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An Optimal Output Feedback Controller Design Method for the Load Frequency Control of A Realistic Power System with Multi-Source Power Generation

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ABSTRACT

Automatic Generation Control (AGC) is an important function in modern Energy Management Systems (EMSs). The successful operation of interconnected power system requires the matching of total generation with total load demand and associated system losses. As the demand deviates from its nominal value with an unpredictable small amount, the operating point of power system changes, and hence, system may experience deviations in nominal system frequency and scheduled power exchanges. The main tasks of automatic generation control are to hold system frequency at or very close to a specified nominal value and to maintain the correct value of interchange power between control areas.

In this thesis, load frequency control (LFC) of a realistic power system with multi-source power generation is presented. The single area power system includes dynamics of thermal with reheat turbine, hydro and gas power plants. Appropriate generation rate constraints (GRCs) are considered for the thermal plant. In practice, access to all the state variables of a system is not possible and also their measurement is costly and difficult. Usually only a reduced number of state variables or linear combinations thereof, are available. To resolve this difficulty, optimal output feedback controller which uses only the output state variables is proposed. The performances of the proposed controller are compared with the full state feedback controller. The action of this proposed controller provides satisfactory balance between frequency overshoot and transient oscillations with zero steady state error in the multi-source power system environment. The effect of regulation parameter (R) on the frequency deviation response is examined. The sensitivity analysis reveals that the proposed controller is quite robust and optimum controller gains once set for nominal condition need not to be changed for ±25% variations in the system parameters and operating load condition from their nominal values. To show the effectiveness of the proposed controller on the realistic power system, the LFC of realistic power system operational in with trapezoidal signal has also been presented.

INTRODUCTION

The function of a power system is to provide customers with an electricity supply of acceptable reliability, where reliability signifies “the ability to supply adequate electric service on a nearly continuous basis with few interruptions over an extended period of time”.

Therefore, to design and operate a power system within adequate reliability margins such that overall costs are minimized is a key objective for all system operators.

Power system security is an indication of the level of robustness of the power system at any instant in time to a disturbance. When operating in a secure state, a power system can withstand most severe disturbances without interruption to customer supply. However, if operating in a state with reduced security margins, a power system will be more susceptible to disturbance, resulting in a

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higher likelihood of customer supply disruption. To maintain adequate reliability it is desirable to maximize the time the power system is operating in a secure state, with frequency and voltage levels within acceptable standards. In order for a power system to be secure, the power system must be operating in a stable state.

Stability indicates the ability of the system to return to an equilibrium operating state subsequent to a disturbance, and is dependent on both the type of disturbance and the initial power system operating conditions. Although the electricity industry is undergoing regulatory and organizational changes, the basic concepts and rules for reliable, secure and stable system operation remain unchanged.

Ancillary services can be broadly defined as the range of technical services required by the system operators to maintain both secure and stable operation of the power system. These include operating reserves for frequency control, voltage control and also system restoration/black start capability. While the methods by which these services are procured may vary and evolve with regulatory structure, the necessity of ancillary services is unquestionable. This is highlighted by a number of recent contingencies worldwide resulting in severe lapses in the security of power systems including blackouts. The control of system frequency is a vital aspect of secure and stable power system operation. A continuous balance between active power generated and active power consumed by the load and losses is required to maintain frequency constant at nominal system frequency. Any imbalance in active power will result in a frequency deviation. While precise instantaneous balancing of active power is not viable, frequency control ensures that the system frequency remains within acceptable frequency limits. Frequency control can be called upon for a variety of conditions ranging from a gradual change in load levels over time to a sudden loss of generation or step increase in demand.

Combined cycle gas turbines (CCGTs) offer higher efficiency, greater flexibility and lower emissions than many conventional thermal generators, in addition to progressively shorter installation times and reducing installation costs. As a result, CCGT generating units comprise an ever increasing proportion of generation capacity for many electricity systems. The efficiency of combined cycle gas turbines is maximized when operating actor near maximum or base load, and declines with decreased loading. The behavior of CCGT generators in response to frequency excursions differs from that of a conventional steam turbine, and may have a detrimental effect on the system frequency response when the CCGT is run at, or near, base load. This effect will be progressively more apparent as CCGTs operating at or near base load comprise increasing proportions of the generation.

