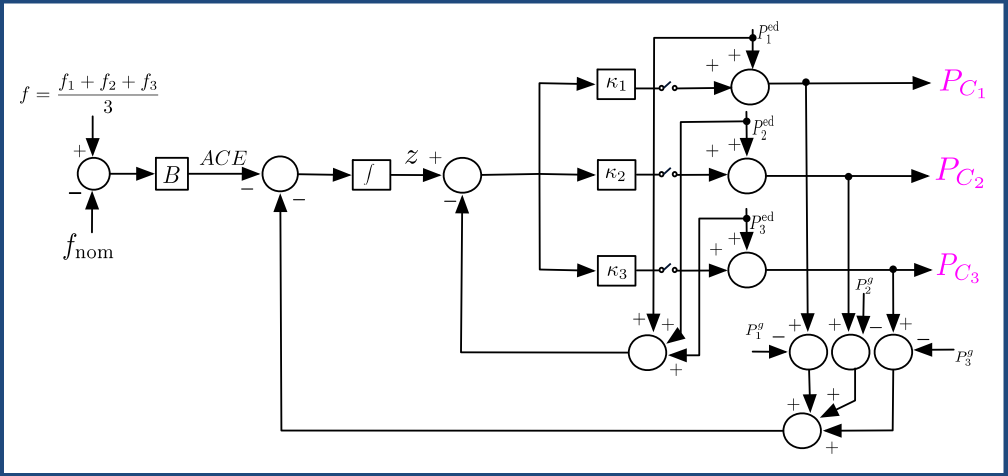
Power System Generation Control



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For

TCIPG reading group

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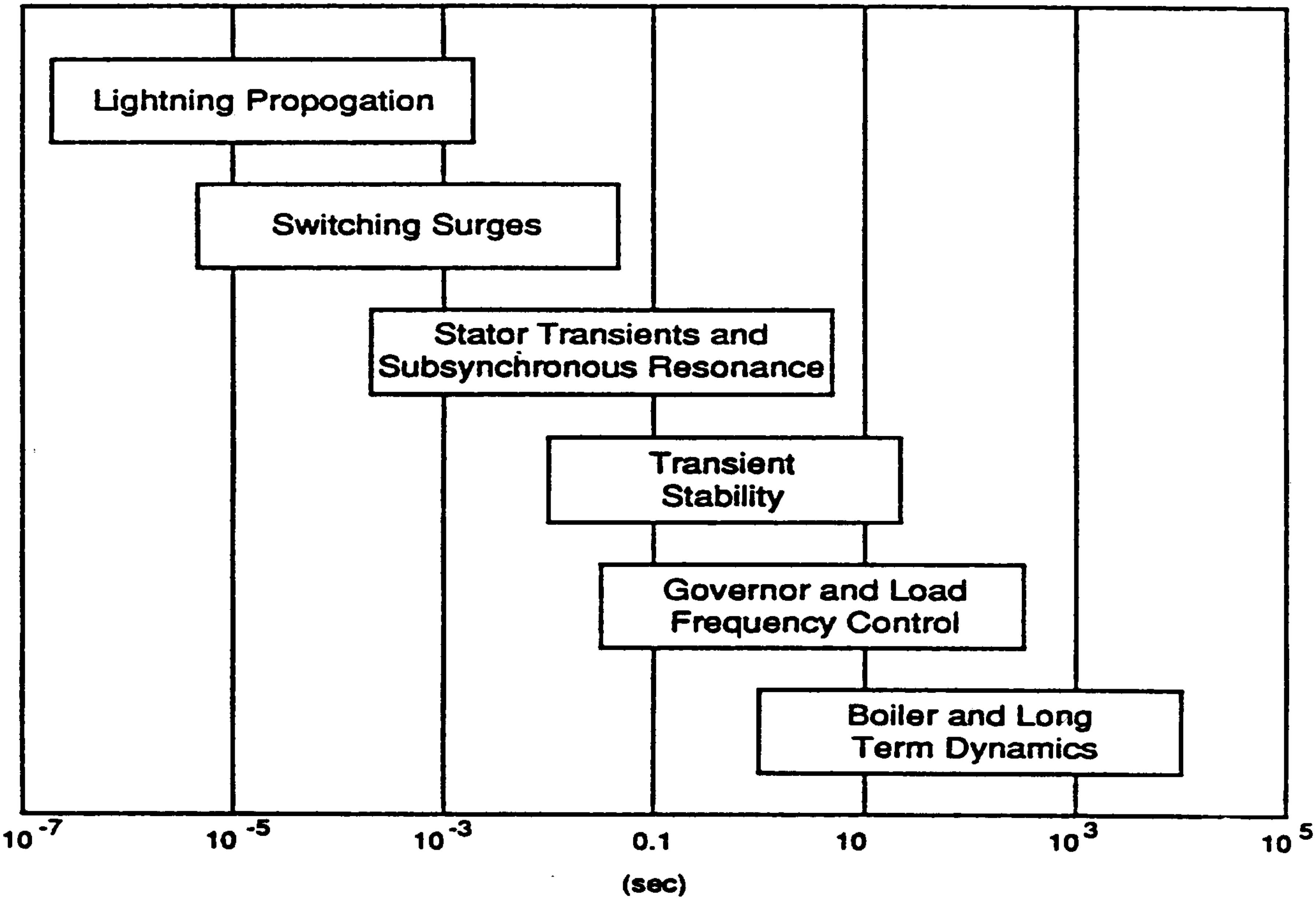
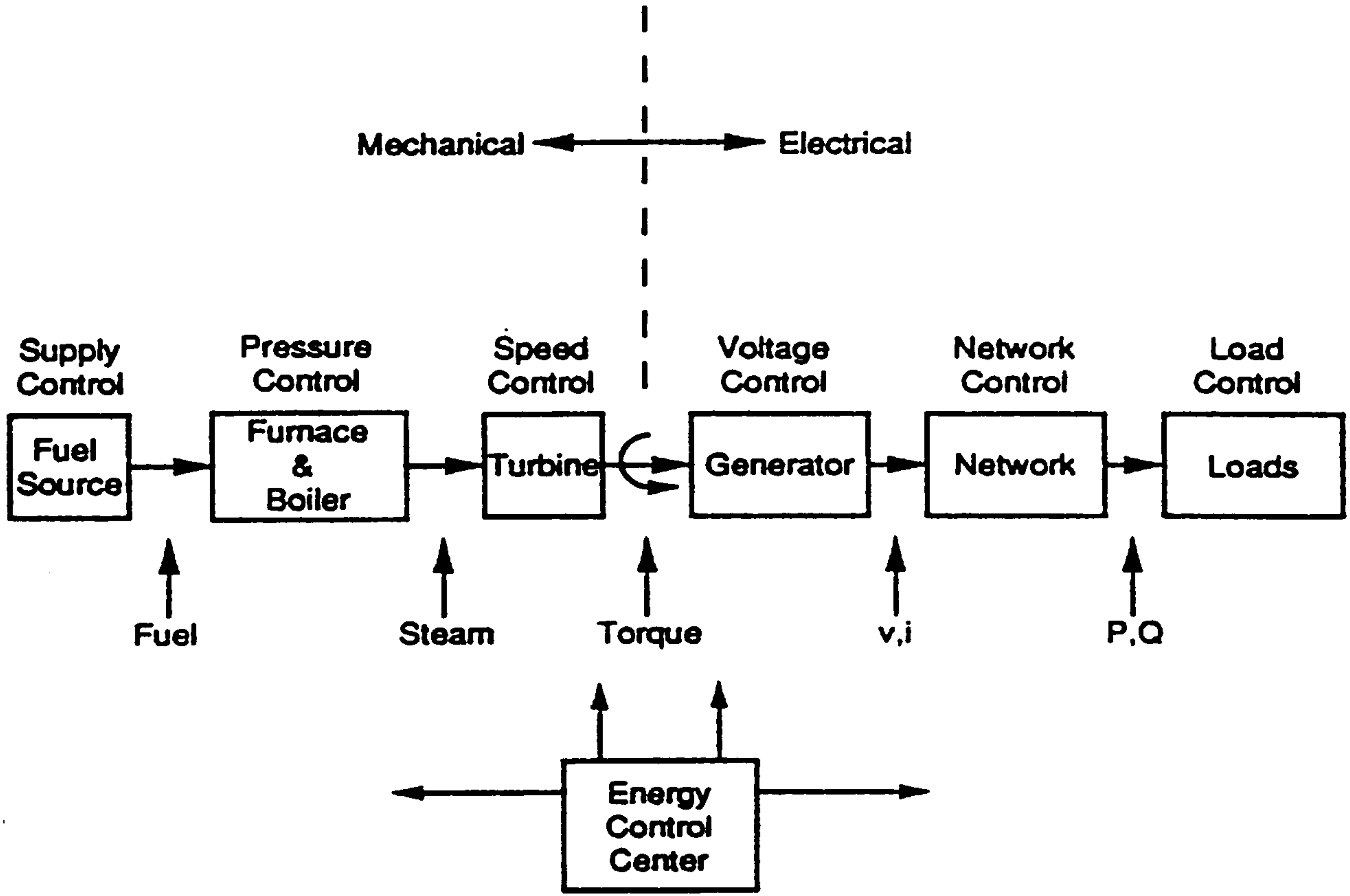
Power System Dynamic Time Scales



