1

Prediction of Load

1.1 Electrical Load Development

It is first necessary to find out the load requirements of the area where electricity is to be supplied. This depends on the nature of the area, the population of the town or village under consideration, the density of the population, the standard of living of the people in the locality, industrial development in the area and the cost of electric power. The problem may be to predict the load requirement of a new township which is to be set up, or the supply of electricity to a village for the first time, or the extension of the supply facilities to a growing city where electricity has been available for years and the need is continuously increasing owing to development. In the first case, no previous data regarding load requirements or trends of development which need electric power, are available. It is necessary to study the possibilities for the sale of electric power by considering the plans for development, the probable number of consumers, the power requirements of each type of load, the time at which loads might be required, the types of loads to be supplied, and various other factors which determine the total power that should be made available at the power station to cope with the need. In the latter case, data of power requirements for the last few years may be available and will be useful as a guide for future load predictions.

1.2 Definition of Terms

Before considering the methods of load prediction, some of the terms used in connexion with power supply must be defined. *Connected load* is the rating (in kilowatts) of the apparatus installed on a consumer's premises. *Maximum demand* is the maximum load which a consumer uses at any time. The ratio of maximum demand to the connected load is called the *demand factor*—

$$\text{Demand factor} = \frac{\text{Maximum demand}}{\text{Connected load}} \qquad (1.1)$$

This can be illustrated by an example.

A residential consumer has 10 electric lamps of 40 W each connected at his premises. His connected load is thus 400 W. It is possible that the maximum number of lamps that he uses at a time is 9 and that he may never use all 10 at once. His maximum demand, then, is 9×40, or 360 W, and the demand factor of hisload is 360/400, or 90%. A consumer of electric power will naturally use the power as and when he likes. The load will, therefore, always be changing with time or the hour of use and will not be constant. A curve showing the load demand of a consumer against time in hours of the day is known as a *load curve*. The curve will show how the load varies with time. If it is plotted for the 24 hours of a single day, it is known as a *daily load curve*. If it is considered for the whole year and plotted showing load demand of the consumer against the time in hours of the year, it is known as an *annual load curve*. This type of curve is useful in predicting the annual requirements for energy, the occurrence of the loads at different hours and days in the year, and in power supply economics. As the load is variable, it will be at a maximum only for a certain time and will be less for the remainder of the time, depending on the nature of the variation. The *average load* during a period of 24 hours, or some other period considered for the load curve, will be less than the *maximum load*. The ratio of average load to maximum load is called the *load factor*—

$$\text{Load factor} = \frac{\text{Average load}}{\text{Maximum load}} \qquad (1.2)$$

The area under the load curve represents the energy consumption in kilowatt-hours during the period. The load factor can also be defined as the ratio of the energy consumed during a given period to the energy which would have been used if the maximum demand had been maintained throughout that period—

$$\text{Load factor} = \frac{\text{Energy consumed during 24 hours}}{\text{Maximum demand} \times 24 \text{ hours}} \qquad (1.3)$$

The terms can be illustrated by an example.

Example 1.1

A residential consumer has 10 lamps of 40 W each connected at his premises. His demand is as follows—

From 12 midnight to 5 a. m.	. . 40 W
From 5 a.m. to 6 p.m.	. . No load
From 6 p.m. to 7 p.m.	. . 320 W
From 7 p.m. to 9 p.m.	. . 360 W
From 9 p.m. to 12 midnight	. . 160 W

Plot the load curve. Find the average load, maximum load, load factor and electric energy consumption during the day.

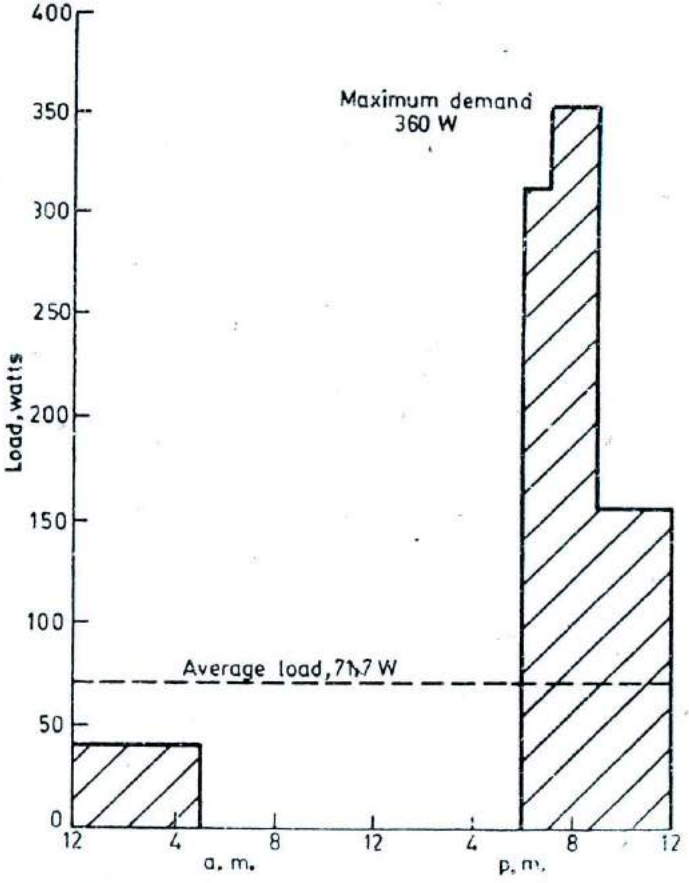


Fig. 1.1. Load curve of a residential consumer (lighting load).

The maximum load is 360 W for 2 hours of the day, from 7 p.m to 9 p.m. The load curve is plotted in Fig. 1.1. It is the plot of the load in watts against the time in hours of the day. The energy consumption during 24 hours of the day is

$$(5\times 40)+(320\times 1)+(360\times 2)+(160\times 3)=1{,}720 \text{ Wh}$$

or 1.720 kWh per day.

$$\text{Load factor} = \frac{\text{Energy used during 24 hours}}{\text{Maximum demand} \times 24 \text{ hours}}$$

$$= \frac{1{,}720 \text{ Wh}}{360 \text{ W} \times 24 \text{ h}} = 0.199, \text{ or } 19.9\%$$

$$\text{Average load} = \frac{1{,}720 \text{ Wh}}{24 \text{ h}} = 71.7 \text{ W}$$

The load factor is also given by the ratio of average load to maximum load—

$$\text{Load factor} = \frac{71.7 \text{ W}}{360 \text{ W}} = 0.199 \text{ or } 19.9\%$$

1.3 Diversity Factor

The needs of a consumer are his maximum demand and his energy consumption during a day. To supply these needs it is necessary to provide generating capacity at least equal to the maximum demand. If the consumer used all this capacity throughout the day, his load factor would be 100% and he would make maximum use of the available energy. In this case the cost of the electrical energy per kilowatt-hour would be a minimum. If the consumer's average load is not equal to his maximum load, his load factor is less than 100% and the cost of the electrical energy is higher than in the last case. The ideal to aim at, therefore, is a 100% load factor, so that the equipment is used to its full extent. This is, however, not possible in practice owing to variable load characteristics. When a number of consumers with different load requirements at different times during the day are to be supplied, an attempt should be made to supply these loads in such a way as to smooth out the load curve of the system and to obtain as high a system load factor as practicable.

Considering Example 1.1, it would be necessary to provide a generation capacity of at least 360 W to supply the consumer,

and his load factor is nearly 20%. This means the energy used by the consumer is only about 20% of the possible energy that could be supplied during the day by an installed capacity of 360 W if the maximum demand persisted uniformly throughout the day and the load factor were 100%.

Consider four consumers each having the same maximum demand, the load consisting of residential lighting and domestic appliances. Each consumer may have different habits and ways of living so that there is a difference between the patterns of the consumers' load curves, and all their maximum demands may not occur at the same time. There is thus diversity in the occurrence of the loads. The ratio of the sum of the maximum demands of the individual consumers to the simultaneous maximum demand of the whole group during a particular time is called the *diversity factor*—

$$\text{Diversity factor} = \frac{\text{Sum of individual maximum demands}}{\text{Simultaneous maximum demand}} \qquad (1.4)$$

As the total maximum demand required at any time during the day is less than the sum of the maximum demands, owing to diversity, the total load factor improves, which is a desirable result.

Diversity helps in obtaining better conditions for power supply; diversity is a silver lining to the dark cloud of the load factor. We have considered only a lighting load. There would be greater diversity between different types of load occurring at different times of the day. It will always be the aim of a power engineer to persuade the commercial department to encourage loads in some places and to discourage them in others in such a way that the total maximum demand is reduced, so that, with lower plant capacity installed at the source of generation, more energy can be supplied, the cost of the electrical energy being less at higher load factors.

The four load curves together illustrate the effect of diversity factor.

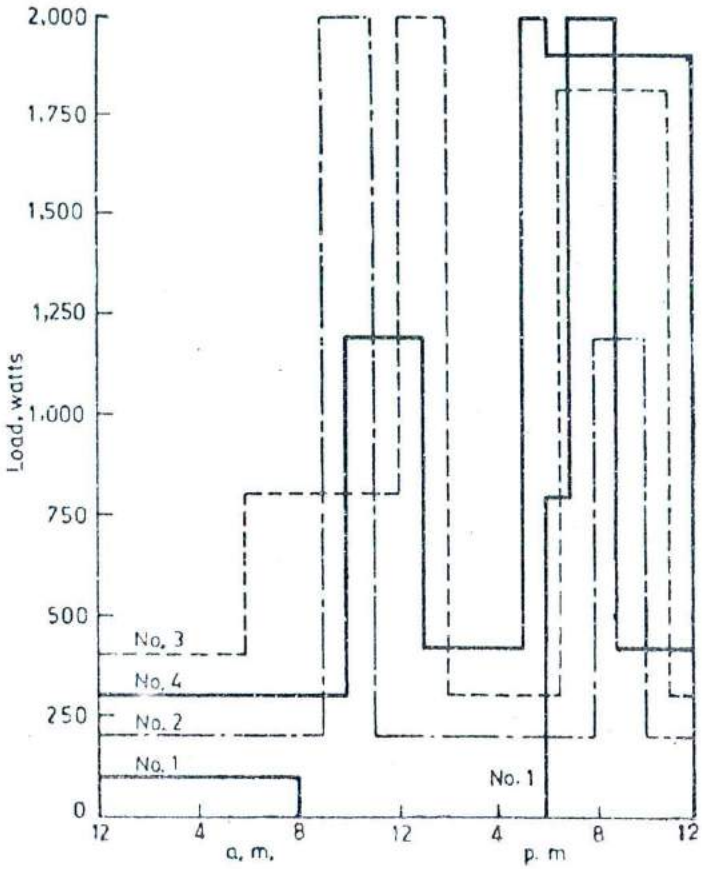


Fig. 1.2. Residential load (light and power).

Example 1.2

Fig. 1.2 shows the load curves of 4 consumers having lighting and domestic-appliances load. Each has a maximum demand of 2,000 W. However, the maximum demand of consumer No. 1 occurs between 8 p.m. and 9 p.m. ; that of consumer No. 2 between 9 a.m. and 11 a m.; that of consumer No. 3 between 12 noon and 2 p. m.; and that of consumer No. 4 between 5 p.m. and 6 p.m. From the curves find the diversity factor of the loads and the simultaneous maximum demand.

From the load curves it will be seen that the simultaneous maximum demand of all four consumers occurs between 7 p.m. and 8 p.m. During this period —

	W
Demand of consumer No. 1	2,000
Demand of consumer No. 2	1,200
Demand of consumer No. 3	1,800
Demand of consumer No. 4	1,900
Simultaneous maximum demand of all 4 consumers	6,900

Sum of individual maximum demands $= 4 \times 2{,}000 = 8{,}000$ W

$$\text{Diversity factor} = \frac{8{,}000}{6{,}900} = 1.16 .$$

1.4 Types of load

The main types of load can be divided into the following categories :—

1. *Residential or domestic load.* This consists mainly of lights and fans, domestic appliances such as heaters, refrigerators, airconditioners for rooms, radio receivers, Television sets, electric cookers, electric water-heaters, small motors for pumping and small electric appliances for use in the home. Most residential consumers use all of the lighting load as their connected load is small, and the demand factor for the prediction of this type of load can be taken as 100%. A consumer having 4 or 5 lamps may use all of them at once for a few hours during the evening, at least on festive occasions. There is, however, diversity between various consumers, and the diversity factor may be taken as 1·2 to 1.3. Most of the residential load occurs only part of the time during the 24-hour day, e.g., the lighting load during-night time only, and the domestic-appliance load for only a few hours. If the load curve is plotted, it is generally seen that the load factor is poor, it may be taken as 10% to 12%.

2. *Commercial load.* This type of load consists mainly of lighting for shops, advertisements, etc., fans and electrical appliances used in commercial establishments—shops, restaurants, market places, etc. It includes small motors and loads similar to residential loads but larger. The demand factor may be taken as 100% and the diversity factor, as 1·1 to 1.2 for preliminary prediction of load. This class of load is spread over more hours of the day compared to residential loads, and the load factor may be

between 25%and 30%. Commercial loads are not as large as industrial loads.

3. *Industrial load.* This type of load can be subdivided into sections depending on the power range required : for example, cottage industries which will require not more than 5 kW each; small-scale industries which take up to about 25 kW; medium-scale industries taking between 25 and 100 kW; large-scale industries requiring 100 to 500 kW; and heavy industries requiring more than 500 kW. The last two types of load need power over a longer period and fairly uniformly throughout the day. For large-scale industrial loads, the demand factor may be taken as 70% to 80% and the load factor between 60% and 65%. For heavy industries a demand factor of 85% to 90% and a load factor of 70% to 80% can be taken for prediction of load.

4. *Government load.* This may be classified as a separate type of load when it has separate feeders and special working conditions, e.g., defence factories.

5. *Municipal load.* Street lighting is one of the loads of the municipalities or municipal corporations. The amount of load will depend on how well these authorities can afford to make more and better lighting available for their towns and cities. This type of load is practically constant throughout the hours of darkness, so that the demand factor is 100%. The deversity factor can be taken as 1.0 or 100% when considered for the duration of the street lighting load. This load will be supplied by a distributor run completely separately and independent of other distributors for lighting loads of other types. This is necessary because all street lights have to be put on and off approximately together. This is done by means of time switches so that the lights are automatically controlled at the required time, e.g., the time switch may be set so that the lights will be on at 7 p.m. and off at 6 a.m. The time setting can be arranged to suit local requirements. Street lights will be required mainly at night, but there will be a small load of traffic-signals throughout the day and night. The load factor for street lighting may be taken as 20% to 25% on a 24-hour basis.

Another type of municipal load is for water supply and drainage. Water is pumped to overhead tanks from the source of water supply. This needs pumps driven by electric motors. This type of load can easily be fitted at a suitable time on the load curve so as to improve the load factor of the whole supply system of the town if it has its own power station. The normal load on the power station will be much less after 11 p.m. or midnight. If the pumping load is supplied during this off-peak period, it will improve the load factor. This may be accomplished by offering cheaper rates--tariffs -for the consumption of electricity during off-peak hours.

6. *Irrigation.* This type of load is required for supplying water for fields as required for crops in different seasons, by means of suitable pumps driven by electric motors.

7. In some areas there is a *mining load.*

8. *Traction load.* Tramcars, trolley buses, suburban railways and main railway systems come under this type of load.

9. *Bulk supplies to different distributing licensees.* For some towns it is more economical to buy power from the electric Grid nearby than to have their own power stations. The load on the main system which supplies several towns' bulk supply for distribution purposes then consists of all the load requirements of these towns.

10. In some locations there may be special industries such as chemical plants, textile industries, paper industries and extraction plants, etc.

When different types of load are supplied by the power system at different times of the day, it will be seen that the load factor of the system improves and is much better than the individual load factors.

Example 1.3

A small town has lighting, industrial and street lighting loads (in kilowatts) as follows :—

Time a. m.	1	2	3	4	5	6	7	8
Lighting	100	100	100	100	100	50	—	—
Street lighting	40	40	40	40	40	40	—	—
Industrial	300	300	400	400	—	—	700	1,000
Total	440	440	540	540	140	90	700	1,000

Time	a.m. 9	10	11	12	p.m. 1	2	3	4
Lighting	—	—	—	—	—	—	—	—
Street lighting	—	—	—	—	—	—	—	—
Industrial	1,000	900	800	700	200	800	700	700
Total	1,000	900	800	700	200	800	700	700

Time p. m.	5	6	7	8	9	10	11	12
Lighting	100	200	600	1,000	900	700	400	200
Street lighting	—	—	40	40	40	40	40	40
Industrial	600	500	300	200	300	400	400	300
Total	700	700	940	1,240	1,240	1,140	840	540

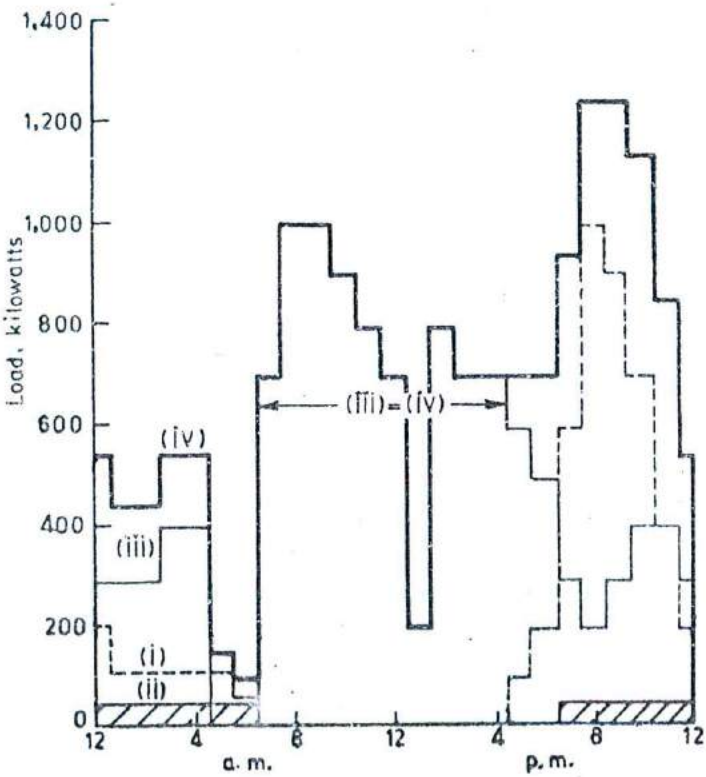


Fig. 1.3. Load of a small town.
(i) Lighting (iii) Industrial
(ii) Street lighting (iv) Total

Plot the individual load curves of the three types of load. Calculate the load factor of each type. Plot the load curve for all loads (total). Find the maximum demand of each load and the time at which it occurs. Find the simultaneous maximum demand. Calculate the diversity factor and the load factor of the total load.

The load curves for lighting, street lighting, industrial load and total load have been plotted in Fig. 1.3. It will be seen that the maximum demand of the lighting load is 1,000 kW at 8 p.m. The maximum demand and the average demand of the street lighting load are the same, namely, 40 kW if taken during the period when the street lights are on. The maximum demand of the industrial load is 1,000 kW at 8 a.m. and 9 a.m. The maximum demand of the total load is 1,240 kW at 8 p.m. and 9 p.m.

For the lighting load the energy consumed during 24 hours is $(100\times5)+(50\times1)+(100\times1)+(200\times1)+(600\times1)+(1,000\times1)+(900\times1)+(700\times1)+(400\times1)+(200\times1)=4,650$ kWh.

$$\text{Load factor of lighting load}=\frac{4,650}{1,000\times24}=0\cdot193, \text{ or } 19\cdot3\%$$

For street lighting load the energy consumed is $12\times40=480$ kWh.

$$\text{Load factor on a 24-hour basis}=\frac{12\times40}{40\times24}=0\cdot50 \text{ or } 50\%$$

For industrial load the energy consumed during 24 hrs $=11,900$ kWh.

$$\text{Load factor of industrial load}=\frac{11,900}{1,000\times24}=0\cdot495 \text{ or } 49.5\%$$

Simultaneous maximum demand $=1,240$ kW.

Sum of individual maximum demands $=1,000+40+1,000=2,040$ kW.

$$\text{Diversity factor}=\frac{2,040}{1,240}=1\cdot64$$

$$\text{Total load factor}=\frac{\text{Total energy consumed during 24 hours}}{\text{Total maximum demand}\times24}$$

$$= \frac{4,650 + 480 + 11,900}{1,240 \times 24}$$

$$= \frac{17,030}{1,240 \times 24} = 0{\cdot}573 \text{ or } 57{\cdot}3\%$$

It will be seen from the above example that the load factor is improved as a result of diversity of load.

1.5 Load Requirements of an Area

The load requirements of an area can be forecast by means of a load survey. For standardization on a national basis, the Load Survey and the Load Development Directorate of the Central Water and Power Commission in India have classified some of the loads to a certain extent on the lines given in the last section. Some average loads can also be assumed for preliminary prediction. Some of the following data regarding loads are based on the paper "National Power Load survey as aid to planning" (See References at the end of the chapter).

General loads include both residential (domestic) and commerical types. The average connected load per consumer may be assumed to be as follows :—

Population	*Connected load per consumer* W
Below 2,000	100
2,000 to 5,000	200
5,000 to 10,000	300
10,000 to 20,000	350
20,000 to 50,000	400
50,000 to 100,000	500

Industrial loads. One of the main requirements for industrial development is cheap power, the other requirements being : raw materials, capital, good transport facilities, technical skill, a market for goods produced, and the way in which the State promotes development.

This type of load may consist of any of the following :—

Cottage industries. These consist of very small loads which can be operated manually but could also use electric power with advantage, e.g., looms, small lathes, utensil making, etc. Loads in this category may be assumed to be approximately as below :—

Load	*Power required* kW
Silk throwing (reeling)	1/2
Single-unit power loom	1/2
Knitting machine	1/2
Carding of wool	3
Wooden toy making	1/2
Small machine shops	3

Small-scale industries. In this category, loads upto 25 kW are grouped together. Though the loads may not be large individually, the total effect may be considerable even in a small town. The following are the average requirements for various types of equipment :

Load	*Average power required* kW
Flour mill vertical type	7
Flour mill, horizontal type	12
Oil kohlus* Bengal type	3 per pair
Oil kohlus Punjab type	10 per pair
Expeller, baby type	10
Expeller, standard type	12·5 to 15
Oil filter	3
Groundnut decorticator	25
Ginning	4
Rice huller	5
Dal (Pulse) roller	12
Disintegrator	10
Saw mill (small)	5
Cinema	15
Ice factory	5 per metric ton of ice
Small workshop	7·5
Foundry	2·5
Ice candy	2

**Kohlus.* A machine for extracting oil from peanuts, etc.

Medium industries. These are classified as industries which have connected loads of 25 to 100 kW. The loads may consist of ginning combined with oil pressing and flour mills.

Large industries. This category will have connected loads of 100 to 500 kW. They may consist of large flour and oil mills, sugar, cotton ginning and pressing factories, small steel rolling mills, large ice plants, etc.

Heavy industries. In this category the loads are more than 500 kW. Examples are chemical factories, textile mills, cement factories, iron and steel rolling mills, aluminium extraction from ore, mining and large-scale manufacturing industries, etc. The load requirement of each type in this category should be assessed individually.

Street lighting. Growth of street lighting should be studied as a function of the growth of population. Demand for power depends on the length of streets and size of shopping centres as well as on the ability of the municipal administration to pay for this amenity. In small towns the average size of street-light lamps is about 40 W each. The supply is at the distribution voltage of 240 V single phase. The average span of poles for street lighting may be taken as 50 m. For bigger towns, the size of street-light lamps may be taken as 60 to 100 W each. Special street-light fixtures and arrangements and the consequent load on this account should be determined individually in cases of big towns.

Water supply. This load may be approximately estimated from the following data.

The requirement of water for rural areas may be taken as 45 litres per day per person; for semi-rural areas, 70 litres per day per person; and for urban areas, 90 litres per day per person. These are minimum requirements. If municipalities can provide better facilities, the cases may be surveyed and estimated individually. Duplicate pumping sets should be installed, and the spare set should always be ready for use because water supply is an essential service and must be available continuously without failure.

Irrigation. The power requirement for this type of load is dependent on the number of waterings required for each kind of crop, the area of the land to be irrigated, the nature of the soil, the working hours and the gross head. The demand factor may be taken as 80% to 90% for tube-well irrigation and 50% to 60% for privately owned individually controlled pump sets. Data applicable to loamy soil and crops requiring 4 to 5 waterings per season are tabulated below :

Head (metres)	Area (hectares)*			
	6 to 10	10 to 20	20 to 32	32 to 40
	kW	kW	kW	kW
30	5	7.5	12.5	15
24	5	7.5	10	12.5
18	3	5	7.5	10
12	3	3	5	7.5

*1 hectare = 10^4 m^2

Traction. In a large metropolis, electric traction is one of the important loads. It may be due to tramcars, trolley buses, or suburban railways. Each tramcar has 4 motors normally of 40 kW each. A trolley bus needs 75 to 100 kW. Suburban railway trains have 4 motors each of 100 to 125 kW capacity. In some places passenger trains and goods trains are driven electrically. These would take their power from a larger system, which might be in the form of a Grid supplying a large area. A passenger train has 4 motors each of about 450 kW, so that the total load is 1,800 kW. A goods train needs about 2,500 kW. Some shunting locomotives are run on Diesel-electric power; if electrically driven, each needs about 150 kW. Electric traction on railways is, however, limited and is undertaken only when it is advantageous compared to steam-locomotives and Diesel-electric traction.

In India, electric suburban trains are used in few cities like Bombay, Madras and Calcutta. Main line electrification uses 1500 V d. c. in Bombay Poona region, the power being fed from converting stations and substations located every 20 to 30 km along the route. For long distances such as Bombay-Nagpur-Calcutta, Calcutta-Delhi, Bombay Ahmedabad etc, 25 kV, single phase electric traction system is used and expansion is under construction on heavy traffic routes. The system uses

25 kV single phase supply for catanery, converted to d. c. voltage by rectifiers on the locomotives and d. c. motors drive for the traction. On long distances where there is no electric traction, Diesel electric locomotives are used. For short lines, and old ones, the steam traction still remains.

Bulk supply to distributing licensees. The load requirement in this category have to be studied and determined in individual cases. If the concerns are convinced that, instead of generating their own power, they can obtain supplies from a large power company or from a Grid at cheaper rates and with full reliability, they may prefer this alternative.

There have been quite a number of cases, e.g., textile mills, of conversion from small local power generation to large consumption of electric power from a power company or a Grid. The change has been noticeable mainly in Bombay, Ahmedabad and other large cities.

In this section, we have considered some of the types of load and their average values for prediction under Indian conditions. In countries which are highly industrialized and have high standards of living, the loads required and the energy used will be much larger. The types of load and method of prediction, however, are similar. The demand factors and diversity factors are higher. The demands are for longer periods. The load factors are better. The lighting loads may be for many hours during the 24 hours and not only at night-time. There may not be cottage and small-scale industries; most of the industries may be large, and the load requirements may have to be decided in individual cases.

1.6 Rural Electrification

With a number of power projects planned and big schemes coming up in India, it is quite possible that a high-voltage Grid will spread all over the country, making cheap power available to small villages and farms in the near future. This, of course, becomes possible when the load development in villages and the proximity of a high-voltage transmission system economically justify the location of near-by substations. It has been the experience of the Tennessee Valley Authority, U. S. A., that when big projects are built and cheap power is made available, the load

increases and the standard of living is improved, then more villages and farms can afford to have electric power.

The rural residential load consists mainly of lighting, domestic heaters, refrigerators and water pumps. The typical average load requirements of rural customers in the Tennessee Valley region were determined as follows—

Type of load	*Average per consumer* kW
Lighting only	0.2
Lighting and refrigerator	0.3
Lighting, refrigerator and water pump	0.4
Lighting, refrigerator and water heater	0.6
Lighting, refrigerator, water pump and water heater	0.8
Lighting, refrigerator and electric cooker	1.4
Lighting, refrigerator, water pump, water heater and electric cooker	1.8

Agricultural load in Western countries having a high standard of living consists mainly of residential loads in cottages, and machines for milking, drying hay, grinding feed for the cattle, pumping water, etc. Typical loads are as follows—

	kW
Electric motor driving milking machine	1 to 3
Storage water heater	3
Motive power for water pumping	1 to 5
Automatic hammer mill	2 to 3
Electric hoist, threshing, grain elevator and conveyor	4 to 5
Estate saw mill	upto 25

In addition, in Britain and the United States, loads consist of poultry farming, crop drying, barn hay drying, grain drying and horticultural applications.

The above information applies to countries with a high standard of living. It cannot be applicable to Indian conditions at present. The immediate load requirements in villages in India are lighting, pumping water on farms and grain grinding. Some

typical loads have already been given. Considerable attention is being paid to rural electrification in India, and schemes of supplying rural areas with cheap power from the Grid are under consideration and under construction. Villages are sparsely populated and the load density is very low. Single-phase mains supplied from high-voltage, 3-phase networks are being considered for the distribution of power. Details of the design principles of distribution for rural areas are discussed in the author's book on the Electrical Power System Design.

1.7 Forecasting of Loads and Electrical Energy Requirements

When planning exploitation of the natural energy resources of a country, progress takes time and needs a lot of capital investment. Advance decisions must be taken for judicious and profitable investment in various projects to make them effective, useful and economical. For this purpose, the anticipated electrical energy demand should be known. The resources available in the country for electrical power production, e.g., for steam stations, hydro-stations and nuclear power stations, can then be developed considering the electrical power and energy requirements, and the locations or regions where demand is expected.

Forecasts may be long term forecasts, medium term forecasts or short term forecasts. Long term forecasts covering a 20 year period provide a basis for examining the energy-supply problems of the country in a broader perspective in relation to various other modes of development, including conversion and substitution of different forms of primary and secondary energy.

It takes 4 to 6 years for construction and installation of equipment in power stations. Medium term forecasts of 5 or 6 years are, therefore, very important for planning the size of stations. Forecasts of demand and energy are required to estimate the additional installed capacity required to facilitate the plant maintenance programme and to estimate the firm capacity of the restricted hydro-plants. Short term forecasts of one or two years are mainly of value for deciding operating procedures, and for preparation of budget estimates.

Discussion in section 1·5 outlines the general approach in estimating the load requirements of a particular area or region. Forecasting of load requirements is an essential part of power project design. The forecast is based upon (a) past development of power requirements in the region, (b) applications received from various prospective consumers and (c) trends in the development of industries and other potentialities for load development. Generally the following methods are used for forecasts or estimates of future demand of electrical energy —

(*a*) Sectional methods or load survey methods.
(*b*) Methods of extrapolation.
(*c*) Mathematical methods.
(*d*) Mathematical methods considering economic parameters.

1.7.1 SECTIONAL METHODS OR LOAD SURVEY METHODS

In this method, the area under consideration is visited and the existing and future load requirements are forecast, taking into account the needs of the communities in the region and the factors which are likely to increase the load demand of the area in the near future. The consumer groups are classified into residential or domestic consumers, commercial consumers, industrial consumers, etc. Enquiries are made consumer category-wise and area-wise to estimate the electrical demand, the expected time of occurrence of the load and the energy requirement. The existing data on loads in the various categories and the expected increase in each category of load yearly for the next 5 or 6 years is then used in the preparation of electrical load demand and energy forecasts.

In general, the engineer engaged in forecasting the load for a particular area, has to consider the availability of raw materials for processing and the related development of industries, the economic conditions and the standard of living of the people, the density of population, transport facilities and the electric power tariffs that can be offered to the consumers.

In a typical survey for the growth of power load, a number of factors need careful analysis :—

1. The general geographical region and the subdivisions of the region where power is to be sold.
2. Physical characteristics, namely, the topography and climate of the region and its effect on load requirement.
3. Population distribution, past growth and estimated future growth.
4. Availability of labour, past distribution and estimated future available labour.
5. Natural resources of the region : agriculture, timber, minerals and raw materials for the manufacturing industries.
6. Main economic activities : agriculture, mining, manufacturing, textile industry, etc.
7. Income per person.
8. Use of electric power and energy : the existing use and the existing rates of consumption of electrical energy.
9. Relative costs of electric and other forms of power available in the region. The cost of electrical energy and the cost of gas, if available.

The principal load centres, the energy requirements, the distribution of power to various classes of load, the maximum or peak demands and the characteristics of the loads supplied should also be studied. The losses that would be incurred in the system should be considered. The energy loss in the distribution system may be taken as 10% to 15%. Diversity among loads should be taken into consideration. The final future requirements may be predicted as annual energy requirements, annual peak demands and annual load factors.

1.7.2 METHODS OF EXTRAPOLATION

These methods involve the study of data collected from various records. These methods are used in the comparison of trends of increase in demand and in energy consumption during past periods comparable with the period of the forecasts. Statistical methods are applied and the average rate of increase of consumption is found out for the past, and also in countries with similar economic structure, then these rates are used for the future estimates of the forecasts.

Grauer has deduced in his paper (ref. 3) that each country passes through four periods of development in its economy for power demand. When the specific annual electricity consumption per head is 100 to 200 kWh, the yearly increase in energy demand is 2 to 5%; when the specific annual electricity consumption per head is about 1000 kWh, the yearly increase in energy demand is 10 to 25%, when the specific annual electricity consumption per head is 2000 to 3000 kWh, the yearly increase in energy demand is 7 to 7·5%, and for specific annual electricity consumption per head above 3000 kWh, the well known rule of thumb of duplication of specific energy consumption in ten years with an average of 7·2% is obtained.

The statistical method, however, has the handicap that it does not consider unforeseen developments, such as the establishment of large and major industries which may alter the future load requirements altogether. For example, in India since independence there has been considerable emphasis on power development under various five year plans, which could not have been predicted from pre-independence conditions. The extrapolation of load curve in order to forecast future requirements can be done with safety, only if the economic trends of the area have also been studied.

In the statistical method of prediction of future load and future possible energy consumption, the curve of load (kilowatts) against years and the curve of energy consumed (kilowatt-hours) against years should be plotted.

1.7.3 MATHEMATICAL METHODS

The curves are plotted with the data of the energy consumption for past years, and the trend is observed by direct extrapolation of the rate of change of energy requirements. The method uses the linear and/or the exponential curve fitting techniques for exploration of the curves. This procedure is applicable where adequate statistical data over a sufficiently long period on the past consumption of electricity are available.

1.7.4. MATHEMATICAL METHODS CONSIDERING ECONOMIC PARAMETERS OR 'ENERGONOMICS'

It is seen that the specific yearly power consumption depends

on the economic factors in the country. The science of 'Energonomics' has been developed. This science considers the following factors in the study :—

(i) Changes in demand for various types of energy by economic sectors.

(ii) A study balanced between the demand for commercial energy and the various activities of the economy.

(iii) Efficiency of the commercial sources in the economic sectors.

(iv) Cost of energy in relation to the rate of growth of the economy.

(v) Energometric indices for per capita consumption of commercial energy, non-commercial energy, electricity, etc.

(vi) Capital investment for energy in relation to the investment of total energy.

The economic standard of living and the electricity consumption bear a particular pattern of relationship. Substitution of various forms of energy by electrical energy is due to the advantages of electricity such as availability, safety, simplicity, and that it can be measured accurately.

The specific electric energy consumption depends on the following essential economic parameters :

(*a*) Specific gross investments.

(*b*) Industrial production.

(*c*) Specific gross national products (GNP).

(*d*) Raw energy consumption.

(*e*) Steel consumption, housing, transport, etc.

Indices for these parameters are found by the construction of curves covering a large number of years and then using extrapolation by linear and/or exponential approximations. The ratios of the parameters are determined from the curves and the estimate of the future energy demand can be obtained by using the ratio of the parameters. Each case will, however, depend on the local factors and also change with time.

When the load requirements have thus been predicted, the next problem is to determine the type of generating plant that will

be required to supply this power and energy demand. It will be necessary to consider the various types of generating plant available, their suitability under various conditions, and which type will be particularly suitable for the case under study. It will also be desirable to consider whether the power should be generated locally or taken from the Grid, if feasible.

1.8 Method of forecast of Electrical Energy used in India

The energy survey committee adopted in its report what are called 'replacement units' for the conversion of different forms of energy. Each type and source of energy is measured in terms of coal, which it would replace, when both the coal and the energy source under consideration are used in appliances or equipment at the same thermal efficiencies likely to be met in practice.

For the energy survey carried out in India, initially the available data for the period between 1953-54 and 1962-63 were utilized to determine the relationship between (*i*) total energy consumption (commercial and non-commercial) and the national income, (*ii*) commercial energy consumption outside the domestic sector and the industrial production indices. Based on the elasticity coefficients, the future energy requirements for 1970-71, 1975-76 and 1980-81 were estimated assuming three alternative rates of growth for national income and the industrial output.

(*i*) 5% per year for national income and 7% per year for industrial output.

(*ii*) 6% per year for national income and 8.5% per year for industrial output.

(*iii*) 7% per year for national income and 10% per year for industrial output.

The forecasts were based on the plant output in individual economic sectors. The estimates in different sectors are suitably integrated for each type of energy supply.

The possible load forecasts in the next 5 to 10 years will be worked out using the various methods and correlating them with the economic indices and GNP. The trend of the energy require-

ment for each class of load and region-wise will be corrected upto date in the future planning.

1.9 Expected Load and Energy Growth in India

The Five Year Plans give the expected load and energy growth. For planning electrical power development, India is divided into five regional zones: (*i*) Northern region, (*ii*) Southern region, (*iii*) Western region, (*iv*) Eastern region, and (*v*) North Eastern region. At a later date, the regional grids will be interconnected making it a super-grid at All India level. The data for All India level is given in Table I. The definitions of the terms used in the Table are as follows :—

Installed capacity is the sum of the manufacturers' ratings of all the installed generating equipment.

Peak load is the maximum simultaneous ultimate customer demand which occurs during the fiscal years as measured by the actual deliveries at bulk power sources.

Energy generated is the aggregate of the energy consumption of all ultimate consumers measured at the H.T. busbars at the generating stations.

Table I

All India Growth of Installed Capacity, Peak Load and Energy Generation—Public Utilities

	Installed Capacity MW	Peak Load MW	Total Energy Generation million kWh
1955/56 II Plan	2695	1683	8110
1960/61 III Plan	4653	3312	16390
1965/66 Annual Plans	9028	5605	30540
1968/69 IV Plan	12957	8025	45010
1973/74 V Plan	16665	11428	64750
1978/79 VI Plan	33061	21392	126990
1983/84	53517	33009	195360

Installed Capacity includes Hydel, Thermal, Nuclear, Diesel and Gas.

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Problems

1.1. Define "connected load", "maximum demand", "demand factor" and "load factor".

A consumer has the following connected load: 10 lamps of 60 *W* each and two heaters of 1,000 *W* each. His maximum demand is 1,500 *W*. On the average, he uses 8 lamps for 5 hours a day and each heater for 3 hours a day. Find his average load, monthly energy consumption and load factor.

(Ans. 350 W ; 252 kWh ; 23.33%)

1.2. What is "diversity factor" ? State the advantage of the diversity of load in a power system.

Prove that the load factor of a power system is improved by an increase in diversity of load.

1.3. There are four consumers of electricity having different load requirements at different times. Consumer No 1 has an average load of 1 kW and his maximum demand is 5 kW at 8 p.m. Consumer No 2 has a maximum demand of 2kW at 9 p.m., a demand of 1.6 kW at 8 p.m and a daily load factor of 15%. Consumer No 3 has a maximum demand of 2 kW at 12 noon, a load of 1 kW at 8 p.m., and an average load of 500 W. Consumer No 4 has a maximum demand of 10 kW at 5 p.m. a load of 5 kW at 8 p.m. and a daily load factor of 25%. The maximum demand on the system occurs at 8 p.m. Find (*a*) the diversity factor, (*b*) the average load and load factor of each consumer, and (*c*) the average load and load factor of the combined load.

(Ans. (*a*) 1.51. (*b*) Consumer 1 : 1 kW ; 20%. Consumer 2: 0.3 kW; 15%. Consumer 3: 0.5 kW; 25% Consumer 4: 2.5 kW; 25% (*c*) 4.3 kW; 34.2%.)

1.4. State the different categories of loads on an electric power system. A power system has the following loads –

(*i*) Residential lighting load : maximum demand, 1,000 kW; load factor, 20% diversity between consumers 1.3.

