MODELING OF AUTOMATIC GENERATION CONTROL OF THERMAL UNIT

Thesis submitted in the partial fulfillment for the award of the degree of

Masters of Engineering
In
Power Systems & Electric Drives

Thapar University, Patiala

By
Umashankar
Roll No: 800841017

Under the Supervision of

Mr. Gaurav Sachdeva
Lecturer, EIED

JULY 2010

ELECTRICAL & INSTRUMENTATION ENGINEERING DEPARTMENT
THAPAR UNIVERSITY
PATIALA-147004

CERTIFICATE

I hereby certify that work which is being presented in the Thesis entitled **"Modeling of Automatic Generation Control of Thermal Unit"** in partial fulfillment of the requirement for the award of degree of Master of Engineering in ***Power Systems & Electric Drives*** submitted in Electrical & Instrumentation Engineering Department of Thapar University, Patiala, is an authentic record of my own work carried out under supervision of **Mr.Gaurav Sachdeva** Lecturer, EIED.

The matter presented in this Thesis has not been submitted for the award of any other degree of this or any other university.

Umashankar

Umashankar
(800841017)

It is certified that the above statement made by the student is correct to the best of our knowledge and belief.

Mr. Gaurav Sachdeva
Thapar University,
Patiala

Countersigned by

Dr. Smarajit Ghosh
Professor & Head, EIED
Thapar University, Patiala

Dr. R. K. Sharma 29.7.10
Dean of Academic Affairs
Thapar Universty, Patiala

ACKNOWLEDGEMENT

I would like to thank **Mr. Gaurav Sachdeva** lecturer, **EIED** for the opportunity to work with him, and also for his encouragement, trust and untiring support. Mr. **Gaurav Sachdeva** has been an advisor in the true sense both academically and morally throughout this project work.

I take this opportunity to express my gratitude and sincere thanks to **Dr. Yaduvir Singh**, **Associate Professor** of Electrical & Instrumentation Engineering Department for their valuable advice and suggestion during the thesis work.

Gratitude is accorded to Thapar University, Patiala, for providing all the necessary facilities to complete my M.E. Thesis work.

I am thankful to **Dr. Smarajit Ghosh, Professor & Head, EIED** for their continuous inspiration during this thesis work.

The paucity of words does not compromise for extending my thanks to all the staff members of EIED, Thapar University, my all family members and friends whose uninterrupted love, inspiration and blessings helped me in completing this research report.

I thank and owe my deepest regards to all who have helped me directly or indirectly.

Umashankar

(Umashankar)

Roll.No.800841017

ABSTRACT

Automatic generation control (AGC) is an essential requirement of modern power system automatic control. At present, slow response to AGC load demand is a serious problem existing in thermal power units taking part in AGC, which makes the control performance of power system AGC poor. The unit one and unit two of are all boiler, its boiler-turbine coordinated control system (CCS) is based on incremental state observer combined with conventional PID control, and the connection logic of CCS with AGC adopted the scheme shown in this paper. Through adopting the connection logic of CCS with AGC, the pre-add coal function can be realized in AGC mode, which assured the rapid response to AGC load demand of the power unit, and this viewpoint has been fully proved by the trend curves of AGC adjusting test of the two units.

And at the last market structure is considered. Availability of frequency based tariff scheme is employed. Demand can be managed by managing the tariff. Therefore to make system in normal State need to study management in generation as well as demand. The objectives are:

1. To develop simulation model for each component of AGC and AVR loops.
2. To develop AGC model considering generating rate constraints.
3. To develop model for coupled automatic generation and voltage control.
4. To develop AGC model based on market structure.

The approach to this solution will include research of the approaches and application of real world values in these approaches. It is expected that research will add the world of AGC struction on demand side management.

Table of Contents

List of Figures

List of Tables

DEFINITION

POOL OPERATION: An extended power system can be divided into a number of LFC areas, which are interconnected by tie lines .such an operation is called a pool operation

AREA CONTROL ERROR: Integral control consists of a frequency sensor and an integrator .the frequency sensor measures the frequency error and this error signal is fed into the integrator .the input is called the ‘area control error’.

DYNAMIC RESPONSE: Is how the frequency changes as a function of time immediately after disturbances before it reaches the steady –state condition

SINGLE AREA: Single are a coherent area in which all the generations swing in unison to the changes in load or speed – changer settings and in which the frequency is assumed to be constant throughout both in static and dynamic conditions.

CONTROL AREA: Control area is possible to divide a very large power system into sub-area in which all the generators are tightly coupled such that they swing in unison with change in load or due to a speed –changer settings. Such an area, where all the generators are running coherently is termed as a control area.

WINDUP LIMITER: The output variables of the transfer function is not limited and free to vary ,hence, the wind up can be treated as a separated block in the modeling of a speed governing system.

NON –WIND UP LIMITER: The output variables of the transfer function are limited and there is no separated block in the modeling of a speed-governing system.

AMPLIDYNE: Is a high –response cross field generator, which has number of control windings that can be supplied from a pilot exciter and a number of feedback circuits of AVR and magnetic amplifier for control purposes

CONTROL VARIABLES: The real and reactive power generations are called control variables since they are used to control the state of the system

DISTURBANCE VARIABLES: The real and reactive power demands are called demand variables and they are beyond system control and are hence called uncontrolled.

Acronyms

B	: Frequency Bias factor
D	: Percent change in load divided by the percent change in frequency
Ki	: Supplementary control constant
H	: Inertia Constant
? P	: Change in power
? P_{Mech}	: Change in mechanical power input
? P_D	: Change in power demanded by the load in an area
? $P_{Tie\text{-}flow}$	: Change in power transmitted over tie line
? P_{valve}	: Change in valve position from nominal
R	: Speed Droop Characteristic
$?_{PS}$	: Power system time constant
$?_{SG}$	: Speed governor time constant
$?_t$	: Turbine time constant
F	: Frequency of system
f_{ref}	: Reference frequency for system
? f	: Change in system frequency
X_{tie}	: Reactance of tie line

CHAPTER 1

INTRODUCTION

1.1 Introduction

This thesis work deals with the automatic generation control considering generator rate constraints of interconnected thermal systems with combination of the automatic voltage control and market based deregulated system.

The primary purpose of the AGC is to balance the total system generation against system load and losses so that the desired frequency and power interchange with neighboring systems are maintained. Any mismatch between generation and demand causes the system frequency to deviate from scheduled value. Thus high frequency deviation may lead to system collapse. Power system operation at a lower frequency affects the quality of power supply [12] and not allowed because of following:

- When operating at frequencies below 49.5 Hz, some types of steam turbines undergo excessive vibration in certain turbine rotor stages with resultant metal fatigue and blade failure.
- When frequency falls below 49 Hz, turbine regulating devices fully open and the generating units becomes completely loaded a, further decrease in frequency reduces the efficiency of the auxiliary mechanisms at thermal power stations, especially feed pumps. The result in case of prolonged operation at a lowered frequency is a drop in the generated output and further loss of power. The decrease in power system frequency may assume an avalanche nature which can stop the power stations for a prolonged outage.
- As the frequency decreases, the generators exciter loss their speed and generator emf falls, the voltage in power system unit drops. This brings the danger of a “voltage avalanche” and disconnection of consumers.

A frequency avalanche drop aggravated by a voltage avalanche drop causes grave breakdown in the power system and complete stoppage of the paralleled station or division of power system in to separately operating sections with interruptions to power supply of many consumers. The function of automatic frequency control to prevent the power system frequency from approaching a critical value, when loss of active power occurs, by disconnecting part of the loads thereby keeping power stations and there auxiliaries operative. In this case the power system supplies to majority of consumers suffer no interruption and system to disconnected load can be restored within a fairly short period of time.

The role of automatic voltage regulator is to hold terminal voltage magnitude of synchronous generator at a specified level. Voltage drop beyond the specified limit may result in:

- Excessive slippage of asynchronous motor with resultant reactive current overload of feeding elements
- Decrease luminous efficiency of incandescent lamp where lighting fitting employing such lamps are installed and radio equipment.

An excessive increase in voltage cause premature deterioration of equipment insulation (increase in leakage current) and may result in its failure. Voltage drop at power system node points reduces the capacity of transmission lines and affects the stability of generators operating in parallel.

The interaction between frequency and voltage exists and cross coupling does exist and can some time troublesome [6]. AVR loop affect the magnitude of generated emf E. As the internal emf determines the magnitude of real power. It is clear that changes in AVR loop must felt in AGC loop. However, the AVR loop is much faster than the AGC loop and there is tendency for AVR dynamics to settle down before they can make themselves in slower AGC channel.

A surplus of MW tends to increase system frequency. A surplus of MVAR tends to increase system voltage.

- If MW increases is felt uniformly while when MVAR increased greatest where Q surplus is greatest.
- As we change MW of one of several generator resulting change in voltage.
- If we change Q inputs also change in real power

It is important to remember that demand undergo slow but wide changes throughout the 24 hr of the day. Need to manage generation as well as demand.

The total amount of real power in network emanates from generator stations, the location and size of which are fixed. The generation must be equal to demand at each moment and since this power must be divided between generators in unique ratio, in order to achieve the economic operation. We conclude that individual generator output must be closely maintained at predetermined set point. But it does not happen. Some times demand is very large than generation and some time surplus power in a duration of 24 hrs. It is important to remember that demand undergo slow but wide changes throughout the 24 hr of the day. Therefore need to manage generation as well as demand.

Here problem for management in demand side. Demand side can be managed by controlling tariff in demand side. This is called Demand Side Management and this can deal with two points as

- AGC, AVR and Frequency Availability Based Tariff for Two Area.
- AGC, AVR and Availability of Scheduled Loading for Two Area

This AAA deals with the automatic generation control of interconnected thermal systems with combination of the automatic voltage control and market based deregulated system

The research about automatic generation and voltage control considering economic dispatch, generator rate constraints and market management structure

1.2 Objectives

A power system is a proper system to transmit power economically efficiently and reliable manner. As we know every one desired the uninterrupted supply. But it is always not possible for a system remains in normal state. For more then 99% of the time, a typical system found in its normal state. In this state the frequency and the bus voltages are kept at prescribed value. As these two are responsible for active and reactive power balance. The match "Equality" between generation and demand is a fundamental prerequisite for system "Normalcy". Therefore objective is to maintain the system in normal state. This can be achieved by manage generation as well as demand. Generation can be manage by better AGC loop response which deals with frequency, voltage and economic dispatch control with considering generator rate constraints .Demand can be managed by managing the tariff. Therefore to make system in normal state need to study management in generation as well as demand. Therefore specific objectives are:

1. To develop simulation model for each component of AGC and AVR loops.
2. To develop AGC model considering generating rate constraints.
3. To develop model for coupled automatic generation and voltage control.
4. To develop AGC model based on market structure.

1.3 TECHNICAL CHALLENGES IN POWER SYSTEM

1.3.1 Introduction

A power system is a proper system to transmit power economically efficiently and reliable manner. As we know every one desired the uninterrupted supply. But it is always not possible for a system remains in normal state. For more then 99% of the time, a typical system found in its normal state. In this state the frequency and the bus voltages are kept at prescribed value. As these two are responsible for active and reactive power balance [6]. The match "Equality" between generation and demand is a fundamental prerequisite for system "Normalcy". Different state of a system is described in figure 1.1

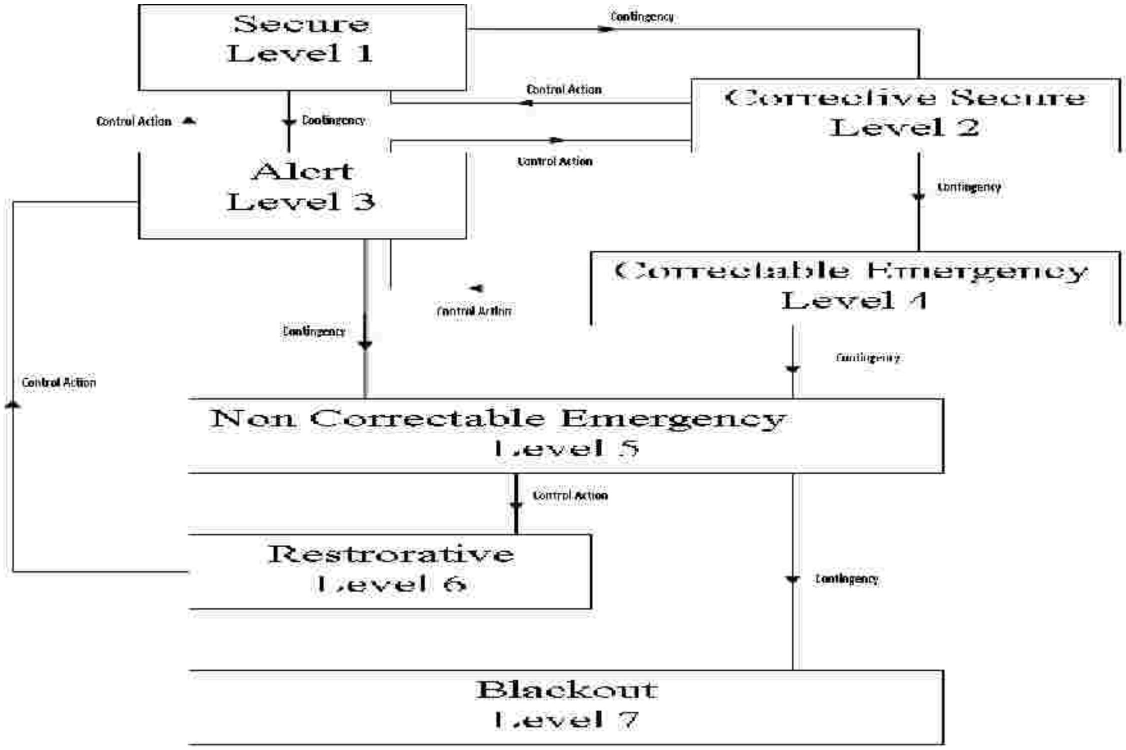


Figure 1.1 Power System States

In this figure if every thing fails means control action fails to maintain system stability. Then system goes in none correctable emergency. Then need of load shedding. So need of study of following problems for a power system to be in normal state.

1. Megawatt -Frequency interaction.
2. Megavar -Voltage interaction.
3. Power flow problem.
4. Optimum dispatch.
5. The control problem.

1.3.2 Megawatt -Frequency (P-f) Interaction

Constant frequency is identified as the primary mark of a normal operating system. There are at least four reasons why the system frequency must not be allowed to deviate from a chosen constant value. :

1. Most type of A.C. motors run at speeds that are directly related to the frequency.
2. The generator turbines, particularly steam driven are designed to operate at very precise speed.

3. The overall operation of power system can be much better controlled if frequency error is kept within strict limit.
4. The large number of electrical clocks are used are driven by synchronous motor. Accuracy of these clocks not only depends on frequency but integral of frequencies.

Load frequency mechanism:

The frequency is closely related to real power balance in network.

Under normal operating generators runs synchronously and generator power tougher that each moment is being drawn by all load plus real transmission losses. Electrical energy cannot be stored. Generation rate must be equal to consumption rate.

Difference would enter into kinetic energy storage. As kinetic energy storage as the kinetic energy depends on generator speed, a power imbalance will thus translates in to speed (frequency) deviation.

Let us consider generator and motor in the power system represents total kinetic energy of 1500MJ (MW) are measured at 50 Hz. System experience a surplus power of 5 MW. Rate at which frequency increases is 0.1Hz/s.

As system load changes, necessary to adjust generation so that power imbalance is continuously zero or minimized.

1.3.3 Megavar Voltage Interaction (Q-V)

Practically all equipment used in or operating of a power system is designed for certain voltage level .If it deviates its performance deviates and life expectancy drops. For example torque of induction motor proportional to square to square of terminal voltage.

For voltage control:

1. Excitation control of generator.
2. Switched shunt capacitor or reactor for controlling reactive power.
3. Synchronous capacitor.
4. Tap changing of transformer.

1.3.4 Cross Coupling between Controls Loops

A surplus of MW tends to increase system frequency. A surplus of MVAR tends to increase system voltage.

- If MW increases is felt uniformly while when MVAR increased greatest where Q surplus is greatest.
- As we change MW of one of several generator resulting change in voltage.
- If we change Q inputs also change in real power

Since there is considerable coupling in opposite direction.

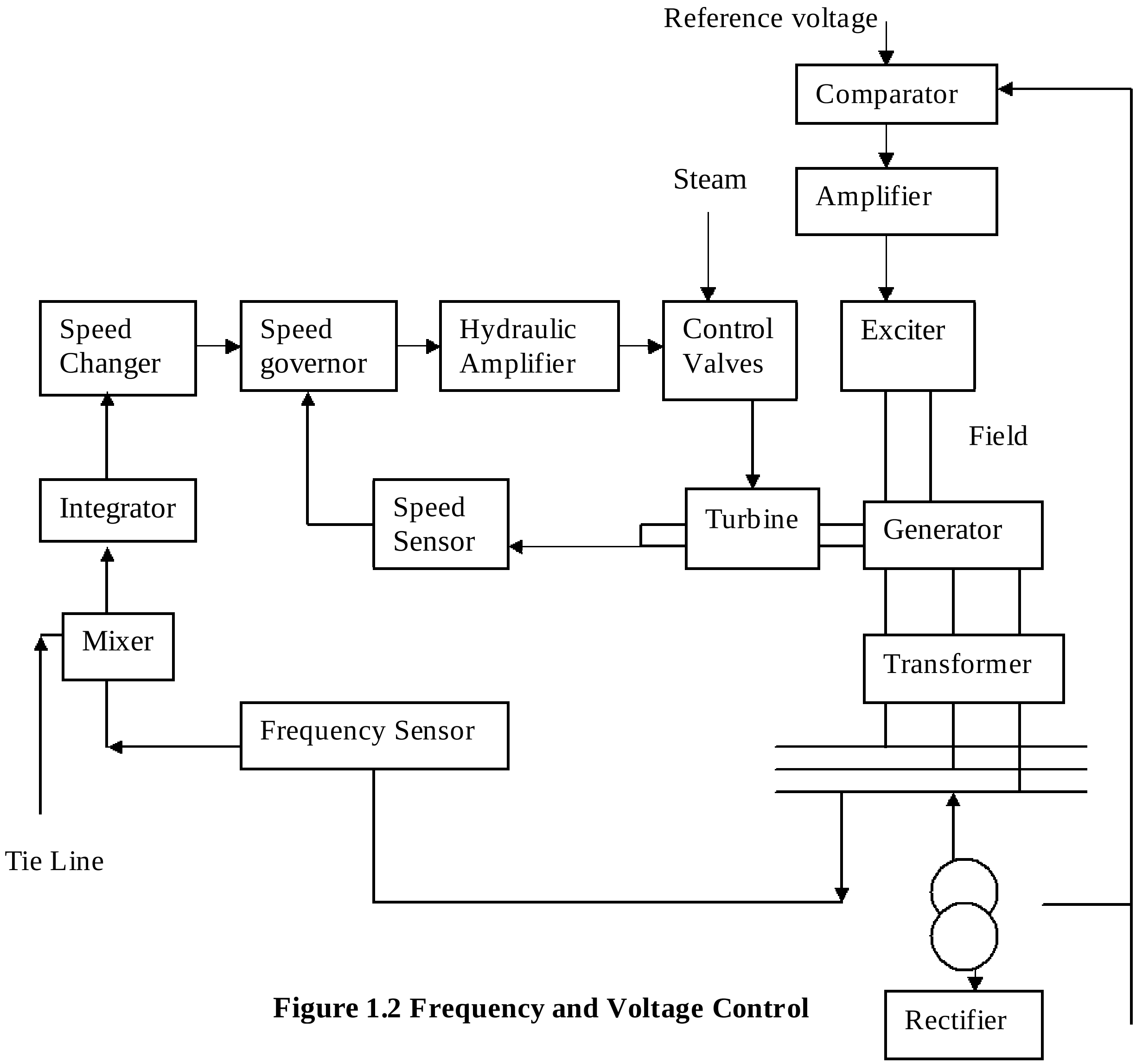


Figure 1.2 Frequency and Voltage Control

1.3.5 Power Flow Problem

The important aspect of power flow analysis:

1. The total amount of real power in network emanates from generator stations, the location and size of which are fixed. The generation must be equal to demand at each moment and since this power must be divided between generators in unique ratio, in order to achieve the economic operation. We conclude that individual generator output must be closely maintained at predetermined set point. It is important to remember that demand undergo slow but wide changes throughout the 24 hr of the day. We must therefore slowly, either continuously or in the discrete steps, change these set point as the hour wears on. This means that a load flow configuration that fits the demand of a certain hour of day may lock quite different the next hour.
2. Transmission link can carry only certain amount of power and we must make sure that we don't these links too close to there stability or thermal limit.
3. It is necessary to keep the voltage levels of certain buses within close tolerances. This can be achieved by proper scheduling of reactive power.
4. If power system is a part of a larger pool. It must fulfill certain contractual power scheduling commitment via its tie lines to neighboring system.
5. The disturbance following a massive network fault can cause system outages, the effect of which can be minimized by proper pre fault power flow strategies.
6. Power flow analysis is very important in planning stages of new network or addition to existing one.

1.3.6 Optimal Dispatch

The energy cost is expressed in Rs/MW will vary greatly between the above types of units. Peaking units are more expensive because on average they are greatly under used. If a utility can save its peak demand by load management, it may possible for years the need acquisition of such units.

Maintain proper generation mix is most important requirement for a power company of any size. The problem is not only due to hourly shifting the power demand. The entire generating unit must be regularly maintained. The operating success of a utility

company depends to a great extent upon ability optimally to match the generation to the load not only
24 hrs daily time span but over seasons and years.

1.3.7 Control Action

Control actions are:

1. Torque and excitation control.
2. Switching in or out of series or shunt capacitors.
3. Regulating transformer tap control.
4. Relay protection control.
5. Stability enhancement using some extra methods.
6. Load shedding..

1.3.8 Interconnected Power System Network

During early years small local generating stations supplied power to respective local loads. Each generating stations needed enough installed capacity to feed local loads. Merits of interconnected ac power system:

- Lesser spinning reserve
- Economic generation.
- Lesser installed capacity.
- Minimized operational cost, maximize efficiency.
- Better use of energy reserve.
- Better service to consumer.

Modern power system network is formed by interconnecting several individual controlled ac networks. Each individual controlled ac network has its own generating, transmission, distribution and loads and load control centers. The regional control centre controls generation and in its geographical region to maintain system frequency within limits (+-0.5%) The exchange of power (import/export) between neighboring ac network is dictated by National Load Control Centre. Thus ac network in an interconnected network called national grid. Even neighboring national grids are interconnected to form super grids.(eg. USA, Canada; European grid; UK-France).Interconnection between India Pakistan, India Sri Lanka, India Nepal etc. in initial planning stage(1997).Main task of interconnection is to transfer power..

Interconnection has significant influence on load – frequency control, short circuit level, power system security and stability, power system protection and control, energy management financial accounting.

System

Configuration and Principal of Interconnection

The system A and B are interconnected by tie line. Each area has its individual load frequency control which controls the total generation of area to match load losses and interchange.

The total control is done by SCADA.

Individual System (Region or Area)

Each individual system generates enough power equal to Regional load, plus net interchange with adjacent system via the tie lines.

Total generation = Total area load + Total net interchange by area

By maintain balance between R.H.S. and L.H.S., the frequency of area A is maintained within targeted limits. This condition is fulfilling by AGC, performed Regional load centre.

Total Generation in Interconnected system:

Total generation of group of interconnected system = total load plus losses

Algebraic sum of net interchange equal to zero.

- If total generation is less than total load on the grid. The frequency of the entire grid starts falling. Fall of frequency cause increase power inflow from neighboring region.
- If total generation is more than total load, frequency starts rising. Load frequency control is automatic.

This is achieved by:

1. Primary load frequency control.
2. Secondary control: By enough interchange of power between regional grid as per instruction of load control centre.

1.3.9 Supervisory Control and Data Acquisition System (SCADA)

Today is need of SCADA system because of following reasons:

- Present day power systems have large interconnected networks.
- Maintaining system security, reliability, quality, stability and ensuring economic operation are the major operating concerns.
- The success of the recently evolving electricity market structure will heavily depend on modern information systems and on line decision tools.
- On line monitoring, operation and control of the modern day power systems have become impossible without computer aided monitoring & dispatching systems.

Such systems at transmission & Generation level are called as **Supervisory Control & Data Acquisition (SCADA)** or **Energy Management System (EMS)** and those for distribution systems are called as **Distribution Automation (DA)** systems.

1.3.10 Demand Side Management

The total amount of real power in network emanates from generator stations, the location and size of which are fixed. The generation must be equal to demand at each moment and since this power must be divided between generators in unique ratio, in order to achieve the economic operation. We conclude that individual generator output must be closely maintained at predetermined set point. But it does not happen. Some times demand is very large than generation and some time surplus power in a duration of 24 hrs. It is important to remember that demand undergo slow but wide changes throughout the 24 hr of the day.

Therefore need to manage generation as well as demand. Here problem for management in demand side. Demand side can be managed by controlling tariff in demand side. This is called Demand Side Management and this can deal with two points as:

- **AGC, AVR and Frequency Availability Based Tariff for Two Area.**

The basic scheme while controlling tariff is based on availability of frequency. If generation is greater than demand than increase the current tariff scheme and vice versa. Also even if situation comes than it can not be controlled by controlling tariff than either use economic dispatch or need of load shedding.

This on line tariff control and economic dispatch control is done through SCADA system.

- **AGC, AVR and Availability of Scheduled Loading for Two Area**

The second scheme is AGC, AVR with Scheduled Loading Available for Two Areas. If scheduled is available for load change in duration of days, a better frequency characteristics can be obtained.

This AAA deals with the automatic generation control of interconnected thermal systems with combination of the automatic voltage control and market based deregulated system.

CHAPTER 2

LITERATURE REVIEW

Many investigations in the field of automatic generation control of interconnected power system have been reported over the past few decades. These investigation deals with how to select a frequency bias, selection of controller parameters and selection of speed regulator parameter of speed governor. Investigation regarding to the AGC of interconnected thermal system is limited to the selection of controller parameter and effect of GRC (generation rate constraints). Intelligent control scheme for interconnected thermal system is yet to be examined. Nanda et al considered the problem of AGC in interconnected thermal system in continuous-discrete mode using conventional integral and proportional-integral controllers. They have considered the appropriate generation rate constraint for the thermal plants.

Nanda and Kothari [14] have extensively studied the AGC problem of a two-area thermal system. They have studied the effect of generator rate constraints and governor dead band.

Kalyan Kumar [13] discusses in his paper entitled: “Modeling and simulation of AGC for SCADA based interconnected power system operation” about the new structure for AGC based on SCADA. The effect of governor dead band and stability analysis of AGC [3, 4, 5] is explained in the contest of recent developments in industry. The author points out that the frequency deviation is major problem in the present context.

Nagrath and Kothari [8] provide detailed design of automatic generation control for steady the performance of power systems. Their study also includes the effect of GRC and governor dead band.

Elgerd and Wood [6,7] provide detailed design of automatic generation and voltage control for steady the performance of power systems. Their study also includes the effect of coupling between AGC and AVR loops.

Prabha Kundur [9] also explains stability analysis of AGC. Barzam [12] studies the effect of deviation of frequency and voltage on power system network.

Power Plant Responses shows that in practice GRC for reheat thermal system varies between 2.5% to 12% per minute. Literature Survey shows that, very little attention has been given to the study of automatic generation control (AGC) of multi-area systems [11].

Bzorm [4] present AGC of a two area no reheat thermal system in deregulated power system. The concept of DISCO participation matrix (DPM) and area participation factor (APF) to represent bilateral contracts are introduced. AGC are provided by a single utility company called a control area that owns both transmission and generation systems. After deregulation, the power system structure has changed allowing specialized companies for generation, transmission, distribution and independent system operator.

Jayant Kumar [2, 3] have presented AGC simulator model for price based operation in a deregulated power system. They have suggested the modifications required in the conventional AGC to study the load following in price based market operations. They have highlighted salient difference between the automatic generation controls in a vertical integrated electric industry (conventional scenario) and a horizontal integrated electric industry (restructured scenario).However, they have not addressed the aspects pertaining to reheat turbine, GRC and hydro-thermal system.

Francesco, Enrico [22, 19] have given the concept that in a deregulated environment, independent generators and utility generators may or may not participate in the load frequency control of the system. Evaluation of the performance of such system has been developed. The method assumes load frequency control is performed by independent system operator (ISO) based on parameters defined by participating generating units. In the paper it has been shown that if the percentage of units participating in this control action is very small, system performance deteriorates to a point that is unacceptable. It is therefore recommended that minimum requirements be established, based on system.

Ibraheem and Prabhat Kumar [20] have made an attempt to present an up to date and exhaustive bibliography on the AGC of power systems. Various control aspects concerning the AGC problem have been highlighted.AGC schemes based on parameters, such as linear and non linear power system models, classical and optimal control, and centralized, decentralized, and multilevel control, is discussed.

