Chapter 3

Problem Identification and System Modeling

3.1 Introduction

In a continuous control of the power system, it is necessary to match the active power demand and generation and to maintain steady – state frequency within a reasonable limit of standard frequency. Load frequency controller thus requires not only information about the change in frequency but also about the change in power demand. As this control is exercised through the speed – governing system, turbine and the synchronous machine, comparatively larger time constants of these components make the system slower in response. But on the other hand, excitation voltage control or QV control is exercised through voltage regulator and exciter having comparatively smaller time constant. For this reason the latter system is fast acting. Under transient condition thus dynamics of load frequency control remain unaffected by QV control dynamics. Constancy of system frequency and tie-line loading must be maintained for satisfactory performance of transformers, auxiliary induction motor drives of generating units in generating stations and large ac drives of various industries in very large scale interconnected systems [7], [9]. Thus automatic generation control in response to area load changes and abnormal system operating parameters and conditions in large-scale interconnected power systems has following objectives.

- The generation must be adequate to meet all the load demands.
- System frequency is to be satisfactorily maintained at or, very close to specified nominal value i.e. deviation in frequency (Δf) must be made zero as quickly as possible.

- Deviation in tie-line interchanges (ΔP_{tie}) from the pre-scheduled contracted interchanges among the areas must also be made zero as fast as possible.
- Lastly, optimal generation scheduling must also be done.

When real power balance between generation and demand is achieved the frequency specification is automatically satisfied. Similarly, with a balance between reactive power generation and demand, voltage profile is also maintained within the prescribed limits. Under steady state conditions, the total real power generation in the system equals the total MW demand plus real power losses. Any difference is immediately indicated by a change in speed or frequency. Generators are fitted with speed governors which will have varying characteristics: different sensitivities, dead bands response times and droops. They adjust the input to match the demand within their limits. Any change in local demand within permissible limits is absorbed by generators in the system in a random fashion [3]-[4].

3.2 Problem Identification

An independent aim of the automatic generation control is to reschedule the generation changes to preselected machines in the system after the governors have accommodated the load change in a random manner. Thus, additional or supplementary regulation devices are needed along with governors for proper regulation. For interconnected operation, the last of the four requirements mentioned earlier is fulfilled by deriving an error signal from the deviations in the specified tie-line power flows to the neighboring utilities and adding this signal to the control signal of the load-frequency control system. Should the generation be not adequate to balance the load demand, it is imperative that one of the following alternatives be considered for keeping the system in operating condition:

- Starting fast peaking units.

- Load shedding for unimportant loads, and
- Generation rescheduling.

It is apparent from the above that since the voltage specifications are not stringent, load frequency control is by far the most important in power system control. The block schematic for such a control is shown, in figure 3.1.

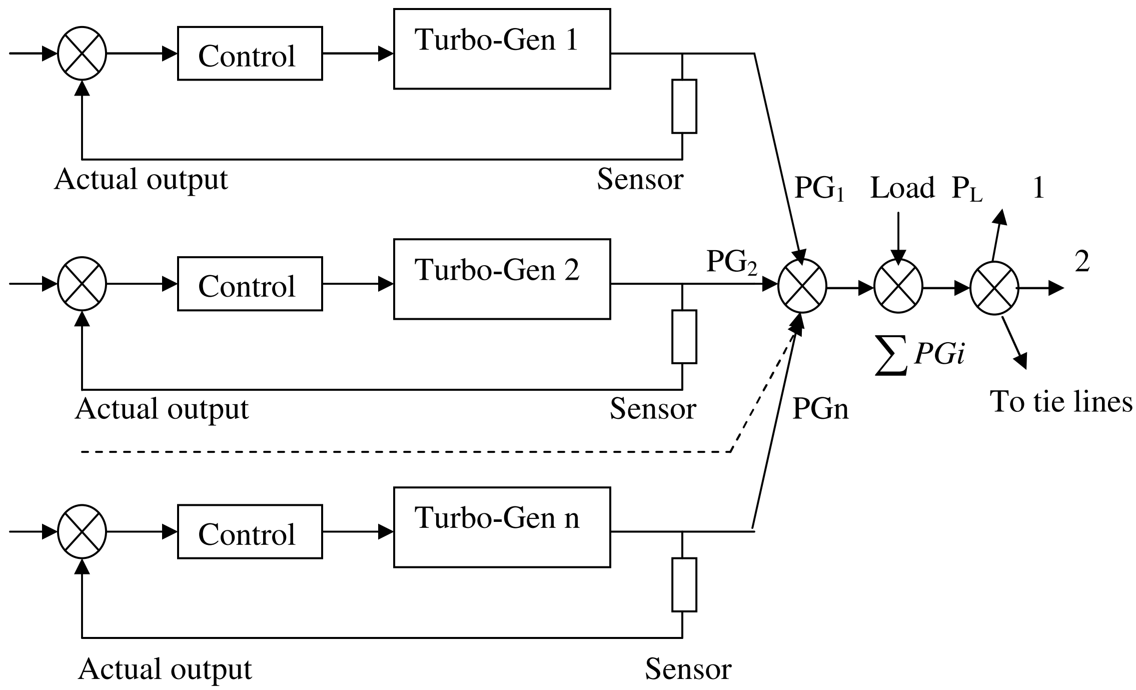

Figure 3.1: Schematic for Load frequency control

In order to understand the mechanism of frequency control, consider a small step increase in load. The initial distribution of the load increment is determined by the system impedance; and the instantaneous relative generator rotor positions. The energy required to supply the load increment is drawn from the kinetic energy of the rotating machines. As a result, the system frequency drops. The distribution of load during this period among the various machines is determined by the inertias of the rotors of the generators partaking in the process.

After the speed or frequency fall due to reduction in stored energy in the rotors has taken place, the drop is sensed by the governors and they divide the load increment between the machines as determined by the droops of the respective governor characteristics. Subsequently, secondary control restores the system frequency to its normal value by readjusting the governor characteristics [2], [5].

3.3 System Modeling

The first step in the analysis and design of a control system is mathematical modeling of the system. The two most common methods are the transfer function method and the state variable approach. The state variable approach can be applied to portray linear as well as non-linear systems. In order to use the transfer function and linear state equations, the system must first be linearized. Proper assumptions and approximations are made to linearize the mathematical equations describing the system, and a transfer function model is obtained for the components.

A generator driven by a turbine can be represented as a large rotating mass with two opposing torques acting on the rotation. 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 fast, 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 generators. 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.

3.3.1 Generator Model

Before starting, it will be useful to define terms.