In conjunction with the shift towards CCGT plant, many power systems worldwide are also experiencing a rapid increase in wind generation. This trend is driven by a variety of reasons including environmental concerns, targets for electricity production from renewable energy resources, the desire for increased fuel diversity, constant advances in technology and economic factors including declining costs. While the addition of conventional synchronous generators to a power system will result in an inherent increase in the system inertial response, this is not necessarily the case with wind turbine generators. Therefore, if rapidly increasing levels of wind generation begin to displace conventional synchronous generation, erosion of system inertial response may result. This effect will result in increasing rates of change of frequency during power imbalances, and the magnitude of frequency excursions may also rise. These effects will influence small isolated power systems, in particular, where system inertia levels are inherently low.

System frequency provides an instantaneous indication of system operating conditions, as any imbalance between active powers generated and consumed manifests itself as a deviation from nominal system frequency. The magnitude of the frequency excursion and the rate of change of frequency are dependent on a

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number of factors, including the size of the power imbalance and the characteristics of the power system.

While small variations in system frequency will not result in a reduction is system reliability or security, large frequency deviations can have a serious impact on power system components and power quality is degraded. Damage to generators and transformers can result from overheating due to increases in the volts/hertz ratio during times of low frequency. In addition, generator damage due to mechanical vibrations can occur if frequency deviations greater than 5% of nominal frequency occur.

In order to limit the frequency excursion from nominal system frequency, and to maintain a stable and secure system, action in addition to the inherent system inertial response is required, i.e. frequency control. Frequency control may be broadly categorized into automatic and manual frequency control. The former responds automatically to either a deviation from nominal system frequency or a rate of change of frequency in excess of a predefined threshold. Sources of automatic frequency control are the natural reduction in system load with low frequency, the automatic increase in generator active power output activated by the speed droop governor, low frequency or rate of change of frequency triggered responses from pumped storage units and the automatic shedding of load. Manual frequency control encompasses all instructions issued by the system operator to generators (and load if applicable, i.e. in the event of load participation) for changes from the reference set point of the generator (or to current active power consumption in the case of load).Additional active power capacity available (i.e. when compared to steady state operation prior to a frequency event) from generation units or through reduction in load for the purpose of frequency control is known as operating reserve.

Many different definitions for the categorization of operating reserve exist. The reserve is categorized into primary, secondary and tertiary operating reserve, as defined and the same illustrated in Fig. 1.1.

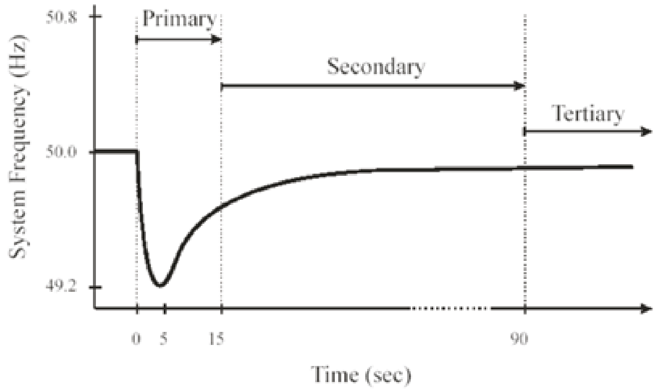

Fig. 1.1 Operating reserve time-scales

Primary operating reserve (POR) is the additional active power available from generators and through reduction of active power consumption of the load which is available between 5 and 15 seconds subsequent to an event on the system. Secondary reserve is defined to be the additional active power available and sustainable for the time period from 15 to 90 seconds after the event. Tertiary reserve is the additional active power available from 90 seconds to 20 minutes subsequent to the event. Finally replacement reserve is the additional active power available from 20 minutes to 4 hours after the event.

In the event of a power imbalance, POR automatically responds to arrest the falling frequency and initiate recovery towards nominal frequency through the reduction of the power imbalance. The predominant source of POR on the majority of systems is the automatic droop governor response of generators operating below maximum rated active power output to a deviation in speed. Other sources of POR from generators can include an increase in active power when under-frequency relays or rate of change of frequency (ROCOF) relays are triggered. One example is under-frequency relaying triggering a rapid increase in active power generation from a pumped storage generating unit.

