Adaptive load frequency control of electrical power systems

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Adaptive Load Frequency Control of Electrical Power Systems

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ABSTRACT

The thesis describes Load Frequency Control techniques which may be used for real–time on–line control of large electrical power systems. Traditionally the frequency control of power systems has been carried out using standard fixed parameter control schemes, which give control over the immediate steady–state error and the long term accumulated frequency error, but do not account for the fact that system conditions can alter due to the change in consumer load and generating patterns. The thesis presents a method of controlling the system frequency using adaptive control techniques, which ensure that optimal control action is calculated based on the present system conditions. It enables the system operating point to be monitored so that optimal control may continue to be calculated as the system operating point alters. The proposed method of frequency control can be extended to meet the problems of system interconnection and the control of inter–area power flows.

The thesis describes the work carried out at Durham on a fixed parameter control scheme which led to the development of an adaptive control scheme. The controller was validated against a real–time power system simulator with full Energy Management software. Results are also presented from work carried out at the Central Electricity Research Laboratories under the C.A.S.E award scheme. This led to the development of a power system simulator, which along with the controller was validated on–line with the Dispatch Project used by the Central Electricity Generating Board.

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MAJOR SYMBOLS USED

ΔP_l	System load p.u.
ΔP_g	System generation p.u.
ΔU	L.F.C. set unit output
$\theta(t)$	Parameter vector
$A(q)$	Polynomial of a_i
$A.C.E.$	Area control error
$A.S.C.$	Area supplementary control
$B(q)$	Polynomial of b_i
$C.R.$	Computational requirement
D_i	Damping coefficient
$G(s)$	System transfer function
I.P.I.	Inadvertent power interchange
K_p	Proportional gain
K_i	Integral gain
K	System gain MW/Hz
$K(t)$	Kalman gain
K_{ps}	Pumped storage constant
$P(t)$	Covariance matrix
R	Governor gain
T.D.	Time deviation
T_{LFC}	L.F.C. time constant
T_1	Rise time
T_2	Decay time
T_{ps}	Pumped storage time constant
T_n	Non–sustained time constant
T_s	Sustained time constant
T_l	Low pressure steam time delay
T_h	High pressure steam time delay
$u(t)$	Ouput from controller
U	Dispatch set unit output
$x(t)$	Array of system input and outputs
$y(t)$	Input to controller

STATEMENT OF COPYRIGHT

DECLARATION

The work contained in this thesis has not been submitted elsewhere for any other degree or qualification and that unless otherwise referenced it is the authors's own work.

CHAPTER 1

INTRODUCTION

1.1 An Introduction to Electrical Power Systems

The primary function of an electrical power system is to provide a secure, economic and reliable source of electricity to the consumer. The term consumer refers to both the domestic user, who will use in the order of a few tens of kilowatts of power, to an industrial user such as a steel works who may use several megawatts of power.

The electricity is supplied to the user as an alternating current with a sinusoidal voltage wave form. Industrial users are usually supplied by three phase supply which consists of three alternating currents with a phase shift of 120 degrees between each of the voltage wave forms. The voltage level is measured between each of the phases and can be as high as several tens of kilovolts depending on the user's requirements. It is more economical in terms of capital expenditure to construct a power system as a three phase supply and it is hence only split into three single phases just before it reaches the domestic user. For the domestic user, the voltage is measured with respect to the neutral line, its value varies from country to country but is usually in the range of 120–240 Volts. The load imposed on the system by the domestic users is divided evenly amongst the three phases, thus it is sufficient for the power system operator to consider only one of the phases of the system and it is usual for diagrams and displays only to detail one phase.

The process of supplying the consumer with electricity can be divided into three distinct functions, these are: generation, transmission and distribution. These are briefly discussed in the following section and are illustrated using references to both the Central Electricity Generating Board [209,210] (C.E.G.B.), which supplies England and Wales, and also to other power system companies where relevant.

The formalisation of the electricity supply industry [42] in England and Wales occurred in 1947, with the Electricity Act. The Nationalised Industry, was formed from the British Electricity Authority, together with fourteen area boards. The Electricity Act in 1957 created the Electricity Council and the C.E.G.B.

Electricity generation is basically a conversion process in which a primary energy source is converted into electrical energy. The primary element of an electrical power system is the plant in which a basic fuel is converted into electricity. The fuel may take many forms from coal or oil to nuclear fission, or the recovery of kinetic energy from moving water. In most plant the basic fuel is directly or indirectly used to produce steam by the extraction of energy from the fuel as heat. The high pressure steam is then used to drive a turbine which in turn supplies mechanical energy to an electric generator. There are many general references available, some of the better ones are [113,114,139,147,215,222].

