LEARNING MATERIAL

UNIT – I
Economic Operation of Power System - I

Objectives:

- To familiarize the students with importance of optimal operation
- To familiarize the students with optimal operation of generators in thermal power stations
- To familiarize the students with input output characteristics of thermal unit.
- To familiarize the students with optimum generation allocation with line losses neglected.

Syllabus:

Economic Operation of Power System - I

Introduction, Heat Rate curve, Cost curve, Incremental fuel & production cost, Input – output characteristics, Optimal operation of generators in thermal power stations, Optimal generation allocation with line losses neglected, Problems.

Outcomes:

Students will be able to

- understand the necessity for optimal operation in power system.
- understand the concept of heat rate curve, cost curve, incremental fuel & production cost.
- Explain optimal allocation of thermal units when transmission losses neglected

1.1 HEAT RATE CURVE:

The heat rate characteristics obtained from the plot of the net heat rate in Btu/kWh or kcal/kWh versus power output in kW is shown in fig.1

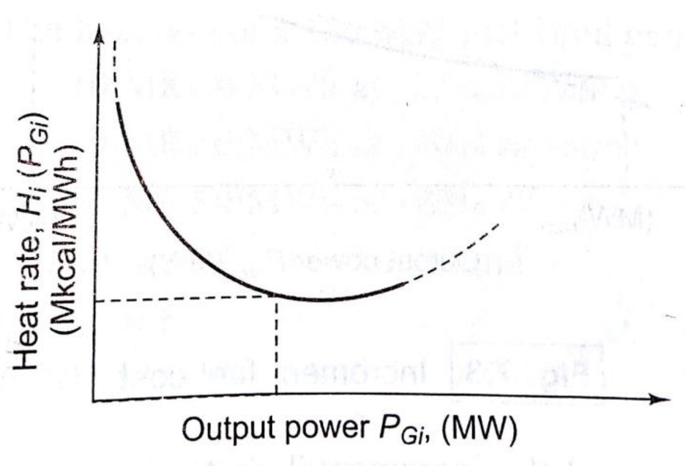


Fig.1. heat rate curve

The thermal unit is most efficient at a minimum heat rate, which corresponds to a particular generation P_G. The curve indicates an increase in heat rate at low and high power limits.

1.2 INCREMENTAL FUEL COST CURVE:

From the input –output curves, the incremental fuel cost (IFC) curve can be obtained. The IFC is defined as the ratio of a small change in the input to the corresponding small change in the output.

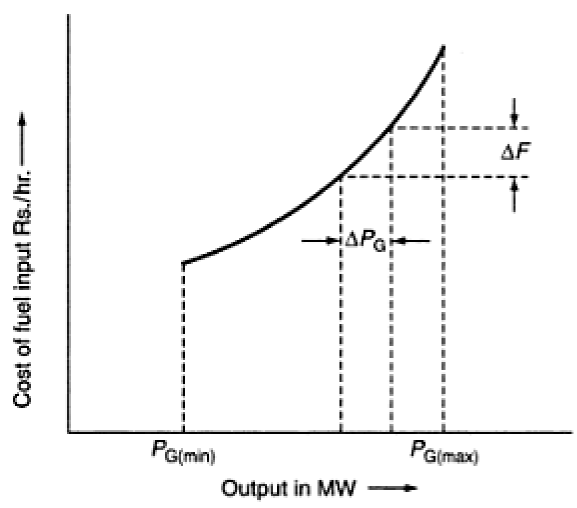
Incremental fuel cost = Δ input / Δ output

` $= \Delta F / \Delta P_G$

Where Δ represents small changes.

As the Δ quantities become progressively smaller, it is seen that the IFC is d(input)/d(output) and is expressed in Rs./MWh. A typical plot of IFC versus output power is shown in fig (a).

The incremental cost curve is obtained by considering the change in the cost of the generation to the change in real-power generation at various points on the input –output curves, i.e., slope of the input-output curve as shown in fig (b).



(a)

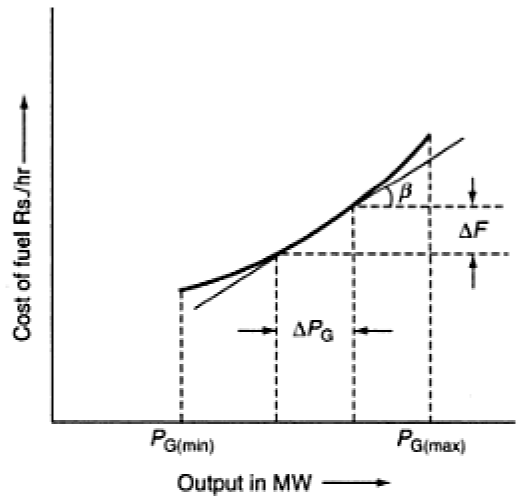


Fig: a) incremental cost curve, (b) incremental fuel cost characteristics in terms of the slope of the input-output curve

The input-output curve can be obtained from the heat-rate curve as

$$F_i(P_{Gi}) = P_{Gi}\, H_i(P_{Gi}) \quad \text{(MK cal/h)} \qquad \text{(i)}$$

Where $H_i(P_{Gi})$ is the heat-rate in MKcal/MWh. The graph of $F_i(P_{Gi})$ is the input-output curve. Let the cost of the fuel be K Rs/MKcal. Then the input fuel-cost, $C_i(P_{Gi})$ is

$$C_i(P_{Gi}) = KF_i(P_{Gi}) = K\, P_{Gi}\, H_i(P_{Gi}) \quad \text{(Rs/h)} \qquad \text{(ii)}$$

The heat-rate curve may be approximated in the form,

$$H_i(P_{Gi}) = (a_i'/P_{Gi}) + b_i' + c_i' P_{Gi} \quad \text{(MK cal/h)} \qquad \text{(iii)}$$

With all coefficients, positive. From Eqs (i) and (iii) we get a quadratic expression for input energy rate $F_i(P_{Gi})$ with positive coefficients in the form

$$F_i(P_{Gi}) = a_i' + b_i' P_{Gi} + c_i\, P_{Gi}^2 \quad \text{(MKcal/h)} \qquad \text{(iv)}$$

From Eqs (ii) and (iv), we also get a quadratic expression for fuel-cost $C_i P_{Gi})$ with positive coefficient in the form

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

$$= a_i + b_i P_{Gi} + c_i P_{Gi}^2 \quad \text{(Rs/h)} \qquad \text{(v)}$$

The slope of the fuel-cost curve, i.e. dc_i/dP_{Gi}, is called the incremental fuel cost (*IC*) and is expressed in Rs/MWh. A typical plot of the incremental fuel cost versus power output is shown in Fig.1. From Eq. (v), the incremental fuel cost is

$$(IC)_i = \quad dC_i/dP_{Gi} = b_i + 2c_iP_{Gi} \qquad \text{(Rs/MWh)} \qquad \text{(vi)}$$

The IFC is now obtained as

$(IC)_i$ = slope of the fuel cost curve

The IFC (IC) of the i^{th} thermal unit is defined, for a given power output, as the limit of the ratio of the increased cost of fuel input (Rs./hr) to the corresponding increase in power output (MW), as the increasing power output approaches zero.

1.3 INCREMENTAL PRODUCTION COST:

The incremental production cost of a given unit is made up of the IFC plus the incremental cost of items such as labor, supplies, maintenance, and water.

It is necessary for a rigorous analysis to be able to express the costs of these production items as a function of output. However, no methods are presently available for expressing the cost of labor, supplies, or maintenance accurately as a function of output.

Arbitrary methods of determining the incremental costs of labor, supplies, and maintenance are used, the commonest of which is to assume these costs to be a fixed percentage of the IFCs.

In many systems, for purposes of scheduling generation, the incremental production cost is assumed to be equal to the IFC.

1.5 Mathematical determination of optimal allocation of total load among different units:

Let us assume that is known as priori which generators are to run to meet a particular load demand on the station. This is, given a station with k generators committed and the active power load P_D given, the real power generation P_{Gi} for each generator has to be allocated so as to minimize the total cost.

$$C = \sum_{i=1}^{n} Ci(PGi) \qquad \text{.......(i)}$$

Where Ci is the cost function of the i^{th} unit.

Subject to the inequality constraint

$$P_{Gimin} \le P_{Gi} \le P_{Gimax}$$

Where P_{Gimin} and P_{Gimax} are the lower and upper real power generation limits of the ith generator. Obviously,

This cost is to be minimized to the equality constraint given by

$$\sum_{i=1}^{n} PGi_{max} > P_D \qquad \text{……..(ii)}$$

Where P_{Gi} is the real power generation of the i^{th} unit.

This is a constrained optimization problem.

To get the solution for the optimization problem, we will define an objective function by augmenting equation (i) with an equality constraint equation(ii) through the legrangian multiplier(λ) as

$$\acute{C} = C - \lambda[\sum_{i=1}^{n} PGi - P_D]$$

$$\mathrm{Min}[\acute{c}] = \min[C - \lambda[\sum_{i=1}^{n} PGi - P_D]] \qquad \text{……..(iii)}$$

The condition for optimality of such an augmented objective function is

$$\frac{\partial \acute{c}}{\partial PGi} = 0$$

From equation (iii)

Or

$$dC_i/dP_{Gi} = \lambda, \qquad i=1,2,\ldots\ldots k.$$

where dC_i/dP_{Gi} is the incremental cost of the ith generator can be written as

$$dC1/dP_{G1} = dC2/dP_{G2} = dC3/dP_{G3} = \ldots\ldots\ldots\ldots = dC_K/dP_{GK} = \lambda$$

Hence, the condition for the optimal allocation of the total load among the various units, when neglecting the transmission losses, is that the incremental costs of the individual units are equal. It is called a co-ordination equation.

Assume that one unit is operating at a higher incremental cost than the other units. If the output power of that unit is reduced and transferred to units with lower incremental operating costs, then the total operating cost decreases. That is, reducing the output of the unit with the higher incremental cost results in a more decrease in cost than the increase in cost of adding the same output reduction to units with lower incremental costs. Therefore, all units must run with same incremental operating costs.

After getting the optimal solution, in the case that the generation of any one unit is below its minimum capacity or above its maximum capacity, then its generation becomes the corresponding limit. For example, if the generation of any unit violates the minimum limit, then the generation of that unit is set at its minimum specified limit and vice versa. Then, the remaining demand is allocated among the remaining units as for the above criteria.

In the solution of an optimization problem without considering the transmission losses, we make use of equal incremental costs, i.e., the machines are so loaded that the incremental cost of production of each machine is the same.

As *IC* is increased or decreased in the iterative process, if a particular generator loading P_{Gj} reaches the limit $P_{Gj\ min}$ or $P_{Gj\ max}$, its loading from then on is held fixed at this value and the balanced load is shared between the remaining generators on equal incremental cost basis. The fact that this operation is optimal can be shown by the Kuhn-Tucker theory.

UNIT-2

ECONOMIC OPERATION OF POWER SYSTEMS-2

Optimum Generation Scheduling (when line losses are accounted)

From the unit commitment table of a given plant, the fuel cost curve of the plant can be determined in the form of a polynomial of suitable degree by the method of least squares fit. If the transmission losses are neglected, the total system load can be optimally divided among the various generating plants using the equal incremental cost criterion. It is, however, unrealistic to neglect transmission losses particularly when long distance transmission of power is involved.

A modem electric utility serves over a vast area of relatively low load density. The transmission losses may vary from 5 to 15% of the total load, and therefore, it is essential to account for losses while developing an economic load dispatch policy. It is obvious that when losses are present, we can no longer use the simple 'equal incremental cost' criterion. To illustrate the point, consider a two-bus system with identical generators at each bus (i.e. the same IC curves). Assume that the load is located near plant 1 and plant 2 has to deliver power via a loss line. Equal incremental cost criterion would dictate that each plant should carry half the total load; while it is obvious in this case that the plant 1 should cane a greater share of the load demand thereby reducing transmission losses.

In this section, we shall investigate how the load should be shared among various plants, when line losses are accounted for. The objective is to minimize the overall cost of generation at any time under equality constraint of meeting the load demand with transmission loss, i.e.

$$C = \sum_{i=1}^{k} C_i(P_{Gi}) \qquad (2.1)$$

$$\sum_{i=1}^{k} P_{Gi} - P_D - P_L = 0 \qquad (2.2)$$

where

k = total number of generating plants

P_{Gi} = generation of i_{ih} plant

P_D = sum of load demand in all buses (system load demand)

P_L = total system transmission loss

To solve the problem, we write the Lagrangian as

$$\mathcal{L} = \sum_{i=1}^{k} C_i(P_{Gi}) - \lambda \left[\sum_{i=1}^{k} P_{Gi} - P_D - P_L \right] \tag{2.3}$$

It will be shown later in this section that, if the power factor 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.

$$P_L = P_L(P_{G1}, P_{G2}, \dots \dots \dots \dots P_{Gk}) \tag{2.4}$$

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

For optimum real power dispatch,

$$\frac{\partial \mathcal{L}}{\partial P_{Gi}} = \frac{dC_i}{dP_{Gi}} - \lambda + \lambda \frac{\partial P_L}{\partial P_{Gi}} = 0 \qquad i = 1, 2, \dots . . k \tag{2.5}$$

Rearranging Eq. (2.5) and recognizing that changing the output of only one plant can affect the cost at only that plant, we have

$$\frac{\frac{dC_i}{dP_{Gi}}}{1 - \frac{\partial P_L}{\partial P_{Gi}}} = \lambda \tag{2.6}$$

$$\frac{dC_i}{dP_{Gi}} L_i = \lambda \, , \qquad i = 1,2, \dots . k \tag{2.7}$$

where

$$L_i = \frac{1}{1 - \frac{\partial P_L}{\partial P_{Gi}}} \tag{2.8}$$

is called the penalty factor of the ith plant.

The Lagrangian multiplier λ is in rupees per megawatt-hour, when fuel cost is in rupees per hour. Equation (2.6) 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 (k + 1) variables $(P_{G1}, P_{G2}, \dots \dots \dots \dots P_{Gk}, \lambda)$ can be obtained from k optimal dispatch Eq. (2.6) together with the power balance Eq. (2.2). The partial derivative $\frac{\partial P_L}{\partial P_{Gi}}$ is termed to as the incremental transmission loss (ITL), associated with the ith generating plant.

