ECEN 667
Power System Stability

Lecture 9: Turbine-Governors and Power-Frequency Control

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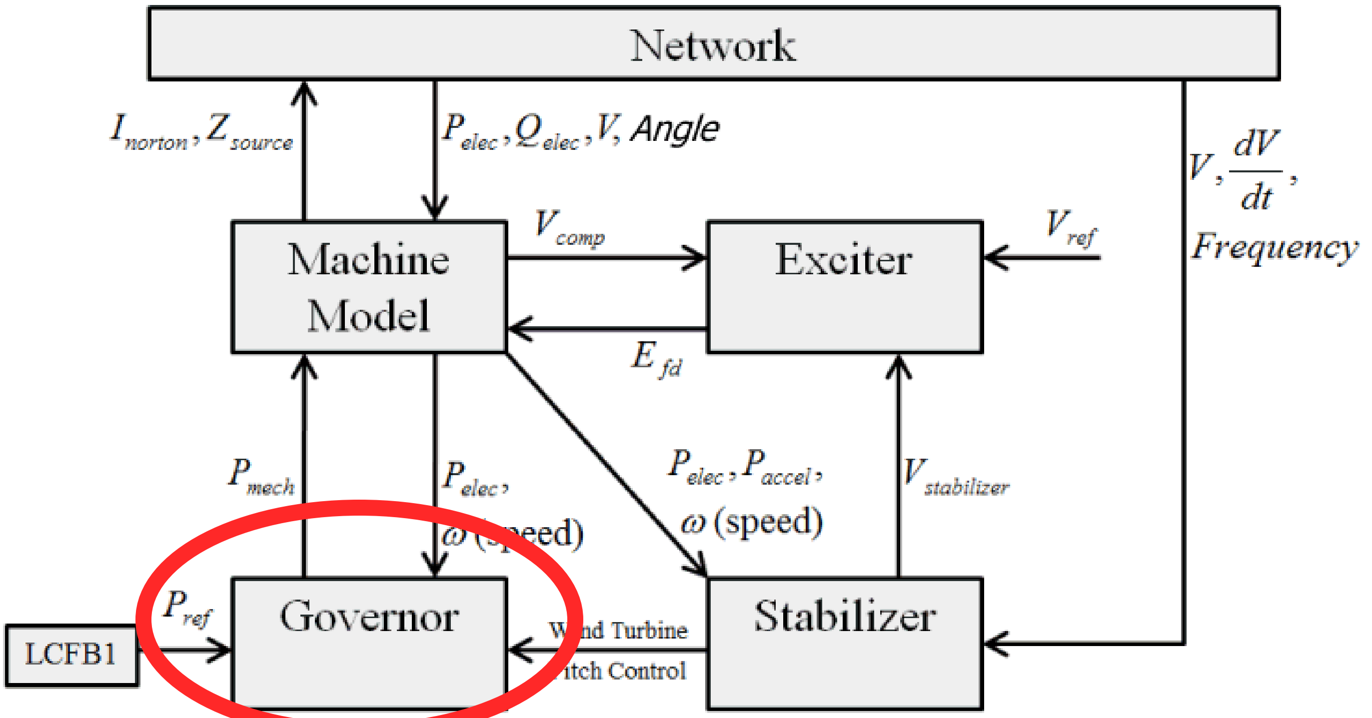
Announcements

- Homework Assignment #2 is due Thursday, Sept. 25th at 8 AM. Email me your solution as a single PDF.
- Homework Assignment #3
- Read book chapters 3, 4, and 5
- Review the slides and PowerWorld examples

Synchronous Machine Controllers

- The turbine-governor system is the part that provides mechanical power P_m to the synchronous machine
- It is two parts in one
  - The mechanical turbine
  - The governor control system



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
ω(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 original 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

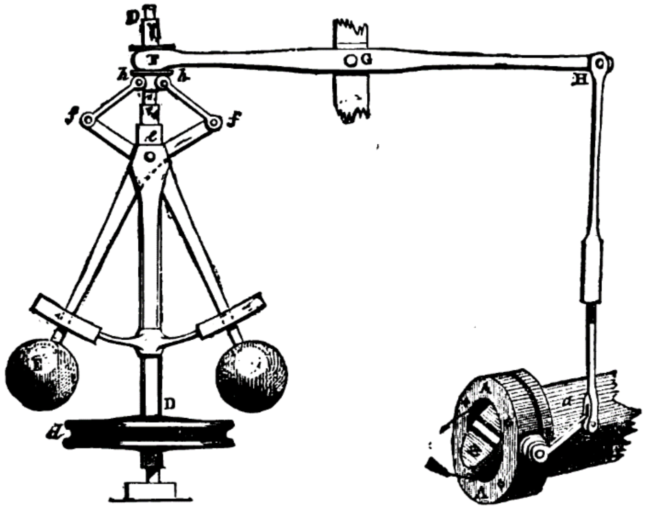


FIG. 4.—*Governor and Throttle-Valve.*

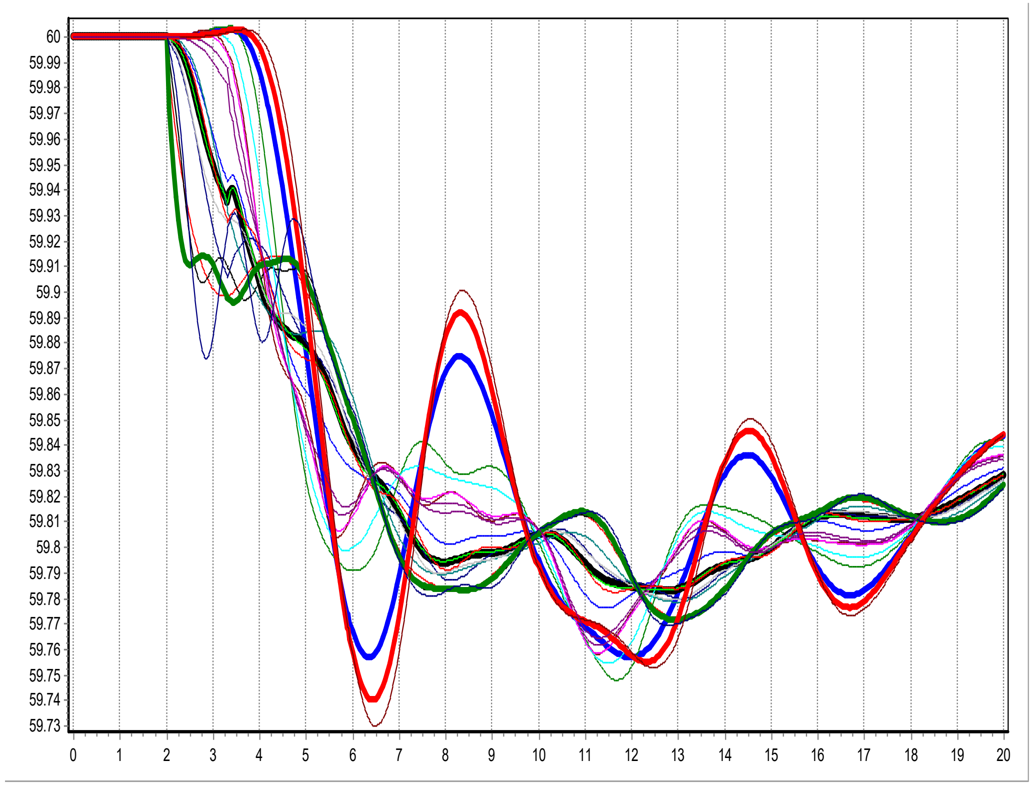
Image source: http://upload.wikimedia.org/wikipedia/commons/1/1e/Centrifugal_governor.png

Prime Movers and Governors, Cont.

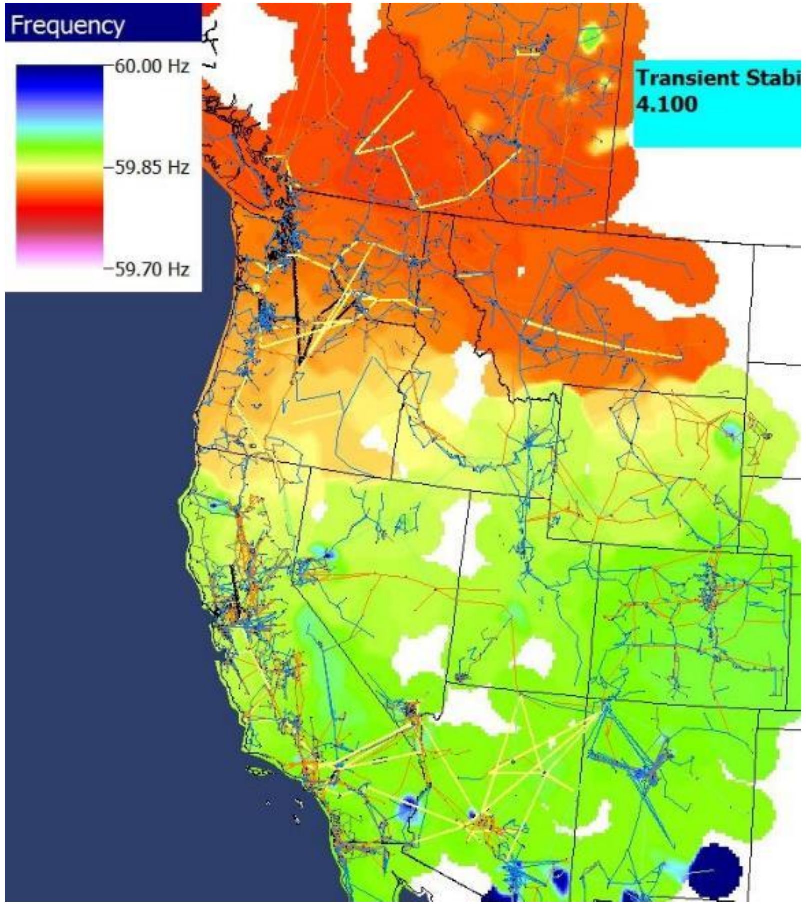
- In transient stability collectively the prime mover and the governor are called the "governor"
- As has been previously discussed, models need to be appropriate for the application
- In transient stability the response of the system for seconds to perhaps minutes is considered
- Long-term dynamics, such as those of the boiler and automatic generation control (AGC), 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



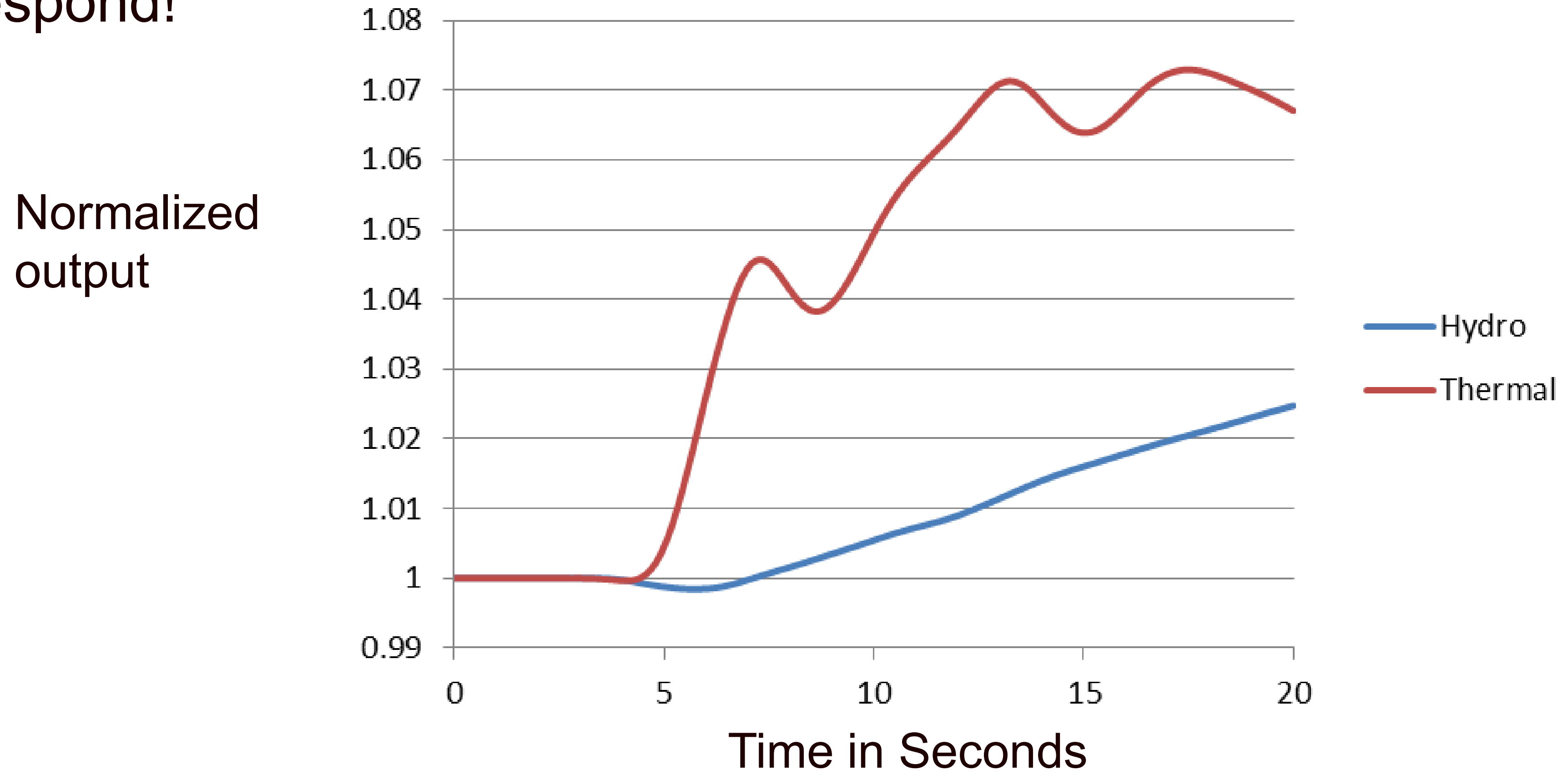
Frequency Contour

Frequency Response for Generation Loss

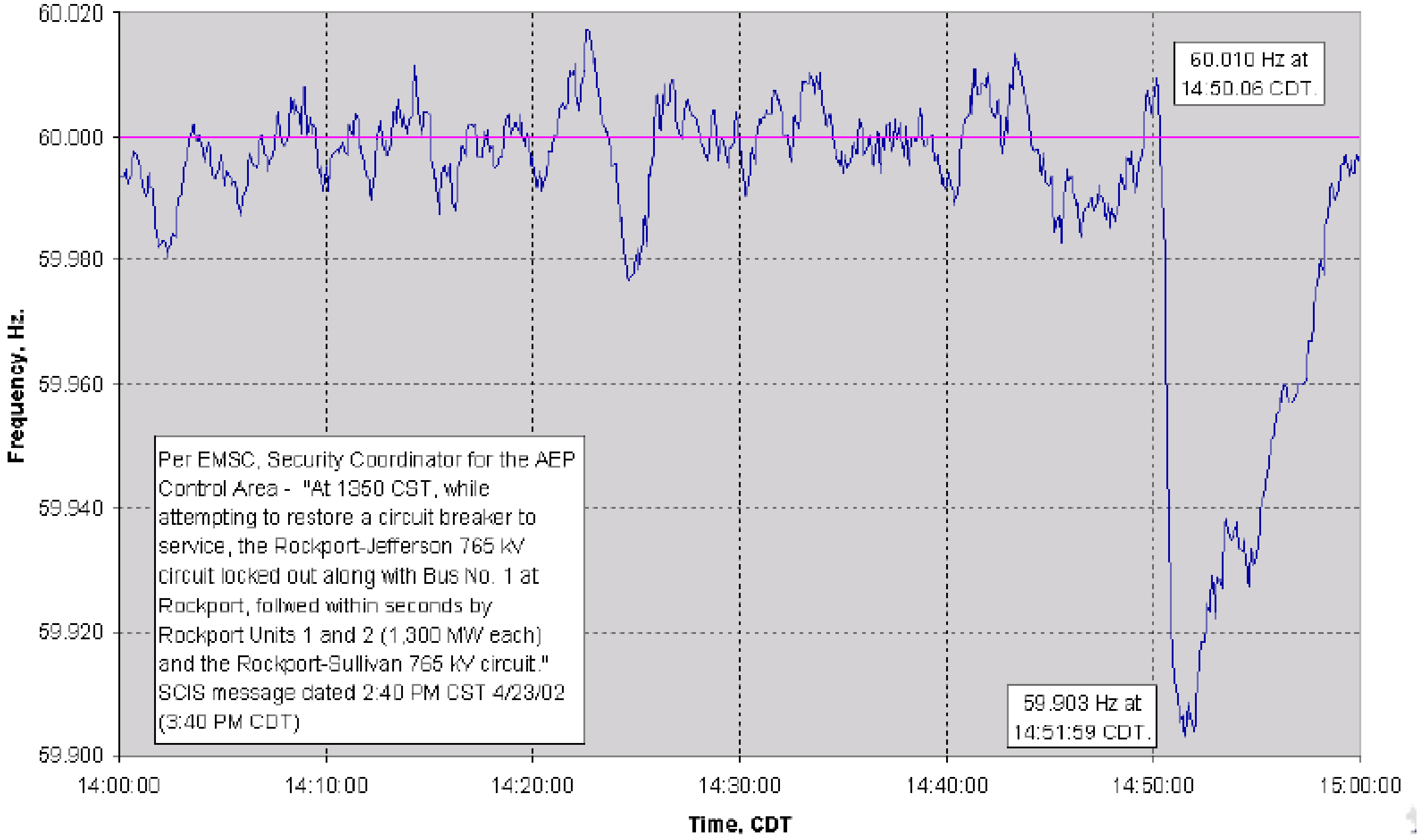
- In response to a rapid loss of generation, in the initial seconds the system frequency will decrease as energy stored in the rotating masses is transformed into electric energy
  - Some generation, such as solar PV has no inertia, and for most new wind turbines the inertia is not seen by the system
- 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!