Coal–fired plant is the type most used in the UK, but this is not so for all countries. The coal is used as the primary energy source, which has a great effect on the positioning of the power station. The schematic diagram for a conventionally fired power station is shown in diagram 1.1.

A steam turbine generally consists of a high pressure (H.P.), intermediate pressure (I.P.), and a low pressure (L.P.) cylinder. The exhaust steam from the H.P. cylinder is reheated in the boiler before it enters the I.P. cylinder. Reheating increases the temperature of the steam, which enables the power output of the unit to be increased by the use of the I.P. and L.P. cylinders. It also reduces the problem of wet steam in the L.P. section of the turbine. In the L.P. section the turbine blades are long and the peripheral blade speed is very high. This means that water droplets in the steam can cause severe pitting of the turbine blades. The I.P. cylinder exhausts to the L.P. cylinders, which in

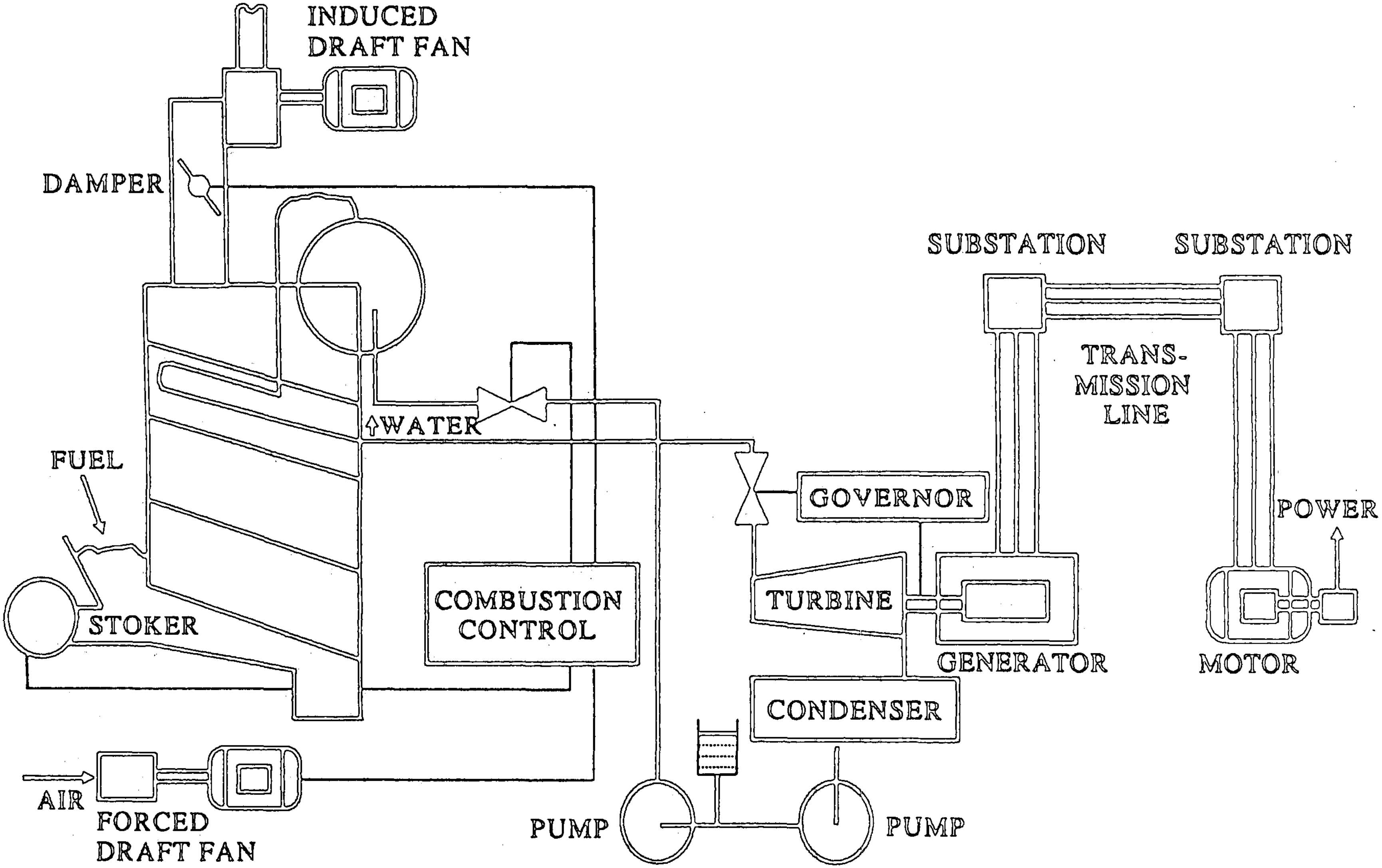


Diagram 1.1 Conventionally Fired Power Station

turn is exhausted under vacuum to the condenser. The condensate is de–aerated and pre–heated prior to being fed–back into the boiler. Turbine-generator sets of 660 MW capacity represent the most recent types used at the moment but units of 1000 MW have been designed and will appear.

