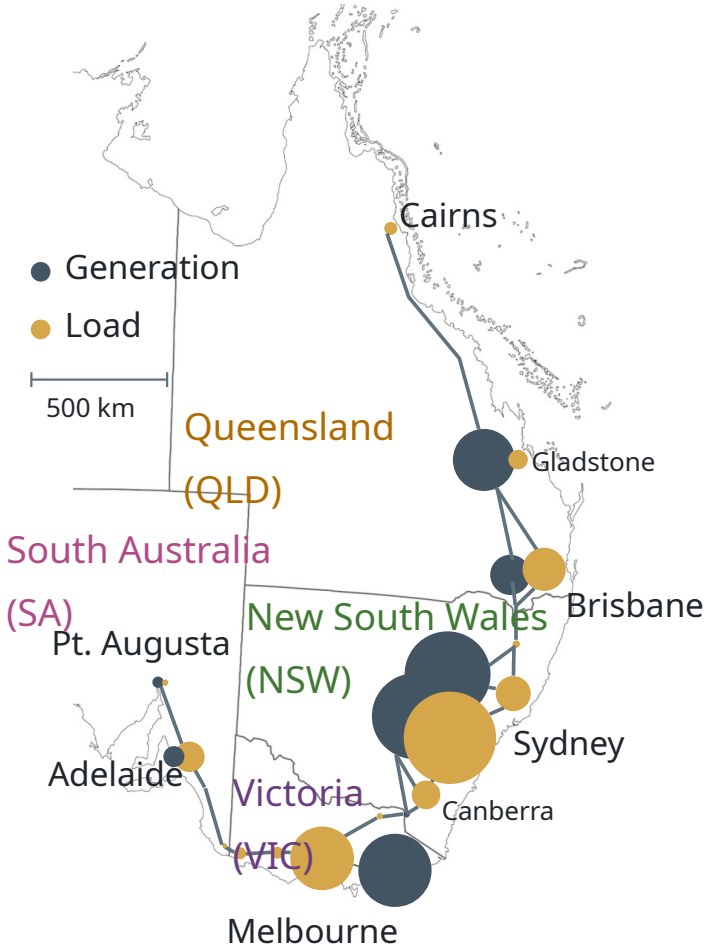
Small Signal Stability

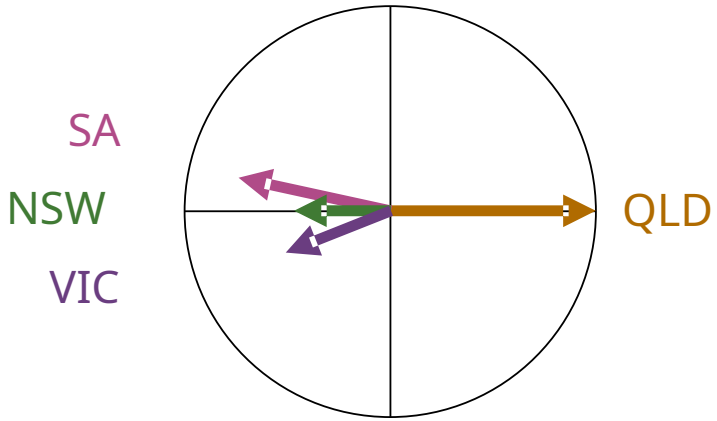
ELEN90060 Power System Analysis

Keith Moffat

Eastern Australia: the I20 inter-area mode



I20, approximately $0.3\ Hz$

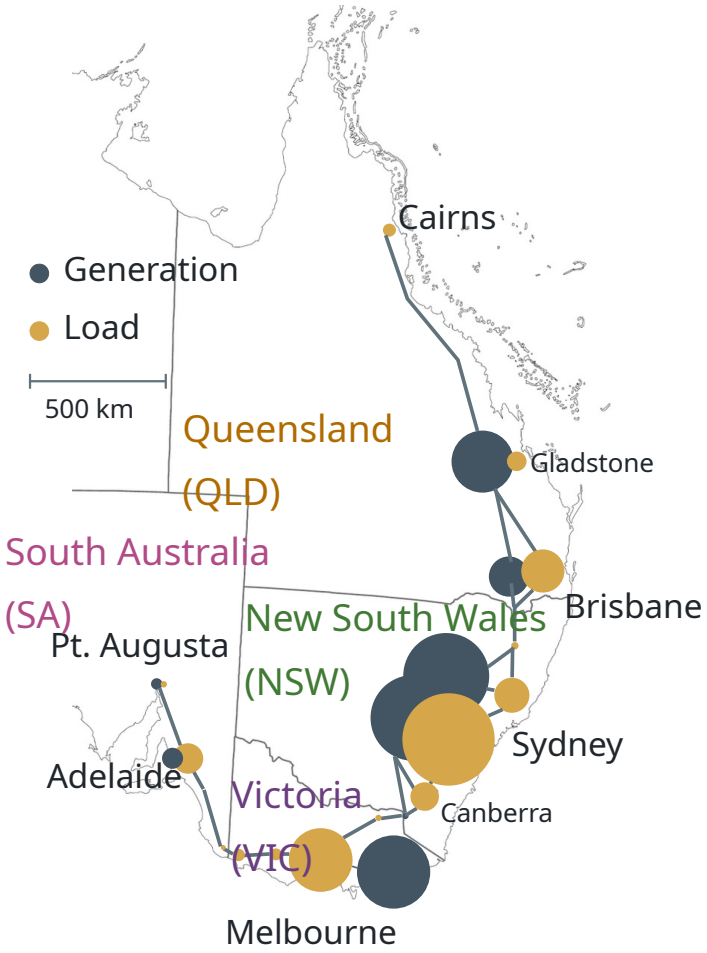


QLD swings against the southern regions.

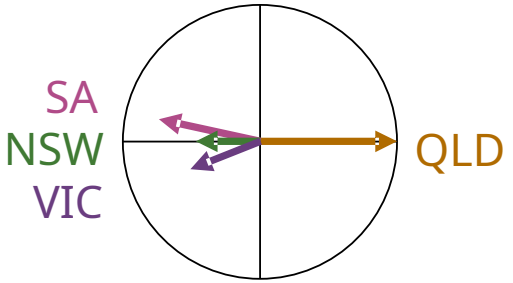
The $0.3\ Hz$ oscillation is an interarea oscillation mode of the Eastern Australian grid.

Adapted from D. Karlsson, Gothia Power, NASPI, 2010, slide 27

The Eastern Australian grid has other oscillatory modes

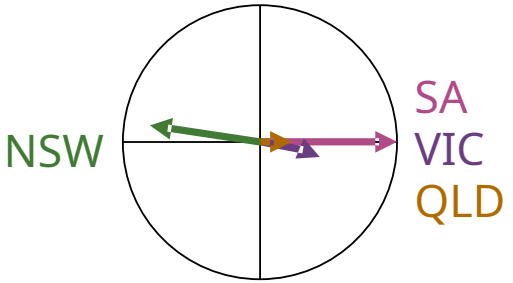


Adapted from D. Karlsson, Gothia Power, NASPI, 2010, slide 27



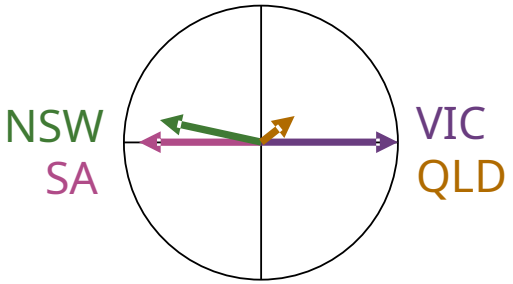
I20

$0.32\ Hz$



I25

$0.40\ Hz$



I35

$0.56\ Hz$

Bayswater coal-fired plant, 25 August 2018



Hunter Valley, New South Wales

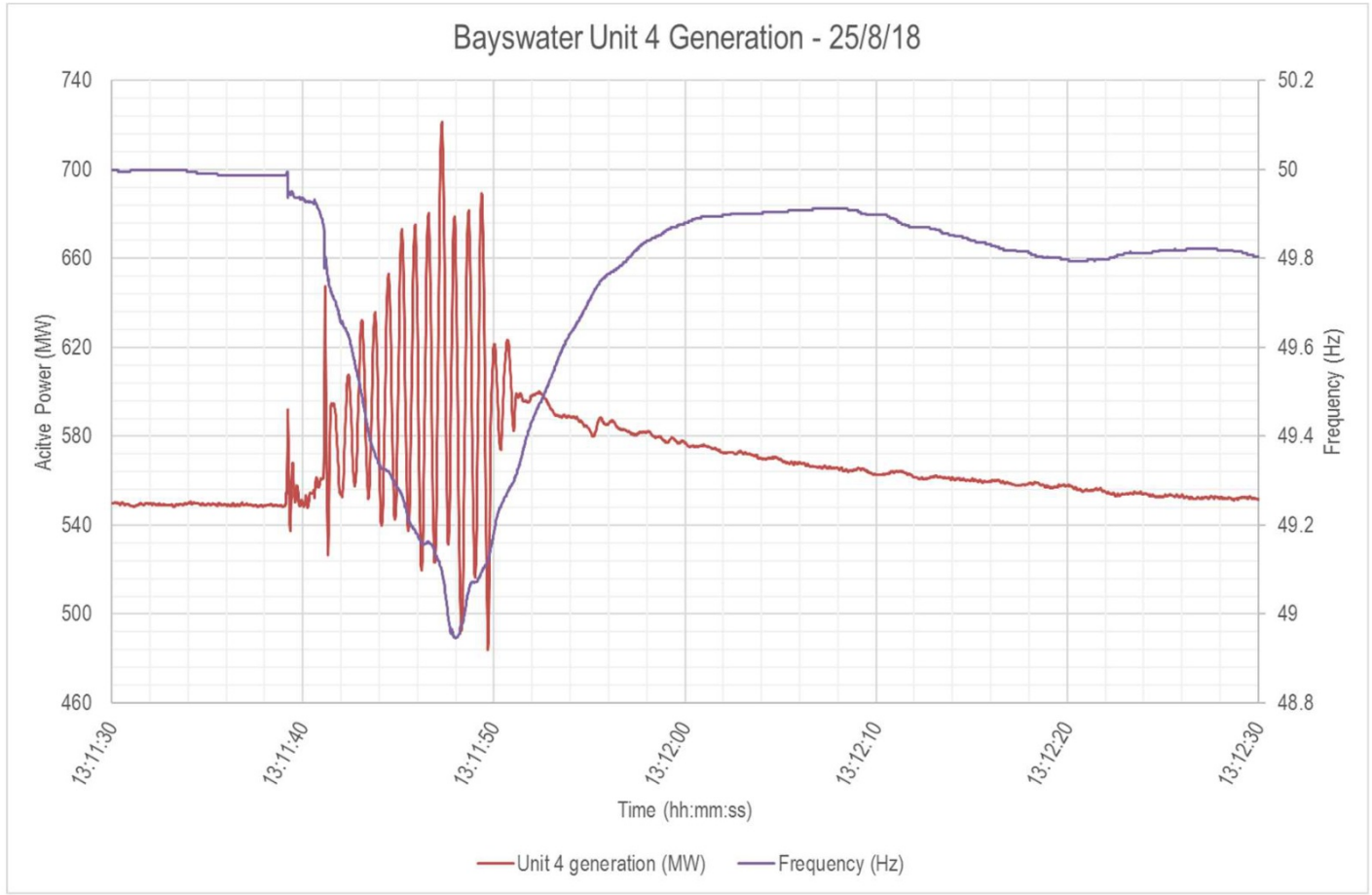


A Queensland–NSW interconnector trip caused a frequency dip in NSW.

Bayswater then developed large power oscillations at $1.2\ Hz$, which is not an interarea mode.

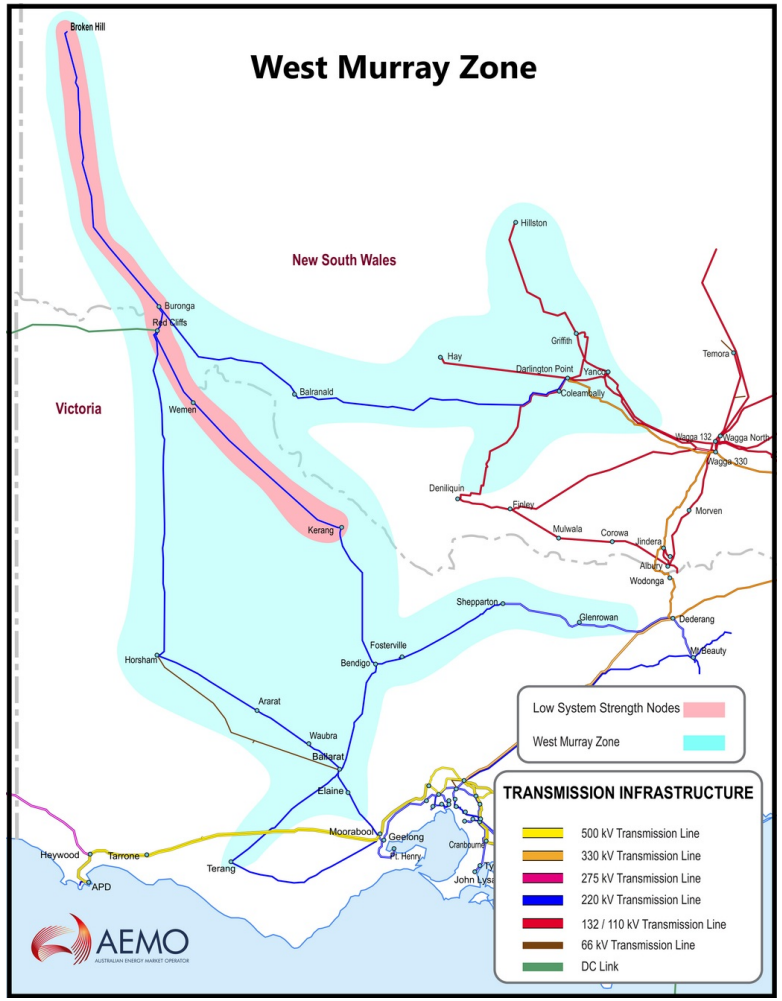
https://server.arcgisonline.com/ArcGIS/rest/services/World_Topo_Map/MapServer
https://www.agl.com.au/content/dam/digital/agl/images/about-agl/operations/about-agl-operations-hunter-bayswater-power-station.jpg

Investigation found a damaged PSS lead–lag potentiometer and "drifted" V/Hz limiter settings.



https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2018/qld---sa-separation-25-august-2018-incident-report.pdf

(But did the oscillations just arise in that gernator? Not the whole NSW?)



North-west Victoria and south-west NSW.

Many solar farms, far from major synchronous generators.



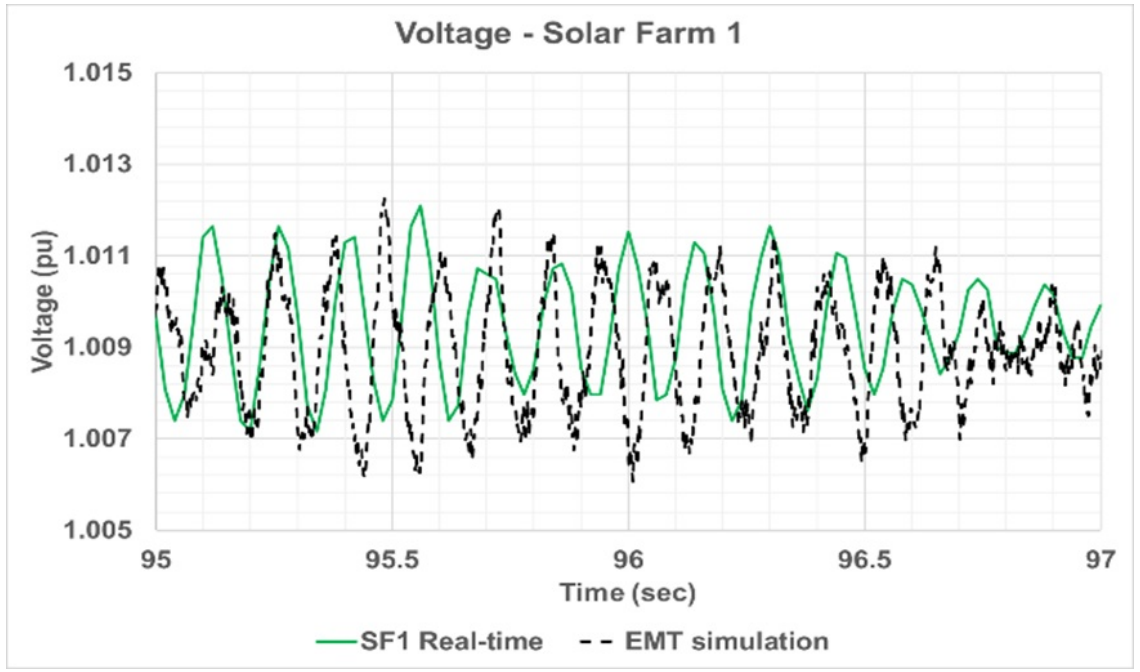
Gannawarra solar farm and battery, near Kerang

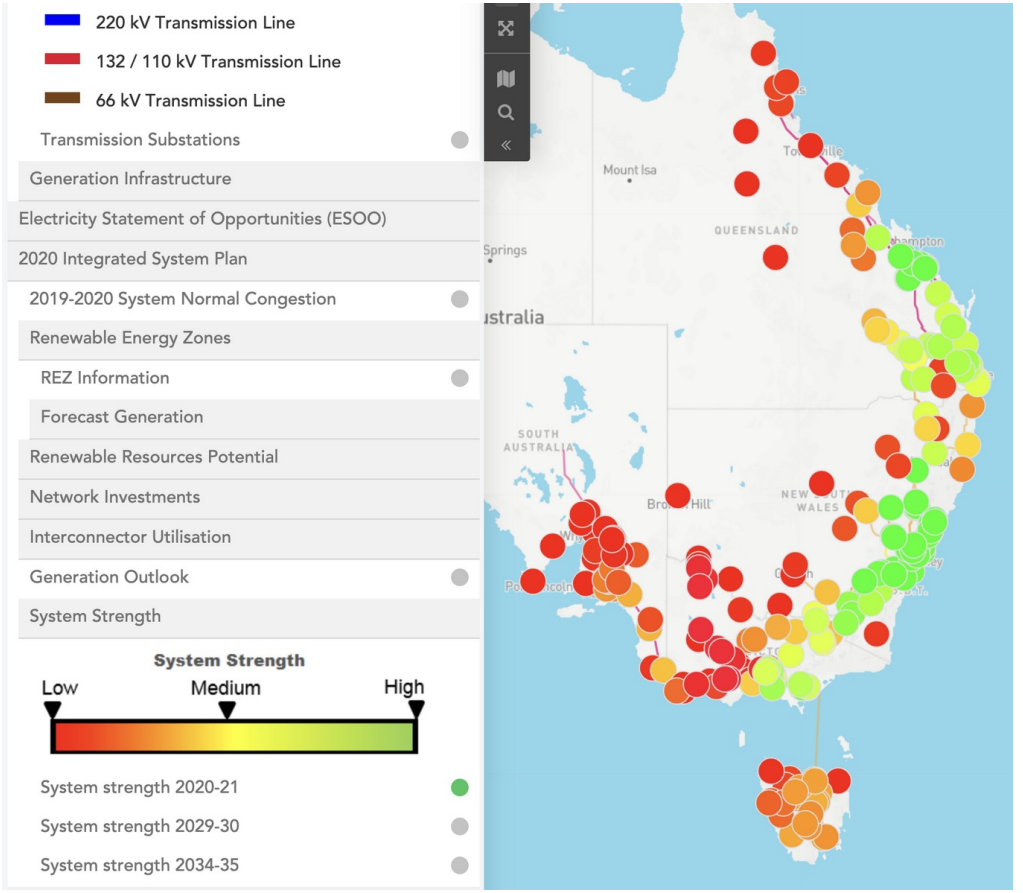
https://edifyenergy.com/project/gannawarra-solarfarm/

https://www.aemo.com.au/-/media/files/electricity/nem/network_connections/west-murray/wmz-nsw_map.pdf

September 2019: Five solar farms were limited to 50% output due to 7 Hz voltage oscillations.

April 2020: AEMO lifted the constraints after testing retuned inverter controls.



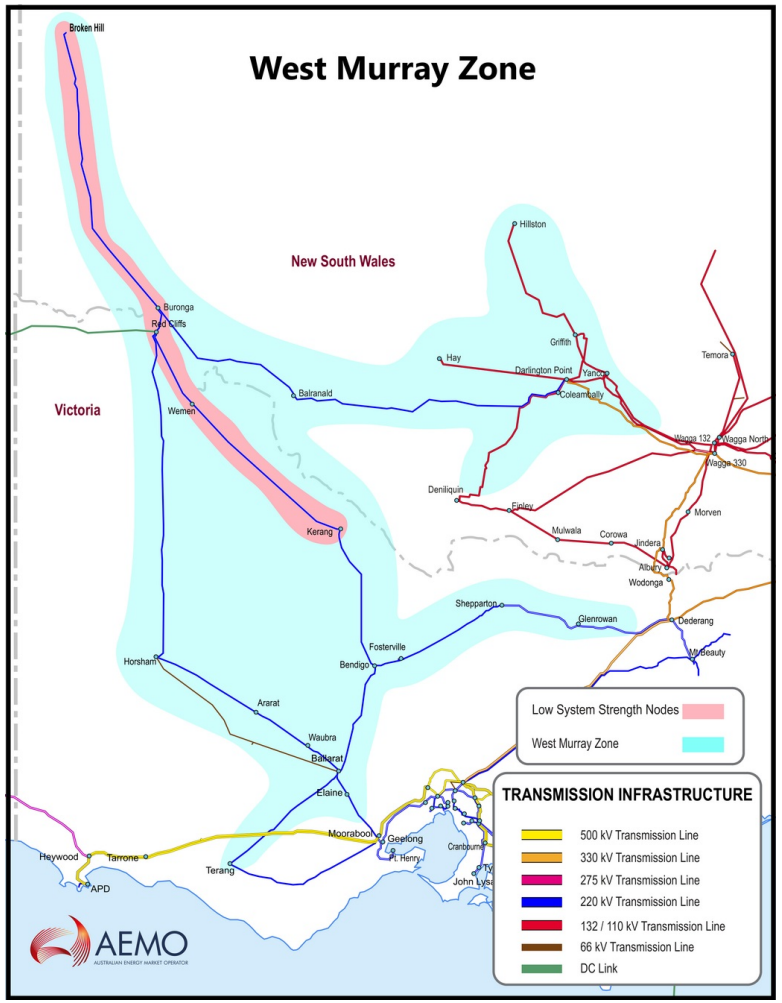


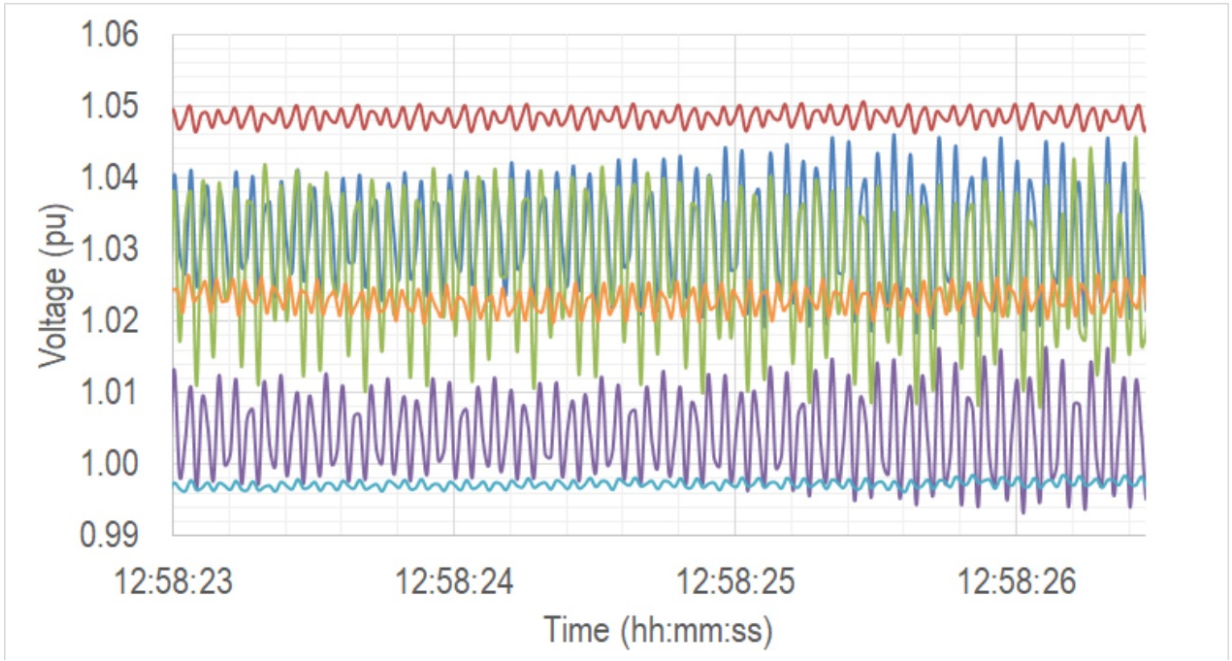
This is a “weak” region of the Australian grid

https://www.osti.gov/servlets/purl/1862948

https://www.aemo.com.au/aemo/apps/visualisations/map.html

Separate event in 2020: $17\ Hz$ oscillations at several buses.

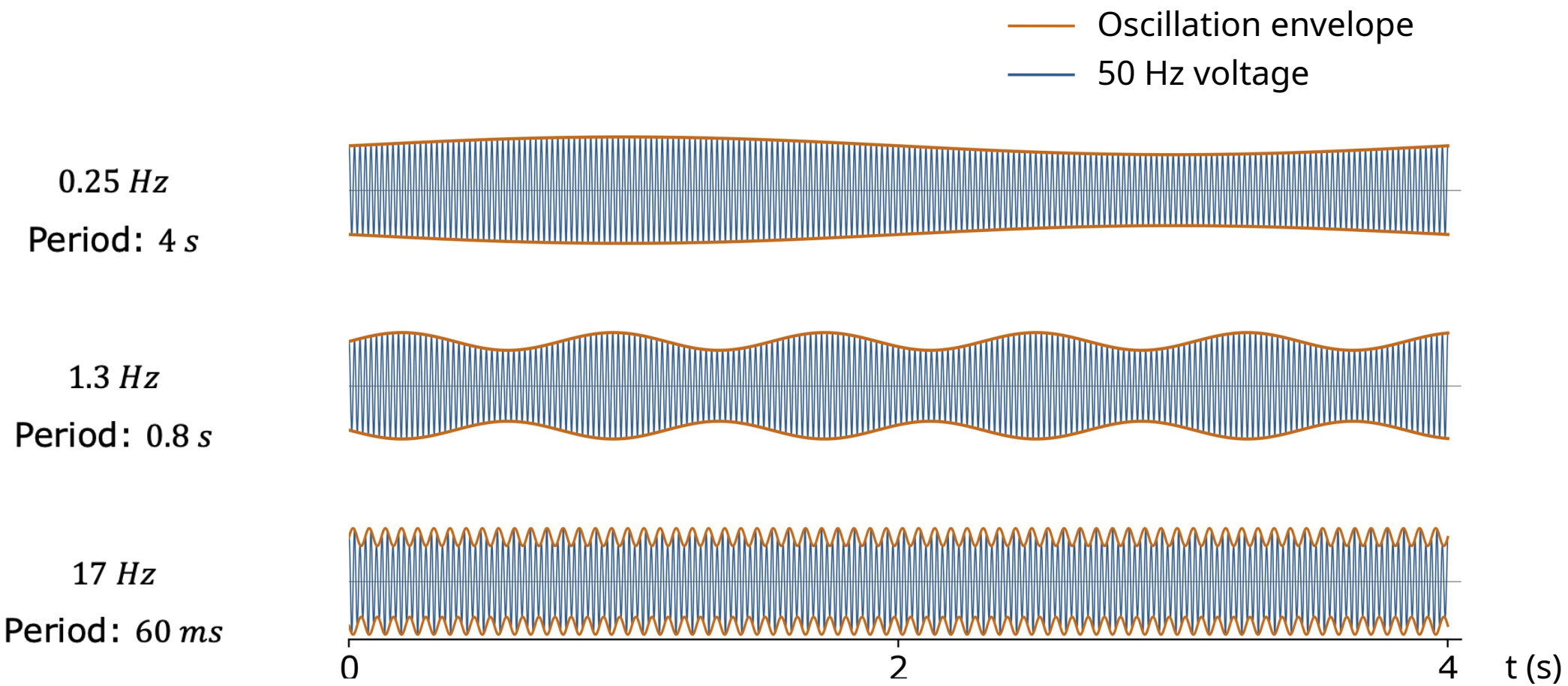




Small-signal analysis predicts the oscillations and demonstrates issues with “grid-following” inverter control

https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2025/analysis-of-sub-synchronous-oscillation-in-west-murray-zone-power-system-in-australia---external.pdf

Voltage-magnitude oscillations on a $50\ Hz$ waveform



These oscillations inhabit different orders-of-magnitude in the frequency spectrum.

Power-system oscillation taxonomy

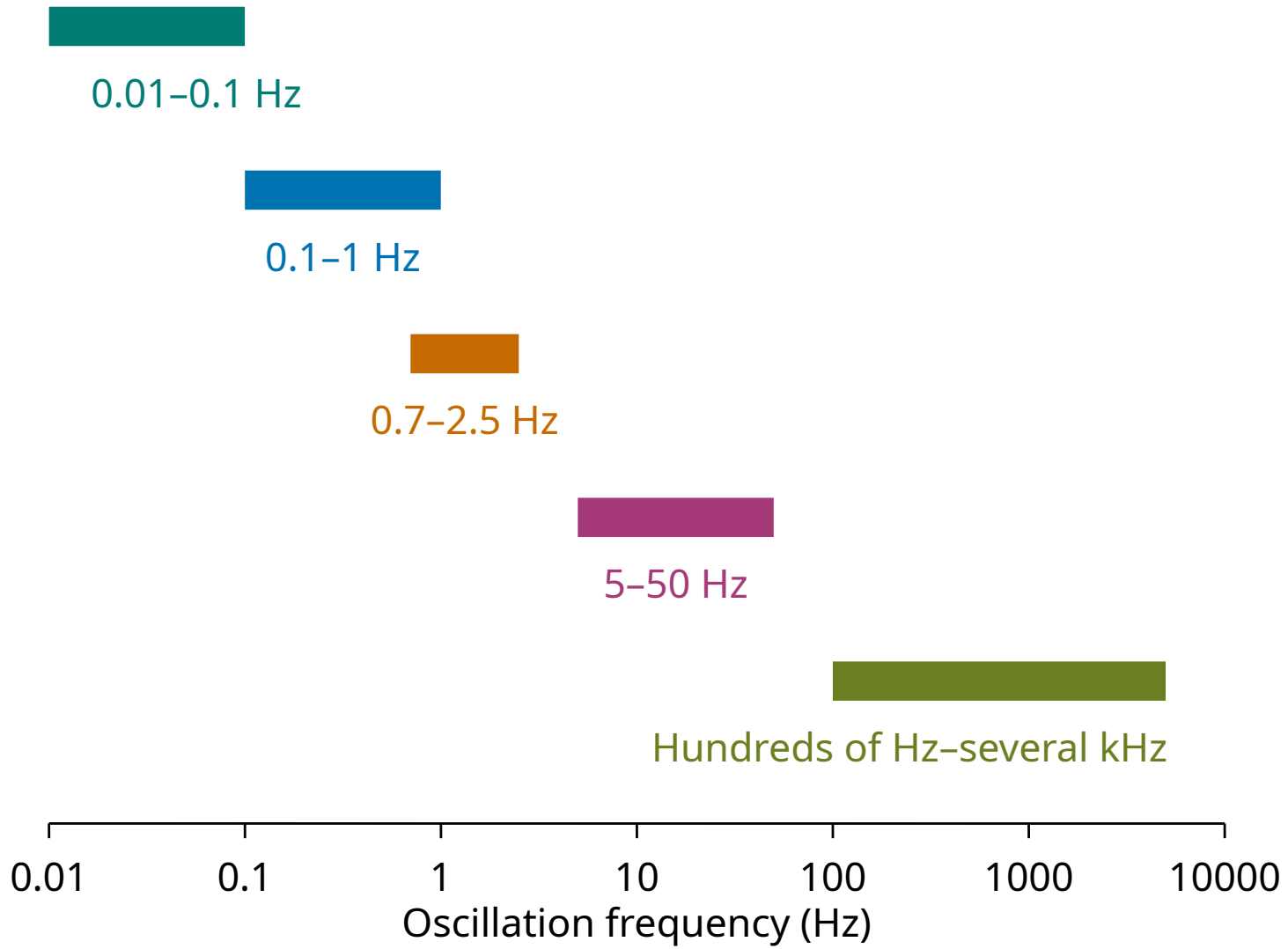
Slow frequency
Grid frequency, turbine–governor and plant-control dynamics

Inter-area rotor
Generator groups in different regions swing against each other

Local rotor
One generator or plant swings against the surrounding grid

Subsynchronous
Shaft twisting or inverter-control interactions through the network

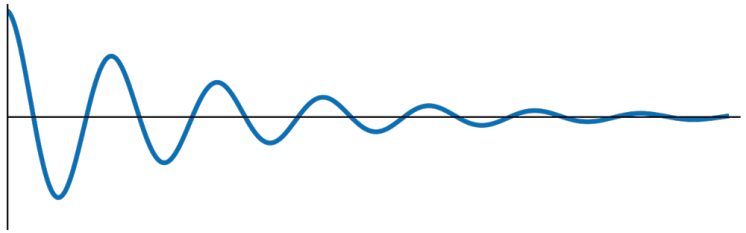
Fast electrical
Electrical resonances and fast converter-control interactions



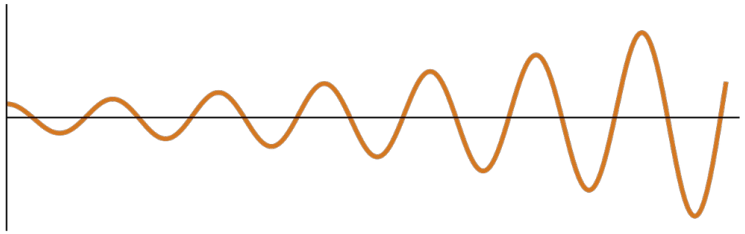
https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/smwg/reliability_guideline_-_forced_oscillations_-_2017-07-31_-_final.pdf
https://www.ree.es/sites/default/files/12_CLIENTES/Documentos/GT_POD_guia_implementacion_controles_POD_EN.pdf
https://par.nsf.gov/servlets/purl/10232629

Small-signal stability:
Determines the response to small perturbations by linearizing system around an equilibrium point

Stable:



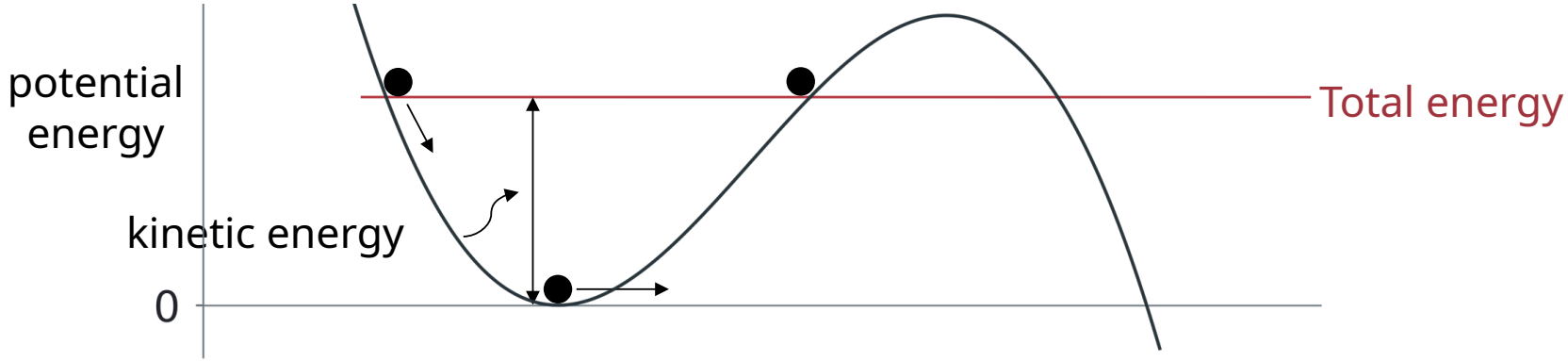
Unstable:



Will an oscillation decay or grow?

