Frequency Control

ELEN90060 Power System Analysis

Keith Moffat

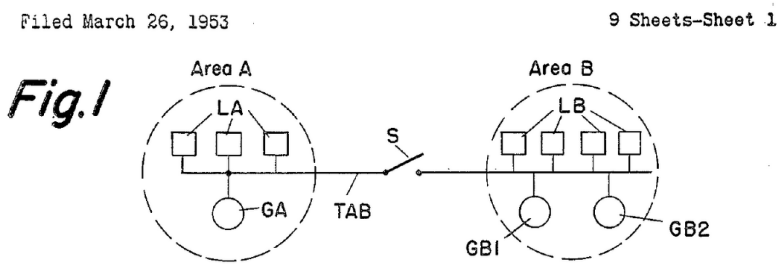
System Interconnection

Merits

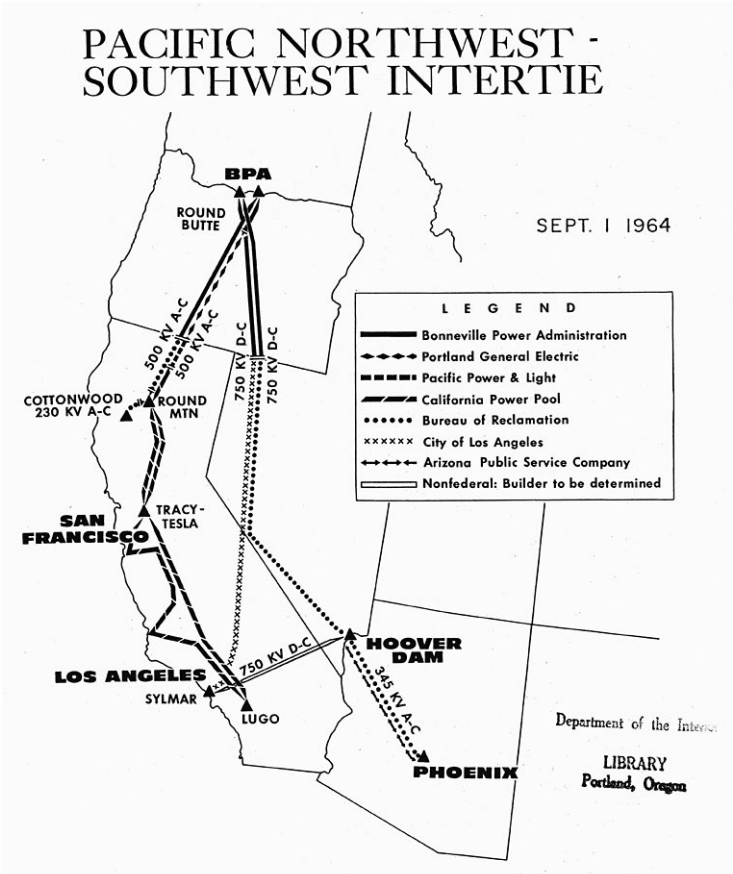
- Allow supplying of demand in the most economical way
  - Production cost of area 1 is lower → sells to area 2
- Less redundancy required bc areas back each other up
  - sharing of frequency response and reserves

Challenges

- The support from one area to another could overload the tie-line flow constraints

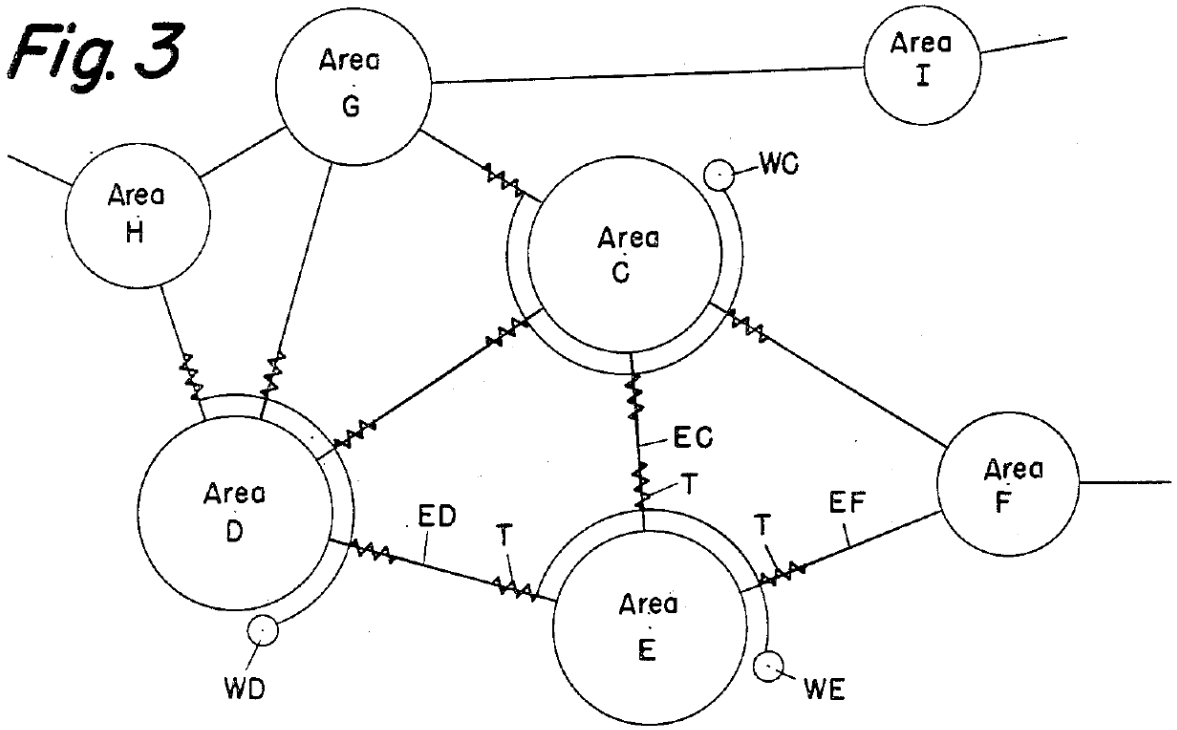


Source: Cohn (1983); US Patent 2,773,994, Fig. 1



https://www.oregonhistoryproject.org/articles/historical-records/pacific-intertie-map/?utm_source=chatgpt.com

How should an area respond a disturbance?



Goal

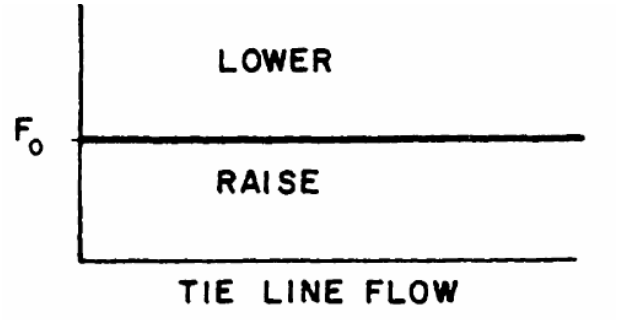
- Restore frequency to nominal
- Restore power flows on all tie lines to scheduled amount

Measurements

- Frequency
- Power flows on all tie lines

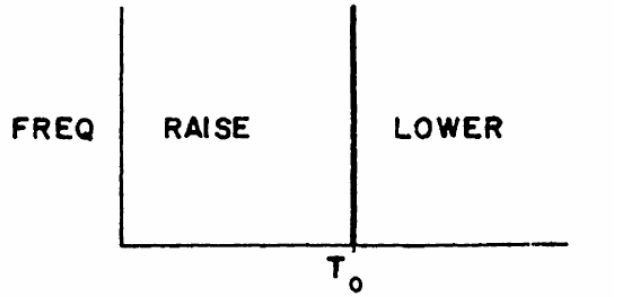
How should an area respond a disturbance?

Frequency only



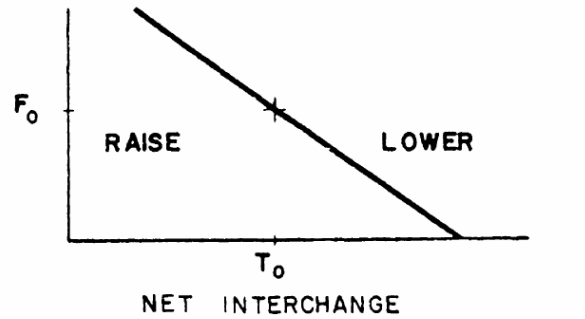
Respond to frequency deviation ignoring area export schedule

Tie line only



Ignore frequency deviation maintaining area export schedule

Tie-Line-Bias Frequency Control



Respond to both frequency deviation and scheduled-interchange error

This was the insight of Nathan Cohn (and others) called “tie-line-bias automatic generation control”

Area Control Error and Automatic Generation Control

ACE combines the net export error with a frequency term:

$$\mathrm{ACE}_i = \Delta P_{\mathrm{tie},i} + B_i \Delta f$$

B_i: each area's AGC frequency bias (units: MW/Hz)

Automatic Generation Control (AGC) for area i:

$$\frac{d}{dt}\Delta P_{\mathrm{ref},i}(t) = -K_i \mathrm{ACE}_i(t) \qquad \text{or, equivalently,} \qquad \Delta P_{\mathrm{ref},i}(s) = -\frac{K_i}{s}\mathrm{ACE}_i(s)$$

The AGC for each area adjusts the droop setpoints for each area to drive the ACE to 0

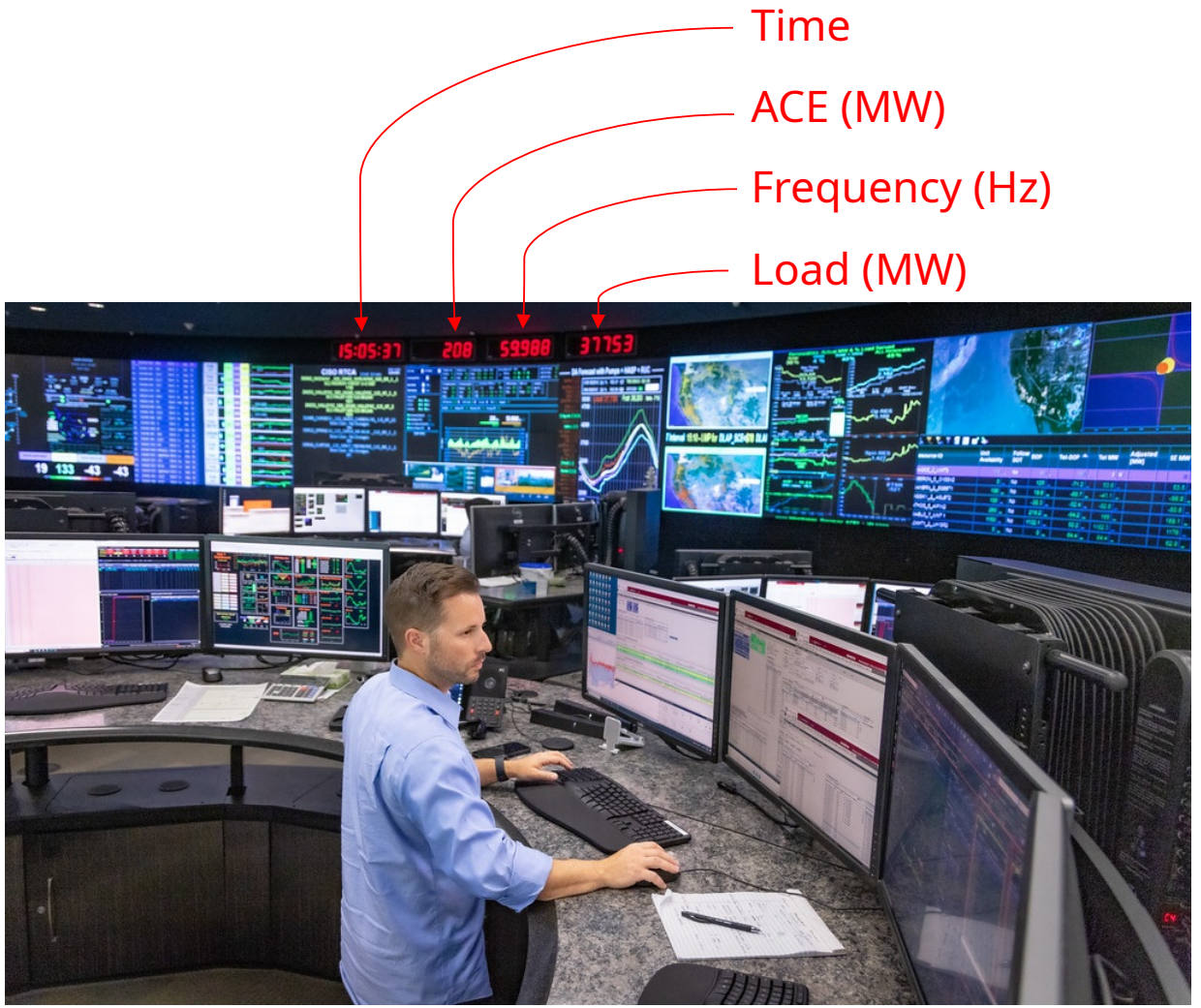
Transmission Network Control Room, 1960s





https://www.waterandpower.org/museum/Early_Load_Dispatch.html

Modern Transmission Network Control Room



CAISO control room, 2023 https://ibew1245.com/2023/07/27/always-planning-ibew-1245-members-at-caiso-manage-and-monitor-the-power-grid/

