PPT ON
POWER SYSTEM OPERATION AND CONTROL
VII SEM (IARE-R16)

UNIT 1
ECONOMIC OPERATION OF POWER SYSTEMS

Optimization Problem

Allocation of load (MW) among the various units of generating station and among the various generating stations in in such a way that, the overall cost of generation for the given load demand is minimum.

The objective of which is to minimize the power generation cost function subject to the satisfaction of a given set of equality and inequality constraints

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NEED FOR UNIT COMMITMENT

- Enough units will be committed to supply the system load

To reduce the loss or fuel cost .

- By running the most economic unit, the load can be supplied by that unit operating closer to its best efficiency.
- Difficulties to find unit commitment solution Time consuming process
- If the umber of units is more, the number of combinations is more in a complex bus system
- If n be the number of units, then the number of combinations will be 2n-1

Unit Commitment

Power systems have grown in size and complexity. In power system, the total generation on the system will generally be higher than total load on the system. The total load on the system will generally be higher during the day time and early evening and lower during the early morning and late evening. It is not economical to run all the units available all the time. So, the commitment of a generating unit is difficult. The cost of the system can be saved by turning off generators when they are not needed.

Characteristics of thermal units

- Input-Output Curve

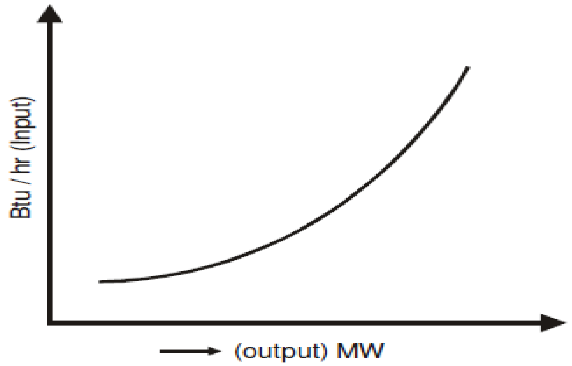


Fig 1: Input – output curve

- Incremental Fuel Rate Curve

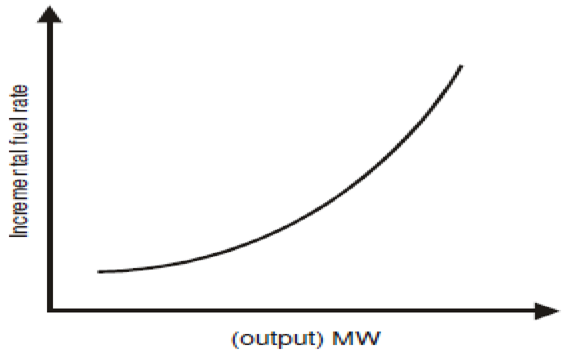
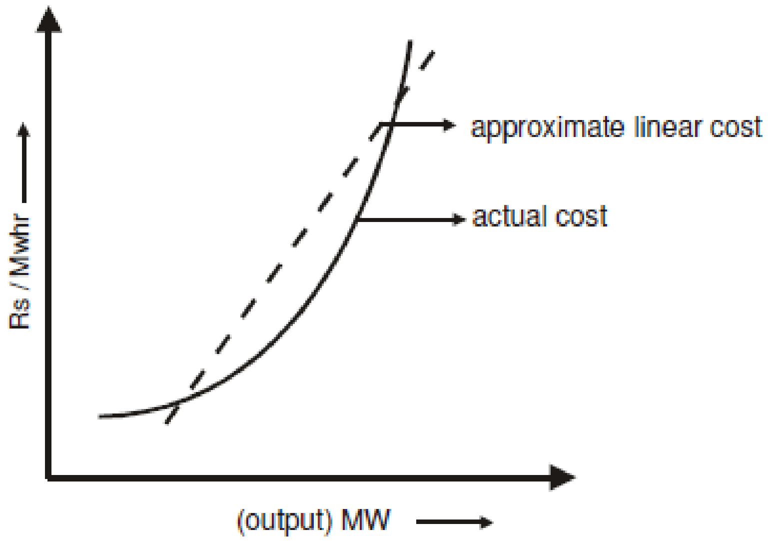


Fig 3: Incremental fuel rate curve

Cont..

- Incremental cost curve



OBJECTIVE FUNCTION AND CONSTRAINTS FOR THE ECONOMIC DISPATCH PROBLEM

As discussed earlier, the ED problem deals with the optimal allocation of total load demand PD amongst n-number of units. The objective function for the ED problem is presented below
The problem is to minimize the function Eq.(1.3) subject to the satisfaction of constraints.

$$C_{\text{Total}} = f\,(P_{G1}, P_{G2}, \ldots , P_{Gn}) \qquad (1.3)$$

The ED problem may be treated as parameter (cost) optimization subject to the satisfaction of system constraints. System constraints are of two types:

- Equality constraints,
- Inequality constraints.

Equality constraints

- The equality constraints *g(x)* of the ELD problem are represented by the power balance constraint, where the total power generation must cover the total power demand and the power loss. This implies solving the load flow problem, which has equality constraints on active and reactive power at each bus as follows

$$P_i = P_{gi} - P_{di} = \sum_{j=1}^{n} V_i . V_j \left(G_{ij} \cos\theta_{ij} + B_{ij} \sin\theta_{ij} \right)$$

$$Q_i = Q_{gi} - Q_{di} = \sum_{j=1}^{n} V_i . V_j \left(G_{ij} \sin\theta_{ij} - B_{ij} \cos\theta_{ij} \right)$$

- where: $i=1,2,\ldots, n$ and $\vartheta_{ij} = \vartheta_i - \vartheta_j$; P_i, Q_i: injected active and reactive power at bus *I*; P_{di}, Q_{di}: active and reactive power demand at bus *i*; V_i, ϑ_i: bus voltage magnitude and angle at bus *i*; G_{ij}, B_{ij}: conductance and susceptance of the *(i,j)* element in the admittance matrix.

Inequality constraints

- The inequality constraints *h(x)* reflect the limits on physical devices in the power system as well as the limits created to ensure system security
- Upper and lower bounds on the active and reactive generations:

$$P_{gimin} \leq P_{gi} \leq P_{gimax}, \quad Q_{gimin} \leq Q_{gi} \leq Q_{gimax}$$

- Upper and lower bounds on the tap ratio (t) and phase shifting (α) of variable transformers

$$t_{ijmin} \leq t_{ij} \leq t_{ijmax}, \quad \alpha_{ijmin} \leq \alpha_{ij} \leq \alpha_{ijmax}$$

- Upper limit on the active power flow (Pij) of line i-j:

$$|P_{ij}| \leq P_{ijmax} \qquad P_{ij} = \left| -G_{ij}V_i^2 + G_{ij}V_iV_j\cos(\theta_i - \theta_j) + B_{ij}V_iV_j\sin(\theta_i - \theta_j) \right|$$

- Upper and lower bounds on the bus voltage magnitude:

$$V_{imin} \leq V_i \leq V_{imax}$$

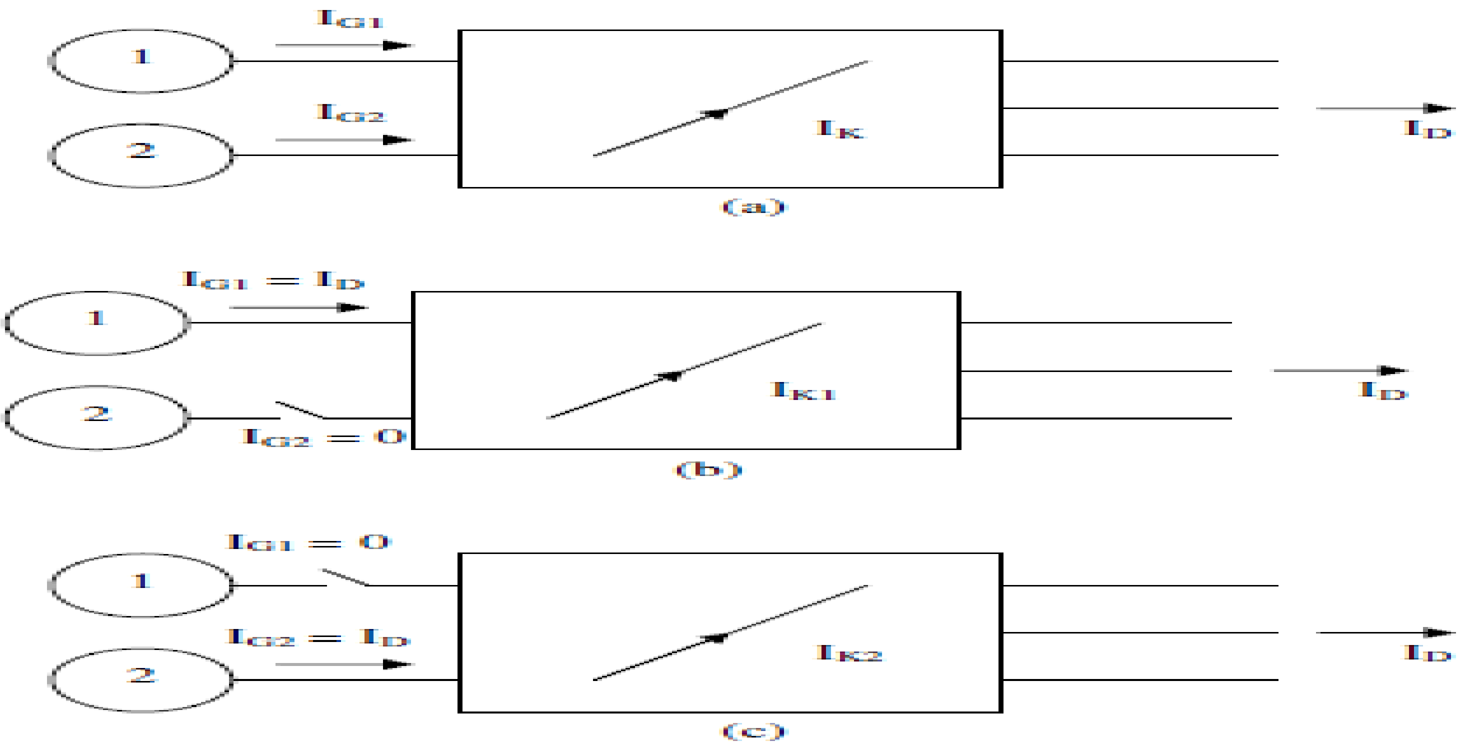
DERIVATION OF TRANSMISSION LOSS FORMULA

An accurate method of obtaining general loss coefficients has been presented by Kroc. The method is elaborate and a simpler approach is possible by making the following assumptions:

(i) All load currents have same phase angle with respect to a common reference

(ii) The ratio X / R is the same for all the network branches

Consider the simple case of two generating plants connected to an arbitrary number of loads through a transmission network as shown in Fig a



Plants connected to a number of loads through a transmission network

- Let's assume that the total load is supplied by only generator 1 as shown in Fig 8.9b. Let the current through a branch K in the network be IK1. We define

$$N_{K1} = \frac{I_{K1}}{I_D}$$

- It is to be noted that IG1 = ID in this case. Similarly with only plant 2 supplying the load

Current ID, as shown in Fig 8.9c, we define

$$N_{K2} = \frac{I_{K2}}{I_D}$$

Cont..

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

Where σ_1 and σ_2 are phase angles of IG1 and IG2 with respect to a common reference. We can write

$$|I_K|^2 = \left(N_{K1}|I_{G1}|\cos\sigma_1 + N_{K2}|I_{G2}|\cos\sigma_2\right)^2 + \left(N_{K1}|I_{G1}|\sin\sigma_1 + N_{K2}|I_{G2}|\sin\sigma_2\right)^2$$

$$= \begin{matrix} N_{K1}{}^2|I_{G1}|^2\left[\cos^2\sigma_1 + \sin^2\sigma_1\right] + N_{K2}{}^2|I_{G2}|^2\left[\cos^2\sigma_2 + \sin^2\sigma_2\right] \\ + 2\left[N_{K1}|I_{G1}|\cos\sigma_1 N_{K2}|I_{G2}|\cos\sigma_2 + N_{K1}|I_{G1}|\sin\sigma_1 N_{K2}|I_{G2}|\sin\sigma_2\right] \end{matrix}$$

$$= N_{K1}{}^2|I_{G1}|^2 + N_{K2}{}^2|I_{G2}|^2 + 2N_{K1}N_{K2}|I_{G1}||I_{G2}|\cos(\sigma_1 - \sigma_2)$$

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

Where PG1, PG2 are three phase real power outputs of plant1 and plant 2; V1, V2 are the line to line bus voltages of the plants and Φ_1 and Φ_2 are the power factor angles. The total transmission loss in the system is given by

$$P_L = \sum_K 3|I_K|^2 R_K$$

Where the summation is taken over all branches of the network and RK is the branch resistance. Substituting we get

$$P_L = \frac{P_{G1}^{\,2}}{|V_1|^2(\cos\phi_1)^2}\sum_K N_{K1}^{\,2} R_K + \frac{2P_{G1}P_{G2}\cos(\sigma_1-\sigma_2)}{|V_1||V_2|\cos\phi_1\cos\phi_2}\sum_K N_{K1}N_{K2}R + \frac{P_{G2}^{\,2}}{|V_2|^2(\cos\phi_2)^2}\sum_K N_{K2}^{\,2} R_K$$

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

where $$B_{11} = \frac{1}{|V_1|^2(\cos\phi_1)^2}\sum_K N_{K1}^{\,2} R_K$$

$$P_L = \sum_{p=1}^{n} \sum_{q=1}^{n} P_{Gp} B_{Pq} P_{Gq}$$

$$B_{Pq} = \frac{\cos(\sigma_p - \sigma_q)}{|V_p||V_q| \cos\phi_p \cos\phi_q} \sum_K N_{KP} N_{Kq} R_K$$

Coefficients can be treated as constants over the load cycle by computing them at average operating conditions

When the transmission losses are included in the economic dispatch problem

$$P_T = P_1 + P_2 + \cdots + P_N - P_{LOSS}$$

$$0 = dP_1 + dP_2 + \cdots + dP_N - dP_{LOSS}$$

Where P_{LOSS} is the total line loss. Since P_T is assumed to be constant, we have

$$dP_{LOSS} = \frac{\partial P_{LOSS}}{\partial P_1} dP_1 + \frac{\partial P_{LOSS}}{\partial P_2} dP_2 + \cdots + \frac{\partial P_{LOSS}}{\partial P_N} dP_N$$

