correct the frequency deviation twice as fast. However, the generation picked up by area 2 will subsequently reflect itself as a component of ACE_2, and will be backed off again in the steady state.

(c) If we set the bias factors significantly lower than the respective area βs, a situation opposite to the above would exist. In this case, the supplementary control in area 2 would tend to back off the generation picked up by its generators as a result of primary speed control or governor action. This would result in a degradation of system frequency control.

In addition to the above considerations, a very high value of bias factor is not desirable from the control stability viewpoint. At values significantly higher than the area β, the control action may become unstable.

The appropriateness of setting the frequency bias factor B nearly equal to the area β from dynamic considerations has been examined by a number of investigators [3-8]. A recommendation made in reference 7 to use significantly lower bias settings (B equal to nearly 0.5β) has not gained acceptance. A subsequent optimization study reported in reference 8 showed that $B=\beta$ is indeed a logical choice.

Systems with more than two areas

The description of the frequency bias tie line control described above applies equally well to systems with more than two areas. The interchange schedule applicable to each area is the algebraic sum of power flows on all the tie lines from that area to the other areas.

When an area is interconnected with more than one additional area, scheduled interchange transfers between them do not necessarily flow directly through the tie lines connecting the respective areas. Actual flows could split over parallel paths through other areas, depending on the relative impedances of the parallel paths. This is illustrated in Figure 11.26 which considers a three-area system.

Performance of AGC under normal and abnormal conditions

Under *normal conditions*, with each area able to carry out its control obligations, steady-state corrective action of AGC is confined to the area where the deficit or excess of generation occurs. Interarea power transfers are maintained at scheduled levels and system frequency is held constant.

Under *abnormal conditions*, one or more areas may be unable to correct for the generation-load mismatch due to insufficient generation reserve on AGC. In such an event, other areas assist by permitting the interarea power transfers to deviate from scheduled values and by allowing system frequency to depart from its pre-disturbance value. Each area participates in frequency regulation in proportion to its available regulating capacity relative to that of the overall system.

The following example illustrates the above aspects of AGC performance.

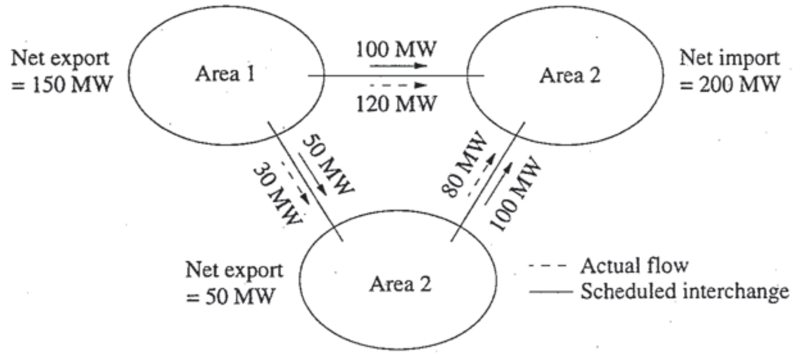
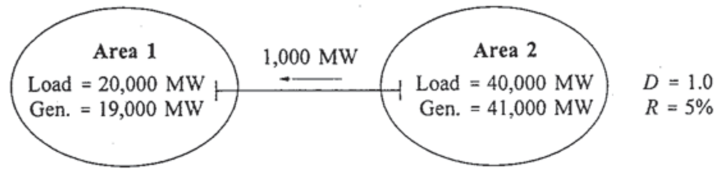


Figure 11.26 Three areas connected by tie lines

Example 11.3

Consider two interconnected areas as follows:



The connected load at 60 Hz is 20,000 MW in area 1 and 40,000 MW in area 2. The load in each area varies 1% for every 1% change in frequency. Area 1 is importing 1,000 MW from area 2. The speed regulation, R, is 5% for all units.

Area 1 is operating with a spinning reserve of 1,000 MW spread uniformly over a generation of 4,000 MW capacity, and area 2 is operating with a spinning reserve of 1,000 MW spread uniformly over a generation of 10,000 MW.