→ Eigenvalues

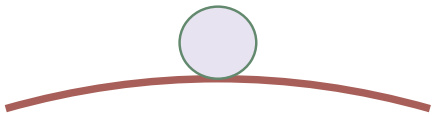
Transient stability:
Determines the response to a large disturbance using an energy-function/region of attraction



Small-Signal stable equilibrium:

the system returns to the steady state equilibrium after a small perturbation



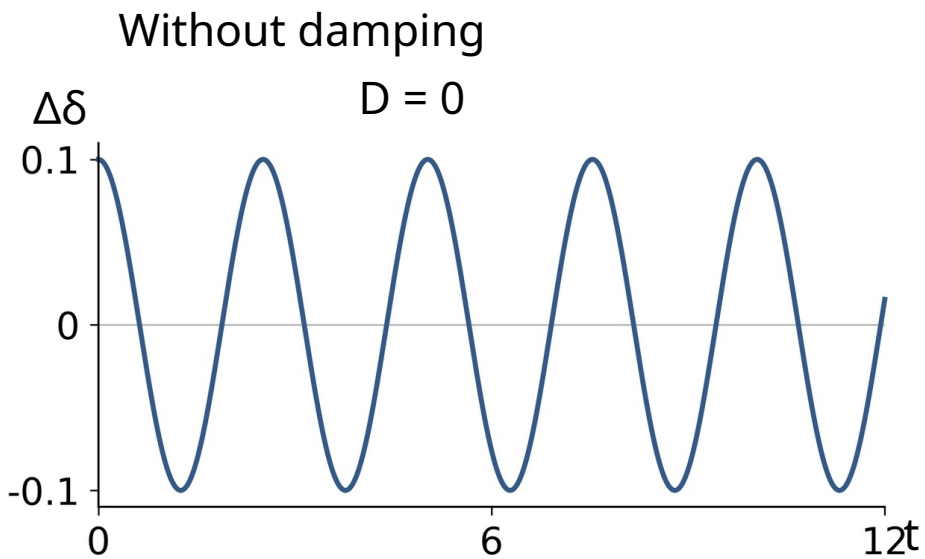


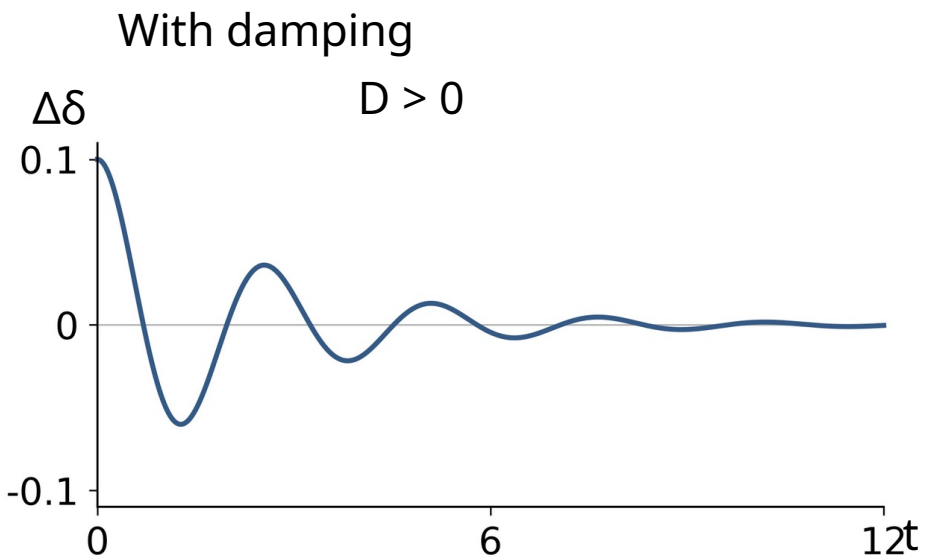
Power system damping

Why rotor oscillations need damping

Synchronising torque pulls the rotor towards its equilibrium angle.

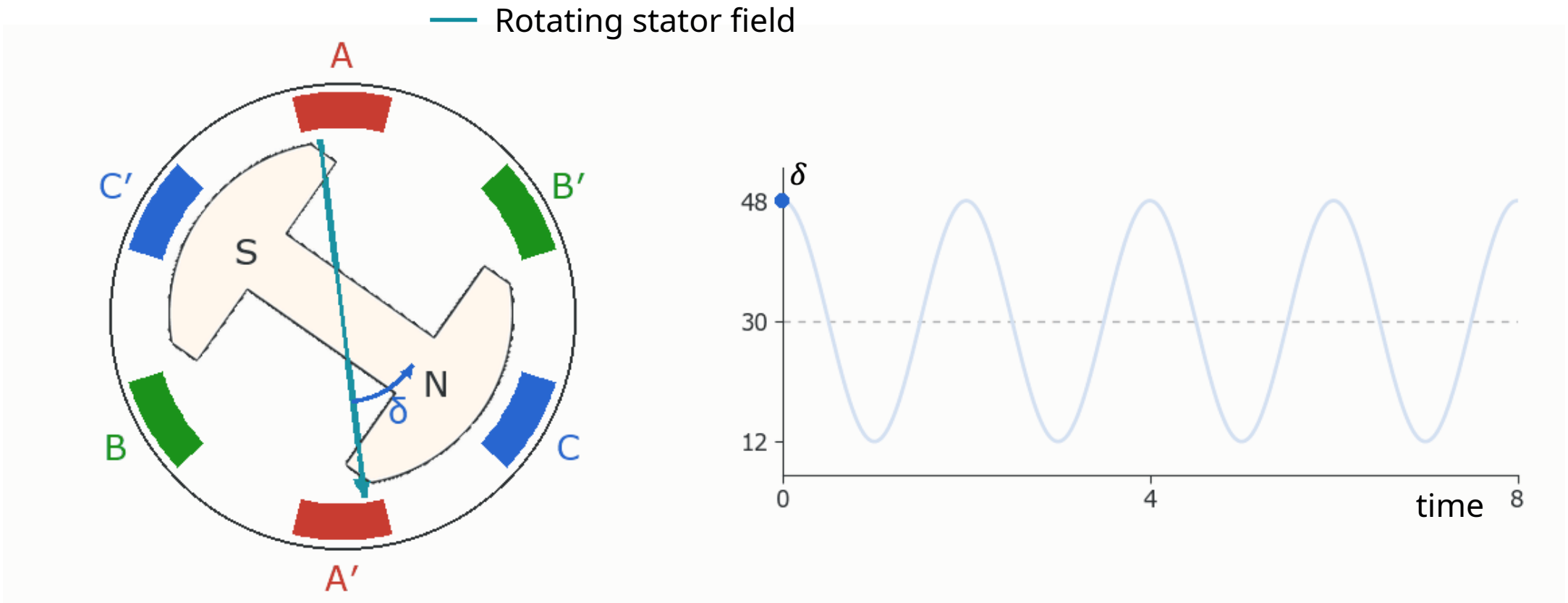
Inertia carries it past equilibrium. Damping removes energy from the swing.





Damper windings help rotor-angle and power oscillations decay.

Rotor-angle oscillations



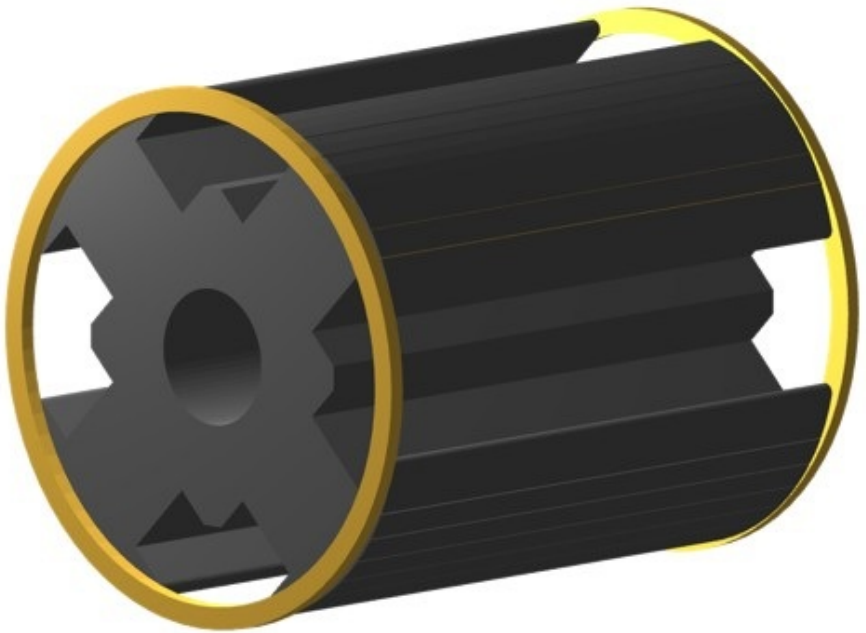
Both magnetic fields keep rotating. Their relative angle oscillates.

This is bad for the rotor and for grid stability.

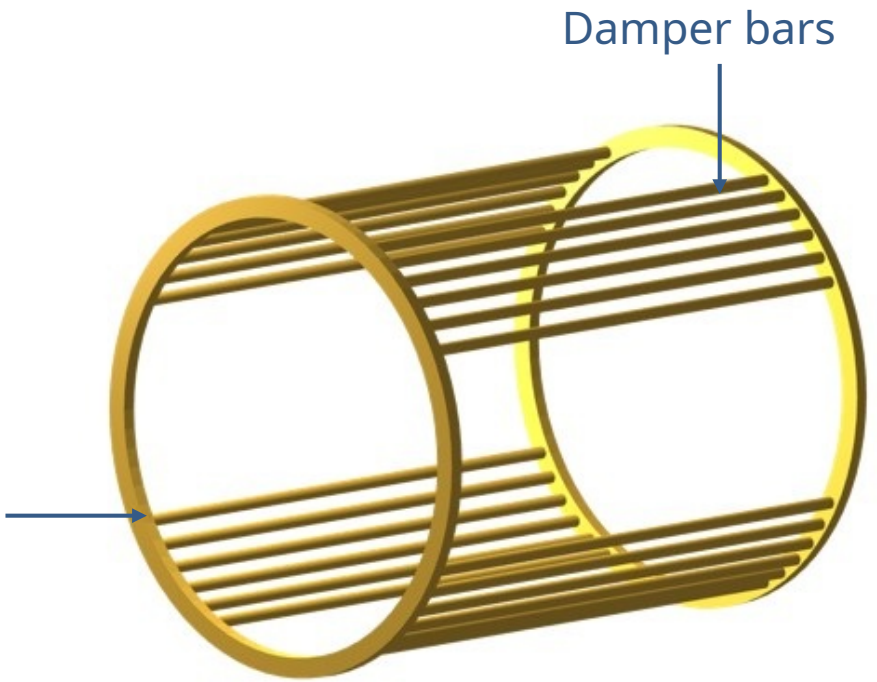
Damper windings on a synchronous rotor

Conducting bars in the pole faces, short-circuited by end rings.

Rotor core with damper winding



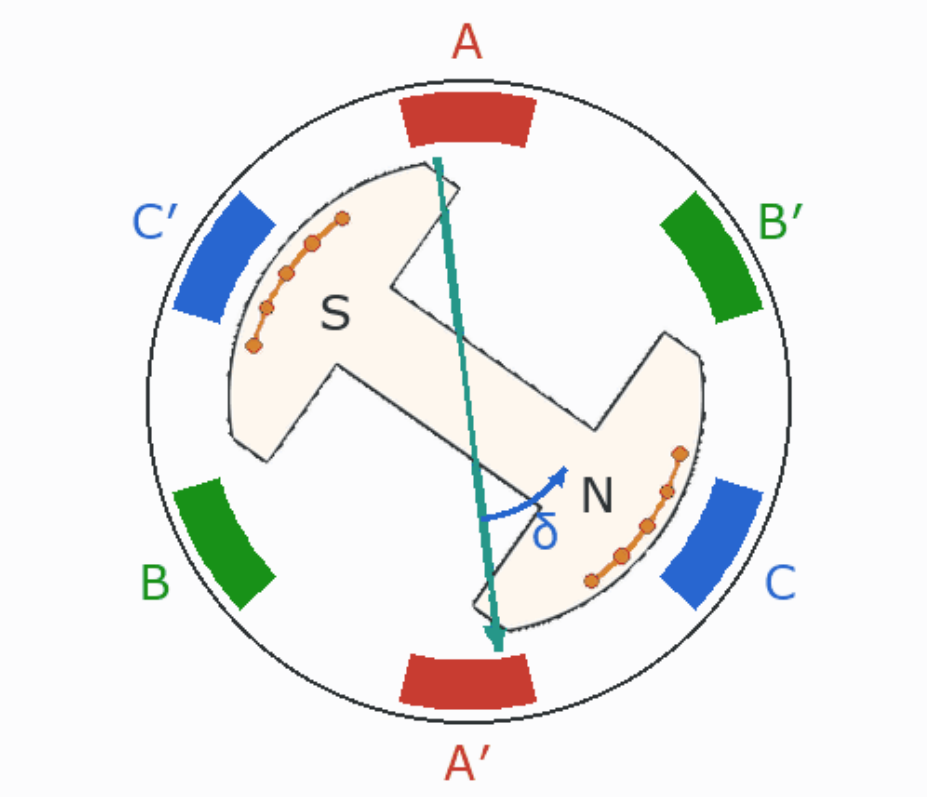
Damper winding alone



A rotor swing induces currents in this closed circuit, producing a damping torque.

https://help.altair.com/FluxMotor/topics/MC_damper.htm

Damper windings damp rotor swings

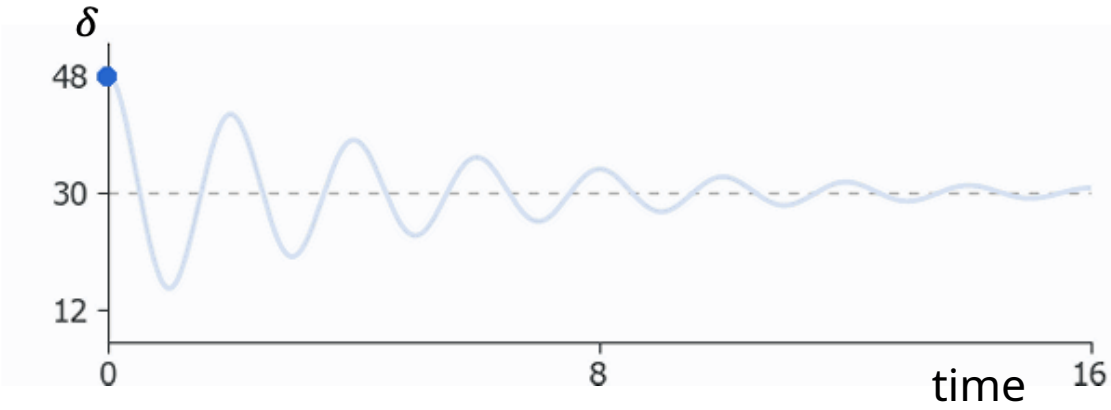


Damper bars in the rotor pole faces, short-circuited at both ends.

Speed deviations induce currents in the short-circuited damper bars.

Their magnetic field produces a torque that opposes the speed deviation.

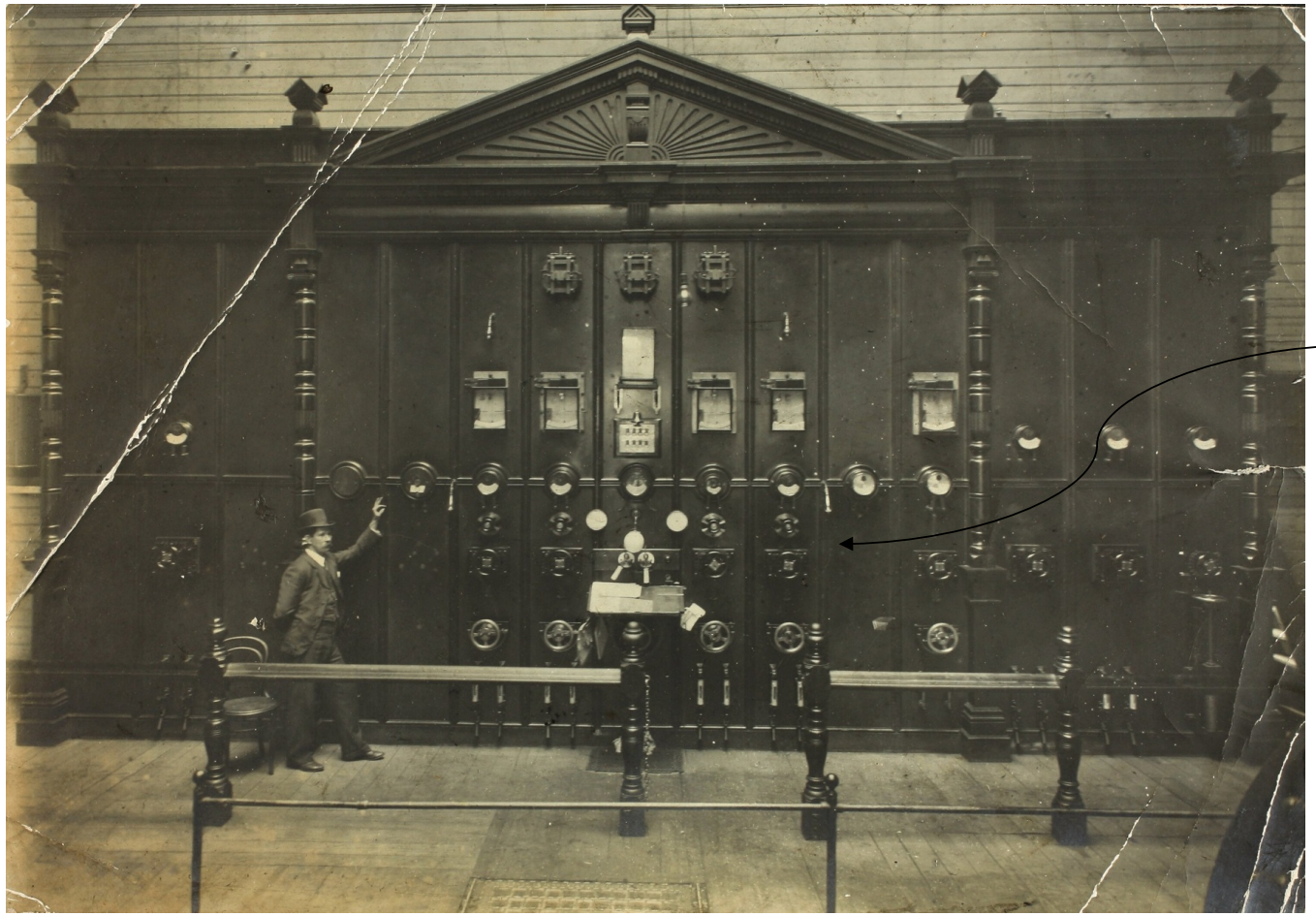
Above synchronous speed: braking torque.
Below synchronous speed: accelerating torque.



Resistive losses remove oscillation energy, so the swings decay.

Damper windings + the natural synchronization of rotating machines make very simple grids asymptotically stable.

Burnley Street Power Station, Richmond, Victoria in 1899

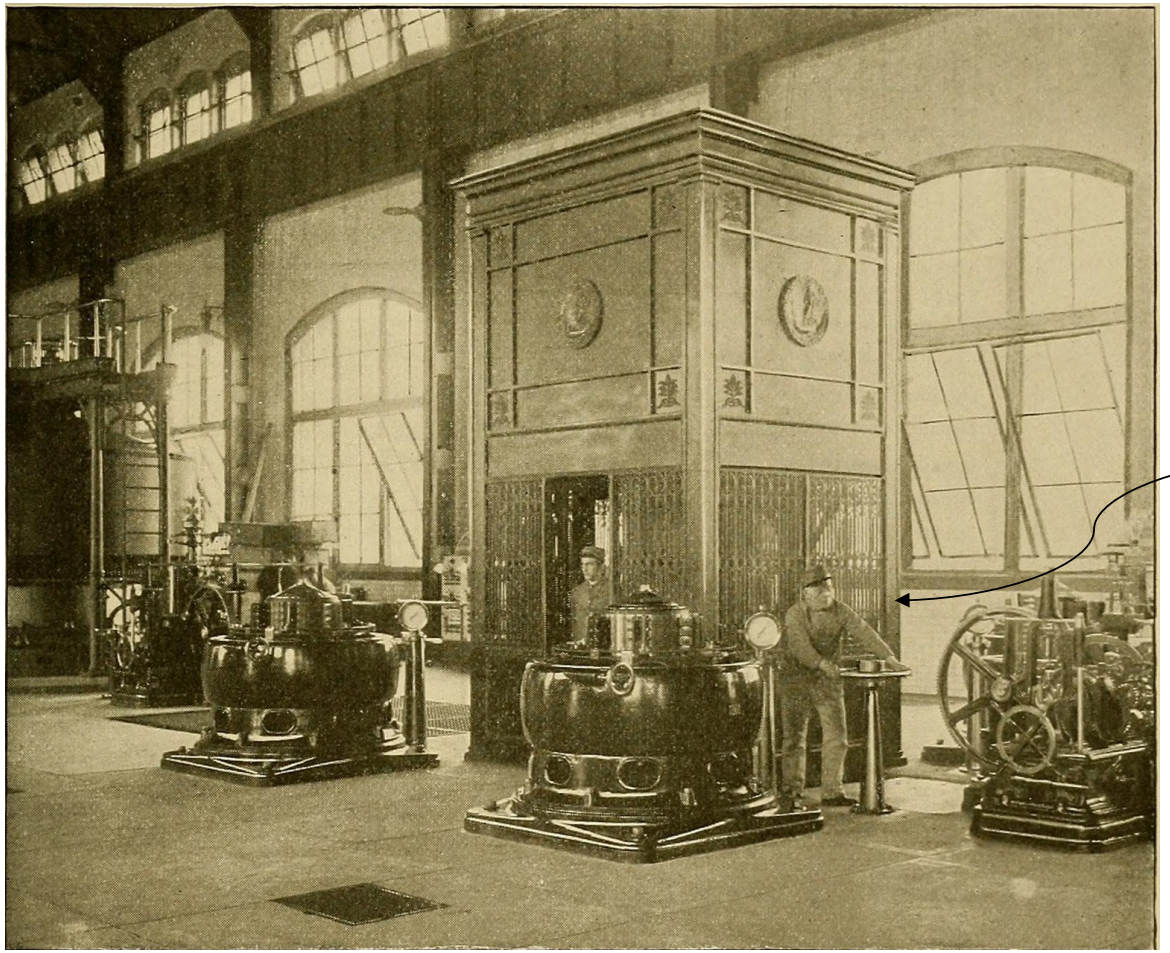


https://collections.museumsvictoria.com.au/items/1547273?utm_source=chatgpt.com

An operator watched the voltmeter and turned a field-rheostat handle to change excitation current and regulate voltage magnitude.

Niagara power plant, 1902

Largest power plant in the world. Provided Streetcars, factory motors and lamps with AC power



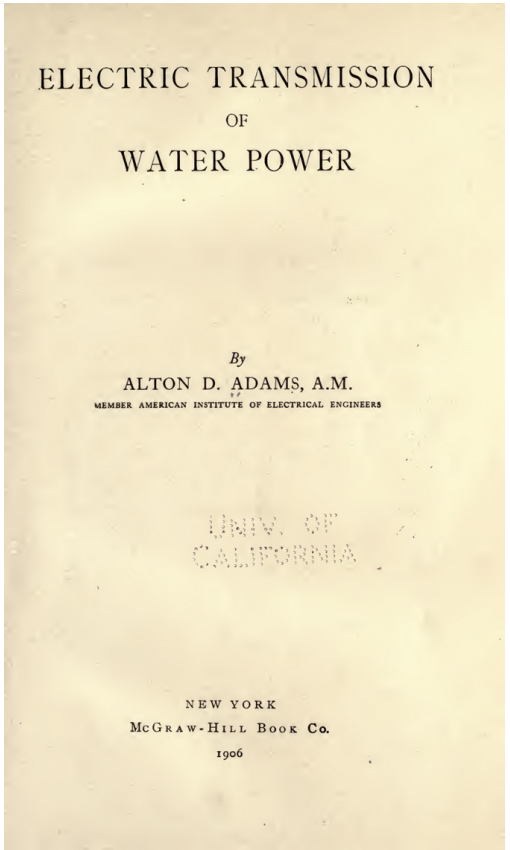
Each DC exciter had its own turbine.

An attendant adjusted its speed.

Manual Voltage Regulation (MVR)

https://archive.org/details/cassiersmagaz21190119newy

Electric Transmission of Water Power, 1906


ELECTRIC TRANSMISSION
OF
WATER POWER

By
ALTON D. ADAMS, A.M.
MEMBER AMERICAN INSTITUTE OF ELECTRICAL ENGINEERS

UNIV. OF CALIFORNIA

NEW YORK
McGRAW-HILL BOOK Co.
1906

https://archive.org/details/electrictransmis00adamrich

Voltage regulation was already a network problem.

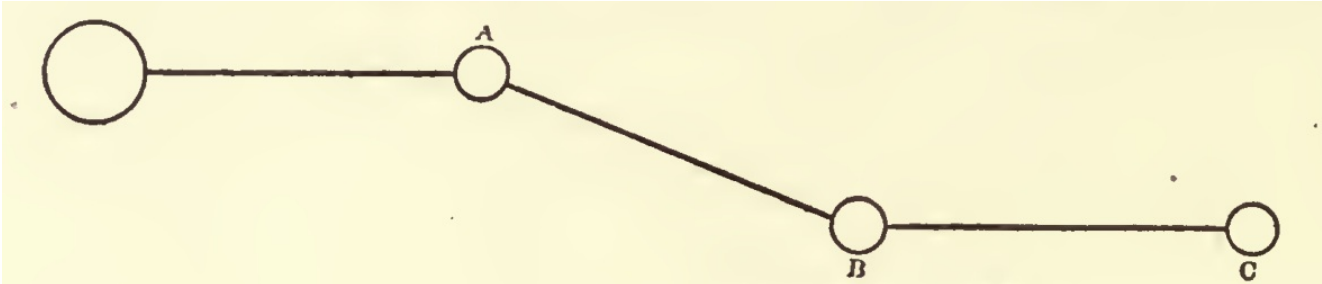
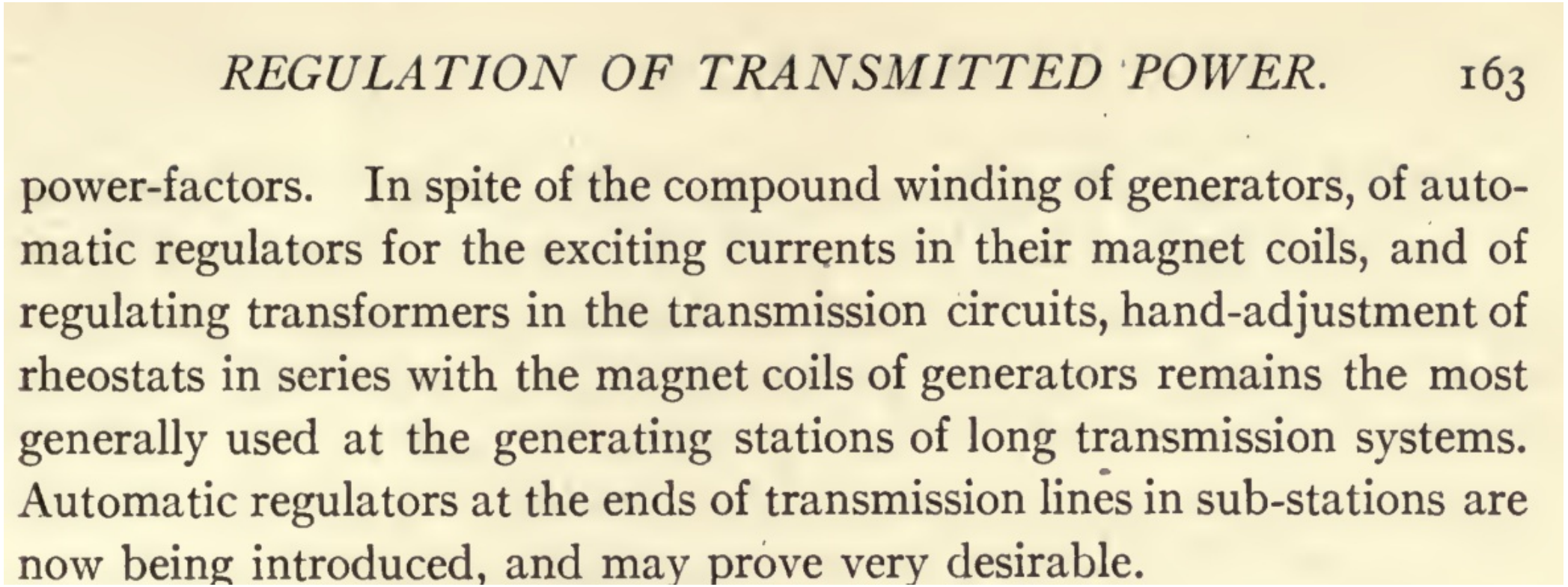


FIG. 66.

5–10% voltage changes with load—too much for lamps.

Manual excitation control in 1906

Alton D. Adams, Electric Transmission of Water Power (1906)

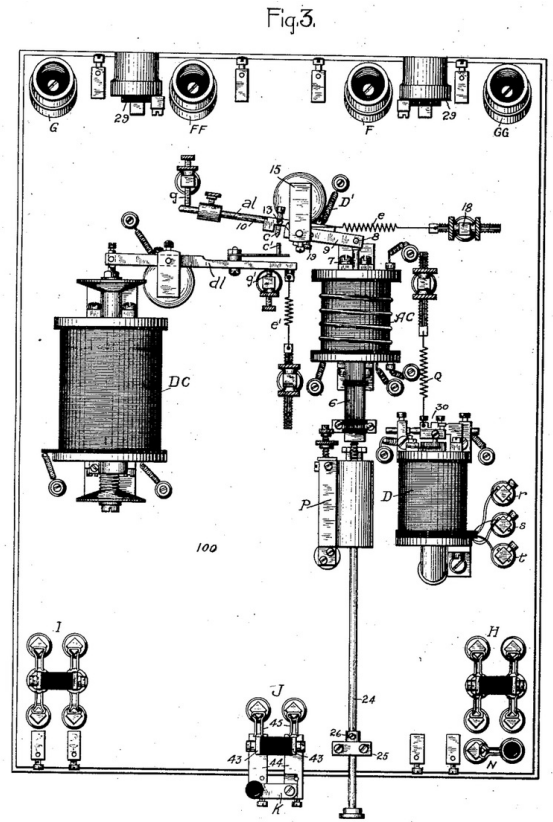


REGULATION OF TRANSMITTED POWER. 163

power-factors. In spite of the compound winding of generators, of automatic regulators for the exciting currents in their magnet coils, and of regulating transformers in the transmission circuits, hand-adjustment of rheostats in series with the magnet coils of generators remains the most generally used at the generating stations of long transmission systems. Automatic regulators at the ends of transmission lines in sub-stations are now being introduced, and may prove very desirable.

https://archive.org/details/electrictransmis00adamrich

Automatic voltage control and the later damping problem



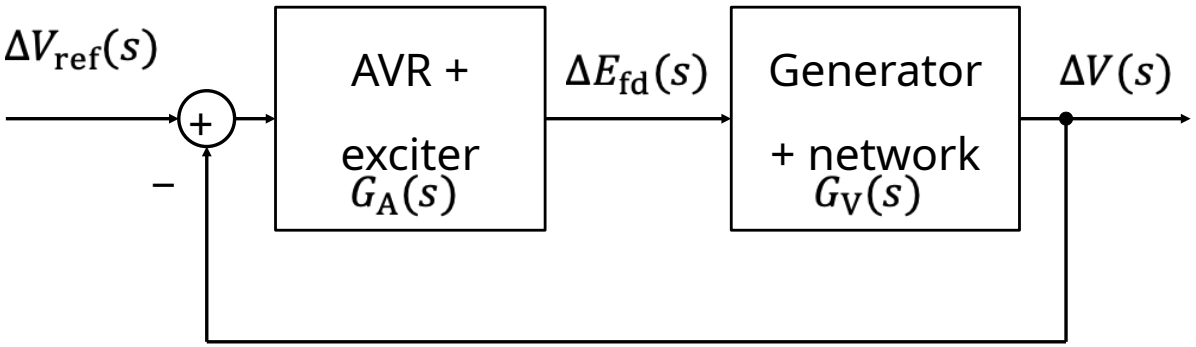
1903: Tirrill’s regulator cycled exciter resistance to correct voltage automatically.

Tirrill regulator, 1903

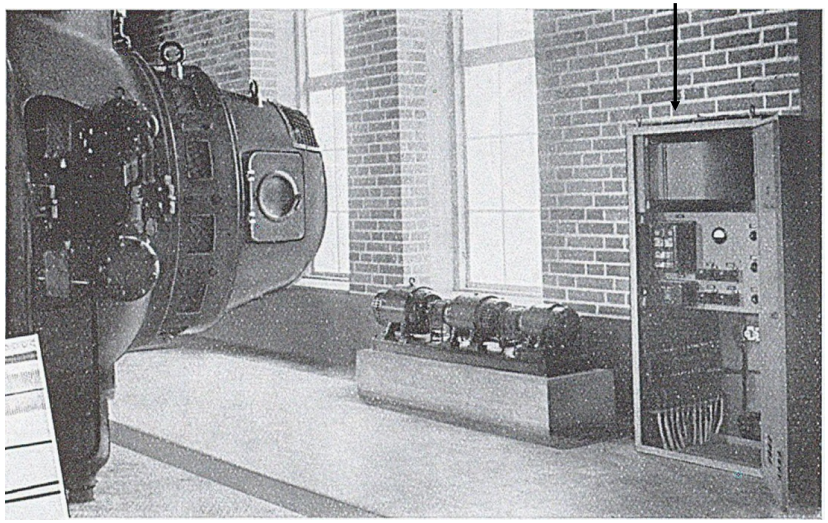
https://patents.google.com/patent/US726234A/en

1950s: Fast, continuously acting AVRs become standard

Automatic voltage-magnitude feedback



Control cabinet



72 MVA generator excitation equipment

https://delibra.bg.polsl.pl/Content/81883

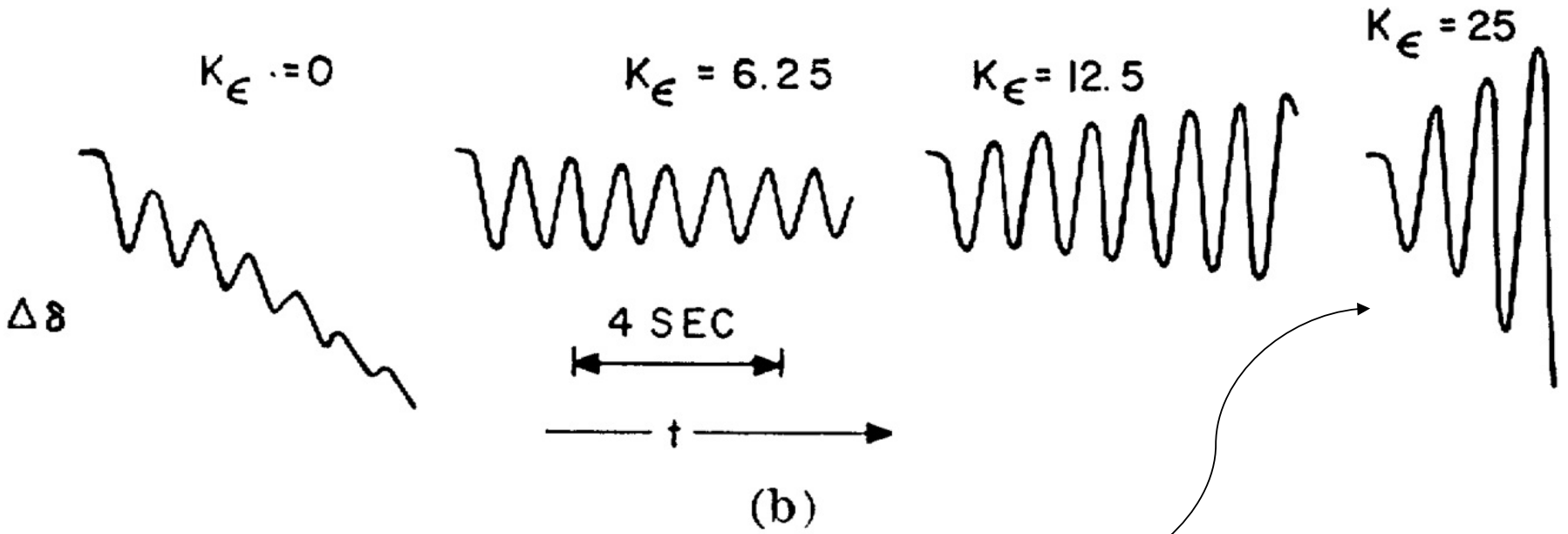
Tubes, magnetic amplifiers and later transistors made AVRs fast and continuous.

By the early 1960s, most new units used continuously acting AVRs.

Early AVRs and oscillatory instability

Late 1950s–early 1960s: Persistent low-frequency oscillations began to limit power transfers.

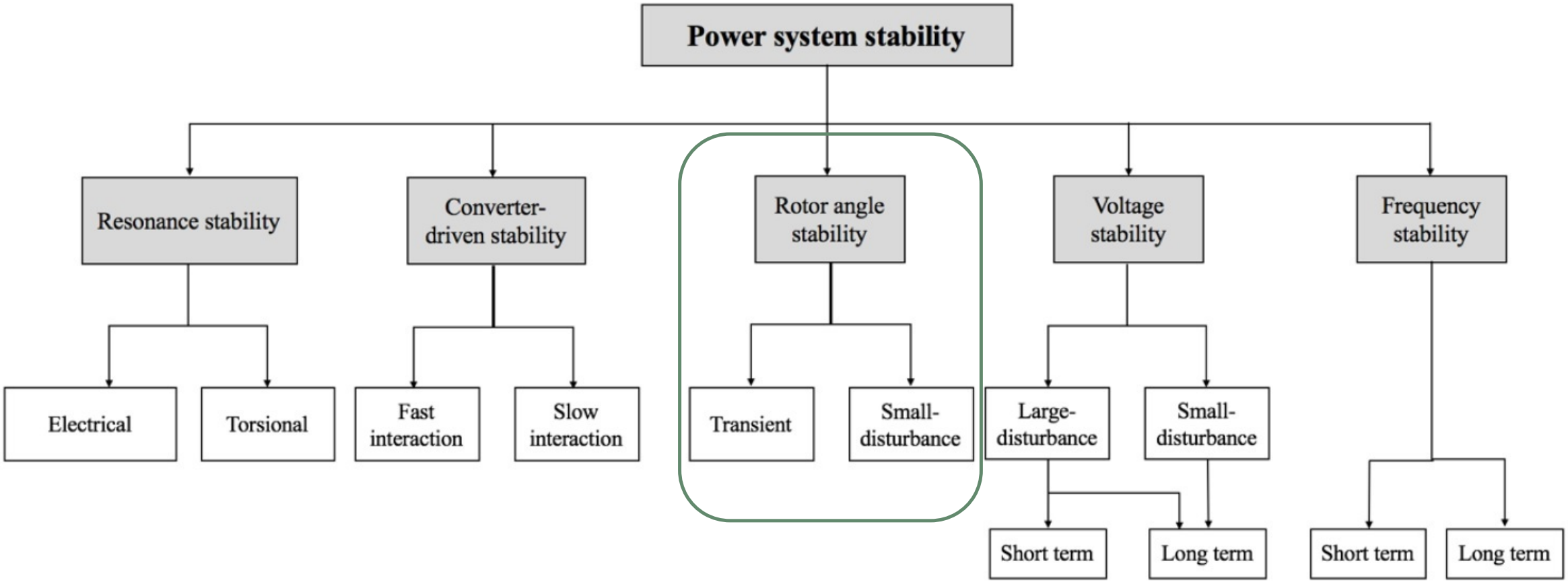
Rotor-angle response without a PSS (1969 analog-computer study)



Higher AVR gain can produce growing rotor-angle oscillations.

https://doi.org/10.1109/TPAS.1969.292452

Power system stability classification



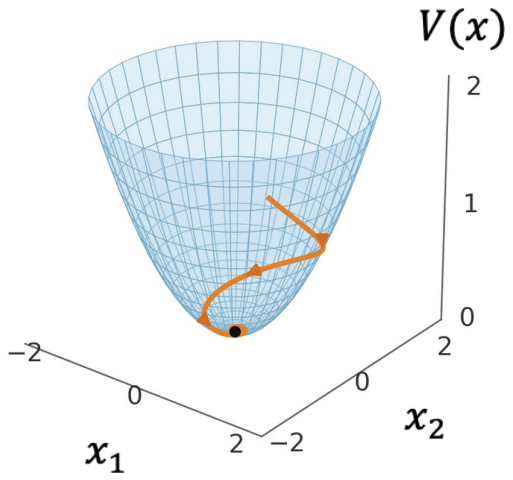
IEEE PES Task Force, 2020

Does this taxonomy make sense?

