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Smart Grid – Modeling and Control

Distributed Generation & Control (Part 1)

University of Hawaii's Renewable Energy Design Laboratory (REDLab)
in collaboration with Powersim Inc. and MyWay

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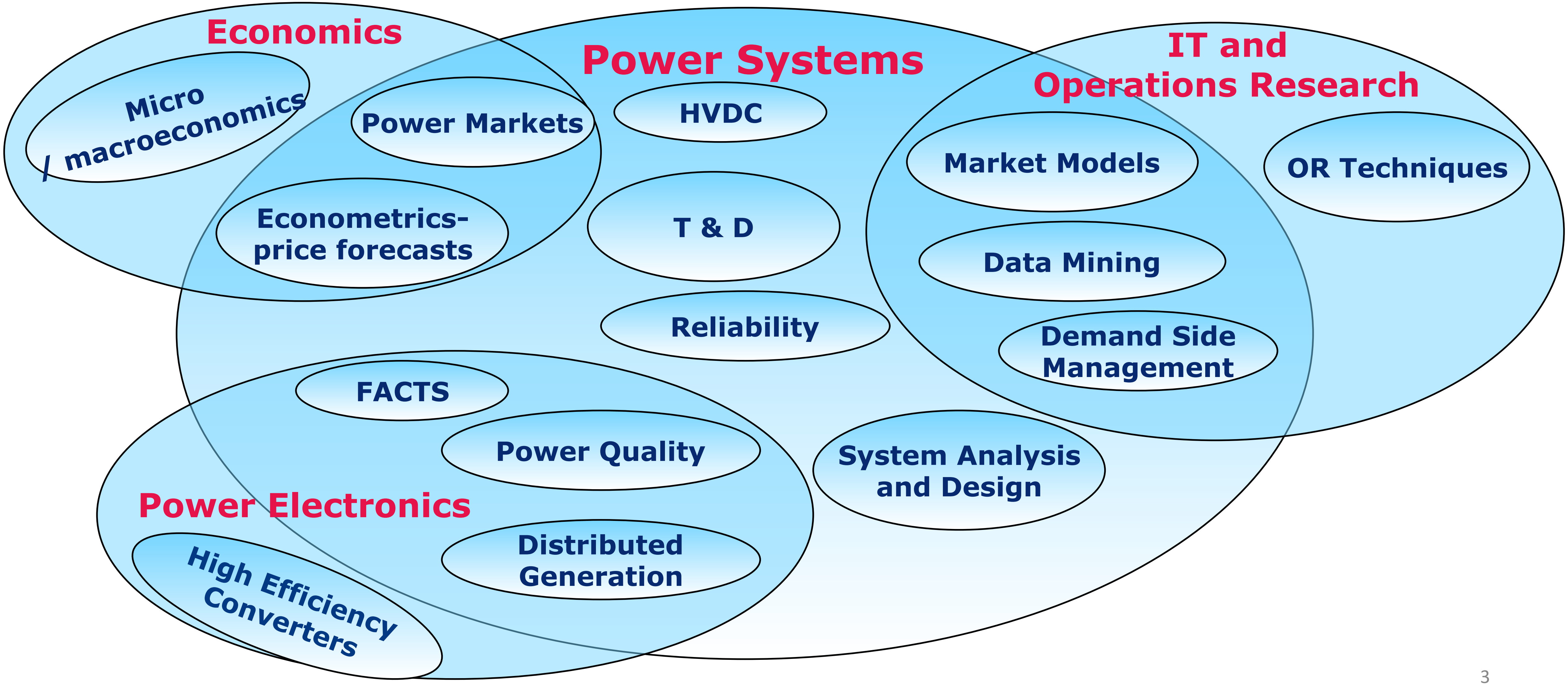
Modern Power System Control Elements



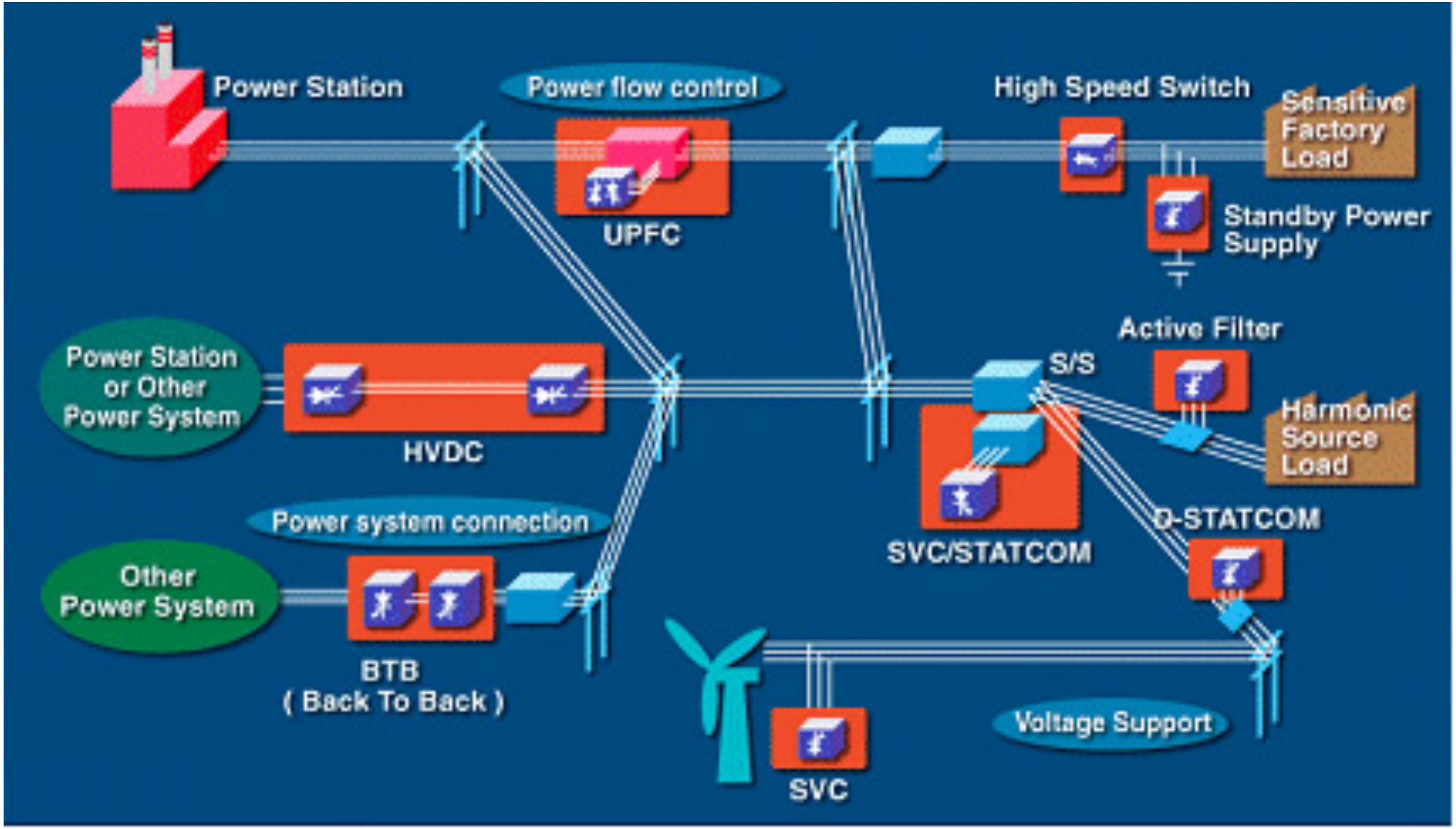
Why do we need Control?

- Power system collapse is extremely expensive
- Time-constants are rather small
- Power system operated closer to stability limit
  - Deregulation of energy market
  - Environmental concerns
  - Increase of electric power demand

Various Controls Modules in Electrical Power System

1. Turbine Governor (TG)
2. Automatic Voltage Regulator (AVR)
3. Over Excitation Limiter (OXL)
4. Power System Stabilizer (PSS)
5. Secondary Voltage Control System (SVC)
   - Includes Central Area Controllers (CACs)
6. Cluster Controllers (CCs)
   - Coordinates AVRs and SVCs
7. Power Oscillation Damper (POD)

Future Power System



Source: Toshiba Japan

Distributed Generation

- Distributed energy, **or** decentralized energy, is generated or stored by a variety of small, grid - connected devices called **distributed energy resources (DER)**
- DER systems typically use renewable energy sources
- A grid-connected device for energy storage can also be classified as DER system and is often called a **distributed energy storage system (DESS)**

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Distributed Generation: Gas Turbine Type

Characteristics of micro turbines

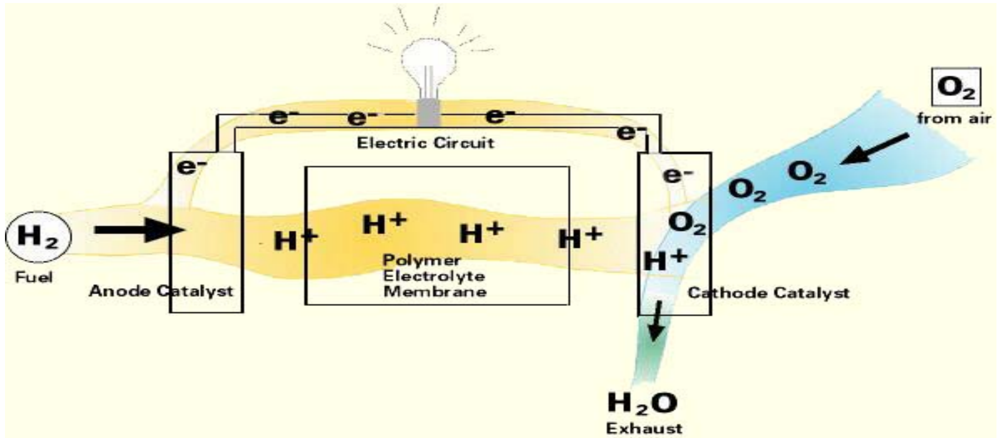
Size:	A refrigerator
Turbine generator:	Usually single shaft
Turbine speed:	70,000 rpm
Generator type:	DC with AC conversion
Fuel efficiency:	32%
Installation Time:	1 week
Typical cost/kW:	$700

Source: Power Plants Around the World

Distributed Generation: Fuel Cell DG

Advantages	Disadvantages
High efficiency for fossil fuel	High initial cost
Low pollution, noise, and vibration	Maintenance needed
Easily re-usable	Fuel sensitivity
Modular available	Unproven track record

Source: Chewonki Foundation



Source: Dueling Fuels

Distributed Generation: Renewable DGs

- Renewable generation has many potential benefits over fossil or nuclear power:
  - Fuel and delivery at no cost
  - Environmentally friendly
- Easy for the DG applications.
- Some limitations
- Different types of DG-applicable renewable sources:
  - Solar, Wind, Low-head Hydro, Biomass, Geothermal, Tidal power, and Ocean-current turbine.

Energy Storage With DGs

- Energy storage can augment DG in three ways:
  - Stabilization purpose
  - Ride-Through
  - Dispatchable

Different types of energy storages:

- Battery
- Superconducting magnetic energy storage (SMES)
- Capacitor storage
- Flywheels
- Thermal storage (molten salt or super-heated oil)

Central Vs Distributed Generation

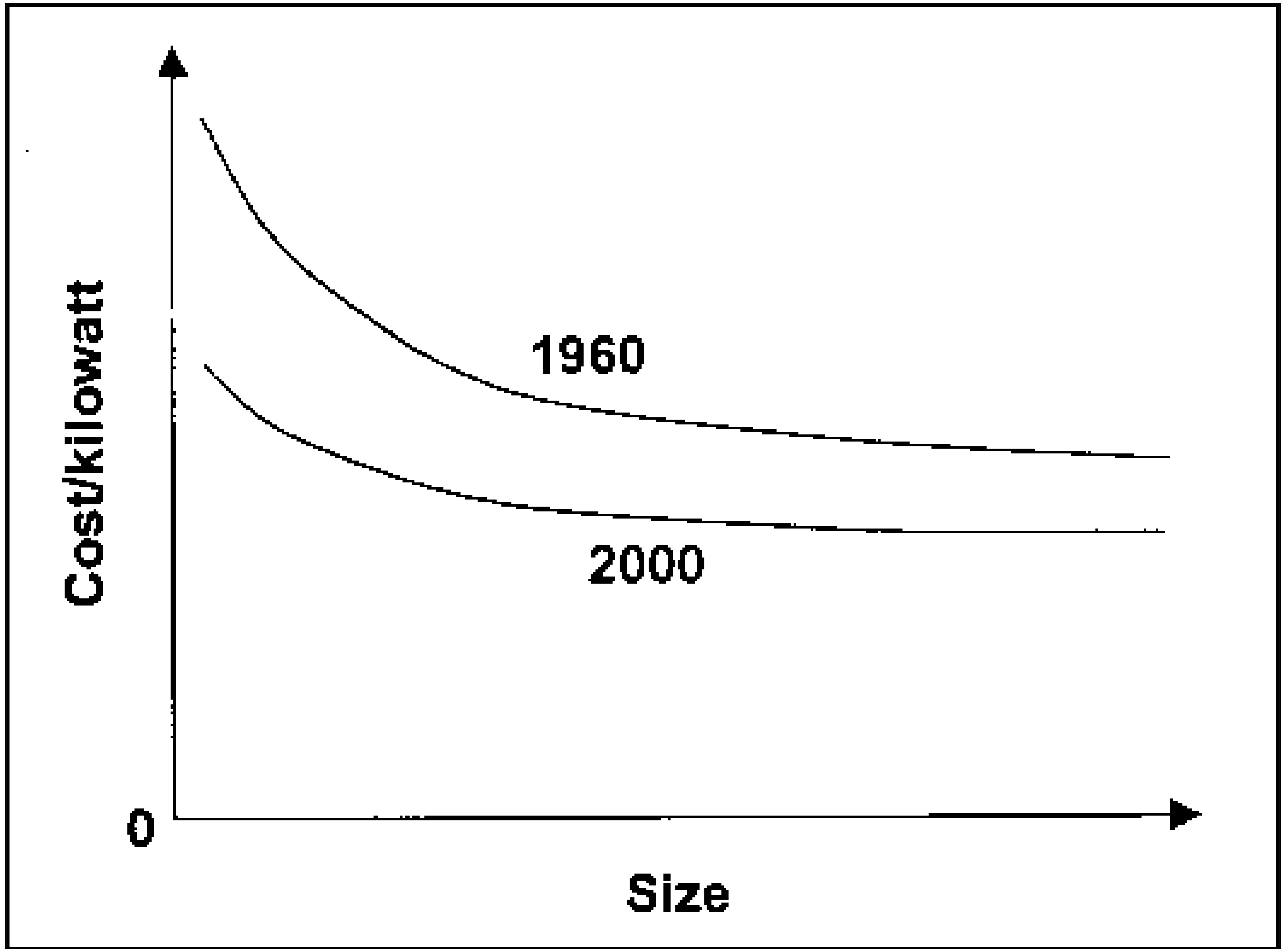


Figure 1. A Shrinking Scale of Economy

Central Vs Distributed Generation

Four basic reasons for this shrinking economy:

1. Technological advancement in fuel conversion
2. Heat containment or insulation and thermal engineering
3. Shift in fuel price
4. Automation and controls

The efficiency is not the only deciding factor

Issues:

- **Total operating cost**
- **Environment impacts**

Central Vs Distributed Generation

DG "wins" over Central

- In the past, T&D costs gradually increased, while the DG costs have dropped
- A high quality DG has a service availability of about 95%, sometimes 100 % with additional capacity, probability that DG power will be available
- Improvement in the reliability spectrum

DG is valuable, because it provides a flexible way to chose a wide range of cost and reliability combinations

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DG Salient Features

✓Peak load saving.

✓Good voltage profile.

✓Reduce system losses.

✓Improve continuity and reliability.

✓Remove some power quality problems.

✓Relax thermal constraints of T&D feeders.

Challenges

- Fuel delivery.
- Grid connection.
- Unproven technology.
- Power quality problems.
- Various stability problems.

Modularity:

Besides their small size, most of DG units are factory assembled units (i.e. build to a common design)

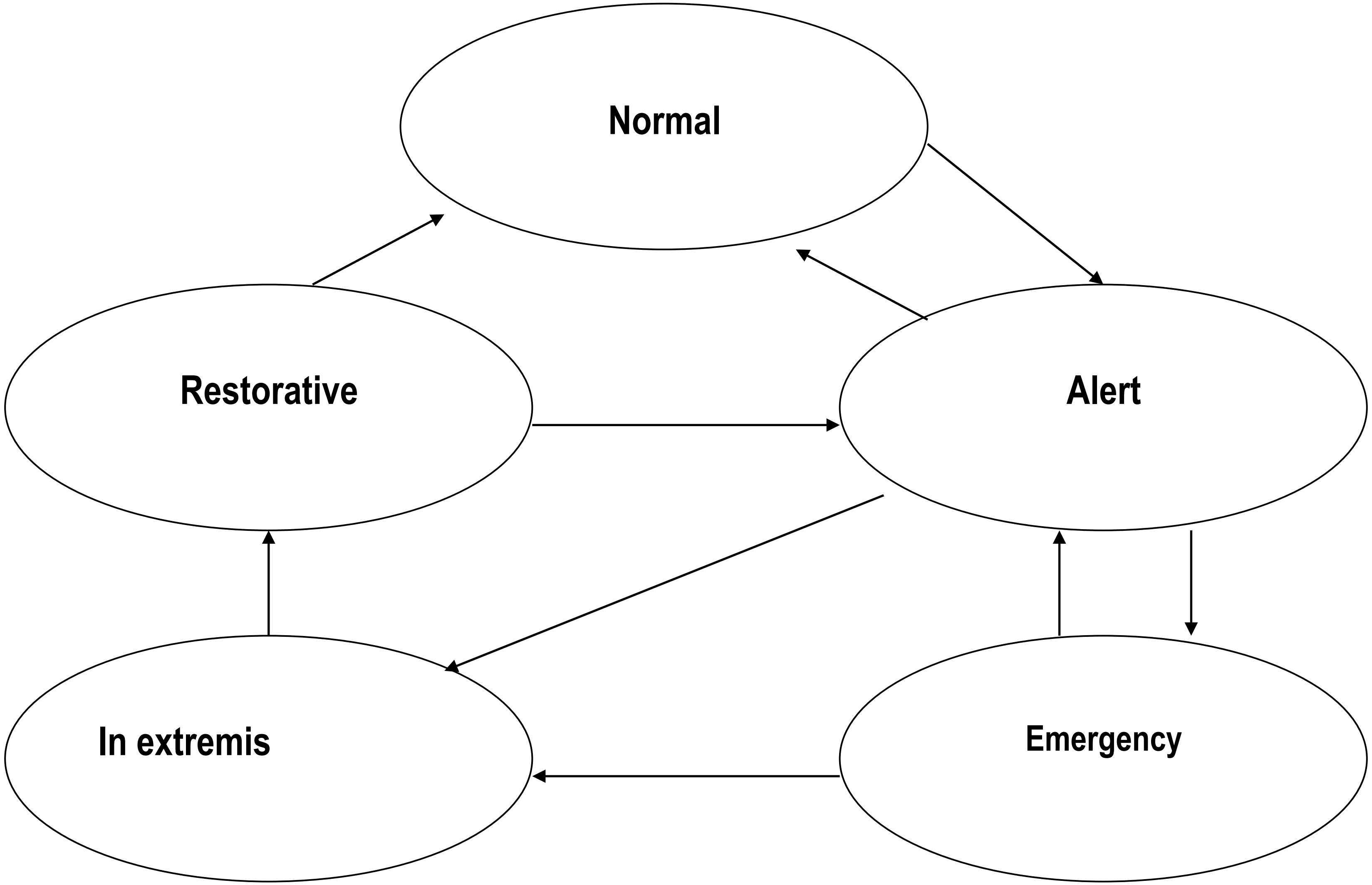
Environmental and Aesthetic Concerns:

Some DGs are extremely clean and silent

Power System Control

- The system must be able to meet the continually changing active and reactive power demand
- An adequate "spinning reserve" of active and reactive power should be maintained and appropriately controlled
- The system should supply energy at minimum cost and with minimum ecological impact, through various control measures
- The "quality" of power supply must meet certain minimum standards for the following factors…
    - Constant frequency
    - Constant voltage
    - Level of reliability

Different Operating States in Power System



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Operating States

- **Normal State:**
  - All the equality (E) and inequality (I) constraints are satisfied
- **Alert State:**
  - There is a danger of violating some inequality constraints
- **Emergency State:**
  - Inequality constraints are violated
- **In Extremis State:**
  - Both equality and inequality constraints are violated
- **Restorative State:**
  - This is a transitional state

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Operating States

Alert State:

- All constraints are satisfied
- The system has been weakened to a level where a contingency may cause an overloading of equipment
- May push the system to "Emergency State" or "In Extremis State" depending on the level of disturbance
- Normally, the system enters the "Alert State" if the security level falls below a certain limit

Emergency State:

- Voltages at many buses are low and/or equipment loadings exceed short-term emergency rating
- The system enters the "Emergency State" if a sufficiently sever disturbance occurs when during the "Alert State"
- The system is still intact (no collapse) and may be restored back to alert state using some control action (e.g. fault clearing, excitation control, fast-valving, generation tripping, load

Operating States

In Extremis:

- If the above measures are not applied or are ineffective, the system enters the "In Extremis State"
- This results in cascading outages and possibly a shut-down of a major portion of the system
- Control action, such as load shedding and controlled system separation, are aimed from a widespread blackout

Restorative State:

- Control action is being taken to reconnect all the facilities and restore system loads
- The system transits from this state to either the "Alert State" or the "Normal State"

The Control Problem

Complex MIMO system

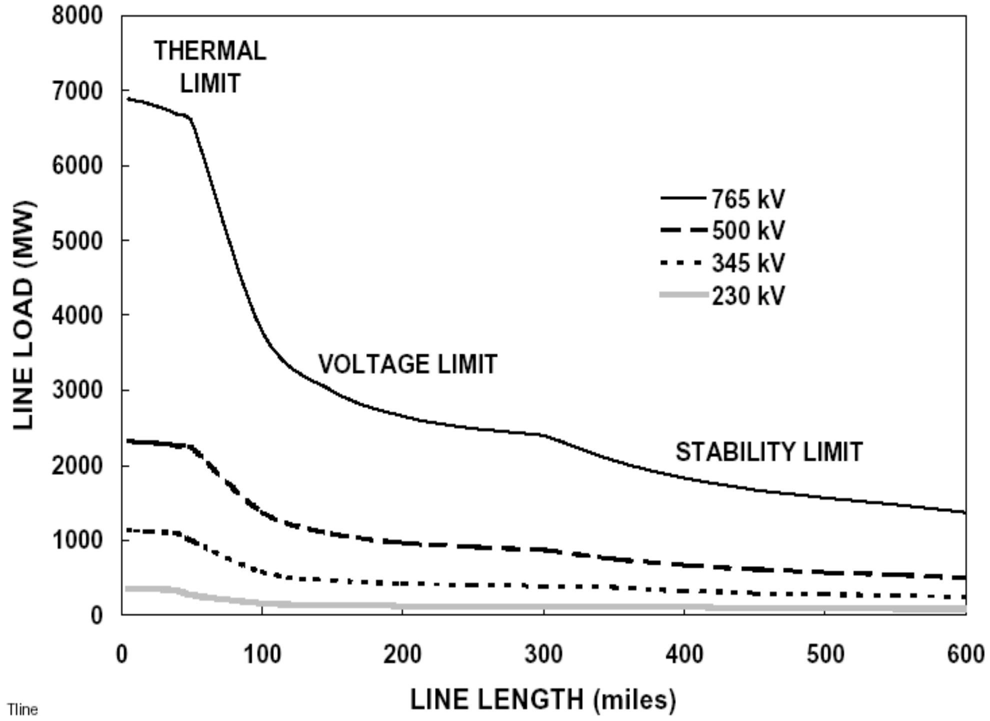
- Thousands of nodes
- Voltage and angle on each node
- Power flows through the lines (P and Q)
- Generated power (P and Q), and voltage
- OLTC positions

Not everything is known!

- Not every flow is known.
- Local or global control
- Cross-border information
- Output of power plants
- Metering equipment is not always available or correct

Control Problem: Basic Requirements

- Voltage must remain between its limits of
  - 1 p.u. +/- 5 or 10 %
- Power flow through a line is limited
  - Thermal limit dependent on section
- Frequency has to remain between strict limits
- Economic optimum



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Control Problem Assumptions

- P-f control and Q-V control can be separated

  Time Constant $\tau_{Q-V} << \tau_{P-f}$

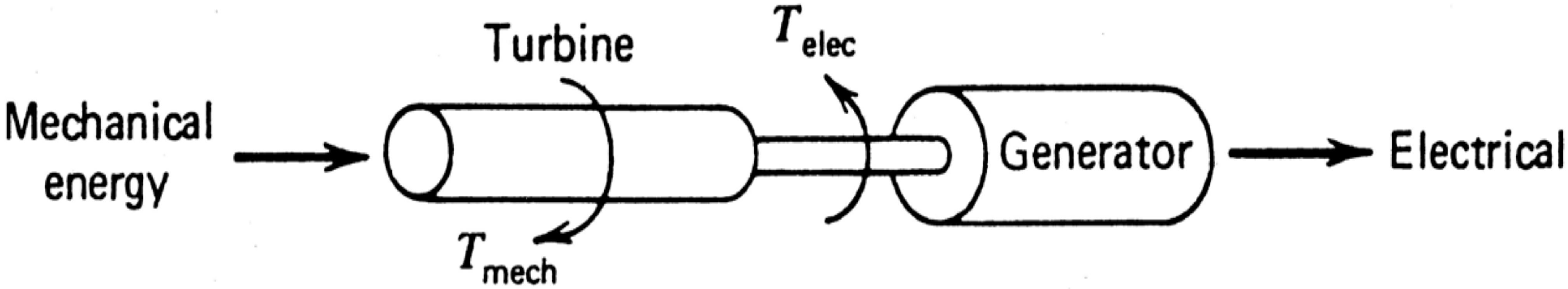
- Voltage control is independent for each voltage controlled node
- Global system can be divided in control areas
  - Control area = Region of generators that experience the same frequency perturbation

$$\Delta fi$$

Automatic Generation Control (AGC)

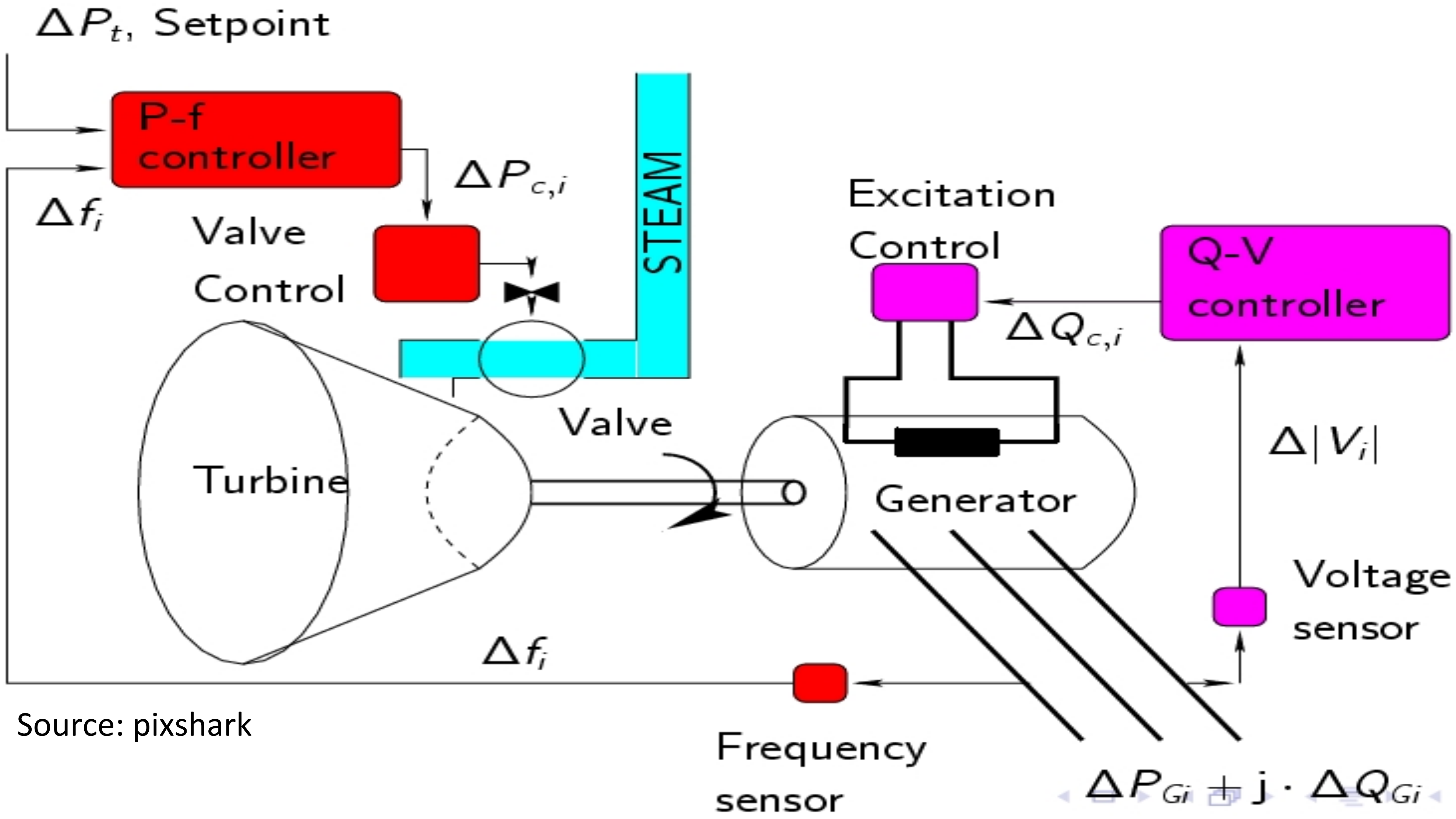
- Restores System Frequency when it deviates from 60 Hz (US)
- Reallocate generation to keep it at economic dispatch
- Keep interchange with other control areas at the scheduled MW
- Monitor and control generators as they ramp up and down

Basic Turbine Generator



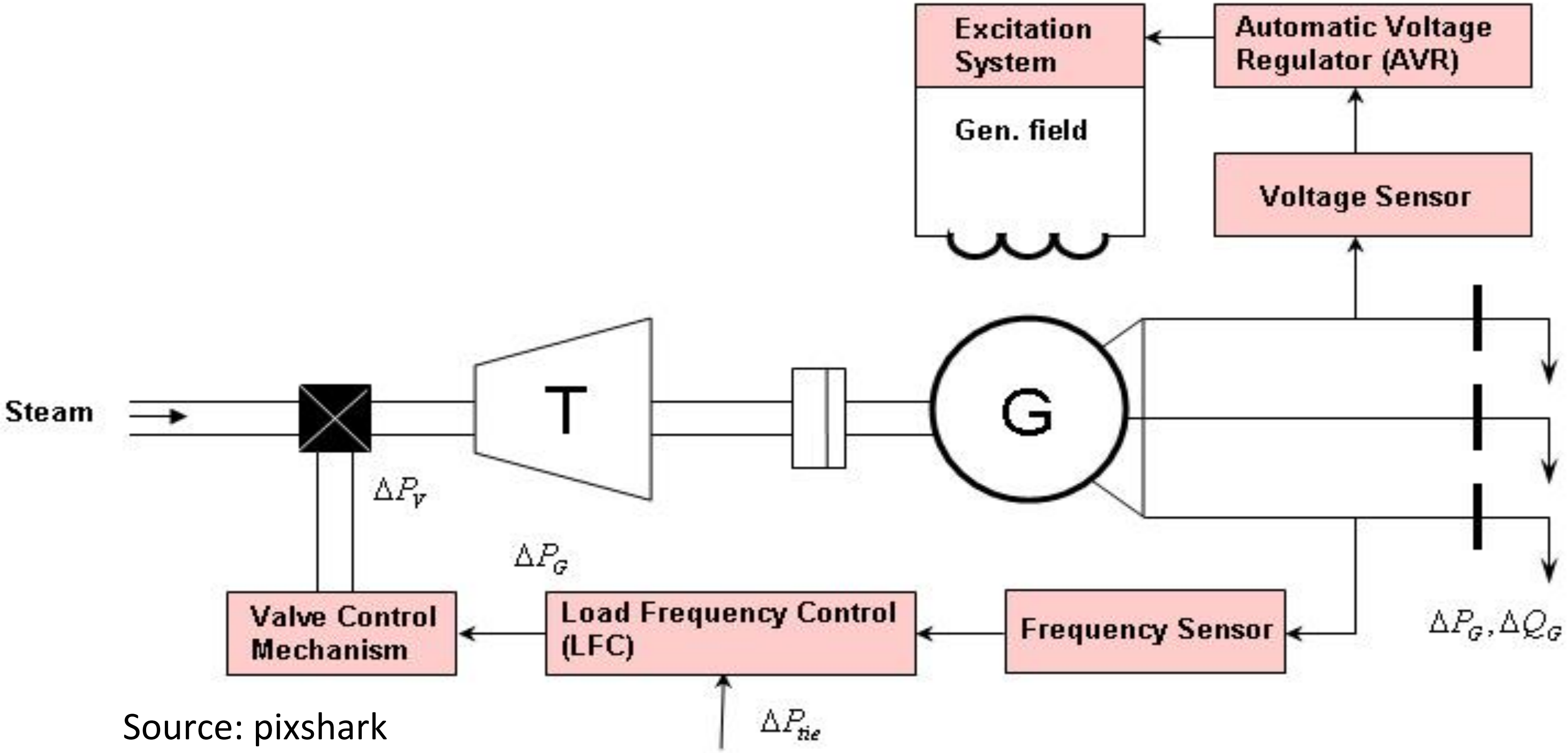
- Frequency directly related to speed of rotation
- Constant frequency = constant speed of rotation
- If mechanical energy in = electrical energy out
- Mechanical torque = negative of electrical torque then speed remains constant
- Electrical load changes are uncontrolled, so we must control mechanical energy input to match

Turbine: Generator control



Source: pixshark

Generator Control System



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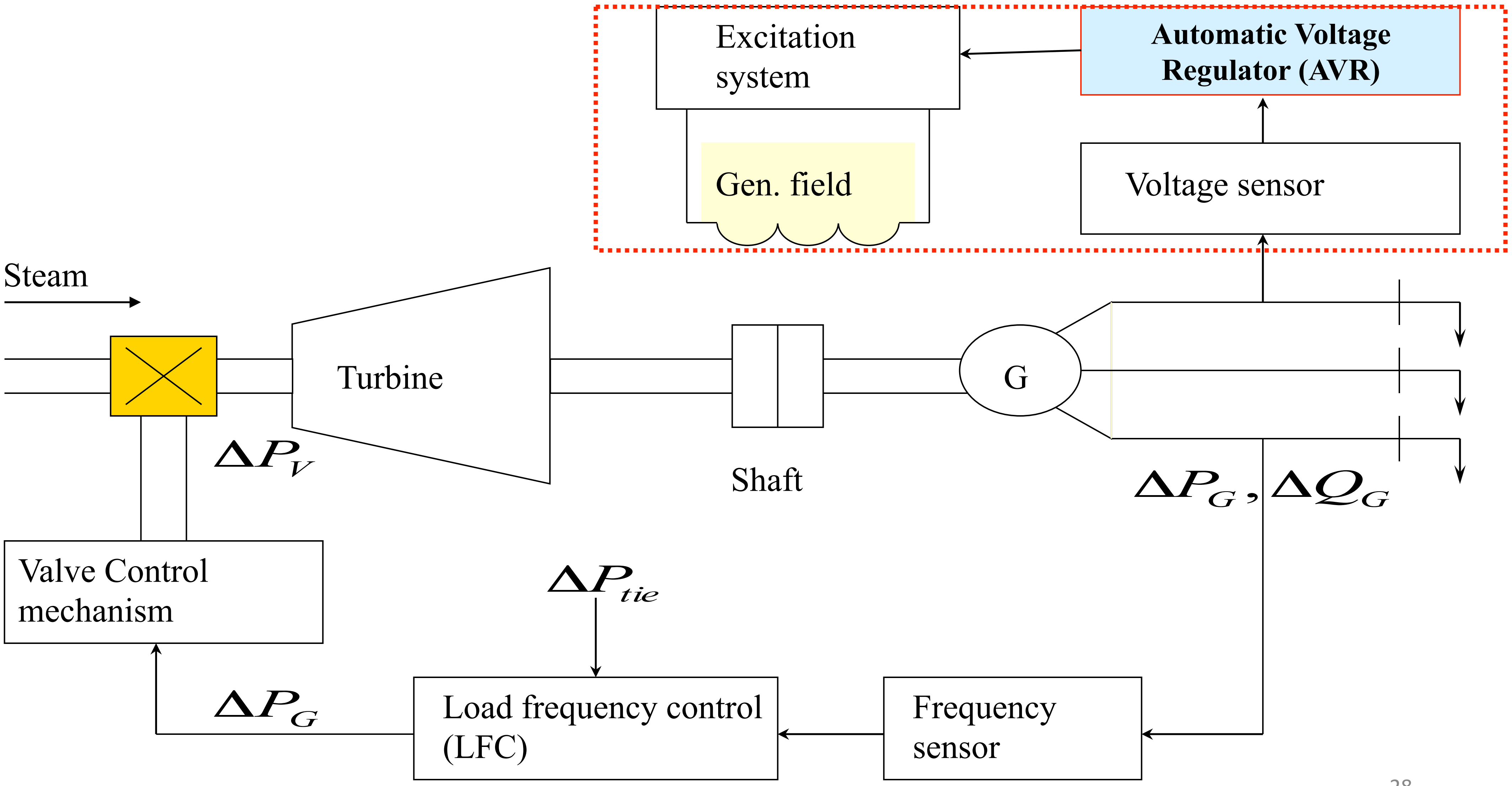
Generator Control System



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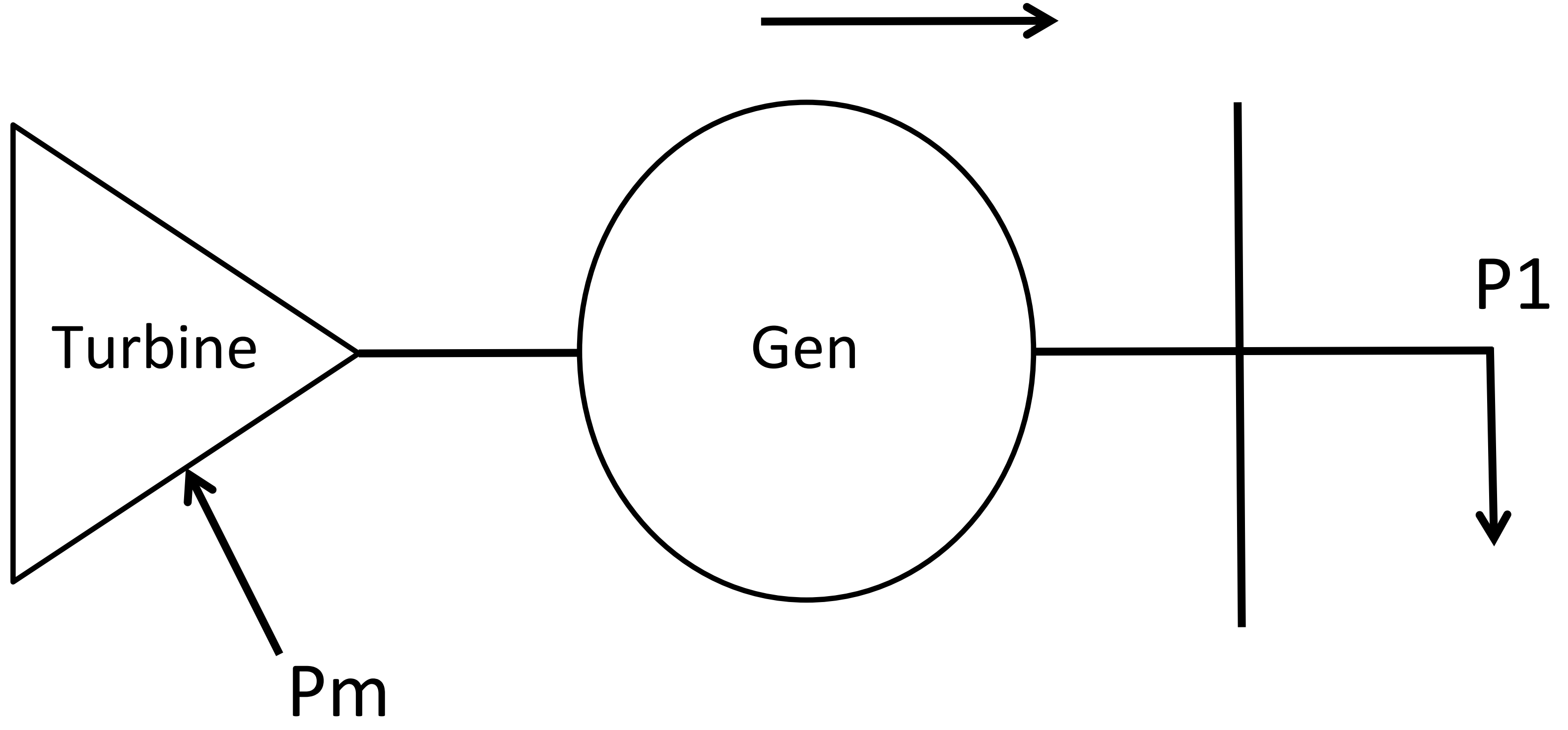
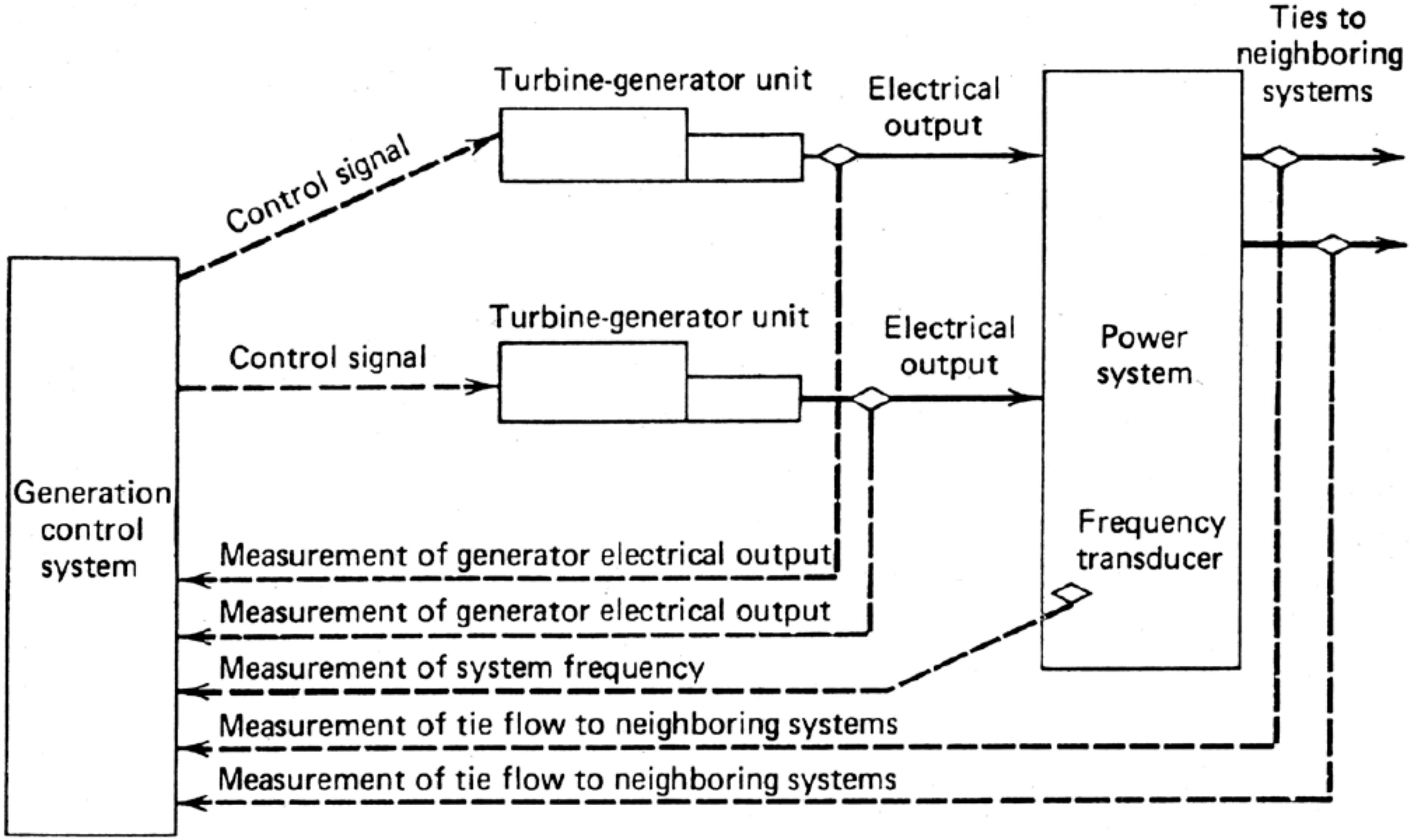
Turbine: Generator Control



Generator Control System



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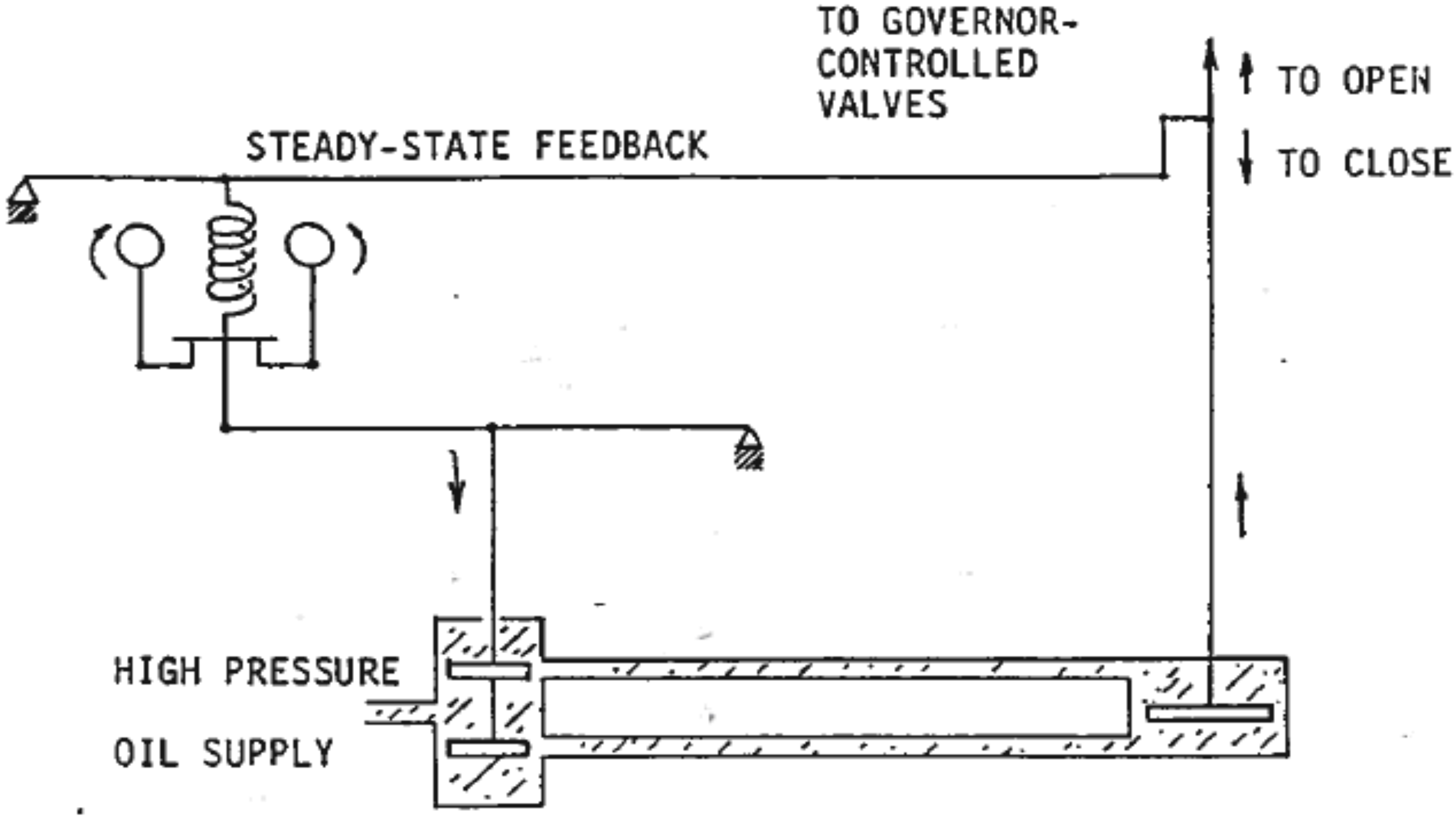
Speed Governor With Output Feedback



Mathematical Modelling

$$I\alpha = T_{\text{net}} \qquad M = \omega I \qquad P_{\text{net}} = \omega T_{\text{net}} = \omega(I\alpha) = M\alpha$$

ω = rotational speed (rad/sec)

α = rotational acceleration

δ = phase angle of a rotating machine

T_{net} = net accelerating torque in a machine

T_{mech} = mechanical torque exerted on the machine by the turbine

T_{elec} = electrical torque exerted on the machine by the generator

P_{net} = net accelerating power

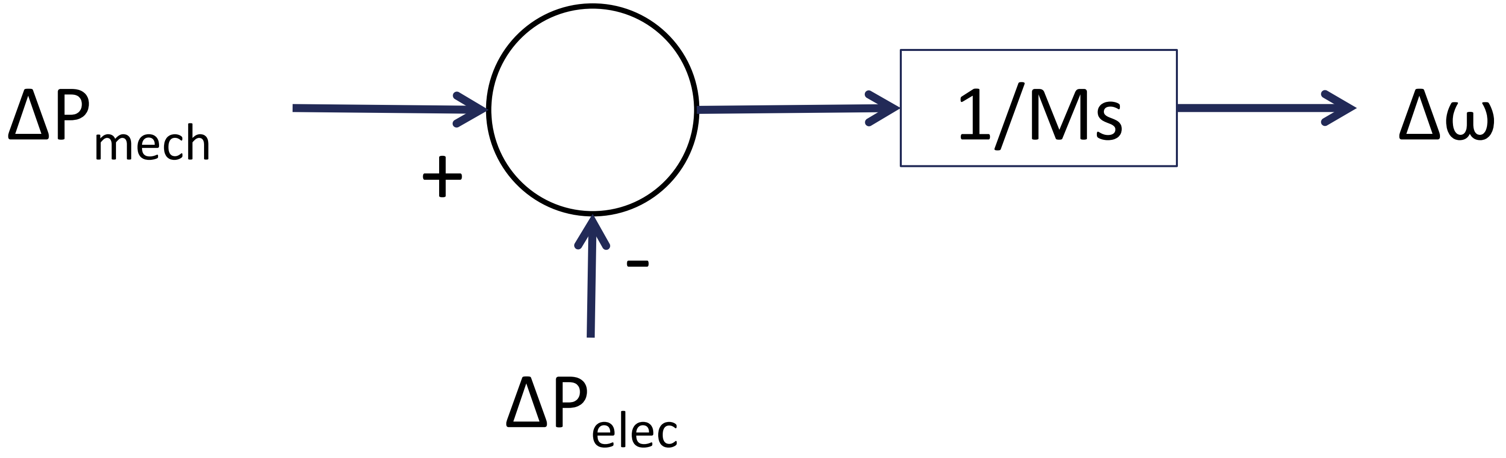
P_{mech} = mechanical power input

P_{elec} = electrical power output

I = moment of inertia for the machine

M = angular momentum of the machine

Mathematical Modelling of Generator Control



$$\Delta P_{mech} - \Delta P_{elec} = \omega_0 I \frac{d}{dt}(\Delta \omega) = M \frac{d}{dt}(\Delta \omega)$$