2600 MW Loss Frequency Recovery



Frequency recovers in about ten minutes

ERCOT Winter Storm Uri Frequency (2/15/21)

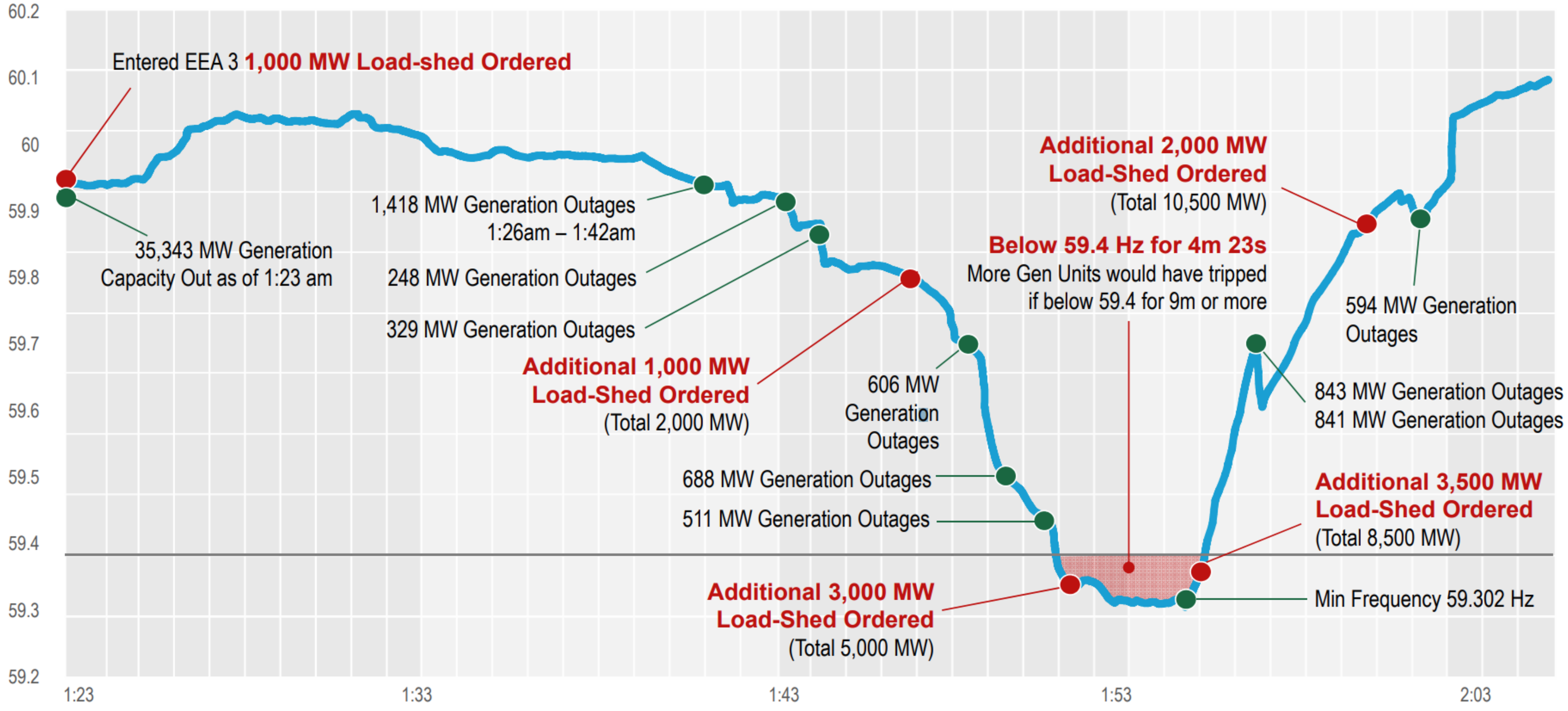
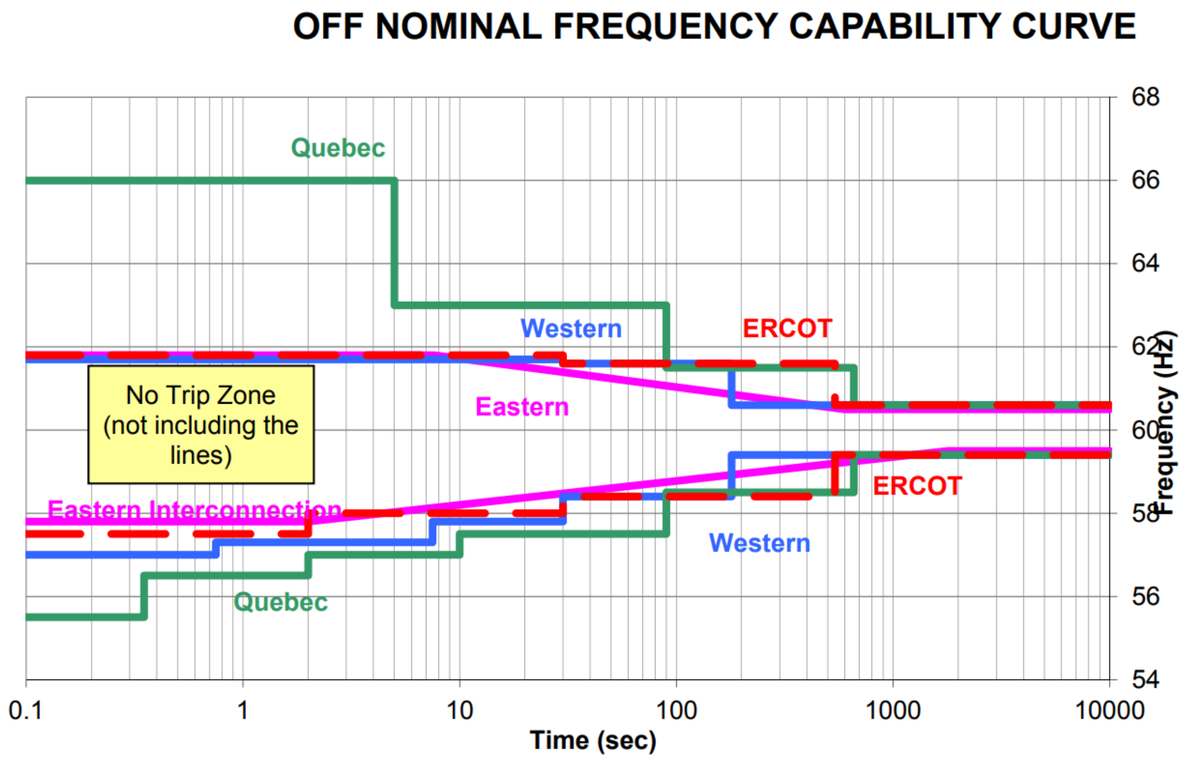


Image source: https://www.ercot.com/files/docs/2021/03/03/Texas_Legislature_Hearings_2-25-2021.pdf

Generator Under and Over Frequency Protection

- Generators have automatic protection systems to trip them if the frequency goes out of range for too long (also their voltage)

PRC-024 — Attachment 1



NERC Standard PRC-024.1

A typical concern with off-nominal frequency operation is the turbine (i.e., not the synchronous machine) operating at close to one of its natural frequencies, resulting in accelerated aging (metal fatigue); this is often shown using a Campbell diagram; see IEEE C37.106.2022

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

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 ensure frequency goes back to the desired value
  - Cannot be used with interconnected systems because of "hunting"

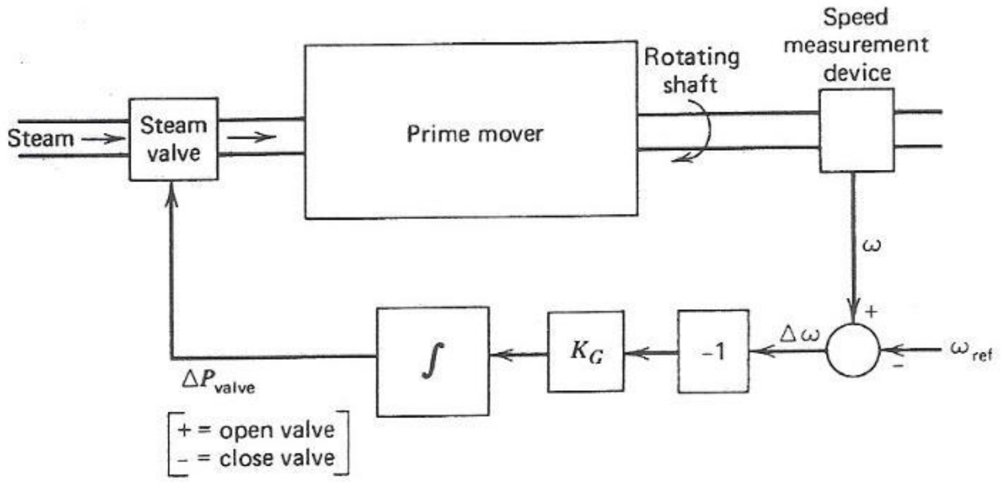


FIG. 9.9 Isochronous governor.

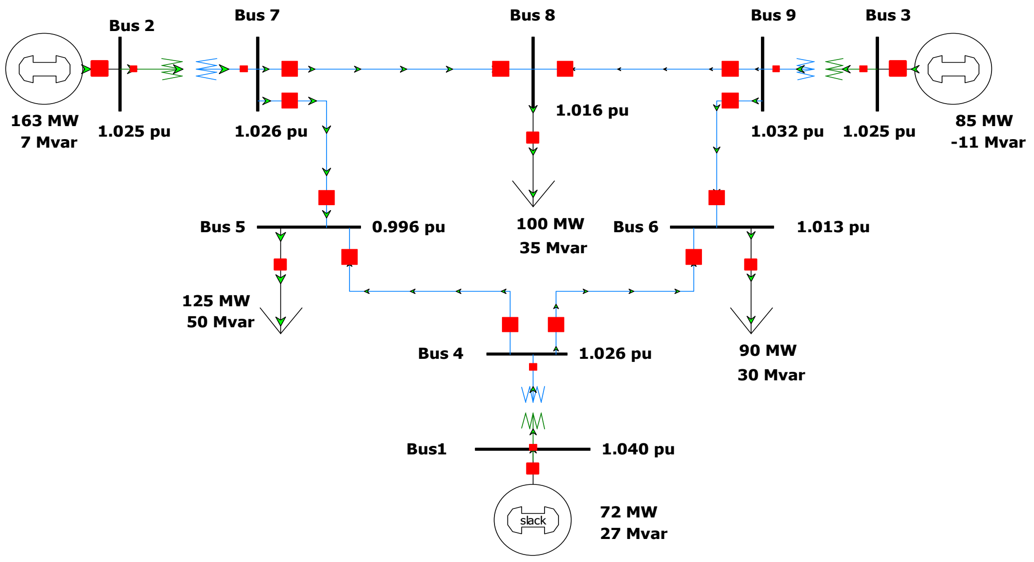
Image source: Wood/Wollenberg, 2nd edition

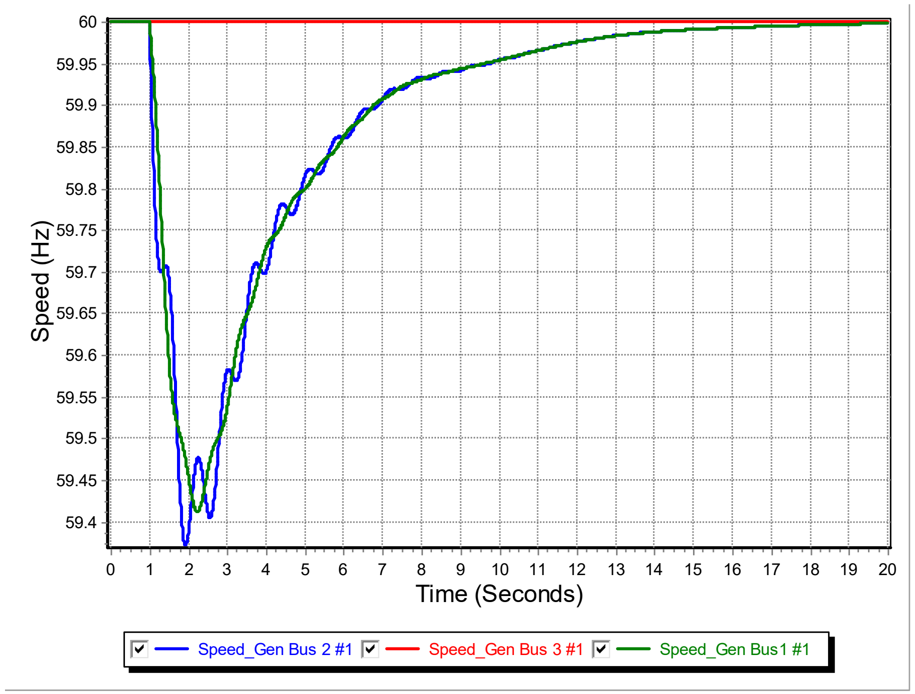
Generator "Hunting"

- Control system "hunting" is oscillation around an equilibrium point
- Trying to interconnect multiple isochronous generators will cause hunting because the frequency setpoints of the multiple generators are never exactly equal.
  - If there are two then 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)

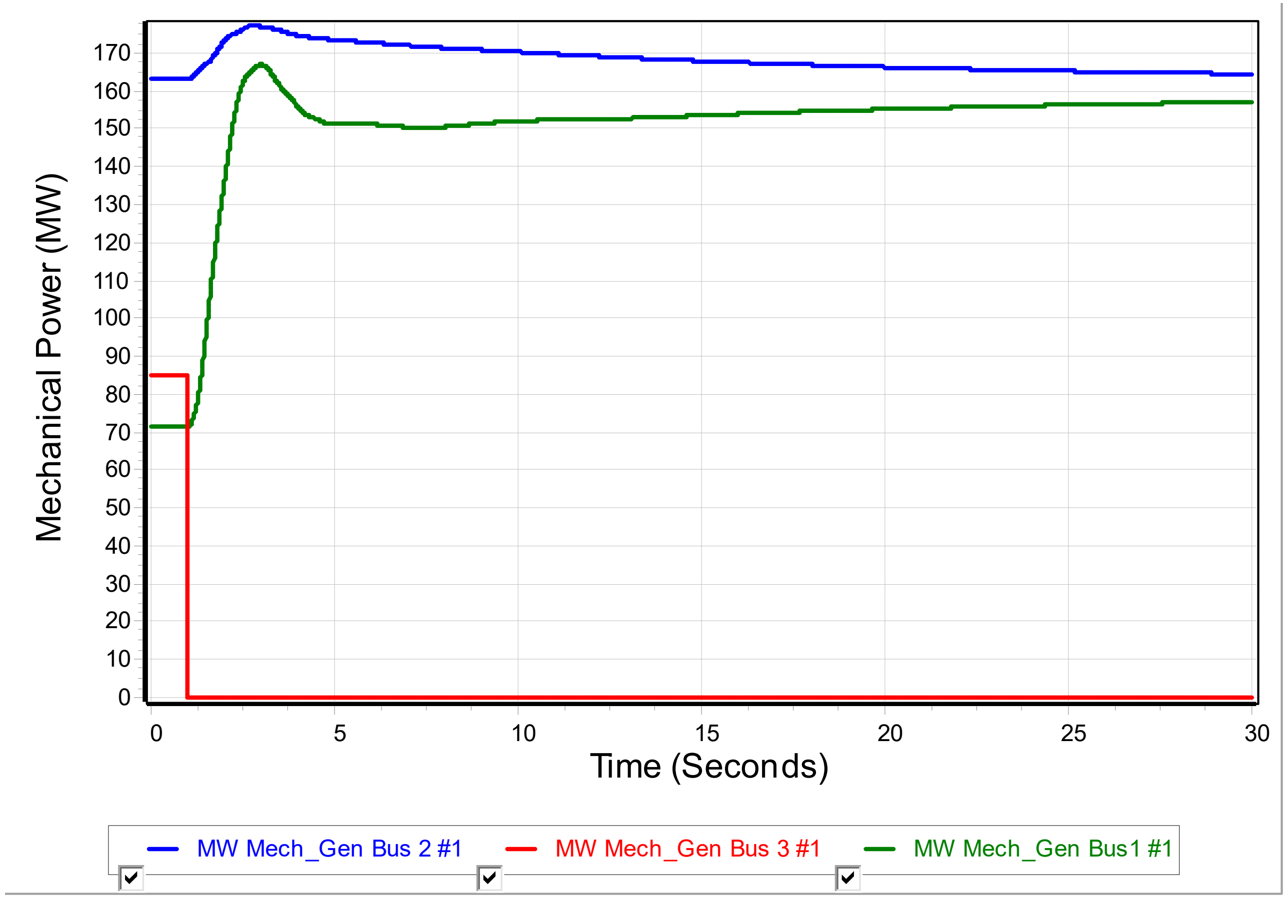




Case is **wscc_9bus_IsoGov**

Isochronous Gen Example, Cont.

