9

Combination of Hydro-Electric and Steam Stations

9.1 Types of Power Station

Electrical power development and its use affect the standard of living in a country. Increased industrialization and hence a better standard of living become possible with increased availability and consumption of electrical energy. With increased industrial development in a country, there is more and more demand for electric power. It is, therefore, necessary to tap all the sources in the country for the development of electric power as well as to use them most economically to produce and use maximum power. Some countries are endowed with rich hydro-resources, and in others the fuel resources such as coal and oil are limited. There is, therefore, a trend to investigate the economics of the combined working of electric power plants, and to investigate all possible ways of generating electric power.

Stations of conventional types that can be developed are hydro-electric, steam and Diesel. These can be supplemented by gas-turbine and nuclear plants wherever it is possible and economical to use them in a given location, depending on the available resources. The detailed factors affecting the location of hydro-electric and thermal stations as well as nuclear stations were discussed in previous chapters. Hydro-electric stations can be developed only at sites where a large quantity of water is available at sufficient head, and where water can be stored by the use of dams in naturally favourable positions. Steam and other thermal stations can be located at or near the load centres, while in most cases hydro-electric power has to be transmitted over long dis-

tances. In considering the economy of power development, the transmission liability of hydro-electric projects should be taken into account, and the economic feasibility of a project should be proved before pursuing it.

When a number of stations are worked in combination to supply an electric power system, they are all connected together and the system is known as an interconnected system. In such a system a number of power stations can be worked with great reliability and economy. Large hydro-electric systems like that of the Tennessee Valley Authority have been extended by the addition of steam stations to effect economy, and the T.V.A. system now consists predominanently of steam stations in combination with hydro-electric stations. When developing different types of power stations to work in combination, the exact capacity of each type at different stages of system load development has to be carefully designed and its detailed economy worked out before the different projects can be finally approved.

9.2 Advantages of Combined Working of Different Types of Power Station

With the interconnexion of a number of power stations, the reliability of supply to the consumers is much greater than in an isolated system with only one power station. This is because, in the event of power failure at one of the stations, the system can be fed from the others to avoid complete shut-down. The reliability of hydro-electric units with reference to the capacity available is dependent on the frequency and duration of forced outages arising from mechanical, electrical or structural failures associated with the units, as well as the effects of the river flow, floods and the storage available at any time during the year at particular locations. Forced outages of steam stations depend on steam supply conditions and failure of efficient working of boilers and turbines as well as the auxiliary plant. The forced outage rates for hydro-electric stations are less than those for steam stations.

The interconnexion of a number of power stations always reduces the amount of generating capacity required to be installed as compared to that which would be required without interconnexion. The amount of such reduction depends on the relation

of the various factors and characteristics of the interconnected system and the desired degree of service reliability. By interconnexion, the spinning reserve required in a power system is reduced. By interconnexion with other systems the construction of new generating capacity in a particular system can be spread over a period, energy being purchased until the additional capacity becomes available.

To determine the capacity benefits resulting from interconnexion, it is necessary to evaluate the composite effect of all the diversities that may exist in the power system. The diversities are due to differences that may exist in the times of occurrence of daily peak loads, variation in daily peak loads, maintenance requirements which cause some plant shut-down, seasonal reduction in load-carrying capacity of hydro-electric or steam or other stations in the system, and forced outages. The effects of the number and size of generating units, pressures and arrangements of boilers and turbines should be considered. The composite effect of all the diversities can be evaluated by probability methods. The various methods of loading the generating units in the most economical way should be studied under interconnexion. An evaluation of the savings derived from reduction of the spinning reserve of the plant and from economic loading of the generator units can be calculated. This is done by computing the annual costs for each system considering all the above items with or without interconnexion. The difference between the two represents the saving that would be effected by interconnexion.

9.3 Need for Co-ordination of Different Types of Power Station

The annual power duration curve of a power system shows the variation of load on the system and hence also on the individual power stations supplying the system. The power plants have to work at different load factors. Some are used to supply the load on the base portion of the load curve and are classified as base-load plants. These run at a high load factor. The remaining plants have to work as peak-load plants to supply the rest of the load, on the top portion of the load curve, and these work at a low load factor.

It is very rare that a country has hydro-resources sufficient to supply economically all the demand for electric power. This is because of the topographical situation of the hydro-projects and the transmission liabilities of hydro electric stations. Also some hydro-electric stations have so little water stored that they have not enough firm capacity to supply any load variation at any time as needed by the system conditions. The loads on a system grow rapidly, and it is necessary to plan and build power stations in time to meet the requirements. Hydro-electric stations take 4 to 8 years for planning and building; some sites are not economical for development. It is possible to plan and install steam stations in 3 to 4 years, and the construction work can be faster than for hydro-electric stations of the same capacity. Steam stations can be used with advantage in combination with hydro-electric stations to obtain economy from the mixed system. The initial capital cost of a steam station is less than that of a hydro-electric station of the same capacity. Steam stations can be used on any portion of the load duration curve, although it is expensive to use them as peak-load stations at low load factors.

In general, the power plants used to supply an electric power system can be divided into two types, base-load plants and peak-load plants. Base-load plants run throughout the year and have high load factors. The economic characteristics of base-load plants should be such that they supply power at high capital costs but low cost of operation. Peak-load plants run for a few hours in the year and work at low load factors. The economic characteristics of peak-load plants should be such that they supply power at low capital costs, although at high cost of operation. Peak-load power stations should be capable of starting quickly and should be inexpensive in starting and shutting-down operations.

In addition to steam stations to be operated in combination with hydro-electric stations, the other types of station that can be used are gas turbine, Diesel, pumped-storage and nuclear. Nuclear power stations are used as base-load stations working at high load factors, generally not less than 80%. The characteristics of nuclear power stations were described in chapter 6. Diesel stations can be used for loads of load factor not less than 20%; at lower load factors they are not economical. As Diesel stations are

quick-starting, they can be used as peak load plants. Details of their characteristics were discussed in chapter 3. Pumped-storage plants are used as short-time peak-load plants in suitable situations.

When considering the use of hydro-electric, steam and other types of power station in a system, it is first necessary to draw the annual load duration curve of the system and fit the various types of plants into the area under the curve. The next consideration is the annual load factor of the hydro-electric stations. Here the firm annual load factor and the average load factor should be considered. The optimum installed capacity of the hydro-project or projects in relation to the total system load should be decided, taking into account the system load curves and load demand at the present time as well as estimated for the near future. It is also necessary to consider whether any other hydro-projects and thermal-station projects are likely to be developed in the future, and how best they can be fitted in with the projects under immediate consideration. Decisions regarding the design of hydro-electric stations will involve the detailed study of the estimated cost of generation and transmission of power for different installed capacities at various possible sites. The total firm power and the energy that would be available from the hydro-electric and thermal plants can be satisfactorily combined so as to meet the practical operating requirements.

9.4 Run-off River Plant in Combination with Steam Plant : Size of Plant in each Station

At run-off river plants, the quantity of water available is not steady throughout the year; the flow varies. It is more abundant in rainy seasons and dries up or is considerably reduced in dry seasons. If pondage is limited or is not available, the firm power is affected and it is not possible to use run-off river plants to supply the load of the power system, which is always variable, depending on the nature of the load curve. It is desirable to work a hydro-electric station of this sort in combination with a steam or other thermal station to supply the load economically and to maintain system reliability. The run-off river hydro-electric station can be used as a base-load station during rainy seasons, when

sufficient water is available, the thermal station supplying the peak load; while in dry seasons, when the flow of water for the run—off river plant is low, the thermal station can be used as a base-load station, the hydro-electric station being used as a peak-load station.

To illustrate the principle, a case of one run-off river station in combination with one steam station will be considered. The steps in which the problem should be considered are as follows :

1. Plot the load curve of the system to be supplied and calculate the load factor. In doing this, study the representative average load curve during the year. Daily load curves would differ to some extent during the year and would not be exactly identical.

2. To find the ability of a hydro-electric station to supply part of the power required by the system, find the flow and head at the project, and the efficiencies of the turbines and generators in the station, and calculate the power duration curve for the year.

$$\text{Power} = \frac{0\,736}{75} Qwh\eta \text{ kilowatts}$$

as given by eqn. (7.2).

Plot the power in kilowatts against the percentage of time for which it would be available during the year.

3. The peak load as obtained from the load curve multiplied by the load factor gives the prime rate of power which must be supplied by the combination of steam and hydro-electric stations. This is known as the prime hydro-steam rate. Find it.

4. From the load duration curve, find the minimum hydro-rate, i.e., the minimum power which can be supplied by the hydro-station even under the worst conditions.

It is a general practice to regard the minimum power available for 97% of the time from the power duration curve as the minimum hydro-rate. If the transmission loss is taken into consideration, the power available is the minimum hydro-rate less the transmission loss.

5. Find the maximum steam rate. This is the power required from the steam station when the hydro-electric station is supplying power at the minimum hydro-rate.

Maximum steam rate=Prime hydro-steam rate

$$-\text{Minimum hydro-rate} \quad (9.1)$$

Find the ratio $\dfrac{\text{Minimum hydro-rate}}{\text{Prime hydro-steam rate.}}$

For our present purposes, call this ratio x.

6. The total energy required by the whole system is given by the area under the load curve. Taking the average daily load curve for a year, the energy required during the whole year will also be known. If the hydro-electric station is worked as a peak-load station during the period of minimum flow, it will supply energy for a shorter time and this energy will be at the top of the area under the load curve (the shaded area in Fig. 9.2). The total area under the curve represents the total energy required. The energy supplied by the hydro-electric station is x times the total energy, where x is the ratio of minimum hydro-rate to prime hydro-steam rate. Thus, when the hydro-electric station is worked as a peak-load station supplying x times the area under the load curve, draw a line of demarcation dividing the area under the load curve into two parts. The hydro-electric capacity required is from th ighest part of the load curve to the line of load division. The remaining load, down to the base line, is to be supplied by the steam station.

The calculations and procedure will be clarified by the following example.

Example 9.1

A hydro-electric power project has the following flow available during the year. A run-off river plant is installed with a small pondage so that the minimum hydro-rate can be taken to correspond to the power that would be available for 97% of the time on the power duration curve for the year. The head is 100 m. The overall efficiency of the plant—turbines and generators—is 88%. The flows available for various percentages of time during the year are shown in Table 9.1. The total load on the power system is shown by the load curve. The variation of load on a representative day of 24 hours is shown in Table 9.2. For the hydro-station, the transmission liability is to be taken into account, and the transmission loss may be taken as 6% for the calculation of plant capacity. The hydro-station is to be used as a peak-load plant

when the flow available is low, and as a base-load plant when a large quantity of water is available in the rainy season. As the hydro-station cannot supply all the load at all times, a steam plant is to be used in association with it. Find the capacity of the plant to be installed in the hydro-station and in the steam station to cope with the load.

Table 9.1

Availability Percentage of year	Q m^3/sec	Power, 0.865 Q MW
1	300	260
5	240	208
10	200	173
15	160	138.5
20	139	120
30	106	92
40	78.5	68
50	56	48.5
60	40	34.6
70	32	27.6
80	28	24.2
90	24	20.8
97	20	17.3
100	12	10.4

Table 9.2

Data for load curve of the power system.

Hour a.m.	Load MW	Hour p.m.	Load MW
1	40	1	80
2	40	2	95
3	20	3	95
4	20	4	120
5	20	5	130
6	75	6	160
7	120	7	200
8	150	8	180
9	140	9	155
10	130	10	80
11	130	11	60
12	110	12	50

The power available from the hydro-station is given by eqn. (7.2)—

$$P=\frac{0.736}{75}\times 1{,}000\times Qh\eta \text{ kilowatts}$$

$$=\frac{0.736}{75}\times Q\times 100\times 0.88=0.865\ Q \text{ megawatts}$$

where Q is the flow in cubic metres per second, and h is in metres, the density of water, w, being 1,000 kg/m³.

Thus from the flow duration curve, the power duration curve can be determined directly. Table 9.1 gives the flows available at the hydro-site, and is plotted as a power duration curve by use of the above relation for this case.

The minimum hydro-rate is the power that the hydro-station can supply for 97% of the time; here it is 17.3 MW. Accounting for 6% transmission loss, the minimum hydro-rate is 94% of 17.3 MW or 16.26 MW. Fig. 9.1 gives the annual flow and power duration curve for the hydro-station.

The total load for 24 hours is 2,400 MW and the maximum load is 200 MW at 7 p.m. Therefore,

$$\text{Load factor}=\frac{2{,}400}{24\times 200}\times 100=50\%$$

Fig. 9.2 shows the load curve of the power system.

$$\text{Prime hydro-steam rate}=\text{Peak-load}\times\text{Load factor}$$

$$=200\times 0.50=100 \text{ MW}$$

$$\frac{\text{Minimum hydro rate}}{\text{Prime hydro-steam rate}}=\frac{16.26}{100}\times 100 = 16.26\%.$$

When the hydro-station is worked as a peak-load station at the time of minimum flow, it can supply 16.26% of the energy to the system. The line of demarcation indicating 16.26% of the total area under the load curve as marked from the top of the curve gives the capacity of the hydro-station that is needed for the purpose. The actual capacity will be greater to take care of the transmission loss incurred in supplying the load to the load centre. The total energy supplied to the power system from the two stations is 200 x 0.50 x 24 or 2,400 MWh. 16.26% of this energy

$$= 2{,}400\times\frac{16.26}{100} = 390 \text{ MWh.}$$

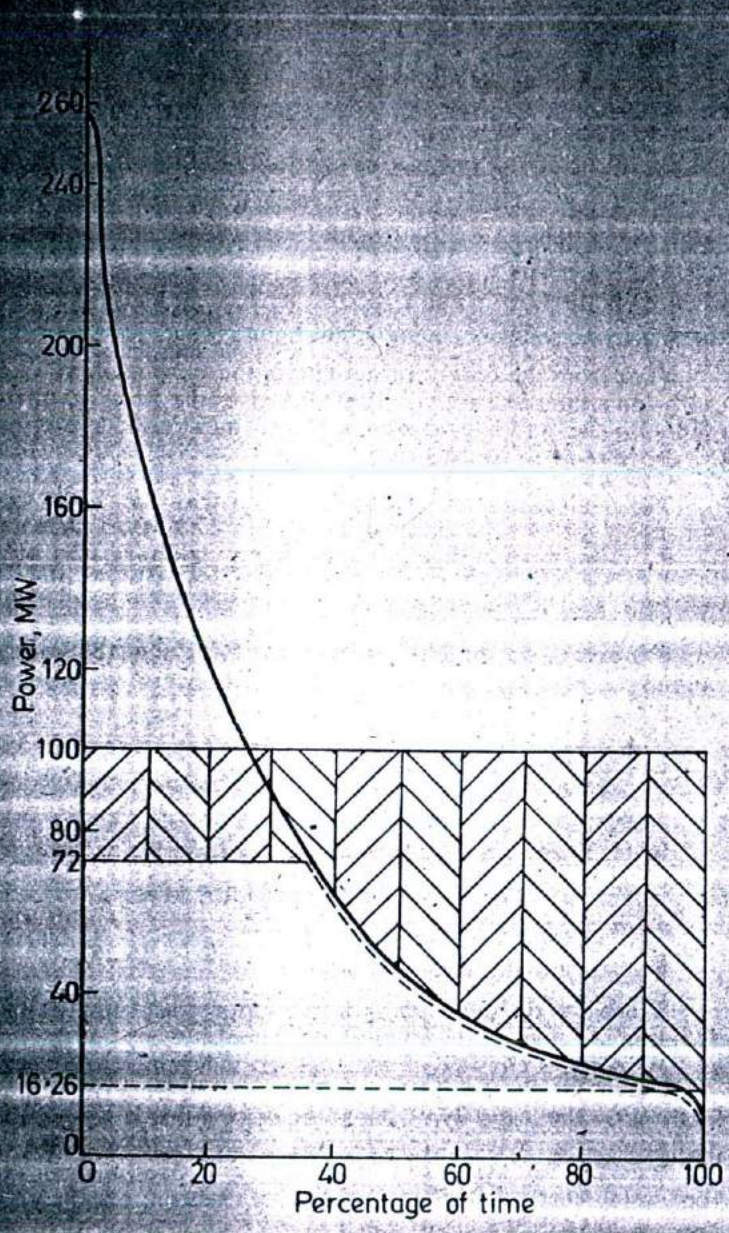


Fig. 9.1. Power duration curve.

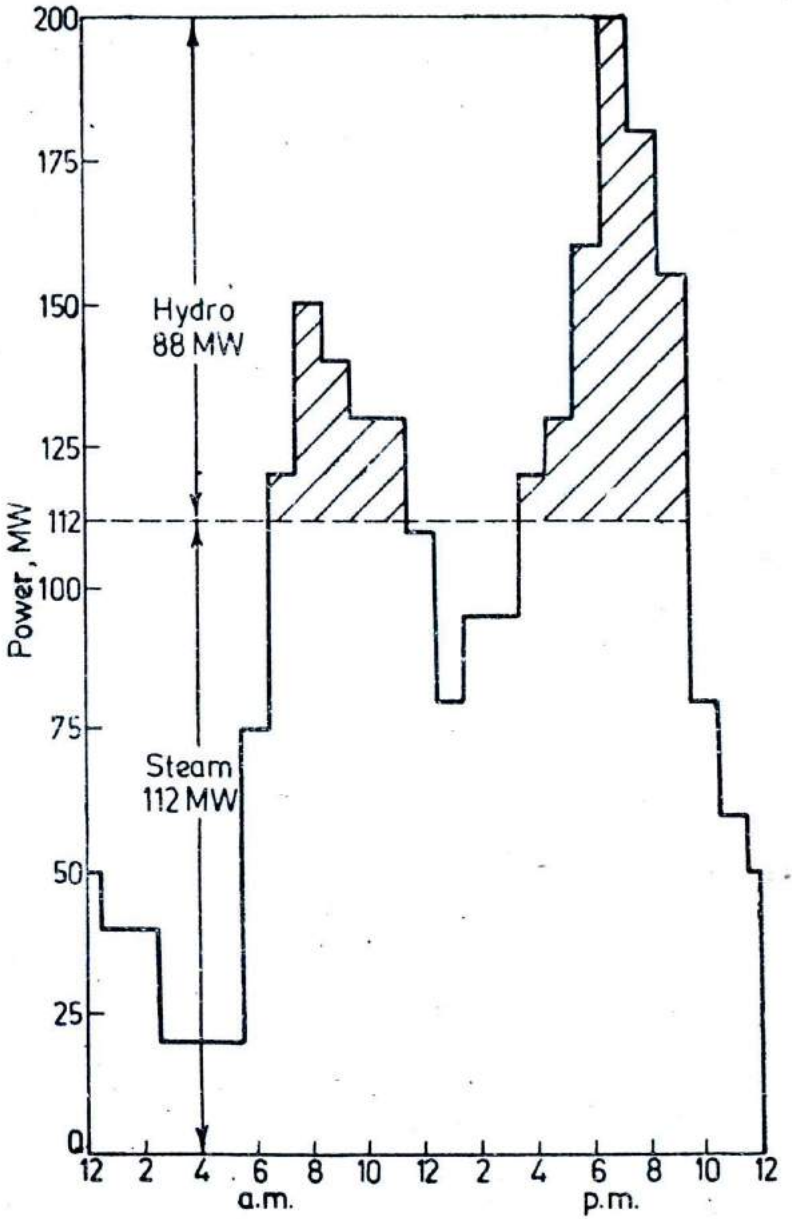


Fig. 9.2. Load Curve

Hydro station worked as a peak-load station with a load factor of 16.26%

The line of demarcation is 88 MW measured downwards from the highest part of the load curve or 112 MW measured upwards from the base line.

The capacity to be installed in the hydro-station, therefore, is 88 MW or taking 6% transmission loss into account, 88/0.94 or 94 MW, and the capacity of the steam station is 112 MW.

9.5 Economics of Run-off River Plant in Combination with Steam Plant

When considering the use of both hydro-electric and steam plants in a power system, a suitable combination for working the hydro-electric plant as a peak-load plant during periods of low flow, and the steam plant as a base-load plant is found as discussed in the last section. The hydro-plant is to be used to the best extent possible when enough water is available, and hence in rainy seasons it will be worked as a base-load plant, the peak-load being supplied by the steam station. It is necessary to work out the economics of the combination during the year, and to find the cost per kilowatt-hour of the energy obtained by combined working and to compare this with the cost when the steam station alone provides the total capacity of the power system. It is then found whether the installation of the hydro-station is justifiable and economically feasible. To illustrate the point, the case is taken of one hydro-station-run-off river type—in combination with one steam station. The load curve of the power system is taken as a representative of the load conditions in the system during the year. The steps in which the problem should be considered are as follows-

1. When the hydro-station is worked on the base-load part of the load curve, draw the line of load division representing the hydro-station installed capacity as measured from the base line. The remaining load, measured above the line of division, will be supplied by the steam station. Find the hydro-station base-load factor.

$$\text{Hydro-station base-load factor} = \frac{\text{Area under base-load portion}}{\text{Area of rectangle circumscribing base-load portion}} \quad (9.2)$$

2. Find the maximum hydro-rate.

$$\text{Maximum hydro-rate.} = \text{Useful hydro installed capacity} \times \text{Hydro-station base-load factor.} \quad (9.3)$$

3. Show the maximum hydro-rate on the power duration curve of the hydro-plant. The difference between the prime hydro-steam rate and the hydro—rate at any time during the year will be supplied by the steam station. The maximum steam rate will occur when the hydro-rate is a minimum, and minimum steam rate will occur when the hydro-rate is a maximum.

4. From the power duration curve, thus marked with different rates of power to be supplied by the two stations, it will be seen that the steam station works at different load factors for different parts of the annual load duration curve or for different parts of the load portions taken by the steam station during the year. The increment in load can be considered for every 5% or 10 % of the time. The load factor of each incremental load on the steam station is given by

$$\text{Load factor of each incremental load} = \frac{\text{Average ordinate intercept}}{\text{Steam station installation.}} \qquad (9.4)$$

5. From the cost data of the steam station, work out the cost per kilowatt-hour of station energy at different load factors, and plot the curve.

6. Find the annual cost of each incremental load for 5% or 10% of time taken as a strip on the power duration curve. Annual Cost of each increment.

$$= \left\{\begin{matrix}\text{Average}\\ \text{ordinate}\end{matrix}\right\} \times \left\{\begin{matrix}\text{Percentage}\\ \text{of time}\end{matrix}\right\} \times 8{,}760 \text{ (hours)} \times \left\{\begin{matrix}\text{Cost}\\ \text{per kWh}\end{matrix}\right\}$$

The total annual cost of the steam station is the sum of all the annual costs of all increments of loads.

7. Find the annual cost of the hydro-station.

8. Find the total annual cost of both the hydro- and the steam station, and hence the cost per kilowatt-hour of the whole system.

9. Make an economic analysis of the combined working of the hydro-electric and steam stations, and find the saving effected per year by installing a hydro-station to work with the steam station instead of using the steam station alone. Find the economics of the combined working and show whether or not the hydro-project is justifiable.

The calculations and procedure will be illustrated by example 9.2. which continues the analysis, begun in example 9.1, of the combined working of the hydro-station and steam station to supply the system load curve shown in Fig. 9.2. The annual power duration curve for the hydro-station is shown in Fig. 9.1.

Example 9.2

The cost data are as follows—

Hydro-electric station

Capital	Rs. 1,500 per kW
Fixed	9%
Operation and maintenance ...	Rs. 4 per kW per year
Transmission liability ...	Rs. 15/- per kW of installed capacity per year.

Steam station

Capital	Rs. 850 per kW
Fixed	13%
Fuel (Coal)	Rs. 30 per metric ton.
Fuel consumption ...	0.5 kg per kWh
Operation and maintenance	18% of fuel cost.

The whole of the operation and maintenance costs may be regarded as variable – a fair approximation – so that the total variable costs will be 1.18 times the fuel cost.

Find the cost per kilowatt-hour with combined working of the hydro-electric and steam stations. Find the cost per kilowatt-hour if only the steam station were used. Find the saving effected by combined working. Work out the economic analysis and show whether or not the hydro-project is justifiable.

The hydro-station has a useful capacity of 88 MW, neglecting the transmission loss. When it is used as a base-load station, this capacity can be represented on the base-load portion of the load curve. The hydro-electric base-load factor is the ratio of the area under the base-load portion of the curve to the area of the rectangle circumscribing the base-load portion, usually expressed as a percentage. This is shown in Fig. 9.3.

$$\text{Hydro-electric base-load factor} = \frac{\begin{array}{l}(40\times 2)+(20\times 3)+(75\times 1)+(6\times 88)\\ +(80\times 1)+(8\times 88)+(80\times 1)\\ +(60\times 1)+(50\times 1)\end{array}}{88\times 24}$$

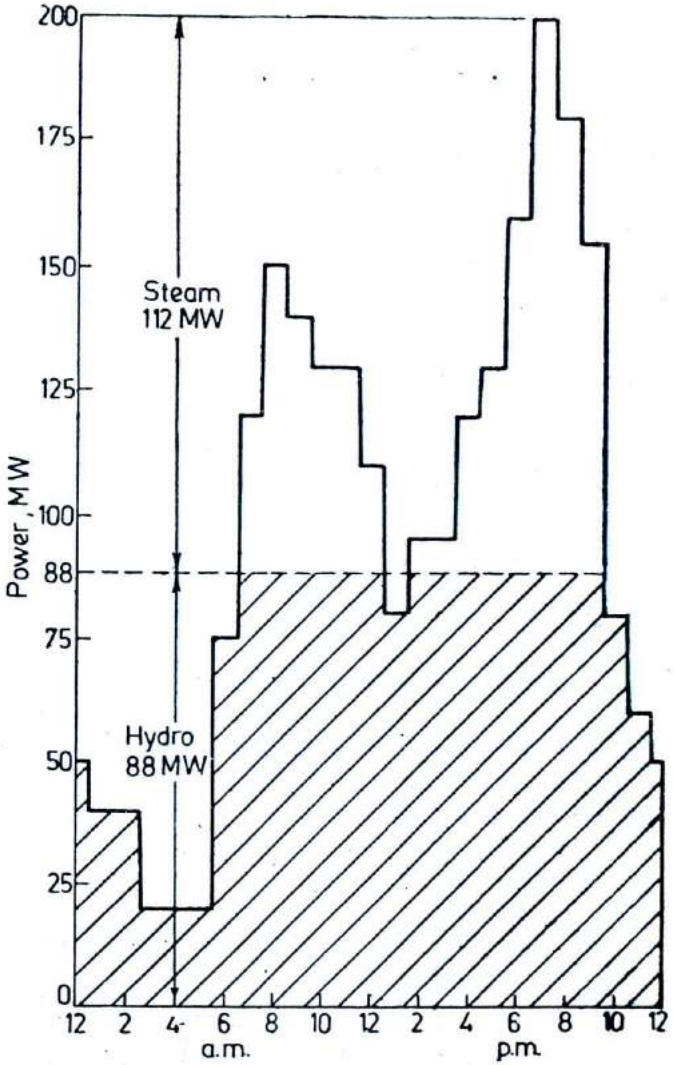


Fig. 9.3. Load Curve.

Hydro station worked-as-base load station with a load factor of 81.3%

$$= \frac{1,717}{2,112} = 0.813$$

Maximum hydro-rate = useful hydro-installed capacity × hydro base-load factor

$$= 88 \times 0.813$$

$$= 72 \text{ MW approximately.}$$

The maximum hydro-rate is shown in Fig. 9.1.

		MW
Prime hydro-steam rate	..	100
Minimum hydro-rate	..	16.26
Maximum steam rate	..	100 − 16.26 = 83.74
Maximum hydro rate		72 approx.
Minimum steam rate		100 − 72 = 28

From the cost data of the steam station, the cost per kilowatt-hour supplied by the steam station at different load factors is worked out.

If the plant capacity is taken as 1 kW for working out the costs, the energy produced per hour is 1 kWh at unity load factor and will be less in other cases, proportionately to the load factors. The cost of fuel is Rs 30 per metric ton, i.e., per 1,000 kg. The cost per kilogramme is 3,000/1,000 or 3 p. The fuel consumption is 0.5 kg/ per kWh. The cost per kilowatt hour is, therefore, 0.5 × 3 or 1.5 p. Adding 18% for operation and maintenance a good approximation of the variable cost is 1.5 × 1.18 or 1.77 p. per kWh.

Table 9.3

Load factor	Energy produced in 1 hour with 1-kW load	Fixed cost per hour	Fuel and operating cost per hour	Total cost per hour	Cost per kWh
per cent	kWh	P	P	P	P
100	1	1.26	1.77	3.03	3.03
80	0.80	1.26	1.416	2.676	3.34
60	0.60	1.26	1.062	2.322	3.88
50	0.50	1.26	0.885	2.145	4.29
40	0.40	1.26	0.708	1.968	4.9
20	0.20	1.26	0.354	1.614	8.07

The capital cost of the steam station is Rs 850 per kW, and its fixed costs are 13%. Therefore,

$$\text{Fixed costs of steam station} = \text{Rs}\frac{850\times 13}{100} \text{ per kW per year}$$

or for a 1-kW installation $\frac{850\times 13\times 100}{100\times 8{,}760} = 1.26$ P per hour

The cost per kilowatt-hour for the steam station working at different load factors can be set out as in Table 9.3.

The curve is plotted showing the variation of cost with load factor as in Fig. 9.4., from Fig.9.1., when the maximum hydro-rate is shown on the diagram, the remaining part, or the difference between the prime hydro-steam rate and the hydro-rate at any point on the power-duration curve, indicates the rate at which power has to be supplied by the steam station. The average ordinate at the centre of each strip considered divided by the installed steam-station capacity gives the load factor of the station for the portion of the strip considered.

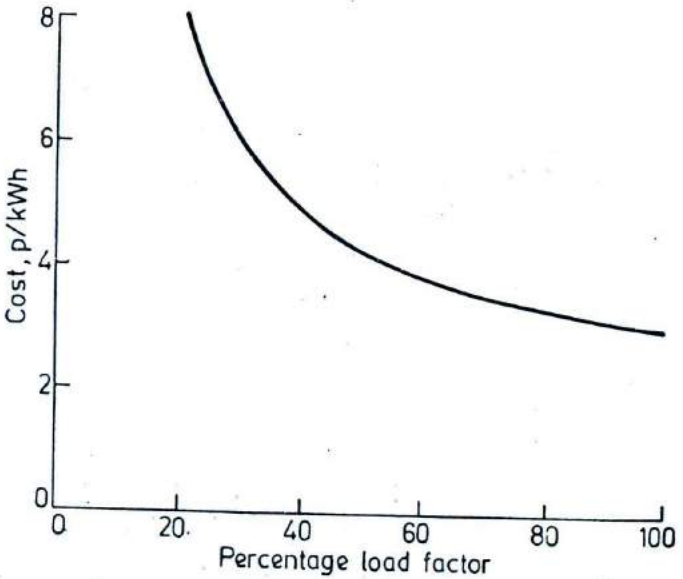


Fig. 9.4. Dependence of cost on load factor (steam station.)

The annual cost of the steam station supplying loads at different load factors, as shown by the shaded area in Fig. 9.1 can be worked out by finding the load factor for each strip taken for 10%

of the time interval, finding the cost of energy per kilowatt-hour for the steam station from Fig. 9.4 for different load factors and calculating the annual cost of load corresponding to each strip. The total annual cost of the steam station will be the sum of the costs for all the strips considered. The results for this particular problem are shown in Table 9.4.

Table 9·4

Steps	Average ordinate	Load factor = Average load / 112 MW	Cost per kWh	Annual cost = Cost per KWh × Average load × $\frac{10}{100} \times 8.760 \times 10^3$
per cent	MW		P	Rs
0-10	28	0.25	6.9	$1,692 \times 10^3$
10-20	28	0.25	6.9	$1,692 \times 10^3$
20-30	28	0.25	6.9	$1,692 \times 10^3$
30-40	29	0.26	6.8	$1,730 \times 10^3$
40-50	40.5	0.36	5.3	$1,878 \times 10^3$
50-60	60	0.535	4.1	$2,155 \times 10^3$
60-70	71	0.633	3.75	$2,330 \times 10^3$
70-80	75	0.67	3.65	$2,400 \times 10^3$
80-90	78	0.685	3.6	$2,460 \times 10^3$
90-100	84	0.75	3.45	$2,540 \times 10^3$
				$20,569 \times 10^3$

The capital cost of the hydro-station and project is Rs 1,500 per kW and its installed capacity is 94 MW. The fixed charges are 9%, or $1,500 \times 0.09$ = Rs 135 per kW. The operation and maintenance costs are Rs 4 per kW, and the transmission cost is Rs 15 per kW. Thus the annual cost of the hydro-station is 135 + 4 + 15 = Rs 154 per kW.

Annual cost of hydro-station $= 154 \times 94 \times 10^3$

$= \text{Rs } 14,476 \times 10^3$

Annual costs

	Rs
Steam station	$20,569 \times 10^3$
Hydro-station	$14,476 \times 10^3$
	$35,045 \times 10^3$

Energy transmitted per year $= 100 \times 10^3 \times 8,760$

$= 876 \times 10^6$ kWh

$$\text{Unit cost of hydro and steam stations} = \frac{35{,}045 \times 10^3 \times 100}{876 \times 10^6}$$

$$= 4 \text{ p per kWh}$$

If the whole system were supplied by a steam station of sufficient capacity, the cost per kilowatt-hour at 50% system load factor would be 4.29 p, from Fig. 9.4.

The saving per annum by installing the hydro-station is $4.29 - 4.00 = 0.29$ p per kWh or

$$\text{Rs } \frac{876 \times 10^6 \ (4.29 - 4.00)}{100} = \text{Rs } 2{,}550 \times 10^3$$

It is, therefore, seen that combined working is economical in this case.

9.6 Hydro-Electric Plants with Ample Storage in Combination with Steam Plants

The hydro-electric station with ample storage has more firm power, as explained in the last chapter and shown in Fig. 8.1. Referring to the diagram, the firm power corresponds to the area defghkd, and this will always be the dependable rate, rather than the minimum hydro-rate corresponding to that shown for a run-off river plant as in the last section. The secondary power is shown by the area dbckd, and is available for short periods. If this is supplemented by a steam station, the effective hydro-steam rate of supplying power to a power system can be increased.

Working on the same principles as in the last section for the combination of run-off river plant and steam plant, the combined capacity of a hydro-electric plant with ample storage and a steam plant working economically can be found. The plant with ample storage can be worked as either a base-load plant or a peak-load plant, depending on the load demand, and there is comparatively more flexibility for its use on the load curve than is possible with a run-off river plant with little storage. The steam station would be working at different load factors during the year and its costs can be worked out under different operating conditions on the same principle as in the last section. The capacities of the hydro-station and steam-station have to be chosen to justify the final economy in the production of electrical energy at a cheaper rate.

The final economy in operation is effected by a proper choice of generator loadings in each type of station, considering the fuel and operational economy of the steam station and the storage position at the hydro-station. Various methods of loading the generators economically will be discussed in detail in a later chapter.

9.7 Pumped-storage Plants in Combination with Ordinary Hydro-Electric Plants

A pumped-storage plant is useful in the system to supply sudden peak-loads of brief duration. Old and inefficient steam stations are used for this purpose where peak-load hydro-plants or pumped-storage plants are not available. Where suitable conditions exist, it is desirable to study the possibilities of installing a pumped-storage plant to replace the old steam plant for the purpose of supplying sudden peaks on the system for very short periods-a few hours in the year.

A pumped-storage plant requires a suitable site at the tail-race of a hydro-station to store water in a tank from which it can be pumped to a higher level nearby and used again at the peak-load time. The pumped-storage plant is useful in combination with a hydro-plant having limited storage so that the water discharged from the turbine to the tail-race can be used again economically.

The electric power required for pumping is supplied at off-peak hours from other thermal stations working in the system. By using a pumped-storage plant at the peak-load time in combination with a hydro-plant with limited storage, the load factor of the station is improved. The pumped-storage plant can be made more effective by the use of reversible pump-turbine sets. The efficiency of such a set for combined operation is about 73%.

The pumped-storage scheme has a number of advantages.. It transfers peak-load and energy from peak to off-peak periods, which permits more economical loading of thermal plants. It minimizes wastage of availiability of off-peak energy. It permits the storage of energy over week-ends and holidays when the load on the system is small. The pumped-storage plant provides

standby power which otherwise would have to come from thermal plants.

It is necessary to study the problem of choosing between an old and inefficient steam station and a pumped-storage station for short peak-load operation. This consists in determining whether a pumped-storage installation could be developed to increase the load capacity of the system at an annual cost lower than that of additional thermal capacity for the same purpose. In this study a number of factors need to be considered—

1. Estimate the output of the main hydro-station under various flow conditions. This will give an idea of the maximum possible load that this station can take.

2. Study the load curve of the system on working days as well as weekly and other holidays. Find how much of the system load can be supplied by the main hydro-plant and how much is short-time sudden peak-load. Compare the loads on working days with those on holidays.

3. Estimate the volume of the reservoir that would be available at the upstream level, and the capacity of the pond that it is possible to build at the tail-race level for pumping water to the higher level, the capacity of the pump-turbine plant that would be required for the purpose, the cost of the pumping and generating set with reversible operation, the time required to fill the storage reservoir, and the time to empty it to supply the required rate of load.

4. Estimate the cost of the steam plant to supply the necessary peak-load, and consider the economics of the steam plant.

5. Compare the economics of the steam plant and the pumped-storage plant of the same capacity, to justify the installation of the pumped-storage plant.

9.8 Co-ordination of Hydro-electric and Gas-turbine Power Stations

Gas-turbine plants are the cheapest type in some situations, when they are used as intermittent or peak-load plants in combination with base-load plants. They are particularly useful and economical when the amount of energy required is a small part of

the total energy to be supplied by the whole system and the load factor of the load is less than 15%.

The size of the gas-turbine plants used in a large system varies normally from 10 to 25 MW, and the largest size used is about 70 MW. Gas-turbine plants are cheaper in capital cost than steam stations of the same size; for example, a 40-MW gas-turbine plant costs about Rs. 600 to 800 per kW, whereas a condensing type of steam generating plant of the same size costs about Rs. 800 to Rs. 1200/- per kW. The fixed charges on gas-turbine plants are lower than those on steam plants, being about 10.5% as against 13%. The thermal efficiency of gas-turbine plants is 22% to 28%, as compared to the 25% to 32% of condensing steam plants. Although there is an increase in fuel costs owing to lower thermal efficiency at low load factors, this is compensated by lower fixed charges as well as lower operating and maintenance charges. Gas-turbine plants have a number of advantages over steam plants.

1. When a gas-turbine plant is not working, no attendance is required.

2. The space required for a gas-turbine plant is smaller than that required for a condensing steam plant of equal size.

3. The attendance required for the operation of a gas-turbine plant is much less—about one-third—than that required for a steam plant of equal size.

4. A gas-turbine plant can be started quickly and has a short starting time, compared to steam stations.

5. The fuel consumption of a gas-turbine plant is low during starting and shutting-down periods.

6. The circulating water consumption of a gas-turbine plant is less than that of a steam-turbine plant of equal size.

7. A gas-turbine plant can be operated partially or fully by automation.

8. A gas-turbine plant does not need very heavy foundations.

9. The installation of a gas-turbine plant takes less time.

10. A gas-turbine plant can be installed at the "end of the line" with particular advantage, as this location enables the

generator to be used as a *synchronous compensator** when necessary in the power system.

When a generator at the end of the line is used as a synchronous compensator, it provides reactive power (KVAr) to improve the power factor of the system. However, the location should be such that the transportation costs of the fuel are not excessive and are within the permissible limits economically. Automatic coupling should be provided between the generator and the turbine so that it can operate at full speed for switching-in or for disconnexion.

Without a compensator the size of the transmission lines would have to be increased merely to improve the power factor: e. g. constructing a double circuit line or increasing the cross section of the conductors for carrying the same load. with a compensator this increase can be deferred until further load has been developed.

When gas-turbine plants are used in combination with hydro-electric plants, they raise the firm capacity of the hydro-electric plants. The gas-turbine stations give the hydro-stations more dependable capacity against normal seasonal variations of stream flows, irregular variations in stream flows from year to year, and transmission line outages due to various causes.