(*ii*) Commercial load : maximum demand, 2000 kW; load factor, 30%; diversity between consumers, 1.1.

(*iii*) Industrial load ; maximum demand, 5,000 kW ; load factor, 80% diversity factor between different industrial loads, 1 2.

The overall diversity factor may be taken as 1.4.

Find (*a*) the maximum demand on the system, (*b*) the daily energy consumption of each type of load and the total energy consumption, (*c*) the load factor and (*d*) the connected loads of each type, assuming that the demand factor for each is 100%

(Ans. (*a*) 5,714 kW. (*b*) (*i*) Residential lighting 4,800 kWh; (*ii*) commercial, 14,400 kWh ; (*iii*) industrial 96,000 kWh; total daily energy consumption, 115,200 kWh. (*c*) 84%. (*d*) (*i*) Residential lighting 1,300 kW; (*ii*) commercial 2,200 kW (*iii*) industrial, 6,000 kW).

1.5. Explain the effect of off-peak load on the load curve. A town has the following loads in kilowatts—

Time a.m.	1	2	3	4	5	6	7	8
Lighting	50	20	20	20	20	30	—	—
Industrial	—	—	—	—	—	—	2,000	3,000

Time	a.m.				p.m.			
	9	10	11	12	1	2	3	4
Lighting	—	—	—	—	—	—	—	—
Industrial	2,800	2,800	2,500	2,000	1,000	2,000	2,500	2,500

Time p.m.	5	6	7	8	9	10	11	12
Lighting	—	500	2,000	5,000	4,000	3000	2000,	500
Industrial	2,000	1,500	1,000	1,000	500	500	—	—

The maximum demand on the system is 6,000 kW at 8 p.m. It is proposed to add a municipal waterworks load to the system. Find the effect of the waterworks load of maximum demand 1,500 kW when supplied uniformly at off-peak times between 11.30 p.m. and 6.30 a.m.

(Ans. System load factor is improved from 32.5% to 39.7%).

1.6. Explain the methods of forecasting loads when planning new projects in electrical power systems.

1.7. A village having a population of 10,000 is to be supplied with electric power. Assume a household of 5 persons on the average and that 80% of the households will buy electricity. Estimate the possible load in the village and the expected load curve, maximum demand, daily energy consumption and load factor. Assume the village to have cottage industries, a few small-scale industries and a lighting load.

1.8. A textile mill having a maximum demand of 3,000 kW and a load factor of 80% on an 8-hour basis is considering whether to have its own generating plant or to buy power from a large public utility company. State the main factors which should be taken into account from the point of view of (*i*) the textile mill and (*ii*) the utility company.

1.9. Plan and estimate the electric power development required for a new township to be erected for workers of a large industrial project, e.g., a steel rolling-mill.

1.10. A metropolis with a population of 1 million has large industries, medium-size industries, modern amenities for street lighting, water supply, etc., suburban railways (electric) and tramcars. Estimate the approximate requirements of electric power, maximum demand, load curve and expected load factor. Make suitable assumptions as to the loads and the times of their occurrence.

2

Choice of Power Station and Units

2.1 Types of Power Station

In the last chapter, the problem of load prediction was discussed. Once the load has been predicted for a particular area, the next problem is how to get this power. It could be obtained from a power station for the particular area and then distributed. Alternatively, cheaper power might be available from the Grid nearby. If so, the power could be bought directly from the Grid authority, received in a transmission substation and then distributed. It is invariably economics that determines the choice between local power station and bulk supply point If it is decided to have a local power station, its type and location must be considered.

There are three main types of stations, namely, Diesel-Electric, steam and hydro-electric In a few cases, gas turbines are used. Nuclear power stations are now used when the size of units is large and this type is economically justified.

2.2 Choice in Type of Generation

The general points which should be considered in choosing the type of generation are as follows :

1. The selection of the type of power station depends on the kind of fuel available and its cost, availability of suitable sites for water power, nature of the load to be supplied, etc.

2. The selection of the site of a power station depends on many factors, including the cost of transmitting the energy to the consumer, of transporting the fuel to the station—road, rail or water transport, or in the case of a station using oil, the cost of an oil pipe-line, etc., the availability of sound foundations and the cost

of land, the availability of an adequate supply of cooling water; and the avoidance of atmospheric pollution. It is only after consideration of these various factors that it is possible to select the most suitable site.

3. The following discussion gives various points in detail. All these points should be considered together in finally deciding the type of generation and the location of the station.

Location of power station for economy in distribution costs. For the most economical distribution and lowest cost of power and energy, the power station should be located at the centre of gravity of the load if a suitable site is available. In a densely populated city this may suggest that the power station should be practically in the heart of the city. A Diesel station of medium size (not very unwieldy) could be located there, but the installation of a steam station would present a number of problems. In general, it would not be economical to have a steam station in the city unless it was of very small capacity for the supply of local power to an industrial plant, e.g., a textile mill. When, as is usual, a steam station is located on the outskirts of a city, it is necessary to have longer feeders than would be required, if it were placed at the centre of gravity of the load.

Hydro-electric power stations need suitable sites which will normally be remote from the load centres. Thus they cannot be located at the centre of gravity of the load, and may need long transmission lines to bring the power to the place where it is required.

Cost of land and taxes. The cost of land as well as taxes on land are dependent on the situation of the proposed power station. In a big city, the cost would be more than in a small town or outside the metropolis. The taxes also would be higher for land in the centre of a commercial city. This is, therefore, an important point to be considered in the economic selection of a site.

Space required. The space and building required by the power station is another point to be considered. If the building and space required are both large, the cost of land as well as building will be large. Thus large plants in the hearts of big cities

and near the centres of gravity of load are not economic. Diesel stations are normally of small size and need less space. Steam stations need much more space for boiler house, mechanical-handling equipment, storage of coal, ash disposal, etc. A hydro-electric station needs a lot of space for civil engineering construction works such as dams, etc., the building has to be much larger than required for other types of plant, and a number of arrangements have to be provided in the building as special features which are quite different from those in other types of power station. The location, however, is at a suitable site where water is available at enough head and the cost of land is not excessive. The height, substructure and superstructure of the building for a hydro-electric station are quite considerable. Steam stations do not need so much space, but they need more than Diesel stations. Space requirements and the size of buildings are among the major items in cost comparison between stations.

Interest and depreciation. The capital required initially depends on the total investment for the station, power system layout and installation. The rate of interest on the capital depends only on the money available in the market, and not on the type of station. The depreciation cost, however, varies with the types of plant. The Diesel station plant may be taken to have a depreciation of about 6%, i. e., the life of a Diesel engine set may be taken as 15 to 16 years. Steam plants have a longer life, of 20 to 25 years, and their depreciation may be taken as $3\frac{1}{2}\%$ to 4%. Hydro-electric plant can last for a very long time, as wear and tear is very slight; their depreciation may be taken as between 1% and 2%.

Size and cost of plant. As the size of plant increases, it may be worth considering the use of larger sizes of generating units in the station, if they are available and if the load curve permits their use. The cost per killowatt of the capacity of a unit decreases as the size of the unit increases. It is, therefore, more economical to use a few generating units of large size than a larger number of small size units for the same total capacity. In the case of Diesel-engine sets, very large units are not available, the normal maxi-

mum size being about 4,000 kW, but even this is seldom compatible with the load curve and much smaller sizes are generally used. The principles determining the choice of generating units to fit a given load curve are explained in Section 2.3. Steam generator units are available in big capacities. Sets of 80 MW to 500 MW are in use in big stations and the largest steam turbo-generator unit under construction in the United States has a capacity of 1200 MW. These large sizes are feasible only where station capacities are very large and they are interconnected by a Grid. For small power plants and schemes it is unnecessary to install such large units. When the capacity of the station required is larger than can be handled by Diesel plants, comparison of cost with other types of power station may be considered. Hydro-electric generator sets, upto a capacity of 200 MW, are in use in the United States and other countries having large power systems. Such large sets may not be required for small schemes and individual power systems, as they may not be compatible with the load curves.

Cost of fuel. The cost of fuel is an important consideration in deciding on the type of power plant for a particular location. Diesel engines need oil as fuel and the cost of this depends on the location of the plant. For exampie, if the plant is to be located near oil-fields where oil is plentiful and cheap and the cost of transportation is extremely small, it may be economical to install a Diesel plant, from the point of view of fuel cost. However, if the location of the plant is remote from the source of oil, the cost of fuel may be excessive. For steam plants, the cost of coal for the boilers and the availability of coal are important considerations. If cheap oil is available, the boilers may be oil fired, and steam plants may compete with other types. With hydro-electric plants there is no cost of fuel as the source of power is water. The required amount of water should be available at the necessary head to drive the water turbine. This involves capital expenditure on civil engineering works. Interest and depreciation on the capital required are a fixed cost. The loss of power due to friction in the penstock depends on the head and the size of the turbine units.

Availability of sites for water power. In deciding the type of power plant to supply a particular system, it is desirable to investigate whether any suitable water sources and sites are available for the development of hydro-electric stations. Some of the considerations are topography of the land, rainfall during the year, catchment area, suitable site for storing water behind the dam, sufficient quantity of water at sufficient head, cost of civil engineering works that would be required for using this water for power station purposes. It is very likely that the site will be remote from the cities or load centres, so that long transmission lines will be required. The cost of such transmission lines should be chargeable as part of the cost of generating electricity at the hydro-electric station. This cost should be considered in deciding the type of power station for the particular area.

Foundations. Foundation construction problems should be taken into account in deciding the location of the power station. These will depend on the weight and size of the machines, the space required for machines and building, and how foundations for such heavy machines can be built on the soil available.

One of the factors to be considered is noise, if the station is in the centre of a city, e.g., a Diesel station. Diesel engines are noisy and people in the vicinity are likely to raise complaints. A steam station in the centre of a city, may also cause noise, though not as much as a Diesel station. Smoke from the chimney of a steam station is undesirable in cities. Noise of the exhaust of Diesel engines is objectionable, but may be reduced to a certain extent by means of silencers. If the noise is likely to be excessive, it is better to choose an alternative site outside the city.

Storage space for fuel. A steam station using coal-fired boilers, which is a common practice, requires space to store coal in amounts depending on the size of the station. A supply of coal for the next two or three weeks at least should always be available on site. The amount of reserve stock required depends on the location of the station. If the station is near a coal mine it may not be necessary to store a large quantity, while if the coal has to be transported from a long distance over rail or lake,

etc., a large stock may be required. For oil fuel the space required is comparatively less. The quantity required as spare depends to a great extent on the degree of security of oil supplies. In both cases, the cost of having money tied up in fuel stocks has to be taken into account.

Transport facilities. The location of a power station is dependent to some extent on the availability of transport facilities. It is necessary to have a railway line available and extended to the yard for bringing in heavy machinery for installation in the beginning and for bringing in fuel-coal or oil as well as materials required for maintenance. Alternatively, the station may be located on the bank of a river where facilities are available for transport by barges or ships. The machinery to be transported for a steam station is rather heavy, as the station will in general be much larger than a Diesel station. For a Diesel station the problem of transport is not so acute, the station is generally small, the machines and equipment to be brought in are not very heavy, and large quantities of fuel are not required. Road transport should, however, be available. For hydro-electric stations, remote from the normal available rail and other transport facilities, roads should be built leading to the site and arrangements made so that the equipment can be taken to the site. Heavy equipment may have to be transported in parts and assembled on site.

Availability of water for cooling engines or prime movers. A steam station requires larger quantities of cooling water than a Diesel station of the same size. Water is circulated through condenser tubes to condense the steam and to maintain a high vacuum in the turbine condensers for high efficiency. The steam station, therefore, needs a site near a river or where a large quantity of water is available. If the river is dry for a part of the year, cooling towers are built and water may be taken from boring wells and used over and over again in a circulatory system through the cooling towers. Cooling towers require make-up water, the quantity depending on the load carried by the station.

The concentration of salts in the water in the cooling system must be kept under control. A steam station also requires water

for the boilers. Normally it is a closed feed system taking condensate back into the boiler as feed water. Owing to losses in the system, however, make-up water is required. This is of the order of 2% to 3% of the total feed water in the boilers. Make-up water should be free from hardness. The hardness may be removed by using lime soda or ion-exchange softening plant, or by the use of heater and evaporator, and then the make-up water may be injected into the feed-water system.

A Diesel station needs water for cooling the cylinders of the engines, and for this purpose, water is circulated through the cylinder jackets. The quantity of water required is, however, very small compared to the requirement of the steam station, and the Diesel plant is also much smaller. The Diesel station, therefore, can be located at a place that is suitable from other points of view. Normally a spray-pond arrangement is satisfactory for cooling the water at a Diesel station. The cold water from the pond is re-circulated through the cylinder jackets.

Nature of load. The nature of the load to be supplied affects the choice of plant to a certain extent. If the load varies suddenly to a great extent, so that the load factor is poor, and if the load is not very large, a Diesel plant will be chosen as it is more adaptable than a steam plant to quick starting and stopping and picking up load quickly. With a steam plant the boilers have to be kept banked and ready to pick up load at any time. The steam plant also needs a longer time for starting and for taking load, as the necessary vacuum has to be produced and maintained before the load can be taken. If a hydro-electric plant of small or suitable capacity is available, it can be started quickly and can take up load quickly, and thus can be used for the above type of varying load.

If two or more types of stations are available and are to be interconnected to supply a load having variable characteristics, the stations can be made to work on the parts of the load curve that suit their different characteristics. The detailed considerations in arranging this and operation for economical working will be discussed in a later chapter.

Degree of reliability. Reliability of service is a very important item in the choice of a power plant. If the supply is to be taken from an isolated individual plant and full reliability is required, the plant should be big enough to supply the maximum demand. Sufficient standby plant must be available to cover the loss of the largest generator on load. If the load is seasonal, then during lightly loaded times of the year, the plant can be taken out of commission for overhaul, leaving the necessary standby available. During heavy loading periods, all plant would be available with the necessary standby ready for immediate use.

Cost of purchased power. While deciding whether power should be generated for supplying the load of a town or an industrial concern, it may also be considered whether it would be economical to buy power from a Grid if available nearby. The tariff for this power will be one of the important points which will influence the decision. The tariff should be compared with the total cost of generation and distribution, including capital charges. Grid supply can assure good reliability of service. If the same degree of reliability is required from the generating plant to be used as an alternative to buying power, enough spare plant capacity has to be bought and installed. This needs more capital investment. By buying power from the Grid, the capital investment for the spare plant is saved, although this saving will be offset to some extent by the tariff charged for standby supply from the Grid.

Process steam. Industrial concerns may need steam for some of the processes in the plant, for example, textile industries need steam for maintaining humidity. A textile concern may, therefore, consider the possibility of generating its electric power by steam turbines and using the exhaust steam for process as a by-product. If a consumer of this type of load is to be converted to buying power from a supply company or Grid, he should be convinced that it would be more economical to buy power than to generate his own. To work out the economics, it is necessary to find out the capital cost of the plant required for supplying the maximum demand, the cost of reserve plant to maintain reliability and continuity of supply, the cost of auxiliary equip-

ment required, the interest and other charges on the capital costs, and the maintenance costs, and then to work out the cost per kilowatt-hour generated, including the cost of the losses. It may be possible to buy electric power and have a small separate boiler to supply the process steam. The cost of buying the power and producing the steam may then be compared with the cost of generation.

The various points mentioned above are some of the considerations in choosing the type of generating plant and its location, and also in finding out in particular cases whether it is better to buy electric power than to generate it. There can be no generalization in respect to the choice of the type of plant. Each case will have to be studied individually and decided on its merits by working out the economics involved. Whatever the choice, the power supply must be reliable. Cheap power without reliability is costly power.

2.3 Choice of Size of Generator Units and Number of Units

The load on a power station is never constant, owing to variable demands at different times of the day. The nature of these demands is seen approximately from the predicted load curve. The variation is greater with a poorer load factor. The minimum capacity of the generating plant in the station must suffice to meet the maximum demand. The minimum number of units chosen could be one. In this case, however, the prime mover and generator would be working on full load only for a short time, during the period of maximum demand or whenever the load is approximated to the maximum demand. As the load is variable and load factor less than 100%, there is a considerable period during the day when the load on the station, and on one unit in this particular case, is much less than a full load. Often it may be on half-load or even practically on no-load. The generating set would, therefore, not be running at all times, under conditions best suited for its operation, giving maximum efficiency. The fuel costs will be greater, and it will be uneconomical to run the set under low-load conditions. It is essential for a power station to maintain reliability and continuity of power supply at

all times. If this requirement is to be satisfied, another set of equal capacity must be installed for use when the first set is out of order or is being opened up for overhaul or repairs. So the capital cost would be for two sets, each of capacity corresponding to the maximum load on the station. The use of one unit only to supply the whole of a variable load where reliability of supply is essential, is neither practical nor economical. We are at present considering an isolated station which supplies the system alone, without any other stations in the same system for interconnexion.

The alternative way of deciding the size and number of generating sets in the station is to choose the number of sets to fit the load curve as closely as possible, i.e., to choose the number of sets and work them on suitable portions of the load curve in such a way that each will operate on about full load, or the load at which it can give maximum efficiency. The reserve required would only be one unit of the largest size chosen. This unit would be much smaller than the maximum load capacity required in the last case. This method of choosing the generator sets needs a large number of units. With increase in the number of sets, the area required for the building increases, and so too does the building cost. More sets involve more starting, stopping and parallel operation of the equipment. The maintenance cost increases. The capital cost of the larger number of sets is greater than that of the same capacity of plant in a smaller number of units of larger size.

There has to be a compromise in the selection of the size and number of generator units in the station and avoidance of both the extremes mentioned above. The aim should be to have a small number of units and to fit them as well as possible on the load curve. There should not be only one unit, nor should there be a large number of small sets of different sizes.

Plant capacity factor and plant use factor. Load factor and diversity factor do not give any idea as to the reserve capacity required in a station. A new term is, therefore, introduced, defined as follows and called the plant capacity factor—

$$\text{Plant capacity factor} = \frac{\text{Actual energy produced}}{\text{Maximum possible energy that could have been produced during the same period}} \quad (2.1)$$

If taken for a day, the plant capacity factor would be the area under the load curve (kilowatt-hours) divided by the total plant capacity installed in the station, including the reserve plant in kilowatts, multiplied by 24 hours. If taken for the whole year, it would be the ratio of the energy produced during the whole year to the energy which could have been produced if all the plant capacity, including the reserve plant, had been run continuously throughout the year. The factor is then known as the annual plant capacity factor. The difference between the load factor and the capacity factor is an indication of the reserve capacity installed in the station.

Another factor is defined to indicate the actual use that is made of the plant and is called the annual plant use factor—

$$\text{Annual plant use factor} = \frac{\text{Annual energy produced (kWh)}}{\text{Capacity of plant (kW)} \times \text{Number of hours plant is in operation during year}} \quad (2.2)$$

The choice of the size and number of generating units in a station is governed by the best compromise between plant capacity factor and plant use factor. This discussion is illustrated by the following example.

Example 2.1

A power station has to supply load as follows—

	kW		kW
11 p.m. to 5 a.m.	500	12 noon to 1 p.m.	1,500
5 a.m. to 6 a.m.	750	1 p.m. to 5 p.m.	2,500
6 a.m. to 7 a.m.	1,000	5 p.m. to 7 p.m.	2,000
7 a.m. to 9 a.m.	2,000	7 p.m. to 9 p.m.	2,500
9 a.m. to 12 noon	2,500	9 p.m. to 11 p.m.	1,000

Draw the load curve. Calculate the load factor. Choose the number and size of generator units to supply this load. Reliability

of supply is to be maintained. Find the reserve capacity of the plant required. Calculate the plant capacity factor. Determine the operating schedule of the units in the Station. Calculate the plant use factor.

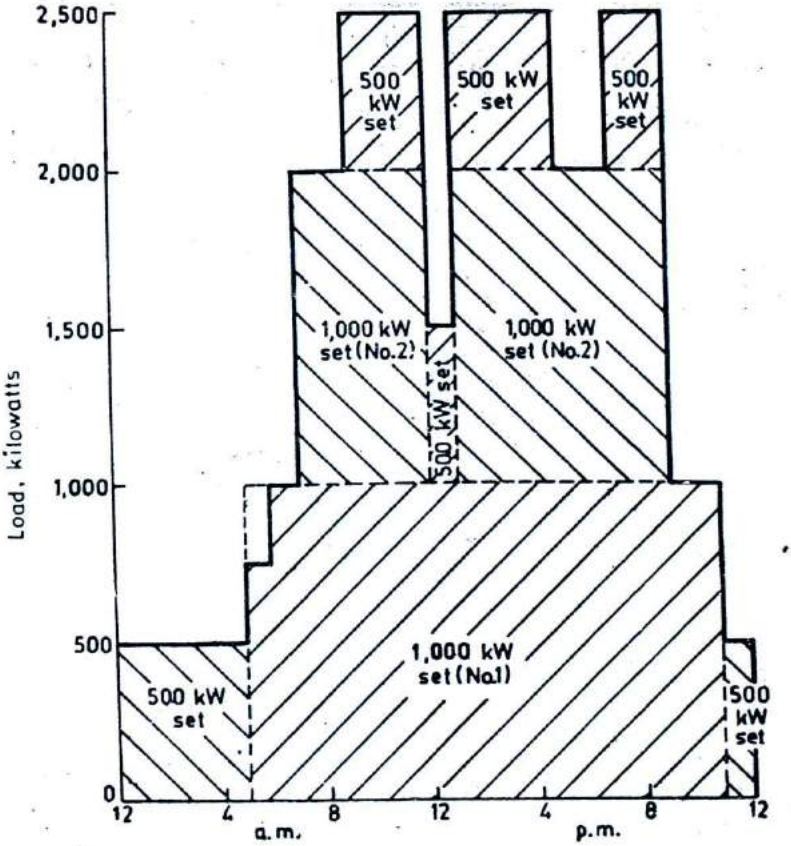


Fig. 2.1. Load curve of a power station.

Fig. 2.1 is a load curve plotted from the above data. The maximum demand is 2,500 kW. If water resources were not available in the vicinity, the plant would normally be Diesel-electric. For a privately owned plant it could be a steam station if local conditions were suitable. The method and considerations for the selection of size of generating units are, however, common to all types of stations so far as fitting in the load curve is concerned.

Energy generated during 24 hours

$$=(500\times5)+(750\times1)+(1{,}000\times1)+(2{,}000\times2)+(2{,}500\times3)+(1{,}500\times1)+(2{,}500\times4)+(2{,}000\times2)+(2{,}500\times2)+(1{,}000\times2)+(500\times1)$$

$$=38{,}750 \text{ kWh}$$

Maximum demand = 2,500 kW

$$\text{Load factor}=\frac{\text{Energy generated during 24 hours}}{\text{Maximum demand}\times 24 \text{ hours}}=\frac{38{,}750}{2{,}500\times24}$$

$$=64{\cdot}7\%$$

From the nature of load curve, it will be seen that this is the load of a small industrial town, well distributed during day and night. From the load curve it will also be seen that three generator sets will suffice with the following ratings—

Two sets each of 1,000-kW capacity

One set of 500-kW capacity

The reserve capacity required will correspond to the largest size of unit in the station. In this case, a set of 1,000 kW will have to be bought and kept as reserve. The total installed capacity of the station will, therefore, be

1,000 + 1,000 + 500 + 1,000 (reserve), i.e., 3,500 kW

$$\text{Plant capacity factor}=\frac{\text{Energy produced during 24 hours (kWh)}}{\text{Installed capacity (kW)}\times 24 \text{ hours}}$$

$$=\frac{38{,}750}{3{,}500\times24}=0{\cdot}46, \text{ or } 46\%$$

The capacity of the individual sets is chosen as far as possible to fit approximately the load curve. Next it should be decided how, when and in what sequence the sets should be started and run. This arrangement is known as the operating schedule of the station. In arranging this schedule, care is taken to see that the plant of the required capacity is kept ready for loading at the expected time of the load. The capacity of the plant started and kept ready might be larger than necessary but should not be inadequate.

With the type of load curve shown in Fig. 2.1 and the sizes of units chosen as above, the operating schedule can be arranged as follows –

From 11 p.m. to 5 a.m. only the 500-kW set is run.

At 5 a.m. the load is expected to increase. The first 1,000-kW set is, therefore, started and parallelled with the 500-kW set, all the load is transferred to the 1,000-kW set, and then the 500-kW set is stopped.

Thus one set of 1,000 kW is run from 5 a.m. to 7 a.m. taking up the necessary load.

Just before 7 a.m. when an increase in load is expected, the second 1,000-kW set is started and parallelled with the first one.

From 7 a.m. to 9 a.m. both the 1,000-kW sets are running together.

At 9 a.m. still more load is expected, the 500-kW set is started and parallelled with the other sets on the busbars and loaded along with them. Thus at the time of supplying the maximum load, between 9 a.m. and 12 noon, all three sets are running on full load.

Between 12 noon and 1 p.m. the load is reduced, owing to recess-lunch time in industrial plants. One of the 1,000-kW sets is stopped after the load has dropped to 1,500 kW.

From 1 p.m. to 5 p.m. this set is run again along with the two others.

At 5 p.m. the load again drops, owing to the working shift in industries being over. The load on the 500-kW set is removed and then this set is taken out of commission.

From 5 p.m. to 7 p.m. only both the 1,000-kW sets are running.

At 7 p.m. the load increases, owing to lighting and all three sets are run until 9 p.m.

At 9 p.m. two sets are taken out and only one 1,000-kW is run until 11 p.m.

After 11 p.m. only the 500-kW set need be run.

At each time of change-over, care should be taken to ensure correct parallelling and load transfer.

With the operating schedule fixed as above, the energy that could have been generated by the capacity of plant actually running for the scheduled time would be

$$(500\times 6)+(1{,}000\times 2)+(2{,}000\times 2)+(2{,}500\times 3)+(1{,}500\times 1)$$
$$+(2{,}500\times 4)+(2{,}000\times 2)+(2{,}500\times 2)+(1{,}000\times 2)=39{,}000 \text{ kWh}$$

Energy actually produced $=38{,}750$ kWh

$$\text{Plant use factor}=\frac{\text{Energy produced (kWh)}}{\text{Capacity of plant (kW)}\times\text{Number of hours plant has been in operation}}$$

$$=\frac{38{,}750}{39{,}000}=0{\cdot}994, \text{ or } 99{\cdot}4\%.$$

In the above example, the load curve variation and the exact size of plant to fit the load curve are chosen as ideal, the plant

use factor being practically 100%. This would rarely be achieved in practice. It would be difficult to choose units of such capacity that when in use they could be run continuously on full load. In practice the plant use factor would be much smaller than 100%, it is, however, higher than the capacity factor when some reserve plant is necessary. A number of starting and loading operations can easily be handled in hydro and Diesel-electric stations but are time consuming in steam stations.

The decision to shut down a machine and restart it later should be made after considering the economics of such a move. On one hand, to shut down and restart involves certain losses which should be determined. On the other hand, to deload partially machines which are on load also involves certain losses, the magnitude of which depends on the length of time they are running at reduced load. If, therefore, it is possible to forecast the length of time during which the station would be running at reduced load, it is easy to estimate whether it is economical to take a machine off or to run all the equipment at a slightly lower load, and, of course, the decision would be made in the light of minimum losses.

2.4 Load Duration Curve

This is another type of curve which is very useful for financial studies of the stations. The daily load curve shows the load demand during the 24 hours of the day as a plot of load against the time at which it occurs. Throughout the year, there is a variation of load demand, from day to day and the daily load curves are not all alike, for example the load curve in summer would be different from that in the winter. There might be development of load during the year, so that demand on the station might increase during the year. To obtain a correct indication of the financial aspects and working of the station, it is necessary to estimate the consumption of energy during the whole year as well as the annual load factor, annual capacity factor and annual use factor. One way to find them would be to plot all the daily load curves on thick sheets and preserve them together. This would show the variation of the load throughout the year

and the data would be useful in calculating the various factors required. The process would, however, be very lengthy and time consuming.

It is more convenient to construct a load duration curve from these data. The method is quite simple. From all the daily load curves for the year, find the maximum demand during the year and the time during which it occurs. Then take any load in kilowatts and find the total time in hours during the year when this and any greater load occur during the year. Plot the load against the number of hours during the year for which it occurs, or against the percentage of time during the year, 8,760 hours representing 100%. The curve thus obtained is known as the annual load duration curve. A load duration curve can be constructed for any period, taken as 100%, the load being plotted against the percentage of the time during which it occurs.

The method of constructing the load duration curve from daily load curves of a certain period is illustrated in the next example.

Example 2.2

The following loads are supplied by a station during one week for the times shown —

Day	Load kW	Time hours	Load kW	Time hours	Load kW	Time hours	Load kW	Time hours	Load kW	Time hours
1	1,000	4	5,000	3	500	8	3,000	4	2,000	5
2	2,000	3	4,000	4	1,000	6	500	5	1,000	6
3	3,000	5	5,000	6	2,000	4	1,000	5	500	4
4	2,000	7	3,000	5	6,000	1	1,000	8	500	3
5	1,000	6	5,000	4	2,000	3	1,000	7	200	4
6	3,000	5	2,000	7	3,000	7	5,000	2	1,000	3
7	4,000	4	5,000	3	2,000	4	3,000	7	500	6

Construct the load duration curve for the week.

The total time is $24 \times 7 = 168$ hours or 100%. The maximum demand during the week is 6,000 kW. The other loads occur for the number of hours shown. The percentages of the time during which these loads occur are tabulated below.

Load (kW)	Hours in week	Percentage time.
6,000	1	0·505
5,000 and above	19	11·3
4,000 and above	27	16
3,000 and above	60	35·7
2,000 and above	93	55·5
1,000 and above	138	82
500 and above	164	97·6
200 and above	168	100

The load duration curve has been plotted in Fig. 2.2.

The annual load factor, annual capacity factor and annual plant use factor can be found from the annual load duration curve, the area under which represents the total annual energy production. The annual load factor is given by the ratio of the area under the curve to the area corresponding to the maximum demand occurring throughout the year. In the same way, the reserve capacity of the plant being known, the annual capacity factor can be obtained. The operating schedule and the time during which each set is worked being known, the plant use factor can be determined.

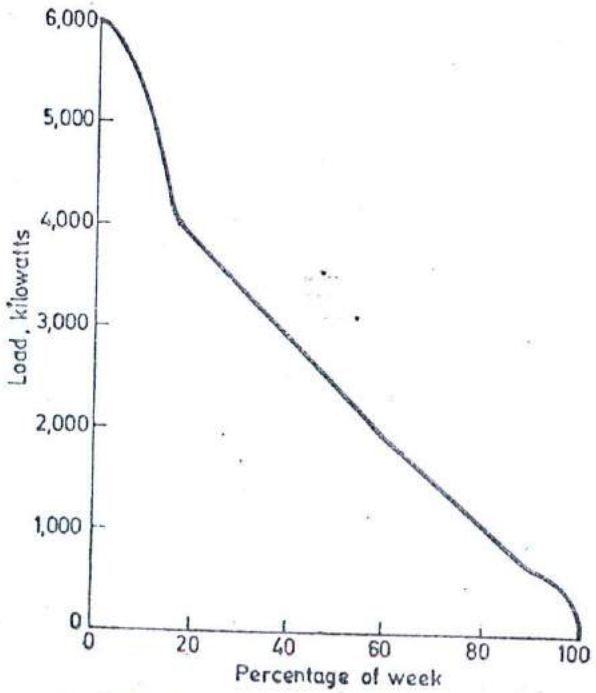


Fig. 2.2. Load duration curve for a week.

Example 2.3

The annual load duration curve of a power system is shown in Fig 2.3. The maximum demand is 20,000 kW. The load is supplied by two power plants, one having a capacity of 12.5 MW, and the other a capacity of 10 MW, Plant No. 1 (12·5 MW) is used throughout the year, and plant No. 2 (10 MW) is used whenever the load exceeds the capacity of plant No. 1. Find the load factor, plant capacity factor, and use factor of each plant.

Fig 2.3 is the load duration curve. The maximum demand is 20 MW. The various points on the curve represent the loads that occur for the percentage of time represented by the corresponding horizontal intercepts. For example, the point *q* indicates that a load of 12.5 MW occurs for 40% of the year; and the point *p* indicates that a load of 10 MW occurs for 80% of the year.

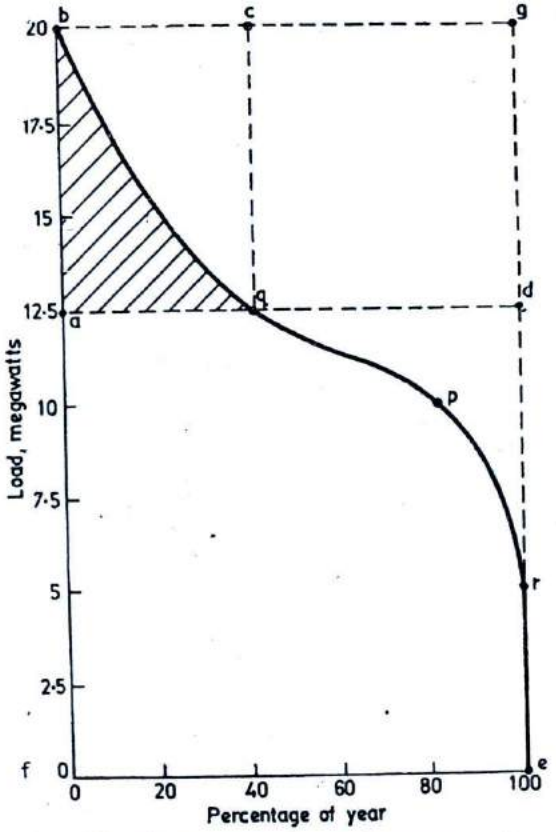


Fig. 2.3. Annual Load duration curve.

Plant No 1 is run to supply as much of the load as it can for 100% of the year. This is, therefore, shown on the lower portion of the load duration curve and when a plant is used in this way it is known as a base-load plant. The line *aq* is the line of demarcation of load, as the maximum load supplied by this plant is 12.5 MW. The remaining load above this line, is supplied by plant No 2. A plant used in this way is known as a peak-load plant, as it supplies the load on the top portion of the curve.

Plant No 1 is run for all the time, namely, 100% of the year, and the maximum load that it can supply is 12.5 MW. It has no reserve capacity. The area *aqprefa* under the load duration curve represents the energy produced by plant No 1 during the year. This is found to be 98×106 kWH.

Load factor of plant No 1 acting as a base-load plant

$$= \frac{\text{Energy produced during year}}{\text{Maximum demand} \times 8{,}760 \text{ hours}}$$

$$= \frac{98{,}000{,}000}{12{,}500 \times 8{,}760} = 0.895, \text{ or } 89.5\%$$

There is no reserve at plant No 1, so that its capacity factor is the same as its load factor, namely, 89.5%. All the plants have been running for the whole year—8,760 hours—continuously. The plant use factor, therefore, is the same as the plant capacity factor or load factor. If the capacities of the units in the station and details of their operating schedule had been known, the plant use factor could have been calculated more accurately.

Plant No 2 supplies the remaining load ; the maximum demand on it is 7·5 MW and it is run for 40% of the year; its capacity is 10 MW. The area *abqa* under the curve represents the energy it produces. The load factor of plant No. 2 is the area *abqa* divided by the product of the maximum demand and the number of hours during which the plant is run. The area *abqa* represents 9,900,000 kWh.

$$\text{Load factor} = \frac{9{,}900{,}000}{7{,}500 \times 0.40 \times 8{,}760} = 0.376 \text{ or } 37.6\%$$

The load factor is on the basis of 40% of the time for which the plant is running during the year, as a peak-load plant.

If taken on the whole year basis

$$\text{Annual load factor} = \frac{9{,}900{,}000}{7{,}500 \times 8{,}760} = 0.15 \text{ or } 15\%$$

$$\text{Annual plant capacity factor} = \frac{9{,}900{,}000}{10{,}000 \times 8{,}760} = 0.113, \text{ or } 11.3\%$$

$$\text{Plant use factor} = \frac{9,900,000}{10,000 \times 0.4 \times 8,760} = 0.282 \text{ or } 28.2\%$$

The annual load factor of the whole system can also be found from the data—

Total energy generated = 98,000,000 + 9,900,000
= 107,900,000 kWh.

$$\text{Annual load factor of system} = \frac{107,900,000}{20,000 \times 8,760} = 0.615 \text{ or } 61.5\%$$

The load duration curve thus helps in choosing plants for base-load and peak-load operation for the required length of time. The load factors, plant capacity factors and plant use factors can be calculated from the load duration curve. From this information it is possible to study the financial aspects of supplying the system load. The cost of generation per kilowatt-hour for base-load plant and for the peak-load plant can be worked out. The capacity required in the base-load plant and peak-load plant, economical load-sharing between the two plants and the minimum combined cost per kilowatt-hour generated by the whole system can be determined. The load factor of the peak-load plant is much less than that of the base-load plant. It is cheaper to generate power at the higher load factor. The cost of energy to supply base-load is, therefore, less than the cost of energy to supply peak load.

The variable load problem affects power plant design and operation, and the cost of generation.

Factors affecting cost of generation and financial aspects of power stations are briefly discussed in the following sections.

2 5. Effect of Variable Load on Power Plant Operation and Design

When it is necessary to cope with a variation of load, the prime movers and generators have to act fairly, quickly and take up or shed load without variation of the voltage or frequency of the system. An important requirement is, therefore, the control of the supply of fuel to the prime mover by the action of the governor. When load on the generator is increased suddenly, the first effect is to slow down the rotor and, therefore, to reduce the frequency. The speed of the prime mover drops. The governor acts, admitting more fuel—enough to bring the speed back

to normal and pick up load. The governor may be set for such operation at the desired load. Exact adjustment of the governor setting may be controlled by means of an electric motor and a pilot valve. In a steam station, as the load increases, the demand for steam for the turbine driving the generator increases. The boiler unit has also to feed the necessary amount of steam to the turbine at the required pressure and temperature. The boiler unit, too, therefore, needs to be controlled. The control may be manual or automatic for admitting the necessary fuel, air, feed water, etc., so that the boiler may pick up the required load quickly. There is, however, a certain time lag; combustion controls should be quick to cope with the demand.

The equipment to be used for variable load conditions should be designed so that it operates at lower loads (half load or less) with nearly the same efficiency as at full load. The efficiency curve should not drop too much with changes of load. We have seen how to choose the size of various generator units to suit and fit portions of the predicted load curve. If this is done properly, the generator units can be run practically at the best points and percentage loads on the units can be in the best efficiency range of units. The same principles hold good for steam-station, Diesel and hydro-electric sets units. Diesel and hydro-electric sets are quick to respond to load variation, as the control required is only for the prime mover. In steam turbine sets control is required for the turbines as well as boilers. Boiler controls take time to act. The overall response in steam station control is, therefore, comparatively slow.

To suit variable load conditions, the generator units should have characteristics which enable them to run parallel without load shedding, i.e., without switching off part of the load. Variable load conditions also create operating problems. These are numerous, starting with the allotment of units to proper portions of the load curve, preparing operating schedules for the best use of the generator units, and trying to operate the plant to produce electrical energy as cheaply as possible. The rate for electricity supply to the consumers—the tariff—largely depends on the variable load

conditions. To cope with variable load operation, it is necessary for the utility undertaking to keep the reserve plant ready for taking load at any time the demand is made because reliability without interruption is an essential feature of power supply. This reserve is necessary for an individual or an isolated plant and is known as the spinning reserve. At steam stations in particular, it is also necessary to keep some boilers banked and ready to take up the load. Expenses are incurred in keeping the standby plant in running condition.

When the load on the system is large and a number of stations are interconnected, it is possible to choose the size of the plant in two or more stations in such a way that the whole load is supplied most economically. This can be done by choosing types of generating plant with different characteristics suitable for base-load and peak-load operation, and operating stations on the proper portions of the load duration curve; for example, hydro or Diesel-electric plant can be used as peak-load plant in preference to steam plant. This problem of the combined working of steam or other thermal stations and hydro-electric stations needs careful study and will be treated in detail in a later chapter. The variable load problem can be solved in some cases by partly generating and partly buying power, particularly for the peak-load portion of the curve, if supply from a Grid is available and if economics demands it.