Equation (2.6) can also be written in the alternative form

$$(IC)_i = \lambda[1 - (ITL)_i] \qquad i = 1,2, \dots \dots . k \qquad (2.9)$$

This equation is referred to as the exact coordination 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 powers of generating plants. There are several methods, approximate and exact, for developing a transmission loss model. One of the most important, simple but approximate, methods of expressing transmission loss as a function of generator powers is through B-coefficients. This method is reasonably adequate for treatment of loss coordination in economic scheduling of load between plants. The general form of the loss formula (derived later in this section) using B-coefficients is

$$P_L = \sum_{m=1}^{k} \sum_{n=1}^{k} P_{Gm} B_{mn} P_{Gn} \qquad (2.10)$$

Where

P_{Gm} ,P_{Gn} = real power generation at m, nth plants

B_{mn}= loss coefficients which are constants under certain assumed operating conditions

If P_G's are in megawatts, B_{mn} are in reciprocal of megawatts.

Equation (2.10) for transmission loss may be written in the matrix form as

$$P_L = P_G^T B_{mn} P_G \qquad (2.11)$$

Where

$$P_G = \begin{bmatrix} P_{G1} \\ P_{G2} \\ \vdots \\ P_{Gk} \end{bmatrix} \quad and \quad B = \begin{bmatrix} B_{11} & B_{12} & \dots & B_{1k} \\ B_{21} & B_{22} & \dots & B_{2k} \\ \vdots & \vdots & \dots & \vdots \\ B_{k1} & B_{k2} & \dots & B_{kk} \end{bmatrix}$$

It may be noted that B is a symmetric matrix.

For a three plant system, we can waste the expression for loss as

$$P_L = B_{11}P^2{}_{G1} + B_{22}P^2{}_{G2} + B_{33}P^2{}_{G3} + 2B_{12}P_{G1}P_{G2} + 2B_{23}P_{G2}P_{G3} + 2B_{31}P_{G3}P_{G1} \qquad (2.12)$$

With the system power loss model as per Eq. (2.10), we can now write

$$\frac{\partial P_L}{\partial P_{Gi}} = \frac{\partial[\sum_{m=1}^{k}\sum_{n=1}^{k} P_{Gm}B_{mn}P_{Gn}]}{\partial P_{Gi}}$$

$$\frac{\partial P_L}{\partial P_{Gi}} = \frac{\partial\left[\sum_{\substack{n=1\\ n\neq i}}^{k} P_{Gi}B_{in}P_{Gn} + \sum_{\substack{m=1\\ m\neq i}}^{k} P_{Gm}B_{mi}P_{Gi} + P_{Gi}B_{ii}P_{Gi}\right]}{\partial P_{Gi}} \qquad (2.13)$$

It may be noted that in the above expression other terms are independent of P_{Gi}, and are, therefore, left out.

Simplifying Eq. (2.13) and recognizing that $B_{ij} = B_{ji}$, we can write

$$\frac{\partial P_L}{\partial P_{Gi}} = \sum_{j=1}^{k} 2B_{ij}P_{Gj} \qquad (2.14a)$$

Assuming quadratic plant cost curves as

$$C_i(P_{Gi}) = \frac{1}{2}a_iP^2{}_{Gi} + b_iP_{Gi} + d_i$$

We obtain the incremental cost as

$$\frac{dC_i}{dP_{Gi}} = a_iP_{Gi} + b_i \qquad (2.14b)$$

Substituting $\frac{\partial P_L}{\partial P_{Gi}}$ and $\frac{dC_i}{dP_{Gi}}$ from above in the coordination Eq. (2.5), we have

$$a_iP_{Gi} + b_i + \lambda\sum_{j=1}^{k} 2B_{ij}P_{Gj} = \lambda \qquad (2.15)$$

Collecting all terms of P_{Gi} and solving for P_{Gi}, we obtain

$$(a_i + 2\lambda B_{ii})P_{Gi} = -\lambda\sum_{\substack{j=1\\ j\neq i}}^{k} 2B_{ij}P_{Gj} - b_i + \lambda$$

$$P_{Gi} = \frac{1 - \frac{b_i}{\lambda} - \sum_{\substack{j=1\\ j\neq i}}^{k} 2B_{ij}P_{Gj}}{\frac{a_i}{\lambda} + 2B_{ii}}\ ;\ \ i = 1,2,\dots,k \qquad (2.16)$$

For any particular value of λ Eq. (2.16) can be solved iteratively by assuming initial values of P_{Gi}'s (a convenient choice is $P_{Gi} = 0$; i = l, 2... k). Iterations are stopped when P_{Gi}'s converge within specified accuracy.

Derivation of Transmission Loss Formula

The aim of this article is to give a simpler derivation by making certain assumptions. Figure 2.1 (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. 2.1(a). Let the current in line p be I_{P1}. Define

$$M_{P1}=I_{p1}/I_D \quad (2.17)$$

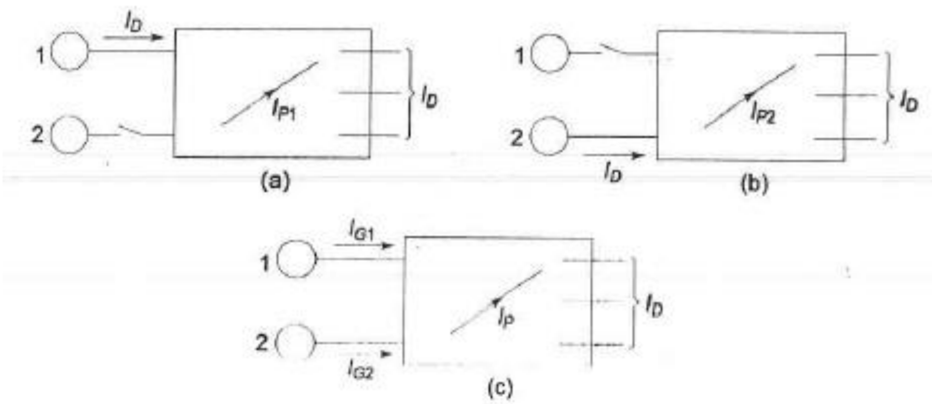


Fig. 2.1 Schematic diagram showing two plants connected through a power network to a number of loads

Fig. 2.1 Schematic diagram showing two plants connected through a power network to a number of loads Similarly, with plant 2 alone supplying the total load current (Fig. 2.1b), we can define

$$M_{P2}=I_{p2}/I_D \quad (2.18)$$

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. 2.1(c), applying the principle of superposition the current in the line p can be expressed as

$$I_P = M_{P1}\, I_{G1} + M_{P2}\, I_{G2} \quad (2.19)$$

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 implications of this assumption consider the load current at the i_{th} bus. It can be written as

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

Where δ_i the phase is angle of the bus voltage and $\emptyset_i$ is the lagging phase angle of the load. Since δ_i and $\emptyset_i$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. 2.1(a)) have the same phase angle and so have I_{P2} and I_D [Fig. 2.1(b)], such that the current distribution factors M_{P1} and M_{P2} are real rather than complex.

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

Where $\angle\sigma_1$ and $\angle\sigma_2$ are phase angles of I_{G1} and I_{G2}, respectively with respect to the common reference.

From Eq. (2.19), we can write

$$|I_P|^2 = (M_{P1}|I_{G1}|\,cos\sigma_1 + M_{P2}|I_{G2}|\,cos\sigma_2)^2 + (M_{P1}|I_{G1}|\,sin\sigma_1 + M_{P2}|I_{G2}|\,sin\sigma_2)^2 \qquad (2.20)$$

Expanding the simplifying the above equation, we get

$$|I_P|^2 = M^2{}_{P1}|I_{G1}|^2 + M^2{}_{P2}|I_{G2}|^2 + 2M_{P1}M_{P2}|I_{G1}||I_{G2}|\cos(\sigma_1 - \sigma_2) \qquad (2.21)$$

Now $|I_{G1}| = \frac{P_{G1}}{\sqrt{3}|V_1|\cos\emptyset_1}$; $|I_{G2}| = \frac{P_{G2}}{\sqrt{3}|V_2|\cos\emptyset_2}$ (2.22)

Where P_{G1} and P_{G2} are the three-phase real power outputs of plants 1 and 2 at power factors of $\cos\emptyset_1$ and $\cos\emptyset_2$, 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

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

Substituting for $|I_p|^2$ from Eq. (2.21), and $|I_{G1}|$ and $|I_{G2}|$ from Eq. (2.22), we obtain

$$P_L = \frac{P_{G1}^{\ 2}}{|V_1|^2(\cos \emptyset_1)^2} \sum_p M^2{}_{p1} R_p + \frac{2 P_{G1} P_{G2} \cos(\sigma_1 - \sigma_2)}{|V_1||V_2| \cos \emptyset_1 \cos \emptyset_2} \sum_p M_{p1} M_{p2} R_p + \frac{P_{G2}^{\ 2}}{|V_2|^2(\cos \emptyset_2)^2} \sum_p M^2{}_{p2} R_p \quad (2.23)$$

Equation (2.23) can be recognized as

$$P_L = P_{G1}^{\ 2} B_{11} + 2 P_{G1} P_{G2} B_{12} B_{12} + P_{G1}^{\ 2} B_{11} \qquad (2.24)$$

$$B_{11} = \frac{1}{|V_1|^2(\cos \emptyset_1)^2} \sum_p M^2{}_{p1} R_p$$

$$B_{12} = \frac{\cos(\sigma_1 - \sigma_2)}{|V_1||V_2| \cos \emptyset_1 \cos \emptyset_2} \sum_p M_{p1} M_{p2} R_p \qquad (2.25)$$

$$B_{22} = \frac{1}{|V_2|^2(\cos \emptyset_2)^2} \sum_p M^2{}_{p2} R_p$$

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

$$P_L = \sum_{m=1}^{k} \sum_{n=1}^{k} P_{Gm} B_{mn} P_{Gn} \qquad (2.26)$$

Where

$$B_{mn} = \frac{\cos(\sigma_m - \sigma_n)}{|V_m||V_n| \cos \emptyset_m \cos \emptyset_n} \sum_p M_{pm} M_{pn} R_p \qquad (2.27)$$

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-3

HYDROTHERMAL SCHEDULING

Objectives:

- Know the importance of hydro-thermal co-ordination.
- Know different Hydro electric power plant models.
- Study the Kirchmayer's method for short-term hydro-thermal co-ordination.
- Study the advantages of hydro-thermal plants combination.

Micro syllabus: Introduction, Optimal scheduling of Hydro-thermal systems, Importance of hydro thermal scheduling, Hydro electric power plant models and Short- term Hydro-thermal scheduling.Problems on short term hydro thermal scheduling

Outcomes:

Students will be able to:

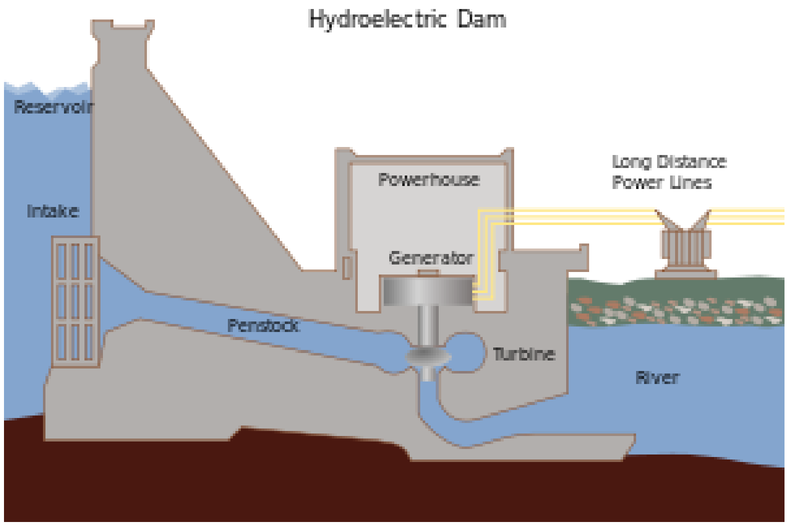
- Understand the importance of hydro-thermal co-ordination.
- Identify different Hydro electric power plant models.
- Solve short-term hydro-thermal co-ordination problem byKirchmayer's method.
- Understand the advantages of hydro-thermal plants combination.

There are three basic types of hydroelectric plants:

run-of-river,

pumped storage,

and reservoir systems.



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. The problem thus belongs to the realm of dynamic optimization. The problem of minimizing the operating cost of a hydrothermal system can be viewed as one of minimizing the fuel cost of thermal plants under the constraint of water availability (storage and inflow) for hydro generation over a given period of operation.

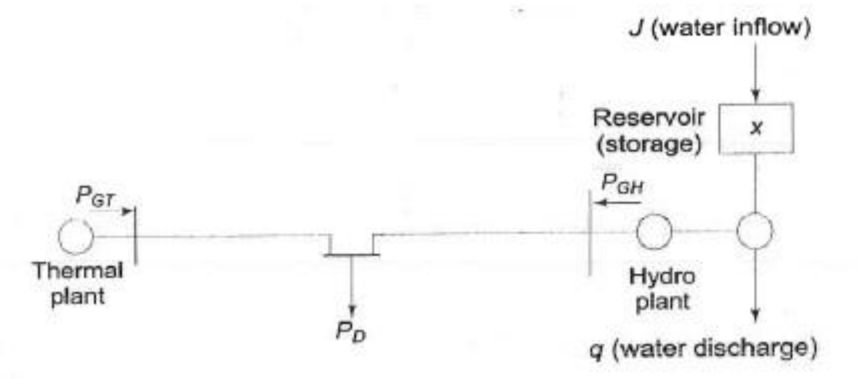


Fig. 3.1 Fundamental hydrothermal system

For the sake of simplicity and understanding, the problem formulation and solution technique are illustrated through a simplified hydrothermal system of Fig. 3.1. This system consists of one hydro and one thermal plant supplying power to a centralized load and is referred to as a fundamental system. Optimization will be carried out with real power generation as control variable, with transmission loss accounted for by the loss formula.

