# POWER SYSTEM CONTROL

## INTRODUCTION:

The preceding chapters were devoted to problems associated with the selection of a normal operating state for the power system and optimum scheduling of generation. The present chapter deals with the continuous control of active and reactive power in order to keep the system in steady state. The power system being dynamic, the demand continuously deviates from its normal value. This leads to a small change in the state of the system. The automatic control should act in a closed loop manner, to detect these changes and initiate actions to eliminate the deviations. Briefly stated, the control strategy should be designed to deliver power to an interconnected system economically and reliably, while maintaining the voltage and frequency within the permissible limits.

Changes in real power mainly affect the system frequency and changes in reactive power mainly depend on changes in voltage magnitude and are relatively less sensitive to changes in frequency. Thus, real and reactive powers can be controlled separately. The Automatic Load Frequency Control (ALFC) controls the real power and the Automatic Voltage Regulator (AVR) regulates the voltage magnitude and hence the reactive power. The two controls, along with the generator and prime mover are shown in Fig.1. Unlike the AVR, ALFC is not a single loop. A fast primary loop responds to the frequency changes and regulates the steam (water) flow via the speed governor and control valves to match the active power output with that of the load. The time period here is a few seconds. The frequency is controlled via control of the active power.

A slower secondary loop maintains fine frequency adjustment to maintain proper active power exchange with other interconnected networks via tie-lines. This loop does not respond to fast load changes but instead focuses on changes, which lead to frequency drifting over several minutes.

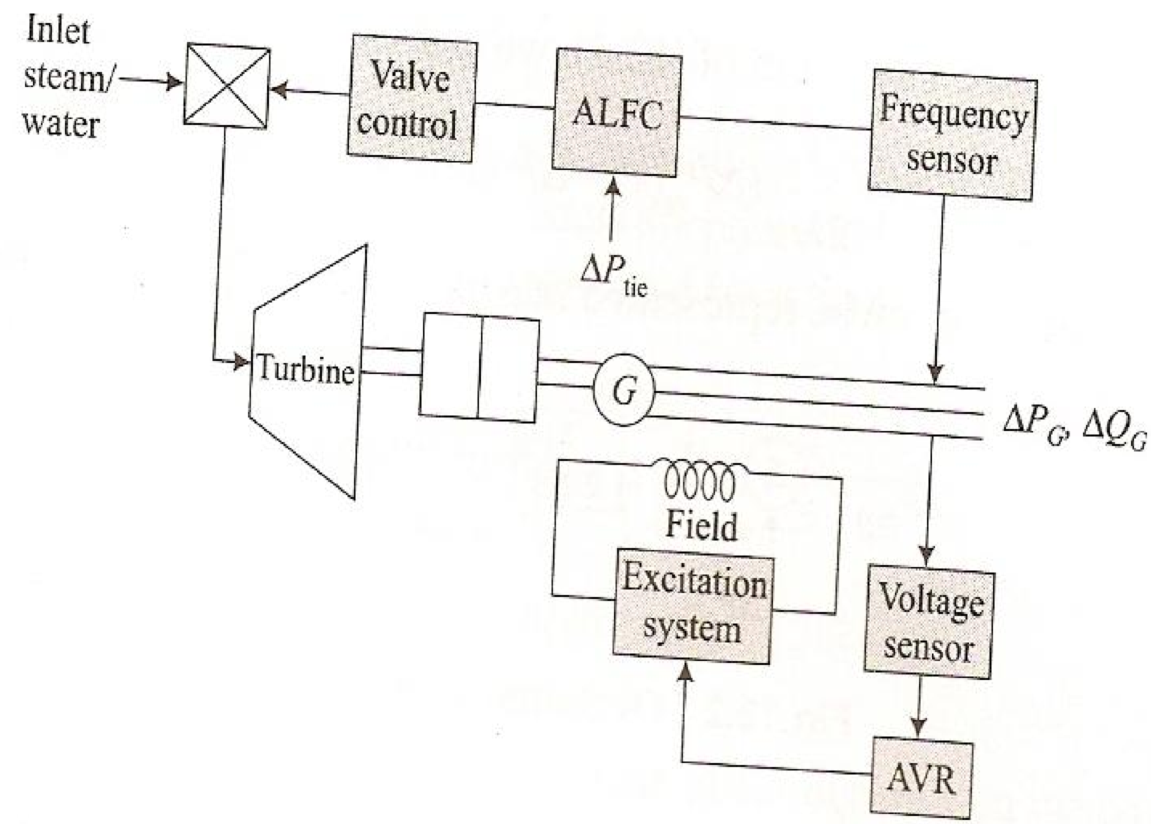



**Fig.1 ALFC and AVR**

Since the AVR loop is much faster than the ALFC loop, the AVR dynamics settle down before they affect the ALFC control loop. Hence, cross-coupling between the controls can be neglected. With the growth of large interconnected systems, ALFC has gained importance in recent times. This chapter presents an introduction to power system controls.

## AUTOMATIC LOAD FREQUENCY CONTROL:

The functions of the ALFC are to maintain steady frequency, control tie-line power exchange and divide the load between the generators. The tie-line power deviation is given by $\Delta P_{tie}$ and the change in frequency $\Delta f$, is measured by $\Delta\delta$, the change in the rotor angle $\delta$. The error signals $\Delta f$ and $\Delta P_{tie}$ are amplified, mixed and transformed to a real power signal, which controls the valve position to generate a command signal $\Delta P_v$. $\Delta P_v$ is sent to the prime mover to initiate change in its torque. The prime mover changes the generator output by $\Delta P_G$ , so as to bring $\Delta f$ and $\Delta P_{tie}$ within acceptable limits. The next step in the analysis is to build the mathematical model for the ALFC.

**Generator Model**:

We can apply the swing equation to a small perturbation  to obtain the linearized equation.

$$\frac{2H}{\mu_s}\frac{d^2\Delta ¢}{dt^2} = \Delta P_m - \Delta P_e$$

Expressing speed deviation in pu,  can be written as

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

Taking the Laplace Transform of  we get

$$\Delta\mu(s) = \frac{1}{2Hs}(\Delta P_m(s) - \Delta P_e(s))$$

**Load Model**:

The details of load modeling are covered in chapter 11. In general, the loads are composite. Resistive loads such as lighting and heating loads are independent of frequency. However, in case of electric motors, the power is dependent on frequency. We can arrive at a composite frequency dependent load characteristic given by

$$\Delta P_e = \Delta P_L + D\Delta\omega$$

where $\Delta P_L$ = non frequency sensitive load change

$D$ = Load damping constant

$D\Delta\omega$ = frequency sensitive load change

The damping constant is expressed as percent change in load for one percent change in frequency. A value of D = 1.2 means a change in frequency by 1% causes the load to change by 1.2%.

**Turbine Model:**

The prime mover for the generator is the turbine, which is mostly a steam turbine or a hydro turbine. In the simplified model, the turbine can be represented by a first order, single time constant transfer function given by

$$G_T(s) = \frac{\Delta P_m(s)}{\Delta P_V(s)} = \frac{1}{1+{}^{2}{}_{T}\, s}$$

where $\Delta P_V$ = Change in valve output

${}^{2}{}_{T}$ = turbine time constant

${}^{2}{}_{T}$ varies from 0.2 – 2 secs. The exact value of ${}^{2}{}_{T}$ , depends on the type of turbine.