2.6 Cost of Electrical Energy

The cost per kilowatt-hour of the electrical energy generated depends on the investment in the plants, distribution system, on operation, and maintenance costs. If reliability is required, the cost of the reserve plant increases the cost of the energy. Variable load conditions change the cost of energy produced under different conditions. If the load conditions differ too much from the ideal, the cost of the energy increases.

The cost of energy can be broadly divided into two parts. A portion of the cost is dependent on the installed capacity of the plant and is independent of the amount of energy produced. The second part depends on the energy production. Fixed costs and

costs proportional to energy can be subdivided for detailed study as follows.

2.6.1 FIXED COSTS

Capital cost of power plant. This includes the cost of land and other real estate, the cost of building and equipment, the cost of installation and the cost of designing and planning the station. The cost of plant differs with the type. A Diesel plant may cost from Rs 1,000 to Rs 1,400 per kW ; a modern steam plant costs Rs. 1000/- to Rs. 1,500 per kW; and the cost of hydro-electric plant might be as much as Rs. 1500/- to Rs. 2500/- per kW. The costs vary with the site and location of the station, the type of equipment, etc., they also vary to a great extent in time, depending partly on developments in equipment design and manufacturing techniques, but mainly on the state of the market.

If the power station is not located near the centre of gravity of the load, a transmission line or primary distribution system will be necessary. The costs of rights of way, of the transmission line and of substations would be included under this heading.

Interest on capital, taxes and insurance. In addition to interest on the capital to be invested in the power station, taxes have to be paid on land and property, the amount depending on the location. If the station is in the heart of a metropolis, the taxes will be high. Insurance charges, too, come under this heading. They will depend on the cost and capacity of the equipment and buildings. It is necessary to insure boilers and other equipment in the station against the risk of accidents. Charges for taxes and insurance may be taken as about 2% to 3% of the fixed costs.

Depreciation of equipment. The cost of depreciation will depend on the size and type of equipment and on its estimated life. This is considered in detail in Section 2.7.

General managerial costs. These include the expenditure on major items of general maintenance incurred even when there is no actual production of energy.

2.6.2 COSTS FOR ENERGY

The costs under this heading are those which are proportional to the electrical energy produced.

Cost of fuel. The fuel consumption depends on the amount of electrical energy produced. As the load on the prime movers increases, the fuel consumption increases and so, therefore, does the cost. The efficiency of the prime movers may not be the same at all loads, and thus when the generator units are run at loads much lower than those at which the efficiency is the best, the consumption of fuel is larger for the same amount of electrical energy, so that the cost of energy per kilowatt-hour increases. The cost of the fuel varies with the different types of fuel depending on their calorific values, availability and transportation charges.

Maintenance costs. Maintenance of plant is necessary to keep it in good condition. The whole cost of maintenance should really be classified under fixed costs but the practice is to take only the major maintenance costs as fixed costs; but minor costs or the whole of the maintenance costs if they form a negligible percentage of the total are taken as costs for energy.

Operation costs. The costs for the operation of plant, salaries of the staff and labour required for the purpose of operation are taken as energy costs. A certain minimum staff will, however, be necessary even at times when very little or no energy is produced.

Cost of water. The cost of water for feeding the boilers and circulating water for cooling the exhaust steam of the turbines in steam stations is proportional to the energy produced as the quantity of water required is dependent on the loading of the turbines.

Costs of consumable stores and materials. These, too, are taken as costs dependent on energy production.

2.6.3 CHARGES FOR ENERGY SUPPLIED TO CONSUMERS

When estimating the charges for supplying electrical energy to the consumers, the types of cost enumerated above are taken

into account. In addition, the cost of the secondary distribution system and of office accommodation have to be included. The extent of the secondary distribution system is proportional to the number of consumers it serves. The charge to each consumer on this account may be the cost of the secondary distribution system divided by the number of consumers, for whom the secondary distribution system has been constructed.

The investors in the business naturally expect some profit. With private companies, this may depend on business conditions and competition. With public utility undertakings, the State generally limits the maximum profit that may be earned. In either case, profit is another item to be considered when fixing the charges to the consumers.

2.7 Depreciation of Plant

The power plant and equipment in the station will have a certain period of useful life. After years of use, the equipment loses its efficiency or becomes obsolete and needs replacement. Sometimes, equipment may have to be changed even when fairly new, if more efficient equipment has come into the market. To enable this to be done when necessary, some money is put aside annually, and is known as the depreciation fund.

There are two methods of accumulating money for the depreciation fund, namely, the straight-line method, and the sinking-fund method. The straight-line method is based on the assumption that depreciation occurs uniformly every year according to a straight-line law. The money saved by this method neglects any interest on the sum during the period. The annual saving to be effected depends only on the amount required at the end of the useful life of the plant. The total amount saved during the life of the plant should be equal to the cost of the plant minus its salvage value at the end of life, if it has any. The present value of a plant at the end of any period can easily be seen to be the cost of the plant at the time of buying and installing it minus the depreciation value for the period of life that has expired.

Fig. 2.4 illustrates this simple, straight-line method of accumulating the depreciation reserve, the money for which is saved at a

uniform rate per year. From the diagram it will be seen that the value of the equipment, which is 100% initially, depreciates to only 15% at the end of its 100% useful years of life. The straight-line *AD* indicates the depreciation, and the slope of the line indi-

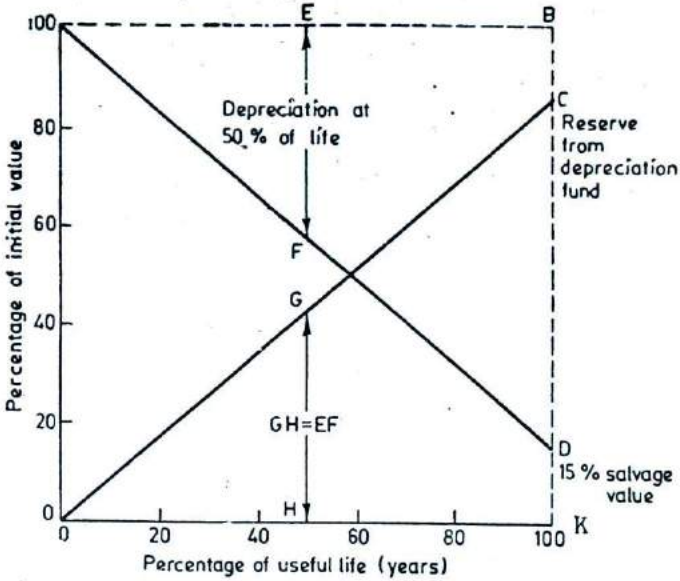


Fig. 2.4. Straight-line method.

cates the rate at which the plant depreciates. The depreciation at the end of 50% of useful life is *EF*, and the total depreciation at the end of 100% of useful life is *BD*. The line *OC* represents the depreciation reserve to be accumulated so that at the end of its useful life the total is *CK*, which is equal to the total depreciation, namely, *BD*. The annual rate of depreciation reserve is given by the slope of the line *OC*.

$$\text{Annual depreciation reserve rate} = \frac{\text{Total depreciation}}{\text{Total number of years of useful life}} \qquad (2.3)$$

The second way of dealing with depreciation is the sinking-fund method. A sinking-fund is a sum of money raised by setting aside from time to time—generally annually—and investing at com-

pound interest a certain sum for the purpose of paying off a particular liability upon a known future date. The sinking-fund method can also be represented by a diagram; this is shown in Fig. 2.5. The curve *OGC* shows the sinking-fund accumulating at a certain rate of compound interest. The total amount at the end of the useful life of the plant is given by the line *KC*, which is the initial cost of the plant minus its salvage value at the end of its useful life. The rate at which the sum is saved annually is not, however, the same as in the straight-line method, as the final sum consists of the annual instalments plus the compound interest on all instalments at the end of the whole period. *KC*= *BD*. The depreciation at the end of 50% of useful life is shown by *EF*, while the sinking fund saved at the end of 50% of useful life is shown by *GH*.

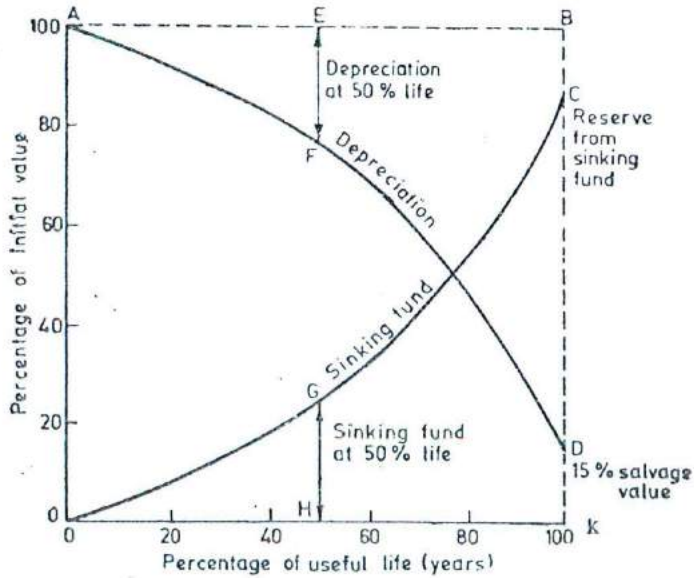


Fig. 2.5. Sinking-fund method.

The amount which should be set aside annually is given by the following expression—

$$\left.\begin{matrix}\text{Annual payment}\\ \text{to sinking-fund}\end{matrix}\right\} = (\text{Initial value} - \text{Salvage value})\frac{r}{(1+r^n)-1} \qquad (2.4)$$

where r is the annual rate of compound interest, and n is the number of years over which the total amount of depreciation is to be saved.

Example 2.4

A 100 KVA transformer with accessories costs Rs 13,000. If the life of the transformer is taken as 20 years, and the salvage value at the end of this period is taken as Rs 1,000, find the annual reserve fund required to be laid aside to take care of the depreciation of the plant by (i) Straight-line method and by (ii) Sinking-fund method. In case of the sinking-fund method, the rate of compound interest may be taken as 10% per annum.

(i) The life of the transformer is 20 years. The annual reserve for depreciation fund

$$= \frac{\text{(Initial value—salvage value)}}{\text{Life in years}}$$

$$= \frac{13,000-1,000}{20} = \text{Rs } 600/-$$

(ii) Annual payment of sinking-fund

$$= \text{(Initial value—salvage value)} \times \frac{r}{(1+r)^n-1}$$

Here $r = 10\%$ and $n = 20$

$$= \frac{(13,000-1,000)\times 0{\cdot}10}{(1+0{\cdot}10)^{20}-1} = \frac{1200}{6{\cdot}655-1}$$

$$= \frac{1200}{5{\cdot}655} = \text{Rs. } 212$$

Both methods show how the total amount can be saved to replace the equipment or plant at the end of its useful life. The life to be expected of the plant, apparatus or equipment has to be estimated from experience, and so, too, do the number of years of useful life used in the calculations. The life of transformers, motors and generators is normally taken as 20 years; steam turbines, about 20 years; and hydraulic turbines, about 30 years. The life of buildings and civil engineering works is much longer, this could be 50 years or more. The total average rate of depreciation of plant, equipment, auxiliaries, etc., for a station has to be computed and then used as the depreciation rate.

There is also another method of finding the depreciation and cost of the plant at the end of any year, the Reducing Balance Method.

Reducing Balance Method. Under this method, depreciation is written off at a fixed rate per cent on the reducing balance of the asset account as appearing at the commencement of each year so as to bring down the book value of the asset to its residual value by the time the asset becomes useless for revenue earning purposes. This method is usually adopted in the case of plant and machinery. As the fixed rate is calculated on the diminishing balance of the asset each year, it follows that the amount chargeable to revenue in respect of depreciation will become less and less as the years progress. It needs to be remembered, however, that in case of an asset of the nature of plant and machinery the amount of expense thereon annually in respect of repairs and renewals becomes heavier as the asset grows older. The advantage of this method of depreciation, therefore, lies in the fact that it tends to equalise the charge against revenue each year in respect of depreciation and repairs put together. Thus, whereas the amount of depreciation will be heavier during the earlier years, this will be counterbalanced by the amounts expended on repairs being lighter and as the years progress, though depreciation will be on the down grade, the amount chargeable in respect of repairs will become heavier as the asset grows older.

The method can be explained by an example.

Example 2.5

A piece of equipment costs Rs. 50,000. The depreciation is written off at a fixed rate of 10% per annum. Find the cost at the end of the first, second, and third year by the Reducing Balance Method.

Cost at the end of the first year = 50,000 − 10% of 50,000
= 50,000 − 5,000 = Rs. 45,000.

Cost at the end of the second year = 45,000 − 10% of 45,000
= 45,000 - 4,500 = Rs. 40,500

Cost at the end of third year = 40,5000 − 10% of 40,500
= 40,500 − 4,050 = Rs. 36,450.

2.8 Effect of Load Factor on Cost per Kilowatt-hour

When considering the cost per kilowatt-hour generated, it is essential to work out the total annual cost of the station, which, as explained in Section 2.6, consists of fixed costs and operating costs. We have seen that the fixed costs are proportional to the kilowatt capacity of the plant. The operating or energy costs are proportional to the total energy produced by the station annually. The fixed costs remain the same whether the station is running or idle. The fuel consumption and operating costs will, however, vary depending on operational conditions. At a 100% load factor, the installed capacity is used to the best possible extent and the maximum possible amount of energy is generated during the year. The total costs, both fixed and operating, are thus chargeable to all the energy produced during the year, when finding the total cost per kilowatt-hour generated. The fixed costs are distributed over the maximum amount of energy produced during the year, and thus the cost per kilowatt-hour is a minimum in this case. When the load factor is lower than 100%, less energy is produced by the same installed kilowatt capacity. The fixed costs remain the same, and although the operating costs may be less than when more energy is produced, the sum of the fixed and operating costs, when distributed over fewer kilowatt-hours at a smaller load factor, gives a higher cost per kilowatt-hour. The effect becomes more pronounced at lower load factors; a poor load factor increases the cost per kilowatt-hour. This is illustrated in the next example.

Example 2.6

The fixed costs of a thermal station are Rs. 262.80 p per kW of installed capacity per year. The fuel and operating costs are 3 p per kWh generated. Find the cost of the electrical energy generated per kilowatt-hour at Station load factors of 100%, 75%, 50% and 25%.

Plot the curve showing the variation of the cost of energy per kilowatt-hour generated.

Fixed costs per year per kilowatt = Rs. 262.80p.

$$\text{Fixed costs per hour} = \frac{26.280}{8,760} = 3\text{p.}$$

Thus, 1-kW capacity of the plant is available at a cost of 3p per hour whether the plant is in use or not; this charge is compul-

sory. The fuel and operating costs depend on the number of kilowatt-hours produced; the rate given is 3p per kWh. The energy produced is, however, dependent on the load factor. If a 1-kW plant is run for 1 hour at 100% load factor, it can produce 1 kWh; if run at 75% load factor, it can produce only 0.75 kWh; and so on. The cost per kilowatt-hour at different load factors can, therefore, be found as follows —

Load factor	Energy produced in 1 hour with 1 kW plant	Fixed cost per hour.	Fuel and operating cost per hour	Total cost per hour	Cost per kWh produced per hour
per cent	kWh	p	p	p	p
100	1	3	3	6	6
75	0.75	3	2.25	5.25	7
50	0.50	3	1.50	4.50	9
25	0.25	3	0.75	3.75	15

From these data a curve showing the relation between the load factor and the cost per kilowatt-hour has been plotted in Fig. 2.6, which clearly indicates that, as the load factor decreases the cost per kilowatt-hour increases-to 1.5 times at 50% load factor

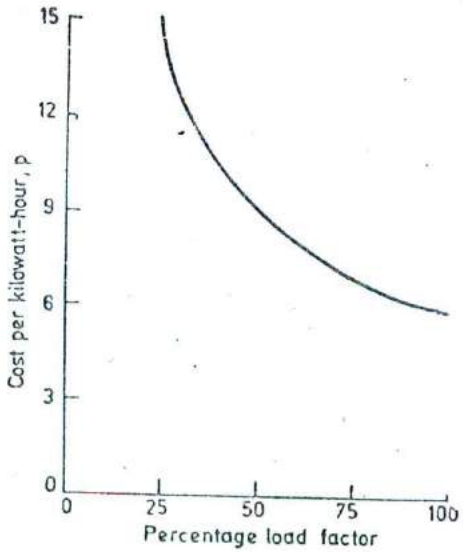


Fig. 2.6. Effect of load factor on cost of energy.

and 2.5 times at 25% load factor, as compared with the cost at 100% load factor.

If the fixed costs form a large proportion of the costs even at 100% load factor, this variation and increase in the cost per kilowatt-hour will be more pronounced.

2.9 Tariff or Charge to Consumer

The cost per kilowatt-hour of the energy generated can be estimated as outlined in the last two sections. When fixing the charge to the consumer, the fixed and operating costs pertaining to the distribution system and an allowance for a reasonable profit must be included.

Different methods of charging consumers are known as tariffs, or rates of payment for the consumption of electricity. It is reasonable to charge a consumer in accordance with his type of load, his maximum demand, the time at which the load is required and power factor of the load, as well as the amount of energy used. We have dealt with these points to show how they affect the plant and its economics.

Increase in maximum demand increases the capacity required in the station. The time at which the maximum demand occurs has an important effect. If a consumer's maximum demand occurs at a time other than that at which the maximum demand on the system occurs, it does not cost much to supply him with energy at that time, as it may not need an increase in plant capacity; moreover, such a load would improve the load factor, and this would help in reducing the overall cost per kilowatt-hour generated. If, however, his maximum demand coincides with the maximum demand on the system, more equipment will be needed in the station.

If the power factor of a load is low, it takes more current, the losses in the distribution and transmission system are correspondingly greater, the power station has to supply more current, and the system may need power-factor-correction and voltage-regulation equipment to maintain the required standard voltage within allowed limits, and thus the cost increases.

A larger amount of energy used for a longer period results in a lower cost of electrical energy.

Essentially, there are two different classes of customers, namely, residential and industrial. For residential (domestic) lighting loads, a flat rate is charged per-kilowatt-hour. For the heating load and domestic appliances of residential consumers, connexion is given through a separate meter, and the rate is much lower. This helps to develop the daytime load. To induce customers to use more energy, some power companies have two or more flat rates—the first few kilowatt-hours are charged at a certain rate, the next few at a slightly lower rate, the next few at a still lower rate, and so on. This type of tariff structure, however, is not universal.

In Britain, for example, a residential consumer's lighting and power circuits are fed through a single meter, and he is charged in accordance with a domestic two-part tariff, consisting of a fixed charge per quarter and a variable charge per kilowatt-hour supplied. In some parts of Britain domestic consumers may be charged less for energy used at night. Again there is only one meter but it has two sets of dials (day and night) selected automatically by means of a time switch.

By industrial consumers, we mean those who need more power and energy, and this for a longer time, than the usual residential consumers. The basis of charging industrial consumers is generally a two part tariff. One part of the charge is proportional to the maximum demand (kilowatts) because this affects the size of plant to be installed in the station and the corresponding fixed charges on the capital. The second part of the charge is proportional to the energy consumed (kilowatt-hours) monthly or annually.

Sometimes, a variation-of-price clause appears in the tariff to account for variation in the cost of fuel. For example, if the cost of coal falls below a certain level, the company supplying power from a steam station may offer a rebate in the charge for energy; if the price of coal increased beyond the level fixed, the charge for energy may be increased.

Consumers taking off-peak power may be given special cheap rates to help to improve the load factor of the system. Consumers whose power factor falls below a specified limit may be charged more or have a penalty clause in the rate structure. Alternatively, the consumers may be charged on a combined kilovolt-ampere-hour and kilowatt-hour basis.

The maximum demand of an industrial consumer is measured by means of a maximum demand meter which records the maximum load (kilowatts) during any 15 minutes or half-hour in a month or some other period. The energy used during the period for which charge is to be made is taken from the recorded readings of the energy meter. Another meter is also connected at the consumer's premises measuring reactive energy and is known as a reactive volt-ampere-hour meter, or varh meter. From the readings of the energy meter and the varh meter, the power factor of the load can be calculated. The load in kilowatts can then be converted to kilovolt-amperes if the charge is based on kilovolt-ampere demand. Meters indicating maximum kilovolt-ampere demand directly and trivector meters also are in use.

The trivector meter, which has been developed by Landis and Gyr (Switzerland), can measure (a) kilowatt-hours (with maximum demand) (b) kilovolt-ampere-hour (with maximum demand), or (c) kilovar-hours (with maximum demand) as required, depending on the way in which it is connected.

In fixing the rates for different types of consumer, all the points mentioned in this section are considered. The rates should be such as to promote more and more sales of electricity, and the rate structure should be arranged so as to help the system to have a better load factor and power factor so that electrical energy can be produced and sold more cheaply.

In the power station, it is necessary to have auxiliary equipment for operation and control, e.g., pumps, etc. The auxiliaries are mostly electrically driven and consume part of the energy generated. The amount varies in practice, depending on the particular auxiliaries used; it may be from 3% to 7% of the energy

generated. The energy available at the station busbars is, therefore, less by this amount.

The diversity between consumers and the transmission and distribution losses also affect the power and energy delivered to them. The effect of these factors on the cost of generation as well as on tariffs is illustrated by the the next two examples.

Example 2.7

The following data relate to a 10,000-kW thermal station.

Cost of plant	Rs. 1,200 per kW.
Interest, insurance and taxes	5% p. a.
Depreciation	5% p. a.
Cost of primary distribution system	Rs. 400,000.
interest, insurance, taxes and depreciation.	5% p. a.
Cost of coal, including transportation	Rs. 40 per metric ton.
Operating costs	Rs. 4,00,000 p. a.
Plant maintenace cost:	
Fixed	Rs. 20,000 p. a.
variable	Rs. 30,000 p. a.
Installed plant capacity	10,000 kW.
Maximum demand	9,000 kW.
Annual load factor	60%
Consumption of coal	25,300 metric tons.

Find the cost of power generation per kilowatt per year, the cost per kilowatt-hour generated, and the total cost of generation per kilowatt-hour. Transmission, or primary distribution is chargeable to generation.

Cost of plant=Cost per kW × capacity	Rs.	12,000,000
Interest, taxes and insurance at 5%	,,	6,00,000 p.a.
Depreciation at 5%	,,	6,00,000 p.a.
Cost of primary distribution	,,	4,00,000
Interest taxes, insurance and depreciation at 5%	,,	20,000 p.a.
Cost of 25,300 tons of coal at Rs. 40/-	,,	10,12,000 p.a.
Operating costs	,,	4,00,000 p.a.
Plant maintenance costs:		
Fixed	...	20,000 p.a.
Variable	...	30,000 p.a.

With a maximum demand of 9,000 kW and a load factor of 60%

$$\text{Energy generated} = \frac{9{,}000 \times 8.760 \times 60}{100} = 47.3 \times 10^6 \text{ kWh}$$

The above information provides the cost data of the plant. These can be separated into fixed and variable costs as follows:

Fixed Costs

		Rs. (p. a.)
Interest, taxes and insurance on plant	...	600,000
Depreciation of plant	...	600,000
Interest, taxes, insurance and depreciation on primary distribution.	...	20,000
Fixed part of maintenance	...	20,000
		1,240,000

Variable costs.

		Rs. (p. a.)
Coal	...	1,012,000
Operation	...	400,000
Variable part of maintenance	...	30,000
		1,442,000

The annual cost of generation may be expressed as the cost per kilowatt of power supplied and the cost per kilowatt-hour of energy generated. The fixed costs will be distributed over the load that the station can supply, while the variable costs will be distributed over the energy produced.

The Station supplies the maximum demand of 9,000 kW so that

$$\text{Cost per kW per year} = \frac{1,240,000}{9,000} = \text{Rs. } 138/-$$

The station generates 47.3×10^6 kW, so that

$$\text{Cost per kWh generated} = \frac{1,442,000}{47.3 \times 10^6} \times 100 \text{ p} = 3.06 \text{ p}$$

Thus it will cost Rs. 138/- per kW per year of demand at the power station, and the energy cost at the power station (including variable costs in addition to the cost per kilowatt demand) is 3.06p per kWh generated.

If the cost of generation is expressed only as cost per kilowatt-hour generated instead of in two components, as above, then the total costs must be divided by the total number of kilowatt-hours generated. The sum of the fixed and variable costs is 1,240,000 + 1,442,000 = Rs 2,682,000, so that

$$\text{Cost of generation per kWh} = \frac{2,682,000}{47.3 \times 10^6} \times 100 = 5.67 \text{ p.}$$

Example 2.8

The following additional data apply to the power system of Example 2.7.

Cost of secondary distribution	...	Rs. 600,000
Interest, insurance, taxes and depreciation	...	5% p. a.
Maintenance	...	Rs. 150,000 p. a.
Dividend to stockholders	...	Rs. 600,000 p. a.
Energy used by auxiliaries	...	3% of generated energy
Transmission and distribution losses	...	7% of generated energy
Diversity factor among consumers maximum demands	...	1.7

Devise a two-part tariff for the consumers, i.e., a tariff per kilowatt per year and per kilowatt-hour consumed.

Fixed Costs

		Rs. (p.a.)
From Example 2.7	...	1,240,000
Dividends	...	600,000
Interest, insurance, taxes and depreciation on secondary distribution	...	30,000
		1,870,000

Variable costs

From Example 2.7	1,442,000
Maintenance of secondary distribution	150,000
	1,592,000

The maximum demand on the station is 9,000 kW, and the diversity factor among the maximum demands of the consumers is 1.7 so that the sum of the maximum demands of the consumers is $1.7 \times 9{,}000 = 15{,}300$ kW.

The charge to the consumer per kilowatt per year is obtained by dividing the total fixed costs by the sum of the maximum demands:

$$\frac{1{,}870{,}000}{15{,}300} = 122.2 \text{ per kW per year.}$$

From example 2.7 the energy generated is 47.3×10^6 kWh per year, and the sum of the energy consumed by the auxiliaries and the transmission and distribution losses is $3\% + 7\% = 10\%$. The

energy actually sold is, therefore, 90% of the energy generated and is.

$$47.3 \times 10^6 \times 0.90 = 42.57 \times 10^6 \text{ kWh.}$$

The charge for energy is obtained by dividing the total variable costs by the total energy sold:

$$\frac{1,592,000}{42.57 \times 10^6} \times 100 = 3.73\ p \text{ per kWh}$$

Thus the charge to the consumer would be Rs. 122.2 per kW per year and 3.73 per kWh consumed.

Example 2.9

Instead of a two-part tariff, it might be desired to make a single charge based on the number of kilowatt-hours consumed. This is done by dividing the total cost per year by the energy sold during the year. The sum of the fixed and variable cost is

$$1,870,000 + 1,592,000 = 3,462,000$$

so that the rate is

$$\frac{3,462,000}{42.57 \times 10^6} 100 = 8.14 \text{ per kWh}$$

References

2.1. JUSTIN and MERVINE, *Power Supply Economics* (Wiley, 1934)
2.2. MORSE, F. T., *Power Plant Engineering* (Van Nostrand, 1957)

Problems

2.1 Discuss considerations influencing the choice of the type of power station.

2.2 Define "annual plant capacity factor" and "annual plant use factor" of a power station.

State the effect of these factors on the choice of the size of generator units, the number of units, the reserve capacity of plant, and the operating schedule of the station.

2.3 A generating station has a maximum demand of 10,000 kW and the daily load on the station is as follows:

	kW		kW
11 p.m. to 6 a.m.	2,000	1 p.m. to 5 p.m.	7,500
6 a.m. to 8 a.m.	3,500	5 p.m. to 7 p.m.	8,500
8 a.m. to 12 noon	8,000	7 p.m. to 9 p.m.	10,000
12 noon to 1 p.m,	3,000	9 p.m. to 11 p.m.	4,500

Choose the size and number of generator units. What reserve plant would be necessary? Find the load factor, plant capacity factor and plant use factor of the station. Draw up the operating schedule. (Ans. Three units of 5,000, 2,500 and, 2.500 kW capacity; one reserve unit of 5,000 kW capacity. Load factor, 55% plant capacity factor, 36. 66%; plant use factor, 86.5%).

2.4 A power station has a maximum demand of 15,000 kW, a load factor of 70%, a plant capacity factor of 52.5% and a plant use factor of 85%. Find (*a*) the daily energy produced, (*b*) the reserve capacity of the plant, (*c*) the maximum energy that could be produced daily if the plant were in use all the time, and (*d*) the maximum energy that could be produced daily if the plant, operating in accordance with operating schedule, is fully loaded when in operation (Ans. (*a*) 2,52,000 kWh; (*b*) 5,000 kW; (*c*) 4,80,000 kWh; (*d*) 2,97,000 kWh).

2.5 Explain the method of constructing a load duration curve using a load curve.

The following data were collected from the daily load curves of a power system during a year:

Load	*Duration*
kW	hours
15,000	87
12,000 and over	876
10,000 and over	1,752
8,000 and over	2,628
6,000 and over	4,380
4,000 and over	7,000
2,000 and over	8,760

Construct the annual load duration curve and find the load factor of the system (Ans. 46.8%).

2.6 If the load in problem 2.5 is supplied by two plants, one acting as a base load plant and having a capacity of 10,000 kW and the other acting as a peak load plant and having a capacity of 7,500 kW, find the annual load factor, annual plant capacity factor and annual plant use factor of each station. (Ans. 10,000-kW plant; annual load factor, 84%; annual plant capacity factor 84%; annual plant use factor, 84%. 7500 kW plant; annual load factor 9.3%annual capacity factor, 6.2%; annual plant use factor 31%.)

2.7. Explain the effect of variable load on (*a*) power plant operation, and (*b*) power plant design. Illustrate by an example.

2.8. Describe the methods of determining the depreciation of electrical power plant.

A plant costing Rs. 65,000 has a useful life of 15 years. Find the amount which should be saved annually to replace the equipment at the end of that time (*a*) by the straight-line method, and (*b*) by the sinking-fund method if the annual rate of compound interest is 5%.

Assume that the salvage value of the equipment is Rs. 5,000 (Ans. (*a*) Rs. 4,000; (*b*) Rs. 2,780).

2.9. Explain the effect of the load factor of an electric power station on the cost per kilowatt-hour generated.

A power station has installed capacity of 20,000 kW. The cost of the station is Rs. 1200/- per kW. The fixed costs are 13% of the cost of investment. On full load at 100% load factor, the variable costs of the station per year are 1.5 times the fixed costs. Assume that there is no reserve capacity of plant and that the variable costs are proportional to the energy production.

Find the cost of generation per kilowatt-hour at load factors of 100%, 80%, 60%, 40%, and 20%. Plot the curve. (Ans. Load factors and costs per kilowatt-hour: 100%, 4.46 p; 80%, 4.90 p; 60%, 5.65 p; 40%, 7.15 p; 20%, 11.5 p.)

2.10. Explain the term "two-part tariff"

The power station of Problem 2.9 supplies load to consumers. The cost of the distribution system increases the fixed cost by 75% (this includes payment of dividend to stock-holders) and the variable cost on full load at 100% load factor (at the station) by 20%. Work out the two-part tariff per kilowatt per month and per kilowatt-hour consumed, when (*a*) the load factor is 80% and (i) the diversity factor among consumers is 2.3, and (ii) the diversity factor among consumers 1.75; (*b*) the load factor is 60% and (i) the diversity factor among consumers is 2.3 and (ii) the diversity factor among consumer is 1.75. The losses in the distribution system may be taken as 10%. (Ans. (*a*) (i) Rs. 9.75 p per kW per month and 3.59 p per kWh; (ii) Rs. 12.8 p per kW per month, and 3.59 p per kWh (*b*) (i) Rs. 9.75 p per kW per month and 3.59 p per kWh (ii) Rs. 12.8 p per kW per month and 3.59 p per kWh.)

3

Diesel-electric Stations : Preliminary Design

3.1 Field of Use

Diesel-electric stations have some advantages over other types of stations, particularly in comparatively small sizes. A Diesel station can be started and stopped quickly, as and when required. It does not need any warming period, and need not be kept running for a long time before picking up load. There are thus no standby losses, as in steam stations. A Diesel station does not need a large amount of water for cooling. The Diesel station, therefore, finds application in localities where fuel costs are low, where oil is cheaper than coal, where water supply is limited, and where loads are relatively small so that they can be handled by a plant of small capacity. If a Grid system is not available in the vicinity, the Diesel station has definite advantages under the above conditions.

The main applications of Diesel-electric plants are as follows:

Central station. The use of a Diesel-electric station as a central station is limited to cases where the plant capacity is not large. Stations of this type in common use have capacities upto about 5000 kW. The limit will be decided by the economics of the cost of plant and the local conditions regarding the various factors mentioned above.

Standby plant. A Diesel station may be used as a standby plant to supply part of the load in a power system when required. For example, if a hydro-electric station is the main source of power supply and falls short of water at sufficient head owing to reduced

rainfall, and the level of water in the reservoir goes down, a Diesel station may be run in parallel with the hydro-station. The capacity of the Diesel-station need be no larger than necessary to supply part of the non-firm load on the hydro-station.

A Diesel station can also be used in conjunction with a steam station as a standby plant to pick up load quickly in case of steam plant failure or sudden increase of load. The advantage of the Diesel plant is that it can be started and put on load quickly.

Peak-load plant. A Diesel station can be used to supply peak load on the power system while the base load is supplied by a steam or hydro-station. The base load factor will thus be improved and the cost of electrical energy per kilowatt-hour will be reduced. The Diesel station is particularly suitable for supplying a load of low load factor. Its characteristics of quick starting and absence of standby losses are very useful in this respect.

Emergency plant. If the main station plants were steam or hydro-electric, and if, owing to certain faults, the main generators were off and the supply completely failed, it would be difficult to supply power to auxiliaries and to essential equipment in the station to enable it to start again. Diesel plant is handy in such circumstances. A small Diesel plant may be installed in a large station to supply essential auxiliaries in case of main supply failure. Arrangements can be made to start the Diesel plant automatically.

Private power plant for small industries. Diesel-electric power plants can be used as private industrial plants supplying electric power to factories. If the capacity requirements are within the limits set by the size of the Diesel units available, the Diesel plant has an advantage over the steam plant. The Diesel plant requires much less water than a steam plant of equal capacity; its other advantages have already been mentioned. The Diesel plant can be conveniently run for shorter periods when required, or for seasonal loads. The reserve capacity for a Diesel plant used in this way depends on the processes in the particular industries, e.g., whether it is absolutely necessary to maintain constant frequency or whether a slight variation would be acceptable, whether continuity

and reliability of supply is essential for all 24 hours of the day or whether some interruption is permissible. Where it is not absolutely necessary to be as rigorous about continuity of supply as in public utility systems, there is no need for reserve plant, so that the cost of the power produced is lower. Small power consumers may thus get cheaper power by installing a Diesel plant instead of other types of plant, and rather than buying power from utility companies or a Grid system.

Nursery stations. In India, a large number of power projects are being developed under various five-year plans, and they are interconnected wherever possible to form a Grid system. This helps to make the power available to a large area and to a number of places. Unless there is enough load, it is, however, not possible to extend the Grid immediately to every village and corner of the country. During the process of development, a small Diesel unit may be temporarily installed to supply the load of a village or small town, including the farm load. When the load develops and the Grid supply becomes available, the power requirements of the village or town can be tapped off the Grid and the Diesel set can be moved to another area which needs power on a small scale and where the Grid supply is not available. The Diesel stations used in this way are known as 'nursery stations'.

Power to sparsely populated areas. A Diesel plant can be used to supply a sparsely populated area where only one transmission line is economically justifiable, to maintain continuity of supply in case the line should fail. Continuity of supply can be maintained by starting the Diesel plant as soon as the transmission line fails or the voltage drops below the permissible limit. In either event the Diesel plant can be started automatically.

For communities which have limited loads and are remote from the existing transmission facilities, it may often be cheaper to take power from a local Diesel station than to construct long transmission lines.

3.2 Diesel Engines : Principle of Working

The Diesel engine may work on a 4-stroke cycle, i.e., suction, compression, ignition and expansion and exhaust. In the first stroke

the air is sucked into the cylinder. In the second stroke the air in the cylinder is compressed, the suction valve being closed; and owing to compression the temperature of the air increases. At the end of this compression stroke, fuel oil is injected into the cylinder, where it is ignited by the heat of compression, and produces work by driving the piston. This is the third stroke, which produces work by expansion of the gases. When the work is done, the combustion gases are released as exhaust, and this is effected in the fourth stroke. Then the whole cycle is repeated. Only one stroke in four, i.e., the third is effective. In the ideal case, the Diesel engine works on the air standard cycle. The ideal pressure/volume diagram—indicator diagram –is shown in Fig. 3.1.

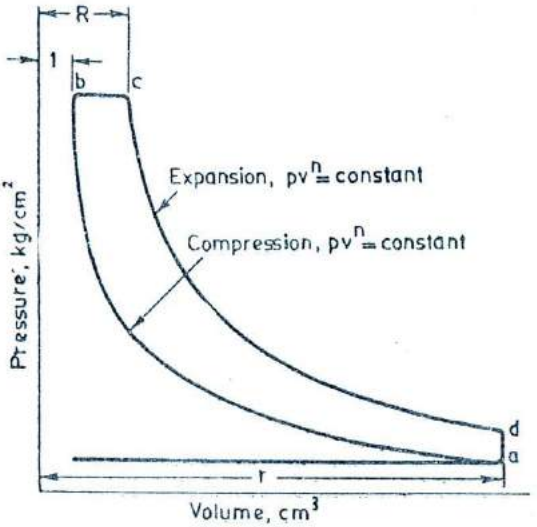


Fig. 3.1. Pressure/volume diagram of air standard cycle.

At the end of the first stroke, the cylinder volume V_a, and also the volume of air inside the cylinder is represented by point a. The ratio of the volume of air at the end of the first stroke to the volume of air at the end of the second stroke is known as the compression ratio (r). The air in the cylinder is compressed adiabatically to point b according to the law $pv^n = a$ constant. The compression ratio is $V_a/V_b = r$. The fuel is admitted and ignited at

the beginning of the third stroke; $b\,c$ represents part of the expansion under constant pressure. The fuel oil supply is cut off at the point c. The ratio of the volume, V_c, at the cut-off point to the volume before the beginning of the third stroke is known as the cut-off ratio (R): $V_c/V_b=R$. After the fuel is cut off, the gases under pressure do effective work and expand to the point d according to the law $pv^n=a$ constant : $d\,a$ represents the exhaust stroke, in which the products of combustion are removed from the cylinder. The air is again sucked in and the process repeated.

The mean effective pressure during this 4-stroke cycle is given by the average height of the indicator diagram, and the area of the diagram represents the work done during the cycle. In the ideal air standard cycle, the index n in the expression $pv^n=a$ constant is the ratio of the specific heat of air at constant pressure to that at constant volume, and is given the special symbol γ. For air $\gamma=1.4$. In practice, n for a Diesel engine is 1.35 approximately.

The mean effective pressure p_m is the ideal case where $n=\gamma$, is given by

$$p_m=p_a r\left[\frac{\gamma r^{\gamma-1}(R-1)-(R^\gamma-1)}{(r-1)(\gamma-1)}\right] \qquad (3.1)$$

and the ideal efficiency, η, is given by

$$\eta=1-\frac{1}{\gamma r^{\gamma-1}}\left[\frac{R^\gamma-1}{R-1}\right] \qquad (3.2)$$

Diesel engines can extract more useful work from each heat unit put in than other types of engine. The cylinders need cooling, as considerable heat is produced during compression and iguition. Generally the cylinders are provided with jackets, through which cold water is circulated.

The fuel is injected into the cylinder at the proper time after compression. This is done either by the use of compressed air from outside at a pressure of about 70 kg/cm² (air injection) or by injecting the fuel by means of a high pressure pump (airless injection). In this method, the fuel is sprayed into the cylinder at a pressure of 100 to 140 kg/cm². This is the better method as it

does not need a continuous supply of compressed air. Also atomization of fuel by spraying it into the cylinder at the higher pressure produces better combustion.

The engine is governed by adjusting the fuel to suit the load. The governing is effected by variable by-pass or suction, keeping the stroke constant: the variable-stroke method is seldom used.

The 4-stroke Diesel engine produces fluctuation of speed to a certain extent as only one of the four strokes is a power stroke. The fluctuation can be smoothed out if the flywheel has a large enough moment of inertia. The flywheel stores energy during the power stroke and returns it to the engine during the remainder of the cycle, so that the speed is fairly uniform.

