5.2. Use of storage technologies for ancillary services provision and its potential for climate change mitigation

Appendix A
Generation Control

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Appendix A

Generation control

A.1 Introduction

The control of the generating units was the first problem faced in the operation of power systems. The methods developed for the control of individual generators and extensive interconnections play a vital role in modern power control centres.

The active and reactive power flows in a transmission system are considered independent of each other and are influenced by different control actions. Control of active power is closely related to control of frequency, and control of reactive power is closely associated with control of voltage *(Kundur, 1994)*. As frequency and voltage constancy are essential factors in determining the quality of power supply, control of active and reactive power is vital for satisfactory operation of the power system.

This appendix focuses on active power and frequency control, specifically on the load-frequency problem.

A generator driven by a steam turbine can be represented as a large rolling mass with two opposing pairs acting on the axis of rotation. As shown in Figure A.1, the mechanical torque, Tmech, works to increase the rotational speed, while the electrical torque, Telec, acts to decrease it. When Tmech and Telec are equal in magnitude, the angular velocity will be constant. If the electrical load increases so that Telec is higher than Tmech, the whole rolling system will start to brake *(Kundur, 1994)*, *(A. J. Wood, B. F. Wollenberg, 1996)*.

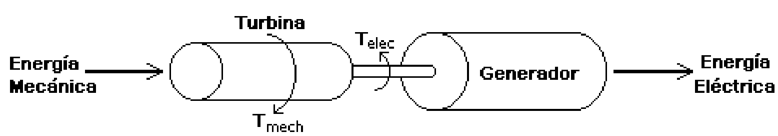

Fig. A.1 Mechanical and electrical torques in a generating unit.

This process is often repeated in a power system because the loads are continually changing. Since there are many generators supplying power to the transmission system, some means must be provided to allocate the load changes in the generators. A series of control actions are dictated to the generator units to accomplish this. A governor on each unit maintains its speed, while a supplemental control, usually managed at a remote control centre, acts to allocate generation.

A.2 Generator model

The following terms are defined:

ω is the angular velocity (rad/s) ɑ is the angular acceleration (rad/s^2)

δ is the phase angle of the rotating machine (rad)

Tnet is the net acceleration torque in a machine

Tmech is the mechanical torque exerted on the rotor by the turbine

Telec is the electrical torque exerted on the rotor by the generator

Pnet is the net acceleration power

Pmech is the mechanical power input

Pelect is the electrical power output

I is the moment of inertia for the machine

H is the machine inertia constant

M is the angular momentum of the machine

Hereafter, it is assumed that all quantities (except the phase angle) will be in per unit based on the nominal data of the machine, or, in the case of ω, on the standard base frequency of the system. Then, for example, M is in power per unit/frequency per unit/second.

In the following, we are interested in deviations of quantities around their steady-state values. All steady-state or nominal values will have a subscript "0" (example: Tnet0), and all deviations from the nominal value will be designated by a Δ (example: ΔTnet). Some necessary relations are:

$$I\alpha = T_{net} \tag{A.1}$$

$$M = 2H = \omega I \tag{A.2}$$

$$P_{net} = \omega T_{net} = \omega(I\alpha) = M\alpha \tag{A.3}$$

As a start, it is considered only a rotary machine. Assuming the device has a stable speed of ω_0 and phase angle δ_0. Due to mechanical and electrical disturbances, the rotor will be subject to mechanical and electrical torque differences, causing it to accelerate or decelerate. Due to mechanical and electrical disturbances, the rotor will be subject to mechanical and electrical torque differences, causing it to accelerate or decelerate.

The phase angle deviation, $\Delta\delta$, is equal to the phase angle difference between the machine subject to constant acceleration α and a rotating reference axis that rotates at speed ω_0 *(A. J. Wood, B. F. Wollenberg, 1996)*.