Oil–fired stations provide an alternative to the problems of fuel transportation and the handling associated with the fuelling plant. However, the economy of such stations has become more difficult to assess due to the change of the cost of oil during the decade. The availability of the supply of oil, and the uncertainty of the national long term energy policy will greatly affect the future of oil–fired stations.

Nuclear plant uses the heat generated by the fissile material to heat water, replacing the boiler in conventional plant.

Pumped storage stations use the excess system power, which is not required by the consumer load when they are in pumping mode. The capital cost of such installations is very high and can only be built in particular geographical conditions. The energy is stored in the potential energy of the water of a lake high above the turbines. As the water falls through the height of the head its kinetic energy is converted into rotational energy by the turbines. The drive shaft is connected to a generator, and a governor is used to control the speed of rotation of the shaft by altering the water flow.

Hydro–electric schemes are organised along the same lines as those of the pumped storage schemes. They use the energy stored in a moving river, whether it be dammed or free flowing.

Diesel generators differ from the others in that a conventional internal combustion engine is used to drive an electrical generator directly.

Gas turbine plant has a relatively high operating cost but a fairly low initial cost. The energy source in gas turbine generators is fuel-oil, its energy is converted into rotational energy by passing the hot exhaust gases through a turbine. They are often used as standby generators because of the high cost involved in their operation, but they have a quick response time and are often used in emergency situations.

The rotational energy produced by the primary energy source is transformed into electrical energy by a generator, which exploits the electro-magnetic interactions between a magnetic field and a moving conductor. A power station generally has several generating sets, with the larger stations having as many as six turbine-generator units. Modern steam turbine generators usually have terminal voltages between 6.6 to 23.5 kV, and a power output of up to 660 MW. The older equipment may operate at lower voltages and ratings. The voltage produced by the generator is increased using generator–transformers to step up the voltage to that value required by the transmission network. Typical gas turbine generators can vary from as little as a few kilowatts to several hundred megawatts.

Recent coal-fired stations built in the UK have a capacity of 2000 MW, but there is a need in the shorter term for more larger capacity stations. The subject of the planning and positioning of power stations is still under review, and involves political decisions as well as engineering ones. In the C.E.G.B., fossil fuels account for approximately 85% of the total fuel used, the remainder is made up from nuclear (approximately 12.5%), gas turbines, and some diesel generators. Pumped storage generation is also used, but this requires energy from the system in pumping mode to keep the top lake full.

Before 1983 the C.E.G.B. had approximately 130 power stations, but by October 1983, it had reduced this number to 90 as new, larger and more efficient power stations were commissioned [42]. The total generating capacity in January 1987 was in excess of 52 GW. The maximum total recorded peak demand was 48 GW. Centres of generation and consumer load are often distributed over a wide area and often do not coincide. The generation sites are generally placed in locations which are acceptable after consideration of the environment and ease of communication. The location of such power stations is governed by two major factors. Firstly, easy transport of the fuel to the power station, and secondly, the availability of a plentiful supply of water for cooling purposes. Hence, power stations are usually situated on the coast or near large rivers. In the case of coal-fired stations, they are generally placed near to, or within easy access of, a coal field. Oil-fired stations are usually situated near an oil-refinery. The placing of pumped-storage stations is generally more difficult, as a very specific geographical location is required. Diagram 1.2 shows the location of the major power stations in the C.E.G.B. network.

The large thermal generators, whether they are fossil fuel or nuclear units, are usually the most economical to run, and hence are usually run continuously at fairly steady output level. As would be expected, the output of large generating units cannot change quickly and it may take several hours to synchronise such a generator to the network from a cold start. Gas turbine generators are, however, expensive to run. This means they are only run for short periods of time, but they have the major advantage that they can be synchronised to the system within a matter of minutes. Hence, they are used to meet sharp increases of load on the system, or during emergency conditions.

Pumped–storage units are operated in a different way again. During periods of low demand electricity is used to pump water from the lower reservoir to the upper reservoir. This usage of power enables some of the large thermal units to remain synchronised with the system during periods of light load. When the load increases, the water stored in the upper reservoir is returned to the lower reservoir. The kinetic energy gained in the fall is used to drive a hydro–electric generator. These units can respond very quickly to the demand of the system, typically ten seconds from rotating in air to the full output of 400 MW. Hydro–electric schemes again are similar to the pumped–storage approach, but the water used is from a river, and hence no pumping action is required.