In the above equation dP_{LOSS} includes the power loss due to every generator, i.e.,

Also minimum generation cost implies $df_T = 0$ as given in (1.5). Multiplying both (2.2) and (2.3) by λ and combining we get

$$0 = \left(\lambda \frac{\partial P_{LOSS}}{\partial P_1} - \lambda\right) dP_1 + \left(\lambda \frac{\partial P_{LOSS}}{\partial P_2} - \lambda\right) dP_2 + \cdots + \left(\lambda \frac{\partial P_{LOSS}}{\partial P_N} - \lambda\right) dP_N$$

$$0 = \sum_{i=1}^{N} \left(\frac{\partial f_T}{\partial P_i} + \lambda \frac{\partial P_{LOSS}}{\partial P_i} - \lambda \right) dP_i$$

Adding above equations we obtain

$$\frac{\partial f_T}{\partial P_i} + \lambda \frac{\partial P_{LOSS}}{\partial P_i} - \lambda = 0, \quad i = 1, \ldots, N$$

The above equation satisfies when

$$\frac{\partial f_T}{\partial P_i} = \frac{d f_T}{d P_i}, \quad i = 1, \ldots, N$$

Cont..

$$\lambda = \frac{df_1}{dP_i} L_1 = \frac{df_2}{dP_2} L_2 = \cdots = \frac{df_N}{dP_N} L_N$$

From above two equations

$$L_i = \frac{1}{1 - \partial P_{LOSS} / \partial P_i}, \quad i = 1, \ldots, N$$

Where L_i is called the **penalty factor** of load- *i* and is given by

Consider an area with *N* number of units. The power generated are defined by the vector

$$P_{LOSS} = P^T B P \qquad B = \begin{bmatrix} B_{11} & B_{12} & \cdots & B_{1N} \\ B_{12} & B_{22} & \cdots & B_{2N} \\ \vdots & \vdots & \ddots & \vdots \\ B_{1N} & B_{2N} & \cdots & B_{NN} \end{bmatrix}$$

Problems

- **There is a simple two units system including two very similar units that have the following input-output cost function and incremental cost function**

$$F_1 = 8P_1 + 0.024P_1^2 + 80$$

$$F_2 = 8.2P_2 + 0.025P_2^2 + 82$$

Economic dispatch

This is mathematically given as

$$\min F = \sum_{i=1}^{N} F_i(P_i)$$

$$\sum_{i=1}^{N} P_i - P_D = 0$$

$$P_{imin} \le P_i \le P_{imax} \qquad i = 1, \ldots\ldots\ldots, N$$

where

F is the operating cost,

N is the number of generating units,

P_i is the power output of i th generating unit,

$F_i(P_i)$ is the individual fuel cost function of i th generating unit,

P_D is the demand,

P_{imin} is the i th generating unit's minimum output,

P_{imax} is the i th generating unit's maximum output.

The fuel cost function or input-output characteristic of the generator maybe obtained from design calculations or from heat rate tests. The fuel cost function of generator that usually used in power system operation and control problem is represented with a second-order polynomial.

$$F_i(P_i) = a_i + b_i P_i + c_i P_i^2 \qquad (7.16)$$

where a_i , b_i and c_i are non-negative constants of the i th generating unit. For some generator such as large steam turbine generators, however, the input-output characteristic is not always smooth. Large steam turbine generators will have a number of steam admission values that are opened in sequence to obtain ever-increasing output of the unit. This kind of unit's input-output curve is shown in Fig. 1. The fuel cost function of this kind of unit can be expressed as

$$F_i(P_i) = a_i + b_i P_i + c_i P_i^2 + \left| e_i \sin(f_i(P_{i\,\min} - P_i)) \right| \qquad (7.17)$$

The dynamic economic dispatch is one of the main functions of power system operation and control. It is a method to schedule the online generator outputs with the predicted load demands over a certain period of time so as to operate an electric power system most economically while the system is operating within its security limits. This problem is a dynamic optimization problem taking into account the constraints imposed on the system operation by generator ramping rate limits. The dynamic economic dispatch is not only the most accurate formulation of the ED problem but also the most difficult to solve because of its large dimensionality.

The problem can be mathematically formulated as follows.

$$\text{Min F} = \sum_{t=1}^{T}\sum_{i=1}^{N} F_{it}(P_{it}) \quad t = 1,\ldots\ldots,T \tag{6}$$

Subject to

(i) Power Balance constraint

$$\sum_{i=1}^{N} P_{it} - P_D = 0 \qquad i = 1,\ldots\ldots\ldots,N \tag{7}$$

(ii) Unit capacity Constraints

$$P_{it\,\min} \le P_{it} \le P_{it\,\max} \qquad i = 1,\ldots\ldots\ldots,N \quad t = 1,\ldots\ldots\ldots,\mathrm{T} \tag{8}$$

(iii) Ramp Rate constraints

$$\begin{aligned} P_{it} - P_{i(t-1)} &\le UR_i \\ P_{i(t-1)} - P_{it} &\le DR_i \end{aligned} \qquad i = 1,\ldots\ldots\ldots,N \quad t = 1,\ldots\ldots,T \tag{9}$$

Since dynamic economic dispatch was introduced, several optimization methods have been used to solve this problem.

Problem

Economic Dispatch:

1) Consider a three generator system

$$H_1 = 510.0 + 7.21\, P_1 + 0.0142\, P^2{}_1 \text{ MBtu/hr.}$$

$$H_2 = 310.0 + 7.85\, P_2 + 0.0194\, P^2{}_2 \text{ MBtu/hr.}$$

$$H_3 = 78.0 + 7.97\, P_3 + 0.0048\, P^2{}_3 \text{ MBtu/hr.}$$

The fuel cost are:

Unit 1: fuel cost = 1.1 Rs/MBtu $150 \leq P_1 \leq 600$

Unit 2: fuel cost = 1.0 Rs/MBtu $100 \leq P_1 \leq 400$

Unit 3: fuel cost = 1.0 Rs/MBtu $50 \leq P_1 \leq 200$

$$F_1 = H_1 \times \text{fuel cost}_1$$
$$=(510 + 7.2 P_1 + 0.00142 P_1^2) \times 1.1$$
$$F_1 = 561 + 7.92 P_1 + 0.001562 P_1^2) \qquad \rightarrow (1)$$

$$F_2 = H_2 \times \text{fuel cost}_2$$
$$F_2 = 310.0 + 7.85 P_2 + 0.00194 P_2^2 \qquad \rightarrow (2)$$

$$F_3 = H_3 \times \text{fuel cost}_3$$
$$F_3 = 78 + 7.97 P_3 + 0.00482 P_3^2 \qquad \rightarrow (3)$$

The total operating load $P_D = 850$ Mw

$$\therefore \; P_1 + P_2 + P_3 = 850 \qquad \rightarrow (4)$$

By lambda iteration method,

$$\frac{dF_1}{dP_1} = \frac{dF_2}{dP_2} = \frac{dF_3}{dP_3} = \lambda$$

for optimal generation scheduling

$$\frac{dF_1}{dP_1} = 7.92 + 0.003124\, P_1 = \lambda$$

$$\frac{dF_2}{dP_2} = 7.85 + 0.00388\, P_2 = \lambda$$

$$\frac{dF_3}{dP_3} = 7.97 + 0.00964\, P_3 = \lambda$$

$$P_1 = \frac{\lambda - 7.92}{0.003124}$$

$$P_2 = \frac{\lambda - 7.85}{0.00388}$$

$$P_3 = \frac{\lambda - 7.97}{0.00964}$$

Sub for P_1, P_2, P_3 in equation (4)

$$\frac{\lambda - 7.92}{0.003124} + \frac{\lambda - 7.85}{0.00388} + \frac{\lambda - 7.97}{0.00964} = 850$$

$$681.57\lambda - 5385.6706 = 850$$

$$\lambda = \frac{850 + 5385.6706}{681.57}$$

$$\boxed{\lambda = 9.148 \ \text{Rs / Mwhr}}$$

$$\therefore P_1 = \frac{9.148 - 7.92}{0.003124} = 393.08\,Mw$$

$$P_2 = \frac{9.148 - 7.85}{0.00388} = 334.5\,Mw$$

$$P_3 = \frac{9.148 - 7.97}{0.00964} = 122.2\,Mw$$

$$\boxed{P_1 = 393.08\,Mw, P_2 = 334.5\,Mw, P_3 = 122.2\,Mw}$$

2) Suppose the price of unit 1 is decreased to 0.9 Rs/Mwhr. Obtain the optimum schedule

Soln: The fuel cost function of unit 1 becomes:

$$F_1(P_1) = (510 + 7.2P_1 + 0.00142P_1^2) \times 0.9$$

$$F_1(P_1) = 459 + 6.48P_1 + 0.001278P_1^2$$

$$\therefore \frac{dF_1}{dP_1} = 6.48 + 0.00256P_1 = \lambda$$

$$P_1 = \frac{\lambda - 6.48}{0.00256}; \; P_2 = \frac{\lambda - 7.85}{0.00388}; \; P_3 = \frac{\lambda - 7.97}{0.00964}$$

Cont..

Sub for P_1, P_2, P_3 in equality constrain

$$P_1 + P_2 + P_3 = P_D = 850$$

$$\frac{\lambda - 6.48}{0.00256} + \frac{\lambda - 7.85}{0.00388} + \frac{\lambda - 7.97}{0.00964} = 850$$

$$752.1\lambda - 5381.21 = 850$$

$$\lambda = \frac{850 + 5381.21}{752.1} = 8.285$$

$$\boxed{\lambda = 8.285 \text{ Rs / Mwhr}}$$

Cont..

Schedule of units :

$$P_1 = \frac{\lambda - 6.48}{0.00256} = 705\,Mw$$

$$P_2 = \frac{\lambda - 7.85}{0.00388} = 112.1\,Mw$$

$$P_3 = \frac{\lambda - 7.97}{0.00964} = 32.67\,Mw$$

Both units P_1 and P_2 are found to violate the inequality constraints

$$P_1 = 600\,Mw\,;\; P_3 = 50Mw$$

$$P_2 = 850 - (650 + 50) = 200\,Mw$$

$$\boxed{P_1 = 600\,Mw\,;\; P_2 = 200\,Mw; P_3 = 50Mw}$$

$$\left.\frac{dF_1}{dP_1}\right|_{P_1=600} = 6.48 + 0.00256 \times 600$$

$$= 8.016 \, Rs / Mwhr$$

$$\left.\frac{dF_3}{dP_3}\right|_{P_3=50} = 7.97 + 0.00964 \times 50$$

$$= 8.452 \, Rs / Mwhr$$

$$\lambda_{new} = \frac{dF_2}{dP_2} = 7.85 + 0.00388 \times 200$$

$$= 8.626 \, Rs / Mwhr$$

For unit 1 and unit 3, the following conditions needs to be satisfied.

$$\frac{dF_1}{dP_1} \leq \lambda_{new} \text{ as } P_1 = P_{1max}$$

$$\frac{dF_3}{dP_3} \leq \lambda_{new} \text{ as } P_3 = P_{3min}$$

The first is satisfied, but 2 condition i.e. $\frac{dF_3}{dP_3} = 8.452 < \lambda_{new}$. Therefore, it cannot be fixed at the lower (minimum) limit.

Now let us fix $P_1 = 600$ Mw , do the economic dispatch for units 2 and units 3.

$$P_{D\,new} = P_D - P_1 = 850 - 600 = 250 \text{ Mw}$$

$$P_2 = \frac{\lambda - 7.85}{0.00388} \; ; \quad P_3 = \frac{\lambda - 7.97}{0.00964}$$

$$P_2 + P_3 = P_{D\,new}$$

$$\frac{\lambda - 7.85}{0.00388} + \frac{\lambda - 7.97}{0.00964} = 250$$

$$361.46\lambda - 2849.95 = 250$$

$$\boxed{\lambda = 8.576 \text{ Rs / Mwhr}}$$

The first is satisfied, but 2 condition i.e. $\frac{dF_3}{dP_3} = 8.452 < \lambda_{new}$. Therefore, it cannot be fixed at the lower (minimum) limit.

Now let us fix $P_1 = 600$ Mw , do the economic dispatch for units 2 and units 3.

$$P_{D\,new} = P_D - P_1 = 850 - 600 = 250 \text{ Mw}$$

$$P_2 = \frac{\lambda - 7.85}{0.00388} \quad ; \quad P_3 = \frac{\lambda - 7.97}{0.00964}$$

$$P_2 + P_3 = P_{D\,new}$$

$$\frac{\lambda - 7.85}{0.00388} + \frac{\lambda - 7.97}{0.00964} = 250$$

$$361.46\lambda - 2849.95 = 250$$

$$\boxed{\lambda = 8.576 \text{ Rs / Mwhr}}$$

Cont..

$$P_2 = \frac{8.576 - 7.85}{0.00388} = 187.17\,\text{Mw}$$

$$P_3 = \frac{8.576 - 7.97}{0.00964} = 62.86\,\text{Mw}$$

$$\left.\frac{dF_1}{dP_1}\right|_{P_1 = 600} = 8.016 \le 8.576\,(\lambda)$$

$\therefore$ Final gen :

$$\boxed{P_1 = 600\text{ Mw};\; P_2 = 187.17\text{ Mw}; P_3 = 62.86\text{ Mw}}$$

Problems

The fuel cost for a two unit steam power plant are given by

$C1 = 0.1\ P1^2 + 25\ P1 + 1.6$ Rupees/hour

$C2 = 0.1\ P_2^{2P} + 32\ P2 + 2.1$ Rupees/hour

Where p's are in megawatt. If there is an error of 1% in the representation of the input data, and the loss in operating economy for a load of 250 MW.