ω = rotational speed (rad/sec)

α = rotational acceleration

δ = phase angle of a rotating machine

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

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_{net0}), and all deviations from nominal will be designated by a ($\Delta\omega$, ΔT_{net}). Some basic relationships are

$I\alpha = T_{net}$, $M = \omega I$

$$P_{net} = \omega T_{net} = \omega(I\alpha) = M\alpha \tag{3.1}$$

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 difference 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

$\omega = \omega_0 + \alpha t$, then

$$\Delta\delta = \underbrace{\int(\omega_0 + \alpha t)dt}_{\text{Machine absolute Phase angle}} - \underbrace{\int \omega_0 dt}_{\text{Phase angle of reference axis}} \tag{3.2}$$

$$= \omega_0 t + \frac{1}{2}\alpha t^2 - \omega_0 t$$

$$= \frac{1}{2}\alpha t^2 \tag{3.3}$$

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

$$\Delta\omega = \alpha t = \frac{d}{dt}(\Delta\delta) \tag{3.4}$$

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

$$T_{net} = I\ \alpha = I\ \frac{d}{dt}(\Delta\omega) = I\ \frac{d^2}{dt^2}(\Delta\delta) \tag{3.5}$$

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

$$P_{net} = P_{mech} - P_{elec} \tag{3.6}$$

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

$P_{net} = P_{neto} + \Delta P_{net}$, Where (3.7)

$P_{neto} = P_{mecho} - P_{eleco}$ (3.8)

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

$\Delta P_{net} = (P_{mecho} - P_{eleco}) + (\Delta P_{mech} - \Delta P_{elec})$ (3.9)

Similarly for torques,

$T_{net} = (T_{mecho} - T_{eleco}) + (\Delta T_{mech} - \Delta T_{elec})$ (3.10)

Using equation 3.1,

$P_{net} = P_{neto} + \Delta P_{net} = (\omega_0 + \Delta\omega)(T_{neto} + \Delta T_{net})$ (3.11)

Substituting equation 3.9 and obtain

$(P_{mecho} - P_{eleco}) + (\Delta P_{mech} - \Delta P_{elec}) = (\omega_0 + \Delta\omega)[(T_{mecho} - T_{eleco}) + (\Delta T_{mech} - \Delta T_{elec})]$ (3.12)

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

$P_{mecho} = P_{eleco}$, and

$T_{mecho} = T_{eleco}$

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

$\Delta P_{mech} - \Delta P_{elec} = \omega_0(\Delta T_{mech} - \Delta T_{elec})$ (3.13)

as shown in equation 3.5, the net torque is related to the speed change as follows:

$$(T_{mecho} - T_{eleco}) + (\Delta T_{mech} - \Delta T_{elec}) = I\frac{d}{dt}(\Delta\omega) \quad (3.14)$$

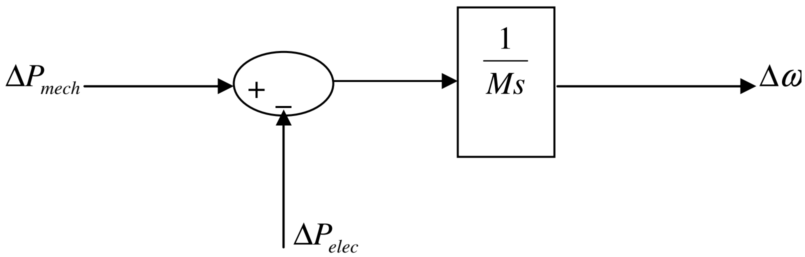

Figure 3.2: Block diagram relating mechanical power, electrical power and speed change.

Then since $T_{mecho} = T_{eleco}$, we can combine equations 3.13 and 3.14 to get

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

$$= M\frac{d}{dt}(\Delta\omega) \quad (3.15)$$

This can be expressed in Laplace transform operator notation as

$$\Delta P_{mech} - \Delta P_{elec} = Ms\ \Delta\omega \quad (3.16)$$

This is shown in block diagram form in figure 3.2. 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.

We shall define the inertia constant H such that

$$GH = K.E. = \frac{1}{2}M\ \omega_0 \ \text{MJ} \quad (3.17)$$

Where

G = machine rating (base) in MVA (3-phase)

H = inertia constant in MJ/MVA or MW-s/MVA

It immediately follows that

$$M = \frac{2GH}{\omega_0} = \frac{GH}{\pi f} MJ - s / elect \text{ rad}$$

$$= \frac{GH}{180 f} MJ - s / elect \text{ degree}$$

M is also called the inertia constant.

Taking G as base, the inertia constant in pu is

$$M \text{ (pu)} = \frac{H}{\pi f} \text{ s}^2 \text{/elect rad}$$

The angular velocity ω_i of the ith bus equals

$$\omega_i = \frac{d}{dt}(\omega_0 t + \delta_{0i} + \Delta\delta_i) = \omega_0 + \frac{d}{dt}\Delta\delta_i$$

and is no longer constant, since it evidently is characterized by a nonzero perturbation

$$\Delta\omega_i \triangleq \frac{d}{dt}\Delta\delta_i \qquad \text{rad./sec.} \tag{3.18}$$

or, if expressed in cycles per second**,**

$$\Delta f_i = \frac{1}{2\pi}\frac{d}{dt}\Delta\delta_i \text{ Hz} \tag{3.19}$$

3.3.2 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

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

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.

$$\text{i.e. } T_{pi} \triangleq \frac{2H_i}{f^0 D_i} \text{ s} \tag{3.20}$$

$$K_{pi} \triangleq \frac{1}{D_i} \text{ Hz / pu MW} \tag{3.21}$$

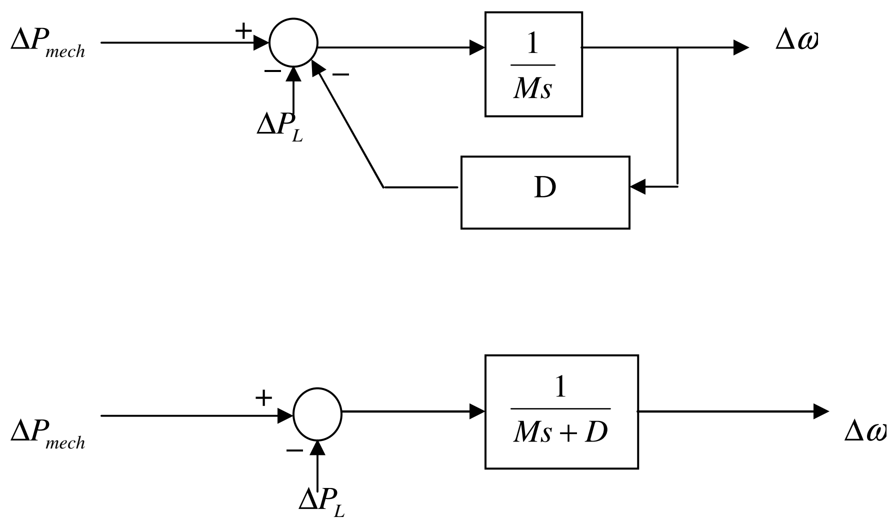

Figure 3.3: Block diagram of rotating mass and load as seen by prime-mover output

From equation (3.20) and (3.21) the rotating mass and load block can be replaced by equation (3.22)

$$G_{pi}(s) \triangleq \frac{K_{pi}}{1 + sT_{pi}} \tag{3.22}$$

3.3.3 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. 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. Such a speed-governing mechanism is illustrated and shown in Figure 3.4.

