# ECEN 667
# Power System Stability

## Lecture 11: Governors

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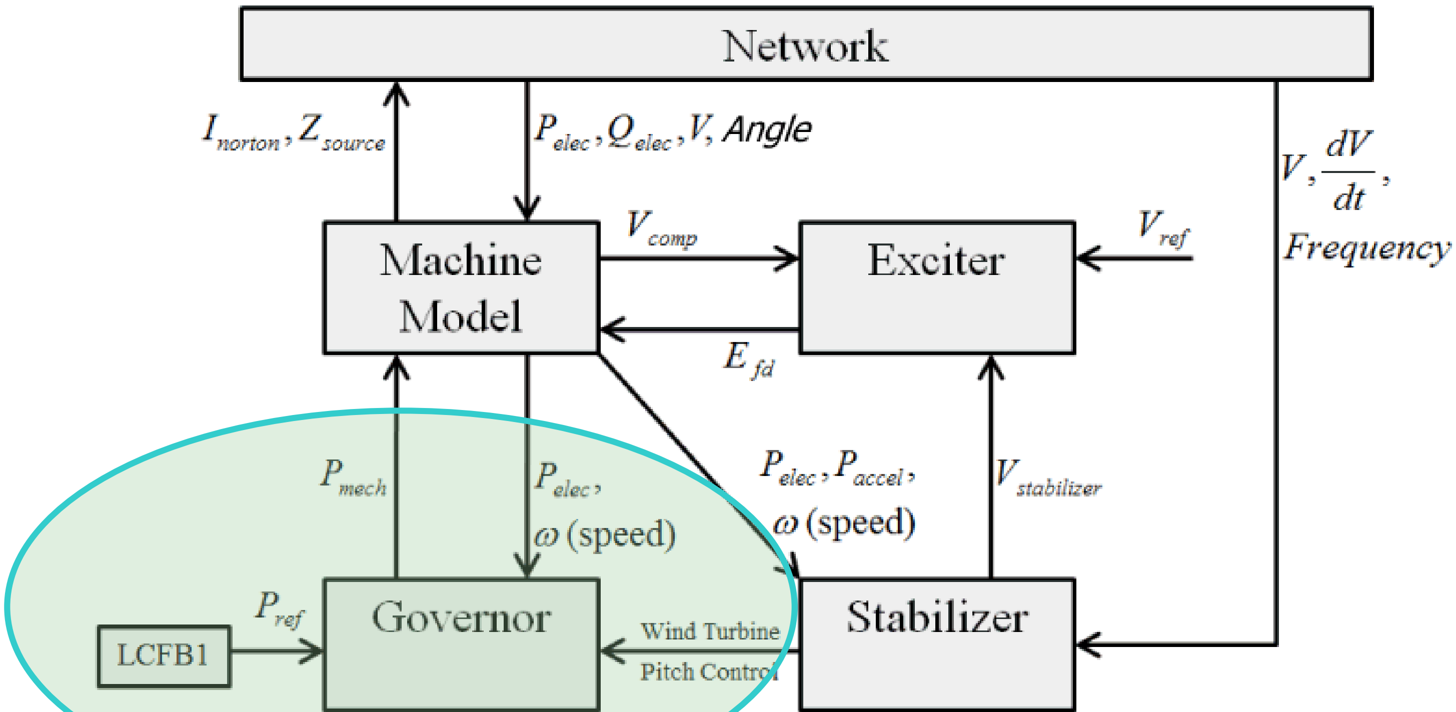
TEXAS A&M UNIVERSITY

# Announcements

- Read Chapter 4
- Homework 3 is due today
- Exam 1 is Thursday October 10 during class; closed book, closed notes. One 8.5 by 11 inch note sheet and calculators allowed.

# Governor Models




$P_{elec}$ = Electrical Power

$Q_{elec}$ = Electrical Reactive Power

$V$ = Voltage at Terminal Bus

$\frac{dV}{dt}$ = Derivate of Voltage

$V_{comp}$ = Compensated Voltage

$P_{mech}$ = Mechanical Power

$\omega$(speed) = Rotor Speed (often it's deviation from nominal speed)

$P_{accel}$ = Accelerating Power

$V_{stabilizer}$ = Output of Stabilizer

$V_{ref}$ = Exciter Control Setpoint (determined during initialization)

$P_{ref}$ = Governor Control Setpoint (determined during initialization)

# Prime Movers and Governors

- Synchronous generator is used to convert mechanical energy from a rotating shaft into electrical energy
- The "prime mover" is what converts the orginal energy source into the mechanical energy in the rotating shaft
- Possible sources: 1) steam (nuclear, coal, combined cycle, solar thermal), 2) gas turbines, 3) water wheel (hydro turbines), 4) diesel/ gasoline, 5) wind (which we'll cover separately)
- The governor is used to control the speed

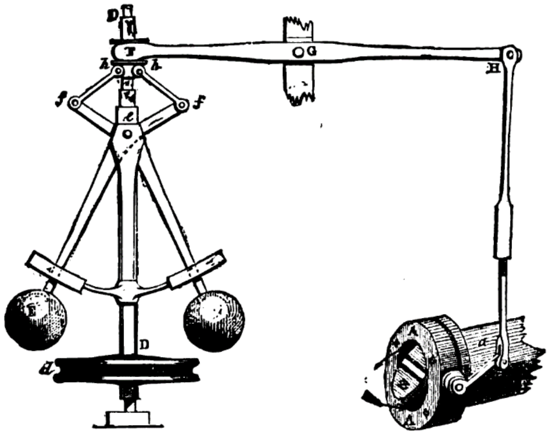


FIG. 4.—*Governor and Throttle-Valve.*

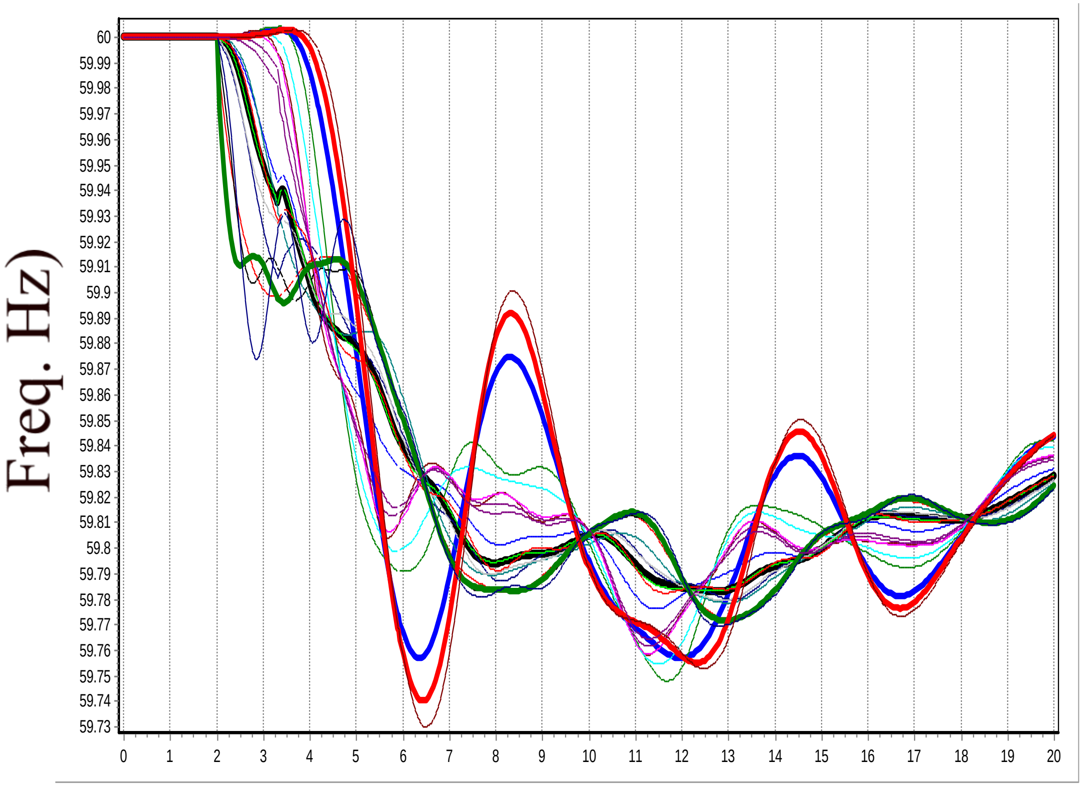
Image source: http://upload.wikimedia.org/wikipedia/commons/1/1e/Centrifugal_governor.png

# Prime Movers and Governors

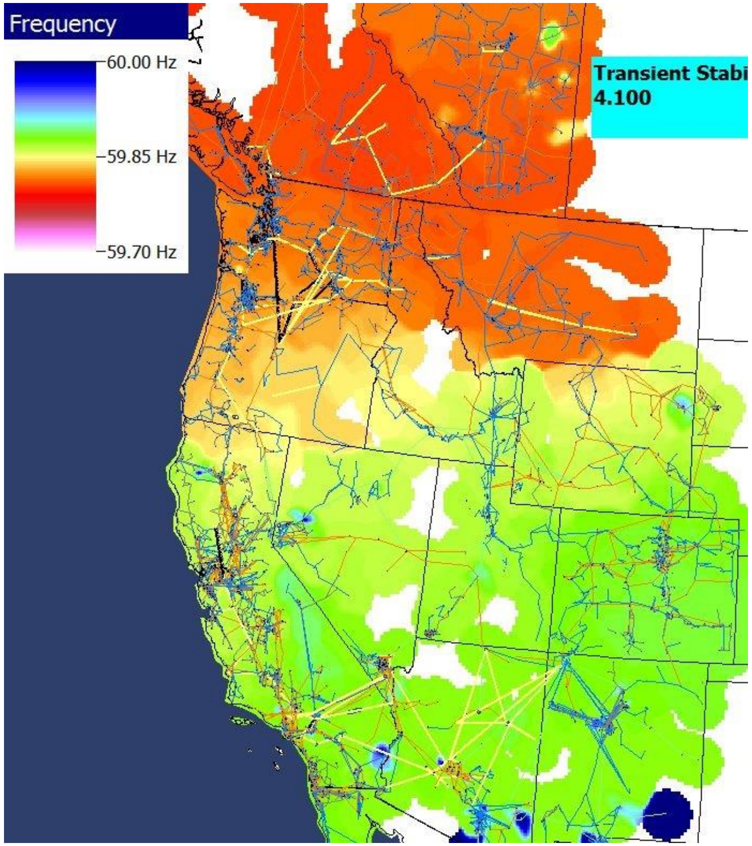
- In transient stability collectively the prime mover and the governor are called the "governor"
- As has been previously discussed, models need to be appropriate for the application
- In transient stability the response of the system for seconds to perhaps minutes is considered
- Long-term dynamics, such as those of the boiler and automatic generation control (AG), are usually not considered
- These dynamics would need to be considered in longer simulations (e.g. dispatcher training simulator (DTS)

# Power Grid Disturbance Example

Figures show the frequency change as a result of the sudden loss of a large amount of generation in the Southern WECC




Time in Seconds




Frequency Contour

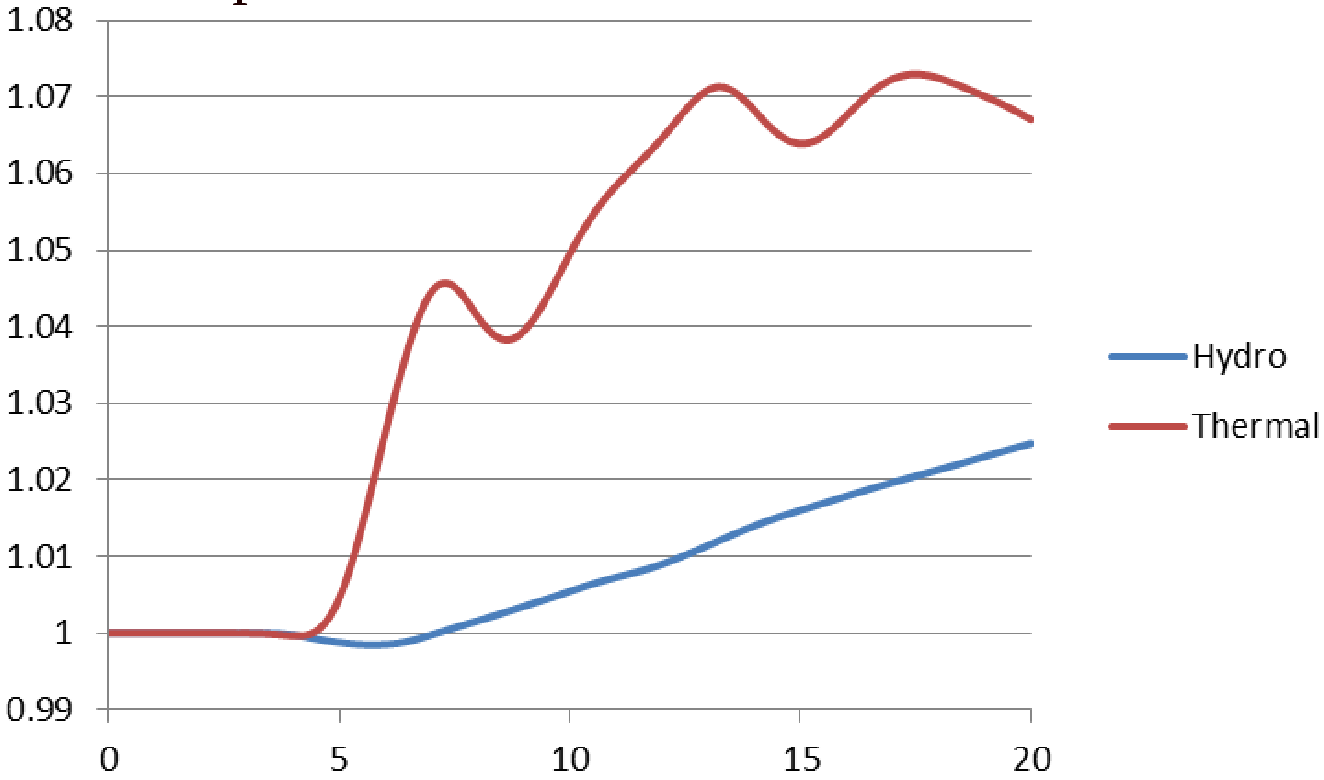
# Frequency Response for Generation Loss

- In response to a rapid loss of generation, in the initial seconds the system frequency will decrease as energy stored in the rotating masses is transformed into electric energy
  - Some generation, such as solar PV has no inertia, and for most new wind turbines the inertia is not seen by the system
- Within seconds governors respond, increasing the power output of controllable generation
  - Many conventional units are operated so they only respond to over frequency situations
  - Solar PV and wind are usually operated in North America at maximum power so they have no reserves to contribute

# Governor Response: Thermal Versus Hydro

Thermal units respond quickly, hydro ramps slowly (and goes down initially), wind and solar usually do not respond. And many units are set to not respond!

