Most Economic power factor when KW demand is constt

- Fig 1 shows phasor diagram of an installation having an active power requirement of P KW.

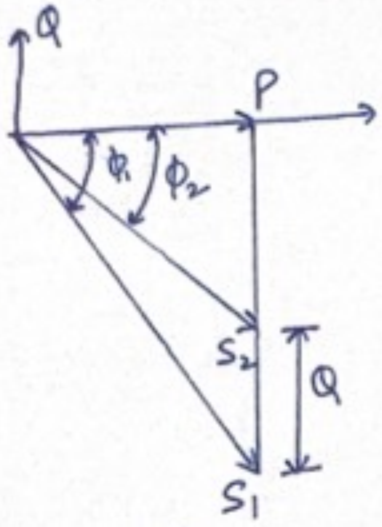


Fig 1.

- Through installation of capacitors the power factor is improved from $\cos\phi_1$ to $\cos\phi_2$ thus causing a reduction in KVA from S_1 and S_2
- The capacitor KVAR is Q.

Let annual charges per KVA of max demand per year = A

Annual interest and depreciation charges for capacitor installation = B per KVAR.

Annual savings $= A(S_1 - S_2) = AP\left(\frac{1}{\cos\phi_1} - \frac{1}{\cos\phi_2}\right)$

Annual cost of capacitor installation $= B.Q$

$= B.P(\tan\phi_1 - \tan\phi_2)$

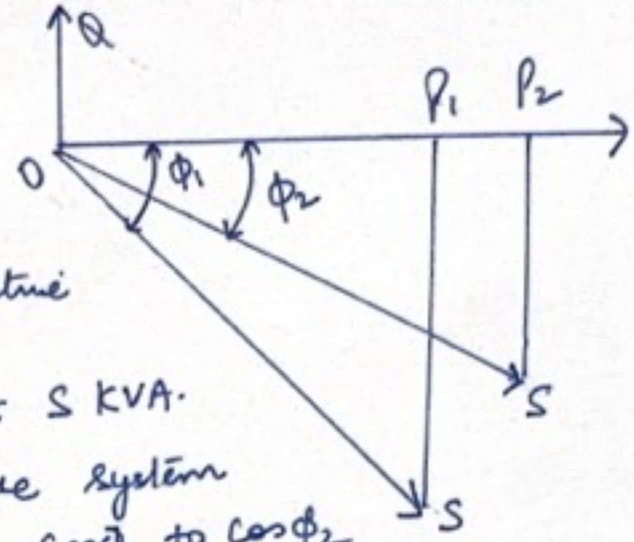
Net savings $= AP\left(\frac{1}{\cos\phi_1} - \frac{1}{\cos\phi_2}\right) - BP(\tan\phi_1 - \tan\phi_2)$

For maximum net savings, $\frac{d}{d\phi_2}$ (Net saving) should be zero

$$AP(0 - \sec\phi_2 \tan\phi_2) - BP(0 - \sec^2\phi_2) = 0$$

$$\sin\phi_2 = \frac{B}{A} = \frac{\text{Annual charges on capacitor installation per KVAR}}{\text{Annual charges per KVA of max demand.}}$$

Most Economic power Factor when KVA demand is constt



- Improvement of power factor to reduce the cost of the plant
- The investment in plant is proportional to KVA
- The revenue is a function of active power (KW).
- KVA output remains constt at S KVA.

Addition of leading KVAR in the system improves the power factor from $\cos\phi_1$ to $\cos\phi_2$ and active power output from P_1 to P_2.

Let annual charges on capacitor installation = C per KVAR

Net return per KW of installation per year = D

Annual increase in return $= D(P_2 - P_1)$

$= DS(\cos\phi_2 - \cos\phi_1)$

Annual charges on capacitor installation $= CQ$

$= CS(\sin\phi_1 - \sin\phi_2)$

Net savings $= DS(\cos\phi_2 - \cos\phi_1) - CS(\sin\phi_1 - \sin\phi_2)$

For maximum savings $\frac{d}{d\phi_2}$ (Net savings) shd be zero.

$$-DS\sin\phi_2 + CS\cos\phi_2 = 0$$

or $\tan\phi_2 = \frac{C}{D} = \frac{\text{Annual charges per KVAR of capacitors}}{\text{Annual return per KW of installation}}$

The most economical p.f is $\cos\phi_2$ when ϕ_2 is given by.

optimum Generation As a function of λ and Cost Coefficients

$$C_1 = a_1 + b_1 P_1 + c_1 P_1^2$$

$$C_2 = a_2 + b_2 P_2 + c_2 P_2^2$$

$$C_K = a_K + b_K P_K + c_K P_K^2$$

$$\frac{dC_1}{dP_1} = \lambda = b_1 + 2c_1 P_1$$

$$\frac{dC_2}{dP_2} = \lambda = b_2 + 2c_2 P_2$$

$$\frac{dC_K}{dP_K} = \lambda = b_K + 2c_K P_K$$

$\div$ by c_1

$\div$ by c_2

$\div$ by c_3

and after adding.