Control theorists understand stability as small signal stability and large signal stability

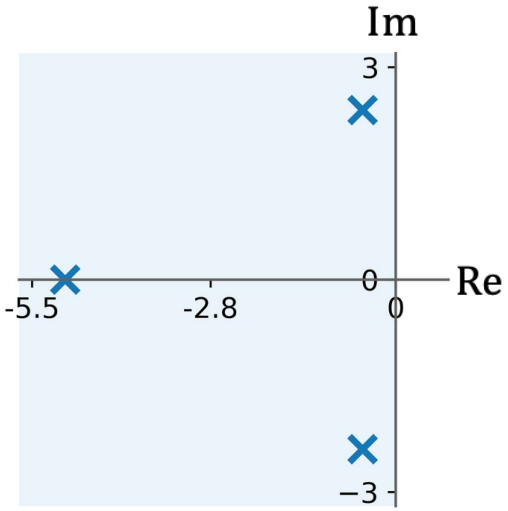
Large signal/Transient

Lyapunov

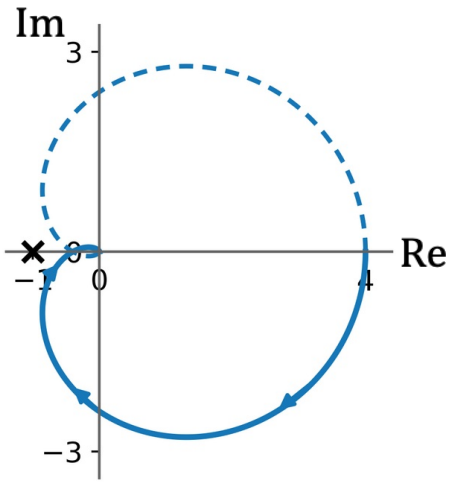


Small signal

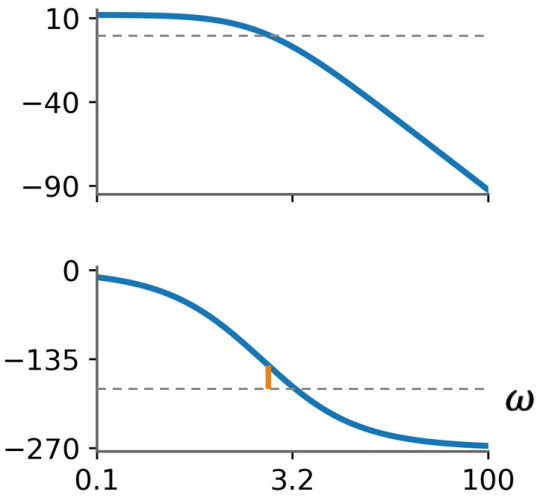
Pole Plot



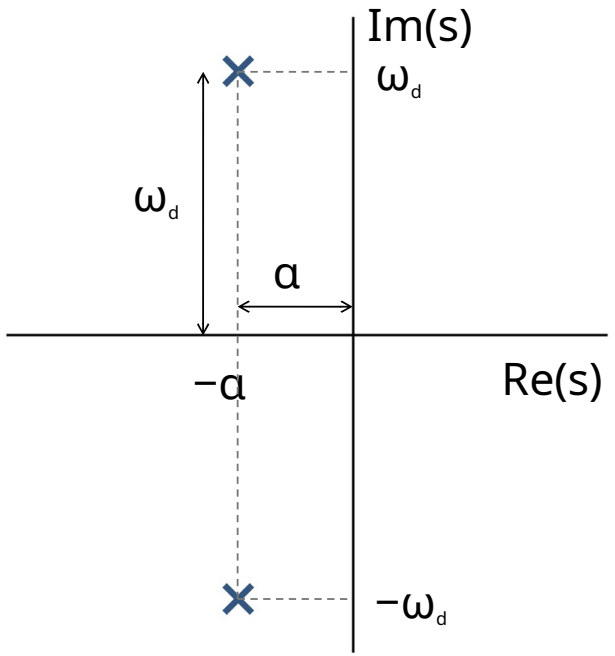
Nyquist



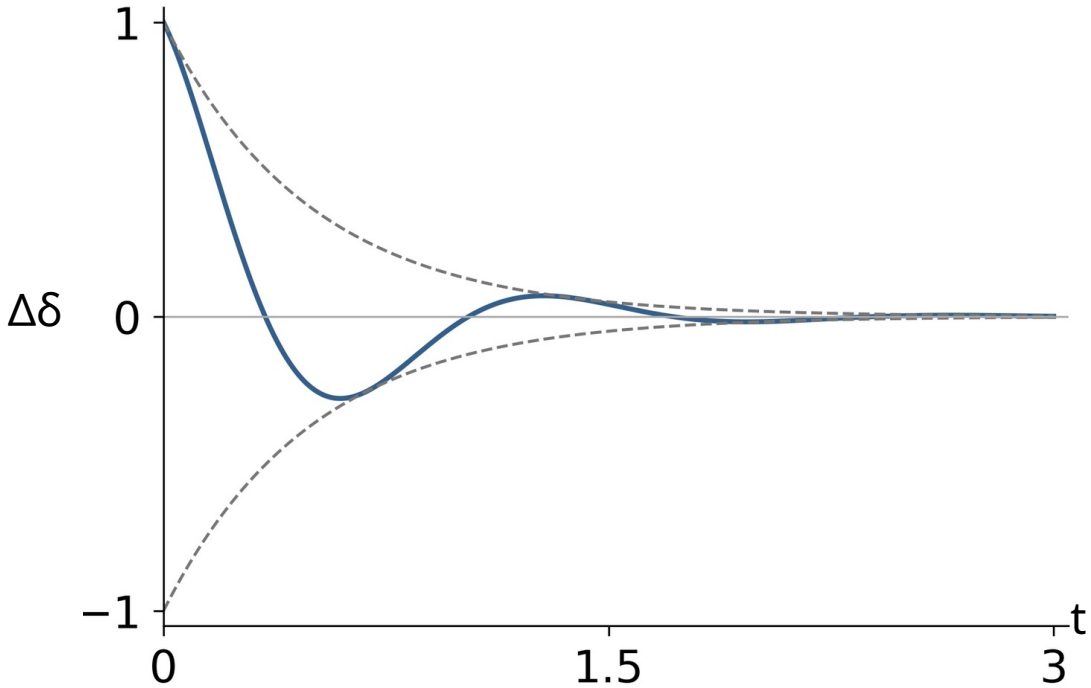
Bode



Pole locations



Ring-down



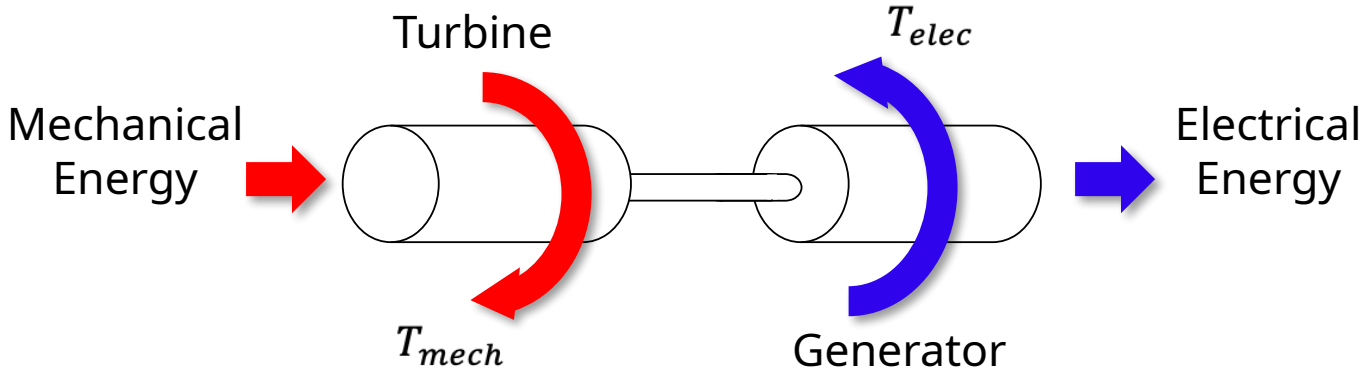
α: decay rate

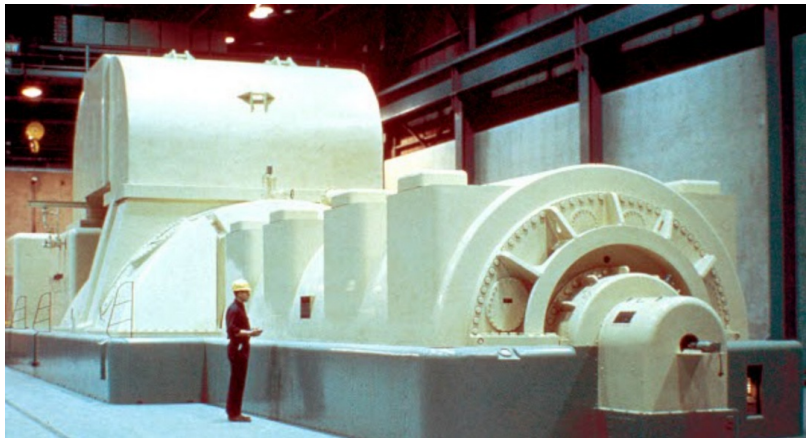
ω_d: oscillation frequency

Power system stability combines the network’s power flow equations with the dynamics of the connected generators and loads.

We will first focus on single-machine connected to an infinite bus.

Power balance and generator dynamics





T_m: Mechanical torque applied by the turbine
T_e: Electromagnetic torque developed by the generator
J: Moment of inertia of the turbine/generator set
δ: Rotor angle in synchronous frame
ω: Actual rotor speed
P_m: Mechanical power delivered by the turbine (per unit)
P_e: Electrical power injected into the network (per unit)
ω_s: Rated synchronous rotor speed

Kinetic energy: $W = \frac{1}{2} J \omega^2$

Inertia constant: $H = \frac{W^\circ}{S_{base}} = \frac{J\omega_s^2}{2S_{base}}$

$$M = \frac{2H}{\omega_s}$$

$$J\frac{d^2\delta}{dt^2} = T_m - T_e \quad \Rightarrow \quad \frac{J\omega}{S_{base}}\frac{d^2\delta}{dt^2} = P_m - P_e$$

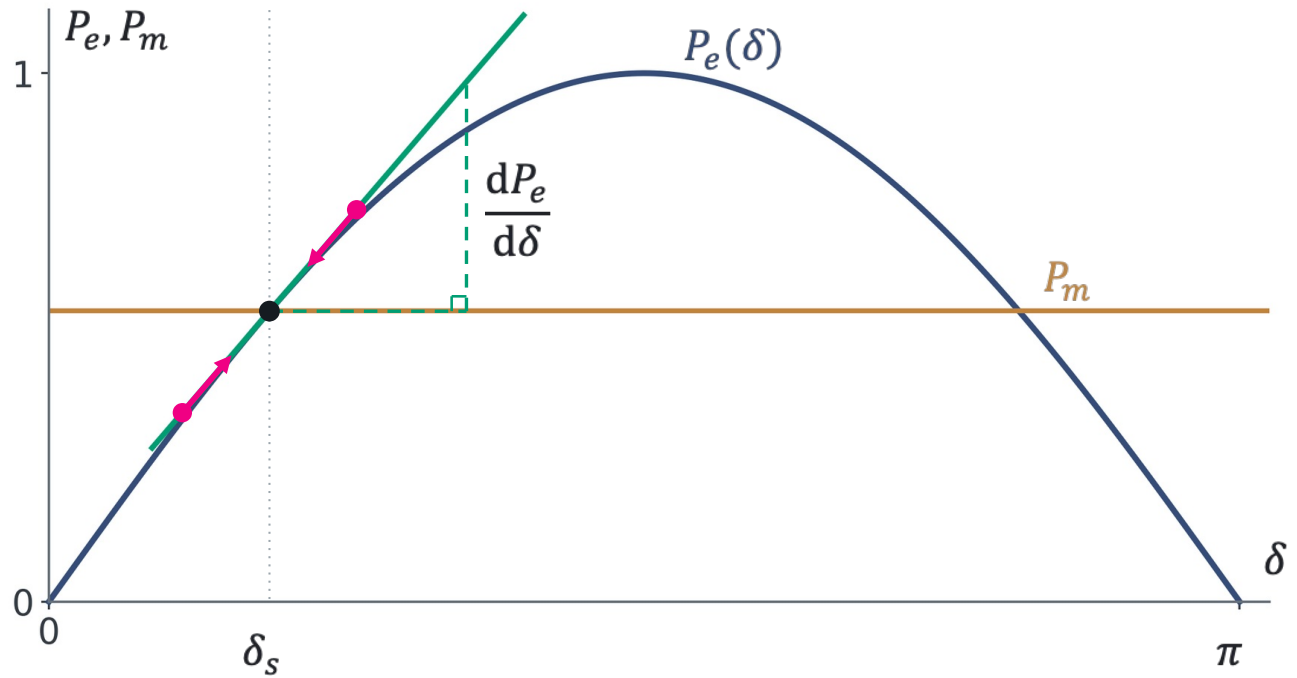
$$J\frac{d\omega}{dt} = T_m - T_e \quad \Rightarrow \quad \frac{J\omega}{S_{base}}\frac{d\omega}{dt} = P_m - P_e$$

$$M\frac{d^2\delta}{dt^2} \approx P_m - P_e$$

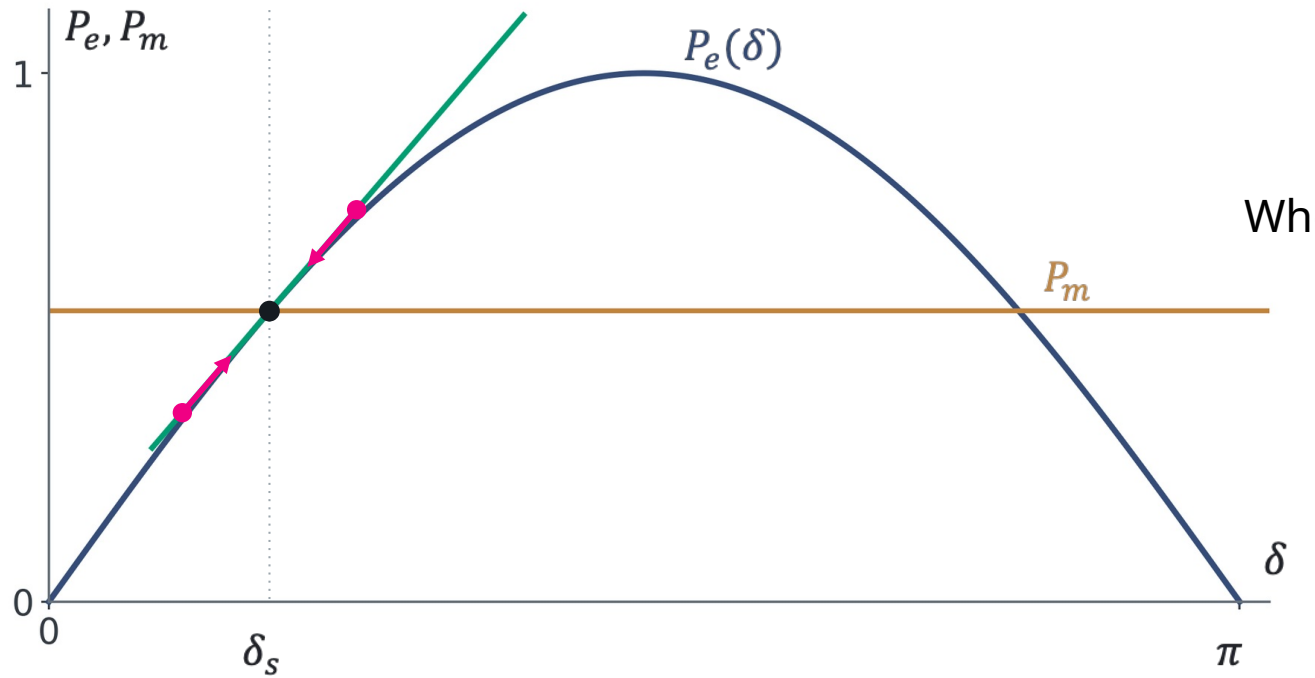
$$\omega \approx \omega_s$$

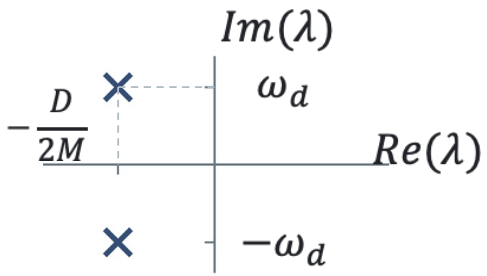
What is synchronising power?

$$\Delta P_e \approx \frac{\mathrm{d}P_e}{\mathrm{d}\delta}\Delta\delta$$



Equilibrium points on the left side of the P_e curve are stable.





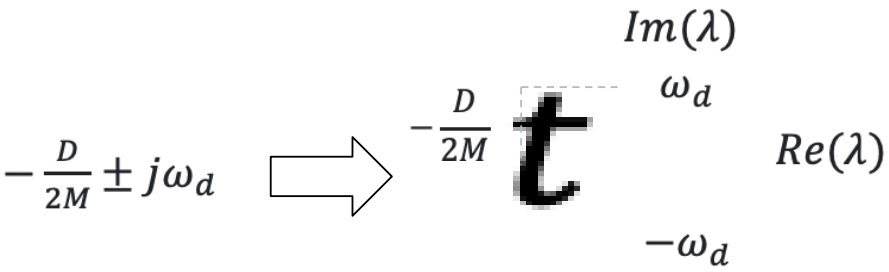
Where do these stable poles come from?

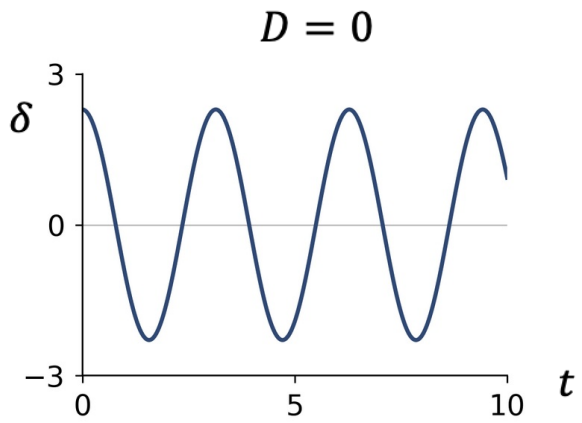
Single machine small-signal model

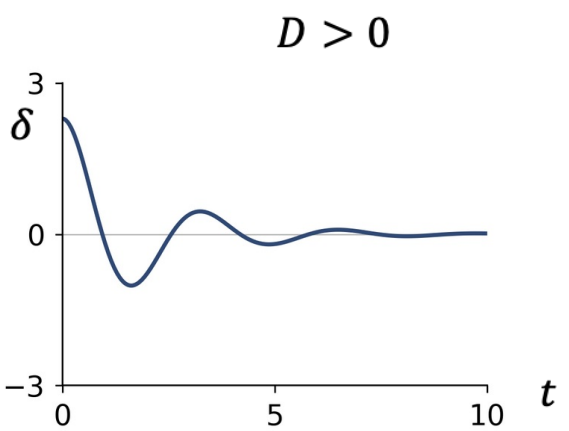
For a small power disturbance u(t):

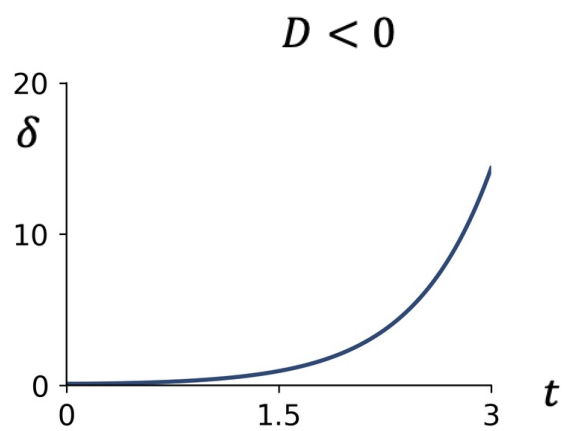
$$M\Delta\ddot{\delta} + D\Delta\dot{\delta} + \frac{dP_e}{d\delta}\Delta\delta = u(t) \quad \Rightarrow \quad \frac{\Delta\delta(s)}{U(s)} = \frac{1}{Ms^2 + Ds + \frac{dP_e}{d\delta}}$$

The poles are the roots of the denominator: $\lambda_{\pm} = -\frac{D}{2M} \pm j\omega_d$ ⇒





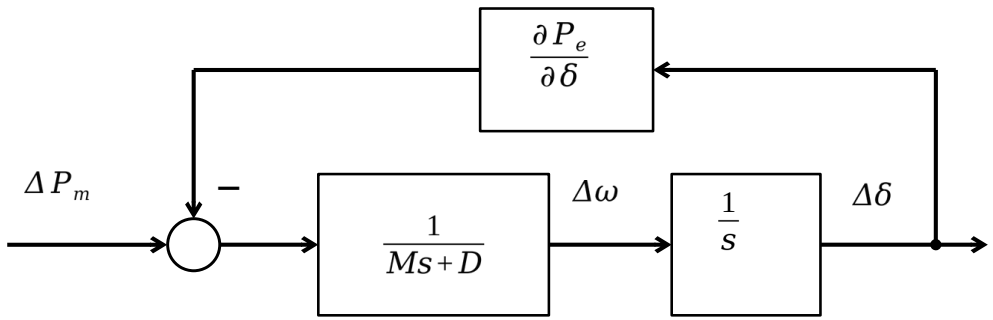


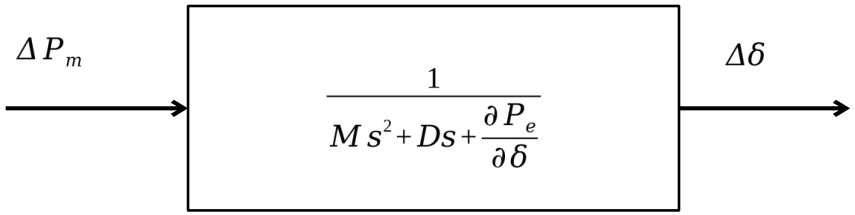


What if we consider more complex dynamics than just the swing equation?

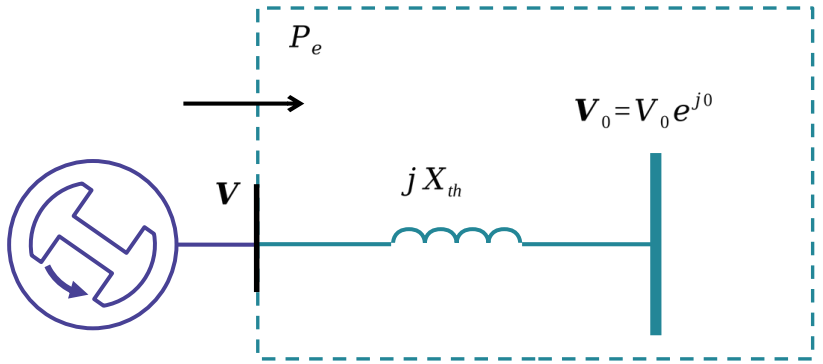
Rotor motion forms stable small-signal dynamics on the left side of the P_e curve.

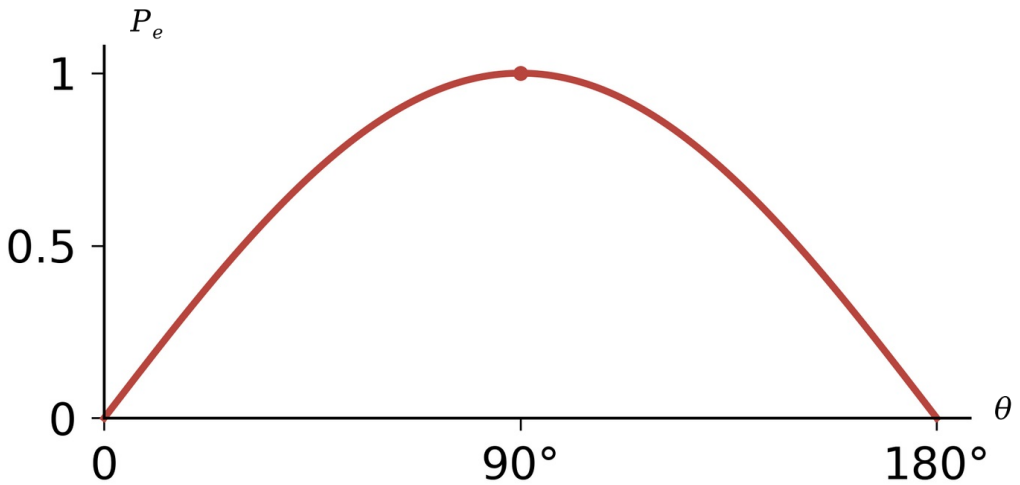
Rotor dynamics



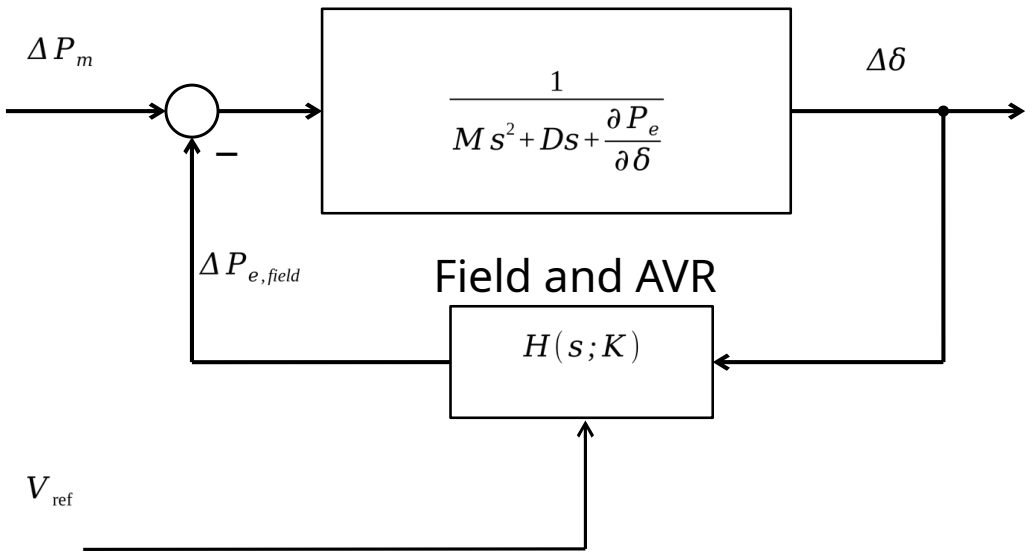


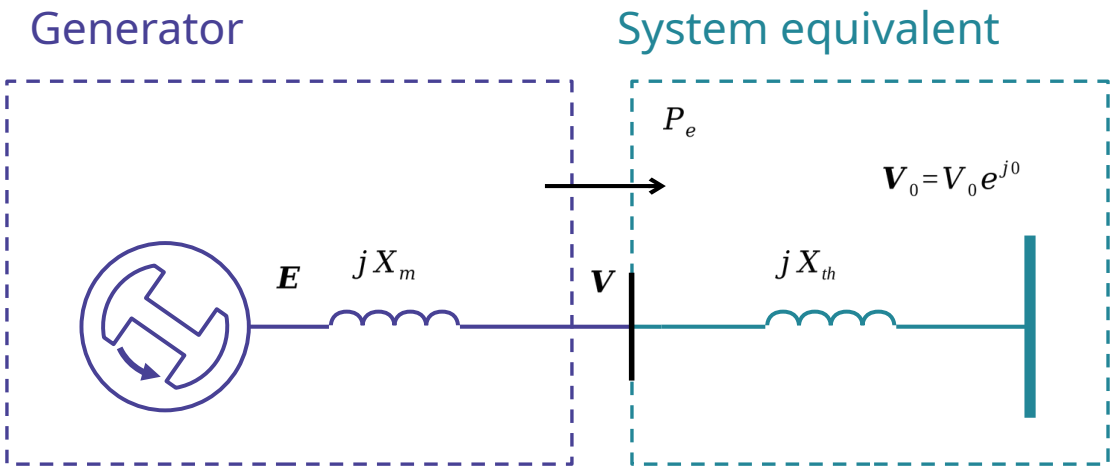
Generator — System equivalent

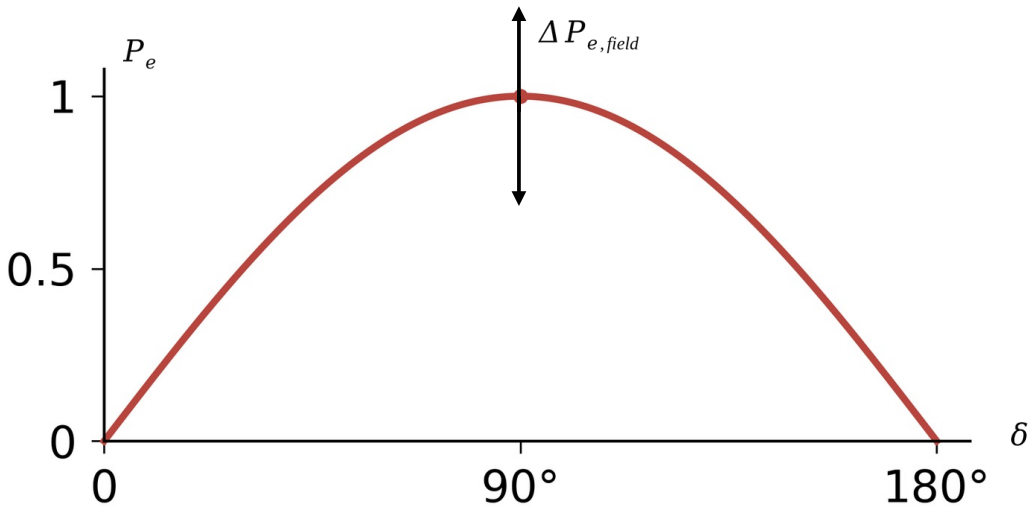




Including excitation dynamics and AVR feedback can cause instabilities.

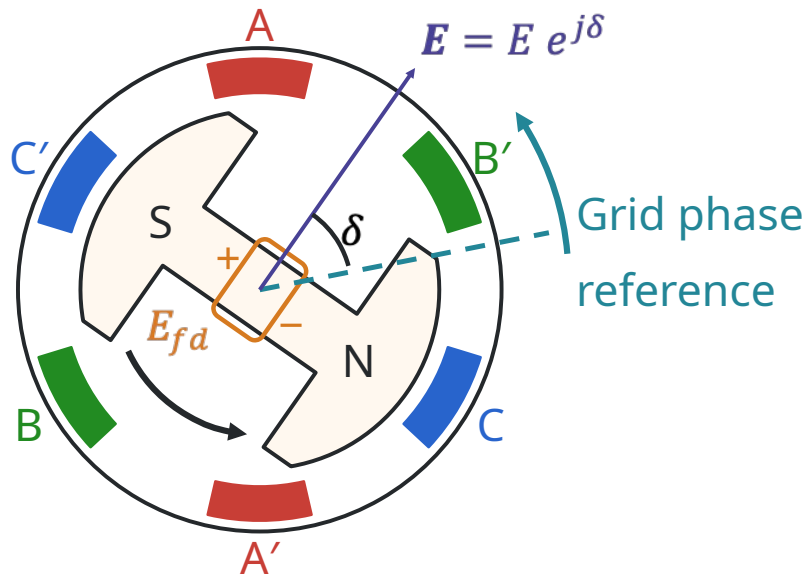




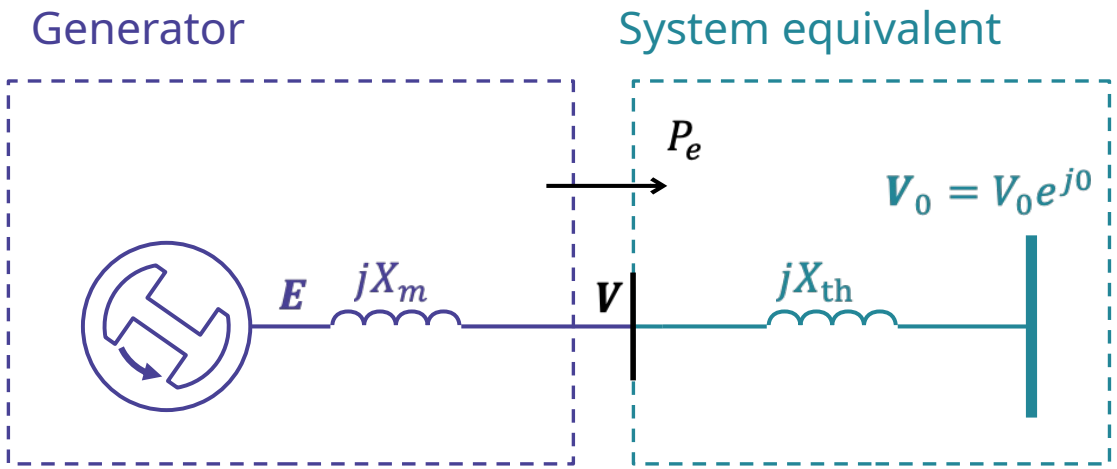


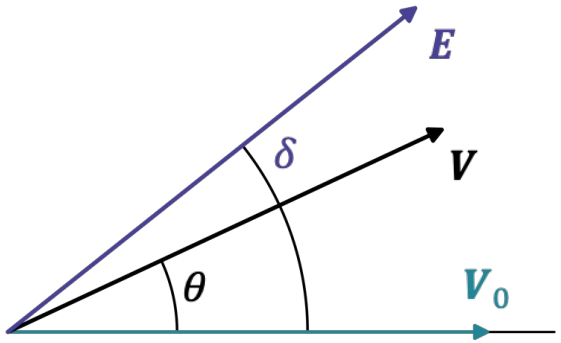
$\Delta P_{e,field}$: change in electrical output power caused by changing excitation at a fixed rotor angle.

Physical machine



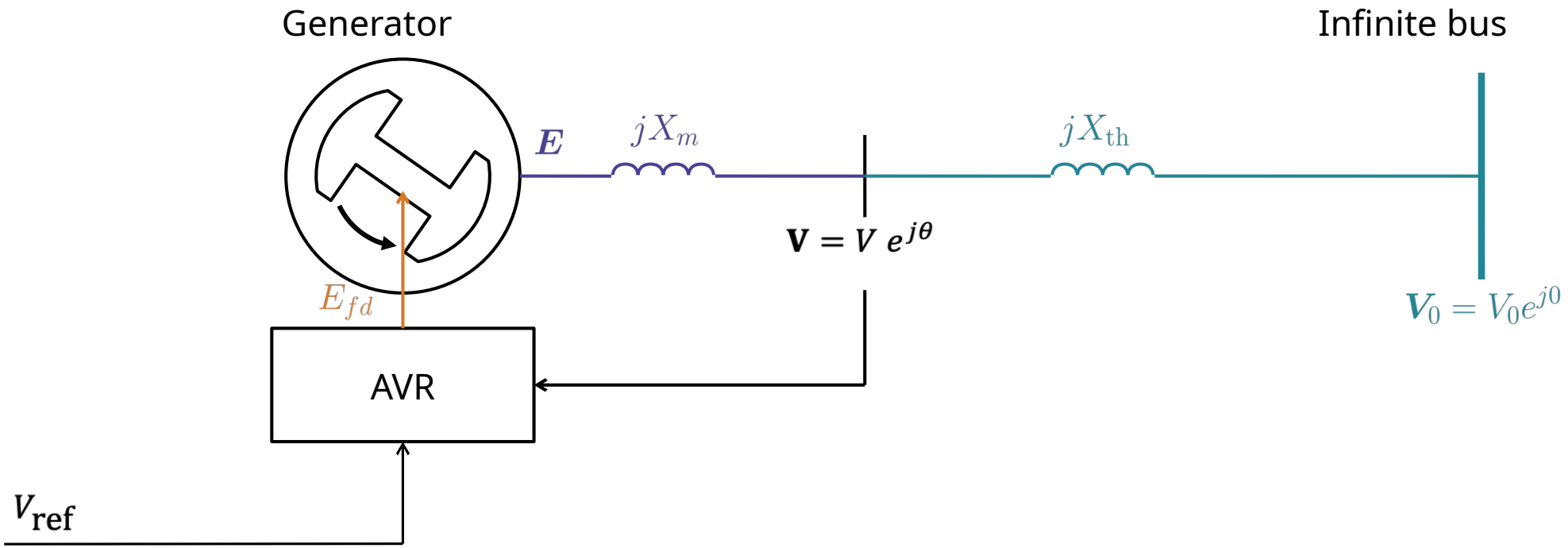
E_{fd}: DC excitation voltage
E: internal AC EMF magnitude
V: terminal AC voltage magnitude
X_m: effective machine reactance
X_{th}: network Thevenin reactance





Why include rotor-field and AVR dynamics in a small-signal model?