- Graph shows the change in the mechanical output



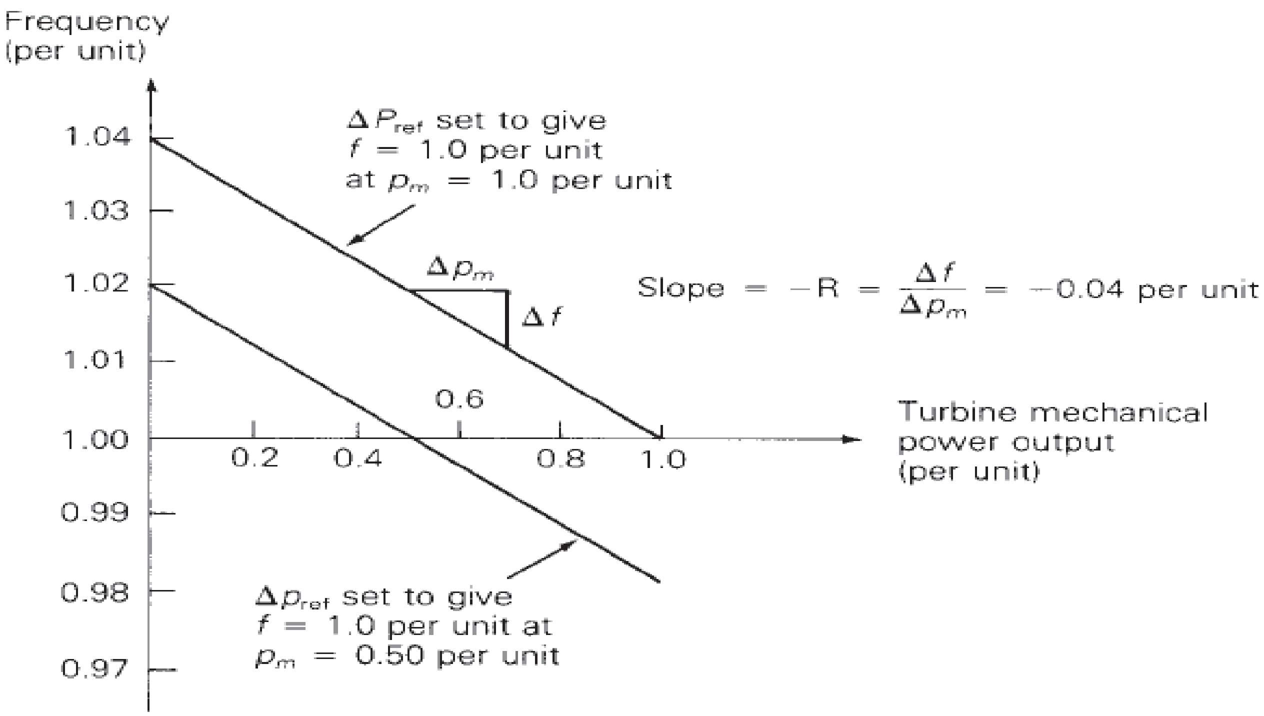
All the change in MWs due to the loss of gen 3 is ultimately being picked up by gen 1

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)

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

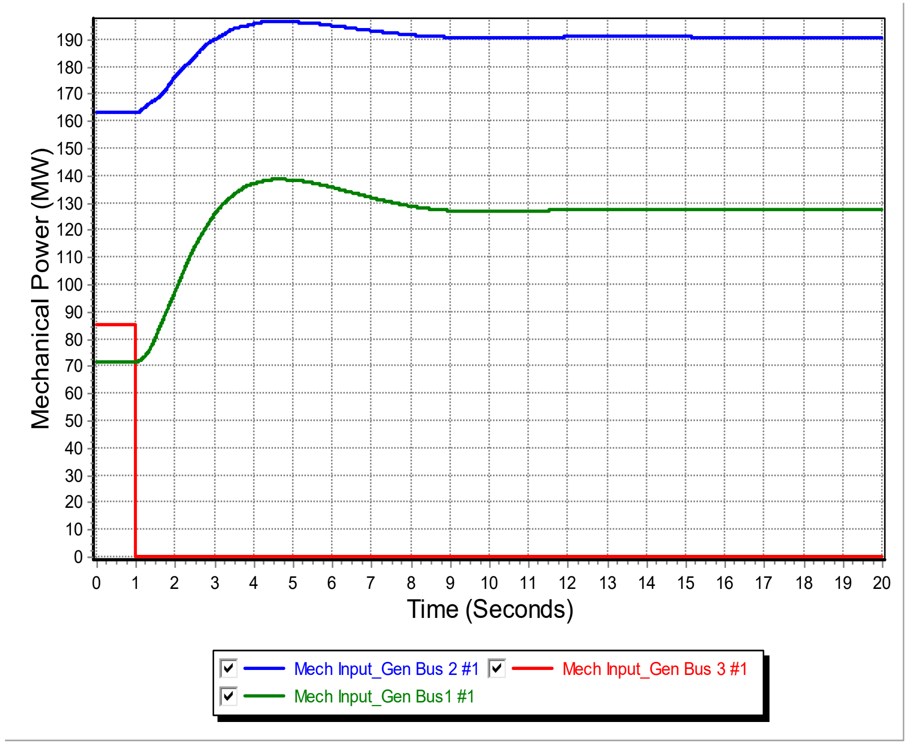
$$R_{1,100MVA} = R_1 \frac{100}{500} = 0.01, \quad R_{2,100MVA} = R_2 \frac{100}{250} = 0.02$$

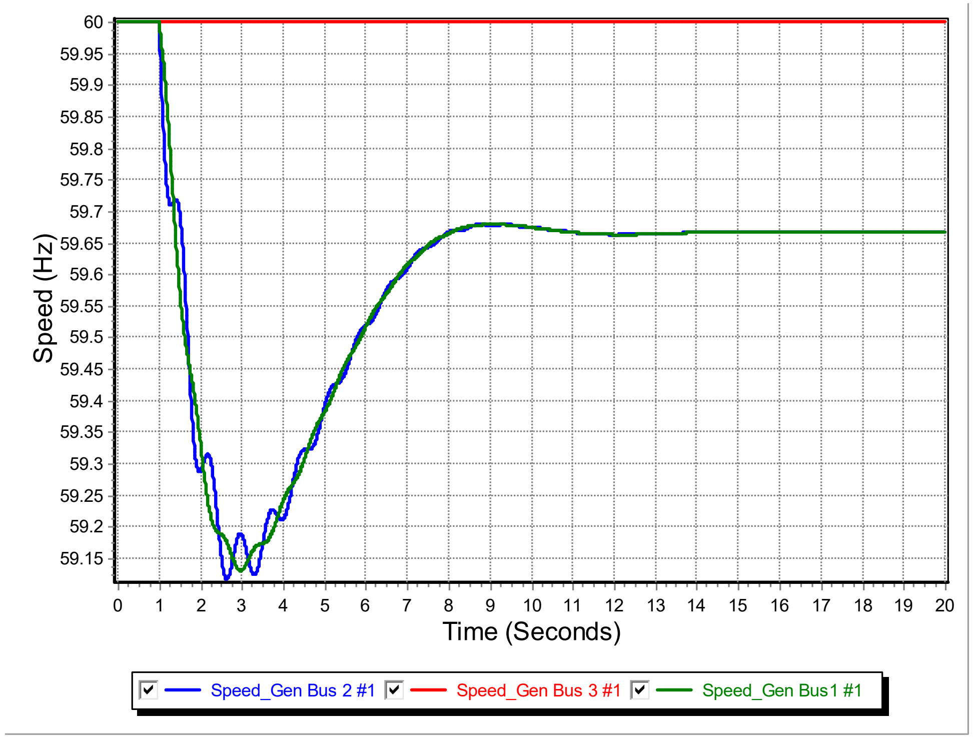
$$\Delta p_{m1} + \Delta p_{m2} = -\left(\frac{1}{R_{1,100MVA}} + \frac{1}{R_{2,100MVA}}\right)\Delta f = 0.85$$

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

WSCC 9 Bus Droop Example, Cont.

- 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 to same) droop, then the final frequency deviation is

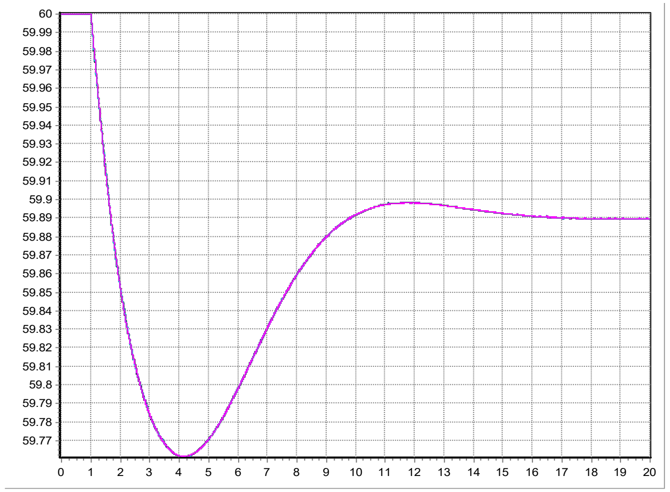
$$\Delta f = -\frac{R \times \Delta P_{gen,MW}}{\sum_{OnlineGens} S_{i,MVA}}$$

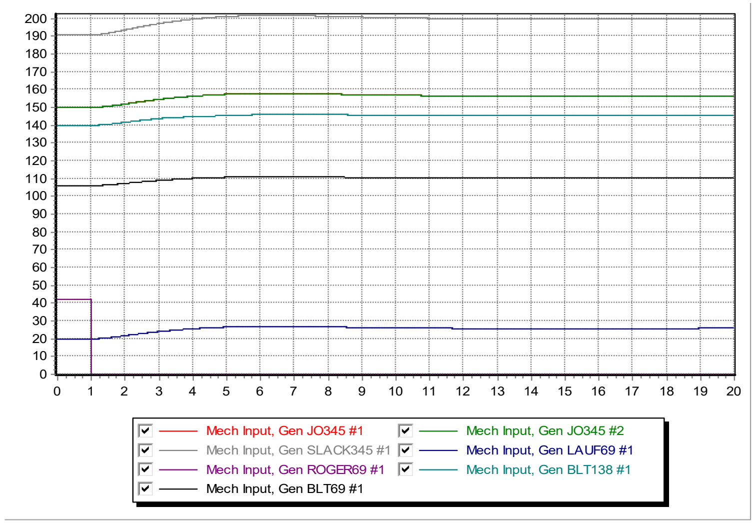
- The online generator summation should only include generators that actually have governors that can respond, and does not take into account generators hitting their limits

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

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



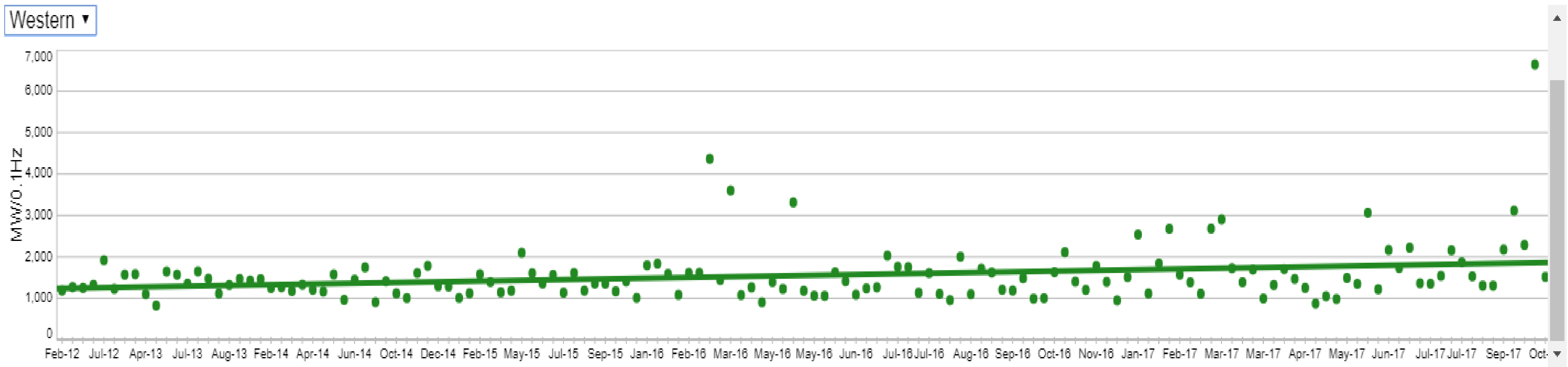


Case is
Bus37_TGOV1

WECC Interconnect Frequency Response

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

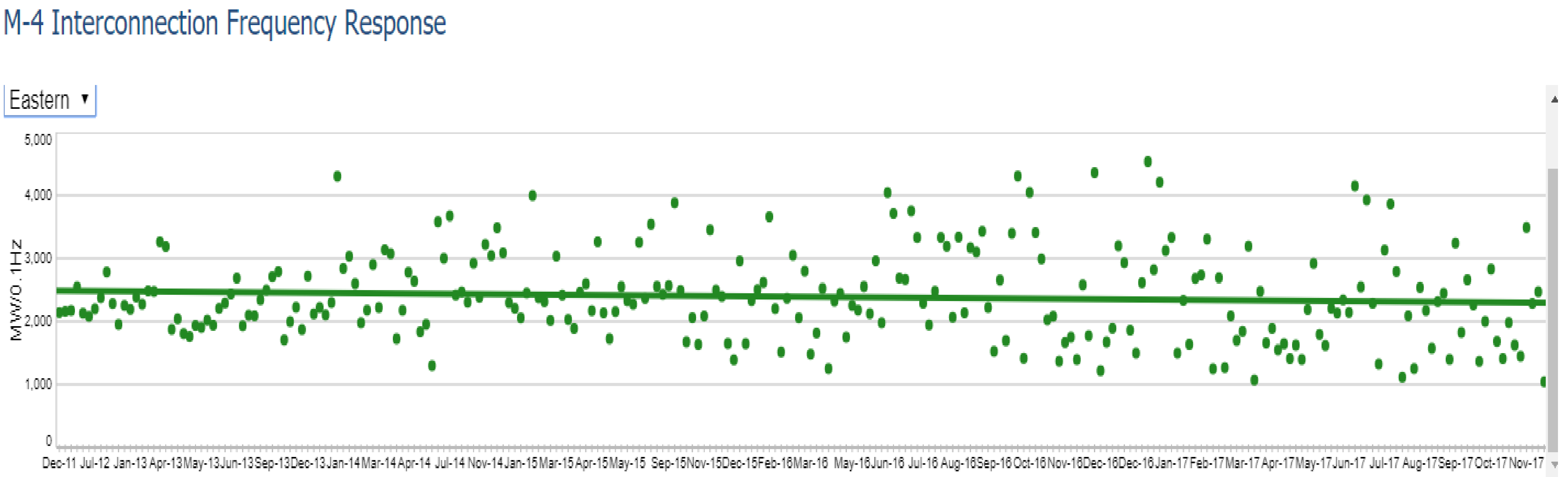
M-4 Interconnection Frequency Response



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

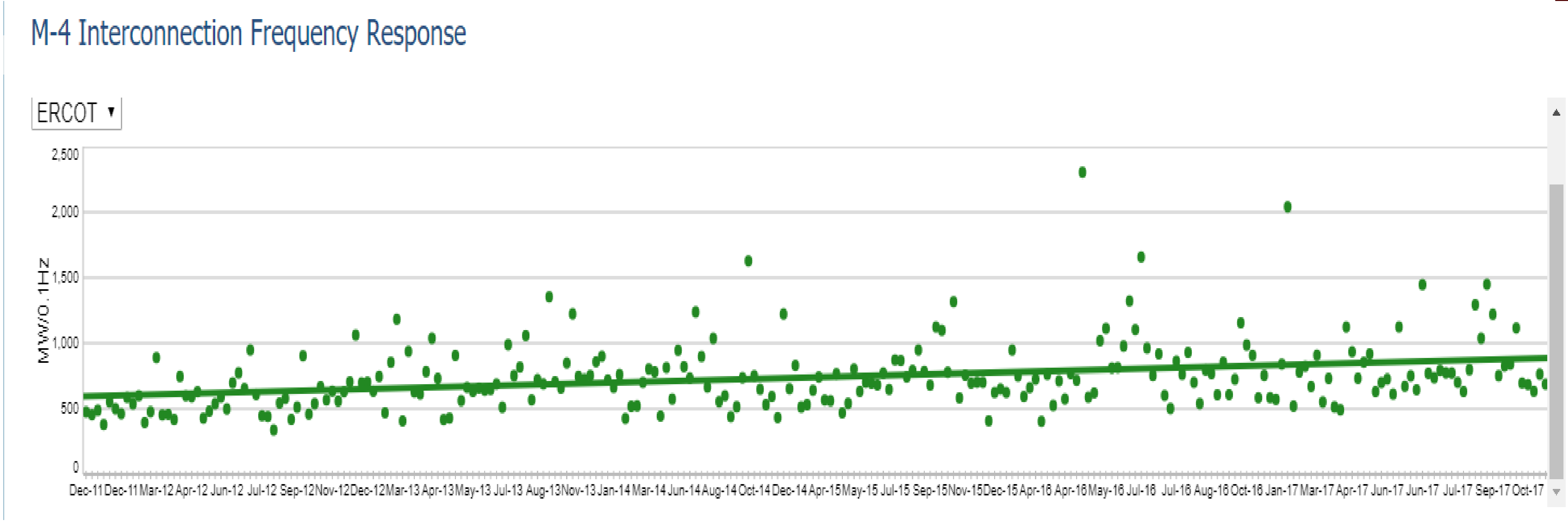
Source: www.nerc.com/pa/RAPA/ri/Pages/InterconnectionFrequencyResponse.aspx