The speed-measurement device's output, ω, is compared with a reference, $\omega_{ref,}$ 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, $\Delta P_{VALVE,}$ which causes the main steam supply valve to open ($(\Delta P_{VALVE}\, position)$ when $\Delta\omega$ is negative.

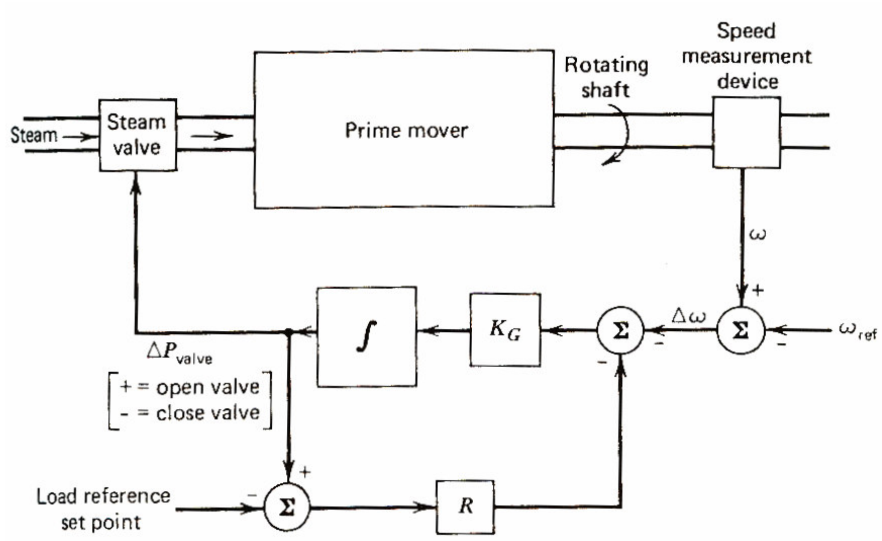

Figure 3.4: Speed-governing mechanism

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 output of the generator and increasing the speed ω. When ω exactly equals $\omega_{ref,}$ 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 3.4 can not 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 3.4. Here a new input is inserted (called load reference). The block diagram for this governor is shown in Figure 3.5, where the governor now has a net gain of 1/R and a time constant $T_{G.}$

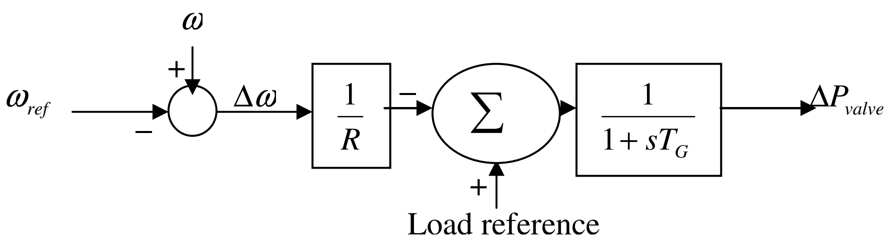

Figure 3.5: Block diagram for governor

3.3.4 Prime Mover Model

The prime mover driving a generator unit may be a steam turbine or a hydro turbine. 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.

The interest is not in turbine valve position per second, but rather the resulting generator power increase ΔP_{mech}. The change in valve position $\Delta X_{E,}$ causes an incremental increase in turbine power, $\Delta P_{T,}$ which, via the electromechanical interactions within the generator, will result in an increased generator power ΔP_{mech} *or* ΔP_G. This overall mechanism is relatively complicated, particularly if the generator voltage simultaneously undergoes wild swings due to major network disturbances.

If, as in the present case, we can assume that the voltage level is constant and the torque variations are of small size, then an incremental analysis of the type we performed for the speed governor will give a relatively simple dynamic relationship between ΔX_E and $\Delta P_{G.}$ Such an analysis reveals considerable differences, not only between steam turbines and hydro-turbines, but also between various types (reheat and non-reheat) of steam turbines. In the crudest model representation we can characterize a non-reheat turbine generator with a single gain factor K_T and a single time constant T_T, and thus write

$$G_T(s) \triangleq \frac{\Delta P_G(s)}{\Delta X_E(s)} = \frac{K_T}{1+sT_T} \tag{3.23}$$

Typically, the time constant T_T lies in the range 0.2 to 2 s. In standard block-diagram symbols we can represent transfer functions as shown in figure 3.6, diagram therefore represents the linearized model of a non reheat turbine controller, including the speed governor mechanism.

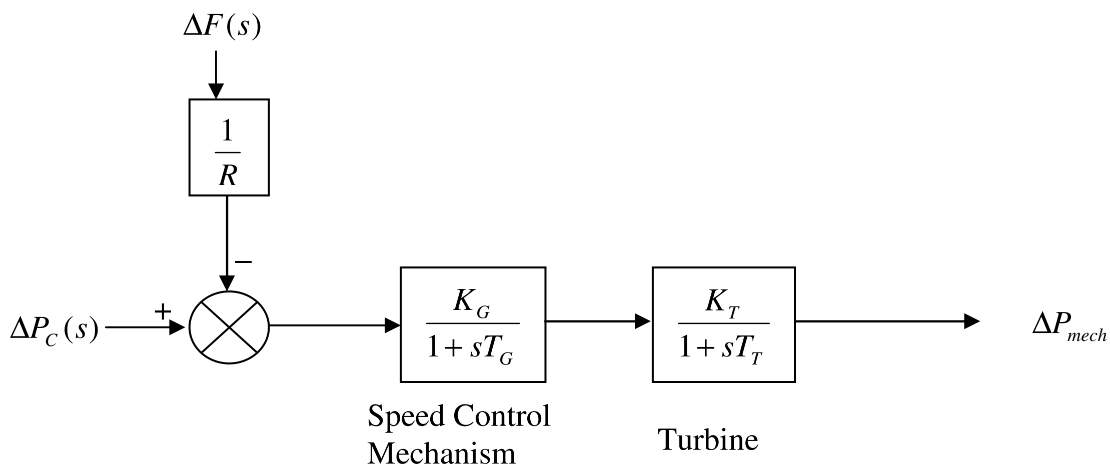

Figure 3.6: Block diagram of turbine generator including speed-control mechanism

In the above figure 3.6, transfer function representation of power control mechanism of generator where non-reheat turbine is assumed. A reheat turbine can quite adequately be represented by the transfer function block

$$G_T(s) \triangleq \frac{\Delta P_G(s)}{\Delta X_E(s)} = \frac{K_T(1+sK_rT_r)}{(1+sT_T)(1+sT_r)} \tag{3.24}$$

The time constant T_r has a value in the range of 10s, and approximates the time delay for charging the reheat section of the boiler. K_r is a reheat coefficient, equal to the proportion of torque developed in the high-pressure section of the turbine, which is approximately equal to 1 minus the fraction of steam reheated. Thus, when there is no reheat, $K_r = 0$, and the transfer function reduces to a single time constant and on the other hand the hydro turbine is given by the equation (3.24 a).

$$G_{hydro}(s) \triangleq \frac{\Delta P_G(s)}{\Delta X_E(s)} = \frac{1 - sT_w}{1 + 0.5sT_w} \qquad (3.24\ a)$$

The transfer functions represented by equation (3.23), equation (3.24) and equation (3.24 a) give good representation [6], [7], [39] [109].

