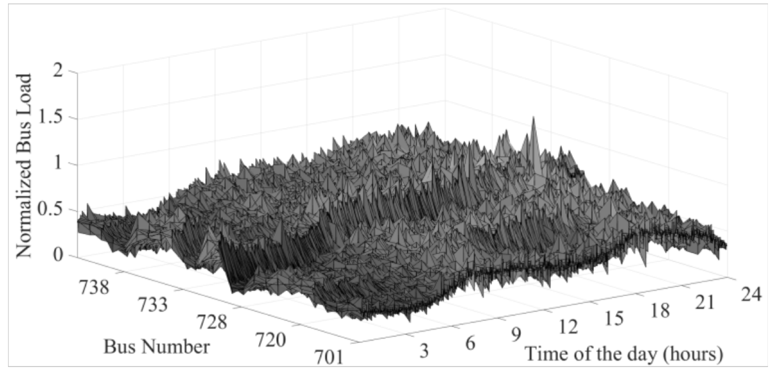
Smart Grid Technology

Principle and Application

Smart Grid Measurement and Control



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PSRC
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Curriculum Vitae

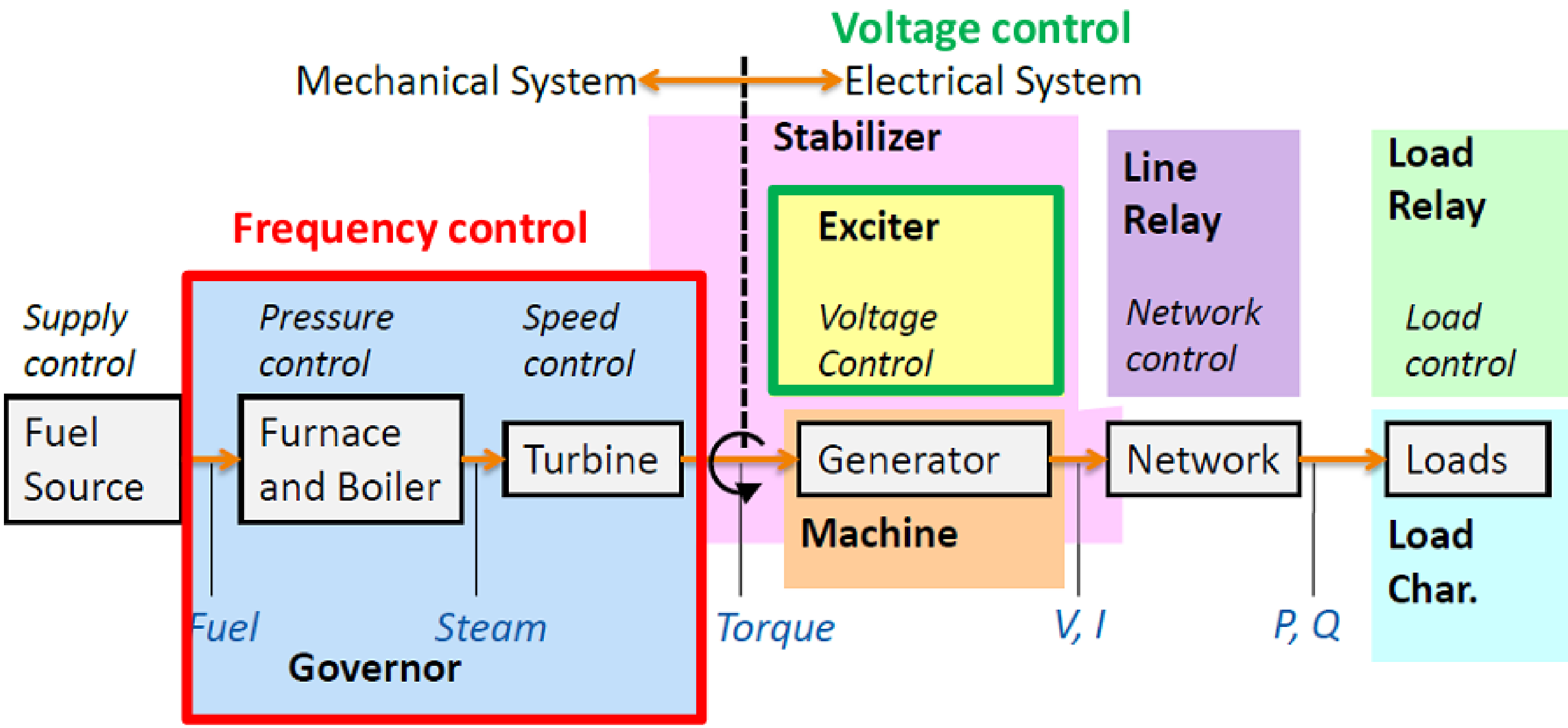
Krischonme Bhumkittipich, D.Eng.(Energy)

- Associate Professor in Electrical Engineering, RMUTT.
- Director of Graduate School, RMUTT.
- Research Associated at
  - Asian Institute of Technology
  - RWTH-Aachen University
- Publications: >100 papers (Both TH and EN)
- Research Interest:
  - Power System Dynamic and Stability
  - Power System Interconnection
  - Smart Grid Technology
- Teaching
  - Advanced Mathematics
  - Computer-Aided Power System Analysis
  - Optimization Technique & AI on Power System
  - Power System Dynamic and Stability
  - Smart Grid Technology

Outline

- **Background of Electrical Power System**
  - **presented by Dr. Krischonme Bhumkittipich (KB)**
- **Smart Grid Concept and Technology**
  - **presented by Dr. Krischonme Bhumkittipich (KB)**
- **Smart Grid Measurement and Control**
  - **presented by Dr. Krischonme Bhumkittipich (KB)**
- **Application of Smart Grid Technology**
  - **presented by Dr. Yuttana Kongjeen**

Physical Structures



P. Sauer and M. Pai, *Power System Dynamics and Stability*, Stipes Publishing, 2006.

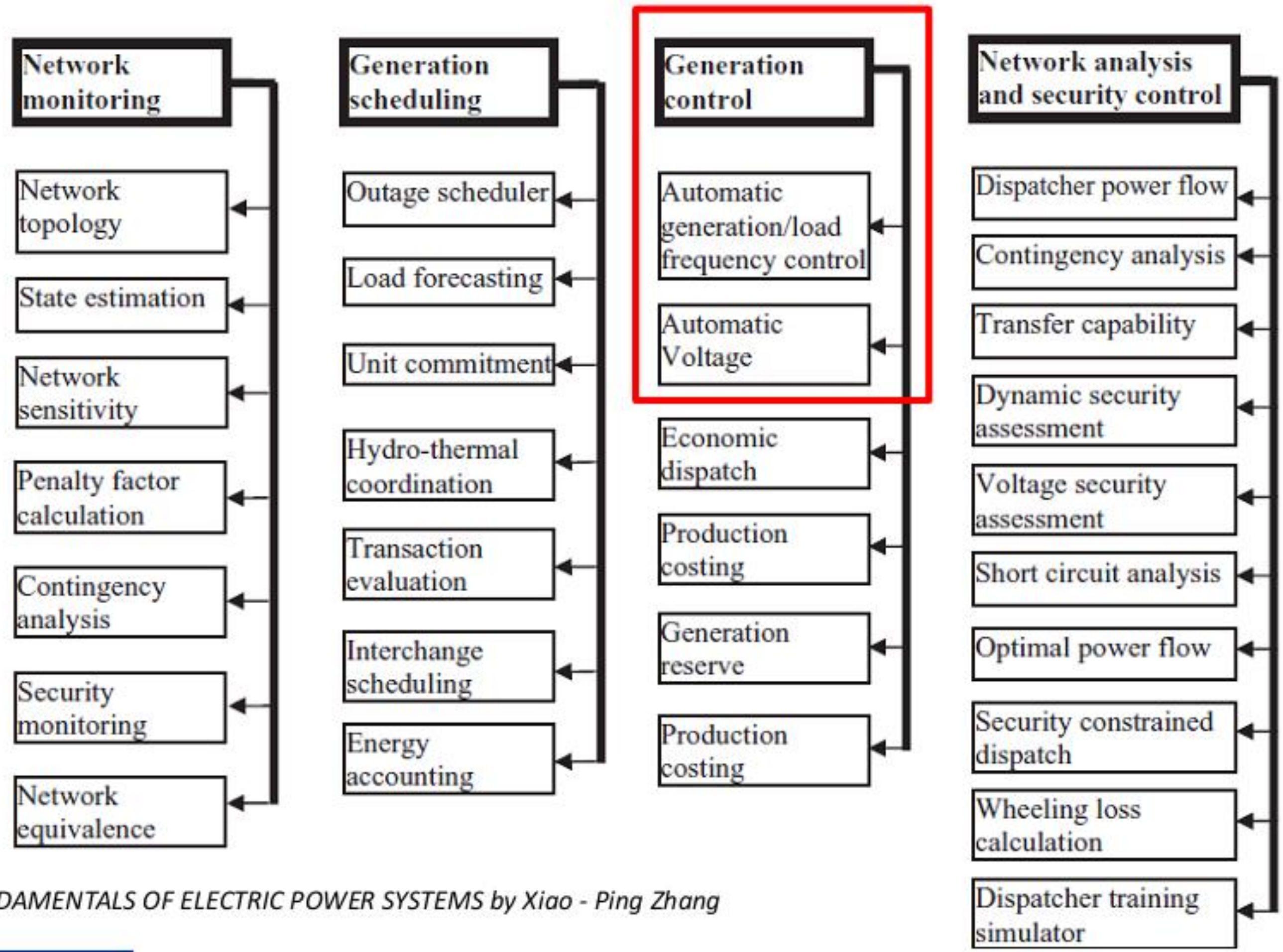
Source: http://www.powerworld.com/files/T01ModelRelationships.pdf

Supervisory Control and Data Acquisition (SCADA)

Source: ABB

Computer Systems that monitor and control energy system. The crucial part of Energy Management System.