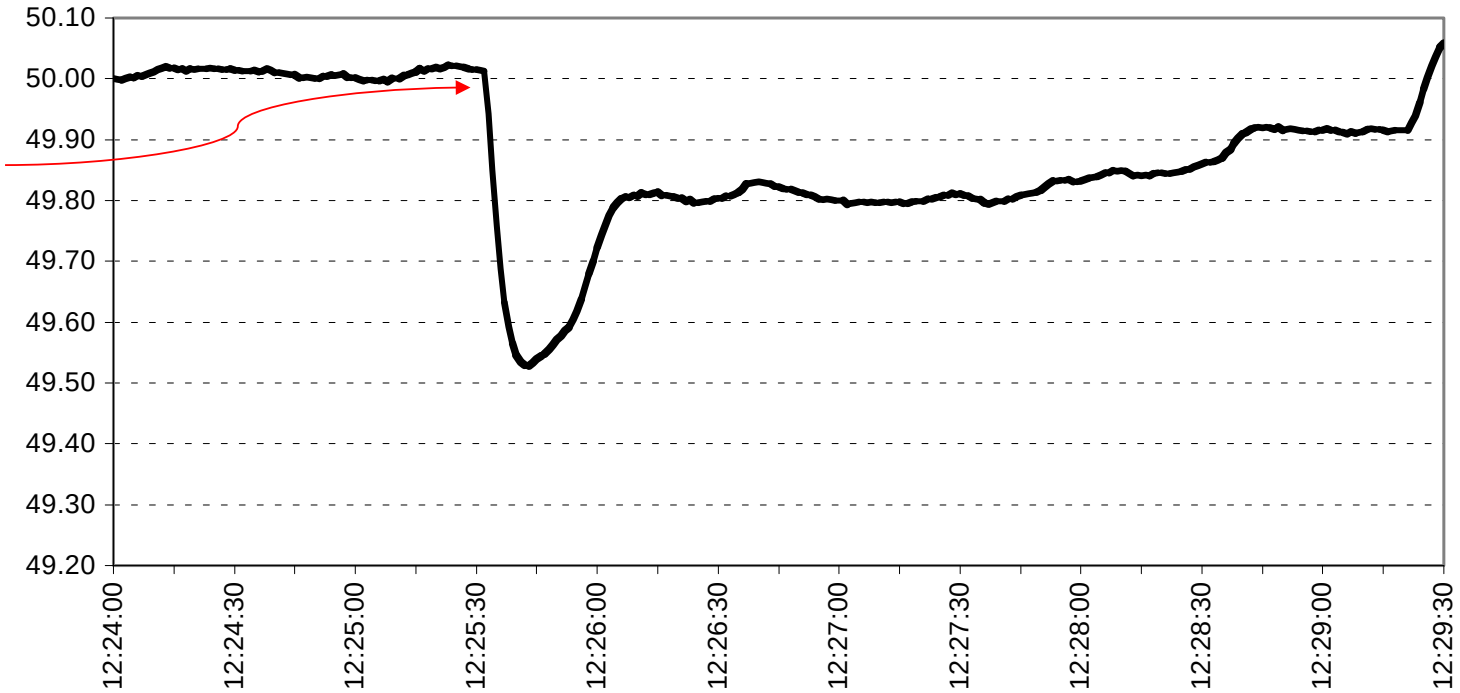
The displays have changed but the high-level operational principles have not changed.

Outline

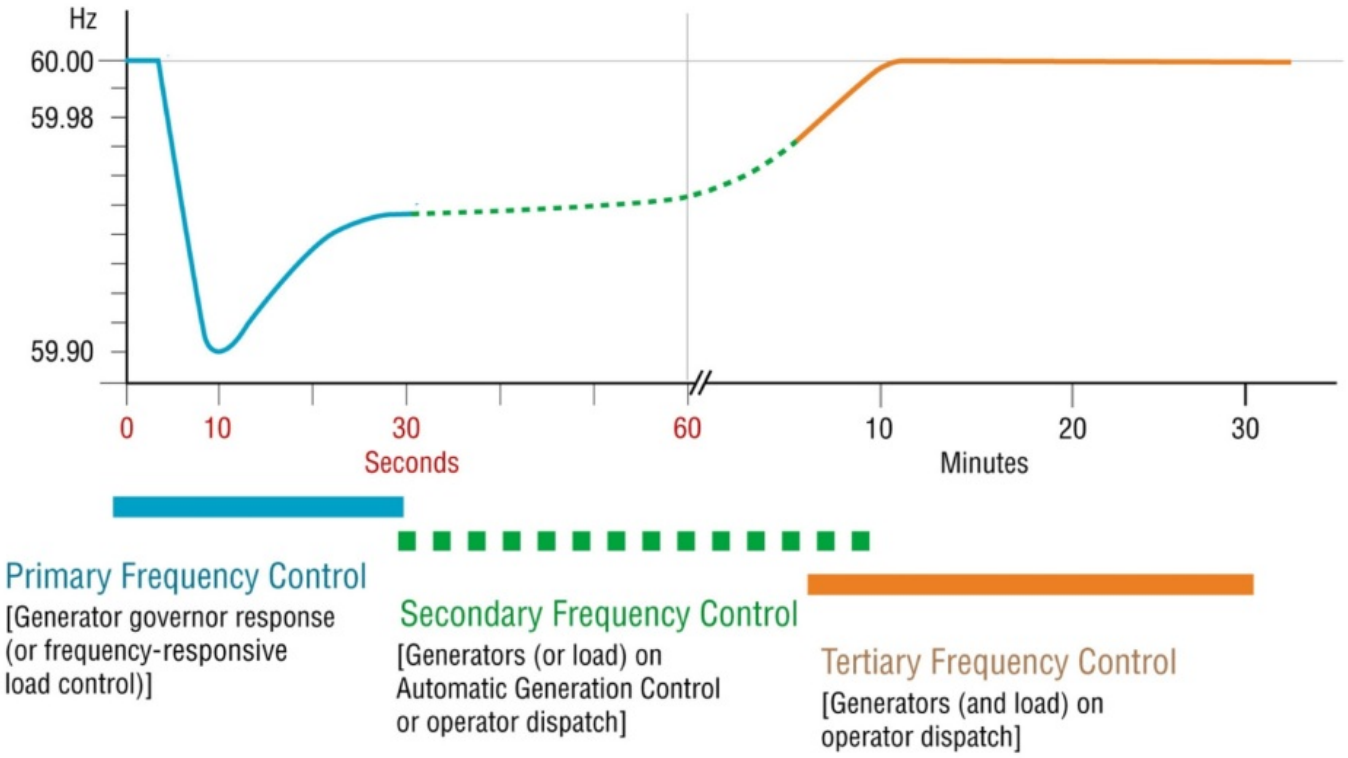
- Primary frequency control from multiple generators
- Secondary frequency control: Supplementary Control and Automatic Generation Control (AGC)

Back to Maintaining Frequency Stability

Generation loss



Frequency control mechanisms



Adapted from Eto et al., LBNL-4142E (2010) by Dr. Sascha von Meier

PRIMARY FREQUENCY CONTROL FROM MULTIPLE GENERATORS (SINGLE-AREA SYSTEM)

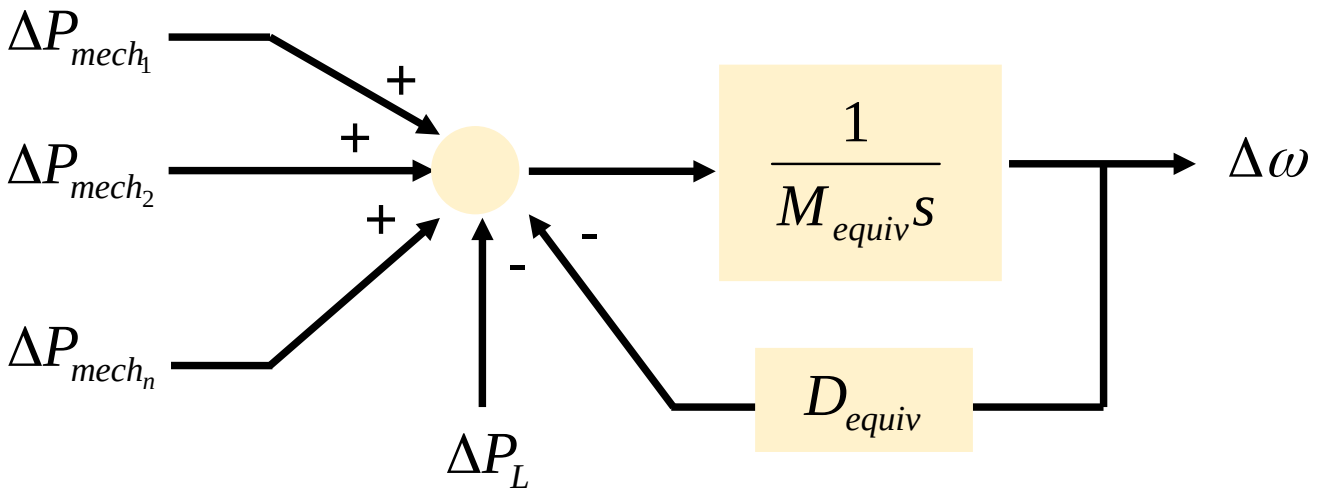
Multi-Generator Model

Consider several generators in a given synchronous *area* of the system (neglecting line dynamics)

All turbine generators in an area can be lumped into a single equivalent rotating mass, M_{equiv}

All individual system loads can be lumped into an equivalent load with damping coefficient, D_{equiv}

Why is it possible to lump inertia and load relief characteristics?



A. J. Wood, B. F. Wollenberg,"Power generation, operation and control", 1996.

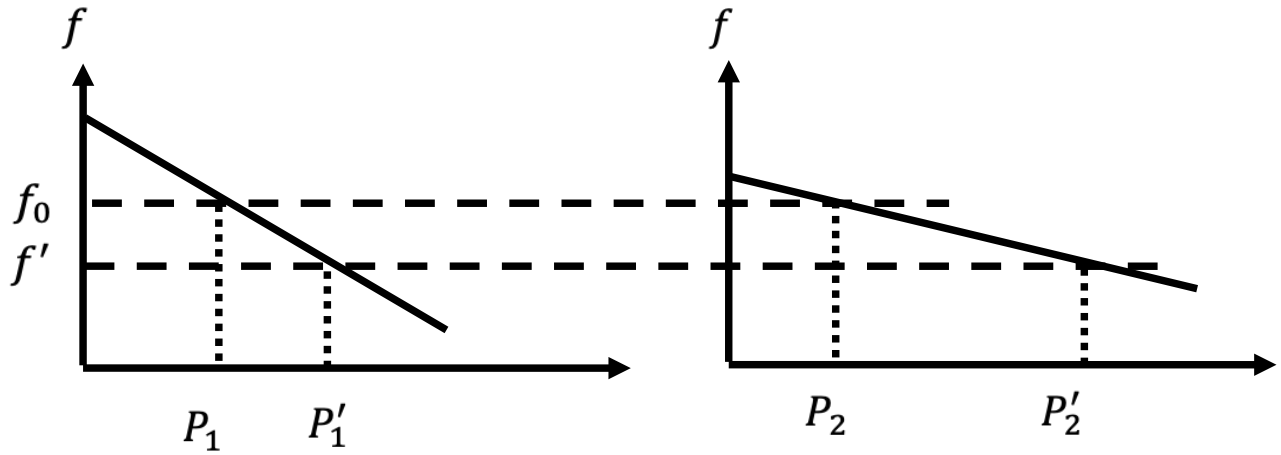
Class Exercise

The is an increase in load ΔP_L on a grid powered by two generators running droop control.

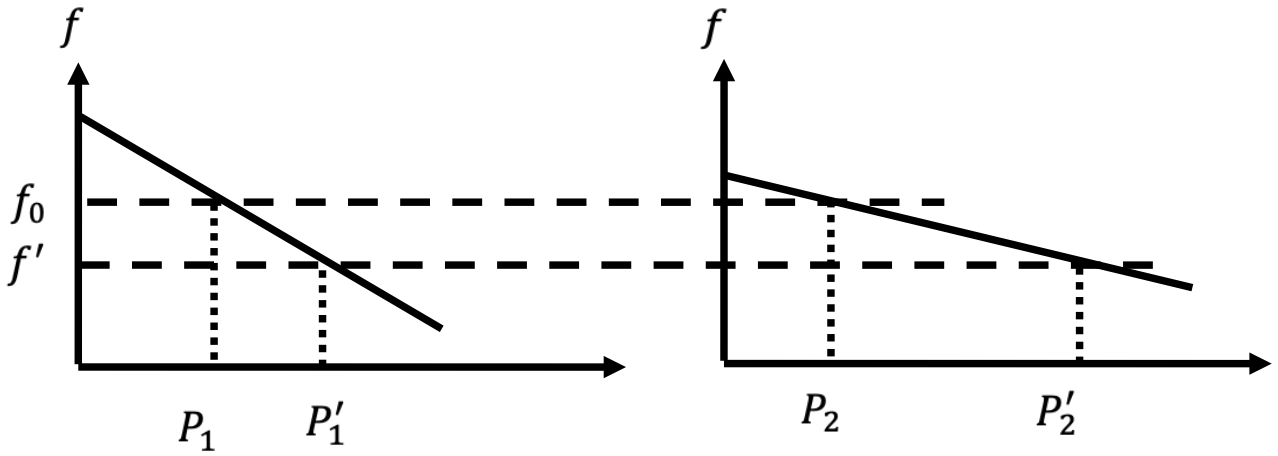
Describe the interaction of the network frequency and each generator's droop control that determines ΔP_1 and ΔP_2 such that $\Delta P_L = \Delta P_1 + \Delta P_2$

What aspect of the droop characteristic determines how much of the load increase is taken by generator 1 and how much is taken by generator 2?