3.4 Division of Power System into Control Areas

3.4.1 Definition of Control Area

The load frequency control, in contrast to the above, is handled collectively by a unison effort by all generator units within a so-called control area, usually; the boundaries of the control areas coincide with those of the individual power systems belonging to the pool. In the strictest sense, all the generators in a control area should constitute a coherent group. In the analysis to follow, coherency is assumed.

3.4.2 LFC in the Multi-area System

In many cases, groups of generators are closely coupled internally and swing in union. Furthermore, the generator turbines tend to have the same response characteristics. Then it is possible to let the LFC loop represent the whole system, which is referred to as a control area. The LFC of a multi-area system can be realized by studying first the AGC for a two area system. Consider two areas represented by an equivalent generating unit interconnected by a lossless tie line with reactance X_{tie}. Each area is represented by a voltage source behind an equivalent reactance as shown in figure 3.7.

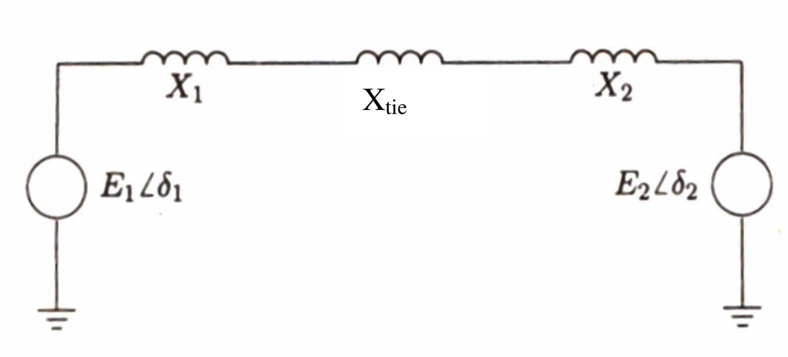

Figure 3.7: Equivalent Network for two area power system.

During normal operation, the real power transferred over the tie line is given by

$$P_{12} = \frac{|E_1||E_2|}{X_{12}} \sin \delta_{12} \qquad (3.25)$$

Where $X_{12} = X_1 + X_{tie} + X_2$, and $\delta_{12} = \delta_1 - \delta_2$. in equation 3.25 which can be linearized for a small deviation in the tie-line flow ΔP_{12} from the nominal value, i.e.,

$$\Delta P_{12} = \frac{dP_{12}}{d\delta_{12}}\bigg|_{\delta_{12_0}} \Delta\delta_{12}$$

$$= P_s \Delta\delta_{12}$$

The quantity P_s is the slope of the power angle curve at the initial operating angle $\delta_{12_0} = \delta_{1_0} - \delta_{2_0}$. This was defined as the synchronizing power coefficient. Thus we have

$$P_s = \frac{dP_{12}}{d\delta_{12}}\bigg|_{\delta 12_0} = \frac{|E_1||E_2|}{X_{12}} \cos \delta_{12_0}$$

The tie-line power deviation then takes on the form

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

The tie-line power flow appears as a load increase in one area and a load decrease in the other area, depending on the direction of the flow. The direction of flow is dictated by the phase angle difference; if $\Delta\delta_1 > \Delta\delta_2$, the power flows from area 1 to area 2. A block diagram representation for the two-area system with LFC containing only primary loop is shown in figure 3.8.

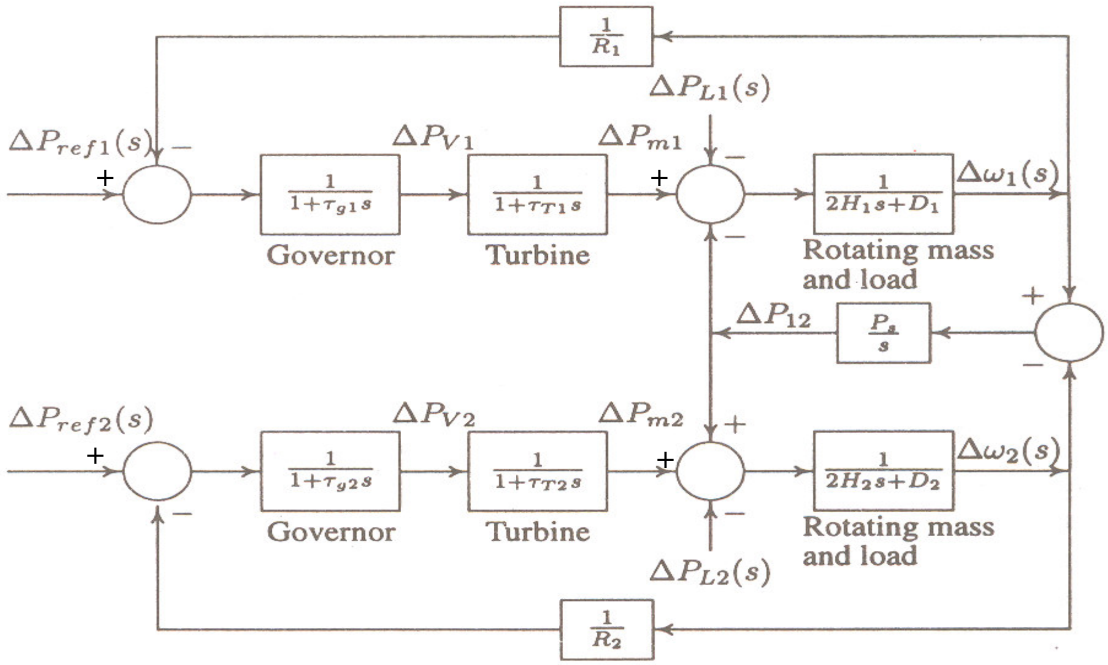

Figure 3.8: Two area model with only primary LFC loop

Let us consider a load change ΔP_{L1} in area 1. In the steady-state, both areas will have the same steady-state frequency deviation, i.e.

$$\Delta\omega = \Delta\omega_1 = \Delta\omega_2$$

and

$$\Delta P_{m1} - \Delta P_{12} - \Delta P_{L1} = \Delta\omega D_{1.}$$

$$\Delta P_{m2} + \Delta P_{12} = \Delta\omega D_2 \tag{3.26}$$

The change in mechanical power is determined by the governor speed characteristics, given by

$$\Delta P_{m1} = \frac{-\Delta\omega}{R_1} \quad , \quad \Delta P_{m2} = \frac{-\Delta\omega}{R_2} \tag{3.27}$$

