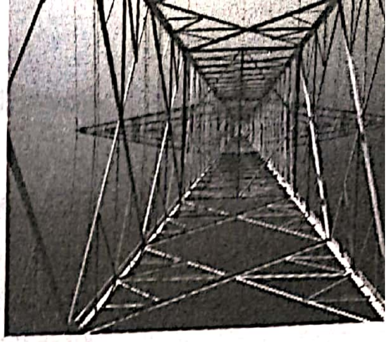


7 Load Frequency Control-I

OBJECTIVES

After reading this chapter, you should be able to:

- study the governing characteristics of a generator
- study the load frequency control (LFC)
- develop the mathematical models for different components of a power system
- observe the steady state and dynamic analysis of a single-area power system with and without integral control

(KVA) True & apparent

reactive KVAR

active (kw)

7.1 INTRODUCTION

In a power system, both active and reactive power demands are never steady and they continually change with the rising or falling trend. Steam input to turbo-generators or water input to hydro-generators must, therefore, be continuously regulated to match the active power demand, failing which the machine speed will vary with consequent change in frequency and it may be highly undesirable. The maximum permissible change in frequency is ±2%. Also, the excitation of the generators must be continuously regulated to match the reactive power demand with reactive power generation; otherwise, the voltages at various system buses may go beyond the prescribed limits. In modern large interconnected systems, manual regulation is not feasible and therefore automatic generation and voltage regulation equipment is installed on each generator. The controllers are set for a particular operating condition and they take care of small changes in load demand without exceeding the limits of frequency and voltage. As the change in load demand becomes large, the controllers must be reset either manually or automatically.

7.2 NECESSITY OF MAINTAINING FREQUENCY CONSTANT

Constant frequency is to be maintained for the following functions:

- All the AC motors should require constant frequency supply so as to maintain speed constant.
- In continuous process industry, it affects the operation of the process itself.
- For synchronous operation of various units in the power system network, it is necessary to maintain frequency constant.
- Frequency affects the amount of power transmitted through interconnecting lines.
- Electrical clocks will lose or gain time if they are driven by synchronous motors, and the accuracy of the clocks depends on frequency and also the integral of this frequency error is loss or gain of time by electric clocks.

E_{ci} applied to the exciter.

7.8 GENERATOR CONTROLLERS (*P–f* AND *Q–V* CONTROLLERS)

The active power P is mainly dependent on the internal angle δ and is independent of the bus voltage magnitude $|V|$. The bus voltage is dependent on machine excitation and hence on reactive power Q and is independent of the machine angle δ. Change in the machine angle δ is caused by a momentary change in the generator speed and hence the frequency. Therefore, the load frequency and excitation voltage controls are non-interactive for small changes and can be modeled and analyzed independently.

Figure 7.4 gives the schematic diagram of load frequency (P–f) and excitation voltage (Q–V) regulators of a turbo-generator. The objective of the MW frequency or the P–f control mechanism is to exert control of frequency and simultaneously exchange of the real-power flows via interconnecting lines. In this control, a frequency sensor senses the change in frequency and gives the signal Δf_i.The P–f controller senses the change in frequency signal (Δf_i) and the increments in tie-line real powers (ΔP_{tie}), which will indirectly provide information about the incremental state error ($\Delta\delta_i$). These sensor signals (Δf_i and ΔP_{tie}) are amplified, mixed, and transformed into a real-power control signal ΔP_{ci}. The valve control mechanism takes ΔP_{ci} as the input signal and provides the output signal, which will change the position of the inlet valve of the prime mover. As a result, there will be a change in the prime mover output and hence a change in real-power generation ΔP_{Gi}. This entire P–f control can be yielded by automatic load frequency control (ALFC) loop.

The objective of the MVAr-voltage or Q–V control mechanism is to exert control of the voltage state $|V_i|$. A voltage sensor senses the terminal voltage and converts it into an equivalent proportionate DC voltage. This proportionate DC voltage is compared with a

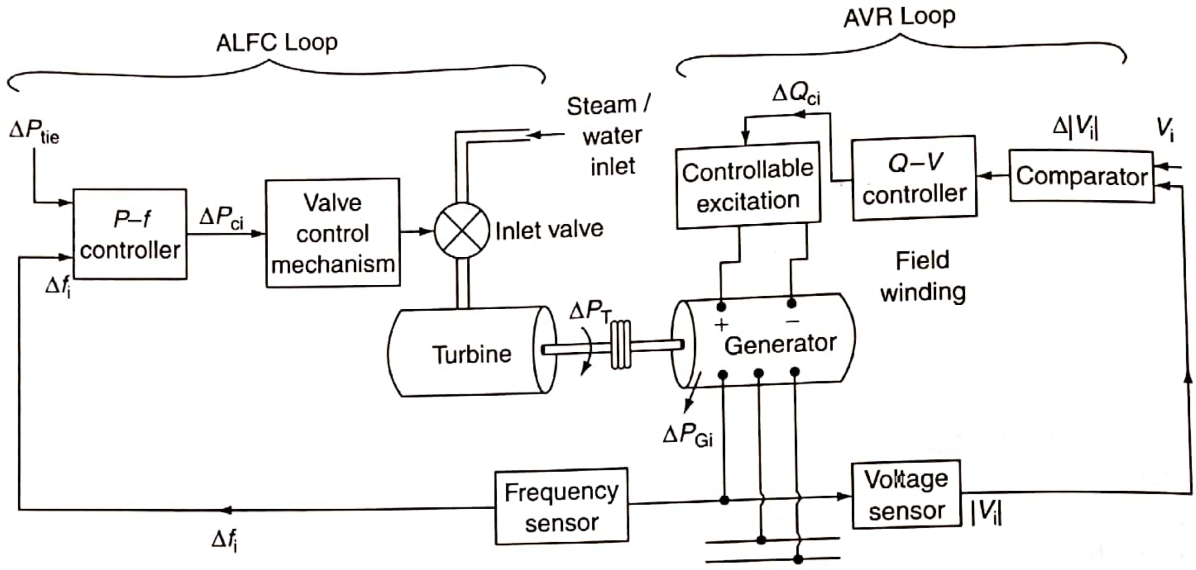


FIG. 7.4 *Schematic diagram of P–f controller and Q–V controller*

reference voltage V_{iref} by means of a comparator. The output obtained from the comparator is error signal $\Delta|V_i|$ and is given as input to Q–V controller, which transforms it to a reactive power signal command ΔQ_{ci} and is fed to a controllable excitation source. This results in a change in the rotor field current, which in turn modifies the generator terminal voltage. This entire Q–V control can be yielded by an automatic voltage regulator (AVR) loop.

In addition to voltage regulators at generator buses, equipment is used to control voltage magnitude at other selected buses. Tap-changing transformers, switched capacitor banks, and static VAr systems can be automatically regulated for rapid voltage control.

7.9 *P–f* CONTROL VERSUS *Q–V* CONTROL

Any static change in the real bus power ΔP_i will affect only the bus voltage phase angles (δ_i) (since $P \propto \delta$), but will leave the bus voltage magnitudes almost unaffected.

Static change in the reactive bus power ΔQ_i affects essentially only the bus voltage magnitudes (since $Q \propto V^2$), but leave the bus voltage phase angles almost unchanged.

Static change in reactive bus power at a particular bus affects the magnitude of that bus voltage most strongly, but in less degree the magnitudes of the bus voltages at remote buses.

7.10 DYNAMIC INTERACTION BETWEEN *P–f* AND *Q–V* LOOPS

In a static sense, for small deviations, there is a little interaction between P–f and Q–V loops. During dynamic perturbations, we encounter considerable coupling between two control loops for two following reasons:

- As the voltage magnitude fluctuates at a bus, the real load of that bus will likewise change as a result of the voltage load characteristic $\dfrac{\partial P_{di}}{\partial V_i}$.
- As the voltage magnitude fluctuates at a bus, the power transmitted over the lines connected to that bus will change. In other words, the change in Q–V loop will affect the generated emf, which also affects the magnitude of real power.

A dynamic perturbation in the Q–V loop will thus affect the real-power balance in the system. In general, the Q–V loop is much faster than the P–f loop due to the mechanical inertial constants in the P–f loop. If it can be assumed that the transients in the Q–V loop are essentially over before the P–f loop reacts, then the coupling between the two loops can be ignored.

7.11 SPEED-GOVERNING SYSTEM

The speed governor is the main primary tool for the LFC, whether the machine is used alone to feed a smaller system or whether it is a part of the most elaborate arrangement. A schematic arrangement of the main features of a speed-governing system of the kind used on steam turbines to control the output of the generator to maintain constant frequency is as shown in Fig. 7.5.

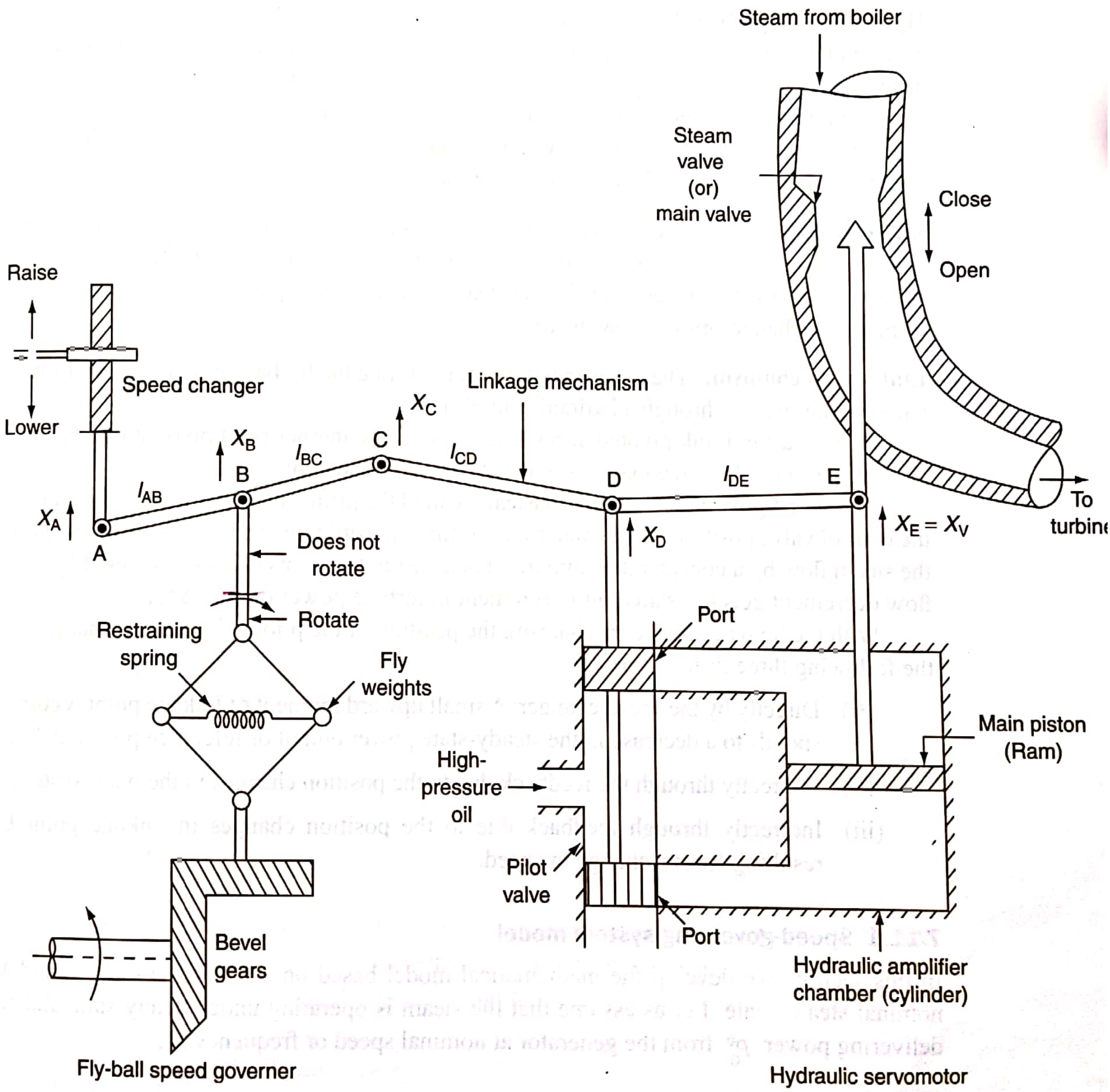


FIG. 7.5 *Speed-governor system*

Its main parts or components are as follows:

Fly-ball speed governor: It is a purely mechanical, speed-sensitive device coupled directly to and builds directly on the prime movers to adjust the control valve opening via linkage mechanism. It senses a speed deviation or a power change command and converts it into appropriate valve action. Hence, this is treated as the heart of the system, which controls the change in speed (frequency). As the speed increases, the fly balls move outwards and the point B on linkage mechanism moves upwards. The reverse will happen if the speed decreases.

The horizontal rotating shaft on the lower left may be viewed as an extension of the shaft of a turbine-generator set and has a fixed axis as shown in Fig. 7.5. The vertical shaft, above the fly-ball mechanism, also rotates between fixed bearings. Although its axis is fixed, it can move up and down, transferring its vertical motion to the pilot point B.

Hydraulic amplifier: It is nothing but a single-state hydraulic servomotor interposed between the governor and valve. It consists of a pilot valve and the main piston. With this arrangement, hydraulic amplification is obtained by converting the movement of low-power pilot valve into movement of high-power level main piston.

In hydraulic amplification, a large mechanical force is necessary so that the steam valve could be opened or closed against high-pressure inlet steam.

Speed changer: It provides a steady-state power output setting for the turbines. Its upward movement opens the upper pilot valve so that more steam is admitted to the turbine under steady conditions. This gives rise to higher steady-state power output. The reverse will happen if the speed changer moves downward.

Linkage mechanism: These are linked for transforming the fly-balls moment to the turbine valve (steam valve) through a hydraulic amplifier.

ABC is a rigid link pivoted at point B and CDE is another rigid pivoted link at point D. Link DE provides a feedback from the steam valve moment.

The speed-governing system is basically called the primary control loop in the LFC. If the control valve position is indicated by x_E, a small upward movement of point E decreases the steam flow by a considerable amount. It is measured in terms of valve power ΔP_v. This flow decrement gets translated into decrement in turbine power output ΔP_T.

With the help of linkage mechanism, the position of the pilot valve can be changed in the following three different ways:

(i) Directly by the speed changer: A small upward moment of linkage point A corresponds to a decrease in the steady-state power output or reference power ΔP_{ref}.

(ii) Indirectly through the feedback due to the position changes in the main system.

(iii) Indirectly through feedback due to the position changes in linkage point E resulting from a change in speed.

7.11.1 Speed-governing system model

In this section, we develop the mathematical model based on small deviations around a nominal steady state. Let us assume that the steam is operating under steady state and is delivering power P_G^0 from the generator at nominal speed or frequency f^o.

Under this condition, the prime mover valve has a constant setting x_E^0, the pilot valve is closed, and the linkage mechanism is stationary. Now, we will increase the turbine power by ΔP_C with the help of the speed changer. For this, *the movement of linkage point A* moves downward by a small distance Δx_A and is given by

$$\Delta x_A = K\,\Delta P_C \quad \text{— (1)} \tag{7.1}$$

With the movement Δx_A, the link point C move upwards by an amount Δx_C and so does the link point D by an amount Δx_D upwards. Due to the movement of link point D, the pilot valve moves upwards, then the high-pressure oil is admitted into the cylinder of the hydraulic amplifier and flows on to the top of the main piston. Due to this, the piston moves downward by an amount Δx_E and results in the opening of the steam valve. Due to the opening of the steam valve, the flow of steam from the boiler increases and the turbine power output increases, which leads to an increase in power generation by ΔP_G. The increased power output causes an accelerating power in the system and there is a slight increase in frequency say by Δf if the system is connected to a finite size (i.e., not connected to infinite bus).

Now with the increased speed, the fly balls of the governor move downwards, thus causing the link point B to move slightly downwards by a small distance Δx_B proportional to Δf. Due to the downward movement of link point B, the link point C also moves downwards by an amount Δx_C, which is also proportional to Δf.

It should be noted that all the downward movements are assumed to be positive in directions as indicated in Fig. 7.5. Now model the above events mathematically.

The net *movement of link point C* contributes two factors as follows:

(i) Δx_A contribution: The lowering of speed changer by an amount Δx_A results in the upward moment of link point C proportional to Δx_A:

$\Delta x_C' = -K_1 \Delta P_C$ — (2)

i.e., $\Delta x'_C = \Delta x_A\, l_{AB} = -\Delta x_C\, l_{BC}$

or $\Delta x'_C = -\left[\dfrac{l_{BC}}{l_{AB}}\right] \Delta x_A$

Substituting Δx_A from Equation (7.1) in the above equation, we get

$$\Delta x'_C = -\left[\frac{l_{BC}}{l_{AB}}\right] K\Delta P_C$$

$$= -K_1 \Delta P_C \quad \text{— (1)} \tag{7.2}$$

where $K_1 = K\left[\dfrac{l_{BC}}{l_{AB}}\right]$

(ii) Δf contribution: Increase in frequency Δf causes an outward moment of fly balls and in turn causes the downward movement of point B by an amount Δx_B, which is proportional to $K_2' \Delta f$, i.e., movement of point 'C' with point 'A' remaining fixed at Δx_A is

$$\left(\frac{l_{BC} + l_{AB}}{l_{AB}}\right) K_2' \Delta f = K_2 \Delta f \quad \text{— (2)}$$

$$\therefore \ \Delta x''_C = K_2 \Delta f \tag{7.3}$$

Therefore, the net movement of link point C can be expressed as

$$\Delta x_C = \Delta x'_C + \Delta x''_C \tag{7.4}$$

Substituting the values of $\Delta x'_C$ and $\Delta x''_C$ from Equations (7.2) and (7.3) in Equation (7.4), we get

$$\Delta x_C = -K_1 \Delta P_C + K_2 \Delta f \quad \text{—— (3)} \tag{7.5}$$

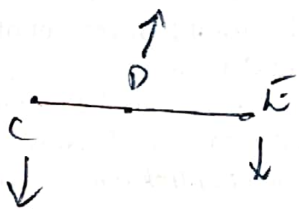
The constants K_1 and K_2 depend upon the length of linkage arms AB and BC and also depend upon the proportional constants of the speed changer and the speed governor.

The *movement of link point D*, Δx_D is the amount by which the pilot valve opens and it is contributed by the movement of point C, Δx_C, and movement of point E, Δx_E.

Therefore, the net movement of point D can be expressed as

$$\Delta x_D = \Delta x'_D + \Delta x''_D \tag{7.6}$$

where $\quad \Delta x'_D (l_{CD} + l_{DE}) = \Delta x_C (l_{DE})$



$$\Delta x'_D = \frac{l_{DE}}{(l_{CD} + l_{DE})} \Delta x_C$$

$$= K_3 \Delta x_C \tag{7.7}$$

$\Delta xp = K_3 \Delta xc + K_4 \Delta x_E$

and $\quad \Delta x''_D (l_{CD} + l_{DE}) = \Delta x_E (l_{CD})$

$$\Delta x''_D = \frac{l_{CD}}{(l_{CD} + l_{DE})} \Delta x_E$$

$$= K_4 \Delta x_E \tag{7.8}$$

Substituting the values of $\Delta x'_D$ and $\Delta x''_D$ from Equations (7.7) and (7.8) in Equation (7.6), we get

$$\Delta x_D = K_3 \Delta x_C + K_4 \Delta x_E \quad \text{—— (4)} \tag{7.9}$$

The movement Δx_D, results in the opening of the pilot valve, which leads to the admission of high-pressure oil into the hydraulic amplifier cylinder; then the downward movement of the main piston takes place and thus the steam valve opens by an amount Δx_E.

Two assumptions are made to represent the mathematical model of the *movement of point E*:

(i) The main piston and steam valve have some inertial forces, which are negligible when compared to the external forces exerted on the piston due to high-pressure oil.

(ii) Because of the first assumption, the amount of oil admitted into the cylinder is proportional to the port opening Δx_D, i.e., the volume of oil admitted into the cylinder is proportional to the time integral of Δx_D.

The movement Δx_E is obtained as

$$\Delta x_E = \frac{\text{volume of oil admitted}}{\text{area of cross-section of the piston}} = \frac{1}{A}\int_0^t (-\Delta x_D)\,dt$$

where A is the area of cross-section of the piston:

$$\therefore \Delta x_E = K_5 \int_0^t (-\Delta x_D)\,dt \quad \text{—(5)} \tag{7.10}$$

where $K_5 = \dfrac{1}{A}$

The constant K_5 depends upon the fluid pressure and the geometry of the orifice and cylinder of the hydraulic amplifier.

In Equation (7.10), the negative sign represents the movements of link points D and E in the opposite directions. For example, the small downward movement of Δx_D causes the movement Δx_E in the positive direction (i.e., upwards).

Taking the Laplace transform of Equations (7.5), (7.9), and (7.10), we get

$$\Delta x_C(s) = -K_1 \Delta P_C(s) + K_2 \Delta F(s) \quad \text{—(3)} \tag{7.11}$$

$$\Delta x_D(s) = +K_3 \Delta x_C(s) + K_4 \Delta x_E(s) \quad \text{—(4)} \tag{7.12}$$

$$\Delta x_E(s) = -K_5 \frac{1}{s} \Delta x_D(s) \quad \text{—(5)} \tag{7.13}$$

Eliminating $\Delta x_C(s)$ and $\Delta x_D(s)$ in the above equations and substituting $\Delta x_D(s)$ from Equation (7.12) in Equation (7.13), we get

$$\Delta x_E(s) = -K_5 \frac{1}{s}\left[K_3 \Delta x_C(s) + K_4 \Delta x_E(s)\right]$$

Substituting $\Delta x_C(s)$ from Equation (7.11) in the above equation, we get

$$\Delta x_E(s) = -K_5 \frac{1}{s}\left[K_3 \left(-K_1 \Delta P_C(s) + K_2 \Delta F(s)\right) + K_4 \Delta x_E(s)\right]$$

$$\Delta x_E(s)\left(1 + \frac{K_4 K_5}{s}\right) = \frac{1}{s}\left(K_1 K_3 K_5 \Delta P_C(s) - K_2 K_3 K_5 \Delta F(s)\right)$$

$$\Delta x_E(s)\left(K_4 + \frac{s}{K_5}\right) = K_1 K_3 \Delta P_C(s) - K_2 K_3 \Delta F(s)$$

$$\Delta x_E(s) = \frac{K_1 K_3 \Delta P_C(s) - K_2 K_3 \Delta F(s)}{\left[K_4 + \dfrac{s}{K_5}\right]} \quad \text{—(6)} \tag{7.14}$$

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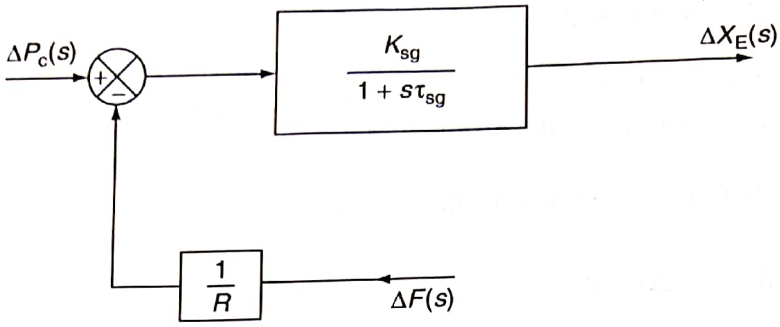


FIG. 7.6 *Block diagram model of a speed-governor system*

Equation (7.14) can be modified as

$$\Delta x_E(s) = \left[\Delta P_C(s) - \frac{1}{R}\Delta F(s)\right]\left[\frac{K_{sg}}{1+s\tau_{sg}}\right] \quad \text{— (7)} \tag{7.15}$$

where $R \triangleq \frac{K_1}{K_2}$ is the speed regulation of the governor it is also termed as regulation constant or setting, $K_{sg} \triangleq \frac{K_1K_3}{K_4}$ the gain of the speed governor, and $\tau_{sg} \triangleq \frac{1}{K_4K_5}$ the time constant of the speed governor. Normally, $\tau_{sg} \leq 100$ ms.

Equation (7.15) can be represented in a block diagram model as shown in Fig. 7.6, which is the linearized model of the speed-governor mechanism.

From the block diagram, $\left[\Delta P_C(s) - \frac{1}{R}\Delta F(s)\right]$ is the net input to the speed-governor system and $\Delta x_E(s)$ is the output of the speed governor.

7.12 TURBINE MODEL

We are interested not in the turbine valve position but in the generator power increment ΔP_G. The change in valve position Δx_E causes an incremental increase in turbine power ΔP_T and due to electromechanical interactions within the generator, it will result in an increased generator power ΔP_G, i.e., $\Delta P_T = \Delta P_G$, since the generator incremental loss is neglected. This overall mechanism is relatively complicated particularly if the generator voltage simultaneously undergoes wild swing due to major network disturbances.

At present, we can assume that the voltage level is constant and the torque variations are small. Then an incremental analysis will give a relatively simple dynamic relationship between Δx_E and ΔP_G. Such an analysis reveals considerable differences, not only between steam turbines and hydro-turbines, but also between various types (reheat and non-reheat) of steam turbines. Therefore, the transfer function, relates the change in the generated power output with respect to the change in the valve position, varies with the type of the prime mover.

7.12.1 Non-reheat-type steam turbines

Figure 7.7 (a) shows a single-stage non-reheat type steam turbine.

In this model, the turbine can be characterized by a single gain constant K_t and a single time constant τ_t as

$$G_T(s) = \frac{\Delta P_T(s)}{\Delta x_E(s)} = \frac{K_t}{1+s\tau_t} \tag{7.16}$$

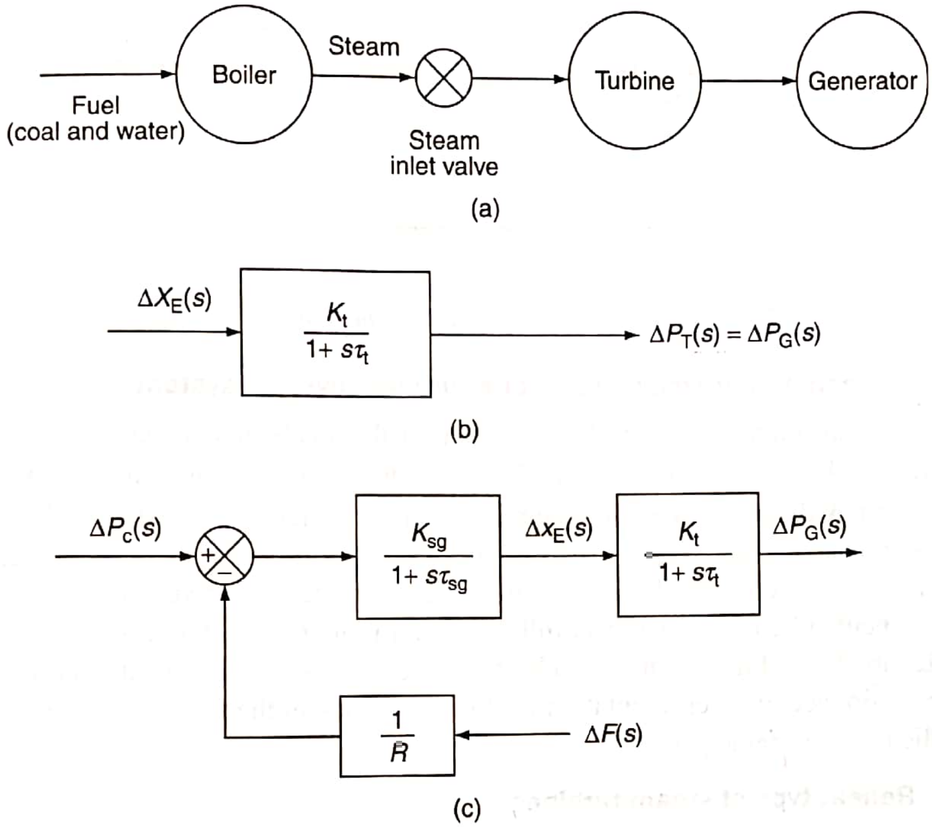


FIG. 7.7 *(a) Single-stage non-reheat-type steam turbine; (b) block diagram representation of a non-reheat-type steam turbine; (c) transfer function representation of speed control mechanism of a generator with a non-reheat-type steam turbine*

Typically, the time constant τ_t lies in the range of 0.2 to 2.

