POWER SYSTEM OPERATION AND CONTROL

Department of Electrical and Electronics Engineering

MR. M. DINESH KUMAR,
ASSISTANT PROFESSOR /EEE

COURSE CODE : 20EE7LT1

UNIT – I:

LOAD FREQUENCY CONTROL: Basics of speed governing mechanism and modeling – speed - load characteristics – load sharing between two synchronous machines in parallel. Control area concept. Load Frequency Control of a single area system. Static and dynamic analysis of uncontrolled and controlled cases. Integration of economic dispatch control with LFC. Two - area system – modeling - static analysis of uncontrolled case - tie line with frequency bias control of two-area system - state variable model.

UNIT– II:

REACTIVE POWER VOLTAGE CONTROL: Basics of reactive power control, Excitation systems – modelling. Static and dynamic analysis: stability compensation generation and absorption of reactive power. Methods of voltage control – tap changing transformer. System level control using generator voltage magnitude setting. Tap setting of OLTC transformer. MVAR injection of switched capacitors to maintain acceptable voltage profile and to minimize transmission loss.

UNIT – III:

ECONOMIC OPERATION OF POWER SYSTEMS: Statement of economic dispatch problem – cost of generation-Incremental cost curve - co-ordination equations without loss and with loss, solution by direct method and λ-iteration method. Economic Aspects of Power Generation**:** Load curve, load duration and integrated load duration curves – load demand, diversity, capacity, utilization and plant use factors - Numerical Problems.

UNIT – IV

UNIT COMMITMENT: Statement of Unit Commitment problem – constraints, spinning reserve, thermal unit constraints, hydro constraints, fuel constraints and other constraints. Solution methods – Priority list methods - forward dynamic programming approach. Numerical problems on priority-list method using full- load average production cost and Forward DP method.

UNIT–V

COMPUTER CONTROL OF POWER SYSTEMS: Need for computer control of power systems. Concept of energy control centre (or) load dispatch centre and the functions – SCADA and EMS functions.

UNIT – I
LOAD FREQUENCY CONTROL

1.1 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.

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).

1.2 Automatic Load Frequency Control:

The ALFC is to control the frequency deviation by maintaining the real power balance in the system. The main functions of the ALFC are to i) to maintain the steady frequency; ii) control the tie-line flows; and iii) distribute the load among the participating generating units. The control (input) signals are the tie-line deviation ΔP_{tie} (measured from the tie line flows), and the frequency deviation Δf (obtained by measuring the angle deviation $\Delta\delta$). These error signals Δf and ΔP_{tie} are amplified, mixed and transformed to a real power signal, which then controls the valve position. Depending on the valve position, the turbine (prime mover) changes its output power to establish the real power balance. The complete control schematic is shown in Fig1.1.

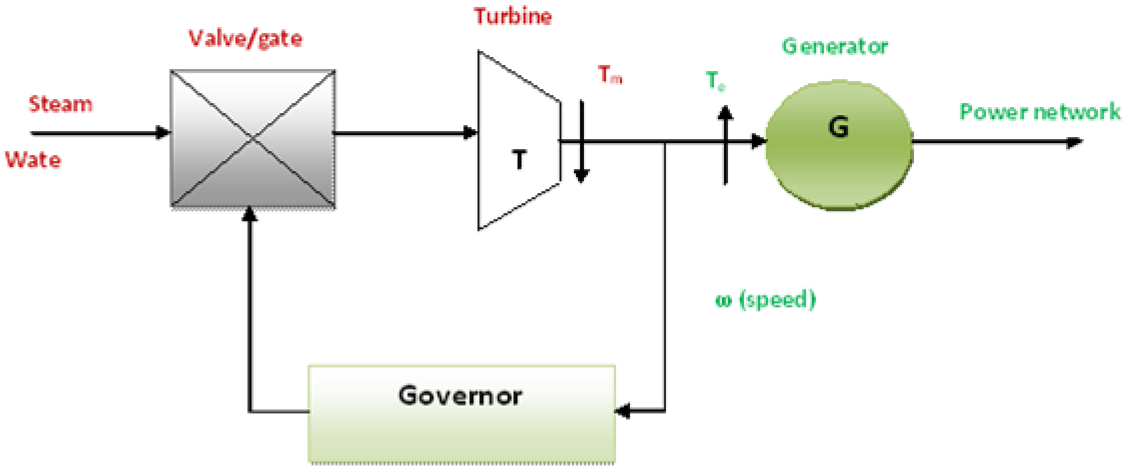


Fig.1.1: The Schematic representation of ALFC system

1.3 Speed Governing System:

Fig. 1.2 is the schematic representation of Turbine Speed Governing system. It has mainly four major components.

Speed governor: Speed governor senses the change in speed (or frequency) hence it can be regarded as heart of the system. The standard model of speed governor operates by fly-ball mechanism. Fly-balls moves outward when

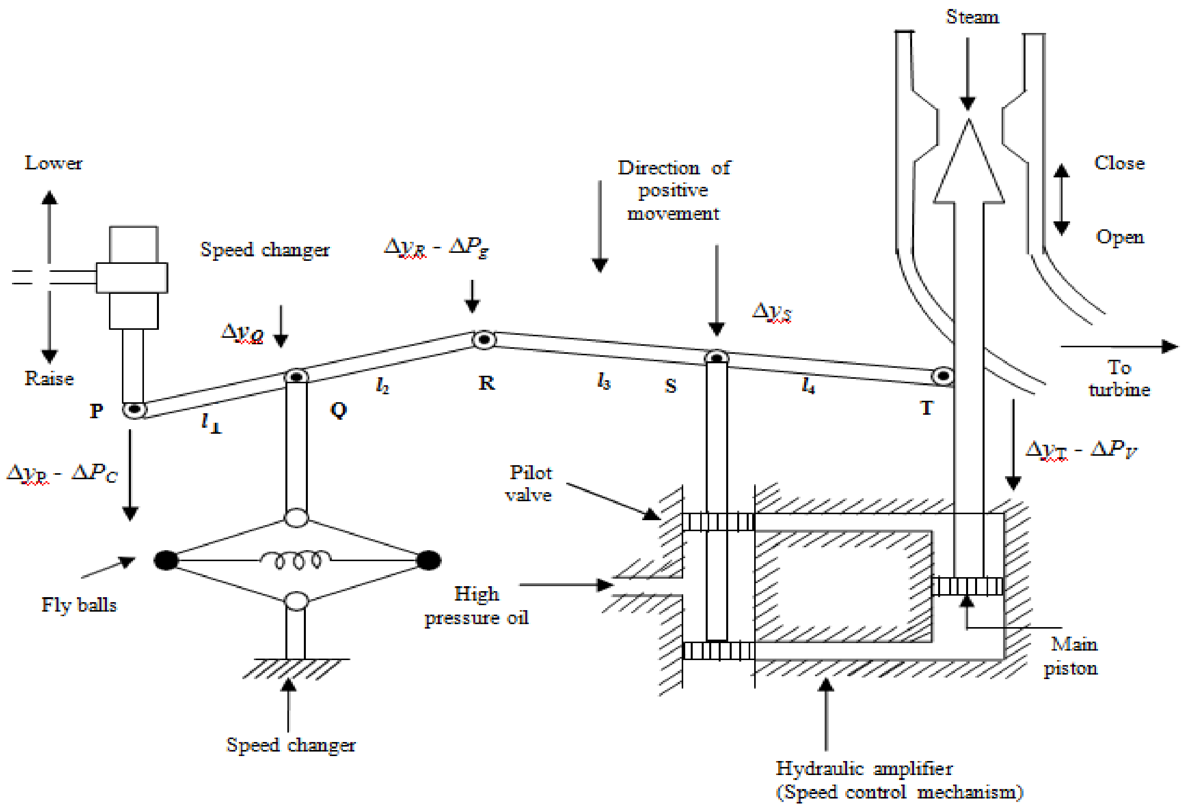
speed increases and the point Q on the linkage mechanism moves downwards. the reverse happens when the speed decreases. The movement of point Q is proportional to change in shaft speed.

Linage mechanism: PQR is a rigid link pivoted at Q and RST is another rigid link pivoted at S. 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.

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

Speed changer: It provides a steady state power output setting for the turbine. Its downwards movement opens the upper pilot valve so that more steam is admitted to the turbine under steady conditions the reverse happens for upward movement of speed changer. By adjusting the linkage position of point P the scheduled speed/frequency can be obtained at the given loading condition.

Fig.1.2: Schematic of Speed Governing System



For the analysis, the models for each of the blocks in Fig1.1 are required. The generator and the electrical load constitute the power system. The valve and the hydraulic amplifier represent the speed governing system. Using the swing equation, the generator can be modeled by

$$\frac{2Hd^2\Delta\delta}{\omega_s dt^2} = \Delta P_m - \Delta P_e$$

Expressing the speed deviation in pu,

$$\frac{d\Delta\omega}{dt} = \frac{1}{2H}(\Delta P_m - \Delta P_e)$$

This relation can be represented as shown in Fig.1.3.

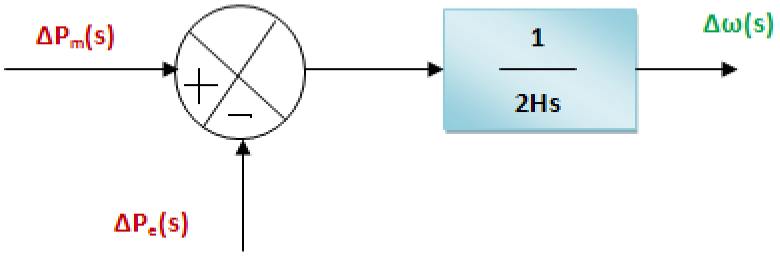


Fig.1.3:The block diagram representation of the Generator

The load on the system is composite consisting of a frequency independent component and a frequency dependent component. The load can be written as $\Delta P_e = \Delta P_0 + \Delta P_f$ where, ΔP_e is the change in the load; ΔP_0 is the frequency independent load component; ΔP_f is the frequency dependent load component. $\Delta P_f = D\Delta\omega$ where, D is called frequency characteristic of the load (also called as damping constant) expressed in percent change in load for 1% change in frequency. If D=1.5%, then a 1% change in frequency causes 1.5% change in load. The combined generator and the load (constituting the power system) can then be represented as shown in Fig 1.4.

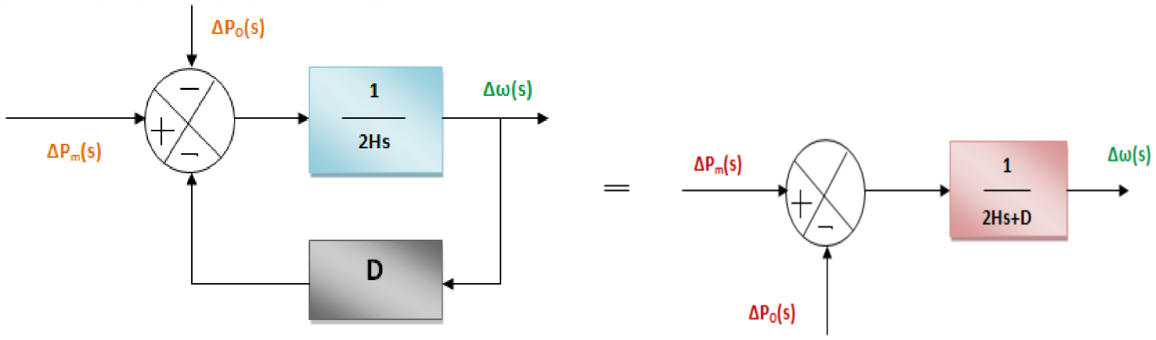
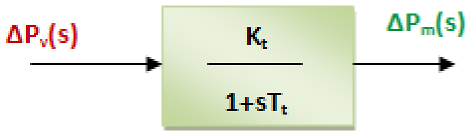


Fig1.4:The block diagram representation of the Generator and load

The turbine can be modeled as a first order lag as shown in the Fig1.5



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

Fig1.5.The turbine model

Gt(s) is the TF of the turbine; ΔPV(s) is the change in valve output (due to action). ΔPm(s) is the change in the turbine output the governor can similarly modeled as shown in Fig1.4. The output of the governor is by

$\Delta P_g = \Delta P_{ref} - \frac{\Delta\omega}{R}$ where ΔP_{ref} is the reference set power, and $\Delta\omega/R$ is the power given by governor speed characteristic. The hydraulic amplifier transforms this signal ΔP_g into valve/gate position corresponding to a power ΔP_V. Thus $\Delta P_V(s) = (K_g/(1+sT_g))\Delta P_g(s)$.

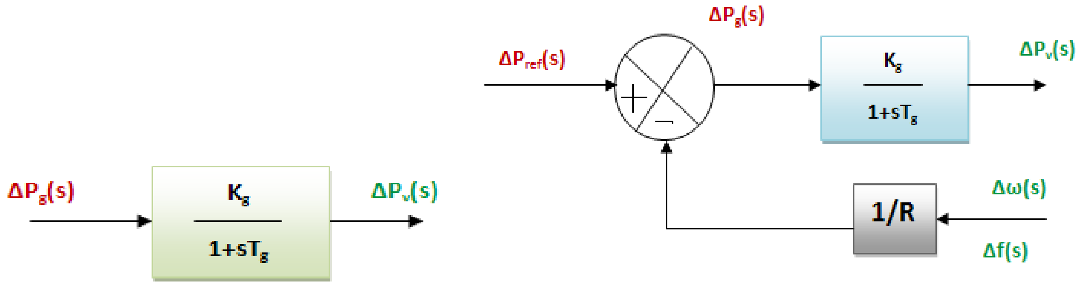


Fig1.6: The block diagram representation of the Governor

All the individual blocks can now be connected to represent the complete ALFC loop as Shown in Fig 1.7.

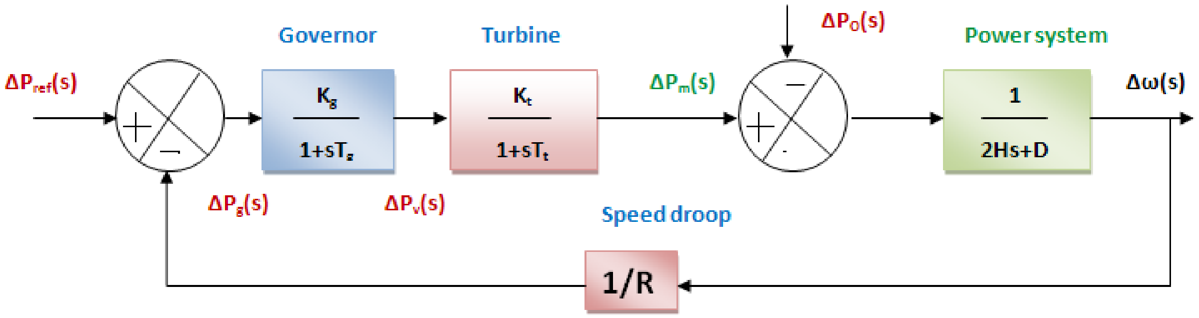


Fig1.7: The block diagram representation of the ALFC.

SINGLE AREA AND TWO AREA LOAD FREQUENCY CONTROL

Modern day power systems are divided into various areas. For example in India, there are five regional grids, e.g., Eastern Region, Western Region etc. Each of these areas is generally interconnected to its neighboring areas. The transmission lines that connect an area to its neighboring area are called **tie-lines.** Power sharing between two areas occurs through these tie-lines. Load frequency control, as the name signifies, regulates the power flow between different areas while holding the frequency constant.

As we have an Example 1 that the system frequency rises when the load decreases if ΔP_{ref} is kept at zero. Similarly the frequency may drop if the load increases. However it is desirable to maintain the frequency constant such that $\Delta f=0$. The power flow through different tie-lines are scheduled - for example, area- i may export a pre-specified amount of power to area- j while importing another pre-specified amount of power from area- k . However it is expected that to fulfill this obligation, area- i absorbs its own load change, i.e., increase generation to supply extra load in the area or decrease generation when the load demand in the area has reduced. While doing this area- i must however maintain its obligation to areas j and k as far as importing and exporting power is concerned. A conceptual diagram of the interconnected areas is shown in Fig. 1.8.

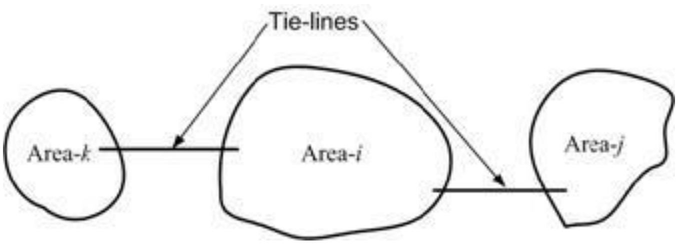


Fig. 1.8: Interconnected areas in a power system

We can therefore state that the load frequency control (LFC) has the following two objectives:

- Hold the frequency constant ($\Delta f = 0$) against any load change. Each area must contribute to absorb any load change such that frequency does not deviate.
- Each area must maintain the tie-line power flow to its pre-specified value.
- $\mathrm{ACE} = (P_{tie} - P_{sch}) + B_f \Delta f = \Delta P_{tie} + B_f \Delta f$

The first step in the LFC is to form the **area control error (ACE)**.

Where P_{tie} and P_{sch} are **tie-line power** and **scheduled power** through tie-line respectively and the constant B_f is called the **frequency bias constant.**

The change in the reference of the power setting $\Delta P_{ref,\, i}$, of the area- i is then obtained by

$$\Delta P_{ref,i} = -K_i \int \mathrm{ACE}\, dt$$

The feedback of the ACE through an integral controller of the form where K_i is the integral gain. The ACE is negative if the net power flow out of an area is low or if the frequency has dropped or both. In this case the generation must be increased. This can be achieved by increasing $\Delta P_{ref,\, i}$. This negative sign accounts for this inverse relation between $\Delta P_{ref,\, i}$ and ACE. The tie-line power flow and frequency of each area are monitored in its control center. Once the ACE is computed and $\Delta P_{ref,\, i}$ is obtained , commands are given to various turbine-generator controls to adjust their reference power settings.

supplementary controls); ii) and to maintain the scheduled tie-line flows. A secondary objective of the AGC is to distribute the required change in generation among the connected generating units economically (to obtain least operating costs).

1.4 Steady State Performance of the ALFC Loop

In the steady state, the ALFC is in 'open' state, and the output is obtained by substituting $s \rightarrow 0$ in the TF.

With $s \rightarrow 0$, Gg(s) and Gt(s) become unity, then, (note that $\Delta P_m = \Delta P_T = \Delta P_G = \Delta P_e = \Delta P_D$;

That is turbine output = generator/electrical output = load demand)

$$\Delta P_m = \Delta P_{ref} - (1/R)\Delta\omega \qquad \text{or} \qquad \Delta P_m = \Delta P_{ref} - (1/R)\Delta f$$

When the generator is connected to infinite bus ($\Delta f = 0$, and $\Delta V = 0$), then $\Delta P_m = \Delta P_{ref}$.

If the network is finite, for a fixed speed changer setting ($\Delta Pref = 0$), then

If there are more than one generator present in the system, then

$$\Delta P_{m.eq} = \Delta P_{ref.eq} - (D + 1/R_{eq})\Delta f$$

where,

$$\Delta P_{m.eq} = \Delta P_{m1} + \Delta P_{m2} + \Delta P_{m3} + \ldots.$$

$$\Delta P_{ref.eq} = \Delta P_{ref1} + \Delta P_{ref2} + \Delta P_{ref3} + \ldots..$$

$$1/R_{eq} = (1/R_1 + 1/R_2 + 1/R_2 + \ldots.)$$

The quantity $\beta = (D + 1/R_{eq})$ is called the area frequency (bias) characteristic (response) or simply the stiffness of the system.

1.5 Concept of AGC (Supplementary ALFC Loop)

The ALFC loop shown in Fig1.7, is called the primary ALFC loop. It achieves the primary goal of real power balance by adjusting the turbine output ΔP_m to match the change in load demand ΔP_D. All the participating generating units contribute to the change in generation. But a change in load results in a steady state frequency deviation Δf. The restoration of the frequency to the nominal value requires an additional control loop called the supplementary loop. This objective is met by using integral controller which makes the frequency deviation zero. The ALFC with the supplementary loop is generally called the AGC. The block diagram of an AGC is shown in Fig1.8. The main objectives of AGC are i) to regulate the frequency (using both primary and

Derivation of Steady state error for single area load frequency control:

From the single area load frequency control block diagram we have,

$\Delta P_G(s) = k_g k_t / (1+sT_g)(1+sT_t)[\Delta P_c(s)-1/R\Delta F(s)]$

The generator is synchronized to a network of very large size. So, the speed or frequency will be essentially independent of any changes in a power output of the generator

ie, $\Delta F(s) = 0$

Therefore $\Delta P_G(s) = k_g k_t / (1+sT_g)(1+sT_t) * \Delta P_c(s)$

Steady state response:

(i) Controlled case:

To find the resulting steady change in the generator output:

Let us assume that we made a step change of the magnitude ΔP_c of the speed changer For step change, $\Delta P_c(s) = \Delta P_c/s$

$\Delta P_G(s) = [k_g k_t/ (1+sT_g) (1+sT_t)]\Delta P_c(s)/s$ $s\Delta P_G(s) = [k_g k_t/ (1+sT_g) (1+sT_t)] \Delta P_c(s)$

Applying final value theorem,

(ii)Uncontrolled case

Let us assume that the load suddenly increases by small amount ΔP_D.