G.V.Hicks[1] has tried to explain the main objective of the AGC i.e. it keep the system frequency and the net interchange in the tie lines near to their scheduled values through generation set points in the units conditioned to this purpose. The AGC implementation requires a careful process of tuning and testing of the remote control devices for generation units and the AGC program installed in the Electric Market Administrator.

Ignacio and Fidel [18] have developed a simple discrete time model of a thermal unit for designing AGC controllers. This model has been developed using data obtained from specific tests and historical records. This model consists of a nonlinear block followed by a linear one. The nonlinear block consists of a dead band and a load change limiter, while the linear block consists of a second order linear model and an offset. It has been found that the unit response is mainly determined by the rate limiter, while the other model components are used for a better fitting to the real response.

Many authors have made attempts to describe modified AGC for deregulated power system. Literature survey shows that most f the earlier work in the area f automatic generation control in deregulated environment pertains to interconnected thermal system and no attention has been devoted AGC with demand management.

CHAPTER 3

CLOSE LOOP AUTOMATIC GENERATION CONTROL (AGC) DESIGN

3.1 Introduction

Power system operation considered so far was under conditions of steady load. However, both and reactive power demands are never steady and they continually change with the rising or falling trend. Steam input to turbo generators (or water input to hydro-generators) must, therefore, be continuously regulated to match the active power demand, failing which may be highly undesirable (maximum permissible change in power frequency is ± 0.5 Hz). Also the excitation of generators must be continuously regulated to match the reactive power demand with reactive generation, otherwise the voltages at various system buses may go beyond the prescribed limits. in modern large interconnected system, manual regulation is not feasible and therefore automatic generation and voltage regulation equipment is installed on each generator [8]. Figure 3.1 gives the schematic diagram of load frequency and excitation voltage regulators of a turbo-generator. The controllers are set for particular operating conditions and they take care of small changes in load demand without frequency and voltage exceeding the prescribed limits. With the passage of time, as the change in load demand becomes large, the controllers must be reset either manually or automatically.

It has been shown in previous chapters that for small changes active power is dependent on machine angle d and is independent of bus voltage; while bus voltage is dependent on machine excitation (therefore on reactive generation Q) and is independent of machine angle d. Change in angle d is caused by momentary change in generator speed. Therefore, load frequency and excitation voltage control are non-interactive for small changes and can be modeled and analyzed independently. Furthermore, excitation voltage control is fast acting in which the major time constant encountered is that of the generator field; while the power frequency control is slow acting with major time constant contributed by the turbine and generator moment of inertia-this time constant is much larger than that of the generator field. Thus, the transients in excitation voltage control vanish much faster and do not affect the dynamics of power frequency control.

Change in load demand can be identified as: (1) slow varying changes in mean demand, and (2) fast random variations around the mean. The regulators must be designed to be insensitive to fast random changes, otherwise the system will be prone to hunting resulting in excessive wear and tear of rotating machines and control equipment.

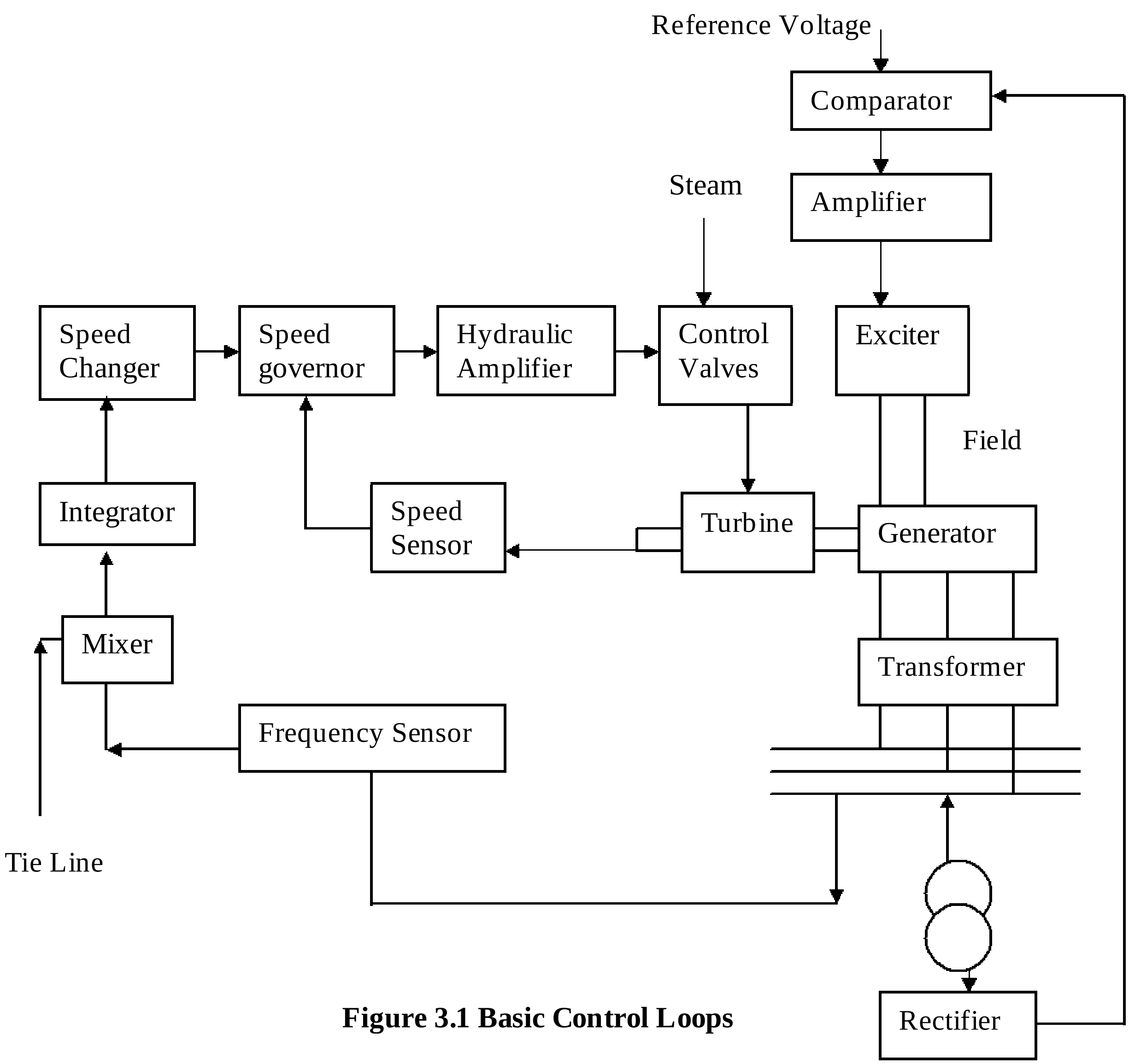


Figure 3.1 Basic Control Loops

3.2 Load Frequency Control (Single Area Case)

Let us consider the problem of controlling the power output of the generators of a closely knit electric area so as to maintain the scheduled frequency. All the generators in such an area constitute a coherent group so that all the generators speed and slow down together maintaining their relative power angles. Such an area is defined as a control area. The boundaries of a control area will generally coincide with that of an individual electricity board company.

To understand the load frequency control problem, let us consider a single turbo-generator system supplying an isolated load.

Turbine speed governing system

Figure 3.2 shows schematically the speed governing system of a steam turbine. The system consists of the following components:

(1) **Fly ball speed governor:** this is the heart of the system which senses the change in speed (frequency). As the speed increases the fly balls move outwards and the point B on linkage mechanism moves downwards. The reverse happens when the speed decreases.

(2) **Hydraulic amplifier:** it comprises a pilot valve movement is converted into high power level piston valve movement. This is necessary in order to open or close the steam valve against high pressure steam.

(3) **Linkage mechanism:** ABC is a rigid link pivoted at B and CDE is another rigid link pivoted at D. this link mechanism provides a movement to the control valve in proportion to change in speed. It also provides a feedback from the steam valve movement (link 4).

(4) **Speed changer:** it provides a steady state power output setting for the turbine. Its downward movement opens the upper pilot valve so that more steam is admitted to the turbine under steady conditions (hence more steady power output). The reverse happens for upward movement of speed changer.

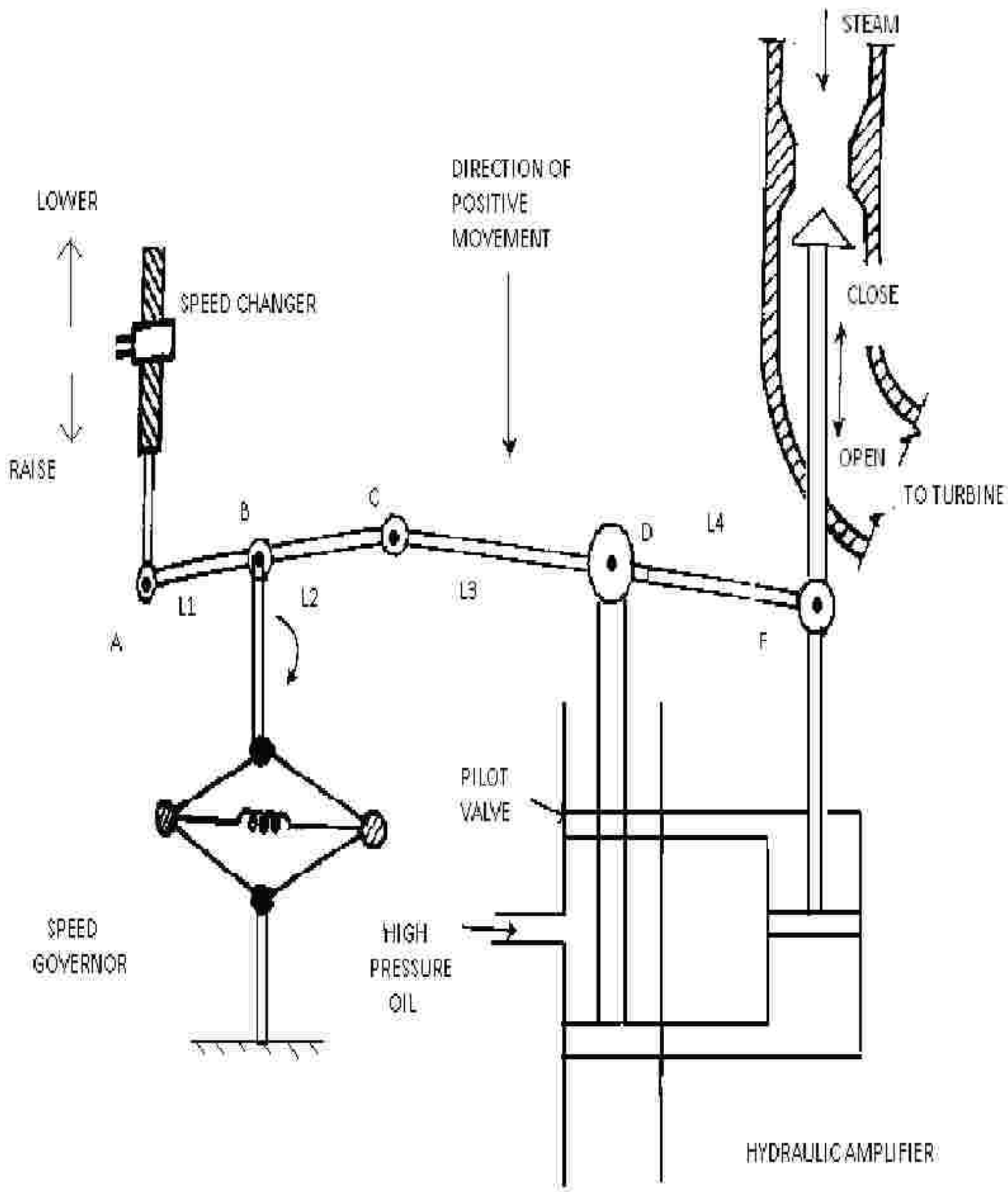


Figure 3.2 Speed governing Model

Model of speed governing system

Assume that the system is initially operating under steady conditions-the linkage mechanism stationary and pilot valve closed, steam valve opened by a definite magnitude, turbine running at constant speed with turbine power output definite magnitude, turbine running at constant speed with turbine power output balancing the generator load. Let the operating conditions be characterized by balancing the generator load. Let the operating conditions be characterized by

F° = system frequency (speed)

P°g = generator output = turbine output

Y°g = steam valve setting

We shall obtain a linear incremental model around these operating conditions.

Let the point A on the linkage mechanism be moved downwards by a small amount ? Ya. It is a command which causes the turbine power output to change and can therefore be written as

$$? Ya = Kc ? Pc \qquad (3.1)$$

Where ? Pc is the commanded increase in power.

The command signal ? Pc (i.e. ? Ye) sets into motion a sequence of events-the pilot valve moves upwards, high pressure oil flows on to the top of the main piston moving it downwards; the steam valve opening consequently increase, the turbine generator speed increase, i.e. the frequency goes up. Let us model these events mathematically.

Two factors contribute to the movement of C:

(1) ? Ya contributes-(L_2/L_1) ? Ya or $-k_1$? Ya (i.e. upwards) of $-k_{1c}$? P_c

(2) Increase in frequency ? f causes the fly balls to move outwards so that B moves downwards by a proportional amount K_2? f. the consequent movement of C with A remaining fixed at ? Ya is + (L_1+L_2/L_1)K_2? f = +K_2? f

(i.e. downwards)

The net movement of C is therefore

$$? Yc = - K_1 Kc ? Pc + K_2 ? f \qquad (3.2)$$

The movement of D, ? Yd, is the amount by which the pilot valve opens. It is contributed by ? Yc and ? Ye and can be written as

$$? Y_d = (L_4/L_3+L_4)\ ? Yc + (L_3/L_3+L_4)\ ? Ye$$

$$= K_3 ? Yc + K_4 ? Ye \quad (3.3)$$

The movement $? Y_d$ depending upon its sign opens one of the ports of the pilot valve admitting high pressure oil into the cylinder thereby moving the main piston and opening the steam valve by ? Ye. Certain justifiable simplifying assumptions, which can be made at this stage, are:

(1) Inertial reaction forces of main piston and steam valve are negligible compared to the forces exerted on the piston by high pressure oil.

(2) Because of (i) above, the rate of oil admitted to the cylinder is proportional to port opening $? Y_d$.

The volume of oil admitted to the cylinder is thus proportional to the time integral of $? Y_d$. The movement ? Ye is obtained by dividing the oil volume by the area of the cross section of the piston. Thus

$$? Ye = K_5\ ?(-? Y_d)\ dt \quad (3.4)$$

It can be verified from the schematic diagram that a positive movement ? Yd, causes negative (upward) movement ? Ye accounting for the negative sign used in Eq. (3.4)

Taking the Laplace transform of equations. (3.2), (3.3) and (3.4), we get

$$? Yc(s) = -K_1 Kc ? Pc(s) + K_2 ? F(s) \quad (3.5)$$

$$? Yd(s) = -K_3 ? Yc(s) + K_4 ? Ye\ (s) \quad (3.6)$$

$$? Ye(s) = -K_5\ 1/S\ ? Y_d(s) \quad (3.7)$$

Eliminating ? Yc(s) and $? Y_d(s)$, we can write

$$? Ye(s) = \frac{K_1 K_3 kc ? Pc(s) - K_2 K_3 ? F(s)}{(K_4 + s/K_5)}$$

$$= [? Pc(s) - 1/R ? F(s)] * (Ksg/1+TsgS)$$

Where

$R = K_1 K_c / K_2$ = speed regulation of the governor

$Ksg = K_1 K_3 K_c / K_4$ = gain of speed governor

$Tsg = 1/K_4 K_5$ = time constant of speed governor (3.8)

Equation (3.8) is represented in the form of block diagram in Figure 3.3

The speed governing system of a hydro-turbine is more involved. An additional feedback loop provides temporary droop compensation to prevent instability. This is necessitated by the large inertia of penstock gate which regulates the rate of water input to the turbine.

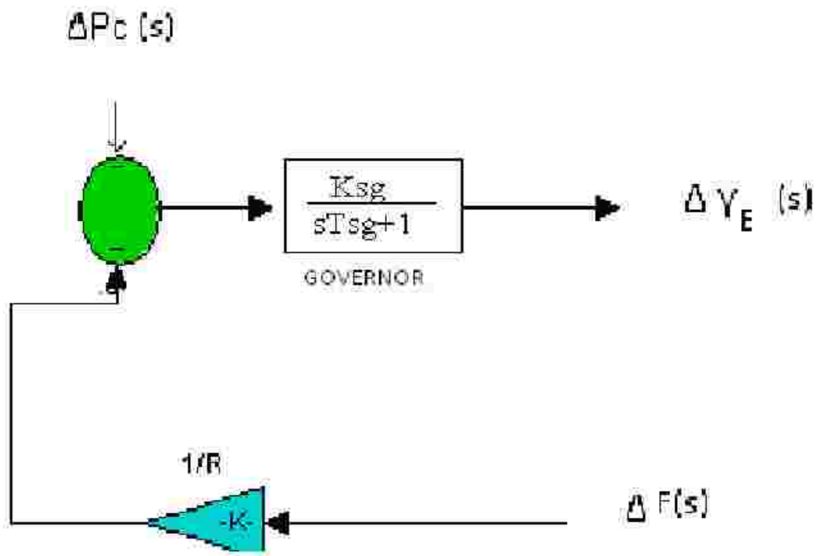


Figure 3.3 Block Diagram Representation of Governor System

Turbine Model

Let us now relate the dynamic response of the steam turbine in terms of changes in power output to changes in steam valve opening ? Ye. Here two stage steam turbine with reheat unit is used. The dynamic response is largely influenced by two factors, (i) entrained steam between the inlet steam valve and first stage of the turbine, (ii) the storage action in the reheated which causes the output if the low pressure stage to lag behind that of the high pressure stage. Thus, the turbine transfer function is characterized by two time constants. For ease of analysis it will be assumed here that the turbine can be modeled to have ease of analysis it will be assumed here that the turbine can be modeled to have a single equivalent time constant. Figure 3.4 shows the transfer function model of a steam turbine. Typically the time constant T_t lies in range 0.2 to 2.5.

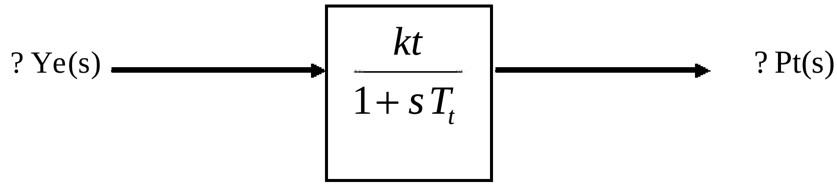


Figure 3.4 Turbine Model

The increment in power input to the generator-load system is

? Pg-? Pd

Where ? Pg = ? Pt, incremental turbine power output (assuming generator incremental loss to be negligible) and ? Pd is the load increment.

This increment in power input to the system is accounted for in two ways:

(i) Rate of increase of stored kinetic energy in the generator rotor. at scheduled frequency (f^o), the stored energy is

$W^o ke = H * PrKW = sec$ (kilojoules)

Where Pr is the KW rating of the turbo-generator and H is defined as its inertia constant.

The kinetic energy being proportional to square of speed (frequency), the kinetic energy at a frequency of ($f^o + f^o$? f) is given by

$Wke = W^o ke\,(f^o + ?\, f)/f^o)^2$

$\tilde{}$ H Pr (1+ (2? f/ f^o)) (3.9)

Rate of change of kinetic energy is therefore

d / dt (Wke) = 2HPr/ f^o * d/dt * (? f) (3.10)

(ii) As the frequency changes, the motor load changes being sensitive to speed, the rate of change of load with respect to frequency, i.e. ?Pd/?f can be regarded as nearly constant for small changes in frequency ? f and can be expressed as

(?Pd/?f) ? f = B ? f (3.11)

Where the constant B can be determined empirically. B is positive for a predominantly motor load.

Writing the power balance equation, we have

? Pg - ? Pd = 2HPr/ f^o * d/dt * (? f) + B? f

Dividing throughout by Pr and rearranging, we get

$$? Pg\,(pu) - ? Pd\,(pu) = 2H/\, f^{o} * d/dt * (? f) + B(pu)\, ? f \qquad (3.12)$$

Taking the laplace transform, we can write ? F(s) as

$$? F(s) = \frac{? Pg(s) - ? Pd(s)}{B + (2H/\, f^{o})\, s}$$

$$= [? Pg(s) - ? Pd(s)] * (Kps/(1+ sTps)) \qquad (3.13)$$

Where

$Tps = 2H/B\ f^{o}$ = power system time constant

$Kps = 1/B$ = power system gain

Equation (3.13) can be represented in block diagram form as in Figure 3.5

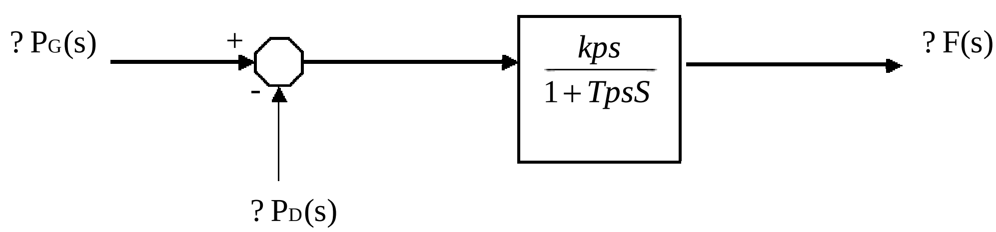


Figure 3.5 Block Diagram for Generator Load Model

Complete Block Diagram Representation of Load Frequency Control of an isolated power system

A complete block diagram representation of an isolated power system comprising turbine, generator, governor and load is easily obtained by combining the block diagram with feedback loop is shown in Figure3.6

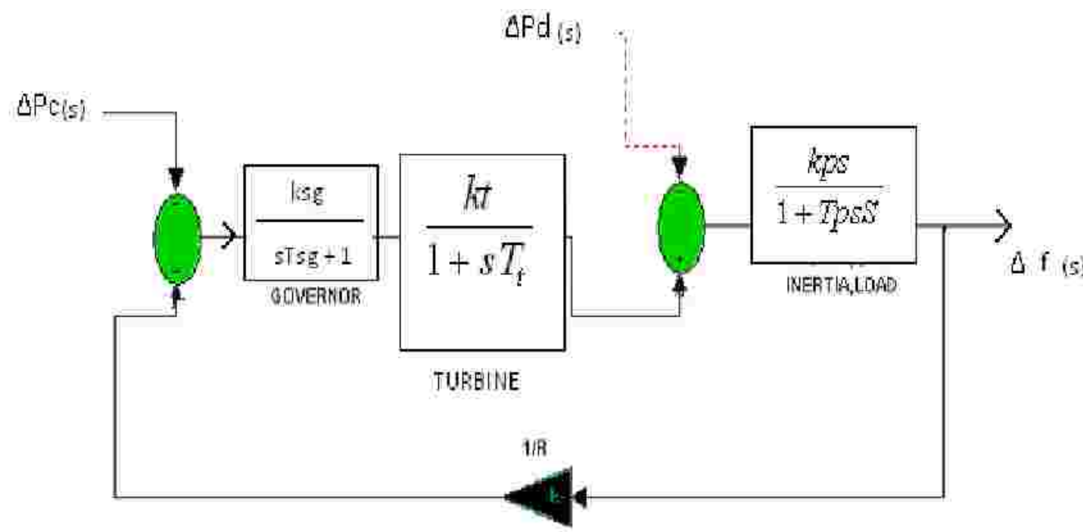


Figure 3.6 Block Diagram Model of Load Frequency Control

Steady States Analysis

The model of figure 3.6 shows that there are two important incremental inputs to the load frequency control system - ? Pc, the change in speed changer setting; and ? Pd, the change in load demand. Let us consider a simple situation in which the speed changer has a fixed setting (i.e ? Pd(s) = ? Pd/s) is obtained as follows:

? F(s)¦ ? Pc(s)=0 = -[Kps/[(1+Tps)+(KsgKtKps/R)/(((1+TsgS)((1+TtS))] * ? Pd/s] (3.14)

? f | steady state = **s**? F(s) |
? Pc = 0

s ⟶ 0 ? Pc(s) = 0

= - [Kps/ (1+ (Ksg Kt Kps / R))] ? Pd (3.15)

While the gain Kt is fixed for the turbine and Kps is fixed for the power system, Ksg, the speed governor gain is easily adjustable by changing by lengths of various links. Let it be assumed for simplicity that Ksg is so adjusted that

KsgKt ˜ 1

It also recognized that Kps = 1/B, where B = (?Pd/?f)/Pr (in pu MW/unit change in frequency). Now

? f = - [1/(B+ (1/R))]* ? Pd (3.16)

The above equation gives the steady state changes in frequency caused by changes in frequency are small (of the order of 5% from no load to full load). With this understanding, figure 3.7 shows the linear relationship between frequency and load for free governor operation with speed changer set to give a scheduled frequency of 100% at full load. The 'drop' or slope of this relationship is

$$\text{DROOP} = -\frac{1}{B + 1/R}$$

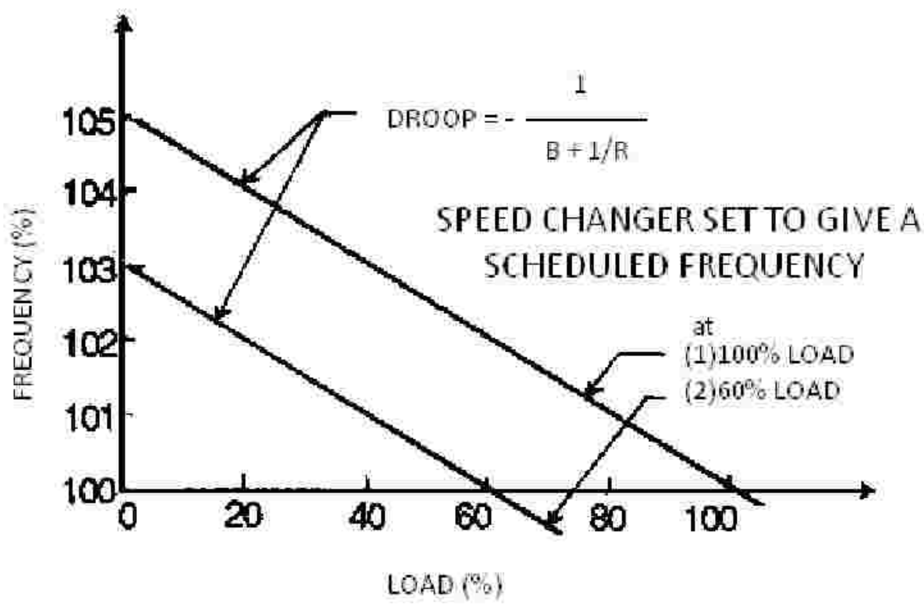


Figure 3.7 Steady State Load frequency characteristics

Power system parameter B is generally much is thus increase in load demand (? Pd) is met under steady conditions partly by increased generation (? Pg) due to opening of the steam valve and partly by decreased load demand due to drop in system frequency. From the block diagram of figure 3.6 (with KsgKt ˜ 1)

? Pg = -1/R * ? f = [1/(BR+1)] ? Pd

Decrease in system load = B? f = [BR/ (BR+1)]* ? Pd

Of course, the contribution of decrease in system load is much less than the increase in generation. For typical values of B and R quoted earlier

? Pg = 0.971 ? Pd

Decrease in system load = 0.029 ? Pd

Consider now the steady effect of changing speed changer setting (? Pc(s) = ? Pc/s) With load demand remaining fixed (i.e. ? Pd=0). The steady state change in frequency is obtained as follows.

? F(s)| ? Pd(s)=0 = [(KsgKtKps)/((1+TsgS)(1+TtS)+(KsgKtKps/R)]*(? Pc/s) (3.18)

? f | steady state = [(Ksg Kt Kps)/ (1+KsgKtKps/R)]* ? Pc (3.19)
? Pd=0

If

Ksg Kt ˜ 1

? f = (1/(B+1/R))* ? Pc (3.20)

If the sped changer setting is changed by ? Pc while the load demand changes by ? Pd the steady frequency change is obtained by superposition, i.e.

? Pc = ? Pd, for ? f = 0

Figure 3.7 depicts two load frequency plots – one to give scheduled frequency at 100% rated load and the other to give the same frequency at 60% rated load.