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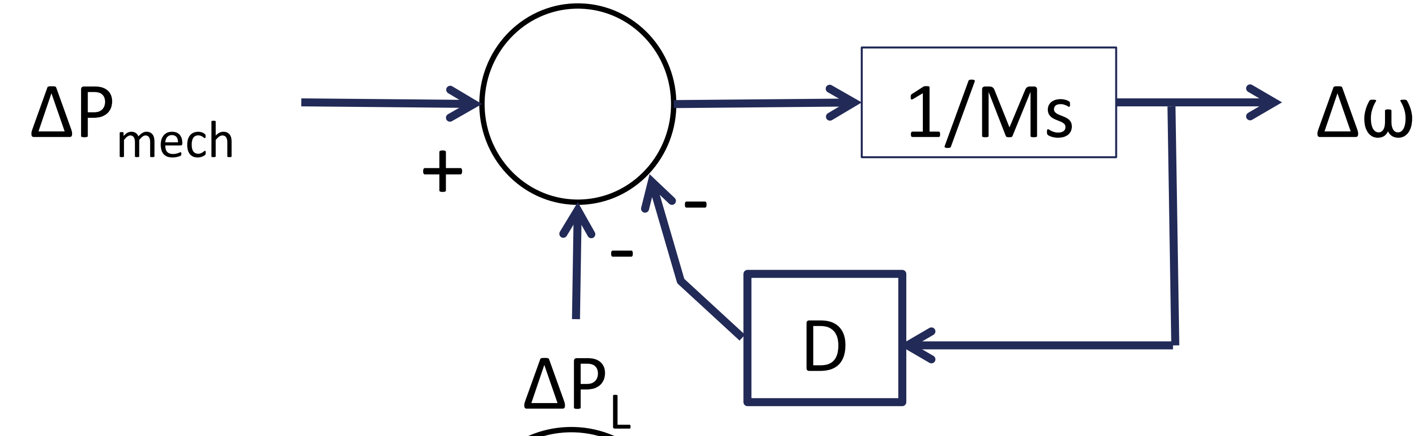
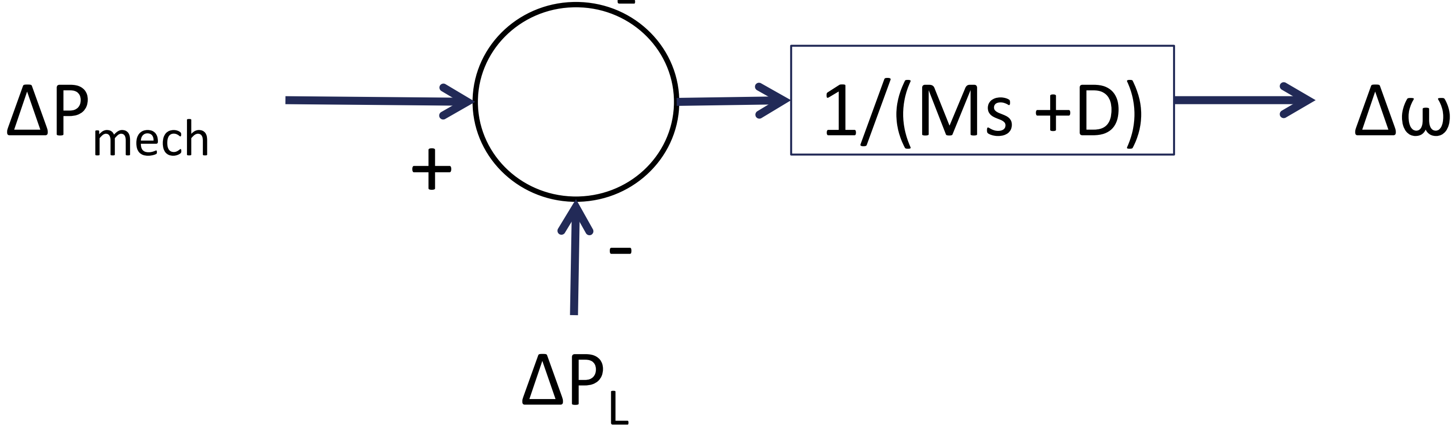
Load Model

$$\Delta P_{\text{elec}} = \underbrace{\Delta P_L}_{\substack{\text{Nonfrequency–sensitive} \\ \text{load change}}} + \underbrace{D\Delta\omega}_{\substack{\text{Frequency–sensitive} \\ \text{load change}}}$$





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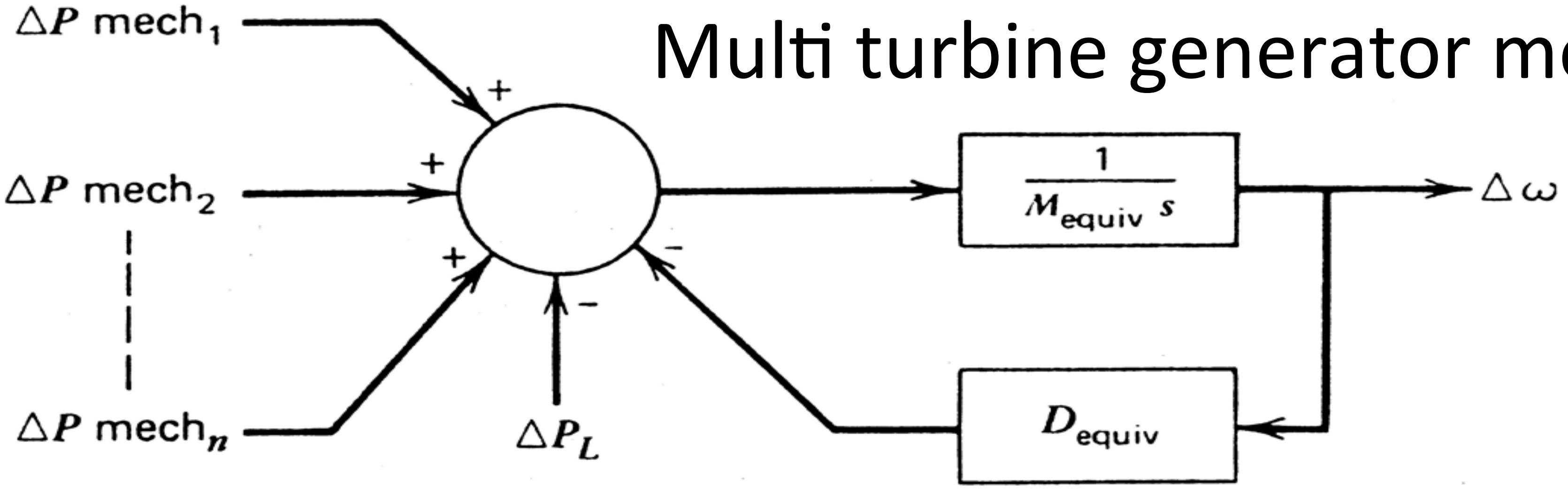
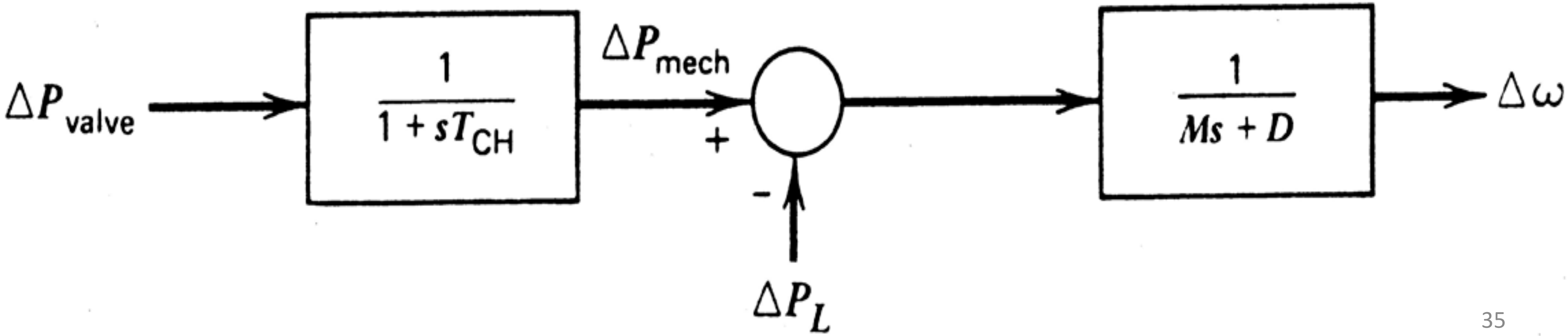
Generator models

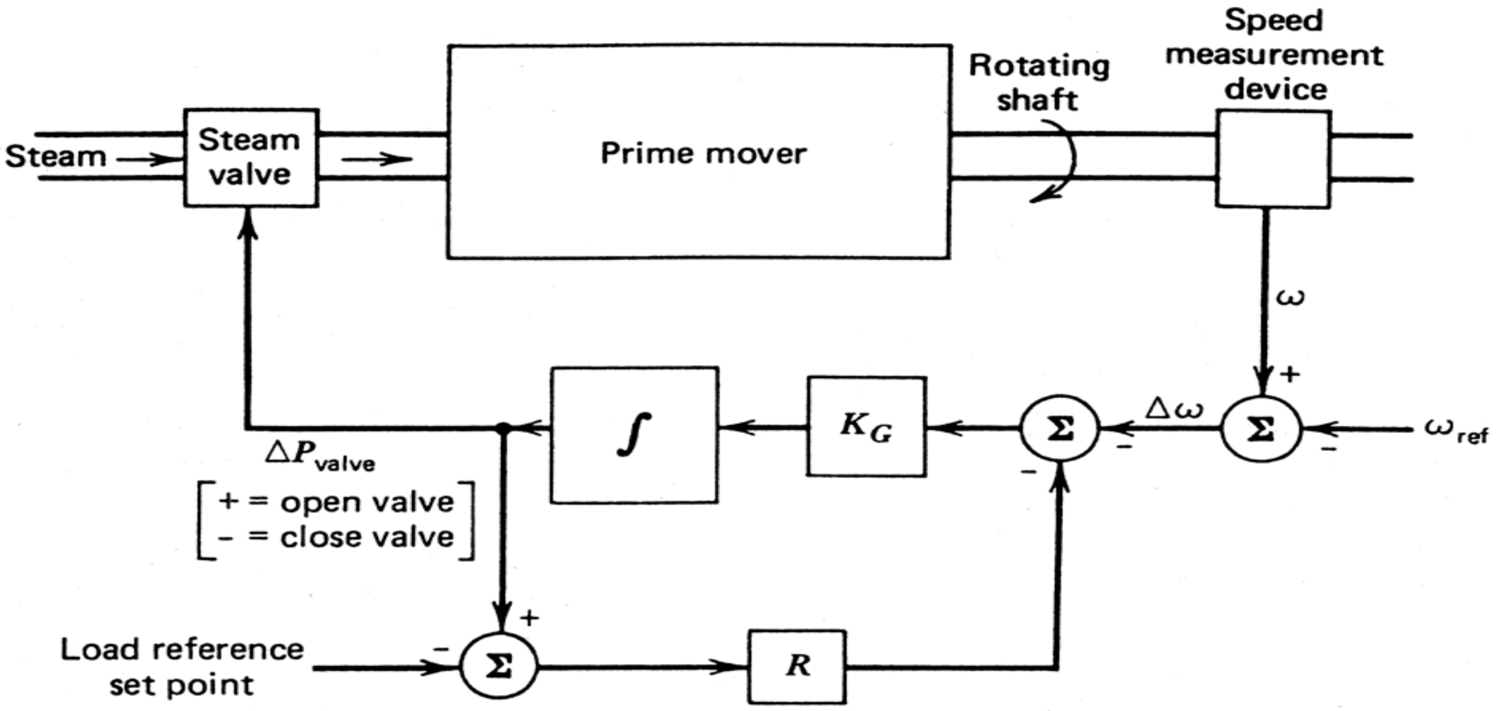
Multi turbine generator model

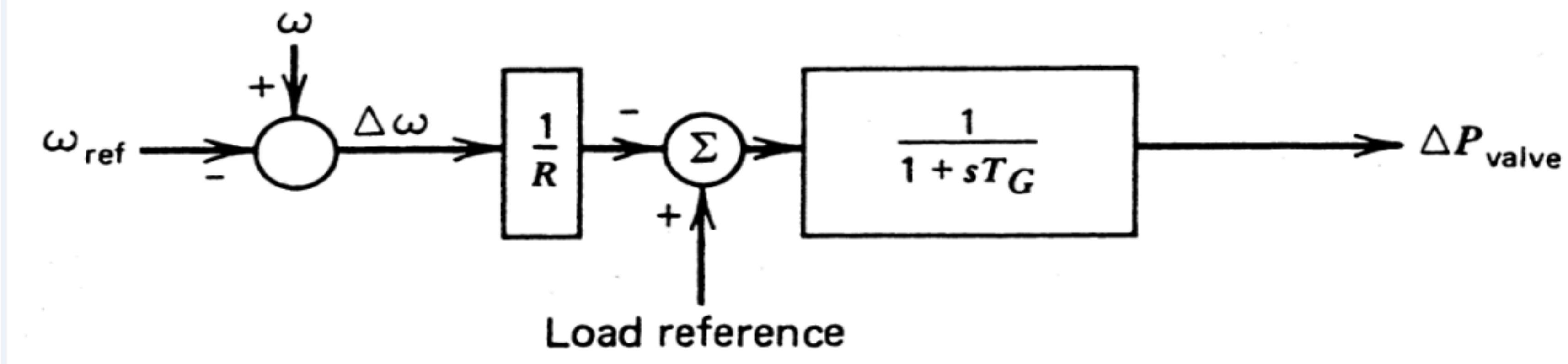


Prime mover model

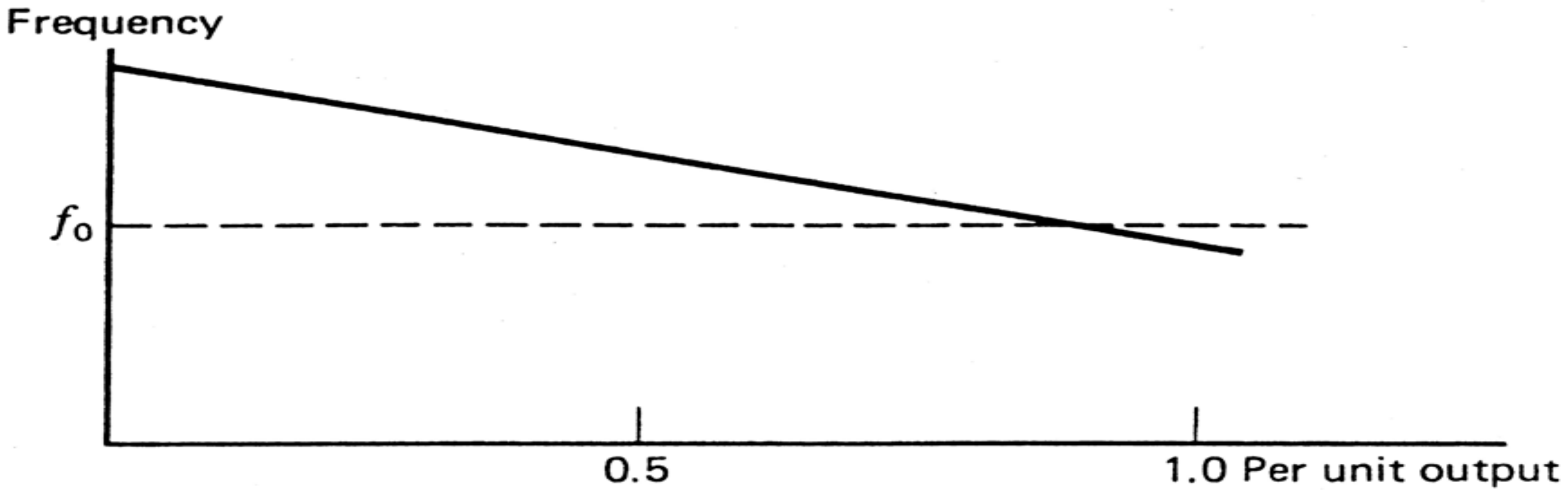


Generator Model with Speed Droop

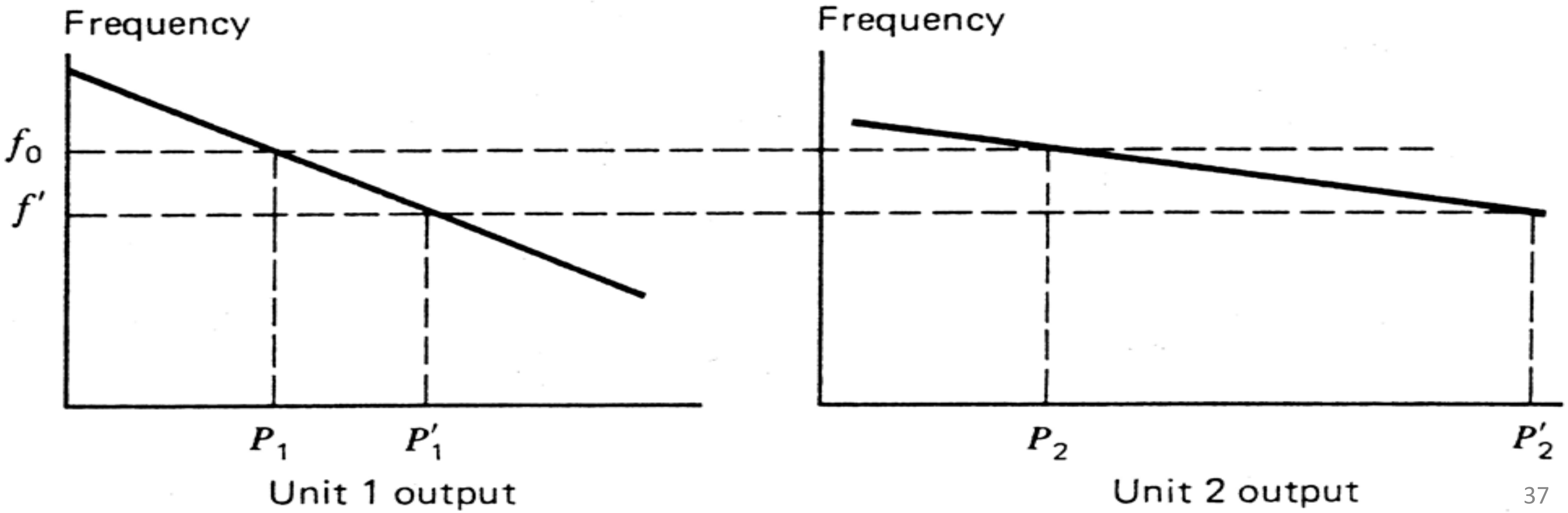




Speed Droop

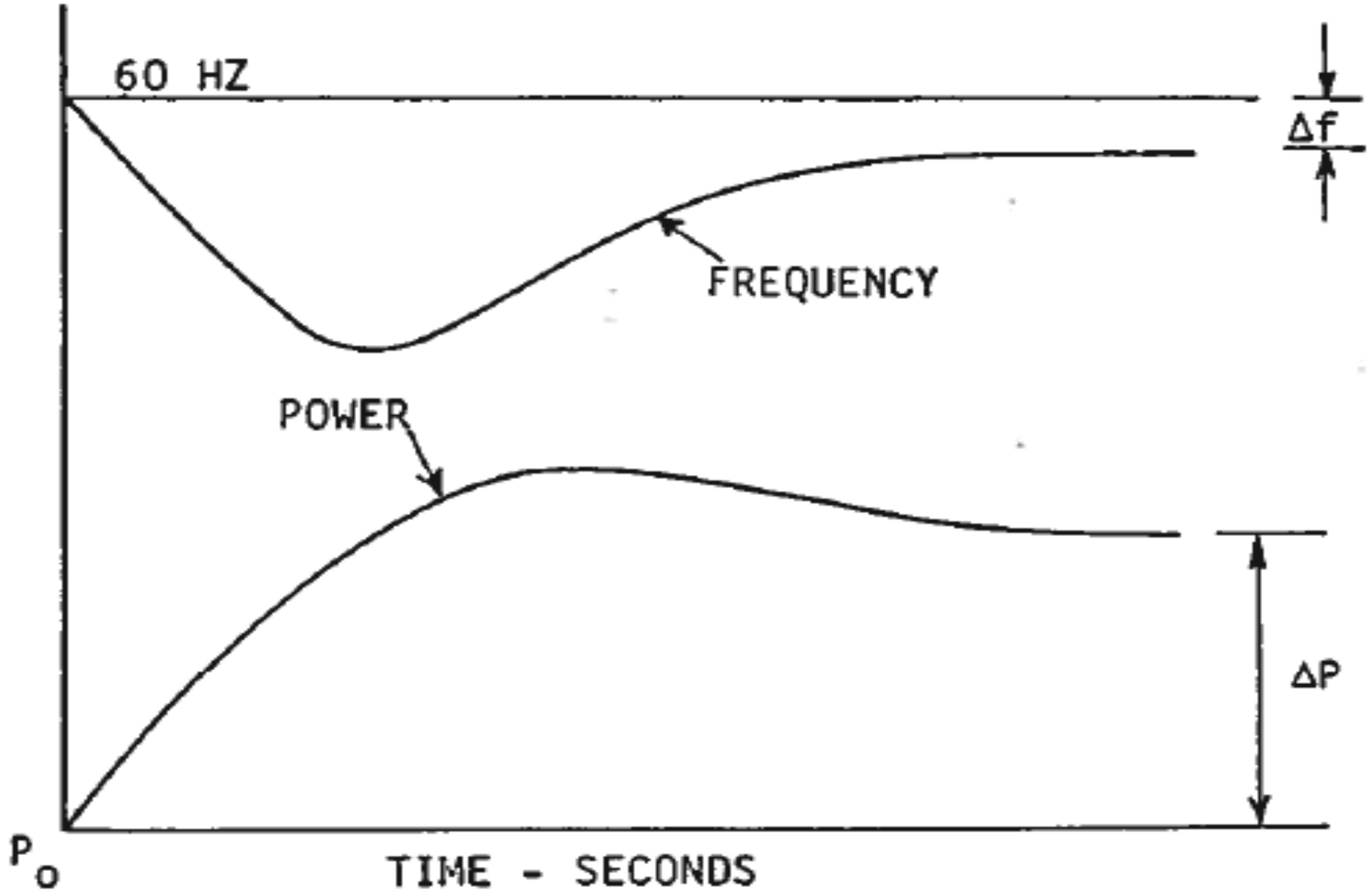


Frequency
f_0
0.5
1.0 Per unit output

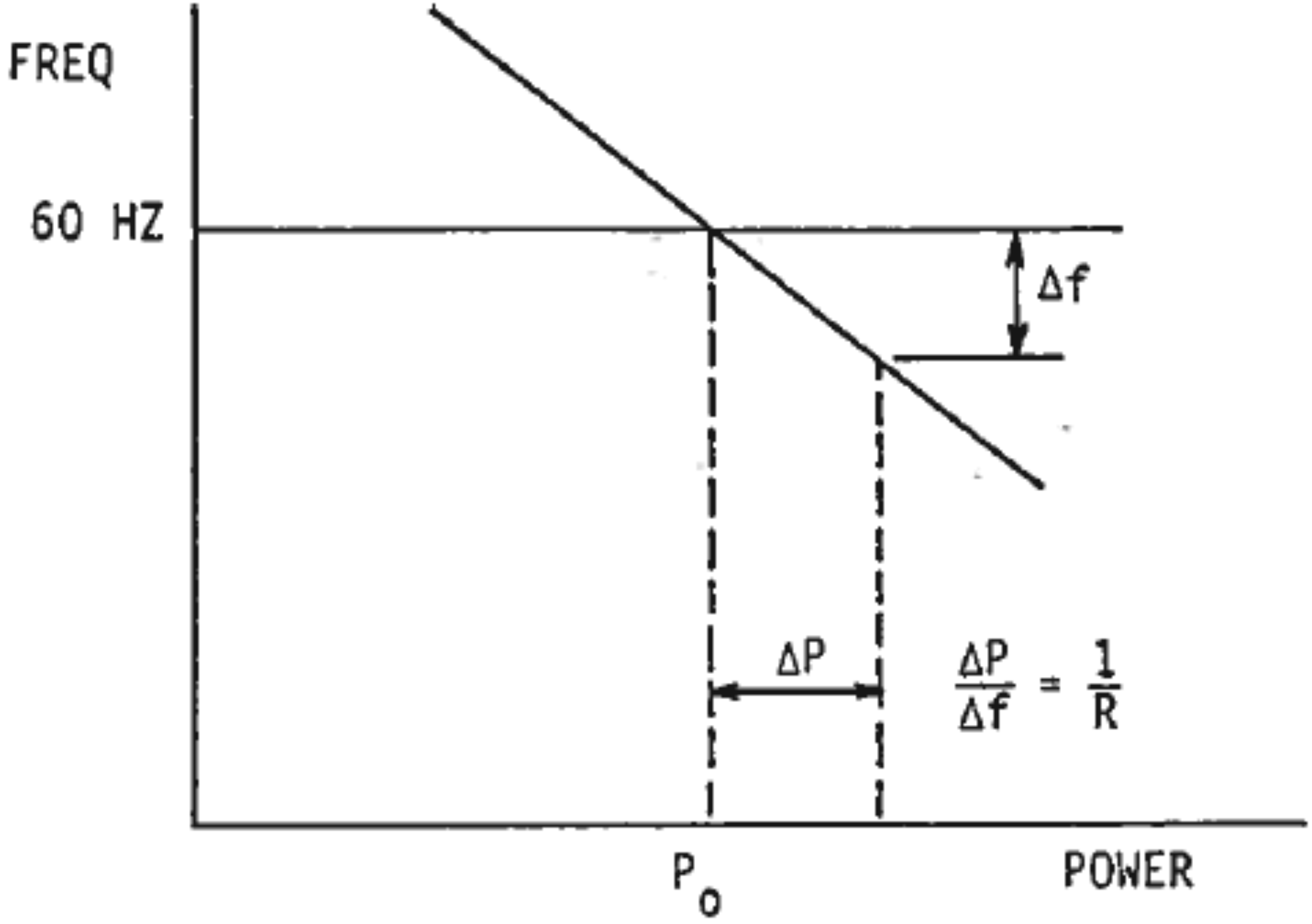


Frequency
f_0
f'
P_1
P'_1
Unit 1 output
Frequency
P_2
P'_2
Unit 2 output

Governor Response with Output Feedback



Droop Characteristics



Calculation of Steady-State Speed Characteristic

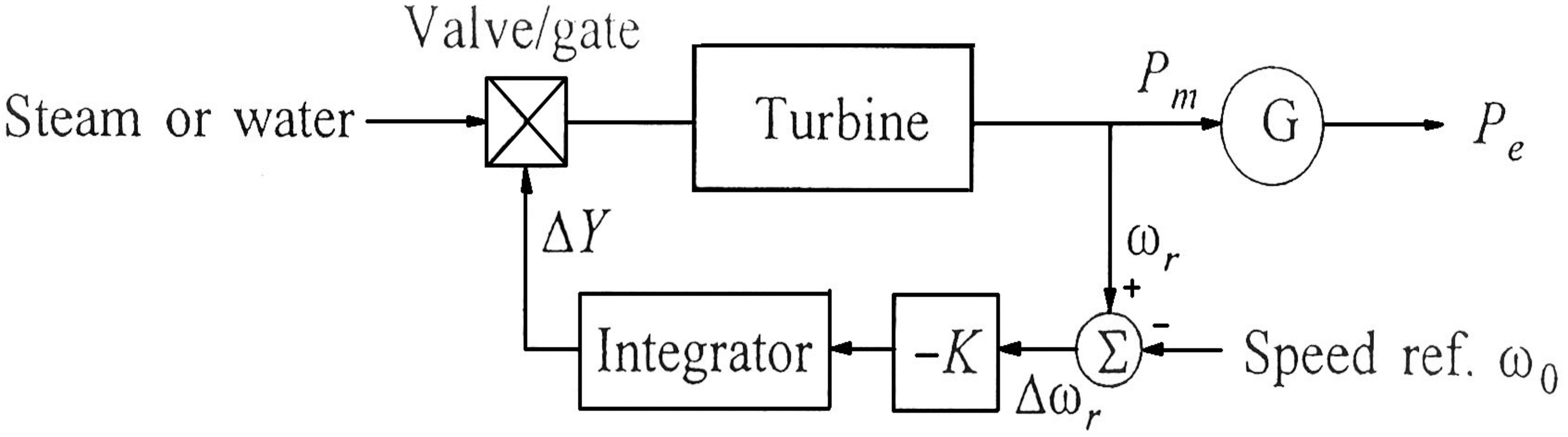
R(per unit), the slope of the "droop" curve, is defined as Δf(p.u.)/ ΔP(p.u.), where Δf(p.u.)= Δf(HZ) / 60.0, and ΔP(p.u.)= ΔP(MW) / Unit Capacity.

For a 600 MW unit that has a governor response of 20 MW for a frequency excursion that settles out at 59.9 HZ, R=Δf(p.u.) / ΔP(p.u.) = (0.1/60)/(20/600) =0.05 or 5% droop.

Once the droop is known, the MW response to frequency deviation can be determined by (ΔP/Δf)=(1/R), or ΔP=(1/R) X Δf.

For the 600 MW unit with 5% droop, (ΔP/600)=(1/0.05) X (Δf/60), or ΔP=200MW/HZ

Schematic of an Isochronous Governor



ω_r = rotor speed; Y = valve/gate position ; P_m = mechanical power

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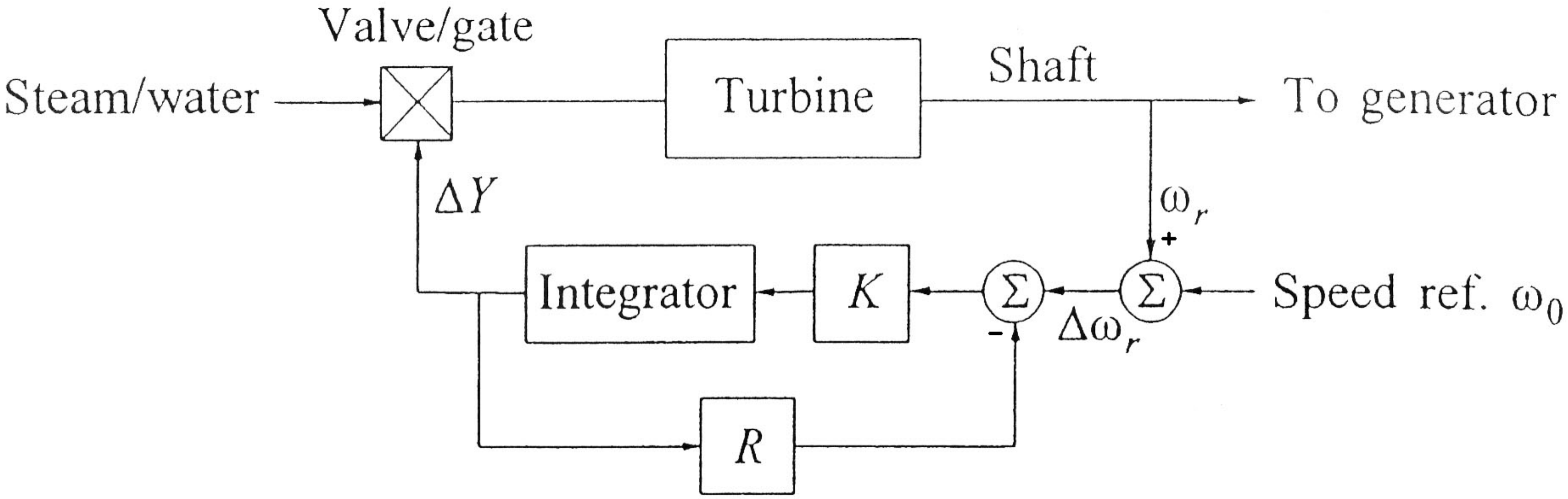
Governor with Steady State Feedback



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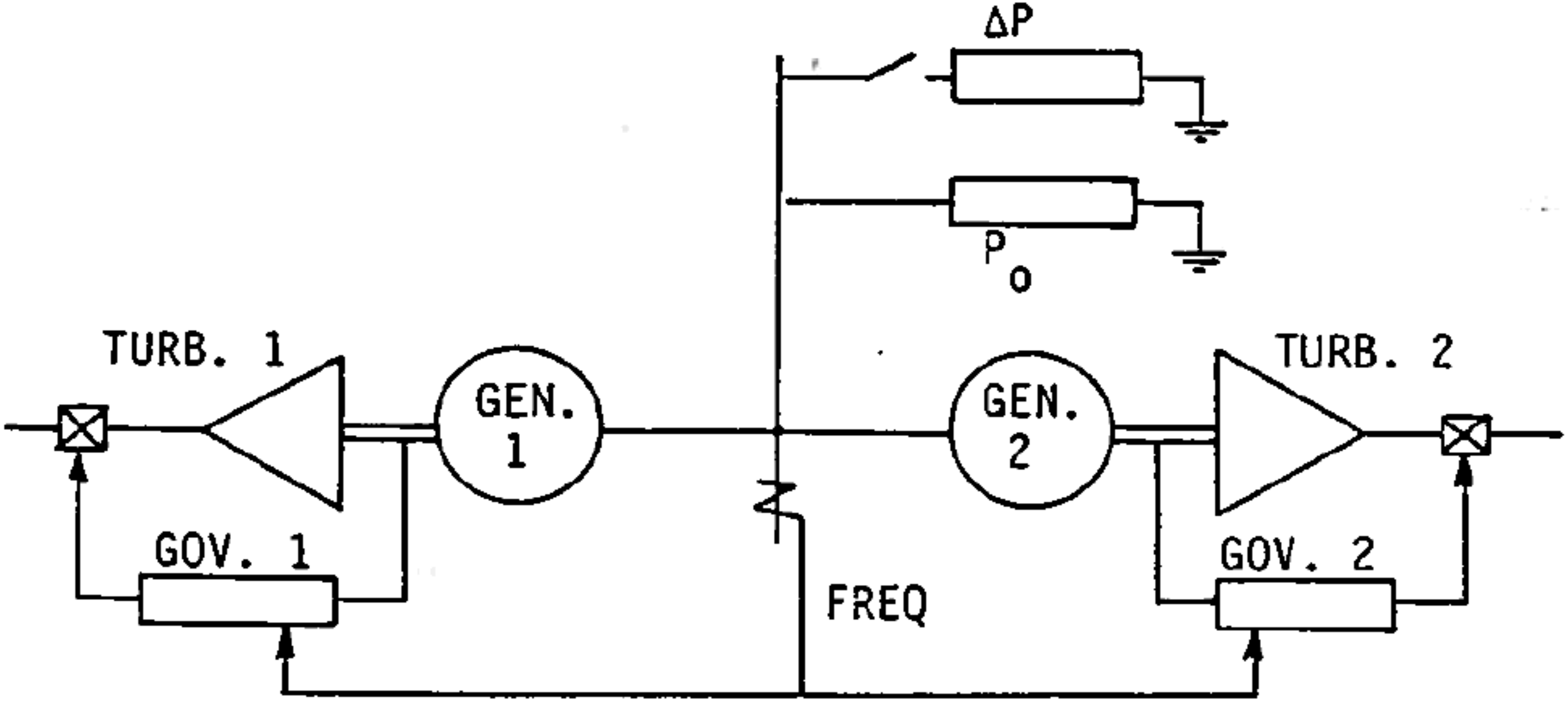
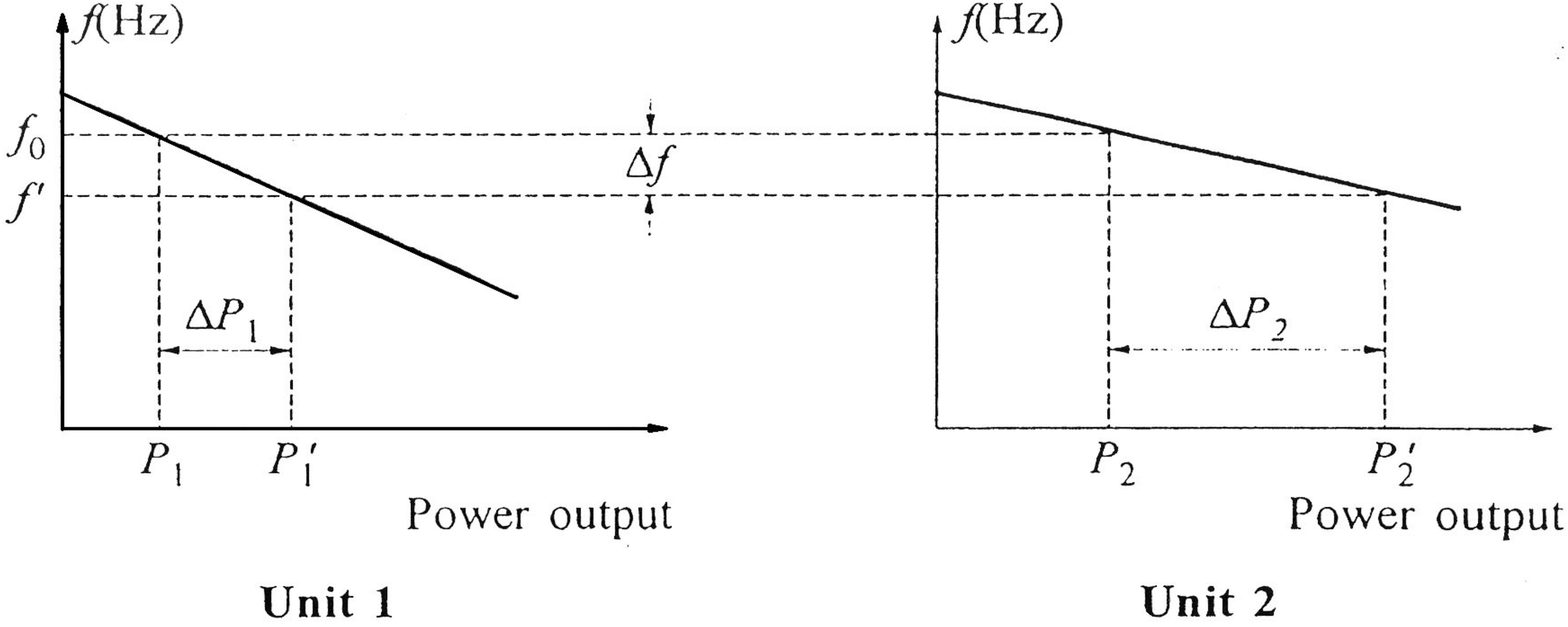
Two Generators equipped with Governors having Output Feedback

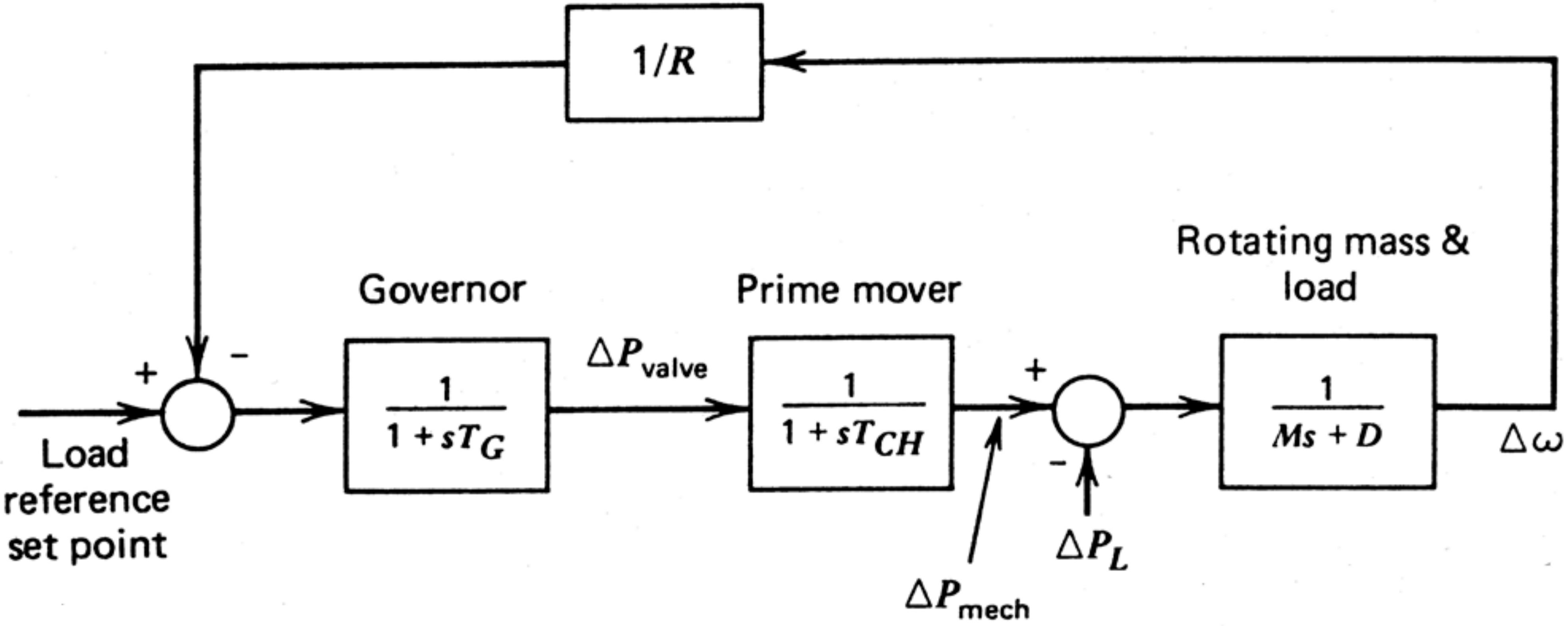


Load Sharing by Parallel Units with Drooping Governor Characteristics



$$\Delta P_1 = P_1' - P_1 = \frac{\Delta f}{R_1} \quad \Delta P_2 = P_2' - P_2 = \frac{\Delta f}{R_2} \quad \frac{\Delta P_1}{\Delta P_2} = \frac{R_2}{R_1}$$

Model of Generation, Governor, Prime Mover, and Rotating Inertia



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

Tie Line Model

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

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

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

Tie flow modeled using linear power flow model

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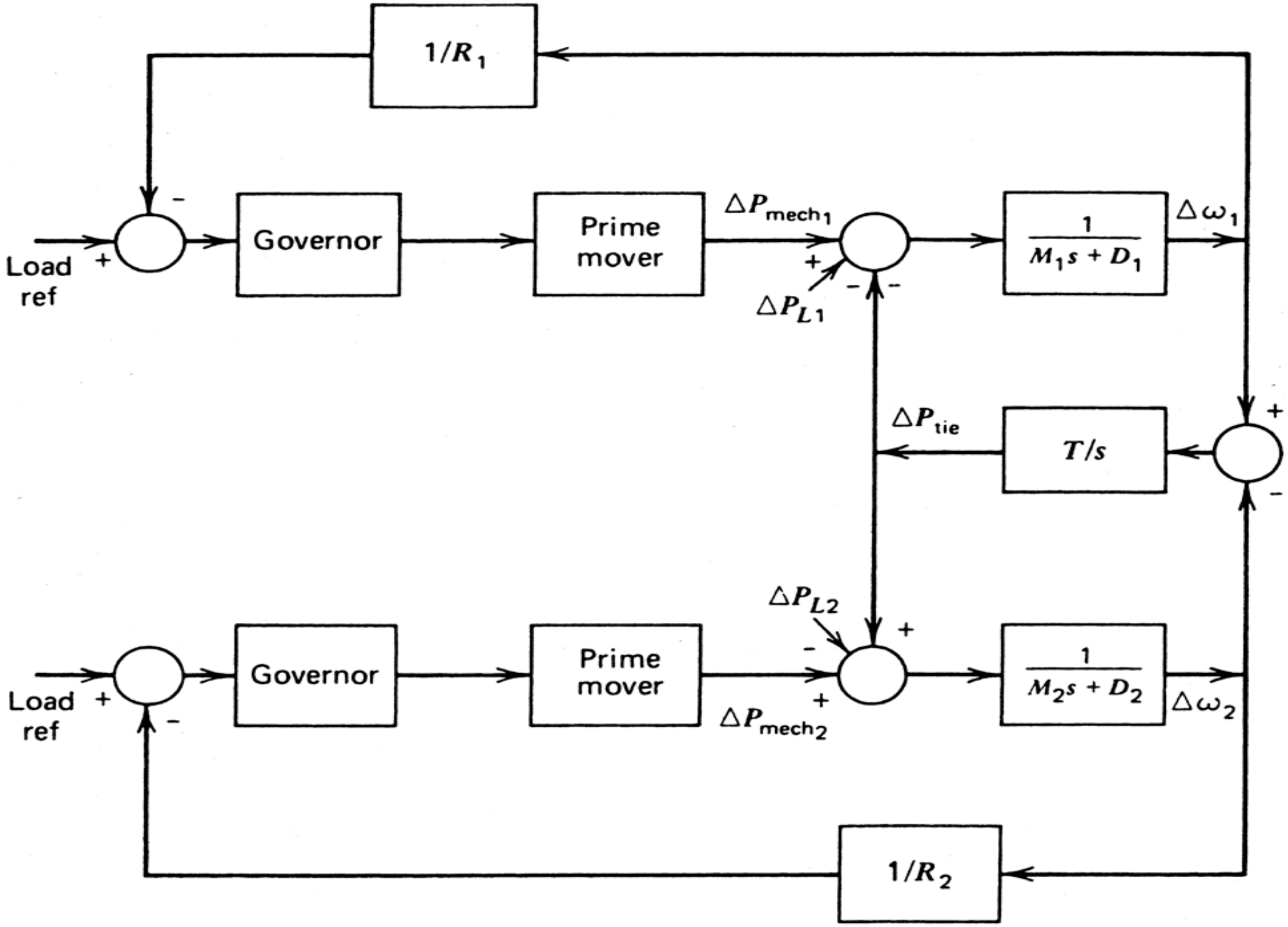
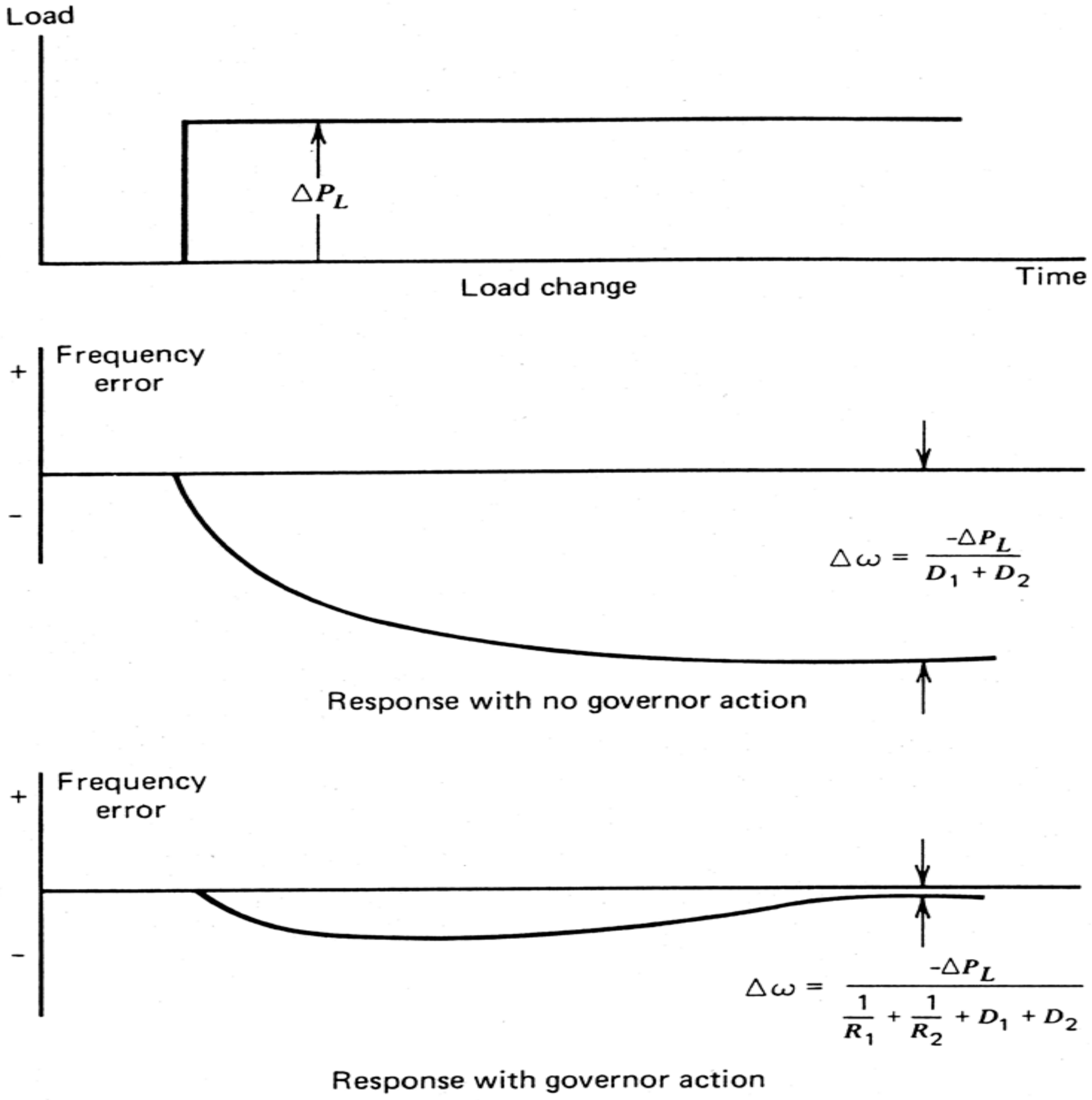
Model of Interconnected Control Areas



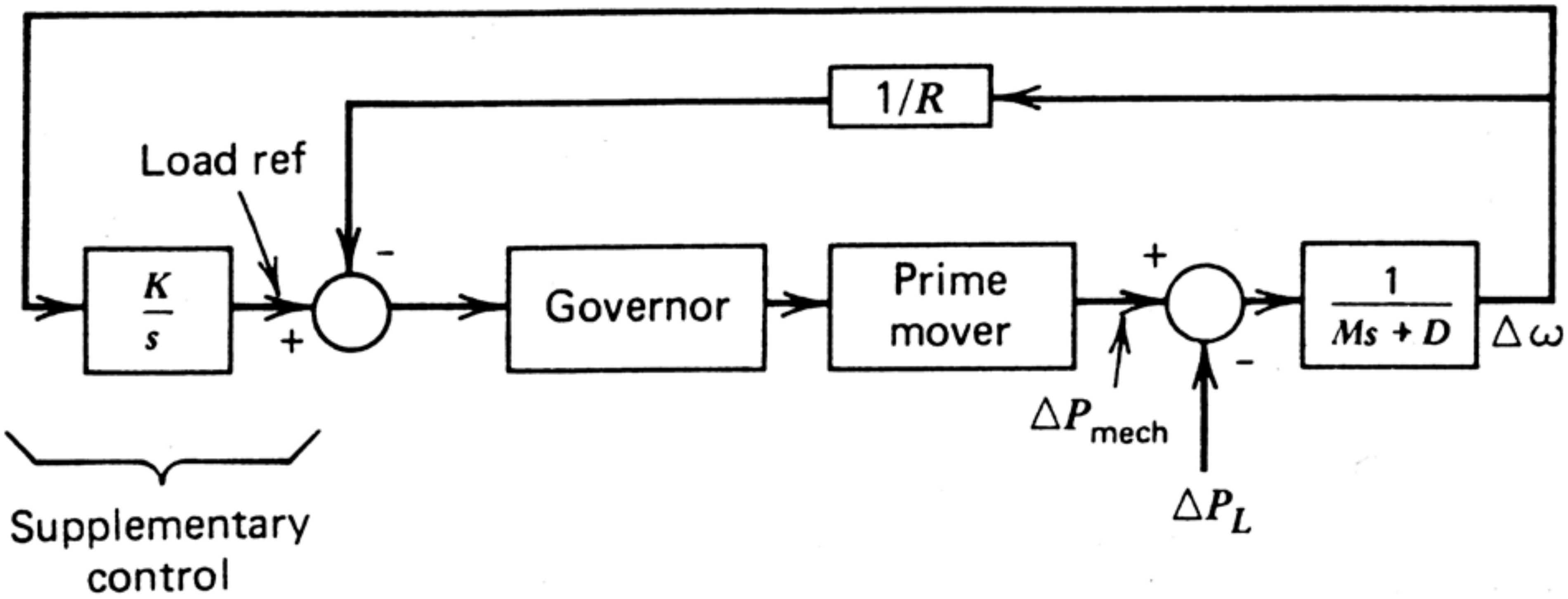
Frequency Response to Load Change



Supplementary Control

- With primary speed control, the only way a change in generation can occur is for a frequency deviation to exist
- Restoration of frequency to rated value requires manipulation of the speed/load reference (speed changer motor)
- Achieved through supplementary control
- Supplementary control acts more slowly than primary control

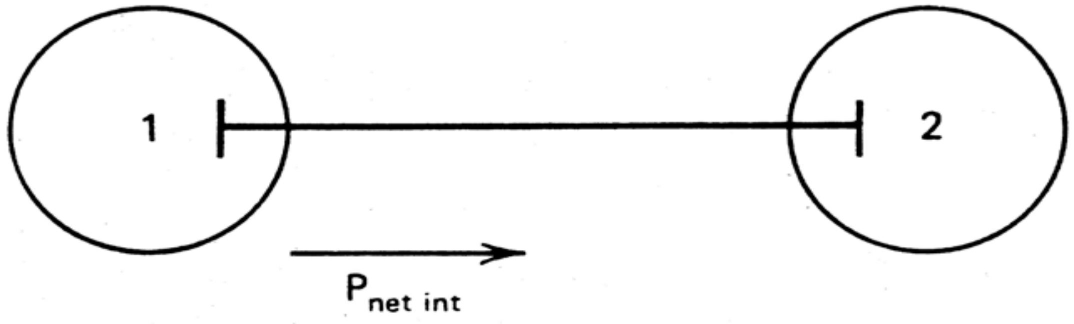
Supplementary Control



Supplementary control is necessary to drive frequency back to nominal 60 Hz (USA)

Rules of Tie Line Control

$\Delta\omega$	$\Delta P_{\text{net int}}$	Load change		Resulting control action
$-$	$-$	ΔP_{L_1}	$+$	Increase P_{gen} in system 1
		ΔP_{L_2}	0	
$+$	$+$	ΔP_{L_1}	$-$	Decrease P_{gen} in system 1
		ΔP_{L_2}	0	
$-$	$+$	ΔP_{L_1}	0	Increase P_{gen} in system 2
		ΔP_{L_2}	$+$	
$+$	$-$	ΔP_{L_1}	0	Decrease P_{gen} in system 2
		ΔP_{L_2}	$-$	