Consider there is no external work and the generator is delivering a power to a single load.

$\Delta Pc = 0$

$Kg\ Kt = 1$

$\Delta P_G(s) = 1/ (1+sT_g) (1+sT_t) [-\Delta F(s)/R]$

For a step change ,$\Delta F(s) = \Delta f/s$

Therefore

$\Delta P_G(s) = 1/(1+sT_g)(1+sT_t)[-\Delta F/sR]$

$\Delta f/\Delta P_{G\ (stat)} = -R$ Hz/MW

Steady State Performance of the ALFC Loop

In the steady state, the ALFC is in open state, and the output is obtained by substituting $s\rightarrow 0$ in the TF.

With $s\rightarrow 0$, Gg(s) and Gt(s) become unity, then,(note that

$\mathbf{\Delta P_m = \Delta P_T = P_G = \Delta Pe = \Delta P_D;}$

That is turbine output = generator/electrical output = load demand)

$\mathbf{\Delta P_m = \Delta Pref - (1/R)\ \Delta\omega}$ **or** $\mathbf{\Delta P_m = \Delta P_{ref} - (1/R)\Delta f}$

When the generator is connected to infinite bus ($\Delta f = 0$, and $\Delta V = 0$), then

$\Delta P_m = \Delta P_{ref}$.

If the network is finite, for a fixed speed changer setting ($\Delta Pref = 0$), then

$\Delta P_m \quad =(1/R)\Delta f$ or $\Delta f = RP_m$.

DYNAMIC RESPONSE OF SINGLE AREA LOAD FREQUENCY CONTROL:

Now we are going to study the effect of a disturbance in the system derived above. Both loss of generation and loss of load can be simulated by imposing a positive or negative step input on the variable P_{load}. A change of the set value of the system frequency f_0 is not considered as this is not meaningful in real power systems. From the block diagram in Figure.

$$\Delta P_{load} \text{ and } \Delta f \ (\Delta P_{m0}^{set} = 0):$$

$$\Delta f(s) = -\frac{1 + sT_t}{\frac{1}{S} + \frac{1}{D_l}(1 + sT_t) + (\frac{2W_0}{f_0} + \frac{2HS_B}{f_0})s(1 + sT_t)}\Delta P_{load}(s)$$

The step response for

$$\Delta P_{load}(s) = \frac{\Delta P_{load}}{s}$$

$$\Delta f_\infty = \lim_{s \to 0}(s \cdot \Delta f(s)) = \frac{-\Delta P_{load}}{\frac{1}{S} + \frac{1}{D_l}} = \frac{-\Delta P_{load}}{\frac{1}{D_R}} = -\Delta P_{load} \cdot D_R$$

with

$$\frac{1}{D_R} = \frac{1}{S} + \frac{1}{D_l}$$

In order to calculate an equivalent time constant Teq, Tt is put to 0. This can be done since for realistic systems the turbine controller time constant Tt is much smaller than the time constant.

$$\Delta f(s) = \frac{-\Delta P_{load}(s)}{\frac{1}{D_R} + T_M \frac{S_B}{f_0}s} = \frac{-1}{1 + T_M D_R \frac{S_B}{f_0}s}\frac{D_R \Delta P_{load}}{s}$$

or

$$\Delta f(s) = \frac{1}{1 + T_M D_R \frac{S_B}{f_0}s}\frac{\Delta f_\infty}{s}$$

with

$$T_{eq} = T_M D_R \frac{S_B}{f_0}$$

as the equivalent time constant.

1.6 AGC in a Single Area System

In a single area system, there is no tie-line schedule to be maintained. Thus the function of the AGC is only to bring the frequency to the nominal value. This will be achieved using the supplementary loop (as shown in Fig.1.7) which uses the integral controller to change the reference power setting so as to change the speed set point. The integral controller gain K_I needs to be adjusted for satisfactory response (in terms of overshoot, settling time) of the system. Although each generator will be having a separate speed governor, all the generators in the control area are replaced by a single equivalent generator, and the ALFC for the area corresponds to this equivalent generator.

1.7 AGC in a Multi Area System

In an interconnected (multi area) system, there will be one ALFC loop for each control area (located at the ECC of that area). They are combined as shown in Fig. 1.9 for the interconnected system operation. For a total change in load of ΔP_D, the steady state deviation in frequency in the two areas is given by $\Delta f = \Delta\omega_1 = \Delta\omega_2 = \dfrac{-\Delta P_D}{\beta_1 + \beta_2}$ where, $\beta_1 = (D_1 + 1/R_1)$; and $\beta_2 = (D_2 + 1/R_2)$.

1.8 Expression for tie-line flow in a two-area interconnected system

Consider a change in load ΔP_{D1} in area1. The steady state frequency deviation Δf is the same for both the areas. That is $\Delta f = \Delta f_1 = \Delta f_2$. Thus, for area1, we have

$$\Delta P_{m1} - \Delta P_{D1} - \Delta P_{12} = D_1 \Delta f$$

where, ΔP_{12} is the tie line power flow from Area1to Area 2; and for Area 2

$$\Delta P_{m2} + \Delta P_{12} = D_2 \Delta f$$

The mechanical power depends on regulation. Hence

$$\Delta P_{m1} = -\frac{\Delta f}{R_1} \qquad \text{and} \qquad \Delta P_{m2} = -\frac{\Delta f}{R_2}$$

Substituting these equations, yields

$$\left(\frac{1}{R_1} + D_1\right)\Delta f = -\Delta P_{12} - \Delta P_{D1} \qquad \text{and} \qquad \left(\frac{1}{R_2} + D_2\right)\Delta f = \Delta P_{12}$$

Solving for Δf, we get

$$\Delta f = \frac{-\Delta P_{D1}}{(1/R_1 + D_1) + (1/R_2 + D_2)} = \frac{-\Delta P_{D1}}{\beta_1 + \beta_2}$$

and

$$\Delta P_{12} = \frac{-\Delta P_{D1}\beta_2}{\beta_1 + \beta_2}$$

where, β_1 and β_2 are the composite frequency response characteristic of Area1 and Area 2 respectively. An increase of load in area1 by ΔP_{D1} results in a frequency reduction in both areas and a tie-line flow of ΔP_{12}. A positive ΔP_{12} is indicative of flow from Area1 to Area 2 while a negative ΔP_{12} means flow from Area 2 to Area1. Similarly, for a change in Area 2 load by ΔP_{D2}, we have

$$\Delta f = \frac{-\Delta P_{D2}}{\beta_1 + \beta_2}$$

and

$$\Delta P_{12} = -\Delta P_{21} = \frac{-\Delta P_{D2}\beta_1}{\beta_1 + \beta_2}$$

Frequency bias tie line control

The tie line deviation reflects the contribution of regulation characteristic of one area to another. The basic objective of supplementary control is to restore balance between each area load generation. This objective is met when the control action maintains

- Frequency at the scheduled value
- Net interchange power (tie line flow) with neighboring areas at the scheduled values

The supplementary control should ideally correct only for changes in that area. In other words, if there is a change in Area1 load, there should be supplementary control only in Area1 and not in Area 2. For this purpose the area control error (ACE) is used (Fig1.9). The ACE of the two areas are given by

For area 1: $ACE_1 = \Delta P_{12} + \beta_1 \Delta f$

For area 2: $ACE_2 = \Delta P_{21} + \beta_2 \Delta f$

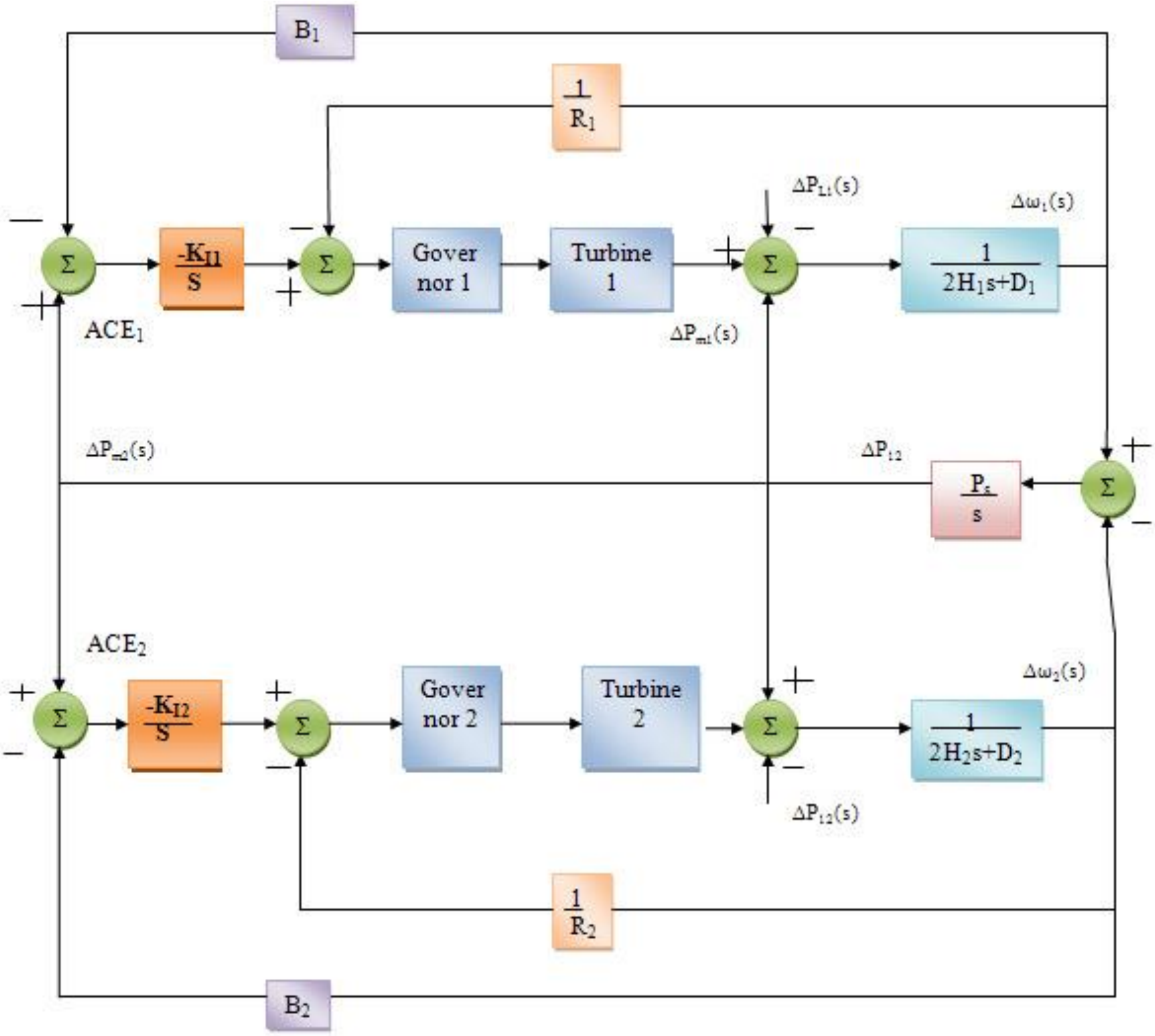


Fig.1.9:AGC for a multi-area operation

1.9 Economic Allocation of Generation:

An important secondary function of the AGC is to allocate generation so that each generating unit is loaded economically. That is, each generating unit is to generate that amount to meet the present demand in such a way that the operating cost is the minimum. This function is called Economic Load Dispatch (ELD).

1.10 Systems with more than two areas:

The method described for the frequency bias control for two area system is applicable to multiage system also.

Section II: Automatic Generation Control:

- **Load Frequency Control**

Automatic Generation Control:

Electric power is generated by converting mechanical energy into electrical energy. The rotor mass, which contains turbine and generator units, stores kinetic energy due to its rotation. This stored kinetic energy accounts for sudden increase in the load. Let us denote the mechanical torque input by T_m and the output electrical torque by T_e . Neglecting the rotational losses, a generator unit is said to be operating in the steady state at a constant speed when the difference between these two elements of torque is zero. In this case we say that the accelerating torque is zero.

$T_a = T_m - T_e$ **..............(1)**

When the electric power demand increases suddenly, the electric torque increases. However, without any feedback mechanism to alter the mechanical torque, T_m remains constant. Therefore the accelerating torque given by (1) becomes negative causing a deceleration of the rotor mass. As the rotor decelerates, kinetic energy is released to supply the increase in the load. Also note that during this time, the system frequency, which is proportional to the rotor speed, also decreases. We can thus infer that any deviation in the frequency for its nominal value of 50 or 60 Hz is indicative of the imbalance between T_m and T_e. The frequency drops when $T_m < T_e$ and rises when $T_m > T_e$.
The steady state power-frequency relation is shown in Fig.1.10 . In this figure the slope of the ΔP_{ref} line is negative and is given by

$$-R = \frac{\Delta f}{\Delta P_m} \quad \text{...............(2)}$$

Where R is called the **regulating constant.** From this figure we can write the steady state power frequency relation as

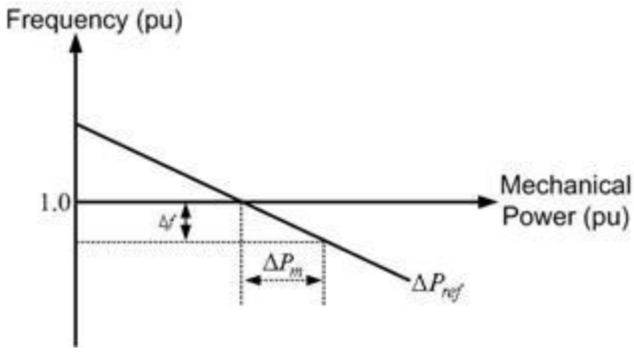


Fig. 1.10: A typical steady-state power-frequency curve.

$$\Delta P_m = \Delta P_{ref} - \frac{1}{R}\Delta f \quad \text{...................(3)}$$

Suppose an interconnected power system contains N turbine-generator units. Then the steady-state power frequency relation is given by the summation of (3) for each of these units as

$$\begin{aligned}\Delta P_m &= \Delta P_{m1} + \Delta P_{m2} + \cdots + \Delta P_{mN} \\ &= \left(\Delta P_{ref1} + \Delta P_{ref2} + \cdots + \Delta P_{refN}\right) - \left(\frac{1}{R_1} + \frac{1}{R_2} + \cdots + \frac{1}{R_N}\right)\Delta f \\ &= \Delta P_{ref} - \left(\frac{1}{R_1} + \frac{1}{R_2} + \cdots + \frac{1}{R_N}\right)\Delta f\end{aligned}$$

In the above equation, ΔP_m is the total change in turbine-generator mechanical power and ΔP_{ref} is the total change in the reference power settings in the power system. Also note that since all the generators are supposed to work in synchronism, the change is frequency of each of the units is the same and is denoted by Δf. Then the **frequency response characteristics** is defined as

$$\beta = \frac{1}{R_1} + \frac{1}{R_2} + \cdots + \frac{1}{R_N}$$

We can therefore modify the equation as

$$\Delta P_m = \Delta P_{ref} - \beta \Delta f$$

Example 1:

Consider an interconnected 50-Hz power system that contains four turbine-generator units rated 750 MW, 500 MW, 220 MW and 110 MW. The regulating constant of each unit is 0.05 per unit based on its own rating. Each unit is operating on 75% of its own rating when the load is suddenly dropped by 250 MW. We shall choose a common base of 500 MW and calculate the rise in frequency and drop in the mechanical power output of each unit.

The first step in the process is to convert the regulating constant, which is given in per unit in the base of each generator, to a common base. This is given as

$$R_{new} = R_{old} \times \frac{S_{base}^{new}}{S_{base}^{old}}$$

We can therefore write

$$R_1 = 0.05 \times \frac{500}{750} = 0.033$$

$$R_2 = 0.05$$

$$R_3 = 0.05 \times \frac{500}{220} = 0.1136$$

$$R_4 = 0.05 \times \frac{500}{110} = 0.2273$$

Therefore

$$\beta = \left(\frac{1}{R_1} + \frac{1}{R_2} + \frac{1}{R_3} + \frac{1}{R_4} \right) = 63.2$$ Per unit

We can therefore calculate the total change in the frequency from while assuming $\Delta P_{ref} = 0$, i.e., for no change in the reference setting. Since the per unit change in load - 250/500 = - 0.5 with the negative sign accounting for load reduction, the change in frequency is given by

$$\Delta f = -\frac{\Delta P_m}{\beta} = -\frac{(-0.5)}{63.2} = 0.0079 \text{ per unit}$$

$$= 0.0079 \times 50 = 0.3956 \text{ Hz}$$

Then the change in the mechanical power of each unit is calculated as

$$\Delta P_{m1} = -\frac{0.0079}{0.033} \times 500 = -118.67 \text{ MW}$$

$$\Delta P_{m2} = -\frac{0.0079}{0.05} \times 500 = -79.11 \text{ MW}$$

$$\Delta P_{m3} = -\frac{0.0079}{0.1136} \times 500 = -34.81 \text{ MW}$$

$$\Delta P_{m4} = -\frac{0.0079}{0.2273} \times 500 = -17.41 \text{ MW}$$

It is to be noted that once ΔP_{m2} is calculated to be - 79.11 MW, we can also calculate the changes in the mechanical power of the other turbine-generators units as

$$\Delta P_{m1} = -79.11 \times \frac{750}{500} = -118.67 \text{ MW}$$

$$\Delta P_{m3} = -79.11 \times \frac{220}{500} = -34.81 \text{ MW}$$

$$\Delta P_{m3} = -79.11 \times \frac{110}{500} = -17.41 \text{ MW}$$

This implies that each turbine-generator unit shares the load change in accordance with its own rating.

Example 2:

Consider a two-area power system in which area-1 generates a total of 2500 MW, while area-2 generates 2000 MW. Area-1 supplies 200 MW to area-2 through the inter-tie lines connected between the two areas. The bias constant of area-1 (β_1) is 875 MW/Hz and that of area-2 (β_2) is 700 MW/Hz. With the two areas operating in the steady state, the load of area-2 suddenly increases by 100 MW. It is desirable that area-2 absorbs its own load change while not allowing the frequency to drift.

The area control errors of the two areas are given by

$\text{ACE}_1 = \Delta P_{tie1} + B_1 \Delta f_1$ And $\text{ACE}_2 = \Delta P_{tie2} + B_2 \Delta f_2$

Since the net change in the power flow through tie-lines connecting these two areas must be zero, we have

$$\Delta P_{tie1} + \Delta P_{tie2} = 0 \Rightarrow \Delta P_{tie1} = -\Delta P_{tie2}$$

Also as the transients die out, the drift in the frequency of both these areas is assumed to be constant, i.e.

$$\Delta f_1 = \Delta f_2 = \Delta f$$

If the load frequency controller is able to set the power reference of area-2 properly, the ACE of the two areas will be zero, i.e., $\text{ACE}_1 = \text{ACE}_2 = 0$. Then we have

$$\text{ACE}_1 + \text{ACE}_2 = (B_1 + B_2)\Delta f = 0$$

This will imply that Δf will be equal to zero while maintaining $\Delta P_{tie1} = \Delta P_{tie2} = 0$. This signifies that area-2 picks up the additional load in the steady state.

Coordination between LFC and Economic Dispatch

Both the load frequency control and the economic dispatch issue commands to change the power setting of each turbine-governor unit. At a first glance it may seem that these two commands can be conflicting. This however is not true. A typical automatic generation control strategy is shown in Fig. 1.12 in which both the objective are coordinated. First we compute the area control error. A share of this ACE, proportional to α_i , is allocated to each of the turbine-generator unit of an area. Also the share of unit- i , γ_i X $\Sigma(P_{DK} - P_k)$, for the deviation of total generation from actual generation is computed. Also the error between the economic power setting and actual power setting of unit- i is computed. All these signals are then combined and passed through a proportional gain K_i to obtain the turbine-governor control signal.