Some Diesel engines work on the *2-stroke cycle*, in which there is no suction stroke or exhaust stroke. The inlet and exhaust ports are placed diametrically opposite to each other at the low-pressure end of the cylinder. Pure air is compressed in the crank case by the piston during its working stroke. As the piston descends during this stroke it opens the inlet and exhaust ports and admits a blast of high-pressure charge. The shape of the piston head is such that the movement of the piston helps in forcing the burnt gases through the exhaust port and completes the scavenging action. On the return stroke, the inlet and exhaust ports are closed, and the new charge is compressed ready for injection. The engine has a working stroke during each revolution of the crankshaft.

Two-stroke engines have the following advantages: (a) theoretically, the power developed is twice that developed in a 4-stroke engine of the same dimensions: and (b) the torque on the crankshaft is uniform and the cyclic irregularity of the 4-stroke engine is practically eliminated.

3.3 Choice of Diesel Engine

Frame. The engines are available in horizontal or vertical frames. Horizontal engines, however, are used for comparatively small sizes. A box-type frame is standard. Vertical engines with multicylinder construction are common in large sizes.

Speed. The engines are available in low, medium and high speed ranges. Low and medium speed engines, from 200 to 1,000 rev/min, are quite common and the tendency is to use these in central stations. Speeds commonly used are in the range from 500 to 1,000 rev/min. Small and medium capacity units with speeds of 1,000 to 3,000 rev/min have very little application.

Number of cylinders. The cylinders may be either horizontal or vertical, but are usually vertical. In large engines, each cylinder is generally designed for a maximum power of about 75 kW or in some cases 110 kW. When the power required is larger than this it is usual to add more cylinders : 6 to 8-cylinder engines are common in power stations. In other words, the common practice is to have a fixed bore and stroke, and to increase the number of cylinders when more power is required. The cylinders are arranged in line.

Rating of engine. The capacity of any cylinder to produce power is determined by the quantity of fuel that can be burnt in it efficiently during each power stroke without creating excessive temperatures in the piston, cylinder walls or cylinder heads. A smoky exhaust indicates incomplete combustion. Sufficient air must be available to permit complete combustion of the fuel charge.

The rating of an ne which should be specified correctly is the net output in kilowatts developed continuously at the crankshaft coupling by the engine in good operating condition, at a height of less than 450 m, at a temperature of 32°C and a barometric pressure of 717.5 mm. Hg. This is the standard sea-level rating. The full-load capacity of a Diesel engine varies with altitude, decreasing as the altitude increases. Loss of capacity can be compensated by supercharging.

For power plant service, the rating should be such that the engine will be capable of delivering at least 10% in excess of its standard commercial sea-level rating. A large engine should be capable of taking this overload for at least two hours with safe operating temperatures.

Capacity of engine. Diesel engines are available in sizes from 75 kW to 3,750 kW. Engines of suitable capacity can be chosen when the approximate capacity of the generator units has been decided from the nature of the load curve. If the engine is to drive auxiliaries such as the air-injection compressor for an air-injection engine, the scavenging air pump for a 2 stroke engine, pumps for circulating lubricating oil or piston cooling oil, the power required to drive these auxiliaries must be deducted to obtain the net power available to drive the generator.

Other factors. The other factors in deciding the choice of engine capacities will be the needs of the consumers and the investment costs.

Specifications. The specification for engines required in a Diesel electric station will cover the following points—

Number of engines required. Capacity of each engine (Kilowatts)—Constant or intermittent rating.

Type of service for which the engine is to be used.

Type of fuel.

Limitations of speed, elevation above sea-level, size and type of crane available, type and speed range of governing.

Electrical generators, their capacities and mechanical and electrical characteristics.

Floor area. An increase in the capacity of a Diesel engine increases its dimensions, as the number of cylinders required will be greater. The capacity of each engine is limited and more engines will have to be installed in a station of larger capacity. This requires more floor area. (On the other hand, a steam turbine plant is compact and its physical dimensions do not increase in proportion to its capacity; large units are available). The floor area in a Diesel station increases nearly in the same proportion as its capacity. This fixes the economic limit to the size of the Diesel station.

Cycles. Most of the Diesel engines installed at present are 4-stroke. Two-stroke engines have less variation of speed and

have more constant speed compared to the 4-stroke type. Two-stroke engines do not have double capacity per engine size, but they have more or less the same thermal efficiency as 4-stroke engines. Two-stroke engines need scavenging pumps to drive out the exhaust gases. The size of the 2-stroke engines available is limited. When larger sizes become available they may be preferred for driving generators in power stations.

Super-charging. The power that an engine can develop per cylinder can be increased by means of super-charging, without the necessity of altering stroke, bore or speed. The super-charging process improves the combustion of fuel by increasing the weight of air charge in the cylinder at the start of compression. When a greater weight of air is available to effect combustion, a greater quantity of fuel can be burnt in the cylinder during each power stroke without change in the efficiency of combustion, or in the mean temperature of the piston, cylinder or engine parts. Thus more power is produced. Super-charging is employed to increase the rated power output capacity of a given engine or to make the rating at high altitudes correspond to the unsuper-charged sea-level rating. To effect super-charging, power is needed for driving the compressor which provides the super-charged air.

3.4 Characteristics of Diesel Engines

Power output and altitude. The rated output of a Diesel engine is reduced at higher altitudes. Upto 450 m altitude, the rating is the same as that at sea-level.

Fig 3.2 shows the rating of a Diesel engine at various altitudes. At 2,750 m, the rating is reduced to 70% of its sea-level rating, at 3,650 m to about 60%.

In considering the required capacity of a Diesel engine, the altitude should be taken into account. If the rating at a particular altitude is too low, the engine should be super-charged.

Engine output. If an indicator diagram is taken for the engine, the area under the curve represents the amount of work done during a cycle; the power obtained from this information is

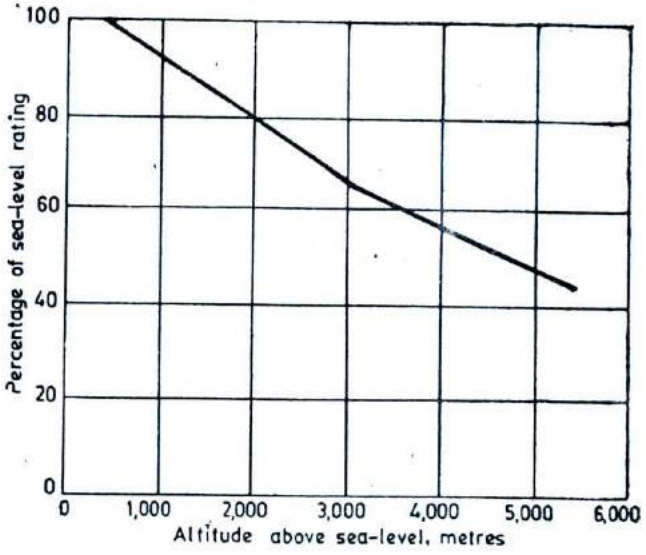


Fig. 3.2. Derating of Diesel engines for altitude.

known as indicated power. The indicated thermal efficiency is the ratio of the heat equivalent of the indicated work performed by the engine to the heat input during the same time—

$$\text{Thermal efficiency} = \frac{859{\cdot}85^{*} \times \text{Indicated power (kW)}}{\left\{\begin{matrix}\text{Weight of} \\ \text{fuel (kg)}\end{matrix}\right\} \times \left\{\begin{matrix}\text{Heat per unit} \\ \text{weight of fuel} \\ \text{per hour (kcal)}\end{matrix}\right\}} \quad (3{\cdot}3)$$

Power at the brake or brake power, is the power measured at the pulley; this is the difference between the indicated power and the power corresponding to the losses.

$$\text{Brake power (kW)} = \text{Indicated power (kW)} - \text{Losses (kW)}. \quad (3.4)$$

The indicated thermal efficiency of a Diesel engine may be as high as 40%. The brake thermal efficiency is the ratio of the heat equivalent of the power at the brake during a certain time to the heat input during the same time.

*1 kW = 859·85 kcal/h.

$$\text{Brake thermal efficiency} = \frac{859{\cdot}85 \times \text{Brake power (kW)}}{\left\{\begin{matrix}\text{Weight of} \\ \text{fuel (kg)}\end{matrix}\right\} \times \left\{\begin{matrix}\text{Heat per unit} \\ \text{weight of fuel} \\ \text{per hour (kcal)}\end{matrix}\right\}} \quad (3{\cdot}5)$$

Brake thermal efficiency is also known as *overall efficiency*.

$$\text{Mechanical efficiency} = \frac{\text{Brake power}}{\text{Indicated power}} \quad (3{\cdot}6)$$

Fuel heat input. Heat is produced in the engine owing to the burning of fuel. The engine converts this heat input into mechanical energy or work, at the coupling. The consumption of fuel oil depends on the load on the engine. From half load to full load the Diesel engine has a nearly flat efficiency characteristic and the fuel consumption increases very little. Fig. 3.3 shows the consumption of fuel oil per unit of output energy plotted against the percentage of rated load on the engine.

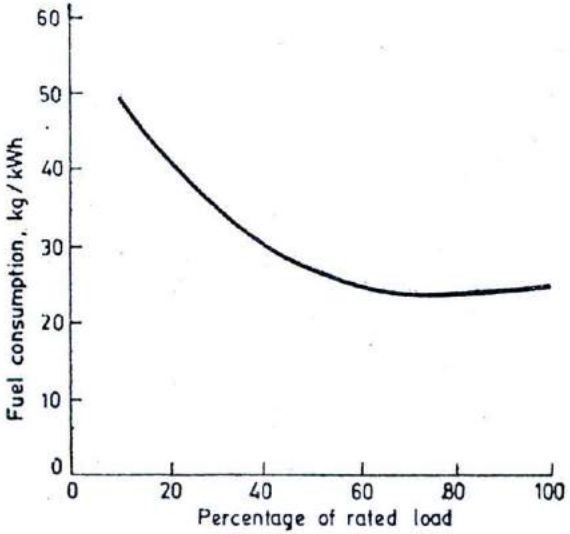


Fig. 3.3. Fuel consumption of Diesel engine.

As the load is reduced to less than 50% the rate of fuel consumption increases, and at very low loads it increases very

rapidly. Compared to other types of prime mover the performance illustrated by this type of curve is much better and the thermal efficiency is higher. It is, however, uneconomical to run Diesel engines at loads of 10% or less. Fig. 3.4 shows the electrical energy produced by the coupled set per unit weight of fuel oil plotted against the plant capacity factor. It can be seen that operation is best at 100% plant capacity factor.

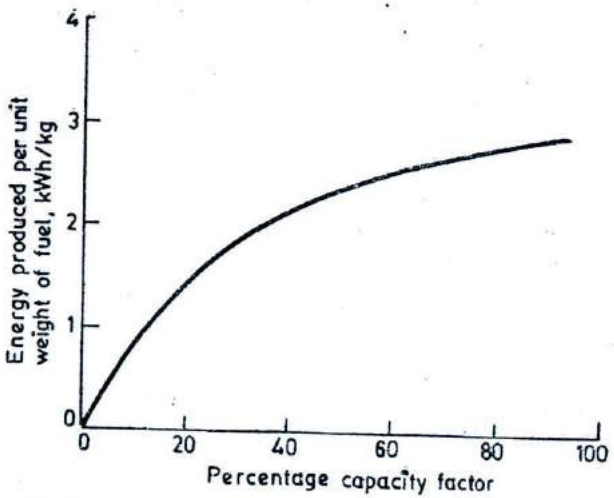


Fig. 3.4. Electrical energy produced by Diesel plant per unit weight of fuel.

Heat to exhaust gases. After useful work has been done, the products of combustion are cleared from the cylinder to make way for fresh air to be sucked in. Part of the heat is lost to these exhaust gases. If the combustion is complete the exhaust is clear; if it is incomplete the exhaust is smoky, and more heat is wasted in the exhaust gases. The exhaust of Diesel engines is noisy and objectionable; silencers should be fitted to reduce the noise.

Heat to cooling water. Owing to compression, the cylinder walls get very hot and cooling is necessary. This is provided by circulating water through the cylinder jackets. During the process, part of the heat is wasted in heating the water.

Heat lost in friction, etc. Part of the heat is lost in overcoming friction, and in radiation, etc.

The heat input less the losses due to the above causes, namely, heat to exhaust gases, heat to cooling water, heat lost owing to friction, radiation, etc., gives the useful brake power.

A typical heat balance sheet of a Diesel engine is as shown below. The heat input may be taken as 100%, the amount of heat required for the various items being shown as percentages of this input.

Heat Balance Sheet

Useful output	33 to 40
Heat lost to cooling water	32 to 30
Heat lost in exhaust gases	30 to 23
Heat lost in friction, radiation, etc.	5 to 7
Total heat input	100

It will be seen from this balance sheet that the brake thermal or overall efficiency of the engine is from 33 to 40%. To obtain this efficiency and useful work from the engine, it is necessary to maintain a clear exhaust and to reduce the heat lost to exhaust gases as much as possible. The limit is about 23% to 30%. It is necessary to provide enough cooling water to prevent the cylinder from reaching excessive temperature. Water circulated through the cylinder jackets can be cooled outside by suitable arrangements and then recirculated through the jackets. The heat lost owing to friction, radiation and unaccounted factors should be reduced to a minimum by providing good lubrication at the bearings, which also ensures that the wear and tear is minimum.

The amount of lubricating oil required is about 1 kg for each 300 to 450 kWh.

3.5 Fuel Requirement of Diesel Engines

Fig 3.4 helps in predicting the fuel-oil consumption for a particular station working at different load factors or having different capacity factors. The fuel consumption during the whole year can be found from the load duration curve. Fig 3.5 (bottom

right-hand corner) shows the load duration curve of a particular station. The maximum load during the year is 1,000 kW, and any other point on the curve represents the loa d that exists on the plant for the corresponding percentage of time. One way of finding the total oil consumption during the year is to find the annual capacity factor from the load duration curve. The area under the curve represents the total energy produced during the year, and if the capacity is the same as the maximum load on the station, no reserve, the ratio of the area under the curve to the area representing the maximum load or capacity of plant multiplied by 8,760 hours will give the annual capacity factor. Using Fig 3.4 find the

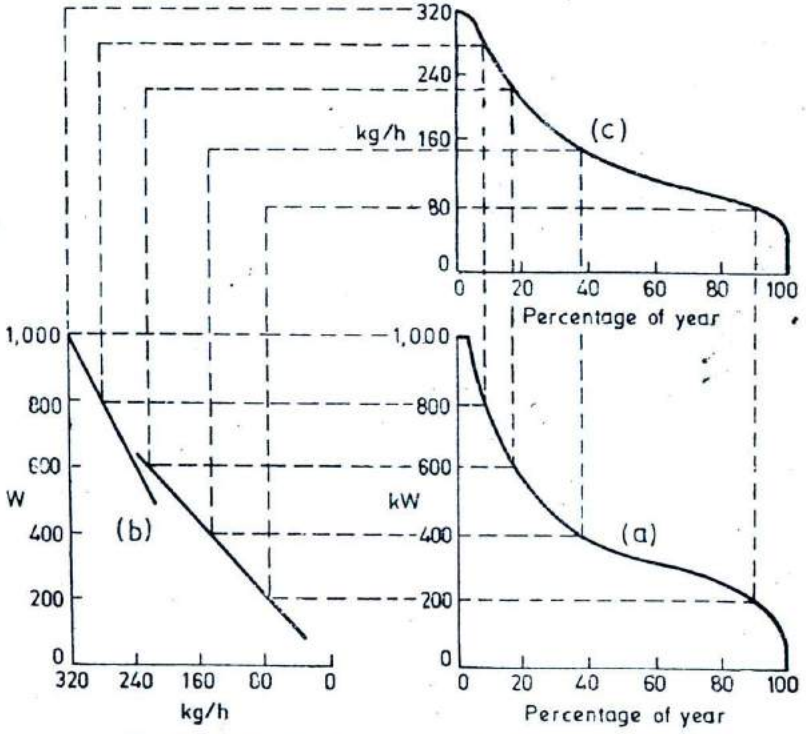


Fig. 3.5. Annual fuel consumption of a Diesel station.

(*a*) Load duration curve
(*b*) Output/input characteristic
(*c*) Fuel-consumption/time curve

number of kilowatt-hours produced per kilogram of fuel oil at this particular capacity factor. Knowing the number of kilowatt-hours produced during the year, find the total oil consumption during the year. This, however, is an approximation as the annual capacity factor is assumed to be the same as the average capacity factor throughout the year. Actually, if we take various strips of load duration curve, the load factor as well as the capacity factors of loads corresponding to various strips lasting for the length of time chosen varies, and the rate of fuel consumption varies correspondingly.

On the left-hand side of the load duration curve in Fig. 3.5 is shown the output/input characteristic, i.e., kilowatt output plotted against fuel oil consumption in kilograms per hour to supply this load. This is shown as two lines—practically straight – one from full load to nearly half-load, and the other over the remaining range. The consumption of fuel oil is greater where the capacity factor is low. When the load duration curve and output/input curve are drawn as in Fig. 3.5, it is very easy to find the total oil consumption during the year graphically. For example, the point 400 kW on the load duration curve shows that this load occurs for 38% of the year. Projecting this point horizontally, the output/input curve gives 148 kg per hour as the rate of input for this load. Projecting this and the percentage time point to the graph at the top right-hand corner of the diagram, it is clearly seen that 148 kg per hour is the rate of fuel consumption for 38% of the year. A number of the points on the two bottom curves can thus be transferred to obtain the curve showing the fuel consumption in kilograms per hour against a percentage of the year. The area under this curve represents the total consumption during the year.

3.6 Cooling Water Requirements of Diesel Engines

From the general heat balance of a Diesel engine, it is seen that about 30% of the heat is lost to the cooling water. This is, however, necessary to maintain the temperatures of the piston, cylinder and other parts within the permissible range. It is necessary to find the weight of water required per hour or per minute, the inlet and outlet temperatures of the water, and the

methods of cooling the water after it has absorbed heat from the cylinder walls. The maximum allowable difference between the inlet and outlet temperatures of cooling water is normally 11°C. Some engines need water for cooling the lubricating oil and exhaust gases in addition to its main purpose of cooling the cylinder walls. The total amount of heat to be removed in kilo calories should first be found for one hour at a particular load. This is 30% of the heat in each kilogram of fuel multiplied by the consumption of fuel in kilograms per hour at that load, plus the heat to be removed to a certain extent (about 10%) from the exhaust gases and lubricating oil. This is the heat which should be transferred to the water.

$$\left\{\begin{matrix}\text{Heat transferred}\\ \text{to water (kcal)}\end{matrix}\right\} = \left\{\begin{matrix}\text{Weight of}\\ \text{water (kg)}\end{matrix}\right\} \times \left\{\begin{matrix}\text{Difference between inlet and}\\ \text{outlet temperatures (11°C)}\end{matrix}\right\} \quad (3.7)$$

The amount of water in kilograms or litres per hour or minute can thus be found. This determines the capacity of the pump required to circulate the water. The maximum water outlet temperatures allowed are 49°C for single-circuit cooling systems and 60°C for double-circuit cooling systems.

For good cooling of a Diesel engine, the following points may be noted:

1. There should be a continuous flow of water throughout the operation of the engine. When the load on the engine increases, the amount of cooling water required is greater.
2. The temperature rise of the cooling water should be limited to 11°C.
3. Water for cooling cylinder jackets should be free from scale-forming impurities.
4. Water for cooling cylinder jackets should not be corrosive to metals.
5. The temperature of the water leaving the engine must not be more than 60°C.

If the quantity of water passing through the cylinder jacket is kept the same at all loads, the inlet and outlet temperatures will vary with the load on the engine.

Methods of cooling water. It may be possible to locate the Diesel station on the bank of a lake or river, and to use the water thus provided. The suction and intake to the engine can then be taken from a point in the river located upstream, the hot water being discharged at a lower point downstream. If sufficient water is available at all times, it can be circulated by means of pumps and need not be cooled and used again.

Another method of arranging the supply of cooling water is to have a cooling-water pond. The water is pumped from the pond and the hot water is delivered back to the pond. If the surface area of the pond is made large enough for most of the cooling to take place at the surface, the temperature of the pond water as a whole will be fairly low and it can be used over and over again. If the evaporating surface and the rate of cooling are to be increased, spray ponds are used. The hot water is delivered through a number of spray nozzles at a height above the pond. The spray distributes the water in smaller amounts and helps in cooling it more quickly, so that the temperature of the pond water as a whole remains low enough for the water to be pumped back into the engine cooling system.

Cooling towers are seldom required at Diesel stations. They are used for very large stations where a large quantity of water is required, and for stations located in places where water is scarce, so that whatever water is available has to be used very sparingly. Evaporation, and hence cooling of the water, increases with the area of the surface and the velocity at which the water falls. The structure of the tower helps in providing a good draught, and this further promotes the cooling action.

3.7 Main Dimensions of Diesel Engines

The main dimensions of an engine are the diameter of the cylinder bore and the length of stroke. Speed should be included in the specification. Diesel engines are classified as low-speed, medium-speed and high-speed. In this classification, piston speed as well as rotational speed is taken into account. Rotational speed does not depend on the size of the engine, but piston speed depends on the stroke.

A good criterion of the speed of an engine is the speed factor, C_s, defined by

$$C_s = \frac{nv}{3{,}048{,}000}$$

where n is the rotation speed in revolution per minute, and v is the piston speed in *cm* per minute.

But $v = 2nl$, where l is the stroke of the piston in centimetres, so that

$$C_s = \frac{n \times 2nl}{3{,}048{,}000}$$

$$= \frac{n^2 l}{1{,}524{,}000} \qquad (3.8)$$

If the speed factor is less than 1.2, the engine is classed as low-speed; between 1.2 and 3.5 as medium-speed; and between 3.5 and 11 as high speed.

Another important factor is the ratio of the piston stroke 1, to the bore of the cylinder d. For internal combustion engines in general, this ratio varies between 0.9 and 1.9; for Diesel engines it may be taken as 1.2 to 1.4.

The number of cylinders will be decided in such a way that equal power is produced in each cylinder and the maximum power produced per cylinder is not more than 75 kW. The bore and stroke of the piston are designed to produce this power in the cylinder. The power produced depends on the mean effective pressure, (kilograms per square centimetre) and the compression pressure, P_c. A suitable compression ratio, r should also be selected.

Typical values are tabulated below :

Type of engine	p_c	r	p_r
	kg/cm²		kg/cm²
Air-injection	32 to 35	14 to 16	5.25 to 6
Solid injection low speed	28 to 32	12 to 14.5	5.25 to 6.5
Solid injection high speed	32 to 46	14 to 18	5.5 to 7.5

Putting K for the stroke/bore ratio, l/d and substituting in eqn. (3.8) the rotational speed may be written.

$$n = \sqrt{\frac{1,524,000\ C_s}{Kd}}$$

$$= 1,240\sqrt{\frac{C_s}{Kd}} \text{ revolutions/minute} \qquad (3.9)$$

The power developed in a 2-stroke single-acting cylinder can be expressed in either metric horse-power or kilowatts. A metric horse-power is defined as 75 kg-m/s. It can, therefore, be shown that

$$1 \text{ metric hp} = 0.736 \text{ kw}$$

In terms of mean effective pressure, bore, stroke and rotational speed,

$$P_{metric\ hp} = \frac{p_e\ (\text{Kg/cm}^2) \times 0.785\ d^2\ (\text{cm}^2) \times l(\text{m}) \times n\ (\text{rev/sec})}{75} \qquad (3.10)$$

$$= \frac{p_e \times 0.785 d^2}{75} \times \frac{l}{100}\ (\text{cm}) \times \frac{n}{60}\ (\text{rev/min})$$

$$= \frac{0.785\ p_e}{75} \frac{d^2 \times Kd \times 1,240\sqrt{(C_s/Kd)}}{100 \times 60} (d \text{ in cm})$$

$$= 0.00216\ p_e d^{2.5}\sqrt{(KC_s)} \qquad (3.11)$$

and $$P_{kw} = 0.736 \times 0.00216\ p_e d^{2.5}\sqrt{(KC_s)}$$

$$= 0.00159 p_e d^{2.5}\sqrt{(KC_s)} \qquad (3.12)$$

The diameter of the cylinder is, therefore, given by

$$d = \left[\frac{630\ P}{p_e\sqrt{(KC_s)}}\right]^{0.4} \qquad (3.13)$$

where P is in kilowatts.

For a 4 stroke engine the number of working strokes is $n/2$, and the power developed in a 4 stroke single-acting cylinder is

$$\left.\begin{aligned} P_{metric\ hp} &= 0.00108\ p_e d^{2.5}\sqrt{(KC_s)} \\ \text{or} \quad P_{kw} &= 0.000795 p_e d^{2.5}\sqrt{(KC_s)} \end{aligned}\right\} \qquad (3.14)$$

and its diameter in centimetres is given by

$$d = \left[\frac{1,260\ P}{p_e\sqrt{(KC_s)}}\right]^{0.4} \qquad (3.15)$$

where P is in kilowatts.

If the speed of rotation of the engine is given or assumed instead of the speed factor, C_s, the expressions for the power and diameter of the engine are simplified.

For a 2 stroke engine, the power developed is

$$P_{kw} = \frac{np_eKd^3}{780{,}000} \tag{3.16}$$

with n in revolutions per minute ; and the diameter in centimetres is

$$d = 92 \left[\frac{P}{np_eK}\right]^{1/3} \tag{3.17}$$

For a 4 stroke engine, use $n/2$ instead of n, as the effective strokes are half those of a 2 stroke engine. Eqns (3.16) and (3.17) will then give P and d.

When a Diesel engine is coupled to an a.c. generator, its speed must be adjusted so that the generator can operate at the rate frequency –

$$f = \frac{pn}{120} \tag{3.18}$$

where f is the frequency in cycles per second, n the speed in revolutions per minutes, and p the number of poles of the generator. The number of poles is necessarily an even number, and the frequency is the standard one used in the particular country. In India, it is 50 c/s.

The speed of a Diesel engine as given by eqn (3.9) should be modified to suit the above condition. With this modification, the calculations should be repeated and the diameter of the cylinder bore modified. When the diameter of the bore has been chosen, the length of the stroke is found from $l = Kd$.

3.8 Main Dimensions of Diesel-electric Generators and Their Characteristics

Characteristics. The generators used with Diesel engines are of the salient pole type having large diameters and short lengths. To obtain a frequency of 50 c/s, the number of poles is from 4

to 28, as the speed range of Diesel engines driving the generators is from 1,500 to 214 rev/min. Four-pole machines are seldom used, and normally the number of poles is from 6 to 28, corresponding to engine speeds of 1,000 to 214 rev/min. The alternators used are of standard available sizes. A common range of capacities is from 25 to 5,000 kVA, the power factor rating being 0.8 lagging, so that the corresponding load is from 20 to 4,000 kW. A 3 phase 50 c/s supply is to be obtained from the generators and a common voltage rating is 440 V. However, large machines, above 1,000 kVA may generate at voltages of 2,200 or 3,300 V. Generator efficiency varies from 92% for small units to about 95% for large units.

The generator needs an exciter to build up the necessary voltage on no-load and then to keep it constant on load, when greater excitation will be required. The exciter is a d.c. generator —shunt or compound—directly driven from the shaft of the engine driving the a.c. generator, or by means of a vee belt or chain so that its speed can be made higher than that of the low speed engine. The capacity of the exciter depends on the speed, on the voltage rating of the a.c. generator and on the voltage required to compensate for the drop due to the load on the a.c. generator. The capacity of the exciter in kilowatts may be about 2% to 4% of that of the a.c. generator. The standard voltage rating of the exciter is 115 or 230 V.

When there are several generators in a station, each may have its own exciter, driven as described above. This system is preferred to the other system in which a small number of exciters—two or three—serve all the generators. Most of these separate exciters are driven by electric motors. If this system is used in any station, care should be taken to see that at least one exciter is driven by one of the engines, so that, in the event of electric supply failure, it at least can be started and run, and the excitation supply maintained continuously.

Main dimensions of a.c. generators. When the speed of the Diesel engine is chosen first approximately and then exactly to

obtain the frequency of 50 c/s from the generator, it is easy to find the number of poles of the generator from

$$f=\frac{pn}{120} \tag{3·18}$$

where f is the frequency in cycles per second, p, the number of poles, and n, the speed in revolutions per minute.

The output equation gives the relation between the output of the generator, in kilovolt-amperes and the main dimensions of the generator, namely, the diameter and length. This can be developed as follows—

The voltage per phase, E_{ph} is given by

$$E_{ph}=4·44\ k_d\ k_p\ fN\ \Phi \text{ volts.} \tag{3·19}$$

Where k_d = distribution or breadth factor

k_p = Chording, coil-span or pitch factor

f = Frequency in cycles per second

N = Number of turns in series per phase

Φ = Flux per pole in webers.

For 3-phase synchronous machines, the winding factor, $k_d k_p$ may be taken as 0·955.

The flux per pole is given by

$$\Phi = B \times \text{Pole pitch} \times L = B\frac{\pi D}{p}L \text{ webers} \tag{3·20}$$

Where B = Average flux density in air-gap in webers per square centimetre.

D = Diameter of stator at the air-gap in centimeters.

L = Length of core in centimetres.

p = Number of poles.

The current per phase is given by

$$I_{ph}=\frac{\pi D a_c}{6N} \tag{3·21}$$

where a_c = Number of ampere-conductors per centimetre of stator periphery.

The frequency is given by

$$f=\frac{pn}{2} \qquad (3.18)$$

where n is now the number of revolutions per second. The output of the 3 phase a.c. generator is given by

$$S=3\times10^{-3}\,E_{ph}I_{ph} \text{ kilovolt amperes.} \qquad (3.22)$$

Substituting eqns (3·19)—(3·21) in eqn. (3.22)

$$S=(3\times10^{-3})\left[4{\cdot}44\times0{\cdot}955\,\frac{pn}{2}\,NB\,\frac{\pi D}{p}\,L\right]\left[\frac{\pi Da_c}{6N}\right] \qquad (3{\cdot}23)$$

$$=10{\cdot}4\times10^{-3}\,Ba_cD^2Ln \text{ kilovolt amperes.}$$

The output of the generator in kilovolt-amperes is seen to be proportional to D^2L, the product of the main dimensions. The average flux density and the ampere-conductors per centimetre of stator periphery are known as the specific-magnetic loading and the specific electric loading, respectively, and are chosen by the designer to suit the particular type of generator. For low-speed salient pole machines, these may be taken as

$a_c=300$ to 430 ampere-conductors per centimetre of stator periphery.

$B=5{\cdot}4\times10^{-5}$ to $7{\cdot}0\times10^{-5}$ Wb/cm^2

When the flux density in the air-gap and the ampere-conductors per centimetre have been chosen, the value of D^2L for a given output can be found from eqn (3·23). The length of the core, L, in low speed salient pole generators is small and can generally be taken as 0·8 to 1·2 times the pole pitch—

$$L=(0{\cdot}8 \text{ to } 1{\cdot}2)\times\frac{\pi D}{p} \qquad (3{\cdot}24)$$

Substituting this expression for L, an expression in terms of D^3 is obtained, and the value of D can then be determined. The value of L follows.

It is also necessary to check that for low-speed generators, the speed does not exceed the limit of 3750 m/min. This is another check on the diameter, D, from the point of view of speed limit.

3.9 Co-ordination of Engine and Generator Characteristics

Governor characteristics. The governor controls the speed of the engine by adjusting the fuel input to suit the load and keeps the speed of the engine and generator within certain limits. This is necessary in order to keep the frequency of the generated voltage constant.

The *speed droop* of a governor is defined as

$$\frac{\text{No-load speed} - \text{Full-load speed}}{\text{No-load speed}} \times 100\% \qquad (3{\cdot}25)$$

The speeds referred to are steady speeds; the speed droop is also known as the steady-state overall speed regulation. The sensitivity of a governor is defined as the percentage speed change required to produce a corrective movement of the fuel control mechanism. Generally, an electric-motor control is used for adjusting the speed. The motor is mounted on the engine governor and connected through a worm-gear drive to the spring adjuster of the governor. Thus by controlling the direction and amount of movement of the motor rotor, the governor can be adjusted from the control board as required by the load conditions.

When a number of Diesel-electric sets are to operate in parallel in a station, it is necessary that their speed regulation should be the same. The droop on full load may be about 2%. This ensures that the load on the sets will be shared in proportion to their capacities and that adjustment on each set is not required too often.

The governors should be free from hunting and should bring the generators to a steady speed without delay. Otherwise, oscillations will result in an unstable condition with a possibility of some set falling out of step.

Cyclic variation. When a 4 stroke engine is used as a prime mover cyclic disturbance in torque is possible, as only one stroke in four is the power stroke. When a rotating system possesses

inertia and restoring torque that tends to restore its position when displacement has occurred, the system has a natural frequency of oscillation f_n,

$$f_n = \frac{1}{2\pi}\sqrt{\frac{Tg}{J}} \tag{3.26}$$

where T = Restoring torque in kilogram-meters per mechanical radian of displacement.

J = Moment of inertia in kilogram-metres^2

g = 9.81 m/s^2

With Diesel-driven generators, the cyclic irregularity in driving torque is due to the prime movers. When a number of generators are operating in parallel the synchronising torque exerted on the rotor of a generator is the restoring torque which tries to keep the rotor axis in a steady position relative to the stator axis. The effect is shown in Fig. 3.6. On no-load the rotor axis is in line with the stator axis, shown at (*a*). When a disturbance occurs and the load changes suddenly, the rotor axis falls back, oscillates and is restored by the synchronising torque to a steady position lagging behind the stator axis as shown at (*b*). The angle, δ, which the rotor axis makes with the stator axis depends on the load.

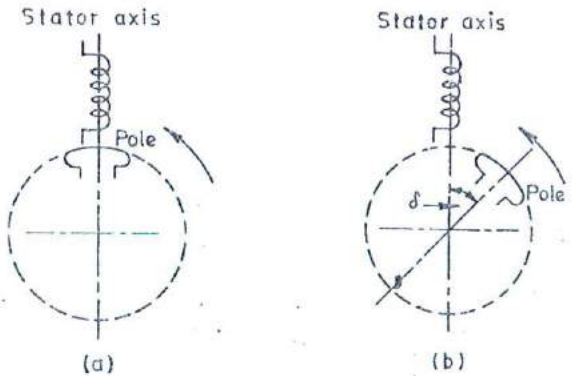


Fig. 3.6. Position of pole axis relative to stator axis.
(a) Initial position. (b) Position on load.

A rhythmically varying driving or load torque can be represented by a constant mean torque with a superimposed sinusoidal

variation of amplitude T_d and frequency f_d. This torque produces acceleration in phase with itself, and the cyclic acceleration causes a cyclic speed change, n_d about the mean speed, n. The speed change produces angular displacement of the rotor axis in addition to that due to the load.

Cyclic irregularity (K) is defined by

$$\text{Cyclic irregularity} = \frac{\text{Total speed change}}{\text{Mean steady speed}}$$

or in symbols,

$$K = \frac{2n_d}{n} \tag{3.27}$$

It follows that

$$\text{Total angular displacement of rotor axis} = K\frac{f}{f_d} \text{ electrical radians}$$

$$= \frac{180}{\pi} K \frac{f}{f_d} \text{ electrical degrees} \tag{3.28}$$

If f_d approaches f_n, the displacement may become so large that the machine will fall out of step.

The part of the displacement that is due to speed change depends on the factor

$$\frac{1}{1-(f_n/f_d)^2}$$

This periodical variation, known as phase swinging, results in a to-and-fro movement of the air gap flux superimposed on its steady rotation. This low-frequency movement produces eddy currents in the pole faces and stator core, and affects the parallel working of the machines. To reduce this effect, generators should have dampers, or amortisseur windings, consisting of bare copper bars embedded in slots or holes in the pole shoes and brazed at the ends of the bars to rings like the cage rotors of induction machines. The damper windings increase the synchronising forces, reduce fluctuations in rotor speed due to engine firing impulses, and thus limit cross-currents.

If f_d is greater than f_n, the phase swinging can be reduced by adding a flywheel to increase the rotating mass. This reduced f_n, thus producing a greater difference between this frequency

and f_d. The flywheel is mounted between the engine and the generator.

The total flywheel effect of each unit should be such that during parallel operation the maximum periodic displacement of the rotor axis in either direction from the position of uniform rotation should not exceed 3 to 4 electrical degrees. The natural frequency of oscillation of the unit should differ by at least 20% from the frequency of forced impulse of any of the engines operating in parallel.

Small high speed Diesel engines generally have ample flywheel effect to meet this condition but care is needed with low speed engines, particularly those with few cylinders. Critical frequencies should be avoided. With 4 stroke engines, avoid frequencies corresponding to speeds n and $\frac{1}{2}n$; with 2-stroke engines, avoid frequencies corresponding to speeds n and $2n$.

3.10 Sizes and Dimensions of Generating Sets

When the size and number of engine cylinders have been determined, the size of the engines can be found from information depending on the type of engine. Detailed and accurate dimensions of engines of various capacities can be obtained from the manufacturers. Similarly, the main dimensions of a generator of the required capacity can be determined as explained in the last section. The overall dimensions can be found accurately from the manufacturers' data.

The approximate overall dimensions of some engine generator units are as follows, the generators having 16 poles and the engines 5 to 8 cylinders—

Capacity	Overall dimensions		
	Length	Width	Height
kW	cm	cm	
400	580	228	
500	670	228	365 cm of which
600 (supercharger)	640	244	274 cm is above
700 (supercharger)	701	244	floor level.
800 (supercharger)	762	244	

3.11 Building Dimensions and General Layout

There are different ways of designing power station buildings from architectural and structural points of view. The cheapest minimal requirement would be a functional building to protect the equipment inside the station from the effects of weather. It is, however, not enough to have only a functional building; it should be architecturally pleasing, as it will be seen by the public, and public goodwill is a great asset for power supply undertakings.

Architecturally, power station buildings should have heavy massive lines suggesting both power and permanence. Generally, they have a structural steel framework, and walls of brick masonry. Foundations and floors are of concrete. Steel doors and window frames and, as far as possible, fire resistant materials are used. Reinforced concrete beams and slabs are used. Roofs are flat and have a covering of tar and gravel composition.

Emergency lighting should be provided for use in the event of failure of the main supply. The buildings are high so that indirect lighting is not possible. Moving parts should be enclosed for protection. High-voltage parts and hazardous locations should have caution signs prominently displayed.

Diesel stations have small capacities and few auxiliaries, and require no coal. The design of the building is made up of simple rectangular blocks to accommodate the engine-generator sets. Oil tanks are sometimes located underground. Ventilation, and, in cold countries, heating, should also be planned properly.

Fig. 3.7 shows the general layout of the ground floor of a Diesel electric power station. In planning the building and the floor area required, it is first necessary to find the approximate dimensions of the equipment. Its location and the minimum clearances between its parts are then decided. The building is then planned around the equipment, rather than first planning the building and then trying to fit the equipment into it. The possibility of future additions to the building with a minimum change must be borne in mind. The spacing required between two units, the distance between their centre-lines, the distance between the centre-

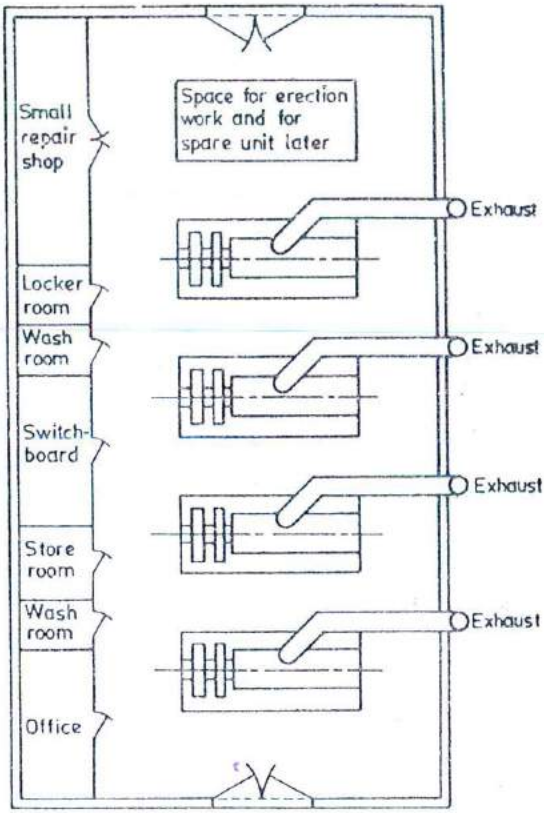


Fig. 3.7. Ground-floor plan of a Diesel-electric station.

line of the end unit and the wall, and the distances between the head end of the engine and the wall and the generator end and the wall should be carefully determined. The location of the switch-board, station auxiliary transformers, battery room, fuel-oil tank, compressed-air cylinder bottle for engine starting, compressors, lubricating-oil circuits and the cooling arrangements for cylinder jackets and suction and exhaust arrangements for the engine should also be considered.