Problem

100 MW, 150 MW and 280 MW are the ratings of three units located in a thermal power station. Their respective incremental costs are given by the following equations:

$dc1/dp1 = Rs(0.15p1 + 12)$;

$dc3/dp3 = Rs(0.21p3 + 13)$

$dc2/dp2 = Rs(0.05p2 + 14)$

Where P1, P2 and P3 are the loads in MW. Determine the economical load allocation between the three units, when the total load on the station is 300 MW

Long-Range Hydro-Scheduling:

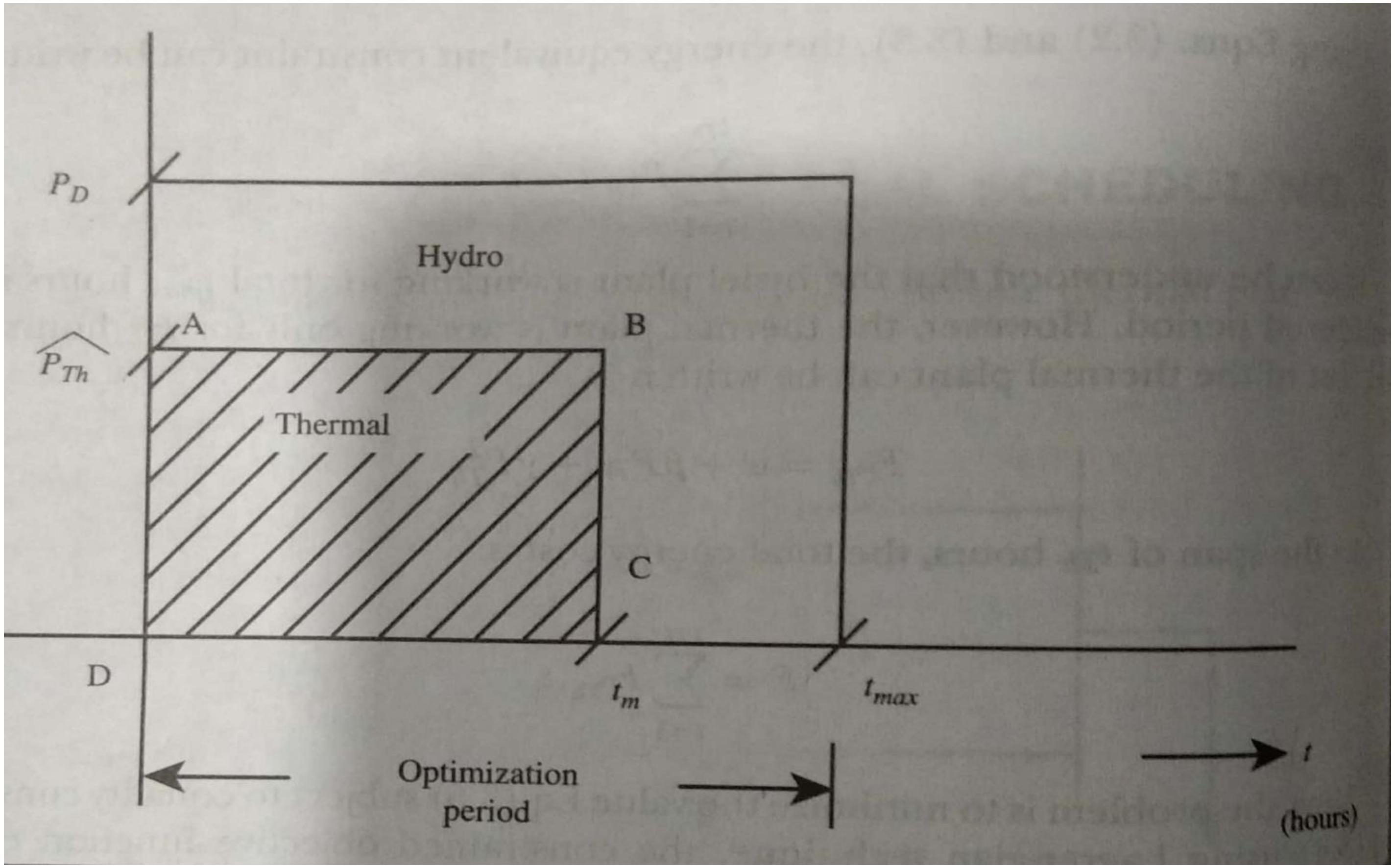
The long-range hydro-scheduling problem involves the long-range forecasting of water availability and the scheduling of reservoir water releases (i.e., “drawdown”) for an interval of time that depends on the reservoir capacities

Short-range Hydro Thermal Scheduling

Short-range hydro-scheduling (1 day to I wk) involves the hour-by-hour scheduling of all generation on a system to achieve minimum production cost for the given time period.

In such a scheduling problem, the load, hydraulic inflows, and unit availabilities are assumed known. A set of starting conditions (e.g., reservoir levels) is given, and the optimal hourly schedule that minimizes a desired objective, while meeting hydraulic steam, and electric system constraints, is sought.

Determination of Optimal Contribution of thermal Plant



UNIT II
MODELLING OF GOVERNOR, TURBINE AND EXCITATION SYSTEMS

Introduction

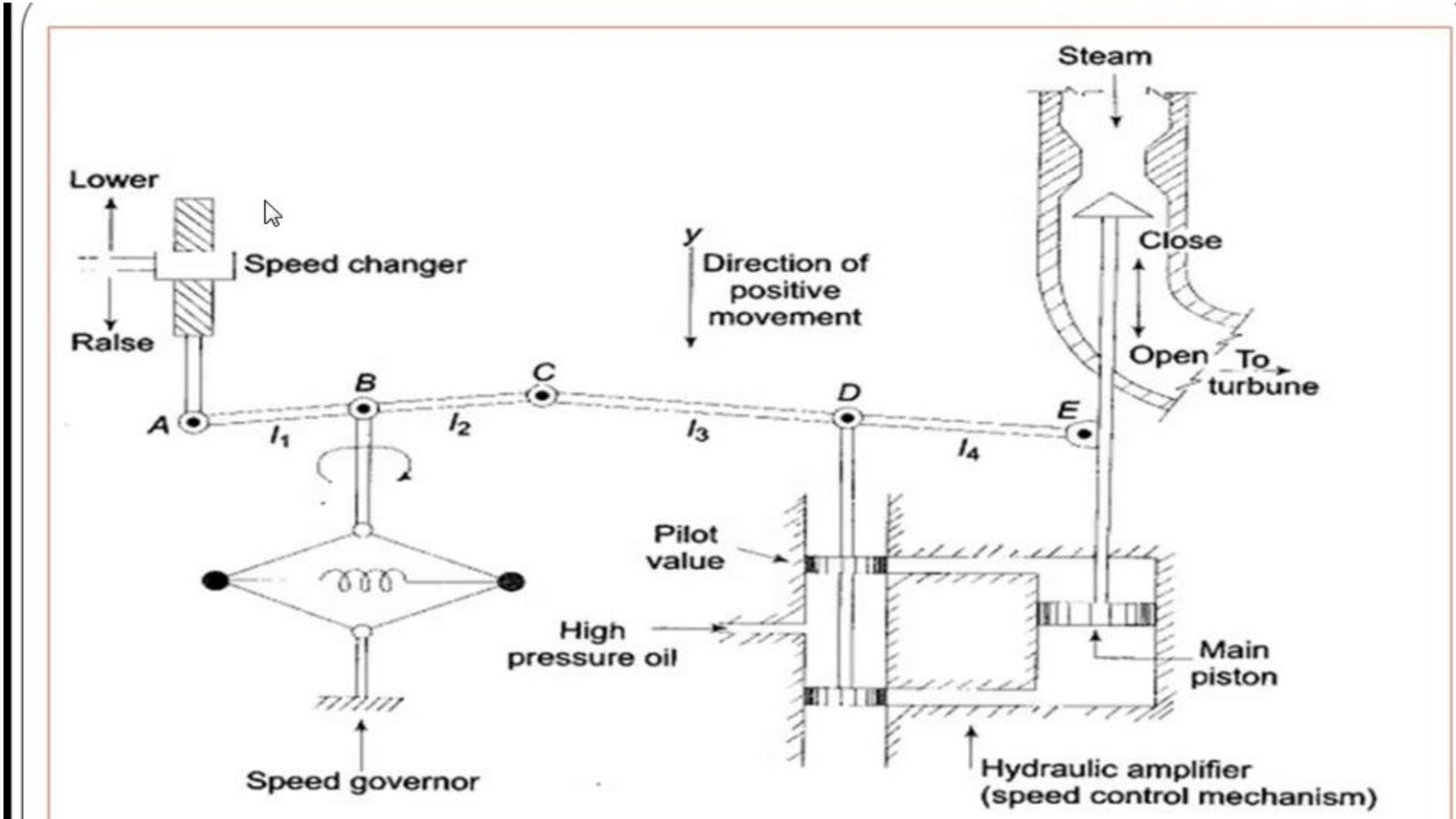
- The main objective of power system operation and control is to maintain continuous supply of power with an acceptable quality, to all the consumers in the system.

- The system will be in equilibrium, when there is a balance between the power demand and the power generated. As the power in AC form has real and reactive components : the real power balance; as well as the reactive power balance is to be achieved

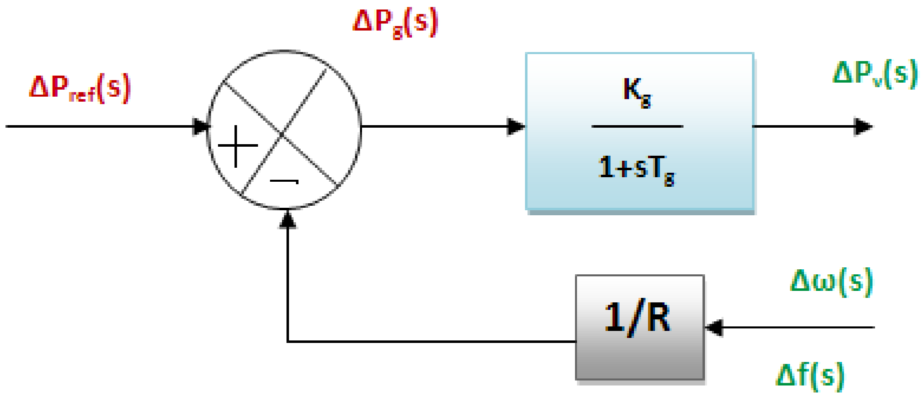
Cont..

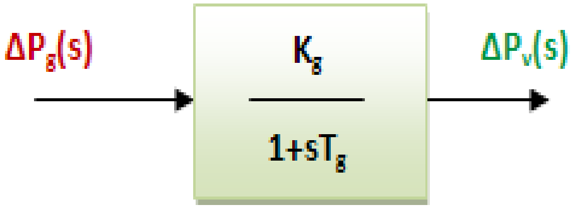
- There are two basic control mechanisms used to achieve reactive power balance (acceptable voltage profile) and real power balance (acceptable frequency values). The former is called the automatic voltage regulator (AVR) and the latter is called the automatic load frequency control (ALFC) or automatic generation control (AGC).

MATHEMATICAL MODEL OF SPEED GOVERNING SYSTEM

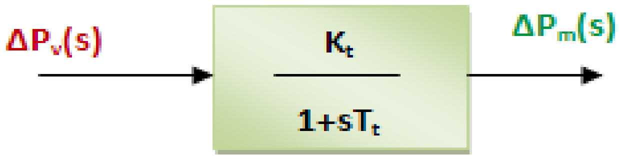


BLOCK DIAGRAM REPRESENTATION OF A SPEED GOVERNOR





MODELLING OF STEAM TURBINE

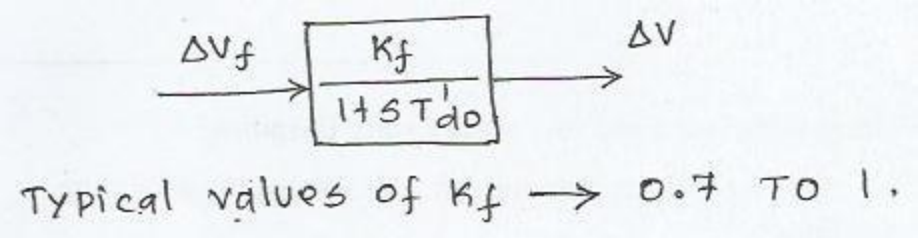


$$G_t(s) = \frac{\Delta P_m(s)}{\Delta P_V(s)} = \frac{K_t}{1+sT_t}$$

The dynamic response of steam turbine is largely influenced by two factors.

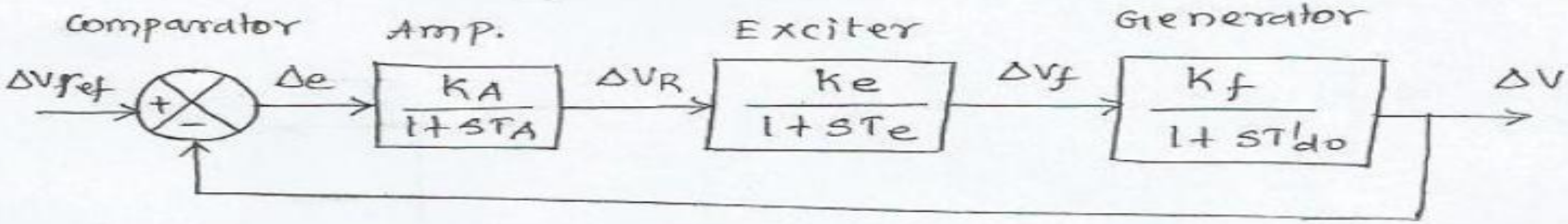
- Entrained steam between the inlet steam valve and the first stage of the turbine,
- The storage action in the re- heater , which causes the outlet of the low pressure stage to lag behind that of the high pressure

GENERATOR LOAD MODEL

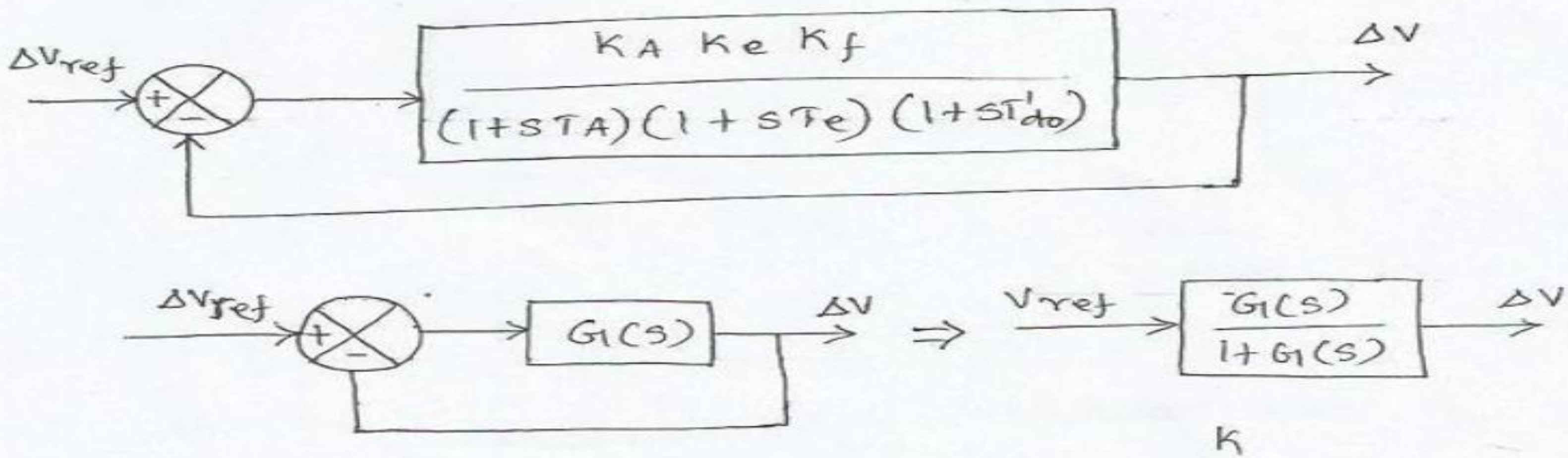


Typical values of k_f = 0.7 to 1. T'_{do} = 1 to 2 sec

Combining all the individual blocks, we get closed loop model of AVR.