**Governor Model:**

If the electrical load on the generator suddenly increases, the output electrical power exceeds the input mechanical power. The difference is supplied by the kinetic energy stored in the system. The reduction in the kinetic energy causes the turbine speed and frequency to fall. The turbine governor reacts to this change in speed, and adjusts the turbine input valve/gate to change the mechanical power output to match the increased power demand and bring the frequency to its steady state value. Such a governor which brings back the frequency to its nominal value is called as *isochronous governor*. The essential elements of a conventional governor system are shown in Fig

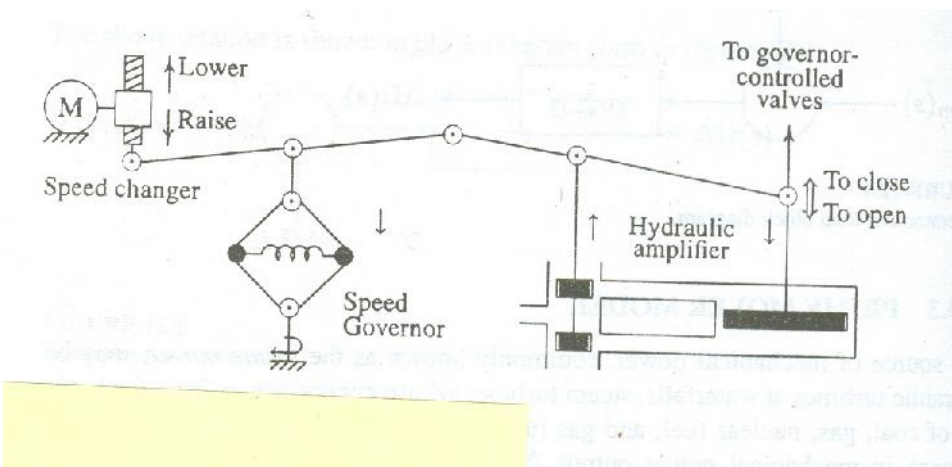



**Fig Conventional governor**

The major parts are

(i) **Speed Governor:** This consists of centrifugal flyballs driven directly or through gears by the turbine shaft, to provide upward and downward vertical movements proportional to the change in speed.

(ii) **Linkage mechanism:** This transforms the flyball movement to the turbine valve through a hydraulic amplifier and provides a feed back from turbine valve movement.

(iii) **Hydraulic amplifiers:** These transform the governor movements into high power forces via several stages of hydraulic amplifiers to build mechanical forces large enough to operate the steam valves or water gates.

(iv) **Speed changer:** This consists of a servomotor which is used to schedule the load at nominal frequency. By adjusting its set point, a desired load dispatch can be scheduled.

An isochronous governor works satisfactorily only when a generator is supplying an isolated load, or when only one generator is required to respond to change in load in a multi generator system. For proper power sharing between a number of generators connected to the system, the governors are designed to permit the speed to drop as the load is increased. This provides the speed – output characteristic a droop as shown in Fig. The speed regulation R is given by the slope of the speed – output characteristic.

$$R = \frac{\Delta\mu}{\Delta P}$$

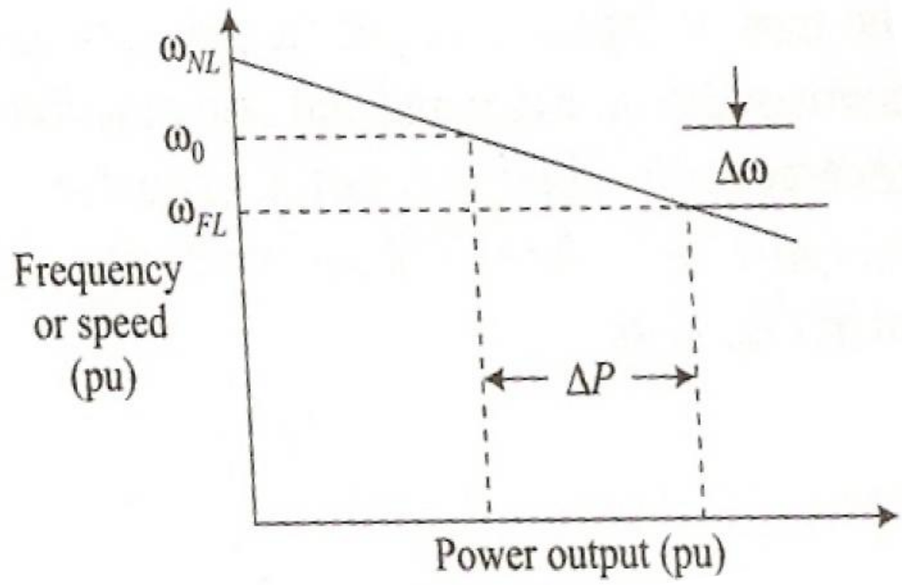
Governor % speed regulation is defined as

$$\%R = \left(\frac{\mu_{NL} - \mu_{FL}}{\mu_o}\right) \times 100$$

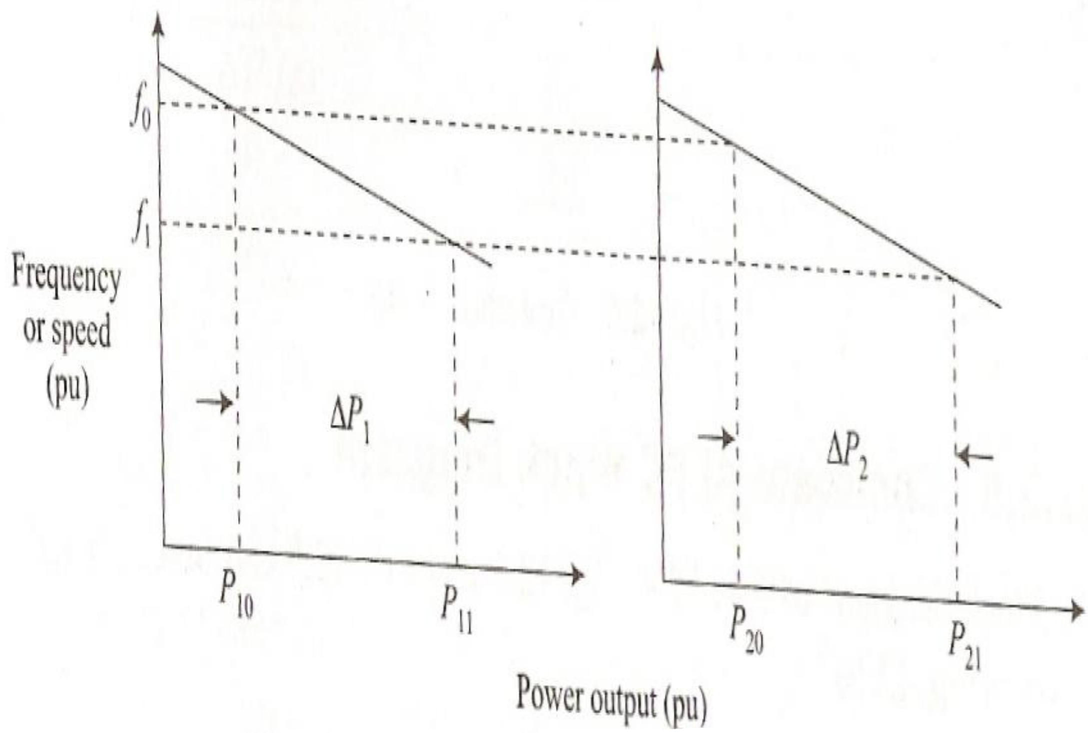
where $\omega_{NL}$ = No–load speed

$\omega_{FL}$ = Full load speed

$\omega_{O}$ = Nominal speed




To illustrate how load is shared between two generators, consider two generators with droop characteristics as shown in Fig below




Let the initial frequency be $f_o$ and the outputs of the two generators be $P_{10}$ and $P_{20}$ respectively. If now the load increases by an amount $\Delta P_L$, the units slow down and the governors increase the output until a common operating frequency $f_1$ is reached. The amount of load picked up by each generator to meet the increased demand $\Delta P_L$ depends on the value of the regulation.

$$\Delta P_1 = \frac{\Delta f}{R_1}$$

$$\Delta P_2 = \frac{\Delta f}{R_2}$$

$$\frac{\Delta P_1}{\Delta P_2} = \frac{R_2}{R_1}$$

The output is shared in the inverse ratio of their speed regulation. The output of the speed governor is $\Delta P_g$ , which is the difference between the set power $\Delta P_{ref}$ and the power $\frac{\Delta \mu}{R}$ which is given by the governor speed characteristic.