Energy Conversion in an "ElectroMechanical" System



Five stages of response to adding load

– Stage 1: Currents redistribute almost instantaneously – nearly the speed of light.

We could model generators as sinusoidal voltage sources during this stage – constant voltage magnitude, frequency, and phase angle – currents in/out of them would change instantaneously. Most mechanical and slow electrical dynamics have not changed significantly during this stage.

We invoke singular perturbation to make the fast stator/network transients instantaneous

$$\varepsilon \frac{d\psi_d}{dt} = R_s I_d + \left(1 + \frac{\varepsilon}{T_s}\omega_t\right)\psi_q + V_d$$

$$\varepsilon \frac{d\psi_q}{dt} = R_s I_q - \left(1 + \frac{\varepsilon}{T_s}\omega_t\right)\psi_d + V_q$$

where

$$\psi_d = E'_q - X'_d I_d$$

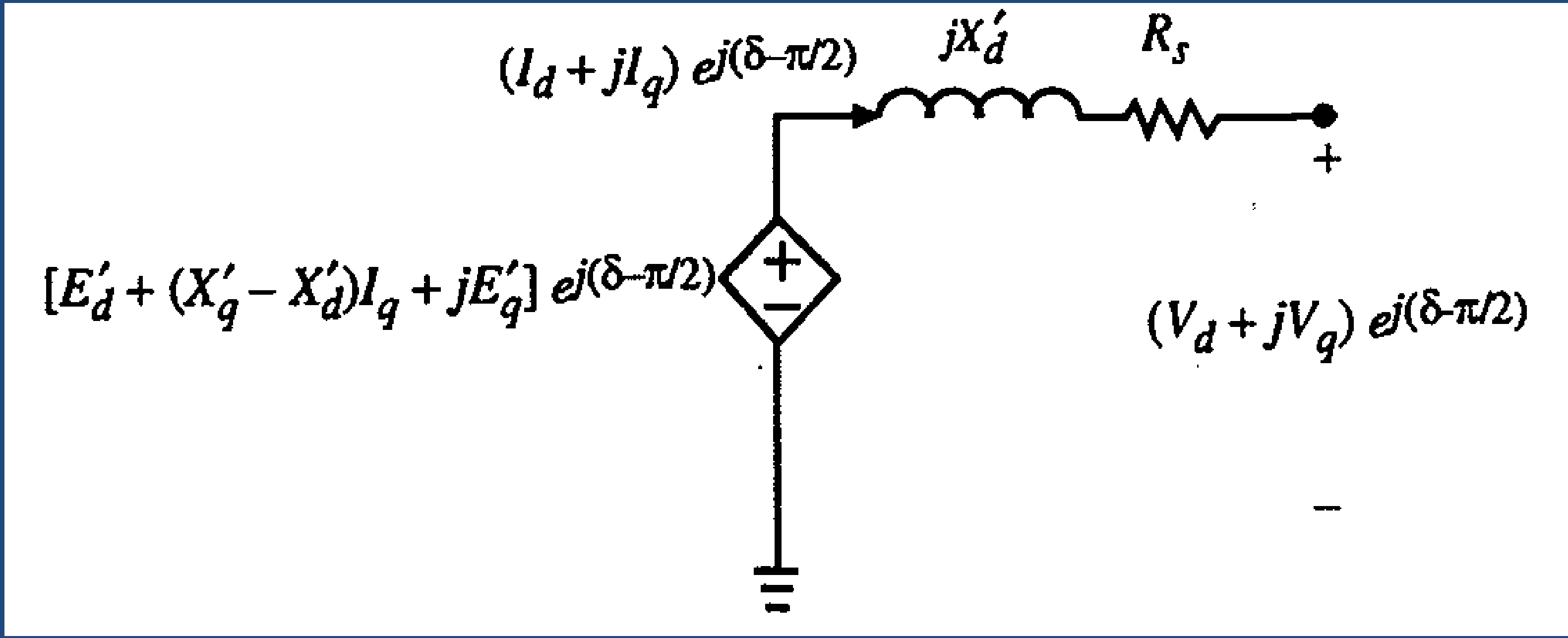
$$\psi_q = -E'_d - X'_q I_q$$

$$\varepsilon = \frac{1}{2\pi 60} \to 0$$

$$0 = R_s I_d - E'_d - X'_q I_q + V_d$$

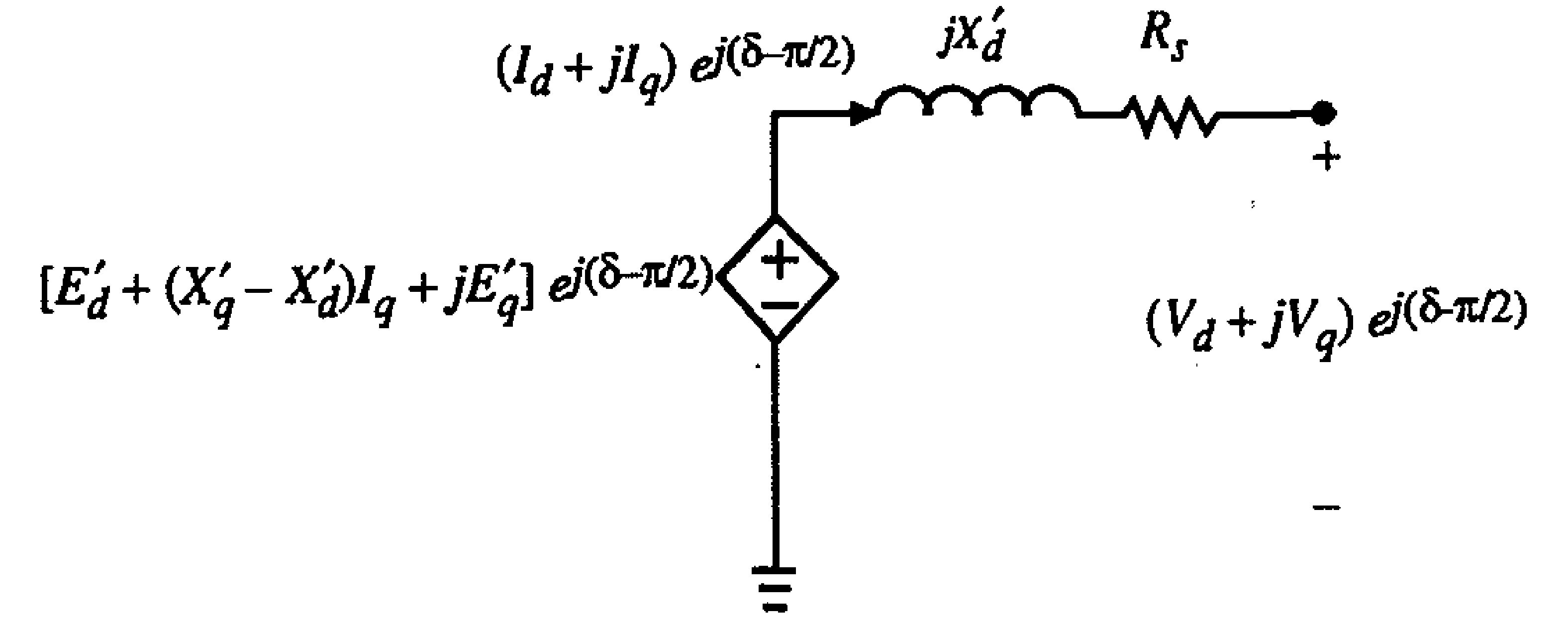
$$0 = R_s I_q - E'_q + X'_d I_d + V_q$$

Synchronous machine dynamic model neglecting the super-fast stator/network electrical transients – i.e. a "quasi steady-state" electrical system



Use this to find I_d, I_q, V_d, V_q in terms of the remaining dynamic states E_d' , E_q' and δ

By the way --- what are the “Phasors” for this circuit?



The “Phasors” are the complex numbers for the current and the voltage. These are “filtered” before they occur whereas PMUs “filter” after they occur. How about frequency (of voltages and currents)?

The slower electrical plus mechanical dynamics

$$T'_{doi}\frac{dE'_{qi}}{dt} = -E'_{qi} - \left(X_{di} - X'_{di}\right) I_{di} + E_{fdi}$$

Field flux linkage

$$T'_{qoi}\frac{dE'_{di}}{dt} = -E'_{di} + \left(X_{qi} - X'_{qi}\right) I_{qi}$$

Damper winding flux linkage

$$\frac{d\delta_i}{dt} = \omega_i - \omega_s$$

Torque equation (NSL)