Applying Block reduction Technique, the above model is reduced.



Open loop transfer function $= \frac{k}{(HsT_a)(1+sT_e)(1+sT'_{do})}$

EXCITATION SYSTEM

- When the load on the power system changes, the terminal voltage of the generator changes. Therefore to maintain the terminal voltage with permissible standards. The excitation of the generator must be decreased or increased depending upon the situation prevailing to protect the devices or apparatus which is operating in the power system. This can be achieved by employing automatic voltage regular.

- The basic function of an excitation system is to provide direct current to the synchronous machine. In addition the excitation system performs control and protective functions essentially to the satisfactory performance of the power system to controlling the field voltage. Thereby the field current.

- The control function include the control of voltage and reactive power flow and the enhancement of system stability. The protective function ensures that the capability limits of the synchronous machine, excitation system and other equipment are not exceeded

- In addition to voltage regulators at generator buses static shunt capacitors, synchronous compensators, static VAR systems, tap changing transformers are also used in the power system for rapid voltage control.

EXCITATION SYSTEM REQUIREMENTS

The excitation system must satisfy the following requirements.

1. Meet specified response criteria. 2
2. Must be able to prevent damage to itself, generation and its associated equipments.
3. It should have good operating flexibility.

TYPES OF EXCITATION SYSTEM

- D.C. Excitation systems:
- This excitation system utilizes D.C generators as source of excitation power and provide current to the rotor of the synchronous machine through slip rings.
- The D.C. excitation systems were used in the earlier days. Now it has been superseded by A.C.exciters.
- Disadvantage: Large time constant (about 3 sec) and commutation difficulties.

AC EXCITAION SYSTEM

- An A.C. excitation system consists of and A.C generator and thyristor rectifier bridge directly connected to the alternator shaft.
- The advantage of this method of excitation is that the moving contacts such as slip lings and brushes are completely eliminated thus offering smooth and maintenance free operation such a system is known as brushless excitation system.
- The A.C output or the exciter is rectifier by either controlled (or) un controlled rectifier to provide the direct current for the generator field.

STATIC EXCITATION SYSTEMS

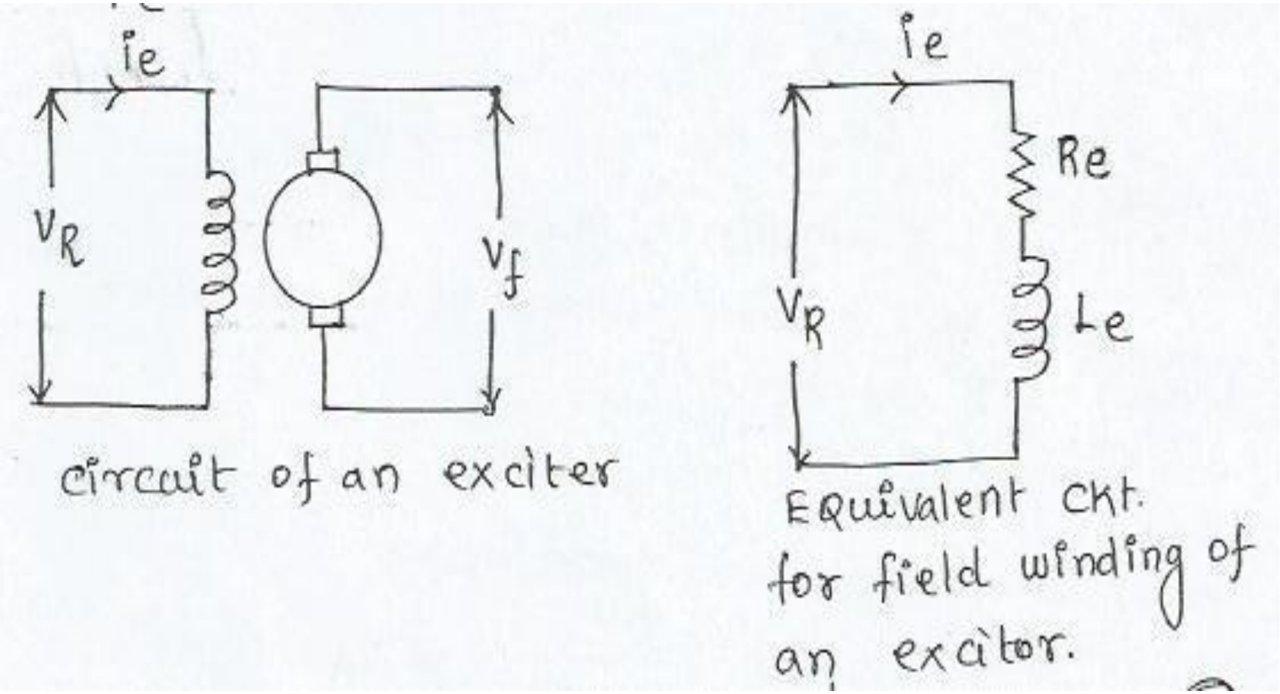
- **The components in these systems are static or stationary. The static rectifier either controlled or un-controlled supply the excitation current directly to the field of the main synchronous generator through slip rings. The main source of power to the rectifiers is from the main generator through a transformer to step down the voltage to a required level. At the time of starting the field is supplied through battery power.**

Advantage:

- 1. By eliminating rotating exciters, the noise level in the plant is reduced.
- 2. The equipment of static excitation may be mounted or placed separately at a convenient place.
- 3. Compared to rotating exciters, the static devices are more reliable

Model of Exciter

The purpose of the exciter is to supply filed current to the rotor field of the synchronous generator



Let

$R_e = The\ exciter\ field\ resistor.$

$L_e = The\ exciter\ field\ inductance.$

Input voltage, $\Delta v_R = R_e\, \Delta i_e + L_e \frac{d}{dt}(\Delta i_e) - - - - - - - - - - - - (4)$

Output voltage of an exciter (or) field voltage of a generator

$\Delta v_f \propto \Delta i_e$

$\Delta v_f = k_1\, \Delta i_e - - - - - - - - - - (5)$

Taking L.T of equations (4) & (5)

$\Delta v_R(s) = [R_e + L_e(s)]\, \Delta i_e(s)$

$\Delta v_f(s) = k_1\, \Delta i_e(s)$

Transfer function of the exciter,

$$G_e = \frac{\Delta v_f(s)}{\Delta v_R(s)} = \frac{k_1}{R_e + L_e(s)} = \frac{k_1}{\left[1 + \left[\frac{L_e}{R_e}\right]s\right] \times R_e}$$

$$G_e = \frac{\frac{k_1}{R_e}}{1 + \left[\frac{L_e}{R_e}\right]s} = \frac{k_e}{1 + sT_e}$$

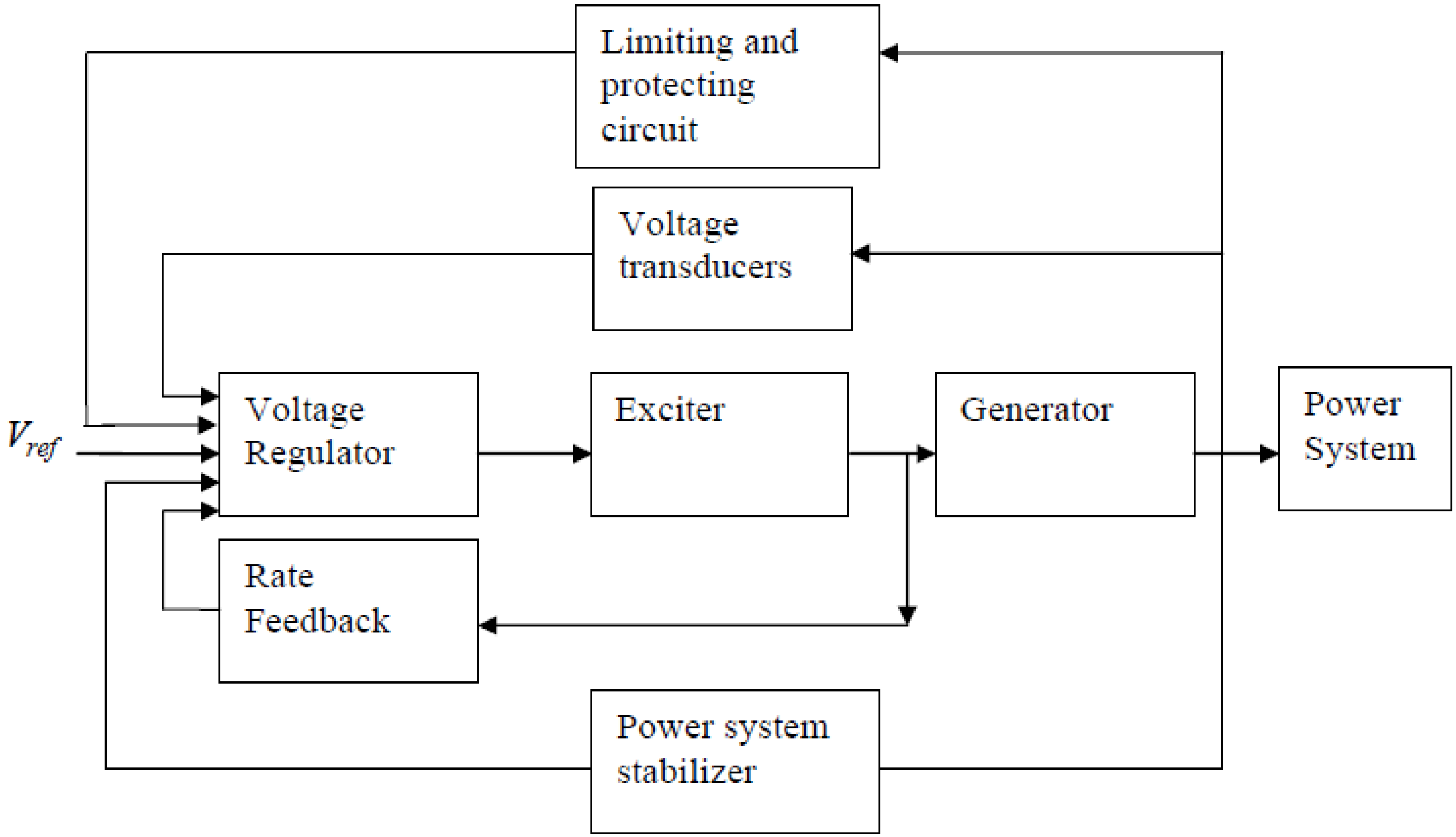
Where,

$$k_e = \frac{k_1}{R_e} = Gain\ of\ the\ exciter$$

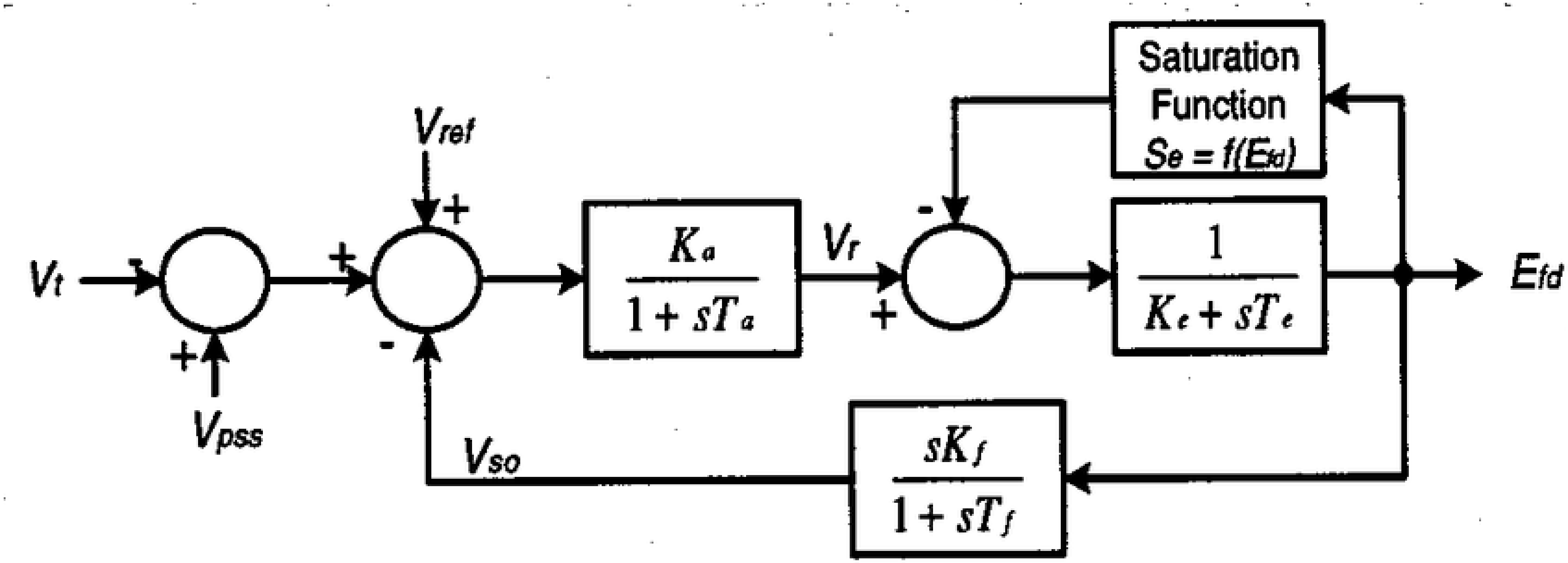
$$T_e = \left[\frac{L_e}{R_e}\right] = Time\ constant\ of\ the\ exciter\ (sec)$$

T_e *are ranges from* 0.5 *to* 1*sec*

Excitation System Block Diagram



Block Diagram representation of IEEE Type – I Model



Problems

- Two turbo alternators rated for 150 MW and 250 MW have governor drop characteristics of 8% from no load to full load. They are connected in parallel to share a load of 300 MW. Determine the load shared by each machine assuming free governor action.
- Two generating stations 1 and 2 have full load capacities of 300 MW and 200 MW respectively at a generating frequency of 50 Hz. The two stations are interconnected by an induction motor and synchronous generator with a full load capacity of 50 MW. The speed regulation of station 1, station 2 and induction motor and synchronous generator sets are 45%, 4% and 3% respectively. The load on respective bus bars is 70 MW and 60 MW respectively. Find the load taken by the motor generator set.