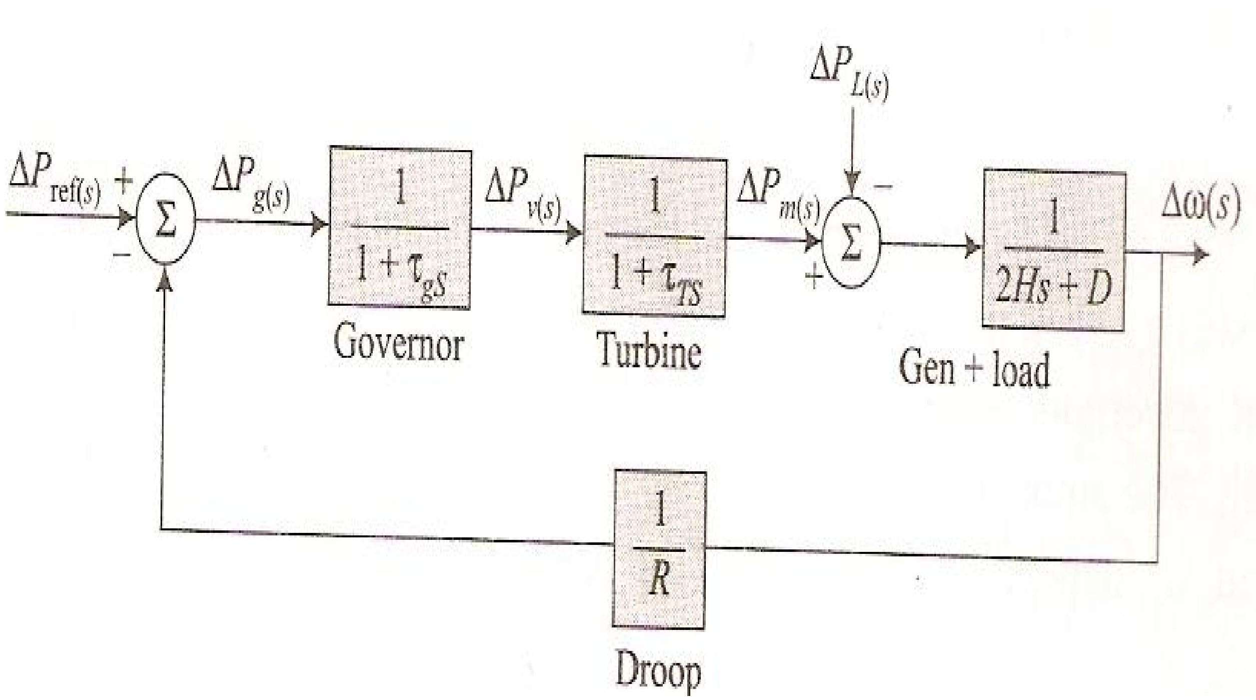
$$\Delta P_g = \Delta P_{ref} - \frac{\Delta\mu}{R}$$

$$\Delta P_g(s) = \Delta P_{ref}(s) - \frac{\Delta\mu(s)}{R}$$

The hydraulic amplifier transforms the command into valve/gate position $\Delta P_V$. Assuming a time constant $\tau_g$ for the governor,

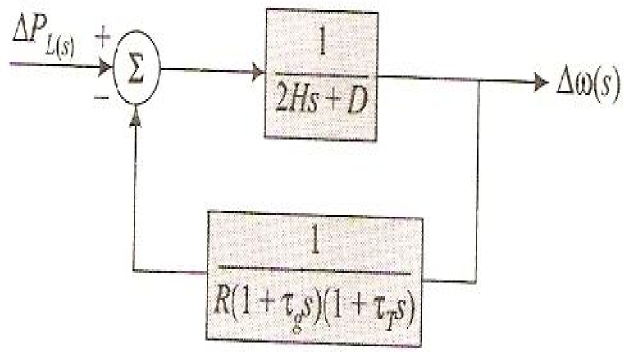
$$\Delta P_V(s) = \frac{1}{1+\tau_g s}\,\Delta P_g(s)$$

**<u>Complete ALFC block diagram</u>:**




**<u>Fig Block diagram of complete governor system</u>**

The Figure shows the complete load frequency control for an isolated generator supplying a load. Since we are interested in the change in speed for change in load, we can obtain the transfer function $\frac{\Delta\mu(s)}{-\Delta P_L(s)}$ from Fig below which is a reduced order model.




**Reduced block diagram**

The closed loop transfer function is obtained from Fig

$$\frac{\Delta\mu(s)}{-\Delta P_L(s)} = \frac{\left(\dfrac{1}{2Hs+D}\right)}{1+\left(\dfrac{1}{2Hs+D}\right)\left(\dfrac{1}{R(1+2_g s)(1+2_T s)}\right)}$$

$$= \frac{(1+2_g s)\,(1+2_T s)}{(2Hs+D)\,(1+2_g s)\,(1+2_T s) + \dfrac{1}{R}}$$

We can write

$$\Delta\omega(s) = \quad \Delta P_L(s)\ T(s)$$

If we consider a step change $\Delta P_L$ in the load,

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

The steady state frequency deviation $\Delta\omega_{ss}$ is given by the limit of $\Delta\omega$ as $t \to \infty$. This can be obtained by application of the final value thereon

$$\Delta\omega_{ss} = \lim_{t\to\infty} \Delta\omega \;=\; \lim_{s\to 0}\ s\Delta\omega(s)$$

$$= \lim_{s\to 0}\ s\left(\frac{-\Delta P_L}{s}T(s)\right)$$

Now $$\lim_{s \to 0} T(s) = \frac{1}{D + \frac{1}{R}}$$

$$\Delta\omega_{ss} = (\ \ \Delta P_L)\ \frac{1}{D + \frac{1}{R}}$$

If there are no frequency sensitive loads, D = 0; in which case

$$\Delta\omega_{ss} = \frac{-\Delta P_L}{\frac{1}{R}}$$

The steady state speed deviation thus, depends on the governor speed regulation. If several generators are connected to the system, the composite frequency – power characteristics depends on the combined effect of the droops of all the generator speed governors. If we consider *n* generators with a composite load damping coefficient D, the steady state speed deviation after a load change $\Delta P_L$ is given by

$$\Delta\omega_{ss} = \frac{-\Delta P_L}{D + \left(\frac{1}{R_1} + \frac{1}{R_2} + .....\frac{1}{R_n}\right)} = \frac{-\Delta P_L}{D + \frac{1}{R_{eq}}}$$

where $$\frac{1}{R_{eq}} = \frac{1}{R_1} + \frac{1}{R_2} + .....\frac{1}{R_n}$$

The *stiffness* of the system, $\beta$ is given by

$$\beta = \frac{-\Delta P_L}{\Delta\mu_{ss}} = \frac{1}{R_{eq}} + D \ \text{MW/Hz}$$

$\beta$ is also called the *frequency bias factor* and is indicative of the change in frequency which would occur for a change in the load.