$$\frac{2H_i}{\omega_s}\frac{d\omega_i}{dt} = T_{Mi} - E'_{di}I_{di} - E'_{qi}I_{qi} - \left(X'_{qi} - X'_{di}\right) I_{di} I_{qi}$$

Five stages of response to adding load

– Stage 2: These currents create a mismatch in power/torque at every generator because the mechanical power/torque cannot change quickly.

This mismatch will cause all the generators to change their speeds – energy is taken from (or supplied to) the shafts (kinetic energy based on shaft inertia). This causes their “angles” and “speeds” to change. We need to model the shaft dynamics to capture this.

Five stages of response to adding load

- Stage 3: The speed control governors sense the change in speed and react to return the generators to near rated speed – they typically have a 5% “droop”. A change from no load to full load results in a 5% drop in speed.

They open or close a turbine valve. (This also initiates the boiler control system when the steam pressure changes). There is a “ramp rate” which constrains the speed of this action. There is also a voltage regulator watching the voltage.

$$T_{Ei}\frac{dE_{fdi}}{dt} = -\left(K_{Ei} + S_{Ei}\left(E_{fdi}\right)\right)E_{fdi} + V_{Ri}$$

$$T_{Fi}\frac{dR_{fi}}{dt} = -R_{fi} + \frac{K_{Fi}}{T_{Fi}}E_{fdi}$$

Excitation (Voltage) control

$$T_{Ai}\frac{dV_{Ri}}{dt} = -V_{Ri} + K_{Ai}R_{fi} - \frac{K_{Ai}K_{Fi}}{T_{Fi}}E_{fdi} + K_{Ai}\left(V_{refi} - V_i\right)$$

$$V_i = \left[V_{di}^{\ 2} + V_{qi}^{\ 2}\right]^{1/2}$$

Recall the V_d and V_q from the circuit

$$T_{CHi}\frac{dT_{Mi}}{dt} = -T_{Mi} + P_{SVi}$$

Speed (Frequency) control

$$T_{SVi}\frac{dP_{SVi}}{dt} = -P_{SVi} + P_{Ci} - \frac{1}{R_{Di}}\frac{\omega_i - \omega_s}{\omega_s}$$

Five stages of response to adding load

- Stage 4: The Load Frequency Control system will detect the change in area frequency and possibly area interchange and Automatic Generation Control (AGC) will react to change the power commands (P_{ci}) to each generator in that area.