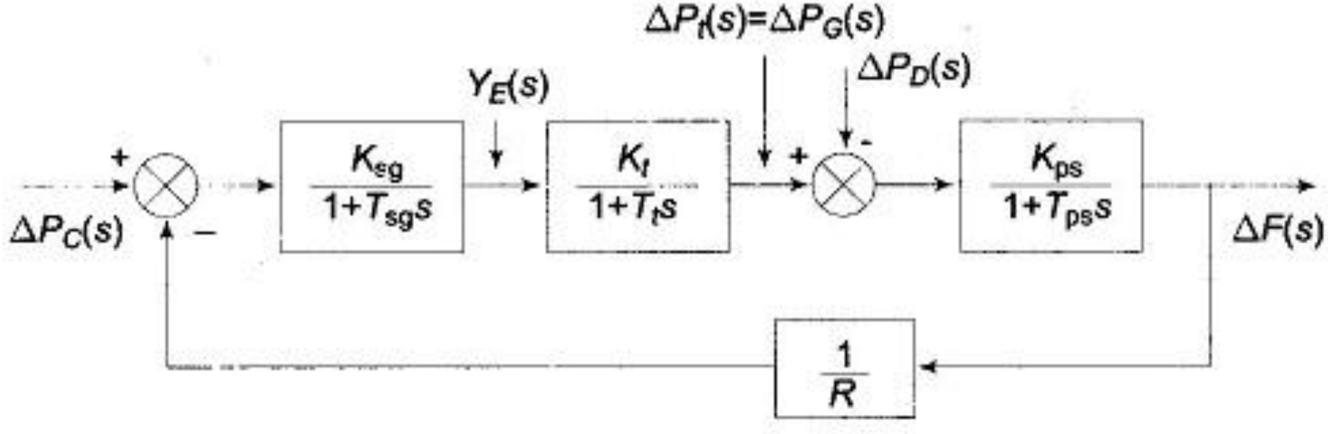
UNIT III
SINGLE AREA AND TWO AREA LOAD FREQUENCY CONTROL

Load Frequency Control (Single Area Case):

- Load Frequency Control – Let us consider the problem of controlling the power output of the generators of a closely knit electric area so 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.

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



Steady States Analysis

The model of above Fig shows that there are two important incremental inputs to the load frequency control system -ΔPC, the change in speed changer setting; and ΔPD, the change in load demand.
Let us consider a simple situation in which the speed changer has a fixed setting (i.e. ΔPC = 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

$$\Delta P_D \left(\text{i.e.} \, \Delta P_D(s) = \frac{\Delta P_D}{s} \right)$$

is obtained as follows

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

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

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

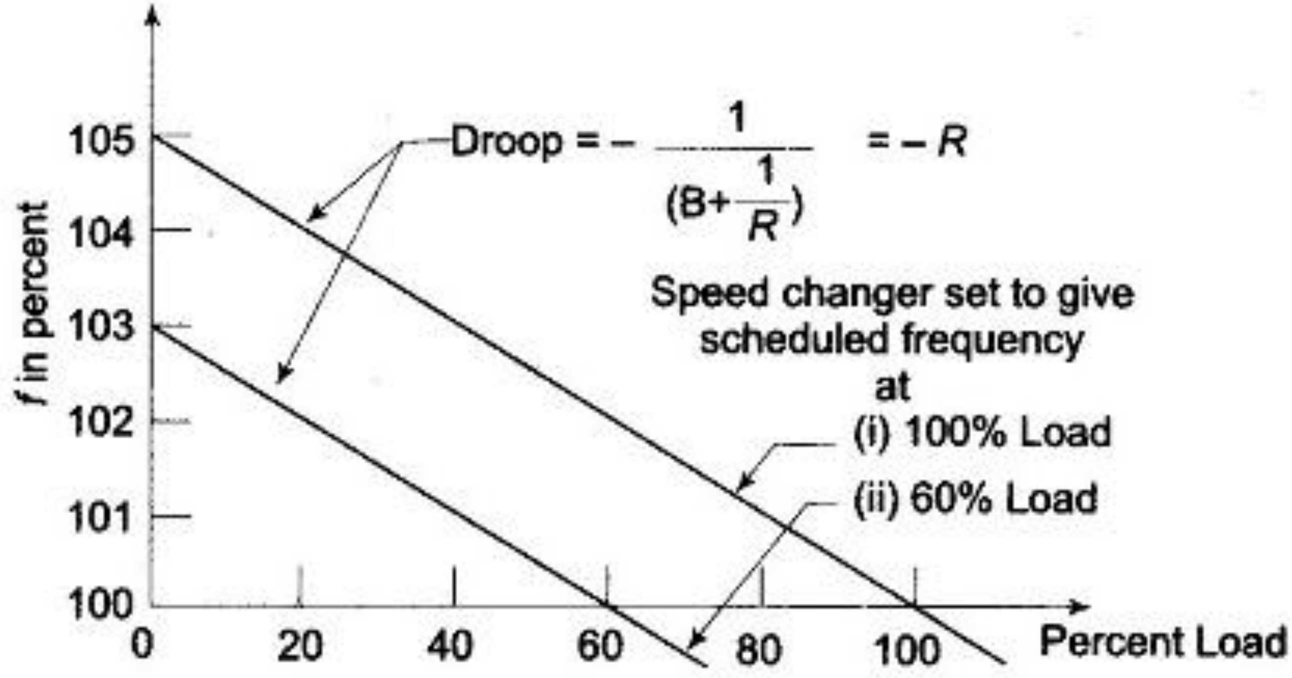
- While the gain Kt is fixed for the turbine and Kps is fixed for the power system, Ksg, the speed governor gain is easily adjustable by changing lengths of various links. Let it be assumed for simplicity that Ksg is so adjusted that

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

- It is also recognized that Kps = 1/B, where B = δPD/δf / Pr (in pu MW/unit change in frequency). Now

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

Cont..



.7 Steady state load-frequency characteristic 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% from no load to full load). Therefore, the linear incremental relation (8.16) can be applied from no load to full load. With this understanding,

The above figure 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

$$-\left(\frac{1}{B+(1/R)}\right)$$

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 (ΔPD) is met under steady conditions partly by increased generation (ΔPG) due to opening of the steam valve and partly by decreased load demand due to drop in system frequency. From the block diagram with KsgKt≈1)

Cont..

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

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

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. ΔPD = 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 $K_{sg}K_t \simeq 1$

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

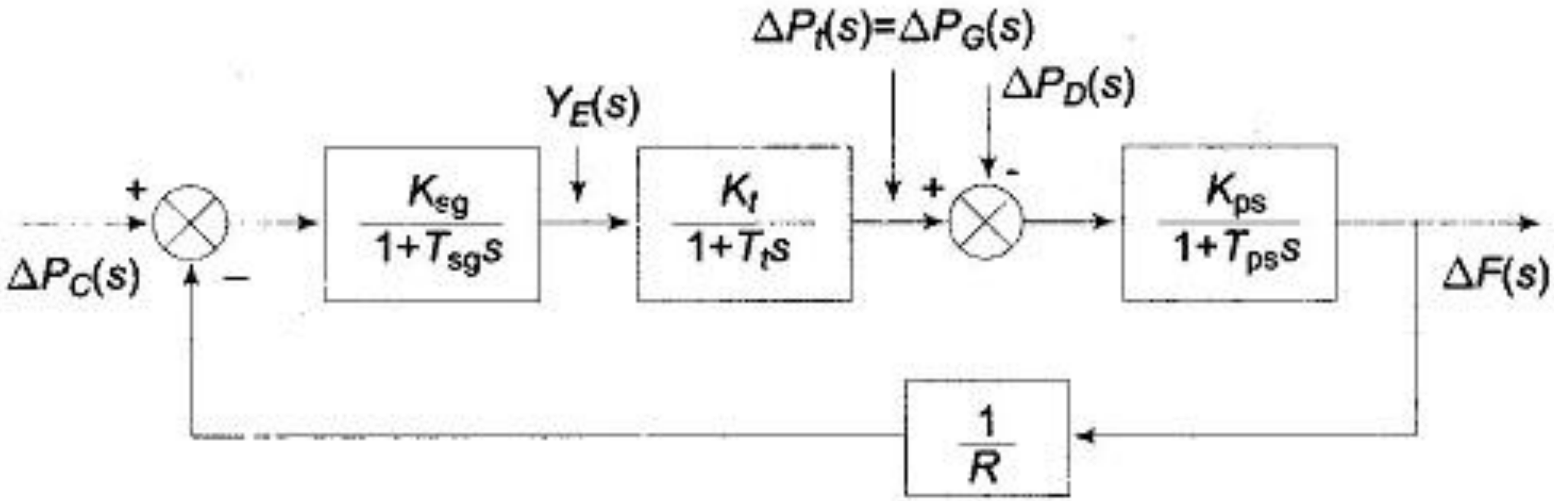
If the speed changer setting is changed by ΔPC while the load demand changes by ΔPD, the steady frequency change is obtained by superposition, i.e.

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

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

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

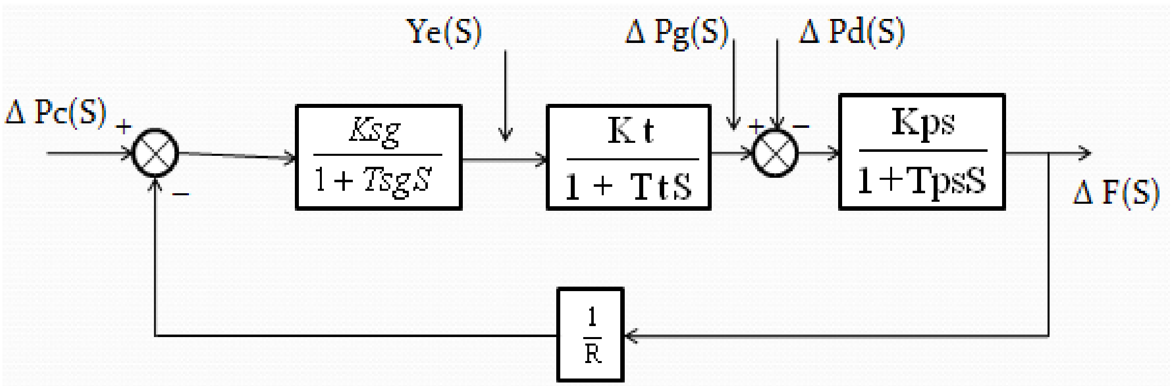
depicts two load frequency plots—one to give scheduled frequency at 100% rated load and the other to give the same frequency at 60% rated load.



$\Delta P_t(s)=\Delta P_G(s)$
$\Delta P_D(s)$
$Y_E(s)$
+
-
+
–
$\frac{K_{sg}}{1+T_{sg}s}$
$\frac{K_t}{1+T_ts}$
$\frac{K_{ps}}{1+T_{ps}s}$
$\Delta P_C(s)$
–
$\Delta F(s)$
$\frac{1}{R}$

Dynamic Response

This is the variation of frequency with respect to time for given step change in load demand.



ΔF(S) → Laplace transform of change in frequency

ƒ (t) → Inverse Laplace transform of ΔF(S).

Time constant of load frequency control follow the relation Tg < Tt < Tp Block diagram of ALFC

Cont..

Tg = Tt = 0 and KtKg ≈ 1

$$\Delta F(S)|_{\Delta P_C=0} = \frac{-\dfrac{K_P}{1+sT_p}}{1+\dfrac{K_p}{1+sT_p}\dfrac{1}{R}}\frac{\Delta P_D}{s}$$

$$= \frac{-\dfrac{K_p}{T_p}}{s[s+\dfrac{R+K_p}{RT_p}]}\Delta P_D$$

Cont..

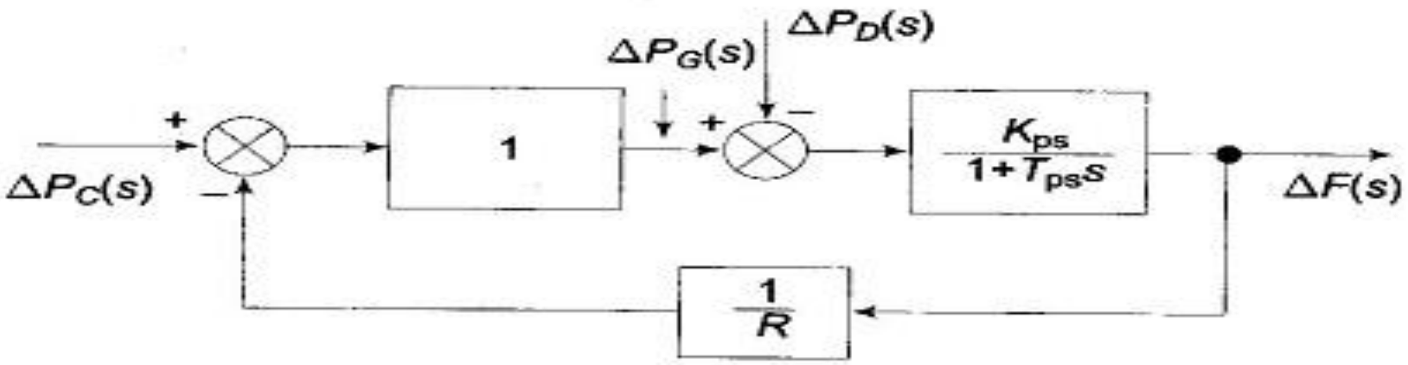
$$\Delta F(S) = -\frac{G_P}{1+\frac{1}{R}G_P}\frac{k}{S}$$

$$= -\left(\frac{K_P}{1+ST_P}\right)\frac{1}{\left(1+\frac{1}{R}\frac{K_P}{1+ST_P}\right)}\frac{k}{S}$$

Applying Partial function,

$$\Delta F(S) = -\frac{K_P k}{T_P}\left(\frac{1}{S\left[S+\left(\frac{1}{T_P}+\frac{K_P}{RT_P}\right)\right]}\right) - \frac{K_P k}{T_P}\left[\frac{1}{S\left[S+\frac{1}{T_P}+\frac{K_P}{RT_P}\right]}\right]$$

Cont..