On opening the steam valve, the steam flow will not reach the turbine cylinder instantaneously. The time delay experienced in this is in the order of 2 s in the steam pipe.

From Equation (7.16), we have

$$\Delta P_G(s) = \frac{K_t}{1+s\tau_t}\Delta x_E(s) \quad (\text{since } \Delta P_T = \Delta P_G) \tag{7.17}$$

We can represent Equation (7.17) by a block diagram as shown in Fig. 7.7(b).

Figure 7.7(c) shows the linearized model of a non-reheat-type turbine controller including the speed-governor mechanism.

From Fig. 7.7(c), the combined transfer function of the turbine and the speed-governor mechanism will be $\dfrac{K_{sg}K_t}{(1+s\tau_{sg})(1+s\tau_t)}$.

Therefore, $$\Delta P_G(s) = \frac{K_{sg}K_t}{(1+s\tau_{sg})(1+s\tau_t)}\left[\Delta P_C(s) - \frac{1}{R}\Delta F(s)\right]$$

In general, it is obtained that the turbine response is low with the response time of several seconds.

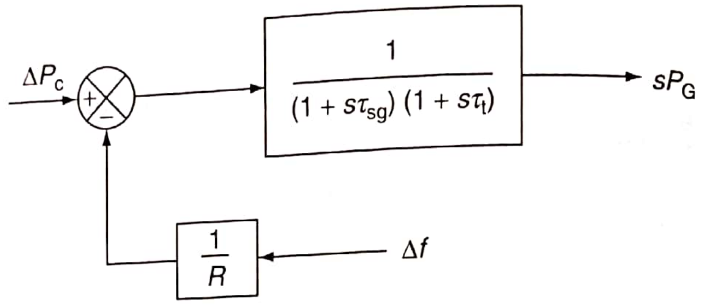


FIG. 7.8 *Block diagram of a simplified turbine governor*

7.12.2 Incremental or small signal for a turbine-governor system

Let the command incremental signal be ΔP_C. Then in the steady state, we get $\Delta P_G = K_{sg} K_t \Delta P_C$. Let $K_{sg} K_t = 1$; the block diagram of Fig. 7.7(c) is reduced to that shown in Fig. 7.8.

This block diagram gives the derivation of an incremental or small signal model. The model is adopted for large signal use by adding a saturation-type non-linear element, which introduces the obvious fact that the steam valve must operate between certain limits. The valve can neither be more open than fully open nor more closed than fully closed.

This model of Fig. 7.8 may also be modified to account for reheat cycles in the turbine and more accurate representation of fluid dynamics in the steam inlet pipes or in the hydraulic turbines in the penstock.

7.12.3 Reheat type of steam turbines

Modern generating units have reheat-type steam turbines as prime movers for higher thermal efficiency.

Figure 7.9 shows a two-stage reheat-type steam turbine.

In such turbines, steam at high pressure and low temperature is withdrawn from the turbine at an intermediate stage. It is returned to the boiler for resuperheating and then reintroduced into the turbine at low pressure and high temperature. This increases the overall thermal efficiency. Mostly, two factors influence the dynamic response of a reheat-type steam turbine:

(i) Entrained steam between the inlet steam valve and the first state of turbine.

(ii) The storage action in the reheater, which causes the output of the low-pressure stage to lag behind that of the high-pressure stage.

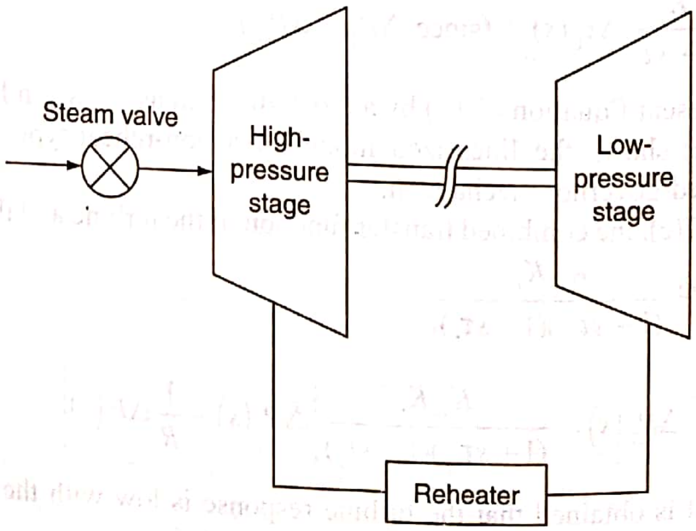


FIG. 7.9 *A two-stage reheat type of a steam turbine*

Thus, in this case, the turbine transfer function is characterized by two time constants. It involves an additional time lag τ_r associated with the reheater in addition to the turbine time constant τ_t. Hence, the turbine transfer function will be of a second order and is given by

$$G_T(s) = -\frac{\Delta P_G(s)}{\Delta x_E(s)} = \left[\frac{K_t}{1+s\tau_t}\right]\frac{(1+sK_r\tau_r)}{(1+s\tau_r)} \tag{7.18}$$

The time constant τ_r has a value in the range of 10 s and approximates the time delay for charging the reheat section of the boiler. K_r is a reheat coefficient and is equal to the proportion of torque developed in the high-pressure section of the turbine:

$K_r = (1 -$ fraction of the steam reheated)

When there is no reheat $K_r = 1$ and the transfer function reduces to a single time constant given in Equation (7.16).

The transfer functions as given by Equations (7.16) and (7.18) give good representation within the first 20 s following the incremental disturbance. They do not account for the slower boiler dynamics. To get an easy analyzation, it can be assumed that the prime mover or turbine is modeled by a single equivalent time constant τ_t as given in Equation (7.16).

7.13 GENERATOR–LOAD MODEL

The generator–load model gives the relation between the change in frequency (Δf) as a result of the change in generation (ΔP_G) when the load changes by a small amount (ΔP_D).

When neglecting the change in generator loss, $\Delta P_G = \Delta P_T$ (change in turbine power output), net-surplus power at the bus bar $= (\Delta P_G - \Delta P_D)$. This surplus power can be absorbed by the system in two different ways:

(i) By increasing the stored kinetic energy of the generator rotor at a rate $\frac{dW_{KE}}{dt}$.

Let W^0_{KE} be the stored KE before the disturbance at normal speed and frequency f^0, and W_{KE} be the KE when the frequency is $(f^0 + \Delta f)$.

Since the stored KE is proportional to the square of speed and the frequency is proportional to the speed,

$$\frac{W_{KE}}{W^0_{KE}} = \left(\frac{f^0 + \Delta f}{f^0}\right)^2$$

$$W_{KE} = W^0_{KE}\left(\frac{f^0 + \Delta f}{f^0}\right)^2 \tag{7.19}$$

$$W_{KE} = W^0_{KE}\left(1 + \frac{2\Delta f}{f^0} + \text{Higher-order terms}\right) \tag{7.20}$$

Neglecting higher-order terms, since $\frac{\Delta f}{f^0}$ is small:

$$\therefore W_{KE} \approx W^0_{KE}\left(1+\frac{2\Delta f}{f^0}\right)$$

Differentiating the above expression with respect to 't', we get

$$\therefore \frac{dW_{KE}}{dt}=\frac{2W^0_{KE}}{f^0}\frac{d}{dt}(\Delta f) \tag{7.21}$$

Let H be the inertia constant of a generator (MW-s/MVA) and P_r the rating of the turbo-generator (MVA):

$$W^0_{KE}=H\times P_r \text{ (MW-s or M-J)} \tag{7.22}$$

Hence, Equation (7.21) becomes

$$\frac{dW_{KE}}{dt}=\frac{2HP_r}{f^0}\frac{d}{dt}(\Delta f) \tag{7.23}$$

(ii) The load on the motors increases with increase in speed. The load on the system being mostly motor load, hence some portion of the surplus power is observed by the motor loads. The rate of change of load with respect to frequency can be regarded as nearly constant for small changes in frequency.

$$\text{i.e.,}\quad \left(\frac{\partial P_D}{\partial f}\right)\Delta f=B\Delta f \tag{7.24}$$

where the constant B is the area parameter in MW/Hz and can be determined empirically. B is positive for a predominantly motor load.
Now, the surplus power can be expressed as

$$\Delta P_G-\Delta P_D=\frac{dW_{KE}}{dt}+\left(\frac{\partial P_D}{\partial f}\right)\Delta f$$

From Equations (7.23) and (7.24), the above equation can be modified as

$$\Delta P_G-\Delta P_D=\frac{2HP_r}{f^0}\frac{d}{dt}(\Delta f)+B\Delta f \tag{7.25}$$

Dividing throughout by P_r of Equation (7.25), we get

$$\Delta P_G(\text{p.u})-\Delta P_D(\text{p.u})=\frac{2H}{f^0}\frac{d}{dt}(\Delta f)+B(\text{p.u})\Delta f$$

Taking Laplace transform on both sides, we get

$$\Delta P_G(s)-\Delta P_D(s)=\frac{2H}{f^0}s\Delta F(s)+B\Delta F(s)$$

$$= \left(\frac{2H}{f^0} s + B \right) \Delta F(s)$$

$$\therefore \Delta F(s) = \frac{\Delta P_G(s) - \Delta P_D(s)}{\frac{2H}{f^0} s + B} = \frac{1}{B} \left[\frac{\Delta P_G(s) - P_D(s)}{\left(1 + \frac{2H}{Bf^0} s \right)} \right]$$

$$= \left(\frac{K_{ps}}{1 + \tau_{ps}} \right) \left[\Delta P_G(s) - \Delta P_D(s) \right] \qquad \textbf{(7.26)}$$

where $\tau_{ps} = \frac{2H}{Bf^0}$ is the power system time constant (normally 20 s) and $K_{ps} = \frac{1}{B}$ the power system gain.

Equation (7.26) can be represented in a block diagram model as given in Fig. 7.10.

The overall block diagram of an isolated power system is obtained by combining individual block diagrams of a speed-governor system, a turbine system, and a generator–load model and is as shown in Fig. 7.11.

This representation being a third-order system, the characteristic equation for the system will be of the third order.

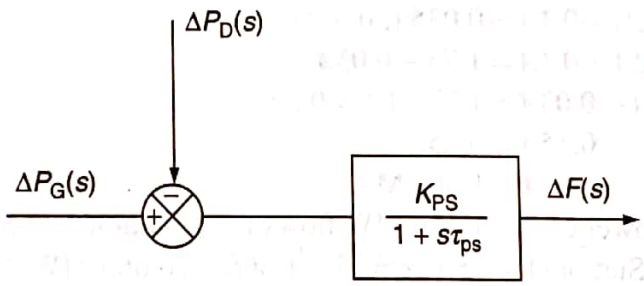


FIG. 7.10 *Block diagram representation of a generator–load model*

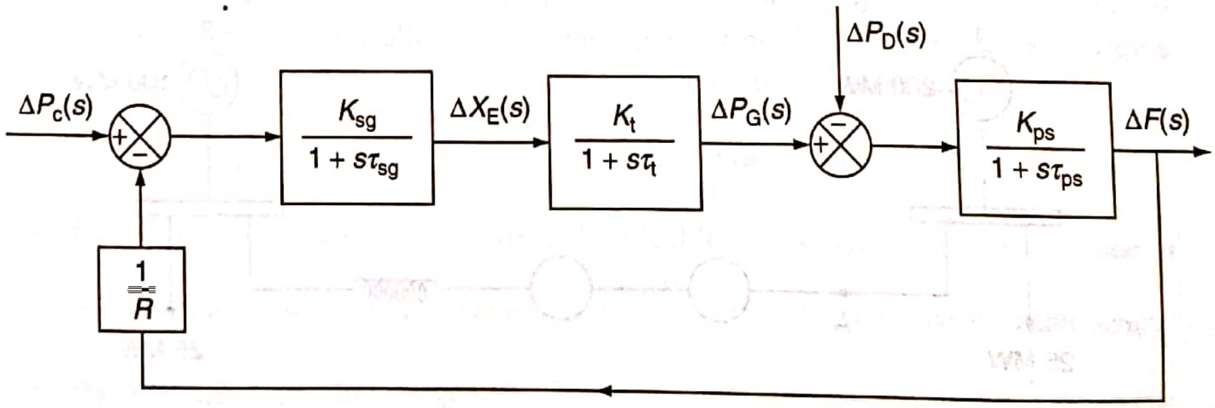


FIG. 7.11 *Complete block diagram representation of an isolated power system*

Example 7.1: Two generating stations 1 and 2 have full-load capacities of 200 and 100 MW, respectively, at a frequency of 50 Hz. The two stations are interconnected by an induction motor and synchronous generator set with a full-load capacity of 25 MW as shown in Fig. 7.12. The speed regulation of Station-1, Station-2, and induction motor and synchronous generator set are 4%, 3.5%, and 2.5%, respectively. The loads on respective bus bars are 750 and 50 MW, respectively. Find the load taken by the motor-generator set.

Solution:

Let a power of A MW flow from Station-1 to Station-2:

$\therefore$ Total load on Station-1 $= (75 + A)$ MW

Total load on Station-2 $= (50 - A)$

$$\% \text{ drop in speed at Station-1} = \frac{4}{200}(750 + A)$$

$$\% \text{ drop in speed at Station-2} = \frac{3.5}{100}(50 - A)$$

The reduction in frequency will result due to the power flow from Station-1 through the interconnector of M-G set.

$$\therefore \% \text{ drop in speed at M-G set} = \frac{2.5}{25}(A) = \frac{2.5A}{25}$$

(reduction in frequency at Station-1 + reduction in frequency at M-G set) = (reduction in frequency at Station-2)

$$\therefore \frac{4}{200}(75 + A) + \frac{2.5A}{25} = \frac{3.5}{100}(50 - A)$$

$$0.02\,(75 + A) + 0.1A = 0.035\,(50 - A)$$
$$1.5 + 0.02A + 0.1A = 1.75 - 0.03A$$
$$0.02A + 0.1A + 0.03A = 175 - 1.5 = 0.25$$
$$0.15A = 0.25$$
$$A = 1.666 \text{ MW}$$

i.e., a power of $A = 1.666$ MW flows from Station-1 to Station-2.

$\therefore$ Total load at Station-1 $= 75 + A = 75 + 1.666 = 76.666$ MW

Total load at Station-2 $= 50 - A = 50 - 1.666 = 48.334$ MW

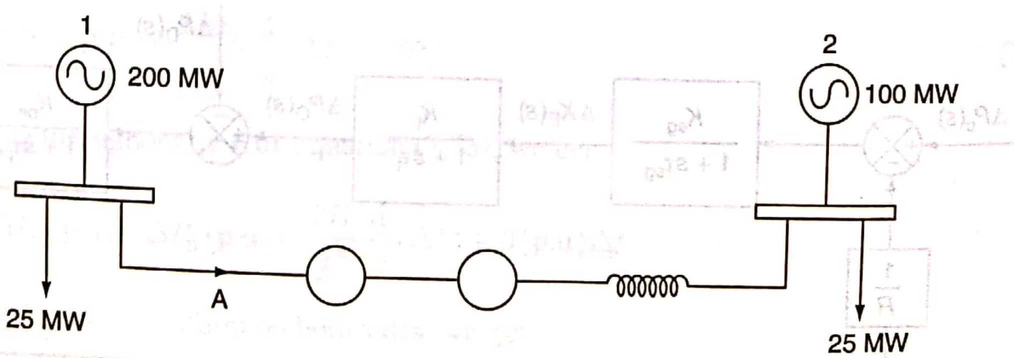


FIG. 7.12 *Illustration for Example 7.1*

Example 7.2: A 125 MVA turbo-alternator operator on full load operates at 50 Hz. A load of 50 MW is suddenly reduced on the machine. The steam valves to the turbine commence to close after 0.5 s due to the time lag in the governor system. Assuming the inertia to be constant, $H=6$ kW-s per kVA of generator capacity, calculate the change in frequency that occurs in this time.

Solution:

By definition, $H = \dfrac{\text{stored energy}}{\text{capacity of the machine}}$

$\therefore$ Energy stored at no load $=6 \times 125 \times 1{,}000 = 750$ MJ

Excessive energy input to rotating parts in 0.5 s $= 50 \times 0.5 \times 1{,}000 = 25$ MJ

As a result of this, there is an increase in the speed of the motor and hence an increase in frequency:

$$W_{\text{KE}} = W^0_{\text{KE}} \left(\frac{f^0 + \Delta f}{f^0} \right)^2$$

$$\therefore f_{\text{new}} = \sqrt{\frac{750+25}{750}} \times 50 \text{ Hz} = 50.83 \text{ Hz}$$

7.14 CONTROL AREA CONCEPT

In real practice, the system of a single generator that feeds a large and complex area has rarely occurred. Several generators connected in parallel, located also at different locations, will meet the load demand of such a geographically large area. All the generators may have the same response characteristics to the changes in load demand.

It is possible to divide a very large power system into sub-areas in which all the generators are tightly coupled such that they swing in unison with change in load or due to a speed-changer setting. Such an area, where all the generators are running coherently is termed as a control area. In this area, frequency may be same in steady state and dynamic conditions. For developing a suitable control strategy, a control area can be reduced to a single generator, a speed governor, and a load system.

7.15 INCREMENTAL POWER BALANCE OF CONTROL AREA

In this section, we shall develop a dynamic model in terms of incremental power and frequency dynamics of a control area 'i' connected via tie lines as shown in Fig. 7.13.

Now assume that control area 'i' experiences a real load change $\Delta P_{\text{D}i}$ (MW). Due to the actions of the turbine controllers, its output increases by $\Delta P_{\text{G}i}$ (MW). The net-surplus power in the area $(\Delta P_{\text{G}i} - \Delta P_{\text{D}i})$ will be absorbed by the system in three ways:

- By increasing the area kinetic energy $W_{\text{KE},\,i}$ at the rate $\dfrac{\mathrm{d}W_{\text{KE}i}}{\mathrm{d}t}$.
- By an increased load consumption. All typical loads (because of the dominance of motor loads) experience an increase, $B = \left(\dfrac{\partial P_{\text{D}}}{\partial f} \right)$ MW/Hz, with speed or frequency.
- By increasing the flow of power via tie lines with the total amount $\Delta P_{\text{tie},\,i}$ MW, which is defined positive for outflow from the area.

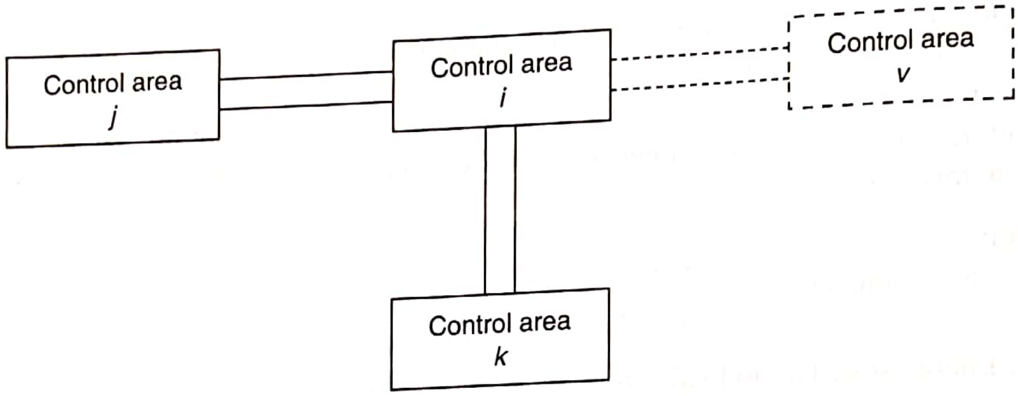


FIG. 7.13 *Interconnected control area*

Hence, the net-surplus power can be expressed as

$$\Delta P_{Gi} - \Delta P_{Di} = \frac{dW_{KEi}}{dt} + B_i \Delta f_i + \Delta P_{tie,\,i} \tag{7.27}$$

ΔP_{tie} is the difference between scheduled real power and actual real power through interconnected lines and it is taken as the input to the LFC system.

7.16 SINGLE AREA IDENTIFICATION

The first two terms on the right-hand side of Equation (7.27) represent a generator–load model (with the subscript 'i' absent). If the third term is absent, it means that there is no interchange of power between area 'i' and any other area. Thus, it becomes a single-area case. 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.

7.16.1 Block diagram representation of a single area

The block diagram of an isolated power system, which in essence is a single-area system, is the same as the block diagram given in Fig. 7.11.

7.17 SINGLE AREA—STEADY-STATE ANALYSIS

The block diagram of an LFC of an isolated power system of a third-order model is represented in Fig. 7.11.

There are two incremental inputs to the system and they are:

(i) The change in the speed-changer position, ΔP_C (reference power input).

(ii) The change in the load demand, ΔP_D.

In this section, we will analyze the response of a single-area system to steady-state changes by three ways:

(i) Constant speed-changer position with variable load demand (uncontrolled case).

(ii) Constant load demand with variable speed-changer position (controlled case).

(iii) Variable speed-changer position as well as load demand.

7.17.1 Speed-changer position is constant (uncontrolled case)

With the model given in Fig. 7.11 and with $\Delta P_C = 0$, the response of an uncontrolled single area LFC can be obtained as follows.

Let us consider a simple case wherein the speed changer has a fixed setting, which means $\Delta P_C = 0$ and the load demand alone changes. Such an operation is known as free governor operation or uncontrolled case since the speed changer is not manipulated (or controlled to achieve better frequency constancy).

For a sudden step change of load demand,

$$\Delta P_D(s) = \frac{\Delta P_D}{s}$$

For such an operation, the steady-state change of frequency Δf is to be estimated from the block diagram of Fig. 7.14 as

$$\Delta F(s)\Big|_{\Delta PC(s)=0} = -\left[\frac{\dfrac{K_{ps}}{(1+s\tau_{ps})}}{1+\dfrac{(K_{sg}K_tK_{ps}/R)}{(1+s\tau_{sg})(1+s\tau_t)}\times\dfrac{K_{ps}}{(1+s\tau_{ps})}}\right]\times\frac{\Delta P_D}{s}$$

$$= -\left[\frac{K_{ps}}{(1+s\tau_{ps})+\dfrac{(K_{sg}K_tK_{ps}/R)}{(1+s\tau_{sg})(1+s\tau_t)}}\right]\times\frac{\Delta P_D}{s} \qquad \textbf{(7.28)}$$

Applying the final value theorem, we have

$$\Delta f\Big|_{\substack{\text{steady state}\\ \Delta P_c=0}} = \underset{s\to 0}{\text{Lt}}\; s\Delta F(s)\Big|_{\Delta P_C=0}$$

$$= -\left(\frac{K_{ps}}{1+\dfrac{K_{ps}K_tK_{sg}}{R}}\right)\Delta P_D \qquad \textbf{(7.29)}$$

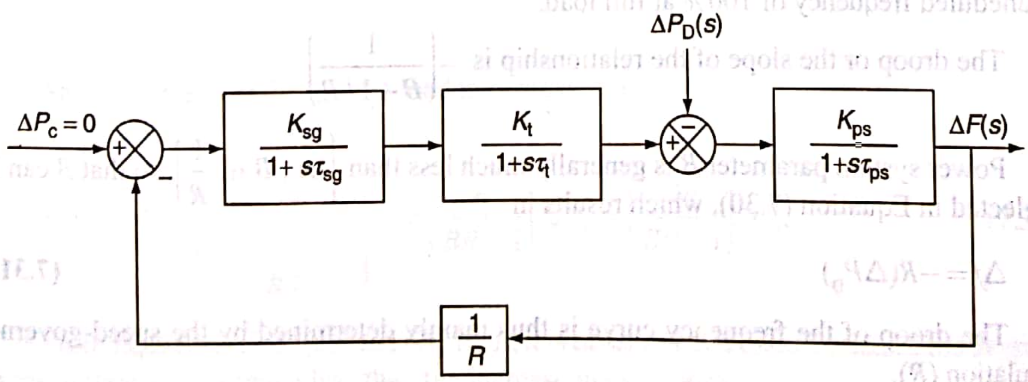


FIG. 7.14 *Block diagram representation of an isolated power system setting $\Delta P_C = 0$*

The gain K_t is fixed for the turbine and K_{ps} is fixed for the power system. The gain K_{sg} of the speed governor is easily adjustable by changing the lengths of various links of the linkage mechanism. K_{sg} is so adjusted such that $K_{sg}K_t \approx 1$.

Therefore Equation (7.29) can be simplified as:

$$\Delta f = -\left(\frac{K_{ps}}{1+\dfrac{K_{ps}}{R}}\right)\Delta P_D$$

Also we know from the dynamics of the generator–load model, $K_{ps} = \dfrac{1}{B}$

where $B = \dfrac{\partial P_D}{\partial f}$ MW/Hz

$$= \frac{\dfrac{\partial P_D}{\partial f}}{P_r} \quad \text{in p.u.MW/unit change in frequency}$$

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

$$\therefore \Delta f = -\left(\frac{1}{B+\dfrac{1}{R}}\right)\Delta P_D = -\frac{1}{\beta}\Delta P_D \quad \textbf{(7.30)}$$

where the factor $\beta = \left(B+\dfrac{1}{R}\right)$ and is known as the area frequency response characteristic (AFRC) or area frequency regulation characteristic.

Equation (7.30) gives the steady-state response of frequency to the changes in load demand. The speed regulation is usually so adjusted that changes in frequency are small (of the order of 5%) from no load to full load. Figure 7.15 gives the linear relationship between frequency and load for a free governor operation, with speed changes set to give a scheduled frequency of 100% at full load.

The droop or the slope of the relationship is $-\left(\dfrac{1}{B+1/R}\right)$.

Power system parameter B is generally much less than $\left(\text{i.e., } B \ll \dfrac{1}{R}\right)$, so that B can be neglected in Equation (7.30), which results in

$$\Delta f = -R(\Delta P_D) \quad \textbf{(7.31a)}$$

The droop of the frequency curve is thus mainly determined by the speed-governor regulation (R).

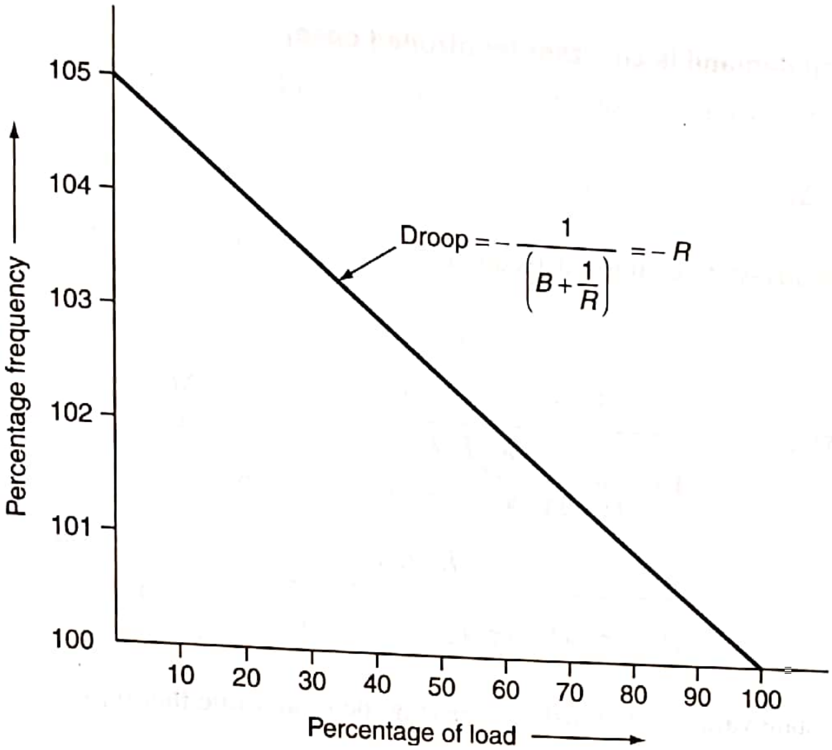


FIG. 7.15 *Steady-state load frequency characteristics of a speed-governing system*

The increase in load demand (ΔP_D) is met under steady-state conditions partly by the increased generation (ΔP_G) due to the opening of the steam valve and partly by the decreased load demand due to droop in frequency.