Hint:



How will steady-state imbalances be shared across units?



Sharing of a change in network load is determined by droop slopes.

Load sharing by units in a same area

If two or more generators with droop governor characteristics are connected to a power system, there will be a *unique frequency at which they will share a load change*

The load change is shared between the units according to their droop characteristics:

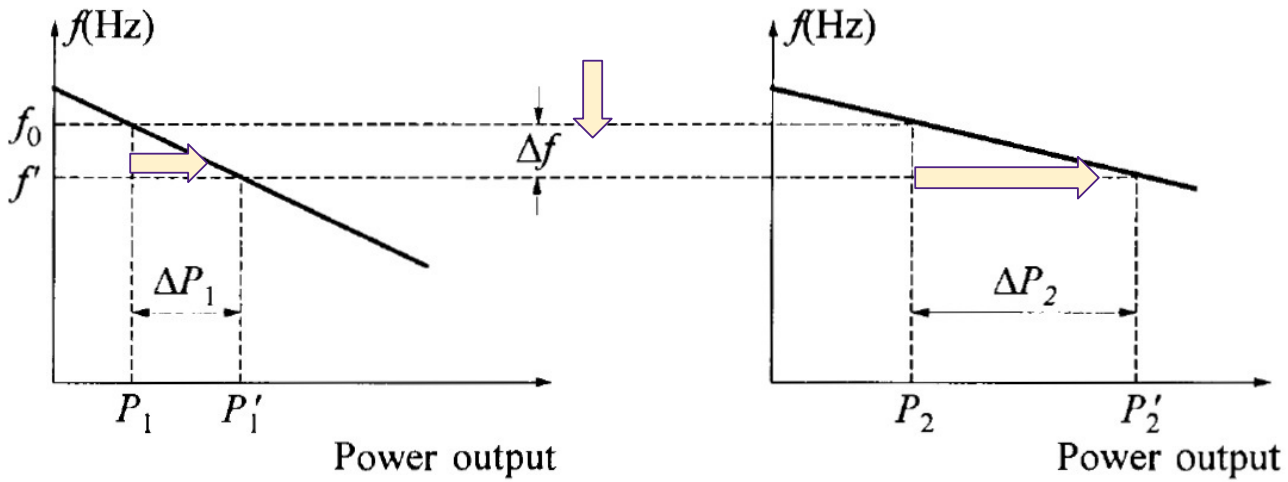
$$\Delta P_L = \Delta P_1 + \Delta P_2$$

Droop law: $R_i := -\frac{\Delta f}{\Delta P_i}$, often expressed in per unit

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

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

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



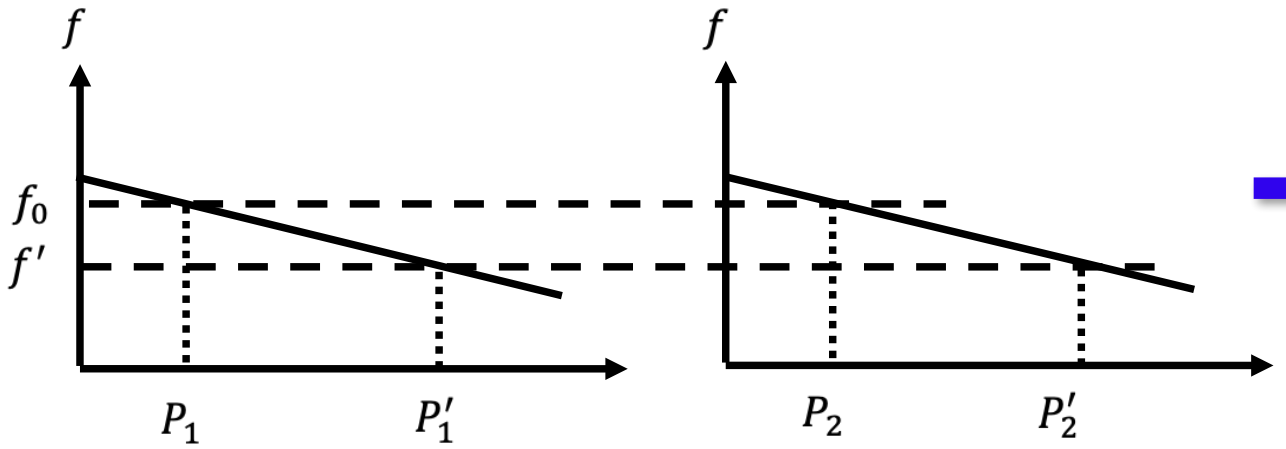
Load sharing by parallel units with drooping governor characteristics

P. Kundur, *Power System Stability and Control*. New York, NY, USA, McGraw-Hill, 1993.

How will imbalances be shared across different units?

Expressing R in per-unit facilitates easy comparison between generator contributions

What if they have the same droop value?



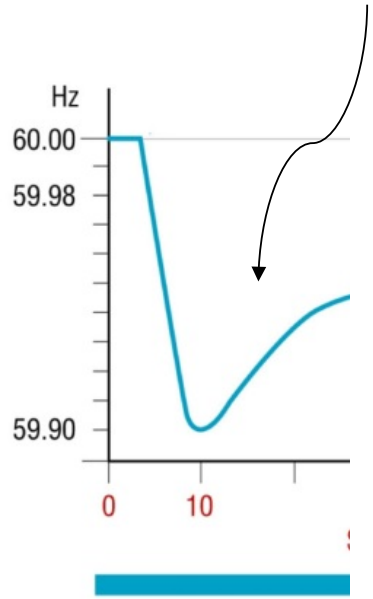
Sharing

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

When all turbine generating units have the same R in per unit on their own ratings, then each machine shares the total power in proportion to its own rating

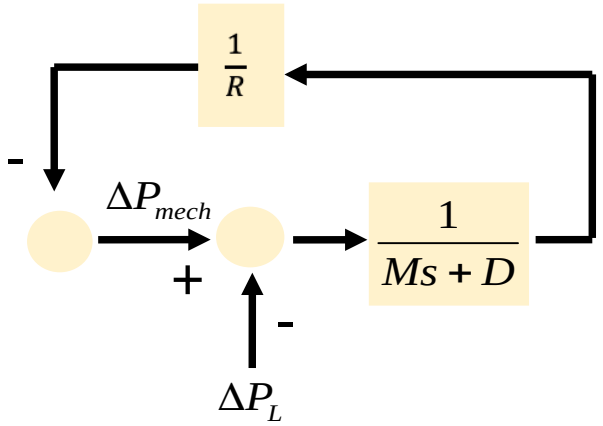
Droop Control with Swing Equation

First-order transfer functions do not describe this type of behavior



Primary Frequency Control
[Generator governor response (or frequency-responsive load control)]

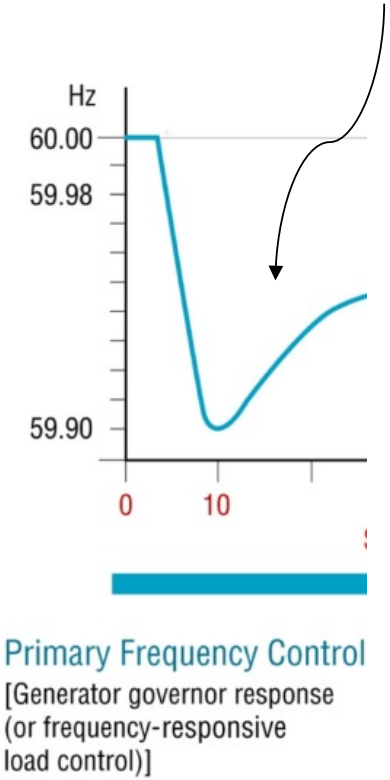
$$\Delta\omega = \frac{-\Delta P_L}{\frac{1}{R} + D}$$



$$\frac{\Delta\omega(s)}{\Delta P_{\mathrm{L}}(s)} = -\frac{1}{Ms + D + \frac{1}{R}}$$

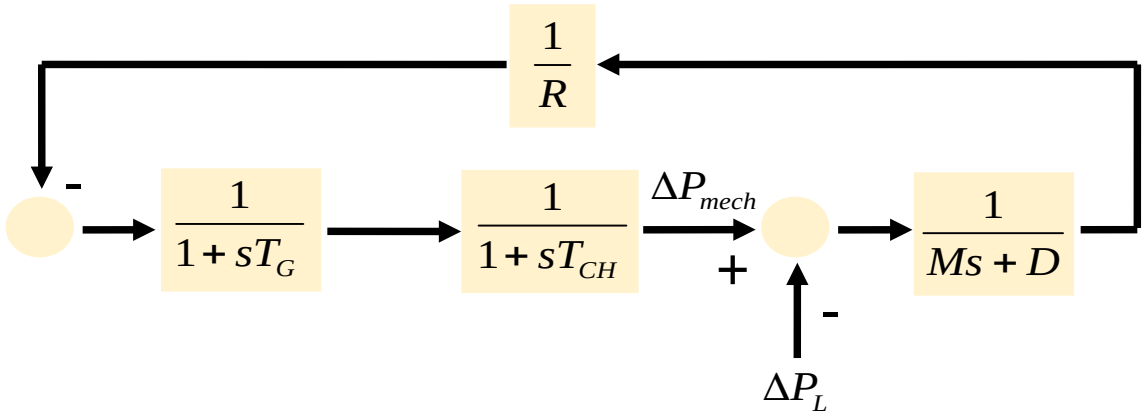
Droop Control with Swing Equation and Other Dynamics

Higher-order transfer functions allow for this type of behavior



Primary Frequency Control
[Generator governor response (or frequency-responsive load control)]

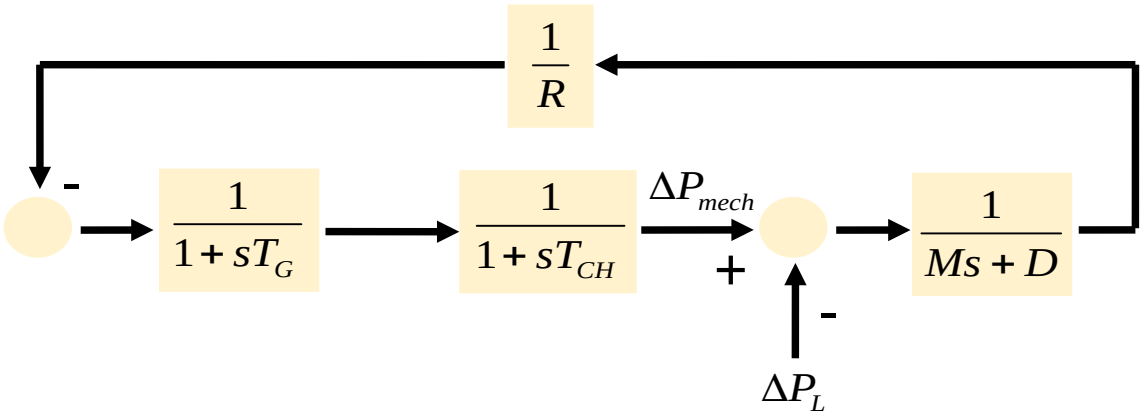
$$\Delta\omega = \frac{-\Delta P_L}{\frac{1}{R} + D}$$



Steady-State frequency response from multiple generators

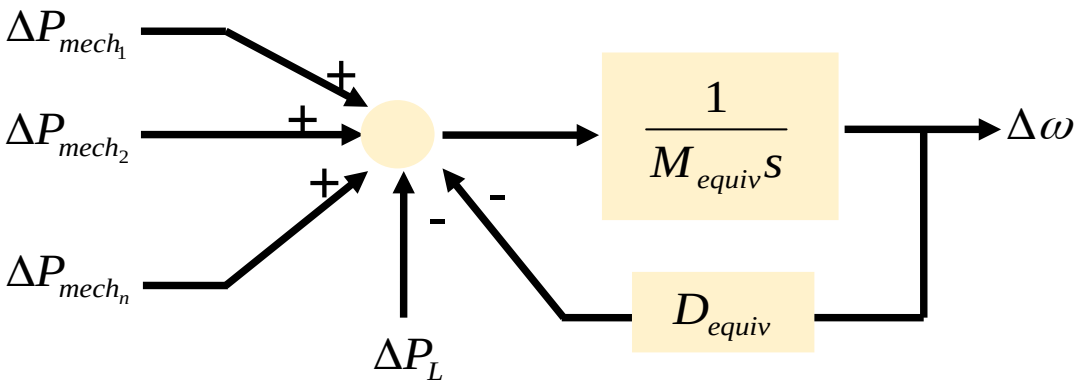
One Generator

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



Multiple Generators

$$\Delta\omega = \frac{-\Delta P_L}{\frac{1}{R_1} + \frac{1}{R_2} + \cdots + \frac{1}{R_n} + D}$$



What if you have **batteries** in the area?