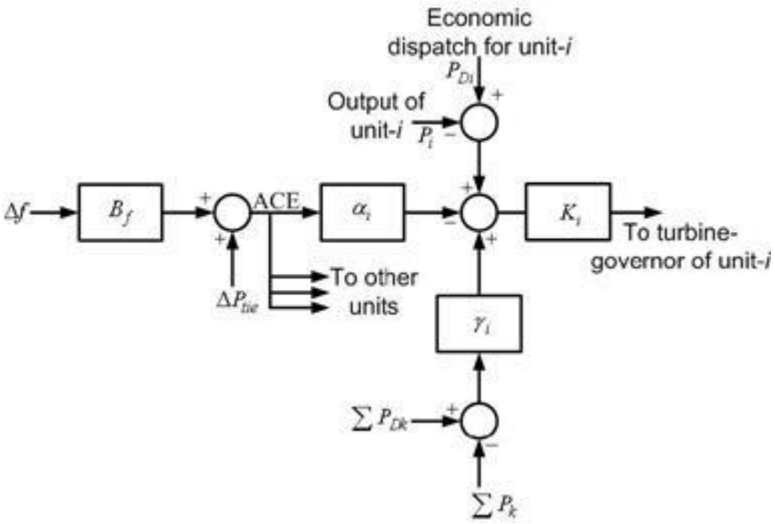


Fig. 1.12: Automatic generation control of unit-I

Section II: Swing Equation:

Let us consider a three-phase synchronous alternator that is driven by a prime mover. The equation of motion of the machine rotor is given by

$$J\frac{d^2\theta}{dt^2} = T_m - T_e = T_a \quad \text{.................(1)}$$

Where

J	is the total moment of inertia of the rotor mass in kgm^2
T_m	is the mechanical torque supplied by the prime mover in N-m
T_e	is the electrical torque output of the alternator in N-m
Θ	is the angular position of the rotor in rad

Neglecting the losses, the difference between the mechanical and electrical torque gives the net accelerating torque T_a . In the steady state, the electrical torque is equal to the mechanical torque, and hence the accelerating power will be zero. During this period the rotor will move at **synchronous speed** ω_s in rad/s.

The angular position θ is measured with a stationary reference frame. To represent it with respect to the synchronously rotating frame, we define

$$\theta = \omega_s t + \delta \quad \text{................(2)}$$

Where δ is the angular position in radians with respect to the synchronously rotating

$$I_S = \frac{V_1\angle\delta - V_2}{jX} = \frac{V_1\cos\delta - V_2 + jV_1\sin\delta}{jX} \quad \text{......................(3)}$$

Reference frame. Taking the time derivative of the above equation we get

Defining the angular speed of the rotor as

$$\omega_r = \frac{d\theta}{dt} \quad \text{................(4)}$$

We can write above equation as

$$\omega_r - \omega_s = \frac{d\delta}{dt} \quad \text{.....................(5)}$$

We can therefore conclude that the rotor angular speed is equal to the synchronous speed only when $d\delta / dt$ is equal to zero. We can therefore term $d\delta /dt$ as the error in speed.

$$J\frac{d^2\delta}{dt^2} = T_m - T_e = T_a \quad ....(6)$$

Taking derivative of (3), we can then rewrite (1) as Multiplying both side of (6) by ω_m we get

$$J\omega_r\frac{d^2\delta}{dt^2} = P_m - P_e = P_a \quad ....(7)$$

Where P_m , P_e and P_a respectively are the mechanical, electrical and accelerating power in MW.

$$H = \frac{\text{Stored kinetic energy at synchronous speed in mega - joules}}{\text{Generator MVA rating}} = \frac{J\omega_s^2}{2S_{rated}} \quad ....(8)$$

We now define a normalized inertia constant as Substituting (8) in (6) we get

$$2H\frac{S_{rated}}{\omega_s^2}\omega_r\frac{d^2\delta}{dt^2} = P_m - P_e = P_a \quad ....(9)$$

In steady state, the machine angular speed is equal to the synchronous speed and hence we can replace ω_r in the above equation by ω_s. Note that in (9) P_m , P_e and P_a are given in MW. Therefore dividing them by the generator MVA rating S_{rated} we can get these quantities in per unit. Hence dividing both sides of (9) by S_{rated} we get

$$\frac{2H}{\omega_s}\frac{d^2\delta}{dt^2} = P_m - P_e = P_a \quad ....(10)$$

Equation (10) describes the behavior of the rotor dynamics and hence is known as the swing equation. The angle δ is the angle of the internal emf of the generator and it dictates the amount of power that can be transferred. This angle is therefore called the **load angle.**

Example 1:

A 50 Hz, 4-pole turbo generator is rated 500 MVA, 22 kV and has an inertia constant (*H*) of 7.5. Assume that the generator is synchronized with a large power system and has a zero accelerating power while delivering a power of 450 MW. Suddenly its input power is changed to 475 MW. We have to find the speed of the generator in rpm at the end of a period of 10 cycles. The rotational losses are assumed to be zero.

We then have

$$\frac{d^2\delta}{dt^2} = \frac{\omega_s}{2H}(P_m - P_e) = \frac{100\pi}{15}\times 25 = 523.6 \text{ electrical deg/s}^2$$

$$= \frac{523.6\pi}{180} = 9.1385 \text{ electrical rad/s}^2$$

Noting that the generator has four poles, we can rewrite the above equation as

$$\frac{d^2\delta}{dt^2} = \frac{9.1385}{2} = 4.5693 \text{ mechanical rad/s}^2$$

$$= 60\times\frac{4.5693}{2\pi} = 43.6332 \text{ rpm/s}$$

The machines accelerates for 10 cycles, i.e., 20 × 10 = 200 ms = 0.2 s, starting with a synchronous speed of 1500 rpm. Therefore at the end of 10 cycles

Speed = 1500 + 43.6332 ´ 0.2 = 1508.7266 rpm.

UNIT-II

REACTIVE POWER VOLTAGE CONTROL

2.1 Generator Voltage Control System:

The voltage of the generator is proportional to the speed and excitation (flux) of the generator. The speed being constant, the excitation is used to control the voltage. Therefore, the voltage control system is also called as excitation control system or automatic voltage regulator (AVR).

For the alternators, the excitation is provided by a device (another machine or a static device) called exciter. For a large alternator the exciter may be required to supply a field current of as large as 6500A at 500V and hence the exciter is a fairly large machine. Depending on the way the dc supply is given to the field winding of the alternator (which is on the rotor), the exciters are classified as: i) DC Exciters; ii) AC Exciters; and iii) Static Exciters. Accordingly, several standard block diagrams are developed by the IEEE working group to represent the excitation system. A schematic of an excitation control system is shown in Fig2.1.

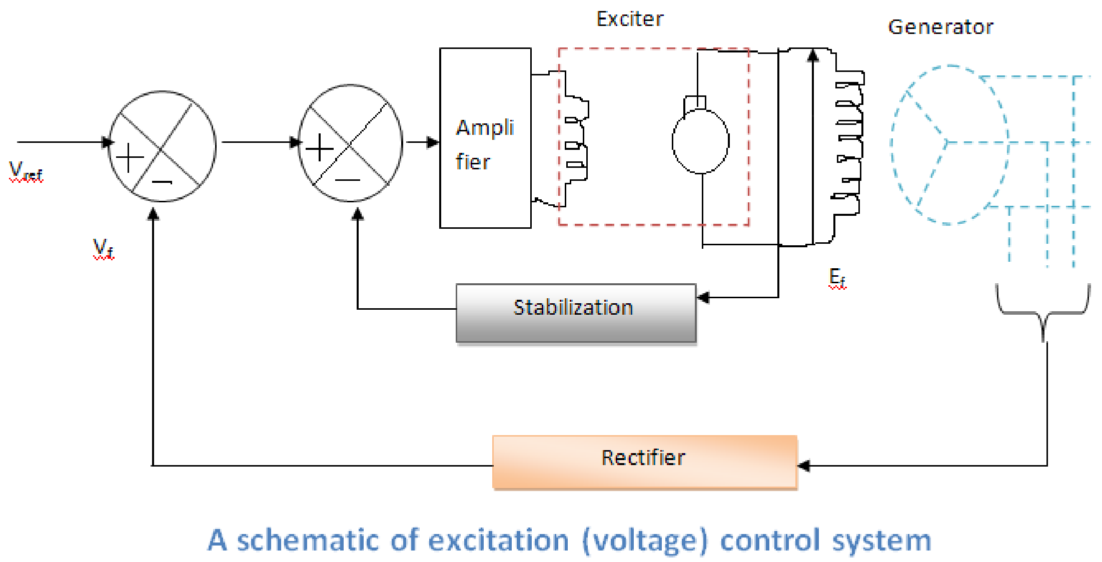
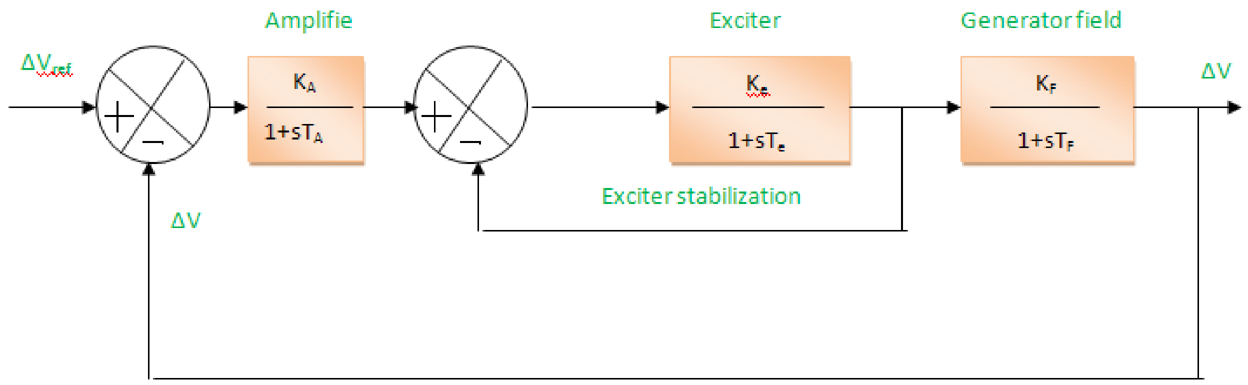


Fig2.1: A schematic of Excitation (Voltage) Control System.

A simplified block diagram of the generator voltage control system is shown in Fig2.2.The generator terminal voltage Vt is compared with a voltage reference Vref to obtain a voltage error signal _V. This signal is applied to the voltage regulator shown as a block with transfer function KA/ (1+TAs). The output of the regulator is then applied to exciter shown with a block of transfer function Ke/ (1+Tes). The output of the exciter e.m.f is then applied to the field winding which adjusts the generator terminal voltage. The generator field can be represented by a block with a transfer function KF/ (1+sTF). The total transfer function is

$$\frac{\Delta V}{\Delta V_{ref}} = \frac{G(s)}{1+G(s)} \quad \text{where,} \quad G(s) = \frac{K_A K_e K_F}{(1+sT_A)(1+sT_e)(1+sT_F)}$$

The stabilizing compensator shown in the diagram is used to improve the dynamic response of the exciter. The input to this block is the exciter voltage and the output is a stabilizing feedback signal to reduce the excessive overshoot.



A simplified block diagram of voltage (excitation) control system

Fig.2.2: A simplified block diagram of Voltage (Excitation) Control System.

Performance of AVR Loop:

The purpose of the AVR loop is to maintain the generator terminal voltage with inacceptable values. A static accuracy limit in percentage is specified for the AVR, so that the terminal voltage is maintained within that value. For example, if the accuracy limit is 4%, then the terminal voltage must be maintained within 4% of the base voltage.

The performance of the AVR loop is measured by its ability to regulate the terminal voltage of the generator within prescribed static accuracy limit with an acceptable speed of response. Suppose the static accuracy limit is denoted by Ac in percentage with reference to the nominal value. The error voltage is to be less than (Ac/100) |Vref. From the block diagram, for a steady state error voltage

$$\Delta e = \Delta|V|_{ref} - \Delta|V|_t < \frac{Ac}{100}\Delta|V|_{ref}$$

$$\Delta e = \Delta|V|_{ref} - \Delta|V|_t = \Delta|V|_{ref} - \frac{G(s)}{1+G(s)}\Delta|V|_{ref}$$

$$= \{1 - \frac{G(s)}{1+G(s)}\}\Delta|V|_{ref}$$

$$\Delta e = \{1 - \frac{G(s)}{1+G(s)}\}\Delta|V|_{ref} = \{1 - \frac{G(0)}{1+G(0)}\}\Delta|V|_{ref}$$

$$= \frac{1}{1+G(0)}\Delta|V|_{ref} = \frac{1}{1+K}\Delta|V|_{ref}$$

For constant input condition, $(s \to 0)$

Where, K= G(0) is the open loop gain of the AVR. Hence,

$$\frac{1}{1+K}\Delta|V|_{ref} < \frac{Ac}{100}\Delta|V|_{ref} \quad \text{or} \quad K > \{\frac{100}{Ac} - 1\}$$

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.

In DC supply system the voltage can be controlled by using over compound generators in case of feeders of equal length, but in the case of feeders of different lengths the voltage at the end of each feeder is kept constant using feeder booster. In AC system the voltage can be controlled by using the various methods likes booster transformers, induction regulators, shunt condensers, etc

Working Principle of Voltage Regulator

It works on the principle of detection of errors. The output voltage of an AC generator obtained through a potential transformer and then it is rectified, filtered and compared with a reference. The difference between the actual voltage and the reference voltage is known as the **error voltage**. This error voltage is amplified by an amplifier and then supplied to the main exciter or pilot exciter

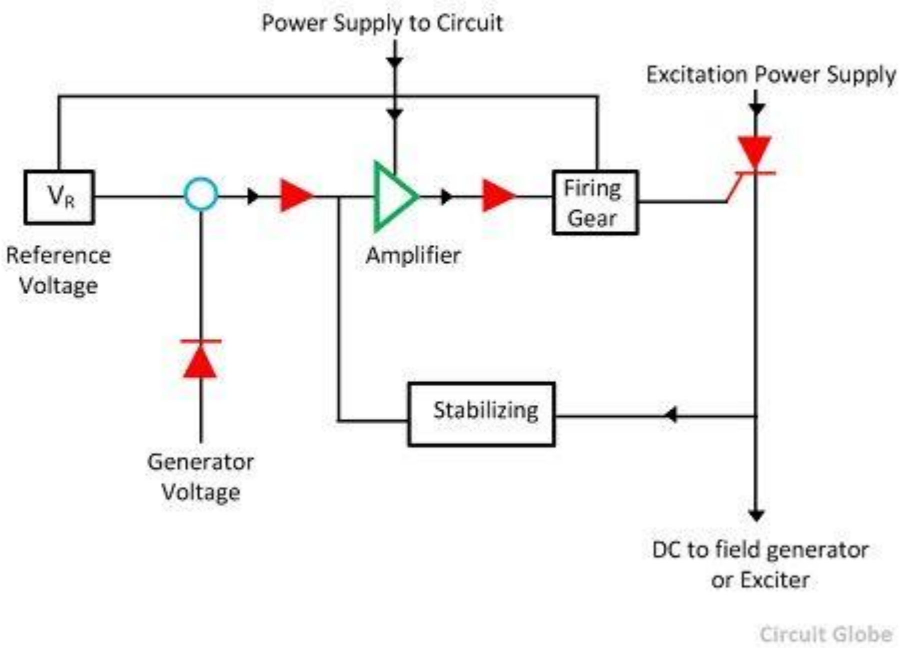


Fig.2.3: Automatic Voltage Regulator

Thus, the amplified error signals control the excitation of the main or pilot exciter through a buck or a boost action (i.e. controls the fluctuation of the voltage). Exciter output control leads to the controls of the main alternator terminal voltage.

Application of the Automatic Voltage Regulator

The main functions of an AVR are as follows.

1. It controls the voltage of the system and has the operation of the machine nearer to the steady state stability.
2. It divides the reactive load between the alternators operating in parallel.
3. The automatic voltage regulators reduce the over voltages which occur because of the sudden loss of load on the system.

4. It increases the excitation of the system under fault conditions so that the maximum synchronizing power exists at the time of clearance of the fault.

When there is a sudden change in load in the alternator, there should be a change in the excitation system to provide the same voltage under the new load condition. This can be done by the help of the automatic voltage regulator. The automatic voltage regulator equipment operates in the exciter field and changes the exciter output voltage, and the field current. During the violent fluctuation, the ARV does not give a quick response.

For getting the quick response, the quick acting voltage regulators based on the overshooting the mark principle are used. In overshoot mark principle, when the load increase the excitation of the system also increase. Before the voltage increase to the value corresponding to the increased excitation, the regulator reduces the excitation of the proper value.

METHODS OF VOLTAGE CONTROL:

In an AC supply system, the voltage can be controlled by the following methods.

1. Excitation control through voltage regulators at generating stations.
2. Employing Tap changing transformers at both sending and receiving end of the transmission lines, industries, substations (both distribution and Transmission).
3. Employing Booster Transformers.
4. Use of Induction regulators.
5. Inserting series capacitors in long EHVAC transmission lines.
6. Employing Switched or Fixed shunt Capacitor banks.
7. Switching in shunt reactors during light loads.
8. Use of synchronous condensers and thyristorised control for step less control of reactive power and voltage.

EXCITATION CONTROL:

The terminal voltage of the alternator varies when the load on the supply system changes which is due to voltage drop in the synchronous impedance of the alternator. The voltage of the alternator cannot be controlled by adjustment of speed, as they have to be run at a constant speed. So the voltage of the alternator can be controlled by using excitation regulation which can be regulated by use of automatic or hand regulator acting in the field circuit of alternator exciter.

The quick acting voltage regulators based on the over-shooting the mark principle gives the quick response which cannot be obtained either by variation of field circuit resistance or change in exciter voltage due to high inductance of alternator. There are two types of automatic voltage regulators. They are

1.Tirril regulator and

2.Brown – Boveri regulator

1. Tirril Regulator: A vibrating type voltage regulator:

The control can be possible by rapidly opening and closing a shunt circuit across the exciter rheostat. In which a fixed resistance is cut in and cut out of the exciter field circuit of the alternator.

2.Brown – Boveri Automatic voltage Regulator:

It works on the principle of the "Over shooting the mark" but differs from Tirril Regulator. In Tirril regulator the resistance is first completely inserted them completely cut out whereas in this type, the regulating resistance is gradually varied in small steps. The system remains rest under steady conditions and the maintenance is less when compared to Tirril regulator.

The excitation control method is limited to small isolated systems because the system becomes unstable if the excitation is below a certain level and also it causes over heating of the rotor if the excitation is above certain level.

TAP CHANGING TRANSFORMERS:

As the excitation control method is limited only to small isolated systems, we have to go for other methods for long transmission lines. One method among them is a Tap changing transformer one which is usually employed where main transformer is necessary

The basic principle is based on changing the ratio of transformation, which can be obtained by adjusting the turns on the primary or secondary depending upon the requirement.

Principal tapping is one in which the tapping on the hr winding when connected to rated voltage gives rise to rated voltage on the LV side.

Positive tapping, is tapping in which the number of turns are more than that of principal tapping whereas a negative tapping is one in which the tapping have loss number of turns than the principal tapping.

Most of the transformers carry rated KVA on over voltage tap and rated current on a reduced voltage tap.

Generally tapping is provided on high voltage side due to following reasons.

1.Smooth and fine control output voltage can be possible as the number of turns on HV side is more.

2.Owing to insulation constraints the LV winding is placed nearer to the core and therefore it is difficult to tap LV winding.

3.Tap chargers on HV side has to carry low currents though it will need more insulation.

Generally there are two types of tap changing's

1.OFF load tap changing :

In this method, there is a need to switch off the supply to the transformer whenever the tap changing takes place. This can be carried out by manually operated switches. This is a very economic method of changing the turn – ratio of a transformer. This is used for occasional adjustments in distribution transformers which are provided with $\pm$ 5% and $\pm$ 2% taps.

2. ON Load Tap Changing :

Almost all the power transformers of large ratings use this type of tap changing. This is based on the principle that, the tap changing on the transformer takes place while delivering the load. The operation can be possible either by local or remote control and also a handle is filled for manual operation in case of emergency if necessary.

The main features of an on-load tap changer is that there is no need to open the main circuit whenever sparking takes place and also no part of the tapping should get short circuited. They are provided with an impedance to limit the short circuit current during the operation.

In general they are also called as resistor or reactor type on-load tap-changers, because in place of impedance they use either resister or centre – tapped reactor. Now days, they are designed by a pair of resistors, which invariably limits the current.

BOOSTER TRANSFORMER:

If the voltage of a feeder has to be controlled at a point far away from the main transformer and if there is no provision for a tap changing gear in the main transformer then we have to use a special transformer which is known as Booster transformer. The primary of booster transformer is supplied from the secondary of the regulating transformer which is fitted with on load tap changing gear. The regulating transformer output is connected to the primary of the booster transformer in such a way that the voltage injected in the line is in phase with the supply voltage. The system becomes expensive if the regulation is required at a point where a main transformer is to be placed and it also requires more floor space and increases the losses.

INDUCTION VOLTAGE REGULATORS:

Induction voltage regulator works on the idea of rotating the primary with respect to secondary. In an Induction voltage regulator the secondary voltage can be varied from zero to maximum value by adjusting the position of the primary - coil axis with respect to the secondary – coil axis, which in turn depends upon the ratio of turns in the two windings. This is also known as step – down transformer. Generally, in this regulator the secondary is connected in series with the circuit and the primary is connected across the circuit to be regulated. They may of single-phase or three-phase and consists of stator and rotor.

The main advantages of this type of voltage control are:

1.They have simple and rugged construction.

2.It gives reliable operation

3.The load and power factor variations do not affect its operation.

4.It provides smooth voltage variation without any arcing or short – circuiting of turns.

The main disadvantage is that it is more expensive than the transformers with tap- changing mechanism. Also they have small magnetizing currents.

The most important application of induction voltage regulator is in distribution systems to maintain the load voltage at a constant value under all load conditions.