$$\lambda \left[\frac{1}{c_1} + \frac{1}{c_2} + \dots \frac{1}{c_K} \right] = \left[\frac{b_1}{c_1} + \frac{b_2}{c_2} + \dots - \frac{b_K}{c_K} \right] + 2(P_1 + P_2 \dots + P_K).$$

$$\lambda \left(\sum_{n=1}^{K} \frac{1}{c_n} \right) = \sum_{n=1}^{K} \frac{b_n}{c_n} + 2 P_T$$

$$\lambda = \frac{\sum_{n=1}^{K} \frac{b_n}{c_n} + 2 P_T}{\sum_{n=1}^{K} \frac{1}{c_n}}$$

and

$$P_n = \frac{\lambda - b_n}{2c_n}.$$

$$\frac{dC_n}{dP_n} = \lambda = b_n + 2c_n P_n$$

$$\Rightarrow \lambda - b_n = 2c_n P_n$$

$$\Rightarrow P_n = \frac{\lambda - b_n}{2c_n}$$

Module 4: Effect of transmission losses Art 10.15 pg 200

Art 10.15 :-

To include the effect of transmission losses in deciding the load allocation, the general form of loss equation is

$$P_L = \sum_{m=1}^{K} \sum_{n=1}^{K} P_m B_{mn} P_n \quad -(1)$$

$P_L \rightarrow$ T. losses in P.U

$P \rightarrow$ plant loading "

$B \rightarrow$ loss coefficients "

for a two generator →

$$P_L = P_1^2 B_{11} + 2 P_1 P_2 B_{12} + P_2^2 B_{22} \quad -(2)$$

for a 3-generator →

$$P_L = P_1^2 B_{11} + P_2^2 B_{22} + P_3^2 B_{33} + 2P_1P_2 B_{12} + 2P_2P_3 B_{23} + 2P_3P_1 B_{13} \quad -(3)$$

$$P_L = P^T B P$$

$$P = \begin{bmatrix} P_1 \\ P_2 \\ \vdots \\ P_K \end{bmatrix} \quad -(4) \qquad \text{and } B = \begin{bmatrix} B_{11} & B_{12} & & B_{1K} \\ B_{21} & B_{22} & & B_{2K} \\ & & & \\ B_{K1} & B_{K2} & & B_{KK} \end{bmatrix} \quad -(5)$$

additional topics to be covered

10.13, 10.14 pg 198-199.

Co-ordination Equations Art: 10.16 pg - 201

$$C_T = C_1 + C_2 + \dots - C_K \quad -(6)$$

$$P_T = P_1 + P_2 + \dots - P_K \quad -(7)$$

$$P_T = P_L + P_D \quad -(8)$$

$$P_T - P_L = P_D \quad -(9)$$

$$dP_T - dP_L = 0 \quad -(10)$$

where $dP_T = dP_1 + dP_2 + \dots \; dP_K \quad -(11)$

$$dP_L = \frac{\partial P_L}{\partial P_1}.dP_1 + \frac{\partial P_L}{\partial P_2}.dP_2 + \dots - \frac{\partial P_L}{\partial P_K}.dP_K \quad -(12)$$

(11) − (12) = (10)

$$=\left(1-\frac{\partial P_L}{\partial P_1}\right)dP_1 + \left(1-\frac{\partial P_L}{\partial P_2}\right)dP_2 + \dots \left(1-\frac{\partial P_L}{\partial P_K}\right)dP_K = 0 \quad -(13)$$

or

$$-dP_1 = \frac{1-\frac{\partial P_L}{\partial P_2}}{1-\frac{\partial P_L}{\partial P_1}}.dP_2 + \frac{1-\frac{\partial P_L}{\partial P_3}}{1-\frac{\partial P_L}{\partial P_1}}.dP_2 + \dots + \frac{1-\frac{\partial P_L}{\partial P_K}}{1-\frac{\partial P_L}{\partial P_1}}.dP_K \quad -(14)$$

For C_T to be minimum

$$dC_T = 0 = \frac{\partial C_T}{\partial P_1}.dP_1 + \frac{\partial C_T}{\partial P_2}.dP_2 + \dots \frac{\partial C_T}{\partial P_K}.dP_K \quad -(15)$$

Put value of dP_1 from (14) to (15) and solving.

$$\frac{dC_1}{dP_1}\left(\frac{1}{1-\frac{\partial P_L}{\partial P_1}}\right) = \frac{dC_2}{dP_2}\left(\frac{1}{1-\frac{\partial P_L}{\partial P_2}}\right) = \frac{dC_K}{dP_K}\left(\frac{1}{1-\frac{\partial P_L}{\partial P_K}}\right) = \lambda \quad -(16)$$

$$\frac{dC_K}{dP_K} = \lambda\left(1-\frac{\partial P_L}{\partial P_K}\right) \quad -(17) \Rightarrow \boxed{\frac{dC_K}{dP_K} + \lambda \frac{\partial P_L}{\partial P_K} = \lambda} \quad -(18)$$

Iterative procedure to solve Coordination Equations Art. 10.18 pg 203

Coordination equation for n^{th} unit is

$$\frac{dC_n}{dP_n} + \lambda \frac{\partial P_L}{\partial P_n} = \lambda \quad -(19)$$

$$\frac{dC_n}{dP_n} = 2C_n P_n + b_n \quad -(20)$$

$$2C_n P_n + b_n + \lambda \sum_m 2 P_m B_{mn} = \lambda \quad -(21)$$

$$\Rightarrow P_n = \frac{1 - \frac{b_n}{\lambda} - \sum_{m \neq n} 2 P_m B_{mn}}{\frac{2C_n}{\lambda} + 2B_{nn}} \quad -(22)$$

For a system having two units

$$P_1 = \frac{1 - \frac{b_1}{\lambda} - 2 P_2 B_{12}}{\frac{2C_1}{\lambda} + 2B_{11}} \quad -(23)$$

$$P_2 = \frac{1 - \frac{b_2}{\lambda} - 2 P_1 B_{12}}{\frac{2C_2}{\lambda} + 2B_{22}} \quad -(24)$$

The iterative procedure is

- find P_1 and P_2 for a particular value of λ.
- find P_1 if $P_2 = 0$ (assumption).
- find P_2 using value of P_1
- find P_1 using value of P_2

↓ so on

Until the value of P_1 and P_2 found in the previous section.

