POWER POINT PRESENTATION
ON
POWER SYSTEM OPERATION CONTROL

IV B. Tech I semester (JNTUH-R15)

Prepared

By

Mr. A Sathishkumar Assistant professor

ELECTRICAL AND ELECTRONICS ENGINEERING

INSTITUTE OF AERONAUTICAL ENGINEERING

(AUTONOMOUS)

DUNDIGAL, HYDERABAD - 500043

Unit-1

Economic operation of power system-I

INTRODUCTION

The optimal system operation, in general, involved the consideration of economy of operation, system security, emissions at certain fossil-fuel plants, optimal releases of water at hydro generation, etc. All these considerations may make for conflicting requirements and usually a compromise has to be made for optimal system operation. In this chapter we consider the economy of operation only, also called the *ecomonic dispatch problem.*

The main aim in the economic dispatch problem is to minimize the total cost of generating real power (production cost) at various stations while satisfying the loads and the losses in the transmission links. For simplicity we consider the presence of thermal plants only in the beginning. In the later part of this chapter we will consider the presence of hydro plants which operate in conjunction with thermal plants. While there is negligible operating cost at a hydro plant, there is a limitation of availability of water over a period of time which must be used to save maximum fuel at the thermal plants.

Optimal Operation of Generators in all Thermal Plants

The total generator operating cost includes fuel, Labour, and maintenance costs for simplicity fuel cost is the only one considered to be variable.

The fuel cost is meaning fuel in case of thermal and nuclear stations, but for hydro stations where the energy storage is apparently free. The operating cost as such is not meaningful.

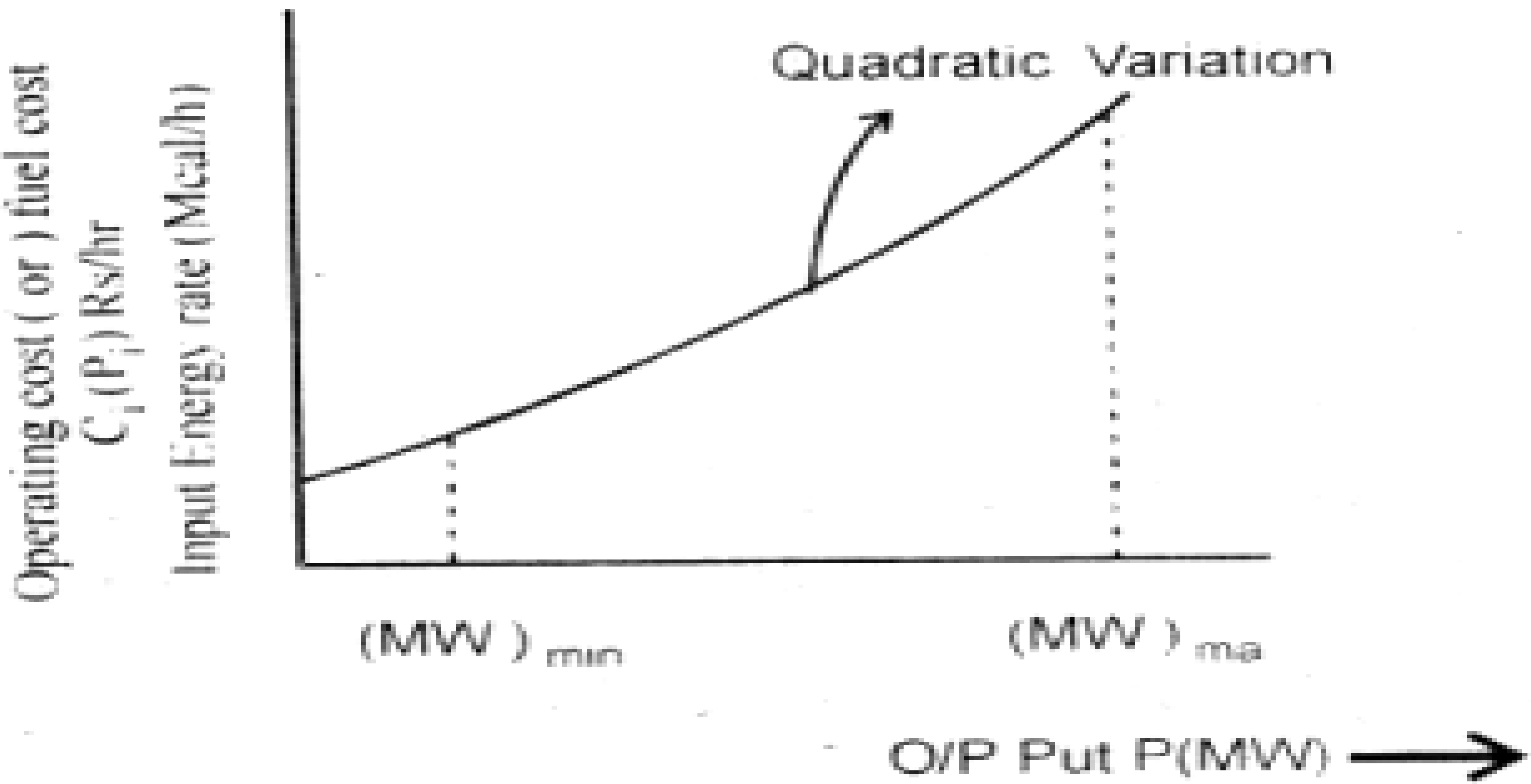


fig Input-Output Curve of Generating Unit

Incremental Fuel Rate Curves

The input – output curves being obtained from the operating data of the power station can be utilized to get the "Incremental fuel rate" (IFR or IR) curve from the relation.

$$IFR = \frac{Incremental\ change\ in\ Input}{Incremental\ change\ in\ Output}$$

Thus by calculating the shape of the input – output curves at various points of operation. The profile of IFR can be obtained. The input - output curve of a unit (it consists of boiler, turbine,

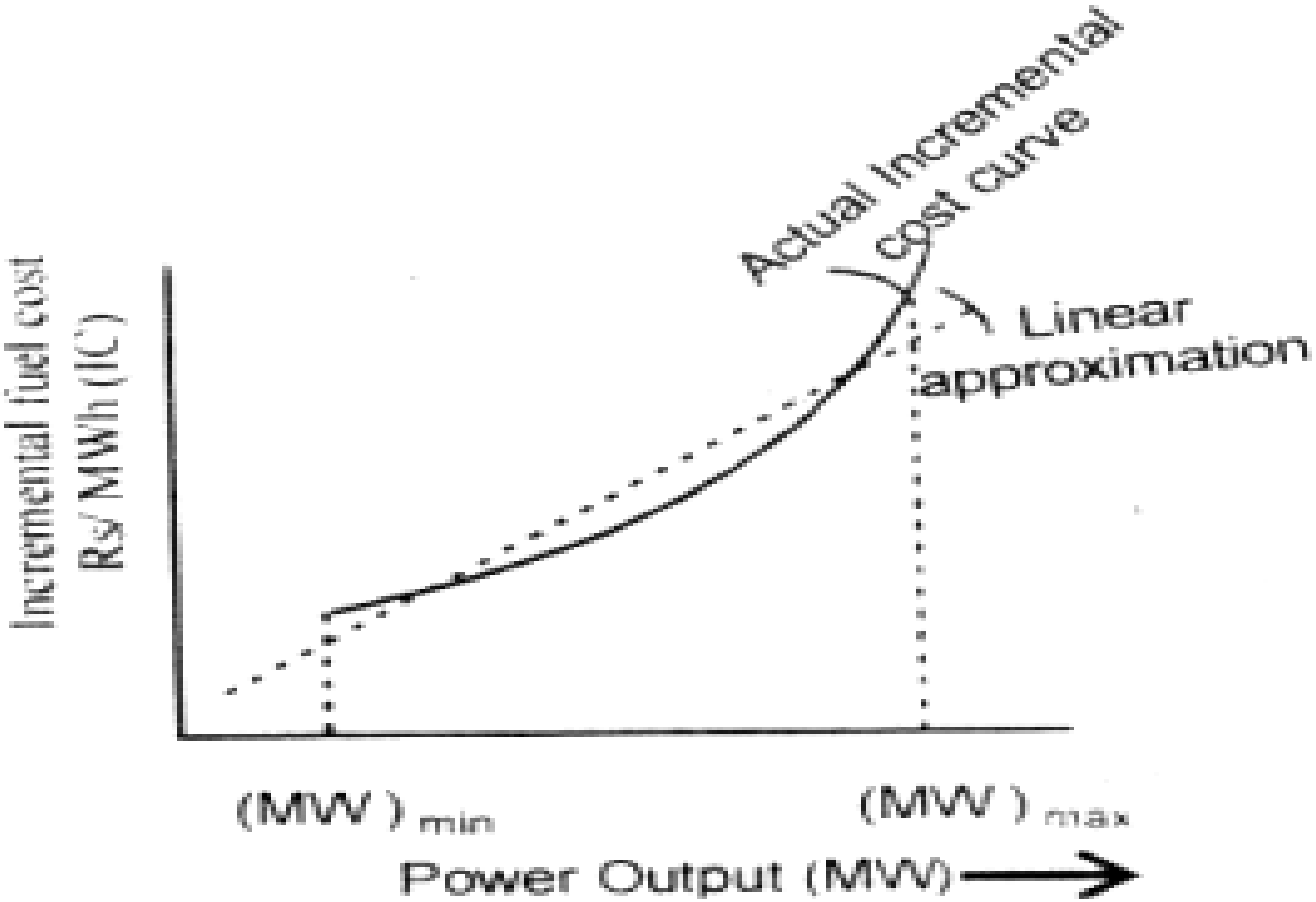


Fig. Incremental Fuel Cost Vs Power Output for the unit whose Input Output Curve is shown in fig (1.1)

An analytical expression for operating cost can be written as

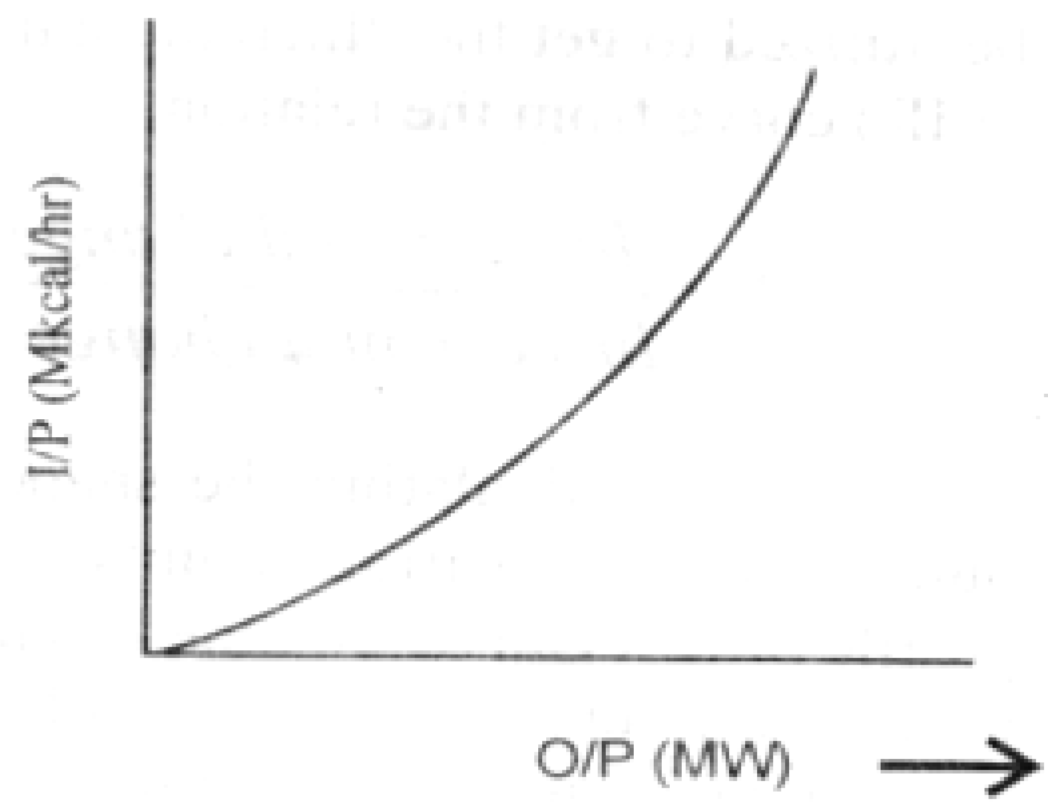
$C_i\,(P_{Gi})$ *Rs / hour at output* P_{Gi}

Where the suffix "*i*" is stands for the number. It generally suffices to fit a second degree polynomial i.e.

$$C_i = a_i + b_i P_{Gi} + Ci\, P_{Gi}^2 \ Rs/hr \qquad \rightarrow$$

The slope of the cost curve i.e. $\dfrac{dc_i}{d\,P_{Gi}}$ is called Incremental fuel cost (IC) and is

The input - output curve of a generating unit as shown in figure. Efficient unit develops a given amount of power with lesser fuel input.



HEAT RATE CURVE

Heat rate curve $H_i(P_{Gi})$ is the heat energy in *(Mkcal)* needed to generate one unit of electrical energy. Figure 1.3 shows the appropriate shape of heat rate curve, which can be obtained experimentally.

