G.RAJESH
EEE

14EE702

Hall Ticket Number:

IV/IV B.Tech (Regular/Supplementary) DEGREE EXAMINATION

January, 2021 — **Electrical and Electronics Engineering**

Seventh Semester — **Power System Operation Control & Stability**

Time: Three Hours — **Maximum :** 60 Marks

Answer ALL Questions from PART-A. (1X12 = 12 Marks)
*Answer **ANY FOUR** questions from PART-B.* (4X12=48 Marks)

Part - A

1 Answer all questions (1X12=12 Marks)

a) Define current distribution factor
b) What is incremental fuel cost and what are its units?
c) Draw heat rate curve.
d) What is the function of speed governor?
e) What is single area?
f) What do you mean by load frequency control?
g) What is shunt compensation?
h) Specify any two equipment used to control the voltage.
i) What is booster transformer?
j) Write swing equation.
k) Define voltage stability.
l) Define critical clearing time.

Part - B

2 a) Obtain the condition for optimum operation of a power system with 'n' plants when losses are considered. 6M

b) A plant consists of two units. The incremental fuel characteristics for the two units are given as 6M
Rs./MWh $\frac{dC_1}{dP_{G1}} = 22+0.08P_{G1}$ Rs/Mwh, $\frac{dC_2}{dP_{G2}} = 15+0.09P_{G2}$ Rs/Mwh
Rs./MWh
Find the optimal load sharing of two units when a total load of 150 MW is connected to the system.

3 a) Derive the transmission loss formula and state the assumptions made in it. 6M
b) Explain the incremental fuel cost curve and incremental production cost curve. 6M

4 a) Explain the P-f and Q-V control loops of power system. 6M
b) Two generators rated 100 MW and 200 MW are operating in parallel with a droop characteristics of [their governors are 4% & 5%] 6% from no load to full load. Determine the load shared by each generator if a load of 270MW is connected across the parallel combination of the generations. Assume free governor operation and calculate the change in frequency. Assuming the generators are operating at 50 HZ at no load. 6M

5 a) Draw the schematic diagram of a speed governing system and explain its components. 6M
b) Discuss the dynamic response of single area load frequency control. 6M

6 a) What are various types of FACTS devices? Explain about STATCOM with neat sketch. 6M
b) Explain induction regulators and static capacitors 6M

7 a) Explain the different methods of voltage control with neat sketches. 6M
b) Compare shunt and series compensation. 6M

8 a) Explain equal area criteria and derive the expression for critical clearing time. 6M
b) Discuss the step by step solution of swing curve 6M

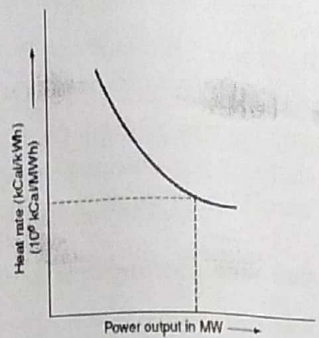
9 a) Explain the factors affecting the steady state and transient stabilities. 6M
b) Discuss the comparison between rotor angle and voltage stability in a system 6M

KEY 14EE702

I a)The current distribution factor of a transmission line with respect to a power source is the ratio of the current it would carry to the current that the source would carry when all other sources are rendered inactive, i.e., the sources that are not supplying any current. (1M)

b)Incremental fuel cost is the cost of the rate of increase of fuel input with the increase in power input.
Its unit is Rs./MWh. (1M)

c)The heat rate characteristic obtained from the plot of the net heat rate in Btu/kWh or kCal/kWh versus power output in kW is shown in Fig.



(1M)

d)This is the heart of the system, which controls the change in speed (frequency). (1M)

e)A single area is a coherent area in which all the generators swing in unison to the changes in load or speed-changer settings and in which the frequency is assumed to be constant throughout both in static and dynamic conditions. This single control area can be represented by an isolated power system consisting of a turbine, its speed governor, generator, and load. (1M)

f) In an electric power system, Load Frequency Control (LFC) is a system to maintain reasonably uniform frequency, to divide the load between the generators, and to control the tie- line interchange schedules (1M)

The **load-frequency control** (LFC) is used to restore the balance between **load** and generation in each **control** area by means of speed **control**. The main goal of LFC is to minimize the transient deviations and steady state error to zero in advance.

g)To improve the voltage at the receiving end shunt capacitors may be connected at the receiving end to generate and feed the reactive power to the load so that reactive power flow through the line and consequently the voltage drop in the line is reduced. (1M)

h) The following are the methods used in the power system for controlling the voltage.

1. On – Load Tap Changing Transformer
2. Off – Load Tap Changing transformer
3. Shunt Reactors
4. Synchronous Phase Modifiers
5. Shunt Capacitor
6. Static VAR System (SVS)

(1M)

Note: Any one point

i) The transformer, which is used to control the voltage of the transmission line at a point far away from the main transformer, is known as booster transformer.

(1M)

j)

$$\frac{H}{\pi f}\frac{d^2\delta}{dt^2} = P_m - P_e \text{ pu}$$

(1M)

This equation is called as "Swing Equation".

k) What is meant by voltage stability?
A power system at a given operating state and subjected to a given disturbance is voltage stable if voltages near loads approach post-disturbance equilibrium values. The disturbed state is within the regions of attractions of stable post-disturbance equilibrium. (1M)

l)The maximum allowable value of the clearing time for the system to remain stable is known as critical clearing time.

(1M)

2.a) (6M)

Let there be n plants in a system integrated by transmission lines and tie. Let P_{G1}, P_{G2},… P_{Gn} be the generation output of the plants in MW, P_D be total load in MW and P_L the losses in transmission lines.

Now we have

Total fuel cost,

$$C\ (\text{Rs/hour}) = C_1(P_{G1}) + C_2(P_{G2}) + \dots + C_m(P_{Gm})$$

$$= \sum_{n=1}^{m} C_n(P_{Gn}) \qquad \dots(9.24)$$

$$P_D + P_L = P_{G1} + P_{G2} + \dots + P_{Gm} = \sum_{n=1}^{m} P_{Gn} \qquad \dots(9.25)$$

where $C_n(P_{Gn})$ is the fuel cost of the nth plant in Rs per hour and P_{Gn} is the output of the nth plant in MW.

Since transmission losses P_L are function of bus voltages and thus reactive power flow in the system. In our analysis, let us ignore the effect of reactive power flow or we assume the magnitudes of all voltages to be constant. Thus transmission losses P_L are function of plant outputs (P_{G1}, P_{G2}, P_{G3},… P_{Gn}).

Equation (9.25) may be rewritten as

$$H(P_{G1}, P_{G2}, \dots P_{Gn}) = P_D + P_L - \sum_{n=1}^{m} P_{Gn} \qquad \dots(9.26)$$

Application of Lagrangian technique, utilized for optimum true or real power dispatch gives

$$C^* = C + \lambda H(P_{G1} \dots P_{Gn}) \quad \text{where } \lambda \text{ is the multiplier}$$

$$\text{or } C^* = \sum_{n=1}^{m} C_n(P_{Gn}) + \lambda\left[P_D + P_L - \sum_{n=1}^{m} P_{Gn}\right] \qquad \dots(9.27)$$

Differentiating the above equation with respect to P_{Gn} and equating to zero, we have

$$\frac{\partial C^*}{\partial P_{Gn}} = \frac{dC_n}{dP_{Gn}} + \lambda\frac{\partial P_L}{\partial P_{Gn}} - \lambda = 0 \quad \text{for } n = 1, 2, \dots m \qquad \dots(9.28)$$

The above equation may be rewritten as

$$\frac{dC_n}{dP_{Gn}} = \lambda\left[1 - \frac{\partial P_L}{\partial P_{Gn}}\right] \quad \text{for } n = 1, 2, 3, \dots m \qquad \dots(9.29)$$

The above Eq. (9.29) represents the modified economics operation criterion for the plants with transmission losses considered.

The above Eq. (9.29) may be rewritten as

$$\frac{dC_n}{dP_{Gn}}\left[\frac{1}{1 - \frac{\partial P_L}{\partial P_{Gn}}}\right] = \lambda \quad \text{or} \quad \frac{dC_n}{dP_{Gn}} \cdot L_n = \lambda \qquad \dots(9.30)$$

where $L_n = \dfrac{1}{1 - \dfrac{\partial P_L}{\partial P_{Gn}}}$ and is known as penalty factor for the nth plant and Eq. (9.30) is called the "exact coordination equation". $\dfrac{dC_n}{dP_{Gn}}$ being the incremental fuel cost, $\dfrac{\partial P_L}{\partial P_{Gn}}$ are known as *incremental transmission losses.*

The minimum fuel cost for a given total load is obtained by solving simultaneous equations represented by Eq. (9.29).

The n optimum loading equations along with the power balance Eq. (9.25) are sufficient to determine the (n + 1) unknown. (P_{G1}, P_{G2}, P_{G3} … P_{Gn} and λ).

λ is thus given by:

$$\lambda = \frac{\text{Incremental fuel cost}}{1 - \text{Incremental transmission losses}} \quad ...(9.31)$$

From Eq. (9.30)

$$\frac{dC_1}{dP_{G1}} L_1 = \frac{dC_2}{dP_{G2}} L_2 = \frac{dC_3}{dP_{G3}} L_3 = ... \frac{dC_m}{dP_{Gm}} L_m = \lambda \quad ...(9.32)$$

So, minimum fuel cost is obtained when the incremental fuel cost of each plant multiplied by its penalty factor is the same for all the plants.