Eastern Interconnect Frequency Response



The larger Eastern Interconnect on average has a higher value

ERCOT Interconnect Frequency Response



The ERCOT values are usually lower

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

NERC M-4 Interconnection Frequency Response

- Now it is easily available in summary form

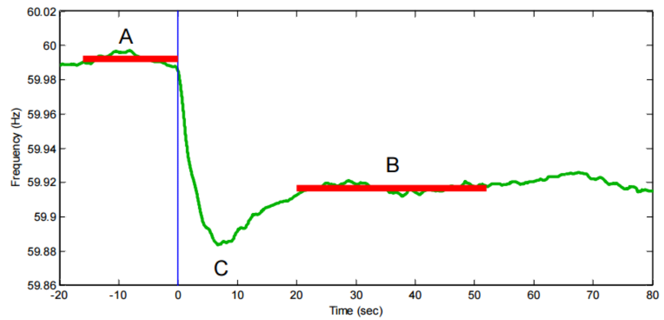
2022 Frequency Response Performance Statistics for Stabilizing Period

	2022 Operating Year Stabilizing Period Performance					
	Mean $IFRM_{A-B}$ (MW/0.1Hz)	Median $IFRM_{A-B}$ (MW/0.1Hz)	Lowest $IFRM_{A-B}$ (MW/0.1Hz)	Maximum $IFRM_{A-B}$ (MW/0.1Hz)	Number of Events	2018–2022 OY Trend
Eastern	2,648	2,423	1,594	5,342	46	Stable
Texas	1,287	1,163	511	2,955	32	Improving
Québec	1,009	859	512	2,331	22	Stable
Western	1,934	1,763	1,114	4,917	30	Stable

2022 Frequency Response Performance Statistics for Arresting Period

	2022 Operating Year Arresting Period Performance					
	Mean $IFRM_{A-C}$ (MW/0.1Hz)	Median $IFRM_{A-C}$ (MW/0.1Hz)	Lowest $IFRM_{A-C}$ (MW/0.1Hz)	Mean UFLS Margin (Hz)	Lowest UFLS Margin (Hz)	2018–2022 $IFRM_{A-C}$ OY Trend
Eastern	2,050	1,921	1,202	0.455	0.419	Stable
Texas	575	532	305	0.584	0.486	Improving
Québec	157	148	95	1.121	0.938	Stable
Western	886	846	535	0.413	0.330	Stable

The Arresting Period is up to 12 seconds after the event; the Stabilizing Period is between 20 and 52 after the event.



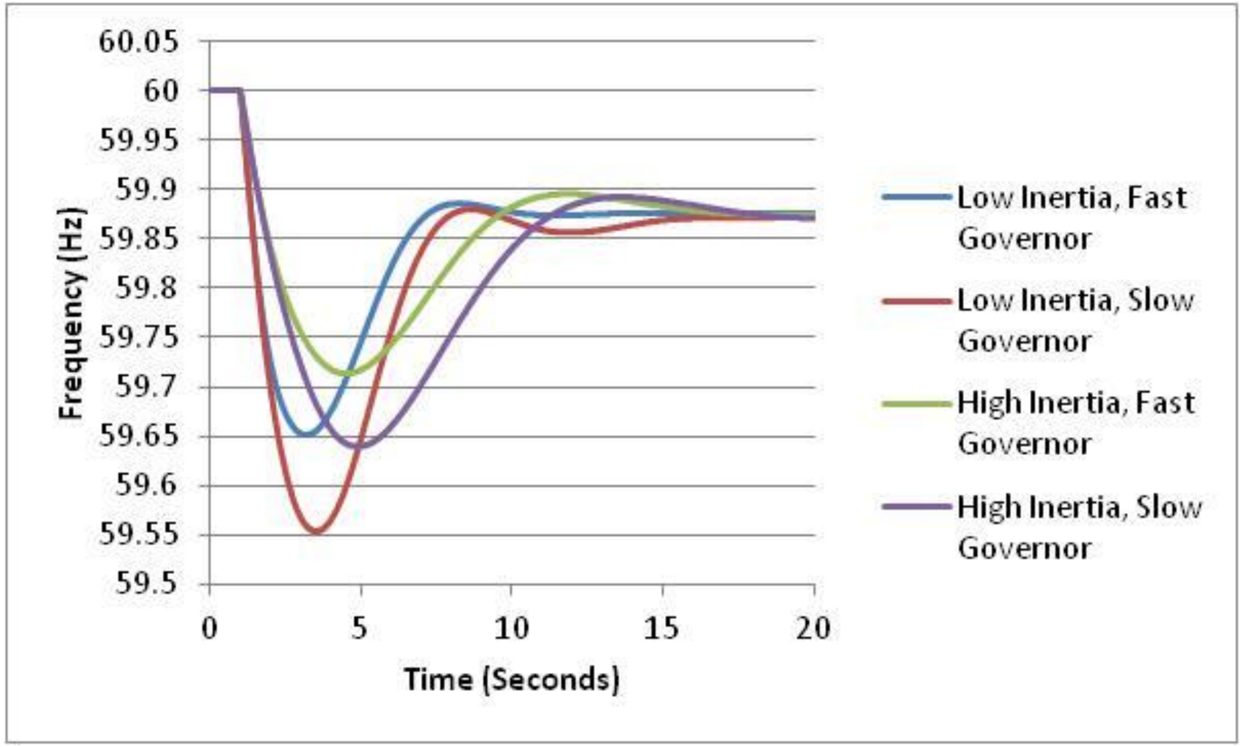
NERC FRM BAL-003-1: Frequency difference between Point A and Point B

LBNL Metrics: Frequency difference between Point A and Point C

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

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

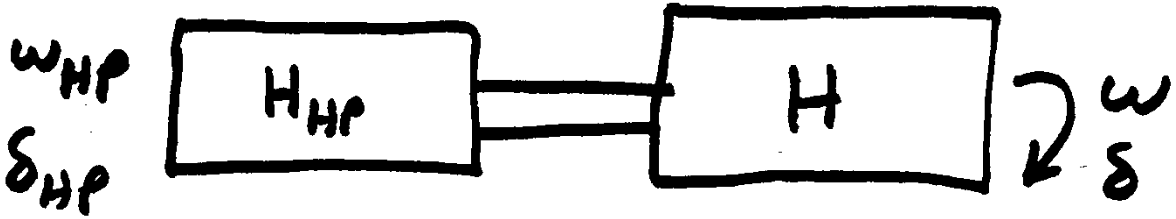
- In an interconnected power system the governors to not automatically restore the frequency to 60 Hz
- Rather this done via the ACE (area control error) calculation.

ACE = Pactual - Psched – 10b(freqact - freqsched)

- b 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 most stability simulations

Turbine Models



model shaft "squishiness" as a spring

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

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

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

$$\left.\begin{aligned} \frac{d\delta_{HP}}{dt} &= \omega_{HP} - \omega_s \\ \frac{2H_{HP}}{\omega_s}\frac{d\omega_{HP}}{dt} &= T_{IN} - T_{OUT} \end{aligned}\right\}$$

High-pressure turbine shaft dynamics

Usually shaft dynamics are neglected

Steam Turbine Models

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

We are assuming $d=d_{HP}$ and $w=w_{HP}$

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

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

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

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

Steam Governor Model

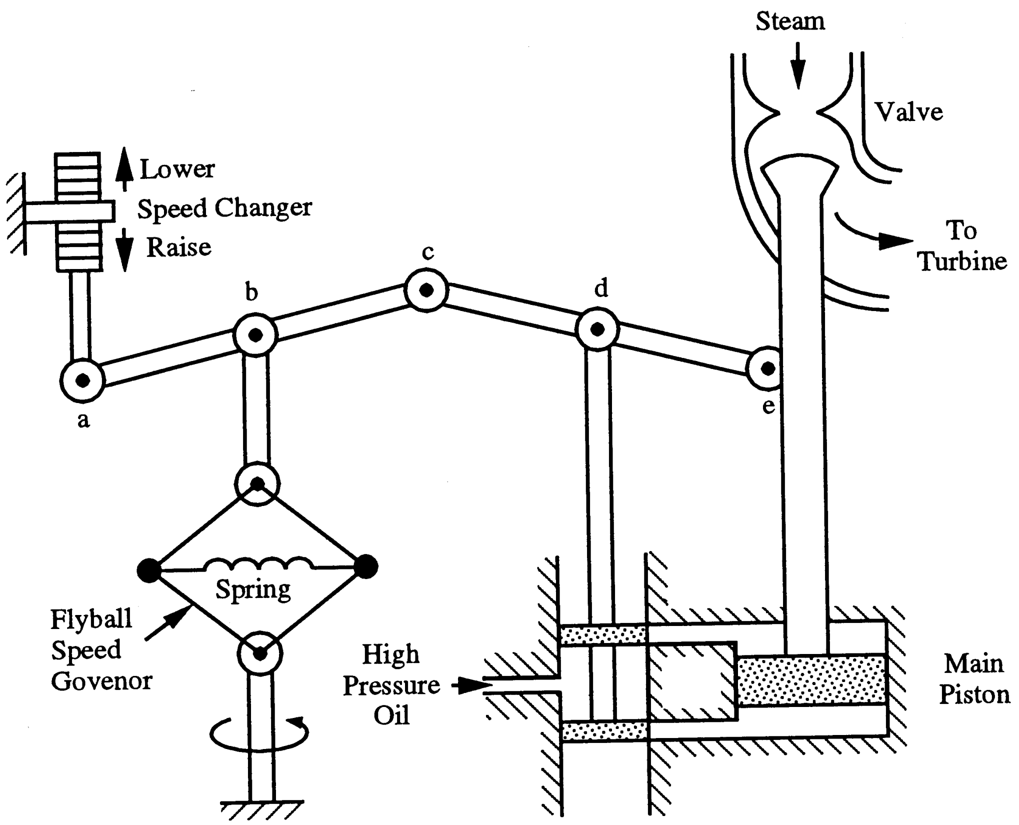
$$T_{SV}\frac{dP_{SV}}{dt} = -P_{SV} + P_C - \frac{1}{R}\Delta\omega$$

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

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

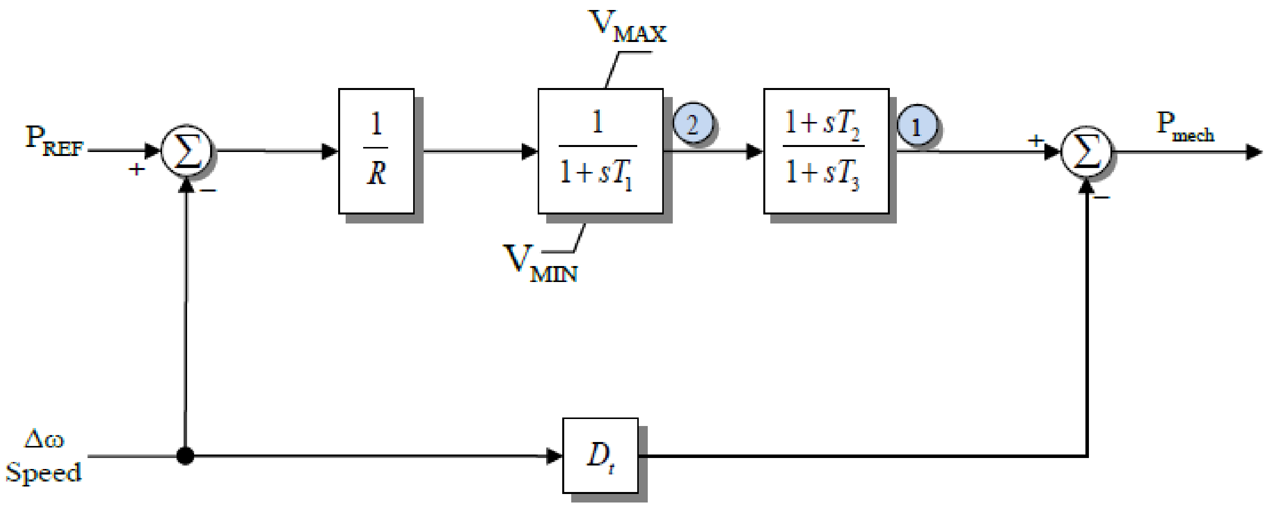
Steam valve limits

R = .05 (5% droop)



TGOV1 Model

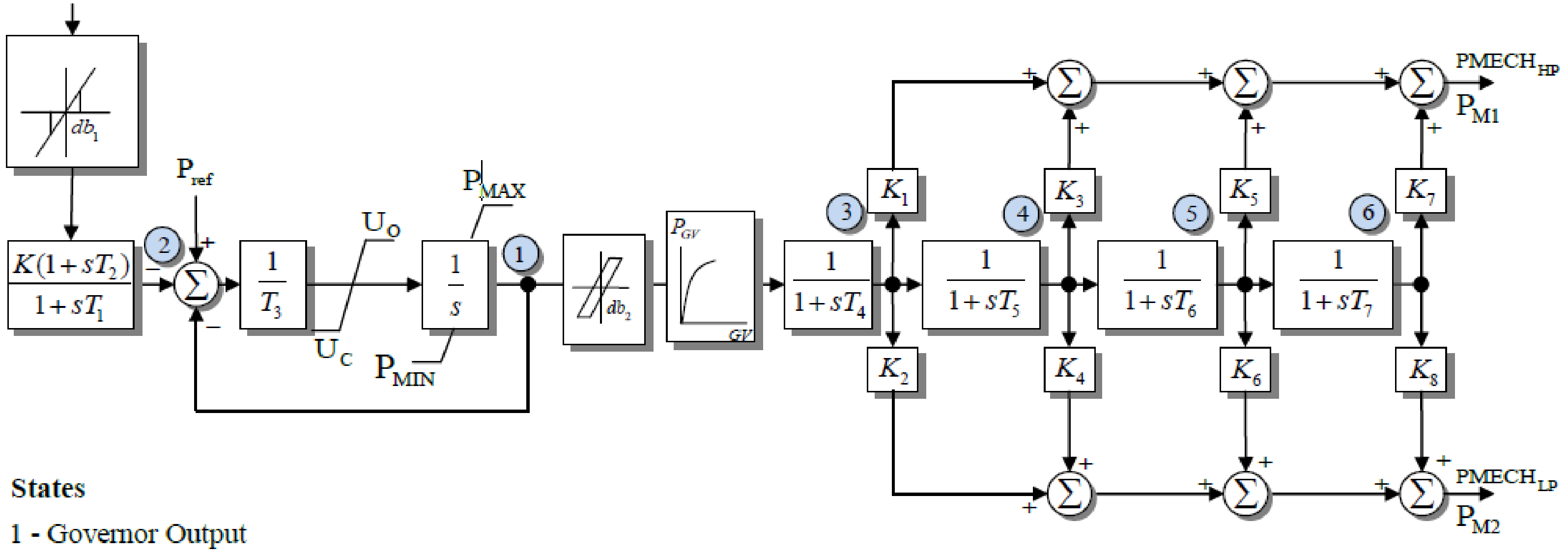
- The standard model that is close to this is the TGOV1



About 3% of governors in the 2022 EI/WECC model are TGOV1; R is about 0.05, T_1 is less than 0.5 (except for one 999!), T_3 has an average of 6, average T_2/T_3 is 0.34; D_t is used to model turbine damping and is often zero (about 90% of the time)

IEEEG1 Model

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



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

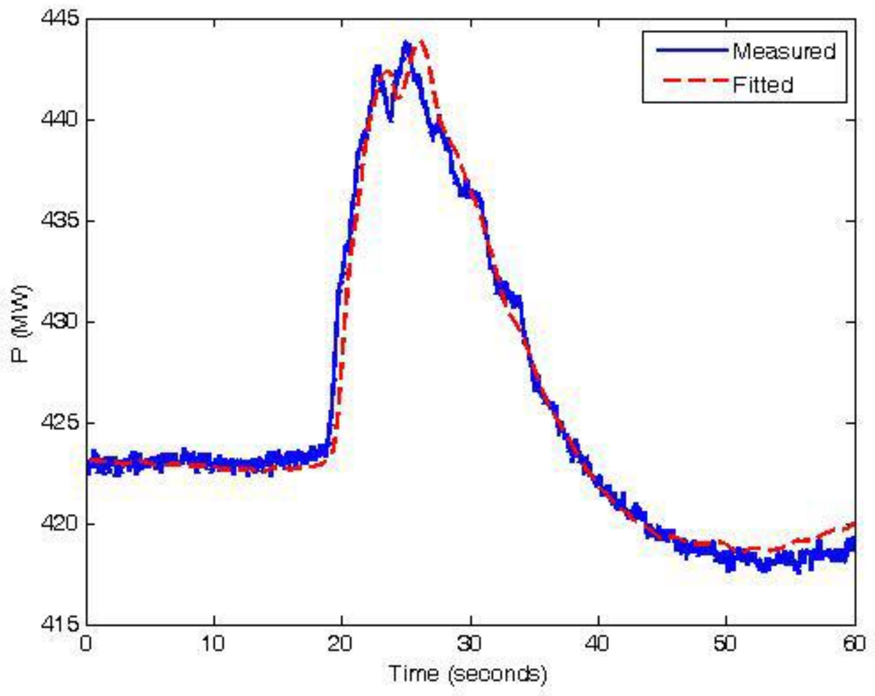
U_o and U_c are rate limits

In this model K=1/R

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 16% of WECC and EI governors are currently IEEEG1s
- Below figures show two test comparison with this model