The generating unit efficiency can be defined as the ratio of electric energy output generated to fuel energy input. Thus, the generating unit is most efficient at the minimum Heat rate which corresponds to a particular P_{Gi}.

And the curve indicates the increase in the Heat Rate at Low and High Power Limits. The typical peak efficiency (Heat Rate) of modern fuel fired plant is around 2.5 Mkcal/MWh and peak efficiency is $= \dfrac{3600 \times 100}{2.5 \times 4.2 \times 100} = 34\%$

The input - output curve can be obtained from heat curve as :

$$F_i(P_{Gi}) = P_{Gi}\, H_i(P_{Gi}) \text{ (Mkcal/h)}$$

$H_i(P_{Gi})$ is the heat rate in Mkcal/h

Let the cost of the fuel be *K Rs / Mkcal*. Then the input fuel cost is $C_i(P_{Gi})$ is

$$C_i(P_{Gi}) = KF_i(P_{Gi}) = K\,P_{Gi}\,H_i(P_{Gi})\ \text{Rs/hr}$$

The heat rate curve can approximated in the form

$$H_i(P_{Gi}) = (Q_i' / P_{Gi}) + b_i' + c_i'\,P_{Gi}\ (\text{Mkcal/MWh})$$

with all co-efficients positive from the above two equations we get the expression for input energy rate $F_i(P_{Gi})$ with positive co-efficients in the form.

$$F_i(P_{Gi}) = a_i^{l} + b_i^{l} P_{Gi} + C_i^{l} P_{Gi}^{2} \ (Mkcal/h)$$

From equation 1.25 & 1.27 we also get a quadratic expression for fuel cost as

$$C_i(P_{Gi}) = Ka_i^{l} + Kb_i^{l} P_{Gi} + Kc_i^{l} P_{G\,i}^{2}$$

$$= a_i + b_i P_{Gi} + C_i P_{Gi}^{2} \ (Rs/h)$$

Contd..

Optimal Operation

Let us assume that it is known a *priori* which generators are to run to meet a particular load demand on the station. Obviously

$$\Sigma P_{Gi,\ max} \geq P_D$$

where $P_{Gi,\ max}$ is the rated real power capacity of the ith generator and P_D is the total power demand on the station. Further, the load on each generator is to be constrained within lower and upper limits, i.e.

$$P_{Gi,\ min} \leq P_{Gi} \leq P_{Gi,\ max},\ i = 1, 2, \ldots, k$$

Problem 1: The fuel cost of two units are given by

$$C_1 = 1.5 + 20\,P_{G1} + 0.1\,P_{G1}^2 \quad Rs/hr$$

$$C_2 = 1.9 + 30\,PG_2 + 0.1\,PG_2^2\ Rs/hr$$

If the total demand on the generators is 200 MW. Find the economic load scheduling of the two units.

Answer From the fuel cost equations we get the Incremental cost equation.

$$\frac{dc_1}{dP_{G1}} = 20 + 0.2P_{G1} \quad Rs/MWh; \quad \frac{dc_2}{dP_{G2}} = 30 + 0.2P_{G2} \quad Rs/MWh$$

for economic load scheduling the condition is

$$\lambda = \frac{dc_1}{dP_{G1}} = \frac{dc_2}{dP_{G2}}$$

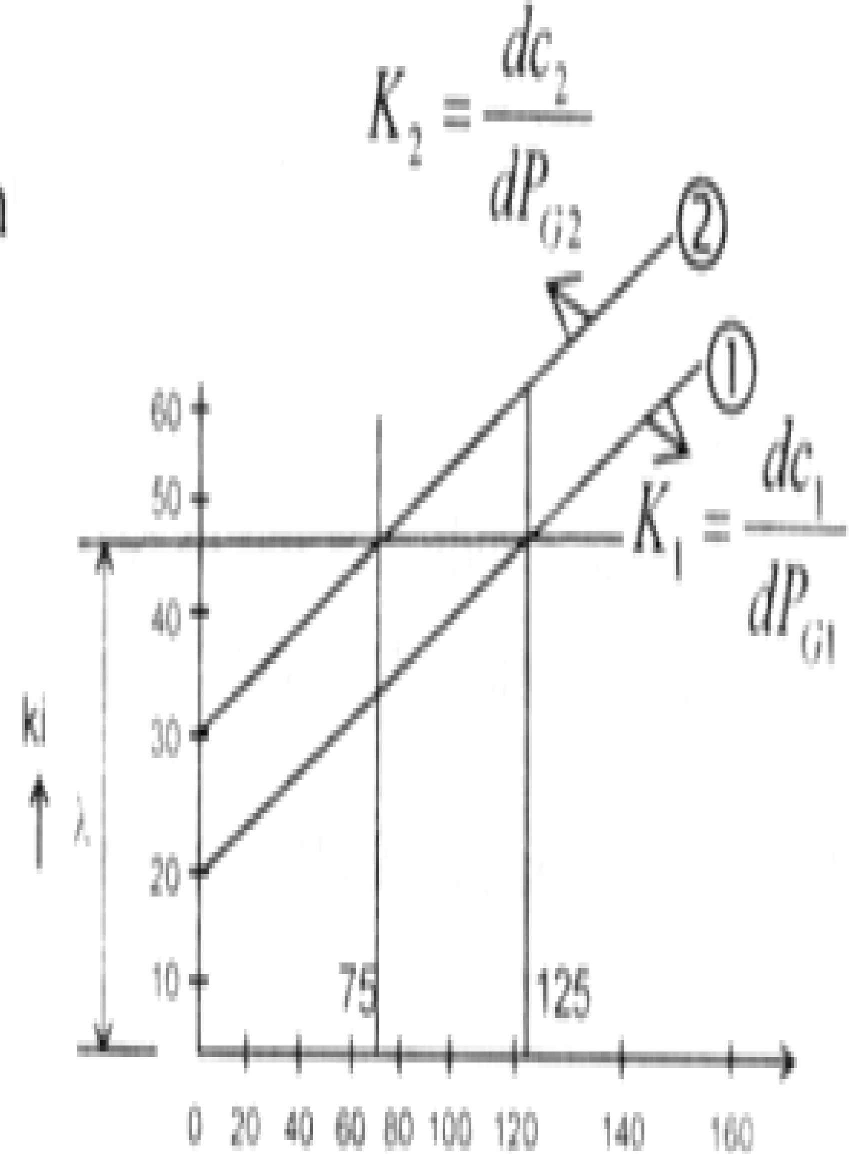
$$\therefore \quad 20 + 0.2P_{G1} = 30 + 0.2P_{G2}$$

From equation 1 & 2 we find the solution

$PG_1 = 125$ MW $PG_2 = 75$ MW and

also depicted graphically also in figure.

$$P_{G1} + P_{G2} = 200MW \quad \rightarrow 2$$



ECONOMIC LOAD DISTRIBUTION BETWEEN THERMAL PLANTS

(Optimum generation allocation including the effect of transmission line losses)

Since the plants are generally at long distance aparts. Therefore In determining the economic load dispatch between plants we encounter the need to consider losses in the transmission lines. Let us consider that we have *n* plants interconnected.

For *n* plants, we have

$$C = C_1(P_{G1}) + C_2(P_{G2}) + ------ C_n(P_{Gn}) = \sum_{i=1}^{n} C_i(P_{Gi})$$

$$P_D + P_L = P_{G1} + P_{G2} + ------ P_{Gn} = \sum_{i=1}^{n} P_{Gi}$$

where C = total fuel cost Rs./hr

$Ci = (P_{Gi})$ = fuel cost of plant i Rs./hr

P_{Gi} = output of plant i, MW

$$P_D = \sum_{i=1}^{n} P_{Di} = \textit{total demand (total load connected systems)}$$

P_L = total transmission loss in the system

n = total number of generating plants

We write equation as

$$P_L(P_{G1}, P_{G2} ------ P_{Gn}) = P_D + P_L - \sum_{i=1}^{n} P_{Gi} = 0$$

To solve the problem, we write the lagragian as

$$\mathcal{L} = \sum_{i=1}^{n} C_i(P_{Gi}) - \lambda \left[\sum_{i=1}^{n} P_{Gi} - P_D - P_L \right]$$

It will be shown later in this section that if the power fact of load at each bus is assumed to remain constant. The system loss P_L can be shown to be a function of active power generation at each plant i.e.

$$P_L = P_L\,(P_{G1}, P_{G2}, P_{Gn})$$

Thus in the optimization problem posed above P_{Gi} (i = 1,2 ..... n) are the only control variables.

For optimum real power dispatch

$$\frac{\partial \mathcal{L}_i}{\partial P_{Gi}} = \frac{\partial C_1}{\partial P_{G1}} - \lambda + \lambda \frac{\partial P_L}{\partial P_{Gi}} = 0 \qquad i = 1, 2, - - - - - n$$

Rearranging the above equation and recognizing that changing the output of only one plant can effect the cost at only that plant, we have

$$\frac{\frac{dc_i}{dP_{Gi}}}{\left(1 - \frac{\partial P_L}{\partial P_{G1}}\right)} = \lambda \ (or) \ \frac{dc_i}{dP_{Gi}} L_i = \lambda \qquad i = 1, 2, - - - - - n$$

where $L_i = \frac{1}{1 - \frac{\partial P_L}{\partial P_{Gi}}} \rightarrow$ is called the penalty factor of i^{th} plant

The Lagragian multiplier λ is in rupees per Mwhr, when fuel cost is in Rs/hr equation implies that minimum fuel cost is obtained, when the incremental fuel cost of each plant multiplied by its penalty factor is the same for all the plants.

The *(n+1)* variables $(P_{G1}, P_{G2} \ldots G_{n\lambda})$ can be obtained from n optimal dispatch equation 1.57 together with the power balance equation. The partial derivative $\frac{\partial P_L}{\partial P_{Gi}}$ is referred to as the incremental transmission loss (ITL) associated with the i^{th} generating plant.

Equation 1.57 can also be written in the alternative form.

$$(IC)_i = \lambda\left[1-(ITL)_i\right]; \quad i = 1, 2 ---- k$$

This equation is referred to as the exact co-ordination equation.

Thus it is clear that to solve the optimum load scheduling problem, it is necessary to compute (ITL) for each plant and therefore we must determine the functional dependence of transmission loss on real power of generating plants.

Derivation of Transmission Loss Formula

An accurate method of obtaining a general formula for transmission loss has been given by Kron [4]. This, however, is quite complicated. The aim of this article is to give a simpler derivation by making certain assumptions.

Figure (c) depicts the case of two generating plants connected to an arbitrary number of loads through a transmission network. One line within the network is designated as branch p.

Imagine that the total load current I_D is supplied by plant 1 only, as in Fig. a. Let the current in line p be I_{p1}. Define

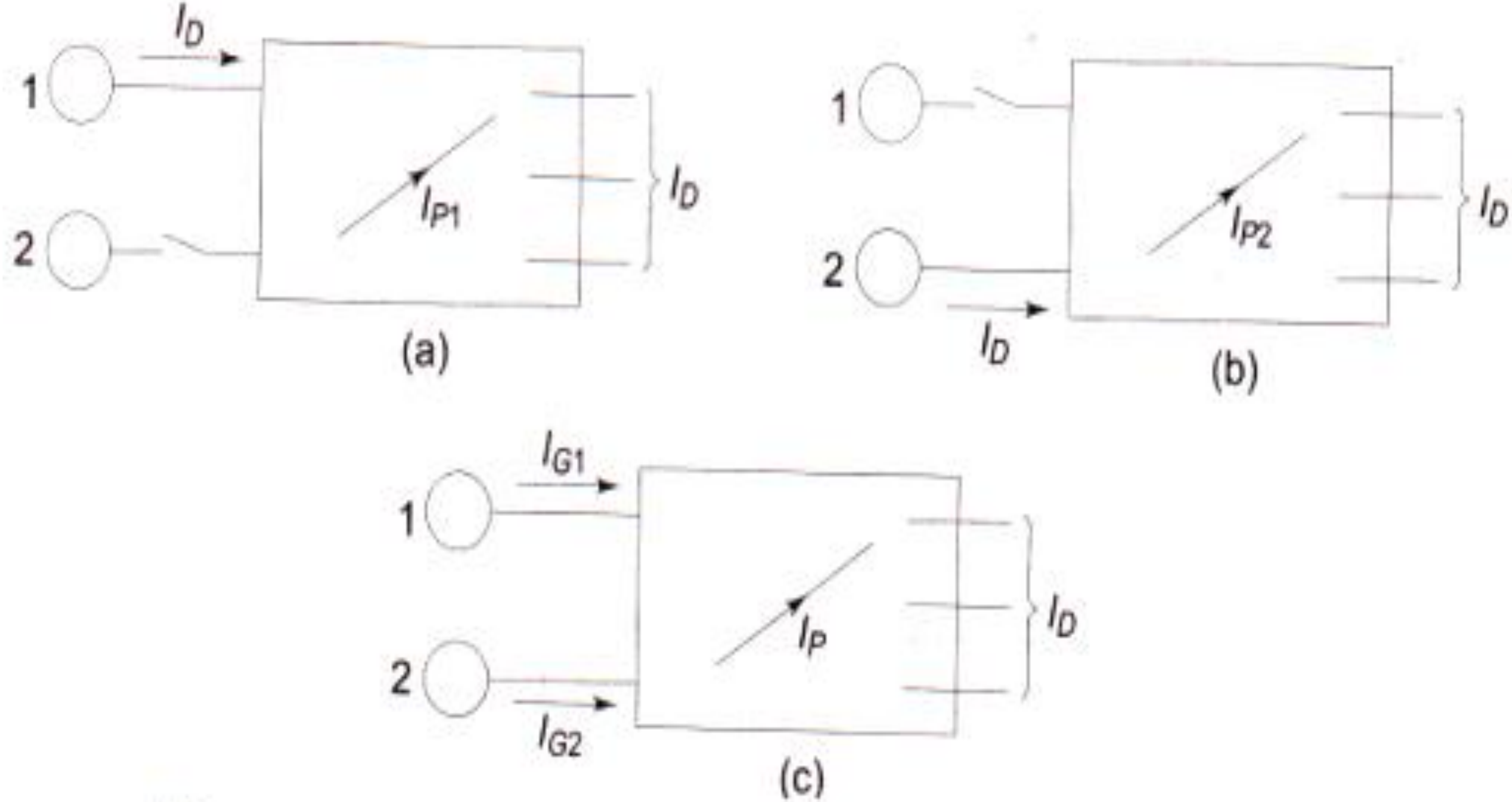


Fig. Schematic diagram showing two plants connected through a power network to a number of loads

$$M_{p1} = \frac{I_{p1}}{I_D}$$

M_{p1} and M_{p2} are called *current distribution factors*. The values of current distribution factors depend upon the impedances of the lines and their interconnection and are independent of the current I_D.