Gas-turbine plants are considered for co-ordination with hydro-plants in countries where the cost of gas is not excessive, the gas-turbine stations being used as peak-load plants. The exact size and location of a gas-turbine station should be found by studying the economics of the plant as well as the power systems in detail.

9.9 Co-ordination of Hydro-Electric and Nuclear Power Stations

The nuclear reactors used for power station purposes can be either thermal or fast reactors. In thermal reactors, the energy of neutrons causing fission corresponds to the temperature inside the reactor. In fast reactors, the energy of the neutrons is nearly at the same level as that at which they emerge as fragments from

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*A synchronous compensator is a machine operating as an unloaded motor and used for the improvement of power factor. It was formerly called a "synchronous condenser" or "synchronous capacitor" but, by controlling its excitation, it may function either as a, capacitor, taking a leading current, or as an inductor, taking a lagging current.

the fissile material. In practice the types of reactor used for nuclear power stations are—

1. Gas-cooled graphite-moderated natural-uranium type.
2. Boiling-water type using enriched uranium.
3. Pressurized-water type which uses slightly enriched uranium and in which water under pressure is used as both coolant and moderator.

Fast reactors have not yet been developed for use in power stations. There is a trend towards building nuclear power stations to conserve the supplies of conventional fuel in countries where there is a shortage of these supplies and deposits of uranium and other materials such as thorium are available.

The nuclear power station unit size is large, generally not smaller than 150 MW, for economic reasons. The initial cost varies between Rs 2,000 and Rs 2,500/- per kW. These plants have to be used at high load factors, generally at least 90% or so. Close and quick regulation of a nuclear power station plant under variable load operation is difficult, and hence it has to be used as a base-load plant, practically on block load (i.e. fixed load). When used in combination with hydro-electric plants in a power system, the role of nuclear power stations is therefore their use on the base load. The hydro-stations can supply the variable load and the load at varying load factors, depending on the type of the hydro plants used. The system should have loads large enough to justify the large size of nuclear power stations.

It is necessary to work out the detailed economics of the combined working of hydro-electric and nuclear power stations to justify the inclusion of nuclear power stations in the system. Some of the factors to be considered are that nuclear power stations can be located near the load centres, whereas hydro-stations may have to be far away from the load centres and need long transmission lines involving transmission liability. Compared to steam stations used in combination with hydro-stations, nuclear power stations have the advantage of not requiring conventional fuels, so that these can be used for other purposes; moreover, nuclear power stations require very small quantities of fuel so

that there is a saving in the cost of transportation. Some details of the costs of various items for working out the economics of nuclear power stations were discussed in Chapter 6. For the combined operation of hydro-electric and nuclear power stations, the annual power duration curve of the system is drawn and the nuclear power station capacity is shown on the base-load portion of the diagram. The cost of the hydro-station working on the remaining portion of the curve is worked out to fiind the cost per kilowatt-hour produced in combined operation. In calculating the cost of a nuclear power station, the fabrication of nuclear fuel must be taken into account. It is also possible to have some fissile products in the reactor which will produce revenue by sale; this revenue also should be estimated.

9.10 Co-ordination of Different Types of Power Plant in a Power System

In a power system which is interconnected and has a number of power stations of different types working in parallel, it is necessary to co-ordinate them and use the plants in the best possible way. Co-ordination is important in the design, planning and development of the system, and in achieving the most economical operation. The types of station that are used are hydro-electric, steam, gas, Diesel and nuclear. It would depend on the available resources in a country whether all or only some types of plant would be used and on the predominance of one type over the others to make the whole system economical.

Diesel plants are used in small capacities-1,000 to 3,000 kW-when cheap oil is available. This type of plant is useful as a peak-load, standby or emergency plant. When it is used as a peak-load plant, the load factor should not be too low. If it is used for load factors of less than 25%, it is expensive and is not cheaper than other types of peak-load plant if they are available in the system. Diesel stations of small capacity are first used as "nursery stations" in a power system when the system load is building up in different areas, the system being extended subsequently by interconnexion, as described in Chapter 3.

Hydro-electric, steam, gas, and nuclear power plants, their characteristics and approximate costs have been discussed in pre-

vious chapters, and the principles of their co-ordination have been discussed in the last few sections of the present chapter. The co-ordination of hydro-electric and steam, hydro-electric and gas, and hydro-electric and nuclear power stations have been discussed. When stations of all types are to be included in the system, the problem of their co-ordination for the best possible working and economy becomes quite complicated and a number of factors have to be considered. Initial capital costs, fuel consumption, operation and maintenance costs, the availability of fuel resources, the economics of base—load and peak-load operation, saving of conventional types of fuel, transmission liability, costs of incremental power, and costs of incremental transmission losses in the interconnected system – these are some of the points to be considered before finally apportioning the area under the annual load curve or power duration curve for the effective and economic working of the plants in combination to supply the total system load. The best co-ordination will depend on the particular situations and availability of the fuels and resources in the country and the particular power system under study.

When all types of power plant are available in the power system, the area under the annual load duration curve may be divided as suggested in Fig. 9.5. If run-off river plants are available and a large amount of power can be used in the year, it is worth while using the power as and when available, and the run-off river plants may be placed on the base-load portion of the curve. The next block can be allotted to nuclear power stations working as base-load plants at a high load factor of not less than 90%. Above this block, hydro-electric plants with ample storage capacity and water availability can be used. The next block can be used by steam plants with a load factor of about 60% or above. For the peak-load portion of the load duration curve with load factors between 30% and 40%, hydro-plants with limited storage can be used with advantage and economically. For peak loads at very low load factors-less than 10% to 15%-gas turbine plants and pumped-storage plants can be used most effectivelly.

Fig. 9.5 is only indicative, the distribution of loads and the types of the plant to be used on the different portions of the annual

load duration or power duration curve being arbitrary. In deciding the types of plant to be used and allocating their loads on the annual load duration curve, location conditions have to be studied carefully, considering a number of points suggested above namely availability of fuel and other resources in the country, types of plant that are possible, and their costs and economics.

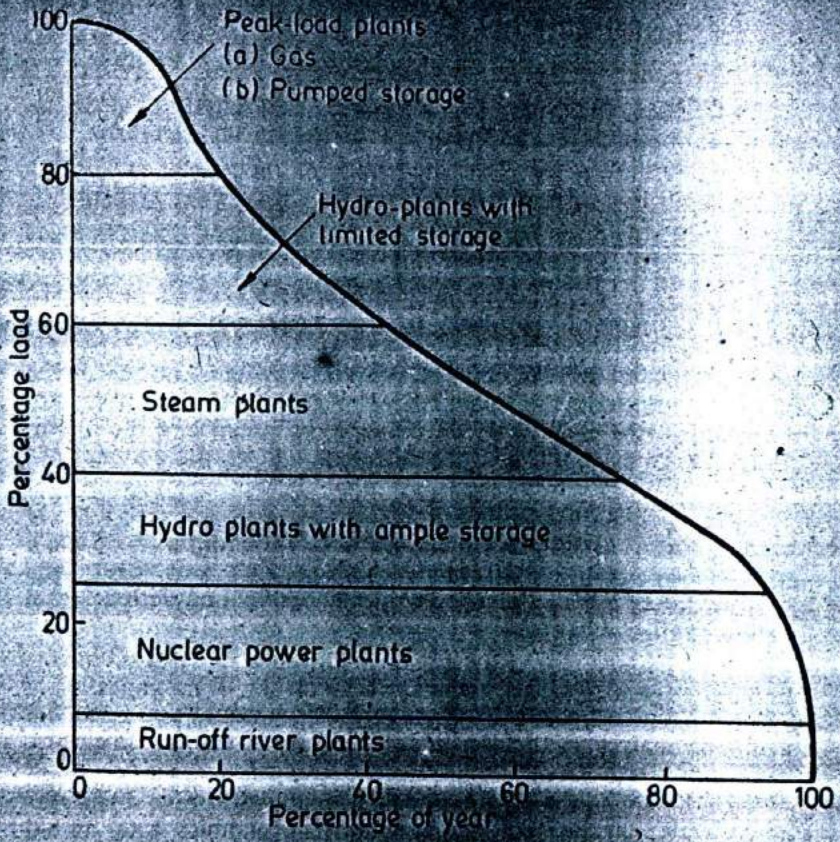


Fig. 9.5. Annual load duration curve showing loads allocated to various plants.

The use of the different generator units in the best possible way by allocating suitable loads to them with automatic control for sharing the load economically will be discussed in a later chapter.

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9.2. DESHPANDE, M.V., "Combination of hydro and steam stations in a power system", *World Power Conference*, Beograd, Paper 33, Section B1 (1957).

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Problems

9.1. State the types of power station that may be used in an electrical power system and mention their characteristics.

9.2. What are the main advantages of the combined working of different types of power plant in an electrical power system ?

9.3. Explain the need for the co-ordination of different types of power station in an interconnected power system. Illustrate by examples.

9.4. Discuss the combined operation of a run-off river plant and a steam plant. Given the annual load duration curve, the representative daily load curve of the power system, and the power duration curve of the run-off river plant, explain the method of determining the capacity of the plant to be installed in the hydro electric as well as in the steam station. State the assumptions made and illustrate by example.

9.5. Explain the method of making an economic analysis of the combined working off a run-off river plant and a steam plant after choosing their capacity as in problem 9.4., and justify the construction of a hydro-plant to work in combination with a steam station to effect economy.

9.6. Discuss the working of hydro-electric plants having ample storage with steam stations. How is the firm capacity of a hydro-plant increased by storage ? How would you make an economic analysis of the combined operation of the hydro-electric and steam plants ?

9.7. Explain the advantages of a pumped-storage plant for short peak-load operation. Compare its economics with an old steam plant to be used for peak-load operation as an alternative to a pumped-storage plant.

Explain the operation of a pumped-storage hydro-plant in combination with a hydro-plant supplying the main bulk load, and state the method of establishing the economic feasibility of the pumped-storage plant.

9.8. How are nuclear power plants used in an electric power system ? Explain their operation in combination with hydro-plants.

9.9. What are the advantages of gas-turbine power plants ? How are they used as "end-of-the-line" plants ? Describe the operation of a gas-turbine station in combination with a-hydro-station in a system. Describe the operation of a gas turbine station in combination with a steam station.

9.10. Discuss the co-ordination of various types of power plant, the factors which decide the distribution of plants for operation on different portions of the annual load duration curve of a power system, and the method of calculating the economics of their combined working.

10

Major Electrical Plant in Power Stations

10.1 Introduction

In the last nine chapters we have studied the different types of electrical power stations from the various basic points of view, arriving at principles for the choice of plant, its main dimensions and layout. The main dimensions of generators of different types were also considered. However, the details of the major electrical equipment in the various types of power stations, their characteristics, the choice of their detailed specifications, etc., must also be studied. In this chapter, the main electrical plant required in power stations is discussed and overall specifications are given for guidance in the choice of the required plant.

The major electrical plant in power stations consists of generators, exciters for the generators, power transformers, reactors, circuit-breakers, switchboard and control-board equipment. In addition, station transformers, auxiliary equipment, emergency lighting equipment, etc., are required. Details of the protective equipment – relays will be discussed in a separate chapter.

10.2 Generators and Exciters

The main specifications of generators and exciters have already been considered. Some of the more detailed specifications of generators which should be considered in making a final choice are discussed in this section.

10.2.1 GENERATORS CONSTANTS

In addition to the normal ratings and other specified quantities, the constants of the generators should be known to enable one

to determine their performance in the power system under different loading conditions at different power factors, under transient conditions and under fault conditions; they are also used in studies of system stability. In addition to the normal continuous rating, specifications given so far have included kVA rating, number of phases, frequency, voltage, power factor, star connexion of the stator and temperature rise limits.

In the analysis of salient-pole machines in particular, as well as in that of synchronous machines in general, the two reaction theory is used. The direct-axis synchronous reactance, X_d, and the quadrature-axis synchronous reactance, X_q, give the performance of a synchronous machine under normal and symmetrical conditions. The direct-axis synchronous reactance is the ratio of the fundamental component of reactive armature voltage, due to the fundamental direct-axis component of armature current, to this component of current under steady-state conditions and at rated frequency. In the same way, the quadrature axis synchronous reactance is the ratio of the fundamental component of reactive armature voltage, due to the fundamental quadrature-axis component of armature current, to this component of current under steady-state conditions and at rated frequency. For cylindrical rotor machines, such as turbo alternators, X_d and X_q are identical. For salient-pole machines X_q is about 0.6 to 0.7 times X_d. The synchronous reactances, X_d and X_q, are useful in determining the regulation of a synchronous generator and also the short-circuit currents under symmetrical short-circuit conditions.

Short-circuit ratio is another important factor. This is the ratio of the field current at rated open-circuit voltage and rated frequency to the field current at rated armature current on sustained symmetrical short-circuit at rated frequency. For large generators short circuit ratio varies between 0.8 and 1.2.

When studying the performance of a synchronous machine under sudden short-circuit conditions, its behaviour under transient conditions should be determined. With the sudden symmetrical short-circuit of an alternator on no-load, the armature current decreases during the first few cycles as shown in Fig. 10.1. With

a prolonged short-circuit, the current finally attains the steady value $I_d = E/X_d$, where E is the synchronous internal voltage and X_d is the synchronous reactance. If the envelope of the current wave is projected back to zero time—the instant of starting the short-circuit – then, neglecting the first few cycles during which the decrement is very rapid, the value of current obtained is the transient current, $I' = E'/X_d'$, where E' is the transient internal voltage and X_d' is the transient reactance. The sub-transient current is the value of the current at zero time, given by $I'' = E''/X_d''$, where E'' is the sub-transient internal voltage and X_d'' is the sub-transient reactance. The increment of armature current represented by the sub-transient component is due to induced currents in the damper windings. The transient reactance of a synchronous machine is equal to the armature leakage reactance.

The time-constants of a synchronous machine give an idea of the time of decay in the voltage or current components which help in setting the relays for protection under particular conditions of faults, etc. Some of the time constants useful in the studies are mentioned below with their definitions.

The direct-axis transient open-circuit time constant, T_{do}', is the time in seconds required for the root mean square (r. m. s.) a.c. value of the slowly decreasing component present in the direct-axis component of symmetrical armature voltage on open circuit to decrease to 1/e or 0.368, of its initial value when the field winding is suddenly short-circuited with the machine running at rated speed.

The direct-axis transient short-circuit time constant, T_d', is the time in seconds required for the r.m.s. a.c. value of the slowly decreasing component present in the direct-axis symmetrical a.c. component of armature current under suddenly applied 3-phase short-circuit conditions, with the machine running at rated speed, to decrease to 1/e, or 0.368 of its initial value.

The direct-axis sub-transient short circuit time constant, T_d'' is the time in seconds required for the rapidly decreasing component present during the first few cycles in the direct axis a.c.

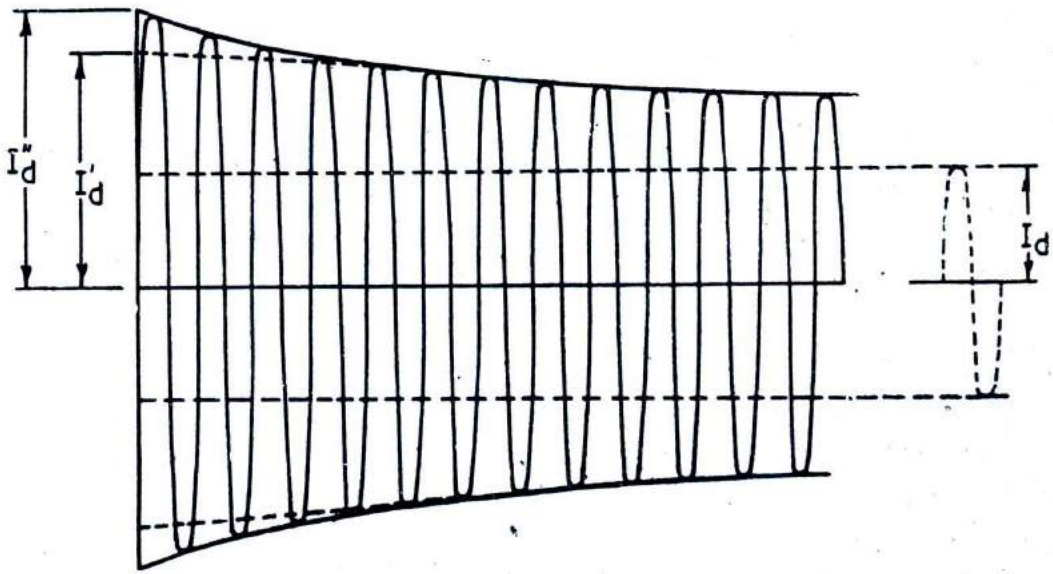


Fig. 10.1. Symmetrical Short-circuit current. (Synchronous machine on no-load)

component of the armature current under suddenly applied 3 phase short-circuit conditions, with the machine running at rated speed, to decrease to 1/e, or 0.368, of its initial value.

The short circuit time constant of the armature winding, T_a, is the time in seconds for the asymmetrical component of armature current under suddenly applied short-circuit conditions, with the machine running at rated speed, to decrease to 1/e, or 0.368, of its initial value.

When studying the performance of a synchronous generator under asymmetrical fault conditions such as a line-to-line or line-to-earth fault, the negative and zero sequence reactances of the machine should be known to enable one to work out the fault current and voltage conditions of the machine. The negative sequence reactance, X_2, and the zero sequence reactance, X_0, are, therefore, other important constants of the synchronous machine which should be given in the detailed specifications. The negative sequence reactance, X_2, is the ratio of the fundamental component of reactive armature voltage, due to the fundamental negative-sequence component of armature current, to this component of armature current at rated frequency. The zero sequence reactance, X_0, is the ratio of the fundamental component of reactive armature voltage, due to the fundamental zero-sequence component of armature current, to this component of current at rated frequency.

Machines	X_d	X_d'	X_d''	X_2	X_0
Steam turbo-generator	95 to 145	12 to 27	7 to 18	7 to 18	1 to 15
Water-wheel generator (no damper winding)	60 to 145	20 to 47	17 to 40	30 to 79	4 to 24
Salient-pole generator (with damper winding)	60 to 145	20 to 52	13 to 36	13 to 36	2 to 20
Synchronous machine used as a com-pensator	150 to 225	27 to 55	18 to 38	18 to 38	2 to 16

Approximate ranges of the values of the percentage reactances of typical synchronous machines are tabulated on page 374.

10.2.2 SPECIFICATIONS OF GENERATORS

Hydro-electric generator. Besides the normal rating and other items in the specifications mentioned in previous chapters, the specifications of a hydro-electric water-wheel generator should include the following particulars

Type, such as vertical shaft, thrust bearing below rotor.

Line-charging capacity.

Synchronous compensator capacity.

Guaranteed overall efficiencies at 50%, 75% and 100% of load and at 15% overload at unity and 0.9 power factors.

Reactances: X_d, X_d', X_d'', X_2, X_0, X_q, X_q', X_q''

Reactances: Stator and rotor.

Short-circuit ratio.

Losses.

Type of voltage regulator.

Full load regulation at rated voltage and speed. Time response of voltage regulator (for example 3 cycles, etc.).

Field-currents at full load at unity and 0.9 power factors.

Mechanical characteristics. The following are the main points to be considered: flywheel effect, Wk^2; runaway speed; lubrication; cooling and weights of different parts.

Main exciter: directly connected to generator, shunt connected (sometimes compound connected), with interpoles, separately excited from pilot exciter. Rating in kilowatts, current, voltage, speed.

Pilot exciter: compound connected, self-excited, rating in kilowatts, current, voltage and speed.

Turbo-alternator. Items in the specifications of a turbo-alternator required in addition to those mentioned in previous chapters are similar to those for hydro-units as far as the constants are concerned, although their numerical values would differ. The exciter specifications, too, are similar to those for the exciters of

hydro-units. The capacities of the exciters would, however, be different as turbo-alternators are high speed machines. The turbo-alternator units would be horizontal. Large units would be cooled by hydrogen at a pressure of 2.1 kg/cm^2

10.3 Earthing of a Power System

A power system is earthed at a suitable point by a suitable method. Some of the advantages of earthing are—

1. Reduced operation and maintenance expenditure.
2. Improved service reliability.
3. Greater safety.
4. Better system and equipment overcurrent protection.
5. Improved lightning protection.

The methods commonly used for earthing the system neutral are—

1. Solid earthing.
2. Resistance earthing.
3. Reactance earthing.
4. Earth fault neutralizer earthing.

In each case, the impedance of the generator, or transformer, whose neutral is earthed is in series with the external circuit. Fig. 10.2 shows the various methods of earthing a power system using the generator neutral for the purpose.

The neutral of a power system can be earthed by earthing the neutral of the generator or that of a power transformer, or using an earthing transformer. When comparing these methods, the following points should be considered—

1. Effect on development of transient over-voltages.
2. Damage at the point of fault due to the magnitude of the earth fault current.
3. Application of standard relays and circuit interrupting devices for selective earth fault tripping.
4. Protection against lightning.

A power system is said to be solidly earthed when the neutral of a generator, power transformer or earthing transformer is con-

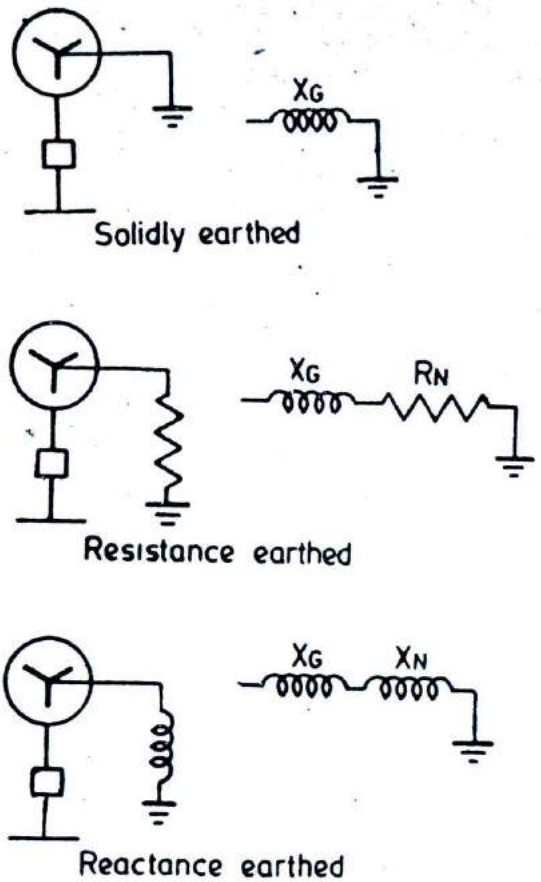


Fig. 10.2. Methods of earthing a power system.

nected direct to the station earth. As the generator or transformer would have its own reactance in series with the neutral circuit, solid earthing does not make a zero impedance circuit. If the impedance of the generator is too low, direct earthing of the generator without any external impedance may cause an earth fault current from the generator to exceed the maximum 3 phase fault current which the generator can deliver, and this may exceed the short circuit current for which its windings are braced. If the reactance of the generator or transformer is too great, then also

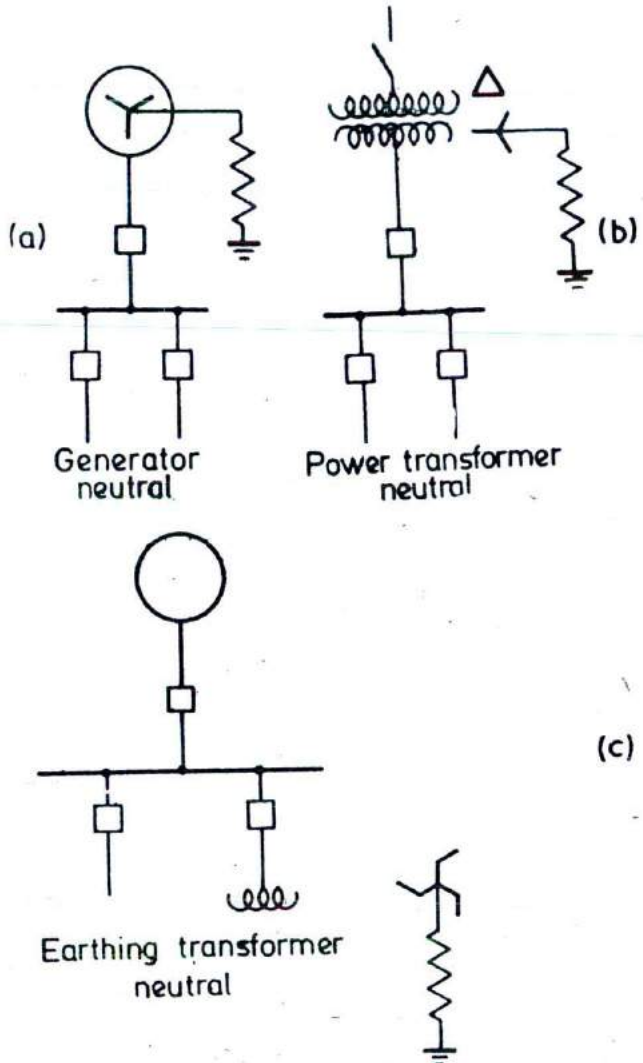


Fig. 10.3. Methods of resistance earthing of a power system.

the purpose of earthing is defeated. For solidly earthed systems, it is necessary that the earth fault current be in the range of 25% to 100% of the 3 phase fault current to prevent the development of high transient over-voltages.

When a power system uses resistance earthing (Fig. 10.3), the neutral is connected to earth through one or more resistors. A system properly earthed in this way is not subject to destructive over-voltages. Resistance earthing reduces the effects of burning and melting in faulted electrical equipment, reduces mechanical stresses in circuits carrying fault currents, reduces electric shock hazards to personnel caused by stray earth fault currents in the earth return path, and also reduces the momentary linevoltage dip caused by the occurrence and clearing of the earth fault.

The value of resistance to be used in the neutral to be earthed is such as will limit the earth fault current to a value which will produce minimum damage at the point of fault. In general, the earth fault current may be limited to 5% to 20% of that which would occur with a 3 phase fault.

The third method of earthing is reactance earthing. In this method, a reactor is connected between the machine neutral and earth, as shown in Fig. 10.2. Since the earth current which may flow in a reactance earthed system is a function of the neutral reactance, the magnitude of the earth fault current is often used as a criterion for the various system characteristics rather than referring to the neutral reactance directly. When a generator neutral is to be connected to the earth, sometimes a low reactance is connected in series with the neutral to limit the earth fault current through the generator. This should not be greater than the 3 phase fault current of the generator. In order to minimise transient over-voltages, the earth fault current in a reactance earthed system should not be less than 25% of the 3 phase fault current. This is considerably more than the minimum current desirable in resistance earthed systems.

When earth fault neutralizers (Fig. 10.4) are used, the reactance is selected so that the current through the reactor is equal to the

small line charging current which would flow into the line-to-earth fault if the system were operated with the neutral unearthed. The reactance of the neutraliser balances the system capacitance so that the net earth fault current is practically zero. With such resonant earthed systems, care should be taken to keep the earth-fault neutraliser tuned to the system capacitance to minimize the development of transient over-voltages.

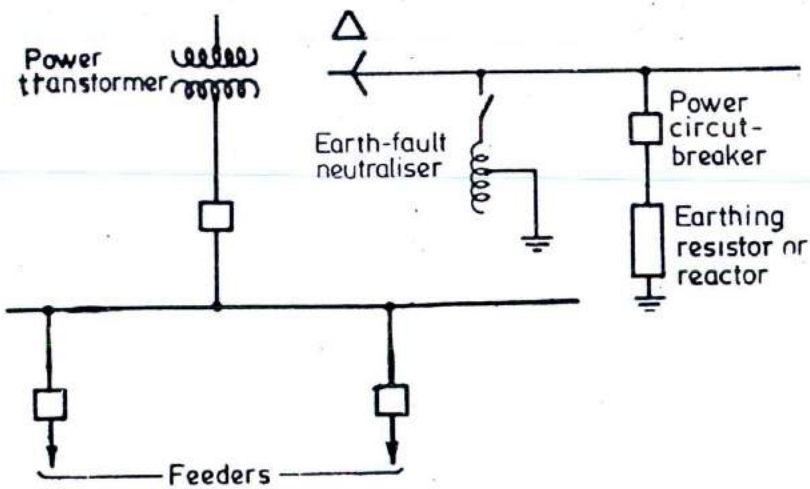


Fig. 10.4. Earth fault netralizer.

When it is required to earth a delta-connected system whose neutral is not directly available, earthing transformers are used to form a neutral and then the neutral is solidly connected to earth or through resistors in the neutral. The earthing transformer is a 3 phase zigzag transformer with no secondary winding. The connexions are shown in Fig. 10.3 (c). The impedance of the transformer to 3 phase currents is so high that, when there is no fault on the system, the magnetising current flowing through the windings is very small. The transformer impedance to earth currents is very low, so that the transformer allows large earth currents to flow. The transformer divides the earth current into three equal components. These are in phase when the earth fault is there, and therefore flow in the three windings of the earthing transformer.

The earthing transformer is connected in zigzag, and is designed for a short time kVA rating equal to the rated line to neutral voltage multiplied by the rated neutral current. The earthing transformer is designed to carry the rated current for a very short time of 10 seconds or for a maximum of one minute. The earthing transformer is therefore much smaller than an ordinary 3 phase transformer of the same rated kVA capacity.

The earthing transformer should be so connected to the power system that the system will always be earthed.

The selection of the type of earthing depends on the type of system and its voltage levels. Generally, solid earthing of the neutral is used for low-voltage systems (600 V). For medium-voltage systems (2.4 to 11 kV) earthing of the neutral through a resistance is preferred, while high-voltage systems usually have the transformer neutrals on the high-voltage side solidly earthed. The choice in each case should be made by considering the points mentioned, namely transient voltages developed, magnitude of earth-fault current as a percentage of 3-phase fault current, and dip in line voltage due to fault conditions. Details of the system data should be known to enable one to calculate the resistance or reactance to be inserted in series with the neutral of the system to be earthed.

10.4 Power Transformers : Types and Characteristics

The power transformers used in power stations and power systems are either single-phase transformer banks of three each or 3-phase transformers. When single-phase transformers are operating in parallel, their voltage rating should be identical, their percentage impedance voltages should be equal and their ratios of reactance to resistance must be equal. This also applies to a bank of three single-phase transformers. Departure from the above ideal conditions of parallel working results in uneconomical load division and a circulating current. This lowers the efficiency and reduces the maximum safe load which the bank can carry. It is not a good practice to operate transformers in parallel under the following conditions—

1. When the load division is such that the total load is equal to the combined kVA rating, the load current flowing in one of the transformers exceeds 110% of the normal full-load current.
2. When the no-load circulating current, exclusive of excitation current, exceeds 10% of the full-load value.
3. When the arithmetic sum of the circulating current and the load currents exceeds 110% of the normal full-load current.

10.4.1 Transformer connexions

Three-phase transformers can be used with advantage in place of banks of three single-phase transformers. The types of connexion for the 3-phase operation of transformers normally considered are delta-star, star-delta and delta-delta. Star-star connexions are not normally used. The merits and demerits of different types of connexion are discussed below. When comparing different types of transformer connexions for 3-phase operation, the degree of voltage symmetry, the voltage and current harmonics and any peculiarities of the connexions should be considered. When comparing three single-phase units with a 3-phase unit, the ratio of kVA-output/ kVA-rating of the bank should be considered.

Balanced 3-phase delta-delta, star-delta and delta-star banks do not introduce third harmonics or their multiples into the line. The waveshapes of the magnetising currents are superior compared to those of symmetrical banks. With the delta connexion, there is current and voltage symmetry. Asymmetry occurs only with open-delta and T-connexions when only two single-phase transformers are used in a 3-phase system to supply part of a 3-phase load. The star connexion gives symmetrical values as far as line currents are concerned but introduces third-harmonic current and voltage between line and neutral, and has the possibility of developing dangerous over-voltages.

Generally, the delta connexion is used for transformer windings when the voltage is small and the currents to be handled are large. This is because the phase voltage is the same as

the line voltage and the phase current is equal to the line current divided by $\sqrt{3}$. When the voltages are large and the line current is small, i.e. for high-voltage windings, it is preferable to use the star connexion. Here the phase voltage is equal to the line voltage divided by $\sqrt{3}$ and the phase current is the same as the line current. Thus, with the star connexion, the windings can be insulated for lower voltage. The delta-star connexion is used if the neutral is to be taken out for loading or for earthing, the star connexion being on the secondary side. The question whether to use delta-delta or delta-star connexions in a particular power system is decided by the need for parallel operation with existing banks of transformers or the interconnexion of the network or system apparatus.

When comparing delta-delta and delta-star banks of transformers, some of the following points are to be noted. The voltages of delta-delta transformers are completely determined by the circuit characteristics. The division of current depends on the internal characteristics of the transformers. The division of load is equal only if the individual transformers have equal impedances. In delta-star the division of current is entirely independent of the difference in the characteristics of the individual transformers. The balanced 3-phase load is equally divided among the phases in delta-star banks regardless of inequalities in impedance.

The effect of difference in voltage ratios is marked in the case of the delta-delta bank of transformers. Large currents flow in both the high-voltage and low-voltage windings if all phases are not alike. By the proper proportioning of impedances, the division of load can be made to be in the same proportion as the ratings of the transformers. Delta-star transformers are insensitive to a difference in voltage ratios.

A delta-delta bank of transformers is versatile. The failure of one single-phase transformer out of the three leaves two transformers connected in open delta, or vee, so that a 3-phase supply can still be obtained. The capacity of the bank is however, reduced to 86.6% of that of the two working units, or 57.7% of that of the

three. With two transformer units connected in open delta initially supplying a certain load, it is possible to add a third unit and connect the bank in delta to supply more load as it grows in the system. With delta-star transformers, the failure of one phase is more serious and may involve discontinuity of supply.

With the star-star connexion there is instability of the neutral, for a number of reasons. The instability is due to differences between the magnetising currents in different phases which occurs owing to differences in the magnetic circuits caused by faults in construction. Also, the neutral is shifted owing to the unbalanced load from line to neutral. The potential of the physical neutral is generally at some point other than the geometric centre of the voltage triangle, and is greatly affected by the characteristics of the load and other circuit conditions. In star-connected transformers, third harmonic magnetising currents cannot flow. This results in higher flux densities, and the peak voltages induced are increased to values upto 50% above normal.

With star-delta or delta-star transformers, the presence of the delta eliminates the third-harmonic voltages associated with the star connexion and stabilizes the neutral. The presence of the star connexion makes the division of load current among the phases independent of impedance. Thus units having different impedances can be used in a star-delta bank. However, the kVA ratings of the individual phases are unequal and the maximum safe output of the bank is three times the rated kVA of the smallest transformer.

10.4.2 VECTOR GROUPS IN TRANSFORMER CONNEXIONS

The polarity of a transformer denotes the phase displacement which exists between its primary and secondary phase voltages. If the windings for the primary and secondary are wound in the same direction and sense from the terminal ends, there is no phase displacement between the voltages and the transformer polarity is termed as subtractive polarity. If the windings are wound in opposite directions, there is 180° phase displacement between the voltages and transformer polarity is additive polarity.

For satisfactory parallel operation of single phase transformers, the polarity of the transformers must be considered for proper connexions.

In case of three phase transformers, the phase displacement between the primary and secondary voltages may occur due to the type of connexions. The main types of transformer connexions were discussed in the above section. If the clock hands represent the displacement between primary and secondary voltage vectors, the phase difference is shown from 0 to 360° by the position of hands e.g. 1 shows − 30°, . 11 shows + 30°; 0 shows no phase displacement ; 6 shows 180° phase displacement, etc.

The vector groups in common use for three phase power transformers are given by I.S. : 2026 − 1962 and for distribution transformers by IS : 1180 — 1964. There are mainly the following groups :—

Groups No. 1	Phase displacement between h.v and l.v. winding voltages = 0°
Y y o	Star/star
D d o	Delta/Delta
D z o	Delta/Zigzag
Groups No. 2	Phase displacement = 180°
Y y 6	Star/star
D d 6	Delta/Delta
D z 6	Delta/Zigzag
Group No. 3	Phase displacement = minus 30°
D y 1	Delta/Star
Y d 1	Star/Delta
Y z 1	Star/Zigzag
Group No. 4	Phase displacement = plus 30°
D y 11	Delta/Star
Y d 11	Star/Delta
Y z 11	Star/Zigzag

All four vector groups are shown by vector diagrams and winding diagrams of h.v. and l.v. windings in fig. 10.5 (a), (b), (c) and (d).

The relative merits and demerits of different types of connexions for power transformers were discussed in the above section. For distribution transformers, the most common type of vector group used is D y 11 Delta/star.

For satisfactory parallel operation of three phase transformers, the vector group of transformers must be the same, or they would match in such a way that there would be no phase displacement between the voltages on the h.v. and l.v. side. Connexion of h.v. is indicated by capital letter, connexion of l. v is indicated by small letter and the figures 0,1,6,11 indicate phase displacements as described by hands of a clock.

The following table indicates at a glance the connexions of the groups of two transformers which can safely be connected in parallel.

Table 10.1

Transformer I —	Delta/ Delta	Star/ Star	Delta/ Star	Star/ Delta	Inter- Star/ Star	Star/ Inter- star.
Transformer II						
Delta/Delta	Yes	Yes	No	No	No	No
Star/Star	Yes	Yes	No	No	No	No
Delta/Star	No	No	Yes	Yes	Yes	Yes
Star/Delta	No	No	Yes	Yes	Yes	Yes
Inter Star/Star	No	No	Yes	Yes	Yes	Yes
Star/Inter-Star	No	No	Yes	Yes	Yes	Yes

10.4.3 HARMONICS IN TRANSFORMERS

The non-sinusoidal nature of the magnetising current necessary to produce a sine wave of flux produces harmonics in current and voltage wave-forms of the three phase transformers. The effect is more pronounced in three phase transformers whose phases are magnetically separate as in the case of a bank of single phase transformers. Third harmonics present in the wave forms, their ill effects and suppression of the third harmonics should be considered. The nature of the harmonics present in the transformers depends on their connexions.