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

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

$$\Delta f(t) = -\frac{RK_{ps}}{R+K_{ps}}\left\{1-\exp\left[-t/T_{ps}\left(\frac{R}{R+K_{ps}}\right)\right]\right\}\Delta P_D \qquad (8.22)$$

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

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

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

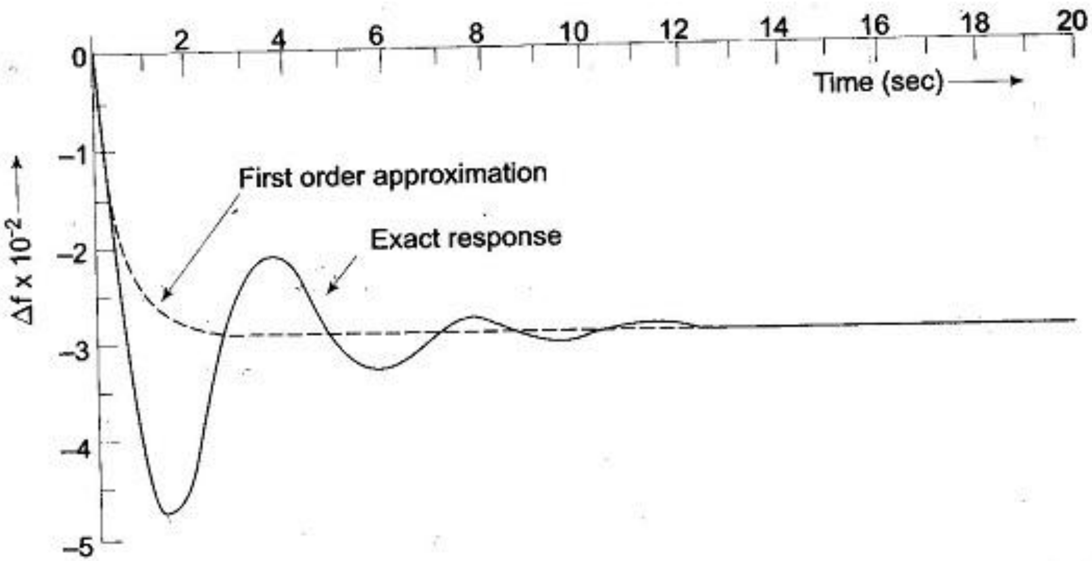


Fig. 8.9 Dynamic response of change in frequency for a step change in load ($\Delta P_D = 0.01$ pu, $T_{sg} = 0.4$ sec, $T_t = 0.5$ sec, $T_{ps} = 20$ sec, $K_{ps} = 100$, $R = 3$)

Cont..

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

NECESSETY OF KEEPING FREQUENCY CONSTANT

1) Steam turbine blades are designed to operate in a narrow band of frequencies. Deviation of frequency beyond this band may cause gradual or immediate turbine damage. Consequently, protective and control equipment take corrective action in case of under/over frequency. A 50 Hz steam turbine may not be able to withstand frequency deviation of +2 Hz to -2.5 Hz for more than an hour in its entire life.
2) Loads and other electrical equipment are usually designed to operate at a particular frequency. Off-nominal frequency operation causes electrical loads to deviate from the desired output. The output of power plant auxiliaries like pumps or fans may reduce, causing reduction in power plant output.

PROBLEMS

A single area consists of two generators with the following parameters: Generator 1 = 1200 MVA; R=6 % (on machine base) Generator 2 = 1000 MVA; R=4 % (on machine base) The units are sharing 1800 MW at normal frequency 50 Hz. Unit supplies 1000 MW and unit 2 supplies 800 MW. The load now increased by 200 MW.

(a) Find steady state frequency and generation of each unit if B=0.

(b) Find steady state frequency and generation of each unit if B=1.5.

Two Area Load Frequency Control

Two Area Load Frequency Control – An extended power system can be divided into a number of Two Area 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

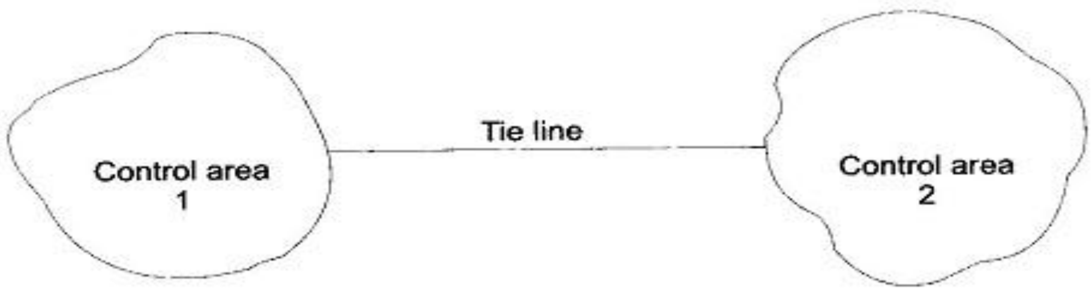


Fig. 8.13 Two interconnected control areas (single tie line)

The control objective now is to regulate the frequency of each area and to simultaneously regulate the tie line power as per inter-area power contracts. As in the case of frequency, proportional plus integral controller will be installed so as to give zero steady state error in tie line power flow as compared to the contracted power.

It is conveniently assumed that each control area can be represented by an equivalent turbine, generator and governor system. Symbols used with suffix 1 refer to area 1 and those with suffix 2 refer to area 2.

Cont..

In an isolated control area case the incremental power (ΔPG-ΔPD) was accounted for by the rate of increase of stored kinetic energy and increase in area load caused by increase in frequency. Since a tie line transports power in or out of an area, this fact must be accounted for in the incremental power balance equation of each area. Power transported out of area 1 is given by

$$P_{\text{tie},\,1} = \frac{|V_1||V_2|}{X_{12}} \sin(\delta_1^o - \delta_2^o) \qquad (8.26)$$

where

δ_1^o, δ_2^o = power angles of equivalent machines of the two areas.

For incremental changes in δ1 and δ2, the incremental tie line power can be expressed as

$$\Delta P_{\text{tie},\,1}(\text{pu}) = T_{12}(\Delta\delta_1 - \Delta\delta_2) \qquad (8.27)$$

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

$$\Delta P_{\text{tie},\,1} = 2\pi T_{12}\left(\int \Delta f_1 \mathrm{d}t - \int \Delta f_1 \mathrm{d}t\right) \qquad (8.28)$$

where Δf1 and Δf2 are incremental frequency changes of areas 1 and 2, respectively. Similarly the incremental tie line power out of area 2 is given by

Cont..

Similarly the incremental tie line power out of area 2 is given by

$$\Delta P_{\text{tie},\,2} = 2\pi T_{21}\left(\int \Delta f_2 \mathrm{d}t - \int \Delta f_1 \mathrm{d}t\right) \qquad (8.29)$$

Where

$$T_{21} = \frac{|V_2||V_1|}{P_{r2}X_{21}}\cos(\delta_2^o - \delta_1^o) = \left(\frac{P_{r1}}{P_{r2}}\right)T_{12} = a_{12}T_{12} \qquad (8.30)$$

With reference to Eq. (8.12), the incremental power balance equation for area 1 can be written as

$$\Delta P_{G1} - \Delta P_{D1} = \frac{2H_1}{f_1^o}\frac{\mathrm{d}}{\mathrm{d}t}(\Delta f_1) + B_1\Delta f_1 + \Delta P_{\text{tie},\,1} \qquad (8.31)$$

It may be noted that all quantities other than frequency are in per unit in Eq. (8.31). Taking the Laplace transform of Eq. (8.31) and reorganizing, we get

$$\Delta F_1(s) = [\Delta P_{G1}(s) - \Delta P_{D1}(s) - \Delta P_{\text{tie},\,1}(s)] \times \frac{K_{ps1}}{1 + T_{ps1}s} \quad (8.32)$$

where as defined earlier

$$K_{ps1} = 1/B_1$$
$$T_{ps1} = 2H_1/B_1 f^o \quad (8.33)$$

Compared to Eq. (8.13) of the isolated control area case, the only change is the appearance of the signal ΔPtie,1(s) as shown in Fig. 8.14. Taking the Laplace transform of Eq. (8.28), the signal ΔPtie,1(s) is obtained as

$$\Delta P_{tie,\ 1}(s) = \frac{2\,\pi T_{12}}{s}[\Delta F_1(s) - \Delta F_2(s)] \qquad (8.34)$$

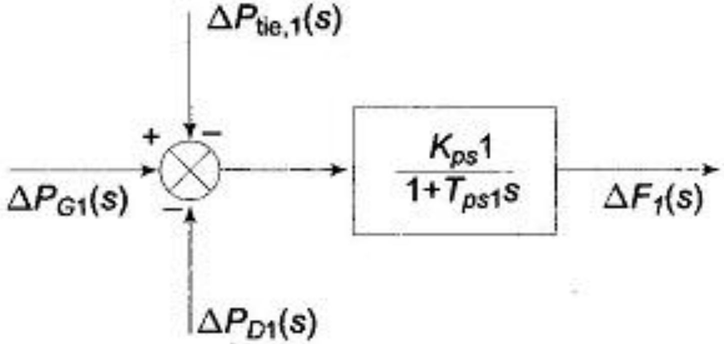


Fig. 8.14

The corresponding block diagram is shown in Fig. 8.15.

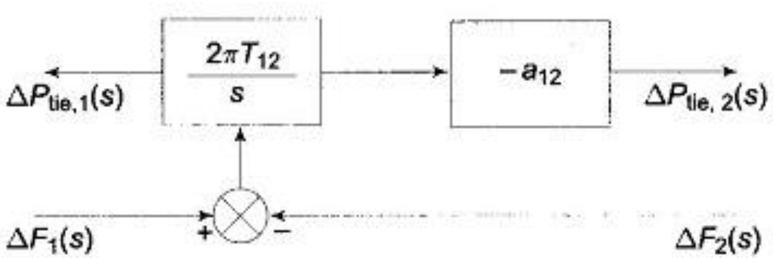


Fig. 8.15

Cont..

- For the control area 2, ΔPtie,2(s) is given by [Eq. (8.29)]

$$\Delta P_{tie,\,2}(s) = \frac{-2\,\pi a_{12} T_{12}}{s}[\Delta F_1(s) - \Delta F_2(s)] \qquad (8.35)$$

- **area control error**
  The presence of a tie line. In the case of an isolated control area, ACE is the change in area frequency which when used in integral control loop forced the steady state frequency error to zero. In order that the steady state tie line power error in a two-area control be made zero another integral control loop (one for each area) must be introduced to integrate the incremental tie line power signal and feed it back to the speed changer.

PROPORTIONAL PLUS INTEGRAL CONTROLL

- The block diagram of an uncontrolled single-area system with an integral controller
- The integral controller gives signal to the speed changer ie ΔPc. Hence we can write integral controller gives signal to the speed changer ie ΔP_c.

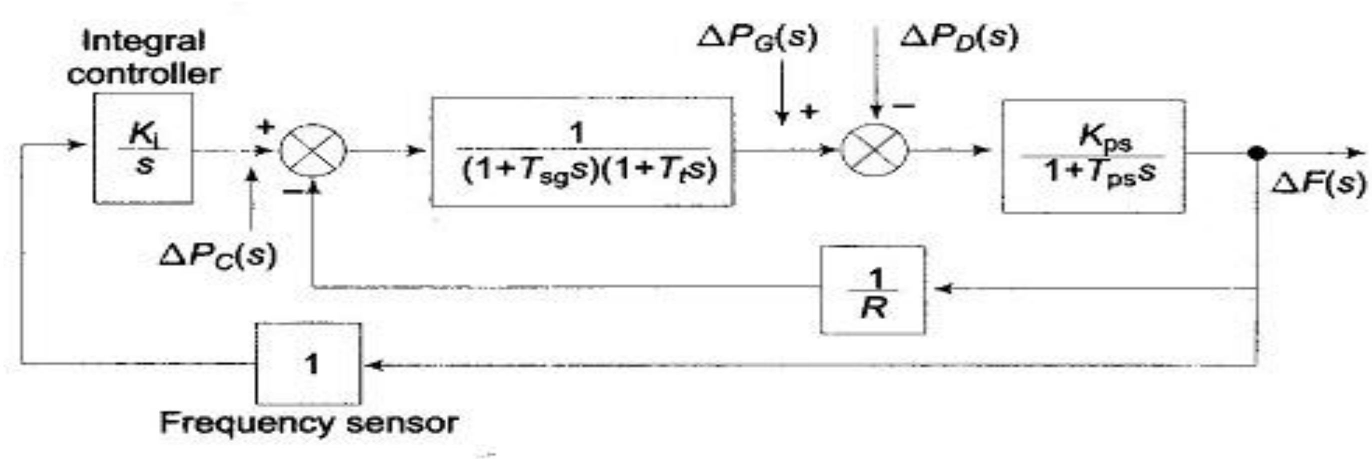


Fig. 8.10 Proportional plus integral load frequency control

Steady State response

$$\Delta f\,|_{\text{steady state}} = \underset{s \to 0}{s}\,\Delta F(s) = 0 \qquad (8.25)$$