2.b). (6 M)

$$\frac{dC_1}{dP_{G_1}} = 0.08 P_{G_1} + 22 \text{ Rs/MWh}$$

$$\frac{dC_2}{dP_{G_2}} = 0.09 P_{G_2} + 15 \text{ Rs/MWh}$$

For economic load scheduling the condition is

$$\frac{dC_1}{dP_{G_1}} = \frac{dC_2}{dP_{G_2}}$$

$$0.08 P_{G_1} + 22 = 0.09 P_{G_2} + 15$$

$$0.08 P_{G_1} - 0.09 P_{G_2} + 7 = 0 \rightarrow (1)$$

$$P_{G_1} + P_{G_2} = 150 \rightarrow (2)$$

Solving Eq (1) and (2)

$$P_{G_1} = 38.23 \text{ MW}$$

$$P_{G_2} = 111.77 \text{ MW}$$

3.a)

Derivation of Transmission Loss Formula(6M).

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

Figure 7.9 (c) depicts the case of two generating plants connected to an arbitrary number of loads through a transmission network. One line within the network is designated as branch p.

Imagine that the total load current I_D is supplied by plant 1 only, as in Fig. 7.9a. Let the current in line p be I_{P1}. Define

$$M_{p1} = \frac{I_{p1}}{I_D} \qquad (7.33)$$

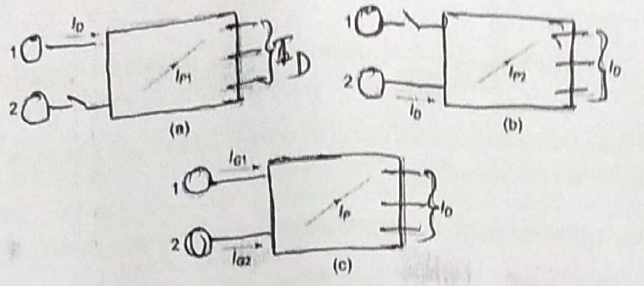


Fig. 7.9 Schematic diagram showing two plants connected through a power network to a number of loads

Similarly, with plant 2 alone supplying the total load current (Fig. 7.9b), we can define

$$M_{p2} = \frac{I_{p2}}{I_D} \qquad (7.34)$$

M_{P1} and M_{P2} are called **current distribution factors.** The values of current distribution factors depend upon the impedances of the lines and their interconnection and are independent of the current I_D.

When both generators 1 and 2 are supplying current into the network as in Fig. 7.9(c), applying the principle of superposition the current in the line p can be expressed as

$$I_p = M_{p1} I_{G1} + M_{p2} I_{G2} \qquad (7.35)$$

where I_{G1} and I_{G2} are the currents supplied by plants 1 and 2, respectively. At this stage let us make certain simplifying assumptions outlined below:

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

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

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

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

These two assumptions lead us to the conclusion that I_{P1} and I_D [Fig. 7.9(a)] have the same phase angle and so have I_{P2} and I_D [Fig. 7.9(b)], such that the current distribution factors M_{P1} and M_{P2} are real rather than complex.

Let,

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

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

From Eq. (7.35), we can write

$$|I_p|^2 = (M_{p1}|I_{G1}| \cos\sigma_1 + M_{p2}|I_{G2}|\cos\sigma_2)^2 + (M_{p1}|I_{G1}|\sin\sigma_1 + M_{p2}|I_{G2}|\sin\sigma_2)^2 \quad (7.36)$$

Expanding the simplifying the above equation, we get

$$|I_p|^2 = M_{p1}^2|I_{G1}|^2 + M_{p2}^2|I_{G2}|^2 + 2M_{p1}M_{p2}|I_{G1}|\,|I_{G2}|\cos(\sigma_1 - \sigma_2) \quad (7.37)$$

Now

$$|I_{G1}| = \frac{P_{G1}}{\sqrt{3}|V_1|\cos\phi_1};\ |I_{G2}| = \frac{P_{G2}}{\sqrt{3}|V_2|\cos\phi_2} \quad (7.38)$$

where P_{G1} and P_{G2} are the three-phase real power outputs of plants 1 and 2 at power factors of $\cos\Phi_1$, and $\cos\Phi_2$, and V_1 and V_2 are the bus voltages at the plants.

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

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

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

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

$$P_L = \frac{P_{G1}^2}{|V_1|^2(\cos\phi_1)^2}\sum_p M_{p1}^2 R_p + \frac{2P_{G1}P_{G2}\cos(\sigma_1 - \sigma_2)}{|V_1||V_2|\cos\phi_1\cos\phi_2}\sum_p M_{p1}M_{p2}R_p + \frac{P_{G2}^2}{|V_2|^2(\cos\phi_2)^2}\sum_p M_{p2}^2 R_p \quad (7.39)$$

Equation (7.39) can be recognized as

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

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

$$B_{12} = \frac{\cos(\sigma_1 - \sigma_2)}{|V_1||V_2|\cos\phi_1\cos\phi_2}\sum_p M_{p1}M_{p2}R_p \quad (7.40)$$

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

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

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

$$P_L = \sum_{m=1}^{k}\sum_{n=1}^{k} P_{Gm} B_{mn} P_{Gn} \quad (7.41)$$

Where

$$B_{mn} = \frac{\cos(\sigma_m - \sigma_n)}{|V_m||V_n|\cos\phi_m \cos\phi_n} \sum_p M_{pm} M_{pn} R_p \quad (7.42)$$

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

(2M)

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

3.b) (6M)

INCREMENTAL FUEL COST CURVE:

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

Incremental fuel cost = Δ input / Δ output

$= \Delta F / \Delta P_G$

Where Δ represents small changes.

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

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

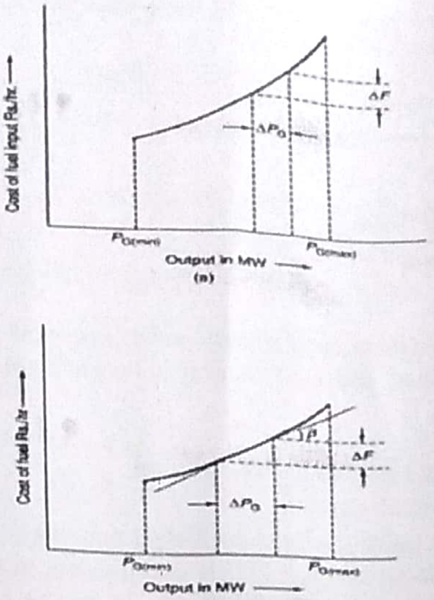


Fig: a) incremental cost curve, (b) incremental fuel cost characteristics in terms of the slope of the input-output curve

The IFC is now obtained as

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

i.e., $\tan\beta = \Delta F / \Delta P_G$ in Rs./MWh.

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

$$\text{i.e., } (IC) = \lim_{\Delta PG_i \to 0} \left(\frac{\partial F_i}{\partial PG_i} \right)$$

$$= \left(\frac{dF_i}{dP_{Gi}} \right)$$

$$(IC)_i = \left(\frac{dC_i}{dP_{Gi}} \right) \quad \left[\left(\frac{dF_i}{dP_{Gi}} \right) = \left(\frac{dC_i}{dP_{Gi}} \right) = \iota \quad \text{Incremental fuel cost of the } i^{th} \text{ unit} \right]$$

Where C_i is the cost of fuel of the i^{th} unit and P_{Gi} is the power generation output of that i^{th} unit.

Mathematically the IFC curve expression can be obtained from the expression of the cost curve.

INCREMENTAL PRODUCTION COST:

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

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

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

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

(6M)

4.a)

1. P-f and Q-V CONTROL LOOPS

In order to perform voltage and frequency control, a basic generator will have two control loops namely:

Automatic voltage regulator loop

Automatic load frequency loop.

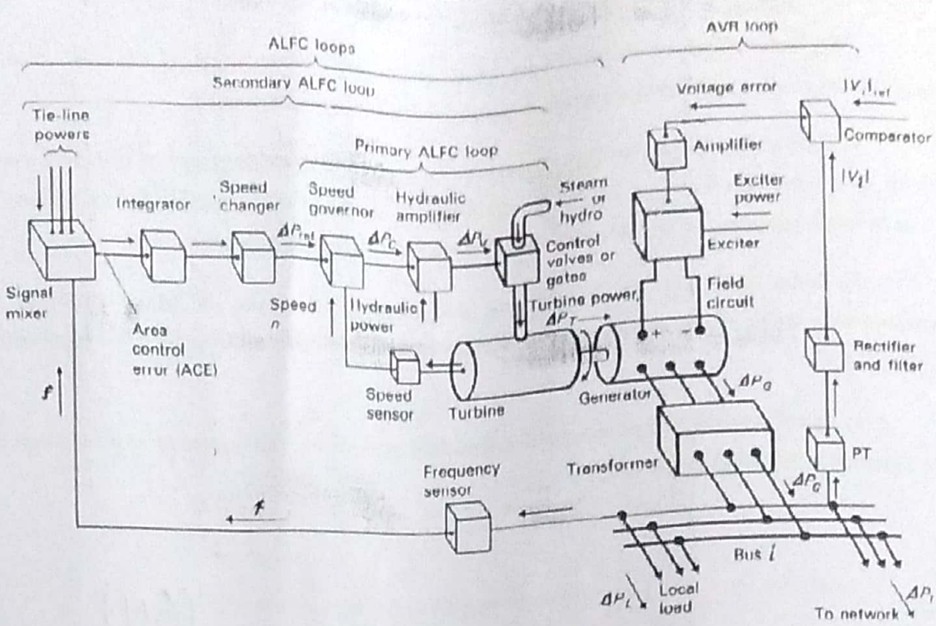
→ The *automatic voltage regulator* (AVR) loop controls the magnitude of terminal voltage, |V|. Terminal voltage is continuously sensed, rectified and smoothed. The strength of this dc signal, being proportional to |V|, is compared with a dc reference $|V|_{ref}$. The resulting "error voltage" after amplification and signal shaping, serves as input to the exciter, which applies the required voltage to the generator field winding, so the generator terminal voltage |V| reaches the value $|V|_{ref}$.