- Stage 5: Unit Commitment , Economic dispatch and energy market activity make changes to ensure optimum production schedules. If congestion occurs, adjustments must be made to provide relief.

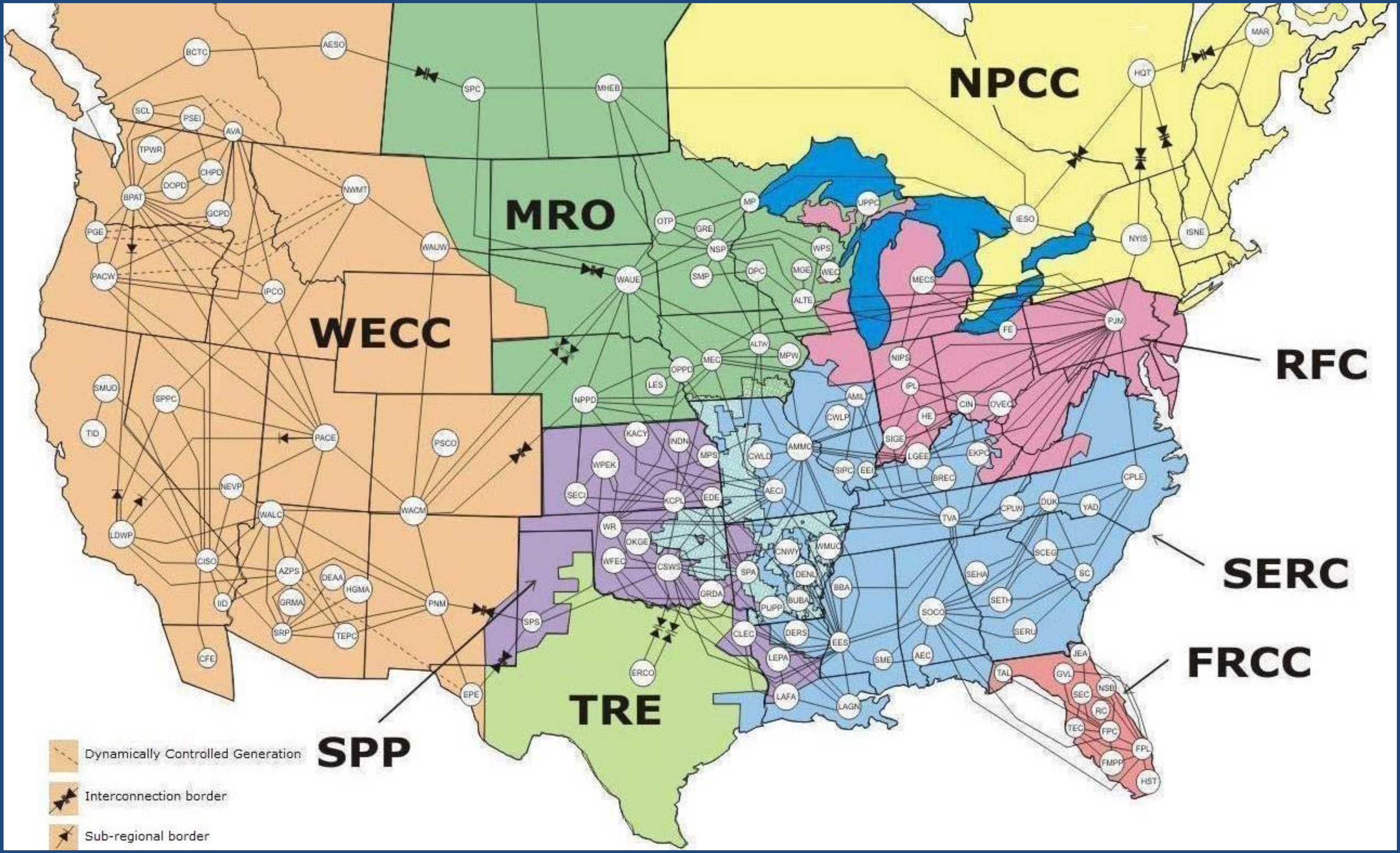
Who's in charge?

The Balancing Authority (BA) is the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time