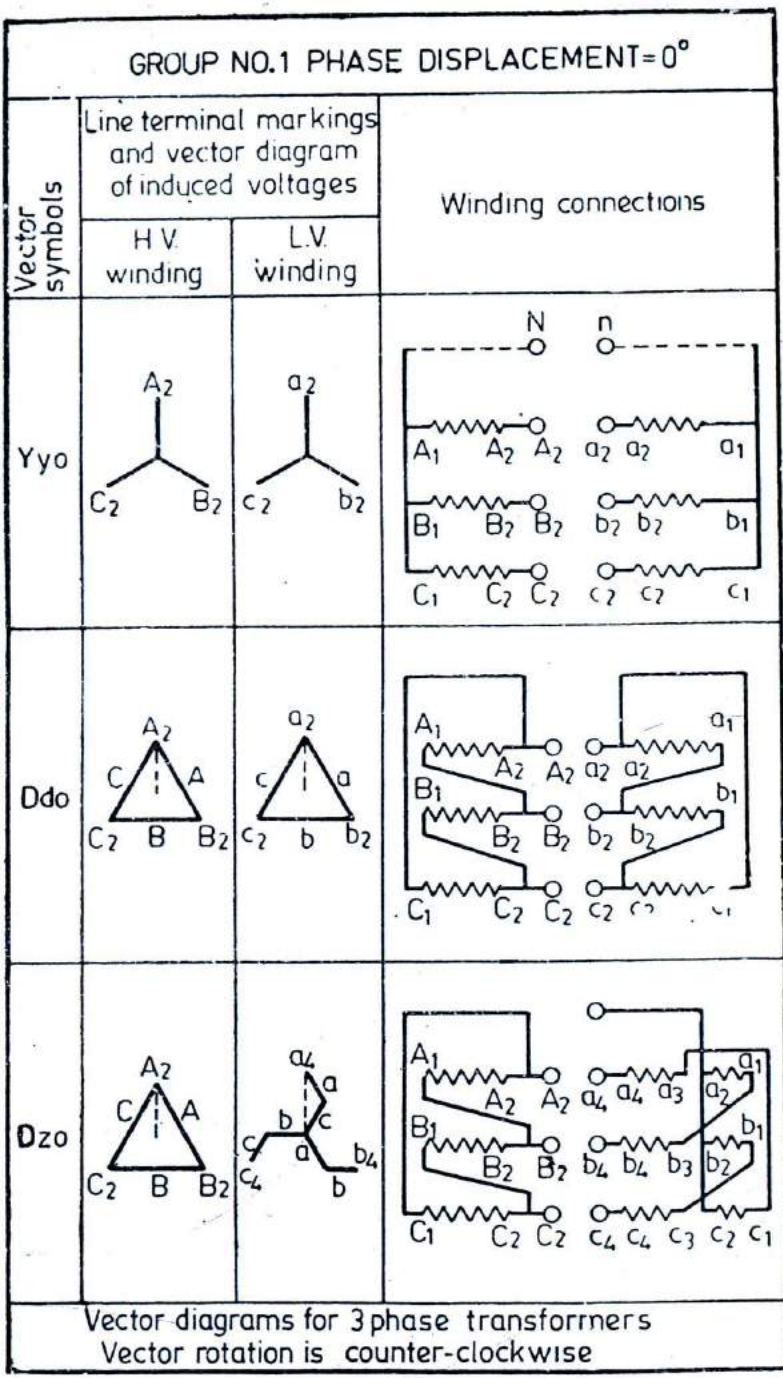


Fig. 10.5 (a), (b), (c), (d), Transformer vector groups

(a) Group No 1 : Phase displacement = 0°

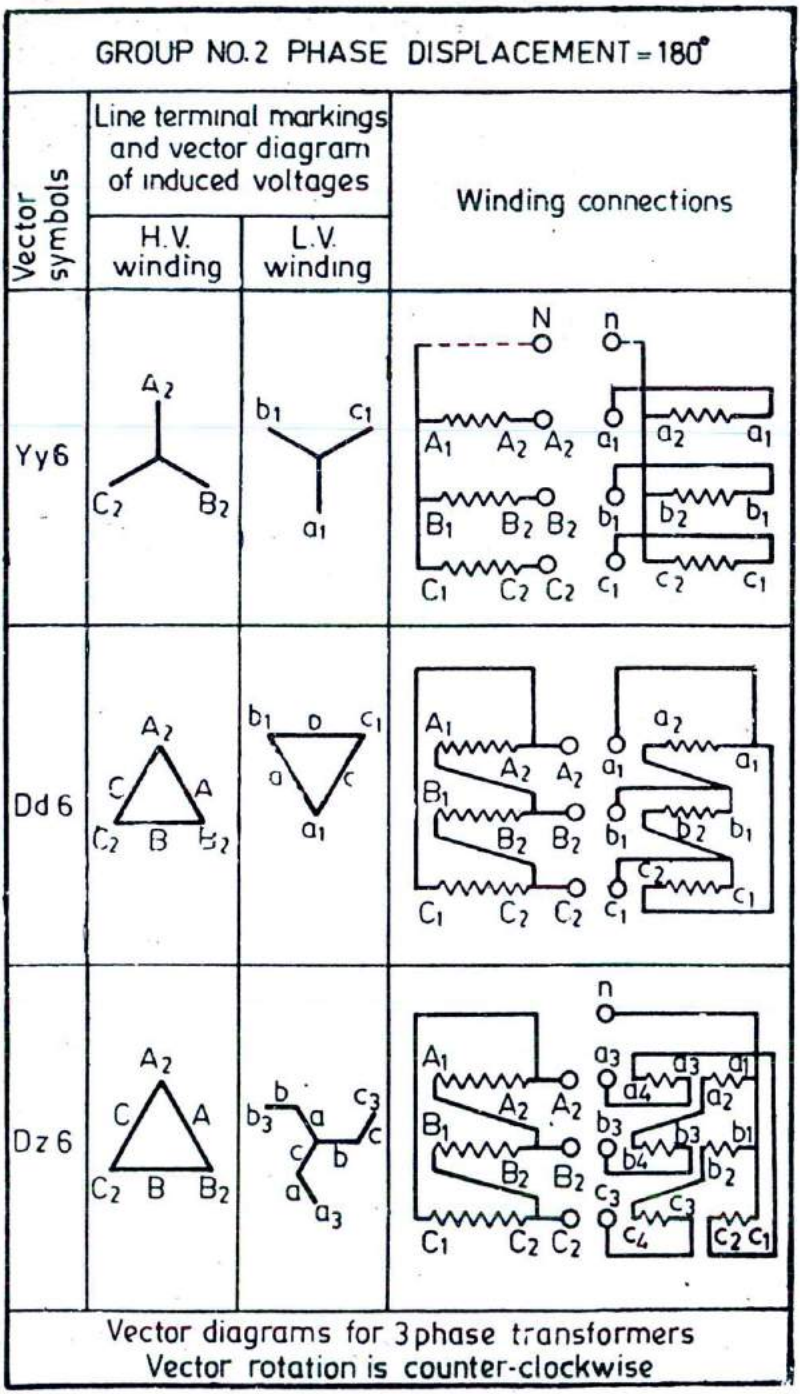
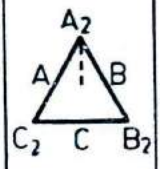
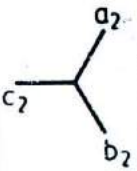
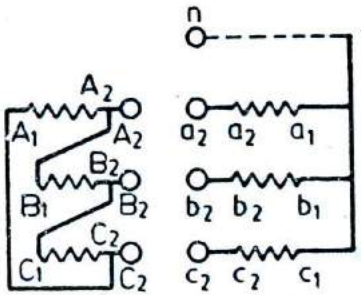
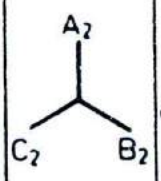
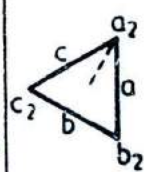
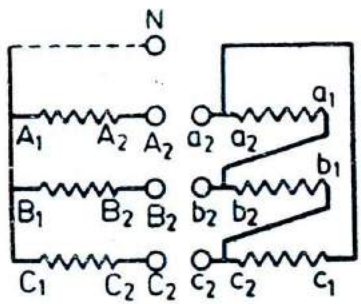
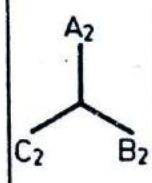
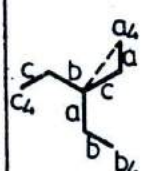
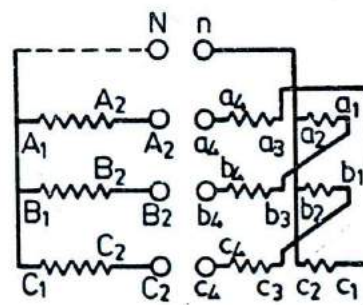


Fig. 10.5 (b). Group No 2 : Phase displacement = 180°

GROUP NO.3 PHASE DISPLACENT=MINUS 30°			
Vector symbols	Line terminal markings and vector diagram of induced voltages		Winding connections
	H.V. winding	L.V winding	
Dy1			
Yd1			
Yz1			

Vector diagrams for 3 phase transformers
Vector rotation is counter-clockwise

Fig. 10.5 (c), Group No 3 : Phase displacement = – 30°

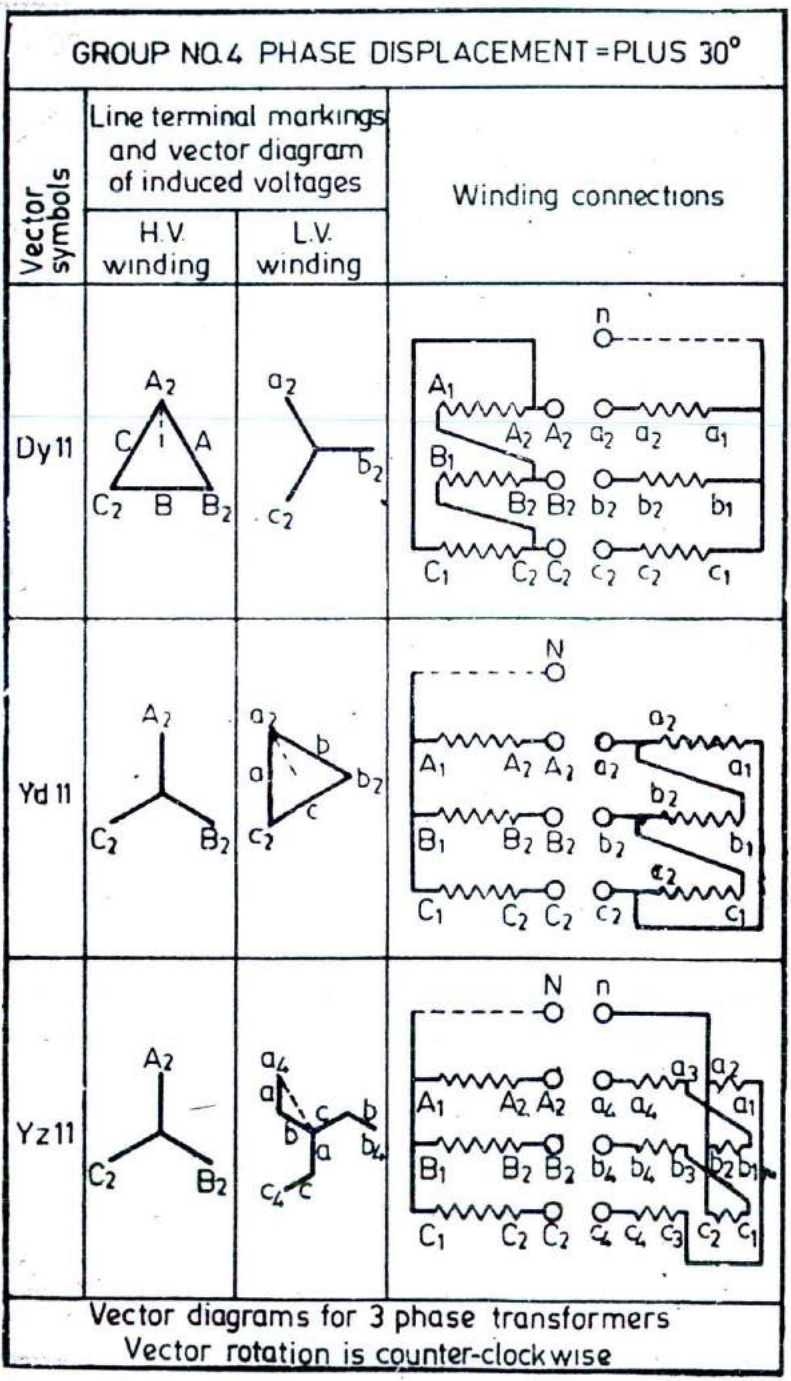


Fig. 10.5(d). Group No 4 : Phase displacement = +30°

The following table shows whether the variation will be sinusoidal or contain harmonics.

Table 10.2

Primary	Secondary	Neutral Pri.	Neutral Sec.	Voltages Primary Phase	Voltages Primary Line	Secondary Phase	Secondary line	Flux	Currents Primary No Load	Currents Primary Line	Currents Secondary No Load	Currents Secondary Line
Delta	Star	No	No	S	S	S	S	S	P	S	S	S
Delta	Star	No	Yes	S	S	S	S	S	P	S	P	P
Delta	Delta	No	No	S	S	S	S	S	P	S	P	S
Star	Zigzag	No	No	P	S	S	S	F	S	S	S	S
Star	Zigzag	No	Yes	P	S	S	S	F	S	S	S	S
Star	Star	No	No	P	S	P	S	F	S	S	—	S
Star	Star	Yes	No	p	S	p	S	f	S	S	—	S
Star	Star	No	Yes	p	S	p	S	f	S	S	p	p
Star	Delta	No	No	S	S	S	S	S	S	S	P	S
Star	Delta	Yes	No	S	S	S	S	S	p	p	p	S

S = Wave form has sinusoidal variations only.
P = Wave form contains peaking third harmonic.
p = Wave form contains small peaking third harmonic
F = Wave form contains flattening third harmonic.
f = Wave form contains small flattening third harmonic.

The effects of current and voltage harmonics are stated below.

Current Harmonics (*a*) Increased heating of windings : Owing to the circulating harmonic currents, additional copper losses and heating are produced.

(*b*) Inductive interference with communication circuits. When the transformer connexions are star/star with four wire supply, this effect is marked.

(*c*) Increased iron loss : Harmonic currents alter the flux wave form and affect iron loss. Where there is resonance with line capacitance, harmonic currents are increased and so also the iron losses.

Voltage Harmonics : (*d*) Voltage stress on the insulation is increased:

In star/star transformer with three wire supply, the phase voltage has its peak value greatly increased by harmonics. As the rated voltage of the transformer is increased, the effect is serious.

(*e*) Capacitive interference with communication circuits :

If any adjacent communication or protective circuits are capacitively coupled to the transformer network, interference is caused by the harmonic voltages.

(*f*) Production of large resonant voltages : In star/star transformer with three wire supply, if one of the star points is earthed, the harmonic voltages may give rise to trouble owing to the resonance between the transformer inductance and line capacitance.

Suppression of Harmonics : Harmonics result from a non-linear magnetising curve of the transformer iron. The greater the saturation, the greater the harmonics. The methods of reducing harmonics in the transformers are :–

(*a*) Use very low flux densities in transformers. This is not economical and is not used.

(*b*) Connect one of the windings in delta.

Where circuit conditions do not permit this, a separate delta winding may be used in an inductive or conductive manner.

(*c*) The inductive way to do this will be to place a third winding on the same magnetic core on which the primary and secondary are wound and connect it in delta. This is known as tertiary winding. This provides a path to the third harmonic currents.

(*d*) The conductive way to do this is to use the arrangement of star/delta earthing transformer. This is shown in Fig. 10.6.

Paths are provided for the third harmonic currents to circulate, so that the neutral voltage of the main star/star transformer is stabilized.

(*e*) Star|zigzag connexion of transformer may be used to reduce harmonics.

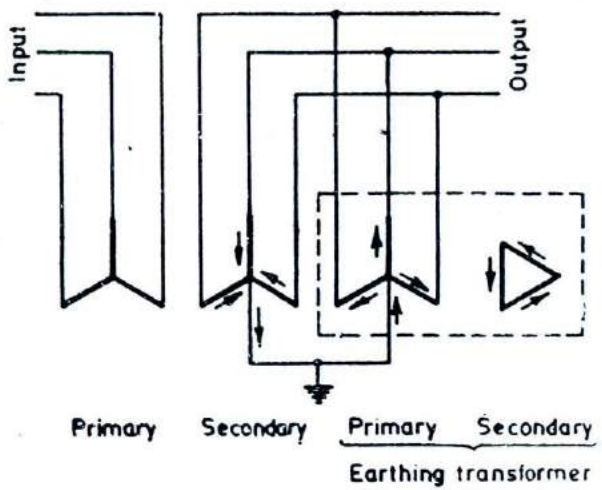


Fig. 10.6. Star/Delta Earthing Transformer used to Suppress Harmonics.

10.4.4 PARALLEL OPERATION OF TRANSFORMERS

Three phase groups of transformers can be operated in parallel on both their primary and secondary sides provided they have the same ratio of primary to secondary line voltages and provided the corresponding secondary line voltages of the groups are in phase when the groups are connected in parallel on their primary sides alone. The various groups suitable for parallel operation were mentioned in the last section. For balanced conditions, the performance of paralleled symmetrical three phase groups of transformers can be determined by the analysis of any one phase as a single phase problem. For the best operation and loading proportional to their ratings, they should have equal ratios of tranformation and their percentage impedances should be equal vectorially. The parallel operation of single phase transformers can be studied for equal and unequal turns ratios—voltage ratios—for general understanding.

If the turns ratios of the two transformers operating in parallel are not equal, their secondary induced voltages are unequal when their primaries are connected to the same source. When

secondaries are connected in parallel, due to unequal voltages, circulating current flows between their windings even on no-load.

(*a*) Parallel operation of transformers with equal turns :

When the transformers have equal turns ratios, and operate in parallel, their primary voltages are equal, their secondary voltages referred to primary are also equal, and the equivalent voltage drops are equal. The equivalent circuit for such a case is shown in fig. 10.7.

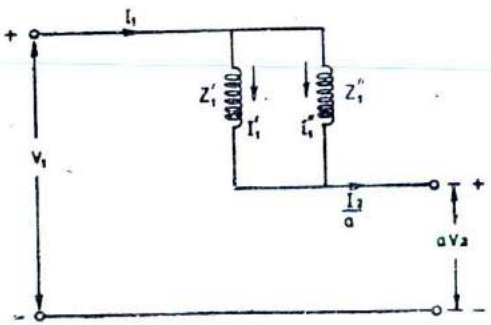


Fig. 10.7. Equivalent circuit for two transformers with equal turns ratios operating in parallel.

From the diagram, it is seen that

$$V_1 - a\,V_2 = I_1' Z_1' = I''_1\, Z''_1 \qquad (10.1).$$

If the transformers are to share loads in proportion to their kVA rating when operating in parallel, their equivalent impedance voltage drops at full load must be equal. Also for best results the ratios of their reactance to resistance must be equal. If this is not satisfied, though the magnitudes of their impedances are equal, there is phase displacement between the currents shared by the two transformers and the total current is reduced, thereby reducing the full load capacity of the combined operation of the transformers working in parallel. The effect is shown in fig. 10.8.

With unequal ratio of $\frac{X}{R}$, there results a phase displacement between the currents I'_1 and I_1'' as below :—

$$\text{angle between } I''_1 \text{ and } I''_1 = \tan^{-1}\frac{X_1'}{R_1'} - \tan^{-1}\frac{X_1''}{R_1''} \qquad (10.2)$$

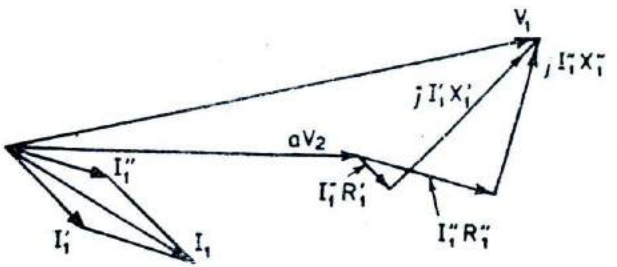


Fig. 10.8. Vector diagram for two transformers operating in parallel-effect of unequal X/R ratios.

If the combined kVA of two transformers is S, the kVA of transformer 1 is S_1 and of transformer 2, S_2, then the load shared by the two transformers when operating in parallel, is given by—

$$S_1 = S\frac{Z_2''}{Z_2' + Z''_2} \tag{10.3}$$

and

$$S_2 = S\frac{Z_2'}{Z_2' + Z_2''} \tag{10.4}$$

Where Z_2' and Z_2'' are impedances of transformers 1 and 2 referred to secondary.

(*b*) Parallel operation of transformers with unequal turns ratio :—

Fig. 10.9 shows two transformers with unequal turns ratios operating in parallel. When the currents, voltages and impedances are referred to the secondary sides, the vector voltage equations for the two transformers are as follows :—

$$\frac{V_1}{a'} - I_2' Z_2' = V_2 \tag{10.5}$$

$$\frac{V_1}{a''} - I_2'' Z_2'' = V_2 \tag{10.6}$$

The total load current is I_L which is supplied by transformers 1 and 2. Due to unequal voltage ratios, circulating current flows between the two transformers and the current actually flowing through the secondaries of the transformers corresponds to their

share of the load current plus the circulating current. Thus the currents are given by the following expressions :—

$$I_2' = I'_L + I'_{nl} \tag{10.7}$$

$$I_2'' = I''_L + I''_{nl} \tag{10.8}$$

where

$$I''_L = \frac{I_L Z_2''}{Z_2'' + Z_2''} \tag{10.9}$$

$$I''_L = \frac{I_L Z_2'}{Z_2' + Z_2''} \tag{10.10}$$

$$I'_{nl} = \frac{\frac{V_1}{a'} - \frac{V_1}{a''}}{Z'_2 + Z_2''} \tag{10.11}$$

$$I''_{nl} = \frac{\frac{V_1}{a''} - \frac{V_1}{a'}}{Z_2' + Z_2''} \tag{10.12}$$

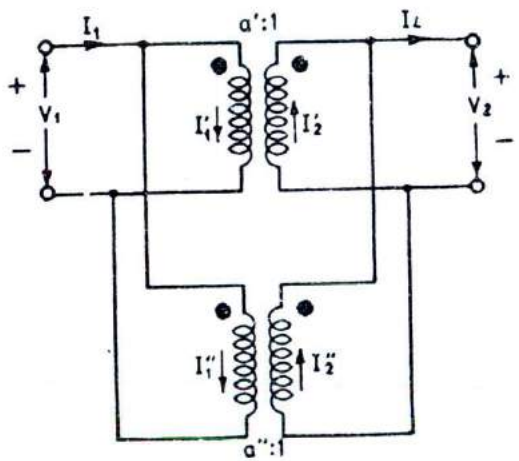


Fig. 10.9. Two transformers with unequal turns ratios operating in parallel.

10.5 Selection of Transformers

When selecting types of transformer for use in power stations, significant operating characteristics of the transformers as well as their initial cost should be considered. The size of the transformers depends on the size of the generator units. The general practice is

to use the unit system of operation, i.e., one transformer for one generator. The kVA capacity of the 3-phase transformer must then be the same as that of the generator to which it is connected. If a bank of three single-phase transformers is used instead of a three-phase transformer unit, the kVA capacity of each single-phase transformer must be one-third of that of the generator. Generators of very large capacity are sometimes first paralleled and connected to low-voltage (voltage of generation) busbars, and then a number of transformers of suitable capacity are connected to the generator-voltage busbars and stepped up to the high-voltage busbars before being connected to the transmission lines. The detailed diagram--shown as a single-line diagram of the connexions of generators, transformers and busbar system—will be discussed in a later section in this chapter. In special cases, where there is a shortage of space for the location of transformers, two generator units may supply a bank of three single-phase transformers each having two low-voltage windings, corresponding to the generator voltage and one high-voltage winding. The capacity of the transformer bank is then equal to that of two generators, and the kVA capacity of each single-phase transformer is two-thirds of that of one generator unit.

We have already discussed some of the points regarding the connexions of transformers. When considering a choice between three single-phase transformers and a 3-phase transformer for a certain location, the following points should be taken into account. With the three single-phase transformer units, it is possible to connect them in delta-delta with full capacity and in open delta on both sides for a smaller load, or, in case of a fault, to separate out one transformer and use only two single phase transformers to supply part of the load. Another advantage of a single-phase unit is that it occupies less space and weighs less than the corresponding 3-phase unit. This may be a valuable asset in some locations, such as underground power stations, where space in the tunnel would be limited and the handling of heavy weights would be difficult. Sometimes height restrictions are also imposed. For surface power stations, however, it is preferable to use a 3-phase transformer rather than a bank of three

singe phase transformers of equal capacity, for a 3-phase unit is cheaper, weighs less, occupies less space and is more compact.

The factors which are to be considered in deciding the suitability of particular types of transformer for particular applications are as follows: continuity of service, load factor, losses, initial cost, cost of losses, methods of cooling and the corresponding advantages and costs involved, insulation, percentage impedance, voltage regulation, floor area, height and weight of transformer, etc.

In the early days of the electricity supply industry, only single-phase self-oil-cooled transformers were used. With the tools now available for study, such as impulse generators and oscilloscopes, and with a better understanding of insulation problems, 3-phase high voltage transformers are now quite common.

The methods of cooling transformers differ and affect their rating and size. In self-oil-cooled transformers, the cooling surface is provided by radiators through which oil circulates by natural convection. The rate of heat dissipation can be increased by directly blowing air over the radiator surface by means of fans: this is known as forced air cooling. The capacity of a transformer can be increased by about 30% to 40% by the use of forced air cooling. The heat dissipation can be still further increased by forced oil cooling, i.e. by circulating oil through the radiators wi th pumps in addition to blowing air over the radiator. With this additional feature the capacity of a transformer can be increased by 60% to 66%.

Self-oil-cooled transformers do not need any external equipment and are, as their name implies, self contained. With forced air-cooling and forced oil-cooling, however, reliable power supply for fans and pumps is necessary as well as the additional equipment, namely the fans and pumps. Sometimes, when large power transformers are located near the sites of dams, e.g., at hydro-electric power stations, water is used for cooling the oil in the radiators in a separate heat exchanger. This method can be used at steam stations also if the water supply is available.

This method needs pumping equipment and a source of power which must be reliable. With reference to weights and dimensions, self-oil-cooled transformers have the largest weights and dimensional size compared to forced-air-cooled and forced-oil-cooled units. In large *KV*A and high voltage ratings, limitations of transport would sometimes dictate the selection of transformers, in which case forced cooled units would be preferable. As an illustration, the following table gives a comparison of the weights and dimensions of a 75,000 kVA 132-kV/11-kV transformer with different methods of cooling.

Methods of cooling	Total weight	Floor area	Overall height
	Per cent	Per cent	per cent
Self-oil-cooled	100	100	100
Self-cooled forced-air	90	90	95
Forced-oil-cooled	70	70	90

The impedances of transformers play an important role in their selection. When transformers are to be operated in parallel and are in an interconnected power system, they must have the same percentage impedance voltage for efficient working. If the transformers are not to work in parallel, their impedance is decided by the system requirements. If transformers are required with lower impedences than their normal standard values they cost more. The impedance of a transformer increases with the insulation level and with forced methods of cooling. Forced-cooled transformers are ideal for systems needing high impedance. The percentage impedance voltage of self-oil-cooled transformers varies between 6%and 14%, that of forced-air-cooled transformers is 9% to 18%, and that of forced-oil-cooled transformers, 12% to 19%.

The regulation of a transformer is the difference between the actual full-load and the no-load secondary voltages when the applied voltage is held constant. This increases with an increase in load and in lagging power factor of the load. The average regulation for self-oil-cooled transformers is 4% to 9%, for forced-air-cooled transformers 6% to 11%, and for forced-oil-cooled transformers 7.5% to 11% at 0.8 power factor lagging.

The efficiency of power transformers of large capacity is as high as 99% to 99.5% owing to modern technical developments. Losses in transformers are an important criterion for their selection for particular applications. From this point of view also it is preferable to use a 3-phase transformer rather than a bank of three single-phase transformers. The combined copper losses will be the same, but the core loss will be about 20% higher for single-phase units because of less efficient use of the core steel. 3-phase self-oil-cooled and water-cooled transformers have the lowest total loss and the highest core loss when compared to transformers cooled in other ways. Forced-oil-cooled transformers have the highest total loss and the lowest core loss, because their capacity is increased with this method of cooling. The core and the coils are designed for about 60% to 70% of the rated load. The copper loss at rated load is proportional to the square of the current. The core loss is low because the core and coils are small.

The initial cost of transformers varies with the type of cooling, the type of construction, the class of insulation required, and to a certain extent with the capacity, the larger transformers costing less per kilovolt-ampere. In addition to the initial cost, it is necessary to calculate the financial loss due to the cost of the I^2R losses. The losses may be evaluated at an approximate cost of Rs 1,000 per kW of no-load loss and Rs 500 per kW of load loss. Another method would be to calculate the energy loss and account for the value of the lost energy at the rate of 2 to 4 p per kWh for the life of the transformer. The expected loss and the cost of the energy should be calculated at various load factors and system conditions for accurate evaluation. The cost per kilowatt-hour loss will depend on the type of power station and its economics. To be accurate, it is not enough to evaluate the loss of energy at the rate per kilowatt-hour at the power station. The consumer must pay for the I^2Rt loss as well as for the plant installed to supply it. This should be considered in accurate evaluation and comparison for the total economics.

When selecting power transformers of large capacity, a number of factors discussed above should be considered, namely first

cost, methods of cooling, insulation, percentage impedance voltage, regulation at different power factors, losses at different load factors, loss evaluation to account for the cost of losses, weights and dimensions, etc. The system engineer must decide the emphasis to be given to each of the above points depending on the particular application of the power transformers in the system. Every power transformer application should be studied very carefully to obtain satisfactory and economical operation.

10.6 Specifications of Transformers

When finally selecting and ordering a power transformer, many of the following important items will have to appear in the specifications.

A bank of three single-phase transformers or a 3-phase transformer unit.

Type of transformer : outdoor or indoor.

Type of cooling : Self-oil-cooled, forced-air-cooled, forced-oil-cooled, or water-cooled.

Rating: kVA as self-oil-cooled, forced-air-cooled, forced-oil cooled or water-cooled. Overload capacity.

Connexions: delta-delta, delta-star or star-delta. Step-up transformer. No tapping.

Voltage: kV on h.v. side; kV on l.v. side. Voltage ratio.

Frequency : cycles per second.

Temperature rise : 40°C, 50°C or 75°C, etc.

Percentage impedance voltage at 75°C.

The transformer will operate in parallel with others (give particulars) under varying power factors and voltages, and the transformers will divide the load approximately in proportion to their respective capacities.

Co-ordination of insulation.

Mention whether the system is solidly earthed or not, whether the star point is to be earthed on the h. v. side of the transformer. Regulation at 75°C at unity and 0.8 power factors lagging on full load.

Magnetising current for the h. v. winding.

Efficiency at normal ratio under 25%, 50%, 75% and 100% loads at 75°C.

Losses : iron loss at normal 100% voltage and at 110% voltage excitation. Copper loss on 100% load and 125% load or higher if available. Copper loss at various part loads. Total loss at the various above loads.

Weight and dimensions.

Oil circulation and cooling system used, and the requirements for this purpose.

When the capacity of a power transformer is large, instead of specifying the efficiency limitations, the total loss, iron loss and copper loss limitations are given.

10.7 Principles of Circuit Interruption

Making, breaking and changing connexions in a circuit when the current through the circuit does not exceed the full load value is called switching, and the device used for the purpose is called a switch. A device for interrupting or breaking abnormal or fault currents as well as performing the duties of a switch is called a circuit breaker. The principle of circuit interruption consists of the rapid conversion of a predetermined section of a circuit from a conductor of electricity into an insulator. This is done by substituting a gaseous conductor for the all metallic current path previously existing, and then depriving this gaseous section its current conducting ability. The gap formed by the separation of a pair of co-operating contacts in a circuit breaker becomes conductive owing to the ionization of electrically neutral gas. The major portion of the arc current is due to the flow of electrons.

The contacts of a circuit breaker are normally held closed under pressure, and the electrical resistance between the contacts depends on the pressure. When the contacts are broken owing to removal of this pressure, high spot temperatures of the contacts cause thermionic emission of electrons from the hot spots of the negative contact. The electrons are accelerated towards the positive contact by the electric field in the gap and ionize the neutral gas

atoms, so that the arc discharge is started. The arc current has to be stopped as quickly as possible by deionization of the ionized gas. Deionization is the process of restoring the ionized gas to its original electrically neutral state. Whether the final extinction of an a.c. arc is achieved immediately after reaching a particular current zero depends on whether the value of the growing electric strength of the arc-gap exceeds permanently the increasing voltage impressed upon the arc-gap tending to reestablish the flow of current.

We have seen the effect of a short circuit on an electric generator. This has to be interrupted by the circuit breakers. The magnitude of the d.c. component and consequently the short circuit current in an a.c. circuit, depends upon the instant of time with respect to the voltage wave at which the short circuit occurs. Considering an inductive circuit, a short circuit current occurring at the instant when the voltage wave passes through zero has twice the peak value of a short circuit current occurring at the instant when the voltage wave passes through a maximum. Power circuit breakers are designed to meet a momentary current test at a value of about 1.6 times their maximum rated interrupting current for an 8 cycle breaker, 1.45 times for a 5 cycle breaker and 1.35 times for a 3 cycle breaker. This test proves the ability of the circuit breakers to withstand the electromagnetic effects of the high inrush currents. To test the thermal effects of high currents, another test is sometimes made, namely, the 4 cycle rating at a current corresponding to the maximum interrupting rating in amperes. When the alternating current passes through zero finally, the voltage across the circuit must be zero, so that the arc will be completely extinguished. There will be a phase angle between the current and voltage wave at the time of circuit tnterruption under transient conditions which causes some voltage to appear across the gap for a few cycles, and this voltage has a tendency to restrike the arc. The recovery voltage is the voltage impressed by the circuit upon the interrupting device after interruption of the current at the instant of the natural current zero. The recovery voltage tends to break down the arc-gap and to reestablish the arc.

When the phase angle between the voltage and current is 90° the recovery voltage is a maximum, and when the phase angle is zero the recovery voltage is zero. The normal frequency recovery voltage depends on the phase angle (δ) between current and voltage. Fig. 10.10 illustrates this relation.

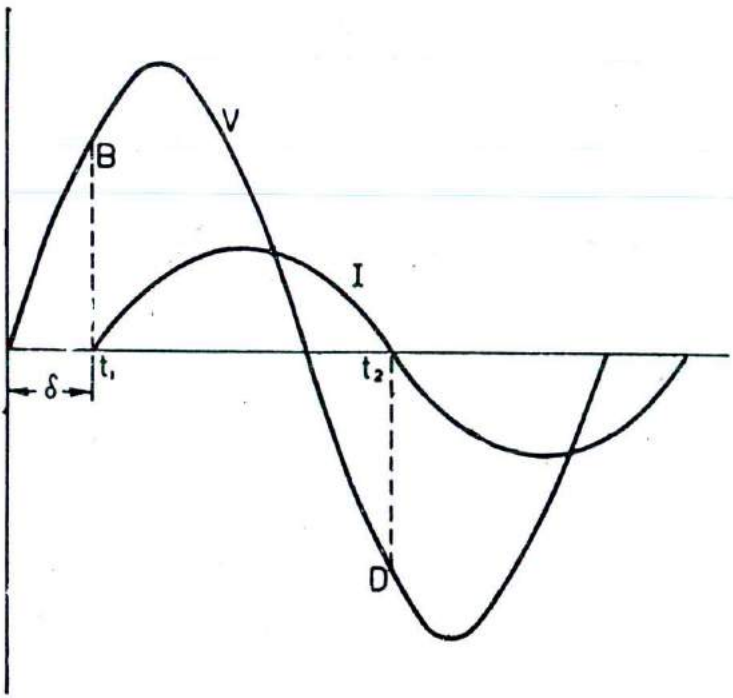


Fig. 10.10. Dependence of normal frequency recovery voltage on phase angle δ

V = Circuit voltage

I = Circuit current

δ = Phase angle

Bt_1 = Recovery voltage at time t_1

Dt_2 = Recovery voltage at time t_2

The effect of the arc on the transient recovery voltage is to make it oscillatory at high frequency. The frequency of the oscillations is the natural frequency, f_n, of the system --

$$f_n = \frac{1}{2\pi\sqrt{(LC)}} \qquad (10.13)$$

This frequency depends on the constants L and C of the circuit. Low natural frequencies are of the order of hundreds of cycles per second and high natural frequencies of the order of thousands of cycles per second.

The major problems in the design of circuit breakers are presented by high currents and high voltages. In power stations the circuit breakers are called upon to interrupt high currents at moderately high voltages. The highest voltages and recovery voltage rates are generally encountered where circuit breakers are required to control long distance transmission lines which are operated at ultra-high voltages. Thus the main points to be considered in the design of circuit breakers are the current to be interrupted, severity of the recovery voltage, the natural frequency of the circuit, the rate of rise of recovery voltage in volts per microsecond, and the peak value of the recovery voltage.

10.8 Circuit-breakers : Types and Characteristics

Basically circuit-breakers are of two types: oil circuit breakers and oilless circuit-breakers. In air break circuit-breakers, the arc is initiated and extinguished in substantially static air in which the arc moves. In air blast circuit breakers, a blast of air having a velocity approaching that of sound is used for converting the arc path into an insulator. In oil-circuit breakers, oil plays an important role in the interrupting process.

Air break circuit breakers (Fig. 10.11) are used for low voltages, generally upto voltages of 15 kV and interrupting capacities of 500 MVA. The main contacts for carrying current permanently are of copper. A pair of contacts of tungsten or similar material is used to carry the total current only during the process of interruption. The arc is elongated by the use of arc horns, arc runners, or arc restraining metal barriers, insulating barriers and magnetic blow-outs.

In modern air blast breakers, compressed air is stored in a tank and released through a nozzle to produce a high velocity jet, and this is used to extinguish the arc. The tank pressure for air blast breakers is generally 8.5 to 17.5 kg/cm^2. In the construction

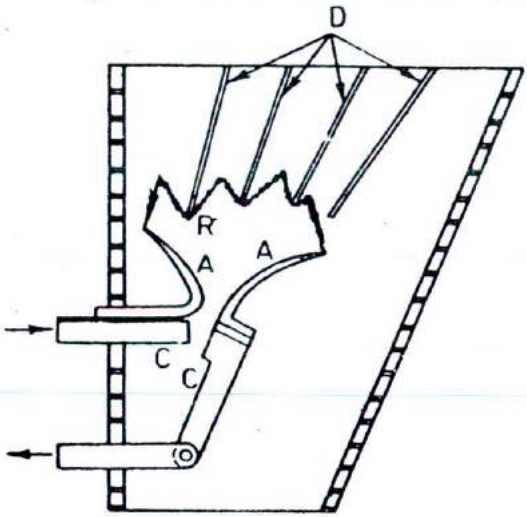


Fig. 10.11. Air break circuit breaker.
AA Horn-shaped arcing contacts.
CC Main contacts.
D Arc-restraining metal barrier.
R. Arc.

of air blast breakers, the principle of aerodynamics is used. There are two types of air blast breakers—axial blast and cross blast. In axial blast breakers (Fig. 10.12) the arc extinguishing blast approaches the arc gap radially through a circular opening and escapes from the arc gap axially in opposite directions.

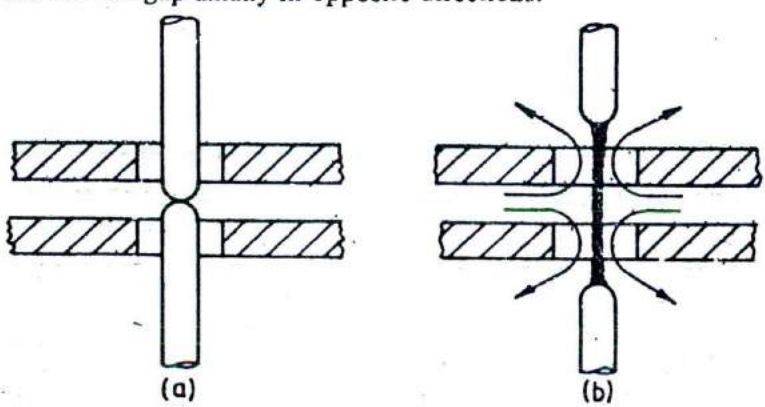


Fig. 10.12. Axial air blast circuit breaker.
(a) Closed. (b) Open

In cross blast breakers (Fig. 10.13), the air blast is at right angles to the breaker contacts. Air blast breakers are used for indoor service in the medium high-voltage field and for medium interrupting capacity – generally up to voltages of 15 kV and capacities of 2,500 MVA. Nowadays, air blast breakers are being used in high voltage circuits in outdoor switchyards for 220-kV lines, etc. The main features of air blast breakers are high speed operation, elimination of oil, prestorage of the interrupting medium (compressed air) readiness to act, convenient means of controlling the recovery voltage, suitability for repetitive duty, high speed reclosing, mechanical simplicity, and cleanliness of maintenance and operation.

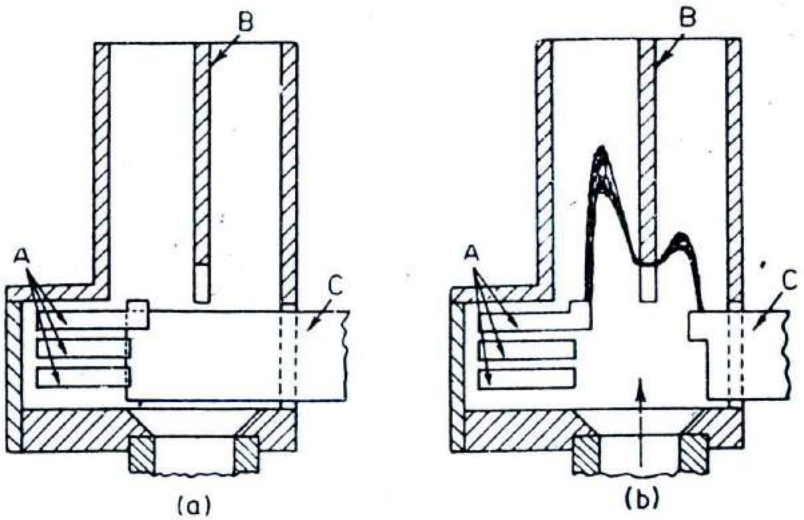


Fig. 10.13. Cross-air-blast circuit breaker.
(a) Closed. (b) open
A. Stationary finger contacts.
B. Arc restraining insulating barrier
C. Movable blade contact.