Substituting from (3.27) into (3.26), and solving for $\Delta\omega$, we have

$$\Delta\omega = \frac{-\Delta P_{L1}}{(\frac{1}{R_1}+D_1)+(\frac{1}{R_2}+D_2)}$$

$$= \frac{-\Delta P_{L1}}{B_1 + B2}$$

where, $$B_1 = \frac{1}{R_1}+D_1$$

$$B_2 = \frac{1}{R_2}+D_2$$

B_1 and B_2 are known as the frequency bias factors. The change in the tie-line power is

$$\Delta P_{12} = -\frac{(\frac{1}{R_1}+D_2)\Delta P_{L1}}{(\frac{1}{R_1}+D_1)(\frac{1}{R_2}+D_2)}$$

$$= \frac{B_2}{B_1+B_2}(-\Delta P_{L1}) \qquad (3.28)$$

3.4.3 Tie-Line Bias Control

So far LFCs were equipped with only the primary control loop; a change of power in area 1 was met by the increase in generation in both areas associated with a change in the tie-line power, and a reduction in frequency. In the normal operating state, the power system is operated so that the demands of areas are satisfied at the nominal frequency. A simple control strategy for the normal mode is

- Keep frequency approximately at the nominal value.
- Maintain the tie-line flow at about schedule.

- Each area should absorb its own load changes.

Conventional LFC is based upon tie-line bias control, where each area tends to reduce the area control error (ACE) to zero. The control error for each area consists of a linear combination of frequency and tie-line error.

$$\mathrm{ACE}_i = \sum_{j=1}^{n} \Delta P_{ij} + K_i \Delta f \qquad (3.29)$$

The area bias K_i determines the amount of interaction during a disturbance in the neighboring areas. An overall satisfactory performance is achieved when K_i is selected equal to the frequency bias factor of the area, i.e., $B_i = \frac{1}{R_i} + D_i$. Thus, the ACEs for a two-area system are

$$\mathrm{ACE}_1 = \Delta P_{12} + B_1 \Delta f_1 \qquad (3.30\ a)$$

$$\mathrm{ACE}_2 = \Delta P_{21} + B_2 \Delta f_2 \qquad (3.30\ b)$$

Where ΔP_{12} and ΔP_{21} are departures from scheduled interchanges. ACEs are used as actuating signals to activate changes in the reference power set points, and when steady-state is reached, ΔP_{12} and Δf will be zero. The integrator gain constant must be chosen small enough so as not to cause the area to go into a chase mode. We can easily extend the tie-line bias control to an n-area system.

3.5 Complete System Dynamic Model

The complete dynamic model for the system to be studied is developed. Two assumptions are made. The first assumption is that for incremental changes in demand power, control of real power and frequency, and control of reactive power and voltage, are decoupled and can be considered separately. The load-frequency control problem is the first of the two problems. By maintaining control over the real power the frequency deviation is kept within prescribed limits. The second assumption is that the individual electrical connections within an area are so strong in comparison to the ties between adjoining areas, that each area may be represented by a single frequency. In other words, all generators in a single area swing in unison during changes in area load.

Power Equilibrium Equation:

The net surplus power in an area, represented by the difference in increased generation ΔP and increased demand $\Delta P_{d,}$ is absorbed by the system in three ways:

1) Increased kinetic energy represented by $\left(2W_{kin} / f^{*}\right)\frac{d}{dt}\Delta f$ where W_{kin} is the kinetic energy of the system and f^{*} is the nominal frequency;
2) Increased load consumption represented by $D\,\Delta f$, where the constant D, MW/H_z, is the rate at which system load changes with frequency evaluated at nominal frequency f^{*};
3) Increased export of power over tie lines represented by $\Delta P_{tie.}$

Expressing what has been said in mathematical form gives the power equilibrium equation in per unit for area i:

$$\frac{2H_i}{f\,*}\;\frac{d}{dt}\Delta f_i + D_i\Delta f_i + \Delta Ptie_i \;=\; \Delta P_{Gi} - \Delta P_{df} \qquad (3.31)$$

where, $H \underline{\underline{\Delta}} \frac{W_{kin}}{P_{ri}}$ inertia constant, seconds

$P_{ri} =$ Rated power of area i, MW.

Tie-line Power:

The total real power exported from area i equals the sum of all out flowing line powers $P_{tie\quad iv}$ to adjoining areas v, i.e.,

$$P_{tie\ i} = \sum_{v} P_{tie\ iv}$$

the real power in per unit transmitted across a lossless line of reactance X_{iv} is

$$P_{tie\ iv} = \frac{|V_i||V_v|}{X_{iv} P_{ri}} \sin(\delta_i - \delta_v) \tag{3.32}$$

where

$$V_i = |V_i| e^{j\delta i}$$

$$V_v = |V_v| e^{j\delta v}$$

Assuming small deviation in phase angles $\delta_i = \delta_i^* + \Delta\delta_i$ and realizing that

$$\Delta\delta_i = 2\pi \int \Delta f_i \ \ dt$$

the expression for incremental changes in tie-line power in area i is

$$\Delta P_{tie\ \ i} = \sum_{v} T_{iv}^{\ *} (\int \ \Delta f_i \ \ dt - \int \ \Delta f_v \ \ dt)$$

where

$$T_{iv}^{\ *} \underline{\underline{\Delta}} \ 2\pi \frac{|V_i||V_v|}{X_{iv} P_{ri}} \cos \ (\delta_i^{\ *} - \delta_v^{\ *}). \tag{3.33}$$

Incremental Generated Power:

The real power generated by a synchronous machine is controlled by means of the prime mover torque. A study of the system for small changes around nominal settings reveals that the generator-turbine-governor system may be represented by two time constants, T_t of the turbine and T_g of the governor. The generator response is considered to be instantaneous in comparison with the time constants of the turbine and governor.

We can write

$$\frac{d}{dt}\Delta P_g = -\frac{1}{T_t}\Delta P_g + \frac{1}{T_t}\Delta X_{gv} \qquad (3.34)$$

$$\frac{d}{dt}\Delta X_{gv} = -\frac{1}{T_g}\Delta X_{gv} - \frac{1}{T_g R}\Delta f + \frac{1}{T_g}\Delta P_c \qquad (3.35)$$

where ΔP_g is the incremental change in generation in pu MW, ΔX_{gv} is the incremental change in the governor valve position in pu MW, R is the self-regulation of the generator in Hz/pu MW, and ΔP_c is the incremental change in the speed changer position in pu MW.

System Equation:

Taking the equations for the power equilibrium, the incremental tie-line flow, and the change in generation and position of the speed governor in area i, we have

$$\frac{2H_i}{f*}\ \frac{d}{dt}\Delta f_i + D_i\Delta f_i + \sum_v T_{iv}{}^{*}\left(\int \Delta f_i dt - \int \Delta f_v dt\right) = \Delta P_{Gi} - \Delta P_{di} \qquad (3.36)$$

$$\frac{d}{dt}\Delta P_{Gi} = -\frac{1}{T_{ti}}\Delta P_{Gi} + \frac{1}{T_{ti}}\Delta X_{gvi} \qquad (3.37)$$

$$\frac{d}{dt}\Delta X_{gvi} = -\frac{1}{T_{gi}}\Delta X_{gvi} - \frac{1}{T_{gi}R_i}\Delta f_i + \frac{1}{T_{gi}}\Delta P_{ci} \qquad (3.38)$$

For each area we have this set of three differential equation describing the dynamic performance of the system to incremental load changes.