Module 5: Hydro-thermal co-ordination

Adv. of combined working of Run off river plant and thermal plant

- No country is filled with ample water resources or abundant coal reserves
- Requirement of power demand can be fulfilled using both the resources.
- Combined operation is flexible in nature
- Economic Adv.
- Security of supply.
- Better utilization of hydro-power.
- Reserve capacity.

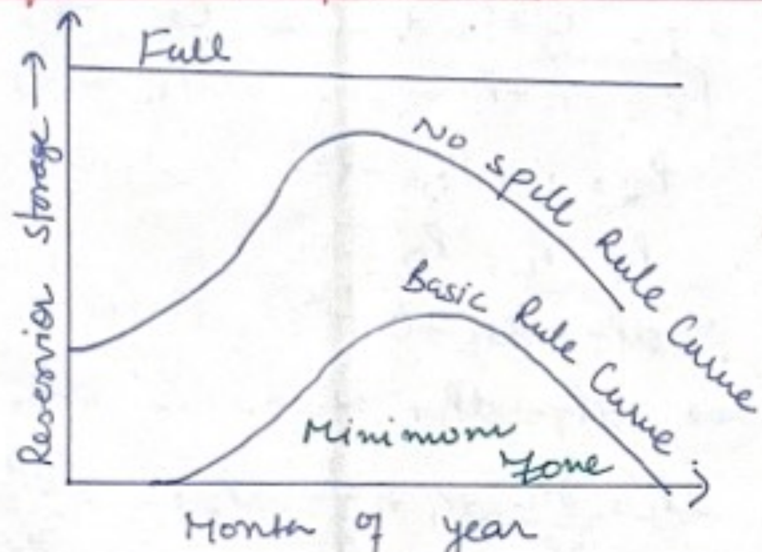
$$P = \frac{735.5}{75} Q H \eta \text{ KW} \quad -(1)$$

(Q → discharge; H → Head; η → efficiency of turbine-alternator)

Art No: 11.1, 11.2, 11.3, 11.4, 11.5, 11.6 (Pg-224)

Chap-11, Hydro thermal coordination

Reservoir hydro plants and thermal plants - long term operational aspects



- Hydro and steam plant can be operated as base load and peak load plants and vice-versa depending on the above factors
- Basic Rule Curve: represents the accumulations in reverse order of time. Supply is guaranteed as long as the storage is above the basic rule curve.
- No spill Rule curve: the aim is to keep the reservoir content upto the no-spill curve level as much as possible to provide additional head with no risk of spill.
- Full → max permissible system storage.

Long-term operational aspects scheduling methods.

- Constant hydro generation: Hydro gen is constt, remaining load is met by steam plant
- Constant steam generation: Steam gen is constt. remaining load is met by hydro plant
- Max. hydro efficient method. Hydro plants are operated at peak load periods, at the points of max η.
- Equal incremental production cost

$$\frac{dC_n}{dP_{sn}} = 2C_n P_{sn} + b_n + \lambda \quad -(2)$$

$$\gamma \frac{dw_j}{dP_{Hj}} = \gamma_j w_{jj} P_{Hj} + \lambda_j \omega_j = \lambda \quad -(3)$$

- Coordination equation method.

COGENERATION :-

- means sequential conversion of energy contained in fuel into two or more usable forms.

- A conventional system uses.

Energy of fuel
to
produce Electrical Energy OR thermal Energy for manufacturing process.

A Cogeneration system produces both from same primary fuel.

A Conventional system needs more fuel to give same total energy O/P than a Cogeneration system.

TOPPING AND BOTTOMING CYCLES :-

In a topping cycle, fuel is burnt in the boiler to produce high temperature steam. This steam is expanded in a turbine coupled to a generator to give electric power. The reject heat from the turbine is used for manufacturing process. The overall η of a topping cycle is around 75% as compared to a combined η of about 55% for two separate systems.

In bottoming cycle, fuel is burnt in the boiler to produce steam. This steam is used for manufacturing process. The rejected heat from the process is used to generate electric power.

Benefits :-

(a) Fuel economy :- results in substantial economy in the consumption of primary fuels i.e coal, oil, gas.