- **The above scheme ACE being zero under steady conditions, a logical design criterion is the minimization of ∫ ACE dt for a step disturbance. This integral is indeed the time error of a synchronous electric clock run from the power supply. In fact, modern power systems keep track of integrated time error all the time. A corrective action (manual adjustment ΔPC the speed changer setting) is taken by a large (preassigned) station in the area as soon as the time error exceeds a prescribed value.**

UNIT IV
COMPENSATION FOR POWER FACTOR IMPROVEMENT AND REACTIVE POWER CONTROL

METHOD OF VOLTAGE CONTROL

- **Voltage level control is accomplished by controlling the generation, absorption and reactive power flow at all levels in the system.**
- **Shunt Capacitors:**
- **Shunt capacitors banks are used to supply reactive power at both transmission and distribution levels, along lines or sub-stations and loads. Capacitors are either directly connected to a bus bar or to the tertiary winding of a main transformer. They may be switched on and off depending on the changes in load having a lagging power factor, the capacitors supply reactive power.**

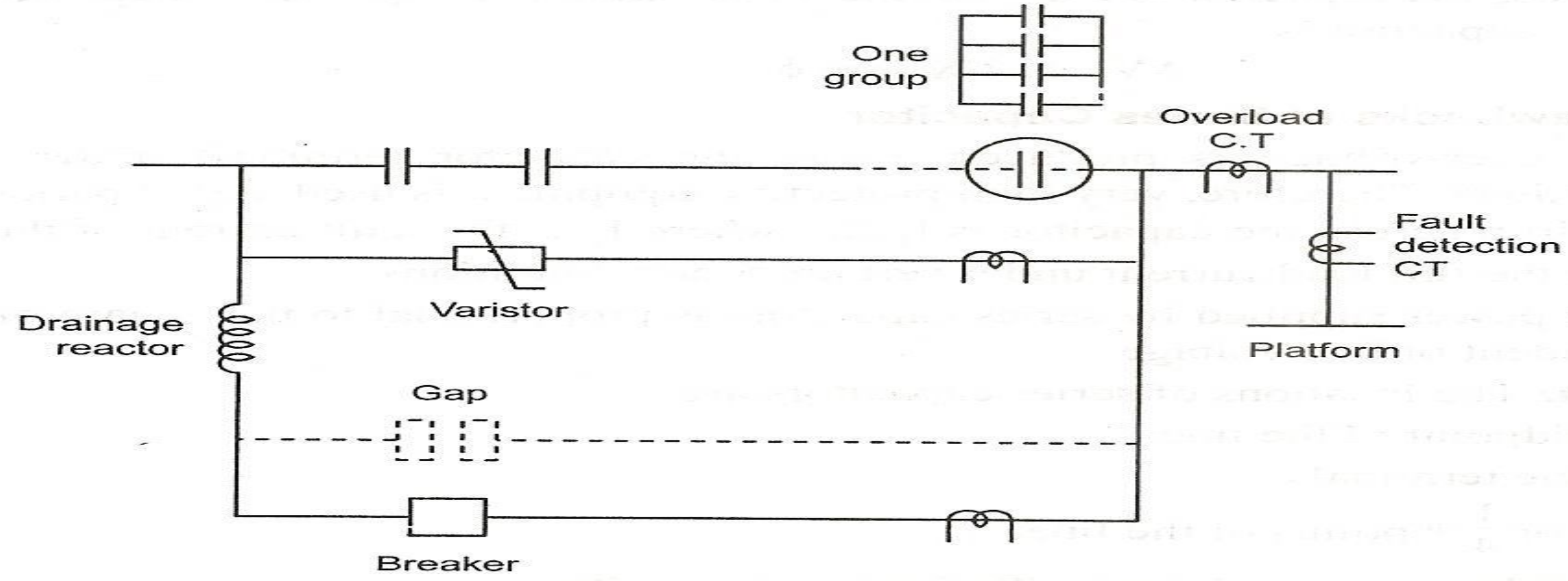
Cont..

- Shunt capacitors are extensively used in industrial and utility systems at all voltage levels. By developing higher power density, lower cast improved capacitors and an increase in energy density by a factor of 100 is possible. These present a constant impedance type of load and the capacitive power output varies with the square of voltage.
- KVar,V2= KVar,V1[V2/V1]2
- Where Kvar, V1 is output at voltage V1
- Kvar, V2 is output at voltage V2

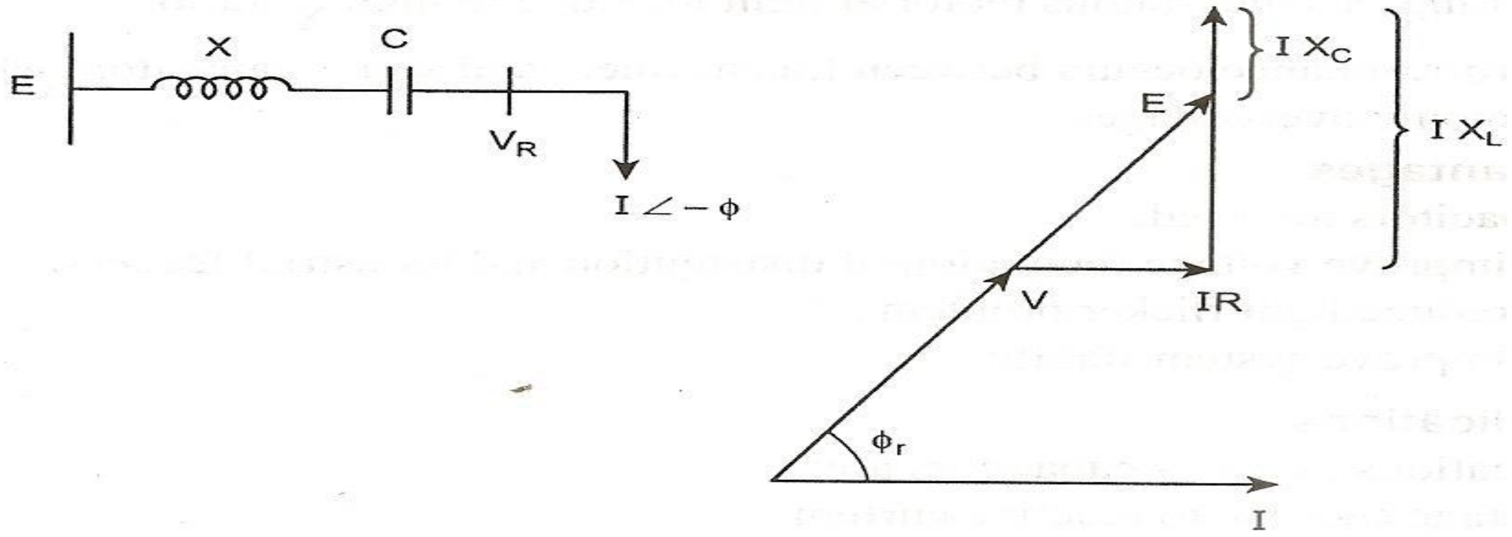
- **Series capacitors**
- **It is connected in series to compensate the inductive reactance of line. This reduces the transfer reactance between the fuses to which the lines is connected. It increases maximum power that can be transmitted and reduce reactive power loss. The reactive power produced by the series capacitor increases with increase in power**

Cont..

- **The schematic diagram of a series capacitor installation is shown in figure.**



- **Phasor diagram when series capacitor is connected on a line.**



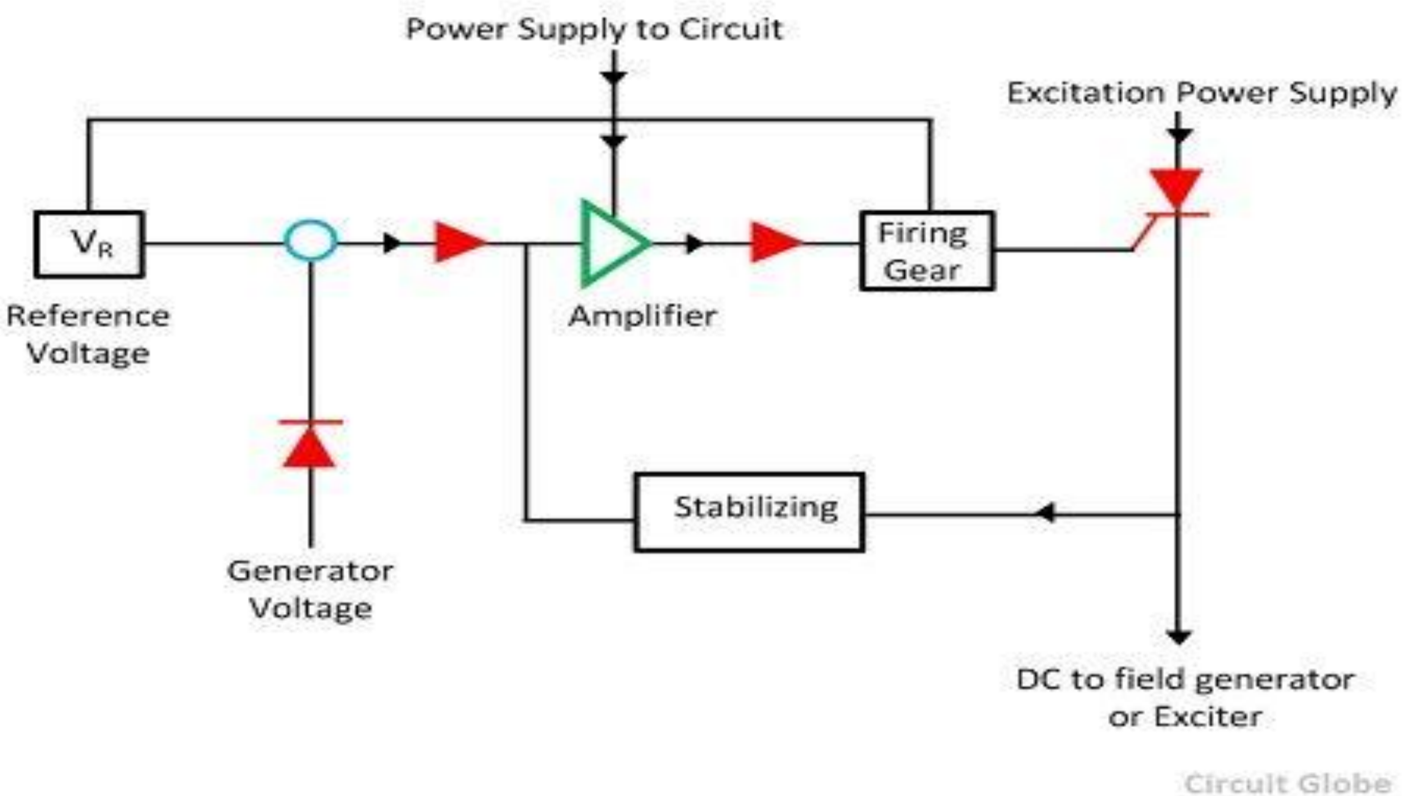
Equipment for voltage control

- Synchronous generator field exciter
- On load tap changer in substation power transformer
- Switched capacitor bank
- Distribution voltage regulating transformer
- Dynamic var regulator

Automatic Voltage Regulator

- **The automatic voltage regulator is used to regulate the voltage. It takes the fluctuate voltage and changes them into a constant voltage.**
- **The fluctuation in the voltage mainly occurs due to the variation in load on the supply system. The variation in voltage damages the equipment of the power system.**
- **The variation in the voltage can be controlled by installing the voltage control equipment at several places likes near the transformers, generator, feeders, etc.,**
- **The voltage regulator is provided in more than one point in the power system for controlling the voltage variations.**

Working Principle of Voltage Regulator



The main functions of an AVR are as follows

- It controls the voltage of the system and has the operation of the machine nearer to the steady state stability.
- It divides the reactive load between the alternators operating in parallel.
- The automatic voltage regulators reduce the over voltages which occur because of the sudden loss of load on the system.
- It increases the excitation of the system under fault conditions so that the maximum synchronising power exists at the time of clearance of the fault

Line Drop Compensation

- For tighter regulation of transmission voltage, line drop compensation may be used. Line drop compensation is a connection option of automatic voltage regulators.
- Regulation speed is the same as the terminal voltage regulation, resulting in improved transient angle and voltage stability. Of course, slow long-term voltage stability is also improved

Best Capacitor location

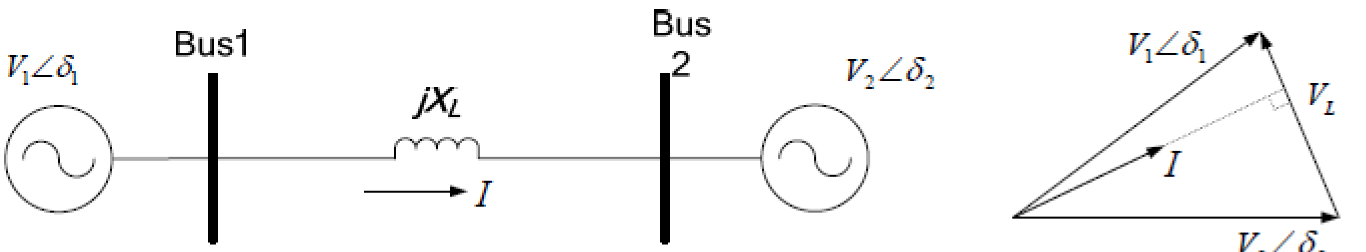
- A distribution system is an interface between the bulk power system and the consumers. Among these systems, radial distribution systems are popular because of low cost and simple design.
- Reduction of total losses in distribution system is very essential to improve the overall efficiency of power delivery. This can be achieved by placing the optimal value of capacitors at proper locations in radial distribution systems.

Best Capacitor location

- The methodology is a fuzzy approach. The best location of the capacitor as well as the sizing of the capacitor is determined using the fuzzy technique. Objective is to place the optimal value of capacitors at best locations, which maximizes net savings in the distribution system.
- The fuzzy approach method is very powerful and directly gives the best locations and identifies the optimal size. The proposed method is tested on IEEE 10 bus system.

