9 Control of Generation

9.1 INTRODUCTION

So far, this text has concentrated on methods of establishing optimum dispatch and scheduling of generating units. It is important to realize, however, that such optimized dispatching would be useless without a method of control over the generator units. Indeed, the control of generator units was the first problem faced in early power-system design. The methods developed for control of individual generators and eventually control of large interconnections play a vital role in modern energy control centers.

A generator driven by a steam turbine can be represented as a large rotating mass with two opposing torques acting on the rotation. As shown in Figure 9.1, T_{mech}, the mechanical torque, acts to increase rotational speed whereas T_{elec}, the electrical torque, acts to slow it down. When T_{mech} and T_{elec} are equal in magnitude, the rotational speed, ω, will be constant. If the electrical load is increased so that T_{elec} is larger than T_{mech}, the entire rotating system will begin to slow down. Since it would be damaging to let the equipment slow down too far, something must be done to increase the mechanical torque T_{mech} to restore equilibrium; that is, to bring the rotational speed back to an acceptable value and the torques to equality so that the speed is again held constant.

This process must be repeated constantly on a power system because the loads change constantly. Furthermore, because there are many generators supplying power into the transmission system, some means must be provided to allocate the load changes to the gnerators. To accomplish this, a series of control systems are connected to the generator units. A governor on each unit maintains its speed while supplementary control, usually originating at a remote control center, acts to allocate generation. Figure 9.2 shows an overview of the generation control problem.

9.2. GENERATOR MODEL

Before starting, it will be useful for us to define our terms.

ω = rotational speed (rad/sec)

α = rotational acceleration

δ = phase angle of a rotating machine

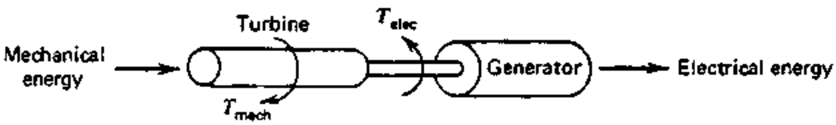

FIG. 9.1 Mechanical and electrical torques in a generating unit.

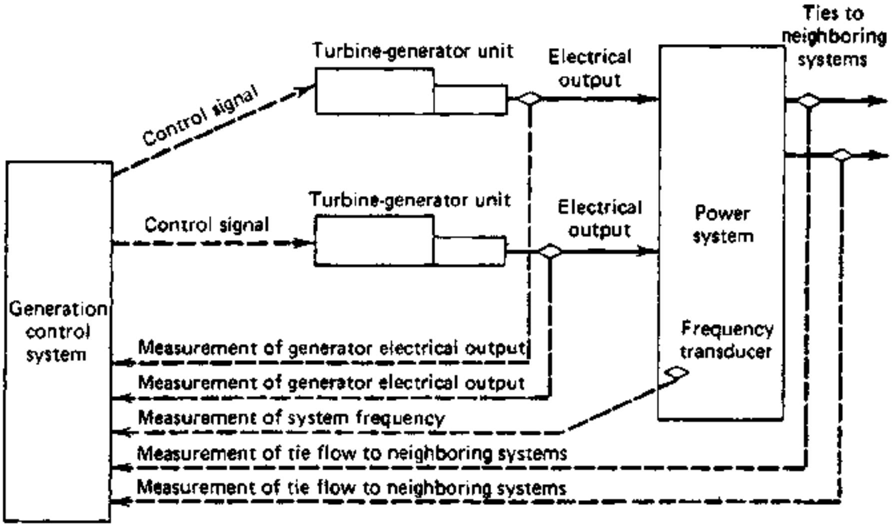

FIG. 9.2 Overview of generation control problem.

T_{net} = net accelerating torque in a machine

T_{mech} = mechanical torque exerted on the machine by the turbine

T_{elec} = electrical torque exerted on the machine by the generator

P_{net} = net accelerating power

P_{mech} = mechanical power input

P_{elec} = electrical power output

I = moment of inertia for the machine

M = angular momentum of the machine

where all quantities (except phase angle) will be in per unit on the machine base, or, in the case of ω, on the standard system frequency base. Thus, for example, M is in per unit power/per unit frequency/sec.

In the development to follow, we are interested in deviations of quantities about steady-state values. All steady-state or nominal values will have a "0" subscript (e.g., ω_0, T_{net_0}), and all deviations from nominal will be designated by a "Δ" (e.g., $\Delta\omega$, ΔT_{net}). Some basic relationships are

$$I\alpha = T_{\text{net}} \tag{9.1}$$

$$M = \omega I \tag{9.2}$$

$$P_{\text{net}} = \omega T_{\text{net}} = \omega(I\alpha) = M\alpha \tag{9.3}$$

To start, we will focus our attention on a single rotating machine. Assume that the machine has a steady speed of ω_0 and phase angle δ_0. Due to various electrical or mechanical disturbances, the machine will be subjected to differences in mechanical and electrical torque, causing it to accelerate or decelerate. We are chiefly interested in the deviations of speed, $\Delta\omega$, and deviations in phase angle, $\Delta\delta$, from nominal.

The phase angle deviation, $\Delta\delta$, is equal to the difference in phase angle between the machine as subjected to an acceleration of α and a reference axis rotating at exactly ω_0. If the speed of the machine under acceleration is

$$\omega = \omega_0 + \alpha t \tag{9.4}$$

then

$$\begin{aligned} \Delta\delta &= \underbrace{\int (\omega_0 + \alpha t)\,\mathrm{d}t}_{\substack{\text{Machine absolute}\\ \text{phase angle}}} - \underbrace{\int \omega_0\,\mathrm{d}t}_{\substack{\text{Phase angle of}\\ \text{reference axis}}} \\ &= \omega_0 t + \tfrac{1}{2}\alpha t^2 - \omega_0 t \\ &= \tfrac{1}{2}\alpha t^2 \end{aligned} \tag{9.5}$$

The deviation from nominal speed, $\Delta\omega$, may then be expressed as

$$\Delta\omega = \alpha t = \frac{\mathrm{d}}{\mathrm{d}t}(\Delta\delta) \tag{9.6}$$

The relationship between phase angle deviation, speed deviation, and net accelerating torque is

$$T_{\text{net}} = I\alpha = I\frac{\mathrm{d}}{\mathrm{d}t}(\Delta\omega) = I\frac{\mathrm{d}^2}{\mathrm{d}t^2}(\Delta\delta) \tag{9.7}$$

Next, we will relate the deviations in mechanical and electrical power to the deviations in rotating speed and mechanical torques. The relationship between net accelerating power and the electrical and mechanical powers is

$$P_{net} = P_{mech} - P_{elec} \tag{9.8}$$

which is written as the sum of the steady-state value and the deviation term,

$$P_{net} = P_{net_0} + \Delta P_{net} \tag{9.9}$$

where

$$P_{net_0} = P_{mech_0} - P_{elec_0}$$

$$\Delta P_{net} = \Delta P_{mech} - \Delta P_{elec}$$

Then

$$P_{net} = (P_{mech_0} - P_{elec_0}) + (\Delta P_{mech} - \Delta P_{elec}) \tag{9.10}$$

Similarly for torques,

$$T_{net} = (T_{mech_0} - T_{elec_0}) + (\Delta T_{mech} - \Delta T_{elec}) \tag{9.11}$$

Using Eq. 9.3, we can see that

$$P_{net} = P_{net_0} + \Delta P_{net} = (\omega_0 + \Delta\omega)(T_{net_0} + \Delta T_{net}) \tag{9.12}$$

Substituting Eqs. 9.10 and 9.11, we obtain

$$(P_{mech_0} - P_{elec_0}) + (\Delta P_{mech} - \Delta P_{elec}) = (\omega_0 + \Delta\omega)[(T_{mech_0} - T_{elec_0}) + (\Delta T_{mech} - \Delta T_{elec})] \tag{9.13}$$

Assume that the steady-state quantities can be factored out since

$$P_{mech_0} = P_{elec_0}$$

and

$$T_{mech_0} = T_{elec_0}$$

and further assume that the second-order terms involving products of $\Delta\omega$ with ΔT_{mech} and ΔT_{elec} can be neglected. Then

$$\Delta P_{mech} - \Delta P_{elec} = \omega_0(\Delta T_{mech} - \Delta T_{elec}) \tag{9.14}$$

As shown in Eq. 9.7, the net torque is related to the speed change as follows:

$$(T_{mech_0} - T_{elec_0}) + (\Delta T_{mech} - \Delta T_{elec}) = I \frac{d}{dt}(\Delta\omega) \tag{9.15}$$

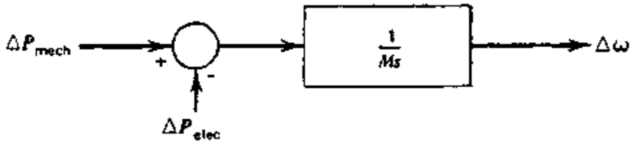

FIG. 9.3 Relationship between mechanical and electrical power and speed change.

then since $T_{mech_0} = T_{elec_0}$, we can combine Eqs. 9.14 and 9.15 to get

$$\Delta P_{mech} - \Delta P_{elec} = \omega_0 I \frac{d}{dt}(\Delta\omega)$$

$$= M \frac{d}{dt}(\Delta\omega) \quad (9.16)$$

This can be expressed in Laplace transform operator notation as

$$\Delta P_{mech} - \Delta P_{elec} = Ms\,\Delta\omega \quad (9.17)$$

This is shown in block diagram form in Figure 9.3.

The units for M are watts per radian per second per second. We will always use per unit power over per unit speed per second where the per unit refers to the machine rating as the base (see Example 9A).