Short term co-ordination:

This type pf hydro-thermal scheduling is required for one day or one week, which involves the hour-by-hour scheduling of all available generations on a system to get the minimum production cost for the given time. Such types of scheduling problems, the load, hydraulic inflows, and unit availabilities are assumed to be known.

Kirchmayer's method

Kirchmayer's method:

In this method , the co-ordination equations are derived in terms of penalty factors of both plants for obtaining the optimum scheduling of a hydro-thermal system and hence it is also known as penalty factor method of solution of short-term hydro-thermal scheduling problems.

Objective function is

Min $c=\sum_{i=1}^{\alpha}\int_0^T C_i dt + \sum_{j=\alpha+1}^{n} Y_j \int_0^T w_j dt$ (1)

Subject to the equality constraint of

$$\sum_{i=1}^{\alpha} P_{GTi} + \sum_{j=\alpha+1}^{n} P_{GHj} = P_D + P_L \qquad (2)$$

And

$\int_0^T Wj$ dt = Kj for j=α+1,α+2,…..n (3)

Where Wj is the turbine discharge in the jth plant in m3/S and Kj the amount of water in m3 utilized during the time period T in the jth hydro plant.

The coefficient ϒ must be selected so as to use the specified amount of water during the operating period.

Now, the objective function becomes

$$\text{Min } C=\sum_{i=1}^{\alpha}\int_0^T Ci\,dt+\sum_{j=\alpha+1}^{n}\Upsilon j\,Kj$$

Substituting Kj from equation (1) in the above equation, we get

$$\text{Min } C=\sum_{i=1}^{\alpha}\int_0^T Ci\,dt+\sum_{j=\alpha+1}^{n}\Upsilon j\int_0^T Wj\,dt \quad (4)$$

For a particular load demand PD, Equation(2) result as

$$\sum_{i=1}^{\alpha}\Delta PGTi+\sum_{j=\alpha+1}^{n}\Delta PGHj-\sum_{i=1}^{\alpha}\frac{\partial PL}{\partial PGTi}\Delta P_{GTi}-\sum_{j=\alpha+1}^{n}\frac{\partial PL}{\partial PGHj}\Delta PGHj=0 \quad (5)$$

For a particular hydro-plant x, Equation (5) can be rewritten as

$$\Delta P_{GHx}-\frac{\partial PL}{\partial PGHx}\Delta PGHx=-\sum_{i=1}^{\alpha}\Delta PGTi-\sum_{j=\alpha+1}^{n}\Delta PGHj+\sum_{i=1}^{\alpha}\frac{\partial PL}{\partial PGTi}\Delta P_{GTi}+\sum_{j=\alpha+1}^{n}\frac{\partial PL}{\partial PGHj}\Delta P_{GHj}$$

By rearranging the above equation, we get

$$\left(1-\frac{\partial PL}{\partial PGHx}\right)\Delta PGHx=-\sum_{i=1}^{\alpha}\left(1-\frac{\partial PL}{\partial PGTI}\right)\Delta PGTi-\sum_{j=\alpha+1}^{n}\left(1-\frac{\partial PL}{\partial PGHj}\right)\Delta PGHj \quad (6)$$

From equation (4) the condition for minimization is

$$\Delta(\left[\left(\sum_{i=1}^{\alpha}\int_0^n Cidt\right)+\sum_{j=\alpha+1}^{n}\Upsilon j\int_0^T Wjdt\right]=0 \quad (7)$$

The above equation can be written as

$$\sum_{i=1}^{\alpha}\frac{dCi}{dPGTi}\Delta PGTi+\sum_{j=\alpha+1}^{n}\Upsilon j\frac{dWj}{dPGHj}\Delta PGHj=0 \quad (8)$$

For hydro-plant x,

$$\Upsilon x\frac{dWx}{dpGHx}\Delta P_{GHx}=-\sum_{i=1}^{\alpha}\frac{dCi}{dPGTi}\Delta PGTi-\sum_{j=\alpha+1}^{n}\Upsilon j\frac{dWj}{dPGHj}\Delta PGHj$$

Multiplying the above equation by $\left[1-\frac{\partial PL}{\partial PGHx}\right]$

$$\left[1-\frac{\partial PL}{\partial PGHx}\right]\gamma x\frac{dW}{dPGHx}=\left[1-\frac{\partial PL}{\partial PGHx}\right]\left|-\sum_{i=1}^{\alpha}\frac{dCi}{dPGTi}\Delta PGTi-\sum_{\substack{j=\alpha+1\\ j\neq x}}^{n}\gamma j\frac{dWj}{dPGHj}\Delta PGHj\right| \quad (9)$$

Substitute for $\left[1-\frac{\partial PL}{\partial PGHx}\right]\Delta PGHx$ from equation (6) in eq (9), we get

$$\gamma x \frac{dWx}{dPHx}\left|-\sum_{i=1}^{\alpha}\left(1-\frac{\partial PL}{\partial PGTi}\right)\Delta PGTi-\sum_{\substack{j=\alpha+1\\ j\neq x}}^{n}\left(1-\frac{\partial PL}{\partial PGHj}\right)\Delta PGHj\right|=$$

$$\left(1-\frac{\partial PL}{\partial PGHx}\right)\left[-\sum_{i=1}^{\propto}\frac{dCi}{dPGTi}\Delta PGTi-\sum_{\substack{j=\propto+1\\ j\neq x}}^{n}\gamma j\frac{dwj}{dPGHj}\Delta PGHj\right]$$

Rewriting the above equation as

$$\sum_{i=1}^{\propto}\left[\frac{dCi}{dPGTi}\left(1-\frac{\partial PL}{\partial PGHx}\right)-\gamma x\frac{dwX}{dPGHx}\left(1-\frac{\partial PL}{\partial PGTi}\right)\right]\Delta PGTi+\left[\sum_{\substack{j=\propto+1\\ j\neq x}}^{n}\gamma j\frac{dwj}{dPGHj}\left(1-\frac{\partial PL}{\partial PGHx}\right)-\right.$$
$$\left.\gamma x\frac{dWx}{dPHx}\left(1-\frac{\partial PL}{\partial PGHj}\right)\right]\Delta PGHj=0$$

(10)

$\therefore\ \Delta PGTi\neq 0\ and\ \Delta PGHj\neq 0$, equation (10) becomes

$$\frac{dCi}{dPGTi}\left(1-\frac{\partial PL}{\partial PGHx}\right)-\gamma x\frac{dwX}{dPGHx}\left(1-\frac{\partial PL}{\partial PGTi}\right)=0\ for\ i=1,2,\ldots\ldots\ldots..\propto \qquad (11)$$

And

$$\sum_{\substack{j=\propto+1\\ j\neq x}}^{n}\gamma j\frac{dwj}{dPGHj}\left(1-\frac{\partial PL}{\partial PGHx}\right)-\gamma x\frac{dWx}{dPHx}\left(1-\frac{\partial PL}{\partial PGHj}\right)=0\ for\ j=\propto+1,\propto+2,\ldots\ldots\ldots..n \qquad (12)$$

Equations (11) and (12) can be written in the form:

$$\frac{dCi}{dPGTi}\frac{1}{\left(1-\frac{\partial PL}{\partial PGTi}\right)}=\gamma x\frac{dwX}{dPGHx}\frac{1}{\left(1-\frac{\partial PL}{\partial PGHx}\right)} \qquad (13)$$

And

$$\gamma j\frac{dwj}{dPGHj}\frac{1}{\left(1-\frac{\partial PL}{\partial PGHj}\right)}=\gamma x\frac{dWx}{dPHx}\frac{1}{\left(1-\frac{\partial PL}{\partial PGHx}\right)} \qquad (14)$$

From eq(13) and (14), we haveType equation here.

$$\frac{dCi}{dPGTi}\frac{1}{\left(1-\frac{\partial PL}{\partial PGTi}\right)}=\gamma x\frac{dwX}{dPGHx}\frac{1}{\left(1-\frac{\partial PL}{\partial PGHx}\right)}=\text{Type equation here.}$$

$$\frac{dCi}{dPGTi}\frac{1}{\left(1-\frac{\partial PL}{\partial PGTi}\right)}=(I_c)_iL_i$$

$$\gamma x\frac{dwX}{dPGHx}\frac{1}{\left(1-\frac{\partial PL}{\partial PGHx}\right)}=\gamma j(Iw)jLj$$

Advantages of operation of hydro-thermal combinations

1. Flexibility
2. Greater economy
3. Security of supply
4. Better energy conservation

5. Reserve capacity maintenance

UNIT-4

Single area load frequency control

Objectives:

- Introduce single area load frequency control.
- Understand Necessity of keeping frequency constant
- Explain the Mathematical modelling of steam turbine, generator, governing system
- Know single area control Block diagram representation of an isolated power system Steady sate analysis Dynamic response in uncontrolled case.

Micro syllabus:

Introduction to single area load frequency control, Necessity of keeping frequency constant Modelling of steam turbine, generator, Mathematical modelling of speed governing system, transfer function Control area, single area control Block diagram representation of an isolated power system Steady sate analysis Dynamic response in uncontrolled case. Problems on single area control

Outcomes:

Student will be able to

- Understand single area load frequency control.
- Know theNecessity of keeping frequency constant
- analyze the Mathematical modelling of steam turbine, generator, governing system
- Learn the single area control Block diagram representation of an isolated power system Steady sate analysis Dynamic response in uncontrolled case.

INTRODUCTION:

Power system operation considered so far was under conditions of steady load. However, both active and reactive power demands are never steady and they continually change with the rising or falling trend. Steam input to turbo generators (or water input to hydro-generators) must, therefore be continuously regulated to match the active power demand, failing which the machine speed will vary with consequent change in frequency which may be highly undesirable (maximum permissible change in power frequency is ±0.5 Hz). Also the excitation of generators must be continuously regulated to match the reactive power demand with reactive generation, otherwise the voltages at various system buses may go beyond the prescribed limits. In modern large interconnected systems, manual regulation is not feasible and therefore automatic generation and voltage regulation equipment is installed on each generator. Figure 4.1 gives the schematic diagram of load frequency and excitation voltage regulators of a turbo-generator. The controllers are set for a particular operating condition and they take care of small changes in load demand without frequency and voltage exceeding the prescribed limits. With the passage of time, as the change in load demand becomes large, the controllers must be reset either manually or automatically. For small changes, active power is dependent on internal machine angle δ and is independent of bus voltage; while bus voltage is dependent on machine excitation (therefore on reactive generation Q) and is independent of machine angle δ. Change in angle δ is caused by momentary change in generator speed. Therefore, load frequency and excitation voltage controls are non-interactive for small changes and can be modelled and analysed independently. Furthermore , excitation voltage control is fast acting in which the major time constant encountered is that of the generator field; while the power frequency control is slow acting with major time constant contributed by the turbine and generator moment of inertia-this time constant is much larger than that of the generator field. Thus, the transients in excitation voltage control vanish much faster and do not affect the dynamics of power frequency control.

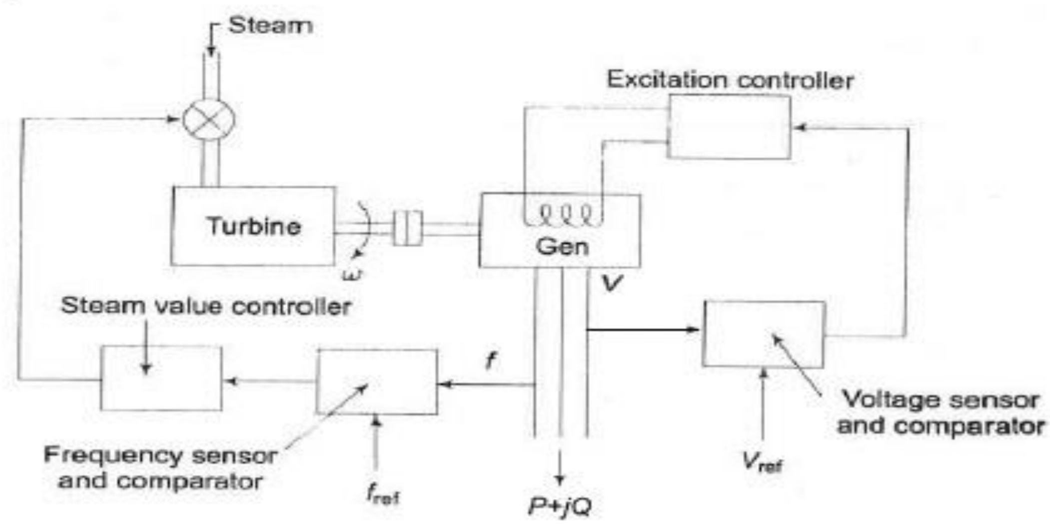


Fig. 4.1 Schematic diagram of load frequency and excitation voltage regulators of a turbo generator

Change in load demand can be identified as: (i) slow varying changes in mean demand, and (ii) fast random variations around the mean. The regulators must be designed to be insensitive to fast random changes, otherwise the system will be prone to hunting resulting in excessive wear and tear of rotating machines and control equipment.

Load Frequency Control (Single Area Case)

Let us consider the problem of controlling the power output of the generators of a closely knit electric areas o as to maintain the scheduled frequency. All the generators in such an area constitute a coherent group so that all the generators speed up and slow down together maintaining their relative power angles. Such an area is defined as a control area. The boundaries of a control area will generally coincide with that of an individual Electricity Board Company.

To understand the load frequency control problem, let us consider a single turbo-generator system supplying an isolated load.

Turbine Speed Governing System

Figure 4.2 shows schematically the speed governing system of a steam turbine.