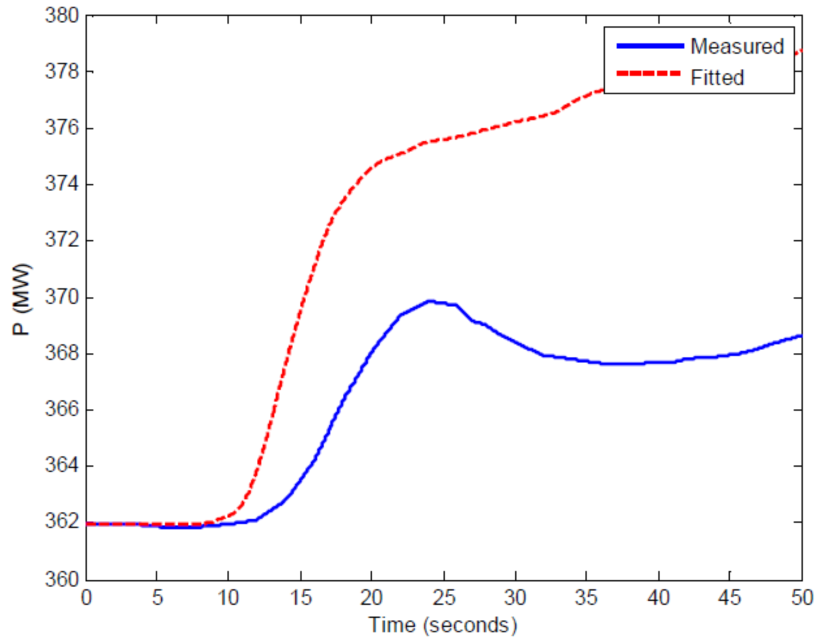
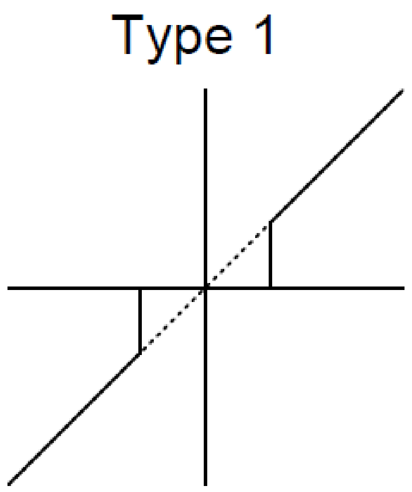


Image Source: Figs 2-4, 2-6 of IEEE PES, "Dynamic Models for Turbine-Governors in Power System Studies," Jan 2013

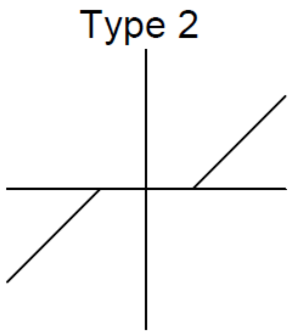
Deadbands

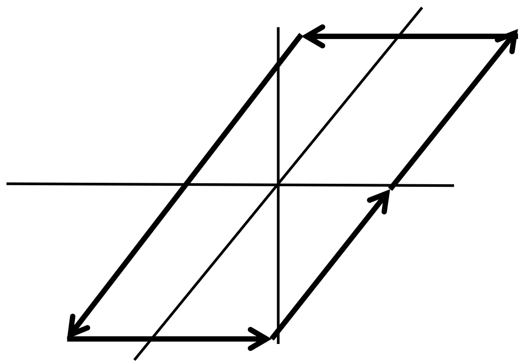
- Before going further, it is useful to briefly consider deadbands, with two types shown with IEEEG1 and described in the 2013 IEEE PES Governor Report
- The type 1 is an intentional deadband, implemented to prevent excessive response
  - Until the deadband activates there is no response, then normal 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, Cont.

- 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 the deadbands usually start at their origin

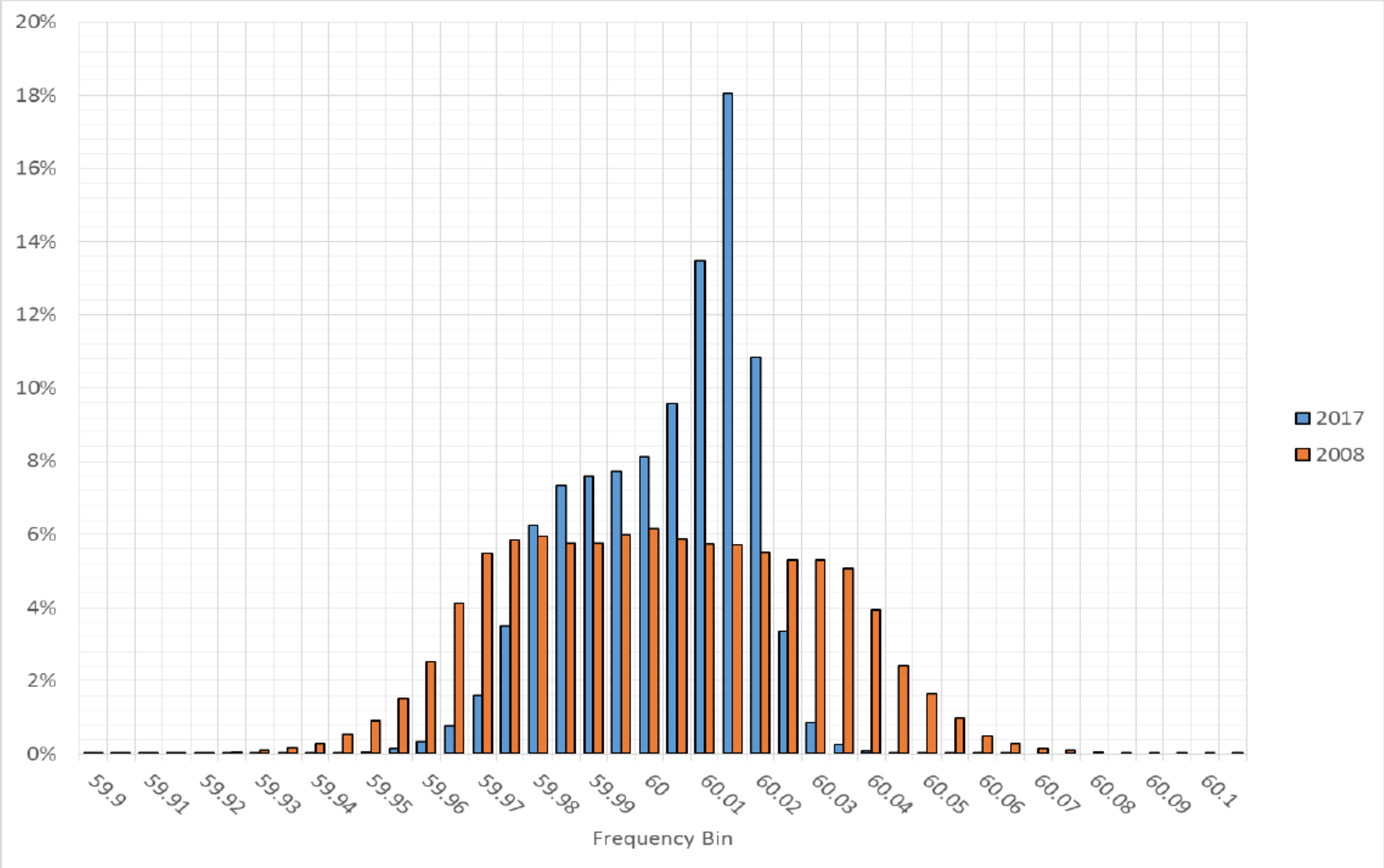
Frequency Deadbands in ERCOT

- 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
  - Controllable load resources used ±0.036 Hz
- The maximum droop setting is 5% for all units except it is 4% for combined cycle combustion turbines

Source: www.ercot.com/content/wcm/libraries/224011/February_1_2021_Nodal_Operating_Guide.pdf

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

Comparing 2017 vs 2008 Frequency Profile in 5 mHz Bins



A good NERC document that addresses deadbands is “Reliability Guideline: Primary Frequency Control,” Jan 2023
(Draft)

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

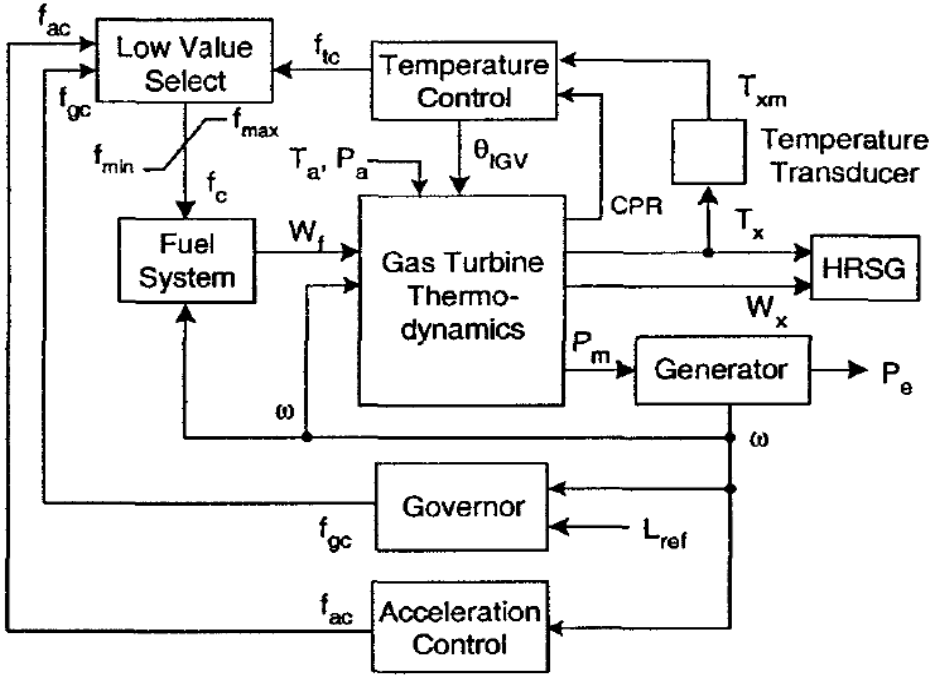


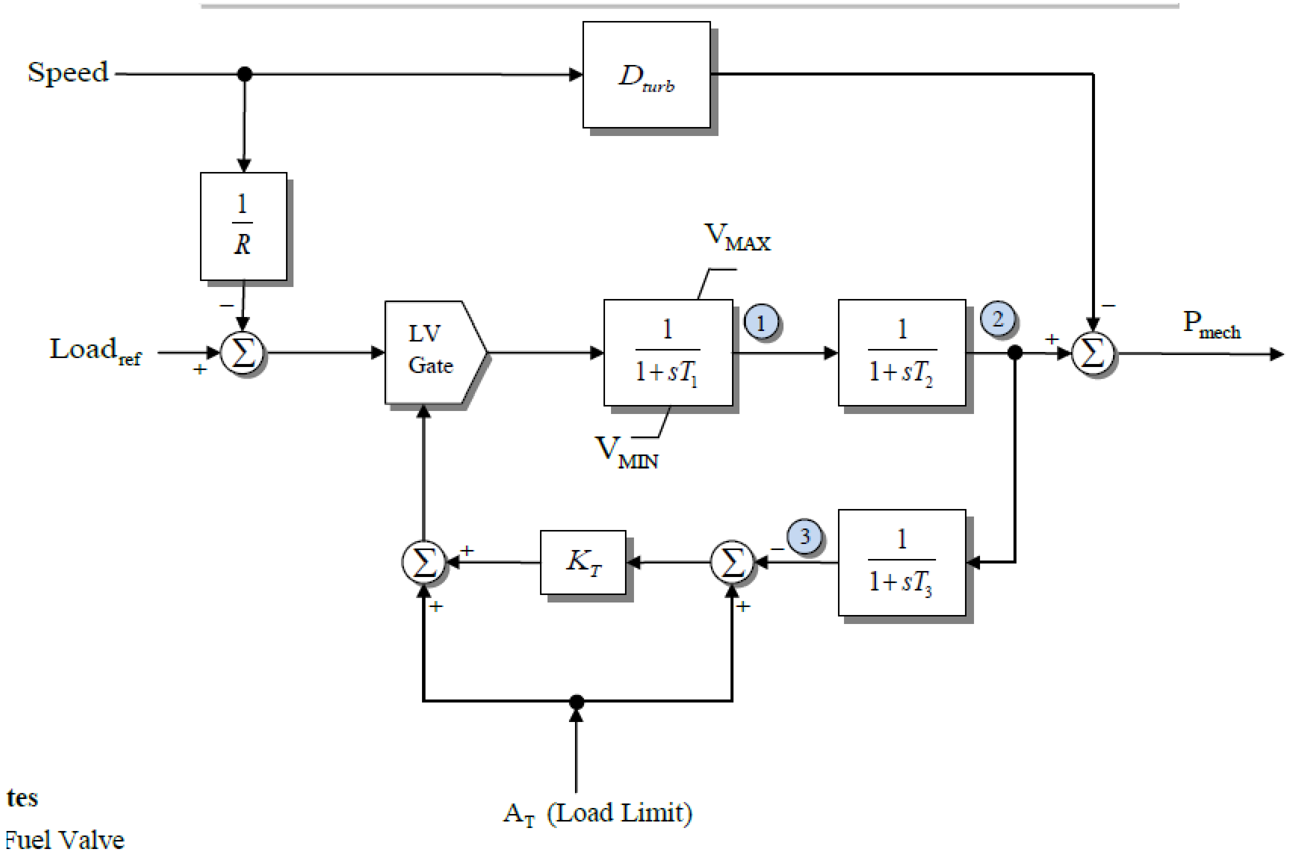
Figure 3-3: Gas turbine controls [17] (IEEE© 2001).