The increase in generation is expressed as

$$\Delta P_G = -\frac{1}{R}\Delta f$$

Substituting Δf from Equation (7.30), we get

$$\therefore \Delta P_G = -\frac{1}{R}\left(-\left(\frac{1}{B+\frac{1}{R}}\right)\Delta P_D\right) = \left[\frac{1}{R}\times\frac{R}{BR+1}\right]\Delta P_D$$

$$= \left(\frac{1}{BR+1}\right)\Delta P_D \qquad \textbf{(7.31b)}$$

And a decrease in the system load is expressed as

$$B\Delta f = B\left(-\left(\frac{1}{B+\frac{1}{R}}\right)\Delta P_D\right) = B\left(\frac{R}{BR+1}\right)\Delta P_D = \left(\frac{BR}{BR+1}\right)\Delta P_D \qquad \textbf{(7.31c)}$$

From Equations (7.31(b)) and (7.31(c)), it is observed that contribution of the decrease in the system load is much less than the increase in generation.

7.17.2 Load demand is constant (controlled case)

Consider a step change in a speed-changer position with the load demand remaining fixed:

$$\text{i.e.,}\quad \Delta P_C(s) = \frac{\Delta P_c}{s} \quad \text{and} \quad \Delta P_D = 0$$

The steady-state change in frequency can be obtained from the block diagram of Fig. 7.16:

$$\Delta F(s)\Big|_{\Delta P_D(s)=0} = \frac{\dfrac{K_{sg}K_t K_{ps}}{(1+s\tau_{sg})(1+s\tau_t)(1+s\tau_{ps})}}{1+\dfrac{K_{sg}K_t K_{ps}}{(1+s\tau_{sg})(1+s\tau_t)(1+s\tau_{ps})}\times\dfrac{1}{R}}\,\frac{\Delta P_c}{s}$$

$$= \frac{K_{sg}K_t K_{ps}}{(1+s\tau_{sg})(1+s\tau_t)(1+s\tau_{ps}) + K_{sg}K_t K_{ps}\times\dfrac{1}{R}}\,\frac{\Delta P_c}{s}$$

The steady-state value is obtained by applying the final-value theorem:

$$\Delta f\Big|_{\Delta P_D(s)=0}^{\text{steady state}},\ \underset{s\to 0}{\text{Lt}}\ s\Delta F(s) = \frac{K_{sg}K_t K_{ps}}{1+\dfrac{K_{sg}K_t K_{ps}}{R}}\Delta P_C$$

$$= \frac{K_{ps}}{1+\dfrac{K_{ps}}{R}}\Delta P_C \quad (\text{since } K_{sg}K_t \approx 1)$$

$$= \left(\frac{\dfrac{1}{B}}{1+\dfrac{1}{BR}}\right)\Delta P_C$$

$$\Delta f = \left(\frac{1}{B+\dfrac{1}{R}}\right)\Delta P_c \qquad (7.32)$$

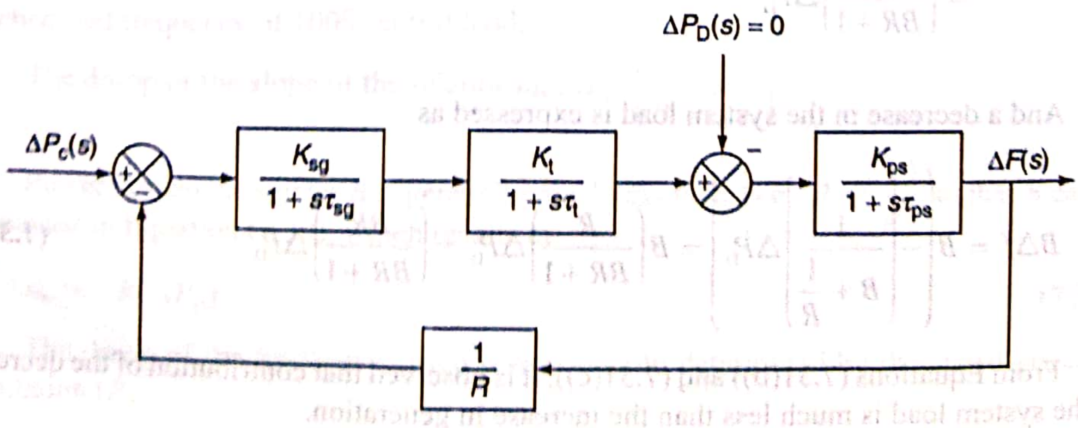


FIG. 7.16 *Block diagram representation of an isolated power system setting $\Delta P_D = 0$*

7.17.3 Speed changer and load demand are variables

By superposition, if the speed-changer setting is changed by ΔP_c while the load demand also changes by ΔP_D, the steady-state change in frequency is obtained from Equations (7.30) and (7.32) as

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

From the above equation, we can observe that the change in load demand causes the changes in frequency, which can be compensated by changing the position of the speed changer.

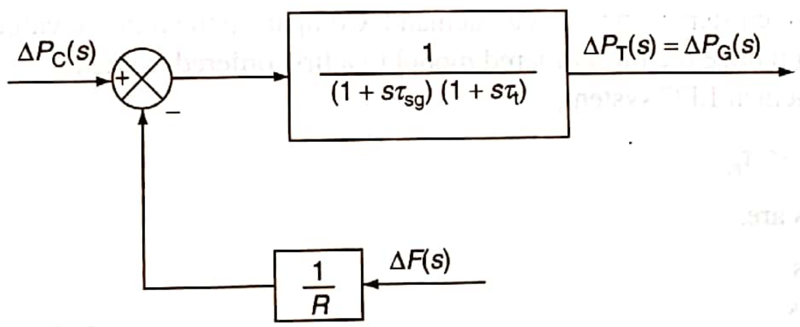
If $\Delta P_C = \Delta P_D$, then Δf will become zero.

7.18 STATIC LOAD FREQUENCY CURVES

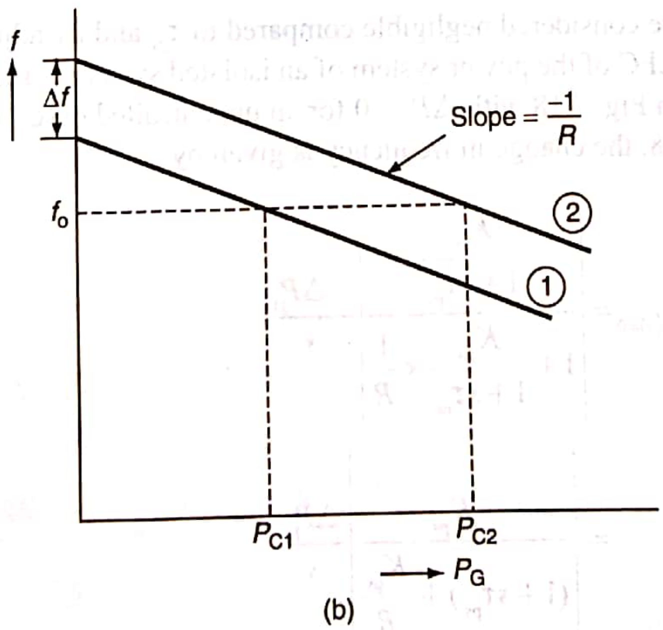
The block diagram representation of a turbine-speed-governor model is shown in Fig. 7.17(a) and their static load frequency curves are shown in Fig. 7.17(b).

The curve relates power generation P_G and frequency f with control parameter P_C.

From the block diagram shown in Fig. 7.17(a), we get the static algebraic relation



(a)



(b)

FIG. 7.17 *(a) Block diagram of a turbine-speed-governor model; (b) static load frequency curves for the turbine governor*

$$\Delta P_G = \Delta P_C - \frac{1}{R}\Delta f$$

from which the local shape of the speed-power curves may be inferred.

Figure 7.17(b) gives the two static load-frequency curves. Adjust power generation, P_G, by using a speeder meter (speed changer) upto $P_G = P_{C1}$, where P_{C1} is the desired command power at synchronous speed $\omega^0(f^0)$. With free governor operation (i.e., $\Delta P_C = 0$), the fixed speed-changer position P_{C1} predicts the straight-line relationship. This straight line (1) has a slope of $-R$.

To get more generation at the same synchronous speed of $\omega^0(f^0)$, adjust P_{C1} to P_{C2} with a speeder meter. This results in the load frequency curve (2). The speed regulation R refers to the variation in frequency with power generation. Better the regulation results, less the droops speed-power (load) characteristics of LFC.

7.19 DYNAMIC ANALYSIS

The meaning of dynamic response is how the frequency changes as a function of time immediately after disturbance before it reaches the new steady-state condition. The analyzation of dynamic response requires the solution of dynamic equation of the system for a given disturbance. The solution involves the solution of different equations representing the dynamic behavior of the system.

The inverse Laplace transform of $\Delta F(s)$ gives the variation of frequency with respect to time for a given step change in load demand. Comparing the relative values of time constants, we can reduce the third ordered model to a first ordered system.

For a practical LFC system,

$$\tau_{sg} < \tau_t << \tau_{Ps}$$

Typical values are:

$$\tau_{sg} = 0.4 \text{ s}$$
$$\tau_t = 0.5 \text{ s}$$
$$\tau_{Ps} = 20 \text{ s}$$

If τ_{sg} and τ_t are considered negligible compared to τ_{Ps} and by adjusting $K_{sg}\,K_t = 1$, the block diagram of LFC of the power system of an isolated system is reduced to a first-order system as shown in Fig. 7.18 with $\Delta P_c = 0$ for an uncontrolled case.

From Fig. 7.18, the change in frequency is given by

$$\Delta F(s)\Big|_{\Delta P_c(s)=0} = \left[\frac{\dfrac{K_{ps}}{1+s\tau_{ps}}}{1+\dfrac{K_{ps}}{1+s\tau_{ps}}\times\dfrac{1}{R}}\right]\frac{-\Delta P_D}{s}$$

$$= \left[\frac{-K_{ps}}{(1+s\tau_{ps})+\dfrac{K_{ps}}{R}}\right]\frac{\Delta P_D}{s}$$

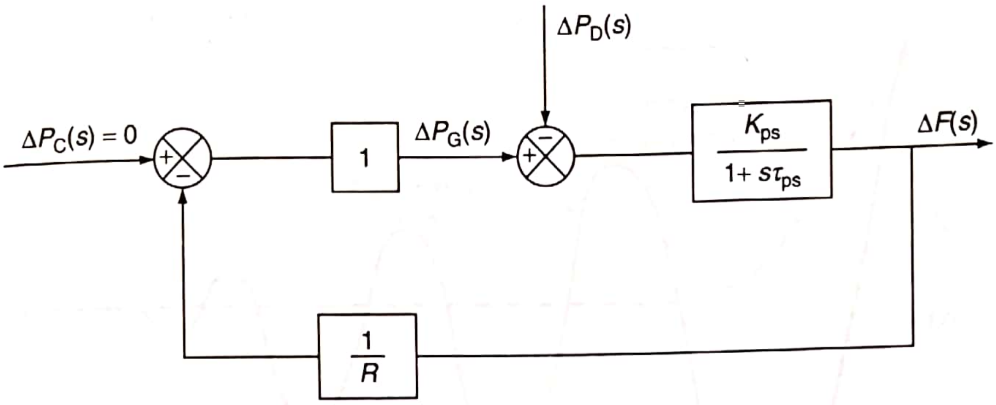


FIG. 7.18 *First-order approximate block diagram of LFC of an isolated area*

$$= \left[\frac{-K_{ps}}{s\tau_{ps} + \dfrac{K_{ps}+R}{R}} \right] \frac{\Delta P_D}{s}$$

$$= \left[\frac{-\dfrac{K_{ps}}{\tau_{ps}}}{s + \dfrac{K_{ps}+R}{R\tau_{ps}}} \right] \frac{\Delta P_D}{s}$$

$$= -\frac{K_{ps} \times \Delta P_D}{\tau_{ps}} \left(\frac{1}{s\left(s + \dfrac{K_{ps}+R}{R\tau_{ps}}\right)} \right)$$

$$= -\frac{K_{ps} \times \Delta P_D}{\tau_{ps}} \times \frac{R\tau_{ps}}{(K_{ps}+R)} \left(\frac{1}{s} - \frac{1}{\left(s + \dfrac{K_{ps}+R}{R\tau_{ps}}\right)} \right)$$

$$\therefore \Delta f(t) = L^{-1}\,\Delta F(s)$$

$$= \frac{-RK_{ps}}{R+K_{ps}} \left(1 - e^{-\frac{t}{\tau_{ps}}\left(\frac{R+K_{ps}}{R}\right)} \right) \Delta P_D$$

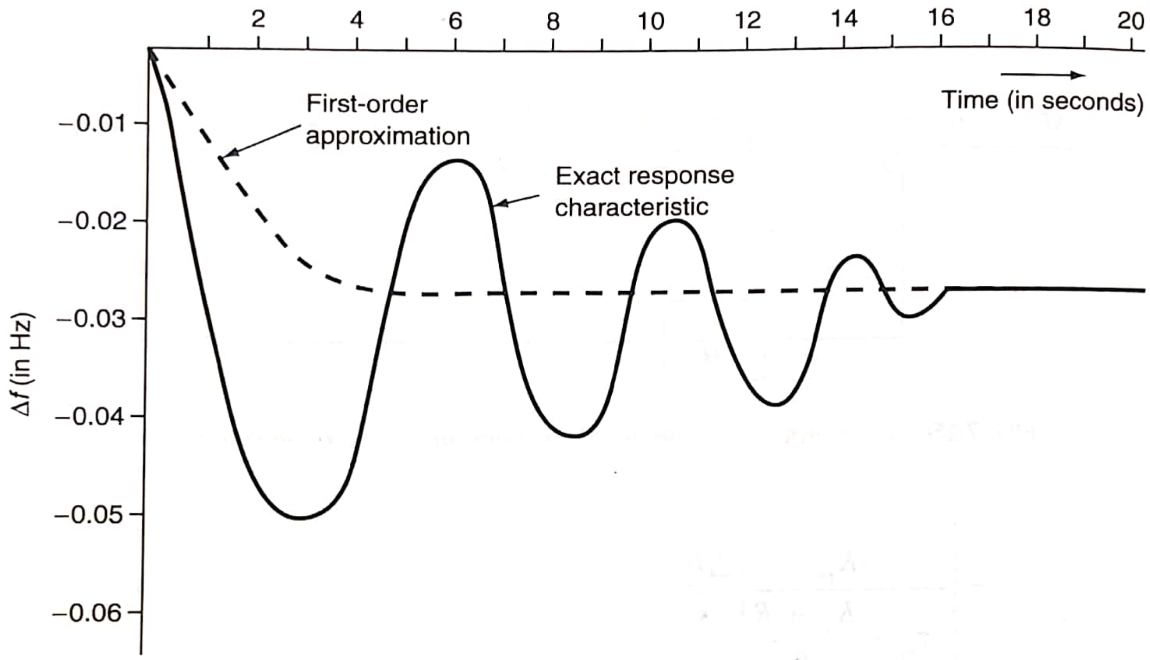


FIG. 7.19 *Dynamic response of frequency change (Δf) for a step-load change*

The plot of change in frequency versus time for a first-order approximation and exact response are shown in Fig. 7.19:

$\Delta P_D = 0.01$ p.u, $K_{ps} = 100$, $R = 3$, $\tau_{sg} = 0.4$ s, $\tau_t = 0.5$ s, and $\tau_{Ps} = 20$ s

Example 7.8: Find the static frequency drop if the load is suddenly increased by 25 MW on a system having the following data:

Rated capacity $P_r = 500$ MW
Operating Load $P_D = 250$ MW
Inertia constant $H = 5$ s
Governor regulation $R = 2$ Hz p.u. MW
Frequency $f = 50$ Hz

Also find the additional generation.

Solution:

Assuming the frequency characteristic to be linear, we have

$$B = \partial P_D / \partial f = \frac{250}{50} \text{ MW/Hz}$$

$\partial P_D / \partial f$ expressed in p.u., $B = \frac{250}{50 \times 500} = 0.01 \text{p.u. MW/Hz}$

ΔP_D in p.u. $= \frac{25}{500} = 0.05$

Area frequency response characteristic (AFRC)

$$\beta = B + \frac{1}{R} = 0.01 + \frac{1}{2} = 0.06$$

The static frequency drop $\Delta f = \frac{-\Delta P_D}{\text{AFRC}} = \frac{-0.05}{0.06} = 0.098$ Hz.

Hence, the system frequency drops to $(50 - 0.098) = 49.902$ Hz.

The amount of additional generation $\Delta P_G = \frac{-\Delta f}{R} = \frac{0.098}{2} = 4.9 \times 10^{-2}$ p.u. MW

$$= 4.9 \times 10^{-2} \times 500 = 24.5 \text{ MW}$$

While the sudden increase in load is 25 MW, the increase in generation is 24.5 MW and 0.5 MW is the loss of load due to the drop in frequency.

7.20 REQUIREMENTS OF THE CONTROL STRATEGY

The following are the basic requirements needed for the control strategy:

- The system frequency control is obtained through a closed loop. Since stability is the major problem associated with a closed-loop control, maintenance of the stability will be the main objective.
- The frequency deviation due to a step-load change should return to zero. The control that offers above is called 'isochronous control'. In addition, the control should keep the magnitude of the transient frequency deviation to a minimum.
- The integral of the frequency error should not exceed a certain maximum value.

Isochronous control ensures that the steady-state frequency error following a step-load change will be zero. However, no control can eliminate transient frequency error. The time error of synchronous clocks is proportional to the integral of this transient frequency error. Therefore, it is necessary to put a limit on the value of this integral.

- The total load should be divided among the individual generators of the control area for optimum economy.

The first three requirements are satisfied when the addition of the integral-control to the system takes place.

7.20.1 Integral control

The integral control is composed of a frequency sensor and an integrator. The frequency sensor measures the frequency error Δf and this error signal is fed into the integrator. The input to the integrator is called the 'Area Control Error' (i.e., ACE $= \Delta f$).

The ACE is the change in area frequency, which when used in an integral-control loop, forces the steady-state frequency error to zero.

The integrator produces a real-power command signal ΔP_C and is given by

$$\Delta P_C = -K_I \int \Delta f \, dt \tag{7.33}$$

$$= -K_I \int (\text{ACE}) \, dt$$

The signal ΔP_C is fed to the speed-changer causing it to move. Here, K_I is called the integral gain constant, which controls the rate of integration. The frequency sensor and the integrator are connected in the system as a closed control loop as shown in the block diagram in Fig. 7.25.

Figure 7.25 consists of Fig. 7.11 augmented by additional loops showing the generation of ACE and its use in changing the area command powers; R is the speed-regulation feedback parameter. $\Delta P_G(s)$, $\Delta P_D(s)$, and $\Delta F(s)$ are the incremental changes in the generation, system load, and frequency, respectively. The block diagram of Fig. 7.25 is the single-area power system (isolated power system) with integral control for small incremental changes.

The negative sign in the integral controller is for producing a negative or decrease command for a positive frequency error. The gain constant K_I is positive and controls the rate of integration, and thus the speed of the response of the control loop. The integrator is an electronic integrator of the same type as used in analog computers.

In view of hardware, we can understand the presence of the integrator by considering the ACE voltages distributed to the speed changers (speeder motors) of individual generator

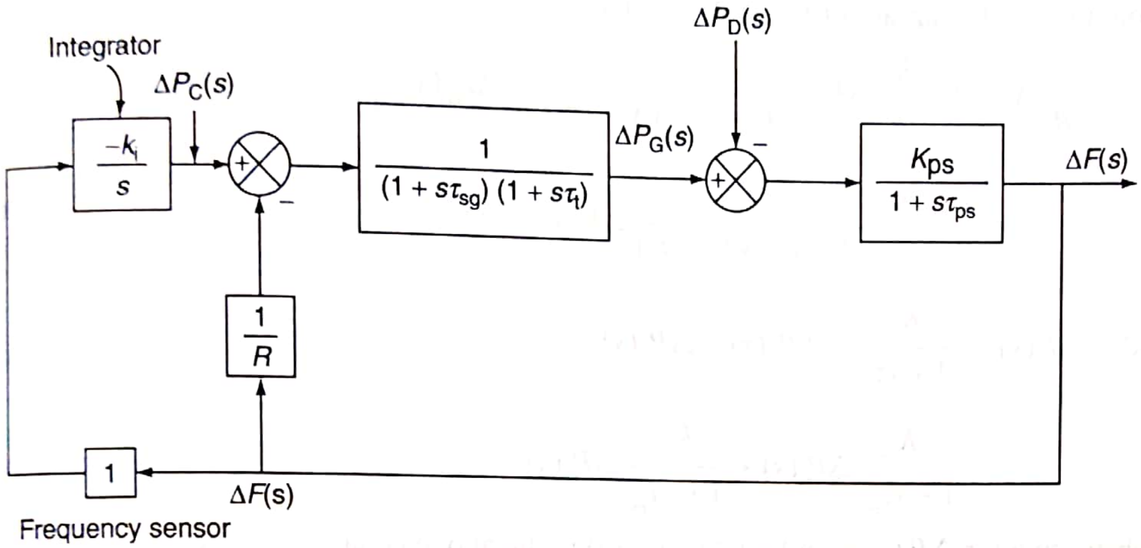


FIG. 7.25 *Proportional plus integral control of LFC of a single-area system*

units that participate in supplementary control within a given area. These motors turn at a rate of θ proportional to the ACE voltage and continue to turn until they are driven to zero.

The integral control will give rise to zero steady-state frequency error ($\Delta f_{\text{steady state}} = 0$) due to a step-load change. As long as the error remains, the integrator output will increase, causing the speed changer to move. The integrator output and thus the speed-changer position attain a constant value only when the frequency error has been reduced to zero. This is proved through a simplified mathematical analysis as follows.

7.21 ANALYSIS OF THE INTEGRAL CONTROL

The following assumptions are made in order to obtain a simple analysis. These assumptions do not distort the essential features. Also, the errors introduced on account of these assumptions affect only the transient and not the steady-state response.

Assumptions

- The time constant of the speed-governor mechanism τ_{sg} and that of the turbine τ_t are both neglected, i.e., $\tau_{sg} = \tau_t = 0$.
- The speed changer is an electromechanical device and hence its response is not instantaneous. However, it is assumed to be instantaneous in the present analysis.
- All non-linearities in the equipment, such as dead zone, etc., are neglected.
- The generator can change its generation ΔP_G as fast as it is commanded by the speed changer.
- The ACE is a continuous signal.

The Laplace transformation of Equation (7.33) gives

$$\Delta P_C(s) = -\frac{K_I}{s}\Delta F(s) \tag{7.34}$$

and, for a step change of load demand ΔP_D,

$$\Delta P_D(s) = \frac{\Delta P_D}{s} \tag{7.35}$$

From the block diagram of Fig. 7.25, we have

$$\left[\frac{-1}{R}\Delta F(s)-\frac{K_{\mathrm{I}}}{s}\Delta F(s)\right]\frac{1}{(1+s\tau_{\mathrm{sg}})(1+s\tau_{\mathrm{t}})}=\Delta P_{\mathrm{G}}(s)$$

$$-\left[\frac{1}{R}+\frac{K_{\mathrm{I}}}{s}\right]\frac{1}{(1+s\tau_{\mathrm{sg}})(1+s\tau_{\mathrm{t}})}\Delta F(s)=\Delta P_{\mathrm{G}}(s) \tag{7.36}$$

and $\Delta F(s)=\left(\frac{K_{\mathrm{ps}}}{1+s\tau_{\mathrm{ps}}}\right)[\Delta P_{\mathrm{G}}(s)-\Delta P_{\mathrm{D}}(s)]$

$$=\frac{-K_{\mathrm{ps}}}{1+s\tau_{\mathrm{ps}}}\Delta P_{\mathrm{D}}(s)+\frac{K_{\mathrm{ps}}}{1+s\tau_{\mathrm{ps}}}\Delta P_{\mathrm{G}}(s)$$

Substituting for $\Delta P_{\mathrm{G}}(s)$ from Equation (7.36) in the above equation, we get

$$\Delta F(s)=\frac{-K_{\mathrm{ps}}}{1+s\tau_{\mathrm{ps}}}\Delta P_{\mathrm{D}}(s)+\frac{K_{\mathrm{ps}}}{1+s\tau_{\mathrm{ps}}}\left[\frac{1}{R}+\frac{K_{\mathrm{I}}}{s}\right]\left[\frac{-1}{(1+s\tau_{\mathrm{sg}})(1+s\tau_{\mathrm{t}})}\right]\Delta F(s)$$

$$\left[1+\frac{K_{\mathrm{ps}}}{1+s\tau_{\mathrm{ps}}}\left[\frac{1}{R}+\frac{K_{\mathrm{I}}}{s}\right]\left[\frac{1}{(1+s\tau_{\mathrm{sg}})(1+s\tau_{\mathrm{t}})}\right]\right]\Delta F(s)=\frac{-K_{\mathrm{ps}}}{1+s\tau_{\mathrm{ps}}}\Delta P_{\mathrm{D}}(s)$$

$$\Delta F(s)=\frac{\dfrac{-K_{\mathrm{ps}}}{1+s\tau_{\mathrm{ps}}}}{\left[1+\dfrac{K_{\mathrm{ps}}}{1+s\tau_{\mathrm{ps}}}\left[\dfrac{1}{R}+\dfrac{K_{\mathrm{I}}}{s}\right]\left[\dfrac{1}{(1+s\tau_{\mathrm{sg}})(1+s\tau_{\mathrm{t}})}\right]\right]}\Delta P_{\mathrm{D}}(s) \tag{7.37}$$

$$=\frac{-sK_{\mathrm{ps}}R(1+s\tau_{\mathrm{sg}})(1+s\tau_{\mathrm{t}})}{\left[s(1+s\tau_{\mathrm{ps}})(1+s\tau_{\mathrm{sg}})(1+s\tau_{\mathrm{t}})R+K_{\mathrm{ps}}(s+RK_{\mathrm{I}})\right]}\times\frac{\Delta P_{\mathrm{D}}}{s} \tag{7.38}$$

Equation (7.38) becomes a fourth-order system.

The steady-state value of $\Delta f(t)$ can be obtained by applying the final-value theorem, viz.,

$$\Delta f(t)\big|_{\text{steady-state}}=\lim_{s\to 0}[s\Delta F(s)]=0$$

Hence, the static- or steady-state frequency error will be zero with integral control.

The nature of transient variation of $\Delta f(t)$ can be found by taking the inverse Laplace transform of Equation (7.39). According to assumption (i), Equation (7.39) simplifies to

$$\Delta F(s)=\frac{-K_{\mathrm{ps}}}{\left[1+s\tau_{\mathrm{ps}}+K_{\mathrm{ps}}\left[\dfrac{1}{R}+\dfrac{K_{\mathrm{I}}}{s}\right]\right]}\Delta P_{\mathrm{D}}(s)$$

$$\Delta F(s)=\frac{-K_{\mathrm{ps}}}{\tau_{\mathrm{ps}}}\left(\frac{s\dfrac{\Delta P_{\mathrm{D}}}{s}}{s^2+\left(1+\dfrac{K_{\mathrm{ps}}}{R}\right)\dfrac{s}{\tau_{\mathrm{ps}}}+\dfrac{K_{\mathrm{ps}}K_{\mathrm{I}}}{\tau_{\mathrm{ps}}}}\right) \tag{7.39}$$

$$\left(\text{since} \quad \Delta P_D(s) = \frac{\Delta P_D}{s}\right)$$

The nature of $\Delta f(t)$ depends on the roots of the characteristic equation of Equation (7.39)

$$s^2 + \left(1 + \frac{K_{ps}}{R}\right)\frac{s}{\tau_{ps}} + \frac{K_{ps} K_I}{\tau_{ps}} = 0 \tag{7.40}$$

The above equation can be rewritten as

$$\left[s + \frac{\left(1 + \frac{K_{ps}}{R}\right)}{2\tau_{ps}}\right]^2 + \frac{K_I K_{ps}}{\tau_{ps}} - \left(\frac{\left(1 + \frac{K_{ps}}{R}\right)}{2\tau_{ps}}\right)^2 = 0$$

or $(s + a)^2 + \omega^2 = 0$ **(7.41)**

where $\alpha = \dfrac{\left(1 + \frac{K_{ps}}{R}\right)}{2\tau_{ps}}$ is a positive real number

and $\omega = \left[\dfrac{K_I K_{Ps}}{\tau_{Ps}} - \left(\dfrac{\left(1 + \frac{K_{ps}}{R}\right)}{2\tau_{ps}}\right)^2\right]^{1/2}$

The nature of the roots of Equation (7.41) depends on whether $\omega^2 = 0$, $\omega^2 > 0$, or $\omega^2 < 0$.