The system consists of the following components:

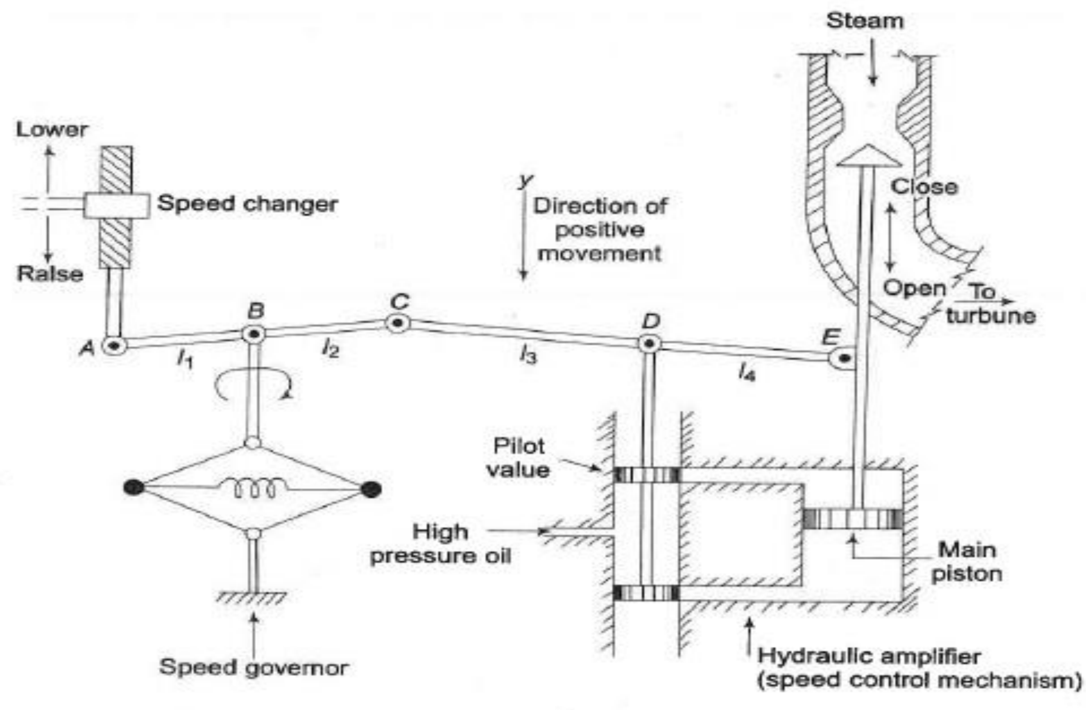


Fig. 4.2 Turbine speed governing system

(i) Fly ball speed governor: This is the heart of the system which senses the change in speed (frequency). As the speed increases the fly balls move outwards and the point B on linkage mechanism moves downwards. The reverse happens when the speed decreases.

(ii) Hydraulic amplifier: It comprises a pilot valve and main piston arrangement. Low power level pilot valve movement is converted into high power level piston valve movement. This is necessary in order to open or close the steam valve against high pressure steam.

(iii) Linkage mechanism: ABC is a rigid link pivoted at B and CDE is another rigid link pivoted at D. This link mechanism provides a movement to the control valve in proportion to change in speed. It also provides a feedback from the steam valve movement (link 4).

(i) Speed changer: It provides a steady state power output setting for the turbine. Its downward movement opens the upper pilot valve so that more steam is admitted to the turbine under steady conditions (hence more steady power output). The reverse happens for upward movement of speed changer.

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 = generator output = turbine output (neglecting generator loss)

y_E = steam valve setting

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

Let the point A on the linkage mechanism be moved downwards by a small amount Δy_A. It is a command which causes the turbine power output to change and can therefore be written as

$$\Delta y_A = K_C \, \Delta P_C \quad (4.1)$$

where ΔP_C is the commanded increase in power.

The command signal ΔP_C, (i.e. Δy_E) sets into motion a sequence of events the pilot valve moves upwards, high pressure oil flows on to the top of the main piston moving it downwards; the steam valve opening consequently increases, the turbine generators speed increases, i.e. the frequency goes up. Let us model these events mathematically.

Two factors contribute to the movement of C:

(i) Δy_A contributes $-(l_2/l_1)\, \Delta y_A$ or $- k_1 \Delta y_A$ (i.e. upwards) of $- k_1 \, Kc \, \Delta P_c$

(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 $+ (l_1+l_2)/l_1 \, k'_2 \Delta f = + k_2 \, \Delta f$ (i.e. downwards)

The net movement of C is therefore

$$\Delta Y_c = - k_1 \, k_c \Delta Pc + k_2 \Delta f \quad (4.2)$$

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

$\Delta y_D = l_4/(l_3+l_4)\ \Delta y_c + l_3\ /(l_3 + l_4)\ \Delta y_E$

$\Delta y_D = k_3 \Delta y_c + k_4 \Delta y_E$ (4.3)

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 $\Delta y_E$is obtained by dividing the oil volume by the area of the cross-section of the-piston. Thus

$$\Delta y_E = k_5 \int_0^t (-\Delta y_D)\,dt \quad (5.4)$$

It can be verified from the schematic diagram that a positive movement Δy_D, causes negative (upward) movement accounting for the negative sign used in Eq. (5.4).

Taking the Laplace transform of Eqs. (5.2), (5.3) and (5.4), we get

$\Delta Y_c(s) = -\ k_1\ k_c \Delta Pc(s) + k_2\ \Delta F(s)$ (4.5)

$\Delta y_D(s) = k_3 \Delta y_c(s) + k_4 \Delta y_E(s)$ (4.6)

$$\Delta y_E(s) = -k_5 \frac{1}{s} \Delta y_D(s) \quad (5.7)$$

Eliminating ΔY_c (s) and ΔY_D (s), we can write

$$\Delta y_E(s) = \frac{k_1 k_3 k_c \Delta P_c(s) - k_2 k_3 \Delta F(s)}{\left(k_4 + \frac{s}{k_5}\right)} = \left[\Delta P_C(s) - \frac{1}{R}\Delta F(s)\right] \times \left(\frac{K_{sg}}{1 + T_{sg} s}\right) (5.8)$$

Where

$R = k_1 k_c / k_2$ = Sseed regulation of the governor

K_{sg} = $(k_1 k_3 k_c) / k_4$ = gain of speed governor

$T_{sg} = 1/(k_4 k_5)$ = time constant of speed governor

Equation (5.8) is represented in the form of a block diagram in Fig. 5.3.

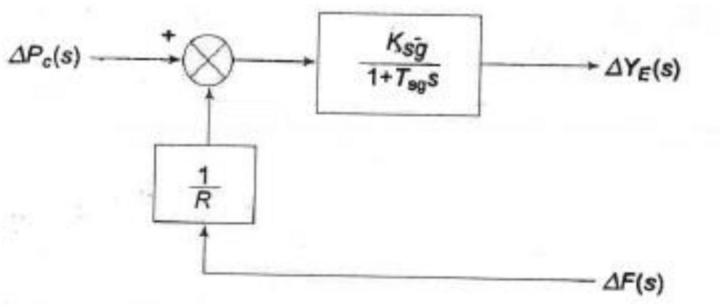


Fig. 4.3 Block diagram representation of speed governor system

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.

Turbine Model

Let us now relate the dynamic response of a steam turbine in terms of changes in power output to changes in steam valve opening Δy_E. Figure 4.4a shows a two stage steam turbine with a reheat unit. The dynamic response is largely influenced by two factors, (i) entrained steam between the inlet steam valve and first stage of the turbine, (ii) the storage action in the reheater which causes the output of the low pressure stage to lag behind that of the high pressure stage. Thus, the turbine transfer function is characterized by two time constants. For ease of analysis it will be assumed here that the turbine can be modelled to have a single equivalent time constant. Figure 4.4b shows the transfer function mode of a steam turbine. Typically the time constant T_t lies in the range 0.2 to 2.5 sec.

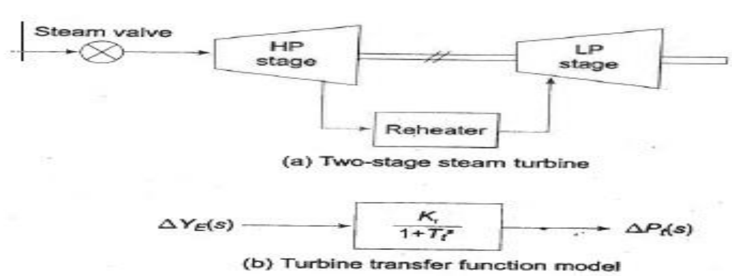


Fig. 4.4

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

$W^o_{ke} = H \times P_r$ kW = 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

$$W_{ke} = W^o_{ke} ((f^o + \Delta f)/ f^o)^2 = H \times P_r ((f^o + \Delta f)/ f^o)^2 \quad (4.9)$$

Rate of change of kinetic energy is therefore

$$dW_{ke}/dt = 2HP_r/ f^o \, d(\Delta f)/dt \quad (4.10)$$

(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. $\frac{\partial P_D}{\partial f}$ can be regarded as nearly constant for small changes in frequency Δf and can be expressed as

$$\frac{\partial P_D}{\partial f} \Delta f = B \, \Delta f \quad (4.11)$$

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

Writing the power balance equation, we have

$\Delta P_G - \Delta P_D = 2HP_r/ f^o \, d(\Delta f)/dt + B \, \Delta f$

Dividing throughout by P_r , and rearranging, we get

$\Delta P_G(pu) - \Delta P_D(pu) = 2H/ f^o \, d(\Delta f)/dt + B(pu) \, \Delta f$ (4.12)

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

$\Delta F(s) = (\Delta P_G(s) - \Delta P_D(s))/(B + 2Hs/ f^o)$

$\Delta F(s) = [\Delta P_G(s) - \Delta P_D(s)] \times (K_{ps}/(1+sT_{PS}))$ (4.13)

Where

$T_{PS} = 2H/Bf^o$ = power system time constant

Kps = 1/B =power system gain

Equation (4.13) can be represented in block diagram form as in Fig. 4.5.

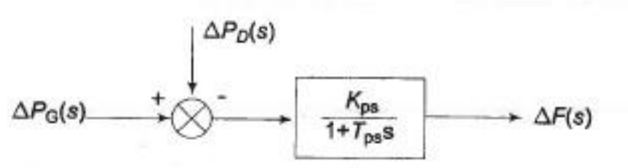


Fig. 4.5 Block diagram representation of generator- load model

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. 4.3, 4.4 and 4.5. The complete block diagram with feedback loop is shown in Fig. 4.6.

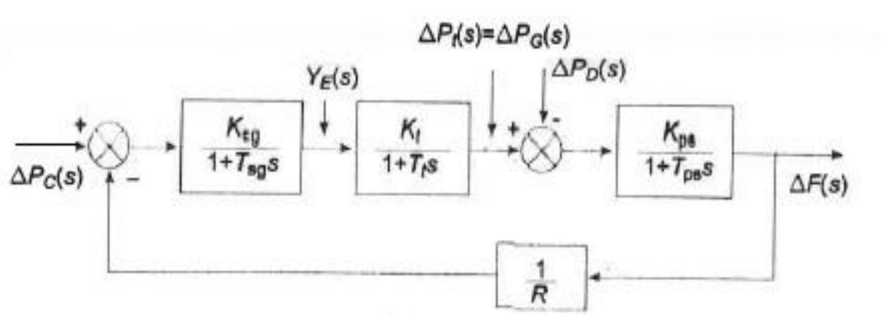


Fig. 4.6 Block diagram model of load frequency control (isolated power system)

Steady States Analysis

The model of Fig. 4.6 shows that there are two important incremental inputs to the load frequency control system - ΔPc, 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 (i.e. $\Delta P_D(s) = \Delta P_D/s$) is obtained as follows:

$$\Delta F(s)|_{\Delta Pc(s)=0} = -\frac{K_{ps}}{(1+sT_{ps})+\frac{K_{sg}K_tK_{ps}/R}{(1+sT_{sg})(1+sT_t)}} \times \frac{\Delta P_D}{s} \qquad (4.14)$$

$$\Delta f|_{\substack{steady\ state \\ \Delta P_c=0}} = s\Delta F(s)|_{\substack{s\to 0 \\ \Delta Pc(s)=0}}$$

$$\Delta f|_{\substack{steady\ state \\ \Delta P_c=0}} = -\frac{K_{ps}}{1+\frac{K_{sg}K_tK_{ps}}{R}} \times \Delta P_D \qquad (4.15)$$

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 $K_{sg}K_t \approx 1$

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

$$\Delta f = -\left(\frac{1}{B+1/R}\right) \times \Delta P_D \qquad (4.16)$$

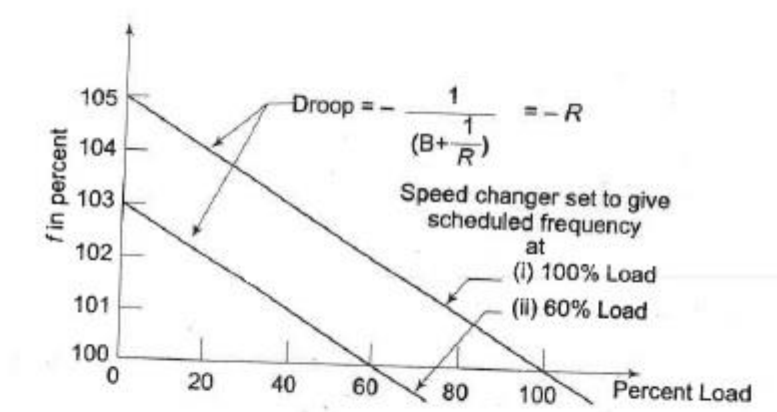


Fig. 4.7 Steady state load-frequency characteristics of a speed governor system

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 percent from no load to full load). Therefore, the linear incremental relation (4.16) can be applied from no load to full load. With this understanding, Fig. 4.7 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 l/R = 1/3) so that B can be neglected in comparison. Equation (4.16) then simplifies to

$$\Delta f = -R(\Delta P_D) \tag{4.17}$$

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_D) 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. 4.6 (with $K_{sg}K_t \approx 1$)

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

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

$\Delta P_G = 0.971\ \Delta P_D$

Decrease in system load = 0.029 ΔP_D

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

$$\Delta F(s)|_{\Delta PD(s)=0} = -\frac{K_{sg}K_tK_{ps}}{(1+sT_{sg})(1+sT_{ps})(1+sT_t)+\frac{K_{sg}K_tK_{ps}}{R}} \times \frac{\Delta P_C}{s} \quad (4.18)$$

$$\Delta f|_{\substack{steady\ state \\ \Delta P_D=0}} = \frac{K_{sg}K_tK_{ps}}{1+\frac{K_{sg}K_tK_{ps}}{R}} \times \Delta P_C \quad (4.19)$$

If $K_{sg}K_t \approx 1$

$$\Delta f = \left(\frac{1}{B+1/R}\right) \times \Delta P_C \quad (4.20)$$

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.

$$\Delta f = \left(\frac{1}{B+1/R}\right) \times (\Delta P_C - \Delta P_D)(5.21)$$

According to Eq. (5.2I) the frequency change caused by load demand can be compensated by changing the setting of the speed changer, i .e.