SHUNT REACTORS:

Shunt Reactors are generally used to control steady state over voltages when operating under light-load conditions. The reactive power generated by the capacitance causes high voltages if the shunt reactors were not employed. The shunt reactive compensation is kept permanently in order to avoid over voltages and insulation stresses followed by sudden load rejection. The shunt reactors reduce the power transfer capability of the line. Generally they appear like power transformers. They are connected to the low – voltage tertiary winding of a transformer through a suitable circuit breaker. Generally, oil immersed magnetically shielded reactors with gapped core are employed.

STATIC SHUNT COMPENSATION:

Due to recent advances in power electronics and their component ratings these compensating techniques are provided to be far superior and have a step less control of variable compensation. A thyristorised control of shunt reactors and capacitors is provided. The stability improvement and transient voltage control can be possible by using static VAR system (SVS).

The thyristors in capacitor control are made to conduct for long time during peak load period and the thyristors in reactor circuit are made to conduct for long time during light-load period. Therefore step less variation of shunt compensation can be obtained by using static compensation.

SYNCHRONOUS CONDENSERS:

Generally synchronous condensers are specially designed synchronous motors, which are used to control receiving end voltage of a transmission line. According to the load on the transmission line, by varying its excitation the watt less kVA is automatically varied. Due to low losses the efficiencies of these machines are high and hence they draw less current. The phase angle between applied voltage and current is 90^0. The main advantages of synchronous condensers are:

1. Both ends of transmission line can be maintained with same voltage.

2. At heavy loads power factor can be improved.

3.As high terminal reactances are used better protection is possible to the line.

The main disadvantages are supply interruption increases if synchronous condenser comes out of synchronism and also short-circuit current increases.

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. Reference 5 describes simulation results where 50% line drop compensation at nine power plants significantly improved long-term voltage stability in the Portland, Oregon load area. The improvement was similar to adding a 460 MVAr, 550-kV capacitor bank in the load area. Difficulties with line drop compensation arise when two or more generators are paralleled at their terminals. Panel session papers describe line drop compensation for this condition. Again, digital AVRs facilitate more complicated control.

Compensation of Power Transmission Systems:

Introduction:

Ideal Series Compensator:

- Impact of Series Compensator on Voltage Profile
- Improving Power-Angle Characteristics
- An Alternate Method of Voltage Injection
- Improving Stability Margin
- Comparisons of the Two Modes of Operation

Power Flow Control and Power Swing Damping

Introduction:

The two major problems that the modern power systems are facing are voltage and angle stabilities. There are various approaches to overcome the problem of stability arising due to small signal oscillations in an interconnected power system. As mentioned in the previous chapter, installing power system stabilizers with generator excitation control system provides damping to these oscillations. However, with the advancement in the power electronic technology, various reactive power control equipment are increasingly used in power transmission systems.

A power network is mostly reactive. A synchronous generator usually generates active power that is specified by the mechanical power input. The reactive power supplied by the generator is dictated by the network and load requirements. A generator usually does not have any control over it. However the lack of reactive power can cause voltage collapse in a system. It is therefore important to supply/absorb excess reactive power to/from the network. Shunt compensation is one possible approach of providing reactive power support.

A device that is connected in parallel with a transmission line is called a **shunt compensator,** while a device that is connected in series with the transmission line is called a *series compensator*. These are referred to as compensators since they compensate for the reactive power in the ac system. We shall assume that the shunt compensator is always connected at the midpoint of transmission system, while the

- voltage profile
- power-angle characteristics
- stability margin
- damping to power oscillations

- A **static var compensator (SVC)** is the first generation shunt compensator. It has been around since 1960s. In the beginning it was used for load compensation such as to provide var support for large industrial loads, for flicker mitigation etc. However with the advancement of semiconductor technology, the SVC started appearing in the transmission systems in 1970s. Today a large number of SVCs are connected to many transmission systems all over the world. An SVC is constructed using the thyristors technology and therefore does not have gate turn off capability.
- With the advancement in the power electronic technology, the application of a gate turn off thyristors (GTO) to high power application became commercially feasible. With this the second generation shunt compensator device was conceptualized and constructed. These devices use synchronous voltage sources for generating or absorbing reactive power. A synchronous voltage source (SVS) is constructed using a voltage source converter (VSC). Such a shunt compensating device is called **static compensator or STATCOM.** A STATCOM usually contains an SVS that is driven from a dc storage capacitor and the SVS is connected to the ac system bus through an

interface transformer. The transformer steps the ac system voltage down such that the voltage rating of the SVS switches are within specified limit. Furthermore, the leakage reactance of the transformer plays a very significant role in the operation of the STATCOM.

- Like the SVC, a thyristors controlled series compensator (TCSC) is a thyristors based series compensator that connects a thyristors controlled reactor (TCR **)** in parallel with a fixed capacitor. By varying the firing angle of the anti-parallel thyristors that are connected in series with a reactor in the TCR, the fundamental frequency inductive reactance of the TCR can be changed. This effects a change in the reactance of the TCSC and it can be controlled to produce either inductive or capacitive reactance.
- Alternatively a **static synchronous series compensator or SSSC** can be used for series compensation. An SSSC is an SVS based all GTO based device which contains a VSC. The VSC is driven by a dc capacitor. The output of the VSC is connected to a three-phase transformer. The other end of the transformer is connected in series with the transmission line. Unlike the TCSC, which changes the impedance of the line, an SSSC injects a voltage in the line in quadrature with the line current. By making the SSSC voltage to lead or lag the line current by 90° the SSSC can emulate the behavior of an inductance or capacitance.

In this chapter, we shall discuss the ideal behavior of these compensating devices. For simplicity we shall consider the ideal models and broadly discuss the advantages of series and shunt compensation.

Section I: Ideal Shunt Compensator

- **Improving Voltage Profile**
- **Improving Power-Angle Characteristics**
- **Improving Stability Margin**
- **Improving Damping to Power Oscillations**

The ideal shunt compensator is an ideal current source. We call this an ideal shunt compensator because we assume that it only supplies reactive power and no real power to the system. It is needless to say that this assumption is not valid for practical systems. However, for an introduction, the assumption is more than adequate. We shall investigate the behavior of the compensator when connected in the middle of a transmission line. This is shown in Fig.2.4, where the shunt compensator, represented by an ideal current source, is placed in the middle of a lossless transmission line. We shall demonstrate that such a configuration improves the four points that are mentioned above.

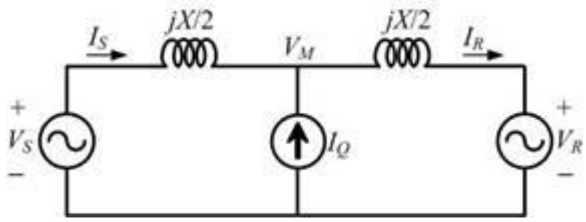


Fig.2.4: Schematic diagram of an ideal, midpoint shunt compensation

Improving Voltage Profile:

Let the sending and receiving voltages be given by $V\angle\delta$ and $V\angle 0°$ respectively. The ideal shunt compensator is expected to regulate the midpoint voltage to

$V_M = V\angle(\delta/2)$ ....(10.1)

Against any variation in the compensator current. The voltage current characteristic of the compensator is shown in Fig. 10.2. This ideal behavior however is not feasible in practical systems where we get a slight droop in the voltage characteristic. This will be discussed later.

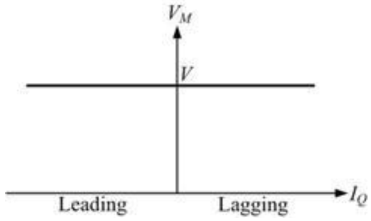


Fig. 2.5: Voltage-current characteristic of an ideal shunt compensator

Under the assumption that the shunt compensator regulates the midpoint voltage tightly as given by (10.1), we can write the following expressions for the sending and receiving end currents

$$I_S = \frac{V\angle\delta - V\angle(\delta/2)}{jX/2} \quad \ldots\ldots\ldots\ldots\ldots\ldots(10.2)$$

$$I_S = \frac{V\angle\delta - V\angle(\delta/2)}{jX/2} \quad \ldots\ldots\ldots\ldots\ldots\ldots(10.3)$$

$$I_S + I_Q = I_R \quad \ldots\ldots\ldots\ldots\ldots(10.4)$$

Again from Fig. 10.1 we write

$$I_Q = -j\frac{4V}{X}\{1-\cos(\delta/2)\}\angle(\delta/2) \quad \ldots\ldots\ldots\ldots\ldots(10.5)$$

We thus have to generate a current that is in phase with the midpoint voltage and has a magnitude of $(4V / X_L)\{1 - \cos(\delta/2)\}$. The apparent power injected by the shunt compensator to the ac bus is then

$$P_Q + jQ_Q = V_M I_Q^* = -j\frac{4V^2}{X}\{1-\cos(\delta/2)\} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots(10.6)$$

Since the real part of the injected power is zero, we conclude that the ideal shunt compensator injects only reactive power to the ac system and no real power.

Improving Power-Angle Characteristics:

The apparent power supplied by the source is given by

$$P_S + jQ_S = V_S I_S^* = V\angle\delta\left[\frac{V\angle-\delta - V\angle-(\delta/2)}{-jX/2}\right] = \frac{V^2 - V\angle(\delta/2)}{-jX/2}$$

$$= \frac{2V^2\sin(\delta/2)}{X} + j\frac{2V^2\{1-\cos(\delta/2)\}}{X} \quad \ldots\ldots\ldots\ldots\ldots\ldots(10.7)$$

Similarly the apparent power delivered at the receiving end is

$$P_R + jQ_R = V_R I_R^* = V\left[\frac{V\angle-(\delta/2) - V}{-jX/2}\right]$$

$$= \frac{2V^2\sin(\delta/2)}{X} + j\frac{2V^2\{\cos(\delta/2)-1\}}{X} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots(10.8)$$

$$P_e = P_S = P_R = \frac{2V^2}{X}\sin(\delta/2) \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots(10.9)$$

Hence the real power transmitted over the line is given by

$$Q_e = Q_S + Q_Q - Q_R = \frac{8V^2}{X}\{1-\cos(\delta/2)\} \quad ....(10.10)$$

The power-angle characteristics of the shunt compensated line are shown in Fig.2.6. In this figure $P_{max} = V^2/X$ is chosen as the power base.

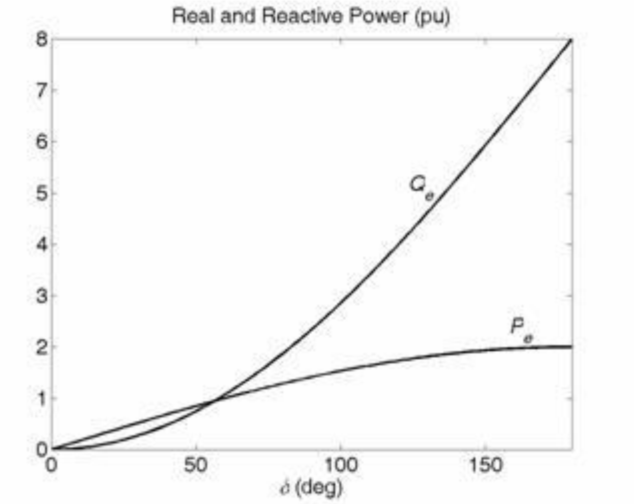


Fig.2.6: Power-angle characteristics of ideal shunt compensated line.

Fig. 2.6 depicts P_e - δ and Q_Q - δ characteristics. It can be seen from fig 10.4 that for a real power transfer of 1 per unit, a reactive power injection of roughly 0.5359 per unit will be required from the shunt compensator if the midpoint voltage is regulated as per (10.1). Similarly for increasing the real power transmitted to 2 per unit, the shunt compensator has to inject 4 per unit of reactive power. This will obviously increase the device rating and may not be practical. Therefore power transfer enhancement using midpoint shunt compensation may not be feasible from the device rating point of view.

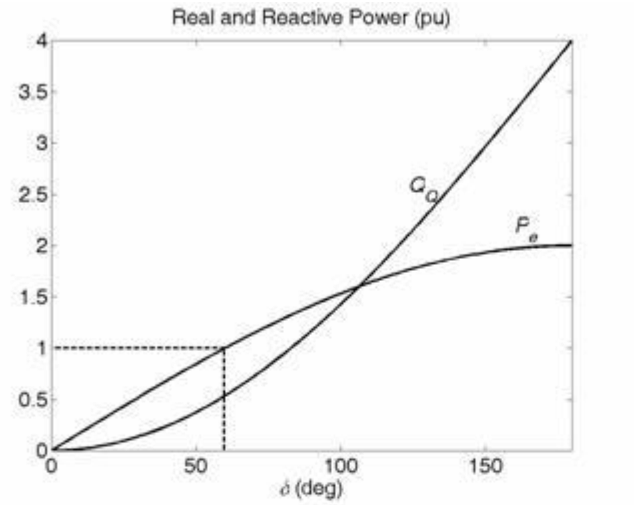


Fig. 2.7: Variations in transmitted real power and reactive power injection by the shunt compensator with load angle for perfect midpoint voltage regulation.

Let us now relax the condition that the midpoint voltage is regulated to 1.0 per unit. We then obtain some very interesting plots as shown in Fig. 10.5. In this figure, the x-axis shows the reactive power available from the shunt device, while the y-axis shows the maximum power that can be transferred over the line without violating the voltage constraint. There are three different P-Q relationships given for three midpoint voltage constraints. For a reactive power injection of 0.5 per unit, the power transfer can be increased from about 0.97 per unit to 1.17 per unit by lowering the midpoint voltage to 0.9 per unit. For a reactive power injection greater than 2.0 per unit, the best power transfer capability is obtained for V_M = 1.0 per unit. Thus there will be no benefit in reducing the voltage constraint when the shunt device is capable of injecting a large amount of reactive power. In practice, the level to which the midpoint voltage can be regulated depends on the rating of the installed shunt device as well the power being transferred.

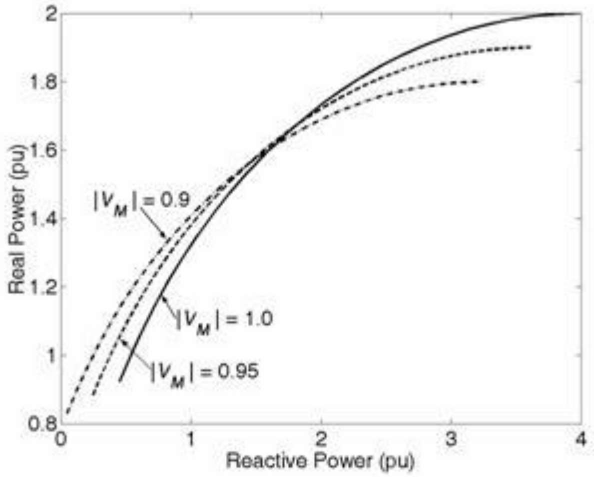


Fig. 2.8: Power transfer versus shunt reactive injection under midpoint voltage constraint.

UNIT-III
ECONOMIC OPERATION OF POWER SYSTEMS

Overview:

- Economic Distribution of Loads between the Units of a Plant
- Generating Limits
- Economic Sharing of Loads between Different Plants

Automatic Generation Control:

- Load Frequency Control

Coordination between LFC and Economic Dispatch :

A good business practice is the one in which the production cost is minimized without sacrificing the quality. This is not any different in the power sector as well. The main aim here is to reduce the production cost while maintaining the voltage magnitudes at each bus. In this chapter we shall discuss the economic operation strategy along with the turbine-governor control that are required to maintain the power dispatch economically.

A power plant has to cater to load conditions all throughout the day, come summer or winter. It is therefore illogical to assume that the same level of power must be generated at all time. The power generation must vary according to the load pattern, which may in turn vary with season. Therefore the economic operation must take into account the load condition at all times. Moreover once the economic generation condition has been calculated, the turbine-governor must be controlled in such a way that this generation condition is maintained. In this chapter we shall discuss these two aspects.

Economic operation of power systems:

Introduction:

One of the earliest applications of on-line centralized control was to provide a central facility, to operate economically, several generating plants supplying the loads of the system. Modern integrated systems have different types of generating plants, such as coal fired thermal plants, hydel plants, nuclear plants, oil and natural gas units etc. The capital investment, operation and maintenance costs are different for different types of plants.

The operation economics can again be subdivided into two parts.

i) Problem of *economic dispatch*, which deals with determining the power output of each plant to meet the specified load, such that the overall fuel cost is minimized.

ii) Problem of *optimal power flow*, which deals with minimum – loss delivery, where in the power flow, is optimized to minimize losses in the system.

In this chapter we consider the problem of economic dispatch. During operation of the plant, a generator may be in one of the following states:

i) Base supply without regulation: the output is a constant.

ii) Base supply with regulation: output power is regulated based on system load.

iii) Automatic non-economic regulation: output level changes around a base setting as area control error changes.

iv) Automatic economic regulation: output level is adjusted, with the area load and area control error, while tracking an economic setting. Regardless of the units operating state, it has a contribution to the economic operation, even though its output is changed for different reasons.

The factors influencing the cost of generation are the generator efficiency, fuel cost and transmission losses. The most efficient generator may not give minimum cost, since it may be located in a place where fuel cost is high. Further, if the plant is located far from the load centers, transmission losses may be high and running the plant may become uneconomical. The economic dispatch problem basically determines the generation of different plants to minimize total operating cost.

Modern generating plants like nuclear plants, geo-thermal plants etc, may require capital investment of millions of rupees. The economic dispatch is however determined in terms of fuel cost per unit power generated and does not include capital investment, maintenance, depreciation, start-up and shut down costs etc.

Performance Curves Input-Output Curve:

This is the fundamental curve for a thermal plant and is a plot of the input in British

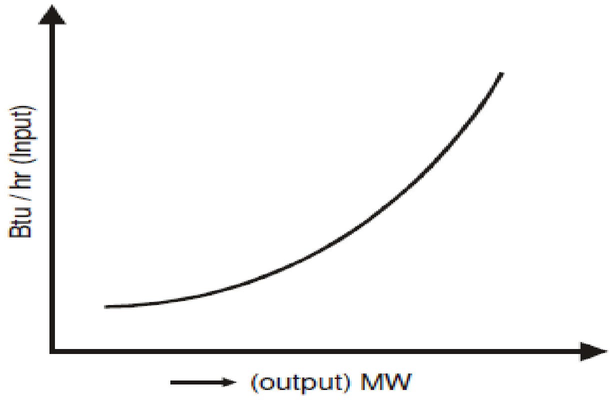


Fig 1: Input – output curve

Thermal units (Btu) per hour versus the power output of the plant in MW as shown in Fig1

Incremental Fuel Rate Curve:

The incremental fuel rate is equal to a small change in input divided by the corresponding change in output.

$$\text{Incremental fuel rate } = \frac{\Delta Input}{\Delta Output}$$

The unit is again Btu / KWh. A plot of incremental fuel rate versus the output is shown in Fig.2.

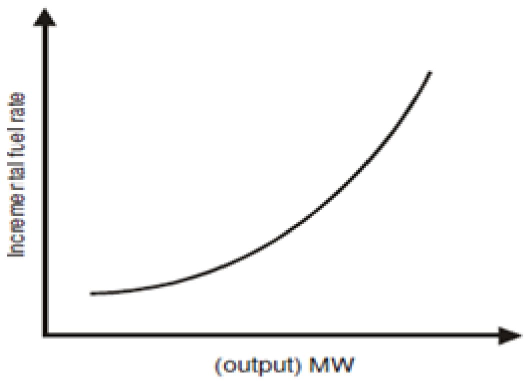


Fig 2 : Incremental fuel rate curve

Incremental cost curve:

The incremental cost is the product of incremental fuel rate and fuel cost (Rs / Btu) the curve is shown in Fig. 3. The unit of the incremental fuel cost is Rs / MWhr.

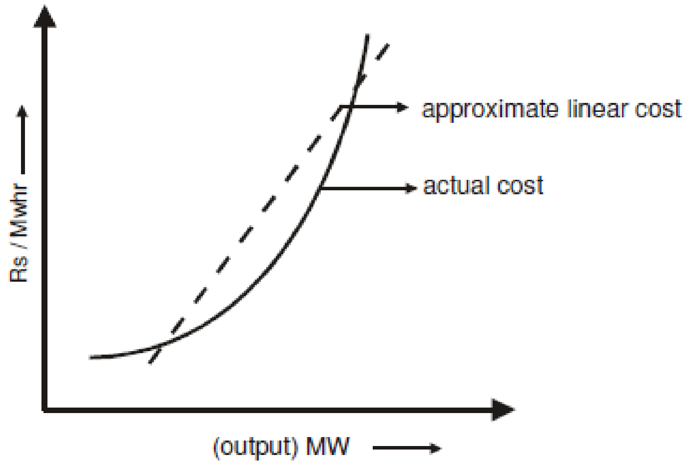


Fig. 3: Incremental cost curve

In general, the fuel cost Fi for a plant, is approximated as a quadratic function of the generated output PGi.

$$F_i = a_i + b_i P_{Gi} + c_i P_{Gi}^2 \quad Rs / h$$

The incremental fuel cost is given by

$$\frac{dF_i}{dP_{Gi}} = b_i + 2c_i P_{Gi} \quad Rs / MWh$$

The incremental fuel cost is a measure of how costly it will be produce an increment of power. The incremental production cost, is made up of incremental fuel cost plus the incremental cost of labor, water, maintenance etc. which can be taken to be some percentage of the incremental fuel cost, instead of resorting to a rigorous mathematical model. The cost curve can be approximated by a linear curve. While there is negligible operating cost for a hydel plant, there is a limitation on the power output possible. In any plant, all units normally operate between PGmin, the minimum loading limit, below which it is technically infeasible to operate a unit and PGmax, which is the maximum output limit.