All engine-generator units are preferably arranged parallel to each other so that it is possible to have the shortest length for the

electrical connexions from generators to switchboards or switchgear. Similarly, on the engine side, it should be possible to have short air intake and exhaust lines. Provision should be made for bringing the equipment into the building, and the doors should be of ample dimensions. When all the above points have been considered, it is easy to decide on the ground-floor plan. Provision should be made for at least one spare unit to be installed. There should also be space for erection work, and for handling the equipment for maintenance, and it should not be a crowded or clumsy arrangement. A crane of sufficient load-carrying capacity should be installed at the proper height so that it will be possible to remove the engine parts when the engines are being dismantled or opened for overhaul.

There should be spaces for a small workshop, for stores, office, wash room, etc. Diesel engines need few spares compared to other types of prime mover, and the building plan is quite simple. The spray pond or other arrangement for cooling the water used for cylinder cooling can be located near the building, preferably just outside.

3.12 Costs of Diesel Plant

Diesel plants cost about Rs. 1,000 to Rs. 1,400 per kW capacity. The fixed costs can be worked out using the principles outlined in chapter 2. The main factors are interest, depreciation, taxes and insurance. The life of the plant can be taken as about 15 to 16 years, *i.e.*, the depreciation will be 6% to 7% annually. If the interest on capital investment is taken at the rate of 6%, insurance and taxes at 2% and depreciation at 7% the total fixed costs per annum will be at the rate of 15%. The factors affecting the initial costs of the plant are its size and speed, design and constructional details.

The operating costs will consist of the costs of fuel, lubricating oil and cooling water, the cost of employing the operators, and the part of the maintenance cost which is proportional to the production of electrical energy. The other part of the maintenance cost, namely, the part incurred in keeping the plant in good

condition whether it is producing electrical energy or not will be charged as a fixed cost.

Fuel. With a known load curve, load factor and capacity factor of the station, the fuel consumption can be found from Fig. 3.4. If the load duration curve of the station is plotted for the whole year and if the output/input characteristics of the station are known, the fuel/time curve can be obtained from these two curves by graphical construction as shown in Fig. 3.5. The area under the fuel/time curve gives the annual fuel oil consumption in kilograms. In India, the cost of fuel varies from 40 p to 50 p per kg. The cost of fuel can, therefore, be found under any particular working condition, or for the whole year, with variable load operation.

Lubricating oils. The consumption of lubricating oil increases as the load increases, and is approximately 1 kg for each 300 to 450 kWh produced. The cost per kilogram is about Rs 1.25.

Water. The cost of suppiying cooling water to the engine will be charged as an operating cost.

Labour and operating staff. It will be necessary to have at least two operators per shift, and also some maintenance staff, a superintendent or a chief engineer, or both. This is another operating cost.

Maintenance. The total annual maintenance costs for a Diesel unit operating continuously will be considerably greater than if the same unit were to operate on a single daily shift or to supply seasonal requirements. Therefore, a large part of the maintenance costs will be proportional to the output in kilowatt-hours, and a small portion will be fixed by the number and size of the units. The maintenance of Diesel plant consists mainly of overhauling and cleaning the parts, *e.g.*, removing and cleaning pistons, cleaning and grinding exhaust valves and air starting valves, checking spray valves, adjustment of governor and crankpin bearings, checking and adjustment of crankshafts, checking of cooling system, lubricating system, fuel pumps and nozzle valves, maintenance of fuel system, checking engine compression and valve timings, starting-

system maintenance, maintenance of generators, exciters, circuit-breakers and brushes, commutator cleaning, etc.

When the various costs under different heads have been worked out—both the fixed and variable costs—it is possible to find the cost of each kilowatt-hour generated. The costs per kilowatt output and per kilowatt-hour generated can be separated if necessary, as they are proportional to the fixed and operating or variable costs respectively. The charge for energy sold can be worked out as a two-part tariff, as explained in chapter 2. The method of finding the main dimensions and general layout of the plant, and the cost per kilowatt-hour produced, are illustrated in the next example.

Example 3.1

A power-supply company has to install a Diesel-electric power plant at a hill station having an altitude of 900 m above sea-level. Four units—2 each of 500 kW and 2 each of 300 kW—are chosen to suit the load curve. The engines used are of the 4-stroke 375-rev|min airless injection type. The maximum demand on the station is to be 1,400 kW at 0.8 power factor lagging. The average load factor will be 50% and the annual capacity factor 44%. The generator efficiency may be taken as 93%.

(*a*) Find the ratings of the Diesel engines.

(*b*) Find the main dimensions of the engines and generators.

(*c*) Find the energy produced per year.

(*d*) Find the annual fuel consumption.

(*e*) Assuming that 30% of the heat in the fuel is lost to the cooling water, find the quantity of water required for cooling purposes. The maximum difference between the inlet and outlet temperatures of the water may be taken as 11°C.

(*f*) Find the space required for each unit, and show the general lay out of the engine-generator sets.

(*g*) If the cost of the plant is Rs. 1,000 per kW, insurance and taxes 2% of costs, interest on investment 6% and depreciation of plant 7%, find the fixed costs. The cost of fuel oil per kilogram may be taken as 40 p, and that of lubricating oil per kilogram as Rs. 1.25 p. It may be assumed that the amount of lubricating oil required is 1 kg for every 400 kWh produced. The calorific value of the fuel oil is 10,000 kcal per kg. Maintenance costs Rs. 30,000 per year; one-third of this may be taken as fixed

and the remainder as variable. Operation costs Rs 50,000 per year. Find the total variable costs. Find the total costs and the cost per kilowatt hour of energy generated.

(*a*) *Ratings of Diesel engines.* There are two types of generators of different capacities, namely, 500 kW and 300 kW. The engines driving these generators will also be of proportionately different capacities. The generator efficiency given is 93%.

Engine capacity to drive 500-kW generator $= \frac{500}{0.93} = 538$ or say, 540 kW.

Engine capacity to drive 300-kW generator $= \frac{300}{0.93} = 323$ or say, 325 kW.

These ratings apply at the altitude where the station is to be installed, namely, 900 m. From Fig. 3.2 it will be seen that the ratings are reduced to 94% of their sea level values for use at this altitude. If the engines are not supercharged, the sea level ratings are, therefore, 540/0.94=575 kW and 325/0.94=346 kW respectively. If the engines are supercharged, capacities of 540 kW and 325 kW will be suitable.

(*b*) *Main dimensions of engines.* At greater altitudes, it is better to use supercharged engines, so that the ratings are not reduced and the engines may have some overload capacity. The question of economy should also be considered in making the choice.

Two 540-kW and two 325 kW engines are used. Each 540 kW engine will have 8 cylinders each of 67.5 kW, and each 325 kW engine will have 6 cylinders each of 54 kW approximately as the maximum power per cylinder should, in general, not be more than 75 kW and the powers in all cylinders should be balanced.

Dimensions of 67.5 kW Cylinder. Take the stroke/diameter ratio as 1.4. For a 4-stroke engine $n=375/2$, or half the number of revolutions per minute. The mean effective pressure may be taken as 6 kg cm^2. The diameter, d, is given by eqn (3.17).

$$d=92\left[\frac{P}{np_eK}\right]^{1/3}$$

Substituting numerical values in this expression,

$$d=92\ (67.5/187.5\times 6\times 1.4)^{1/3}=32.2 \text{ cm}$$

The length of stroke, l, is $1.4\times 32.2=45$ cm approximately. Thus for the 67.5 kW cylinder, the diameter is 32.2 cm and the stroke 45 cm.

Dimensions of 54-kW cylinder. The dimensions of this cylinder can be found in the same way –

$$d=92\ (54/187.5\times 6\times 1.4)^{1/3}=30\ \text{cm}$$

$$l=30\times 1.4=42\ \text{cm}$$

Main dimensions of generators. The rating of the 500 kW generator at 0.8 power factor lagging is 500/0.8=625 kVA and is given by eqn (3.23) in terms of the main dimensions, D and L—

$$S=10.4\times 10^{-5}\ Ba_c\ D^2Ln$$

Taking an average flux density, B, of 6.2×10^{-5} Wb/cm², and a specific electric loading a_c, of 350 ampere conductors per centimetre of periphery, then, with a rotational speed n, of 375/60 rev/sec, the above equation becomes

$$625=10.4\times 10^{-3}\times 6.2\times 10^{-5}\times 350\times D^2L\times\frac{375}{60}$$

whence $D^2L=442{,}000$ cm³.

The speed of the generator is 375 rev/min, so that the number of poles is 16 The length of the core may be taken equal to the pole pitch –

$$L=\frac{\pi D}{16}$$

Substituting this value of L,

$$D^2L=\frac{\pi D^3}{16}=442{,}000\ \text{cm}^3$$

whence $D^3=2{,}260{,}000$

$$D=100\ (2.26)^{1/3}=131.5\ \text{cm}$$

and

$$L=\frac{\pi\ 131.5}{16}=25.8\ \text{cm}$$

Take the diameter of the 500-kW generator as 132 cm and the length of core as 26 cm.

The rating of the 300-kW generator at 0.8 power factor lagging is 300/0.8=375 kVA.

Proceeding in the same way, assuming the same loading and again taking the length of core as equal to the pole pitch,

$$D^3=22{,}60{,}000\times 375/625=13{,}60{,}000$$

$$D=100\ (1.36)^{1/3}=111\ \text{cm}$$

$$L=\frac{\pi 111}{16}=21.8\ \text{cm}$$

Take the diameter of the 300-kW generator as 111 cm and the length of core as 22 cm.

(*c*) *Energy produced per year*

$$\text{Maximum demand} \times \text{Load factor} \times 8{,}760 = 1{,}400 \times 0{\cdot}5 \times 8{,}760 = 6.132 \times 10^6 \text{ kWh.}$$

(*d*) *Annual fuel consumption.* The capacity factor given is 44% so that from Fig. 3.4 it will be seen that 2.3 kWh are produced per kilogram of oil. Since the energy produced during the year is 6.132×10^6 kWh.

$$\text{Annual fuel oil consumption} = \frac{6.132 \times 10^6}{2.3} = 2.66 \times 10^6 \text{ kg}$$

(*e*) *Water required.* From (*d*) the amount of fuel consumed per year is 2.66×10^6 kg. Thus

$$\text{Fuel consumption per hour} = \frac{2.66 \times 10^6}{8760} = 304 \text{ kg}$$

Heat input from fuel per hour $= 10{,}000 \times 304$ kcal of this heat input, 30% is absorbed by the cooling water, i.e.,

$$\text{Heat absorbed by water} = 10{,}000 \times 304 \times \frac{30}{100} = 9.12 \times 10^5 \text{ kcal}$$

The difference between the inlet and outlet temperatures is 11°C.

$$\text{Water required per hour} = \frac{9.12 \times 10^5}{11} = 83 \times 10^3 \text{ kg}$$

$$\text{Water required per minute} = \frac{83 \times 10^3}{60} = 1{,}380 \text{ kg}$$

This figure, 1,380 kg, represents an average water demand per minute over the year. If it were converted to the consumption of water per year it would serve as an indication of the probable cost of cooling water. If the demand for cooling water under the worst condition is required for design purposes, this demand would occur at a maximum peak load of 1,400 kW and would be

$$\frac{1{,}380}{\text{Load factor}} = \frac{1{,}380}{0.50} = 2{,}760 \text{ kg/min}$$

The capacity of the pumps should, therefore, at least correspond to this figure, or preferably to 3,000 kg/min, or 3,000 litres/min.

(*f*) *Space required by station.* For the 500 kW set, the diameter of each cylinder is 32.2 cm. The minimum space required for 8 cylinders is $40 \times 8 = 320$ cm, allowing for the thickness of the cylinder walls. The length of the generator core is 26 cm. The total length including all other mechanical arrangements for flywheel, bearings, etc., will be about 750 cm. The width will be about 228 cm, and the total height of the engine about 365 cm, of which 274 cm will be above the floor level.

The space required by a 300-kW unit can be estimated in the same way. It has a 6-cylinder engine. The inside diameter of the cylinder is 30 cm. The space required for 6 cylinders is, therefore, $6 \times 37.5 = 225$ cm, allowing for the thickness of the cylinder walls. The length of the generator core is 22 cm. The total length of the set including the mechanical arrangements will be about 580 cm. The width is about 228 cm. The height will be about 365 cm, of which 274 cm will be above the floor level.

The general layout with the main dimensions is shown in Fig 3.8.

(*g*) *Costs of the plant*

Capacity of plant = 1,600 kW

Initial cost of plant = $1{,}600 \times 1{,}000$ = Rs. 1,600,000

Fixed costs

Fixed costs = Interest + Depreciation + Insurance and taxes

$= 6\% + 7\% + 2\% = 15\%$

$= 1{,}600 \times 1{,}000 \times 15/100$ = Rs. 240,000

One-third of maintenance costs 10,000

250,000

The rate of consumption of lubricating oil is given as 1 kg for 400 kWh.

Annual lubricating oil consumption $= \dfrac{6.132 \times 10^6}{400} = 1.533 \times 10^4$ kg

Variable costs	Rs.
Fuel costs $= 2{,}660{,}000 \times 0.40$	= 1,063,000
Lubricating oil costs $= 15{,}330 \times 1.25$ =	19,200
Operating costs	50,000
Two-thirds of maintenance costs	20,000
	1,152,200

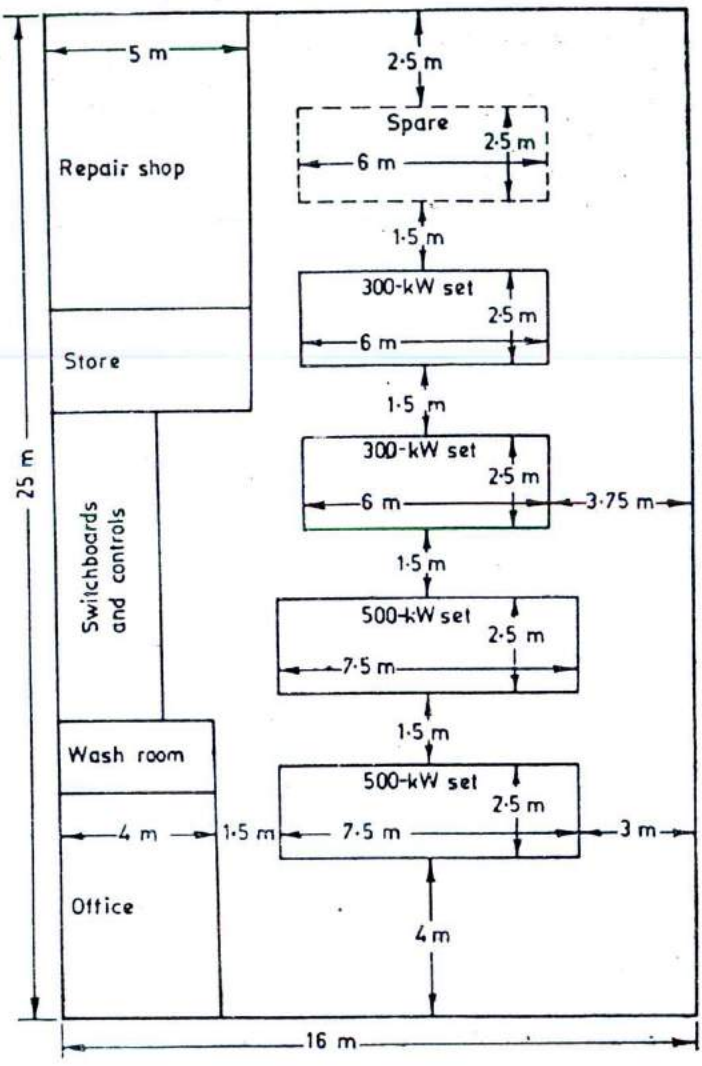


Fig. 3.8. General layout of the Diesel station.

Total annual costs	Rs.
Fixed costs	250,000
Variable costs	1,152,200
	1,402,200

$$\text{Cost per kilowatt-hour generated} = \frac{1,402,2 \times 1,000 \times 100}{6,132 \times 1,000} = 22.85\text{p.}$$

It will be seen from the above example that the cost per kilowatt-hour generated in a Diesel-electric station is high compared to other types of generation. This is because the load and capacity factors are low. This increases the fuel oil consumption, which is the highest cost item.

3.13 Alternative Source of Power Supply to Industries Under Power Shortage

Recently there has been a problem of power and energy shortage. Industries do not get power and/or energy to their full requirement at the time required. Under such circumstances, Diesel sets can be used as an alternative source of supplying power/energy to make up for the deficit in their requirement from power supply systems.

3.13.1 POWER SHORTAGE

Industries have certain contract demand for power which means that the power supply organisation should supply that much power during any part of the month or year. This is indicated by the maximum demand. Under certain circumstances, it is not possible to have power available for some time at the required rate. This may be due to undue expansion of the load on the supply organisation, or to non-availability of necessary generating capacity in the power stations working actively all the time during the year. A cut is, therefore, applied by the supply organisation, with Government orders for the reduced supply of power to industries. This necessitates limitations of the maximum demand permissible, and of the time durations within which this has to be limited from day to day when enough power is not available. This is power shortage.

3.13.2 ENERGY SHORTAGE

Under normal conditions, there is no limit imposed on the use of energy by the industries. However, when the power supply organisations cannot supply the required energy to industries, a cut has to be applied as for the use of power mentioned above. This may be due to shortage of water storage in dams for hydro-electric stations due to shortage of rainfall, or it may be due to non-availability of thermal stations for a sufficient time to produce the necessary energy. This may be on account of the maintenance and overhauling of the equipment required annually and/or under fault conditions.

If industries do not get the required power and energy, their working will be affected and production will suffer. The first thing to be attended to by industries under such circumstances would be to check their installations and try to effect saving in power and energy. In case it is seen that for loads essential to the working of industries, it is absolutely necessary to have an additional source of power supply, Diesel engine generators may be considered as an alternative source of power supply. This may be used to the minimum extent after considering and studying the technical and economical feasibility of this form of alternative power supply.

The need for an alternative source of power supply will be most in continuous process industries where failure of supply even for a short interval affects production and losses mount due to disruption of the continuous process used in the industry for production, e.g., a nylon factory.

In such cases, the cost of the loss of production and damages incurred is also to be considered in the economic studies of the Diesel plant to be installed as an alternative source of power supply. In case of power shortages, the following situation may arise for industries:

(i) Electricity shut down is known in advance.

(ii) Electricity cut with reference to power and energy is

known in advance and the industrial consumer has to limit his requirements within the limitation prescribed.

(iii) Electricity shut down without previous intimation. This may happen sometimes due to failure of lines because of sudden faults developed in the system.

3.14 Use of Diesel Sets as Alternative Power Plant

(1) When electricity shut down is known in advance, the Diesel sets can be started well in advance before the shut down time expected and the load supplied by the sets.

(ii) When electricity cut is to be observed with reference to power and energy, the sets can be used to supply the deficit. The working of the sets can be planned considering the load curve of the industrial loads; and separating them into essential and less essential loads.

Temporary shutdowns of short duration, less than a few minutes, and without notice, cannot be taken care of by Diesel sets unless they are continuously operated in parallel with the power supply organisation's system. This is not advisable. The frequency of the Diesel sets is manually controlled and not automatic. The capacity of Diesel sets is very small compared to the capacity of a power system (grid) which can be taken as infinite bus. With unforeseen fault conditions in the system the stability of the Diesel sets is not ensured. There is also the danger of lines remaining live in case only Diesel sets remain in parallel with the system and the system shuts down due to fault or maintenance requirements. This should be prevented for safety purposes.

Diesel engines can be started and stopped quickly and can take load quickly. They need less space, and less quantity of water for cooling, as compared to steam plants. They are, therefore, considered for use as an alternative source of power for industries where power requirement is limited. The sets are available in small sizes from about 200 kVA to 1500 kVA.

Capacity of the Diesel plant in industries should be chosen to supply essential load in case of power shortages. The sets should

be run only when enough power and energy is not available from the supply organisation. They may be run to make up for the energy shortage during the period by supplementing the power supply arrangement with a separate circuit to take up part of the load. The time for which the sets should be run is decided by the energy requirement to be made up due to the cut imposed.

3.14.1 COSTS OF DIESEL PLANT

Recently due to the very high price of oil, and also to difficulty in obtaining it in large quantities, Diesel sets are used only when absolutely essential as an alternative source of supply when power and energy cuts prevail.

The method of calculating fixed costs, variable costs and cost per kWh were explained in the last section. The latest cost of HSD oil is about Rs. 1.30 per litre. The density of oil may be taken as 0.87. The recent cost of lubricating oil is about Rs. 12/- per litre. The specific gravity of lubricating oil may be taken as 0.92. Work out the fuel requirement at required load and load factor, and the cooling water requirement. (Compare to the cost of power supply from the supply organisation.) Find the cost of Diesel generation per kWh.

3.14.2 LOSS OF PRODUCTION IN INDUSTRIES

If a cut in the use of electricity is imposed, find out whether the loss of production that will result due to the cut justifies installing Diesel sets to make up for the loss, considering the higher cost of energy supplied by Diesel sets, as the cost per kWh by Diesel sets is going to be much higher than the rate charged by the Power Supply Organisation. The cost may be 5 to 6 times more.

If it is assumed that production is proportional to electrical energy consumption, the % loss of production will be proportional to the % cut on electricity consumption. Work out loss of production for the various cuts expected for planning. Work out the cost of production, omit cost of material, and find out the annual cost of the loss which will result.

Without the supply of enough energy, there cannot be expansion of a factory, and any further plans for expansion will have to be postponed. The economy and justification for installing Diesel sets as alternative source of supply should be studied in detail before taking a decision regarding the capacity to be installed and the working of the new installation.

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Problems

3.1. State the field of use of Diesel-electric stations.

3.2. Explain the factors to be considered in choosing the Diesel Engines for driving generators in Diesel-electric stations.

3.3. Describe the characteristics of Diesel engines and state the approximate heat balance.

3.4. Explain methods of determining the annual fuel consumption of a Diesel plant working on variable load.

3.5. (*a*) Explain the method of determining the cooling water requirement of a Diesel plant of given capacity. (*b*) State methods of cooling the circulating water of a Diesel plant.

3.6. Derive expressions for the main dimensions (diameter and stroke) of a Diesel engine of capacity P kilowatts.

3.7. Derive the output equation for a 3 phase a.c. generator and determine the main dimensions (diameter of stator at the airgap and length of stator core) of a 3 phase generator having a capacity of S kilovolt amperes.

3.8. State the effect of cyclic irregularity in a Diesel-electric unit working on the 4 stroke cycle. Explain the methods of reducing this effect.

3.9. A Diesel station has 4 units, 3 each of 600-kW, and one of 400-kW capacity. The engines used are 4 stroke 300-rev/min airless-injection type. The maximum demand on the station is 2,000 kW at 0.8 power factor lagging. The average load factor of the station is 55% and the annual capacity factor is 50%. The generator efficiency is 92%.

(*a*) Design the main dimensions of the engines and generators used. Give detailed specifications of the units.

(*b*) Show the general layout of the station, indicating the spaces required for various units, auxiliaries, control boards, etc.

(Ans. For 600 kW set: Diesel engine, 650 kW, 10 cylinder 4 stroke 300 rev/min solid injection type, diameter of each cylinder 34.3 cm, stroke 48 cm; generator, 750-KVA 600 kW 0.8 power factor (lagging) 3 phase 50 c/s 300 rev/min; 20 pole, diameter of stator at airgap 162 cm, length of core 25.4 cm. For 400 kW set. Diesel engine, 435 kW 8 cylinder 4 stroke 300 rev/min solid-injection type, diameter of each cylinder 32.4 cm, stroke 45.5 cm; generator, 500-KVA 400-kW 0.8-power-factor (lagging) 3 phase 50-c/s 300-rev/min, 20-pole, diameter of stator at airgap 142 cm, length of core 22.3 cm).

3.10. The station of problem 3.9 has the following data: Cost of station, Rs. 900 per kW installed; insurance and taxes, 2% of the costs; interest on investment, 6%; depreciation of plant, 7%.

(*a*) Find the fixed costs.

(*b*) Find the energy produced per year and the annual fuel consumption. Find the consumption of lubricating oil if 1 kg is used for every 450 kWh. If the cost of fuel oil is 40 p per kg, and of lubricating oil is Rs. 1.20 p per kg, find the cost due to this consumption. The calorific value of the fuel is 10,000 kcal/kg.

(*c*) Find the thermal efficiency of the Diesel plant.

(*d*) If 32% of the heat in the fuel is lost to the cooling water, and the maximum difference between the inlet and outlet temperatures of the water is 11°C, find the quantity of cooling water required. Find the capacity of the cooling-water pump under the condition of maximum load.

(*e*) The operation costs are Rs. 50,000 per year, and the maintenance costs, Rs. 33,000 per year. One-third of the maintenance costs may be taken as fixed costs and two-thirds as variable costs. Find the total fixed costs and total variable costs.

(*f*) Find the cost per kilowatt-hour of energy generated.

(Ans. (*a*) Rs. 297,000. (*b*) Energy produced per year, 9.65×10^6 kWh; annual fuel consumption, 4.02×10^6 kg; cost of fuel oil, Rs. 16,08,000; annual lubricating oil consumption 21.42×10^3 kg. ; cost of lubricating oil Rs. 25,750. (*c*) 20.6%. (*d*) cooling water required during year, $1,173 \times 10^6$ kg; average rate of water, 2,240 litres/min; for maximum load capacity of pumps, 4,070 litres/min. (*e*) Total fixed costs, Rs. 308,000; total variable costs, Rs. 1,705,750. (*f*) 20.85 p per kWh.

4

Steam Station : Preliminary Design

4.1. Field of Use

Private industrial Plants: Industries which require steam for process purposes may sometimes use steam turbines for power production also, so that the electric power required by the industry can be supplied from the steam turbine sets. The back pressure turbines can exhaust steam at constant pressure, as for evaporator supply, or at varying pressure, as for heating purposes. Industrial turbo generators are of capacities upto 10 MW. The steam for process purposes may be tapped from extraction bleeding of the turbines at a pressure of 1.4 to 7 kg/cm^2. The machines are either 4 pole or 2 pole. In some cases speed reduction gearing is required between the turbine and generator.

Before deciding to build a private power plant for an industry, it is necessary to consider the economics as to whether it is cheaper to buy power from an external source such as a Grid nearby, or to build a power plant for the industry independently. Further, if low pressure steam is required for process purposes, this will also affect the economics and should be taken into consideration in the economic study.

Central Stations: Steam stations are mainly used as Central stations to produce electric power for supply undertakings. In these stations, the a.c. generators are driven by turbines with condensing arrangements at high vacuum of about 73.6 cm Hg. The size of the sets may be from 10 MW to 500 MW or even larger, depending on the system requirements. All modern stations have 2 pole machines, the speed being 3,000 revs/min when the frequency is 50 c/s.

Suitable locations for stations of different types were discussed in Chapter 2. A large steam station will be located at a site to which fuel can be easily transported by either rail or ship and where enough water is available for cooling the condensate. A steam station needs a large amount of water compared to a Diesel Station.

Steam stations are in common use where Diesel stations cannot be installed with advantage for small power requirements. When hydro stations are available in the system, steam stations are used in combination with them to supply the total load economically and to ensure reliability of power supply at all times.

The steam station needs a lot of space for storing fuel, elaborate arrangements for fuel handling, ash handling, lay-out of high pressure boilers, steam turbines, generators, control switchboards, cooling water arrangements, etc. Economic considerations will decide the type to be used in a particular case. This will be considered later in the chapter.

4.2 Main Parts and Working of a Steam Station

The main parts of a steam station are the boiler or steam generator, the steam turbine, and the electric generator which is coupled to it. The fuel is burned and the heat in the fuel is used in the boiler to convert water into steam at the required pressure and temperature. The steam is supplied to the turbine, where its expansion produces mechanical power at the turbine shaft. This power is used to drive the generator, which in turn produces electric power.

The boiler is a device for producing steam under pressure. Generally water tube boilers are used for electric power stations. A number of different types of boiler working at different steam pressures and temperatures have been developed. The boiler consists of a drum and a set of tubes connected to it, in which water provided by the feed system is converted into steam. Steam pressures from 17 kg/cm^2 (guage) to 167.5 kg/cm^2 (guage) and temperatures from 315°C to 575°C are attainable. The heat transfer takes place through the walls of the tubes and the drum is pro-

tected from direct contact with the hot flue gases. The steam is superheated in a superheater before passing from the boiler to the prime mover.

4.2.1 FUEL HANDLING

Let us first see how the fuel flows. The fuel normally used is coal, oil or gas. Gaseous fuel is rarely used except in special circumstances where it is available cheaply. Oil is used only when it is available cheaply and in plenty. In India, oil is very expensive and coal is the most common fuel. In large size boilers, when the load is very low, oil is used for part of the time.

The coal handling plant is divided into three sections.

(*i*) Unloading plant : Wagon tippler.

(*ii*) Conveying plant for conveying coal from unloading to the coal yard or directly to the bunkers.

(*iii*) Crushing plant: For crushing the coal to the required size.

(*i*) *Unloading plant* : The coal is brought to the power station site by rail wagons. About 6 to 8 wagons are placed in the wagon marshalling area by means of a shunter. Each wagon is adjusted on the tippler platform in proper position. The wagon tippler tilts the wagon and unloads the coal into the hoppers. The coal from the hoppers is fed to the belt conveyors 'A' or 'B' by means of electric vibrating feeders. Fig 4.1 shows the coal handling plant in schematic way.

(*ii*) *Conveying plant* : The conveying plant consists of belt conveyors 1A,1B, 2, 3, 4, 5, 6. Belt No. 4 can be rotated in either direction while all the others have only one direction. The coal from belt No. 1A or 1B is taken by belt No. 2 to vibrating screens and then to the crushers. The crushed coal from the crushers and small size coal from screens falls on to belt No. 4. This is reversible. While direct bunkering, the coal falls on belt No. 5, while stocking the coal falls on belt No. 3. This belt is a revolving type with telescopic hopper and is run when the coal is to be stored in the outside station yard. When direct bunkering, coal falls from belt No. 4 to belt No. 5 which takes the coal to the tipper

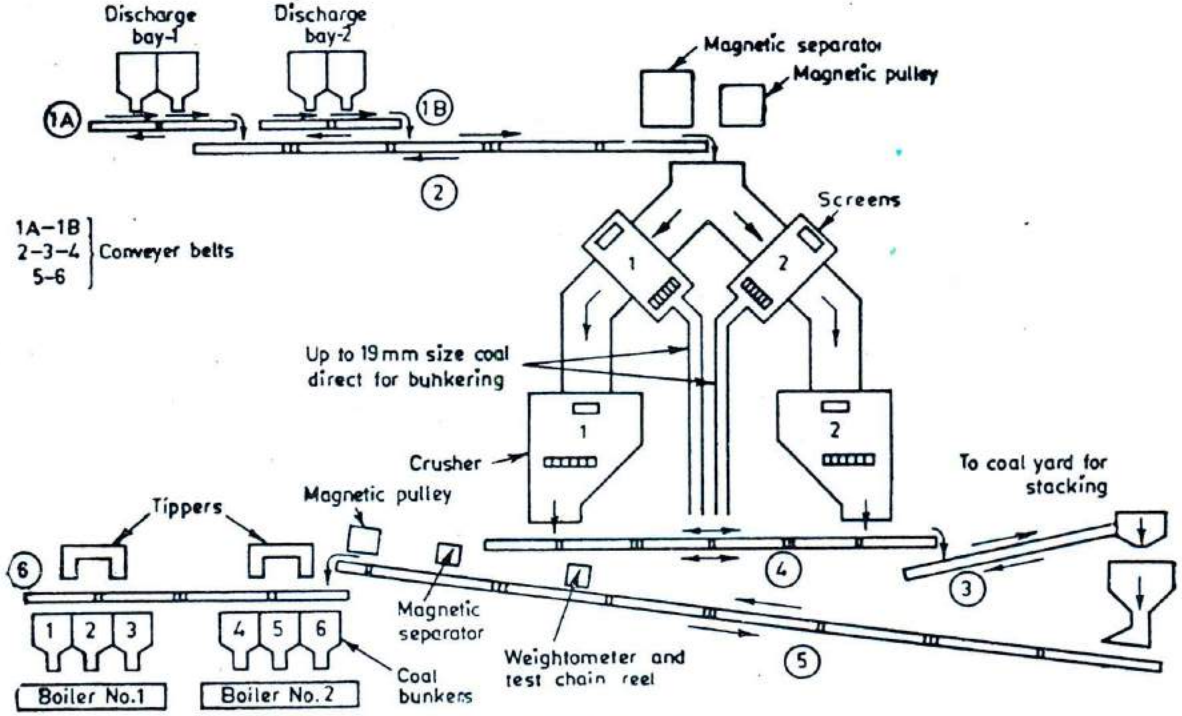


Fig 4.1. Schematic diagram of coal handling plant.

and then to the boiler bunkers. On conveyor No. 6, two controls are provided for filling the coal into bunkers, one for each unit. On the various belts, magnetic separators are provided to remove any magnetic iron material such as bolts, iron scrap, etc., which may be in the coal, so that it does not go into the crusher and also into the bunkers at their final stage.

(*iii*) *Crushing plant*: Screens are provided to reduce load on the crusher. The coal size of 19 mm and below passes through it and the remaining goes to the crusher. Vibrating equipment is provided on the screen. Coal of size larger than 19 mm is crushed in the crusher. The crusher is coupled to the motor through a fluid coupling so that there is no sudden pressure on the motor due to failure of coupling for control of the speed or the output shaft, as may be required depending on the load on the crusher.

The capacity of the bunkers should be enough to feed coal to the boilers for at least 8 hours on full load. Knowing the requirement of the boiler per 24 hours, the capacity of the crushers and the coal conveying plant size can be worked out. If the coal is received at a faster rate than required, it is stored in the yard. If the rate is low, the coal from the yard is used to make up the deficit and taken to the bunkers.

The above description is of coal handling arrangements for one of the large steam stations. If the station is located near a coal pit, transport cost by rail is avoided. If a coal mine is very near, sometimes aerial ropeways are used to take coal to the station site. The arrangements of the belts may differ, but the principle is the same.

In modern steam stations, pulverised coal is used. The coal from the bunkers is passed through coal feeders and the rate of coal fed to the boiler is measured. The coal is then taken to a pulverizing coal mill where it is ground to very small particles, of the required mesh size. The pulverised coal is then forced by primary air into the burners of the boiler furnace.

In some arrangements, pulverised coal is transported to a pulverised fuel store, usually a bin, and then flows through the

feeder to the burners in accordance with the load requirements by variation of feeder speed. The fuel is then burned in the furnace of the boiler.

For efficient combustion, enough air must be supplied. Natural draft is provided by the chimney, and additional draft by induced draft fans and forced draft fans. Heat is produced due to combustion of the fuel. The gaseous products of combustion give most of their heat to the water in the tubes of the boiler and the superheater. To make use of the remaining heat, the gases pass through an economiser, thus heating the feed water in the economiser tubes and also through an air heater arrangement whereby air to be admitted to the furnace is initially heated. Finally, the gases pass through electrostatic precipitators and then out to the atmosphere through the chimney. Fig. 4.2 shows the flue gas flow arrangement.

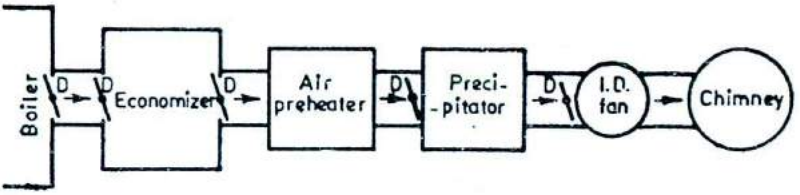


Fig. 4.2. Flue gas flow arrangement.

The residue of the burnt fuel reduces to ash. Care should be taken to ensure that combustion is as perfect as possible and that no unburned carbon is wasted in ash. Also the particles of coal should split up and no clinker should be formed. The handling and removing of ash is also a problem which needs careful planning.

4.2.2 ASH HANDLING

When pulverised coal is burned in the boiler, about 84% of the total ash content of the coal goes with the flue gases in the form of dust or fly ash. The remaining 16% drops into the furnace bottom slag hopper in the form of ash lumps formed on the water walls. Sometimes hard clinkers are also formed which come out at the bottom slag hopper. Thus, in order to estimate the total

quantity of fly ash, we must know the ash content of the coal burnt and coal consumption of the boiler per day.

The dust or fly ash contained in the flue gases is collected and separated out in electrostatic. precipitators. The electrostatic precipitator efficiency is of the order of 98 to 98.5%. It is, therefore, evident that very fine microscopic dust particles having a diameter upto 10 microns escape through the electrostatic precipitators and pass out to the atmosphere through I. D. fans and chimney. The total ash which causes pollution in the atmosphere is of the order of 1.5 to 2% of the fly ash content.

The ash collected in the electrostatic precipitators, and in some cases in mechanical cyclone type precipitators in place of electrostatic ones or assisting the electrostatic precipitators in series, is moved either pneumatically with air under pressure or vacuumatically upto the main ash silos. Air compressors or vacuum pumps assisted with filters, and self capping shutters for prevention of leakage of vacuum are provided. In the case of pneumatic ash handling systems ash/air mixing nozzles and ash virling aero jet pumps are required for fluidisation and mixing of fly ash with the conveying air.

The furnace bottom slag is handled either by a slag extractor chain or fluidised operation. Crushing of slag ash and hydraulic handling of the same is robust and reliable. Belt conveyors—horizontal and inclined—are also used for transport of slag ash from boiler bottom hoppers to slag silos. In some cases, bucket conveyors are used. In the case of belt conveyors and bucket conveyors more maintenance is required than for hydraulic ejectors and the wet sluicing process.

The ash and slag stored in silos must ultimately be handled upto the ash dumping site. This can be done by dumpers departmentally or by contract. The most reliable, clean and efficient handling system is the ash sluicing system. Water should be available in sufficient quantity, since about three to four times the quantity of water is required for handling a unit volume of ash. The ash slurry, or thick suspension of ash in water having a speci-

fic gravity upto 1.30 (25% to 30% ash in suspension), can be handled by specially designed wear and abrasion resistant pumps. At the ash dumping site a suitable valley is chosen in between two or three hillocks, where slurry is discharged through an open channel from the delivery pipe outlet. The site for dumping ash is chosen away from the power station and should have large enough capacity to accommodate the ash disposed of for many years.

Fig. 4.3 shows a section through a boiler. It shows the position of the drum, tubes and superheater.