$\Delta P_C = \Delta P_D$, for $\Delta f = 0$

Figure 4.7 depicts two load frequency plots-one to give scheduled frequency at I00 percent rated load and the other to give the same frequency at 60 percent 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. (4.14). 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.

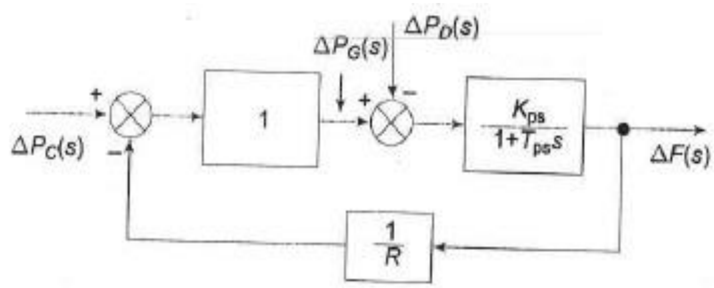


Fig. 4.8 First order approximate block diagram of load frequency control o f an isolated area

Letting $T_{sg} = T_t = 0$ (and $K_{sg}K_t \approx 1$), the block diagram of Fig. 5.6 reduced to that of fig.4.8, from which we can write

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

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

$$\Delta f(t) = -\frac{RK_{ps}}{R+K_{ps}}\left\{1 - exp\left[-t/T_{ps}\left(\frac{R}{R+K_{ps}}\right)\right]\right\}\Delta P_D \,(5.22)$$

Taking R=3, K_{ps} = 1/B = 100, T_{ps}= 20, ΔP_D = 0.01 pu

$\Delta f(t) = -0.029\ (1- e^{-1.717t})$ (4.23a)

$\Delta f|_{\text{steady state}} = -0.029$ Hz (4.23b)

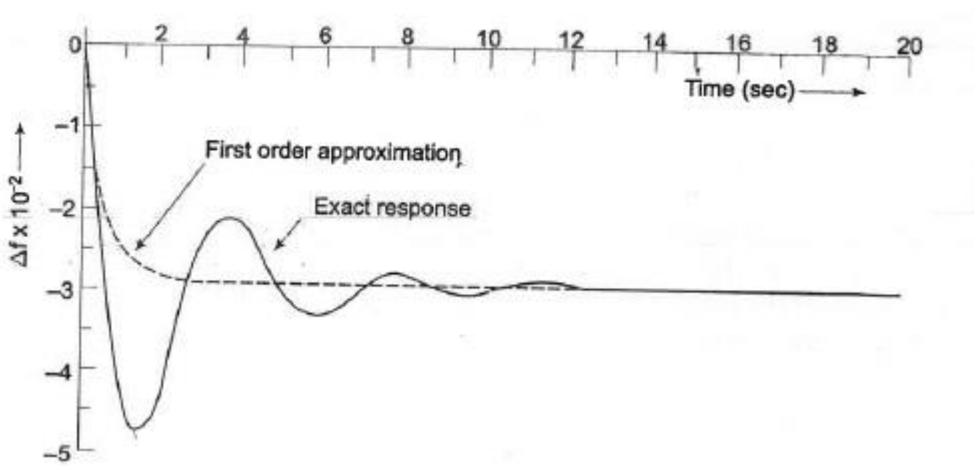


Fig. 4.9 Dynamic response of change in frequency for a step change in load (ΔP_D = 0.01 pu,

T_{sg} = 0.4 sec, T_t = 0.5 sec, T_{ps}= 20 sec, K_{ps} = 1/B = 100, R= 3)

The plot of change in frequency versus time for first order approximation given above and the exact response are shown in Fig.4.9. First order approximation is obviously a poor approximation.

UNIT-5

LOAD FREQUENCY CONTROLLERS AND TWO AREA LOAD FREQUENCY CONTROL

Objectives:

- To introduce proportional plus integral control of single area load frequency control.
- To familiarizethe concept of steady state response, load frequency control and economic dispatch control
- To introduce load frequency control of two area system
- To familiarize uncontrolled and controlled case (Tie – line bias control) of two area load frequency control.

Micro syllabus: Proportional plus integral control of single area and its block diagram representation, steady state response, load frequency control and economic dispatch control, Load frequency control of two area system, Analysis of system in uncontrolled and controlled case, Tie – line bias control.

Outcomes:

Student will be able to

- Describeproportional plus integral control of single area load frequency control.
- Explain the concepts of Steady state response load frequency control and economic dispatch control
- Understandthe Load frequency control of two area system
- Analyze thesystem in uncontrolled and controlled case.

INTRODUCTION:

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. Such a coherent area is called a control area in which the frequency is assumed to be the same throughout in static as well as dynamic conditions. For purposes of developing a suitable control strategy, a control area can be reduced to a single speed governor, turbo-generator and load system. All the control strategies discussed so far are, therefore, applicable to an independent control area.

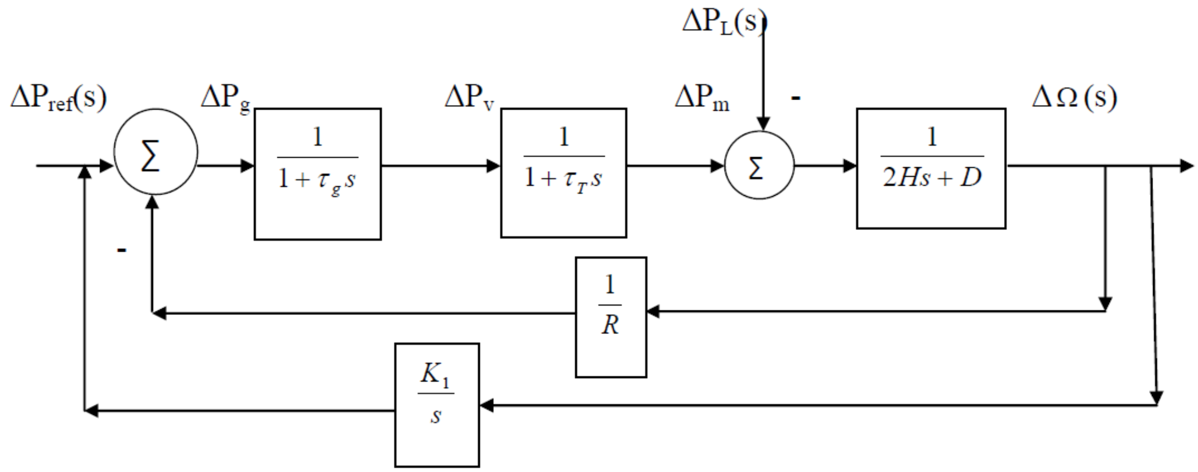
PROPORTIONAL PLUS INTEGRAL CONTROL (Secondary ALFC loop)

It is seen from the previous discussion that with the speed governing system installed in each area, for a given speed changer setting, there is considerable frequency drop for increased system load. In the example seen, the frequency drop is 0.01961 Hz for 20 MW. Then the steady state drop in frequency from no load to full load (2000 MW) will be 1.961 Hz. System frequency specification is rather stringent and therefore, so much change in frequency cannot be tolerated. In fact, it is expected that the steady state frequency change must be zero. In order to maintain the frequency at the scheduled value, the speed changer setting must be adjusted automatically by monitoring the frequency changes.For this purpose, INTEGRAL CONTROLLER is included. In the integral controller the frequency error is first amplified and then integrated. Further, a negative polarity is also included so that a NEGATIVE frequency deviation will give rise to RAISE command. The signal fed into the integrator is referred as Area Controlled Error (ACE). For this case ACE = Δf .

Thus $\Delta P_{ref} = -K_1 \int \Delta f dt$

Taking Laplace transformation $\Delta P_{ref}(s) = \frac{K1}{s} \Delta F_{ref}(s)$

The gain constant KI controls the rate of integration and thus the speed of response of the loop.For this signal Δf (s) is fed to an integrator whose output controls the speed changer position resulting in the block diagram configuration shown in Fig.



As long as an error remains, the integrator output will increase, causing the speed changer to move. When the frequency error has been reduced to zero, the integrator output ceases and the speed changer position attains a constant value.Integral controller will give rise to ZERO STEADY STATE FREQUENCY ERROR following a step load change because of the reason stated above.Referring to the block diagram of single control area with integral controller shown in Fig.

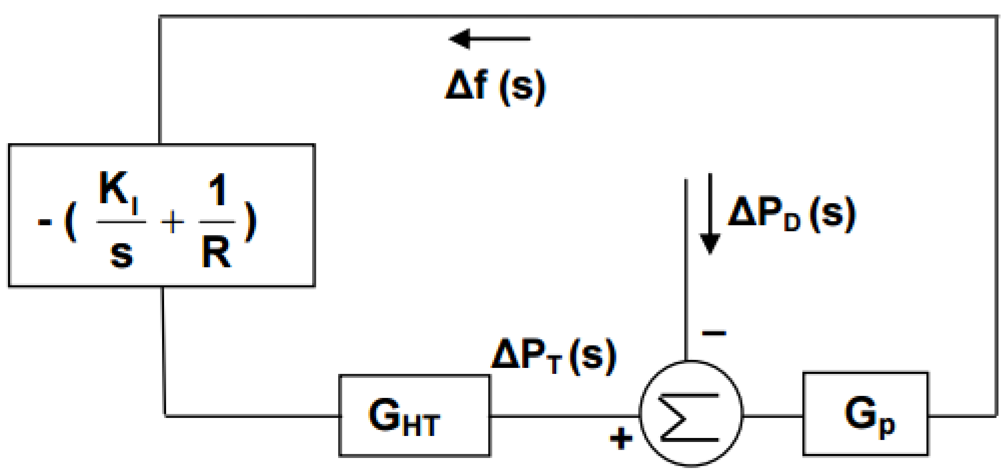


Fig. Reduced block diagram

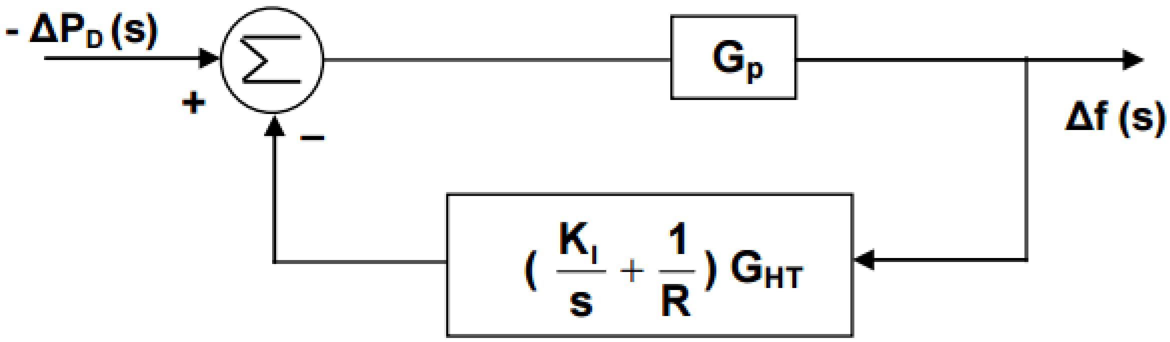


Fig.Reduced block diagram

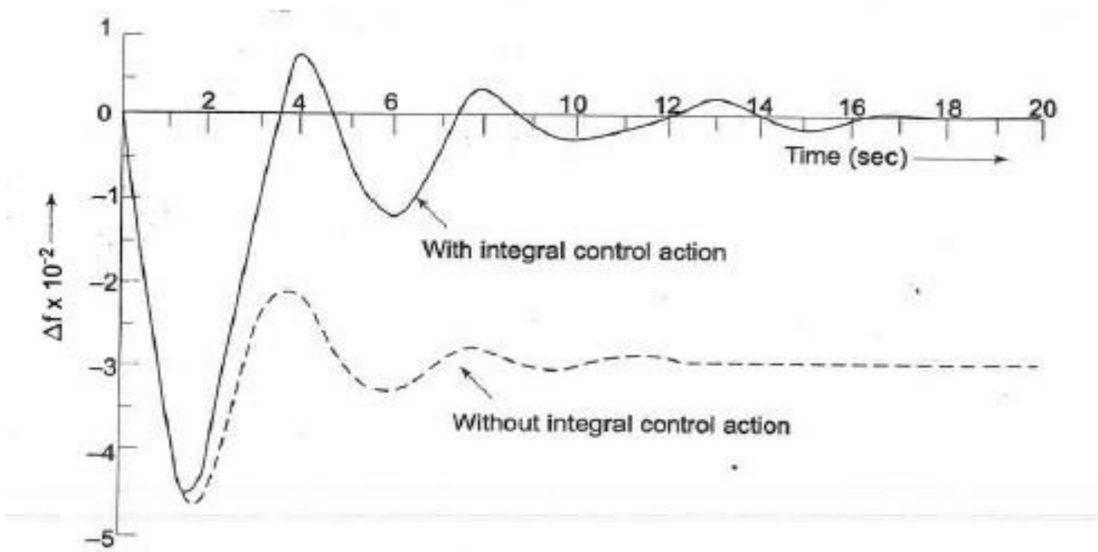
Let the step load change be ΔP_D, which is equal to M. Then $\Delta P_D(s) = \frac{M}{s}$

Using final value theorem,

$$\Delta f_0 = \lim_{s \to 0} [\, s \, \Delta f(s) \,]$$

$$= - \left. \frac{G_p \, M}{1 + \frac{K_I}{s} G_{HT} \, G_p + \frac{1}{R} G_{HT} \, G_p} \right|_{s \to 0} = - \left. \frac{K_p \, M}{1 + \frac{K_I}{s} K_p + \frac{1}{R} K_p} \right|_{s \to 0}$$

$$= 0$$



Thus static frequency drop due to step load change becomes zero, which is a desired feature we were looking. This is made possible because of the integral controller that has been introduced.