Energy Management Systems



Source: *FUNDAMENTALS OF ELECTRIC POWER SYSTEMS by Xiao - Ping Zhang*

Control structure

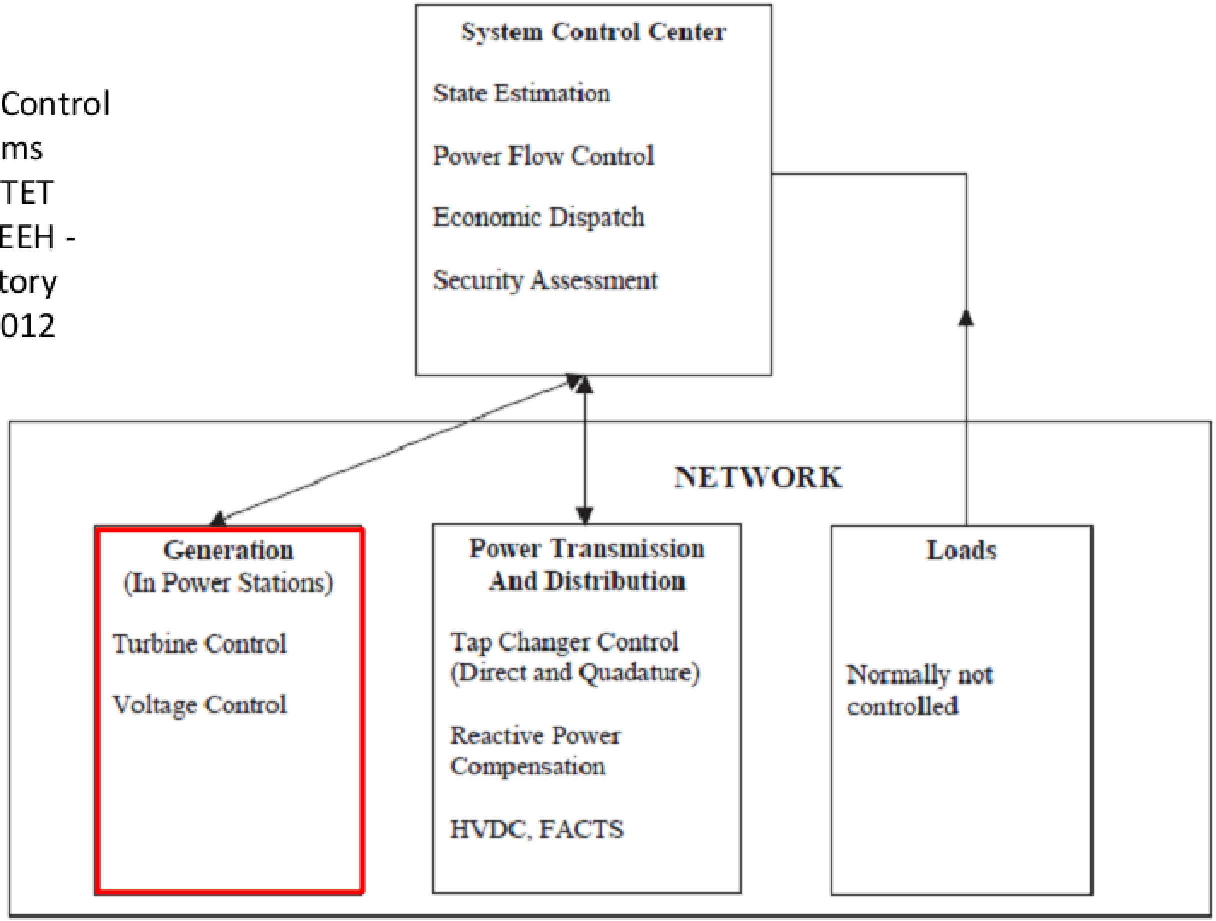
Time scale

Basic generator control loop

POWER SYSTEM CONTROLS

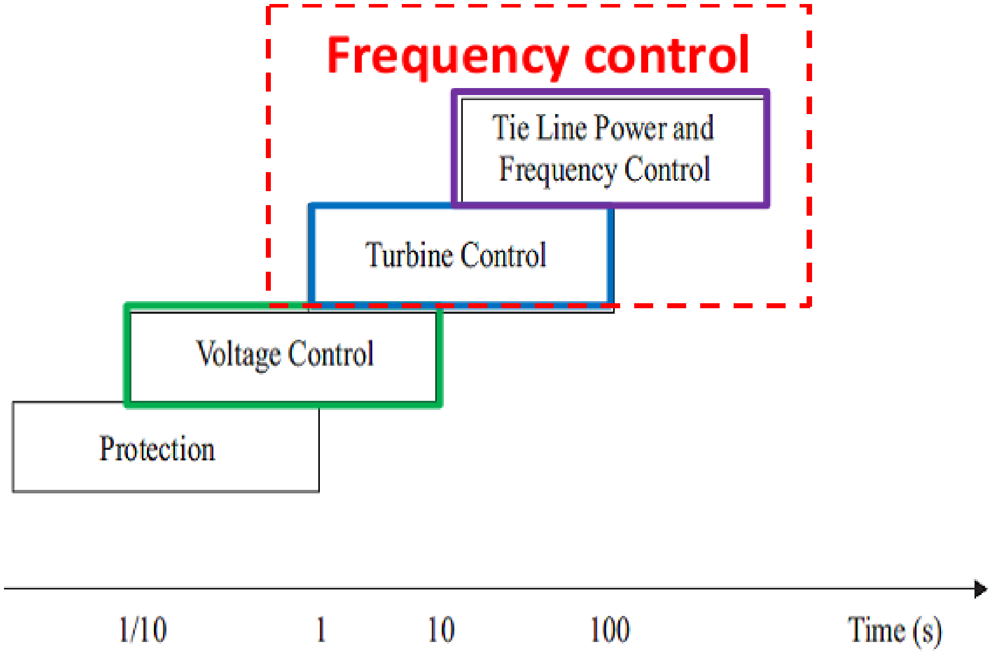
Hierarchical Control Structure

Source: Dynamics and Control of Electric Power Systems Lecture 227-0528-00, ITET ETH Göran Andersson EEH - Power Systems Laboratory ETH Zürich, February 2012



The lecture focuses on how we can control 'generators'.

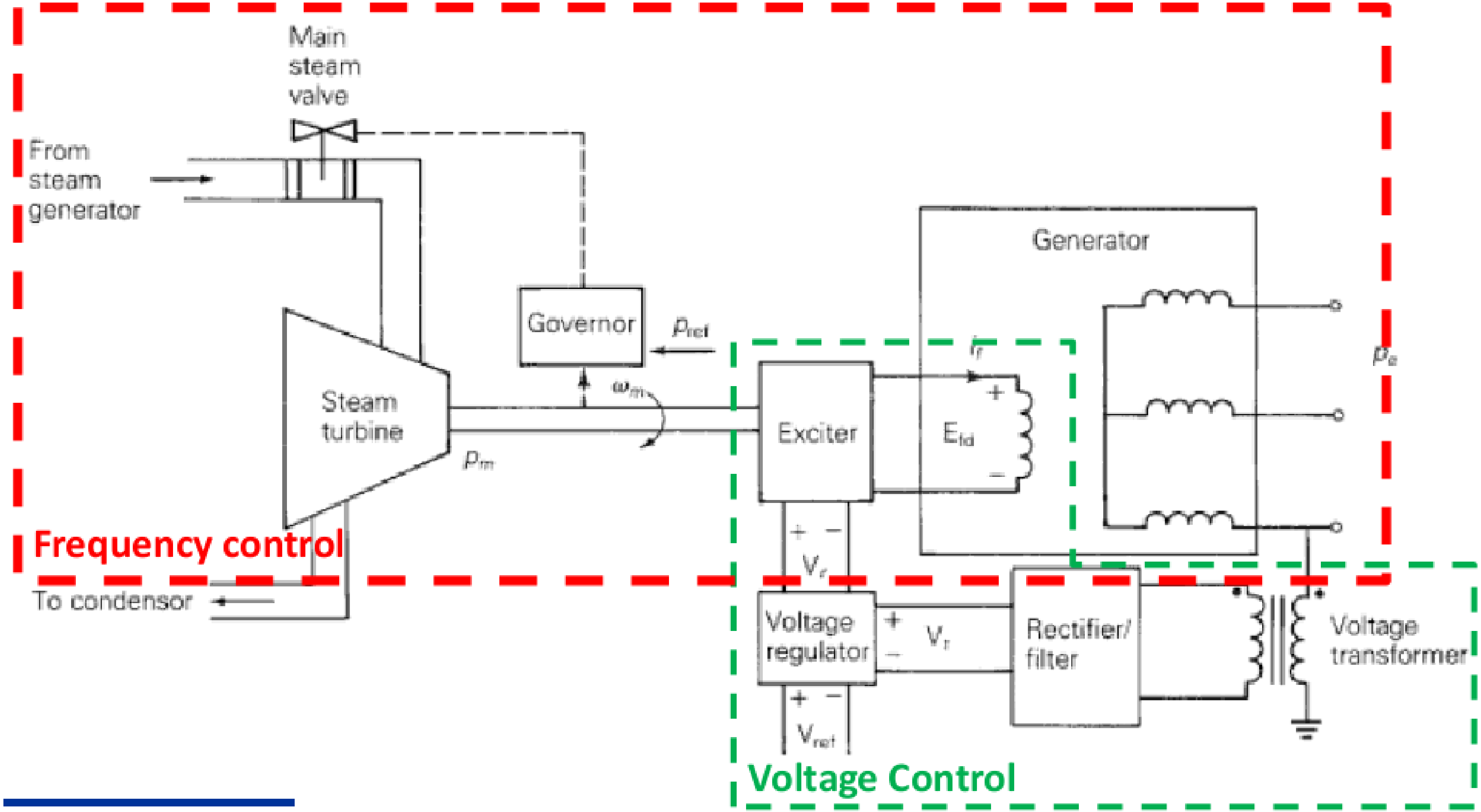
Time Scales of Power System Control



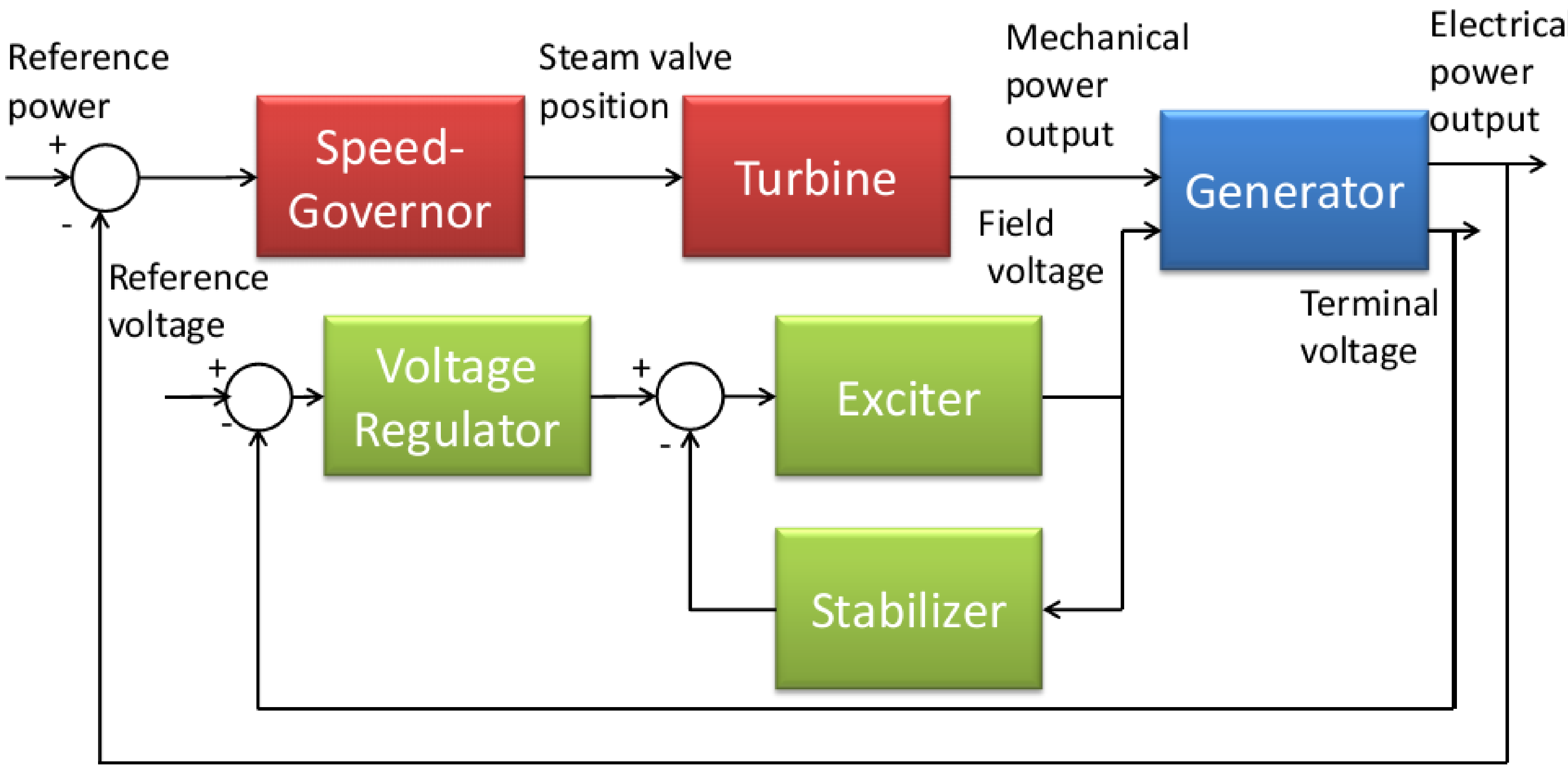
Source: Dynamics and Control of Electric Power Systems Lecture 227-0528-00, ITET ETH Göran Andersson EEH - Power Systems Laboratory ETH Zürich, February 2012

- Generator-Voltage control
  - Reactive power control
- Turbine-Governor control
  - Real power control
- Load-Frequency control
  - Bring frequency back to the nominal value.

Schematic Diagram of a Steam-Turbine Generator



Basic Generator Control Loops



Reactive Power and Voltage Control

Generator Excitation System

- The exciter delivers DC power to the field winding on the rotor of a synchronous generator.
- "Automatic Voltage Regulator" (AVR)
- Reactive power control of a generator.