9.3 LOAD MODEL

The loads on a power system consist of a variety of electrical devices. Some of them are purely resistive, some are motor loads with variable power–frequency characteristics, and others exhibit quite different characteristics. Since motor loads are a dominant part of the electrical load, there is a need to model the effect of a change in frequency on the net load drawn by the system. The relationship between the change in load due to the change in frequency is given by

$$\Delta P_{L(freq)} = D\,\Delta\omega \quad \text{or} \quad D = \frac{\Delta P_{L(freq)}}{\Delta\omega}$$

where D is expressed as percent change in load divided by percent change in frequency. For example, if load changed by 1.5% for a 1% change in frequency, then D would equal 1.5. However, the value of D used in solving for system dynamic response must be changed if the system base MVA is different from the nominal value of load. Suppose the D referred to here was for a net

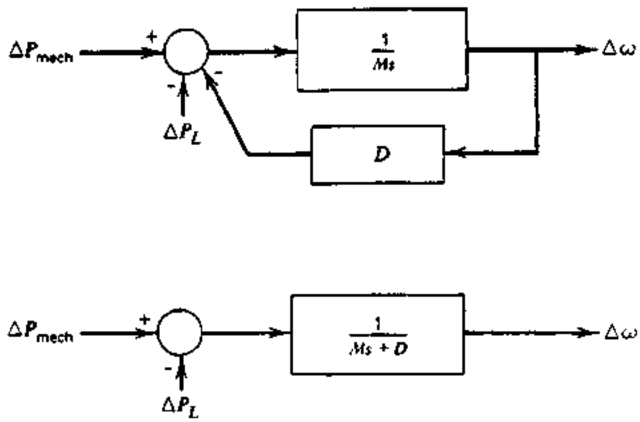

FIG. 9.4 Block diagram of rotating mass and load as seen by prime-mover output.

connected load of 1200 MVA and the entire dynamics problem were to be set up for a 1000-MVA system base. Note that $D = 1.5$ tells us that the load would change by 1.5 pu for 1 pu change in frequency. That is, the load would change by 1.5×1200 MVA or 1800 MVA for a 1 pu change in frequency. When expressed on a 1000-MVA base, D becomes

$$D_{1000\text{-MVA base}} = 1.5 \times \left(\frac{1200}{1000}\right) = 1.8$$

The net change in P_{elec} in Figure 9.3 (Eq. 9.15) is

$$\Delta P_{elec} = \underbrace{\Delta P_L}_{\substack{\text{Nonfrequency-}\\ \text{sensitive load}\\ \text{change}}} + \underbrace{D\,\Delta\omega}_{\substack{\text{Frequency-sensitive}\\ \text{load change}}} \tag{9.18}$$

Including this in the block diagram results in the new block diagram shown in Figure 9.4.

EXAMPLE 9A

We are given an isolated power system with a 600-MVA generating unit having an M of 7.6 pu MW/pu frequency/sec on a machine base. The unit is supplying a load of 400 MVA. The load changes by 2% for a 1% change in frequency.

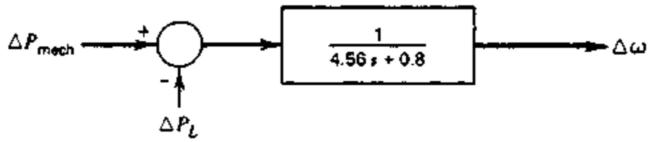

FIG. 9.5 Block diagram for system in Example 9A.

First, we will set up the block diagram of the equivalent generator load system. Everything will be referenced to a 100 MVA base.

$$M = 7.6 \times \frac{600}{1000} = 4.56 \text{ on a 1000-MVA base}$$

$$D = 2 \times \frac{400}{1000} = 0.8 \text{ on a 1000-MVA base}$$

Then the block diagram is as shown in Figure 9.5.

Suppose the load suddenly increases by 10 MVA (or 0.01 pu); that is,

$$\Delta P_L(s) = \frac{0.01}{s}$$

then

$$\Delta\omega(s) = -\frac{0.01}{s}\left(\frac{1}{4.56s + 0.8}\right)$$

or taking the inverse Laplace transform,

$$\Delta\omega(t) = (0.01/0.8)e^{-(0.8/4.56)t} - (0.01/0.8)$$

$$= 0.0125e^{-0.175t} - 0.0125$$

The final value of $\Delta\omega$ is -0.0125 pu, which is a drop of 0.75 Hz on a 60-Hz system.

When two or more generators are connected to a transmission system network , we must take account of the phase angle difference across the network in analyzing frequency changes. However, for the sake of governor analysis, which we are interested in here, we can assume that frequency will be constant over those parts of the network that are tightly interconnected. When making such an assumption, we can then lump the rotating mass of the turbine generators together into an equivalent that is driven by the sum of the individual turbine mechanical outputs. This is illustrated in Figure 9.6 where all turbine generators were lumped into a single equivalent rotating mass, M_{equiv}.

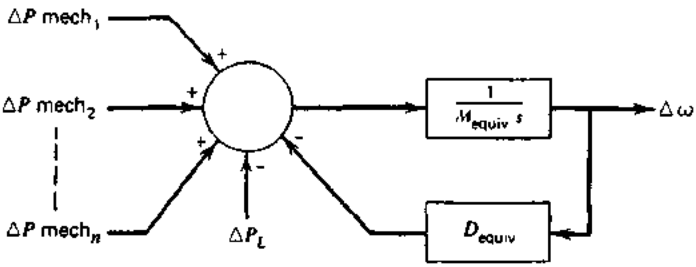

FIG. 9.6 Multi-turbine-generator system equivalent.

Similarly, all individual system loads were lumped into an equivalent load with damping coefficient, D_{equiv}.

9.4 PRIME-MOVER MODEL

The prime mover driving a generator unit may be a steam turbine or a hydroturbine. The models for the prime mover must take account of the steam supply and boiler control system characteristics in the case of a steam turbine, or the penstock characteristics for a hydro turbine. Throughout the remainder of this chapter, only the simplest prime-mover model, the nonreheat turbine, will be used. The models for other more complex prime movers, including hydro turbines, are developed in the references (see Further Reading).

The model for a nonreheat turbine, shown in Figure 9.7, relates the position of the valve that controls emission of steam into the turbine to the power output of the turbine, where

T_{CH} = "charging time" time constant

ΔP_{valve} = per unit change in valve position from nominal

The combined prime-mover–generator-load model for a single generating unit can be built by combining Figure 9.4 and 9.7, as shown in Figure 9.8.

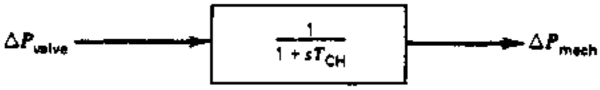

FIG. 9.7 Prime-mover model.

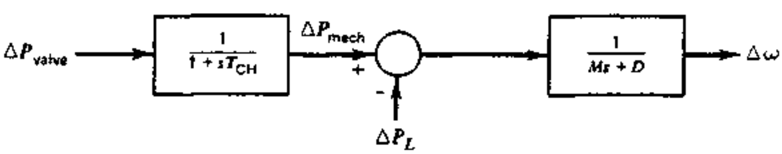

FIG. 9.8 Prime-mover–generator-load model.

9.5 GOVERNOR MODEL

Suppose a generating unit is operated with fixed mechanical power output from the turbine. The result of any load change would be a speed change sufficient to cause the frequency-sensitive load to exactly compensate for the load change (as in Example 9A). This condition would allow system frequency to drift far outside acceptable limits. This is overcome by adding a governing mechanism that senses the machine speed, and adjusts the input valve to change the mechanical power output to compensate for load changes and to restore frequency to nominal value. The earliest such mechanism used rotating "flyballs" to sense speed and to provide mechanical motion in response to speed changes. Modern governors use electronic means to sense speed changes and often use a combination of electronic, mechanical, and hydraulic means to effect the required valve position changes. The simplest governor, called the *isochronous governor*, adjusts the input valve to a point that brings frequency back to nominal value. If we simply connect the output of the speed-sensing mechanism to the valve through a direct linkage, it would never bring the frequency to nominal. To force the frequency error to zero, one must provide what control engineers call reset action. Reset action is accomplished by integrating the frequency (or speed) error, which is the difference between actual speed and desired or reference speed.

We will illustrate such a speed-governing mechanism with the diagram shown in Figure 9.9. The speed-measurement device's output, ω, is compared with a reference, ω_{ref}, to produce an error signal, $\Delta\omega$. The error, $\Delta\omega$, is negated and then amplified by a gain K_G and integrated to produce a control signal, ΔP_{valve}, which causes the main steam supply valve to open (ΔP_{valve} position) when $\Delta\omega$ is negative. If, for example, the machine is running at reference speed and the electrical load increases, ω will fall below ω_{ref} and $\Delta\omega$ will be negative. The action of the gain and integrator will be to open the steam valve, causing the turbine to increase its mechanical output, thereby increasing the electrical

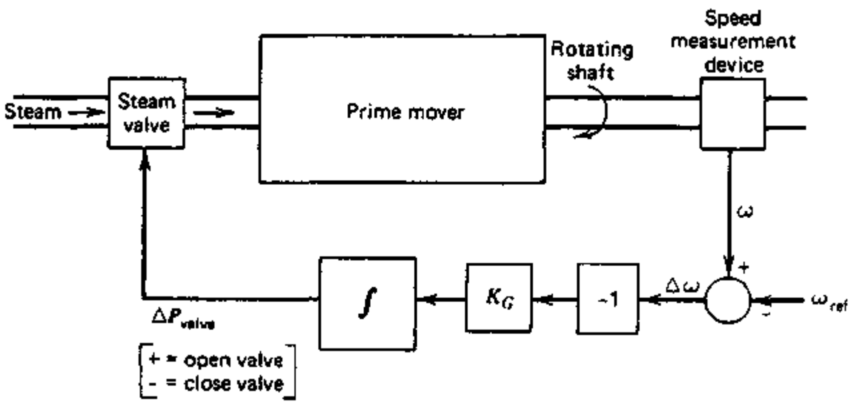

FIG. 9.9 Isochronous governor.