LOAD FREOUENCY CONTROL AND ECONOMIC DESPATCH CONTROL

Load frequency control with integral controller achieves zero steady state frequency error and a fast dynamic response, but it exercises no control over the relative loadings of various generating stations (i.e. economic dispatch) of the control area. For example, if a sudden small increase in load (say, 1 percent) occurs in the control area, the load-frequency control changes the speed changer settings of the governors of all generating units of the area so that, together these units match the load and the frequency returns tp the scheduled value (this action takes place in a few seconds). However, in the process of this change the loadings of various generating units change in a manner independent of economic loading considerations. In fact, some units in the process may even get overloaded. Some control over loading of individual units can be exercised by adjusting the gain factors (K_i) include in the signal representing integral of the area control error as fed to individual units. However, this is not satisfactory.

A satisfactory solution is achieved by using independent controls for load frequency and economic dispatch. While the load frequency controller is a fast acting control (a few seconds), and regulates the system around an operating point; the economic dispatch controller is a slow acting control, which adjusts the speed changer every minute (or half a minute) in accordance with a command signal generated by the central economic dispatch computer. Figure gives the schematic diagram of both these controls for two typical units of a control area. The signal to change the speed changer setting is constructed in accordance with economic dispatch error,

[P_G(desired) – P_G(actual)], Suitably modified by the signal representing integral ACE at that instant of time. The signal P_G (desired) is computed by the central economic dispatch computer (CEDC) and is transmitted to the local economic dispatch controller (EDC) installed at each station. The system thus operates with economic dispatch error only for very short periods of time before it is readjusted.

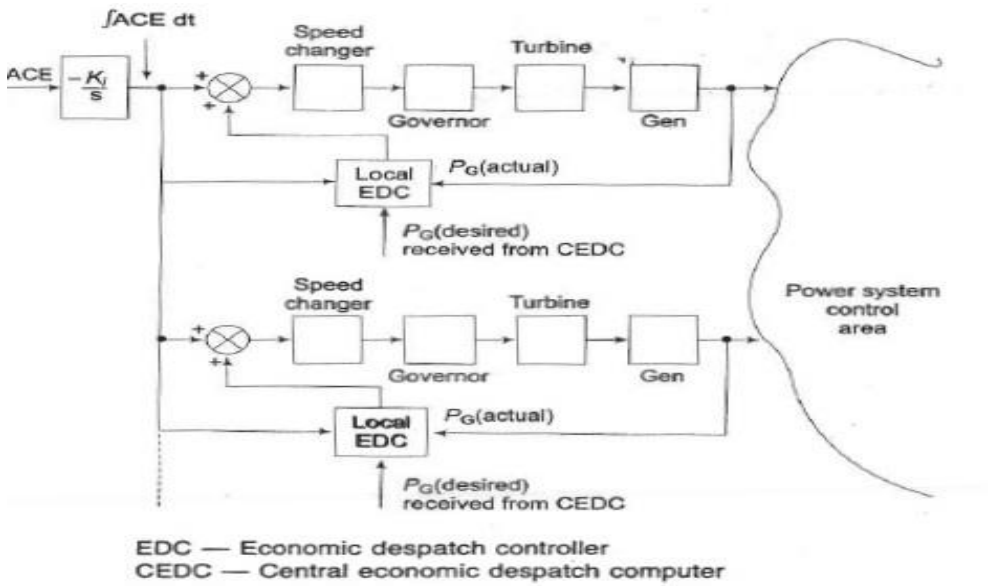


Fig. Control area load frequency and economic dispatch control

TWO AREA CONTROL:

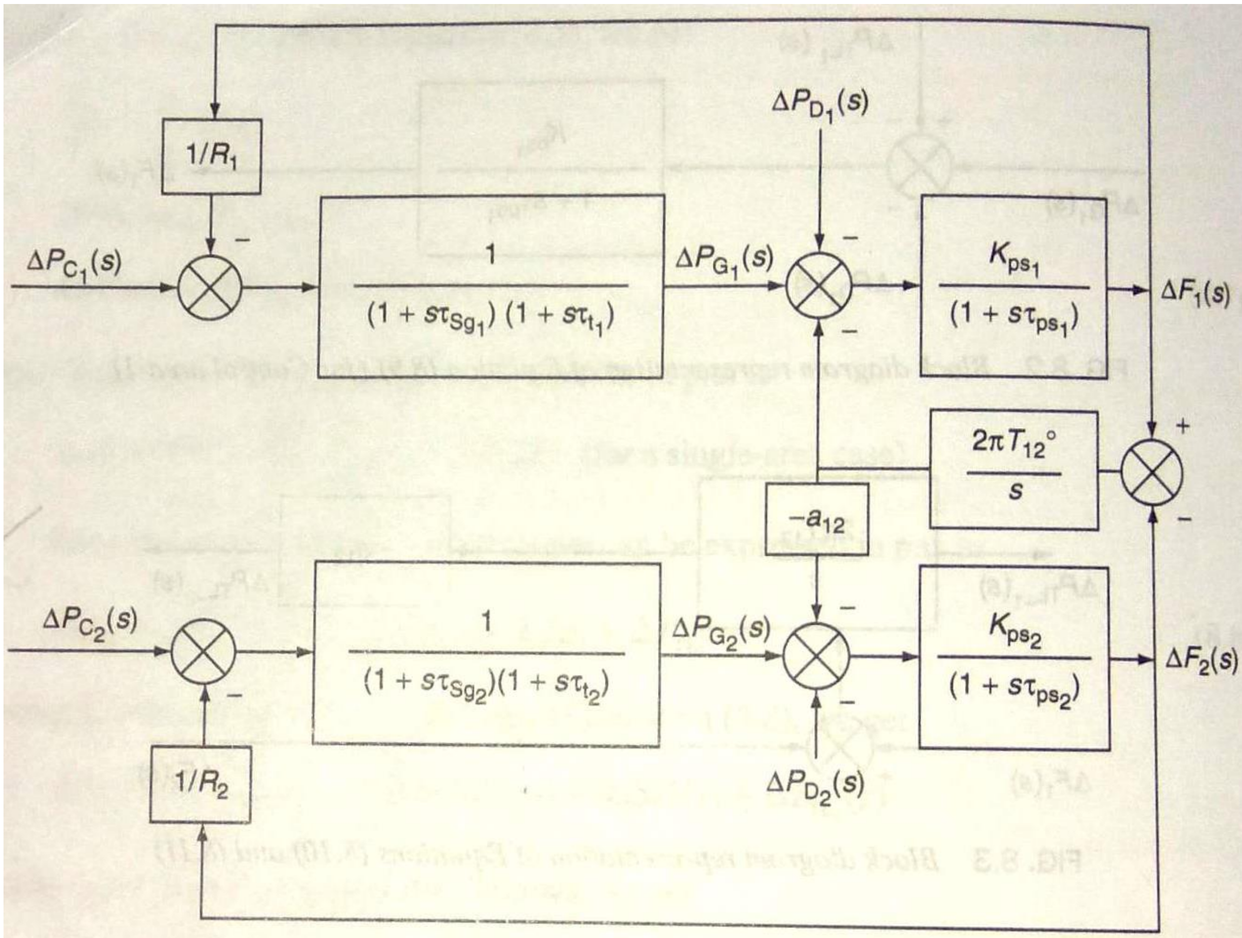
A control area is characterized by the same frequency throughout. This tantamount to saying that the area network is “rigid” or “strong”. In the singlearea case we could thus represent the frequency deviation by the single variable Δf. In the present case we assume each area individually “strong”. Having interconnected them with a “weak” tie-line therefore leads us to the assumption that the frequency deviations in the two areas can be represented by two variablesΔf_1 and Δf_2 respectively.

MODELING THE TIE-LINE and BLOCK DIAGRAM FOR TWO-AREA SYSTEM

In normal operation the power flows in the tie-line connecting the areas 1 and 2 is given by

$$P^0_{12} = \frac{|V_1^0||V_2^0|}{X} \sin(\delta_1^0 - \delta_2^0)$$

Where $\delta_1^0 \delta_2^0$ are the angles of end voltages V1 and V2 respectively. The order of the subscripts indicates that the tie-line power is defined in direction 1 to 2.Knowing dy/dx = Δy/Δx, for small deviations in angles δ1 and δ2 the tie-line power changes by an amount



Similarly we need to add ΔP21 in area 2. Defining the tie-line power in direction 2 to 1 as ΔP_{21}.

$$\Delta F1(s) = [\Delta PG1(S) - \Delta Ptie(s)] * \frac{Kps}{1+\tau ps}$$

$$\Delta F1(s) = \left[\frac{\Delta \text{PG1}}{S} - \frac{\Delta PD1}{S} - \frac{\Delta Ptie1}{s}\right] * \frac{\frac{1}{\beta 1}}{1+\tau ps1}$$

$$\Delta f1ss = s\Delta F1(s) = \frac{\Delta PG1 - \Delta PD1 - \Delta Ptie1}{\beta 1}$$

Since $\Delta f1\beta 1 = \frac{-\Delta f1}{R1} - \Delta PD1 - \Delta Ptie1$ (1)

$$\Delta f2\beta 2 = \frac{-\Delta f2}{R2} - \Delta PD2 - \Delta Ptie2$$

Since $\Delta Ptie2 = -a12\,\Delta Ptie1$

$$\Delta f2\beta 2 = \frac{-\Delta f2}{R2} - \Delta PD2 + a12\Delta Ptie1 \qquad (2)$$

$$\Delta Ptie1 = \frac{-\Delta f1}{R1} - \Delta PD1 - \Delta f1 \qquad (3)$$

Substitute (3) in (2)

$$\Delta f2\beta 2 = \frac{-\Delta f2}{R2} - \Delta PD2 + a12(\frac{-\Delta f1}{R1} - \Delta PD1 - \Delta f1)$$

At steady state $\Delta f1 = \Delta f2 = \Delta f$

$$\Delta fB2 = \frac{-\Delta f}{r2} - \Delta PD2 - a12\left(\frac{\Delta f}{R1} + \Delta f\beta 1\right) - a12\Delta PD1$$

$$\Delta f = \frac{-\Delta PD2 - a12\Delta PD1}{\left(\beta 2 + \frac{1}{R_2}\right) + a12(\beta 1 + \frac{1}{R_2})}$$

$$\Delta Ptie1 = -\Delta f\left(\beta 1 + \frac{1}{R1}\right) - \Delta PD1$$

$$\Delta Ptie1 = \frac{\left(\beta 1 + \frac{1}{R_1}\Delta PD2\right) - \left(\beta 2 + \frac{1}{R_2}\right)\Delta PD1}{\left(\beta 2 + \frac{1}{R_2}\right) + a12(\beta 1 + \frac{1}{R_1})}$$

For this reason, transfer function of -1 is introduced in the block diagram. Further, we remember that the powers in the single-area diagram were expressed in per unit of area rating. The parameters R, D and H, likewise were based on the same base power. When two or more areas of different ratings, are involved, we must refer all powers and parameters to the one chosen base power.

The above two equations tell us, in a nutshell, the advantages of pool operation:

1. The frequency drop will be only half that would be experienced if the areas were operating alone.

2. 50% of the added load in area 2 will be supplied by area 1 via. the tie-line.

TIE-LINE BIAS CONTROL FOR TWO-AREA SYSTEM

The persistent static frequency error is intolerable. Also, a persistent static error in tie-line power flow would mean that one area would have to support the other on a steady state basis. To circumvent this, some form of reset integral control must be added to the two-area system. The control strategy of “tie-line bias control” is based upon the principle that all operating pool members must contribute their share to frequency control in addition to taking care of their own net interchange. This means that for two-area system, at steady state, both Δf_0 and $\Delta P12\ _0$ must be zero. To achieve these objectives, the Area Control Error (ACE) for each area consists of a linear combination of frequency and tie-line error. Thus