When both generators 1 and 2 are supplying current into the network as in Fig applying the principle of superposition the current in the line p can be expressed as

$$I_p = M_{p1} I_{G1} + M_{p2} I_{G2}$$

where I_{G1} and I_{G2} are the currents supplied by plants 1 and 2, respectively.

At this stage let us make certain simplifying assumptions outlined below:

(1) All load currents have the same phase angle with respect to a common reference. To understand the implication of this assumption consider the load current at the *i*th bus. It can be written as

$$|I_{Di}| \angle (\delta_i - \phi_i) = |I_{Di}| \angle \theta_i$$

where δ_i is the phase angle of the bus voltage and ϕ_i is the lagging phase angle of the load. Since δ_i and ϕ_i vary only through a narrow range at various buses, it is reasonable to assume that θ_i is the same for all load currents at all times.

(2) Ratio X/R is the same for all network branches.

These two assumptions lead us to the conclusion that I_{p1} and I_D [Fig. (a)] have the same phase angle and so have I_{p2} and I_D [Fig. (b)], such that the current distribution factors M_{p1} and M_{p2} are real rather than complex.

Let, $$I_{G1} = |I_{G1}| \angle \sigma_1 \text{ and } I_{G2} = |I_{G2}| \angle \sigma_2$$

where σ_1 and σ_2 are phase angles of I_{G1} and I_{G2}, respectively with respect to the common reference.

From Eq. ( ), we can write

$$|I_p|^2 = (M_{p1}|I_{G1}| \cos \sigma_1 + M_{p2} |I_{G2}| \cos \sigma_2)^2 + (M_{p1}|I_{G1}| \sin \sigma_1 + M_{p2}|I_{G2}| \sin \sigma_2)^2 \qquad (\;.36)$$

Expanding the simplifying the above equation, we get

$$|I_p|^2 = M_{P1}^2|I_{G1}|^2 + M_{p2}^2|I_{G2}|^2 + 2M_{p1}M_{p2}|I_{G1}|\,|I_{G2}|\cos(\sigma_1 - \sigma_2)$$

Now $$|I_{G1}| = \frac{P_{G1}}{\sqrt{3}|V_1|\cos\phi_1}; \ |I_{G2}| = \frac{P_{G2}}{\sqrt{3}|V_2|\cos\phi_2}$$

where P_{G1} and P_{G2} are the three-phase real power outputs of plants 1 and 2 at power factors of cos ϕ_1, and cos ϕ_2, and V_1 and V_2 are the bus voltages at the plants.

If R_p is the resistance of branch p, the total transmission loss is given by*

*The general expression for the power system with k plants is expressed as

$$P_L = \frac{P_{G1}^2}{|V_1|^2(\cos\phi_1)^2}\sum_{v} M_{p1}^2 R_p + \ldots + \frac{P_{Gk}^2}{|V_k|^2(\cos\phi_k)^2}\sum_{p} M_{pk}^2 R_p$$

$$+2\sum_{\substack{m,n=1 \\ m\neq n}}^{k}\left\{\frac{P_{Gm}P_{Gn}\cos(\sigma_m-\sigma_n)}{|V_m||V_n|\cos\phi_m\cos\phi_n}\sum_{p} M_{pm}M_{pn}R_p\right\}$$

$$P_L = \sum_p 3|I_p|^2 R_p$$

Substituting for $|I_p|^2$ from Eq. (7.37), and $|I_{G1}|$ and $|I_{G2}|$ from Eq. (7.38), we obtain

$$P_L = \frac{P_{G1}^2}{|V_1|^2(\cos\phi_1)^2}\sum_p M_{p1}^2 R_p$$

$$+\frac{2P_{G1}P_{G2}\cos(\sigma_1-\sigma_2)}{|V_1||V_2|\cos\phi_1\cos\phi_2}\sum_p M_{p1}M_{p2}R_p$$

$$+\frac{P_{G2}^2}{|V_2|^2(\cos\phi_2)^2}\sum_p M_{p2}^2 R_p$$

Equation can be recognized as

$$P_L = P_{G1}^2 B_{11} + 2P_{G1}P_{G2}B_{12} + P_{G2}^2 B_{22}$$

$$B_{11} = \frac{1}{|V_1|^2 (\cos\phi_1)^2} \sum_p M_{p1}^2 R_p$$

$$B_{12} = \frac{\cos(\sigma_1 - \sigma_2)}{|V_1||V_2|\cos\phi_1 \cos\phi_2} \sum_p M_{p1} M_{p2} R_p$$

$$B_{22} = \frac{1}{|V_2|^2 (\cos\phi_2)^2} \sum_p M_{p2}^2 R_p$$

The terms B_{11}, B_{12} and B_{22} are called *loss coefficients* or *B-coefficients*. If voltages are line to line kV with resistances in ohms, the units of B-coefficients are in MW^{-1}. Further, with P_{G1} and P_{G2} expressed in MW, P_L will also be in MW.

The above results can be extended to the general case of k plants with transmission loss expressed as

$$P_L = \sum_{m=1}^{k} \sum_{n=1}^{k} P_{Gm} B_{mn} P_{Gn}$$

where

$$B_{mn} = \frac{\cos(\sigma_m - \sigma_n)}{|V_m||V_n| \cos\phi_m \cos\phi_n} \sum_p M_{pm} M_{pn} R_p$$

It can be recognized as

$$P_L = P_{G1}^2 B_{11} + \dots + P_{Gk}^2 B_{kk} + 2 \sum_{\substack{m,n=1 \\ m \neq n}}^{k} P_{Gm} B_{mn} P_{Gn}$$

The following assumptions including those mentioned already are necessary, if *B*-coefficients are to be treated as constants as total load and load sharing between plants vary. These assumptions are:

1. All load currents maintain a constant ratio to the total current.
2. Voltage magnitudes at all plants remain constant.
3. Ratio of reactive to real power, i.e. power factor at each plant remains constant.
4. Voltage phase angles at plant buses remain fixed. This is equivalent to assuming that the plant currents maintain constant phase angle with respect to the common reference, since source power factors are assumed constant as per assumption 3 above.

Unit-II

HYDROTHERMAL SCHEDULING

OPTIMAL SCHEDULING OF HYDROTHERMAL SYSTEM

The previous sections have dealt with the problem of optimal scheduling of a power system with thermal plants only. Optimal operating policy in this case can be completely determined at any instant without reference to operation at other times. This, indeed, is the static optimization problem. Operation of a system having both hydro and thermal plants is, however, far more complex as hydro plants have negligible operating cost, but are required to operate under constraints of water available for hydro generation in a given period of time.

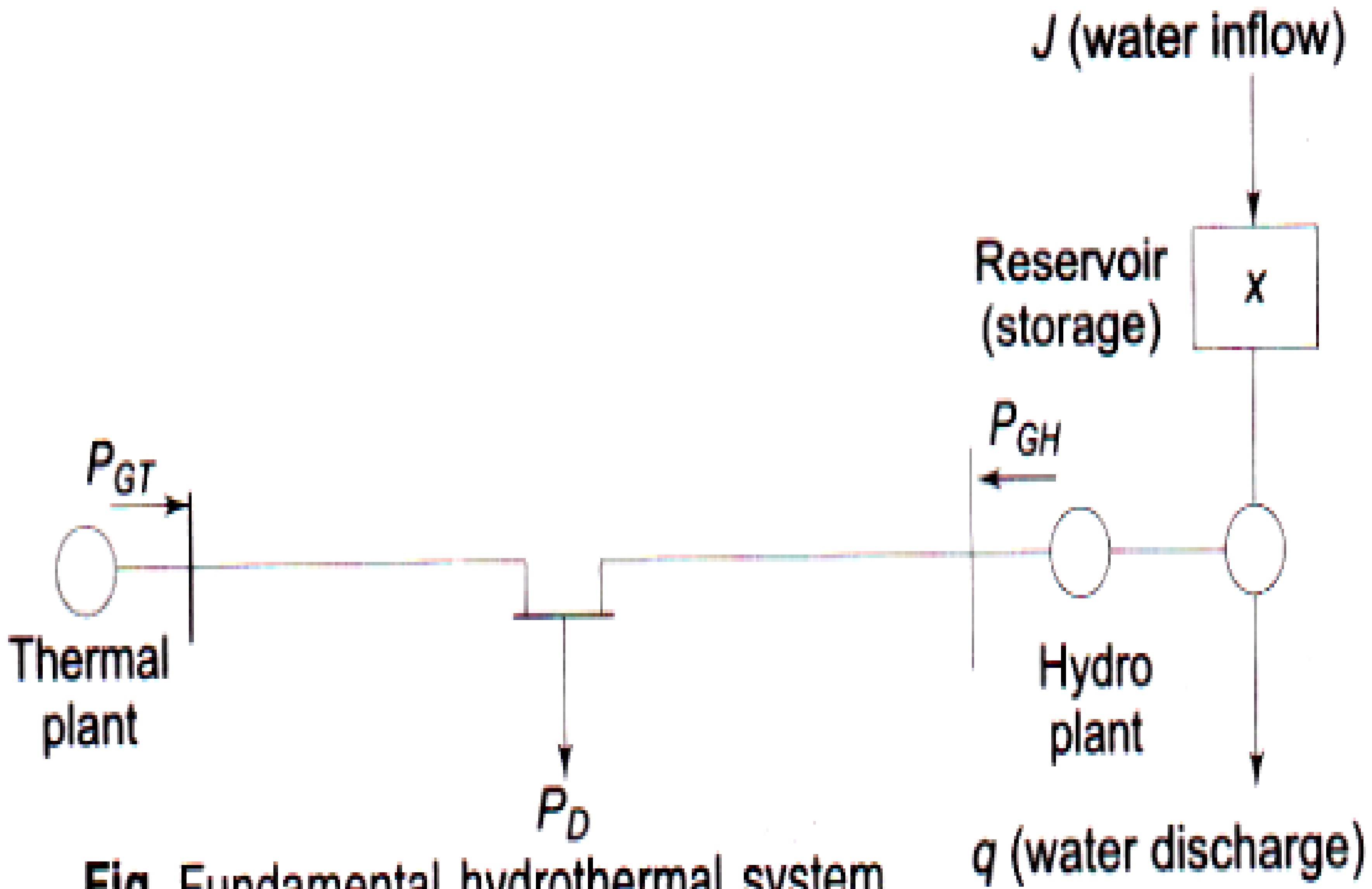


Fig. Fundamental hydrothermal system

Mathematical Formulation

For a certain period of operation T (one year, one month or one day, depending upon the requirement), it is assumed that (i) storage of hydro reservoir at the beginning and the end of the period are specified, and (ii) water inflow to reservoir (after accounting for irrigation use) and load demand on the system are known as functions of time with complete certainty (deterministic case). The problem is to determine $q(t)$, the water discharge (rate) so as to minimize the cost of thermal generation.

$$C_T = \int_0^T C'(P_{GT}(t))\, dt$$

where

P_{GT}^{m} = thermal generation in the mth interval

P_{GH}^{m} = hydro generation in the mth interval

P_{L}^{m} = transmission loss in the mth interval

$$= B_{TT}(P_{GT}^{m})^2 + 2B_{TH}P_{GT}^{m}P_{GH}^{m} + B_{HH}(P_{GH}^{m})^2$$

P_{D}^{m} = load demand in the mth interval

(ii) Water continuity equation

$$X'^{m} - X'^{(m-1)} - J^{m}\,\Delta T + q^{m}\,\Delta T = 0$$

where

X'^{m} = water storage at the end of the mth interval

J^{m} = water inflow (rate) in the mth interval

q^{m} = water discharge (rate) in the mth interval

The above equation can be written as

$$X^m - X^{m-1} - J^m + q^m = 0; \; m = 1, 2, ..., M$$

where $X^m = X'^m / \Delta T$ = storage in discharge units.