Reactive Power Compensation of Transmission Lines

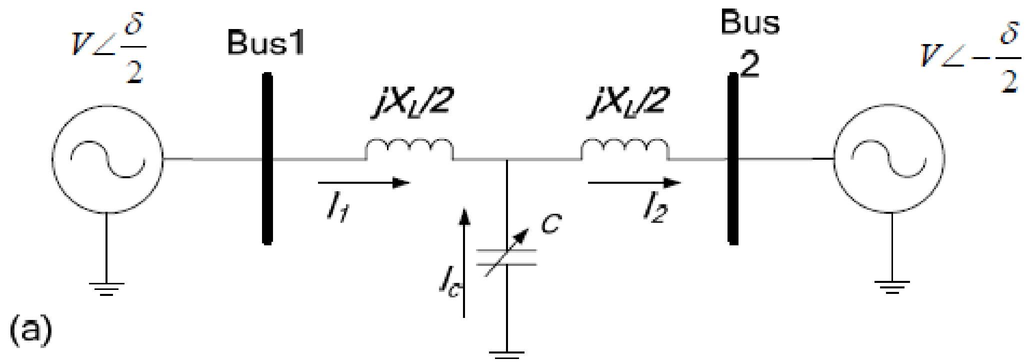
- **The simplified model of a power transmission system. Two power grids are connected by a transmission line which is assumed lossless and represented by the reactance XL. V ∠δ 11 and V ∠δ 22 represent the voltage phasors of the two power grid buses with angle δ= δ1- δ2 between the two. The corresponding phasor diagram is shown in Figure**



(a) (b)

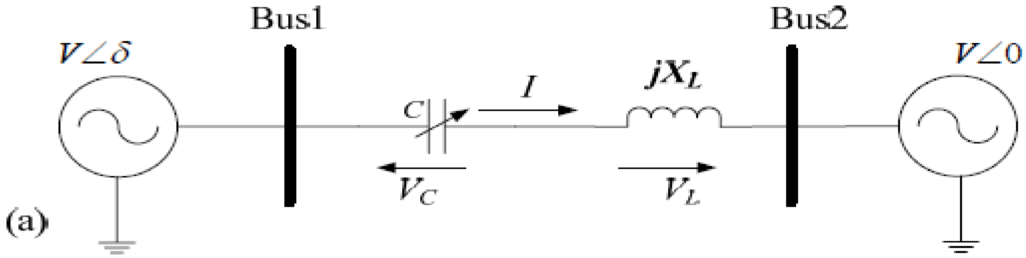
Shunt compensation

- Shunt compensation, especially shunt reactive compensation has been widely used in transmission system to regulate the voltage magnitude, improve the voltage quality, and enhance the system stability
- Shunt-connected reactors are used to reduce the line .over-voltages by consuming the reactive power, while shunt-connected capacitors are used to maintain the voltage levels by compensating the reactive power to transmission



Series compensation

- Series compensation aims to directly control the overall series line impedance of the transmission line. Tracking back to Equations (1-1) through (1-5), the AC power transmission is primarily limited by the series reactive impedance of the transmission line.
- A series-connected can add a voltage in opposition to the transmission line voltage drop, therefore reducing the series line impedance



UNIT V
LOAD COMPENSATION

Introduction to Distribution Systems

- **The electric utility industry was born in 1882 when the first electric power station, Pearl Street Electric Station in New York City, went into operation.**
- **In general, the definition of an electric power system includes a generating, a transmission, and a distribution system. The economic importance of the distribution system is very high, and the amount of investment involved dictates careful planning, design, construction, and operation**

Cont..

- The objective distribution system planning is to assure that the growing demand for electricity in terms of increasing growth rates and high load densities can be satisfied in an optimum way by additional distribution Systems from the secondary conductors through the bulk power substations, which are both technically adequate and reasonably

The various types of loads on the power system

- **Domestic load.**

  Domestic load consists of lights, fans, refrigerators, heaters, television, small motors for pumping water etc. Most of the residential load occurs only for some hours during the day (i.e., 24 hours) e.g., lighting load occurs during night time and domestic appliance load occurs for only a few hours. For this reason, the load factor is low (10% to 12%).

Commercial load.

Commercial load consists of lighting for shops, fans and electric appliances used in restaurants etc. This class of load occurs for more hours during the day as compared to the domestic load. The commercial load has seasonal variations due to the extensive use of air conditioners and space heaters

Industrial load.

Industrial load consists of load demand by industries. The magnitude of industrial load depends upon the type of industry. Thus small scale industry requires load upto 25 kW, medium scale industry between 25kW and 100 kW and large-scale industry requires

Municipal load.

Municipal load consists of street lighting, power required for water supply and drainage purposes. Street lighting load is practically constant throughout the hours of the night. For water supply, water is pumped to overhead tanks by pumps driven by electric motors. Pumping is carried out during the off-peak period, usually occurring during the night. This helps to improve the load factor of the power system.

Irrigation load.

This type of load is the electric power needed for pumps driven by motors to supply water to fields. Generally this type of load is supplied for 12 hours during night.

Traction load

This type of load includes tram cars, trolley buses, railways etc. This class of load has wide variation. During the morning hour, it reaches peak value because people have to go to their work place. After morning hours, the load starts decreasing and again rises during evening since the people start coming to their homes.

Load Characteristics

- **Demand:** The demand of a system is the load at receiving end over a specified time interval.
- **Maximum Demand**: The maximum demand of a system is the greater of all the demands within the time interval specified.
- **Diversified demand (or coincident demand):** It is the demand of the composite group, as a whole, of somewhat unrelated loads over a specified period of time
- **Demand factor**: It is the "ratio o f the maximum demand of a system to the total connected Load. It is dimension less. Demand factor is usually less than 1.0.
- Demand factor = Maximum demand/ Total connected demand

- **Non-coincident demand**: It is “the sum of the demands of a group of loads with no restrictions on the interval to which each demand is applicable.
- **Connected load**: It is "the sum of the continuous ratings of the load consuming apparatus connected to the system”
- **Utilization factor**: It is "the ratio of the maximum demand of a system to the rated capacity of the system " Fu = Maximum Demand/ rated system capacity

Cont..

- **Plant factor:** It is the ratio of the total actual energy produced or served over a designated period of time to the energy that would have been produced or served if the plant (or unit) had operated continuously at maximum rating. It is also known as the capacity factor or the use factor.
- Plant Factor = actual energy production (or) served * time/ maximum plant rating

- **Load factor** It is "the ratio of the average load over a designated period of time to the peak load occurring on that period"

FLD = average load/ peak load Annual load factor = total annual energy/ annual peak load*8760

Diversity factor: It is "the ratio of the sum of the individual maximum demands of the various subdivisions of a system to the maximum demand

$$F_D = \frac{D_1 + D_2 + D_3 + \cdots + D_n}{D_g} \qquad F_D = \frac{\sum_{i=1}^{n} D_i}{D_g},$$

$$F_D = \frac{\sum_{i=1}^{n} \mathrm{TCD}_i \times \mathrm{DF}_i}{D_g}$$

- **Contribution factor:** **The contribution factor of the ith load to the group maximum demand." It is given in per uni t of the individual maximum demand of the ith load**

$$F_c = \frac{\sum_{i=1}^{n} c_i \times D_i}{\sum_{i=1}^{n} D_i}$$

$$D_g = c_1 \times D_1 + c_2 \times D_2 + c_3 \times D_3 + \cdots + c_n \times D_n.$$

Substituting Equation 2.18 into Equation 2.15,

$$F_c = \frac{c_1 \times D_1 + c_2 \times D_2 + c_3 \times D_3 + \cdots + c_n \times D_n}{\sum_{i=1}^{n} D_i}$$

Factors Affecting System Planning

- The number and complexity of the considerations affecting system planning appears initially to be staggering.
- Demands for ever-increasing power capacity, higher distribution voltages, more automation, and greater control sophistication constitute only the beginning of a list of such factors. ,
- the planning problem is an attempt to minimize the cost of sub transmission, Substations, feeders, laterals, etc., as well as the cost of losses

Relationship Between Load and Loss Factor

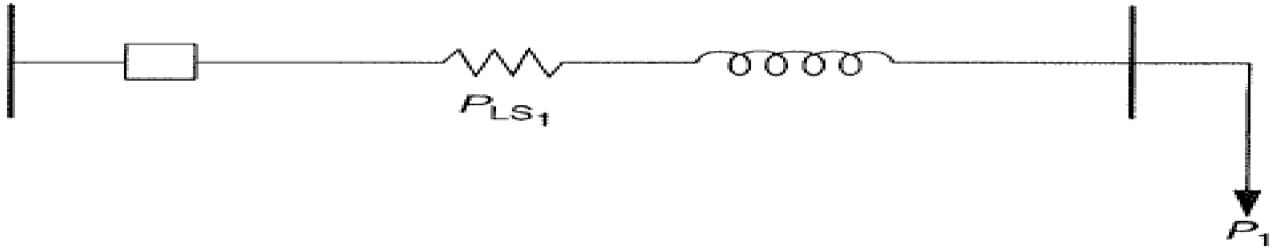
Relationship between Load & loss factors:

$$F_{LD} = \frac{P_{av}}{P_{max}} = \frac{P_{av}}{P_2}.$$

$$P_{av} = \frac{P_2 \times t + P_1 \times (T - t)}{T}.$$

$$F_{LD} = \frac{P_2 \times t + P_1 \times (T - t)}{P_2 \times T}$$

$$F_{LD} = \frac{t}{T} + \frac{P_1}{P_2} \times \frac{T - t}{T}$$



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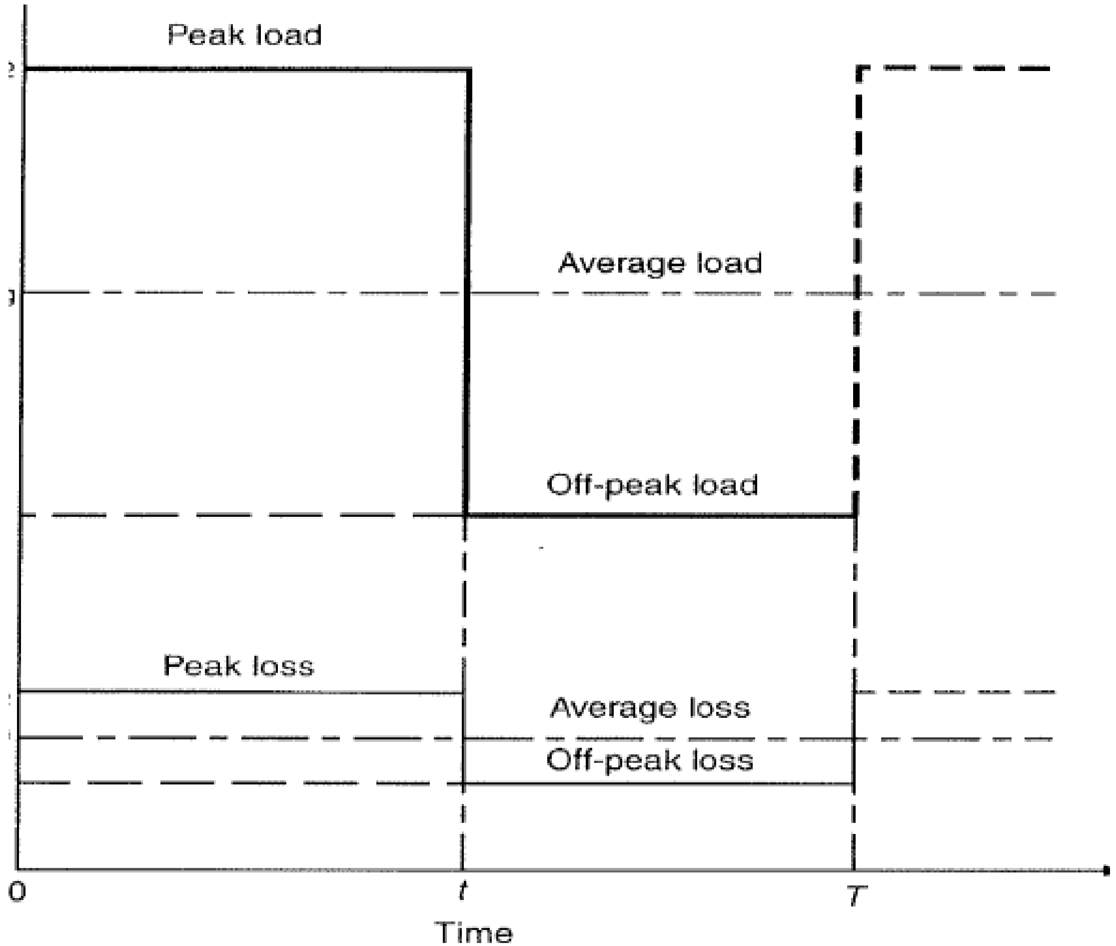

Peak load
Average load
Off-peak load
Peak loss
Average loss
Off-peak loss
0
t
T
Time

$$F_{LS} = \frac{P_{LS,av}}{P_{LS,max}} = \frac{P_{LS,av}}{P_{LS,2}},$$

Where PLs,avg the average power loss, PLS,max is the maximum power loss, and PLS,2 is the peak loss at peak load.

$$P_{LS,av} = \frac{P_{LS,2} \times t + P_{LS,1} \times (T - t)}{T}.$$

- **Substituting**

$$F_{LS} = \frac{P_{LS,2} \times t + P_{LS,1} \times (T - t)}{P_{LS,2} \times T},$$

- **Where PLS,1 is the off-peak loss at off-peak load, t is the peak load duration, and T - t i s the off-peak load duration.**
- **The copper losses are the function of the associated loads. Therefore, the off-peak and peak loads can be expressed, respectively, as**

Cont..

$$P_{LS,1} = k \times P_1^2$$

$$P_{LS,2} = k \times P_2^2$$

Where *k* is a constant. Thus, substituting Equations 2.32 and 2.33 into Equation 2.31, the loss factor can be expressed as

$$F_{LS} = \frac{(k \times P_2^2) \times t + (k \times P_1^2) \times (T - t)}{(k \times P_2^2) \times T}$$

$$F_{LS} = \frac{t}{T} + \left(\frac{P_1}{P_2}\right)^2 \times \frac{T - t}{T}.$$

Cont..

- Load factor can be related to loss factor for three different cases
- Case 1: Off-peak load is zero. Here,
- Since P, = 0. Therefore, from Equations 2.28 and 2.35,

$$F_{LD} = F_{LS} = \frac{t}{T}.$$

- That is, the load factor is equal to the loss factor and they are equal to the t/T constant
- the formula given before has been modified for rural areas and expressed as

$$F_{LS} = 0.16 F_{LD} + 0.84 F_{LD}^2.$$

THANK YOU