Section I: Economic Operation of Power System

- **Economic Distribution of Loads between the Units of a Plant**
- **Generating Limits**
- **Economic Sharing of Loads between Different Plants**

In an early attempt at economic operation it was decided to supply power from the most efficient plant at light load conditions. As the load increased, the power was supplied by this most efficient plant till the point of maximum efficiency of this plant was reached. With further increase in load, the next most efficient plant would supply power till its maximum efficiency is reached. In this way the power would be supplied by the most efficient to the least efficient plant to reach the peak demand. Unfortunately however, this method failed to minimize the total cost of electricity generation. We must therefore search for alternative method which takes into account the total cost generation of all the units of a plant that is supplying a load.

Economic Distribution of Loads between the Units of a Plant:

To determine the economic distribution of a load amongst the different units of a plant, the variable operating costs of each unit must be expressed in terms of its power output. The fuel cost is the main cost in a thermal or nuclear unit. Then the fuel cost must be expressed in terms of the power output. Other costs, such as the operation and maintenance costs, can also be expressed in terms of the power output. Fixed costs, such as the capital cost, depreciation etc., are not included in the fuel cost.

The fuel requirement of each generator is given in terms of the Rupees/hour. Let us define the input cost of an unit- i, f_i in Rs/h and the power output of the unit as P_i . Then the input cost can be expressed in terms of the power output as

$$f_i = \frac{a_i}{2} P_i^2 + b_i P_i + c_i \quad \text{Rs/hr} \quad \text{..................(1.1)}$$

The operating cost given by the above quadratic equation is obtained by approximating the power in MW versus the cost in Rupees curve. The incremental operating cost of each unit is then computed as

$$\lambda_i = \frac{df_i}{dP_i} = a_i P_i + b_i \quad \text{Rs/MWh} \quad \text{....................(1.2)}$$

Let us now assume that only two units having different incremental costs supply a load. There will be a reduction in cost if some amount of load is transferred from the unit with higher incremental cost to the unit with lower incremental cost. In this fashion, the load is transferred from the less efficient unit to the more efficient unit thereby reducing the total operation cost. The load transfer will continue till the incremental costs of both the units are same. This will be optimum point of operation for both the units. The above principle can be extended to plants with a total of N number of units. The total fuel cost will then be the summation of the individual fuel cost f_i , $i = 1, \dots, N$ of each unit, i.e.,

$$f_T = f_1 + f_2 + \cdots + f_N = \sum_{k=1}^{N} f_k \quad \text{....................(1.3)}$$

Let us denote that the total power that the plant is required to supply by P_T , such that

$$P_T = P_1 + P_2 + \cdots + P_N = \sum_{k=1}^{N} P_k \quad \text{....................(1.4)}$$

Where $P_1 , \dots , P_N$ are the power supplied by the N different units.

The objective is minimizing f_T for a given P_T. This can be achieved when the total difference df_T becomes zero, i.e.

$$df_T = \frac{\partial f_T}{\partial P_1} dP_1 + \frac{\partial f_T}{\partial P_2} dP_2 + \cdots + \frac{\partial f_T}{\partial P_N} dP_N = 0 \quad \text{............ (1.5)}$$

Now since the power supplied is assumed to be constant we have

$$dP_T = dP_1 + dP_2 + \cdots + dP_N = 0 \quad \text{................ (1.6)}$$

Multiplying (1.6) by λ and subtracting from (1.5) we get

$$\left(\frac{\partial f_T}{\partial P_1}-\lambda\right)dP_1+\left(\frac{\partial f_T}{\partial P_2}-\lambda\right)dP_2+\cdots+\left(\frac{\partial f_T}{\partial P_N}-\lambda\right)dP_N=0 \quad \text{.....................(1.7)}$$

The equality in (5.7) is satisfied when each individual term given in brackets is zero. This gives us

$$\frac{\partial f_T}{\partial P_i}-\lambda=0,\quad i=1,\ldots,N \quad \text{......................(1.8)}$$

Also the partial derivative becomes a full derivative since only the term f_i of f_T varies with P_i, i = 1... N. We then have

$$\lambda=\frac{df_1}{dP_i}=\frac{df_2}{dP_2}=\cdots=\frac{df_N}{dP_N} \quad \text{....................(1.9)}$$

Generating Limits:

It is not always necessary that all the units of a plant are available to share a load. Some of the units may be taken off due to scheduled maintenance. Also it is not necessary that the less efficient units are switched off during off peak hours. There is a certain amount of shut down and start up costs associated with shutting down a unit during the off peak hours and servicing it back on-line during the peak hours. To complicate the problem further, it may take about eight hours or more to restore the boiler of a unit and synchronizing the unit with the bus. To meet the sudden change in the power demand, it may therefore be necessary to keep more units than it necessary to meet the load demand during that time. This safety margin in generation is called spinning reserve.

The optimal load dispatch problem must then incorporate this startup and shut down cost for without endangering the system security.

The power generation limit of each unit is then given by the inequality constraints

$$P_{\min,i}\le P_i\le P_{\max,i},\quad i=1,\ldots,N \quad \text{.............(1.10)}$$

The maximum limit P_{Gmax} is the upper limit of power generation capacity of each unit. On the other hand, the lower limit P_{Gmin} pertains to the thermal consideration of operating a boiler in a thermal or nuclear generating station. An operational unit must produce a minimum amount of power such that the boiler thermal components are stabilized at the minimum design operating temperature.

Example 1:

Consider two units of a plant that have fuel costs of

$$f_1=\frac{0.8}{2}P_1^2+10P_1+25\ \text{Rs/hr and}\ \ f_2=\frac{0.7}{2}P_2^2+6P_2+20\ \text{Rs/hr}$$

Then the incremental costs will be

$$\lambda_1=\frac{df_1}{dP_1}=0.8P_1+10\ \text{Rs/MWhr and}\ \ \lambda_2=\frac{df_2}{dP_2}=0.7P_2+6\ \text{Rs/MWhr}$$

If these two units together supply a total of 220 MW, then P_1 = 100 MW and P_2 = 120 MW will result in an incremental cost of

$$\lambda_1=80+10=90\ \text{Rs/MWhr and}\ \ \lambda_2=84+6=90\ \text{Rs/MWhr}$$

This implies that the incremental costs of both the units will be same, i.e., the cost of one extra MW of generation will be Rs. 90/MWhr. Then we have

$$f_1 = \frac{0.8}{2}100^2 + 10\times 100 + 25 = 5025 \text{ Rs/hr} \text{ and } f_2 = \frac{0.7}{2}120^2 + 6\times 120 + 20 = 5780 \text{ Rs/hr}$$

And total cost of generation is p

$$f_T = f_1 + f_2 = 10{,}805 \text{ Rs/hr}$$

Now assume that we operate instead with P_1 = 90 MW and P_2 = 130 MW. Then the individual cost of each unit will be

$$f_1 = \frac{0.8}{2}90^2 + 10\times 90 + 25 = 4{,}165 \text{ Rs/hr} \text{ and } f_2 = \frac{0.7}{2}130^2 + 6\times 130 + 20 = 6{,}175 \text{ Rs/hr}$$

And total cost of generation is

$$f_T = f_1 + f_2 = 10{,}880 \text{ Rs/hr}$$

This implies that an additional cost of Rs. 75 is incurred for each hour of operation with this non-optimal setting. Similarly it can be shown that the load is shared equally by the two units, i.e. $P_1 = P_2$ = 110 MW, then the total cost is again 10,880 Rs/hr.

Example 2:

Let us consider a generating station that contains a total number of three generating units. The fuel costs of these units are given by

$$f_1 = \frac{0.8}{2}P_1^2 + 10P_1 + 25 \text{ Rs/hr}$$

$$f_2 = \frac{0.7}{2}P_2^2 + 5P_2 + 20 \text{ Rs/hr}$$

$$f_3 = \frac{0.95}{2}P_3^2 + 15P_3 + 35 \text{ Rs/hr}$$

The generation limits of the units are

$$30 \text{ MW} \le P_1 \le 500 \text{ MW}$$

$$30 \text{ MW} \le P_2 \le 500 \text{ MW}$$

$$30 \text{ MW} \le P_3 \le 250 \text{ MW}$$

The total load that these units supply varies between 90 MW and 1250 MW. Assuming that all the three units are operational all the time, we have to compute the economic operating settings as the load changes.

The incremental costs of these units are

$$\frac{df_1}{dP_1} = 0.8P_1 + 10 \text{ Rs/MWhr}$$

$$\frac{df_2}{dP_2} = 0.7P_2 + 5 \text{ Rs/MWhr}$$

$$\frac{df_3}{dP_3} = 0.95P_3 + 15 \text{ Rs/MWhr}$$

At the minimum load the incremental cost of the units are

$$\frac{df_1}{dP_1} = \frac{0.8}{2}30^2 + 10 = 34 \text{ Rs/MWhr}$$

$$\frac{df_2}{dP_2} = \frac{0.7}{2}30^2 + 5 = 26 \text{ Rs/MWhr}$$

$$\frac{df_3}{dP_3} = \frac{0.95}{2}30^2 + 15 = 43.5 \text{ Rs/MWhr}$$

Since units 1 and 3 have higher incremental cost, they must therefore operate at 30 MW each. The incremental cost during this time will be due to unit-2 and will be equal to 26 Rs/MWhr. With the generation of units 1 and 3 remaining constant, the generation of unit-2 is increased till its incremental cost is equal to that of unit-1, i.e., 34 Rs/MWhr. This is achieved when P_2 is equal to 41.4286 MW, at a total power of 101.4286 MW.

An increase in the total load beyond 101.4286 MW is shared between units 1 and 2, till their incremental costs are equal to that of unit-3, i.e., 43.5 Rs/MWhr. This point is reached when P_1 = 41.875 MW and P_2 = 55 MW. The total load that can be supplied at that point is equal to 126.875. From this point onwards the load is shared between the three units in such a way that the incremental costs of all the units are same. For example for a total load of 200 MW, then we have

$$P_1 + P_2 + P_3 = 200$$

$$0.8P_1 + 10 = 0.7P_2 + 5$$

$$0.7P_2 + 5 = 0.95P_3 + 15$$

Solving the above three equations we get P_1 = 66.37 MW, P_2 = 80 MW and P_3 = 50.63 MW and an incremental cost (λ) of 63.1 Rs./MWhr. In a similar way the economic dispatch for various other load settings are computed. The load distribution and the incremental costs are listed in Table 5.1 for various total power conditions.

At a total load of 906.6964, unit-3 reaches its maximum load of 250 MW. From this point onwards then, the generation of this unit is kept fixed and the economic dispatch problem involves the other two units. For example for a total load of 1000 MW, we get the following two equations

$$P_1 + P_2 = 1000 - 250$$

$$0.8P_1 + 10 = 0.7P_2 + 5$$

Solving which we get P_1 = 346.67 MW and P_2 = 403.33 MW and an incremental cost of 287.33 Rs/MWhr. Furthermore, unit-2 reaches its peak output at a total load of 1181.25. Therefore any further increase in the total load must be supplied by unit-1 and the incremental cost will only be borne by this unit. The power distribution curve is shown in Fig. 4.

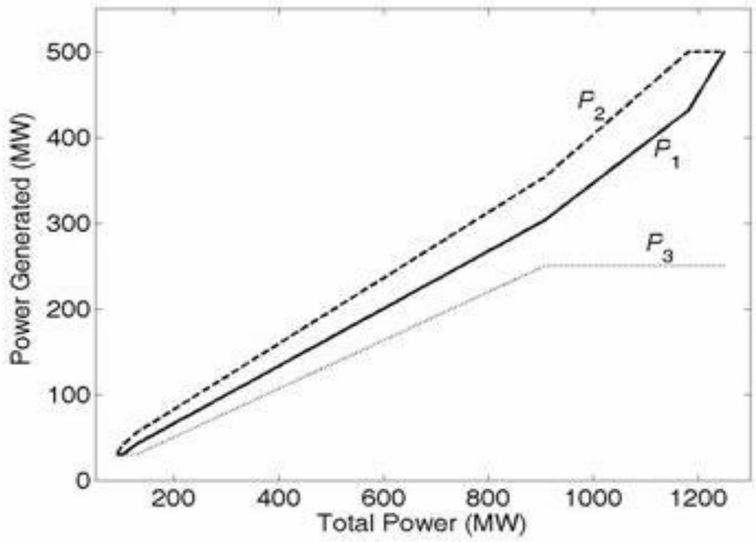


Fig.4: Power distribution between the units of Example 2

Example 3:

Consider two generating plant with same fuel cost and generation limits. These are given by

$$f_i = \frac{0.8}{2}P_i^2 + 10P_i + 25 \text{ Rs./h} \quad i = 1,2$$

$$100 \text{ MW} \le P_i \le 500 \text{ MW}, \quad i = 1,2$$

For a particular time of a year, the total load in a day varies as shown in Fig. 5.2. Also an additional cost of Rs. 5,000 is incurred by switching of a unit during the off peak hours and switching it back on during the during the peak hours. We have to determine whether it is economical to have both units operational all the time.

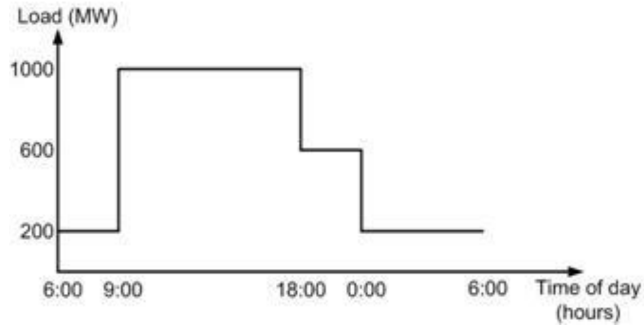


Fig.5. Hourly distribution of a load for the units of Example 2

Since both the units have identical fuel costs, we can switch of any one of the two units during the off peak hour. Therefore the cost of running one unit from midnight to 9 in the morning while delivering 200 MW is

$$\left(\frac{0.8}{2}200^2 + 10 \times 200 + 25\right) \times 9 = 162{,}225 \text{ Rs.}$$

Adding the cost of Rs. 5,000 for decommissioning and commissioning the other unit after nine hours, the total cost becomes Rs. 167,225. 0

On the other hand, if both the units operate all through the off peak hours sharing power equally, then we get a total cost of

$$\left(\frac{0.8}{2}100^2 + 10 \times 100 + 25\right) \times 9 \times 2 = 90{,}450 \text{ Rs.}$$

Which is significantly less that the cost of running one unit alone?

Table 1.1 Load distribution and incremental cost for the units of Example 1

P_T (MW)	P_1 (MW)	P_2 (MW)	P_3 (MW)	λ (Rs./MWh)
90	30	30	30	26
101.4286	30	41.4286	30	34
120	38.67	51.33	30	40.93
126.875	41.875	55	30	43.5
150	49.62	63.85	36.53	49.7
200	66.37	83	50.63	63.1
300	99.87	121.28	78.85	89.9
400	133.38	159.57	107.05	116.7
500	166.88	197.86	135.26	143.5
600	200.38	236.15	163.47	170.3
700	233.88	274.43	191.69	197.1
800	267.38	312.72	219.9	223.9
906.6964	303.125	353.5714	250	252.5
1000	346.67	403.33	250	287.33
1100	393.33	456.67	250	324.67
1181.25	431.25	500	250	355
1200	450	500	250	370
1250	500	500	250	410

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.6(a),

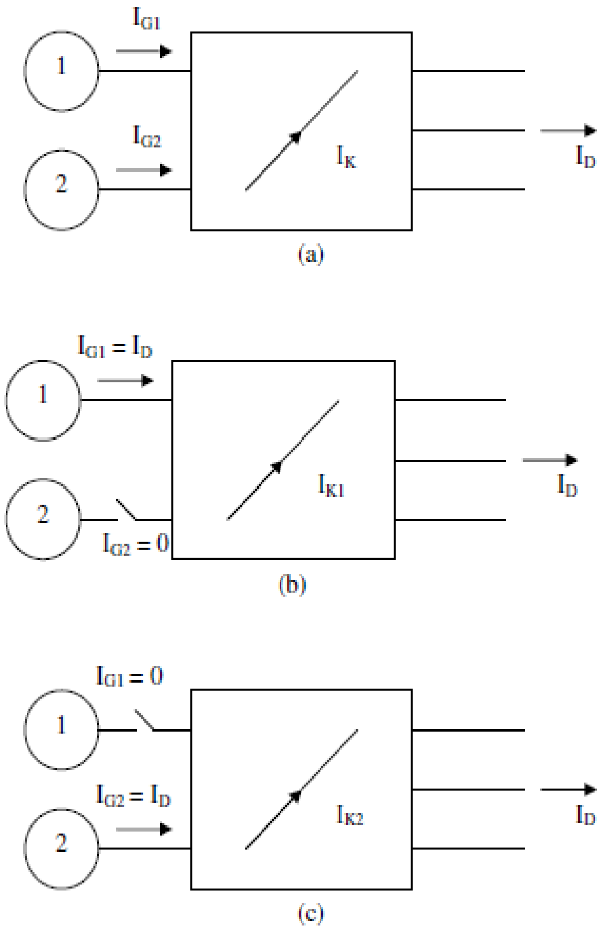


Fig.6: Two plants connected to a number of loads through a transmission network

Let's assume that the total load is supplied by only generator 1 as shown in Fig.6(b). 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

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

NK1 and NK2 are called current distribution factors and their values depend on the impedances of the lines and the network connection. They are independent of ID. When both generators are supplying the load, then by principle of superposition IK = NK1 IG1 + NK2 IG2

Where IG1, IG2 are the currents supplied by plants 1 and 2 respectively, to meet the demand ID. Because of the assumptions made, IK1 and ID have same phase angle, as do IK2 and ID. Therefore, the current distribution factors are real rather than complex. Let

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

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

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

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

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

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

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

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

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

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

$$B_{12} = \frac{\cos(\sigma_1 - \sigma_2)}{|V_1||V_2|\cos\phi_1\cos\phi_2}\sum_K N_{K1}N_{K2}R_K$$

$$B_{22} = \frac{1}{|V_2|^2(\cos\phi_2)^2}\sum_K N_{K2}^{\ 2}R_K$$

The loss – coefficients are called the B – coefficients and have unit MW^{-1}

For a general system with n plants the transmission loss is expressed as

$$P_L = \frac{P_{G1}^{\ 2}}{|V_1|^2(\cos\phi_1)^2}\sum_K N_{K1}^{\ 2} + \dots\dots + \frac{P_{Gn}^{\ 2}}{|V_n|^2(\cos\phi_n)^2}\sum_K N_{Kn}^{\ 2}R_K$$
$$+ 2\sum_{\substack{p,q=1 \\ p\neq q}}^{n}\frac{P_{GP}P_{Gq}\cos(\sigma_p - \sigma_q)}{|V_p||V_q|\cos\phi_p\cos\phi_q}\sum_k N_{KP}N_{Kq}R_K$$

In a compact form

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

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

B – Coefficients can be treated as constants over the load cycle by computing them at average operating conditions, without significant loss of accuracy.

Economic Sharing of Loads between Different Plants:

So far we have considered the economic operation of a single plant in which we have discussed how a particular amount of load is shared between the different units of a plant. In this problem we did not have to consider the transmission line losses and assumed that the losses were a part of the load supplied. However if now consider how a load is distributed between the different plants that are joined by transmission lines, then the line losses have to be explicitly included in the economic dispatch problem. In this section we shall discuss this problem.