Normalized output

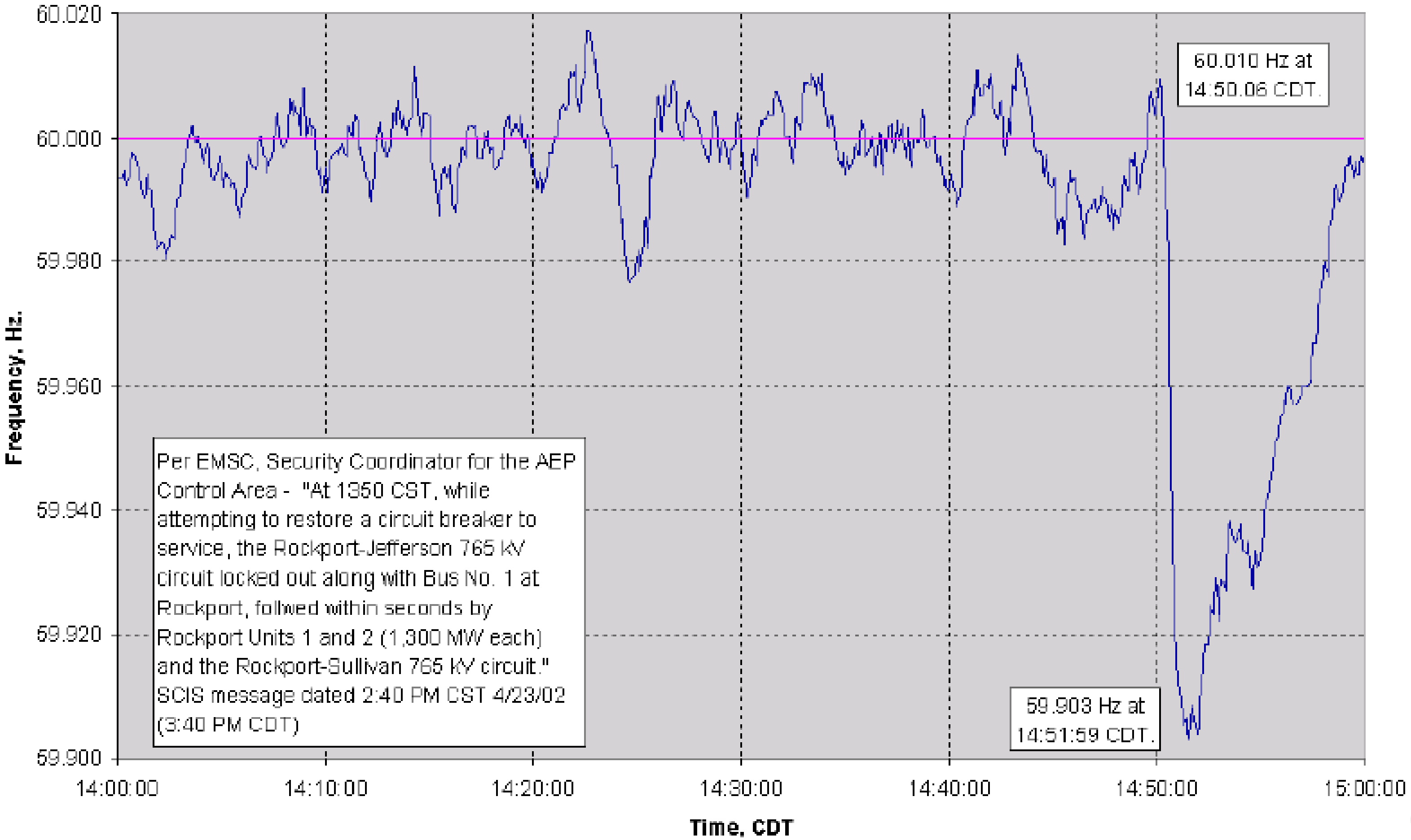



Time in Seconds

# Some Good References

- Kundur, *Power System Stability and Control*, 1994
- Wood, Wollenberg and Sheble, *Power Generation, Operation and Control*, third edition, 2013
- IEEE PES, "Dynamic Models for Turbine-Governors in Power System Studies," Jan 2013
- "Dynamic Models for Fossil Fueled Steam Units in Power System Studies," *IEEE Trans. Power Syst.*, May 1991, pp. 753-761
- "Hydraulic Turbine and Turbine Control Models for System Dynamic Studies," *IEEE Trans. Power Syst.*, Feb 1992, pp. 167-179

# 2600 MW Loss Frequency Recovery



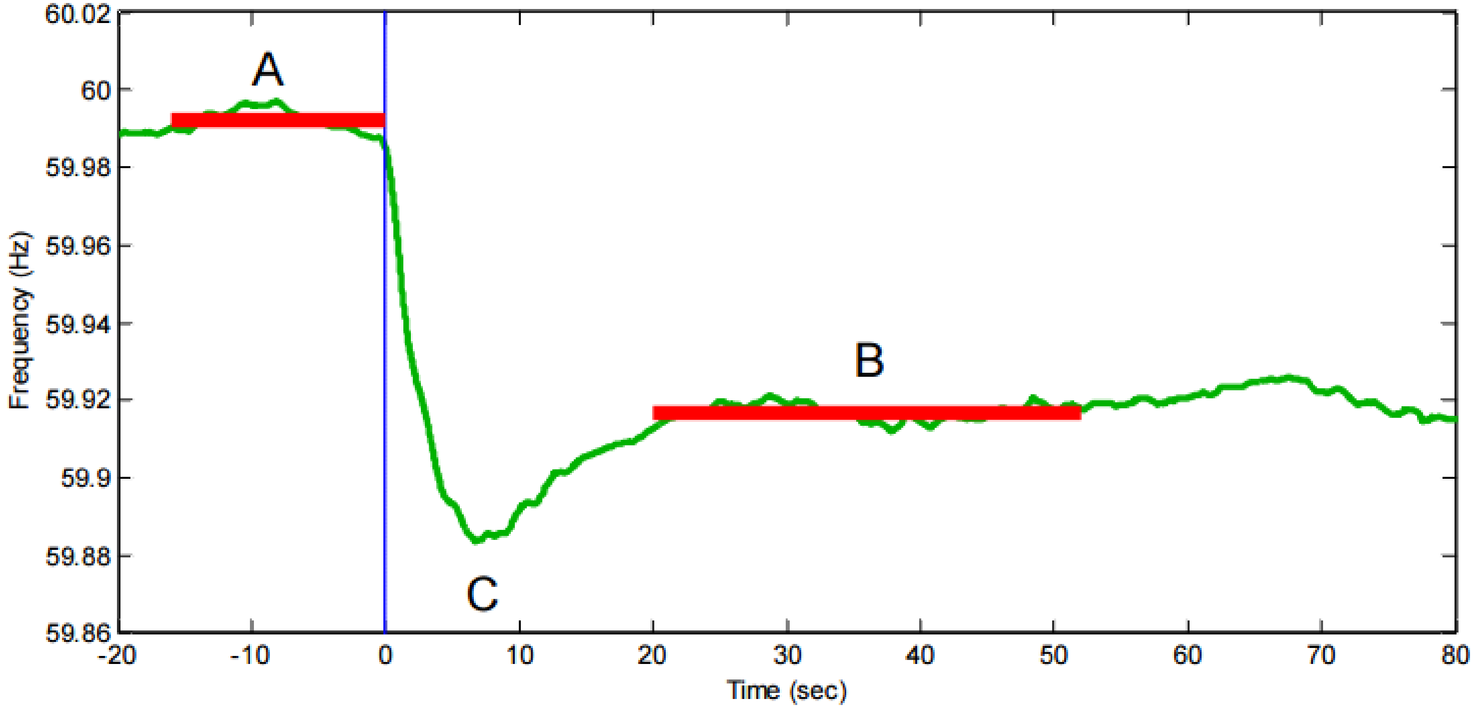

Frequency recovers in about ten minutes

# Frequency Response Definition

- FERC defines in RM13-11: “Frequency response is a measure of an Interconnection’s ability to stabilize frequency immediately following the sudden loss of generation or load, and is a critical component of the reliable operation of the Bulk-Power System, particularly during disturbances and recoveries.”
- Design Event for WECC is N-2 (Palo Verde Outage) not to result in UFLS (59.5 Hz in WECC)

Source: wecc.biz/Reliability/Frequency%20Response%20Analysis%20-%20Dmitry%20Kosterev.pdf

# Frequency Response Measure




**NERC FRM BAL-003-1: Frequency difference between Point A and Point B**

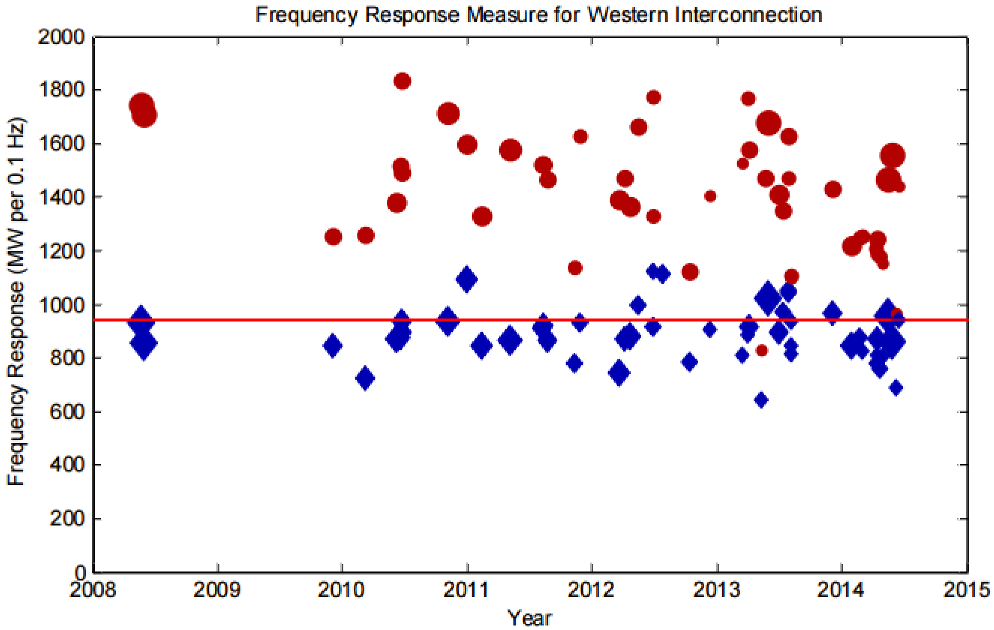
LBNL Metrics: Frequency difference between Point A and Point C

Source: wecc.biz/Reliability/Frequency%20Response%20Analysis%20-%20Dmitry%20Kosterev.pdf

# WECC Interconnection Performance

## Western Interconnection Performance

WECC IFRO ~950 MW per 01. Hz, WECC IFRM is trending ~ 1,400 to 1,600 MW per 0.1 Hz
Response at nadir: required ~580 MW per 0.1 Hz, actual is about 800 MW per 0.1 Hz

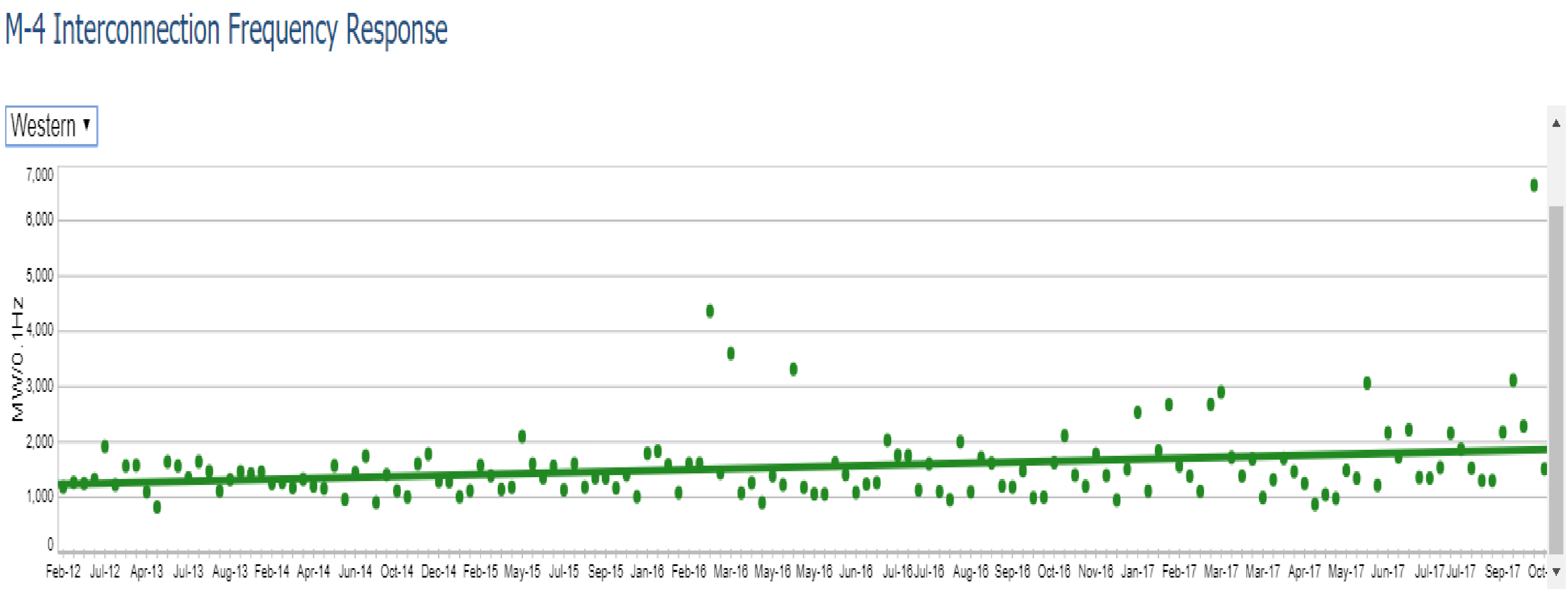



- Red dots – frequency response measured at point B (settling) using NERC FRM methodology
- Blue diamonds – frequency response is measured at point C (nadir)