(* The pu speed deviation $\Delta\omega$ is same as pu frequency deviation $\Delta f$)

**Example 1**: A system consists of 4 identical 250 MVA generators feeding a load of 510 MW. The inertia constant H of each unit is 2.5 on the machine base. The total load varies by 1.4% for a 1% change in frequency. If there is a drop in load of 10MW, determine the system block diagram expressing H and D on a base of 1000MVA. Give expression for the speed deviation, assuming there is no speed governor.

**Solution**:

H for 4 units on 1000MVA base = $4 \times 2.5 \times \frac{250}{1000} = 2.5$

Load after drop of 10 MW = 510     10 = 500 MW

D for load on base of 1000 MVA is given by

$$D = 1.4 \times \frac{500}{1000} = 0.7\%$$

[note that a change of load of 1.4% on base 500 MW corresponds to 0.7% on base of 1000MVA]

The standard first order transfer function form is given by $\frac{K}{1 + sT}$. In the reduced order model, the feedback loop is zero, since no governor is modeled. Substituting the values, and expressing in standard form we get

The gain = 1.428 and time constant = 7.14 secs.

$$\Delta P_L = \quad 10 \text{ MW} = \frac{-10}{1000} = \quad 0.01 \text{ pu.}$$

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

From block diagram

$$\Delta\omega(s) = -\left(\frac{-0.01}{s}\right)\left(\frac{1.428}{1+7.14s}\right)$$

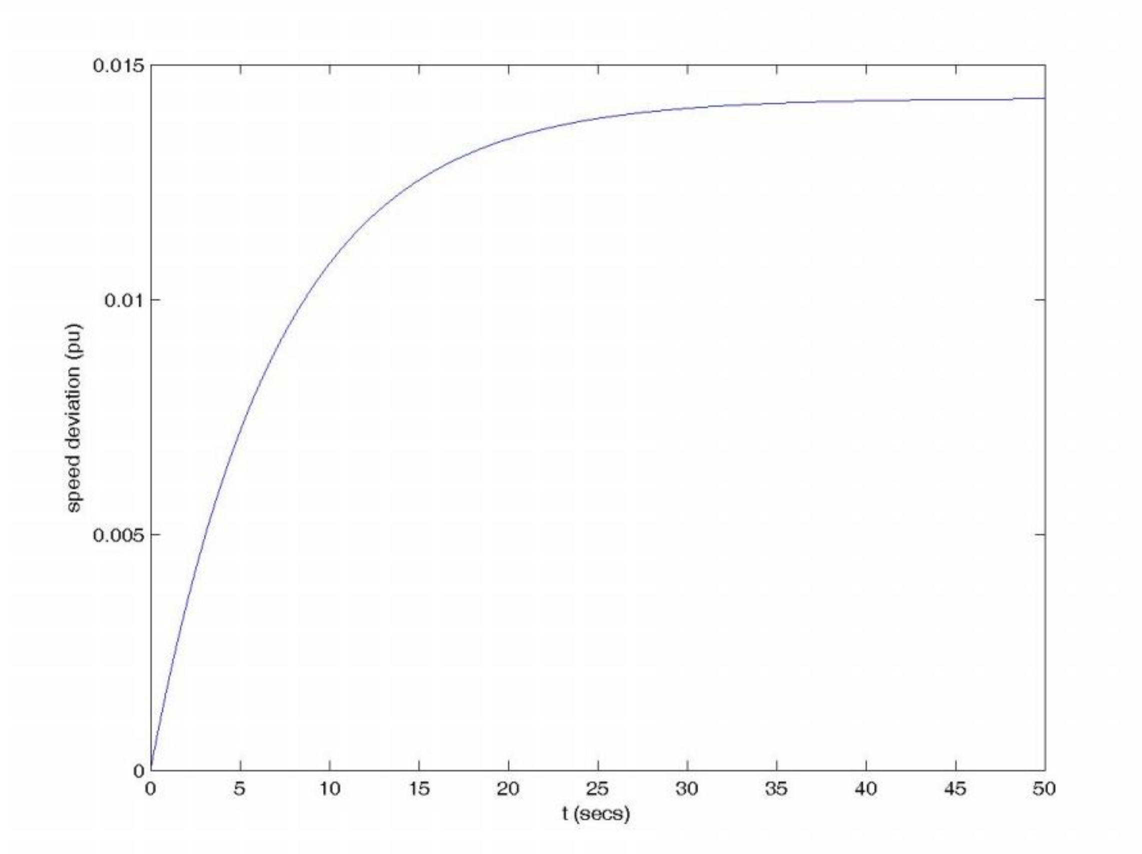
$$= \left(\frac{0.01}{s}\right)\left(\frac{1.428}{1+7.14s}\right) = \frac{0.01428}{s} - \frac{0.10196}{1+7.14s}$$

$$= \frac{0.01428}{s} - \frac{0.01428}{s + 0.14}$$

Taking inverse laplace transform

$$\Delta\omega(t) = 0.01428\,(1 \quad e^{\;0.14t})$$

The pu speed deviation as function of time is shown in Fig below.




The steady state speed deviation is 0.01428 pu. If frequency is 50 Hz, steady state frequency deviation = 50 × 0.01428 = 0.714 Hz. The frequency deviation is positive since a decrease in load leads to increase frequency.

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**Example 2.**

An isolated generator and its control have following parameters

Generator inertia constant = 5sec

Governor time constant $\tau_g$ = 0.25sec

Turbine time constant $\tau_T$ = 0.6sec

Governor speed regulation = 0.05 pu

D = 0.8

The turbine rated output is 200 MW at 50 Hz. The load suddenly increases by 50 MW. Find the steady state frequency deviation. Plot the frequency deviation as a function of time.

**Solution**:

The transfer function is given by

$$\frac{\Delta\mu(s)}{-\Delta P_L(s)} = T(s) = \frac{(1+0.25s)(1+0.6s)}{(10s+0.8)(1+0.25s)(1+0.6s)+\dfrac{1}{0.05}}$$

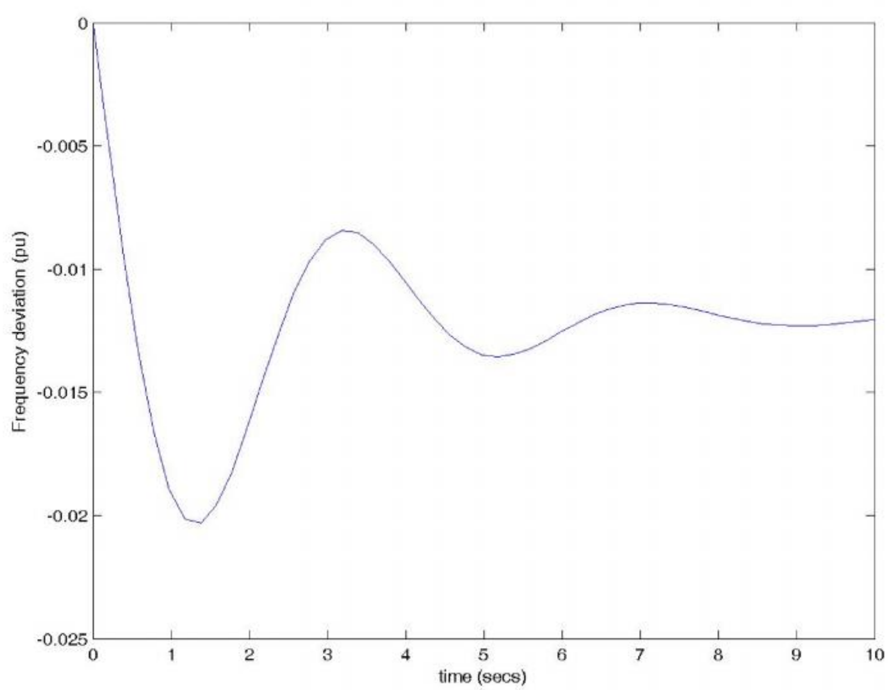
$$= \frac{0.15s^2 + 0.85s + 1}{1.5s^3 + 8.62s^2 + 10.68s + 20.8}$$