Case (i): $\omega^2 = 0$

The characteristic equation has a repeated root (viz., α repeated twice). Hence, the expression for $\Delta f(t)$ contains terms of the type

$e^{-\alpha t}$ and $t\, e^{-\alpha t}$

Consequently, the response [viz., $\Delta f(t)$] is a critically damped one. For this critical case,

$$\omega^2 = \frac{K_I K_{ps}}{\tau_{ps}} - \left(\frac{\left(1 + \frac{K_{ps}}{R}\right)}{2\tau_{ps}}\right)^2 = 0$$

Solving the above for K_I, we get

$$K_I = \frac{1}{4\tau_{ps} K_{ps}}\left(1 + \frac{K_{ps}}{R}\right)^2 = K_{Icrit} \tag{7.42}$$

Case (ii): $\omega^2 > 0$

Now, $(s + \alpha)^2 = -\omega^2$, where ω^2 is a positive real number.

$(s + \alpha) = \pm j\omega$

(or) $s = (-\alpha \pm j\omega)$

The time response $\Delta f(t)$ will therefore consist of damped oscillatory terms of the type

$e^{-\alpha t} \sin \omega t$ and $e^{-\alpha t} \cos \omega t$.

This case is called a supercritical case. In this case, $K_I > K_{I_{crit}}$.

Case (iii): $\omega^2 < 0$

Then, ω^2 is a negative real number.

So, $(s+\alpha)^2 = -\omega^2$ is a positive real number

$= \gamma^2$ (say)

$\therefore (s+\alpha) = +\gamma$ [since $\gamma < \alpha$]

or $s = (-\alpha + \gamma)$ or $(-\alpha - \gamma)$

$= \beta_1$ or $-\beta_2$ (say)

Accordingly, in this case, the time response $\Delta f(t)$ will comprise terms of the type

$e^{-\beta_1 t}$ and $e^{-\beta_2 t}$

Hence, the response will be damped and non-oscillatory. The control, in this case, is called the subcritical integral control. In this case, $K_I < K_{Icrit}$.

In all the three cases described above, $\Delta f(t)$ will approach zero. This was proved earlier using the final-value theorem. It can be observed that the transient frequency error does remain finite. This is a proof that the control is both stable and isochronous. Thus, the first two control requirements stated earlier (Section 7.20) are fulfilled with this integral control. This control is also called 'proportional plus integral control'. The proportional control is provided by the closed loop of gain constant of $1/R$.

The actual simulated time responses of a single-area control system with and without integral control are as shown in Fig. 7.26.

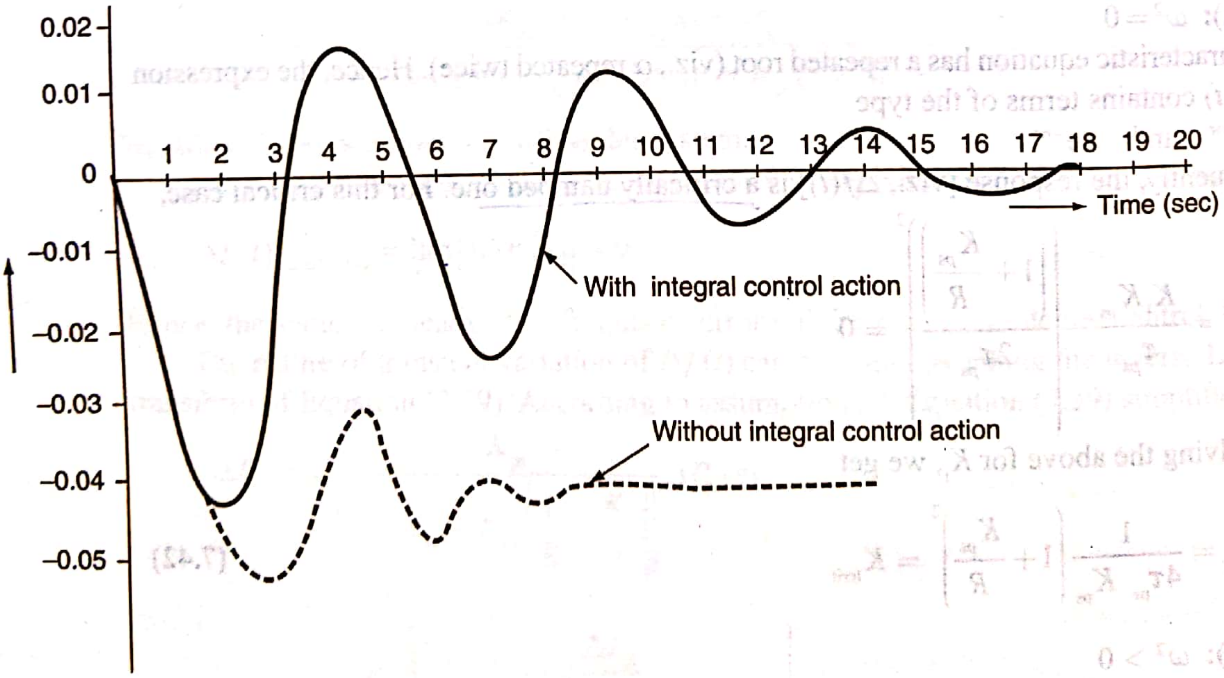


FIG.7.26 *Dynamic response of LFC of a single-area system with and without integral control action*

Example 7.11: Given a single area with three generating units as shown in Fig. 7.29:

Unit	*Rating (MVA)*	*Speed droop R (per unit on unit base)*
1	100	0.010
2	500	0.015
3	500	0.015

The units are loaded as $P_1 = 80$ MW; $P_2 = 300$ MW; $P_3 = 400$ MW. Assume $B = 0$; what is the new generation on each unit for a 50-MW load increase? Repeat with $B = 1.0$ p.u. (i.e., 1.0 p.u. on load base).

Solution:

(a) $$\Delta f = \frac{-\Delta P}{\sum_{i=1}^{3} \frac{1}{R_i} + B} = \frac{-\Delta P}{\frac{1}{R_1} + \frac{1}{R_2} + \frac{1}{R_3} + B}$$

with $B = 0$; at a common base of 1,000 MVA

$$R_1 = 0.01 \times \frac{1{,}000}{100} = 0.1 \text{ p.u.}$$

$$R_2 = 0.015 \times \frac{1{,}000}{500} = 0.03 \text{ p.u.}$$

$$R_3 = 0.015 \times \frac{1{,}000}{500} = 0.03 \text{ p.u.}$$

$$\Delta P = \frac{50}{1{,}000} = 0.05 \text{ p.u.}$$

$$\Delta f = \frac{-0.05}{\frac{1}{0.1} + \frac{1}{0.03} + \frac{1}{0.03}} = -652.17 \times 10^{-6} \text{ p.u.}$$

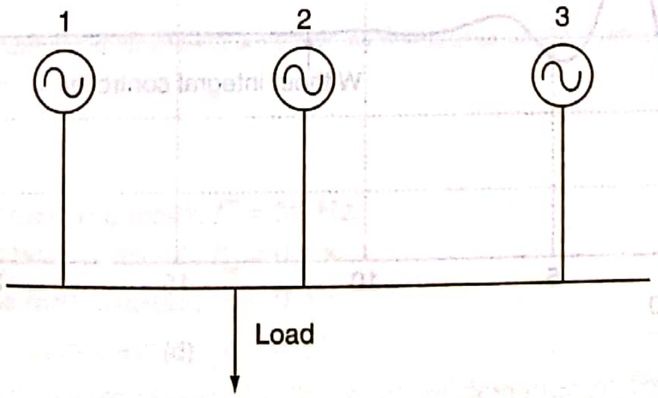


FIG. 7.29 *A single area with three generating units*

$$f = f^0 + \Delta f$$

$$= 50 - 652.17 \times 10^{-6}\,(50) = 49.96 \text{ Hz}$$

Changes in unit generation:

$$\Delta P_1 = \frac{-\Delta f}{R_1} = 0.00652 \text{ p.u.} = 6.52 \text{ MW}$$

$$\Delta P_2 = \frac{-\Delta f}{R_2} = 21.739 \times 10^{-3} \text{ p.u.} = 21.74 \text{ MW}$$

$$\Delta P_3 = \frac{-\Delta f}{R_3} = 21.739 \times 10^{-3} \text{ p.u.} = 21.74 \text{ MW}$$

Total = 50 MW

New generation:

$$P_1' = P_1 + \Delta P_1 = 80 + 6.52 = 86.52 \text{ MW}$$

$$P_2' = P_2 + \Delta P_2 = 300 + 21.74 = 321.74 \text{ MW}$$

$$P_3' = P_3 + \Delta P_3 = 400 + 21.74 = 421.74 \text{ MW}$$

(b) with $B = 1$ p.u. (on load base)

$$\Delta f = \frac{-0.05}{\frac{1}{0.1} + \frac{1}{0.03} + \frac{1}{0.03} + 1} = 643.78 \times 10^{-6}$$

$$\therefore f = f^o + \Delta f = 50 - 643.78 \times 10^{-6}\,(50) = 49.9614 \text{ Hz}$$

Changes in unit generation:

$$\Delta P_1 = \frac{-\Delta f}{R_1} = \frac{643.78 \times 10^{-6}}{0.1} = 6.44 \text{ MW}$$

$$\Delta P_2 = \frac{-\Delta f}{R_2} = \frac{643.78 \times 10^{-6}}{0.03} = 21.459 \text{ MW}$$

$$\Delta P_3 = \frac{-\Delta f}{R_3} = \frac{643.78 \times 10^{-6}}{0.03} = 21.459 \text{ MW}$$

New generation:

$$P_1' = P_1 + \Delta P_1 = 80 + 6.44 = 86.44 \text{ MW}$$

$$P_2' = P_2 + \Delta P_2 = 300 + 21.459 = 321.459 \text{ MW}$$

$$P_3' = P_3 + \Delta P_3 = 400 + 21.459 = 421.459 \text{ MW}$$

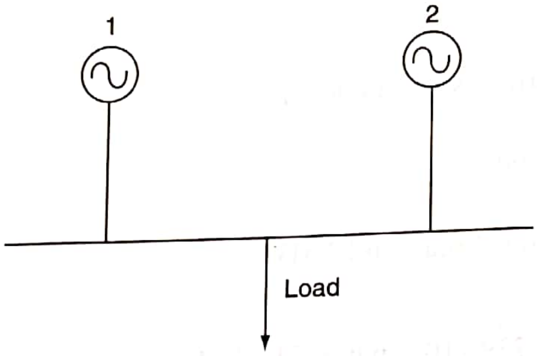


FIG. 7.30 *Single area with two generating units*

Example 7.12: Given a single area with two generating units as shown in Fig. 7.30:

Unit	Rating (MVA)	Speed droop R (per unit on unit base)
1	400	0.04
2	800	0.05

The units share a load of $P_1 = 200$ MW; $P_2 = 500$ MW. The units are operating in parallel, sharing 700 MW at 1.0 (50 Hz) frequency. The load is increased by 130 MW.

With $B = 0$, find the steady-state frequency deviation and the new generation on each unit.

With $B = 0.804$, find the steady-state frequency deviation and the new generation on each unit.

Solution:

(a) $$\Delta f = \frac{-\Delta P}{\dfrac{1}{R_1} + \dfrac{1}{R_2} + B}$$

At a common base of 1,000 MVA:

$$R_1 = 0.04 \times \frac{1{,}000}{400} = 0.1$$

$$R_2 = 0.05 \times \frac{1{,}000}{800} = 0.0625$$

$$\Delta f = \frac{-130/1{,}000}{\dfrac{1}{0.1} + \dfrac{1}{0.0625}} = -5 \times 10^{-3} \text{ p.u.}$$

$$f = f^0 + \Delta f = 50 - 5 \times 10^{-3} (50) = 49.75 \text{ Hz}$$

Change in unit generation:

$$\Delta P_1 = \frac{-\Delta f}{R_1} = \frac{5 \times 10^{-3}}{0.1} = 50 \text{ MW}$$

$$\Delta P_2 = \frac{-\Delta f}{R_2} = \frac{5\times10^{-3}}{0.0625} = 80 \text{ MW}$$

Total = 130 MW

New generation:

$$P_1' = P_1 + \Delta P_1 = 200 + 50 = 250 \text{ MW}$$

$$P_2' = P_2 + \Delta P_2 = 500 + 80 = 580 \text{ MW}$$

(b) With $B = 0.804$ (on load base)

$$\Delta f = \frac{-130/1{,}000}{\frac{1}{0.1} + \frac{1}{0.0625} + 0.804} = -4.85\times10^{-3} \text{ p.u.}$$

$$f = f^0 + \Delta f = 50 - 4.85\times10^{-3}\,(50) = 49.457 \text{ Hz}$$

Change in unit generation:

$$\Delta P_1 = \frac{-\Delta f}{R_1} = \frac{4.85\times10^{-3}}{0.1} = 48.5 \text{ MW}$$

$$\Delta P_2 = \frac{-\Delta f}{R_2} = \frac{4.85\times10^{-3}}{0.0625} = 77.6 \text{ MW}$$

New generation:

$$P_1' = P_1 + \Delta P_1 = 200 + 48.5 = 248.5 \text{ MW}$$

$$P_2' = P_2 + \Delta P_2 = 500 + 77.6 = 577.6 \text{ MW}$$

Example 7.13: A 500-MW generator has a speed regulation of 4%. If the frequency drops by 0.12 Hz with an unchanged reference, determine the increase in turbine power. And also find by how much the reference power setting should be changed if the turbine power remains unchanged.

Solution:

Case 1:

Speed regulation, $R = 4\%$ of 50 Hz

$$= \frac{4}{100}\times 50 = 2 \text{ Hz}$$

$$R = \frac{2 \text{ Hz}}{500 \text{ MW}} = 0.004 \text{ Hz/MW}$$

Given a drop in frequency, $\Delta f = -0.12$ Hz

Increase in turbine power, $\Delta P = -\frac{1}{R}\Delta f$

$$= -\frac{1}{0.004}\times(-0.12)$$

$$= 30 \text{ MW}$$

$\therefore$ Turbine power increase, $\Delta P = 30$ MW

Case 2:

If the turbine power remains unchanged, the reference power setting at the point of the block diagram must be changed such that the signal to the increase in generation is blocked:

$$\text{i.e.,}\quad \Delta P_{ref} - \frac{1}{R}\Delta f = 0$$

$$\Delta P_{\text{ref}} = \frac{1}{R}\Delta f = 30 \text{ MW}$$

Example 7.14: Two generating units having the capacities 600 and 900 MW and are operating at a 50 Hz supply. The system load increases by 150 MW when both the generating units are operating at about half of their capacity, which results in the frequency falling by 0.5 Hz. If the generating units are to share the increased load in proportion to their ratings, what should be the individual speed regulations? What should the regulations be if expressed in p.u. Hz/p.u. MW?

Solution:

Rated capacity of Unit-1 = 600 MW
Rated capacity of Unit-2 = 900 MW
System frequency, $f = 50$ Hz
System load increment, $\Delta P = 150$ MW
Falling in frequency, $\Delta f = 0.5$ Hz

We know that $\Delta P = -\frac{1}{R}\Delta f$

$$\therefore \Delta P_1 = \frac{1}{-R_1}\Delta f \tag{7.43}$$

$$\Delta P_2 = -\frac{1}{R_2}\Delta f \tag{7.44}$$

If the load is shared in proportional to their ratings,

$$\Delta P_1 = 150 \times \frac{600}{1{,}500} = 60 \text{ MW}$$

$$\Delta P_2 = 150 \times \frac{900}{1{,}500} = 90 \text{ MW}$$

$$\therefore \text{From Equation (7.43)},\ R_1 = \frac{-\Delta f}{\Delta P_1} = \frac{-0.5}{60} = -0.00833 \text{ Hz/p.u. MW}$$

$$R_2 = -\frac{\Delta f}{\Delta P_2} = -\frac{0.5}{90} = 0.0055 \text{ Hz/MW}$$

$$R_1 = -\frac{0.00833}{50} \times \frac{600}{1} = 0.099 \simeq 0.1 \text{ p.u. Hz/p.u. MW}$$

$$R_2 = -\frac{0.0055}{50} \times \frac{900}{1} = 0.099 \simeq 0.1 \text{ p.u. Hz/p.u. MW}$$

It is observed that the speed regulations in p.u. Hz/p.u. MW are attaining the same value, even when they are based on their individual ratings and they have different regulations.

Example 7.15: A single-area system has the following data:

Speed regulation, $R = 4$ Hz/p.u. MW

Damping coefficient, $B = 0.1$ p.u. MW/Hz

Power system time constant, $T_P = 10$ s

Power system gain, $K_P = 75$ Hz/p.u. MW

When a 2% load change occurs, determine the AFRC and the static frequency error. What is the value of the steady-state frequency error if the governor is blocked?

Solution:

$$\text{AFRC} = \beta = B + \frac{1}{R}$$

$$= 0.1 + \frac{1}{4}$$

$$= 0.35 \text{ MW/Hz}$$

$$\text{Static frequency error} = \Delta f_{ss} = \frac{-\Delta P_D}{\left(B + \frac{1}{R}\right)} = \frac{-\Delta P_D}{\beta}$$

$$= -\frac{2}{100} \times \frac{1}{0.35}$$

$$= -\ 0.0571 \text{ Hz}$$

If the governor is blocked, the feedback loop will not be present; therefore, R will become infinite:

i.e., $R \to \infty$, $\therefore \frac{1}{R} = 0$

$$\therefore \beta = B + \frac{1}{R} = B = 0.1 \text{ p.u. MW/Hz}$$

$$\text{Static frequency error} = \Delta f_{ss} = \frac{-\Delta P_D}{B + \frac{1}{R}} = \frac{-\Delta P_D}{B}$$

$$= \frac{-2}{100} \times \frac{1}{0.1}$$

$$= -0.2 \text{ Hz}$$

i.e., frequency falls by 0.0571 Hz.

$$\therefore \text{New frequency}, f' = 50 - 0.0571$$

$$= 49.94 \text{ Hz}$$

Observation:

With speed-governor action:

Frequency falls by 0.0571 Hz

$\therefore$ New frequency, $f' = 50 - 0.0571$

$= 49.94$ Hz

Without speed-governor action:

Frequency falls by 0.2 Hz

$\therefore$ New frequency, $f' = 50 - 0.2 = 49.8$ Hz

From the above results, it is noted that the speed-governor action is necessary for obtaining a reduction in the steady-state frequency error.

Example 7.16: A 200-MVA synchronous generator is operated at 3,000 rpm, 50 Hz. A load of 40 MW is suddenly applied to the machine and the station valve to the turbine opens only after 0.4 s due to the time lag in the generator action. Calculate the frequency to which the generated voltage drops before the steam flow commences to increase so as to meet the new load. Given that the valve of H of the generator is 5.5 kW-s per kVA of the generator energy.

Solution:

Given:

Rating of the generator = 200 MVA

Load applied on the m/c = 40 MW

Time taken by the valve to open = 0.4 s

$H = 5.5$ kW-s/kVA

$= 11 \times 10^5$ s

Energy stored at no-load = $5.5 \times 200 \times 1{,}000 = 1{,}100$ MW-s = 1,100 MJ

Before the steam valve opens, the energy lost by the rotor = $40 \times 0.4 = 16$ MJ.

The energy lost by the rotor results in a reduction in the speed of the rotor and hence the reduction in frequency.

We know

$$\omega = \omega^0 \left(\frac{f^0 + \Delta f}{f^0}\right)^2$$

$$\therefore \text{Frequency at the end of 0.4 s} = f_{\text{new}} = \sqrt{\frac{1{,}100 - 16}{1{,}100}} \times 50$$

$$= \sqrt{0.09854} \times 50 = 0.9927 \times 50$$

$$= 49.635 \text{ Hz}$$

Example 7.17: Two generators of rating 100 and 200 MW are operated with a droop characteristic of 6% from no load to full load. Determine the load shared by each generator, if a load of 270 MW is connected across the parallel combination of those generators.

Solution:

The two generators are operating with parallel connection; the % drop in frequency from two generators due to different loads must be same.

Let power supplied by (100 MW) Generator-1 = x

Percentage drop in frequency = 6%

$\therefore$ Percentage drop in the speed of Generator-1 = $\dfrac{6x}{100}$

Total load across the parallel connection = 270 MW

Power supplied by (200 MW) Generator-2 = (270 − x)

$\therefore$ Percentage drop in the speed of Generator-2 $= \dfrac{6(270-x)}{200}$

Percent drop in frequency (or speed) of both machines must be the same:

$$\therefore \frac{6x}{100} = \frac{6(270-x)}{200}$$

By solving the above equation, we get

$x = 90$ MW

$\therefore$ Load shared by Generator-1 (100 MW unit) = 90 MW

Load shared by Generator-2 (200 MW unit) = 270 − x

= 270 − 90 = 180 MW

KEY NOTES

- **Necessity of maintaining frequency constant**
  - (i) All the AC motors should be given a constant frequency supply so as to maintain the speed constant.
  - (ii) In continuous process industry, it affects the operation of the process itself.
  - (iii) For synchronous operation of various units in the power system network, it is necessary to maintain the frequency constant.
  - (iv) Frequency affects the amount of power transmitted through interconnecting lines.
- **Load frequency control (LFC)** is the basic control mechanism in the power system operation whenever there is a variation in load demand on a generating unit momentarily if there is an occurrence of unbalance between real-power input and output. This difference is being supplied by the stored energy of the rotating parts of the unit.
- Prime movers driving the generators are fitted with governors, which are regarded as primary control elements in the LFC system. Governors sense the change in a speed control mechanism to adjust the opening of steam valves in the case of steam turbines and the opening of water gates in the case of water turbines.
- The steady-state speed regulation in per unit is given by

$$R = \frac{N_0 - N}{N}$$

The value of R varies from 2% to 6% for any generating unit.

- The speed governor is the main primary tool for the LFC, whether the machine is used alone to feed a smaller system or whether it is a part of the most elaborate arrangement.

  Its main parts are fly-ball speed governor, hydraulic amplifier, speed changer, and linkage mechanism.
- **Control area** is possible to divide a very large power system into sub-areas in which all the generators are tightly coupled such that they swing in unison with change in load or due to a speed-changer setting. Such an area, where all the generators are running coherently is termed as a control area.
- **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.
- **Dynamic response** is how the frequency changes as a function of time immediately after disturbance before it reaches the new steady-state condition. The canalization of dynamic response requires the solution of a dynamic equation of the system for a given disturbance.

- **Integral control consists** of a frequency sensor and an integrator. The frequency sensor measures the frequency error Δf and this error signal is fed into the integrator. The input to the integrator is called the **'area control error (ACE)'**.
- The ACE is the change in area frequency, which when used in an integral-control loop forces the steady-state frequency error to zero.

SHORT QUESTIONS AND ANSWERS

(1) What is the effect of speed of a generator on its frequency?

The effect of speed of a generator on its frequency is

$$f = \frac{pN}{120} \text{ Hz}$$

where p is the number of poles and N the speed in rpm.

(2) Why should the system frequency be maintained constant?

Constant frequency is to be maintained for the following functions:

- All the AC motors should be given constant frequency supply so as to maintain the speed constant.
- In continuous process industry, it affects the operation of the process itself.
- For synchronous operation of various units in the power system network, it is necessary to maintain the frequency constant.

(3) What is the nature of the generator–load frequency characteristic?

The nature of the generator is drooping straight-line characteristics.

(4) How do load frequency characteristics change during on-line control?

By shifting the load frequency characteristics as a whole up or down varying the inlet valve opening of the prime mover.

(5) How do load frequency characteristics change during off-line control?

By changing the slope of the load characteristics by varying the lever ratio of the speed governor.

(6) State why P–f and Q–V control loops can be treated as non-interactive?

The active power P is mainly dependent on the internal angle δ and is independent of bus voltage magnitude $|V|$. The bus voltage is dependent on machine excitation and hence on reactive power Q and is independent of the machine angle δ. The change in the machine angle δ is caused by a momentary change in the generator speed and hence the frequency. Therefore, the load frequency and excitation voltage controls are non-interactive for small changes and can be modeled and analyzed independently.

(7) What will be the order of the system for non-reheat steam turbine and reheat turbine?

The order of the system for non-reheat and reheat steam turbine are first order and second order, respectively.

(8) What are the transfer functions of non-reheat steam turbine and reheat turbine? What will be the value of their time constants?

The transfer function of non-reheat type of steam turbine is

$$G_{T(s)} = \frac{K_t}{1+s\tau_t}, \quad \tau_1 = 0.2 \text{ to } 2 \text{ s}$$

The transfer function of reheat type of steam turbine is

$$G_T(s) = \frac{\Delta P_G(s)}{\Delta X_E(s)} = \left[\frac{K_t}{(1+s\tau_t)}\right] \frac{(1+sK_r\tau_r)}{(1+s\tau_r)}$$

The time constant τ_r has a value in the range of 10 s.

(9) Under what condition will the model developed for a turbine be valid?

The condition for the turbine is the first 20 s following the incremental disturbance.

(10) Explain the control area concept.

It is possible to divide a very large power system into sub-areas in which all the generators are tightly coupled such that they swing in unison with change in load or due to a speed-changer setting. Such an area, where all the generators are running coherently, is termed the control area. In this area, frequency may be same in steady-state and dynamic conditions.

For developing a suitable control strategy, a control area can be reduced to a single generator, a speed governor, and a load system.

(11) What is meant by single-area power system?

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.

(12) What is meant by dynamic response in LFC?

The meaning of dynamic response is how the frequency changes as a function of time immediately after disturbance before it reaches the new steady-state condition.

(13) What is meant by uncontrolled case?

For uncontrolled case, $\Delta P_c = 0$; i.e., constant speed-changer position with variable load.

(14) What is the need of a fly-ball speed governor?

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

(15) What is the need of a speed changer?

It provides a steady-state power output setting for the turbines. Its upward movement opens the upper pilot valve so that more steam is admitted to the turbine under steady conditions. This gives rise to higher steady-state power output. The reverse happens for downward movement of the speed changer.

(16) What is meant by area control error?

The area control error (ACE) is the change in area frequency, which when used in an integral-control loop forces the steady-state frequency error to zero.

(17) What is the nature of the steady-state response of the uncontrolled LFC of a single area?

The nature of the steady-state response of a single area is the linear relationship between frequency and load for free governor operation.

(18) How and why do you approximate the system for the dynamic response of the uncontrolled LFC of a single area?

The characteristic equation of the LFC of an isolated power system is third order, dynamic response that can be obtained only for a specific numerical case.

However, the characteristic equation can be approximated as first order by examining the relative magnitudes of the different time constants involved.

(19) What are the basic requirements of a closed-loop control system employed for obtaining the frequency constant?

The basic requirements are as follows:

(i) Good stability;

(ii) Frequency error, accompanying a step-load change, returns to zero;

(iii) The magnitude of the transient frequency deviation should be minimum;

(iv) The integral of the frequency error should not exceed a certain maximum value.

(20) What are the basic components of an integral controller

It consists of a frequency sensor and an integrator.

(21) Why should the integrator of the frequency error not exceed a certain maximum value?

The frequency error should not exceed a maximum value so as to limit the error of synchronous clocks.

(22) What are the assumptions made in the simplified analysis of the integral control?

- The time constant of the speed-governing mechanism τ_{sg} and that of the turbine are both neglected, i.e., it is assumed that $\tau_{sg} = \tau_t = 0$.
- The speed changer is an electromechanical device and hence its response is not instantaneous. However, it is assumed to be instantaneous in the present analysis.
- All non-linearities in the equipment, such as dead zone, etc., are neglected.
- The generator can change its generation ΔP_G as fast as it is commanded by the speed-changer.
- The ACE is a continuous signal.

(23) State briefly how the time response of the frequency error depends upon the gain setting of the integral control.

If K_I is less than its critical value, then the response will be damped non-oscillatory. $\Delta f(t)$ reduces to zero in a longer time. Hence, the response is sluggish. This is an overdamped case. This is the subcritical case of integral control.

If K_I is greater than its critical value, the time response would be damped oscillatory. $\Delta f(t)$ approaches zero faster. This is an underdamped case. This is the supercritical case of the control.

If K_I equals its critical value, no oscillations would be present in the time response and $\Delta f(t)$ approaches zero in less time than in the subcritical case. The integral of the frequency error would be the least in this case.

MULTIPLE-CHOICE QUESTIONS

(1) If the load on an isolated generator is increased without increasing the power input to the prime mover:

(a) The generator will slow down.

(b) The generator will speed up.

(c) The generator voltage will increase.

(d) The generator field.

(2) Governors of controlling the speed of electric-generating units normally provide:

(a) A flat-speed load characteristic.

(b) An increase in speed with an increasing load.

(c) A decrease in speed with an increasing load.