In Eqs. (7.73), X^o and X^M are the specified storages at the beginning and end of the optimization interval.

(iii) Hydro generation in any subinterval can be expressed* as

$$P_{GH}^m = h_o\{1 + 0.5e\,(X^m + X^{m-1})\}\,(q^m - \rho)$$

where $h_o = 9.81 \times 10^{-3} h'_o$

h_o = basic water head (head corresponding to dead storage)

$$^{*}\quad P_{GH}^{m} = 9.81 \times 10^{-2}\, h_{av}^{m}\,(q^{m} - \rho\,)\ \text{MW}$$

where

$$(q^{m} - \rho) = \text{effective discharge in } m^{3}/s$$

$$H_{av}^{m} = \text{average head in the } m\text{th interval}$$

Now

$$h_{av}^{m} = h'_{o} + \frac{\Delta T(X^{m} + X^{m-1})}{2A}$$

where

A = area of cross-section of the reservoir at the given storage

h'_{o} = basic water head (head corresponding to dead storage,

$$h_{av}^{m} = h'_{o}\{1 + 0.5e(X^{m} + X^{m-1})\}$$

where

$$e = \frac{\Delta T}{Ah'_{o}}; \ e \text{ is tabulated for various storage values.}$$

Now

$$P_{GH}^{m} = h_{o}\,\{1 + 0.5e(X^{m} + X^{m-1})\}\,(q^{m} - P)$$

where

$$h_{o} = 9.81 \times 10^{-3} h'_{o}$$

e = water head correction factor to account for head variation with storage

ρ = non-effective discharge (water discharge needed to run hydro generator at no load).

In the above problem formulation, it is convenient to choose water discharges in all subintervals except one as independent variables, while hydro generations, thermal generations and water storages in all subintervals are treated as dependent variables. The fact, that water discharge in one of the subintervals is a dependent variable, is shown below:

Adding Eq. (7.73) for $m = 1, 2, ..., M$ leads to the following equation, known as *water availability equation*

$$X^M - X^0 - \sum_m J^m + \sum_m q^m = 0$$

Because of this equation, only $(M - 1)$ *qs* can be specified independently and the remaining one can then be determined from this equation and is, therefore, a dependent variable. For convenience, q^1 is chosen as a dependent variable, for which we can write

$$q^1 = X^0 - X^M + \sum_m J^m - \sum_{m=2}^{M} q^m$$

Solution Technique

The problem is solved here using non-linear programming technique in conjunction with the first order gradient method. The Lagrangian $\mathcal{L}$ is formulated by augmenting the cost function of Eq. (7.71) with equality constraints of Eqs. (7.72)– (7.74) through Lagrange multipliers (dual variables) λ_1^m, λ_2^m and λ_3^m. Thus,

$$\mathcal{L} = \sum [C(P_{GT}^m) - \lambda_1^m (P_{GT}^m + P_{GH}^m - P_L^m - P_D^m) + \lambda_2^m (X^m - X^{m-1} - J^m +$$

The dual variables are obtained by equating to zero the partial derivatives of the Lagrangian with respect to the dependent variables yielding the following equations

$$\frac{\partial \mathcal{L}}{\partial P_{GT}^{m}} = \frac{\mathrm{d}C(P_{GT}^{m})}{\mathrm{d}P_{GT}^{m}} - \lambda_1^m \left(1 - \frac{\partial P_L^m}{\partial P_{GT}^m}\right) = 0$$

[The reader may compare this equation with Eq. (7.23)]

$$\frac{\partial \mathcal{L}}{\partial P_{G}^{m}} = \lambda_3^m - \lambda_1^m \left(1 - \frac{\partial P_L^m}{\partial P_{GH}^m}\right) = 0$$

$$\left(\frac{\partial \mathcal{L}}{\partial X^m}\right)_{\substack{m \neq M \\ \neq 0}} = \lambda_2^m - \lambda_2^{m+1} - \lambda_3^m \{0.5h_o e(q^m - \rho)\} - \lambda_3^{m+1} \{0.5h_0 e (q^{m+1} - \rho)\} = 0$$

and using Eq. in Eq. , we get

$$\left(\frac{\partial \mathcal{L}}{\partial q^1}\right) = \lambda_2^1 - \lambda_3^1 h_o \{1 + 0.5e\ (2X^o + J^1 - 2q^1 + \rho)\} = 0$$

The dual variables for any subinterval may be obtained as follows:

(i) Obtain λ_1^m from Eq. .

(ii) Obtain λ_3^m from Eq. .

(iii) Obtain λ_2^1 from Eq. and other values of λ_2^m $(m \neq 1)$ from Eq.

The gradient vector is given by the partial derivatives of the Lagrangian with respect to the independent variables. Thus

$$\left(\frac{\partial \mathcal{L}}{\partial q^m}\right)_{m\neq 1} = \lambda_2^m - \lambda_3^m h_o \{1 + 0.5e\,(2X^{m-1} + J^m - 2q^m + \rho)\}$$

For optimality the gradient vector should be zero if there are no inequality constraints on the control variables.

SHORT TERM HYDRO THERMAL SCHEDULING PROBLEM

For a system with one hydro and one steam plant, a simple dynamic programming algorithm is given below:

The water storage (state variable) X is quantised to levels. The computation is started with the n^{th} (last) sub-interval. Corresponding to every quantised level of storage at the beginning of stage. The value of Q_N the water discharge to the final specified level is calculated from the equation.

$$X_N - X_{N-1} - J_N + Q_N = 0$$

Where J_N is the water flow during the n^{th} sub-interval

X_N *and* X_{N-1} refer to the water level at the end of n^{th} and $(n-1)^{th}$ sub Intervals respectively. Values of discharge which are not within the limits are rejected. The cost corresponding to each Q_N is calculated. Next considering a quantised level of storage X(m) at the beginning of the interval, all the water discharges that this level to all the quantised levels at the end of $(N-1)^{th}$ interval are determined. The cost corresponding to all these dischargers are calculated and added to the costs stored at end of previous step.

These sums are then compared and the minimum of these is found and stored. The computation is repeated for all the remaining quantised level of storage at the beginning of the $(N-1)^{th}$ interval.

The procedure is repeated for all the remaining intervals till the first interval is reached. When the initial specified storage level is reach for the first interval. The water discharge which takes the level to every quantised level a the end of the first interval is found and the corresponding operating cost determined. The total operating costs are

1. In the power system network, the real and reactive power demands are continuously varying with a falling and rising trend but never steady.
2. The system frequency and voltage are maintained at their normal values by monitoring the load variations and taking suitable control action, to match the real and reactive power generations with load demand and the losses in the system at that time.

3. The system frequency is closely related to the real power balance in the power systems network.
4. The system frequency is mainly controlled by the real power balance in the system.
5. Whenever there is an increase in load on a generating unit, more amount of real power is to be supplied, which is immediately received from the kinetic energy (KE) power in rotating part, there by reducing the "KE" of angular velocity or speed of the machine. There will be a change in speed which is measure of

real power in balance. The change in speed in sensed by a speed governing mechanism and controls the position of inlet valve to the prime mover, thereby controlling the steam water supplied to turbine. Consequently, the machine comes back to normal speed and hence frequency. This action is a slow process, since mechanical elements are involved and usually the time involves is one to two seconds. The maximum permissible change in frequency i.e. $\Delta f\ is \pm 0.55 HZ$.

6. The system voltage is mainly controlled by the reactive power balanced in the system. The excitation of generator must be continuously regulated to match the reactive power demand with reactive power generation otherwise the voltages at various system may go varying in the large interconnected system. Manual system is not suitable hence "automatic voltage regulator" is installed. These controllers are set for a given operation condition and they take care of small change in load without frequency and voltages exceeding permissible range.For any change in the operating condition, the above controller must be reset either manually or automatically.

Turbine Speed Governing System

Figure shows schematically the speed governing system of a steam turbine. The system consists of the following components:

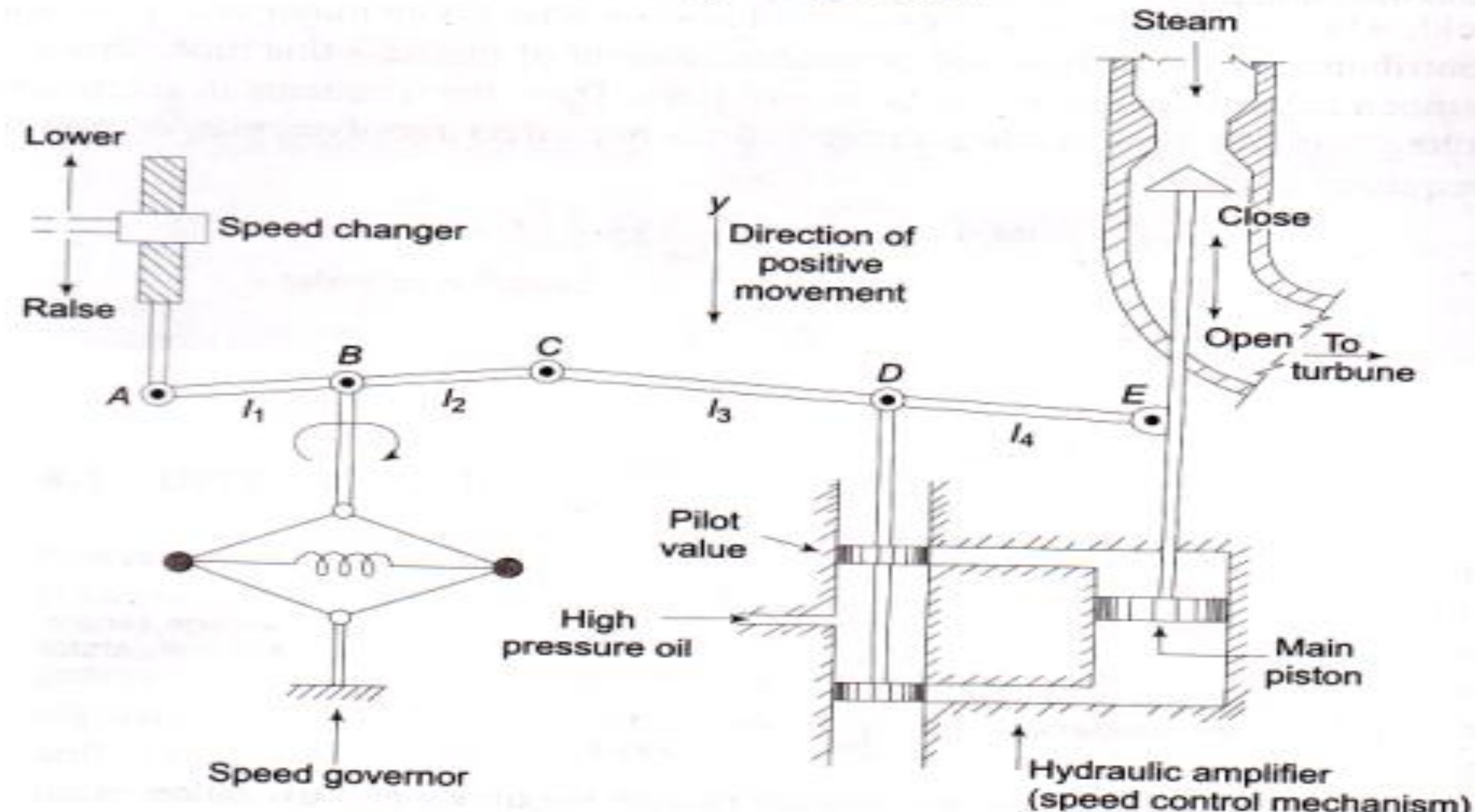


Fig. Turbine speed governing system

Model of Speed Governing System

Assume that the system is initially operating under steady conditions—the linkage mechanism stationary and pilot valve closed, steam valve opened by a definite magnitude, turbine running at constant speed with turbine power output balancing the generator load. Let the operating conditions be characterized by

f^o = system frequency (speed)

P_G^o = generator output = turbine output (neglecting generator loss)

y_E^o = steam valve setting

We shall obtain a linear incremental model around these operating conditions.

Two factors contribute to the movement of C:

(i) Δy_A contributes — $\left(\frac{l_2}{l_1}\right)$ Δy_A or $- k_1 \Delta y_A$ (i.e. upwards) of $- k_1 K_C \Delta P_C$

(ii) Increase in frequency Δf causes the fly balls to move outwards so that

B moves downwards by a proportional amount $k'_2 \ \Delta f$. The consequent movement of C with A remaining fixed at Δy_A is $+ \left(\frac{l_1 + l_2}{l_1}\right) k'_2 \Delta f = + k_2 \Delta f$ (i.e. downwards)

The net movement of C is therefore

$$\Delta y_C = - k_1 k_C \Delta P_C + k_2 \Delta f \tag{8.2}$$

The movement of D, Δy_D, is the amount by which the pilot valve opens. It is contributed by Δy_C and Δy_E and can be written as

$$\Delta y_D = \left(\frac{l_4}{l_3 + l_4}\right) \Delta y_C + \left(\frac{l_3}{l_3 + l_4}\right) \Delta y_E$$

$$= k_3 \Delta y_C + k_4 \Delta y_E \qquad (3)$$

The movement Δy_D depending upon its sign opens one of the ports of the pilot valve admitting high pressure oil into the cylinder thereby moving the main piston and opening the steam valve by Δy_E. Certain justifiable simplifying assumptions, which can be made at this stage, are:

(i) Inertial reaction forces of main piston and steam valve are negligible compared to the forces exerted on the piston by high pressure oil.

