassing this region in the relay characteristic, the relay will operate when the generator rotor starts to slip and disconnects the machine and the field before there is any danger of system instability or internal damage to the stator and rotor. The other three circles shown are the impedance loci seen by the generator for various initial states and referred to as "System Characteristics".

An example on the setting of an impedance relay for loss of excitation is as illustrated:

Synchronous impedance seen by the relay (150%) is:

$$\begin{aligned} &= 12.7 \times 1.5 \\ &= 19.05 \text{ ohms} \end{aligned}$$

Usually the relay settings are chosen as follows:

$$\begin{aligned} X_t = \text{half the transient impedance} &= 6.35/2 \\ &= 3.175 \text{ ohms} \end{aligned}$$

$$X_s = \text{synchronous impedance} = 19.05 \text{ ohms}$$

$$\begin{aligned} \text{Thus: } X_s &= X_s - X_t \\ &= 19.05 - 3.175 \\ &= 15.875 \text{ ohms} \end{aligned}$$

$$\text{Value of the relay} = 15.875 \text{ ohms}$$

$$X_s = 19.05 \text{ ohms}$$

5.0 MISCELLANEOUS FAULTS AND ABNORMAL CONDITIONS

Abnormal conditions that do not directly affect the rotor or stator alone are over-speed, motoring, loss of synchronism and bearing failure.

5.1 Over-speed

Over-speed may result either due to a sudden loss of the field or due to loss of load. In the case of turbo-generators, steam admission can be shut off quickly. But not so in the case of hydro-generators where the

water flow cannot be stopped quickly due to mechanical and hydraulic inertia; and similarly in the case of gas turbines. Hence over-speed relays are generally provided only on hydro-generators and gas turbine sets. However, the practice today is to provide over-speed devices on all prime mover generating sets to limit the speed to 115% for steam and 140% for hydro and gas turbine sets. The over-speed device trips both the generator main breaker and the field breaker.

5.2 Motoring

Motoring is prevented by a sensitive wattmeter relay which operates at about 0.5% of the reverse power. The reverse power relay is generally provided with a time delay varying from a few seconds to minutes.

Motoring protection is for the benefit of the prime mover and not for the generator. Steam turbines tend to overheat. In the case of hydro turbines cavitation occurs, and in diesel and gas turbine systems there is the risk of fire due to the unused fuel.

5.3 Loss of Synchronism

An out of step relay can be used but is seldom used on an individual generator because it is unlikely to run out of synchronism with the system unless there is a loss of field.

5.4 Bearing Overheating

Bearing overheating is detected by a relay actuated by temperature detectors such as that described under stator overheating in paragraph 3.13. The temperature of the bearing or of the lubricating oil is detected instantly to give an alarm and then to trip if the temperature exceeds the pre-set value.

CHAPTER NINE

PROTECTION OF TRANSFORMERS

1.0 INTRODUCTION

The advancement of technology has resulted in the manufacture of very large capacity transformers. The increasing size and capacity of transformer units have enabled considerable reduction in operation and maintenance costs. But the risk of interruption of power supplies is always there if there is a breakdown in the transformer. Although every precaution is taken in the design, manufacture, assembly, erection and installation of a transformer, yet there is still a need to provide an adequate scheme of protection to prevent a forced outage. To understand as to what scheme of protection is required, it is necessary to have knowledge of the faults to which a transformer is subjected to while in service, their causes and effects.

2.0 NATURE OF TRANSFORMER FAULTS

2.1 A transformer is subjected to the following types of faults:

- a) Through faults or External faults
- b) Internal faults.

2.2 Through Faults or External Faults

These may be further classified into:

- a) Overloads
- b) External short circuits

- c) Terminal faults
- d) Over-voltages and Over-fluxing

A transformer must be isolated from these faults as these faults produce electro-mechanical and thermal stresses in the windings which may ultimately lead to the failure of the transformer. Hence, these faults must be cleared on time or after a predetermined time.

2.3 Overloads

A transformer is capable of withstanding a sustained overload for long periods. This period is determined by the permissible temperature rise of the oil and windings and the type of cooling. Normally a 10% overload is permissible for not more than an hour; a 25% overload for not more than 15 to 30 minutes; a 50% overload for not more than 5 to 10 minutes.

Excessive overloading for long, frequent and intermittent periods results in rapid deterioration of the insulation and subsequently to failure.

An overload condition with permissible overloads can be detected by a Thermal Relay or a Temperature Relay initially to give an alarm and finally to trip the transformer. When an alarm is sounded the operator must ensure relieve of the transformer from overload by pulling out non-essential loads. Normally winding and oil temperature indicators are provided with alarm and trip contacts on all power transformers.

2.4 External short circuits

An external short circuit subjects the transformer to sudden electromagnetic stresses and overheating. Modern power transformers are designed to withstand short circuit currents of a certain KA value for 1 second. The external short circuit must be cleared within this period.

An external short circuit is detected primarily by the main protection of the loads or feeders and subsequently by the backup protection of the transformers. As such these faults are detected by time graded over-current relays.

2.5 Terminal faults

A terminal fault on the primary side of the transformer has no adverse effect. But a similar fault on the secondary side does have a serious effect. Such a fault falls within the purview of the protection zone of a transformer and is detected by protection schemes to be covered under internal faults and also by gas pressure relays.

2.6 Over-Voltage and Over-Fluxing

This is covered separately in paragraph 3.9.

2.7 Internal Faults

Internal faults are classified into two main categories:

- a) Electrical faults
- b) Incipient or Miscellaneous faults

2.8 Electrical Faults

These cause serious damage to the transformer and are detected by unbalanced currents and voltages.

These faults may be categorised as:

- a) Terminal faults on the secondary.
- b) Phase to earth fault on the primary/secondary terminals inside the transformer or on the windings.
- c) Short circuits between turns of H.V. and L.V. windings or terminals inside the transformer.
- d) Phase to phase faults between H.V. and L.V. windings or terminals inside the transformer.
- e) Interturn faults in H.V. and/or L.V. windings.

Faults between phases and to earth inside a transformer are generally rare. But it is claimed that most of the transformer failures are due to inter-turn faults. These faults being serious have to be isolated instantaneously.

2.9 Miscellaneous or Incipient Faults

These are actually faults of a minor nature, but if not taken care of may gradually, sooner or later, develop into a major fault.

Such faults are due to:

- a) Poor quality or inadequacy of the insulation of the laminations and core-bolt.

- b) Accidental damage to lamination and core-bolt during erection and/or assembly.
- c) Poor quality or inadequacy of the insulation between the windings, the winding conductors and between the windings and the core.
- d) Mechanical damage to the windings due to bad handling during erection/assembly.
- e) Badly formed joints or connection.
- f) Deterioration of the insulation due to overloading and/or ageing.
- g) Deterioration of the oil due to ingress of moisture, decomposition caused by overloading or punctures oxidation of the oil due to over heating and sludge formation.
- h) Coolant failure causing rise of temperature even when operating below full load conditions; choking of radiator tubes and fins due to sludge.
- i) Improper load sharing causing over heating due to circulating currents.

3.0 Protection against internal faults

The protections applied to a transformer against these faults are:

- a) Gas operated relays or sudden pressure relays.
- b) Over-current and earth fault protection (Unrestricted).
- c) Balanced Earth Fault Protection or Restricted Earth Fault Protection.
- d) Frame Leakage protection.
- e) Differential protection.

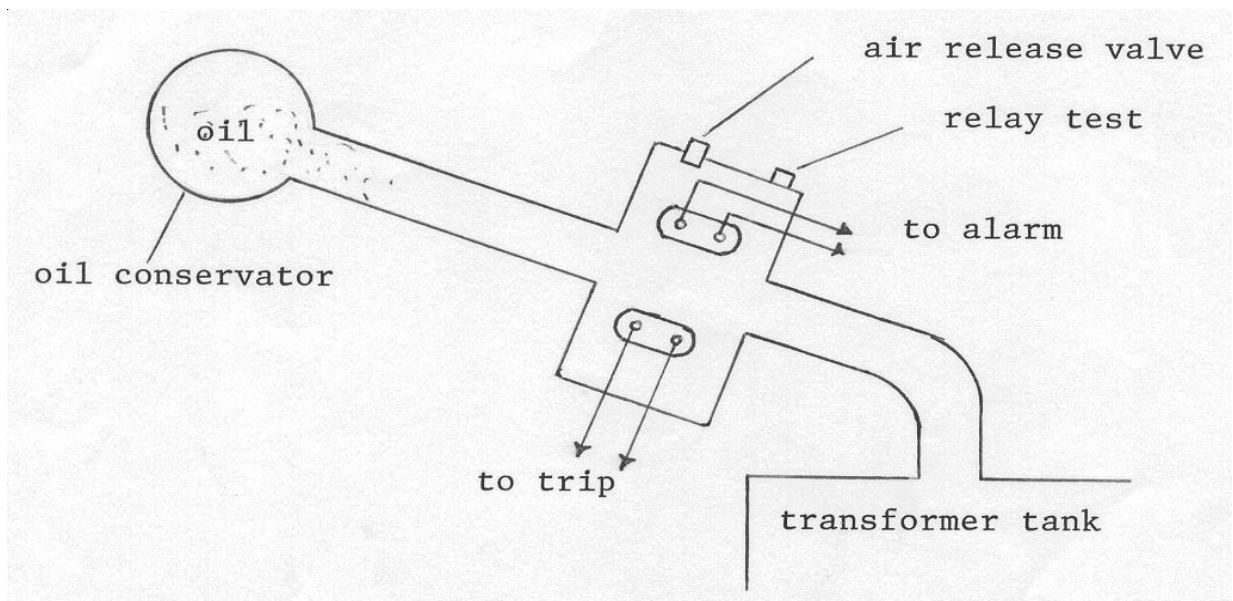
3.1 Gas Actuated Relays

3.1.1 The failure of the insulation of the core windings causes local heating around the point of failure. This local heating causes the rise of the oil temperature surrounding it. When the oil reaches a temperature of 300 to 350°C depending upon the characteristics of the oil, it decomposes and evolves gases. The gases rise through the oil and accumulate at the top of the transformer. The evolution of the gas and the quantity and rate at which it evolves is made use of to actuate these relays.

3.1.2 Buchholz relay

This is the most common type of gas actuated relay used on almost all types of power transformers fitted with an oil conservator.

The relay is connected in the piping between the oil conservator and the transformer tank as shown:

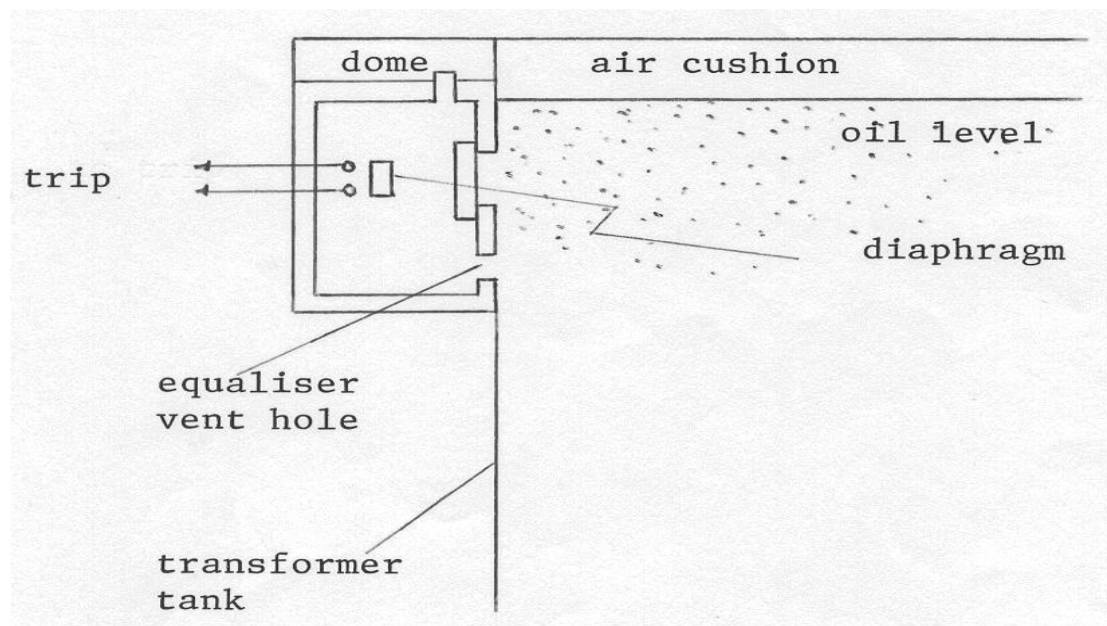


The relay has two mercury operated float switches; one located at the top; the other at the bottom is in the direct line of oil flow from the conservator to the tank. The angle of displacement of the mercury switch for making contact is between 5 to 15 degrees. Hence the piping in which it is located is at an angle, and the inclination must be at least 2 degrees to permit accumulation of gas. When gases accumulate slowly, the upper float switch is displaced and makes contact to give an alarm. The analysis of the gas gives an indication as to the nature and type of fault such as burning of paper, wood etc. When there is a sudden surge of oil or when the gas rate of evolution is very rapid, the bottom float switch operates and trips or isolates the transformer from the sources. This sudden oil surge or rapid gas evolution takes place if there is arcing, burning or local over heating inside the transformer indicating seriousness. There is an arrow indication of the gas flow to operate the relay. Hence while mounting the Bucholz relay, care is taken to mount it with the arrow pointed towards the conservator.

Initially when a transformer is first put into service, the relay may mal-operate, sounding an alarm. This is due to the release of entrapped air within the transformer. Such a gas may be confirmed to be air by testing it as to whether it is combustible or not.

3.1.3 Sudden Pressure Relay (SPR)

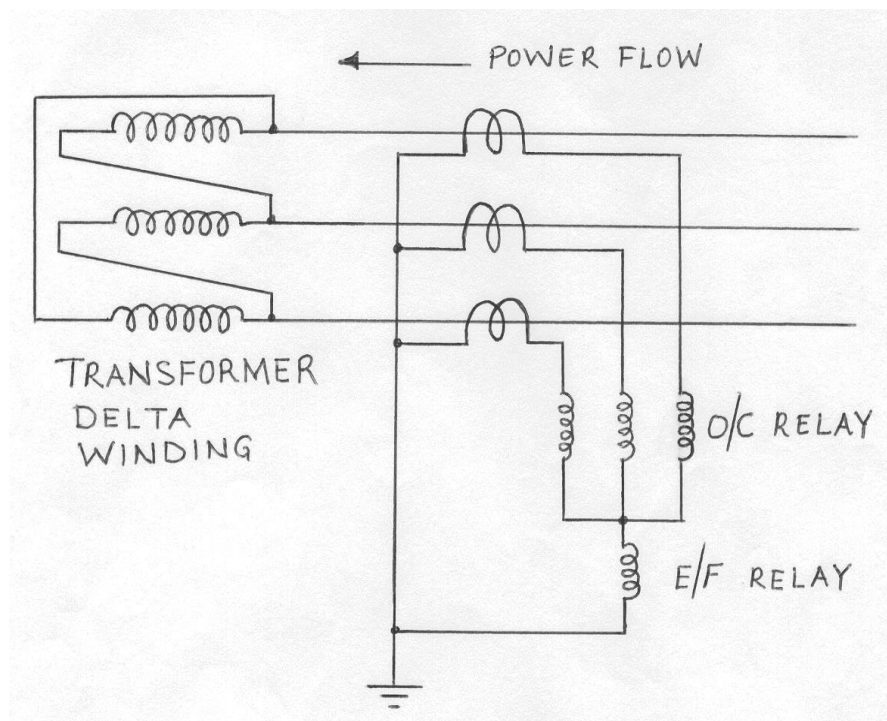
The SPR is a gas operated relay which operates on the rate of rise of gas in the transformer. Some manufacturers also call it a Fault Pressure Relay. These relays are popular only in America where transformers are manufactured without a conservator but with a sealed air cushion or chamber above the oil level. The relay is mounted unto the tank or manhole cover above the oil level or near the oil level. It will not operate on static pressure or pressure changes resulting from normal operation of the transformer. It is extremely sensitive and will operate at pressure changes as low as 0.33 lbs/in^2 . The operating time varies from $\frac{1}{2}$ cycle to 30 cycles depending upon the severity and magnitude of the fault. The location of the SPR is as shown:

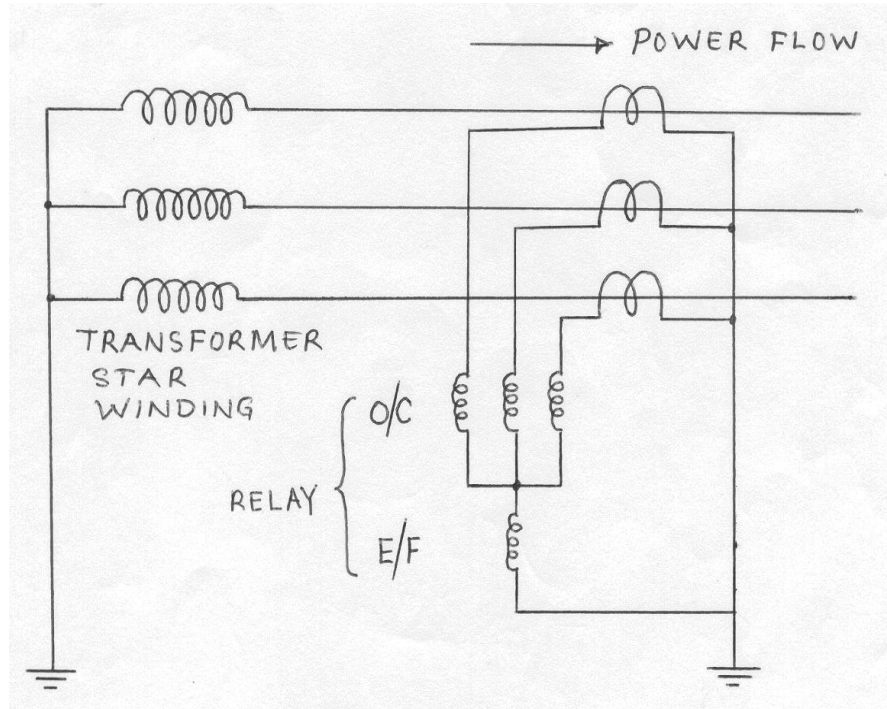


The relay has a diaphragm which is deflected by differential oil pressures and it is by-passed by an equaliser hole which normally equalises the pressure on the two sides of the diaphragm and also makes it responsive to the rate of rise of pressure. The gas accumulating unit is at the top in the dome.

3.2 Over Current and Unrestricted Earth Fault Protection

This protection is applied against external short circuits and excessive overloads. It also acts as a backup protection to the feeder loads connected to the transformer and to the transformer itself if there are other forms of protection. The relays used are time over current relays of the inverse type or of the IDMT type or of the definite time. The protection is applied separately to both the primary and secondary windings as shown:



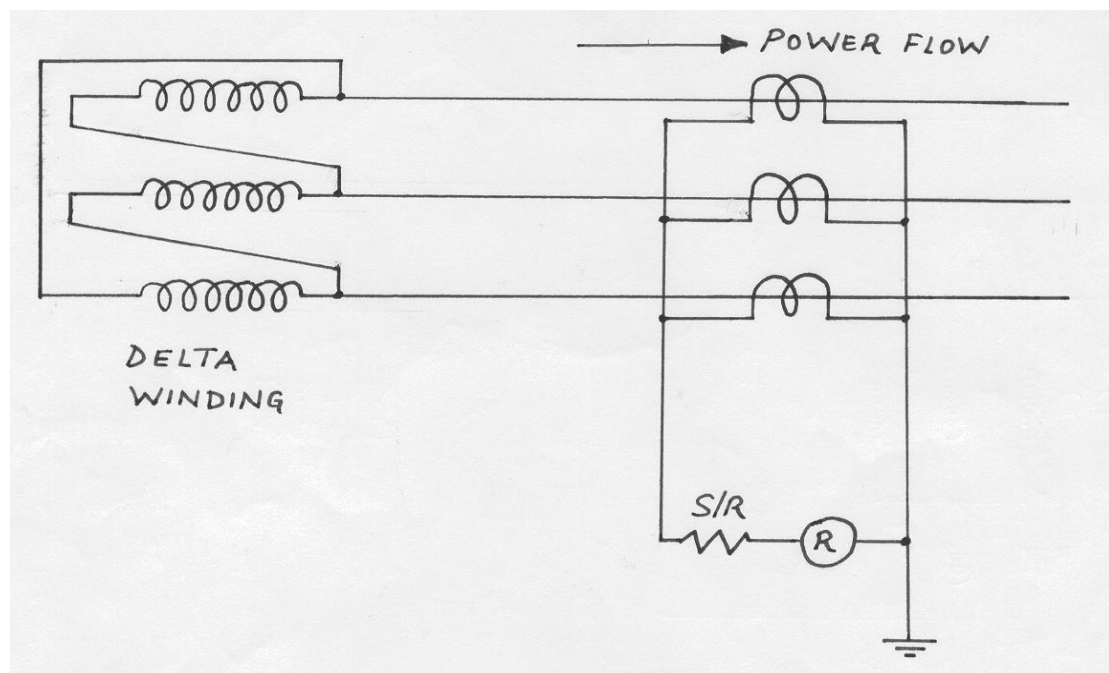


The over-current relays fail to distinguish between conditions of external short circuits, overloads or internal faults within the transformer. The operation is governed purely by the current and time setting. Hence in order to make use of the permissible overload capacity of the transformer and also to co-ordinate with similar other relays in the system, it is necessary to set the relays at about 120 to 150% of the full load current of the transformer but well below the short circuit current. Thus they seldom serve as a reliable form of protection and are only in the form of a backup protection. If this type of protection is provided on both the windings, then each protection trips its' own breaker and no inter- tripping of breakers is provided. For example if the L.V. side relays act, they trip

only the L.V. side breaker but not the H.V. side breaker. The earth fault relay at times tends to mal-operate on external earth faults if the earth fault relays are not properly coordinated. Its operation is therefore unrestricted. Similarly the over-current relays also operate if they are not properly coordinated. Thus this unrestricted form of protection should be properly coordinated with the other relays in the system to avoid indiscriminate tripping.

3.3 Balanced Earth Fault or Restricted Earth Fault Protection (REFP)

3.3.1 This form of protection is provided to prevent the EFR acting on spurious external faults and acts only when there is an internal earth fault within the transformer. Thus its operation is limited to detection of earth faults within the transformer. Hence the name Restricted Earth Fault Protection. The protection is applied separately to each winding of the transformer as shown:



instantaneously. Hence the use of an instantaneous relay. The scheme is also called Balanced Earth Fault protection because of the balancing of the line C.T. current.

3.3.3 Use of Stabilising Resistors

In such balanced type of protective schemes, spill currents or operating currents in the relay circuit can cause indiscriminate operation. To avoid unwanted operation, a Stabilising Resistor (S.R) is connected in series with the current relay. The value of the stabilising resistor is so chosen that under maximum steady state through fault conditions, there is insufficient voltage developed across the C.T. leads to cause a spill current equal to the relay operating current. In calculating the value of the S.R. the following assumptions are made:

- a) One set of C.Ts is completely saturated.
- b) The whole of the primary fault current is perfectly transformed by the remaining C.Ts.
- c) The maximum loop lead burden between the relay and the C.Ts is used.

With one set of C.Ts saturated, the maximum voltage appearing across the relay circuit, namely across the relay coil and the S.R is:

$$V_{\text{max}(\text{relay cct})} = \frac{I_f}{N} (R_s + R_b) \text{ Volts}$$

Where: I_f is the maximum fault current
 N is the C.T. ratio.

R_s is the secondary internal resistance of the C.T.

R_b is the maximum lead burden.

For stability, the current through the relay coil at this voltage must be insufficient to cause relay operation. A S.R. is chosen which will just allow the setting current to flow through the relay coil.

Example:

$$\begin{aligned} I_f &= 2.0\text{KA} \\ N &= 200/5 = 40 \\ R_s &= 0.25 \text{ ohms} \\ R_b &= 1.75 \text{ ohms} \end{aligned}$$

Then maximum voltage across S.R. and Relay will be:

$$\begin{aligned} &= \frac{2 \times 10^3}{40} (0.25+1.75) \\ &= 100 \text{ Volts} \end{aligned}$$

Let the relay be on a 0.1 tap with a burden setting of 4VA.

Relay impedance at this setting:

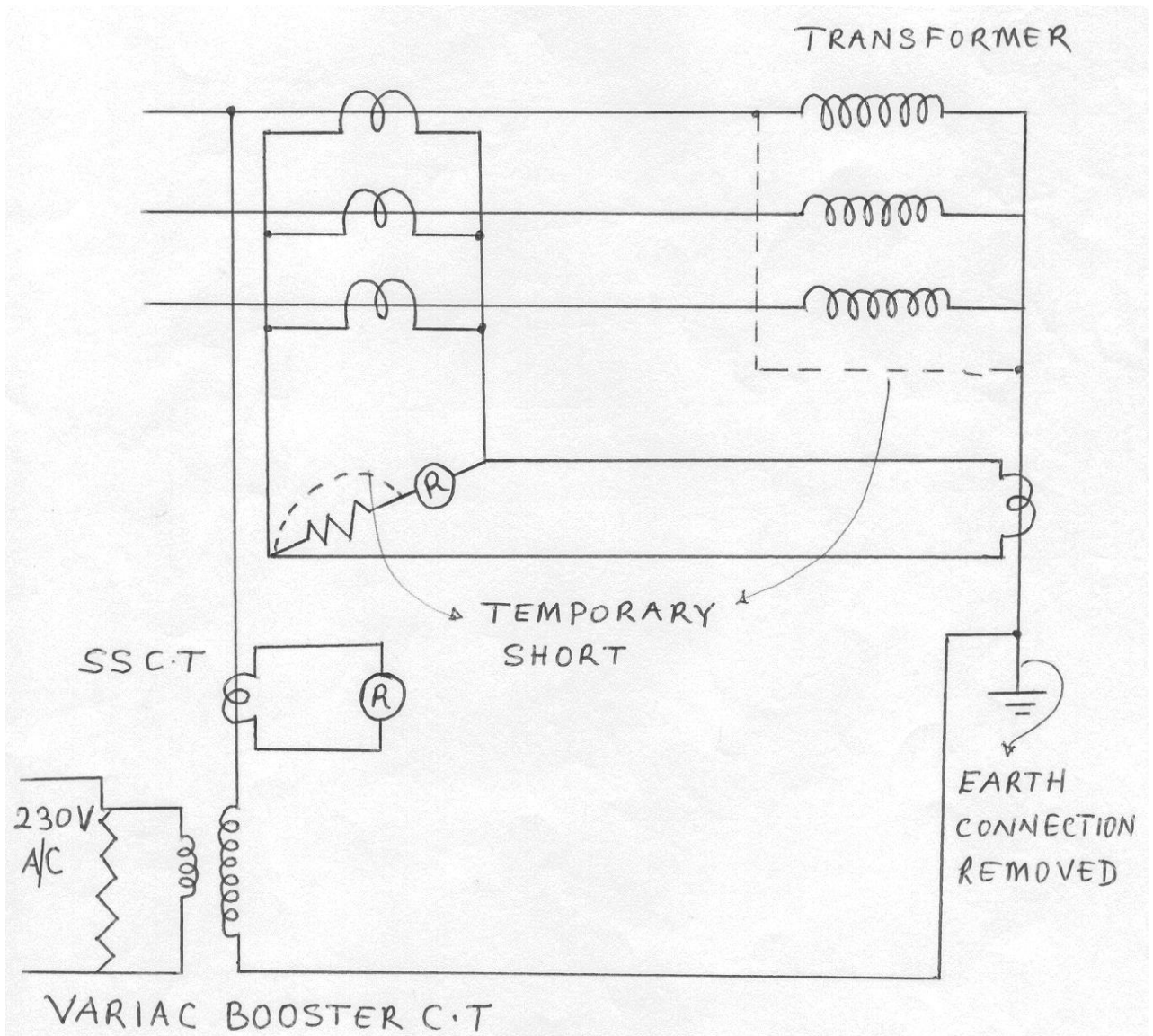
$$\begin{aligned} &= \frac{4.0}{(0.1)^2} \\ &= 400 \text{ ohms} \end{aligned}$$

Total Relay circuit impedance

$$= \frac{100}{0.1} = 1000 \text{ ohms}$$

$$\begin{aligned} \text{Value of stabilising resistor required} &= 1000 - 400 \\ &= 600 \text{ Ohms} \end{aligned}$$

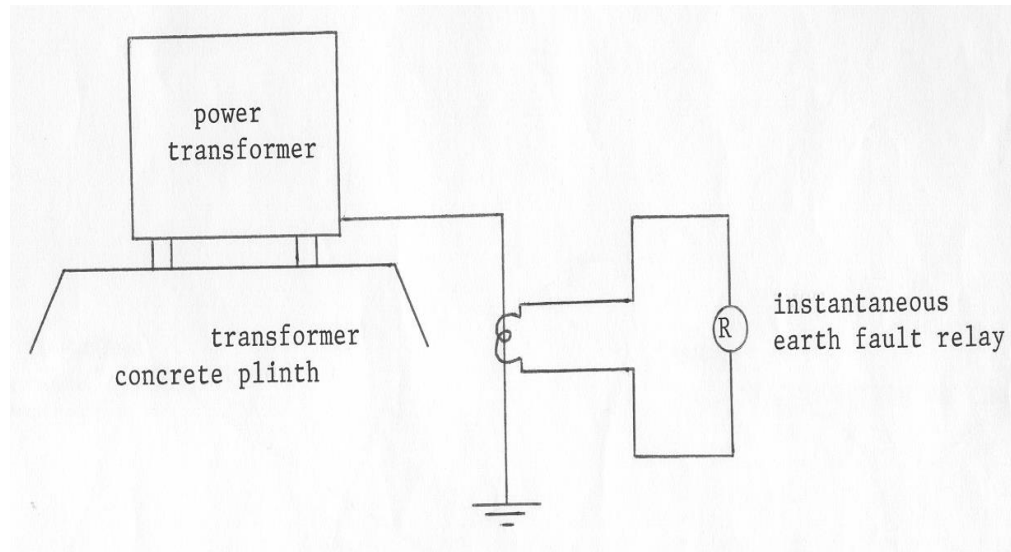
3.3.4 When such a restricted earth fault scheme is to be put into service, a stability test has to be carried out on the scheme as follows:



With the same current passing through one line C.T. and the Neutral C.T., the relay should not pick up. The test is repeated for similar condition when current is passed through the other two line C.Ts and neutral C.T.

3.4 Frame Leakage Protection

This protection is also called Tank Earth Leakage Protection. It is a comparatively inexpensive and a simpler alternative to Restricted Earth Fault Protection. This scheme is very popular in France but elsewhere it has not gained much popularity. In this scheme, the transformer is lightly insulated from the earth by mounting it on a concrete plinth so that the insulation resistance is not less than 10 ohms. The earthing of the tank is done as shown with a C.T. in



series. The secondary of this C.T. is connected to an instantaneous E.F.R of the attracted armature type. Earth fault current due to insulation breakdown in any winding finds its way to the earth through this path thus energising the C.T. and the relay. This scheme is extremely sensitive in detecting earth faults within the transformer zone. The scheme though it appears to be simple and cheap has many disadvantages.

These are:

- a) Incapability to respond to faults in the jumper connections between transformer terminals and the bus bars.
- b) The setting must be kept sufficiently high to prevent mal-operation due to capacitance currents resulting from external faults.
- c) It is difficult under humid and dusty atmospheric conditions to keep the insulation resistance below 10 ohms.
- d) There is a possibility of the fault current of one transformer finding its way into the tank circuit of another adjacent transformer thereby causing a healthy transformer to be isolated.
- e) It is not practical to adopt this system in water cooled transformers or in forced oil cooled transformers.

3.5 Differential Protection

3.5.1 This is the principal form of protection for all power transformers rated at 5MVA and above. Transformer differential relays are subject to several factors, not ordinarily present for generators that can cause mal-operation. These are:

- a) Different voltage levels, including taps, which result in different primary currents in the connecting circuits.
- b) Possible mismatch of ratios among different current transformers.

For units with ratio changing taps, mismatch can also occur on the taps. Current transformer performance is different particularly at high currents.

- c) A 30° phase angle shift introduced by Delta-star or Star-Delta connections.
- d) Magnetising inrush currents which the differential relay sees as internal faults.

3.5.2 All the above factors can be accommodated by a combination of relay and current transformer design along with the use of auxiliary C.Ts, proper application and connections.

These auxiliary C.Ts that are used for matching the C.T. ratios of the primary and secondary currents and also for accounting for the 30° phase shift are also called Interposing Current Transformers (I.C.Ts) or Matching Current Transformers. In a power system where there are a number of power transformers of different voltage and power ratings and provided with C.Ts of different ratios, it is common practice to adopt a Universal Matching C.T. which has several tapings both on its primary and secondary. The simple advantage of the use of Universal Matching C.Ts is that the appropriate ratio and connections can be selected and formed thereby eliminating the necessity of having separate auxiliary C.Ts for each and every individual application of differential protection for transformers of different rating voltages and vector groups. This necessarily reduces the store inventory on such spares.