The deviation in the nominal speed, $\Delta\omega$, can then be expressed as,

$$\Delta\omega = \alpha t = \frac{d}{dt}(\Delta\delta) \tag{A.6}$$

From Newton's second law, can be expressed in Laplace operator as (A. J. Wood, B. F. Wollenberg, 1996), (F. Aboytes et al, 1990), (F. Aboytes, 1985), Fig. A.2.

$$\Delta P_{mech} - \Delta P_{elec} = Ms\Delta\omega \qquad \text{(A.17)}$$

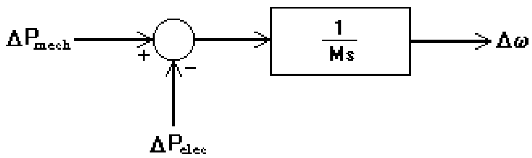

Fig. A.2 Relationship between mechanical and electrical power and speed change.

Within the range of study for speed variation, the mechanical power of the turbine is mostly a function of the position of its valve or gate, and independent of frequency.

The units for M are watts per radians per square second. Power per unit will always be used over speed per unit per second, where per unit refers to the machine's nominal values.

A.3 Load model

The load on a power system consists of a variety of electrical devices. Some of them are purely resistive, some are motors with variable power-frequency characteristics, and others exhibit quite different characteristics *(Kundur, 1994)*, *(A. J. Wood, B. F. Wollenberg, 1996)*, *(F. Aboytes et al, 1990)*. The relationship between the change in load due to the change in frequency is given by,

$$\Delta P_{L(freq)} = D\Delta\omega \qquad \text{o} \qquad D = \frac{\Delta P_{L(freq)}}{\Delta\omega}$$

where the load-damping constant, D, is expressed as the percentage change in load divided by the percentage change in frequency *(Kundur, 1994), (A. J. Wood, B. F. Wollenberg, 1996), (F. Aboytes et al., 1990), (F. Aboytes, 1985)*. For example, if the load changes by 1.5% for a 1% change in frequency, then D would equal 1.5. However, the value of D used to find the dynamic response of the system must be changed if the MVA basis of the system is different from the nominal value of the load.

Thus the net change in electrical power, Pelec, in Figure A.2 (Eq. A.17) becomes

$$\Delta P_{elec} = \underline{\Delta P_L} + \underline{D\Delta\omega} \qquad \text{(A.18)}$$

Change of load Not sensitive to frequency	Frequency Sensitive Load Change.

Including this in the block diagram results in the new diagram shown in Fig. A.3 *(A. J. Wood, B. F. Wollenberg, 1996)*, *(F. Aboytes et al, 1990)*.

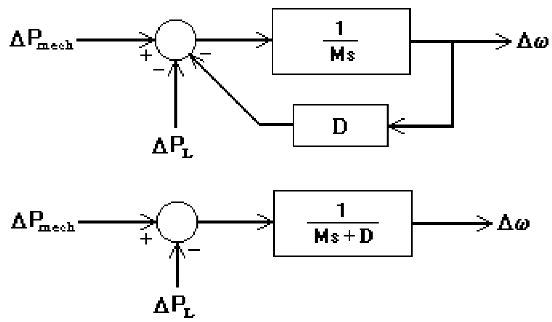

Fig.A.3 Block diagram of rotating mass and load as seen from the turbine outlet

In the absence of a speed governor, the response of the system to a change in load is determined by the inertia constant and the damping constant. The steady-state speed deviation is such that the load change is precisely compensated by the frequency sensitive load variation.

When two or more generators are connected in a transmission network, the difference in phase angle across the network must be taken into account when analysing changes in frequency. However, for the governor's analysis, for convenience, it can be assumed that the frequency will be constant in those parts of the network that are strictly interconnected. Then the rotating mass of the turbines and generators can be joined into an equivalent rotating mass, Mequiv, which is driven by the sum of the individual mechanical outputs of the turbines *(A. J. Wood, B. F. Wollenberg, 1996)*, *(F. Aboytes et al, 1990)*. Similarly, the effects of all loads are joined into an equivalent load with damping coefficient, Dequiv. The equivalent generator speed represents the system frequency, and in per unit the two are equal. The rotor speed and frequency will then be used interchangeably in the study of load-frequency control, Fig. A.5.