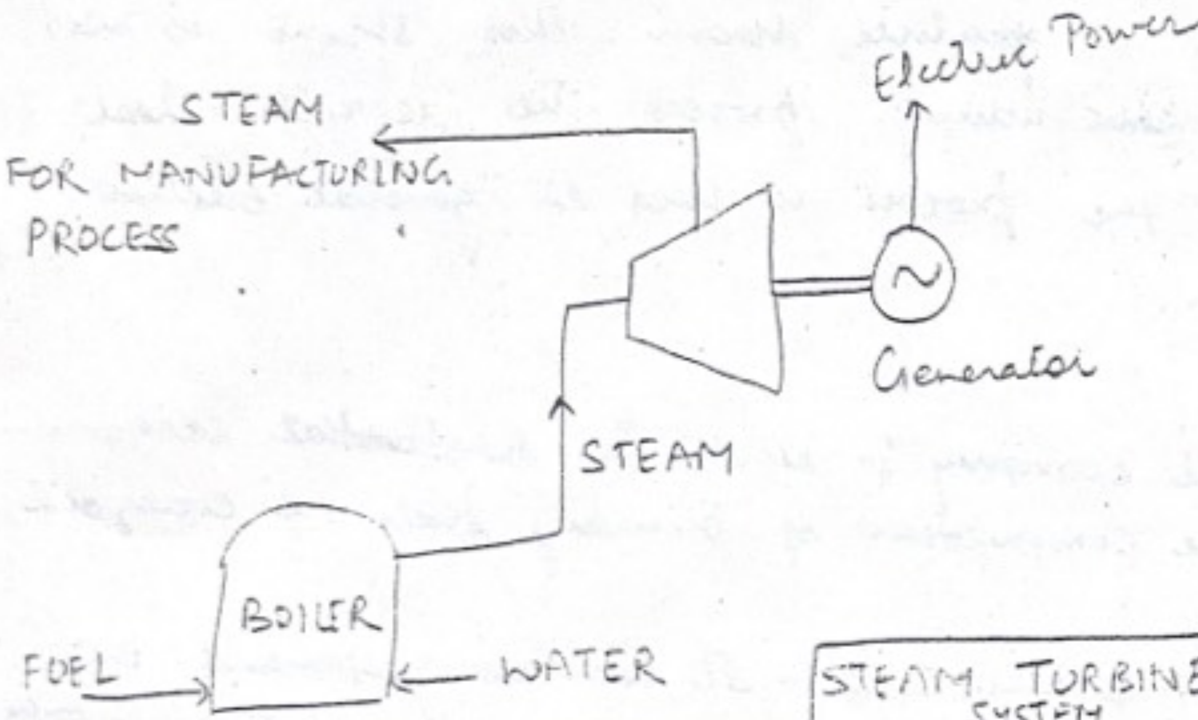
(b) Lower capital costs :- It has been estimated that incremental investment in cogeneration systems is only about 50% of the investment needed by an electric utility to supply the same power to industry.

(c) Low gestation period :- A utility needs 6 years to install, whereas a cogeneration system needs only 3 years. Results in savings in interest, early utilization, early return of investment.

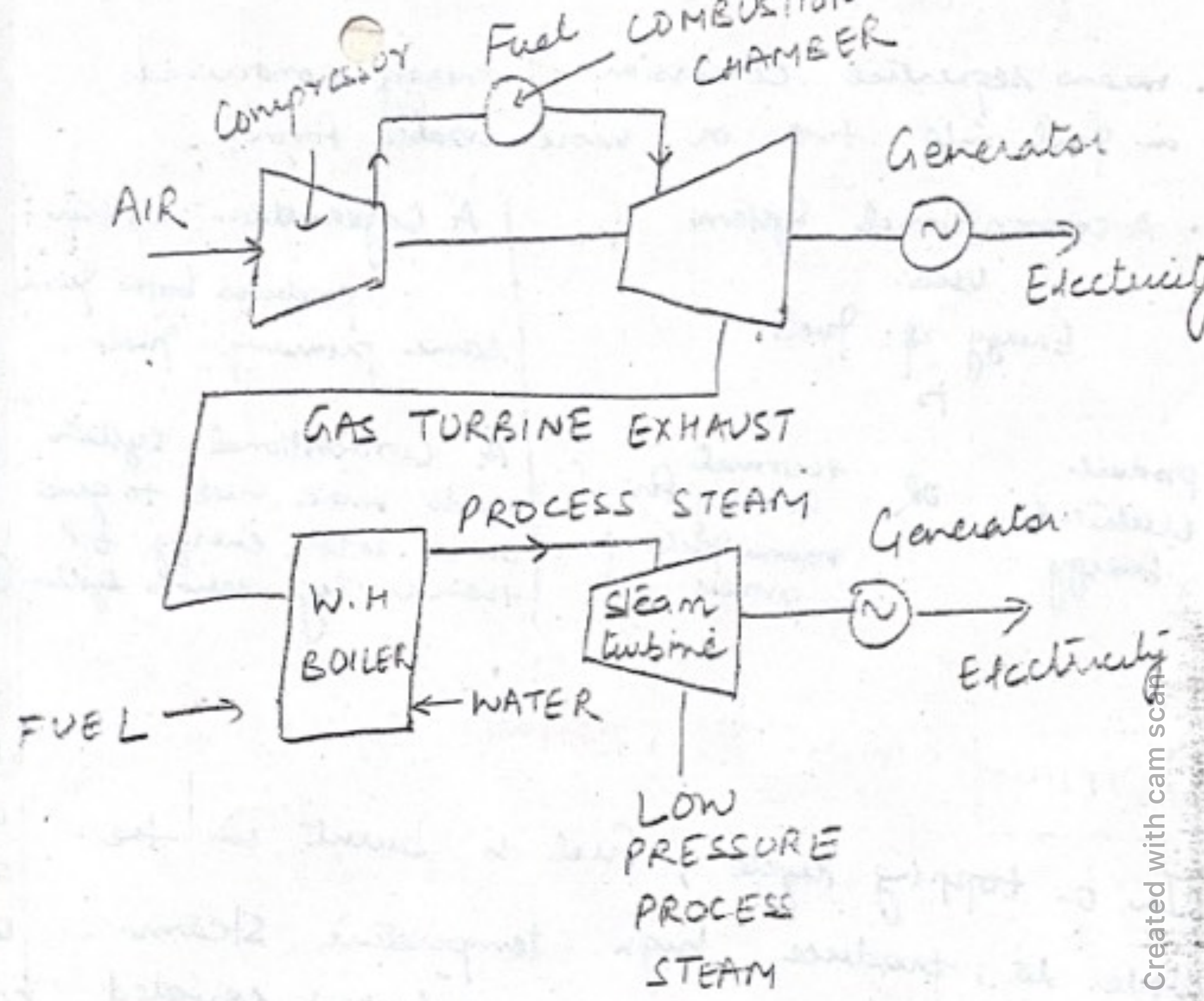
(d) Saving to industry from power cuts and power system interruption.