3.5.3 Current Transformer Characteristics

The C.Ts on the different sides of the power transformers are often purchased from different suppliers. Moreover, the ratios of these

protective C.Ts vary in the inverse ratio of the voltages. The magnetisation characteristics of these C.Ts, seldom match, even though the secondary currents are of equal magnitude at normal load. There may be an appreciable difference in these currents during fault conditions because of the difference in C.T characteristics; unless all the C.Ts are designed liberally so that saturation is avoided at the highest value of the fault current. This mismatch of the C.T. characteristics may cause indiscriminate operation of the relay even though the fault may be external to the protective zone.

Furthermore the unequal length of the current transformer secondary leads may well cause a difference in the VA burden between the two sets of C.Ts. This generally tends to give a current error between the sets of C.Ts.

These factors are overcome by the use of matching C.Ts and percentage Differential relays.

3.5.4 Ratio change as a result of change of tappings

Almost all modern power transformers are fitted with on load tap changing gear. The ratio between the primary C.Ts and the secondary C.Ts will therefore match at only one tap namely the normal tap. During a tap change, the transformer ratio is changed and so also is the ratio between the primary and secondary C.Ts. Thus an unbalanced or spill

current will flow causing mal-operation of the differential relay. This is overcome by the use of percentage Differential Relays.

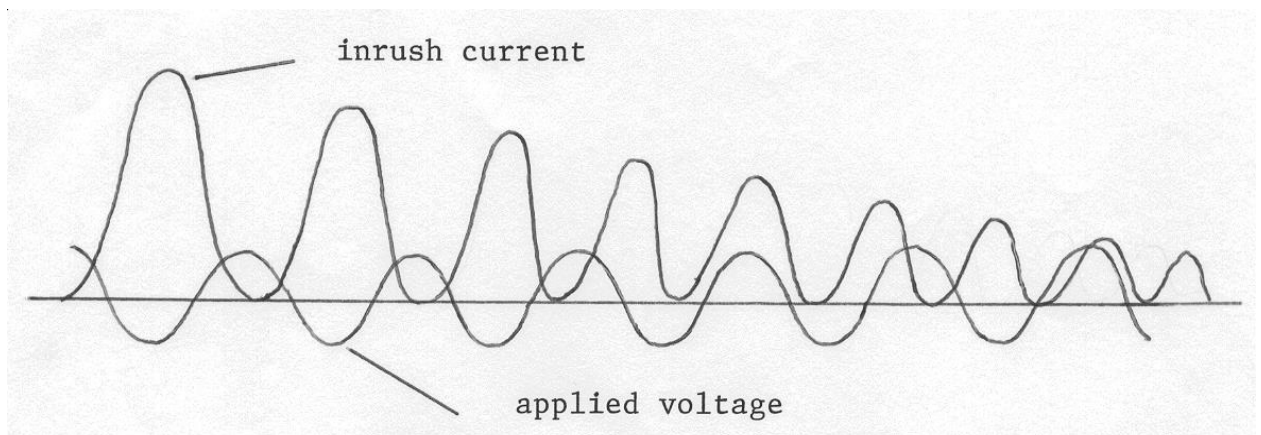
3.5.5 Magnetising Inrush

When a transformer is first switched on, transient magnetising current or exciting current flows. This inrush current which appears as an internal fault to the differentially connected relays may reach instantaneous peaks of 8 to 30 times those for full load.

The factors affecting the duration and magnitude of the magnetising inrush are:

- a) Size of the transformer bank
- b) Size of the power system
- c) Resistance in the power system from the source to the transformer bank
- d) Type of iron used in the transformer core and its saturation density.
- e) Prior history or residual flux level of the bank
- f) How the bank is energised.

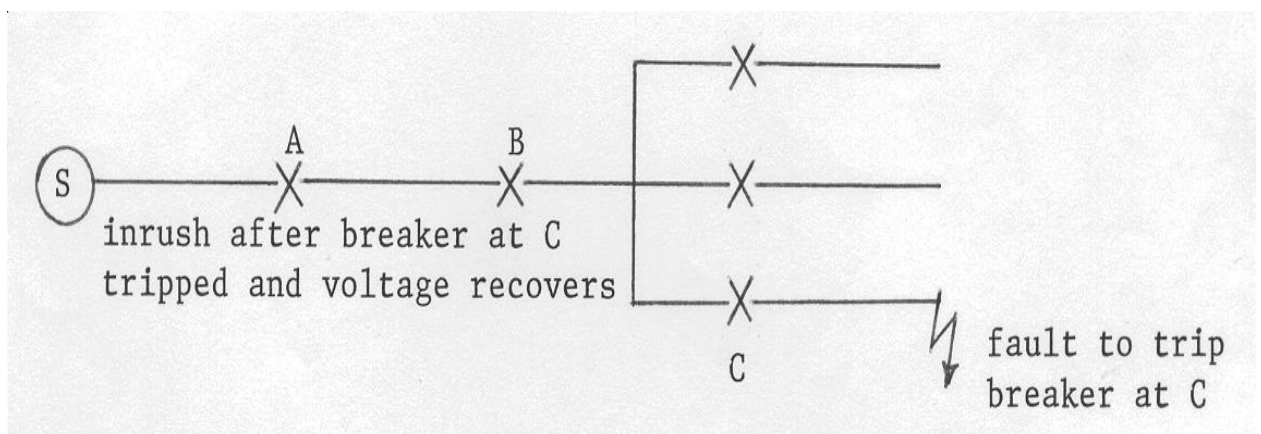
A typical inrush current wave is as shown below:



For the first few cycles, the inrush current decays rapidly. Then however, the current subsides very slowly, sometimes taking many seconds if the resistance is low. The resistance from the source to the bank determines the damping of the current wave. Banks near a generating source will have a longer inrush because the resistance is very low. Likewise large transformer units tend to have a long inrush as they have inherently a large inductance relative to the system resistance. At remote substations, the inrush will not be nearly so severe, since the resistance in the connecting line will quickly damp the current. Maximum inrush will not, of course, occur on every energisation. The inrush will depend upon the angle of switching and will be a maximum when the applied voltage passes through zero. In a 3-phase bank the inrush in each phase will vary appreciably.

3.5.6 Recovery Inrush

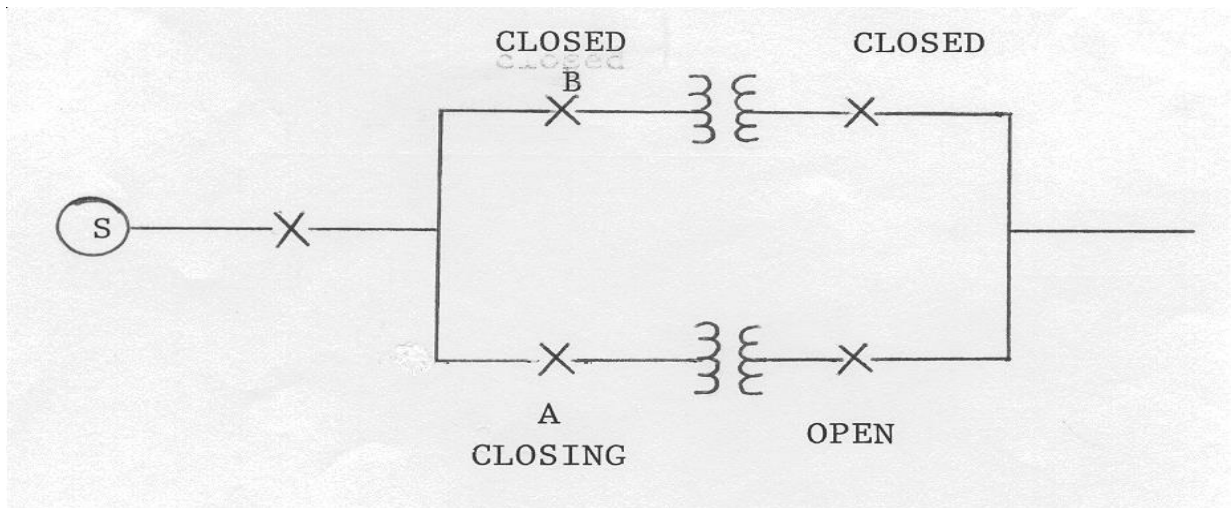
An inrush can also occur after a fault external to the bank is cleared and the voltage returns to normal. An example of which is shown in the following diagram.



Since the transformer is partially energised, the recovery inrush is always less than the initial inrush.

3.5.7 Sympathetic Inrush

When a bank is paralleled with a second energised bank, the energised bank can experience an inrush called the Sympathetic Inrush. An example of which is shown in the following diagram.



A sympathetic inrush is again much less severe than an initial inrush.

3.5.8 Since the differential relays see the inrush current as an internal fault, some method of distinguishing between faults and inrush current is necessary. There are several methods which will be discussed later in paragraph 3.8.

3.5.9 Phase Shift Introduced by Delta-Star and Star-Delta

Transformers

A simple rule of thumb is to connect the C.Ts in Star for Delta windings and C.Ts in Delta for Star windings.

Where there is no phase shift as in Y-Y Transformers, and even in case of power transformers, the practice is to connect the C.Ts in delta-delta. This is to ensure stability of the differential relays on external through faults.

The formation of Delta in the C.T. secondary must be similar to the Delta connection in the Transformer windings.

3.6 Guidelines in the selection of Current Transformers for Differential Protection

- a) Only standard C.T. ratings are chosen such that there is flexibility and interchangeability with either 5A or 1A secondary. The standard primary rating nearest to the full load current is chosen.
- b) The secondary knee point voltage should equal or exceed the value given by:

$$V_k = I_f (R_{CT} + R_R + 2R_L)$$

Where V_k = Knee point voltage

I_f = Maximum secondary fault current

R_{CT} = C.T. secondary resistance in ohms.

R_R = Relay impedance in ohms

R_L = Maximum one way lead resistance from C.T. to relay.

3.7 Examples on providing Differential Protection for Power Transformers

3.7.1 To provide differential Protection for a 30MVA, 132/33KV DY 11 Transformer

$$\text{Primary full load current} = \frac{30 \times 10^6}{\sqrt{3} \times 132 \times 10^3}$$

$$= 131.22 \text{ A}$$

Hence select primary 132 KV C.T. Ratio: 150/5

$$\text{Secondary full load current} = \frac{30 \times 10^6}{\sqrt{3} \times 33 \times 10^3}$$

$$= 524.86 \text{ A}$$

Hence select secondary 33KV C.T. ratio: 600/5

$$\text{Primary full load current in C.T. secondary} = \frac{131.22 \times 5}{150}$$

$$= 4.374 \text{ A}$$

The primary Transformer Winding is in Delta. Then the primary C.Ts are connected in Star.

The secondary Transformer winding is in Star, then C.Ts are to be connected in Delta.

$$\begin{aligned}\text{Secondary full load in C.T. secondary} &= \frac{524.86 \times 5}{600} \\ &= 4.374 \text{ A}\end{aligned}$$

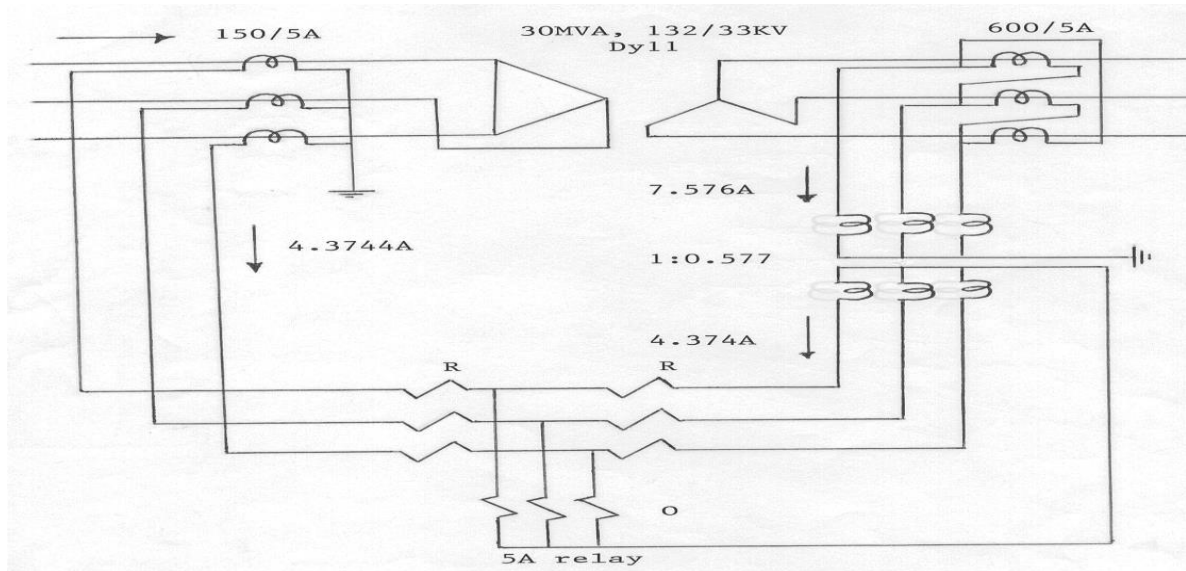
Secondary C.Ts are connected in Delta.

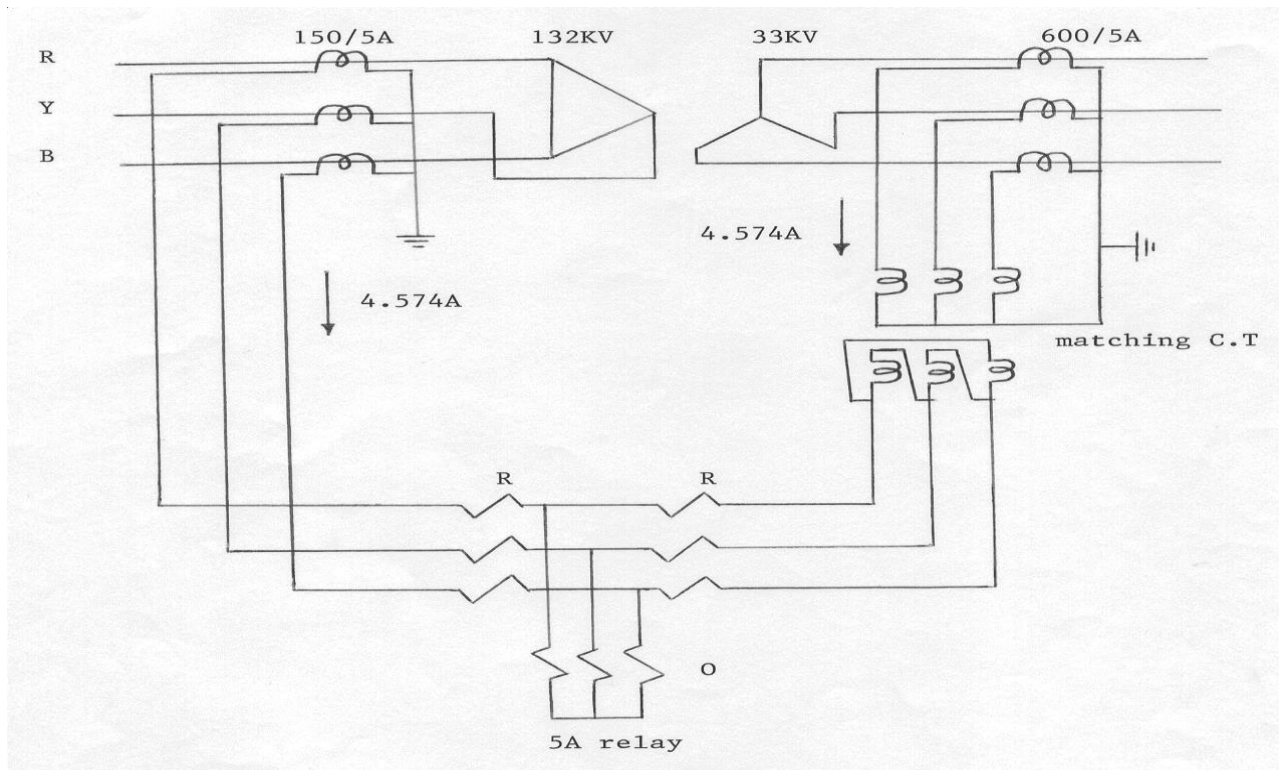
$$\begin{aligned}\text{C.T. secondary line current to Differential relay} &= \sqrt{3} \times 4.374 \\ &= 7.576 \text{ A}\end{aligned}$$

The secondary C.T. secondary line current of 7.576 A has to be matched with primary C.T. secondary line current of 4.375 A.

Introduce a matching C.T. of ratio 7.576/4.374 A in the C.T. secondary or 1:0.577. This is one way of connection.

The second method is as follows. Both the primary and secondary C.Ts are connected in Star. The phase shift is corrected in the secondary matching C.T.





3.7.2 To provide Differential Protection for a 7.5MVA, 33/11KV DY1

Transformer

$$\text{Primary full load current} = \frac{7.5 \times 10^6}{\sqrt{3} \times 33 \times 10^3}$$

$$= 131.22 \text{ A}$$

$$\text{Select primary C.T.R} = 150/5$$

$$\text{Secondary full load current} = 131.22 \times \frac{5}{150}$$

$$= 4.374 \text{ A}$$

$$\text{Secondary full load current} = \frac{7.5 \times 10^6}{\sqrt{3} \times 11 \times 10^3}$$

$$= 393.65 \text{ A}$$

$$\text{Select secondary C.T.R} = 400/5$$

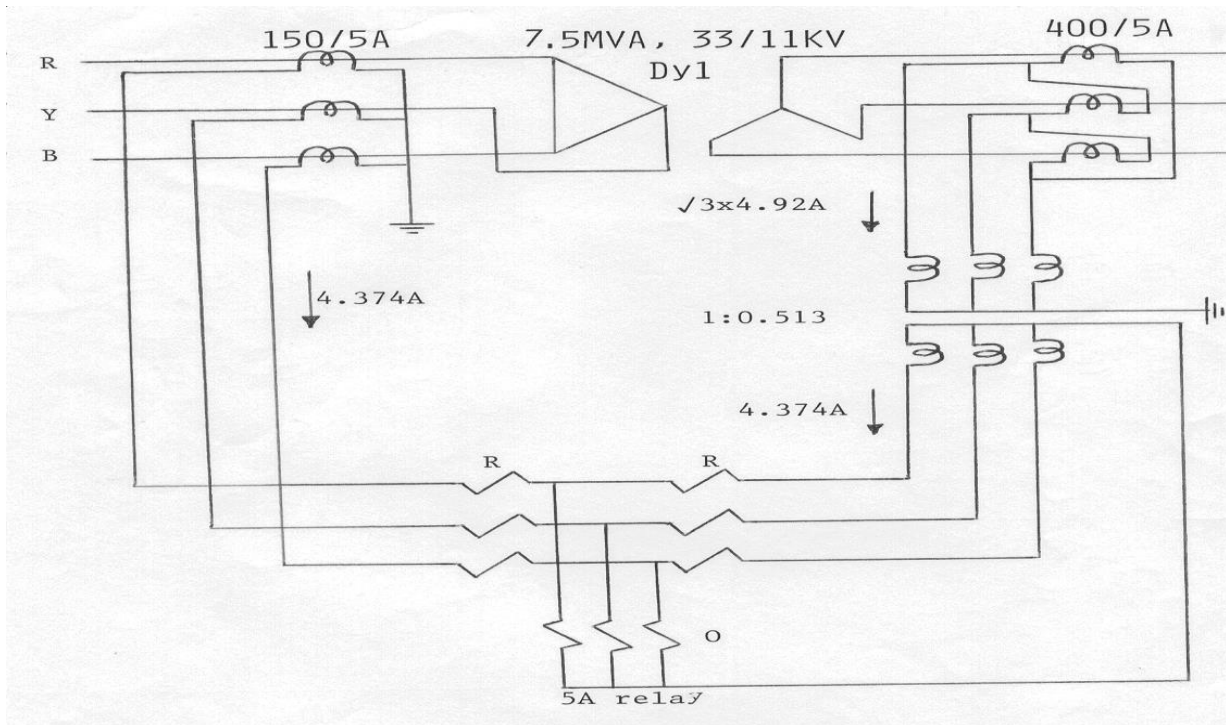
$$\text{Full Load Current in C.T. Sec.} = 393.65 \times \frac{5}{400}$$

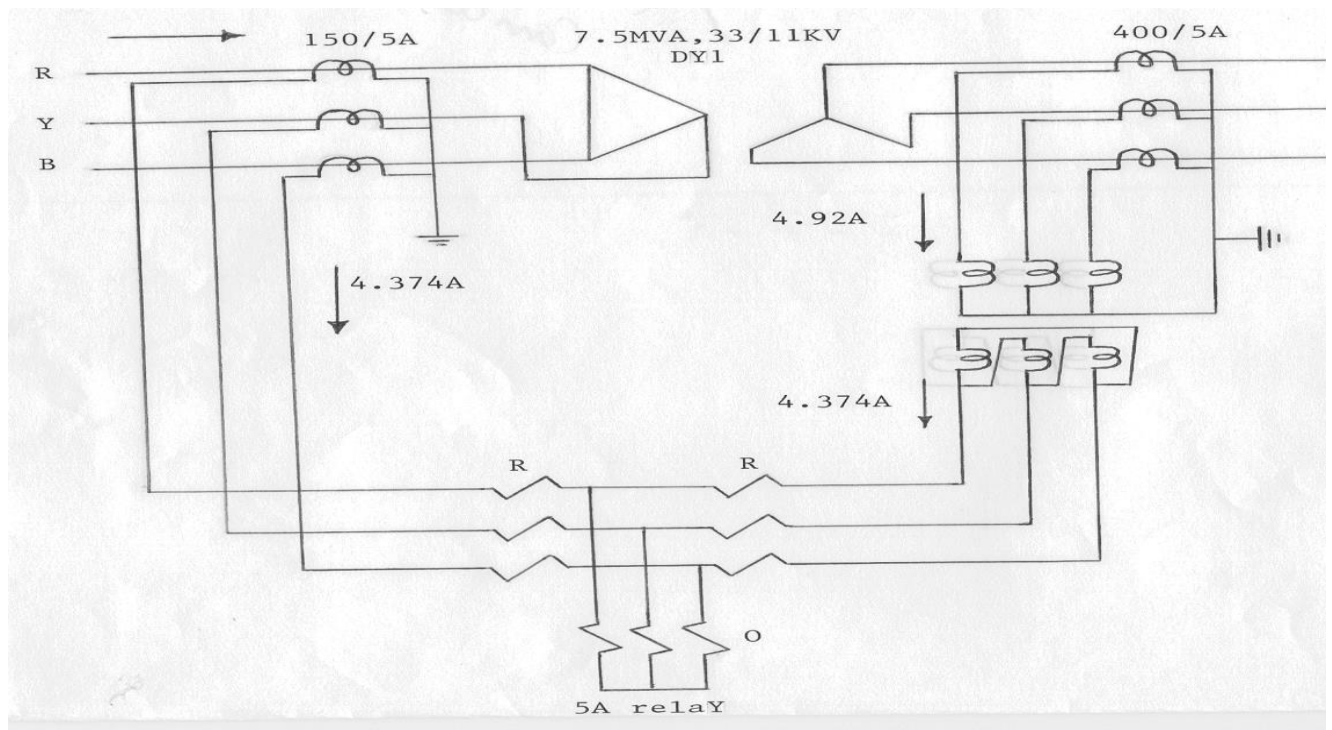
$$= 4.92 \text{ A}$$

Method 1: Transformer Primary is Delta, then connect Primary C.Ts in Star.

Transformer Secondary is Star, then connect Secondary C.Ts in Delta.

Method 2: Both C.Ts are connected in Star. Phase shift is corrected in Matching CT.



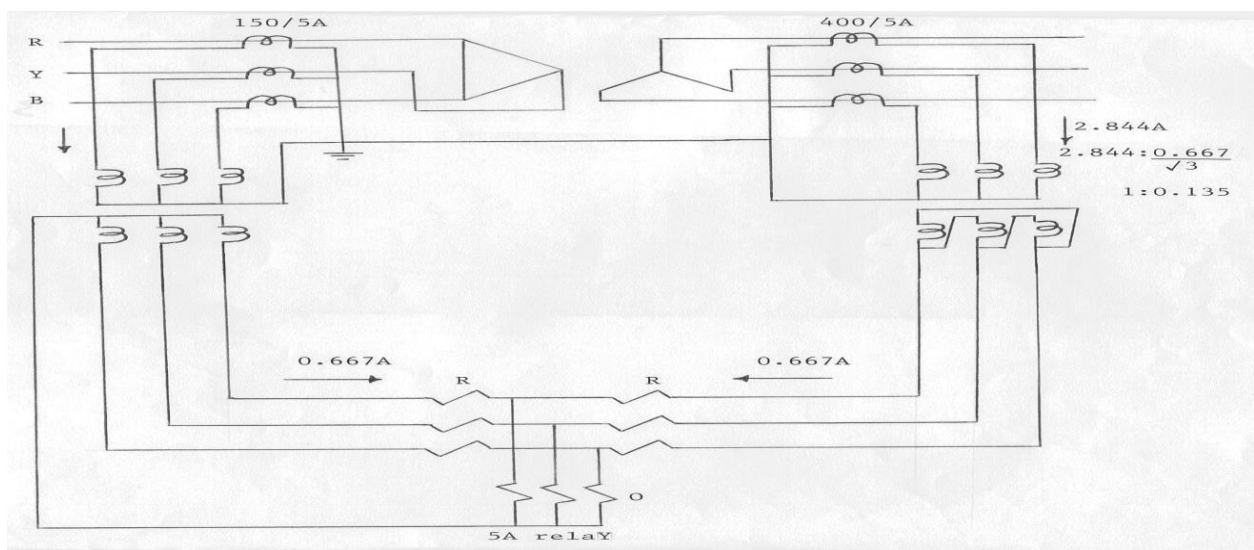


Method 3: Select primary C.T.R. as 150/2.89

$$\begin{aligned} \text{Full Load current in C.T. secondary} &= 131.22 \times \frac{2.89}{150} \\ &= 2.53 \text{ A} \end{aligned}$$

Select secondary CTR as 400/2.89

$$\text{Full Load current in C.T. Secondary} = 393.65 \times \frac{2.89}{400}$$



DIFFERENTIAL PROTECTION FOR A THREE WINDING TRANSFORMER

1. Consider a power transformer with rating 132KV/33KV/11KV, 45MVA/30MVA/20MVA with cooling system ONAN - Oil Natural Air Natural.

The differential protection scheme is designed considering separately the high voltage winding and the medium voltage winding using a full load MVA rating of 30MVA. Then the medium voltage winding is considered separately with the tertiary winding using 20MVA rating. The above method enables the relay to be stable for any mix of load or fault currents between the windings even when one winding is not in service.

The calculations for the Differential scheme for the transformer in 1 are as shown below:

Step (1): Choose winding pair 132KV/33KV leaving the 11KV side; select 30MVA load rating for 33KV as base.

For: 132KV Star connected.

$$\begin{aligned}\text{Primary current } I_p &= \frac{\text{MVA}}{\sqrt{3} \text{ KV}} \\ &= \frac{30 \times 10^6}{1.732 \times 132 \times 10^3} \\ &= 131.22 \text{ A}\end{aligned}$$

$$\text{Given C.T Ratio for 132KV C.T} = 300/1\text{A}$$

$$\text{Secondary Current } I_s = \frac{I_p}{\text{C.T.R.}}$$

$$= \frac{131.22}{300}$$

$$= 0.4374 \text{ A}$$

$$\begin{aligned} \text{Secondary Current considering phase shift} &= \sqrt{3} I_s \\ &= 0.4374 \times \sqrt{3} \\ &= 0.7576 \text{ A} \end{aligned}$$

For 33KV Delta connected D11

$$\text{MVA} = 30\text{MVA.}$$

$$\text{Primary Current } I_p = \frac{30 \times 10^6}{\sqrt{3} \times 33 \times 10^3}$$

$$= \frac{30000}{1.732 \times 33}$$

$$= 524.88 \text{ A}$$

$$\text{Given C.T. ratio} = 1200/1\text{A.}$$

$$\text{Secondary Current } I_s = \frac{524.88}{1200}$$

$$= 0.4374 \text{ A}$$

Matching Ratio between primary and secondary windings K1 is:

$$\frac{I_s \text{ 33KV}}{I_s \text{ 132KV}} = \frac{0.4374}{0.7576}$$

$$= 0.5774$$

Step (II): Choose winding pair 33KV/11KV leaving the 132KV side;

Select 11KV load MVA of 20 as base; 33KV - Delta connected

$$\begin{aligned} I_p &= \frac{20 \times 10^6}{\sqrt{3} \times 33 \times 10^3} \\ &= \frac{20000}{1.732 \times 33} \\ &= 349.92 \text{ A} \end{aligned}$$

$$\text{C.T.R.} = 1200/1$$

$$\begin{aligned} I_s &= \frac{349.92}{1200} \\ &= 0.2916 \text{ A} \end{aligned}$$

11KV Star connected

$$\begin{aligned} I_p &= \frac{20 \times 10^6}{1.732 \times 11 \times 10^3} \\ &= 1049.76 \text{ A} \\ \text{C.T.R.} &= 1200/1 \\ I_s &= \frac{1049.76}{1200} \\ &= 0.8748 \text{ A} \end{aligned}$$

$$\begin{aligned} \text{Considering the phase shift} &= \sqrt{3} I_s = 1.732 \times 0.8748 \\ &= 1.5152 \end{aligned}$$

$$K2 = \frac{0.2916}{1.5152}$$

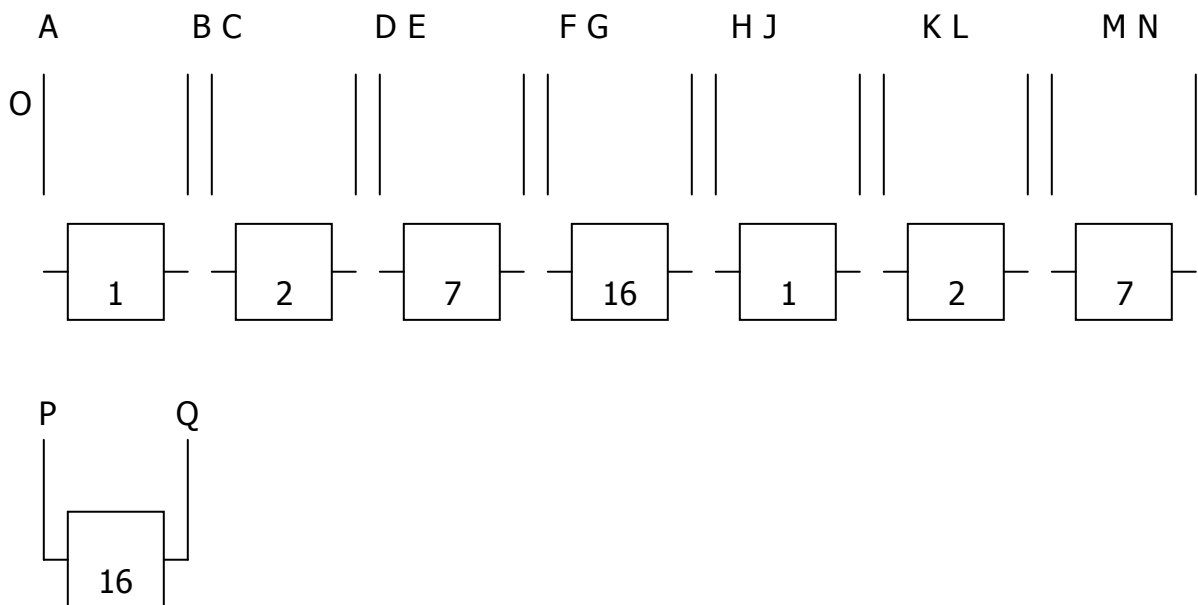
$$= 0.1925$$

MATCHING C.T. SELECTION

Choice of Matching C.Ts

Universal matching C.Ts can be used to select the turns for I.C.T. matching to avoid tripping on external faults. One of the popular ones is the Siemens Universal Matching C.Ts. The windings can be manipulated to obtain different ratios.