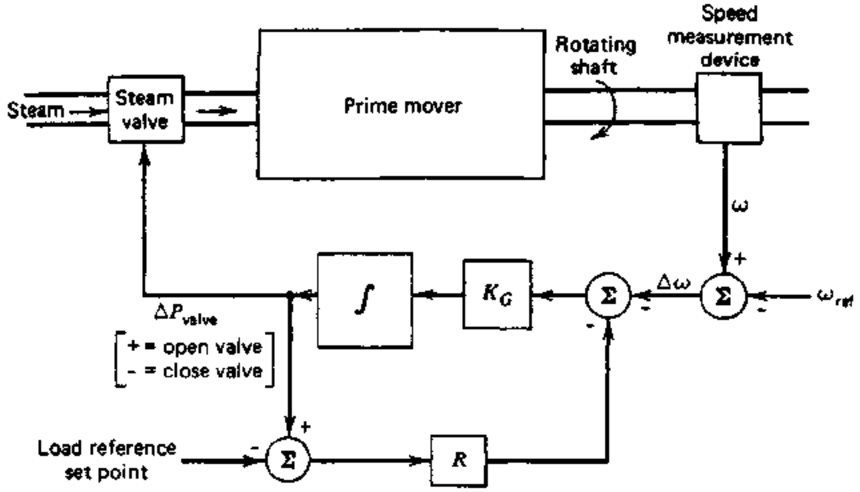

FIG. 9.10 Governor with speed-droop feedback loop.

output of the generator and increasing the speed ω. When ω exactly equals ω_{ref}, the steam valve stays at the new position (further opened) to allow the turbine generator to meet the increased electrical load.

The isochronous (constant speed) governor of Figure 9.9 cannot be used if two or more generators are electrically connected to the same system since each generator would have to have precisely the same speed setting or they would "fight" each other, each trying to pull the system's speed (or frequency) to its own setting. To be able to run two or more generating units in parallel on a generating system, the governors are provided with a feedback signal that causes the speed error to go to zero at different values of generator output.

This can be accomplished by adding a feedback loop around the integrator as shown in Figure 9.10. Note that we have also inserted a new input, called the *load reference*, that we will discuss shortly. The block diagram for this governor is shown in Figure 9.11, where the governor now has a net gain of $1/R$ and a time constant T_G.

The result of adding the feedback loop with gain R is a governor characteristic as shown in Fig. 9.12. The value of R determines the slope of the characteristic. That is, R determines the change on the unit's output for a given change in frequency. Common practice is to set R on each generating unit so that a change from 0 to 100% (i.e., rated) output will result in the same frequency change for each unit. As a result, a change in electrical load on a system will be compensated by generator unit output changes proportional to each unit's rated output.

If two generators with drooping governor characteristics are connected to a power system, there will always be a unique frequency, at which they will share a load change between them. This is illustrated in Figure 9.13, showing two units with drooping characteristics connected to a common load.

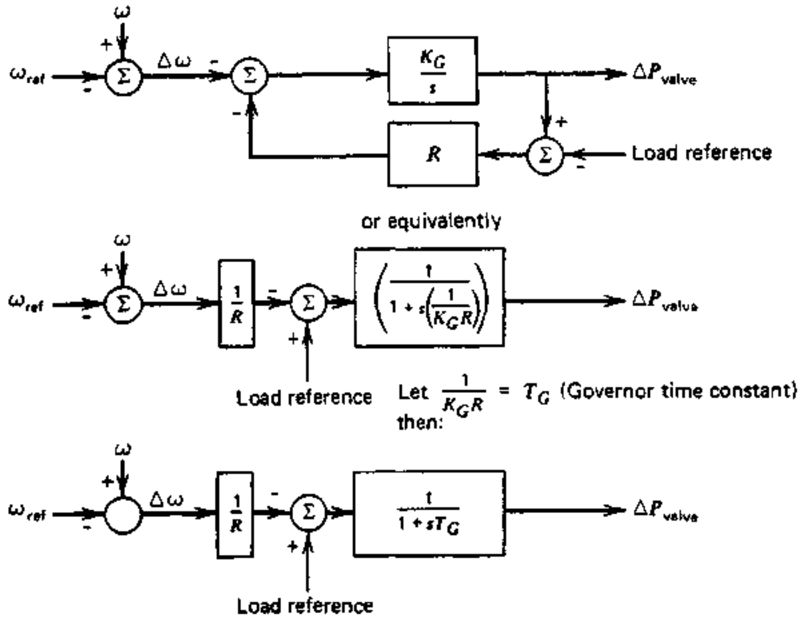

FIG. 9.11 Block diagram of governor with droop.

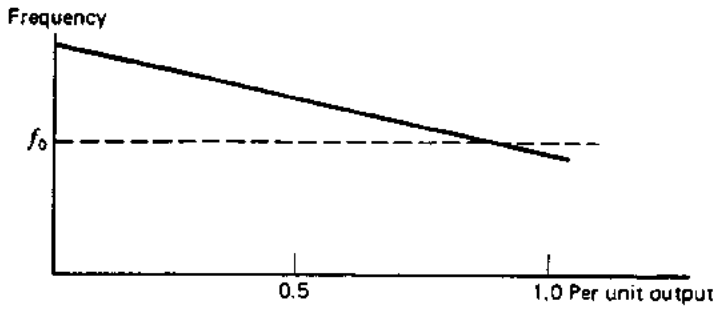

FIG. 9.12 Speed-droop characteristic.

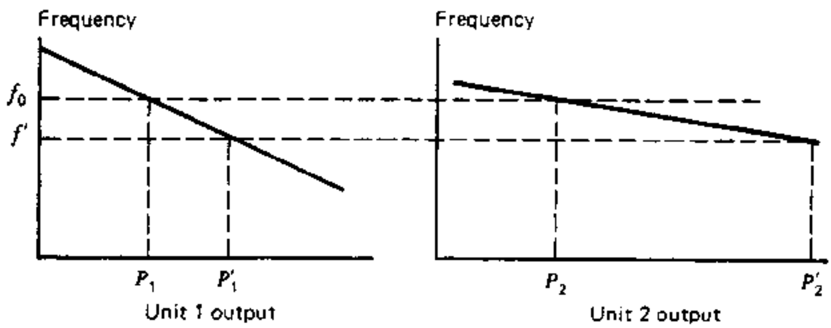

FIG. 9.13 Allocation of unit outputs with governor droop.

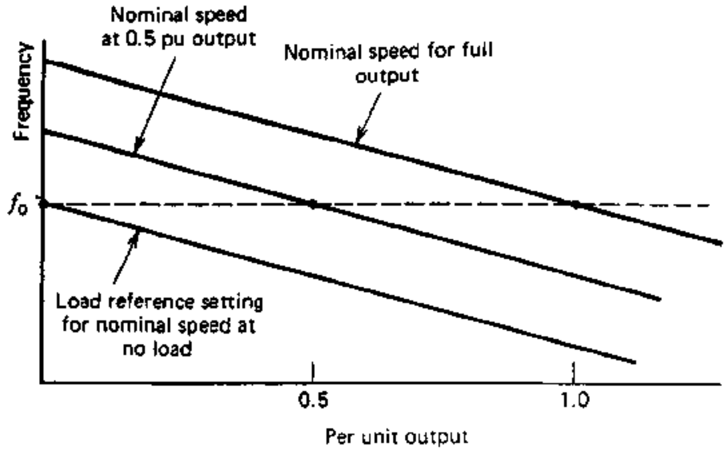

FIG. 9.14 Speed-changer settings.

As shown in Figure 9.13, the two units start at a nominal frequency of f_0. When a load increase, ΔP_L, causes the units to slow down, the governors increase output until the units seek a new, common operating frequency, f'. The amount of load pickup on each unit is proportional to the slope of its droop characteristic. Unit 1 increases its output from P_1 to P_1', unit 2 increases its output from P_2 to P_2' such that the net generation increase, $P_1' - P_1 + P_2' - P_2$, is equal to ΔP_L. Note that the actual frequency sought also depends on the load's frequency characteristic as well.

Figure 9.10 shows an input labeled "load reference set point." By changing the load reference, the generator's governor characteristic can be set to give reference frequency at any desired unit output. This is illustrated in Figure 9.14. *The basic control input to a generating unit as far as generation control is concerned is the load reference set point.* By adjusting this set point on each unit, a desired unit dispatch can be maintained while holding system frequency close to the desired nominal value.

Note that a steady-state change in ΔP_{valve} of 1.0 pu requires a value of R pu change in frequency, $\Delta\omega$. One often hears unit regulation referred to in percent. For instance, a 3% regulation for a unit would indicate that a 100% (1.0 pu) change in valve position (or equivalently a 100% change in unit output) requies a 3% change in frequency. Therefore, R is equal to pu change in frequency divided by pu change in unit output. That is,

$$R = \frac{\Delta\omega}{\Delta P} \text{ pu}$$

At this point, we can construct a block diagram of a governor–prime-mover–rotating mass/load model as shown in Figure 9.15. Suppose that this generator

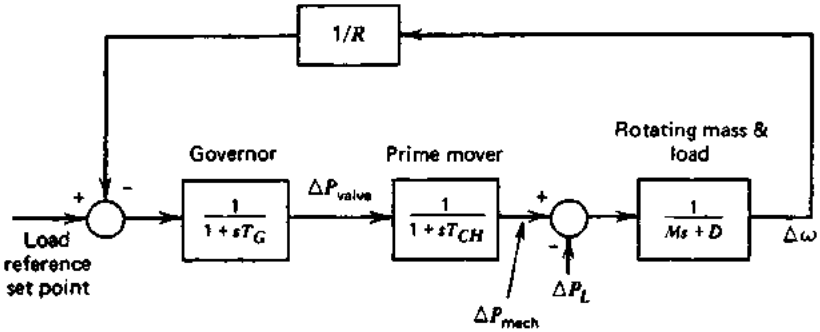

FIG. 9.15 Block diagram of governor, prime mover, and rotating mass.

experiences a step increase in load,

$$\Delta P_L(s) = \frac{\Delta P_L}{s} \tag{9.19}$$

The transfer function relating the load change, ΔP_L, to the frequency change, $\Delta\omega$, is

$$\Delta\omega(s) = \Delta P_L(s)\left[\frac{\dfrac{-1}{Ms + D}}{1 + \dfrac{1}{R}\left(\dfrac{1}{1 + sT_G}\right)\left(\dfrac{1}{1 + sT_{CH}}\right)\left(\dfrac{1}{Ms + D}\right)}\right] \tag{9.20}$$

The steady-state value of $\Delta\omega(s)$ may be found by

$$\Delta\omega \text{ steady state} = \lim_{s\to 0} [s\,\Delta\omega(s)]$$

$$= \frac{-\Delta P_L\left(\dfrac{1}{D}\right)}{1 + \left(\dfrac{1}{R}\right)\left(\dfrac{1}{D}\right)} = \frac{-\Delta P_L}{\dfrac{1}{R} + D} \tag{9-21}$$