$$\Delta P_L = \frac{50}{200} = 0.25 \text{ pu}$$

$$\Delta\omega_{ss} = \frac{-\Delta P_L}{D+\dfrac{1}{R}} = \frac{-0.25}{0.8+\dfrac{1}{0.05}} = \quad 0.01202 \text{ pu.}$$

Steady state frequency deviation $\Delta f_{ss}$ = $0.01202 \times 50 =$ 0.601 Hz.

The frequency decreases since the load has increased. The time response to a step deviation of 0.25 is shown Fig




**Frequency deviation for step response for example 2**

## CONCEPT OF AUTOMATIC GENERATION CONTROL (AGC):

With the primary ALFC, it was seen that a change in the system load results in a steady state frequency deviation, depending on the regulation and frequency sensitivity (as indicated by D) of the load. All the connected generator units of the system contribute to the overall change in generation, irrespective of the location of the load change. Thus, restoration to nominal system frequency requires additional control action which changes the load reference set point to match the variations in the system load. This control scheme is called the Automatic Generation Control (AGC). The main objectives of the AGC are to regulate the system frequency and maintain the scheduled power inter changes, between the interconnected areas, via the tie–lines. A secondary objective of the AGC is to distribute the required change in generation among the various units to obtain least operating costs. During large transient disturbances and emergencies, AGC is bypassed and other emergency controls act.

### AGC in a single area:

In a single area system since there is no tie–line schedule to be maintained, the function of AGC is only to bring the frequency to the nominal value. This is achieved by introducing an integral controller to change the load reference setting so as to change the speed set point. The integral controller forces the steady state speed deviation to zero.

The gain $K_I$ of the integral controller needs to be adjusted for satisfactory response in terms of over shoot, setting time etc.

The closed loop transfer function with integral controller is given by

$$T(s) = \frac{\Delta\mu(s)}{-\Delta P_L(s)} = \frac{s(1+\tau_g s)(1+\tau_T s)}{s(2Hs+D)(1+\tau_g s)(1+\tau_T s) + K_I + \frac{s}{R}}$$

**Example 4**:

In example 2, an integral controller with gain $K_I = 6$ is added .Obtain the dynamic response, if all other conditions are same.

**Solution**:

From the transfer function

$$\frac{\Delta\mu(s)}{-\Delta P_L(s)} = \frac{0.15s^3 + 0.85s^2 + s}{1.5s^4 + 8.62s^3 + 10.68s^2 + 20.8s + 6}$$

The change in $P_L$, $\Delta P_L = 0.25$ pu.

The response of the above function for a step change of 0.25 pu is plotted using Matlab. The response is shown if Fig below.

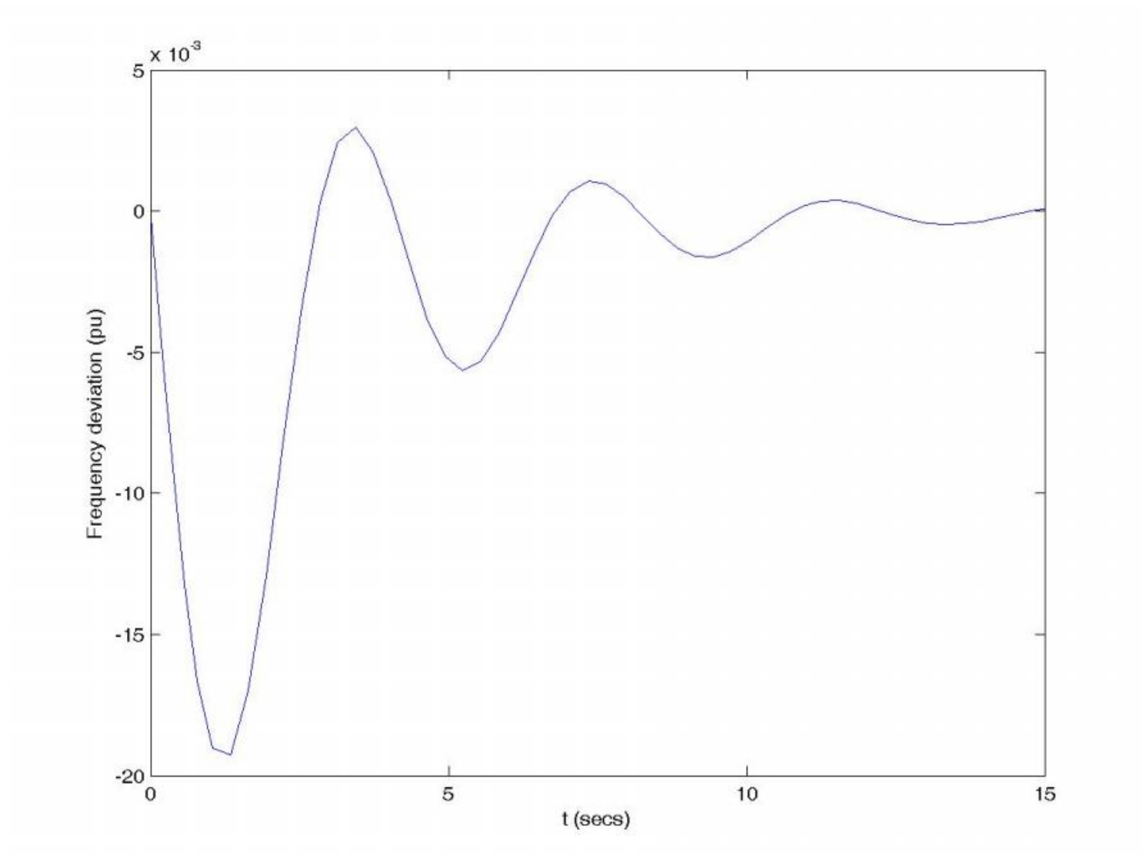



**Fig: Dynamic response of example 4**

It can be seen that the steady state frequency deviation is now zero. However, the overshoot and setting time are more.

**AGC in multi area systems**:

In inter connected systems, a group of generators are closely coupled internally and swing in phase. Such a group is called coherent group. The ALFC loop can be represented for the whole area, referred to as control area.

Consider two areas interconnected by lossless tie–line of reactance $X_{tie}$, with a power flow $P_{12}$ from area 1 to area 2 as shown in Fig. a. Let the generators be represented by a single equivalent generator for area 1 and area 2. The generators are modeled simply as constant voltage sources behind reactance as shown in Fig. b. We first consider only primary ALFC loop as shown in Fig. c.