(ii) Because of (i) above, the rate of oil admitted to the cylinder is proportional to port opening Δy_D.

The volume of oil admitted to the cylinder is thus proportional to the time integral of Δy_D. The movement Δy_E is obtained by dividing the oil volume by the area of the cross-section of the piston. Thus

$$\Delta y_E = k_5 \int_0^t (-\Delta y_D)\mathrm{d}t \qquad (4)$$

It can be verified from the schematic diagram that a positive movement Δy_D, causes negative (upward) movement Δy_E accounting for the negative sign used in Eq. (8.4).

Taking the Laplace transform of Eqs. (8.2), (8.3) and (8.4), we get

$$\Delta Y_C(s) = -\ k_1 k_C \Delta P_C(s) +\ k_2 \Delta F(s) \qquad (5)$$

$$\Delta Y_D(s) = k_3 \Delta Y_C(s) +\ k_4 \Delta Y_E(s) \qquad (6)$$

$$\Delta y_E(s) = -\ k_5 \frac{1}{s}\ \Delta Y_D(s) \qquad (7)$$

Eliminating $\Delta Y_C(s)$ and $\Delta Y_D(s)$, we can write

$$\Delta Y_E(s) = \frac{k_1 k_3 k_C \Delta P_C(s) - k_2 k_3 \Delta F(s)}{\left(k_4 + \frac{s}{k_5}\right)}$$

$$= \left[\Delta P_C(s) - \frac{1}{R}\Delta F(s)\right] \times \left(\frac{K_{sg}}{1 + T_{sg} s}\right) \qquad (8)$$

where

$$R = \frac{k_1 k_C}{k_2} = \text{speed regulation of the governor}$$

$$K_{sg} = \frac{k_1 k_3 k_C}{k_4} = \text{gain of speed governor}$$

$$T_{sg} = \frac{1}{k_4 k_5} = \text{time constant of speed governor}$$

Equation (8) is represented in the form of a block diagram in Fig.

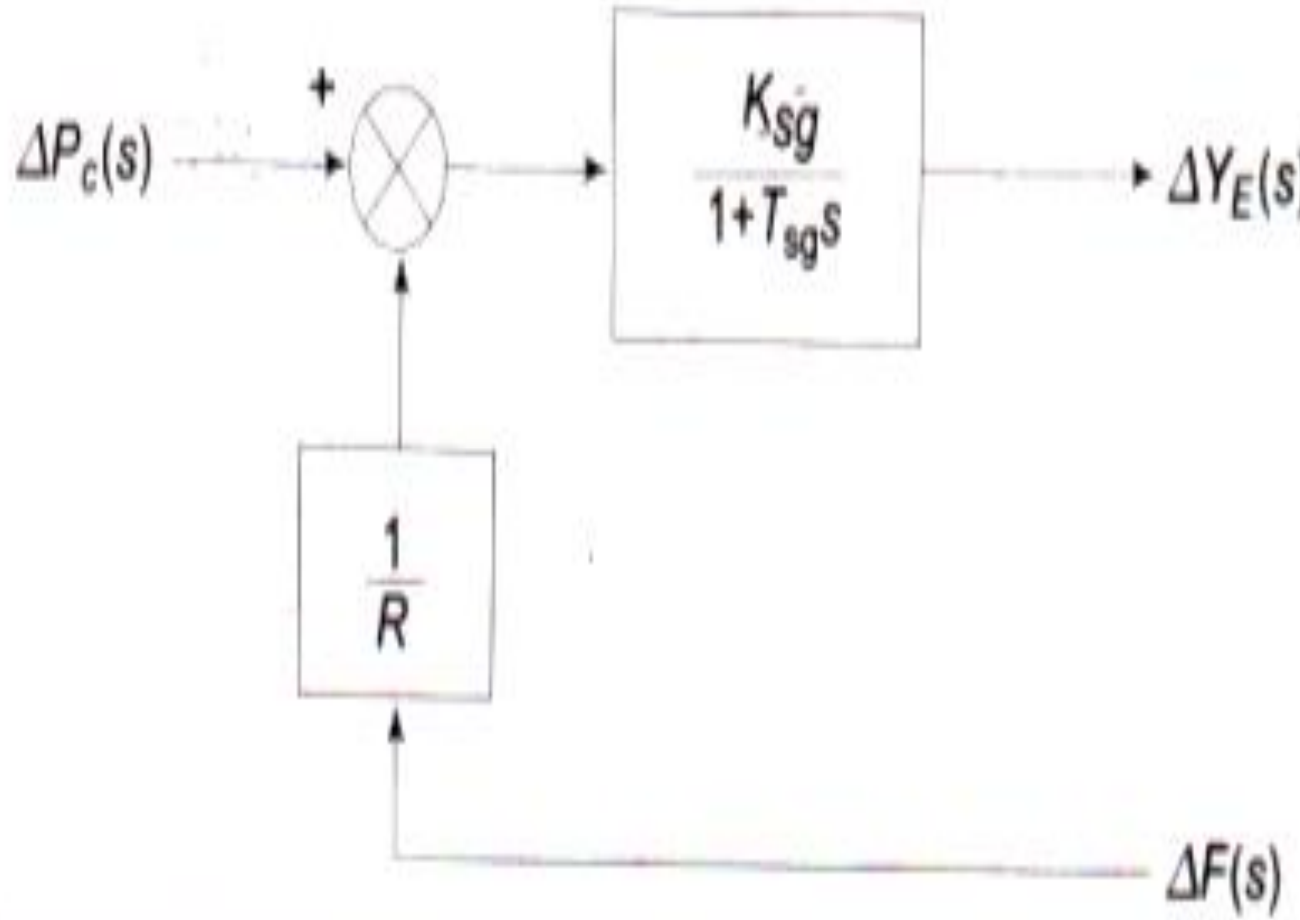
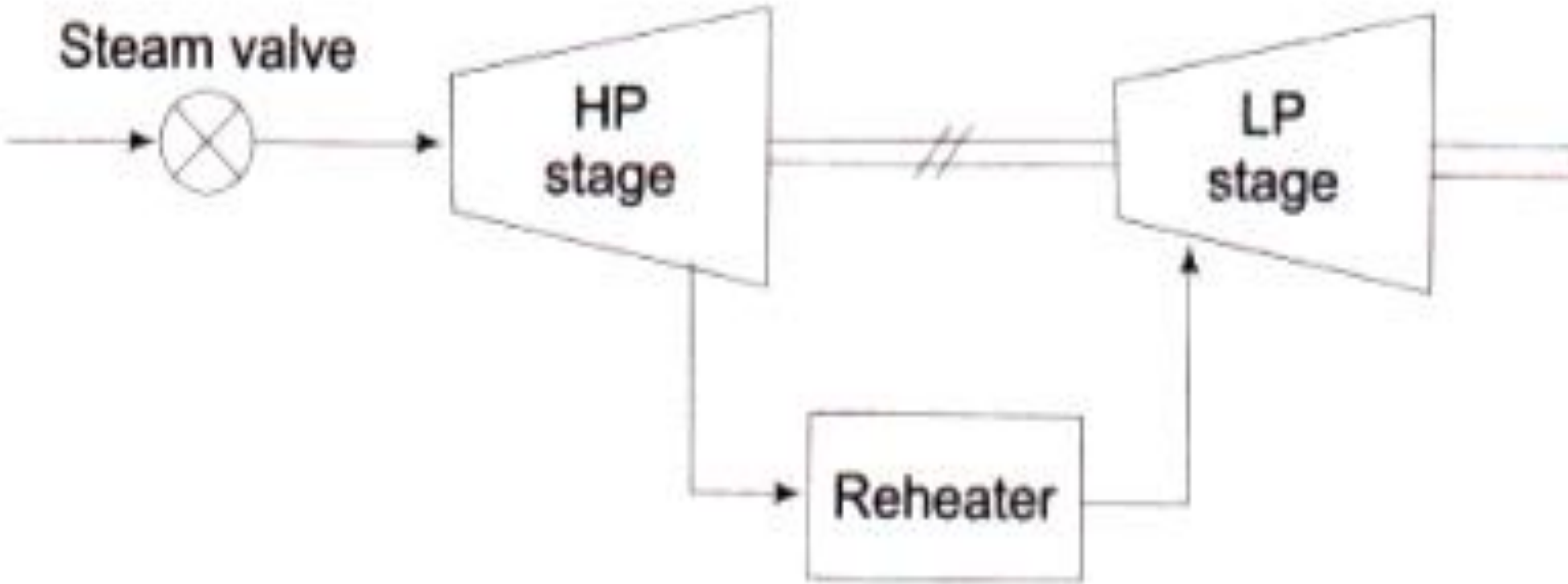
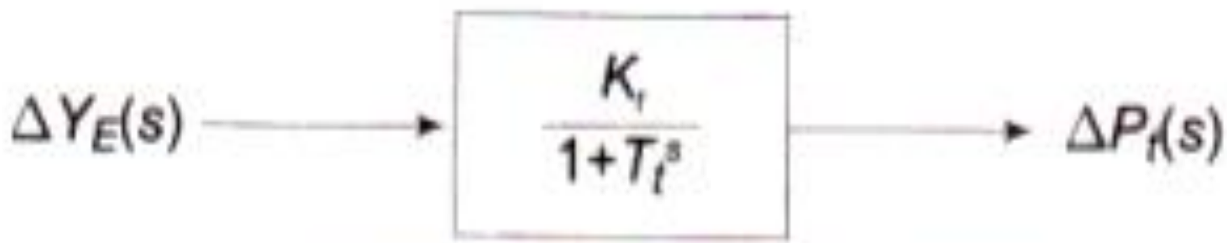


Fig. Block diagram representation of speed governor system

The speed governing system of a hydro-turbine is more involved. An additional feedback loop provides temporary droop compensation to prevent instability. This is necessitated by the large inertia of the penstock gate which regulates the rate of water input to the turbine.



(a) Two-stage steam turbine



(b) Turbine transfer function model

Generator Load Model

The increment in power input to the generator-load system is

$$\Delta P_G - \Delta P_D$$

where $\Delta P_G = \Delta P_t$, incremental turbine power output (assuming generator incremental loss to be negligible) and ΔP_D is the load increment.

This increment in power input to the system is accounted for in two ways:

(i) Rate of increase of stored kinetic energy in the generator rotor. At scheduled frequency (f^o), the stored energy is

$$W^o_{ke} = H \times P_r \text{ kW} = \text{sec (kilojoules)}$$

where P_r is the kW rating of the turbo-generator and H is defined as its inertia constant.

The kinetic energy being proportional to square of speed (frequency), the kinetic energy at a frequency of $(f^o + \Delta f)$ is given by

$$W_{ke} = W^o_{ke}\left(\frac{f^o + \Delta f}{f^o}\right)^2$$

$$\simeq HP_r\left(1 + \frac{2\Delta f}{f^o}\right) \qquad (9)$$

Rate of change of kinetic energy is therefore

$$\frac{d}{dt}(W_{ke}) = \frac{2HP_r}{f^o}\frac{d}{dt}(\Delta f) \qquad (10)$$

Rate of change of kinetic energy is therefore

$$\frac{\mathrm{d}}{\mathrm{d}t}(W_{\mathrm{ke}}) = \frac{2HP_r}{f^o}\frac{\mathrm{d}}{\mathrm{d}t}(\Delta f) \tag{8.10}$$

(ii) As the frequency changes, the motor load changes being sensitive to speed, the rate of change of load with respect to frequency, i.e. $\partial P_{\mathrm{D}}/\partial f$ can be regarded as nearly constant for small changes in frequency Δf and can be expressed as

$$(\partial P_D/\partial f)\ \Delta f = B\ \Delta f \tag{8.11}$$

where the constant B can be determined empirically. B is positive for a predominantly motor load.

Writing the power balance equation, we have

$$\Delta P_G - \Delta P_D = \frac{2HP_r}{f^\circ}\frac{d}{dt}(\Delta f) + B\,\Delta f$$

Dividing throughout by P_r and rearranging, we get

$$\Delta P_G(\text{pu}) - \Delta P_D(\text{pu}) = \frac{2H}{f^\circ}\frac{d}{dt}(\Delta f) + B(\text{pu})\,\Delta f \quad (\ \ 12)$$

Taking the Laplace transform, we can write $\Delta F(s)$ as

$$\Delta F(s) = \frac{\Delta P_G(s) - \Delta P_D(s)}{B + \frac{2H}{f^o}s}$$

$$= [\Delta P_G(s) - \Delta P_D(s)] \times \left(\frac{K_{ps}}{1 + T_{ps} s} \right) \qquad (13)$$

where $T_{ps} = \dfrac{2H}{Bf^o}$ = power system time constant

$K_{ps} = \dfrac{1}{B}$ = power system gain

Equation (13) can be represented in block diagram form as in Fig.