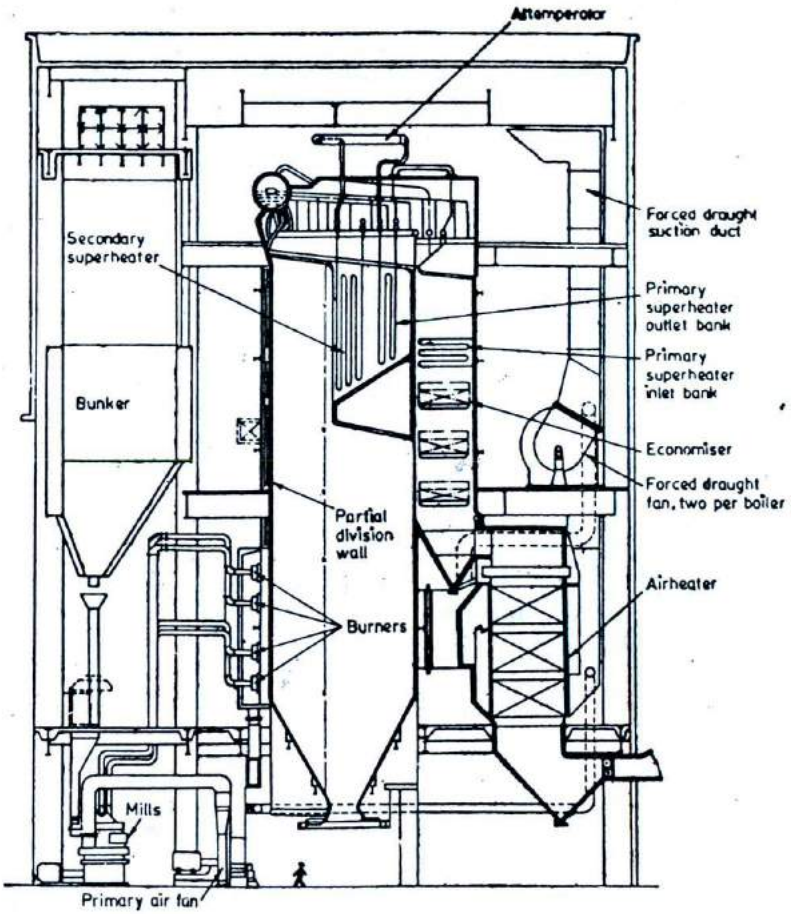


Fig. 4.3. Section through a boiler.

Fig. 4.4. shows the general arrangement of the economizer, with its water inlet and outlet. In its passage through the economizer, the feed water is heated by the flue gases.

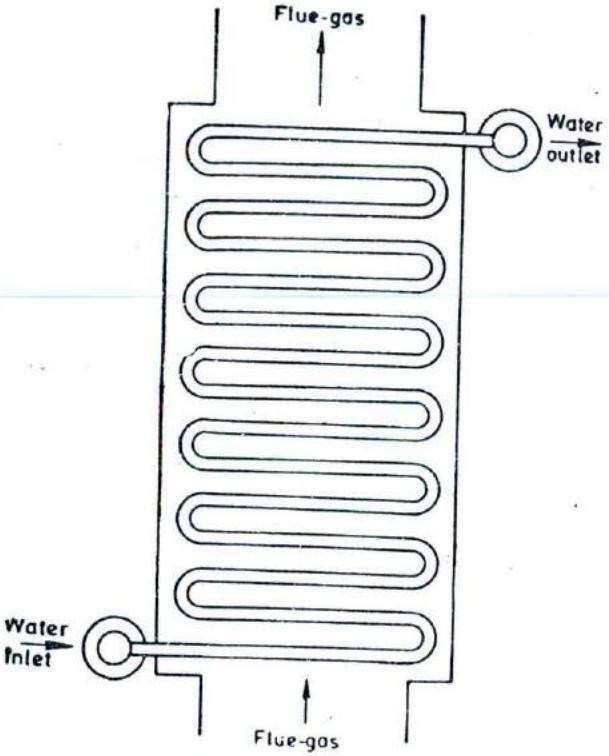


Fig. 4.4. Economizer.

The air preheater is shown in Fig. 4.5. The air is heated by the flue gases before they leave the chimney, so that some of their heat is used, which would otherwise be wasted. This heated air is supplied to the furnace instead of cold air, thus improving the heat balance.

Let us now consider the flow of water and steam in the boiler and turbine system. Water in the boiler drums and tubes is converted to steam by the heat supplied by the combustion of fuel in the furnace. The pressure and temperature of the steam depend on the design of the boiler. The steam is saturated. To increase

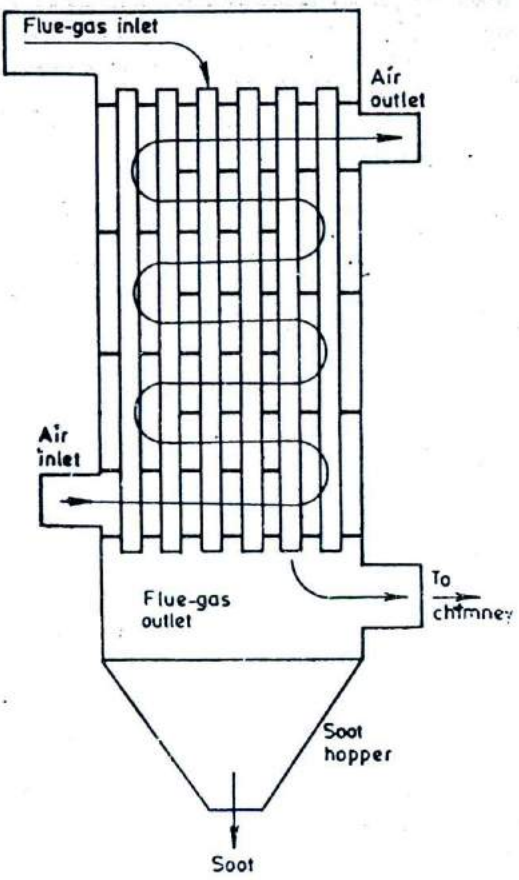


Fig. 4.5. Air preheater.

the temperature of steam, it is passed through a superheater. Through the superheater, the superheated steam is supplied to the turbine at the throttle valve.

4 2.3 STEAM TURBINES

The turbines are generally of two types, impulse and reaction. In the impulse type, expansion of steam takes place in nozzles and not in turbine blades. The potential energy in steam due to pressure and internal energy is converted to kinetic energy when passing

through the nozzles. There are a number of stationary blades and moving blades. The pressure drop can be arranged in stages. This is known as pressure compounding when the steam passes through the rotor blades, motion is produced, the energy being absorbed to give velocity to the rotor. A combination of pressure and velocity compounding is used in 'Curtis' type turbines.

Fig. 4.6 is a section through a Curtis turbine showing the nozzles, stationary blades, and the flow of steam through the turbine.

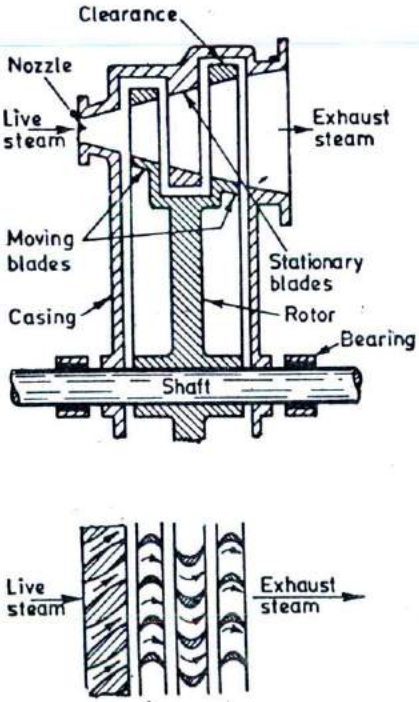


Fig. 4.6. Impulse turbine (Curtis).

Reaction turbines have no nozzles. These, too, have fixed blades and moving blades. A partial drop of pressure is used to let the steam into the moving blades. The pressure is gradually reduced in the blades as the steam passes through them and the kinetic energy produced drives the moving blades by reaction.

Sufficient stages are provided to expand the steam down to exhaust pressure.

Fig. 4.7 is a section through a Parsons turbine showing the stationary blades, moving blades, and the flow of the steam through the turbine.

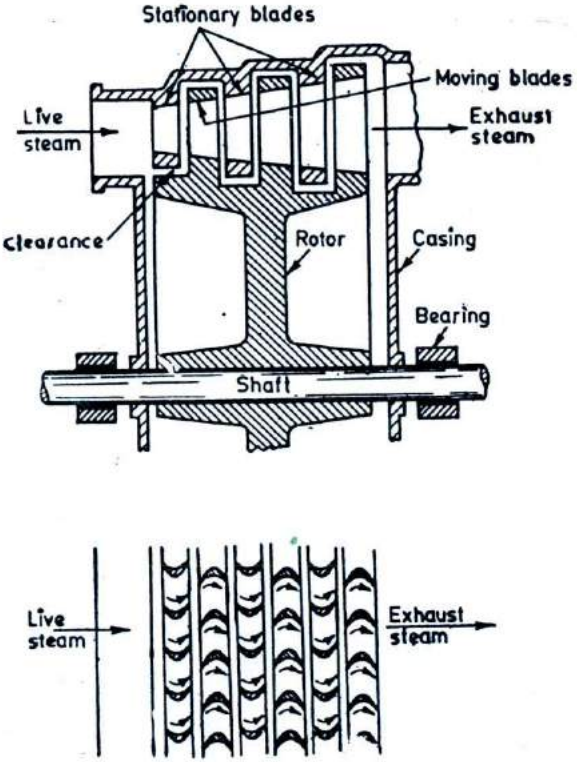


Fig. 4.7. Reaction turbine (Parsons).

In practice, arrangement of a combination of impulse wheel for high pressure turbine and reaction type for low pressure turbines is used.

The steam is expanded through a turbine from high pressure at the throttle valve to a back pressure corresponding to a vacuum of 71 to 73.5 cm. Hg. or an absolute pressure of 5 to 2.5 cm Hg. The expansion takes place approximately in accordance with the

Rankine cycle. The efficiency is increased by expanding steam to the lowest possible pressure or the highest possible vacuum in the system.

In practice, for large capacity steam turbines a multi-cylinder arrangement is used, e.g., high pressure, intermediate pressure and low pressure. The flow of steam is suitably arranged, and after full expansion through the various stages of the turbines the steam enters the condenser.

A typical arrangement of three cylinder type of turbines is shown in Fig. 4.8.

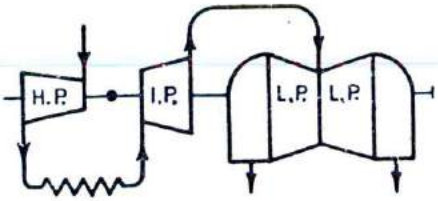


Fig. 4.8. Arrangement of 120 MW, 3 cylinder 2 exhaust reheat turbine.

Generally surface condensers are used. Sufficient vacuum is maintained in the system by the use of a steam ejector when necessary. Circulating water pumps circulate cooling water through the condenser tubes and condense the exhaust steam into condensate. Fig. 4.9 shows a typical surface condenser.

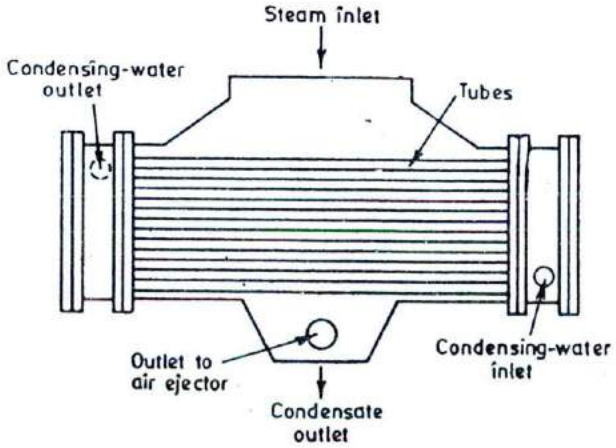


Fig. 4.9. Surface condenser.

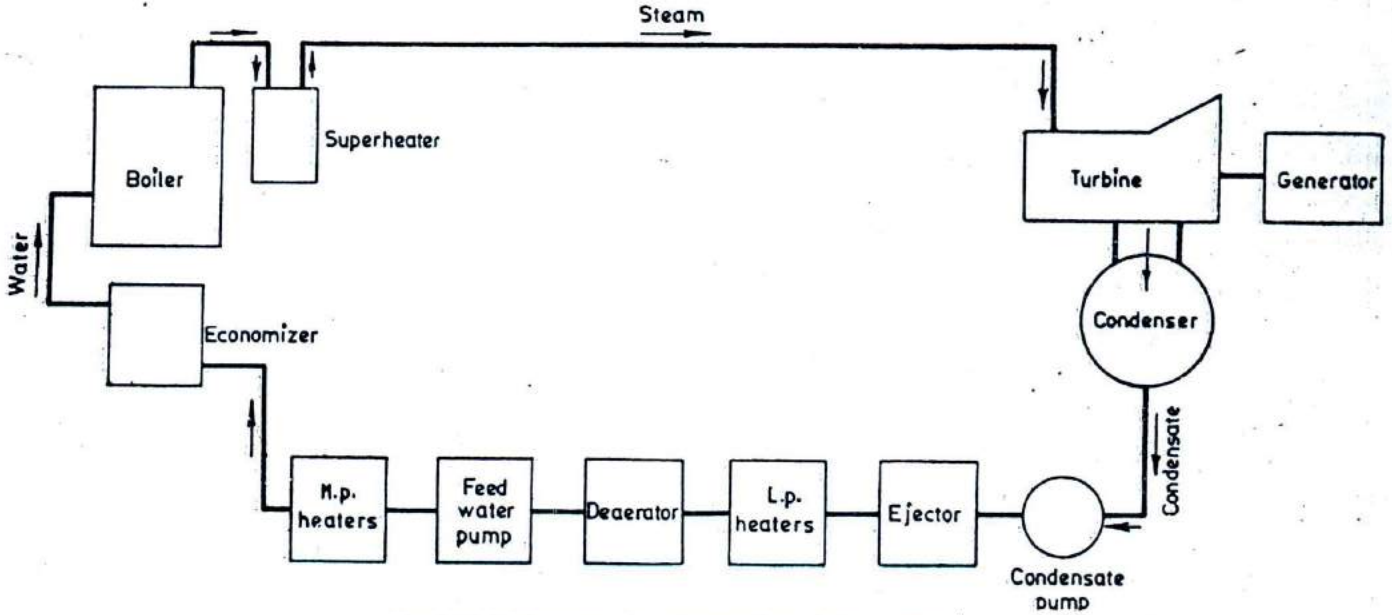


Fig. 4.10. Water steam flow diagram for a boiler turbine unit.

4.2.4 WATER STEAM FLOW

A water steam flow diagram for a boiler turbine unit is shown in Fig. 4.10.

The condensate is pumped to the deaerator by condensate pumps through low pressure heaters and a steam ejector. Feed water is pumped from the deaerator to the boiler through h. p. heaters and an economizer. A regenerative feed water system is used. Heating steam is provided by extraction from a number of bleeding points in the turbine at different stages, as required.

Some water may be lost owing to leakage through steam traps, etc., at various stages of the piping system. To make up for this loss, water is added to the feed water system. For large power stations, a demineralised water plant is installed and the demineralised water is pumped into the feed system as make up water. This may be about 1%.

Thus the water steam cycle is a closed feed cycle, the condensate being pumped back and used again as feed water to the boiler, and the cycle repeated again and again.

4.2.5 WATER TREATMENT PLANT

All modern high pressure boilers need make up water of the following purity :

pH value : 9 ± 0.2
Maximum silica content 20 micrograms/litre.
Maximum conductivity : 1 micro Siemons.
Maximum dissolved Oxygen content : 7 micrograms/litre.
Maximum iron and copper content : 10 microgram/litre.

For obtaining a make up water of this quality either evaporators or a water distilling plant have to be provided. The process of distillation of water, however, does not eliminate silica completely. The modern trend is to provide a demineralisation plant for total elimination of all dissolved salts in the water, including silica. The make up water is further dosed suitably to increase its pH value and to eliminate dissolved oxygen.

The water treatment plant mainly comprises (a) The clarifier system, (b) The filtration system and (c) The demineralisation system.

The water treatment plant flow is shown in Fig. 4.11.

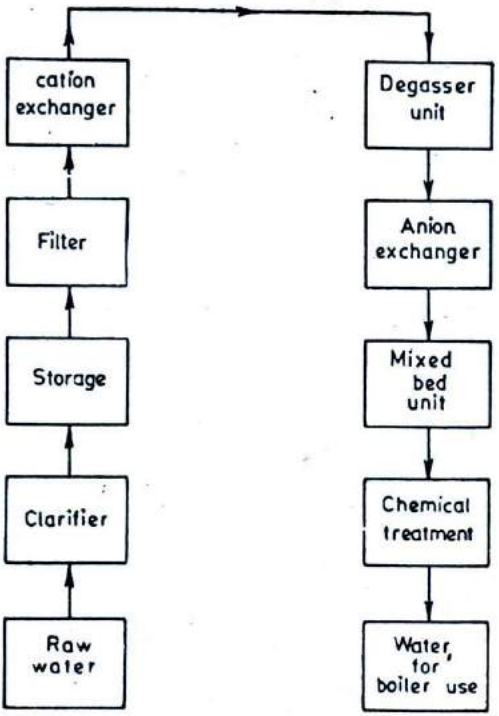


Fig. 4.11. The water treatment plant flow.

The raw water is first treated in the clarifier system with alum and lime solutions. Alum helps in coagulating the turbidity of raw water, while lime acts to maintain favourable value of the water. The clarified water, substantially free from the original turbidity, is collected at the storage tank for further processing.

From the clarified water storage tank, water is made to pass through the pressure filters, to discharge clear water, virtually free from suspended impurities.

The demineralisation system treats the filtered water by the ion exchange technique to provide water of the highest degree of purity. In this section, water is successively passed through the cation exchanger, degasser unit, the anion exchanger and the mixed bed units.

The cation exchanger unit contains strongly acidic cation exchange resins which, in their active form, take up all the metallic cations of the mineral salts present in the influent water and exchanger, and release an equivalent amount of hydrogen ions or the acidity.

At the degasser unit, the acidic water is treated with a counter current flow of air, when the carbondioxide formed as a result of splitting of bicarbonate of water, is eliminated from the water.

The acidic 'degassed' water is then passed through the Anion exchange unit, where strongly basic anion exchange resins in their active form take up all the anionic impurities of the water and in exchange release equivalent hydroxylions, with the effect that neutral water, virtually free from all ionic impurities, emerges from the system.

The demineralised water is finally polished at the mixed bed unit containing a mixture of Cation and Anion exchange resins where the last traces of ionic impurities are removed and water of the highest degree of chemical purity is collected.

4.2.6 RANKINE CYCLE

Maximum efficiency for a selected temperature range would be obtained by operation on the Carnot cycle, but the constant temperature and constant entropy parts of the cycle are difficult to attain in pratice. The Rankine cycle represents the cyclic operation very closely. Fig. 4.12 shows the cycle.

a b represents ideal pressure increase at constant entropy in the feed pump, *b c d e* represents heating at constant pressure. Out of this, *c d* represents the vapourisation of water to steam in a saturated condition. If the steam is expanded in the turbine from

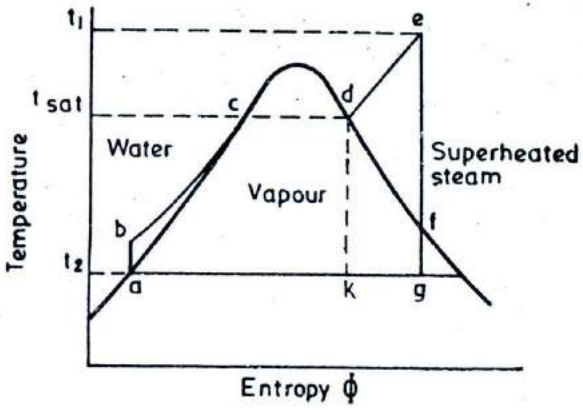


Fig. 4.12. Temperature/entropy diagram of rankine cycle

the saturated condition only, without being superheated, *d k* represents the expansion. If the steam is superheated *d e* represents the superheating operation whereby the steam temperature is raised. *e f g* represents ideal expansion at constant entropy, *g a* represents extraction of latent heat in the condenser.

In case of large sizes of turbines using high steam pressures, steam is reheated after part of the expansion and admitted again to the next cylinder in multicylinder turbines. This increases the work done and improves the efficiency of the turbine cycle. Fig. 4.13 shows the effect of reheating the steam.

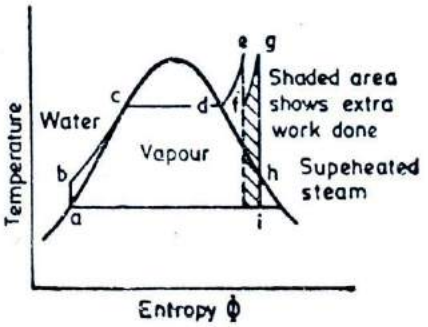


Fig. 4.13. Temperature/entropy diagram of rankine cycle with reheating of steam.

The average temperature of *b c d e* and *f g* has increased due to reheating. *a b* represents ideal pressure increase at constant entropy in the feed pump. *b c d e* represents heating at constant pressure. Out of this *d e* represents superheating, *e f* is ideal expansion at constant entropy before reheating. *f g* represents reheating at constant pressure. *g h* represents ideal expansion at constant entropy after reheating, *i a* represents extraction of latent heat in the condenser.

The shaded area shows extra work done in the cycle owing to reheating of the steam. It will also be seen that after expansion, the dryness fraction of the steam improves as an effect of reheating

4.2.7 COOLING WATER SYSTEM FOR CONDENSERS

Exhaust steam in the condenser is cooled to reduce it to condensate and this is pumped back to the boiler as described in the last section, thus forming a closed feed water cycle. This cooling is effected by water pumped through circulating water pumps. The source of this water may be a river or lake and if the power station is suitably located with enough water available in the river throughout the year, a direct cooling system may be used. In this system, water is pumped from the river to an open channel and taken to the circulating water pumps through strainers. The circulating water is then pumped through the condenser tubes. For such arrangements, a settling tank and syphon system is used before the circulating water pump at the inlet. This water is then returned to the river on the downstream side by gravity.

If the quantity of water required for condensing the steam in various units in the power station is very large and is not easily available for a direct cooling system from the river, cooling towers are used in the system. Water is circulated from the basin of the cooling tower through the condenser. It absorbs latent heat from the exhaust steam and gets warm. This hot water is returned to the cooling tower where it is dropped from a height (about 8 to 10 m). The height of the tower and its water handling capacity is suitably designed for particular cases. The effect of the cooling tower is to reduce the temperature of this hot water by about 7° to

10°C as it falls down into the basin in the bottom of the tower. This water at lower temperature is circulated through the condenser and the cycle repeated over and over again.

Types of cooling towers: Cooling towers used for power station purposes may be classified as follows :

(i) Wet type cooling towers,
(ii) Dry type cooling towers, and
(iii) Wet and dry cooling towers.

(i) In wet type cooling towers, which are also called "Evaporative", water comes in intimate contact with the cooling air and transfers about 75% of the total heat by evaporation. Air water contact occurs in the fill packing.

Two types of fill are used in wet towers. Splash-bar fill is a series of horizontal staggered bars which break the water into droplets as it falls through the fill and cooling air. Film type fill is a series of vertical plates which form the falling water into thin sheets through which the cooling air passes.

(ii) The dry type of cooling tower uses either air cooled condensers or air cooled heat exchangers, and there is no contact between air and water.

(iii) The wet dry tower has both wet fill and dry heat exchange surface.

The cooling towers can also be classified as 'crossflow' and 'counterflow' types of towers. This is with respect to the relative flow directions of air and falling water in the fill. In crossflow type towers, air flows crosswise to the falling water. In counterflow type towers, air flows vertically upwards, counter to the falling water.

Towers can also be classified by the method of creating air movement through them. Such as (*i*) natural draft, (*ii*) mechanical draft and (*iii*) mechanical and natural draft.

In natural draft towers, air movement is induced by a large chimney and the density difference between the air inside and out-

side the chimney. In mechanical draft, air is moved by fans, either of the induced type that pull air through the tower, or the forced type that push the air through. Combination of mechanical and natural draft towers incorporate both a chimney and fans.

Heat transfer from water to air: Heat transfer from water to air takes place by conduction, evaporation, radiation and convection. Conduction or convection is directly proportional to the amount and characteristic of water air surface interface and the difference between the water temperature and the ambient-air dry bulb. The rate of heat transfer by both conduction and evaporation increases with increases in air to water interface surface, relative velocity, contact time and temperature differential. Packing and fill in a tower serve to increase the interface surface; the tower chimney or fans create the relative air to water velocity; contact time is a function of tower size. Temperature differential is related to ambient wet and dry bulb temperature.

It is characteristic for natural draft towers to have relatively better output at lower wet bulb and for mechanical draft towers to have better performance at higher wet bulbs. Relative humidity influences buoyancy drive and chimney effect in the natural draft tower; its performance improves at higher relative humidity. This effect is absent in mechanical draft towers.

The mechanical induced draft evaporative cross flow tower is the most prevalent type of cooling tower used in power stations.

The various types of towers mentioned and discussed above are shown in Fig. 4.14.

A natural draft cooling tower is shown in more detail in Fig. 4.15. Circulating water is diverted in small channels all round the tower and towards the centre and arranged to descend in droplets, thus producing considerable evaporation and cooling. The draft is produced by the difference in pressure of the hot air column inside the tower and the equivalent column of cold air outside. Water from the base of the cooling tower is pumped in the condenser and the cycle is repeated.

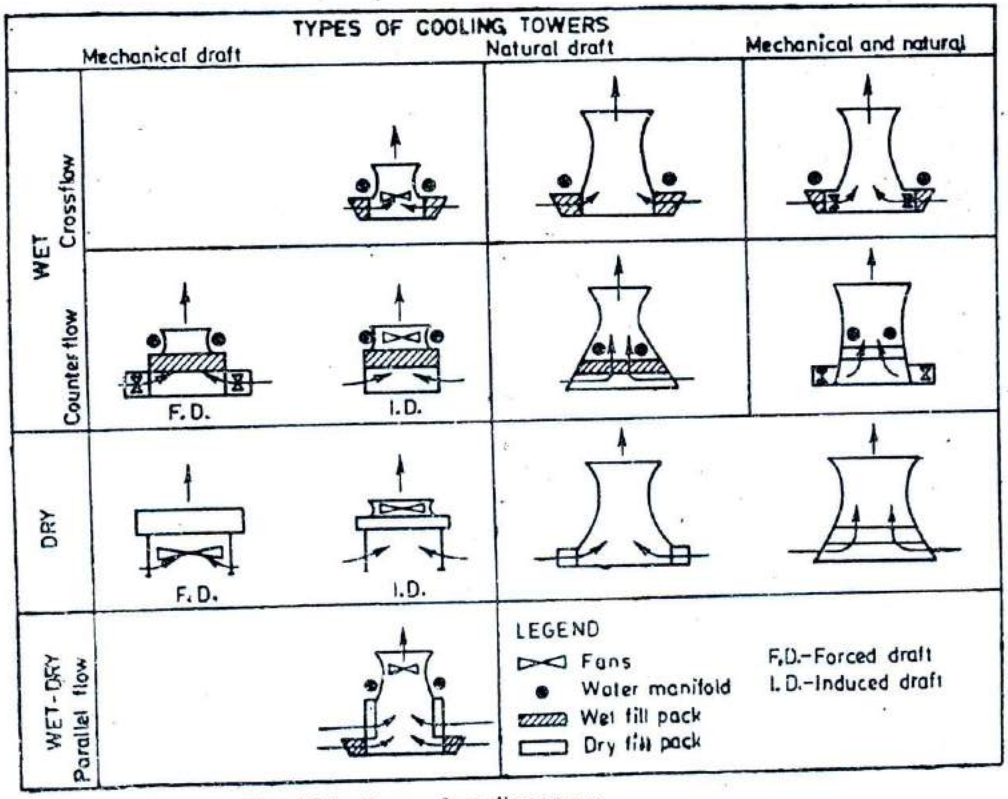


Fig. 4.14. Types of cooling towers.

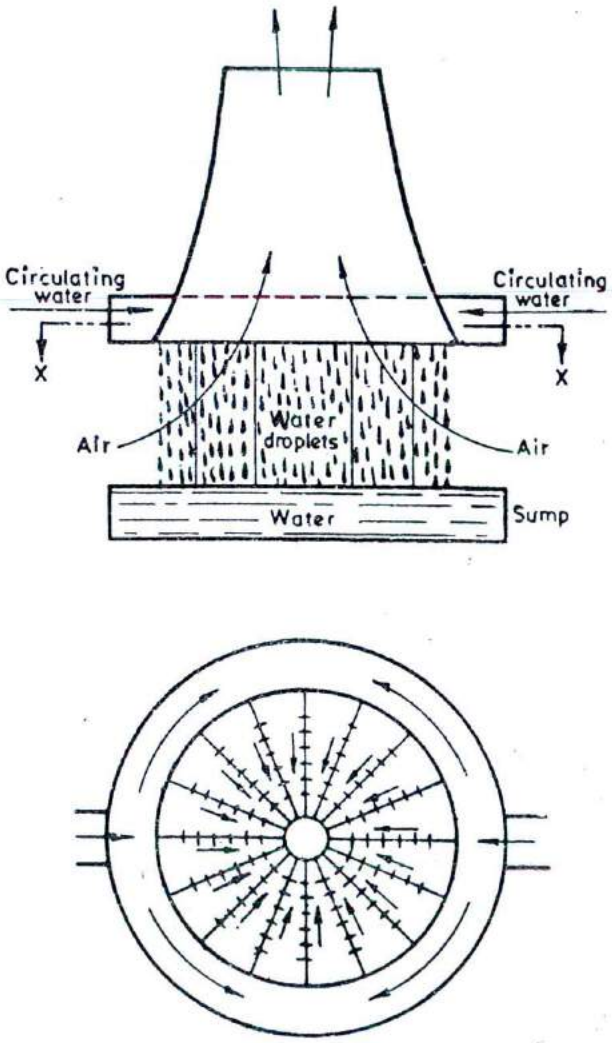


Fig. 4.15. Natural draft cooling tower.

Cooling water passing through the condenser tubes absorbs heat and in general promotes conditions suitable for the growth of algae. This growth adhering to the walls of the tubes interferes with the heat transfer and results in a poorer vacuum and higher consumption of steam by the turbine. Chlorine is, therefore, added to the water at regular intervals in order to kill the growth and to maintain the tubes in a clean condition. A secondary advantage is also gained in that the cooling towers and ponds are kept free from algae when enough chlorine is added to the cooling water.

4.3 Types of Boiler and Their Characteristics

Water-tube boilers of the two or three drum type and for different steam pressures are in common use in steam stations. Sometimes water-tube boilers with only one drum are used, and they operate satisfactorily. High-pressure boilers have now been developed, and consequently the capacities of individual boiler units have been increased. Boiler units with pressures as high as 168 kg/cm² (gauge) and with capacities upto 1,000 tons per hour are available. The development of high pressure, high temperature boilers has been possible mainly owing to the development of materials capable of withstanding high pressures and particularly high temperatures, and also as a result of improvements in the design of furnaces and in modern applications of reheat-recovery apparatus.

The pressure and temperature ranges used for steam generators may be grouped into the following categories—

9 to 17.5 kg/cm² saturated steam superheated to 65°C superheat

17.5 to 28 kg/cm² saturated steam heated to 400°C total

28 to 56 kg/cm² steam with temperature range of 400 to 440°C.

56 to 70 kg/cm² steam with temperature range of 440 to 482°C.

70 to 140 kg/cm² steam with temperature range of 450 to 565°C.

168 or 182 kg/cm² steam at 620°C (a special case)

The following points have to be considered in the design of furnaces :—

1. Quantity of fuel to be burned.
2. Load on boiler and maximum steam output required.
3. Operating pressure and desired total temperature.
5. Degree of heat recovery required.
5. Type of firing.
6. Type of fuel.

The capacity of a boiler is expressed in terms of the thousands of kilograms or tons of steam that it can supply per hour at certain rates of pressure and temperature.

The amount of fuel to be burned, the weight of air required for good combustion, and the weight of the resulting flue gases can be calculated. For good combustion a certain amount of excess air has to be supplied. The approximate amount of excess air required for different fuels is as follows—

Fuel	*Excess air*
Coal : Stoker-fired furnaces	20%
Pulverized-fuel furnaces	18 to 22%
Oil . . .	15%
Gaseous fuels . . .	10 to 15%

In pulverized-fuel-fired furnaces the combustion equipment has burners with short flame, long flame or tangential. With modern boilers a high-turbulance furnace called a cyclone furnace is sometimes used. The cyclone furnace is a horizontal cylinder of water-cooled construction. Its inner surface is lined with chrome ore. Primary air and partially crushed fuel are admitted tangentially to a small scroll section at the end of the cyclone. A swirling motion is imparted and this motion is amplified by secondary air admission tangential to the inner surface. Combustion is effected at a rapid rate with high temperatures of the order of 1,650°C. This type of furnace gives a rate of heat release which may be as high as 3.5 kcal/cm^3 per hour.

There are two systems of pulverized fuel operation, the bin system and the unit system. In the bin system, coal is ground at

a constant rate and then transported to a pulverized fuel store or bin. From the bin, the coal flows through the feeder to the burners, the speed of the feeder being varied to suit the load. In the unit system there is no storage, the fuel being ground and fired directly into the furnace at a rate demanded by the load.

The above methods are used for high pressure high temperature boilers. For moderate pressures and temperatures, overfeed or underfeed strokers are used. In the overfeed stroker, the fuel is fed on to a travelling horizontal surface and air is fed upward through the grate to the coal. The coal is burned on a travelling grate, or chain grate. When fuels need breaking up and agitation of the fuel bed, underfeed strokers of the multi retort type are used. The retorts may be either horizontal or sloping. In the underfeed stoker, the coal is fed below the point of air admission to agitate the fuel bed. The coal used in these two methods is crushed to a small size of about 1 cm square For medium and small size boilers, firebrick lined furnaces are used. Modern high pressure boilers have water-cooled low-heat-release furnaces.

The approximate efficiency of water-tube boilers used for power purposes without heat recovery and using coal as fuel, may be taken as about 75% to 77%. With the addition of heat recovery apparatus, the efficiency of modern boilers can be increased to between 85% and 90%. With oil as fuel, the efficiency may be about 2% to 3% higher.

The efficiency of a boiler is increased by the use of an air heater, superheater, economizer, feed-water heater, etc. Since the air-heater surface is generally the least expensive, the trend is towards the use of a liberal furnace, a minimum tube surface, a small economizer and a large air heater. The temperature of the air used for burning the fuel is raised by preheating it with the flue gases. The use of air heaters and economizers reduce the heat lost in the flue gases and hence increases the boiler efficiency. Without the use of a superheater, a boiler produces steam of about 98% dryness fraction, or nearly saturated. It is not desirable to admit this steam to a turbine because the turbine exhaust will then have steam of low dryness fraction—practically wet steam.

This results in the presence of moisture which causes corrosion of the turbine parts. Apart from this, the efficiency of the turbine is reduced. It is, therefore, necessary to increase the temperature of the steam at the point of admission to the turbine, i.e. from the boiler outlet also. This is done by raising the temperature of the steam by superheating. The use of superheated steam increases the turbine efficiency, and the use of bled steam reduces the heat rejected to the condenser and hence also increases the turbine efficiency.

Superheaters are of two types, convection and radiant. The convection type uses heat in the flue gases to heat the saturated steam, while the radiant type is customarily located in the surface between the furnace-wall tubes and absorbs heat from the luminous fuel just as the furnace-wall tubes transmit radiant heat to the saturated steam in them. A convection superheater has a rising characteristic, and a radiant superheater has a falling characteristic, with increased output of the boiler. To produce steam at a constant high temperature, a radiant superheater is used in series with a convection superheater.

	Per cent
Heat absorbed by boiler (transferred to convert water to steam)	75 to 77
Heat lost to flue gases	16 to 14
Evaporation of moisture formed by burning hydrogen in fuel	4 to 3
Loss due to unburned carbon in ash	about 1
Radiation and unaccounted for	4 to 5
	100

The addition of an economizer may improve the efficiency by 4% to 10% and the addition of an air heater, 6% to 8%. The maximum efficiency with these attachments may be taken as between 87% to 90%. The exact value of the efficiency in each case depends on a number of factors such as steam pressure, calorific value of the fuel, effective burning of fuel, preheating of air and capacities of boilers, etc. An indication of the effective burning of fuel is given by the percentage of carbon dioxide (CO_2) in the flue

gases. The percentage of CO_2 that shows maximum efficiency and satisfactory operation will depend on the fuel--oil, gas, or coal—and, in the latter case, on the method of firing.

In modern boiler development, binary vapour cycles have been tried. One successful cycle uses mercury as the top fluid, and water as the bottom fluid. This type of cycle enables high temperatures to be attained without high pressures. With mercury vapour a pressure of only 9.8 to 10.5 kg/cm² is required to reach a temperature range of 510°C to 565°C. Mercury boilers are mainly of the radiant heating surface type. Liquid mercury is heated in the boiler, from which saturated mercury vapour flows to the mercury turbine, which is normally a simple impulse turbine; a generator is coupled to it. After expansion to a high vacuum, the mercury vapour is exhausted to a condenser boiler, where it is cooled by water; liquid mercury returns to the mercury boiler drum.

In the steam cycle, water in the condenser boiler, or heat exchanger, is heated by transfer of heat from the mercury vapour, and is converted into steam, which goes through a superheater located in the gas passage of the mercury boiler. The superheated steam is admitted to a steam turbine driving a second generator. After exhaust from the steam turbine into the condenser, the condensate is pumped to the condenser boiler and the cycle is repeated.

The resulting efficiency of the whole cycle can be improved. The system is still in the experimental stage and is used in only a few cases of comparatively small capacity at present.

4.4. Characteristics of Steam Turbines

The steam turbines used for power station purposes are impulse or reaction types, or use a mixed arrangement of both principles. The rotor shaft of the turbine is of forged steel and the turbine blading is fixed onto it in the required number of stages. The blades are milled from solid steel blocks. The bottom and top halves of the casing contain the stationary blades. A number of extraction stages may be fixed, depending on the economic use

of the bled steam for feed-water heating or in evaporators. For best working the highest possible vacuum is maintained in the condenser : a vacuum of 70 to 73.5 cm Hg, or an exhaust pressure of 6 to 2.5 cm Hg (absolute) is aimed at. The thermal efficiency of the steam turbine may be taken as between 24% and 32%. Units of high capacity maintain the higher vacuum (73.5 cm Hg). The efficiency depends on a number of factors, such as steam pressure and temperature at the throttle valve of the turbine, exhaust steam pressure and temperature, number of bleedings, etc.

Industrial types of turbine are generally back-pressure or non-condensing. These have very poor thermal efficiencies. Their capacities are upto 2,250 kW. Some small condensing plants upto 7,500 kW capacity are used in industry. The non-condensing types are characterised by short rotors, relatively few stages and small exhaust openings. These are less expensive than the condensing types.

For power stations, all steam turbines are of the condensing type, with as high a vacuum as possible. Surface condensers are used. Cooling water is circulated to cool and condense the exhaust steam. The capacities of turbines have been increased considerably. Units are now available upto 550 MW, and sizes upto 1,200 MW are being designed and installed.

The steam consumption of a turbine at any load can be found by tests. Small steam turbines have a steam flow at no load corresponding to 20% to 25% of the full, or rated load flow. Large central stations have a no-load steam flow corresponding to 3% to 10% of the full-load steam flow. During operation at any load, the steam flow in kilograms per hour required by a turbine can be assumed to vary in proportion to the output of the turbine, in accordance with Willan's law.

Steam flow at any load

$$= \text{No-load flow} + \left\{ \text{Load} \times \frac{\text{Full-load flow} - \text{No-load flow}}{\text{Full-load flow}} \right\} \qquad (4.1)$$

The variation of steam consumption with load is shown in Fig. 4.16 for a turbine that is not fitted with an overload valve.

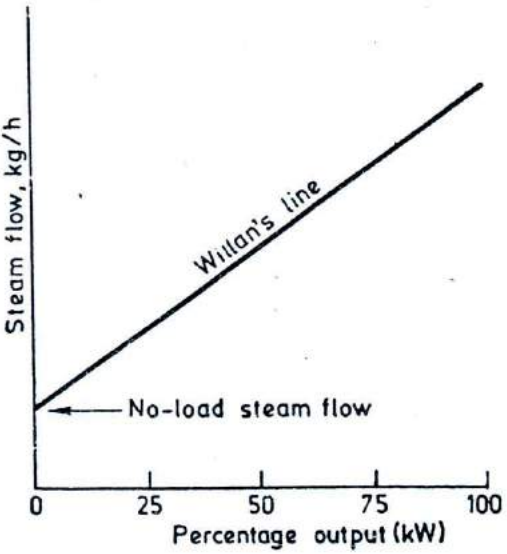


Fig. 4.16. Variation of steam consumption with load.