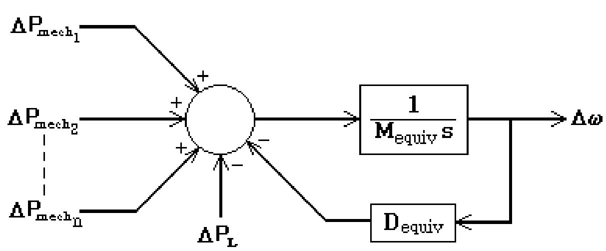

Fig.A.5 Multi-turbine-generator equivalent system

A.4 Turbine model

The prime mover that drives a generating unit can be a steam turbine or a water turbine. Prime mover models must take into account the characteristics of the steam supply system and the boiler control system in the case of a steam turbine *(Kundur, 1994), (A. J. Wood, B. F.*

Wollenberg, 1996), *(F. Aboytes et al, 1990)*. The simplest model of the prime mover, the non-overheating turbine, should then be used.

The model for a non-overheating turbine, shown in Figure A.6, relates the position of the valve that controls the steam emission inside the turbine to the turbine output

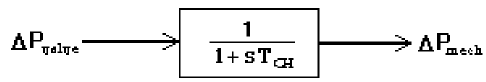

Fig.A.6 Prime mover model

where:

T_{CH} is the time constant "charging time". (typical value = 0.3 s).

ΔP_{valve} is the change in valve position from the nominal position in per unit.

The combined model of the turbine, generator and load for a single generating unit is achieved by combining Figure A.3 and A.6, Fig. A.7.

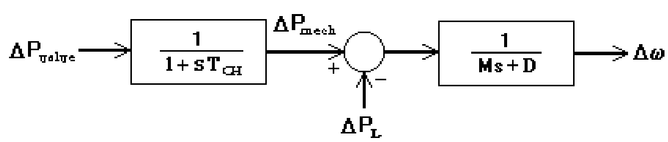

Fig.A.7 Model of turbine-generator-load

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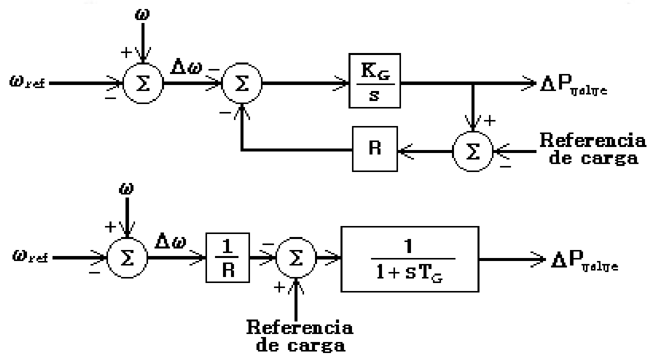
A.5 Governor model

Suppose that a generating unit is operated with constant mechanical power in the turbine. The result of any change in load would be a change in speed sufficient to cause the frequency sensitive load to compensate precisely for the difference in load. This condition would cause the frequency to be outside acceptable limits. This is resolved by placing a governor mechanism that measures the speed of the machine and adjusts the position of the input valve. This modifies the mechanical power output to compensate for the load changes and to reset the frequency to its nominal value.

Fig. A.11 illustrates the block diagram of a governor with a net gain of 1/R and a time constant TG.



where: $T_G = \dfrac{1}{K_G R}$

Fig.A.11 Governor block diagram with speed drop

The result of adding a feedback loop with R gain represents a feature, Fig. A.12. The value of R determines the slope of the characteristic. That is, R determines the change in the unit's power output for a given change in frequency. R is set at each generation unit so that a change from 0 to 100% in the power output results in the same frequency change for each unit. As a result, a change in the electrical load in the system will be compensated by a change in the output of the generating units proportional to the nominal capacity of each unit *(F. Aboytes et al., 1990), (F. Aboytes, 1985)*.