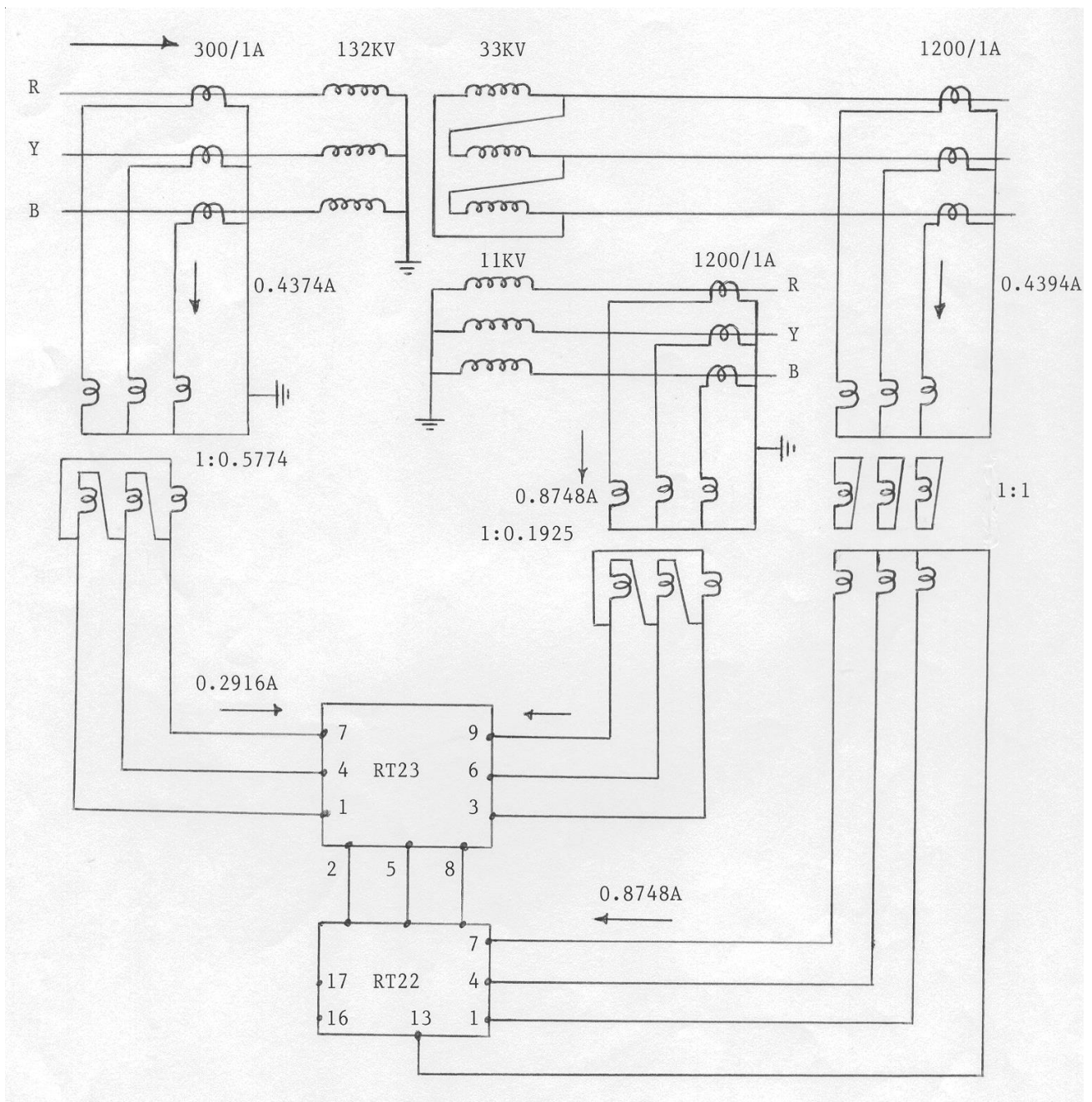
The M.C.T. winding diagram is as shown below:



The numbers indicate the number of turns for each winding. Thus to obtain a ratio of 0.5; linking D and E, M and P gives the ratio of $9/18 = 0.5$. Other selections can be made to obtain the same ratio as above. In

order to avoid saturation of the M.C.T., it is advisable to choose winding ratio a little bit higher than the calculated value. Standard Matching C.T. manuals are usually provided by various matching C.T. Manufacturers.

THREE WINDING TRANSFORMER DIFFERENTIAL CONNECTION



**3.7.3 To provide Differential Protection for a 80MVA; 330/132/11KV
Three Winding Transformer YY0/D1 loaded Tertiary of 25MVA
rating**

$$\text{Primary full load current} = \frac{80 \times 10^3}{\sqrt{3} \times 330}$$

$$= 139.96 \text{ A}$$

Select Primary C.T ratio as 150/1A

Primary full load current in C.T secondary

$$= \frac{140 \times 1}{150}$$

$$= 0.933 \text{ A}$$

$$\text{Secondary Full load current} = \frac{80 \times 10^3}{\sqrt{3} \times 132}$$

$$= 349.91 \text{ A say } 350 \text{ A}$$

Select the secondary C.T ratio as 400/1A.

Secondary full load current in C.T secondary

$$= \frac{350 \times 1}{400}$$

$$= 0.875 \text{ A}$$

$$\text{Tertiary full load current} = \frac{80 \times 10^3}{\sqrt{3} \times 11}$$

$$= 4198.91 \text{ A}$$

Select the Tertiary C.T. ratio as 5000/1A

Tertiary full load current in C.T secondary

$$= \frac{4198.91 \times 1}{5000}$$

$$= 0.84 \text{ A}$$

**3.7.4 To provide Differential Protection for a Unit Generator -
Transformer 145MVA; 16/330KV. Generator in Star and
Transformer Yd1.**

$$\begin{aligned} \text{Generator full load current} &= \frac{145 \times 10^3}{\sqrt{3} \times 16} \\ &= 5232.4 \text{ A} \end{aligned}$$

Select Generator C.T ratio of 6000/5A

Generator full load current in C.T. secondary

$$= \frac{5232.4 \times 5}{6000}$$

$$= 4.36 \text{ A}$$

$$\text{Transformer full load current} = \frac{145 \times 10^3}{\sqrt{3} \times 330}$$

$$= 253.69 \text{ A}$$

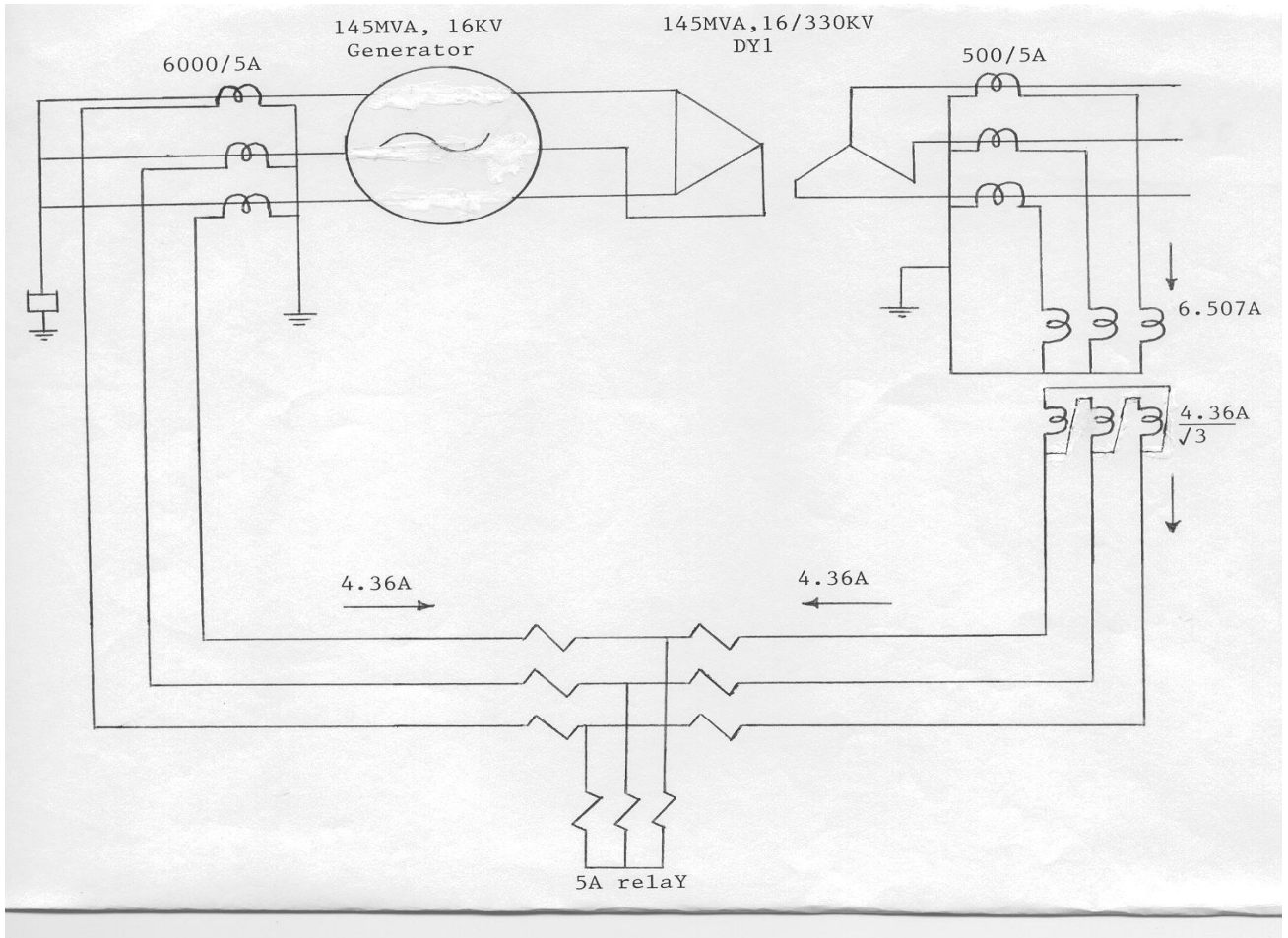
Select C.T of ratio 500/1A since C.T. is located far away in the switchyard.

Transformer full load current in C.T. secondary

$$= \frac{253.69 \times 1}{500}$$

$$= 0.507 \text{ A}$$

All C.Ts are connected in Star and in necessary ratio; the phase angle shift is corrected in matching C.Ts.



3.8 As already stated in paragraph 3.5.8 the differential relays see the inrush current as an internal fault. The methods adopted to distinguish between a fault and an inrush current are several. These are:

- Desensitization of the differential relay during bank energisation.
- Differential relay with reduced sensitivity to the inrush current wave.

- c) Harmonic restraint, Harmonic Blocking, Harmonic cancellation, etc. or Harmonic relays.

3.8.1 Desensitization of the Transformer bank

This is a method to prevent false operation of the differential relays on magnetising current inrush. A differential relay is desensitized at the time of switching by inserting a resistance in parallel with the operating coil. This temporarily raises the relay pick up by a factor of three or more. The resistor can be switched either manually as the bank is being energised or automatically by time delay drop out over-voltage relays.

Another method is to isolate the relay at the time of switching or to isolate the trip circuit of the differential relay at the time of switching.

3.8.2 Differential Relays with Reduced Sensitivity to Inrush

These are differential relays of the induction disc type with an inherently delayed operating time of about 5 to 6 cycles. Thus the delayed time of operation is referred to as the lack of sensitivity of the relay to inrush current as this current generally persists for about 5 to 6 cycles. The relay may operate in extreme cases such as in the case of a large transformer close to a generating source where the inrush current may last for a duration of more than 6 cycles. Hence these relays can be used only for energising transformer banks if the magnetising current inrush is not severe and the duration also does not extend beyond 5 to 6 cycles.

3.8.3 Harmonic Relays

These relays were developed following an analysis conducted on the wave form of a transformer magnetising current inrush. A typical analysis conducted in the USA indicated the following harmonics expressed as a percentage of the fundamental.

Fundamental	100%
D.C. Component	55%
2nd Harmonic	63%
3rd Harmonic	26%
4th Harmonic	5.1%
5th Harmonic	4.1%
6th Harmonic	3.7%
7th Harmonic	2.4%
Other Harmonics	Less than 1%

A more recent study conducted in Europe has indicated that the fifth harmonic component is also higher than 35%. Thus the components of the magnetising inrush current wave which cause operation of the differential relay are the D.C. components, 2nd harmonic and 5th harmonic components. The relay will be safe from false operation if these components are suppressed or eliminated. The methods therefore employed are:

- a) Even harmonic cancellations

- b) Harmonic restraint
- c) Harmonic Blocking
- d) D.C. bias.

3.8.4 Harmonic Cancellation

In this method, the D.C. component and all even harmonics are cancelled out in the operating circuit of a bridge rectifier relay and added to the restraint of the relay. The odd harmonics being a small percentage of the fundamental are ignored. This relay tends to mal-operate if the 5th harmonic component is large.

3.8.5 Harmonic Restraint

In this method, the harmonics are filtered out from the differential circuit, rectified and added to the percentage restraint. Only the current of fundamental frequency is allowed to enter the operating circuit; the D.C. and harmonics being diverted into the Harmonic Restraining coil. The relay is adjusted so that it will not operate when the second harmonic exceeds 15% of the fundamental. The maximum pick up is 15% of C.T. rating and the minimum operating time is 2 cycles. This is the most widely used form of Harmonic restraint Differential relay.

It is customary to provide an instantaneous over-current relay in the differential circuit to account for the presence of D.C. offset and harmonics in any fault current.

The instantaneous over-current element is set to operate above the maximum inrush current but will operate on heavy internal faults in less than one cycle.

3.8.6 Harmonic Blocking

In this scheme, a separate harmonic blocking is used. The contacts of this relay are in series with those of a biased or percentage differential relay. The scheme operates when the second harmonic is less than 15% of the fundamental.

3.8.7 D.C. Bias

In this scheme, a shunt loaded current operated transducer is used in which the operating current increases linearly with increasing D.C. in the control circuit for a constant voltage output. By this method, the required percentage bias on through faults is obtained by rectifying the through current and using it to control linearly the A.C. primary winding current carrying the differential current from the same phase. The output from the transducer goes to a second transducer which controls a tripping relay. The D.C. component of the magnetising inrush is used as an auto-bias to the relay in the relay of the first transducer. When the magnetising inrush current is symmetrical and does not contain a D.C. component, the relay is made stable by a cross fed bias from the D.C. component of the inrush current from another phase for which another transducer is required.

3.9 Over-voltages and Over-fluxing

3.9.1 Protection against over-voltages and over-fluxing was considered not necessary a few years ago. But it has assumed importance with large interconnected power systems. Hence large capacity E.H.V transformers are provided with this protection.

In PHCN, this protection may be limited to 330KV transformers and is not required for transformers of voltage rating 132KV and below. There are two types of over-voltages to which a transformer is subjected to. These are:

- a) Sustained Over-voltages at power frequency
- b) Transient Over-voltages

3.9.2 Sustained Over-voltages

A transformer is designed for the highest system voltage which is generally 10% higher than the nominal rated voltage. Hence no protection is necessary for 10% over-voltage above the rated voltage. But protection is necessary for sustained over-voltages greater than this 10%. For this, an over-voltage relay is used. The over-voltage relay is of the two step type with a delayed time. When the over-voltage exceeds 15%, an alarm is sounded and after a time delay of 2 to 3 minutes, it trips and isolates the transformer from the supplies if the over-voltage still persists. However, the main problem with over-voltage is the over-fluxing

caused by it. This is evident from the fundamental e.m.f. equation of a transformer namely:

$$V = 4.44 \Phi n f$$

$$\text{Or } V \propto \Phi f$$

Power frequency over-voltages cause considerable damage to a transformer if allowed to persist because of the increased hysteresis and eddy current losses produced by the increased flux. Besides the heat produced by the losses stresses the insulation. The increased flux also flows through the structural parts of the transformer from the core area. Although the structural parts carry a very small amount of flux under normal conditions, yet when they are subjected to this large leakage flux, rapid overheating takes place. This leads to deterioration of the insulation between the steel structural parts and the active part.

Over-voltage also damages the insulation of the windings due to voltage stress.

It can also be seen from the fundamental equation that the flux Φ is proportional to V/f i.e.

$$\Phi \propto \frac{V}{f}$$

This relationship indicates that over-fluxing can also arise from under frequency and not necessarily due to over-voltage.

Under frequency problems are encountered in large interconnected power systems during system instability. The relationship between flux, voltage

and frequency has helped the design of a relay against over-fluxing. This over-fluxing relay constantly monitors the ratio V/f . The relay is of the two-step type similar to the two step voltage relay. A safe value for V/f is taken as 1.1 where 'V' and 'f' are expressed in per unit of the rated values. The modern practice is to install this Over-Fluxing relay of the two step type instead of over-voltage relays. This is to take care of not only system over-voltages but also system under frequency.

3.9.3 Transient Over-voltages

Transient over-voltages are impressed on transformers connected to long overhead lines leading to inter-turn short circuits in the transformer windings. Sometimes these transient over-voltages may be due to lightening or switching. Protection against such transient over-voltages is basically provided by:

- a) Spark gaps or rod gaps on the transformer bushings.
- b) By lightening arresters and surge diverters located close to the transformers.

The voltage rating of the surge diverter and the rod gap spacing is coordinated with the Basic Impulse Level (BIL) of the transformer.

A thumb rule for the location of the surge diverter is that it should be located at a distance of not greater than 0.5ft/KV ; the distance however being measured from the transformer winding along the circuit path to the surge diverter.

CHAPTER TEN

BASIC LINE PROTECTION

1.0 INTRODUCTION

The term line, is a general term applied in a power network for any passage through which power is transmitted from a generating station to a receiving station and substation or between substations and from substations to consumers. The line is termed a transmission line for system voltage of 33KV and above sometimes also called a transmission feeder. It is also called a distribution feeder for system voltages of 11KV and below. A line also includes cables and to distinguish them, the term either "Overhead" (O.H.) or "Under Ground" (U.G.) cable is also added. For example a line could mean a 330KV O.H. Transmission line or 132KV O.H. Transmission line or an 11KV Distribution O.H. feeder or an 11KV U.G. Cable Feeder.

2.0 TYPES OF PROTECTION

A composite transmission system consisting of transmission lines and feeders may be protected with all or some of the following types of protection:

- a) Over-current and Earth Fault Protection
- b) Distance Protection
- c) Pilot Protection

2.1 OVER CURRENT AND EARTH FAULT PROTECTION

This is done either by using Inverse Definite Minimum Time (IDMT) O.C and E.F relays or with instantaneous O.C and E.F relays or with inverse time O.C and E.F relays or with directional O.C and E.F relays or current balance and power balance relays.

This form of protection is the simplest and cheapest of all the types of protection. It is a widely used form of protection for:

- 1) Distribution feeders of 11KV
- 2) Transmission feeders of 33KV
- 3) Radial Transmission Lines up to 132KV

This is applicable where the cost of protection by other schemes such as Distance and Pilot wire cannot be economically justified.

This type of protection is also used as a form of back up protection where Distance type of protection is used as the main protection.

2.2 DISTANCE PROTECTION

Distance relays or distance protection schemes employ methods of continuously monitoring the basic parameters of the line namely: Impedance, Reactance, Admittance, etc. Such relays are termed Impedance relays, Reactance relays, Mho relays, etc., with definite geometrical characteristics which may be a circle or a straight line. A combination of such relays used in a scheme is called a Distance Protection scheme. Such a scheme comprises of a fault detector (to

detect the faulted phase), the nature of the fault (i.e. as to whether it is a ground fault or a line to line fault), a fault measuring unit (to measure the relay parameter such as Admittance, Reactance or Impedance) and the auxiliary tripping unit.

The characteristics of these relays have also been modified to obtain other geometrical characteristics such as quadrilateral, an ellipse etc. The advent of static relays has made it possible to obtain these specially modified characteristics with ease though some of these modified characteristics can also be obtained with a combination of electromagnetic impedance, reactance and admittance relays. These distance relays are used as the main form of protection for all transmission lines of 66KV and above, both radial and interconnected.

It is not intended in this course to go into details of the different types of distance relays, their applications and uses and of the distance protection scheme as this will be covered under a separate course.

2.3 PILOT PROTECTION

Pilot protection as the name implies means that pilots or separate channels are used at either ends of a line to compare the system parameters sent out over a line. These include either comparing the voltages, currents or the phase angle between the voltages and currents at the two ends of a line. The pilots used could be separate control cables run between the two ends of a line. The pilots used could also be wire

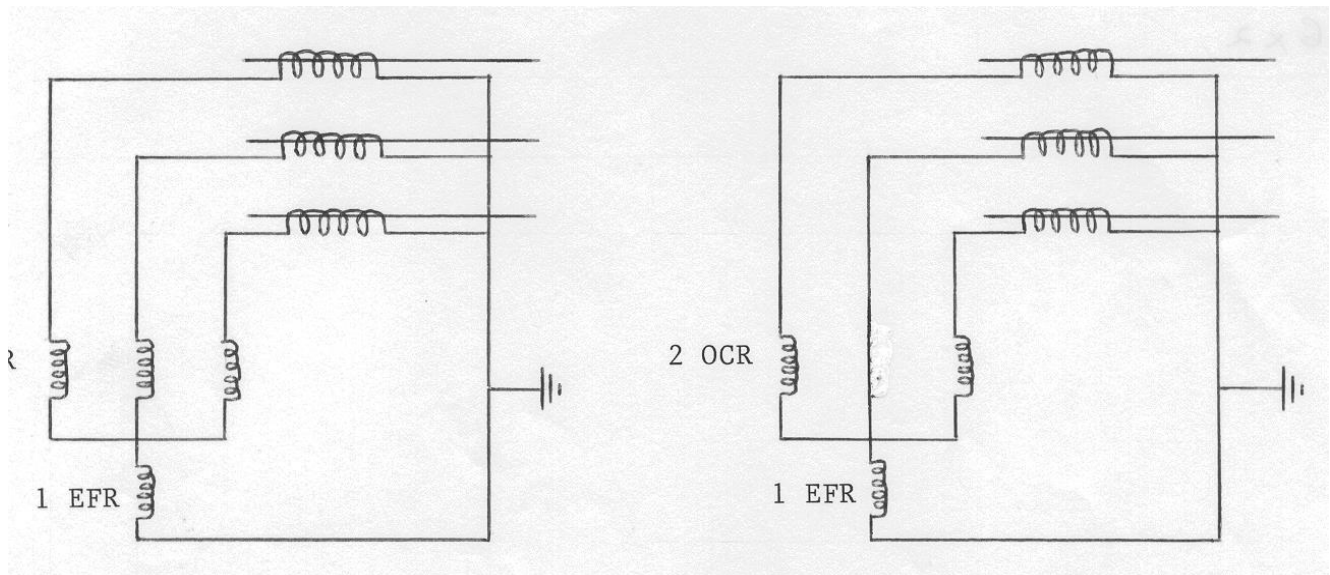
pilots or it could be a channel of the power-line carrier coupling between the two ends of a line. Wire pilots are not used for long lines as the cost of running separate pilot wires or cables would be prohibitive. Hence such schemes are employed for short lines within maximum length of 10kms. Power Line Carrier Coupling (PLCC) pilots are mostly used on lines where PLCC equipment has been installed for other purpose such as telecommunication, tele-metering, etc.

These pilots are called carrier protection pilots and are used at no extra cost and where instantaneous tripping of both ends of a faulted line is desired.

Again as set out in paragraph 2.2, it is not within the scope of this course to cover Pilot Protection. As such, emphasis in this course is towards over current and Earth Fault Protection.

3.0 OVER CURRENT AND EARTH FAULT PROTECTION FOR SINGLE LINES

Over-current and Earth Fault Protection is provided on feeders either by a combination of three over-current relays and a single earth fault relay or by two over-current relays and a single earth fault relay as shown. The O.C.Rs are connected in star with the E.F.R in the residual circuit.



3.2 The E.F.R is also similar to the O.C.R but with low current settings. For example if a 5A, O.C.R has current taps from 2.5 to 10A, (50 to 200%), then the current taps on the E.F.R will be from 0.5 to 2A.

3.3 Or if a 1A O.C.R has current taps from 0.5 to 2.0A (10 to 40%), then the current taps on E.F.R will be from 0.1 to 0.4 A, or 0.2 to 0.8A for 1A O.C.R with 1 to 4A settings.

3.4 Operation of the O.C and E.F relays on successive line sections is coordinated by the proper selection of current and time settings as described in the handout on "Co- ordination of relays and relay settings"

Whenever Inverse time relays are used they must be provided with high set instantaneous units to reduce the fault clearing time on close faults and to enable use of automatic re-closing successfully. Normally, no separate relay units are required for instantaneous units as most of the relay manufacturers supply O.C relays with a built in high set instantaneous unit on request.

3.5 The relay pick up should be so chosen so that:

- a) It will provide primary protection for all short circuits on the section it is protecting.
- b) It will provide back up protection for short-circuits on an adjoining section immediately beyond the protected section.
- c) It will not pick up on instantaneous maximum or emergency overloads.
- d) It will be positive for minimum fault current condition so as to enable the use of the most inverse portion of the relay time current characteristic.

3.6 SELECTION OF THE INVERSENESS OF A RELAY CHARACTERISTIC

- a) The lesser the effect of generating capacity on the magnitude of short circuit currents for a fault at a given location, the more inverse time current characteristic should be used to take advantage of the reduced time of fault clearing for faults near the relay location. Accordingly I.D.M.T., Very Inverse or Extremely inverse in order of increased inverse ness can be applied.
- b) In systems where the magnitude of the ground fault current is severely limited by the neutral grounding impedance and or arc plus ground resistance, little or no advantage can be taken of the inverse ness of an E.F.R characteristic as the fault current does not change much with the fault location. In such cases a relay with I.D.M.T characteristic may as well be used.

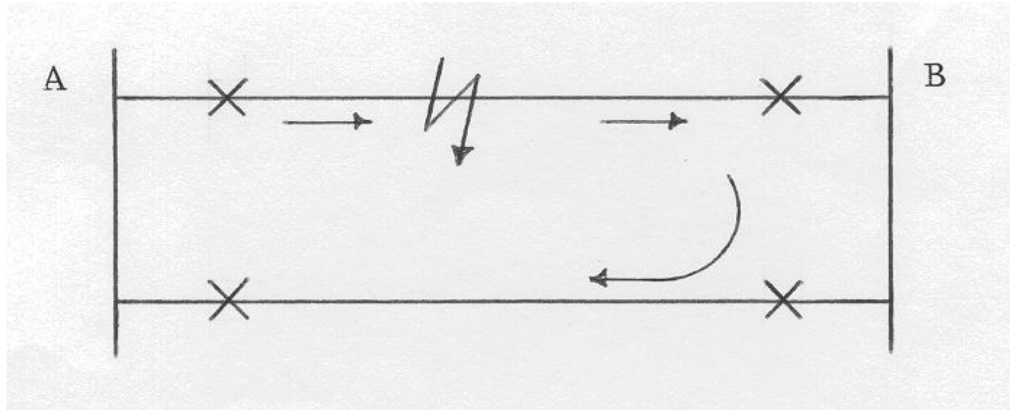
- c) In cases where O.C relays have to be coordinated with fuses very closely, then very inverse or extremely inverse characteristic relays are well suited.

3.7 APPLICATIONS OF INSTANTANEOUS O.C RELAYS

- a) It is considered advisable to use an instantaneous O.C relay to supplement an inverse time O.C relay if the fault current under maximum generating condition for a fault at the relay locations is about three times that when the fault is at the far end of the line section.
- b) The pick-up of the instantaneous relay is normally adjusted to be 25% higher than the magnitude of the maximum fault current for faults at the far end of the line section. This is to avoid operation of the relay for faults beyond the far end of the protected line section due to overreach of the relay.
- c) For most faults, the addition of an instantaneous unit reduces the overall fault clearing time. Even if such reduction is obtained only under maximum generating conditions, the use of a supplementary instantaneous unit is considered to be worthwhile as it adds very little to the cost of relaying with relays built in with instantaneous units.

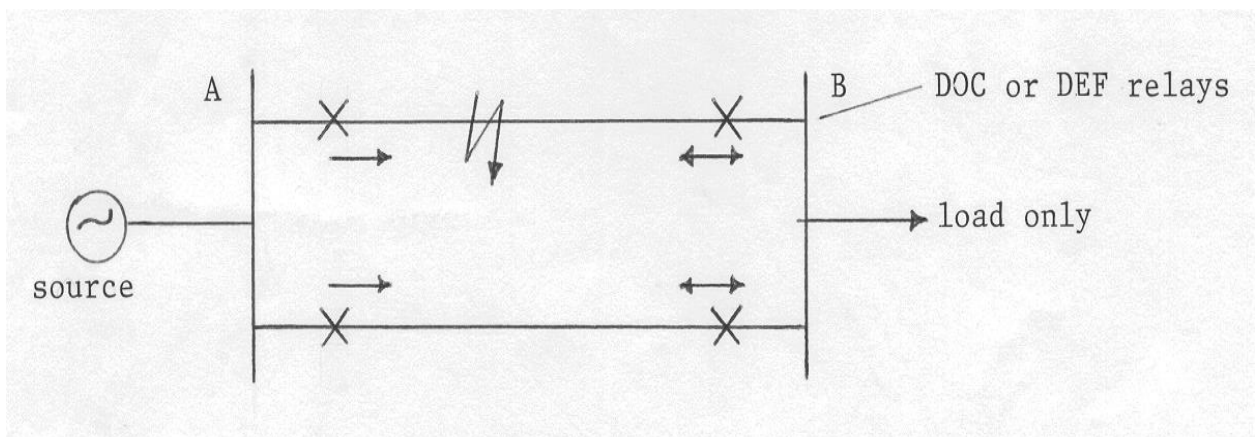
4.0 PROTECTION FOR PARALLEL LINES

- 4.1** Adequate protection cannot be provided with non-directional O.C and E.F relays as a fault on one line would cause isolation of the other healthy circuit.



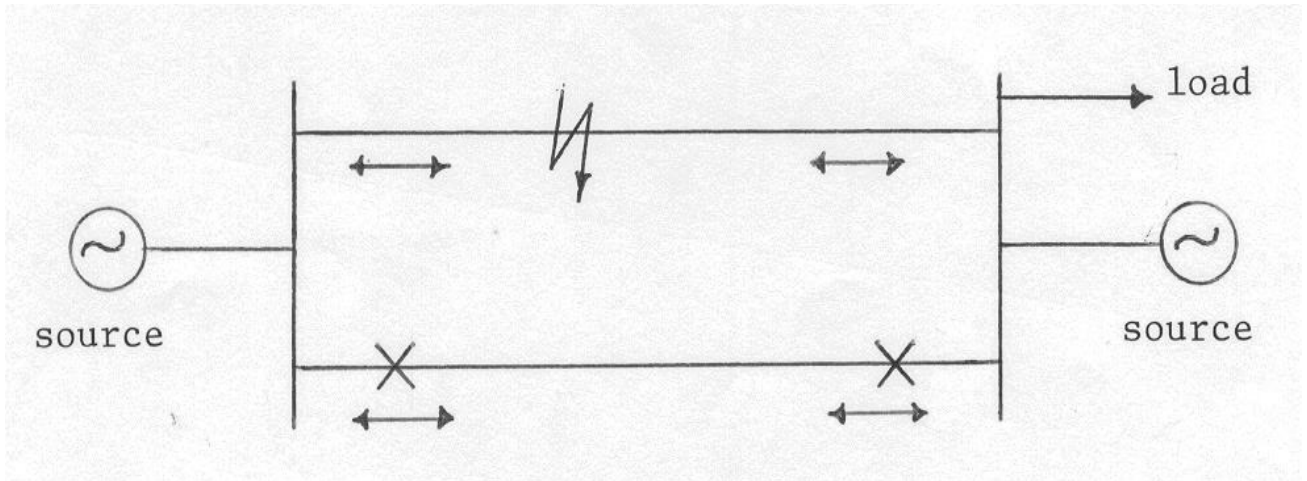
For example if a fault occurs on line (1), the relays located at station A and B for both the lines will pick up. The arrow direction indicates the direction in which the fault current is fed from stations A and B. This is therefore an undesirable feature.

4.2 Parallel feeders are therefore protected with directional O.C and E.F relays. If there is only one source for power flow along parallel feeders, it is then sufficient to install D.O.C. and D.E.F. relays at the receiving end as shown.



If a fault occurs on line (1), then the relay at A on line (1) will operate and the directional relay at B on line (1) will also operate to isolate the fault.

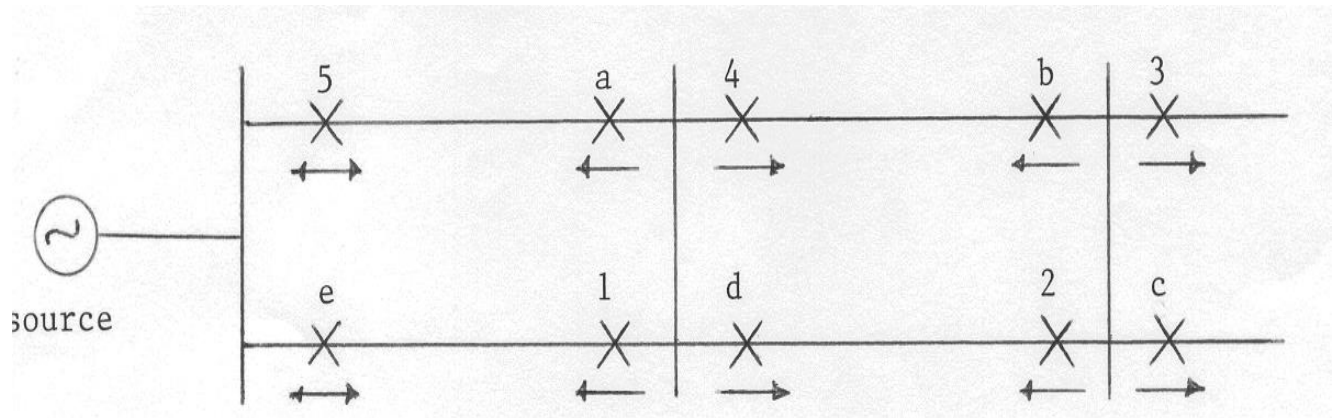
- 4.3** However, if there are sources at both ends, directional relays at both ends have to be installed.



In the normal course, when the fault is isolated from one source only, then the fault current will also be fed from the other source. Hence directional relays have to be installed at both ends. The co-ordination of the relays should be such that they operate simultaneously.

4.4 ADJUSTMENTS FOR LOOP AND INTERCONNECTED CIRCUITS

- a) In practical distribution systems, particularly in large cities and with large load densities, radial circuits are rather rare and most of the circuits are looped and have a number of interconnections.
- b) The principles involved here in achieving proper co-ordinations are as for radial lines except that for selectivity, directional relays are used.