Source: wecc.biz/Reliability/Frequency%20Response%20Analysis%20-%20Dmitry%20Kosterev.pdf

# WECC Interconnect Frequency Response

- Data for the four major interconnects is available from NERC; these are the values between points A and B

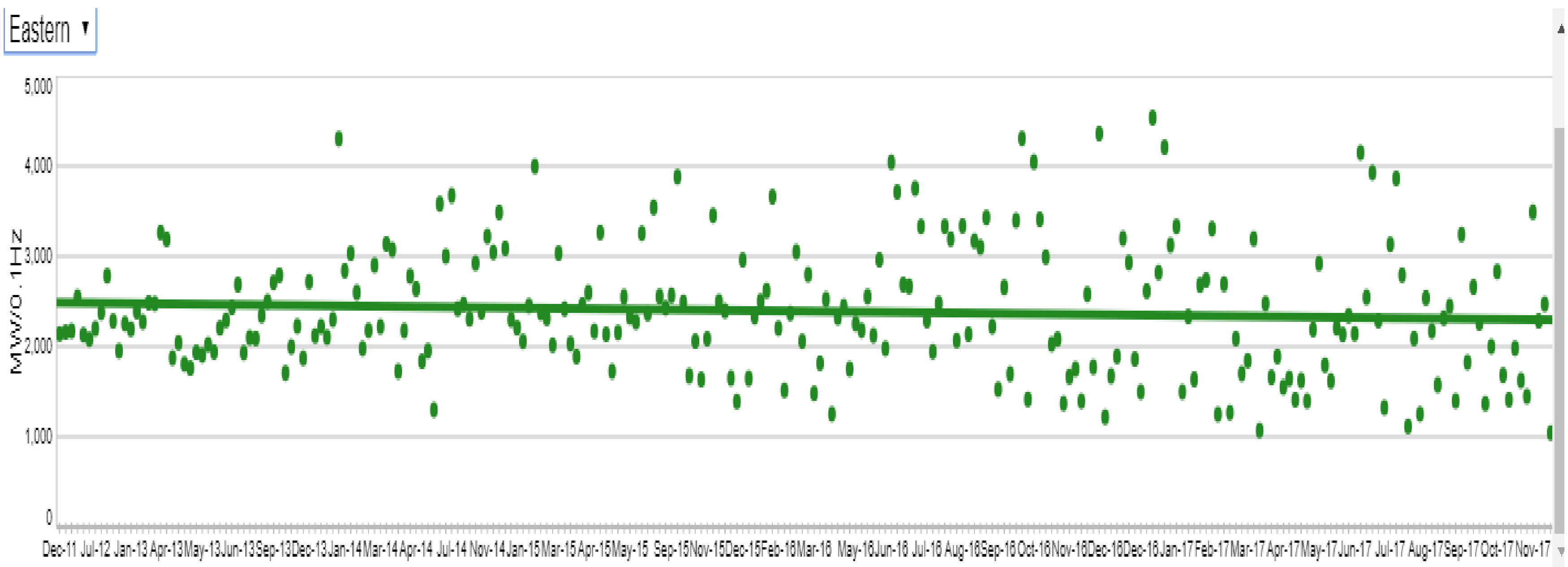



A higher value is better (more generation for a 0.1 Hz change)

Source: www.nerc.com/pa/RAPA/ri/Pages/InterconnectionFrequencyResponse.aspx

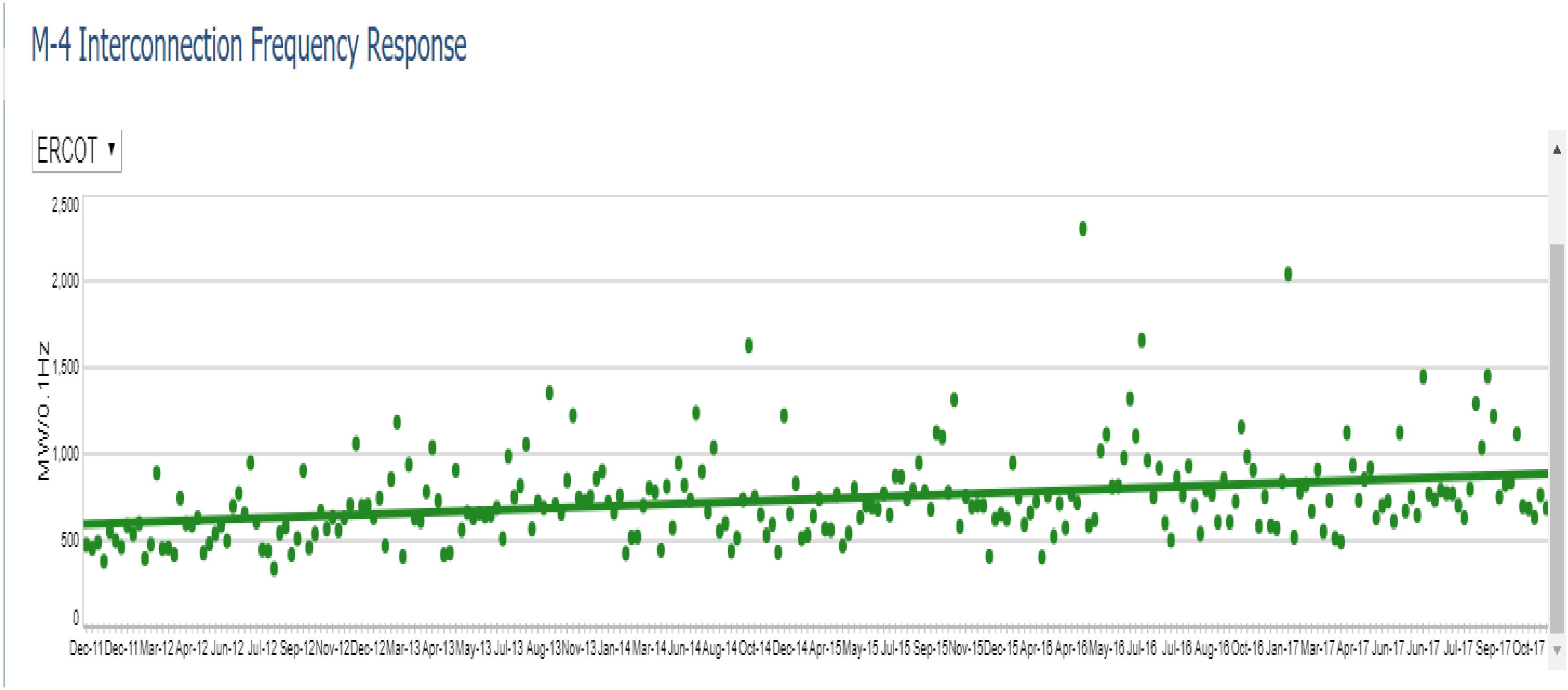
# Eastern Interconnect Frequency Response

M-4 Interconnection Frequency Response




The larger Eastern Interconnect on average has a higher value

# ERCOT Interconnect Frequency Response




An ERCOT a lower value

Source: www.nerc.com/pa/RAPA/ri/Pages/InterconnectionFrequencyResponse.aspx

# Control of Generation Overview

- Goal is to maintain constant frequency with changing load
- If there is just a single generator, such with an emergency generator or isolated system, then an isochronous governor is used
  - Integrates frequency error to insure frequency goes back to the desired value
  - Cannot be used with interconnected systems because of "hunting"

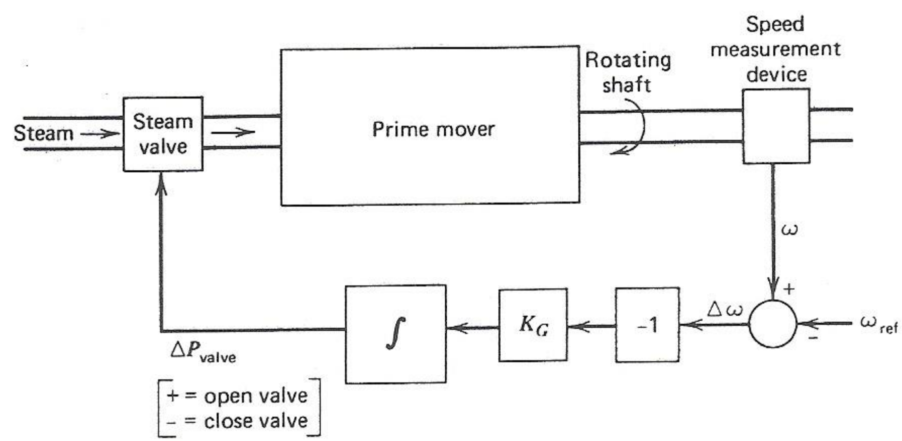



FIG. 9.9 Isochronous governor.

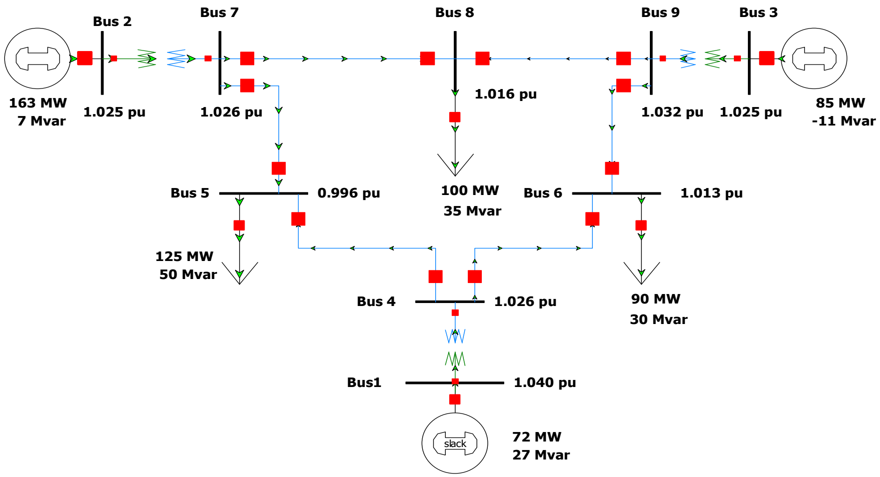
Image source: Wood/Wollenberg, 2nd edition

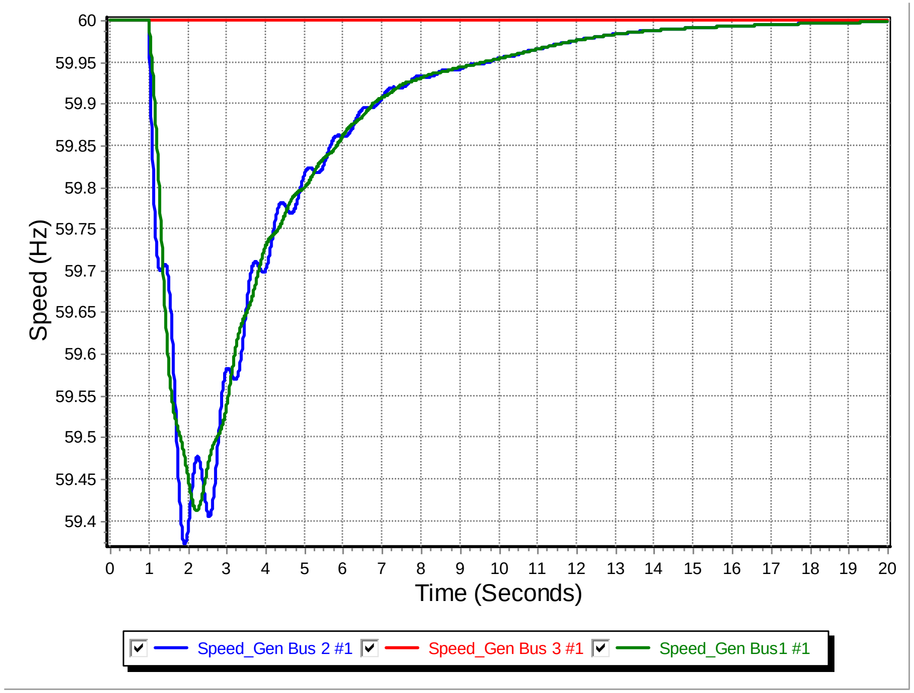
# Generator "Hunting"

- Control system "hunting" is oscillation around an equilibrium point
- Trying to interconnect multiple isochronous generators will cause hunting because the frequency setpoints of the two generators are never exactly equal
  - One will be accumulating a frequency error trying to speed up the system, whereas the other will be trying to slow it down
  - The generators will NOT share the power load proportionally

# Isochronous Gen Example

- WSCC 9 bus from before, gen 3 dropping (85 MW)
  - No infinite bus, gen 1 is modeled with an isochronous generator (PW ISOGov1 model)