Area Power-Frequency Characteristic

$$\Delta\omega = \frac{-\Delta P_L}{\frac{1}{R_1} + \frac{1}{R_2} + \cdots + \frac{1}{R_n} + D}$$

Area Frequency Response Characteristic

$$\beta = \frac{1}{R_1} + \frac{1}{R_2} + \cdots + \frac{1}{R_n} + D \quad \left[\frac{MW}{Hz}\right] \text{ or } pu$$

- β is also often named "**stiffness**"

The total change in mechanical power output in the area in response to the frequency change is:

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

Assuming *D=0*

$$\Delta P_m = -\beta \Delta f$$

Example #1

A 50 Hz power system has three generators with power rating of 1000 MVA, 750 MVA, and 500 MVA

The generating units have the same value of $R_1=R_2=R_3=0.05$ (per unit)

Units are initially operated at half of their nominal capacities when the system load suddenly increases by 200 MW

- Do I have enough “headroom” in the three plants to meet the load change?
- What is the maximum load change I can accommodate?

Determine

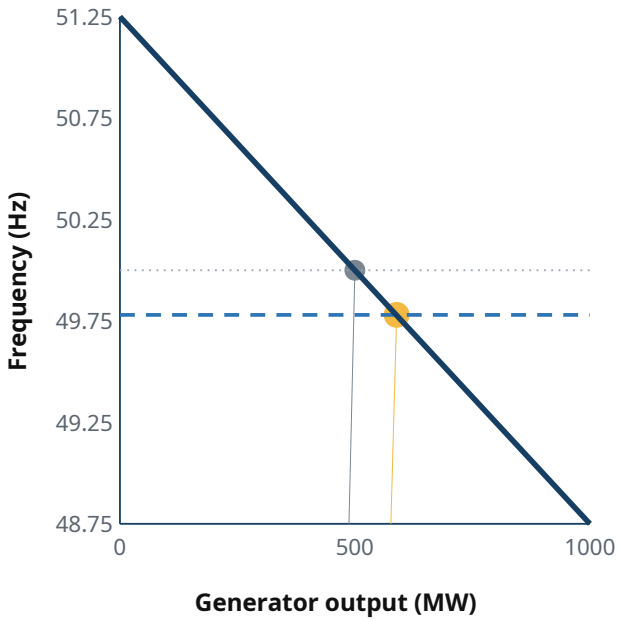
A. The area frequency stiffness in per unit on a 1000 MVA system base
B. Steady-state area frequency variation
C. The change in MW mechanical power of each generating unit

Ignore the load relief effect

Example #1: droop-curve interpretation

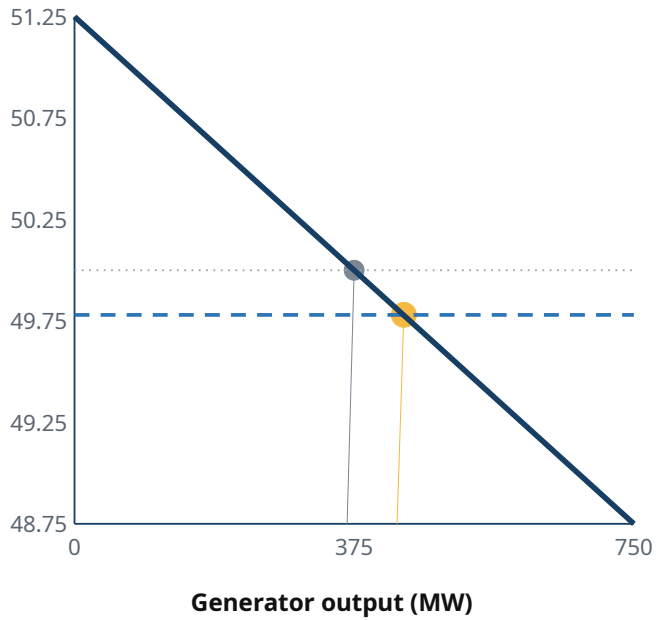
A 200 MW load increase moves all three units to the same steady-state frequency.

Generator 1 (1000 MVA)



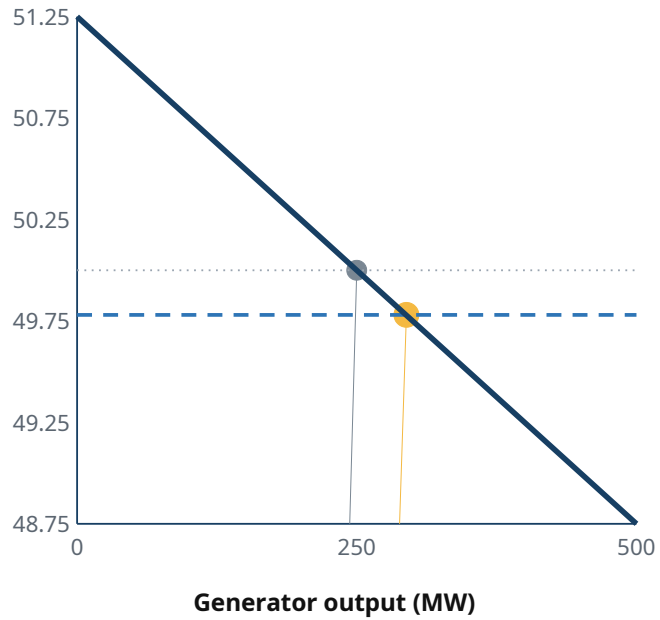
500 MW to 588.9 MW

Generator 2 (750 MVA)



375 MW to 441.7 MW

Generator 3 (500 MVA)



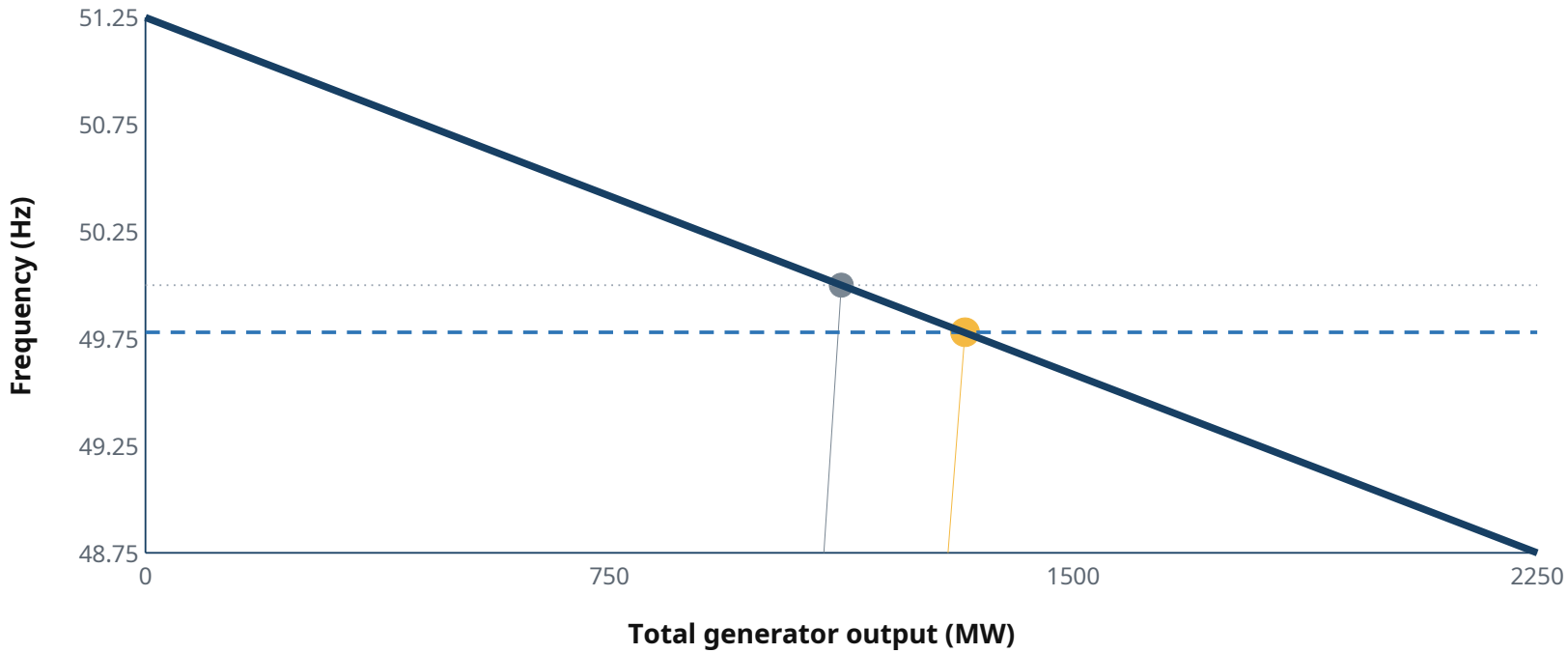
250 MW to 294.4 MW

New common frequency: 49.78 Hz

Additional generation: 88.9 MW, 66.7 MW, and 44.4 MW

Example #1: aggregate droop curve

The individual slopes add: 400 + 300 + 200 = 900 MW/Hz.



Initial point: 1125 MW at 50.00 Hz

New point: 1325 MW at 49.78 Hz

A 200 MW load increase moves the system frequency from 50.00 to 49.78 Hz.

Example #1 Solution
Part A

Tip: We need to make sure that all parameters are in a same base

$$R_{\text{p.u. } new} = R_{\text{p.u. } old} \frac{S_{base\ new}}{S_{base\ old}}$$

Common base from the question: **1000 MVA**

Generation 1 power rating: 1000 MVA → do not worry then ☺!

$$R_{1\,\text{p.u. } new} = R_{1\,\text{p.u. } old} = 0.05\ \text{p.u.}$$

Generation 2 power rating: 750 MW → We need to convert its droop value to the new base!

$$R_{2\,\text{p.u. } new} = 0.05 \cdot \frac{1000}{750} = 0.06667\ \text{p.u.}$$

Generation 3 power rating: 500 MW → We need to convert its droop value to the new base!

$$R_{3\,\text{p.u. } new} = 0.05 \cdot \frac{1000}{500} = 0.1\ \text{p.u.}$$

$$\beta = \frac{1}{R_1} + \frac{1}{R_2} + \frac{1}{R_3} = \frac{1}{0.05} + \frac{1}{0.06667} + \frac{1}{0.10} = 45\ \text{p.u.}$$

Example #1 Solution
Part B & C

Part B

Steady-state area frequency variation can then be calculated as follows:

200 MW load increase ⇨ $\Delta P_L = \frac{200}{1000} = 0.2$ per unit

$$\Delta f = -\frac{\Delta P_L}{\beta} = -\frac{0.2}{45} = -4.444 \times 10^{-3}\ per\ unit \Rightarrow \Delta f = -4.444 \times 10^{-3} \times 50 = -0.222\ Hz$$

Part C

$$\Delta P_m = -\beta \Delta f$$

Remember: 1000 MVA base power

$$\Delta P_{m1} = -\frac{1}{0.05}\cdot(-4.444\times10^{-3}) = 0.08888\ \text{p.u.} = 88.88\ \text{MW}$$

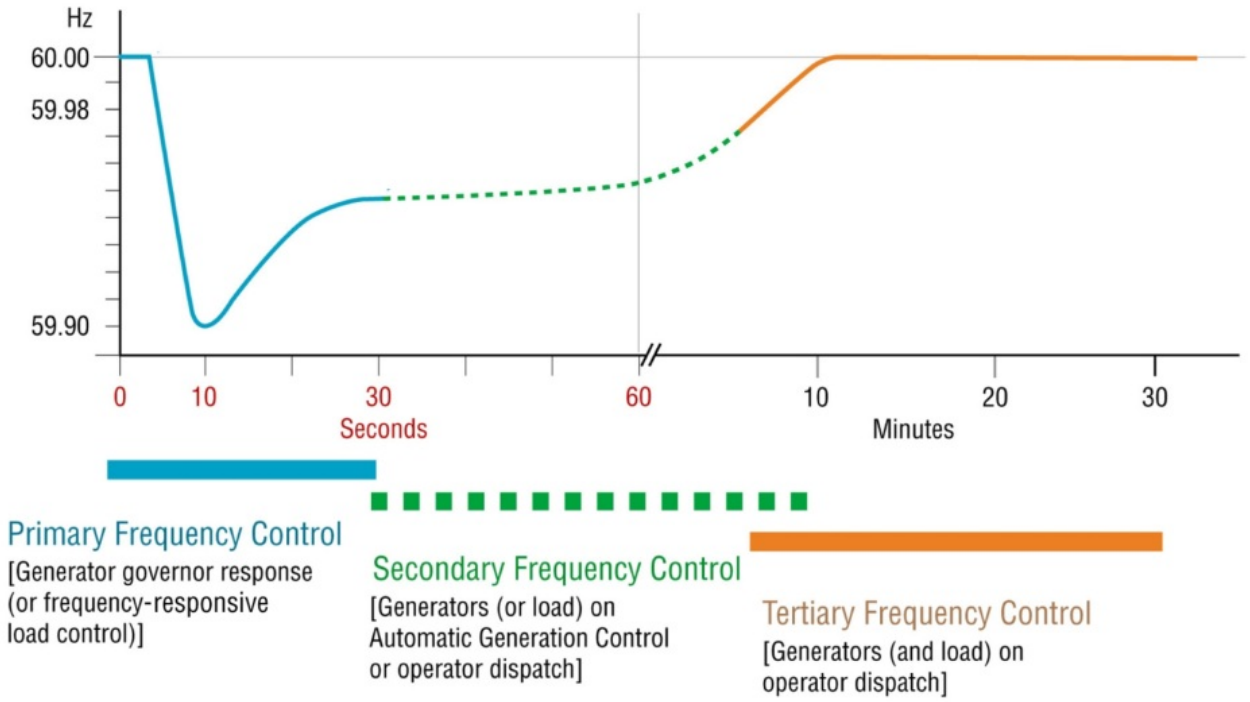
$$\Delta P_{m2} = -\frac{1}{0.06667}\cdot(-4.444\times10^{-3}) = 0.06666\ \text{p.u.} = 66.66\ \text{MW}$$

$$\Delta P_{m2} = -\frac{1}{0.10}\cdot(-4.444\times10^{-3}) = 0.04444\ \text{p.u.} = 44.44\ \text{MW}$$

SECONDARY FREQUENCY CONTROL AND AUTOMATIC GENERATION CONTROL

(SINGLE-AREA SYSTEM)

Frequency control mechanisms



Type of response	**Time scale**	**How is it implemented?**
Primary Control (Droop)	1 to 30 seconds	Locally using governor response. Governor can be implemented using analog or digital design.
Secondary Control (AGC)	30 seconds to a few minutes	For each region, a central control center sends signals to individual generators, adjusting their droop curves.
Tertiary Control (Economic Dispatch)	5 minutes to a day	For each region, a centralized optimization dispatches generators taking operating cost into account.