Other Voltage Control Devices

- Reactive shunt devices
- Transformer tap changers
- Flexible AC transmission system (FACTS) controllers
  - Static VAR Compensator (SVC)
  - STATic Synchronous COMpensator (STATCOM)
  - Unified power flow controller (UPFC)

Real Power and Frequency Control

Turbine-Governor control

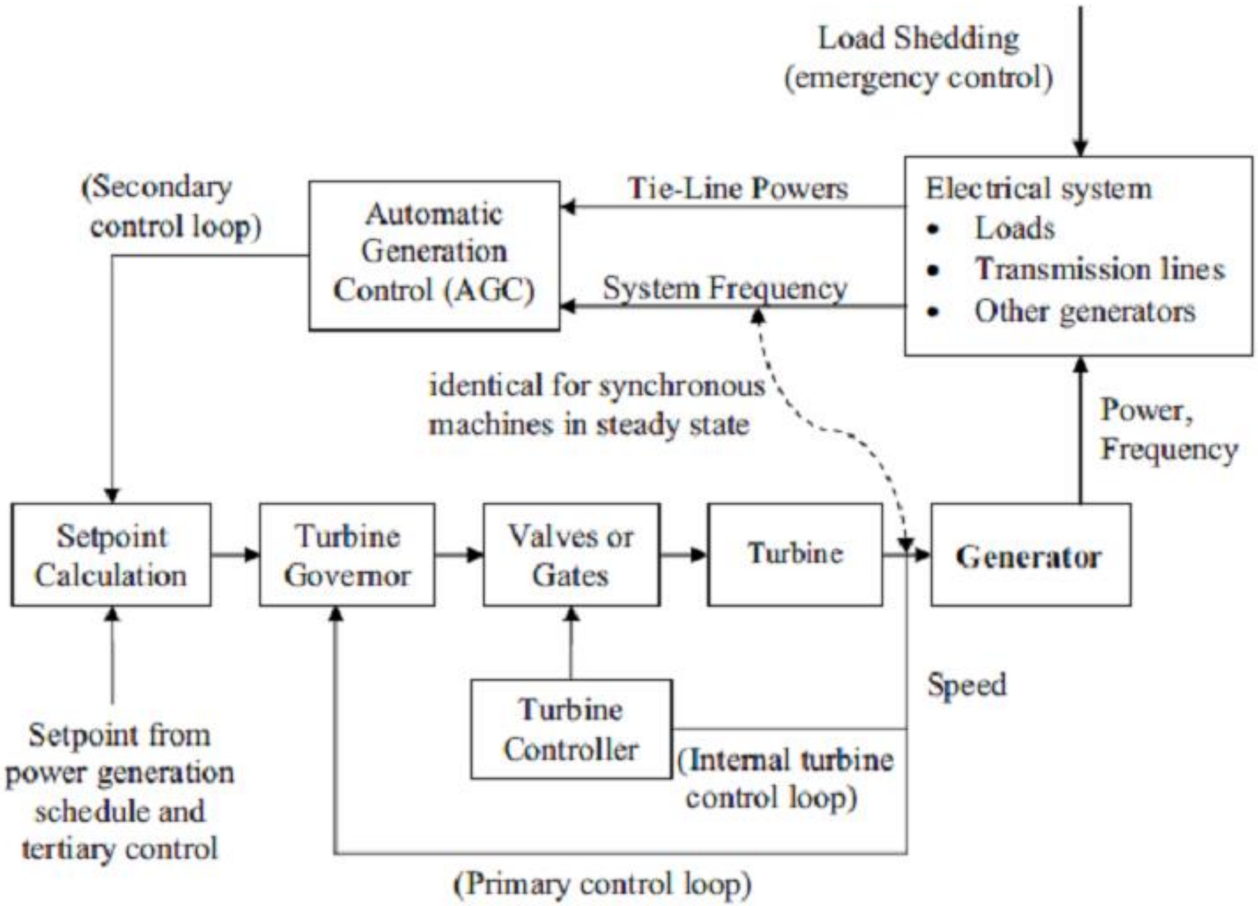
- **Primary** control loop
- Real power control
- Immediate (automatic) action to sudden change of load.
- Governor accelerate/decelerate, which affects the frequency

Load-Frequency control

- **Secondary** control loop
- Automatic Generation Control, "AGC".
- Detect deviation in frequency and tie-line power flows.
- Adjust the input power to each generator to bring back:
  - System frequency
  - Tie-line flow agreement

  to nominal value.

Automatic Generation Control (AGC)



Purpose of AGC

- To maintain power balance in the system.
- Make sure that operating limits are not exceeded:-
  - Generators limit
  - Tie-lines limit
- Make sure that system frequency is constant (not change by load).

3 Components of AGC

- Primary control “Turbine-Governor Control”
  - Immediate (automatic) action to sudden change of load.
  - For example, reaction to frequency change.
- Secondary control “Load-Frequency Control”
  - To bring tie-line flows to scheduled.
  - Corrective actions are done by operators.
- Economic dispatch
  - Make sure that the scheduled of units are done in the most economical way.
- This presentation covers only primary and secondary control of AGC.

Basic Control Theory

- Analysis and design of a control system requires the mathematical modeling of the system.
  - Transfer function method
  - State variable method
- In this lecture, we will use transfer function method.
- See the lecture note on basic control and MATLAB simulink.

Generator model

Load model

Generator-Load model

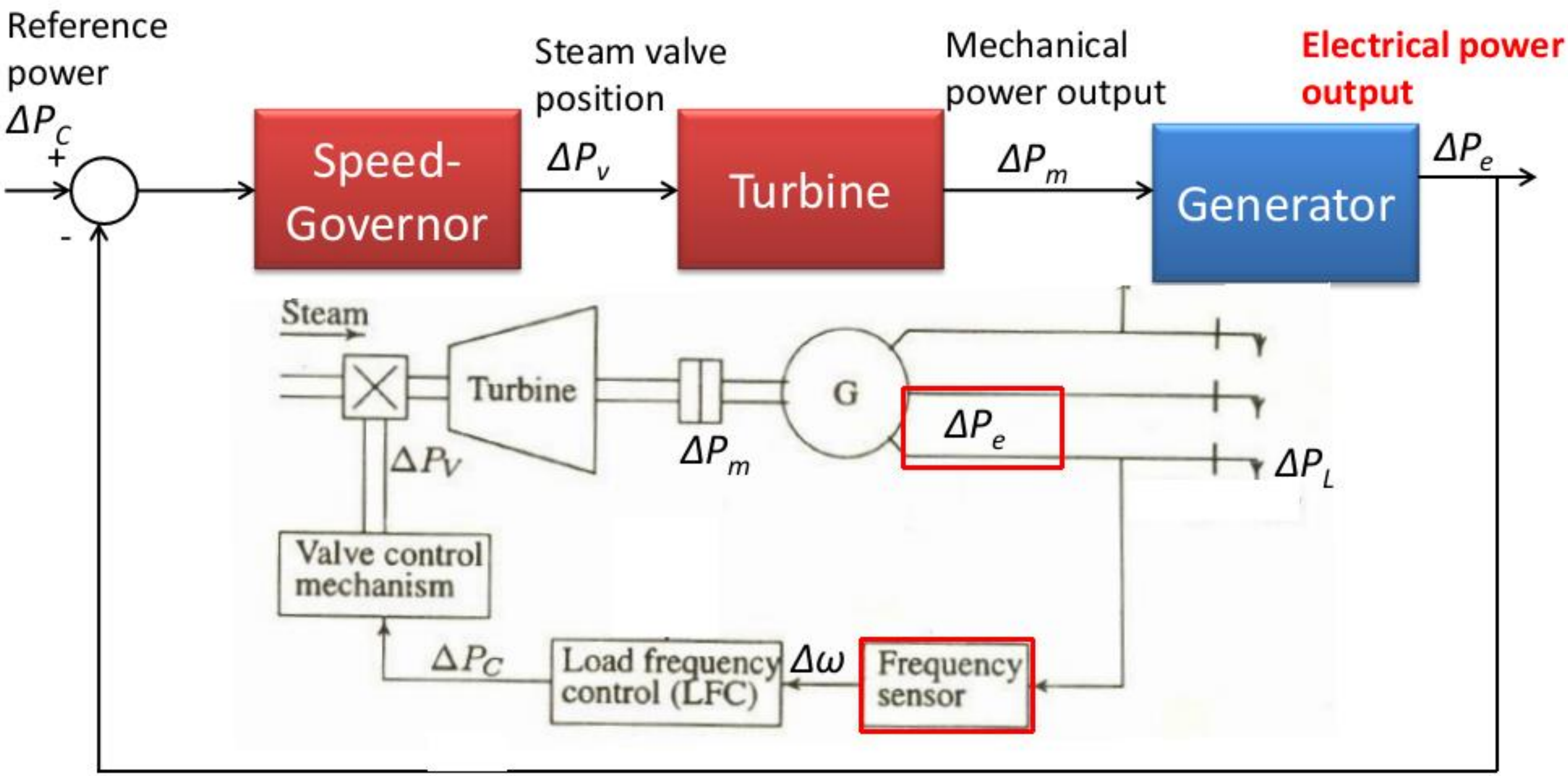
Turbine (Prime mover) model

Governor model

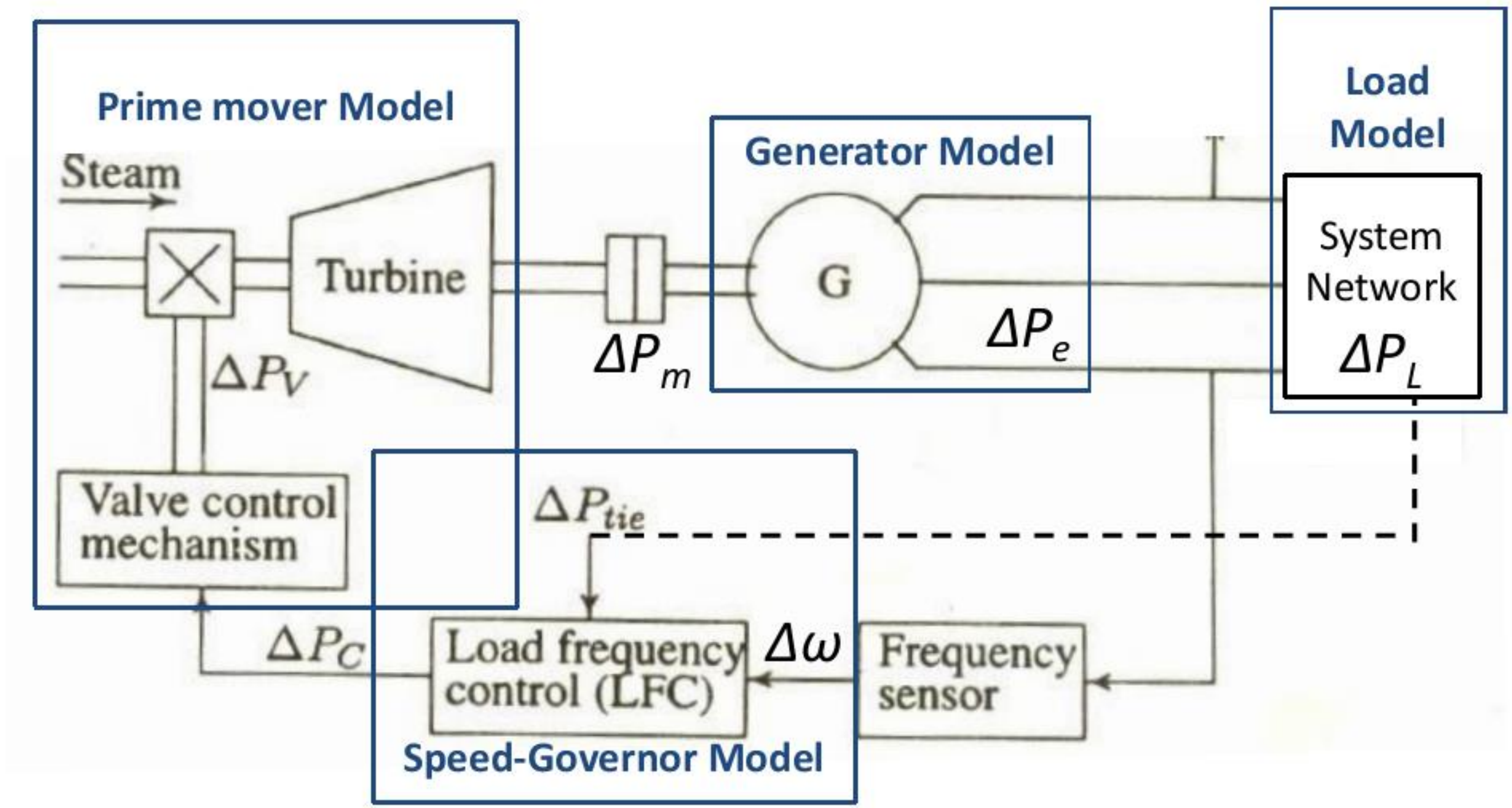
Turbine-Governor model

BASIC CONTROL BLOCK DIAGRAM

Basic Frequency Control Loops



Real Power Control: Block Diagram



Generator Model

- According to swing equation to small perturbation (linearized model):

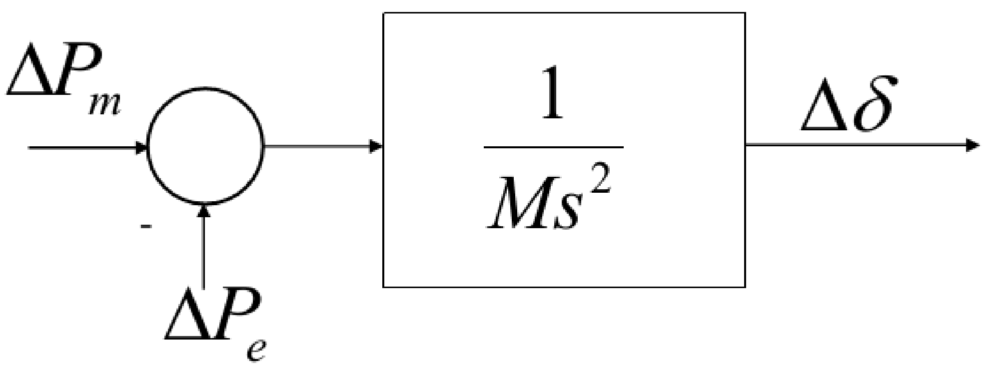
$$M\Delta\ddot{\delta} = \Delta P_m - \Delta P_e$$

- Taking Laplace transform, we have.

$$\Delta P_m - \Delta P_e = Ms^2\Delta\delta$$

Generator Model: Block Diagram

- The block diagram of the generator model is given below.
- As the transfer function is derived from swing equation, we call ‘Rotor angle transfer function’.
- This model assume that the damping “D” of the generator is negligible.