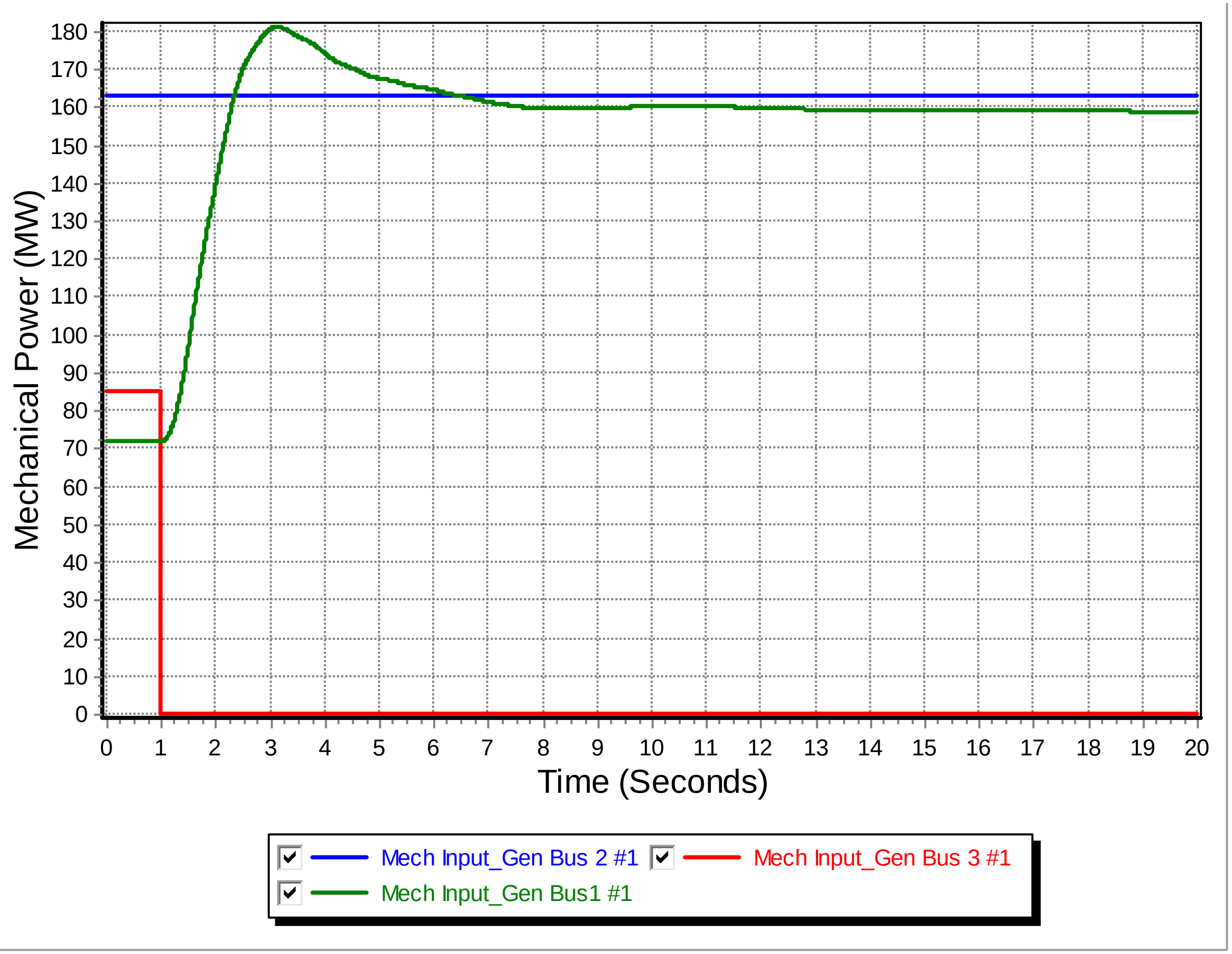




Gen 2 is modeled with no governor, so its mechanical power stays fixed

Case is **wscc_9bus_IsoGov**

# Isochronous Gen Example

- Graph shows the change in the mechanical output

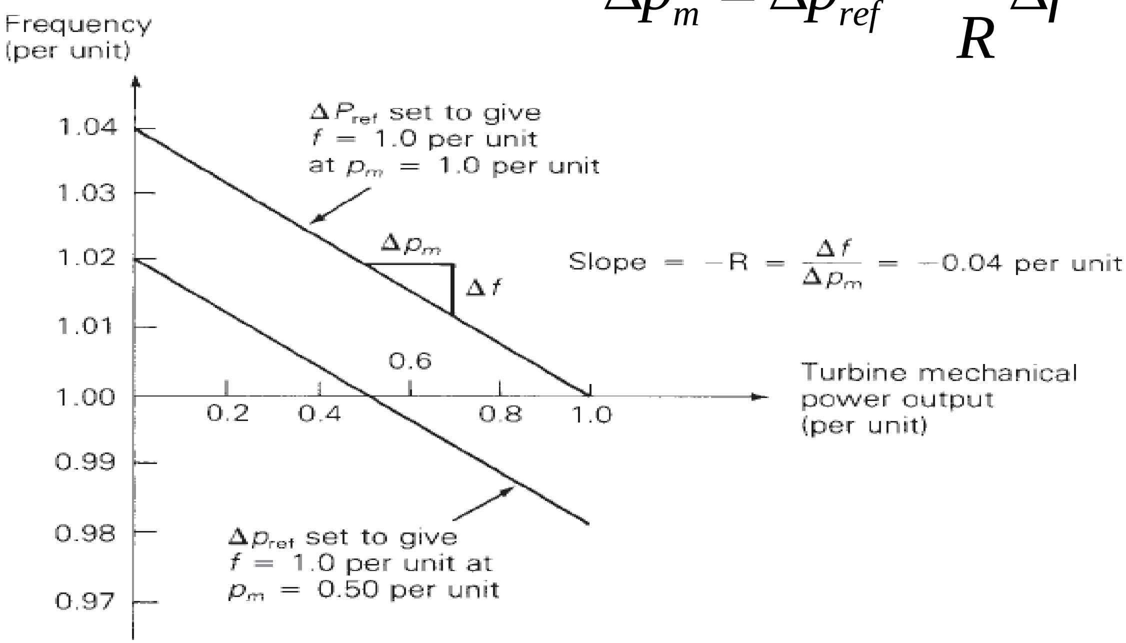



All the change in MWs due to the loss of gen 3 is being picked up by gen 1

# Droop Control

- To allow power sharing between generators the solution is to use what is known as droop control, in which the desired set point frequency is dependent upon the generator's output

$$\Delta p_m = \Delta p_{ref} - \frac{1}{R}\Delta f$$




R is known as the regulation constant or droop; a typical value is 4 or 5%.

At 60 Hz and a 5% droop, each 0.1 Hz change would change the output by 0.1/(60*0.05)= 3.33%

# WSCC 9 Bus Droop Example

- Assume the previous gen 3 drop contingency (85 MW), and that gens 1 and 2 have ratings of 500 and 250 MVA respectively and governors with a 5% droop. What is the final frequency (assuming no change in load)?

To solve the problem in per unit, all values need to be on a common base (say 100 MVA)

$$\Delta p_{m1} + \Delta p_{m2} = 85/100 = 0.85$$

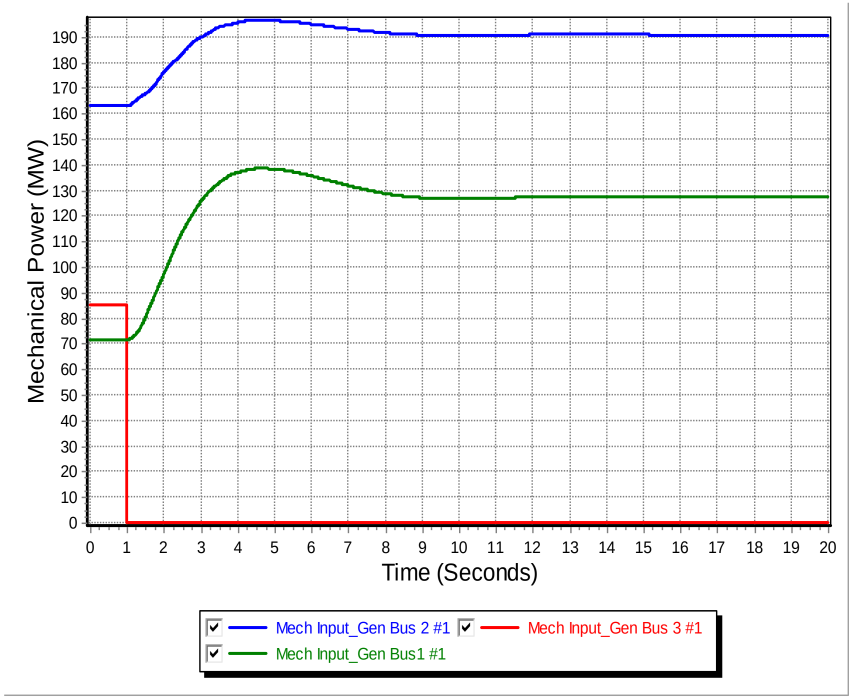
$$R_{1,100MVA} = R_1 \frac{100}{500} = 0.01, \quad R_{2,100MVA} = R_2 \frac{100}{250} = 0.02$$

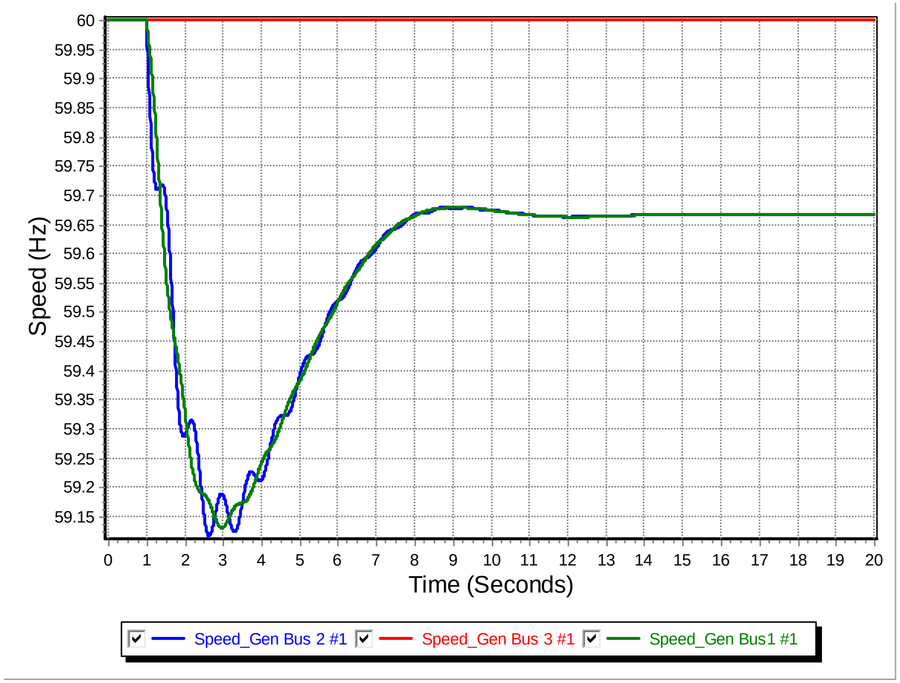
$$\Delta p_{m1} + \Delta p_{m2} = -\left(\frac{1}{R_{1,100MVA}} + \frac{1}{R_{2,100MVA}}\right)\Delta f = 0.85$$

$$\Delta f = -.85/150 = 0.00567 = -0.34 \text{ Hz} \rightarrow 59.66 \text{ Hz}$$

# WSCC 9 Bus Droop Example

- The below graphs compare the mechanical power and generator speed; note the steady-state values match the calculated 59.66 Hz value




Case is **wscc_9bus_TGOV1**

# Quick Interconnect Calculation

- When studying a system with many generators, each with the same (or close) droop, then the final frequency deviation is

$$\Delta f = -\frac{R \times \Delta P_{gen,MW}}{\sum_{OnlineGens} S_{i,MVA}}$$

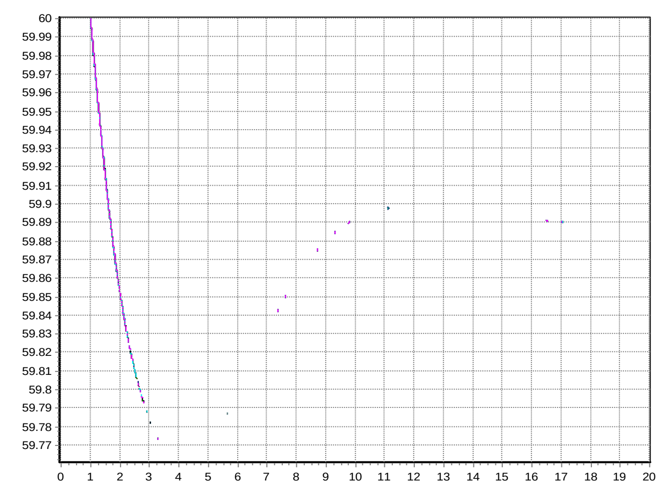
The online generator group obviously does not include the contingency generator(s) that are opened

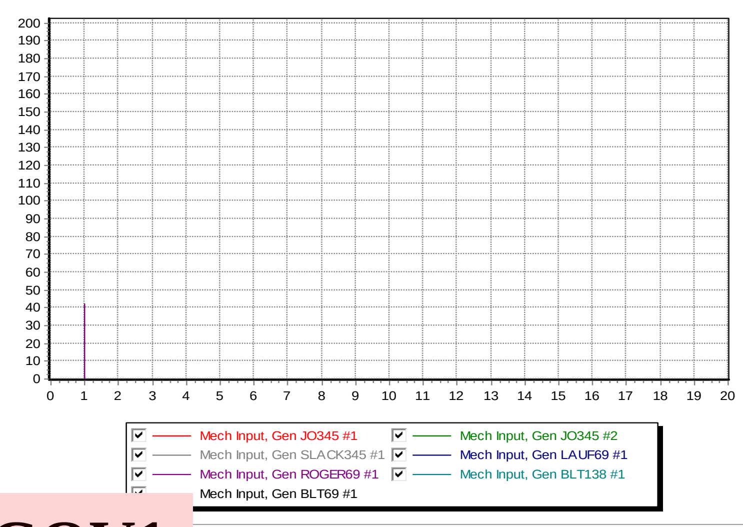
- The online generator summation should only include generators that actually have governors that can respond, and does not take into account generators hitting their limits