(d) None

(3) When two identical AC-generating units are operated in parallel on governor control, and one machine has a 5% governor droop and the other a 10% droop, the machine with the greater governor droop will:

(a) Tend to take the greater portion of the load changes.

(b) Share the load equally with the other machine.

(c) Tend to take the lesser portion of the load changes.

(d) None.

(4) On LFC installations, error signals are developed proportional to the frequency error. If the frequency declines, the error signal will act to:

(a) Increase the prime mover input to the generators.

(b) Reduce the prime mover input to the generators.

(c) Increase generator voltages.

(d) None.

(5) If KE reduces

(a) w decreases.

(b) Speed falls.

(c) Frequency reduces.

(d) All.

(6) The changing of slope of a speed governer characteristic is achevied by changing the ratio of lever L of governer and can be made during

(a) On-line condition only.

(b) Off-line condition only.

(c) Both (a) and (b).

(d) Either (a) or (b).

(7) Unit of R is ________.

(a) Hz/MVAr.

(b) Hz/MVA.

(c) Hz/MW.

(d) Hz-s.

(8) Unit of B is ________.

(a) MVAr/Hz.

(b) MVA/Hz.

(c) MW/Hz.

(d) MW-s.

(9) Unit of H of a synchronous machine is:

(a) MJ/MW.

(b) MJ/MVA.

(c) MJ/s.

(d) MW-s.

(10) KE and frequency of a synchronous machine are related as:

(a) KE$=f$.

(b) KE$=1/f$.

(c) $KE = f^2$.

(d) None of these.

(11) Input signals to an ALFC loop is ________.

(a) ΔP_{ref}

(b) ΔP_D

(c) Both (a) and (b).

(d) None of these.

(12) Two main control loops in generating stations are:

(a) ALFC.

(b) AVR.

(c) Both (a) and (b).

(d) None of these.

(13) The speed regulation can be expressed as

(a) Ratio of change in frequency from no-load to full load to the rated frequency of the unit.

(b) Ratio of change in frequency to the corresponding change in real-power generation.

(c) (a) and (b).

(d) None of these.

(14) In an ALFC loop, Δf can be reduced using ________ controller.

(a) Differential.

(b) Integral.

(c) Proportional.

(d) All of these.

(15) Time constant of a power syste when compared to a speed governor is:

(a) Less.

(b) More.

(c) Same.

(d) None of these.

(16) Δf is of the order of ________ Hz.

(a) 0 to 0.05.

(b) −0.05 to 0.

(c) Both (a) and (b).

(d) None of these.

(17) In a power system ________ are continuously changing.

(a) Active and reactive power generation.

(b) Active and reactive power demands.

(c) Voltage and its angle.

(d) All of these.

(18) In a normal state, the frequency and voltage are kept at specified values that carefully maintain a balance between:

(a) Real-power demand and real-power generation.

(b) Reactive power demand and reactive power generation.

(c) Both.

(d) None of these.

(19) Real-power balance will control the variations in ________.

(a) Voltage.

(b) Frequency.

(c) Both.

(d) None of these.

(20) The excitations of the generators must be continuously regulated:

(a) To match the reactive power generations with reactive power demand.

(b) To control the variations in voltage.

(c) Both.

(d) None of these.

(21) ________ is the basic control mechanism in the power system.

(a) LFC.

(b) Voltage.

(c) Both.

(d) None of these

(22) Setting of speed-load characteristic parallel to itself is known as ________ and its adapted as on-line control.

(a) Primary control.

(b) Supplementary control.

(c) Basic.

(d) All of these.

(23) The basic function of LFC is:

(a) To maintain frequency for variations in real-power demand.

(b) To maintain voltage for variations in reactive power demand.

(c) To maintain both voltage and frequency for variations in real-power demand.

(d) To maintain both voltage and frequency for variations in real-power demand.

(24) The degree of unbalance between real-power generation and real-power demand is indicated by the index:

(a) Speed regulation R.

(b) Change in voltage,

(c) Frequency error.

(d) None.

(25) The LFC system __________ in the system.

(a) Does consider the reactive power flow.

(b) Does not consider the reactive power flow.

(c) Does not consider the real-power flow.

(26) __________ controls the excitation voltage and modifies the excitation.

(a) Change in real-power, ΔP_a.

(b) Change in frequency Δ.

(c) Change in tie-line power, ΔP_{tie}.

(d) Change in reactive power ΔQ_{ci}.

(27) The p–f controller is employed to:

(a) Control the frequency.

(b) Monitor the active power flows in interconnection.

(c) Control the voltage.

(i) Only (a).

(ii) Only (b).

(iii) (b) and (c).

(iv) (a) and (b).

(28) Which of the following is correct regarding p–f controller?

(a) It senses the frequency error.

(b) It changes the tie-line powers.

(c) Provides the information about incremental error in power angle $\Delta\delta$.

(i) (a) and (b).

(ii) (b) and (c).

(iii) (a) and (c).

(iv) All of these.

(29) The control signal that will change the position of the inlet valve of the prime mover is:

(a) ΔP_{ci}.

(b) ΔP_{gi}.

(c) ΔP_{di}.

(d) None of these.

(30) The objective of Q–V controller is to transform the:

(a) Terminal voltage error signal into a reactive power control signal, ΔQ_{ci}.

(b) Terminal voltage error signal into a real-power control signal, ΔP_{ci}.

(c) Frequency error signal into a real-power control signal, ΔP_{ci}.

(d) None of these.

(31) The active power P is:

(a) Mainly dependent on the internal torque angle, δ.

(b) Almost independent of the voltage magnitude.

(c) totally dependent on both the torque angle and the voltage.

(d) Mainly dependent on voltage and independent of torque angle, δ.

(i) (a) and (d).

(ii) (b) and (c).

(iii) (a) and (b).

(iv) Only (d).

(32) The bus voltage V is:

(a) Dependent on the internal torque angle, δ.

(b) Almost independent of active power, P.

(c) Dependent on machine excitation and hence on reactive power.

(d) Almost independent of internal torque angle, δ.

(i) (a) and (d).

(ii) (b) and (c).

(iii) (a) and (b).

(iv) (c) and (d).

(33) Usually p–f controller and Q–V controller for __________ change, can be considered as __________ type.

(a) Dynamic, non-interacting.

(b) Static, interacting.

(c) Static, non-interacting.

(d) None of these.

(34) AVR loop is __________ control mechanism.

(a) Slow.

(b) Faster.

(c) Slow in some cases and faster in some other cases.

d) None of these.

(35) ALFC loop is __________ control mechanism.

(a) Slow.

(b) Faster.

(c) Slow as well as fast.

(d) None of these.

(36) Which of the following indicates the large-signal analysis of power system dynamics?

(a) Large and sudden variations in the system variables due to sudden disturbances.

(b) Mathematical model is a set of non-linear differential equations.

(c) Mathematical model is a set of linear differential equations.

(d) Small and gradual variations of system variables.

(i) (a) and (b).

(ii) (b) and (c).

(iii) (c) and (d).

(iv) None of these.

(37) Laplace transform methods are employed to determine the response of the system in __________ analysis.

(a) Large signal.

(b) Small signal.

(c) Both.

(d) None of these.

(38) A signal area system is one in which:

(a) It is not connected to any other system.

(b) Total demand on the system should be fully met by its own local generation.

(c) All generators swing together.

(d) All of these.

(39) In a signal area system, all generators working remain in synchronism maintaining their relative power angles; such a group of generators is called __________.

(a) Swing group.

(b) Synchro group.

(c) Coherent group.

(d) None of these.

(40) The heart of the speed governor system, which controls the change in speed is:

(a) Linkage mechanism.

(b) Fly-ball speed governor.

(c) Speed changer.

(d) Hydraulic amplifier.

(41) In a hydraulic amplifier:

(a) High-power-level pilot valve moment is converted into low-power-level main piston movement.

(b) Low-power pilot valve moment is converted into low-power-level piston movement.

(c) Low-power-level pilot valve moment is converted into high-power-level piston movement.

(d) Low-power-level pilot valve moment is converted into high-power-level pilot valve moment.

(42) Linkage mechanism provides:

(a) The moment of control valve in propositional to the inlet steam.

(b) The feedback from the control valve moment.

(c) Both (a) and (b).

(d) None of these.

(43) The primary control loop in generator control is:

(a) Linkage mechanism.

(b) Fly-ball speed governor.

(c) Speed changer.

(d) Hydraulic amplifier.

(44) The position of the pilot valve can be affected through linkage mechanism in __________ way.

(a) Directly by the speed changer.

(b) Indirectly through feedback due to position changes of the main system.

(c) Indirectly through feedback due to position changes of the linkage point E resulting from a change in speed.

(d) All of these.

(45) For non-reheat type of steam turbine, the mathematical model is:

(a) $\dfrac{\Delta P_G(s)}{\Delta X_E(s)} = \dfrac{K_t}{1+s\tau_t}$

(b) $\dfrac{\Delta P_G(s)}{\Delta X_E(s)} = 1 - \dfrac{K_t}{1+s\tau_t}$

(c) $\dfrac{\Delta P_G(s)}{\Delta X_E(s)} = \left(\dfrac{k_E}{1+s\tau_t}\right)\left(\dfrac{1+s\tau_r k_r}{1+s\tau_t}\right)$

(d) None of these.

(46) In reheat type of steam turbine,

(a) Steam at high pressure with low temperature is transformed into steam at low pressure with higher temperature.

(b) Steam at low pressure with higher temperature is transformed into steam at high pressure with low temperature.

(c) Steam at low pressure with low temperature is transformed into steam at high pressure with higher temperature.

(d) None of these.

(47) Transfer function of reheat type of steam turbine is of __________ order.

(a) First.

(b) Second.

(c) Third.

(d) None of these.

(48) Transfer function of non-reheat type of steam turbine is of __________ order.

(a) First.

(b) Second.

(c) Third.

(d) None of these.

(49) The surplus power ($\Delta P_G - \Delta P_D$) can be absorbed by a system:

(a) By increasing the stored $K \in$ of the system at the rate $\dfrac{d}{dt}(W_{KE})$.

(b) By motor loads.

(c) There is no absorption of surplus power by the system.

(d) Both (a) and (b).

(50) The block diagram of the LFC of an isolated power system is of __________ model.

(a) First.

(b) Second.

(c) Third.

(d) Fourth.

REVIEW QUESTIONS

(1) Develop the block diagram of the LFC of a single-area system.

(2) Compare the steady state and dynamic operations of an isolated system.

(3) Draw the schematic diagram of a speed-governing system and explain its components on the dynamic response of an uncontrolled system with necessary equations. Hence, obtain the transfer function of a speed-governing system.

(4) How do the governor characteristics of the prime mover affect the control of system frequency and system load?

(5) Explain why it is necessary to maintain the frequency of the system constant.

(6) What do you mean by LFC?

(7) Draw a neat sketch of a typical turbine speed-governing system and derive its block diagram representation.

(8) For a single-area system, show that the static error in frequency can be reduced to zero using frequency control and comment on the dynamic response of an uncontrolled system with necessary equations.

(9) Explain the *p*–*f* and *Q*–*V* control loops of power system.

(10) What is meant by control area and ACE?

(11) Explain clearly about proportional plus integral LFC with a block diagram.

(12) Discuss the adverse effects of change in the voltage and the frequency of a power system. Mention the acceptable ranges of these changes.

PROBLEMS

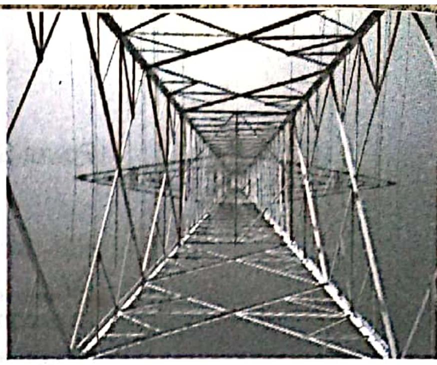
(1) A 250-MVA synchronous generator is operating at 1,500 rpm, 50 Hz. A load of 50 MW is suddenly applied to the machine and the station valve to the turbine opens only after 0.35 s due to the time lag in the generator action. Calculate the frequency at which the generated voltage drops before the steam flow commences to increase to meet the new load. Given that the valve of *H* of the generator is 3.5 kW-s per kVA of the generator energy.

(2) Two generating stations A and B have full-load capacities of 250 and 100 MW, respectively. The interconnector connecting the two stations has an induction motor/synchronous generator (Plant C) of full-load capacity 30 MW; percentage changes of speeds of A, B, and C are 4, 3, and 2, respectively. The loads on bus bars A and B are MW and 50 MW, respectively. Determine the load taken by Plant C and indicate the direction of the power flow.

(3) A 750-MW generator has a speed regulation of 3.5%. If the frequency drops by 0.1 Hz with an unchanged reference, determine the increase in turbine power. And also find by how much the reference power setting should be changed if the turbine power remains unchanged.

CHAPTER 7

(1) a
(2) c
(3) c
(4) a
(5) d
(6) b
(7) c
(8) c
(9) b
(10) c
(11) c
(12) c
(13) c
(14) b
(15) b
(16) b
(17) b
(18) c
(19) b
(20) c
(21) a
(22) b
(23) a
(24) c
(25) b
(26) d
(27) d
(28) d
(29) a
(30) a
(31) c
(32) d
(33) c
(34) b
(35) a
(36) a
(37) b
(38) d
(39) c
(40) b
(41) c
(42) c
(43) c
(44) d
(45) a
(46) a
(47) b
(48) a
(49) d
(50) c



8 Load Frequency Control-II

OBJECTIVES

After reading this chapter, you should be able to:

- develop the block diagram models for a two-area power system
- observe the steady state and dynamic analysis of a two-area power system with and without integral control
- develop the dynamic-state variable model for single-area, two-area, and three-area power system networks

8.1 INTRODUCTION

An extended power system can be divided into a number of load frequency control (LFC) areas, which are interconnected by tie lines. Such an operation is called a *pool operation*. A power pool is an interconnection of the power systems of individual utilities. Each power system operates independently within its own jurisdiction, but there are contractual agreements regarding internal system exchanges of power through the tie lines and other agreements dealing with operating procedures to maintain system frequency. There are also agreements relating to operational procedures to be followed in the event of major faults or emergencies. The basic principle of a pool operation in the normal steady state provides:

(i) Maintaining of scheduled interchanges of tie-line power: The interconnected areas share their reserve power to handle anticipated load peaks and unanticipated generator outages.

(ii) Absorption of own load change by each area: The interconnected areas can tolerate larger load changes with smaller frequency deviations than the isolated power system areas.

For analyzing the dynamics of the LFC of an *n*-area power system, primarily consider two-area systems.

Two control areas 1 and 2 are connected by a single tie line as shown in Fig. 8.1.

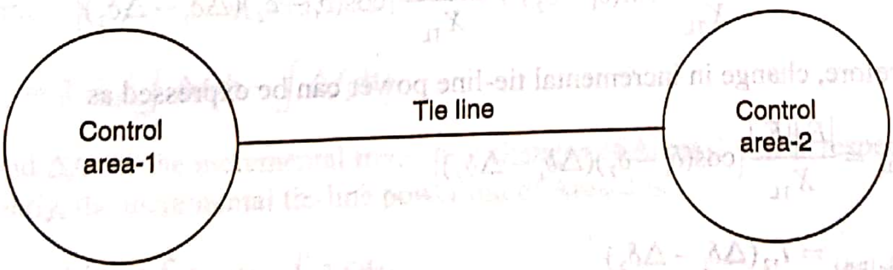


FIG. 8.1 *Two control areas interconnected through a single tie line*

Here, the control objective is to regulate the frequency of each area and to simultaneously regulate the power flow through the tie line according to an interarea power agreement.

In the case of an isolated control area, the zero steady-state error in frequency (i.e., $\Delta f_{\text{steady state}} = 0$) can be obtained by using a proportional plus integral controller, whereas in two-control area case, proportional plus integral controller will be installed to give zero steady-state error in a tie-line power flow (i.e., $\Delta P_{TL} = 0$) in addition to zero steady-state error in frequency.

For the sake of convenience, each control area can be represented by an equivalent turbine, generator, and governor system.

In the case of a single control area, the incremental power ($\Delta P_G - \Delta P_D$) was considered by the rate of increase of stored KE and increase in area load caused by the increase in frequency.

In a two-area case, the tie-line power must be accounted for the incremental power balance equation of each area, since there is power flow in or out of the area through the tie line.

Power flow out of Control area-1 can be expressed as

$$P_{TL_1} = \frac{|E_1||E_2|}{X_{TL}} \sin(\delta_1 - \delta_2) \tag{8.1}$$

where $|E_1|$ and $|E_2|$ are voltage magnitudes of Area-1 and Area-2, respectively, δ_1 and δ_2 are the power angles of equivalent machines of their respective areas, and X_{TL} is the tie-line reactance.

If there is change in load demands of two areas, there will be incremental changes in power angles ($\Delta\delta_1$ and $\Delta\delta_2$). Then, the change in the tie-line power is

$$P_{TL_1} + \Delta P_{TL_1} = \frac{|E_1||E_2|}{X_{TL}} \sin[(\delta_1 - \delta_2) + (\Delta\delta_1 - \Delta\delta_2)]$$

$$= \frac{|E_1||E_2|}{X_{TL}} [\sin(\delta_1 - \delta_2)\cos(\Delta\delta_1 - \Delta\delta_2) + \cos(\delta_1 - \delta_2)\sin(\Delta\delta_1 - \Delta\delta_2)]$$

$$= \frac{|E_1||E_2|}{X_{TL}} [\sin(\delta_1 - \delta_2) + \cos(\delta_1 - \delta_2)(\Delta\delta_1 - \Delta\delta_2)]$$

$$[\text{since } (\Delta\delta_1 - \Delta\delta_2) \approx 0]$$

$$= \frac{|E_1||E_2|}{X_{TL}} \sin(\delta_1 - \delta_2) + \frac{|E_1||E_2|}{X_{TL}} [\cos(\delta_1 - \delta_2)(\Delta\delta_1 - \Delta\delta_2)]$$

Therefore, change in incremental tie-line power can be expressed as

$$\Delta P_{TL_1} = \frac{|E_1||E_2|}{X_{TL}} [\cos(\delta_1 - \delta_2)(\Delta\delta_1 - \Delta\delta_2)]$$

$$\Delta P_{TL_1(\text{p.u.})} = T_{12}(\Delta\delta_1 - \Delta\delta_2) \tag{8.2}$$

where $$T_{12} = \frac{|E_1||E_2|}{X_{TL} P_1} \cos(\delta_1 - \delta_2) \tag{8.3}$$

T_{12} is known as the synchronizing coefficient or the stiffness coefficient of the tie-line. Equation (8.3) can be written as

$$T_{12} = \frac{P_{\max_{12}}}{P_1}\cos(\delta_1 - \delta_2)$$

where $P_{\max_{12}} = \dfrac{|E_1||E_2|}{X_{TL}}$ = Static transmission capacity of the tie line.

Consider the change in frequency as

$$\Delta\omega = \frac{d}{dt}(\Delta\delta)$$

$$2\pi\Delta f = \frac{d}{dt}(\Delta\delta)$$

$$\Delta f = \frac{1}{2\pi} \times \frac{d}{dt}(\Delta\delta) \text{ Hz}$$

In other words,

$$\frac{d}{dt}(\Delta\delta) = 2\pi\Delta f$$

$$\int \frac{d}{dt}(\Delta\delta) = \int 2\pi\Delta f$$

$$\Delta\delta = 2\pi\int \Delta f \, dt \text{ radians}$$

Hence, the changes in power angles for Areas-1 and 2 are

$$\Delta\delta_1 = 2\pi\int \Delta f_1 dt$$

and $$\Delta\delta_2 = 2\pi\int \Delta f_2 dt$$

Since the incremental power angles are related in terms of integrals of incremental frequencies, Equation (8.2) can be modified as

$$\Delta P_{TL_1} = 2\pi T_{12}\left(\int \Delta f_1 dt - \int \Delta f_2 dt\right) \quad \textbf{(8.4)}$$

Δf_1 and Δf_2 are the incremental frequency changes of Areas-1 and 2, respectively. Similarly, the incremental tie-line power out of Area-2 is

$$\Delta P_{TL_2} = 2\pi T_{21}\left(\int \Delta f_2 dt - \int \Delta f_1 dt\right) \quad \textbf{(8.5)}$$

where $$T_{21} = \frac{|E_1||E_2|}{X_{TL}P_2}\cos(\delta_2 - \delta_1) \quad \textbf{(8.6)}$$

Dividing Equation (8.6) by Equation (8.3), we get

$$\frac{T_{21}}{T_{12}} = \frac{P_1}{P_2} = a_{12}$$

Therefore, $T_{21} = a_{12}T_{12}$

and hence $\Delta P_{\mathrm{TL}_2} = a_{12}\Delta P_{\mathrm{TL}_1}$ **(8.7)**

From Equation (7.25) **(LFC-1)**, surplus power in p.u. is

$$\Delta P_{\mathrm{G}} - \Delta P_{\mathrm{D}} = \frac{2H}{f^0}\frac{\mathrm{d}}{\mathrm{d}t}(\Delta f) + B\Delta f \quad \text{(for a single-area case)}$$

For a two-area case, the surplus power can be expressed in p.u. as

$$\Delta P_{\mathrm{G}_1} - \Delta P_{\mathrm{D}_1} = \frac{2H_1}{f^0}\frac{\mathrm{d}}{\mathrm{d}t}(\Delta f_1) + B_1\Delta f_1 + \Delta P_{\mathrm{TL}_1} \tag{8.8}$$

Taking Laplace transform on both sides of Equation (8.8), we get

$$\Delta P_{\mathrm{G}_1}(s) - \Delta P_{\mathrm{D}_1}(s) = \frac{2H_1}{f^0}s(\Delta F_1(s)) + B_1\Delta F_1(s) + \Delta P_{\mathrm{TL}_1}(s)$$

Rearranging the above equation as follows, we get

$$\Delta P_{\mathrm{G}_1}(s) - \Delta P_{\mathrm{D}_1}(s) = \Delta F_1(s)\left(\frac{2H_1}{f^0}s + B_1\right) + \Delta P_{\mathrm{TL}_1}(s)$$

$$\Delta F_1(s) = \left[\Delta P_{\mathrm{G}_1}(s) - \Delta P_{\mathrm{D}_1}(s) - \Delta P_{\mathrm{TL}_1}(s)\right]\left[\frac{1/B_1}{1+\left(2H_1/B_1 f^0\right)s}\right]$$

$$\Delta F_1(s) = \left[\Delta P_{\mathrm{G}_1}(s) - \Delta P_{\mathrm{D}_1}(s) - \Delta P_{\mathrm{TL}_1}(s)\right]\frac{K_{\mathrm{ps}_1}}{1+s\tau_{\mathrm{ps}_1}} \tag{8.9}$$

where $K_{\mathrm{ps}_1} = 1/B_1$

$$\tau_{\mathrm{ps}_1} = \frac{2H_1}{B_1 f^0}$$

By comparing Equation (8.9) with single-area Equation (7.26), the only additional term is the appearance of signal $\Delta P_{\mathrm{TL}_1}(s)$

Equation (8.9), can be represented in a block diagram model as shown in Fig. 8.2. Taking Laplace transformation on both sides of Equation (8.4), we get

$$\Delta P_{\mathrm{TL}_1}(s) = 2\pi T_{12}\left(\frac{\Delta F_1(s)}{s} - \frac{\Delta F_2(s)}{s}\right)$$

$$= \frac{2\pi T_{12}}{s}(\Delta F_1(s) - \Delta F_2(s)) \tag{8.10}$$

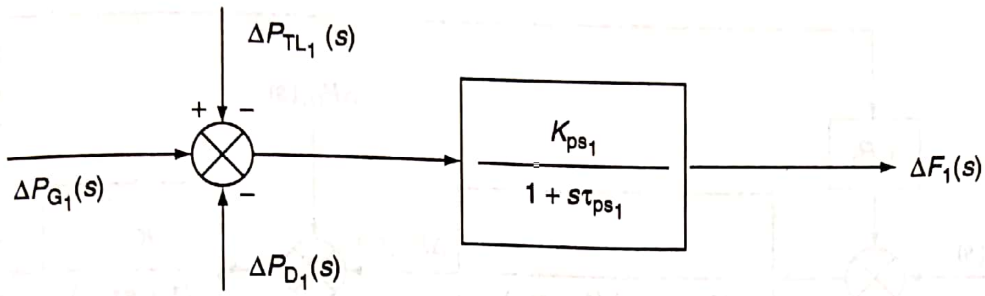


FIG. 8.2 *Block diagram representation of Equation (8.9) (for Control area-1)*

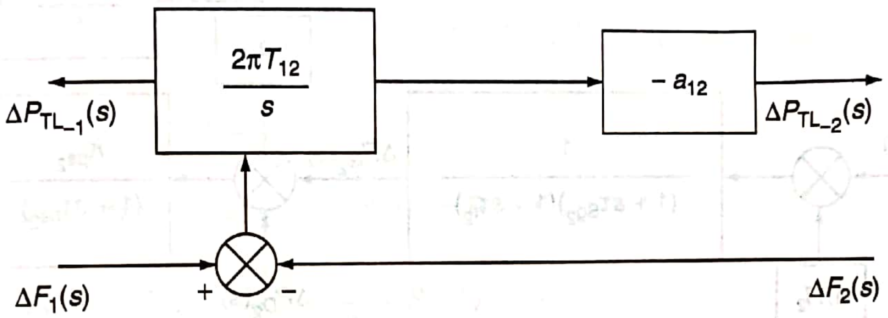


FIG. 8.3 *Block diagram representation of Equations (8.10) and (8.11)*

For Control area-2, we have

$$\Delta P_{TL_2}(s) = 2\pi T_{21}\left(\frac{\Delta F_2(s)}{s} - \frac{\Delta F_1(s)}{s}\right)$$

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

$$= -\frac{2\pi a_{12} T_{12}}{s}(\Delta F_1(s) - \Delta F_2(s)) \tag{8.11}$$

The block diagram representation of Equations (8.10) and (8.11) is shown in Fig. 8.3.

8.2 COMPOSITE BLOCK DIAGRAM OF A TWO-AREA CASE

By the combination of basic block diagrams of Control area-1 and Control area-2 and with the use of Figs. 8.2 and 8.3, the composite block diagram of a two-area system can be modeled as shown in Fig. 8.4.

8.3 RESPONSE OF A TWO-AREA SYSTEM—UNCONTROLLED CASE

For an uncontrolled case, $\Delta P_{c_1} = \Delta P_{c_2} = 0$, i.e., the speed-changer positions are fixed.

8.3.1 Static response

In this section, the changes or deviations, which result in the frequency and tie-line power under steady-state conditions following sudden step changes in the loads in the two areas, are determined.

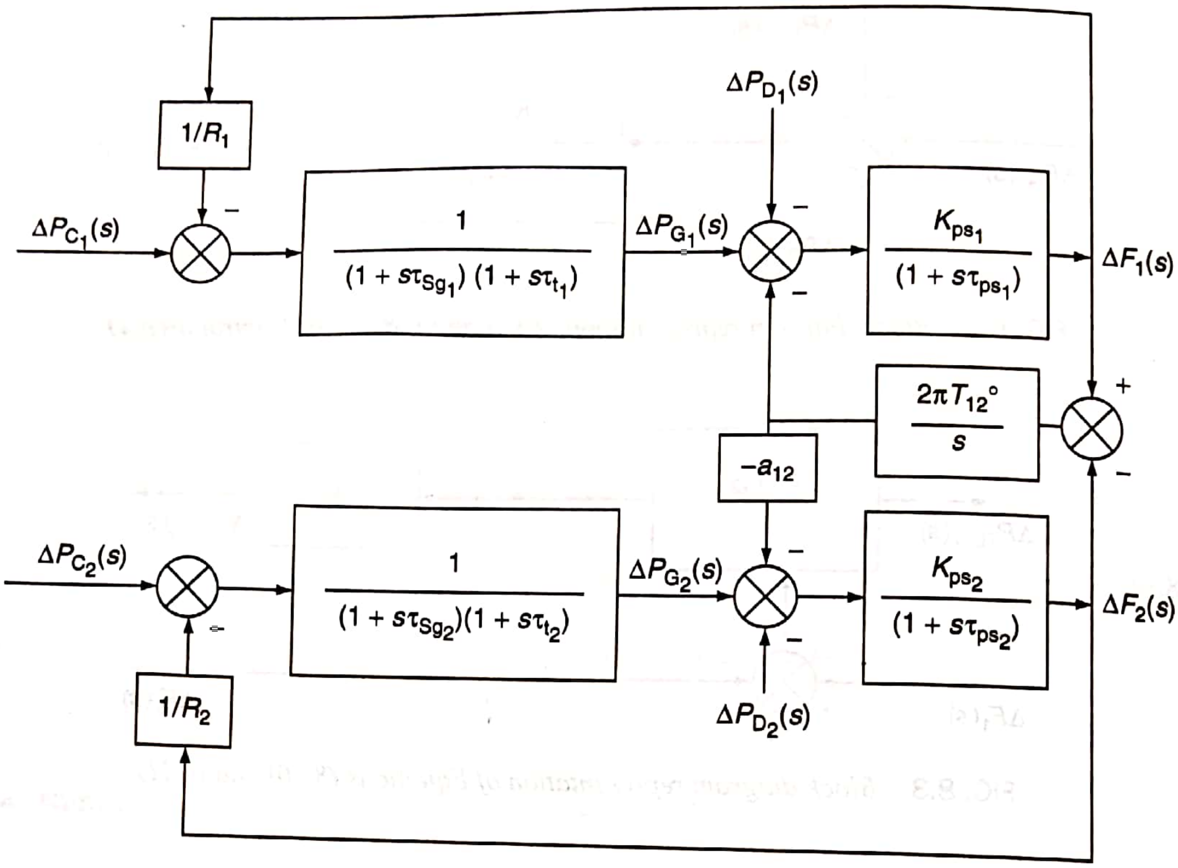


FIG. 8.4 *Block diagram representation of a two-area system with an LFC*

Let ΔP_{D_1}, ΔP_{D_2} be sudden (incremental) step changes in the loads of Control area-1 and Control area-2, simultaneously.