Note that if D were zero, the change in speed would simply be

$$\Delta\omega = -R\,\Delta P_L \tag{9.22}$$

If several generators (each having its own governor and prime mover) were connected to the system, the frequency change would be

$$\Delta\omega = \frac{-\Delta P_L}{\dfrac{1}{R_1} + \dfrac{1}{R_2} + \cdots + \dfrac{1}{R_n} + D} \tag{9.23}$$

9.6 TIE-LINE MODEL

The power flowing across a transmission line can be modeled using the DC load flow method shown in Chapter 4.

$$P_{\text{tie flow}} = \frac{1}{X_{\text{tie}}}(\theta_1 - \theta_2) \tag{9.24}$$

This tie flow is a steady-state quantity. For purposes of analysis here, we will perturb Eq. 9.24 to obtain deviations from nominal flow as a function of deviations in phase angle from nominal.

$$P_{\text{tie flow}} + \Delta P_{\text{tie flow}} = \frac{1}{X_{\text{tie}}}[(\theta_1 + \Delta\theta_1) - (\theta_2 + \Delta\theta_2)]$$

$$= \frac{1}{X_{\text{tie}}}(\theta_1 - \theta_2) + \frac{1}{X_{\text{tie}}}(\Delta\theta_1 - \Delta\theta_2) \tag{9.25}$$

Then

$$\Delta P_{\text{tie flow}} = \frac{1}{X_{\text{tie}}}(\Delta\theta_1 - \Delta\theta_2) \tag{9.26}$$

where $\Delta\theta_1$ and $\Delta\theta_2$ are equivalent to $\Delta\delta_1$ and $\Delta\delta_2$ as defined in Eq. 9.6. Then, using the relationship of Eq. 9.6,

$$\Delta P_{\text{tie flow}} = \frac{T}{s}(\Delta\omega_1 - \Delta\omega_2) \tag{9.27}$$

where $T = 377 \times 1/X_{\text{tie}}$ (for a 60-Hz system).

Note that $\Delta\theta$ must be in radians for ΔP_{tie} to be in per unit megawatts, but $\Delta\omega$ is in per unit speed change. Therefore, we must multiply $\Delta\omega$ by 377 rad/sec (the base frequency in rad/sec at 60 Hz). T may be thought of as the "tie-line stiffness" coefficient.

Suppose now that we have an interconnected power system broken into two areas each having one generator. The areas are connected by a single transmission line. The power flow over the transmission line will appear as a a positive load to one area and an equal but negative load to the other, or vice versa, depending on the direction of flow. The direction of flow will be dictated by the relative phase angle between the areas, which is determined by the relative speed deviations in the areas. A block diagram representing this interconnection can be drawn as in Figure 9.16. Note that the tie power flow was defined as going from area 1 to area 2; therefore, the flow appears as a load to area 1 and a power source (negative load) to area 2. If one assumes that mechanical powers are constant, the rotating masses and tie line exhibit damped oscillatory characteristics known as synchronizing oscillations. (See problem 9.3 at the end of this chapter.)

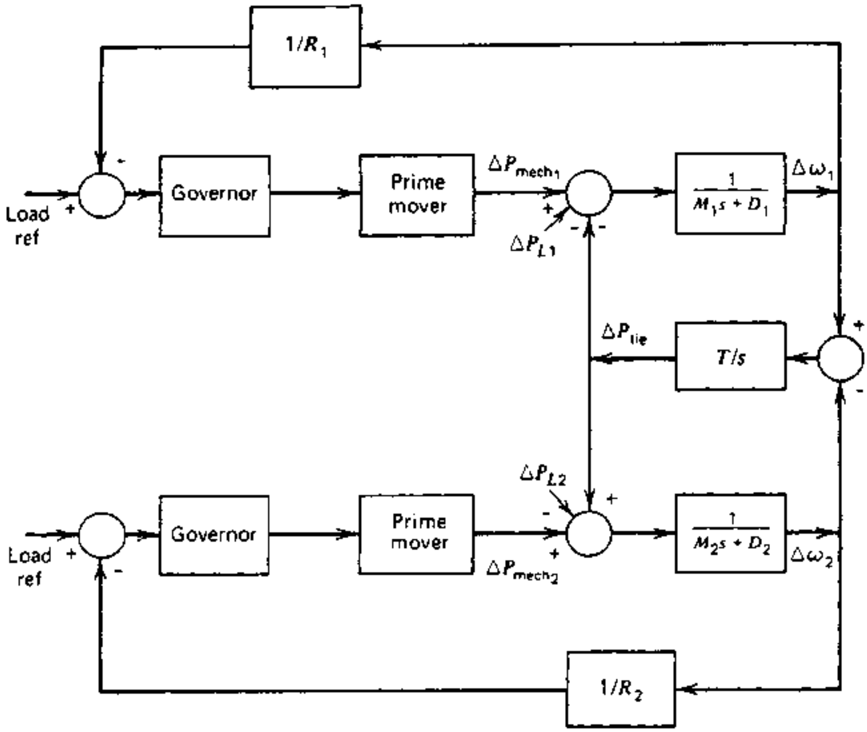

FIG. 9.16 Block diagram of interconnected areas.

It is quite important to analyze the steady-state frequency deviation, tie-flow deviation, and generator outputs for an interconnected area after a load change occurs. Let there be a load change ΔP_{L_1} in area 1. In the steady state, after all synchronizing oscillations have damped out, the frequency will be constant and equal to the same value on both areas. Then

$$\Delta\omega_1 = \Delta\omega_2 = \Delta\omega \quad \text{and} \quad \frac{d(\Delta\omega_1)}{dt} = \frac{d(\Delta\omega_2)}{dt} = 0 \tag{9.28}$$

and

$$\begin{aligned} \Delta P_{\text{mech}_1} - \Delta P_{\text{tie}} - \Delta P_{L_1} &= \Delta\omega D_1 \\ \Delta P_{\text{mech}_2} + \Delta P_{\text{tie}} &= \Delta\omega D_2 \\ \Delta P_{\text{mech}_1} &= \frac{-\Delta\omega}{R_1} \\ \Delta P_{\text{mech}_2} &= \frac{-\Delta\omega}{R_2} \end{aligned} \tag{9.29}$$

By making appropriate substitutions in Eq. 9.29,

$$
\begin{aligned}
-\Delta P_{\text{tie}} - \Delta P_{L_1} &= \Delta\omega\left(\frac{1}{R_1} + D_1\right) \\
+\Delta P_{\text{tie}} &= \Delta\omega\left(\frac{1}{R_2} + D_2\right)
\end{aligned}
\tag{9.30}
$$

or, finally

$$
\Delta\omega = \frac{-\Delta P_{L_1}}{\dfrac{1}{R_1} + \dfrac{1}{R_2} + D_1 + D_2} \tag{9.31}
$$

from which we can derive the change in tie flow:

$$
\Delta P_{\text{tie}} = \frac{-\Delta P_{L_1}\left(\dfrac{1}{R_2} + D_2\right)}{\dfrac{1}{R_1} + \dfrac{1}{R_2} + D_1 + D_2} \tag{9.32}
$$

Note that the conditions described in Eqs. 9.28 through 9.32 are for the new steady-state conditions after the load change. The new tie flow is determined by the net change in load and generation in each area. We do not need to know the tie stiffness to determine this new tie flow, although the tie stiffness will determine how much difference in phase angle across the tie will result from the new tie flow.

EXAMPLE 9B

You are given two system areas connected by a tie line with the following characteristics.

Area 1	Area 2
$R = 0.01$ pu	$R = 0.02$ pu
$D = 0.8$ pu	$D = 1.0$ pu
Base MVA = 500	Base MVA = 500

A load change of 100 MW (0.2 pu) occurs in area 1. What is the new steady-state frequency and what is the change in tie flow? Assume both areas were at nominal frequency (60 Hz) to begin.

$$\Delta\omega = \frac{-\Delta P_{L_1}}{\dfrac{1}{R_1} + \dfrac{1}{R_2} + D_1 + D_2} = \frac{-0.2}{\dfrac{1}{0.01} + \dfrac{1}{0.02} + 0.8 + 1} = -0.00131752 \text{ pu}$$

$$f_{\text{new}} = 60 - 0.00132(60) = 59.92 \text{ Hz}$$

$$\Delta P_{\text{tie}} = \Delta\omega\left(\frac{1}{R_2} + D_2\right) = -0.00131752\left(\frac{1}{0.02} + 1\right) = -0.06719368 \text{ pu}$$

$$= -33.6 \text{ MW}$$

The change in prime-mover power would be

$$\Delta P_{\text{mech}_1} = \frac{-\Delta\omega}{R_1} = -\left(\frac{-0.00131752}{0.01}\right) = 0.13175231 \text{ pu} = 65.876 \text{ MW}$$

$$\Delta P_{\text{mech}_2} = \frac{-\Delta\omega}{R_2} = -\left(\frac{-0.00131752}{0.02}\right) = 0.06587615 \text{ pu} = 32.938 \text{ MW}$$

$$= 98.814 \text{ MW}$$

The total changes in generation is 98.814 MA, which is 1.186 MW short of the 100 MW load change. The change in total area load due to frequency drop would be

$$\text{For area 1} = \Delta\omega D_1 = -0.0010540 \text{ pu} = -0.527 \text{ MW}$$

$$\text{For area 2} = \Delta\omega D_2 = -0.00131752 \text{ pu} = -0.6588 \text{ MW}$$

Therefore, the total load change is $=1.186$ MW, which accounts for the difference in total generation change and total load change. (See Problem 9.2 for further variations on this problem.)

If we were to analyze the dynamics of the two-area systems, we would find that a step change in load would always result in a frequency error. This is illustrated in Figure 9.17, which shows the frequency response of the system to a step-load change. Note that Figure 9.17 only shows the average frequency (omitting any high-frequency oscillations).