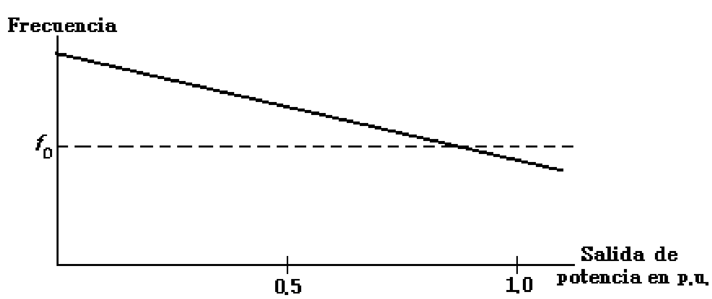


Fig. A.12 Speed drop feature

At this point, the block diagram can be constructed: governor, prime mover, rotating mass and load, as shown in Figure A.16 *(A. J. Wood, B. F. Wollenberg, 1996), (F. Aboytes et al., 1990)*.

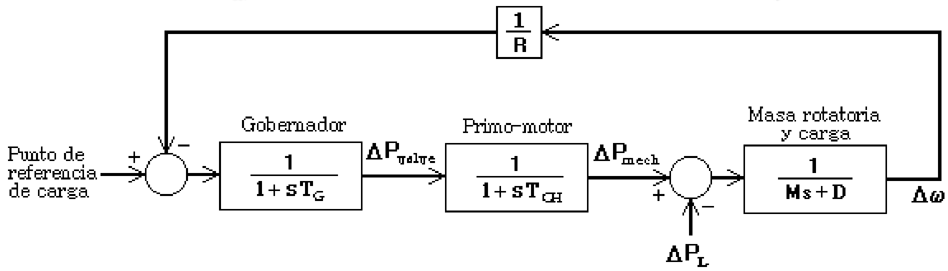


Fig. A.16 Block diagram of the governor, prime mover and rotating mass

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

$$\Delta\omega = \frac{-\Delta P_L}{\frac{1}{R_1}+\frac{1}{R_2}+\ldots+\frac{1}{R_n}+D} = \frac{-\Delta P_L}{\frac{1}{R_{eq}}+D} \tag{A.23}$$

where

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

$$\beta = \frac{-\Delta P_L}{\Delta\omega} = \frac{1}{R_{eq}}+D \tag{A.24}$$

The composite frequency response characteristic, β, is generally expressed in MW/Hz. It is also sometimes referred to as the rigidity of the system. The composite attribute of system regulation is 1/β.

A.6 Model of the link

The power flowing through a transmission line can be approximated by *(A. J. Wood, B. F. Wollenberg, 1996)*,

$$P_{tieflow} = \frac{1}{X_{tie}}(\theta_1 - \theta_2) \tag{A.25}$$

This is the amount of steady-state link flow. For analysis purposes, Eq. A.25 is disturbed to obtain deviations from the nominal power flow as a function of phase angle deviations from the nominal value.

$$P_{tieflow} + \Delta P_{tieflow} = \frac{1}{X_{tie}}\left[(\theta_1 + \Delta\theta_1) - (\theta_2 + \Delta\theta_2)\right]$$

$$= \frac{1}{X_{tie}}(\theta_1 - \theta_2) + \frac{1}{X_{tie}}(\Delta\theta_1 - \Delta\theta_2) \quad \text{(A.26)}$$

Then

$$\Delta P_{tieflow} = \frac{1}{X_{tie}}(\Delta\theta_1 - \Delta\theta_2) \quad \text{(A.27)}$$

where $\Delta\theta_1$ y $\Delta\theta_2$ become equivalents to $\Delta\delta_1$ y $\Delta\delta_2$, Eq. A.6. Using this relationship,

$$\Delta P_{tieflow} = \frac{T}{s}(\Delta\omega_1 - \Delta\omega_2) \quad \text{(A.28)}$$

where T = 377 x 1/X_{tie} (60 Hz system).