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 start by considering the simplest, which is still used some (about 6% of 2022 EI/WECC governors; not recommended for new models though)



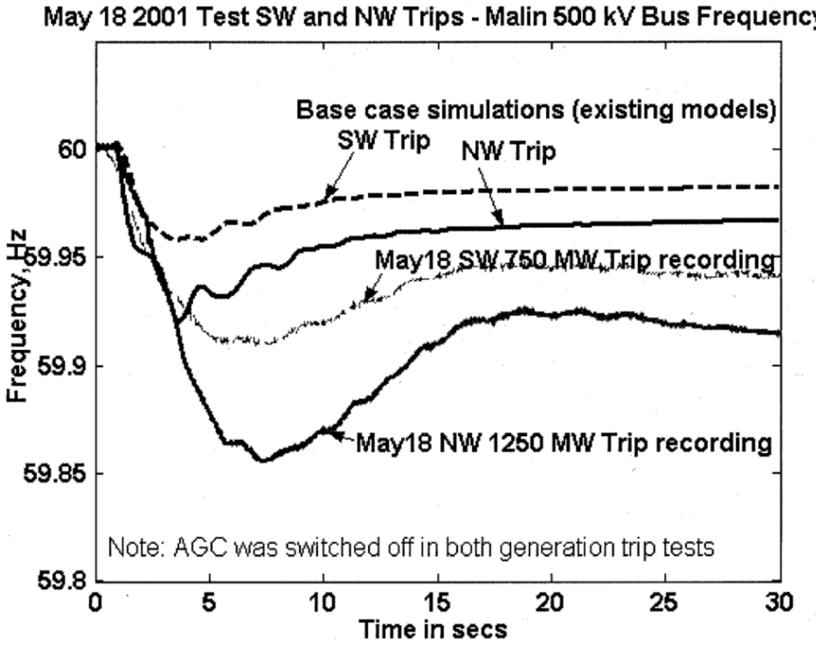
It is somewhat similar to the TGOV1. T_1 is for the fuel valve, T_2 is for the turbine, and T_3 is for the load limit response based on the ambient temperature (At); T_3 is the delay in measuring the exhaust temperature

T_1 average is 0.9, T_2 is 0.6 sec

GGOV1

- GGOV1 was introduced in early 2000's by WECC for modeling thermal plants (including steam and gas turbines)
  - Existing models greatly under-estimated the frequency drop
  - GGOV1 is now the most common WECC governor, used with about 40% of the units
- A useful reference is L. Pereira, J. Undrill, D. Kosterev, D. Davies, and S. Patterson, "A New Thermal Governor Modeling Approach in the WECC," IEEE Transactions on Power Systems, May 2003, pp. 819-829

GGOV1: Selected Figures from 2003 Paper



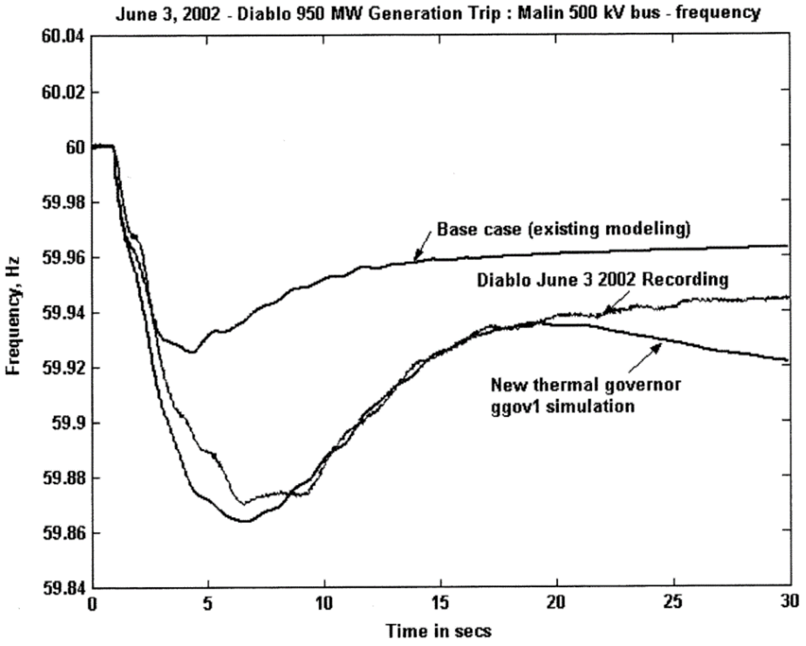
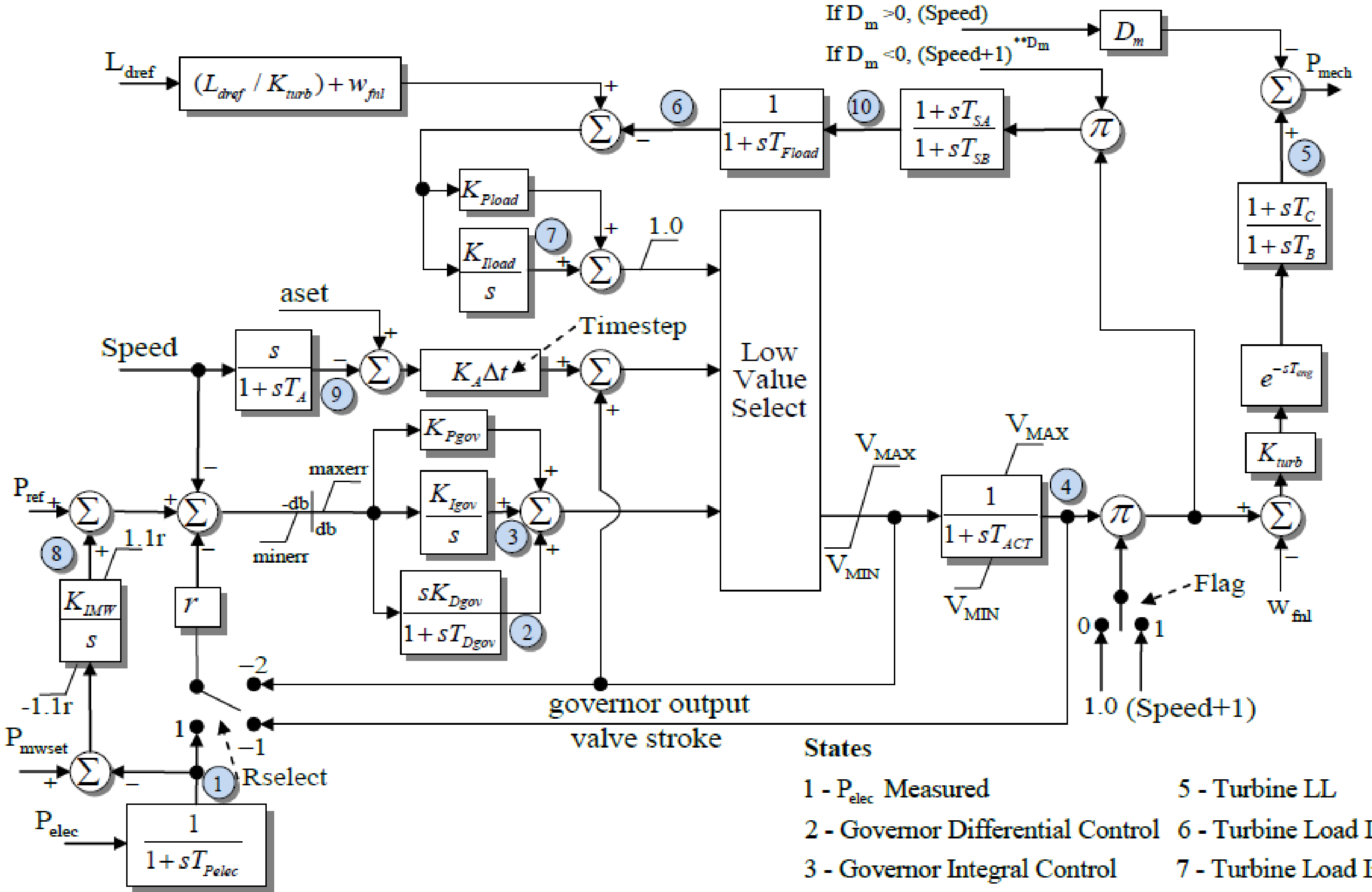


Fig. 1. Frequency recordings of the SW and NW trips on May 18, 2001. Also shown are simulations with existing modeling (base case).

Governor model verification—950-MW Diablo generation trip on June 3, 2002.

Diablo Canyon is California’s last nuclear plant; Unit 1 had been scheduled to shutdown in 2024 and Unit 2 in 2025. However, in March 2023 the NRC provided an exemption to PGE to operate both units past these dates (reference is California Senate Bill No. 846, which was signed on 9/2/2022)

GGOV1 Block Diagram



States

1 - P_{elec} Measured
2 - Governor Differential Control
3 - Governor Integral Control
4 - Turbine Actuator
5 - Turbine LL
6 - Turbine Load Limiter
7 - Turbine Load Integral Control
8 - Supervisory Load Control
9 - Accel Control
10 - Temp Detection LL

Model supported by PSLF

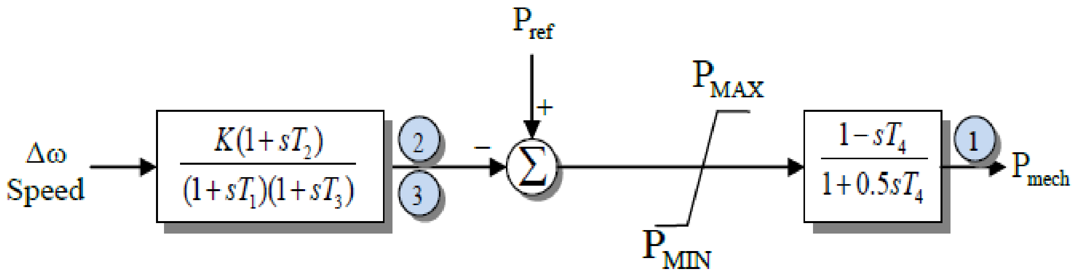
Model supported by PSSE does not include non-windup limits on K_{IMW} block

R_{UP}, R_{DOWN}, R_{CLOSE}, and R_{OPEN} inputs not implemented in Simulator

GGOV1 and the related GGOV3 are the most common governors in WECC, with more than 40% in 2019

Hydro Units

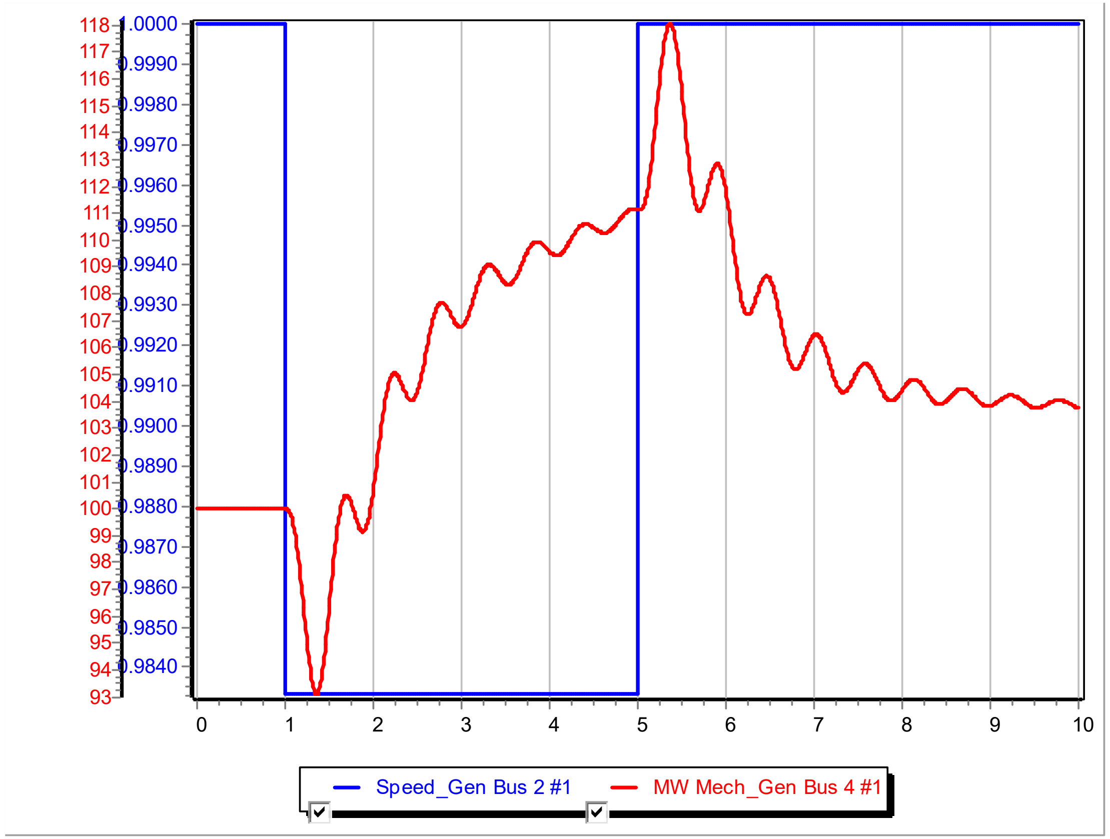
- Hydro units tend to respond slower than steam and gas units; since early transient stability studies focused on just a few seconds (first or second swing instability), detailed hydro units were not used
  - The original IEEEG2 and IEEEG3 models just gave the linear response; now considered obsolete
- 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; the flow does not change instantaneously because of the water's inertia.

Case name:
B4_SignalGen_IEEEG2

Washout Filters

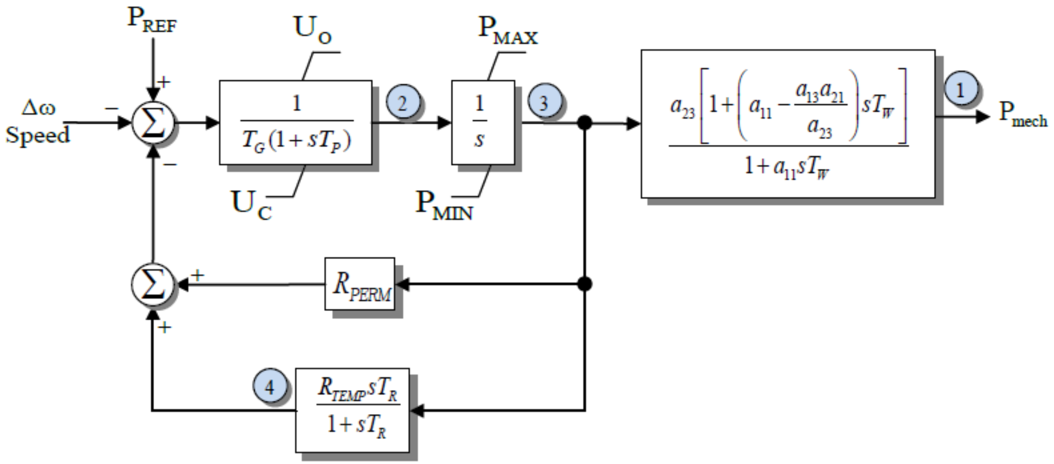
- A washout filter is a high pass filter that removes the steady-state response (i.e., it "washes it out") while passing the high frequency response

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

- They are commonly used with hydro governors and (as we shall see) with power system stabilizers
- With hydro turbines ballpark values for Tw 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)

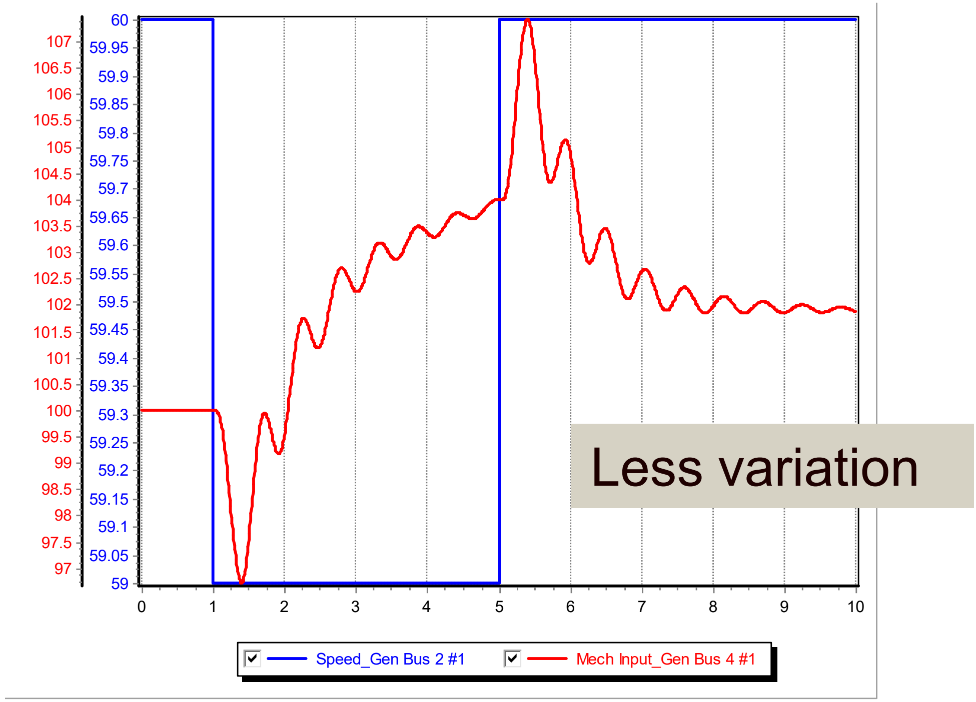


Previously WECC had about 10% of their governors modeled with IEEEG3s; in 2022 it is less than 1%

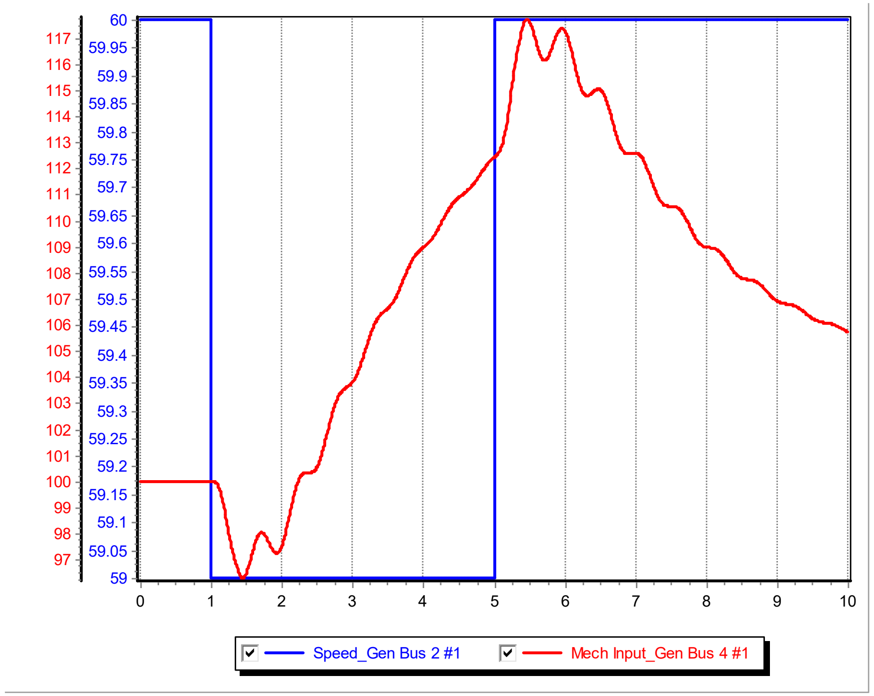
Because of the washout filter at high frequencies R_{TEMP} dominates (on average it is 10 times greater than R_{PERM})

IEEEG3 Four Bus Frequency Change

- The two graphs compare the case response for the frequency change with different RTEMP values



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



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

Case name: **B4_SignalGen_IEEEG3**

Basic Nonlinear Hydro Turbine Model

- Basic hydro system is shown below
  - Hydro turbines work be converting the kinetic energy in the water into mechanical energy
  - assumes the water is incompressible
- At the gate assume a velocity of U, a cross-sectional penstock area of A; then the volume flow is A*U=Q;

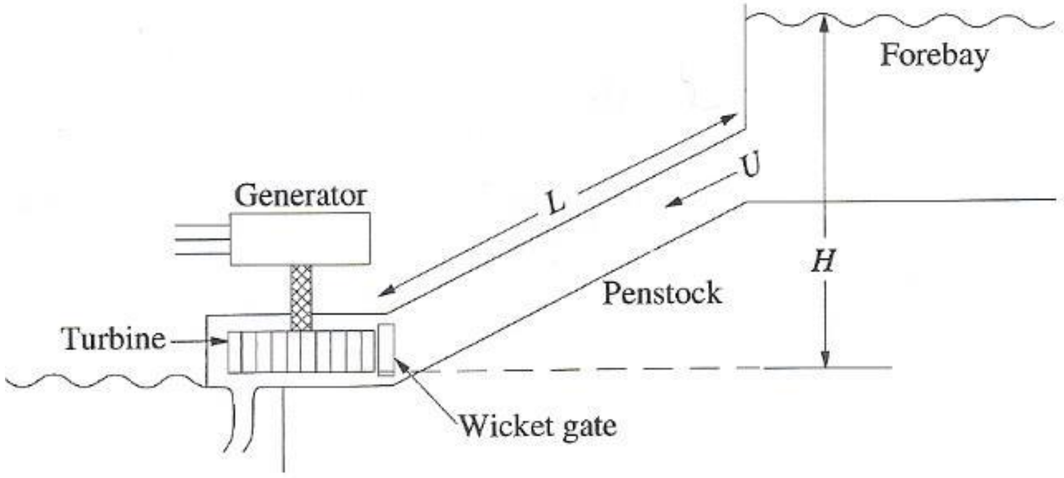


Figure 9.2 Schematic of a hydroelectric plant

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

Basic Nonlinear Hydro Turbine Model, Cont.