→ The *automatic load frequency control* (ALFC) loop regulates the real power output of the generator and its frequency (speed).

This loop is not a single one as in the case of AVR. A relatively fast *primary loop* responds to a frequency (speed) changes via the speed governor and the steam (or hydro) flow is regulated with the aim of matching the real power generation to relatively fast load fluctuations. By "fast" we mean changes that takes place in one to several seconds. Thus, aiming to maintain a megawatt balance, this primary loop performs a course speed or frequency control.

A slower *secondary loop* maintains the fine adjustment of the frequency, and also maintains proper real power interchange with other pool members. This loop is insensitive to rapid load and frequency changes, but focuses drift-like changes which take place over periods of minutes.

Fig. shows the two control loops, AVR loop and ALFC loop.



The AVR and ALFC loops are not fully non-interacting. Little cross coupling does exist between AVR and ALFC loops. AVR loop affects the magnitude of the generator emf E. As the internal emf determines the magnitude of the real power, it is clear that changes in the AVR loop will be felt in the ALFC loop. However, the AVR loop is much faster than the ALFC loop and hence AVR dynamics may settle before they can make themselves felt in the slower load-frequency control channel.

4(b) Since the generators are in parallel, they will operate at the same frequency at steady state

Let load on generator 1 (100MW) = x MW
and load on generator 2 (200MW) = (270−x) MW
Reduction in frequency = Δf

4% $\quad \frac{\Delta f}{x} = \frac{0.04 \times 50}{100}$ —(1)

6% $\quad \frac{\Delta f}{270 - x} = \frac{0.06 \times 50}{200}$ —(2)

Equating Δf in ① and ② we get
$x = 130$ MW (load on generator 1)

$270 - x = 140$ MW (load on generator 2)

System frequency $= 50 - \frac{0.04 \times 50}{100} \times 130$
$= 47.4$ HZ

It is observed here that due to difference in droop characteristics of governors, generator 1 gets overloaded while generator 2 is under loaded.

5.a) (6M)

Turbine Speed Governing System

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

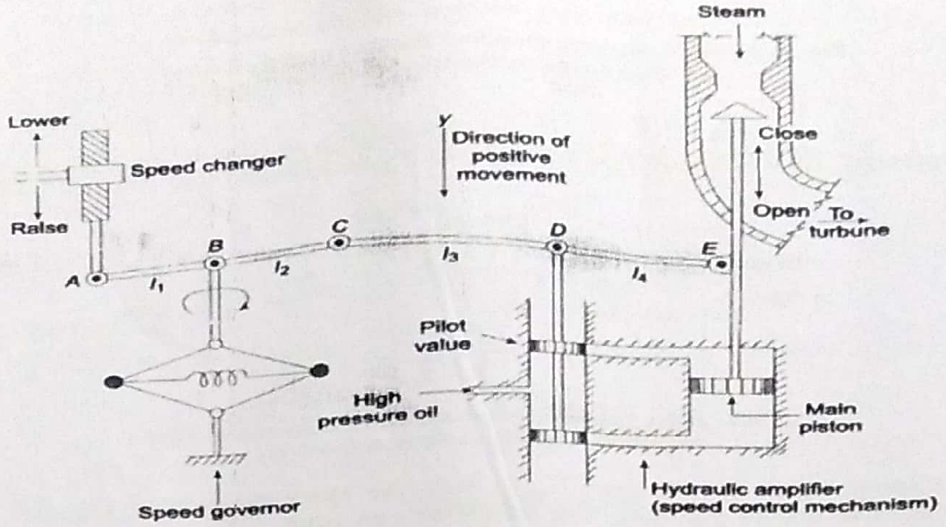


Fig. Turbine speed governing system

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

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

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

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

5.b) (6M)

Dynamic Response of Single area LFC

To obtain the dynamic response giving the change in frequency as function of the time for a step change in load, we must obtain the Laplace inverse of Eq. (8.14). The characteristic equation being of third order, dynamic response can only be obtained for a specific numerical case. However, the characteristic equation can be approximated as first order by examining the relative magnitudes of the time constants involved. Typical values of the time constants of load frequency control system are related as

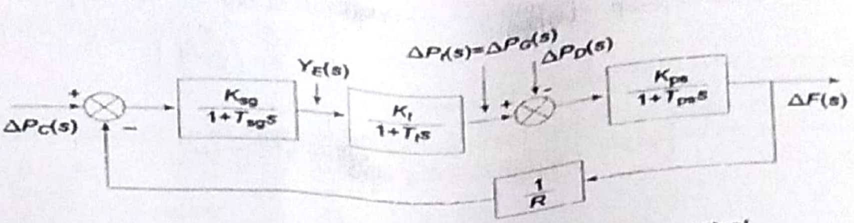


Fig. 8.6 Block diagram model of load frequency control (isolated power system)

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

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

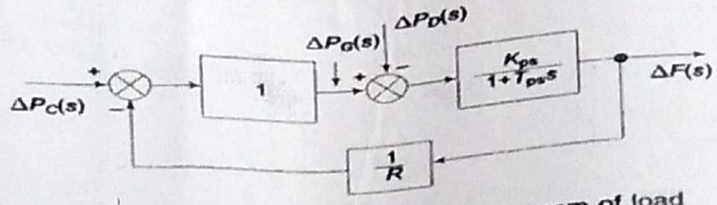


Fig. 8.8 First order approximate block diagram of load frequency control of an isolated area

Letting $T_{sg} = T_t = 0$, (and $K_{sg} K_t \cong 1$), the block diagram of Fig. 8.6 is reduced to that of Fig. 8.8, from which we can write

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

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

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

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

$$\Delta f(t) = -0.029\,(1 - e^{-1.717t}) \quad (8.23a)$$

$$\Delta f|_{\text{steady state}} = -0.029 \text{ Hz} \quad (8.23b)$$

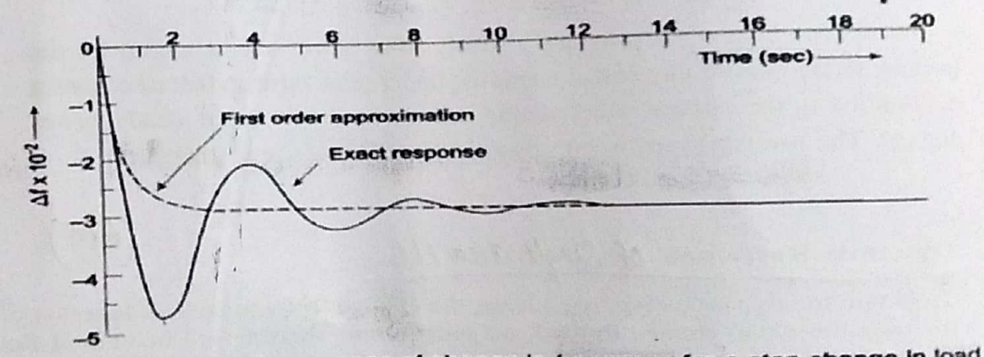


Fig. 8.9 Dynamic response of change in frequency for a step change in load ($\Delta P_D = 0.01$ pu, $T_{sg} = 0.4$ sec, $T_t = 0.5$ sec, $T_{ps} = 20$ sec, $K_{ps} = 100$, $R = 3$)

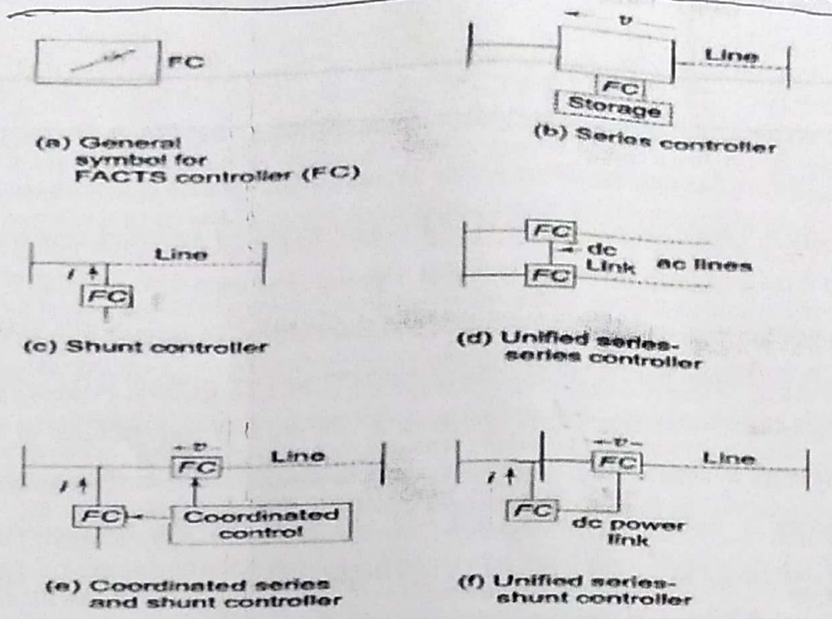
6.a) (6M)