$\Delta\theta$ must be in radians so that ΔP_{tie} be in megawatts per unidad, but $\Delta\omega$ is the change of speed in per unit. Then you have $\Delta\omega$ times 377 rad/seg (the base frequency in rad/sec at 60 Hz). T is the "line stiffness" coefficient.

Suppose you have an interconnected power system, split into two areas, each with a generator. The areas are connected by a transmission line. The power flow in the transmission line will appear as a positive load for one area, and equal load, but negative for the other, or vice versa depending on the direction of flow. The direction of flow will be determined by the relative phase angle between the areas, which is determined by the relative speed deviations in the regions *(A. J. Wood, B. F. Wollenberg, 1996)*. A block diagram representing this interconnection is shown in Figure A.18.

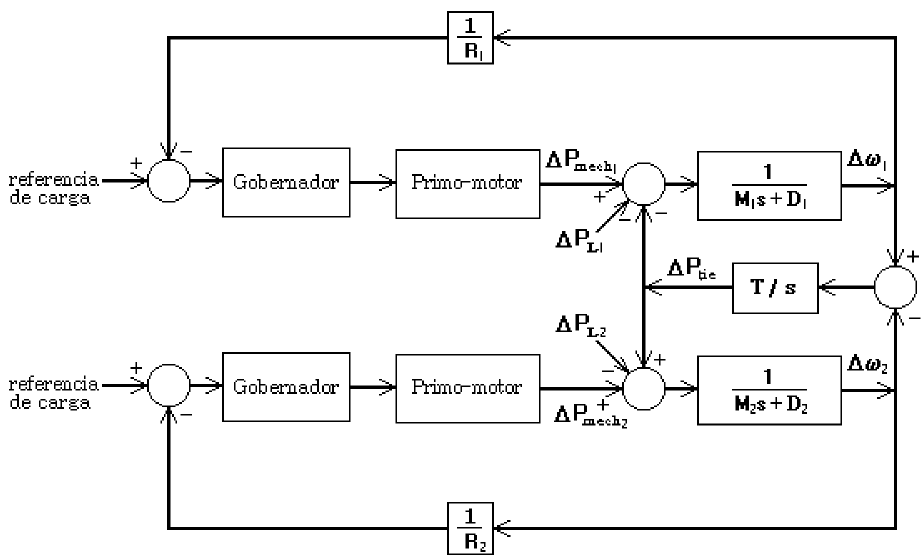


Fig. A.18 Block diagram of the interconnected areas

The link power flow has been defined as exiting area 1 to area 2; then the flow acts as a load for area 1 and as a power source (negative load) for area A. If the mechanical power is assumed to be constant, the rotating masses and the link line exhibit damped oscillatory characteristics known as timing oscillations.

A.7 Generation control

Automatic Generation Control (AGC) is the name given to a control system that has three main objectives:

1. To maintain the frequency at a value quite close to the specified nominal value (e.g. 60 Hz).

2. To keep the correct amount of power exchange between the control areas.

3. To maintain the generation in each unit at the most economical value *(A. J. Wood, B. F. Wollenberg, 1996).*

Primary objectives 1 and 2 refer to the load-frequency control (LFC) *(Kundur, 1994), (A. J. Wood, B. F. Wollenberg, 1996)*, *(N. Jaleeli et al, 1994).*

A.7.1 Supplementary control action

To understand each of the above objectives, one can start by assuming that only one generation unit is being studied, supplying load to an isolated power system. As shown in section A.5, a load change produces a frequency change with a magnitude that depends on the governor's characteristic and the frequency characteristics of the system's load. Once a load change occurs, a supplementary control must act to restore the frequency to its nominal value *(Kundur, 1994), (A. J. Wood, B. F. Wollenberg, 1996), (F. Aboytes, 1985)*. This can be accomplished by adding a reset (integral) command to the governor, as shown in Figure A.20.