Oil circuit breakers are the most common type in power stations as well as for transmission lines. The ratings range from 25 MVA at 2.5 kV to 5,000 MVA at 230 kV. Plain tank type oil breakers operate satisfactorily when the current under interruption is neither

too small nor too large. Modern high speed tank type oil breakers have arc enclosing interrupting devices. When studying the operation of oil circuit breakers, the speed of contact separation and the viscosity of the liquid are important considerations. When both these factors are high, a gaseous tunnel is formed in the liquid which separates the arc at the instant of its inception from the surrounding body of liquid. The chemical composition of the oil helps to extinguish the arc formed when the contacts separate at the time of breaking the circuit. When the contacts are separating, oil in the oil breakers decomposes under the influence of the extreme heat produced, the process being known as cracking. The heat of the arc converts liquid hydrocarbons into lighter hydrocarbons and gaseous hydrocarbons. The arc bubble is formed by the mixture of vapours and gas. This helps in extinguishing the arc. Fig. 10.14 shows a cross jet explosion pot for an oil circuit breaker.

Tank type breakers have their stationary contacts and arc enclosing devices arranged inside large oil filled steel tanks. The tank is at earth potential, and the oil insulates all live parts of the breaker from earth. Plain tank type oil breakers require relatively large tanks and a large volume of oil, which increases in proportion to the voltage rating of the particular breaker.

Another type of oil breaker is the oil-impulse breaker, in which an arc-extinguishing oil jet is produced by a piston pump which is externally energized by means of either a spring or compressed air. This jet of oil is aimed at the gap formed between the separating contacts of the breaker to extinguish the arc. The oil-impulse breaker has many features and characteristics similar to those of the air-blast breaker. Both types rely on the common principle of prestoring blast energy in ready-to-act form. As a result, both types are capable of producing a substantially constant blast pressure irrespective of the current under interruption. Their arcing times do not increase with decreasing current. The moving contacts of both types have short lengths of travel from the fully-closed to the fully-open position. and are of relatively light weight.

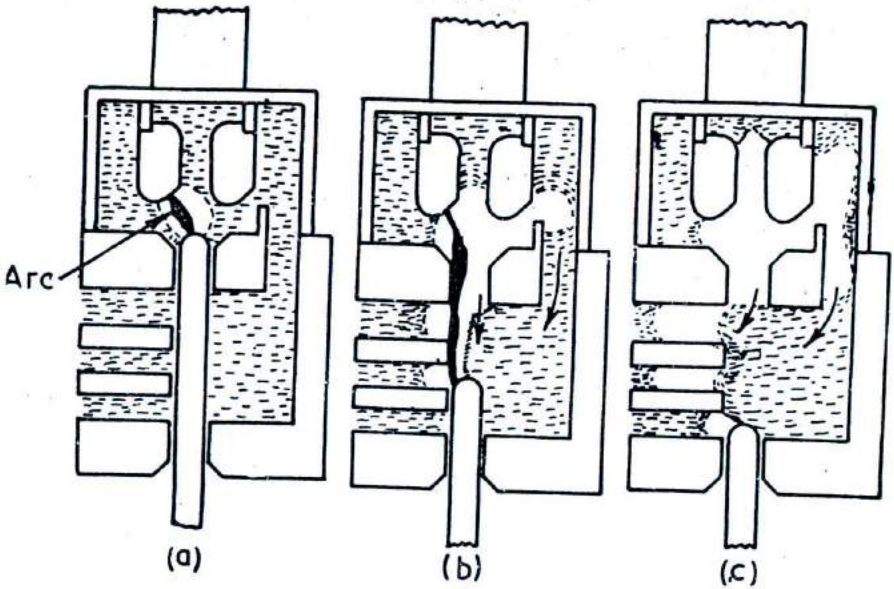


Fig. 10.14. Cross jet explosion pot for oil circuit breaker.
(a) Moving contact just open
(b) Arc path during switching off process
(c) Final arc extinction.

In low-oil-content breakers, oil is used for arc extinction by blast action, and is used chiefly for this function and not so much for insulating live parts from earth as a result of its property of electric strength. In these types of breakers, the oil-filled arc-enclosing chamber is arranged within a hollow porcelain insulator which insulates the live parts of the breaker from earth. In this way it is possible to reduce greatly the volume of oil required compared to that in tank-type oil breakers.

In designing oil breakers, there is nowadays a tendency towards high interrupting capacities, shorter interrupting and arcing times, and a reduction in the arc energy. The maximum ratings are upto 5,000 MVA and higher ratings are under development. The interrupting time has been reduced from 8 cycles to 5 cycles, and in some cases to 3 cycles. Arcing time has been reduced to a few half-cycles and even to only half a cycle The higher interrupting capacities have two aspects: they are used at existing transmission voltages, and will be required at the higher voltages of the proposed new transmission systems.

In general, there is a trend towards building transmission lines at minimum cost by reducing insulation levels. This has the effect of reducing the overvoltages due to switching operations. There is a trend towards a reduction of the capital investment and operating costs of circuit-breakers. The construction of a circuit-breaker should be such that it is easy to handle and maintain.

10.9 Circuit-breakers : Selection and Specifications

The interruption of an a.c. arc is basically a process of energy dissipation, as well as an insulation problem. The process of oil disintegration is an excellent energy-absorbing mechanism. Oil is also an excellent insulating material having very high electric strength. Both these properties are fully used in oil-tank breakers.

Oil breakers as well as air-blast breakers can be built for any interrupting duty required. The choice between different types of circuit-breaker, is a matter of economics rather than technical limitations. The cost of the labour and the material required should be considered. Modern oil circuit-breakers are explosion proof. From the point of view of fire hazard, there is little difference between circuit-breakers containing different quantities of oil.

Another point for consideration in selecting suitable circuit-breakers is the economics of the auxiliary equipment required, *e.g.* current and voltage transformer devices. The bushings of tank-type oil circuit breakers facilitate the use of ring-type bushing current transformers, which are less expensive than the type required for use with airblast breakers or small-oil-content breakers. Also

the bushings of tank-type oil breakers make possible, at little or no extra cost, their use as capacitance voltage dividers for voltage measurements, while the voltage transformers used with the other types of breaker are more expensive. These tank-type breakers have an advantage over other types so far as the economics of the auxiliary equipment is concerned.

The switchgear for power stations, which is normally of the indoor type, has to be rated at the generation voltage. The high-voltage switchgear in the switchyards is at the voltage of transmission as stepped up by the transformers; this is generally of the outdoor type. Switchgear consists of circuit-breakers, operating mechanisms, control switches, current and voltage transformers, indicating instruments and control panels. The specifications for switchgear would include the following main items:—

Circuit-breakers; type-oil, small-oil or air-blast. Normal current. Breaking capacity in kiloamperes, symmetrical and asymmetrical. Making capacity in kiloamperes (peak), Short-time current rating; one second (amperes) and 5-sec (amperes), kilovolt rating. Number of units per 3-phase circuit-breaker: one 3-phase unit or three single-phase units. Temperature rise.

Metering equipment.

Current and voltage transformers.

Instruments and indicating lamps, etc.

The main specification of a circuit breaker or switchgear is its interrupting capacity on faulty conditions such as short circuit. The severe faults in the system would be three phase faults. By studying the system under faulty conditions, find the fault current at the point of location of circuit breaker in the system and the rating of the breaker to interrupt the short circuit MVA. Examples 10.2 and 10.3 illustrate method of calculating short circuit MVA. For more details of the short circuit calculations and testing of switchgears as well as details of the relays used in the power systems, please refer to the author's companion volume 'Elements of Electrical Power Transmission and Distribution Design'.

10.10 Layout of Electrical Equipment

The layout of the electrical equipment of a power station mainly consists of the arrangement of the busbars at generation

valtage, arrangement of circuit-breakers and switches, location of transformers for high-voltage conversion, arrangement of high-voltage switchgear—generally outdoor—and the controlling switchboard arrangement. The low-voltage switchgear includes protective arrangements and instrumentation for the particular circuit. The control board has detailed arrangements to control the operation of the station, detailed instrumentation to indicate the behaviour of the equipment at any time, and an arrangement of relays, etc., to protect the station equipment against abnormal fault conditions.

The main station connexions and arrangement can be shown by a single-line diagram. As the three phases of the station supply are normally balanced, instead of showing all the three phase connexions for all the apparatus, it suffices to indicate by only one phase or connexion.

In a power station there are two types of switch-circuit-breakers and isolating switches. The circuit-breakers must break or interrupt the maximum short-circuit currents. The isolating switches operate under the condition of no-load current. They are cheaper and consist of knife switches in air or oil.

In a power station having a number of generators and a single busbar arrangement, the busbar is sectionalized by circuit-breakers so that a fault on one part of the busbar or system does not completely shut down the whole station. The arrangement is shown in Fig. 10.15. This shows a circuit-breaker and isolating switch between each generator and the low voltage busbars, a circuit-breaker and isolating switch on both the low-voltage and high-voltage sides of the step-up transformer, and a circuit-breaker and isolating switch to tie up the two busbar sections. The use of such a large number of circuit-breakers is somewhat out of date, and nowadays there is tendency to use fewer. In some cases the circuit-breakers on the low-voltage side of the transformers can be omitted. In modern stations where the unit system is used one generator and one transformer as a unit connected directly to the high-voltage busbars even the low-voltage switchgear at generation voltage is omitted and there is only one set of high-voltage switchgear. The paralleling of the generators is done on the high-

voltage side directly after the transformer, the unit being in circuit all the time.

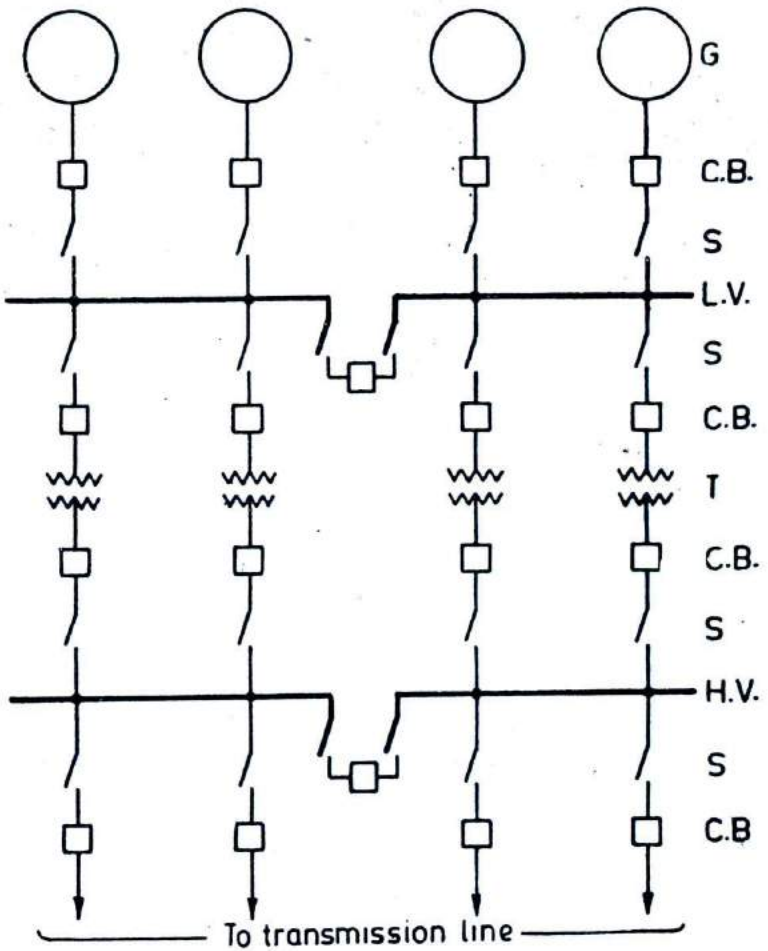


Fig. 10. 15. Single busbar system.

C. B. Circuit-breaker
G. Generator.
H. V. High-voltage busbar.
L. V. Low-voltage busbar.
S. Isolator or switch.
T. Step-up transformer.

Another busbar arrangement which is used as an alternative in some situations is the ring busbar arrangement. The sections

of each busbar are connected in a ring with circuit-breakers in series in the ring. In this arrangement, there are always two parallel paths to the circuit and the failure of one section does not interrupt the service completely.

A third type of busbar arrangement is the duplicate busbar system; this is shown in Fig. 10.16. Both the low-voltage and high voltage busbars are duplicated and any one of the busbar sections can be used as desired, a busbar coupling switch being provided to transfer operation from one busbar to the other. It is possible to have one busbar "live" and to carry out repairs on the other when required. The use of a busbar coupler and sectionalizing breakers converts the duplicate busbar system into a ring system, thus providing greater flexibility.

The busbars can be sectionalized and duplicated on the high-voltage as well on the low-voltage side. The high-voltage switch-gear is generally outdoor and for greater flexibility there is always a duplicate busbar arrangement. This is not absolutely necessary with the low-voltage busbars in the station itself, although it is used in some stations.

10.11 Current limiting Reactors : Use and Location

With an increase in the reactance of a system, the short-circuit currents under fault conditions are reduced. In a large inter-connected system having a number of generators the total rating of the generators is very large and under fault conditions the current fed into a fault will be enormous. This can be reduced considerably by the use of current limiting reactors and by their judicious placing. The reactors thus help in protecting the system. A reactor may be arranged in such a way that, while there is no large voltage drop across it under normal conditions of operation, it will prevent a large short-circuit current being fed by the generators into the fault, thereby limiting the breaking currents of the circuit-breakers. When a system is extended, its capacity increases, and to cope with this the circuit-breakers may have to be replaced by others of higher rating. Circuit-breakers of the same rating can, however, be used if current-limiting reactors are fitted.

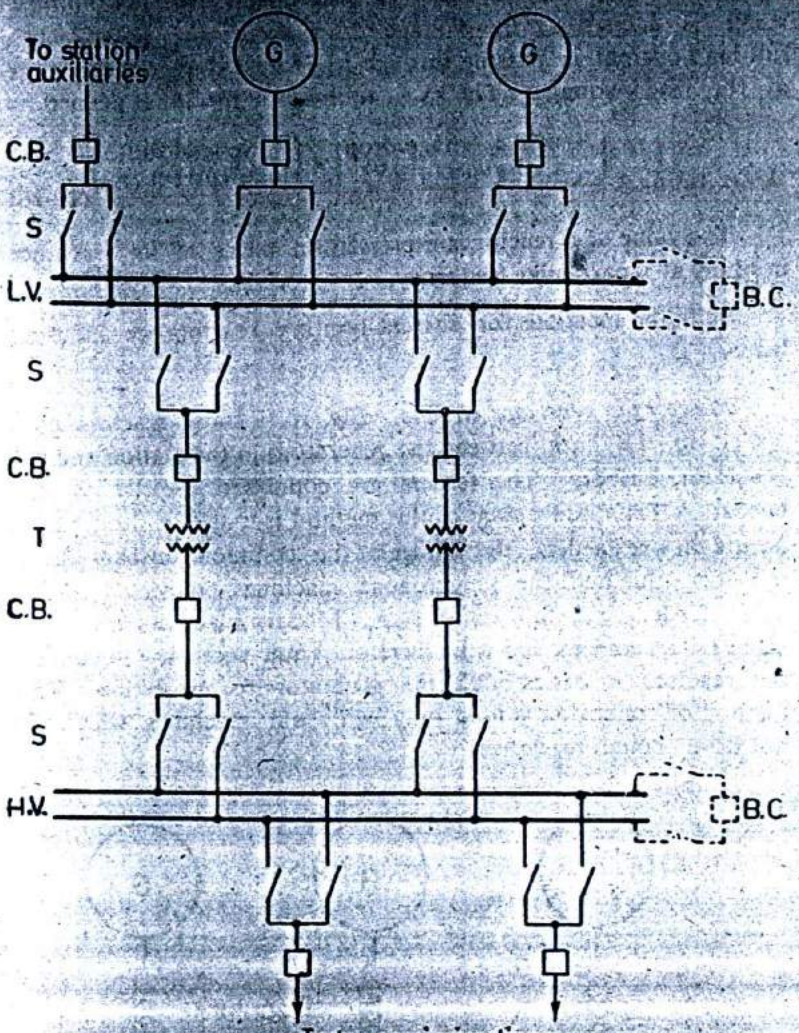


Fig. 10.16. Duplicate busbar system.

B. C. Busbar coupler
C. B. Circuit-breaker
G. Generaror
H. V. High-voltage busbars
L. V. Low-voltage busbars
S. Isolator or switch.
T. Step-up transformer

A reactor is rated in terms of percentage reactance voltage, which is defined as the voltage drop across the reactor when full-load current is passing through it, expressed as a percentage of the rated voltage. The kVA. rating of a reactor is defined by

$$\text{kVA rating} = \frac{\left\{\begin{matrix}\text{Reactive voltage drop} \\ \text{across reactor (V)}\end{matrix}\right\} \times \left\{\begin{matrix}\text{Normal full-} \\ \text{load current (A)}\end{matrix}\right\}}{1{,}000} \quad (10\text{-}14)$$

The value of a reactor is expressed in terms of its reactance in ohms at a particular frequency.

Suitable locations for current-limiting reactors are discussed below.

Reactors in generator circuits. Fig. 10.17 shows reactors connected in the lines between the generators in the station and the generator busbars The feeders are connected directly to the busbars. The disadvantage of this method is that, if a short-circuit occurs on one feeder, the voltage at the common busbars drops to a low value and the synchronous machines connected to the other feeders may fall out of step. Modern machines have large transient reactances, and it is, therefore, not necessary to connect the reactors in series with the generators for protection. This method of connexion is used only with old machines which do not have enough reactance.

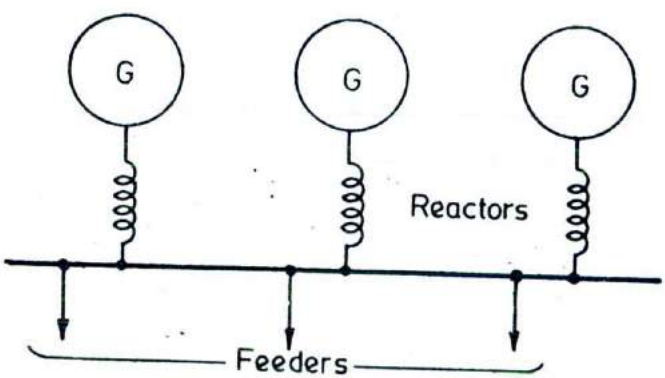


Fig 10.17. Reactors in generator circuits.

Reactors in series with feeders. The reactance of a feeder circuit can be increased by connecting reactors in series with the feeders to protect the circuit against excessive fault current. In this method, when a short-circuit occurs on one of the feeders, most of the voltage drop occurs across its reactor and the busbar voltage does not drop to any considerable extent. Fig 10.18 shows the method of connexion.

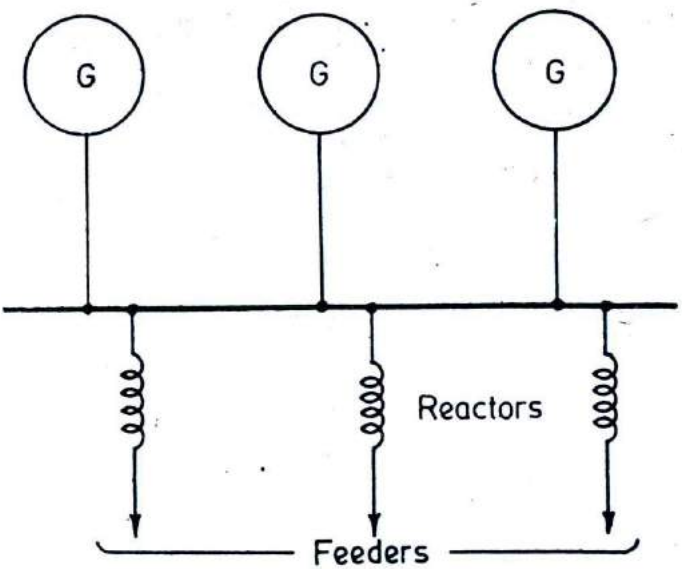


Fig 10.18. Reactors in feeder circuits.

Both the above methods of connexion have the disadvantage that the reactors carry full-load current, with its attendant I^2R loss, under normal operation.

Busbar reactors in a ring system. The constant I^2R loss in a reactor is avoided by connecting the reactors in the busbar sections. One method of doing this is the ring system, in which each feeder is fed normally by one generator only very little power being fed by the others through the reactors. The reactors can be made of high ohmic value. There is not much voltage drop across a reactor. Under fault conditions, the faulty feeder is mainly fed by one generator. The other generators feed the faulty

feeder only through the reactors, which thus limit the fault current. Fig. 10.19 shows the method of connexion.

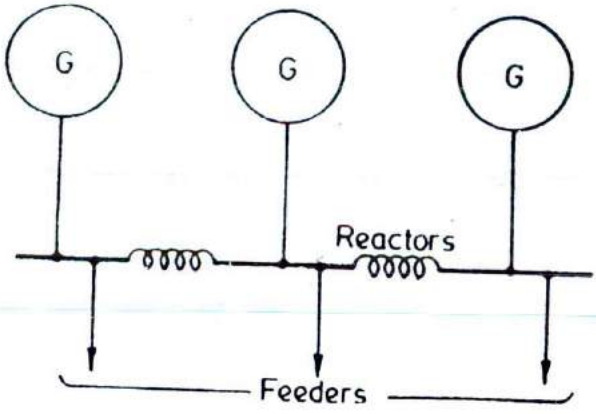


Fig. 10.19 Busbar reactors in a ring system.

Busbar reactors in a tie-bar system. An alternative method of connecting reactors in the busbar sections is the tie-bar system. Fig. 10.20 shows this arrangement. This helps in reducing fault currents in the same way as the ring-busbar reactor system, but in addition it has the advantage of limiting the currents. If the

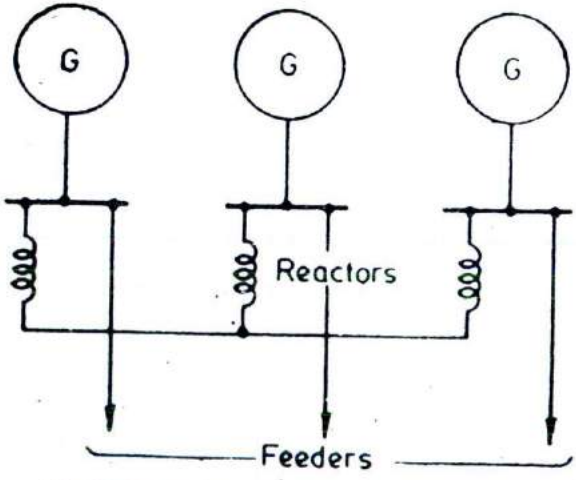


Fig. 10.20. Busbar reactors in a tie-bar system.

number of sections in the tie system is increased, the current that flows into the fault will not exceed a certain value which is fixed by the size of the individual reactors. The switchgear may be designed to operate successfully on this value of limited current. If this is done, the system can be extended to a number of sections without modification or replacement of the switchgear.

10.12 Short-circuit Currents and Size of Reactor

When a short-circuit occurs at any particular part of a system it is necessary for detailed study and planning to know the maximum possible currents which will flow through the various parts of the system. The short-circuit currents depend on the reactance of the appartus and its method of connexion. The reactance rating of electrical apparatus is expressed as a percentage. The percentage reactance voltage (ϵ_x) of a piece of electrical apparatus is defined by

$$\epsilon_x = \frac{IX}{V} \times 100\% \qquad (10.15)$$

where V is the rated voltage and I is the full-load current. If the apparatus is short-circuited, the short-circuit current is

$$I_{s.c.} = \frac{V}{X} = \frac{I}{\epsilon_x} \times 100 \qquad (10.16)$$

Symmetrical 3-phase short-circuit currents give the worst conditions of current in a system. A study of system short-circuit currents is useful in the selection of circuit-breakers and of protective relay settings, and in determining the size of protective reactors. The short-circuit currents are determined by the magnitudes of the reactances of the alternators, transformers and lines upto the point of fault, and by the way in which these are connected together. If the reactances are in series the short-circuit current is

$$I_{s.c.} = \frac{V}{X_1 + X_2 + X_3} \qquad (10.17)$$

When the rated percentage reactance voltages are given with reference to different kVA capacities, take the highest as the base rating and refer all percentage reactance voltages to this rating for calculation of short circuit currents.

When the generators are in parallel, their reactances are to be taken in parallel in the solution. If three generators of reactances, X_1, X_2, X_3 are in parallel, the resultant reactance, X, is given by

$$\frac{1}{X}=\frac{1}{X_1}+\frac{1}{X_2}+\frac{1}{X_3} \qquad (10.18)$$

The capacities and reactances of the reactors required for protection can be found by a study of short circuit conditions in the system. This is illustrated by the three examples which follow.

Example 10.1

Find the reactance per phase, external to a generator with 6% internal reactance voltage, such that the steady current on short circuit shall not exceed 8 times the full load current. The generator rating is 3 phase, 10 MVA, 11 kV.

$$\text{Full load current, } I=\frac{S}{V}=\frac{10^7}{\sqrt{3}\times 11\times 10^3}=525\ A$$

$$\text{Voltage per phase, } V=\frac{11{,}000}{\sqrt{3}}=6{,}350\ V$$

From eqn. (10.15), $\epsilon_x=\frac{IX_g}{V}\times 100$, where X_g is the reactance of the generator; therefore

$$X_g=\frac{\epsilon_x V}{100I}=\frac{6\times 6{,}350}{100\times 525}=0.725\Omega$$

Short circuit, current, $I_{s\cdot c\cdot}=8I=8\times 525=4{,}200\ A$

If X_e is the external reactance in series with the generator, the total reactance will be $X=X_g+X_e$ or $(0.725+X_e)$ ohms, so that, from eqn. (10.15), $I_{s\cdot c\cdot}=V/X$

$$X_e=\frac{V}{I_{s\cdot c\cdot}}-X_g=\frac{6{,}350}{4{,}200}-0.725=0.785\ \Omega$$

This is the external reactance required per phase.

Example 10.2

A power station has two alternators of 2,500 kVA and 5,000 kVA capacity and the reactance voltages are 6% and 8% respectively. The circuit breakers are rated at 150 MVA. The system is to be extended by taking supply from a Grid via a transformer of

5,000 kVA rating having a reactance voltage of 7.5%. If the same circuit breakers are to be used, find the reactance necessary to be placed between the busbar sections of the generators and the supply from the Grid to protect the switchgear. The voltage of the system at the busbars is 3 phase, 3.3 kV. Fig. 10.21 shows the layout.

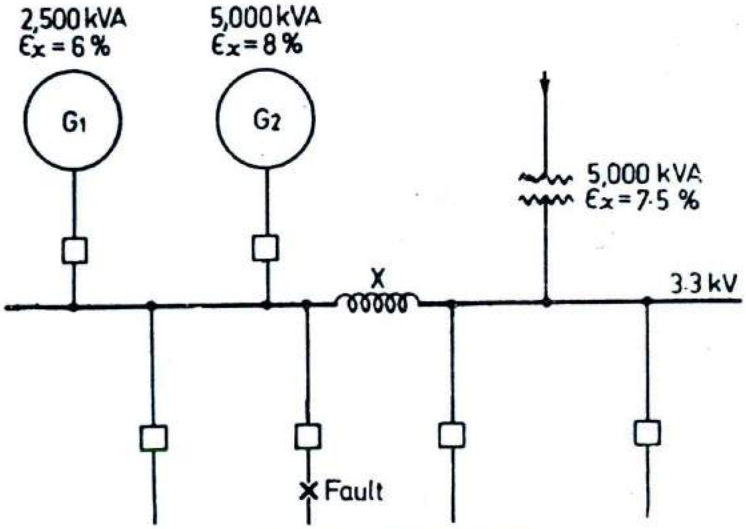


Fig. 10.21. Layout of system.

Take base kVA = 5,000 kVA

Reactance voltage of generator No. 1 $= \frac{5,000}{2,500} \times 6 = 12\%$

Reactance voltage of generator No. 2 $= 8\%$

Combined reactance voltages of two in parallel $= \frac{8 \times 12}{8+12} = 4.8\%$

Short circuit kVA $= \frac{5,000 \times 100}{4.8} = 104,000$ kVA

If a protective reactor is not introduced in the busbar section,

Short circuit kVA due to Grid supply $= \frac{5,000 \times 100}{7.5}$

$= 66,600$ kVA

This would be in series with the combined short-circuit kVA of the generators.

Total short circuit kVA = 104,000 + 66,600 = 170,600 kVA. If the circuit breakers of 150,000 kVA capacity are to be used and not changed to 170,600 kVA capacity the short circuit kVA should be reduced to 150,000 kVA by introducing a reactor of ϵ_x percentage reactance voltage (on 5,000 kVA base) in series. Then

$$\text{Short circuit kVA of Grid supply} = \frac{5,000 \times 100}{7.5 + \epsilon_x}$$

This must not exceed 150,000 − 104,000 = 46,000 kVA

Put $\frac{5,000 \times 100}{7.5 + \epsilon_x} = 46,000$; then $7.5 + \epsilon_x = 10.88$, so that

Reactance voltage of reactor on 5,000 kVA base = 3.38%

Full load current per phase corresponding to 5,000 kVA

$$= \frac{5,000 \times 1,000}{\sqrt{3} \times 3,300} = 880 \ A$$

Reactance per phase, $X = \frac{3.38 \times 3,300/\sqrt{3}}{880 \times 100} = 0.0735 \ \Omega$

Example 10.3

The plant capacity of a power station consists of two 8,000 kVA generators each of 14% reactance voltage and one 4,000 kVA. Generator of 10% reactance voltage. These are connected to common busbars from which load is taken through a number of 3,000 kVA step-up transformers each having a reactance voltage of 4%. Determine the maximum MVA which the circuit breakers on (*a*) the low voltage side and (*b*) the high voltage side, may have to deal with. The circuit is shown in Fig. 10.22.

Take base kVA = 8,000 kVA

Each generator has a reactance voltage of 14%, so that

Combined reactance voltage of the two 8,000 kVA generators in parallel

$$= \frac{1 \times 14}{2} = 7\%$$

Reactance voltage of 4,000 kVA generator = 10% on 4,000 kVA base

= 20% on 8,000 kVA base.

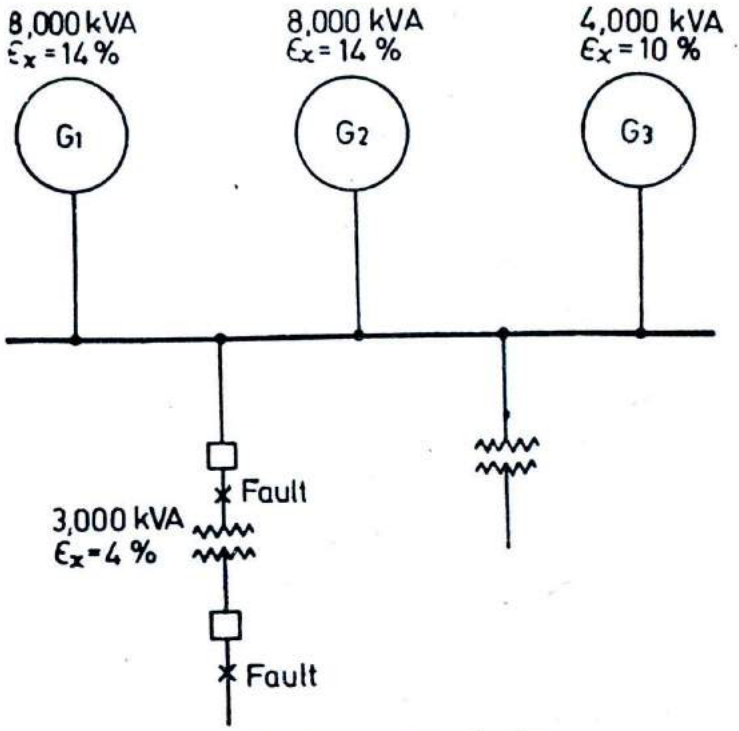


Fig. 10.22. Layout of system.

Combined reactance voltages of all three generators in parallel

$$= \frac{7 \times 20}{7 + 20} = 5.2\%$$

Short circuit kVA on low voltage side of breakers

$$= \frac{8{,}000 \times 100}{5.2}$$

$$= 154{,}000 \text{ kVA}$$

$$= 154 \text{ MVA}$$

Reactance voltage of 3,000 kVA transformer

$$= 4\% \text{ on } 3{,}000 \text{ kVA base}$$

$$= 4 \times \frac{8{,}000}{3{,}000} = 10.66\% \text{ on } 8{,}000 \text{ kVA base}$$

If a fault occurs on the high voltage side of the transformer, the total reactance voltage upto the point of fault will be 5.2+10.66, or 15.86%,

Short-circuit kVA on the high voltage side of transformer

$$= \frac{8{,}000 \times 100}{15.86} = 50{,}500 \text{ kVA or } 50.5 \text{ MVA}$$

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Problems

10.1. Define and discuss the constants of synchronous generators. State their use in design and application.

10.2. Describe the specifications for a.c. generators and exciters in power stations.

10.3. Explain with sketches the methods used for earthing power systems.

10.4. (*a*) Discuss the various types of connexion of power transformers used in power stations. Describe their characteristics and applications. (*b*) Explain the factors to be considered in selecting transformers for power stations.

10.5. State the main items in specifications for power transformers used in power stations.

10.6. Explain the principle of circuit interruption and its application in circuit breakers. Define the "interrupting capacity" and "recovery voltage" of a circuit breaker.

10.7. Discuss the following types of circuit breaker and compare them for selection in a power system: (*a*) oil-circuit breakers, and (*b*) air-blast circuit breakers.

10.8. (*a*) Discuss the layout of the main electrical equipment in power stations. (*b*) Show the types of busbar arrangement used in power stations.

10.9. (*a*) Explain the use of reactors to limit the short circuit current in a power system. Define the percentage reactance—voltage rating and kVA rating of a current limiting reactor.

(*b*) Four 20,000 kVA generators, each having a reactance voltage of 15% are connected through four 12,000 kVA reactors to common busbars. Four feeders, each connected to the generator side of a reactor, have circuit breakers of 200 MVA capacity. Find the percentage reactance voltage of the reactors required. It is necessary to protect against short circuit faults on the feeder side with existing circuit breakers. (Ans. 11.25%).

10.10. A power station has three busbar sections: *A*, *B* and *C*. A 50,000 kVA generator having a reactance voltage of 14% is connected to each busbar section. If sections *A* and *B* are interconnected by a busbar reactor of 10% reactance voltage, and sections *B* and *C* by another busbar reactor of 10% reactance voltage, calculate the maximum MVA that would be fed into a fault at the busbars. (Ans 775 MVA).

11

Power Station Control and Interconnexion

11.1 Excitation Systems

The alternators are provided with shaft or gear mounted exciters for providing d.c. excitation to their field windings. The usual practice is to have a shunt wound d.c. machine as exciter. For a large alternator, the main exciter is a separately excited d.c. machine supplied by the pilot exciter. As the rating of generators continues to increase, it is getting difficult to supply excitation for the large generators by d.c. exciters for the following reasons :

(*a*) High excitation current at comparatively low voltages; this will need large number of brushes on the commutator.

(*b*) Commutation troubles flashover.

(*c*) Reliability of the system.

These difficulties have led to the use of an a.c. excitation system: a.c. exciter/static rectifier system. This system eliminates the commutator and brushgear problems of the d.c. system; it has, however, problems of current collection at the slip rings of the main generator. The present development aims at eliminating the slip rings by the use of a rotating rectifier excitation system, which would be on the shaft of a direct driven rotating armature of an a.c. exciter. The direct current could then be taken from rectifier terminals along the generator shaft direct to the rotor field winding.

11.1.1 D.C. EXCITERS

Fig. 11.1 (*a*) shows a d.c. shunt exciter. A few series turns are added for compounding and interpoles are used. The shunt

field has a variable resistance in series with it which is used for controlling the excitation. The exciter supplies the field for the main generator.

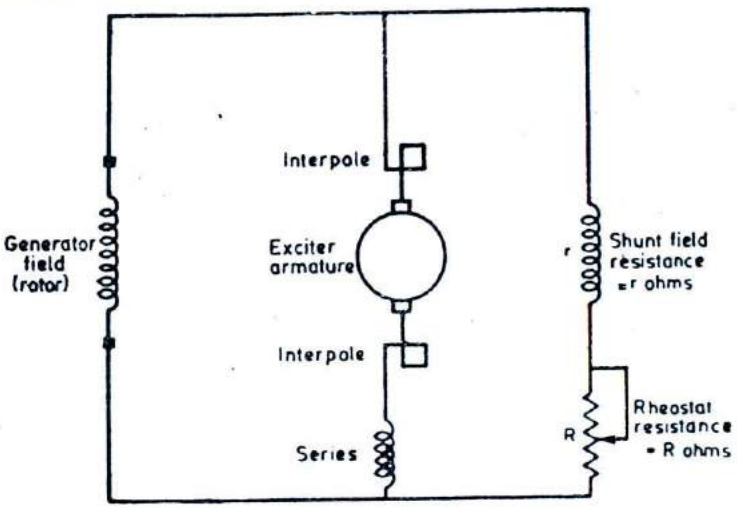


Fig. 11.1. (a) A d.c. shunt wound exciter.

The open circuit characteristics of a shunt wound machine are shown in Fig. 11.1 (*b*)

The output voltage is directly proportional to the field current in the earlier part of the curve as shown by the straight line, *A.B.* After that the magnetic circuit saturates rapidly to the ceiling voltage at *D*. The ratio of output voltage to field current represents the resistance of the field circuit. It will be seen that in the range *AB*, the shunt field circuit resistance $\frac{BG}{OG}$ will set any voltage from the residual voltage *OA* to voltage *BG*. The exciter is therefore unstable over this range *A-B*. These shunt exciter characteristics can be improved by arranging part of the magnetic circuit to be saturated. This is done by restricting part of the iron cross section with a composite brass iron shim at the point where the pole is attached to the frame of the exciter. With this modification, the characteristics are reduced to the lower curve in Fig. 11.1 (*b*) and the range of control is now from *EF* to *JK*, instead of from *BG* to *DK*.

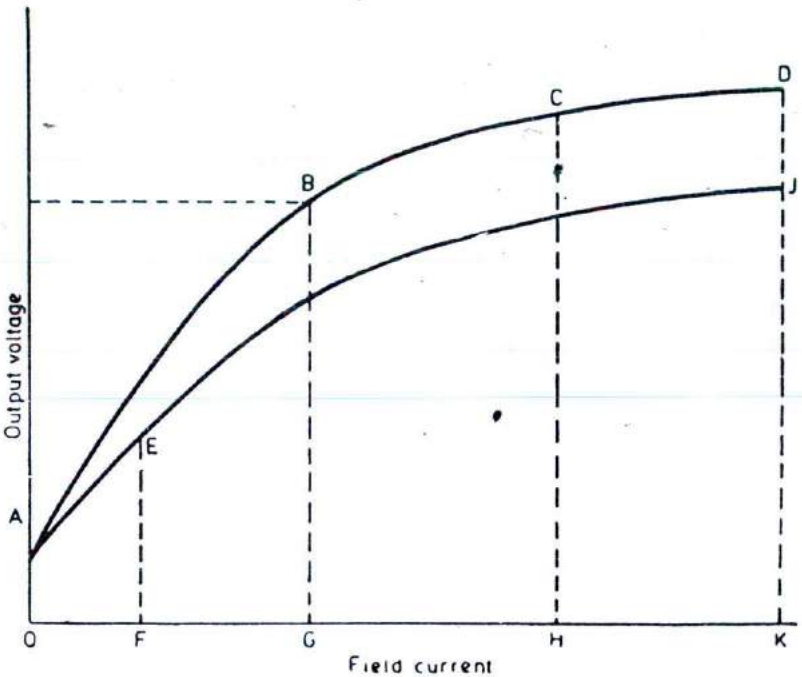


Fig. 11.1 (b). Open circuit characteristics of a d.c. shunt wound exciter.