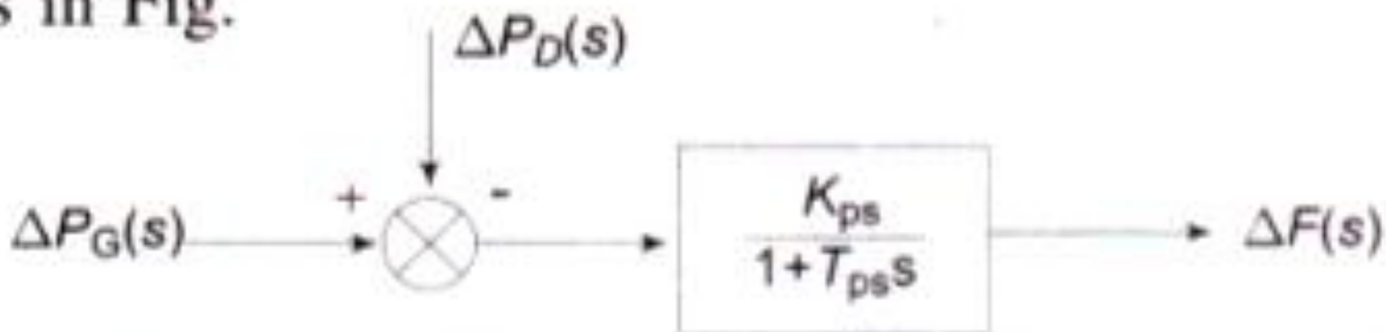


Fig. Block diagram representation of generator-load model

Unit-III

Single Area Load Frequency Control

Complete Block Diagram Representation of Load Frequency Control of an Isolated Power System

A complete block diagram representation of an isolated power system comprising turbine, generator, governor and load is easily obtained by combining the block diagrams of individual components, i.e. by combining Figs. ˉ ǀ and . The complete block diagram with feedback loop is shown in

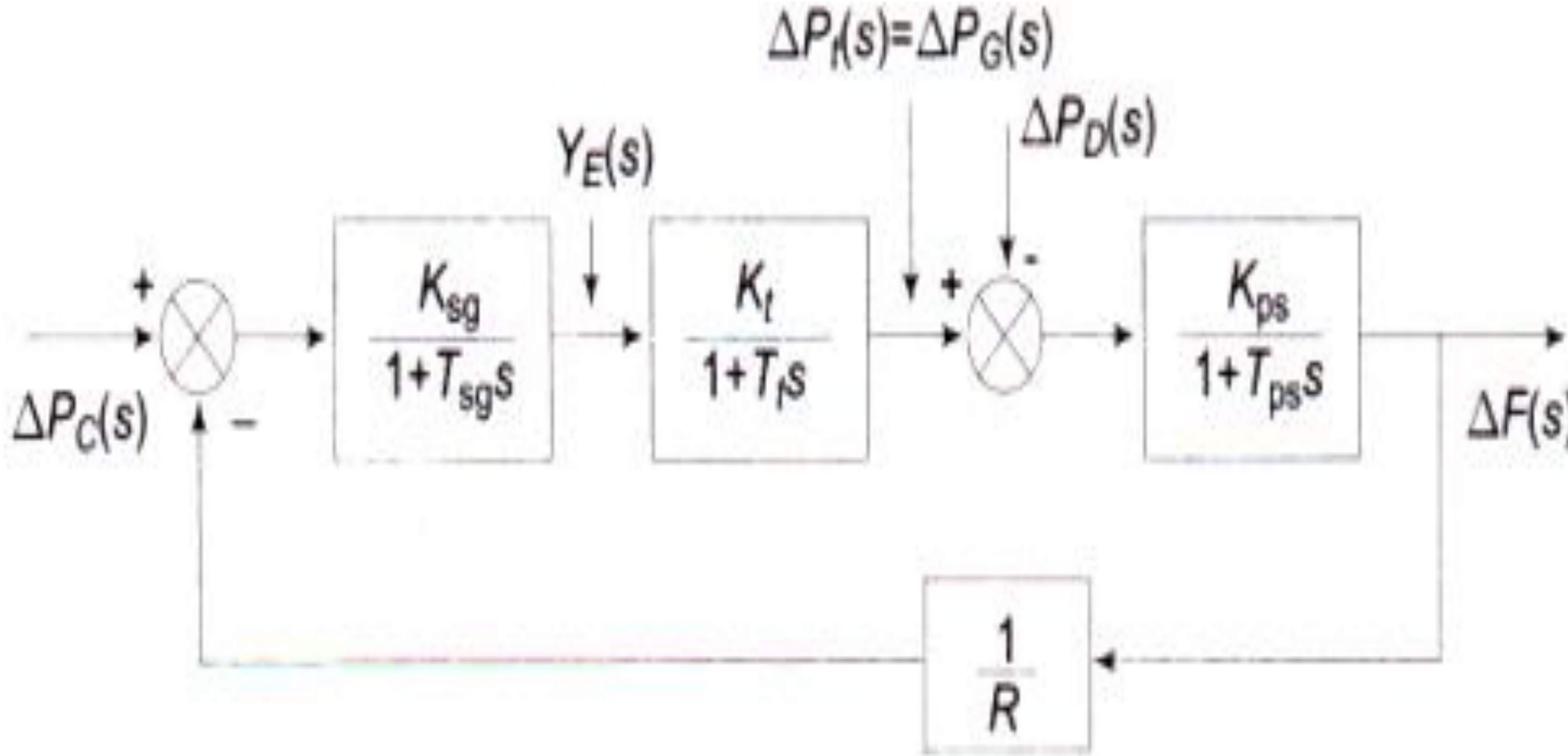


Fig. Block diagram model of load frequency control (isolated power system)

Steady States Analysis

The model of Fig. shows that there are two important incremental inputs to the load frequency control system – ΔP_C, the change in speed changer setting; and ΔP_D, the change in load demand. Let us consider a simple situation in which the speed changer has a fixed setting (i.e. $\Delta P_C = 0$) and the load demand changes. This is known as *free governor operation*. For such an operation the steady change in system frequency for a sudden change in load demand by an amount ΔP_D $\left(\text{i.e.} \Delta P_D(s) = \frac{\Delta P_D}{s}\right)$ is obtained as follows:

which the speed changer has a fixed setting (i.e. $\Delta P_C = 0$) and the load demand changes. This is known as *free governor operation*. For such an operation the steady change in system frequency for a sudden change in load demand by an amount ΔP_D $\left(\text{i.e.} \, \Delta P_D(s) = \frac{\Delta P_D}{s} \right)$ is obtained as follows:

$$\Delta F(s)\Big|_{\Delta P_C(s)=0} = -\frac{K_{ps}}{(1+T_{ps}s)+\dfrac{K_{sg}K_t K_{ps}/R}{(1+T_{sg}s)(1+T_t s)}} \times \frac{\Delta P_D}{s}$$

$$\Delta f\Bigg|_{\substack{\text{steady state}\\ \Delta P_C = 0}} = s\,\Delta F(s)\Bigg|_{\substack{s\to 0\\ \Delta P_C(s)=0}}$$

$$= -\left(\frac{K_{ps}}{1+(K_{sg}K_t K_{ps}/R)}\right)\Delta P_D$$

While the gain K_t is fixed for the turbine and K_{ps} is fixed for the power system, K_{sg}, the speed governor gain is easily adjustable by changing lengths of various links. Let it be assumed for simplicity that K_{sg} is so adjusted that

$$K_{sg} K_t \simeq 1$$

It is also recognized that $K_{ps} = 1/B$, where $B = \frac{\partial P_D}{\partial f} / P_r$ (in pu MW/unit change

The above equation gives the steady state changes in frequency caused by changes in load demand. Speed regulation R is naturally so adjusted that changes in frequency are small (of the order of 5% from no load to full load).

Therefore, the linear incremental relation can be applied from no load to full load. With this understanding, Fig. shows the linear relationship between frequency and load for free governor operation with speed changer set to give a scheduled frequency of 100% at full load. The 'droop' or slope of this relationship is $-\left(\frac{1}{B+(1/R)}\right)$.

Power system parameter B is generally much smaller* than $1/R$ (a typical value is $B = 0.01$ pu MW/Hz and $1/R = 1/3$) so that B can be neglected in comparison. Equation (8.16) then simplifies to

$$\Delta f = -\ R(\Delta P_D)$$

The droop of the load frequency curve is thus mainly determined by R, the speed governor regulation.

It is also observed from the above that increase in load demand (ΔP_D) is met under steady conditions partly by increased generation (ΔP_G) due to opening of the steam valve and partly by decreased load demand due to drop in system frequency. From the block diagram of Fig. ˜ ˊ (with $K_{sg}K_t \simeq 1$)

$$\Delta P_G = -\frac{1}{R}\Delta f = \left(\frac{1}{BR+1}\right)\Delta P_D$$

$$\text{Decrease in system load} = B\Delta f = \left(\frac{BR}{BR+1}\right)\Delta P_D$$

Of course, the contribution of decrease in system load is much less than the increase in generation. For typical values of B and R quoted earlier

$$\Delta P_G = 0.971 \ \Delta P_D$$

$$\text{Decrease in system load} = 0.029 \ \Delta P_D$$

Consider now the steady effect of changing speed changer setting $\left(\Delta P_C(s) = \frac{\Delta P_C}{s} \right)$ with load demand remaining fixed (i.e. $\Delta P_D = 0$). The steady state change in frequency is obtained as follows.

$$\Delta F(s)\Big|_{\Delta P_D(s)=0} = \frac{K_{sg}K_t K_{ps}}{(1+T_{sg}s)(1+T_t s)(1+T_{ps}s)+K_{sg}K_t K_{ps}/R} \times \frac{\Delta P_C}{s}$$

$$\Delta f\Big|_{\substack{\text{steady state} \\ \Delta P_D = 0}} = \left(\frac{K_{sg}K_t K_{ps}}{1+K_{sg}K_t K_{ps}/R}\right)\Delta P_C$$

If

$$K_{sg}K_t \simeq 1$$

$$\Delta f = \left(\frac{1}{B+1/R}\right)\Delta P_C$$

If the speed changer setting is changed by ΔP_C while the load demand changes by ΔP_D, the steady frequency change is obtained by superposition, i.e.

$$\Delta f = \left(\frac{1}{B + 1/R}\right)(\Delta P_C - \Delta P_D)$$

According to Eq. (8.21) the frequency change caused by load demand can be compensated by changing the setting of the speed changer, i.e.

$$\Delta P_C = \Delta P_D, \text{ for } \Delta f = 0$$

Figure depicts two load frequency plots—one to give scheduled frequency at 100% rated load and the other to give the same frequency at 60% rated load.

Dynamic Response

To obtain the dynamic response giving the change in frequency as function of the time for a step change in load, we must obtain the Laplace inverse of Eq. . The characteristic equation being of third order, dynamic response can only be obtained for a specific numerical case. However, the characteristic equation can be approximated as first order by examining the relative magnitudes of the time constants involved. Typical values of the time constants of load frequency control system are related as

$$T_{sg} \ll T_t \ll T_{ps}$$

Typically* $T_{sg} = 0.4$ sec, $T_t = 0.5$ sec and $T_{ps} = 20$ sec.