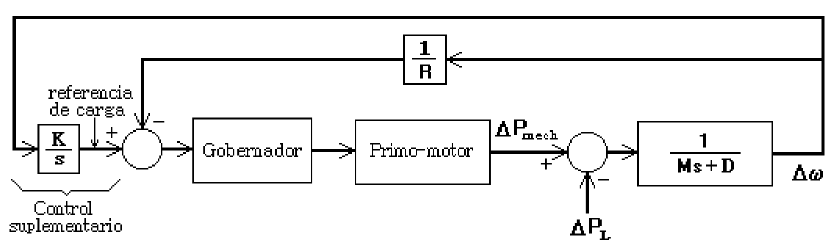


Fig. A.20 Supplementary control included to a generator unit

The resetting control action of the supplementary control will force the frequency error to zero by adjusting the speed reference point. This control action is much slower than the primary speed control action because it takes effect after the central speed control (which acts on all regulated units) has stabilised the system frequency. The AGC then adjusts the load set points of the selected units, and thus their power output, to cancel the effect of the power system's frequency compound control characteristics. This resets the generation of all units not under AGC to their rated value.

A.7.2 Control de la Línea de Enlace

There are several reasons why two companies interconnect their systems. One is to be able to buy or sell power to neighbouring systems whose operating costs allow such transactions *(Kundur, 1994), (A. J. Wood, B. F. Wollenberg, 1996)*, *(F. Aboytes et al, 1990)*. Besides, even if there is no exchange of energy between nearby systems, if a system suddenly loses a generating unit, the units across the interconnection will experience a change in frequency and may help to restore the frequency, Fig. A.21.

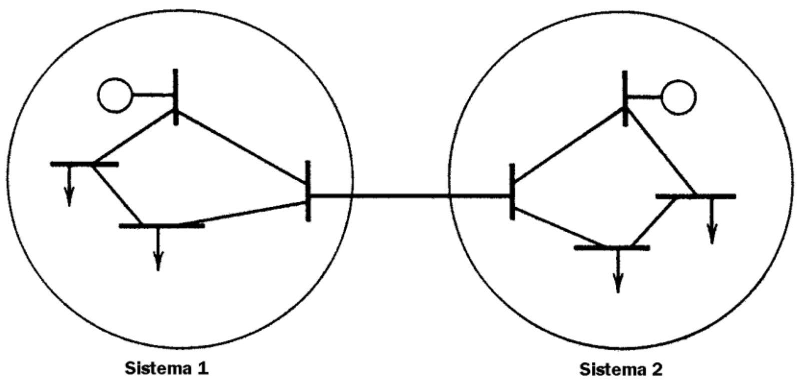


Fig. A.21 Sistema de dos áreas.

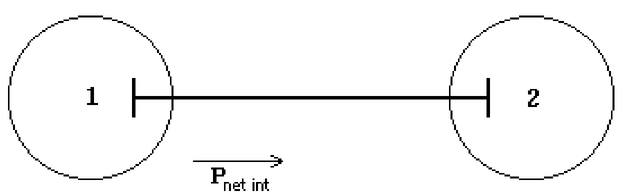
This control would use two pieces of information: the system frequency and the net power flow in or out of the link lines. This control scheme would have to recognise the following:

1. If the frequency decreases and the net power exchange leaving the system increases, then a load increment has occurred outside the system.
2. If the frequency decrements and the net power exchange leaving the system decreases, then a load rise has occurred within the system.

This can be extended for cases where the frequency increases.

A *control area* is defined as a part of an interconnected system in which the rules will control the load and generation in Figure A.22. The boundary of the area is simply the points on the tie line where the power flow is measured. All link lines crossing the border must be gauged so that the total net power exchange of the control area can be calculated.

The rules set out in Figure A.22 can be implemented by a control mechanism that measures the frequency deviation, $\Delta\omega$, and the net power change, $\Delta P_{net\ int}$.