LOAD FREQUENCY CONTROL

Power systems are used to convert natural energy into electric power. They transport electricity to factories and

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houses to satisfy all kinds of power needs. To optimize the performance of electrical equipment, it is important to ensure the quality of the electric power. It is well known that three-phase alternating current (AC) is generally used to transport the electricity. During the transportation, both the active power balance and the reactive power balance must be maintained between generating and utilizing the AC power. Those two balances correspond to two equilibrium points: frequency and voltage. When either of the two balances is broken and reset at a new level, the equilibrium points will float. A good quality of the electric power system requires both the frequency and voltage to remain at standard values during operation. For North America, the standard values for the frequency and voltage are 60 Hertz and 120 Volts respectively. However, the users of the electric power change the loads randomly and momentarily. It will be impossible to maintain the balances of both the active and reactive powers without control. As a result of the imbalance, the frequency and voltage levels will be varying with the change of the loads. Thus a control system is essential to cancel the effects of the random load changes and to keep the frequency and voltage at the standard values.

Although the active power and reactive power have combined effects on the frequency and voltage, the control problem of the frequency and voltage can be decoupled. The frequency is highly dependent on the active power while the voltage is highly dependent on the reactive power. Thus the control issue in power systems can be decoupled into two independent problems. One is about the active power and frequency control while the other is about the reactive power and voltage control. The active power and frequency control is referred to as load frequency control (LFC) [1].

REASONS FOR THE LIMITS ON FREQUENCY

Following are the reasons for keeping a strict limit on the system frequency variation:

1. The speed of the alternating current motors depends on the frequency of the power supply. There are situations where speed consistency is expected to be of high order.
2. The electric clocks are driven by the synchronous motors. The accuracy of the clocks are not only dependent on the frequency but also is an integral of the frequency error.
3. If the normal frequency id 50 Hertz and the system frequency falls below 47.5 Hertz or goes up above 52.5 Hertz then the blades of the turbine are likely to get damaged so as to prevent the stalling of the generator.
4. The under frequency operation of the power transformer is not desirable. For constant system voltage if the frequency is below the desired level then the normal flux in the core increases. This sustained under frequency operation of the power transformer results in low efficiency and over-heating of the transformer windings.
5. The most serious effect of subnormal frequency operation is observed in the case of Thermal Power Plants. Due to the subnormal frequency operation the blast of the ID and FD fans in the power stations get reduced and thereby reduce the generation power in the thermal plants. This phenomenon has got a cumulative effect and in turn is able to make complete shutdown of the power plant if proper steps of load shedding technique is not engaged. It is pertinent to mention that, in load shedding technique a sizable chunk of load from the power system is disconnected from the generating units so as to restore the frequency to the desired level.

REALISTIC POWER SYSTEM LOAD FREQUENCY CONTROL MODEL

The power systems means, it is the interconnection of more than one control areas through tie lines. The generators in a control area always vary their speed together (speed up or slow down) for maintenance of frequency and the relative power angles to the predefined values in both static and dynamic conditions.

If there is any sudden load change occurs in a control area of an interconnected power system then there will be frequency deviation as well as tie line power deviation.

The two main objective of Load Frequency Control (LFC) are

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1. To maintain the real frequency and the desired power output (megawatt) in the interconnected power system.
2. To control the change in tie line power between control areas.

If there is a small change in load power in a single area power system operating at set value of frequency then it creates mismatch in power both for generation and demand. This mismatch problem is initially solved by kinetic energy extraction from the system, as a result declining of system frequency occurs. As the frequency gradually decreases, power consumed by the old load also decreases. In case of large power systems the equilibrium can be obtained by them at a single point when the newly added load is distracted by reducing the power consumed by the old load and power related to kinetic energy removed from the system. Definitely at a cost of frequency reduction we are getting this equilibrium. The system creates some control action to maintain this equilibrium and no governor action is required for this. The reduction in frequency under such condition is very large.

However, governor is introduced into action and generator output is increased for larger mismatch. Now here the equilibrium point is obtained when the newly added load is distracted by reducing the power consumed by the old load and the increased generation by the governor action. Thus, there is a reduction in amount of kinetic energy which is extracted from the system to a large extent, but not totally. So the frequency decline still exists for this category of equilibrium. Whereas for this case it is much smaller than the previous one mentioned above. This type of equilibrium is generally obtained within 10 to 12 seconds just after the load addition. And this governor action is called primary control.