$$ACE_1 = \Delta P_{12} + B_1\ \Delta f_1$$

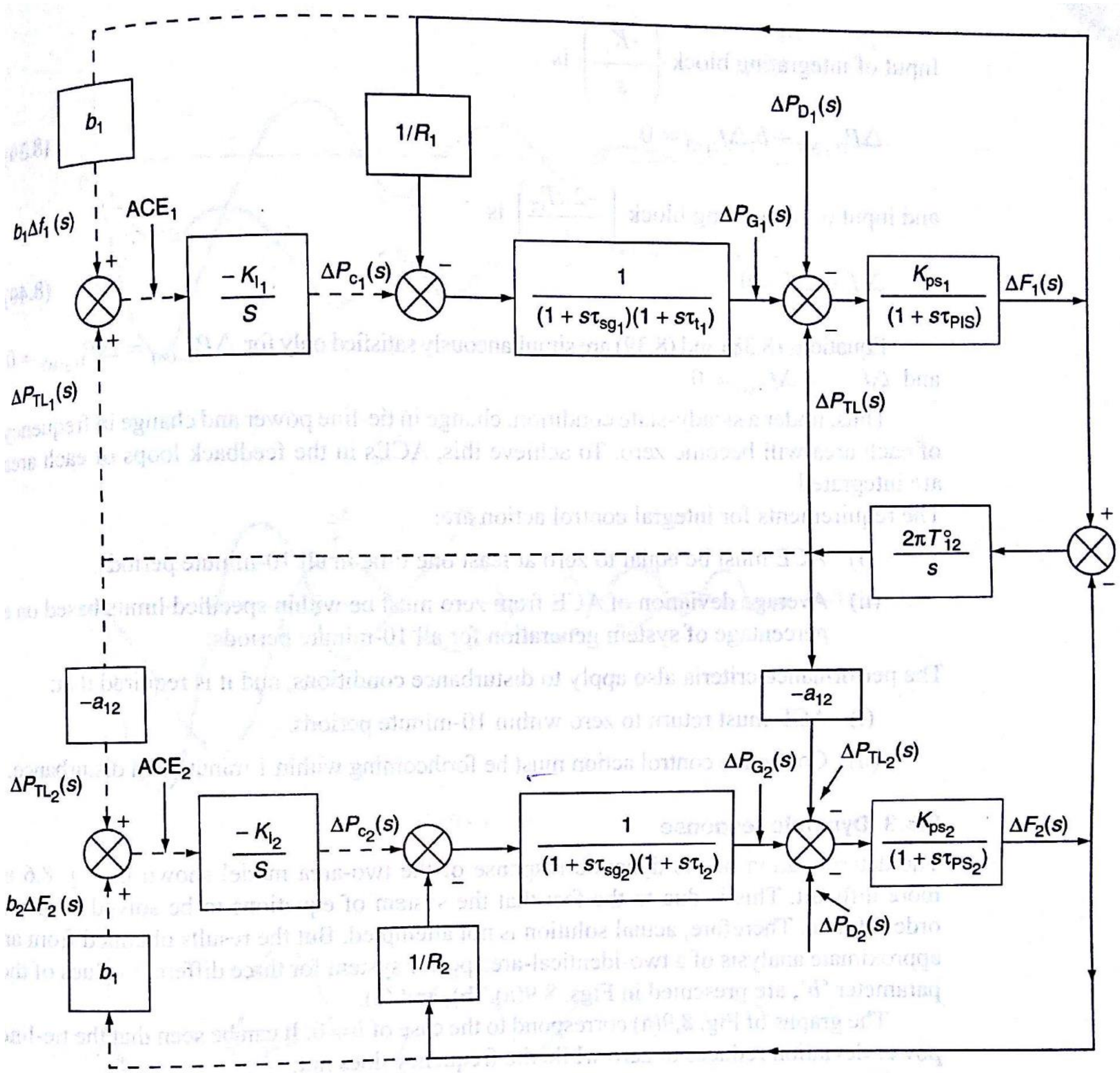
$$ACE_2 = \Delta P_{21} + B_2\ \Delta f_2$$

The speed changer commands will thus be of the form

$$\Delta Pref\ 1 = - KI1 \int (\Delta P_{12} + B_1\ \Delta f_1)\ dt$$

$$\Delta Pref\ 2 = - KI2 \int (\Delta P_{21} + B_2\ \Delta f_2)\ dt$$

The constants KI 1 and KI 2 are integrator gains and the constants B1 and B2 are the frequency bias parameters. The minus sign must be included to ensure that, if there is positive frequency deviation or tie-line power deviation, then each area should decrease its generation



ΔPref 1 (s) = $-\frac{KI1}{s}$– [ΔP12 (s) + B1 Δf1 (s)];ΔPref 2 (s) = $-\frac{KI2}{s}$– [ΔP21 (s) + B2 Δf2 (s)]

UNIT-6

Reactive power and emergency control

Objectives:

- Study the reactive power and emergency control.
- Know the importance of voltage control and different methods to control it.
- Concepts of reliability, security and transient stability.
- Long term frequency dynamics analysis.

Micro syllabus: reactive power control, voltage control methods, concepts of reliability, security and transient stability transient stability enhancement methods, long term frequency analysis.

Outcomes:

Students will be able to:

- Understand the importance of different voltage control.
- Analyze transient stability enhancement methods
- do long term frequency analysis.

In an ideal AC power system, the voltage and the frequency at every supply point would remain constant, free from harmonics and the power factor would remain unity.

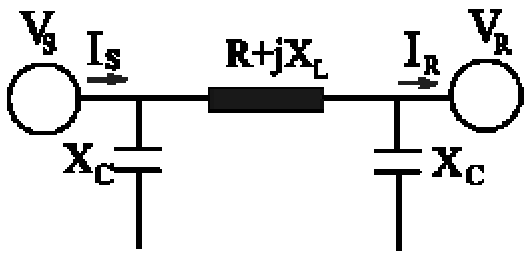
Most electrical power systems in the world are interconnected to achieve reduced operating cost and improved reliability with lesser pollution. In a power system, the power generation and load must be balanced at all the times. If an unbalance between power generation and load occurs, then it results in a variation in the voltage and the frequency.

The quality of supply should be maintained. Here, the quality of supply means maintaining constant voltage magnitude and frequency under all loading conditions. It is also desirable to maintain the three phase currents and voltages as balanced as possible so that under heating of various rotating machines due to unbalancing could be avoided.

In a three phase system, the degree to which the phase currents and voltages balanced must also be taken into consideration to maintain the quality of supply.

Relation between reactive power and voltage.

The equation of power flow relates the power transfer between two buses and the electrical data of the system. The electrical data comprises the receiving and sending bus voltages, the power angle between the two buses and the series impedance and natural capacitance of the transmission line connecting the two buses. We consider the model shown below for a transmission line and we express the reactive power at the two ends as a function of the voltages VS and VR and the characteristic of the line (R, XL, XC).



Using the phasor representation (bar symbol above the respective quantity) we have for the voltages

$$\overline{V}_S = \overline{V}_R + \overline{I}_R \overline{Z} - \frac{\overline{V}_R \overline{Z}}{\overline{X}_C}$$

$$\overline{V}_R = \overline{V}_S - \overline{I}_S \overline{Z} + \frac{\overline{V}_S \overline{Z}}{\overline{X}_C}$$

and for the currents

$$\overline{I}_S = \frac{\overline{V}_S}{\overline{X}_C} + \frac{\overline{V}_S - \overline{V}_R}{\overline{Z}}$$

$$\overline{I}_R = -\frac{\overline{V}_R}{\overline{X}_C} + \frac{\overline{V}_S - \overline{V}_R}{\overline{Z}}.$$

The complex power for each end can be calculated by multiplying the voltage with the complex conjugate of the corresponding current. As we are interested to evaluate the reactive power Q (according with our definition the amplitude of the instantaneous reactive power), we take the complex part of the complex powers which are

$$Q_S = \frac{V_S}{Z^2}\Big[V_S X_L - X_L V_R \cos\theta + R V_R \sin\theta - \frac{V_S}{X_C} Z^2\Big]$$

$$Q_R = \frac{V_R}{Z^2}\Big[-V_R X_L + X_L V_S \cos\theta - R V_S \sin\theta + \frac{V_R}{X_C} Z^2\Big].$$

Considering a small resistance comparative with the inductance (R<<<L) This assumption does not affect the results as the reactive power is stored, absorbed or produced by the reactive part of the network (inductance or capacitance). The simplified equations for the reactive power at the two ends are then

$$Q_S = \frac{V_S^2 - V_S V_R \cos\theta}{X_L} - \frac{V_S^2}{X_C}$$

$$Q_R = \frac{-V_R^2 + V_S V_R \cos\theta}{X_L} + \frac{V_R^2}{X_C}.$$

So far the standard procedure followed by textbooks to introduce the power flow equations was followed. As Q_R and Q_S are not equal, the reactive power loss is introduced as the difference of the two expressions

$$\Delta Q_{loss} = Q_S - Q_R.$$

Different voltage control methods

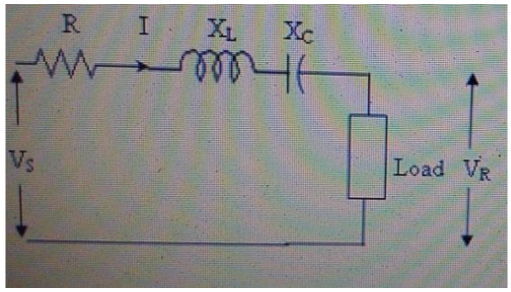
The different voltage control methods are:

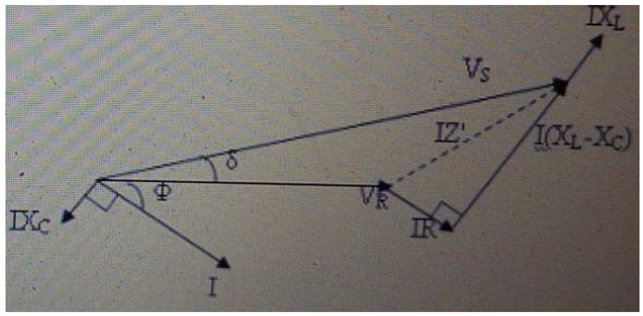
1. Shunt and series compensation
2. On-load tap changing transformer
3. Booster transformer
4. Alternator voltage regulator

Shunt and Series Compensation:

Shunt capacitors are used for leading power factor circuits whereas reactors are used for leading power factor circuits such as those created by lightly loaded conditions. In both cases, the effect is to supply the required reactive power to maintain the values of the voltage. Apart from synchronous machines, static shunt capacitors offer the cheapest means of reactive power supply but these are not flexible as synchronous condensers.

Capacitors are installed in series with transmission lines in order to reduce voltage drop in line by reducing voltage drop. The series capacitors compensate the reactance voltage drop in the line by reducing net reactance. A capacitor in series with a transmission line serving a lagging power factor load will cause a rise in voltage as the load increases. The power factor of the load through the series capacitor and line must be lagging if the voltage drop is to decrease appreciably. The voltage on the load side of the series capacitor is raised above the source side, acting to improve voltage regulation of the feeder. Since the voltage rise or drop occurs instantaneously with variations in the load, the series capacitor response as a voltage regulator is faster and smoother than the regulators. The main drawback of the capacitor is the high voltage produced across the capacitor terminals under short-circuit conditions. The drop across the capacitor is $I_f X_c$. where I_f is the fault current which is many times the full-load current under certain circuit conditions. It is essential, therefore that the capacitor is taken out of service as quickly as possible. A spark gap with a high-speed contactor can be used to protect the capacitor under these conditions.





Comparison of series and shunt capacitors

Shunt capacitors:

1. Supplies fixed amount of reactive power to the system at the point where they are installed. Its effect is felt in the circuit from the location towards supply source only.
2. It reduces the reactive power flowing in the line and causes improvement of power factor of a system, voltage profile improvement, decreases KVA loading on source, i.e generators, transformers and line up to location and thus provides an additional capacity.
3. The location has to be as near to the load point as possible. In practice, due to the high compensation required, it is found to be economical to provide group compensation on lines and sub stations
4. As a fixed Kvar is supplied this may sometimes result in over compensation in the light-load period. Switched Kvar banks are comparatively costlier than fixed Kvar and became necessary.
5. As the power factor approaches unity, large compensation is required for the improvement of power factor.
6. This compensation is required when lines are heavily loaded.
7. Cost of compensation is lower than that of the cost required for series capacitor.

Series capacitors:

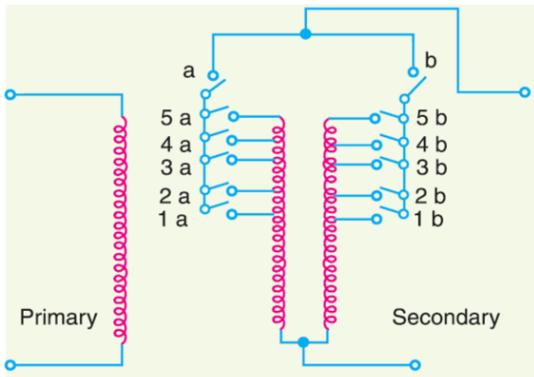
1. Quantum of compensation is independent of load current and instantaneous changes occur. Its effect is from its location towards the load end.
2. It is effective, on the lines the power transfer is greater and specifically, suitable for situations when flickers due to respective load functions occur.
3. As a thumb rule, the best location is one third of electrical impedance from the source bus.
4. As full-load current is to pass through, the capacity should be more than the load current.
5. As series capacitors carry fault current special protection is required to protect from fault current.
6. It causes sudden rise in voltage at the location.
7. Cost of a series capacitor is higher than that of a shunt capacitor.

Tap- changing transformers:

A tap changing transformer is a static device having a number of tap settings on its secondary side for obtaining different secondary voltages. The basic function of this device is to change the transformation ratio, where by the voltage in the secondary circuit is varied making possible voltage control at all voltage levels at any load. The supply may not be interrupted when tap changing is done with and without load. There are two types of tap-changing transformers, they are off-load tap-changing transformers and on-load tap-changing transformer.

On-load tap-changing transformers:

To supply uninterrupted power to the load, tap-changing has to be performed when the system is on load. The secondary winding in a tap-changing transformer consists of two identical parallel windings with similar tapings. For example, 1,2,3……N. and 1^1,2^1,3^1…. N^1 are the tapings on both the parallel windings of such a transformer. These two parallel windings are controlled by switches S_a and S_b as shown below.



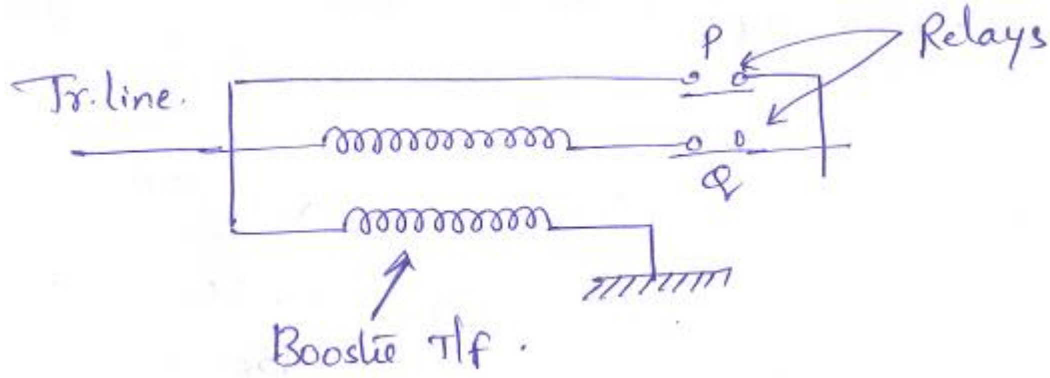
In the normal operating conditions, switches S_a, S_b and tapings 1 and $1^1$are closed i.e both the secondary windings of the transformer are connected in parallel and each winding carries half of the total load current by an equal sharing. The secondary side of the transformer is ta a rated voltage under no load, when the switches S_a and S_b are closed and movable arms make contact with stud 1 and 1^1, whereas it is maximum (above the rated value) under no load, when the movable arms are in position N and N^1. The voltage at the secondary terminal decreases with an increase in the load. To compensate for the decreased voltages, it is required to change switches from position 1 and 1^1 to positions 2 and 2^1 (number of turns on the secondary is decreased) for this, open any one of the switches S_a and S_b, assuming that S_a is opened. At this instant, the secondary winding controlled by switch S_b carries full load current through one winding. Then, the tapings is changed to position 2 on the winding of the disconnected transformer and close the switch S_a. after this, switch S_b is opened for disconnecting its winding and change the taping position from 1^1 and 2^1 and then switch S_b is closed. . similarly, taping position can be changed without interrupting the power supply to the consumers.