Load Model

- For resistive load, the impedance is independent of frequency.
- For motor loads, the power drawn is sensitive to frequency, depending on speed-load characteristics and is approximated by,

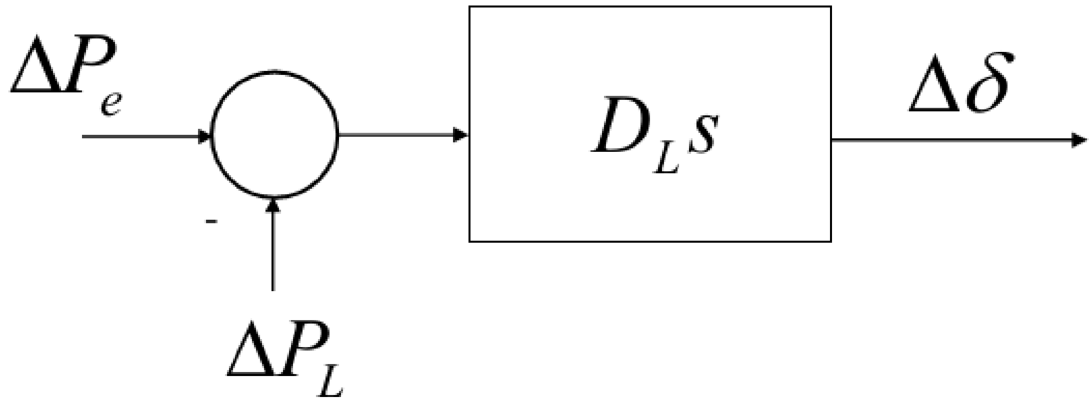
$$\Delta P_e = \Delta P_L + D_L \Delta \dot{\delta}$$

- Taking Laplace transform, we have.

$$\Delta P_e - \Delta P_L = D_L s \Delta \delta$$

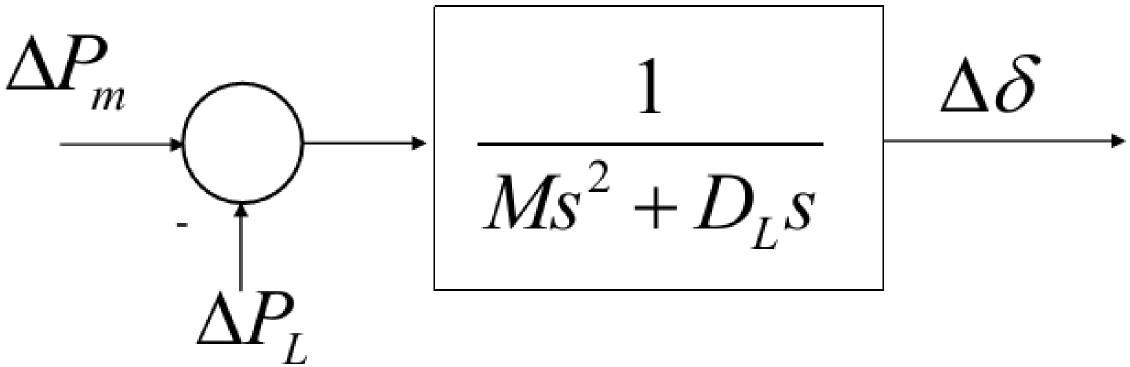
Load Model: Block Diagram

- The block diagram of the load model is given below.



- We will now eliminate ΔP_e by combining generator and load model.

Generator-Load Model



Turbine (Prime Mover) Model

- Prime mover is the source of mechanical power such as hydraulic turbines, steam turbines, or gas turbines.
- This model relates the changes in mechanical power output ΔP_m to the change in steam valve position ΔP_v
- The simplest model can be approximated with a single time constant (τ_T) as shown in the following transfer function.

$$\Delta P_v \longrightarrow \boxed{\frac{1}{1+s\tau_T}} \longrightarrow \Delta P_m$$

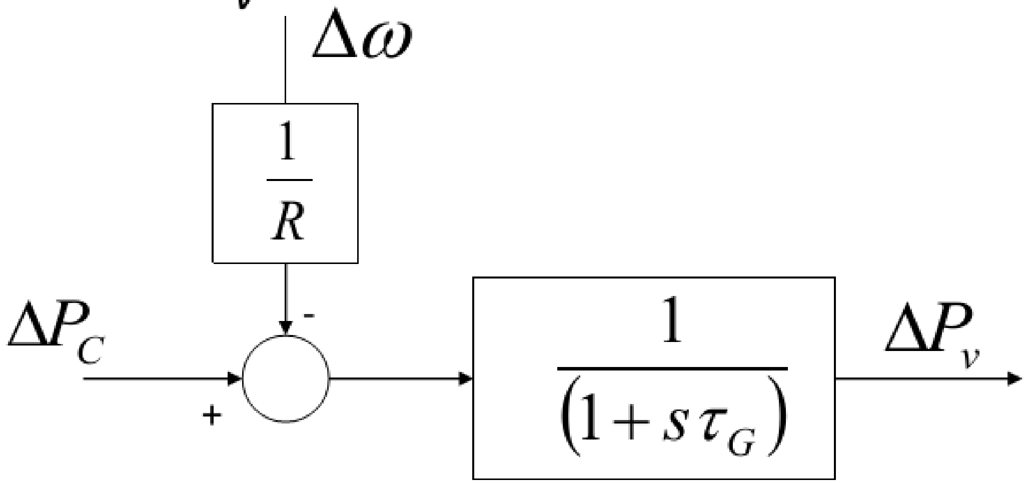
Governor Model

- The speed governor compares the control set point ΔP_c to the change of power consumed that is measured by the deviation in frequency $\Delta\omega$.
- It is assumed that the deviation in frequency $\Delta\omega$ causes the change in power consumption proportionally. This type of governor is characterized as a proportional controller with a gain of 1/R.
- Consider a time constant (τ_G) of the governor, we can write the following transfer function.

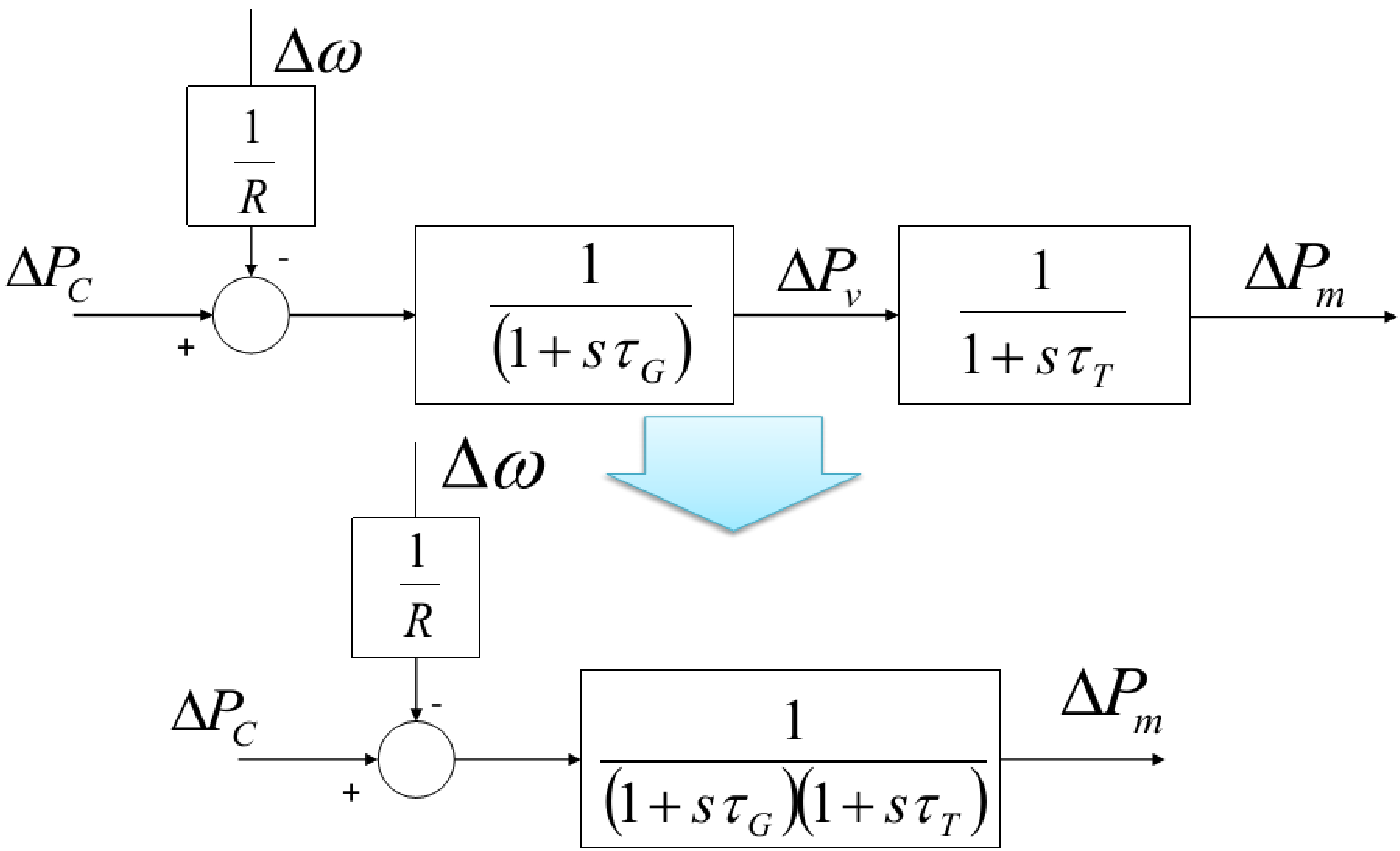
$$\Delta P_v = \left(\frac{1}{1+s\tau_G}\right)\left(\Delta P_c - \frac{1}{R}\Delta\omega\right)$$

Governor Model: Block Diagram

- The inputs of this model are the frequency deviation and the control set point.
- The output of this model is the valve position command ΔP_v.



Turbine-Governor Model



Speed-Power Relationship

- From synchronous turbine-governor,

$$\Delta P_m = \frac{1}{(1+s\tau_G)(1+s\tau_T)}\left(\Delta P_c - \frac{1}{R}\Delta\omega\right)$$

- At steady state (s = 0), we have,

$$\Delta P_m = \Delta P_c - \frac{1}{R}\Delta\omega$$

- “R’” is called speed regulation or droop. It refers to the variation of frequency with turbine mechanical power output.
- The unit of “R” depends on the units of ω and P_m.

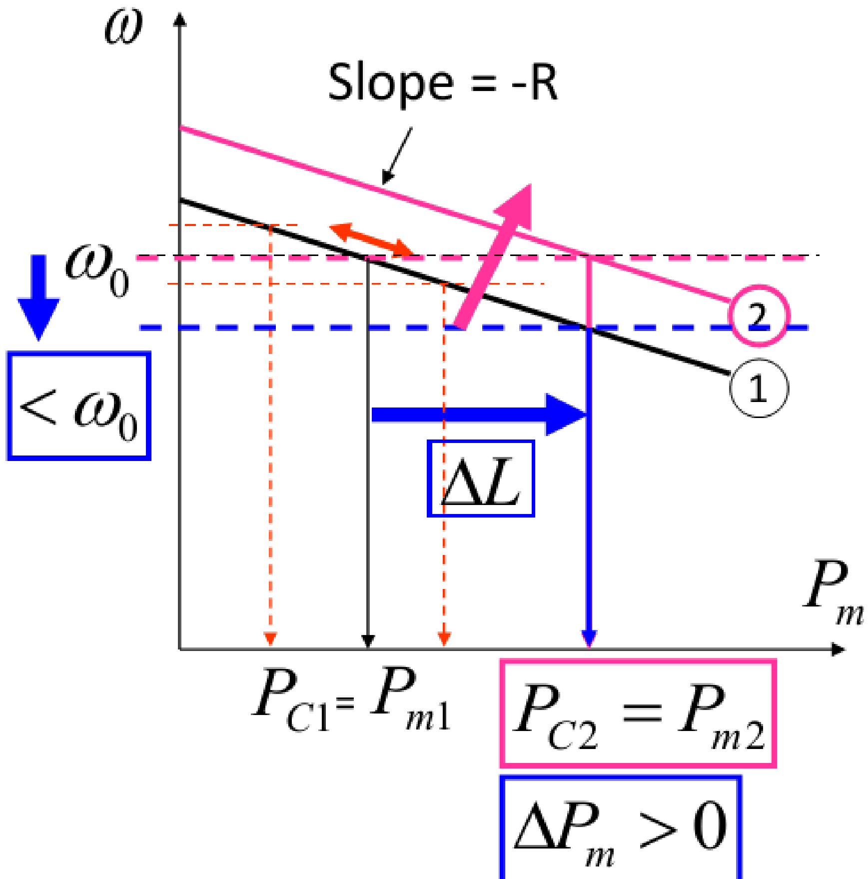
The Unit for Regulation (R)

- Unit for regulation (R) is radian per sec/ MW.
- Consider a static-speed power curve in per unit system,

$$\Delta P_M = \Delta P_C - \frac{1}{R}\Delta\omega \quad \Rightarrow \quad \frac{\Delta P_M}{S_B} = \frac{\Delta P_C}{S_B} - \frac{\omega_B}{R \times S_B}\frac{\Delta\omega}{\omega_B}$$

- Or, $$\Delta P_{M,\text{p.u.}} = \Delta P_{C,\text{p.u.}} - \frac{1}{R_{\text{p.u.}}}\Delta\omega_{\text{p.u.}}$$
- This means that, $$R_{\text{p.u.}} = \frac{S_B}{\omega_B} R$$

Static Speed-Power Curve



- At steady state, the change in frequency can be related to power output linearly.

$$\Delta P_m = \Delta P_c - \frac{1}{R}\Delta\omega$$

Example

- A standard figure for R is 0.05 p.u. (or 5%). This relates fractional changes in ω to fractional (per unit) changes in P_m. Thus, we have $\Delta\omega/\omega_0 = -0.05\Delta P_m$, where ΔP_m is in p.u.
  - If the frequency changes from 60 Hz to 59 Hz, find the increase in P_m.
  - What change in frequency would cause P_m to change from 0 to 1 i.e. no load to full load?