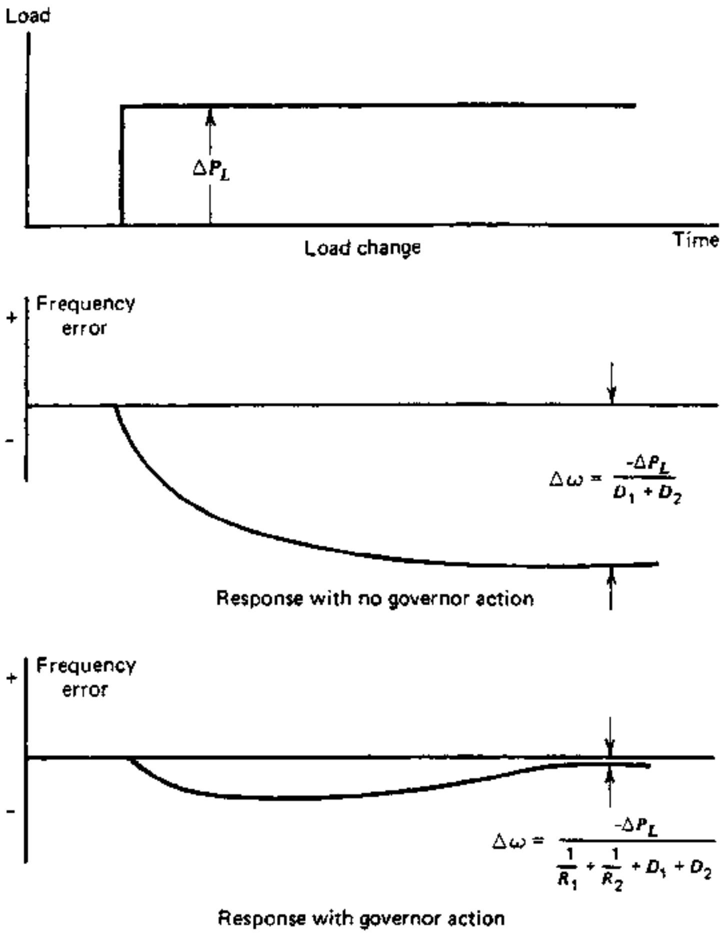

FIG. 9.17 Frequency response to load change.

9.7 GENERATION CONTROL

Automatic generation control (AGC) is the name given to a control system having three major objectives:

1. To hold system frequency at or very close to a specified nominal value (e.g., 60 Hz).
2. To maintain the correct value of interchange power between control areas.
3. To maintain each unit's generation at the most economic value.

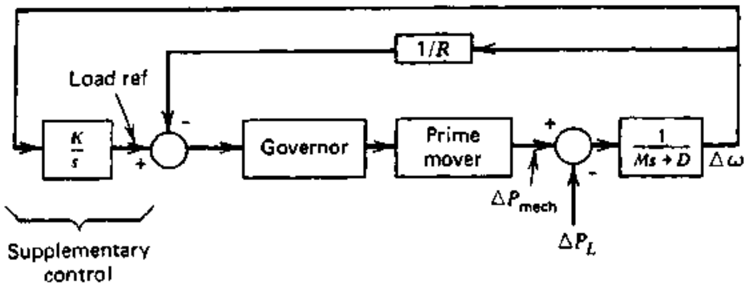

FIG. 9.18 Supplementary control added to generating init.

9.7.1 Supplementary Control Action

To understand each of the three objectives just listed, we may start out assuming that we are studying a single generating unit supplying load to an isolated power system. As shown in Section 9.5, a load change will produce a frequency change with a magnitude that depends on the droop characteristics of the governor and the frequency characteristics of the system load. Once a load change has occurred, a supplementary control must act to restore the frequency to nominal value. This can be accomplished by adding a reset (integral) control to the governor, as shown in Figure 9.18.

The reset control action of the supplementary control will force the frequency error to zero by adjustment of the speed reference set point. For example, the error shown in the bottom diagram of Figure 9.17 would be forced to zero.

9.7.2 Tie-Line Control

When two utilities interconnect their systems, they do so for several reasons. One is to be able to buy and sell power with neighboring systems whose operating costs make such transactions profitable. Further, even if no power is being transmitted over ties to neighboring systems, if one system has a sudden loss of a generating unit, the units throughout all the interconnection will experience a frequency change and can help in restoring frequency.

Interconnections present a very interesting control problem with respect to allocation of generation to meet load. The hypothetical situation in Figure 9.19 will be used to illustrate this problem. Assume both systems in Figure 9.19 have equal generation and load characteristics ($R_1 = R_2$, $D_1 = D_2$) and, further, assume system 1 was sending 100 MW to system 2 under an interchange agreement made between the operators of each system. Now, let system 2 experience a sudden load increase of 30 MW. Since both units have equal generation characteristics, they will both experience a 15 MW increase, and the tie line will experience an increase in flow from 100 MW to 115 MW. Thus, the 30 MW load increase in system 2 will have been satisfied by a 15 MW increase in generation in system 2, plus a 15 MW increase in tie flow into system 2. This

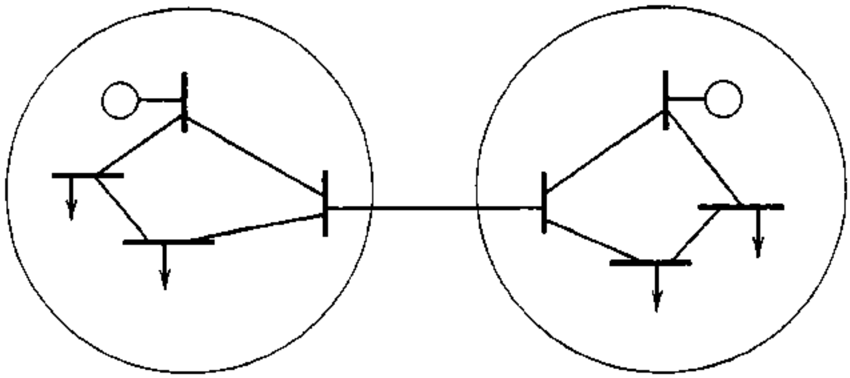

FIG. 9.19 Two-area system.

would be fine, except that system 1 contracted to sell only 100 MW, not 115 MW, and its generating costs have just gone up without anyone to bill the extra cost to. What is needed at this point is a control scheme that recognizes the fact that the 30 MW load increase occurred in system 2 and, therefore, would increase generation in system 2 by 30 MW while restoring frequency to nominal value. It would also restore generation in system 1 to its output before the load increase occurred.

Such a control system must use two pieces of information: the system frequency and the net power flowing in or out over the tie lines. Such a control scheme would, of necessity, have to recognize the following.

1. If frequency decreased and net interchange power leaving the system increased, a load increase has occurred outside the system.
2. If frequency decreased and net interchange power leaving the system decreased, a load increase has occurred inside the system.

This can be extended to cases where frequency increases. We will make the following definitions.

$$P_{\text{net int}} = \text{total actual net interchange}$$
$$(+ \text{ for power leaving the system; } - \text{ for power entering})$$

$$P_{\text{net int sched}} = \text{scheduled or desired value of interchange} \tag{9.33}$$

$$\Delta P_{\text{net int}} = P_{\text{net int}} - P_{\text{net int sched}}$$

Then, a summary of the tie-line frequency control scheme can be given as in the table in Figure 9.20.

$\Delta\omega$	$\Delta P_{\text{net int}}$	Load change		Resulting control action
−	−	ΔP_{L_1}	+	Increase P_{gen} in system 1
		ΔP_{L_2}	0	
+	+	ΔP_{L_1}	−	Decrease P_{gen} in system 1
		ΔP_{L_2}	0	
−	+	ΔP_{L_1}	0	Increase P_{gen} in system 2
		ΔP_{L_2}	+	
+	−	ΔP_{L_1}	0	Decrease P_{gen} in system 2
		ΔP_{L_2}	−	

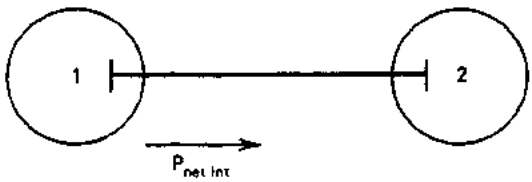

FIG. 9.20 Tie-line frequency control actions for two-area system.

We define a *control area* to be a part of an interconnected system within which the load and generation will be controlled as per the rules in Figure 9.20. The control area's boundary is simply the tie-line points where power flow is metered. All tie lines crossing the boundary must be metered so that total control area net interchange power can be calculated.

The rules set forth in Figure 9.20 can be implemented by a control mechanism that weighs frequency deviation, $\Delta\omega$, and net interchange power, $\Delta P_{\text{net int}}$. The frequency response and tie flows resulting from a load change, ΔP_{L_1}, in the two-area system of Figure 9.16 are derived in Eqs. 9.28 through 9.32. These results are repeated here.

Load Change	Frequency Change	Change in Net Interchange	
ΔP_{L_1}	$\Delta\omega = \dfrac{-\Delta P_{L_1}}{\dfrac{1}{R_1} + \dfrac{1}{R_2} + D_1 + D_2}$	$\Delta P_{\text{net int}_1} = \dfrac{-\Delta P_{L_1}\left(\dfrac{1}{R_2} + D_2\right)}{\dfrac{1}{R_1} + \dfrac{1}{R_2} + D_1 + D_2}$	(9.34)

This corresponds to the first row of the table in Figure 9.20; we would therefore require that

$$\Delta P_{\text{gen}_1} = \Delta P_{L_1}$$
$$\Delta P_{\text{gen}_2} = 0$$

The required change in generation, historically called the *area control error* or ACE, represents the shift in the area's generation required to restore frequency and net interchange to their desired values. The equaions for ACE for each area are

$$\begin{aligned} \text{ACE}_1 &= -\Delta P_{\text{net int}_1} - B_1\,\Delta\omega \\ \text{ACE}_2 &= -\Delta P_{\text{net int}_2} - B_2\,\Delta\omega \end{aligned} \tag{9.35}$$

where B_1 and B_2 are called *frequency bias factors*. We can see from Eq. 9.34 that setting bias factors as follows:

$$\begin{aligned} B_1 &= \left(\frac{1}{R_1} + D_1\right) \\ B_2 &= \left(\frac{1}{R_2} + D_2\right) \end{aligned} \tag{9.36}$$

results in

$$\text{ACE}_1 = \left(\frac{+\Delta P_{L_1}\left(\dfrac{1}{R_2} + D_2\right)}{\dfrac{1}{R_1} + \dfrac{1}{R_2} + D_1 + D_2}\right) - \left(\frac{1}{R_1} + D_1\right)\left(\frac{-\Delta P_{L_1}}{\dfrac{1}{R_1} + \dfrac{1}{R_2} + D_1 + D_2}\right) = \Delta P_{L_1}$$

$$\text{ACE}_2 = \left(\frac{-\Delta P_{L_1}\left(\dfrac{1}{R_2} + D_2\right)}{\dfrac{1}{R_1} + \dfrac{1}{R_2} + D_1 + D_2}\right) - \left(\frac{1}{R_2} + D_2\right)\left(\frac{-\Delta P_{L_1}}{\dfrac{1}{R_1} + \dfrac{1}{R_2} + D_1 + D_2}\right) = 0$$

This control can be carried out using the scheme outlined in Figure 9.21. Note that the values of B_1 and B_2 would have to change each time a unit was committed or decommitted, in order to have the exact values as given in Eq. 9.36. Actually, the integral action of the supplementary controller will guarantee a reset of ACE to zero even when B_1 and B_2 are in error.