Speed – Governor Model

Governors are the units that are used in power systems to sense the frequency bias caused by the load change and cancel it by varying the inputs of the turbines. The speed governing unit is shown with R and Tg, where Ris the speed regulation characteristic andTgis the time constant of the governor [7]. If without load reference, then the load change occurs, part of the change will be compensated by the valve/gate adjustment while the rest of the change is represented in the form of frequency deviation. The goal of LFC is to regulate frequency deviation in the presence of varying active power load. Thus, the load reference set point can be used to adjust the valve/gate positions so that all the load change is canceled by the power generation rather than resulting in a frequency deviation. The Laplace transform representation of speed governor model is given in eqn. (2.1) and shown in Fig. 2.1.

$$U(s) - \frac{\Delta F(s)}{R_{TH}} = (1 + sT_{SG}).\Delta P_V(s)(3.1)$$

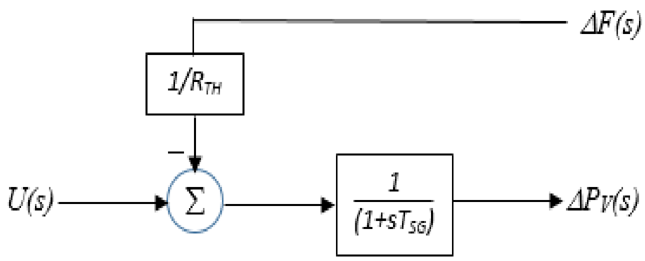

Fig. 3.1 Block diagram of the speed governing unit

Reheat Turbine Model

A turbine unit in power systems is used to transform the natural energy, such as the energy from steam or water, into mechanical power (ΔPm) that is supplied to the generator. In LFC model, there are three kinds of commonly used turbines: non-reheat and turbines, all of which can be modeled by transfer functions.

Non-reheat turbines are first-order units. A time delay (denoted by TT) occurs between switching the valve and producing the turbine torque. The transfer function can be of the non-reheat turbine is represented as

$$\frac{\Delta P_{GTH}(s)}{\Delta P_V(s)} \frac{1}{(1 + sT_T)}. \qquad (3.2)$$

where ΔP_V is the valve/gate position change [1].

Reheat turbines are modeled as second-order units, since they have different stages due to high and low steam pressure. The Laplace transform representation of reheat turbine model is given in eqn. (2.3) and shown in Fig. 2.1.The transfer function can be represented as

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$$\frac{\Delta P_{GTH}(s)}{\Delta P_V(s)} = \frac{1+sK_RT_R}{(1+sT_R)(1+s)} \quad (3.3)$$

where T_R stands for the low pressure reheat time and K_R represents the high pressure stage rating [7].

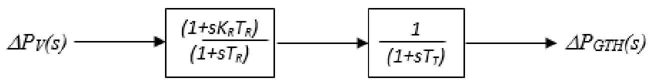

Fig. 3.2 Block diagram of the Reheat turbine unit

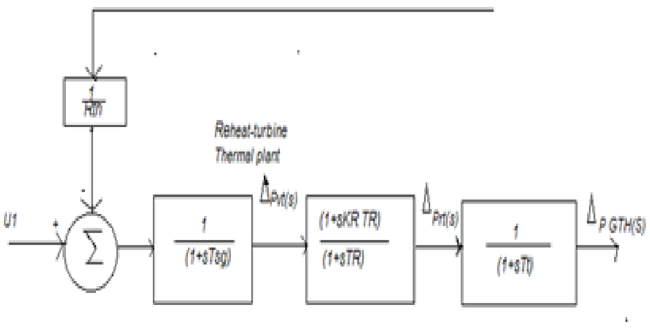

Fig 3.2.1 Block Diagram of Reheat-Turbine Thermal Power Plant

Hydraulic Turbine Model

The representation of the hydraulic turbine and water column in stability studies is usually based on the following assumptions:

1. The hydraulic resistance is negligible
2. The penstock pipe is inelastic and the water is incompressible
3. The velocity of the water varies directly with the gate opening and with the square root of the net head
4. The turbine output power is proportional to the product of head and volume flow