Example

- Let $R_{\text{p.u.}} = 0.05$,

(a) Find increase in $\Delta P_{M,\text{p.u.}}$ when frequency change from 60 Hz to 59 Hz.

$$\Delta\omega_{\text{p.u.}} = \frac{2\pi\cdot(59-60)}{2\pi\cdot 60} = \frac{-1}{60}$$

$$\Delta P_{M,\text{p.u.}} = \Delta P_{C,\text{p.u.}} - \frac{1}{R_{\text{p.u.}}}\Delta\omega_{\text{p.u.}} = 0 - \frac{1}{0.05}\cdot\left(\frac{-1}{60}\right) = 0.333$$

(b) Find change in frequency when $\Delta P_{M,\text{p.u.}}$ changes from 0 to 1.

$$\Delta P_{M,\text{p.u.}} = -\frac{1}{0.05}\Delta\omega_{\text{p.u.}} = 0-1 \qquad \Delta\omega_{\text{p.u.}} = 5\% = \frac{3}{60}$$

AGC for single generator

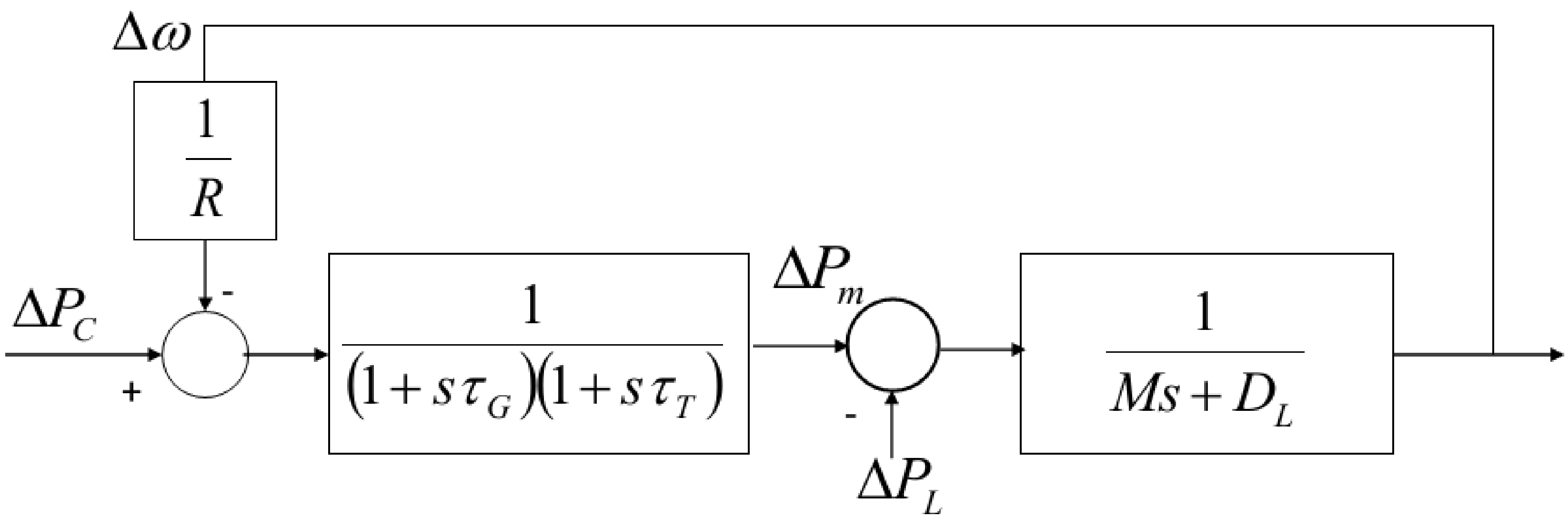
AGC for multi generators

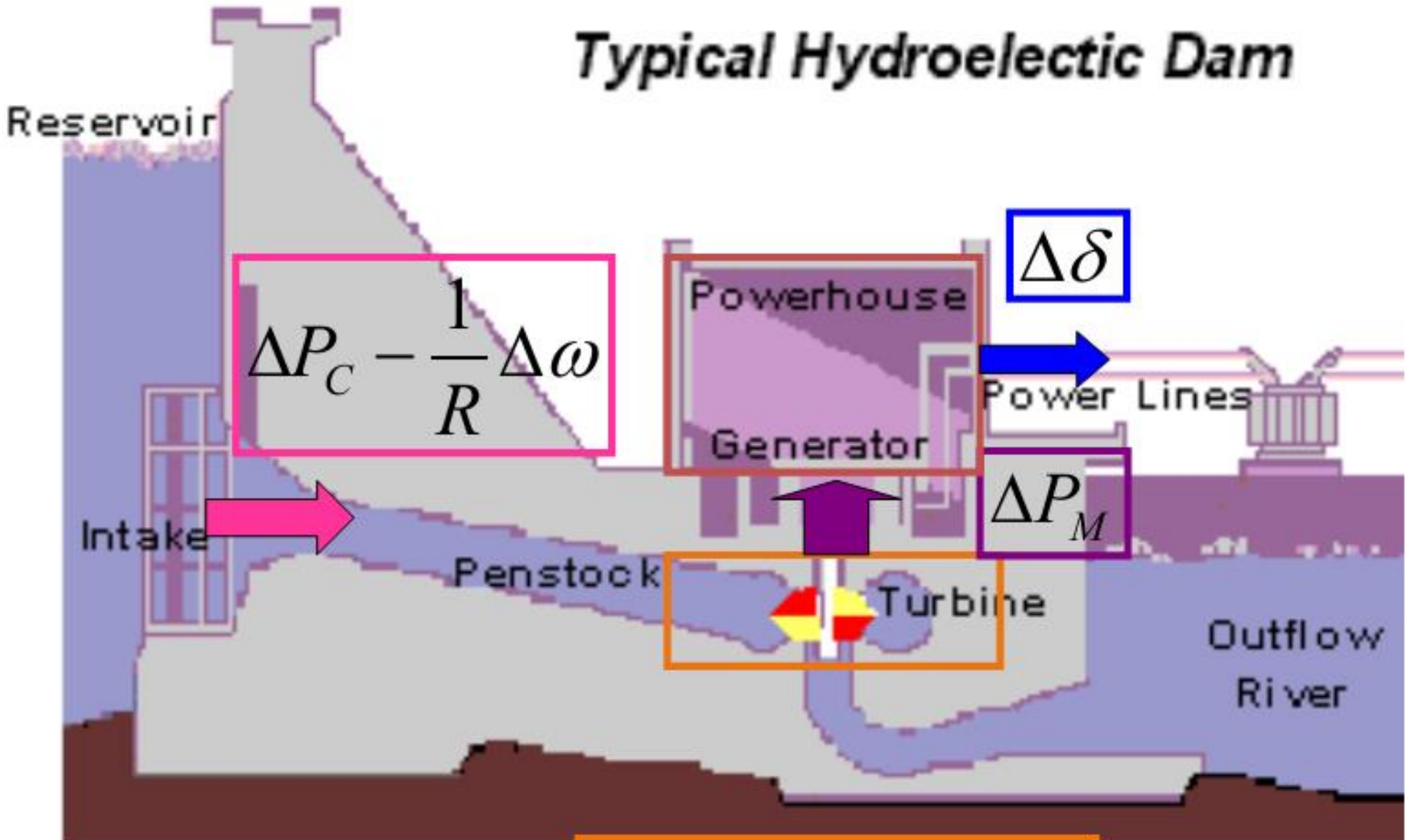
Special case: AGC for two generators

AUTOMATIC GENERATION CONTROL FOR SINGLE AREA

AGC for Single Generator

- Combine all the control block diagrams, we can draw closed-loop real power control of a synchronous generator as follows.





$$\frac{1}{(1+s\tau_G)(1+s\tau_T)}$$

Steady-State Frequency Calculation: Without Load Damping

- At steady-state, s=0, we can write:

$$\Delta P_m = \Delta P_c - \frac{1}{R}\Delta\omega$$

$$\Delta P_m = \Delta P_L$$

- When the control power setting of the generator remains constant, the change in load will cause the frequency to vary according to:

$$\Delta\omega = \frac{-\Delta P_L}{1/R}$$

Steady-State Frequency Calculation: With Load Damping

- At steady-state, s=0, we can write:

$$\Delta P_m = \Delta P_c - \frac{1}{R}\Delta\omega$$

$$\Delta P_m = \Delta P_L + D_L \Delta\omega$$

- When the control power setting of the generator remains constant, the change in load will cause the frequency to vary according to:

$$\Delta\omega = \frac{-\Delta P_L}{D_L + \frac{1}{R}}$$

Example

- A single area consists of two generating units, 600 MVA and 500 MVA with 6% and 4% per unit based on its own rating. Both units are sharing 900 MW at the nominal frequency. Unit 1 supplies 500 MW and unit 2 supplies 400 MW at 60 Hz. The load is increased by 90 MW.
  - Assume there is no frequency-dependent load i.e. D=0. Find the new steady state frequency and the new generation on each unit.
  - The load varies 1.5 percent for every 1 percent change in frequency i.e. D = 1.5. Find the new steady state frequency and the new generation on each unit.

Assume that the two units are from the same power plant i.e. ignore the effect of transmission lines.

$$\Delta P_{m1} = \Delta P_{c1} - \frac{1}{R_1}\Delta\omega$$

$$\Delta P_{m2} = \Delta P_{c2} - \frac{1}{R_2}\Delta\omega$$

$$\Delta P_{m1} + \Delta P_{m2} = \Delta P_L + D_L\Delta\omega$$

$$\Delta\omega = \frac{-\Delta P_L}{D_L + \frac{1}{R_1} + \frac{1}{R_2}}$$

Ans: 59.76 Hz, (540,450) MW,59.775 Hz, (537.5,446.875) MW

Example

- Change the base of the regulation of both units to the same value. Let the base complex power be 1000 MVA, then

$$R_{\mathrm{p.u.},new} = \frac{S_{\mathrm{B,\,new}}}{S_{\mathrm{B,\,old}}} R_{\mathrm{p.u.},old}$$

- The per unit load change is 90/1000 = 0.09 p.u.
- When D = 0, per unit frequency deviation is,
- The new steady state frequency is,
- Change in generation for each unit can be found from:

Example

- When D = 1.5, per unit frequency deviation is,
- The new steady state frequency is,
- Change in generation for each unit can be found from:

AGC for Multiple Generators

- Consider effect of
  - power flows in transmission lines, and
  - loads at each bus

  to mechanical power of each generator.
- This analysis assumes that **every bus is a generator bus**.