- From Newton's second law of motion the change in the flow volume Q

$$\rho L \frac{dQ}{dt} = F_{net} = A\rho g\left(H - H_{gate} - H_{\text{loss}}\right)$$

- where ρ is the water density, g is the gravitational constant, H is the static head (at the drop of the reservoir) and Hgate is the head at the gate (which will change as the gate position is changed, Hloss is the head loss due to friction in the penstock, and L is the penstock length.

- As per [a] paper, this equation is normalized to

$$\frac{dq}{dt} = \frac{\left(1 - h_{gate} - h_{\text{loss}}\right)}{T_W}$$

T_W is called the water time constant, or water starting time

[a] "Hydraulic Turbine and Turbine Control Models for System Dynamic Studies," *IEEE Trans. Power Syst.*, Feb, 92

Basic Nonlinear Hydro Turbine Model, Cont.

- With hbase the static head, qbase the flow when the gate is fully open, an interpretation of Tw is the time (in seconds) taken for the flow to go from stand-still to full flow if the total head is hbase
- If included, the head losses, hloss, vary with the square of the flow
- The flow is assumed to vary as linearly with the gate position (denoted by c)

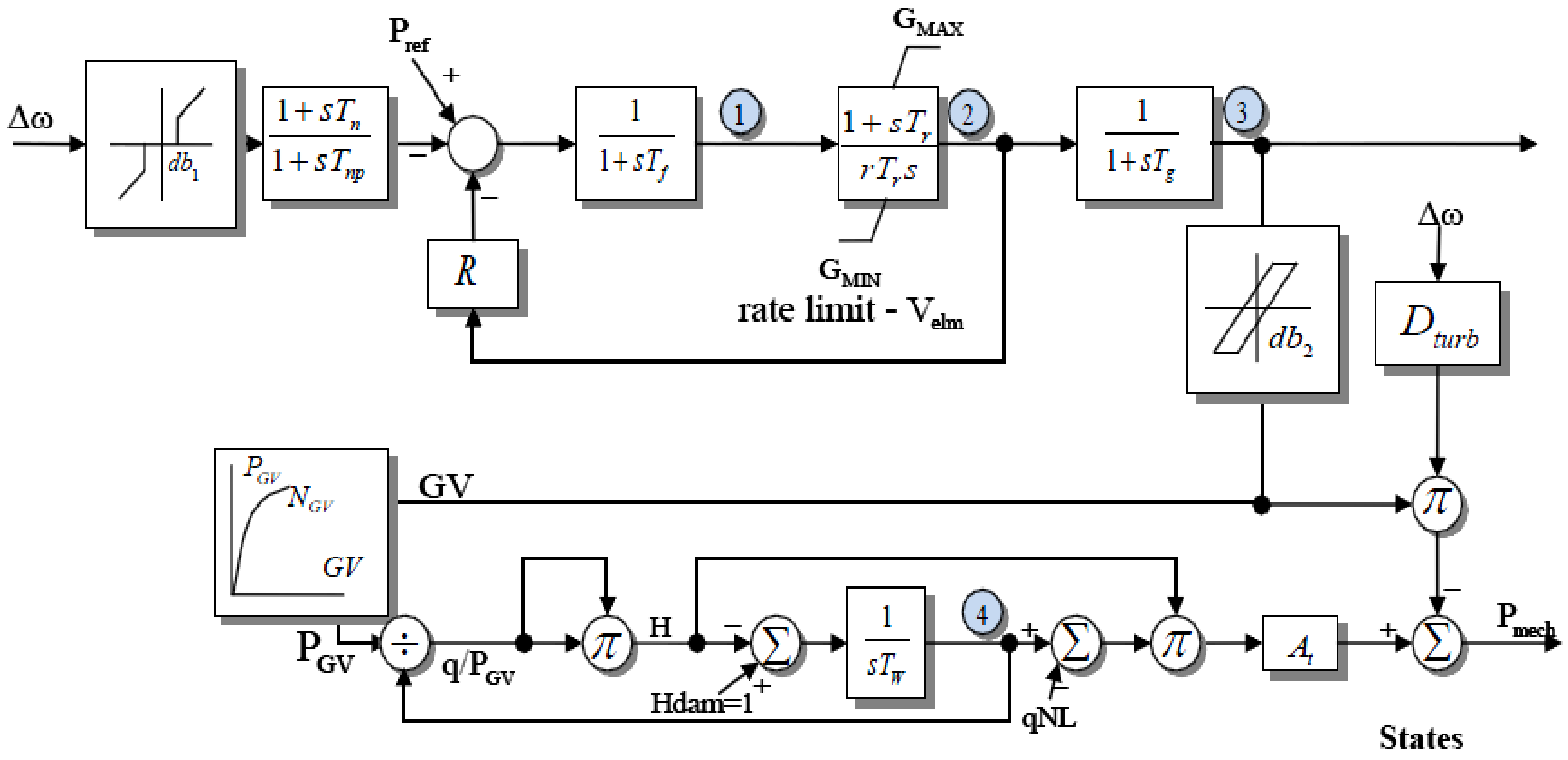
$$q = c\sqrt{h} \text{ or } h = \left(\frac{q}{c}\right)^2$$

- Power developed is proportional to flow rate times the head, with a term qnl added to model the fixed turbine (no load) losses
  - The term At is used to change the per unit scaling to that of the electric generator

$$P_m = A_t h(q - q_{nl})$$

Model HYGOV

- This simple model, combined with a governor, is implemented in HYGOV



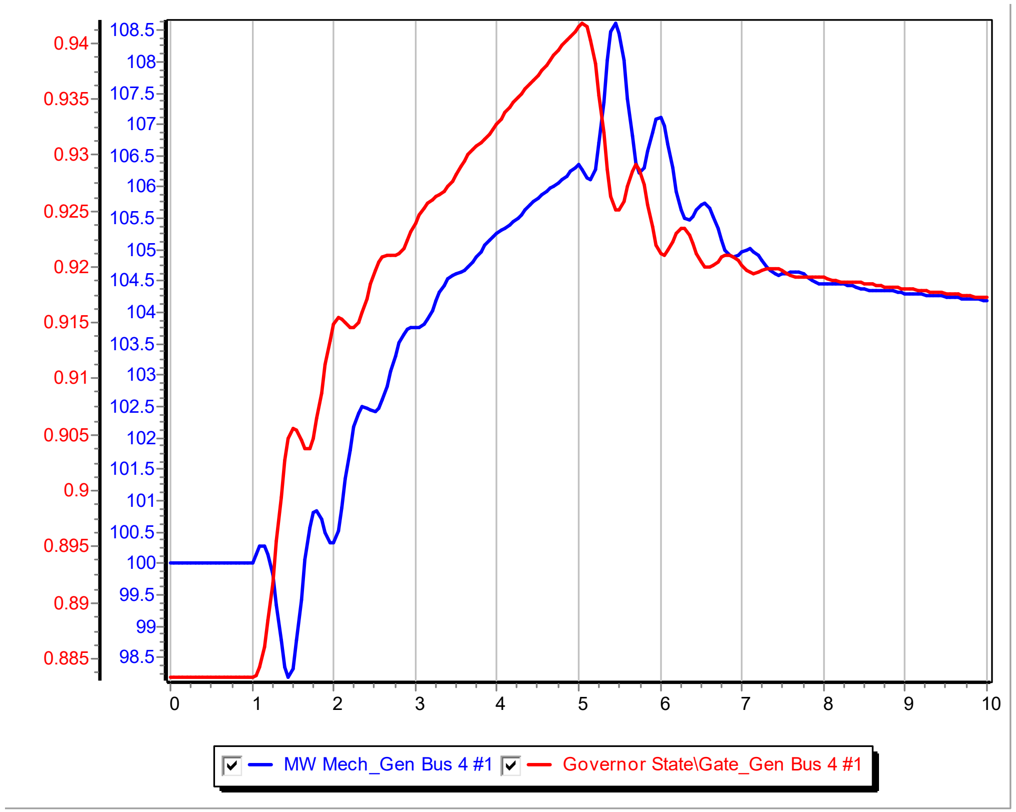
About 6% of WECC governors use this model; average T_W is two seconds

The gate position (GV) to gate power (P_{GV}) is sometimes represented with a nonlinear curve

H_{loss} is assumed small and not included

Four Bus Case with HYGOV

- The below graph plots the gate position and the power output for the bus 2 signal generator decreasing the speed then increasing it



Note that just like in the linearized model, opening the gate initially decreases the power output

Case name: **B4_SignalGen_HYGOV**

PID Controllers

- Governors and exciters often use proportional-integral-derivative (PID) controllers
- PIDs combine
  - Proportional gain, which produces an output value that is proportional to the current error
  - Integral gain, which produces an output value that varies with the integral of the error, eventually driving the error to zero
  - Derivative gain, which acts to predict the system behavior. This can enhance system stability, but it can be quite susceptible to noise

PID Controller Characteristics

- Four key characteristics of control response are 1) rise time, 2) overshoot, 3) settling time and 4) steady-state errors

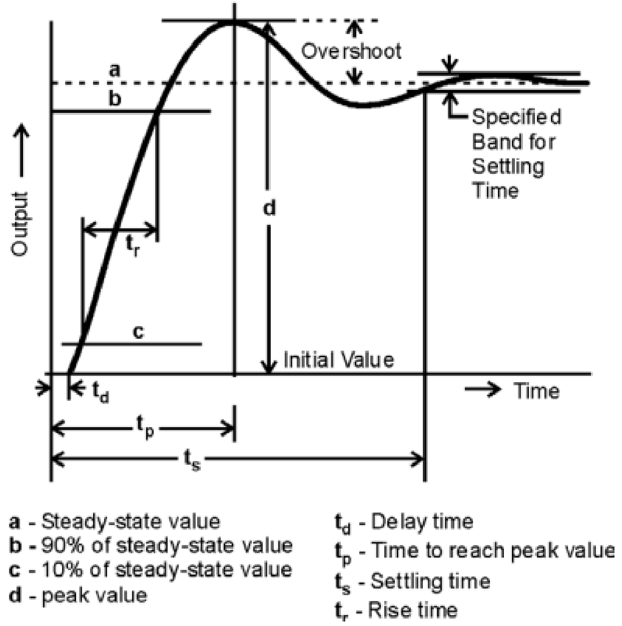


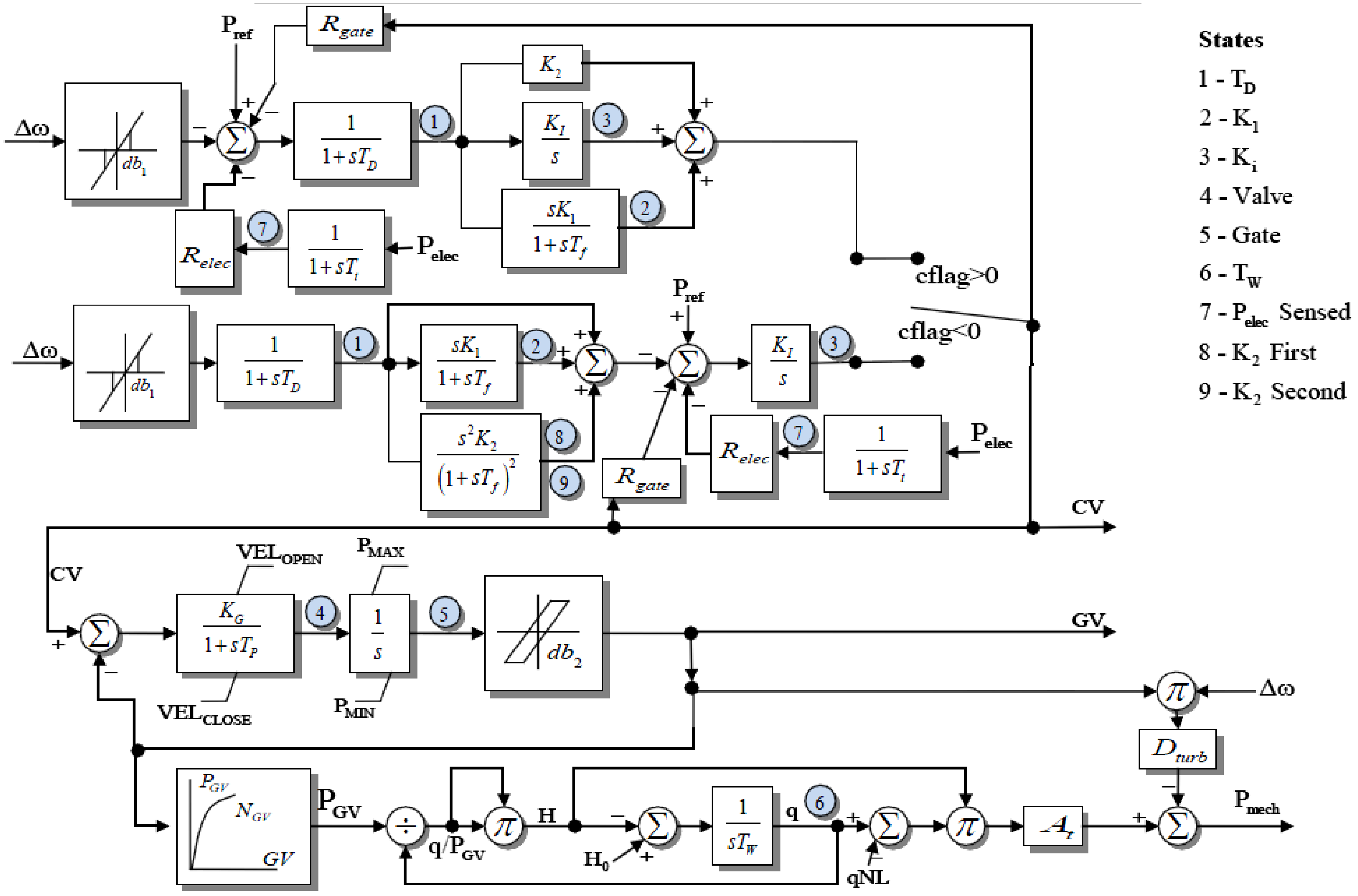
Figure F.1—Typical dynamic response of a turbine governing system to a step change

Increasing Gain	Rise Time	Overshoot	Setting Time	Steady-State Error
K_P	Decreases	Increases	Little impact	Decreases
K_I	Decreases	Increases	Increases	Zero
K_D	Little impact	Decreases	Decreases	Little Impact

Image source: Figure F.1, IEEE Std 1207-2011

HYG3

- The HYG3 models has a PID or a double derivative



Looks more complicated than it is since depending on cflag only one of the upper paths is used