The essential elements of the hydraulic plant are depicted in Fig. 3.3

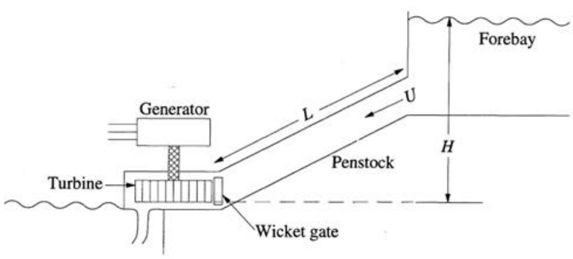

Fig. 3.3 Schematic of a hydroelectric plant

The turbine and penstock characteristics are determined by three basic equations relating to the following:

(a) Velocity of water in the penstock
(b) Turbine mechanical power
(c) Acceleration of water column

Governor for Hydraulic Turbines Model

The basic function of a governor is to control speed and/or load. The primary speed/load control function involves feeding back speed error to control the gate position. In order to ensure satisfactory and stable parallel operation of multiple units, the speed governor is provided with a droop characteristic. The purpose of the droop is to ensure equitable load sharing between generating units. Typically, the steady state droop is set at about 5%, such that a speed deviation of 5% causes 100% change in gate position or power output; this corresponds to a gain of 20. For hydro turbine, however, such a governor with simple steady-state droop characteristic would be unsatisfactory.

On older units the governing function is realized using mechanical and hydraulic components. Fig. 3.5 shows a simplified schematic of a mechanical hydraulic governor. Speed sensing, permanent droop feedback, and computing functions are achieved through mechanical components; functions involving higher power are achieved through hydraulic components. A dash pot is used to provide transient droop compensation. A bypass arrangement is usually provided to disable the dashpot if so desired.

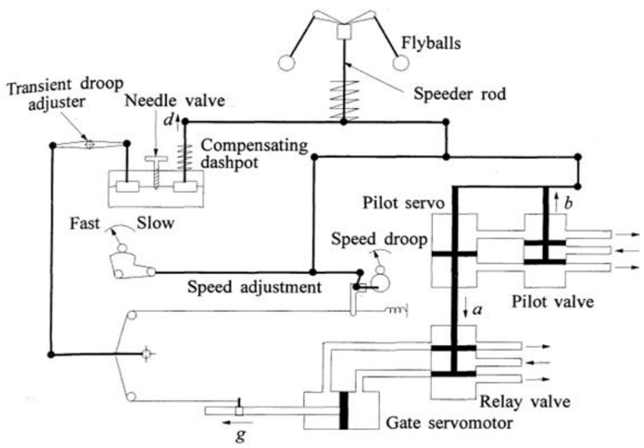

Fig. 3.5 Schematic of a mechanical-hydraulic governor for a hydro turbine

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Gas Generation Unit

A gas turbine power plant usually consists of valve positioner, speed governor, fuel system &combustor and gas turbine. The load-frequency model of gas turbine power plant is shown in Fig. A, where U is reference power setting of the gas plant and □ PGG is the gas turbine output power. The system frequency deviation and governor speed regulation parameters are represented by □ F in pu and RG in Hz/puMW respectively. The transfer function representation of valve positioner is shown in Fig. 2.8, where, CG is the gas turbine valve positioner, BG is the gas turbine constant of valve positioner. The speed governing system is represented by a lead-lag compensator as shown in Fig. 2.8, where, XC is the lead time constant of gas turbine speed governor in sec, YC is the lag time constant of gas turbine speed governor in sec. the fuel system and combustor is represented by a transfer function with appropriate time constants as shown in Fig. 2.8, where, TF is the gas turbine fuel time constant in sec and TCR is the gas turbine combustion reaction time delay in sec. The gas turbine is represented by a transfer function, consisting of a single time constant i.e. the gas turbine compressor discharge volume–time constant (TCD) in sec.

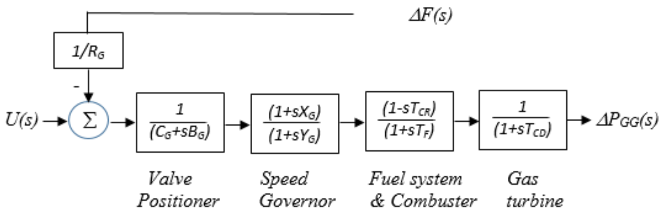

Fig. 3.8 Load frequency model of gas turbine power plant

Gas Turbine:

The gas turbine engine is a complex assembly of different components. such as compressors, turbines, combustion chambers, etc., designed on the basis of thermodynamic laws. Gas turbines usually consist of an axial compressor, a combustion chamber and a turbine operating under Brayton cycle. These three elements form the thermal block are complemented by the air intake system, the exhaust system, auxiliaries and controls (Figure 1).