“Speed changer” is old mechanical-governor terminology. It was the mechanism that adjusted the governor’s reference speed, usually by changing the preload on its spring.



It does not directly change the speed of a grid-connected generator. The grid fixes the steady-state frequency, adjusting it shifts the droop setpoint:

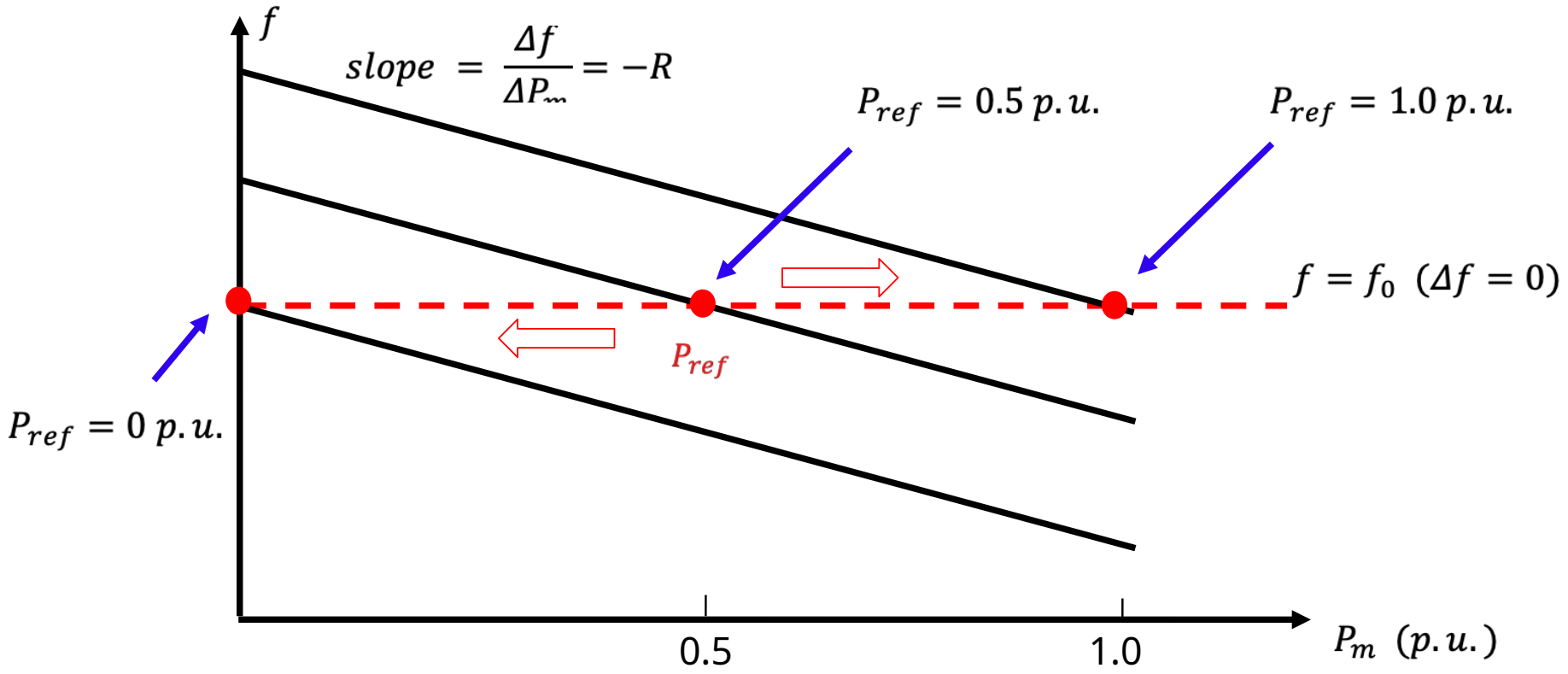
$$\Delta P_m = \Delta P_{\text{ref}} - \frac{1}{R}\Delta f$$

What immediate effect does changing the droop setpoint have on the generator?

Over time what effect will the new droop setpoint have on the frequency/speed of the grid?

"Speed Changer" Settings

$$\Delta P_m = \Delta P_{ref} - \frac{1}{R}\Delta f$$



For each generator, after its primary response has settled:

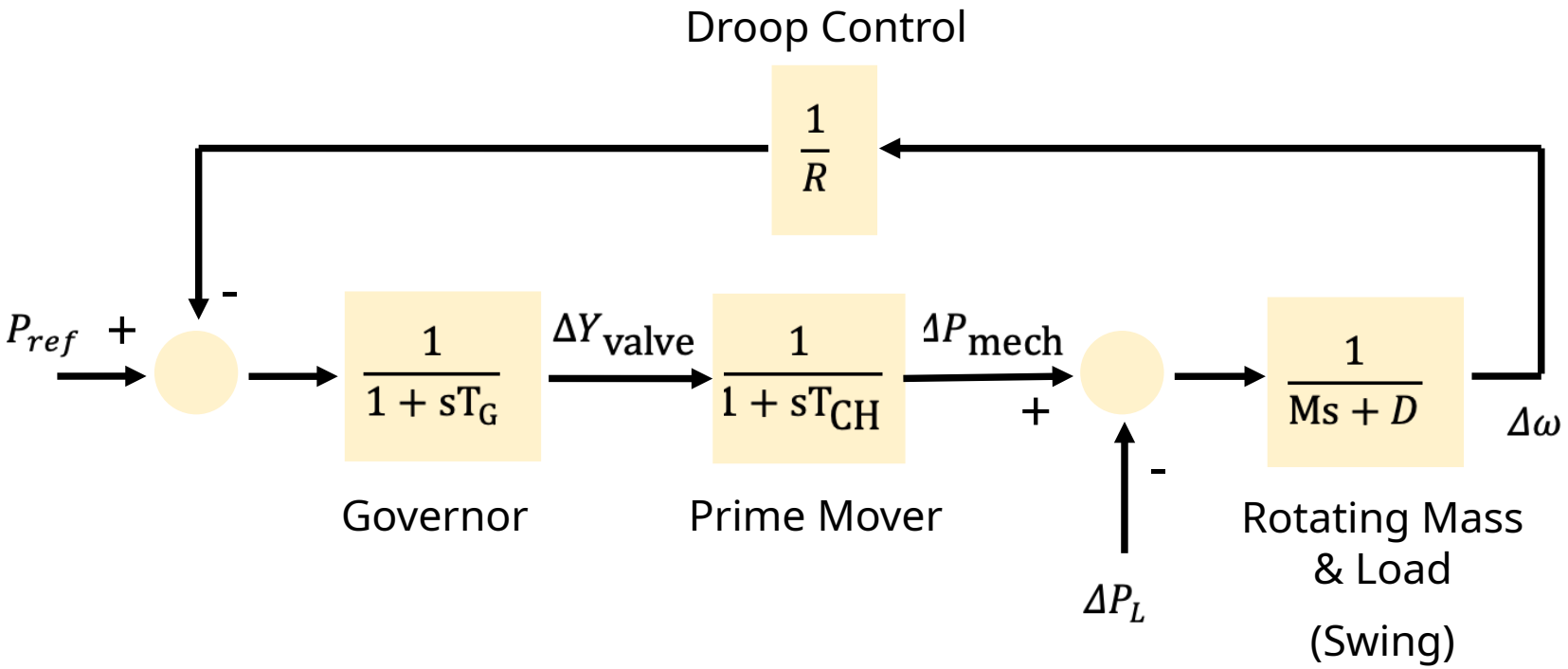
$$\Delta P_{m,g} = \Delta P_{\mathrm{ref},g} - \frac{1}{R_g}\Delta f$$

Adjusting the reference power of a generator adjusts its power output.

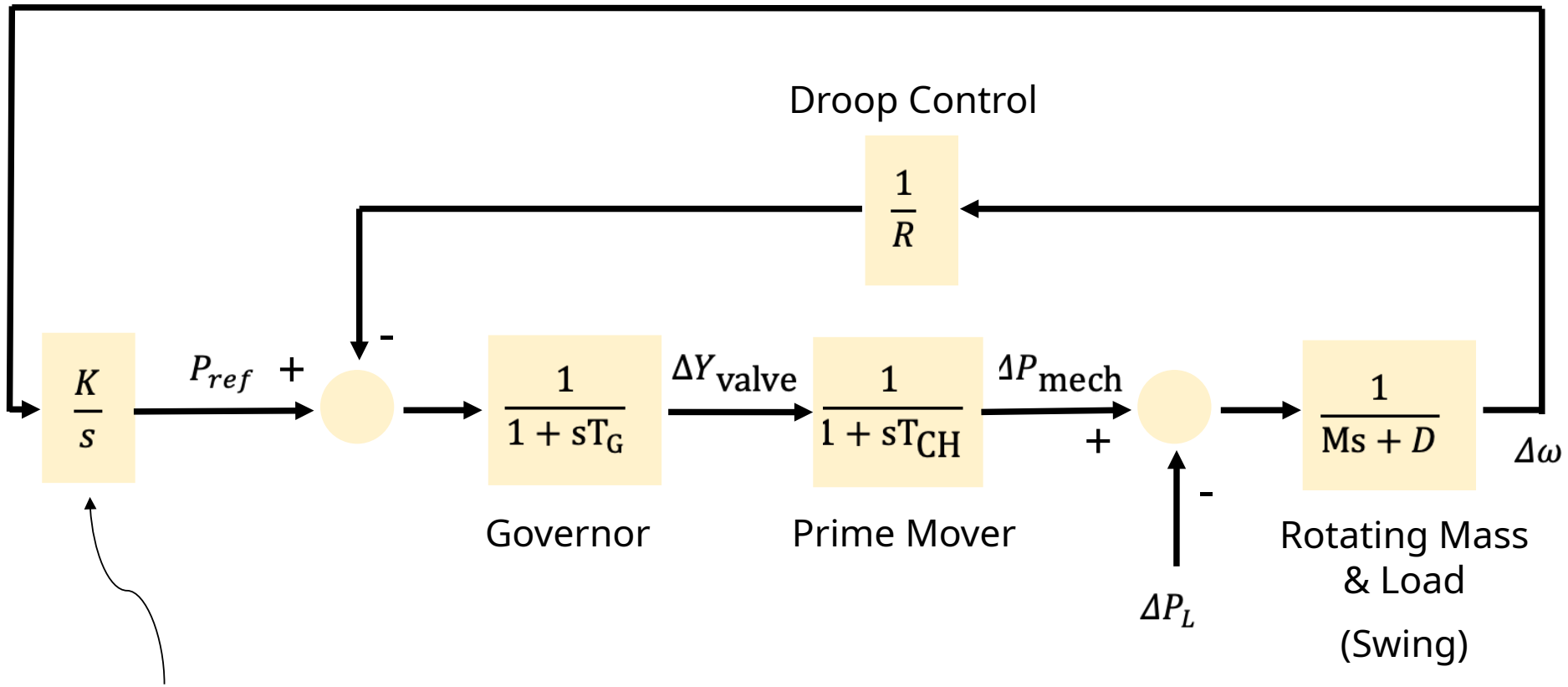
However the reference point adjustment need not wait for the system to settle.

Adjusting the reference point can be seen as the input to a dynamical system which includes the swing equation, load damping, governor dynamics, and prime-mover dynamics.

Single Area Dynamics



Single Area Dynamics



"Supplementary Control"

(frequency-restoring integral control)

Class exercise: Supplementary Control

Without supplementary control:

$$\frac{\Delta\omega(s)}{\Delta P_L(s)} = -\frac{(1+sT_G)(1+sT_{\mathrm{CH}})}{(Ms+D)(1+sT_G)(1+sT_{\mathrm{CH}})+1/R}$$

With supplementary integral control:

$$\frac{\Delta\omega(s)}{\Delta P_L(s)} = -\frac{s(1+sT_G)(1+sT_{\mathrm{CH}})}{s(Ms+D)(1+sT_G)(1+sT_{\mathrm{CH}})+s/R+K}$$

The Final Value Theorem (assuming a stable response) gives the steady-state value $\Delta\omega(\infty)$ for a step increase in load $\Delta P_L(s) = \frac{d}{s}$:

$$\Delta\omega(\infty) = \lim_{s\to 0} s\ \Delta\omega(s) = \lim_{s\to 0} s\left(\frac{\Delta\omega(s)}{\Delta P_L(s)}\right)\frac{d}{s} = d\lim_{s\to 0}\frac{\Delta\omega(s)}{\Delta P_L(s)}$$

What is the steady-state frequency deviation with and without Supplementary Control?