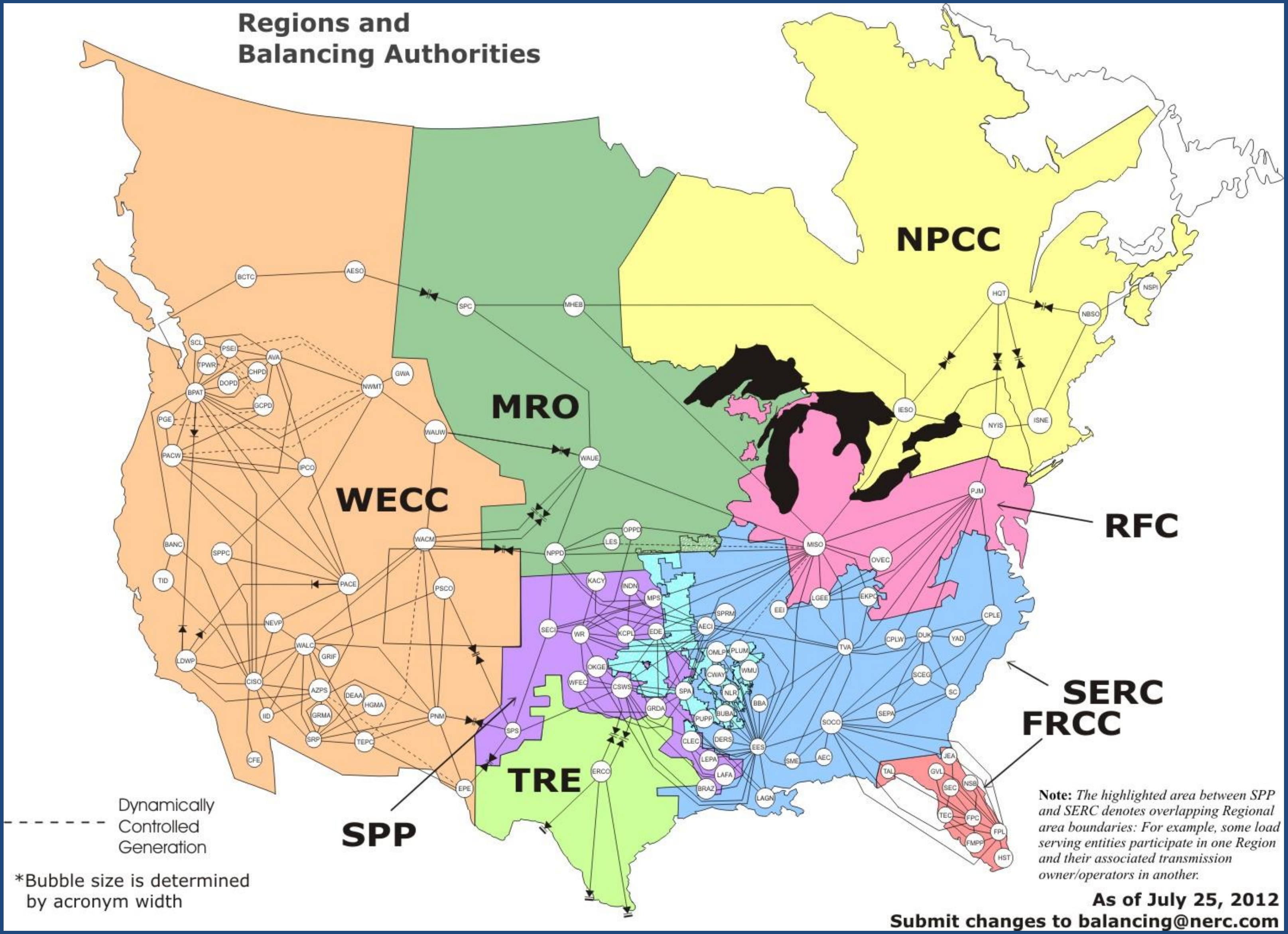
NERC regional councils

Florida Reliability Coordinating Council (FRCC)
Midwest Reliability Organization (MRO)
Northeast Power Coordinating Council (NPCC)
Reliability First Corporation (RFC)
SERC Reliability Corporation (SERC)
Southwest Power Pool (SPP)
Texas Reliability Entity (TRE)
Western Electric Coordinating Council (WECC)

NERC Balancing Authorities - 2007



NERC Balancing Authorities - 2012



Automatic Generation Control (AGC)

There are three objectives for AGC:

1. Maintain frequency near rated.
2. Maintain area interchange near the desired value.
3. Maintain each units generation at the most economical value.

AGC includes Load Frequency Control and Economic Dispatch

Load Frequency Control (LFC)

Area Control Error (ACE) is the instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of frequency bias.

$$ACE\ (\text{Wood/Wollenberg}) = -P_{tie\ act} + P_{tie\ sch} - B(f-60)$$

$$ACE\ (\text{Glover/Sarma}) = P_{tie\ act} - P_{tie\ sch} + B(f-60)$$

Frequency bias (B) is a value (often expressed as a negative number). It is also often expressed in megawatts per 0.1 Hertz (MW/0.1 Hz), which would require a multiplier of 10. The tieline powers are sometimes import and sometimes export. Normally negative ACE means too little generation.

Using "negative B" and "importing tie-line powers", the generation needed for this area is $P_{c(area)}$:

$$T_{ACE(area)} \frac{dP_{c(area)}}{dt} = P_{tie(act\ \mathrm{in})area} - P_{tie(sch\ \mathrm{in})area} + \frac{10 B_{area}}{2\pi} (\omega_{area} - \omega_s)$$

LFC is integral (of negative ACE) control.

- If the frequency is too low, this will call for an increase in area generation.
- If the actual tie-line power import is greater than scheduled, this will call for an increase in area generation.
- This is allocated to individual units using either raise/lower pulses or actual total required:

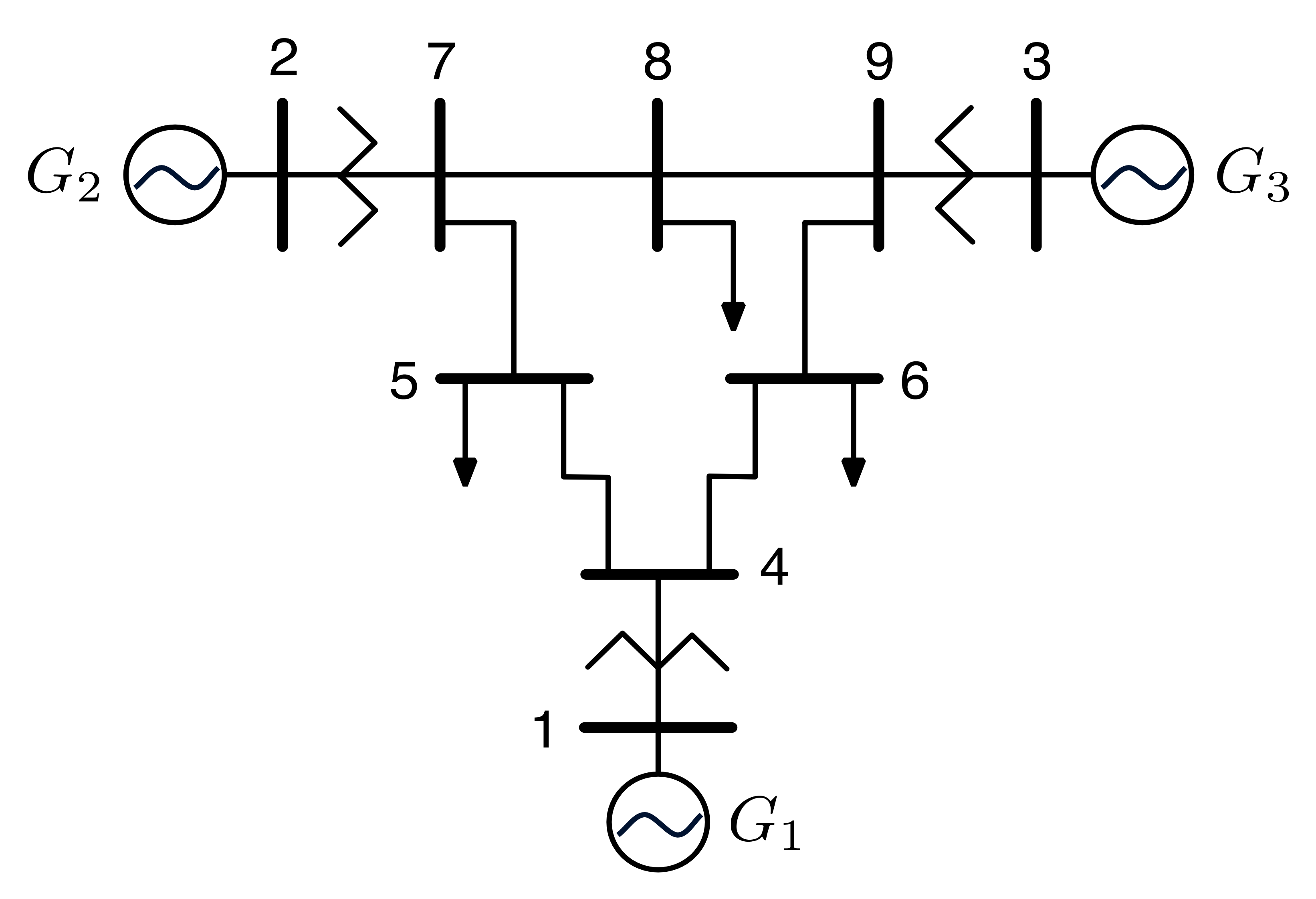
$$P_{ci} = C_i P_{c(area)}$$

- Eventually economic dispatch and markets affect the C_i

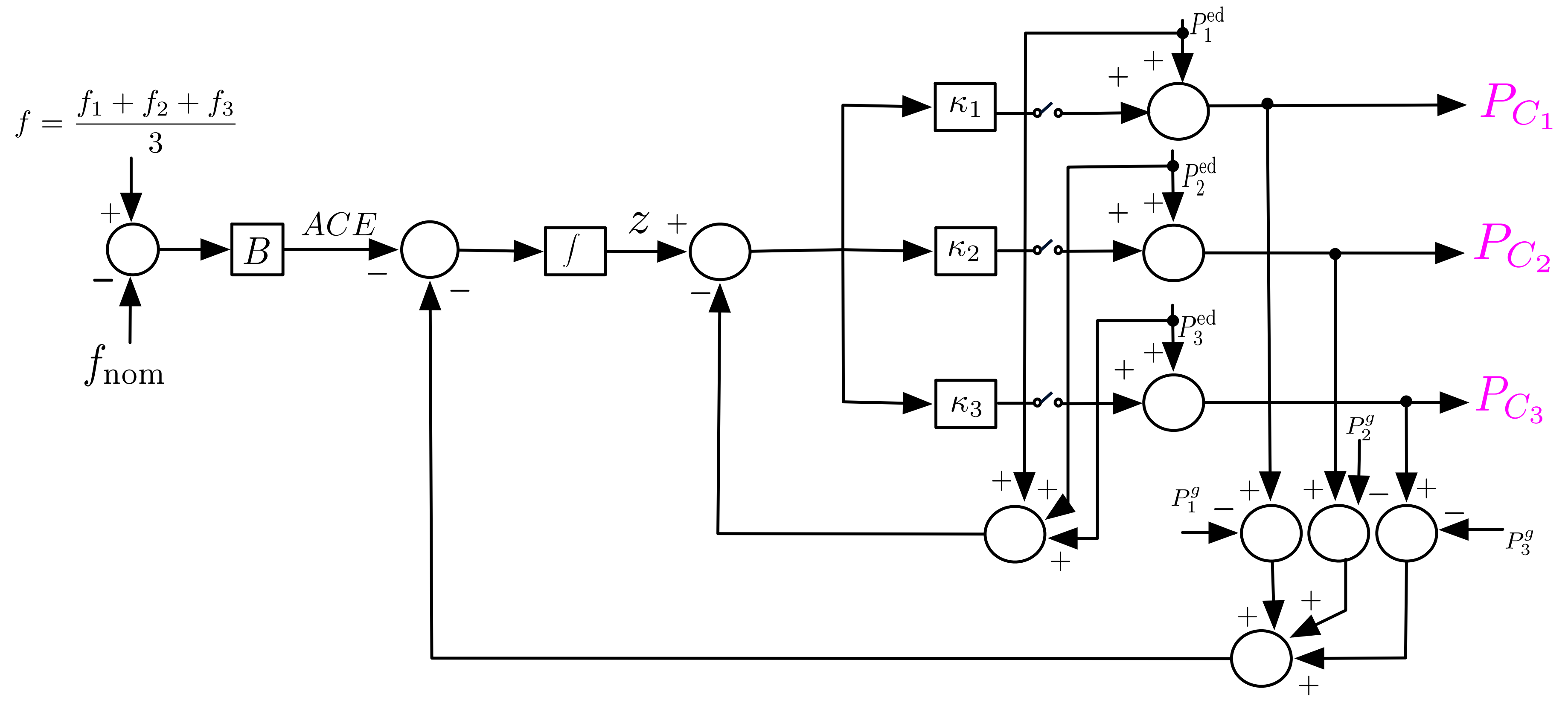
Economics

- Unit Commitment
  - startup costs, shutdown costs
  - spinning reserve
  - ramp rates
- Market Mechanisms – auctions, clearing
- Economic Dispatch – incremental costs
  - Security Constrained
  - Nodal prices
- Demand Response
- Renewables and Storage