- c) For a simple loop system as shown above, the direction of the arrows indicate, the fault currents for which the relays should act. Thus at all relay locations except at (5) and (e), fault currents can flow in either direction. Hence at all relay locations except at (5) and (e), the relays installed are directional relays.
- d) Relays at locations (1), (2), (3), (4), and (5) are to operate for one direction of fault current flow and their time settings are adjusted to make them mutually selective.
- e) Similarly, relays located at (a), (b), (c), (d) and (e) are treated as a second group independent of the first one and are coordinated accordingly.
- f) Current settings are selected as in the case of any radial feeder. However the first relays i.e. the relays at (1) and (a) should have the minimum current setting permitted by the maximum load condition. This is because the current at these locations reduce to a minimum as the fault is nearer from the source in one direction.

4.5 The directional relays widely used are those with a voltage restraint. The potential for directional O.C relays is obtained from the secondary of a star connected P.T. whilst the potential for the directional E.F relays is obtained from an open delta connected P.T.

CHAPTER ELEVEN

AUTORECLOSING SCHEMES

1.0 INTRODUCTION

- 1.1** The large majority of transmission line faults are transient and can be cleared by momentarily de-energizing the line. A fault analysis of overhead lines above 66KV has indicated the following information regarding faults:

Transient faults	-	80%
Semi-permanent faults	-	10%
Permanent faults	-	10%

- 1.2** A transient fault is one such as an insulator flash over which is cleared by the immediate opening of the circuit breaker and does not re-occur when the circuit breaker is closed.
- 1.3** A semi-permanent fault is one such as a tree falling on a line. Here the cause of the fault will not be removed by the immediate tripping of the circuit breaker but could be burnt away after a second or third closing of the circuit breaker.
- 1.4** Permanent faults are those which have to be necessarily attended to and cleared before the line can be safely energized.

2.0 ADVANTAGES OF RECLOSING

- 2.1** It is evident from the introduction on the nature of faults, that it is a feasible proposition to improve service continuity by automatically

reclosing the circuit breaker after fault relay operation. The obvious advantage of automatically reclosing the circuit breaker is reduction in the period of supply interruption.

2.2 Although auto-reclosing was first applied to radial feeders transmitting power to isolated places, yet later, the scheme was extended to tie lines to maintain system stability which would otherwise be adversely affected by the loss of the tie. In this latter case, since system stability is very much affected by the duration of the disturbance, i.e. from fault inception to a successful re-closure, it became a necessity for a short fault clearance and reclosing time.

2.3 There are also other economic considerations involved in auto-reclosing. It could permit the running of a remote substation as an unattended substation, thereby saving the wages of personnel and staff. However, in the case of an unattended substation, it may take hours or days for a person to travel to the substation if the circuit breaker that has tripped has to be closed manually. A direct advantage is therefore, a reduction in interruption time from hours/days to a few seconds. But should the fault be permanent, there is no advantage in time or money, as the substation has to be visited to correct the fault.

2.4 A further benefit resulting from introduction of auto-reclosing is the opportunity to introduce instantaneous tripping of the circuit breaker to systems where discrimination is obtained with inverse or definite time

over current protection. Instantaneous tripping of the circuit breaker brings three main benefits:

- a) Reduction of the time the supply is interrupted as the fall in voltages resulting from the fault is virtually an interruption.
- b) Reduction of damage to faulted equipment as the fault current is allowed to flow for a fraction of a second.
- c) Consequent on the reduction in damage, many faults which would otherwise have become permanent with time delay protection are now restricted to the transient type.

3.0 DEFINITION OF COMMON TERMS USED IN AUTORECLOSE SCHEMES

3.1 Operating Time

This refers to the time taken from the inception of a fault until it is finally cleared by the circuit breaker and a successful re-closure.

This time is governed by:

- a) Protective Relay time - time from fault inception to closing of tripping contacts.
- b) Auxiliary relay time - time from energising the coil to the closing of the Normally Open (NO) contacts or opening of the Normally Closed (NC) contacts.
- c) Circuit breaker time - time from energising of the trip coil until the fault arc is extinguished.

3.2 Dead time

This is time for which a circuit remains de-energised and it's governed by:

- a) Circuit breaker or system time from the extinguishing of the arc and the re-making of the circuit breaker contacts.
- b) Auto Reclose Relay time - the time the auto-reclose scheme being energised and the completion of the circuit to the circuit breaker closing contactor.

On all but instantaneous or very high speed reclosing schemes, this time which is normally adjustable and marked on a calibrated dial is virtually the same as the circuit breaker dead time. In multi-shot schemes, the individual dead times may be the same or separately adjusted.

3.3 Closing Impulse time.

This is the time during which the closing contacts on the auto-reclose relay are made.

3.4 Reclaim time

The time from the making of the closing contacts on the auto-reclose relay to the completion of another circuit within the scheme, or lock out the scheme or a circuit breaker as required. This time may be fixed or variable or dependent upon the dead time setting. In multi-shot schemes, the individual reclaim time may be the same or independently adjustable.

3.5 Lock Out

This is a feature in the auto-reclose scheme to prevent further automatic closing of the circuit breaker after the chosen sequence of re-closures has been unsuccessful. For this position, the circuit breaker must be closed manually.

This feature is also provided in the auto-reclose relay to prevent further automatic closing after the chosen sequence regardless of whether the reclosure was successful or not.

3.6 Anti-pumping

This is a feature incorporated in the circuit breaker or in the auto-reclose relay whereby in the event of a permanent fault, repeated operations of the circuit breaker are avoided i.e. when the closing impulse is longer than the sum of the protective relay and circuit breaker operating times.

3.5 Number of shots

This is the number of attempts at reclosing which an auto-reclose scheme will make before locking out on a permanent fault. The number of shots may be fixed or adjustable.

4.0 APPLICATION OF AUTORECLOSE SCHEMES

4.1 The application of any auto-reclosing scheme is decided by the Dead time and Reclosing time.

4.2 There are many factors influencing the choice of Dead time and these are discussed below.

4.2.1 System Stability and Synchronism

This consideration arises only in interconnected power networks. It is essential that the system dead time be kept down to a few cycles so that the interconnected power sources do not swing out of synchronism. The problem is mainly with protective relays and circuit breakers if the dead time has to be kept down to a minimum. There must be high speed relays which operate in 1 to 2 cycles. The circuit breakers must also be capable of interrupting the fault current and clearing the arc products within a few cycles so that they are ready to be re-closed.

High speed auto-reclose schemes are built around specially designed H.V. circuit breakers which are fast enough to allow some control over the system dead time by means of a relay. The relay dead time is adjustable over a range of 2 to 25 cycles. This equipment is relatively expensive and would only be justified in E.H.V systems.

4.2.2 Synchronous and Induction Motor Loads

A fairly short dead time is attractive to consumers so as to cause the minimum disturbance and would allow the consumer plant to run without interruption when supply is restored.

This practice cannot be tolerated with synchronous motors as the dead time would have to be long enough for the operation of the no volt trips associated with these motors but short enough to allow for coasting of

induction motors. A dead time of 0.3 secs is necessary for the synchronous motors to be disconnected. In the case of induction motors, the motor will generate for a short time and the supply may be reconnected in anti-phase thus doubling the voltage with the risk of insulation breakdown hence a dead time of 0.4 secs is considered as satisfactory for these loads.

4.2.3 Street Lighting - Street Lighting demands special attention on busy roads and with fast moving traffic. Obviously the time the lights are out should be as short as possible. A time of 1 to 2 secs is considered as usually satisfactory.

4.2.4 Domestic Consumers - There are no dangerous conditions involved with domestic consumers except for the inconvenience. A dead time of a few seconds or minutes is of no consequence. It is only TV sets which have a bearing on this matter as it is recommended that if they cannot be switched on again within 10 secs, they should be left idle for 2 to 3 minutes. This therefore gives a desirable time of 10 secs for domestic consumers. The only other consideration from the point of view of the supply authority is that the dead time should be shorter than the time required for an irate consumer to get to the telephone to make a complaint.

4.2.5 De-ionisation of an Arc - It is essential to know the time interval for which a line must be kept de-energised in order to allow for the complete de-

ionisation of the fault arc and also to prevent re-strike when the line is reconnected to the system.

The de-ionisation time of an uncontrolled arc in free air depends upon a number of unpredictable factors. The most important of all is by far the system voltage. As a general rule, the higher the system voltage, the longer is the time required to de-ionise the arc. The factors affecting the de-ionisation time are:

- a) Magnitude and duration of the fault current
- b) System voltage and length of line involved
- c) Capacitive coupling between the faulty and adjacent healthy conductors
- d) Configuration of the transmission lines and spacing between conductors.

Typical values of de-ionising times for an arc in free air as per studies conducted in England are as follows:

Transmission Line Voltage (KV)	Minimum De-ionising Time (Seconds)
66	0.1
132	0.17
330	0.35

An American study based on 40 years experience has indicated that the minimum dead time required for de-ionization of an arc can be reasonably represented by a straight line using the following equation:

$$t = 10.5 + \frac{KV}{34.5} \text{ cycles}$$

Where KV is the rated line to line voltage. Thus for a 330KV system, $t = 20.06$ cycles corresponding to about 0.4 secs.

4.3 Reclosing Time

The reclosing time is generally defined as the time taken by the circuit breaker to open and re-close the line. It is measured from the instant the protective relay energizes the trip circuit to the instant when the breaker contacts remake the circuit. This period is made up of the circuit breaker time plus the system electrical dead time.

The general sequence of operations for a successful re-closure is:

- i. High speed trip on transient fault
- ii. Re-closure after allowance for reclosing time.

If the re-closure becomes unsuccessful, then the above sequence (i) and (ii) will be followed in case of single shot by:

- iii. High speed trip
- iv. Lock out

In the case of multi-shot, lock out will take place only after several unsuccessful re-closures depending upon the number of re-closures set to be attempted.

5.0 RECLOSING SYSTEM CONSIDERATIONS

5.1 One shot Versus Multiple Shot Reclosing relays

The desired attributes of a reclosing system vary widely with user requirements. In an area with a high level of lightning incidence, most

transmission line breakers will be successfully re-closed on the first try. Here, the small additional percentage of successful re-closures afforded by multiple operations does not warrant the additional breaker operations. Single shot reclosing relays are entirely justified. Sub-transmission circuit reclosing practices vary widely depending upon requirements of the loads supplied. If there are motors or generators in the system, the first re-closure may be sufficiently delayed as dealt with in paragraph 4.0. Most often, two or three re-closures are used for sub-transmission circuits operating radially.

Multiple shot reclosing relays are warranted on distribution circuits with significant tree exposure, where an unsuccessful re-closure would mean a customer outage.

5.2 Three Phase Versus Single Phase Auto reclosing

When three phase auto-reclosure is applied to single circuit inter-connectors controlling the link between two power systems, the clearing of a system disturbance by opening the three phases of the circuit breaker makes the generators in each group to drift apart in relation to each other. Much of the change in speed of the generators occurs during this period owing to the uneven loading on the two halves of the system since no interchange of synchronizing power can take place.

If on the other hand, during a single earth fault, only the faulty phase is tripped, then synchronizing power can still be transmitted through the

healthy phases. This method of auto-reclosure is called a single pole Auto-reclosing. Similarly if two conductors are faulty, only the faulty phases are isolated and reclosed. Through the use of single pole tripping and reclosing, the stability limit of a single tie line can be raised above the limit as that can be obtained with a three pole tripping and reclosing with the same speed. The increase in stability limit is great for a line to ground or line to line fault; considerable for a two line to ground fault and nothing for a three phase fault. On a double circuit tie line, these increases in stability limit obtainable through single pole switching are not so great as can be obtained on a single circuit tie line. In appraising these results, it should be borne in mind that about 80% of all faults on overhead transmission lines are of the transient one line to ground type and that single pole reclosing may therefore be successfully employed. In assessing further the advantages of single pole reclosing, it is worthwhile to note that on multiple earthed systems, the opening of one of the phases has little effect or interference with the transmission of the load. The open phase current can flow through the earth via the various earthing points until the fault current is cleared and the faulty phase is reclosed. Single phase switching has another advantage as it decreases the amplitude of power swing and the consequent voltage dip during the swing. This reduces the great mechanical shock to the generator and its coupling at the instant of reclosing.

The main disadvantage of single pole switching is that each breaker pole must have its own operating mechanism for closing and tripping and a scheme that will correctly select the faulted phase or phases. Thus it is necessary to fit phase selective relays that will detect and select the faulty phases. This makes the scheme more complex and expensive than that required for a three phase auto-reclosure.

The other disadvantage is that even if only the faulted phase is isolated then all three poles must be isolated and locked out after an unsuccessful re-closure as otherwise there may be inductive interference with telecommunication circuits.

6.0 AUTO RECLOSURES

6.1 These are small, automatic pole mounted circuit breakers suitable for connecting directly in the line. The contacts are normally held closed by a spring and are opened by a series solenoid. No auxiliary supply is required and the mechanism is tripped by the fault energy. A timing device is incorporated to give an operating cycle of two instantaneous trips followed by two delayed trips with an interval of approximately one second between each trip and re-closure. This time corresponds to the dead time. The main contacts will remain closed and the mechanism will return to normal should the fault be cleared during this cycle. If the fault is permanent the contacts will be locked open at the end of the cycle and must be re-closed by hand.

- 6.2** These reclosers are normally single phase units and perform the above cycle as such but when any one unit locks out, the other two are tripped and locked out also.
- 6.3** These auto-reclosers are intended for use on rural overhead lines, main and spur lines and sections. They are used in conjunction with fuses on adjacent sections.
- 6.4** The instantaneous tripping times are made as fast as possible so that the fuses will not blow and minimum deterioration is caused to the fuse on the occurrence of a fault. In addition, of course, high speed clearance of the fault increases the chances of the fault being transient. If this should be so, the contacts will remain closed and the mechanism reset to normal. If the fault is permanent, a time delayed trip follows which will allow the fuse on the faulted line to blow. A second time delayed trip is provided in order to assist co-ordination with the fuses at low fault levels by pre-heating the fuse and should the fault be on the main line, the recloser will again trip and lock out.
- 6.5** These reclosers afford a cheap and effective method of substantially increasing the continuity of service. Their chief limitation is their breaking capacity. The largest unit available is around 100 MVA, 3-phase at 11KV.

7.0 LIMITATIONS IN USE OF AUTORECLOSE SCHEMES

- 7.1** Automatic re-closure should not be employed on cable networks as nearly all cable faults are permanent.

7.2 Likewise, re-closure is seldom if ever, used in the event of bus faults because such faults are most likely caused by damaged apparatus connected to the bus or by operating errors. Such contingencies require repairing of the damaged apparatus, or replacement there of or manual switching to correct the operational errors.

8.0 An example of the operation of a 4 shot Auto-Reclosing Type VAR 42 manufactured by GEC and English Electric is explained below.

8.1 Sequence of Operations

1. The sequence is initiated by contact 52b-1 which closes when the circuit breaker opens. A is energized and sealed in through its own contact A-2 while the circuit breaker remains open.
2. T is energized through A-3 and seals in through its own contact T-3. The instantaneous trip circuit is isolated by T-1.
3. At the end of the first dead time, passing timer contact T-5 energizes B, which re-closes the circuit breaker via B-1 provided the latch-check switch is closed. The closing impulse is applied for approximately four seconds. Contact T-5 also energizes Co which records one fault clearance.
4. When the circuit breaker has re-closed, contacts 52b-1 de-energizes A and A-1 prevents further re-closure (pumping) even if the circuit breaker trips again immediately. A cannot be re-energized until the reclosing impulse is finished and B has dropped out to close B-2.

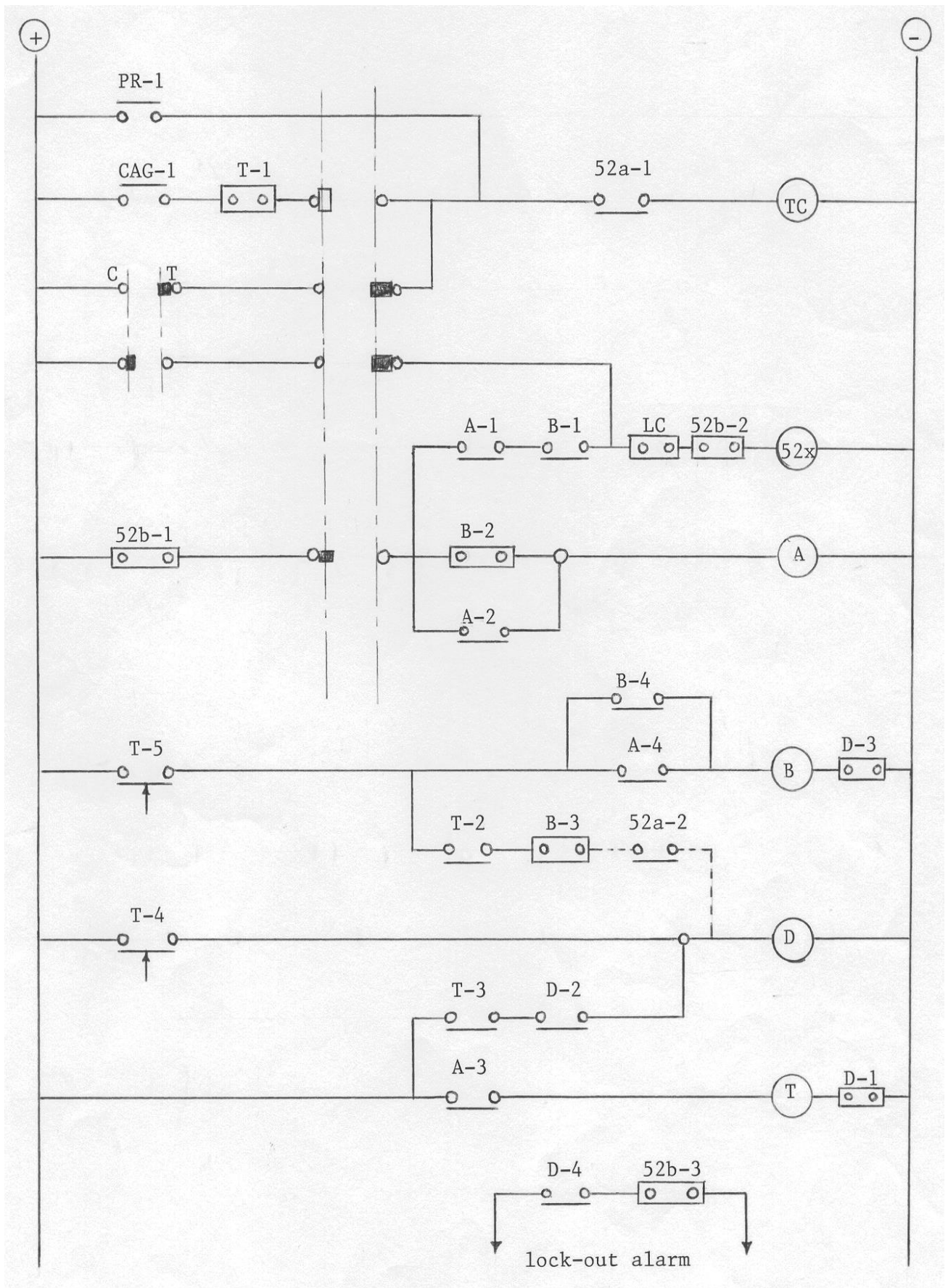
5. After unsuccessful re-closures, sequences 3 and 4 will be repeated two, three or four times as required until timer contact T-4 closes, energizing D which seals in through D-2 and A-3.

T is de-energized by D-1 and contacts D-4 (D.C. version only) can be used to close a lockout alarm circuit. The relay is reset after lockout by closing the circuit breaker non-automatically.

The relay can either be arranged to proceed to the end of the sequence before resetting, or when a short reclaim time is required, to reset after the first successful re-closure.

6. When the full sequence is required, auxiliary contact 52a-2 is omitted and provided the circuit breaker is closed at the end of the reclaim time, contact T-4 energises D which de-energises T and resets the scheme (A-3 is open when the circuit breaker is closed).
7. When the relay is to reset after the first successful re-closure, contact 52a-2 prepares the circuit to D, which is energised by B-3 at the end of the closing impulse and resets the scheme as in sequence 6.

In the arrangement shown, provision is made for isolating the instantaneous protection when the control switch is set to 'non-automatic' so that the circuit breaker will not be tripped unnecessarily on remote faults.



DEVICE	DESCRIPTION
CAG-1 relay	Normally open contacts on instantaneous over current
PR-1	Normally open contacts on main protective relay.
TC	Trip coil
52x	Closing contactor
52a-1, 52a-2	Close when circuit breaker closes
52b-1, 52b-2, 52b-3	Close when circuit breaker opens.
T	Time lag relay.
T-1	Instantaneous normally closed contacts
T-2, T-3	Instantaneous normally open contacts.
T-4	Final timer contact; closes after adjustable interval.
T-5	Timer contact closed successively by four independently adjustable rollers.
A	Self reset relay.
A-1, A-2, A-3, A-4	Normally open contacts.
B	Self reset relay.
B-1, B-4	Normally open contacts.
B-2, B-3	Normally closed contacts.
Co fitted).	Operation counter (counted across coil of unit when
D	Self reset lockout relay.

D-1, D-3	Normally closed contacts.
D-2, D-4	Normally open contacts.
LC	Latch check contacts on circuit breaker.
A/NA	Auto/Non-Auto control switch.
C/T	Close/Trip switch.
Note	The lockout alarm circuit (D-4) is omitted in the A.C. version because there are insufficient case terminals.

CHAPTER TWELVE

OVERVOLTAGES AND SURGE PROTECTION

1.0 INTRODUCTION

The insulations of electrical equipment in generating stations, substations etc. are subject from time to time to momentary over voltages. Those over voltages may be caused by system faults, switching on or off of lines and equipment or by lightning phenomena. These over voltages may be of sufficient magnitude to flash over or cause breakdown of equipment insulation and thereby affect continuity of service.

2.0 OVERVOLTAGES

Over voltages are classified as:

- Atmospheric Over voltages
- Switching Over voltages
- Temporary Over voltages

2.1 Atmospheric Over voltages

These are those caused by lightning phenomena. The severity and incidence of lightning in a particular region is described in terms of the number of thunderstorm days per year and is called the Isokeraunic level. This value is around 100 for tropical countries. Another popular method of describing the incidence of lightning is the number of lightning strokes to ground per 100 KM² per year.

Lightning phenomena is explained commonly by the stroke theory. The direct stroke is lightning striking a tall object above the ground level such as a transmission line tower or a tall building. There is in such a strike an initial so called leader stroke from cloud to ground at a relatively slow rate.

When this leader contacts the ground an extremely bright return streamer propagates upwards from ground to the cloud following the same path of the downward leader at a very rapid rate. The rate of propagation of this stroke is of the order of 50 to 100 microseconds with a high magnitude of current of 1,000 to 20,000 A. Direct strokes of a given polarity produce surges of the same polarity to the stroke itself. It has been learnt in the U.S.A. that a large number of direct strokes were of negative polarity, that is they reduced the negative charge to ground surrounding the part contacted. The lightning impulse is one which more or less rises to its peak or crest value in 1.2 microseconds and it is half the crest value in 50 microseconds.

It was originally felt that the lightning stroke was substantially a single impulse. Later data has shown that 50% of all strokes were multiple in character; that is after the first discharge has subsided a second and subsequent discharge occurred. The subsequent discharges are usually lower in magnitude than the initial one.

2.2 Switching over voltages

These are those caused by system operations such as:

- a) The closing or reclosing of an unloaded line.
- b) Low voltage energisation of a transformer connected to a long unloaded line.
- c) Energisation of a long line terminated by an unloaded transformer
- d) Load rejection at the receiving end of a line
- e) Load rejection at the receiving end of a line followed by line dropping at the sending end
- f) Switching off of transformers on no load
- g) Switching off of reactor loaded transformers
- h) Switching off of H.V reactors
- i) Switching at intermediate stations with long unloaded lines at either ends
- j) Switching on a load with trapped charge.

It is a well known fact that neglecting the effect of attenuation, there is a voltage double at the far end of a long unloaded line. Over voltage factors larger than 2.0 will also occur if there is a trapped charge on the line or due to interaction with the other phases. Extensive field studies conducted in U.S.A. and Canada have indicated that the highest switching over voltage factor that can occur is 3.0. But the most common value is around 2.0.

These switching over voltages appear as transient over voltages superimposed on the power system frequency voltage. It is extremely difficult to give an acceptable wave shape for this transient over voltage except to state that the wave front propagation is of the order of 1 microsecond per KM. Switching over voltages are also referred to as Internal Transient Over voltages.

2.3 Temporary Over voltages

These are an oscillatory phase to ground or phase to phase over voltage at or near power frequency of relatively long duration at a given location which is un-damped or weakly damped in contrast to switching and lightning over voltages. These occur mainly due to load rejection and or to one phase to ground faults. Other types of such temporary over voltages are caused by resonance phenomena or by phenomena related to the inrush current when transformers or reactors are energised. A sudden load throw off at the receiving end may cause the generator under excited conditions to instantaneously develop dynamic over voltages. The over voltage factor of temporary over voltages rarely exceeds 1.5. Temporary over voltages are often referred to as Internal Dynamic over voltages.

3.0 SIGNIFICANCE OF OVER VOLTAGES IN POWER SYSTEMS

1. For voltages of 170 up to 220KV, over voltages caused by system faults or switching, that is switching and temporary over voltages do not cause

damage to equipment insulation, although they may be detrimental to protective devices.

2. Lightning is not a very important source of over voltage for system voltages above 220KV. It is only the lightning striking the lines directly which constitutes a risk for the EHV system.
3. Switching over voltages or Temporary over voltages is the determining factor for system voltages above 220KV as the insulation begin breakdown under a switching surge rather than under a lightning surge.
4. Over voltage caused by a lightning stroke close to the line are of importance only for lines with a system voltage of say 132KV and below.
5. Lightning strokes between clouds are of no consequence to any system voltage.
6. A lightning surge is of serious consequence to system voltage of 220KV and below as the insulation begins to breakdown due to such a surge than due to other over voltage.

4.0 PROTECTION AGAINST OVER VOLTAGES IN POWER SYSTEMS

- 4.1** Protection for Lines: - The risk of a lightning strike to a transmission line is always there irrespective of the system voltage. Hence lines are designed to meet this contingency.

There are four principles involved in the design of a line against a direct strike of lightning. These are:

- a) The static or ground wires should be so located that they effectively shield the line from direct strokes.
- b) The clearance from line conductor to tower, or to points at ground potential should be adequate to prevent flash over at that point.
- c) There must be sufficient clearance between line conductor and static wires in the span to prevent flash over at this point.
- d) Tower foot impedance should be kept down to a value as low as can be economically justified.

Experience has shown, and tests on model lines have demonstrated that, if the static wire is so located such that the angle between a vertical line and the line joining the static and phase conductors is 30 degrees or less there will be little chance of a stroke contacting the phase wire.

The importance of tower footing impedance is due to the fact that the maximum potential at the tower top is a function of the tower footing impedance. Thus with high values of tower footing impedance, the potential of the tower itself can rise to a value sufficient to flash the insulator string from tower to line conductor, which is equally as bad, if the flash-over was in the reverse direction. A reasonable value for the tower footing impedance is a value of less than 10 ohms.

The tower footing impedance depends upon the soil in which the tower is located. In swampy wet ground, clay soils or garden soils values as low

as 1 to 2 ohms can be obtained. Where a high tower footing resistance is encountered, it can be reduced in several ways such as:-

1. Driving ground rods around the base of the tower to be connected electrically to the tower leg.
2. Running lateral wires buried in the ground from each tower leg and generally called "crow-foot" arrangement.
3. Placing a counter-phase of one or more wires or rods in the ground and extending under the line between the towers.

4.2 Protection to Equipment

The protection to equipment is essentially made by the following means:-

- a) Surge Diverters (Lightning Arresters)
- b) Rod gaps
- c) Protector tubes
- d) Insertion of Linear or Non Linear Shunt Reactors.
- e) Insertion of Resistors at circuit breakers.

4.3 Lightning Arresters

4.3.1 Requirements:

The basic requirement of a lightning arrester is that:-

- a) It should behave as a perfect insulator for the highest system voltage to ground
- b) It should discharge any over voltage into the ground safely.
- c) It should restore itself as an insulator after discharging the excess voltage.

The voltage to ground is determined for a system of given voltage largely by the method used for system grounding with the maximum voltage to ground during the existence of a single line to ground fault.

4.3.2 Classification of Lightning Arresters

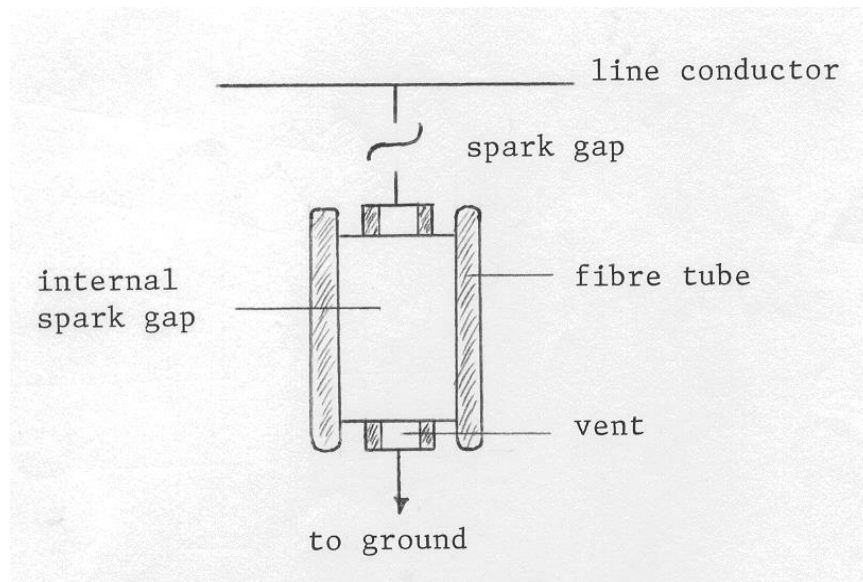
One method of classification is by the method of location in the power system network.

- | | | |
|----------------------|---|--|
| a) Distribution type | - | 3 to 15KV |
| b) Line type | - | 20 to 72KV |
| c) Station type | - | 20 to highest system voltage prevailing. |
- in the power system network

A second method of classification is by the characteristic that is, as to whether it is linear or non linear. A linear characteristic is described by a lightning arrester which discharges into the ground when the voltage reaches a preset value and the resistance offered to the voltage is the same irrespective of the magnitude of the voltage. On the other hand, in a non-linear type, the resistance decreases as the magnitude of the voltage increases.

Yet another method of classification is by the material through which the discharge takes place like silicon carbide, thyrite, zinc oxide etc., and upon their functioning such as Expulsion type etc.

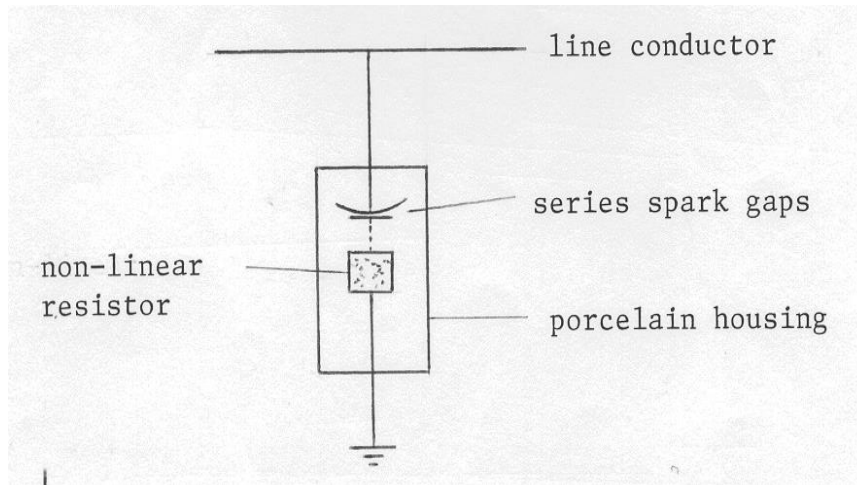
4.3.3 Expulsion type



The expulsion type Lightning Arrester as shown comprises of a spark gap enclosed in a fibre tube and another external rod gap in series. On the occurrence of a high voltage, the two spark gaps break down at once establishing a conducting path from the line to the ground in the form of an arc. The arc in passing down vapourises a small part of the fibre material. The gas thus produced is an ionized mixture of water vapour previously absorbed by the fibre and volatile fibre material. The gas drives out the air ionized by the arc and as a consequence, when the follow up current passes through its zero point, the arc path is de-ionized. Thus when the normal voltage is left at the arrester terminal, the space between the spark gap will have recovered its di-electric properties. The gases thus liberated are expelled for which reason the arrester is open at its lower end to permit the gases to escape; hence the name Expulsion

type. Their ability to interrupt power frequency follow current depends on the short circuit level at the point of installation. They are therefore used mainly in distribution circuits and are also called Distribution type.

4.3.4 Valve type



This type consists of a divided spark gap in series with a resistance element having non-linear characteristics as shown. On the arrival of a high voltage, the spark gaps break down causing a conducting path to the ground. The spark gaps cannot on their own, interrupt the power frequency follow current. As such they are aided by the non linear resistor which has the property of offering a low resistance to the flow of heavy currents and high resistances to the power frequency follow current. The spark gap assembly consists of a series of electrodes some of which are flat and some of special design with pressed out projections. The resistance elements are generally made up in the form of cylindrical blocks. These blocks contain small crystals of silicon carbide or thyrite or

zinc oxide bound together by an inorganic binder. The capacity of a block to pass surge currents increases with diameter. The complete assembly is housed in a sealed porcelain housing to prevent ingress of atmospheric moisture, humidity and condensation.