Dynamic Response

To obtain the dynamic response giving the change in frequency as function of the time for a step change in load, we must obtain the Laplace inverse of eq. (3.14). The characteristic equation being of third order, dynamic response can only be obtained for a specific numerical case. However, the characteristic eq. can be approximated as first order by examining the relative magnitudes of the time constants involved. Typical values of the time constants of load frequency control system are related as

Tsg << Tt <<Tps

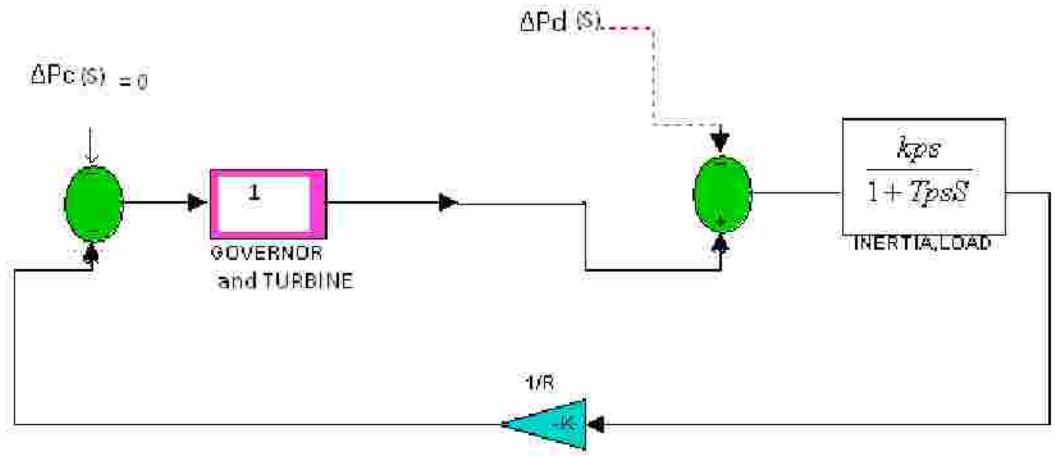


Figure 3.8 Model for Dynamic study

By considering typically Tsg, Tt and Tps .

Letting Tsg = Tt = 0, (and KsgKt ˜ 1), the block diagram of fig. 3.6 is reduced to that of figure 3.8, from which we can write

? F(s) | ? Pc(s)=0 = -[Kps/((1+Kps/R)+Tps)]* ? Pd/s

= -[(Kps / Tps) / s(s+(R+Kps/RTps))]* ? Pd

? f(t) = - (RKps/R+Kps) * {1-exp [-t/Tps(R/(R+Kps))]} ? Pd (3.22)

The plot of change in frequency versus time for first order approximation given above shown in fig. 3.9. First order approximation is obviously a poor approximation.

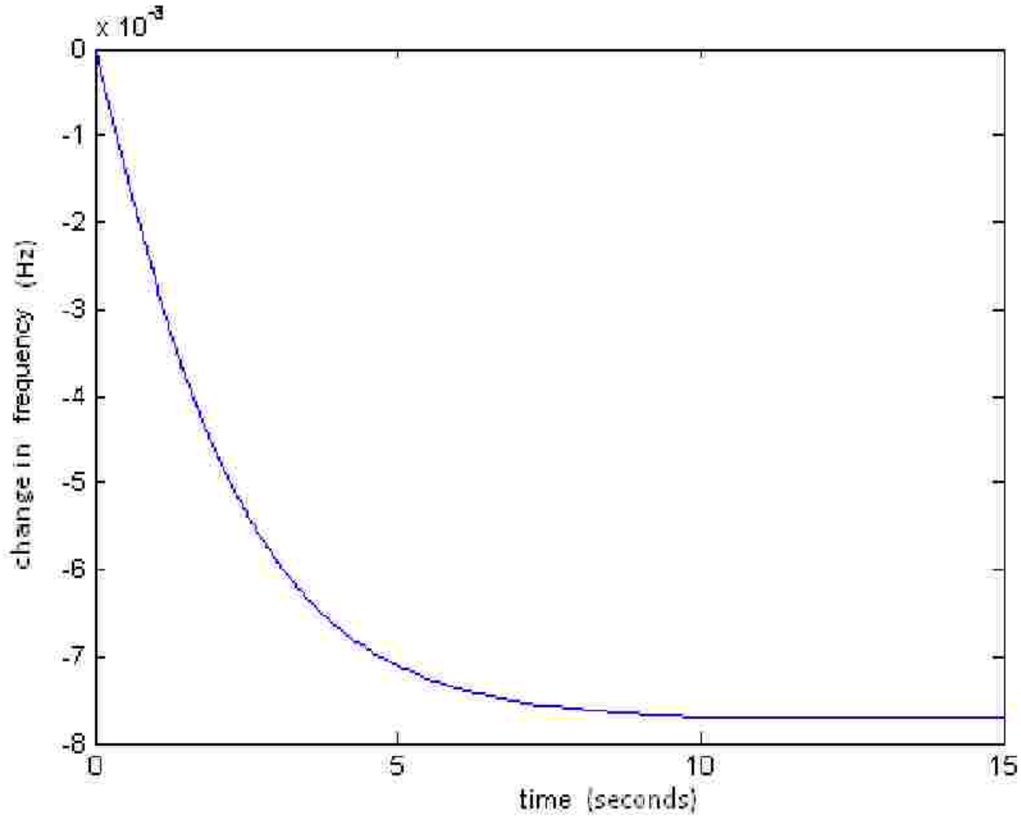


Figure 3.9 Change in frequency vs. time

Control Area Concept

So far we have considered the simplified case of a single turbo-generator supplying an isolated load. Consider now a practical system with a number of generating stations and loads. It is possible to divide an extended power system (say, national grid) into sub areas (may be, state electricity boards) in which the generators are tightly coupled together so as to form a coherent group, i.e. all the generators respond in unison to changes in load or speed changer settings. Such a coherent area is called a control area in which the frequency is assumed to be the same throughout in static as well as dynamic conditions. For purposes of developing a suitable control strategy, a control area can be reduced to single speed governor, turbo-generator and load system. All the control strategies discussed so far are, therefore, applicable to an independent control area.

Proportional Plus Integral Control

It is seen from the above discussion that with the speed governing system installed on each machine, the steady load frequency characteristic for given speed changer setting has considerable droop, e.g. for the system being used for the illustration above, the steady state droop in frequency will be 2.9 Hz from no load to full load. System frequency specifications are rather stringent and, therefore, so much change in frequency cannot be tolerated. In fact, it is expected that the steady change in frequency cannot be tolerated. In fact, it is expected that the steady change in frequency will be zero. While steady state frequency can be brought can back to the scheduled value by adjusting speed changer setting, the system could under go intolerable dynamic frequency changes with changes in load. It leads to the natural suggestion that the speed changer setting be adjusted automatically by monitoring the frequency changes. For this purpose, a signal from ? f is fed through an integrator to the speed changer resulting in the block diagram configuration shown in fig. 3.10. The system now modifies to a proportional plus integral controller, which, as is well known from control theory, gives zero steady state error, i.e. ? f(steady state) = 0

The signal ? Pc(s) generated by the integral control must be of opposite sign to ? F(s) which accounts for negative sign in block for integral controller.

Now

? F(s) = - [Kps/{(1+TpsS) + (1/R + Ki/s)*Kps/(1+Tsgs)(1+Tts)}]* ? Pd/s

= - [RKpss (1+Tsgs)(1+Tts)/{s(1+Tsgs)(1+Tts)(1+Tpss)R + Kps (Ki R + s)}]* ? Pd/s

(3.23)

Obviously,

? f (steady state = s? F(s)

s → 0

In contrast to eq. (3.16) we find that the steady state change in frequency has been reduced to zero by the addition of the integral controller. This can be argued out physically as well. ? f reaches steady state (a constant value) only when ? Pc = ? Pd = constant. Because of the integrating action of the controller, this is only possible

if ? f = 0 (3.24)

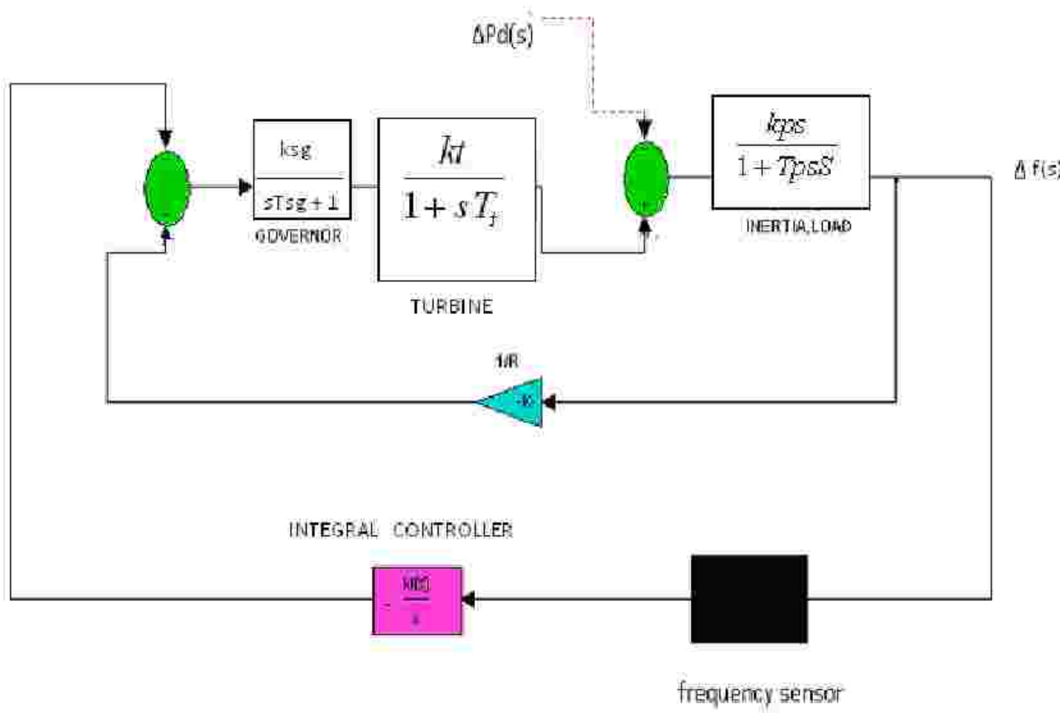


Figure 3.10 PI controller of AGC

In central load frequency control of a given control area, the change (error) in frequency is known as area control error (ACE). The additional signal fed back in the modified control scheme presented above is the integral of ACE.

In the above scheme ACE being zero under steady conditions, a logical design criterion is minimization of ?ACE dt for a step disturbance. This integral is indeed the time error of a synchronous electric clock run from the power supply. In fact, modern power systems keep track of integrated time error all the time. A corrective action (manual adjustment ? Pc, the speed changer setting) is taken by a large (pre assigned) station in area as soon as the time error exceeds a prescribed value.

The dynamics of the proportional plus integral controller can be studied numerically only, the system being of fourth order- the order of the system has increased by one with the addition of the integral loop. The dynamic response of the

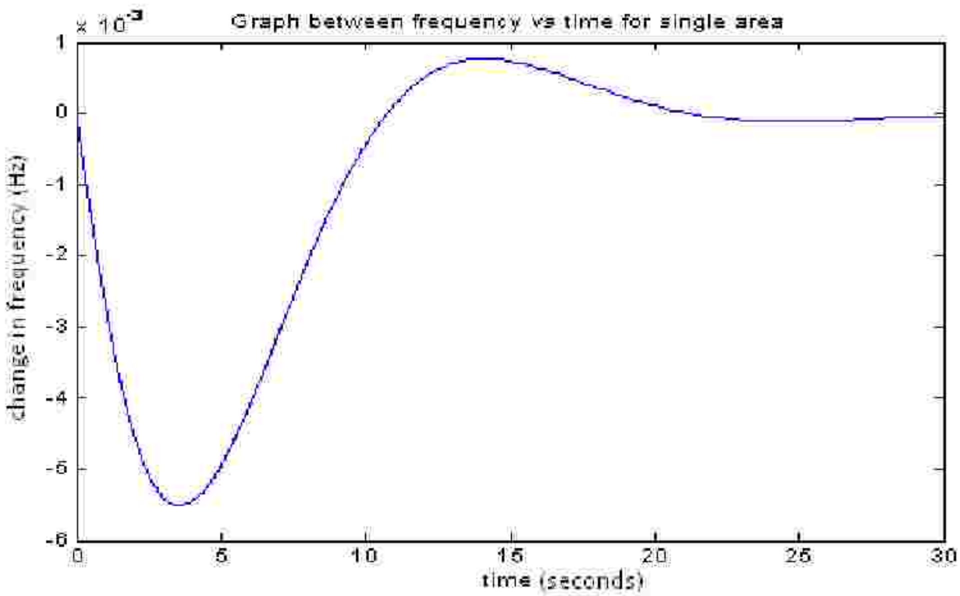


Figure 3.11 Close Loop AGC response for Single Area System

Proportional plus integral controller with Ki = 0.03 for step load disturbance of 0.182 pu is shown in figure 3.11

3.3 Load Frequency Control with Economic Dispatch Control

Load frequency control with integral controller achieve zero steady state error and fast dynamic response, but it exercise no control over the relative loading of various generating station (i.e. economic dispatch) of the control area. If a sudden increase in load(1%) occurs in control area, the load frequency control changes the speed changer settings of governor of all generating unit of the area so that ,together these unit match the load and the frequency returns to scheduled value (This action place in few seconds).

However, in process of this change loading of various generating unit change in manner independent of economic loading consideration. In fact, some units may get overloaded. Some control over loading of individual unit can be exercise by adjusting the gain factor of integral. However this is not satisfactory.

A satisfactory solution is achieved by using independent controls for load frequency and economic dispatch. While load frequency control is fast acting control and economic dispatch control is slow acting control, which adjust the speed changer setting in every minute in accordance with command signal generated by central economic dispatch centre. Figure 3.12 shows schematic diagram.

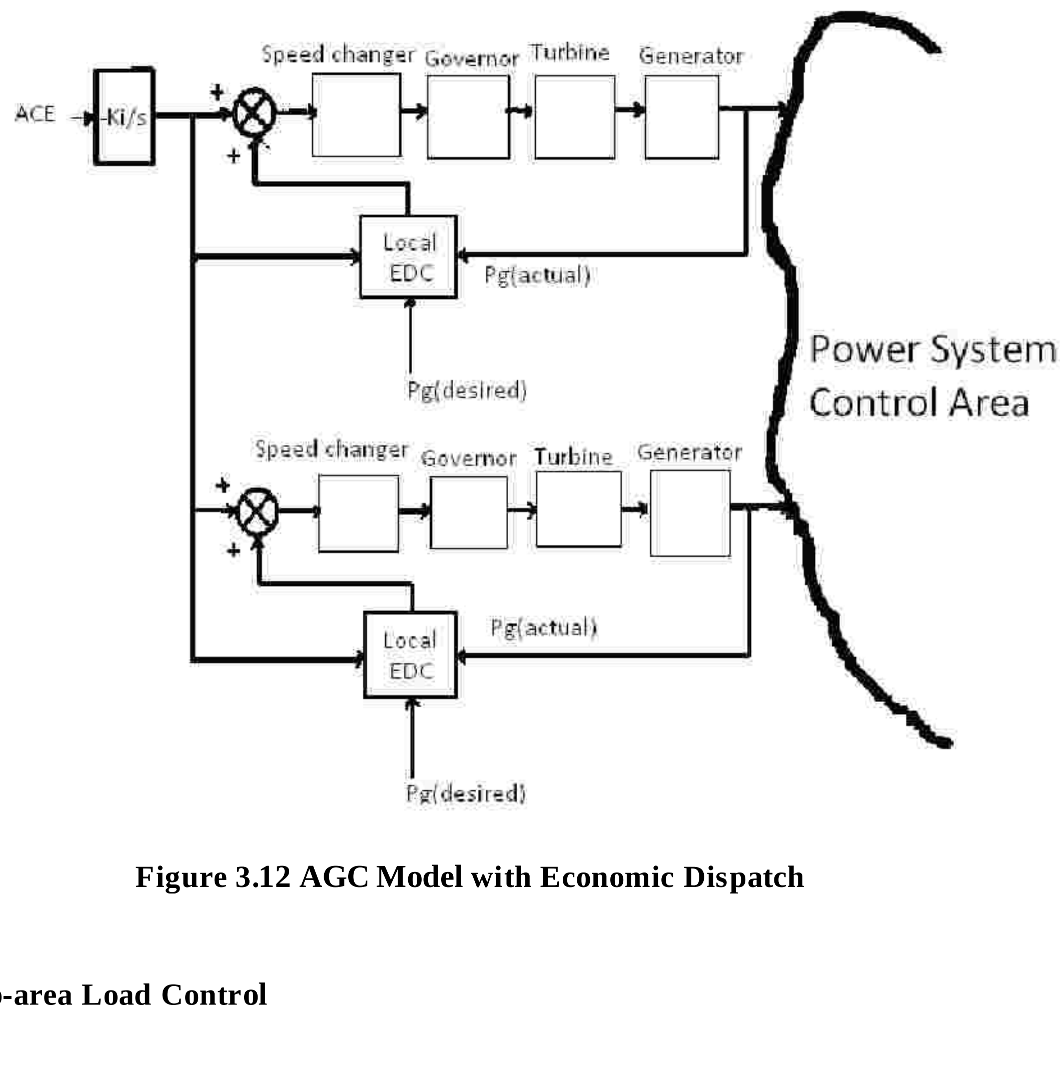


Figure 3.12 AGC Model with Economic Dispatch

3.4 Two-area Load Control

An extended power system can be divided into a number of load frequency control areas interconnected by means of tie lines. Without loss of generality we shall consider a two-area case connected by a single line as illustrated in Figure 3.13

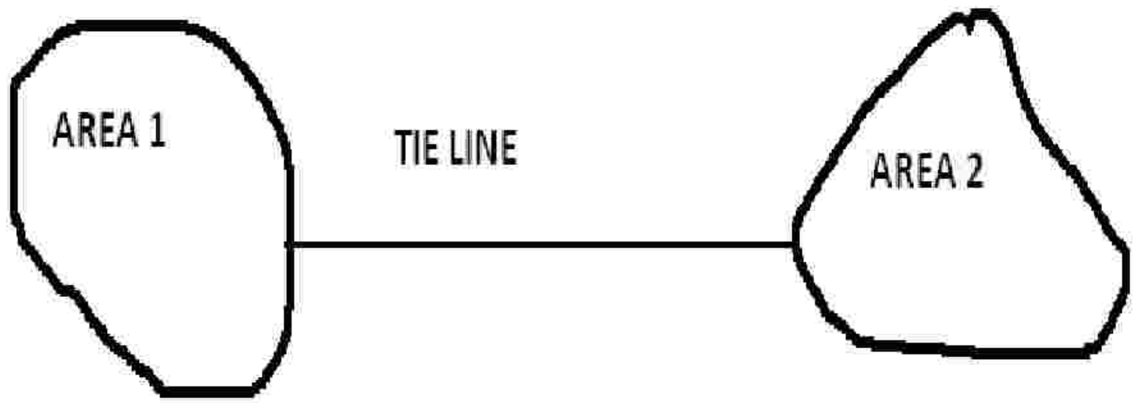


Figure 3.13 Two interconnected control areas (single tie line)

The control objective now is to regulate the frequency of each area and to simultaneously re4gulate the tie line power as per inter-area power contracts. As in the case of frequency, proportional; plus integral controller will be installed so as to give zero steady state error in tie line power flow as compared to the contracted power.

It is conveniently assumed that each control area can be represented by an equivalent turbine, generator and governor system. Symbols used with suffix 1 refer to area 1 and those with suffix 2 refer to area 2.

In an isolated control area case the incremental power (ΔP_G - ΔP_D) was accounted for by the rate of increase of stored kinetic energy and increase in area load caused by increase in frequency. Since a tie line transports power in or out of an area load caused by increase in frequency. Since a tie line transports power in or out of an area, this fact must be accounted for in the incremental power balance equation of each area.

Power transported out of area 1 is given by

$$P_{tie,1} = \frac{|V_1||V_2|}{X_{12}} \sin(\delta_1° - \delta_2°)$$

Where

$\delta_1°$, $\delta_2°$ = power angles of equivalent machines of the two areas.

For incremental changes in δ_1 and δ_2, the incremental tie line power can be expressed as

$$\Delta P_{tie,1(pu)} = T_{12} (\Delta\delta_1 - \Delta\delta_2)$$

Where

$$T_{12} = \frac{|V_1||V_2|}{P_{r1} \; X_{12}} \cos(\delta_1° - \delta_2°) = \textit{synchronizing coefficient}$$

Since incremental power angles are integrals of incremental frequencies, we can write as

$$\Delta P_{tie,1} = 2\underline{?}\, T_{12} (\int\Delta f_1 \, dt - \int\Delta f_2 \, dt)$$

where Δf_1 and Δf_2 are incremental frequency changes of areas 1 and 2 respectively.

Similarly the incremental tie line power out of area 2 is given by

$$\Delta P_{tie,2} = 2\underline{?}\, T_{21} (\int\Delta f_2 \, dt - \int\Delta f_1 \, dt)$$

Where

$$T_{21} = \frac{|V_2||V_1| \cos(\delta_2° - \delta_1°)}{P_{r2} \; X_{21}}$$

$= \; a_{12} \; T_{21}$

the incremental power balance equation for area1 can be written as

$$\Delta P_{G1} - \Delta P_{D1} = \frac{2H_1}{f_1^{\circ}} \frac{d}{dt}(\Delta f_1) + B_1 \Delta f_1 + \Delta P_{tie,1}$$

It may be noted that all quantities other than frequency are in per unit

Taking the Laplace transform and reorganizing, we get

$$\Delta F_1(s) = [\Delta P_{G1}(s) - \Delta P_{D1}(s) - \Delta P_{tie,1}(s)] * \frac{K_{ps1}}{1+T_{ps1}s}$$

Where as defined earlier

$K_{ps1} = 1/B_1$

$T_{ps1} = 2H_1/B_1 f^{\circ}$

Compared with the isolated control area case, the only change is appearance of the signal $\Delta P_{tie,1}(s)$ as shown in figure 3.14

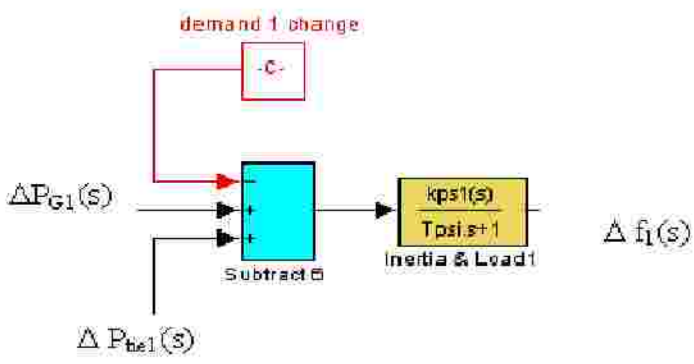


Figure 3.14 Two Area Load Model

$$\Delta P_{tie,\,1}(s) = \frac{2?\,T_{12}}{s}\,[\Delta F_1(s) - \Delta F_2(s)]$$

The corresponding block diagram is shown in Figure 3.15

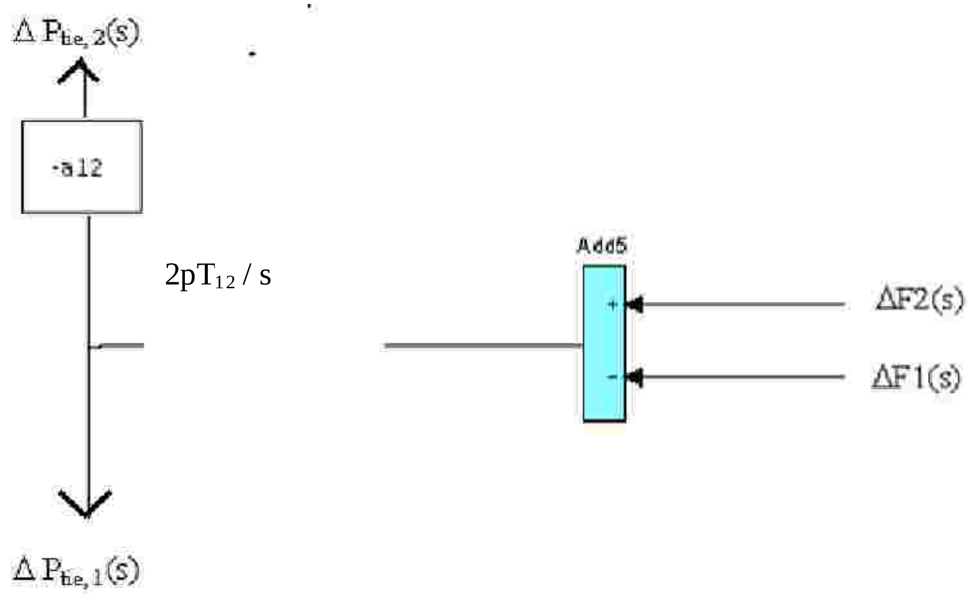


Figure 3.15 Model Corresponding to Tie Power Change

For the control area 2, $\Delta P_{tie,\,2}(s)$ is given as

$$\Delta P_{tie,\,2(s)} = -\frac{2?\,a_{12}T_{12}}{s}\,[\Delta F_1(s) - \Delta F_2(s)]$$

Which is also indicated by the block diagram of Figure 3.15?

Let us now turn our attention to ACE (area control error) in the presence of a tie line. In the case of an isolated control area, Ace is the change in area frequency which when used in integral control loop forced the steady state frequency which when used in integral control loop forced the steady state frequency error to zero. In order that the steady state tie line power error in a two-area control be made zero another control loop (one for each area) must be introduced to integrate the incremental tie line power signal and feed it back to speed changer. This is accomplished by a single line-integrating block by redefining ACE as linear combination of incremental frequency and tie line power. Thus, for control area 1

$$ACE_1 = \Delta P_{tie,1} + b_1 \Delta f_1$$

Where the constant b1 is called ***area frequency bias***

Above Eqn. can be expressed in the Laplace transform as

$$ACE_1(s) = \Delta P_{tie,1}(s) + b_1 \Delta F_1(s)$$

Similarly, for the control area 2, ACE2 is expressed as

$$ACE_2(s) = \Delta P_{tie,2}(s) + b_2 \Delta F_2(s)$$

Combining the basic block diagrams of the two control areas with $\Delta P_{C1}(s)$ and $\Delta P_{C2}(s)$ generated by integrals of respective ACEs (obtained through signals representing changes in tie line power and local frequency bias) and employing the block diagrams of Figs.we easily obtain the composite block diagram of Figure 3.4.4

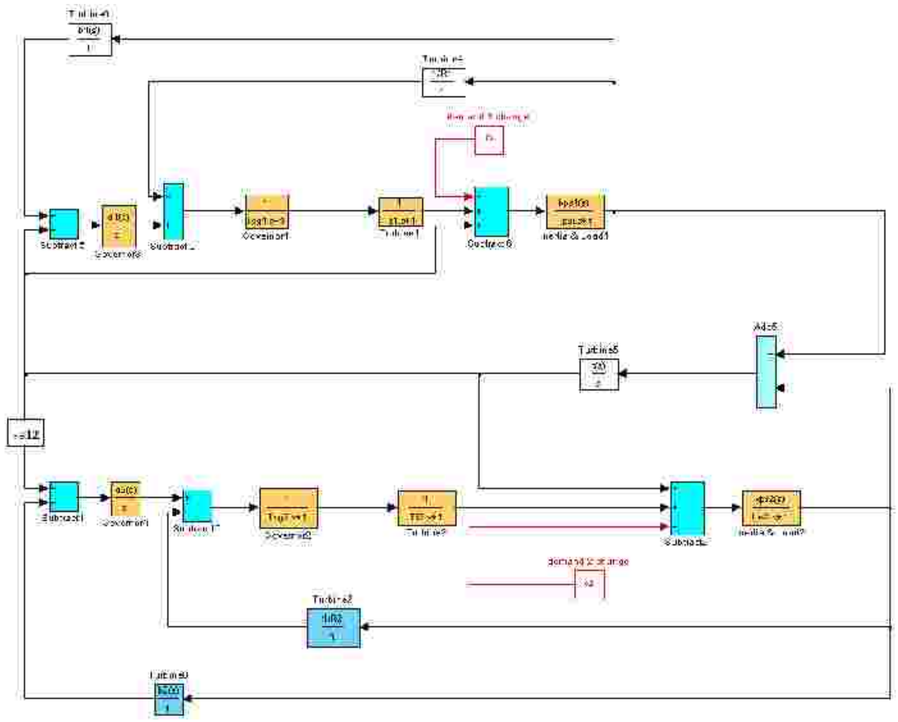


Figure 3.16 Two Area Model

Let the step changes in loads ΔP_{D1} and ΔP_{D2} be simultaneously applied in control, areas 1 and 2, respectively. When steady conditions are reached, the output signals of all integrating blocks will become constant and in order for this to be so, their output signals become zero. We have, therefore, from Figure 3.16

$\Delta P_{tie,1} + b_1\Delta f_1 = 0$ (input of integrating block $-K_{i1}/s$)

$\Delta P_{tie,2} + b_2\Delta f_2 = 0$ (input of integrating block $-K_{i2}/s$)

$\Delta f_1 - \Delta f_2 = 0$ (input of integrating block $-2\prod T_{12}/s$)

$$\frac{\Delta P_{tie,1}}{\Delta P_{tie,2}} = \frac{-T_{12}}{T_{21}} = \frac{-1}{a_{12}} = \text{constant}$$

Hence Eqns. are simultaneously satisfied only for

$$\Delta P_{tie,1} = \Delta P_{tie,2} = 0$$

and $$\Delta f_1 = \Delta f_2 = 0$$

Thus, under steady conditions change in the tie line power and frequency of each area is zero. This has been achieved by integration of ACEs in the feedback loops of each area.