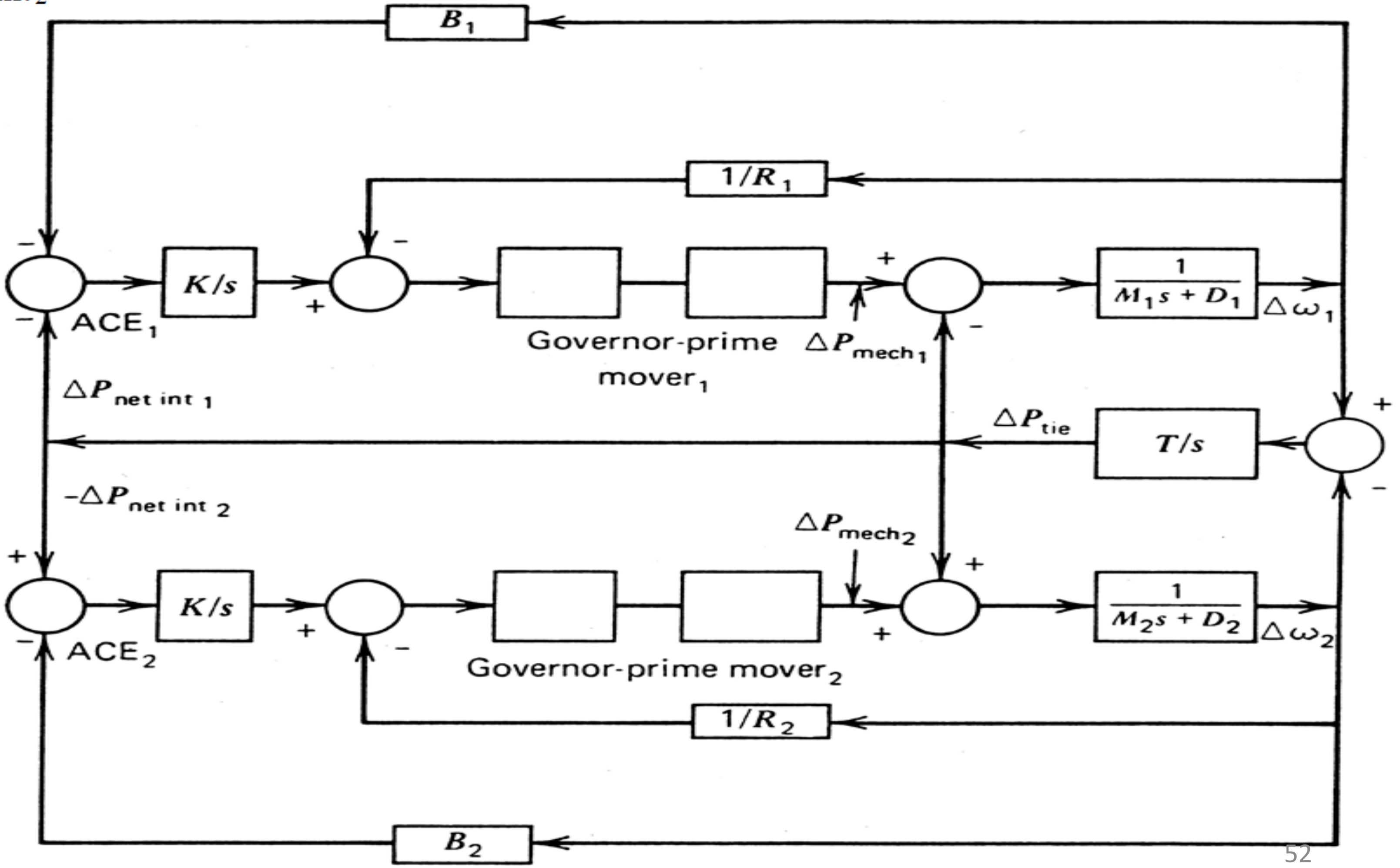


ΔP_{L_1} = Load change in area 1

ΔP_{L_2} = Load change in area 2

Area Control Error

$$\mathrm{ACE}_1 = -\Delta P_{\mathrm{netint}_1} - B_1 \Delta\omega$$
$$\mathrm{ACE}_2 = -\Delta P_{\mathrm{netint}_2} - B_2 \Delta\omega$$



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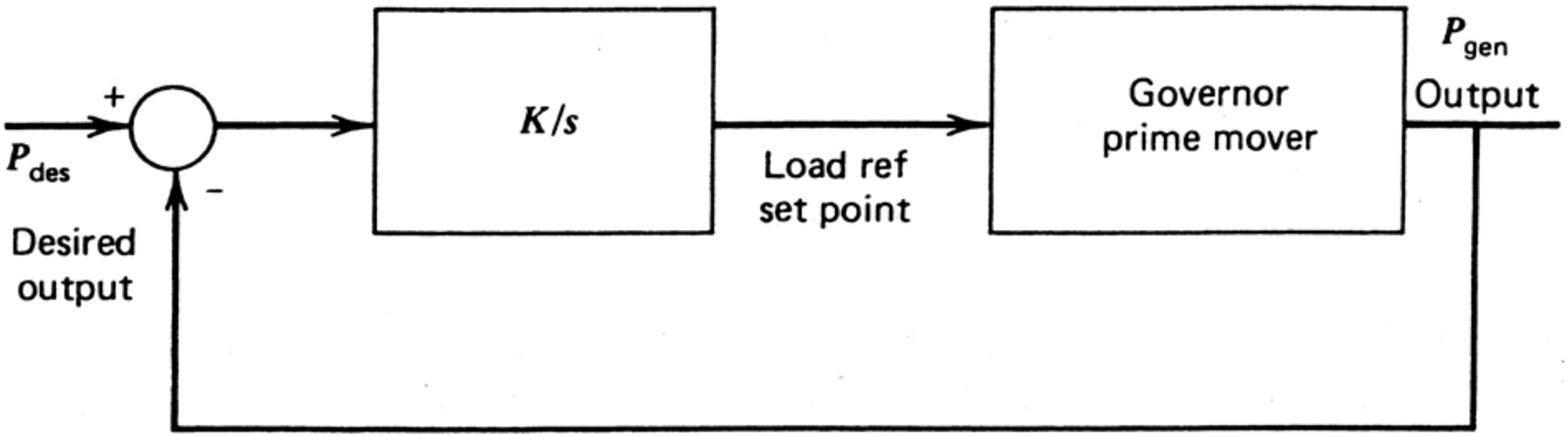
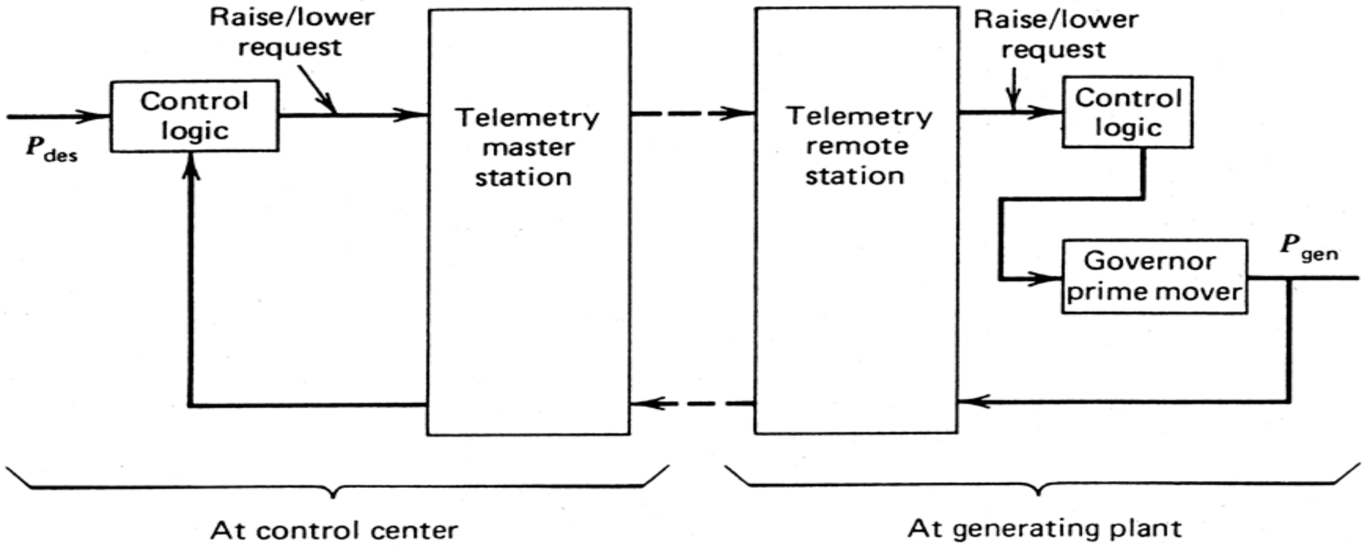
Generation Allocation using Participation Factors

$$P_{i_{\text{des}}} = P_{i_{\text{base}}} + pf_i \times \Delta P_{\text{total}}$$

$$\Delta P_{\text{total}} = P_{\text{newtotal}} - \sum_{\substack{\text{all} \\ \text{gen}}} P_{i_{\text{base}}}$$

Generator Control Loop





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Automatic Generation Control

- Objectives
  - System frequency within desired limits
  - Area interchange power at scheduled levels
  - Correct time (integrated frequency)
- Accomplished by using a control signal for each area referred to as area control error (ACE):
  - Tie line flow deviation, plus
  - Frequency deviation weighted by a bias factor
- Bias factor, B, set nearly equal to regulation characteristic (1/R + D) of the area; gives good dynamic performance
- A secondary function of AGC is to allocate generation economically

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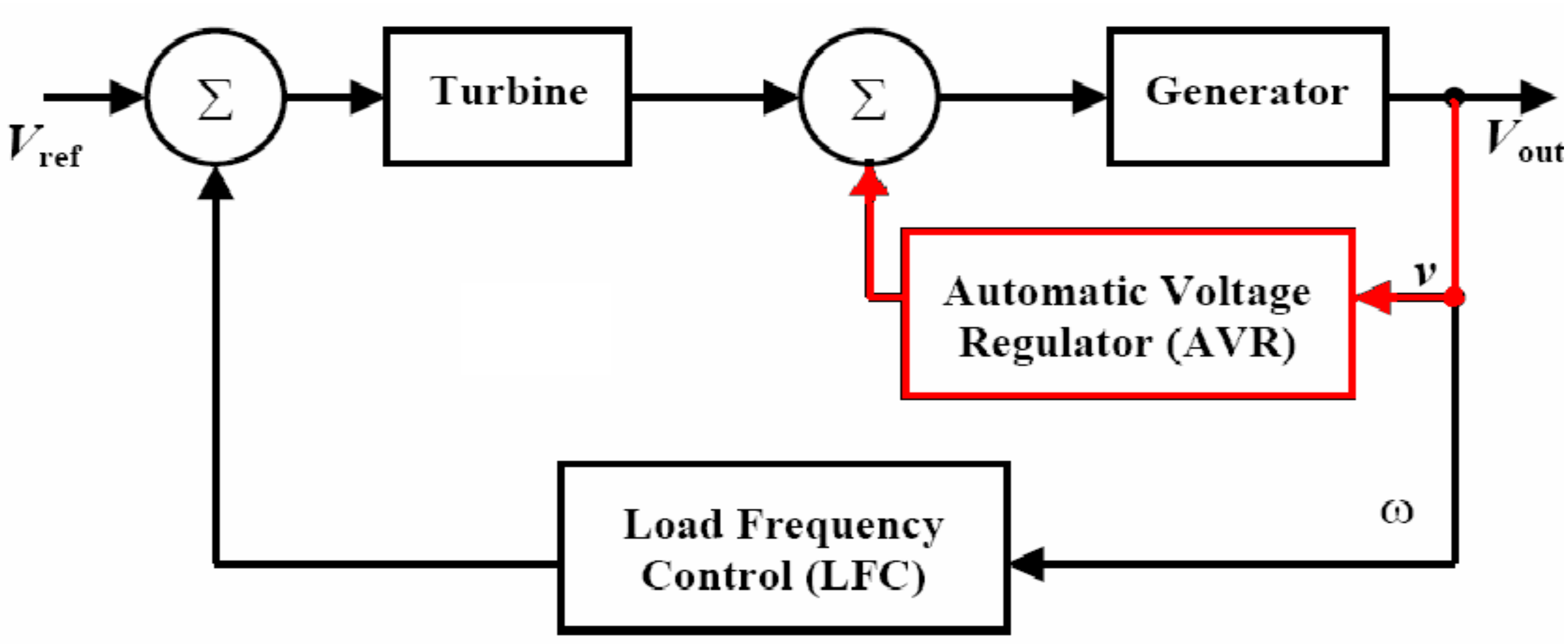
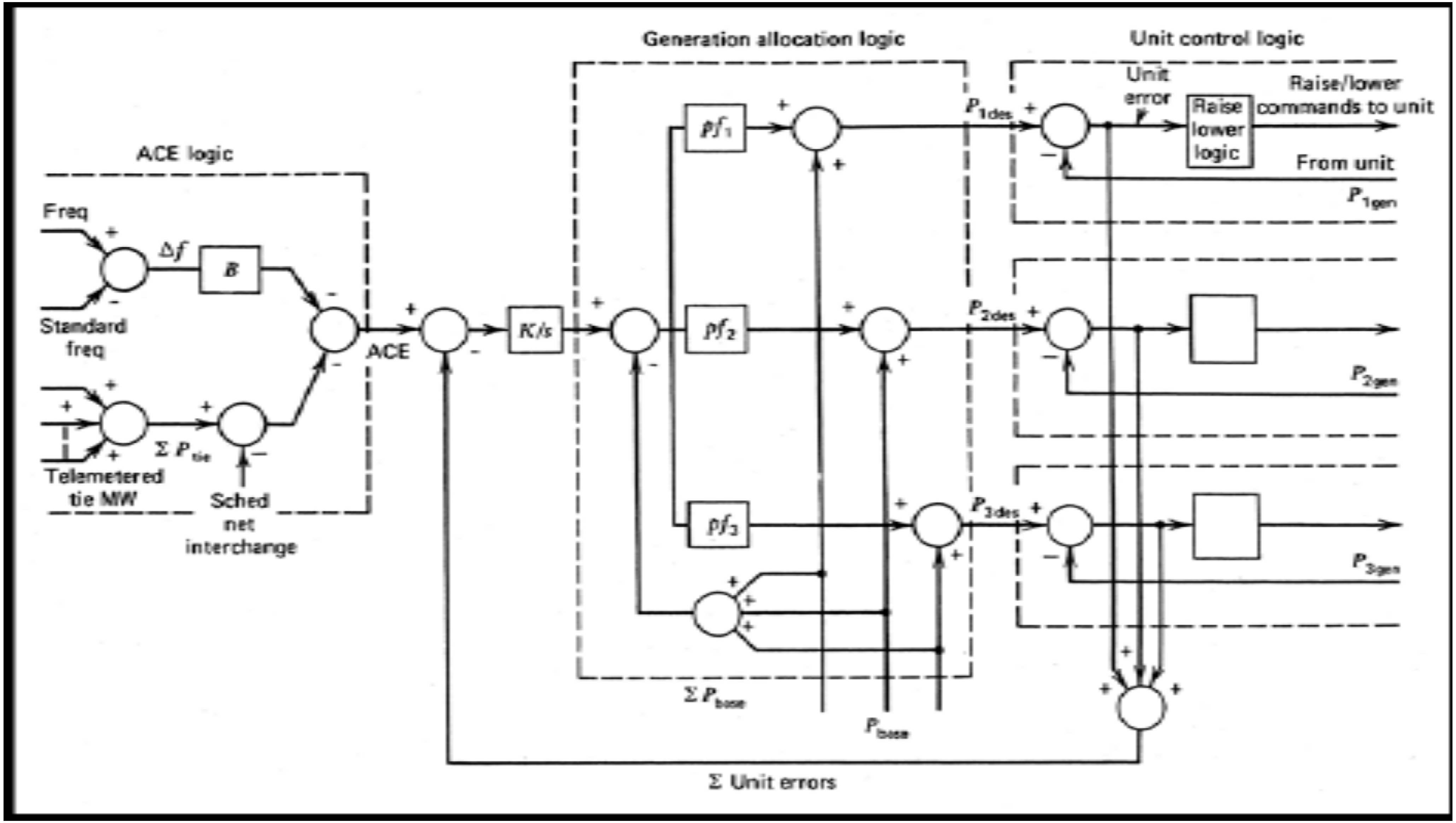
Block diagram of AGC model



AGC system


Generation allocation logic
Unit control logic
ACE logic
Freq
Standard freq
Telemetered tie MW
Sched net interchange
B
ACE
K/s
pf1
pf2
pf3
P1des
P2des
P3des
Unit error
Raise lower logic
Raise/lower commands to unit
From unit
P1gen
P2gen
P3gen
Σ Pbase
Pbase
Σ Unit errors

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AGC Features

Assist Action:

Move more units to speed up control of ACE

Filtering ACE:

Don’t try to follow random noise

Telemetry failure logic:

Don’t take wrong action when telemetry fails

Unit control detection:

Monitor generators to be sure they are responding to control inputs

Ramp control:

Control rate of unit ramping

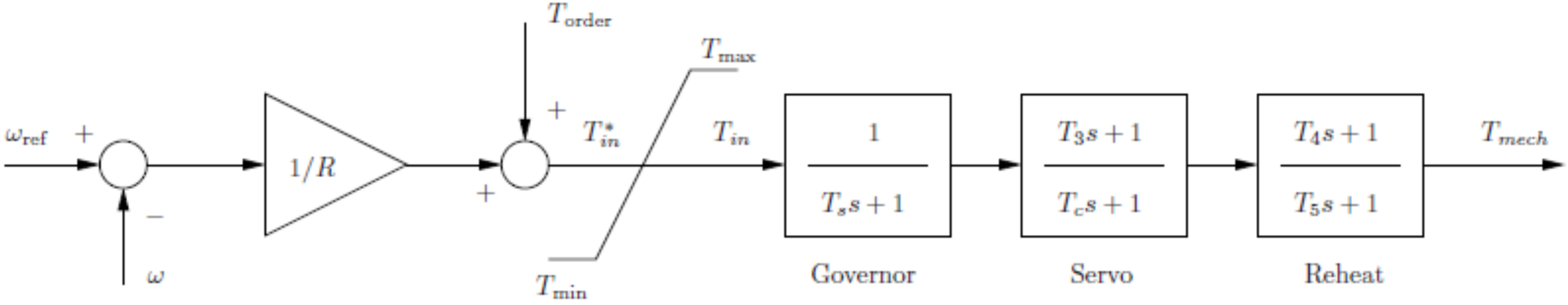
Rate Limiting:

Keep unit changes within rate limits

Unit Control Modes:

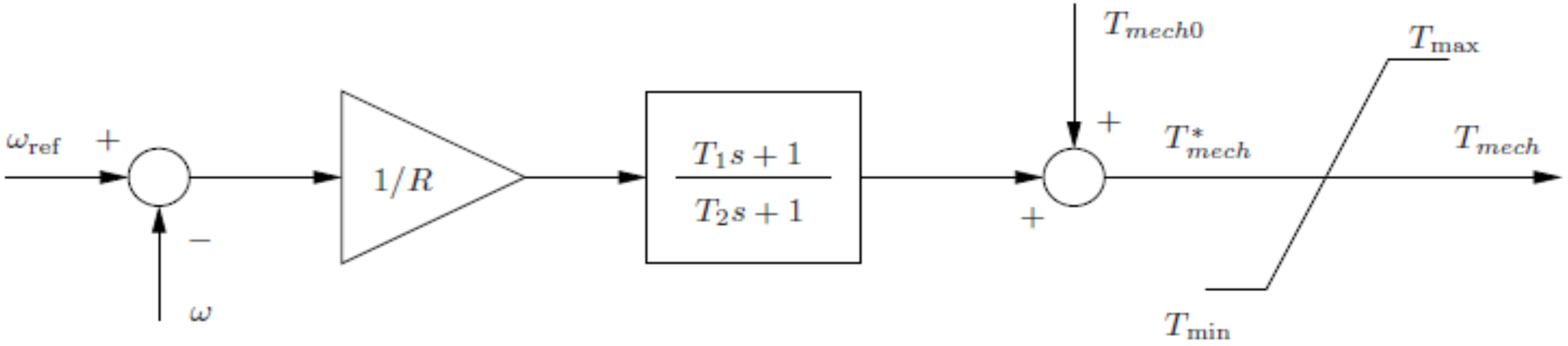
Examples are manual, base load, base load and regulating

Turbine Governor Type I.



Variable	Description
ω_{ref0}	Reference speed
R	Droop
$T_{\max}$	Maximum turbine output
$T_{\min}$	Minimum turbine output
T_s	Governor time constant
T_c	Servo time constant
T_3	Transient gain time constant
T_4	Power fraction time constant
T_5	Reheat time constant
u	Connection status

Turbine Governor Type II



Variable	Description
ω_{ref0}	Reference speed
R	Droop
$T_{\max}$	Maximum turbine output
$T_{\min}$	Minimum turbine output
T_2	Governor time constant
T_1	Transient gain time constant

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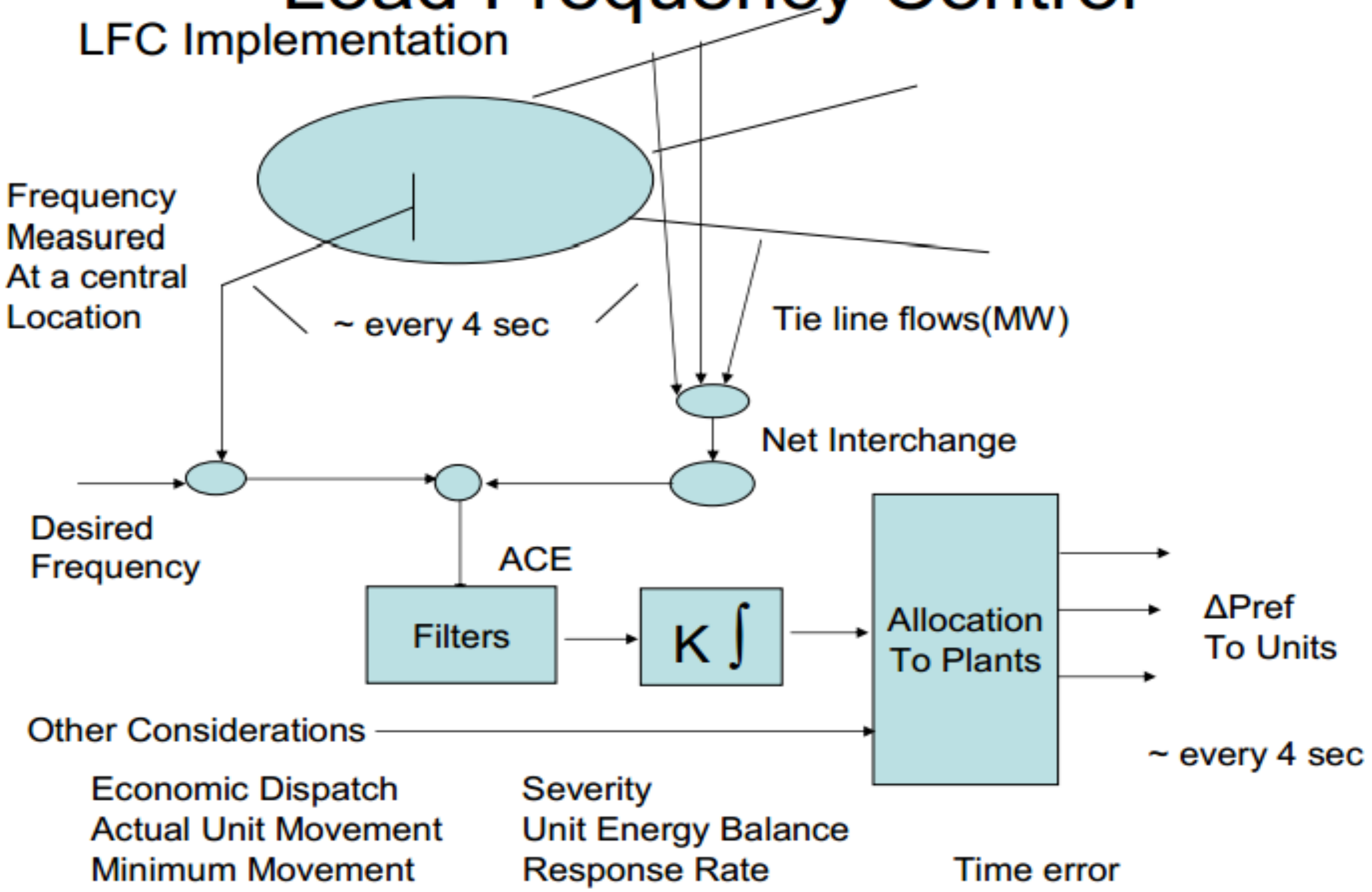
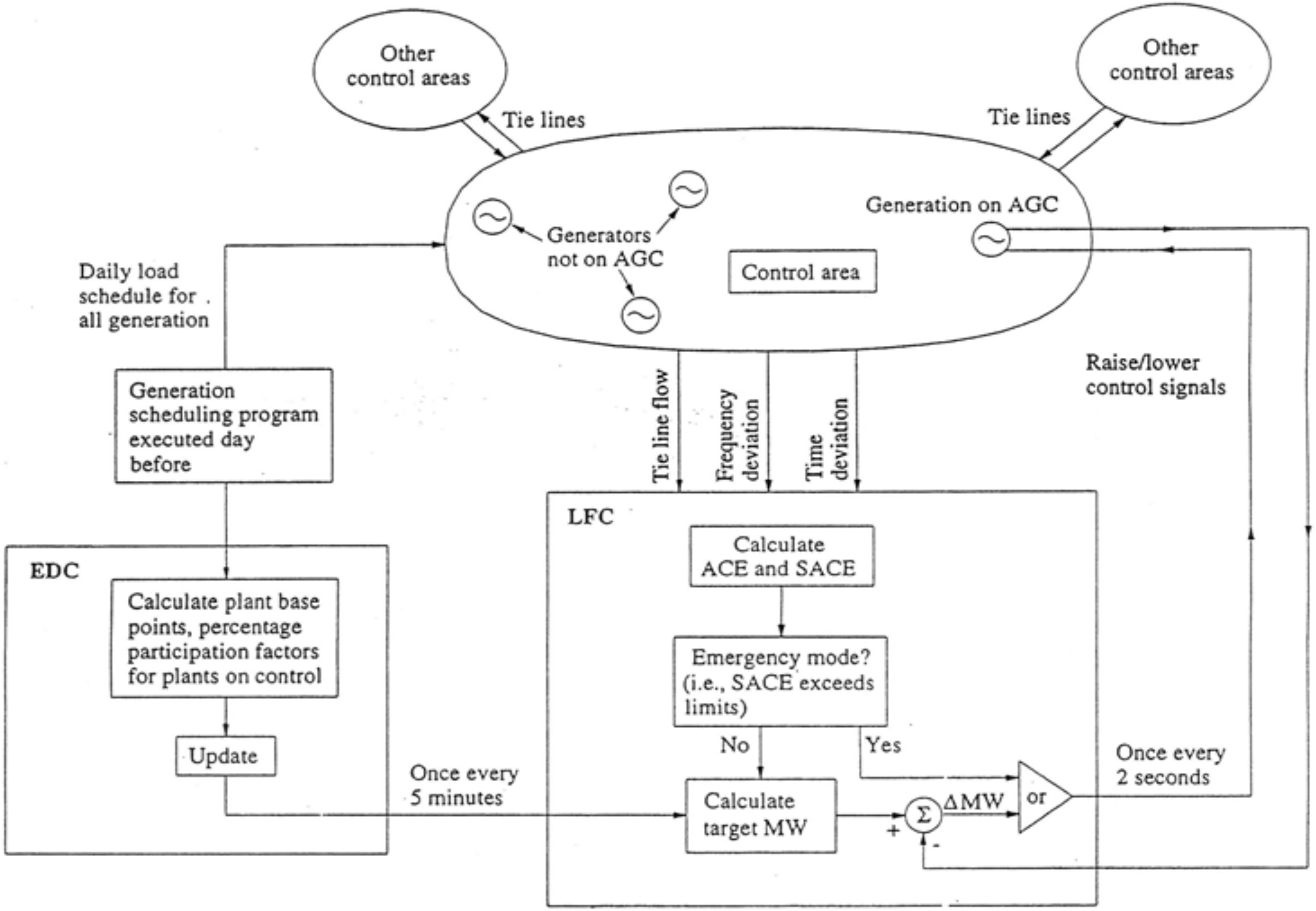
Load Frequency Control

LFC Implementation



Functional Diagram of a Typical AGC System



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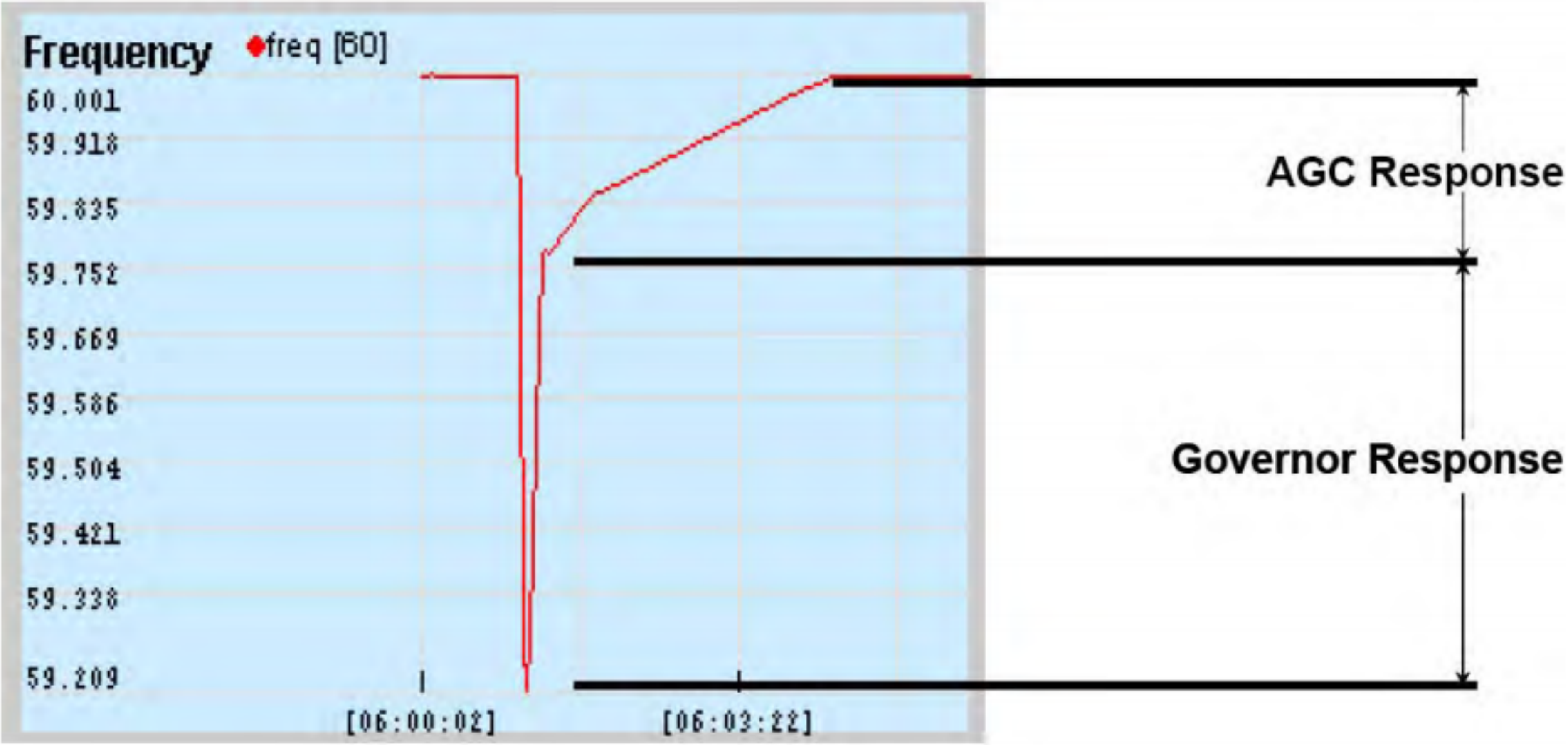
Frequency Response with AGC for Step Load Increase



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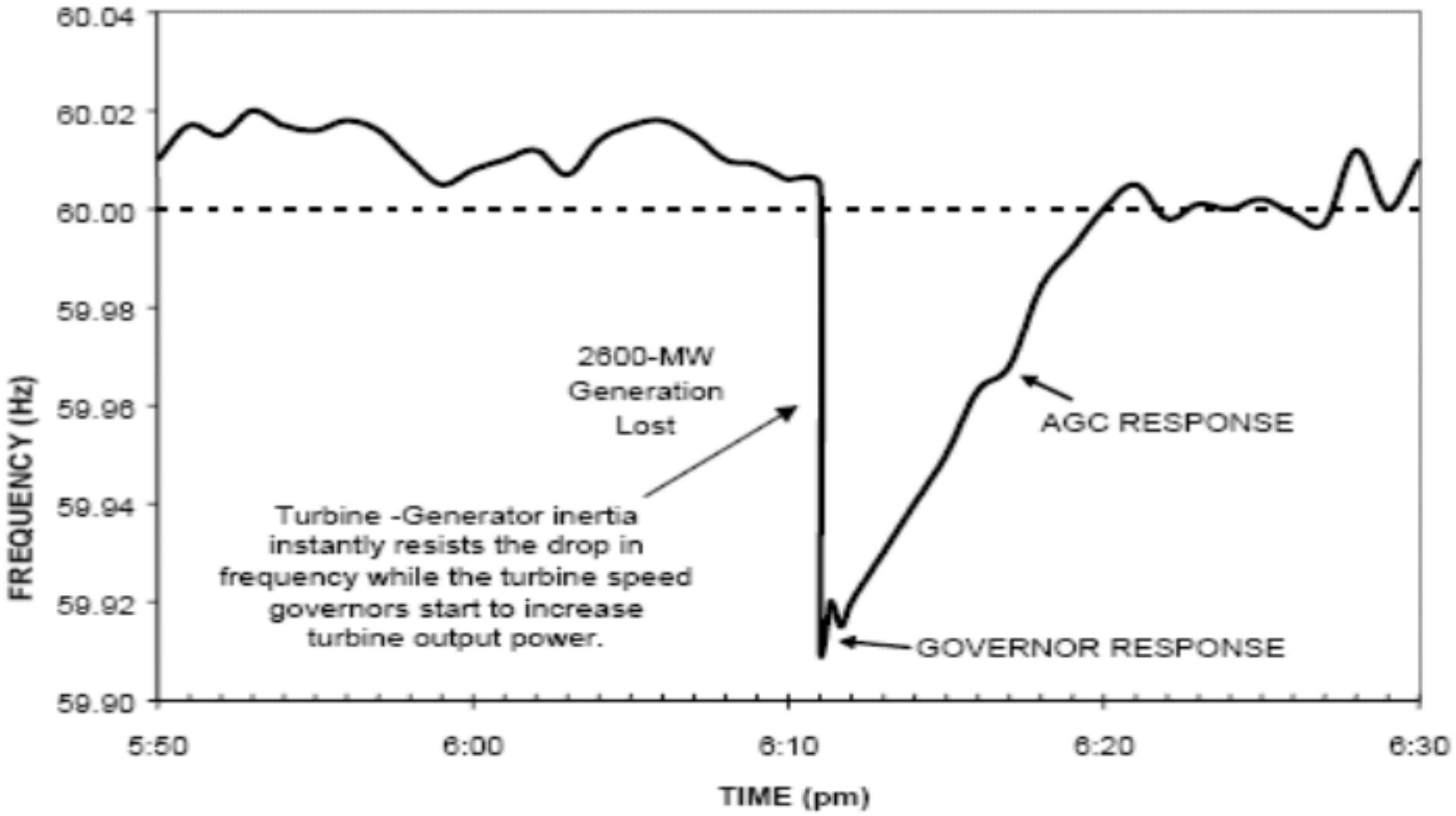
Frequency Response with AGC for Generation Loss



Case Study

Consider an isolated power system with three generators on-line and operating at 60HZ. The load is 360 MW and the generator outputs for units #1, #2 and #3 are 80MW, 120MW and 160MW, respectively. A load of 21MW (ΔP) is added.

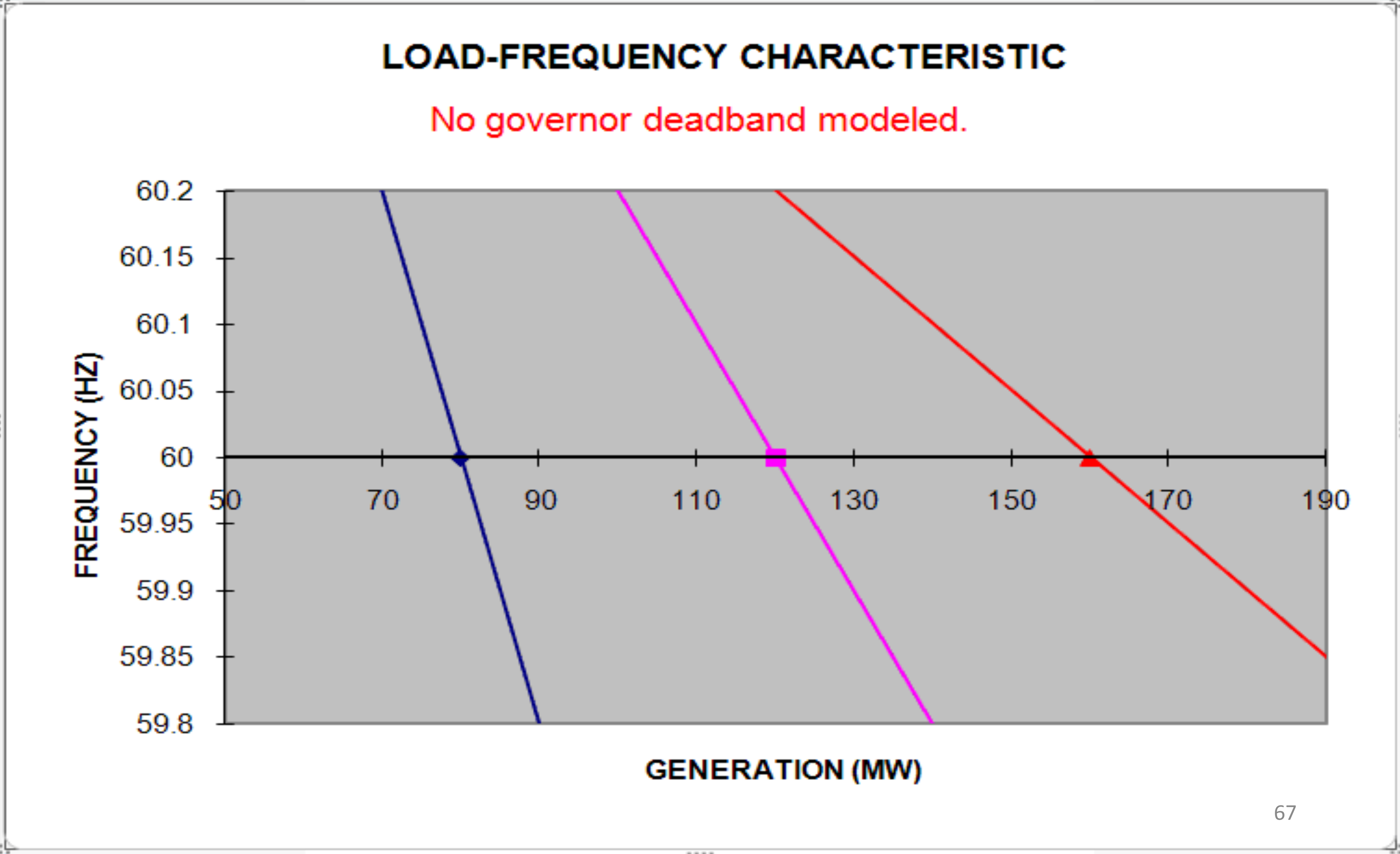
- At what frequency does the system settle?
- How much does each unit pick-up (MW)?
- Since R(p.u.)=(Δf(HZ)/60)/(ΔP(MW)/Capacity), then (ΔP/ Δf)=(1/R) X Capacity/60)

Case Study

UNIT	CAPACITY	R (DROOP)	$\Delta P/\Delta f$
#1	300MW	0.100 (10%)	50MW/HZ
#2	450MW	0.075 (7.5%)	100MW/HZ
#3	600MW	0.050 (5%)	200MW/HZ
<u>Solution:</u> Unit #1: $\Delta P_1=50 \text{ X } \Delta f$ Unit #2: $\Delta P_2=100 \text{ X } \Delta f$ Unit #3: $\Delta P_3=200 \text{ X } \Delta f$ $\Sigma\Delta P_i=350\Delta f=21MW$, and $\Delta f=21/350=0.06HZ$ Frequency=60-0.06=<u>59.94HZ</u>		$\Delta P_1=50 \text{ X } 0.06=\underline{3MW}$ $\Delta P_2=100 \text{ X } 0.06=\underline{6MW}$ $\Delta P_3=200 \text{ X } 0.06=\underline{12MW}$ check: $\Sigma\Delta P_i=21MW$	

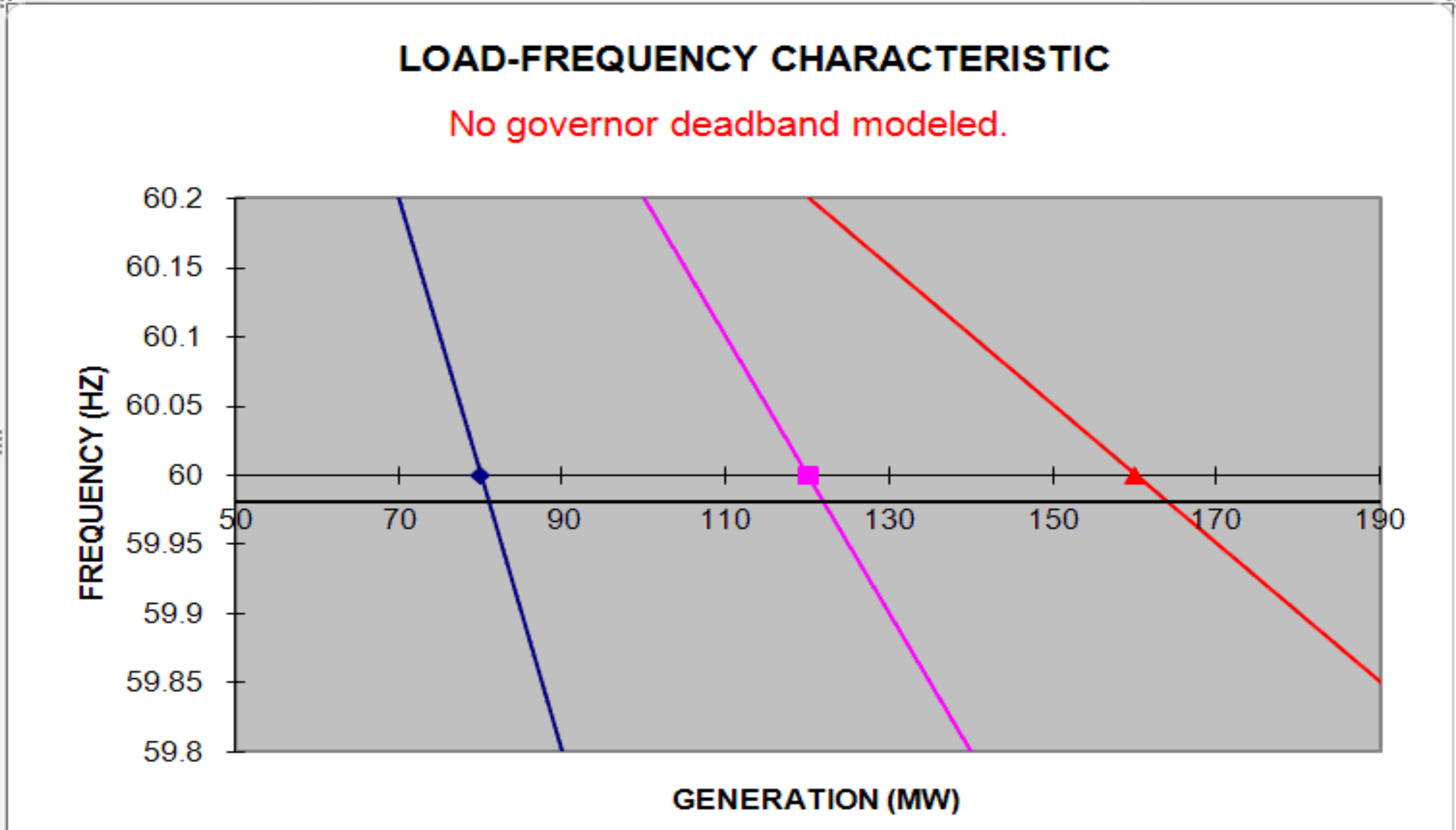
Three generators serving 360MW

Freq (hz)	60.0000
60hz load (MW)	360
GENERATOR #1	
Gen (MW)	80.00
60hz setpt (MW)	80
Rating (MW)	300
Droop (%)	10.0%
Slope(MW/hz)	50
GENERATOR #2	
Gen (MW)	120.00
60hz setpt (MW)	120
Rating (MW)	450
Droop (%)	7.5%
Slope(MW/hz)	100
GENERATOR #3	
Gen (MW)	160.00
60hz setpt (MW)	160
Rating (MW)	600
Droop (%)	5.0%
Slope(MW/hz)	200



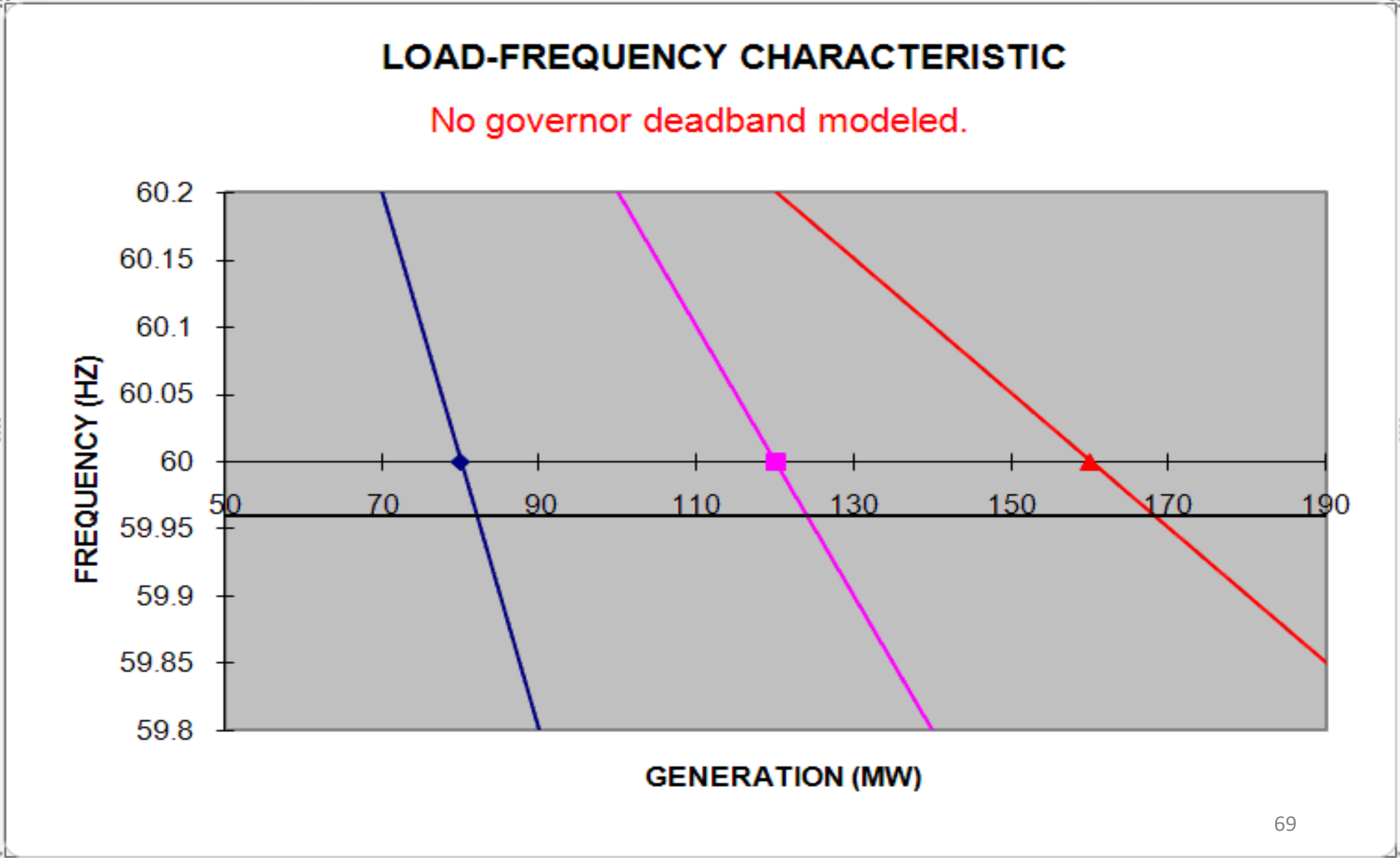
Three generators serving 367MW

Freq (hz)	59.9800
60hz load (MW)	367
GENERATOR #1	
Gen (MW)	81.00
60hz setpt (MW)	80
Rating (MW)	300
Droop (%)	10.0%
Slope(MW/hz)	50
GENERATOR #2	
Gen (MW)	122.00
60hz setpt (MW)	120
Rating (MW)	450
Droop (%)	7.5%
Slope(MW/hz)	100
GENERATOR #3	
Gen (MW)	164.00
60hz setpt (MW)	160
Rating (MW)	600
Droop (%)	5.0%
Slope(MW/hz)	200



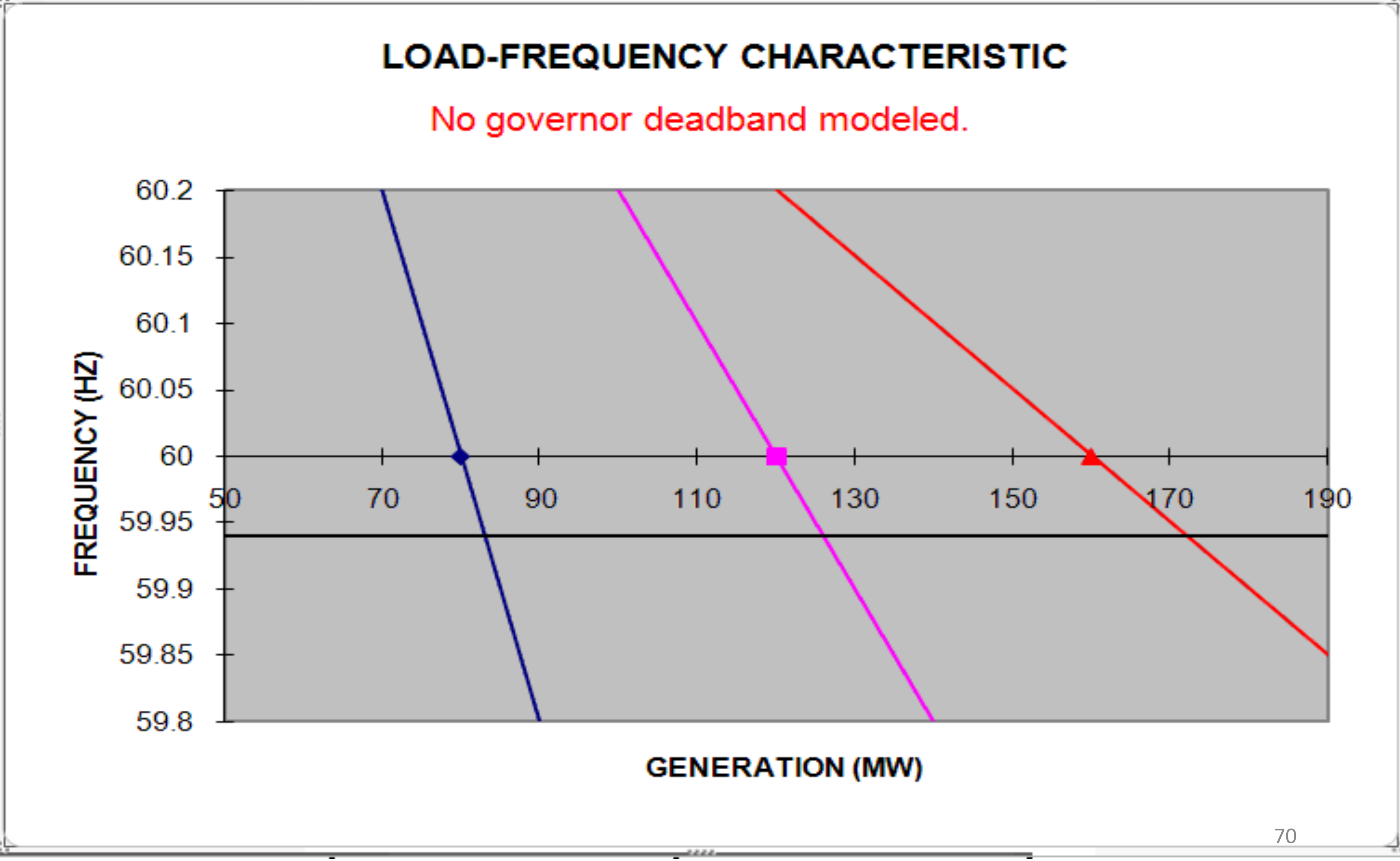
Three generators serving 374MW

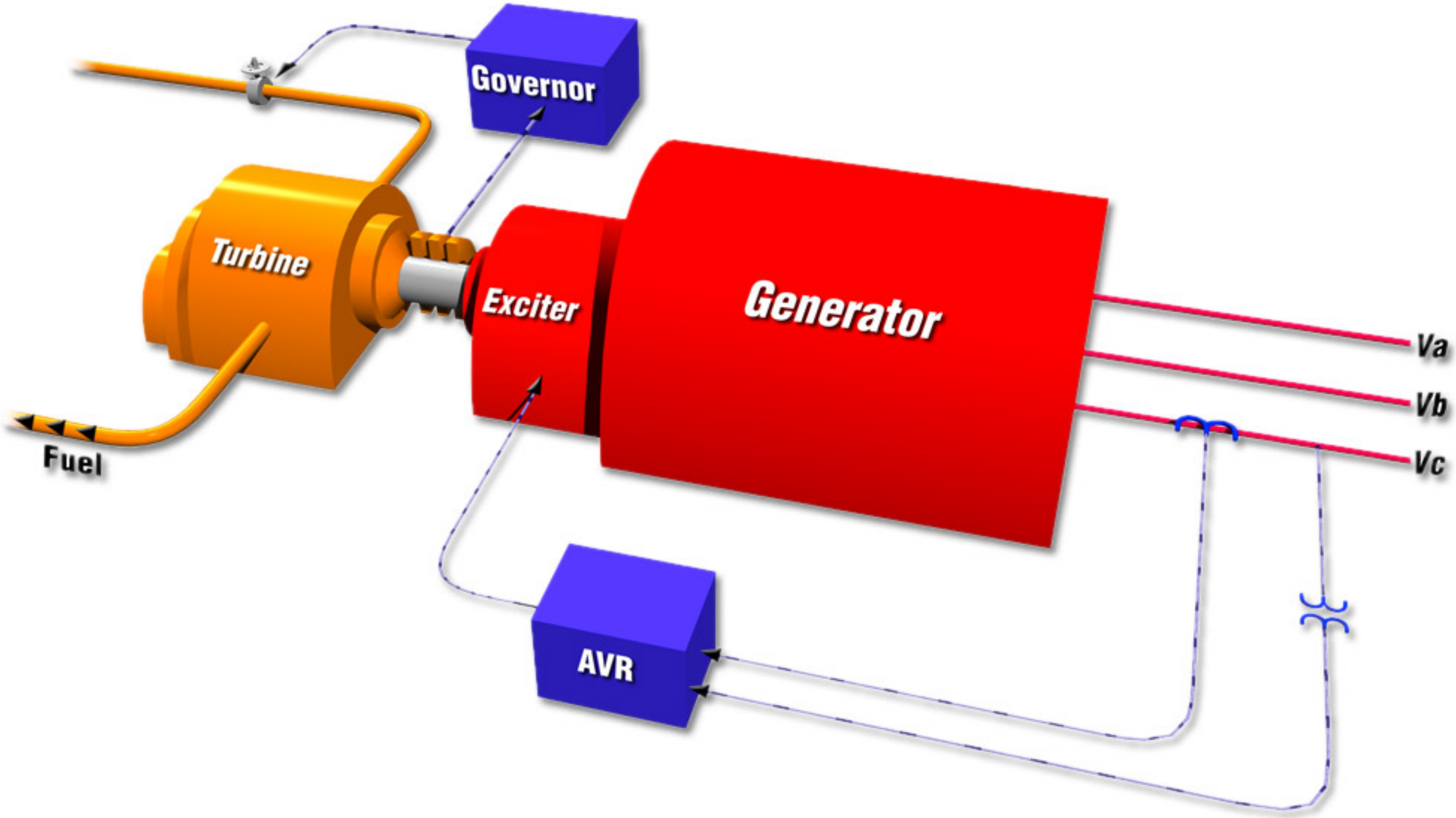
Freq (hz)	59.9600
60hz load (MW)	374
GENERATOR #1	
Gen (MW)	82.00
60hz setpt (MW)	80
Rating (MW)	300
Droop (%)	10.0%
Slope(MW/hz)	50
GENERATOR #2	
Gen (MW)	124.00
60hz setpt (MW)	120
Rating (MW)	450
Droop (%)	7.5%
Slope(MW/hz)	100
GENERATOR #3	
Gen (MW)	168.00
60hz setpt (MW)	160
Rating (MW)	600
Droop (%)	5.0%
Slope(MW/hz)	200