Determine the steady-state frequency, generation and load of each area, and tie line power for the following cases.

(a) Loss of 1,000 MW load in area 1, assuming that there are no supplementary controls.

(b) Each of the following contingencies, when the generation carrying spinning reserve in each area is on supplementary control with frequency bias factor settings of 250 MW/0.1 Hz for area 1 and 500 MW/0.1 Hz for area 2.

(i) Loss of 1,000 MW load in area 1

(ii) Loss of 500 MW generation, carrying part of the spinning reserve, in area 1

(iii) Loss of 2,000 MW generation, not carrying spinning reserve, in area 1

(iv) Tripping of the tie line, assuming that there is no change to the interchange schedule of the supplementary control

(v) Tripping of the tie line, assuming that the interchange schedule is switched to zero when the ties are lost

Solution

(a) *With no supplementary control.*

Assuming that none of the governors are blocked, all generating units in the two areas respond to the loss of load.

A 5% regulation on 20,000 MW generating capacity (including spinning reserve of 1,000 MW) in area 1 corresponds to

$$\frac{1}{R_1} = \frac{1}{0.05}\times\frac{20{,}000}{60} = 6{,}666.67 \quad \text{MW/Hz}$$

Similarly, a 5% regulation on 42,000 MW generating capacity in area 2 corresponds to

$$\frac{1}{R_2} = \frac{1}{0.05}\times\frac{42{,}000}{60} = 14{,}000.00 \quad \text{MW/Hz}$$

Total regulation due to 62,000 MW generating capacity in the two areas is

$$\frac{1}{R} = \frac{1}{R_1}+\frac{1}{R_2} = 20{,}666.67 \quad \text{MW/Hz}$$

Load damping due to 19,000 MW load (remaining after loss of 1,000 MW load) in area 1 is

$$D_1 = 1\times\frac{19{,}000}{100}\times\frac{100}{60} = 316.67 \quad \text{MW/Hz}$$

Load damping due to 40,000 MW load in area 2 is

$$D_2 = 1\times\frac{40{,}000}{100}\times\frac{100}{60} = 666.67 \quad \text{MW/Hz}$$

Total effective load damping of the two areas is

$$D = D_1+D_2 = 983.33 \quad \text{MW/Hz}$$

Change in system frequency due to loss of 1,000 MW load in area 1 is

$$\Delta f = \frac{-\Delta P_L}{1/R+D} = \frac{-(-1000)}{20{,}666.67+983.33} = 0.04619 \quad \text{Hz}$$

Load changes in the two areas due to increase in frequency are

$$\Delta P_{D1} = D_1\Delta f = 316.67\times 0.04619 = 14.63 \quad \text{MW}$$

$$\Delta P_{D2} = D_2\Delta f = 666.67\times 0.04619 = 30.79 \quad \text{MW}$$

Generation changes in the two areas due to speed regulation are

$$\Delta P_{G1} = -\frac{1}{R_1}\Delta f = 6{,}666.67\times 0.04619 = -307.93 \quad \text{MW}$$

$$\Delta P_{G2} = -\frac{1}{R_2}\Delta f = 14{,}000.00\times 0.04619 = -646.65 \quad \text{MW}$$

The new load, generation and tie line power flows are as follows.

Area 1		Area 2	
Load	= 20,000.00 − 1,000.00 + 14.63 = 19,014.63 MW	Load	= 40,000.00 + 30.79 = 40,030.79 MW
Generation	= 19,000.00 − 307.93 = 18,692.07 MW	Generation	= 41,000.00 − 646.65 = 40,353.35 MW

Tie line power flow from area 2 to area 1 is 322.56 MW. Steady-state frequency is 60.04619 Hz.