11.1.2 EXCITER RESPONSE

Fig. 11.2 (*a*) shows curve of exciter response, which is the exciter voltage built up against the time in which it is built up.

The straight line *ACB* is drawn so that the area under the curve bound by *AE* and *DE* is equal to the area of the triangle *ACBE*. Slope of the line $ACB = \frac{BE}{AE}$ volts/second. As $AE = 0.5$ second, $\frac{BE}{AE} = 2\ BE.$; OA = Voltage required at rated excitation of the generator. Rotor temperature is allowed as 75°C. The nominal excitation response is defined as the ratio of the slope of the line *ACB* in volts/second to the nominal excitation voltage *OA*. Thus here it is $2\frac{BE}{OA}$

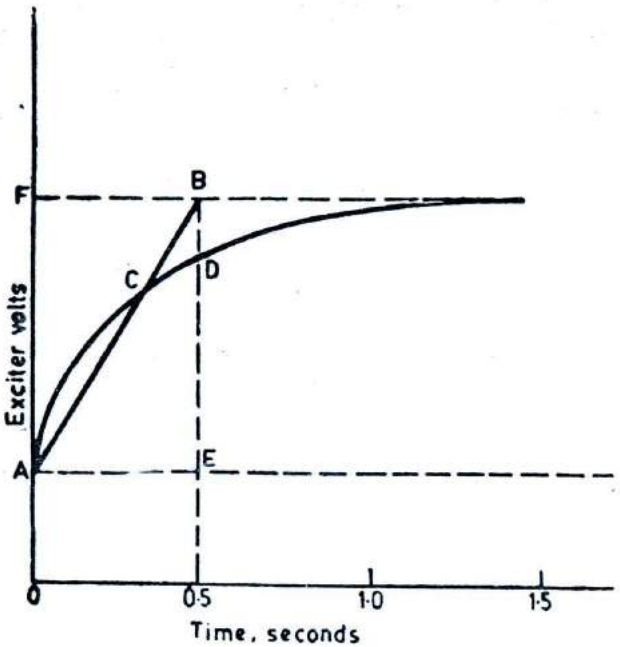


Fig. 11.2 (a). Exciter response.

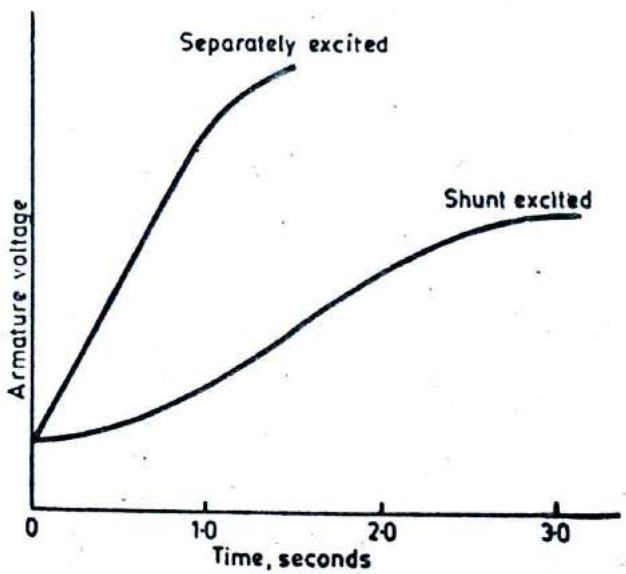


Fig. 11.2 (b). Response of separately excited and shunt excited machines.

A separately excited machine is supplied by pilot exciter. In such a case full pilot exciter voltage is available at all times to effect a rise in field current when required. The response of a separately excited machine can be 4 or 5 times that of a shunt excited machine. This is therefore faster. The curves in Fig.11. 2(*b*) show comparative response.

11.1.3 EXCITER DESIGN

The excitation power required for large turbo-generators is of the order of 0.4-0.5% of the generator rating. Except for small generators, the main exciter is usually separately excited from a pilot exciter. The advantage of this is not only more stable voltage but also improved voltage response to changes of field current.

The limiting speed for the exciter armature is 3000 m/min and for commutators about 2000 m/min. With more rigid binding arrangements of armature end windings and commutator reinforcement by means of steel retaining rings shrunk on the commutator, speed of 5000 m/min for armature and 4000 m/min for commutator are now possible. Direct driven exciters for 3000 r.p.m. can be designed for machines upto 100 MW. or so. For larger sizes, gear driven exciters running at lesser speed are sometimes designed. The advantage of a low speed gear driven exciter is that the brushwear is considerably reduced.

The minimum requirements of the main exciter are:—

(*i*) Rated current must not be less than 110% of rotor current for rated generator output.

(*ii*) Rated voltage must not be less than 110% of slip ring voltage for rated generator output.

The exciter voltage is generally 230 V. In some cases nominal voltage of 440 V is used.

(*iii*) Ceiling voltage must not be less than 120% of rated slip ring voltage.

(*iv*) Nominal response must not be less than 0.5.

The main exciter load is the resistance of the generator rotor. This is generally between 0.25 to 1.0 ohm. The rotor current is about 10 amps per MVA of generator rating.

Exciter field windings are generally two or more separate windings. This permits easier automatic voltage regulation. Main exciter voltage should be controlled from zero to ceiling voltage to obtain rapid correction of exciter voltage after fault or disturbance. Faults or system disturbances cause an automatic voltage regulator to force excitation up. After the fault clearance, rapid field reduction is necessary to adjust excitation to the correct value. This is easily done by the negative field. Fig. 11.3 shows a typical arrangement of exciter with positive and negative field.

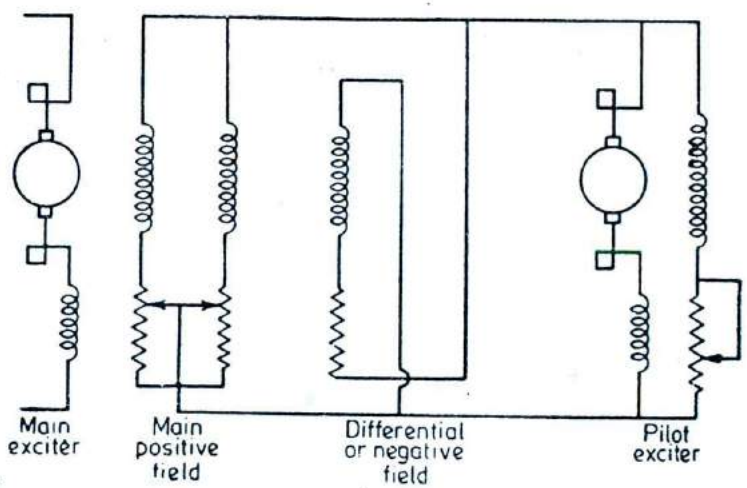


Fig. 11.3. Typical exciter field arrangements.

A pilot exciter is a level compounded machine and maintains constant voltage separate excitation for the main exciter. The negative field has constant current flowing in it in such a direction as to reduce the excitation. The positive field is in two parallel sections and has field rheostats for adjusting the field currents as required. The positive and negative field windings of the main exciter with adjustment of currents corresponding to the load on the exciter maintain the exciter voltage and excitation as required.

In most modern machines requiring large excitation, the main field rheostats are avoided and an amplidyne is used which can handle larger currents and have fast response in regulating excitation. The amplidyne is a cross field direct current generator. In this machine, brushes placed in the quadrature axis are short circuited. A small field m.m.f. is required to produce a large quadrature axis current as armature resistance is very small. This production of a large quadrature axis current by a small direct axis current amounts to the first stage of amplification in the machine. The quadrature axis current produces a flux in time and space phase with itself. The voltage will be developed across the brushes placed on the direct axis corresponding to the quadrature axis flux. The voltage produced by the quadrature axis current corresponds to the second stage of amplification. The direct axis brushes are connected to the load and the load current flows. A compensating winding is used so that there is no resultant excitation due to load current which may reduce the original field excitation. The machine is known as 'Amplidyne' and magnifies the current manyfold. The amplidyne has a number of control windings which can be supplied from pilot exciter and a number of feed back circuits of automatic voltage regulator and magnetic amplifier, etc., for control purposes. The advantage of this system is that the control power is very small and the response is very fast.

11.1.4 D.C. EXCITATION SYSTEM

Fig. 11.4 shows a basic schematic diagram of a D. C. excitation system.

The pilot exciter is a d.c. shunt wound machine. The main exciter is a d.c. shunt machine with a number of control field windings. The main exciter and pilot exciter are coupled to the main generator shaft. A d.c. motor drives an amplidyne or rotating amplifier which is a cross field d.c. machine, as explained in the last section. It has a number of control windings. The voltage transformer secondaries supply automatic voltage regulator (AVR) and magnetic amplifier circuits. The magnetic amplifier, after due correction of voltage through AVR, supplies singal to one of the control windings (2)

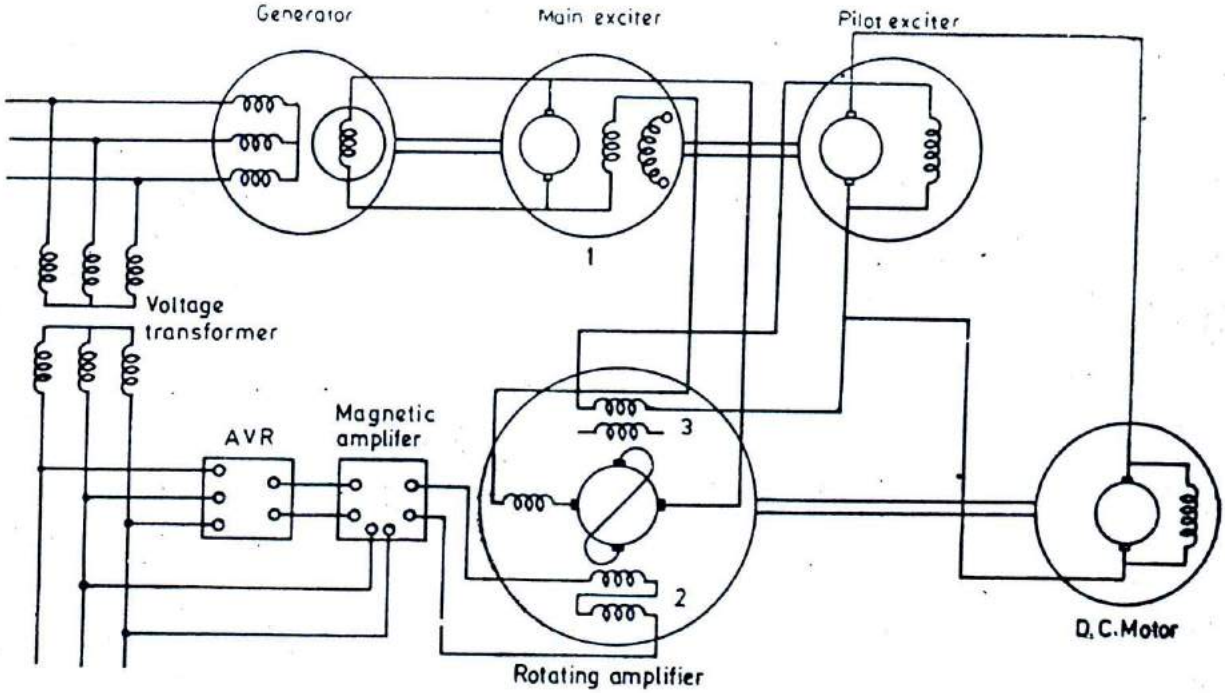


Fig. 11.4. Basic schematic diagram of a D.C. excitation system.
1. Main exciter auxiliary control field winding. 2. and 3. Auxiliary control field windings in rotary amplifier.

of the amplidyne. The pilot exciter supplies one of the control windings (3) of the amplidyne. The amplidyne then amplifies the current and supplies the field of the main exciter. The main exciter then supplies the field of the generator with required excitation to maintain load on the generator at rated voltage.

11.1.5 A.C. EXCITATION SYSTEM

Fig. 11.5 Shows a basic schematic diagram of an a.c. excitation system

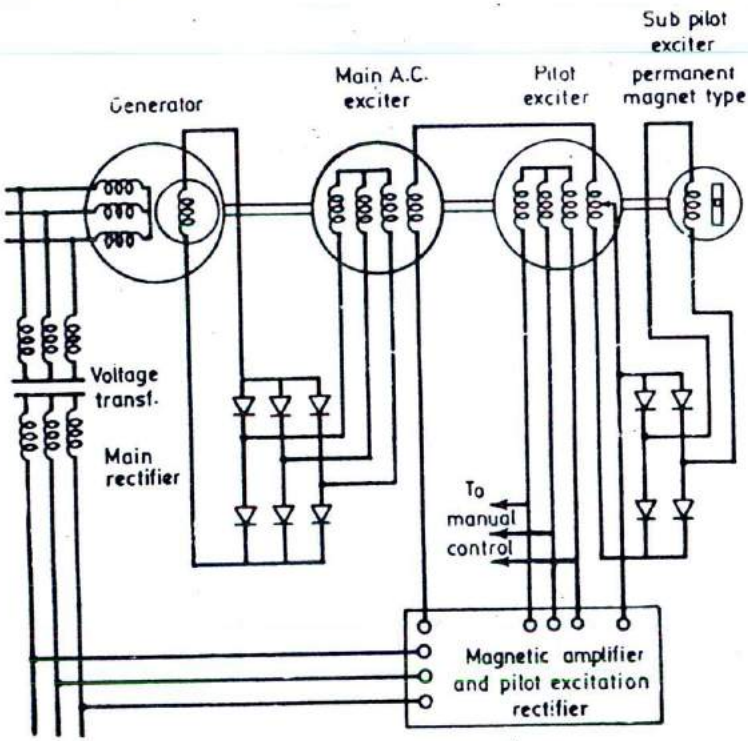


Fig. 11.5. Basic schematic diagram of an a.c. excitation system.

The a.c. system of excitation shown consists of a sub-pilot exciter of permanent magnet type, pilot exciter and the main a.c. exciter all coupled to the main generator on the same shaft. The

permanent magnet type generator is a single phase generator whose field is provided by a permanent magnet. The single phase supply from the armature is converted to d.c. by means of rectifiers and this d.c. supplies the field of the pilot exciter and main a.c. exciter. The pilot exciter and main exciter are a.c. three phase machines. The voltage transformer supplies voltage proportional to the generator voltage to magnetic amplifier.

Three phase voltage from the pilot exciter feeds into the magnetic amplifier. If an automatic voltage regulator is not in use, this can be supplied to manual control. The main exciter stator generates required voltage which is rectified by the main rectifiers and the excitation is fed to the field winding of the generator.

11.1.6 BRUSHLESS THYRISTOR EXCITATION SYSTEM

As the generators increase in rating, the problem of brush maintenance gets more and more difficult. Hence brushless excitation systems are attracting attention. The advent of silicon diodes made it possible to have compact rectified system converting a.c. to d.c. at higher power levels. A brushless diode excitation system consists of an exciter having a stationary field system, and a rotating armature diode rectifier assembly solidly coupled to the main generator rotor. The most commonly used rectifier configuration is that of the three phase bridge. If the silicon diodes are replaced by thyristors and suitable arrangements are made to apply firing pulses to their gates, with the firing angle under control of the operator, then it is possible to change the excitation voltage over the whole range in 10 milliseconds or less. The input voltage to the thyristor converter has a constant value equivalent to the ceiling excitation voltage required by the generator. The thyristor converter performs dual functions, viz. rectification and control of the mean voltage supplied to the generator field. This voltage can be varied from full positive ceiling to a substantial negative ceiling.

Static thyristor excitation systems usually draw excitation power from the generator terminals through a step down trans-

former or from a generator coupled a.c. exciter. Developments are well advanced towards combining the principles of thyristor control and brushless excitation and also provide an excitation supply which is independent of the main power system voltage fluctuations. This enables direct control of generator field current supplied from a shaft mounted exciter.

11.1.7 HARMONIC EXCITATION SYSTEM

A harmonic excitation system utilises the harmonic power developed in a generator to self-excite it. This power is captured by means of a separate stator winding which is controlled and rectified with magnetic amplifier and silicon rectifiers. With proper static control equipment, this power can be controlled to match the generator excitation requirements for all loads and power factors. Protective features are included to prevent loss of excitation in the event of rectifier failure.

Third harmonic excitation is normally used in such systems. This is direct self-excitation and saves having a separate exciter machine coupled to the main generator.

11.1.8 400 CYCLES EXCITER SYSTEM

In some cases, a 400 cycles exciter is used. The machine is of hetero polar inductor type with no windings on the rotor. It is designed for supply of 400 cycles voltage. The power is supplied to a static system consisting of rectification system, magnetic amplifier, etc. In some cases only an auxiliary exciter is of this type, supplying power to the automatic voltage regulator and to the field of the main exciter which may be a d.c. machine.

11.2 Excitation Control

The excitation control system does not differ for either a.c. or d.c. excitation systems. This is because, in automatic voltage regulators (AVR), the generator, AVR, and exciter control circuits form a closed loop system. The AVR senses the generator terminal voltage and if necessary alters the excitation in order to keep the voltage within the required limits. A reactive volt ampere limiting device is built into the AVR. At a predetermined value

of generator leading MVAR, the limiter overrides the basic AVR function and keeps the excitation current at a value to ensure that there is no further increase in rotor load angle and in the risk of instability.

A manual control system is invariably a part of the excitation control system and is used whenever automatic control is not being used. When the AVR is in service, a circuitry is provided which causes the manual control to follow up the changes in excitation, so that in the event of AVR failure the generator excitation control is immediately transferred to manual control without any change in excitation current.

11.2.1 AUTOMATIC VOLTAGE REGULATORS

Alternating current machines have inherently high internal reactance and inferior voltage regulation. There is therefore the need to have automatic voltage regulation equipment to maintain constant voltage under various operating conditions. The main functions of the automatic voltage regulator are as follows :

(i) to control the system voltage within prescribed limits and have the operation of the machine nearer to the steady state stability limit.

(ii) to regulate sharing of the reactive load between machines operating in parallel.

(iii) to maintain voltage under system fault conditions to ensure rapid operation of protective gear.

(iv) to control closely the field circuit to keep the machine in synchronism with the system when operating at unity or leading power factor.

When a sudden change of alternator load occurs, there should be a change in its excitation to give the same voltage under the new load conditions. The automatic voltage regulating equipment must first operate on the exciter field which changes the exciter voltage and then the alternator field current. The response of a voltage which controls the alternator's terminal voltage is thus a function of responses of the voltage regulator, the exciter.

and the main alternator flux. The response time of the regulator is the time required for the regulator to take action following the voltage change. For a particular regulator, this can be shown by a curve of % voltage change against the time in seconds. The 'dead band' is the voltage range over which no regulator response is expected.

Fig. 11.6 shows time for voltage regulator to start acting.

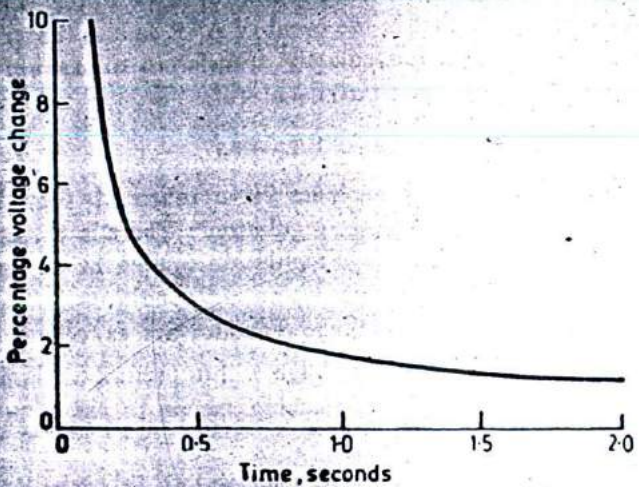


Fig. 11.6. Time for the voltage regulator to start acting.

To obtain rapid action, modern regulators employ the overshoot principle. If the busbar voltage falls, the regulator changes the excitation to secure more than a compensating rise. However before the voltage rises above normal appreciably, the regulator acts to reduce it again.

For steam turbo alternators a response of 0.5 is adequate, e.g., a mean rate of rise of 110 V/sec for nominal 220 V. The rate of rise of voltage per second required for hydro-electric generators is considerably larger, because of the overspeed to which these machines may be subjected.

11.2.2 DIRECT ACTING VOLTAGE REGULATOR

The operation of this type of regulator depends on the adjustment of variable resistances in the main exciter. The schematic diagram is shown in Fig. 11.7.

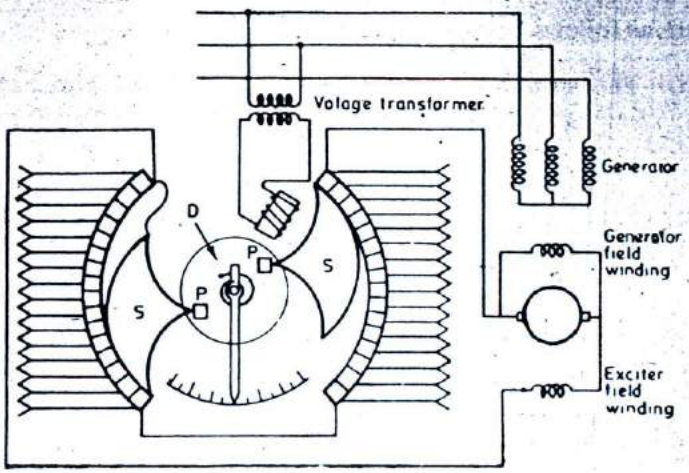


Fig. 11.7. A direct acting voltage regulator.

The voltage transformer steps down the voltage from the generator and supplies exact proportional voltage to the operating coil, thus producing operating torque. This torque operates on the drum *D*. Restraining torque is provided by springs. The two sectors *SS* are such that the clockwise movement of their pivots *PP* cause each of them to roll over a series of contacts and thus increase the resistance in the exciter field circuit. The motion in the counter clockwise direction reduces the resistance in the exciter field circuit. The motion of the drum takes place due to Ferraris effect in one direction or the other depending on whether the generator voltage has increased or decreased on load conditions.

11.2.3 PULSE TYPE VOLTAGE REGULATOR

The field rheostat in the exciter field circuit is cut in and cut out by vibrating contacts. A voltage sensitive electro-magnet

initiates the force for the operation of vibrating contacts and damping is provided by a spring loaded dashpot. The average field current depends on the relative break and make periods.

The shortcomings of electro-mechanical type voltage regulators are as follows :

(i) The variation of resistances in the exciter produces a variable time constant. The response time of the exciter will vary with different excitation conditions.

(ii) The response time of the regulator and main exciter field circuit is too slow. Dead band is not suitable for generators when running near steady state limit.

(iii) With the size of the machines increasing, the excitation increases and it is difficult for regulator contacts to handle this power.

11.2.4 SERVO TYPE VOLTAGE REGULATOR

Fig. 11.8 shows a servo type voltage regulator.

The main exciter is driven from the alternator shaft. This exciter has a saturated magnetic circuit and hence has a substantially constant output voltage. Variation in the main excitation current is obtained by an auxiliary series buck boost exciter. The auxiliary exciter and amplidyne are driven by a d.c. motor coupled to both the machines. The motor is fed from the main exciter. The field of the auxiliary exciter in supplied by the amplidyne. The voltage transformer supplies voltage proportional to the generator voltage to a voltage sensitive bridge one arm of which consists of saturated diode. Any deviation of output voltage of the alternator produces a corresponding change in the output of an electronic amplifier. The amplifier supplies the field of the amplidyne. As a result, the amplidyne output which supplies the field of the auxiliary exciter is changed and thus the auxiliary exciter and main exciter in series adjust the field current of the main generator as per load requirements to maintain its voltage

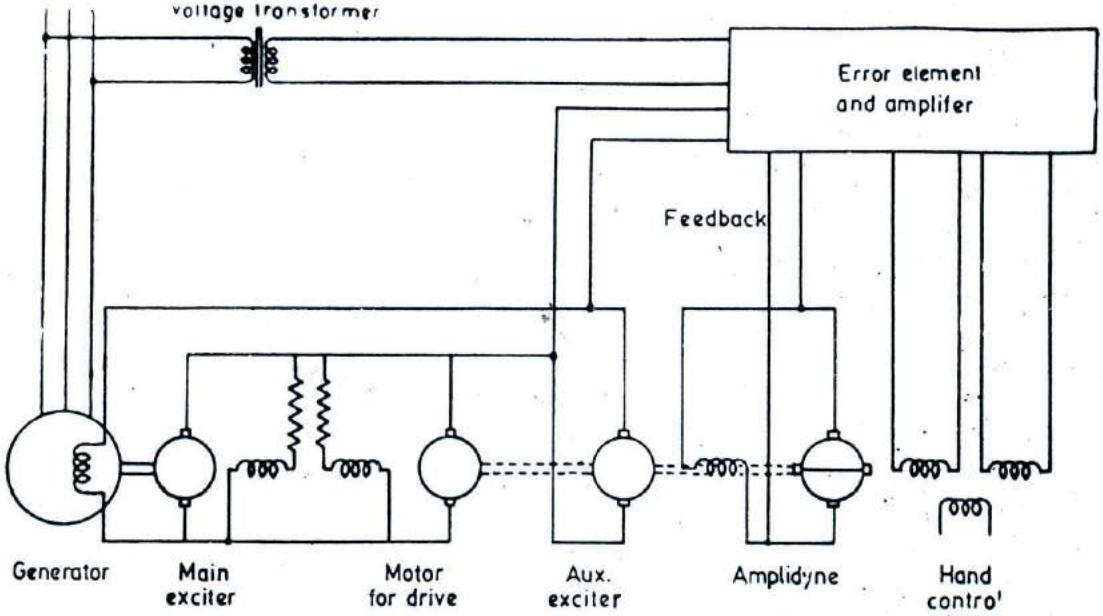


Fig. 11.8. servo type voltage regulator.

constant within limits. Feed back is also given from the error and amplifier circuits to the amplidyne as well as the auxiliary exciter.

11.2.5 ELECTRONIC VOLTAGE REGULATORS

Fig. 11.9 shows an electronic type voltage regulator.

Early designs introducing electronic type voltage regulators for generators consisted of the use of bridge circuits, voltage sensing circuits, rectifiers and thyratrons to control the excitation of the exciter by adjusting the required current through its field as per load conditions so as to maintain a constant generator voltage. The bridge circuit has two fixed and two variable arms. The bridge is fed from the reference voltage and the other two bridge terminals give error voltage between the existing and the prearranged setting. The variable bridge arm consists of tungsten filament lamps. Their response is a function of voltage. The

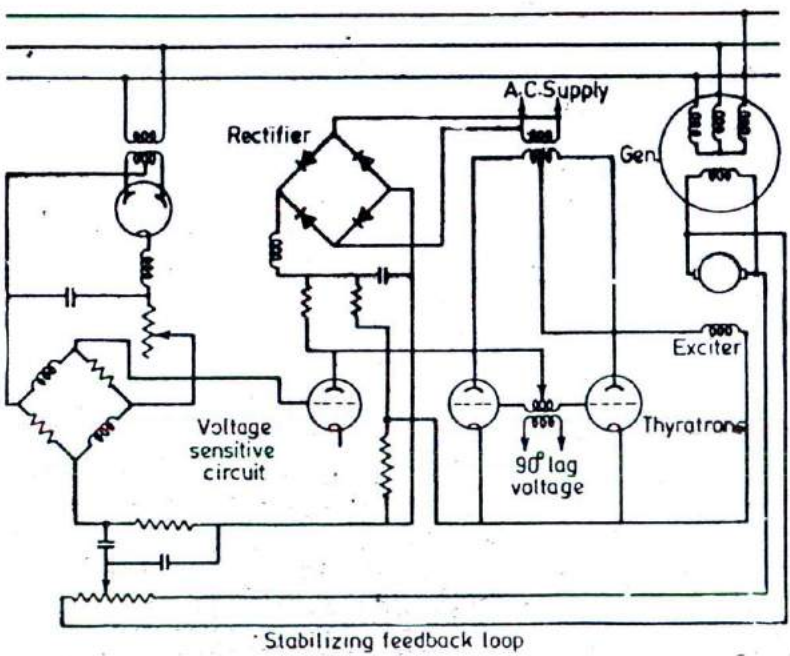


Fig. 11.9. An electronic type voltage regulator.

error voltage from the bridge is fed into an electronic amplifier which may be a series of thyratrons in series with the field of the main exciter. Thus the arrangement controls the field current.

There are a number of disadvantages and limitations in this type of arrangement. The life of the components is short; amplifying valves are expendable. Thyratrons have restricted temperature range and require time to warm up. The equipments and components are costly. A static excitation system is therefore preferable.

11.2.6 STATIC EXCITER REGULATOR SYSTEM

Fig. 11.10. shows the simplified circuit arrangements of a static exciter voltage regulating system.

The static regulator equipment uses alternating terminal voltage and line current to provide field excitation. The equipment is designed so that the field excitation will be at a level that will maintain desired line voltage of the generator regardless of load conditions. The generator voltage is applied to power potential transformers (PPT's) and fed through linear reactors to a water cooled three phase full wave bridge rectifier using silicon diodes which supplies the field current of the generator. Three saturable current transformers (SCT's) also supply power to the rectifier. The primary of each SCT is connected in line with the generator. Current in the primaries causes an increase in the current flowing into the field. Voltage reference, magnetic amplifier and stabilising components circuits are used. By varying d.c. control winding current on each SCT (by AVR), the secondary current of SCT is varied corresponding to given load conditions. Alternative arrangement for hand control is also made in case the automatic equipment for voltage regulation fails.

11.2.7 MAGNETIC AMPLIFIER TYPE VOLTAGE REGULATOR

If the B-H curve of magnetic material is plotted and the permeability-H curve is also plotted, it will be seen that the permeability is low for small and very large values of H and assumes good levels for moderate values of H. With increase in the values of H, the permeability can be reduced. The saturable core reactor

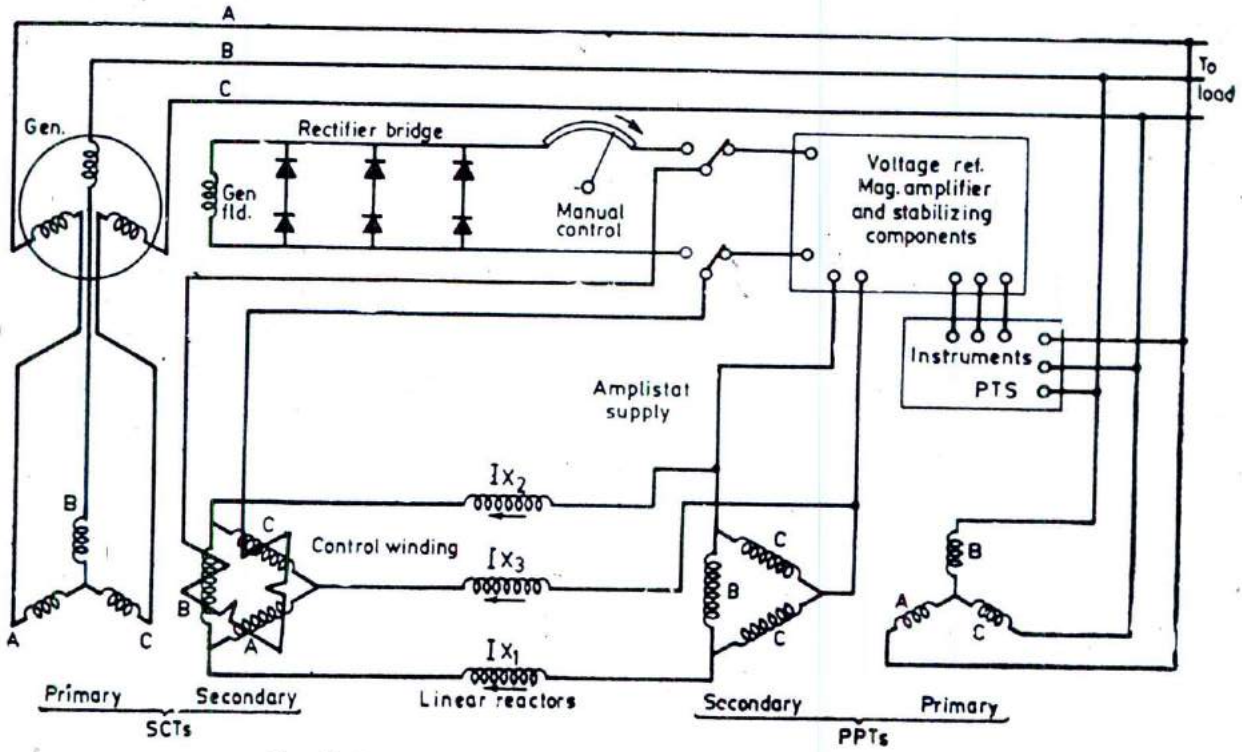


Fig. 11.10. Simplified static exciter regulator system.

can be designed so that when no d.c. is flowing in the d.c. control coil, the inductive reactance of a.c. coils is very high. This limits the flow of a.c. to a small value. With moderately large d.c. through the control coil, the core is saturated, the permeability is greatly decreased and the inductance and reactance of a.c. coils is decreased so that more a.c. power flows to the load. Fig. 11.11 shows the simple arrangement.

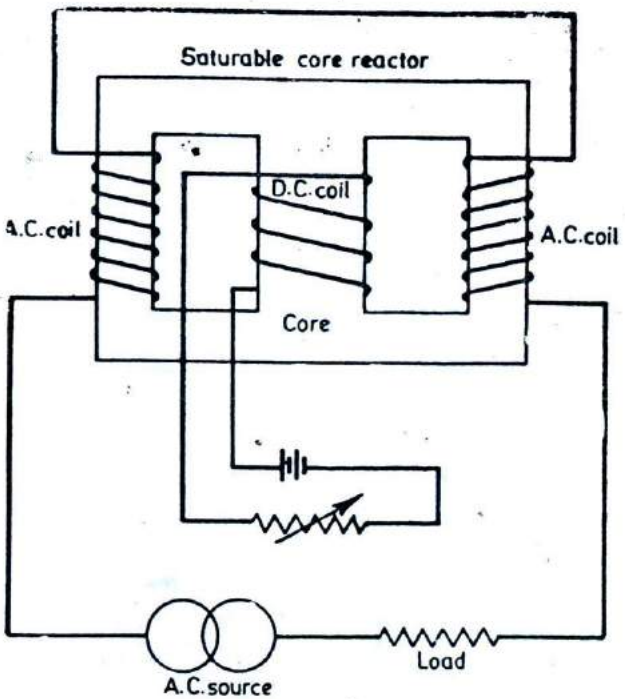


Fig. 11.11. Saturable core reactor circuit for simple magnetic amplifier.

Fig. 11.12 shows a single stage magnetic amplifier giving d.c. output to load. Here the input is d.c. signal and the conventional a.c. output is rectified by means of full wave dry-disc rectifiers so as to feed the resistive load with d.c. output.

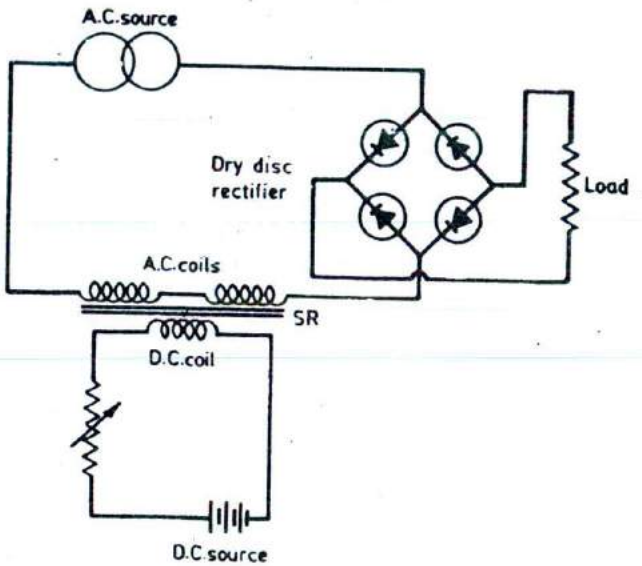


Fig. 11.12. Single stage magnetic amplifier. (d.c. Output to Load).

Magnetic amplifiers have the following advantages :

(i) Easy and effective amplification of weak d.c. signals.

(ii) Complete conductive isolation of input and output circuits of the amplifier for d.c. signals.

(iii) Magnetic amplifier is sturdy, mechanically shock-proof, and practically needs no maintenance.

(iv) It can be used as a device to operate as a.d.c. to a.c. convertor.

(v) It can amplify several separate signals simultaneously, the output of the device responds to the algebraic sum of the separate input signals.

Fig 11.13 shows a block diagram of the magnetic amplifier type voltage regulator.

The generator, main exciter (d. c.) and pilot exciter (a. c.) are coupled together and are driven by the same shaft. A_1 is the actual value unit which converts the generated a. c. voltage to be

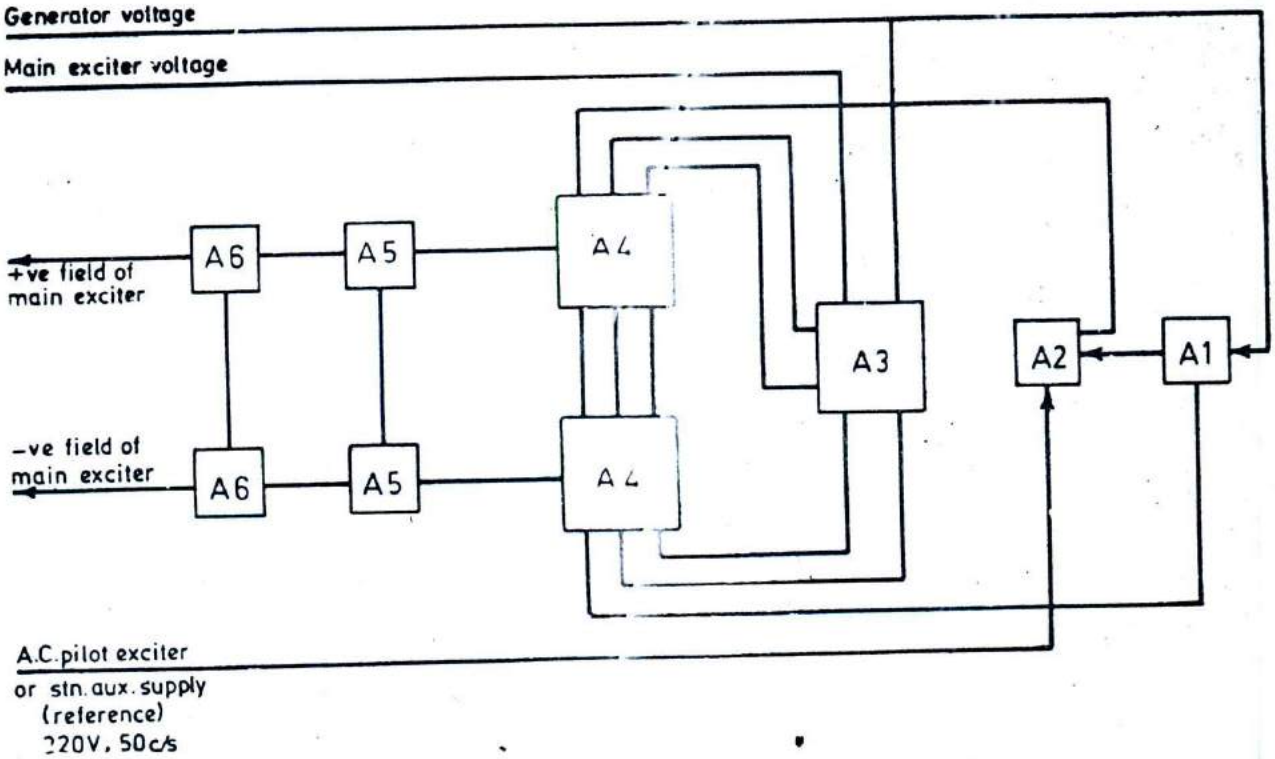


Fig. 11.13. Block diagram of magnetic amplifier type voltage regulator

regulated into a direct voltage suitable for magnetic amplifier type A. V. R. The potential transformer supplies voltage proportional to the generator voltage to three isolating transformers. These three voltages are rectified by rectifiers and added to obtain a mean value representing the generated voltage. This d. c. voltage is applied across a voltage divider. There is a rheostat for coarse adjustment of no-load generator voltage.