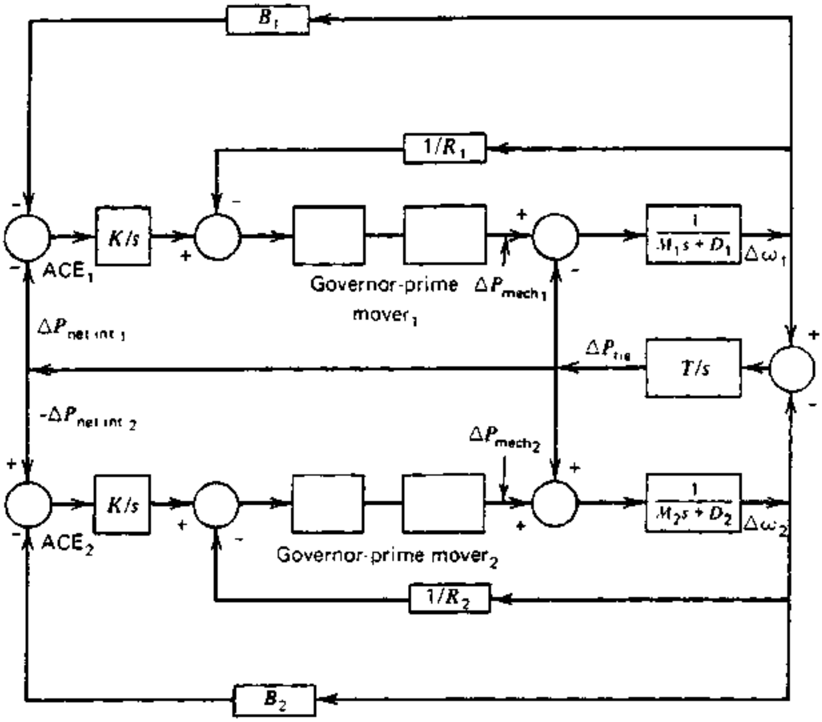

FIG. 9.21 Tie-line bias supplementary control for two areas.

9.7.3 Generation Allocation

If each control area in an interconnected system had a single generating unit, the control system of Figure 9.21 would suffice to provide stable frequency and tie-line interchange. However, power systems consist of control areas with many generating units with outputs that must be set according to economics. That is, we must couple an economic dispatch calculation to the control mechanism so it will know how much of each area's total generation is required from each individual unit.

One must remember that a particular total generation value will not usually exist for a very long time, since the load on a power system varies continually as people and industries use individual electric loads. Therefore, it is impossible to simply specify a total generation, calculate the economic dispatch for each unit, and then give the control mechanism the values of megawatt output for each unit—unless such a calculation can be made very quickly. Until the widespread use of digital computer-based control systems, it was common practice to construct control mechanisms such as we have been describing using analog computers. Although analog computers are not generally proposed for new control-center installations today, there are some in active use. An analog computer can provide the economic dispatch and allocation of generation in an area on an instantaneous basis through the use of function generators set to equal the units' incremental heat rate curves. B matrix loss formulas were also incorporated into analog schemes by setting the matrix coefficients on precision potentiometers.

When using digital computers, it is desirable to be able to carry out the economic-dispatch calculations at intervals of one to several minutes. Either the output of the economic dispatch calculation is fed to an analog computer (i.e., a "digitally directed analog" control system) or the output is fed to another program in the computer that executes the control functions (i.e., a "direct digital" control system). Whether the control is analog or digital, the allocation of generation must be made instantly when the required area total generation changes. Since the economic-dispatch calculation is to be executed every few minutes, a means must be provided to indicate how the generation is to be allocated for values of total generation other than that used in the economic-dispatch calculation.

The allocation of individual generator output over a range of total generation values is accomplished using base points and participation factors. The economic-dispatch calculation is executed with a total generation equal to the sum of the present values of unit generation as measured. The result of this calculation is a set of base-point generations, $P_{i_{\text{base}}}$, which is equal to the most economic output for each generator unit. The rate of change of each unit's output with respect to a change in total generation is called the unit's *participation factor*, *pf* (see Section 3.8 and Example 3I in Chapter 3). The base point and participation factors are used as follows

$$P_{i_{\text{des}}} = P_{i_{\text{base}}} + pf_i \times \Delta P_{\text{total}} \tag{9.37}$$

where

$$\Delta P_{\text{total}} = P_{\text{new total}} - \sum_{\substack{\text{all}\\ \text{gen}}} P_{i_{\text{base}}} \tag{9.38}$$

and

$$\begin{aligned} P_{i_{\text{des}}} &= \text{new desired output from unit } i \\ P_{i_{\text{base}}} &= \text{base-point generation for unit } i \\ pf_i &= \text{participation factor for unit } i \\ \Delta P_{\text{total}} &= \text{change in total generation} \\ P_{\text{new total}} &= \text{new total generation} \end{aligned}$$

Note that by definition (e.g., see Eq. 3.35) the participation factors must sum to unity. In a direct digital control scheme, the generation allocation would be made by running a computer code that was programmed to execute according to Eqs. 9.37 and 9.38.

9.7.4 Automatic Generation Control (AGC) Implementation

Modern implementation of automatic generation control (AGC) schemes usually consists of a central location where information pertaining to the system is telemetered. Control actions are determined in a digital computer and then transmitted to the generation units via the same telemetry channels. To implement an AGC system, one would require the following information at the control center.

1. Unit megawatt output for each committed unit.
2. Megawatt flow over each tie line to neighboring systems.
3. System frequency.

The output of the execution of an AGC program must be transmitted to each of the generating units. Present practice is to transmit raised or lower pulses of varying lengths to the unit. Control equipment then changes the unit's load reference set point up or down in proportion to the pulse length. The "length" of the control pulse may be encoded in the bits of a digital word that is transmitted over a digital telemetry channel. The use of digital telemetry is becoming commonplace in modern systems wherein supervisory control (opening and closing substation breakers), telemetry information (measurements of MW, MVAR, MVA voltage, etc.) and control information (unit raise/lower) is all sent via the same channels.

The basic reset control loop for a unit consists of an integrator with gain K as shown in Figure 9.22. The control loop is implemented as shown in Figure 9.23. The P_{des} control input used in Figures 9.22 and 9.23 is a function of system frequency deviation, net interchange error, and each unit's deviation from its scheduled economic output.

The overall control scheme we are going to develop starts with ACE, which is a measure of the error in total generation from total desired generation. ACE is calculated according to Figure 9.24. ACE serves to indicate when total generation must be raised or lowered in a control area. However, ACE is not the only error signal that must "drive" our controller. The individual units

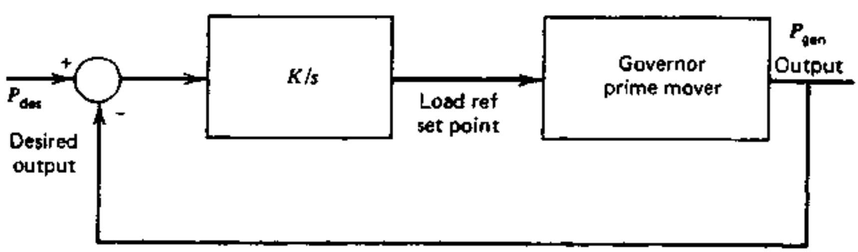

FIG. 9.22 Basic generation control loop.

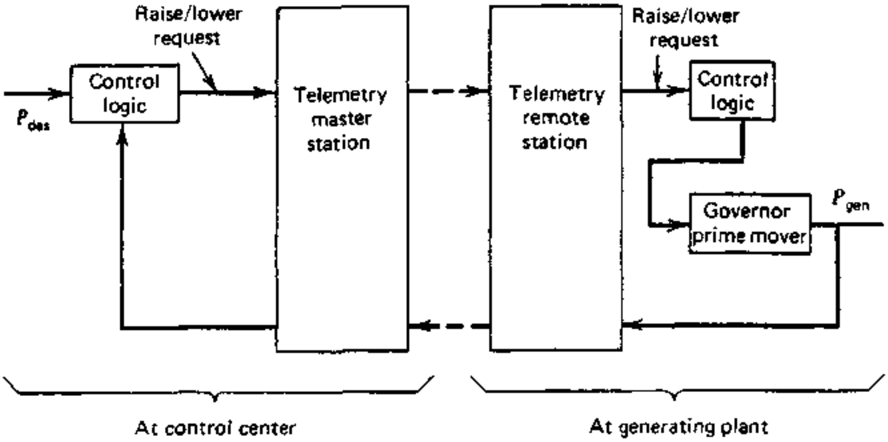

FIG. 9.23 Basic generation control loop via telemetry.