Power Balance Equation at Each Bus

- At each bus,

$$P_{ei} = P_{Di} + P_i$$

Where

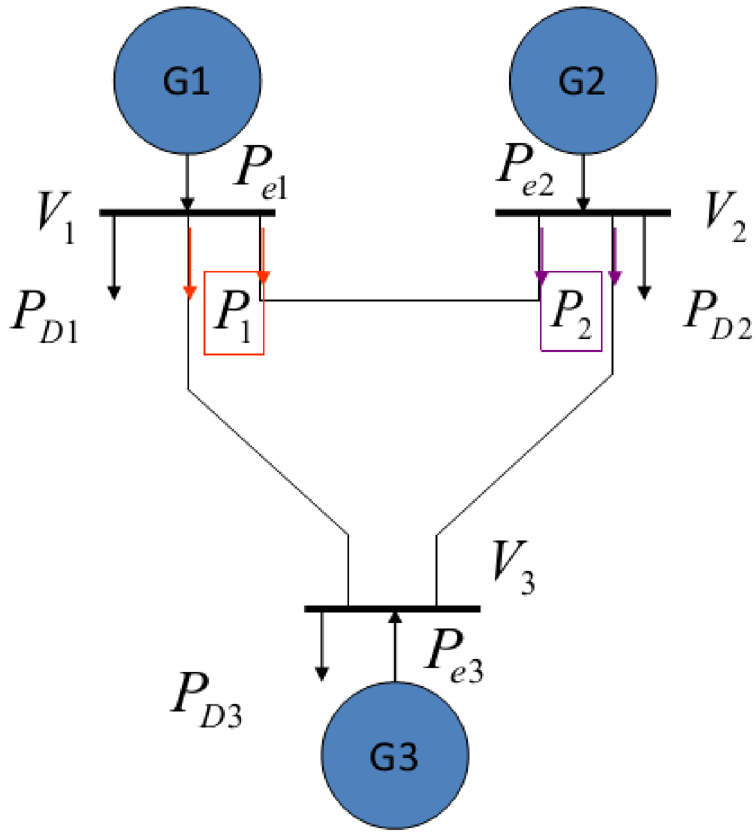
P_{ei} = Electrical power output of Generator i

P_{Di} = Load power at bus i

P_i = Net power injection from bus i

- Consider a small change,

$$\Delta P_{ei} = \Delta P_{Di} + \Delta P_i$$



Load Power Equation (ΔP_{Di})

- Assume that

$$\Delta P_{Di} = D_{Li}\Delta\dot{\theta}_i + \Delta P_{Li} = D_{Li}\Delta\dot{\delta}_i + \Delta P_{Li}$$

Where ΔP_{Li} = Small change of load input
ΔP_{Di} = Small change of load power
$\Delta\dot{\theta}_i$ = Small change of voltage angle

- Substitute in power balance equation,

$$\Delta P_{ei} = \Delta P_{Di} + \Delta P_i$$

- We have

$$\Delta P_{ei} = D_{Li}\Delta\dot{\delta}_i + \Delta P_{Li} + \Delta P_i$$

Turbine Mechanical Power Output

- Linearized equation relating mechanical power to generator power and generator speed.

$$\Delta P_{mi} = M_i \Delta\ddot{\delta}_i + \Delta P_{ei}$$

- From,

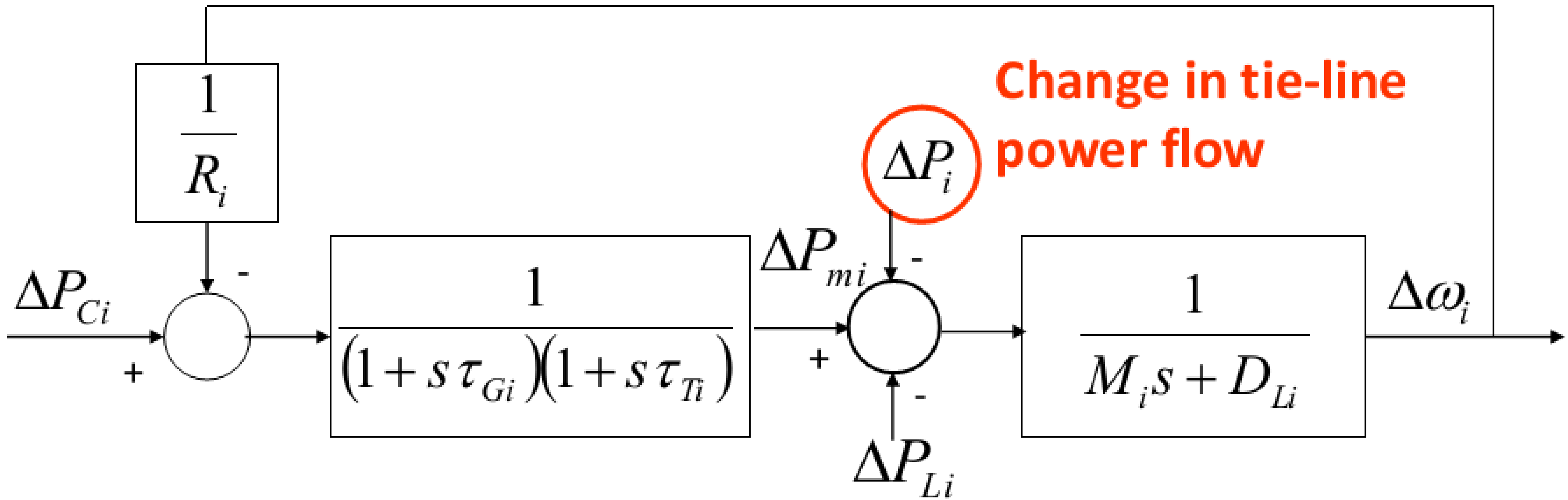
$$\Delta P_{ei} = D_{Li} \Delta\dot{\delta}_i + \Delta P_{Li} + \Delta P_i$$

- We have

$$\Delta P_{mi} = M_i \Delta\ddot{\delta}_i + D_{Li} \Delta\dot{\delta}_i + \Delta P_{Li} + \Delta P_i$$

How to represent this term?

AGC for Multiple Generators



$$G_{Mi}(s) \equiv \frac{1}{(1+s\tau_{Gi})(1+s\tau_{Ti})} \qquad G_{Pi}(s) \equiv \frac{1}{(M_i s + D_{Li})}$$

Tie-line Model (ΔP_i)

- From power flow equation,

$$P_i = \sum_{k=1}^{n} |V_i||V_k| B_{ik} \sin(\theta_i - \theta_k)$$

- Approximate at normal operating condition, we have

$$P_i \approx \sum_{k=1}^{n} B_{ik} (\theta_i - \theta_k)$$

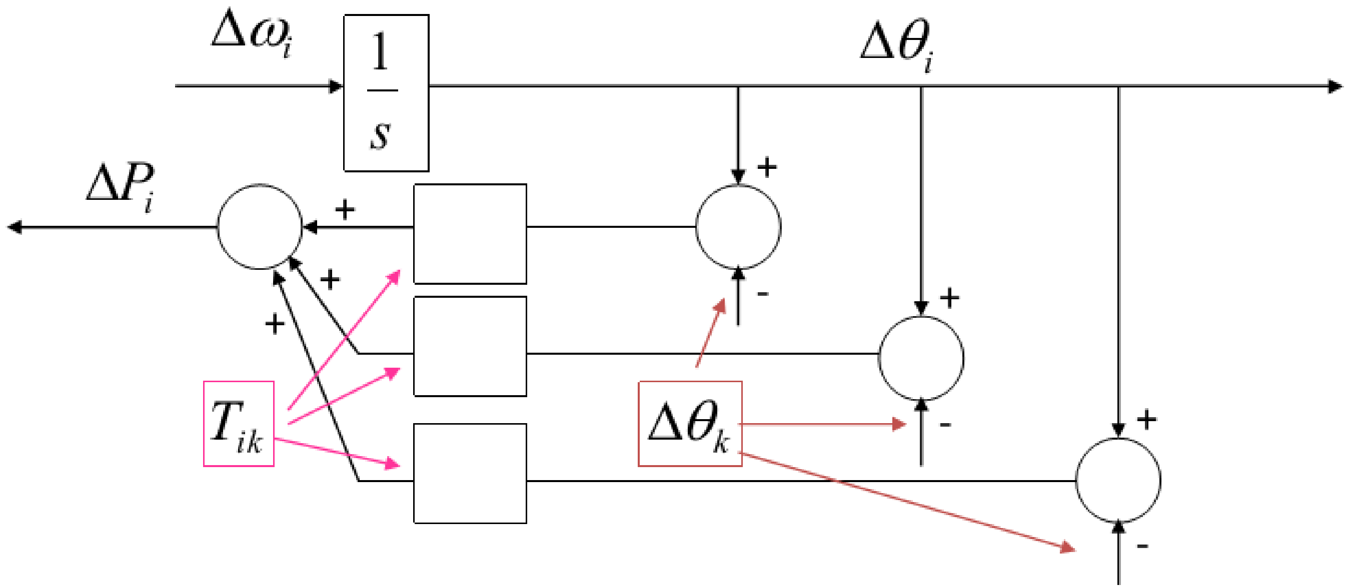
- Then, for small change,

$$\Delta P_i \approx \sum_{k=1}^{n} B_{ik} (\Delta\theta_i - \Delta\theta_k) = \sum_{k=1}^{n} T_{ik} (\Delta\theta_i - \Delta\theta_k)$$

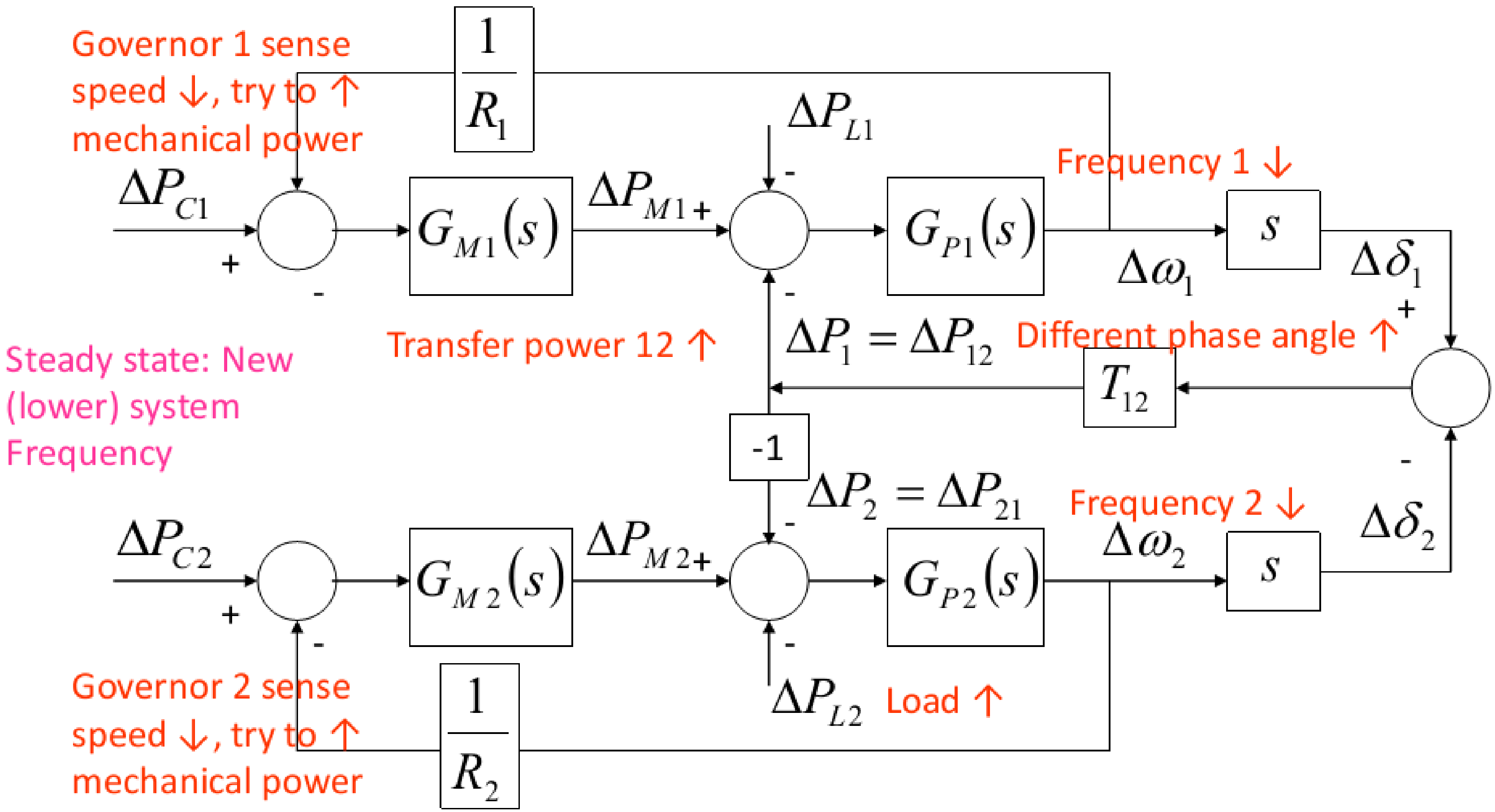
Where T_{ik} is called stiffness or synchronizing power coefficient

Tie-Line Block Diagram

- From $\Delta P_i = \sum_{k=1}^{n} T_{ik}(\Delta\theta_i - \Delta\theta_k)$ and $\Delta\theta = \frac{1}{s}\Delta\omega$
- We have, $\Delta P_i = \sum_{k=1}^{n} \frac{T_{ik}}{s}(\Delta\omega_i - \Delta\omega_k)$