A_3 is the reference value unit. A stabilised d. c. voltage produced by A_3 is used as a reference value for the generator terminal voltage. A_2 is supplied from the shaft driven a.c. pilot exciter at 220 V, 50 c/s or alternately from station auxiliary supply. The unit has a potential transformer, bridge type rectifier zener diodes and resistors for stabilisation. The output of the reference value unit supplies the no-load voltage adjustment rheostat.

A_4 is a push pull type magnetic pre-amplifier. This has a number of control windings. Only three are shown in the diagram. The pre-amplifier winding no. 1 gets the resultant difference of the two voltages, viz. the generator terminal voltage and reference voltage, which is actually the error by which the generator terminal voltage is to be corrected. Winding no. 2 is for generator voltage feedback. Winding no. 3 is for exciter voltage feedback. A_5 is a magnetic intermediate amplifier and A_6 the final magnetic amplifier. The premagnetising and core saturating a. c. currents required for the basic functioning of magnetic amplifiers A_4, A_5 and A_6 are supplied from the pilot exciter output or alternative a. c. auxiliary station supply. The output from the magnetic pre-amplifier is rectified and fed to the control winding of A_5. The output of A_5 is rectified and fed to the control winding of A_6 and the final output of A_6 is rectified and fed to the main exciter field in a positive direction and the other field winding in the negative direction. Generally, the capacity of the negative field winding of the main exciter is of the order of 50% of the positive field.

A necessary feedback element is introduced for smooth rise or fall of the generator field as well as to avoid sudden rise of generator terminal voltage on loss of load or sudden change of reactive load on the system. The generator actual terminal voltage feed-

back is introduced through the feedback unit A_3. The unit contains rectifiers to convert a. c. voltage to average value d. c. and supply one of the control windings of A_4. Similarly d. c. voltage feedback (main exciter voltage) is fed to one of the control windings of A_4.

The exciter voltage is thus adjusted taking into account all the changes necessary owing to load and working conditions of the generator. The armature of the main exciter then supplies current to the field of the main generator and maintains the voltage constant.

In case automatic working of the voltage ragulator fails, there is a provision to change over from auto to hand control for adjusting the voltage of the generator.

11.3 Field Protection

The rotor winding of a generator is highly inductive and if suitable precautions are not taken, the voltage induced in the winding when a current flowing in it is suddenly interrupted may be high enough to break down the winding insulation. One of the most effective methods of field suppression is by insertion of a non-inductive resistance in the rotor-circuit shortly before the main excitation circuit is broken. The protection provided by a field discharge resistance has the following effect :

(i) It reduces the circuit-breaker arcing time thereby limiting the extent of any damage to the generator.

(ii) It reduces the di/dt value of the interrupted rotor field current thereby limiting the over-voltage induced in the winding. The effectiveness of the protection provided is dependent on the value of the discharge resistance. The non-inductive resistance values used are generally 1.0 to 1.5 times the hot resistance of the rotor winding. In normal practice, NIR (non inductive resistance) time rating is unlikely to exceed 10 seconds.

Automatic discharge of field is used to decrease rapidly the generator e. m. f. when internal faults develop within a machine, e.g., a phase to phase short circuit. Such a necessity arises from the fact that the current flowing into the fault in the machine will

not be interrupted by disconnexion of the machine from the circuit with which it has been operating in parallel. The flow of the internal fault current maintained by the generator e. m. f. can only be cut off by suppression of the latter through automatic discharge of the generator magnetic field. Protective relay action should result in tripping both the generator circuit-breaker and its automatic field discharge contactor. As soon as the automatic field discharge contactor is tripped, it switches out the exciter and shorts the rotor winding across the field discharge resistance. When the contactor of the automatic field discharge opens, it automatically throws discharge resistance in series with the exciter field winding to sharply reduce its excitation current. This is a precaution taken to prevent any excessive jump in voltage across the exciter terminals when the rotor winding is switched out. The value of this discharge resistance is about ten times greater than the hot resistance of the exciter field.

11.4 Commissioning of Alternators

The following steps are taken for electrical commissioning of an alternator erected and assembled before it is started and put on load. This is done after mechanical commissioning tests are carried out and are found satisfactory.

(*a*) Drying out the windings of the machine. The machine is run with the terminals short-circuited. The excitation is adjusted to regulate the current in the stator winding corresponding to full load current. Adjust cooling to maintain the temperature constant—70° to 80°C.

(*b*) Test the insulation of the stator winding to earth by a high voltage megger. The dry out should continue until the insulation resistance of at least one megohm per kV is reached.

(*c*) After dry out, a pressure test is applied between the stator windings and earth which will be 75% of twice the line voltage plus 1 kV.

(*d*) Carry out protective gear commissioning tests.

(*e*) Excite the machine on open circuit upto normal voltage.

(*f*) Carry out an over-voltage test during which the machine is excited upto 10% above rated voltage for about 10 minutes.

(g) Check whether the machine is in synchronism with the system before the circuit-breaker is closed and the machine connected to the system.

11.4.1 SYNCHRONISING OF ALTERNATORS

An alternator must be synchronised if it is to run in parallel with the other synchronous machines working in the system. For connecting the machine to an energized bus, the following conditions should be satisfied and checked :

(i) Voltage of the incoming machine and the bus between corresponding lines must be equal.

(ii) Phase sequence of the bus voltage and the incoming machine voltage must be the same. This is checked by proper connexions at the time of erection.

(iii) Frequency of the system at the bus and the frequency of the incoming machine must be equal.

(iv) The phases of the bus voltage and the phases of the incaming mochine voltage must be exactly in synchronism.

If all these conditions are satisfied, there will be no voltage difference between any corresponding pairs of terminals of the machine and the bus and such pairs of terminals can be electrically connected together without any disturbance to the system.

The principle of synchronising equipment is shown in Fig. 11.14 (*a*) and synchronoscope connexions in Fig. 11.14 (*b*). The incoming machine G is shown connected to busbars 1, 2, 3, through open switch. V_{bus} and V_G show the voltages between lines 1, 2 of the bus and the incoming machine respectively. These voltages should be adjusted to be equal. L_1, L_2 are lamps connected across phases 1 of bus to 2 of machine and 2 of bus to 1 of machine with the switch open. At the time of synchronising these should be equally bright. Lamp L_3 is connected across phase 3 of the bus and 3 of the machine. At the time of synchronising, this should be completely dark and the voltage across it shown by voltmeter v must be zero.

In case of high voltage machines, voltage transformers are used to supply 110 V. to instruments. In addition to a bright

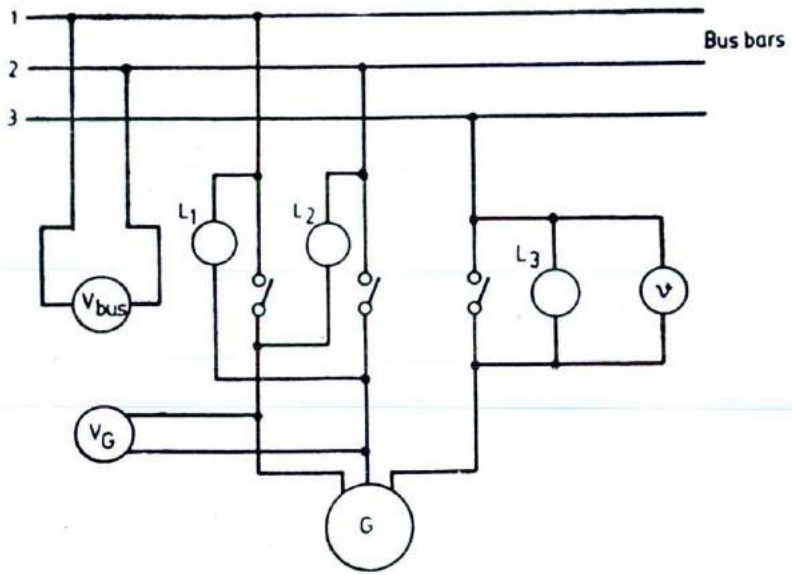


Fig. 11.14 (a). Synchronising of alternators.

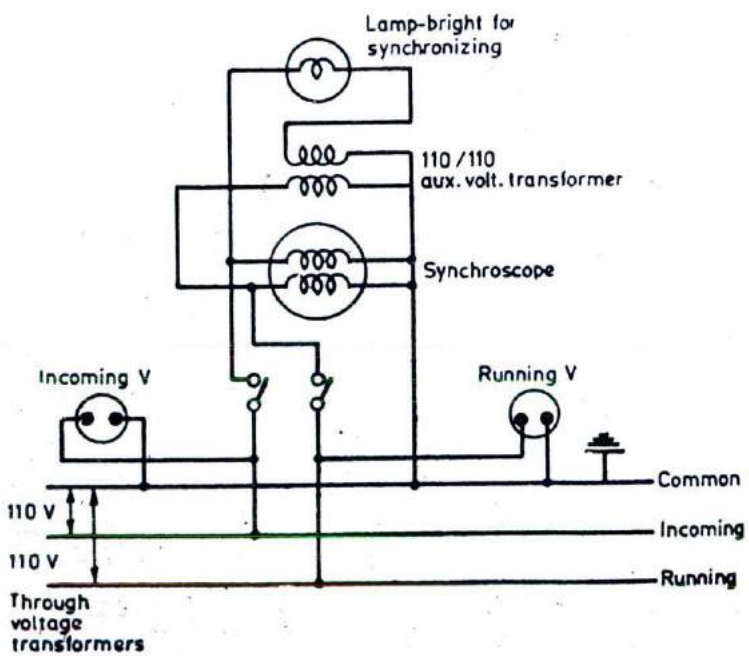


Fig. 11.14 (b). Synchronoscope connexions.

lamp which is connected across the auxiliary voltage transformer, a synchronoscope is used as shown in Fig. 11.14 (*b*). At the correct position of phases, the synchronoscope pointer shows zero or centre position—vertical—marked on the dial. The machine circuit-breaker is then closed and the machine synchronised at the correct time.

11.4.2 SYNCHRONOUS MACHINE ON INFINITE BUSBARS

Practically all synchronous generators in industrial use can be considered as connected to infinite bus as the system to which the machine is connected is generally large and arrangements are made to maintain the voltage constant by automatic voltage control.

The characteristics of a synchronous generator are quite different when it works on its local load and when it is connected to infinite bus. When working on local load, a change in excitation changes the terminal voltage, but the power factor is determined by the load. When working on infinite bus, a change of excitation does not change the terminal voltage of the machine, which is fixed by the network but the power factor is affected.

In both cases, the power developed by the generator depends on the mechanical power input by the prime mover.

While operating the generator under different loading and system conditions, it should be ensured that the machine is stable and gives the load within its stability limit. This point is discussed in the next section.

11.5 Power/Angle Diagrams

When two sets of synchronous machines are connected together by a transmision line, the power transmitted from one to the other depends on the voltage and phase angle at each end and the impedance characteristics of the transmission line. Fig. 11.15 is a simple diagrammatic representation of the line. The impedance of the line is $Z\angle\theta$. The voltage at one end is $V_1\angle\delta_1$ and sends out a current I_1 and the voltage at the other end is $V_2\ \angle\delta_2$ and receives a current I_2. There is transfer of power because of the difference in magnitude and phase angle between the two voltages.

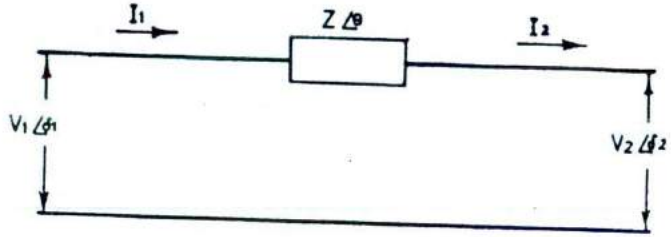


Fig. 11.15. Transmission line between two sets of synchronous generators.

The difference between the angles is denoted by

$$\delta_1 - \delta_2 = \delta_{12} \text{ or } \delta_2 - \delta_1 = \delta_{21}$$

The power at the sending end, P_1, is given by

$$P_1 = \frac{V^2}{Z} \cos\theta - \frac{V_1 V_2}{Z} \cos(\delta_{12} + \theta) \tag{11.1}$$

and the power at the receiving end, P_2, is given by

$$P_2 = \frac{V^2}{Z} \cos\theta - \frac{V_1 V_2}{Z} \cos(\delta_{21} + \theta) \tag{11.2}$$

where $\tan\theta = x/R$, if R is negligible,

$$P_1 = \frac{V_1 V_2}{x} \sin\delta_{12} \tag{11.3}$$

$$P_2 = \frac{V_1 V_2}{x} \sin\delta_{21} \tag{11.4}$$

When δ_{12} is positive, P_1 is positive and P_2 is negative. The maximum power that can be transferred from one end to the other is given by

$$P_{max} = \frac{V_1 V_2}{x} \tag{11.5}$$

It will be seen that reactance in the line is necessary for the transfer of power from one station to the other. The power transferred is a maximum when the angle δ_{12} is 90°. A curve showing the power available at various values of the angle δ_{12} from 0° to 180° is known as a power/angle curve. The shape of the power/angle curve for a line having appreciable reactance and negligible resistance is as shown in Fig. 11.16. The system is stable as long

as the derivative of the power/angle characteristic, $dP/d\delta$ is positive. The limiting condition is that $dP/d\delta = 0$.

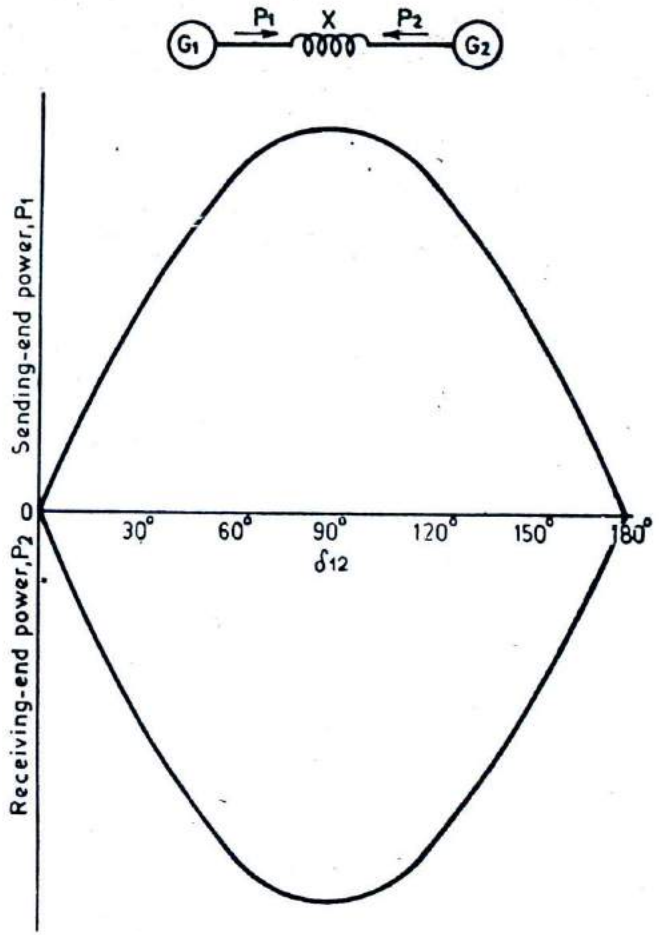


Fig. 11.16. Power/angle curves.

If the sending-end voltage, V_1, and the receiving-end voltage, V_2, are maintained constant by synchronous compensators or other means, the phase shift between them determines the power that can be transferred or transmitted.

11.6 System Stability

The load on a system may change gradually or suddenly. A gradual change may have little effect on the voltage and excitation of the synchronous machines in the system. Sudden changes of load may be due to quick switching operations or sudden faults, followed by tripping of the line and the load, etc. Whether or not the system will behave well and continue to supply load and keep the various synchronous machines in step under various conditions is a special study in itself and is known as system stability. There are, broadly, two kinds of system stability—steady-state and transient. The steady-state stability limit of a generator or system is defined as the maximum power, P_{max}, that can be transmitted for a change in load which occurs slowly enough to allow for a similar change in excitation to bring the terminal voltage back to normal. Thus P_{max} is the maximum load which can be supplied by the generator through the line to a synchronous load which is applied very gradually and is called the limit of static stability. Transient stability can be determined by considering the effects of the moments of inertia of the moving parts of the machines, of governor operation, of voltage regulators, of the performance of the plants under transient conditions, etc. Under transient conditions, there is a tendency for synchronous machines to swing or oscillate around the relative angular displacement. Whether or not a machine can come back to a steady condition after a temporary swing decides the transient stability of the system and the machines. For studying the details, angle/time curves, or swing curves, are plotted after calculation for the system conditions, and the operating conditions are judged on whether these would lead to stable or unstable operation.

When power/angle or torque/angle curves are plotted for transient conditions, the equal-area criterion decides the system stability conditions. If we consider the power angle curve under transient condition and steady state condition, it is seen that the maximum power possible in the transient state is higher than in the steady-state. The difference in the angle between the relative positions of the two rotors of the synchronous machines increases very rapidly and it is not safe to reach a maximum load corresponding to $\delta = 90°$

In practice the load is limited to two-thirds of the theoretically maximum permissible power for $\delta=90°$.

The stability of a power system can be increased by a number of means—

1. By designing the governors to follow closely the load on the machines.

2. By designing the excitation systems to give close voltage regulation under transient conditions.

3. By designing the voltage regulators for quick action with a small time-constant.

4. By making the exciter relays and regulators fast acting.

5. By making the lines and the terminal apparatus stiffer (i.e. not reacting quickly to sudden changes).

6. By including synchronous compensators in the system. The synchronous compensators keep the voltage constant at the points where they are installed and improve the power factor, thus increasing the power that can be transmitted.

11.6.1 STEADY-STATE STABILITY

High speed generators such as steam turbo alternators have round rotor or cylindrical rotor construction. While slow speed machines such as water wheel generators have salient pole rotor construction.

For round rotor machine operating at constant speed with constant excitation and no saturation connected to infinite bus, the power delivered, P_1, is given by—

$$P_1=-P_2=\frac{E_1E_2}{x_d}\sin\delta_{12} \qquad (11.16)$$

where P_2 is the power at the infinite bus.

E_1 = Voltage corresponding to the field excitation or voltage back of x_d.

E_2 = Voltage of the infinite bus.

x_d = Synchronous reactance.

δ_{12} = angle between the equivalent field excitation voltage and terminal voltage or the load angle.

$$\text{The maximum power } p_{max} = \frac{E_1 E_2}{x_d} \tag{11.7}$$

This is also termed as pull-out power of a synchronous generator against an infinite bus at constant field excitation.

The expression for power output of a salient pole machine neglecting saturation and connected to infinite bus is given by—

$$P = \frac{E_i e_t}{x_d} \sin \delta + e^2_t \frac{(x_d - x_q)}{2 x_d x_q} \sin 2\delta \tag{11.8}$$

where x_d = Direct axis synchronous reactance

x_q = Quadrature axis synchronous reactance

E_i = Voltage behind excitation.

e_t = Terminal voltage.

The additional term in the expression of power is not a function of field excitation of the machine. This is reluctance torque or the reluctance power component caused by the difference in magnetic reluctance of the direct axis and the quadrature axis. For round rotor generators, $x_d = x_q$; for salient pole machines x_q/x_d is about 0.6. The effect of saliency is to increase the maximum power to some extent and the angle at which this maximum power occurs is less than 90°, the angle where P_{max} occurs for round rotor machines.

The procedure in calculating the steady-state stability limit is as follows :

(i) Reduce the system to its simplest form, preserving the identity of the points at which specified voltages and/or power factors are maintained.

(ii) For an assumed load under given conditions, calculate the internal voltages of all machines in phase and magnitude.

(iii) Calculate the transfer impedances between all machines.

(iv) Calculate $dP/d\delta$ of all the machines according to the assumed loading distribution between them.

(v) If the system is stable for the assumed load, increase the load and proceed as before till the steady-state limit is reached. For a system to be stable, the synchronising power coefficient $dP/d\delta$ of the machines should be positive.

Instead of by hand calculations, the procedure can be set and worked out on a network analyser.

The above criterion is conservative. A more accurate one would take into account the effect of inertia action and governor action.

For analysing the steady-state stability characteristics of generators, the effect of magnetic saturation should be included.

S. C. R. : The steady-state stability characteristics are important from the point of view of the design of turbo alternators. Short-circuit ratio (S.C.R.) of a synchronous generator is defined as follows :—

$$S.\ C.\ R. = \frac{\text{Excitation for normal voltage on open circuit Saturation Curve}}{\text{Excitation for full load short-circuit current}}$$

This is shown in Fig 11.17.

OA is the excitation required to produce normal voltage on the air gap line. *OB* is the excitation required on the *O.C.* saturation curve to produce normal voltage. *OC* is the excitation required when short-circuit occurs with normal full load armature current flowing in the machine.

$$\text{Short-Circuit Ratio } (S.C.R.) = \frac{OB}{OC}$$

$$x_d = \frac{OC}{OA};\ S.C\ R. = \frac{k}{x_d};$$

$$k \text{ is no load saturation factor} = \frac{OB}{OA}$$

Short-circuit ratio is used as a measure of generator stability. With manual or slow excitation control, machines of high short-circuit ratio are more stable than machines with low short-circuit ratio. The field excitation for a given load condition is a function

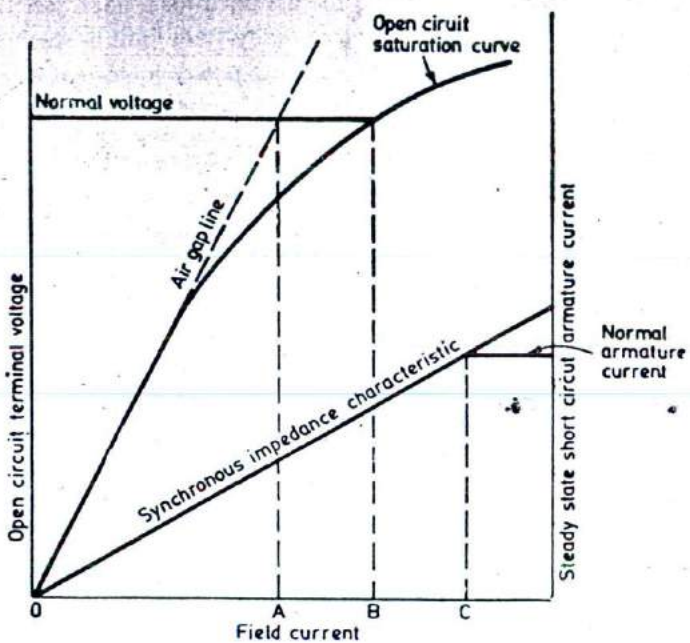


Fig. 11.17. Generator open circuit saturation and synchronous impedance characteristics.

of the load saturation for that load. Therefore, two machines which have identical short-circuit ratios but different load saturations, pick up different increments of load from the same initial loading. The machine which has the largest initial load saturation picks up the greatest amount of load. Another advantage of high short-circuit ratios is that the turbo generator can be operated under excited to hold its voltage down to normal and thus provide line charging capacity to the system. The disadvantages are that generators with high short-ciruit ratios are more expensive, have higher short-circuit currents and greater losses.

Effect of voltage regulators : In modern machines of large size, voltage regulators take their proper share of responsibility for maintaining the stability of the system. As part of the responsibility of maintaining synchronism is shifted to the excita-

tion system, it is possible to have a more economic design of generator which can give higher efficiency and reduced weight and size for a given rating.

The function of the regulator is to make changes in field excitation to maintain the terminal voltage of the machine or the system voltage constant after load changes. A regulator which makes rapid and continuous change in the field excitation as required by the load condition is able to maintain the stability of a generator above the static stability limit. Automatic voltage regulators help in maintaining stability.

For machines with voltage regulators located near their load which have inherently stable characteristics such as rectifier, lighting load, etc., special attention need not be paid to the stability characteristics. For such loads, S.C.R. of the generators used may be as low as 0.6 or even 0.4. For generators which are located away from loads and where the loads consist of synchronous motor loads, it is necessary to be careful about the stability characteristics of the generators. Higher short-circuit ratios should be used for generators in such cases to guard against instability. It should also be watched that pull-out usually occurs under conditions of higher saturation than those corresponding to no-load normal voltage saturation.

A generator not equipped with voltage regulator may require a short-circuit ratio of 1.0 if it is expected to pick up load to full load value from no-load or lightly loaded condition with no change of excitation.

11.5.2 TRANSIENT STABILITY

The factors which affect the transient performance of synchronous machines are :

(*i*) Occurrence, type and location of short-circuits.

(*ii*) Response of the system to sudden changes in current and voltage.

(*iii*) Speed of circuit-breakers and relays.

(*iv*) Response of excitation systems and governors of synchronous mahines.

An analysis of steady-state performance of a system involves the system power flow characteristics and the synchronous machine power angle characteristics, while for analysis of transient performances of a system it is necessary to consider the system and machine torque angle characteristics.

For a synchronous machine, the torque angle characteristics are given—

$$T=\frac{e'_q e_t}{x'_d}\sin\delta+e^2_t\frac{(x'_d-x_q)}{2x'_d x_q}\sin 2\delta \qquad (11.9)$$

where e'_q=the quadrature axis voltage corresponding to a voltage generated by the flux linking the main field winding of the direct axis.

x'_d=direct axis transient reactance.

e_t=terminal voltage−voltage at the infinite bus.

x_q=quadrature axis synchronous reactance.

It will be seen that for a salient pole synchronous machine, peak of the steady-state torque characteristics occurs at an angle less than 90° (electrical) and that the peak of the transient torque angle characteristics occurs at an angle greater than 90° (electrical). This is because of the change in the sign of the reluctance torque component. The transient torque is also of greater magnitude.

For cylindrical rotor machines, $x_d=x_q$, while for salient pole machines x_q is about 0.6 x_d. In the case of a round rotor machine, there is no saliency effect in its steady state torque angle characteristic. However, saliency effect exists in its transient torque angle characteristic. The value of the transient torque is also higher than that at steady state.

In a study of the behaviour of the system with reference to stability, equal area is used as the criterion. This can be illustrated by the example of a system shown in Fig. 11.18.

The system considered consists of a generator, step-up transformer, transmission lines (two in parallel) step-down transformer and infinite bus. The torque angle curve for the system under no fault is shown. It is carrying a normal load unit

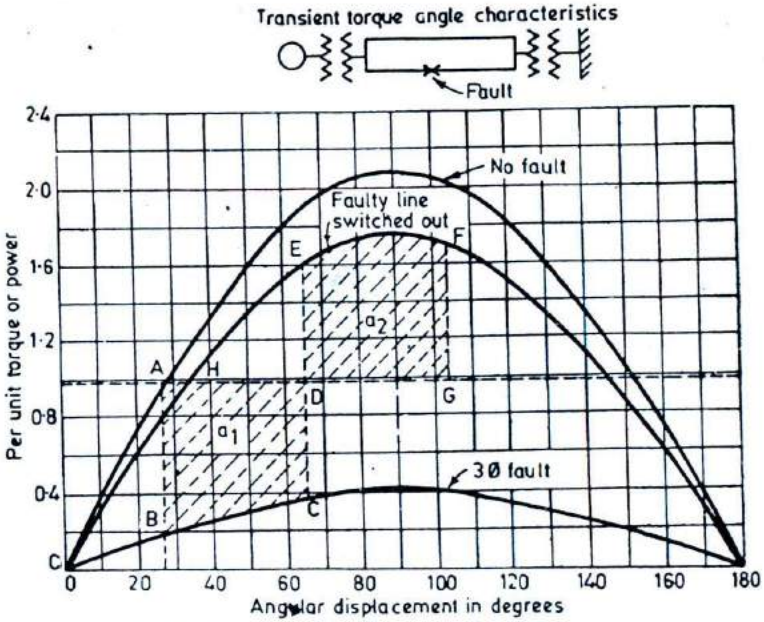


Fig. 11.18 Torque angle curves of a system.

corresponding to point *A* on the curve. If three-phase fault is applied at the centre of one of the parallel circuits, the torque angle of the curve of the system is shown. Here the system is definitely unstable unless the fault is simultaneously switched off at both ends of the faulty line. If the fault is switched off, the torque angle curve changes as shown. If switching takes place, e.g., at angle 65°, equal area criterion can be applied to find out whether the system will be stable after the switching off operation. With application of fault, electrical torque will be corresponding to point *B* and the rotor velocity will increase owing to accelerating torque *AB*, until the fault is removed. At the angle at which switching takes place – here 65° – the torque point *C* on the three phase short curve jumps to point *E*, corresponding to the torque angle curve with the faulty line switched off. At this point E, the electrical output exceeds the mechanical input and a decelerating torque, *DE*, is effective. The forward rotor velocity above synchronous speed now begins to decrease until at point *F* this

velocity is zero. The position F is such that area a_1=area a_2. Here the rotor has decelerating torque FG acting upon it. The angular displacement of the rotor decreases and the rotor will oscillate about its new angular position of equilibrium H. H is the point of stable equilibrium. The angular displacement in either direction from the point H develops force which tends to return the rotor to its normal position.

There is angular displacement for switching beyond which it is impossible to go if stability is to be maintained. If the switching off of the faulty circuit is accomplished before this angular displacement is reached, the system stability will be maintained. If switching off occurs late, and at an angle such that the area a_2 is less than the area a_1 the system will be unstable. The time that it takes the rotor to swing to this position of critical angular displacement is the maximum time that the fault can be allowed to persist on the line with stability. This angular position is known as the critical switching angle.

Equal area criterion can very easily be applied by the graphical method. Mathematically this condition can be put as follows—

$$\left(\frac{d\,\delta_{12}}{dt}\right)^2 = \int T_a\, d\delta_{12} = 0 \qquad (11.10)$$

For studying the transient system stability of multimachines, swing curve should be calculated. The procedure for long hand calculation is as follows :—

(*i*) Reduce the system network to a simple equivalent circuit.

(*ii*) Determine transfer point and driving point impedances for circuit conditions of fault on, fault off, etc.

(*iii*) Determine initial conditions and power flow equations for the various subsequent transient conditions.

(*iv*) Determine the accelerating torque constant for each machine group.

(*v*) Prepare a swing curve sheet.

(*vi*) Assume fault clearing time and make calculations for every 0.05 second interval of time. Plot the swing curve and check whether the system is stable or not.

The procedure can also be set on a network analyser. The swing curve calculations can be done by the step by step method.

The following generator characteristics should be taken into consideration with reference to transient stability:

(*i*) To reduce any appreciable increase in the first swing of the transient power limit the transient reactance of the generator must be reduced to a great extent.

(*ii*) With reduced fault clearing times, increasing the inertia of the ganerator above normal values is not as effective as reducing the transient reactance of the generator.

(*iii*) Moderate rates of excitation response are good for stability.

(*iv*) In case of salient pole generators, low resistance amortisseur windings help to some extent in increasing first swing transient stability limits.

(*v*) Governor characteristics have little effect on the first swing transient stability limits.

11.7. Voltage Regulation of Transformers and Transmission Lines

It is necessary to regulate the voltage of the system at various points within prescribed limits; otherwise the voltage decreases in magnitude owing to the load and the phase angles of the voltages in some parts of the system are displaced with respect to those of voltages in other parts owing to the nature of the load (reactive) and the system characteristics. Some of the methods of regulation are mentioned below.

1. Brown-Boweri regulators are used in power stations to regulate the generator voltages by adjusting the excitation. This is done by varying a resistance in the field circuit whenever there is a tendency for the voltage to change, thereby keeping it constant. Various types of regulators used in generating stations have already been described earlier.

2. Tap-changing transformers are used with tappings on their windings which are changed to adjust the voltage levels at the sub-station or load points. The tappings may be changed on no-load, but where quick action in regulation is required without any break in the circuit, on-load tap-changing transformers either alone or in conjunction with preventive auto-transformers, are used.

The decision as to whether the tappings on the transformers are to be placed on the primary (h.v.) or secondary (l.v.) side depends on the following considerations :

(a) Transformers having large ratio of turns and heavy output current on the l.v. side, may have insufficient turns on the l.v. side to give the required voltage variation in steps. This is not so on the h.v. side.

(b) The interruption of current will be less severe on the h.v. side than on the l.v. side.

(c) If a transformer is intended to be suitable for operation on various supply voltages, then primary tappings would be appropriate.

(d) H.V. windings are placed outside the l.v. windings and l.v. windings are placed near the core of the transformer during construction for insulation purposes.

Hence, in most cases the h.v. side of the transformer windings are tapped, which are easily accessible.

Normally, the taps are changed with the switch off and the circuit made dead by what is known as an 'Off Load Tap Changer'. The arrangement for this type of tap changer is shown in fig. 11.19. for one of the phases. for 2.5% and 5% tappings.

When a transformer is connected to a system and the voltage is to be maintained normal under all conditions of load on the transformer, by variation of voltage ratios without interruption of supply, an on load tap changer is required. The best position of placing the tappings is at the neutral end of the high voltage windings.

Fig. 11.20 shows the arrangement for an 'On Load Tap Changer'.

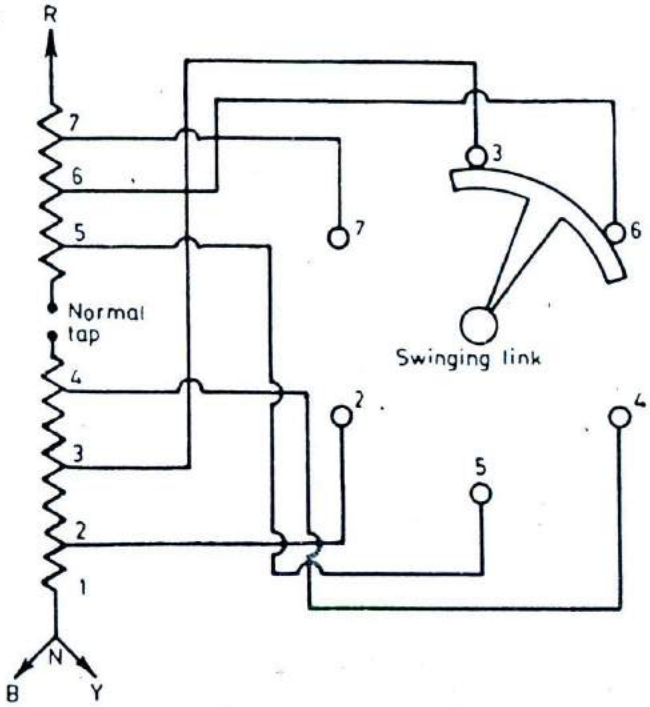


Fig. 11.19. Off load tap changer for transformer.

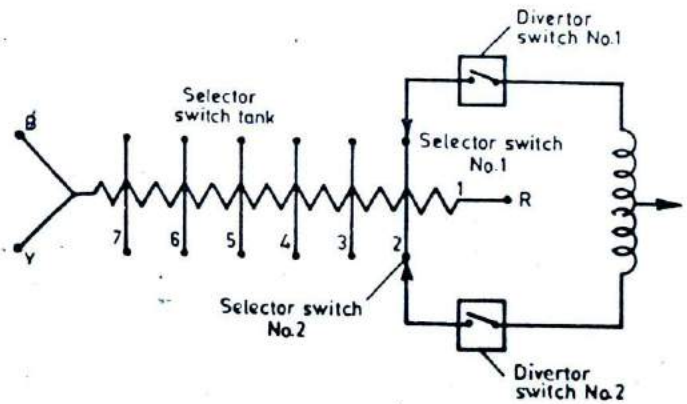


Fig. 11.20. On load tap changer for transformer.

As tap-changing must take place under load, before one tap has left contact, the contact must be made with the other tap without a break in the circuit. This would cause short-circuit on few turns and the current would be large. This is prevented by the use of resistors or reactors. Fig. 11.20 shows the divertor switches, selector switches, taps and reactor with the centre point tapped.

The procedure for operation would be —

(i) Divertor switches No. 1 and No. 2 on.

(ii) Open divertor switch No. 1, move selector switch from position 2 to 3.

(iii) Close divertor switch No. 1.

(iv) Open divertor switch No. 2, move selector switch from position 2 to 3 (lower side).

(v) Switch on divertor switch No. 2.

This changes the position of the tap from 2 to 3.

The operation is started and stopped by the voltmeter indication in the circuit, a contactor, a time switch and motor driven arrangements effect the tap changing.

3. Booster transformers are used to increase the voltage at a point or points in a transmission line at a distance from the main transformers. The capacity of a booster transformer is generally 10% to 20% of that of the main transformer. The advantage of a booster transformer is that it is independent of the main transformer. It is cheaper when there is no main transformer at the point where regulation is desired.

4. Phase-angle control. When the stations in a system are inter-connected it is essential to be able to dispatch loads via selected lines so that the lines may not be overloaded. For selective dispatching, it is necessary to control the magnitudes and phase angles of the various line voltages.

Phase-angles control can be effected in the following ways :

(a) The in-phase voltage-booster transformer can be used to inject a voltage in phase with the line. As shown in Fig. 11.21 (a)

a voltage which can be adjusted by taps on the secondary of an additional transformer is fed to the primary of the series transformer. The voltage induced in the secondary of this transformer is added vectorially to that of the main transformer as this winding is in series with it. From the vector diagram at (b) it will be seen that the line voltages are increased in magnitude but there is no phase shift. Thus the in-phase voltage-booster transformer gives the necessary in phase voltage control.

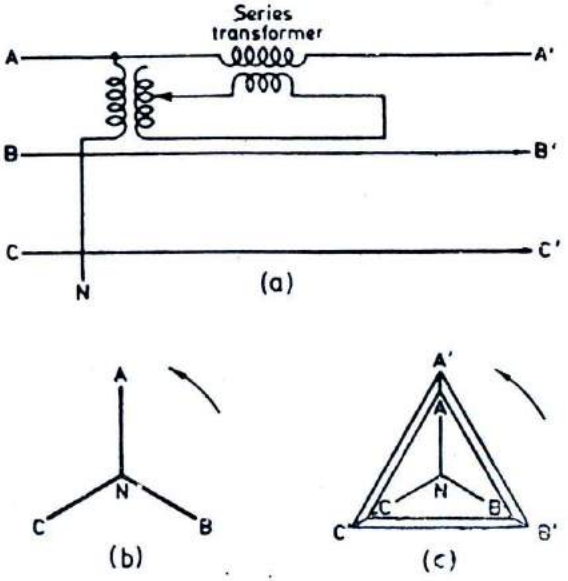


Fig. 11.21. In-phase voltage-booster transformer.
(a) Circuit diagram (for one-phase) (b) Vector diagram.

(b) The quadrature voltage-booster transformer, or phase-shifting transformer, can be used to inject voltage at right angles to, or in quadrature with, the line voltage. The circuit diagram for one phase is shown in Fig. 11.22 (a). The voltage induced in the secondary of the additional transformer and fed to the primary of the series transformer is in quadrature compared to the last case. The vector diagram is shown at (b). The voltages are shifted from positions A, B, C to positions A', B', C' and there is thus a phase shift.

A combined unit can control both the magnitude and the phase angle of a voltage .