(FACTS)

FACTS Categories

1. Series Connected -FACTS Devices
2. Shunt Connected -FACTS Devices
3. Combined Series-series Connected -FACTS Device
4. Combined Series-shunt Connected -FACTS Device

Different FACTS controllers



(a) General symbol for FACTS controller (FC)

(b) Series controller

(c) Shunt controller

(d) Unified series-series controller

(e) Coordinated series and shunt controller

(f) Unified series-shunt controller

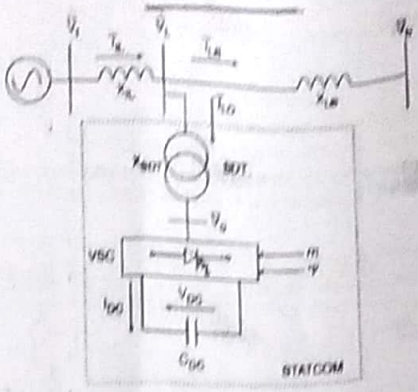
→ SERIES COMPENSATION

- Improper load distribution in transmission line
- In case inductance is prominent in the transmission line we suffer Voltage drop.
- To compensate, series capacitors are connected.
- Capacitors add voltage to line current.
- Effect of Inductance thus eliminated.

→ SHUNT COMPENSATION

- In case capacitance is prominent in the transmission line we suffer low current in transmission line.
- To compensate, shunt inductors are connected.
- inductors add current to line voltage.
- Effect of Capacitance thus eliminated.

STATCOM



STATCOM: it stands for Static Synchronous Compensator or Static Synchronous condenser(STATCON) It is basically regulating device use in A.C transmission system to control the reactive and it is also a voltage converter. STATCOM is an example for switching converter type FACT devices and it not a variable impedance type FACT device. The main function of STATCOM is to generate 3-Φ voltages with controllable magnitude and phase angles. In general, STATCOM can be implemented with the help of 6-pulse voltage source converter which consists of GTO's. Based on the principle of operation 3-Φ voltage source converter it will act as a both rectifier as well as inverter, if the generated voltages at the 3-Φ converter will be more than the bus bar voltage then converter will operate in leading conditions i.e it will acts as a TSC and corresponding V-I characteristics are represented in second quadrant as represented in V-I characteristics as shown in figure during this period voltage is positive and current is negative. Similarly, if the generated voltages at the 3-Φ converter will be less than the bus bar voltage then converter will operate in lagging conditions i.e it will acts as a TCR and corresponding V-I characteristics are represented in first quadrant as represented in V-I characteristics as shown in figure during this period both voltage and current is positive.

6.b) (6M)

Induction Regulators

An induction regulator is essentially a constant voltage transformer, one winding of which can be moved *w.r.t.* the other, thereby obtaining a variable secondary voltage. The primary winding is connected across the supply while the secondary winding is connected in series with the line whose voltage is to be controlled. When the position of one winding is changed w.r.t. the other, the secondary voltage injected into the line also changes. There are two types of induction regulators *viz.* single phase and 3-phase.

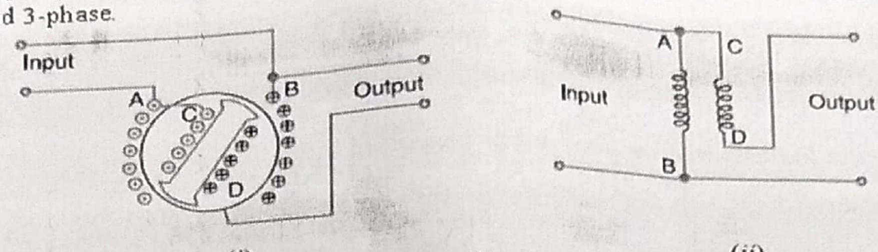


Fig. 15.9

(*i*) **Single-phase induction regulator.** A single phase induction regulator is illustrated in Fig. 15.9. In construction, it is similar to a single phase induction motor except that the rotor is not allowed to rotate continuously but can be adjusted in any position either manually or by a small motor. The primary winding *AB* is wound on the *stator and is connected across the supply line. The secondary winding *CD* is wound on the rotor and is connected in series with the line whose voltage is to be controlled.

The primary exciting current produces an alternating flux that induces an alternating voltage in the secondary winding *CD*. The magnitude of voltage induced in the secondary depends upon its position *w.r.t.* the primary winding. By adjusting the rotor to a suitable position, the secondary voltage can be varied from a maximum positive to a maximum negative value. In this way, the regulator can add or subtract from the circuit voltage according to the relative positions of the two windings. Owing to their greater flexibility, single phase regulators are frequently used for voltage control of distribution primary feeders.

(*ii*) **Three-phase induction regulator.** In construction, a 3-phase induction regulator is similar to a 3-phase induction motor with wound rotor except that the rotor is not allowed to rotate continuously but can be held in any position by means of a worm gear. The primary windings either in star or delta are wound on the stator and are connected across the supply. The secondary windings are wound on the rotor and the six terminals are brought out since these windings are to be connected in series with the line whose voltage is to be controlled.

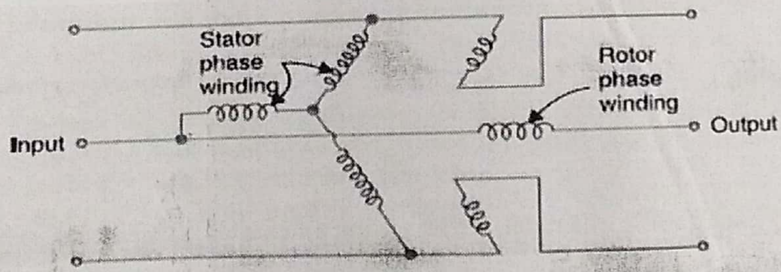


Fig. 15.10

When polyphase currents flow through the primary windings, a rotating field is set up which induces an e.m.f. in each phase of rotor winding. As the rotor is turned, the magnitude of the rotating flux is not changed; hence the rotor e.m.f. per phase remains constant. However, the variation of the position of the rotor will affect the phase of the rotor e.m.f. *w.r.t.* the applied voltage as shown in Fig. 15.11. The input primary voltage per phase is V_p and the boost introduced by the regulator is V_r. The output voltage V is the vector sum of V_p and V_r. Three phase induction regulators are used to regulate the voltage of feeders and in connection with high voltage oil testing transformers.

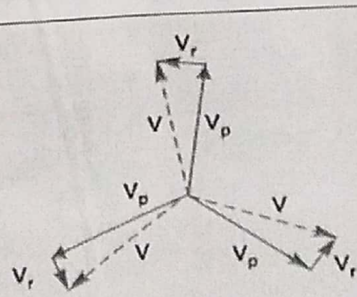


Fig. 15.11

6.b)Shunt Capacitors

Shunt capacitor banks are used to supply reactive power at both transmission and distribution levels; along lines or sub-stations and loads. Capacitors are either directly connected a to a busbar or to the tertiary winding of a main transformer. They may be switched on and off depending on the changes in load demand. When they are in parallel with a load having a lagging power factor, the capacitors supply reactive power.

Shunt capacitors are extensively used in industrial and utility systems at all voltage levels. By developing higher power density, lower cost improved capacitors and an increase in energy density by a factor of 100 is possible. These present a constant impedance type of load, and the capacitive power output varies with the square of voltage.

Kvar, V2=Kvar,v1V2V12

where,

Kvar,v1 is output at voltage V1, and Kvar,v2is output at voltage V2

As the voltage reduces, SO does the reactive power, output, when it is required the most. This is called the destabilizing effect of power capacitors. Capacitors can be switched in certain discrete steps and do not provide a stepless control. A two-step sequential reactive power switching control is used to maintain, voltage within a certain band. As the reactive power demand increases, voltage falls.

Rise in Voltage Due to Shunt Capacitance

The equivalent circuit of a short transmission line with static shunt capacitor is as shown in Image.

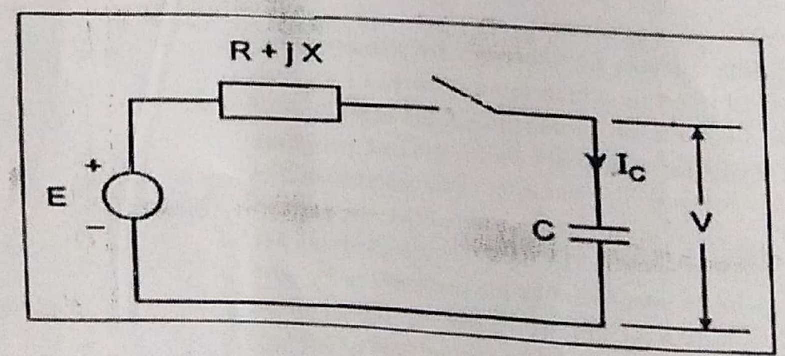
Voltage drop without the shunt capacitor

ΔV = P2R+Q2X/V

Voltage drop with shunt capacitor is,.