These valve type L.As are further classified as:

- i. Station type: - Most expensive, very efficient and used for all voltage ratings in substations.
- ii. Line type: - Used generally for protection of equipment in substations of 66KV and below.

Note that the Line type is a confusing word and does not mean that it is used for the protection of transmission lines. They are smaller in cross section, less in weight and cheaper in cost than the Station type.

4.3.5 Ratings and Characteristics of Lightning Arresters

Lightning Arresters are designated by:

- a) Rated voltage
- b) Rated frequency
- c) Rated current

In addition there are certain other characteristics which are required to be known to determine the protective value of a L.A. for proper selection and use. Thus the various terms connected with the same are described below.

4.3.6 Rated Voltage

It is the voltage to which the characteristics of the L.A. are referred. It is the designated maximum permissible R.M.S value of power frequency voltage which it can support across its line and earth terminals while still carrying out effectively and without damage, the automatic extinction of the follow up current. (The follow up current is explained in paragraph 4.3.4).

A lightning arrester is often called upon to operate for an earth fault elsewhere in the system. The voltage rating must therefore be higher than the sound phase to ground voltage as otherwise the arrester may draw too high a follow up current which may lead to thermal overloading and failure. To know the maximum voltage which can appear between healthy phase(s) and ground in the event of an earth fault on one phase, it is necessary to know the highest system voltage and the co-efficient of earthing. The system highest voltage has already been explained earlier in the handout on instrument transformers.

4.3.7 Co-efficient of Earthing

It is defined as the ratio of the highest R.M.S. voltage to earth of sound phase or phases at the point of application of an arrester during a line to earth fault (irrespective of the fault location) to the highest line to R.M.S. voltage expressed as a percentage of the latter voltage.

For the purpose of voltage ratings of a lightning arrester three types of earthing are defined.

a) **Effectively earthed system**

A system is said to be effectively earthed if under any fault condition, the line to earth voltage on the healthy phase(s) will not exceed 80% of the system line to line voltage.

The over voltage likely to appear on a system can be calculated by the method of symmetrical components. It has been determined that if the ratio R_0/X_1 is less than 1 and X_0/X_1 is less than 3, the voltage from line to earth on healthy phases, will not, in practice, exceed 80% of the line to line voltage. Here R_0 is the zero sequence resistance, X_0 the zero sequence reactance and X_1 is the positive sequence reactance of the system up to the point of installation of the lightning arrester.

For example, in a 132KV effectively earthed system for which the highest system voltage is 145KV, the voltage rating of the lightning arrester will be $145 \times 0.8 = 116\text{KV}$. However in practice a margin is allowed and 85% line voltage is selected i.e. (123KV L.A. for 132KV system).

b) **Non-Effectively Earthed System**

A system is said to be non-effectively earthed if the line to earth voltage on healthy phase, in case of an earth fault is more than 80% but does not exceed 100% of the line to line voltage. Systems with limited number of

solidly earthed neutrals or those earthed through resistors or reactors of low ohmic value fall in this category.

c) Isolated or Unearthed Neutral Systems

In such systems, the neutral is not grounded and line to earth voltage of a healthy phase may exceed 100% of line to line voltage in the event of a ground fault on one phase. Generally the voltage will not exceed 110% of the system voltage.

For systems at b) and c) above it is common practice to apply arresters rated at 105% of the highest system voltage.

4.3.8 Nominal Discharge Current

It is the discharge current having a designated crest value and wave shape which is used to classify an arrester with respect to durability and protective characteristics. These are generally at 1.5, 2.5, 5.0, 10, 15 and 20KA ratings. The wave shape specified is 8/20 microseconds in B.S.S. and in American/Continental specifications it is 10/20 microseconds. Ratings of 10KA and above are specified for system voltages of 66KV and above. Ratings of 5KA are for system voltages of 11KV and below. Field studies have indicated that 95% of the surges are within the 10KA range.

4.3.9 Rated frequency

This refers to the standard system frequency which is 50Hz in NEPA.

4.3.10 Power Frequency Spark-Over Voltage

It is not desirable that an arrester should spark-over frequently under internal over voltages of insufficient amplitude and thus endanger the installation. It is for this reason, a maximum spark-over voltage at power frequency is fixed, which as per B.S.S. is 1.6 times the rated voltage of the lightning arresters.

For example if an 80% L.A. is used, then it will not discharge for a system voltage equal to or less than 2.43 times the normal line to ground voltage as shown below:

$$\frac{1.6 \times (KV_r) \times 1.1 \times 0.8}{KV/\sqrt{3}} = 2.43$$

Where KV_r is the L.A. rated voltage

KV is system line to line voltage.

4.3.11 Maximum Impulse Spark-Over Voltage

The Maximum Impulse Spark-Over Voltage is the amplitude of 1/50 micro second voltage wave on which the arrester sparks over 5 times out of 5. This indicates that a lightning surge of the peak voltage of the L.A. will be discharged through it satisfactorily. Many specifications specify this voltage in their national standards. For example in BS 2914 it is 418KV peak for an 116KV rated L.A. at 10KA discharge current rating. It is generally 3.6 times the L.A. voltage rating.

4.3.12 Residual or Discharge Voltage

The Residual Voltage is the crest value of the voltage appearing between the terminals of a L.A. at the time of discharge of the surge current wave. Maximum discharge residual voltages are laid down in standard specifications and they are fixed for discharge currents of 5KA and 10KA. At higher discharge currents the increase in residual voltage is not proportional to the current due to the non linear characteristics of the resistor.

In most of the specifications this value is equal to the maximum Impulse Spark-over voltage.

4.3.13 Maximum Discharge Current

The maximum discharge current is the crest value of the discharge current which the L.A. can pass without damage or modification of its characteristics. This rating is referred to a wave of 5/10 micro seconds. For lightning arresters of the Station type, the test current is 100KA and for other types it is 65KA. This is also determined by the formula:

$$i_a = \frac{2e_i - e_a}{Z}$$

$$i_a = \text{Discharge Current}$$

$$e_i = \text{Voltage of a travelling wave}$$

$$e_a = \text{Residual voltage of the L.A.}$$

$$Z = \text{Surge impedance of the line}$$

(generally 400 ohms)

The value of e_i is determined by the line insulator string flash over characteristic.

4.3.14 Follow Current

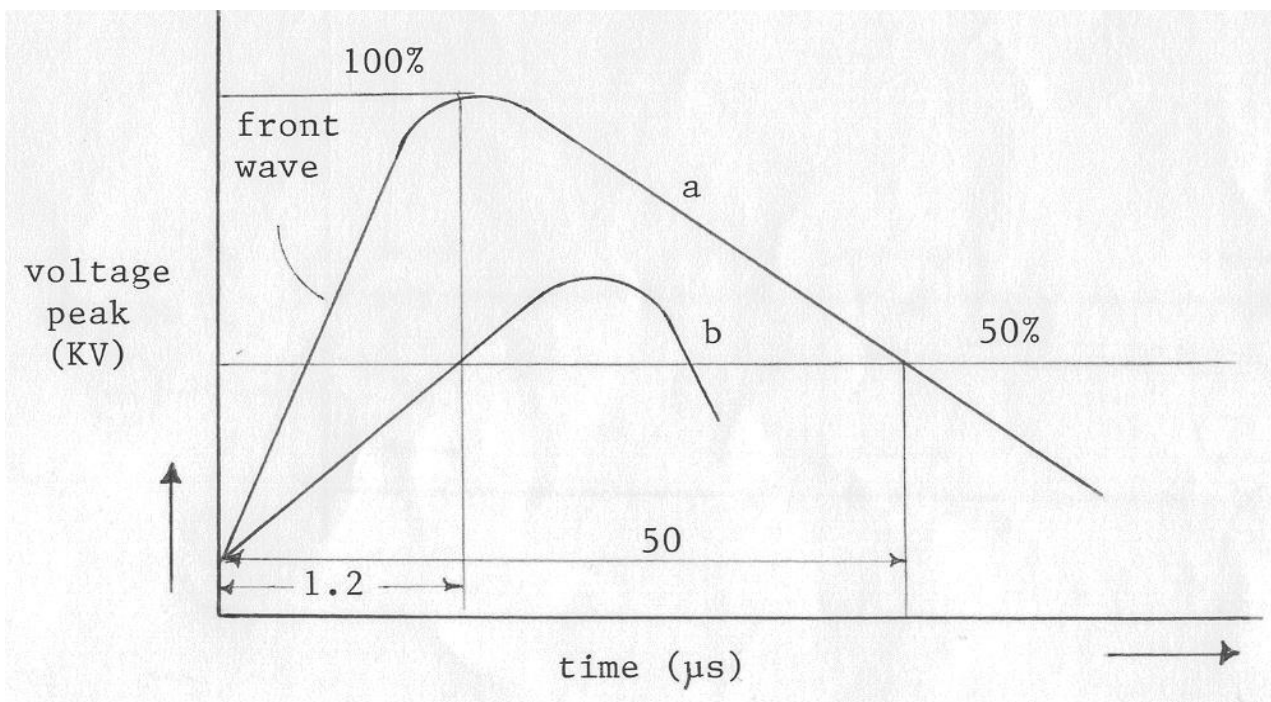
Arcing over of a L.A. under the effect of a surge causes a wave of current from the line towards the earth. The arc thus created sets up a shunt from the network to the earth and this shunt being of low impedance, a current of power frequency will flow. This current is called the Follow Current and must be interrupted as soon as is possible after the passage of the surge current. The amplitude of this current is decided by the network characteristics and by the impedance of the L.A.

4.3.15 Cut-off Voltage

It is the highest R.M.S. voltage at power frequency which the L.A. can withstand across its terminals, whilst still being capable of interrupting the follow current effectively and without damage.

4.3.16 Impulse Spark-over Volt-time Characteristics

This characteristic is plotted on the time abscissa that is the time which elapses between the moment the voltage wave is applied and the moment of the spark-over voltage. On the ordinate, the crest voltages at the moment of spark-over voltage occurring on the wave front and on the wave tail are plotted.



- a - Breakdown at wave front
- b - Breakdown at wave tail.

4.3.17 Front of Wave Spark-over Voltage

It is the value of the impulse voltage at the instant of spark-over of the L.A. on the wave front. A maximum specified in almost all national and international standards like IEC, BS, ANSI, NEMA, etc. is a value which is generally over 4 times the rated voltage of the L.A.

4.3.18 Front of Wave Steepness

The steepness of the wave front for the front of wave spark-over test is specified in all standards. A figure of 8.3KV per micro second per KV of arrester rating is considered as a representative value.

4.3.19 Protection Level of a Lightning Arrester

It is the crest value of the highest voltage appearing at the terminals of the L.A. in specific conditions of over-voltage and of discharge current

being carried out. Two values are considered for this, namely the impulse spark-over voltage and the residual voltage. Generally impulse spark-over voltage is less than the residual voltage although many standards have fixed these two voltage values to be the same and the level of protection is determined mostly by the value of the impulse spark-over voltage.

4.3.20 Protective Margin

The difference between the Basic Impulse Level or Basic Insulation Level (B.I.L) of the equipment to be protected and the protection level of a L.A. is called the "Protective Margin". A margin equal to 20% of the B.I.L is normally considered adequate when the L.A. is installed very close to the equipment in question.

4.3.21 Selection of Lightning Arresters

There are a few basic steps followed when a L.A. is to be selected for a particular installation. These are:

- i. The calculation of the maximum line to ground dynamic over-voltage to which the arrester may be subjected to for any condition of system operation.
- ii. The calculation of the maximum R.M.S line to ground voltage during a system fault.
- iii. To determine the ratio R_o/X_1 and X_o/X_1 at the point of installation and also the Co-efficient of Earthing. This is to decide the voltage rating of the L.A.

- iv. To make a tentative selection of the power frequency voltage rating of the arrester. This selection may have to be reconsidered after step (viii) is completed.
- v. To select the impulse current likely to be discharged through the arrester.
- vi. To determine the maximum arrester discharge voltage for the impulse current and type of arrester selected.
- vii. To establish the full wave impulse voltage withstand level of the equipment to be protected.
- viii. To make certain that the maximum arrester discharge voltage is below the full wave impulse withstand level of the equipment insulation to be protected by an adequate margin.
- ix. To establish the separation limit between the arrester and the equipment to be protected.

Items (i) to (viii) have already been discussed earlier except for item (ix); this will now be discussed.

4.3.22 Establishment of Separation Limit

When arresters must be separated physically from equipment, additional voltage components are introduced, which add instant by instant to the arrester discharge voltage. A travelling wave entering a substation is limited in magnitude at the arrester location, to the discharge voltage of the arrester. However a wave with the same rate of rise of voltage as the original wave and with a magnitude equal to the discharge voltage of the

arrester travels to the substation. It is reflected back at almost twice its value if the line dead ends or terminates at a transformer. This reflected wave travels back to the L.A. and a negative reflected wave travels from the L.A. back to the transformer. The maximum voltage at the terminals of a line or a transformer beyond a L.A. as a first reflection of the travelling wave is expressed mathematically as follows:

$$E_t = e_a + 2 \frac{de}{dt} \times \frac{L}{1000}$$

Where e_a = arrester discharge voltage, $\frac{de}{dt}$
rate of rise of wave front in KV per micro second

L = distance between L.A. and line terminal in feet.

Normally the rate of voltage wave front is taken as 500KV per microsecond and with this the voltage added would be 1KV for every foot of distance between the L.A. and the equipment protected. An approximate rule of thumb for the location of a L.A is:

$$\text{Maximum distance in feet} = \frac{\text{Nominal system voltage in KV}}{2}$$

For arresters located close to within 30ft of a transformer, the protection level is given by:

$$1.15 \times \text{Residual Voltage} + 30.$$

4.3.23 An example on selection of a L.A. for a 132 KV system

$$\text{Nominal voltage} = 132\text{KV}$$

$$\text{Highest system voltage} = 145\text{KV}$$

System is effectively grounded

$$\text{With 80\% rating; rating of L.A.} = 145 \times 0.80 = 116\text{KV}$$

$$\text{With 85\% rating; rating of L.A.} = 145 \times 0.85 = 123.25\text{KV}$$

Select voltage rating at 123KV or at 116KV as both are recommended values of L.A. voltage rating in B.S.S.

$$\begin{aligned}\text{Residual voltage of a 123KV L.A.} &= 123 \times 3.6 = 442.8 \\ &= 443 \text{ KV peak}\end{aligned}$$

$$\begin{aligned}\text{Power frequency spark-over voltage} &= 123 \times 1.6 = 196.8 \\ &= 197 \text{ KV (R.M.S.)}\end{aligned}$$

For a 132 KV system with 9 units in suspension and 10 units at tension and from a volt-time curve it is 860 KV for string flash over.

$$\begin{aligned}\text{Discharge current} &= \frac{2(860) - 443}{400} \\ &= 3.1925 \text{ KA}\end{aligned}$$

Hence we can select either 5 KA or 10 KA discharge current. It is always better to select for systems above 66KV, a discharge current of 10KA.

$$\text{Discharge current selected} = 10\text{KA}$$

Protection level if the L.A. is located within 30 feet of the transformer is given by:

$$1.15 \times 443 + 30 = 539 \text{ KV peak}$$

$$\begin{aligned} \text{Impulse spark over voltage} &= 123 \times 3.6 \\ &= 443 \text{ KV peak.} \end{aligned}$$

A protective margin of 15% for switching over-voltages and 25% for lightning over-voltages is adopted.

Protection level for lightning and switching surges will be:

$$\begin{aligned} &= 443 \times 1.25 \\ &= 553.75 \text{ KV peak} \end{aligned}$$

Thus the 123 KV L.A. will protect a transformer if the B.I.L of the transformer is greater than 553.75 KV. The nearest B.I.L for 132 KV to correspond to 553.75KV is 650KV.

$$\text{Protective margin} = \frac{650}{553.75} = 1.17$$

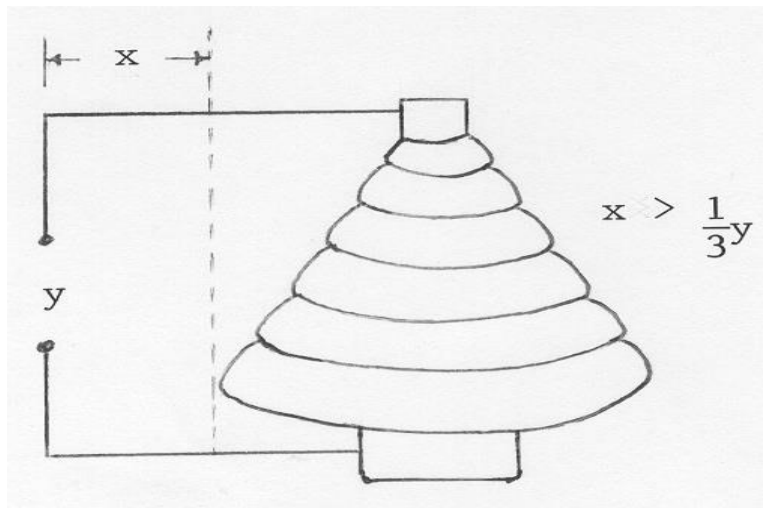
That is 117% for switching and lightning and for temporary over-voltages

4.4 Rod Gaps

This type of protective device is simple and robust. It does not; however fulfill the requirements of a true protective device as it does not cut off the power voltage after it has been flashed over by a surge. This would mean a short circuit on the system every time a surge causes a flash over across the rod gap.

Rod gaps are generally mounted on:

- a) Transformer bushings
- b) Circuit breakers
- c) Isolators
- d) Bus-bar insulators
- e) Line insulator strings.



Rod gaps are used as a sort of back up protection to L.As and are also referred to as Spark gaps or Coordinating gaps. Such gaps for co-ordination are normally set to have an impulse flash over voltage of 80% of the impulse voltage withstand level or B.I.L of the transformer. The withstand voltage of the gap must be higher than the protection level of the L.A. For very steep fronted waves, the gaps will not provide adequate protection. On the other hand, if the gaps are set to provide protection for these waves, their minimum spark-over voltages will be too low and there may be outages even for normal switching over-voltages and minor

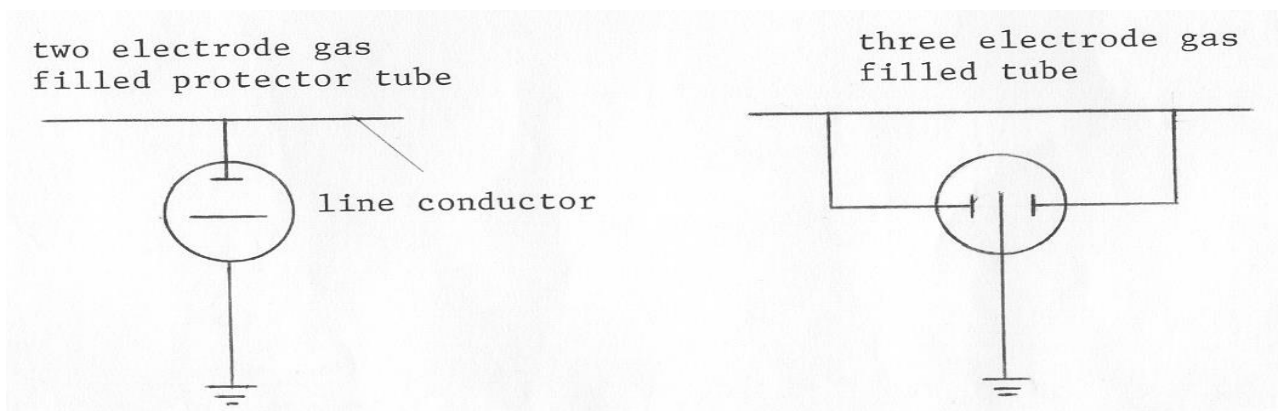
lightning surges. The practical gap setting is therefore a compromise. The distance between the gap and the insulator should also be not less than about one third of the gap length in order to prevent the arc from being blown on to the insulator.

The gaps on line and bus-bar insulator strings are used for the following in addition to what has been mentioned earlier

- a) To equalize the potential gradient over the string and to produce a more uniform field.
- b) To provide an alternative path for flash-overs to avoid damage to insulator strings.

4.5 Protector tubes

These are gas filled tubes with two or three electrodes, one of which is connected to the ground. The gas is a rare gas such as Neon, Argon, etc. They are connected between the line and ground in case of a two electrode gas tube or shunted across a line in case of a three electrode tube as shown:

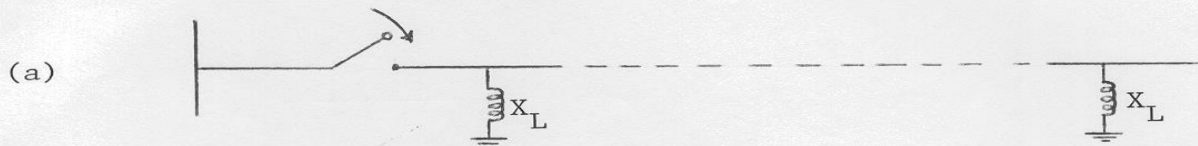


When a voltage surge arrives, the gas conducts between the electrodes to the ground. These protector tubes are used mostly in the surge protection of telecommunication circuits and occasionally in L.V. or medium voltage distribution circuits.

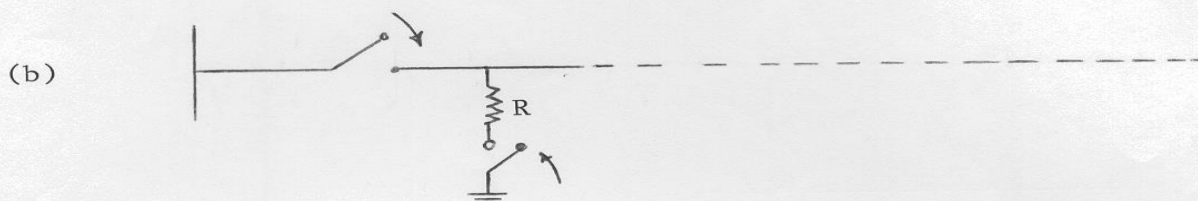
4.6 Insertion of Linear or Non-Linear Shunt Reactors and Insertion of Resistors at Circuit Breakers

These methods are employed only in E.H.V systems (above 220KV) to reduce temporary over-voltages and switching over-voltages to an acceptable level as can be handled by L.As and the B.I.L of the protected equipment with an adequate protective margin.

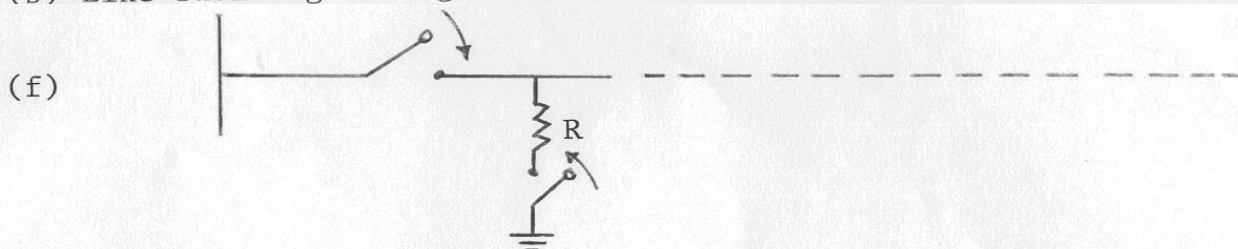
The methods employed are as follows:



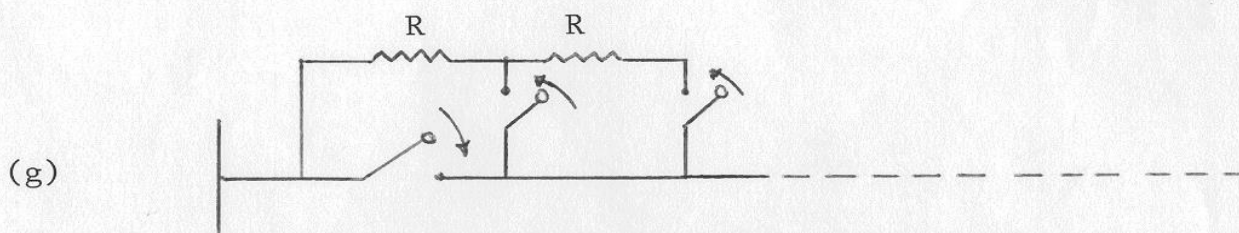
(a) High voltage reactors connected to the line to reduce power frequency overvoltage.



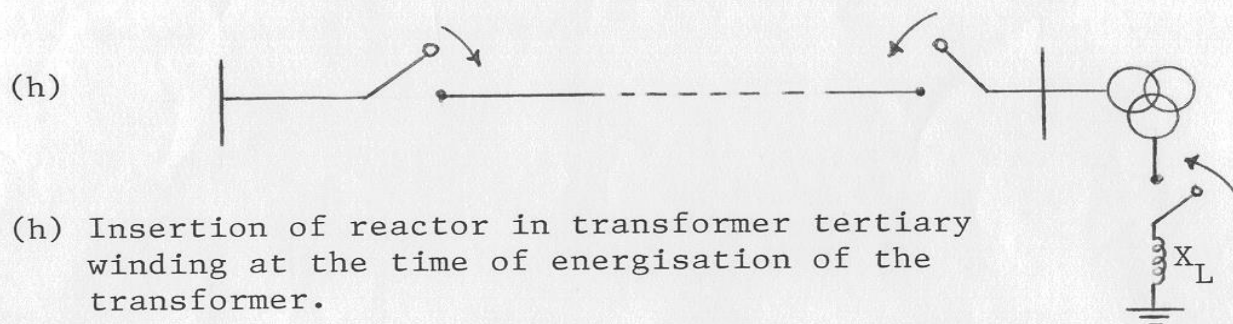
(b) Line shunting through resistor after line opening to



(f) Insertion of resistors in shunt during line opening.



(g) Multi-step insertion of resistors during line closing.



(h) Insertion of reactor in transformer tertiary winding at the time of energisation of the transformer.

(e) Insertion of resistors in series

One or all of the above methods are employed to reduce the over-voltage factor due to switching to less than 2.0 and the temporary over-voltage factor to less than 1.5. The most common method employed is the insertion of reactors as shown in (a) and (h)

5.0 Tests on L.As

The following tests are prescribed for L.As in almost all of the national and international specifications.

- a) Type tests
- b) Sample tests
- c) Routine tests

5.1 Type Tests

- (i) 1/50 Impulse Spark-over test
- (ii) Wave Front Impulse Spark-over test
- (iii) Peak discharge residual voltage at low current
- (iv) Peak discharge residual voltage at rated diverter current.
- (v) Operating duty cycle
- (vi) Impulse current withstand test

5.2 Sample tests

- (i) Temperature cycle test on porcelain housing
- (ii) Tests for galvanization on exposed metal parts

5.3 Routine tests

- (i) Peak discharge residual voltage at low current

- (ii) Dry power frequency spark-over test
- (iii) Leakage current test.

CHAPTER THIRTEEN

FUSES AND FUSE CO-ORDINATION

1.0 FUSES

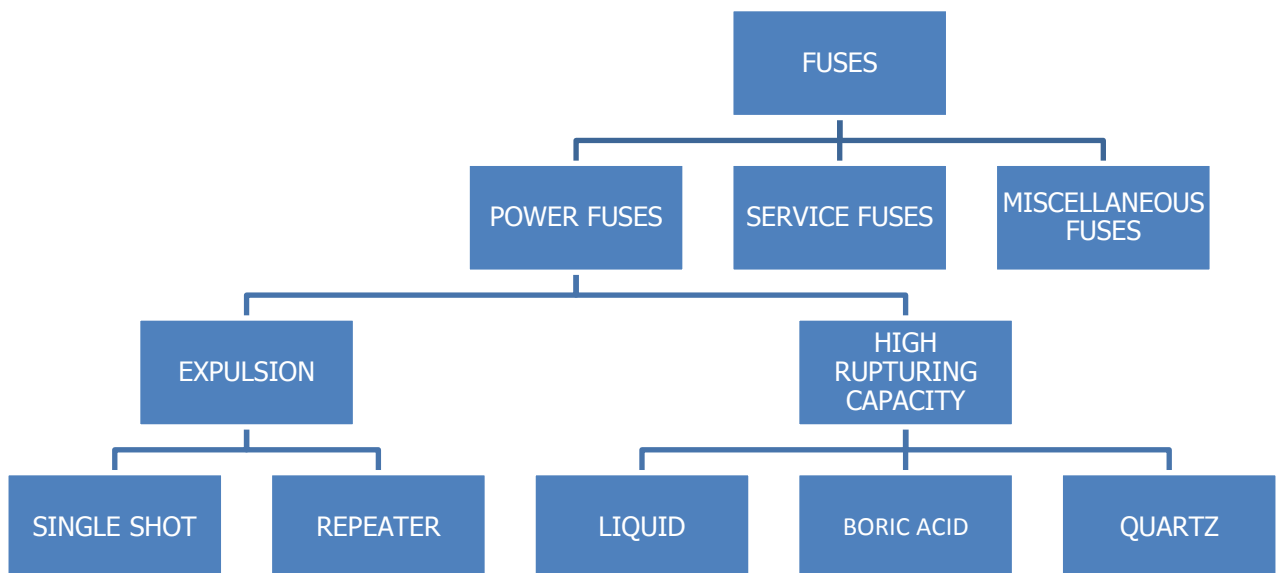
1.1 Introduction

Fuses are used in electric power systems, devices or equipment for the protection of circuits.

It is defined as an over-current device with a circuit opening component heated and destroyed by 'excessive' current passing through it. The fuse should be able to carry normal current continuously - subject to its nominal rating - without deterioration and when subjected to excessive current, it should open the circuit reliably and quickly.

1.2 Types of Fuses

There are many types of fuses in use; they are normally classified according to their application as illustrated in the figure below.



The focus in this lecture is on Power Fuses which find application in NEPA power system network.

1.3 Power Fuses

Power fuses consist of three major components:

- a) Fuse Mounting or Support
- b) Fuse Holder
- c) Fuse Link

1.31 The Fuse Mounting

It is used to terminate the conductors and hold the Fuse Holder. The Mounting consists of a base on which is mounted two insulators of the correct voltage rating. The jaw into which the fuse holder fits is mounted on one insulator. The hinge is mounted on the other. The size and design of the jaws are primarily dependent on the normal current carrying capacity rating of the fuse. The distance between the two insulators is a function of the voltage rating of the fuse.

1.32 Fuse Holder

A Fuse Holder is an assembly of a fuse tube together with the parts required to enclose and provide means of making contact between the link and the fuse clips. The Holder usually consists of a tube made of fibre, porcelain or glass with conducting ferrules on each end and with means to connect the link to the ferrules. The tube may be empty or filled with a liquid or a solid.

The ability to interrupt large current safely is dependent on the design of the Holder.

1.33 Fuse Link

Fuse links abound in different forms depending on the design. The type of link used in the Fuse Holder described above consists of two current carrying conductors connected together by a current responsive element. This element consists of a metal alloy with a low melting temperature. When the current carried by the fuse exceeds a predetermined value, the element melts to break the circuits. The more current carried by the element, the faster it melts.

The time required to melt the fusible link depends on:

- a) The magnitude of the current.
- b) The electrical properties of the fusible element.

The time required to melt the fuse is referred to as the **MELTING TIME**.

When the element separates into two places, an arc tends to be formed which is extinguished very quickly. The time taken to do this is known as

ARCING TIME.

TOTAL CLEARING TIME is the sum of the melting time and the arcing time.

Melting time $t \propto \frac{1}{i^2}$ where: i - the current

Values of melting time for fuse of the same type and various current ratings are plotted on log-log paper. These values must be known for the fuses to enable the user obtain co-ordination.

Fuse links are divided into two types:

- 1) Fast operating link (K type)
- 2) Slow operating link (T type)

1.4 Expulsion Fuse

This is one classification of Power Fuses which is commonly used in power system distribution networks. There are two types of Expulsion Fuses. We have the **DROP-OUT** and **NON DROP-OUT** types. The former has its fuse Holder kept closed by a positive latch. When the link blows, the latch collapses and the holder drops out.

The Non Drop-out type of fuse has its two ends fixed to the fuse Mounting.