3-machine system, 9-bus system

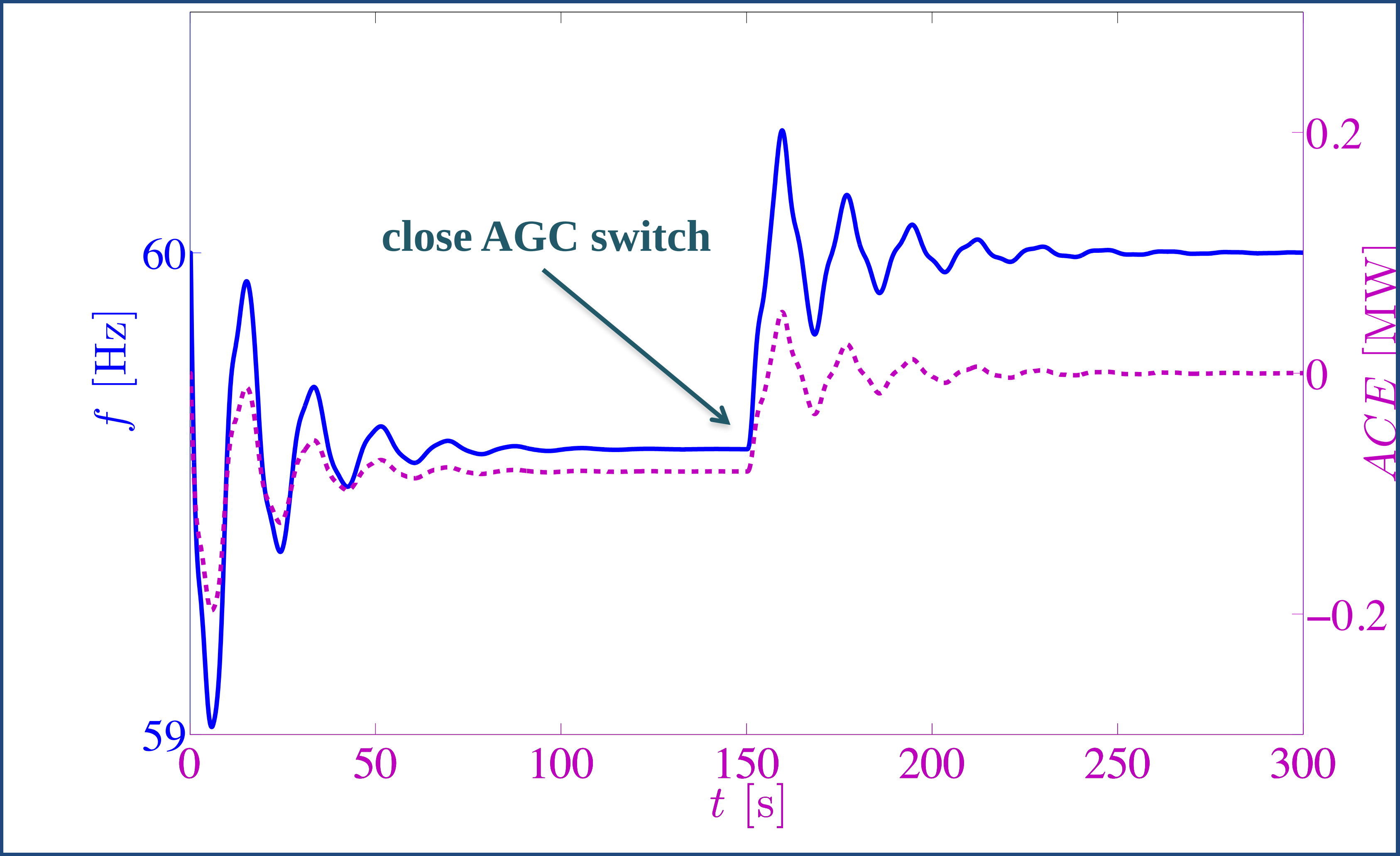


AGC system for 3-machine, 9-bus system

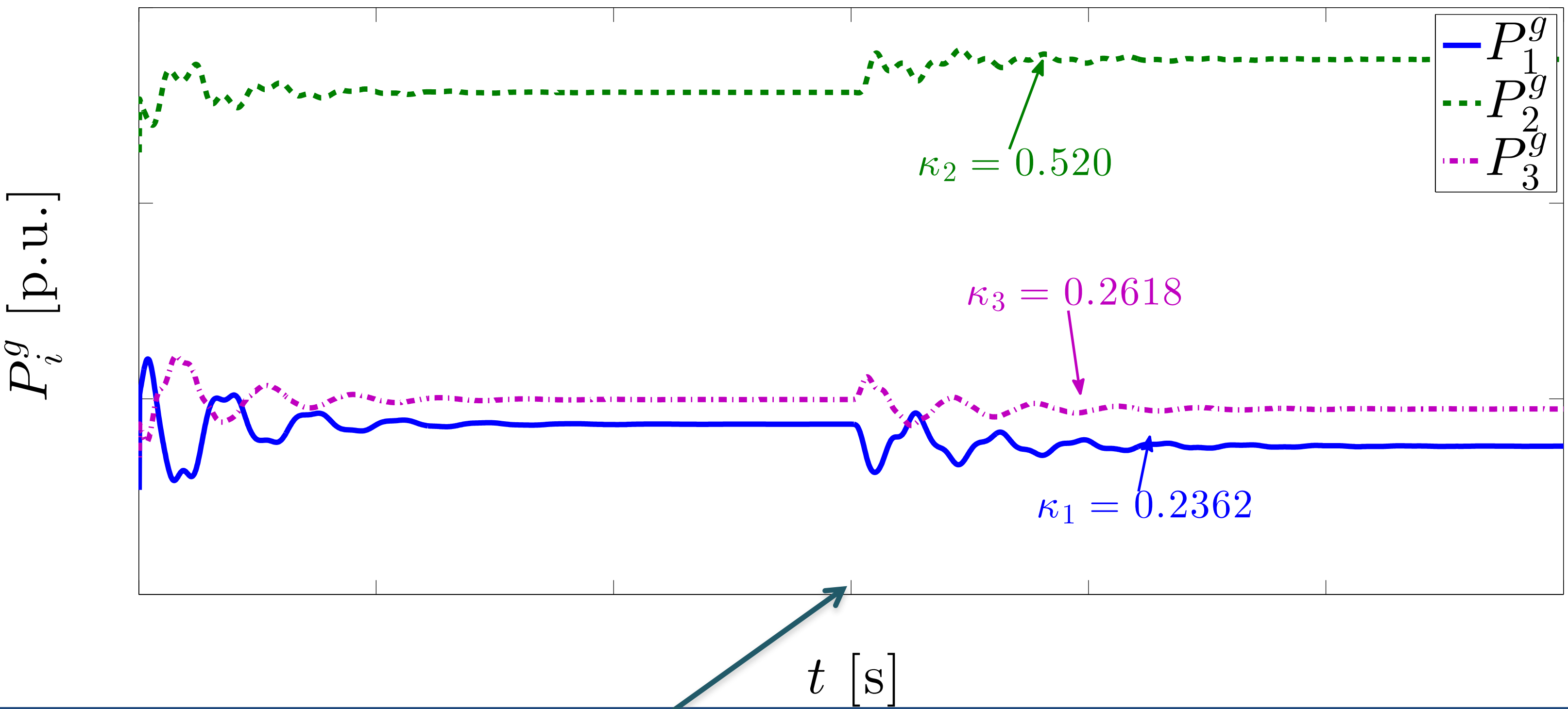


Load Modification

$$\Delta P_5 = 0.45$$



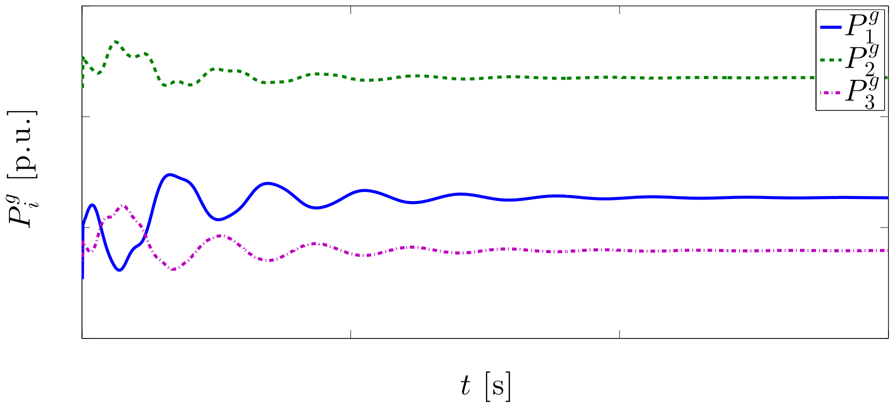
Evolution of generators' output



close AGC switch

Modification of participation factors

$$\kappa_1 = 0.8, \kappa_2 = 0.1, \kappa_3 = 0.1$$