In the industry opts for cogeneration to meet its electricity demand, it will not face any power cuts. A well designed cogeneration scheme can be very reliable.

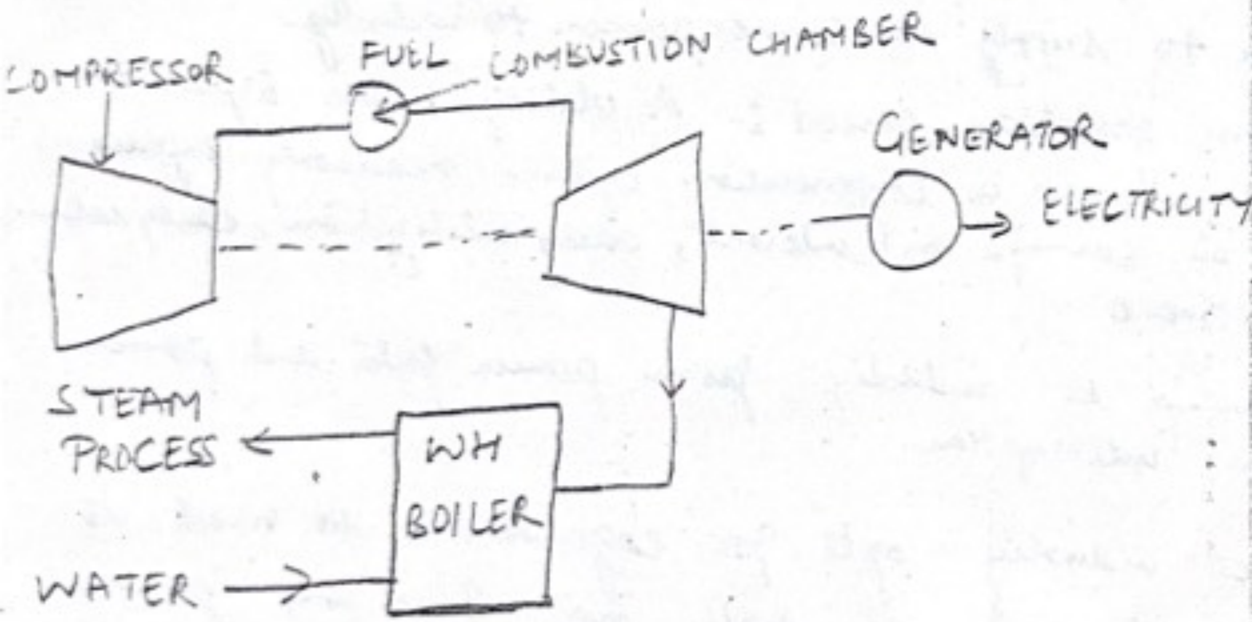
CO-GENERATION Techniques



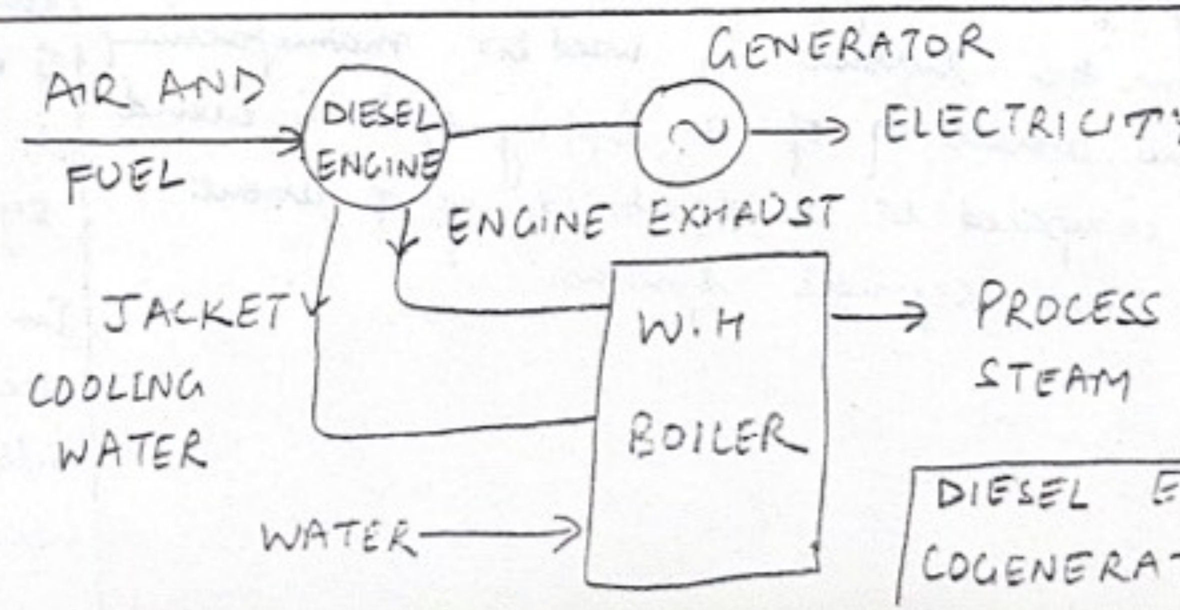
STEAM TURBINE SYSTEM



COMBINED CYCLE COGENERATION SYSTEM



GAS TURBINE SYSTEM



DIESEL ENGINE COGENERATION SYSTE

ALLEN. J. WOOD

a large wave traveling downstream with potentially damaging effects. Fish ladders may be needed. Water releases may be dictated by international treaty.

To repeat: all hydrosystems are different.

7.1.1 Long-Range Hydro-Scheduling

The coordination of the operation of hydroelectric plants involves, of course, the scheduling of water releases. The *long-range hydro-scheduling problem* involves the long-range forecasting of water availability and the scheduling of reservoir water releases (i.e., "drawdown") for an interval of time that depends on the reservoir capacities.

Typical long-range scheduling goes anywhere from 1 wk to 1 yr or several years. For hydro schemes with a capacity of impounding water over several seasons, the long-range problem involves meteorological and statistical analyses.

Nearer-term water inflow forecasts might be based on snow melt expectations and near-term weather forecasts. For the long-term drawdown schedule, a basic policy selection must be made. Should the water be used under the assumption that it will be replaced at a rate based on the statistically expected (i.e., mean value) rate, or should the water be released using a "worst-case" prediction. In the first instance, it may well be possible to save a great deal of electric energy production expense by displacing thermal generation with hydro-generation. If, on the other hand, a worst-case policy was selected, the hydroplants would be run so as to minimize the risk of violating any of the hydrological constraints (e.g., running reservoirs too low, not having enough water to navigate a river). Conceivably, such a schedule would hold back water until it became quite likely that even worst-case rainfall (runoff, etc.) would still give ample water to meet the constraints.