ΔV = P2R+(Q2-Qc)X/V

Capacitor raises the voltage, Voltage profile of a radial feeder having a capacitor is depicted in image.



7.a) (6M)

Methods of Voltage Control

There are several methods of voltage control. In each method, the system voltage is changed in accordance with the load to obtain a fairly constant voltage at the consumer's end of the system. The following are the methods of voltage control in an *a.c. power system:

(i) By excitation control
(ii) By using tap changing transformers
(iii) Auto-transformer tap changing
(iv) Booster transformers
(v) Induction regulators
(vi) By synchronous condenser

Method (i) is used at the generating station only whereas methods (ii) to (v) can be used for transmission as well as primary distribution systems. However, methods (vi) is reserved for the voltage control of a transmission line.

Tap-Changing Transformers

The excitation control method is satisfactory only for relatively short lines. However, it is *not suitable for long lines as the voltage at the alternator terminals will have to be varied too much in order that the voltage at the far end of the line may be constant. Under such situations, the problem of voltage control can be solved by employing other methods. One important method is to use tap-changing transformer and is commonly employed where main transformer is necessary. In this method, a number of tappings are provided on the secondary of the transformer. The voltage drop in the line is supplied by changing the secondary e.m.f. of the transformer through the adjustment of its number of turns.

(i) **Off load tap-changing transformer.** Fig. 15.4 shows the arrangement where a number of tappings have been provided on the secondary. As the position of the tap is varied, the effective number of secondary turns is varied and hence the output voltage of the secondary can be changed. Thus referring to Fig. 15.4, when the movable arm makes contact with stud 1, the secondary voltage is minimum and when with stud 5, it is maximum. During the period of light load, the voltage across the primary is not much below the alternator voltage and the movable arm is placed on stud 1. When the load increases, the voltage across the primary drops, but the secondary voltage can be kept at the previous value by placing the movable arm on to a higher stud. Whenever a tapping is to be changed in this type of transformer, the load is kept off and hence the name off load tap-changing transformer.

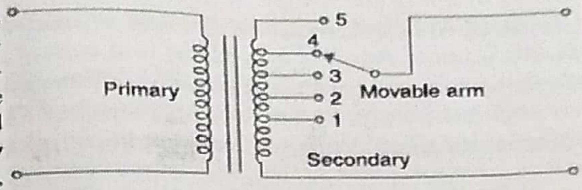


Fig. 15.4

The principal disadvantage of the circuit arrangement shown in Fig. 15.4 is that it cannot be used for tap-changing on load. Suppose for a moment that tapping is changed from position 1 to position 2 when the transformer is supplying load. If contact with stud 1 is broken before contact with stud 2 is made, there is break in the circuit and arcing results. On the other hand, if contact with stud 2 is made before contact with stud 1 is broken, the coils connected between these two tappings are short-circuited and carry damaging heavy currents. For this reason, the above circuit arrangement cannot be used for tap-changing on load.

(ii) **On-load tap-changing transformer.** In supply system, tap-changing has normally to be performed on load so that there is no interruption to supply. Fig. 15.5 shows diagrammatically one type of on-load tap-changing transformer. The secondary consists of two equal parallel windings which have similar tappings 1a...... 5a and 1b .... 5b. In the normal working conditions, switches a, b and tappings with the same number remain closed and each secondary winding carries one-half of the total current. Referring to Fig. 15.5, the secondary voltage will be maximum when switches a, b and 5a, 5b are closed. However, the secondary voltage will be minimum when switches a, b and 1a, 1b are closed.

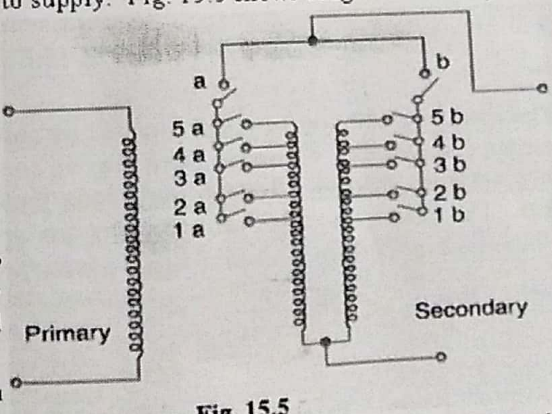


Fig. 15.5

Suppose that the transformer is working with tapping position at 4a, 4b and it is desired to alter its position to 5a, 5b. For this purpose, one of the switches a and b, say a, is opened. This takes the secondary winding controlled by switch a out of the circuit. Now, the secondary winding controlled by switch b carries the total current which is twice its rated capacity. Then the tapping on the disconnected winding is changed to 5a and switch a is closed. After this, switch b is opened to disconnect its winding, tapping position on this winding is changed to 5b and then switch b is closed. In this way, tapping position is changed without interrupting the supply. This method has the following disadvantages:

(i) During switching, the impedance of transformer is increased and there will be a voltage surge.

(ii) There are twice as many tappings as the voltage steps.

Auto-transformer

Auto-Transformer Tap-changing

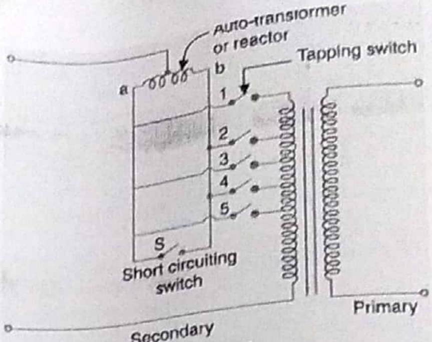


Fig. 15.6

Fig. 15.6 shows diagrammatically auto-transformer tap changing. Here, a mid-tapped auto-transformer or reactor is used. One of the lines is connected to its mid-tapping. One end, say *a* of this transformer is connected to a series of switches across the odd tappings and the other end *b* is connected to switches across even tappings. A short-circuiting switch *S* is connected across the auto-transformer and remains in the closed position under normal operation. In the normal operation, there is *no inductive voltage drop across the auto-transformer. Referring to Fig. 15.6, it is clear that with switch 5 closed, minimum secondary turns are in the circuit and hence the output voltage will be the lowest. On the other hand, the output voltage will be maximum when switch 1 is closed.

Suppose now it is desired to alter the tapping point from position 5 to position 4 in order to raise the output voltage. For this purpose, short-circuiting switch *S* is opened, switch 4 is closed, then switch 5 is opened and finally short-circuiting switch is closed. In this way, tapping can be changed without interrupting the supply.

It is worthwhile to describe the electrical phenomenon occurring during the tap changing. When the short-circuiting switch is opened, the load current flows through one-half of the reactor coil so that there is a voltage drop across the reactor. When switch 4 is closed, the turns between points 4 and 5 are connected through the whole reactor winding. A circulating current flows through this local circuit but it is limited to a low value due to high reactance of the reactor.

Booster Transformer

Sometimes it is desired to control the voltage of a transmission line at a point far away from the main transformer. This can be conveniently achieved by the use of a booster transformer as shown in Fig. 15.7. The secondary of the booster transformer is connected in series with the line whose voltage is to be controlled. The primary of this transformer is supplied from a regulating transformer *fitted with on-load tap-changing gear. The booster transformer is connected in such a way that its secondary injects a voltage in phase with the line voltage.

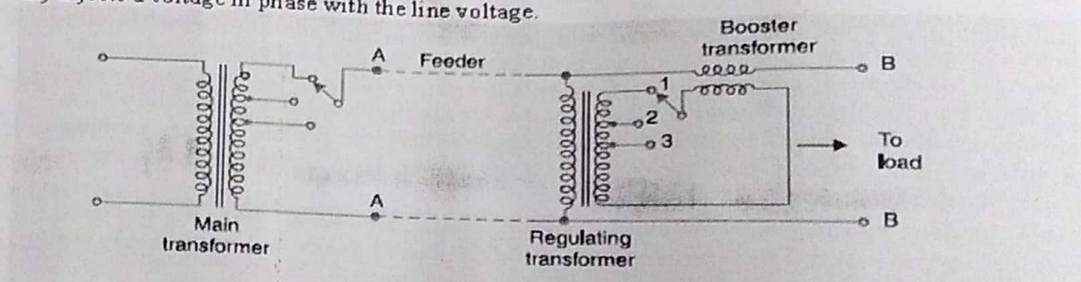


Fig. 15.7

The voltage at *AA* is maintained constant by tap-changing gear in the main transformer. However, there may be considerable voltage drop between *AA* and *BB* due to fairly long feeder and tapping of loads. The voltage at *BB* is controlled by the use of regulating transformer and booster transformer. By changing the tapping on the regulating transformer, the magnitude of the voltage injected into the line can be varied. This permits to keep the voltage at *BB* to the desired value. This method of voltage control has three disadvantages. Firstly, it is more expensive than the on-load tap-changing transformer. Secondly, it is less efficient owing to losses in the booster and thirdly more floor space is required. Fig. 15.8 shows a three-phase booster transformer.