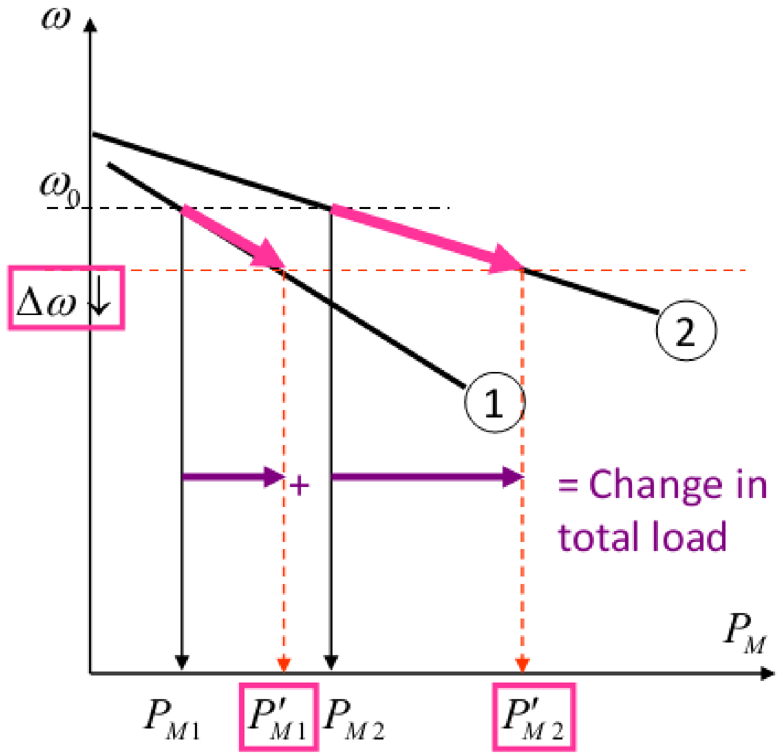


AGC for Two Generators



Static Speed-Power Characteristic

- Consider two generators, each with different regulation R_1 and R_2.
- When the load increases, frequency drops.
- Steady state is reached when the frequency of both generators are the same.



Steady State Frequency Calculation

- Consider a special case of 2 generators connected via a transmission line.
- Consider the frequency at steady state,

$$\Delta P_{m1} = D_{L1}\Delta\omega + \Delta P_{L1} + \Delta P_{t-line} \qquad \Delta P_{m2} = D_{L2}\Delta\omega + \Delta P_{L2} - \Delta P_{t-line}$$

- When the control power setting of each generator remains constant,

$$\Delta P_{M1} = -\frac{1}{R_1}\Delta\omega \qquad \Delta P_{M2} = -\frac{1}{R_2}\Delta\omega$$

- Then,

$$\Delta\omega = \frac{-\Delta P_{L1} - \Delta P_{L2}}{\left(D_{L1} + D_{L2} + \frac{1}{R_1} + \frac{1}{R_2}\right)}$$

Note that…

- In single area- multi generators case, we have not discussed how to systematically **bring back the new steady state frequency** by adjusting control power: ΔP_c.
- We will discuss this in the following section.

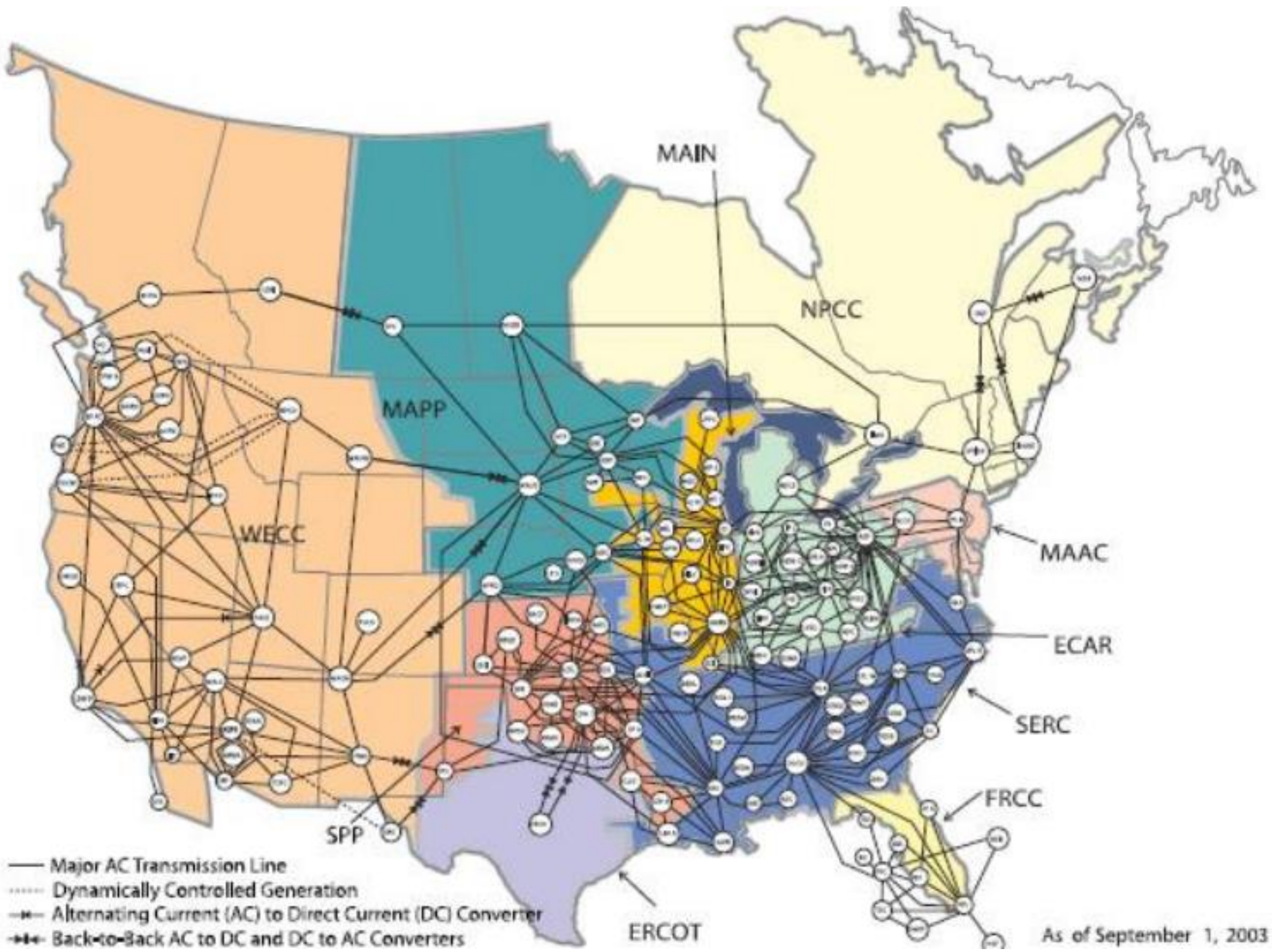
Simplified Control Model

Area Control Error (ACE)

Example 11.5

AUTOMATIC GENERATION CONTROL FOR MULTI-AREA

NERC Control Areas



Simplified Control Model

- Generators are grouped into control areas.
- Consider
  - An area as one generator in single area, and,
  - Tie-lines between areas as transmission lines connecting buses in single area.

  We can apply the same analysis to multi-area!!
- However, we have to come up with frequency-power characteristics of each area.
- Actual application of this model is for power pool operation.

Area Frequency Response Characteristic "β"

- Consider a one-area system with multiple generators.
- Neglecting losses and dependence of load on frequency, steady-state frequency-power relation can be found as follows.

$$\Delta P_m = \Delta P_{m1} + \Delta P_{m2} + \Delta P_{m3} + \cdots$$

$$= (\Delta P_{c1} + \Delta P_{c2} + \Delta P_{c3} + \cdots) - \left(\frac{1}{R_1} + \frac{1}{R_2} + \frac{1}{R_3} + \cdots \right) \Delta\omega$$

$$\Delta P_m = \Delta P_c - \beta \Delta\omega$$

$$\Delta\omega = \frac{-\Delta P_L}{\beta}$$

$$\boxed{\beta \equiv \frac{1}{R_1} + \frac{1}{R_2} + \frac{1}{R_3} + \cdots}$$

Area Frequency Response Characteristic "β" with Load Damping

- From

$$\Delta P_m = \Delta P_{m1} + \Delta P_{m2} + \Delta P_{m3} + \cdots$$
$$= \left(\Delta P_{c1} + \Delta P_{c2} + \Delta P_{c3} + \cdots\right) - \left(\frac{1}{R_1} + \frac{1}{R_2} + \frac{1}{R_3} + \cdots\right)\Delta\omega$$

- And

$$\Delta P_m = \Delta P_L + D_L \Delta\omega$$

- We can write

$$\Delta P_m = \Delta P_c - \beta\Delta\omega$$

$$\boxed{\beta \equiv D_L + \frac{1}{R_1} + \frac{1}{R_2} + \frac{1}{R_3} + \cdots}$$

$$\Delta\omega = \frac{-\Delta P_L}{\beta}$$

Example

An interconnected 60 Hz power system consists of one area with three turbine-generator units rated 1000, 750, and 500 MVA. The regulation constant of each unit is R = 0.05 per unit based on its own rating. Each unit is initially operated at one-half of its own rating, when the system load suddenly increases by 200 MW. Assume that the control power setting of each generator remains constant. Neglect losses and the dependence of load on frequency. Find:

- The per-unit area frequency response characteristic "β" on a 1000 MVA system base.
- The steady-state drop in area frequency.
- The increase in turbine mechanical power output of each unit.

Power Pool Operation

- Power pool is an interconnection of the power systems of individual utilities.
- Each company operates independently, BUT,
- They have to maintain
  - contractual agreement about power exchange of different utilities, and,
  - same system frequency.
- Basic rules
  - Maintain **scheduled tie-line capacities**.
  - Each area **absorbs its own load changes**.

AGC for Multi Areas

- During transient period, sudden change of load causes each area generation to react according to its frequency-power characteristics.

  This is "called primary control".
- This change also effects steady state frequency and tie-line flows between areas.
- We need to
  - Restore system frequency,
  - Restore tie-line capacities to the scheduled value, and,
  - Make the areas absorb their own load.

  This is called "secondary control".

Area Control Error (ACE)

- Control setting power of each area needs to be adjusted corresponding to the change of scheduled tie-line capacity and change of system frequency.
- For two-area case, ACE measures this balance, and is given by,

$$ACE_1 = \Delta P_{12} + B_1 \Delta\omega$$

$$ACE_2 = \Delta P_{21} + B_2 \Delta\omega$$

- "B" is called frequency bias setting.

Frequency Bias Setting "B"

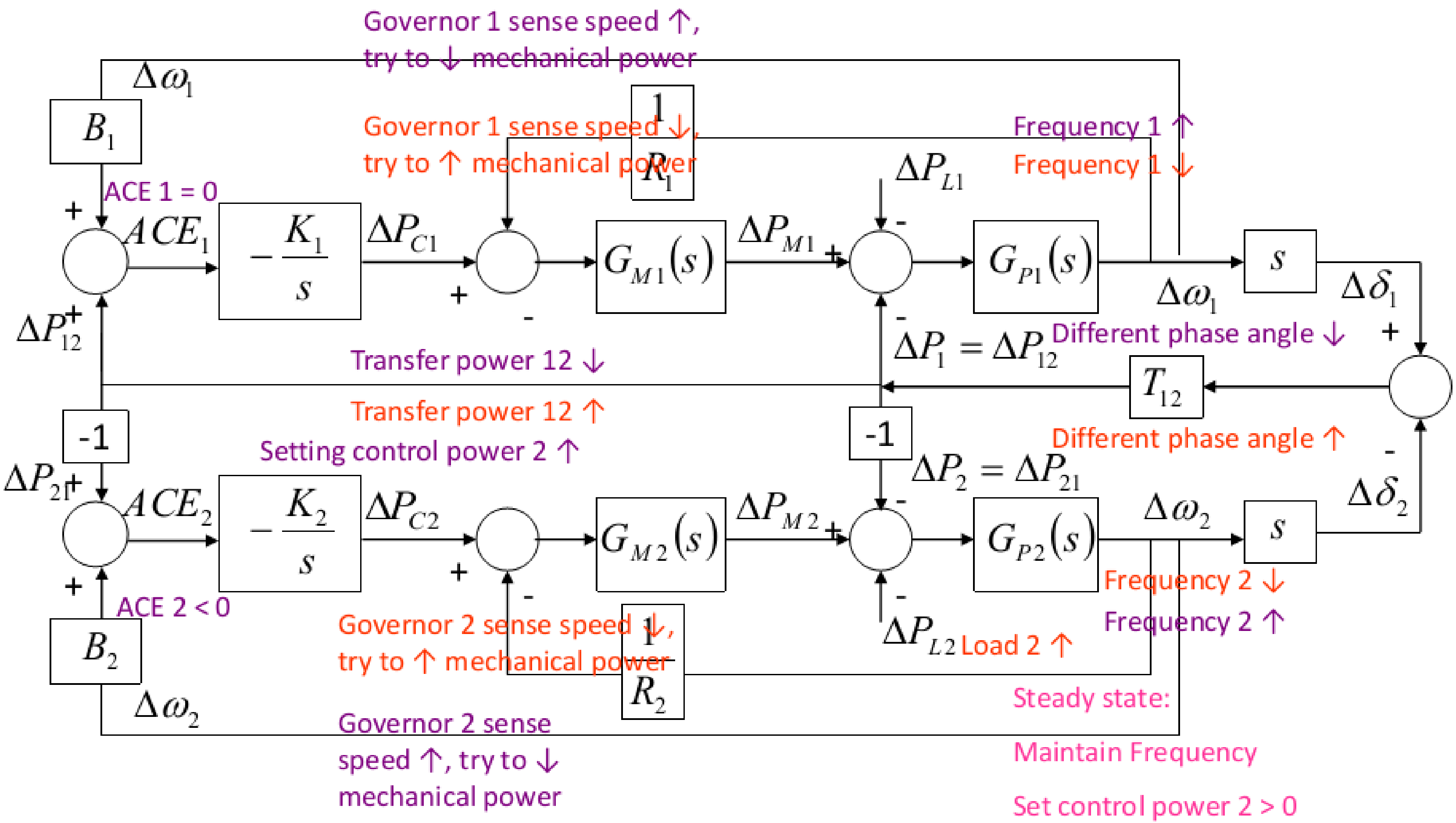
- The constant 'B' is called frequency bias setting.
- The choice of 'B' depends on the control center.
- To get the accurate adjustment of the control power setting of each generator unit, the frequency bias setting should be set as follows.