2.0 FUSE CO-ORDINATION

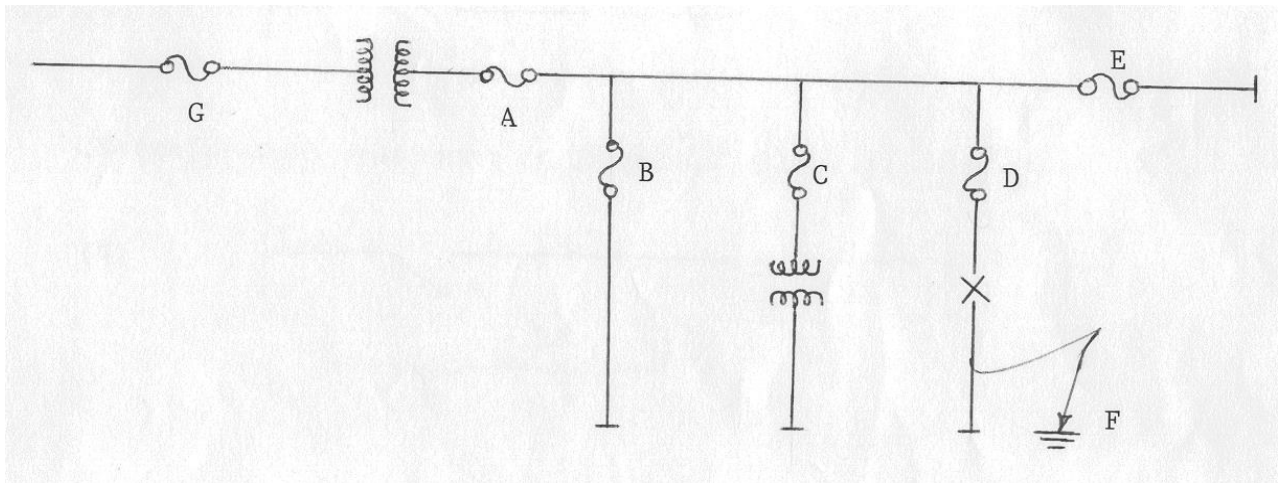
2.1 Introduction

In any electricity supply agency such as NEPA, power and distribution fuses are used primarily for protection against short circuits on lines or faults in equipment. The object is to remove faulted equipment from service reliably and as fast as is necessary to prevent damage while also ensuring system security. Much in the same fashion as in Relay Co-

ordination, circuits and equipment must be studied first for proper fuse selection and co-ordination.

2.2 Illustration

Let us consider a simple distribution system of the form given below.



First, a study must be made of the system being protected. A single line diagram is made and values of fault current calculated for each point where fuses are located as well as the load expected at each of these points.

The values of fault current and load current are calculated for points G, A, B, C, D and E as well as the fault current at the end of all the branch circuits.

Suppose a fault occurs at point F; for proper co-ordination, the fuse at D should blow before the fuse at A or G is damaged. Fuse D is referred to

as the protecting link as far as the branch D is concerned and A is called the protected link. Similarly, for a fault occurring between A and B, fuse A is the protecting link and fuse G the protected link.

2.3 Method of Determining Coordinated Fusing

After the short circuit values and load values at the various points on the foregoing diagram have been arrived at, pre-determined fuse curve tables are consulted. The remote end fuses are established first, and then the links calculated from the end of the line to the transformer in logical sequence. In calculating for these links, the following concepts should be noted:

1) Minimum Melting Time

Most manufacturers do supply time current curves of their fuse links showing the minimum melting time of their links without taking into account several operating conditions. Improved versions of these curves are now readily available; they are referred to as **FUSE LINK DAMAGE CURVES**. These take into account such variables as pre-loading, ambient temperature and surge capacity.

2) Total Clearing Time

The total clearing time curves are made up of three components, viz:

- a) Manufacturer's minimum melting time current curves.
- b) Manufacturer's tolerance allowance curve.
- c) Manufacturer's arcing time allowance curve

Having obtained these curves, the various points to be coordinated are studied.

CHAPTER 14

REDUCING FORCED OUTAGES

LEARNING OUTCOMES

- Know the key contributors to Reducing Forced or Unplanned Outages
- Understand the importance of systematic outage recording
- Understand the importance of Analysis of relevant Accumulated Data
- Understand the importance of correctly identifying the damaged equipment
- Understand the importance of applying appropriate countermeasures in exogenous and endogenous cases
- Know some typical countermeasures for identified root causes.
- Know the Key tasks that reduce outage duration

Reduction of the amount of forced outage is composed of **“reduction of the frequency of outage incidents”** and **“reduction of outage duration per one outage incident”**.

Reduction of the frequency of outage incidents

In order to reduce the frequency of outage incidents, it is necessary and important to “record the data of outage incidents properly”, to “analyze the accumulated data”, to “plan and undertake the appropriate countermeasures”, and to “verify the countermeasure effectiveness”.

1. Proper recording of the data of outage incidents

(1) Detecting the outage incident

Information such as the time it occurred and the feeder protective relay that worked has to be delivered as soon as possible from operator in substation to operator in dispatch center of DisCos.

It is also important for DisCos to detect outage incidents by internal cooperation of the DisCos departments. This will include customer care units, because sometimes outage incidents can occur without any work of relays at substation and in such cases the report from customers is the only way for DisCos to notice the outage incident.

(2) Items that have to be recorded

Items that have to be recorded includes the following, but is not limited thereto.

- Date and time of outage
- Date and time of full restoration
- Relay that worked
- Number of customers affected
- Converted duration
- Damaged equipment that became the fault point, and its manufacturer, model number, manufacture year, and so on
- Root cause
- Location of the fault point and its geographical characteristic
- Weather condition
- Other and remarks

(3) System used for outage recording

In order to record the things above efficiently, it is better to use a pre-programmed system i.e., a computer application (software), than to use media like paper. The use of a computer application for the analysis is also recommended and will be mentioned afterwards. The system should have the function to output the data into a spreadsheet like Excel. Especially, damaged equipment or root cause are crucial information. **For an efficient analysis, such items should be input from drop list, not from a free description form, otherwise it will be very difficult to implement an efficient analysis.**

In the future, it is desirable that sensors that detect the status of CB and communication line between substation and offices will let the office detect the outage, and outage data to a certain extent will input to the system automatically.

2. Analysis of the accumulated data

(1) Analysis from the perspective of “equipment”

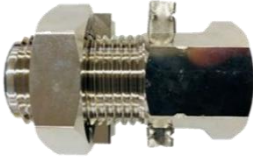
It is necessary and important to identify what the frequently-damaged (i.e. becoming the fault point frequently) equipment is, and to plan and undertake the appropriate countermeasures.

(2) Analysis from the perspective of “root cause”

It is also necessary and important to identify what the most frequent root cause(s) is (are), and to plan and undertake the appropriate countermeasures.

3. Appropriate countermeasures

Generally, root causes are classified roughly into **exogenous** and **endogenous** ones. Exogenous causes include natural disasters and objects touching the distribution equipment, which are difficult to control. However, DisCos have to make the effort to prevent exogenous causes by preplanned trimming of vegetation, or installing instruments that prevent things from touching the distribution equipment. Endogenous causes include aging of distribution equipment. The main countermeasure for that is replacement, but in order to advance the replacement efficiently, it is important to analyze the tendency of: the manufacturer, the model number, the year of manufacture, and so on for trends relating to aged, damaged, and deteriorated equipment.

	Root cause	Example of countermeasure
Conductor	Break due to the aging	Replacement
Conductor		Use of bolt-type (split-bolt connector) connector or compression connector 
Transformer	Burnout due to an overload	Decentralization of load by installing additional transformers
Conductor	Vegetation touching the conductor	
		 Installing insulated conductor

Here are some typical examples of the countermeasures for the combination of the damaged equipment and the root cause.

Here are some typical examples of the countermeasures for the combination of the damaged equipment and the root cause.

Conductor	Birds and their nest touching the conductor	Instruments that preventing birds from perching on the conductor or from making nest on the distribution facility
		
		Patrolling to find the nests and removing them beforehand
Conductor and equipment	Thunder and lightning	Installing additional ground wire and lightning arrester
Equipment	Aging	Observe carefully the tendency of damaged equipment. If some specific manufacturer, model number, or manufacture year tend to give the frequent malfunction on the equipment, the total amount of the equipment to be replaced should be grasped, and preplanned replacement should be executed.

Replacement work is done by contractors; therefore, such works have to be planned together with requesting the budget and when it will be executed.

4. Verification of the effectiveness of the countermeasure

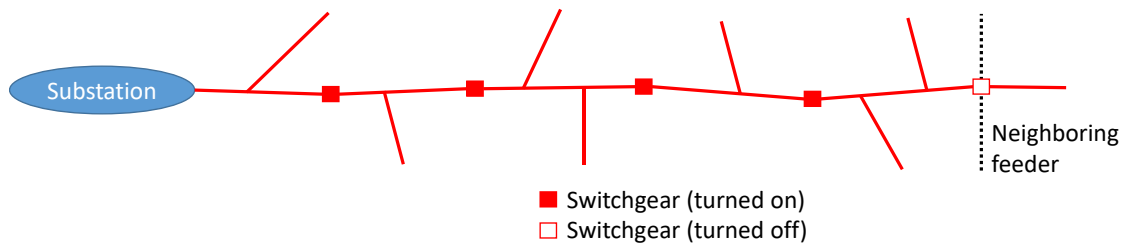
As the result of the countermeasure, it is necessary to verify the frequency of outage incidents decreased or not. If there is no decrease in outage incidents, alternative countermeasures have to be considered.

Reduction of outage duration per one outage incident

In order to reduce outage duration, it is necessary and important to “energize the healthy section as early as possible”, and to “restore the faulty point as early as possible”.

1. Energizing the healthy section as early as possible

In order to energize the healthy section as early as possible, what is most important is to identify and isolate the faulted section as early as possible. To establish this, the feeder should be divided into some sections (see the sample figure below) so that fault detection work can be done efficiently. **It is advisable that switchgear dividing the feeder into some sections are able to cut off the load.**

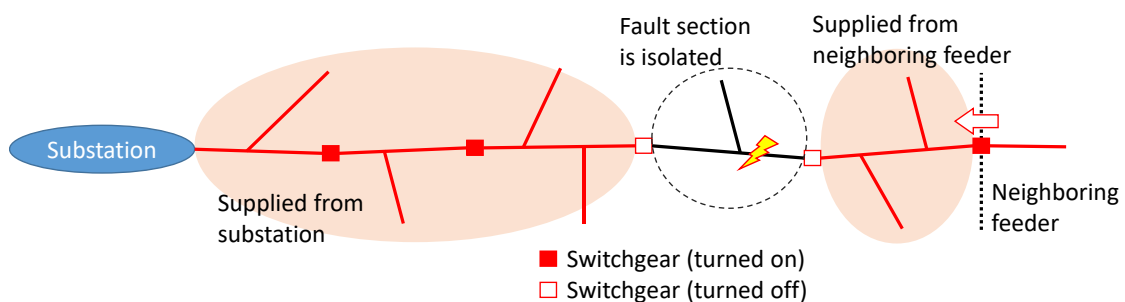


Normally Open Position

The healthy section in “source-side” of the fault section can be supplied from the substation, however the healthy section in “load-side” of the fault section cannot be supplied from the substation. In such cases, the load-side section is to be supplied from the other feeders surrounding the fault feeder. **Thus, for reduction of outage duration per one outage incident, supply from surrounding feeders is the major condition to be taken into account when the distribution grids are configured, and switchgears for that purpose are also needed.**

Example.

Assume that the 4th section was identified as the fault section, and isolated by the 2 switchgears that are turned off. The 1st, 2nd, and 3rd sections are in source-side of the fault section, therefore they are supplied from the substation. On the other hand the 5th section is in load-side of the fault section, therefore it will be supplied from the neighboring feeder, by turning on the switchgear between those 2 feeders which is usually turned off.



In some countries “Distribution Automation System” (DAS) can automatically detect

the fault section and supplies the healthy sections, but both the initial and running cost for DAS are very high.

2. Restoring the faulty point as early as possible

It is important to train those who are engaged in restoration work regularly, maintaining and improving their restoration skills.

Other

- If anyone found and established the effective method for the reduction of the frequency of outage incidents or the reduction of outage duration per one outage incident, such sample cases should be actively rolled out and shared by everyone involved. For that purpose, it is advisable that offices from many areas have chance to gather regularly, share the good examples, and propose the better method.

SUMMARY

- The driving objective of reducing forced outages is quick service restoration, and maximizing the number of customers restored
- A systematic method of properly recording outage incidents is helpful for analysing accumulated outage data, planning and implementing countermeasures and verifying the effectiveness of countermeasures

DESCRIPTIONS

Analysis The process of studying a system by partitioning the system into parts (functions, components, or objects) and determining how the parts relate to each other. (Institute Of Electrical And Electronics Engineers, 2000, p. 36)

Compression connectors these are connectors that are attached to conductors with the use of compression tools and dies. They are chosen when conductivity and secureness of conductor performance requirements are high. (Gryska, 2013)

Computer Application (software) (1) The use to which a computer system is put; for example, a payroll application, an airline application, or a network application. (2) The use of capabilities provided by an information system specific to the satisfaction of a set of user requirements. Note: These capabilities include hardware, software, and data. (4) A software program consisting of one or more processes and supporting functions. (Institute Of Electrical And Electronics Engineers, 2000, p. 46)

Converted Duration This is a Reliability Key Performance Index (KPI) used to measure the effort taken by DisCos towards the restoration of healthy sections of a feeder before

complete restoration of the whole feeder after an outage on the feeder

Countermeasures Corrective actions

DAS (Distribution Automation System) This is a part of the Distribution Management System and it includes all SCADA-related remote monitoring and control actions. DAS includes the automation spread over entire distribution systems from substation to feeder to customer and the communication infrastructure for implementation of the functions. DAS provides real-time monitoring and control functionalities for the downstream network. (Thomas & John Douglas McDonald, 2017, p. 216)

DisCos Distribution Companies

Energize (1) (conductor stringing equipment) (power line maintenance) Electrically connect to a source of potential difference, or make electrically charged so as to have a potential which is different from that of the ground. Synonyms: make alive; make hot; make live. (Institute Of Electrical And Electronics Engineers, 2000, p. 381)

Feeder A cable or set of conductors that originates at a main distribution center (main switchboard) and supplying secondary distribution centers, transformers, or motor control centers. (Institute Of Electrical And Electronics Engineers, 2000, p. 422)

Forced Outage An outage that results from conditions directly associated with a component requiring that it be taken out of service immediately, either automatically or as soon as switching operations can be performed, or an outage caused by improper operation of equipment or human error. *Notes:* 1. This definition derives from transmission and distribution applications and does not necessarily apply to generation outages. *Notes:* 2. The key test to determine if an outage should be classified as forced or scheduled is as follows. If it is possible to defer the outage when such deferment is desirable, the outage is a scheduled outage; otherwise, the outage is a forced outage. Deferring an outage may be desirable, for example, to prevent overload of facilities or an interruption of service to consumers. (Institute Of Electrical And Electronics Engineers, 2000, p. 449)

Geographical characteristics: Assessment of the quantity, spatial distribution, and ecological characteristics of land cover types, categorized into agroecological zones and analyzed through the use of a geographical information system (GIS). (Etter, 2016) Etter, H. (2016). Land Degradation: An Economic Perspective. *Land Restoration*, 311–317. <https://doi.org/10.1016/b978-0-12-801231-4.00024-0>

Grid Network, usually of a power company, for transmitting and distributing electric power. (Institute Of Electrical And Electronics Engineers, 2000, p. 488)

Initial Cost Initial cost means the asset's purchase price plus any costs directly attributable to bringing the asset to the location and condition necessary for it to be

capable of use in the manner intended.

Interruption The loss of service to one or more customers. *Note:* It is the result of one or more component outages, depending on system configuration. (Institute Of Electrical And Electronics Engineers, 2000, p. 584)

Isolate Make Physically separate, electrically and mechanically, from all sources of electrical energy. *Such separation may not eliminate the effects of electrical induction.* (Institute Of Electrical And Electronics Engineers, 2000, p. 591)

Outage Duration The period from the initiation of an outage until the affected component once again becomes available to perform its intended function. *Note:* Outage durations may be defined for specific types of outages; for example, permanent forced outage duration, transient forced outage duration, and scheduled outage duration. (Institute Of Electrical And Electronics Engineers, 2000, p. 776)

Outage The state of a component or system when it is not available to properly perform its intended function due to some event directly associated with that component or system. *Notes:* 1. An outage may or may not cause an interruption of service to consumers, depending on system configuration. 2. This definition derives from transmission and distribution applications and does not necessarily apply to generation outages. (Institute Of Electrical And Electronics Engineers, 2000, p. 776)

Protective Relay A device whose function is to detect defective lines or apparatus or other power system conditions of an abnormal or dangerous nature and to initiate appropriate control action (Institute Of Electrical And Electronics Engineers, 2000, p. 882)

Root Cause The underlying or physical cause of problem /failure (Institute Of Electrical And Electronics Engineers, 2000, p. 990)

Running Cost Money that needs to be spent regularly to keep a system operational.

Substation: a general term for a facility that can serve a wide variety of critical roles on the power grid. Those roles depend on which parts of the electrical grid are being connected together and the types, number, and reliability requirements of the eventual customers downstream. Examples of substation roles are: switching, protection, load shedding, monitoring, metering, provision of a safe environment to inspect, repair and replace equipment. (Hillhouse, 2019)

Switchgear A general term covering switching and interrupting devices and their combination with associated control, instrumentation, metering, protective and regulating devices, also assemblies of these devices with associated interconnections, accessories and supporting structures used primarily in connection with the generation, transmission, distribution, and conversion of electric power. (Institute Of Electrical And Electronics Engineers, 2000, p. 1135)

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Further Learning

DIGITAL DEVICES FOR PATROL WORK

Utilizing digital devices is a good method to streamline the maintenance work (patrol). This method works well when the Network is properly mapped out in a standardized format. This aids in pre-planning and prioritization of the maintenance work. Using Digital Devices also works well when the processes involved in gathering data from maintenance work are well organized and clearly delineated. In other words, processes for assigning and documenting the maintenance work using pre-defined viewpoints must be foolproof before they are converted for use on digital devices.

Digital Devices are very useful for speeding up work and for training new employees. For example, a digital device can upload a large amount of the patrol result to the maintenance management system and create the work slip automatically. Additionally, the recorded Data can be easily recalled for analysis and also, it can be used in training scenarios.

Patrol crews with experience in the use of these devices work smarter and faster with the aid of these devices. If such devices are not present in the workflow of the maintenance crews, the maintenance work is done and recorded manually, takes a lot of time, and is less efficient.



CHAPTER FIFTEEN

STABILITY, RECLOSING AND LOAD SHEDDING

POWER SYSTEM FREQUENCY CONTROL

1.0 INTRODUCTION

The quality of electric power supply is defined in terms of permissible variation in the statutory requirements of frequency ($\pm 1\%$) and voltage ($\pm 6\%$). System instability has a direct effect on the quality and security of supply; as such, it is of interest to the protection engineer. This chapter, therefore, aims at examining the phenomenon vis-a-vis the associated protection in an inter-connected system such as ours.

1.1 System Instability/Frequency Control

Any large inter-connected power system is composed of several generators synchronously connected. A perfect real or active power balance (active generation = active demand including losses) ensures constant speed and frequency of operation. Unfortunately, the load impressed on the system does fluctuate; more so in a random fashion. Thus, it is virtually impossible to accomplish equilibrium of active generation and active demand. An excess or deficiency in active generation will always be present. This mismatch normally results in frequency fluctuation.

If active generation, $P_G >$ system demand including losses, machines in the system will increase in speed and frequency will rise. On the other

hand, if active generation, $P_G < \text{system demand including losses}$, machines will decelerate and frequency will fall. A nominal frequency of 50Hz is obtained when active power generation in the system equals the total demand including losses.

In practice, this is achieved by manual load shedding/generation scheduling or by the appropriate application of frequency relays.

1.2 Interconnected Power System

System response following an instantaneous loss of generation is a function of many factors; such as stored energy, governor action, system voltage, spare capacity and demand response to frequency and voltage.

The change in active power for a given change in frequency in an interconnected system is known as the STIFFNESS in the system. Thus, the smaller the changes in frequency for a given load, the stiffer or more stable the system.

Assume a system operating at steady state, i.e.

$$P_G = P_D$$

$$\text{Where } P_G = \text{generation}$$

$$P_D = \text{demand}$$

Let there be an increase in demand, dP_D followed by an increase in generation, dP_G . Then the out of balance power, dP is given by:

$$dP = dP_G - dP_D$$

dP affects the system in three ways namely:

- a) Changing the energy potential of the generators
- b) Changing the load demand
- c) Changing the export of power via the tie lines.

System stiffness is defined by:

$$K = \frac{dP}{df} = \frac{dP_G}{df} - \frac{dP_D}{df}$$

The unit of K is MW/Hz.

Power generation, $P_G = f(P_T)$; where P_T is the turbine input power.

Hence, K may be re-defined as

$$K = K_1 P_T - K_2 P_D = \text{Stiffness.}$$

K_1 and K_2 are coefficients associated with the turbine and load respectively.

Quite often K_1 and K_2 are taken as being approximately equal to 0.8 and 0.6 respectively.

Where $2500 \leq K \leq 10000$ MW/Hz depending on the system load.

Considering the two limits of stiffness K, a loss of 500 MW will lead to frequency change of:

$$\frac{500\text{MW}}{2500\text{MW/HZ}} = 0.2 \text{ Hz at light load}$$

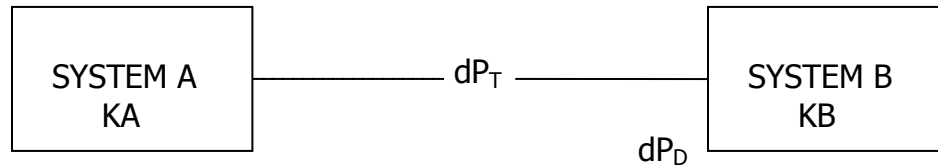
$$\frac{500\text{MW}}{10000\text{MW/HZ}} = 0.05 \text{ Hz at heavy load}$$

The stiffness figures reveal the importance of having spare capacity running (or otherwise) immediately available to offset the frequency change. The response of the units involved is also important in controlling the frequency. In small power systems, the change in frequency for a reasonable load change is relatively large; as such, control measures must be introduced to improve the power frequency (P-f) characteristics.

1.3 Illustrations/Case Study

Consider two separate systems A and B. Power is transferred from A to B.

An extra load in B - dP_D , causes an extra input dP_T from system A.



Drop in system A frequency due to extra input, dP_T

$$= - \frac{dP_T}{K_A} \text{ Hz}$$

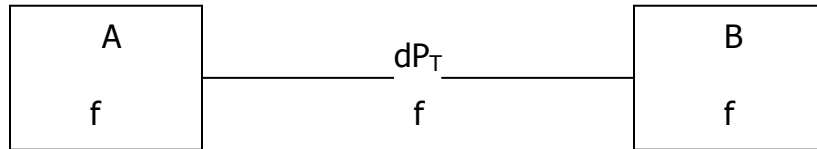
Drop in system B frequency due to extra load dP_D and extra input dP_T

$$= - \frac{(dP_D - dP_T)}{K_B}$$

$$\frac{dP_T}{K_A} = \frac{dP_D - dP_T}{K_B}$$

$$\text{or } dP_T = \frac{(K_A) dP_D}{K_A + K_B}$$

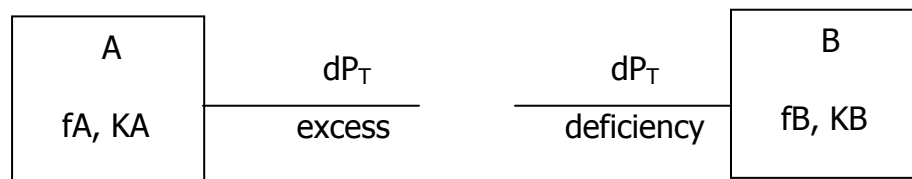
Suppose A and B are operating at a common frequency f with A exporting power (dP_T) to B.



Consider the link (or tie-line) between A and B broken.

System A will have excess generation corresponding to dP_T . Therefore frequency in A will rise.

System B will have extra load corresponding to dP_T . Therefore frequency in B will fall.



$$f_A = f + \frac{dP_T}{K_A}$$

$$f_B = f - \frac{dP_T}{K_B}$$

$$f_A - f_B = \frac{dP_T}{K_A} + \frac{dP_T}{K_B}$$

$$\text{OR } \frac{dP_T}{f_A - f_B} = \frac{K_A K_B}{K_A + K_B}$$

Hence, opening the tie line and measuring the resultant changes in frequency in the two systems f_A and f_B , the values of K_A and K_B may be obtained.

Problem

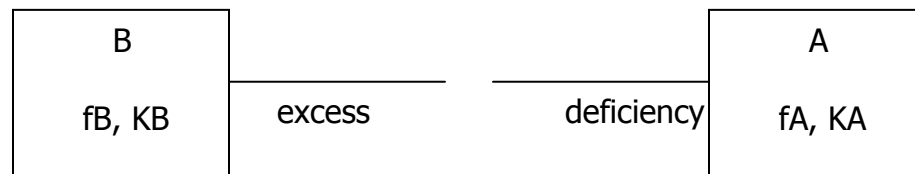
Two power systems A and B are inter-connected by a tie line and have P-f constants K_A and K_B . An increase in load of 500MW on system A causes a power transfer of 300MW from B to A. When the tie line is open, the frequency of system A is 49Hz and of system B is 50 Hz.

Determine the values of K_A and K_B .

Solution

$$f_A = 49\text{Hz}$$

$$f_B = 50\text{Hz}$$



$$f_A = f - \frac{dP_T}{K_A}$$

$$49 = 50 - \frac{500}{K_A}$$

$$49 K_A = 50 K_A - 500$$

$$50 K_A - 49 K_A = 500$$

$$K_A = 500 \text{ MW/Hz}$$

$$\frac{dP_T}{f_B - f_A} = \frac{K_A K_B}{K_A + K_B} \quad \text{established}$$

$$\frac{300}{50 - 49} = \frac{500 K_B}{500 + K_B}$$

$$300 = \frac{500 K_B}{500 + K_B}$$

$$150000 + 300 K_B = 500 K_B$$

$$200 K_B = 15 \times 10^4$$

$$2 K_B = 1500$$

$$K_B = 750 \text{ MW/Hz}$$

1.4 Load Shedding and Under Frequency Relay

Load shedding is the attempt to match load to the available generation after a disturbance that has left a deficiency in the generation relative to the connected loads.

It is carried out either manually by system operation personnel or by the control action of under frequency relays deployed in circuit. Thus, the primary application of under frequency relays is to detect system over load and, thereby, save the system from failure resulting from instability due to excessive frequency decay.

Normal load changes can be absorbed by the spinning reserve in the system, as all the generators are usually not operating at full capacity. Moderate over loads result in small increments of speed and frequency

which activate the governors to increase the prime mover input. Transient changes such as those that result from faults involve the exchange of kinetic energy of the rotating masses to the system until the system can re-adjust to equilibrium. Load shedding is especially useful when the spinning reserve is inadequate or not available to compensate for increase in demand.

When the load requirements significantly exceed the generation capabilities, the frequency of the system decreases. The system survives only if enough load is dropped until all the generator outputs equal or are greater than that of the connected loads. This imbalance often results from the loss of a key or major transmission line or transformers which are involved in a major transfer of power either within the system or between two inter-connected systems. This could be the consequence of faults cleared without high-speed reclosing, undesirable relay operation or other situations which interrupt large power flows.

A veritable means of checking this unhealthy trend of excessive system demand (i.e. $P_{\text{demand}} > P_{\text{Generation}}$) is by the appropriate use of under frequency relays.

These relays are set at different frequency levels to switch off quickly, varying amounts of load to restore system equilibrium.

The application and setting of under frequency relays is not standardised and is based - for a large system - on a study of the most probable and

worst-case possibilities seasoned with general experience, factual knowledge and judgement. In the NEPA system, three-stage under frequency relays are in use. Their settings are as given hereunder:

Stage 1	49.8Hz	-	trips approximately 250 MW load
Stage 2	49.5Hz	-	trips approximately 300 MW load.
Stage 3	49.2Hz	-	trips approximately 600 MW load.

They all operate in 0.3 seconds.

1.5 Load Scheduling

Under normal operating condition, it is ensured that the current plant availability is reviewed under a carefully planned generation scheduling. Accurate knowledge of the generation status of the various stations facilitates proper matching of generation with demand to obtain a stable generation - demand profile over a period of twenty four hours.

The production of a workable generation schedule is usually derived from a reliable hour by hour demand forecast as prepared by the System Planning Department of the National Control Centre. Generation scheduling entails reviewing of plant availability at all power stations in the grid. The reliability of generation schedule is a function of the accuracy and dependability of plant status reports normally supplied to the N.C.C. by various power plants on daily basis.

The objective of generation schedules is to obtain economic water and fuel usage by the hydro and thermal plants taking into consideration the following:

1. Actual unit cost of thermal fuel type.
2. Heat rate of steam turbine/gas turbines.
3. Efficiency curves of hydro turbines.
4. Spinning reserve requirements.
5. Unit limitations (minimum load for stability, rate of loading constraints, peculiar unit faults, etc.)

CHAPTER SIXTEEN

EARTHING

1.0 INTRODUCTION

Earthing means a connection to the general mass of earth. The use of earthing is so widespread in an electric system that at practically every point in the system, from the generating system to the consumers' equipment, earth connections are made.

Earthing is divided into two main categories:

- Neutral Earthing
- General Earthing

2.0 OBJECTS OF EARTHING

2.1 Neutral Earthing

This is the earthing of the star or neutral point of power system lines and apparatus.

The objects of neutral earthing are:

- a) To reduce the voltage stress due to switching and lightning surges and to discharge safely into the ground over voltages occurring in the system.
- b) To permit the use of graded insulation in H.V. and E.H.V systems with consequent reduction in weight, size and cost.
- c) To control the fault currents to satisfactory values.
- d) To ensure the operation of ground or earth fault relays.

2.2 General Earthing

This is a term applied to all earthing of metal parts of lines and apparatus used in electrical systems and equipment used in the utilisation of electrical energy other than neutral earthing.

The objects of general earthing are:

- a) To provide protection to plant and personnel due to accidental grounding of equipment.
- b) To cordon off the zone of dead line working to make it safe during working to prevent electrostatic and electromagnetic induction and also accidental contact from other energised lines and apparatus.

Examples of general earthing are the earthing of the frames of generators, rotors, motors, tanks of transformers, circuit breakers, body of domestic apparatus, lines, electric stoves, electric irons etc.

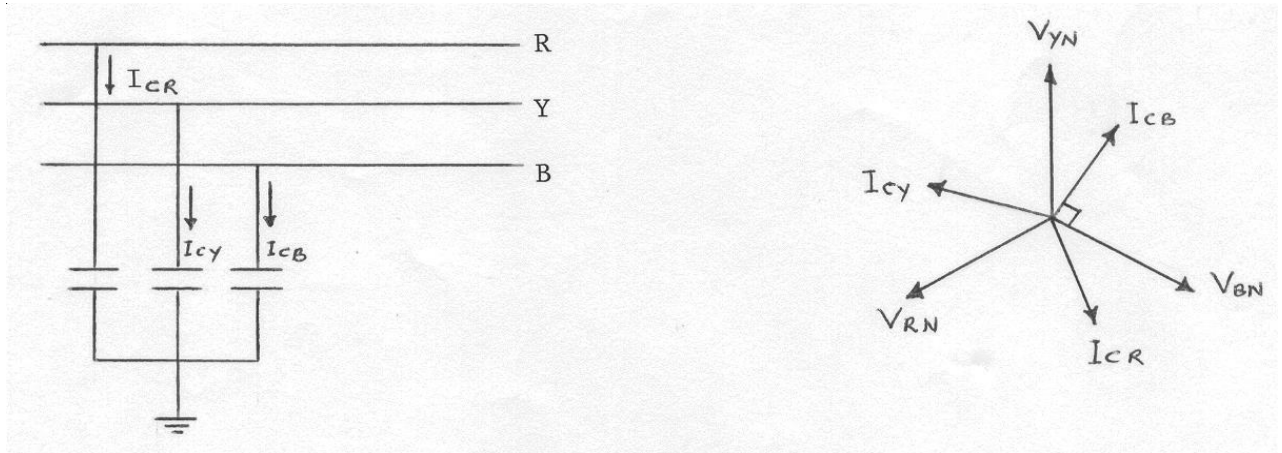
3.0 NEUTRAL EARTHING

The various methods of neutral earthing are:

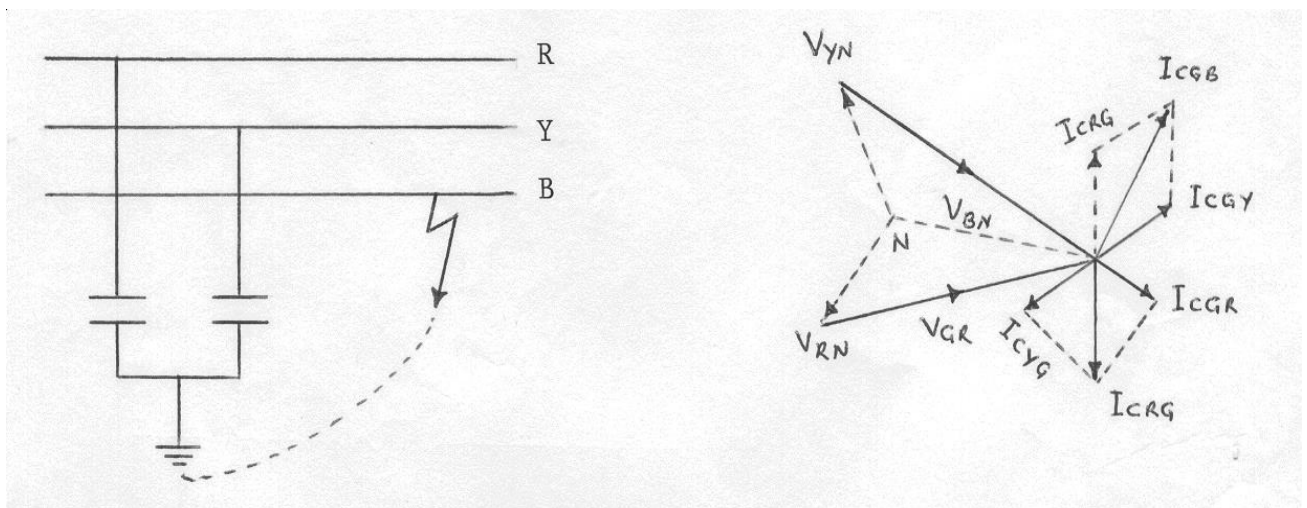
- a) Solid Earthing or Effectively Grounded Earthing
- b) Resistance Earthing
- c) Reactance Earthing
- d) Arc suppression coil earthing.