Multiple Areas



What happens if there are multiple areas?

Should each area run its own integral control?

How do you coordinate the integral controllers of each area?

FREQUENCY CONTROL IN INTERCONNECTED (MULTI-AREA) SYSTEM

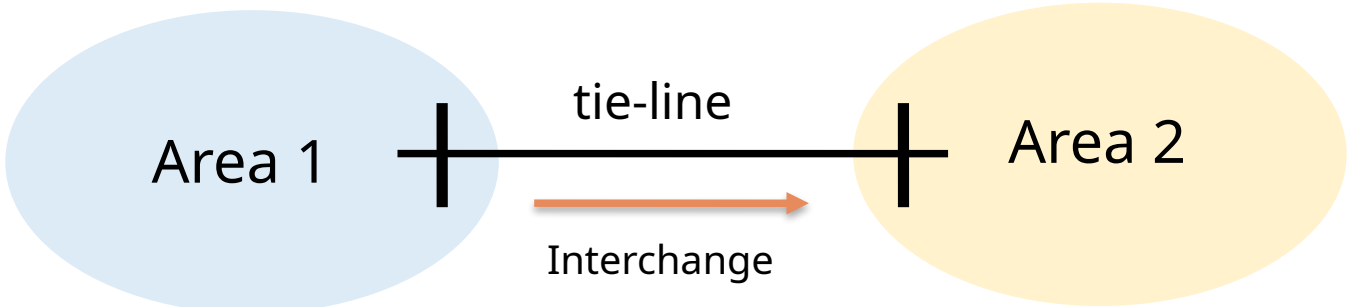
Interconnections and Tie-Lines

Economic interchanges:

- Supply demand in the most economic way
  - Production cost of area 1 is lower → sells to area 2

Emergency interchanges

- Sharing of frequency response and reserves → less redundancy required



Class Exercise



What happens to the steady-state tie line flow when a load d_2 is added to Area 2?

Consider only the primary response, which arrests the frequency drop.

Each area has stiffness $\beta_i = D_i + \frac{1}{R_i}$

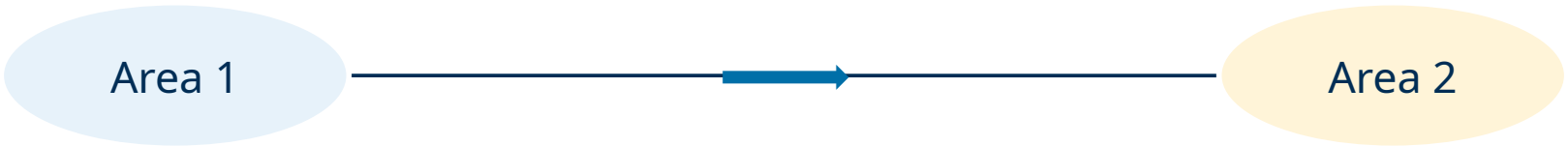
Hint: when connected, grid stiffnesses add such that $\Delta\omega = -\frac{d_2}{\beta_1+\beta_2}$

Class Exercise



What happens to the steady-state tie line flow when a load d_2 is added to Area 2 and both areas run uncoordinated supplementary control to restore frequency?

=



Can we be more rigorous with the analysis of the inter-area dynamics?

→ Block diagrams

Tie-line power depends on angle difference



positive export

$$\Delta P_{\text{tie},1} = \frac{\Delta\theta_1 - \Delta\theta_2}{X_{\text{tie}}}$$

or

$$\frac{d\,\Delta P_{\text{tie},1}}{dt} = \frac{\omega_0}{X_{\text{tie}}}(\Delta\omega_1 - \Delta\omega_2) \qquad \text{(using } \frac{d\,\Delta\theta_i}{dt} = \omega_0\Delta\omega_i\text{)}$$

Equal steady-state frequencies make tie-line power constant

Per-unit frequency

Nominal frequency: $f_0 = 50\,Hz, \quad \omega_0 = 2\pi f_0$

Frequency in per unit: $f_{pu} = \frac{f}{f_0}$ or $\omega_{pu} = \frac{\omega}{\omega_0}$

Per-unit frequency deviation: $\Delta\omega_i = \frac{\omega_i - \omega_0}{\omega_0}$

At nominal frequency, $\Delta\omega_i = 0$

Example: $f_0 = 50\,\text{Hz}, \quad f_i = 50.5\,\text{Hz} \quad \Rightarrow \quad \Delta\omega_i = 0.01\,\text{pu}$

Tie-Line "Stiffness"

$$P_{\text{tie}} = \frac{1}{X_{\text{tie}}}(\theta_1 - \theta_2)$$

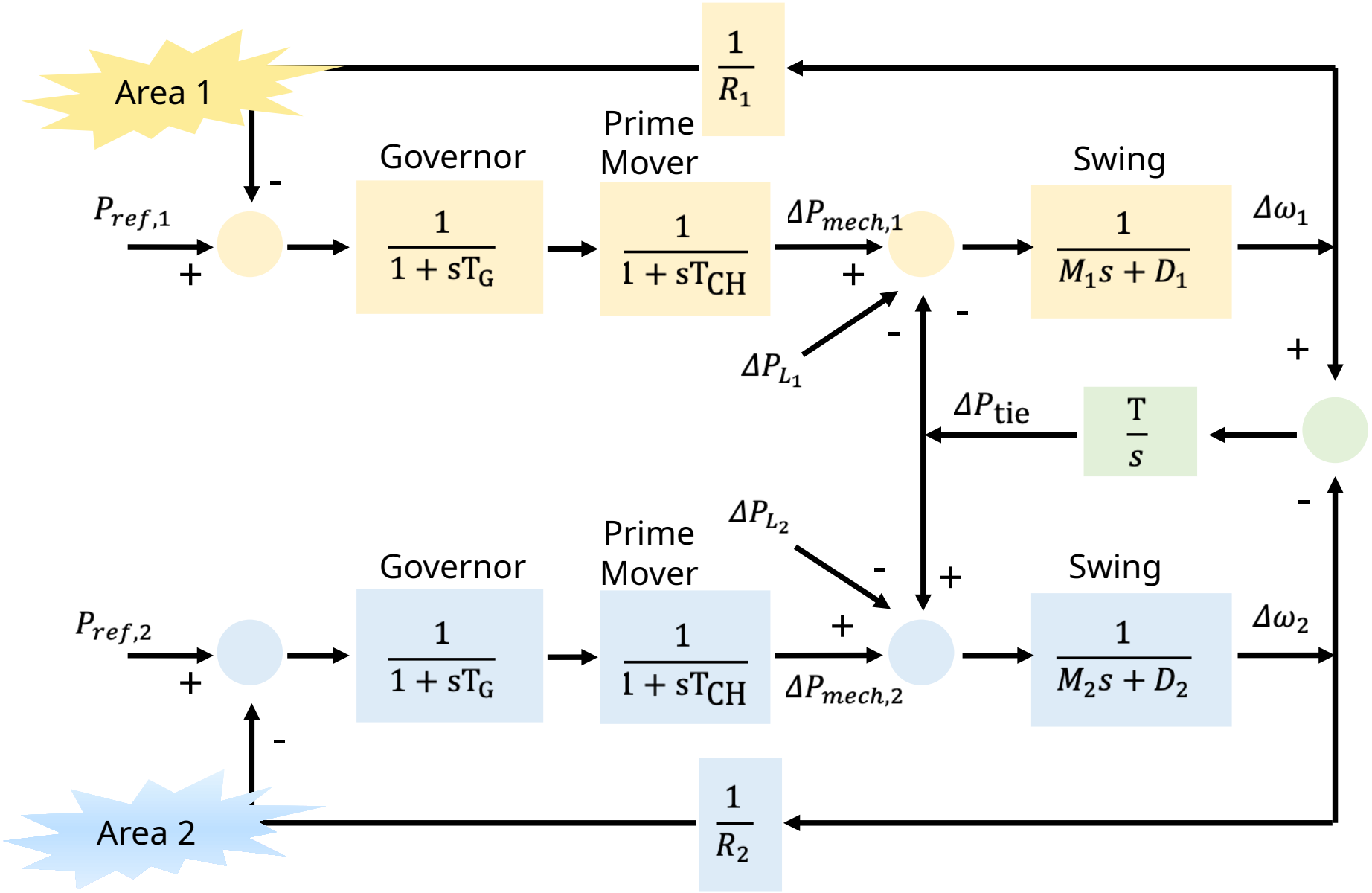
Remembering that $\omega_0 \Delta\omega = \frac{d(\Delta\theta)}{dt}$, the Laplace Transform gives $\frac{\omega_0}{s}\Delta\omega = \Delta\theta$

Base angular velocity, in [rad/s]

$$\Delta P_{\text{tie}} = \frac{T}{s}(\Delta\omega_1 - \Delta\omega_2)$$

$$T = \frac{\omega_0}{X_{tie}} = \frac{2\pi f_0}{X_{tie}}$$

T is also often called as **"stiffness" of the tie line**



A. J. Wood, B. F. Wollenberg,"Power generation, operation and control", 1996.

INTERCONNECTED SYSTEMS:

AUTOMATIC GENERATION CONTROL AND SECONDARY FREQUENCY CONTROL

Net interchange and AGC targets

Net interchange is the total active power exported from an area i

$P_{net,i}$ is positive → export

$P_{net,i}$ is negative → import

For each area i, we are interested in the deviation from the scheduled net interchange:

$$\Delta P_{\text{tie},i} = P_{\text{net},i}^{\text{actual}} - P_{\text{net},i}^{\text{scheduled}}$$

A disturbance and subsequent primary response can result in

- a frequency deviation from the nominal frequency, $\Delta f \neq 0$
- a deviation in the net interchange from the scheduled interchange, $\Delta P_{\text{tie},i} \neq 0$

Area Control Error and Automatic Generation Control

ACE combines the net export error with a frequency term:

$$\mathrm{ACE}_i = \Delta P_{\mathrm{tie},i} + B_i \Delta f$$

B_i: each area's AGC frequency bias (units: MW/Hz)

Automatic Generation Control (AGC) for area i:

$$\frac{d}{dt}\Delta P_{\mathrm{ref},i}(t) = -K_i \mathrm{ACE}_i(t) \qquad \text{or, equivalently,} \qquad \Delta P_{\mathrm{ref},i}(s) = -\frac{K_i}{s}\mathrm{ACE}_i(s)$$

The AGC for each area adjusts the droop setpoints for each area to drive the ACE to 0

For area i, AGC adjusts the $\Delta P_{ref,i}$ of the area, which is then divvied amongst the participating generators in area i :

$$\Delta P_{\mathrm{ref},g} = \alpha_g \Delta P_{ref,i} \qquad \sum_{g \in i} \alpha_g = 1$$

Area power balance after primary response

d_i : net load increase in area i

$\Delta P_{ref,i}$: aggregate AGC reference change for area i

area stiffness: $\beta_i = D_i + \sum_{g \in i} \frac{1}{R_g}$

Area power balance: $\Delta P_{\text{tie},i} = -d_i + \Delta P_{ref,i} - \beta_i \Delta f$

Substituting in the area power balance $\Delta P_{\text{tie},i} = -d_i + \Delta P_{ref,i} - \beta_i \Delta f$ into $\text{ACE}_i = \Delta P_{\text{tie},i} + B_i \Delta f$ gives

$$\text{ACE}_i = -d_i + \Delta P_{ref,i} + (B_i - \beta_i)\Delta f$$

Class exercise

Say $B_i = \beta_i$ and $\Delta P_{ref,i} = 0$.

Does the AGC in area i respond to a disturbance in area i? in area k?