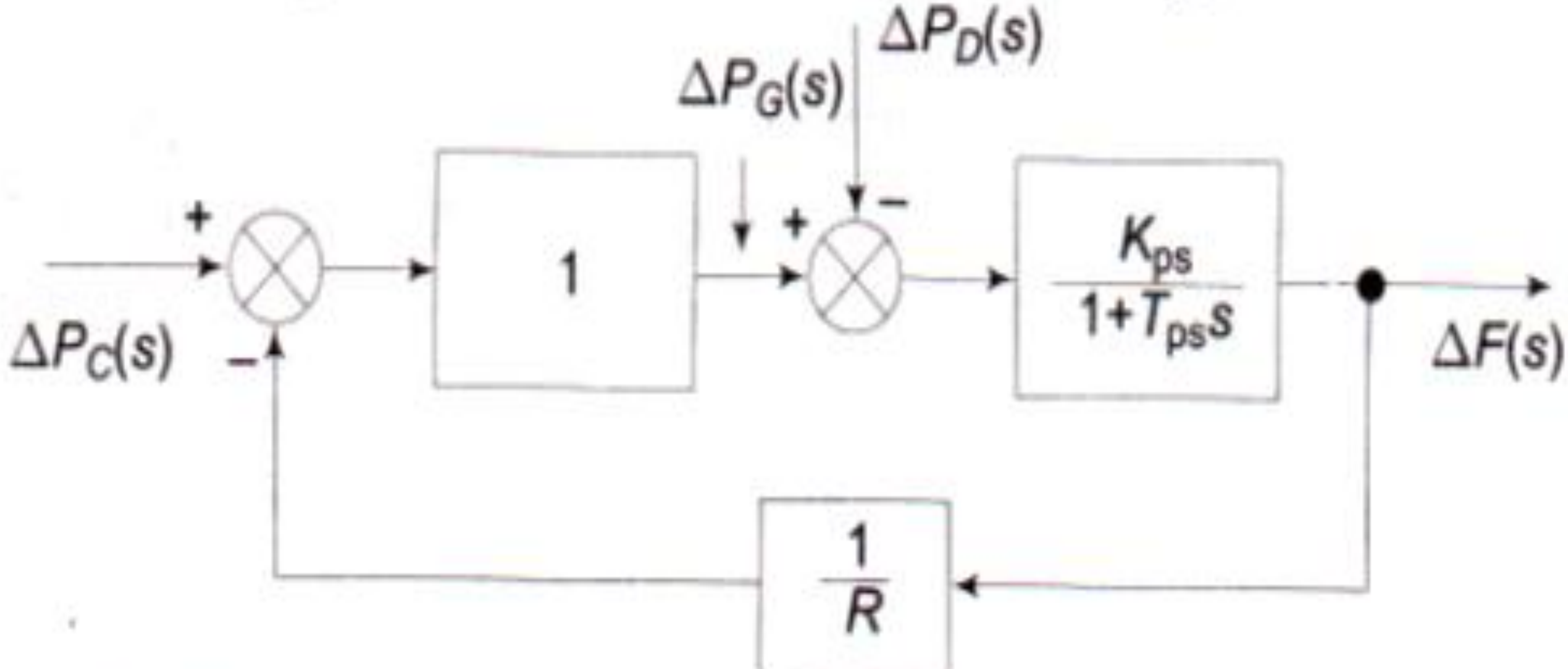


Fig. First order approximate block diagram of load frequency control of an isolated area

Letting $T_{sg} = T_t = 0$, (and $K_{sg} K_t \cong 1$), the block diagram of Fig. is reduced to that of Fig. 8.8, from which we can write

$$\Delta F(s)|_{\Delta P_C(s)=0} = -\frac{K_{ps}}{(1+K_{ps}/R)+T_{ps}s} \times \frac{\Delta P_D}{s}$$

$$\Delta F(s)|_{\Delta P_C(s)=0} = -\frac{K_{ps}}{(1+K_{ps}/R)+T_{ps}s} \times \frac{\Delta P_D}{s}$$

$$= -\frac{K_{ps}/T_{ps}}{s\left[s+\frac{R+K_{ps}}{RT_{ps}}\right]} \times \Delta P_D$$

$$\Delta f(t) = -\frac{RK_{ps}}{R+K_{ps}}\left\{1-\exp\left[-t/T_{ps}\left(\frac{R}{R+K_{ps}}\right)\right]\right\}\Delta P_D$$

Taking $R = 3,\ K_{ps} = 1/B = 100,\ T_{ps} = 20,\ \Delta P_D = 0.01$ pu

$$\Delta f\ (t) = -\ 0.029\ (1\ -\ e^{-1.717t})$$

$$\Delta f|_{\text{steady state}} = -\ 0.029\ \text{Hz}$$

The plot of change in frequency versus time for first order approximation given above and the exact response are shown in Fig. First order approximation is obviously a poor approximation.

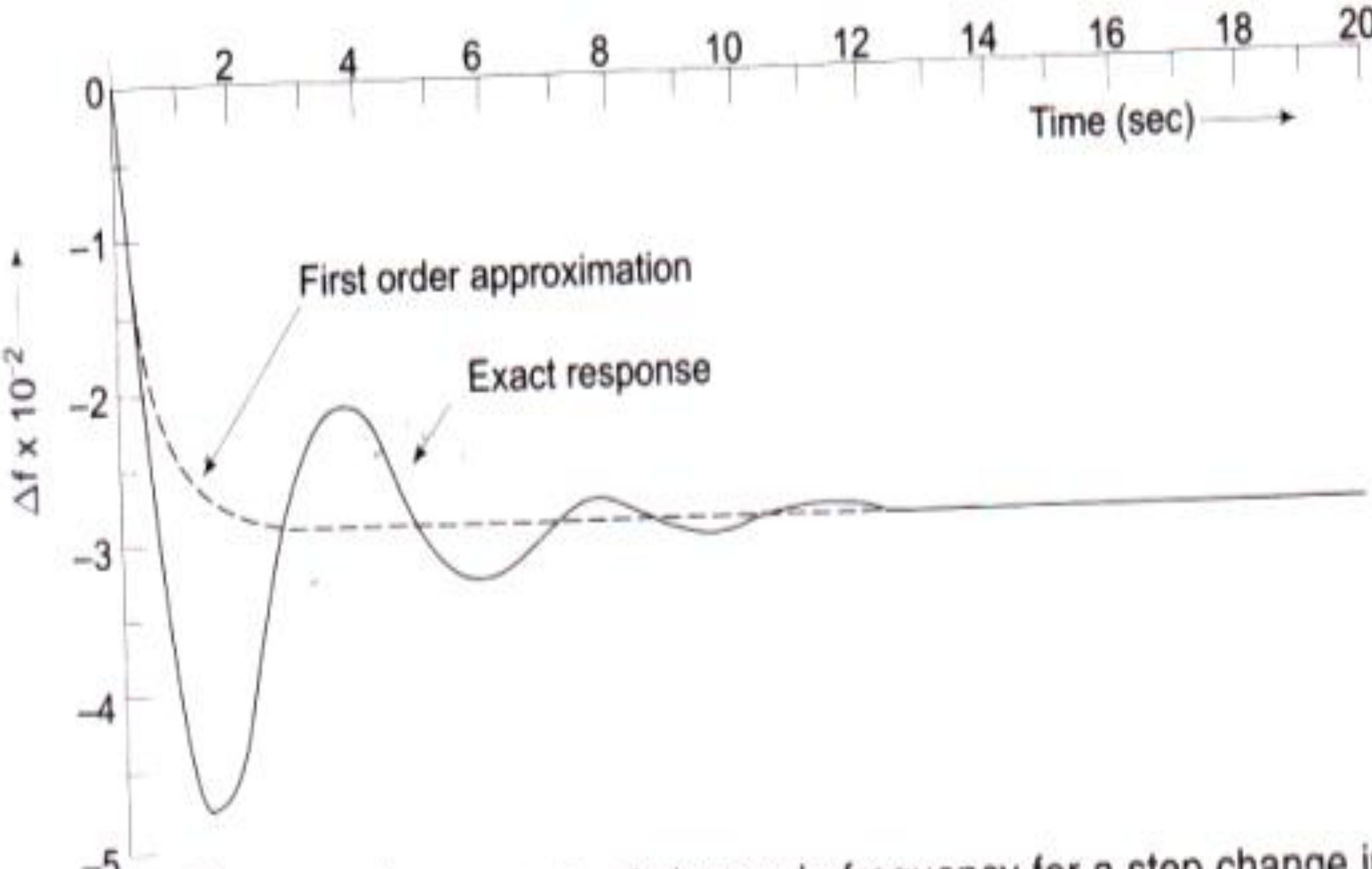


Fig. Dynamic response of change in frequency for a step change in load

Control Area Concept

So far we have considered the simplified case of a single turbo-generator supplying an isolated load. Consider now a practical system with a number of generating stations and loads. It is possible to divide an extended power system (say, national grid) into subareas (may be, State Electricity Boards) in which the generators are tightly coupled together so as to form a *coherent* group, i.e. all the generators respond in *unison* to changes in load or speed changer settings.

TWO-AREA LOAD FREQUENCY CONTROL

An extended power system can be divided into a number of load frequency control areas interconnected by means of tie lines. Without loss of generality we shall consider a two-area case connected by a single tie line as illustrated in Fig.

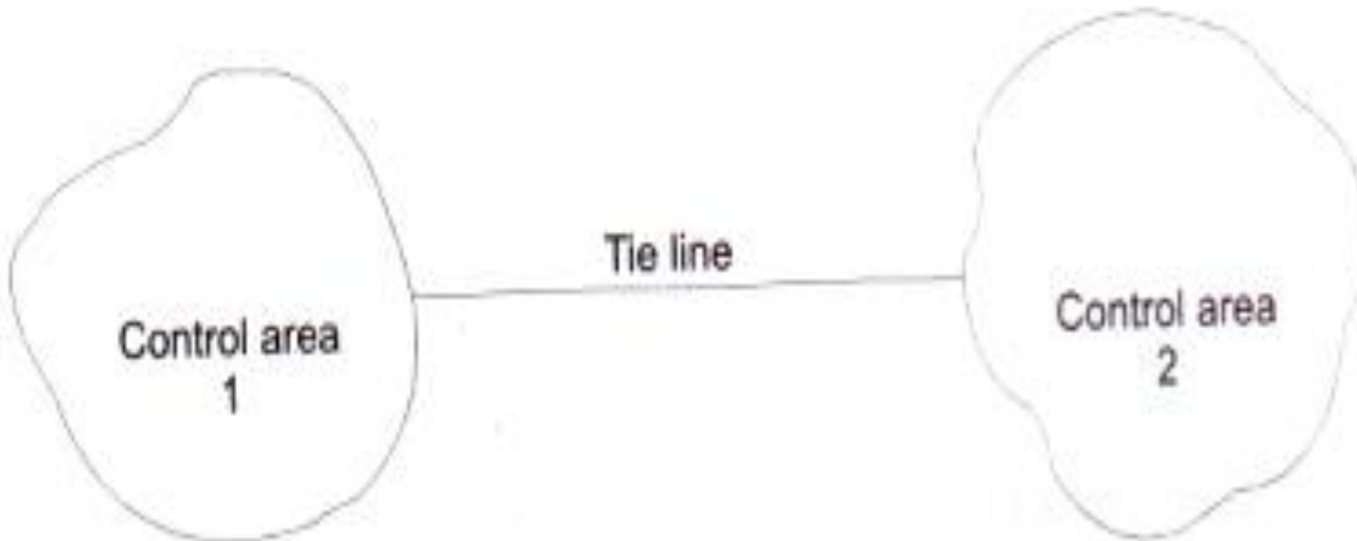


Fig. Two interconnected control areas (single tie line)

For incremental changes in δ_1 and δ_2, the incremental tie line power can be expressed as

$$\Delta P_{\text{tie, 1}}(\text{pu}) = T_{12}(\Delta\delta_1 - \Delta\delta_2)$$

where
$$T_{12} = \frac{|V_1||V_2|}{P_{r1}X_{12}} \cos(\delta_1^o - \delta_2^o) = \textit{synchronizing coefficient}$$

Since incremental power angles are integrals of incremental frequencies, we can write Eq. (8.27) as

$$\Delta P_{\text{tie, 1}} = 2\pi T_{12}\left(\int \Delta f_1 \mathrm{d}t - \int \Delta f_1 \mathrm{d}t\right)$$

where Δf_1 and Δf_2 are incremental frequency changes of areas 1 and 2 respectively.

Taking the Laplace transform of Eq. and reorganizing, we get

$$\Delta F_1(s) = [\Delta P_{G1}(s) - \Delta P_{D1}(s) - \Delta P_{\text{tie},1}(s)] \times \frac{K_{ps1}}{1+T_{ps1}s}$$

where as defined earlier [see Eq.] $K_{ps1} = 1/B_1$

$$T_{ps1} = 2H_1/B_1 f^o$$

Compared to Eq. of the isolated control area case, the only change is the appearance of the signal $\Delta P_{\text{tie},1}(s)$ as shown in Fig. .

Taking the Laplace transform of Eq. , the signal $\Delta P_{\text{tie},1}(s)$ is obtained as

$$\Delta P_{\text{tie},1}(s) = \frac{2\pi T_{12}}{s}[\Delta F_1(s) - \Delta F_2(s)]$$

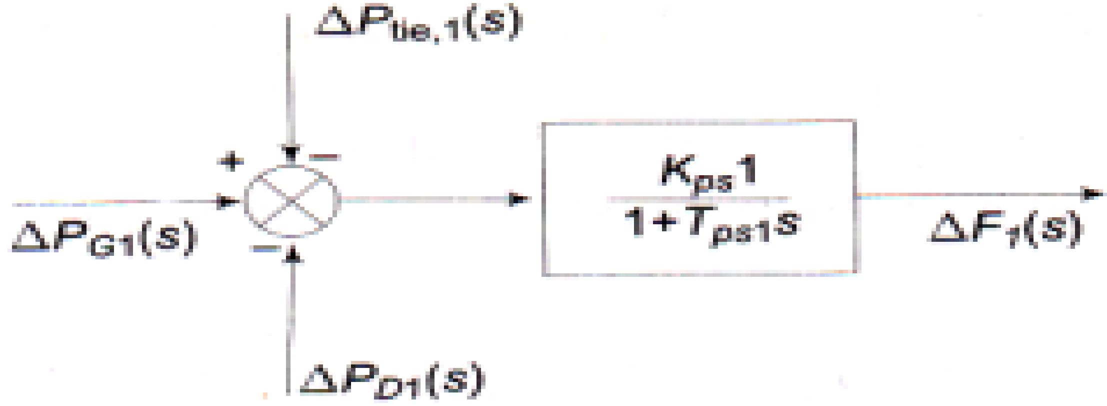


Fig.

[redacted]rresponding block diagram is shown in Fig.