The AVR adjusts rotor excitation E_{fd} to regulate terminal-voltage magnitude V.
Its interaction with field and rotor dynamics can amplify oscillations.



Field and AVR dynamics add two states to rotor angle and speed $x = \begin{bmatrix} \delta \\ \omega \\ E \\ E_{fd} \end{bmatrix}$

$$\frac{d\delta}{dt} = \omega - \omega_s$$

$$M\frac{d\omega}{dt} = P_m - P_e - D(\omega - \omega_s)$$

$$T_E\frac{dE}{dt} = E_{fd} - E - K_X(E - V_0\cos\delta)$$

$$T_A\frac{dE_{fd}}{dt} = -E_{fd} + K(V_{ref} - V)$$

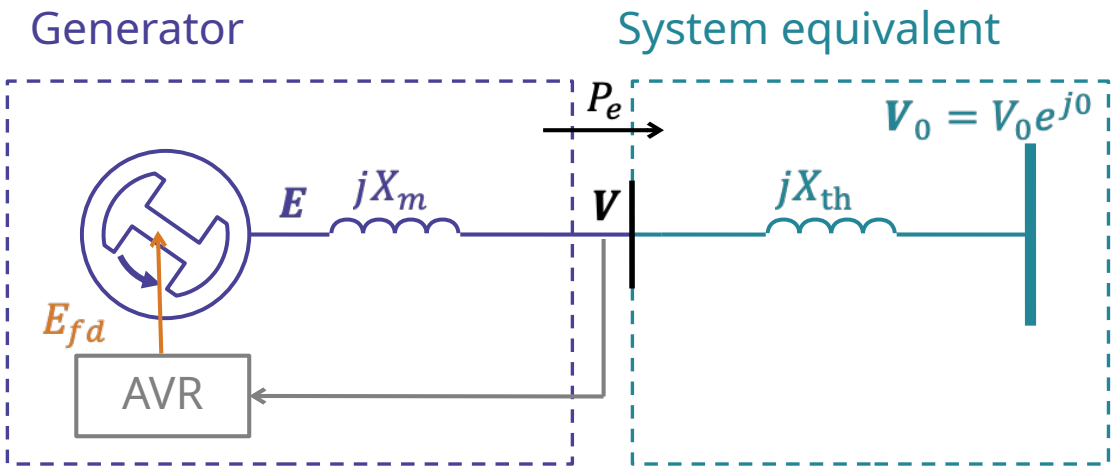
K: AVR gain
T_A: AVR time constant
V_{ref}: voltage reference
P_m: mechanical input
ω_s: synchronous speed
D: damping coefficient
X_d: synchronous reactance
T_E: rotor-field time constant

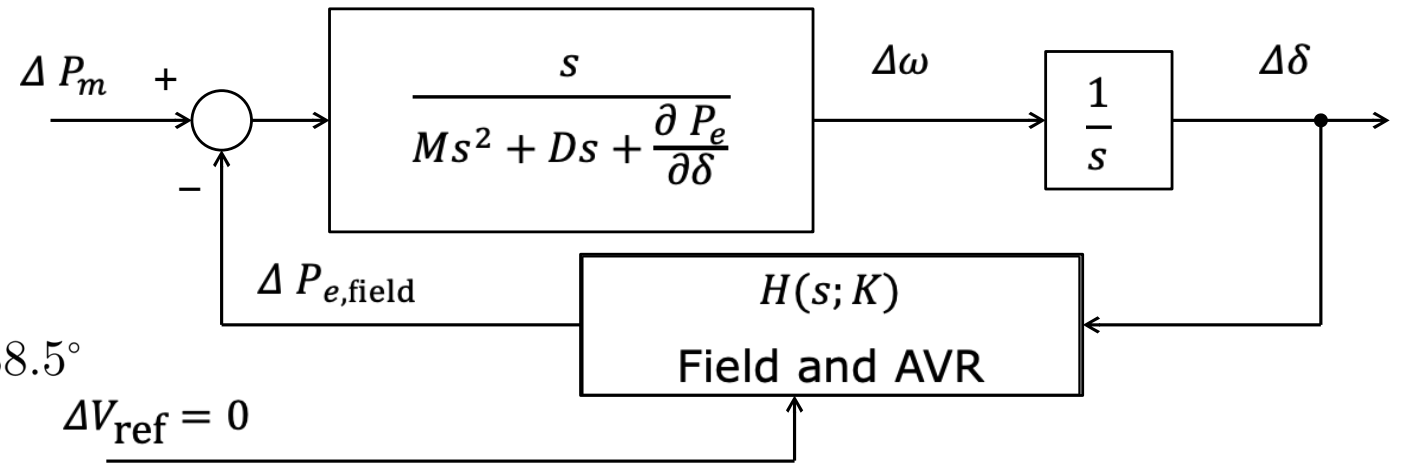
$$K_X = \frac{X_d - X_m}{X_m + X_{\text{th}}} \qquad P_e = \frac{EV_0}{X_m + X_{\text{th}}}\sin\delta$$

https://courses.grainger.illinois.edu/ece576/sp2018/Sauer and Pai book - Jan 2007.pdf#page=241

Example: increase AVR gain while keeping the voltage reference fixed

Parameter	Value
X_d, X_m	1.8, 0.3
X_{th}, V_0	0.5, 1
H	4 s
T_E, T_A	5 s, 0.2 s
ω_s	$2\pi\times50$ rad/s
M, D	$2H/\omega_s$, $2/\omega_s$
K	5 or 100





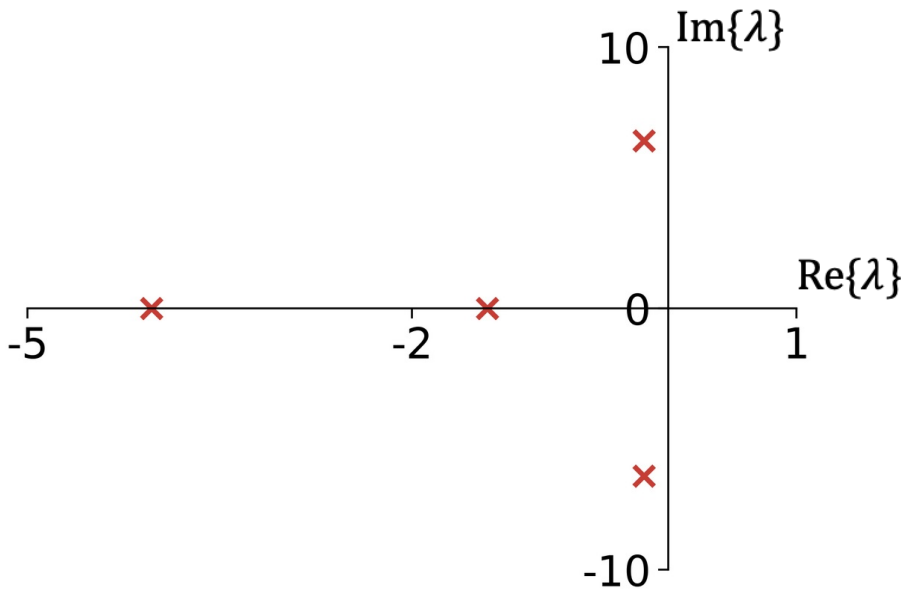
$$K = 5: \quad V^\circ = 1, \quad \theta^\circ = 25^\circ, \quad \delta^\circ = 38.5^\circ$$

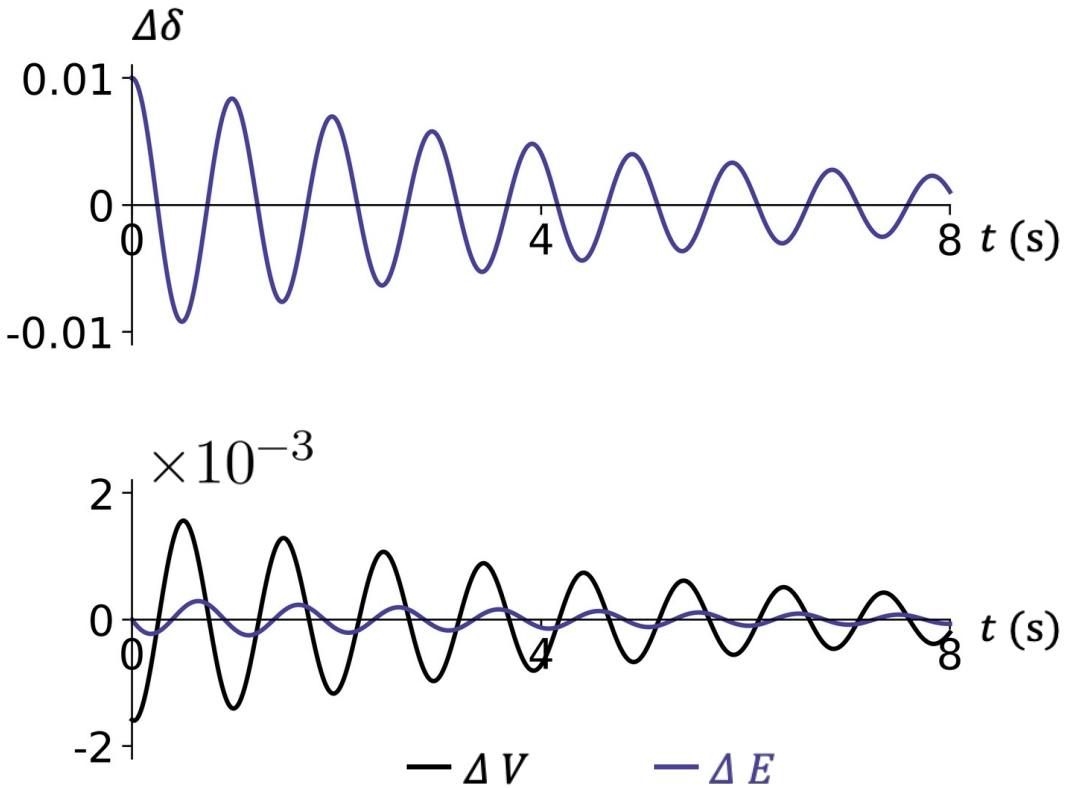
At $t = 0$, increase δ by 0.01

With lower AVR gain, all poles lie in the left half-plane

$$K = 5$$

$$\lambda = -0.2 \pm j6.4$$

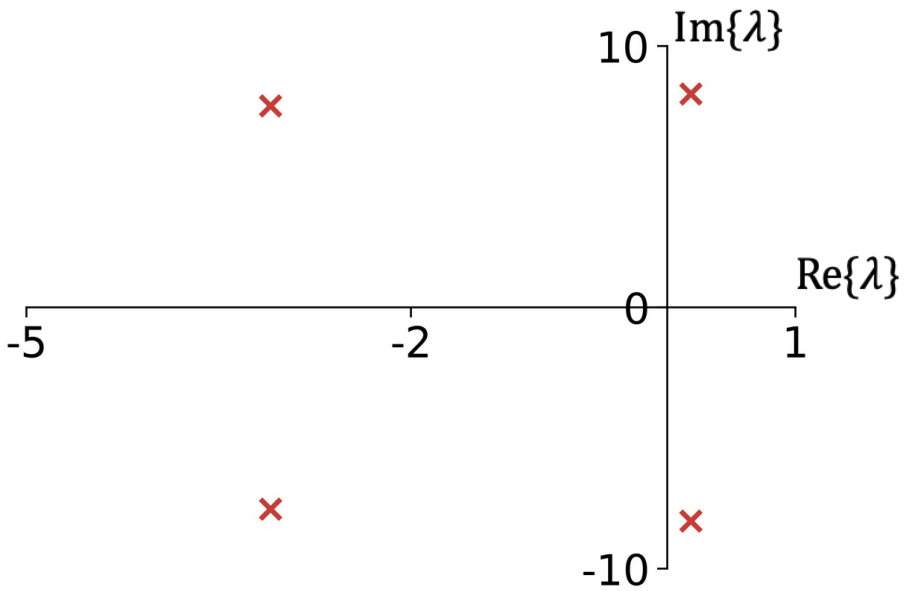


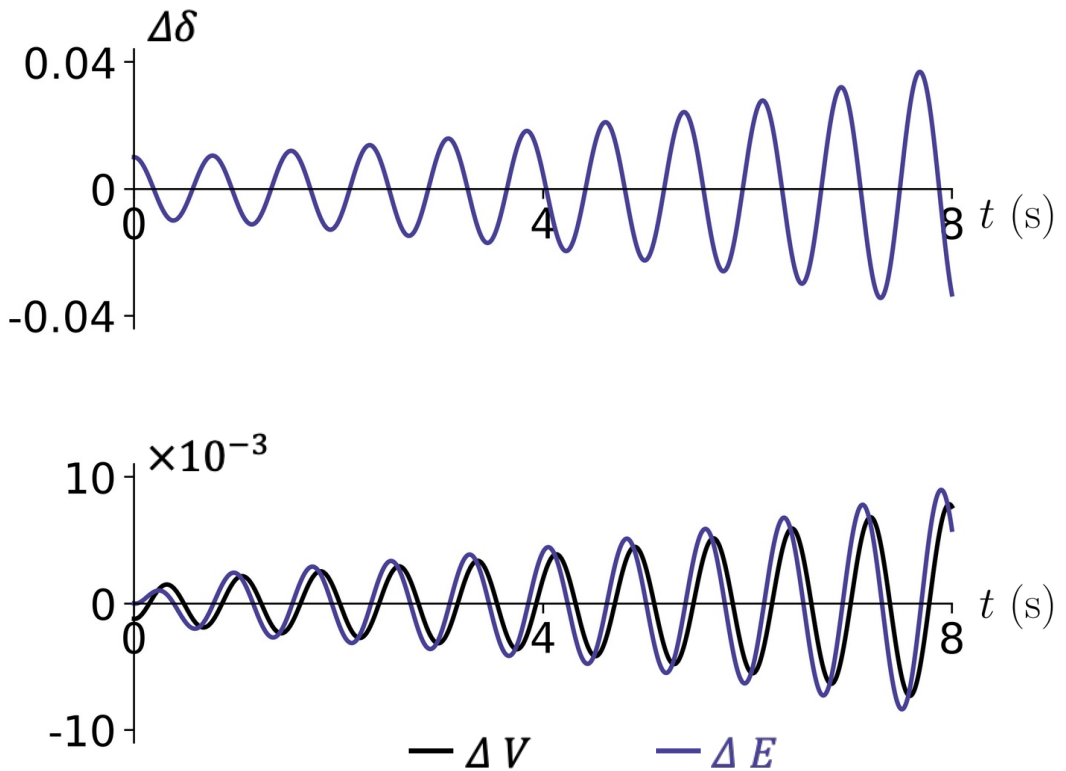


With higher AVR gain, one pole pair moves into the right half-plane

$$K = 100$$

$$\lambda = 0.2 \pm j8.2$$





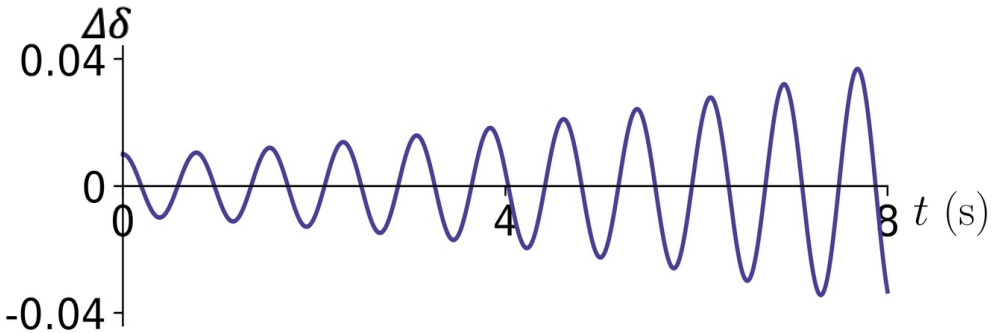
Small signal stability assesses the stability of *modes*, not states.

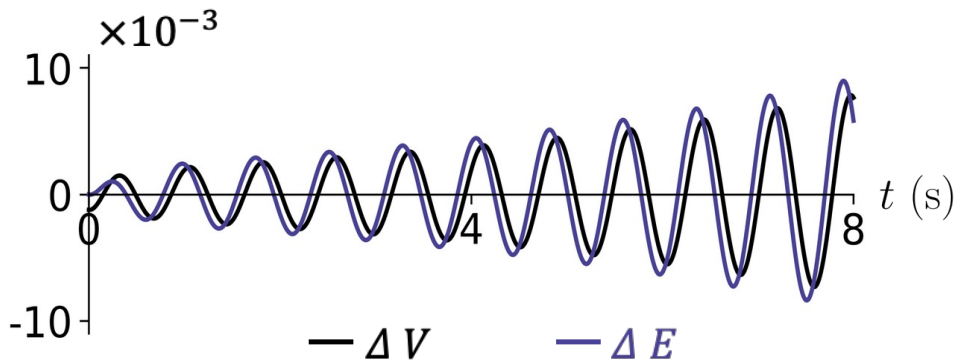
For a given mode,
the eigenvector gives the mode shape—the relative amplitudes and phases of the state variables,
the eigenvalue (pole) gives the mode's growth/decay rate and oscillation frequency.

This system has 4 states $\Delta x = \begin{bmatrix} \Delta\delta \\ \Delta\omega \\ \Delta E \\ \Delta E_{fd} \end{bmatrix}$ and two unstable modes with eigenvalues $\lambda = 0.2 \pm j8.2$

The unstable mode produces oscillations in both angle

and voltage according to its eigenvector $\boldsymbol{\rho} \approx \begin{bmatrix} 1 \\ 0.2 + j8.2 \\ -0.03 - j0.2 \\ 10.2 - j2.2 \end{bmatrix}$



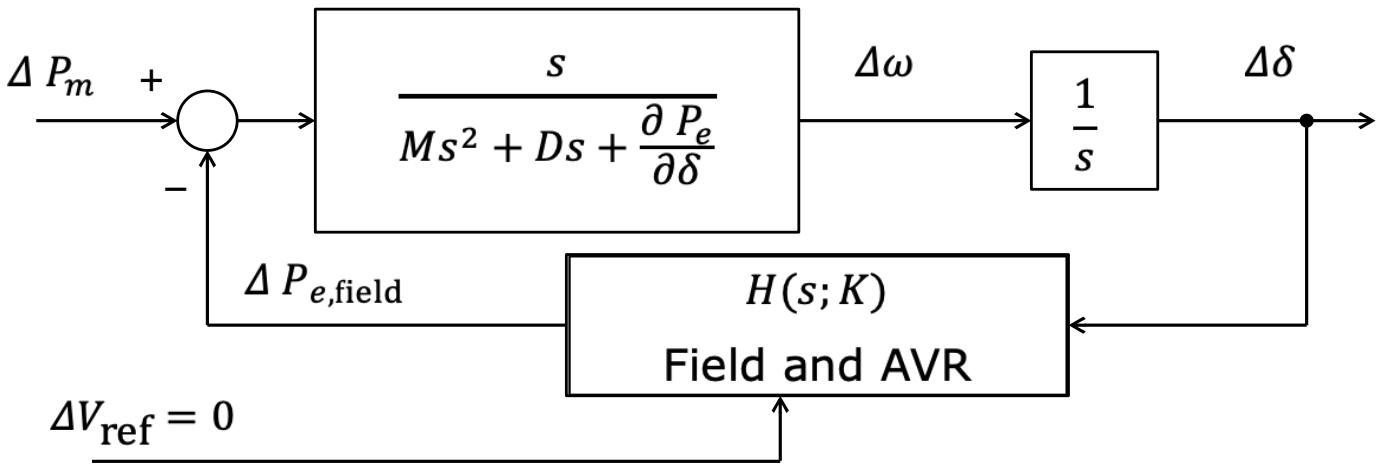


Summary: Unintended effects of the AVR

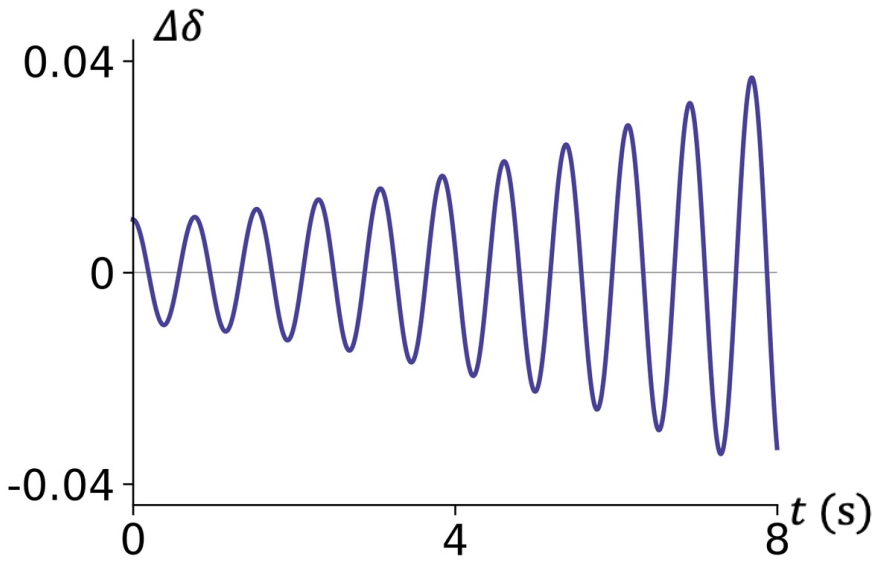
The AVR regulates terminal voltage by changing excitation.

Its delayed electrical-power response can add energy to a rotor swing.

This can produce negative damping.



Simulation with $K = 100,\ \Delta\delta(0) = 0.01$



Thus, AVR, which was regulates the voltage magnitude, can destabilize the angle dynamics.

Participation factors and parameter sensitivities

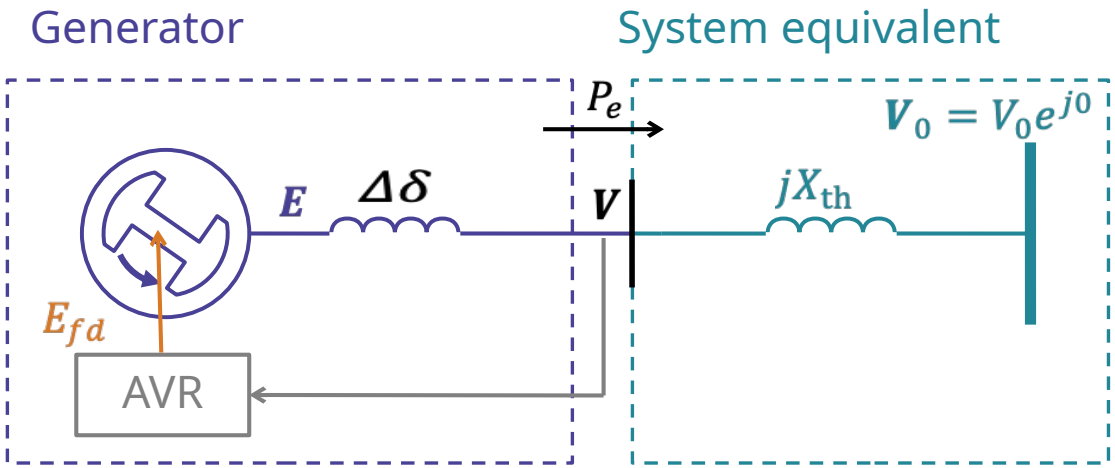
Where do the poles come from?

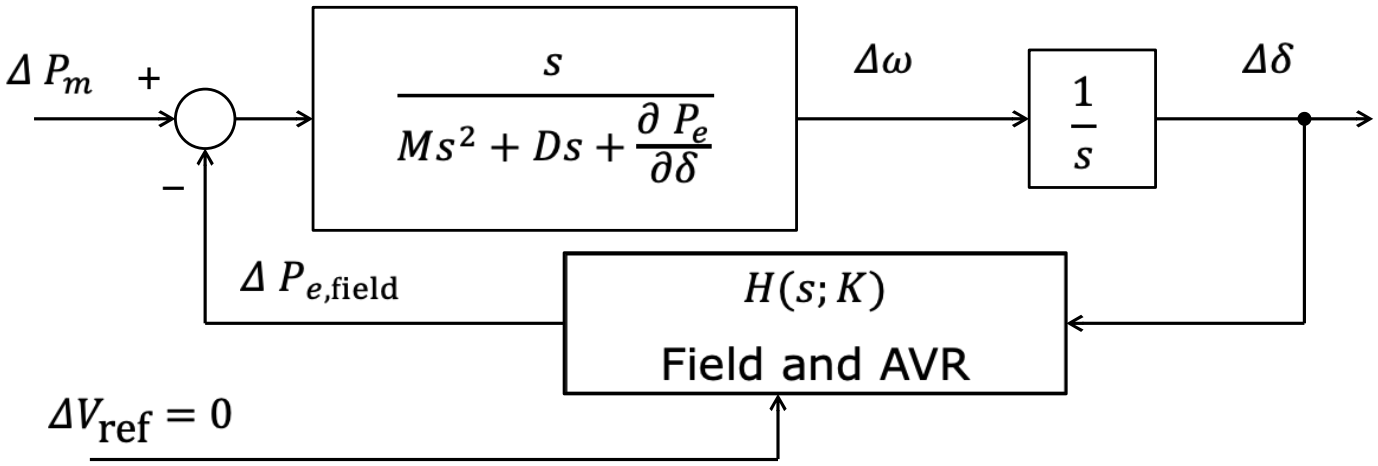
For the simple single-machine system: $\Delta x = \begin{bmatrix} \Delta\delta \\ \Delta\omega \\ \Delta E \end{bmatrix}$

$$\frac{d\Delta x}{dt} = A\Delta x$$

$$A = \begin{bmatrix} 0 & 1 & 0 & 0 \\ -\frac{1}{M}\frac{\partial P_e}{\partial \delta} & -\frac{D}{M} & -\frac{1}{M}\frac{\partial P_e}{\partial E} & 0 \\ -\frac{K_X V_0 \sin\delta^\circ}{T_E} & 0 & -\frac{1+K_X}{T_E} & \frac{1}{T_E} \\ -\frac{K}{T_A}\frac{\partial V}{\partial \delta} & 0 & -\frac{K}{T_A}\frac{\partial V}{\partial E} & -\frac{1}{T_A} \end{bmatrix}$$

You do not have to memorize this matrix.





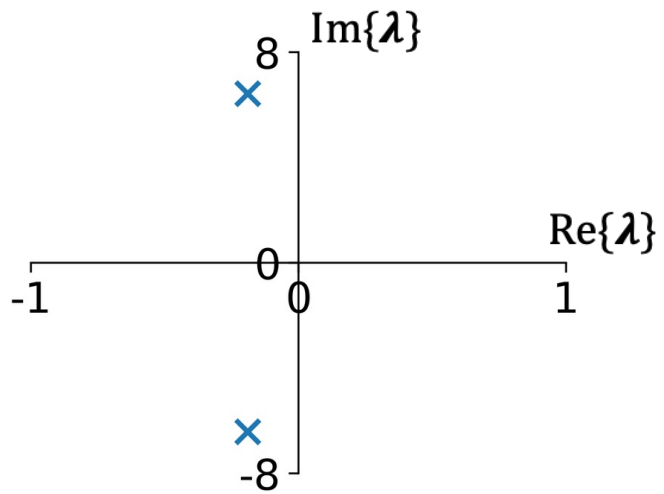
$\boldsymbol{\lambda}_i$: The system poles, which describe growth and frequency of each mode. Eigenvalues of A.

Each **right Eigenvector** $\boldsymbol{\rho}_i$ describes a system mode.

$$A\boldsymbol{\rho}_i = \boldsymbol{\lambda}_i\boldsymbol{\rho}_i, \qquad \boldsymbol{\lambda}_i = \sigma_i + j\omega_i$$

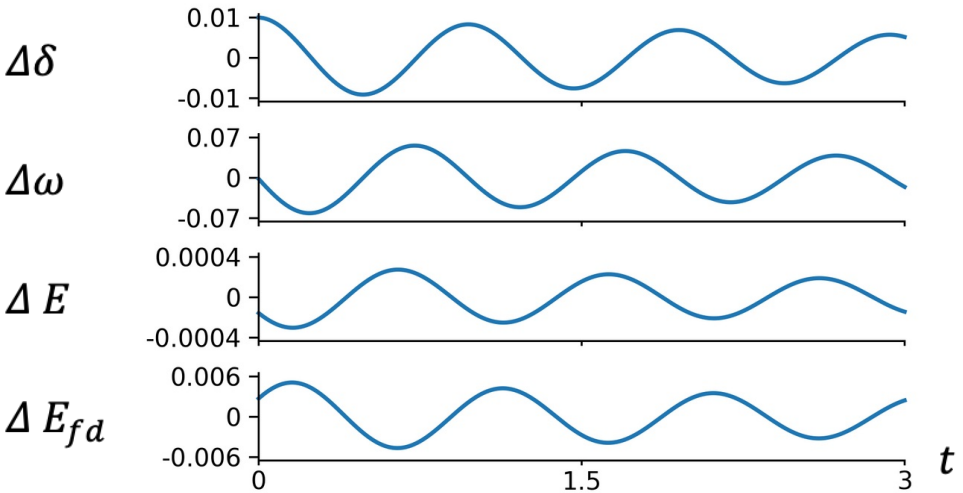
i selects a mode. σ_i is its growth rate.

ω_i is its oscillation frequency in rad/s.



For the Single-Machine system: $\boldsymbol{\rho}_i = \begin{bmatrix} \boldsymbol{\rho}_{\delta,i} \\ \boldsymbol{\rho}_{\omega,i} \\ \boldsymbol{\rho}_{E,\mathrm{i}} \\ \boldsymbol{\rho}_{E_{fd},i} \end{bmatrix}$

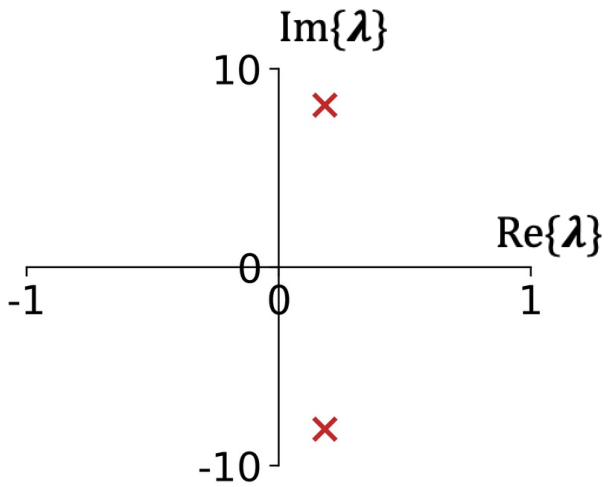
One mode:

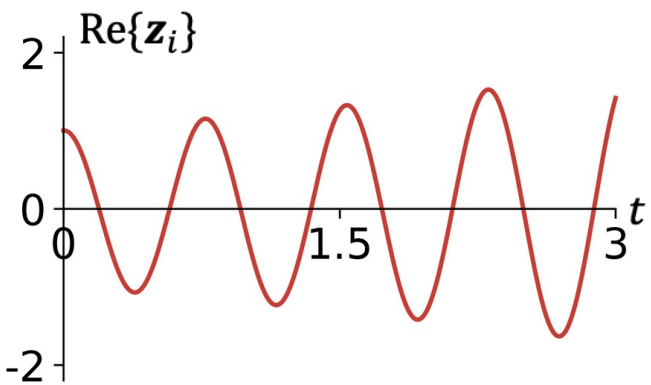


The **modes** of a linear system describe its independent directions of movement.

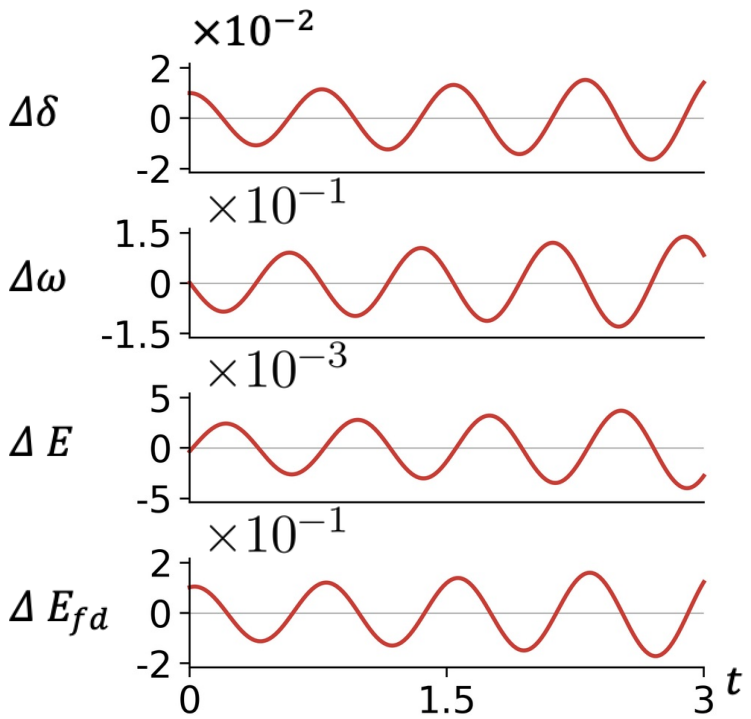
They are a convenient way of describing linear system dynamics as often just one mode is unstable.

$$\Delta \boldsymbol{x} = \boldsymbol{\rho}_1 \boldsymbol{z}_1 + \cdots + \boldsymbol{\rho}_n \boldsymbol{z}_n \qquad \boldsymbol{z}_i(t) = \boldsymbol{z}_i(0) e^{\lambda_i t}$$





States in this mode



Which states participate in each mode?

Left eigenvectors determine how each state excites each mode.

$$\boldsymbol{z}_i(0) = \boldsymbol{\gamma}_i \Delta \boldsymbol{x}(0), \qquad \boldsymbol{\gamma}_i = [\boldsymbol{\gamma}_{i1} \quad \cdots \quad \boldsymbol{\gamma}_{in}]$$

For a diagonalizable A,

$$A = \underbrace{[\boldsymbol{\rho}_1 \quad \cdots \quad \boldsymbol{\rho}_n]}_{R} \underbrace{\begin{bmatrix} \lambda_1 & & 0 \\ & \ddots & \\ 0 & & \lambda_n \end{bmatrix}}_{\Lambda} \underbrace{\begin{bmatrix} \boldsymbol{\gamma}_1 \\ \vdots \\ \boldsymbol{\gamma}_n \end{bmatrix}}_{R^{-1}}$$

Participation factors combine left and right eigenvectors.

$$\boldsymbol{p}_{ki} := \rho_{ki} \boldsymbol{\gamma}_{ik}$$

k selects a state. i selects a mode.

For a mode i, large $|\boldsymbol{p}_{ki}|$ identifies strongly participating states.

Normalized magnitude: $\frac{|p_{ki}|}{\sum_{\ell=1}^{n} |p_{\ell i}|} \times 100\%$

https://courses.grainger.illinois.edu/ece576/sp2018/Sauer and Pai book - Jan 2007.pdf#page=242

https://doi.org/10.1109/TPAS.1982.317524 https://doi.org/10.1109/TPAS.1982.317525

Parameter sensitivities: How sensitive is an eigenvalue to changes in a parameter?