3.5.1 Dynamic System in State Variable Form

The three equations (3.36)-(3.38) that describe a single area of the multi-area system must be rewritten in terms of the state and control variables. The state and control variables are defined in the following way:

$$x_1 \triangleq \int \Delta P_{tie\ 1}\, dt$$

$$x_2 \triangleq \int \Delta f_1\, dt$$

$$x_3 \triangleq \Delta f_1$$

$$x_4 \triangleq \Delta P_{g1}$$

$$x_5 \triangleq \Delta X_{gv1}$$

$$u_1 \triangleq \Delta P_{c1}$$

In each area the control input is the generator power. By manipulating the output of the generator we can maintain the frequency deviation within limits following load changes. To vary the generator power, we must change the speed-changer position. Hence we define the control variable as the speed-changer position.

The variables that change as a result of surplus power in an area are the governor valve position, the generator output, the frequency deviation, and the tie-line power, which is a function of the integral of frequency deviation. We define these variables as states. The integral of tie-line deviation must also be defined as a state. One of the specifications we place on the system is that the tie-line deviation be zero following a step-load disturbance. To guarantee this we must have knowledge of the integral of the tie-line deviation.

For each area there is a set of five state variables and one control input. However in the two-area problem, the tie-line deviation in the first area is proportional to the tie-line deviation in the second by a constant is considered:

$$\Delta P_{tie\ 2} = a_{12} \Delta P_{tie\ 1}$$

where, $$a_{12} \triangleq -P_{r1} / P_{r2}$$

In this case we need not define an additional state for the integral of tie-line deviation in area 2.

Matrices A and B-Two-Area Problem

For the two-area problem the states and the control variables

$$x_1 \triangleq \int \Delta P_{tie1} \, dt$$

$$x_2 \triangleq \int \Delta f_1 \, dt$$

$$x_3 \triangleq \Delta f_1$$

$$x_4 \triangleq \Delta P_{g1}$$

$$x_5 \triangleq \Delta X_{gv1}$$

$$u_1 \triangleq \Delta P_{c1}$$

$$x_6 \triangleq \int \Delta f_2 dt$$

$$x_7 \triangleq \Delta f_2$$

$$x_8 \triangleq \Delta P_{g2}$$

$$x_9 \triangleq \Delta X_{gv2}$$

$$u_2 \triangleq \Delta P_{c2}.$$

Substituting the definition of the states and the control into the six differential equations that define the two-area problem places the system in the form $\dot{x}$ = Ax + Bu + Γ ΔP_d where

$$A = \begin{bmatrix} 0 & T_{12^*} & 0 & 0 & 0 & -T_{12^*} & 0 & 0 & 0 \\ 0 & 0 & 1 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & -\frac{f^*T_{12^*}}{2H_1} & \frac{f^*D_1}{2H_1} & \frac{f^*}{2H_1} & 0 & \frac{f^*T_{12^*}}{2H_1} & 0 & 0 & 0 \\ 0 & 0 & 0 & -\frac{1}{T_{t1}} & \frac{1}{T_{t1}} & 0 & 0 & 0 & 0 \\ 0 & 0 & -\frac{1}{T_{gv1}R_1} & 0 & -\frac{1}{T_{gv1}} & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 1 & 0 & 0 \\ 0 & -\frac{a_{12}f^*T_{12}{}^*}{2H_2} & 0 & 0 & 0 & \frac{a_{12}f^*T_{12^*}}{2H_2} & -\frac{f^*D_2}{2H_2} & \frac{f^*}{2H_2} & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & -\frac{1}{T_{t2}} & \frac{1}{T_{t2}} \\ 0 & 0 & 0 & 0 & 0 & 0 & -\frac{1}{T_{gv2}R_2} & 0 & -\frac{1}{T_{tv2}} \end{bmatrix}$$

$$B' = \begin{bmatrix} 0 & 0 & 0 & 0 & \frac{1}{T_{gv1}} & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & \frac{1}{T_{gv2}} \end{bmatrix}$$

$$\Gamma' = \begin{bmatrix} 0 & 0 & -\dfrac{f^*}{2H_1} & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & -\dfrac{f^*}{2H_2} & 0 & 0 \end{bmatrix}$$

The matrix Γ, which is of dimension n x p, is called the disturbance distribution matrix. We observe that our model is not in the form we desire for two reasons. First, in the optimal control theory there is no Γ matrix, and second, the cost function requires the states to be driven to zero for it to have a minimum. For a step-load change in area 1, we will require the steady-state frequency deviation in each area to be zero. But the increased generation in area 1 will by necessity in steady state equal the increased demand, a nonzero quantity:

$$\Delta P_{g1} = \Delta P_{d1}.$$

Some of the other states will also be nonzero.

the states in terms of their steady-state values are redefined, i.e.,

$$x_i^1 \triangleq x_i - x_{iss,} \;\; i = 1,2, \ldots, \text{n}.$$

This change of variable puts the system in the form

$$x^1 = Ax^1 + Bu^1$$

$$x^1(0) = -x_{ss}.$$

By redefining the state in terms of their steady-state values we have shifted the reference position of the system. We shall drop the superscript 1 to prevent unnecessary notation problems. The matrices A and B remain unchanged.

After the complete system model for two-area with non-reheat turbine system without generation rate constraint in state variable form and transfer function form, three area system can also be designed following the same steps. Main emphasis is now given on controller design, which is discussed in detail in the next chapter. Before elaborating control strategies, all models studied for load frequency control problem here are shown below.