The preferred sizes for small turbines and coupled generators are 500, 600, 750, 1,000, 1,250, 1,500, 2,000, 2,500, 3,000, 5,000 and 7,500 kW, with steam at 28 kg/cm² and 400°C. Turbine driven a.c. generators are commonly known as turbo-alternators. Large turbo-alternators have the following preferred sizes :

Turbo-alternator rating MW	Throttle pressure kg/cm²	Throttle temperature °C
10	42	440
15	60	482
20	60	482
30	60	482
40	70 to 87	482 to 510
60	70 to 87	482 to 510
90	100	535
100	100	535
120	125	538 reheat
140	125	538 ,,
150	130/167.5	538/565 ,,
200	130/167.5	538/565 ,,
350	168	568 ,,
500	168	568 ,,

Larger units use higher-pressure boilers as well as temperatures upto 621°C for the input conditions of the steam. To suit 2-pole generators the speed of the turbines should be 3,000 rev/min for a frequency of 50 c/s or 3,600 rev/min for 60 c/s. In large turbines the size of the rotor blades is from 50 to 63 cm. Tandem compound and cross-compound arrangements with multiple exhausts are available in steam turbine units.

The efficiency ratio of a steam turbine is defined as the ratio of the thermal efficiency of the actual turbine to that of a perfect turbine —

Efficiency ratio

$$= \frac{\text{Thermal efficiency of actual turbine}}{\text{Thermal efficiency of perfect turbine}}$$

$$= \frac{\text{Steam per kWh in ideal turbine}}{\text{Steam per kWh in actual turbine}}$$

$$= \frac{\text{Work done per kg of steam in actual turbine}}{\text{Work done per kg of steam in ideal turbine}} \qquad (4.2)$$

The following tests can be carried out to determine the steam consumption in kilograms per kilowatt-hour.

When the pressure and temperature of steam at the throttle of the turbine are known, the work done per kilogram of steam is found for the ideal case by using a Mollier diagram, if the pressure of the exhaust steam is also known. This is done by locating the correct starting point of the expansion from the initial conditions of pressure and temperature and drawing a line corresponding to isentropic expansion from this point to the back-pressure line of the turbine exhaust condition. The total heat drop represented by the difference of the heat at the initial and final conditions gives the amount of work done by the steam under ideal conditions.

The heat energy corresponding to 1 kWh is 859.85 kcal. Thus

$$\frac{859.85}{\text{Heat drop in kcal in ideal expansion per kg as obtained from Mollier diagram}} = \text{kg per kWh in ideal turbine} \qquad (4.3)$$

$$\text{Turbine output} = \frac{\text{Generator output}}{\text{Generator efficiency}} \tag{4.4}$$

The generator efficiency may be taken as 97% for small machines and 98% to 99% for large machines, the efficiency being higher for hydrogen-cooled sets. The output of the generator can be measured. Thus it is possible to find the efficiency ratio of the turbine. The steam consumption during the test can be measured by a steam-flow meter.

The pressure and temperature of the steam, the amount of coal consumed, the feed-water temperature, vacuum, etc. are all measured during the test.

$$\text{Overall thermal efficiency} = \frac{\text{Generator output per kg of steam}}{\text{Heat input per kg of steam from perfect boiler supplied with feed water at hot-well temperature}} \tag{4.5}$$

Thermal efficiency of ideal turbine

$$= \frac{\text{Heat drop (kcal) from Mollier diagram}}{\left\{\begin{array}{l}\text{Heat input (kcal) corresponding to conditions of steam at admission}\end{array}\right\} - \left\{\begin{array}{c}\text{Heat in condensate (kcal)}\end{array}\right\}} \tag{4.6}$$

This is the thermal efficiency of the steam turbine and condenser together. The exhaust steam is condensed into condensate, the temperature of which may be about 38°C. The heat in the condensate, in kilocalories per kilogram, at a pressure of 0.035 kg/cm² (absolute) can be calculated. The condensate is pumped back into the boiler through the condensate pump and feed-water pump, being heated on the way to a higher temperature before passing into the boiler.

Heat absorbed by cooling water

$$= \left\{\begin{array}{l}\text{Heat in exhaust steam at a pressure taking dryness fraction into account}\end{array}\right\} - \left\{\begin{array}{l}\text{Heat in condensate at back pressure (say 0.035 kg/cm² abs.)}\end{array}\right\} \tag{4.7}$$

The steam consumption of large steam turbines is about 3.5 to 5 kg per kWh. The exact value depends on the particular conditions of operation, namely, steam pressure and temperature at the inlet, exhaust pressure, number of bleeding stages, etc. For the above approximation, it is assumed that the steam pressure is at least 42 kg/cm² at a temperature of 440°C, and that the absolute pressure at exhaust is 5 to 2·5 cm Hg. The steam consumption of smaller units is higher.

The average heat balance of a large turbine and surface condenser together may be taken to be approximately as follows :

	per cent
Work done, or thermal efficiency	24 to 32
Friction and windage loss	2 to 1
Heat to circulating water	67 to 62
Heat to condensate to be returned to boiler	7 to 5
	100

Most of the heat input to the condenser is given to the cooling water to condense the exhaust steam into condensate—water—at the exhaust steam pressure, the heat in the liquid condensate being negligible. Practically 90% to 92% of the condenser heat is given to the cooling water, and only 8% to 10% remains in the condensate.

Overall efficiency of steam station

$$= \left\{\begin{matrix}\text{Generator}\\ \text{efficiency}\end{matrix}\right\} \times \left\{\begin{matrix}\text{Thermal efficiency}\\ \text{of steam turbine}\\ \text{(including condenser)}\end{matrix}\right\} \times \left\{\begin{matrix}\text{Boiler}\\ \text{efficiency}\end{matrix}\right\} \quad (4.8)$$

The calorific value of coal is 6,725 to 7,850 kcal/kg. With large units the heat rate for the whole station is 5,600 to 7,850 kcal/kWh and the overall thermal efficiency is between 18% and 32%. With smaller units the efficiency is much less.

4.5 Characteristics of Turbo-alternators

Small industrial steam-turbine-driven a.c. generators are sometimes 4 pole machines with a speed of 1,500 rev/min for

50-c/s operation, or 1,800 rev/min for 60-c/s. If a turbine is of high speed, the speed of the generator coupled to it is reduced by means of gears. All high capacity machines are 2-pole, with a speed of 3,000 rev/min for 50-c/s operation, and 3,600 rev/min for 60-c/s. Thus most of the turbo-alternators in central power stations are 2-pole. Preferred sizes of turbo-alternators from 10 to 500 MW were listed in Section 4.4. The largest set available is 550 MW, while sets upto 1,200 MW are being designed and installed.

The rotor of a synchronous machine may be of either the cylindrical type or the salient pole type. Turbo-alternators have cylindrical rotors, and, therefore, a uniform air-gap. The 2-pole winding for the field system is accommodated in slots in the solid rotor, the slots being made by slotting and shaping machines. The conductors are bare copper strips insulated by layers of mica. The connexions are brought out to the sliprings through the rotor shaft, which is hollow. The rotor of a turbo-alternator is of small diameter and is very long compared to that of a salient pole machine used for low-speed operation. The air-gap of the turbo-alternator is also long compared to that of a salient pole machine.

In designing the rotor the critical speed should be avoided. Critical speed is the rotational speed of a shaft at which some periodic disturbing force coincides with the fundamental, or some higher mode of the natural frequency of transverse vibration of the shaft and its attached masses. If a large force is applied to the centre of the shaft and then released, the shaft will vibrate up and down at its natural frequency. The stiffer the shaft, the higher its critical speed. The rotor should be carefully balanced. Small machines have their critical speed above the running speed. Large machines generally pass through their first critical speed before coming to the running speed.

The rotor and stator of a turbo-alternator may be air cooled if the machine can be maintained within the specified temperature limits on load. The air circulates through ducts in the stator and along the air-gap, and then passes through a set of water-cooled coils. This arrangement is generally used upto a capacity of 40 MW. Above this capacity, the rotor and stator are cooled by hydrogen, which passes through ducts in both rotor and stator.

There are a number of advantages in using hydrogen. The windage losses of the rotor turning in hydrogen are only 10% of those in air. The higher thermal conductivity of hydrogen allows generators to develop about 25% more output than with air cooling for the same physical dimensions. The generators can carry greater loads with losses no greater than those with air cooling. Hydrogen increases the life of the insulation because of the absence of oxygen. The generator enclosure must be gas-tight. An automatic system of gas control and alarms helps to keep the hydrogen at the proper pressure and temperature. Special labyrinth-type oil gland seals on the bearings keep hydrogen leakage to a safe minimum. It is necessary to maintain the hydrogen in a pure condition, and hence precautions should be taken to prevent any air from leaking into the machine. A mixture of air and hydrogen inside the machine casing is risky and may cause an explosion.

The stator and rotor of the hydrogen-cooled turbo-alternator are sealed from outside air, and the pressure of the hydrogen is normally maintained at least 0.035 kg/cm^2 higher than the outside atmospheric pressure. Vertical coolers are mounted in duplicate at four points in the stator yoke. Centrifugal fans at the end of the rotor circulate the hydrogen. The hydrogen pressure can be increased to 1 kg/cm^2 to reduce the possibility of air leakage into the machine.

The efficiency of large turbo-alternators can be taken as 98% with air cooling and 99% with hydrogen cooling.

With the development of higher capacity units, it becomes more difficult to provide effective cooling of the stator. For sets above 150 MW, some manufacturers use hollow stator conductors with which there are three methods of cooling, the one selected depending on the size of the machine :

1. The rotor is air cooled, and air circulates through the stator conductors.
2. The rotor is hydrogen cooled, but no coolant circulate through the stator conductors.
3. The rotor is hydrogen cooled, and oil is forced through stator conductors. The use of water instead of oil is being considered.

A common voltage rating for turbo-alternators is 11 kV; the 3-phase star connexion of the stator windings is universal. In India and Britain the standard frequency is 50 c/s. In the United States the usual voltage rating is 13.8 kV, and the standard frequency 60 c/s. Higher voltages of 22 kV and 33 kV are also used in large machines in some cases. The machines with higher voltage ratings are expensive, and their insulation is a serious problem. There is not much advantage in choosing a very high voltage for generation in a power system when transformers are to be used for stepping up the voltage for transmission.

Turbo-alternators are generally rated at 0.8 power factor lagging. In large systems, where the power factor is much better on the whole, the tendency is to rate the generators at 0.9 power factor. The exciters for producing the field current are coupled to the main generators. With a large machine, a pilot exciter may be used to excite the main exciter. The main exciters are compound d.c. generators of 115 V or 230 V rating and of sufficient capacity to give the required excitation for the main generators on full load, and with an overload of about 20% at rated power factor. The generators and turbines are rated to carry at least 10% overload at an exhaust pressure of 5 cm Hg (absolute) when working under normal throttle pressure and temperature.

4.6 Design of a Steam Power Station : Capacity of Main Equipment

The first thing to decide is the choice of turbo-alternator units to suit the load curve of the station, as discussed in chapter 2. The size of the generators will mainly depend on the nature of the load curve, the location of the load centre and its distance from the station, the availability of condensing water, the space available for the units and for future expansion, the rate of load growth and the reserve capacity required.

The sizes of generator units available are considered. In selecting the size of a unit, its initial cost and efficiency at various loads are taken into account. As the unit capacity is increased

there is reduction in cost per kilowatt, in floor space required per kilowatt, and in the building volume per kilowatt. Larger units also have higher efficiencies. When choosing the units, choose them in as large a size as possible, keeping the load curve in view. The heat rate of the unit in terms of kilocalories per kilowatt-hour at various load factors should be considered. Determine the load duration curve of the station. Guaranteed heat rates are modified for seasonal variation of circulating-water temperature, which changes the possible vacuum attainable in the condenser. When it is necessary to choose between units of the same capacity but of different makes, it is worthwhile to plot all the heat rates for the same operating conditions and circulating-water temperature on a graph sheet and study the different heat rates at various fractional loads. The final economy may then be compared with the charges on the investment costs.

The choice of sizes of generators to be installed is thus made. The voltage of generation is normally chosen as 11 kV, although 22 kV and 33 kV are sometimes considered. The frequency is the standard one used in the particular country. The speed of the generator must suit 2-pole operation. The power factor rating is 0·8 or 0.9 lagging. The generators will be air cooled or hydrogen cooled, depending on their size. The kVA capacity of the generators should be mentioned. The generators are 3-phase and star-connected. Their efficiency may be taken as between 98% and 99% depending on the size and the type of cooling.

The next step is to find the size of the turbine.

$$\text{Turbine output (kW) at shaft on full load} = \frac{\text{Capacity of generator (kW)}}{\text{Generator efficiency}} \qquad (4.9)$$

The thermal efficiency of the turbine to be chosen must be considered, and the heat output per hour at full load should be found. This is the number of kilowatt-hours produced in one hour on full load multiplied by 859.85 kcal per hour.

$$\text{Heat input per hour} = \frac{\text{Heat output per hour}}{\text{Thermal efficiency of turbine}} \qquad (4.10)$$

The approximate steam consumption per kilowatt-hour on full load will be known from the rate of steam consumption guaranteed by the manufacturer, or can be found by testing the turbines. The number of kilowatt-hours produced per hour on full load being known, the steam consumption per hour can be found. The pressure and temperature of the steam inlet to the turbine are chosen to suit the size of the turbine and to give enough heat input to supply full load easily. About 10% extra capacity is added for the steam inlet, as the machine should be capable of taking about 10% overload for sometime without affecting the performance. The approximate pressures and temperatures of the steam used for different standard sizes of turbine were mentioned in Section 4.4 for preliminary choice.

If the operation of the turbo-alternator at different fractional loads is considered, the efficiency of the generator at partial load, the thermal efficiency of the turbine at partial load, and the corresponding steam consumption for that load, may be used in finding the total steam consumption required for the partial load for one hour. If the load is continuously changing, the total steam consumption during a given period may be obtained from the load duration curve and the heat input/output characteristic of the turbine.

When the capacity of the turbines has been determined, the next problem is to choose the size of the boiler. The maximum heat input to the turbine under full load or 10% overload operation is determined. This must be the minimum capacity of the boiler if the unit system is to be used, i.e., one boiler for one turbine; this is preferable if possible. As boilers with capacities as large as 1,000 tons per hour are now available, the unit system is possible even with very large machines.

The boiler capacity in terms of tons of steam per hour is thus determined. The pressure and temperature of steam are as required for turbine operation at the throttle valve. The selection of a particular type of boiler depends on a number of factors, namely, the type of fuel, the space available for boiler installation, the cost of fuel and the desirability of using heat recovery equip-

ment, the type of load to be supplied by the boiler, and the controls necessary to enable the load to be picked up quickly. To justify the use of an air heater and economizer, the increased fixed cost due to the installation of heat-recovery apparatus should be balanced by the saving in the operating costs due to improved efficiency. The choice of steam pressure and temperature is made in accordance with the turbine requirements and the standard sizes available. The boiler efficiency is about 75% to 77% without heat recovery, and about 85% with heat recovery.

$$\text{Heat input to boiler per hour} = \frac{\text{Heat output per hour}}{\text{Boiler efficiency}} \qquad (4.11)$$

Knowing the calorific value of the fuel, the consumption of fuel per hour can be found.

Specifications of Boilers and Turbines: The main specifications of boilers include the following items :

Capacity in MW, steam flow in tons/hour. This should be given as maximum continuous rating and minimum continuous rating; type of furnaces, temperature of steam, type of burners, type of fuel burned (coal or oil) type of coal mills, design pressure of steam, operating steam presure kg/cm^2, boiler auxiliaries such as forced draft, induced draft, type of precipitator, air heaters, economizer, superheaters, whether reheat arrangement used, etc. coal and ash handling plant—type and capacity per hour.

The main specifications of steam turbines will include the following items:

Capacity of turbine MW, steam pressure at throttle valve, kg/cm^2, temperature °C, number of cylinders, arrangement of cylinders, H. P., I. P., L. P. Steam pressures and temperatures at input and output of each. Type of turbine (impulse, reaction or mixed), stages in each cylinder, bleeding points, number of heaters, feed pumps, condensate pumps, circulating water pumps, Types of condenser—surface, vacuum in kg/cm^2 abs or cm of Hg.

Generator specifications are dealt with in a later chapter.

4.7 Main Dimensions of Turbo-alternators

The main dimensions of a generator are the diameter at the air-gap and the length of the stator core. The general expression for the kVA rating in terms of these main dimensions was developed in chapter 3 (eqn. 3.23) :

$$S = 10.4 \times 10^{-3} B a_c \, D^2 L \, n$$

This expression applies equally to turbo-alternators.

The difference between the Diesel-driven generator and the steam turbo-alternator is that the Diesel generator is a low-speed machine, and has a salient pole field construction, while the turbo-alternator is a high speed machine with a cylindrical rotor and only a 2 pole field system. The diameter of the turbo-alternator is, therefore, small in comparison with its length; the speed limit is generally 100 m/s, which decides the maximum possible diameter that can be chosen; the air gap is uniform. The specific electric loading can be larger, but the flux density, or specific magnetic loading, for turbo-alternators is less than in low-speed machines. For turbo-alternators, the values for these constants may be taken approximately as follows :

a_c = 400 to 500 ampere conductors per centimetre of stator periphery.

$B = 4.8 \times 10^{-5}$ to 5.6×10^{-5} Wb/cm^2

The length of the core, L, may be taken as 2 to 2.4 times the pole pitch :

$$L = (2 \text{ to } 2.4) \times \frac{\pi D}{p} \qquad (4.12)$$

When the average flux density and the specific electric loading have been chosen, the product D^2L can be found for a given kVA output of the alternator. The speed will be 3,000 rev/min for 50-c/s or 3,600 rev/min for 60-c/s machines having 2 poles. When L has been chosen (say, twice the pole pitch), the D^2L product can be expressed in terms of D^3; the diameter can then be determined. This should be checked with reference to the maximum speed limit.

4.8 Economic Considerations in Selection of the Main Equipment of Steam Station

Boilers. Large boilers are preferable when available for turbine generator sets of similar large capacity, the unit system being preferable, i.e., one boiler for one turbine generator set. With large boilers, the building costs are reduced. The number of boiler auxiliaries, the space required and the fixed and labour costs are reduced by having one large boiler rather than two or more smaller ones to make up the required capacity. In selecting the capacity of boiler, the load factor and the capacity factor of the station unit as well as the reserve requirements of the station must be taken into consideration.

The cost of steam generating equipment depends on a number of factors, such as operating steam pressure and temperature, type of boiler, efficiency of boiler, type of firing and choice of fuel.

In choosing fuel for the boiler, the following economic considerations are important when the choice is restricted by the location of the station :

Cost of fuel per million kilocalories
Average plant efficiency
Cost of plant
Effect on boiler plant capacity
Operation and maintenance cost of fuel burning and heat absorbing apparatus
Operation and maintenance cost of fuel preparation and storage equipment.
Annual fixed charges on investment in fuel handling and storage equipment.
Annual fixed charges on investment in fuel burning and heat absorbing apparatus.

When comparing different types of fuel for use in the boiler, the above points are considered and the economic analysis is worked out to decide which will be the best choice.

In selecting the fuel burning equipment, the relative combustion

rates per cubic centimetre of furnace volume and of building volume should be considered.

The selection of economizer and air heater surfaces is an economic problem. Heat recovery equipment and added flue work and building area increase the cost. The fixed costs due to increased investment and the saving in operation costs due to reduction of flue-gas temperature should balance and show the justification for the use of heat recovery apparatus. Generally, economizers improve boiler efficiency by 4% to 8%; air heaters by 6% to 8%. It does not pay to cool the exhaust gases to a temperature below 135°C. When economizers and air heaters are both to be used, an economical balance can be found between the amount of boiler surface, preheater surface and economizer surface which can be installed at the minimum cost to give the desired efficiency.

Choice of steam pressure and temperature. For each combination of fuel cost, load factor and capacity factor, there is an economical pressure and temperature of steam which will result in the lowest total cost of power. The limiting condition is reached when the increase in efficiency due to increase in steam pressure and temperature ceases to justify additional investment in equipment required for the purpose. The following points may be considered in the economic analysis of the choice of steam pressure and temperature :

Steam pressure
Total temperature of steam
Reheat if any
Plant capacity
Annual capacity factor (percentage)
Energy generated, gross and net (kilowatt-hours)
Cost of fuel per million kilocalories
Kilocalories consumption per kilowatt-hour
Cost of plant
Annual fixed costs
Annual variable costs
Total annual costs
Cost, net, per kilowatt-hour

Turbines. The choice of turbines depends on the capacity of the plant required, the load factor and capacity factor of the station, thermal efficiency, reliability and availability factors, location of plant with reference to the availability of cooling water for condensate and cost of land. Large units will save floor space and building area as well as volume. Cross-compound machines take less turbine-room width. Tandem compound or cross-compound turbine units with multiple exhausts are used.

Condensers. The function of a condenser is to reduce the back pressure at the turbine exhaust. The lower the back pressure, the lower is the steam consumption. To reduce the back-pressure, either the quantity of cooling water to convert the exhaust steam into condensate should be increased, or the condenser and the heat exchange surface should be increased. Both these methods of improving the performance of the condenser increase the investment. The most economically acceptable condenser will be that which will balance the fixed cost on the extra investment with the saving due to decreased steam consumption, owing to a greater condenser surface or increased pumping of cooling water.

The problem of selecting the number of heaters and the amount of steam extraction is also an economic problem of balancing thermal gains against increased costs—fixed and operating—due to the additional equipment required.

4.9 Steam Station Auxiliaries

The steam station auxiliaries can be classified in two main groups. (i) Essential auxiliaries and (ii) service auxiliaries. The unit system is followed in modern stations, i.e., boiler, turbine and generator are each a unit. Each boiler, turbine and generator has its own auxiliaries for efficient working; they are not mixed up with the auxiliaries of the other plant, nor are they operated in common.

Essential or urgent auxiliaries are unit auxiliaries which are associated with the running of a unit, and whose loss would cause an immediate reduction of unit output. Service auxiliaries are those whose loss would not affect the output until after a considerable time.

Typical essential or urgent auxiliaries for a unit are generally as follows :

For boilers :

(1) Forced draft fans.
(2) Induced draft fans.
(3) Primary air fans.
(4) Coal mills.
(5) Mill feeders.
(6) Recirculating fans.
(7) Air heaters.
(8) Precipitators for boilers.
(9) Service air compressors.
(10) Fuel oil heater and fuel oil supply pumps.

For turbines:

(1) Extraction pumps.
(2) Low pressure pumps.
(3) Deaerator pumps.
(4) Distilled water pumps.
(5) Vacuum pumps.
(6) Circulating water pumps.
(7) Boiler feed pumps.
(8) Turbine lubricating oil seal, generator hydrogen seal, oil turbine control circuit feed pumps.
(9) Air pumps.

A pulverised fuel milling plant consists of a mill of low speed, 17 to 20 r.p.m., or a medium speed mill of 80 to 100 r.p.m., working on the principle of suction or under pressure.

Mill feeders are table type. Their output is controlled by a 2 speed motor/variable speed motor, or constant speed motor with variable drivers.

Types of oil pumps used in steam stations are either reciprocating, gear, rotary or screw type.

Air pumps used are rotary air pumps with 2 impellers, or hydraulic air pumps.

Boiler feed pumps are centrifugal multistage pumps and have a capacity in excess of the guaranteed turbine continuous maximum rating, steam rate to provide cover for low vacuum, make up steam supply to soot blowers, etc. Generally, 20% excess capacity is used. Location of feed water pumps is after the deaerator and before the high pressure heaters. In some stations, 2 electrically driven feed pumps of 50% capacity are used and a third one with 50% capacity is kept as a standby in case of failure of one pump. Some emergency oil pumps are also steam driven.

Two 100% duty, 2 or 3 stage extraction pumps are usually provided in a modern steam station; one acts as standby.

Circulating water pumps are generally 2 of 50% capacity for each unit. They are of axial flow or mixed flow type. Some condensers of surface type are built in two halves so that one half can be separated out if required.

Some typical service auxiliaries are as follows :

(1) Dust and ash handling plant
(2) Coal handling plant
(3) Boiler house—valves, crane, drains.
(4) Turbine house—valves, evaporators, deaerators, lift, cranes, air-conditioning plant.
(5) Soot blowers.
(6) Electrically operated valves and pumps.
(7) Battery charging equipment.
(8) Cooling water booster pumps.
(9) General service supply pumps.
(10) Domestic water supply pumps.
(11) Fire fighting pumps.
(12) Barring gear motor.
(13) Water treatment plant—general auxiliaries—crane, make up pump.
(14) Cooling water pump, valves and cranes.
(15) Lighting and heating.
(16) Workshop.

Electrostatic precipitators are used for extraction of dust in flue gases by passing the laden gas through a strong magnetic

field. This causes the dust to absorb freed ions and thereby become electrically charged. The charged particles then follow the path of the ions from discharge to receiving electrodes. Generally, the design is done for a negatively charged electrode suspended in the centre of a vertical body of tubes or plates which form the positive receiving electrodes. The discharged electrodes are charged negatively. The voltage used is about 33 kV—high voltage—d.c. for charging. The efficiency of the electrostatic precipitators is about 98 to 99%.

Types of drives. The types of motors used for steam station auxiliaries are :

(1) *Squirrel cage induction motors:* These are robust in construction. However, their disadvantages are high starting current and fixed speed. They are used for drives which have fixed speed. Multi-speed operation is possible by pole changing in specified ratios only.

(2) *Slip ring type induction motors:* These are used where variable speed operation is necessary. The speed of this type of motor can be varied by changing the resistance in the slip ring circuit. The disadvantage of the motor is, therefore, the loss of power in speed adjustment, which cannot be regained except by special arrangements using commutator machines. These drives are used for feed water pumps, wagon tipplers, E. O. T. cranes, lifts, etc.

(3) *Commutator motors:* Whose voltage may be maintained with induction regulator are used in spacial cases for variable speed drives, though they are not very common.

(4) *D. C. motors* are used for emergency drives when the main power supply fails.

In most cases induction motors are used as drives. Sometimes reduction of speed is obtained by means of gears. To avoid sudden overloading, sometimes flexible couplings are used between the drives, e.g., (i) gear coupling, (ii) rubber bush or pad type flexible coupling, (iii) hydraulic coupling, etc.

The ratings of the motors will depend on the load on the motors corresponding to the amount of material to be handled by the auxiliary.

Emergency drives are from the D. C. supply from the station battery, e.g.,

1. Hydrogen seal oil pumps.
2. Air heater drive motors.
3. Emergency flushing D. C. lub. oil pumps.
4. Supply of emergency station lighting.
5. Emergency guage glass lighting for the boiler, etc.

4.10 Steam Station Layout

In considering the layout of a steam station, it is necessary to arrange the main and auxiliary machinery and integrate all the machinery from a number of view points. The important factors to be kept in view in planning are reliability, economic operation and performance, station cost per kilowatt, convenience of access to all important apparatus, ease of control for the operators, the area in square centimetres required per kilowatt of plant capacity, and the volume in cubic centimetres per kilowatt required for the station, so that the building requirements can be determined. The size and type of equipment is first chosen, and the layout to give the most effective and convenient operation is then planned. Finally, the building is designed to accommodate the layout.

The approximate area and other dimensions for boilers of different sizes are given on the next page.

Boilers should have gangways 3 to 6 m wide. Staircases should be 1 m wide and run at an angle of 45° if possible. Proper clearances should be maintained in the boiler room while the details of the equipment are laid out. With stoker operated and pulverized fuel boiler units, suitable clearances in the boiler room are 3-5 m between adjacent units. For stoker operated boilers, area is limited by the projected area of the stoker for heat release; this is a two dimensional limitation. Pulverized fuel boilers are limited in all three dimensions, and the height of the furnace can.

TABLE

Rating of boilers steam flow	Approximate plan dimensions : length ×width.	Approximate furnace dimensions.			Steam drum diametre	Bottom drum diametre	Vertical distance between two drum centres.
		Width	Length	Heights			
T/hr	m^2	m	m	m	cm	cm	m
11	8.2×3.2	2.4	4.1	5.2	107	92	4.25
22	8.2×4.1	3.3	4.1	6.9	122	92	5.5
34	8.5×5.4	4.4	4.6	7.6	122	92	6.0
45	9.3×5.4	4.7	5.1	8.2	137	92	6.75
68	9.6×6.7	6.1	5.7	9.3	152	92	7.3
90	10.0×7.6	7.2	5.9	9.6	152	92	8.0
114	10.7×8.2	7.7	6.4	10.4	152	92	8.5

be adjusted to give the required heat release. The volume of a furnace is an important consideration with any type of boiler.

Pulverizing mills are located in the basement. Forced and induced draught fans can be located either in the boiler room base ment or on the main operating floor. Sometimes they are located on an elevated gallery. For small capacity boilers, the feed water pumps may be of the reciprocating type. Large boilers have multi-stage centrifugal feed water pumps driven by electric motors to conserve space. The other factors in favour of electric motor drives are lower initial cost, running cost and maintenance cost. One of the feed water pumps should, however, be driven by a steam turbine as a safety measure in the event of failure of the electricity supply. Heaters, evaporators and feed water pumps are located in a bay adjacent to the turbine room. The location of these items of equipment is decided by the cost of piping, heat losses and the cost of space.

There are two possible layouts of the turbine generator sets in the main turbine room. One arrangement is to have the units perpendicular to the division wall between the boiler and the turbine room; the other is to have the units parallel to the division wall.

In the layout of units perpendicular to the division wall (Fig. 4.17) the unit plan can be followed with ease, by setting the boiler on the turbine shaft centre line. The throttle valve of each machine can be placed near the division wall. The steam lead to the turbine is thus relatively short. The turbine room should be sufficiently wide to accommodate the largest unit which is ever likely to be installed; otherwise it might be necessary to widen the room at the time of extension, which would be more expensive than extending the building lengthwise. The arrangement of the boiler room and turbine sets depends on the number of boilers required per set. With the unit system the firing aisle should normally be between the boilers and the division wall. The switch-boards, generator busbars, controls, etc., can be located adjacent to the turbine room. This gives short and direct electrical con-nexions.

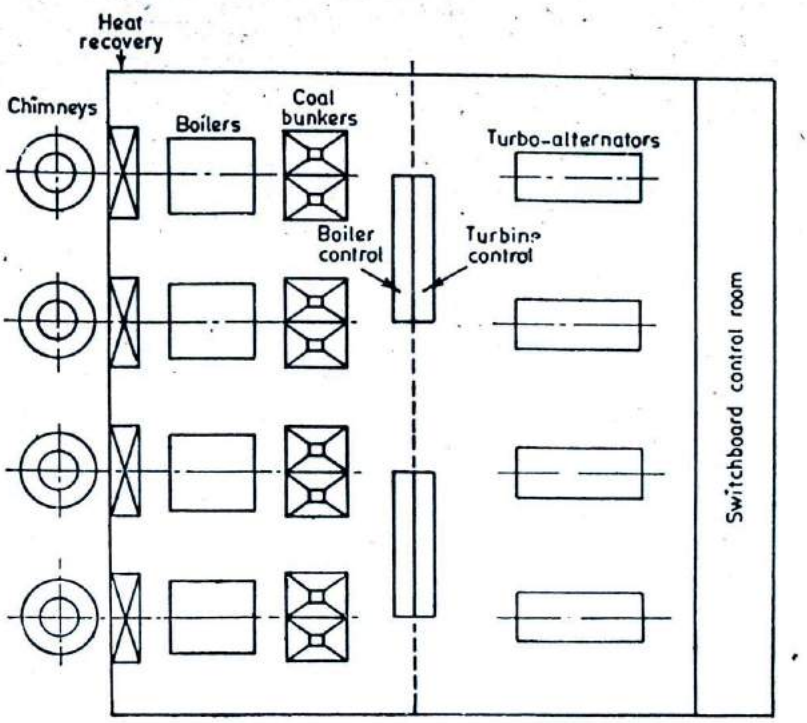


Fig. 4.17. Turbo alternators as well as boilers perpendicular to the wall between the boiler and turbine rooms.

The alternative (Fig. 4.18) is to place the turbine units parallel to the division wall. The turbine units are then set much closer together. The condensers under the turbines have their longer dimensions parallel to the turbine shafts to make close spacing possible. The turbine room is narrower than in the first arrangement. An advantage is that more turbine units can be added without increasing the width of the station.

In the turbine room, special care should be taken to provide clearance for withdrawing condenser tubes for overhaul when required. Also clearance should be left for removing the rotor of the generators when necessary for overhauling and checking. This clearance is also required during installation.

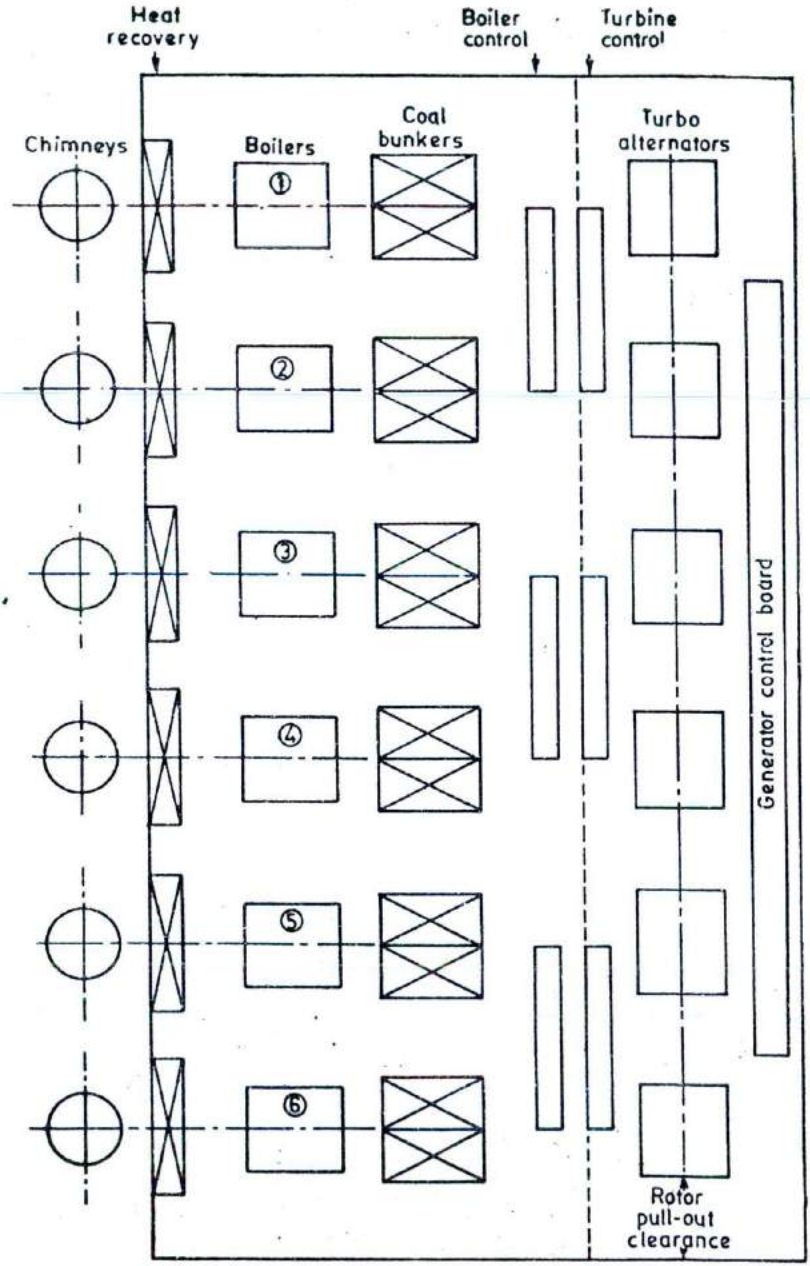


Fig. 4.18. Turbo alternators parallel to the wall between the boiler and turbine rooms.

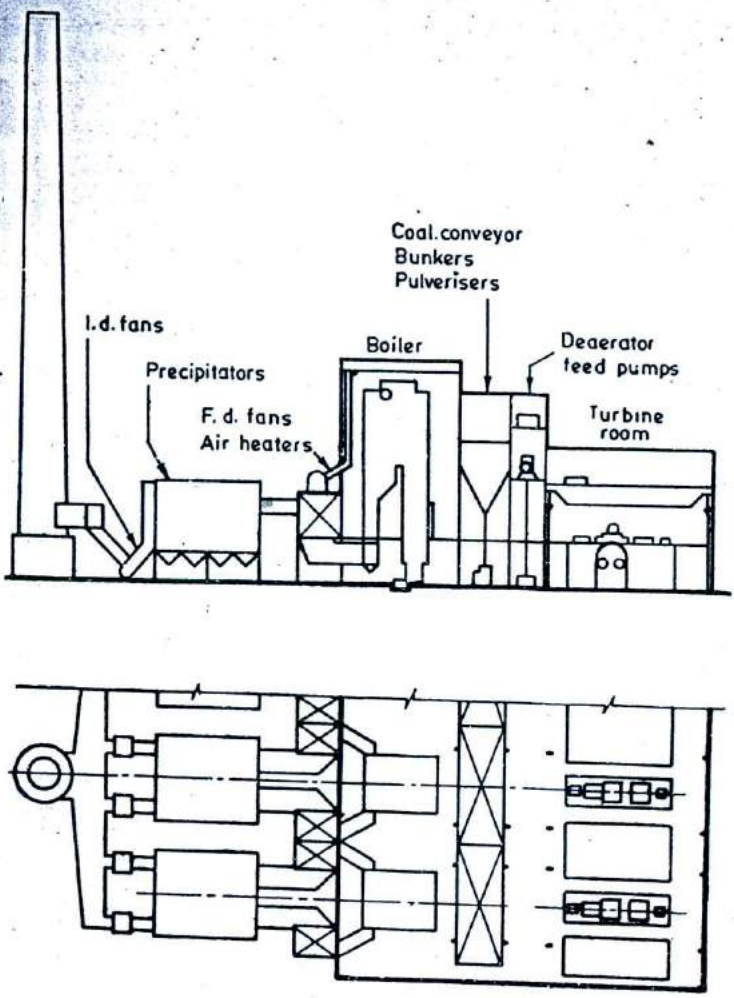


Fig. 4.19. Typical Cross station of a modern steam station.

The approximate dimensions of turbine generator sets of various sizes are given below :

Capacity	Overall dimensions		
	Length	Width	Height
KW	m	m	m
10,000	11.5	3.65	2.4
15,000	12.5	4.00	2.4
25,000	13.25	4.5	3.0
40,000	17.25	4.5	4.5
50,000	18.5	4.5	4.8

The condensers are generally of the surface type. The necessary surface in square metres can be found, and the overall dimensions of the particular type determined, by considering heat transfer properties and temperature conditions. Generally, the condenser is set perpendicular to the turbine axis.

Fig. 4.19 shows a typical layout of a steam station. It shows position of boilers, coal conveyors, bunkers, pulverisers, F. D. fans and air heaters, precipitators, I.D. fans and chimney. The location of deaerators and feed water pumps, and the location of the main steam turbo-generators in the turbine room are also shown. The arrangement is shown both in elevation and plan.

The Table on the next page gives approximate volume of the boiler house, turbine house and the station in cubic metres per kW for different sizes of the plant.

In the layout of the station, the connexions between various main items of the plant are for the following :

(*a*) Circulating water mains piping arrangements.
(*b*) Main steam and feed water piping.
(*c*) Coal conveyors.
(*d*) Flues arrangement.
(*e*) Electrical connexions.

It is necessary to strike a balance between the lowest cost, and the best arrangement from the structural and operational point of view.

TABLE

Building volume

	Unit Size MW	Station size Sets × MW	Boilers Tons/hr.	Boiler house Cu. m/kW	Turbine house cu. m/kW	Station Cu. m/kW
	200	4 × 200	4 × 635	0.473	0.315	0.788
	350	4 × 350	4 × 1060	0.423	0.250	0.673
cross compound 2 × 275	550	2 × 550	2 × 1700	0.364	0.250	0.614
Longitudinal turbine arrangement	500	2 × 500	2 × 1560	0.336	0.211	0.547
Transverse turbine arrangement	500	2 × 500	2 × 1560	0.318	0.204	0.522

4.11 Instrumentation and Controls

Instruments are installed in a power station for a number of reasons. The main functions of the instruments are as follows :

(*a*) *Operating guidance.* The instruments are a guide to safe, continuous and proper plant operation.