Three generators serving 381MW

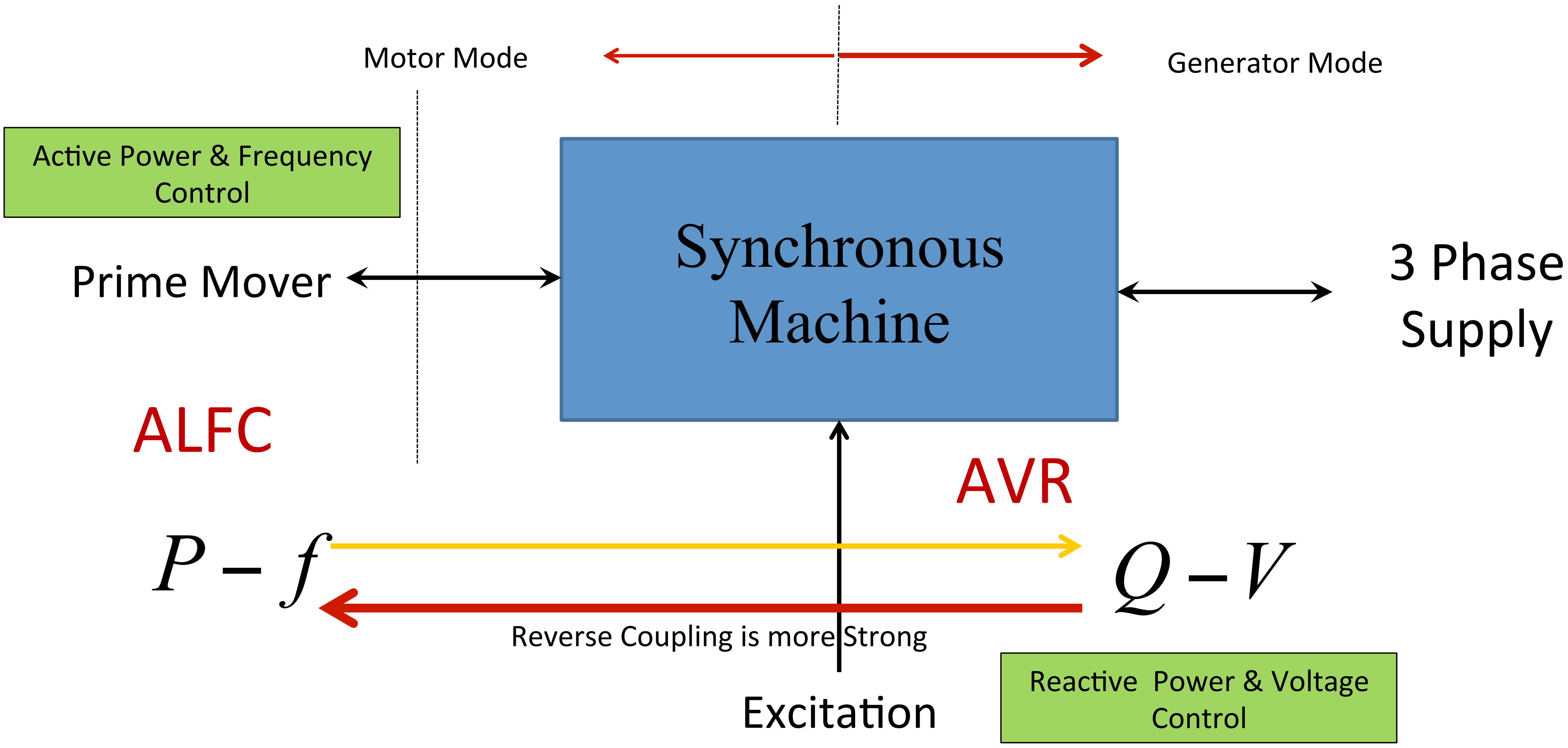
Freq (hz)	59.9400
60hz load (MW)	381
GENERATOR #1	
Gen (MW)	83.00
60hz setpt (MW)	80
Rating (MW)	300
Droop (%)	10.0%
Slope(MW/hz)	50
GENERATOR #2	
Gen (MW)	126.00
60hz setpt (MW)	120
Rating (MW)	450
Droop (%)	7.5%
Slope(MW/hz)	100
GENERATOR #3	
Gen (MW)	172.00
60hz setpt (MW)	160
Rating (MW)	600
Droop (%)	5.0%
Slope(MW/hz)	200





Source: www.eal.ei.tum.de

Synchronous Machine Black Box Model



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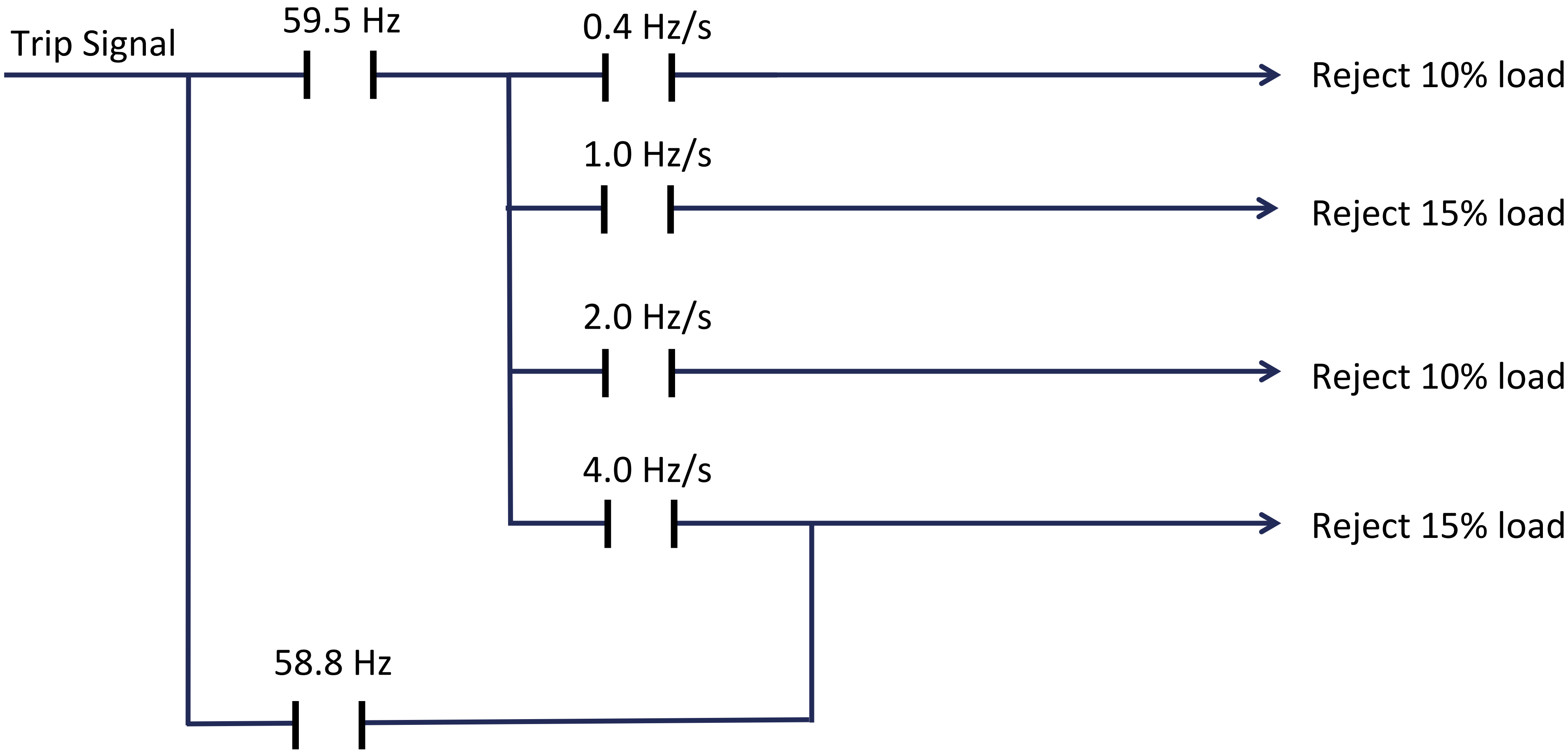
Under Frequency Load Shedding

A typical scheme:

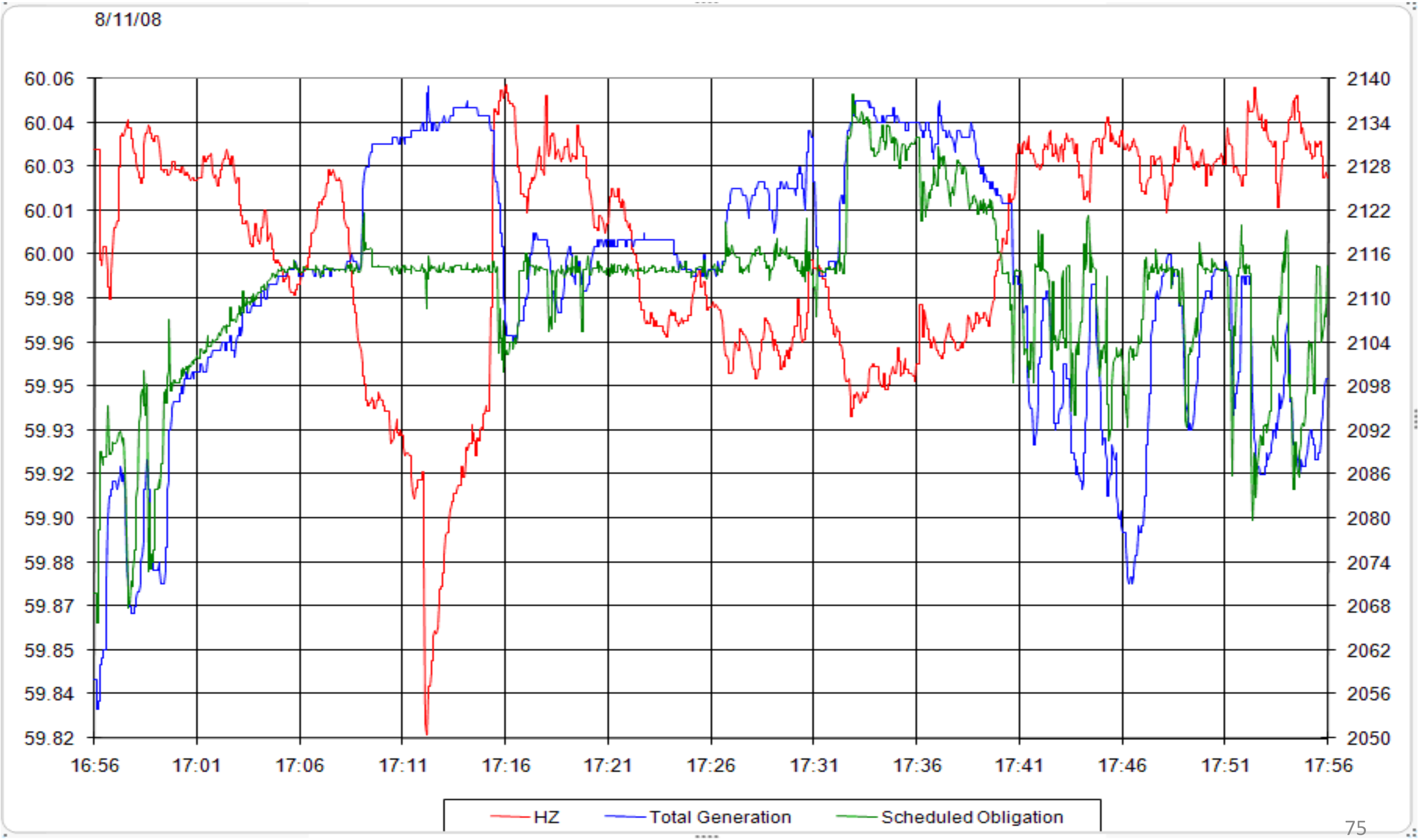
- 10% load shed when frequency drops to 59.2 Hz
- 15% additional load shed when frequency drops to 58.8 Hz
- 20% additional load shed when frequency reaches 58.0 Hz

- For greater generation deficiencies, a scheme taking into account both ***frequency drop*** and ***rate-of-change of frequency*** provides increased selectivity

Tripping Logic for Frequency Trend Relay



Typical Power Frequency Oscillations



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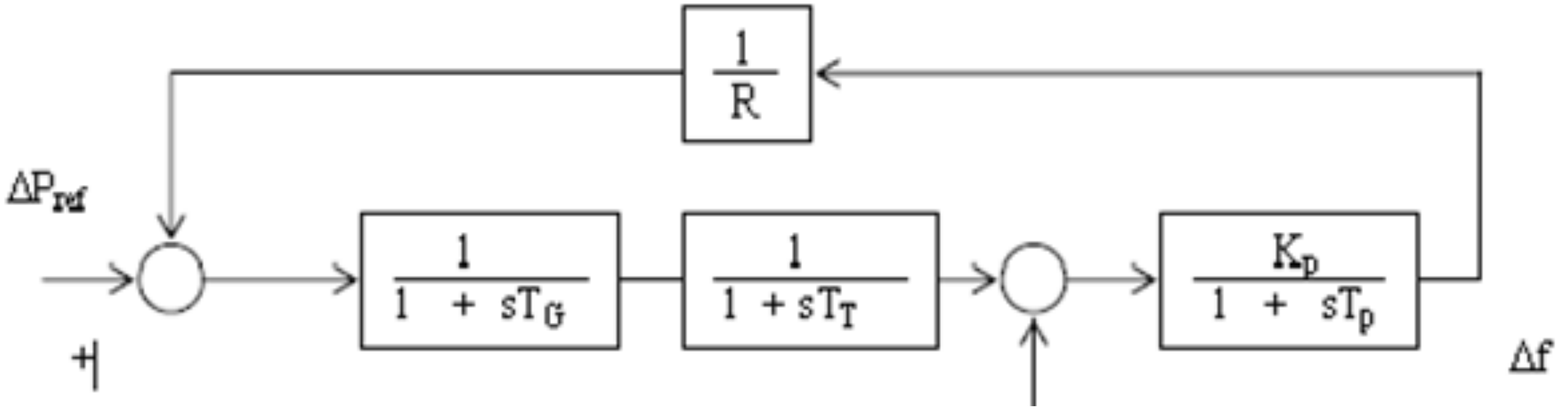
Assignment (ALFC)



Derive the equation of the transfer function of Δf(s) as a function of R, time constants of power systems (Tp), Governor (TG) and Turbine(TT), gain Kp and ΔPL as shown in the figure

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Question 1

Starting from the transfer function of Δf driven for the above control loop, prove that the steady state frequency error for a step in load demand, ΔPL (without the secondary loop for steady state analysis ΔPref can be assumed to be zero)

$$\Delta fss = \frac{-\Delta P_L}{\dfrac{1}{K_p + \dfrac{1}{R}}} \text{ p.u.}$$

Question 2

Using Matlab ("ilaplace" and other commands) plot the Δf against time (make approximation in the transfer function, if necessary) by assuming TG=0.1 sec,TT=0.3 sec, Tp=20 sec, Kp=1.25 p.u., R=0.02 p.u. and ΔPL=0.1 p.u.

Question 3

Calculate the steady state error using the equation in question (1) and verify the results (compare with simulation steady state error).

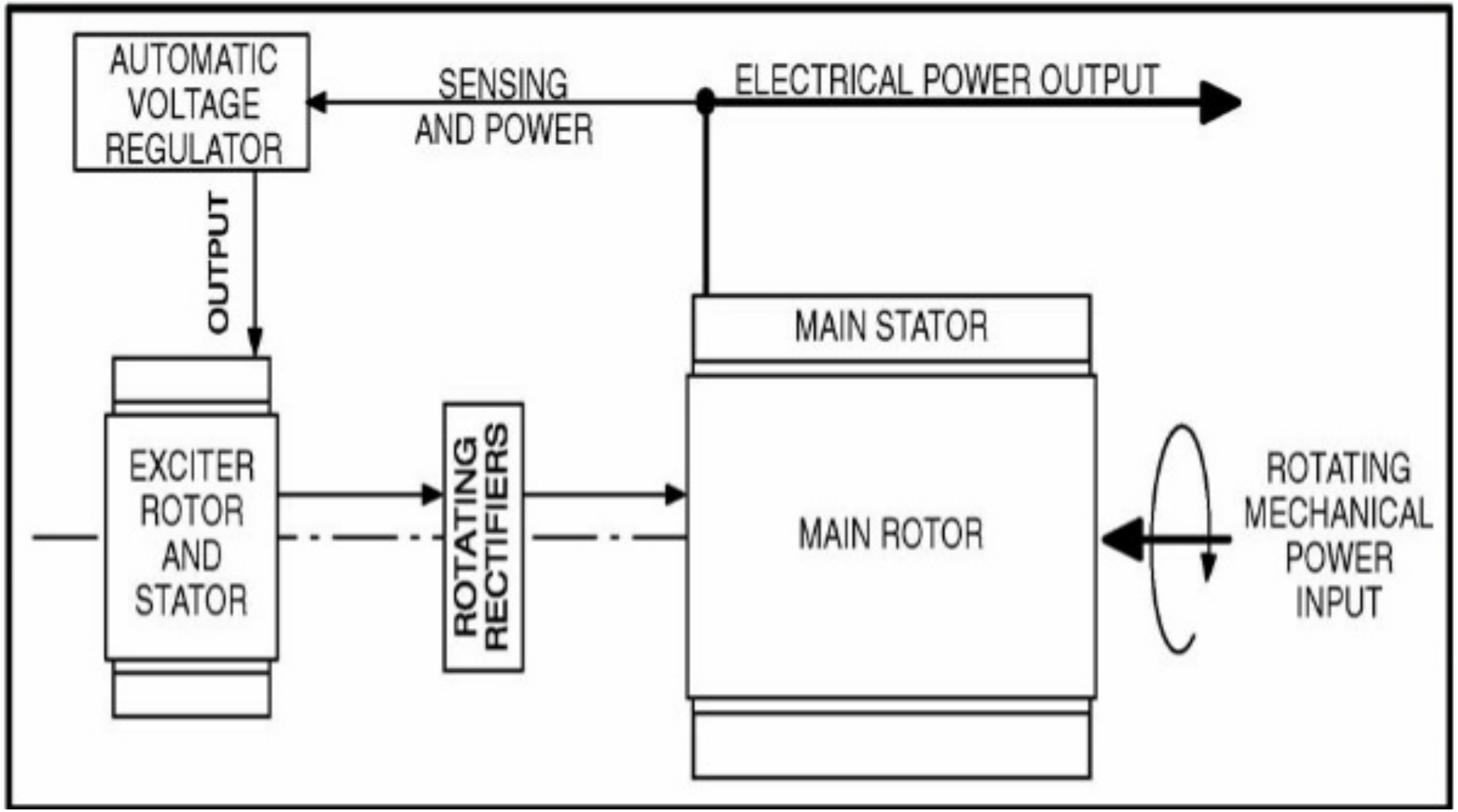
Question 4

What can be done to reduce the steady state error to zero?

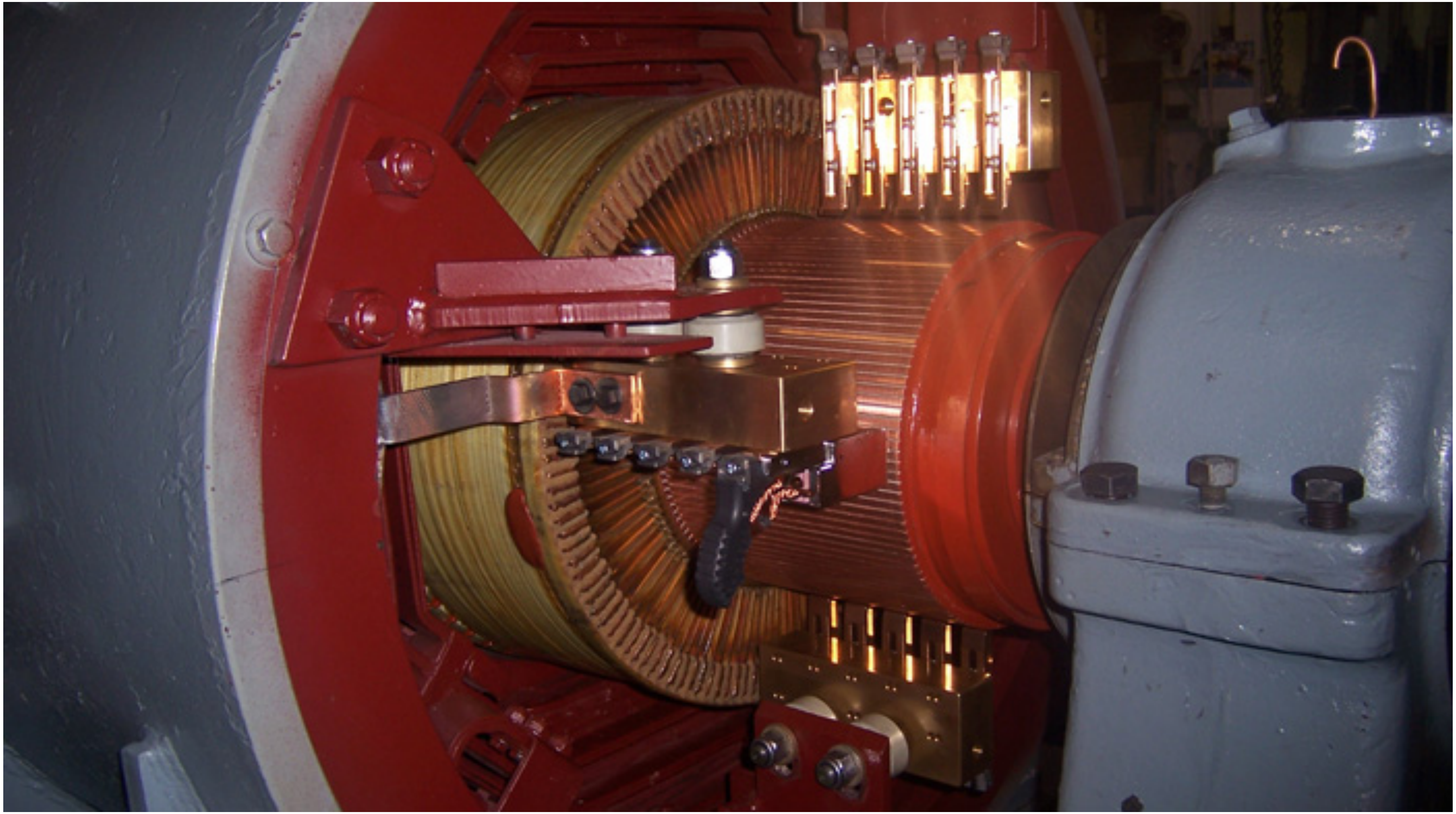
In order to reduce the steady state error, a secondary loop can be used. There are basically three types of controllers.

1. Proportional Controller (P)
2. Derivative controller (D)
3. Integral Controller (I)
4. Or a combination of the above controllers, PI, PD, PID

Reactive Power, Voltage Control & Excitation Systems



Source: M. Murali Mohan, Dy. Suptd



Source: EME Associates

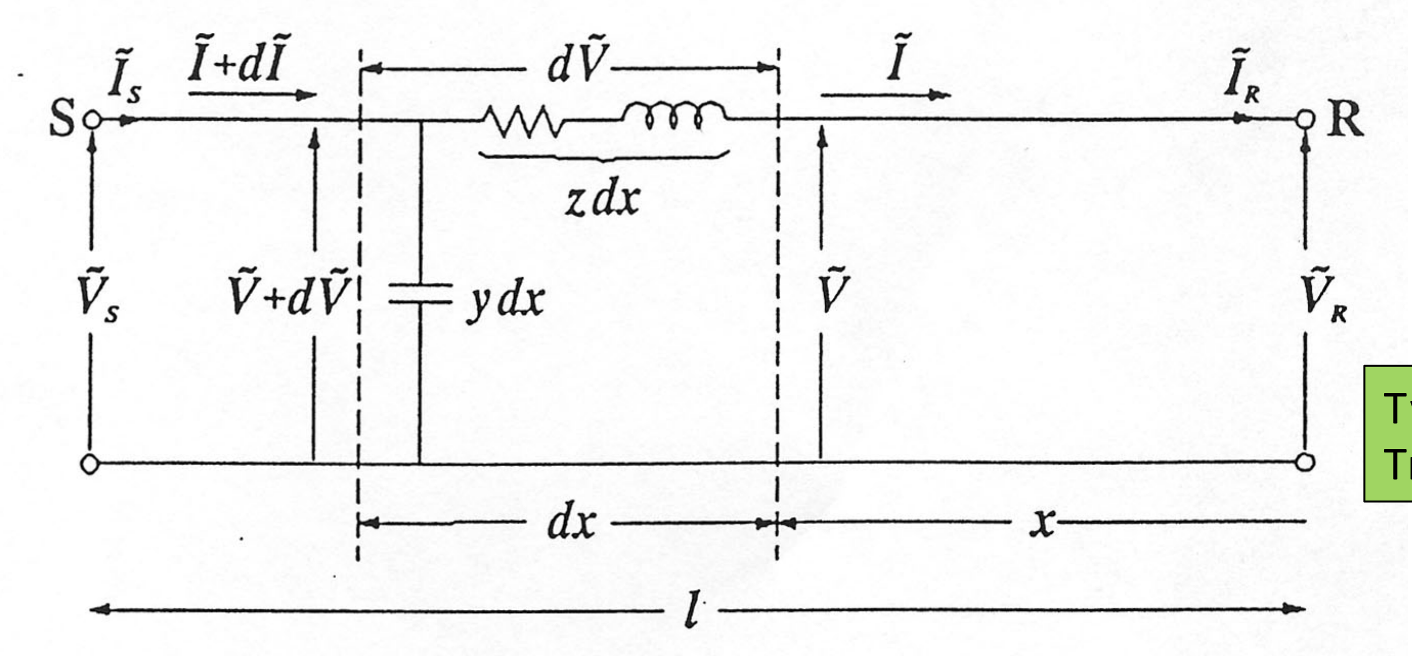
Synchronous Generators

- Can generate or absorb Q depending on excitation
- Capability limited by field current, armature current, and end-region heating limits
- Automatic voltage regulator continuously adjusts excitation to control armature voltage
- Primary source of voltage support!

Overhead Lines

- At loads below natural or surge impedance load (SIL), produce Q
- At loads above SIL, absorb Q

Surge Impedance Loading



Typical Model of Transmission Line

$$\textit{Characteristic}\ \text{Impedance}\ Z_C = \sqrt{z/y}$$

If Losses are Neglected

$$Z_C = \sqrt{\frac{L}{C}} = \text{Real Number}$$

(pure resistance)

The power delivered by a line when terminated by its surge impedance is known as the natural load or surge impedance load.

$$SIL = \frac{V_0^2}{Z_C}\ watts$$

Surge Impedance Loading

For a lossless line at SIL,

- V and I have constant amplitude along the line
- V and I are in phase throughout the length of the line
- The line neither generates nor absorbs VARS
- Typical values of SIL for overhead lines:

Nominal (kV):	230	345	500	765
SIL (MW):	140	420	1000	2300

Underground Cables

- Have **high SIL** due to **high capacitance**
- Always loaded below SIL, and hence generate Q

Transformers

- Absorb Q due to shunt magnetizing reactance and series leakage inductance

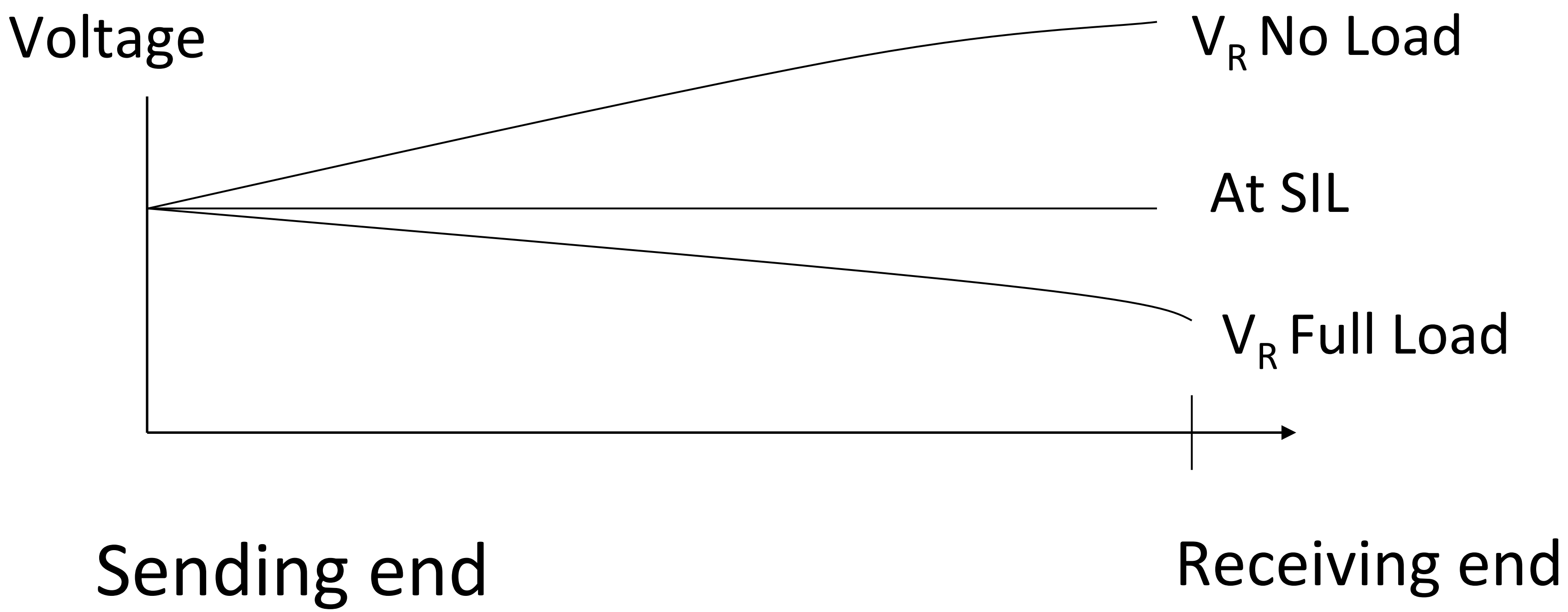
Loads

- A typical "load bus" is composed of a large number of devices
- Composite characteristics are normally such that a load bus absorbs Q
- Industrial loads usually have shunt capacitors to improve power factor

Production and Absorption of Reactive Power

Over-head Lines:

Voltage profile of a transmission line for various loads, above, below and equal to SIL:



Method of Voltage Control

- The control of **voltage** level is accomplished by controlling the production, absorption and flow of **reactive power** in the system
- There is a strong correlation between reactive power and voltage
- The generating units provide the basic means of voltage control; the automatic voltage regulators control field excitation to maintain a schedule voltage level at the terminals of the generators
- **Compensator** control absorbs reactive power and thereby controls the reactive power balance in a desired manner.
- Shunt and series capacitors and reactors are early compensation devices.
- **FACTS controllers** are the latest arrival in compensation devices, which are quite expensive compared to the capacitors or inductors

Method of Voltage Control

Generator Voltage Control:

- The exciter delivers DC power to the field winding on the rotor of a synchronous generator
- Generators now are supplied with "static" or **"brushless" exciters**
- In the case of a **static exciter**, AC power is obtained directly from the generator terminals nearby station service bus
- In brushless exciters, AC power is obtained form an "inverted" synchronous generator whose three-phase armature windings are located on the main generator rotor and filed windings are located on the stator

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- Shunt and series capacitors and reactors provide **passive compensation**
  - They are either permanently connected or switched to improve the network characteristics
- Synchronous condensers and SVCs provide **active compensation**
- The reactive power absorbed/supplied by them are automatically adjusted so as to maintain voltages of the buses to which they are connected
  - Together with the generating units, they establish voltages at specific points in the system
  - Voltages at other locations in the system are determined by active and reactive power flows through various circuit elements, including the passive compensating devices

Excitation System

The functions of an excitation system are…

- To provide direct current to the synchronous generator field winding
- To perform control and protective functions essential to the satisfactory operation of the power system

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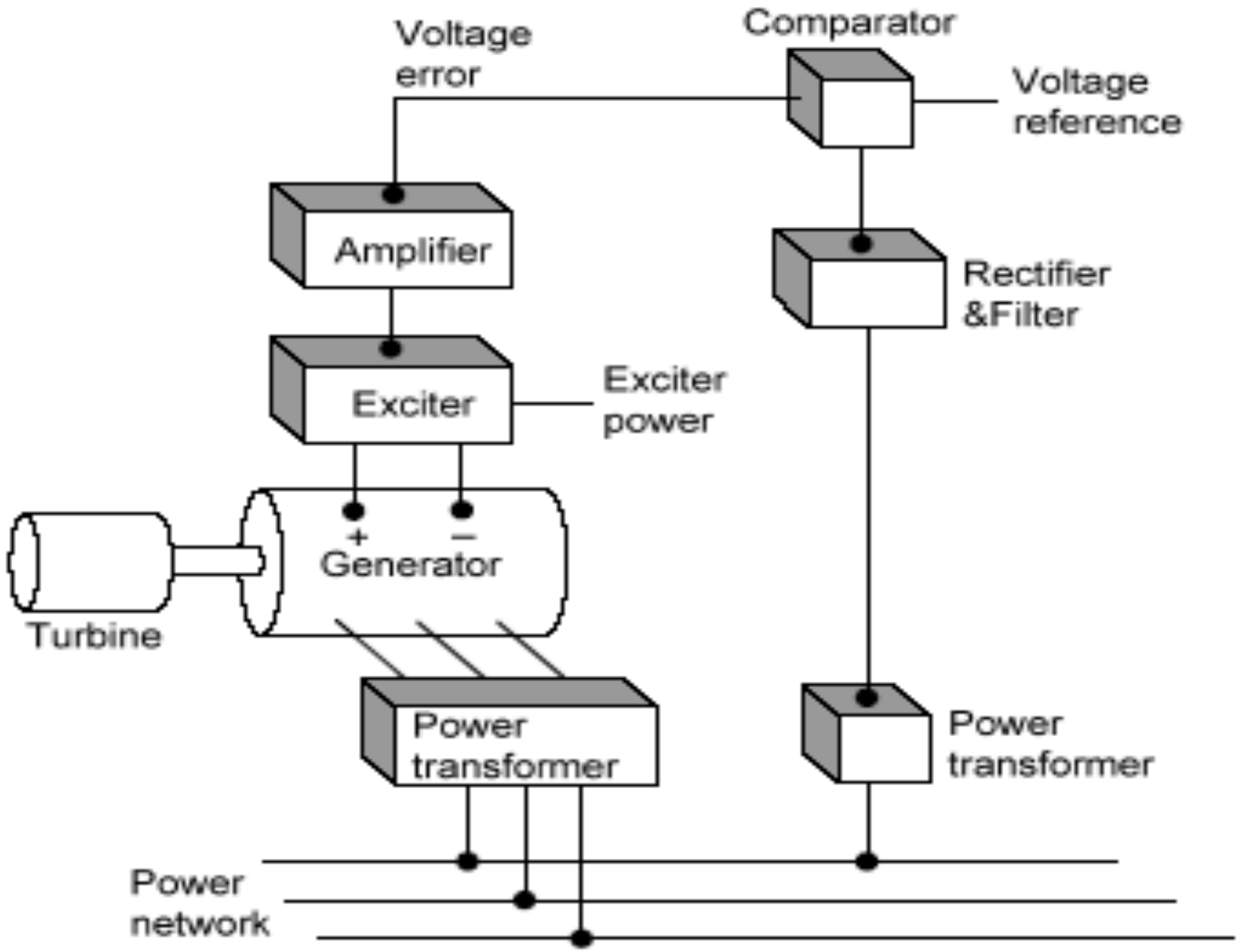
Excitation System- Block Diagram



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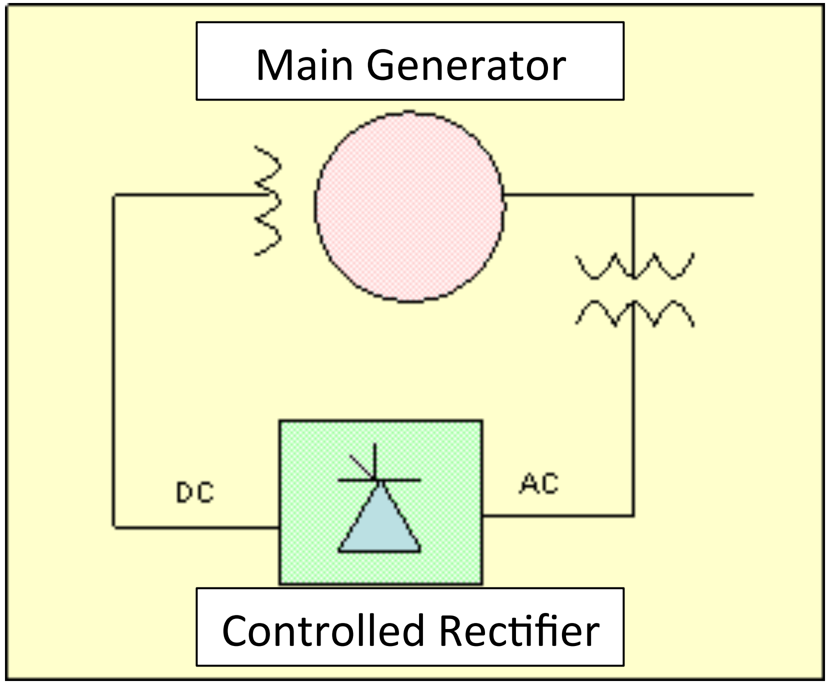
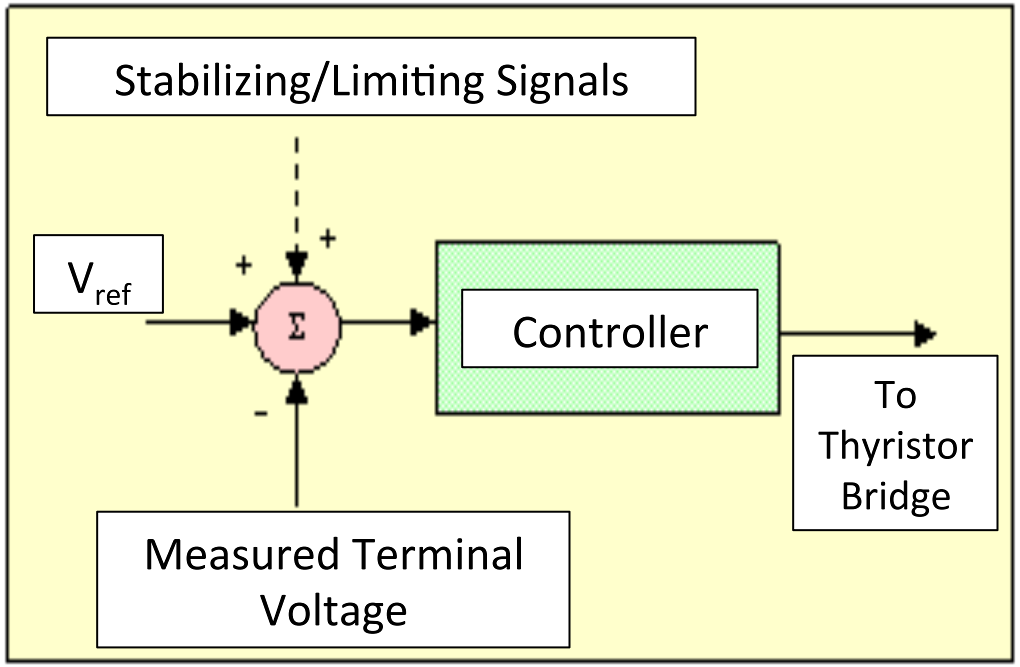
Excitation Systems





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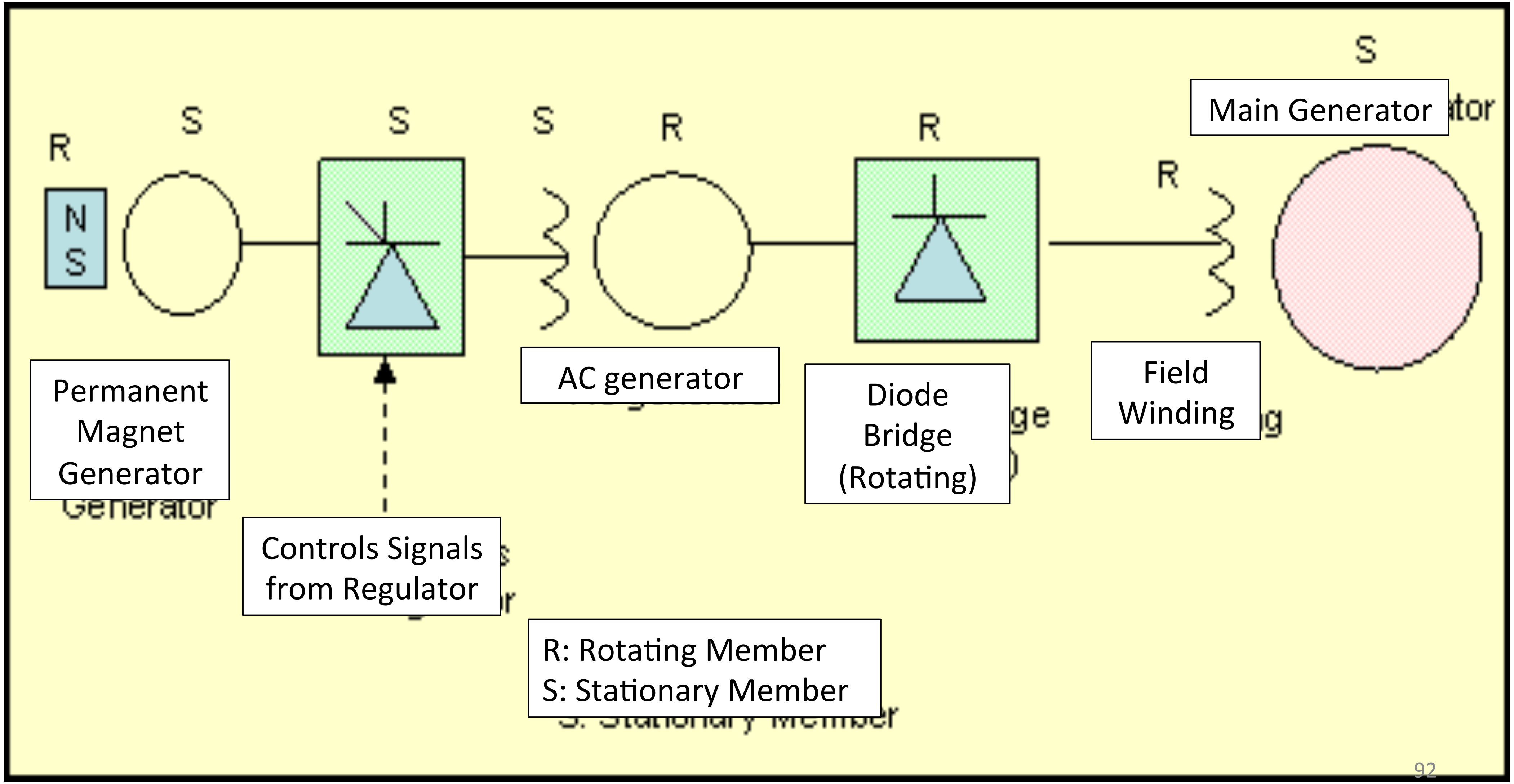
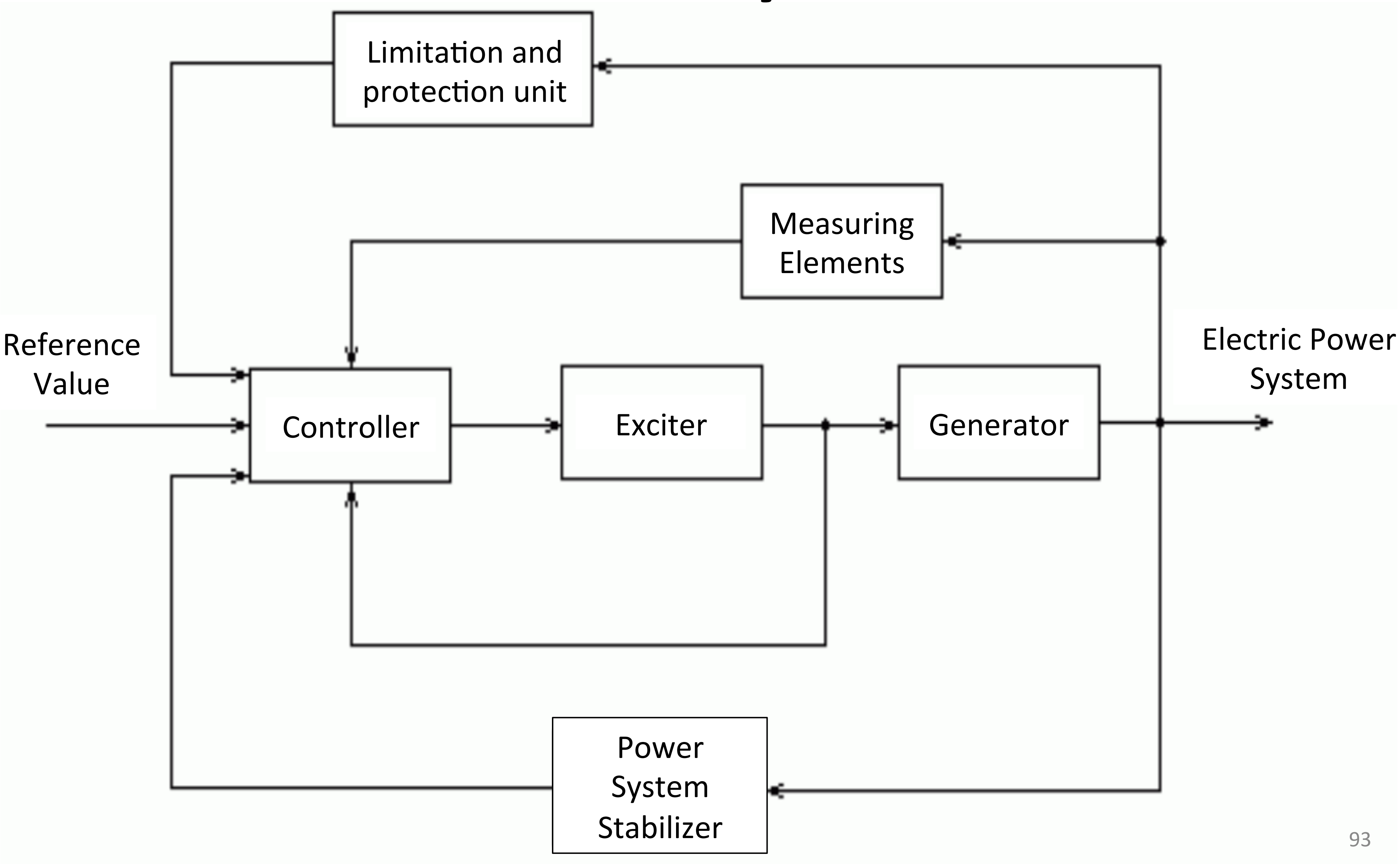
Excitation Systems



Excitation Systems



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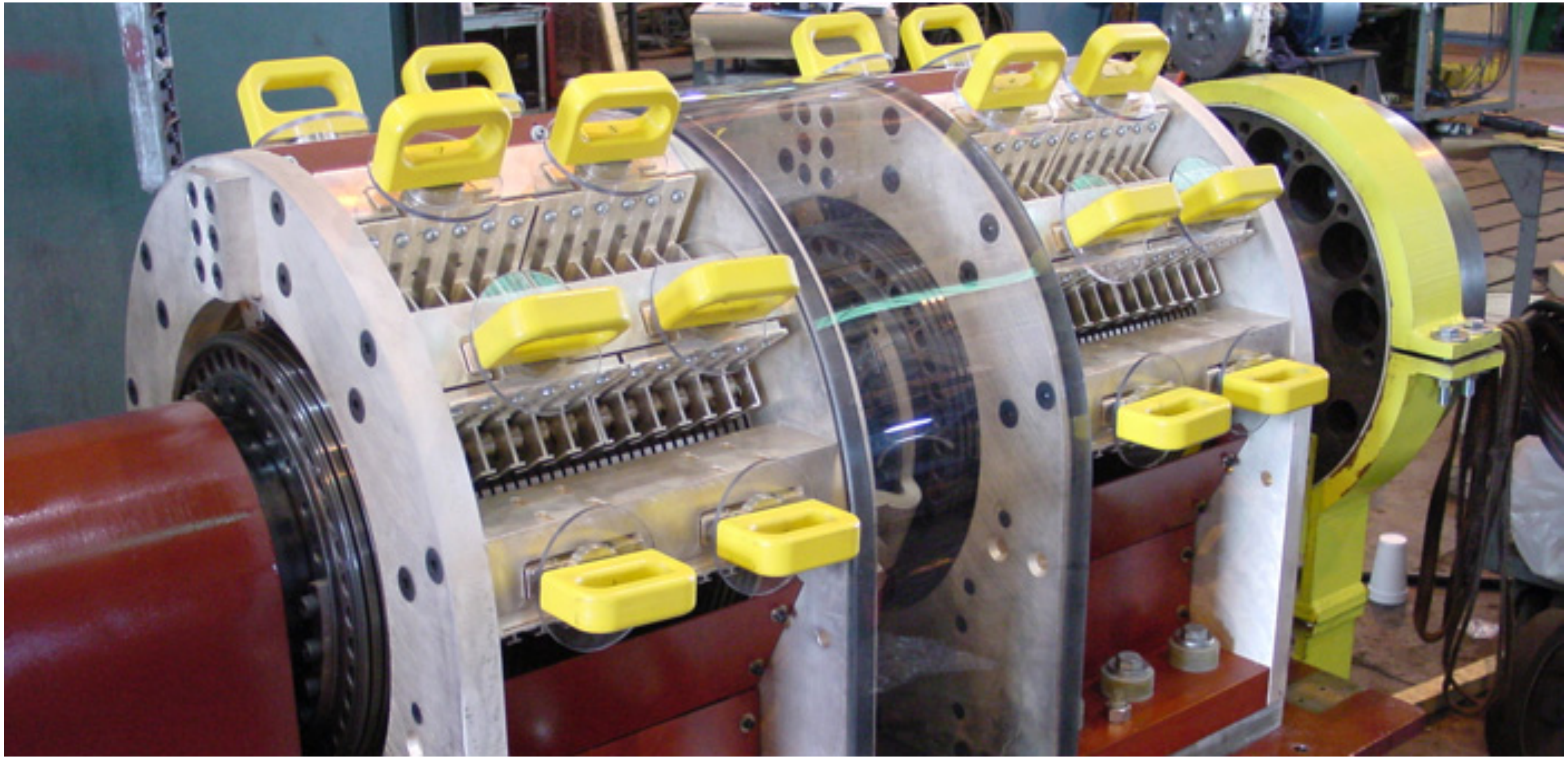