ΔP_{G_1}, ΔP_{G_2} are the incremental changes in the generation in Area-1 and Area-2 as a result of the load changes.

Δf is the static change in frequency. This will be the same for both the areas and ΔP_{TL_1} is the static change in the tie-line power transmitted from Area-1 to Area-2. Since only the static changes are being determined, the incremental changes in generation can be determined by the static loop gains. So, we have

$$\Delta P_{G_1} = -\frac{\Delta f}{R_1} \tag{8.12}$$

and $$\Delta P_{G_2} = -\frac{\Delta f}{R_2} \text{ for static changes} \tag{8.13}$$

For the two areas, the dynamics are described by:

$$(\Delta P_{G_1} - \Delta P_{D_1}) = \frac{2H_1}{f^0}\frac{d}{dt}(\Delta f_1) + B_1\,\Delta f_1 + \Delta P_{TL_1} \tag{8.14}$$

and $$(\Delta P_{G_2} - \Delta P_{D_2}) = \frac{2H_2}{f^0}\frac{d}{dt}(\Delta f_2) + B_2\,\Delta f_2 + \Delta P_{TL_2} \tag{8.15}$$

Under steady-state conditions, we have

$$\frac{d}{dt}(\Delta f) = 0 \tag{8.16}$$

After substituting Equations (8.12), (8.13), and (8.16) in Equations (8.14) and (8.15), we get

$$\frac{-\Delta f}{R_1} - \Delta P_{D_1} = B_1\,\Delta f + \Delta P_{TL_1} \tag{8.17}$$

and
$$\frac{-\Delta f}{R_2} - \Delta P_{D_2} = B_2 \Delta f - a_{12}\,\Delta P_{TL_1} \tag{8.18}$$

Since $\Delta P_{TL_2} = -a_{12}\Delta P_{TL_1}$ and $\Delta f_1 = \Delta f_2 = \Delta f$, from Equation (8.17), we have

$$\Delta P_{TL_1} = -\left(\frac{1}{R_1} + B_1\right)\Delta f - \Delta P_{D_1} \tag{8.18(a)}$$

Substituting ΔP_{TL_1} from Equation (8.18(a)) in Equation (8.18), we get

$$\frac{-\Delta f}{R_2} - \Delta P_{D_2} = B_2\,\Delta f - a_{12}\left[-\left(\frac{1}{R_1} + B_1\right)\Delta f - \Delta P_{D_1}\right]$$

$$\frac{-\Delta f}{R_2} - B_2\Delta f = \Delta P_{D_2} + a_{12}\left(\frac{1}{R_1} + B_1\right)\Delta f + a_{12}\Delta P_{D_1}$$

$$-\left(\frac{1}{R_2} + B_2\right)\Delta f - a_{12}\left(\frac{1}{R_1} + B_1\right)\Delta f = \Delta P_{D_2} + a_{12}\Delta P_{D_1}$$

$$-\left\{\left(\frac{1}{R_2} + B_2\right) + a_{12}\left(\frac{1}{R_1} + B_1\right)\right\}\Delta f = \Delta P_{D_2} + a_{12}\,\Delta P_{D_1}$$

$$\Delta f = \frac{\Delta P_{D_1} + a_{12}\Delta P_{D_2}}{\left(B_2 + \frac{1}{R_2}\right) + a_{12}\left(B_1 + \frac{1}{R_1}\right)} \tag{8.18(b)}$$

Substituting Δf from Equation (8.18(b)) in Equation (8.18 (a)), we get

$$\Delta P_{TL_1} = -\left(\frac{1}{R_1} + B_1\right)\left[\frac{\Delta P_{D_1} + a_{12}\Delta P_{D_2}}{\left(B_2 + \frac{1}{R_2}\right) + a_{12}\left(B_1 + \frac{1}{R_1}\right)}\right] - \Delta P_{D_1}$$

$$= \frac{\left(B_1 + \frac{1}{R_1}\right)\Delta P_{D_2} - \left(B_2 + \frac{1}{R_2}\right)\Delta P_{D_1}}{\left(B_2 + \frac{1}{R_2}\right) + a_{12}\left(B_1 + \frac{1}{R_1}\right)} \tag{8.18(c)}$$

Equations (8.18(b)) and (8.18(c)) are modified as

Tie-line frequency, $$\Delta f = \frac{\Delta P_{D_1} + a_{12}\Delta P_{D_2}}{\beta_2 + a_{12}\beta_1} \tag{8.19}$$

Tie-line power, $$\Delta P_{TL_1} = \frac{\beta_1 \Delta P_{D_2} - \beta_2 \Delta P_{D_1}}{\beta_2 + a_{12}\beta_1} \tag{8.20}$$

where $\beta_1 = \left(B_1 + \frac{1}{R_1}\right)$

$$\beta_{12} = \left(B_2 + \frac{1}{R_2}\right)$$

Equations (8.19) and (8.20) give the values of the static changes in frequency and tie-line power, respectively, as a result of sudden step-load changes in the two areas. It can be observed that the frequency and tie-line power deviations do not reduce to zero in an uncontrolled case.

Consider two identical areas,

$B_1 = B_2 = B$, $\beta_1 = \beta_2 = \beta$, $R_1 = R_2 = R$ and $a_{12} = +1$

Hence, from Equations (8.19) and (8.20), we have

$$\Delta f = \frac{(\Delta P_{D_2} + \Delta P_{D_1})}{2\beta} \text{ Hz} \tag{8.21}$$

and $$\Delta P_{TL_1(p.u.)} = \frac{\Delta P_{D_2} - \Delta P_{D_1}}{2} = -\Delta P_{TL_2} \text{ (p.u.) MW} \tag{8.22}$$

If a sudden load change occurs only in Area-2 (i.e., $\Delta P_{D_1} = 0$), then we have

$$\Delta f = \frac{\Delta P_{D_2}}{2\beta} \text{ Hz} \tag{8.23}$$

and $$\Delta P_{TL_1} = \frac{\Delta P_{D_2}}{2} \text{ p.u.} \tag{8.24}$$

Equations (8.23) and (8.24) illustrate the advantages of pool operation (i.e., grid operation) as follows:

- Equations (8.19) represents the change in frequency according to the change in load in either of a two-area system interconnected by a tie line. When considering that those two areas are identical, Equation (8.19) becomes Equation (8.21). Hence, it is concluded that if a load disturbance occurs in only one of the areas (i.e., $\Delta P_{D_1} = 0$ or $\Delta P_{D_2} = 0$), the change in frequency (Δf) is only half of the steady-state error, which would have occurred with no interconnection (i.e., an isolated case). Thus, with several systems interconnected, the steady-state frequency error would be reduced.
- Half of the added load (in Area-2) is supplied by Area-1 through the tie line.

The above two advantages represent the necessity of interconnecting the systems.

8.3.2 Dynamic response

To describe the dynamic response of the two-area system as shown in Fig. 8.4, a system of seventh-order differential equations is required. The solution of these equations would be tedious. However, some important characteristics can be brought out by an analysis rendered simple by the following assumptions. A power system of two identical control areas is considered for the analysis:

(i) $\tau_{gt} = \tau_t = 0$ for both the areas.

(ii) The damping constants of two areas are neglected,

i.e., $B_1 = B_2 = 0$

By virtue of the second assumption, Equations (8.14) and (8.15) become

$$(\Delta P_{G_1} - \Delta P_{D_1}) = \frac{2H_1}{f^0}\frac{d}{dt}(\Delta f_1) + \Delta P_{TL_1} \tag{8.25}$$

$$(\Delta P_{G_2} - \Delta P_{D_2}) = \frac{2H_2}{f^0}\frac{d}{dt}(\Delta f_2) + \Delta P_{TL_2} \tag{8.26}$$

Taking Laplace transformation on both sides of Equations (8.25) and (8.26) and by rearrangement, we get

$$\Delta F_1(s) = \frac{f^0}{2H_1 s}\left[\Delta P_{G_1}(s) - \Delta P_{D_1}(s) - \Delta P_{TL_1}(s)\right] \tag{8.27}$$

$$\Delta F_2(s) = \frac{f^0}{2H_2 s}\left[\Delta P_{G_2}(s) - \Delta P_{D_2}(s) - \Delta P_{TL_2}(s)\right] \tag{8.28}$$

From the block diagram of Fig. 8.4, the following equations can be obtained:

$$\Delta P_{G_1}(s) = -\frac{\Delta F_1(s)}{R}$$

$$\Delta P_{G_2}(s) = -\frac{\Delta F_2(s)}{R} \tag{8.29}$$

$$\Delta P_{TL_1}(s) = \frac{2\pi T_{12}^0}{s}\left[\Delta F_1(s) - \Delta F_2(s)\right]$$

$$\Delta P_{TL_2}(s) = -\Delta P_{TL_1}(s) \tag{8.30}$$

($a_{12} = -\dfrac{P_1}{P_2} = -1$, since two control areas are identical)

By solving Equations (8.27)–(8.30), we get

$$\Delta P_{TL_1}(s) = \frac{\Delta P_{D_2}(s) - \Delta P_{D_1}(s)}{\left(s^2 + \left(\dfrac{f^0}{2RH}\right)s + \dfrac{2\pi f^0 T_{12}}{H}\right)}\,\frac{\pi f^0 T_{12}}{H} \tag{8.31}$$

From the above equation, the following observations can be made:

(i) The denominator is of the form:

$$s^2+2\alpha\, s+\omega^2=(s+\alpha)^2+(\omega^2-\alpha^2) \tag{8.32}$$

where $\alpha=\dfrac{f^0}{4RH}$ and $\omega=\sqrt{\dfrac{2\pi f^0 T_{12}}{H}}$

and α and ω^2 are both real and positive. Hence, it can be concluded from the roots of characteristic equation that the time response is stable and damped.

The three conditions are:

If $\alpha=\omega_n$, system is critically damped

$\alpha>\omega_n$, system becomes overdamped

$\alpha<\omega_n$, then $s_{12}=-\alpha\pm j\sqrt{\omega_n^2-\alpha^2}$

$$=-\alpha\pm j\omega_n\sqrt{1-\left(\frac{\alpha}{\omega_n}\right)^2}$$

$$=-\alpha\pm j\omega_0$$

where $\alpha=$ damping factor or decrement of attenuation

$$\omega_0=\text{damped angular frequency}=\sqrt{\frac{2\pi f^0 T_{12}^0}{H}-\left(B+\frac{1}{R}\right)^2\frac{f^{02}}{16H^2}}$$

Since parameter α also depends on B, but $B\leq\dfrac{1}{R}$ in practice, therefore, the effect of coefficient B is neglected on damping.

(ii) After a disturbance, the change in tie-line power oscillates at the damped angular frequency.

(iii) The damping of the tie-line power variation is strongly dependent upon the parameter α, which is equal to $\dfrac{f^0}{4RH}$. Since f^0 and H are essentially constant, the damping is a function of the R parameters. If the R value is low, damping becomes strong and vice versa.

The transient change in the tie-line power will be of undamped oscillations of frequency, $\omega_0=\omega$.

If $R=\infty$, i.e., if the speed governor is not present ($\alpha=0$), the variation in frequency deviation and the tie-line power would be as shown in Fig. 8. 5.

It can be seen that the steady-state frequency deviation is the same for both the areas and does not vanish. The tie-line power deviation also does not become zero.

Although the above approximate analysis has confirmed stability, it has been found through more accurate analyses that with certain parameter combinations, the system becomes unstable.

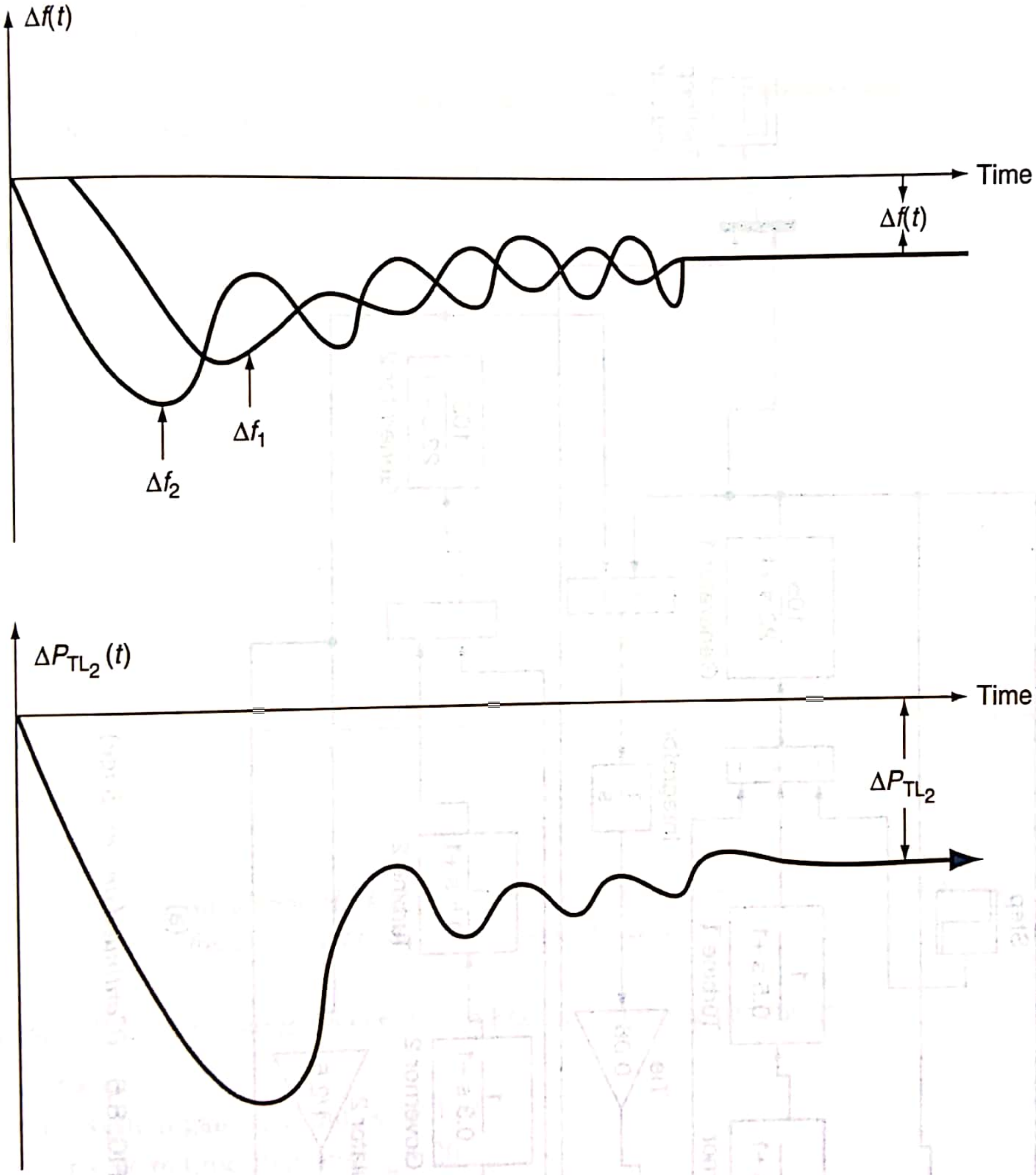


FIG. 8.5 *Frequency deviation and tie-line power change following a step-load change in Area-2 (two areas are identical)*

Example 8.3: Determine the frequency of oscillations of the tie-line power deviation for a two-identical-area system given the following data:

$R = 3.0$ Hz/p.u.; $H = 5$ s; $f^0 = 60$ Hz

The tie-line has a capacity of 0.1 p.u. and is operating at a power angle of 45°.

Solution:

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The synchronizing-power coefficient of the line is given by

$$T_{12}^0 = P_{\rm m} \cos \delta_{12} = 0.1 \times \cos 45° = 0.0707 \text{ p.u.}$$

Hence, the frequency of oscillations is given by

$$\omega_0 = \sqrt{\frac{2\pi f^0 T_{12}^0}{H} - \left(\frac{f^0}{4RH}\right)^2}$$

$$= \sqrt{\frac{2\pi \times 60 \times 0.0707}{5} - \left(\frac{60}{4 \times 3 \times 5}\right)^2} = 2.1 \text{ rad/s}$$

$$\therefore f_0 = \frac{2.1}{2\pi} = 0.33 \text{ Hz}$$

8.4 AREA CONTROL ERROR—TWO-AREA CASE

In a single-area case, ACE is the change in frequency. The steady-state error in frequency will become zero (i.e., $\Delta f_{ss} = 0$) when ACE is used in the integral-control loop.

In a two-area case, ACE is the linear combination of the change in frequency and change in tie-line power. In this case to make the steady-state tie-line power zero (i.e., $\Delta P_{\text{TL}} = 0$), another integral-control loop for each area must be introduced in addition to the integral frequency loop to integrate the incremental tie-line power signal and feed it back to the speed-changer.

Thus, for Control area-1, we have

$$\text{ACE}_1 = \Delta P_{\text{TL}_1} + b_1 \Delta f_1 \tag{8.33}$$

where b_1 = constant = area frequency bias. Taking Laplace transform on both sides of Equation (8.33), we get

$$\text{ACE}_1(s) = \Delta P_{\text{TL}_1}(s) + b_1 \Delta F_1(s) \tag{8.34}$$

Similarly, for Control area-2, we have

$$\text{ACE}_2(s) = \Delta P_{\text{TL}_2}(s) + b_2 \Delta F_2(s) \tag{8.35}$$

8.5 COMPOSITE BLOCK DIAGRAM OF A TWO-AREA SYSTEM (CONTROLLED CASE)

By the combination of basic block diagrams of Control area-1 and Control area-2 and with the use of Figs. 8.2 and 8.3, the composite block diagram of a two-area system can be modeled as shown in Fig. 8.4. Figure 8.8 can be obtained by the addition of integrals of ACE_1 and ACE_2 to the block diagram shown in Fig. 8.4. It represents the composite block diagram of a two-area system with integral-control loops. Here, the control signals $\Delta P_{c_1}(s)$ and $\Delta P_{c_2}(s)$ are generated by the integrals of ACE_1 and ACE_2. These control errors are obtained through the signals representing the changes in the tie-line power and local frequency bias.

8.5.1 Tie-line bias control

The speed-changer command signals will be obtained from the block diagram shown in Fig. 8.6 as

$$\Delta P_{c_1} = -K_{I_1} \int (\Delta P_{\text{TL}_1} + b_1 \Delta f_1)\, dt \tag{8.36}$$

and

$$\Delta P_{c_2} = -K_{I_2} \int (\Delta P_{\text{TL}_2} + b_2 \Delta f_2)\, dt \tag{8.37}$$

The constants K_{I_1} and K_{I_2} are the gains of the integrators. The first terms on the right-hand side of Equations (8.36) and (8.37) constitute and are known as tie-line bias controls. It is observed that for decreases in both frequency and tie-line power, the speed-changer position decreases and hence the power generation should decrease, i.e., if the ACE is negative, then the area should increase its generation.

So, the right-hand side terms of Equations (8.36) and (8.37) are assigned a negative sign.

8.5.2 Steady-state response

That the control strategy, described in the previous section, eliminates the steady-state frequency and tie-line power deviations that follow a step-load change, can be proved as follows:

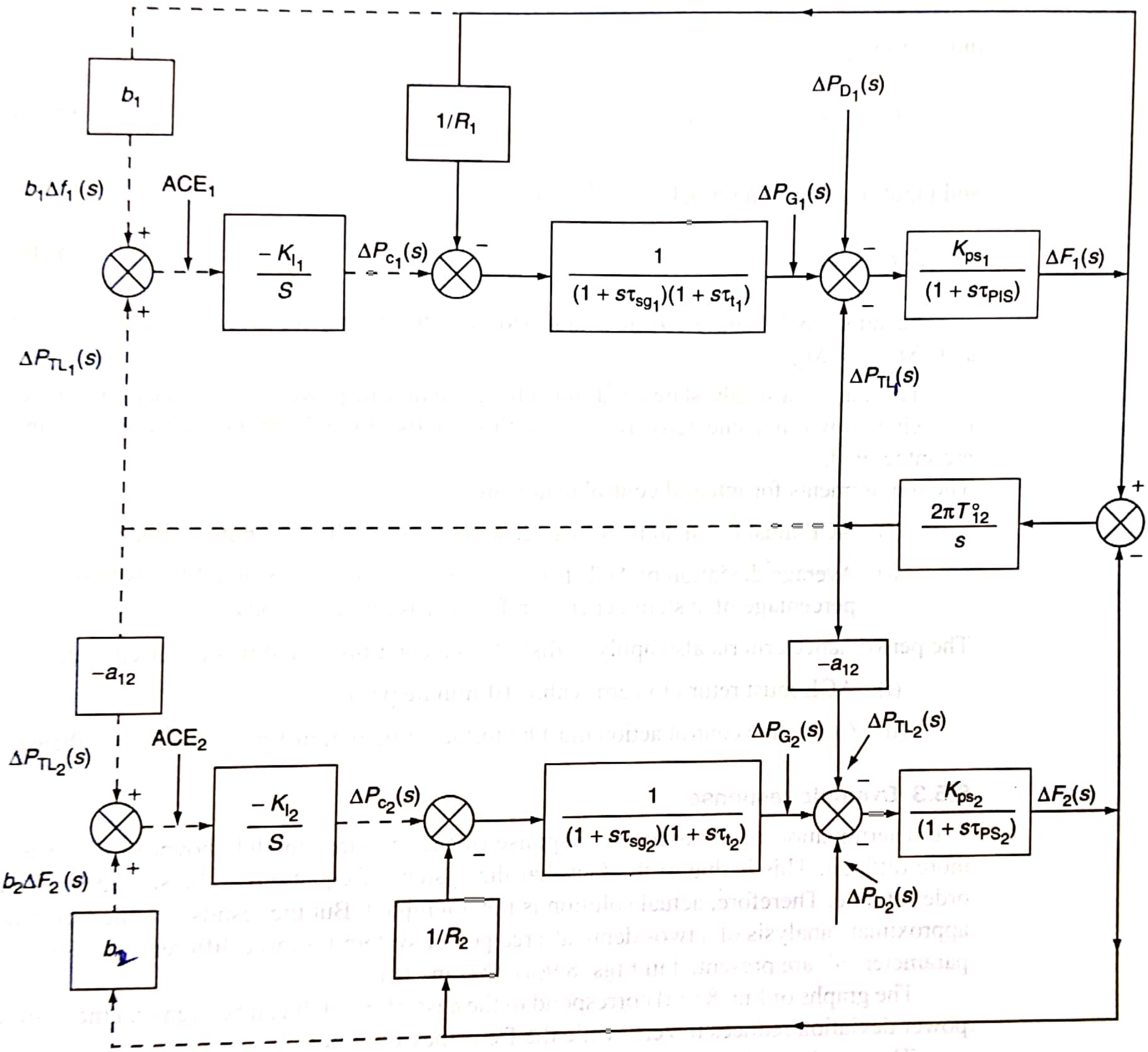

FIG. 8.8 *Two-area system with integral control*

Let the step changes in loads ΔP_{D_1} and ΔP_{D_2} simultaneously occur in Control area-1 and Control area-2, respectively, or in either area. A new static equilibrium state, i.e., steady-state condition is reached such that the output signal of all integrating blocks will become constant. In this case, the speed-changer command signals ΔP_{c_1} and ΔP_{c_2} have reached constant values. This obviously requires that both the integrands (input signals) in Equations (8.36) and (8.37) be zero.

Input of integrating block $\left(\dfrac{-K_{I_1}}{s}\right)$ is

$$\Delta P_{TL_1(ss)} + b_1\Delta f_{1(ss)} = 0 \tag{8.38}$$

Input of integrating block $\left(\frac{-K_{I_2}}{s}\right)$ is

$$\Delta P_{TL_2(ss)} + b_2 \Delta f_{2(ss)} = 0 \tag{8.39}$$

and input of integrating block $\left(\frac{-2\pi T_{12}}{s}\right)$ is

$$\Delta f_1 - \Delta f_2 = 0 \tag{8.40}$$

Equations (8.38) and (8.39) are simultaneously satisfied only for $\Delta P_{TL_1(ss)} = \Delta P_{TL_2(ss)} = 0$ and $\Delta f_{1(ss)} = \Delta f_{2(ss)} = 0$.

Thus, under a steady-state condition, change in tie-line power and change in frequency of each area will become zero. To achieve this, ACEs in the feedback loops of each area are integrated.

The requirements for integral control action are:

(i) ACE must be equal to zero at least one time in all 10-minute periods.

(ii) Average deviation of ACE from zero must be within specified limits based on a percentage of system generation for all 10-minute periods.

The performance criteria also apply to disturbance conditions, and it is required that:

(i) ACE must return to zero within 10-minute periods.

(ii) Corrective control action must be forthcoming within 1 minute of a disturbance.

8.5.3 Dynamic response

The determination of the dynamic response of the two-area model shown in Fig. 8.6 is more difficult. This is due to the fact that the system of equations to be solved is of the order of nine. Therefore, actual solution is not attempted. But the results obtained from an approximate analysis of a two-identical-area power system for three different values of the parameter 'b', are presented in Figs. 8.9(a), (b), and (c).

The graphs of Fig. 8.9(a) correspond to the case of $b=0$. It can be seen that the tie-line power deviation reduces to zero while the frequency does not.

The graphs of Fig. 8.9(b) correspond to the other extreme case of $b=\infty$. Now, the frequency error vanishes. But, the tie-line power does not vanish.

The graphs of Fig. 8.9(c) show an intermediate case wherein both the frequency and the tie-line power errors decrease to zero. This is the desired case.

Therefore, it can be concluded that the stability is not always guaranteed. Hence, there is a need for proper parameter selection and adjustment of their values.

8.6 OPTIMUM PARAMETER ADJUSTMENT

The graphs given in Fig. 8.9(c) stress the need for proper parameter settings. The choice of b and K_I constants affects the transient response to load changes. The frequency bias b should be high enough such that each area adequately contributes to frequency control. It is proved that choosing $b=\beta$ gives satisfactory performance of the interconnected system.

The integrator gain K_I should not be too high, otherwise, instability may result. Also the time interval at which LFC signals are dispatched, two or more seconds, should be low enough so that LFC does not attempt to follow random or spurious load changes.