For a simple/nonrepeated eigenvalue:

$$A\,\rho_k = \lambda_k \rho_k \,,\; \gamma_k A = \lambda_k \gamma_k \,,\; \gamma_k \rho_k = 1$$

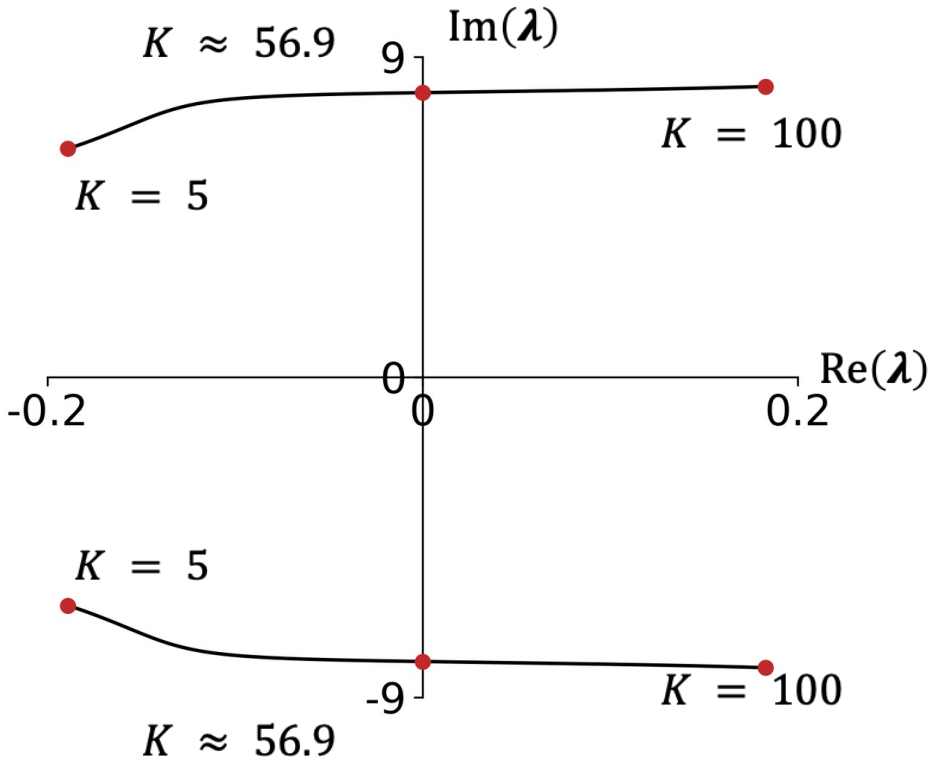
Sensitivity to a matrix entry:

$$\frac{\partial \lambda_k}{\partial a_{ij}} = \gamma_{ki}\,\rho_{kj}$$

$$\Delta \lambda_k \approx \gamma_k \Delta A \rho_k$$

Sensitivity to a parameter K in $A(K)$:

$$\frac{d \lambda_k}{dK} = \gamma_k \frac{dA}{dK} \rho_k$$



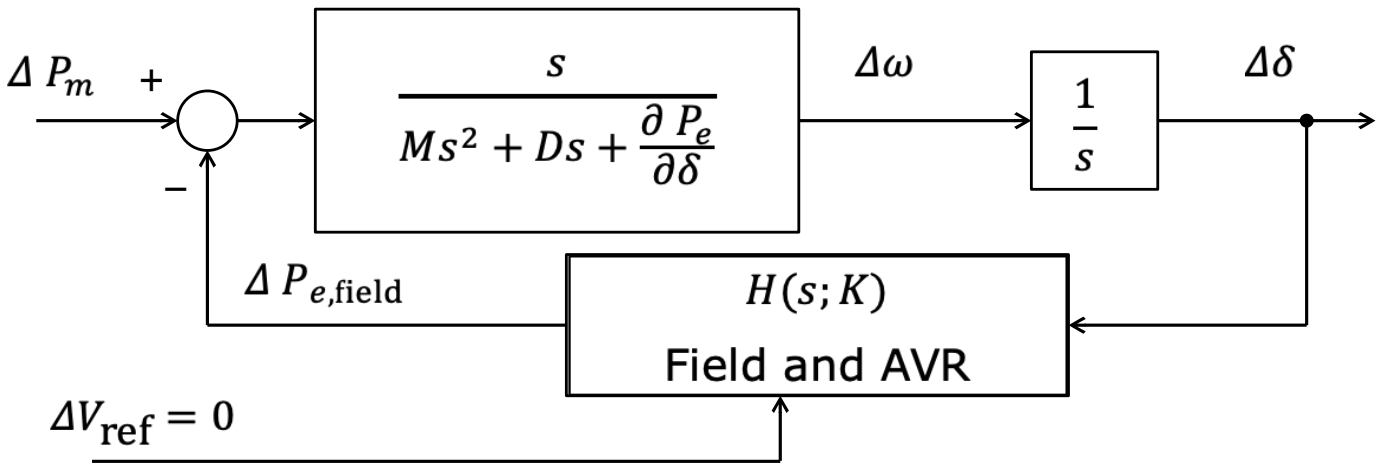
Increasing K moves the pole right, towards instabilityRe((dλ_(k))/(dK))> 0

Recall: Unintended effects of the AVR

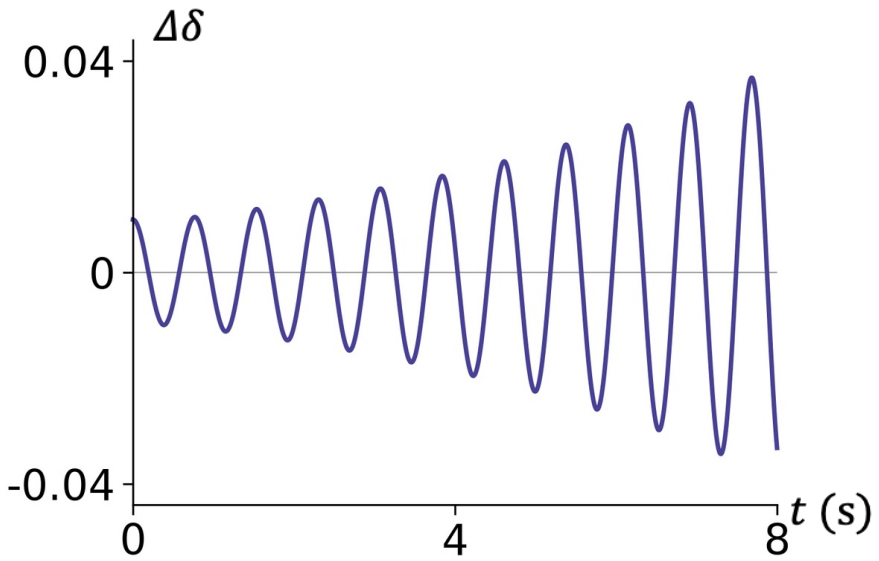
The AVR regulates terminal voltage by changing excitation.

Its delayed electrical-power response can add energy to a rotor swing.

This can produce negative damping.



Simulation with $K = 100$, $\Delta\delta(0) = 0.01$



Thus, AVR, which was regulates the voltage magnitude, can destabilize the angle dynamics.

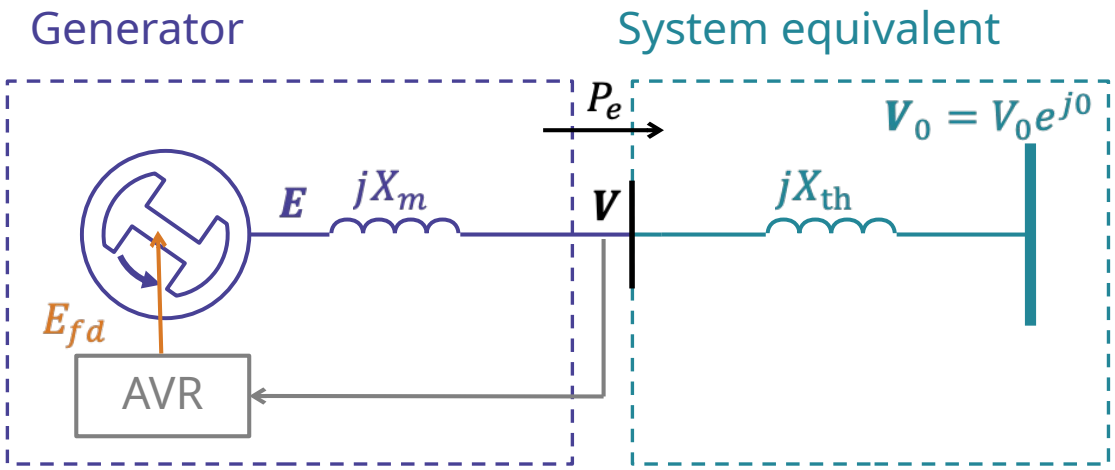
Which states dominate the unstable mode? → Participation Factors

K = 100, λ_(i) ≈ 0.2 + j8.2

$$\Delta x = \begin{bmatrix} \Delta\delta \\ \Delta\omega \\ \Delta E \\ \Delta E_{fd} \end{bmatrix}$$

Normalized participation

$$\begin{bmatrix} 44.7\% \\ 44.7\% \\ 5.5\% \\ 5.1\% \end{bmatrix}$$



Angle and speed: 89.4% Voltage and excitation: 10.6%

→ The AVR destabilizes a mode dominated by rotor motion.

Does increasing *K* destabilize the rotor mode? → Sensitivity analysis

$$\mathrm{A}\boldsymbol{\rho}_1 = \boldsymbol{\lambda}_1\boldsymbol{\rho}_1, \qquad \boldsymbol{\gamma}_1\mathrm{A} = \boldsymbol{\lambda}_1\boldsymbol{\gamma}_1, \qquad \boldsymbol{\gamma}_1\boldsymbol{\rho}_1 = 1$$

Stability depends on the real part of a pole.

$$\frac{\mathrm{dRe}(\boldsymbol{\lambda}_1)}{\mathrm{d}K} = \mathrm{Re}\left(\frac{\mathrm{d}\boldsymbol{\lambda}_1}{\mathrm{d}K}\right)$$

Sensitivity of the unstable mode:

$$\frac{\mathrm{d}\boldsymbol{\lambda}_1}{\mathrm{d}K} = \boldsymbol{\gamma}_1\left(\frac{\mathrm{dA}}{\mathrm{d}K}\right)\boldsymbol{\rho}_1$$

$$\mathrm{Re}\left(\frac{\mathrm{d}\boldsymbol{\lambda}_1}{\mathrm{d}K}\right) \approx 3\times10^{-3} > 0$$

→ increasing K makes mode more unstable

Unstable rotor mode at $K = 100$:

$\boldsymbol{\lambda}_1 \approx 0.2 + j8.2$

$$\gamma_1 \approx \begin{bmatrix} 1.0 \\ -j0.1 \\ 0.3+j0.5 \\ 0.011 \end{bmatrix}^{\mathrm{T}} \qquad \rho_1 \approx \begin{bmatrix} 0.5 \\ j3.7 \\ -j0.1 \\ 4.6-j0.9 \end{bmatrix}$$

$$\left.\frac{dA}{dK}\right|_{K=100} \approx \begin{bmatrix} 0 & 0 & 0 & 0 \\ -0.02 & 0 & 0.006 & 0 \\ 0.00004 & 0 & 0 & 0 \\ 0.6 & 0 & -3.1 & 0 \end{bmatrix}.$$

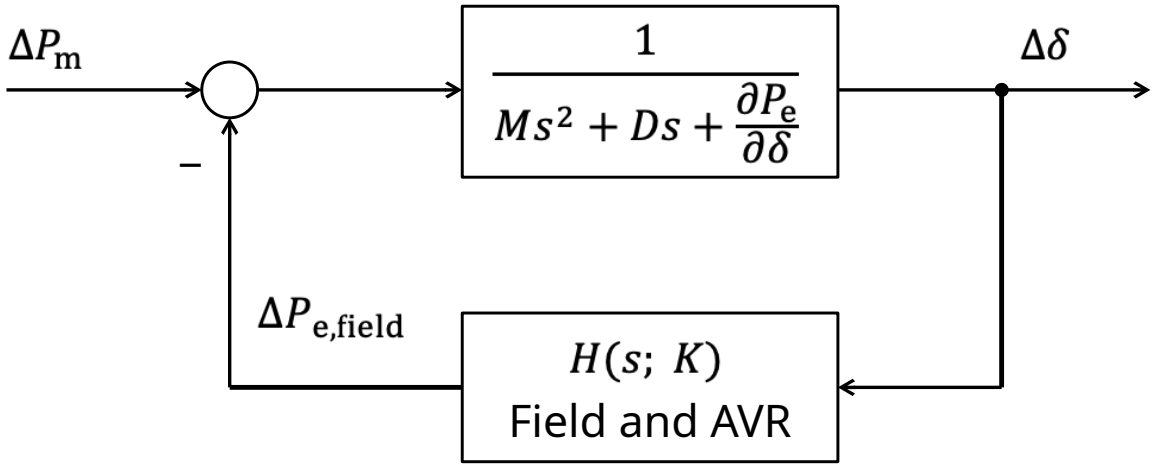
When does the rotor mode cross the jω axis?

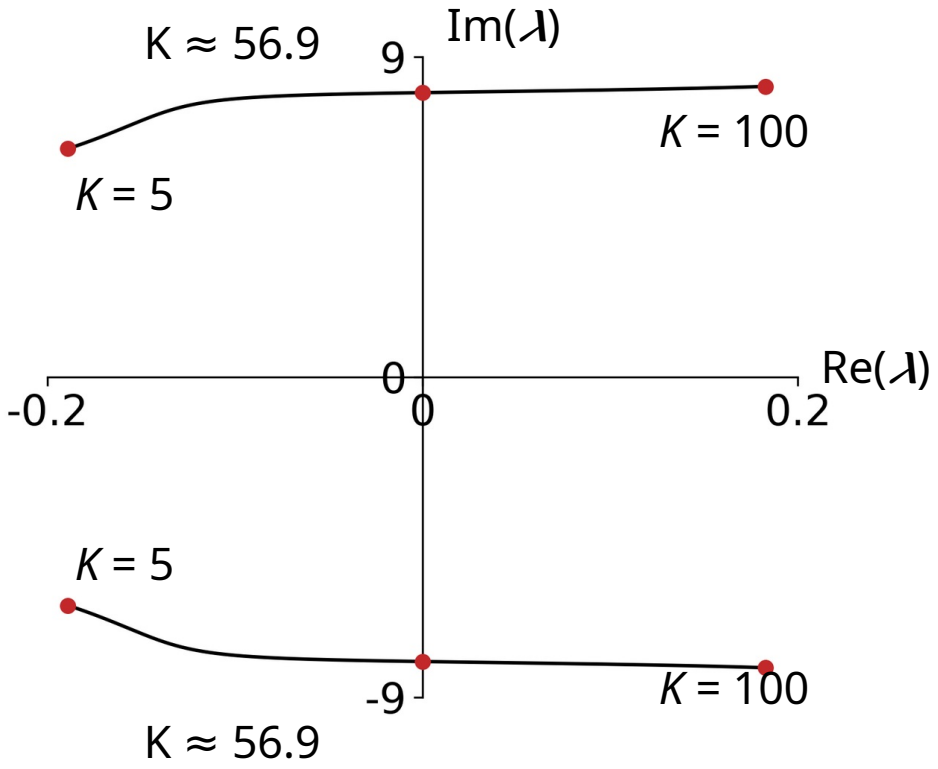
Vref and Pm remain at their K = 5 values.

$K = 5$ $\quad \dfrac{d\,\mathrm{Re}(\lambda_1)}{dK} \approx 1.6 \times 10^{-2}$

K ≈ 56.9 $\quad \dfrac{d\,\mathrm{Re}(\lambda_1)}{dK} \approx 4.4 \times 10^{-3}$

$K = 100$ $\quad \dfrac{d\,\mathrm{Re}(\lambda_1)}{dK} \approx 3 \times 10^{-3}$

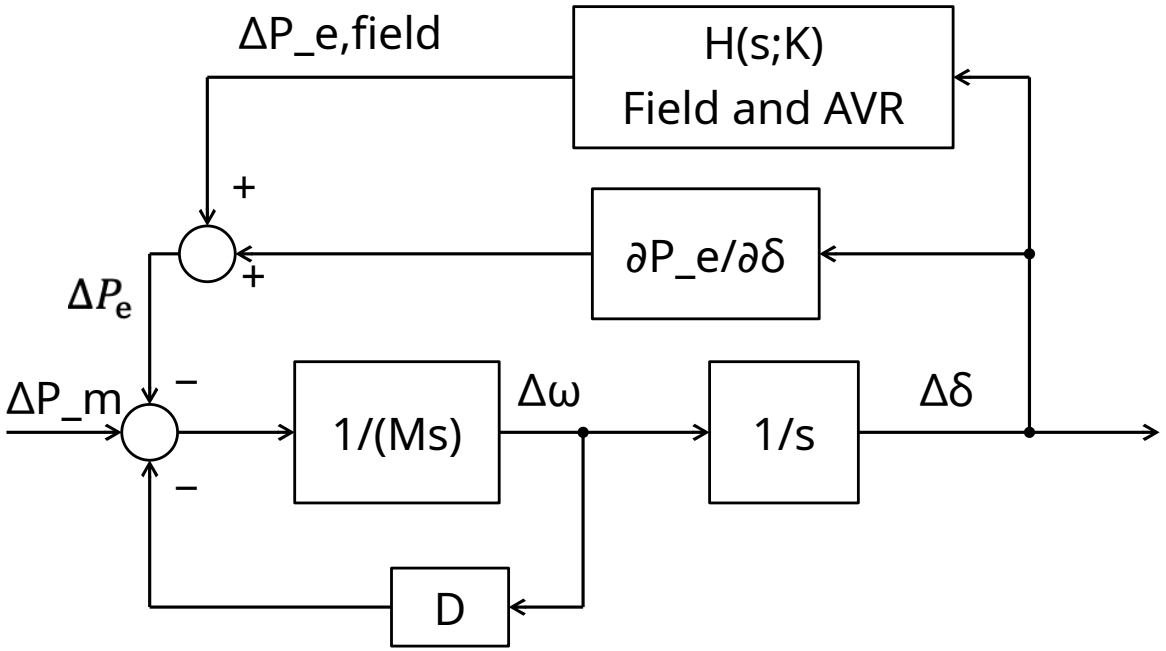




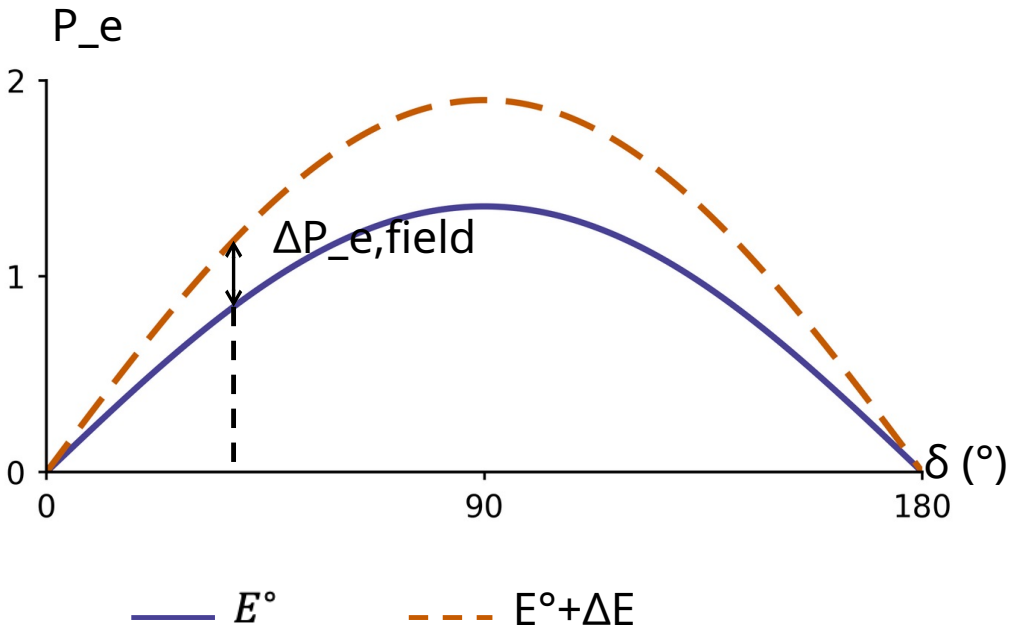
At all three gains, increasing *K* moves this pole pair to the right.

How does the AVR feedback affect angle damping?

$$\Delta P_e = \frac{\partial P_e}{\partial \delta}\Delta\delta + \Delta P_{e,field}$$



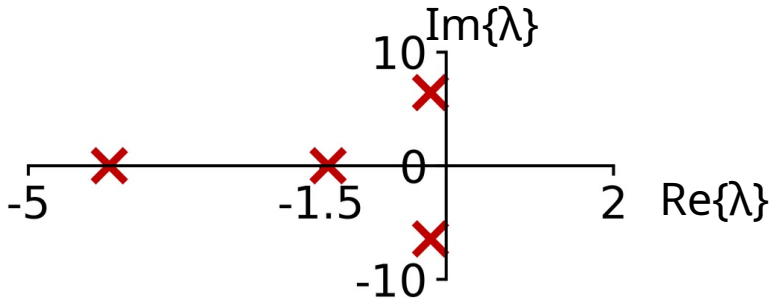
ΔP_e,field=(∂P_e/∂E)ΔE

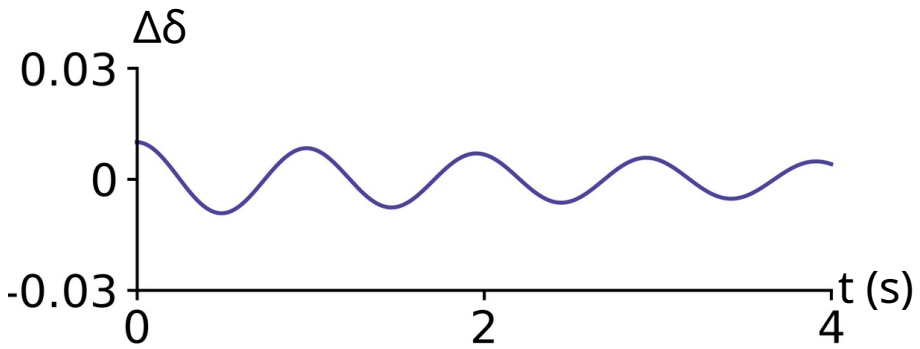


How does AVR gain affect the rotor poles and oscillations?

Low AVR gain

K=5, λ≈−0.2±j6.4

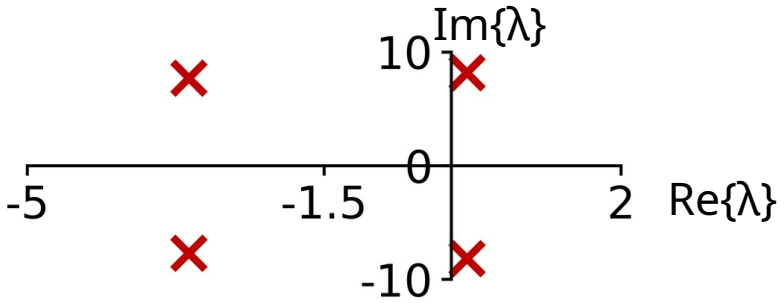


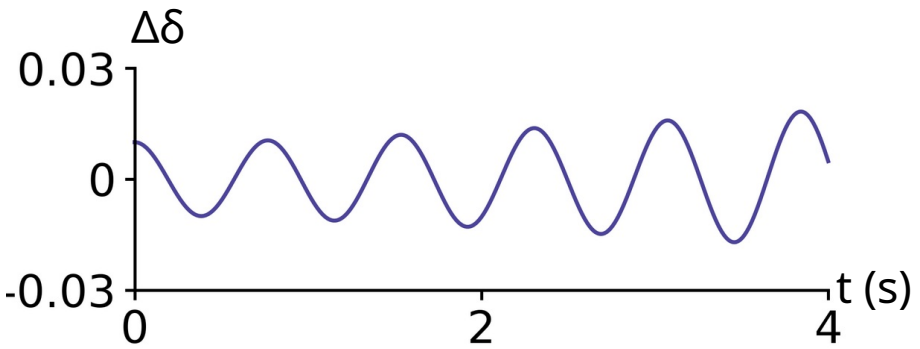


Negative real part: the oscillation decays.

High AVR gain

K=100, λ≈0.2±j8.2





Positive real part: the oscillation grows.

Does the field-induced electrical power brake or reinforce the rotor's swing?

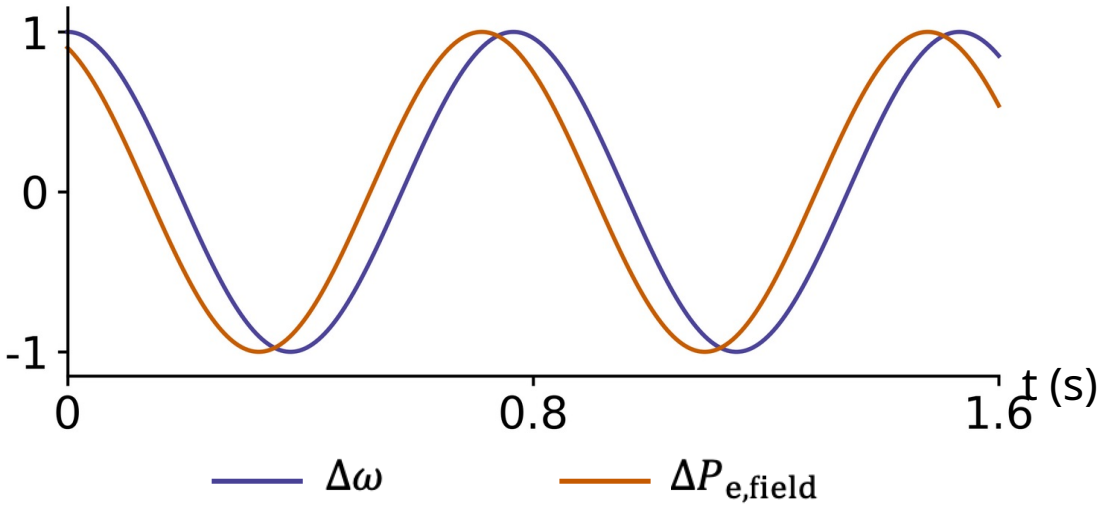
P_e increases when the rotor runs fast → brakes the swing

P_e decreases when the rotor runs fast → reinforces the swing

f = 8.2/(2π) ≈ 1.3 Hz

The timing depends on K, the AVR's feedback gain

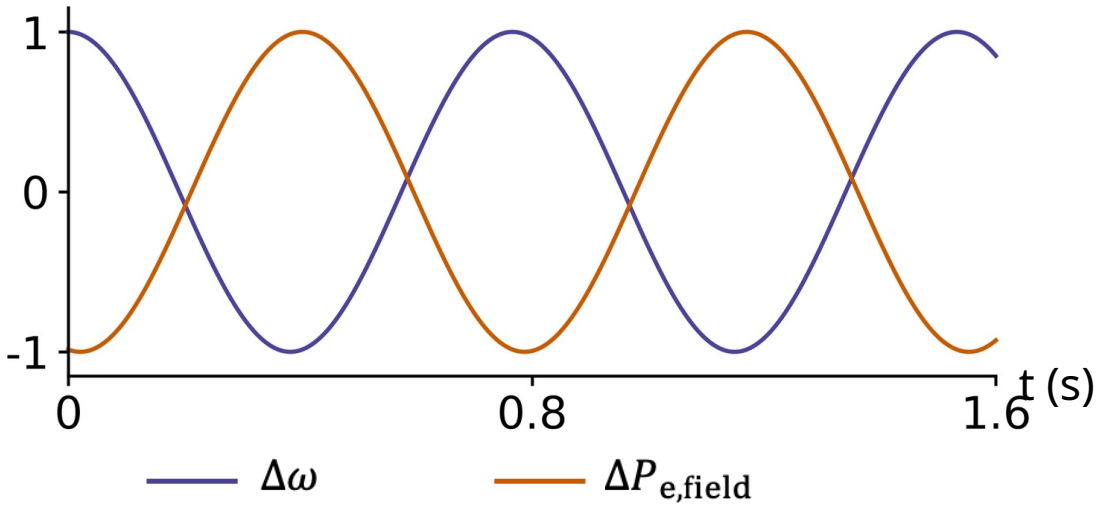
K = 5: phase ≈ +26°



$\Delta P_{e,field}$ is mostly in phase with $\Delta\omega$

→ Positive damping

K = 100: phase ≈ −190°



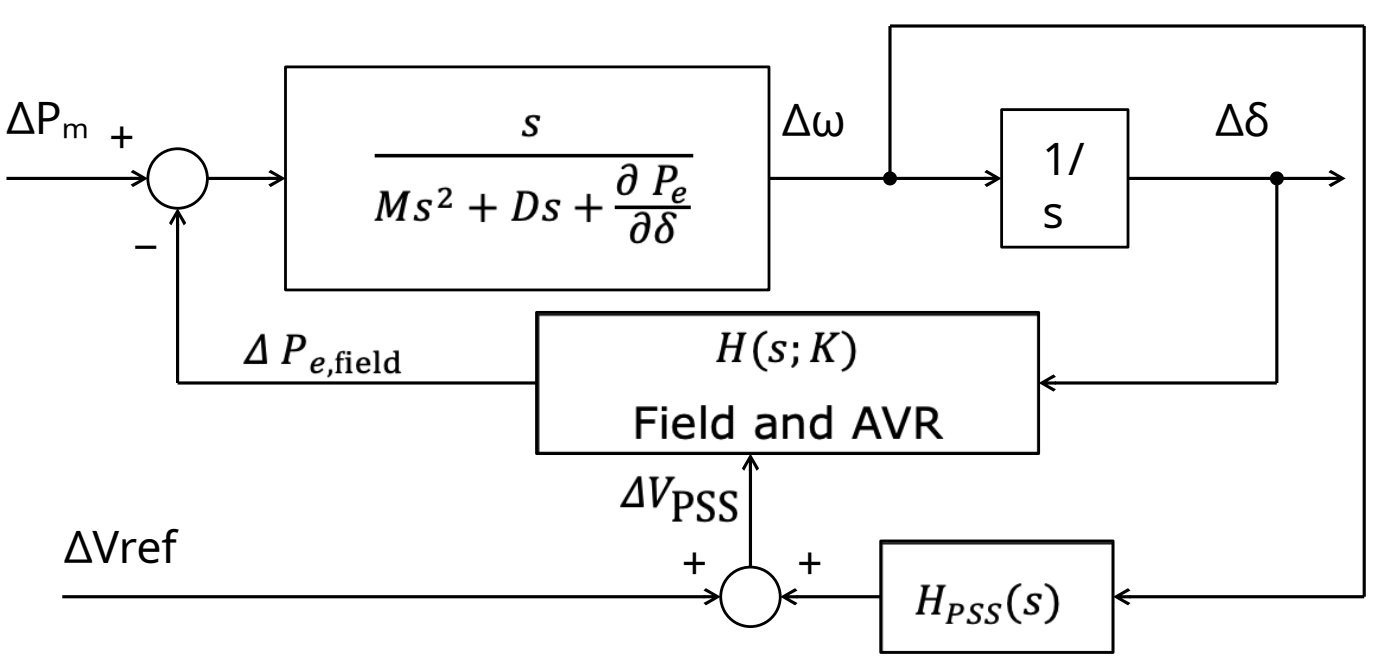
$\Delta P_{e,field}$ is mostly out of phase with $\Delta\omega$

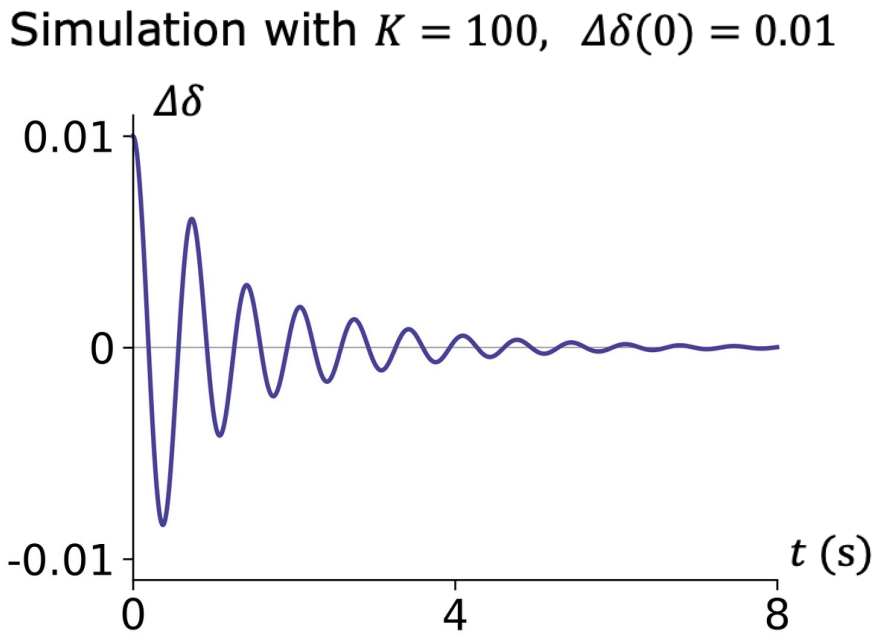
→ Negative damping

Power System Stabilizers (PSSs) are an additional feedback loop to damp rotor swings.

A PSS uses rotor-speed deviations to add a stabilizing signal to the AVR.

Properly timed excitation changes remove energy from the swing.





Example: $H_{PSS}(s) = \frac{4}{\omega_s}\frac{5s}{1+5s}\left(\frac{1+0.3s}{1+0.1s}\right)^2$

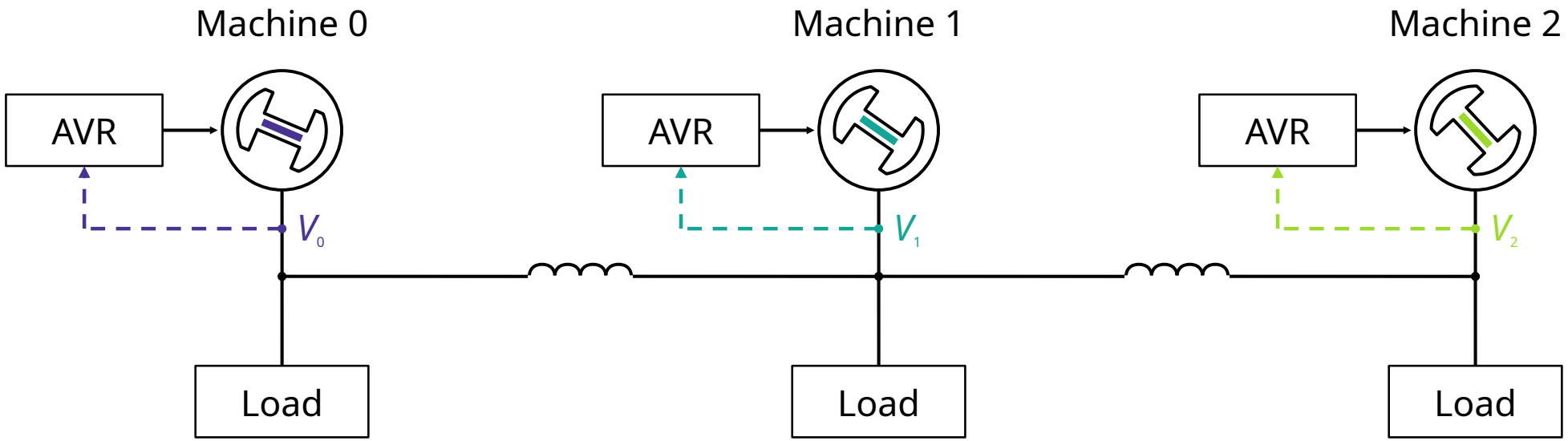
Oscillations in grids with many machines

All of the methods we have discussed thus far apply to grids with many machines, buses, and loads.

The state dimension of x is larger and the linearized dynamics matrix A is more difficult to compute.

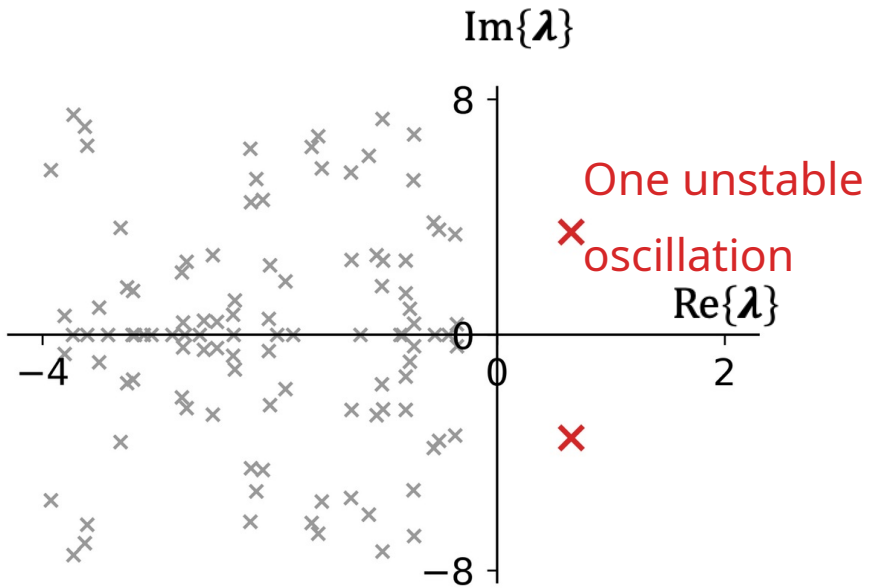
Commercial software can compute A (which is useful if the nonlinear model is accurate).
AVRs can produce instabilities and PSSs can stabilize the system.
Participation factors and parameter sensitivity calculations are useful tools.

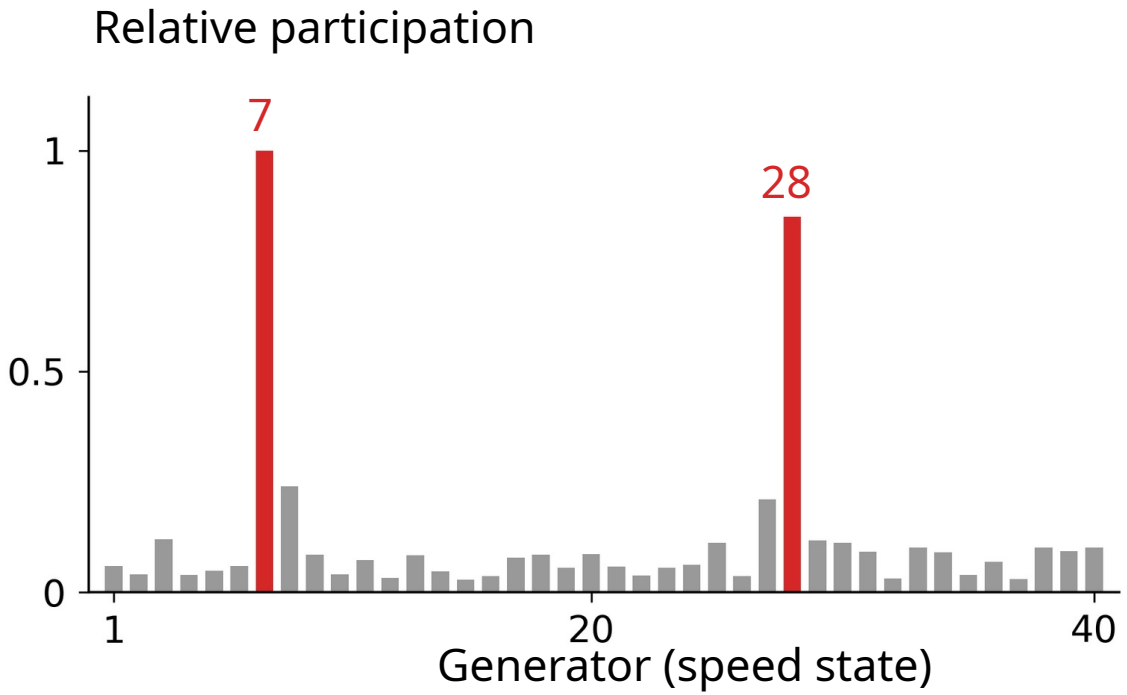
When oscillations arise in grids with many machines, it is hard to determine which generators are responsible for the oscillations.