Long-range scheduling involves optimizing a policy in the context of unknowns such as load, hydraulic inflows, and unit availabilities (steam and hydro). These unknowns are treated statistically, and long-range scheduling involves optimization of statistical variables. Useful techniques include:

1. Dynamic programming, where the entire long-range operation time period is simulated (e.g., 1 yr) for a given set of conditions.
2. Composite hydraulic simulation models, which can represent several reservoirs.
3. Statistical production cost models.

The problems and techniques of long-range hydro-scheduling are outside the scope of this text, so we will end the discussion at this point and continue with short-range hydro-scheduling.

7.1.2 Short-Range Hydro-Scheduling

Short-range hydro-scheduling (1 day to 1 wk) involves the hour-by-hour scheduling of all generation on a system to achieve minimum production cost for the given time period. In such a scheduling problem, the load, hydraulic inflows, and unit availabilities are assumed known. A set of starting conditions (e.g., reservoir levels) is given, and the optimal hourly schedule that minimizes a desired objective, while meeting hydraulic steam, and electric system constraints, is sought. Part of the hydraulic constraints may involve meeting "end-point" conditions at the end of the scheduling interval in order to conform to a long-range, water-release schedule previously established.

7.2 HYDROELECTRIC PLANT MODELS

To understand the requirements for the operation of hydroelectric plants, one must appreciate the limitations imposed on operation of hydro-resources by flood control, navigation, fisheries, recreation, water supply, and other demands on the water bodies and streams, as well as the characteristics of energy conversion from the potential energy of stored water to electric energy. The amount of energy available in a unit of stored water, say a cubic foot, is equal to the product of the weight of the water stored (in this case, 62.4 lb) times the height (in feet) that the water would fall. One thousand cubic feet of water falling a distance of 42.5 ft has the energy equivalent to 1 kWh. Correspondingly, 42.5 ft^3 of water falling 1000 ft also has the energy equivalent to 1 kWh.