(b) *With supplementary control.*

(i) Loss of 1,000 MW load in area 1:

Area 1 has a generating capacity of 4,000 MW on supplementary control, and this will reduce generation so as to bring ACE_1 to zero. Similarly, area 2 generation on supplementary control will keep ACE_2 at zero:

$$\mathrm{ACE}_1 = B_1\Delta f+\Delta P_{12} = 0$$

$$\mathrm{ACE}_2 = B_2\Delta f-\Delta P_{12} = 0$$

Hence,

$$\Delta f = 0 \qquad \Delta P_{12} = 0$$

Area 1 generation and load are reduced by 1,000 MW. There is no steady-state change in area 2 generation and load, or the tie flow.

(ii) Loss of 500 MW generation carrying part of spinning reserve in area 1:

Prior to loss of generation, area 1 had a spinning reserve of 1,000 MW spread uniformly over a generation of 4,000 MW capacity (3,000 MW generation plus 1,000 MW reserve). Spinning reserve lost with generation loss is

$$\frac{500}{3{,}000}\times 1{,}000 = 166.67 \quad \text{MW}$$

Spinning reserve remaining is 1,000.00−166.67=833.33 MW. This is sufficient to make up for 500 MW generation loss. Hence, the generation and load in the two areas are restored to their pre-disturbance values. There are no changes in tie line flow or system frequency. However, area 1 spinning reserve is reduced from 1,000 MW to 833.33 MW.

(iii) Loss of 2,000 MW generation in area 1, not carrying spinning reserve:

Half of the generation loss will be made up by the 1,000 MW spinning reserve on supplementary control in area 1. When this limit is reached, area 1 is no longer able to control ACE. Supplementary control in area 2, however, is able to control its ACE. Hence,

$$\text{ACE}_2 = B_2\Delta f - \Delta P_{12} = 0$$

or

$$\Delta P_{12} = B_2\Delta f = 5{,}000\Delta f$$

There is thus a net reduction in system frequency. This causes a reduction in loads due to frequency sensitivity.

Area 1 load damping is

$$D_1 = 1\times\frac{20{,}000}{100}\times\frac{100}{60} = 333.33 \quad \text{MW/Hz}$$

The balance of generation loss in area 1 is made up by a reduction in load and tie flow from area 2. Hence,

$$\begin{aligned} -1{,}000 &= D_1\Delta f + \Delta P_{12} \\ &= 333.33\Delta f + 5{,}000\Delta f \end{aligned}$$

Solving for Δf, we have

$$\Delta f = \frac{-1{,}000}{5{,}000+333.33} = -0.1875 \quad \text{Hz}$$

Change in area 1 load is

$$\begin{aligned} \Delta P_{D1} &= D_1\Delta f = 333.33\times(-0.1875) \\ &= -62.5 \quad \text{MW} \end{aligned}$$

The tie flow change is

$$\Delta P_{12} = 5{,}000\times(-0.1875) = -937.5 \quad \text{MW}$$

Change in area 2 load is

$$\begin{aligned} \Delta P_{D2} &= D_2\Delta f = 666.67\times(-0.1875) \\ &= -125.00 \quad \text{MW} \end{aligned}$$

The area load and generation are as follows.

Area 1		Area 2	
Load	= 20,000.0−62.5 = 19,937.5 MW	Load	= 40,000.0−125.0 = 39,875.0 MW
Generation	= 19,000.0−1,000.0 = 18,000.0 MW	Generation	= 41,000.0−125.0+937.5 = 41,812.5 MW

The steady-state tie line power flow from area 2 to area 1 is 1,937.50 MW, and the system frequency is 60.0−0.1875=59.8125 Hz.