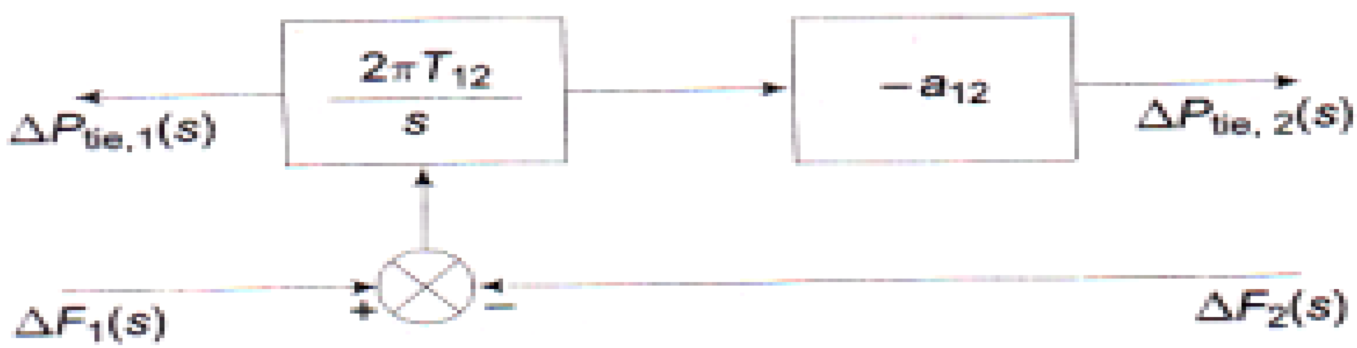


Fig.

[redacted] the control area 2, $\Delta P_{tie,\ 2}(s)$ is given by [Eq.]

$$\Delta P_{tie,\ 2}(s) = \frac{-2\,\pi a_{12} T_{12}}{s}\left[\Delta F_1(s) - \Delta F_2(s)\right]$$

Let the step changes in loads ΔP_{D1} and ΔP_{D2} be simultaneously applied in control areas 1 and 2, respectively. When steady conditions are reached, the output signals of all integrating blocks will become constant and in order for this to be so, their input signals must become zero. We have, therefore, from Fig. 8.16

$$\Delta P_{\text{tie},1} + b_1 \Delta f_1 = 0 \left(\text{input of integrating block} - \frac{K_{i1}}{s} \right)$$

$$\Delta P_{\text{tie},2} + b_2 \Delta f_2 = 0 \left(\text{input of integrating block} - \frac{K_{i2}}{s} \right)$$

$$\Delta f_1 - \Delta f_2 = 0 \left(\text{input of integrating block} - \frac{2\pi T_{12}}{s} \right)$$

From Eqs. (and (

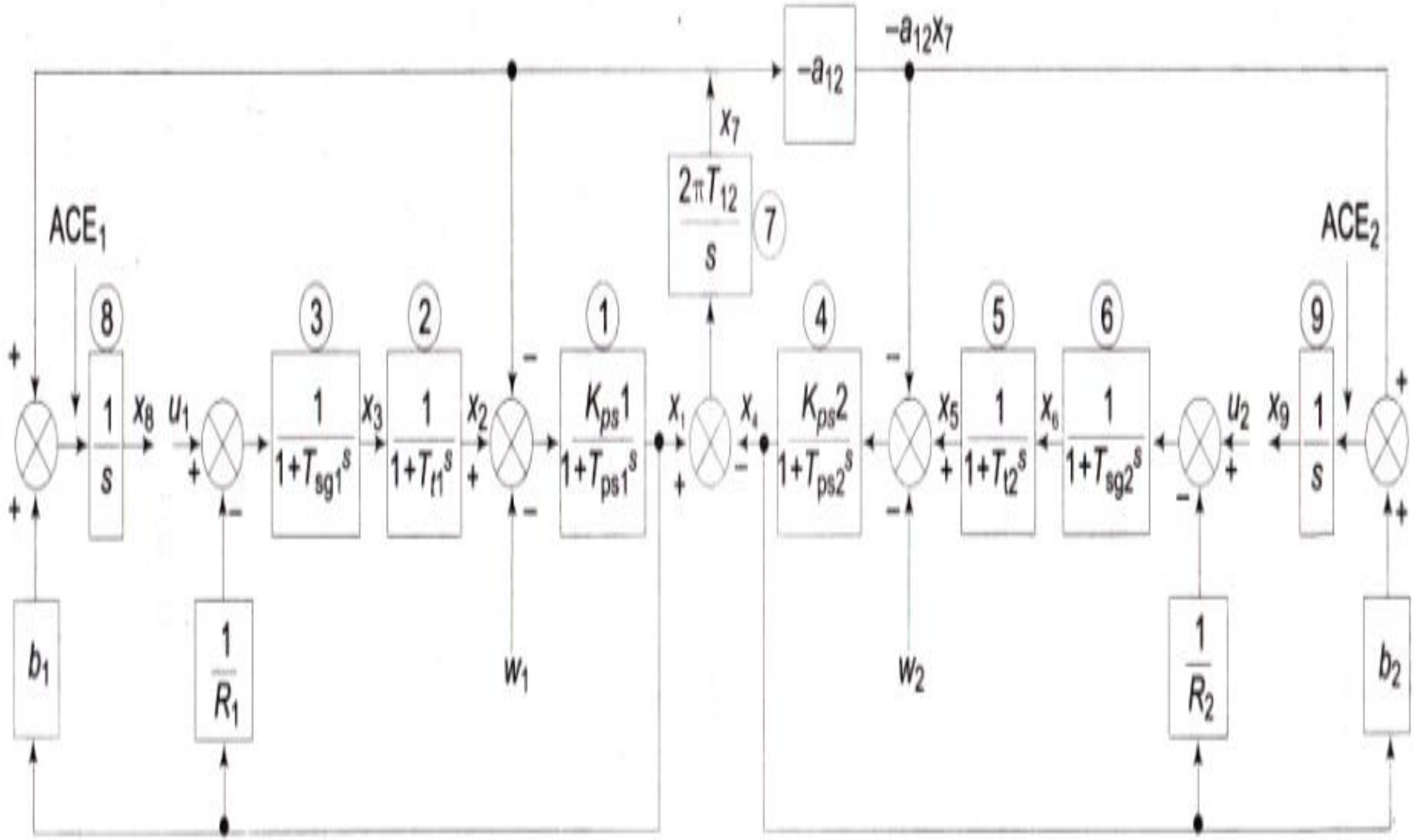


Fig. State space model of two-area system

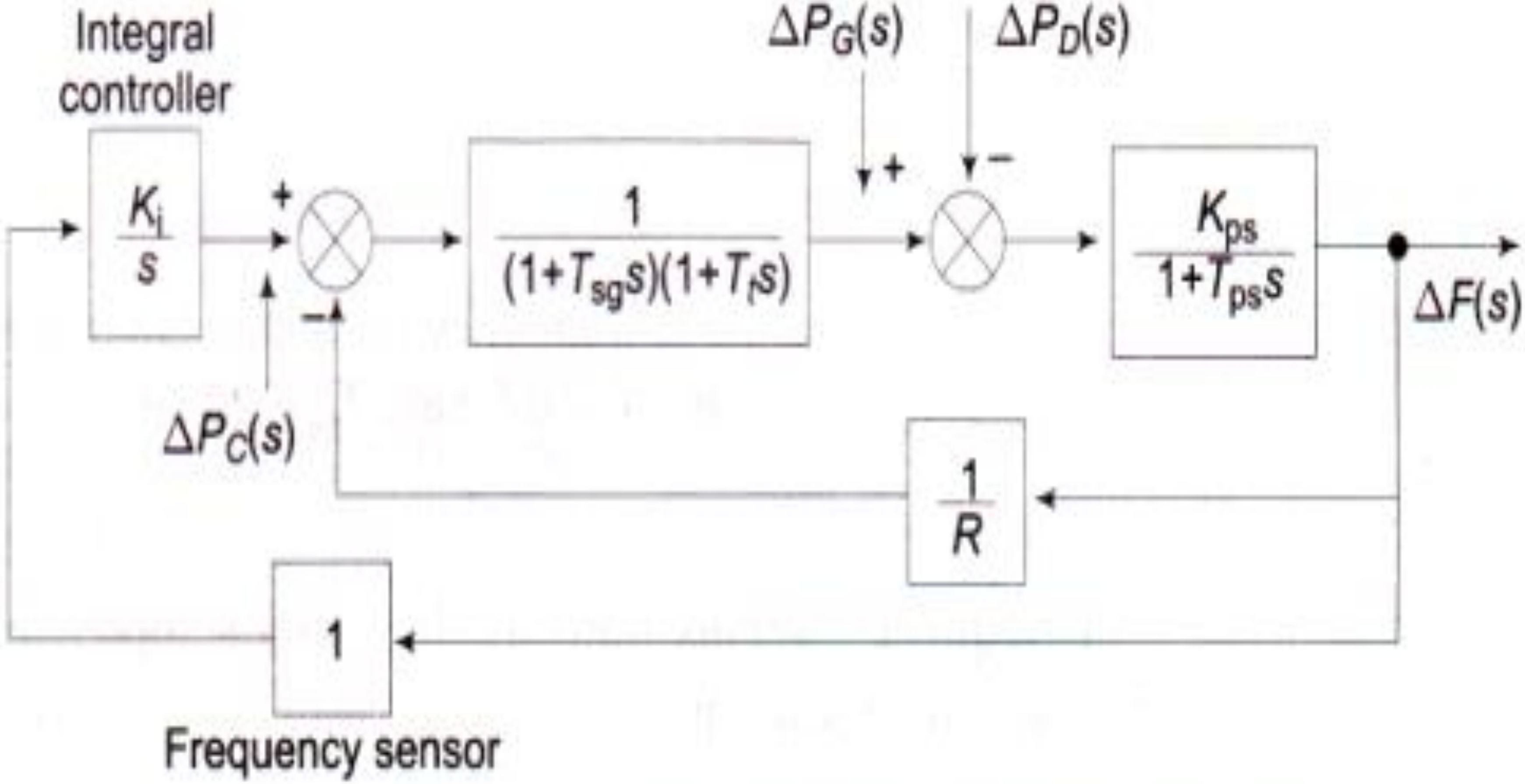


Fig. Proportional plus integral load frequency control

The signal $\Delta P_C(s)$ generated by the integral control must be of opposite sign to $\Delta F(s)$ which accounts for negative sign in the block for integral controller. Now

$$\Delta F(s) = -\frac{K_{ps}}{(1+T_{ps}S) + \left(\frac{1}{R} + \frac{K_i}{s}\right) \times \frac{K_{ps}}{(1+T_{sg}s)(1+T_t s)}} \times \frac{\Delta P_D}{s}$$

$$= -\frac{RK_{ps}s(1+T_{sg}s)(1+T_t s)}{s(1+T_{sg}s)(1+T_t s)(1+T_{ps}s)R + K_{ps}(K_i R + s)} \times \frac{\Delta P_D}{s}$$

Obviously,

$$\Delta f \mid_{\text{steady state}} = \underset{s \to 0}{s} \, \Delta F(s) = 0$$

Unit-V

Reactive Power Compensation

LOAD COMPENSATION

Load compensation is the management of reactive power to improve power quality i.e. V profile and pf. Here the reactive power flow is controlled by installing shunt compensating devices (capacitors/reactors) at the load end bringing about proper balance between generated and consumed reactive power. This is most effective in improving the power transfer capability of the system and its voltage stability. It is desirable both economically and technically to operate the system near unity power factor. This is why some utilities impose a penalty on low pf loads. Yet another way of improving the system performance is to operate it under near balanced conditions so as to reduce the flow of negative sequence currents thereby increasing the system's load capability and reducing power loss.

SERIES COMPENSATION

A capacitor in series with a line gives control over the effective reactance between line ends. This effective reactance is given by

$$X_l' = X - X_c$$

where X_l = line reactance

X_C = capacitor reactance

It is easy to see that capacitor reduces the effective line reactance*. This results in improvement in performance of the system as below.

(i) Voltage drop in the line reduces (gets compensated) i.e. minimization of end-voltage variations.

(ii) Prevents voltage collapse.

(iii) Steady-state power transfer increases; it is inversely proportional to X_l'.

(iv) As a result of (ii) transient stability limit increases.

The benefits of the series capacitor compensator are associated with a problem. The capacitive reactance X_C forms a series resonant circuit with the total series reactance

$$X = X_l + X_{gen} + X_{trans}$$

The natural frequency of oscillation of this circuit is given by.

$$f_C = \frac{1}{2\pi\sqrt{LC}}$$

$$= \frac{1}{2\pi\sqrt{\frac{X}{2\pi f}\,\frac{2\pi f C}{2\pi f}}} = f\sqrt{\frac{X_C}{X}}$$

where f = system frequency

$$\frac{X_C}{X} = \text{degree of compensation}$$

$$= 25 \text{ to } 75\% \text{ (recommended)}$$

For this degree of compensation

$$f_C < f$$

which is subharmonic oscillation.

UNCOMPENSATED TRANSMISSION LINE :

The basic equation describing a transmission line given as

$$\frac{\partial^2 V}{\partial x^2} = \gamma^2 V$$

$$\frac{\partial^2 I}{\partial x^2} = \gamma^2 I$$

and $\frac{\partial V}{\partial X} = IZ$

where $\gamma^2 = (r + j\omega L)\ (g + j\omega C)$

and $Z = (r + j\omega L)$, $Y = (g + j\omega L)$