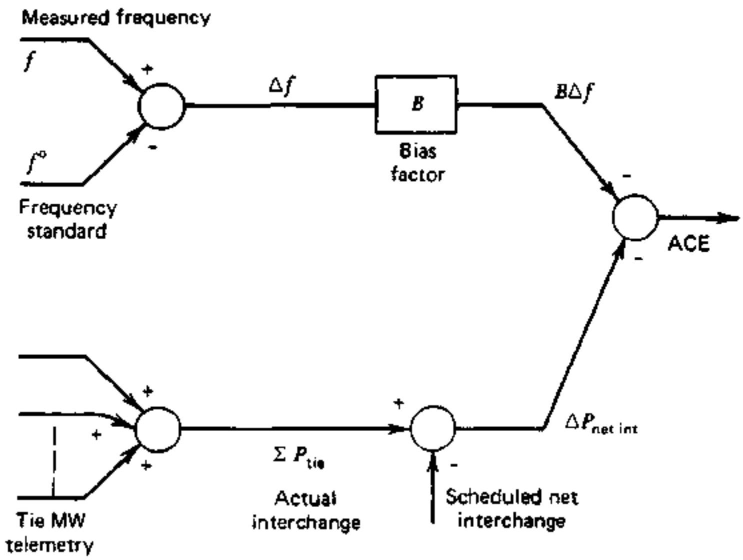

FIG. 9.24 ACE calculation.

may deviate from the economic output as determined by the base point and participation-factor calculation.

The AGC control logic must also be driven by the errors in unit output so as to force the units to obey the economic dispatch. To do this, the sum of the unit output errors is added to ACE to form a composite error signal that drives the entire control system. Such a control system is shown schematically in Figure 9.25, where we have combined the ACE calculation, the generation allocation calculation, and the unit control loop.

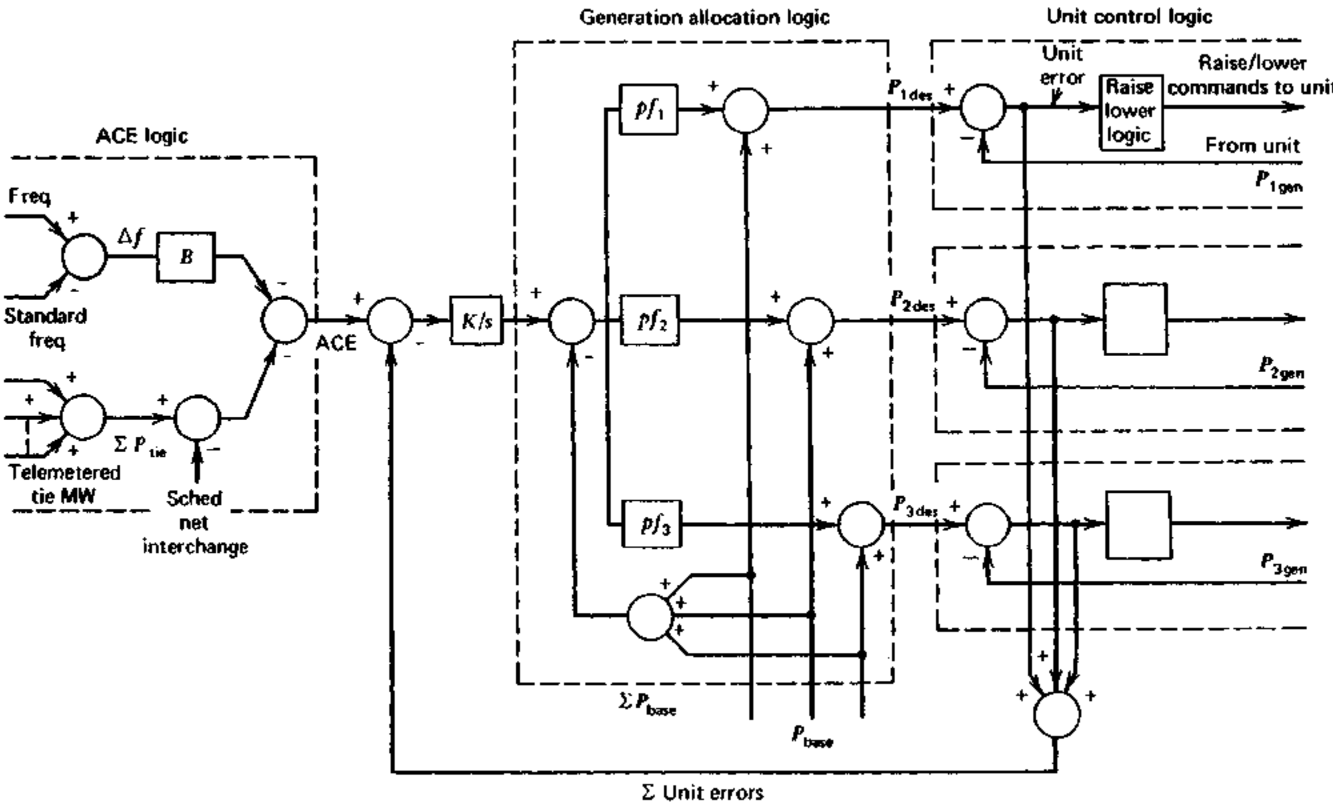

FIG. 9.25 Overview of AGC logic.

Investigation of Figure 9.25 shows an overall control system that will try to drive ACE to zero as well as driving each unit's output to its required economic value. Readers are cautioned that there are many variations to the control execution shown in Figure 9.25. This is especially true of digital implementations of AGC where great sophistication can be programmed into an AGC computer code.

Often the question is asked as to what constitutes "good" AGC design. This is difficult to answer, other than in a general way, since what is "good" for one system may be different in another. Three general criteria can be given.

1. The ACE signal should ideally be kept from becoming too large. Since ACE is directly influenced by random load variations, this criterion can be treated statistically by saying that the standard deviation of ACE should be small.
2. ACE should not be allowed to "drift." This means that the integral of ACE over an appropriate time should be small. "Drift" in ACE has the effect of creating system time errors or what are termed *inadvertent interchange errors.*
3. The amount of control action called for by the AGC should be kept to a minimum. Many of the errors in ACE, for example, are simply random load changes that need not cause control action. Trying to "chase" these random load variations will only wear out the unit speed-changing hardware.

To achieve the objectives of good AGC, many features are added, as described briefly in the next section.

9.7.5 AGC Features

This section will serve as a simple catalog of some of the features that can be found in most AGC systems.

Assist action: Often the incremental heat rate curves for generating units will give trouble to an AGC when an excessive ACE occurs. If one unit's participation factor is dominant, it will take most of the control action and the other units will remain relatively fixed. Although it is the proper thing to do as far as economics are concerned, the one unit that is taking all the action will not be able to change its output fast enough when a large ACE calls for a large change in generation. The assist logic then comes into action by moving more of the units to correct ACE. When the ACE is corrected, the AGC then restores the units back to economic output.

Filtering of ACE: As indicated earlier, much of the change in ACE may be random noise that need not be "chased" by the generating units. Most

AGC programs use elaborate, adaptive nonlinear filtering schemes to try to filter out random noise from true ACE deviations that need control action.

Telemetry failure logic: Logic must be provided to insure that the AGC will not take wrong action when a telemetered value it is using fails. The usual design is to suspend all AGC action when this condition happens.

Unit control detection: Sometimes a generating unit will not respond to raised lower pulses. For the sake of overall control, the AGC ought to take this into account. Such logic will detect a unit that is not following raised/lower pulses and suspend control to it, thereby causing the AGC to reallocate control action among the other units on control.

Ramp control: Special logic allows the AGC to ramp a unit form one output to another at a specified rate of change in output. This is most useful in bringing units on-line and up to full output.

Rate limiting: All AGC designs must account for the fact that units cannot change their output too rapidly. This is especially true of thermal units where mechanical and thermal stresses are limiting. The AGC must limit the rate of change such units will be called on to undergo during fast load changes.

Unit control modes: Many units in power systems are not under full AGC control. Various special control modes must be provided such as manual, base load, and base load and regulating. For example, base load and regulating units are held at their base load value—but are allowed to move as assist action dictates, and are then restored to base-load value.

PROBLEMS

9.1 Suppose that you are given a single area with three generating units as shown in Figure 9.26.

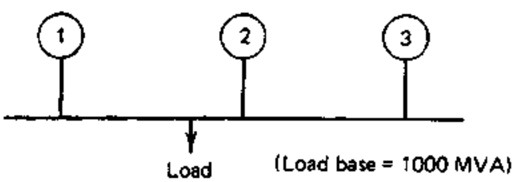

FIG. 9.26 Three-generator system for Problem 9.1.

Unit	Rating (MVA)	Speed Droop R (per unit on unit base)
1	100	0.01
2	500	0.015
3	500	0.015

The units are initially loaded as follows:

$$P_1 = 80 \text{ MW}$$
$$P_2 = 300 \text{ MW}$$
$$P_3 = 400 \text{ MW}$$

Assume $D = 0$; what is the new generation on each unit for a 50-MW load increase? Repeat with $D = 1.0$ pu (i.e., 1.0 pu on load base). Be careful to convert all quantities to a common base when solving.

9.2 Using the values of R and D in each area, for Example 9B, resolve for the 100-MW load change in area 1 under the following conditions:

Area 1: base MVA = 2000 MVA

Area 2: base MVA = 500 MVA

Then solve for a load change of 100 MW occurring in area 2 with R values and D values as in Example 9B and base MVA for each area as before.

9.3 Given the block diagram of two interconnected areas shown in Figure 9.27 (consider the prime-mover output to be constant, i.e., a "blocked" governor):

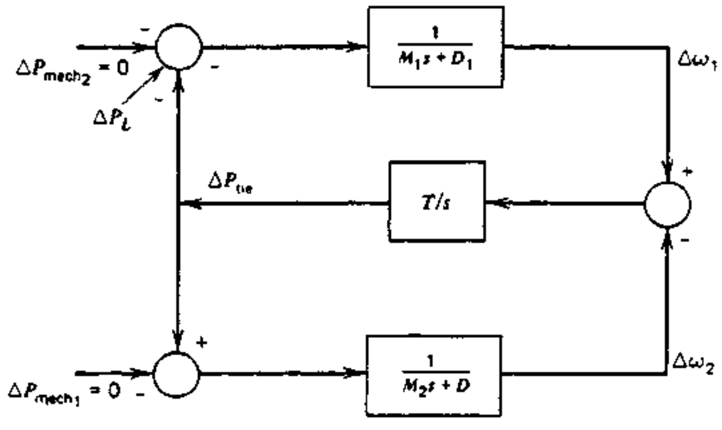

FIG. 9.27 Two-area system for Problem 9.3

a. Derive the transfer functions that relate $\Delta\omega_1(s)$ and $\Delta\omega_2(s)$ to a load change $\Delta P_L(s)$.

b. For the following data (all quantities refer to a 1000-MVA base),

$$M_1 = 3.5 \text{ pu} \qquad D_1 = 1.00$$
$$M_2 = 4.0 \text{ pu} \qquad D_2 = 0.75$$
$$T = 377 \times 0.02 \text{ pu} = 7.54 \text{ pu}$$

calculate the final frequency for load-step change in area 1 of 0.2 pu (i.e., 200 MW). Assume frequency was at nominal and tie flow was 0 pu.

c. Derive the transfer function relating tie flow, $\Delta P_{tie}(s)$ to $\Delta P_L(s)$. For the data of part b calculate the frequency of oscillation of the tie power flow. What happens to this frequency as tie stiffness increases (i.e. $T \rightarrow \infty$)?