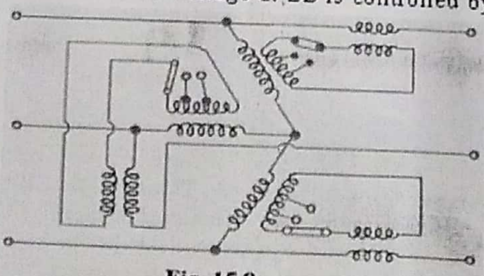
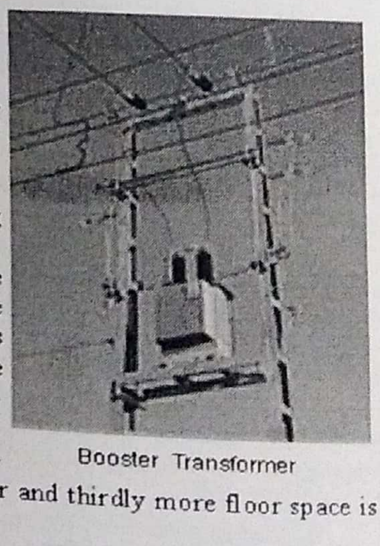
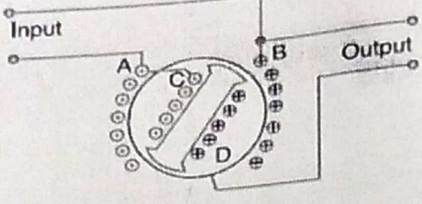


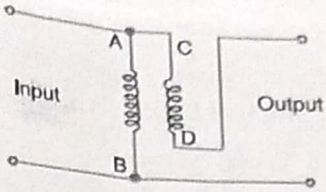
Fig. 15.8


Booster Transformer

Induction Regulators

An induction regulator is essentially a constant voltage transformer, one winding of which can be moved *w.r.t.* the other, thereby obtaining a variable secondary voltage. The primary winding is connected across the supply while the secondary winding is connected in series with the line whose voltage is to be controlled. When the position of one winding is changed w.r.t. the other, the secondary voltage injected into the line also changes. There are two types of induction regulators *viz.* single phase and 3-phase.





(*i*) **Fig. 15.9** (*ii*)

(*i*) **Single-phase induction regulator.** A single phase induction regulator is illustrated in Fig. 15.9. In construction, it is similar to a single phase induction motor except that the rotor is not allowed to rotate continuously but can be adjusted in any position either manually or by a small motor. The primary winding *A B* is wound on the *stator and is connected across the supply line. The secondary winding *CD* is wound on the rotor and is connected in series with the line whose voltage is to be controlled.

The primary exciting current produces an alternating flux that induces an alternating voltage in the secondary winding *CD*. The magnitude of voltage induced in the secondary depends upon its position *w.r.t.* the primary winding. By adjusting the rotor to a suitable position, the secondary voltage can be varied from a maximum positive to a maximum negative value. In this way, the regulator can add or subtract from the circuit voltage according to the relative positions of the two windings. Owing to their greater flexibility, single phase regulators are frequently used for voltage control of distribution primary feeders.

(*ii*) **Three-phase induction regulator.** In construction, a 3-phase induction regulator is similar to a 3-phase induction motor with wound rotor except that the rotor is not allowed to rotate continuously but can be held in any position by means of a worm gear. The primary windings either in star or delta are wound on the stator and are connected across the supply. The secondary windings are wound on the rotor and the six terminals are brought out since these windings are to be connected in series with the line whose voltage is to be controlled.

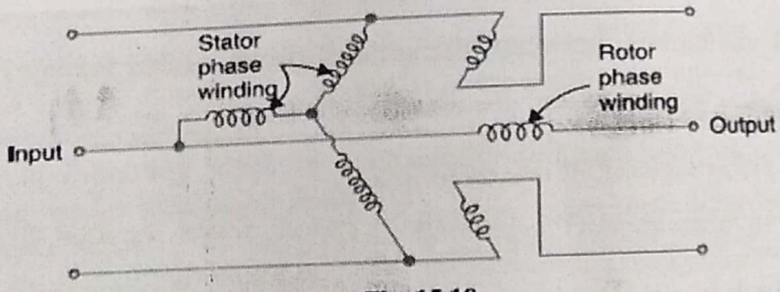


Fig. 15.10

When polyphase currents flow through the primary windings, a rotating field is set up which induces an e.m.f. in each phase of rotor winding. As the rotor is turned, the magnitude of the rotating flux is not changed; hence the rotor e.m.f. per phase remains constant. However, the variation of the position of the rotor will affect the phase of the rotor e.m.f. *w.r.t.* the applied voltage as shown in Fig. 15.11. The input primary voltage per phase is V_p and the boost introduced by the regulator is V_r. The output voltage V is the vector sum of V_p and V_r. Three phase induction regulators are used to regulate the voltage of feeders and in connection with high voltage oil testing transformers.

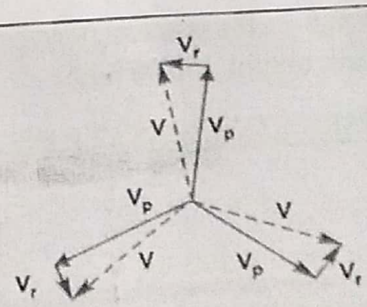


Fig. 15.11

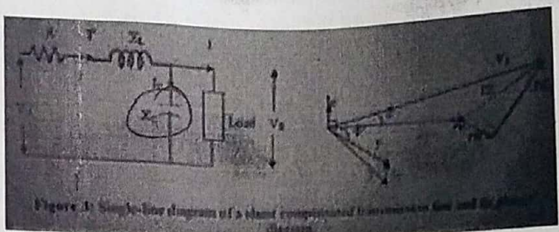
Note: Consider Any one method

7.b) (6M)

SHUNT COMPENSATION:

At the buses where reactive power demand increases the bus voltage is controlled by connecting capacitor banks in parallel to lagging load. Capacitor banks supply a part of or full reactive power of load, which reduces magnitude of the source current needed to supply load. While the voltage drops between sending end and load gets reduced. The power factor improves and increases active power output which is available from the source.

Depending upon the load demand the capacitor banks can be permanently connected to the system or it can be varied by switching on or off the parallel connected capacitors either manually or automatically. Figure below shows the single line diagram of a transmission line and its phasor diagram after the addition of the shunt capacitor.



Single line diagram of a Shunt Compensation transmission line

Voltage drop is $\mathbf{VD = I_R R + I_X X_L - I_C X_L}$

The expression for the difference between the voltage drops is the voltage rises due to installation of capacitor is $\mathbf{VR = I_C X_L}$

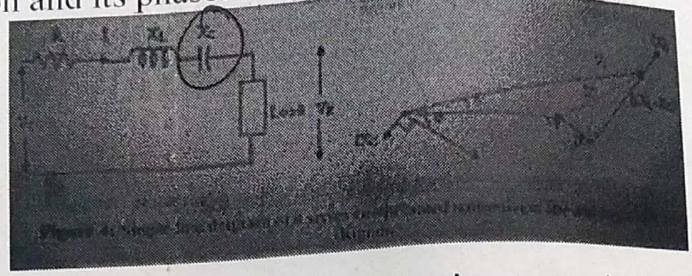
The drawbacks of using shunt capacitors are as follows:

- The Shunt capacitors does not affect current or power factor beyond their point of application
- The reactive power which is supplied by the shunt capacitor banks is directly proportional to bus voltage
- When the reactive power is required less on light load the capacitor bank output will be high.

SERIES COMPENSATION:

When the line has the value of high reactance to resistance ratio than the inductive reactance of the transmission line could be decreased by introducing series capacitors as a results in low voltage drop. If a load with lagging power factor is connected at the end the voltage drop in the line is given by $\mathbf{VD = I\,(R\cos\acute{o} + X_L \sin\acute{o})}$

If a capacitance **C** with reactance **X_c** is connected in series with the line, then the reactance will reduce to **[XLXc]** and the voltage drop is reduced. And also the reactive power taken by the line is reduced. Figure below shows the equivalent circuit of the line with series compensation and its phasor diagram are presented



Single line diagram of a Series Compensation transmission line

From the phasor diagram the line voltage drop is, **VD = I (Rcosó + (X_L-X_C) sinó)**

Hence the series capacitors are used to reduce the voltage drop in the lines with low power factor and also improves the voltage at the receiving end specifically with low power factor loads. For variable load conditions the voltage is controlled by switching in suitable series capacitors in the line.

OBJECTIVES OF SERIES COMPENSATION:

The effect of series compensation on the basic factors, determining attainable

- MAXIMAL POWER TRANSMISSION,
- STEADY-STATE POWER TRANSMISSION
- LIMIT, TRANSIENT STABILITY,
- VOLTAGE STABILITY
- POWER OSCILLATION DAMPING

OBJECTIVES OF SHUNT COMPENSATION: ¬

Change the natural electrical characteristics of the transmission line to make it more compatible wit the prevailing load demand.

Thus, shunt connected, fixed or mechanically switched reactors are applied **to minimize lin overvoltage under light load conditions.**

The ultimate objective of applying reactive shunt compensation in a transmission system is **increase the transmittable power**

(6M)

8.a)

Equal Area Criterion:

Equal Area Criterion – In a system where one machine is swinging with respect to an infinite bus, it is possible to study transient stability by means of a simple Equal Area Criterion, without resorting to the numerical solution of a swing equation.