When the transmission losses are included in the economic dispatch problem

$$P_T = P_1 + P_2 + \cdots + P_N - P_{LOSS} \text{ ....}(2.1)$$

$$0 = dP_1 + dP_2 + \cdots + dP_N - dP_{LOSS} \text{ ....}(2.2)$$

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

$$dP_{LOSS} = \frac{\partial P_{LOSS}}{\partial P_1} dP_1 + \frac{\partial P_{LOSS}}{\partial P_2} dP_2 + \cdots + \frac{\partial P_{LOSS}}{\partial P_N} dP_N \text{ ....}(2.3)$$

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

$$0 = \left(\lambda \frac{\partial P_{LOSS}}{\partial P_1} - \lambda\right) dP_1 + \left(\lambda \frac{\partial P_{LOSS}}{\partial P_2} - \lambda\right) dP_2 + \cdots + \left(\lambda \frac{\partial P_{LOSS}}{\partial P_N} - \lambda\right) dP_N \text{ ....}(2.4)$$

$$0 = \sum_{i=1}^{N} \left(\frac{\partial f_T}{\partial P_i} + \lambda \frac{\partial P_{LOSS}}{\partial P_i} - \lambda \right) dP_i \text{ ....}(2.5)$$

Adding (2.4) with (1.5) we obtain

$$\frac{\partial f_T}{\partial P_i} + \lambda \frac{\partial P_{LOSS}}{\partial P_i} - \lambda = 0, \quad i = 1, \ldots, N \text{ ....}(2.6)$$

The above equation satisfies when

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

Again since

$$\lambda = \frac{df_1}{dP_i} L_1 = \frac{df_2}{dP_2} L_2 = \cdots = \frac{df_N}{dP_N} L_N \text{ ....}(2.7)$$

From (2.6) we get

$$L_i = \frac{1}{1 - \partial P_{LOSS} / \partial P_i}, \quad i = 1, \ldots, N \text{ ....}(2.8)$$

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

$$P = \begin{bmatrix} P_1 & P_2 & \cdots & P_N \end{bmatrix}^T$$

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

$$P_{LOSS} = P^T B P \text{ ....}(2.9)$$

Then the transmission losses are expressed in general as

Where B is a symmetric matrix given by

$$B = \begin{bmatrix} B_{11} & B_{12} & \cdots & B_{1N} \\ B_{12} & B_{22} & \cdots & B_{2N} \\ \vdots & \vdots & \ddots & \vdots \\ B_{1N} & B_{2N} & \cdots & B_{NN} \end{bmatrix}$$

The elements B_{ij} of the matrix B are called the **loss coefficients.** These coefficients are not constant but vary with plant loading. However for the simplified calculation of the penalty factor L_i these coefficients are often assumed to be constant.

When the incremental cost equations are linear, we can use analytical equations to find out the economic settings. However in practice, the incremental costs are given by nonlinear equations that may even contain nonlinearities. In that case iterative solutions are required to find the optimal generator settings.

Introduction to Economic operation of 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.

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 economical.

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.

A device which taps electrical energy from the electric power system is called a load on the system. The load may be resistive (e.g., electric lamp), inductive (e.g., induction motor), capacitive or some combination of them. The various types of loads on the power system are :

1.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%).

2.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

3.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 load above 500 kW. Industrial loads are generally not weather dependent.

4.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.

5.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.

6.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:

1. Demand: The demand of a system is the load at receiving end over a specified time interval.

2. Maximum Demand: The maximum demand of a system is the greater of all the demands within the time interval specified.

3. 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.

4. 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

5. Non-coincident demand: I t i s “the sum of the demands of a group of loads with no restrictions on the interval to which each demand is applicable.

6. Connected load: It is "the sum of the continuous ratings of the load consuming apparatus connected to the system”

7. 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

8. 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

9. 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

10. 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 of the whole system"

$$F_D = \frac{D_1 + D_2 + D_3 + \cdots + D_n}{D_g}$$

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

Coincidence factor: It is "the ratio of the maximum coincident total demand of a group of consumers to the sum of the maximum power demands of individual consumers comprising the group both taken at the same point of supply for the same time"

$$F_c = \frac{1}{F_D}.$$

Load diversity It is "the difference between the sum of the peaks of two or more individual loads and the peak of the combined load"

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

$$F_c = \frac{\sum_{i=1}^{n} c_i \times D_i}{\sum_{i=1}^{n} D_i} \quad \text{.................(1)}$$

$$D_g = c_1 \times D_1 + c_2 \times D_2 + c_3 \times D_3 + \cdots + c_n \times D_n. \quad \text{..............(2)}$$

Substituting eq:(2) in eq:(1),we get

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

Loss factor: It is " the ratio of the average power loss to the peak-load power loss during a specified period o f time"

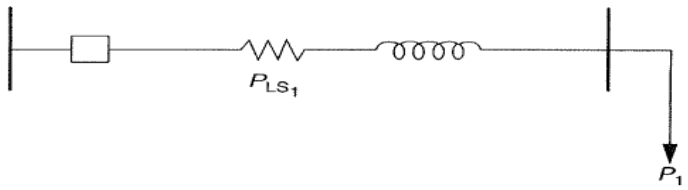
Relationship between Load & loss factors:

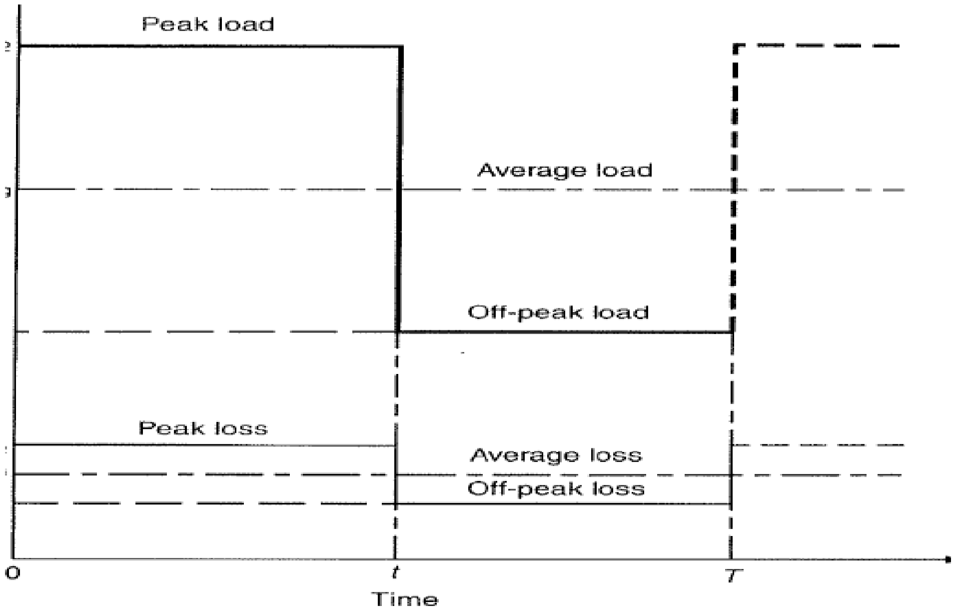
$$F_{LD} = \frac{P_{av}}{P_{max}} = \frac{P_{av}}{P_2}.$$

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

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

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





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

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

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

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

Where *k* is a constant. Thus, from the equations, the loss factor can be expressed as

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

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

Load factor can be related to loss factor for three different cases

Case 1: Off-peak load is zero. Here,

$$P_{LS,1} = 0$$

Since P=0,we will get

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

That is, the load factor is equal to the loss factor and they are equal to the *t/T* constant

Case 2: Very short lasting peak. Here,

$$t \longrightarrow 0$$

$$\frac{T - t}{T} \longrightarrow 1.0;$$

$$F_{LS} \longrightarrow (F_{LD})^2$$

That is, the value of the loss factor approaches the value of the load factor squared

Case 3: Load is steady. Here,

$$t \longrightarrow T.$$

That is, the difference between the peak load and the off-peak load is negligible. For example, if the customer's load is a petrochemical plant, this would be the case

$$F_{LS} \longrightarrow F_{LD}.$$

That is, the value of the loss factor approaches the value of the load factor. Therefore, in general, the value of the loss factor is

$$F_{LD}^2 < F_{LS} < F_{LD}.$$

Therefore, the loss factor cannot be determined directly from the load factor. The reason is that the loss factor is determined from losses as a function of time, which, in turn, is proportional to the time function of the square load

However, Buller and Woodrow developed an approximate formula to relate the loss factor to the load factor as

$$F_{LS} = 0.3\,F_{LD} + 0.7\,F_{LD}^2$$

Where FLS is the loss factor (pu) and FLD is the load factor (pu).

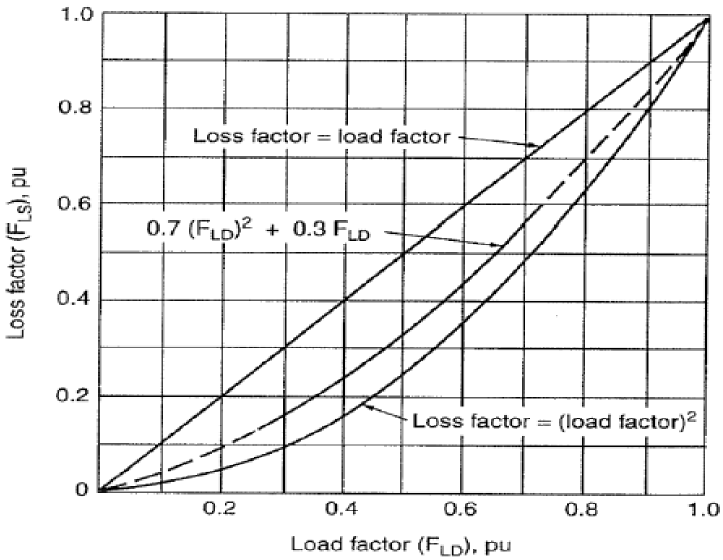
Equation 2.40a gives a reasonably close result. Figure 2.10 gives three different curves of loss factor as a function of load factor. Relatively recently, the formula given before has been modified for rural areas and expressed as

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

Problem: The average load factor of a substation is 0.65. Determine the average loss factor of its feeders, if the substation services

(a) An urban area.

(b)A rural area



(a) For the urban area,

$$FLS = 0.3F_{LD} + 0.7(F_{LD})^2$$

$$= 0.3(0.65) + 0.7(0.65)^2$$

$$= 0.49.$$

(b) For the rural area,

$$FLS = 0.16F_{LD} + 0.84(F_{LD})^2$$

$$= 0.16(0.65) + 0.84(0.65)^2$$

$$= 0.53.$$

UNIT-IV

UNIT COMMITMENT

Introduction:

The life style of a modern man follows regular habits and hence the present society also follows regularly repeated cycles or pattern in daily life. Therefore, the consumption of electrical energy also follows a predictable daily, weekly and seasonal pattern. There are periods of high power consumption as well as low power consumption. It is therefore possible to commit the generating units from the available capacity into service to meet the demand. The previous discussions all deal with the computational aspects for allocating load to a plant in the most economical manner. For a given combination of plants the determination of optimal combination of plants for operation at any one time is also desired for carrying out the aforesaid task. The plant commitment and unit ordering schedules extend the period of optimization from a few minutes to several hours. From daily schedules weekly patterns can be developed. Likewise, monthly, seasonal and annual schedules can be prepared taking into consideration the repetitive nature of the load demand and seasonal variations. Unit commitment schedules are thus required for economically committing the units in plants to service with the time at which individual units should be taken out from or returned to service.

Constraints in Unit Commitment:

Many constraints can be placed on the unit commitment problem. The list presented here is by no means exhaustive. Each individual power system, power pool, reliability council, and so forth, may impose different rules on the scheduling of units, depending on the generation makeup, load-curve characteristics,

and such.

Spinning Reserve:

Spinning reserve is the term used to describe the total amount of generation available

from all units synchronized (i.e., spinning) on the system, minus the present load and losses being supplied. Spinning reserve must be carried so that the loss of one or more units does not cause too far a drop in system frequency. Quite simply, if one unit is lost, there must be ample reserve on the other units to make up for the loss in a specified time period. Spinning reserve must be allocated to obey certain rules, usually set by regional reliability councils (in the United States) that specify how the reserve is to be allocated to various units. Typical rules specify that reserve must be a given percentage of forecasted peak demand, or that reserve must be capable of making up the loss of the most heavily loaded unit in a given period of time.Others calculate reserve requirements as a function of the probability of not having sufficient generation to meet the load. Not only must the reserve be sufficient to make up for a generation-unit failure, but the reserves must be allocated among fast-responding units and slow-responding units. This allows the automatic generation control system to restore frequency and interchange quickly in the event of a generating-unit outage. Beyond spinning reserve, the unit commitment problem may involve various classes of "scheduled reserves" or "off-line" reserves. These include quick-start diesel or gas-turbine units as well as most hydro-units and pumped-storage hydro- units that can be brought on-line, synchronized, and brought up to full capacity quickly. As such, these units can be "counted" in the overall reserve assessment, as long as their time to come up to full capacity is taken into account. Reserves, finally, must be spread around the power system to avoid transmission system limitations (often called "bottling" of reserves) and to allow various parts of the system to run as "islands," should they become electrically disconnected.

<u>Thermal Unit Constraints:</u>

Thermal units usually require a crew to operate them, especially when turned on and turned off. A thermal unit can undergo only gradual temperature changes, and this translates into a time period of some hours required to bring the unit on-line. As a result of such restrictions in the operation of a thermal plant, various constraints arise, such as:

1. **Minimum up time:** once the unit is running, it should not be turned off immediately

2. **Minimum down time:** once the unit is decommitted, there is a minimum time before it can be recommitted.

3. **Crew constraints:** if a plant consists of two or more units, they cannot both be turned on at the same time since there are not enough crew members to attend both units while starting up. In addition, because the temperature and pressure of the thermal unit must be moved slowly, a certain amount of energy must be expended to bring the unit on-line. This energy does not result in any MW generation from the unit and is brought into the unit commitment problem as a ***start-up*** *cost.* The start-up cost can vary from a maximum "cold-start" value to a much smaller value if the unit was only turned off recently and is still relatively close to operating temperature. There are two approaches to treating a thermal unit during its down period. The first allows the unit's boiler to cool down and then heat back up to operating temperature in time for a scheduled turn on. The second (called *banking)* requires that sufficient energy be input to the boiler to just maintain operating temperature. The costs for the two can be compared so that, if possible, the best approach (cooling or banking) can be chosen.

4. Cf= fixed cost (includes crew expense, maintenance expenses) (in R)

5. α = thermal time constant for the unit

6. ***t*** = time (h) the unit was cooled

7. Start-up cost when banking = Ct x ***t***

8. x F+Cf

9. Ct = cost (MBtu/h) of maintaining unit at operating temperature up to a certain number of hours, the cost of banking will be less than the cost of cooling, as is illustrated in Figure 5.3.Finally, the capacity limits of thermal units may change frequently, due to maintenance or unscheduled outages of various equipment in the plant; this must also be taken.

Other Constraints:

Hydro-Constraints:

Unit commitment cannot be completely separated from the scheduling of hydro-units. In this text, we will assume that the hydrothermal scheduling (or "coordination") problem can be separated from the unit commitment problem. We, of course, cannot assert flatly that our treatment in this fashion will always result in an optimal solution.
Some units are given a must-run status during certain times of the year for reason of voltage support on the transmission network or for such purposes as supply of steam for uses outside the steam plant itself.

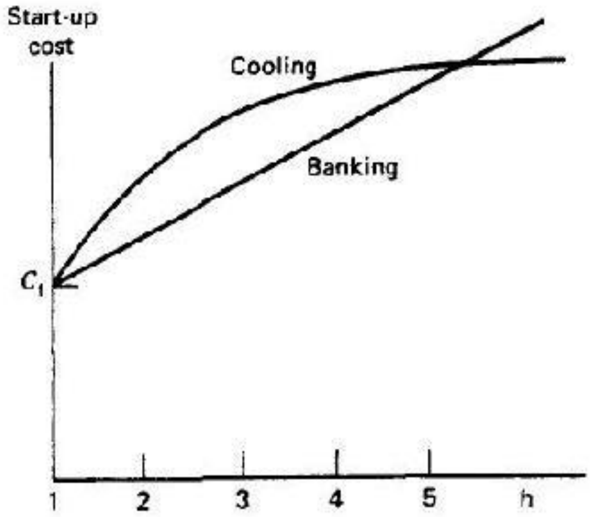


Fig.1:Hydro constraints

Fuel Constraints:

We will treat the "fuel scheduling" problem system in which some units have limited fuel, or else have constraints that require them to burn a specified amount of fuel in a given time, presents a most challenging unit commitment problem.

Unit Commitment Solution Methods:

The commitment problem can be very difficult. **As** a theoretical exercise, let us postulate the following situation.

1.We must establish a loading pattern for *M* periods.

2.We have *N* units to commit and dispatch.

3.The ***M*** load levels and operating limits on the ***N*** units are such that any one unit can supply the individual loads and that any combination of units can also supply the loads.

Next, assume we are going to establish the commitment by enumeration (brute force). The total number of combinations we need to try each hour is,

$$C(N,1) + C(N,2) + \ldots + C(N, N-1) + C(N, N) = 2^N - 1 \quad \ldots\ldots\ldots(18)$$

Where C (N, j) is the combination of ***N*** items taken *j* at a time. That is,

$$C(N,j) = \left[\frac{N!}{(N-j)!\,j!}\right] \quad \ldots\ldots\ldots\ldots\ldots(19)$$

$$j! = 1 \times 2 \times 3 \times \ldots \times j$$

For the total period of *M* intervals, the maximum number of possible combinations is $(2^N - 1)^M$, which can become a horrid number to think about.

For example, take a 24-h period (e.g., 24 one-hour intervals) and consider systems with 5, 10, 20 and 40 units.

These very large numbers are the upper bounds for the number of enumerations required. Fortunately, the constraints on the units and the load-capacity relationships of typical utility systems are such that we do not approach these large numbers. Nevertheless, the real practical barrier in the optimized unit commitment problem is the high dimensionality of the possible solution space.

The most talked-about techniques for the solution of the unit commitment problem are:

1.Priority-list schemes,

2.Dynamic programming (DP),

3. Forward Dynamic programming (FDP).

Priority-List Method for unit commitment solution:

The simplest unit commitment solution method consists of creating a priority list of units. As a simple shut-down rule or priority-list scheme could be obtained after an exhaustive enumeration of all unit combinations at each load level. The priority list of Example 5B could be obtained in a much simpler manner by noting the full- load average production cost of each unit, where the full-load average production cost is simply the net heat rate at full load multiplied by the fuel cost.

Priority List Method:

Priority list method is the simplest unit commitment solution which consists of creating a priority list of units.

Full load average production cost= Net heat rate at full load X Fuel

Cost Assumptions:

1.No load cost is zero

2.Unit input-output characteristics are linear between zero output and full load

3.Start up costs are a fixed amount

4.Ignore minimum up time and minimum down time

Steps to be followed

1.Determine the full load average production cost for each units

2.Form priority order based on average production cost

3.Commit number of units corresponding to the priority order

4.Caluclate PG1, PG2 ,PGN from economic dispatch problem for the feasible combinations only.

5.For the load curve shown, Assume load is dropping or decreasing, determine whether dropping the next unit will supply generation & spinning reserve.

If not, continue as it is

If yes, go to the next step

6.Determine the number of hours H, before the unit will be needed again.

7.Check H< minimum shut down time.

If not, go to the last step If yes, go to the next step

8.Calculate two costs

1. Sum of hourly production for the next H hours with the unit up
2. Recalculate the same for the unit down + start up cost for either cooling or banking

9.Repeat the procedure until the priority.

Merits:

1. No need to go for N combinations
2. Take only one constraint
3. Ignore the minimum up time & down time
4. Complication reduced

Demerits:

1. Start up cost are fixed amount
2. No load costs are not considered.

Dynamic-Programming Solution:

Dynamic programming has many advantages over the enumeration scheme, the chief advantage being a reduction in the dimensionality of the problem. Suppose we have found units in a system and any combination of them could serve the (single) load.

There would be a maximum of 24 - 1 = 23 combinations to test. However, if a strict priority order is imposed, there are only four combinations to try:

Priority 1 unit

Priority 1 unit + Priority 2 unit

Priority 1 unit + Priority 2 unit + Priority 3 unit

Priority 1 unit + Priority 2 unit + Priority 3 unit + Priority 4 unit

The imposition of a priority list arranged in order of the full-load average cost rate would result in a theoretically correct dispatch and commitment only if:

1. No load costs are zero.
2. Unit input-output characteristics are linear between zero output and full load.
3. There are no other restrictions.
4. Start-up costs are a fixed amount.

In the dynamic-programming approach that follows, we assume that:

1. A *state* consists of an array of units with specified units operating and
2. The start-up cost of a unit is independent of the time it has been off-line
3. There are no costs for shutting down a unit.
4. There is a strict priority order, and in each interval a specified minimum the rest off-line. (i.e., it is a fixed amount).amount of capacity must be operating.

A feasible state is one in which the committed units can supply the required load and that meets the minimum amount of capacity each period.

Forward DP Approach:

One could set up a dynamic-programming algorithm to run backward in time starting from the final hour to be studied, back to the initial hour. Conversely, one could set up the algorithm to run forward in time from the initial hour to the final hour. The forward approach has distinct advantages in solving generator unit commitment. For example, if the start-up cost of a unit is a function of the time it has been off-line (i.e., its temperature), then a forward dynamic-program approach is more suitable since the previous history of the unit can be computed at each stage. There are other practical reasons for going forward. The initial conditions are easily specified and the computations can go forward in time as long as required. A forward dynamic-programming algorithm is shown by the flowchart

The recursive algorithm to compute the minimum cost in hour K with combination I is

Fcost(K,I)= min[Pcost(K,I)+Scost(K-1,L:K,I)+Fcost(K-1,L)] ----------------(20)

Fcost(K, I) = least total cost to arrive at state (K , I)

Pcost(KI,) = production cost for state(K ,I)

Scost(K - 1, L: K , I)= transition cost from state (K - 1, L) to state(K , I)

State (K, 1) is the Zth combination in hour K. For the forward dynamic programming approach, we define a strategy as the transition, or path, from one state at a given hour to a state at the next hour.