Disadvantages:

1. It requires two windings with rated current-carrying capacity instead of one winding.
2. It requires two operations for the change of a single step
3. Complications are introduced in the design in order to obtain a high reactance between the parallel windings.

Booster transformer:

The booster transformer performs the function of boosting the voltage. It can be installed at a sub-station or at any intermediate point if time. In the circuit, there will be two relays P and Q. The secondary of the booster transformer is connected in series with the line whose voltage is to be controlled, and the primary of the booster transformer is supplied from a regulating transformer with on-load-tap changing gear. The booster can be brought in to the circuit by the closure of relay Q and opening of P and vice-versa. The secondary of the booster transformer injects a voltage in phase with the line voltages. By changing the tapping on the regulating transformers, the magnitude can be changed and thus the feeder voltage can be regulated.



Advantages:

1. It can be installed at any intermediate point in the system.
2. The rating of the booster transformer is about 10% of the main transformer.

Disadvantages:

When used in conjunction with main transformer

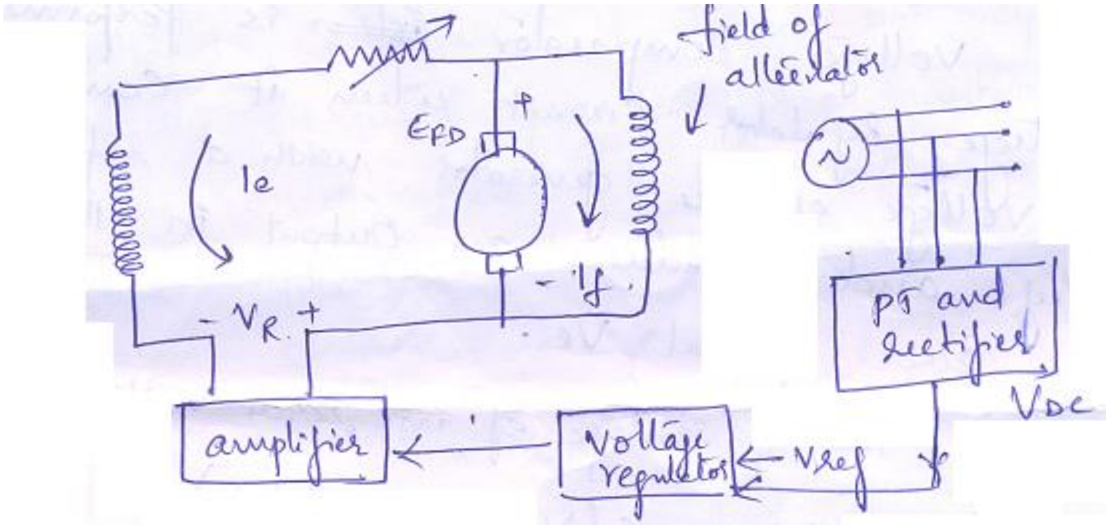
1. More expensive than a transformer with on load tap changes
2. Less efficient due to losses in booster.
3. Requires more space.

AVR (Alternator Voltage Regulator):

The excitation system consists of an exciter and an automatic voltage regulator (AVR). An exciter provides the required field current to the rotor winding of the alternator. The simplest form of an excitation system is an exciter only. When the task of the system becomes maintaining the constant terminal voltage of an alternator during variable load conditions, it incorporates the voltage regulator. The voltage regulator senses the requirement from the terminal voltage of the alternator and actuates the exciter for the necessary increasing or decreasing of the voltage across the alternator field.

An AVR in conjunction with the exciter tries to maintain constant terminal voltage of an AC generator. The voltage regulator, in fact, couples the output variables of the synchronous generator to the input of the exciter through feedback and forwarding elements for the purpose of regulating the synchronous machine output variables. Then, the voltage regulator may be assumed to consist of an error detector, pre-amplifier, power amplifier, stabilizers, compensators, auxiliary inputs and limiters. The voltage regulator is treated as the heart of an excitation system. Exciter and regulator constitute an excitation system, exciter, regulator and an synchronous generator constitute a system known as the excitation control system.

A typical excitation control scheme is shown. The field winding of an alternator is connected to the exciter. The alternator terminal voltage is rectified by means of a potential transformer and rectifier and is fed to a voltage regulator. A voltage regulator compares the rectified output voltage with a reference voltage v_{ref}. The error signal output from the voltage regulator is amplified by an amplifier and the amplifier output voltage is fed to the exciter field winding.



There is no error signal output from the regulator and the field winding current of exciter ie is constant when the output voltage of an alternator is at a nominal value.

When the load on the alternator varies, the terminal voltage also varies. Hence, the error signal can be produced by the regulator, amplified and fed to the field winding of the exciter. The field winding current of the exciter is varied and hence the terminal voltage reaches the required level. A voltage comparator action is performed in a voltage regulator circuit when it compares the DC voltage of the generator with a reference voltage $V_{ref}$and produces an output in the form of an error signal V_e.

The output voltage of an error signal $V_e$is

$V_e(s)= k(V_{ref}(s)-V_{dc}(s))$

Concepts of reliability, security and transient stability:

Power system failures or emergencies can built slowly over minutes and even hours. They can also strike suddenly and damage the system within seconds. As the power systems are exposed to the natural forces of nature it is impossible to design them completely failure safe.

Reliability and security are two separate concepts by means of which one attempts to measure the robustness of power system against disturbances.

Reliability is an index defined as the long-term average number of days on which daily peak load exceeds the available generating capacity. Determining the reliability is thus considered as a mathematical problem of computing the probability for generated power to reach the load in a given system. Reliability will not change with time and its achievement becomes a system planning problem. It is a mathematical definition in terms of probabilities, security is an operational problem that will change with operational conditions. It depends not only on the reserve capacity available in a given situation but also on the disturbances. A typical feature of power system security is its cumulative deterioration resulting from sequence of events.

Transient stability is a concept often used in assessing robustness. A system is said to be transient stable if all its generations are kept operating in a parallel synchronous mode.

Preventive and emergency control:

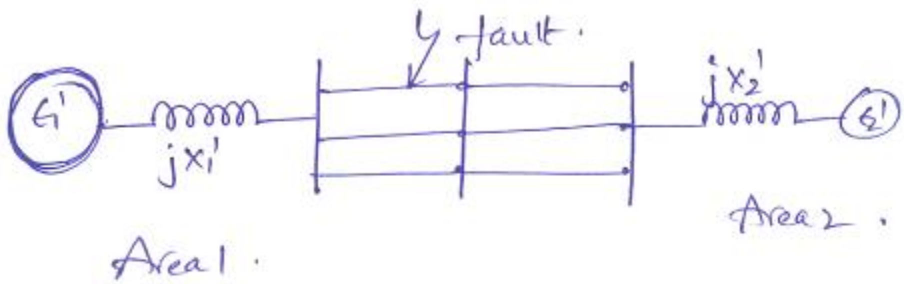
In the normal state the system is secure. In this state both equality and inequality constraints are satisfied. Equality means that the total system generation equal total system load. Inequality refers to currents and voltages being kept within rated limits. If the system has got some problem called first contingency the system enters the alert state. Thee security level now falls below some threshold and the system is insecure, both equality and inequality constraints are observed. If a second problem or another contingency may cause over load in the system, then system enters the emergency state. Note that the equality constraints are observed. When the generation is no longer in track, system disintegrates and the extremist state is reached. In this point, events usually follow rapid sequence. If the system reaches the alert state prevention controls are taken to restore the system to normal state. Such control action may consist of startup of reserve generation or putting in service other equipment. If these actions prove inadequate or if another problem push the system in to emergency state then collectively emergency controls would be initiated. Load shedding being the most common method. These control actions center, either automatically or by operator intervention. If speed of action is of extreme importance the control actions are implemented through local means.

Transient stability analysis

1) **Coherent area dynamics:**

Figure below depicts two regional networks interconnected by relatively long tie-lines. Area 1 has a generating capacity of 20 GW but a load demand of only 18GW. Area 2 has 20GW of generation but a load demand of 22GW. By interconnecting the two areas with one or several tie-lines, area 1 will be able to export on a continuing basis of 2GW power to area 2

Assume that a fault occurs that results in total or partial loss of the ties causing a sudden total or partial interruption of the power flow. As a consequence, area 1 generators will experience an acceleration those in area 2 will decelerate. These power swings that will ensue, are referred to as inter area oscillations or coherent area dynamics.



2) **Stability enhancement methods:**

The methods which are proposed is to reduce the acceleration property during the fault so that area of acceleration is less than deceleration and the synchronous machine will become stable.

a) Selection of MI value:

In order to maintain the transient stability of a synchronous machine the MI of the machine should be larger so that the swinging of the machine should be less and the acceleration area of the machine will be reduced, in modern power systems it is preferred to have larger 500 MW and above for the purpose of stability

b) Selection of the speed of circuit breaker:

Speed of the circuit breaker operation is inversely proportional to time of the operation. If time of operation is less, the speed of operation is high so that acceleration period will be reduced and the synchronous machine is stable. In a modern power system network, it is preferred to install SF6 circuit breaker.

c) Speed of operation of speed governor:

We know that the output of the machine is reduced during the fault so that the synchronous machine will experience acceleration. In order to reduce, the mechanical input is to be reduced by reducing the time of operation of the speed governor for which the speed should be designed with electronic devices.

d) Excitation control:

The short circuit is inductive in nature which will result as the excitation voltage of the generator reduced and the machine accelerates. In order to reduce the acceleration the output of the machine is to be increased by compensating fall in excitation voltage for which AVR's are to be employed.

Series capacitor used for steady state stability is also very much helpful to improve the transient stability by reducing to improve the transient stability by reducing the net reactance so that the electrical output will be increased and the accelerating property will be reduced. During unsymmetrical faults or unbalanced faults single pole circuit breaker and dynamic resistance switching or grounding is helpful.

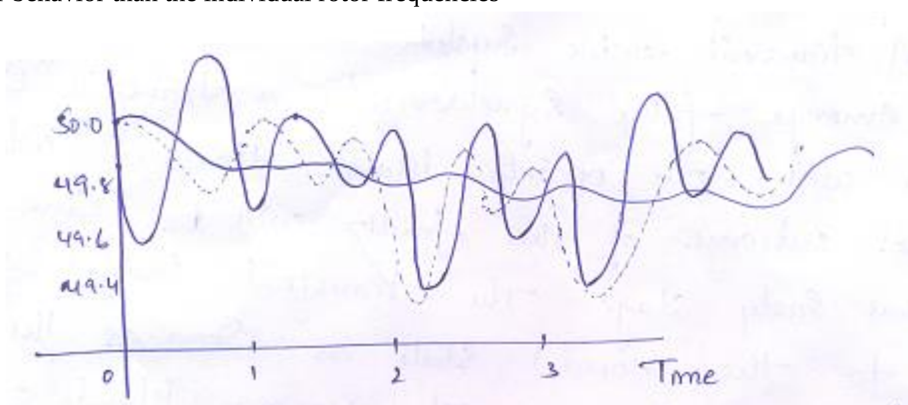
Long term frequency dynamics

A transient stable system will ride through the fault and emerge fully synchronized. A transient unstable system will split up into islands. However, what the eventual outcome of the fault will be cannot ascertained at this early stage. The transient stable system may return to the normal state as soon as the rotors swings have subsided. The various islands forms in the transient unstable case may be kept individually operating later to be synchronized and returned perhaps to its pre-fault normal state, without the loads having been greatly affected by the fault.

The severity of the power imbalance that will be caused by the initial fault will greatly affect the final outcome. The imbalance will cause a change in frequency, the frequency deviations may well assume magnitudes that will cause automatic generator tripping and other major equipment outages. The frequency behavior will thus become a very important secondary fault. Often it may take minutes, even hours, for the frequency to fully stabilize. By studying these long-term frequency dynamics simulation one can learn of their causes and how best to control them.

1) **Average system frequency:**

Figure reveals that after about one second in to the post fault state one can draw the conclusion that the system is transient stable. The individual generators are still swinging against each other but they are holding together. If we were to plot in this figure an average area frequency we should find it a much smoother behavior than the individual rotor frequencies



2) **Center of inertia:**

In this principle, a frequency simulation study could be performed by extending the integration of the generator swing equation beyond the initial transient period and focusing on angular frequency rather than machine angle

The machine angle $\delta_i$of generator i is measured relative to a reference frame rotating at the constant radian frequency ω^o. the instantaneous radian frequency $\omega_i$measured at the generator terminals equals

$\omega_i = \omega^o + \dot{\delta}_i$rad/s

if to be expressed in hertz then $f_i = f^o + (1/2\pi)\dot{\delta}_i$hz

$$\dot{\omega}_i = \ddot{\delta}_i = 2\pi\dot{f}_i$$

We know from swing equation that

Pacc= $P_T - P_G = H/(\pi f^o)\, d^2\delta/dt^2 = H/(\pi f^o)\, 2\pi\dot{f}_i$

By using this the n individual differential equations describing the n individual and fast changing frequencies have been aggregated in to one differential equation describing the slow changing area frequency