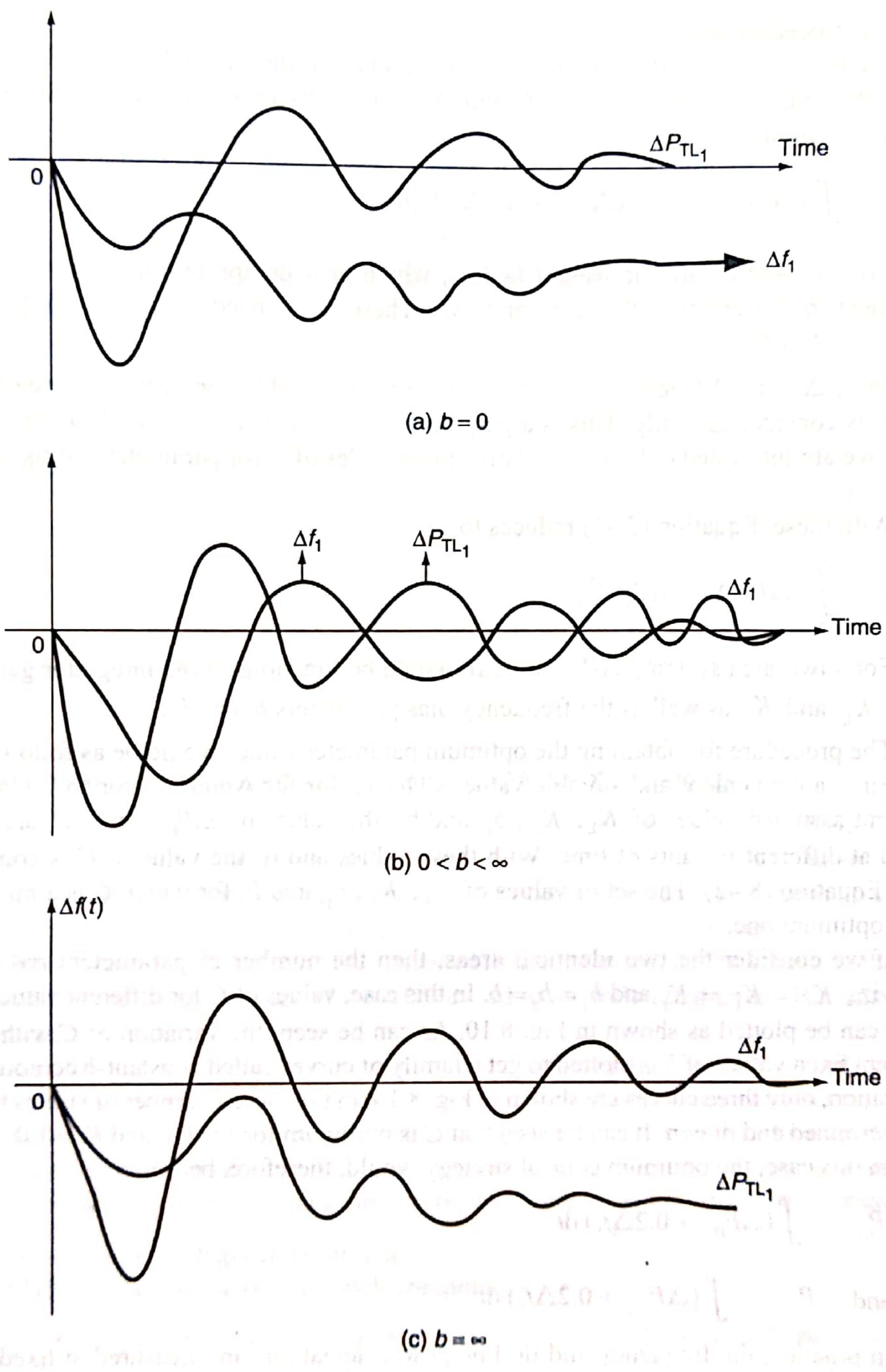

FIG. 8.9 ***Approximate dynamic response of two-identical-area power systems with three different values of b parameters***

First, a set of parameters, which ensure stability of the control, is selected. For example, b_1 and b_2 cannot both be zero, i.e., one of them should be chosen for the control strategy. Later, the values of these parameters are adjusted so that a best or an optimum response is obtained. In other words, the values of parameters, which give rise to an optimum response, are to be determined.

The procedure is as follows:

The popular error criterion, known as the integral of the squared errors (ISE), is chosen for the control parameters Δf_1, Δf_2, and ΔP_{TL_1}. For a two-area system, the ISE criterion function C would be

$$C = \int_0^\infty \left[\alpha_1(\Delta P_{TL_1})^2 + \alpha_2(\Delta f_1)^2 + \alpha_3(\Delta f_2)^2\right] dt \tag{8.41}$$

where α_1, α_2, and α_3 are the weight factors, which provide appropriate importance, i.e., weightage to the errors ΔP_{TL_1}, Δf_1, and Δf_2. There is no need to choose ΔP_{TL_2}, since $\Delta P_{TL_2} = -a_{12}\Delta P_{TL_1}$.

Since Δf_1 and Δf_2 behave in a similar manner, we need to consider only one of them. So, let us consider Δf_1 only. This is a parameter selection. Then, $\alpha_3 = 0$. Also, let $\alpha_2 = \alpha$. Since, we are interested only in the relative magnitudes of C for parameter setting, we can set $\alpha_1 = 1$.

With these, Equation (7.41) reduces to

$$C = \int_0^\infty \left[(\Delta P_{TL_1})^2 + \alpha(\Delta f_1)^2\right] dt \tag{8.42}$$

For a two-area system, ΔP_{TL_1} and Δf_1 would be functions of the integrator gain constants K_{I_1} and K_{I_2} as well as the frequency bias parameters b_1 and b_2.

The procedure for obtaining the optimum parameter values would be as follows:

First, a convenient and suitable value is chosen for the weight factor 'α'. Then, for different assumed values of K_{I_1}, K_{I_2}, b_1, and b_2, the values of ΔP_{TL_1} and Δf_1 are determined at different instants of time. With these values and α, the value of C is computed using Equation (8.42). The set of values of K_{I_1}, K_{I_2}, b_1, and b_2 for which C is a minimum is the optimum one.

If we consider the two identical areas, then the number of parameters reduces to two, viz., $K_{I_1} = K_{I_2} = K_I$ and $b_1 = b_2 = b$. In this case, values of C for different values of K_I and b can be plotted as shown in Fig. 8.10. As can be seen, the variation of C with K_I for different fixed values of b is plotted to get a family of curves called constant-b contours. For illustration, only three curves are shown in Fig. 8.10. In practice, a number of curves have to be determined and drawn. It can be seen that C is minimum for $b = 0.2$ and $K_I = 1.0$.

In this case, the optimum control strategy would, therefore, be

$$P_{C_1} = -\int (\Delta P_{TL_1} + 0.2\Delta f_1)\, dt$$

and $$P_{C_2} = -\int (\Delta P_{TL_2} + 0.2\Delta f_1)\, dt \tag{8.43}$$

In practice, the frequency and tie-line power deviations are measured at fixed intervals of time in a sample-data fashion. The sampling rate (the rate at which the frequency deviation and tie-line power deviation samples are measured) should be sufficiently high to avoid errors due to sampling.

Note: LFC provides enough control during normal changes in load and frequency, i.e., changes that are not too large. During emergencies, when large imbalances between generation and load occur, LFC is bypassed and other emergency controls are applied, which is beyond the scope of this book.

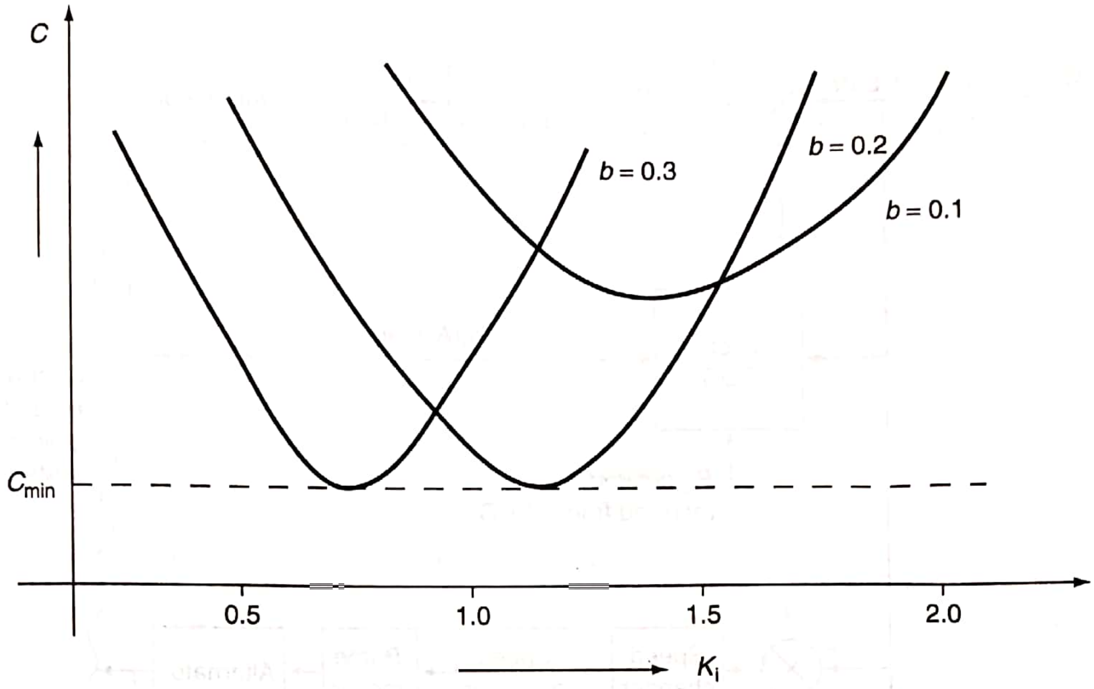

FIG. 8.10 *Constant b-contours of the ISE criterion function C*

8.7 LOAD FREQUENCY AND ECONOMIC DISPATCH CONTROLS

Economic load dispatch and LFC play a vital role in modern power system. In LFC, zero steady-state frequency error and a fast, dynamic response were achieved by integral controller action. But this control is independent of economic dispatch, i.e., there is no control over the economic loadings of various generating units of the control area.

Some control over loading of individual units can be exercised by adjusting the gain factors (K_I) of the integral signal of the ACE as fed to the individual units. But this is not a satisfactory solution.

A suitable and satisfactory solution is obtained by using independent controls of load frequency and economic dispatch. The load frequency controller provides a fast-acting control and regulates the system around an operating point, whereas the economic dispatch controller provides a slow-acting control, which adjusts the speed-changer settings every minute in accordance with a command signal generated by the central economic dispatch computer.

EDC—economic dispatch controller
CEDC—central economic dispatch computer

The speed-changer setting is changed in accordance with the economic dispatch error signal, (i.e., $P_{G\,(desired)} - P_{G\,(actual)}$) conveniently modified by the signal $\int$ACE dt at that instant of time. The central economic dispatch computer (CEDC) provides the signal $P_{G\,(desired)}$, and this signal is transmitted to the local economic dispatch controller (EDC). The system they operate with economic dispatch error is only for very short periods of time before it is readily used (Fig. 8.11).

This tertiary control can be implemented by using EDC and EDC works on the cost characteristics of various generating units in the area. The speed-changer settings are once again operated in accordance with an economic dispatch computer program.

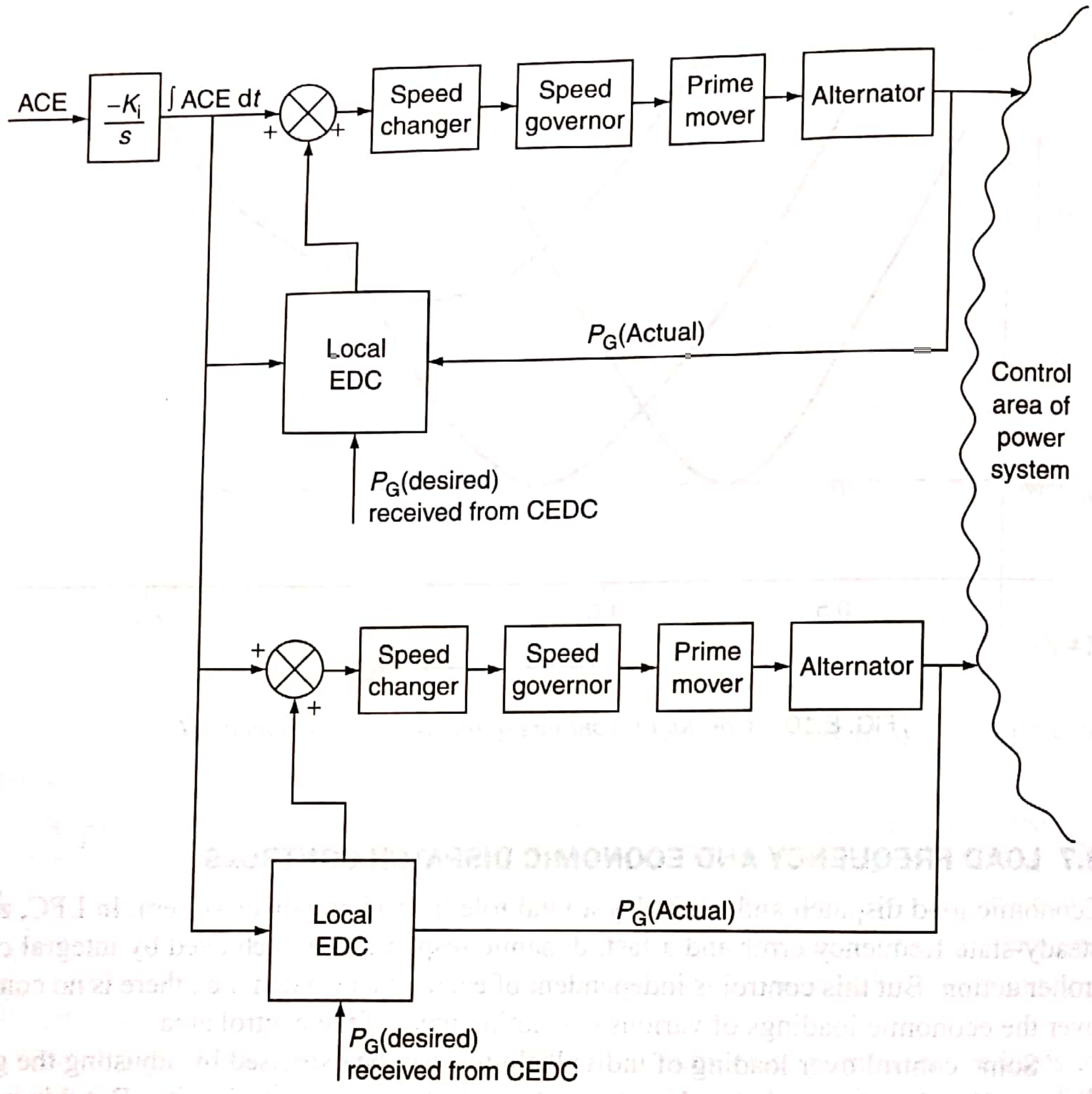

FIG. 8.11 *Load frequency and economic dispatch control of the control area of a power system*

The CEDCs are provided at a central control center. The variable part of the load is carried by units that are controlled from the central control center. Medium-sized fossil fuel units and hydro-units are used for control. During peak load hours, lesser efficient units, such as gas-turbine units or diesel units, are employed in addition; generators operating at partial output (with spinning reserve) and standby generators provide a reserve margin.

The central control center monitors information including area frequency, outputs of generating units, and tie-line power flows to interconnected areas. This information is used by ALFC in order to maintain area frequency at its scheduled value and net tie-line power flow out of the area at its shedding value. Raise and lower reference power signals are dispatched to the turbine governors of controlled units.

Economic dispatch is co-ordinated with LFC such that the reference power signals dispatched to controlled units move the units toward their economic loading and satisfy LFC objectives.

Example 8.4: Two interconnected Area-1 and Area-2 have the capacity of 2,000 and 500 MW, respectively. The incremental regulation and damping torque coefficient for each area on its own base are 0.2 p.u. and 0.8 p.u., respectively. Find the steady-state change in system frequency from a nominal frequency of 50 Hz and the change in steady-state tie-line power following a 750 MW change in the load of Area-1.

Solution:

Rated capacity of Area-1 $= P_{1(\text{rated})} = 2{,}000$ MW

Rated capacity of Area-2 $= P_{2(\text{rated})} = 500$ MW

Speed regulation, $R = 0.2$ p.u.

Nominal frequency, $f = 50$ Hz

Change in load power of Area-1, $\Delta P_1 = 75$ MW

Speed regulation, $R = 0.2 = 0.2$ p.u. $\times\, 50 = 10$ Hz/p.u. MW

Damping torque coefficient, $B = 0.8$ p.u. MW/p.u. Hz

$$= \frac{0.8}{50} = 0.016 \text{ p.u. MW/Hz}$$

Change in load of Area-1, $\Delta P_{D_1} = 75$ MW

$$\text{p.u. change in load of Area-1} = \frac{\Delta P_{D_1}}{P_{1(\text{rated})}} = \frac{75}{2{,}000} = 0.0375 \text{ p.u. MW}$$

$$\text{p.u. change in load of Area-2} = \frac{\Delta P_{D_2}}{P_{2(\text{rated})}} = 0$$

$$\frac{P_{1(\text{rated})}}{P_{2(\text{rated})}} = a_{12} = \frac{2{,}000}{500} = 4$$

$$\text{Steady-state change in system frequency, } \Delta f_{ss} = \frac{-\Delta P_{D_2} + a_{12}\Delta P_{D_1}}{\beta_2 + a_{12}\beta_1}$$

$$\Delta f_{ss} = -\left(\frac{\Delta P_{D_2} + a_{12}\Delta P_{D_1}}{\beta(1+a_{12})}\right) \quad (\because \beta_1 = \beta_2 = \beta)$$

$$= \left(\frac{-a_{12}\Delta P_{D_1}}{\beta(1+a_{12})}\right)\text{Hz} \quad [\therefore \Delta P_{D_2} = 0]$$

where $\beta = B + \frac{1}{R} = 0.016 + \frac{1}{10} = 0.116$ p.u. MW/Hz

$$\therefore \Delta f_{ss} = -\left[\frac{-4\times 0.0375}{0.116(1+4)}\right] = +0.2586 \text{ Hz}$$

Steady-state change in tie-line power following load change in Area-1:

$$\Delta f_{\text{tie-1(ss)}} = \frac{(\beta_1 \Delta P_{D_2} - \beta_2 \Delta P_{D_1})}{\beta_2 + a_{12}\beta_1} = \frac{\beta(\Delta P_{D_2} - \Delta P_{D_1})}{\beta(1+a_{12})}$$

$$= \frac{-\Delta P_{D_1}\,\beta}{\beta(1+a_{12})} = \frac{-\Delta P_{D_1}}{(1+a_{12})}$$

$$\Rightarrow \Delta P_{\text{tie-1(ss)}} = \frac{-\Delta P_{D_1}}{(1+a_{12})} = \frac{-0.0375}{1+4} = -0.0075 \text{ p.u. MW}$$

$$= -0.0075 \times P_{1(\text{rated})} = -0.0075 \times 2000$$

$$= -15 \text{ MW}$$

Example 8.5: Solve Example 8.4, without governor control action.

Solution:

Without the governor control action, $R = 0$

$$\beta = B + \frac{1}{R} = 0.016 + \frac{1}{0}$$

$\because R = 0, \qquad \beta = B = 0.016 \qquad [\because \beta_1 = \beta_2 = \beta]$

$$\Delta f_{ss} = -\left(\frac{\Delta P_{D_2} + a_{12}\,\Delta P_{D_1}}{(\beta_2 + a_{12}\,\beta_1)}\right) = -\frac{\Delta P_{D_2} + a_{12}\,\Delta P_{D_1}}{\beta(1+a_{12})}$$

$$\because \Delta f_{ss} = -\frac{a_{12}\,\Delta P_{D_1}}{\beta(1+a_{12})} \qquad [\because \Delta P_{D_2} = 0]$$

$$= -\left[\frac{4\times 0.0375}{0.016(1+4)}\right] = -1.875 \text{ Hz}$$

Steady-state change in tie-line power following load change in Area-1:

$$\Delta P_{\text{tie-1(steady state)}} = \frac{-\beta\,\Delta P_{D_1}}{\beta(1+a_{12})} = \frac{-\Delta P_{D_1}}{1+a_{12}}$$

$$= \frac{0.0375}{1+4} = -0.0075 \text{ p.u. MW}$$

$$= -0.0075 \times 2000$$

$$= -15 \text{ MW}$$

It is observed from the result that the power flow through the tie line is the same in both the cases of with governor action and without governor action, since it does not depend on speed regulation R.

Example 8.6: Find the nature of dynamic response if the two areas of the above problem are of uncontrolled type, following a disturbance in either area in the form of a step change in electric load. The inertia constant of the system is given as $H=3$ s and assume that the tie line has a capacity of 0.09 p.u. and is operating at a power angle of 30° before the step change in load.

Solution:

Given:

Speed regulation, $R=0.2$ p.u. $=0.2 \times 50=10$ Hz/p.u. MW

Damping coefficient, $B=0.8$ p.u. MW/p.u. Hz

$$=\frac{0.8}{50}=0.016 \text{ p.u. MW/Hz}$$

Inertia constant, $H=3$ s

Nominal frequency, $f^0=50$ Hz

Tie-line capacity, $0.1 \text{ p.u.}=\dfrac{P_{\text{tie(max)}}}{P_{\text{rated}}}$

From the theory of dynamic response, we know that

$$\Delta P_{\text{tie-1}(s)}=\frac{\Delta P_{D_2}(s)-\Delta P_{D_1}(s)}{s^2+2\alpha s+\omega_n^2}$$

$$\alpha=\frac{f^0}{4H}\left(B+\frac{1}{R}\right)=\frac{50}{4\times 3}\left[0.016+\frac{1}{10}\right]=0.4833$$

$$T_{12}^0=\frac{P_{\text{tie(max)}}}{P_{\text{rated}}}\cos(\delta_1^0-\delta_2^0)=0.1\times\cos(30°)$$

$$=0.866\times 0.1$$

$$=0.0866$$

$$\therefore \omega_n^2=\frac{2\pi T_{12}^0 f^0}{H}=\frac{2\pi\times 0.0866\times 50}{3}=9.068$$

$$\Rightarrow \omega_n=3.0114 \text{ rad/s}$$

It is observed that the damped oscillation type of dynamic response has resulted since $\alpha<\omega_n$:

$$\therefore \text{Damped angular frequency}=\omega_d=\sqrt{\omega_n^2-\alpha^2}$$

$$=\sqrt{9.068-0.2335}$$

$$=2.9723 \text{ rad/s}$$

$$\therefore \text{Damped frequency}=f_d=\frac{\omega_d}{2\pi}=\frac{2.9723}{2\pi}=0.473 \text{ Hz}$$

Example 8.7: Two control areas have the following characteristics:

Area-1: Speed regulation = 0.02 p.u.
Damping coefficient = 0.8 p.u.
Rated MVA = 1,500

Area-2: Speed regulation = 0.025 p.u.
Damping coefficient = 0.9 p.u.
Rated MVA = 500

Determine the steady-state frequency change and the changed frequency following a load change of 120 MW, which occurs in Area-1. Also find the tie-line power flow change.

Solution:

Given $R_1 = 0.1$ p.u.; $R_2 = 0.098$ p.u.

$B_1 = 0.8$ p.u.; $B_2 = 0.9$ p.u.

$P_{1\,\text{rated}} = 1{,}500$ MVA; $P_{2\,\text{rated}} = 1{,}500$ MVA

Change in load of Area-1,

$\Delta P_{D_1} = 120$ MW, $\Delta P_{D_2} = 0$

p.u. change in load of Area-1 $= \dfrac{120}{1{,}500} = 0.08$ p.u.

$$\Delta f_{ss} = \frac{\Delta P_{D_2} + a_{12}\,\Delta P_{D_1}}{\beta_2 + a_{12}\,\beta_1}$$

$$\beta_1 = B_1 + \frac{1}{R_1} = 0.8 + \frac{1}{0.02} = 50.8$$

$$\beta_2 = B_2 + \frac{1}{R_2} = 0.9 + \frac{1}{0.025} = 40.9$$

$$a_{12} = \frac{P_{1(\text{rated})}}{P_{2(\text{rated})}} = \frac{1{,}500}{500} = 3$$

$\therefore$ Steady-state frequency change, $\Delta f_{ss} = \dfrac{a_{12}\,\Delta P_{D_1}}{\beta_2 + a_{12}\,\beta_1}$

$$= \frac{-3\times 0.08}{40.9 + 3(50.8)}$$

$$= -\frac{3\times 0.08}{193.3} = -0.0012415 \text{ p.u. Hz}$$

i.e., Steady-state change in frequency, $\Delta f_{ss} = 0.0012415 \times 50$

$= 0.062$ Hz

$\therefore$ New value of frequency, $f = f^0 - \Delta f_{ss} = 50 - 0.062$

$= 49.937$ Hz

Steady-state change in tie-line power $= \Delta P_{(\text{tie-1})ss} = \dfrac{\beta_1 \Delta P_{D_2} - \beta_2 \Delta P_{D_1}}{\beta_2 + a_{12}\beta_1}$ p.u. MW

$$= \frac{50.8(0) - 40.9(0.08)}{40.9 + 3(50.8)}$$

$$= -0.0169 \text{ p.u. MW}$$

$$\therefore \Delta P_{(\text{tie-1})} = 0.0169 \times P_{1(\text{rated})} = -0.0169 \times 1500 = 25.35 \text{ MW}$$

Example 8.8: In Example 8.6, if the disturbance also occurs in Area-2, which results in a change in load by 75 MW, determine the frequency and tie-line power changes.

Solution:

Change in load of Area-1, $\Delta P_{D_1} = 120$ MW

p.u. change in load of Area-1 $= \dfrac{\Delta P_{D_1}}{P_{1\text{rated}}} = \dfrac{120}{1{,}500} = 0.08$ p.u. MW

Change in load of Area-2, $\Delta P_{D_2} = 75$ MW

p.u. change in load of Area-2 $= \dfrac{\Delta P_{D_2}}{P_{2\text{rated}}} = \dfrac{75}{500} = 0.15$ p.u. MW

Steady-state frequency change, $\Delta f_{ss} = \dfrac{\Delta P_{D_2} + a_{12}\Delta P_{D_1}}{\beta_2 + a_{12}\beta_1}$

$$= \frac{0.15 + 3(0.08)}{193.3} = 0.002 \text{ p.u Hz}$$

$\therefore$ Steady-state frequency change $= 0.002 \times 50 = 0.1$ Hz

$\therefore$ New value of frequency $= f^0 - \Delta f_{ss} = 50 - 0.1 = 49.899$ Hz

Steady-state change in tie-line power, $\Delta P_{\text{tie}(ss)} = \dfrac{\beta_1 \Delta P_{D_2} - \beta_2 \Delta P_{D_1}}{\beta_2 + a_{12}\beta_1}$ p.u. MW

$$= \frac{(50.8)(0.15) - (40.9)(0.08)}{40.9 + 3(50.8)}$$

$$= 7.62 - 3.273$$

$$= \frac{4.348}{133.3} = 0.02249 \text{ p.u. MW}$$

Example 8.9: Two areas of a power system network are interconnected by a tie line, whose capacity is 250 MW, operating at a power angle of 45°. If each area has a capacity of 2,000 MW and the equal speed-regulation coefficiency of 3 Hz/p.u. MW, determine the frequency of oscillation of the power for a step change in load. Assume that both areas have the same inertia constants of $H = 4$ s. If a step-load change of 100 MW occurs in one of the areas, determine the change in tie-line power.

Solution:

Given:

Tie-line capacity, $P_{\text{tie(max)}} = 250$ MW

Power angle of two areas, $(\delta_1^0 - \delta_2^0) = 45°$

Capacity of each area, $P_{\text{rated}} = 2{,}000$ MW

Speed-regulation coefficient $= R_1 = R_2 = R = 3$Hz/p.u. MW

Inertia constant, $H = 4$ s

$$\alpha = \frac{f^0}{4H}\left(B + \frac{1}{R}\right) = \frac{50}{4\times 4}\left(0 + \frac{1}{3}\right)$$

$$= \frac{50}{4\times 4\times 3} = \frac{50}{48} = 1.04$$

$$T_{12}^0 = \frac{P_{\text{tie}_{12}\text{(max)}}}{P_{\text{rated}}}\cos(\delta_1^0 - \delta_2^0)$$

$$= \frac{250}{2{,}000}\cos(45°) = 0.125\cos(45°) = 0.0883$$

$$\omega_n^2 = \frac{2\pi T_{12}^0}{H} = \frac{2\pi\times 0.0883\times 50}{4} = 6.935$$

$$\therefore \omega_n = 2.6334 \text{ rad/s}$$

Since, $\alpha < \omega_n$, the dynamic response will be of a damped oscillation type.