$$B_i = \left(D_{Li} + \frac{1}{R_i} \right)$$

ACE: Tie-Line Bias Control

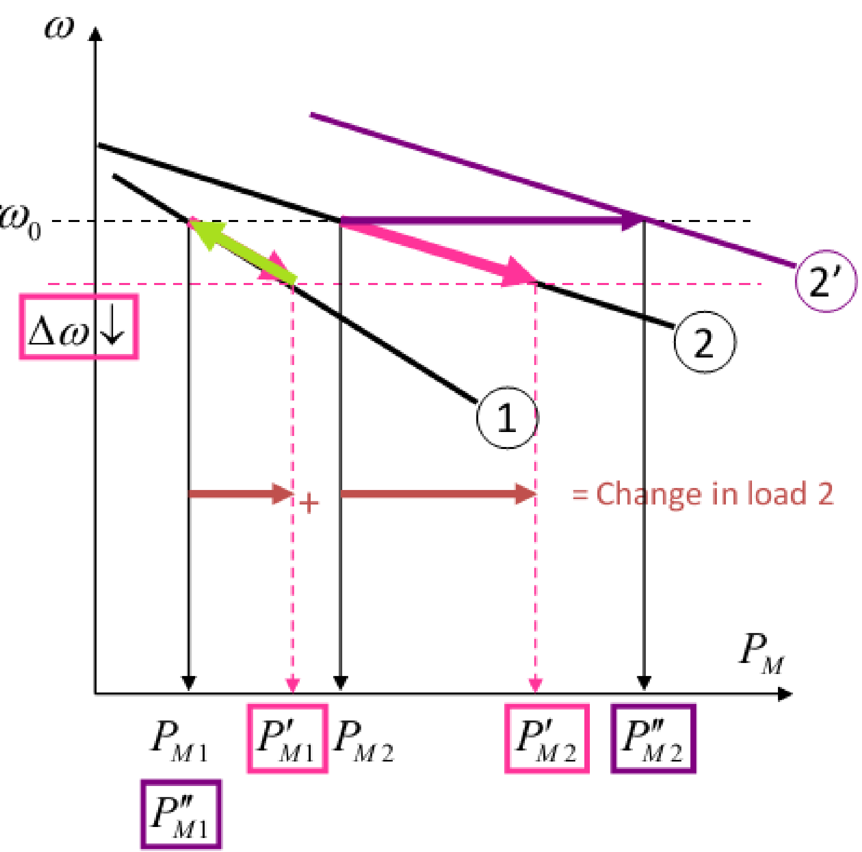
- Use ACE to adjust setting control power ΔP_{ci} of each area.
- Goal:
  - To drive ACE in all area to zero.
  - To send appropriate signal to setting control power ΔP_{ci}
- We should therefore use “integrator” controller so that ACE goes to zero at steady state.

AGC for 2-Area with Tie-line Bias Control: Block Diagram



AGC for 2-Area with Tie-line Bias Control : Static Speed-Power Curve

- Load in area 2 increases.
- Frequency of both area drops.
- ACE makes Control power of area 2 increases.
- Steady state is reached when frequency is back at the operating point and generator in area 2 take its own load.



Example

- Two-area system,

$$P_{G0}^{A} = P_{L0}^{A} = 1000\ \text{MW} \qquad P_{G0}^{B} = P_{L0}^{B} = 10{,}000\ \text{MW}$$

$$R_A = 0.015\ \text{rad per sec/MW} \qquad D_L^A = D_L^B = 0 \qquad R_B = 0.0015\ \text{rad per sec/MW}$$

$$\boxed{\Delta P_L^A = 10\ \text{MW}}$$

- Find change in frequency, ACE, and appropriate control action.

Example Frequency Calculation

- From, $\Delta P_M^A = D_L^A \Delta\omega_A + \Delta P_L^A + \Delta P_{AB} = \Delta P_L^A + \Delta P_{AB}$

  $\Delta P_M^B = D_L^B \Delta\omega_B + \Delta P_L^B + \Delta P_{BA} = \Delta P_{BA}$
- And, $\boxed{\Delta\omega = \Delta\omega_1 = \Delta\omega_2}$
- And,

$$\Delta P_M^A = -\frac{1}{R_A}\Delta\omega \qquad \Delta P_M^B = -\frac{1}{R_B}\Delta\omega$$

- We have,

$$\boxed{\Delta\omega = \frac{-\Delta P_L^A}{\left(\frac{1}{R_A}+\frac{1}{R_B}\right)} = \frac{-10}{\frac{1}{0.015}+\frac{1}{0.0015}} = -0.0136 \text{ rad per sec}}$$

Example ACE Calculation

- First, find ΔP_{AB} from

$$\Delta P_M^A = -\frac{1}{R_A}\Delta\omega = \frac{-1}{0.015}\times(-0.0136) = 0.9091 \text{ MW}$$

$$\Delta P_M^A = \Delta P_L^A + \Delta P_{AB} \Rightarrow \Delta P_{AB} = \Delta P_M^A - \Delta P_L^A = -9.091 \text{ MW}$$

$$\boxed{\Delta P_{BA} = -\Delta P_{AB} = 9.091 \text{ MW}}$$

- Then,

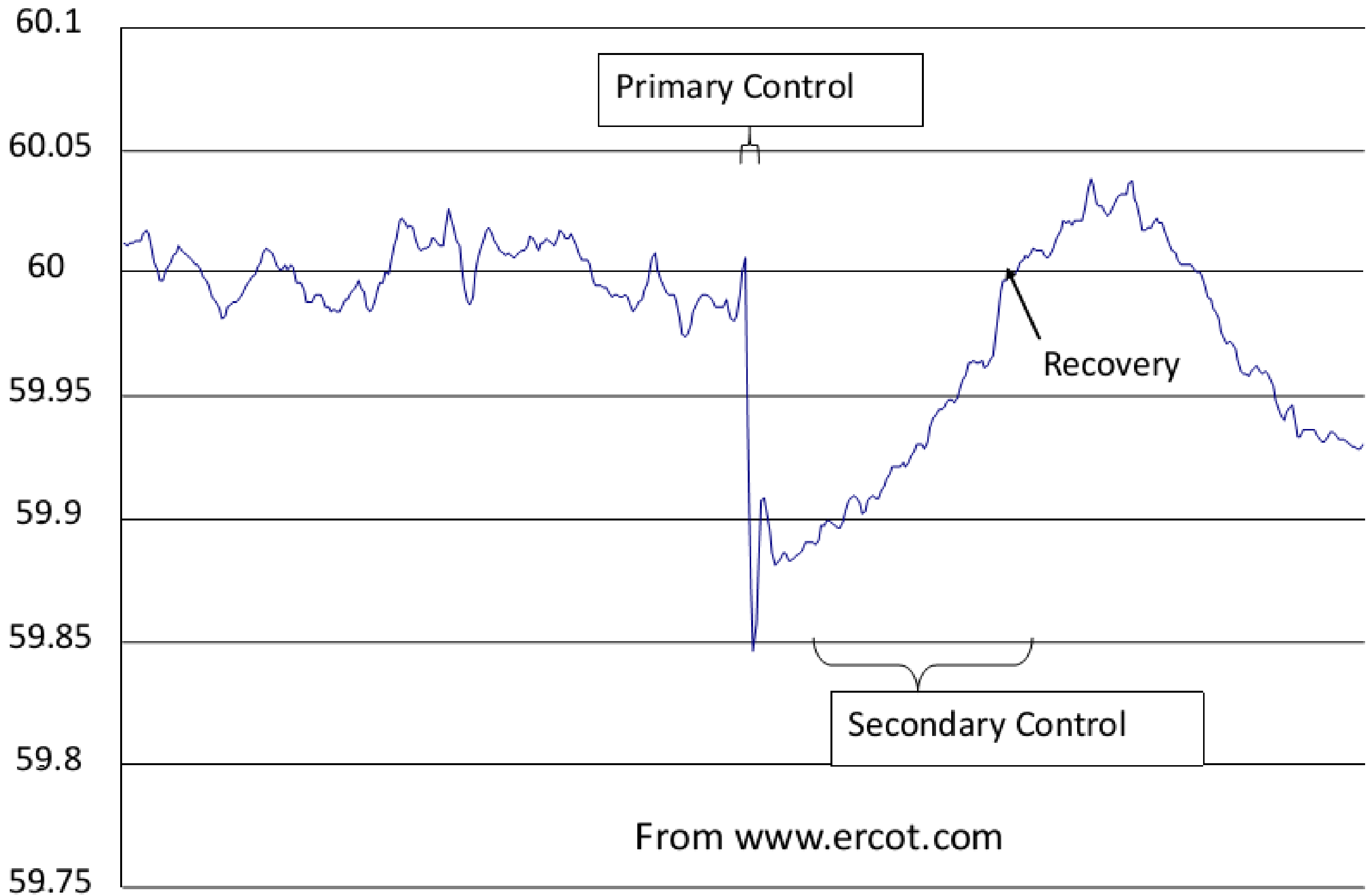
$$ACE_A = \Delta P_{AB} + \frac{1}{R_A}\Delta\omega = -9.091 + \frac{1}{0.015}(-0.0136) = -10 \text{ MW}$$

$$ACE_B = \Delta P_{BA} + \frac{1}{R_B}\Delta\omega = 9.091 + \frac{1}{0.0015}(-0.0136) = 0 \text{ MW}$$

Example: Control Action

- ACE indicates each area action to the change of load.
- ACE of area B is zero, this means that nothing should be done in area B.
- ACE of area A < 0, this means that area A should increase the setting control power by – (-10) = 10 MW to cover its own load.

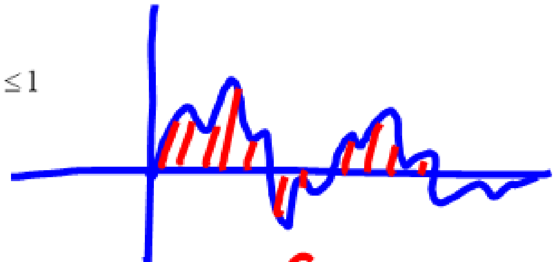
ERCOT Frequency Plot



ERCOT ACE

Operating requirement: Standard BAL-001-0 — Real Power Balancing Control Performance, effective April 1, 2005 from www.ercot.com

$$AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right] \le \epsilon_1^2 \quad or \quad \frac{AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right]}{\epsilon_1^2} \le 1$$



$\int ACE < \varepsilon$

The equation for ACE is:

$ACE = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME}$

where:

- NI_A is the algebraic sum of actual flows on all tie lines.
- NI_S is the algebraic sum of scheduled flows on all tie lines.
- B is the Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz.
- F_A is the actual frequency.
- F_S is the scheduled frequency. F_S is normally 60 Hz but may be offset to effect manual time error corrections.
- I_{ME} is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NI_A) and the hourly net interchange demand measurement (megawatt-hour). This term should normally be very small or zero.

Economic Dispatch

- The last component of AGC is economic dispatch.
- The main goal of economic dispatch is to make sure that the scheduled of units are done in the most economical way.
  - This section is covered in Lecture 4: Economic dispatch and optimal power flow.