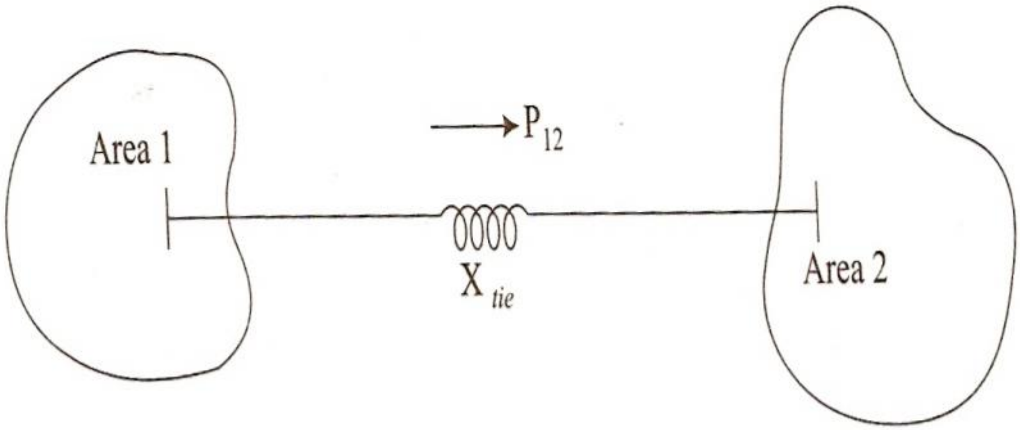



**Fig a : Two area system**

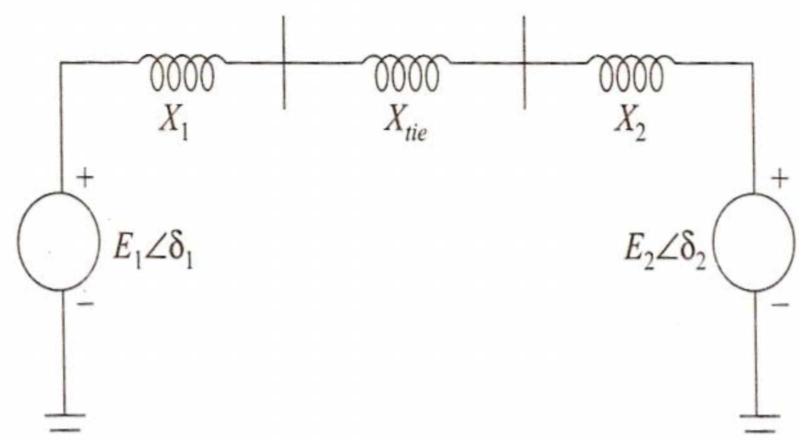



**Fig 12.19b: Electrical equivalent**

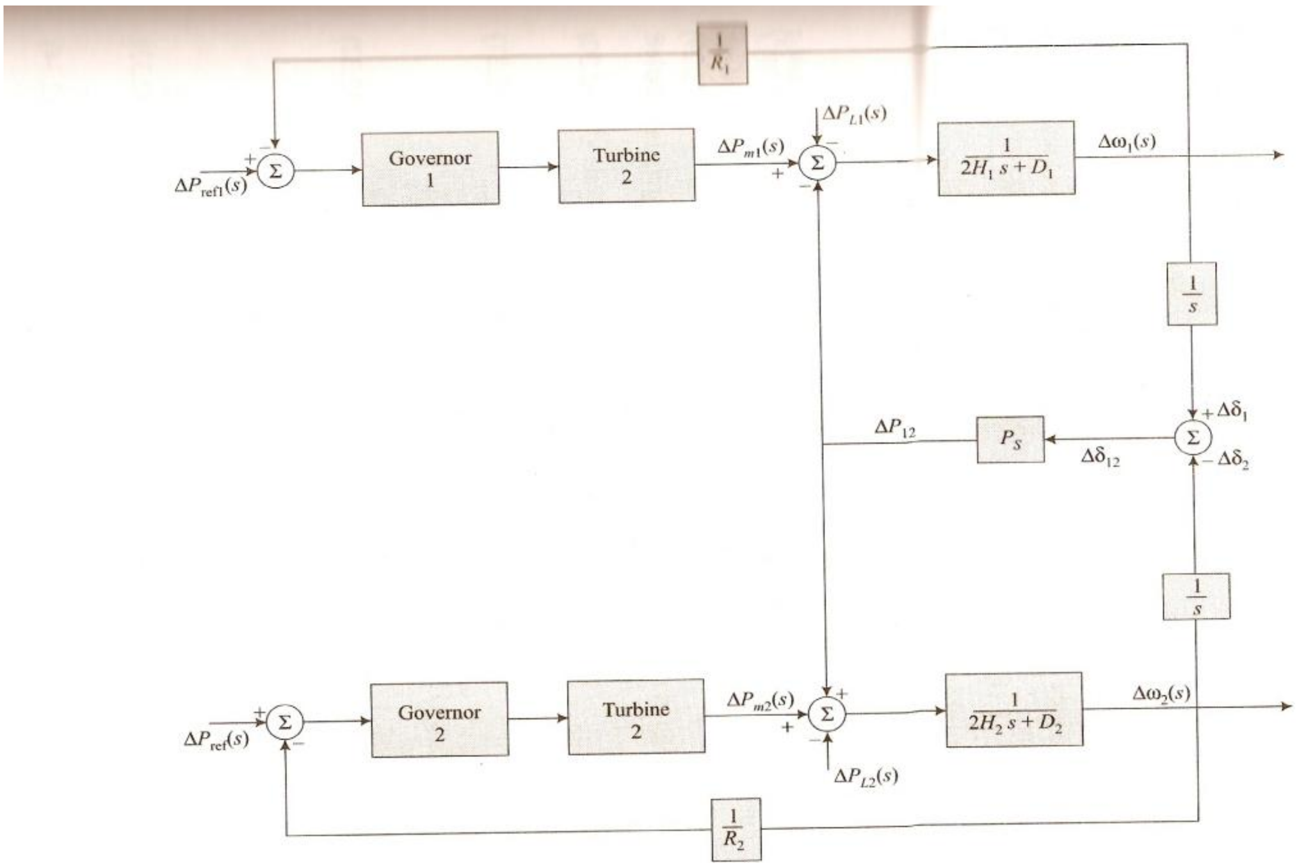



**Fig c: Two area system with primary ALFC**

H is the equivalent inertia constant of each area. The turbines are represented by the effective speed droop R and load damping constant D.

Under steady state the power transferred over the tie–line is given by

$$P_{12} = \frac{|E_1|\,|E_2| \sin ¢_{12}}{X_{12}}$$

where $X_{12} = X_1 + X_{tie} + X_2$ and $\delta_{12} = \delta_1 - \delta_2$. For a small deviation $\Delta P_{12}$ of the tie line power flow, we can write

$$\Delta P_{12} = \left.\frac{\partial P_{12}}{\partial ¢_{12}}\right|_{¢120} \Delta ¢_{12} = P_S\, \Delta\delta_{12}$$

where $\left.\dfrac{\partial P_{12}}{\partial ¢_{12}}\right|_{¢120}$ = $P_{S,}$ is the slope of the power angle curve evaluated at the initial operating point ($\delta_{120} = \delta_{10}$    $\delta_{20}$) and is the synchronizing power coefficient..

$$P_S = \left.\frac{\partial P_{12}}{\partial ¢_{12}}\right|_{¢120} = \frac{|E_1|\,|E_2|}{X_{12}} \cos ¢_{120}$$

$$\Delta P_{12} = P_S\,(\Delta\delta_1 \quad \Delta\delta_2)$$

A positive $\Delta P_{12}$ occurs when $\Delta\delta_1 > \Delta\delta_2$ and indicates a flow of real power from area 1 to area 2. This has the effect of increasing load on area 1 and decreasing load on area 2. Hence $\Delta P_{12}$ has negative sign for area 1 and positive sign for area 2 in Fig c.