Damped angular frequency, $\omega_d = \sqrt{\omega_n^2 - \alpha^2}$

$$= \sqrt{6.935 - 1.0816}$$

$$= 2.4193 \text{ rad/s}$$

$\therefore$ Frequency of oscillation, $f_d = \dfrac{\omega_d}{2\pi} = \dfrac{2.4193}{2\times\pi} = 0.385$ Hz

If a step-load change of 100 MW occurs in any one of the areas, the total load change will be shared equally by both areas since the two areas are equal, i.e., a power of $\dfrac{100}{2} = 50$ MW will flow from the other area into the area where a load change occurs.

Example 8.10: Two power stations A and B of capacities 75 and 200 MW, respectively, are operating in parallel and are interconnected by a short transmission line. The generators of stations A and B have speed regulations of 4% and 2%, respectively. Calculate the output of each station and the load on the interconnection if

(a) the load on each station is 100 MW,

(b) the loads on respective bus bars are 50 and 150 MW, and

(c) the load is 130 MW at Station A bus bar only.

Solution:

Given:

Capacity of Station-A = 75 MW

Capacity of Station-B = 200 MW

Speed regulation of Station-A generator, $R_A = 4\%$

Speed regulation of Station-B generator, $R_B = 2\%$

(a) If the load on each station = 100 MW

$$\text{i.e., } P_1 + P_2 = 100 + 100 = 200 \text{ MW} \quad (8.47)$$

$$\text{Speed regulation } = \frac{N_0 - N}{N_0} = \frac{f_0 - f}{f_0}$$

$$\frac{P_1}{75} = \frac{1-f}{0.04}$$

$$\Rightarrow (1-f) = \frac{0.04}{75} \times P_1 \quad (8.48)$$

$$\frac{P_2}{200} = \frac{1-f}{0.02}$$

$$\therefore (1-f) = 0.0001 P_2 \quad (8.49)$$

From Equations (8.48) and (8.49), we have

$$0.000533 P_1 = 0.0001 P_2$$

$$5.33 P_1 = P_2 \quad (8.50)$$

$$P_1 + P_2 = 200$$

Substituting Equation (8.50) in Equation (8.47), we get

$$P_1 + 5.33\, P_1 = 200$$

$$6.33 P_1 = 200$$

$$\text{or} \quad P_1 = \frac{200}{6.33} = 31.60 \text{ MW}$$

$$\therefore P_2 = 200 - 31.59 = 168.40 \text{ MW}$$

The power generations and tie-line power are indicated in Fig. 8.14(a).

(b) If the load on respective bus bars are 50 and 150 MW, then we have

$$\text{i.e., } P_1 + P_2 = 50 + 150 = 200 \text{ MW}$$

$$5.33\, P_1 = P_2$$

$$P_1 + 5.33\, P_1 = 200$$

$$\Rightarrow 6.33 P_1 = 200$$

$$P_1 = 31.6 \text{ MW}$$

$$\therefore P_2 = 200 - 31.60 = 168.4 \text{ MW}$$

The power generations and tie-line power are indicated in Fig. 8.14(b).

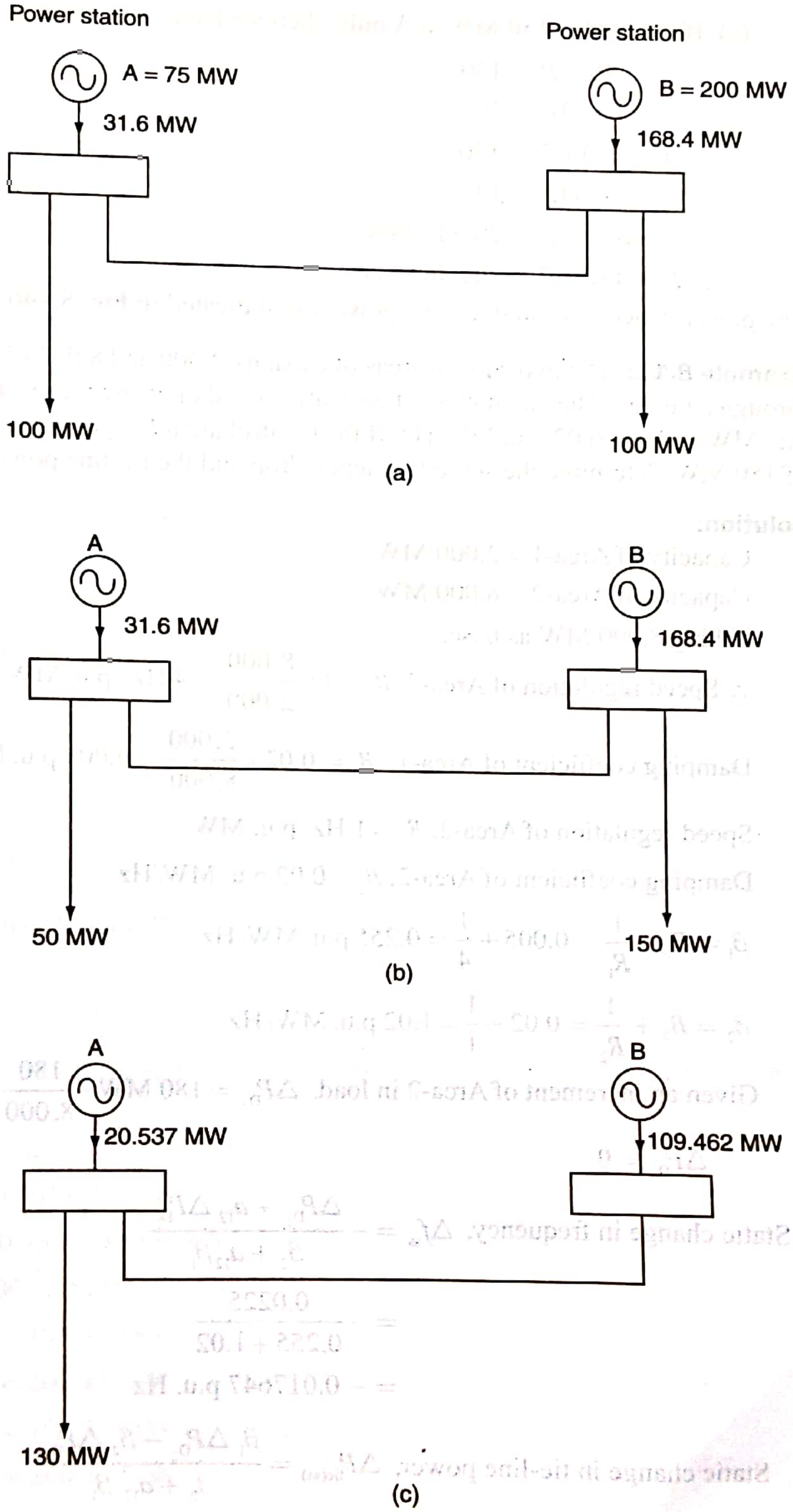

FIG. 8.14 *(a) Illustration for Example 8.10; (b) illustration for Example 8.10; (c) illustration for Example 8.10*

(c) If the load is 130 MW at A only, then we have

$$P_1 + P_2 = 130$$
$$5.33P_1 = P_2$$
$$\therefore P_1 = 5.33\ P_1 = 130$$
$$6.33P_1 = 130$$
$$\Rightarrow \quad P_1 = 20.537 \text{ MW}$$
$$\therefore P_2 = 130 - P_1 = 109.462 \text{ MW}$$

The power generations and tie-line power are indicated in Fig. 8.14(c).

Example 8.11: The two control areas of capacity 2,000 and 8,000 MW are interconnected through a tie line. The parameters of each area based on its own capacity base are $R = 1$ Hz/p.u. MW and $B = 0.02$ p.u. MW/Hz. If the Control area-2 experiences an increment in load of 180 MW, determine the static frequency drop and the tie-line power.

Solution:

Capacity of Area-1 = 2,000 MW

Capacity of Area-2 = 8,000 MW

Taking 8,000 MW as base,

$$\therefore \text{ Speed regulation of Area-1, } R_1 = 1 \times \frac{8{,}000}{2{,}000} = 4 \text{ Hz / p.u. MW}$$

$$\text{Damping coefficient of Area-1, } B_1 = 0.02 \times \frac{2{,}000}{8{,}000} = 0.005 \text{ p.u. MW/Hz}$$

Speed regulation of Area-2, $R_2 = 1$ Hz/p.u. MW

Damping coefficient of Area-2, $B_2 = 0.02$ p.u. MW/Hz

$$\beta_1 = B_1 + \frac{1}{R_1} = 0.005 + \frac{1}{4} = 0.255 \text{ p.u. MW/Hz}$$

$$\beta_2 = B_2 + \frac{1}{R_2} = 0.02 + \frac{1}{1} = 1.02 \text{ p.u. MW/Hz}$$

$$\text{Given an increment of Area-2 in load, } \Delta P_{D_2} = 180 \text{ MW} = \frac{180}{8{,}000} = 0.025 \text{ p.u. MW}$$

$$\Delta P_{D_1} = 0$$

$$\therefore \text{ Static change in frequency, } \Delta f_{ss} = -\frac{\Delta P_{D_2} + a_{12}\,\Delta P_{D_1}}{\beta_2 + a_{12}\beta_1}$$

$$= -\frac{0.0225}{0.255 + 1.02}$$

$$= -0.017647 \text{ p.u. Hz}$$

$$\text{Static change in tie-line power, } \Delta P_{\text{tie(ss)}} = \frac{\beta_1\,\Delta P_{D_2} - \beta_2\,\Delta P_{D_1}}{\beta_2 + a_{12}\,\beta_1}$$

$$= \frac{0.255 \times 0.0225}{0.255 + 1.02} = 0.0051 \text{ p.u. MW}$$

Note: Here, a_{12} value determination is not required since values of R_1, B_1, and β_1 are obtained according to the base values.

Alternate method:

Find $a_{12}\dfrac{P_{1\text{rated}}}{P_{2\text{rated}}} = \dfrac{2,000}{8,000} = 0.25$. Then, obtain the $\Delta f_{(ss)}$ and $\Delta P_{\text{tie(ss)}}$ values.

Here, there is no need to obtain, R_1, B_1, R_2, and B_2 separately.

Example 8.12: Two generating stations A and B having capacities 500 and 800 MW, respectively, are interconnected by a short line. The percentage speed regulations from no-load to full load of the two stations are 2 and 3, respectively. Find the power generation at each station and power transfer through the line if the load on the bus of each station is 200 MW.

Solution:

Given data:

Capacity of Station-A = 500 MW

Capacity of Station-B = 800 MW

Percentage speed regulation of Station-A = 2% = 0.02

Percentage speed regulation of Station-B = 3% = 0.03

Load on bus of each station = $P_{DA} = P_{DB} = 200$ MW

Total load, $P_D = 400$ MW

Speed regulation of Station-A:

$$R_A = (0.02)\frac{50}{500} = 0.002 \text{ Hz/MW}$$

Speed regulation of Station-B:

$$R_B = (0.03)\times\frac{50}{800} = 0.001875 \text{ Hz/MW}$$

Let P_{GA} be the power generation of Station-A and P_{GB} the power generation of Station-B:

$$P_{GB} = \text{Total load} - P_{GA} = (400 - P_{GA})$$

$$\Rightarrow 0.002P_{GA} = 0.001875\,(400 - P_{GA})$$

$$= 0.75 = 193.55 \text{ MW}$$

$$(0.002 + 0.001875)\,P_{GA} = 0.75$$

$$\Rightarrow \quad P_{GA} = 193.55 \text{ MW}$$

$$P_{GB} = 206.45 \text{ MW}$$

$$P_{GA} = 193.55 \text{ MW}$$

$$\therefore \quad P_{GB} = 206.45 \text{ MW}$$

The power transfer through the line from Station-B to Station-A

$$= P_{GB} - (\text{load at bus bar of B})$$

$$= 206.45 - 200$$

$$= 6.45 \text{ MW}$$

Example 8.13: Two control areas of 1,000 and 2,000 MW capacities are interconnected by a tie line. The speed regulations of the two areas, respectively, are 4 Hz/p.u. MW and 2.5 Hz/p.u. MW. Consider a 2% change in load occurs for 2% change in frequency in each area. Find steady-state change in frequency and tie-line power of 10 MW change in load occurs in both areas.

Solution:

Capacity of Area-1 = 1,000 MW

Capacity of Area-2 = 2,000 MW

Speed regulation of Area-1, $R_1 = 4$ Hz/p.u. MW (on 1,000-MW base)

Speed regulation of Area-2, $R_2 = 2$ Hz/p.u. MW

Let us choose 2,000 MW as base, 2% change in load for 2% change in frequency

Damping coefficient of Area-1, $B_1 = \dfrac{0.02 \times 1{,}000}{0.02 \times 50} = 20$ MW/Hz

$$= \frac{20}{2{,}000} = 0.01 \text{ p.u. MW/Hz}$$

Similarly, damping coefficient of Area-2 on 2,000-MW base

$$B_2 = \frac{0.02}{0.02} \times \frac{2{,}000}{50} = 40 \text{ MW/Hz}$$

$$= \frac{40}{2{,}000} = 0.02 \text{ p.u. MW/Hz}$$

Speed regulation of Area - 1on 2,000-MW base $= R_1$

$$= 4 \times \frac{2{,}000}{1{,}000} = 8 \text{ Hz/p.u. MW}$$

Speed regulation of Area-2, $R_2 = 2$ Hz/p.u. MW

$$\therefore \beta_1 = B_1 + \frac{1}{R_1} = 0.01 + \frac{1}{8} = 0.135 \text{ p.u. MW/Hz}$$

$$\beta_2 = B_2 + \frac{1}{R_2} = 0.02 + \frac{1}{2} = 0.52 \text{ p.u. MW/Hz}$$

If a 10-MW change in load occurs in Area-1, then we have

$$\Delta P_{D_1} = \frac{10}{2{,}000} = 0.005; \quad \Delta P_{D_2} = 0$$

Steady-state change in frequency,

Steady-state change in frequency, $\Delta f(\text{ss}) = -\dfrac{\Delta P_{D_2} + a_{12}\Delta P_{D_1}}{\beta_2 + a_{12}\,\beta_1} = -0.007633$ p.u. Hz

or $\quad \Delta f_{(ss)} = -0.007633 \times 50 = 0.38$ Hz

Steady-state change in tie-line power:

$$\Delta P_{\text{tie(ss)}} = \frac{\beta_1 \Delta P_{D_2} - \beta_2 \Delta P_{D_1}}{\beta_2 + a_{12}\,\beta_1}$$

$$= \frac{0.135 \times 0 - 0.52 \times 0.005}{0.52 + 0.135}$$
$$= -0.003964 \text{ p.u. MW}$$
$$= -0.003964 \times 2{,}000$$
$$= -7.938 \text{ MW}$$

i.e., the power transfer of 7.938 MW is from Area-2 to Area-1.

If a 10-MW change in load occurs in Area-2, then we have

$$\Delta P_{D_2} = \frac{10}{2{,}000} = 0.005; \quad \Delta P_{D_1} = 0$$

$\therefore$ Steady-state change in frequency, $\Delta f_{ss} = -\left(\frac{0.005}{0.52 + 0.135}\right)$

$$= -0.007633 \text{ p.u. Hz}$$
$$= -0.38 \text{ Hz}$$

Steady-state change in tie-line power: $\Delta P_{tie(ss)} = \left(\frac{0.135 \times 0.005 - 0.52 \times 0}{0.52 + 0.135}\right)$

$$= 0.00103 \text{ p.u. MW}$$
$$= 0.00103 \times 2000$$
$$= 2.061 \text{ MW}$$

i.e., A power of 2.061 MW is transferred from Area-1 to Area-2.

Example 8.14: Two similar areas of equal capacity of 5,000 MW, speed regulation $R = 3$ Hz/p.u. MW, and $H = 5$ s are connected by a tie line with a capacity of 500 MW, and are operating at a power angle of 45°. For the above system, the frequency is 50 Hz; find:

(a) The frequency of oscillation of the system.

(b) The steady-state change in the tie-line power if a step change of 100 MW load occurs in Area-2.

(c) The frequency of oscillation of the system in the speed-governor loop is open.

Solution:

Given:

Capacity of each control area $= P_{1(rated)}\ P_{2(rated)} = 500$ MW

Speed regulation, $R = 2$ Hz/p.u. MW

Inertia constant, $H = 5$ s

Power angle $= 45°$

Supply frequency, $f^0 = 50$ Hz

(a) Stiffness coefficient, $T_{12} = \frac{P_{max(tie)}}{P_{1(rated)}} \cos(\delta_1^0 - \delta_2^0)$

$$= \frac{500}{5{,}000} \cos 45° = 0.0707$$

$$\omega_n^2 = \frac{2\pi T_{12} f^0}{H} = \frac{2\pi \times 0.0707 \times 50}{5} = 4.4422$$

$$\omega_n = 2.1076 \text{ rad/s}$$

$$\alpha = \frac{f^0}{4H}\left(B + \frac{1}{R}\right) = \frac{50}{4\times 5}\left[0 + \frac{1}{4}\right] = \frac{50}{4\times 5\times 4} = \frac{50}{80} = 0.625$$

Since $\alpha < \omega_n$, damped oscillations will be present.

$\therefore$ Damped angular frequency, $\omega_d = \sqrt{\omega_n^2 - \alpha^2}$

$$= \sqrt{4.4422 - (0.625)^2}$$

$$= 2.0128 \text{ rad/s}$$

$$f_d = \frac{\omega_d}{2\pi} = 0.32 \text{ Hz}$$

(b) Since the two areas are similar, each area will supply half of the increased load:

$$\therefore \beta_1 = \beta_2$$

$\Delta P_{tie} = 50$ MW from Area-1 to Area-2.

If the speed-governor loop is open, then $R \to \infty \Rightarrow \frac{1}{R} = 0$

$$\therefore \alpha = \frac{f^0}{4DH} = 0$$

Damped angular frequency, $\omega_d = \sqrt{\omega_n^2 - \alpha^2}$

$$= \omega_d = \omega_n = 2.1076 \text{ rad/s}$$

$$f_d = \frac{wd}{2\pi} = \frac{2.1076}{2\times\pi} = 0.335 \text{ Hz}$$

KEY NOTES

- An extended power system can be divided into a number of LFC areas, which are interconnected by tie lines. Such an operation is called a **pool operation.**

  The basic principle of a pool operation in the normal steady state provides:

  (i) Maintaining of scheduled interchanges of tie-line power.

  (ii) Absorption of own load change by each area.

- The advantages of a pool operation are as follows:

  (i) Half of the added load (in Area-2) is supplied by Area-1 through the tie line.

  (ii) The frequency drop would be only half of that which would occur if the areas were operating without interconnection.

- The speed-changer command signals will be:

$$\Delta P_{c_1} = -K_{I_1}\int(\Delta P_{TL_1} + b_1 \Delta f_1)\, dt$$

and

$$\Delta P_{c_2} = -K_{I_2} \int (\Delta P_{TL_2} + b_2 \Delta f_2)\, dt$$

The constants K_{I_1} and K_{I_2} are the gains of the integrators. The first terms on the right-hand side of the above equations constitute what is known as a tie-line bias control.

- The load frequency controller provides a fast-acting control and regulates the system around an operating point, whereas the EDC provides a slow-acting control, which adjusts the speed-changer settings every minute in accordance with a command signal generated by the CEDC.

SHORT QUESTIONS AND ANSWERS

(1) What are the advantages of a pool operation?

The advantages of a pool operation (i.e., grid operation) are:

(i) Half of the added load (in Area-2) is supplied by Area-1 through the tie line.

(ii) The frequency drop would be only half of that which would occur if the areas were operating without interconnection.

(2) Without speed-changer position control, can the static frequency deviation be zero?

No, the static frequency deviation cannot be zero.

(3) State the additional requirement of the control strategy as compared to the single-area control.

The tie-line power deviation due to a step-load change should decrease to zero.

(4) Write down the expressions for the ACEs.

The ACE of Areas-1 and 2 are:

$$ACE_1(s) = \Delta P_{TL_1}(s) + b_1 \Delta F_1(s).$$

$$ACE_2(s) = \Delta P_{TL_2}(s) + b_2 \Delta F_2(s).$$

(5) What is the criterion used for obtaining optimum values for the control parameters?

Integral of the sum of the squared error criterion is the required criterion.

(6) Give the error criterion function for the two-area system.

$$C = \int_0^{\infty} \left[\alpha_1 (\Delta P_{TL_1})^2 + \alpha_2 (\Delta f_1)^2 + \alpha_3 (\Delta f_2)^2\right] dt.$$

(7) What is the order of differential equation to describe the dynamic response of a two-area system in an uncontrolled case?

It is required for a system of seventh-order differential equations to describe the dynamic response of a two-area system. The solution of these equations would be tedious.

(8) What is the difference of ACE in single-area and two-area power systems?

In a single-area case, ACE is the change in frequency. The steady-state error in frequency will become zero (i.e., $\Delta f_{ss} = 0$) when ACE is used in an integral-control loop.

In a two-area case, ACE is the linear combination of the change in frequency and change in tie-line power. In this case to make the steady-state tie-line power zero (i.e., $\Delta P_{TL} = 0$), another integral-control loop for each area must be introduced in addition to the integral frequency loop to integrate the incremental tie-line power signal and feed it back to the speed-changer.

(9) What is the main difference of load frequency and economic dispatch controls?

The load frequency controller provides a fast-acting control and regulates the system around an operating point, whereas the EDC provides a slow-acting control, which adjusts the speed-changer settings every minute in accordance with a command signal generated by the CEDC.

(10) What are the steps required for designing an optimum linear regulator?

An optimum linear regulator can be designed using the following steps:

(i) Casting the system dynamic model in a state-variable form and introducing appropriate control forces.

(ii) Choosing an integral-squared-error control index, the minimization of which is the control goal.

(iii) Finding the structure of the optimal controller that will minimize the chosen control index.

MULTIPLE-CHOICE QUESTIONS

(1) Changes in load division between AC generators operation in parallel are accomplished by:

(a) Adjusting the generator voltage regulators.

(b) Changing energy input to the prime movers of the generators.

(c) Lowering the system frequency.

(d) Increasing the system frequency.

(2) When the energy input to the prime mover of a synchronous AC generator operating in parallel with other AC generators is increased, the rotor of the generator will:

(a) Increase in average speed.

(b) Retard with respect to the stator-revolving field.

(c) Advance with respect to the stator-revolving field.

(d) None of these.

(3) When two or more systems operate on an interconnected basis, each system:

(a) Can depend on the other system for its reserve requirements.

(b) Should provide for its own reserve capacity requirements.

(c) Should operate in a 'flat frequency' mode.

(4) When an interconnected power system operates with a tie-line bias, they will respond to:

(a) Frequency changes only.

(b) Both frequency and tie-line load changes.

(c) Tie-line load changes only.

(5) In a two-area case, ACE is:

(a) Change in frequency.

(b) Change in tie-line power.

(c) Linear combination of both (a) and (b).

(d) None of the above.

(6) An extended power system can be divided into a number of LFC areas, which are interconnected by tie lines. Such an operator is called

(a) Pool operation.

(b) Bank operation.

(c) (a) and (b).

(d) None.

(7) For the static response of a two-area system,

(a) $\Delta P_{ref_1} = \Delta_{ref_2}$.

(b) $\Delta P_{ref_1} = 0$.

(c) $\Delta P_{ref_2} = 0$.

(d) Both (b) and (c).

(8) Area of frequency response characteristic 'β' is:

(a) $1/R$.

(b) B.

(c) $B + 1/R$.

(d) $B - 1/R$.

(9) The tie-line power equation is ΔP_{12}=________.

(a) $T(\Delta\delta_1 + \Delta\delta_2)$.

(b) $T/(\Delta\delta_1 + \Delta\delta_2)$.

(c) $T/(\Delta\delta_1 - \Delta\delta_2)$.

(d) $T(\Delta\delta 1 - \Delta\delta 2)$.

(10) The unit of synchronizing coefficients 'T' is:

(a) MW-s.

(b) MW/s.

(c) MW-rad.

(d) MW/rad.

(11) For a two-area system, Δf is related to increased step load M_1 and M_2 with area frequency response characteristics β_1 and β_2 is:

(a) $M_1 + M_2/\beta_1 + \beta_2$.

(b) $(M_1 + M_2)(\beta_1 + \beta_2)$.

(c) $-(M_1 + M_2)/(\beta_1 + \beta_2)$.

(d) None of these.

(12) Tie-line power flow for the above question (11) is ΔP_{12}=________.

(a) $(\beta_1 M_2 + \beta_2 M_1)/\beta_1 + \beta_2$.

(b) $(\beta_1 M_2 - \beta_2 M_1)/\beta_1 + \beta_2$.

(c) $(\beta_1 M_1 - \beta_2 M_2)/\beta_1 + \beta_2$.

(d) None of these.

(13) Advantage of a pool operation is:
(a) Added load can be shared by two areas.
(b) Frequency drop reduces.
(c) Both (A) and (B).
(d) None of these.

(14) Damping of frequency oscillations for a two-area system is more with:
(a) Low-R.
(b) High-R.
(c) $R=\alpha$.
(d) None of these.

(15) ACE equation for a general power system with tie-line bias control is:
(a) $\Delta P_{ij}+B_i\,\Delta f_i$.
(b) $\Delta P_{ij}-B_i\,\Delta f_i$.
(c) $\Delta P_{ij}/B_i\,\Delta f_i$.
(d) None of these.

(16) For a two-area system Δf, ΔP_L, R_1, R_2, and D are related as $\Delta f=$________.
(a) $\Delta P_L/R_1+R_2$.
(b) $-\Delta P_L/(1/R_1+R_2+B)$.
(c) $-\Delta P_L/(B+R_1+1/R_2)$.
(d) None of these.

(17) If the two areas are identical, then we have:
(a) $\Delta f_1=1/\Delta f_2$.
(b) $\Delta f_1\,\Delta f_2=2$.
(c) $\Delta f_1=\Delta f_2$.
(d) None of these.

(18) Tie-line between two areas usually will be a ________ line.
(a) HVDC.
(b) HVAC.
(c) Normal AC.
(d) None of these.

(19) Dynamic response of a two-area system can be represented by a ________ order transfer function.
(a) Third.
(b) Second.
(c) First.
(d) Zero.

(20) Control of ALFC loop of a multi-area system is achieved by using ________ mathematical technique.
(a) Root locus.
(b) Bode plots.
(c) State variable.
(d) Nyquist plots.

REVIEW QUESTIONS

(1) Obtain the mathematical modeling of the line power in an interconnected system and its block diagram.

(2) Obtain the block diagram of a two-area system.

(3) Explain how the control scheme results in zero tie-line power deviations and zero-frequency deviations under steady-state conditions, following a step-load change in one of the areas of a two-area system.

(4) Deduce the expression for static-error frequency and tie-line power in an identical two-area system.

(5) Explain about the optimal two-area LFC.

(6) What is meant by tie-line bias control?

(7) Derive the expression for incremental tie-line power of an area in an uncontrolled two-area system under dynamic state for a step-load change in either area.

(8) Draw the block diagram for a two-area LFC with integral controller blocks and explain each block.

(9) What are the differences between uncontrolled, controlled, and tie-line bias LFC of a two-area system.

(10) Explain the method involved in optimum parameter adjustment for a two-area system.

(11) Explain the combined operation of an LFC and an ELDC system.

PROBLEMS

(1) Two interconnected areas 1 and 2 have the capacity of 250 and 600 MW, respectively. The incremental regulation and damping torque coefficient for each area on its own base are 0.3 and 0.07 p.u. respectively. Find the steady-state change in system frequency from a nominal frequency of 50 Hz and the change in steady-state tie-line power following a 850 MW change in the load of Area-1.

(2) Two control areas of 1,500 and 2,500 MW capacities are interconnected by a tie line. The speed regulations of the two areas, respectively, are 3 and 1.5 Hz/p.u. MW. Consider that a 2% change in load occurs for a 2% change in frequency in each area. Find the steady-state change in the frequency and the tie-line power of 20 MW change in load occurring in both areas.

(3) Find the nature of dynamic response if the two areas of the above problem are of uncontrolled type, following a disturbance in either area in the form of a step change in an electric load. The inertia constant of the system is given as $H=2$ s and assume that the tie line has a capacity of 0.08 p.u. and is operating at a power angle of 35° before the step change in load.

CHAPTER 8

(1) b	(6) a	(11) c	(16) b
(2) c	(7) d	(12) b	(17) c
(3) b	(8) c	(13) c	(18) a
(4) b	(9) d	(14) a	(19) b
(5) c	(10) d	(15) a	(20) c