# Larger System Example

- As an example, consider the 37 bus, nine generator example from earlier; assume one generator with 42 MW is opened. The total MVA of the remaining generators is 1132. With R=0.05

$$\Delta f = -\frac{0.05 \times 42}{1132} = -0.00186 \text{ pu} = -0.111 \text{ Hz} \rightarrow 59.889 \text{ Hz}$$

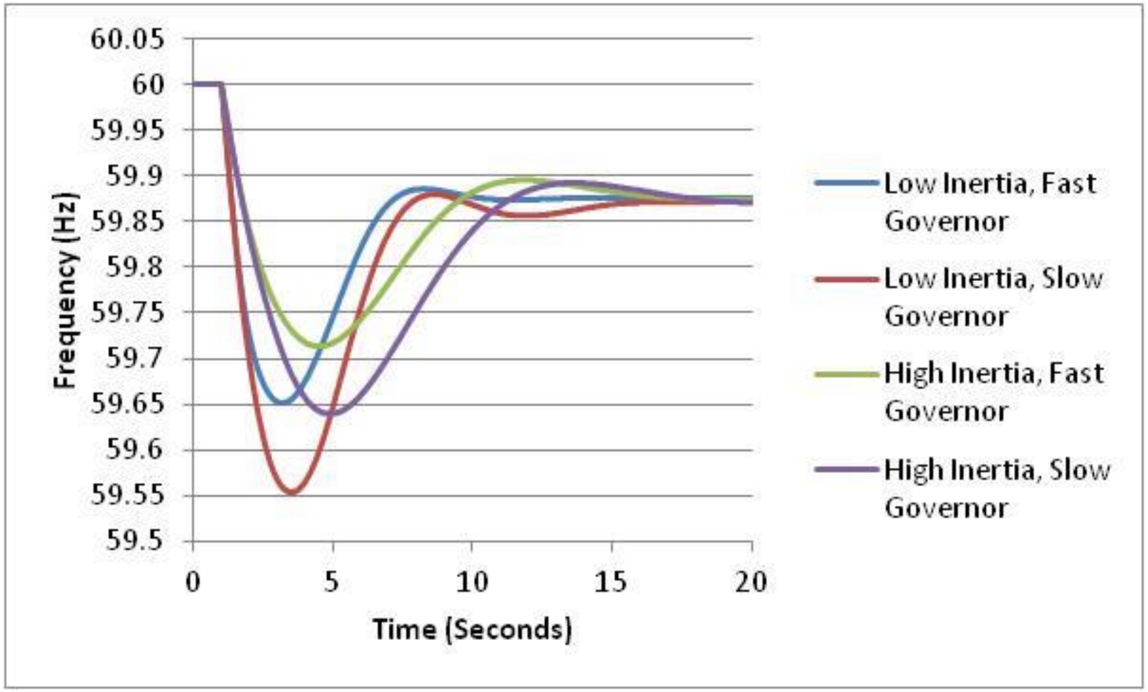





Case is **Bus37_TGOV1**

# Impact of Inertia (H)

- Final frequency is determined by the droop of the responding governors
- How quickly the frequency drops depends upon the generator inertia values



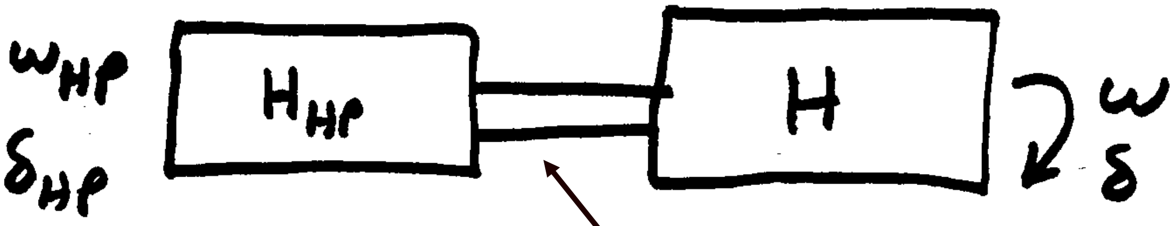

The least frequency deviation occurs with high inertia and fast governors

# Restoring Frequency to 60 (or 50) Hz

- In an interconnected power system the governors to not automatically restore the frequency to 60 Hz
- Rather done via the ACE (area control area calculation). Previously we defined ACE as the difference between the actual real power exports from an area and the scheduled exports. But it has an additional term
  $ACE = P_{actual} - P_{sched} - 10\beta(freq_{act} - freq_{sched})$
- $\beta$ is the balancing authority frequency bias in MW/0.1 Hz with a negative sign. It is about 0.8% of peak load/generation

This slower ACE response is usually not modeled in transient stability

# Turbine Models




model shaft "squishiness" as a spring

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

$$\frac{2H}{\omega_s}\frac{d\omega}{dt} = T_M - T_{ELEC} - T_{FW}$$

$$T_M = -K_{shaft}(\delta - \delta_{HP}) = T_{OUT}$$

Usually shaft dynamics are neglected

$$\frac{d\delta_{HP}}{dt} = \omega_{HP} - \omega_s$$

$$\frac{2H_{HP}}{\omega_s}\frac{d\omega_{HP}}{dt} = T_{IN} - T_{OUT}$$

High-pressure turbine shaft dynamics

# Steam Turbine Models

Boiler supplies a "steam chest" with the steam then entering the turbine through a value

$$T_{CH}\frac{dP_{CH}}{dt} = -P_{CH} + P_{SV}$$

Assume $T_{in} = P_{CH}$ and a rigid shaft with $P_{CH} = T_M$

Then the above equation becomes

$$T_{CH}\frac{dT_M}{dt} = -T_M + P_{SV}$$

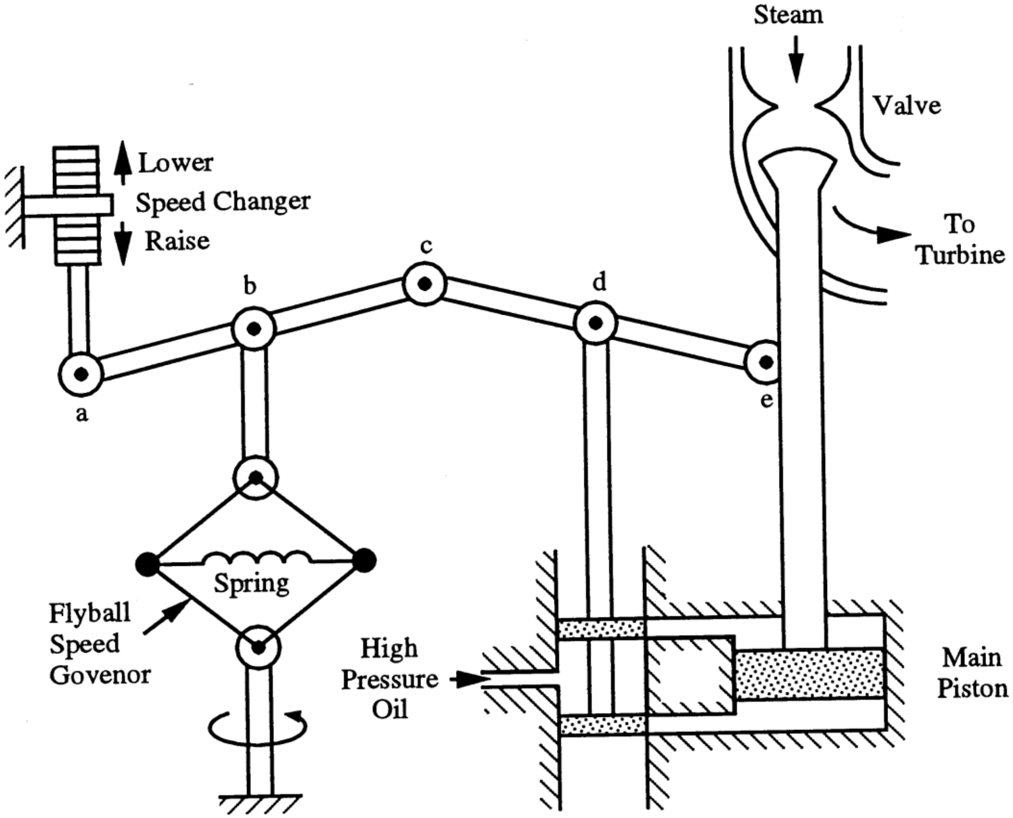
And we just have the swing equations from before

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

$$\frac{2H}{\omega_s}\frac{d\omega}{dt} = T_M - T_{ELEC} - T_{FW}$$

We are assuming $\delta=\delta_{HP}$ and $\omega=\omega_{HP}$

# Steam Governor Model



# Steam Governor Model

$$T_{SV} \frac{dP_{SV}}{dt} = -P_{SV} + P_C - \frac{1}{R}\Delta\omega$$

$$\text{where } \Delta\omega = \frac{\omega - \omega_s}{\omega_s}$$

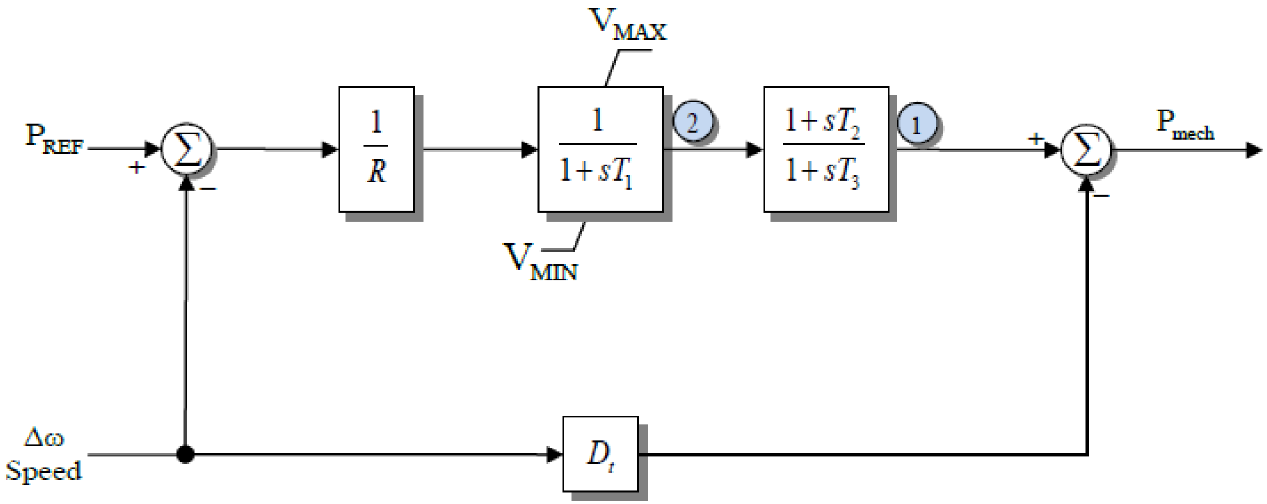
$$0 \le P_{SV} \le P_{SV}^{\max}$$

Steam valve limits

$R$ = .05 (5% droop)

# TGOV1 Model

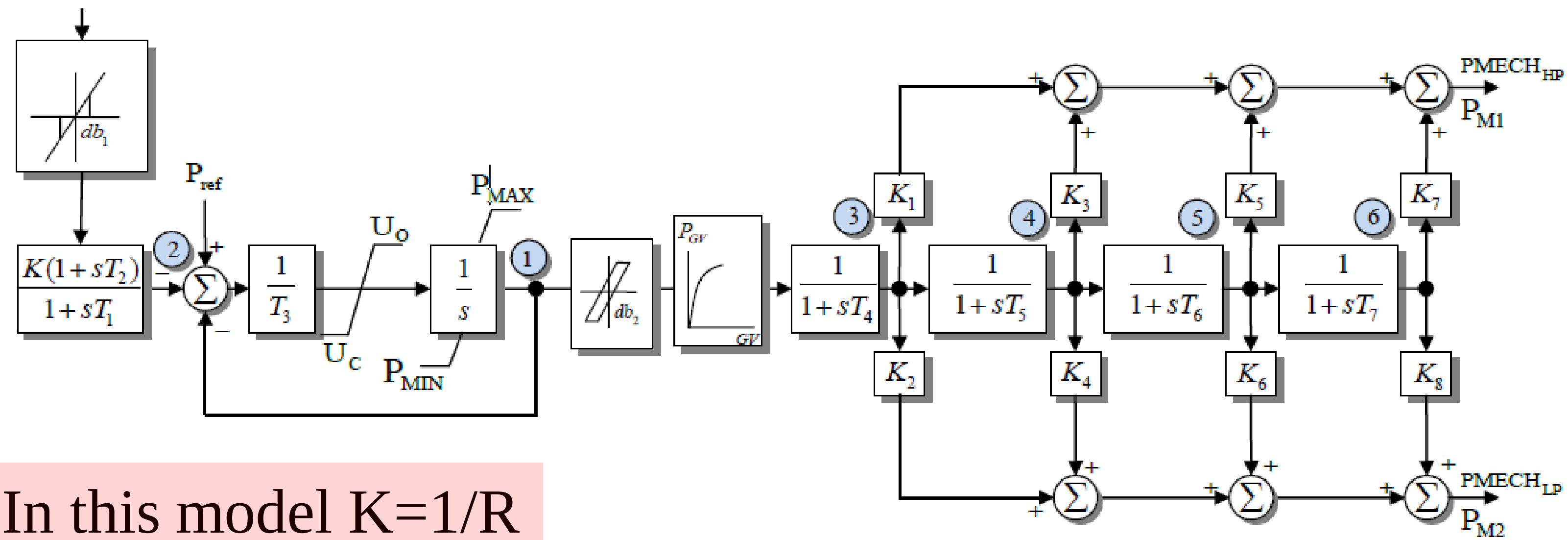
- Standard model that is close to this is TGOV1




About 12% of governors in a 2015 EI model are TGOV1; R = 0.05, $T_1$ is less than 0.5 (except a few 999's!), $T_3$ has an average of 7, average $T_2/T_3$ is 0.34; $D_t$ is used to model turbine damping and is often zero (about 80% of time in EI)