Consider the sketch of a reservoir and hydroelectric plant shown in Figure 7.1. Let us consider some overall aspects of the falling water as it travels from the reservoir through the penstock to the inlet gates, through the hydraulic turbine down the draft tube and out the tailrace at the plant exit. The power that the water can produce is equal to the rate of water flow in cubic feet per

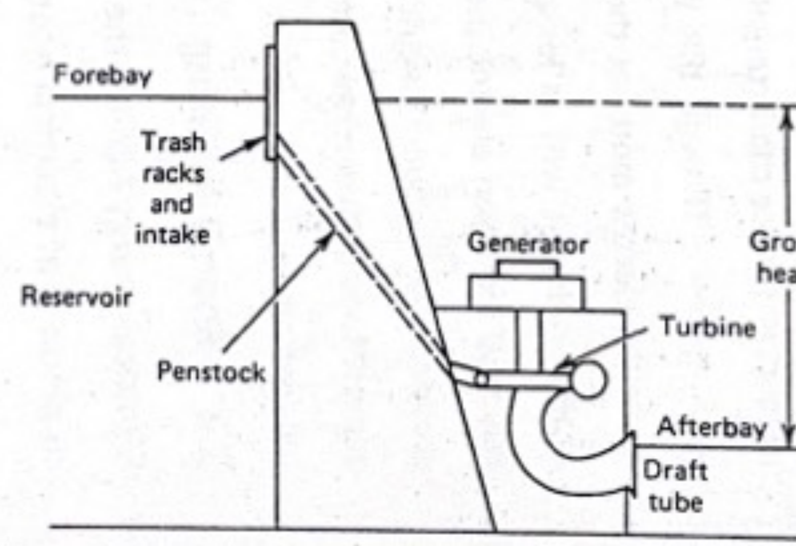


FIG. 7.1 Hydroplant components.

7.3 SCHEDULING PROBLEMS

7.3.1 Types of Scheduling Problems

In the operation of a hydroelectric power system, three general categories of problems arise. These depend on the balance between the hydroelectric generation, the thermal generation, and the load.

Systems without any thermal generation are fairly rare. The economic scheduling of these systems is really a problem in scheduling water releases to satisfy all the hydraulic constraints and meet the demand for electrical energy. Techniques developed for scheduling hydrothermal systems may be used in some systems by assigning a pseudo-fuel cost to some hydroelectric plant. Then the schedule is developed by minimizing the production "cost" as in a conventional hydrothermal system. In all hydroelectric systems, the scheduling could be done by simulating the water system and developing a schedule that leaves the reservoir levels with a maximum amount of stored energy. In geographically extensive hydroelectric systems, these simulations must recognize water travel times between plants.

Hydrothermal systems where the hydroelectric system is by far the largest component may be scheduled by economically scheduling the system to produce the minimum cost for the thermal system. These are basically problems in scheduling energy. A simple example is illustrated in the next section where the hydroelectric system cannot produce sufficient energy to meet the expected load.

The largest category of hydrothermal systems include those where there is a closer balance between the hydroelectric and thermal generation resources and those where the hydroelectric system is a small fraction of the total capacity. In these systems, the schedules are usually developed to minimize thermal-generation production costs, recognizing all the diverse hydraulic constraints that may exist. The main portion of this chapter is concerned with systems of this type.

7.3.2 Scheduling Energy

Suppose, as in Figure 7.3, we have two sources of electrical energy to supply a load, one hydro and another steam. The hydroplant can supply the load

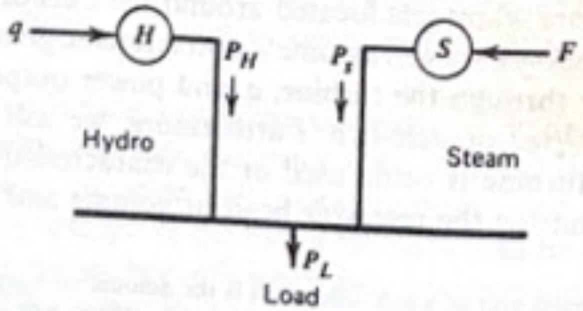


FIG. 7.3 Two-unit hydrothermal system.

by itself for a limited time. That is, for any time period j,

$$P_{Hj}^{\max} \geq P_{\text{load } j} \qquad j = 1 \ldots j_{\max} \tag{7.1}$$

However, the energy available from the hydroplant is insufficient to meet the load.

$$\sum_{j=1}^{j_{\max}} P_{Hj} n_j \leq \sum_{j=1}^{j_{\max}} P_{\text{load } j} n_j \qquad n_j = \text{number of hours in period } j \tag{7.2}$$

$$\sum_{j=1}^{j_{\max}} n_j = T_{\max} = \text{total interval}$$

We would like to use up the entire amount of energy from the hydroplant in such a way that the cost of running the steam plant is minimized. The steam-plant energy required is

$$\underset{\substack{\text{Load}\\\text{energy}}}{\sum_{j=1}^{j_{\max}} P_{\text{load } j} n_j} - \underset{\substack{\text{Hydro-}\\\text{energy}}}{\sum_{j=1}^{j_{\max}} P_{Hj} n_j} = \underset{\substack{\text{Steam}\\\text{energy}}}{E} \tag{7.3}$$

We will not require the steam unit to run for the entire interval of $T_{\max}$ hours. Therefore,

$$\sum_{j=1}^{N_s} P_{Sj} n_j = E \qquad N_s = \text{number of periods the steam plant is run} \tag{7.4}$$

Then

$$\sum_{j=1}^{N_s} n_j \leq T_{\max}$$

the scheduling problem becomes

$$\text{Min } F_T = \sum_{j=1}^{N_s} F(P_{Sj}) n_j \tag{7.5}$$

subject to

$$\sum_{j=1}^{N_s} P_{Sj} n_j - E = 0 \tag{7.6}$$

and the Lagrange function is

$$\mathscr{L} = \sum_{j=1}^{N_s} F(P_{Sj}) n_j + \alpha \left(E - \sum_{j=1}^{N_s} P_{Sj} n_j \right) \tag{7.7}$$