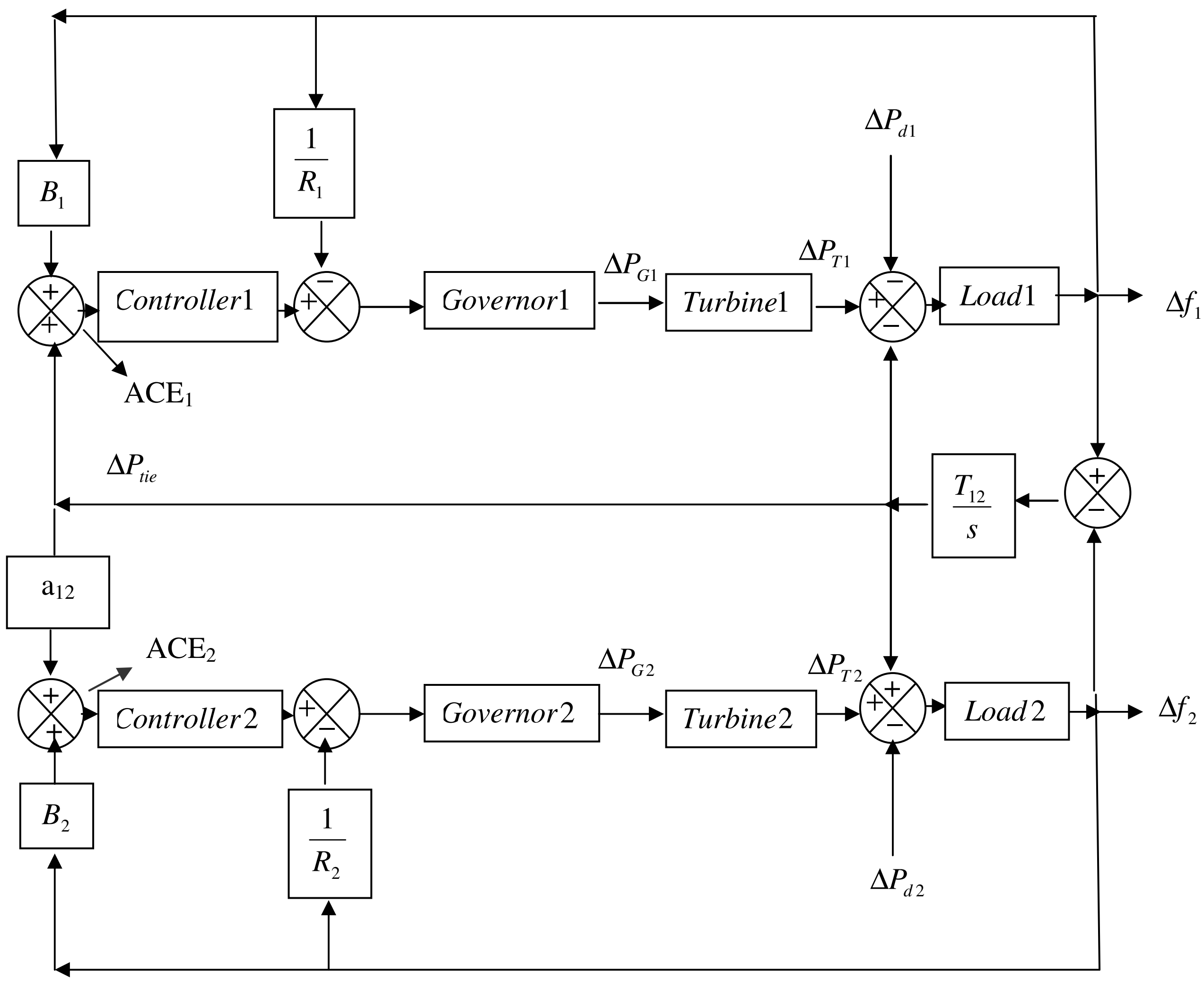

Figure 3.9: Generalized two area model with primary and secondary control

Figure 3.9 is generalized block diagram with primary and secondary control of two area system. In case of non-reheat steam turbine, governor and turbine will be represented by equation 3.39 (a) and 3.39 (b) while the load by equation 3.39 (c).

Governor transfer function = $\frac{K_{Gi}}{1+sT_{Gi}}$ (3.39 a)

Turbine transfer function = $\frac{K_{Ti}}{1+sT_{Ti}}$ (3.39 b)

Load transfer function = $\frac{K_{Pi}}{1+sT_{Pi}}$ (3.39 c)

In case of reheat steam turbine, another block for reheat will be cascaded with turbine block given in equation (3.24). The load frequency control problem discussed so far does not consider the effect of the restriction on the rate of change of power generation. In power systems having steam plants, power generation can change only at a specified maximum rate. The generation rate for reheat units is quite low and most of them have a GRC between 5 % to 10 %. The generation rate in the hydro area normally remains below safe limit and therefore GRCs for all the hydro plants can be ignored. Non-linear turbine model with generation rate constraint is presented in figure 3.10.

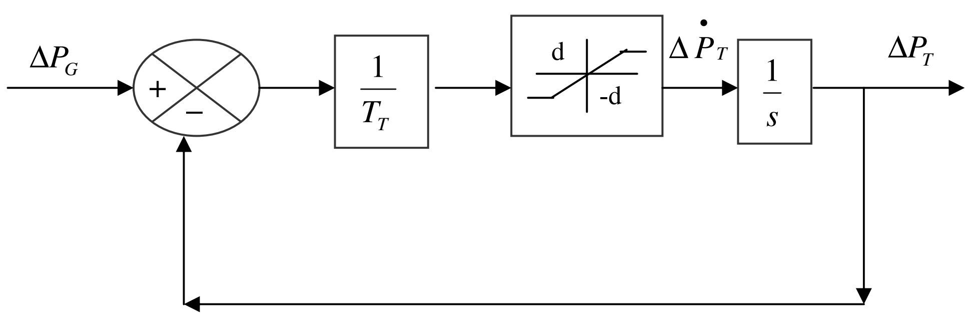

Figure 3.10: Non-linear turbine model with GRC

The three area system with non-reheat turbine is shown in figure 3.11. Similarly this model can also be analyzed with reheat turbine and GRC. Dynamic performance analysis of all above mentioned models is carried out with different operating conditions, mainly varying B, $T_{tie,}$ and $T_{P.}$ Observations are also taken when; Area 1 is subjected to sudden disturbance, Area 2 is subjected to sudden disturbance and Any two areas are subjected to sudden disturbance.