→ Same Small Signal Analysis tools: linearize and inspect the eigenvalues and eigenvectors

Participation factors are helpful in multi-machine scenarios



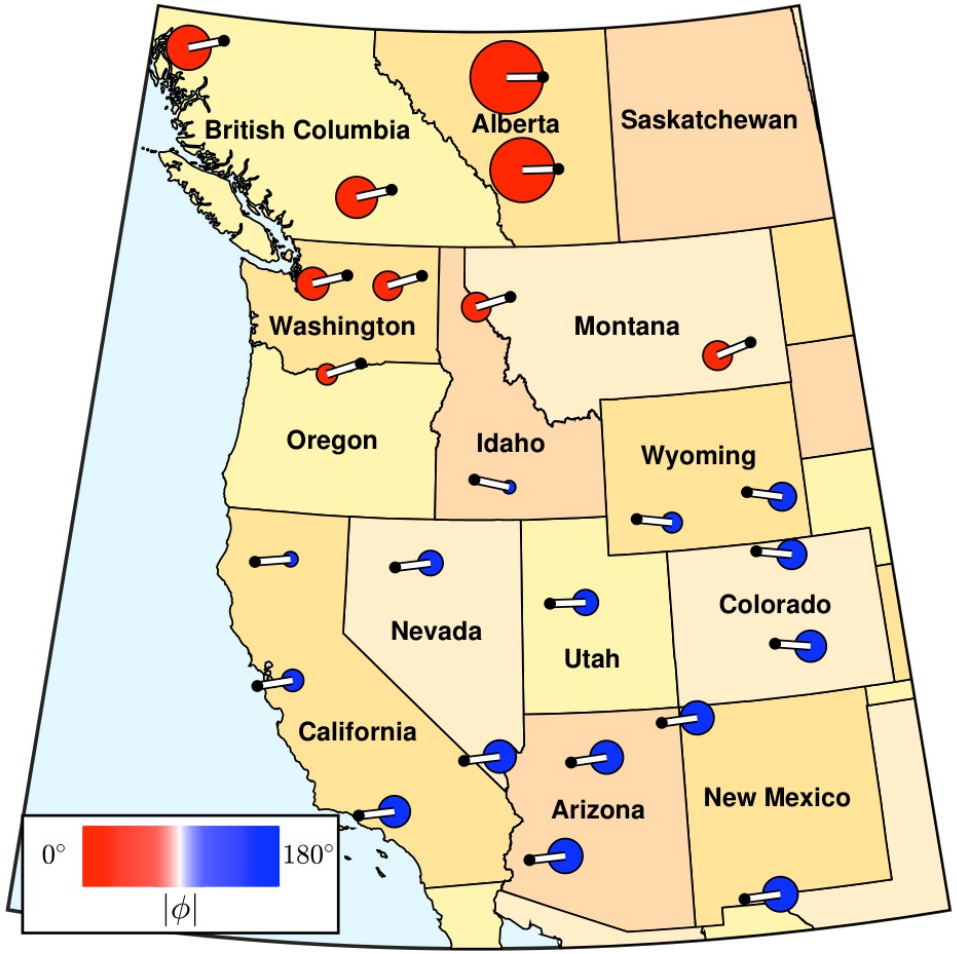


To calculate participation factors, you need

- The admittance matrix Y describing the network
- Dynamics models for all significant generators and loads
- The operating point/state to calculate the linearization

https://doi.org/10.36227/techrxiv.19765591.v1

Where should we add damping for a mode that spans the grid?



North–South A: about 0.25 Hz.

The northern grid, especially Alberta, oscillates against the southern grid.

Participation analysis identifies Alberta generators as important damping locations.

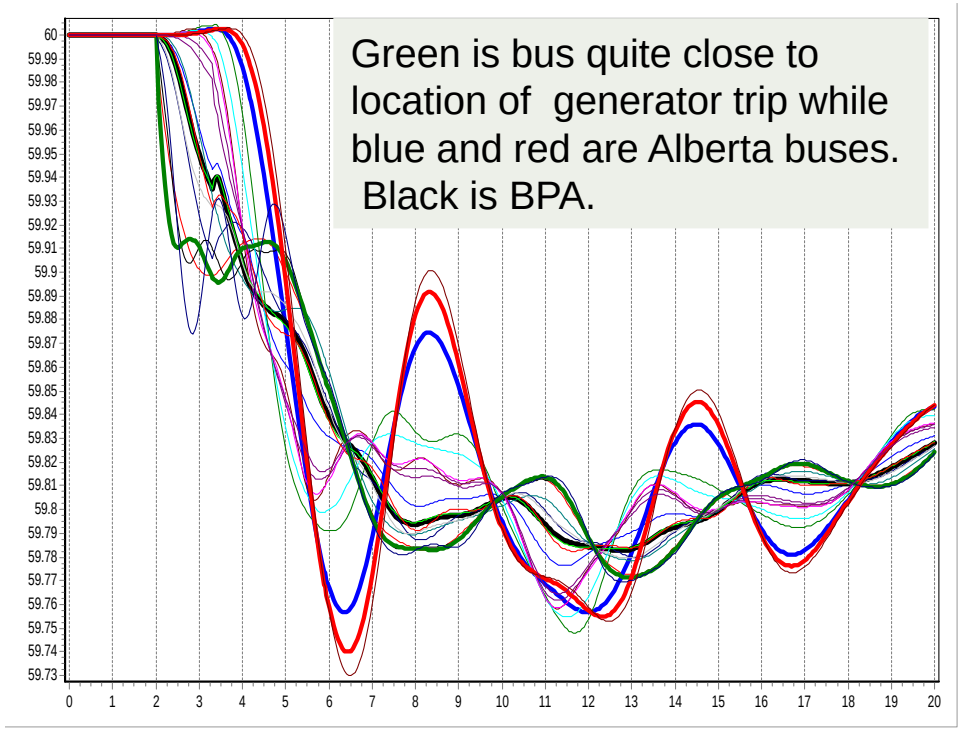
Their power system stabilizers are tuned to the 0.25 Hz North/South mode.

https://doi.org/10.1109/PESGM48719.2022.9916761
https://doi.org/10.36227/techrxiv.19765591.v1

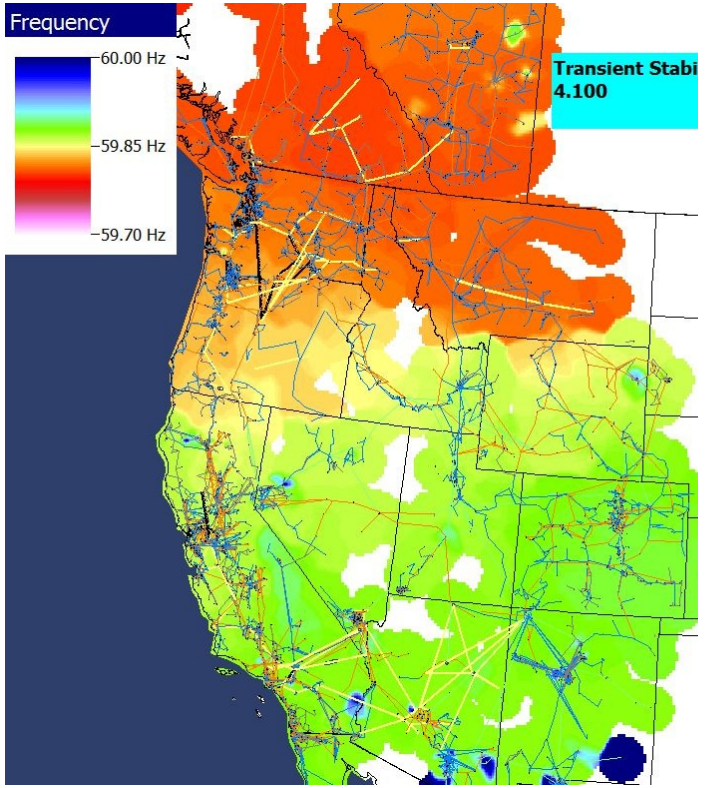
frequency change due to loss of generation in the Southern WECC

The largest swing is in Alberta

Frequency



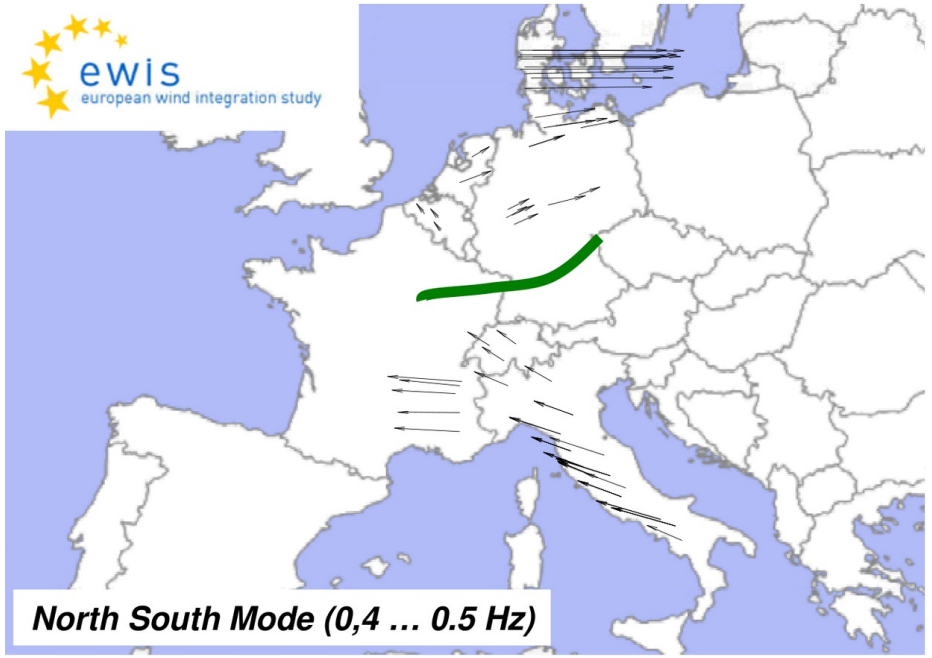
Time (s)



East–West mode 1: about 0.2 Hz



North–South: about 0.4–0.5 Hz



EWIS final report (2010), Figs. 4-22 and 4-24 (2015 scenarios).

Oscillations in Spain prior to the 2025 blackout

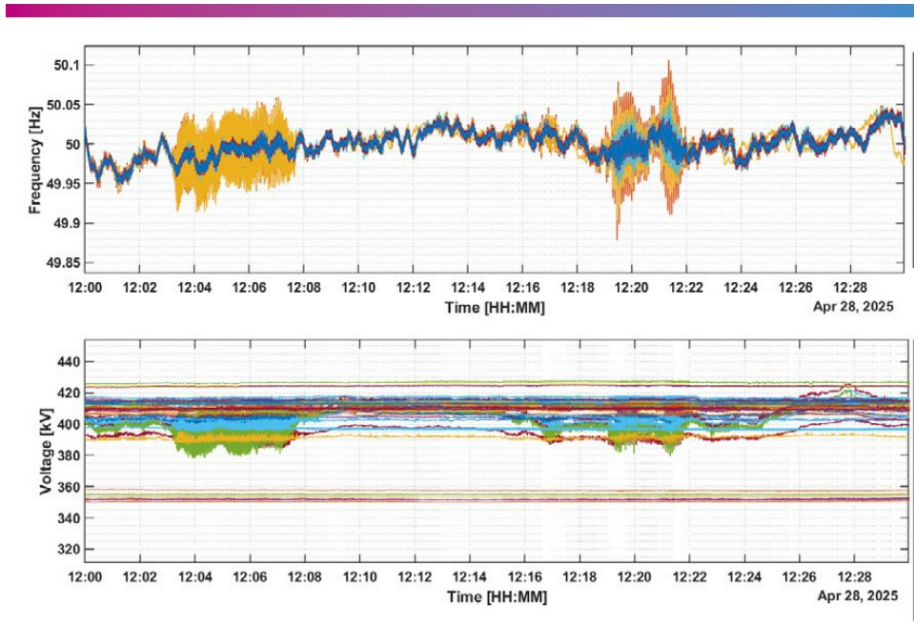


Figure 2-63: Frequency and voltage phasor magnitude measurements from European PMUs

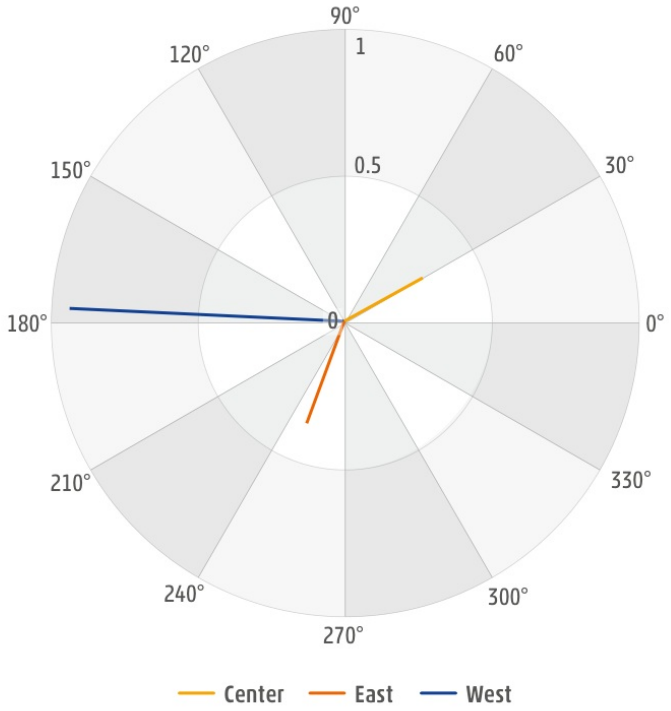


Figure 2-65: Polar plot of the ECW mode at 12:20:00

mode shape of the ≈0.21 Hz oscillation

Arrow length: oscillation amplitude

Arrow direction: oscillation phase

ENTSO-E, *Grid Incident in Spain and Portugal on 28 April 2025: Final Report*, 20 March 2026,

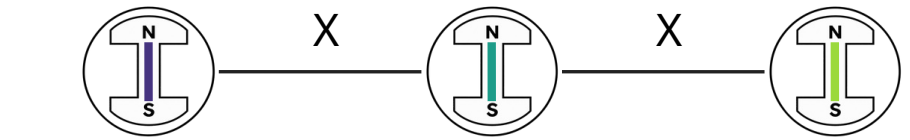
To calculate participation factors, you need

- The admittance matrix $\boldsymbol{Y}$ describing the network
- Dynamics models for all significant generators and loads
- The operating point/state to calculate the linearization

Can we say anything about the grid oscillations from $\boldsymbol{Y}$ alone?

When can the eigendecomposition of $\boldsymbol{Y}$ describe the system modes?

System: Lossless lines. No shunts. Identical inertia M and damping D.
Operating point: Equal fixed internal voltage magnitudes. Equal operating angles.



$$\boldsymbol{Y} = \frac{-\mathrm{j}}{X}\begin{bmatrix} 1 & -1 & 0 \\ -1 & 2 & -1 \\ 0 & -1 & 1 \end{bmatrix}$$

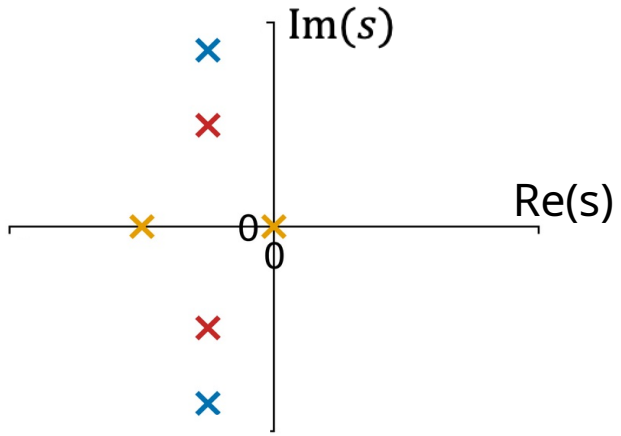
$$\boldsymbol{Y}\boldsymbol{\rho}_k = \boldsymbol{\lambda}_k\boldsymbol{\rho}_k$$

$\rho_0 = [1; 1; 1]$ $\rho_1 = [1; 0; -1]$ $\rho_2 = [1; -2; 1]$

$\lambda_0 = 0$ $\lambda_1 = \frac{-\mathrm{j}}{X}$ $\lambda_2 = -3\mathrm{j}/X$

eigenvectors and eigenvalues of $\boldsymbol{Y}$

$$M\boldsymbol{s}^2 + D\boldsymbol{s} + \mathrm{j}V^2\boldsymbol{\lambda}_k = 0$$



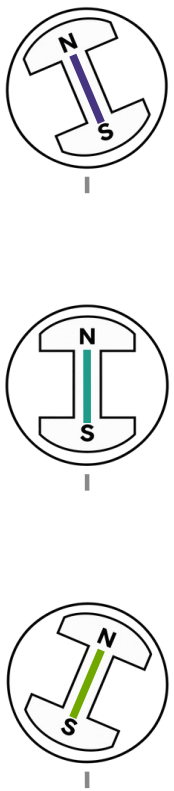
Poles of the dynamic system that includes swing, etc.

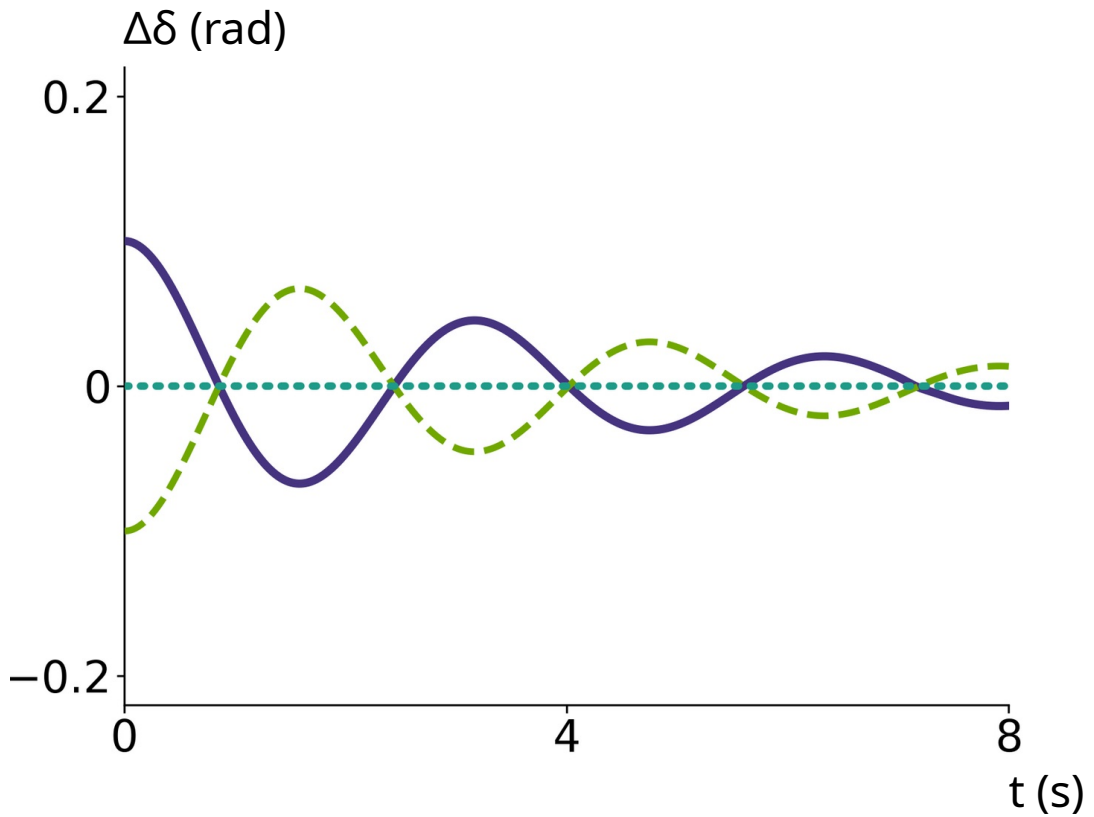
See the Appendix for a derivation of this connection

How do the generators move in Mode 1?

$\Delta\delta 1(0) = 0$

$\Delta\delta 2(0) = -0.1$



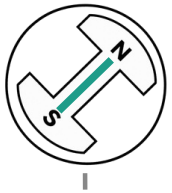


How do the generators move in Mode 2?

$\Delta\delta 0(0) = 0.1$

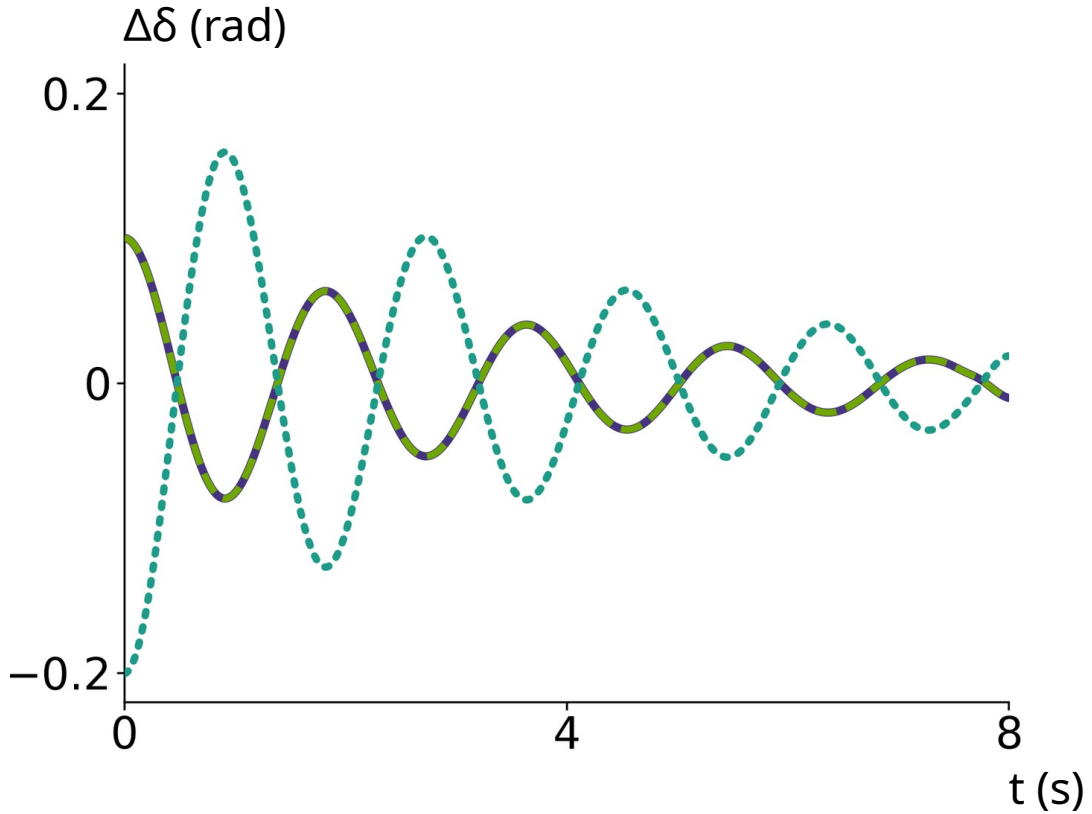


$\Delta\delta 1(0) = -0.2$

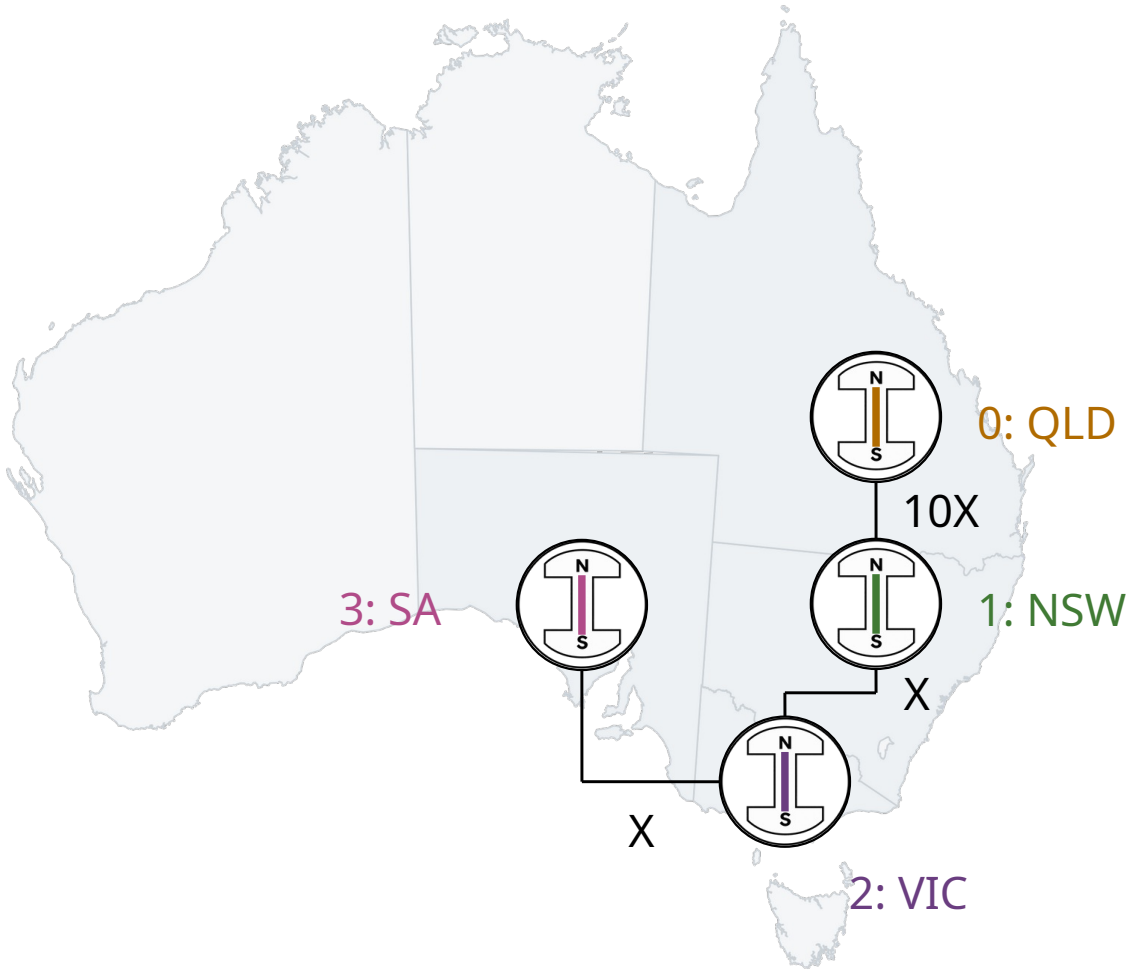


$\Delta\delta 2(0) = 0.1$





What oscillations might arise in the NEM?



$$\boldsymbol{Y} = \frac{-j}{10X}\begin{bmatrix} 1 & -1 & 0 & 0 \\ -1 & 11 & -10 & 0 \\ 0 & -10 & 20 & -10 \\ 0 & 0 & -10 & 10 \end{bmatrix}$$

Simplifying assumptions:

- Identical inertia and damping
- Equal fixed voltage magnitudes
- Equal operating angles

https://geo.abs.gov.au/arcgis/rest/services/ASGS2021/STE/MapServer

$$\boldsymbol{Y} = \frac{-j}{10X}\begin{bmatrix} 1 & -1 & 0 & 0 \\ -1 & 11 & -10 & 0 \\ 0 & -10 & 20 & -10 \\ 0 & 0 & -10 & 10 \end{bmatrix} \quad \Longrightarrow \quad \boldsymbol{Y}\boldsymbol{\rho}_{\mathrm{k}} = \boldsymbol{\lambda}_{\mathrm{k}}\boldsymbol{\rho}_{\mathrm{k}}$$

Mode 1

$$\boldsymbol{\rho}_1 \approx \begin{bmatrix} 1 \\ -0.3 \\ -0.3 \\ -0.4 \end{bmatrix}$$

I20-like grouping:

QLD

oscillating against

NSW + VIC + SA

Mode 2

$$\boldsymbol{\rho}_2 \approx \begin{bmatrix} 0.1 \\ -1 \\ -0.1 \\ 0.9 \end{bmatrix}$$

I25-like grouping:

QLD + SA

oscillating against

NSW + VIC

Mode 3

$$\boldsymbol{\rho}_3 \approx \begin{bmatrix} 0.02 \\ -0.5 \\ 1 \\ -0.5 \end{bmatrix}$$

I35-like grouping:

QLD + VIC

oscillating against

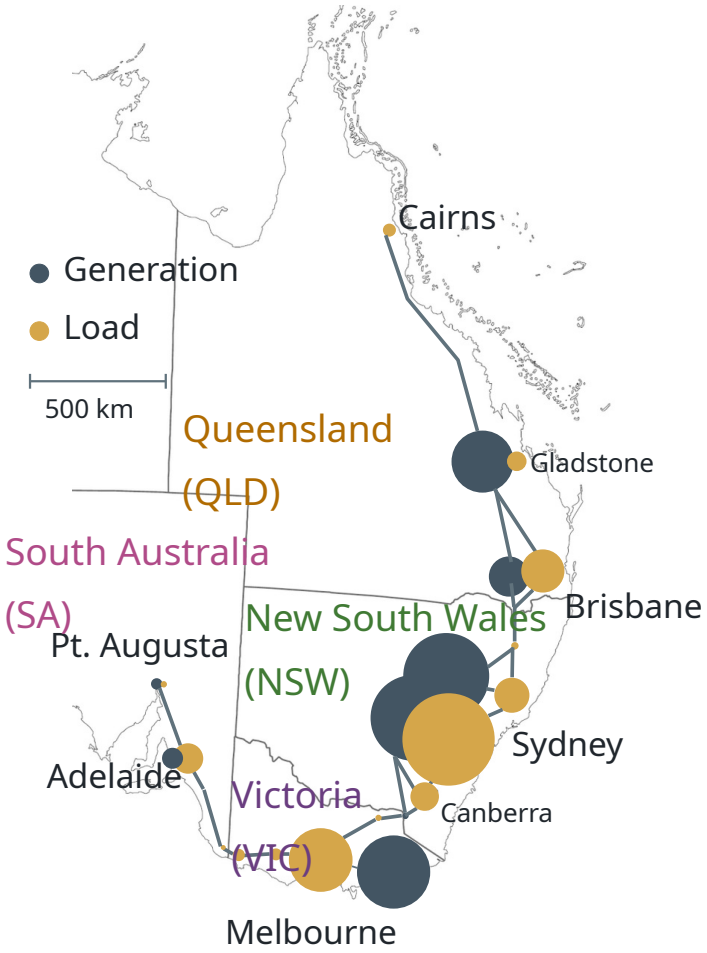
NSW + SA

State order: QLD, NSW, VIC, SA

Actual modes also depend on coupling strengths, inertia and controls.

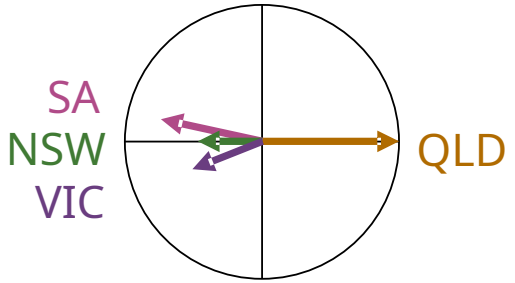
https://aemo.com.au/-/media/files/stakeholder_consultation/working_groups/other_meetings/nemoc/2023/nemoc-minutes-27-april-2023.pdf

Eastern Australian modes



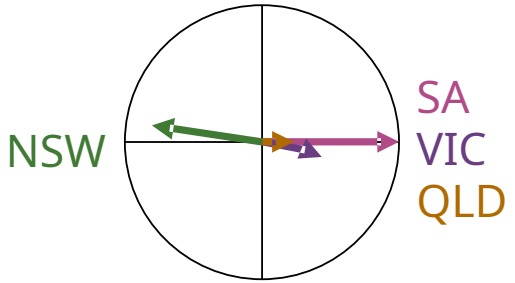
Adapted from D. Karlsson, Gothia Power, NASPI, 2010, slide 27

Mode shapes observed in data



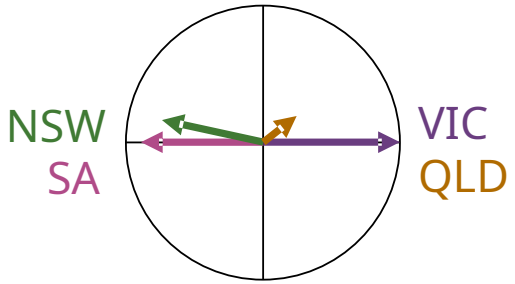
I20

$0.32\ Hz$



I25

$0.40\ Hz$



I35

$0.56\ Hz$

Power-system oscillation taxonomy

Slow frequency / control

Grid frequency, turbine–governor and plant-control dynamics

Inter-area rotor

Generator groups in different regions swing against each other

Local rotor

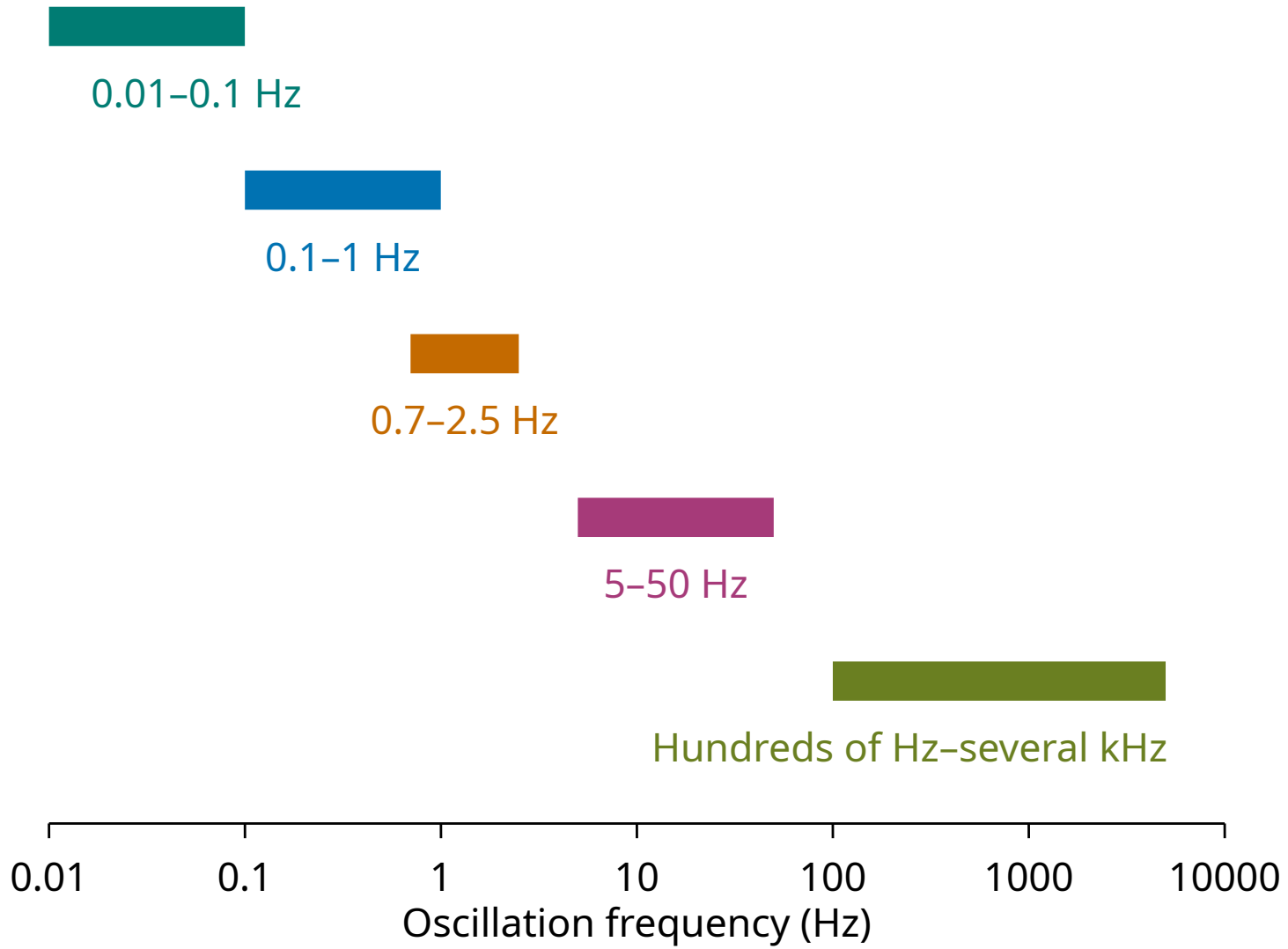
One generator or plant swings against the surrounding grid

Subsynchronous / torsional

Shaft twisting or inverter-control interactions through the network

Fast electrical / control

Electrical resonances and fast converter-control interactions

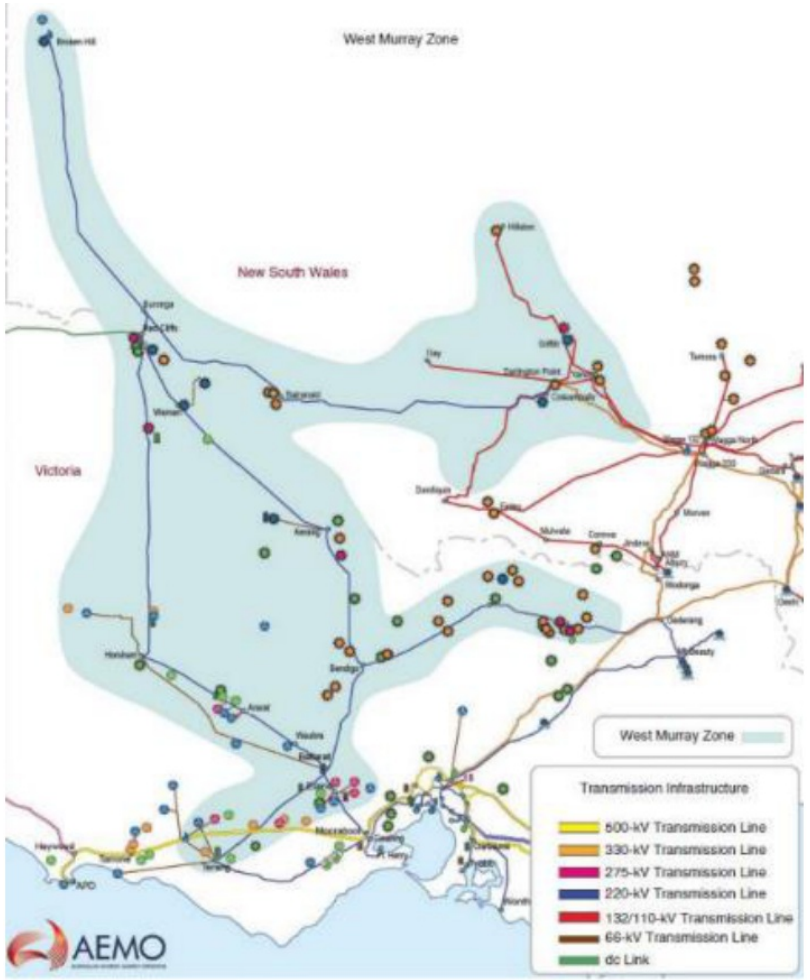


https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/smwg/reliability_guideline_-_forced_oscillations_-_2017-07-31_-_final.pdf
https://www.ree.es/sites/default/files/12_CLIENTES/Documentos/GT_POD_guia_implementacion_controles_POD_EN.pdf
https://par.nsf.gov/servlets/purl/10232629

Inverter control

Fast control modes can also involve several plants.