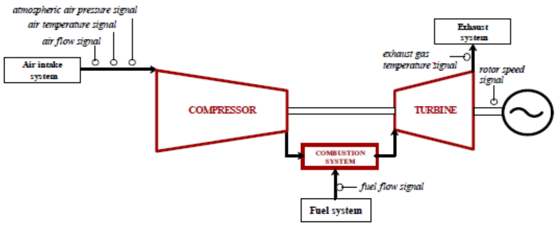

Fig.1. Single shaft gas turbine configuration

The air flow is drawn into the axial compressor and compressed through multiple stages of stator and rotor blades. The compressed air in the axial compressor is then mixed with fuel in the combustion chamber, where the combustion process takes place. The resulting hot gas is expanded through a multi stage turbine to drive the generator and the compressor. The fuel flow determines the power output of a gas turbine. The fuel and air flow together determine the firing temperature, which is the gas temperature at the exit of the combustion chamber. The fuel flow and air flow are adjusted based on measurement of the exhaust temperature and the compressor pressure ratio in order to keep the firing temperature below a design limit. The compressor\ pressure ratio is determined from measurements of the inlet and discharge air pressure of the compressor (for the entire axial compressor this ratio is typical 15to 20). The air flow can be adjusted by changing the angular position of the variable inlet guide vanes (VIGVs). These vanes are essentially the first few stages of the stator blades inside the axial compressor assembly. When the gas turbine is loaded close to base load, the VIGVs are wide open. The air flow is a function of VIGV angle, ambient temperature at compressor inlet, atmospheric pressure and the shaft speed. Summarizing the gas turbine outputs / inputs dependencies, a black-box system representation is given in figure 2.

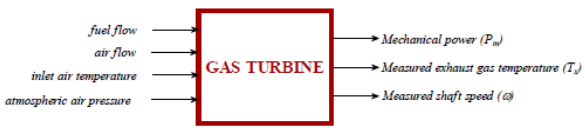

Fig. 2. System representation of gas turbine

Realistic Power System Load Frequency Control Model

A single area system comprising hydro, thermal with reheat turbine and gas units is considered at the first

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instance for designing controller for the system. The linearized models of governors, reheat turbines, Hydro turbines, Gas turbines are used for simulation and LFC study of the power system as shown in Fig. 2.10.

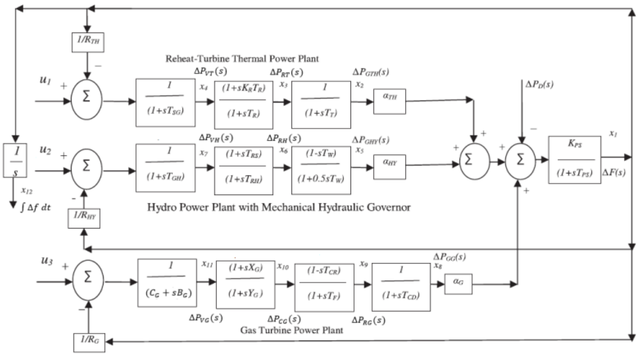

Fig. 3.10 Transfer function model of realistic power system single area system

Each unit has its regulation parameter and participation factor which decide the contribution to the nominal loading. Summation of participation factor of each control should be equal to 1. In Fig. 3.10, RTH, RHY, RG are the regulation parameters of thermal, hydro and gas units respectively, U1, U2 and U3 are the control outputs for of thermal, hydro and gas units respectively, αTH, αHY and αG are the participation factors of thermal, hydro and gas generating units, respectively, TSG is speed governor time constant of thermal unit in sec, TT is steam turbine time constant in sec, KR is the steam turbine reheat constant, TR is the steam turbine reheat time constant in sec, TW is nominal starting time of water in penstock in sec, TRS is the hydro turbine speed governor reset time in sec, TRH is hydro turbine speed governor transient droop time constant in sec, TGH is hydro turbine speed governor main servo time constant in sec, XC is the lead time constant of gas turbine speed governor in sec, YC is the lag time constant of gas turbine speed governor in sec, cg is the gas turbine valve positioner, bg is the gas turbine constant of valve positioner, TF is the gas turbine fuel time constant in sec, TCR is the gas turbine combustion reaction time delay in sec, TCD is the gas turbine compressor discharge volume-time constant in sec, KPS power system gain in Hz/puMW, TPS is the power system time constant in sec, □ F is the incremental change in frequency and □ PD incremental load change.