Source: EME Associates

Elements of Excitation System

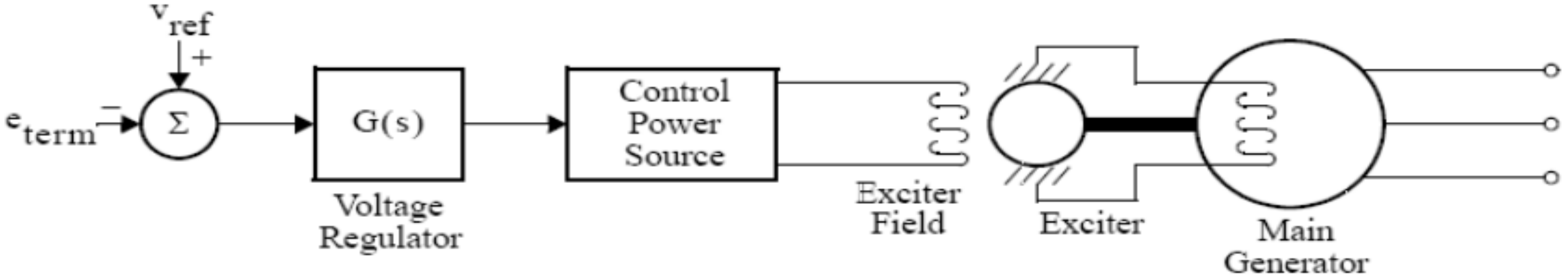
1. **Exciter**: provides dc power to the generator field winding
2. **Regulator**: processes and amplifies input control signals to a level and form appropriate for control of the exciter
3. **Terminal voltage transducer and load compensator**: senses generator terminal voltage, rectifies and filters it to dc quantity and compares with a reference; load comp may be provided if desired to hold voltage at a remote point
4. **Power system stabilizer**: provides additional input signal to the regulator to damp power system oscillations
5. **Limiters and protective circuits**: ensure that the capability limits of exciter and generator are not exceeded

Classification of Excitation Systems

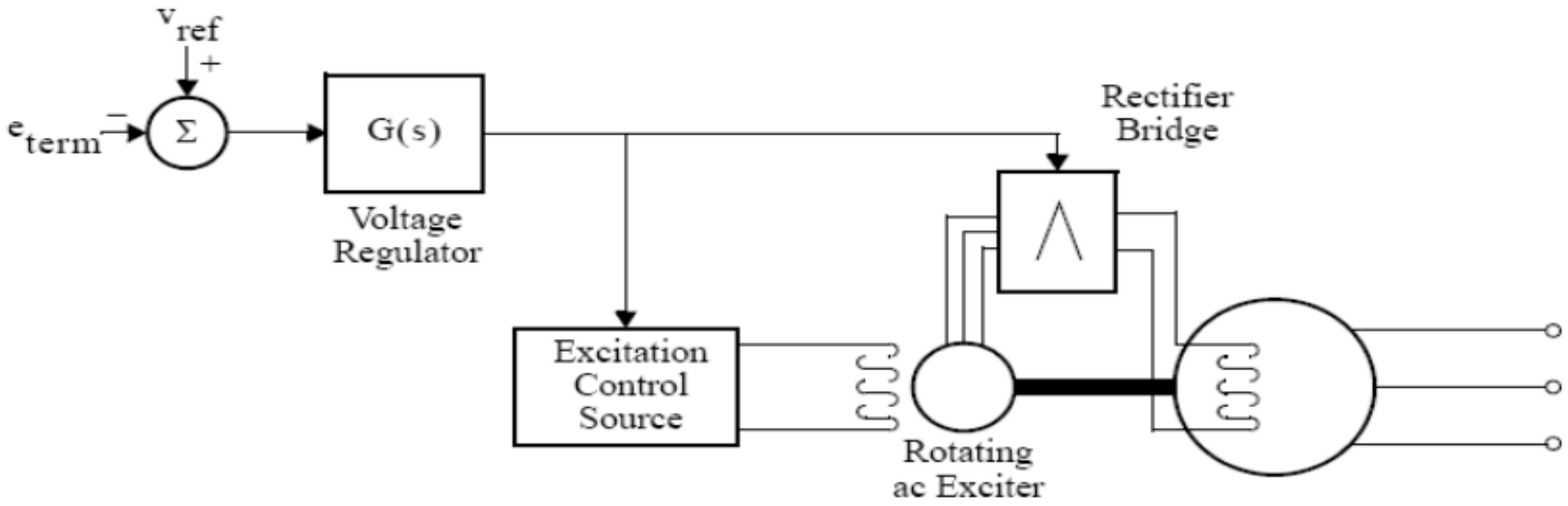
Classified into three broad categories based on the excitation power source:

1. DC excitation systems
2. AC excitation systems
3. Static excitation systems

Rotating Excitation Systems

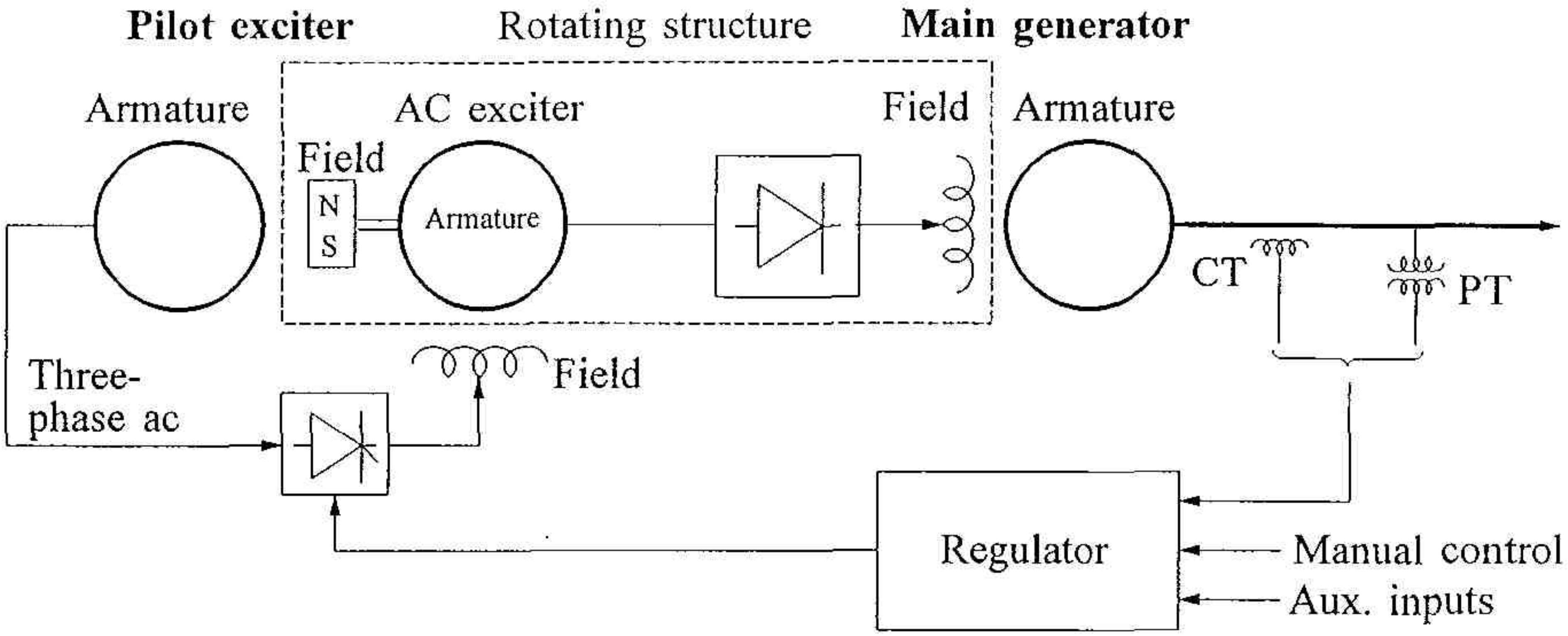


a. Rotating dc Exciter

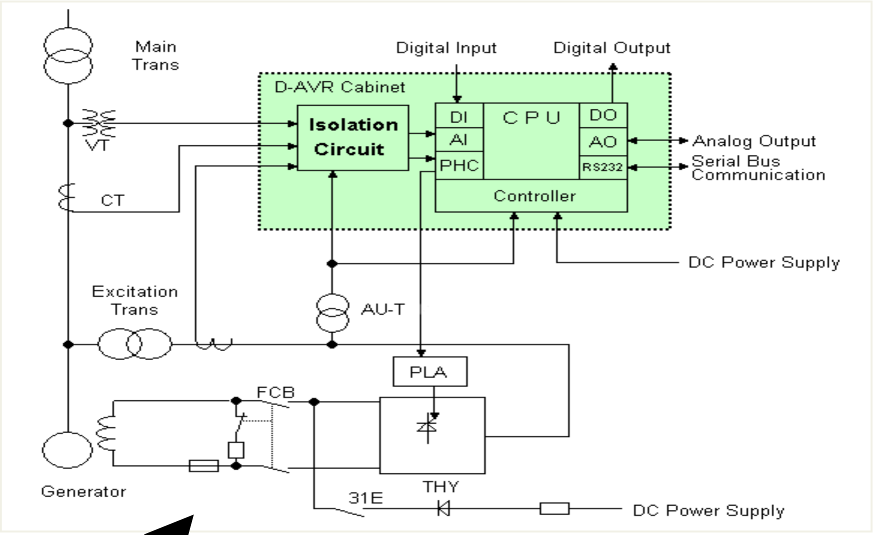


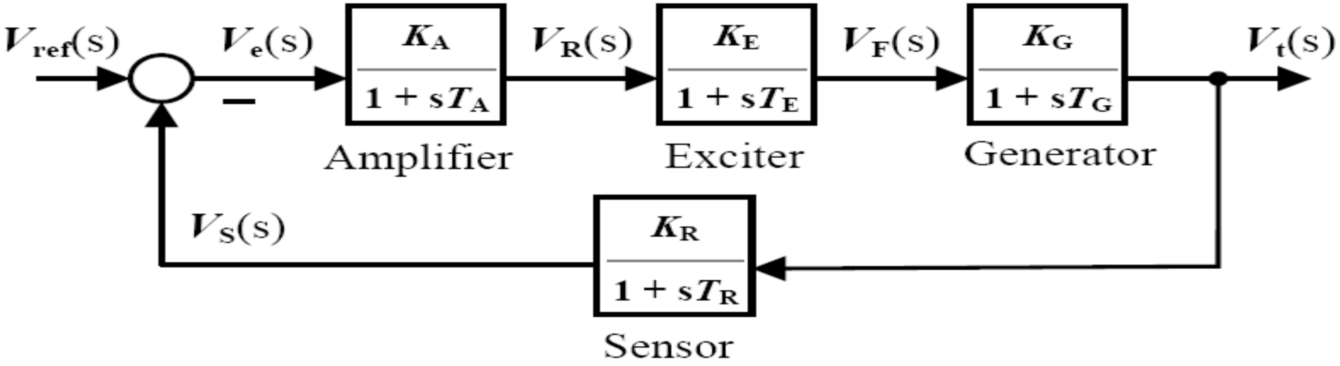
b. Rotating ac Exciter

Non Rotating Excitation Systems

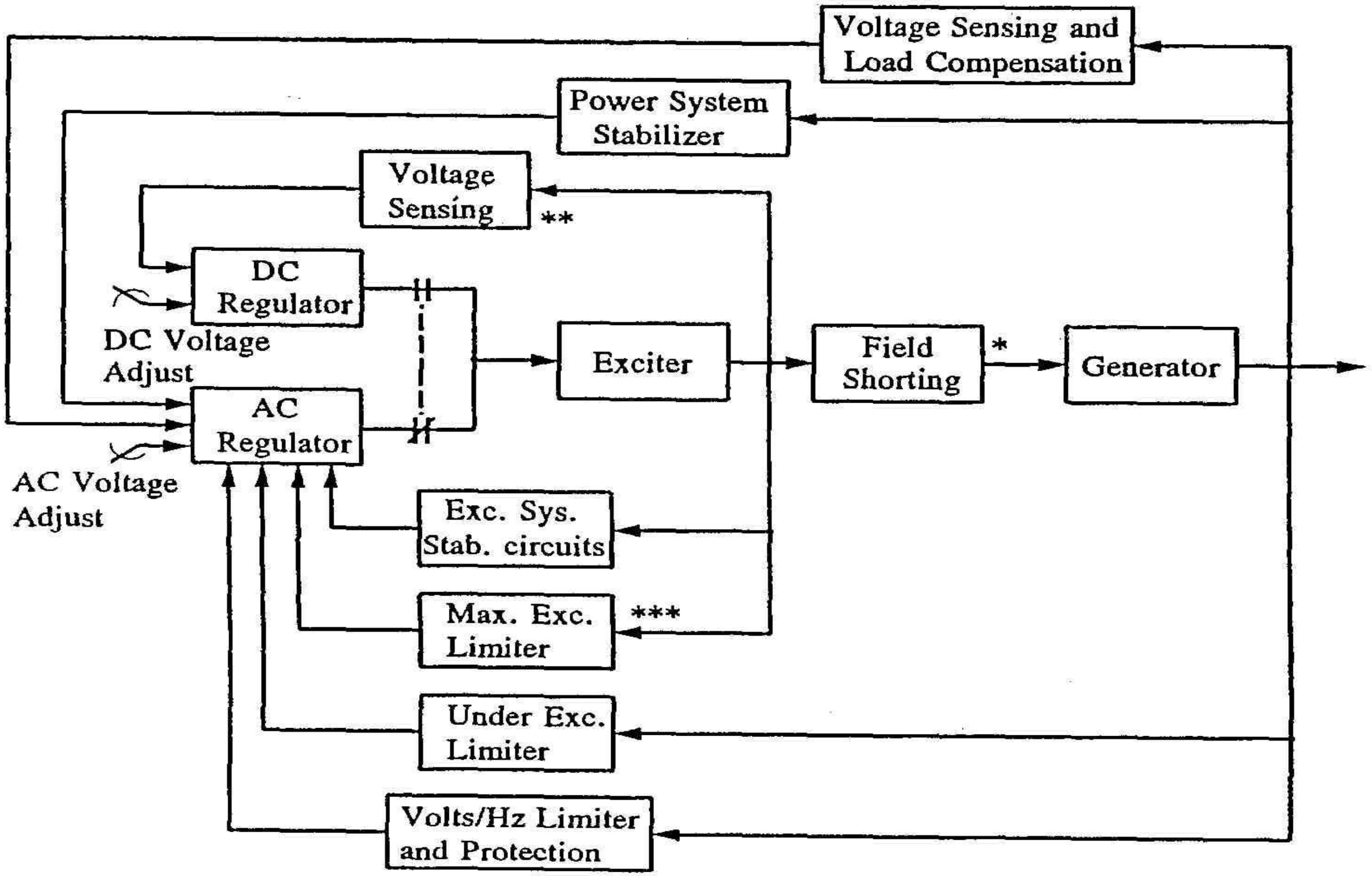


AVR Model


Main
Trans
Digital Input
Digital Output
D-AVR Cabinet
Isolation
Circuit
DI
AI
PHC
C P U
DO
AO
RS232
Controller
Analog Output
Serial Bus
Communication
VT
CT
DC Power Supply
Excitation
Trans
AU-T
PLA
FCB
Generator
31E
THY
DC Power Supply


$V_{ref}(s)$
$V_e(s)$
$\frac{K_A}{1+sT_A}$
Amplifier
$V_R(s)$
$\frac{K_E}{1+sT_E}$
Exciter
$V_F(s)$
$\frac{K_G}{1+sT_G}$
Generator
$V_t(s)$
$V_S(s)$
$\frac{K_R}{1+sT_R}$
Sensor
−

Complete Excitation Systems



* Field shorting circuits are applicable to ac and static exciters only
** Some systems have open loop dc regulator
*** Max. exc. limiter may also be used with dc regulator

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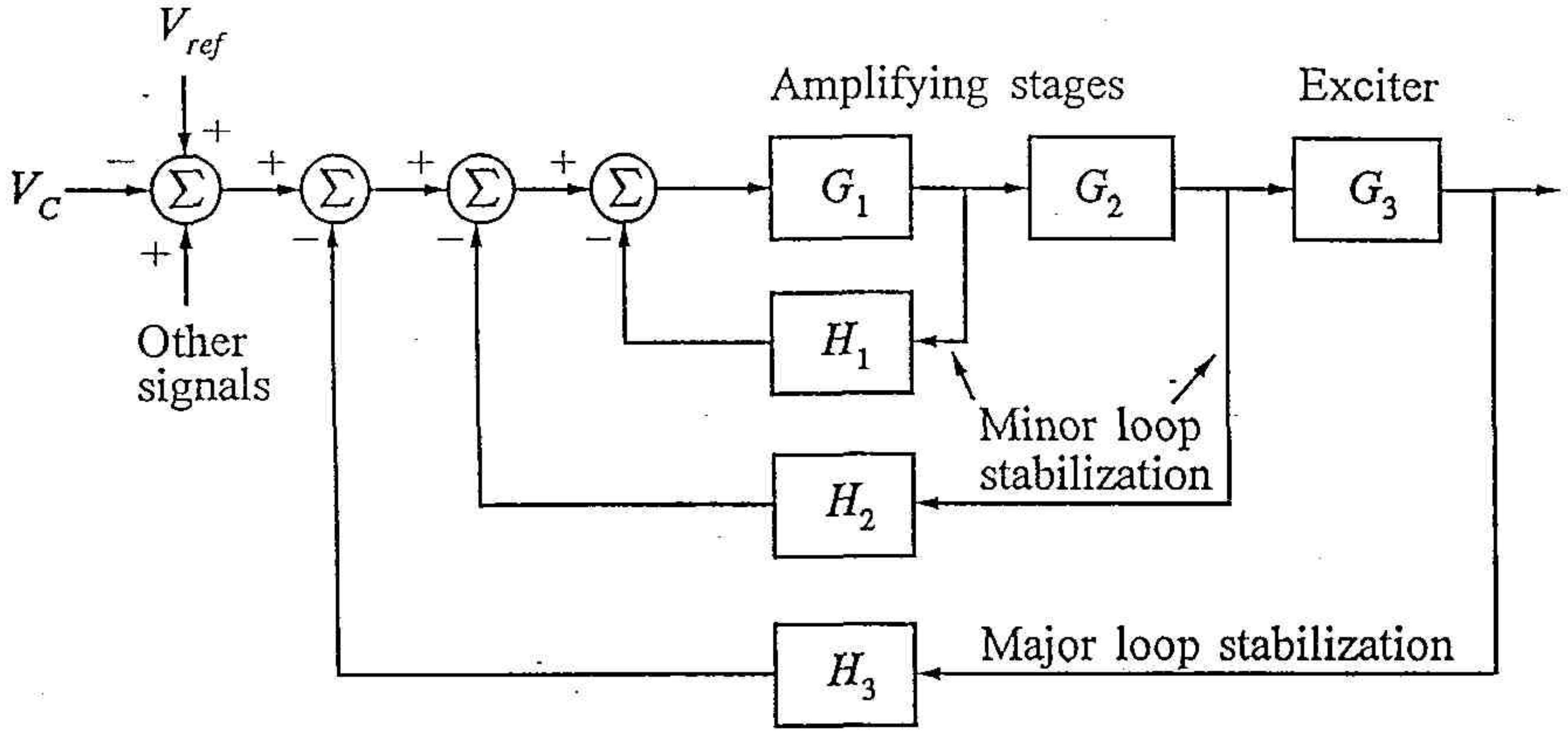
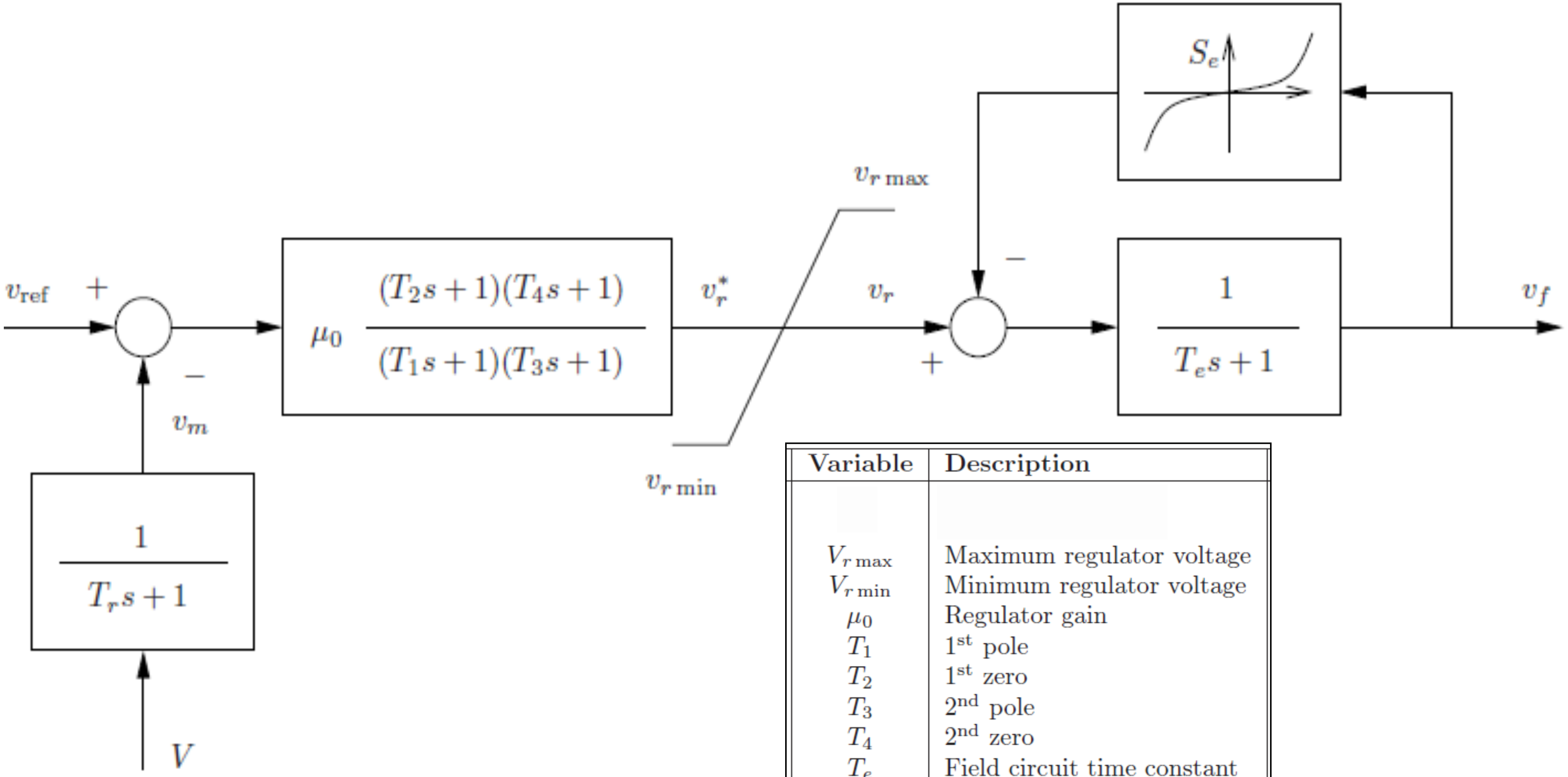
Excitation system model



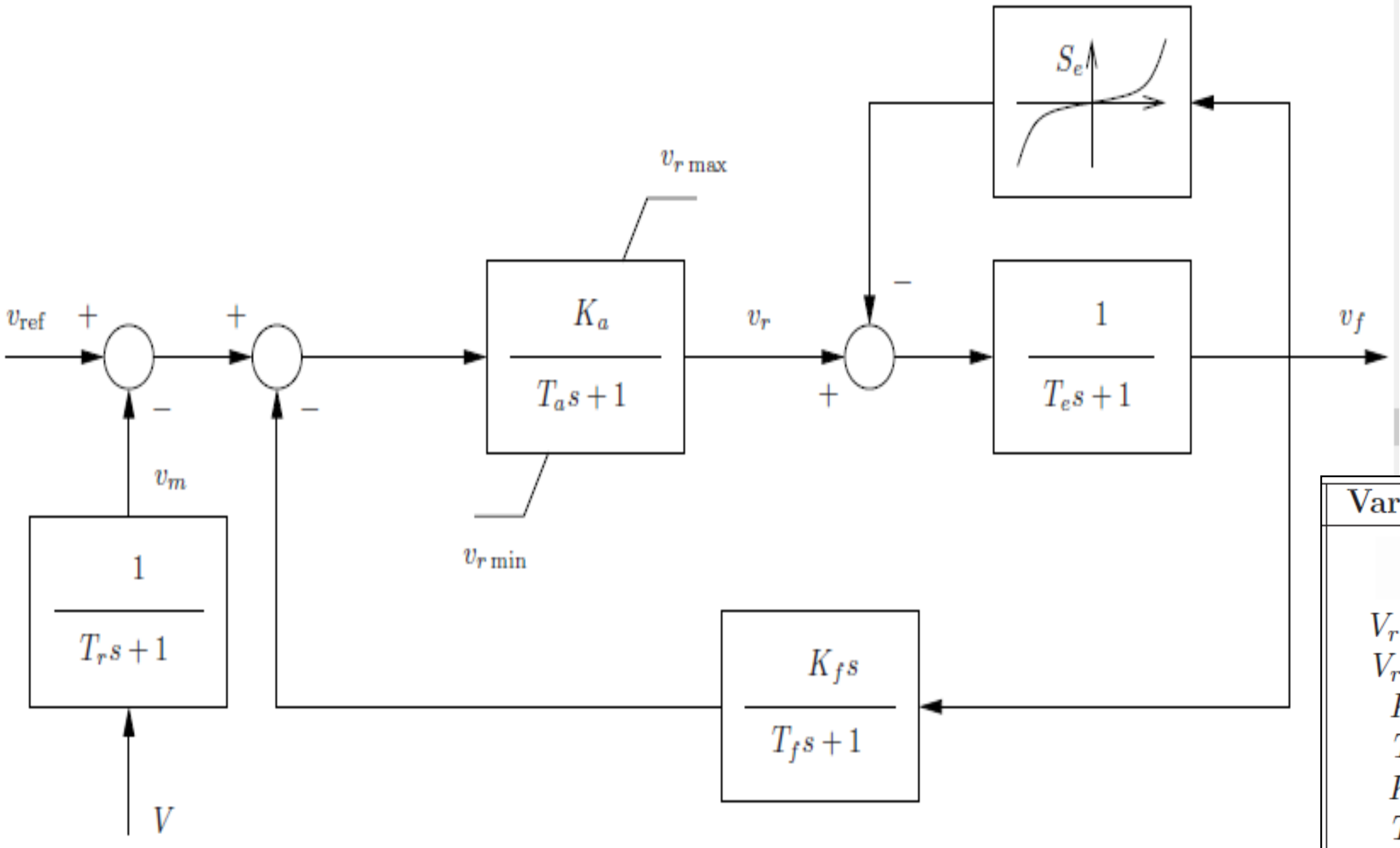
IEEE Type I Exciter Simplified Model



Variable	Description
$V_{r\,\max}$	Maximum regulator voltage
$V_{r\,\min}$	Minimum regulator voltage
μ_0	Regulator gain
T_1	1st pole
T_2	1st zero
T_3	2nd pole
T_4	2nd zero
T_e	Field circuit time constant
T_r	Measurement time constant
A_e	1st ceiling coefficient
B_e	2nd ceiling coefficient

Reference: PSAT Manual/ Power System Modeling and Scripting F Milano

IEEE Type II Exciter Simplified Model



Variable	Description
$V_{r\,\max}$	Maximum regulator voltage
$V_{r\,\min}$	Minimum regulator voltage
K_a	Amplifier gain
T_a	Amplifier time constant
K_f	Stabilizer gain
T_f	Stabilizer time constant
-	(*not used*)
T_e	Field circuit time constant
T_r	Measurement time constant
A_e	1st ceiling coefficient
B_e	2nd ceiling coefficient

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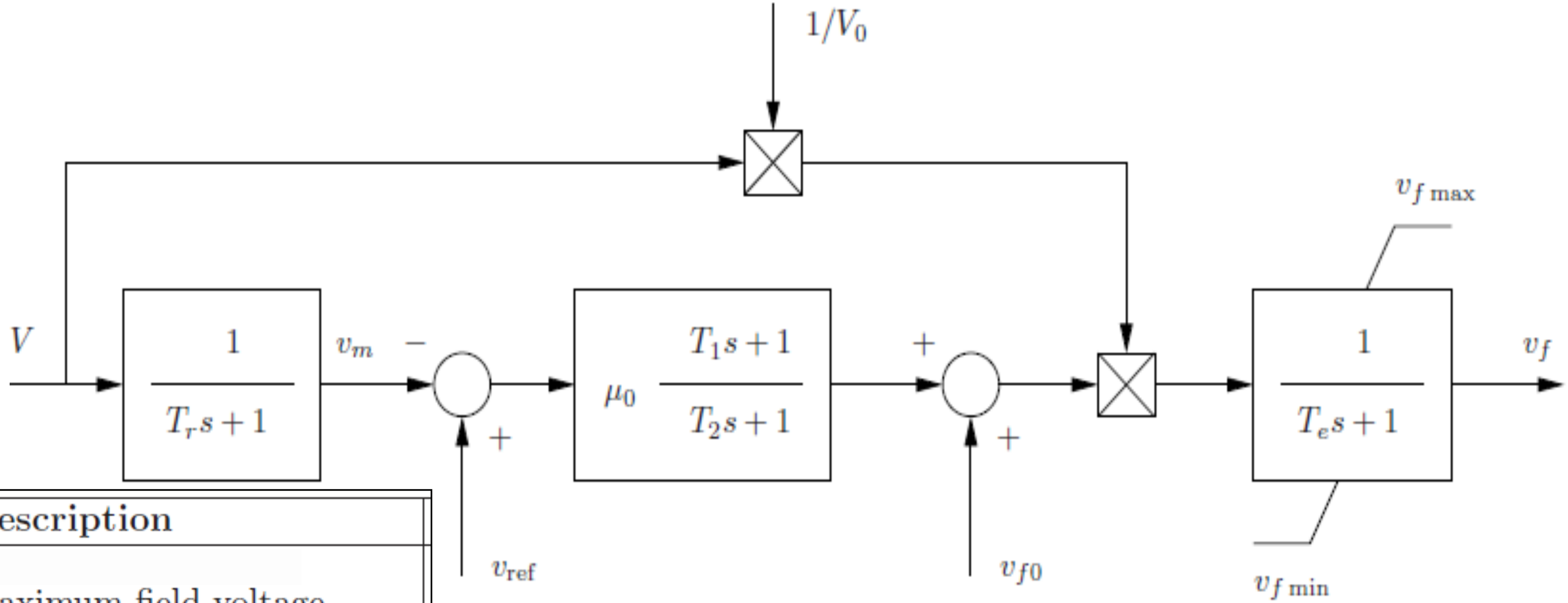
IEEE Type III Exciter Simplified Model



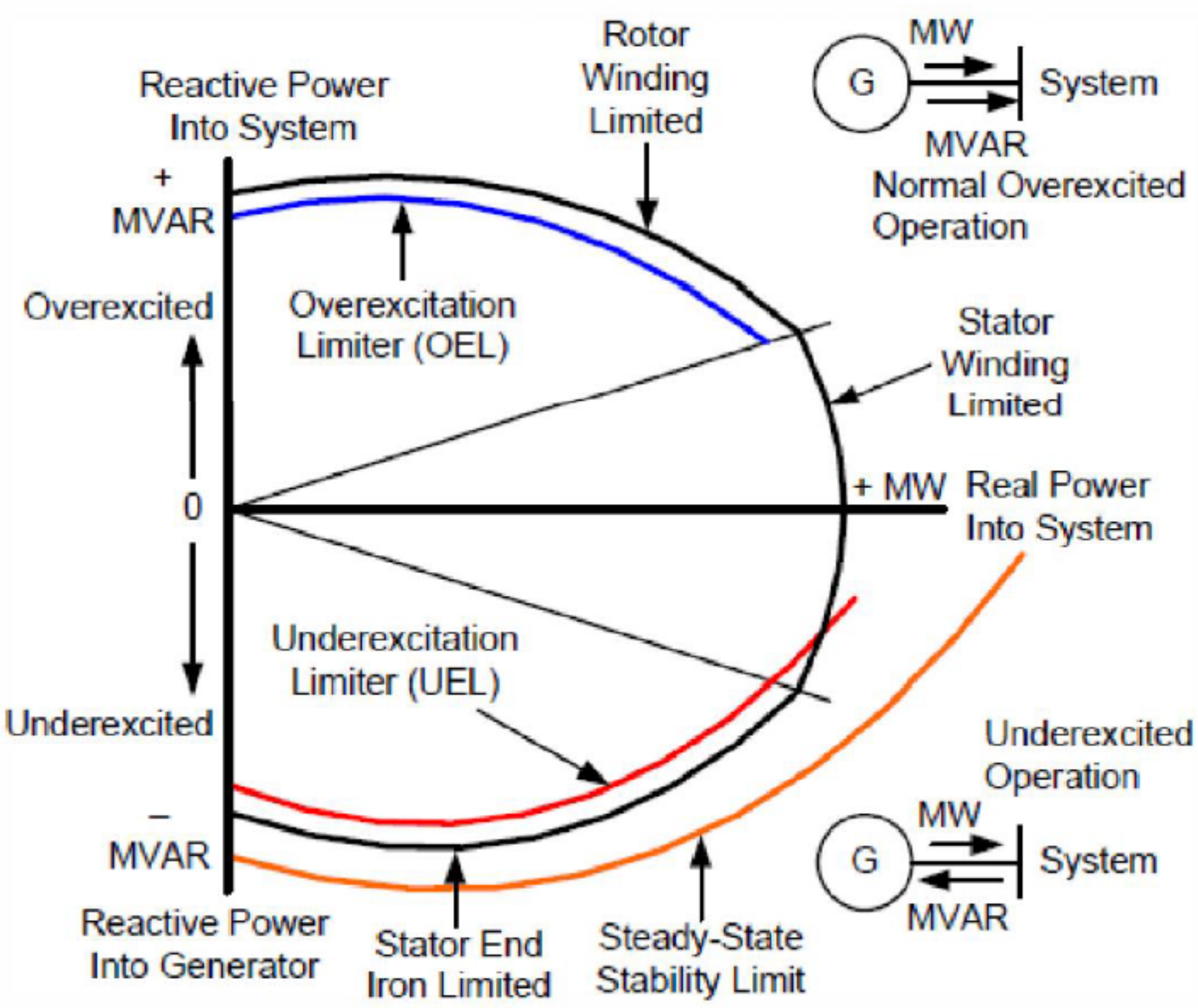
Variable	Description
$v_{f\,\max}$	Maximum field voltage
$v_{f\,\min}$	Minimum field voltage
μ_0	Regulator gain
T_2	Regulator pole
T_1	Regulator zero
v_{f_0}	Field voltage offset
V_0	Bus voltage offset
T_e	Field circuit time constant
T_r	Measurement time constant

Excitation System Advantages and Disadvantages

Parameter	DC	AC		ST
		Stationary	Brushless	
Excitation supply	Small transformer	Small transformer	Small transformer	Transformer
Length of machine	Medium	Medium	Long	Short
Response time	Slow	Medium	Medium	Very fast
Components requiring maintenance	Sliprings and commutator	Sliprings	-	Sliprings
De-excitation	Medium	Medium	Slow	Fast

ST: Static Excitation System

Capability Curve: End Limits



Source: M. Murali Mohan, Dy. Suptd

Under Excitation Limiter (UEL)

- Intended to prevent reduction of generator excitation to a level where steady-state (small-signal) **stability limit or stator core end -region heating limit** is exceeded
- Control signal derived from a combination of either voltage and current or active and reactive power of the generator
- Should be coordinated with the loss-of-excitation protection.

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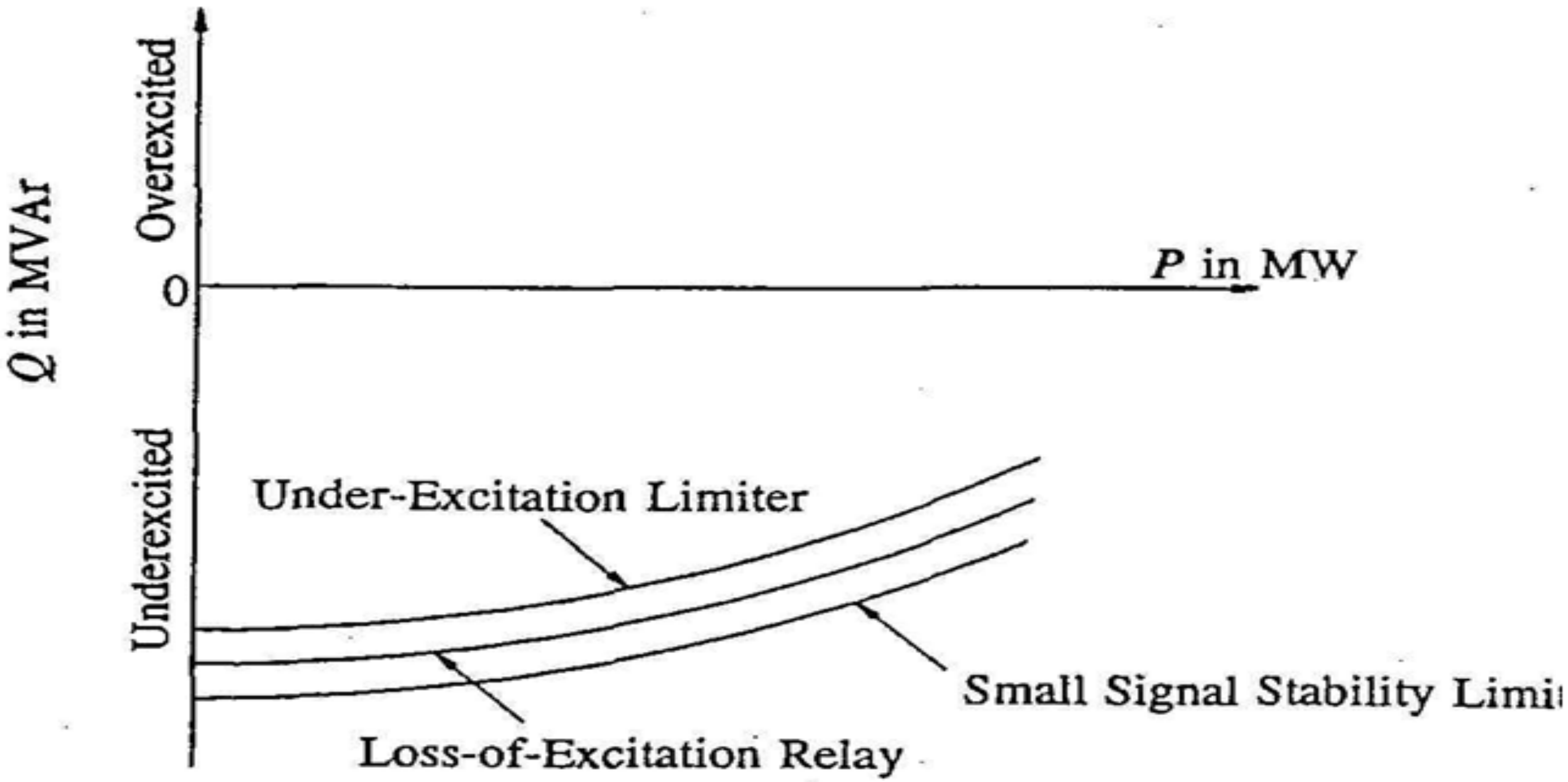
Over Excitation Limiter (OXL)

Purpose is to protect the generator from **overheating due to prolonged field over-current**

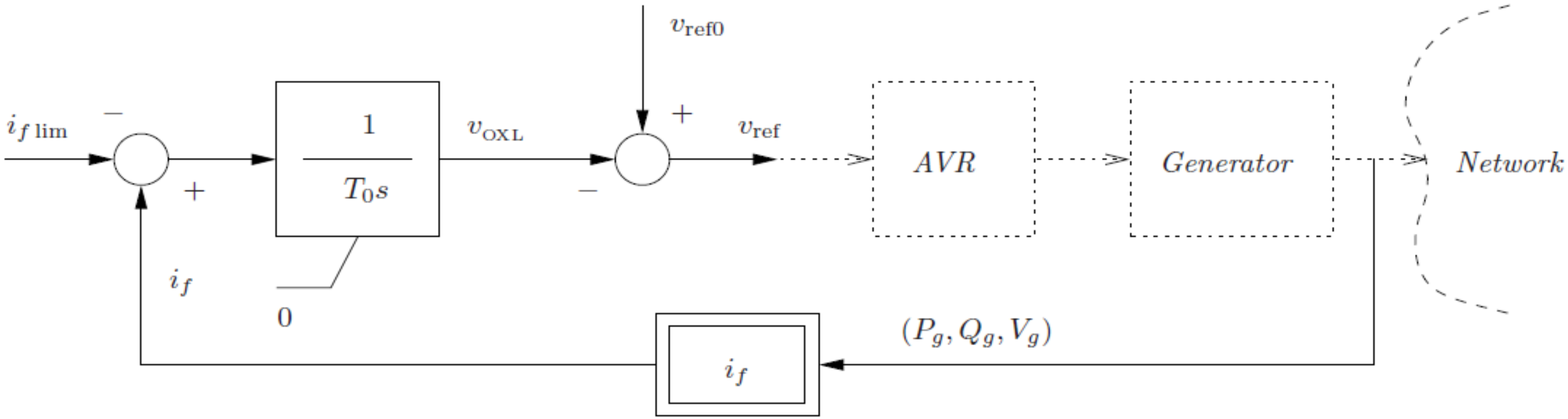
- OXL detects the high field current condition and, after a time delay, acts through the AC regulator to ramp down the excitation to about 110% of rated field current; if unsuccessful, trips the ac regulator, transfers to dc regulator, and repositions the set point corresponding to rated value two types of time delays used: **(a) fixed time, and (b) inverse time**
- With inverse time, the delay matches the thermal capability as shown in Figure

Coordination between UEL
Loss of Excitation Relay and Stability Limit



Coordination between UEL, LOE relay and stability limit

Over Excitation Limiter



Variable	Description
T_0	Integrator time constant
-	Use estimated generator reactances
x_d	d-axis estimated generator reactance
x_q	q-axis estimated generator reactance
$I_{f\text{lim}}$	Maximum field current
v_{max}	Maximum output signal

Over excitation limiter.

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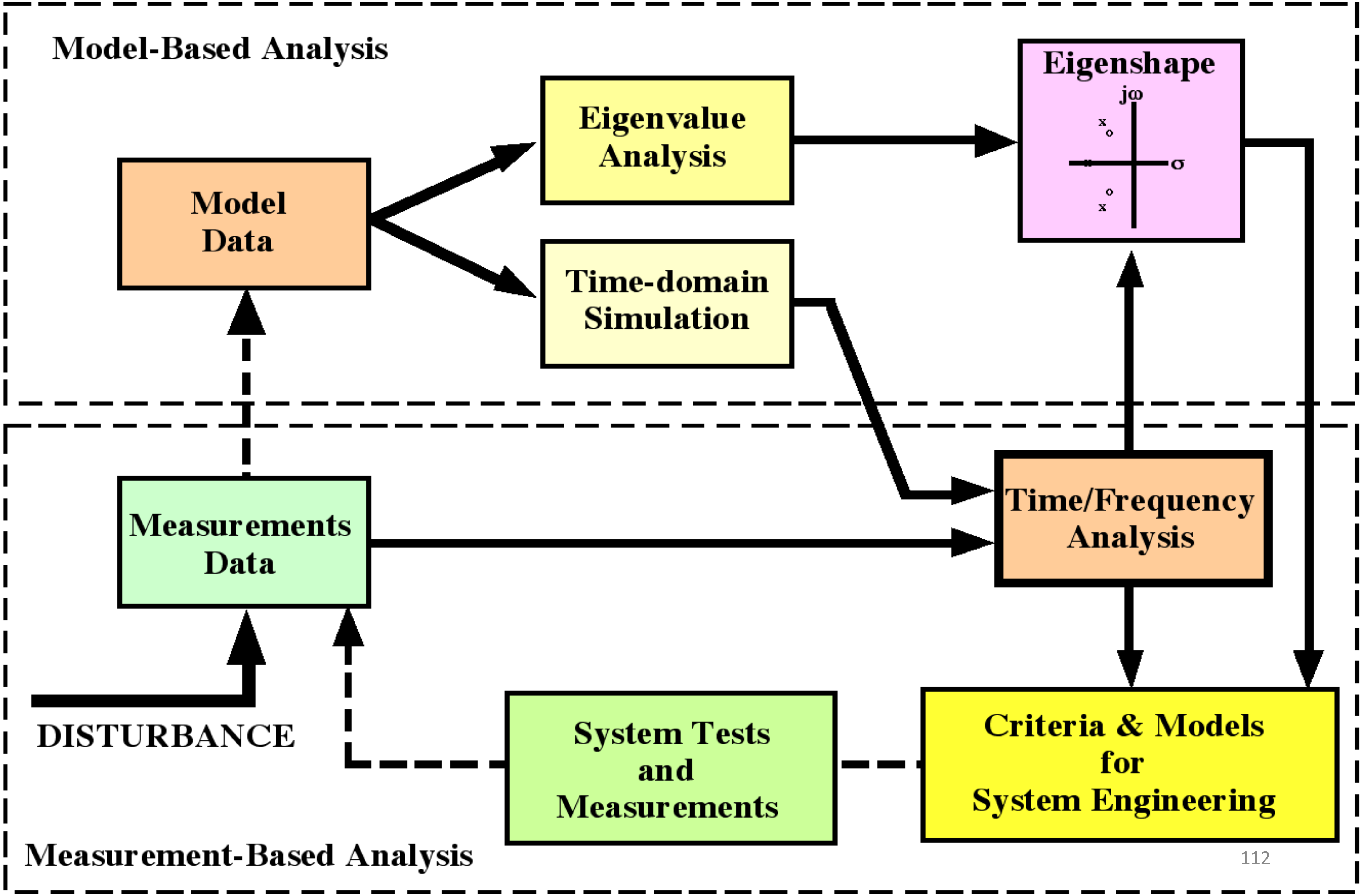
Smart Grid – Modeling and Control

Volts Per Hertz Limiter and Protection

Used to protect generator and step-up transformer from damage due to excessive magnetic flux

V/Hz (p.u.)		1.25	1.2	1.15	1.10	1.05
Damage Time in Minutes	GEN	0.2	1.0	6.0	20.0	∞
	XFMR	1.0	5.0	20.0	∞	∞

- V/Hz limiter (or regulator) controls the field voltage so as to limit the generator voltage when V/Hz exceeds a preset value
- V/Hz protection trips the generator when V/Hz exceeds the preset value for a specified time

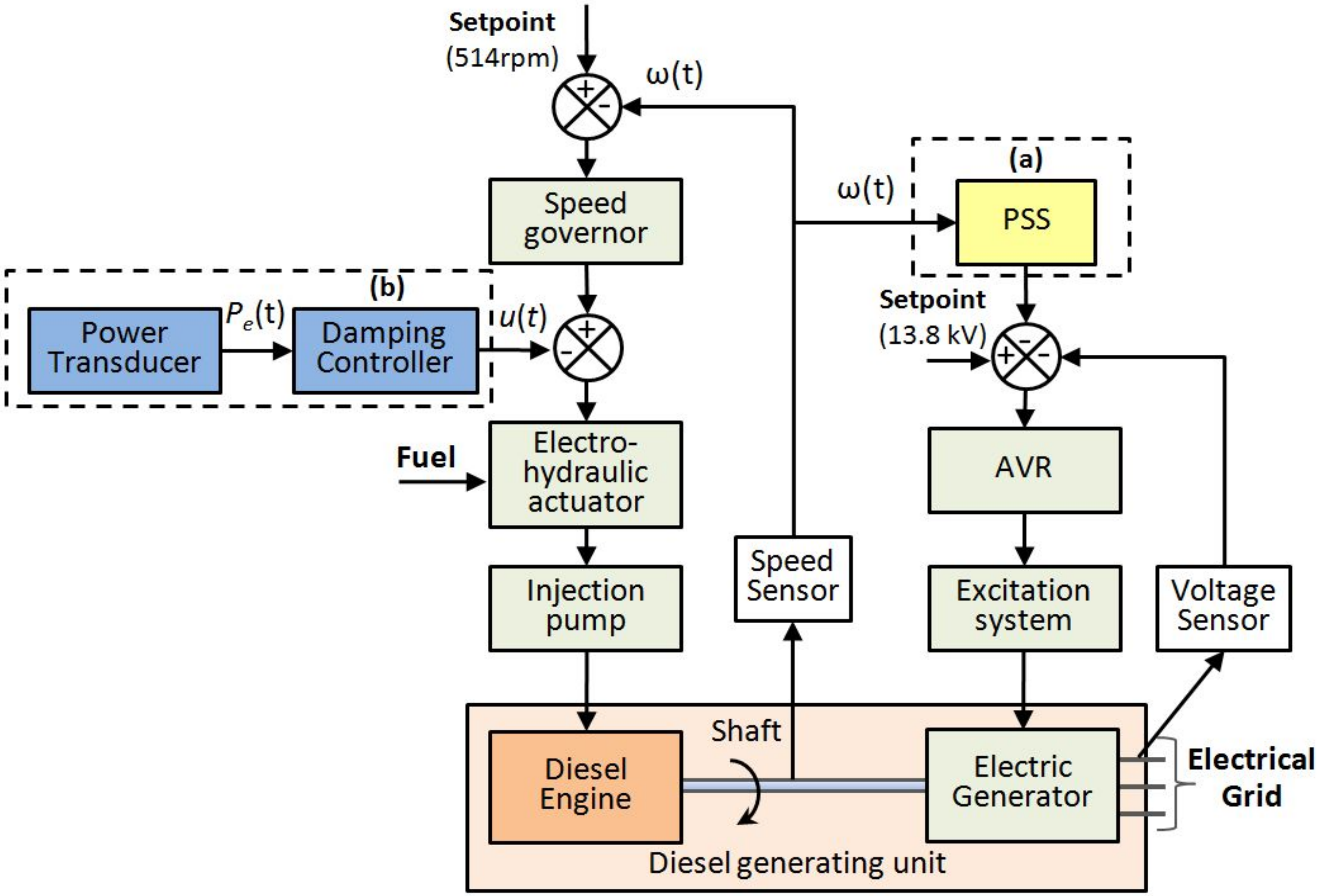


Model-Based Analysis
Model Data
Eigenvalue Analysis
Time-domain Simulation
Eigenshape
jω
σ
x
o
Measurements Data
Time/Frequency Analysis
DISTURBANCE
System Tests and Measurements
Criteria & Models for System Engineering
Measurement-Based Analysis

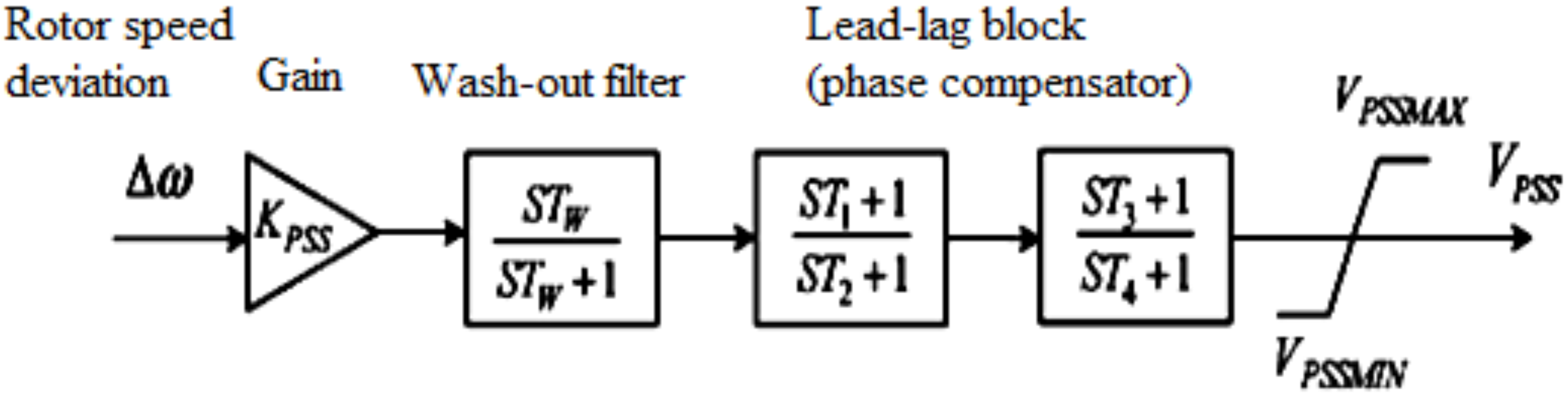
Power System Stabilizer

- Power System Stabilizers (PSSs) are typically used for damping **power system oscillations**
- The action of a PSS is to **extend the angular stability limits** of a power system by providing **supplemental damping to the oscillation** of synchronous machine rotors through the generator excitation
- This damping is provided by a electric torque applied to the rotor
- This supplementary control is very **beneficial during line outages** and large power transfers
- However, power system instabilities can arise due to negative damping effects of the PSS on the rotor
- During severe disturbances, a **PSS may actually cause the generator under its control to lose synchronism** in an attempt to control its excitation field

Role of Power System Stabilizer

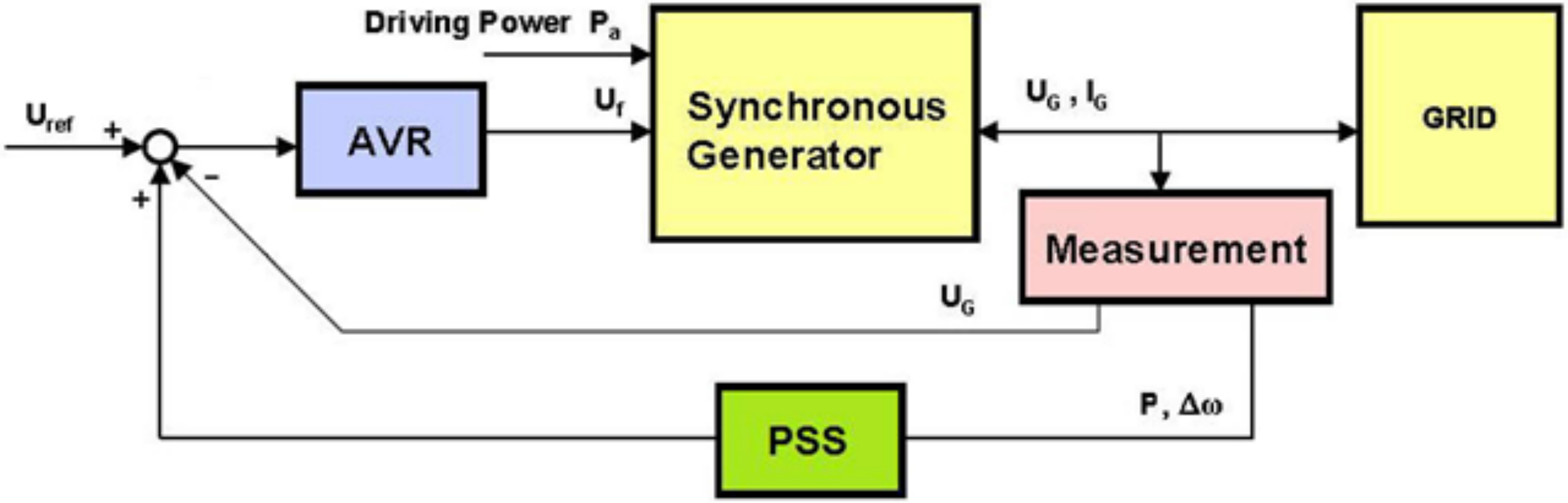


Power System Stabilizer - Model



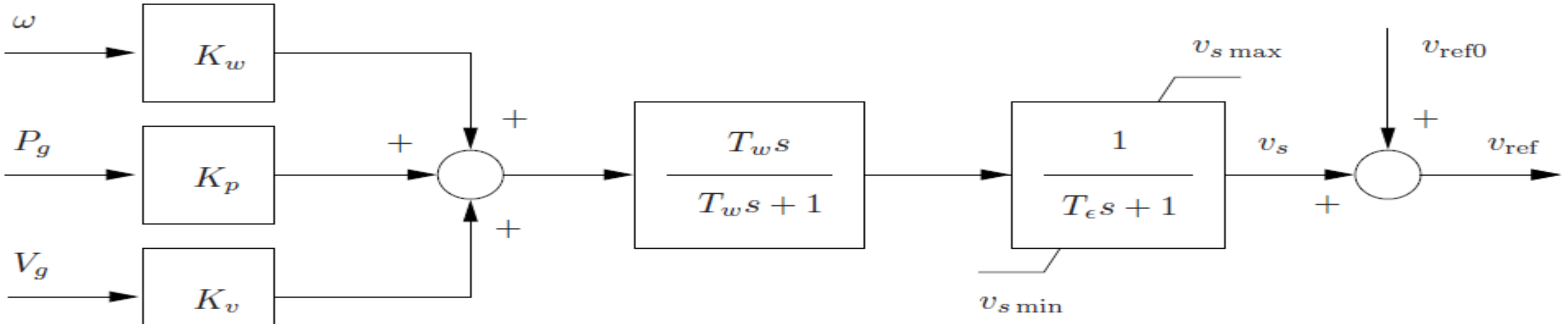
Source: http://reivax.com

Role of Power System Stabilizer

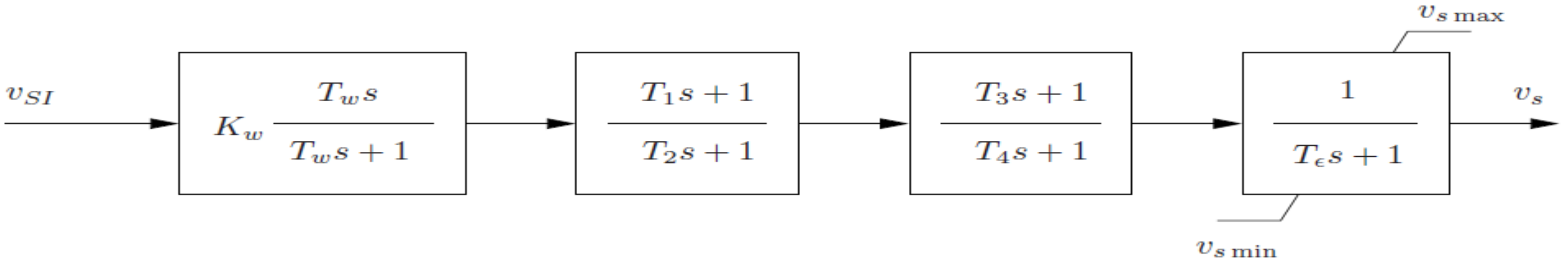


Smart Grid – Modeling and Control

Power System Stabilizer Models



Power system stabilizer Type I.