Consider the swing equation

$$\frac{d^2\delta}{dt^2} = \frac{1}{M}(P_m - P_e) = \frac{P_a}{M};\ P_a = \text{accelerating power} \tag{12.53}$$

$$M = \frac{H}{\pi f} \text{ in pu system}$$

$$\frac{d^2\delta}{dt^2} = \frac{1}{M}(P_m - P_e) = \frac{P_a}{M};\ P_a = \text{accelerating power} \tag{12.53}$$

$$M = \frac{H}{\pi f} \text{ in pu system}$$

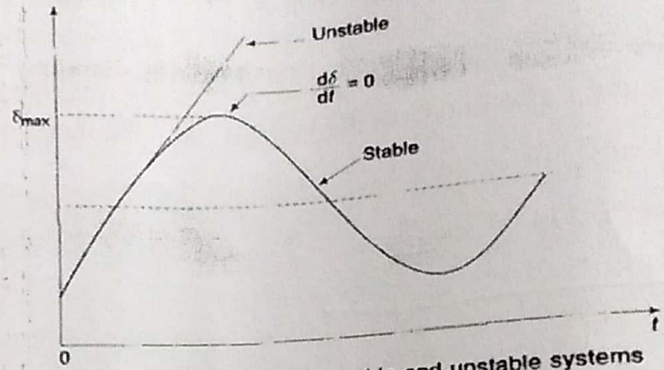


Fig. 12.18 Plot of δ vs t for stable and unstable systems

If the system is unstable δ continues to increase indefinitely with time and the machine loses synchronism. On the other hand, if the system is stable, δ(t) performs oscillations (nonsinusoidal) whose amplitude decreases in actual practice because of damping terms (not included in the swing equation). These two situations are shown in Fig. 12.18. Since the system is non-linear, the nature of its response [δ(t)] is not unique and it may exhibit instability in a fashion different from that indicated in Fig. 12.18, depending upon the nature and severity of disturbance. However, experience indicates that the response δ (t) in a power system generally falls in the two broad categories as shown in the figure. It can easily be visualized now (this has also been stated earlier) that for a stable system, indication of stability will be given by observation of the first swing where δ will go to a maximum and will start to reduce. This fact can be stated as a stability criterion, that the system is stable if at some time

$$\frac{d\delta}{dt} = 0 \tag{12.54}$$

and is unstable, if

$$\frac{d\delta}{dt} > 0 \tag{12.55}$$

for a sufficiently long time (more than 1 s will generally do).

The stability criterion for power systems stated above can be converted into a simple and easily applicable form for a single machine infinite bus system.

Multiplying both sides of the swing equation by (2 dδ/dt), we get

$$2\frac{d\delta}{dt} \cdot \frac{d^2\delta}{dt^2} = \frac{2P_a}{M}\frac{d\delta}{dt}$$

Integrating, we have

$$\left(\frac{d\delta}{dt}\right)^2 = \frac{2}{M}\int_{\delta_0}^{\delta} P_a \, d\delta$$

or

$$\frac{d\delta}{dt} = \left(\frac{2}{M}\int_{\delta_0}^{\delta} P_a \, d\delta\right)^{\frac{1}{2}} \qquad (12.56)$$

where δ_0 is the initial rotor angle before it begins to swing due to disturbance. From Eqs. (12.55) and (12.56), the condition for stability can be written as I

$$\left(\frac{2}{M}\int_{\delta_0}^{\delta} P_a d\,\delta\right)^{\frac{1}{2}} = 0$$

or

$$\int_{\delta_0}^{\delta} P_a \, d\delta = 0 \qquad (12.57)$$

The condition of stability can therefore be stated as: the system is stable if the area under P_a (accelerating power) – δ curve reduces to zero at some value of 6. In other words, the positive (accelerating) area under P_a — δ curve must equal the negative (decelerating) area and hence the name 'equal area' criterion of stability.

CRITICAL CLEARING ANGLE AND CRITICAL CLEARING TIME IN TRANSIENT STABILITY.

If a fault occurs in a system, δ begins to increase under the influence of positive accelerating power, and the system will becáme unstable If δ becomes very large. There is a critical angle within which the fault must be cleared if the system is to remain stable and the equal-area criterion is to be satisfied. This angle is known as the critical clearing angle. Consider the system of Fig. 11.9 operating with mechanical input Pi at stady angle δ0.(Pi=Pe) as shown by the point 'a' on the power angle diagram of Fig 11.10.

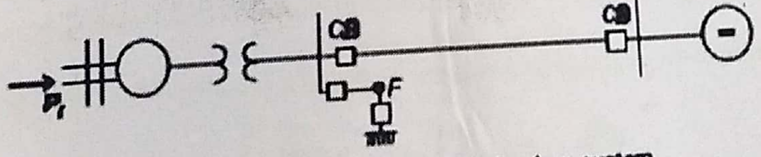


Fig. 11.9: Single machine infinite bus system.

Now if a three phase short circuit occurs at the point F o the outgoing radial line, the terminal voltage goes to zero and hence the electrical power output of the generator instantly reduces to aero, i.e., Pe = 0 and the state point drops to 'b'. The acceleration area A1 starts to increase while the state point moves along bc. At time tc corresponding clearing angle δo the fault is cleared by the opening of the line circuit breaker. tc is called clearing time and δe is called clearing angle. After the fault is cleared, the system again becomes healthy and transmits poer Pe = Pmaxsin δ, i.e., the state point shit to 'd' on the power angle curve. The rotor now decelerates and the decelerating area A2 begins to increase while the state point moves along de.

For stability, the clearing angle, δo must be such that area A1 = area A2.

Expressing area A1 = area A2 mathematically, we have

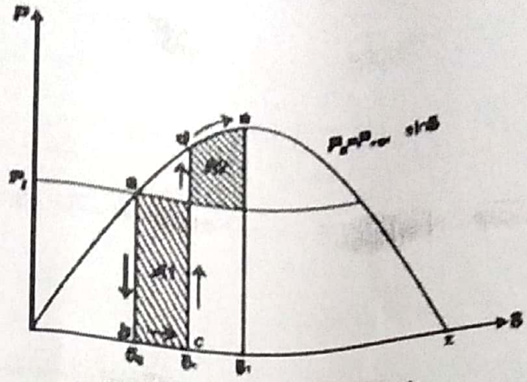


Fig. 11.10: $P_e - \delta$ characteristic.

$$P_i(\delta_c - \delta_0) = \int_{\delta_c}^{\delta_1} (P_e - P_i)\, d\delta$$

$$\therefore \quad P_i(\delta_c - \delta_0) = \int_{\delta_c}^{\delta_1} P_{max} \sin\delta . d\delta - P_i(\delta_1 - \delta_c)$$

$$\therefore \quad P_i\delta_c - P_i\delta_0 = P_{max}(-\cos\delta_1 + \cos\delta_c) - P_i\delta_1 + P_i\delta_c$$

$$\therefore \quad P_{max}(\cos\delta_c - \cos\delta_1) = P_i(\delta_1 - \delta_0) \qquad \text{...(11.47)}$$

Also

$$P_i = P_{max} \sin\delta_0 \qquad \text{...(11.48)}$$

Using eqns. (11.47) and (11.48) we get

$$P_{max}(\cos\delta_c - \cos\delta_1) = P_{max}(\delta_1 - \delta_0)\sin\delta_0$$

$$\therefore \quad \cos\delta_c = \cos\delta_1 + (\delta_1 - \delta_0)\sin\delta_0 \qquad \text{...(11.49)}$$

To reiterate, with reference to Fig. 11.10, the various angle in eqn.(11.49) are δe = clearing angle; δ0 = initial poer angle; and δ1 = power angle to which the rotor advances (or overshoots) beyond δe.

In order to determine the clearing time, we re-write eqn.(11.20), with Pe=0, since we have a three phase fault,

$$\frac{d^2\delta}{dt^2} = \frac{\pi f}{H} P_i \qquad \text{...(11.50)}$$

Integrating eqn. (11.50) twice and utilizing the fact that when $t = 0$, $\frac{d\delta}{dt} = 0$ yields

$$\delta = \frac{\pi f P_i}{2H} t^2 + \delta_0 \qquad \text{...(11.51)}$$

If t_c is a clearing time corresponding to a clearing angle δ_c, then we obtain from eqn. (11.51),

$$\delta_c = \frac{\pi f P_i}{2H} t_c^2 + \delta_0$$

$$t_c = \sqrt{\frac{2H(\delta_c - \delta_0)}{\pi f P_i}}$$

∴ ...(11.52)

Note that δ_c can be obtained from eqn. (11.49). As the clearing of the faulty line is delayed, A_1 increases and so does δ_1 to find $A_2 = A_1$ till $\delta_1 = \delta_m$ as shown in Fig. 11.11. For a clearing

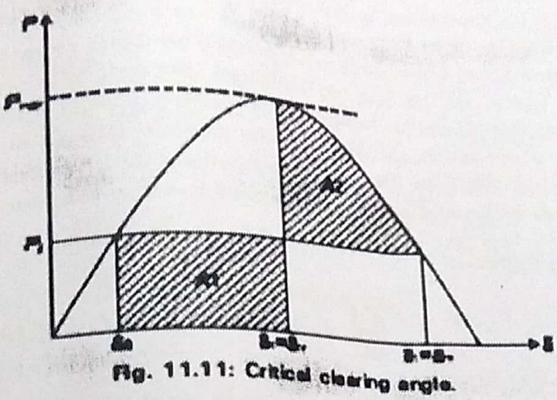


Fig. 11.11: Critical clearing angle.

Angle (or clearing time) larger than this value, the system would be unstable. The maximum allowable value of the clearing angle and clearing time for the system to remain stable are known as critical clearing angle and critical clearing time respectively.