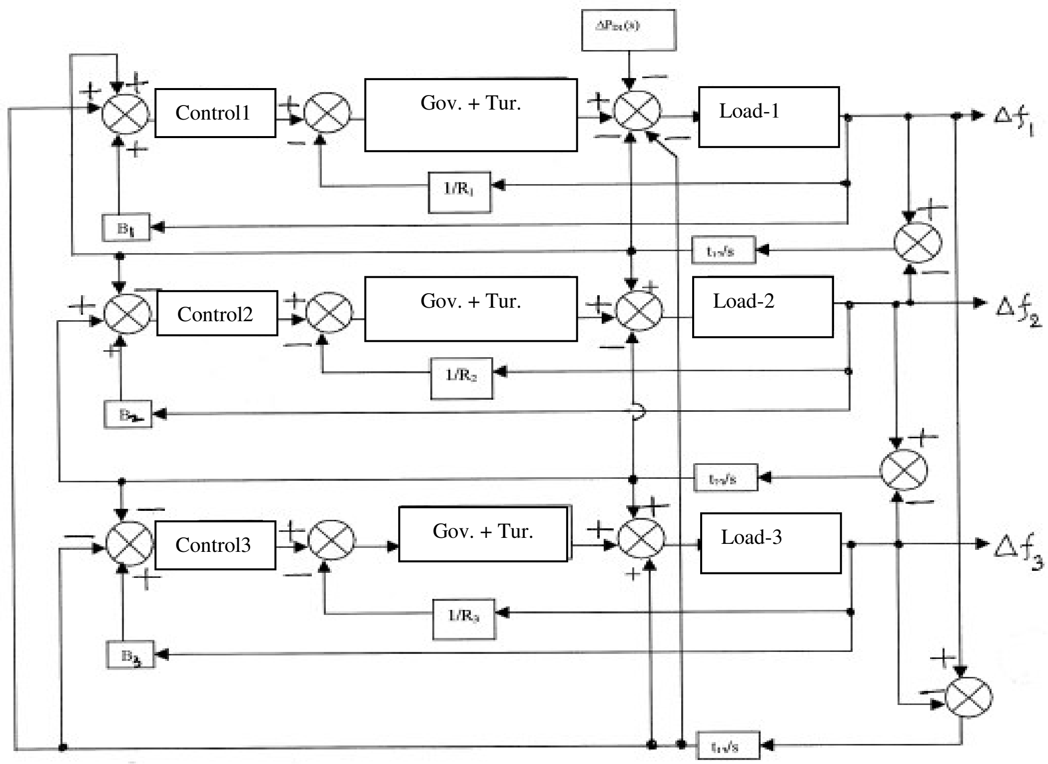

Figure 3.11: Three area interconnected power system

Another technique studied for dynamic performance enhancement of two area interconnected power system in this work, is use of parallel AC/DC transmission link when subjected to parametric uncertainties. The dynamic model of incremental power flow through DC transmission link is derived based on frequency deviation at rectifier end. Moreover, the DC link is considered to be operating in constant current control mode. The single line diagram of power system model under study is shown in figure 3.12 and its transfer function block diagram is described in figure 3.13. The transmission links are considered as long transmission lines specifically of length (L_{ac} and L_{dc}) greater than break even distance length of EHVAC and HVDC transmission lines.

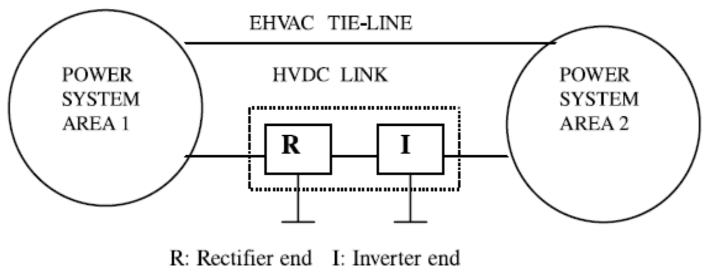

Figure 3.12: Two-area power system with parallel EHVAC/HVDC links.

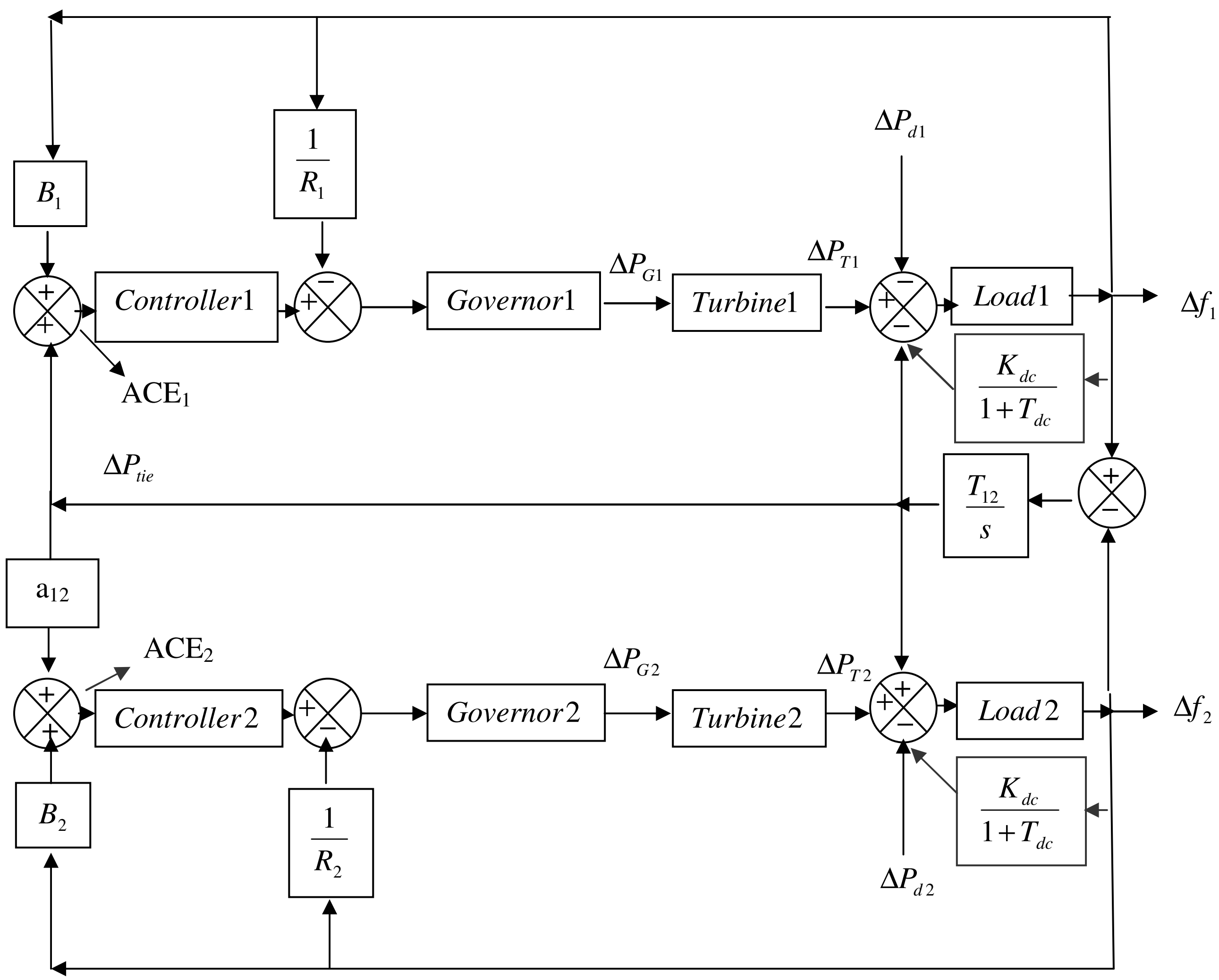

Figure 3.13: Transfer function block diagram with DC link for two area system.

Having designed all models for the study of load frequency control problem of interconnected power system, next step is to decide the control strategy for the same. Three different types of control strategies have been discussed to comprehensively analyze the dynamic performance of two and three area interconnected power system with different operating conditions. Dynamic performance characteristics like peakovershoot and settling time for the systems are studied and compared with other researcher's work.

3.6 Summary

This chapter thoroughly discusses the mathematical models of two area and three area interconnected power system. Transfer function and state variable models for each component contributing in load frequency control problem of interconnected system have been devised. Apart from linearity and non reheat turbine model, reheat turbine and non-linear model are also designed to make system more realistic. HVDC link parallel to EHVAC link is also incorporated in study for improvement of dynamic performance enhancement and achieving the objectives of load frequency control.