(iv) Tripping of the tie line, assuming no change in interchange schedule:

The supplementary control of area 1 attempts to maintain interchange schedule at 1,000 MW. Hence,

$$\text{ACE}_1 = \Delta P_{12}+B_1\Delta f_1 = 1{,}000+2{,}500\Delta f = 0$$

Solving, we find

$$\Delta f_1 = -\frac{1000}{2500} = -0.4 \quad \text{Hz}$$

Change in area 1 load is

$$\Delta P_{D1} = D_1 \Delta f_1 = 333.33\times(-0.4) = -133.33 \text{ MW}$$

Similarly for area 2, we have

$$\Delta f_2 = \frac{1{,}000}{5{,}000} = 0.2 \text{ Hz}$$

and

$$\Delta P_{D2} = 666.67\times 0.2 = 133.33 \text{ MW}$$

The area load, generation, and frequencies are as follows:

Area 1		Area 2	
Load	= 20,000.00 − 133.33 = 19,866.67 MW	Load	= 40,000.00 + 133.33 = 40,133.33 MW
Generation	= 19,866.67 MW	Generation	= 40,133.33 MW
f_1	= 59.6 Hz	f_2	= 60.2 Hz

(v) Tripping of the tie line, with interchange schedule switched to zero:

With interchange schedule switched to zero, area 1 supplementary control will pick up 1,000 MW generation to make up for loss of import power. Similarly, area 2 supplementary control reduces generation by 1,000 MW to compensate for loss of export. The generation in each area is equal to the respective loads and the area frequencies are equal to 60 Hz. ■

Economic allocation of generation

As noted earlier, an important secondary function of automatic generation control is to allocate generation so that each power source is loaded most economically. This function is referred to as *economic dispatch control* (EDC). The theory of economic dispatch is based on the principle of equal incremental costs.

For control of tie line power and frequency, it is necessary to send signals to generating plants to control generation. It is possible to use these signals to control generation to satisfy economic dispatch criteria. Thus, the requirements for EDC can be handled as part of the AGC function.

Since system load is continually changing, economic dispatch calculations have to be made at frequent intervals. The allocation of individual generation output is accomplished by using *base points* and *participation factors* (PFs). The base point represents the most economic output for each generating unit, and the participation factor is the rate of change of the unit output with respect to a change in total generation. The new desired output for each generator is calculated as follows [2]:

$$P_{desired} = P_{base\ point} + \mathrm{PF}(\Delta P_{total}) \tag{11.29}$$

where

$$\Delta P_{total} = \text{total new generation} - \text{sum of } P_{base\ point} \text{ for all generation}$$

Sum of participation factors of all units is equal to unity.

11.1.6 Implementation of AGC

In modern AGC schemes, the control actions are usually determined for each control area at a central location called the dispatch centre. Information pertaining to tie line flows, system frequency, and unit MW loadings is telemetered to the central location where the control actions are determined by a digital computer. The control signals are transmitted via the same telemetering channels to the generating units on AGC as shown in Figure 11.27. The normal practice is to transmit raise or lower pulses of varying lengths to the units. The control equipment at the plants then changes the reference setpoints of the units up or down in proportion to the pulse length.

Figure 11.27 illustrates the implementation of AGC for one control area (normally the service area of an individual utility). Each control area of an interconnected system is controlled in a similar manner, but independently of the other control areas. That is, the control of generation in the interconnected system is "area-wise decentralized."

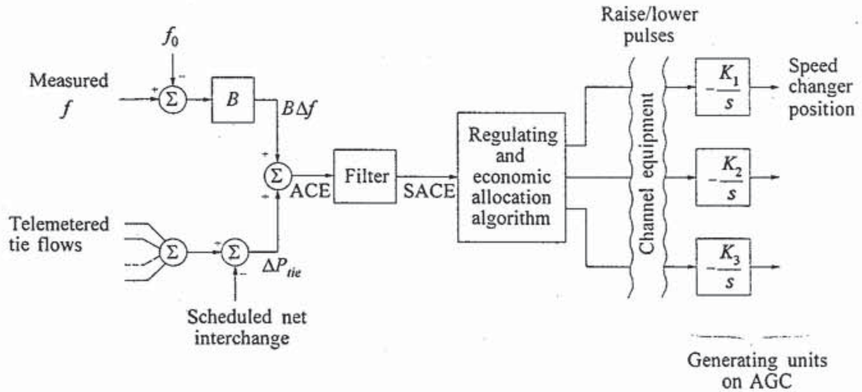


Figure 11.27 AGC control logic for each area