# IEEEG1 Model

- A common stream turbine model, is the IEEEG1, originally introduced in the below 1973 paper




In this model K=1/R

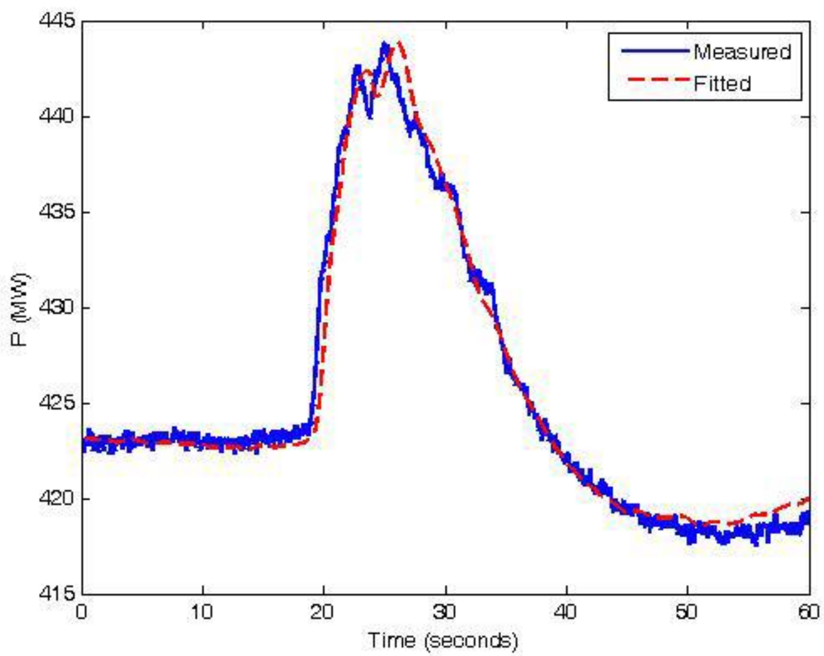
$U_o$ and $U_c$ are rate limits

It can be used to represent cross-compound units, with high and low pressure steam

IEEE Committee Report, "Dynamic Models for Steam and Hydro Turbines in Power System Studies," Transactions in Power Apparatus & Systems, volume 92, No. 6, Nov./Dec. 1973, pp 1904-15

# IEEEG1

- Blocks on the right model the various steam stages
- About 12% of WECC and EI governors are currently IEEEG1s
- Below figures show two test comparison with this



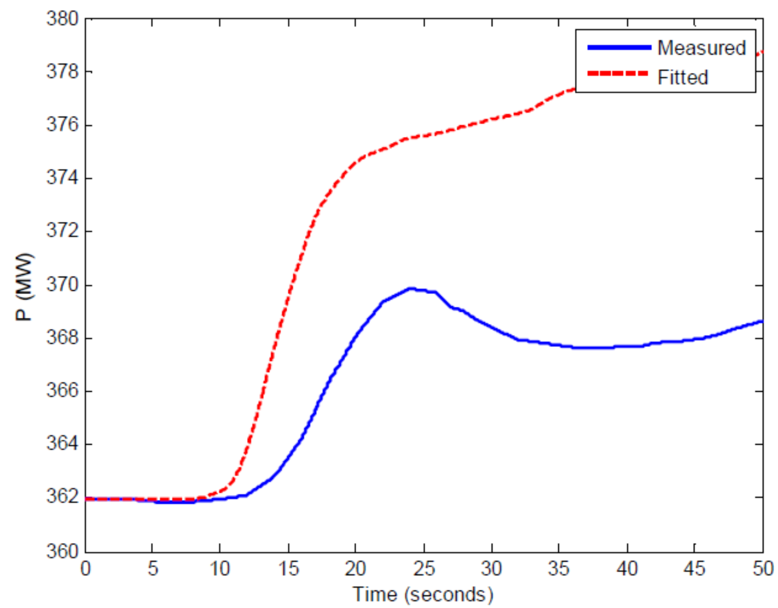
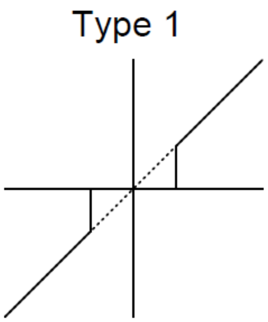




Image Source: Figs 2-4, 2-6 of IEEE PES, "Dynamic Models for Turbine-Governors in Power System Studies," Jan 2013

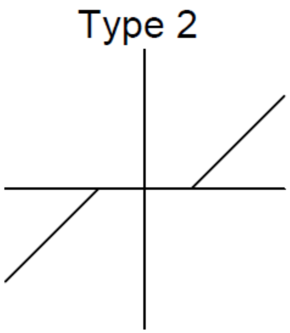
# Deadbands

- Before going further, it is useful to briefly consider deadbands, with two types shown with IEEEG1 and described in the 2013 IEEE PES Governor Report
- The type 1 is an intentional deadband, implemented to prevent excessive response
  - Until the deadband activates there is no response, then normal response after that; this can cause a potentially large jump in the response
  - Also, once activated there is normal response coming back into range
  - Used on input to IEEEG1

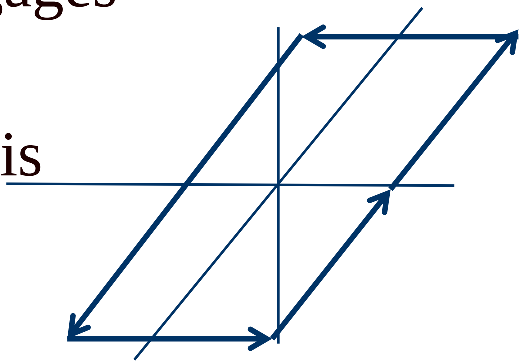


# Deadbands

- The type 2 is also an intentional deadband, implemented to prevent excessive response
  - Difference is response does not jump, but rather only starts once outside of the range




- Another type of deadband is the unintentional, such as will occur with loose gears
  - Until deadband "engages" there is no response
  - Once engaged there is a hysteresis in the response



When starting simulations deadbands usually start at their origin

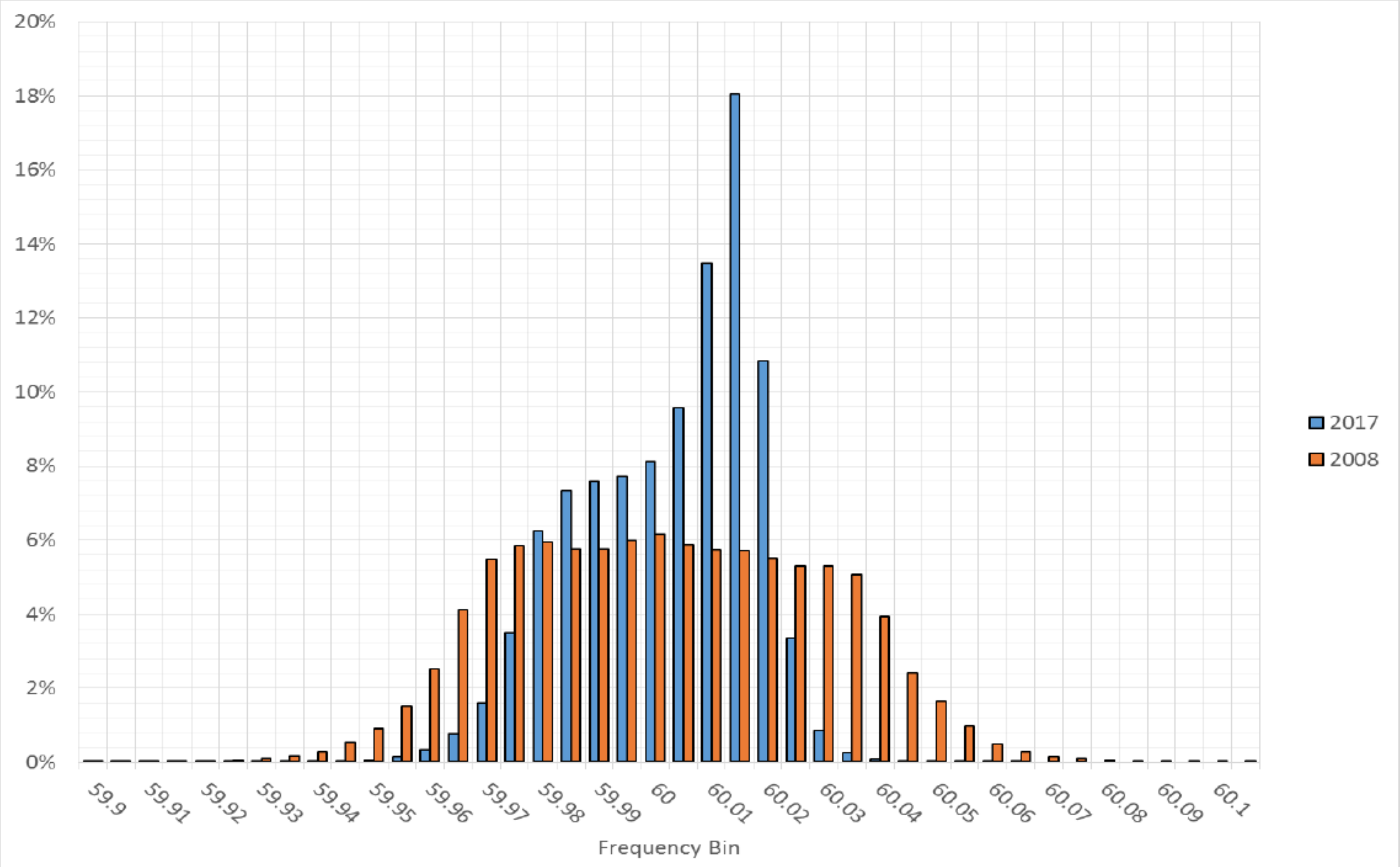
# Frequency Deadbands in ERCOT

- In ERCOT NERC BAL-001-TRE-1 ("Primary Frequency Response in the ERCOT Region") has the purpose "to maintain interconnection steady-state frequency within defined limits"
- The deadband requirement is +/- 0.034 Hz for steam and hydro turbines with mechanical governors; +/- 0.017 Hz for all other generating units
- The maximum droop setting is 5% for all units except it is 4% for combined cycle combustion turbines

Source: NERC BAL-001-TRE-1 and ERCOT, Demonstration of PFR Improvement, ERCOT Operations Planning, Sept. 2017 presentation

# Comparing ERCOT 2017 Versus 2008 Frequency Profile (5 mHz bins)

## Comparing 2017 vs 2008 Frequency Profile in 5 mHz Bins



# Gas Turbines

- A gas turbine (usually using natural gas) has a compressor, a combustion chamber and then a turbine
- The below figure gives an overview of the modeling

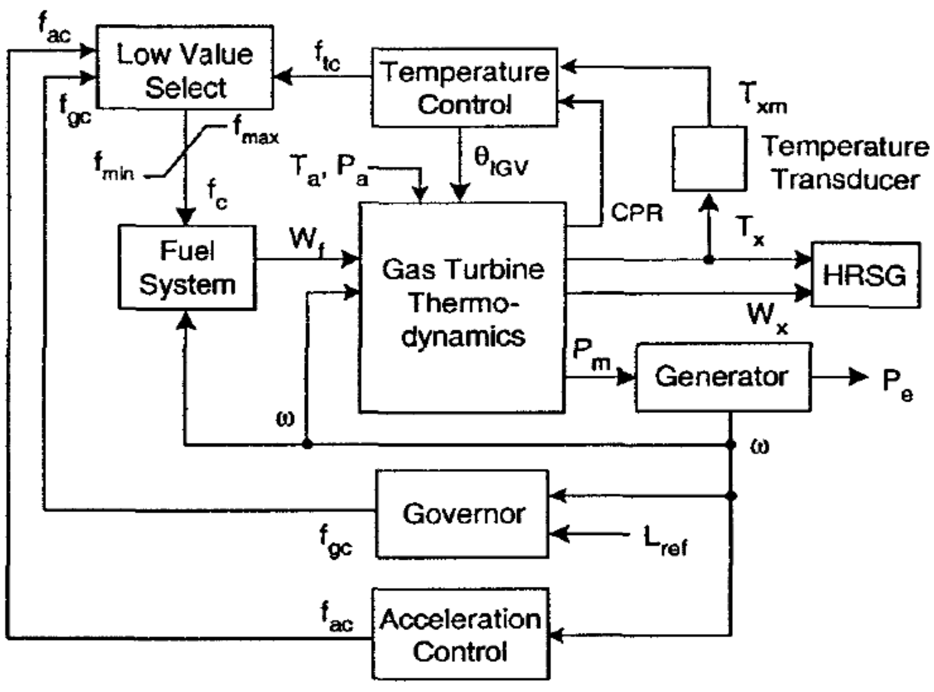


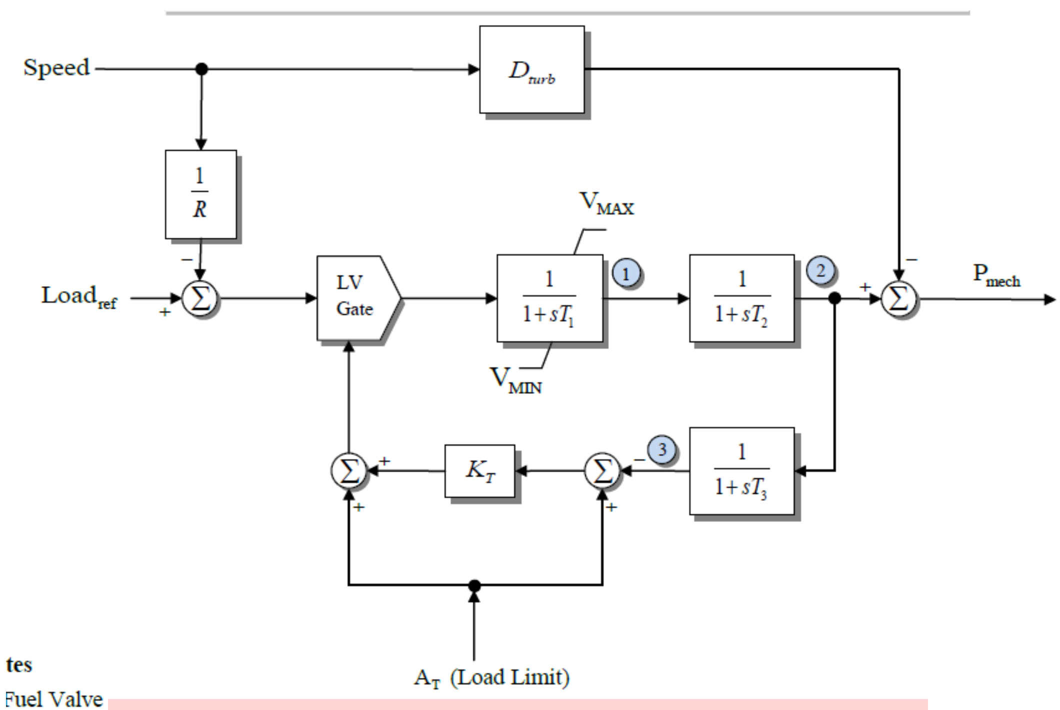

**Figure 3-3: Gas turbine controls [17] (IEEE© 2001).**

HRSG is the heat recovery steam generator (if it is a combined cycle unit)