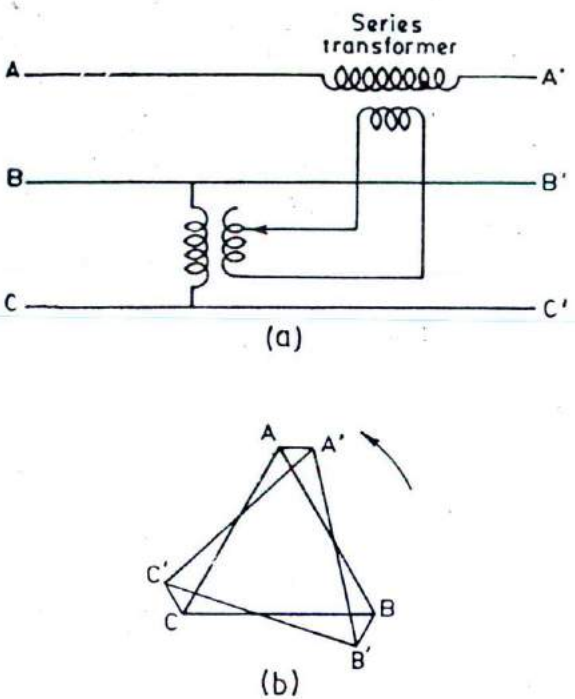


Fig. 11.22. Quadrature voltage-booster transformer.
(a) Circuit diagram (for one phase); (b) Vector diagram.

(c) The induction regulator can be used to boost the line voltage. It is similar to a wound-rotor induction motor, but the rotor is not free to rotate. The rotor winding is connected in series with the stator winding, and the rotor position can be mechanically shifted with respect to the stator. The stator is supplied with a 3-phase voltage. Magnetic flux is produced and the voltage induced in the rotor depends on the ratio of the number of turns of the stator to those of the rotor. The phase of the rotor voltage with respect to the applied stator voltage depends on the position of the rotor winding with respect to that of the stator. The circuit diagram is shown in Fig. 11.23 (a), and the vector diagram in Fig. 11.23 (b). There is a phase shift bet-

ween initial positions of the line voltages, A.B.C., and their final positions A'. B', C'.

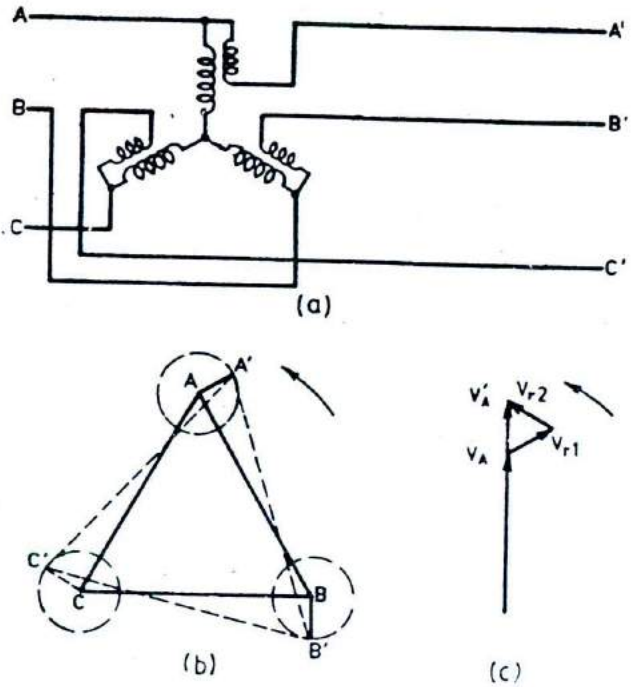


Fig. 11.23. Twin induction regulator.
(a) Circuit diagram
(b) Vector diagram (complete)
(c) Vector diagram (for one phase)

If a twin 3-phase induction regulator is used, the phase shift can be avoided. A twin induction regulator is comprised of two 3-phase induction regulators each of half the total required kVA capacity. The secondary windings are connected in series and the rotors have opposite phase rotation. The net effect is that the voltage is increased as required and the phase shift is avoided. The vector diagram for one phase is shown in Fig. 11.23 (c) : the voltage of phase A has been increased from V_A to V'_A.

(d) The voltage at one or more points on a transmission line can be controlled by varying the power factor. Power factor control is effected as follows :

(i) By the use of capacitors connected in star or delta across the load.

(ii) By the use of phase advancers—Leblanc exciter scherbius type phase advancers, etc.

(iii) By the use of synchronous motors operating on no load as synchronous compensators.

The adjustment of power factor and the regulation of voltage help in improving the stability of a transmission line system.

11.8 Instrument Transformers

Instrument transformers are potential or voltage transformers and current transformers. These are used in the station and in switchyards to supply the instruments and relays with voltages and currents exactly proportional to those in the main circuits. The main advantages of instrument transformers are :—

(i) To avoid handling high voltages and currents directly for control purposes, since the control can be effected from the control room, at a safe distance.

(ii) Only lower voltage and current are applied to the voltage and current circuits for control purposes, relays and instrumentation. This limits the size of the instruments and ensures safety of operators.

11.8.1 VOLTAGE TRANSFORMERS OR POTENTIAL TRANSFORMERS

A voltage transformer is used to reduce voltage to a standard value—generally 110 volts—stepped down from the line voltages of high values such as 220 kV, 132 kV..... 11 kV, etc. This voltage is given to the pressure circuits of instruments and voltage circuits of relays.

These are different from the power transformers or distribution transformers. The differences between power transformers and distribution transformers were explained in the previous chapter. The main features of potential transformers are as follows:—

Capacity: VA generally from 15 VA to 200 VA

Connexions: Single phase units. For three phase circuits, two units may be connected in vee. In some cases three units may be connected in star.

Voltage range: High voltage side—voltage of the h.t. lines or high voltages: secondary side or low voltage side: 110 volts.

Flux density: 1.1. weber/sq. meter or so compared to 1.35 webers/sq. meter for distribution transformers and 1.5 webers/sq. meter for power transformers.

No tappings

Self-oil cooled.

The ratios of transformation of voltages have to be exact and there should be no ratio error. This is limited to 0.3% to 2%. Similarly, as the voltages on the secondary side should be an exact replica of the voltages on the h.v. side, there should not be any phase displacement between these voltages. The phase angle error is limited to 20′ to 40′ depending on the degree of accuracy or class of potential transformers. When they are used in conjunction with measuring instruments, the accuracy should be more. When used with relay circuits the accuracy may be comparatively less.

11.8.2 CURRENT TRANSFORMERS

Current transformers are used to reduce the current exactly proportional to the load current and use this for supplying current circuits of measuring instruments. The primary winding of a current transformer is connected in series with the load circuit in which the current is to be measured. There is no appreciable voltage between the two terminals of this winding; also primary current is not determined by the secondary load on the transformer, as in the case of power transformers. The secondary rating of the current transformer is generally 5 *A* (the latest trend is to 1 *A*). The current coil of the wattmeter, energy meter, and ammeter are connected across the secondary of the current transformer. This is the burden or the load on the current transformer.

Capacity : VA generally 5 VA to 50 VA.

Connexions : Single phase units.
Flux density : 0.1 to 0.2 webers/sq. meter.

Current transformers have to be designed for low flux densities so that the *B-H* curve is a straight line and the secondary current is exactly proportional to the current in the primary. The ratio error is reduced and avoided. The other factor is magnetising current, which causes ratio error. This is reduced by a lower value of *B*. The core material for current transformers should be low loss material such as mumetal or nickel iron alloy.

$$\text{Ratio error} = \frac{\text{Nominal ratio} - \text{Actual ratio}}{\text{Actual ratio}} \qquad (11.11)$$

The ratio error is considered to be positive when the actual ratio of the transformer is less than the nominal ratio.

In most current transformers, turns compensation is used in order to obtain a ratio of transformation more nearly equal to the nominal ratio corresponding to $\frac{\text{No. of secondary turns}}{\text{No. of primary turns}}$

There should be no phase angle error between the primary and secondary current. The limitations of the ratio errors are 0.15% to 1%; limits of phase angle errors are from 5′ to 120′.

In a current transformer, the number of primary ampere-turns is a fixed quantity depending on the primary current. This is not reduced when the secondary of the current transformer is opened, as in the case of a power transformer. Therefore, if the secondary of a current transformer is opened when the current is flowing in the primary circuit, high flux density is produced in the core of the transformer because there are no back ampere turns due to the current flowing in the secondary. This high flux density induces very high voltages across secondary terminals, and this causes danger to the operator. It also strains the insulation and sometimes breaks it, causing flashover and damage to the secondary windings. This also causes ratio and phase angle errors in the current transformers to increase after open circuit so that its accuracy is impaired. Therefore, the secondary of a current transformer should never be open-circuited. It should always be

connected to the instrument coils which act as burden on the current transformer.

The ratios may be high such as 5000/5 A, 1000/5 A, 250/5 A, 50/5 A, etc. Current transformers may also have multi-ratios, so that they can supply two or more circuits separately, if necessary.

11.9 Power Supply for Station Auxiliaries

The various auxiliaries required for steam stations were discussed in chapter 4. They were classified as essential unit auxiliaries, station auxiliaries and emergency auxiliaries. The types of drives used for various auxiliaries were also discussed.

A unit transformer supplies essential unit auxiliaries. The primary of the unit transformer is supplied from the generator and the secondary voltage of the transformer is selected depending on the size of the auxiliaries. For generators upto 100 MW size, the system for supplying unit auxiliaries is designed for 3.3 kV and 415 V. For generators of a size higher than 100 MW, 6.6 kV system is used as an alternative to 3.3 kV. For 500 MW generator unit, 11 kV, 3.3. kV and 415 V are used. Loads above 150 kW are supplied from 3.3. kV or 6.6 kV supply, while small loads are supplied from 415 V supply. To obtain low voltage 415 V supply another transformer of 6.6 kV/415 V or 3.3 kV/415 V is used depending on whether 6.6 kV or 3.3 kV supply is used for large unit auxiliaries. For loads above 500 kW, a 11 kV supply is preferably used.

The service auxiliaries are supplied by station transformers, generally in duplicate, deriving power from the outside station at high voltage. At the starting time, unit boards are fed from the station board. Immediately after synchronising, the unit supply is changed over to all unit auxiliaries. When a set trips, station supply is automatically changed to station boards. This change over takes place automatically by sensitive electronic devices.

In case of emergency, a diesel set or a gas turbine set is provided in the power station to run emergency auxiliaries and charge the station batteries in case of complete shutdown from the Grid.

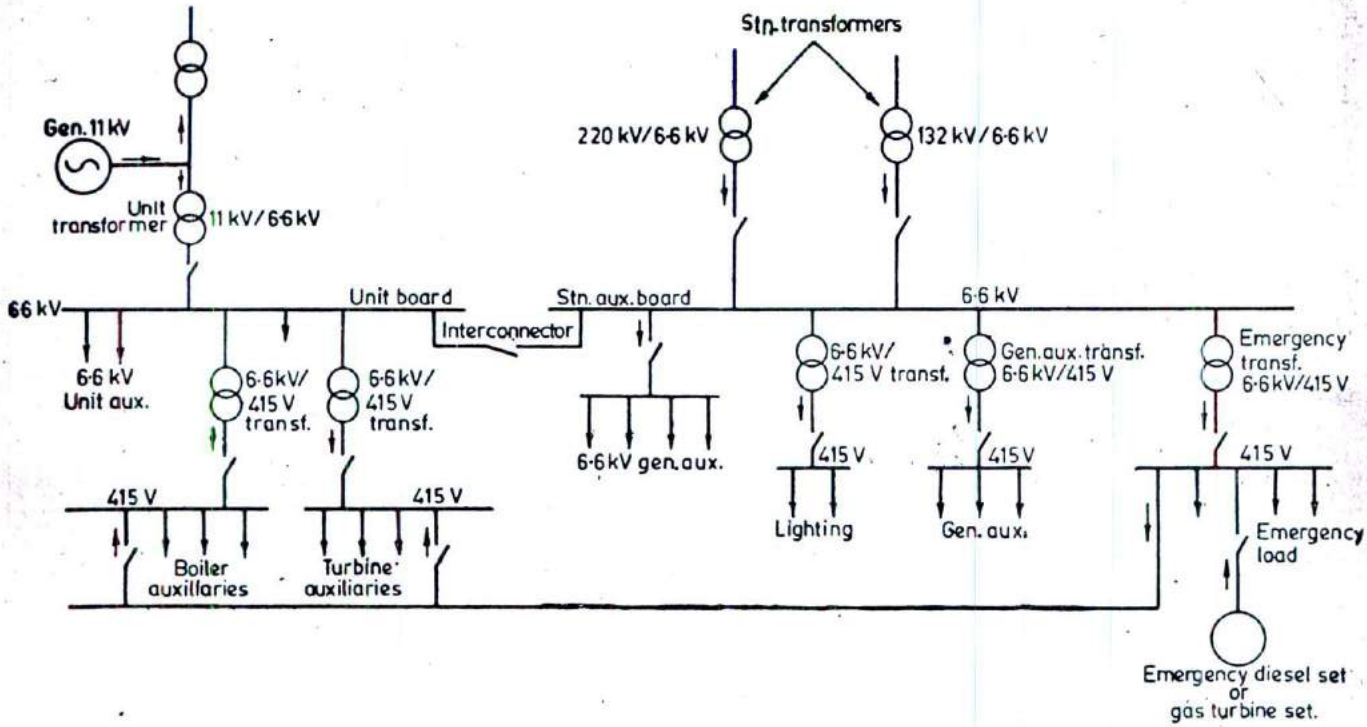


Fig. 11.24. Single line diagram for supply to auxiliaries.

Fig. 11.24 shows a typical single line diagram for supplying auxiliaries in a steam station.

Generation voltage is 11 kV. From the generator connexion is taken to power transformers to supply the Grid system through the arrangements in the switchyard. The generator also supplies unit transformer 11 kV/6.6 kV. From this transformer, supply is given to the Unit Board at 6.6 kV through a circuit-breaker. The unit auxiliaries needing 6.6 kV supply are supplied from these busbars. There is a transformer to step down 6.6 kV to 415 V to supply boiler auxiliaries at 415 V. Similarly another transformer supplies turbine auxiliaries at 415 V.

The station Auxiliaries Board is fed from two separate sources in the Grid through two transformers, one 220 kV/6.6 kV and the other 132 kV/6.6 kV. The station auxiliary bus is interconnected to the Unit Board to supply unit auxiliary in case unit transformer supply fails. The station auxiliary bus supplies station auxiliaries at 6.6 kV., *A* 6.6 kV/415 V transformer supplies low voltage bus at 415 V to supply lighting load. There is another transformer 6.6 kV/415 V to supply generator auxiliaries at 415 V. An emergency transformer 6.6 kV/415 V supplies 415 V bus to supply emergency load.

In case of complete breakdown of transformers from the Grid side, 415 V bus is fed from a Diesel engine set or Gas turbine set run in the thermal station for the purpose. This gives supply to Boiler auxiliaries and turbine auxiliaries from this bus as an alternative arrangement in case of emergency.

The arrangements of the various supplies can therefore be adjusted as required by the system condition for ease and reliability in power station operation.

The power required by various auxiliaries in a large steam station varies between 7% and 10% of the power at the station main bus. This decides the size of the unit transformer and station transformer.

11.10 Power Station Control

The methods of control and instrumentation principles for both steam stations and hydro-stations were discussed in the pre-

vious chapters, together with the principles of control room arrangement.

The active load on the generator unit depends on the speed drop and is controlled by regulating the steam input for the steam turbine of a turbo generator, or the water inlet to the water wheel of a hydro-generator. As the voltage at the bus is maintained constant by automatic voltage regulators and the system can be considered as infinite bus, the change of excitation of a generator unit affects its reactive load only and changes the power factor.

Watts and Vars of each unit are checked on instruments. Total watts and Vars of the various units in a station are summated and recorded as total watts and total vars of the station. This information is also sent by telemetering arrangement to the load dispatch centre.

Fig. 11.25 shows the block diagram of watt and var telemetering and recording arrangement in a modern station.

The figure shows the connexions in block diagram for one of the generator units, G_1, in the station. Similar connexions are used for the other units also.

Transducers are used for telemetering watts, vars, and current to the control room. Generator var is obtained by switching the transducer output to the input of an operational amplifier. For these circuits, shielded, twisted leads are used and mercury-wetted relays are used. The var amplifier gives indication of vars on the switchboard type instruments of the control room console. The var transducers are also all connected in series with shielded leads and connected to total station megavar recorders. In watt transducer circuits, the transducer output leads are brought out directly to the unit load recorders on the console. The output of the watt transducers provides the unit mw signal which is used by load frequency control equipment for necessary operation. The watt transducers are switched with mercury-wetted transfer relays to operate the indicating instruments on the console.

Logging : To obtain the station total whrs, impulses from impulse generators operated by unit watt-hour meters are used.

The impulses are totalised and the total stored in the printing demand meter on the recorder switchboard. The printing demand meter prints the accumulated whrs at the end of the hour, and provides a printed log of the total station whrs each hour.

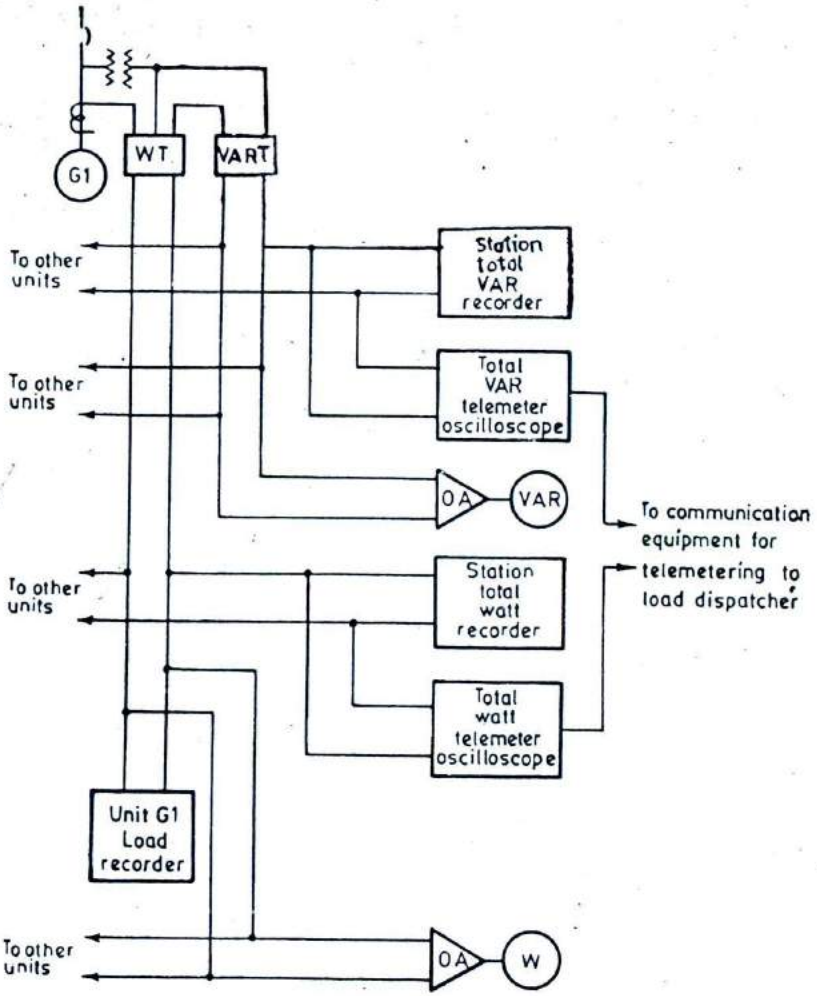


Fig. 11.25. Block diagram of watt and var telemetering and recording.

WT Watt transducer
W Wattmeter
OA Operational amplifier.
VAR T Var Transducer.
VAR Varmeter.

11.10.1 LOAD AND FREQUENCY CONTROL

Load and frequency control of interconnected generators pose problems. These are fairly simple in the case of a small system having one or two generating stations. However, they are more difficult in large interconnected systems having many stations which are scattered over a wide area.

In a single station system the operator can easily adjust the governors of the prime movers so as to have the load division between the generator units as desired from the economical point of view. The operator can also hold the frequency of the station accurately with the help of an accurate frequency meter and an electric clock in comparison with a standard clock. Clocks are available with a pointer which is operated differentially from the electric and standard clock mechanisms. This indicates the number of seconds that the electric clock is fast or slow as compared to the standard time.

Closer frequency control can be provided with steam turbo generators than with hydraulic turbine driven generators owing to slower governor action and greater speed changes resulting from the greater inertia of water turbines.

For larger system with a number of generating stations, the load sharing and allotment is done from the central load dispatch centre. Frequency control is generally assigned to one of the largest generating stations. Economic load sharing and automatic frequency control are discussed in a later chapter.

11.11 Interconnexion

The interconnexion of a number of stations results in many advantages. We have already seen that the combined working and operation of different types of power station results in better handling of the system load. The interconnexion of two or more power stations always reduces the amount of generating capacity required as compared with that which would be required without interconnexion. The reliability is greater, as power can be supplied even with one of the major power stations out of operation for some time.

These advantages apply equally when whole systems are interconnected, especially when their peak loads occur at different times, as in the British and French systems, which are interconnected by a cable under the English Channel. Again, the construction of new generating capacity can be deferred until it becomes more economic than the purchase of energy from the proprietors of the interconnected system. At all times less spinning reserve is required.

Some of the advantages of interconnexion and the methods of control will now be illustrated by a few examples.

Example 11.1

Two power stations Fig. 11.26 are joined by an interconnector having a resistance voltage of 2% and a reactance voltage of 10%. Find the phase angle between the station busbars with the interconnector carrying full load (*a*) when the voltages at the two stations are equal, and (*b*) when the voltages at the stations are 105% and 100% respectively. In each case, find the percentage active (kilowatt) and reactive (kilovar) loads at the receiving-end.

In either case, $IR=2\%$ and $IX=10\%$, so that the impedance voltage is $IZ=\sqrt{(10^2+2^2)}=\sqrt{(104)}=10.2\%$ where I is the full-load current and Z is the impedance of the interconnector.

(*a*) In the vector diagram Fig 11.26 (*a*), CD represents the resistance voltage, IR, in phase with current, BD represents the reactance voltage. IX, in quadrature with the current, and BC represents the impedance voltage, IZ. We have found that $V_{BC}=BC=IZ=10.2\%$. Also from the data, $V_{AB}=100\%$ and $V_{AC}=100\%$. The angle BAC, or δ, is the phase difference between the two station voltages.

A graphical solution gives the phase angle δ and the angle ϕ between the receiving-end voltage V_{AC} and the current I, so that the active and reactive components of power at the receiving-end can be easily found. If AE is drawn perpendicular to BC,

$$\sin\frac{\delta}{2}=\frac{BE}{AB}=\frac{5.1}{100}=0.051, \text{ so that } \frac{\delta}{2}=2.9^\circ \text{ and } \delta=5.8^\circ$$

$$\theta=\tan^{-1}\frac{BD}{CD}=\tan^{-1}\frac{10}{2}=\tan^{-1}5=78.6^\circ$$

$$\phi=180^\circ-(90^\circ-2.9^\circ)-78.6^\circ=14.3^\circ$$

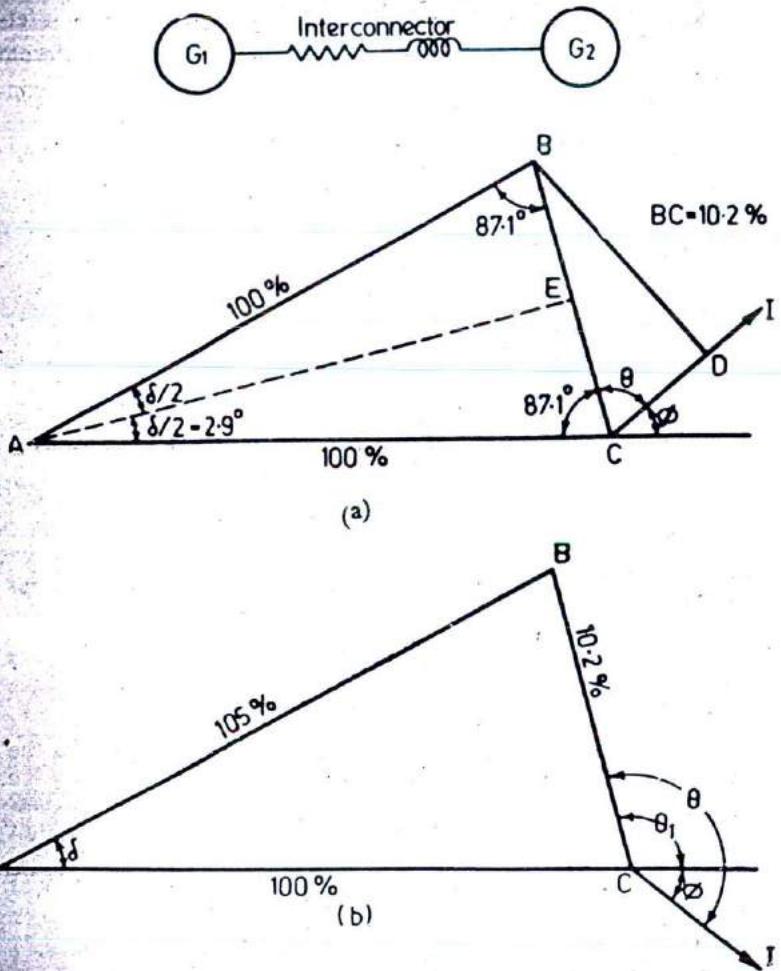


Fig. 11.26. System for example 11.1 Not to scale : the angle has been greatly exaggerated to make the diagrams clear.

Alternatively, the angle δ can be found from the trigonometrical relations between the sides of the triangle ABC—

$10.2^2 = 100^2 + 100^2 - (2 \times 100 \times 100 \times \cos \delta)$, so that

$$\cos \delta = \frac{19,896}{20,000} = 0.9948, \text{ and } \delta = 5.8°$$

The active power at the receiving end is proportional to cos ϕ, and is therefore given by cos 14.3°=0.97, or 97%. The reactive power is proportional to sin ϕ, and is given by sin 14.3°=0.247, or 24.7%.

(*b*) In Fig. 11.26 (*b*) the receiving-end voltage is 100% and the impedance voltage is 10.2% as before, but the sending-end voltage is 105%.

Solving trigonometrically,

$10.2^2=105^2+100^2-(2\times105\times100\cos\delta)$, so that

$\cos\delta=0.9962$, and $\delta=5°$

$105^2=100^2+10.2^2+(2\times100\times10.2\cos\theta_1)$, so that

$\cos\theta_1=0.451$ and $\theta_1=63.2°$; also, $\theta=78.6°$ as before

$\phi=\theta-\theta_1=78.6°-63.2°=15.4°$.

The active power at the receiving-end under condition (*b*) is proportional to cos ϕ, and is therefore given by cos 15.4°, or 96.4%. The reactive power is proportional to sin ϕ and is given by sin 15.4°, or 26.6%.

Example 11.2

An interconnector which links two stations, *A* and *B* has an impedance of $3+j2$ ohms per phase. If the supply voltages at *A* and *B* are to be maintained at 33 kV and in phase with each other, suggest an arrangement for voltage control. If a booster transformer is used for the purpose, find the booster voltage per. phase in magnitude and phase angle which should be supplied at station *A* to allow the transfer of a load of 10MW at unity power factor from station *A* to Station *B*.

Fig. 11.27 shows the interconnector and vector diagram.

Voltage to neutral at Stations *A* and $B=\dfrac{33{,}000}{\sqrt{(3)}}$

$=19{,}100\ V$

When transferring the load of 10 MW, the current is

$$I=\frac{10\times10^6}{\sqrt{3}\times33\times10^3}=175\ A$$

Impedance of interconnector per phase, $Z=3+j2$ ohms

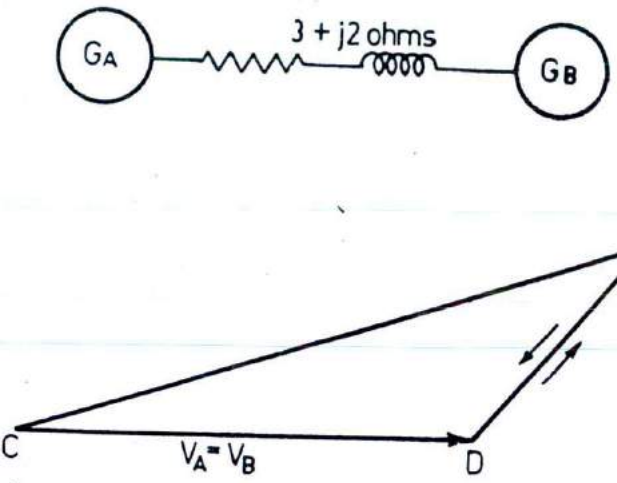


Fig 11.27. System for example 11.2.

The impedance voltage of the interconnector, *ED* in the vector diagram is

$$IZ = 175\,(3 + j2) = 525 + 350 \text{ volts per phase}$$

The voltage drop in the interconnector must be compensated for both in magnitude and phase shift, so that the voltage to neutral of the booster, *DE* in the vector diagram, must be $525 + j350$ volts.

Example 11.3

Two power stations, *A* and *B*, operating in parallel, are interconnected by a short transmission line. The capacity of station *A* is 10,000 kW, and that of station *B* is 5,000 kW. The no-load to full-load speed regulation of station *A* is 2% and that of station *B* is 4%. Calculate the output of each station and the load on the interconnector when the load on the busbars at Station *A* is 6,500 kW, and that on the busbars at Station *B* is 6,000 kW.

Let the loads on stations *A* and *B* be P_A and P_B, and let the total load be *P*.

$$P = P_A + P_B = 6{,}500 + 6{,}000 = 12{,}500 \text{ kW}$$

The drop in speed at station *A* should be the same as that at *B* to maintain the same frequency at the busbars. Since the speed regulation at *A* is 2% on full load (10,000 kW)

Speed regulation at load of $P_A = \frac{P_A}{10{,}000} \times 2\%$

The speed regulation B is 4% on full load (5,000 kW), so that

Speed regulation at load of $P_B = \frac{P_B}{5{,}000} \times 4\%$

For satisfactory parallel operation, these two regulations should be equal –

$$\frac{P_A}{10{,}000} \times 2\% = \frac{P_B}{5{,}000} \times 4\% \text{ so that } P_A = 4P_B$$

$4P_B + P_B = P = 12{,}500$ kW, so that $P_B = 2{,}500$ kW and $P_A = 10{,}000$ kW

Load through interconnector from A to $B = 10{,}000 - 6{,}500 = 3{,}500$ kW.

Fig. 11.28 shows the distribution of load.

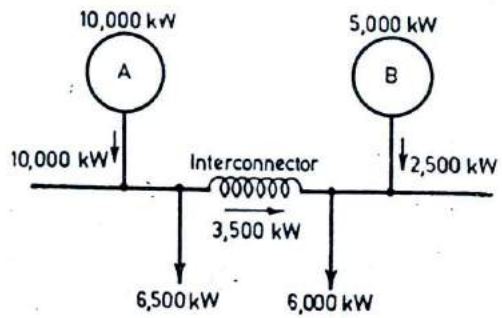


Fig. 11.28 system for example 11.3.

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Problems

11.1. Explain the functions of excitation systems. Compare the basic D. C. excitation system and A. C. excitation system for large generators unit.

11.2. Explain the principle and working of various types of voltage regulators used for controlling the voltage of generators.

11.3. Explain automatic voltage regulator for generators (AVR) in a modern station.

11.4. What are the points to be considered in commissioning of alternators? Explain the method of synchronising alternators.

11.5. Describe power/angle curves and discuss the principle of stability of power systems.

11.6. Explain the behaviour of synchronous machines under steady state stability and transient state stability. Explain 'equal area' criterion for checking the stability of a system.

11.7. Explain the characteristics, errors and limitations of potential transformers and current transformers.

11.8. Explain the method of supplying power to the auxiliaries in a power station.

11.9. Describe the methods of controlling (i) the active power (kilowatts) and (ii) the reactive power (kilovars) between two interconnected power stations.

11.10. The busbars at station A supply a load of 5,000 kW at 11 kV 0.9 power factor lagging, and busbars at station *B* supply a load of 9,000 kW at 11 kV 0.8 power factor lagging. If the station loads are equalized by the flow of power through an interconnector having a reactance of 2Ω per phase, linking stations *A* and *B*, find the station power factors and the phase angle between the busbar voltages of the stations (Ans. Station *A*, 0.943 lagging; Station *B*, 0.7145 lagging; angle between V_A and V_B, 2°.).

12

Protective Relaying for Power Stations

12.1 Principles and Characteristics of Protective Relaying

The main equipment in a power station consists of the generators, transformers, busbar sections, circuit-breakers and circuits going out of the station. Circuit-breakers are provided to make the circuit connexions when required and to trip or disconnect the circuits under faulty or abnormal conditions when they are unsafe for continued operation. To enable a circuit to be isolated from the system only under fault conditions, it is necessary to ensure the correct operation of the circuit-breakers by means of protective relaying. The main causes of fault conditions are short-circuits either in the power station itself or elsewhere in the system.

Fig. 12.1 shows a portion of the main parts of a power system. The power station has generators, low-voltage switchgear, transformers to step up the voltage of generation to that of the transmission lines outside, high-voltage switchgear and high-voltage busbars. The transmission lines go out from the station switchyard. It is necessary to protect each main part of the system, which is therefore divided into primary zones for protection purposes. There are two types of relaying equipment, namely primary protective relaying and back-up protective-relaying. If the primary relaying fails to act, the back-up relaying helps in isolating the faulty part of the system and thus protects it against damage due to short-circuits.

The primary relaying may some times fail to cause disconnexion of faulty parts in the system because of a failure in any of the following :

Current or voltage supply to the relays, tripping voltage supply, tripping circuit or circuit-breaker mechanism, operation of protective relay mechanism itself.

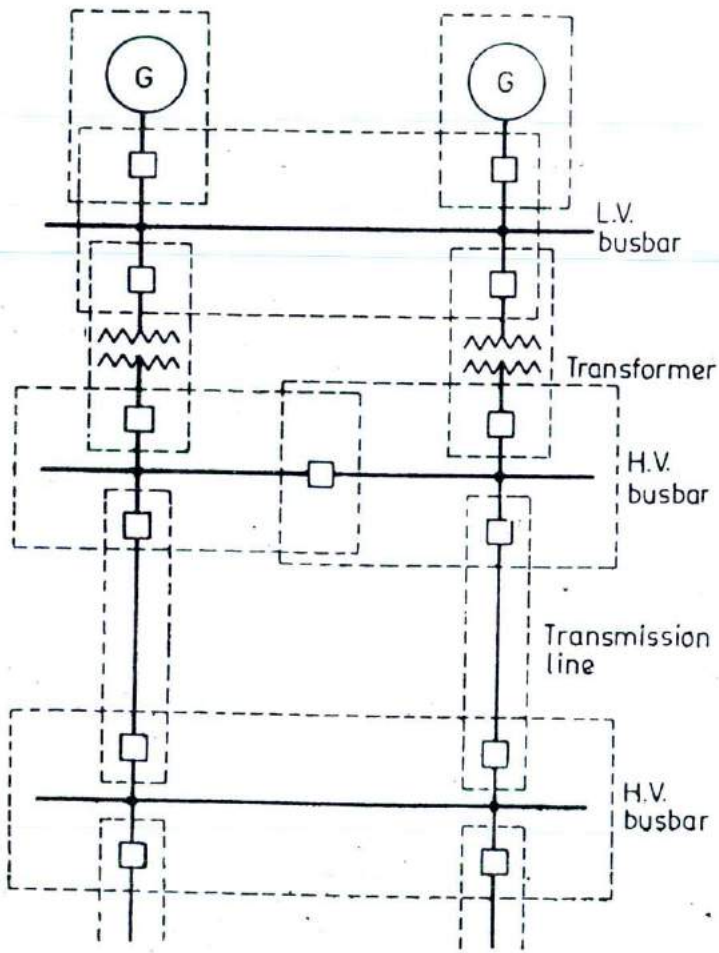


Fig. 12.1 Primary relaying.
Protection zones are shown in the broken-line enclosures.

The main characteristics of protective relaying equipment are sensitivity, selectivity and speed. The relaying equipment must

be sufficiently sensitive to operate reliably when required under the actual conditions that produce the least operating tendency. However, it should not operate wrongly. The relaying equipment must be able to select between conditions under which prompt operation is required and those under which no operation or a time delay is required. The ability of the protective relay system to operate so as to trip only the minimum number of breakers directly supplying the defective part of the system is called the sensitivity of the relaying system. The function of the relaying system is to recognise a short-circuit and to initiate the operation of devices to isolate the defective element with minimum disturbance to the normal service of the power system. A protective relay must operate at the required speed and must be reliable. The speed with which relays and circuit breakers operate has a direct bearing on the quality of service to the consumer, the stability of the system, and the amount of power that can be transmitted without exceeding the stability limit and endangering life and equipment.

The use of protective relays should be evaluated on the basis of their contribution to the best economy in service to the consumers. Protective relays avoid damage to equipment, or if there is damage, minimise the cost of repairs. There is less likelihood that the fault will spread to other equipment which is not faulty. Protective relaying reduces the time during which the equipment is out of service, thereby reducing loss of revenue and also maintaining good public relations.

All the relays used for protection against short-circuits operate by virtue of the current and/or voltage supplied to them by current transformers and voltage transformers. Failures in the system are indicated by the individual or relative changes in the currents or voltages supplied to the protective relaying equipment. For every type and location of failure, there is some distinctive difference in these quantities, and there are various types of protective relay available, each of which is designed to recognise a particular difference and to operate in response to it. The difference may be in terms of the magnitude, frequency, phase angle, duration of the

conditions, rate of change, direction or order of change, harmonics or waveshape.

The main principle used in the operation of relays is either electromagnetic attraction or electromagnetic induction. In an electromagnetic relay, a plunger is drawn into a solenoid or an armature is attracted to the poles of an electromagnet. The principle can be applied with either direct current or alternating current. In the second method the principle of the induction motor is used, so that it is applicable only to alternating current.

With reference to the speed of working of the relays, they may be of the high-speed or instantaneous type, or in induction-type relays there can be a time delay, introduced by means of a drag magnet.

12.2 Theory and Classification of Relays

Most of the protective relays consist of some arrangement of electromagnets with an armature, or an induction motor, carrying contacts the closing or opening of which controls devices such as the trip coils of the circuit-breakers. The electromagnets have current windings, voltage windings, or both. Currents through the windings produce magnetic fluxes, and torque is developed by interaction between the fluxes of the same winding or between fluxes of both windings.

$$\text{Torque produced by current winding} = KI^2$$

$$\text{Torque produced by voltage winding} = K'V^2$$

Interaction between the fluxes produced by the two windings current and voltage-produces torque corresponding to $VI\cos(\phi - \theta)$, where ϕ is the angle between V and I, and θ is the phase angle of the relay. If all the elements are present, the torque will be produced by all three causes, so that the total torque produced in the general case is

$$T = KI^2 - K'V^2 + VI\cos(\phi - \theta) - K'' \qquad (12.1)$$

K and K' are tap settings or constants of I and V, and K'' is the mechanical restraint due to a spring or gravity.

The torque for the operation of a relay is produced by the above three elements; there is also a control or restraining torque produced by a spring or gravity. At the time when a relay will just operate, the torque is zero. Therefore the general equation for the operation of a relay is

$$T_0 = KI^2 - K'V^2 + VI\cos(\phi - \theta) - K'' = 0 \qquad (12.2)$$

Since force or torque is proportional to the square of a flux or to the product of two fluxes, this equation contains second-degree terms only.