Consider a change in load $\Delta P_{L1}$ in area 1. The steady state frequency deviation $\Delta f$ is same for both the areas. Hence

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

For area 1,

$$\Delta P_{m1} \quad \Delta P_{12} \quad \Delta P_{L1} = \Delta f D_1$$

For area 2,

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

The change in mechanical powers depends on the respective regulations.

$$\Delta P_{m1} = \frac{-\Delta f}{R_1}$$

$$\Delta P_{m2} = \frac{-\Delta f}{R_2}$$

Substituting we get

$$\Delta f\left(\frac{1}{R_1} + D_1\right) = -\Delta P_{12} - \Delta P_{L1}$$

$\dfrac{1}{R_1} + D_1 = \beta_1$, the frequency bias factor for area 1.

$\Delta f\ \beta_1 = -\Delta P_{12} - \Delta P_{L1}$

Similarly

$\Delta f\ \beta_2 = \Delta P_{12}$

Solving for $\Delta f$ we get

$$\Delta f = \frac{-\Delta P_{L1}}{{}_1 + {}_2}$$

$$\Delta P_{12} = \frac{-\Delta P_{L1} \quad {}_2}{{}_1 + {}_2}$$

Thus an increase of load in area 1 reduces frequency in both areas. Similarly for a change in load $\Delta P_{L2}$ in area 2,

$$\Delta f = \frac{-\Delta P_{L2}}{{}_1 + {}_2}$$

and $\quad \Delta P_{12} = \quad \Delta P_{21} = \frac{-\Delta P_{L2} \quad {}_1}{{}_1 + {}_2}$

**Example 5**

A two area system connected by a tie–line has following parameters on 1000 MVA base;

$R_1 = 4.5\%$; $\quad D_1 = 0.6$; $\quad H_1 = 4.5$;

$R_2 = 6\%$; $\quad D_2 = 0.85$; $\quad H_2 = 5.0$;

The units are running in parallel at a frequency of 50 Hz. The synchronizing power coefficient is 1.9 pu at the initial operating angle. A load change of 150 MW occurs in area 1. Determine the new steady state frequency and the change in tie–line power flow.

**Solution**:

$$\Delta P_{L1} = \frac{150}{1000} = 0.15 \text{ pu.}$$

Steady state frequency deviation is

$$\Delta f = \frac{-\Delta P_{L1}}{{}_1 + {}_2}$$

$$\beta_1 = \frac{1}{R_1} + D_1 = \frac{1}{0.045} + 0.6 = 22.822$$

$$\beta_2 = \frac{1}{R_2} + D_2 = \frac{1}{0.06} + 0.85 = 17.516$$

$$\Delta f = \frac{-0.15}{22.822 + 17.516} = \quad 0.0037 \text{ pu}$$

Steady state frequency = 50 $\quad$ (0.0037 × 50) = 49.815 Hz.

$\Delta P_{12} = \Delta f\, \beta_2 =$ 0.0037 × 17.516 = 0.0648 pu = 64.8 MW.

Since $\Delta P_{12}$ is negative, it implies that 64.8 MW flows from area 2 to area 1.

Change in mechanical powers is given by

$$\Delta P_{m1} = \frac{-\Delta f}{R_1} = \left(\frac{-0.0037}{0.045}\right) = 0.082 \text{ pu} = 82 \text{ MW}$$

$$\Delta P_{m2} = \frac{-\Delta f}{R_2} = \left(\frac{-0.0037}{0.06}\right) = 0.0617 \text{ pu} = 61.7 \text{ MW}$$

Change in load in area 1 due to frequency sensitive loads is $\Delta f D_1$ = ( 0.0037) (0.6) = 0.0022 pu = 2.2MW. Similarly for area 2 $\Delta f D_2$ = ( 0.0037) (0.85) = 0.0031 pu = 3.1MW. Total change in load is 5.3 MW. The power flow of 64.8 MW from area 2 to area 1 is contributed by an increase in generation of area 2 by 61.7 MW and reduction in load of area 2 by 3.1 MW.

**<u>Tie–line bias control</u>**:

From discussion it can be seen that, if the areas are equipped only with primary control of the ALFC, a change in load in one area met is with change in generation in both areas, change in tie–line power and a change in the frequency. Hence, a supplementary control is necessary to maintain

- Frequency at the nominal value
- Maintain net interchange power with other areas at the scheduled values
- Let each area absorb its own load

Hence, the supplementary control should act only for the areas where there is a change in load. To achieve this, the control signal should be made up of the tie–line flow deviation plus a signal proportional to the frequency deviation. A suitable proportional weight for the frequency deviation is the frequency – response characteristic β. This is the reason why β is also called the frequency bias factor. This control signal is called the area control error (ACE). In a two area system

$ACE_1 = \Delta P_{12} + B_1\, \Delta f$ ; $\qquad B_1 = \beta_1$

$ACE_2 = \Delta P_{21} + B_2\, \Delta f$ ; $\qquad B_2 = \beta_2$

The ACE represents the required change in area generation and its unit is MW. ACEs are used as control signals to activate changes in the reference set points. Under steady state $\Delta P_{12}$ and $\Delta f$ will be zero. The block diagram with the supplementary control is shown below. It is applied to selected units in each area.