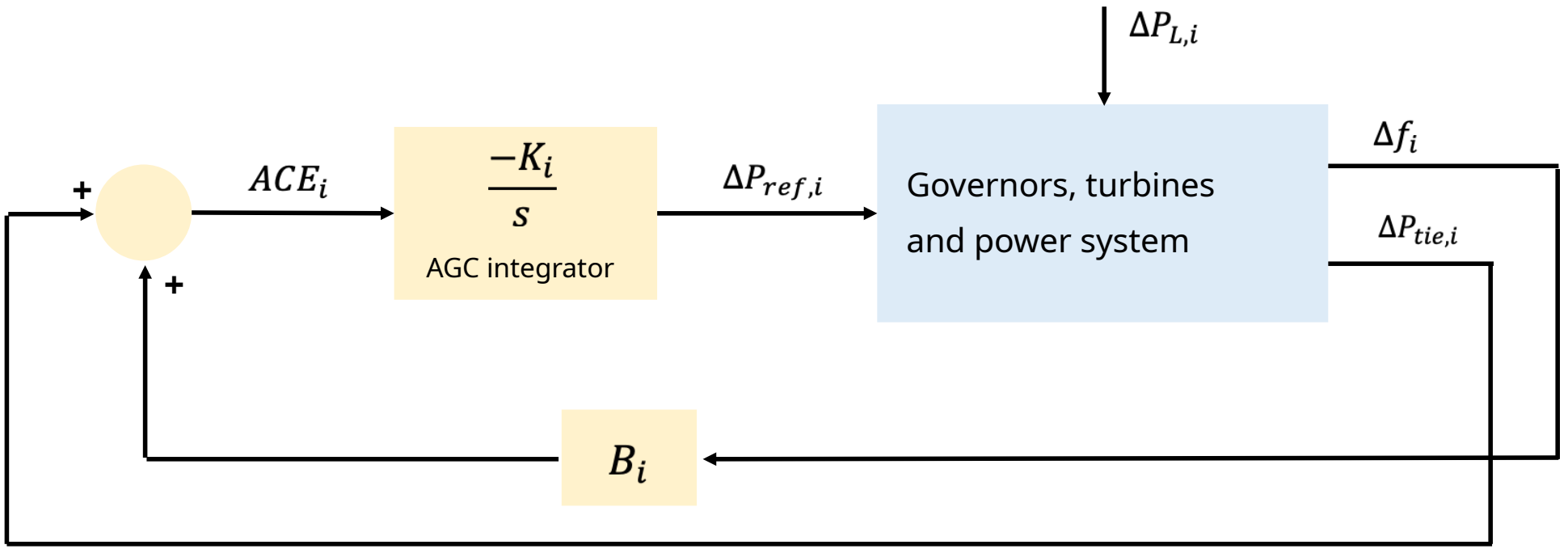
Example: 100 MW load increase in Area 1

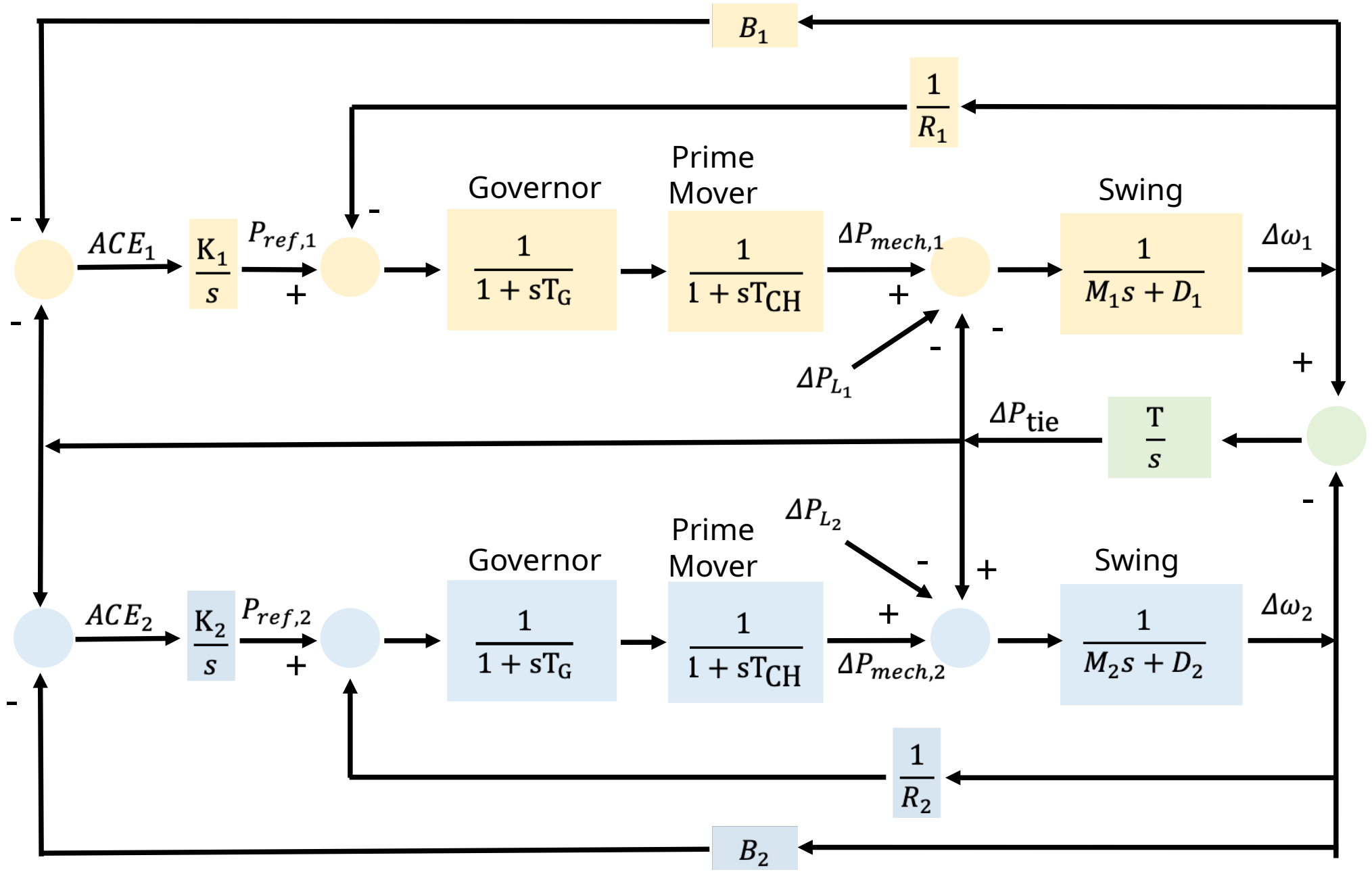
$$\beta_1 = \beta_2 = B_1 = B_2 = 1000 \text{ MW/Hz}$$

$$\Delta f = -\frac{100}{1000 + 1000} = -0.05 \text{ Hz}$$

	Area 1	Area 2
Net export error	−50 MW	+50 MW
Frequency-bias term	−50 MW	−50 MW
ACE	−100 MW	0 MW

AGC feedback loop for Area i




B_1
$\frac{1}{R_1}$
Governor
Prime Mover
Swing
ACE_1
$\frac{K_1}{s}$
$P_{ref,1}$
$\frac{1}{1+sT_G}$
$\frac{1}{1+sT_{CH}}$
$\Delta P_{mech,1}$
$\frac{1}{M_1 s + D_1}$
$\Delta\omega_1$
ΔP_{L_1}
ΔP_{tie}
$\frac{T}{s}$
ΔP_{L_2}
ACE_2
$\frac{K_2}{s}$
$P_{ref,2}$
$\frac{1}{1+sT_G}$
$\frac{1}{1+sT_{CH}}$
$\Delta P_{mech,2}$
$\frac{1}{M_2 s + D_2}$
$\Delta\omega_2$
$\frac{1}{R_2}$
B_2

Class exercise: two-area AGC

Assume a common slow frequency ($\Delta\omega 1 \approx \Delta\omega 2 \approx \Delta\omega$), unity governor/turbine gains, and equal AGC gains K.

Without AGC: $\frac{\Delta\omega(s)}{\Delta P_{L,1}(s)} \approx -\frac{1}{(M_1+M_2)s+\beta_1+\beta_2}$

With AGC in both areas: $\frac{\Delta\omega(s)}{\Delta P_{L,1}(s)} \approx -\frac{s}{(M_1+M_2)s^2+(\beta_1+\beta_2)s+K(B_1+B_2)}$

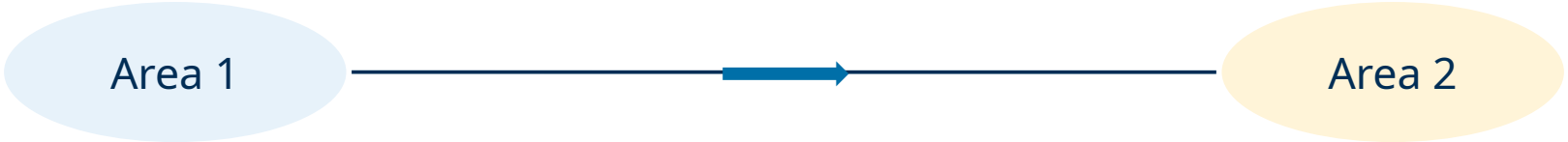
For a step increase in area 1: $\Delta P_{L,1}(s) = \frac{d}{s}$

Final value theorem (assume a stable response):

$$\Delta\omega(\infty) = \lim_{s\to 0} s\Delta\omega(s) = \lim_{s\to 0} s\left(\frac{\Delta\omega(s)}{\Delta P_{L,1}(s)}\right)\frac{d}{s} = d\lim_{s\to 0}\frac{\Delta\omega(s)}{\Delta P_{L,1}(s)}$$

Class Exercise: What is the steady-state frequency deviation with and without AGC?

Class exercise: frequency and interchange



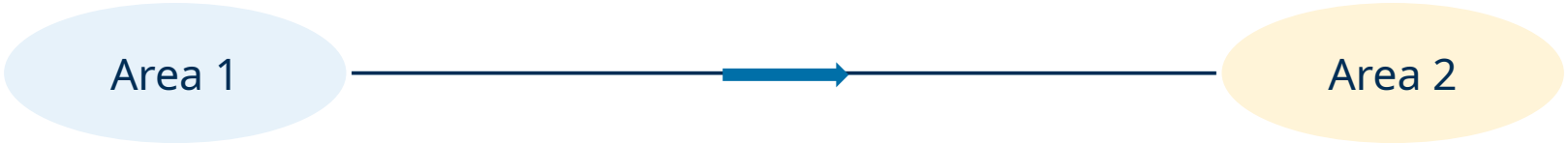
Two areas share a frequency error. Their net interchange errors are equal and opposite:

$$\Delta P_{\text{tie},1} = -\Delta P_{\text{tie},2}$$

$$\text{ACE}_i = \Delta P_{\text{tie},i} + B_i \Delta f, \qquad \frac{d\Delta P_{ref,i}}{dt} = -K_i \text{ACE}_i$$

Class exercise: What is necessary for the system to be at steady state?

Class exercise: frequency and interchange



Two areas share a frequency error. Their net interchange errors are equal and opposite:

$$\Delta P_{\text{tie},1} = -\Delta P_{\text{tie},2}$$

$$\text{ACE}_i = \Delta P_{\text{tie},i} + B_i \Delta f, \qquad \frac{d\Delta P_{ref,i}}{dt} = -K_i \text{ACE}_i$$

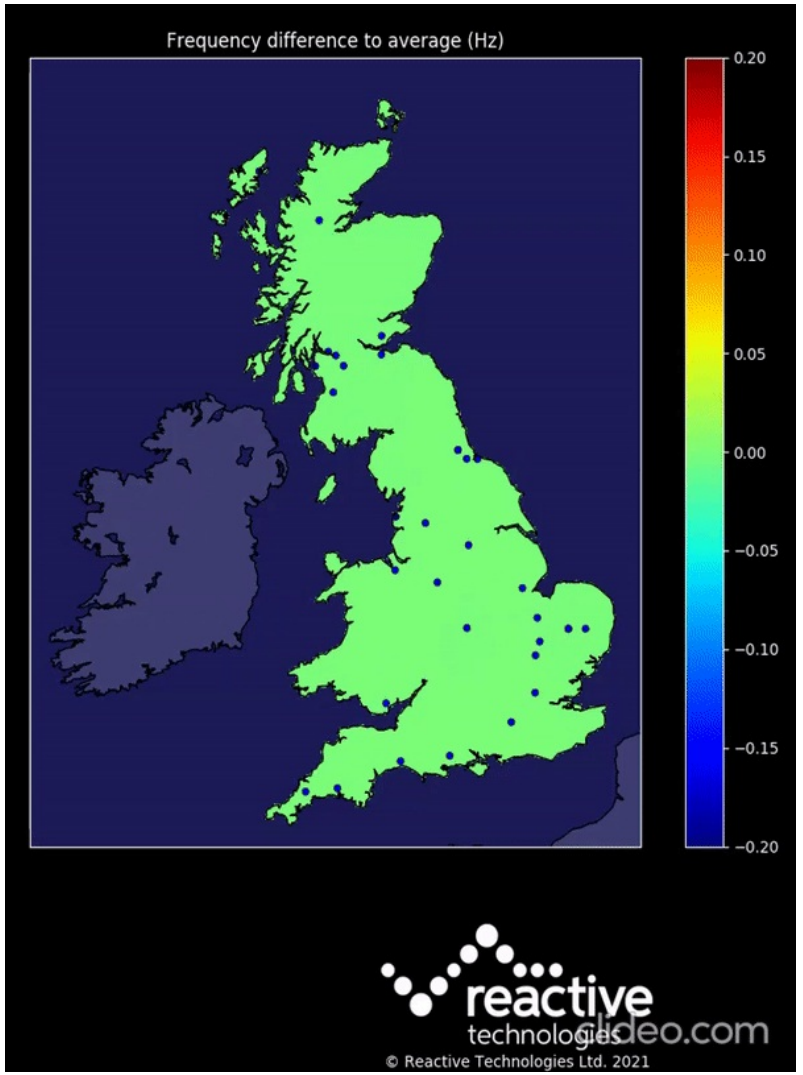
From the AGC control equation $\frac{d\Delta P_{ref,i}}{dt} = -K_i \text{ACE}_i$, the system is at steady state when $\text{ACE}_1 = \text{ACE}_2 = 0$

Summing the ACEs, $0 = \text{ACE}_1 + \text{ACE}_2 = (B_1 + B_2)\Delta f$, thus $\Delta f = 0$