STATE SPACE MODEL OF REALISTIC POWER SYSTEM

The Power system proposed for study is a realistic system comprising Reheat thermal, hydro and gas generating units. The linearized models of governors, reheat-turbines, Hydro turbines, Gas turbines are taken to study the power system as shown in Fig. 4.1 [6,7,20–23,25–27]. The model mentioned here is the integral control scheme of an interconnected realistic power system. This chapter dealt with the state space modeling of the mentioned power system which is designed for the implementation of optimal controllers and their stability studies.

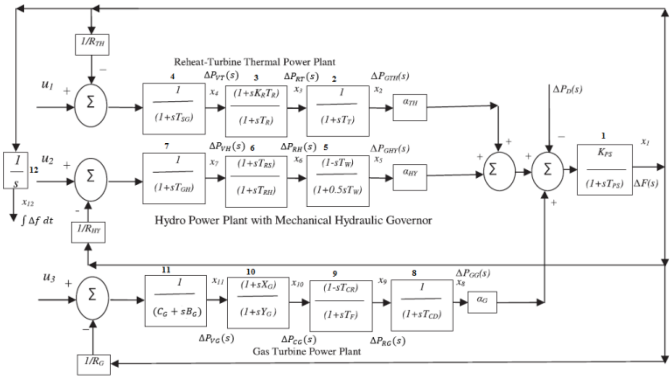

Fig. 4.1 Block diagram of the single area power system comprising reheat-thermal, hydro and gas generating units.

The state equations of the system are produced with the help of the transfer function of the blocks named 1 to 12. From the block diagram model it is clearly seen that there are three control inputs named u1, u2and u3.The block diagram below which represents a realistic power system model is having control area connected to its own dynamics.

From the figure it is clearly seen that the control area are made-up with three blocks each with an integral controller block. The three blocks are namely governor block, turbine block, and the power system block which is actually the load block. Therefore total 9 blocks are present for the whole system.

Explaining about the block diagram, it is constructed by the combination of two control areas through tie line.

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Both areas consist of four blocks each and another one block (block 7) represents the tie line power. So there are total nine blocks present, which says that there is nine state equations for a two area power system (thermal non reheat) with integral controller.

SIMULATION RESULTS AND ANALYSIS

The optimum values of controller gains for full state feedback and optimal output feedback are obtained by minimizing the performance indices. Dynamic responses of the system are obtained for 1% step load perturbation in the area through computer simulation. The frequency deviation responses are depicted in Fig. 6.1. It has been observed that the output feedback controller gives better frequency deviation response having relatively smaller peak overshoot and lesser settling time with zero steady state error as compared to the full state feedback controller. The output power deviation responses of thermal, hydro and gas units to 1% load perturbation are shown in Figs. 6.2–6.4, respectively.