Note that two new variables, X and N, have been introduced X = number of states to search each period

N = number of strategies, or paths, to save ateach step

These variables allow control of the computational effort (see below Figure).For sn

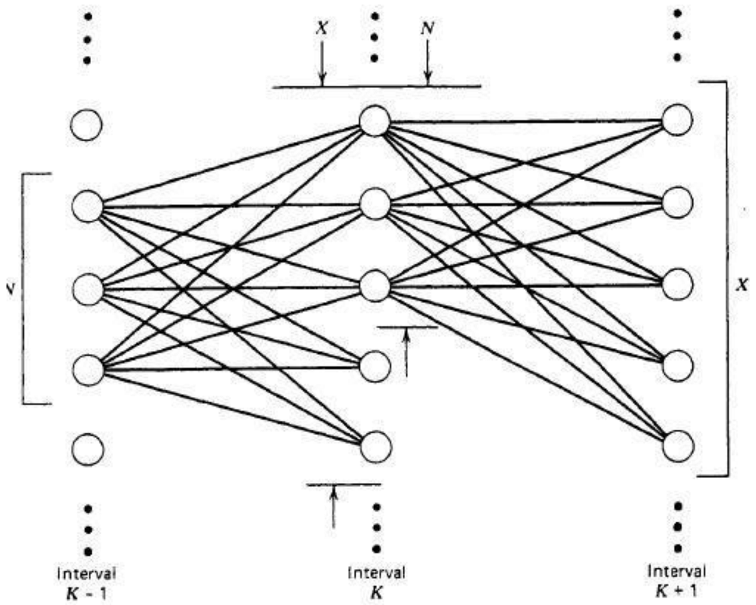
complete enumeration, the maximum number of the value of *X* or ***N*** is 2 – 1.

Note that two new variables, X and **N,** have been introduced X = number of states to search each period

N = number of strategies, or paths, to save ateach step

These variables allow control of the computational effort (see below Figure).

For n complete enumeration, the maximum number of the value of *X* or ***N*** is 2 – 1



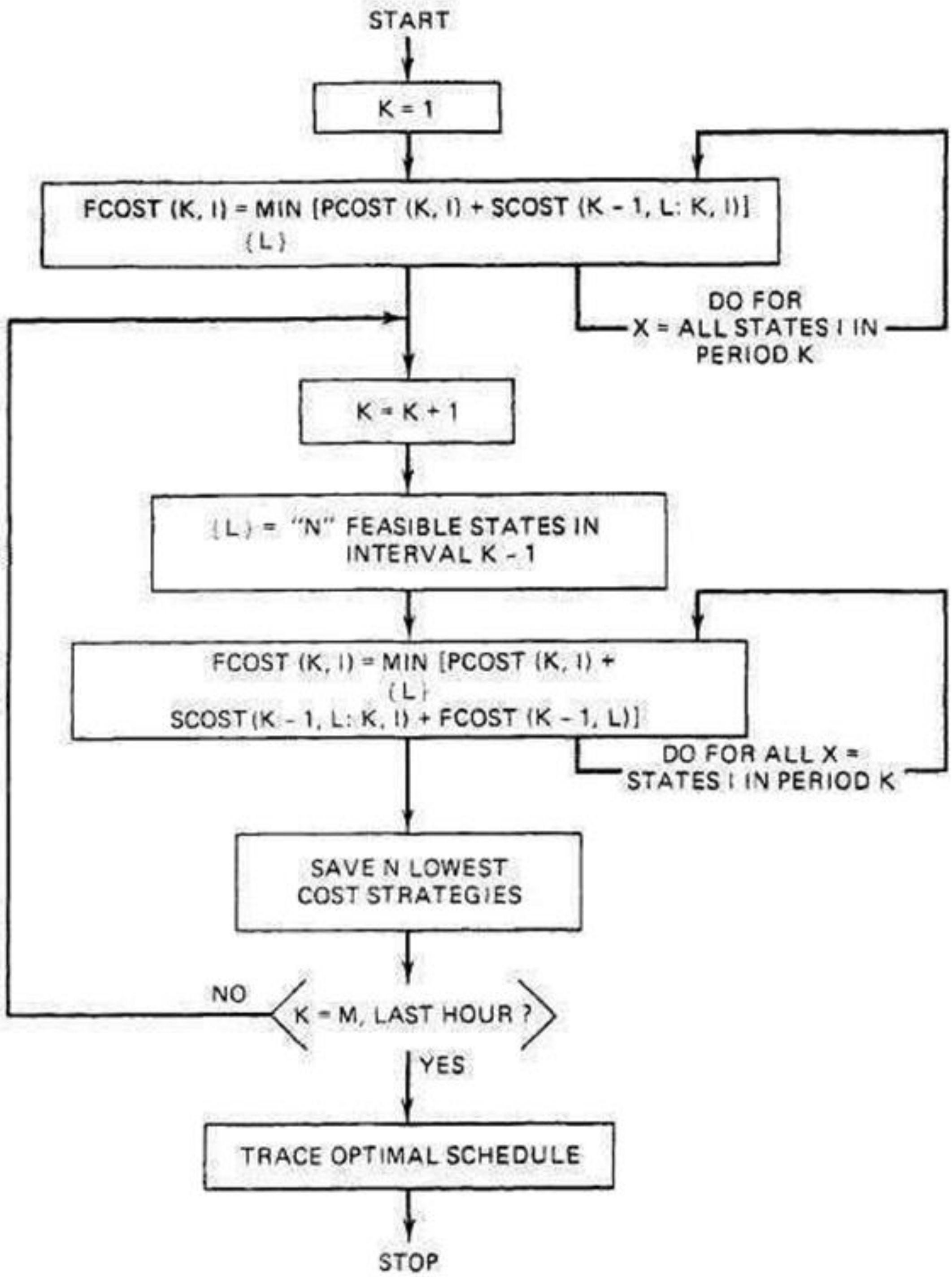


Fig.1: Forward DP Approach

UNIT-V

COMPUTER CONTROL OF POWER SYSTEM

ENERGY CONTROL CENTRE:

The energy control center (ECC) has traditionally been the decision-center for the electric transmission and generation interconnected system. The ECC provides the functions necessary for monitoring and coordinating the minute-by-minute physical and economic operation of the power system. In the continental U.S., there are only three interconnected regions: Eastern, Western, and Texas, but there are many *control areas*, with each control area having its own ECC.

Maintaining integrity and economy of an inter-connected power system requires significant coordinated decision-making. So one of the primary functions of the ECC is to monitor and regulate the physical operation of the interconnected grid.

Most areas today have a two-level hierarchy of ECCs with the Independent System Operator (ISO) performing the high-level decision-making and the transmission owner ECC performing the lower-level decision-making.

A high-level view of the ECC is illustrated. Where we can identify the substation, the remote terminal unit (RTU), a communication link, and the ECC which contains the energy management system (EMS). The EMS provides the capability of converting the data received from the substations to the types of screens observed.

In these notes we will introduce the basic components and functionalities of the ECC. Note that there is no chapter in your text which provides this information.

Regional load control centre:

It decides generation allocation to various generating stations within the region on the basics of equal incremental operating cost considering line losses are equal and Frequency control in the region.

Plant load control room:

It decides the allocation of generation of various units in the plant on the basis of:

1. Equal incremented operating cost of various units

2. Minimize the reactive power flow through line so as to minimize line loss and maintain voltage levels and Frequency control in the plant

ECC Components:

The system control function traditionally used in electric utility operation consists of three main integrated subsystems: the energy management system (EMS), the supervisory control and data acquisition (SCADA), and the communications interconnecting the EMS and the SCADA (which is often thought of as part of the SCADA itself). Figure 3 provides a block diagram illustration of these three integrated subsystems. The SCADA and communications subsystems are indicated in the dotted ovals at the top left hand corner of the figure. The res1of the figure indicates the EMS. We will describe each one in the following subsections.

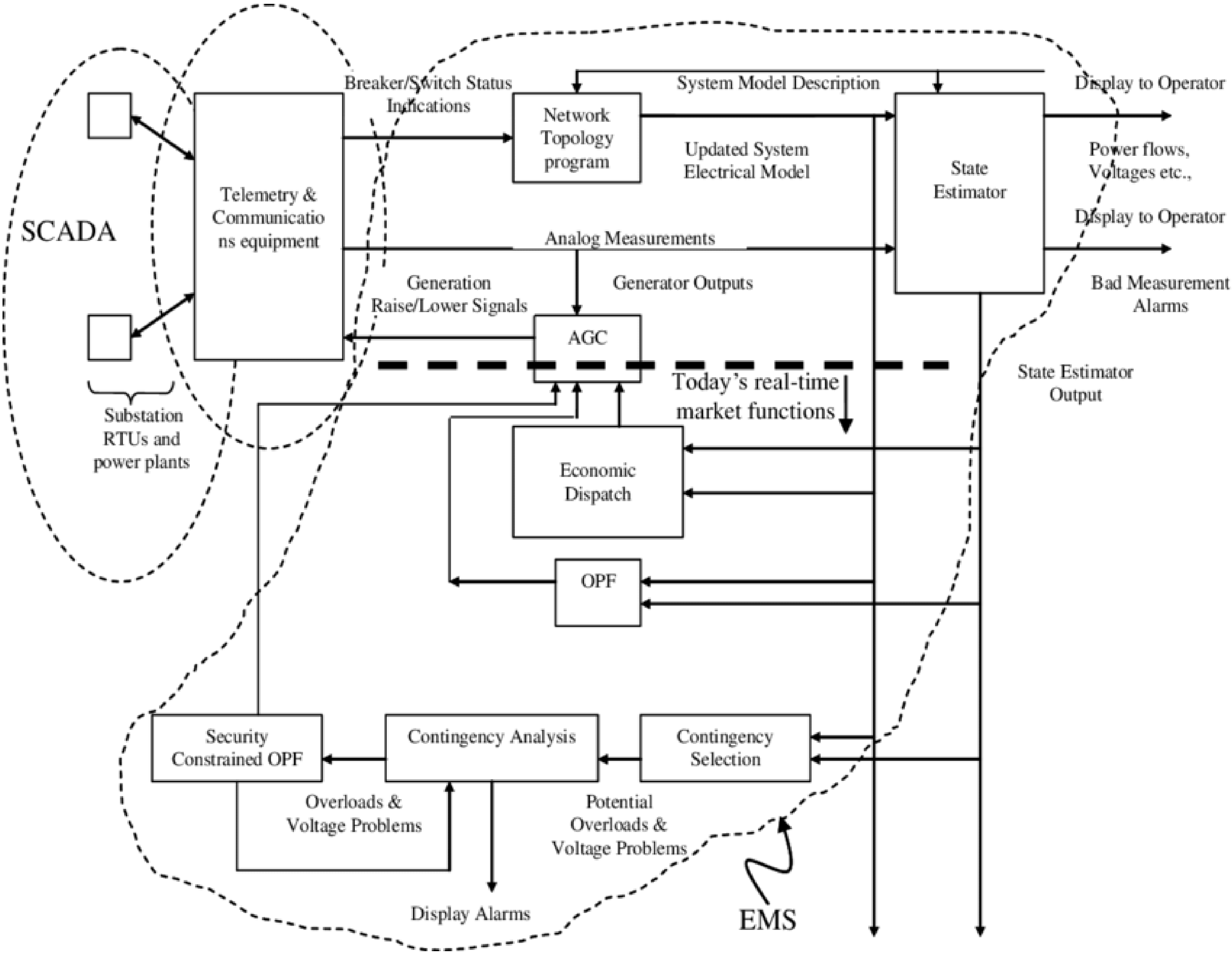


Fig.1:Block diagram of ECC

We distinguish EMS from distribution management systems (DMS). Both utilize their own SCADA, but for different functions. Whereas EMS/SCADA serves the high voltage bulk transmission system from the ECC, the DMS/SCADA serves the low voltage, distribution system from a distribution dispatch center. We are addressing in these notes the EMS/SCADA.

Operation of control centre:

- **Monitoring**
- **Data acquisition and Remote control level control**

1. Turbine – governor to adjust generation to balance changing load-instantaneous control.
2. AGC (called load frequency control (LFC)) maintains frequency and net power interchange.
3. Economic Dispatch Control (EDC) distributes the load among the units such that fuel cost is minimum.

B. Primary Voltage control

1. Excitation control
2. Transmission voltage control, SVC, Shunt capacitors, transformer taps.

2. SUPERVISORY CONTROL AND DATA ACQUISITION (SCADA)

There are two parts to the term SCADA *Supervisory control* indicates that the operator, residing in the energy control center (ECC), has the ability to control remote equipment. *Data acquisition* indicates that information is gathered characterizing the state of the remote equipment and sent to the ECC for monitoring purposes.

The monitoring equipment is normally located in the substations and is consolidated in what is known as the remote terminal unit (RTU). Generally, the RTUs are equipped with microprocessors having memory and logic capability. Older RTUs are equipped with modems to provide the communication link back to the ECC, whereas newer RTUs generally have intranet or internet capability.

Relays located within the RTU, on command from the ECC, open or close selected control circuits to perform a supervisory action. Such actions may include, for example, opening or closing of a circuit breaker or switch, modifying a transformer tap setting, raising or lowering generator MW output or terminal voltage, switching in or out a shunt capacitor or inductor, and the starting or stopping of a synchronous condenser.

Information gathered by the RTU and communicated to the ECC includes both analog information and status indicators. Analog information includes, for example, frequency, voltages, currents, and real and reactive power flows. Status indicators include alarm signals (over-temperature, low relay battery voltage, illegal entry) and whether switches and circuit breakers are open or closed. Such information is provided to the ECC through a periodic scan of all RTUs. A 2 second scan cycle is typical.

Functions of SCADA Systems

1. Data acquisition
2. Information display.
3. Supervisory Control (CBs: ON/OFF, Generator: stop/start, RAISE/LOWER command)
4. Information storage and result display.
5. Sequence of events acquisition.
6. Remote terminal unit processing.
7. General maintenance.
8. Runtime status verification.
9. Economic modeling.
10. Remote start/stop.
11. Load matching based on economics.
12. Load shedding.

Control Functions:

1.Control and monitoring of switching devices, tapped transformers, auxiliary devices etc..

2. Bay-and a station-wide interlocking Automatic functions such as load shedding,
power restoration, and high speed bus bar transfer, Time synchronization by radio clock satellite signal.

Monitoring Functions:

1. Measurement and displaying of current, voltage, frequency, active and reactive power, energy, temperature, etc..

Alarm Functions:

1. Storage and evaluation of time stamped events.

Protection functions:

1**.** Substation protection functions includes the monitoring of events like start and trip.

2. Protection of bus bars. Line feeders, transformers, generators.

Communication technologies:

The form of communication required for SCADA is *telemetry*. Telemetry is the measurement of a quantity in such a way so as to allow interpretation of that measurement at a distance from the primary detector. The distinctive feature of telemetry is the nature of the translating means, which includes provision for converting the measure into a representative quantity of another kind that can be transmitted conveniently for measurement at a distance. The actual distance is irrelevant.

Telemetry may be analog or digital. In analog telemetry, a voltage, current, or frequency proportional to the quantity being measured is developed and transmitted on a communication channel to the receiving location, where the received signal is applied to a meter calibrated to indicate the quantity being measured, or it is applied directly to a control device such as a ECC computer.

Forms of analog telemetry include variable current, pulse-amplitude, pulse- length, and pulse-rate, with the latter two being the most common. In digital telemetry, the quantity being measured is converted to a code in which the sequence of pulses transmitted indicates the quantity. One of the advantages to digital telemetering is the fact that accuracy of data is not lost in transmitting the data from one location to another. Digital telemetry requires analog to digital (A/D) and possible digital to analog (D/A) converters, as illustrated in the earliest form of signal circuit used for SCADA telemetry consisted of twisted pair wires; although simple and economic for short distances, it suffers from reliability problems due to breakage, water ingress, and ground potential risk during faults.

Improvements over twisted pair wires came in the form of what is now the most common, traditional type of telemetry mediums based on leased-wire, power-line carrier, or microwave. These are *voice grade* forms of telemetry, meaning they represent communication channels suitable for the transmission of speech, either digital or analog, generally with a frequency range of about 300 to 3000 Hz.

SCADA requires communication between Master control station and Remote control station:

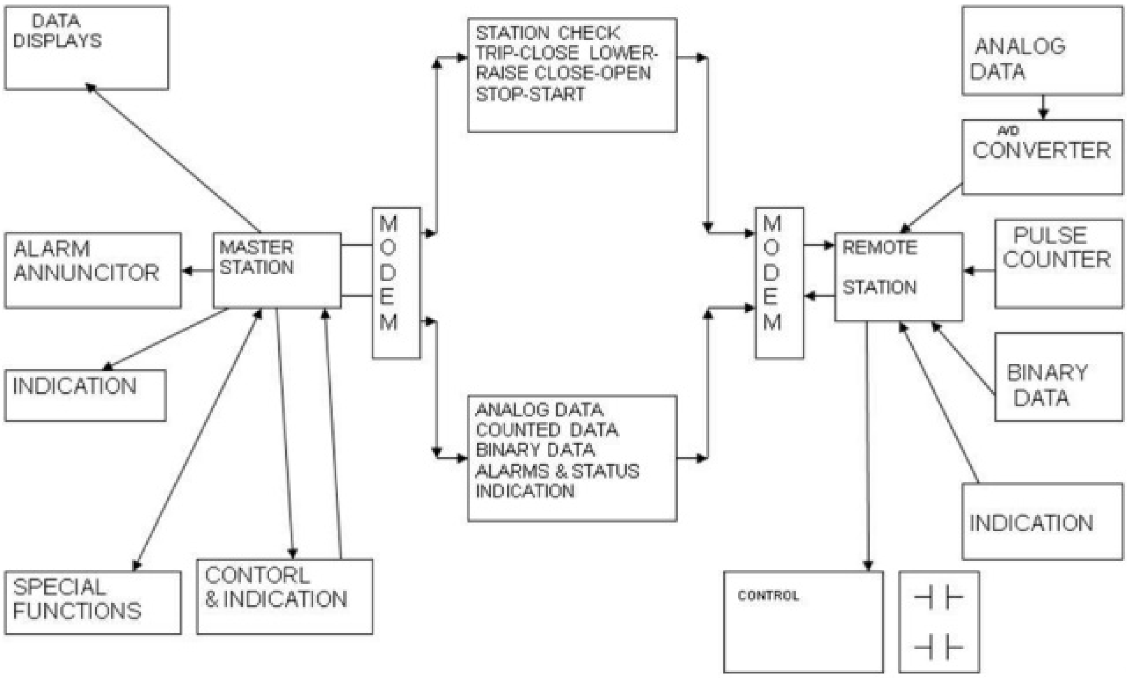


Fig.2:Communication between master and remote control station

Master and Remote station:

Leased-wire means use of a standard telephone circuit; this is a convenient and straightforward means of telemetry when it is available, although it can be unreliable, and it requires a continual outlay of leasing expenditures. In addition, it is not under user control and requires careful coordination between the user and the telephone company. Power-line carrier (PLC) offers an inexpensive and typically more reliable alternative to leased-wire. Here, the transmission circuit itself is used to modulate a communication signal at a frequency much greater than the 60 Hz power frequency. Most PLC occurs at frequencies in the range of 30-500 kHz. The security of PLC is very high since the communication equipment is located inside the substations through open disconnects, i.e., when the transmission line is outaged. Often, this is precisely the time when the communication signal is needed most. In addition, PLC is susceptible to line noise and requires careful signal-to-noise ratio analysis. Most PLC is strictly analog although digital PLC has become available from a few suppliers during the last few years.

Microwave radio refers to ultra-high-frequency (UHF) radio systems operating above 1 GHz. The earliest microwave telemetry was strictly analog, but digital microwave communication is now quite common for EMS/SCADA applications. This form of communication has obvious advantages over PLC and leased wire since it requires no physical conducting medium and therefore no right-of-way. However, line of sight clearance is required in order to ensure reliable communication, and therefore it is not applicable in some cases.

A more recent development has concerned the use of fiber optic cable, a technology capable of extremely fast communication speeds. Although cost was originally prohibitive, it has now decreased to the point where it is viable. Fiber optics may be either run inside underground power cables or they may be fastened to overhead transmission line towers just below the lines. They may also be run within the shield wire suspended above the transmission lines.

One easily sees that communication engineering is very important to power system control. Students specializing in power and energy systems should strongly consider taking communications courses to have this background. Students specializing in communication should consider taking power systems courses as an application area.

ENERGY MANAGEMENT SYSTEM (EMS):

The EMS is a software system. Most utility companies purchase their EMS from one or more EMS vendors. These EMS vendors are companies specializing in design, development, installation, and maintenance of EMS within ECCs. There are a number of EMS vendors in the U.S., and they hire many power system engineers with good software development capabilities during the time period of the 1970s through about 2000, almost all EMS software applications.

An attractive alternative today is, however, the application service provider, where the software resides on the vendor"s computer and control center personnel access it from the Internet. Benefits from this arrangement include application flexibility and reliability in the software system and reduced installation cost.

One can observe from Figure 3 that the EMS consists of 4 major functions: network model building (including topology processing and state estimation), security assessment, automatic generation control, and dispatch. These functions are described in more detail in the following subsections.