Power system stabilizer Type II.

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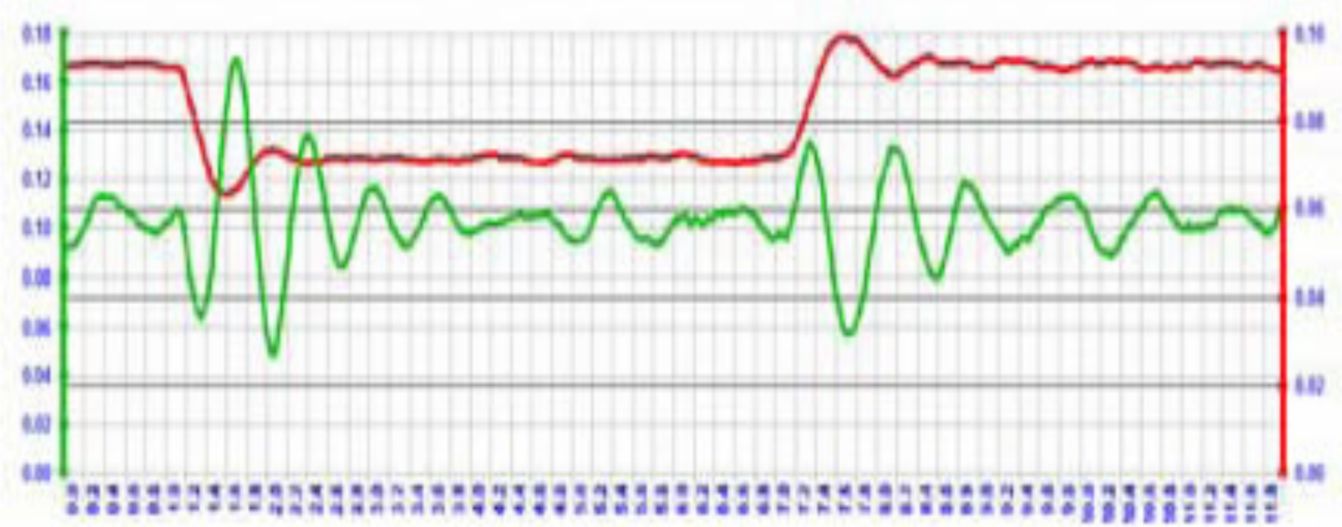
Effect of Power System Stabilizer

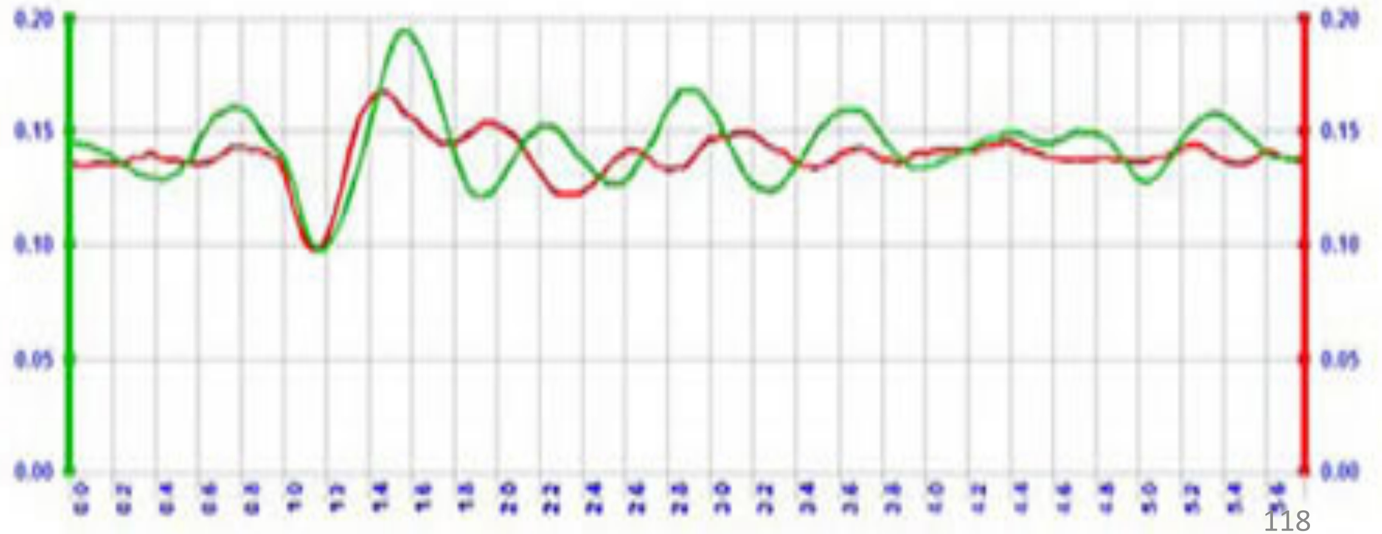


Without the PSS

Two traces are shown, the AC machine voltage on line and the MW. Notice how the MW is excited into oscillations by the step change of voltage.

With PSS

Top line (Green) with PSS gain =0 and Lower line (Red) with PSS gain =5.



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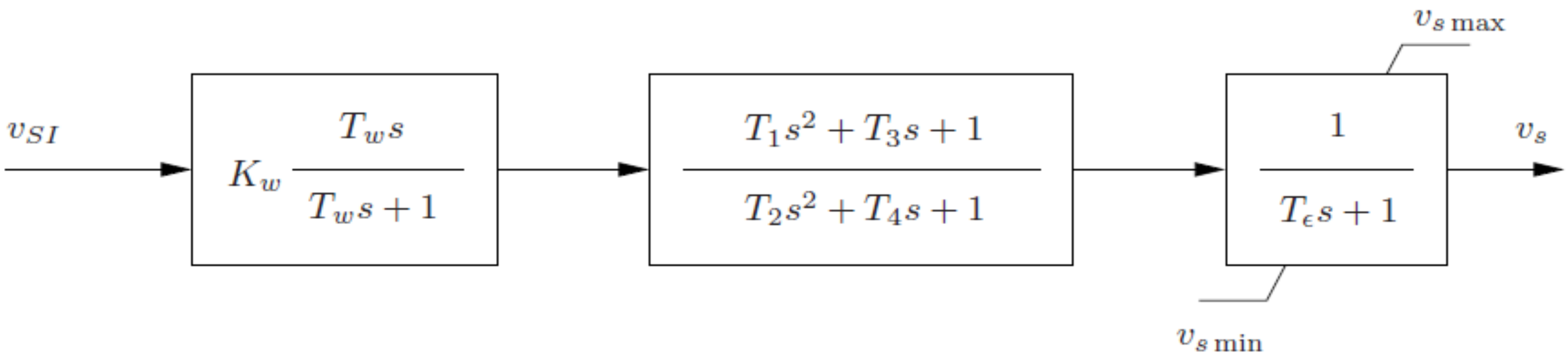
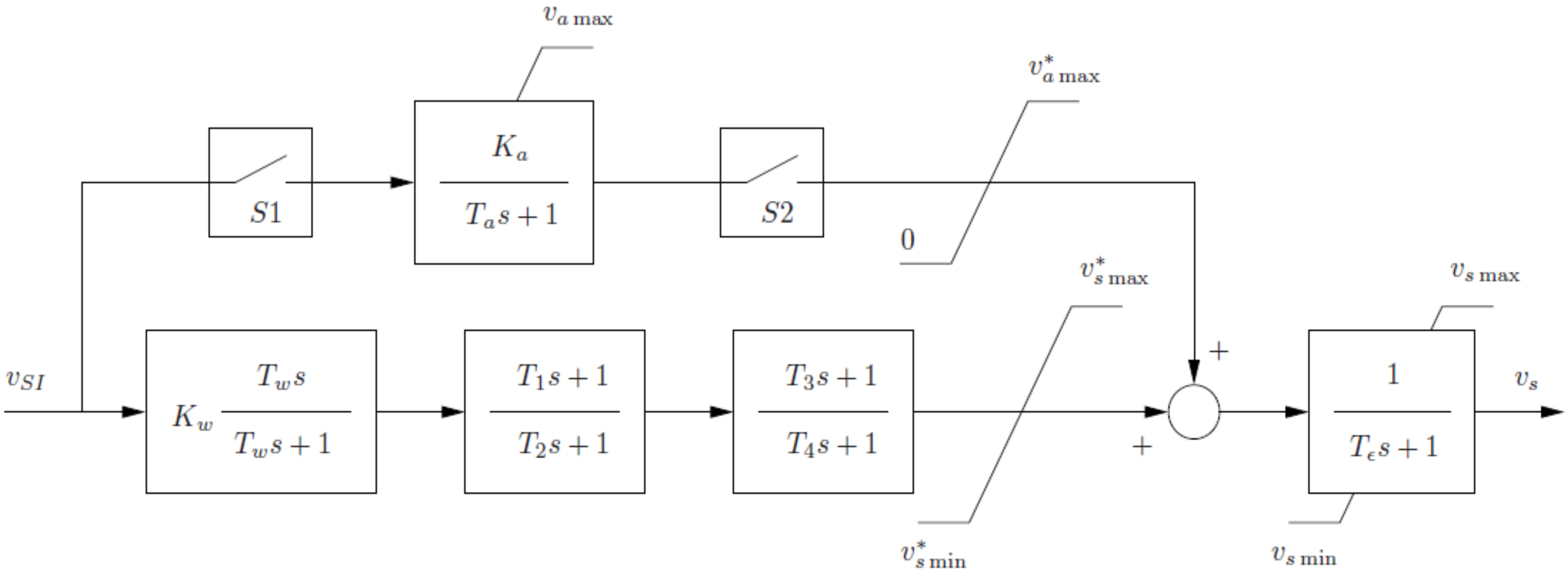
Power System Stabilizer – Type III



Power system stabilizer Type III.

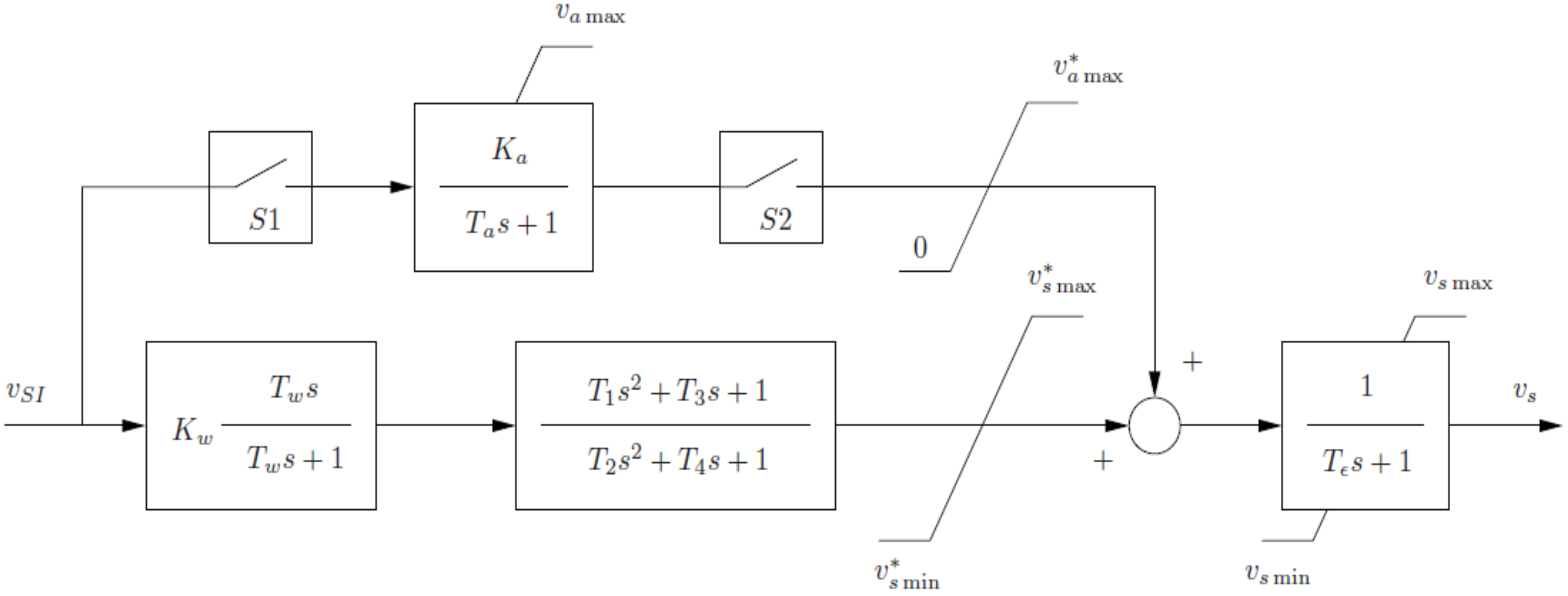
Variable	Description
-	AVR number
-	PSS model
-	PSS input signal 1 $\Rightarrow\ \omega$, 2 $\Rightarrow\ P_g$, 3 $\Rightarrow\ V_g$
$v_{s_{\max}}$	Max stabilizer output signal
$v_{s_{\min}}$	Min stabilizer output signal
K_w	Stabilizer gain (used for ω in model I)
T_w	Wash-out time constant
T_1	First stabilizer time constant
T_2	Second stabilizer time constant
T_3	Third stabilizer time constant
T_4	Fourth stabilizer time constant
K_a	Gain for additional signal
T_a	Time constant for additional signal
K_p	Gain for active power
K_v	Gain for bus voltage magnitude
$v_{a_{\max}}$	Max additional signal (anti-windup)
$v^*_{a_{\min}}$	Max additional signal (windup)
$v^*_{s_{\max}}$	Max output signal (before adding v_a)
$v^*_{s_{\min}}$	Min output signal (before adding v_a)
e_{thr}	Field voltage threshold
ω_{thr}	Rotor speed threshold
s_2	Allow for switch S2

Power System Stabilizer – Type IV



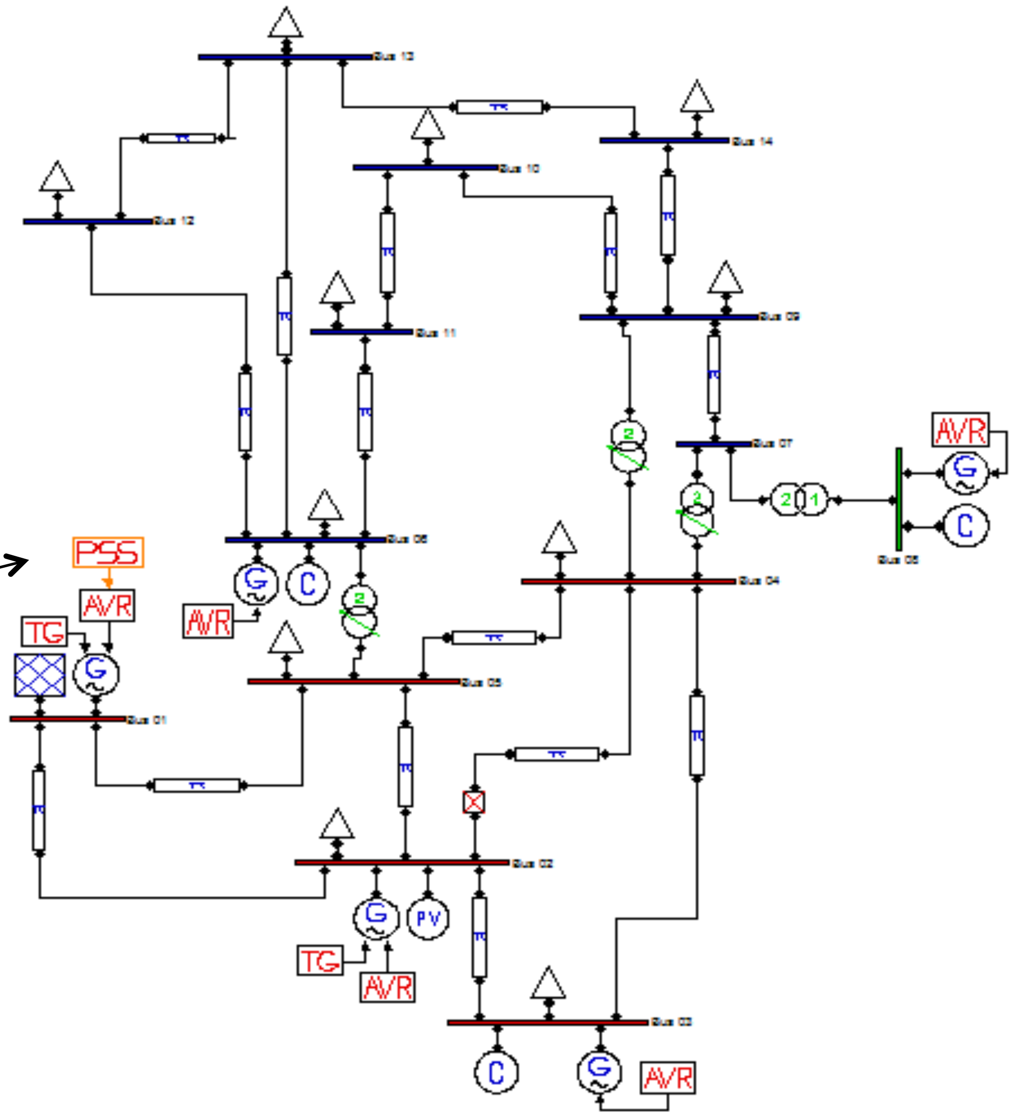
Power system stabilizer Type IV.

Power System Stabilizer – Type V



Power system stabilizer Type V.

Connection of PSS to IEEE-14 Bus System



PSS Connected to
the AVR of Bus - 1

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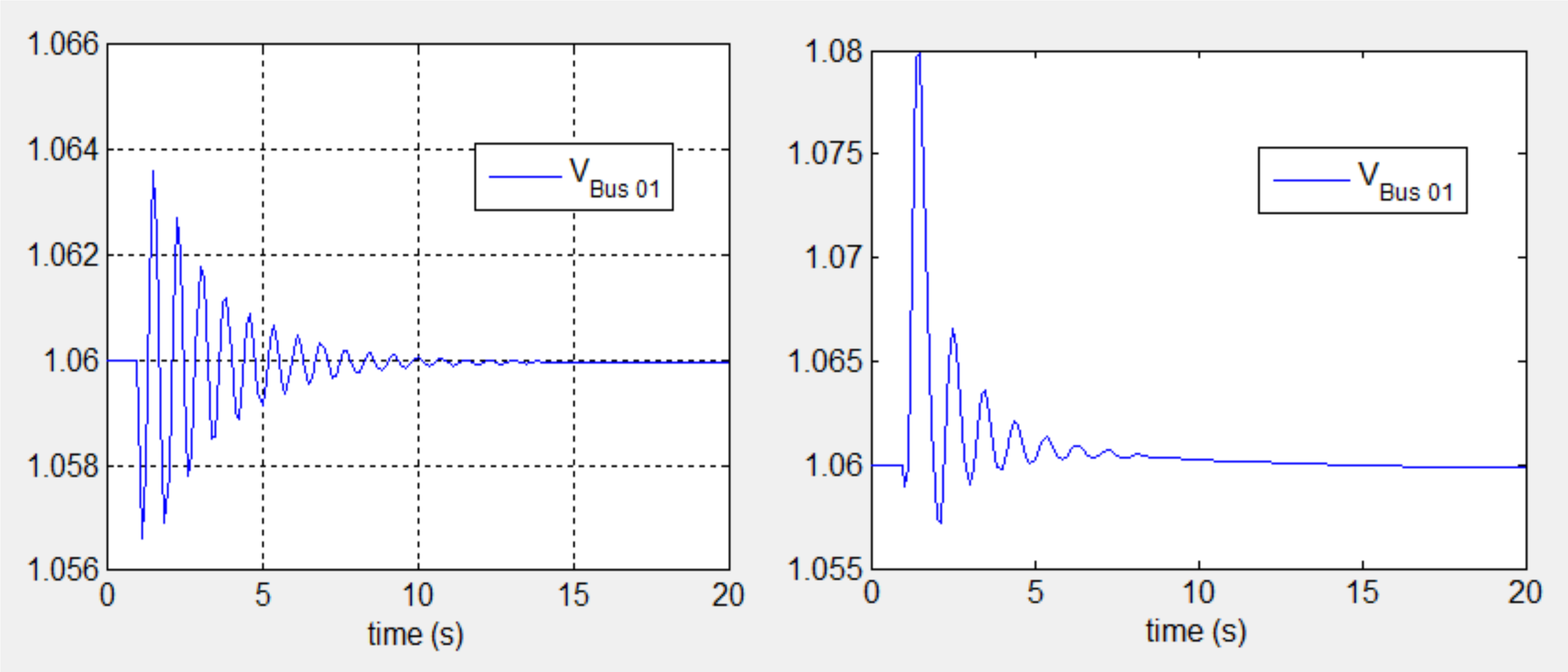
Performance Characteristics

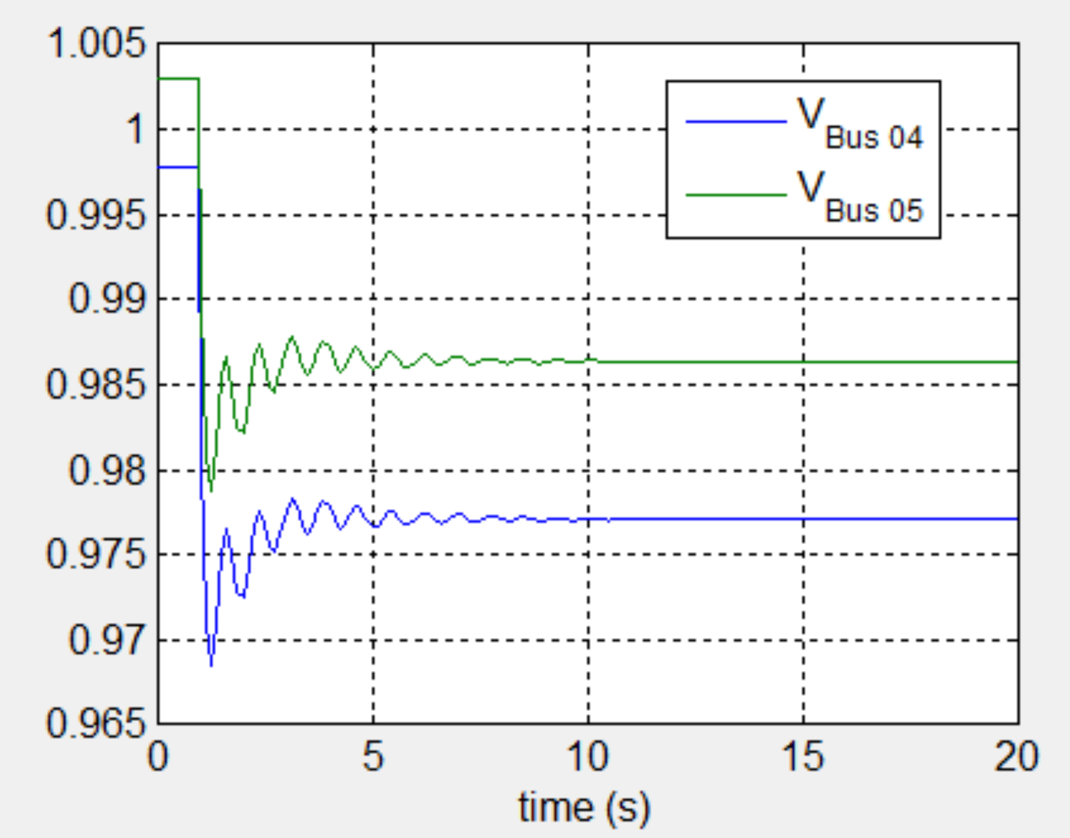
With PSS

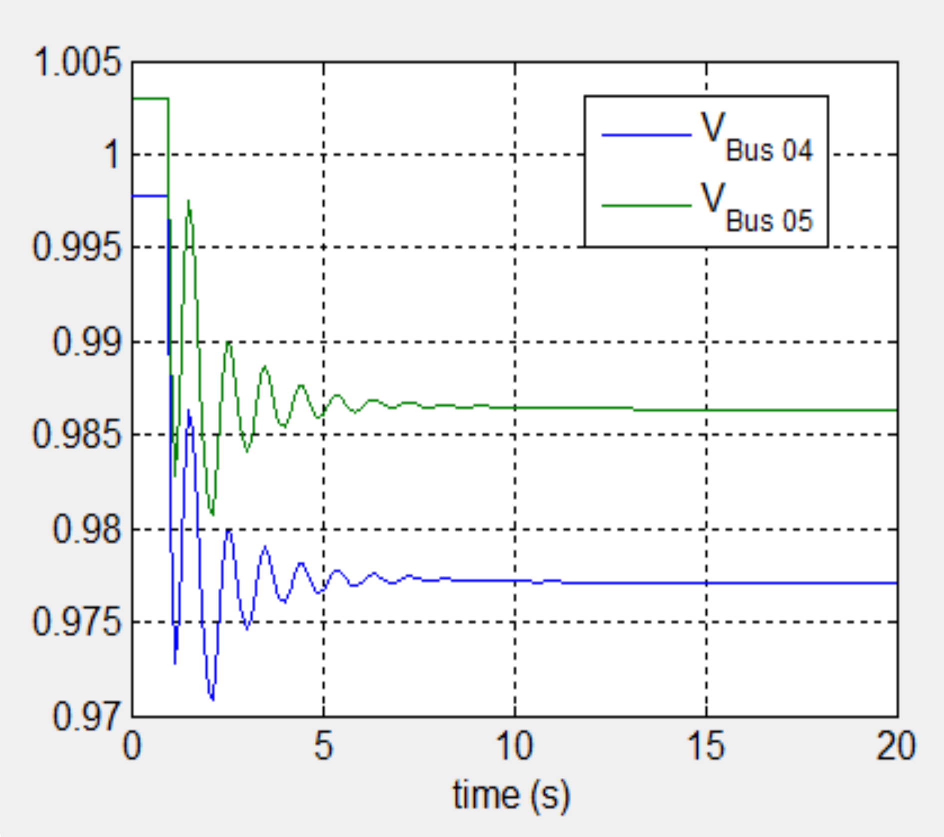


With Out PSS

Performance Characteristics with PSS

With PSS





Without PSS

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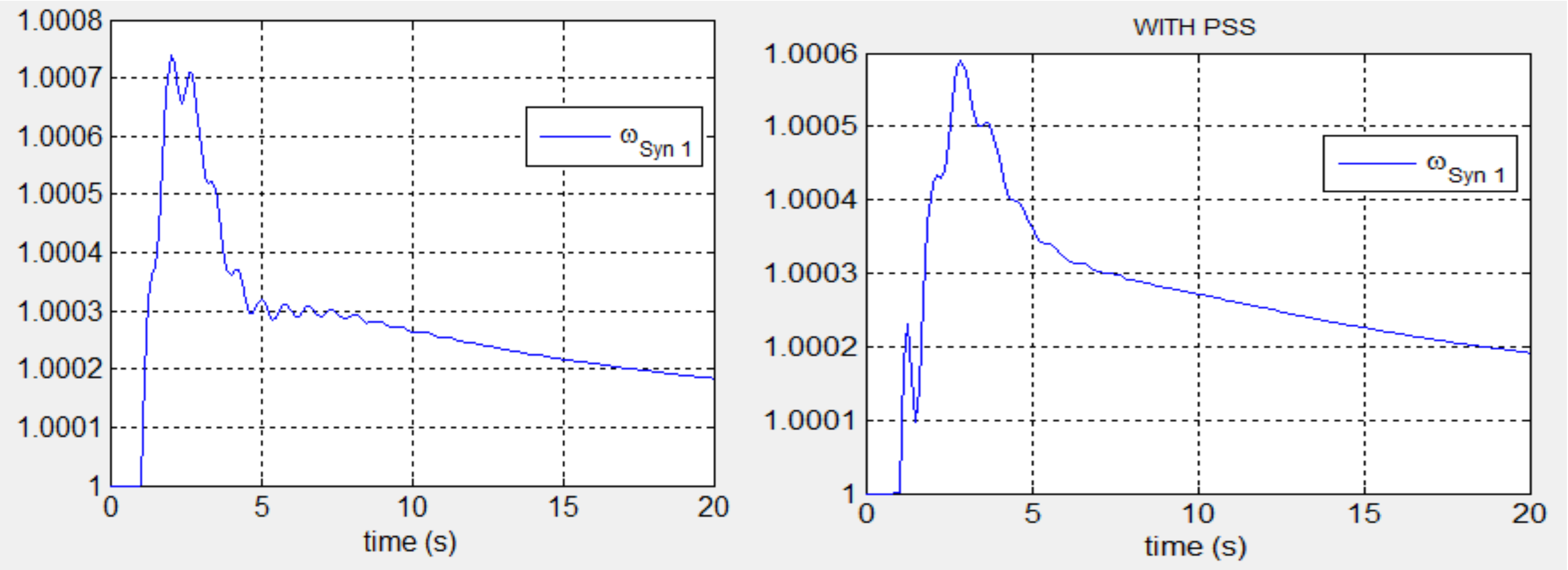
Omega of the Machine 1

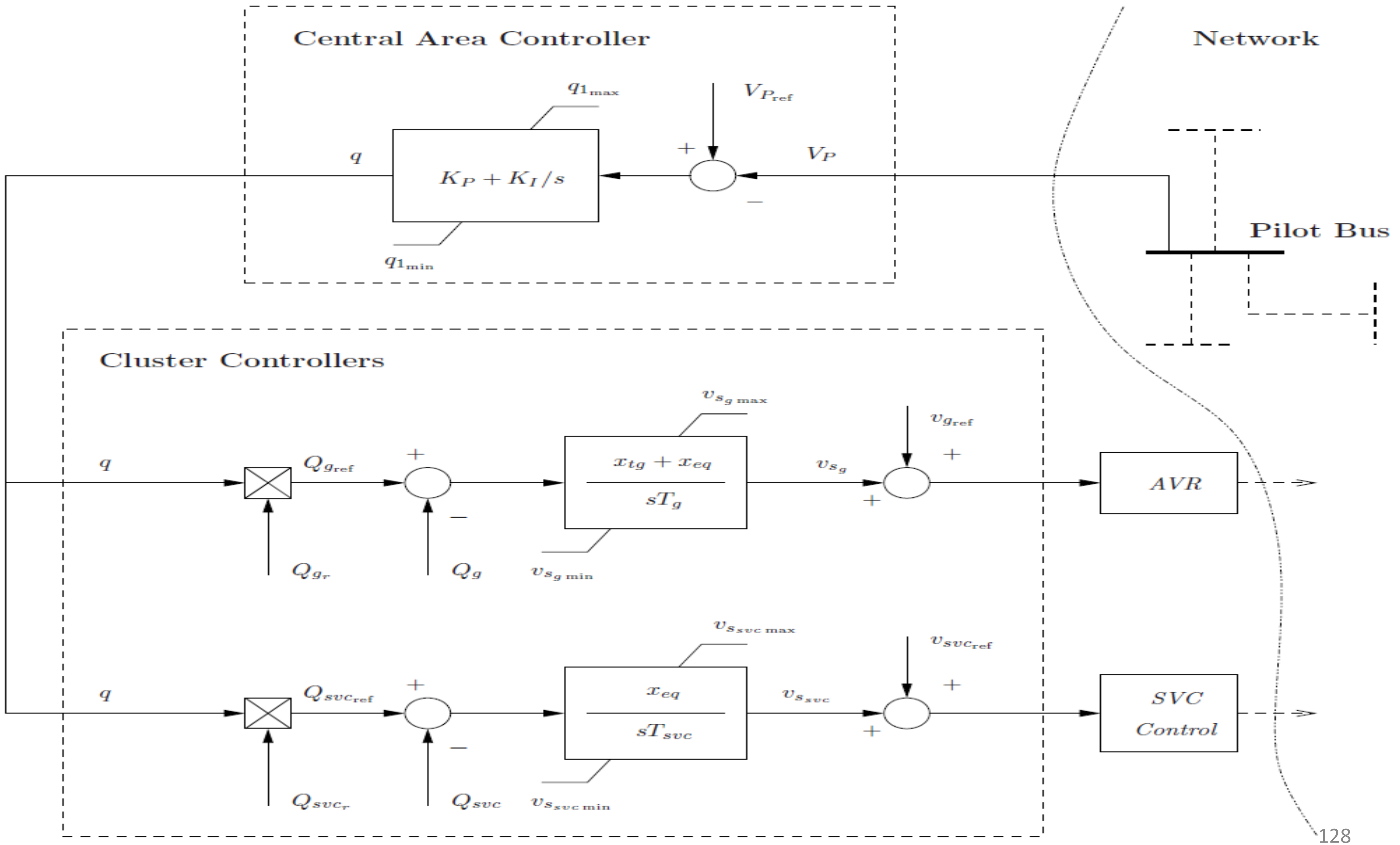


With Out PSS

Secondary Voltage Control

- Secondary Voltage Control is normally implemented by means of Cluster Area Controller (CAC)
- Cluster Area Controller (CAC) controls the voltage at a pilot bus
- Cluster Controllers (CC), compare the CAC signal with the reactive power generated by synchronous machines and/or SVCs and modify the reference voltages of AVRs

Central Area Controller & Cluster Controller



Smart Grid – Modeling and Control

Central Area Controller & Cluster Controller

Variable	Description
S_n	Power rating
V_n	Voltage rating
-	number of connected CC
$V_{P_{\mathrm{ref}}}$	Reference pilot bus voltage
K_I	Integral control gain
K_P	Proportional control gain
$q1_{\max}$	Maximum output signal
$q1_{\min}$	Minimum output signal

Variable	Description
-	Central Area Controller number
-	AVR or SVC number
-	Control type (1) AVR; (2) SVC
T_g (T_{svc})	Integral time constant
x_{t_g}	Generator transformer reactance
x_{eq_g} ($x_{eq_{svc}}$)	Equivalent reactance
Q_{g_r} (Q_{svc_r})	Reactive power ratio
$V_{s_{\max}}$	Maximum output signal
$V_{s_{\min}}$	Minimum output signal

Power Oscillation Damper

- Control scheme of the POD are the same as the PSS
- The output signal for the POD can be used with SVC,TCSC, STATCOM, SSSC and UPFC components.

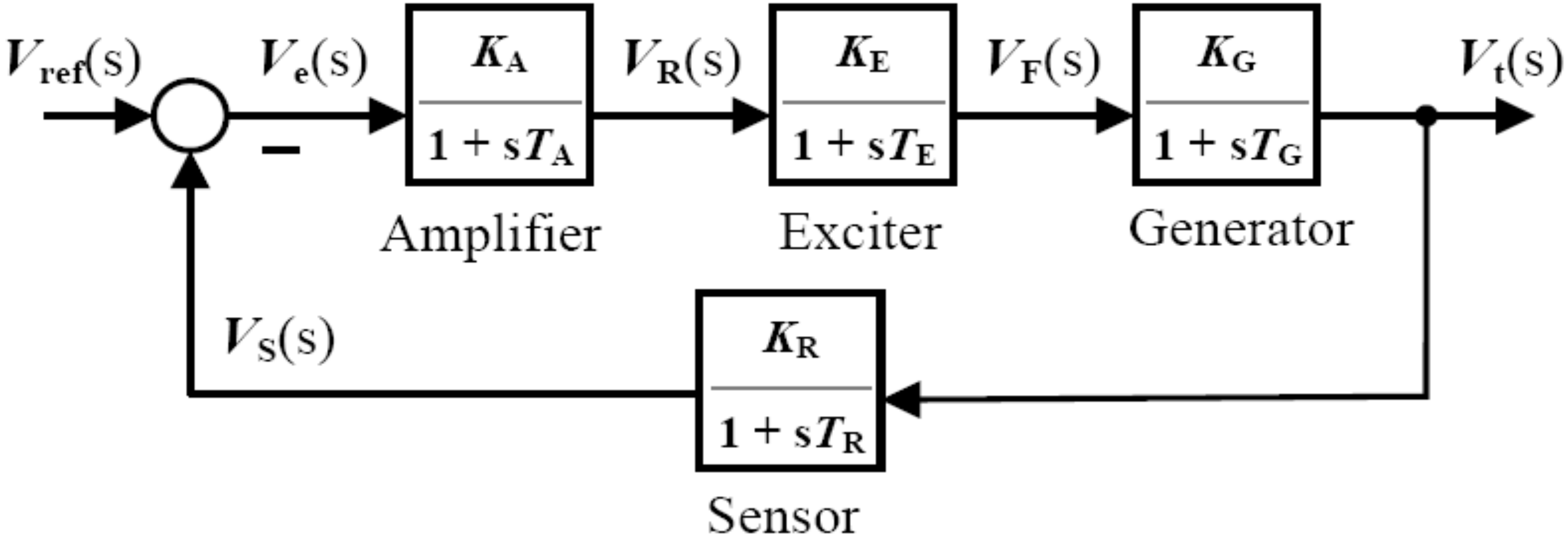
CASE STUDY

SPPA-E3000 Compound Excitation System

Source: http://www.energy.siemens.com

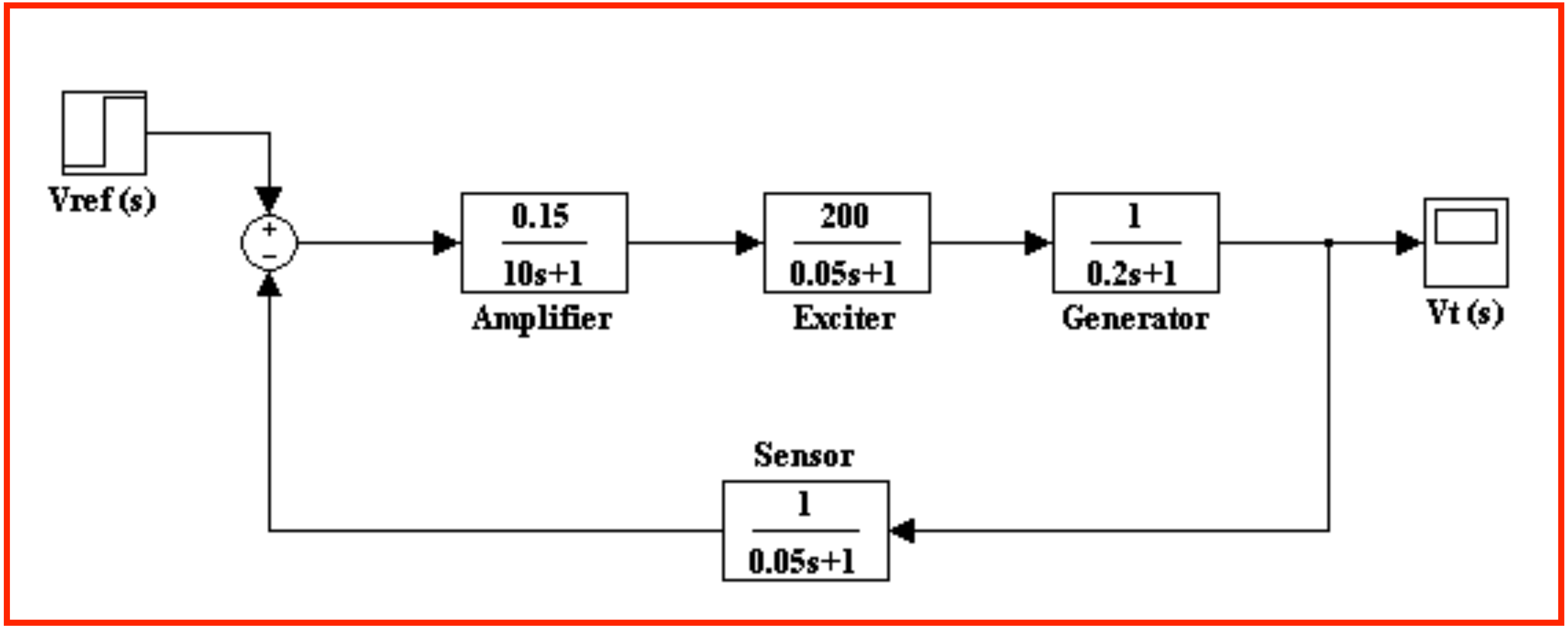
Smart Grid – Modeling and Control

Block diagram of a Simple (AVR)



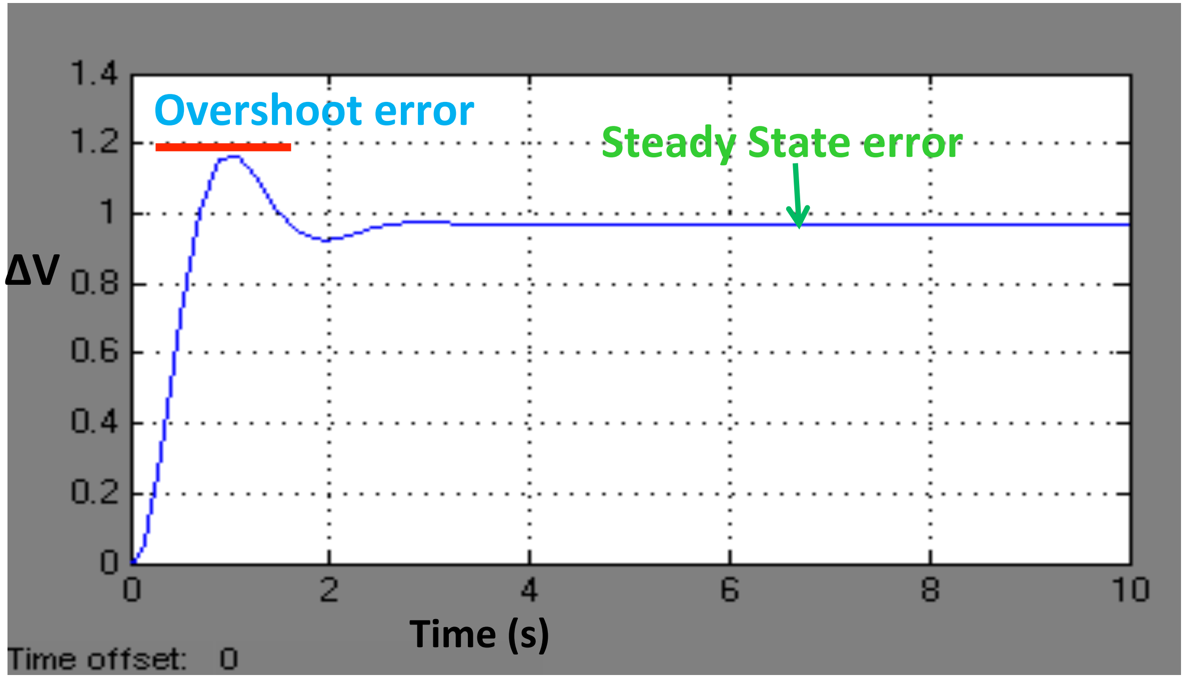
K_E=200	T_E =0.05
K_G=1	T_G =0.2
K_R=0.05	T_R =0.05
KA=0.15	TA=10

Case 1: AVR without PI controller.

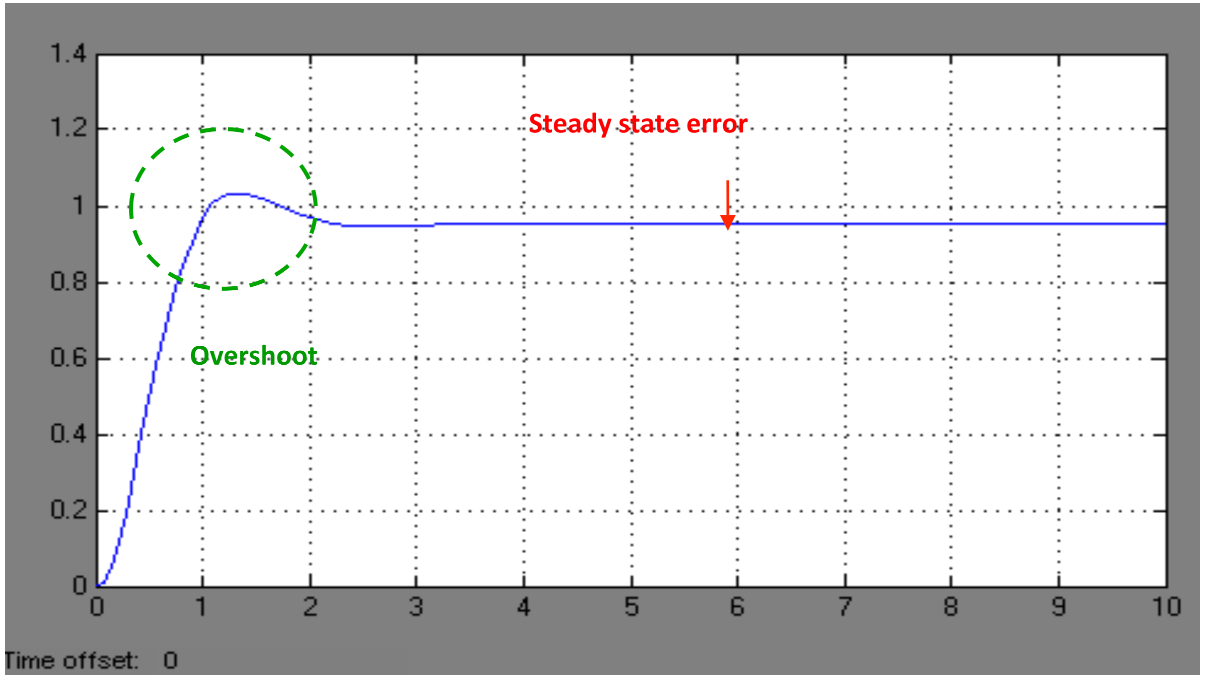


Block diagram of AVR model without PI controller

Output Voltage Response without Controller

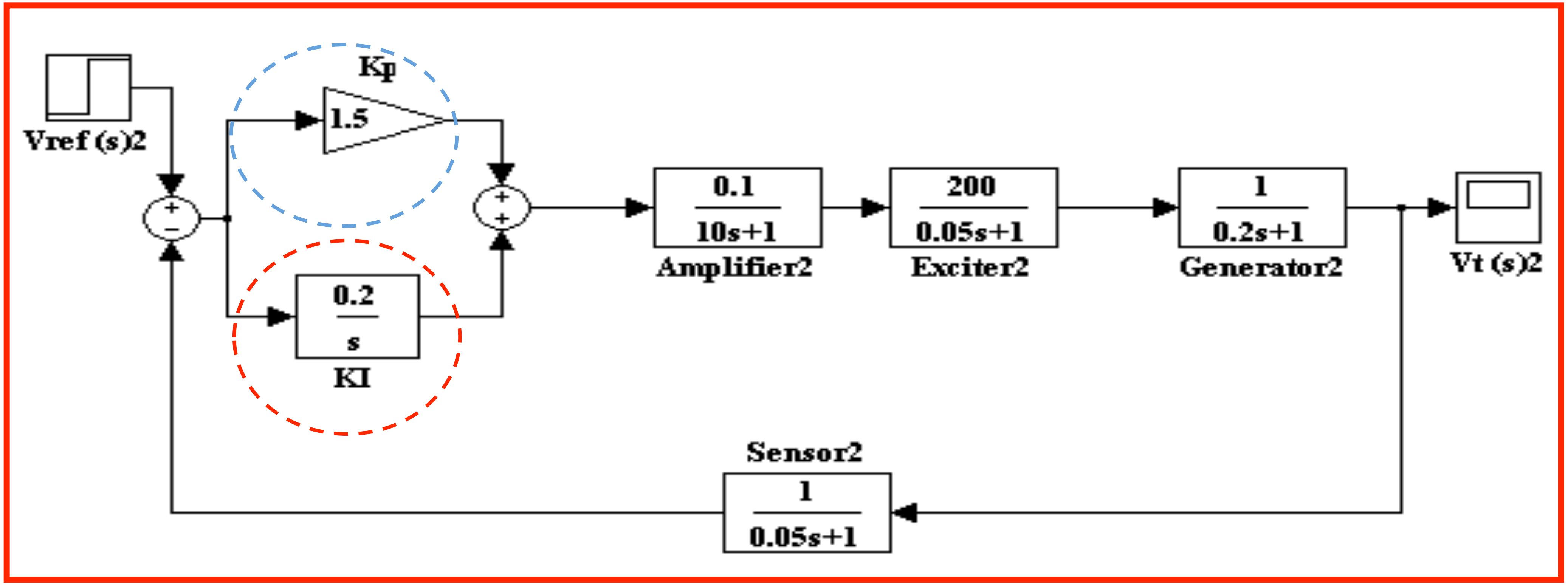


The output voltage response when Ka of the amplifier is 0.15



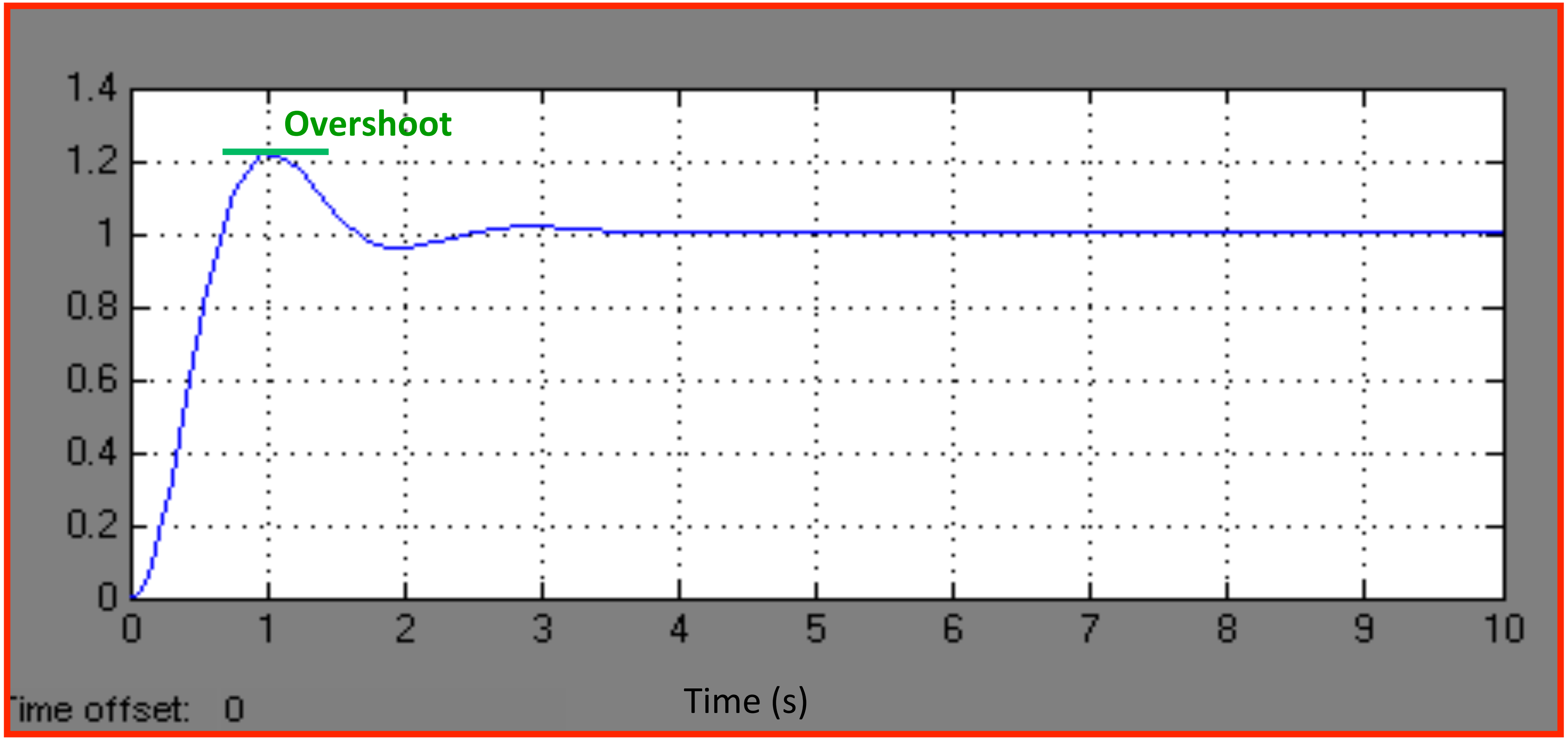
The output voltage response when Ka of the amplifier was changed to 0.1

Case 2: AVR with PI controller.