(*b*) *Economic supervision.*

(*c*) *Performance evaluation* : The instruments furnish data for evaluating overall piant performance and checking the efficiency of individual plant components.

(*d*) *Costs and costs allocation* : The cost accounting system depends on meter readings and correct cost figures may point towards possible economies.

(*e*) *Maintenance guidance* : Instruments check on the internal condition of equipment and indicate when and where maintenance or repair is needed.

It is necessary to couple the measuring instruments to the auxiliary power devices to provide automatic control. Interlocks ensure proper sequence during the starting of the equipment, shutdown and emergency operations. Automatic controls of auxiliary apparatus are found essential for reliable performance of modern high pressure, high temperature, high capacity steam turbogenerator units.

The main purpose of providing controls are as follows :

(i) Safety : Controls to prevent damage.
(ii) Convenience of Operation.
(iii) Overall operation efficiency.
(iv) Reduction of operating cost.

4.11 Selection of Instrumentation

Several factors should be considered in deciding the proper type of instrumentation and controls for a steam station. Some of the factors are as follows :

(i) Boiler and Cycle design : Size, complexity, and operating conditions.

(ii) Type of fuel used : Coal, gas, oil and fuel burning equipment.

(iii) Feedwater system : Drum size, pump characteristics.

(iv) Auxiliary equipment : Such as fan arrangements, source of fan power, damper arrangements, etc.

(v) Load characteristics : Anticipated change, rate and magnitude of change.

Measurements of flow of water, steam, fuel, air for combustion, drafts and pressures, temperatures of fluids and metal parts are essential for safe and reliable operation of boilers. Levels of water in the various component parts of the system should be measured correctly. Precise measurements of conductivity, pH value, and dissolved O_2 are essential to proper water treatment.

4.11.2 AUTOMATIC CONTROL SYSTEMS

The steam station being a combination of complex processes, requires a combination of several closely allied control systems.

The types of the control systems used are :

(*a*) On-off or 2 position control.
(*b*) 3 position or multiposition control.
(*c*) Fixed speed floating control.
(*d*) Variable speed floating control—integral action.
(*e*) Proportional control.
(*f*) Derivative control.

On-off and multiposition controllers use step function adjustments and are suitable for plants which have one or two time lags. Fixed speed floating controls are used with low and high contacts of limit switches and drive the servo at a fixed speed, until the system conditions are satisfied. Variable speed floating controls are arranged to drive control valves at a rate proportional to the deviation from normal or required setting.

A general form of single loop feedback control system is shown in Fig. 4.20

Here $r(t)$ is the reference input.

$c(t)$ is the controlled variable and $e(t)$ is system error.

$$e(t)=r(t)-c(t) \qquad (4.13)$$

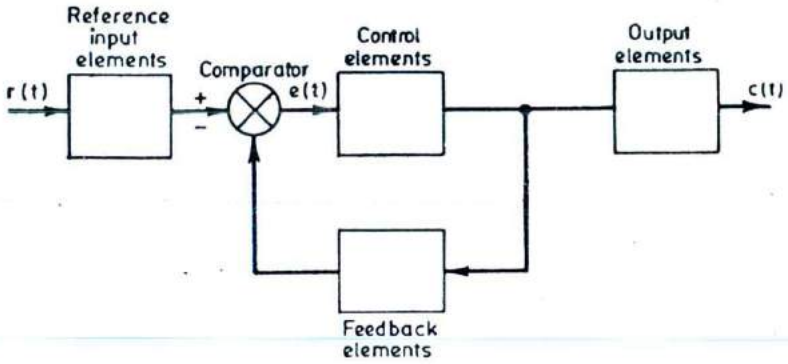


Fig. 4.20. A single loop feed-back control system.

The device that is used to determine the error is called a comparator. The feed-back control system consists of reference input elements, control elements and output elements. If the output is not as required, the error signal is fed back by feedback elements to the comparator which adjusts it to requirements.

If the output of the device is proportional to the input, the operation of the controller can be represented as

$$y(t)=K_1x(t) \tag{4.14}$$

Such a controller is known as a *proportional controller*. In some cases, the output of the devices depends not only on the magnitude of the input, but upon various derivatives and integrals of the input, and it is necessary to express the relation in terms of input, output, and certain integrals and derivatives, e.g., if the operation of a typical controller is expressed as

$$y(t)=K_1x(t)+K_2\int x(t)dt \tag{4.15}$$

where $x(t)$, and $y(t)$ are the changes in the input and output respectively of the controller from their reference values, and K_1 and K_2 are constants which can be adjusted by the operator of the systems,

K_1 is proportional gain or proportional sensitivity.
K_2 is integral gain or integral sensitivity.

This type of controller is known as proprortional plus integral controller or proportional reset controller or as proportional controller with reset action.

$$\text{Reset rate} \quad R=\frac{K_2}{K_1} \tag{4.16}$$

Some controllers also include derivative action, as a result of which the output contains a component proportional to the derivative of the input. If the controller contains the action in addition to the two above, the operation of the control can be expressed as

$$y(t)=K_1x(t)+K_2\int x(t)dt+K_3\frac{dx(t)}{dt} \tag{4.17}$$

$$\text{Rate time} \quad T=\frac{K_3}{K_1} \tag{4.18}$$

A controller of this type is called a proportional reset controller with rate response, or a proportional-plus-derivative-plus-integral controller. The input, output, and feed-back elements can be described with the aid of integro-differential equations. The quantitative analysis of a given system consists of solving simultaneously the set of integro-differential equations describing the entire system.

4.11.3 COMBUSTION CONTROL SYSTEM

In selecting a combustion control system, some of the following factors should be taken into consideration :

(*a*) Type of boiler.

(*b*) Its capacity, maximum operating pressure and temperature.

(*c*) Range of minimum to maximum load.

(*d*) Pattern of load changes.

(*e*) Type of fuels, their availability and the sequence in which they should be burned.

(*f*) Types of burner.

(*g*) Arrangement of fans and dampers.

The main function of a combustion control system is :

(i) to supply the correct amount of fuel and air to the furnace so as to release heat as required by the heat demand.

(ii) to minimise controllable losses due to excess air or incomplete combustion by adjusting suitable fuel/air ratio.

The most common method used for controlling the fuel/air ratio within the combustion zone is a steam flow/air flow ratio controller. This device constantly monitors the flow of steam and indicates the relative changes in the air flow as compared with the steam flow. Thus it compares the amount of heat being released in the funace to the amount of air being supplied for combustion.

A second method is the use of a fuel flow/air flow ratio controller, when burning fuel oil and fuel gases.

A third method is based on continuous flue gas analysis and the subsequent correction of air flow, to maintain optimum excess air, as a further refinement to the above methods of air flow control.

The simplified principles of combustion control methods are shown in Fig. 4.21 and Fig. 4.22.

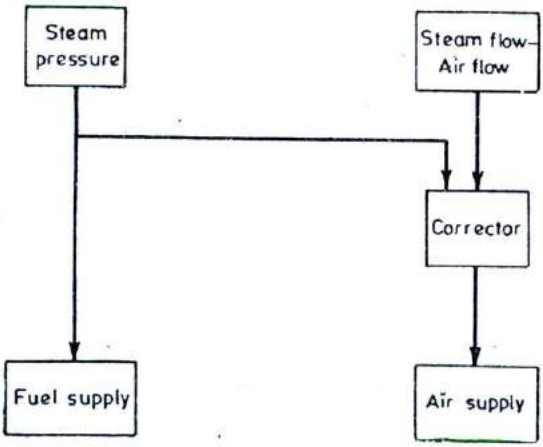


Fig. 4.21. Series parallel control system with corrector.

Fig. 4.21 shows the series parallel method of control of combustion. This method uses a correcting factor to the input of the fuel or combustion air supply. The correction is made on the basis of the steam flow/air flow ratio. Variation in steam pressure and the steam flow/air flow ratio are used for controlling fuel and air supply to the boiler. This method of control can be

applied to every type of fuel and firing equipment used for the boiler.

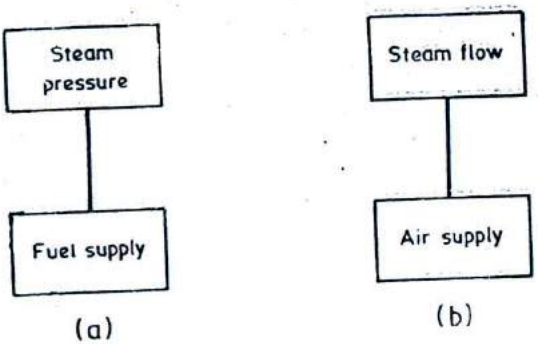


Fig. 4.22. Series parallel control system.
(a) Steam pressure is used to adjust fuel supply.
(b) Steam flow rate is used to adjust air supply.

Another series parallel method of control commonly used is shown in Fig. 4.22. Here variation of steam pressure from a master position is used to adjust fuel supply. The rate of steam flow measures heat liberation from fuel. Combustion air requirements for each heat unit released by a fuel remain constant. Thus a measurement of steam flow rate can be used to adjust the supply of combustion air. This method is used when calorific value of fuel may vary or where fuel feeding mechanisms may be subject to variation in delivery rate. The examples are pulverised coal, or oil refinery waste gas.

For maintaining correct air supply, the induced and forced draft fans are adjusted so as to obtain the necessary draft. The excess air is controlled so that the carbon-dioxide content in the flue gases or the oxygen content is maintained at a value corresponding to the best operation. It is also necessary to maintain a constant water level in the boiler by means of regulators in the feed water line to the boiler.

4.11.4 STEAM TEMPERATURE CONTROL SYSTEM

With the increase in steam temperature and adoption of the reheat cycle in modern boilers, accurate control of steam tem-

perature is very important to insure best operation of the system. Many operating variables such as load, excess air, feed water temperature, heating surface cleanliness, and burner operation affect steam temperature. If optimum heat rate is to be maintained over the design load range, it is essential to regulate steam temperature by effective control systems.

The methods used for steam temperature control are as follows :

(i) Desuperheating
(ii) Gas by-passing
(iii) Gas recirculation
(iv) Excess air
(v) Burner tilt

Desuperheating : The desuperheater steam temperature control consists of a spray head installed in the high temperature steam line. This is direct contact type. High purity water is steam atomised and forced into the path of the high temperature steam. The desuperheater is located between the two stages of the superheater.

Gas By-passing : A portion of the total gas flow may pass over all, or part of, the superheater by controlling the position of the regulating damper located at the entrance of the by-pass section.

By the above two methods, the temperature of the superheated steam can be reduced if required. The other three methods, viz., gas recirculation, excess air and burner tilt can be used to increase the steam temperature if required.

Gas Recirculation : By recirculating the major portion of the hot gas leaving the boiler unit back into the furnace, it can be used to control steam temperature, gas temperature or furnace heat absorption.

Excess Air : Variation in excess air is very useful in changing the final steam temperature. If the air to the furnace is increased

the retention time in the furnace of the products of combustion is reduced and more heat, proportionally, is made available at the superheater.

Burner tilt : By tilting the burners downwards, a larger area of furnace wall is exposed to radiant heat, thereby increasing the radiant heat absorption. This results in a lowering of the temperature of gas entering the super-heater section and a decrease in the final steam temperature. By tilting the burners upwards, the reverse action takes place, and the steam temperature is increased.

4.11.5 FEED WATER CONTROL SYSTEM

A feed water control system has to perform three functions : (*a*) Control the level of water in the boiler drum and prevent damage from burning out boiler tubes because of low water in the boiler drum. (*b*) Prevent an abnormally high water level in the boiler drum to avoid the chance of carrying over dissolved solids with the steam into the superheater. This would result in the blockage and consequent heating of and rupture of superheater tubes. (*c*) Regulate the water in such a manner that the entire system is kept approximately in balance and not subjected to severe changes in the water flow.

The types of the water control systems are :—

(1) Single element self operated.
(2) Single element relay operated.
(3) Two element relay operated.
(4) Three element relay operated.

For large capacity boilers, the last method is most commonly used. This is shown diagrammatically in Fig. 4.23.

In this system, the feed water flow to the boiler is measured and compared with the steam flow out of the boiler. Ratio relay and proportionate control affects the change in position of the control valve. Boiler water level in the drum is transmitted, and any change in it will affect the proportionate and reset relay

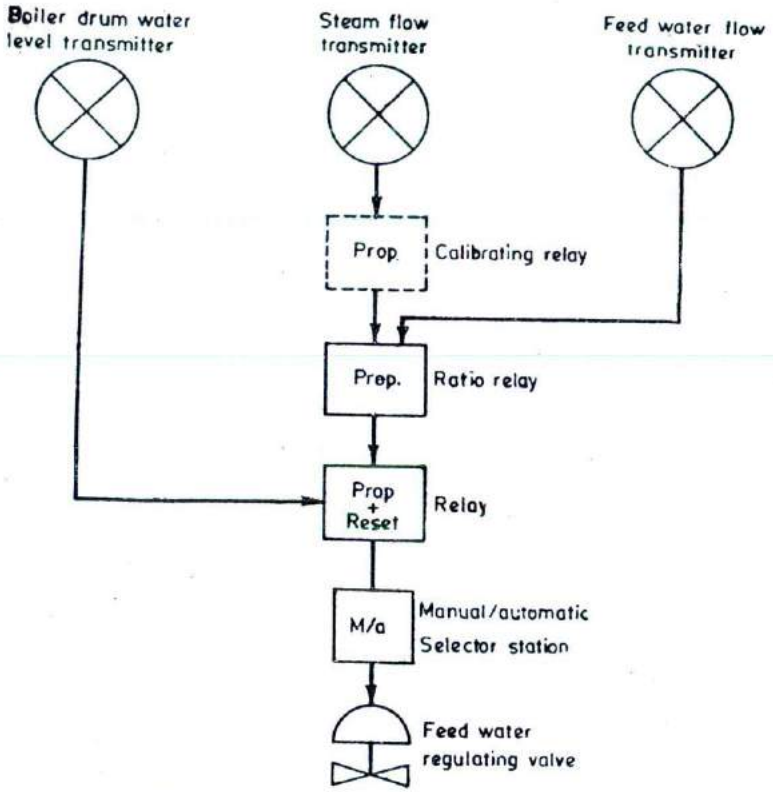


Fig. 4.23. Three element relay operated feed water control system.

control. The net variation is passed on through a manual or automatic selecter station to a feed water regulating valve or pump speed control drive. Sometimes variable speed couplings are installed between a constant speed motor and the feed pump or a throttle valve is used at the discharge of the pump to obtain constant pressure.

The three major control systems were described above. In addition to this, a number of control systems are required to control various variable factors, and provide safe operation. Also it is necessary to provide automatic protection for station auxiliaries. The various station auxiliaries for boilers and tur-

bines as well as service auxiliaries were mentioned in 4.9, e.g., automatic controls are required for forced draft fans, induced draft fans, primary air fans, coal mills, various pump drives, etc.

The controls may be pneumatic, hydraulic, electric/electronic type or their combinations. The control systems should be properly designed to have the correct response, and should be stable.

Turbine governing is effected in either of two ways. For a small turbine, the governing is done by throttling at a single inlet valve. For a large turbine, there are a number of nozzles at the steam inlet, which gradually open one after the other as the load on the turbine is increased. The governing is done by varying the number of first-stage inlet nozzles in action, and only the last one is throttled at any one time. The governor is controlled by oil pressure through a pilot valve. The opening of the pilot valve can be controlled by a small d.c. motor.

The other requirements at the turbine are the maintenance of vacuum in the condenser, enough circulating water, a number of pumps, oil pressure for control of circuits, steam bleeding if any and the heater and feed-water control.

At the generator, the main effect of an increase in load is a reduction in frequency, if the unit is isolated and not in parallel with a large number of other machines. The frequency can be adjusted by adjusting the speed of the turbine as explained above. The voltage also may drop. This can be adjusted by means of a regulator controlling the excitation. A reactive load affects the power factor, and if a lagging power factor decreases, more excitation must be supplied to bring the power factor of the station to the required value.

If two or more generators are connected in parallel the load on the station is shared between the generators in a manner depending on the speed and excitation of each machine. By adjusting the speed of the turbine, the load taken by the machine can be adjusted. If a machine is connected to infinite busbars, i.e., if it is in parallel with a large number of other machines, the

frequency remains constant, and the change of excitation changes the power factor of the machine.

Generally, centralised control is adopted for modern steam stations, boiler and turbine controls being at one place in the turbine room, and the generator and feeder controls in the control room; in some cases all controls are centralised at one place in the control room. It is necessary to group together in one area the essential information in gauges, flowmeters, indicators and the necessary controls to permit regulation and adjustment either automatically or manually.

Draught gauges, indicators and annunciators should be mounted high on the board. Recorders should be at a low level. On and off switches should be on the same horizontal level, and the operating switches below them on a second horizontal level. A further help to the operator is provided by the suitable arrangement from left to right as the controls are operated in sequence. A number of instruments on the panel help in adjusting the necessary operating conditions—ammeters, wattmeters, frequency meters, power-factor meters, synchronoscope, hydrogen thermometer, hydrogen pressure gauge, hydrogen-cooler thermometer, etc. A control handle to regulate the governor spring tension, adjustment of excitation for the generator field, and the oil circuit-breaker control are provided in the control room.

The boiler control room has draught gauges, measuring air and gas pressures at points such as the forced draught fan outlet, furnace, economizer inlet, induced-draught fan inlet, etc.; controls for keeping water level in the boiler drum constant, for feed-water heaters, pressure in the furnace, pumps speeds, pulverizer and oilpump speeds; controls for damper positions indicating lights and auxiliary controls.

4.11.6 CENTRALISED CONTROL

A central control room is located between boiler and turbine rooms. Most of the controls are automatic, and centralised control with a number of annunciators and indicating instruments helps in controlling the operation of the steam station very effec-

tively. The recent trend is towards the common control centre for boiler, turbine-generator and all auxiliary equipment. This has resulted in marked reduction in operating staff and improved supervision through co-ordination of the various segments of plant operation. Application of miniature equipment has made the operating panel compact. The miniature instruments are pneumatic and electronic receivers, coupled with pneumatic and electric recorders which permit transmission of values from the location of the primary elements. A typical layout of a central control room is shown in fig. 4.24.

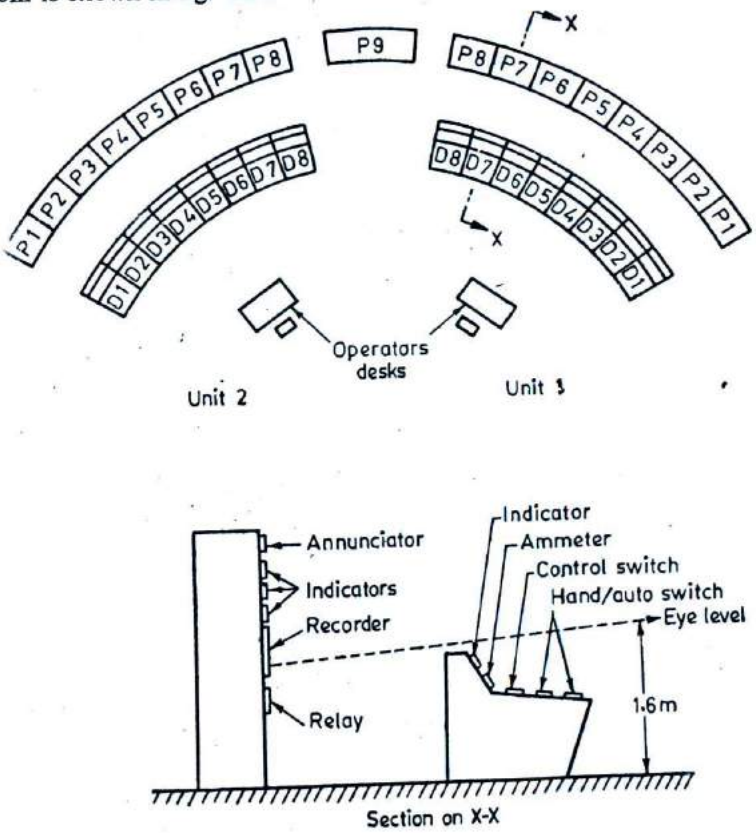


Fig. 4.24. A typical central control room layout.

D1, D2, D3, D4, D5, D6, D7 and D8 represent desks for coal; P.A. fan. fuel oil, boiler Master, Air and Flue gas, steam, water,

Condensate, Turbine, Generator controls respectively—P_1 to P_6 present corresponding panels. P_8 is panel for common auxiliaries. Section on through D_7 and P_7 shows the arrangement of panel and the desk. The panel has equipment of annunciators, indicators, recorders and relays and the desk has indicator, ammeter, control switch and change over switch for manual or auto operation as shown in the diagram.

The latest trend in highly automated steam power stations is the use of computers to perform functions such as data logging, alarming, scanning and performance monitoring. In this way the steam station can be considered as the whole plant. The fuel supply, feed water and air supply is directly integrated with load changes. The automatic operation of the station includes direct communication with the other units and the dispatcher.

4.12 Costs of Steam Stations

The investment cost varies from Rs. 800/- to Rs. 1,200 per kilowatt capacity of plant. Conditions affecting the investment depend on a number of factors :

(*a*) Plant location, characteristics of site selected, type of fuel and its storage and unloading.

(*b*) Size and number of units, reserve equipment, size and character of building required and nature of the electrical distribution.

(*c*) Thermal efficiency of station.

Of the total cost, (*a*) may be about 15%, (*b*) about 45% and (*c*) about 40%. The investment costs include costs of land, buildings, mechanical equipment and electrical equipment, and cost of construction.

4.12.1 FIXED COSTS

The fixed costs include interest on capital invested, taxes and insurance and depreciation of the station.

Taxes depend on the location of the site, and insurance costs depend on the type of equipment, safety devices, type of building,

ease of layout, etc. Depreciation depends on the life of the equipment, plant, buildings, etc. The life of the main equipment may be taken approximately as follows :

	Years
Water-tube boilers ..	20
Steam-turbines ..	15 to 20
Turbo-alternators ..	15 to 20
Transformers ..	15 to 20
Circuit-breakers ..	15
Power station building ..	50
Compressors and pumps ..	20
Coal crushing machines ..	10 to 20

The exact period of life of the equipment will depend on its design and conditions of use. The depreciation may be taken as approximately between 4.5% and 5% annually. A rate of interest of 6% and an insurance rate of 2% may be assumed, although the details depend on the particular station. The fixed costs may be taken as : interest 6%; insurance 2%; depreciation 5%; total 13%.

4.12.2 PRODUCTION COSTS

Fuel costs. The major part of production costs are fuel costs. The fuel consumption depends on the load factor of the plant, the calorific value of the fuel, and the heat required in kilocalories per kilowatt hour. This depends on the thermal efficiency of the plant—boiler as well as turbine. The cost of the fuel also depends on the distance from the main source of supply, so that the cost of transport to the site must be added to the fuel cost. The cost of fuel handling has also to be considered; this may normally account for 3,024 to 3,528 kcal per kilowatt-hour generated, and the cost per kilowatt-hour generated will correspondingly be affected.

Operation costs. These include the salaries of the supervising employees, turbine room attendants, boiler room attendants, switchboard or control board operators, and maintenance staff. Nearly 50% to 70% of the labour costs in the steam station are due to labour in the boiler room.

Maintenance costs. These are the costs for maintenance, repairs, and overhauling of pulverizing machinery, stokers, furnace, firebrick work, for cleaning of condenser tubes, maintenance of pumps and mechanical equipment, maintenance of electrical equipment such as generators, transformers, oil circuit breakers, etc.

Other production costs. Allowance should be made for consumption by auxiliary apparatus in the station. There are also some expenses for miscellaneous supplies.

The total production costs may be assumed to be approximately in the following proportions :

	Per cent
Fuel . . .	60 to 75
Operation . . .	20 to 10
Maintenance . . .	15 to 10
Miscellaneous supplies	5
	100

To find the heat required from the fuel and hence the consumption under different loading conditions, the heat released by the fuel per hour can be plotted against the load , as in Fig. 4.25.

The cost may be subdivided under three different conditions :

y_1 represents the heat required per hour when the boilers are fired and kept ready to take up the expected load and are running the boiler feed pumps and auxiliary service pumps, with all steam lines and electrical equipment ready for service.

y_2 represents the heat required when one main unit, with its necessary auxiliaries, is kept running but not generating, and enough boilers are under fire to carry the expected peak load.

y_3 represents the final condition when the power station is carrying the expected load. The slope of the line indicates the rate of fuel consumption per unit load. In some cases this rate may rise above a certain load, as shown in the diagram.

The consumption of fuel is assumed to follow a straightline law within certain limits. When the cost of fuel per kilocalorie

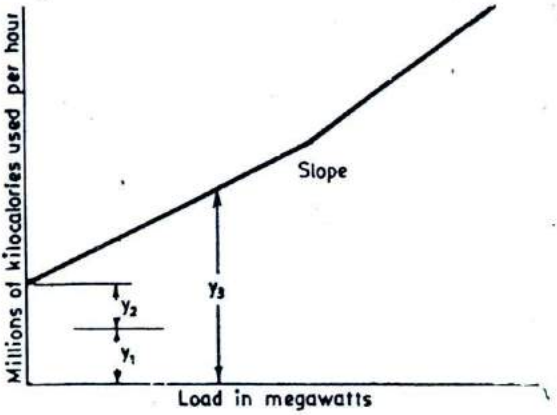


Fig. 4.25. Relation between heat consumption and load.

has been found, it is easy to calculate the total cost of the fuel used per year under different loading conditions.

Part of the maintenance cost may be taken as fixed, while the major portion of it may be taken as variable. Part of the fuel costs come under fixed costs which are necessary to keep the equipment ready though not giving electrical output.

The cost of the electrical energy can then be worked out either in two parts on the basis of the cost per kilowatt and the cost per kilowatt hour or on the total cost per kilowatt hour. In large power systems the cost of distribution and the overhead expenditure of the office and sales organization may increase the charge to the consumer per kilowatt hour to about 2.5 to 3.0 times the cost at the station.

The method of calculating the cost at the station and the charge to the consumer as a two part tariff is explained in chapter 2.

Example 4.1 illustrates the design principles regarding choice of equipment, layout of station, costs per kilowatt-hour generated and charge per kilowatt-hour to the consumer.

4.13 Superpressure Steam Stations

The latest development in steam stations is the working of steam at very high pressure and temperature, which has become possible with the development of high pressure high temperature alloys.

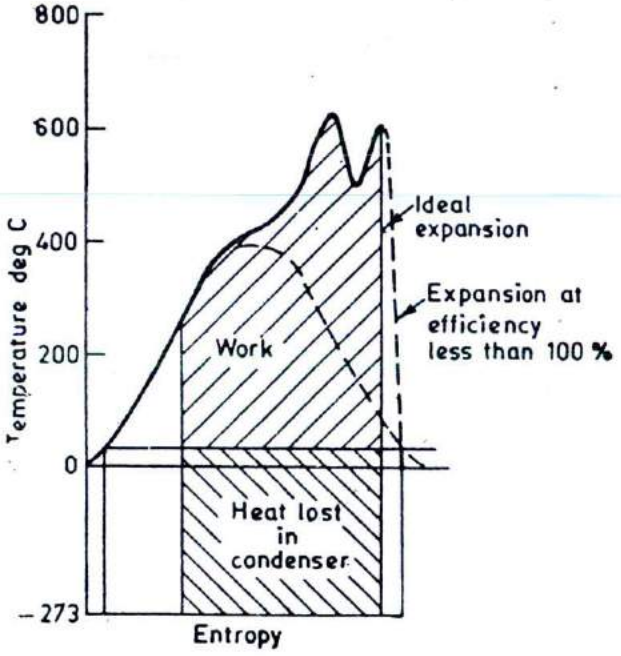


Fig. 4.26. Heat Cycle of superpressure steam station.

Steam at 316 kg/cm² and 621°C with two or more reheats, and at 352 kg/cm² and 650°C with two or more reheats, for units of 120 to 275-MW capacity are now used in superpressure steam stations. Steam at such high pressures behaves differently than at normal pressures. Below 225 kg/cm² (absolute), water boils or bubbles as it evaporates to steam. This is known as the critical pressure. Above the critical pressure, there is no bubbling as the water changes to steam, and the water acts much like an extremely dense gas. As it is heated, its temperature rises and it gradually expands in volume. At pressures higher than the critical pressure,

the water always completely fills the vessel holding it, and then there is no water level in it as such.

A conventional steam generator consists of an economizer, a boiler, a superheater, etc. The components of a superpressure steam generator are not so clearly defined, but they may perhaps to some extent be divided into low temperature and high temperature components. The superpressure steam generator, which uses the once-through principle of heating, needs no conventional boiler. The once-through feature and the cyclone furnaces make a compact steam generator.

As the pressures and temperatures increase, the required cross sectional area of turbine steam path decreases, so that the overall size of the turbine becomes smaller for the same plant capacity. Higher pressures and temperatures and improved heat utilization allow to reduce furnace volume and condenser siee for steam plant of the same capacity. When more steam is bled for feed water heating, the throttle steam rate increases, while the condenser steam rate decreases. The condenser volume flow rate decreases. This contributes to reduction in condenser size. The heat cycle of a superpressure steam station is shown in Fig. 4.26.

When using superpressure steam, a special high pressure turbine in tandem with reheat turbines of the reverse flow type, and a double flow pressure turbine make up the unit. The thermal efficiency of such a unit may be as high as 40%.

The generators are conventional 2-pole machines, the larger ones being hydrogen cooled.

Example 4.1

A power supply company has a steam station to supply power to a city. The maximum demand is 50,000 kW at 0.8 power factor lagging, and the load factor of the station is 60%. The generator efficiency may be taken as 96%, the thermal efficiency of the turbine as 28%, the boiler efficiency as 75% and the overall thermal efficiency of the station as 20%.

(*a*) Choose the main equipment for the station. Find the size of each generator, turbine and boiler.

(*b*) Find the main dimensions of the turbo-alternators and show the general layout of the station.

(*c*) The steam consumption may be taken to follow Willan's law approximately, corresponding to

0.8 + (3.6 × Percentage load factor) Kilograms of steam per kilowatt load on the station per hour. Find the steam consumption per kilowatt hour.

(*d*) The fuel used is coal having a calorific value of 6,100 kcal/kg. Find the fuel consumption per year.

(*e*) The cost of the fuel at the site of the power station is Rs. 30/- per metric ton, assuming that the station is located at the Coal pit head. Find the annual fuel cost.

(*f*) The operators' pay and labour cost is Rs. 1,000,000 per year. The maintenance cost is Rs. 525,000 per year; two thirds of this may be taken as variable and one-third as fixed. The miscellaneous costs are Rs. 100,000. Find the total variable cost per year.

(*g*) The station investment costs are Rs. 800/- per kilowatt installed. Interest, insurance and taxes and depreciation may be taken as 6%, 2% and 5% respectively—a total of 13%. Find the total fixed costs.

(*h*) Find the cost of generation per kilowatt-hour.

(*a*) the maximum demand is 50,000 kW. If the generators chosen are four in number, each of capacity 15,000 kW at 0.8 power factor lagging.

$$\text{Capacity of each generator} = \frac{15.000}{0.8} = 18{,}750 \text{ kVA}$$

The specification of each generator is, therefore, 18,750 kVA, 15,000 kW, 0.8 power factor lagging, 3 phase, 50-c/s, 11,000 V, 3,000 rev/min turbo-alternator; air cooled.

The number of generator units would really be selected to fit the load curve following the principles given in chapter 2.

$$\text{The steam turbine rating for each generator} = \frac{15{,}000}{0.96}$$
$$= 15{,}600 \text{ kW}$$

as the efficiency is given as 96%.

Impulse-type turbines are chosen. (Some reaction blading may be used in addition, for combined impulse and reaction working.) The steam pressure chosen for the unit is 60 kg/cm² (gauge), with a steam inlet temperature of 482°C.

In finding the boiler capacity, it is assumed that the unit system is used, as is common practice for ease of control. The full load on the generator and turbine is 15,000 kW and the energy produced is 15,000 kWh in one hour when working at 100% load factor. At this load factor the steam consumption as given in (*c*) is $0.8+3.6=4.4$ kg of steam per kilowatt hour.

Steam required per hour $=15{,}000\times 4.4=66{,}000$ kg.

The boiler unit chosen for each set should, therefore, be rated at 67,000 kg per hour, 60 kg/cm² (gauge) steam pressure, 482°C temperature. The boiler would have an economizer, a superheater and induced as well as forced draught fans for combustion control. The fuel used is coal.

The main dimensions of the main boiler equipment can be found from the data in the chapter.

(*b*) The main dimensions of the turboalternators each of 15,000 kW or 18,750 kVA capacity can be found from eqn. (3.23)

$$S=10.4\times 10^{-3}Ba_cD^2Ln$$

In this case $S=18{,}750$ kVA and $n=50$ rev/sec.

The average flux density, B, can be taken as 5×10^{-5} Wb/cm² and the ampere conductors per centimetre of stator periphery, a_c, as 450. The length of the stator or rotor core, L is twice the pole pitch, and the number of poles is 2. Thus

$$L=2\frac{\pi D}{2}=\pi D$$

Substituting in eqn. (3.23) the assumed values of the various constants,

$$18{,}750=10.4\times 10^{-3}\times 5\times 10^{-3}\times 450\times D^2\times \pi D\times 50 \text{ kVA}$$

whence $D^3=510\times 10^3$, so that $D=80$ cm, and $L=2D=2\times 80$
$=160$ cm.

The diameter, D, of the stator at the air gap is 80 cm. The diameter of the rotor is the diameter at the stator air gap minus twice the length of the air gap, which may be about 2.5 cm in a machine of this size. The diameter D_r, of the rotor is, therefore, $80-(2\times 2.5)=75$ cm.

Peripheral speed $=\pi D_r n$ centimetres per second.

$$=\pi\times 75\times 50/100=118 \text{ m/sec.}$$

The peripheral speed is somewhat high, and sufficient ventilating ducts should be provided to cool the stator as well as the rotor, in particular, to keep the machine within the permissible temperature rise.

The unit system is used. The layout chosen is with boilers in a row perpendicular to the line of division between the boiler and the turbine house. The turbines are also placed perpendicular to the division wall between the boiler and the turbine. The necessary clearances are provided so that there is room for removing the rotor of the generator and the condenser tubes for overhauling and repairs. The switchgear control house is accomodated on the same floor and in the turbine room. Only a wood and glass partition separates the switchgear control house from the turbine room. The layout of the plan can be shown as suggested in Fig. 4.17.

(*c*). The steam consumption of the station is given as 0.8 + (3.6 × percentage load factor) kilograms of steam per kilowatt per hour, and the load factor is 60%. The average load corresponding to a maximum demand of 1 kW is 0.6 kW and the corresponding energy per hour is 0.6 kWh. The steam consumption is, therefore, $0.8 + (0.6 \times 3.6) = 2.96$ kg for 0.6 kWh, or 4.95 kg/kWh.

(*d*) The overall thermal efficiency of the station is 20% and 1 kWh = 859.85 kcal. Thus for 1 kWh output, the heat obtained from the fuel should be 859.85/0.20 = 4,300 kcal. The calorific value of the coal is 6,100 kcal/kg.

$$\text{Weight of coal per kWh} = \frac{4,300}{6,100} = 0.705 \text{ kg.}$$

With a maximum demand of 50,000 kW and a load factor of 60%
Energy generated $= 50,000 \times 0.60 \times 365 \times 24 = 26.3 \times 10^7$ kWh per year.

$$\text{Weight of coal per year} = \frac{26.3 \times 10^7 \times 0.705}{1,000} = 185 \times 10^3$$

metric tons.

(*e*) The cost of the fuel per metric ton at site is Rs. 30.
Fuel cost $= 185 \times 1,000 \times 30 =$ Rs. $5,550 \times 10^3$.

(*f*) The variable costs are as follows :

	Rs.
Fuel costs	$5,550 \times 10^3$
Operation costs	$1,000 \times 10^3$
Maintenance costs (2/3 of Rs. 525,000)	350×10^3
Miscellaneous	100×10^3
	$7,000 \times 10^3$

(*g*) The station investment costs are Rs. 800 per kW installed, i.e., $800 \times 60,000$ or Rs. $48,000 \times 10^3$, and the fixed costs of interest, insurance, etc., are 13% of the total investment costs, so that the fixed costs are as follows :

Interest, insurance, etc. $13/100 \times 48{,}000 \times 10^3 = 6{,}240 \times 10^3$
One-third of maintenance costs $525{,}000/3 = 175 \times 10^3$
Total Rs. $6{,}415 \times 10^3$

(*h*) The total costs of the station per year are, therefore,

	Rs.
Fixed costs	$6{,}415 \times 10^3$
Variable costs	$7{,}000 \times 10^3$
	$13{,}415 \times 10^3$

Energy generated per year $= 26.3 \times 10^7$ kWh.

Cost per kilowatt-hour generated $= \frac{13{,}415 \times 10^5}{26.3 \times 10^7} = 5.12$ p.

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Problems

4.1. State the field of use of steam stations.

4.2. Describe the characteristics of boilers used in steam stations and give an approximate heat balance sheet.

4.3. Describe the characteristics of steam turbines used in steam stations and give an approximate heat balance sheet.

4.4. Describe the characteristics of turbo-alternators used in steam stations.

4.5. Describe the method of determining the capacity of the main equipment required in a steam station having an output of P kilowatts.

(*a*) Discuss the choice of turbo-alternator units and the method of designing the main dimensions of a 3-phase turbo-alternator having a capacity of S kilovolt-amperes.

(*b*) Enumerate the factors to be considered in the choice of steam turbines and condensers for a steam station.

(*c*) Enumerate the factors to be considered in the selection of boilers for a steam station.

Write specifications for (*a*), (*b*) and (*c*).

4.6. Discuss methods of layout for steam stations and compare their advantages and disadvantages. Show typical layouts.

4.7. Discuss steam station controls with reference to boiler control, turbine control and electrical control.

4.8. Write a short note on superpressure stations.

4.9. A steam station has a maximum demand of 1,000 MW at 0.8 power factor lagging, and the load factor for the station is 80%. The generator efficiency may be taken as 97%, the thermal efficiency of the turbines as 28%, the boiler efficiency as 77% and the overall thermal efficiency of the whole station as 20.5%.

(*a*) Choose the main equipment for the station. Find the size of each generator, turbine and boiler used. Give the main specifications.

(*b*) Design the main dimensions of the turbo-alternator units, and give detailed specifications.

(*c*) Suggest a general layout.

Ans. (*a*) Ten 100-MW units. Each generator : 125-MVA 100-MW 0.8-power factor (lagging) 3-phase 50-c/s 11-kV 3,000-rev/min turbo-alternator, hydrogen cooled, Boiler unit : capacity, 430,000 kg per hour; steam pressure, 100 kg/cm^2; steam temperature, 565°C; to have an economizer, a superheater and induced, as well as forced draught fans for combustion control. Steam turbine unit: 103,000-kW impulse turbine (some reaction blading may be used) at steam pressure and temperature of steam from boiler as stated above. (*b*) Main dimensions of the 125-MVA 100-MW turbo-alternator unit: stator diameter at airgap, 132.5 cm; length of core, 500 cm; diameter of rotor at air-gap 122.5 cm).

4.10. The following data refer to the steam station of problem 4.9:

The steam consumption is [0.8+(3.5×percentage load factor)] kilograms of steam per kilowatt load on the station per hour. The fuel used is coal having a calorific value of 6,200 kcal/kg. The cost of the coal on site is Rs. 28 per metric ton. Operators' pay and labour costs are Rs. 1,500,000 per year. The maintenance costs are Rs. 900,000 per year. Two-thirds of the maintenance costs may be taken as variable and one-third as fixed. Miscellaneous costs are Rs. 100,000 per year. The station costs are Rs. 1,100 per kW installed. Interest, insurance, taxes and depreciation may be taken as 6%, 2%, and 4.5% respectively, or a total of 12.5%.

Find (*a*) the steam consumption per kilowatt-hour, (*b*) the annual fuel costs, (*c*) the annual fixed costs of the station, (*d*) the annual variable costs of the station, and (*e*) the cost of generation per kilowatt hour. (Ans. (*a*) 4.5 kg per kWh; (*b*) Rs. $13,300\times10^4$ (*c*) Rs. $13,780\times10^4$; (*d*) Rs. $13,520\times10^4$; (*e*) 3.90 p.)