From Fig. 11.11, $\delta_m = \pi - \delta_0$, we have upon substitution into eqn. (11.49)

$$\cos\delta_{cr} = \cos\delta_m + (\delta_m - \delta_0)\sin\delta_0$$

$$\cos\delta_{cr} = \cos\delta_m + (\pi - \delta_0 - \delta_0)\sin\delta_0$$

∴ $$\cos\delta_{cr} = \cos(\pi - \delta_0) + (\pi - 2\delta_0)\sin\delta_0$$

∴ $$\cos\delta_{cr} = (\pi - 2\delta_0)\sin\delta_0 - \cos\delta_0$$ ...(11.53)

∴ $$\delta_{cr} = \cos^{-1}[(\pi - 2\delta_0)\sin\delta_0 - \cos\delta_0]$$

∴ Using eqn. (11.52), critical clearing time can be written as:

$$t_{cr} = \sqrt{\frac{2H(\delta_{cr} - \delta_0)}{\pi f P_i}}$$ ...(11.54)

(6M.)

8.b)

Numerical Solution of Swing Equation:

Numerical Solution of Swing Equation – In most practical systems, after machine lumping has been done, there are still more than two machines to be considered from the point of view of system stability. Therefore, there is no choice but to solve the swing equation of each machine by a numerical technique on the digital computer. Even in the case of a single machine tied to infinite bus bar, the critical clearing time cannot be obtained from equal area criterion and we have to make this calculation numerically through swing equation. There are several sophisticated methods now available for the solution of the swing equation including the powerful Runge-Kutta method. Here we shall treat the point-by-point method of solution which is a conventional, approximate method like all numerical methods but a well tried and proven one. We shall illustrate the point-by-point method for one machine tied to infinite bus bar. The procedure is, however, general and can be applied to every machine of a multimachine system.

Consider the swing equation

$$\frac{d^2\delta}{dt^2} = \frac{1}{M}(P_m - P_{max}\sin\delta) = P_a/M;$$

$$\left(M = \frac{GH}{\pi} \text{ or in pu system } M = \frac{H}{\pi f}\right)$$

The solution δ(t) is obtained at discrete intervals of time with interval spread of Δt uniform throughout. Accelerating power and change in speed which are continuous functions of time are discretized as below:

1. The accelerating power P_a computed at the beginning of an interval is assumed to remain constant from the middle of the preceding interval to the middle of the interval being considered as shown in Fig. 12.38.

2. The angular rotor velocity $\omega = d\delta/dt$ (over and above synchronous velocity ω_s) is assumed constant throughout any interval, at the value computed for the middle of the interval as shown in Fig. 12.38.

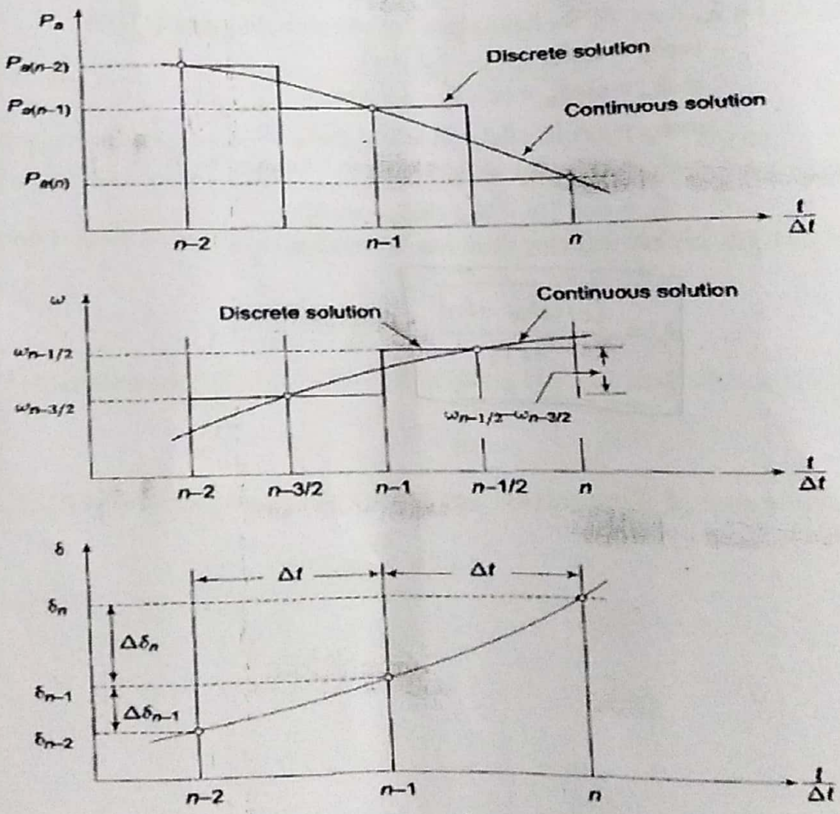


Fig. 12.38 Point-by-point solution of swing equation

In Fig. 12.38, the numbering on t/Δt axis pertains to the end of intervals. At the end of the (n —1)th interval, the acceleration power is

$$P_{a\,(n-1)} = P_m - P_{max} \sin \delta_{n-1} \qquad (12.68)$$

where δ_{n-1} has been previously calculated. The change in velocity ($\omega = d\delta/dt$), caused by the $P_{a(n-1)}$, assumed constant over Δt from (n-3/2) to (n-1/2) is

$$w_{n-1/2} - w_{n-3/2} = (\Delta t/M)\ P_{a(n-1)} \qquad (12.69)$$

The change in δ during the (n-1)th interval is

$$\Delta\delta_{n-1} = \delta_{n-1} - \delta_{n-2} = \Delta t \omega_{n-3/2} \qquad (12.70a)$$

and during the nth interval

$$\Delta\delta_n = \delta_n - \delta_{n-1} = \Delta t \omega_{n-1/2} \qquad (12.70b)$$

Subtracting Eq. (12.70a) from Eq. (12.70b) and using Eq. (12.69), we get

$$\Delta\delta_n = \Delta\delta_{n-1} + \frac{(\Delta t)^2}{M} P_{a(n-1)} \qquad (12.71)$$

Using this, we can write

$$\delta_n = \delta_{n-1} + \Delta\delta_n \qquad (12.72)$$

The process of computation is now repeated to obtain $P_{a(n)}$, $\Delta\delta_{n+1}$ and δ_{n+1}. The time solution in discrete form is thus carried out over the desired length of time, normally 0.5 s. Continuous form of solution is obtained by drawing a smooth curve through discrete values as shown in Fig. 12.38. Greater accuracy of solution can be achieved by reducing the time duration of intervals.

The occurrence or removal of a fault or initiation of any switching event causes a discontinuity in accelerating power P_a. If such a discontinuity occurs at the beginning of an interval, then the average of the values of P_a before and after the discontinuity must be used. Thus, in computing the increment of angle occurring during the first interval after a fault is applied at t = 0, Eq. (12.71) becomes

$$\Delta\delta_1 = \frac{(\Delta t)^2}{M} + \frac{P_{a0+}}{2}$$

where P_{a0+} is the accelerating power immediately after occurrence of fault. Immediately before the fault the system is in steady state, so that $P_{a0-}=0$ and (δ_0 is a known value. If the fault is cleared at the beginning of the nth interval, in calculation for this interval one should use for $P_{a(n-1)}$ the value $1/2[P_{a(n-1)}^- + P_{a(n-1)}^+]$ where $P_{a(n-1)}^-$ is the accelerating power immediately before clearing and $P_{a(n-1)}^+$ is that immediately after clearing the fault. If the discontinuity occurs at the middle of an interval, no special procedure is needed. The increment of angle during such an interval is calculated, as usual, from the value of P_a at the beginning of the interval.

(6M)

9.a)

Factors Affecting Transient Stability

The following factors can affect transient stability:

1. **Generator WR²X rpm²**. The greater this quantity the lower the acceleration factor.
2. **System Impedance**, which must include the transient reactances of all generating units. This affects phase angles and the flow of synchronizing power.
3. **Duration of the fault**, chosen as the criterion for stability. Duration will be dependent upon the circuit-breaker speeds and the relay schemes used.
4. **Generator loadings** prior to the fault which will determine the internal voltages and the change in output.
5. **System loading**, which will determine the phase angles among the various internal voltages of the generators

(6M)

9.b)

The main difference between voltage stability and angle stability is that voltage stability depends on the balance of reactive power demand and generation in the system where as the angle stability mainly depends on the balance between real power generation and demand.

Rotor Angle Stability with Voltage Stability:–

1. Rotor Angle Stability refers to the ability of the synchronous machine of an interconnected power system to remove in synchronism after being subjected to a disturbances.
2. Voltage stability refers to the ability of the power system to maintain steady acceptable voltages at all the buses in the system after being subjected to a disturbances.
3. Rotor angle stability is normally concerned with integrating remote power plant to a large system over long transmission line whereas voltage stability is concerned with load area and load characteristics.
4. Rotor angle stability is basically generator stability. Voltage stability is basically load stability.
5. Rotor angle stability depends on the ability of each synchronous machine to maintain equilibrium between electromagnetic torque and mechanical torque.
6. Voltage stability depends on the system to maintain equilibrium between load demand and load supply.
7. If voltage collapse at a point in a transmission system it is an angle instability situation however if voltage collapse in a load area is a voltage instability.

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