Image from IEEE PES, "Dynamic Models for Turbine-Governors in Power System Studies," Jan 2013

# GAST Model

- Quite detailed gas turbine models exist; we'll just consider the simplest, which is still used some




$T_1$ average is 0.9, $T_2$ is 0.6 sec

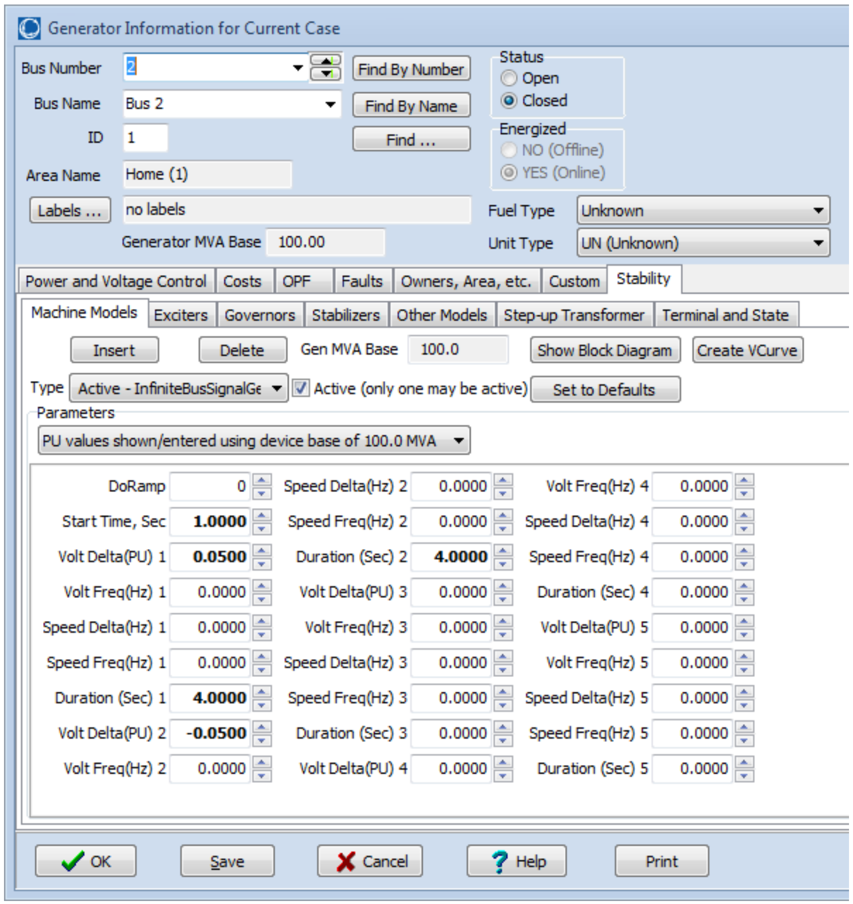
It is somewhat similar to the TGOV1. $T_1$ is for the fuel valve, $T_2$ is for the turbine, and $T_3$ is for the load limit response based on the ambient temperature (At); $T_3$ is the delay in measuring the exhaust temperature

# Play-in (Playback) Models

- Often time in system simulations there is a desire to test the response of units (or larger parts of the simulation) to particular changes in voltage or frequency
  - These values may come from an actual system event
- "Play-in" or playback models can be used to vary an infinite bus voltage magnitude and frequency, with data specified in a file
- PowerWorld allows both the use of files (for say recorded data) or auto-generated data
  - Machine type GENCLS_PLAYBACK can play back a file
  - Machine type InfiniteBusSignalGen can auto-generate a signal

# PowerWorld Infinite Bus Signal Generation

- Below dialog shows some options for auto-generation of voltage magnitude and frequency variations




**Start Time** tells when to start; values are then defined for up to five separate time periods

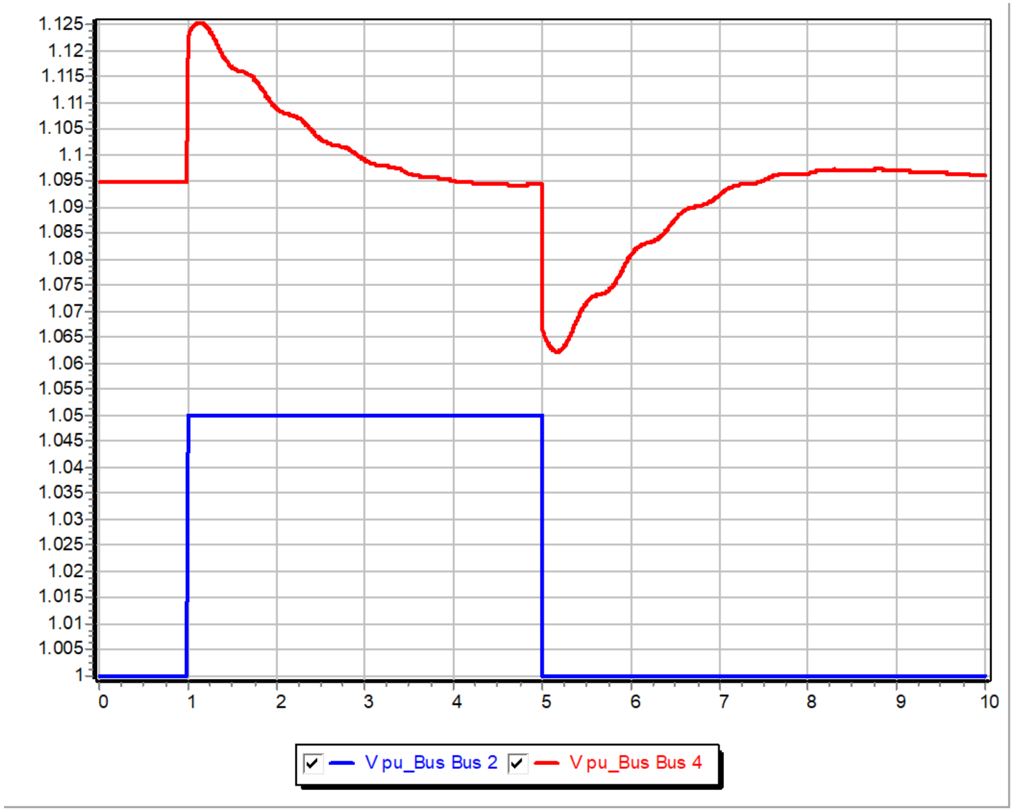
**Volt Delta** is the magnitude of the pu voltage deviation; **Volt Freq** is the frequency of the voltage deviation in Hz (zero for dc)

**Speed Delta** is the magnitude of the frequency deviation in Hz; **Speed Freq** is the frequency of the frequency deviation

**Duration** is the time in seconds for the time period

# Example: Step Change in Voltage Magnitude

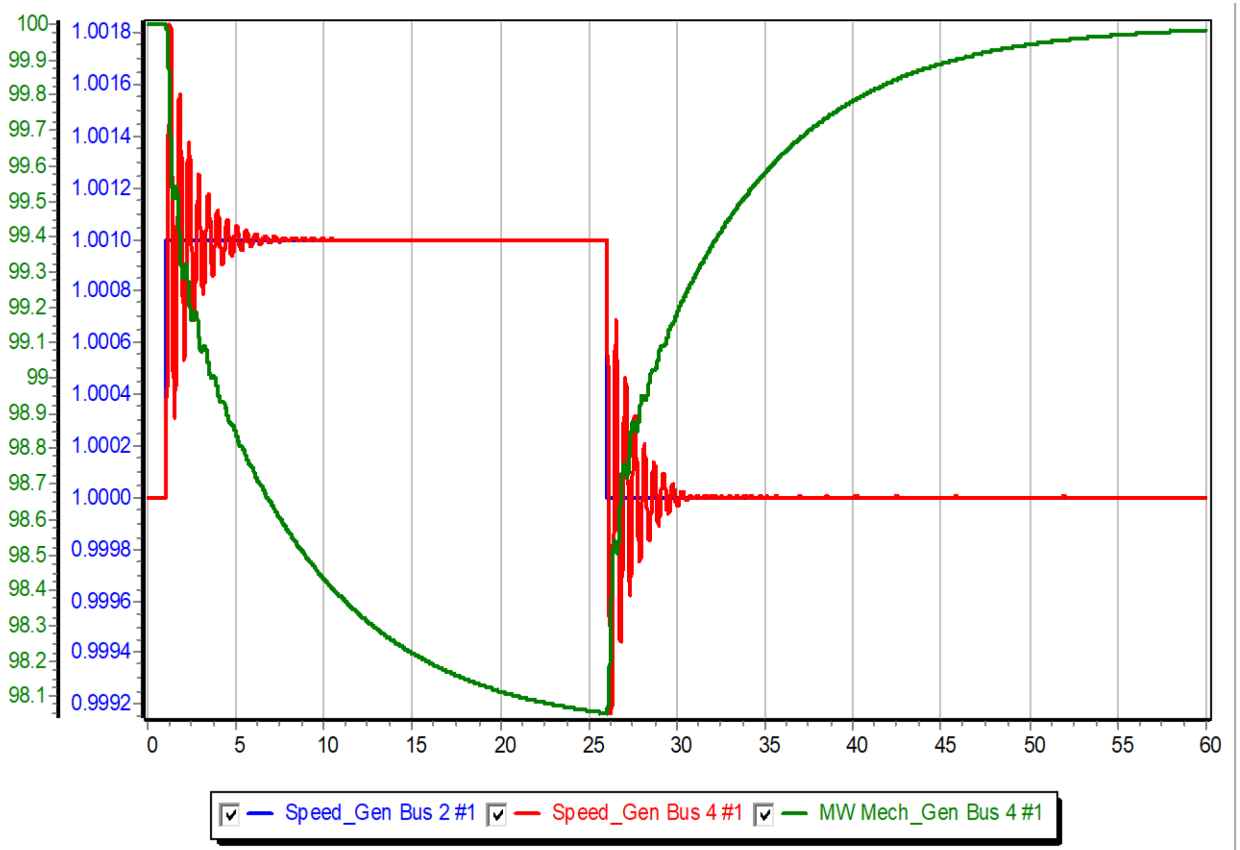
- Below graph shows the voltage response for the four bus system for a change in the infinite bus voltage




Case name: **B4_SignalGen_Voltage**

# Example: Step Change Frequency Response

- Graph shows response in generator 4 output and speed for a 0.1% increase in system frequency




This is a 100 MVA unit with a per unit R of 0.05

$$\Delta f = -\frac{0.05 \times \Delta P_{gen,MW}}{100}$$

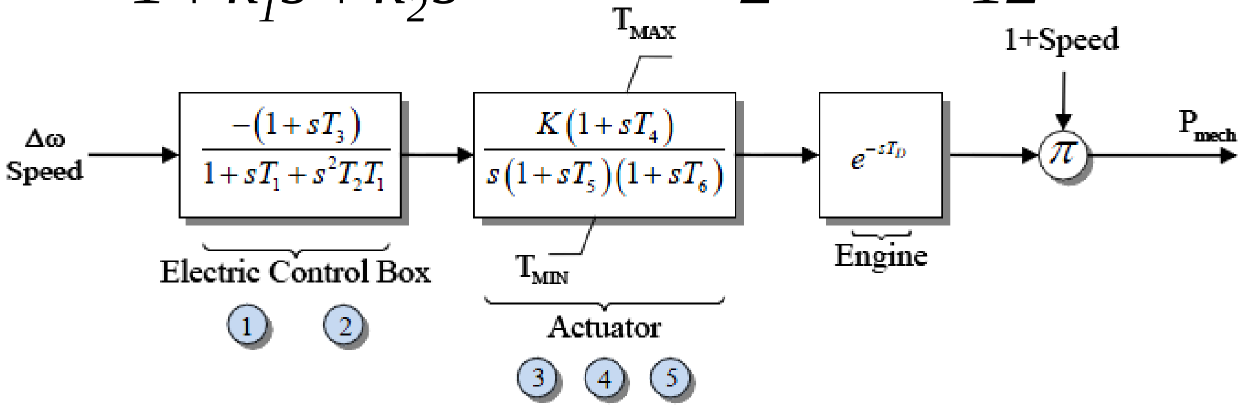
$$\frac{-0.001 \times 100}{0.05} = \Delta P_{gen,MW}$$