However before discussing the effects, the merits and demerits of the above methods, an isolated Neutral system is considered.

3.1 ISOLATED NEUTRAL SYSTEM



Each line conductor has a capacitance to the earth and the magnitude of this capacitance is the same in a perfectly transposed three phase line. With balanced voltages applied to such a line, the capacitance currents will be equal in magnitude as shown above. Assume an earth fault in conductor B. Hence no capacity current flows between the phase B and earth.

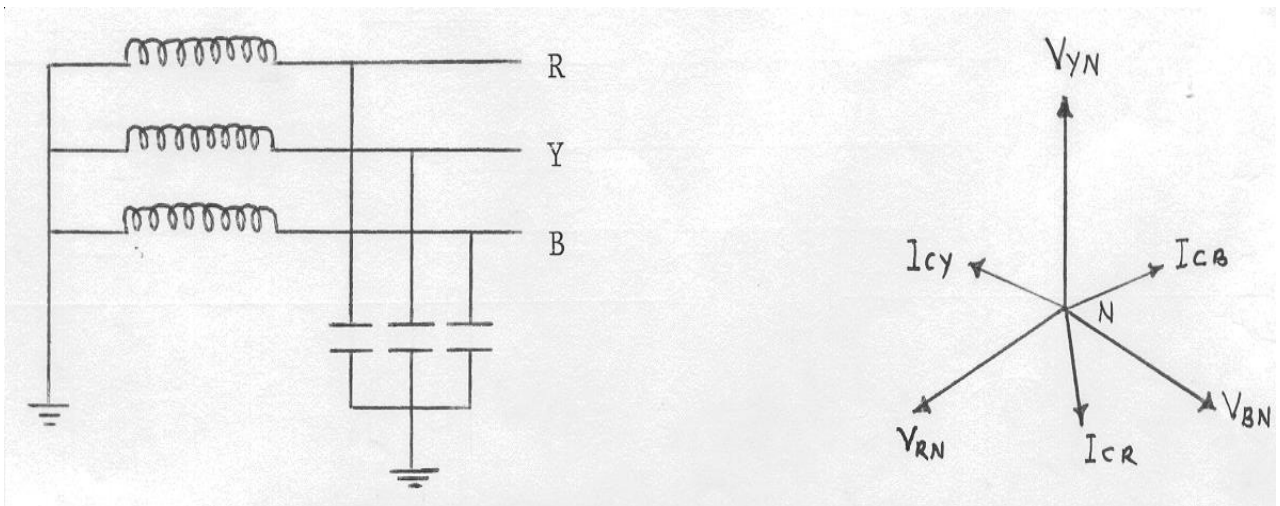


But the voltage across the other two phases rises to phase to phase voltage, as shown.

The fault phase B supplied the currents I_{CGR} and I_{CGY} . These being capacitive currents, no current flows when the line capacitance is charged. Hence, an arcing takes place at the faulted point. During this period, the line capacitance discharges and capacitive current once again flows. This repetitive cycle of charging and discharging causes intermittent arcing at the point of fault and also gives rise to abnormal voltages across the healthy phases due to the capacitance effect. In practice, voltages of 3 to 4 times the system phase voltage may occur thereby causing damage to the system insulation. Hence isolated neutral system is not being practiced.

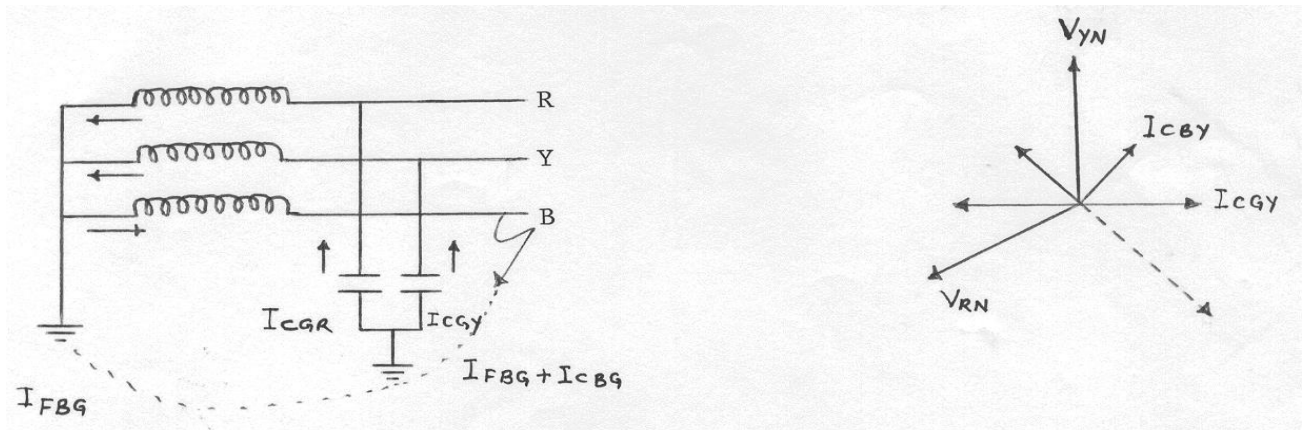
3.2 Solid Earthing

In solid earthing a direct metallic connection is made between the system neutral and the ground. The ground electrode resistance will be very small usually less than one ohm.



Under balanced voltage conditions and perfectly transposed line conductors, the phase to ground capacitance currents will be equal and

120° apart. The neutral point of the capacitances will be at ground potential and no current flows between the capacitances and the neutral.



Now consider a ground fault on phase B. The ground fault current consists of two components I_{FBG} which flows into the system neutral and $I_{CBG} = I_{CGR} + I_{CGY}$ the capacitive currents. I_{FBG} is a very large component compared to I_{CBG} .

The potentials V_{RN} and V_{YN} will still be the phase to ground voltages as the neutral is not displaced from the ground potential as it is held at ground potential.

3.21 The Main Advantages are:

- a) There is no abnormal voltage rise on the other healthy phases.
- b) Permits the use of discriminative protective gear.
- c) No voltage stress on the system insulation.
- d) Efficient and correct operation of Earth fault Relays is ensured.

- e) Additional savings are possible in power transformers of 132KV and above with the use of graded insulation.
- f) No arcing grounds.

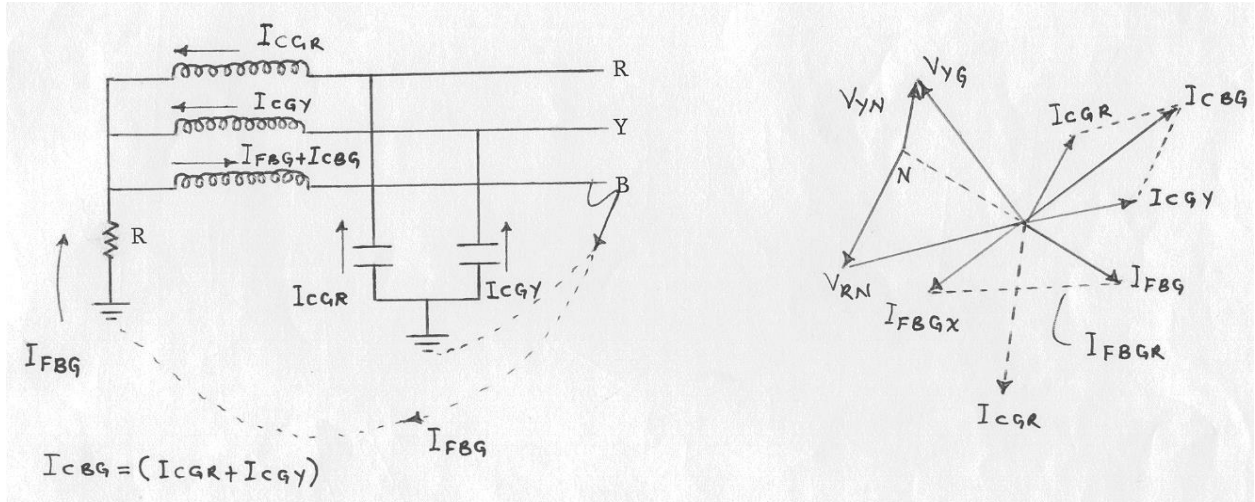
3.22 Disadvantages are:

- a) On overhead transmission lines, a majority of the faults are to the ground. Thus, the number of severe shocks to the system is relatively much greater than with resistance or reactance grounding.
- b) The ground fault current is generally lower than the three-phase current. But near generating stations, it may be relatively higher and may exceed the three phase short circuit currents. In such cases circuit breakers with higher rupturing capacity are required.
- c) The increased ground fault currents affect neighboring telecommunication circuits.

Most of the adverse effects have been overcome nowadays by the use of high rupturing capacity, high speed circuit breaker and fast acting protective relays. Hence in the world over, it is the practice to adopt solid earthing for the neutrals of power systems.

3.3 Resistance Earthing

This is one form of impedance earthing and introduced when it becomes necessary to limit the earth fault current. The resistance used may be a solid metallic resistor or a liquid resistor or a metallic resistor immersed in a liquid like transformer oil.



The magnitude and phase relationship of the fault current I_{FBG} depends upon the relative values of the zero sequence reactance of the power source and the ohmic value of the earthing resistance. The fault current can be resolved into two components one in phase with the voltage to neutral of the faulty phase and the other lagging it by 90° . The lagging component I_{FBGX} is in direct phase opposition to the capacity current I_{cBG} at the fault location. By a suitable choice of the ohmic value of the earthing resistance, the lagging component of the fault current can be made equal to or more than the capacity current so that no transient oscillation due to arcing grounds can occur. However, if the value of the

earthing resistance is sufficiently high so that the lagging component of the fault current is less than the capacity current ICBG, then the system approaches an isolated neutral system.

Another important but conflicting consideration in the choice of the ohmic value of the resistance is the power loss in the resistance. It is common practice to fix a value of the earthing resistance which will limit the fault current to the full rating of the largest generator or transformer. Based on this practice the value of the resistance to be inserted in the neutral connections of the earth is given by:

$$R = \frac{V_{ph}}{I}$$

Where R = resistance in ohms

V_{ph} = phases to neutral voltage in volts

I = full load current, in amperes of the largest generator/transformer.

The main advantages are:

- 1) Permits the use of discriminative gear.
- 2) Effects of arcing grounds are avoided with suitable low ohmic resistance.
- 3) Ground fault currents are reduced, thus obviating the harmful effects of the large currents associated with solid earthing.
- 4) Interference with adjoining communication circuits is avoided.

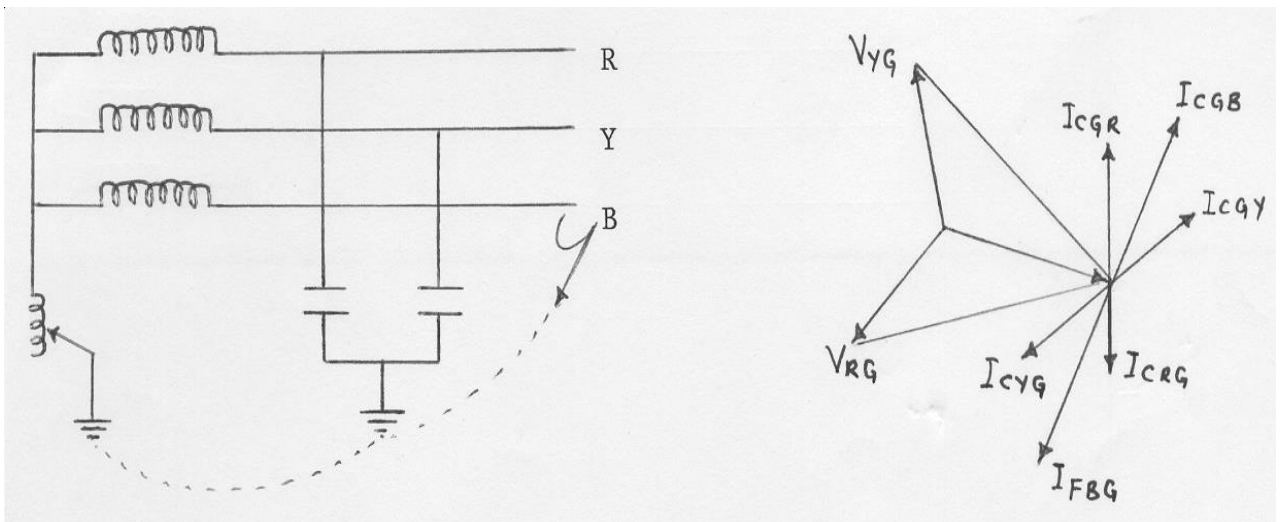
The disadvantages are:

- 1) System neutral will almost invariably be fully displaced in the case of a ground fault, thereby necessitating the use of 100% lightning Arresters at an increase in cost.
- 2) Cost of transformers will increase because graded insulation cannot be used.

Resistance earthing, if at all used, is limited to system voltages of 33KV and below and when the total system capacity does not exceed 5000 KVA.

3.4 Reactance Earthing

This is another form of impedance earthing also called 'Peferson Coil Earthing' after the name of the inventor.



This is a logical development of reactance earthing and is based on a value of reactance in the system neutral such that the reactance current due to the coil exactly neutralises the network capacitance current at the

fault. The resultant capacity current is theoretically nil and in any case inadequate to maintain the arc. Hence the name 'arc suppression coil'

It can be seen from the phasor diagram that:

- a) Voltage of the faulted phase at the point of fault is zero.
- b) Voltage of the healthy phases rises to $\sqrt{3}$ times the phase voltage.
- c) A resultant capacity current I_{CBG} equal to 3 times the line to neutral charging current flows through the fault, leading the voltage of the faulty phase by 90° .
- d) Voltages of the faulty phase i.e. the phase voltage is impressed across the arc suppression coil and a fault current I_{FBG} restricted in magnitude by the impedance of the coil flows, lagging the voltage of the faulty phase by 90° .
- e) The capacity current I_{CBG} and the fault current I_{FBG} are in direct phase opposition. By suitably adjusting the value of the reactance with the help of tappings provided on such coils, I_{FBG} can be made equal to the capacity current I_{CBG} so that the resultant fault current is practically limited to zero.

In actual practice, however, there will always be a small residual current present in the fault due to the effect of resistance in the arc suppression coil. But the current is too small to maintain an arc.

A system earthed through an arc suppression coil is similar to an isolated earth system except for the arcing grounds. Since the voltage on the

healthy phases rises to $\sqrt{3}$ times the phase voltage, there is always the risk of insulation failure, causing a fault on the other healthy phases. To obviate such situations, an arrangement as shown below is adopted sometimes.

Here, the arc suppression coil is shunted by a resistor in series with a circuit breaker. Normally the circuit breaker is open and the coil is fully effective. Temporary earth faults are cleared in a usual manner.

A relay with a delayed action is energised at the inception of the fault. If the earth fault persists for more than three or four seconds, the relay operates to close the bye-pass breaker. The arc suppression coil then becomes ineffective and the earthing is reduced to a solid type or resistance type. This cause sufficient current to flow and to operate the discriminative protective gear to isolate the fault.

The inductance of the arc suppression coil and the current rating of the coil are determined as follows.

$$ICBG = \frac{3 V_{ph}}{X_c}$$

$$\text{Also IFBC} = \frac{V_{ph}}{X_l}$$

Where X_l is the inductance of the coil.

At resonance $ICBG = IFBG$

$$\frac{3 V_{ph}}{X_c} = \frac{V_{ph}}{X_l}$$

$$X_l = \frac{X_c}{3} \text{ ohms}$$

$$\omega L = \frac{1}{3 \omega c}$$

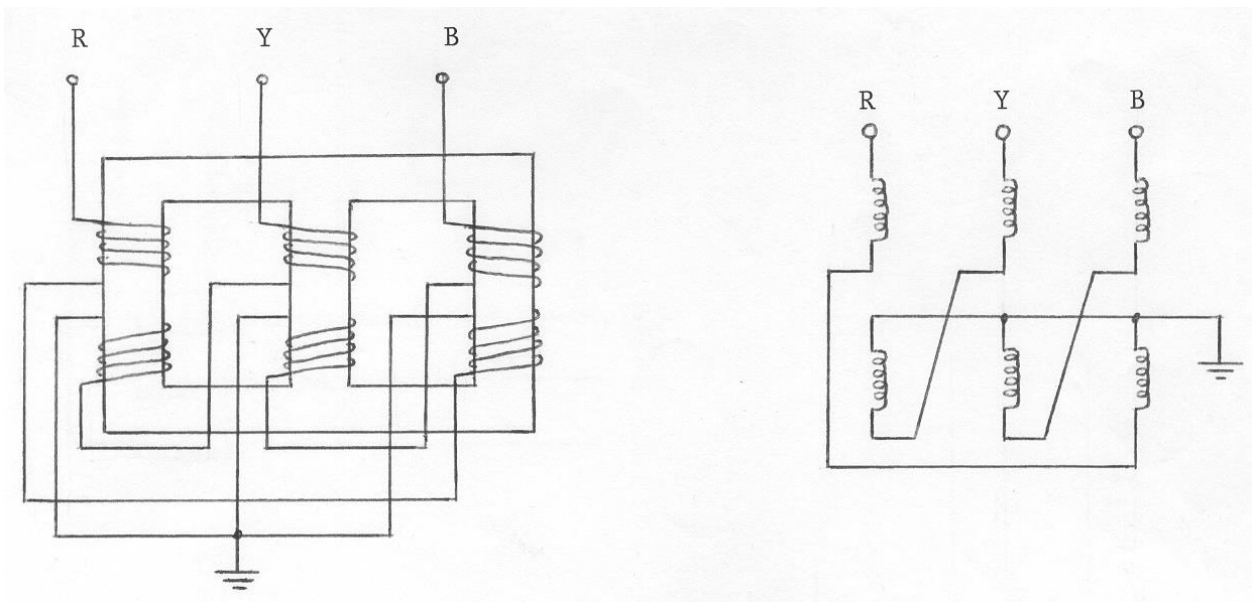
$$L = \frac{1}{3 \omega^2 c} \text{ Henries}$$

Current rating of the coil is:

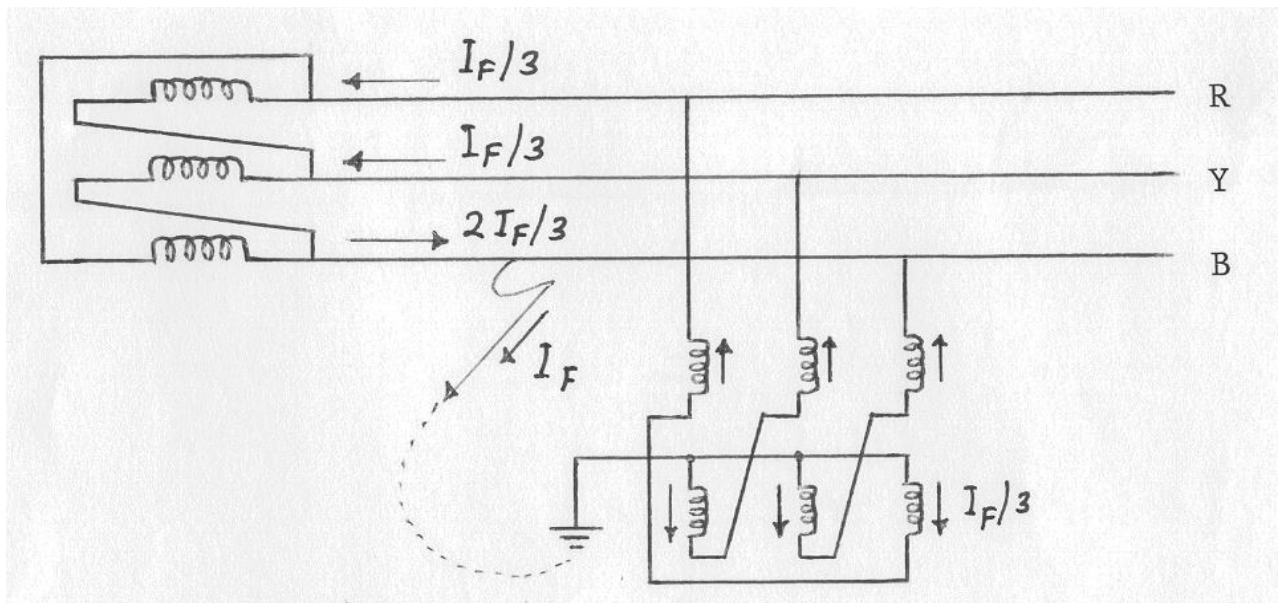
$$\text{IFBG} = \text{ICBG} = \frac{3V_{ph}}{X_c}$$

4.0 EARTHING TRANSFORMERS

4.1 Earthing Transformers are used to create an artificial neutral point in delta connected systems. It is an interconnected star earthing transformer as shown below:



Earthing Transformer is a three limbed core type transformer having two equally proportioned windings on each core. One set of windings are connected in star as shown to provide the neutral point.



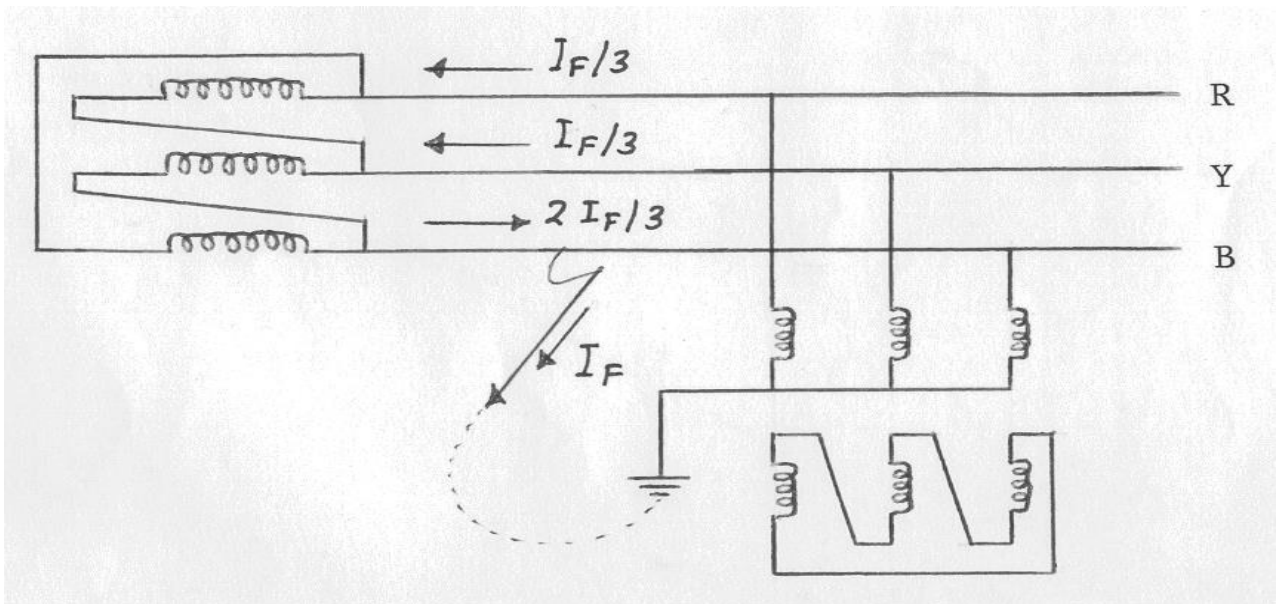
The earth fault current flowing in the earth returns to the power system by way of the earthed star point of the earthing transformer. This current gets equally, divided in all opposite direction to the source and to the fault as shown. Consequently, the magnetic flux balance is maintained in the transformer. Such earthing transformers are also called Zig-Zag transformers because of the manner in which the windings are interconnected.

The voltage rating of this transformer is the full line to line voltage of the delta system. The 3-phase KVA rating is the product of the line to neutral

voltage and the expected fault current. For example if fault current is 1000 Amps and line to line voltage is 11KV, then KVA rating of the earthing transformer is:

$$= \frac{11 \times 1000}{\sqrt{3}}$$

$$= 6350 \text{ KVA}$$



It can be seen that the primary and secondary ampere-turns balance each other and there is no effect on the magnetic balance. This method is adopted if an earthing transformer has failed and where no ready replacement is available and where Star - Delta transformers are available. The cost of this transformer is however more than that of a Zig-Zag earthing transformer.

5.0 CHOICE OF THE METHOD OF NEUTRAL EARTHING

5.1 Although each method of earthing has its own advantages and disadvantages, yet a few combinations of conditions cover the great majority of systems and some generalization is possible for these combinations.

5.2 In the vicinity of large cities and industrial areas, continuity of service is regarded so important that multiple circuit lines and two directional feeds are a must. On such systems a momentary line trip does not interrupt service because additional circuits are available. There is a large amount of equipment tied to these lines. To save in the lightning arresters' costs and insulation costs of transformers and other equipment, effective grounding appears to be the best practice. It has already been stated that fast clearance of faults with the help of modern breakers and relays have taken out much of the excessive ground fault currents.

5.3 In less densely populated regions where loads are small but distances are long, only single circuit lines are justified. Such systems are good fields for the application of arc suppression coils. The number of interruptions can be greatly reduced at moderate cost by such means. While full rated lightning arresters and transformers are required, the spacing of substations will usually be large enough that this does not unduly increase the cost. At some locations, ground fault current limitations may be necessary from the view point of circuit breaker interrupting duty or

inductive effects. In such situations, a small value of resistance or reactance may be added in the connections between the neutral and earth. The value of resistance or reactance can be so chosen that it does not cause the X_0/X_1 to exceed 3 so that lightning arresters for grounded neutral service can be made use of.

- 5.4** It should be ensured that a system designed to operate with solid or resistance earthed neutral can maintain its neutral earth connection under all switching conditions. If the loss of a neutral earth point on any part of the system under fault conditions results in the whole or part of the system being left in service with an insulated neutral then a possible risk of over voltages due to arcing grounds may occur and cause insulation failures. In order to prevent such conditions arising, it is a usual practice to earth the neutral points of all power sources and not to rely on only one power source neutral for maintaining an earth connection. In systems with such multiple earthing points, excessive harmonic currents may sometimes flow between the neutral earthing points. The usual method of limiting the value of circulating harmonic current is by the introduction of a harmonic suppressor in the neutral earthing connection of the generator from which the harmonics emanate.

For thermal considerations, the size of conductor depends upon:

- a) Ground fault current.
- b) Fault clearing time.

Time duration of fault in seconds						
	Welded Joints			Bolted Joints		
	Copper	Steel	Aluminium	Copper	Steel	Aluminium
30	50	120	91	64	143	123
3	16	38	29	21	46	39
1	9.5	22	17	12	27	23
0.5	6.5	16	12	8.5	19	16

$$1 \text{ circular mil} = 0.0005067 \text{ mm}^2$$

For mechanical strength, a large number of utilities in USA have adopted 4/0 AWG (107.2mm²) copper section as a minimum size of the conductor.

The corresponding minimum size of steel and aluminium conductors for the same mechanical (tensile) strength would be 61 mm² and 195 mm².

The size of steel grounding conductor used should be checked for corrosion. For soils with low corrosive effect, the minimum size of steel conductor used for mechanical reasons is enough to ensure proper corrosion resistant level. In corrosive soils, steel strips should have a minimum thickness of 6mm and minimum cross section of circular section of steel should be 200mm. The requirement of conductor size for adequacy in conductivity is assumed to be met with where the criteria discussed above are satisfied.

Conductors of adequate capacity and mechanical ruggedness should be used for connection to:

- a) All non-current carrying parts such as metal structures, buildings, steel, transformer tanks, machine frames, oil circuit breakers, etc.
- b) Electrodes e.g. ground rods, water pipes etc.
- c) Lightning arresters, coupling capacitors, etc.

6.0 SELECTION OF GROUNDING MATERIAL

6.1 Material for the grounding conductor should have:

- a) High conductivity
- b) Low rate of corrosion by soil
- c) Low rate of corrosion due to galvanic action.

6.2 Copper fulfills all these requirements and at one time used to be the only material for grounding systems. No doubt, it creates galvanic cell with other dissimilar metals i.e. zinc, lead, iron etc buried in the vicinity. Yet it is cathodic with respect to all these metals. This causes the corrosion of other buried materials like steel pipes, conduits, cable sheaths etc, and keeps the copper earthing materials intact. However, scarcity and high cost of this metal prompted research in the use of other materials for the grounding systems. The knowledge gained has brought forth steel and to some extent aluminium in to use. Steel has the following advantages as a grounding material:

- 1) It is available in plenty
- 1) It is cheaper than copper.

- 2) It avoids galvanic action in the soil because most of other material buried in soil is iron and steel.

6.3 Its main disadvantage is its corrosion in soil which is approximately 6 times faster than copper. Therefore, either a bigger section of the steel conductor has to be used or means have to be provided to reduce and if possible to avoid corrosion so that the grounding system can serve its purpose for many years. Galvanizing is one of the methods available for controlling corrosion. As a result, coatings have also been employed. The duration of protection of iron by zinc is usually proportional to the thickness of the zinc coating. Depending upon resistivity of soils (low resistivity soil are generally more corrosive), the zinc coating may be destroyed within 2 to 20 years. Galvanized steel in ground corrodes at a slow rate in the beginning but the rate of corrosion increases once the coating is destroyed. Therefore, galvanizing as a means of protection against underground corrosion for extended periods of time should not be depended upon.

6.4 Size of Conductor:

While deciding the size of grounding material, the following factors should be kept in view:

1. That it has thermal stability to ground fault currents.
2. That it is mechanically strong.

3. That it will last for at least 50 years without causing a break in the grounding circuit due to corrosion.
4. That it has sufficient conductivity so that it does not contribute substantially to local potential gradients.

It is a common practice to allow for 50% margin to cover excessive corrosion in certain soils particularly those of low resistivity because such soils by virtue of free salts and moisture cause heavy corrosion.

7.0 EARTHING SYSTEM

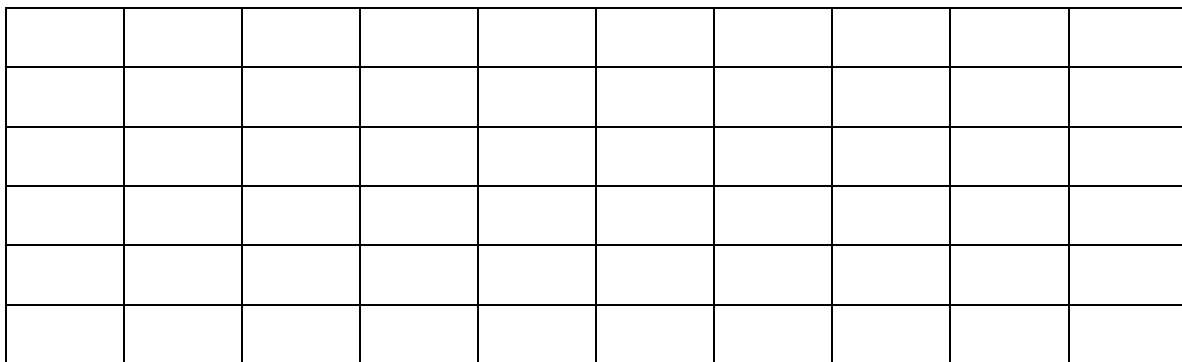
7.1 The object of earthing system is to provide as nearly as possible a surface, under and around a station, which shall be at a uniform potential and as nearly zero or absolute earth potential as possible with a view to ensure that:

- 1) All parts of apparatus (other than live parts) connected to the earthing system through earthing conductors shall be at ground potential.
- 2) Operators and attendants shall be at ground potential at all times.

Also by providing such a ground surface of uniform potential under and surrounding the station, there can exist no difference of potential in a short distance great enough to shock or injure an attendant when short circuits or other abnormal occurrences take place.