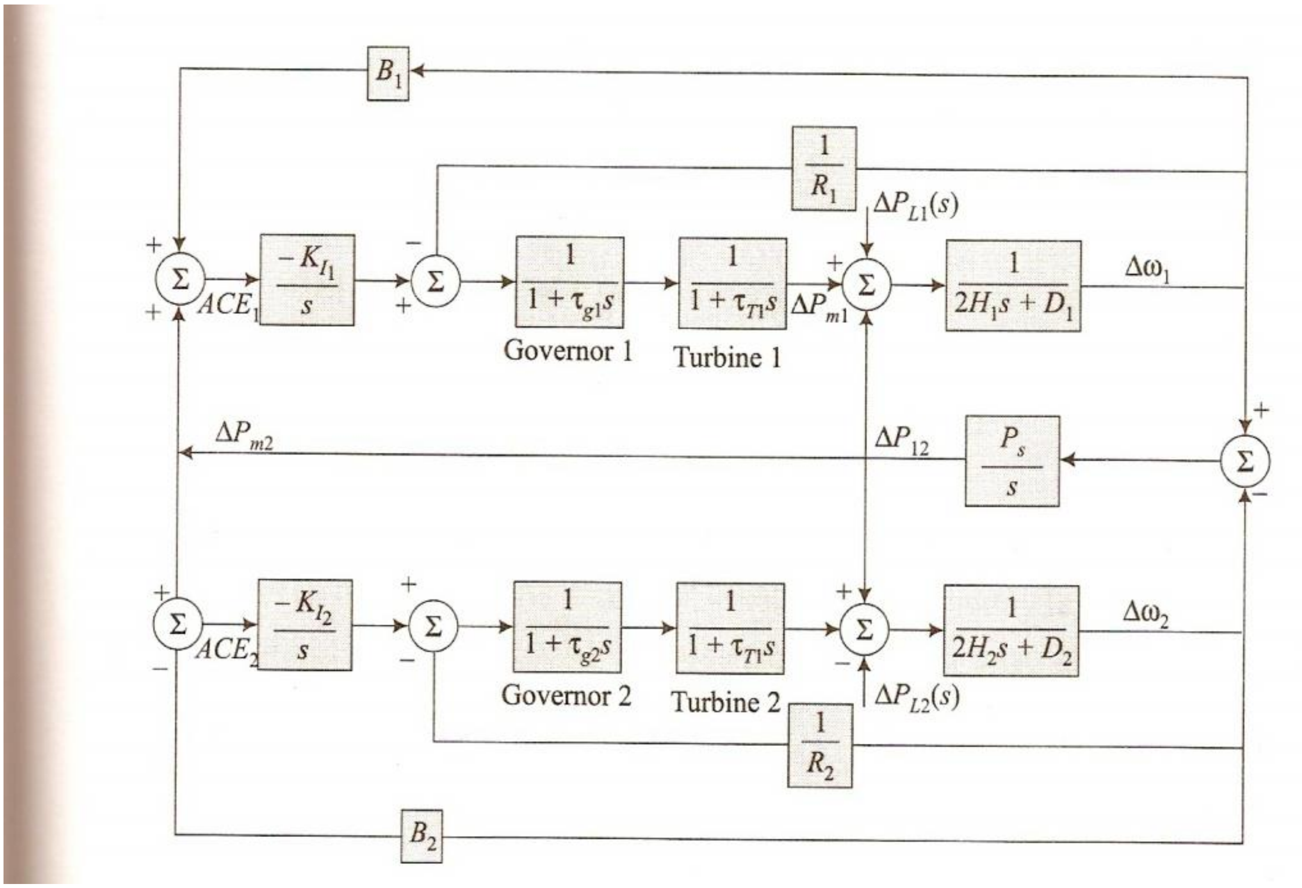



**Fig : Block diagram with supplementary control**

The operation of the ACE can be explained as follows. Consider an increase in load of area 1, which leads to a decrease in system frequency. The primary ALFC loop limits the frequency deviation to

$$\Delta f = \frac{-\Delta P_{L1}}{{}_1 + {}_2}$$

The tie–line power has a deviation $\Delta P_{12} = \beta_2 \Delta f$. The slower acting supplementary control, starts responding now.

$$ACE_1 = \quad \Delta P_{12} + B_1\,\Delta f = \frac{(\;_1 + \;_2)}{(\;_1 + \;_2)}(-\Delta P_{L1}) = \quad \Delta P_{L1}$$

and $$ACE_2 = \quad \Delta P_{12} + B_2\,\Delta f = \frac{(-\Delta P_{L1})}{(\;_1 + \;_2)}(- \;_2 + \;_2) = 0$$

Thus only supplementary control of area 1 responds to $\Delta P_{L1}$ and the generation changed so that $ACE_1$ becomes zero.

**Example 6**:

Two areas are connected via an inter tie. The load at 50Hz, is 15,000 MW in area 1and 35,000 MW in area 2. Area 1 is importing 1500 MW from area 2. The load damping constant in each area is D = 1.0 and the regulation R = 6% for all units. Area 1 has a spinning reserve of 800 MW spread over 4000 MW of generation capacity and area 2 has a spinning reserve of 1000 MW spread over 10,000 MW generation. Determine the steady state frequency, generation and load of each area and tie–line power for

(a) Loss of 1000 MW in area 1, with no supplementary control

(b) Loss of 1000 MW in area 1, with supplementary controls provided on generators with reserve.

$\beta_1$ = 250 MW/0.1 Hz and $\beta_2$ = 400 MW/0.1 Hz

**Solution**:

**(a)** Assume a lossless system

Area 1: Load = 15,000 MW

Power import from area 2 = 1,500 MW

Generation = 15,000 – 1500 = 13,500 MW

Reserve = 800 MW

Total generation capacity = 13,500 + 800 = 14,300 MW

Area 2: Load = 35,000 MW

Export to area 1 = 1,500 MW

Generation = 35,000 + 1,500 = 36,500 MW

Reserve = 1000 MW

Total generation capacity = 36,500 + 1000 = 37,500 MW

Regulation of 6% on a generation capacity of 14,300 MW (including reserve) corresponds to

$$R_1 = \frac{0.06 \times 50}{14300}$$

$$\frac{1}{R_1} = \frac{1}{0.06} \times \frac{14300}{50} = 4{,}766.67 \text{ MW/Hz}$$

Similarly

$$\frac{1}{R_2} = \frac{1}{0.06} \times \frac{37500}{50} = 12{,}500 \text{ MW/Hz}$$

$$\frac{1}{R_{eq}} = \frac{1}{R_1} + \frac{1}{R_2} = 17{,}266.6 \text{ MW/Hz.}$$

Load damping D = 1.0, which means a 1% change in load occurs for a 1% change in frequency. $D_1$ is computed for area 1 on a total load of 14000 MW, considering the loss of 1000 MW.

$$D_1 = 1 \times \frac{14000}{100} \times \frac{100}{50} = 280 \text{ MW/Hz.}$$

Similarly $D_2$ is calculated on a load of 35,000 MW since there is no change in load of area 2.

$$D_2 = 1 \times \frac{35000}{100} \times \frac{100}{50} = 700 \text{ MW/Hz.}$$

$$D_{eq} = D_1 + D_2 = 980 \text{ MW/Hz.}$$

The change in system frequency is given by

$$\Delta f = \frac{-\Delta P_L}{\frac{1}{R_{eq}} + D_{eq}} = \frac{-(-1000)}{17{,}266.6 + 980} = 0.0548 \text{ Hz.}$$

Load changes due to load damping are,

$$\Delta P_{D1} = D_1\,\Delta f = 280 \times 0.0548 = 15.344 \text{ MW}$$

$$\Delta P_{D2} = D_2\,\Delta f = 700 \times 0.0548 = 38.36 \text{ MW}$$

Change in generations are

$$\Delta P_{G1} = \frac{-\Delta f}{R_1} = \quad 4766.6 \times 0.0548 = \quad 261.2 \text{ MW}$$

$\Delta P_{G2} = \dfrac{-\Delta f}{R_2} = \quad 12500 \times 0.0548 = \quad 685$ MW

We recalculate powers as follows

<u>Area 1</u>: New load = 15,000    1,000.00 + 15.344 = 14,015.344 MW

New generation = 13,500 – 261.2 = 13,238.8 MW

Deficit = 14,015.34    13,238.8 = 776 MW

<u>Area 2</u>: New load = 35,000 + 38.36 = 35,038.36 MW

New generation = 36,500 – 685 = 35,815 MW

Excess = 35,815    35,038.36 = 776 MW

Thus tie–line power is 776 MW and flows from area 2 to area 1.

Steady state frequency = 50 + 0.0548 = 50.0548 Hz

**(b)** *With supplementary control and $\beta_1$ = 250 MW/0.1 Hz and $\beta_2$ = 400 MW/0.1 Hz*

Generating capacity with supplementary control in area 1 is 4000 MW (on reserve) and in area 2 it is 1000 MW. These supplementary controls will keep $ACE_1$ and $ACE_2$ at zero.

$ACE_1 = \beta_1 \, \Delta f + \Delta P_{12} = 0$

$ACE_2 = \beta_2 \, \Delta f + \Delta P_{21} = \beta_2 \, \Delta f \quad \Delta P_{12} = 0$

This means $\Delta P_{12} = 0$ and $\Delta f = 0$

Thus the load and generation in area 1 are reduced by 1000 MW. There is no steady state deviation of tie–line power flow and frequency. The generation and load of area 2 also do not change.