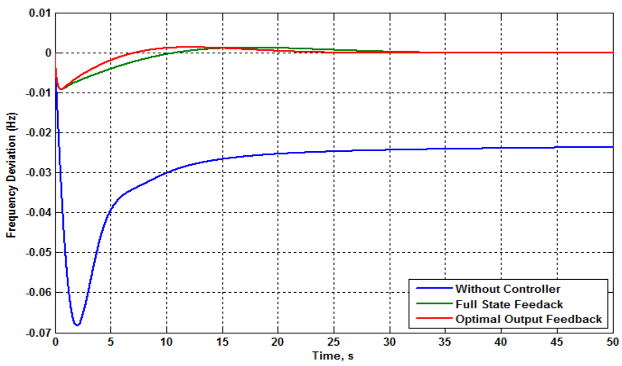

Fig. 6.1 Frequency deviation response to 1% step load perturbation in the area

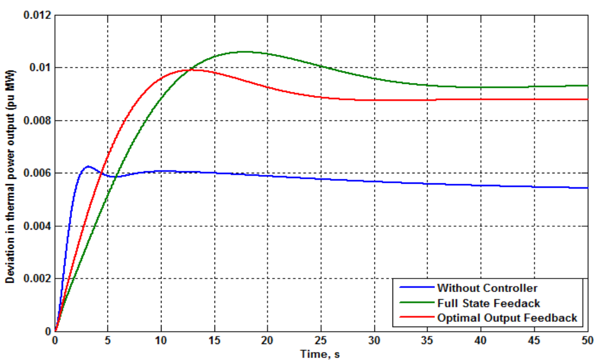

Fig. 6.2 Thermal unit power output deviation response to 1% step load perturbation in the area

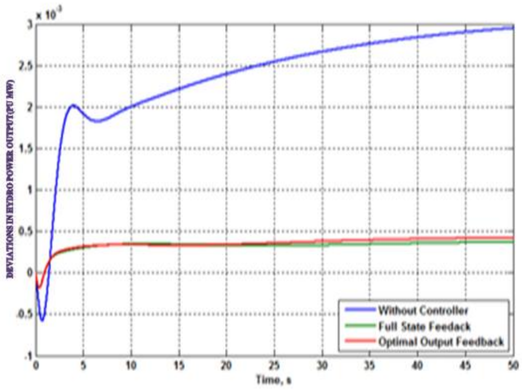

Fig.6.3 Hydro unit power output deviation response to 1% step load perturbation in the area

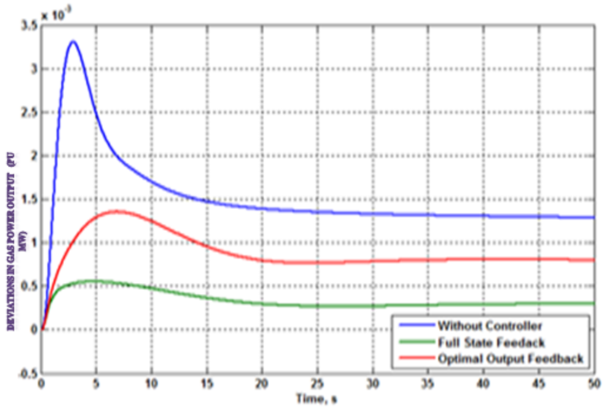

Fig. 6.4 Gas unit power output deviation response to 1% step load perturbation in the area

CONCLUSION

There is a need to study of the multi-source power system due to the future needs where lot of renewable energy sources available with combination of the fossil fuel energy systems. In this thesis an optimal output feedback controller design method is proposed for the LFC of a realistic power system. The performance of the proposed controller is demonstrated on the multi-source power system and its dynamic responses are compared with full state feedback controller. The effect of GRC on frequency deviation response is discussed. The dynamic performance of the system deteriorates if GRC is not incorporated for realistic study of the system. Frequency deviation response of the area and generator output power deviation response to 1% step load perturbations have been obtained.

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The output feedback controller gives better frequency deviation response having relatively smaller peak overshoot and lesser settling time with zero steady state error as compared to full state feedback controller response. The effect of varying the regulation parameter has been examined. It is better to prefer the value of R between 3% and 4% with corresponding optimum controller gains to provide better dynamic response of AGC for the proposed system. The sensitivity analysis reveals that ±25% change in system parameters and operating load condition from their nominal values considering their optimum controller gains do not affect the system responses appreciably.

Thus the optimum values of controller gains obtained for nominal system parameters and load condition are quite insensitive to wide parameter variation ±25%. The LFC of hydro power plants operational has also been studied. The proposed controller performs well on this system and improves the frequency deviation responses remarkably.

Hence for all practical purposes, the controller is quite robust. Application of optimal output feedback controller is more simple and economic as lesser no. of sensors/information is required and satisfies the LFC problem requirements.

FUTURE SCOPE OF WORK

The following is the future scope of the work for the realistic load frequency control

- Can be extend the work with PID controller and analyze the gains
- Can be extend to the two area control of the realistic load frequency control
- Can be compute the gains using the different optimization techniques
- Can be analyze the load frequency control with the hydro and gas power units with the exact models also

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