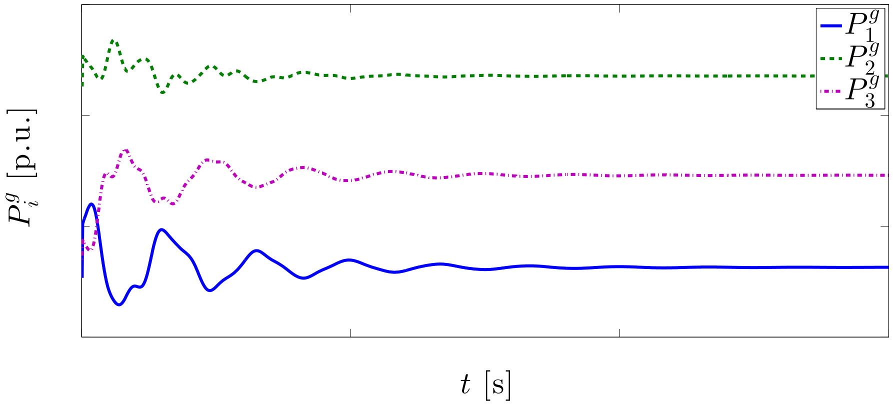


$$\Delta P_1^g = 0.3671$$

$$\Delta P_2^g = 0.0462$$

$$\Delta P_3^g = 0.0461$$

$$\kappa_1 = 0.1, \kappa_2 = 0.1, \kappa_3 = 0.8$$

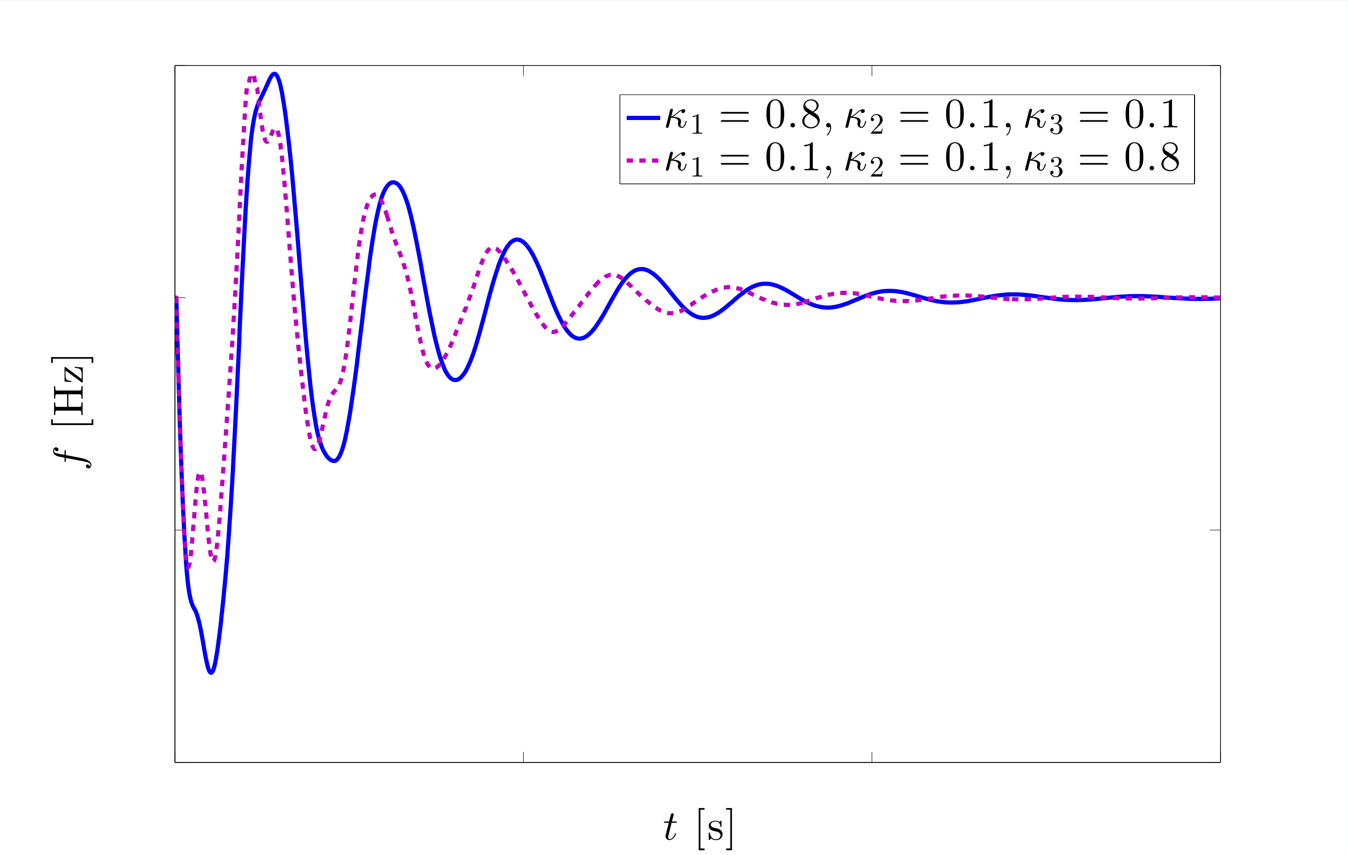


$$\Delta P_1^g = 0.0478$$

$$\Delta P_2^g = 0.0474$$

$$\Delta P_3^g = 0.3794$$

Quality of AGC service



$$\text{Ramp rate}_1 < \text{Ramp rate}_2 < \text{Ramp rate}_3$$