Dynamic response is difficult to obtain by the transfer function approach (as used in single area case) because of the complexity of blocks and multi-input (ΔP_{D1}, ΔP_{D2}) and multi-output ($\Delta P_{tie,1}$, $\Delta P_{tie,2}$, Δf_1,Δf_2) situation.

The results of the two-area system (ΔP_{tie}, change in tie line power and Δf, change in frequency) obtained through simulation as shown in the in Figs.3.17. The two areas are assumed to be identical with system parameters given by

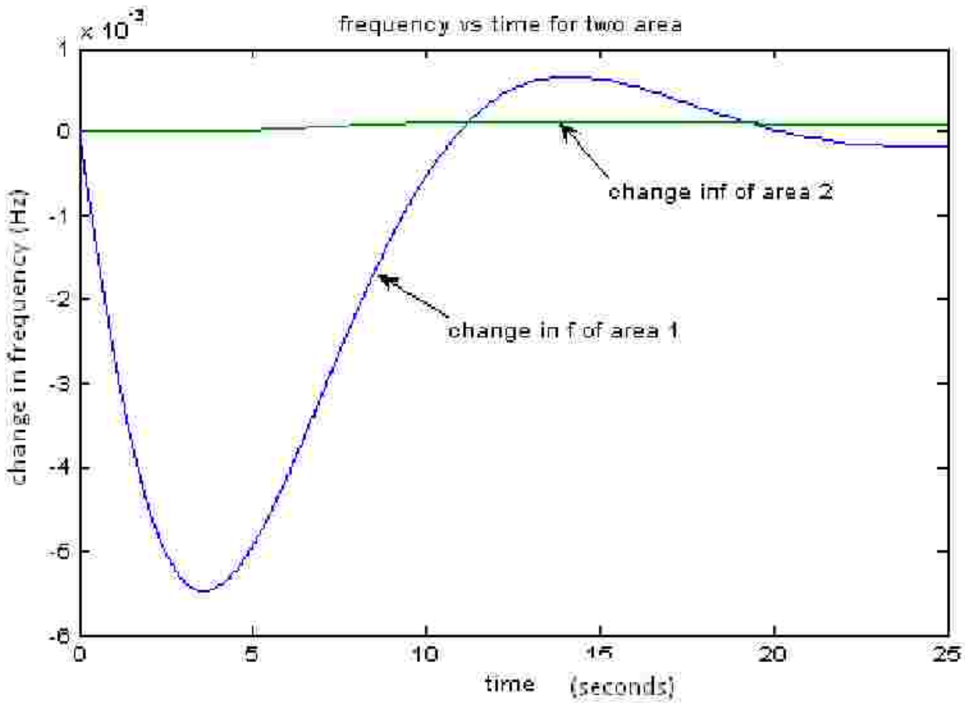


Figure 3.17 Dynamic Response of Two areas

3.5 Load Frequency Control with Generation Rate Constraints (GRCs)

Load frequency control problem discussed so far does not consider the effect of the restrictions on the rate of change of power generation. In power systems having steam plants, power generation can change only at a specified maximum rate. The generation rate (from safety considerations of the equipment) for reheat units is quit low. Most of the reheat units have a generation rate around 3%/min. some have a generation rate between 5 to 10%/min. if these constraints are not considered, system is likely to chase large momentary constraints are not considered, system is likely to chase large momentary disturbances. This results in undue wear and tear of the controller. Several methods have been proposed to consider the effect of GRC is considered, the system dynamic model becomes non-linear and linear control techniques cannot be applied for the optimization of the controller setting.

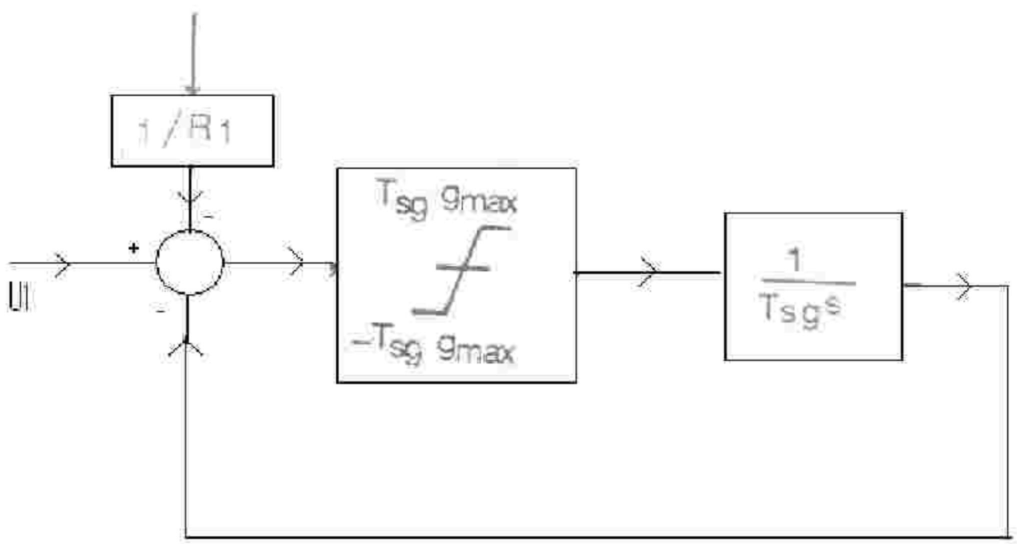


Figure 3.18 Governor Model with GRC

If the generation rates denoted by Pgi are included in the state vector, the system order will be altered. Instead of augmenting them, while solving the state equations, it may be verified at each step if GRCs are violated. Another way of considering GRCs for both areas is to add limiters to the governors as shown in figure 3.18, i.e. the maximum rate of valve opening or closing speed is restricted by the limiters. Here Tsg Gmax is power rate limit imposed by valve or gate control. In this model

¦ ? Ye¦ <Gmax

The banded values imposed by the limiters are selected to restrict the generation rate by 10% per minute.

The GRC result in larger deviations in ACEs as the rate at which generation can change in the area is constrained by limits imposed. Therefore, the duration for which the power needs to be imported increased considerably as compared to the case where generation rate is not constrained. With GRCs, R should be selected with care so as to give the best dynamic response. In hydrothermal system, the generation rate in the hydro area normally remains below the safe limit and therefore GRCs for all the hydro plants can be ignored.

3.6 Speed Governor Dead-Band and Its Effect on AGC

The effect of the speed governor dead-band is that for given position of the governor control valves, an increase/decrease in speed can occur before the position of the valve changes. The governor dead-band can materially affect the system response. In AGC studies, the dead band effect indeed can be significant, since relatively small signals are under considerations.

The speed governor characteristic, though non-linear, has been approximated by linear characteristics in earlier analysis. Further, there is another non-linearity introduced by the dead-band in the governor operation. Mechanical friction and backlash and also valve overlaps in hydraulic relays cause the governor dead-band. Due to this, though the input reaches a particular value. Similar action takes place when the input signal decreases. Thus the governor dead-band is defined as the total magnitude of sustained speed change within which there is no change in valve position. The limiting value of dead-band is specified as 0.06%. It was shown by Concordia that one of the effects of governor

Dead-band is to increase the apparent steady-state speed regulation R. The presence of governor dead-band makes the dynamic response oscillatory. It has been seen that the governor dead-band does not influence the selection of integral controller gain settings in the presence of GRCs. In the presence of GRC and dead band even for small load perturbation, the system becomes highly non-linear and hence the optimization problem becomes rather complex.

3.7 Digital LF Controller

In recent years, increasingly more attention is being paid to the question of digital implementation of the automatic generation control algorithms. This is mainly due to the facts that digital control turns out to be more accurate and reliable, compact in size, less sensitive to noise and drift and more flexible. It may also be implemented in a time shared fashion by using the computer systems in load dispatch centre, if so desired. The ACE, a signal which is used for AGC is available in the discrete form, i.e. there occurs sampling operation between the system and the controller. Unlike the continuous-time system, the control vector in the discrete mode is constrained to remain contact between the sampling instants. The digital control process is inherently a discontinuous process and the designer has thus to resort to the discrete-time analysis for optimization of the AGC strategies.

CHAPTER 4

AUTOMATIC VOLTAGE REGULATOR (AVR) DESIGN

4.1 Introduction

The generator excitation system maintains generator voltage and controls the reactive power flow. The generator excitation of older system may be provided through slip rings and brushes by mean of DC generator mounted on the same shaft as the rotor of the synchronous motor.

As we have seen, a change in the real power demand affects essentially the frequency, whereas a change in the real power affects mainly the voltage magnitude. the interaction b/w voltage and frequency controls in generally weak enough to justify their analysis separately.

The sources of reactive power are generators, capacitors, and reactors. The generator reactive powers are controlled by field excitation. other supplementary method of improving the voltage profile in the electric transmission are transformer load tap changers, switched capacitors, step voltage regulators and static vars control equipment. The primary means of generator reactive power control is the generator excitation control using automatic voltage regulator (AVR). The role of an AVR is to hold the terminal voltage magnitude of synchronous generator at the specified level. The schematic diagram of AVR is shown in figure 4.1

As increase in the reactive power load of the generator is accompanied by the drop in the terminal voltage magnitude. The voltage magnitude is sensed through the potential transformer on one phase. This voltage is rectified and compared to DC set point signal. The amplified error signal controls the exciter field and increases the exciter terminal voltage. Thus, the generator field current is increased, which result in an increase in

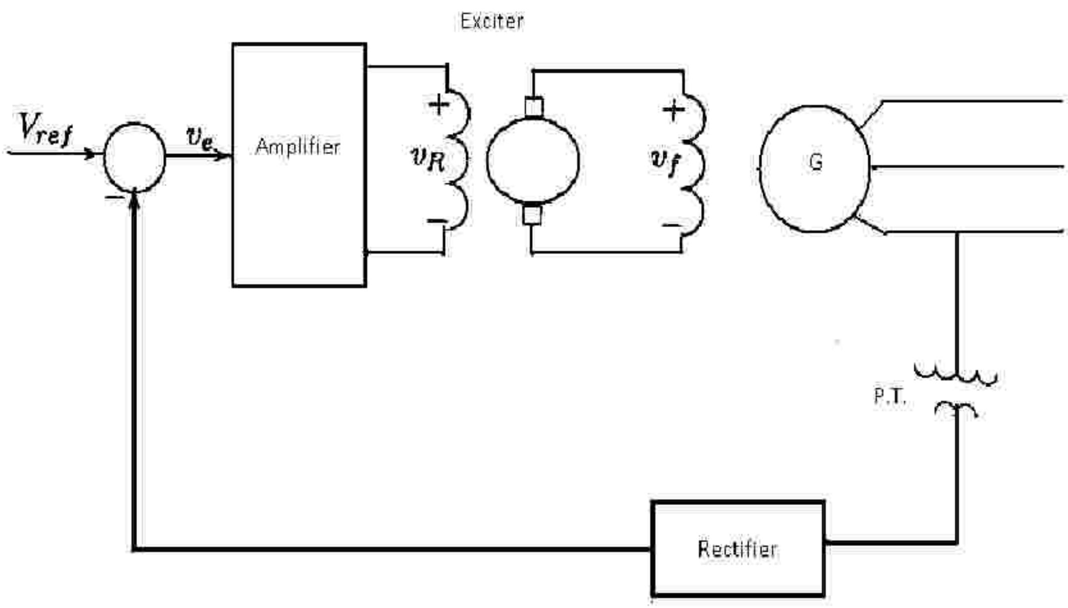


Figure 4.1 Simple AVR

Generated emf. The reactive power generation is increased to a new equilibrium, raising the terminal voltage to desired value.

4.2 AVR Design

4.2.1Amplifier Model

The excitation system amplifier may be magnetic amplifier, rotating amplifier, or modern electronic amplifier. The amplifier is represented by a gain K_A and a time constant T_A and the transfer function is

$$\frac{V_R(s)}{V_e(s)} = \frac{K_A}{1+sT_A}$$

Typical value of K_A is in the range of 10 to 400.the amplifier time constant is very small, in the range of 0.02 to 0.1 sec, and often is neglected.

4.2.2 Exciter Model

There is variety of different excitation types. However, modern excitation system uses ac power source through solid state rectifier such as SCR. The output voltage of the exciter is non-linear function of the field voltage because saturation affects the magnetic circuit, thus there is no simple relationship between the terminal voltage and the field voltage of the exciter. Many models with various degree of sophistication have been developed and available on IEEE recommendation publications. A reasonable model of reasonable exciter is a lineralized model which takes into account the major time constant and ignores the saturation and other nonlinearities. In the simplest form, the transfer function of the modern exciter may be represented by the single time constant T_E and a gain $K_{E,}$ i.e.

$$\frac{V_F(s)}{V_R(s)} = \frac{K_E}{1 + sT_E}$$

The time constant of the modern exciter are very small.

4.2.3 Generator Field Model

The synchronous machine generated emf is a function of the machine magnetization curve, and its terminal voltage is dependent on generator load. In the lineralized model, the transfer function relating to generator terminal voltage to its field voltage can be represented by a gain K_G and a time constant T_G and the transfer function is

$$\frac{V_t(s)}{V_F(s)} = \frac{K_G}{1+sT_G}$$

These time constant are load dependent, K_G may vary between 0.7 to 1, and Γ_G between 1.0 to 2.0 sec from full load to no load.

4.2.4 Sensor Model

The voltage is sensed through a potential transformer and, in one form, it is rectified through a bridge rectifier. The sensor is modeled by is simple first order transfer function, is given by

$$\frac{V_S(s)}{V_t(s)} = \frac{K_R}{1+sT_R}$$

T_R is very small, and we may assume a range of 0.01 to 0.06 sec. utilizing the above models results in the AVR block diagram shown in figure 4.2

The open loop transfer function of block diagram

$$K_G(s)\,H(s) = \frac{K_A K_E K_G K_R}{(1+sT_A)\,(1+sT_E)\,(1+sT_G)\,(1+sT_R)}$$

and the closed loop transfer function relating the generator terminal voltage $V_t(s)$ to the reference voltage $V_{ref}(s)$ is

$$\frac{V_t(s)}{V_{ref}(s)} = \frac{K_A K_E K_G K_R\ (1 + T_R)}{(1+ sT_A)(1+sT_E)(1+sT_G)(1+sT_R) + K_A K_E K_G K_R}$$

4.2.5 Complete AVR Block diagram

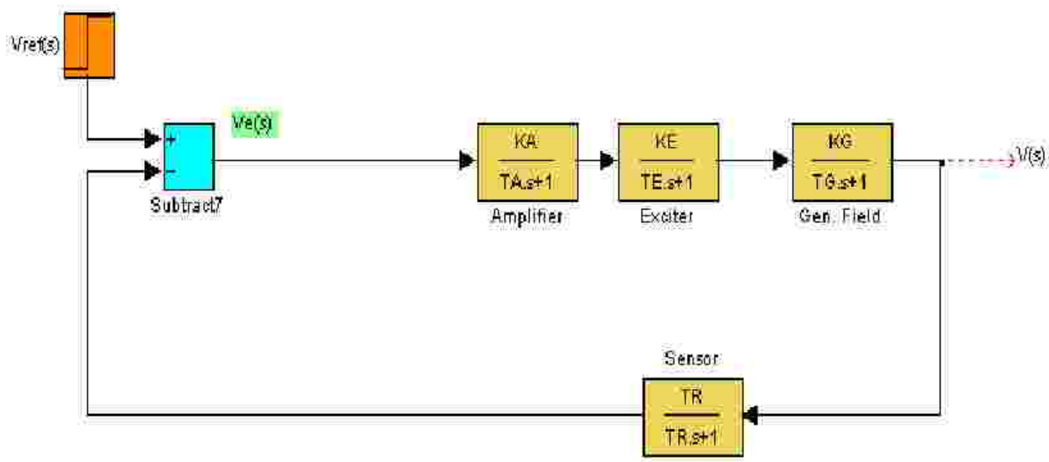


Figure 4.2 AVR Model

In order to study AVR model, its simulation diagram is shown in figure 4.3. Its response is shown in figure 4.4

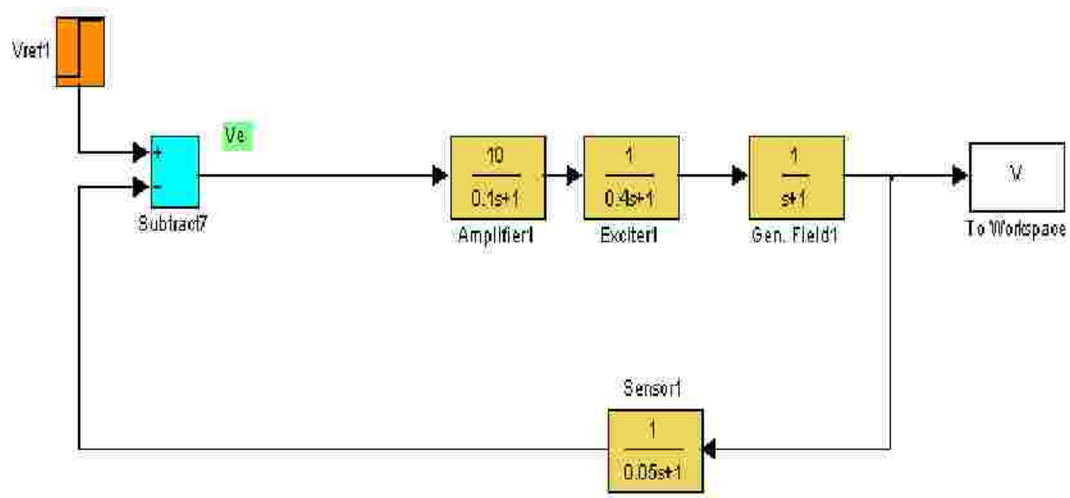


Figure 4.3 Simulink Model for AVR

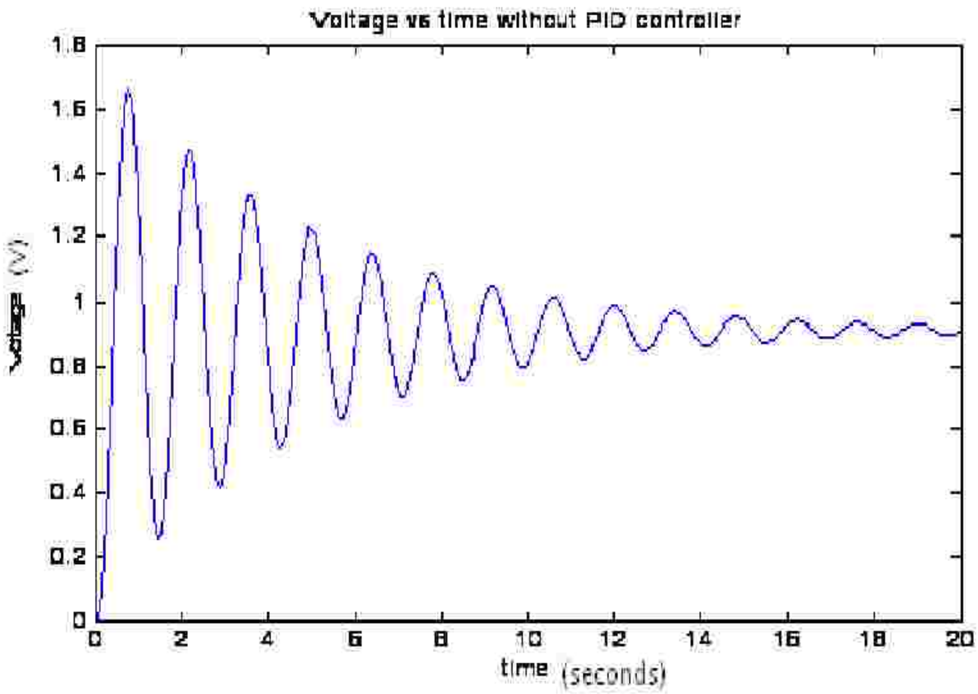


Figure 4.4 AVR Responses without PID Controller

4.3 AVR with PID Controller

One of the most common controllers available is Proportional integral derivative (PID) controller The PID controller is used to improve the dynamic response as well as to reduce or eliminate the steady-state error. The derivative controller adds a finite zero to the open-loop plant transfer function and improves the transient response. The integral controller adds a pole at origin and increases the system type by one and reduces the steady state error due to a step function to zero. The PID controller transfer function is

$$G_c(s) = K_p + K_I/s + sK_D$$

The block diagram of AVR with PID is shown in figure 4.5

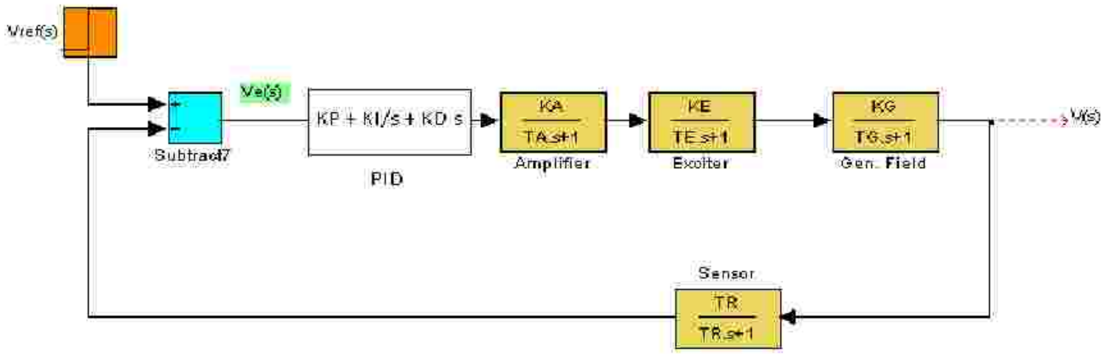


Figure 4.5 AVR Model with PID Controller

Simulation block diagram is shown in figure 4.6.Its response is shown in figure 4.7

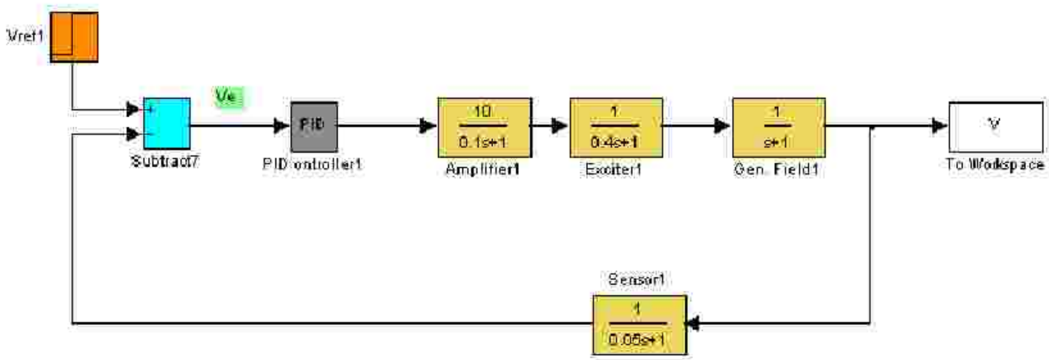


Figure 4.6 AVR Simulink Model with PID Controller

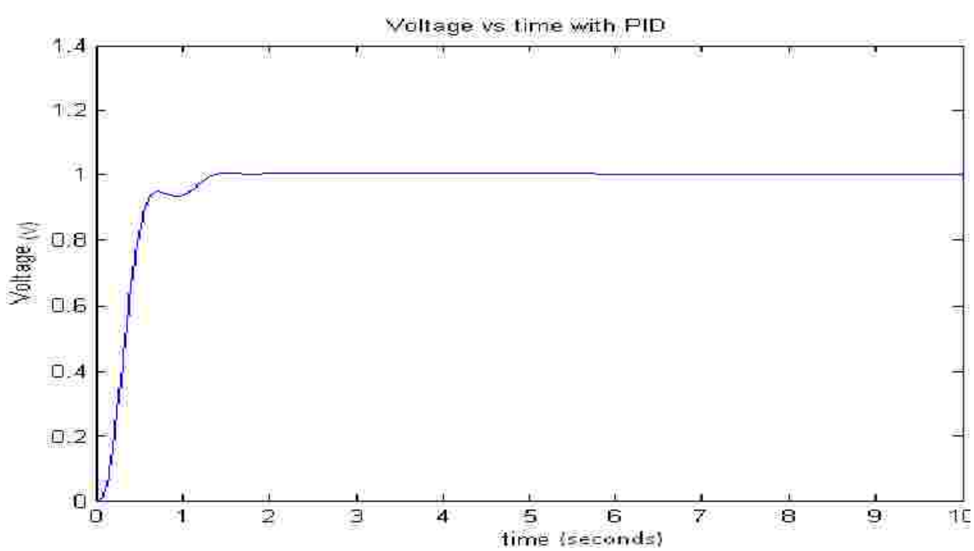


Figure 4.7 AVR Response with PID Controller

CHAPTER 5

AUTOMATIC GENERATION CONTROL WITH AUTOMATIC VOLTAGE CONTROL AND AVAILABILITY OF POWER BASED DESIGN (AAA)

5.1 Introduction

The electrical energy demand throughout the world has been observed rapidly increasing with the progress of technological advancement in various fields. Since this energy is considered to be one of the most convenient form of energy amongst the others, its consumption starting from domestic / household appliances to industries of different types has been found drastically growing up. In order to cater / meet this challenging demand, the option available before the power suppliers/ supplying authorities is to increase the generating unit size. Also, this approach calls upon for multi-area SCADA based interconnected electric power system operation. The management of the real-time operation of an electric power system network is a very complex task requiring man-machine interfaces, computer systems, communication networks and real-time data gathering devices in power plants and sub-stations. The continuity with which electric energy is supplied has become extremely important in the modern societies and any interruption of it to a large number of customers at a time is considered as an emergency situation and is of utmost concern in an industrial country. On the other hand, the electric energy supplying authorities intend to operate the power system as economically as possible within the safety and security limits. Therefore, the major task ahead of power system designers / planners is to ensure system operation to manage such a large power systems network efficiently and effectively.

The power system collapse occurring in all over the world have shown the urgent need for stabilizing multi-area interconnected power system beyond the common technologies. Increasing load demands on the power system is always viewed in terms of threats or likelihood of system problems such as instabilities and collapses. One of the promising ways is to provide a system based protection and control complementary to the conventional local equipments; and this calls for the enhancement or improvement of the SCADA system capability by inducting additional advanced features.

This AAA design mainly focuses on the AGC and AVR system with market structure, which is a key component for the power system SCADA configuration. However, some important features of the SCADA system which would enhance the reliability and security of the modern electric power system network has been discussed.

5.2 Combined AGC and AVR Loops

The AVR and AGC Loops are not in the truest sense no interacting; **cross coupling does exist** and can some time troublesome. There is little if any coupling from AGC to AVR loop, but interaction exist in the opposite direction [11] .We understand this readily by realizing that control action in the AVR loop affect the magnitude of generated emf E. As the internal emf determines the magnitude of real power. ***It is clear that changes in AVR loop must felt in AGC loop.***

However, the AVR loop is much faster than the AGC loop and ***there is tendency for AVR dynamics to settle down before they can make themselves in slower AGC channel.***

A surplus of MW tends to increase system frequency. A surplus of MVAR tends to increase system voltage.

- If MW increases is felt uniformly while when MVAR increased greatest where Q surplus is greatest.
- As we change MW of one of several generator resulting change in voltage.
- If we change Q inputs also change in real power

Since there is considerable coupling in opposite direction.

If we include small effect of voltage on real power, we obtained following liberalized equation:

? Pe = Ps ? d + K_2 E

Where K_2 is change in electrical power for small change in stator emf and Ps is synchronizing power. Also including the small effect of rotor angle upon generator terminal voltage,

We may write

? Vt = K_5 ? d + K_6 E

Where K_5 is change in terminal voltage for small change in rotor angle at constant stator emf and K_6 is change in terminal voltage for small change in stator emf at constant rotor angle.

Finally modifying the generator field transfer function to include effect of rotor angle we may express the stator emf as

$$E = \frac{Kg}{1 + Tg} (Vf - K_4 \, ?\, d)$$

The above constant depends on network parameters and operating conditions.