Not in the standard frequency range for machine-caused oscillations

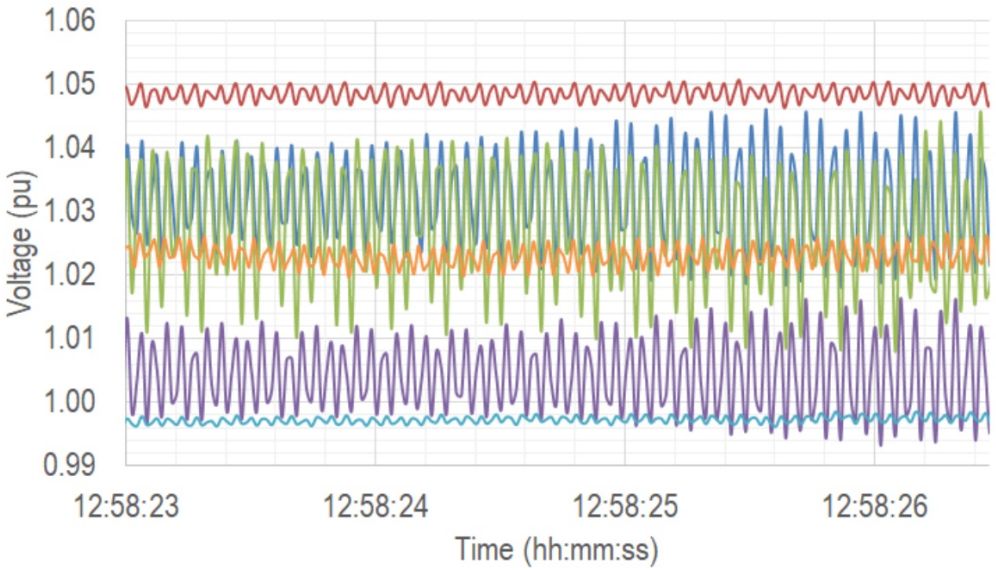


West Murray: $17\ Hz$ voltage oscillations.

Several solar plants interact through a "weak grid."

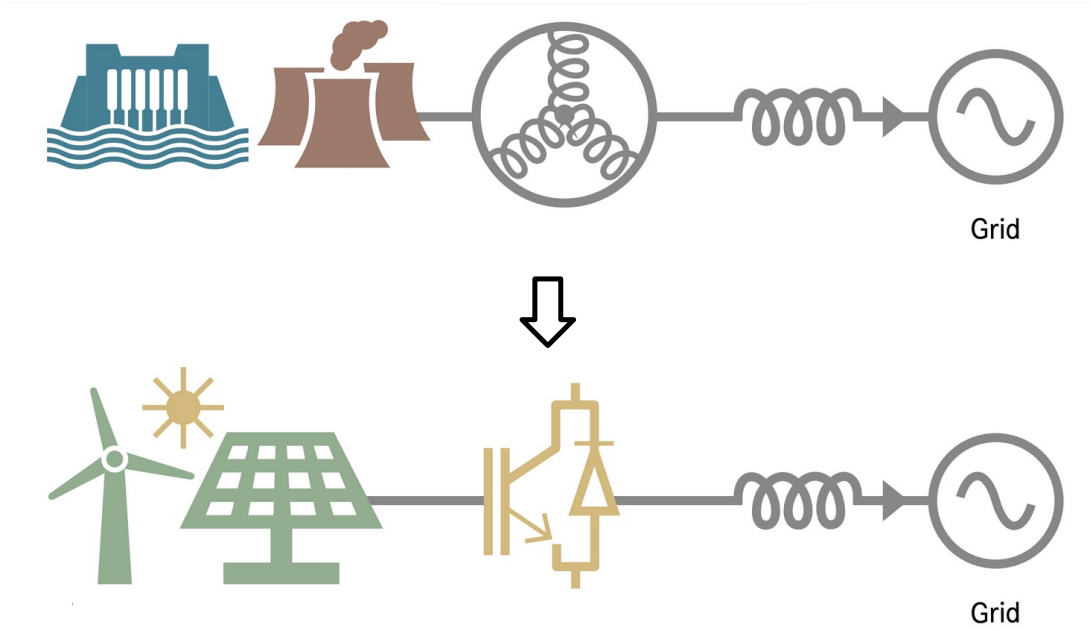
AEMO identified the main contributing plant using impedance scans and detailed simulations. Updating its inverter controls improved damping.

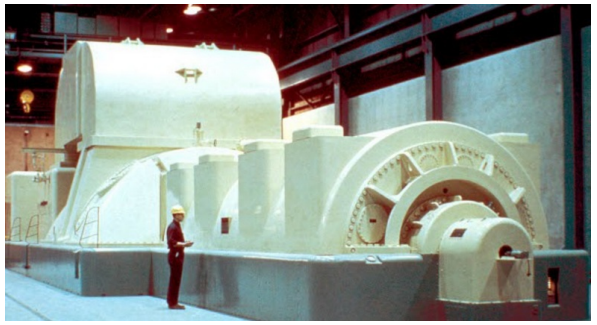
Measured voltages at several buses



https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2025/analysis-of-sub-synchronous-oscillation-in-west-murray-zone-power-system-in-australia---external.pdf

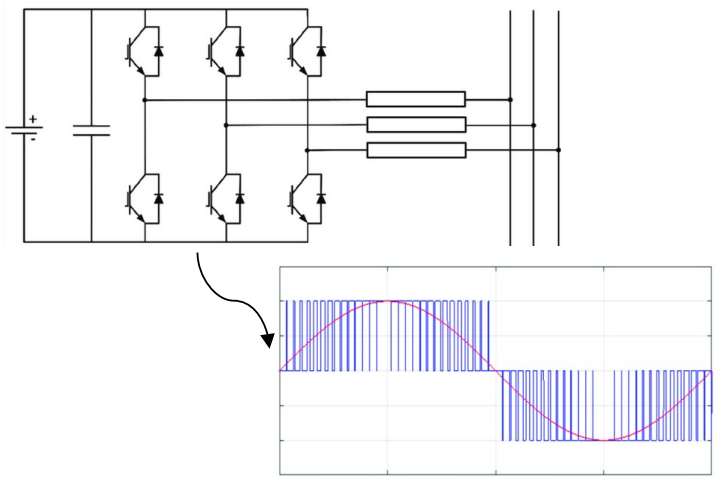
Energy Transition



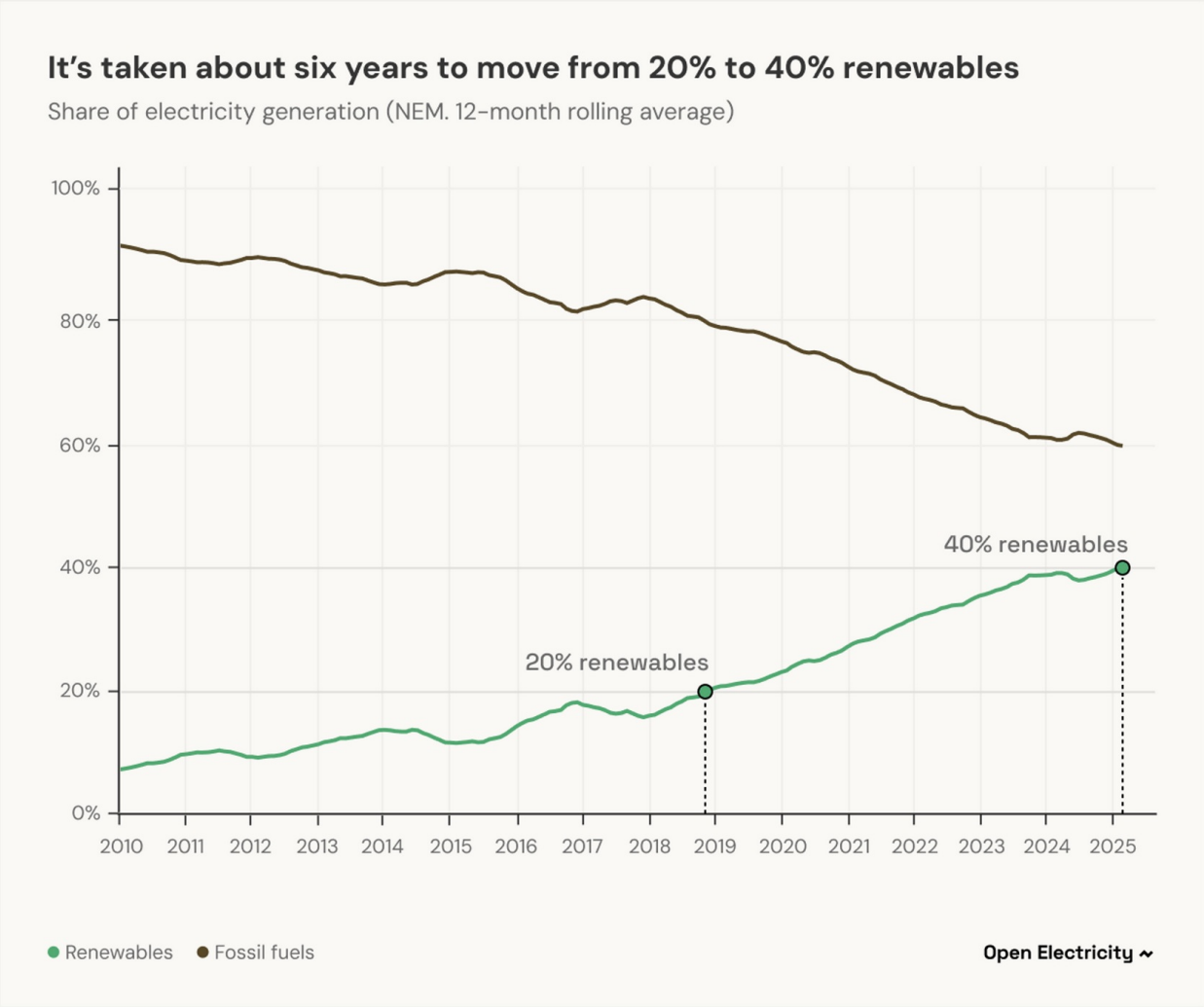








Inverter-Connected Generators





https://www.pv-magazine-australia.com/2022/07/27/hornsdale-big-battery-begins-providing-inertia-grid-services-at-scale-in-world-first/

Grid following (idealized)

Behaves like a controlled current source, allowing the grid to assert the voltage. (voltage-following, current-forming)

A phase-locked loop estimates the angle of the grid voltage, then determines the current phasor.

Requires an existing voltage waveform to follow
→ Can perform poorly in ”weak” grid locations with large Z_{th}

Grid forming (idealized)

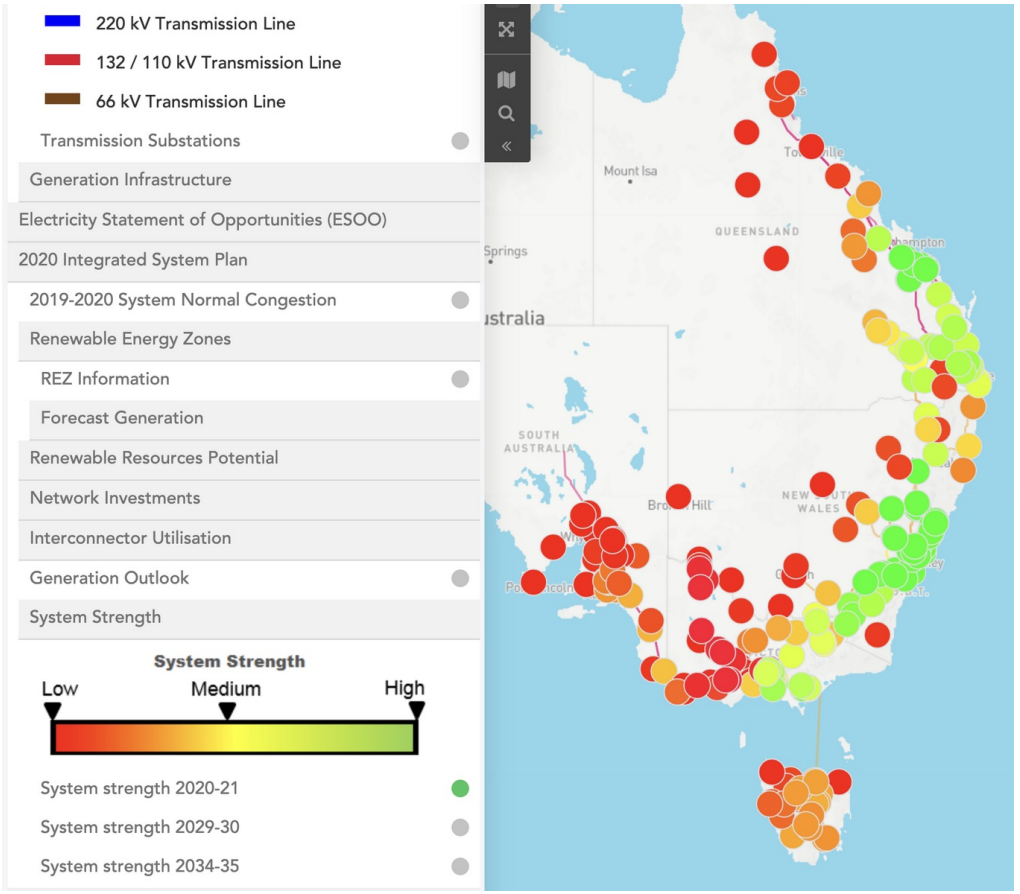
Behaves like a controlled voltage source, allowing the grid to assert the current. (voltage-forming, current-following)

The controller generates an internal voltage. Power and frequency feedback adjust the phase and magnitude of the internal voltage.

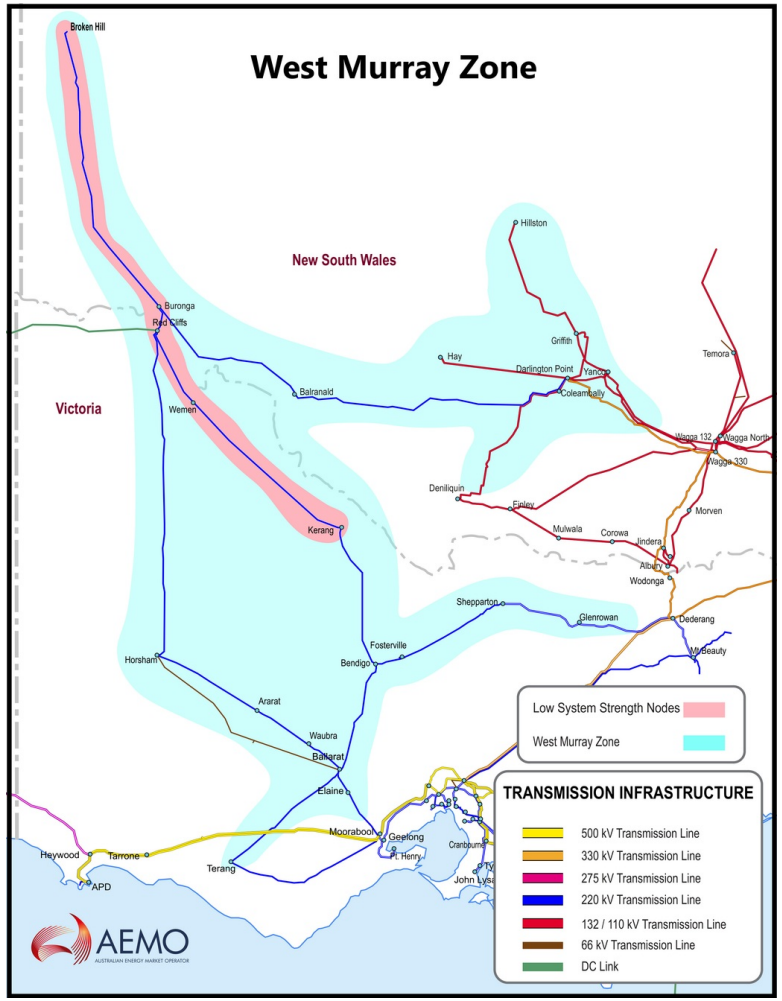
Can perform poorly in ”strong” grid locations with small Z_{th}

“Grid Strength”

AEMO is actively developing new metrics for where it is safe to connect grid-following control.



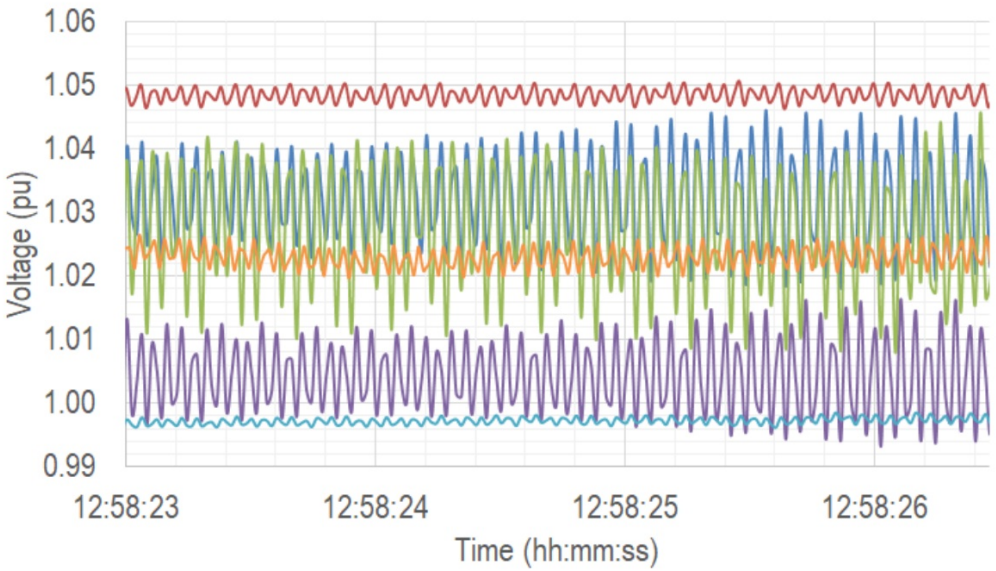
https://www.aemo.com.au/aemo/apps/visualisations/map.html



West Murray: 17 Hz voltage oscillations.

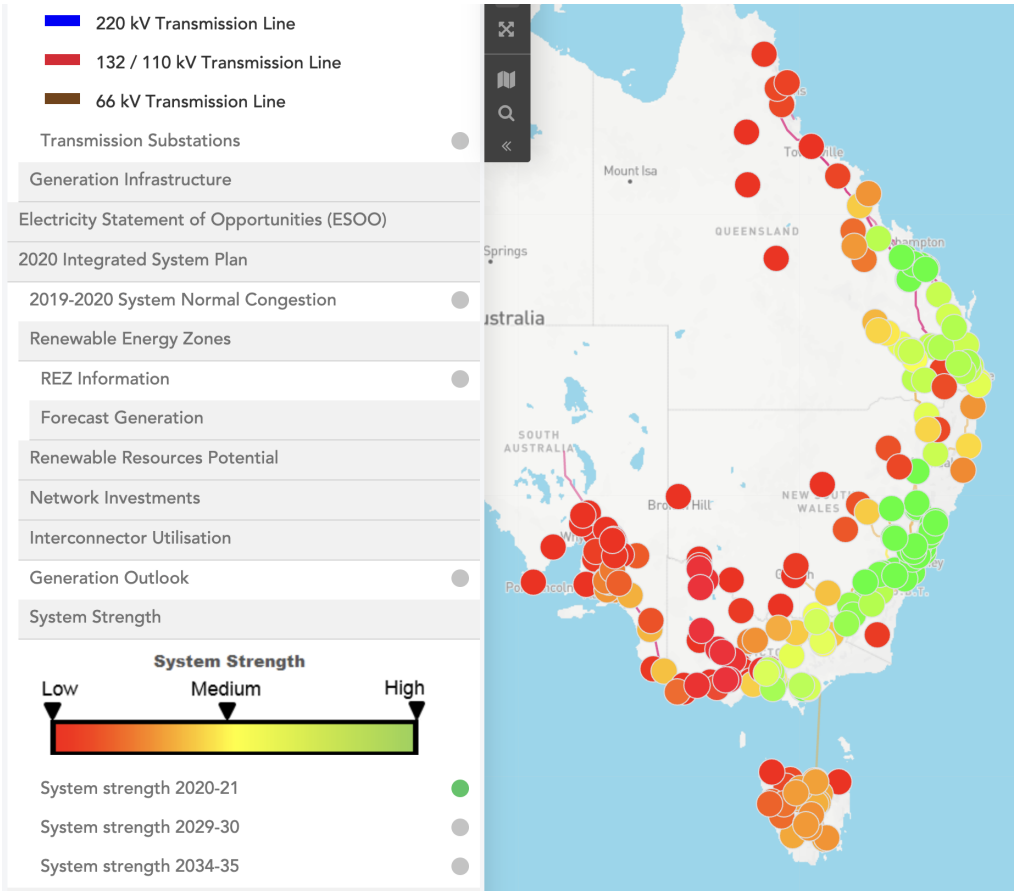
Several solar plants interact through a "weak" grid location

Measured voltages at several buses



https://www.aemo.com.au/-/media/files/electricity/nem/network_connections/west-murray/wmz-nsw_map.pdf

If we come up with better inverter control, then we can connect inverters anywhere.



https://www.aemo.com.au/aemo/apps/visualisations/map.html

Small Signal Stability

ELEN90060 Power System Analysis

Keith Moffat

Appendix I: Relating admittance matrix eigenvalues to dynamic poles

Lossless lines, no shunts. Equal fixed voltage magnitudes V

Lines 0–1 and 1–2 have reactance X. $\delta_0° = \delta_1° = \delta_2°$

Machine 1 injects the sum of its two outgoing line powers

$$P_{e,1} = \frac{V^2}{X}\sin\left(\delta_1 - \delta_0\right) + \frac{V^2}{X}\sin\left(\delta_1 - \delta_2\right)$$

At equal operating angles, the sine has slope cos(0) = 1

$$\sin\left(\delta_i - \delta_l\right) = \sin\left(\Delta\delta_i - \Delta\delta_l\right) \approx \Delta\delta_i - \Delta\delta_l$$

$$\Delta P_{e,1} \approx \frac{V^2}{X}\left[\left(\Delta\delta_1 - \Delta\delta_0\right) + \left(\Delta\delta_1 - \Delta\delta_2\right)\right] = \frac{V^2}{X}\left(-\Delta\delta_0 + 2\Delta\delta_1 - \Delta\delta_2\right)$$

Collecting the three machine equations gives

$$\begin{bmatrix} \Delta P_{e,0} \\ \Delta P_{e,1} \\ \Delta P_{e,2} \end{bmatrix} \approx \frac{V^2}{X}\begin{bmatrix} 1 & -1 & 0 \\ -1 & 2 & -1 \\ 0 & -1 & 1 \end{bmatrix}\begin{bmatrix} \Delta\delta_0 \\ \Delta\delta_1 \\ \Delta\delta_2 \end{bmatrix} = jV^2\boldsymbol{Y}\,\Delta\boldsymbol{\delta}$$

Appendix I: Relating admittance matrix eigenvalues to dynamic poles

All three machines have the same M, D. $\Delta P_m = 0$

For one mode

$$\Delta\boldsymbol{\delta}(t)=\begin{bmatrix}\Delta\delta_0(t)\\ \Delta\delta_1(t)\\ \Delta\delta_2(t)\end{bmatrix}=\begin{bmatrix}\boldsymbol{\rho}_{0k}\\ \boldsymbol{\rho}_{1k}\\ \boldsymbol{\rho}_{2k}\end{bmatrix}z_k(t)=\boldsymbol{\rho}_k z_k(t)$$

ρ_k: angle pattern (vector) $z_k(t)$: amplitude (scalar)

$$\boldsymbol{Y}\,\boldsymbol{\rho}_k=\boldsymbol{\lambda}_k\boldsymbol{\rho}_k$$

Swing equations

$$M\,\Delta\ddot{\boldsymbol{\delta}}+D\,\Delta\dot{\boldsymbol{\delta}}+jV^2\boldsymbol{Y}\,\Delta\boldsymbol{\delta}=0$$

Substitute one mode

$$M\,\boldsymbol{\rho}_k\ddot{z}_k+D\,\boldsymbol{\rho}_k\dot{z}_k+jV^2\boldsymbol{Y}\,\boldsymbol{\rho}_k z_k=0$$

Use the eigenvector equation

$$\boldsymbol{\rho}_k\left[M\ddot{z}_k+D\dot{z}_k+jV^2\boldsymbol{\lambda}_k z_k\right]=0$$

$\rho_k \neq 0$, so the scalar bracket must be zero

$$M\ddot{z}_k+D\dot{z}_k+jV^2\boldsymbol{\lambda}_k z_k=0$$

$$z_k(t)\propto e^{\boldsymbol{s}t}\Rightarrow M\boldsymbol{s}^2+D\boldsymbol{s}+jV^2\boldsymbol{\lambda}_k=0$$

λ_k: admittance eigenvalue s: dynamic pole

GEP phase compensation

de Mello–Concordia, 1969. Larsen–Swann field procedure, 1981.

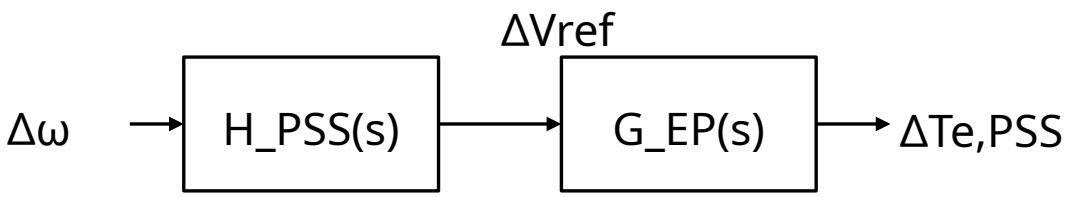
Concepts of Synchronous Machine Stability as Affected by Excitation Control

FRANCISCO P. DEMELLO, SENIOR MEMBER, IEEE, AND CHARLES CONCORDIA, FELLOW, IEEE

Find the excitation-to-torque phase lag.

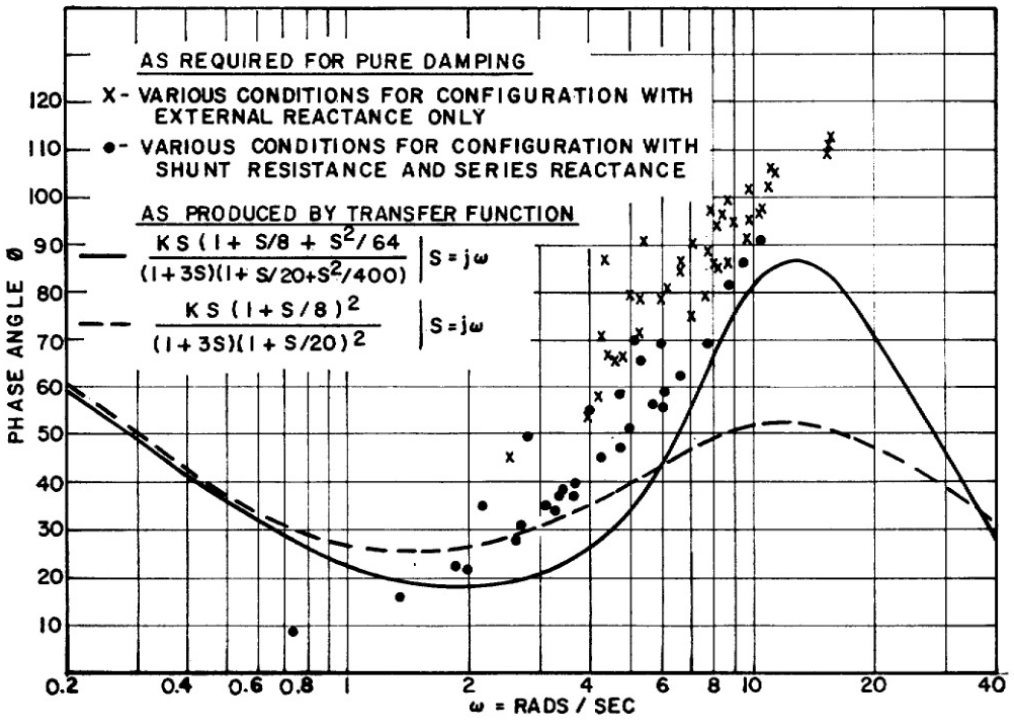
Choose PSS phase lead to cancel that lag.

Use field tests to set the practical gain.



Target over the rotor-mode band

$$H_{PSS}(j\omega)\, G_{EP}(j\omega) \approx D_{PSS} > 0$$



Points: required phase lead.

Curves: proposed stabilizers.

https://doi.org/10.1109/TPAS.1969.292452

P–Vref compensation, Gibbard, 1988

Co-ordinated design of multimachine power system stabilisers based on damping torque concepts

M.J. Gibbard, BSc, PhD

Disable all shaft dynamics.

Keep excitation and network dynamics.

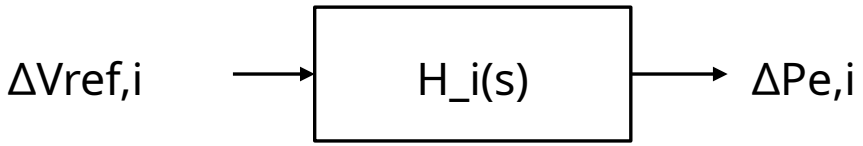
Find each AVR-reference-to-power response.

Approximate its inverse over the mode band.

Choose gains; check coupled-mode damping.

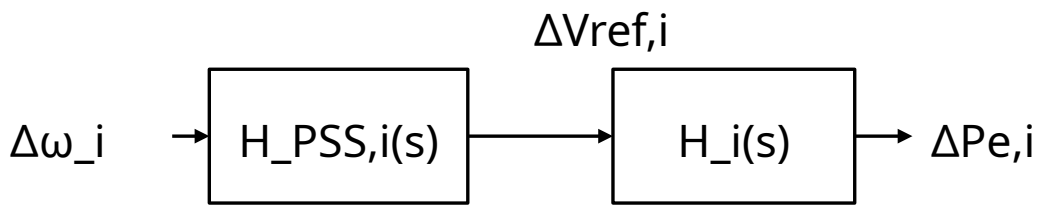
Add washout and high-frequency roll-off.

1 Identify the P–Vref response



$$H_i(s) = \Delta P_{e,i}(s) / \Delta V_{ref,i}(s)$$

2 Compensate gain and phase



Target over the rotor-mode band

$$H_{PSS,i}(j\omega) \approx D_i / H_i(j\omega),\ D_i > 0$$

https://www.scribd.com/document/462985851/Co-ordinated-design-of-multimachine-power-system-stabilisers-based-on-damping-torque-con

In the lecture we described how PSSs can be used to compensate for phase lag.

But, in practice, how do you know how much phase lag to compensate for?

And what should the PSS gain be?

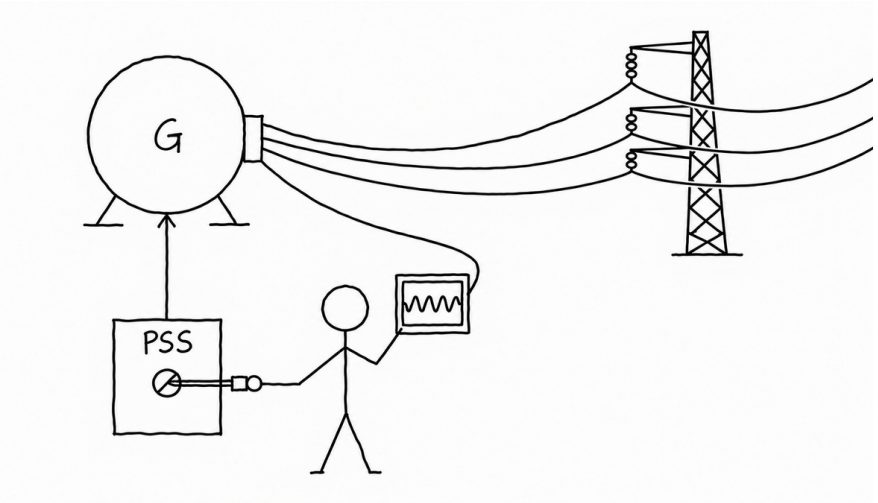
WECC PSS tuning still uses GEP

1. Measure the generator’s response to small test signals.

2. Adjust the PSS phase compensation from the measurements.

3. Increase the gain until small oscillations persist.

   Then reduce it to one-third of that gain.



GEP: The original data-driven power system stabilizer:

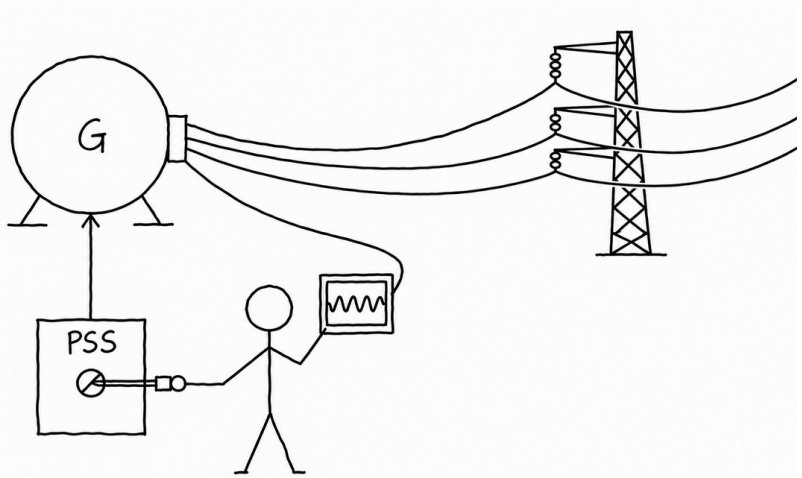
WECC Power System Stabilizer Tuning Guidelines

Phase Compensation

Identify inter-area modes of oscillation. Measure generator and excitation system response without PSS. Tune PSS to provide as close to 0 degrees of phase shift as possible at the inter-area frequency or frequencies.

If local stability concerns require PSS settings resulting in an inter-area phase shift other than zero, the setting shall in no case result in a phase shift in excess of 30 degrees at inter-area modes.

The PSS provides substantial phase shift so that the electrical torque provided by the generator is approximately in phase with speed. The goal is to eliminate phase lag as best as possible throughout a wide range of frequencies of interest, then adjust gain as outlined below.



https://www.wecc.org/sites/default/files/documents/program/2024/Power%20System%20Stabilizer%20Tuning%20Guidelines.pdf

And GEP is used throughout the world

Finland, 2018

FINGRID

1 (129)

UNOFFICIAL TRANSLATION 16.11.2018

Grid Code Specifications for Power Generating Facilities VJV2018

https://eepublicdownloads.blob.core.windows.net

§23.5.6, p. 124

Raise gain to oscillation onset.

Use one-half or one-third of that gain.

Verify inter-area damping by simulation.

India, 2023

Western Regional Power Committee

PROCEDURE FOR PSS TUNING IN INDIAN POWER SYSTEM

https://www.wrpc.gov.in/allfile/PSS_Tuning_Report.pdf

§5.7.3, p. 52

the maximum gain should tentatively be considered as 7

Example: gain 20 reduced to about 7.

Confirm damping with further tests.

Power System Stabilizer tuning methods

Method	Description	Theoretical basis	Model or data needed
GEP	Set phase from a field test, then test gain	Phase compensation and gain margin	Measured response and gain tests
P–Vref	Calculate phase with shaft dynamics fixed	Phase compensation	Dynamic model Shafts fixed
Residues	Set phase from residues, then trace poles	Eigenvalue sensitivity	Linearized model Shafts active
Optimization e.g., H_∞	Optimize damping or disturbance response	Constrained numerical optimization	Usually a model or simulator

IEEE TRANSACTIONS ON POWER APPARATUS AND SYSTEMS, VOL. PAS-88, NO. 4, APRIL 1969

Concepts of Synchronous Machine Stability as Affected by Excitation Control

FRANCISCO P. DEMELLO, SENIOR MEMBER, IEEE, AND CHARLES CONCORDIA, FELLOW, IEEE

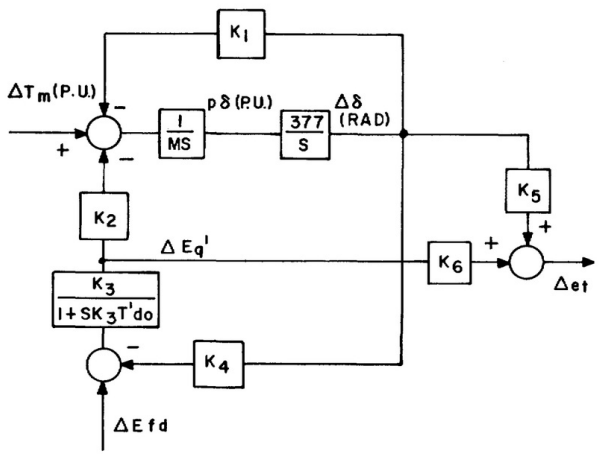


Fig. 1. Linearized small perturbation relations of a single generator supplying an infinite bus through external impedance.