$$\Delta P_{gen,MW} = -2$$

# Simple Diesel Model: DEGOV

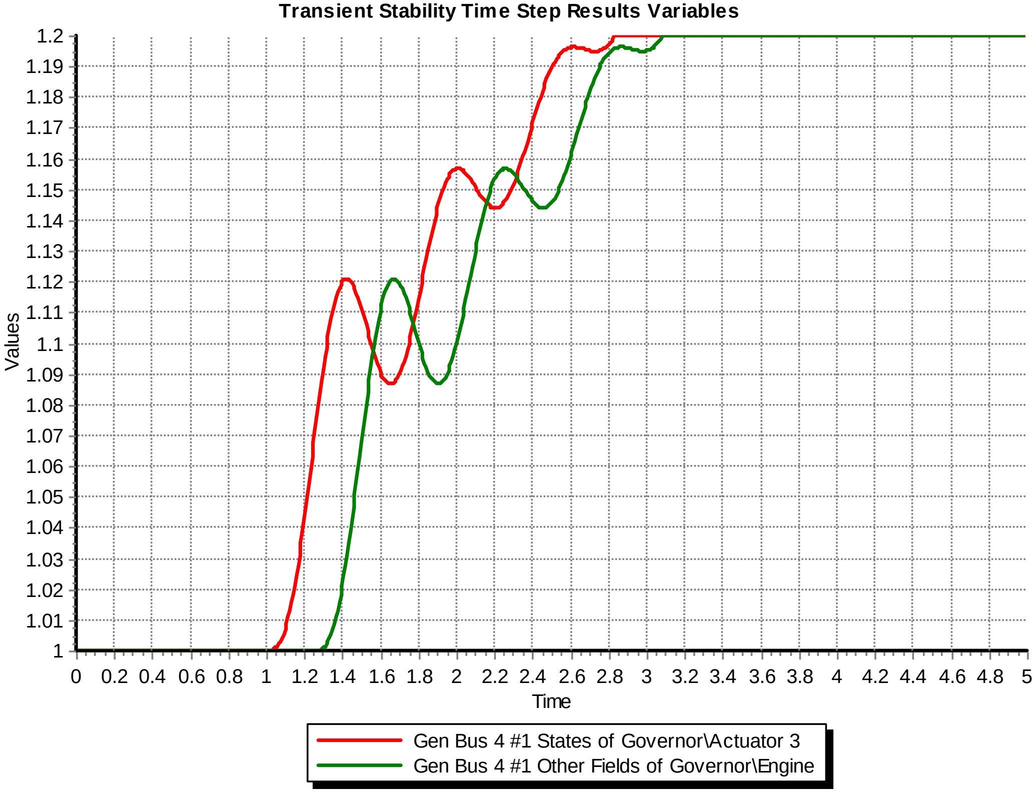
- Sometimes models implement time delays (DEGOV)
  - Often delay values are set to zero
- Delays can be implemented either by saving the input value or by using a Pade approximation, with a 2nd order given below; a 4th order is also common

$$e^{-sT_D} \approx \frac{1 - k_1 s + k_2 s^2}{1 + k_1 s + k_2 s^2}, \quad k_1 = \frac{T_D}{2}, k_2 = \frac{T_D^2}{12}$$



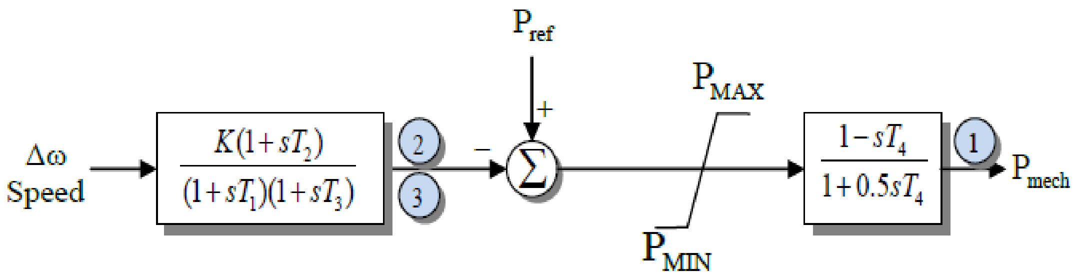
# DEGOV Delay Approximation

- With $T_D$ set to 0.5 seconds (which is longer than the normal of about 0.05 seconds in order to illustrate the delay)



# Hydro Units

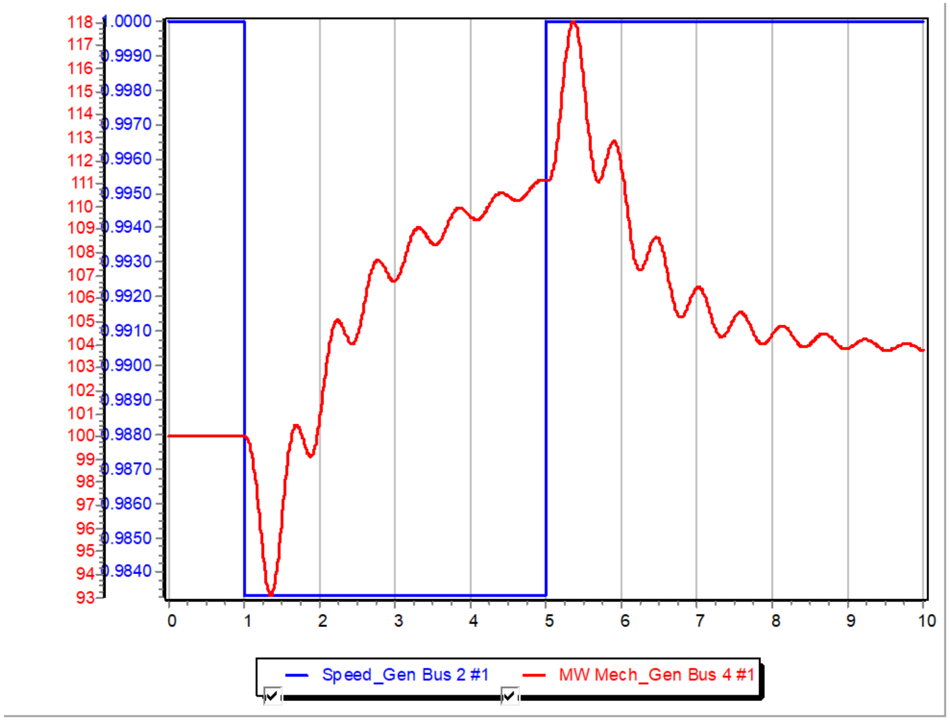
- Hydro units tend to respond slower than steam and gas units; since early transient stability studies focused on just a few seconds (first or second swing instability), detailed hydro units were not used
  - The original IEEEG2 and IEEEG3 models just gave the linear response; now considered obsolete
- Below is the IEEEG2; left side is the governor, right side is the turbine and water column




For sudden changes there is actually an inverse change in the output power

# Four Bus Example with an IEEEG2

- Graph below shows the mechanical power output of gen 2 for a unit step decrease in the infinite bus frequency; note the power initially goes down!




This is caused by a transient decrease in the water pressure when the valve is opened to increase the water flow; flows does not change instantaneously because of the water's inertia.

Case name: **B4_SignalGen_IEEEG2**

# Washout Filters

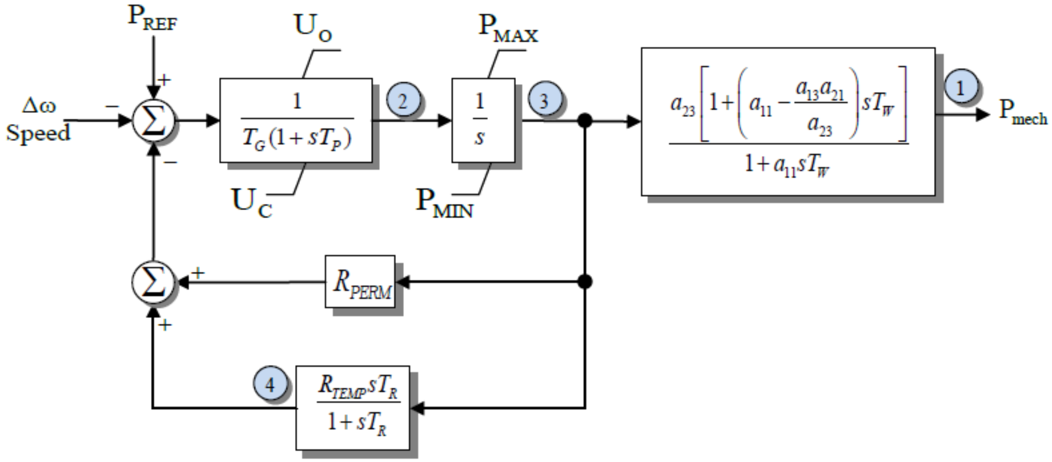
- A washout filter is a high pass filter that removes the steady-state response (i.e., it "washes it out") while passing the high frequency response

$$\frac{sT_w}{1+sT_w}$$

- They are commonly used with hydro governors and (as we shall see) with power system stabilizers
- With hydro turbines ballpark values for $T_w$ are around one or two seconds

# IEEEG3

- This model has a more detailed governor model, but the same linearized turbine/water column model
- Because of the initial inverse power change, for fast deviations the droop value is transiently set to a larger value (resulting in less of a power change)




Previously WECC had about 10% of their governors modeled with IEEEG3s; in 2019 it is about 5%

Because of the washout filter at high frequencies $R_{TEMP}$ dominates (on average it is 10 times greater than $R_{PERM}$)

# Tuning Hydro Transient Droop

- As given in equations 9.41 and 9.42 from Kundar (1994) the transient droop should be tuned so

$$R_{TEMP} = \left(2.3 - (T_W - 1) \times 0.15\right) \frac{T_W}{T_M}$$

$$T_R = \left(5.0 - (T_W - 1) \times 0.5\right) T_W$$

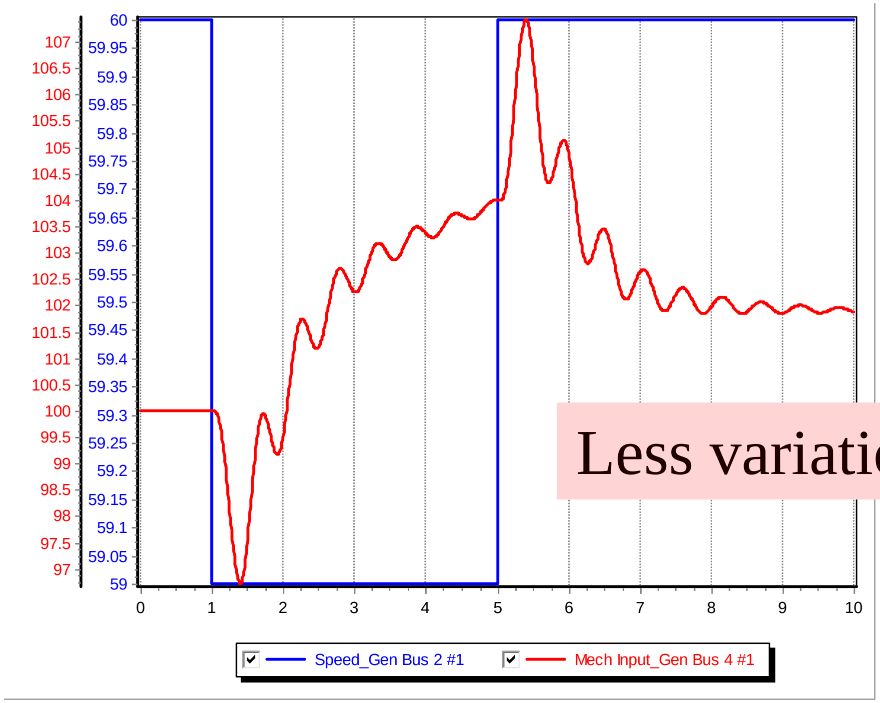
where $T_M$ =2H (called the mechanical starting time)

In comparing an average H is about 4 seconds, so $T_M$ is 8 seconds, an average $T_W$ is about 1.3, giving an calculated average $R_{TEMP}$ of 0.37 and $T_R$ of 6.3; the actual averages in a WECC case are 0.46 and 6.15. So on average this is pretty good! $R_{perm}$ is 0.05

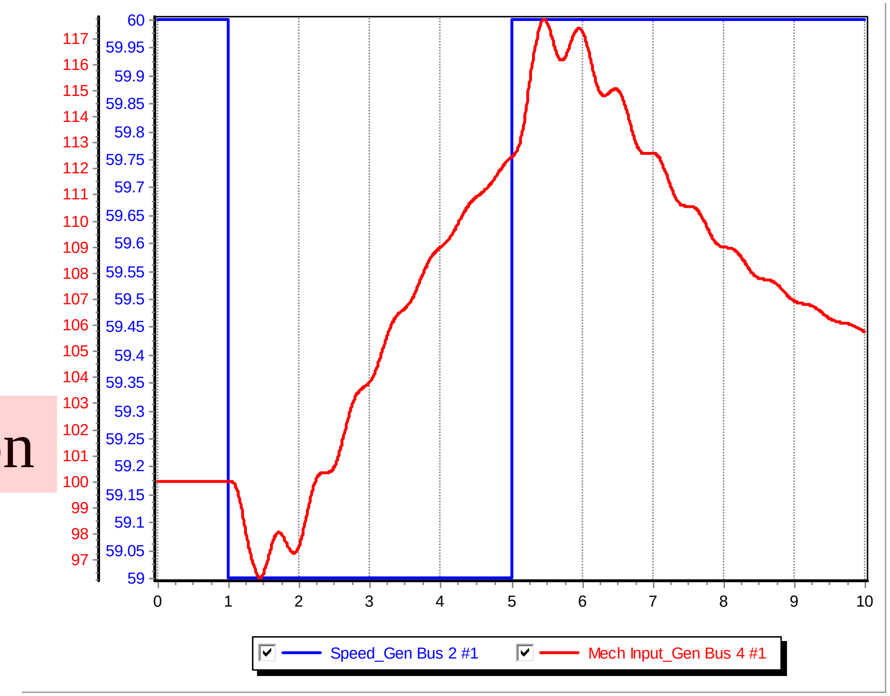
Source: 9.2, Kundur, *Power System Stability and Control*, 1994

# IEEEG3 Four Bus Frequency Change

- The two graphs compare the case response for the frequency change with different $R_{TEMP}$ values




$R_{TEMP} = 0.5$, $R_{PERM} = 0.05$




$R_{TEMP} = 0.05$, $R_{PERM} = 0.05$

Case name: **B4_SignalGen_IEEEG3**