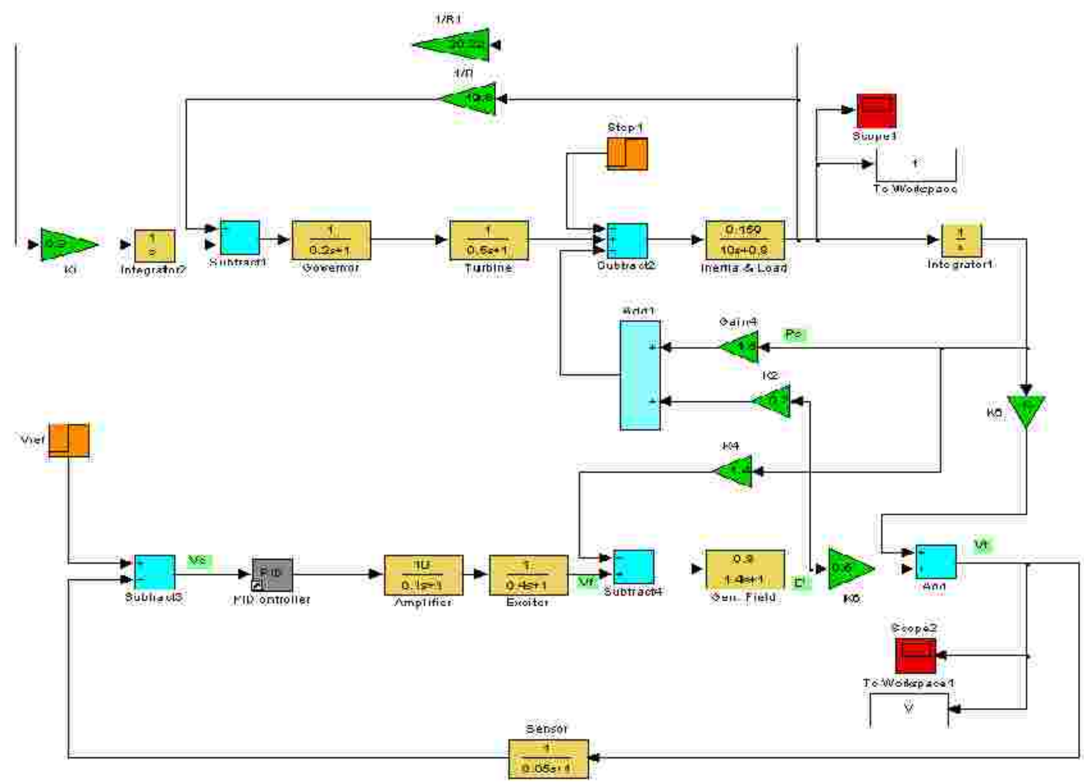
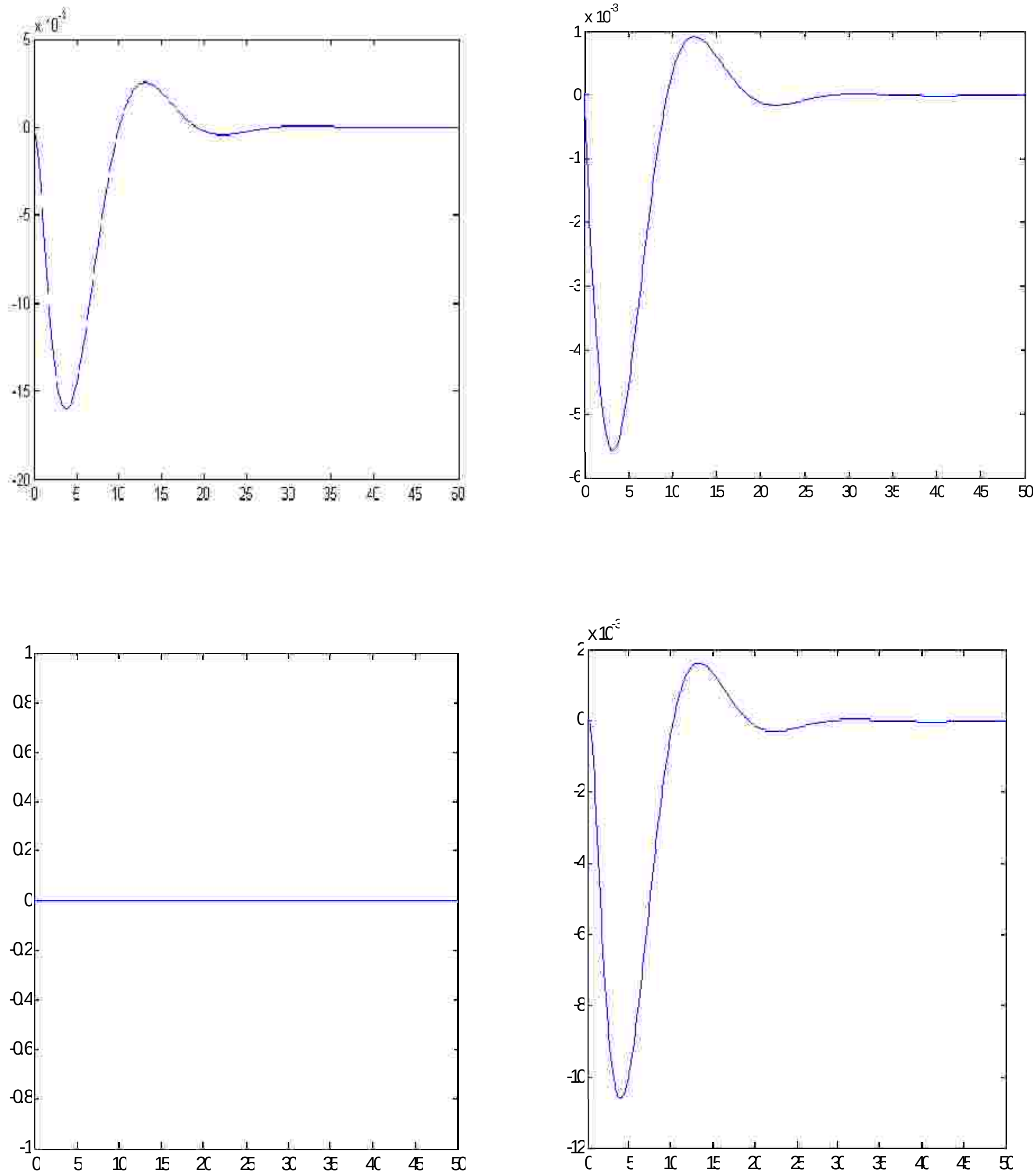


Figure 5.1 Models for Coupling between Two Loops

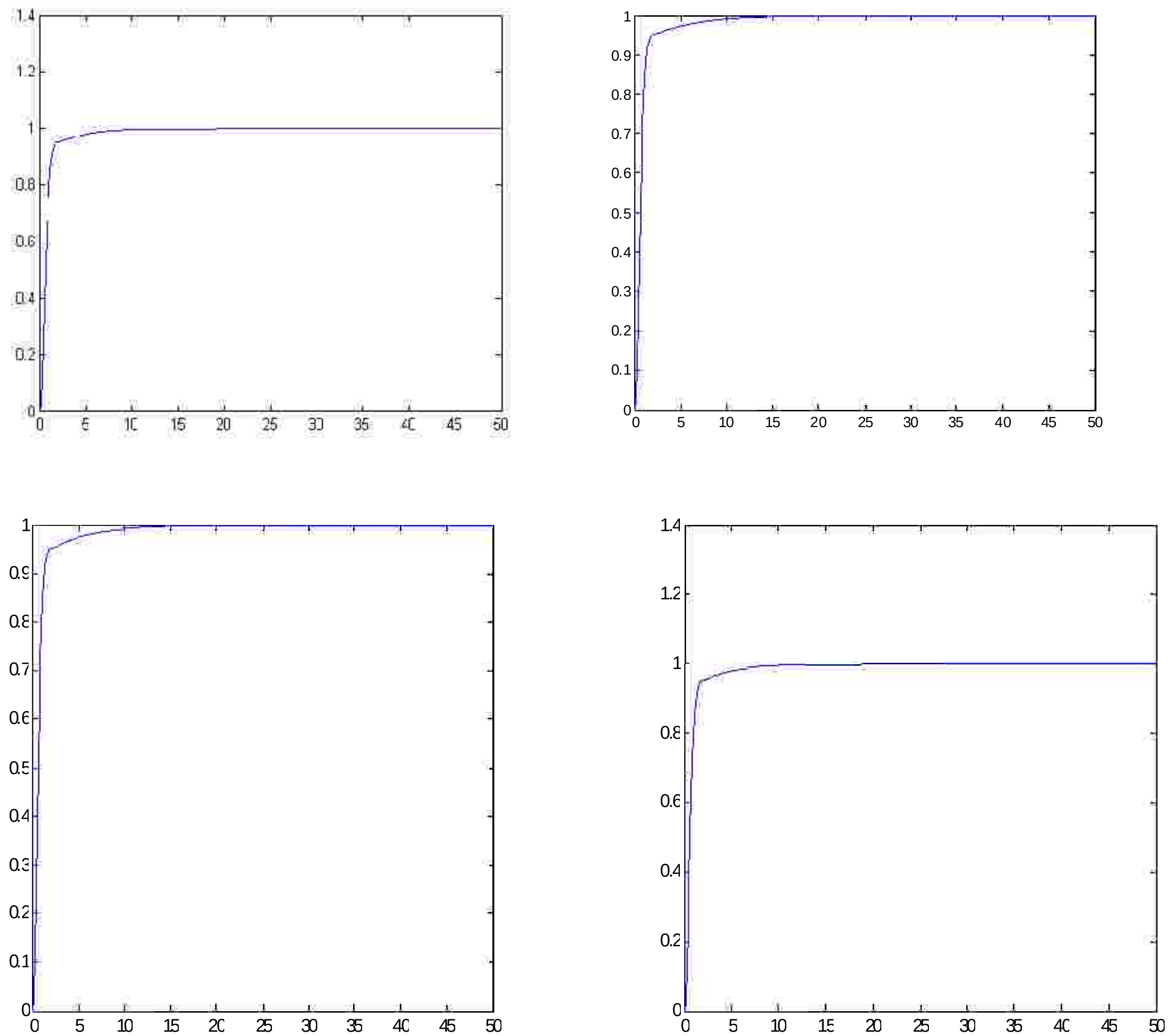
Demand increment = 180MW, AVR is coupled　　Demand increment = 180MW, AVR is not coupled



Demand increment = 0MW, AVR is not coupled　　Demand increment = 0MW, AVR is coupled

Figure 5.2 Frequency Responses for Coupling between Two Loops
X –axis time (seconds)　Y- axis change in frequency (Hz)

Demand increment = 180MW, AVR is coupled   Demand increment = 180MW, AVR is not coupled



Demand increment = 0MW, AVR is not coupled   Demand increment = 0MW, AVR is coupled

X –Axis time (seconds)
Y- Axis voltage (volt)

Figure 5.3 Voltage Responses for Coupling between Two Loops

Simulink model for AGC and AVR shown in figure 5.1. Its response is shown in figure 5.3

5.3 AAA Design

AAA is AGC, AVR and Availability of power.

- AGC, AVR and Frequency Availability Based Tariff for Two Area.
- AGC, AVR and Availability of Scheduled Loading for Two Area

5.3.1 Need of AAA Design

The total amount of real power in network emanates from generator stations, the location and size of which are fixed. ***The generation must be equal to demand at each moment*** and since this power must be divided between generators in unique ratio, in order to achieve the economic operation. We conclude that individual generator output must be closely maintained at predetermined set point.

But it does not happen. Some times demand is very large than generation and some time surplus power in a duration of 24 hrs. ***It is important to remember that demand undergo slow but wide changes throughout the 24 hr of the day.***

Basic idea for its solution ***to manage generation as well as demand.***

Here problem for management in demand side. Demand side can be managing controlling tariff in demand side. This is called Demand Side Management and this can deal with two points as

- AGC, AVR and Frequency Availability Based Tariff for Two Area.
- AGC, AVR and Availability of Scheduled Loading for Two Area

This AAA deals with the automatic generation control of interconnected thermal systems with combination of the automatic voltage control and market based deregulated system

5.3.2 Model scheme for AGC, AVR and FAT (Frequency Availability Based Tariff)

The model scheme for AGC, AVR and Frequency Availability Based Tariff for Two Areas is shown in figure 5.4

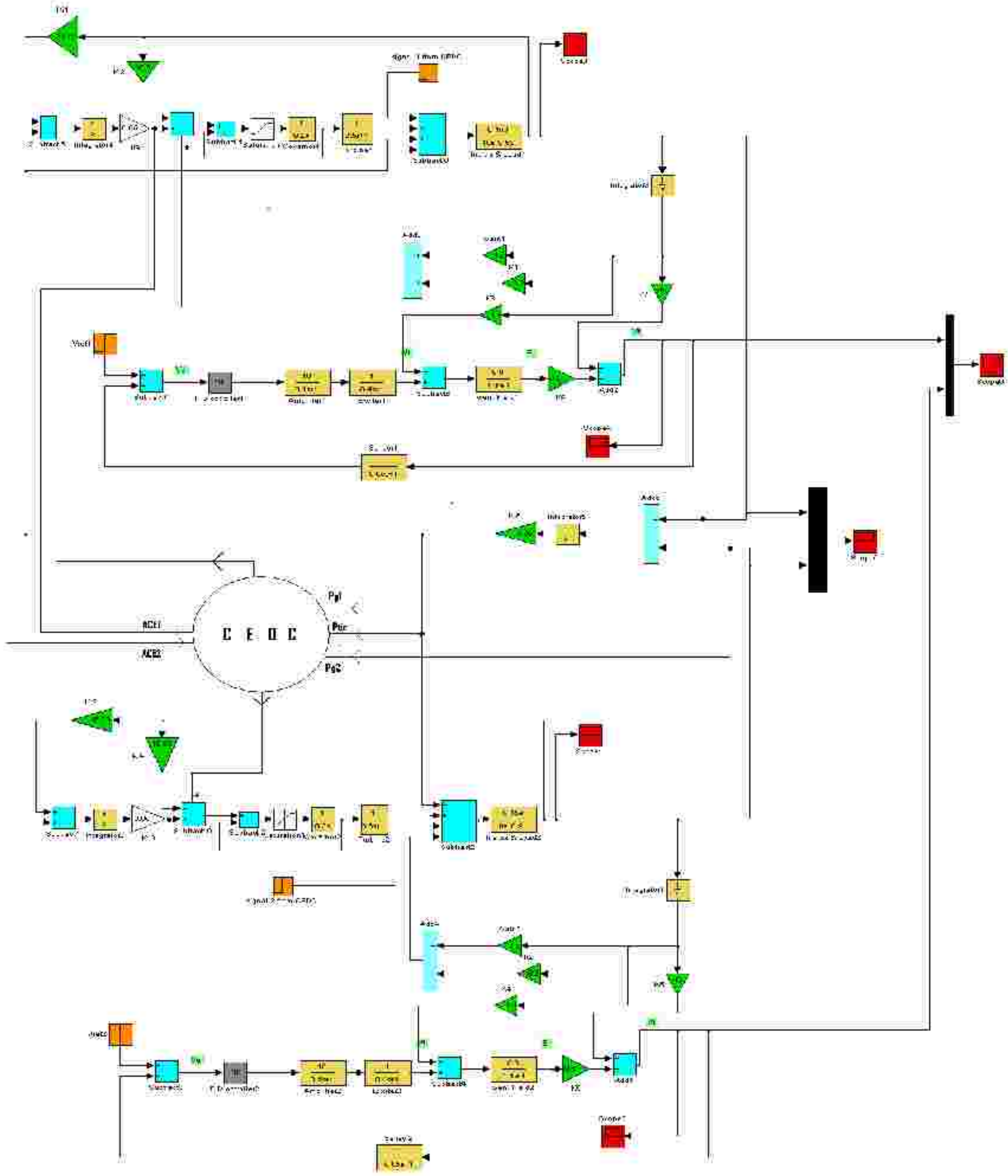
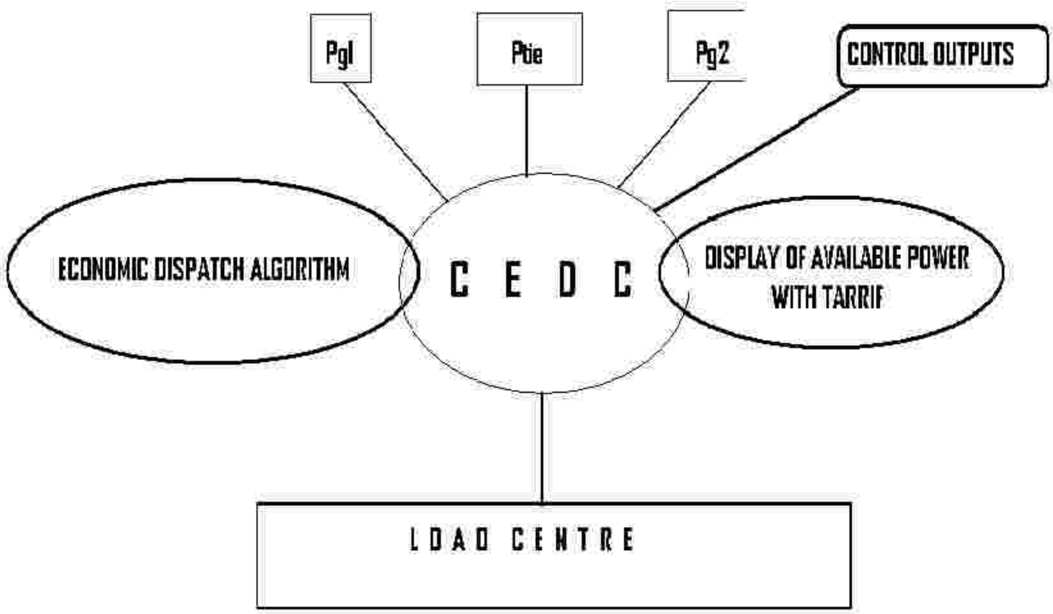


Figure 5.4 Model scheme for AGC, AVR and Frequency Availability Based Tariff for Two Areas

The basic need of CEDC for these functions performance is shown in figure 5.5



.

Figure 5.5 Central Economic Dispatch Centre

Advance Functions of Central Economic Dispatch Centre:

- Supervisory Control & Data Acquisition (SCADA) functions.
- System Monitoring and Alarm Functions.
- State Estimation.
- On line Load Flow.
- Economic Load Dispatch.
- Optimal Power Flow (including Optimal Reactive Power Dispatch).
- Security Monitoring and Control.
- Automatic Generation Control.
- Unit Commitment.
- Load Forecasting.
- On Line Tariff Control

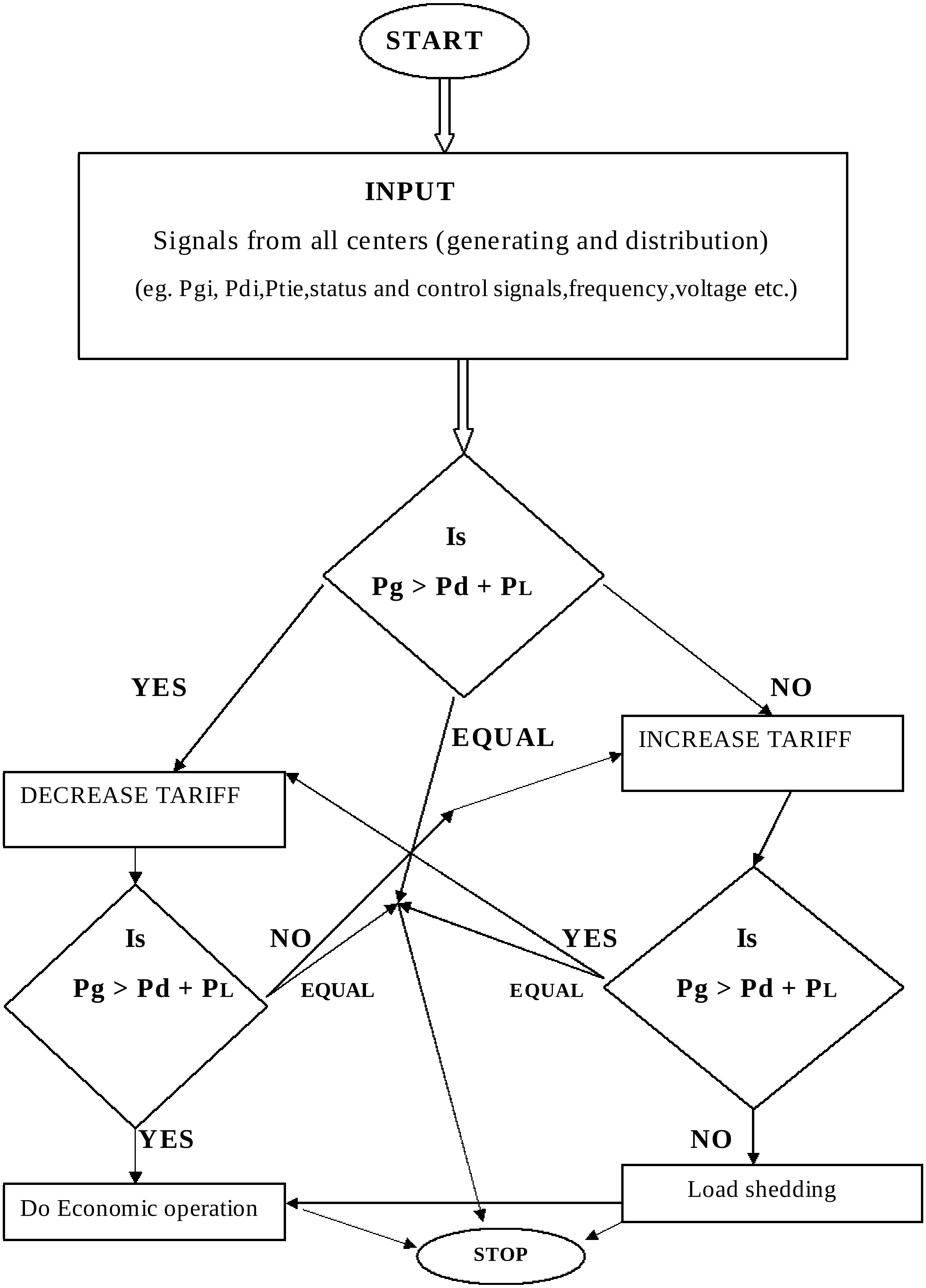


Figure 5.6 Tariff Control

The basic scheme while controlling tariff is shown in figure 5.6. If generation is greater than demand than change the current tariff scheme. Also even if situation comes than it can not be controlled than either use economic dispatch or need of load shedding.

This on line tariff control and economic dispatch control is done through SCADA system.

5.3.3 SCADA System

Some Important Features of the SCADA System

The power system SCADA consists of three modules:

(a) Generation control and scheduling module

(b) Network analysis module

(c) Operator training module.

These modules are discussed as follows.

Generation Control and Scheduling Module:

The task of managing the generation of a large interconnected power system starts with the control of generation to maintain the system frequency and tie-line power flow while keeping the generators at their economic output. This is the module where the AGC plays its key role. The important aspects that determine the most economic output of each generator for a given load, the ON / OFF scheduling / commitment of generator to meet varying load demand, the determination of the pricing and amount of energy to buy and sell with neighboring power system network are dealt with in this module.

Network Analysis Module: The transmission system network management requires monitoring of thousands of tele-metered values and estimation of the effect of any plausible outage on the operation of the power system network. From the view point of reliability and security analysis, it is required that the energy management system be capable of analyzing thousands of possible outage (generating units, transmission line and distribution network) events and informing the operator of the best strategy to handle these outages if they result in loss of generation, overload or voltage dip problems.

Operator Training Module: The operators should be highly trained to use the SCADA system besides acquainting themselves with how to respond to emergency situations. In order to ensure that operators are trained effectively, simulator software is incorporated in the system. The developed software is capable of simulating the effects of an emergency situation on the given power system. The operator is then required to respond to by taking necessary control action(s) on the simulator in order to solve the emergency problem.

However, deficiency of skilled / well-trained operator may lead to poorer quality of services related to maintenance and scheduling. So, it is suggested that there is a need for developing an “Expert system” that can replace the human operator. The emerging field of IT can play a vital role in such endeavor with its expertise knowledge on artificial intelligence. Such expert system can be integrated into the SCADA system architecture as an application program or a separate processor.

SCADA System Architecture

The SCADA system supports the power system operator in controlling the remote or local terminal equipments such as opening or closing of the circuit breaker with security features like authorization and a “Select – Verify – Execute” procedure. The data acquisition section gathers tele-metered data for use by all other functions within the EMS. Data are obtained from various sources including remote terminal units (RTU’s) installed in plants and sub-stations and delivered at the system control centre by local I/O devices. A SCADA system performs three critical functions in the operation of a power system network as discussed below.

Data Acquisition Function: The data acquisition sub-module of the SCADA system periodically collects data in processed or raw form from remote terminal units.

Supervisory Control Function: This function allows the operator to control remote devices and to condition or replace values in the database. All operations follow multi-step procedures. Selection of the device to be operated is the first step. The next step is visual verification and the final step is operator execution or cancellation. Data conditioning includes operations such as manual replacement of telemetric data, alarm inhibit/enable, reverse normal (to change definition of the normal state of a device), bypass entry (due to failed telemetry).

Alarm Display and Control Function: This sub-system is responsible for the presentation of alarm signals to the operator. It also supports alarm presentation and its presentation control. The alarm presentation is responsible for constructing the alarm message, organizing alarms in categories, maintaining an alarm summary display and abnormal summary, maintaining console logs, and initiating audio/visual annunciations and interfacing to other functions. Presentation control assigns priorities to alarm messages, recognizing points which are inhibited from alarming or manually replacing by the operator, and which provide operator functions such as alarm acknowledgement. To perform the above three critical functions, the EMS / SCADA system also requires the following sub-systems.

Communication sub-system: This sub-system encompasses management of LAN / WAN supporting the SCADA itself. The medium of communication may be a dual redundant Ethernet, fiber-optic or satellite communication based on the size of the power system network figure 5.7. In addition to the users within the control room, there may be schedulers, trainees, programmers, engineers and executives who require access to the EMS / SCADA system through standard console displays, remote displays or even personal computers. All of these have to be connected to the EMS via LAN / WAN network that may be extended outside the main control centre building to other facilities. Other connections within the power system may include off-line engineering systems for planning or long range scheduling, other control systems such as load management, distribution, plant management and control, and corporate policy planning, billing and customer care.

Information management sub-system: This system supports definition of and access to data used by the EMS / SCADA system. This includes all the static data descriptive of the power system operation, the EMS configuration, and data shared with other systems.

It also includes organization of data for specific applications such as data acquisition, monitoring and analysis for network analysis algorithms. Advanced algorithms and computation programs that assist the operator can also be included in the SCADA system, such as "faster than real-time simulations" to calculate power transfer margins based on contingencies.

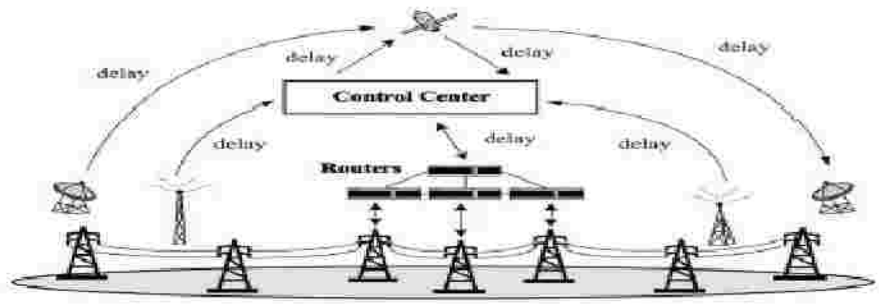


Figure5.7 Satellite communication technology used in power system SCADA.

Generation and Power Flow Control

The automatic control of the generation and the power flow are very essential for the smooth, neighborly and effective operation of the multi-area interconnected power system. There are three main control objectives in a multi-area interconnected power system; first objective is that the total generation of the interconnection as a whole must be matched moment to moment to the total prevailing customer demand. This in itself can be achieved by the self-regulating forces of the system. Second objective is that the total generation of the interconnected power system is to be allocated among the participating control areas so that each area follows its own load changes and maintains scheduled power flows over its inter-ties with neighboring areas. This can be achieved by area regulation. The third objective is that within each control area, its share of total system generation is to be allocated among available area generating sources for optimum area economy consistent with area security and environmental considerations. This objective can be achieved by economic dispatch, supplemented as required by security and environmental dispatch. The second and third objectives can be achieved by means of a system named AGC. Such a control system can be regarded as a re-allocation control redistributing the system wide governing responses to load changes in various areas to cause output of the participating generators to change. Each area then follows its own load change with scheduled internal distribution. These functions enable the functioning of the overall system in regulating the real power output of generation, economically allocating demand among committed units, computing various reserve quantities, determining production costs, and accounting for interchange of power between the utilities and/or control areas. Therefore, it is obvious that AGC system plays an indispensable role in the successful performance of EMS / SCADA system within the multi-area interconnected power system.

5.3.4 Model for AGC, AVR and SLA (Scheduled Loading Available)

The second scheme is AGC, AVR with Scheduled Loading Available for Two Areas. If scheduled is available for load change in duration of days, a better frequency characteristics can be obtained.