Substituting $\Delta f = 0$ into $\text{ACE}_i = \Delta P_{\text{tie},i} + B_i \Delta f$, we find that $\Delta P_{\text{tie},i} = 0$ as well

Thus, for the AGC system to be at steady state, both the tie line and freq. deviations must be zero

Real-world example: frequency in Great Britain



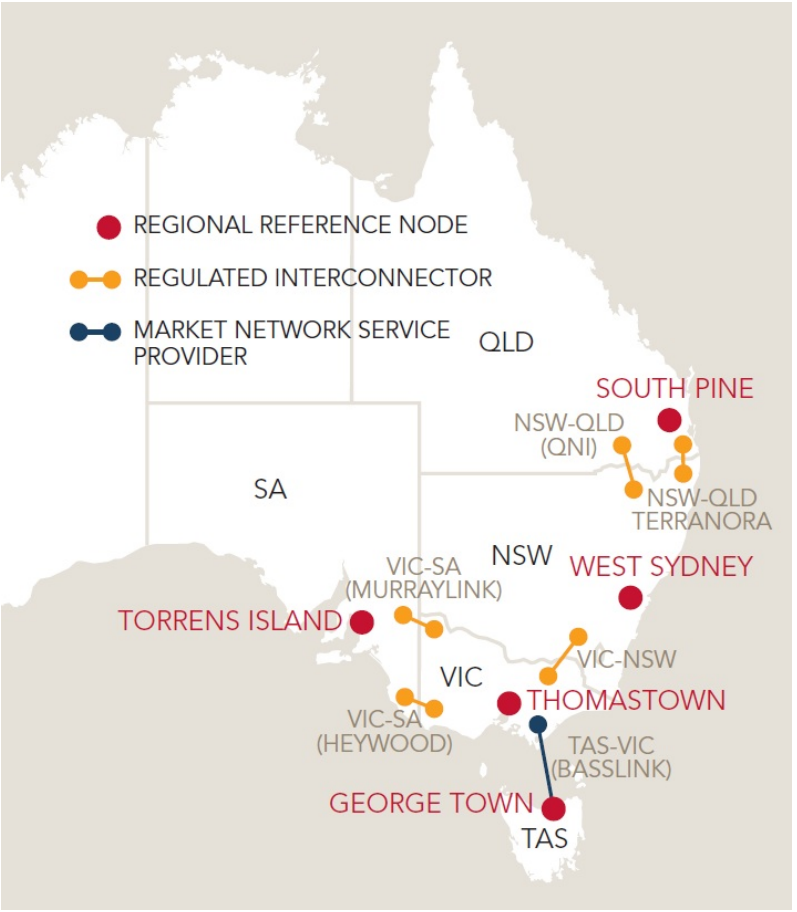
What does Australia do?

The NEM (Eastern Australian Grid) is treated as one area

Thus, Australia does not use AGC to restore tie line flows, just frequency

AEMO's five-minute, security-constrained dispatch manages interconnector flows

So, tie-line-bias AGC is important to understand, but it is not the only way to effectively manage a grid



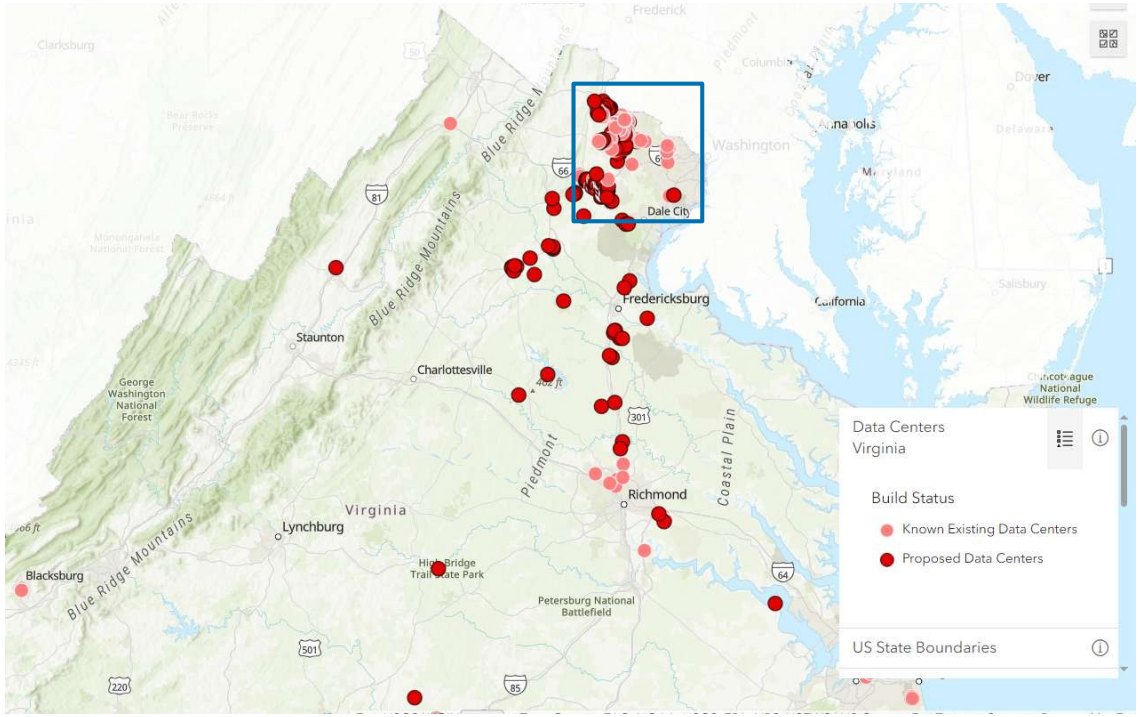
https://www.aemc.gov.au/energy-system/electricity/electricity-market/how-power-dispatched-across-system

Frequency Control

ELEN90060 Power System Analysis

Keith Moffat

22 July 2026: A $230\,kV$ line fault triggered $3.8\,GW$ of data center load to disconnect from the grid.





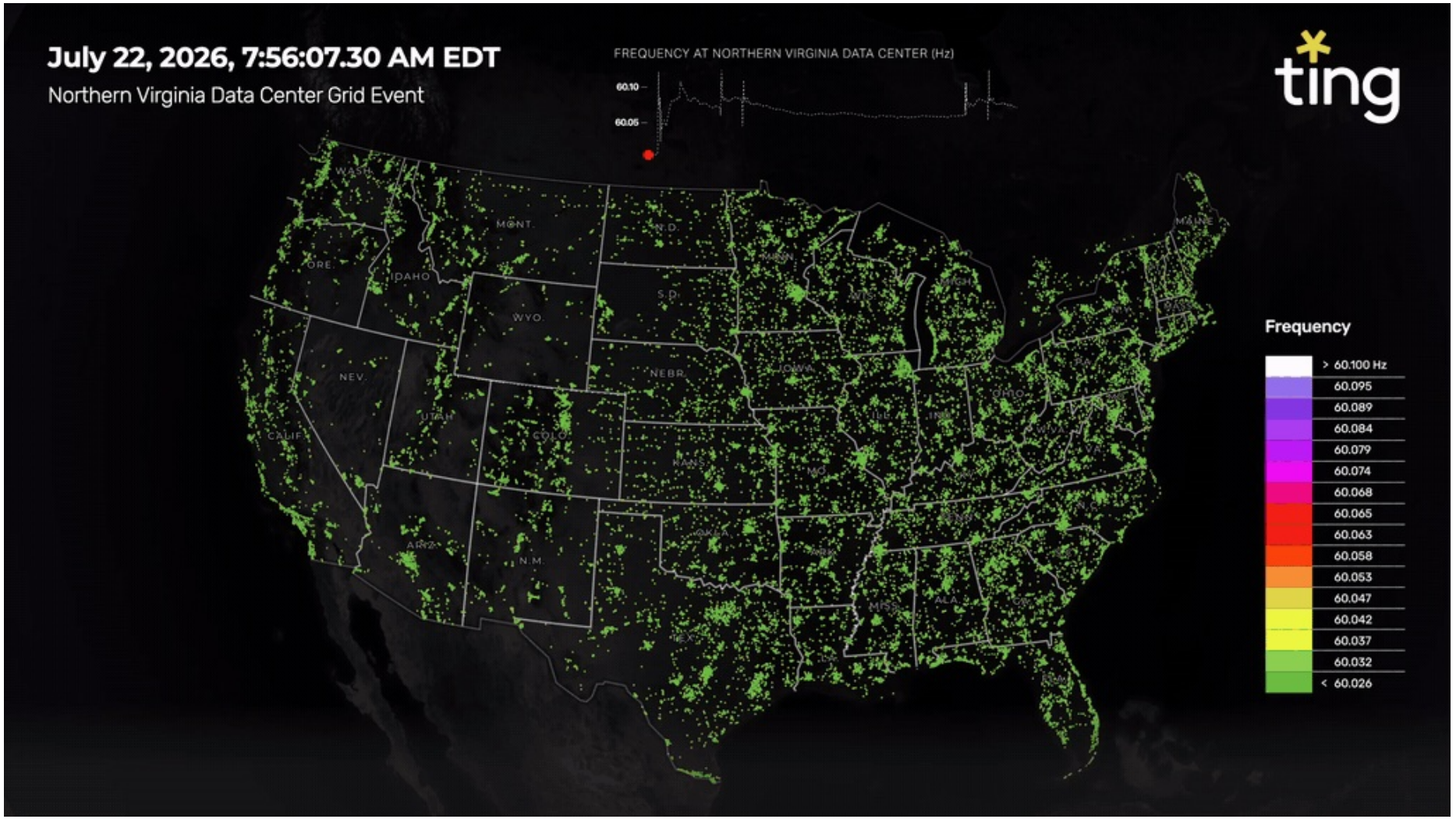
(Victoria's electricity demand typically ranges between 4.5 and $6.5\,GW$)

Why have you not heard of this event?

(The grid operators did a great job and Virginia is in the middle of a very large grid)

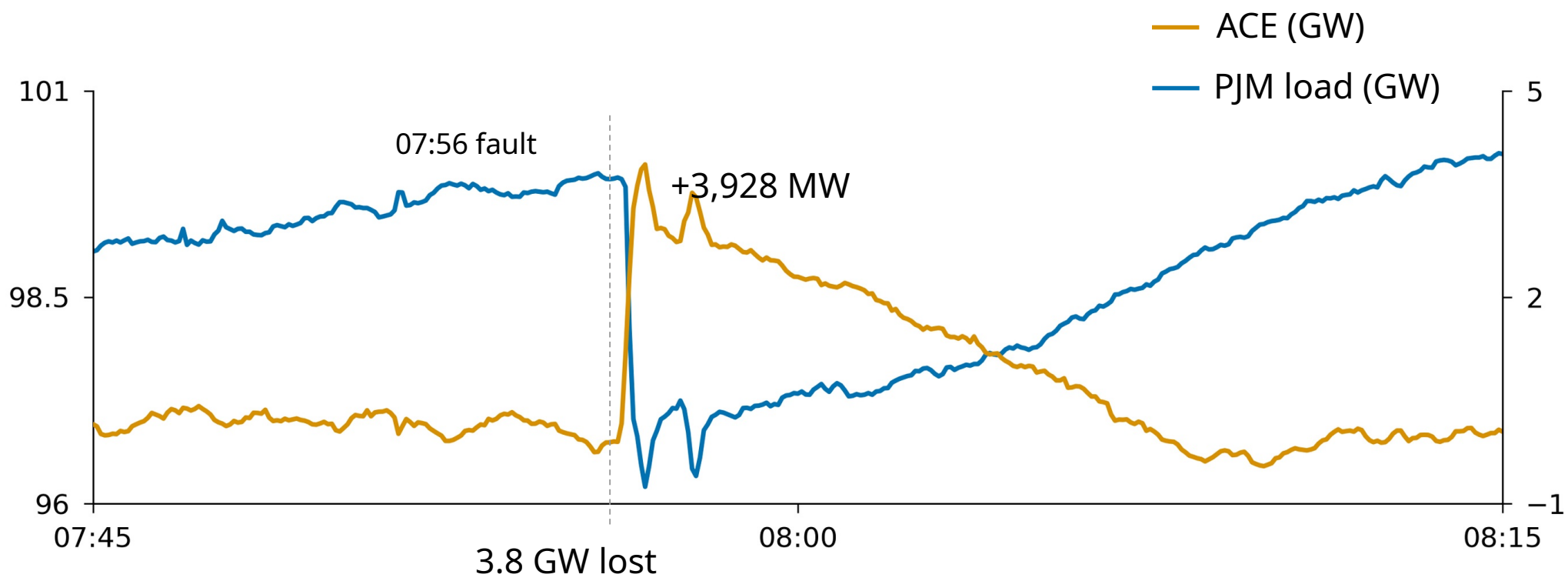
https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2026/20260806/20260806-item-05---dominion-july-loss-of-load-event---presentation.pdf

https://www.dpr.com/projects/digital-realty-ground-up-data-center-building-m1



https://www.tingfire.com/blog/what-happened-when-3-gigawatt-of-data-center-demand-disappeared-from-the-grid/

How did PJM rebalance after the load loss?



Positive ACE indicates over-frequency and excess exports. Frequency peaked at 60.092 Hz.

PJM reduced generation in response to the ACE, and ACE returned near zero in 10 minutes.

https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2026/20260806/20260806-item-05---dominion-july-loss-of-load-event---presentation.pdf