Energy management is the process of monitoring, coordinating, and controlling the generation, transmission and distribution of electrical energy. The physical plant to be managed includes generating plants that produce energy fed

through transformers to the high-voltage transmission network (grid), interconnecting generating plants, and load centers. Transmission lines terminate at substations that perform switching, voltage transformation, measurement, and control. Substations at load centers transform to sub transmission and distribution levels. These lower-voltage circuits typically operate radially, i.e., no normally closed paths between substations through sub transmission or distribution circuits.(Underground cable networks in large cities are an exception.)

Since transmission systems provide negligible energy storage, supply and demand must be balanced by either generation or load. Production is controlled by turbine governors at generating plants, and automatic generation control is performed by control center computers remote from generating plants. Load management, sometimes called demand- Side management, extends remote supervision and control to sub-transmission and distribution circuits, including control of residential, commercial, and industrial loads.

Functionality Power EMS:

1. System Load Forecasting-Hourly energy, 1 to 7 days.
2. Unit commitment-1 to 7days.
3. Economic dispatch.
4. Hydro-thermal scheduling- up to 7 days.
5. MW interchange evaluation- with neighboring system.
6. Transmission loss minimization.
7. Security constrained dispatch.
8. Maintenance scheduling Production cost calculation.

Power System Data Acquisition and Control

A SCADA system consists of a master station that communicates with remote terminal units (RTUs) for the purpose of allowing operators to observe and control physical plants. Generating plants and transmission substations certainly justify RTUs, and their installation is becoming more common in distribution substations as costs decrease. RTUs transmit device status and measurements to, and receive control commands and setpoint data from, the master station. Communication is generally via dedicated circuits operating in the range of 600 to 4800 bits/s with the RTU responding to periodic requests initiated from the master station (polling) every 2 to 10 s, depending on the criticality of the data.

The traditional functions of SCADA systems are summarized:

• Data acquisition: Provides telemetered measurements and status information to operator.
• Supervisory control: Allows operator to remotely control devices, e.g., open and close circuit breakers. A “select before operate” procedure is used for greater safety.
• Tagging: Identifies a device as subject to specific operating restrictions and prevents unauthorized operation.
• Alarms: Inform operator of unplanned events and undesirable operating conditions. Alarms

are sorted by criticality, area of responsibility, and chronology. Acknowledgment may be required
• Logging: Logs all operator entry, all alarms, and selected information.
• Load shed: Provides both automatic and operator-initiated tripping of load in response to system emergencies.
• Trending: Plots measurements on selected time scales.

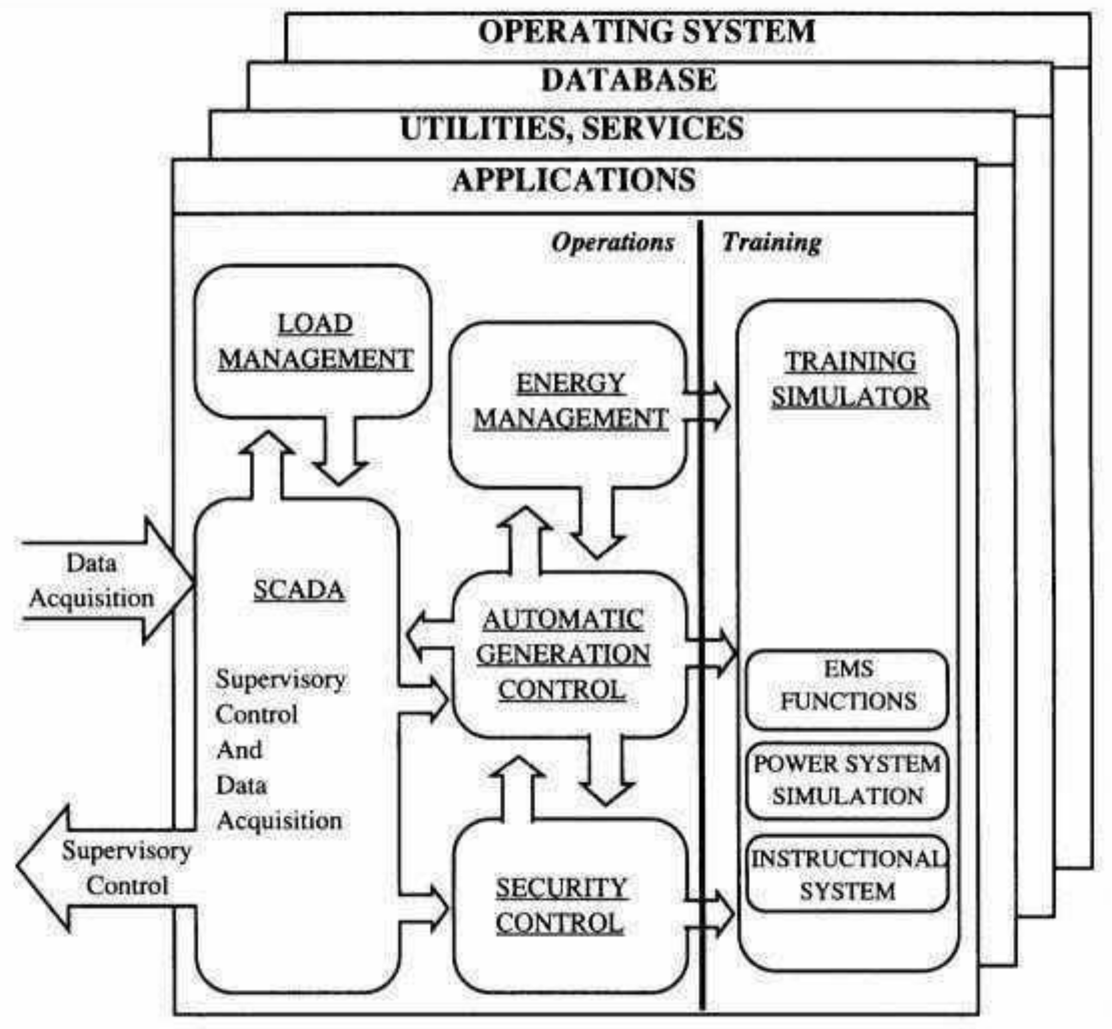


Fig.3.Layers of EMS

Layers of a modern EMS:

Since the master station is critical to power system operations, its functions are generally distributed among several computer systems depending on specific design. A dual computer system configured in primary and standby modes is most common. SCADA functions are listed below without stating which computer has specific responsibility.

• Manage communication circuit configuration
• Downline load RTU files
• Maintain scan tables and perform polling
• Check and correct message errors
• Convert to engineering units
• Detect status and measurement changes
• Monitor abnormal and out-of-limit conditions
• Log and time-tag sequence of events

• Detect and annunciate alarms
• Respond to operator requests to:
– Display information
– Enter data
– Execute control action
– Acknowledge alarms Transmit control action to RTUs
• Inhibit unauthorized actions
• Maintain historical files
• Log events and prepare reports
• Perform load shedding

Automatic Generation Control:

Automatic generation control (AGC) consists of two major and several minorfunctions that operate online in real time to adjust the generation against load at minimum cost. The major functions are load frequency control and economic dispatch, each of which is described below. The minor functions are reserve monitoring, which assures enough reserve on the system; interchange scheduling, which initiates and completes scheduled interchanges; and other similar monitoring and recording functions.

Load Frequency Control:

Load frequency control (LFC) has to achieve three primary objectives, which are stated below in priority order:

1. To maintain frequency at the scheduled value
2. To maintain net power interchanges with neighboring control areas at the scheduled values
3. To maintain power allocation among units at economically desired values.

The first and second objectives are met by monitoring an error signal, called *area control error* (ACE), which is a combination of net interchange error andfrequency error and represents the power imbalance between generation and load at any instant. This ACE must be filtered or smoothed such that excessive and random changes in ACE are not translated into control action. Since these excessive changes are different for different systems, the filter parameters have to be tuned specifically for each control area.

The filtered ACE is then used to obtain the proportional plus integral control signal. This control signal is modified by limiters, dead bands, and gain constants that are tuned to the particular system. This control signal is then divided among the generating units under control by using participation factors to obtain *unit control errors* (UCE).

These participation factors may be proportional to the inverse of the second derivative of the cost of unit generation so that the units would be loaded according to their costs, thus meeting the third objective. However, cost may not be the only consideration because the different units may have different response rates and it may be necessary to move the faster generators more to obtain an acceptable response. The UCEs are then sent to the various units under control and the generating units monitored to see that the corrections take place. This control action is repeated every 2 to 6 s. In spite of the integral control, errors in frequency and net interchange do tend to accumulate over time. These time errors and accumulated interchange errors have to be corrected by adjusting the controller settings according to procedures agreed upon by the whole interconnection. These accumulated errors as well as ACE serve as performance measures for LFC.

The main philosophy in the design of LFC is that each system should follow its own load very closely during normal operation, while during emergencies; each system should contribute according to its relative size in the interconnection without regard to the locality of the emergency. Thus, the most important factor in obtaining good control of a system is its inherent capability of following its own load. This is guaranteed if the system has adequate regulation margin as well as adequate response capability. Systems that have mainly thermal generation often have difficulty in keeping up with the load because of the slow response of the units.

SECURITY ANALYSIS & CONTROL:

Security monitoring is the on line identification of the actual operating conditions of a power system. It requires system wide instrumentation to gather the system data as well as a means for the on line determination of network topology involving an open or closed position of circuit breakers. A state estimation has been developed to get the best estimate of the status and the state estimation provides the database for security analysis shown .

- **Data acquisition**:
  1. To process from RTU
  2. To check status values against normal value
  3. To send alarm conditions to alarm processor
  4. To check analog measurements against limits.
- **Alarm processor:**
  1. To send alarm messages
  2. To transmit messages according to priority
- **Status processor:**
  1. To determine status of each substation for proper connection.
- **Reserve monitor:**
  1. To check generator MW output on all units against unit limits
- **State estimator:**
  1. To determine system state variables
  2. To detect the presence of bad measures values.
  3. To identify the location of bad measurements
  4. To initialize the network model for other programs

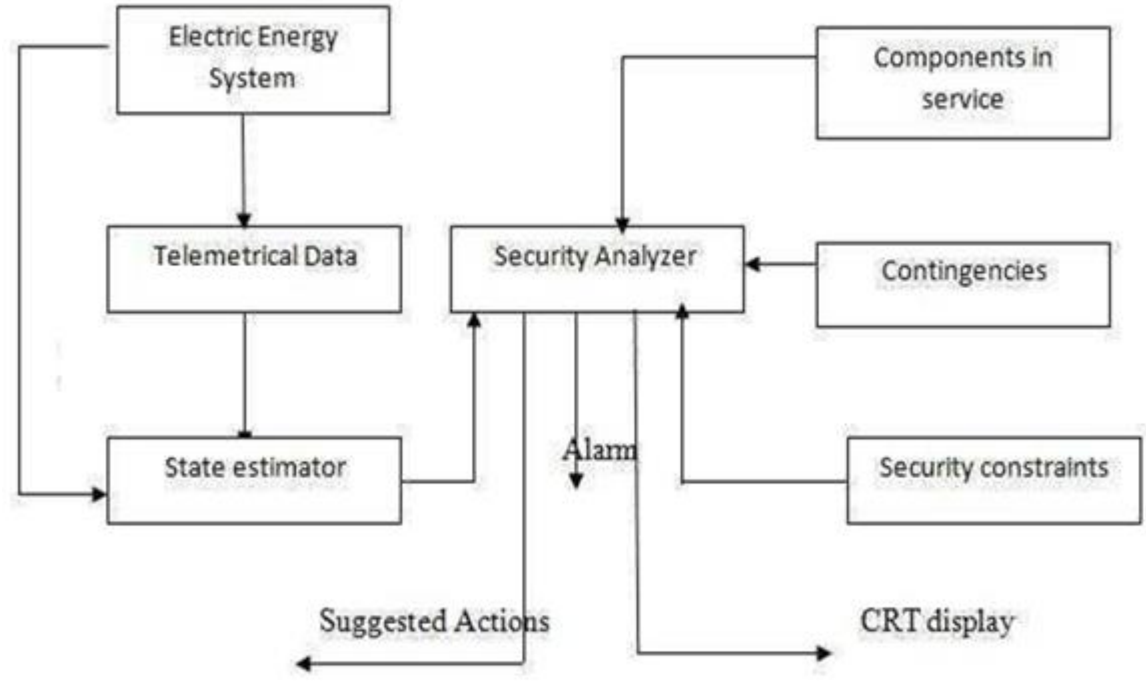


Fig.4: Practical Security Monitoring System

System Security:

1. System monitoring.
2. Contingency analysis.
3. Security constrained optimal power flow

Security Assessment:

Security assessment determines first, whether the system is currently residing in an acceptable state and second, whether the system would respond in an acceptable manner and reach an acceptable state following any one of a pre-defined contingency set. A *contingency* is the unexpected failure of a transmission line, transformer, or generator. Usually, contingencies result from occurrence of a *fault*, or short-circuit, to one of these components. When such a fault occurs, the protection systems sense the fault and remove the component, and therefore also the fault, from the system. Of course, with one less component, the overall system is weaker, and undesirable effects may occur. For example, some remaining circuit may overload, or some bus may experience an under voltage condition. These are called *static* security problems.

Dynamic security problems may also occur, including uncontrollable voltage decline, generator over speed (loss of synchronism), or undamped oscillatory behavior.

Security Control:

Power systems are designed to survive all probable contingencies. A contingency is defined as an event that causes one or more important components such as transmission lines, generators, and transformers to be unexpectedly removed from service. Survival means the system stabilizes and continues to operate at acceptable voltage and frequency levels without loss of load. Operations must deal with a vast number of possible conditions experienced by the system, many of which are not anticipated in planning. Instead of dealing with the impossible task of analyzing all possible system states, security control starts with a specific state: the current state if executing the real-time network sequence; a postulated state if executing a study sequence. Sequence means sequential execution of programs that perform the following steps:

1. Determine the state of the system based on either current or postulated conditions.
2. Process a list of contingencies to determine the consequences of each contingency on the system in its specified state.
3. Determine preventive or corrective action for those contingencies which represent unacceptable risk.

Security control requires topological processing to build network models and uses large-scale AC network analysis to determine system conditions. The required applications are grouped as a network subsystem that typically includes the following functions:

•**Topology processor**: Processes real-time status measurements to determine an electrical connectivity (bus) model of the power system network.

•**State estimator:** Uses real-time status and analog measurements to determine the„„best""

estimate of the state of the power system. It uses a redundant set of measurements; calculates voltages, phase angles, and power flows for all components in the system; and reports overload conditions.

•**Power flow:** Determines the steady-state conditions of the power system network fora specified generation and load pattern. Calculates voltages, phase angles, and flows across the entire system.

•**Contingency analysis:** Assesses the impact of a set of contingencies on the state ofthe power system and identifies potentially harmful contingencies that cause operating limit violations.

•**Optimal power flow:** Recommends controller actions to optimize a specified objective function (such as system operating cost or losses) subject to a set of power system operating constraints.

•**Security enhancement:** Recommends corrective control actions to be taken to alleviate an existing or potential overload in the system while ensuring minimal operational cost.

•**Preventive action:** Recommends control actions to be taken in a "preventive" mode before a contingency occurs to preclude an overload situation if the contingency were to occur.

•**Bus load forecasting:** Uses real-time measurements to adaptively forecast loads for the electrical connectivity (bus) model of the power system network.

•**Transmission loss factors:** Determines incremental loss sensitivities for generating units;

calculates the impact on losses if the output of a unit were to be increased by 1 MW.

•**Short-circuit analysis:** Determines fault currents for single-phase and three-phase faults for fault locations across the entire power system network.

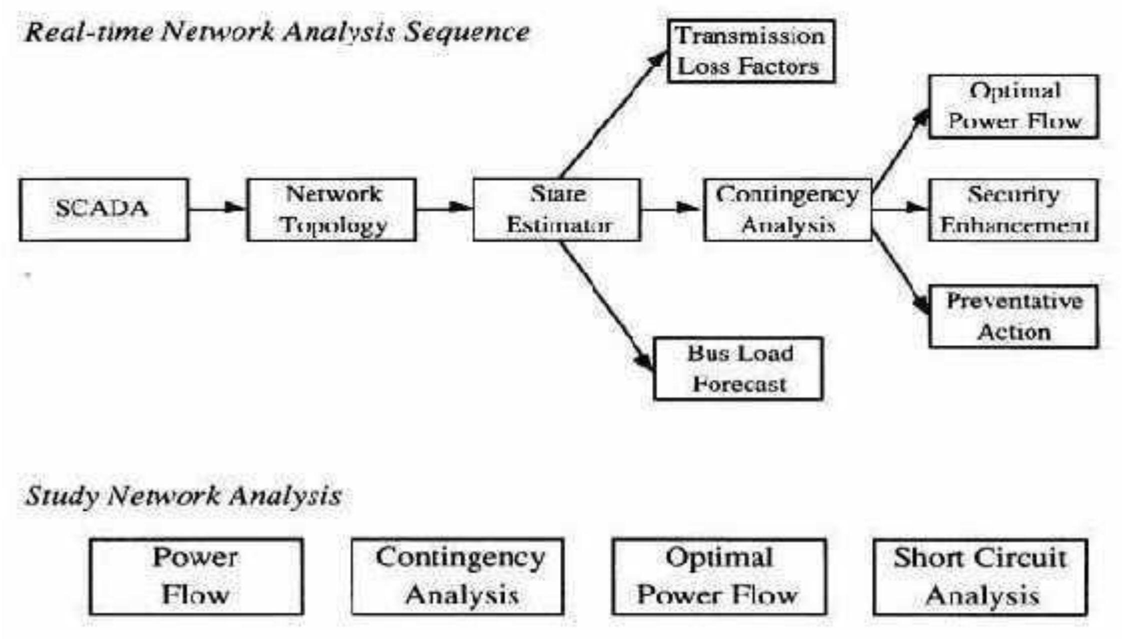


Fig.5:Real time network analysis sequence

VARIOUS OPERATING STATES:

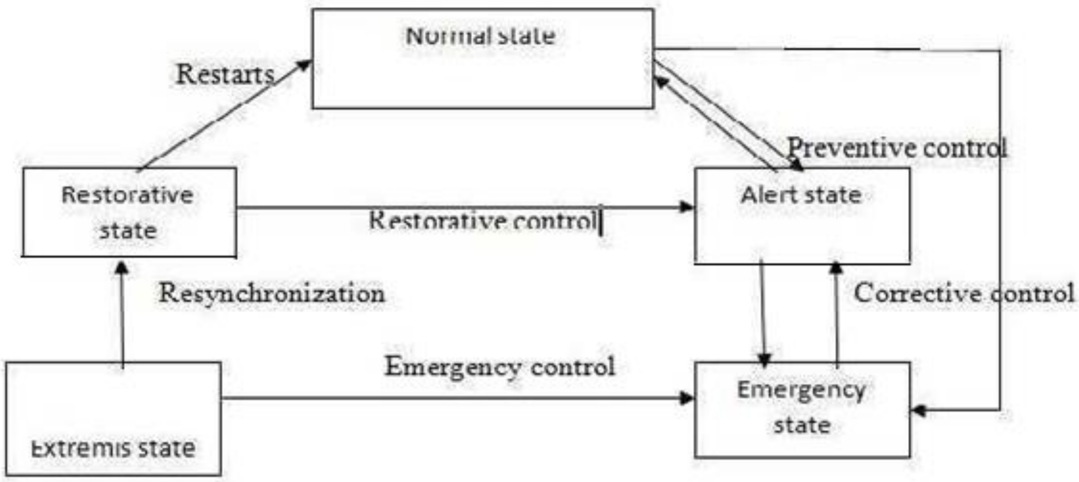


Fig.6:Various operating states

Operating states are:

1. Normal state
2. Alert state
3. Emergency state
4. Extremis state
5. Restorative state

- **Normal state:**

A system is said to be in normal if both load and operating constraints are satisfied .It is one in which the total demand on the system is met by satisfying all the operating constraints.

- **Alert state**:

A normal state of the system said to be in alert state if one or more of the postulated contingency states, consists of the constraint limits violated. When the system security level falls below a certain level or the probability of disturbance increases, the system may be in alert state .All equalities and inequalities are satisfied, but on the event of a disturbance, the system may not have all the inequality constraints satisfied. If severe disturbance occurs, the system will push into emergency state. To bring back the system to secure state, preventive control action is carried out.

- **Emergency state:**

The system is said to be in emergency state if one or more operating constraints are violated, but the load constraint is satisfied .In this state, the equality constraints are unchanged. The system will return to the normal or alert state by means of corrective actions, disconnection of faulted section or load sharing.

- **Extremis state:**

When the system is in emergency, if no proper corrective action is taken in time, then it goes to either emergency state or extremis state. In this regard neither the load or nor the operating constraint is satisfied, this result is islanding. Also the generating units are strained beyond their capacity .So emergency control action is done to bring back the system state either to the emergency state or normal state.

- **Restorative state:**

From this state, the system may be brought back either to alert state or secure state .The latter is a slow process. Hence, in certain cases, first the system is brought back to alert state and then to the secure state .This is done using restorative control action.