ΔP_{L1} = Load change in area 1

ΔP_{L2} = Load change in area 2

Fig. A.22 Link line frequency control actions for a two-area system

The required generation change, called the area control error or ACE, represents the change in area generation, required to reset the frequency and net exchange to its desired values *(Kundur, 1994)*, *(A. J. Wood, B. F. Wollenberg, 1996)*, *(F. Aboytes et al, 1990)*, *(F. Aboytes, 1985)*. The equations for the ACE of each area are

$$\begin{aligned} ACE_1 &= -\Delta P_{net\,int_1} - B_1 \Delta\omega \\ ACE_2 &= -\Delta P_{net\,int_2} - B_2 \Delta\omega \end{aligned} \qquad \text{(A.35)}$$

where B1 and B2 are called *Bias Factors (Kundur, 1994), (A. J. Wood, B. F. Wollenberg, 1996)*. In Eq. A.34 the bias factors are defined as:

$$\begin{aligned} B_1 &= \beta_1 = \left(\frac{1}{R_1} + D_1 \right) \\ B_2 &= \beta_2 = \left(\frac{1}{R_2} + D_2 \right) \end{aligned} \qquad \text{(A.36)}$$

That yields

$$ACE_1 = \left(\frac{+\Delta P_{L_1}\left(\frac{1}{R_2} + D_2 \right)}{\frac{1}{R_1} + \frac{1}{R_2} + D_1 + D_2} \right) - \left(\frac{1}{R_1} + D_1 \right) \left(\frac{-\Delta P_{L_1}}{\frac{1}{R_1} + \frac{1}{R_2} + D_1 + D_2} \right) = \Delta P_{L_1}$$

$$ACE_2 = \left(\frac{-\Delta P_{L_1}\left(\frac{1}{R_2} + D_2 \right)}{\frac{1}{R_1} + \frac{1}{R_2} + D_1 + D_2} \right) - \left(\frac{1}{R_2} + D_2 \right) \left(\frac{-\Delta P_{L_1}}{\frac{1}{R_1} + \frac{1}{R_2} + D_1 + D_2} \right) = 0$$

This control can be performed using the scheme in Figure A.23. The values of B1 and B2 would have to change each time a unit is added or removed from the system, to have the exact amounts. In reality, the integral action of the supplementary controller guarantees the resetting of the ACE to zero, even if B1 and B2 had an error.

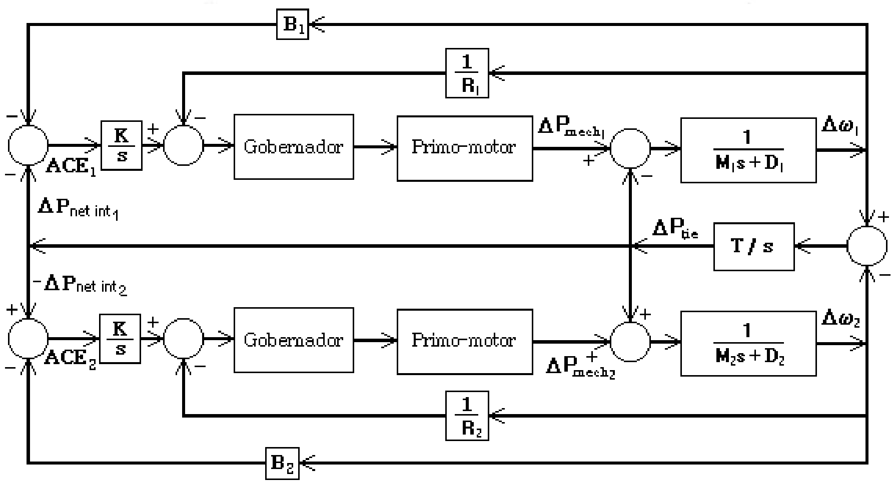


Fig. A.23 Supplementary link line trend control for two areas

The description of the control of the tie line using trend factors can be applied equally to systems with more than two areas. The planned exchange applicable to each region is the algebraic sum of the power flows in all the tie lines from the area in question to other areas.

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