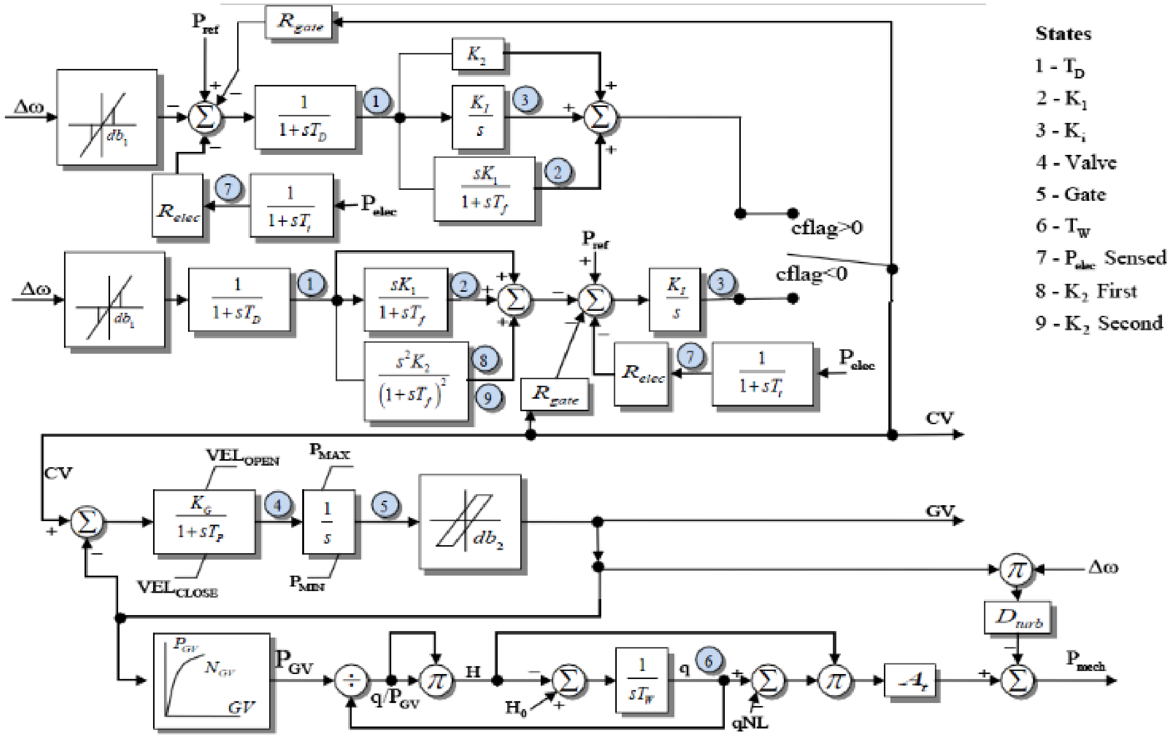
About 15% of current WECC governors at HYG3

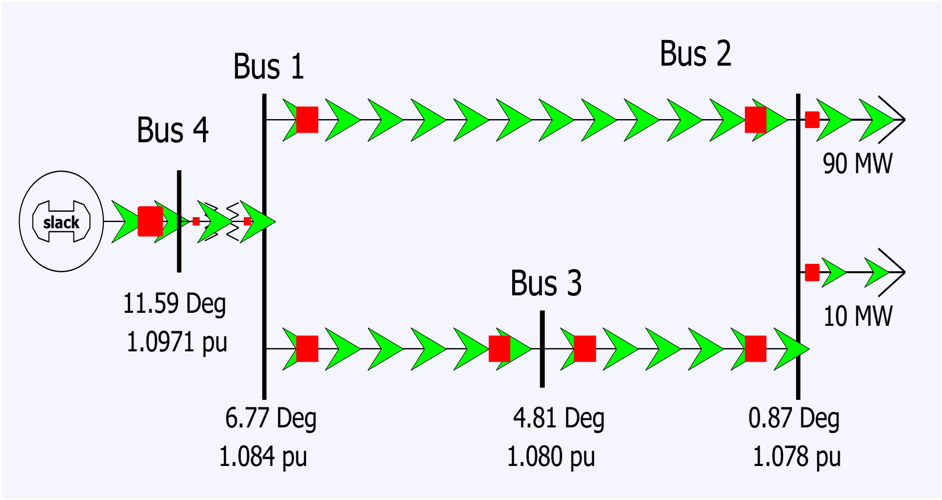
Tuning PID Controllers

- Tuning PID controllers can be difficult, and there is no single best method
  - Conceptually simple since there are just three parameters, but there can be conflicting objectives (rise time, overshoot, setting time, error)
- One common approach is the Ziegler-Nichols method
  - First set KI and KD to zero, and increase KP until the response to a unit step starts to oscillate (marginally stable); define this value as Ku and the oscillation period at Tu
  - For a P controller set Kp = 0.5Ku
  - For a PI set KP = 0.45 Ku and KI = 1.2* Kp/Tu
  - For a PID set KP=0.6 Ku, KI=2* Kp/Tu, KD=KpTu/8

Tuning PID Controller Example

- Use the four bus case with infinite bus replaced by load, and gen 4 has a HYG3 governor with cflag > 0; tune KP, KI and KD for full load to respond to a 10% drop in load (K2, KI, K1 in the model; assume Tf=0.1)

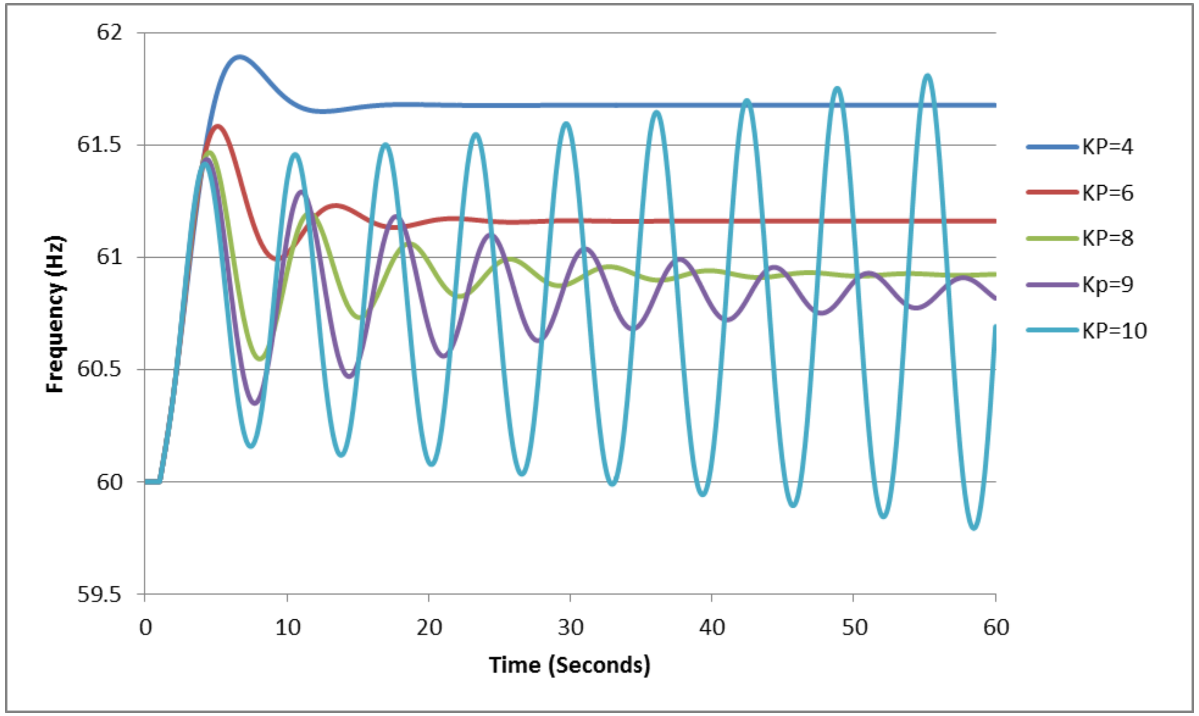




Case name: **B4_PIDTuning**

Tuning PID Controller Example, Cont.

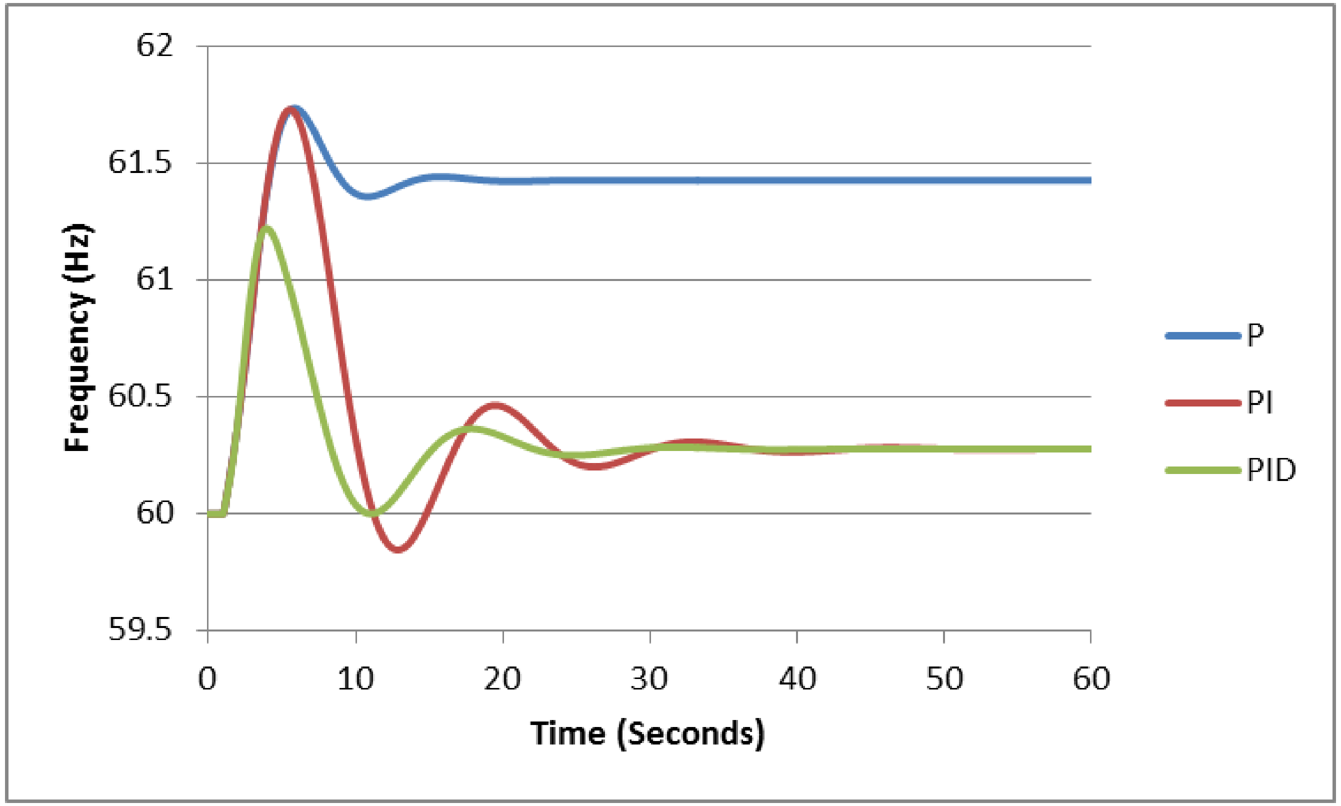
- Based on testing, Ku is about 9.5 and Tu is 6.4 seconds
- Using Ziegler-Nichols a good P value 4.75, is good PI values are KP = 4.3 and KI = 0.8, while good PID values are KP = 5.7, KI = 1.78, KD=4.56



Further details on tuning are covered in IEEE Std. 1207-2011

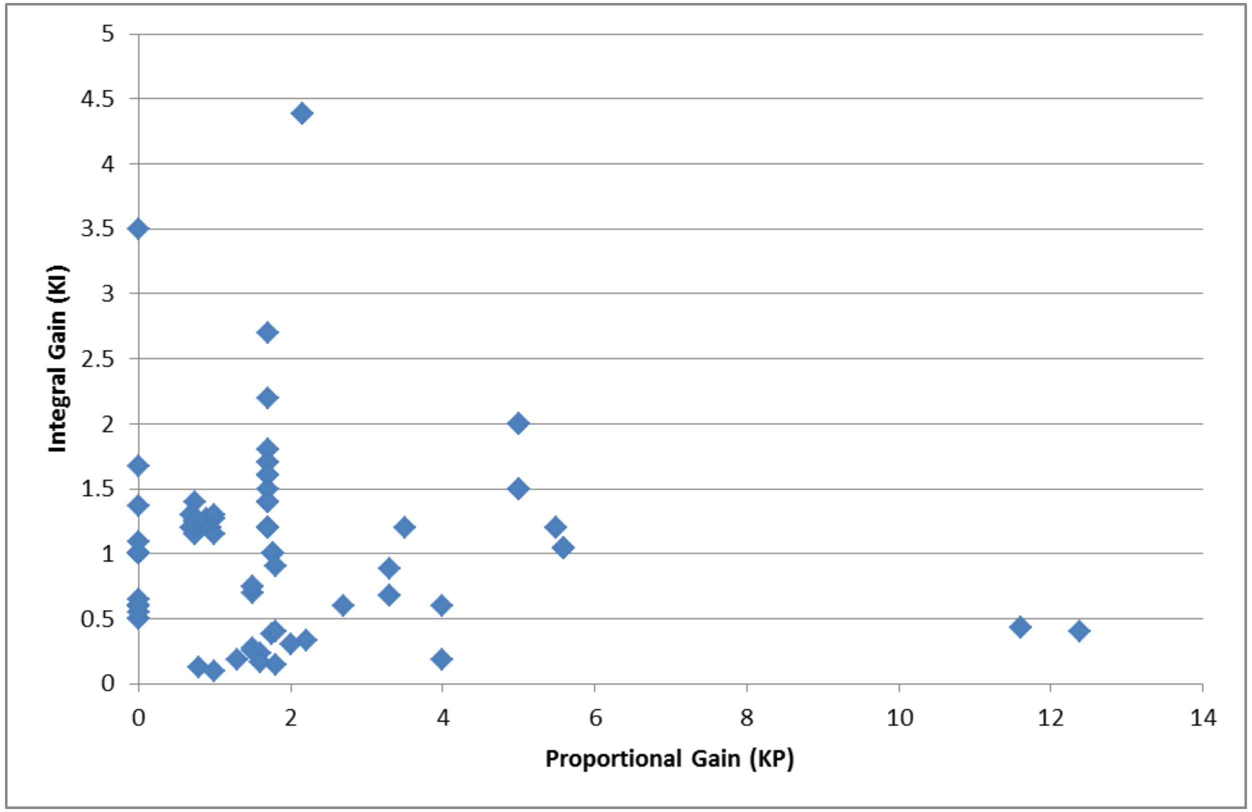
Tuning PID Controller Example, Cont.

- Figure shows the Ziegler-Nichols for a P, PI and PID controls. Note, this is for stand-alone, not interconnected operation



Example KI and KP Values

- Figure shows example KI and KP values from an actual system case



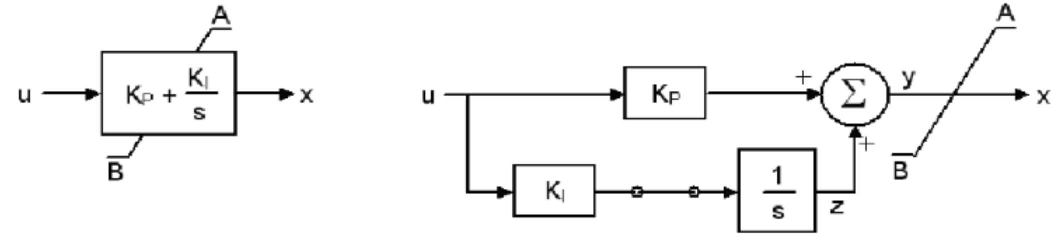
About 60% of the models also had a derivative term with an average value of 2.8, and an average T_D of 0.04 sec

Non-Windup Limits

- An important open question is whether the governor PI controllers should be modeled with non-windup limits
  - Currently models show no limit, but transient stability verification seems to indicate limits are being enforced
- This could be an issue if frequency goes low, causing governor PI to "windup" and then goes high (such as in an islanding situation)
  - How fast governor backs down depends on whether the limit winds up

PI Non-Windup Limits

- There is not a unique way to handle PI non-windup limits; the below shows two approaches from IEEE Std 421.5



$y > A$, then $x = A$ and $dz/dt = 0$

$y < B$, then $x = B$ and $dz/dt = 0$

Figure E.7—Non-windup proportional-integral block

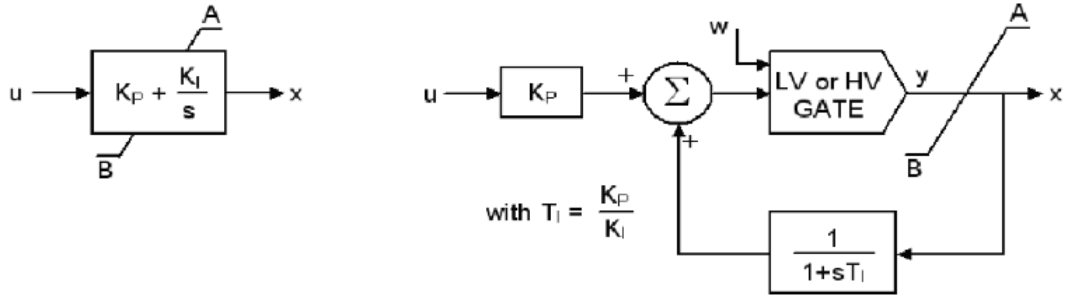


Figure E.8—Non-windup proportional-integral block

Another common approach is to cap the output and put a non-windup limit on the integrator