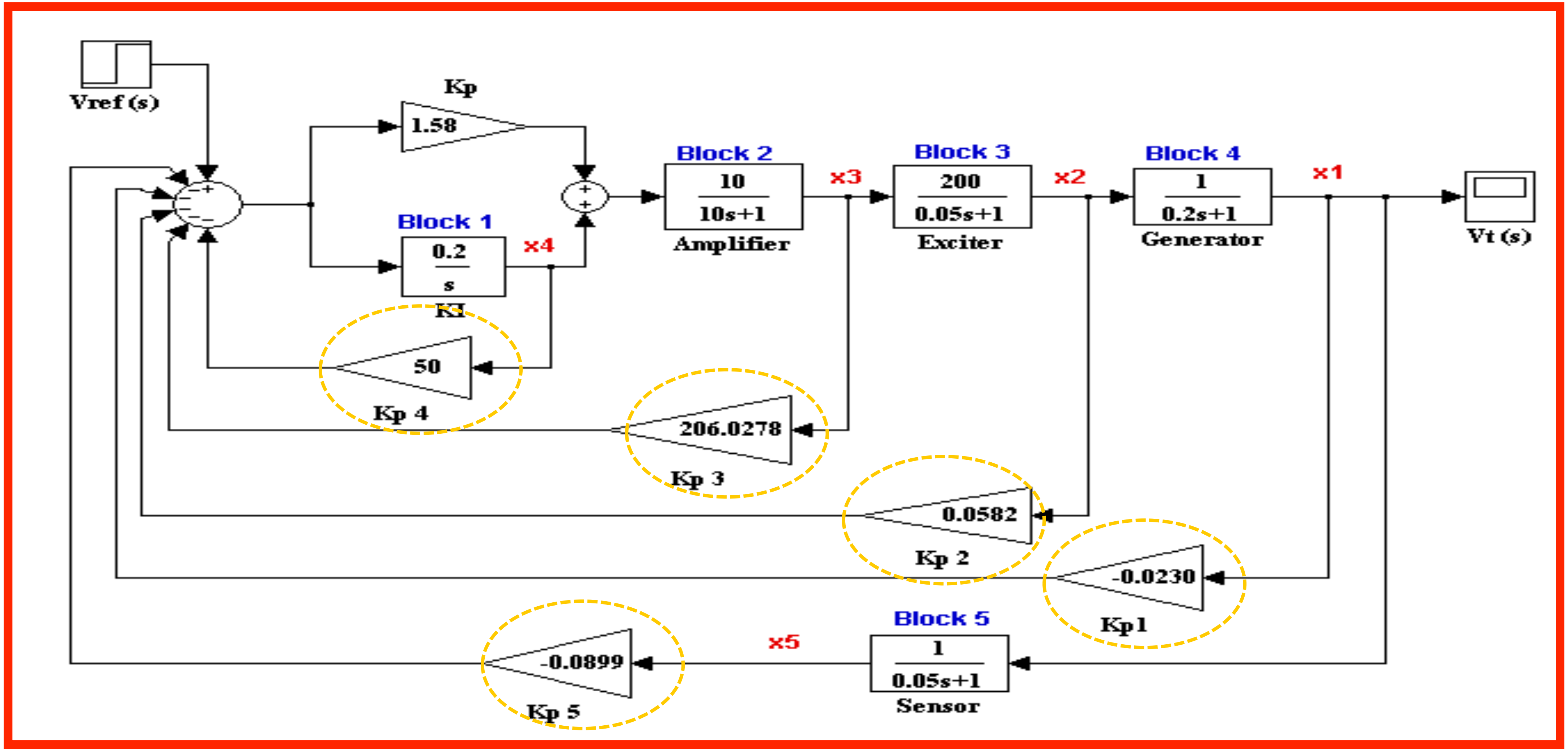
Block diagram of AVR model with K_i and K_p gains

Output Voltage Response with PI Controller



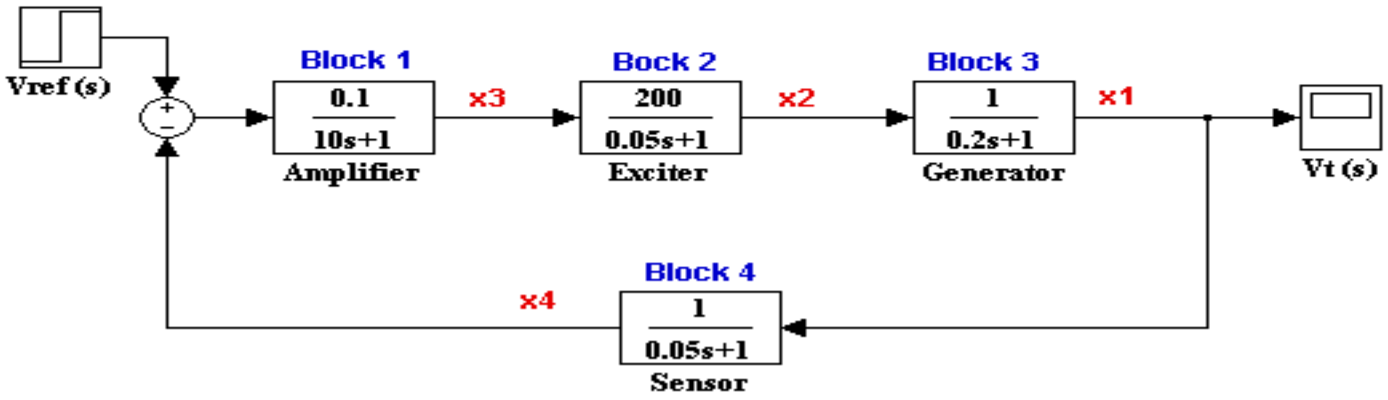
The output voltage response when K_i=0.2 and K_p= 1.5

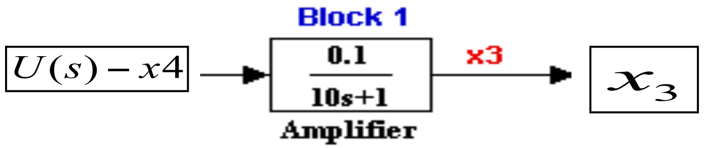
Case 3: AVR with optimal control

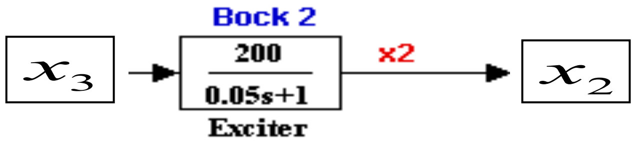


Block diagram of AVR model with feedback gains

Step 1:
Find the state variables and output equations

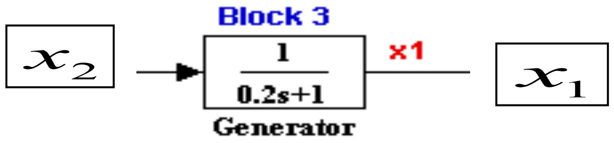


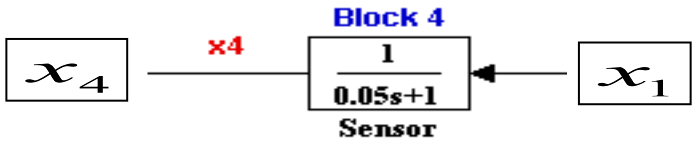




$$\dot{x}3 = -0.1x_3 - 0.01x_4 + 0.01u(t)$$

$$\dot{x}2 = -20x_2 + 4000x_3$$





$$\dot{x}_1 = -5x_1 + 5x_2$$

$$\dot{x}_4 = -20x_4 + 20x_1$$

Step 2: Find A,B, C, D matrices

State differential Equation:

$$\boxed{\dot{x}(t) = A_{n\times n}x(t) + B_{n\times m}u(t)}$$

Output Equation:

$$\boxed{y(t) = C_{p\times n}x(t) + D_{p\times m}u(t)}$$

A=[-5 5 0 0; 0 -20 4000 0; 0 0 -0.1 -0.01;20 0 0 -20]

B=[0;0;0.01;0]

C=[1 0 0 0]

D=[0]

Step 3: MATLAB command to find feedback gains

MATLAB command

```
A=[-5 5 0 0; 0 -20 4000 0; 0 0 -0.1 -0.01;20 0 0 -20]
Q=[5 0 0 0; 0 5 0 0; 0 0 5 0; 0 0 0 5]
B=[0;0;0.01;0]
R=5
[F,P,ev]=lqr(A,B,Q,R)
```

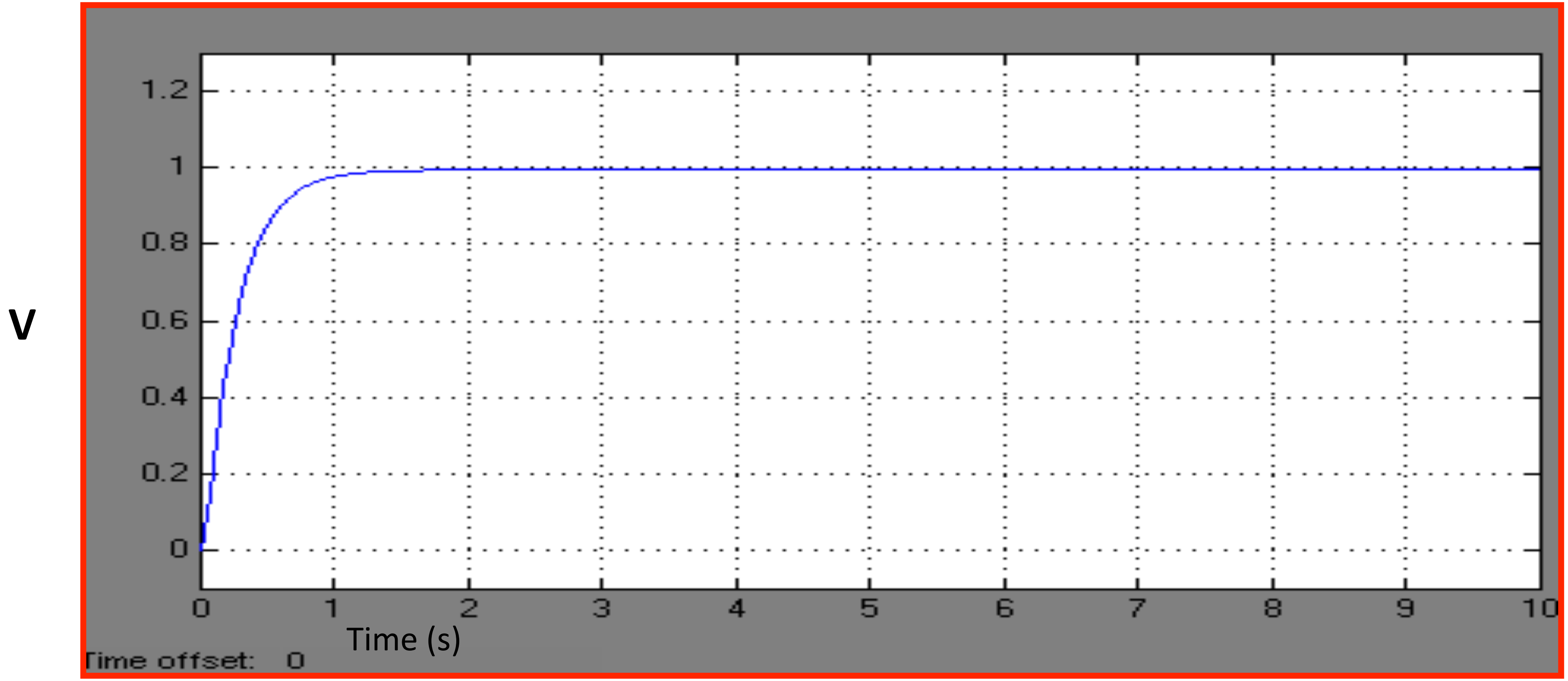
MATLAB Function

Result of running the program:

values of feedback gains k_1,k_2,k_3,k_4

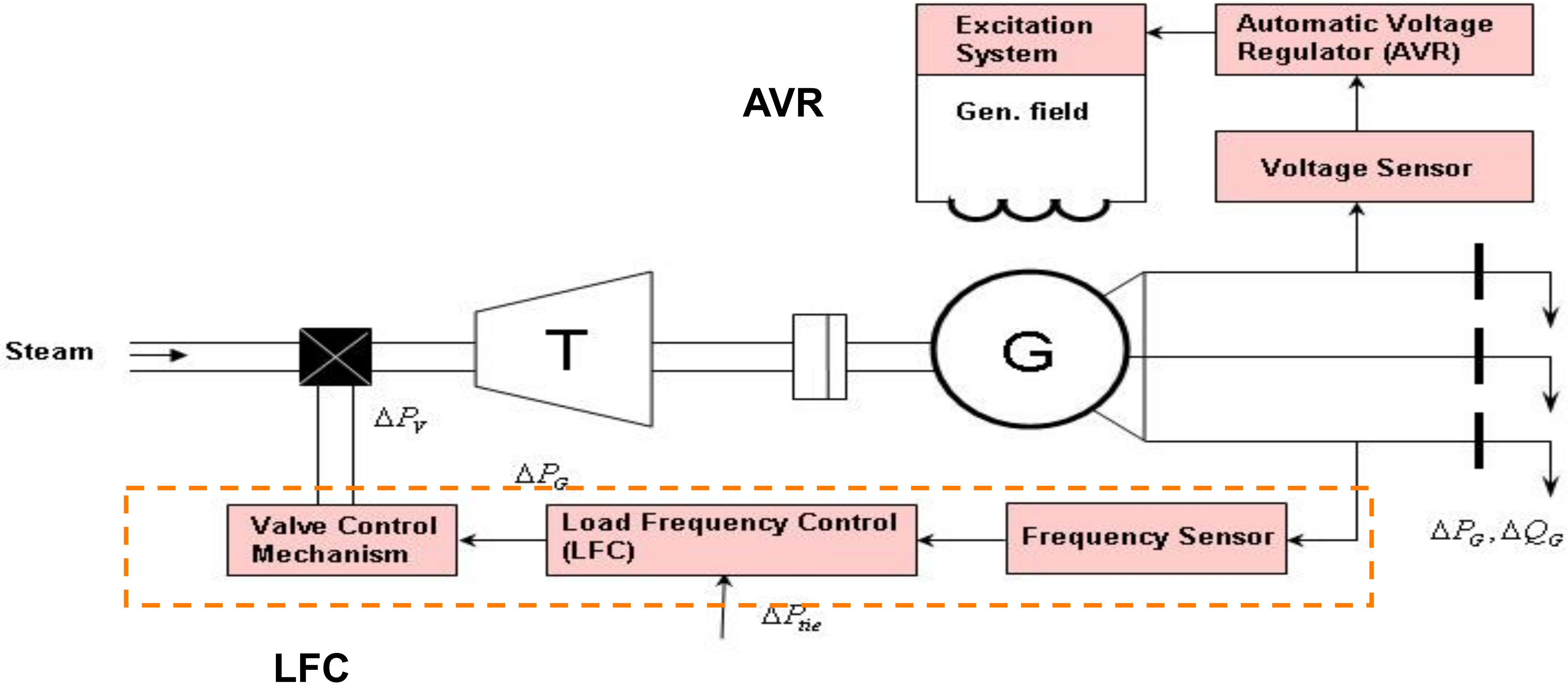
```
F =

   -0.0230    0.0582  206.0278   -0.0899

P =

  1.0e+005 *

    0.0000    0.0000   -0.0001    0.0000
    0.0000    0.0000    0.0003    0.0000
   -0.0001    0.0003    1.0301   -0.0004
    0.0000    0.0000   -0.0004    0.0000

ev =

 -20.6225 + 3.4261i
 -20.6225 - 3.4261i
  -2.9577 + 3.1290i
  -2.9577 - 3.1290i
```

Output Voltage Response with Optimal and Integral Control



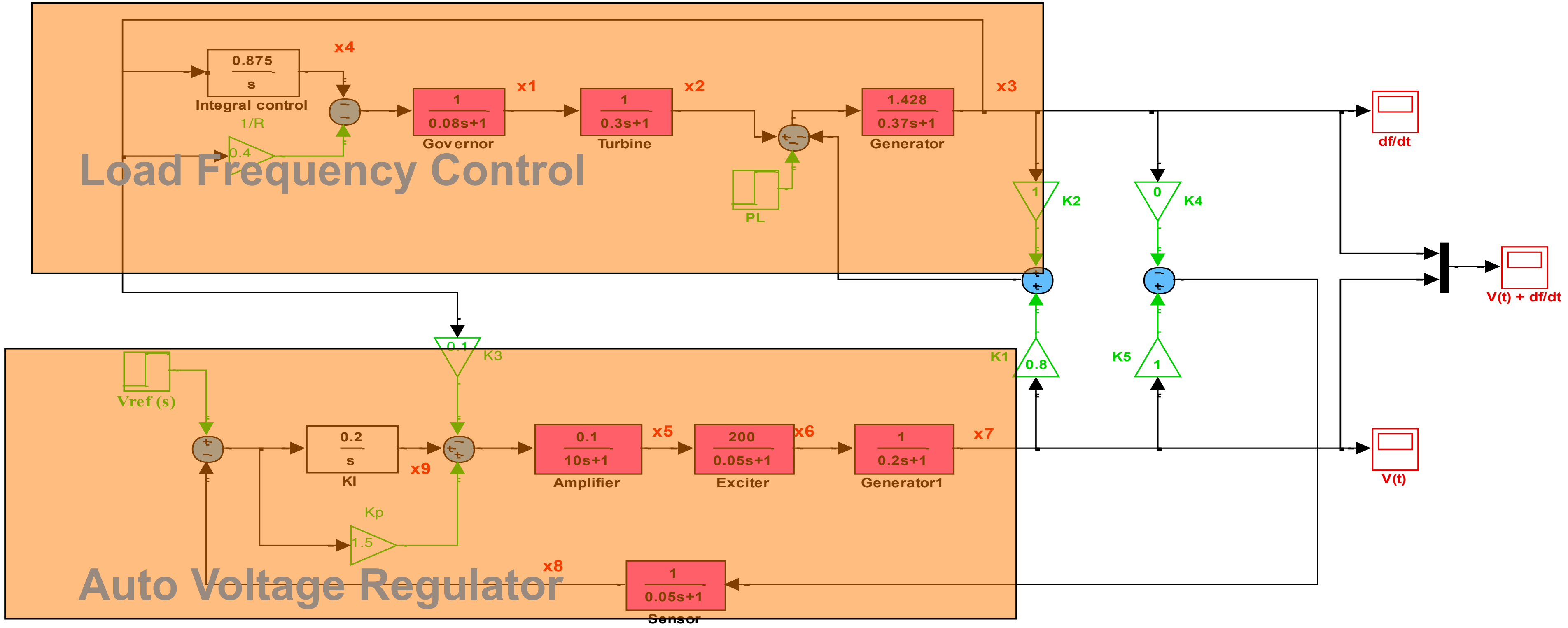
Smart Grid – Modeling and Control

AGC System



Smart Grid – Modeling and Control

AVR and LFC Combination



AVR and LFC Combination

Forming A, B, C, D and F Matrices:

- State Differential Equation
- Output Equation
- MATLAB

Tuning K_1,K_2,K_3,K_4 and K_5 Between 0 and 1:

<u>Trial and Error:</u>

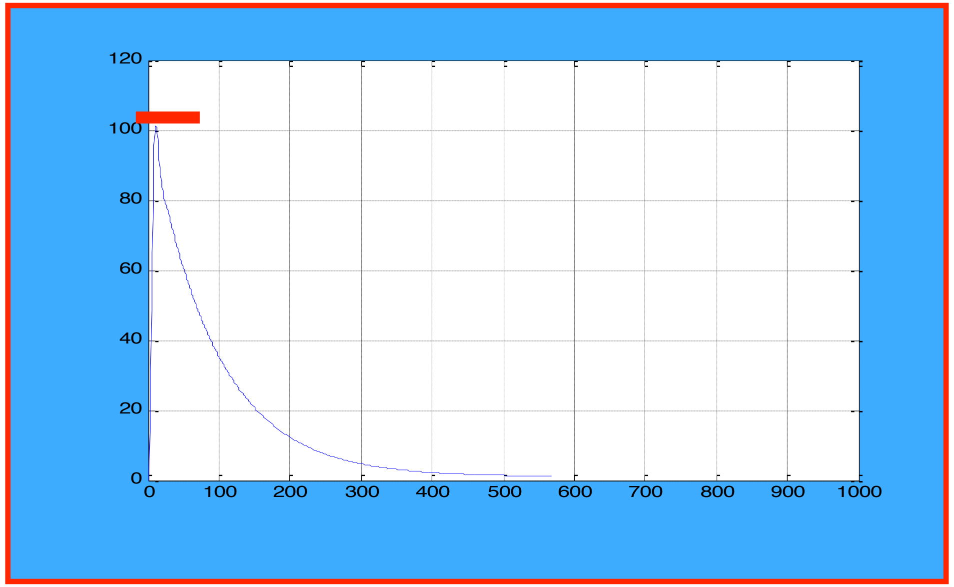
- K_1 has no affect on either one of the two systems
- K_2 has an affect on the LFC response
- K_3 has an affect on both the LFC and the AVR system stability
- K_4 and K_5 both have an affect on the AVR overshoot

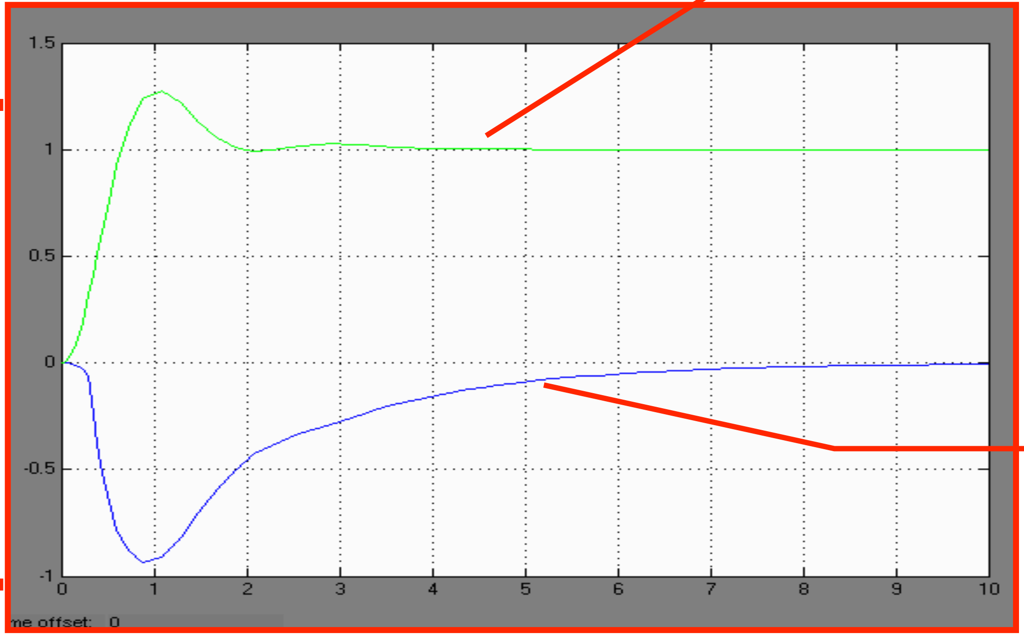
AVR and LFC Combination

Tuning K_1,K_2,K_3,K_4 and K_5 Between 0 and 1:

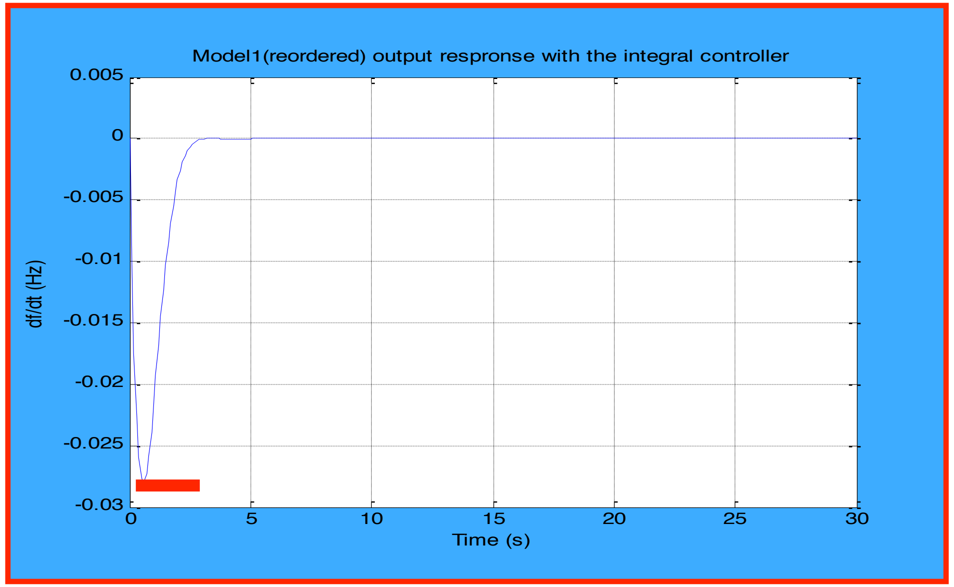
- K at which the responses of both AVR and LFC are behaving normally:
  - $K_1 = 1$
  - $K_2 = 0.8$
  - $K_3 = 0.1$
  - $K_4 = 0$
  - $K_5 = 1$

AVR response





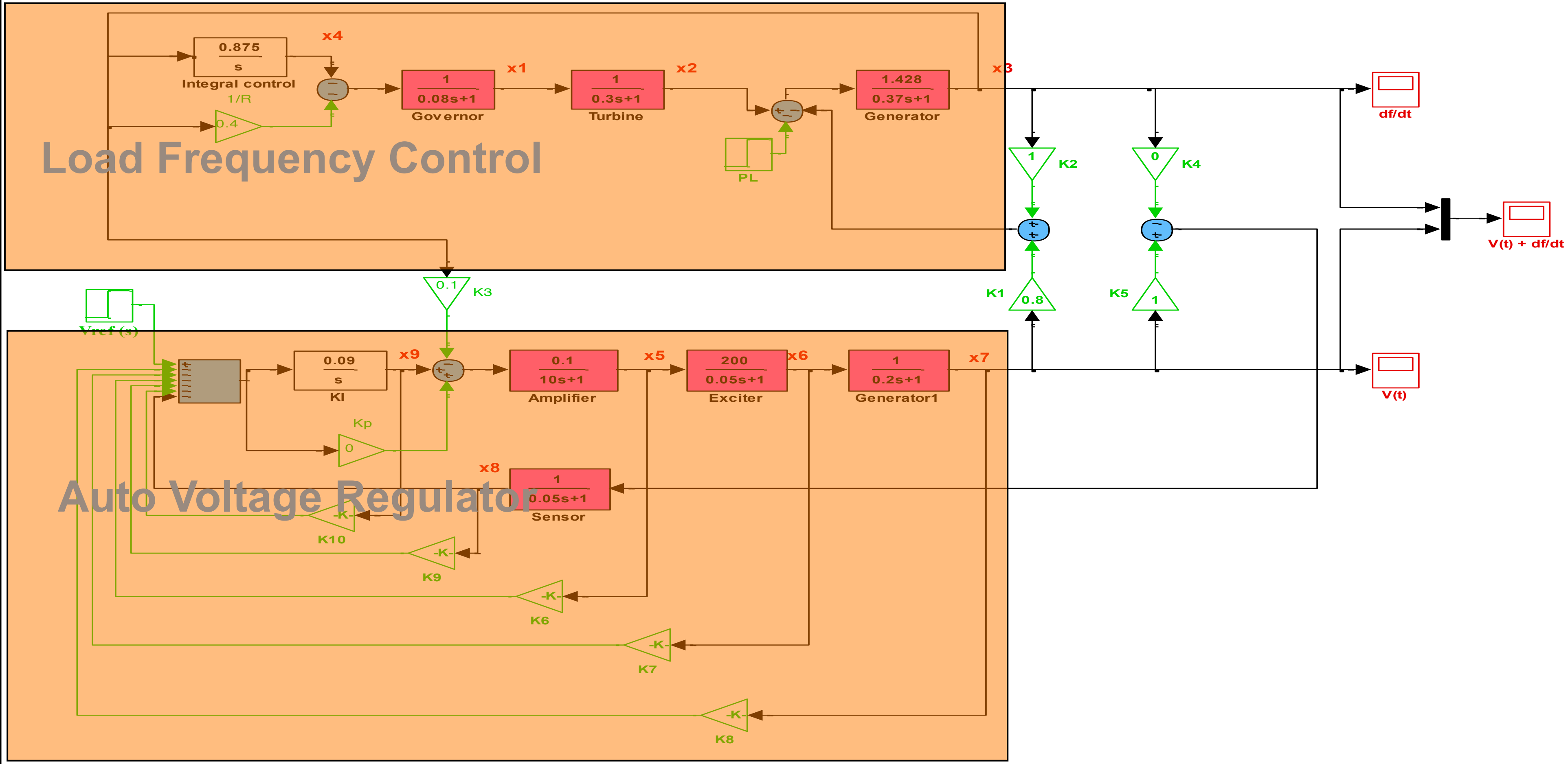
AGC response



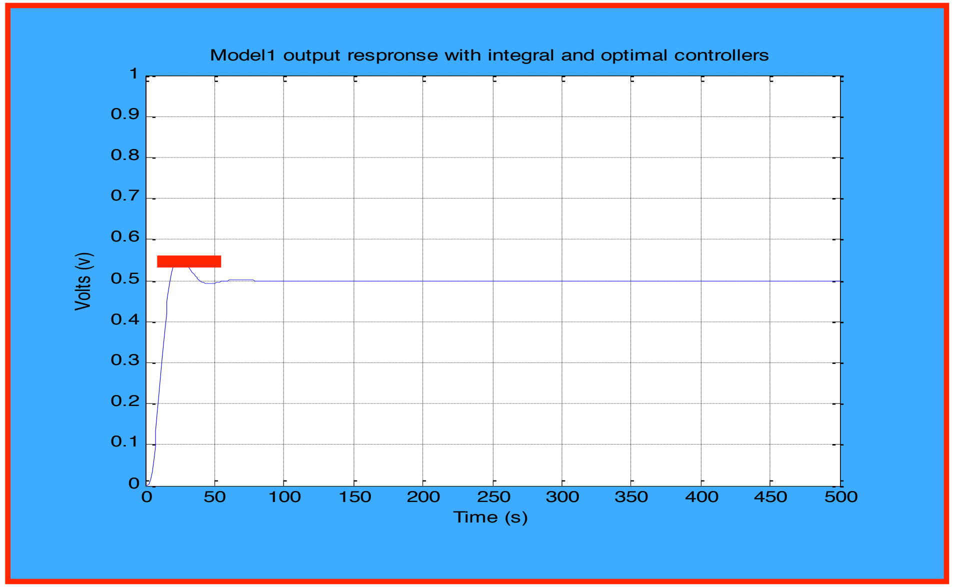
LFC response

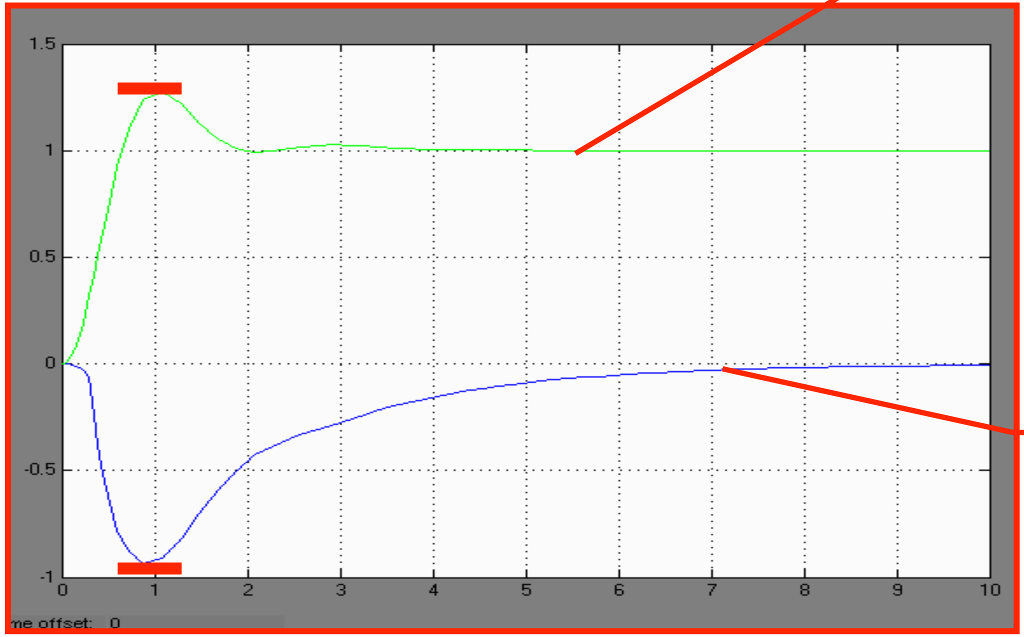
Smart Grid – Modeling and Control

AVR and LFC Combination

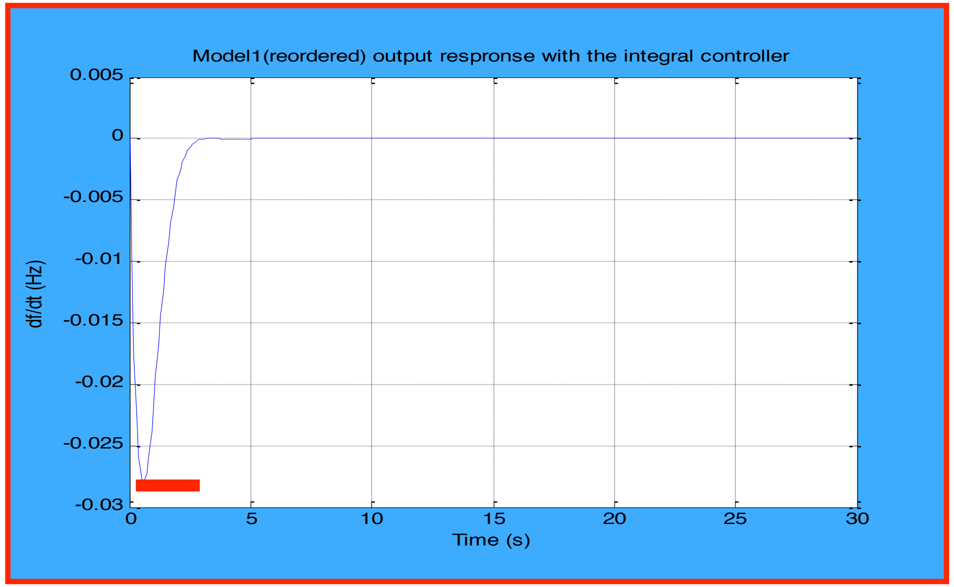


AVR response



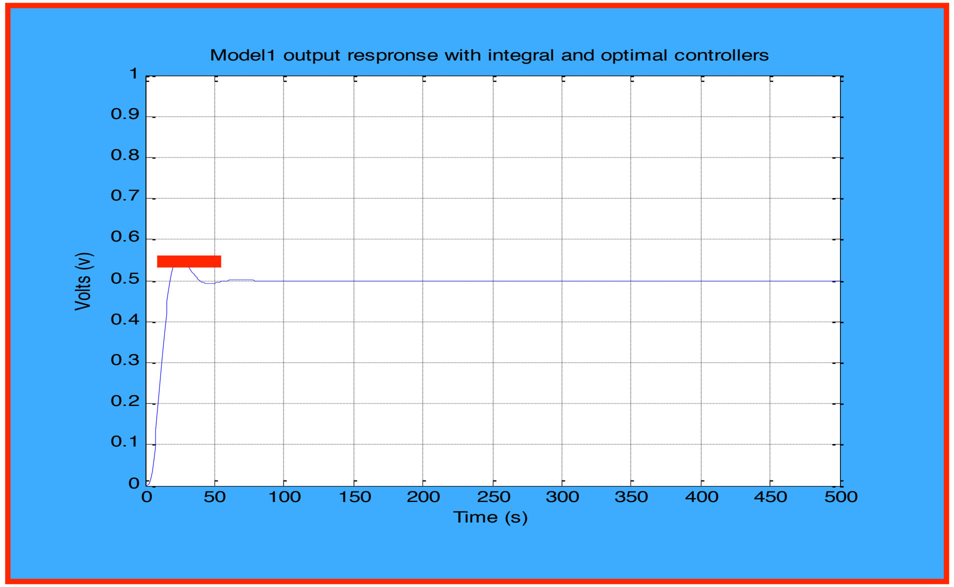


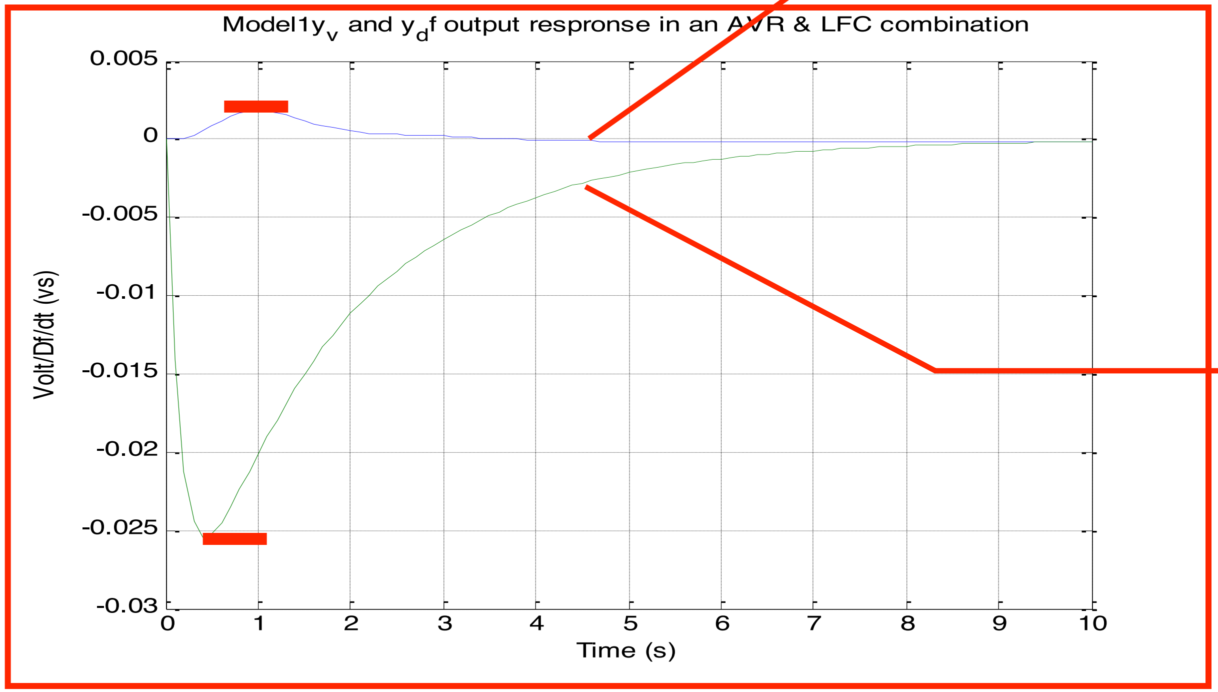
AGC response



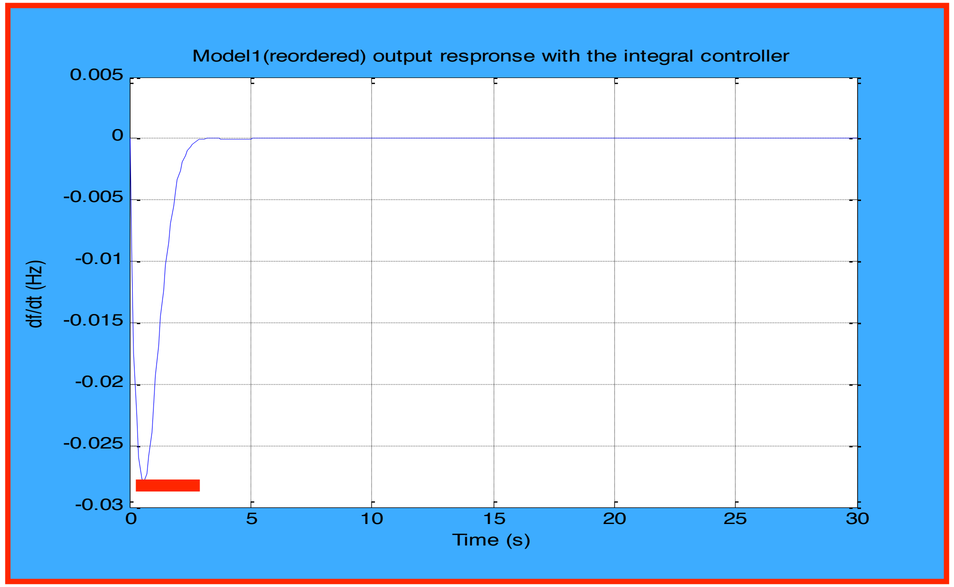
LFC response

AVR response





AGC response



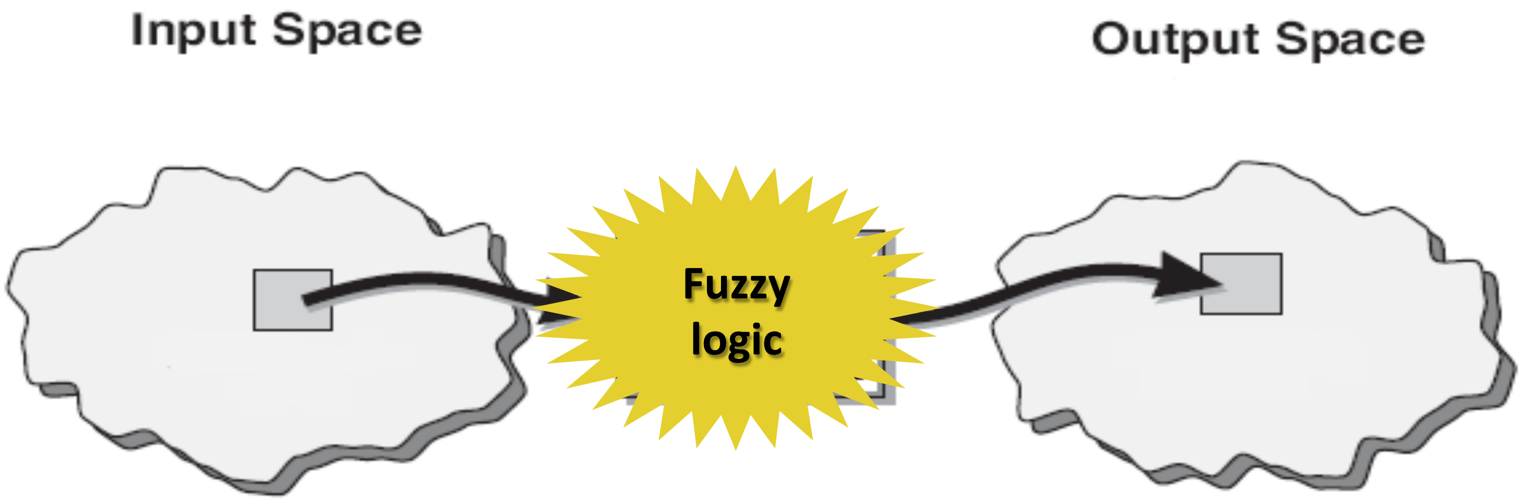
LFC response

AVR and LFC Combination

- The combination of both AVR and LFC systems might cause slight changes in their responses
- Fortunately the undershoots and overshoots never exceeded 20%
  - AVR stand alone system ; Overshoot = 2.2%
  - With the optimal control the overshoot almost eliminated
  - AVR within AGC system ; Overshoot= 0.2%
  - LFC stand alone system ;Undershoot= 2.8%
  - LFC within AGC system ; Undershoot= 2.5%

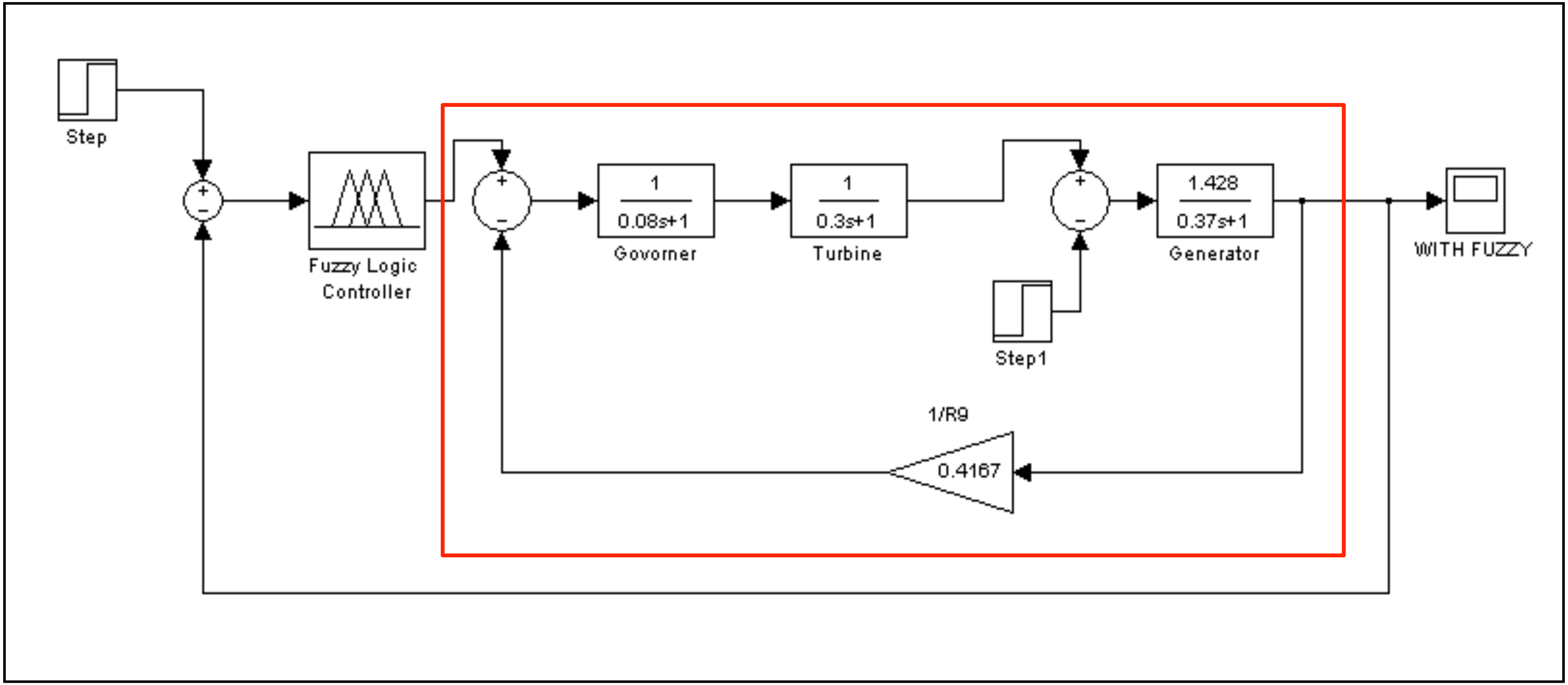
Fuzzy Logic Control

- Flexible
- Natural languages

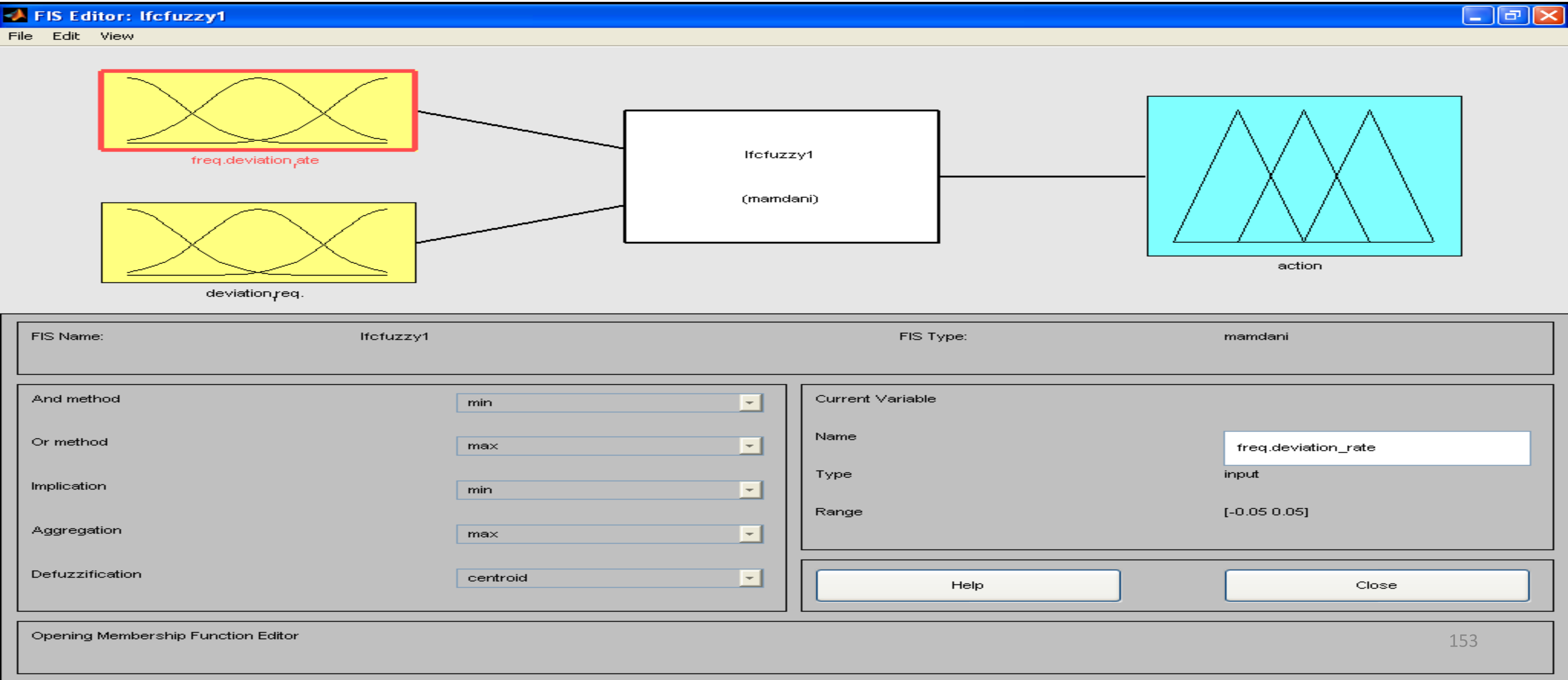


- Cheaper
- Faster
- Model nonlinear function
- Easy to understand

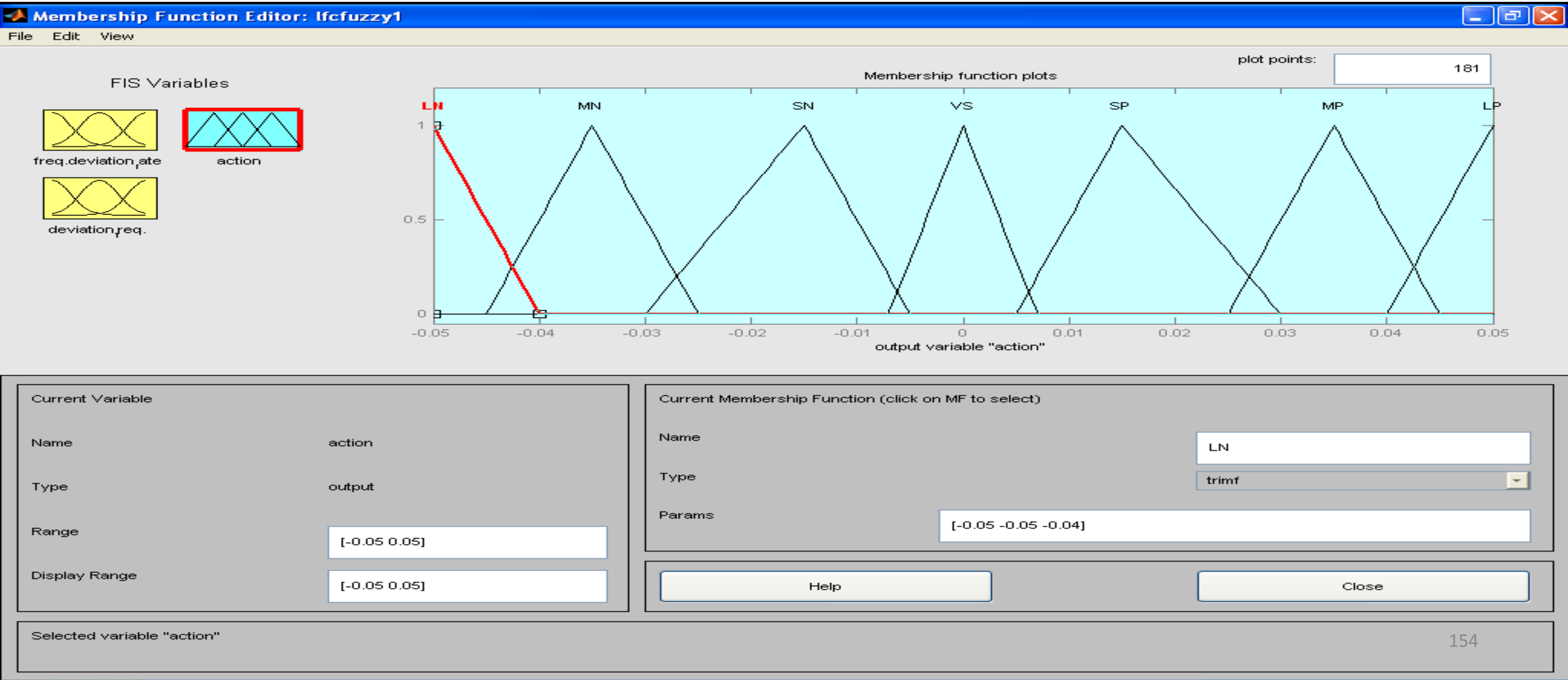
Modeling One Area LFC with Fuzzy Logic Control