7.2 Until recently, the concept of good earthing has been to obtain an earth resistance as low as possible. However, in systems where the ground fault currents are excessively high, it may be impossible to keep

grounding potential within safe limits even though the earth resistance may be kept low. Modern research has brought forth the concept of voltage gradient control under ground fault conditions so as to keep the potential difference between nearby points within safe limits and avoid danger to the persons working in the area. As a consequence, the present day earthing system in a substation takes the form of a grid or mat comprising a number of square or rectangular meshes of earthing conductor buried horizontally and connected to several earth electrodes driven at intervals as shown in Fig. 7.0 below

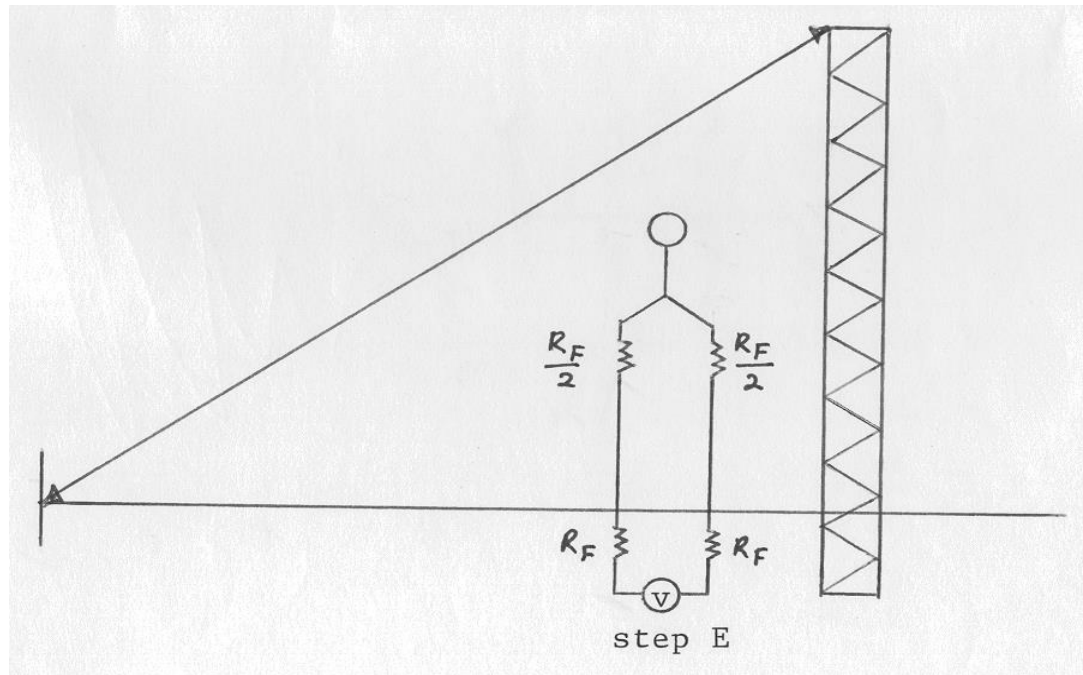


CONDUCTOR MESH

It may be mentioned here that these electrodes may or may not be used depending upon the design of the earthing grid. All metal structures and frames including fencing posts are then securely connected to the earthing grid by running multiple connections as far as possible.

7.3 Step Potential, Touch Potential and Transfer Potential Definitions

The flow of ground fault current results in voltage gradients on the surface of the earth in the vicinity of the grounding system. The voltage that exists between the two feet of a person standing on such a ground is called Step Potential as shown in fig. 7.1 below whereas the voltage that exists between the hand and both feet of a person is called Touch



From Fig. 7.1 above the tolerable value of E step is:

$$E \text{ step (tolerable)} = (R_k + 2 R_f) I_k \text{ volts}$$

Where R_f is the grounding resistance of one foot in ohms.

For practical purposes it is assumed to be $3 P_s$ where P_s is the resistivity of the soil near the surface of the ground in ohm-meter.

R_k is the resistance of the body in ohms, usually 1000 ohms.

I_k is the R.M.S current flowing through the body in amps =

$$0.165/\sqrt{t}$$

where 't' is time duration of shock in seconds and is less than 3 seconds.

$$= 0.009 \text{ A for sustained faults.}$$

Therefore for faults of duration less than 3 seconds:

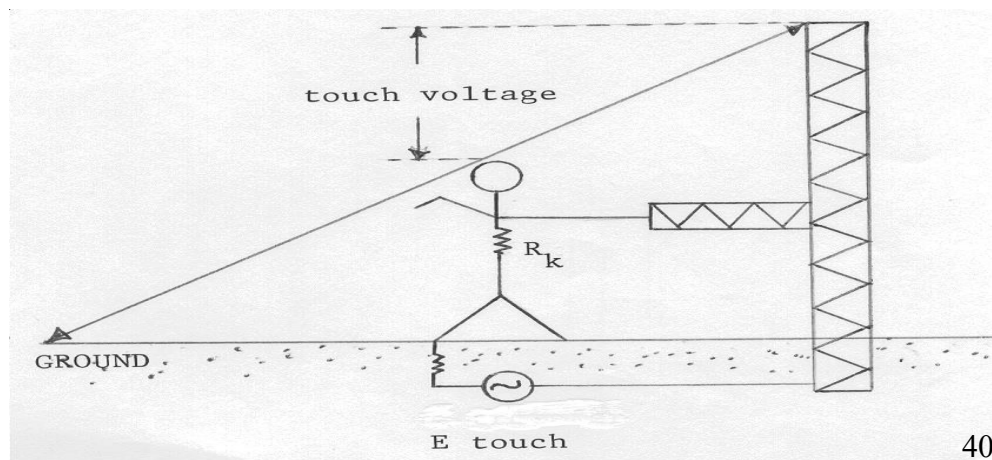
$$\begin{aligned} \text{E step (tolerable)} &= (1000 + 6P_s) 0.165/\sqrt{t} \\ &= (165 + P_s)/\sqrt{t} \text{ volts} \end{aligned} \quad -1$$

$$\text{And for sustained faults} = (1000 + 6P_s) 0.009$$

$$\text{E step (tolerable)} = 9 + 0.054 P_s \text{ volts} \quad -2$$

For grounding to be safe, for step contact, under fault conditions the voltage gradient in volts per meter (assuming distance of one pace to be one meter) on the surface of the ground should not exceed the value given by equation (1) or (2) as the case may be.

Similarly, from Fig. 7.2, the tolerable potential difference between any point on the ground where a man may stand and any point on the structures or equipment frames which can be touched simultaneously by either hand is given by:



$$E_{\text{touch (tolerable)}} = (R_k + R_f/2) I_k$$

For faults of duration less than 3 seconds:

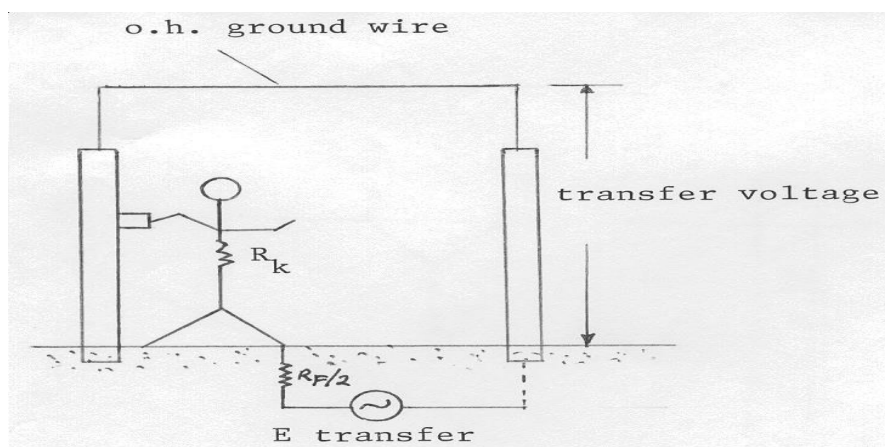
$$E_{\text{touch (tolerable)}} = (165 + 0.25 P_s)/\sqrt{t} \text{ volts} \quad -3$$

And for sustained faults

$$E_{\text{touch (tolerable)}} = (9 + 0.0135 P_s) \text{ volts} \quad -4$$

If the object touched were grounded immediately below itself, the maximum horizontal reach may be one meter. So that for safe grounding the potential gradient on the surface of the earth in volts per meter in the immediate vicinity of the object, under fault conditions, should not exceed the value given by equation (3) or(4) as the case may be. When the object touched is grounded remotely, this fact must be taken into account.

If a person touches a conductor grounded at a distance much greater than the dimensions of the grounding system, the shock voltage may be essentially equal to the full voltage rise of the grounding system under fault conditions. Such a touch contact is called Transferred Potential contact and is illustrated in fig. 7.3



8.0 GENERAL INSTRUCTIONS FOR LAYING EARTHING GRID

- 8.1** Trenches dug for burying the grounding conductor should be filled with earth free of stones. The filling should be carefully rammed.
- 8.2** All joints of grounding steel strip between themselves and grounding electrodes should be overlap welded. The length of welds should be equal to at least double the width of the strip. Where copper conductor is used, the joints should be riveted and sweated, brazed or bolted. As the maximum temperature approaches the maximum permissible for most types of brazing, brazed joints without mechanical retention should not be used.
- 8.3** Joints in the earth bar between the switchgear units or to cable sheathe which may subsequently require being broken should be bolted.
- 8.4** For protection against rust of buried welded joints, located in soil, the weld should be coated with molten bitumen and covered with bitumen impregnated tape. In case of copper conductor the joint faces should be tinned.
- 8.5** Before welding, the steel strip should be clamped tightly to ensure good surface contact between them.
- 8.6** Where the diameter of the bolt for connecting the earth bar to apparatus exceeds one quarter of the width of the earth bar, the connection to the bolt shall be made with a wider piece or flag of metal jointed to the earth bar. If of copper the earth bars or flags shall be tinned at the point of

connection to equipment and special care is required to ensure a permanent low-resistance contact to iron or steel.

The frame of every generator, stationary motor, and so far as is practicable, portable motor, and the metallic parts (not intended as conductors) of all transformers, and any other apparatus used for regulating or controlling energy and all medium voltage energy consuming apparatus shall be earthed by the owner by two separate and distinct connections with earth.

- 8.7** The overhead ground wires of transmission lines should be solidly connected to the grounding grid.
- 8.8** All the area over which the ground grid is spread should be covered by 7.5 cm thick crushed rock which should also be spread 1 to 1.5 meters from the periphery grounding system. Crushed rock should be placed outside along the periphery of the fencing.
- 8.9** Separate earthing electrodes should be provided in the vicinity of the lightning arresters, coupling capacitors and transformer neutrals. These electrodes should, however, be connected to the general earthing system so as to have minimum of impedance between the lightning arresters, ground terminals and the equipment.

CHAPTER SEVENTEEN

TESTING AND MAINTENANCE OF RELAYS

1.0 Introduction:

The complexity of the present day systems and the ever increasing technological improvements, where products have greater number of functions to perform, warrants a high reliability in such affairs.

In general terms "Quality Control" is defined as "An effective system for coordinating quality maintenance and quality improvement efforts of the various groups in an organization so as to enable production at the most economical levels which allows for all customer satisfaction".

The reliability of a product may be defined as "a mathematical probability that will operate in a specified manner for a specific period of time".

2.0 TESTS ON RELAYS

Basically the tests conducted on relays are classified as:

- 1) Type tests
- 2) Routine tests

The above are the tests conducted in a factory at the manufacturing stage. Subsequently when the relays are received at site the following tests are conducted:

- 3) Acceptance tests
- 4) Installation tests

- 5) Maintenance or Functional tests
- 6) Repair tests.

3.0 Type Tests

3.1 Type tests are tests conducted to ensure adherence to guaranteed design details and conformity to conditions of use. This is conducted on a typical sample of the product immediately after new development and periodically depending upon its application, performance and customer requirement.

The following type tests are to be conducted on relays as per IEC 225 - 4

3.2 Thermal Requirements

3.2.1 The relay shall be subjected to both continuous as well as temporary duties (energised for withstand value for the particular duty) at ambient temperature. After the test and when restored to reference conditions, the relay shall meet all other specification requirements.

3.2.2 Overload tests relating to input energising circuits and the tests shall be accomplished with all connections made to the relay in a normal manner. After the tests and after reference conditions are restored, the relay shall comply with all other specification requirements. The relay shall also withstand a single application of the limiting short time thermal withstand value stated by the manufacturer for the following times:

Current relays	-	1 sec
Voltage relays	-	10 secs

3.2.3 The relay shall also withstand a single application of the dynamic value of the energising quantity. The duration of the test should be half a cycle of the sinusoidal waveform at rated frequency. The test may be made with either symmetrical waveform or with asymmetrical waveform.

3.3 Accuracy

The accuracy of the dependent time relay is primarily associated with the specified time, but may also be concerned with the accuracy associated with the basic value of the characteristic quantity.

3.4 Mechanical Endurance

The mechanical endurance for relay is conducted under the following conditions:

- a) Mounted as for normal service
- b) At rated value of the auxiliary energising quantity
- c) At values of the characteristic or input energising quantity.
- d) At specified rate
- e) For relays with adjustable time setting; at the time setting values which gives the most severe conditions for mechanical durability.

After the tests, the relay shall be substantially in good condition and should be capable of fulfilling its designed functions throughout its setting range at least once at the minimum and once at the maximum values of the operative range of the auxiliary energising quantities.

The contact circuit should be carrying the maximum current ratings assigned to them and the error limits shall not be more than twice the limiting error. The relay shall be capable of withstanding a dielectric stress of not less than 0.75 times the value originally specified.

3.5 Shock Vibration

The relay shall be subjected to shock and vibration tests and the test value is to be decided mutually between the manufacturer and the purchaser.

3.6 Contact Performance

The contact performance of the relay contacts to be verified with respect to the guaranteed values.

3.7 Rated Burden and Rated Impedance

The value of rated burden and rated impedance of the relay as guaranteed by the manufacturer has to be verified.

3.8 Insulation Requirements

3.8.1 Di-electric Withstand Capacity

The input transformer, relay contacts and auxiliary energising terminals must withstand 2KV insulation level for one minute between ground and between each other.

3.8.2 Impulse Test

An impulse voltage withstand test is performed to determine whether the relay and its individual components will withstand, without damage, high voltage surges for short durations.

The conditions for such a test are as follows:

Impulse Waveform - A standard 1.2/50 micro second impulse having the following tolerances:

- a) Voltage rise time $\pm 30\%$
- b) Voltage fall time $\pm 20\%$
- c) Standard value of test voltage - 5KV
- d) Test voltage tolerance $\pm 10\%$
- e) Source impedance 500 ohms; tolerance $\pm 10\%$
- f) Source energy 0.55 KVA; tolerance $\pm 10\%$
- g) Test leads not to be longer than 2 meters.

The positive and three negative impulses shall be applied at intervals of not less than 5 seconds. The test voltage shall be applied between all terminals connected together and earth and between each of the terminals.

After the test, the relay will still comply with all relevant performance characteristics.

- b) Operating time
- c) Resetting performance
- d) Any other characteristics

The relay shall not change its output state in a faulty manner when the auxiliary energising quantity is switched on or off.

3.10 Operating Value Test

All relays shall be tested for their operating values by gradually increasing or decreasing the characteristic quantity of the relay until the relay just operates. The relay shall then conform to the accuracy class specified.

3.11 Operating Time Test

The time of operation for both dependent and independent time relays shall be measured and it should conform to the accuracy class specified.

3.12 Reset Value Test

The relay shall be tested for the resetting value by gradually increasing or decreasing the characteristic quantity of the relay, until the relay returns to the un-operated condition.

3.13 Reset Time Test

The time taken by the relay to return to its un-operated position from its operated position by sudden removal of the characteristic quantity shall be determined.

4.0 ROUTINE TESTS

4.1 The routine tests on the relay comprises of the following:

- 1) Visual checks and inspection
- 2) Verification of operational characteristics
- 3) Verification of operation on auxiliary supply variation
- 4) Verification of operation of target coils and flag indicators
- 5) Dielectric test

4.2 The check list on Visual Inspection of all types of relays is listed below:

4.2.1 Verification with respect to purchase order to confirm:

- a) Setting range
- b) Inscriptions
- c) Number of flag indicators
- d) Indicating/Name plate

4.2.2 Soldering:

Check for proper soldering in:

- a) Printed Circuit Boards
- b) Connections of wiring
- c) Components fixed to the lugs or terminals
- d) Short, if any

4.2.3 Terminations:

Ensure the following:

- a) Fixing of all necessary wires to the terminal blocks

- b) Proper locking of all the current and voltage terminals
- c) Keying code and its mechanical fixation.

4.2.4 Wiring:

Ensure the following:

- a) Proper connections of wires to the lugs and current terminals
- b) That the wires do not have large sag to prevent entry and withdrawal of the relay
- c) That the heads of the wire straps are turned towards the interior of the relay to facilitate easy entry
- d) That the earth wire is connected and fixation is alright
- e) That the wiring does not come between the frameworks obstructing the easy entry and withdrawal of the relay either from the case or from the rack.

4.2.5 Varnishing:

Verify:

- a) Whether all parts are varnished as per drawing particularly windings and relays coils
- b) Whether from appearance the terminal settings/terminals are free from varnish

4.2.6 Winding:

Verify:

- a) Whether the identification stamp, number or catalogue code is fixed

- b) If the protection tape is properly wound and the winding is not exposed

4.2.7 Indication/Name Plate:

- a) Verify the inscription details
- b) Ensure that they are legible and can be easily read
- c) Ensure that the surface is free of scratches, stains, scale formations and reasonably clean

4.2.8 Mechanical Fixing:

Verify that the mechanical fixation of transformers, armature and coil assembly, disc spindle, printed circuit boards, sub-assembly of settings and setting boards, flag indicators and accessories is rigid.

4.2.9 Finish:

- a) Observe for a good and pleasing general appearance
- b) Ensure the removal of excess solder, excess of component lugs, excess length of loose and sagging wires, excess varnish, stained varnish on undesirable terminals.
- c) Ensure that the components are painted for locking to facilitate removal of damaged component and re-assembly.
- d) Endorse for approval.

4.3 VERIFICATION OF OPERATIONAL CHARACTERISTICS

4.3.1 I.D.M.T. O.C. and E.F. Relays

a) Pick up and Drop Off Value

I.D.M.T. Relays shall pick up between 110% to 130% of the setting value and the ratio of drop off to pick up shall be greater than 70%

b) Time Delay

The time of operation of the relay with various current inputs is to be verified for confirmation of the inverse characteristics of the relay.

Tolerance allowed is 12.5% at any current from 2 to 4 times setting for electromagnetic relays and 5% for static relays.

4.3.2 Definite Time O.C. and E.F. Relays

a) Pick Up and Drop Off Value:

The pick up value shall be within $\pm 5\%$ of the setting. The ratio of drop off to pick up shall be greater than 80%

b) Operating Time Test:

The value shall be verified to be within $\pm 5\%$ tolerance limit by passing 5 times the current.

4.3.3 Directional Relays (Voltage Restraint)

a) Quadrature Test:

With the rated voltage applied at current up to 5 times the rated current of the relay, the relay shall always operate when the current vector lags or leads by an angle which is less than $90^\circ - 9^\circ$ with respect to its position

giving maximum torque and shall never operate when this angle is greater than $90^\circ + 9^\circ$

b) Sensitivity Test:

The relay shall operate with accuracy when 1% rated voltage and currents up to 5 times the rated current are applied.

4.3.4 Directional Relay (Current Restraint)

Tests as described in paragraph 4.3.2 are conducted except that instead of the restraining voltage, the restraining current is applied.

4.3.5 Voltage Relays (Over Voltage)

a) Pick Up Value:

The tolerance limit for the pick up value shall be within $\pm 5\%$. The ratio of drop off to pick up value shall be greater than 90%.

b) Operating Time:

The operating time for definite time over voltage relays shall be verified by suddenly applying 1.1 times the set voltage. The time delay shall be within $\pm 5\%$ tolerance limit.

4.3.6 Voltage Relays (Under Voltage)

a) Pick Up Value:

The tolerance limit of the pick up value shall be $\pm 5\%$. The ratio of drop off to pick up value shall not be more than 115%.

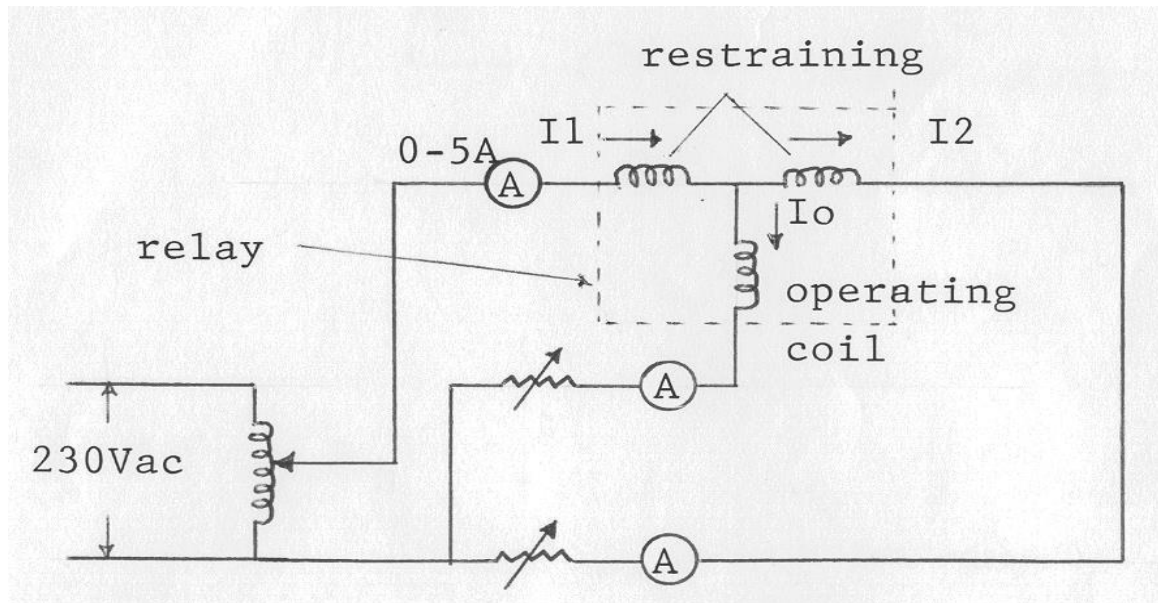
b) Operating Time:

The operating time for the definite time under voltage relays shall be measured by suddenly reducing the rated voltage to 80% of the set voltage. The time delay shall be within $\pm 5\%$ of the tolerance limit.

4.3.7 Transformer Differential Relays

a) Operating Characteristics:

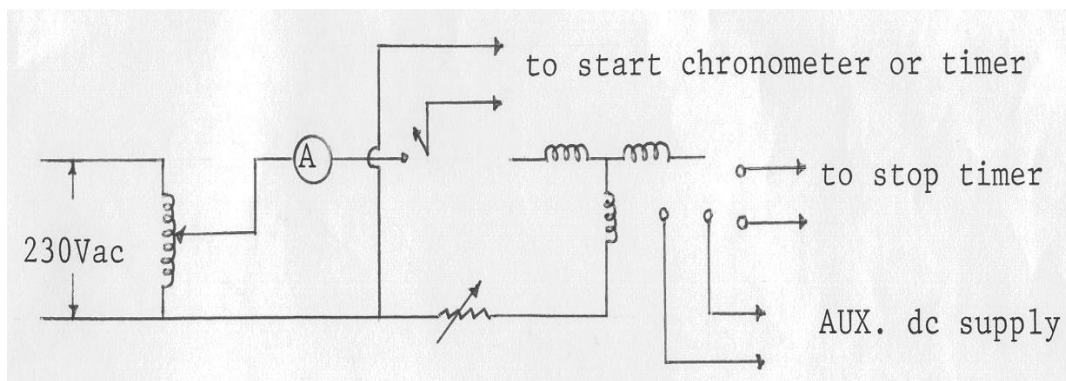
The test circuit is shown for a single phase relay.



The pick value is verified as follows:

- With $I_2 = 0$, check the threshold value of the relay
- With low values of I_2 , increase I_o until the relay operates
- Increase I_2 to higher values. Again increase I_o until relay operates

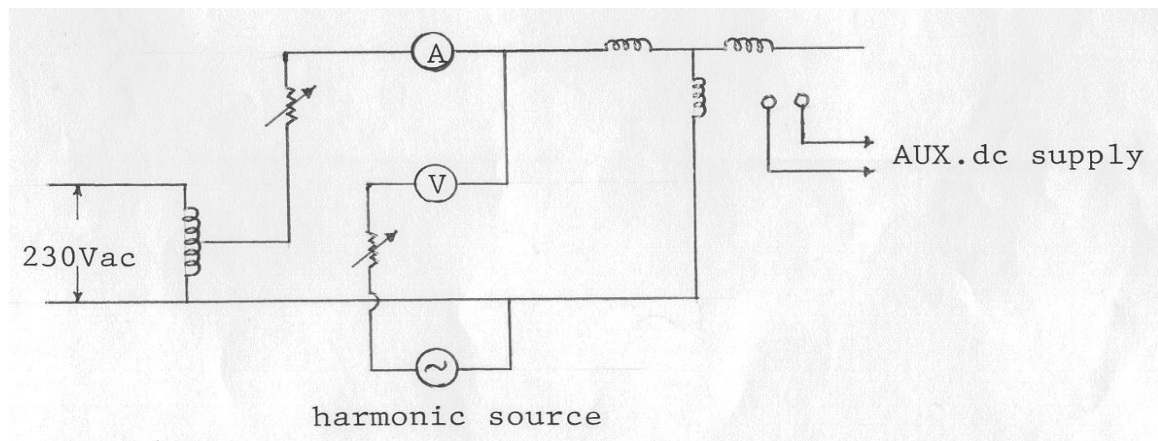
b) Operating Time Test:



The operating time shall be measured by suddenly applying the test current.

c) Harmonic Restraint Characteristics

The test circuit is as shown below:



- i. I_f is the current at rated frequency and $I \times F$ is the current at specified harmonic frequency
- ii. Set $I \times F$ to an initial value. Increase I_f from current zero until relay operates.
- iii. Repeat test for different values of $I \times F$.

d) Stability Test:

The differential relays with independent operating and restraining coils shall remain in-operative at all currents up to 15 times the rated current of each coil or 30 times the current setting whichever is lower when currents are passed simultaneously through the operating and restraining coils so as to oppose each other in effect.

e) Auxiliary Supply Variation:

The operating value and time shall be within tolerance specified for variation in the auxiliary voltage supply from 80% to 110% of the rated voltage.

f) Operation of flag Indicator:

During each energisation of the relay, the operation of the flag indicator shall be verified and it shall be reset.

5.0 ACCEPTANCE TESTS

5.1 Generally Acceptance tests are done once and in a laboratory only. These tests are separated into two types:

- a) New products supplied for the first time: - Such products having not been used previously in the system are subject to extensive tests on a sample to gain experience and knowledge and/or additional technical information. Sometimes they are installed in the field in parallel with an existing similar relay to study the performance as above.
- b) Tests on each product received: - Every product received from the manufacturer is subject to a minimum of practical checks to ensure:
 - i. That the product is what the manufacturer specifies
 - ii. To ensure that the relay can be safely accepted into the store inventory and dispatched to site for subsequent installation.

6.0 INSTALLATION TESTS

6.1 Installation tests also referred to as Commissioning tests are conducted at site as field tests to determine that the relay will perform correctly in actual service. These tests are not normally repeated unless the relay frequently mal-operates. Most frequently these tests are performed by simulation with the secondary circuits energised from a portable source.

Other methods of conducting such tests include:

- a) Simulated tests using primary load current and voltage
- b) Operating tests with the primary energised at a reduced voltage
- c) Staged fault tests.

6.2 Staged Fault tests are actual faults applied to the power system to verify the relay operations. Usually several types of faults, both internal and external are applied. While this is the best method, the cost and potential hazards are high. Therefore staged faults tests are limited to very important and/or new relay installations to the power system.

6.3 Normally the commissioning tests include the following:

- a) Checking the circuit and wiring diagrams, studying the relay and equipment catalogues.
- b) General inspection of equipment, checking all the connections, wires on relays and terminals.
- c) Checking the insulation resistance of all circuits to ground.

- d) Checking the insulation resistance of control cables to ground and between different cores of a control cable and between different control cables.
- e) Checking the insulation resistance between current, voltage secondary circuits and auxiliary A.C. and D.C. supplies.
- f) C.Ts tested for insulation, polarity, ratio and excitation characteristics.
- g) V.Ts tested for insulation, polarity and ratio.
- h) Relays tested independently by secondary simulated tests.
- i) Relays tested by injection of current in primary of C.T. and secondary circuits of V.T., Burden on C.Ts and P.Ts checked.
- j) Operation of relays checked with 80% of D.C. voltage supply.
- k) Relay flag indicator and alarm circuits checked
- l) Tripping of circuit breaker checked by relay operation at 100% of D.C. voltage and at 80% of D.C voltage.
- m) Maintaining a commissioning log of all tests conducted.

7.0 MAINTENANCE OR FUNCTIONAL TESTS

7.1 Maintenance or functional testing is generally done in the field at regular intervals. The question of the frequency of maintenance tests is a subject of debate. This is because in actual service, a relay or a protective gear may stand quiescent for months and yet be required to operate with precision if a fault occurs on its associated primary equipment. Thus the keynote should be minimum testing for maximum performance. Several

electrical utilities the world over conduct maintenance tests with a time interval varying from once in 6 months to once in a year or even to once in two years. These intervals vary among users depending upon:

- a) Past experience
- b) Type of protective relays employed (electromagnetic or static)
- c) Voltage class of the power system
- d) Importance of equipment being protected
- e) Supporting system amongst others.

A large majority of users perform maintenance or functional testing at least once in a year which is quite a reasonable interval. Besides functional testing is also carried out in the course of fault investigation when a relay or protective gear has failed to operate or when it has mal-operated or when relay settings are altered after a study of the relay co-ordination during the course of fault investigation.

7.2 Relay maintenance tests generally consists of:

- a) Covers cleaned, gaskets seated properly in position
- b) Dusting inside, brushing, removal of foreign matter
- c) Contacts inspected, cleaned and burnished
- d) Screws checked for tightness
- e) Mechanical free movement and contact follow through checked
- f) Proper shape of springs, alignments and their cleanliness checked
- g) Magnet gaps cleaned

- h) Fall of mechanical flag indicator just before contact closure checked
- i) Adjustments and operations checked in 'as found' settings of relay or 'as found' settings of relay noted; adjustments and operations checked at minimum value of relay settings or at test settings prescribed by relay manufacturer and then restoring relay settings 'as left' instead of 'as found' and recording 'as left' settings
- j) Occasionally breakers are tripped by relay operation or by manual contact closing.

8.0 REPAIR TESTS

Repair tests as the name implies, involves re-calibration after major repairs have been made. Such tests are usually made in a laboratory attached to a relay repair shop. Many minor repairs are frequently carried out during maintenance tests and need not involve complete re-calibration tests.

After a component is changed, a test need only to be performed to indicate that the circuit is operational and that the change of the component has not affected the performance of the relay.

9.0 ACCESSORIES FOR TESTING, PRECAUTIONS DURING TESTING AND MAINTENANCE TESTS

- i. Test switches are normally supplied with relays and are installed in the control panels in the case of non-draw out type relays. But in the case of draw-out type relays this is not the case as relay test jacks (plug) are provided. Sometimes relay test terminal blocks are installed where test switches are not installed. These test switches or test jacks (plugs) or test terminal blocks are a convenient access to the voltages and currents seen by the relay. However, sufficient care must be taken to ensure, when checking the currents that the secondary circuits of the C.T. do not become open circuited.
- ii. The test accessories also provide a convenient location to isolate the trip circuits and potential circuits. They also allow test personnel to short out and isolate the current circuits from the relay panel for separate source testing.
- iii. When testing on line it is important to take out only one relay or relay system at a time leaving the other back-up relay or relay system intact in the event of a fault.
- iv. Caution must be taken when using separate source test quantities. The test plug must be inserted into the test switch ensuring isolation from the power system before any equipment is connected to the test plug. Ungrounded test supplies should be used to prevent accidentally

introducing a ground on the secondary circuits which could cause a false trip.

- v. At all times when testing relays on an energised power system, all safety precautions for both personnel and equipment must be observed.
- vi. Many manufacturers offer a variety of portable test sets varying in function and capability. These test sets offer a convenient and quick means of conducting functional tests instead of rigging up a test circuit with several separate instruments and leads.
- vii. Relay and test equipment manufacturer's manuals or NEPAs' own test procedures must be followed. This is the basic information that is to be known before any maintenance test is carried out.
- viii. Past records of relay performance should also be consulted during testing.
- ix. The typical tests on several relays is as follows:

a) **Test method:**

This is by secondary injection by isolating the relay from the power source.

b) **O.C. and E.F. Relays:**

The pick up current at minimum setting checked and adjusted. This is similarly done at relay setting.

Operating times at 2 times and 4 times of relay current checked and adjusted as per relay characteristic.

c) Directional O.C. and E.F. Relays (Voltage/Current restraint):

The directional feature checked up with voltage/current polarity in direction of operation and with reversal of voltage/current polarity.

Other tests on current units are checked as in item (b) above with the directional unit blocked.

c) Differential Relays:

Minimum operating values are checked and adjusted.

d) Distance Relays

Distance characteristic is checked at or near both the fault and load angles. All operating sequences are checked and adjusted.

- x. Tests on the following equipment is conducted at the time of installation/commissioning:
 - a) Bucholz Relay
 - b) C.Ts
 - c) P.Ts
 - d) Thermal Relays
- xi. A maintenance record of the tests conducted is always maintained for future tests, study, co-ordination station-wise / feeder-wise and for fault investigation

10.0 FAULT INVESTIGATION/RELAY OPERATION

10.1 Immediately on the occurrence of a fault and tripping caused by relay operation, an investigation is carried out to ensure that the relay co-ordination is in order and also that the relay operation is in order.

10.2 The procedure generally followed for fault investigation is as follows:

- a) The cause of the fault is located, and considered
- b) The effect of the fault on the protective gear is considered
- c) The clearing of the fault by the current operation of the primary relays is verified with reference to tripping, relay flag indication and audio visual annunciation.
- d) If there is any mal-operation or if the primary relays have failed to act, the relay co-ordination is checked and subsequently functional tests carried out on the relays and protective gear.

10.3 Normally a register of tripping is maintained feeder-wise/station-wise and alongside relay operations are remarked as OK/Not OK and if Not OK, measures taken to rectify are recorded.