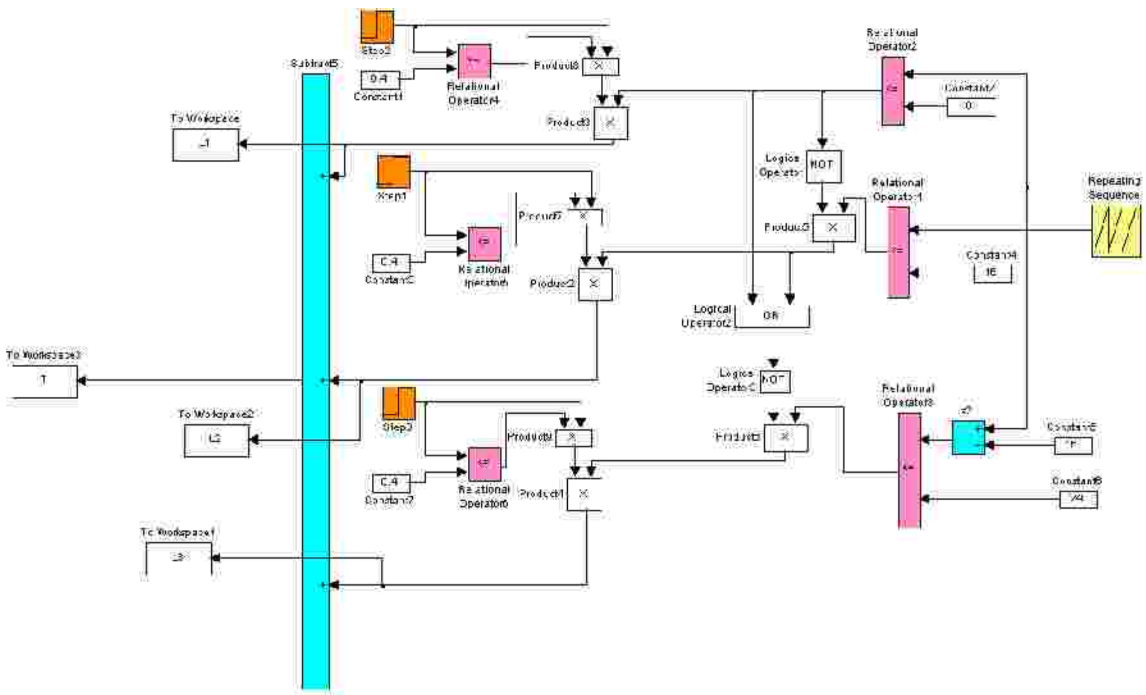


Figure 5.8 Scheduled Availability Model

Scheduled Availability Model is shown in Figure 6.10.3. Here scheduled for 24 hrs in a day as under:

1. Demand L1 for first 8 hrs.
2. Demand L2 for next 8 hrs.
3. Demand L3 for next 8 hrs.

This is also shown in figure 5.9

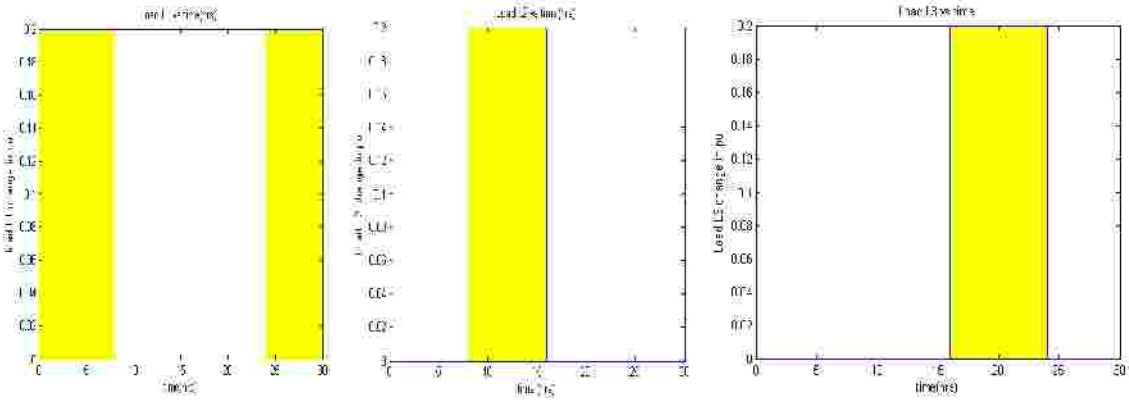


Figure 5.9 Scheduled for Demand L1, L2 and L3 respectively

The model shown in figure 5.8 is connected with AGC is shown in figure 5.10.

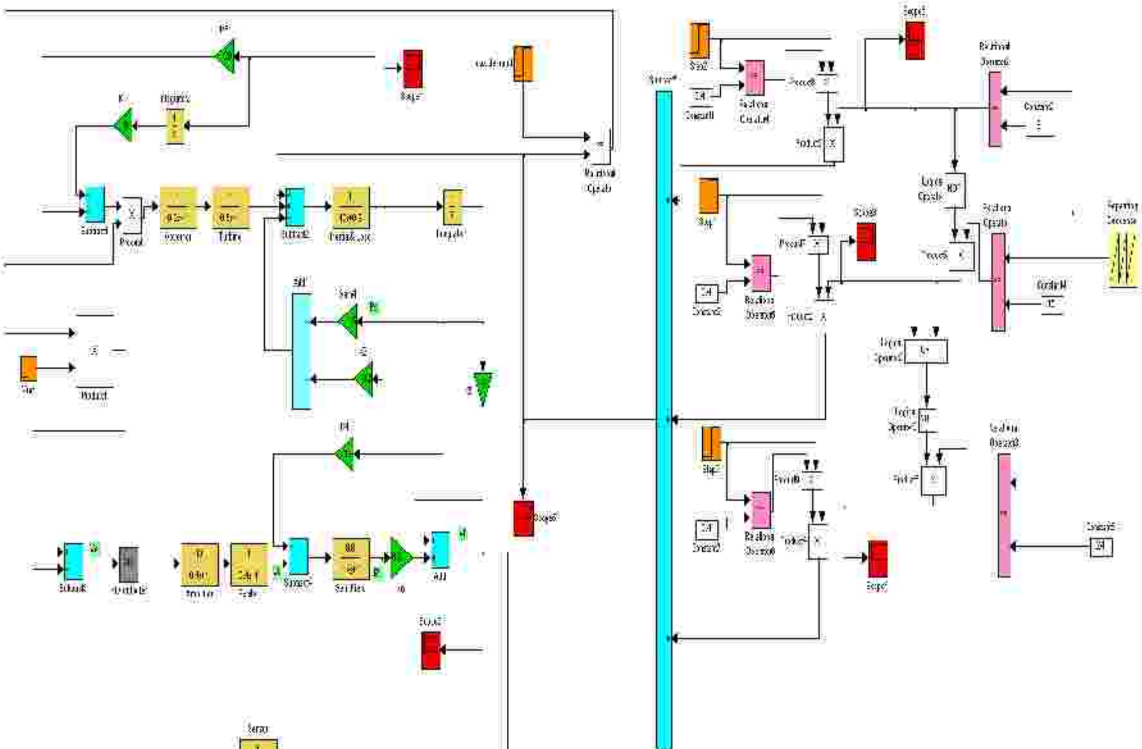


Figure 5.10 Model for AGC, AVR with Scheduled Loading Available for Two Areas.

CHAPTER 6

SIMULATION AND RESULT

6.1 Assumption and Requirement

Extensive testing was involved in the completion of this project. Not only was our final automatic generation control block diagram tested, but also the intermediate steps in the development of that block diagram. The testing of our AGC system was done in **MATLAB** in **ELECTRICAL & INSTRUMENTATION ENGINEERING DEPARTMENT** at **THAPAR UNIVERSITY, PATIALA**. The testing was completed using the MATLAB Simulink tool. Testing was done on each of the individual blocks of the AGC system. Tests were also conducted on the uncontrolled AGC system, and the integrator controlled system. Each test included inserting the block diagram into Simulink and plugging in the values for each of the parameters. Also involved was the addition of the scopes that would be used to measure the outputs of the system. The inputs for each of the tests were varied to allow for more data. The testing forms and the completed testing forms are included into this report. A Simulink model for the block diagram shown in figure 6.1 representing a simple two-area interconnected power system has been studied with the following assumptions as shown in Table.

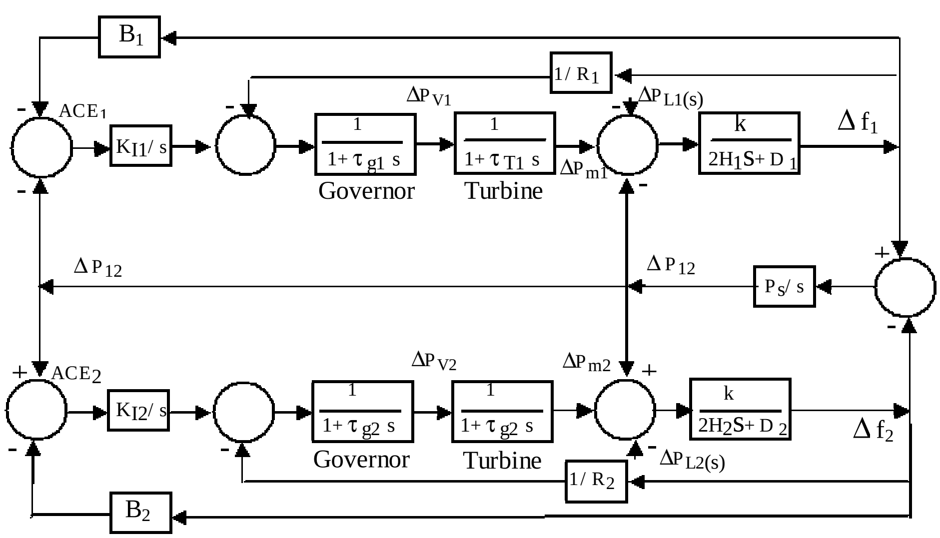


Figure 6.1 Two areas AGC Model

Quantity	**Area–I**	**Area-II**
Governor Speed regulation	$R_1 = 0.051$	$R_2 = 0.065$
Frequency bias factors	$D_1 = 0.62$	$D_2 = 0.91$
Inertia constant	$H_1 = 5$	$H_2 = 4$
Base power	1000MVA	1000MVA
Governor time constant	$\tau_{g1} = 0.2$ sec	$\tau_{g2} = 0.3$ sec
Turbine time constant	$\tau_{T1} = 0.5$ sec	$\tau_{T2} = 0.6$ sec
Constant	$k = 1/2\pi = 0.159$	$k = 1/2\pi = 0.159$
Nominal frequency	$f_1 = 50$ Hz	$f_2 = 50$ Hz
Load change	$\Delta P_{L1} = 180.2$ MW	$\Delta P_{L2} = 0$
Load disturbance in per unit	$(\Delta P_{L1})_{p.u} = 0.1802$	$(\Delta P_{L2})_{p.u} = 0$

Table 6.1: Assumptions used in the simulation runs for AGC

Quantity	**Gain**	**Time Constant**
Amplifier	10	0.1
Exciter	1	0.4
Generator	1	1.0
Sensor	1	0.05

Quantity	**Gain**
PID Controller	$K_P = 1.0$ $K_I = 0.25$ $K_D = 0.28$

Table 6.2: Assumptions used in the simulation runs for AVR

Requirements

MATLAB in **ELECTRICAL & INSTRUMENTATION ENGINEERING DEPARTMENT** at **THAPAR UNIVERSITY, PATIALA**. The testing was completed using the MATLAB Simulink tool.

Operating Environment

Since the end product is simulation, the operating environment is not applicable

Assumptions

- We will assume a model of a combined cycle generation plant
- We will also assumed a system with two control areas that had one tie line between them
- We assumed the basic block diagram for a two area AGC
- We assumed the system is in a normal operating mode
- The loss of a generating unit will not be considered

Limitations

- The Area Control Error or the power interchange between areas must be equal to zero at least one time for every ten minutes
- The average power interchange between areas must be zero in ten minutes period and follow limits of the generation system
- Power interchange between areas must be returned to zero in ten minutes
- Corrective actions must be accommodating within one minute of a disturbance

6.2 Open Loop AGC for Single Area System

Open loop AGC for single area system for simulation is shown in figure 6.2

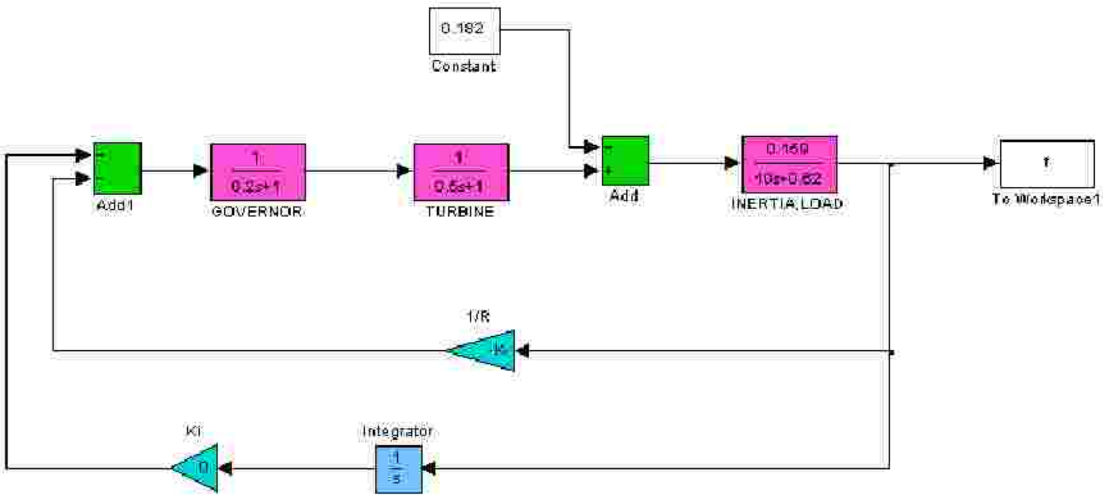


Figure 6.2 Open Loop AGC Model for Single Area System

In order to check frequency response, following programming is used to plot graph between frequency and time:

```
Sim(' FIRSTsingle_area_agc_open');
t=0:0.01:15;
Plot (t, f);
```

The plot between frequency and time is shown in figure 6.3. It is found that with change in load of 180 MW, frequency deviates and error is continuously exists in the system. This frequency error must be removed.

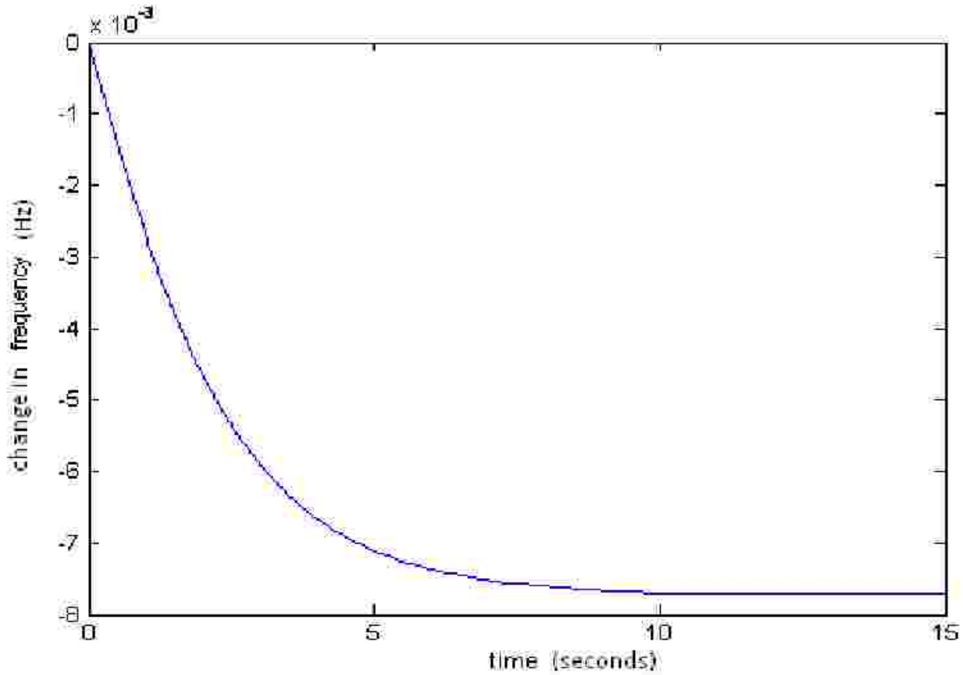


Figure 6.3 Open Loop AGC responses for Single Area System

It is found from graph that with open loop if demand changes to 0.180 Pu, a steady state error exists in frequency of 0.008 units.

6.3 Close Loop AGC for Single Area System

System frequency specifications are rather stringent and, therefore, so much change in frequency cannot be tolerated. In fact, it is expected that the steady change in frequency cannot be tolerated. In fact, it is expected that the steady change in frequency will be zero. While steady state frequency can be brought can back to the scheduled value by adjusting speed changer setting, the system could under go intolerable dynamic frequency changes with changes in load. It leads to the natural suggestion that the speed changer setting be adjusted automatically by monitoring the frequency changes. For this purpose, a signal from ? f is fed through an integrator to the speed changer. The close loop AGC model is shown in figure 6.4

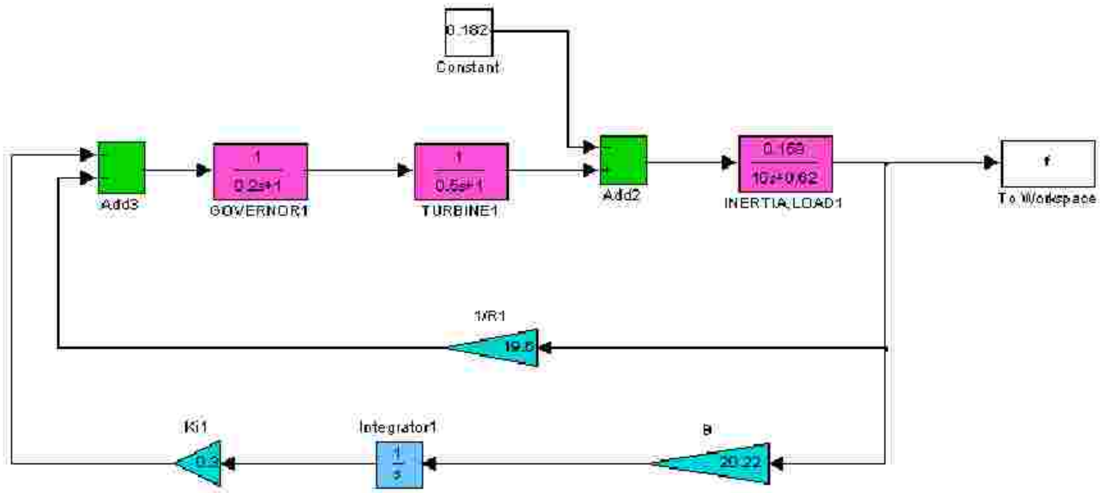


Figure 6.4 Close Loop AGC Model for Single Area System

In order to check frequency response, following programming is used to plot graph between frequency and time:

Sim ('SECONDsingle_area_agc_closed');

t=0:0.01:30;

Plot (t, f);

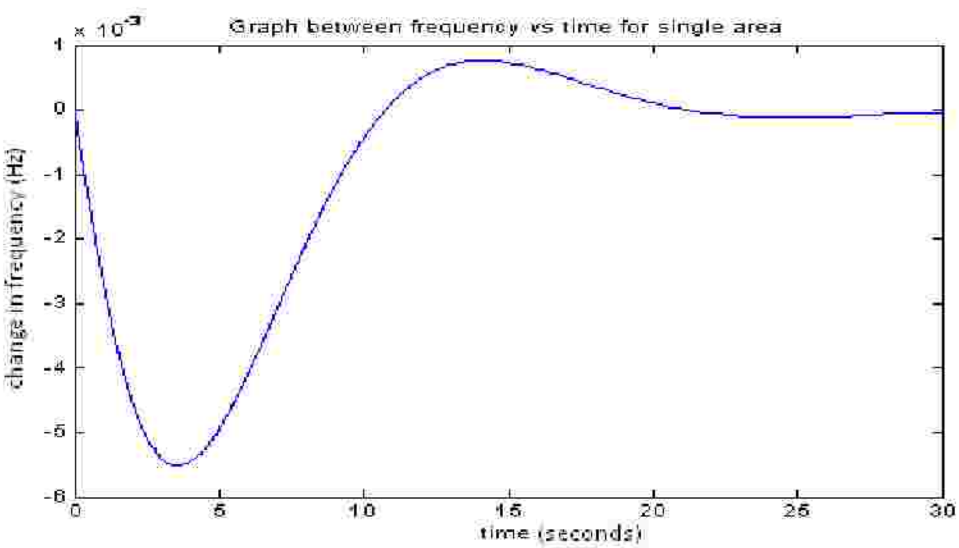


Figure 6.5 Close Loop AGC response for Single Area System

It is concluded that the system now modifies to a proportional plus integral controller, which, as is well known from control theory, gives zero steady state error, i.e. ? f(steady state) = 0

6.4 AVR without PID Controller

AVR without PID Simulink model is shown in figure 6.6

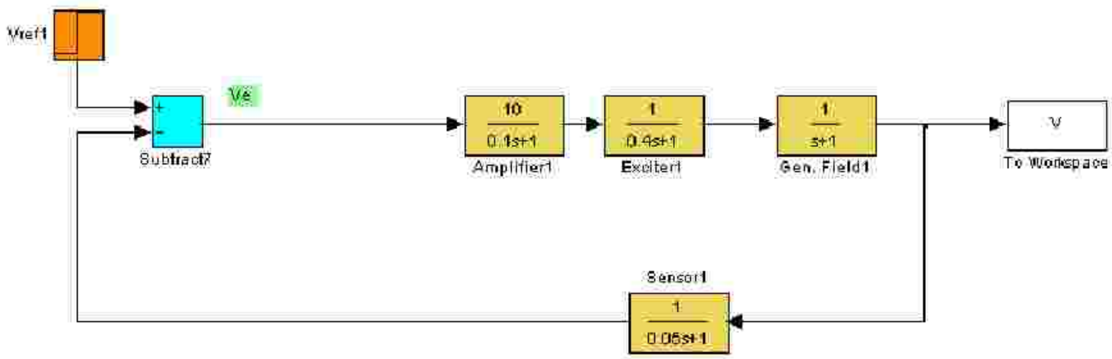


Figure 6.6 AVR Model without PID Controller

In order to check response, following programming is used to plot graph between frequency and time:

Sim ('THIRDavr_withoutPID');

t=0:0.01:20;

Plot (t, V);

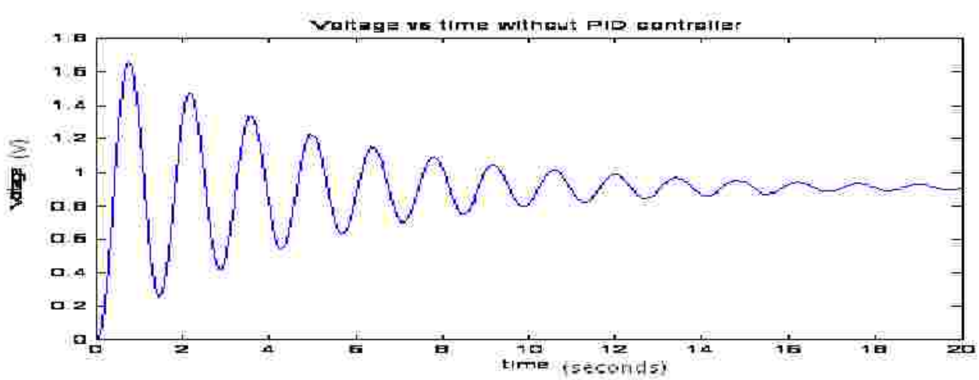


Figure 6.7 AVR Responses without PID Controller

Since it is found that there are large number of oscillation occurs.

6.5 AVR with PID Controller

AVR with PID Simulink model is shown in figure 6.8

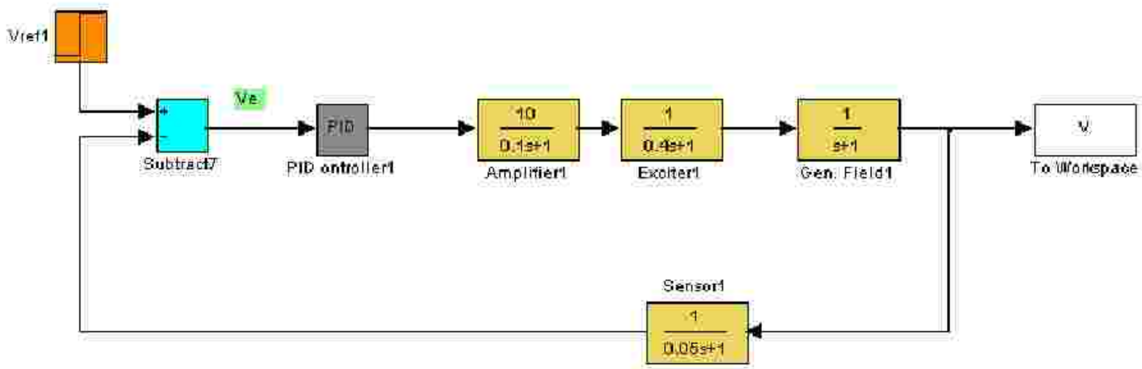


Figure 6.8 AVR Model with PID Controller

In order to check response, following programming is used to plot graph between frequency and time:

Sim ('FOURTHavr_withPID');

t=0:0.01:10;

Plot (t, V);

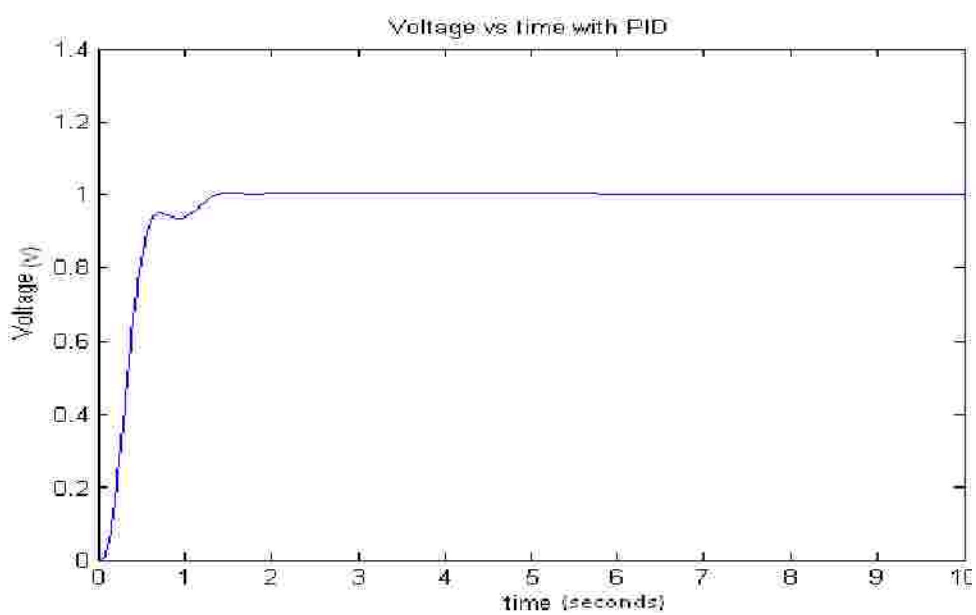


Figure 6.9 AVR Response with PID Controller

6.6 AGC and AVR Control of Single Area

AGC and AVR Control of Single Area Simulink model is shown in figure 6.10

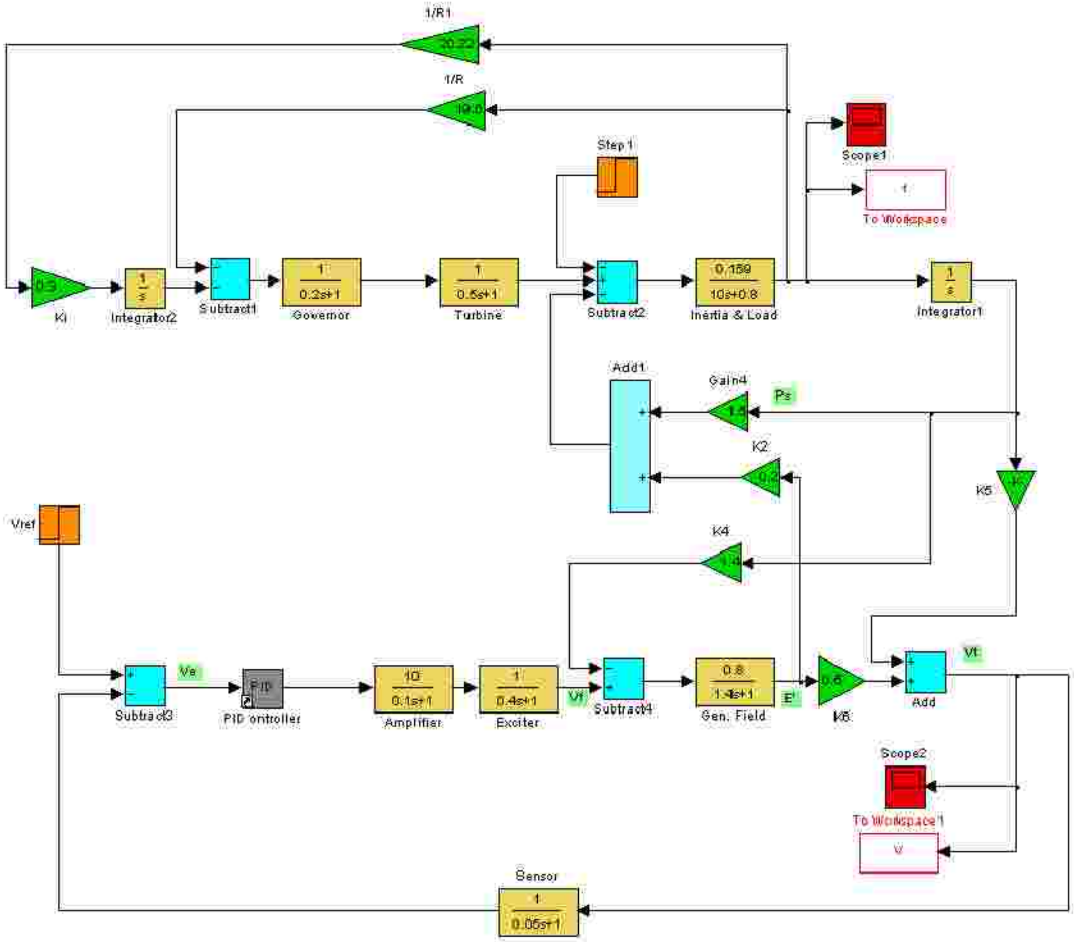


Figure 6.10 AGC and AVR Model for Single area

In order to check model response, following programming is used to plot graph between frequency and time:

Sim ('FIFTHsingle_area_agc_avr');
t=0:0.01:50;
Figure (1), plot (t, V);
Figure (2), plot (t, f);

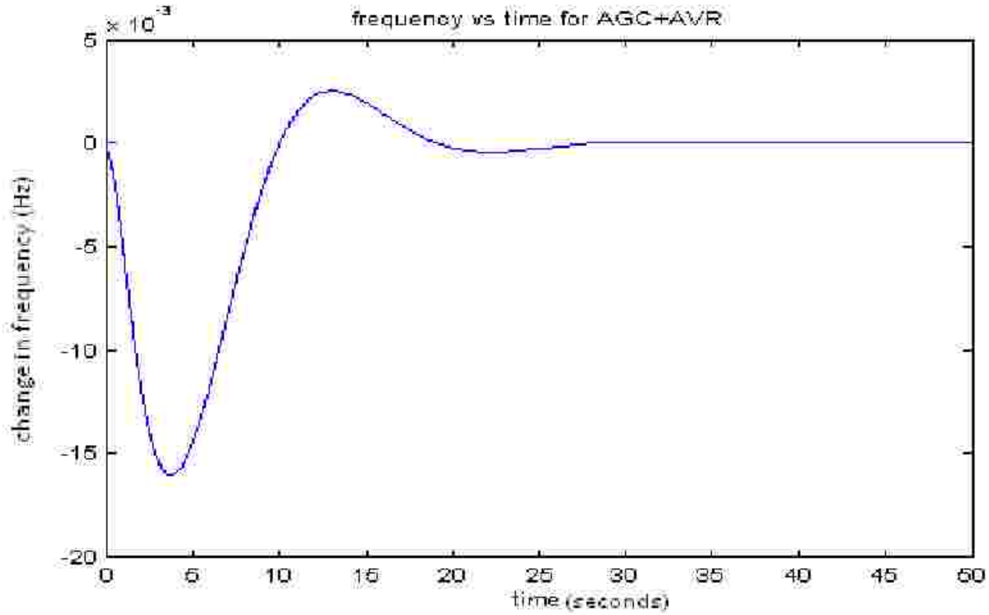


Figure 6.11 AGC and AVR Response for Single Area

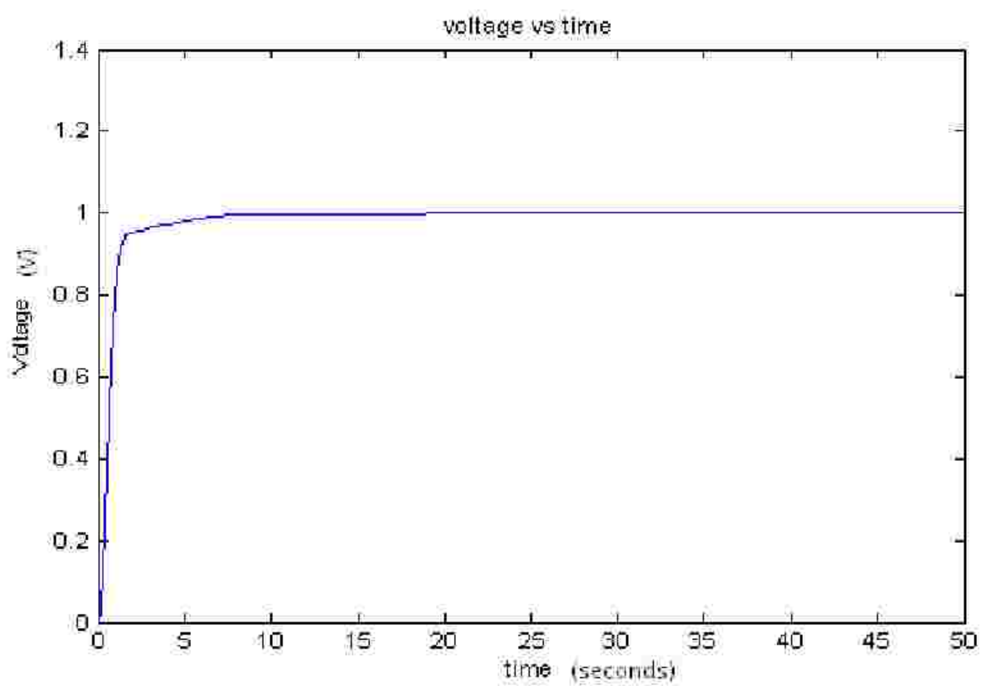


Figure 6.12 AGC and AVR Response for Single Area

It is found that variation of frequency effects on system voltage.

6.7 AGC for Two Areas System

AGC Model for Two Areas System is shown in figure 6.13

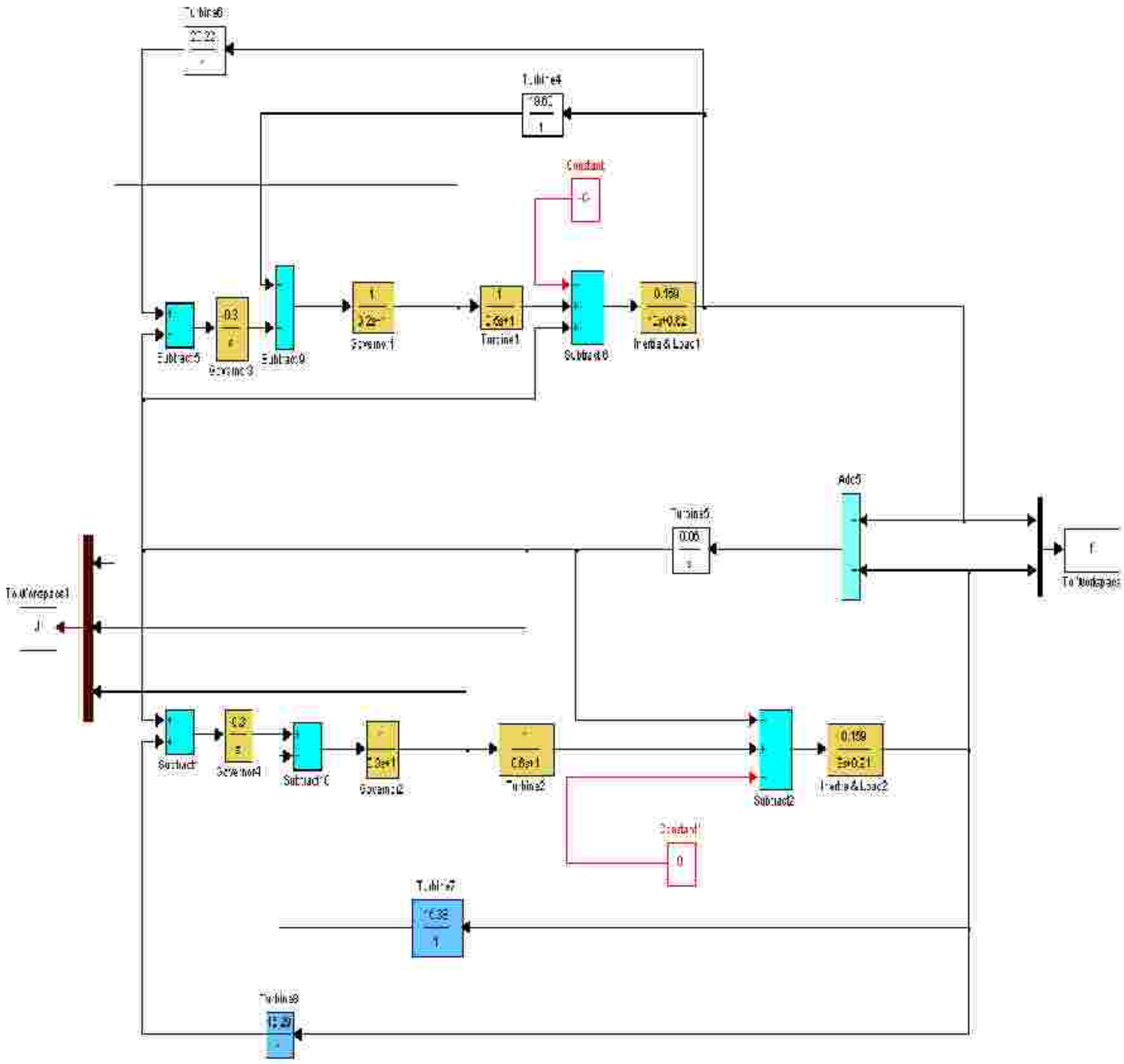


Figure 6.13 AGC Model for Two Areas System

In order to check model response, following programming is used to plot graph between frequency and time:

Sim ('eight_two_area_agc');

t=0:0.01:25;

Figure (1), plot (t, f);

Figure (2), plot (t, J);

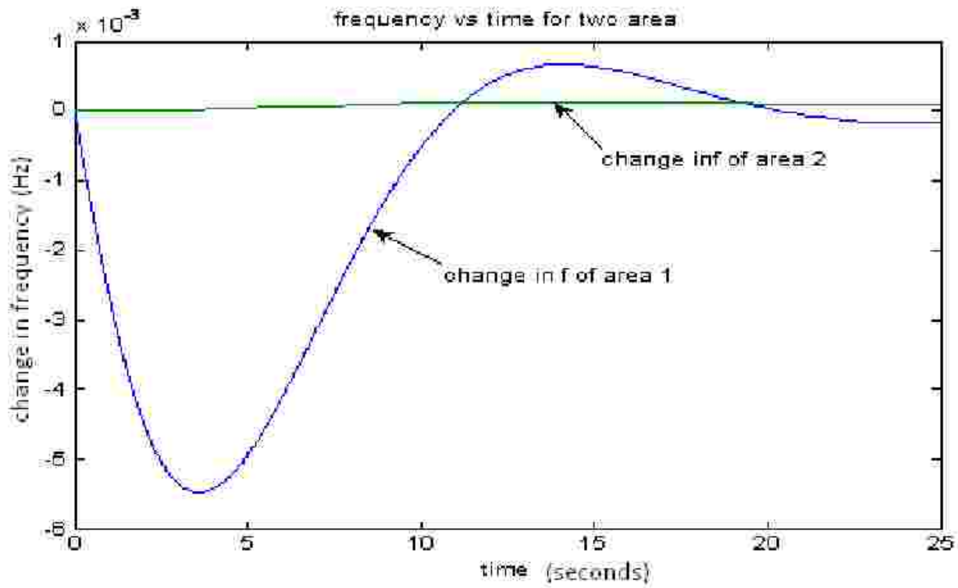


Figure 6.14 AGC Response for workspace ‘f’ for Two Areas System

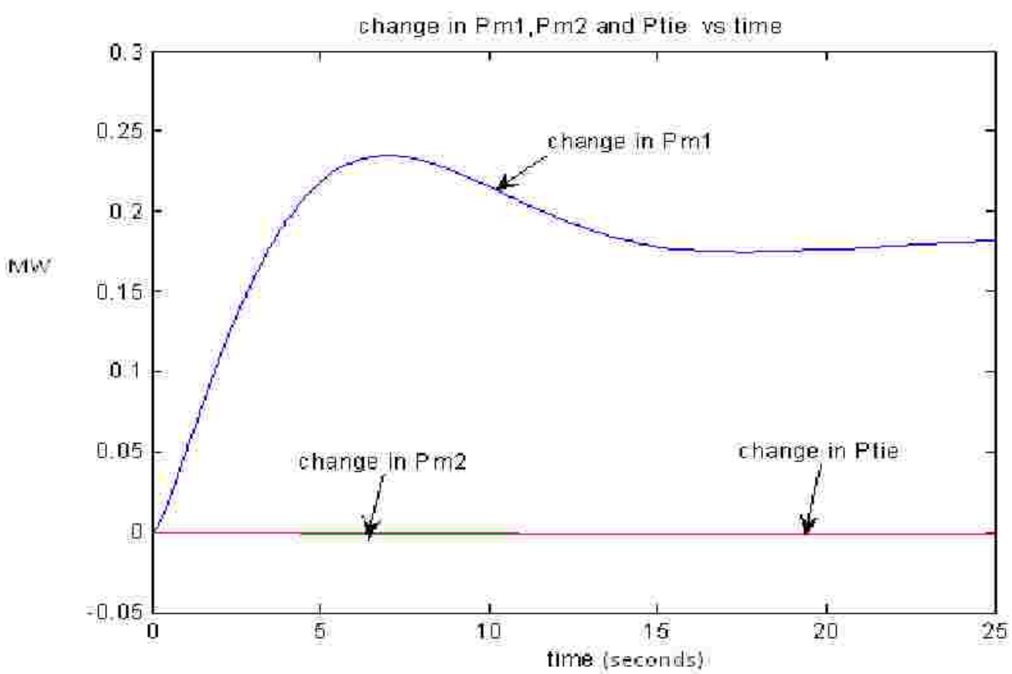


Figure 6.15 AGC Response for workspace ‘J’ for Two Areas System

From response of system (figure 6.14) it is found that system wills normal in 20 seconds.

6.8 AGC and AVR for Two Areas System

AGC and AVR model for Two Areas System is shown in figure 6.16

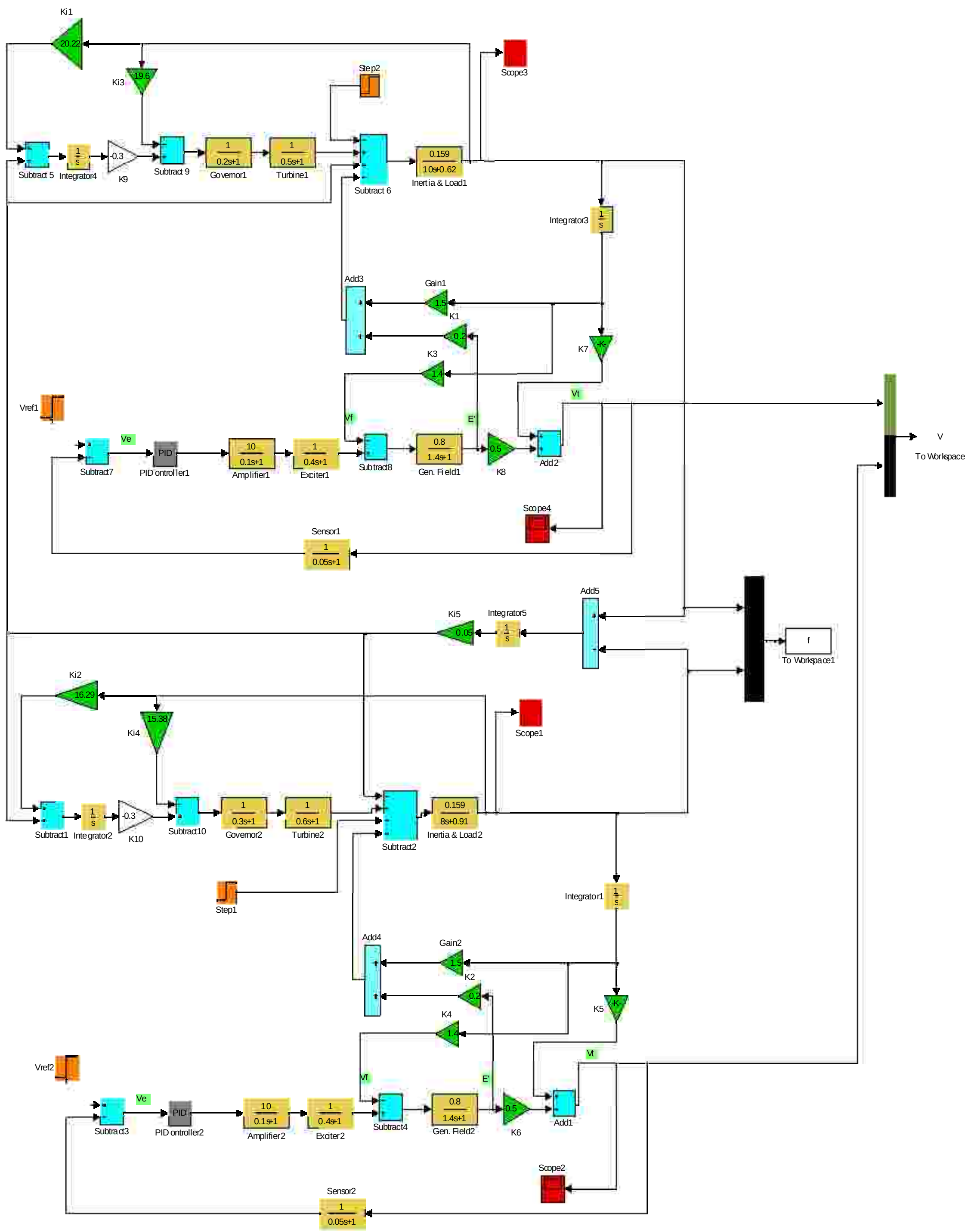


Figure 6.16 AGC and AVR Model for Two Areas System

In order to check model response, following programming is used to plot graph between frequency and time:

Sim ('ninth_two_area_agc_avr');

t=0:1:100;

Figure (1), plot (t, f);

Figure (2), plot (t, V);

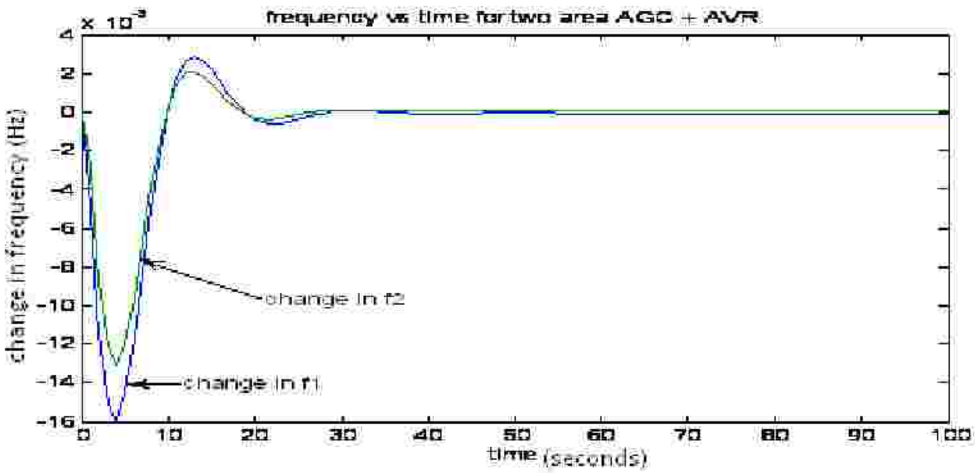


Figure 6.17 AGC and AVR Response for workspace 'f' for Two Areas System

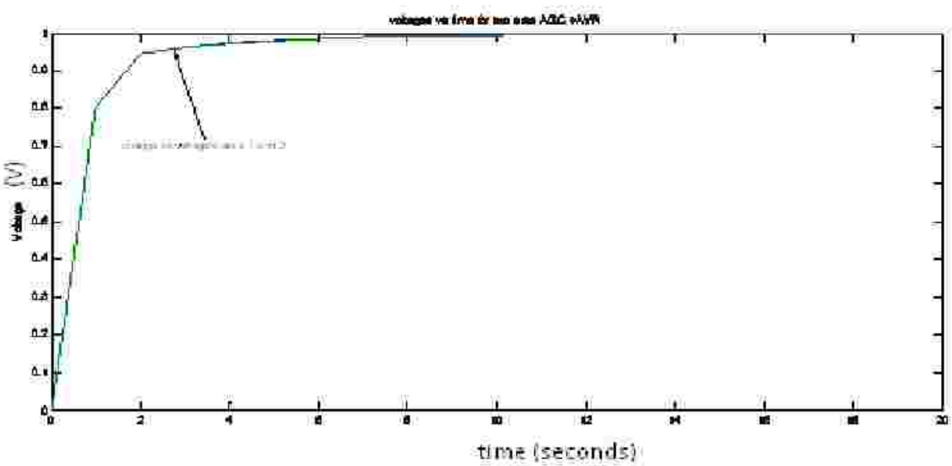


Figure 6.18 AGC and AVR Response for workspace 'V' for Two Areas System

Here it is found that system wills normal in 35 seconds (figure 6.17)

6.9 AGC, AVR and GRC for Two Areas System

AGC, AVR and GRC model for Two Areas System is shown in figure 6.19

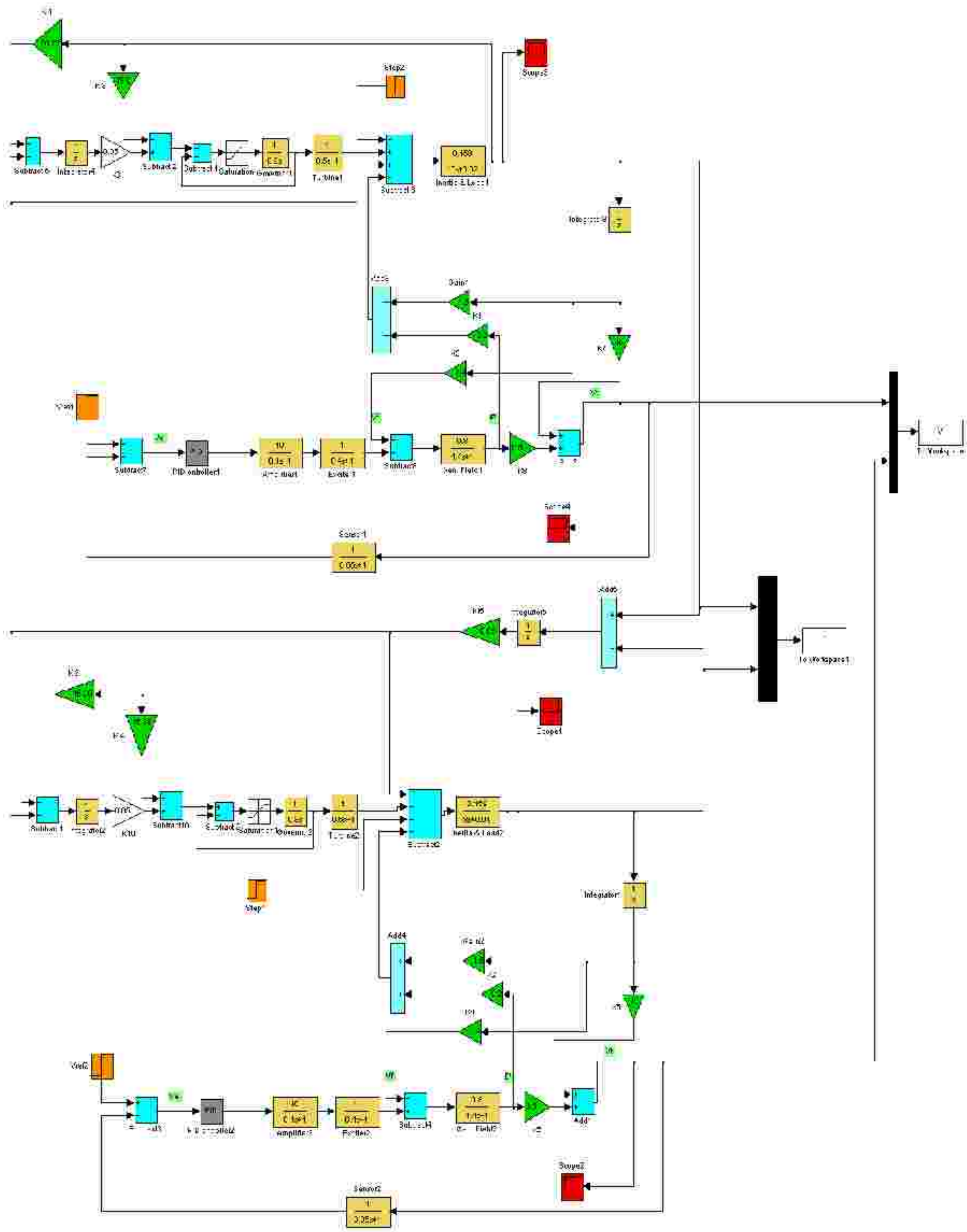


Figure 6.19 AGC, AVR and GRC model for Two Areas System

In order to check model response, following programming is used to plot graph between frequency and time:

Sim ('tenth_two_area_agc_avr_grc');

t=0:1:200;

Figure (1), plot (t, f);

Figure (2), plot (t, V);

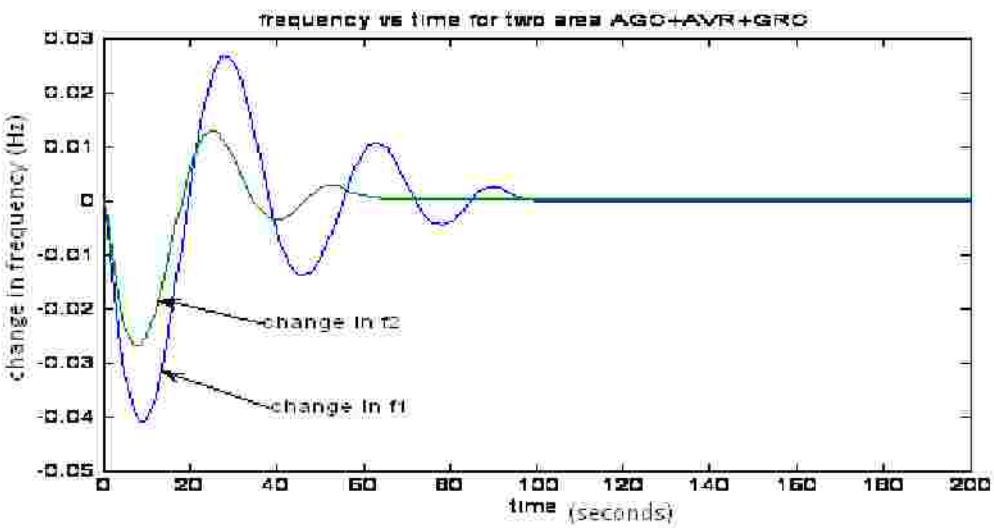


Figure 6.20 AGC, AVR and GRC Response for workspace 'f' for Two Areas System

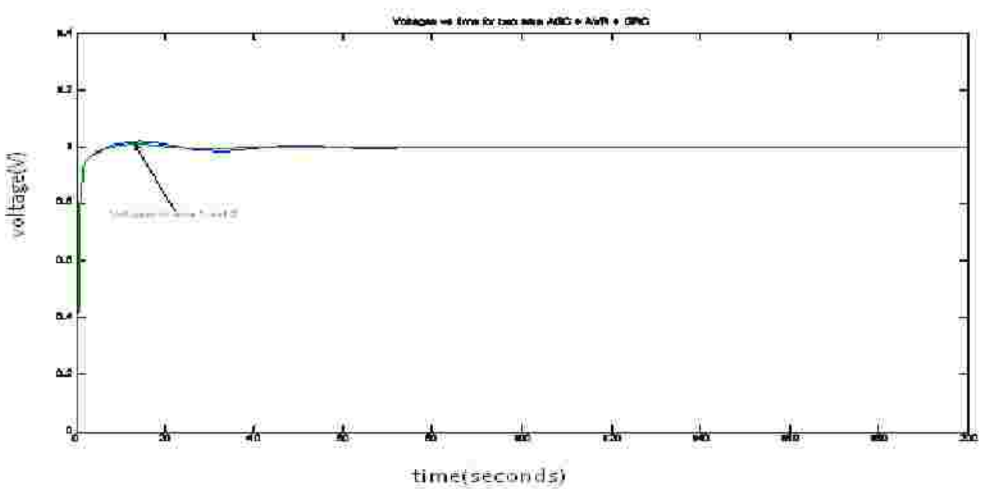


Figure 6.21 AGC, AVR and GRC Response for workspace 'V' for Two Areas System

Here it is found that system wills normal in 100 seconds.