Then

$$\frac{\partial \mathscr{L}}{\partial P_{sj}} = \frac{dF(P_{sj})}{dP_{sj}} - \alpha = 0 \qquad \text{for } j = 1 \ldots N_s$$

or

$$\frac{dF(P_{sj})}{dP_{sj}} = \alpha \qquad \text{for } j = 1 \ldots N_s \tag{7.8}$$

This means that the steam plant should be run at constant incremental cost for the entire period it is on. Let this optimum value of steam-generated power be P_s^*, which is the same for all time intervals the steam unit is on. This type of schedule is shown in Figure 7.4.

The total cost over the interval is

$$F_T = \sum_{j=1}^{N_s} F(P_s^*)n_j = F(P_s^*) \sum_{j=1}^{N_s} n_j = F(P_s^*)T_s \tag{7.9}$$

where

$$T_s = \sum_{j=1}^{N_s} n_j = \text{the total run time for the steam plant}$$

Let the steam-plant cost be expressed as

$$F(P_s) = A + BP_s + CP_s^2 \tag{7.10}$$

then

$$F_T = (A + BP_s^* + CP_s^{*2})T_s \tag{7.11}$$

also note that

$$\sum_{j=1}^{N_s} P_{sj}n_j = \sum_{j=1}^{N_s} P_s^* n_j = P_s^* T_s = E \tag{7.12}$$

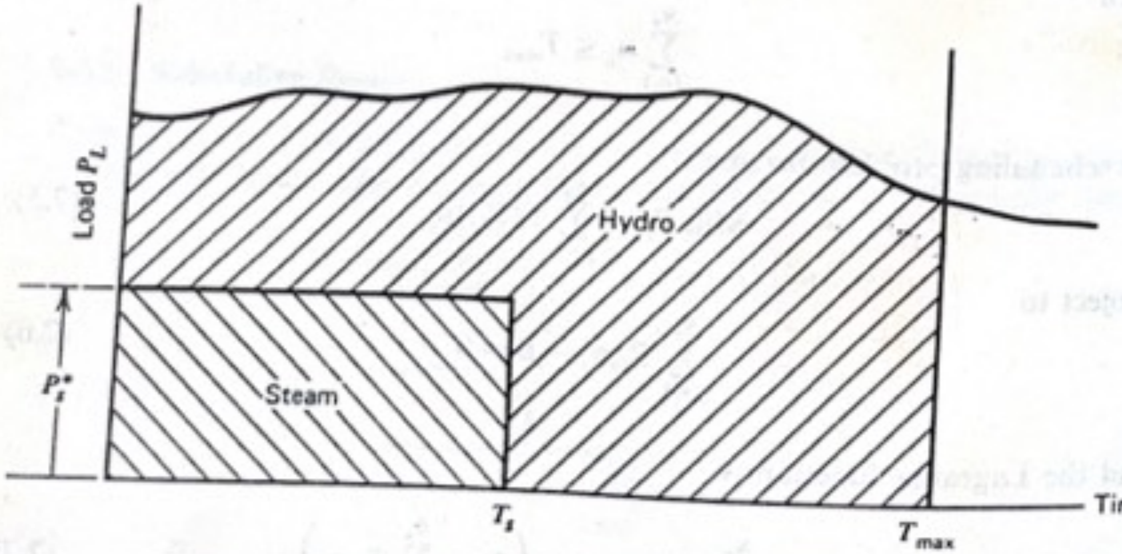


FIG. 7.4 Resulting optimal hydrothermal schedule.

Then

$$T_s = \frac{E}{P_s^*} \tag{7.13}$$

and

$$F_T = (A + BP_s^* + CP_s^{*2})\left(\frac{E}{P_s^*}\right) \tag{7.14}$$

Now we can establish the value of P_s^* by minimizing F_T:

$$\frac{dF_T}{dP_s^*} = \frac{-AE}{P_s^{*2}} + CE = 0 \tag{7.15}$$

or

$$P_s^* = \sqrt{A/C} \tag{7.16}$$

which means the unit should be operated at its maximum efficiency point long enough to supply the energy needed, E. Note, if

$$F(P_s) = A + BP_s + CP_s^2 = f_c \times H(P_s) \tag{7.17}$$

where f_c is the fuel cost, then the heat rate is

$$\frac{H(P_s)}{P_s} = \frac{1}{f_c}\left(\frac{A}{P_s} + B + CP_s\right) \tag{7.18}$$

and the heat rate has a minimum when

$$\frac{d}{dP_s}\left[\frac{H(P_s)}{P_s}\right] = 0 = \frac{-A}{P_s^2} + C \tag{7.19}$$

giving best efficiency at

$$P_s = \sqrt{A/C} = P_s^* \tag{7.20}$$

EXAMPLE 7A

A hydroplant and a steam plant are to supply a constant load of 90 MW for 1 wk (168 h). The unit characteristics are

Hydroplant: $q = 300 + 15P_H$ acre-ft/h

$0 \le P_H \le 100$ MW

Steam plant: $H_s = 53.25 + 11.27P_s + 0.0213P_s^2$

$12.5 \le P_s \le 50$ MW