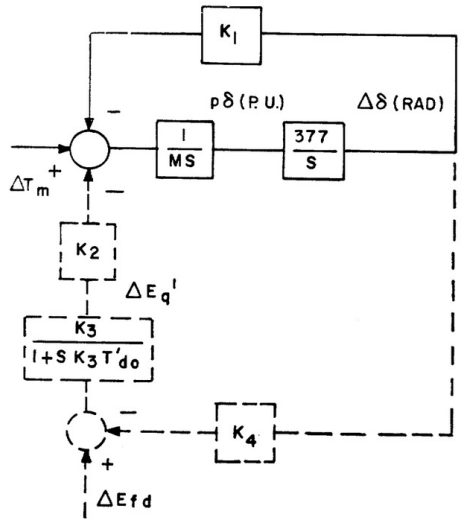


Fig. 4. Torque-angle loop including direct axis field effects.

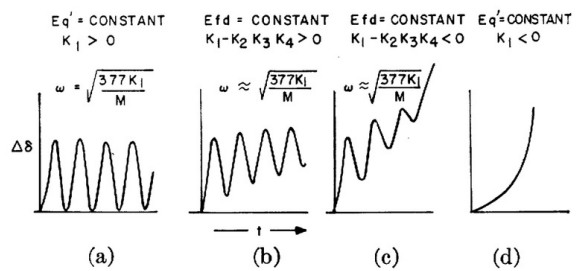


Fig. 5. Typical responses of rotor angle following small step increases in mechanical torque.

IEEE Transactions on Power Apparatus and Systems, Vol. PAS-100, No. 6 June 1981

APPLYING POWER SYSTEM STABILIZERS
PART I: GENERAL CONCEPTS

E.V. Larsen (Member) D.A. Swann (Member)
General Electric Company, Schenectady, New York

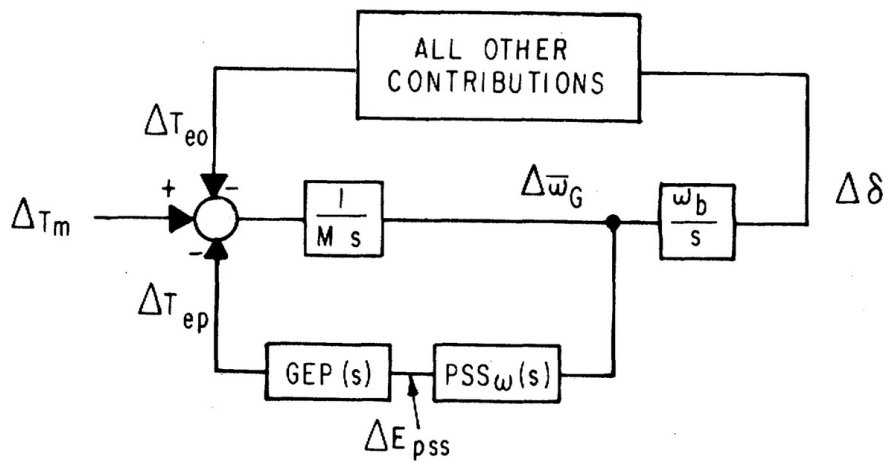


FIGURE 1 STABILIZER WITH SPEED INPUT - SYSTEM BLOCK DIAGRAM

P-Vref: Gibbard, 1988

Co-ordinated design of multimachine power system stabilisers based on damping torque concepts

M.J. Gibbard, BSc, PhD

1. Disable all shaft dynamics in the system model.

2. Compute the response from voltage reference to electrical power on each machine.

3. Tune each PSS to compensate phase and gain over the oscillation band.

4. Set equal initial damping targets on each machine’s own MVA base.

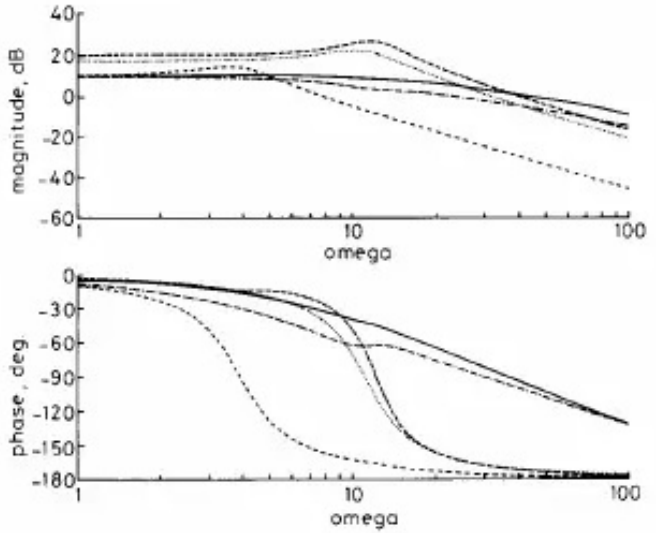
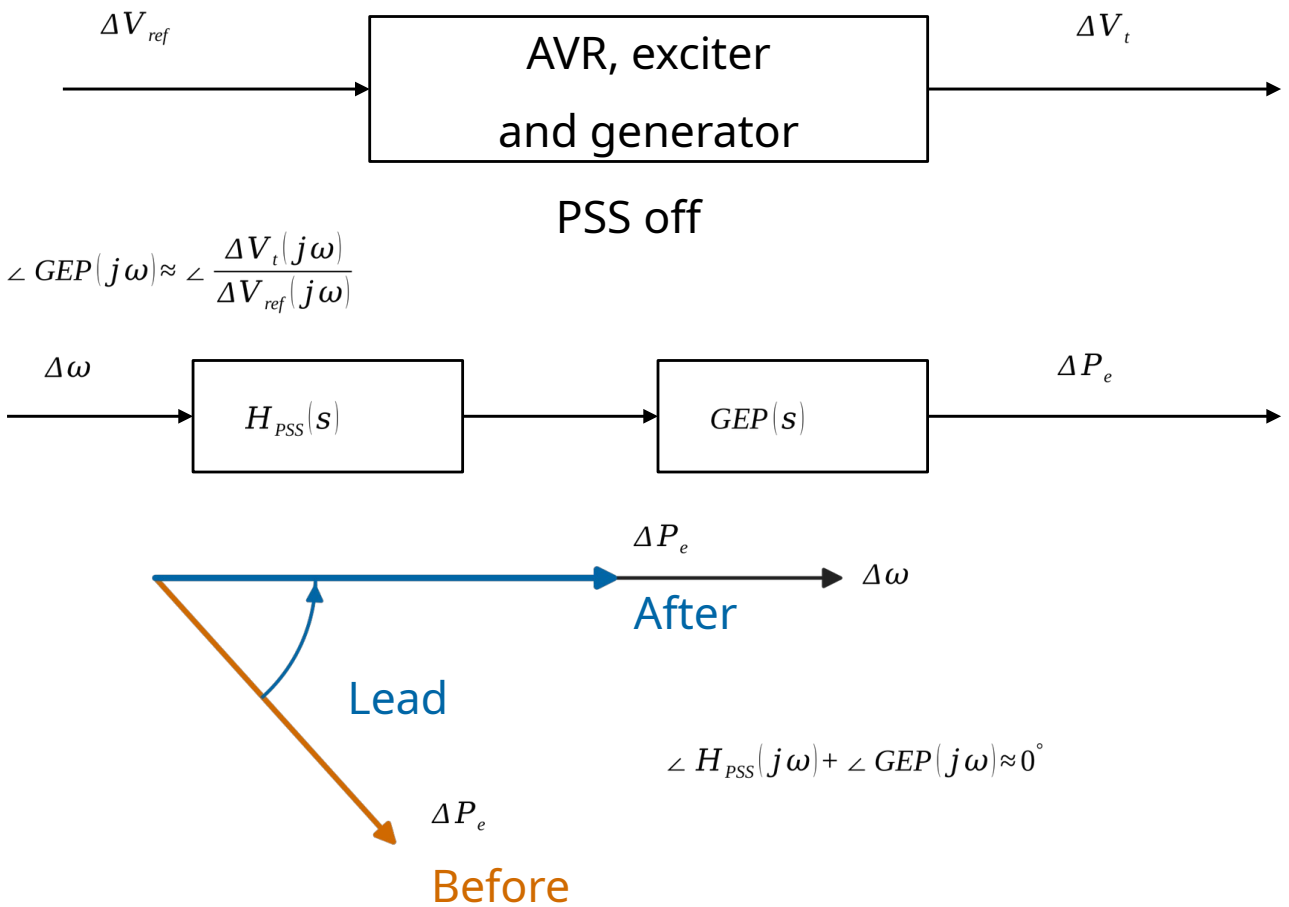


Fig. 3 *Frequency responses for $H_{vd}(s) = \Delta P_{Pe1}(s)/\Delta v_{r1}(s)$ (eqn. 7) for the system without PSSs and with shaft dynamics disabled*

https://doi.org/10.1049/ip-c.1988.0038

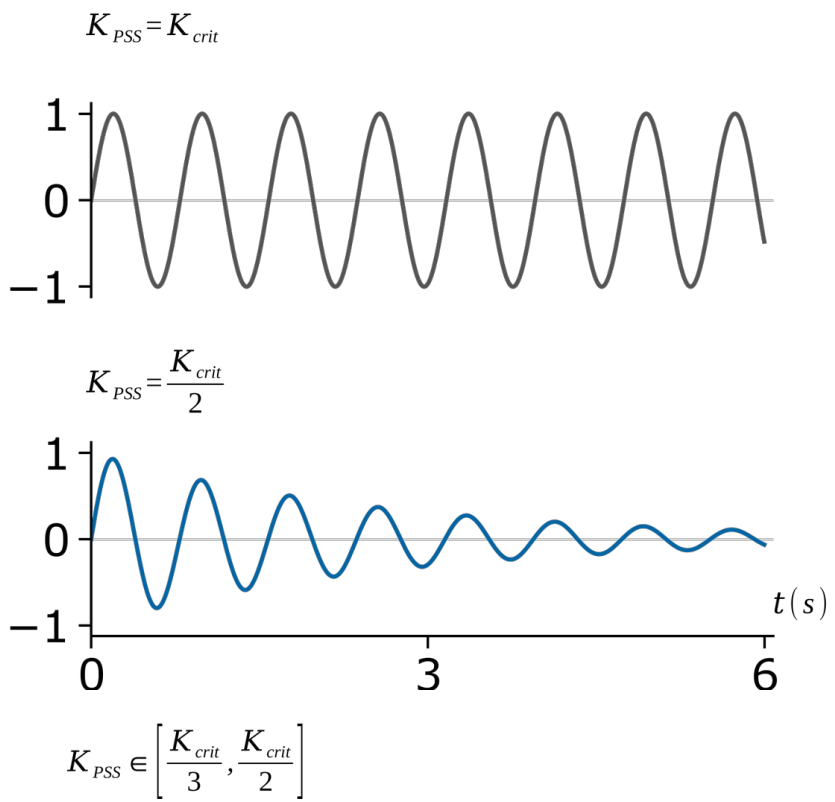
GEP field tuning

Phase from a field test



Gain from an oscillation test

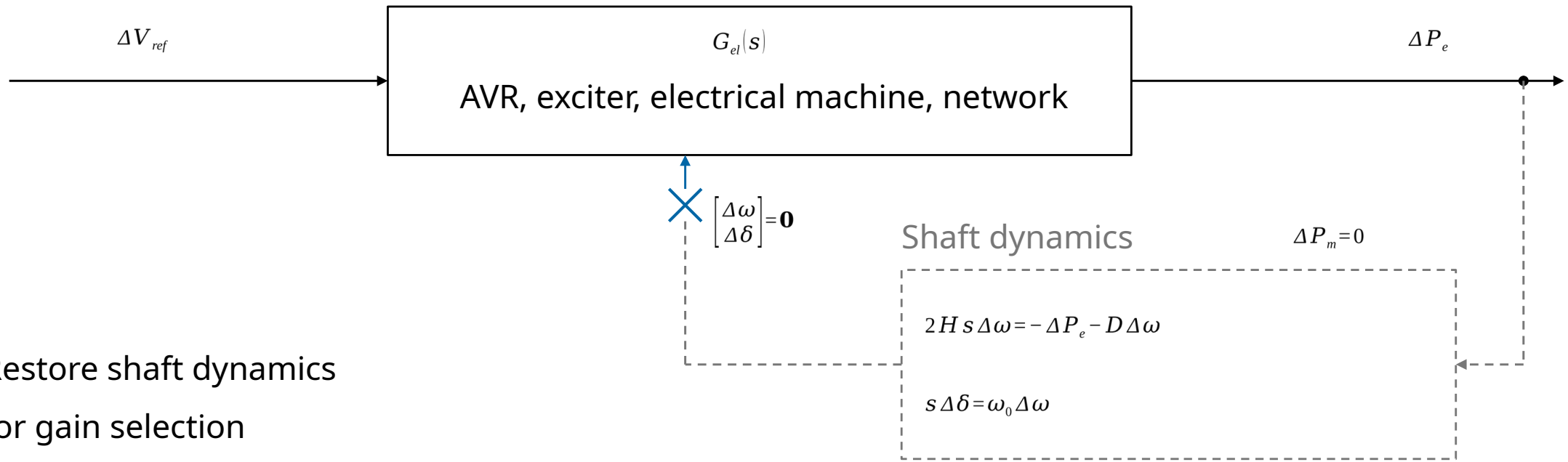
Normalized speed response



$$K_{PSS} \in \left[\frac{K_{crit}}{3}, \frac{K_{crit}}{2}\right]$$

P–Vref tuning with shaft dynamics fixed

Phase tuning with all generator shafts fixed



Restore shaft dynamics

for gain selection

$$G_{P-V_{ref}}(s)=\frac{\Delta P_e(s)}{\Delta V_{ref}(s)}$$

$$\angle H_{PSS}(j\omega)+\angle G_{P-V_{ref}}(j\omega)\approx 0^\circ$$

Residues tuning: phase sets the pole direction

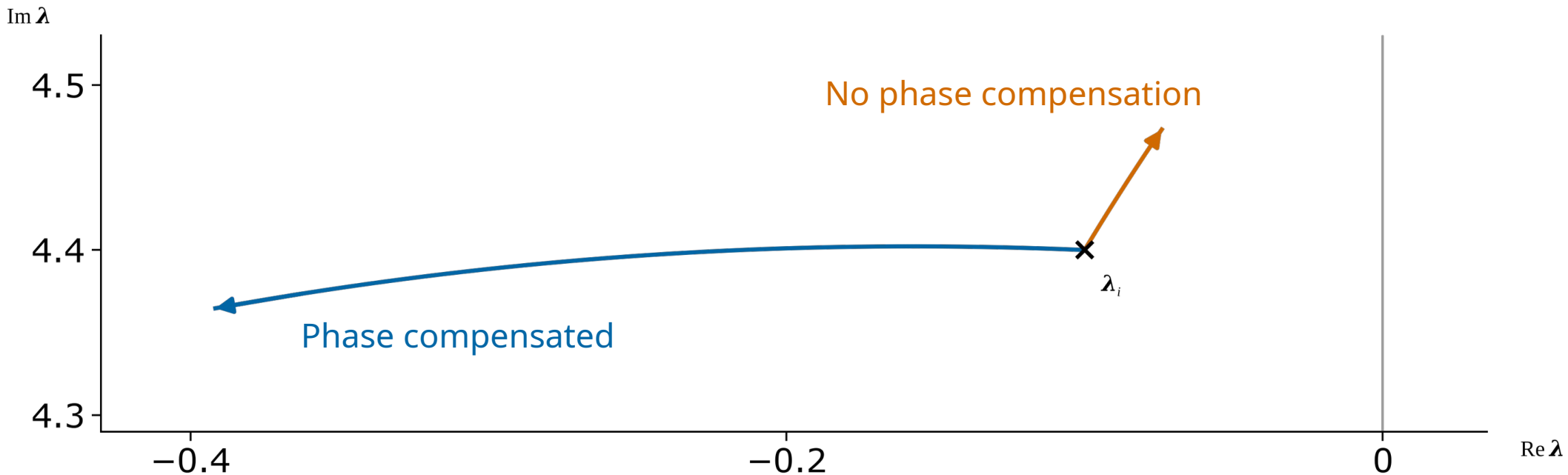
$$G(s)=\frac{\Delta\omega(s)}{\Delta V_{PSS}(s)}=\sum_i \frac{R_i}{s-\lambda_i}$$

Simple poles

$$H_{PSS}(s)=K_{PSS}H_0(s)$$

Gain selection: check all modes

$$0\le K_{PSS}\le 6$$



$$\Delta\lambda_i \approx K_{PSS}R_iH_0(\lambda_i)\quad(K_{PSS}\to 0)$$

$$\angle\left[R_iH_0(\lambda_i)\right]\approx 180^\circ$$

Forced vs natural oscillations

Florida oscillation, 11 January 2019

What caused this oscillation?

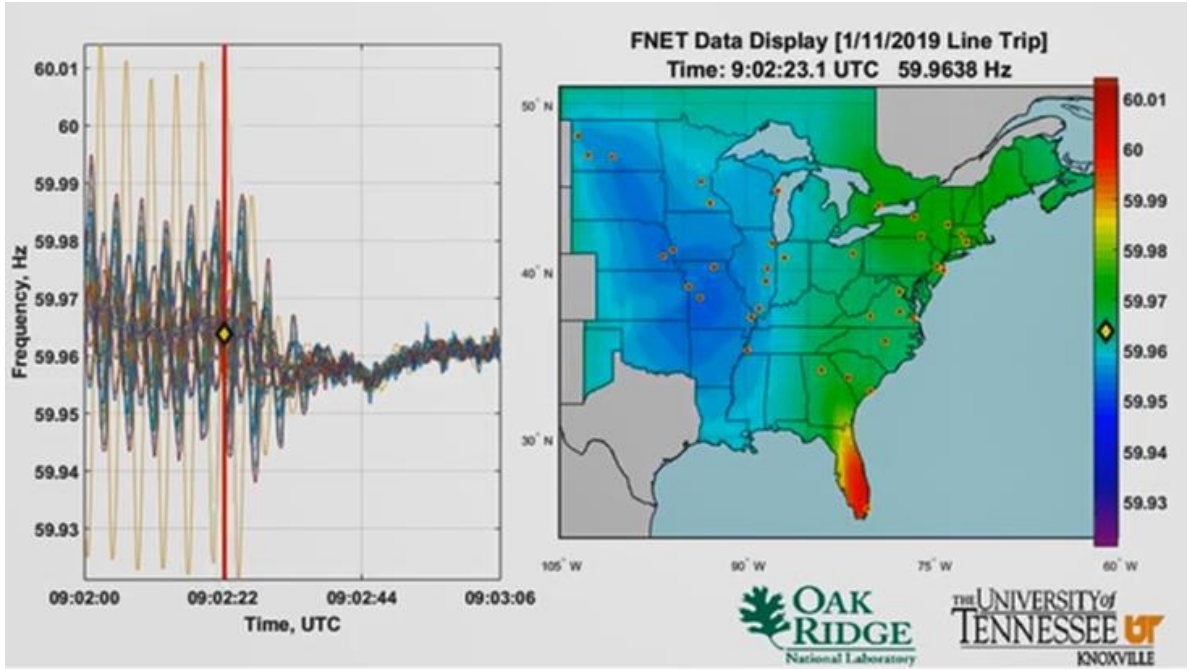
https://www.youtube.com/watch?v=xilfYKxqEDo

Faulty turbine controls at one generator in Florida forced a grid oscillation

The controls repeatedly closed and reopened the steam valves every 4 s.

This forced generator power to oscillate at 0.25 Hz and excited a natural grid mode that extended up to Canada.

After about 18 minutes, operators shut down the unit. The forcing stopped and the oscillation decayed.



Oscillations decayed after shutdown

https://www.nerc.com/globalassets/our-work/reports/event-reports/january_11_oscillation_event_report.pdf

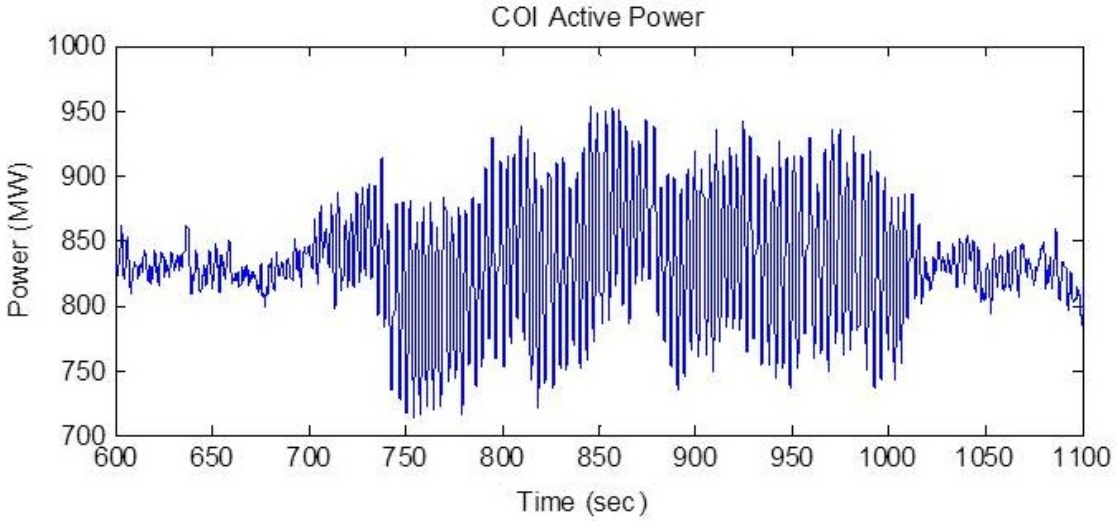
Alberta forced oscillation, 29 November 2005



https://energyinfo.oregon.gov/transmission-distribution-2020

A failed steam extractor valve at Nova Joffre caused 0.27 Hz oscillations: ≈20 MW peak-to-peak at the plant.

Resonance with the well-damped 0.26 Hz north–south mode amplified the response at the California–Oregon Intertie (COI) to ≈200 MW peak-to-peak, about 1800 km away.



https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/smwg/reliability_guideline_-_forced_oscillations_-_2017-07-31_-_final.pdf

The largest observed oscillation can be far from its source.

“Natural” oscillation modes exist as well

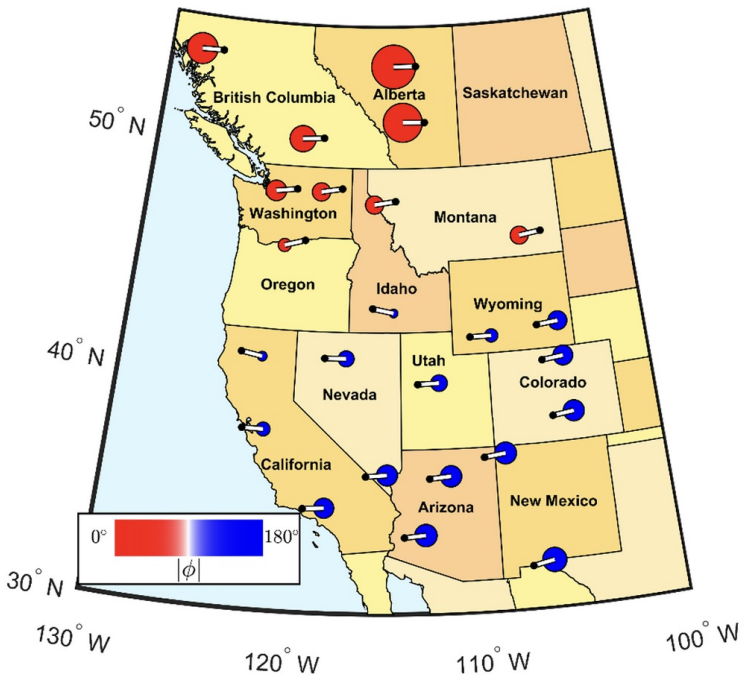


Figure 2.5: Map of the Shape for the 0.26 Hz North-South A Mode

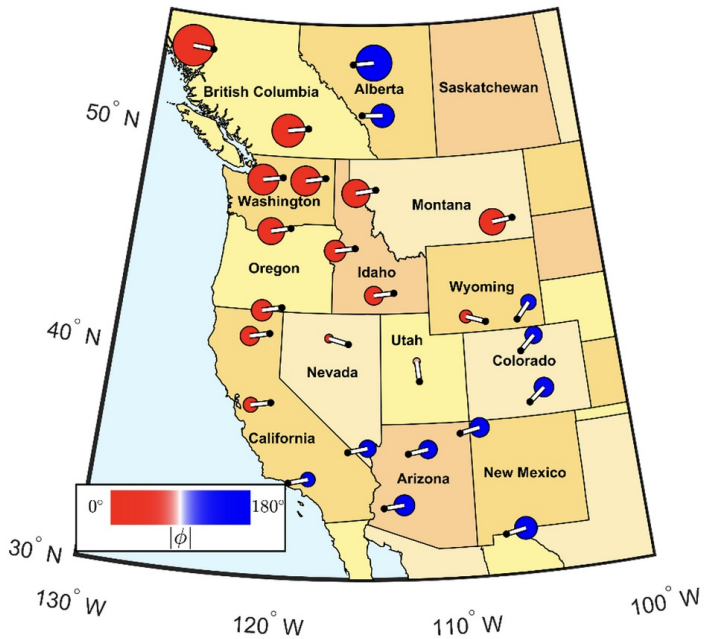


Figure 2.6:Map of the Shape for the 0.36 Hz North-South B Mode

- **Natural oscillations:** the system's response governed by its own electromechanical modes, defined by the state matrix's eigenvalues and eigenvectors. They can decay **or grow**, depending on damping.
- **Forced oscillations:** the system's response to a periodic disturbance. Their frequency is governed by the **forcing input**, rather than the system's natural dynamics.

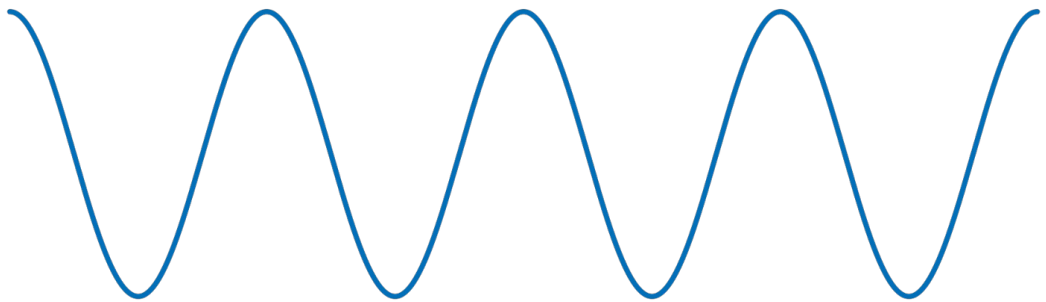


https://www.nerc.com/globalassets/our-work/technical-reference-documents/power-system-oscillation-monitoring-and-mitigation-trd.pdf

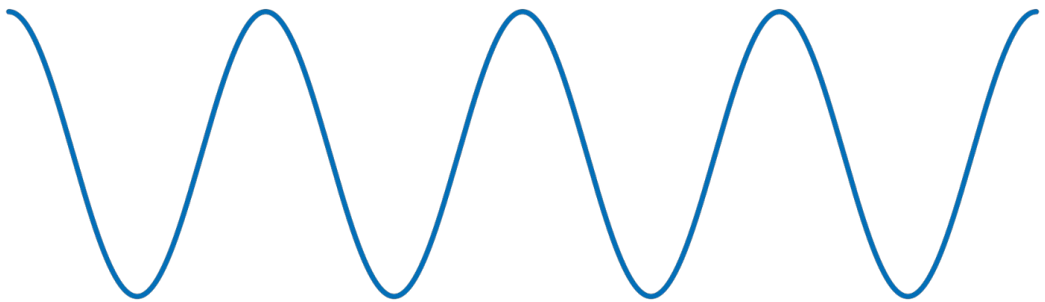
Distinguishing natural and forced oscillations is a hard problem

A PMU alarm shows oscillatory motion. It does not identify the mechanism.

Natural response with zero damping



Periodically forced response



The traces can look the same, even though different mechanisms sustain them.

Both can spread across the grid. Geographic extent does not classify them.

How engineers distinguish the mechanisms

Evidence	Interpretation
Damping before and during the event	A known mode losing damping supports natural-mode instability. A well-damped mode at a nearby frequency alongside the sustained oscillation supports forcing.
Frequency spectrum	A narrow frequency peak and harmonics suggest periodic forcing. They are clues, not proof.
Plant records	Look for a cycling valve, controller command or load at the oscillation frequency.
Dynamic models and operating changes	Check for an unstable mode without a periodic input, and compare model predictions with the measured response.

Source-location methods help narrow the search to a plant or area.

Plant evidence and models help establish what sustains the oscillation.

Oscillations are oscillations

We classify oscillations because it helps us classify them.

Forced oscillation

A periodic input sustains the response.

Remove the driver, often by repairing or adjusting plant equipment.

Unstable natural mode (self-excited)

Feedback gives a mode negative damping.

Improve damping through controls or changes to system operation.

Finding a periodic driver can be hard. Once identified, it gives a clear repair target.

A system-wide natural mode can also be stabilized by changing one plant’s controls.

Power System Oscillation Monitoring and Mitigation

Technical Reference Document

April 30, 2026

https://www.nerc.com/globalassets/our-work/technical-reference-documents/power-system-oscillation-monitoring-and-mitigation-trd.pdf

Forced Oscillations - Examples

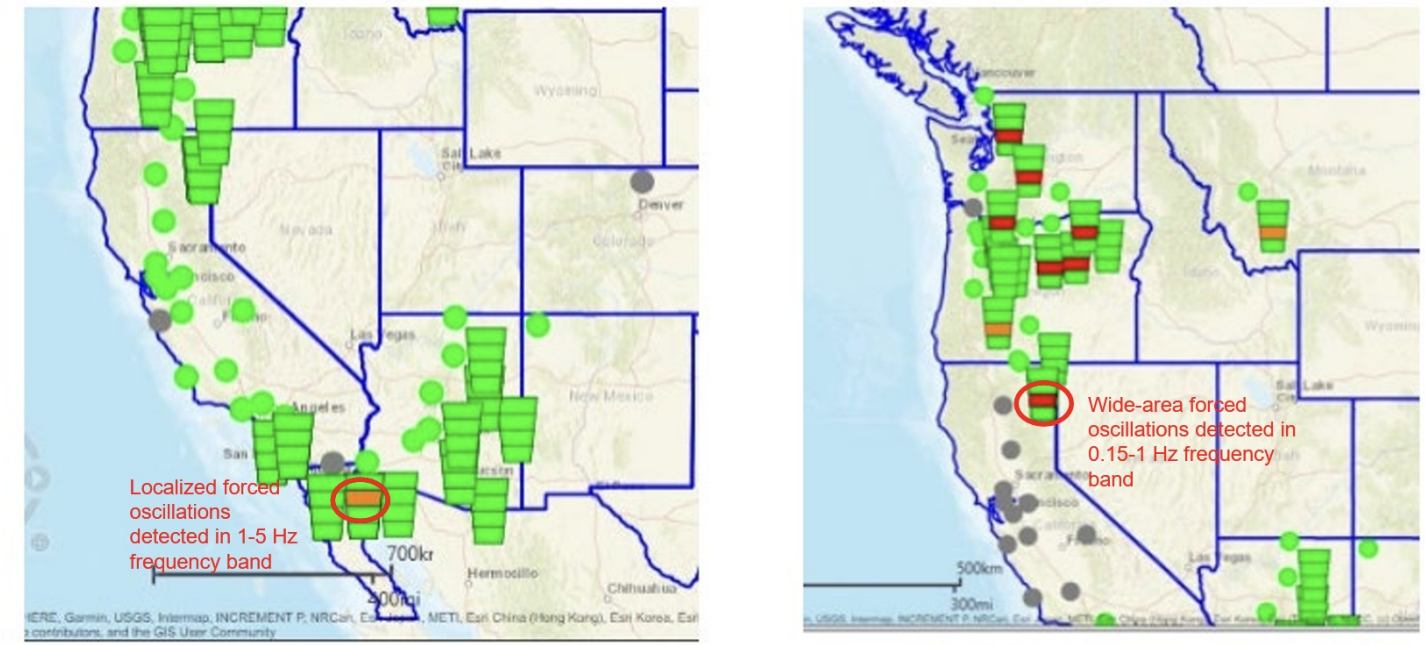


Figure: Example of localized forced oscillations (left) and wide-area forced oscillations (right).

https://www.nerc.com/globalassets/our-work/technical-reference-documents/power-system-oscillation-monitoring-and-mitigation-trd.pdf

Severe impact of forced oscillations likely to occur during “near-resonance” condition[1]

- Condition 1: Frequency of forced oscillations closely matches with the frequency of a system-mode
- Condition 2: Damping ratio of that system mode is low
- Condition 3: The source of the forced oscillation is at a highly participating location of that system mode.

The appropriate responses to natural and forced oscillations differ, so it is important to either classify the oscillation as forced or natural before taking action or ensure control and operator responses are appropriate for either type of oscillation. Currently, many of the entities operating grids are doing neither because methods for classifying sustained oscillations are not yet widely available in commercial tools.

https://www.nerc.com/globalassets/our-work/technical-reference-documents/power-system-oscillation-monitoring-and-mitigation-trd.pdf

One readily observable difference between natural and forced oscillations that is widely agreed upon is the presence of harmonics. Forced oscillations are often accompanied by harmonics due to the periodic nature of the driving input. For example, a 0.25 Hz oscillation may be accompanied by harmonics at 0.75 Hz, 1.25 Hz, etc. The appearance of harmonics is a clear indication of a forced oscillation because inter-area electromechanical modes do not possess harmonics. However, not all forced oscillations have harmonics, and they may be too small to detect if they do. Thus, harmonics are an important characteristic to consider but are not sufficient to make the distinction in all cases.

https://www.nerc.com/globalassets/our-work/technical-reference-documents/power-system-oscillation-monitoring-and-mitigation-trd.pdf

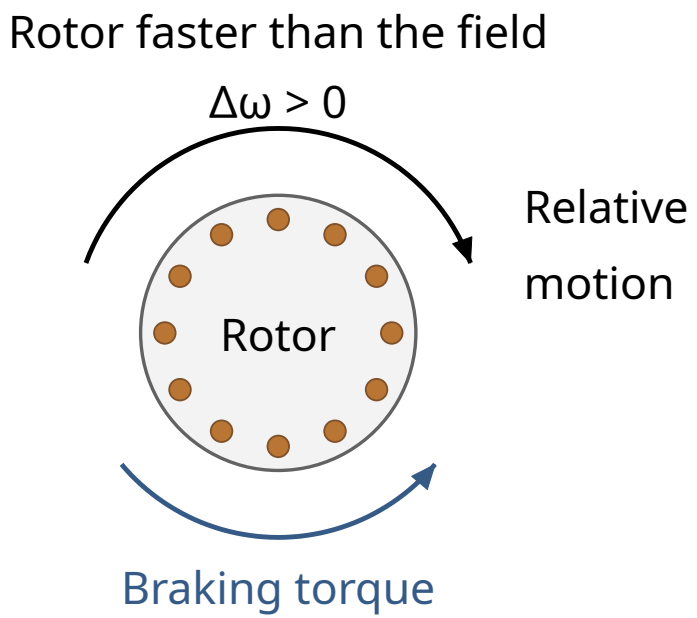
Forced oscillations are often (but not always) blue-sky events because they can be caused by a single piece of equipment. In contrast, poorly damped inter-area natural oscillations are often (but not always) associated with high-stress conditions and/or multiple contingencies. Monitoring tools can provide an early warning of modes headed toward instability. If sustained oscillations occur following a progressive decline in a mode's damping, the oscillation is likely natural. If a sustained oscillation occurs under low-stress conditions apart from contingencies, there is a greater chance that it is forced.

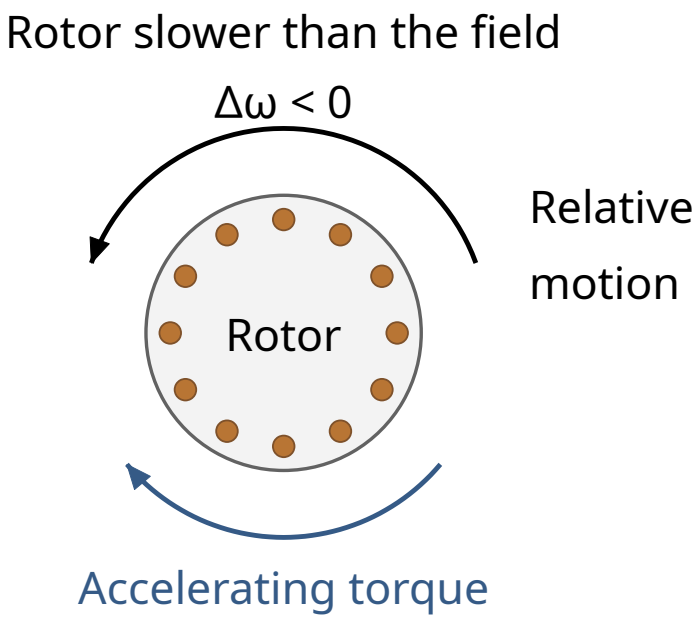
https://www.nerc.com/globalassets/our-work/technical-reference-documents/power-system-oscillation-monitoring-and-mitigation-trd.pdf

Damper torque reduces rotor–field speed differences

View rotating with the stator field.

The damper cage is stationary at synchronism; a swing creates relative motion.





Simple swing model: $M\,d\Delta\omega/dt = \Delta P_m - \Delta P_e - D\,\Delta\omega$

$\Delta\omega = \omega - \omega_s$, $M = 2H/\omega_s$, $D > 0$

Damper currents turn swing energy into heat, reducing grid oscillations.