6.10 AAA for Two Areas

AAA is AGC, AVR, and Availability.

- AGC, AVR and Frequency Availability Based Tariff for Two Area.
- AGC, AVR and Availability of Scheduled Loading for Two Area

6.10.1 AGC, AVR and Availability of Frequency Based Tariff for Two Areas

Advance Functions of Central Economic Dispatch Centre:

- Supervisory Control & Data Acquisition (SCADA) functions.
- System Monitoring and Alarm Functions.
- State Estimation.
- On line Load Flow.
- Economic Load Dispatch.
- Optimal Power Flow (including Optimal Reactive Power Dispatch).
- Security Monitoring and Control.
- Automatic Generation Control.
- Unit Commitment.
- Load Forecasting.
- On Line Tariff Control

The basic need of CEDC for these functions performance is shown in figure 6.22

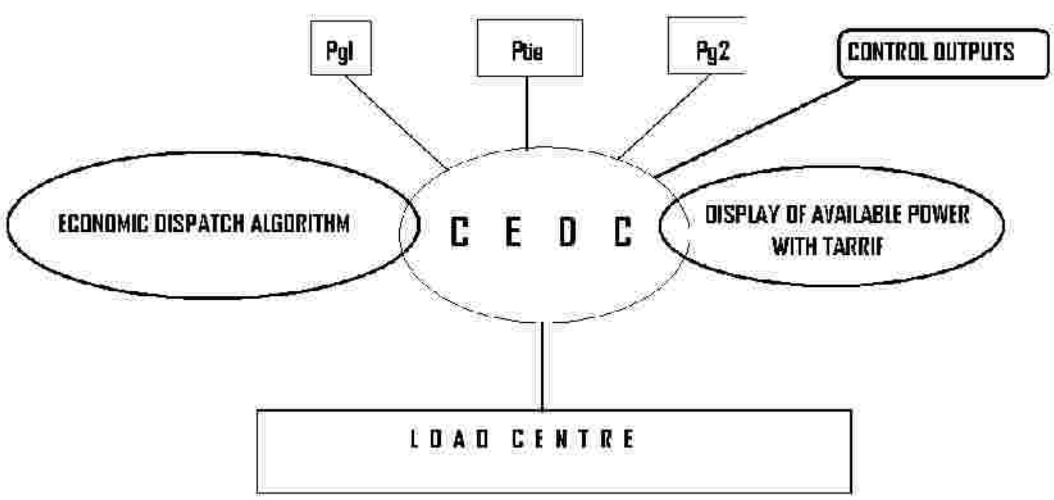


Figure 6.22 Central Economic Dispatch Centre

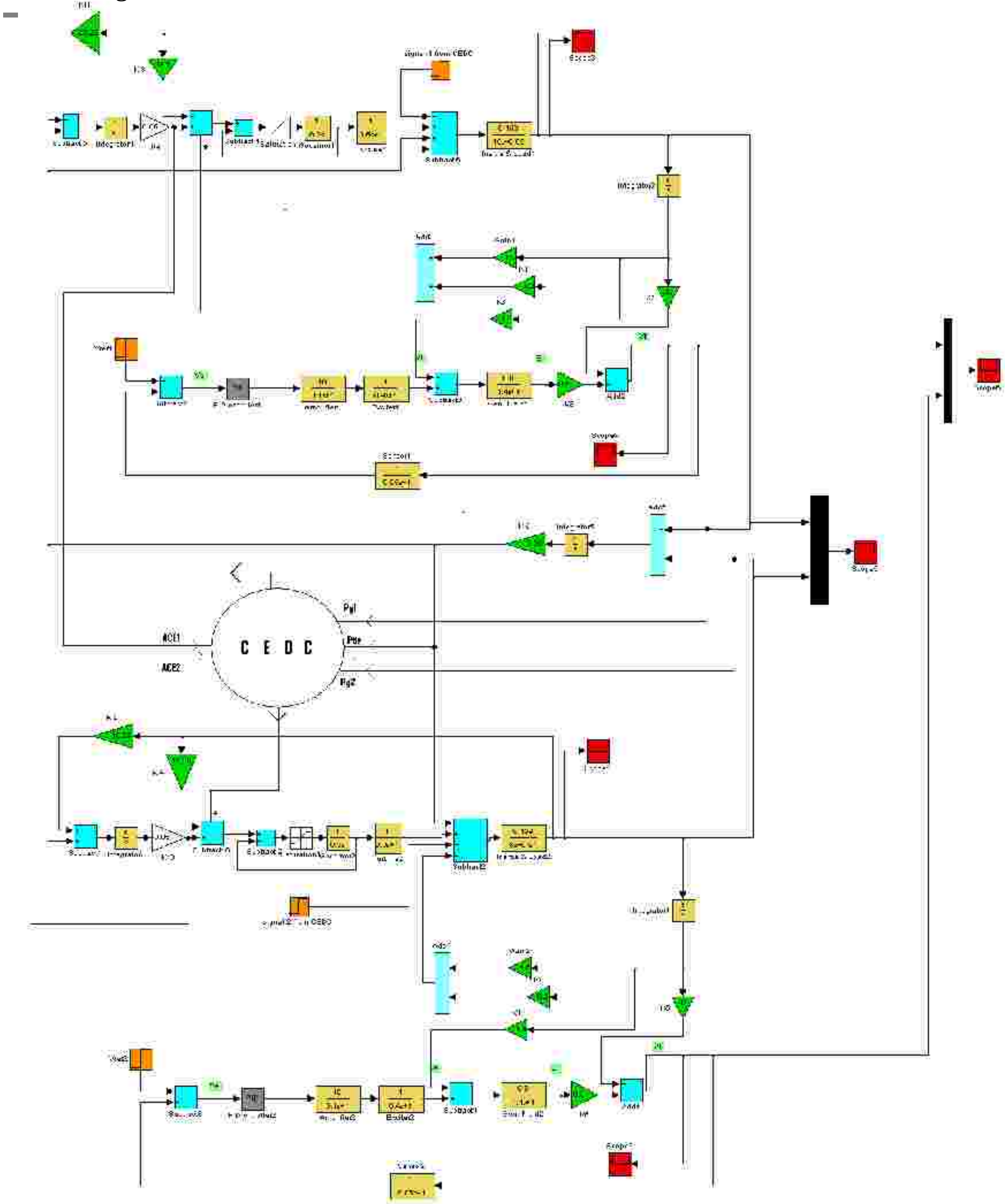


Figure 6.23 Model scheme for AGC, AVR and Frequency Availability Based Tariff for Two Areas

The model scheme for AGC, AVR and Frequency Availability Based Tariff for Two Areas is shown in figure 6.23

6.10.2 AGC, AVR with Scheduled Loading Available for Two Areas

The second scheme is AGC, AVR with Scheduled Loading Available for Two Areas. If scheduled is available for load change in duration of days, a better frequency characteristics can be obtained.

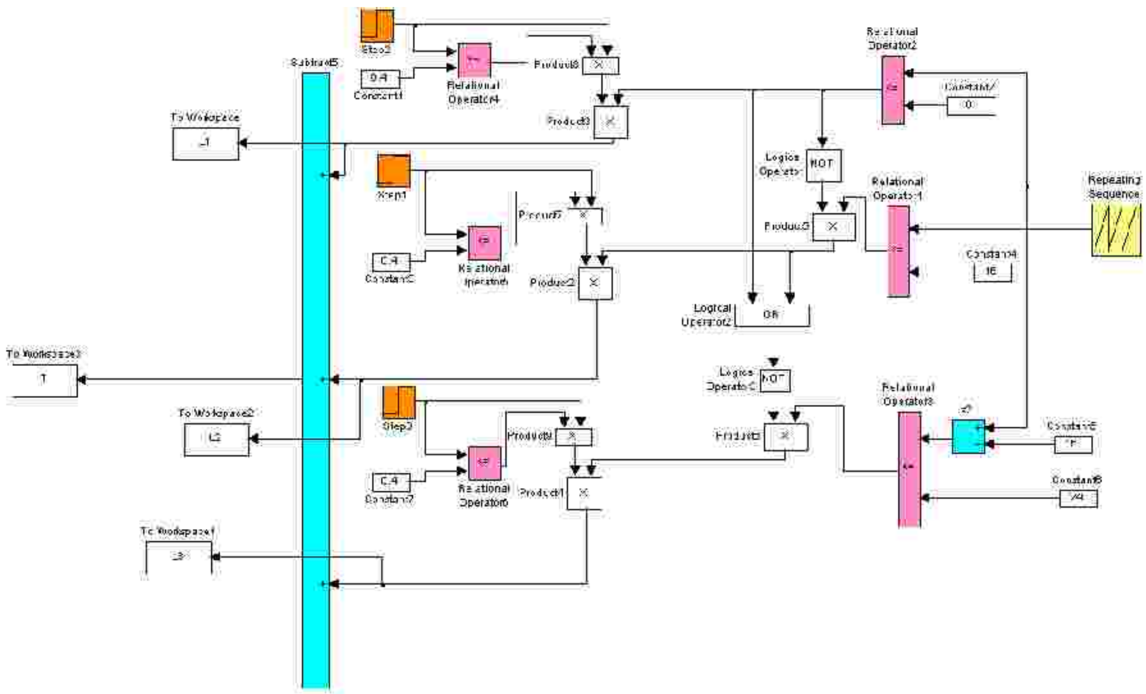


Figure 6.24 Scheduled Availability Model

Scheduled Availability Model is shown in Figure 6.24. Here scheduled for 24 hrs in a day as under:

1. Demand L1 for first 8 hrs.
2. Demand L2 for next 8 hrs.
3. Demand L3 for next 8 hrs.

In order to check model response, following programming is used to plot graph between frequency and time:
Sim ('sixthdemand_loop');

```
t=0:0.01:30;
Figure (1), plot (t, L1);
Figure (2), plot (t, L2);
Figure (3), plot (t, L3);
Figure (4), plot (t, T);
```

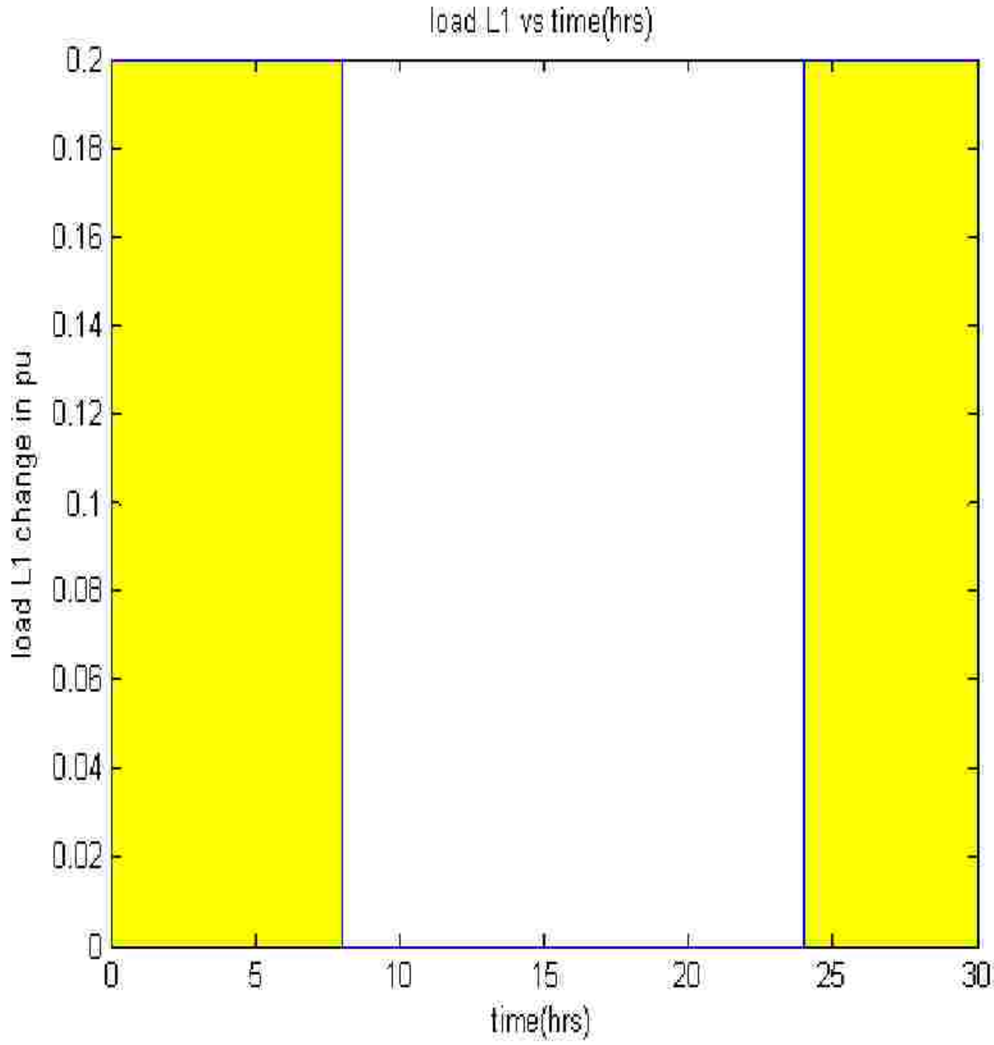


Figure 6.25 Scheduled for Demand L1

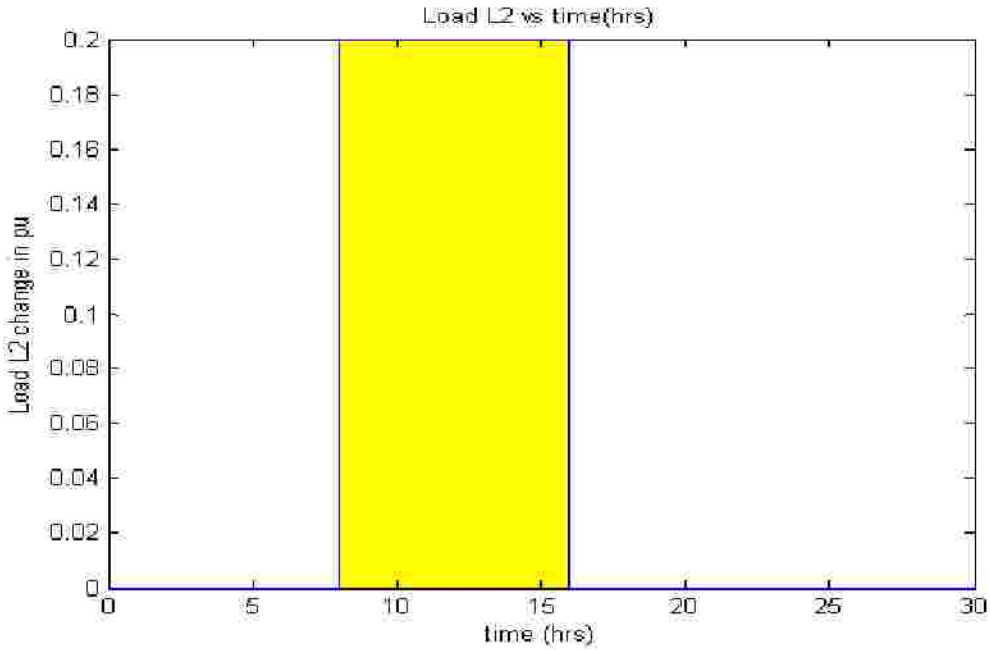


Figure 6.26 Scheduled for Demand L2

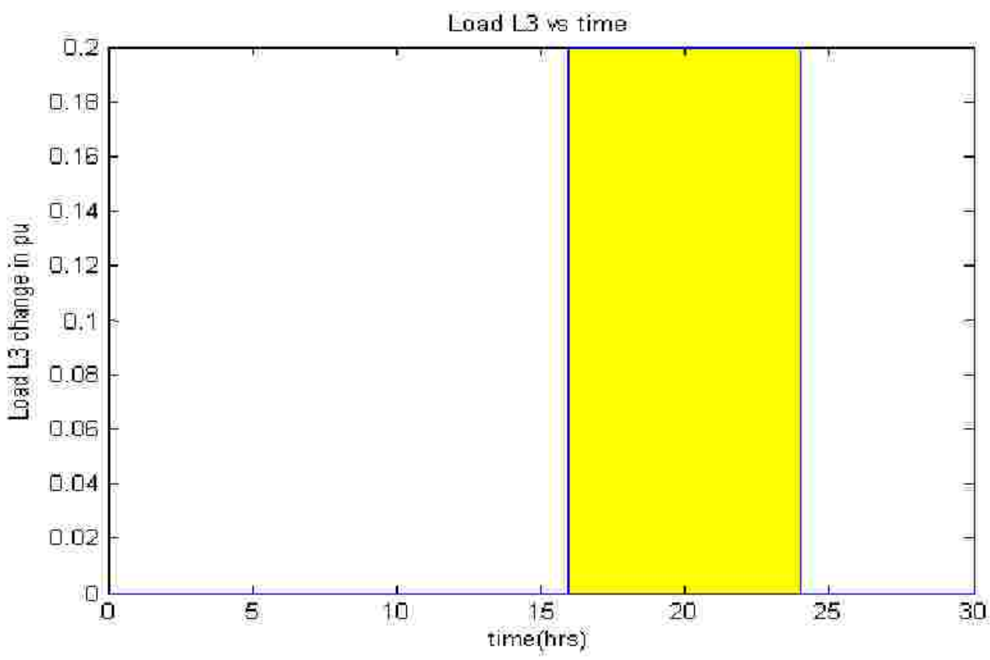


Figure 6.27 Scheduled for Demand L3

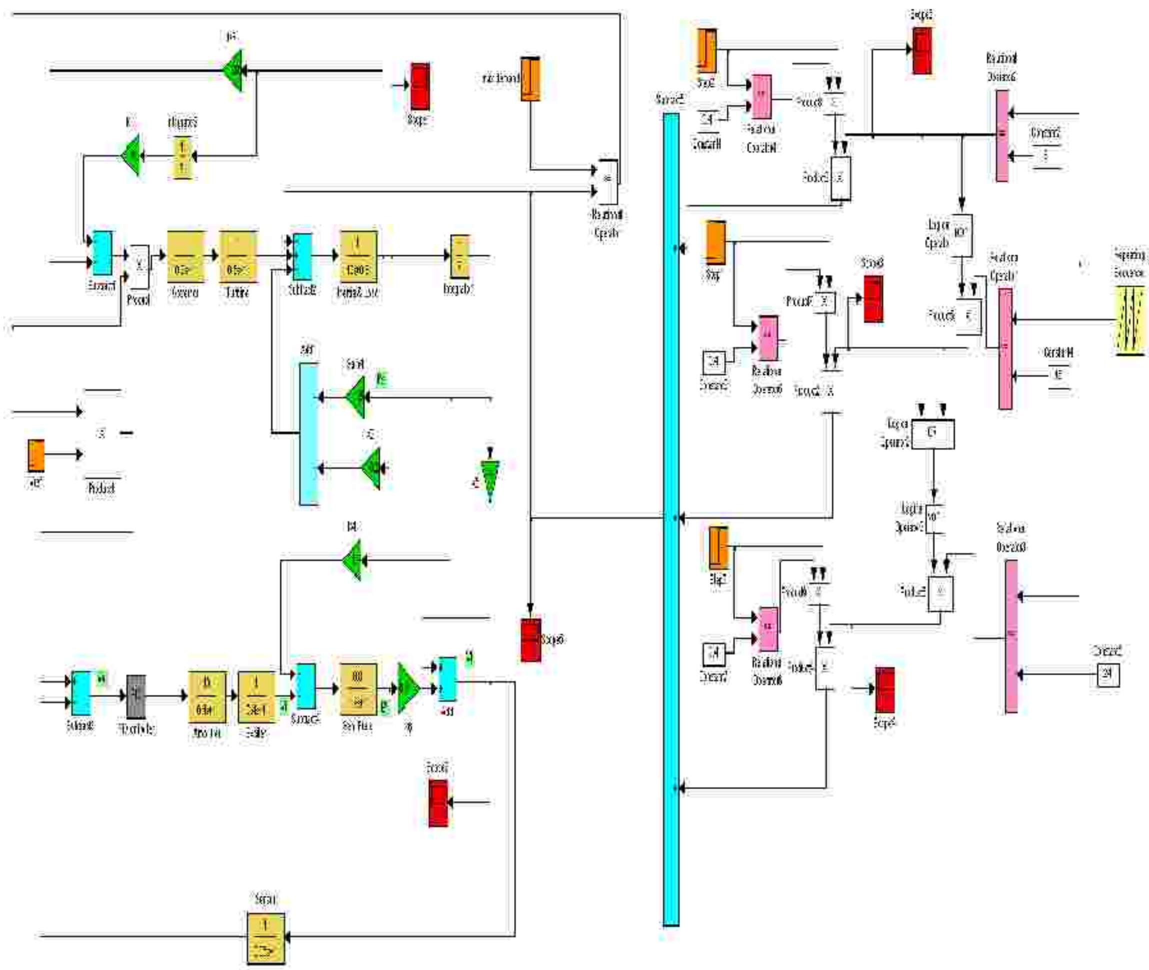


Figure 6.28 Model for AGC, AVR with Scheduled Loading Available for Two Areas

Model shown in figure 6.28 is for AGC, AVR with scheduled loading available for two areas. System performance can be improved in this way. Tariff may also be changed in this scheme depends on working scheduled of loads. Also if demand change is very large can not accomplished by AAA, then need of Load shedding, even if frequency error is large then need to stop generation.

CHAPTER 7

CONCLUSION AND FUTURE SCOPE

Many investigations in the field of automatic generation control of interconnected power system have been reported over the past few decades. Investigation regarding to the AGC of interconnected thermal system is limited to the selection of controller parameter and effect of GRC (generation rate constraints).

In this thesis attempt is made to develop AGC scheme is employed with AVR and market structure. Here coupling between AGC and AVR scheme is employed. The interaction between frequency and voltage exists and cross coupling does exist and can some time troublesome. AVR loop affect the magnitude of generated EMF. The internal EMF determines the magnitude of real power. It is concluded that changes in AVR loop is felt in AGC loop.

A power system is a proper system to transmit power economically efficiently and in reliable manner. Every one desires the uninterrupted supply. The total amount of real power in network emanates from generating stations. The generation must be equal to demand at each moment and since this power must be divided between generators in unique ratio, in order to achieve the economic operation. We conclude that individual generator output must be closely maintained at predetermined set point. But it does not happen. Some times demand is very large than generation and some time surplus power in a duration of 24 hrs. It is important to remember that demand undergo slow but wide changes throughout the 24 hr of the day. This is a need to manage generation as well as demand.

AGC and AVR scheme is extended with management in demand side. Demand is managed with controlling tariff. Demand Side Management deals with two points as

- AGC, AVR and Frequency Availability Based Tariff for Two Area.
- AGC, AVR and Availability of Scheduled Loading for Two Area

In this thesis attempt is made to make a scheme for automatic generation control with considering effect of voltages and market structure to make power system network in normal state.

Recommendations for Future Work

In this research, a scheme for automatic generation control indulges the effect of voltages and market structure has been developed. This approach is the real solution for power system problem. This research will make a power system economically efficient and more reliable. It is expected that the research will add the world of AGC structure on demand side management.

The new framework will be required for AGC scheme based on market structure with intelligence controller to solve complex problem and need another technical issues to be solved. In general, a variety of technical scrutiny will be needed to ensure secure system operation and a fair market place.

REFERENCES

1) G. V. Hicks, B Jeyasurya, P. Eng; "An investigation of automatic generation control for an isolated transmission system", *IEEE* 1997. Pages: 31- 34.
2) Jyant Kumar, Kh- Hoi Ng, Gerald Shevle; "AGC simulator for price based operation". *IEEE transaction in power system*, Vol.12, No- 2, may 1997. Pages: 527- 532.
3) Jayant Kumar, Kh- Hoi Ng, Gerald Shevle; "AGC simulator for price based operation Part- 2". *IEEE transaction in power system*, Vol.12, No- 2, may 1997. Pages: 533- 538.
4) Bzorm H. Bakken, Kjetil Uhlen; "Market based AGC with online bidding of regulating reserves". *IEEE* 2001. Pages: 848- 853.
5) Vaibhav Donde, M.A.Pai, and Ian A.Hiskens;"Simulation and Optimization in an AGC system after Deregulation",*IEEE transactions on power systems*,Vol.16,No -3,August 2001.
6) Olle L.Elgerd, "Electrical Energy Systems Theory", Mc Graw- Hill, New Delhi, 2002.
7) Allen J Wood, "Power Generation Operation and Control ", John Wiley and Sons Publishing, 1984
8) I.J.Nagrath, D.P.Kothari, "Modern Power System Analysis", BSP, Hyderabad, 2002.
9) Prabha Kundur, "Power System Stability and Control", Mc Graw- Hill, New Delhi, 2002.
10) K.R. Padiyar, "Power System Dynamics", Mc Graw- Hill, New Delhi, 2002.
11) Hadi Saadat, "Power System Analysis", Mc Graw- Hill, New Delhi, 2002.
12) A Barzam; "Automation in Electrical Power System", Pages: 1- 420. MIR Russian 1977.
13) Kalyan Kumar, M. Deben Singh, Arvind Kumar Singh; "Modelling and simulation of AGC for SCADA based interconnected power system operation". Pages: 1- 10.

14) J. Nanda, M.L. Kothari "Automatic generation control of an interconnected power system considering generation rate constraints and governor deadband". Deptt of Electrical Engineering, IIT Delhi. Pages: 48- 49.

15) S. C. Tripathy, N. Saha; "A comparative study of the effects of governor deadband nonlinearity on stability of conventional and dynamic load frequency controls". Deptt of Electrical Enginering, IIT Delhi. Pages: 20- 21.

16) V Ramamurthi, P.S. Kodandaraman swami; "Combined consideration of generation controller terbine dynamics and instability analysis". Pages: 24- 25.

17) M. L. Kothari, D. P. Kothari; "Variable structure controller for AGC of interconnected power system". Pages: 79- 82.

18) Ignacio Egido, Fidel Fernandez- Bernai; "Modelling of thermal generating units for automatic generation control purposes", *IEEE transaction on control system technology*, Vol-12, No-1, January 2004. Pages: 205- 210.

19) ZOU Bin; "A new evaluation method for AGC unit's performance", *IEEE/ PES transmission and distribution* 2005, pages: 1-5.

20) Ibraheem. Prabhat Kumar, and Dwarka P.Kothari; "Recent philosophies of Automatic Generation Control Strategies in Power Systems",*IEEE transactions* on power systems,Vol.20,No 1,February 2005.Pages :346-400.

21) Miguel A. Plazas, Antonio J. Conjo; "Multi market Optimal bidding for a power producer", *IEEE transaction on power systems* vol-20, No-4, Nov. 2005. Pages: 2041- 2049.

22) Enrico Detugli; "Load following control schemes for deregulated energy markets", *IEEE transactions on power systems* vol-21, No-4, Nov. 2006. Pages: 1691- 1698.

23) BOOTH, R.R.: 'Power system simulation model based on probability analysis', *IEEE Trans.*, 1972, PAS-91, pp. 62-69

24) VARDI, J., ZAHAVI, J., and AVI-ITZHAK, B.: 'The combined load duration curve and its derivation', *ZEEE Trans.*, 1977, PAS-96,

25) JENKINS, R.T., and JOY, D.S.: 'WIEN automatic system planning package (WASP) - An electric utility optimal generation expansion planning computer code', Report ORNL-4945, Oak Ridge National Laboratory, USA, July 1974

26) KIRCHMAYER, L.K.: ‘Economic operation of power systems’ (John Wiley & Sons, New York, 1958)

27) ZAHAVI, J., VARDI, J., and AVI-ITZHAK, B.: ‘Operating cost calculation of an electric power generating system under incremental loading procedure’, *IEEE Trans.*, 1977, PAS%, pp. 285-292

28) BABB, R.A., and LEE, M.B.: ‘POWRSYM (Power system simulation)’, Tennessee Valley Authority, Division of Power Resource Planning, March 1975.

29) FOX, R.L.: ‘Optimization methods for engineering design’ (Addison- Wesley, New York, 1971)

30) KIRCHMAYER, L.K.: ‘Economic control of interconnected systems’ (John Wiley & Sons, New York, 1959) pp. 978-983 188