9.4 Given two generating units with data as follows.

Unit 1: Fuel cost: $F_1 = 1.0$ R/MBtu

$H_1(P_1) = 500 + 7P_1 + 0.002P_1^2$ MBtu/h

$150 < P_1 < 600$ Rate limit = 2 MW/min

Unit 2: Fuel cost: $F_2 = 0.98$ R/MBtu

$H_2(P_2) = 200 + 8P_2 + 0.0025P_2^2$ MBtu/h

$125 \leq P_2 \leq 500$ MW Rate limit = 2 MW/min

a. Calculate the economic base points and participation factors for these two units supplying 500 MW total. Use Eq. 3.35 to calculate participation factors.

b. Assume a load change of 10 MW occurs and that we wish to clear the ACE to 0 in 5 min. Is this possible if the units are to be allocated by base points and participation factors?

c. Assume the same load change as in part b, but assume that the rate limit on unit 1 is now 0.5 MW/min.

This problem demonstrates the flaw in using Eq. 3.35 to calculate the participation factors. An alternate procedure would generate participation factors as follows.

Let t be the time in minutes between economic-dispatch calculation executions. Each unit will be assigned a range that must be obeyed in performing the economic dispatch.

$$\begin{aligned} P_i^{max} &= P_i^0 + t \times \text{rate limit}_i \\ P_i^{min} &= P_i^0 - t \times \text{rate limit}_i \end{aligned} \qquad (9.39)$$

The range thus defined is simply the maximum and minimum excursion the unit could undergo within t minutes. If one of the limits described is outside the unit's normal economic limits, the economic limit would be used. Participation factors can then be calculated by resolving the economic dispatch at a higher value and enforcing the new limits described previously.

d. Assume $T = 5$ min and that the perturbed economic dispatch is to be resolved for 510 MW. Calculate the new participation factors as

$$pf_i = \frac{P_i^{\Delta} - P_{i_{\text{base pt}}}}{\Delta P_{\text{total}}}$$

where

$$P_{i_{\text{base pt}}} = \text{base economic solution}$$

$$P_{1_{\text{base}}} + P_{2_{\text{base}}} = 500 \text{ MW}$$

$$P_i^{\Delta} = \text{perturbed solution}$$

$$P_1^{\Delta} + P_2^{\Delta} = 510 \text{ MW}$$

with limits as calculated in Eq. 9.35.

Assume the initial unit generations P_i^0 were the same as the base points found in part a. And assume the rate limits were as in part c (i.e., unit 1 rate lim = 0.5 MW/ min, unit 2 rate lim = 2 MW/min). Now check to see if 1part c gives a different result.

9.5 The interconnected systems in the eastern United States and Canada have a total capacity of about 5×10^5 MW. The equivalent inertia and damping constants are approximately

$$M = 8 \text{ pu MW/pu frequency/sec}$$

and

$$D = 1.5$$

both on the system capacity base. It is necessary to correct for time errors every so often. The electrical energy involved is not insignificant.

a. Assume that a time error of 1 sec is to be corrected by deliberately supplying a power unbalance of a constant amount for a period of 1 h. Find the power unbalance required. Express the amount in MWH.

b. Is this energy requirement a function of the power unbalance? Assume a power unbalance is applied to the system of a duration "delta T". During this period, the unbalance of power is constant; after the period it is zero. Does it make any difference if the length of time is long or short? Show the response of the system. The time deviation is the integral of the frequency deviation.

9.6 In Fig. 9.16 assume that system 2 represents a system so large that it is effectively an "infinite bus." M_2 is much greater than M_1 and the frequency deviation in system 2 is zero.

a. Draw the block diagram including the tie line between areas 1 and 2. What is the transfer function for a load change in area 1 and the tie flow?

b. The reactance of the tie is 1 pu on a 1000-MW base. Initially, the tie flow is zero. System 1 has an inertia constant (M_1) of 10 on the same base. Load damping and governor action are neglected. Determine the equation for the tie-line power flow swings for a sudden short in area 1 that causes an instantaneous power drop of 0.02 pu (2%), which is restored instantly. Assume that $\Delta P_{L_1}(s) = -0.02$, and find the frequency of oscillation and maximum angular deviation between areas 1 and 2.

FURTHER READING

The reader should be familiar with the basics of control theory before attempting to read many of the references cited here. A good introduction to automatic generation control is the book *Control of Generation and Power Flow on Interconnected Systems*, by Nathan Cohn (reference 4 in Chapter 1). Other sources of introductory material are contained in references 1–3.

Descriptions of how steam turbine generators are modeled are found in references 4 and 5; reference 6 shows how hydro-units can be modeled. Reference 7 shows the effects to be expected from various prime-mover and governing systems. References 8–10 are representative of advances made in AGC techniques through the late 1960s and early 1970s. Other special interests in AGC design include special-purpose optimal filters (see references 10 and 11), direct digital control schemes (see references 12–15), and control of jointly owned generating units (see reference 16).

Research in control theory toward "optimal control" techniques was used in several papers presented in the late 1960s and early 1970s. As far as is known to the authors, optimal control techniques have not, as of the writing of this text, been utilized successfully in a working AGC system. Reference 17 is representative of the papers using optimal control theory.

Recent research has included an approach that takes the short-term load forecast, economic dispatch, and AGC problems, and approaches them as one overall control problem. References 18 and 19 illustrate this approach. References 20–22 are excellent overviews of more recent work in AGC.

1. Friedlander, G. D., "Computer-Controlled Power Systems, Part I—Boiler-Turbine Unit Controls," *IEEE Spectrum*, April 1965, pp. 60–81.
2. Friedlander, G. D., "Computer-Controlled Power Systems, Part II—Area Controls and Load Dispatch," *IEEE Spectrum*, May 1965, pp. 72–91.
3. Ewart, D. N., "Automatic Generation Control—Performance Under Normal Conditions," *Systems Engineering for Power: Status and Prospects*, U. S. Government Document, CONF-750867, 1975, pp. 1–14.

4. Anderson, P. M., *Modeling Thermal Power Plants for Dynamic Stability Studies*, Cyclone Copy Center, Ames, IA, 1974.
5. IEEE Committee Report, "Dynamic Models for Steam and Hydro Turbines in Power System Studies," *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-92, November/December 1973, pp. 1904–1915.
6. Undril, J. M., Woodward, J. L., "Nonlinear Hydro Governing Model and Improved Calculation for Determining Temporary Droop," *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-86, April 1967, pp, 443–453.
7. Concordia, C., Kirchmayer, L. K., de Mello, F. P., Schulz, R. P., "Effect of Prime-Mover Response and Governing Characteristics on System Dynamic Performance," *Proceedings of the American Power Conference*, 1966.
8. Cohn, N., "Considerations in the Regulation of Interconnected Areas," *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-86, December 1967, pp. 1527–1538.
9. Cohn N. "Techniques for Improving the Control of Bulk Power Transfers on Interconnected Systems," *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-90, November/December 1971, pp. 2409–2419.
10. Cooke, J. L., "Analysis of Power System's Power-Density Spectra," *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-83, January 1964, pp. 34–41.
11. Ross, C. W., "Error Adaptive Control Computer for Interconnected Power Systems," *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-85, July 1966, pp. 742–749.
12. Ross, C. W., "A Comprehensive Direct Digital Load-Frequency Controller," *IEEE Power Industry Computer Applications Conference Proceedings*, 1967.
13. Ross, C. W., Green, T. A., "Dynamic Performance Evaluation of a Computer-Controlled Electric Power System" *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-91, May/June 1972, pp. 1158–1165.
14. de Mello, F. P., Mills, R. J., B'Rells, W. F., "Automatic Generation Control—Part I: Process Modeling," *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-92, March/April 1973, pp. 710–715.
15. de Mello, F. P., Mills, R. J., B'Rells, W. F., "Automatic Generation Control—Part II: Digital Control Techniques," *IEEE Transactions on Powder Apparatus and Systems*, Vol. PAS-92, March/April 1973, pp. 716–724.
16. Podmore, R., Gibbard, M. J., Ross, D. W., Anderson, K. R., Page, R. G., Argo, K., Coons, K., "Automatic Generation Control of Jointly Owned Generating Unit," *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-98, January/February 1979, pp. 207–218.
17. Elgerd, O. I., Fosha, C. E., "The Megawatt-Frequency Control Problem: A New Approach Via Optimal Control Theory," *Proceedings, Power Industry Computer Applications Conference*, 1969.
18. Zaborszky, J., Singh, J., "A Reevaluation of the Normal Operating State Control of the Power Systems using Computer Control and System Theory: Estimation," *Power Industry Computer Applications Conference Proceedings*, 1979.
19. Mukai, H., Singh, J., Spare, J., Zaborszky, J. "A Reevaluation of the Normal Operating State Control of the Power System using Computer Control and System

Theory—Part II: Dispatch Targeting," *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-100, January 1981, pp. 309–317.

20. Van Slyck, L. S., Jaleeli, N., Kelley, W. R., "Comprehensive Shakedown of an Automatic Generation Control Process," *IEEE Transactions on Power Systems*, Vol. 4, No. 2, May 1989, pp. 771–781.
21. Jaleeli, N., Van Slyck, L. S., Ewart, D. N., Fink, L. H., Hoffmann, A. G., "Understanding Automatic Generation Control," *IEEE Transactions on Power Systems*, Vol. 7, No. 3, August 1992, pp. 1106–1122.
22. Douglas, L. D., Green, T. A., Kramer, R. A., "New Approaches to the AGC Non-Conforming Load Problem," 1933 *IEEE Power Industry Computer Applications Conference*, pp. 48–57.