In a broad way the different types of relay used in power systems can be classified as follows:

Overcurrent relays. These have no voltage windings, so that there are no V^2 or VI terms in their equation.

$$KI^2 = K'' \qquad (12.3)$$

The relay pick up current, I, must exceed $\sqrt{(K''/K)}$, i.e.,

$$I > \sqrt{\frac{K''}{K}}$$

Undervoltage relays. These have no current, windings, so that there are no I^2 terms or VI terms in their equation—

$$-K'V^2 = K'' \qquad (12.4)$$

The relay will pick up under the condition that

$$V < \sqrt{\frac{K''}{K'}}$$

Directional relays. For this type of relay, $K = K' = O$, and their equation is

$$VI\cos(\phi - \theta) = K'' \qquad (12.5)$$

The condition for relay pick-up is

$$VI\cos(\phi - \theta) > K''$$

Reactance (or ohm) unit. For this type, $K' = K'' = O$, and $\theta = 90°$. The equation is

$$KI^2 = VI\cos(\phi - \theta) = VI\sin\phi \qquad (12.6)$$

The condition for relay pick-up is

$$Z\sin\phi < K, \text{ i.e., } X < K$$

Directional impedance (or mho) unit. For this type, $K=K''=0$, and $\theta=75°$. The equation is

$$-VI\cos(\phi-75°)=K'V^2 \tag{12.7}$$

The condition for relay pick-up is

$$\frac{Z}{\cos(\phi-\theta)}<\frac{1}{K'}$$

Impedance (or ohm) unit. Here the V and I windings are separate. There is no VI term. The equation is

$$KI^2=K'V^2 \tag{12.8}$$

and the condition for relay pick up is

$$Z<\sqrt{\frac{K}{K'}}$$

12.3 Theory of Application of Relays

The principal factors used in obtaining selectivity in protective relays are magnitude, comparison, time and direction.

Time overcurrent relays. A short-circuited section in a power system is fed from several lines in the network and with the largest current. A number of overcurrent relays are arranged in different sections and are so graded with reference to the operating time required that by suitably damping their motion, the relay nearest the fault will operate fastest and be arranged to clear the fault before any of the more remote circuit-breakers open. The operating coil of the inverse time overcurrent relay is supplied through a current transformer of suitable ratio. The ratio can be changed by tappings on the transformer. The time of operation is adjusted by means of a lever.

Fig. 12.2 shows an induction-type overcurrent relay, giving inverse time operation characteristics. Mechanically it is much the same as a consumer's electricity meter. The upper electromagnet has two windings. One of these is supplied through a current transformer in the line to be protected and through tapping to give the desired current rating. The second winding and the winding of the lower electromagnet are in series and are energized by induction. The displacement between the fluxes of the two electromagnets produces a torque on the metal disc. The

disc spindle carries a moving contact which bridges a pair of fixed contacts when moved through a certain angle which can be adjusted for a particular setting, thus completing the circuit through the relay trip coil.

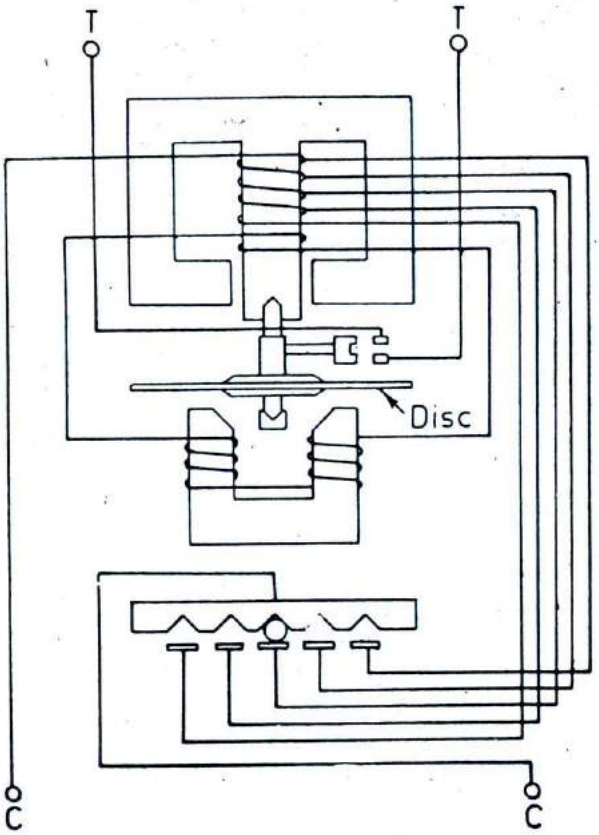


Fig. 12.2. Induction-type overcurrent relay.
C. Current-coil terminals
T. Trip-coil terminals

Directional relays : Directional relays are operated by the product of the circuit current and the circuit voltage. If the product is positive, the torque closes the relay contacts; if the product is negative, the torque holds the contacts open. Thus the relay can be arranged to trip only when current flows out of the busbars.

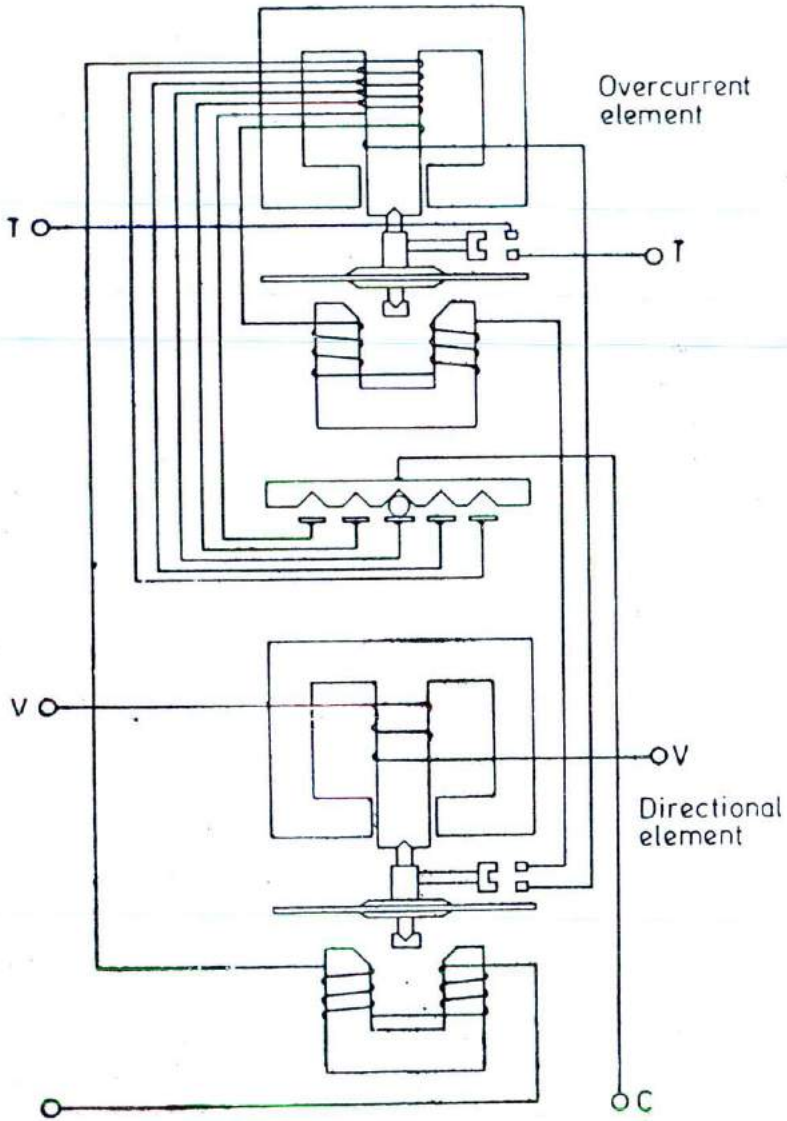


Fig. 12.3. Induction type directional overcurrent relay.
C. Current-coil terminals
T. Trip-oil terminals
V. Voltage-coil terminals

Fig. 12.3 shows an induction-type directional overcurrent relay. The relay consists of an overcurrent element in combination with a wattmeter element actuated by both current and voltage. The wattmeter element rotates only when a reversal of power takes place. The disc of the element then completes the circuit and gives the directional feature. When the contacts in the lower element are closed the upper element comes into action, as explained earlier, to make the relay effective.

Directional relays may be used in combination with overcurrent relays to prevent operation except in one predetermined direction of power flow. By connecting a directional relay in series with each overcurrent relay, only the relays at the two ends of the faulty section will operate and isolate the faulty section without disturbing the other lines.

Differential protection. Differential protective relaying is the most positive in selectivity and in action. In this method two currents, or a voltage and a current, etc., are compared. Comparing two electrical quantities in a circuit by means of differential relays is simple in application and positive in action. For example, compare the current entering a line and the current leaving it. If more current enters the protected circuit than leaves it, the extra current must flow in the fault. The difference between the two quantities can operate a relay to isolate the circuit. This type of protection is limited at present to equipment terminating at points relatively close together.

Balanced current protection. This method compares the currents in two similar parallel lines, and the relays trip out the line carrying the larger current. Fig. 12.4 shows a current balance relay of the electromagnetic type. When the current I_A is greater than the current I_B, the armature moves and closes the contact to trip out line A.

Instead of the magnitudes, the directions of the currents at the ends of a line may be compared. Fig. 12.5 shows a section to be protected, with relays S and R at the ends. If there is no fault in the section, the directions of the currents through the relays will be the same, either from S to R or from R to S, depending on the power flow. When a fault occurs in the section the

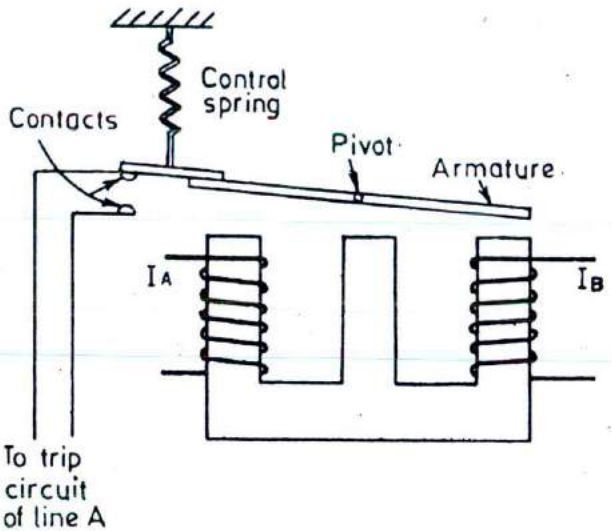


Fig. 12.4. Electromagnetic current-balance relay.

directions of the currents through S and R will be opposite, for both will be feeding the fault. The relays which normally are energized, will now trip.

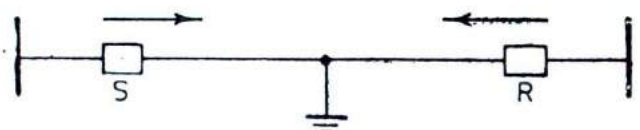


Fig. 12.5. A line section.

Distance relays. The impedance of a line up to a fault will be given by the ratio of the voltage and current, $V/I=Z$, Z being the impedance of the line upto the fault. Instead of comparing the magnitudes or directions of the currents at the two ends, the pilot wire can be omitted and the current at one end can be compared with the voltage at that end. In distance relays, the relay elements respond to indicated impedance or reactance. If V/I is less than the impedance ratio corresponding to the length of the pro tected section, the relay will cause tripping.

Where neither differential nor distance relays are used, selectivity is obtained by using graded-time overcurrent relays. Instantaneous overcurrent relays are set to operate at a current greater than the maximum through fault current in addition to the time overcurrent relays.

12.4 A.C. Generator Protection

Modern generators have high capacities and need to be protected against faults. The types of fault which are likely to damage the equipment are short-circuits in the stator windings, the faults being between phases or between a phase and earth. If a generator has multi-turn windings, there is also the possibility of a short-circuit between turns. Protection is required to prevent large overloading or overheating and unbalanced currents in the machine. The field winding of a generator needs to be protected against earth faults, loss of excitation and overspeed. Stator overvoltage should be avoided; and there should also be protection against undervoltage. The different kinds of protection can be obtained by the careful use of different types of relaying equipment. Some of the major types illustrating the basic principles are discussed below.

12.4.1 DIFFERENTIAL PROTECTION

Protection against short-circuit faults in the stator windings of a generator is effected by differential relays. Differential protection may be used for generators of capacities above 1,000 kVA, and is universal for generators of capacities of 10,000 kVA and above. Generally percentage differential relaying is used, protecting about 80% of the stator winding.

The protection of a 3-phase star-connected generator by means of percentage differential relays is shown in Fig. 12.6. Current transformers, connected in star, are provided on both the outgoing side and the machine winding connexions to earth. The restraining coils are energized by the secondary connexions of the current transformers in each phase, and the operating coils are energized from the tappings on the restraining coils and the earth connexion.

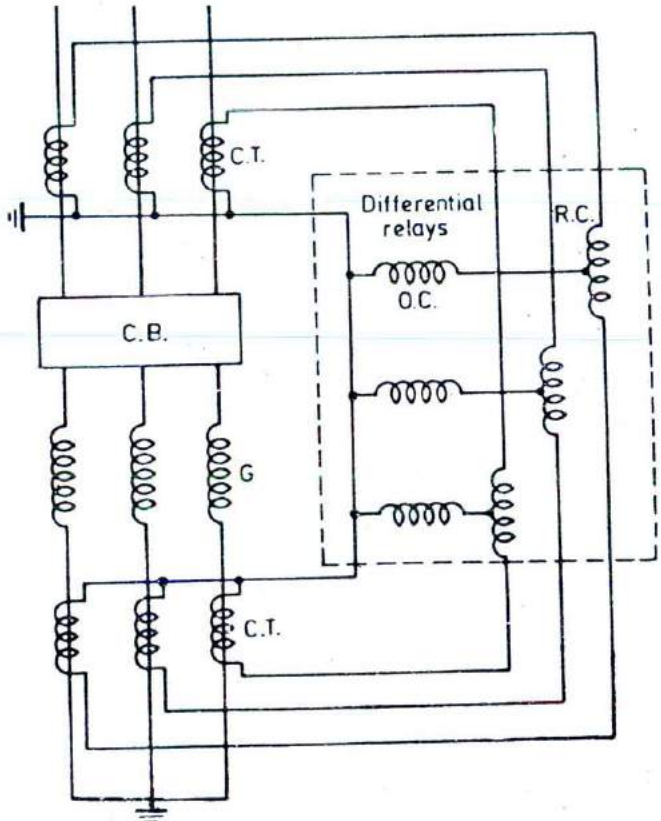


Fig. 12.6. Percentage differential relay protection.

C. B. Circuit-breaker
C. T. Current transformer (the primary winding is either a single bar or the line itself).
G. Generator windings.
O. C. Operating coils.
R. C. Restraining coils.

For the greatest sensitivity of differential relaying, the primary current rating of the current transformers must be equal to the rated full-load current of the generator; in practice it is about 25% higher.

If there is a fault due to a short-circuit in the protected zone of the windings, it produces a difference between the currents in

the primary windings of current transformers on both sides of the generator winding of the same phase. This results in a difference between the secondary currents of the two transformers. Thus under fault conditions a current flows through the operating coils and causes them to trip the circuit-breakers. The tripping can be arranged for a certain setting, and restraint can be adjusted to a certain percentage of the winding to be protected. Generally, 80% of a winding is protected.

The percentage differential relays trip a hand-reset multi-contact auxiliary relay. This auxiliary relay simultaneously initiates the following operations—

1. Tripping of the main circuit-breaker of the generator.
2. Tripping of the field circuit-breaker.
3. Tripping of the neutral circuit-breaker if there is one.
4. Shut-down of the prime mover.
5. Turn-on of CO_2 gas if provided for the safety of the generator under faulty and short-circuit conditions.
6. Operation of alarm and/or annunciator to indicate the occurence of the fault and the operation of the relay.

The auxiliary relay may also interchange the transformer connexions of the station auxiliaries from the generator terminals to the reserve source by tripping the auxiliary circuit-breaker.

The differential current flows through the operating coil. Differential relay operation depends on the relation between the current in the operating coil and that in the restraining coil. The slope of the line showing the relation between the two currents is known as the percentage slope of the differential relays.

When differential relaying is used for protection, the current transformers at both ends of a generator winding must be of equal accuracy; otherwise, if the error is excessive, it will cause wrong operation of the relay. The difference between the ratios of the two current transformers should not exceed 0.5% slope of the differential relays, for external fault beyond the generator termi-

nals. The causes of the unequal currents on the secondary sides of the current transformers—in addition to their ratio errors—are unequal lengths of the leads, unequal secondary burdens, etc. The steady-state errors of current transformers for the condition of external fault can be found by means of a simple equivalent circuit indicating their secondary burden, which consists of the coils of the differential relay. Each operating coil is connected across one side of the transformer secondary windings and a tapping on the restraining coil. The impedance of the loads may also have to be taken into consideration.

12.4.2 PROTECTION AGAINST TURN-TO-TURN FAULTS IN STATOR WINDINGS

Differential relays will not operate on faults between turns, as there is no difference between the currents at the ends of a winding

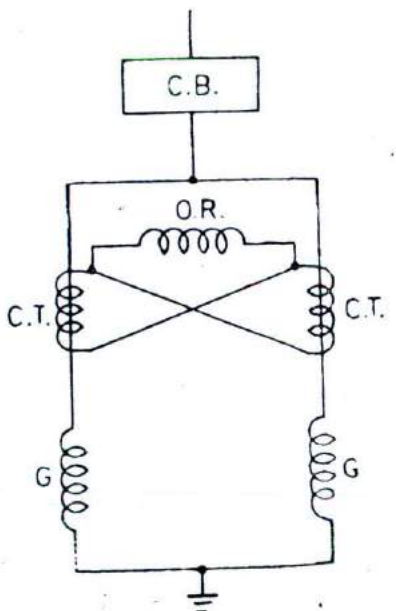


Fig. 12.7. Split-phase relaying for a multi-circuit Generator (shown for one phase only).

C. B. Circuit-breaker.
C. T. Current transformer.
G. Generator windings.
O. R. Overcurrent relay.

with short-circuited turns. The coils of modern large steam-turbine generators usually have one turn and hence they do not need turn-to-turn protection. Turn-to-turn fault protection is used for multi-turn generators, such as large hydro-electric generators. The conventional method of providing turn-fault protection is called split-phase relaying. The circuits are divided into two equal parallel groups with a current transformer for each group. The arrangement is shown in Fig. 12.7.

Split-phase relays will operate on any type of fault in the stator windings. The relay coil is connected across the two current transformers, and under fault conditions it will carry current due to the difference between the faulty and healthy phase and will trip the circuit. Split-phase relays should operate the same hand-reset auxiliary tripping relay that is operated by the differential relays, so that the same sequence of operation takes place for removing the generator from the system. An inverse-time over-current relay is used for split-phase relaying rather than an instantaneous percentage differential relay in order to obtain the required sensitivity.

For large generators, combined split-phase and differential relay protection is used.

12.4.3 PROTECTION OF STATOR WINDINGS BY OVERCURRENT RELAYS

If current transformers are not connected in series with the neutral ends of the star-connected generator windings, the protection can be effected by overcurrents, the relay coils being operated only by the short-circuit currents supplied by the power system. For this type of protection to be effective, the main oil circuit-breaker of the generator should be closed and the power system should have some other source of power in addition to the generator to be protected. If the generator neutral is not earthed, sensitive and fast earth overcurrent protection can be provided. If the neutral is earthed, directional over current relaying should be used for the greatest sensitivity and speed.

Fig. 12.8 shows the arrangement for the protection of stator windings by overcurrent relays and an earth relay.

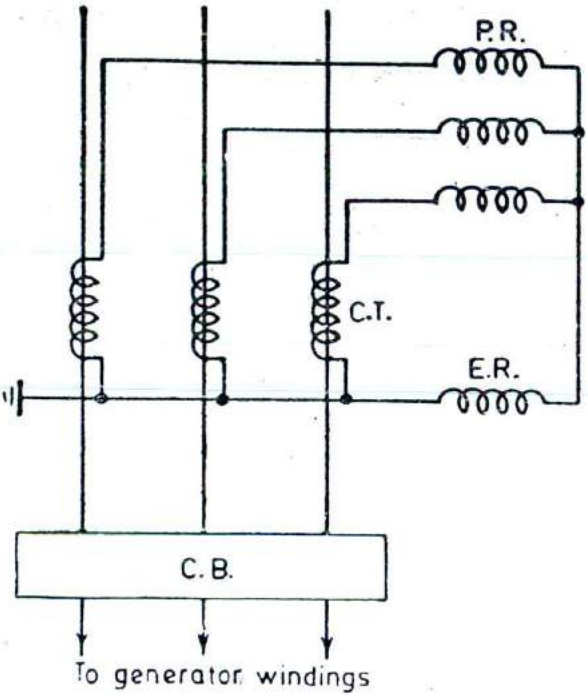


Fig. 12.8. Overcurrent protection for generator.
C. B. Circuit-breaker
C. T. Current transformer
E. R. Earth relay
P. R. Phase relays.

Three current transformers are connected in the three phases. The phase-relay coils are connected across the secondaries of the current transformers. The earth-relay coil is connected between the junction of the three phase-relay coils and the star-point of the three current transformers.

When a fault occurs, thereby causing large currents to flow in one or more phases, there is more current in the secondaries of the current transformers and the relay coils of the phase relays. These relays can be set to operate at a particular value of the current. If there is a fault between any phase and earth, the

earth-relay coil carries a current proportional to the zero phase-sequence current and can be set to operate at a particular value.

12.4.4 OTHER TYPES OF PROTECTION FOR GENERATORS

Overheating protection for the stator. Resistance temperature detector coils or thermocouples are embedded in slots below the stator coils of generators of large capacity—say above 1MVA—for protection against overheating. A number of detectors are used in conjunction with a temperature indicator or recorder. Detector-operated relaying equipment using a Wheatstone-bridge circuit and directional relays can be used to give an alarm and/or indication of high temperature in a particular part of the generator.

Overvoltage protection. If there is an overvoltage in a generator, and if it persists, the generator main circuit-breaker and the generator or exciter field breaker should be tripped, for it is not safe for the generator to continue to work under this condition. The relay for overvoltage protection should have a time-delay unit with pick-up at 110% of the rated voltage. It should also have an instantaneous unit with pick-up at 130% to 150% of the rated voltage. The relay should be energized from a voltage transformer other than the one used for the automatic voltage regulator. The operation of the relay should first insert additional resistance in the generator field circuit or the exciter field circuit; then, if the overvoltage persists, the circuits should trip as mentioned above.

Field earth-fault protection. Field circuits are operated unearthed, and it is not necessary to trip such a circuit completely if there is only one earth fault, but the relay should give an indication that the fault has occurred. When a second earth fault occurs in the field circuit, the condition should not be allowed to continue and the generator breaker as well as the field breaker should trip. Otherwise the fault would cause serious damage. In unattended stations, it may be worthwhile to trip the generator and field circuits even with a single earth fault.

Protection against unbalanced currents. If, owing to a fault, there is imbalance in the 3-phase stator currents, double-frequency currents will be induced in the rotor iron. This causes overheating of the rotor and possible damage to the generator. Unbalanced

currents may also cause vibration. If current balance relaying equipment is used for protection against this type of fault, it will be seen that such equipment, energized by means of the phase currents, would operate too quickly for small imbalances and too slowly for large imbalances, and thus would not be very effective.

Fig. 12.9 shows the arrangement of the protection for imbalanced stator currents. Three current transformers are connected in the three phases, and the output from their secondary windings is fed to the coil of the overcurrent relay through a negative-phase sequence filter. The type of relay used is the inverse-time-overcurrent relay. This can be set to operate at a particular value of the imbalanced current or negative-sequence-component current.

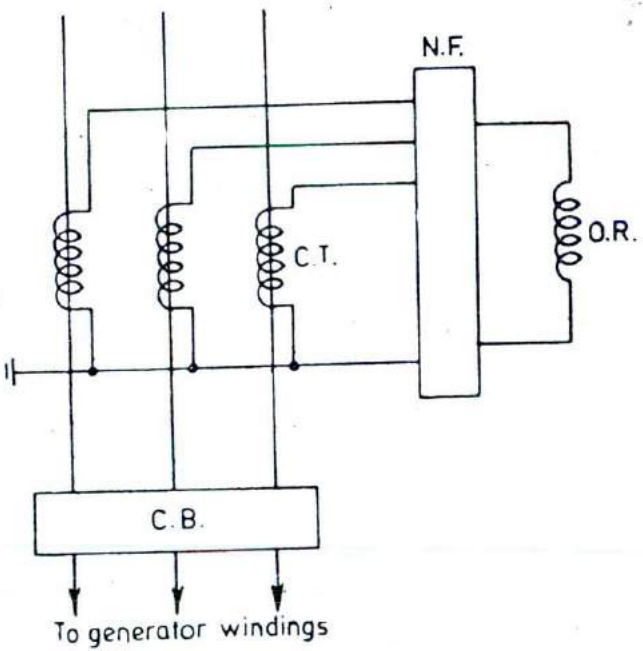


Fig. 12.9. Generator protection against imbalanced currents

C. B. Circuit-breaker
C. T. Current transformer
N. F. Negative-phase-cequence current filter.
O. R. Overload relay.

Protection against motoring. Protection against motoring is beneficial to the prime movers and to the system as a whole, but not to the generator. At a steam station, the turbine becomes overheated when its steam supply is cut off and the generator coupled to it acts as a motor. This overheating occurs because there is not enough steam in the turbine to carry away the heat produced owing to windage losses. A sensitive power directional relaying equipment should be used, and it should operate at less than 3% of the power rating of the generator.

With hydraulic turbines, motoring protection may occasionally be useful for unattended stations. This prevents the possibility of cavitation of the turbine blades. Power directional relaying equipment operating on a motoring current of less than 2.5% of the full load rating of the generator can be provided. With Diesel engines, the generator would take about 15% of its rated power when acting as a motor, and motoring action should be avoided by suitable protective relaying The power required for driving a gas turbine with the generator working as a motor varies from 10% to 50% of its full-load rating and such heavy load on the system must be avoided by protective relaying.

Overspeed protection. Prime movers should not be run at overspeeds. The overspeed of a generator would result in over-frequency operation of the generator itself and of the system supplied by it. The overspeed element should operate the governor and shut down the prime mover, and should usually be adjusted to operate at about 3% to 5% above the full-load rejection speed.

12.5 Transformer Protection

Generators may be subjected to a number of abnormal conditions and need protection from them for safe working. Transformers do not have so many kinds of fault. They need protection against overload due to different kinds of short-circuit or due to faults in the external system and protection against overheating. Basically the relay protection to be provided for transformers is protection against short-circuits in their windings or connexions, and external-fault back-up protection. Thermal accessories are used to sound an alarm or to control fans for cooling the transformers.

12.5.1 SHORT-CIRCUIT PROTECTION OF TRANSFORMERS BY PERCENTAGE DIFFERENTIAL RELAYS

Percentage differential relays are recommended for the short-circuit protection of power transformers rated at 1 MVA and above. The differential relay should operate a hand reset auxiliary relay that will trip all the transformer circuit-breakers and isolate them from the system.

Two basic requirements should be satisfied by differential relay connexions: the differential relay must not operate on load or external faults; and it must operate on severe internal faults. Current transformers on any star windings of a transformer should be connected in delta, and current transformers on any delta winding of a transformer should be connected in star. In practice, the current transformer ratios and relay or auto-transformer taps are generally chosen to balance the currents at the mid-point of the tap-changing range. The mismatch between the current-transformer currents and relay-tap ratings is a maximum corresponding to one-half of the difference between the two relay-tap ratings expressed as a percentage. The imbalance in the currents is caused by tap changing of power transformers, mismatch between current-transformer currents and relay-tap ratings, and the difference between the errors of the current transformers on either side of the power transformer. Assuming that the imbalances due to all three causes are in the same direction and are 5%, the minimum percentage slope for the differential relay is chosen.

The differential relay should not trip owing to inrush magnetizing currents. A time delay of 0.2 second or so is given to avoid this.

Fig. 12.10 shows the arrangement of percentage differential relaying for power transformers.

The power transformer is star connected on one side and delta connected on the other. The current transformers on the star-connected side are delta connected, and those on the delta-connected side are star connected. The restraining coils are connected across the current-transformer secondary windings. The

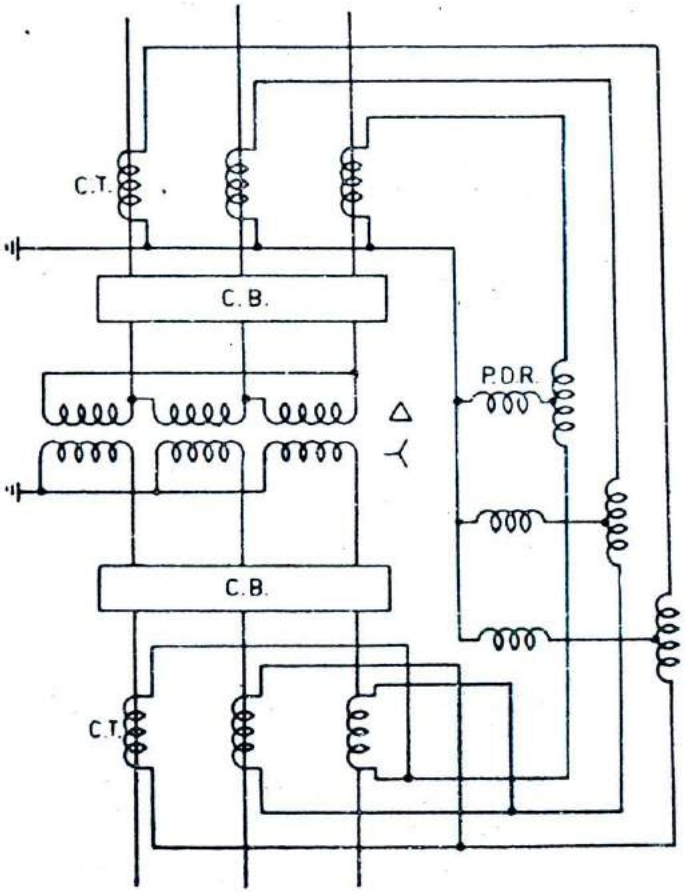


Fig. 12.10. Percentage differential relaying for transformer protection

C. B. Circuit-breaker
C. T. Current transformer
P. D. R. Percentage differential relays.

operating coils are connected between the tapping points on the restraining coils and the star point of the current-transformer secondary windings. These coils normally carry no current as they are balanced on both sides of the current transformers. With an internal fault in the power transformer windings, the balance

in the current transformers is disturbed and the operating coils of the differential relays carry current corresponding to the difference of current between the two sides of the power transformers, and operate the relays to trip the main circuit-breakers on both sides of the power transformers.

12.5.2 SHORT-CIRCUIT PRCTECTION OF TRANSFORMERS BY OVERCURRENT RELAYS

When it is very expensive and uneconomical to use differential relaying for transformers, overcurrent relaying is used for the fault protection of transformers having circuit-breakers. The overcurrent relaying method is not as sensitive as that of differential relaying.

With overcurrent relaying, there are three current transformers, one in each phase, and at least two-phase overcurrent relays and one overcurrent earth relay on each side of the transformer bank, which is connected to the power system through a circuit-breaker. When a short-circuit occurs between phases, the phase overcurrent relays operate; and when the fault is between a phase and earth, the zero-sequence current passing through the earth relay operates, tripping the circuit-breaker and thus isolating the transformer and protecting it. The overload relays should have an inverse-time element whose pick-up can be adjusted to above 150% of the maximum rated load current and should have sufficient time delay so as to have enough selectivity with reference to the relaying equipment of the adjacent relay system elements during the occurrence of external faults. The relays should also have an instantaneous element whose pick-up can be adjusted to be slightly higher than the maximum possible short-circuit current due to an external fault or the maximum inrush current at the time of switching-in the transformer.

The use of overcurrent relays in conjunction with differential relaying is recommended to prevent dangerous overheating of power transformers. A differentially protected transformer bank should have inverse-time overcurrent relays, preferably energized from current transformers other than those associated with the differential relays which trip the circuit-breakers on the fault side of the system when the external fault persists for too long a time.

12.5.3 OTHER TYPES OF PROTECTION FOR TRANSFORMERS

In addition to differential relay and overcurrent protection, other types of protection for transformers give an indication of high temperature or high pressure.

Gas accumulator and pressure relays. Buchholz relays used with conservator-type transformers, give an alarm when the gas, due to slow deterioration of the insulation, has accumulated. A sample of the gas can be taken and analysed for the type of insulation which has weakened and deteriorated. The transformer can then be taken out of service for inspection and repair if necessary.

Fig. 12.11 shows the principal parts of a Buchholz relay.

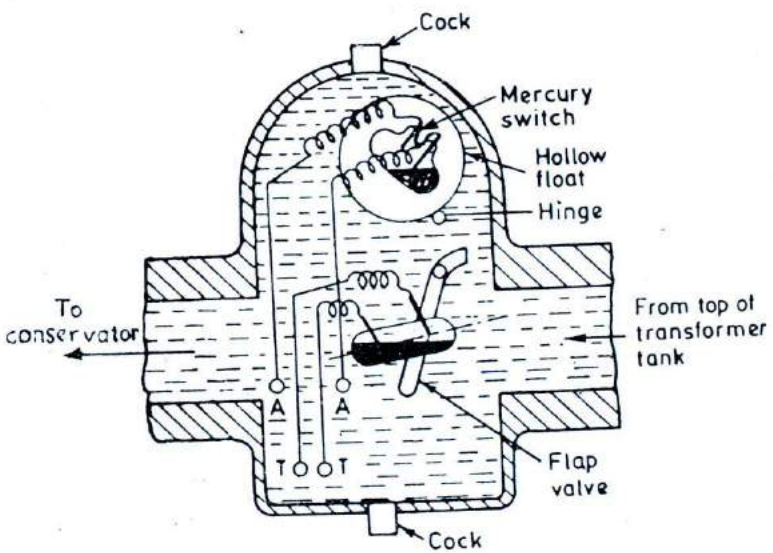


Fig. 12.11. Buchholz relay.

The relay is connected between the top of the tank and the conservator by means of the pipes and is normally full of oil. The upper part of the housing contains a hollow float with a mercury switch inside it. A hinged flap valve with another mercury switch is located in the path of the oil between tank and the conservator. In the event of a fault, the gas bubbles rise to the top of the housing,

the oil level falls, and the hollow float turns on its hinge, so that the mercury switch operates and gives an alarm. If a serious fault occurs the volume of gas is considerable, so that the flap valve is deflected, thus closing its mercury switch. The trip coils of the circuit-breakers are then energized.

Temperature relays. If the temperature of the transformer increases beyond the permissible limit, an alarm is sounded and an indicator shows that the relay has operated. As a rule the transformer is not automatically tripped, but in special cases this can be arranged.

The station auxiliary transformers supply the station auxiliary equipment such as motors for various pump drives, etc. These transformers are delta connected on the high-voltage side corresponding to the voltage of generation, and the low-voltage side is 3-phase 415V/240V star-connected with the neutral available for a single-phase supply to lighting circuits, etc. The auxiliary transformers are not connected in parallel with the main transformers on the secondary side.

Protection of a station transformer is provided by means of an inverse-time overcurrent relay, connected to current transformers in series with the primary windings of the station transformer. The relay protects the station transformer from undue overload and from faults due to short-circuits. In either event the transformer should be isolated and the faults cleared in the system of auxiliaries. The relays are given high current settings.

12.6 Busbar Protection

With the large system that are now common (the present practice), it is necessary to protect the busbar sections and to isolate faulty sections before the faults spread over the whole system and cause great damage and long shut-downs.

12.6.1 PARTIAL DIFFERENTIAL RELAYING WITH OVERCURRENT RELAYS

In this method of protecting the busbar sections only the current transformers in generating-source circuits are parallelled. The protection provided by the overcurrent relays is similar to that provided by back-up relays in the individual source circuits. The

overcurrent relays must have a time delay that is long enough to prevent their operation before the relays of the load circuits, which respond to external faults, have operated. The relays must also have a pick-up higher than the total maximum load current of all source circuits.

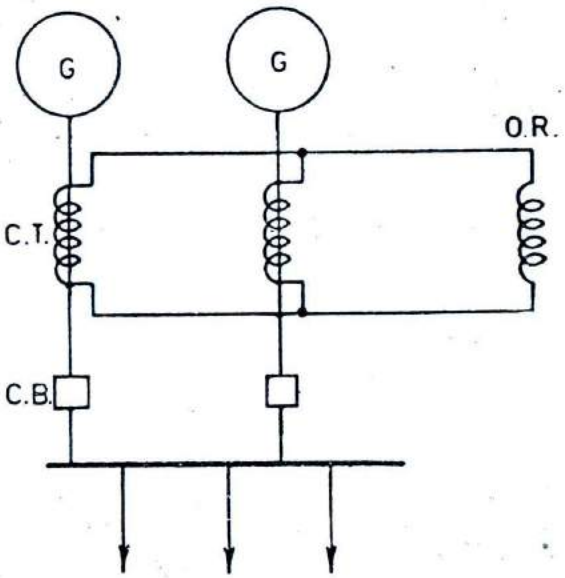


Fig. 12.12. Partial differential relaying with overcurrent relays for busbar protection.

C. B. Circuit-breaker.
C. T. Current trasformer
G. Generator
O. R. Overcurrent relay

Fig. 12.12 shows the arrangement of partial differential relaying with overcurrent relays, with two sources of generation. The current transformers of the two sources are paralleled and the overcurrent-relay is connected across them. Under fault conditions, the relay coil will carry current, and can be set to operate at a certain value of the current thus tripping the circuit-breakers. The advantage of partial differential relaying with overcurrent relays is that local protective equipment is provided for busbar

protection, and that back-up protection is provided for the load circuits.

12.6.2 VOLTAGE DIFFERENTIAL RELAYING

Another method of protecting busbar sections is by means of voltage differential relays. In this method, current transformers are used which do not have iron cores, so that they have a much larger number of secondary turns than an iron-core transformer. These are called linear couplers.

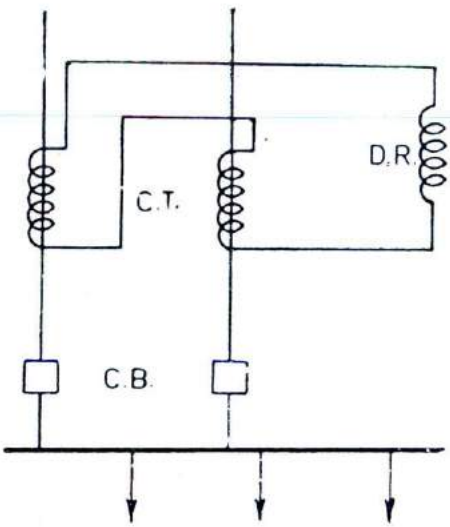


Fig. 12.13. Voltage differential relaying for busbar protection.

C. B. Circuit-breaker.
C. T. Current transformer.
D. R. Differential relay.

Fig. 12.13 shows the arrangement of busbar protection with voltage differential relaying. The current transformer secondary windings are connected together in series, and the differential-relay coil is connected across them. For normal load or external fault conditions, the sum of the voltages induced in the secondary windings is zero. When a busbar fault occurs, the voltages of the current transformers in all source circuits add to cause current to flow through all secondary windings and the coil of the differential

relay. This provides high-speed protection for a relatively small net voltage in the differential circuit.

12.6.3 RELAYING FOR SWITCHGEAR

The switchgear needs protection for busbar sections; this is generally of the differential type. In addition, overcurrent and overvoltage protection is necessary.

References

12.1. WARRINGTON, A. R. VAN C., "A condensation of the theory of relays." *Distribution Magazine* (Oct., 1948).

12.2. Silent Sentinels (Westinghouse protective relays).

12.3. MASON, C. R., *The Art and Science of Protective Relaying* (Wiley, 1956).

Problems

12.1. Explain the principle of operation of protective relays. What are their main characteristics? State what is meant by "primary protection" and "back-up protection".

12.2. Describe the basic theory and classification of relays. Mention the types of relay, derive their conditions of operation and state their limitations.

12.3. Distinguish between time overcurrent relays, directional relays and differential relays.

12.4. Explain with a diagram the method of protecting a 3-phase a. c. generator by means of partial differential relays.

12.5. Describe the protection of the stator windings of an a. c. generator against turn-to turn faults.

12.6. How are a c. generators protected against unbalanced currents? What other types of protection are necessary for a. c. generators? How is the protection effected?

12.7. Describe with a diagram the protection of 3-phase power transformers by means of partial differential relays. If a power transformer is connected delta-star, how are the current transformers for the relay connected, and why?

12.8. Describe the short-circuit protection of transformers by overcurrent relays. What other types of protection are necessary for transformers, and how are they effected?

12.9. Describe the methods of protecting busbars by partial differential relaying with overcurrent relays and by voltage differential relays.

12.10. Describe methods used for switchgear protection in a power station