FIS Editor


FIS Editor: lfcfuzzy1
File
Edit
View
freq.deviation rate
deviation freq.
lfcfuzzy1
(mamdani)
action
FIS Name:
lfcfuzzy1
FIS Type:
mamdani
And method
min
Or method
max
Implication
min
Aggregation
max
Defuzzification
centroid
Current Variable
Name
freq.deviation_rate
Type
input
Range
[-0.05 0.05]
Help
Close
Opening Membership Function Editor

Membership Function



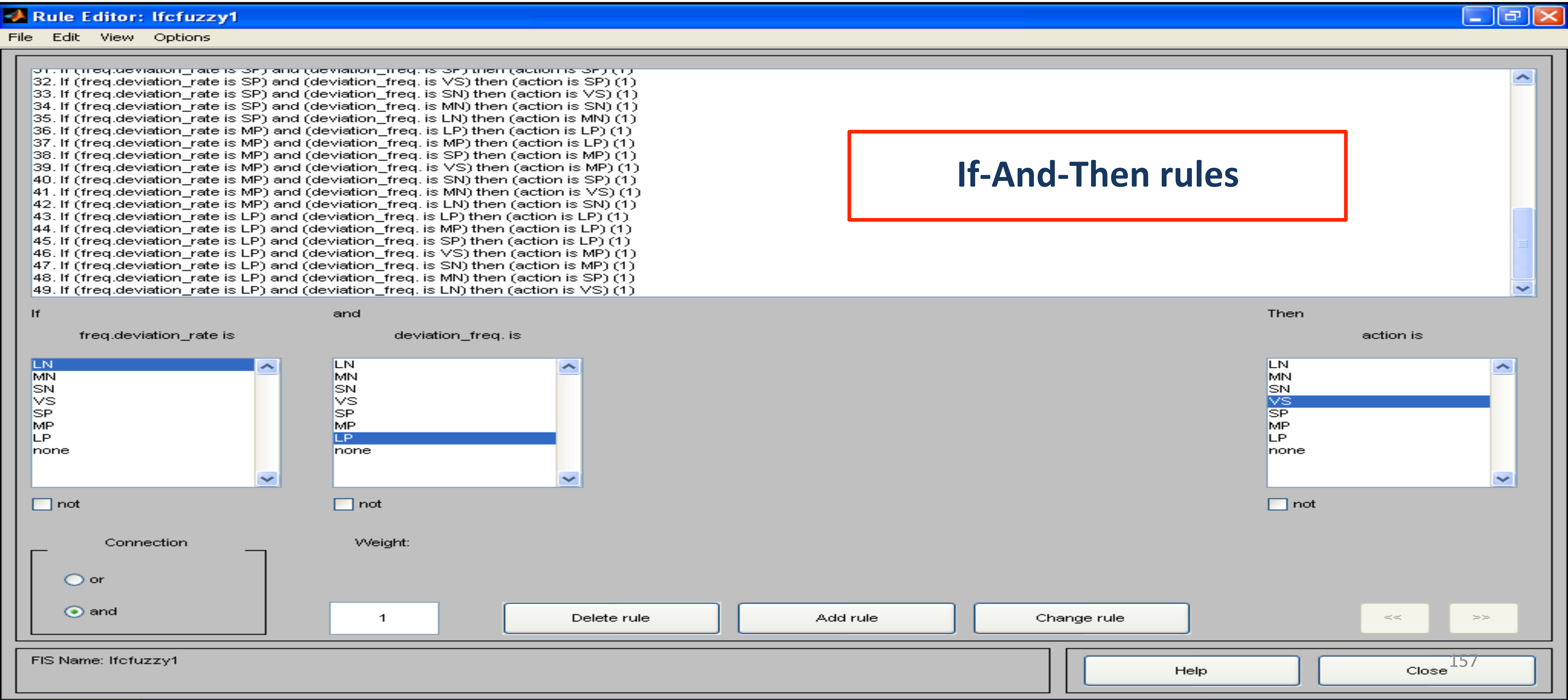
FIS Variables

de\e	LN	MN	SN	VS	SP	MP	LP
LP	VS	SP	MP	LP	LP	LP	LP
MP	SN	VS	SP	MP	MP	LP	LP
SP	MN	SN	VS	SP	SP	MP	LP
VS	MN	MN	SN	VS	SP	MP	MP
SN	LN	MN	SN	SN	VS	SP	MP
MN	LN	LN	MN	MN	SN	VS	SP
LN	LN	LN	LN	LN	MN	SN	VS

FIS variables

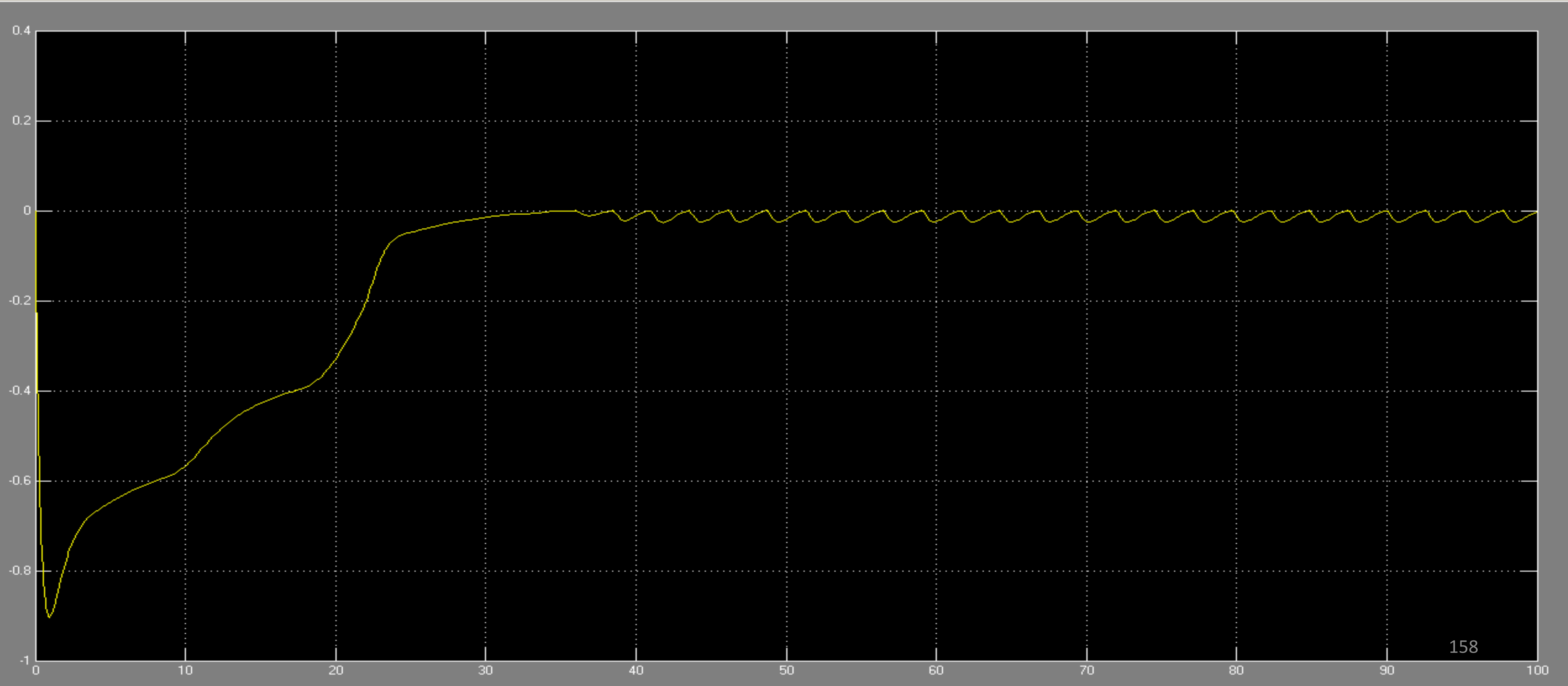
Variables	Linguistic Term	Range of linguistic term
Near +0.05	LP (large positive)	[+0.04 +0.05 +0.05]
Near -0.05	LN (large negative)	[-0.05 -0.05 -0.04]
So far from +0.05	MP (medium positive)	[+0.025 +0.035 +0.045]
So far from -0.05	MN (medium negative)	[-0.045 -0.035 -0.025]
Very far from +0.05	SP (small positive)	[+0.005 +0.015 +0.03]
Very far from -0.05	SN (small negative)	[-0.03 -0.015 -0.005]
$\Delta f=0$	VS (very small)	[-0.007 0 +0.007]

Rule Editor

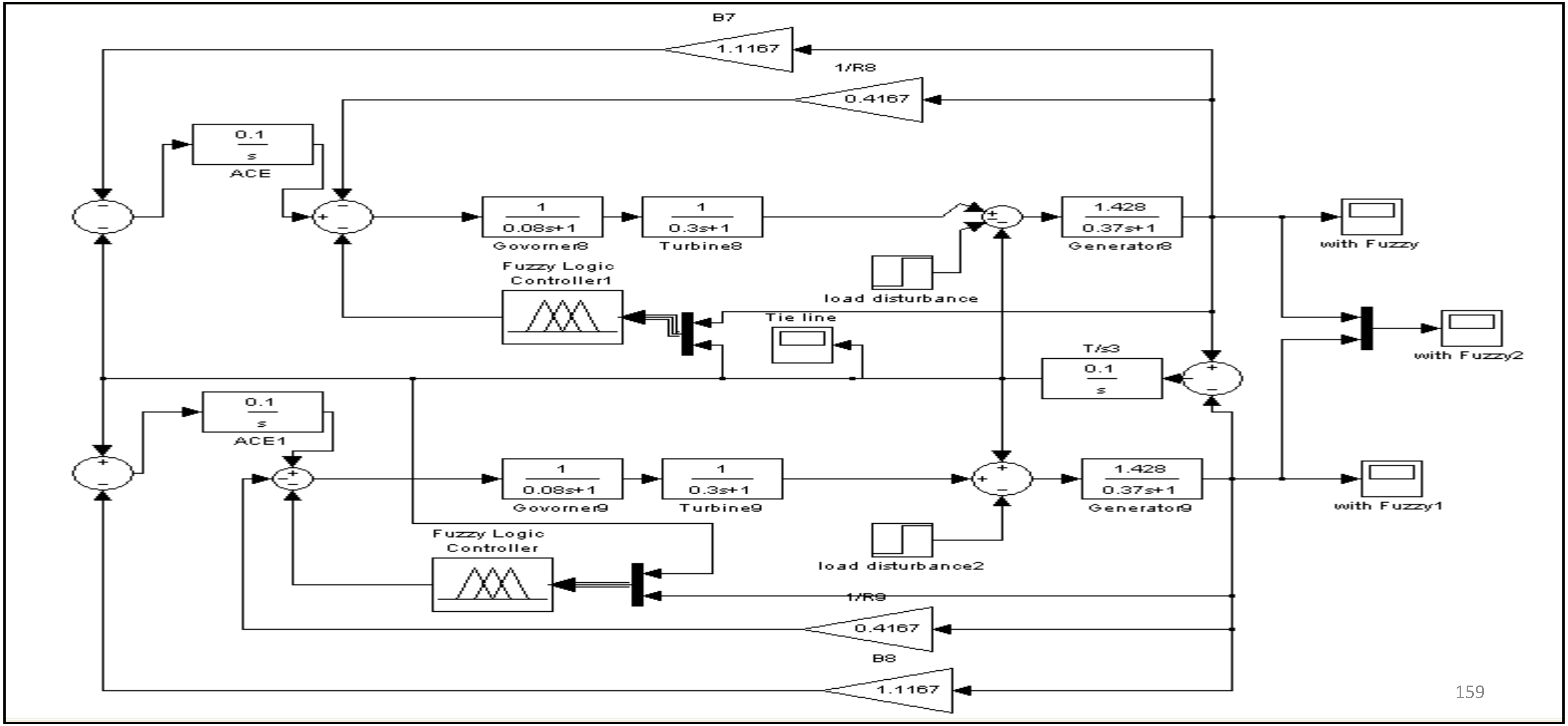


If-And-Then rules

Response of LFC of One Area Fuzzy Control



Modeling Two Area LFC with Fuzzy Logic Control



Area Control Error

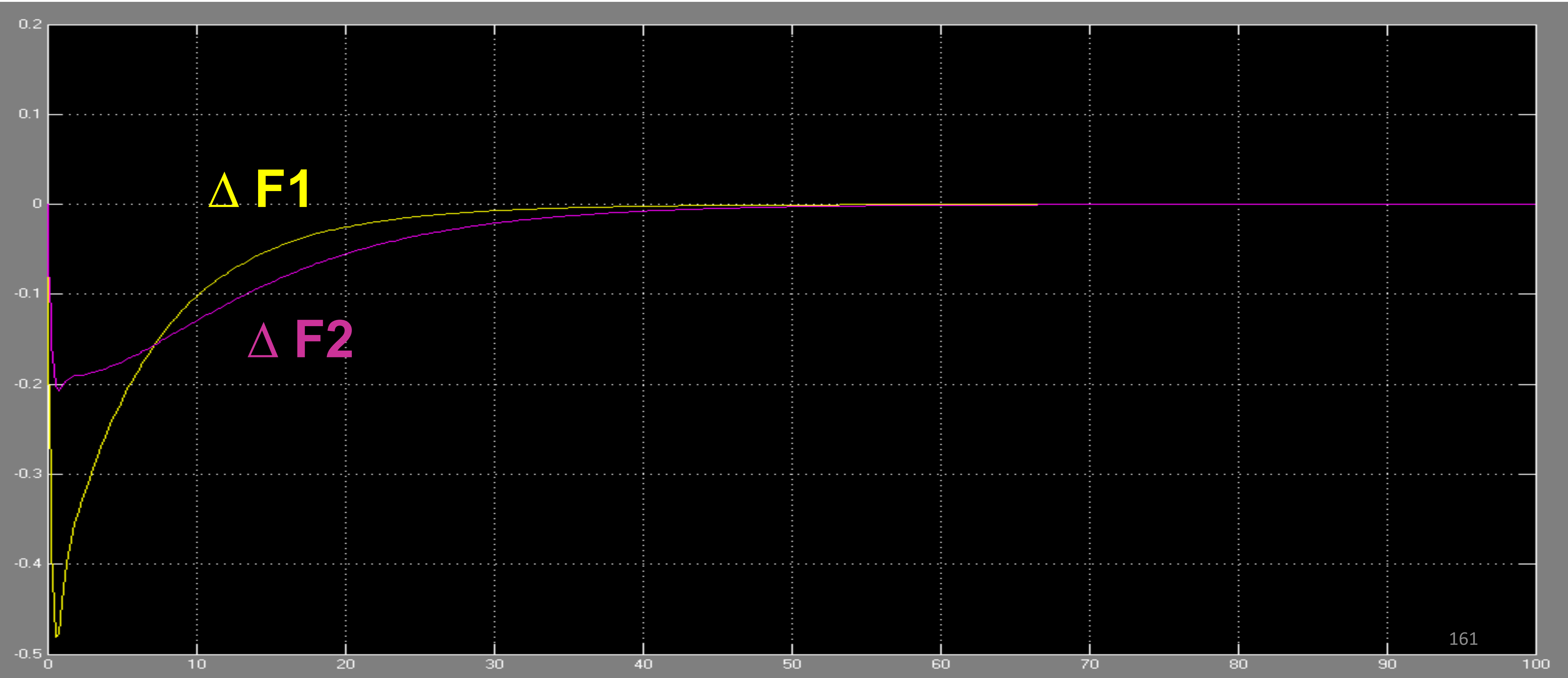
Area control error is the difference between the actual power flow out of area and scheduled power flow. ACE also includes a frequency component

$$\Delta P_g = P_g^{sch} - P_g$$

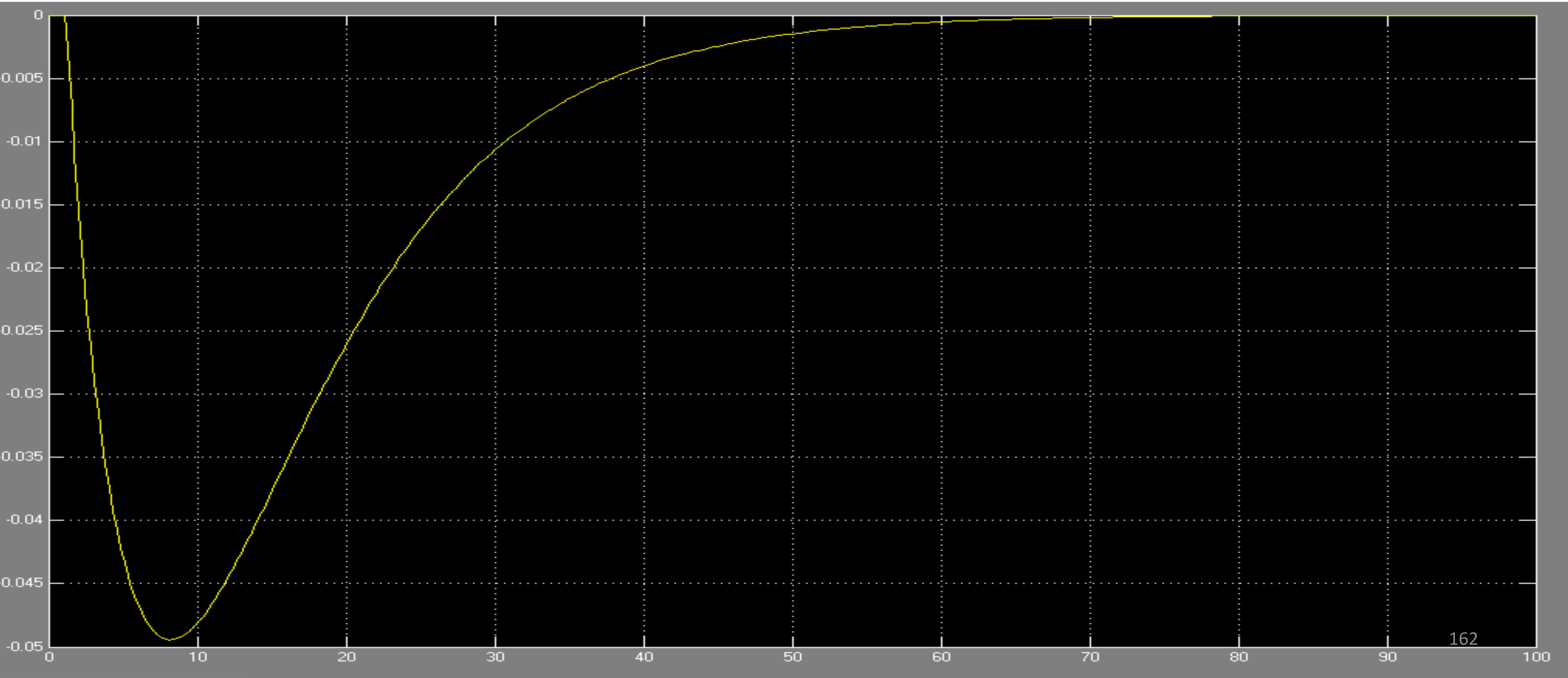
$$\Delta P_{tie} = P_{tie}^{sch} - P_{tie}$$

$$\Delta f = f^{sch} - f$$

The Response of LFC Two Areas Fuzzy Control



The Response of Tie Line for LFC Two Areas Fuzzy Control



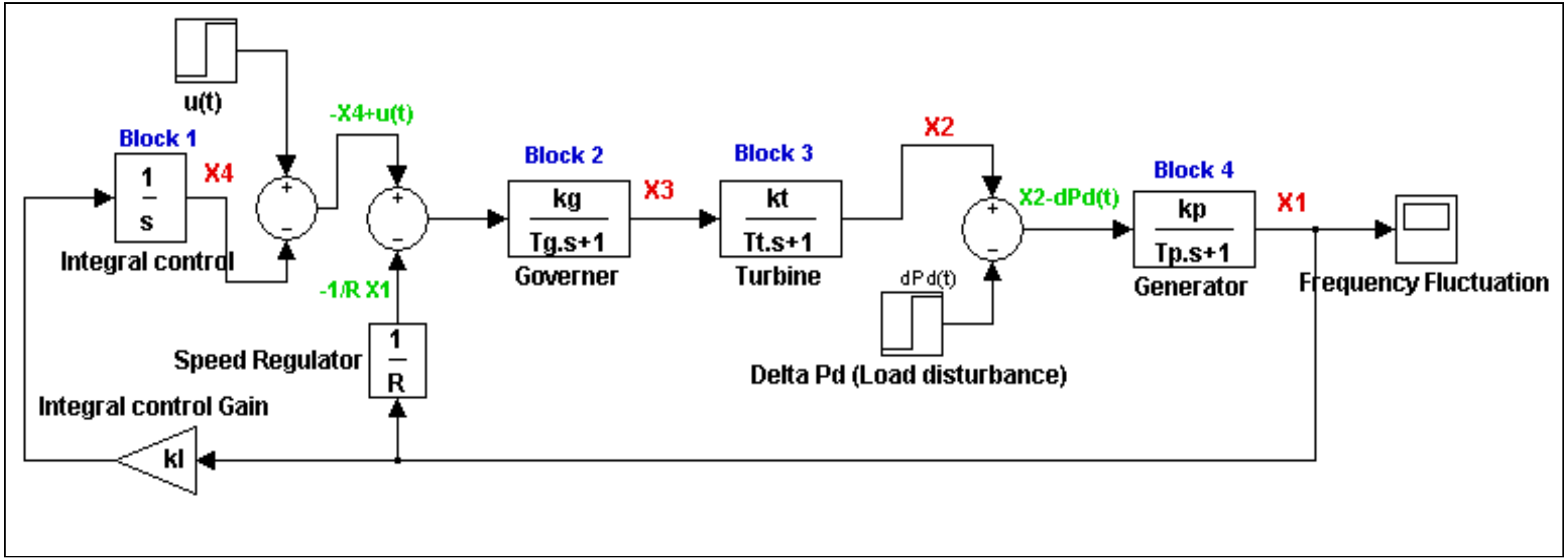
Robust Controller

- The dynamic behavior of electric power systems is heavily affected by disturbances and changes in the operating points
- An industrial plant, such as power systems, always contain parametric uncertainties
- In many control applications, it is expected that the behavior of the designed system will be insensitive (robust) to external disturbance and parameter variations

Applications of Robust control

- Robust control of temperature
- Disk drive read system
- Mobile, Remote-Controlled Video Camera
- Spacecraft
- Control of a DAT (Digital audio tape) player
- Elevator
- Microscope control

Robust controller design



LFC Block diagram of power system

$\Delta P_d(t)$ **:** load disturbance (P.u. MW)
T_g **:** governor time constant (s)
K_g **:** governor gain
T_t **:** turbine time constant (s)
K_t **:** Turbine gain
T_p **:** Generator time constant (s)
K_p **:** Generator gain
R **:** speed regulation due to governor action (HZ p.u. MW^{-1})
KI**:** Integral control gain

Our robust load-frequency controller design procedure is as follows:

Step 1

Find the range of the system parameters

State equation:

$$\dot{x}(t) = Ax(t) + Bu(t) + F\Delta P_d(t)$$

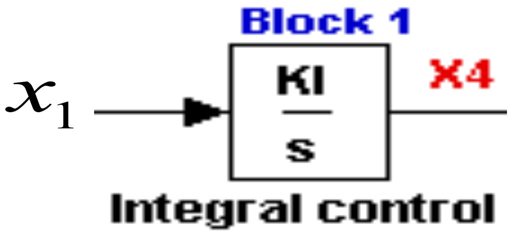
Output equation:

$$y(t) = C_{p\times n}x(t) + D_{p\times m}u(t)$$

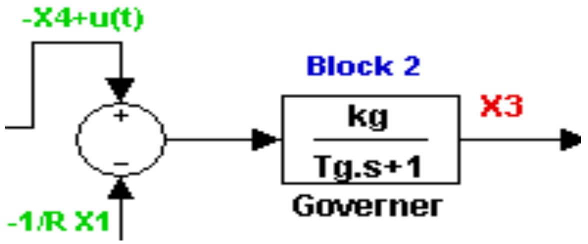
Where :

$$x(t) = [x_1(t), x_2(t), x_3(t), x_4(t)]$$

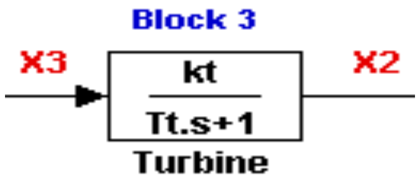
Smart Grid – Modeling and Control



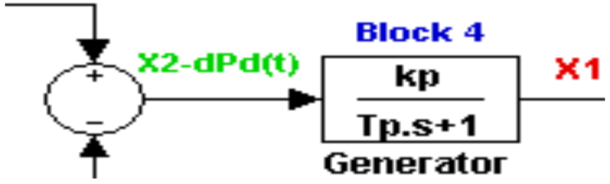
$$\dot{x}_4 = K_I x_1$$



$$\dot{x}_3 = -\frac{1}{T_g}x3 - \frac{kg}{Tg}x_4 + \frac{k_g}{T_g}u(t) - \frac{k_g}{T_g R}x_1$$



$$\dot{x}_2 = -\frac{1}{T_t}x_2 + \frac{k_t}{T_t}x_3$$



$$\dot{x}_1 = -\frac{1}{T_P}x_1 + \frac{k_P}{T_P}x_2 - \frac{k_P}{T_P}\Delta P_d$$

A =

-1/Tp	Kp/Tp	0	0
0	-1/Tt	1/Tt	0
-1/RTg	0	-1/Tg	-1/Tg
K	0	0	0

$$B = [0,0,1/T_G,0]$$

$$F = [-K_P/T_P,0,0,0]$$

The range of the system parameters is:

$$1/T_P \in [\underline{a}_1, \overline{a_1}]$$
$$K_P/T_P \in [\underline{a}_2, \overline{a_2}]$$
$$1/T_T \in [\underline{a}_3, \overline{a_3}]$$
$$1/T_G \in [\underline{a}_4, \overline{a_4}]$$
$$1/RT_G \in [\underline{a}_5, \overline{a_5}]$$

$$1/T_P \in [0.033,0.1]$$
$$K_P/T_P \in [4,12]$$
$$1/T_T \in [2.564,4.762]$$
$$1/T_G \in [9.615,17.857]$$
$$1/RT_G \in [3.081,10.639]$$

Step 2

Choose the nominal parameters for the system and decide the bound of the uncertainties

The nominal parameters are from the original model of LFC:

A =

-2.7030	3.8595	0	0
0	-3.3330	3.3330	0
-31.2500	0	-12.5000	-12.5000
0.8800	0	0	0

B=[0;0;12.5;0]

F=[3.8595;0;0;0]

$$A = \overline{A} + \Delta A \qquad B = \overline{B} + \Delta B$$

$$\dot{x}(t) = (\overline{A} + \Delta A)x(t) + (\overline{B} + \Delta B)u(t)$$

- Now, let decide the bound of the uncertainties:

$$\Delta A = \alpha \overline{A}$$

$$\Delta B = \beta \overline{B}$$

$$\alpha = 0.3, \beta = 0.5 \,\&\, \gamma = 0.7$$

$$\Delta F = \gamma \overline{F}$$

- Hence, the parametric uncertainties are:

A =

-0.8109	1.1579	0	0
0	-0.9990	0.9999	0
-9.3750	0	-3.7500	-3.7500
0.2640	0	0	0

B=[0;0;6.25;0]

F=[2.70165;0;0;0]

$$A = \overline{A} + \Delta A \qquad B = \overline{B} + \Delta B$$

After this change in the system the new matrices are as follow:

A =

-3.5139	5.0174	0	0
0	-4.3320	4.3320	0
-40.6250	0	-16.2500	-16.2500
1.1440	0	0	0

B=[0;0;18.75;0]

F=[6.56115;0;0;0]

Step 3

Choose the design constants ε and the design constant matrices Q and R

Algebraic Riccati equation:

$$P\overline{A} + \overline{A^T}P - P\left\{\frac{2}{\varepsilon}(1-\alpha)\overline{B}R^{-1}\overline{B^T} - \frac{1}{\varepsilon_1}T\right\}P + \varepsilon_1 U + \varepsilon Q = 0 \ldots Eq(1)$$

Where , $\boldsymbol{Q} > 0$ and $\boldsymbol{R} > 0$

ε & $\varepsilon_1 > 0$, very small value

T & U are the rate change of the generation

And because the algebraic Riccati equation is nonlinear, we use MATLAB program to solve it

Smart Grid – Modeling and Control

Step 4

Use the algorithm given eq. (1) to solve Riccati equation and obtain the solution *P.* By using the command from the MATLAB we can found P as follow:

MATLAB Command

```
A=[-3.5139 5.0174 0 0;0 -4.332 4.332 0; -40.625 0
-16.25 -16.25; 1.144 0 0 0]
Q=[5 0 0 0; 0 5 0 0; 0 0 5 0; 0 0 0 5]
B=[0;0;18.75;0]
R=0.01
[F,P,ev]=lqr(A,B,Q,R)
```

Smart Grid – Modeling and Control

Result of the command

F =

9.6166 17.6707 21.6925 21.5108

P =

1.1042	0.6104	0.0051	1.7927
0.6104	0.9237	0.0094	1.1636
0.0051	0.0094	0.0116	0.0115
1.7927	1.1636	0.0115	7.7951

ev =

1.0e+002 *

-4.1956

-0.0522 + 0.0168i

-0.0522 - 0.0168i

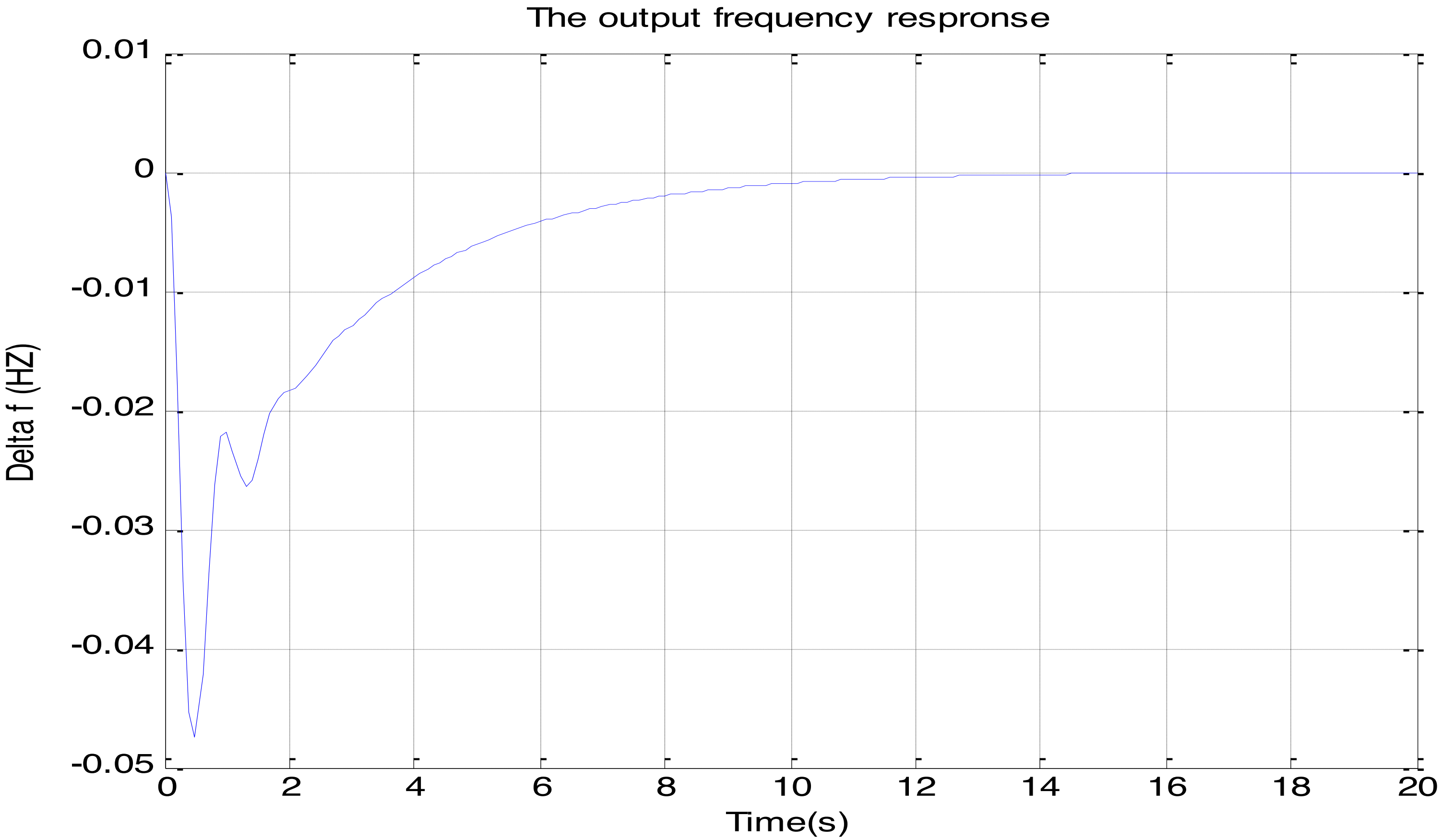
-0.0083

By using MATLAB the output frequency response was drawn without considering the feedback gains:

MATLAB Command

```
clc
t=[0:0.1:20];
u=-0.1*ones(length(t),1);
x0=[0 0 0 0];
A=[-3.5139 5.0174 0 0;0 -4.332 4.332 0; -40.625 0 -16.25 -16.25; 1.144 0 0 0];
eig(A)
B=[0;0;18.75;0];
C=[1 0 0 0];
D=[0];
sys=ss(A,B,C,D);
[y,x]=lsim(sys,u,t,x0);
plot(t,y)
Title('The output frequency response');
xlabel('Time');
ylabel('f');
grid
```

Output frequency response with uncertainties parameters and without feedback gains



Feed Back Gain

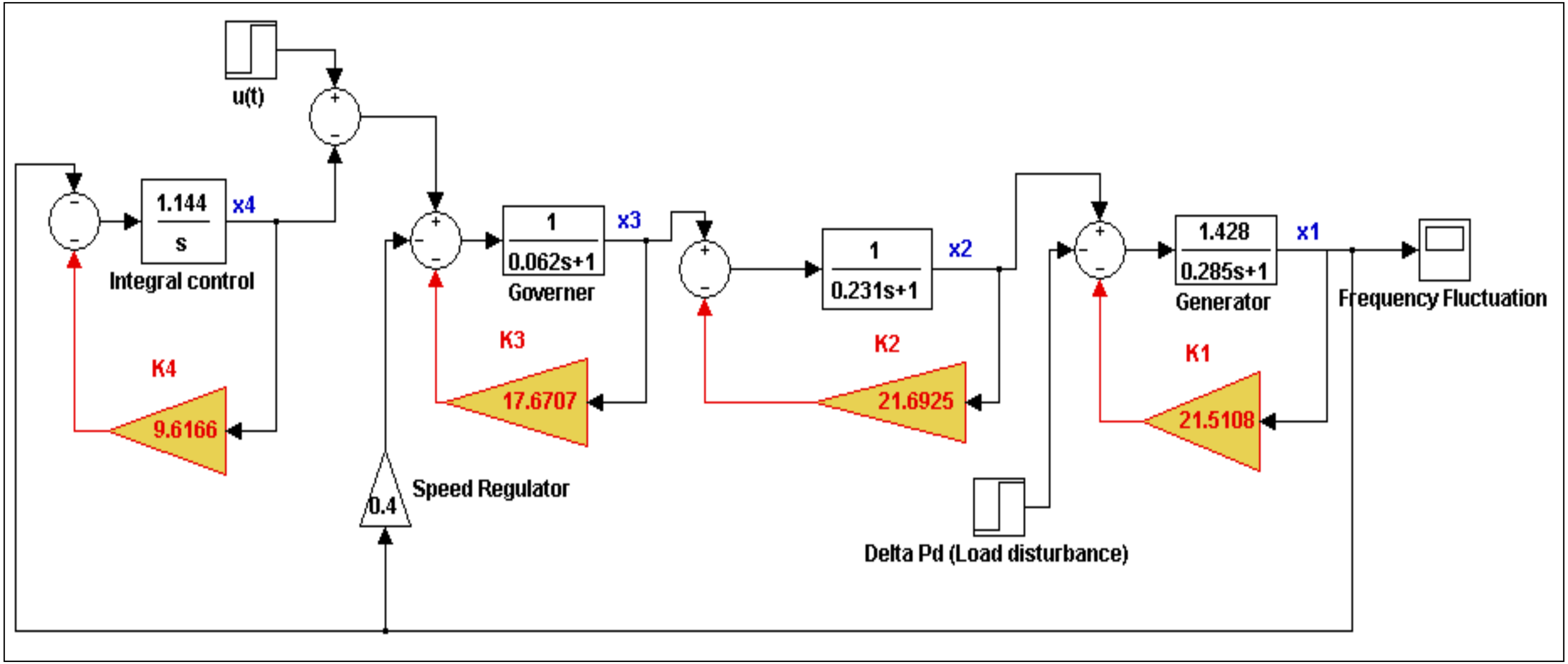
Step 5

Construct the feedback gain

Also, by using the same commands from MATLAB the optimal gains are…

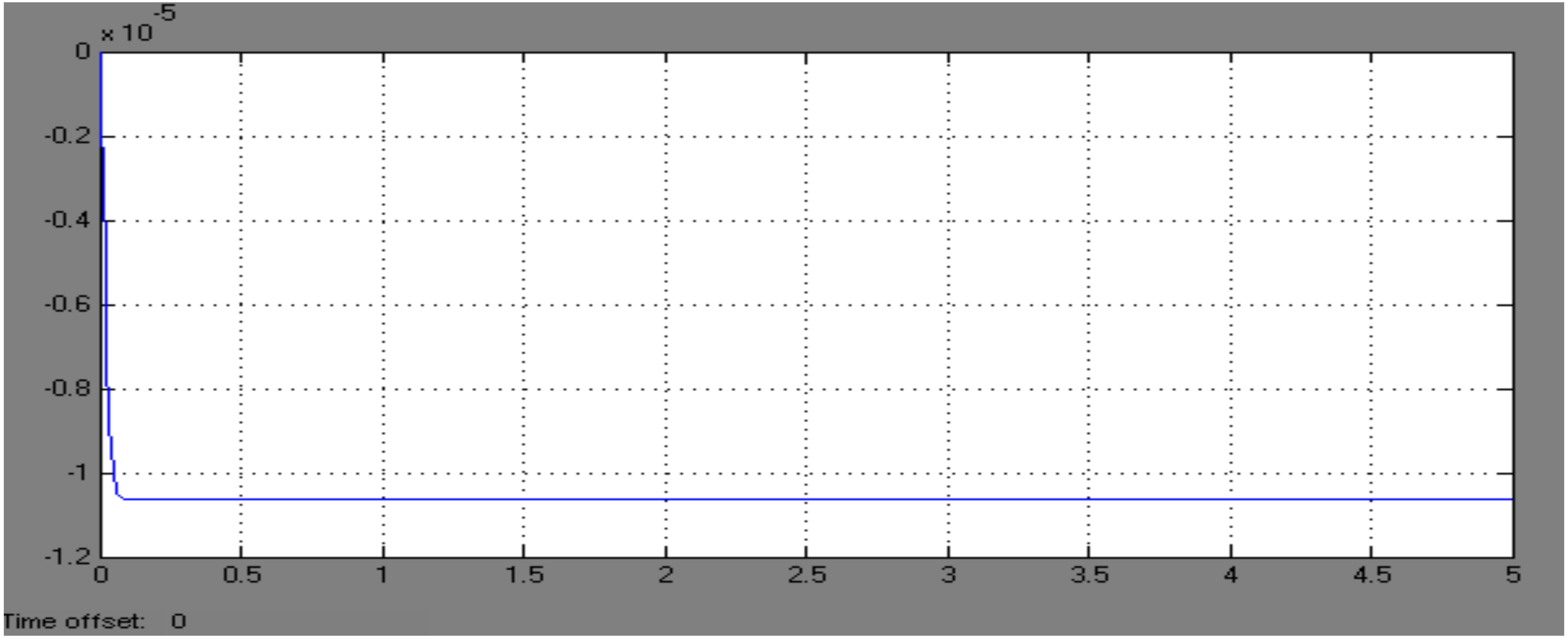
$$F = \begin{bmatrix} 9.6166 & 17.6707 & 21.6925 & 21.5108 \end{bmatrix}$$

LFC Block Diagram of Robust Controller



LFC Block diagram of power system for the proposed robust controller

Robust Controller – Frequency Response



The output frequency response for the proposed robust controller

Comparison between Robust and Integral Controller

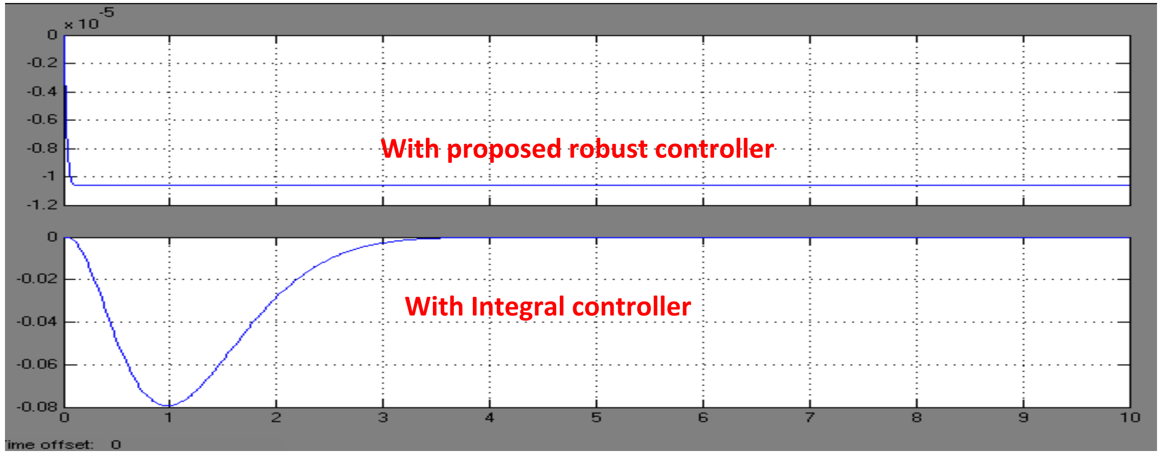


Figure 1: With nominal parameters $1/T_p$= 2.7030, K_p/T_p= 3.8595, $1/T_T$ = 3.333, $1/T_G$ =12.5, $1/RT_G$= 31.25, K_I= 0.88

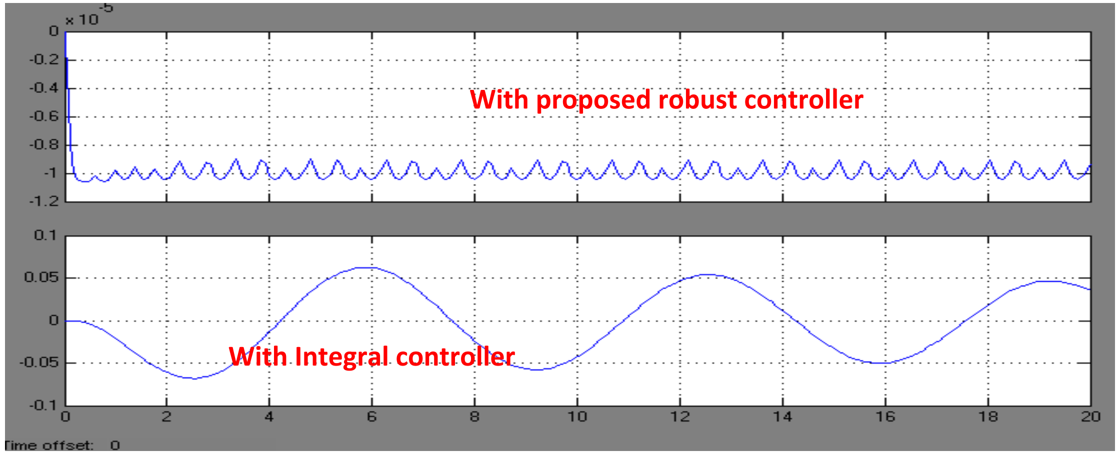


Figure 2: With $1/T_p$=1.05, K_p/T_p=1.494, $1/T_T$=1.3, $1/T_G$=1.79,$1/RT_G$=0.7143,K_I=1.144

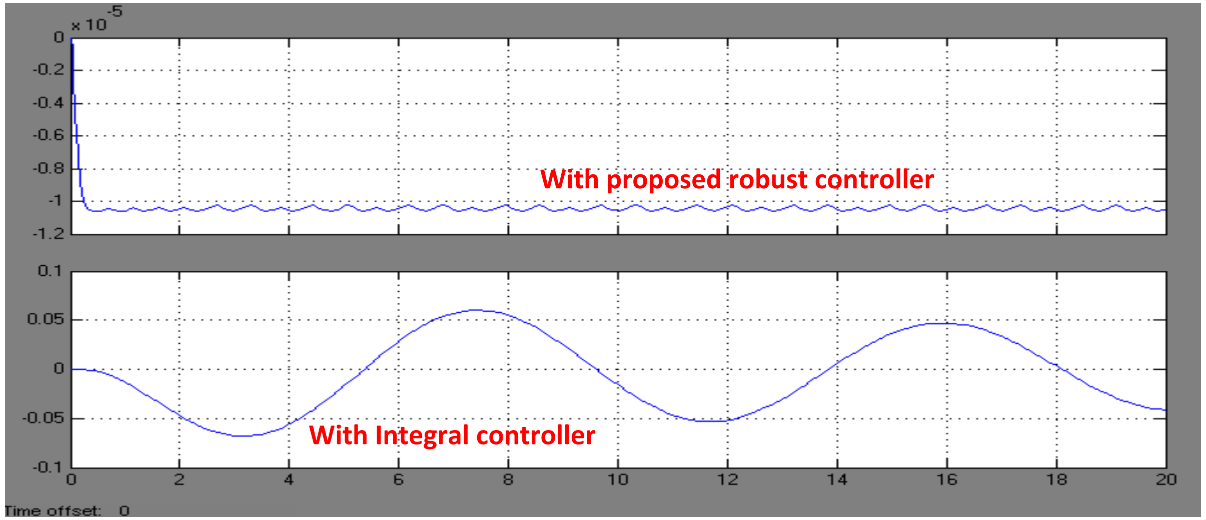


Figure 3 : With $1/T_p$ = 0.8, K_p/T_p= 1.1424, $1/T_T$=1.031, $1/T_G$=1.52,$1/RT_G$=0.61,K_I=0.88

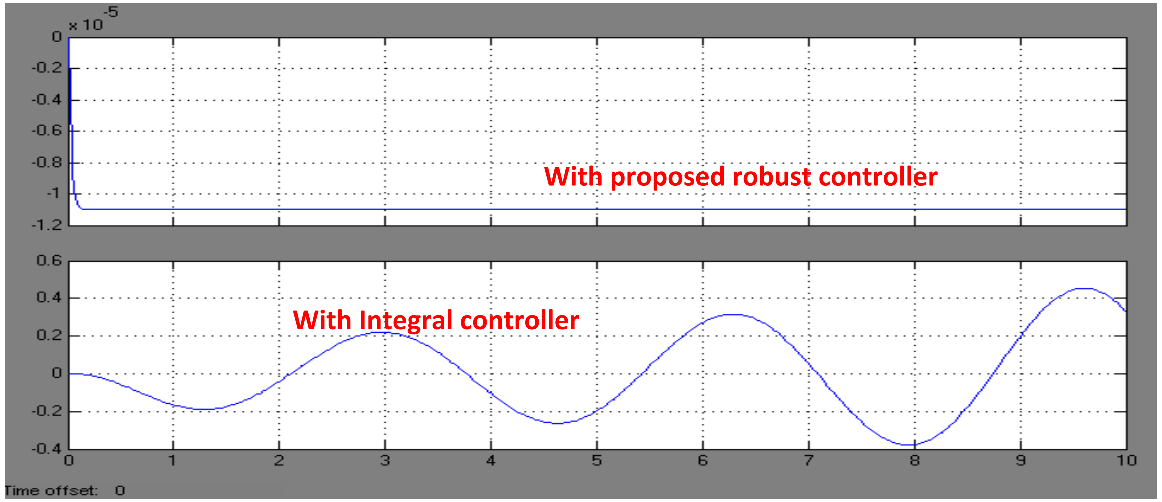


Figure 4: With $1/T_p$ = 0.033, K_p/T_p= 4, $1/T_T$=2.564, $1/T_G$=9.615,$1/RT_G$=3.081,K_I=0.88

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Questions?

[REDLAB](http://manoa.hawaii.edu/me/redlab)

Renewable Energy Design Laboratory

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