The control of the generating units is a complex problem which takes into consideration the following criteria: the predicted load both in the near future (that is, the next 30 minutes) and the more distant future (that is, the next 4-6 hours), the time taken to synchronise a generator if it is not already

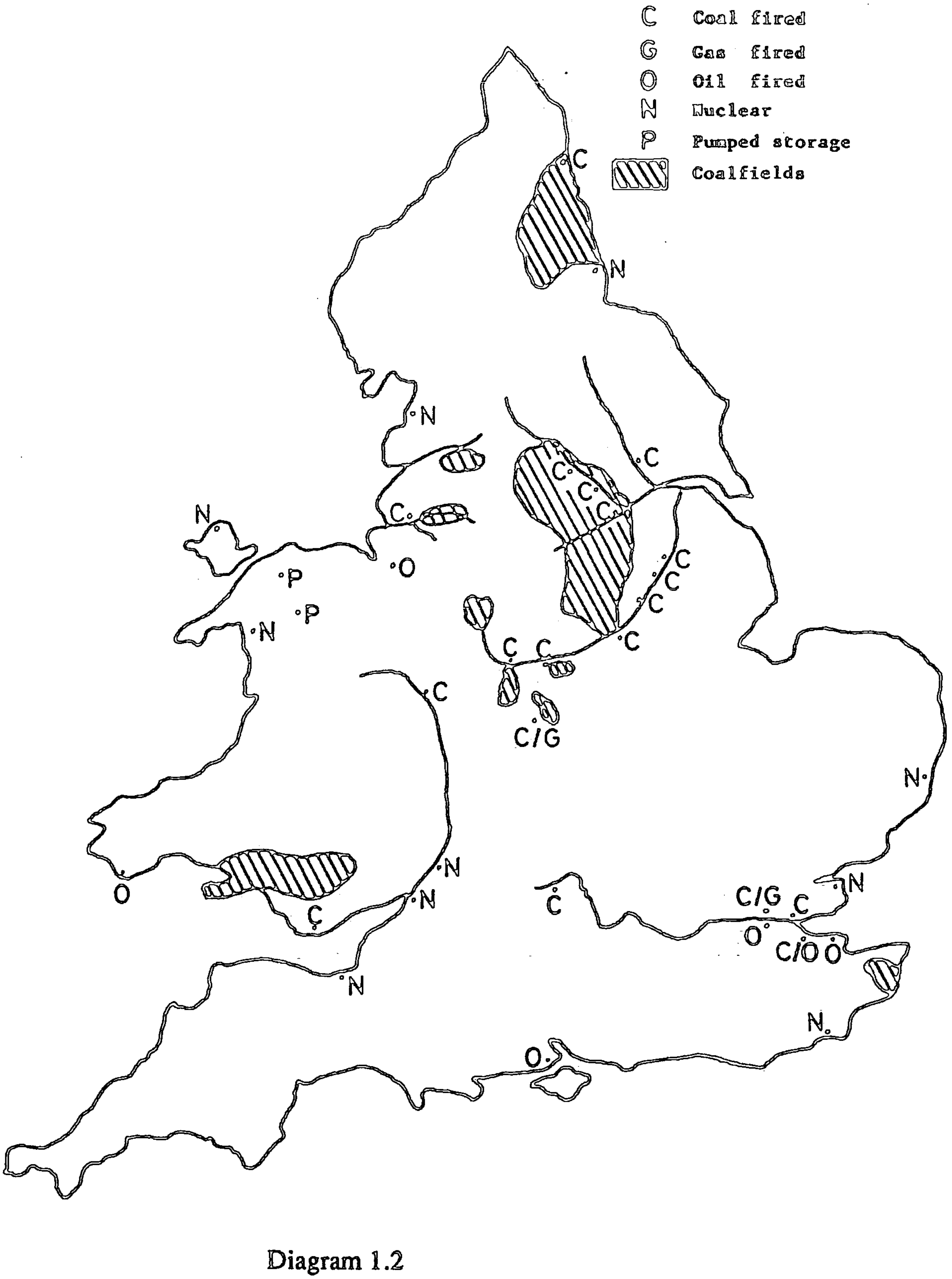


Diagram 1.2

Power Stations in the C.E.G.B. network

synchronised, and the rate of change of the output of a generator once it is synchronised. In the case of the pumped-storage schemes the volume of water available, and in the case of hydro-electric schemes, the rate of flow of the river, also have to be considered.

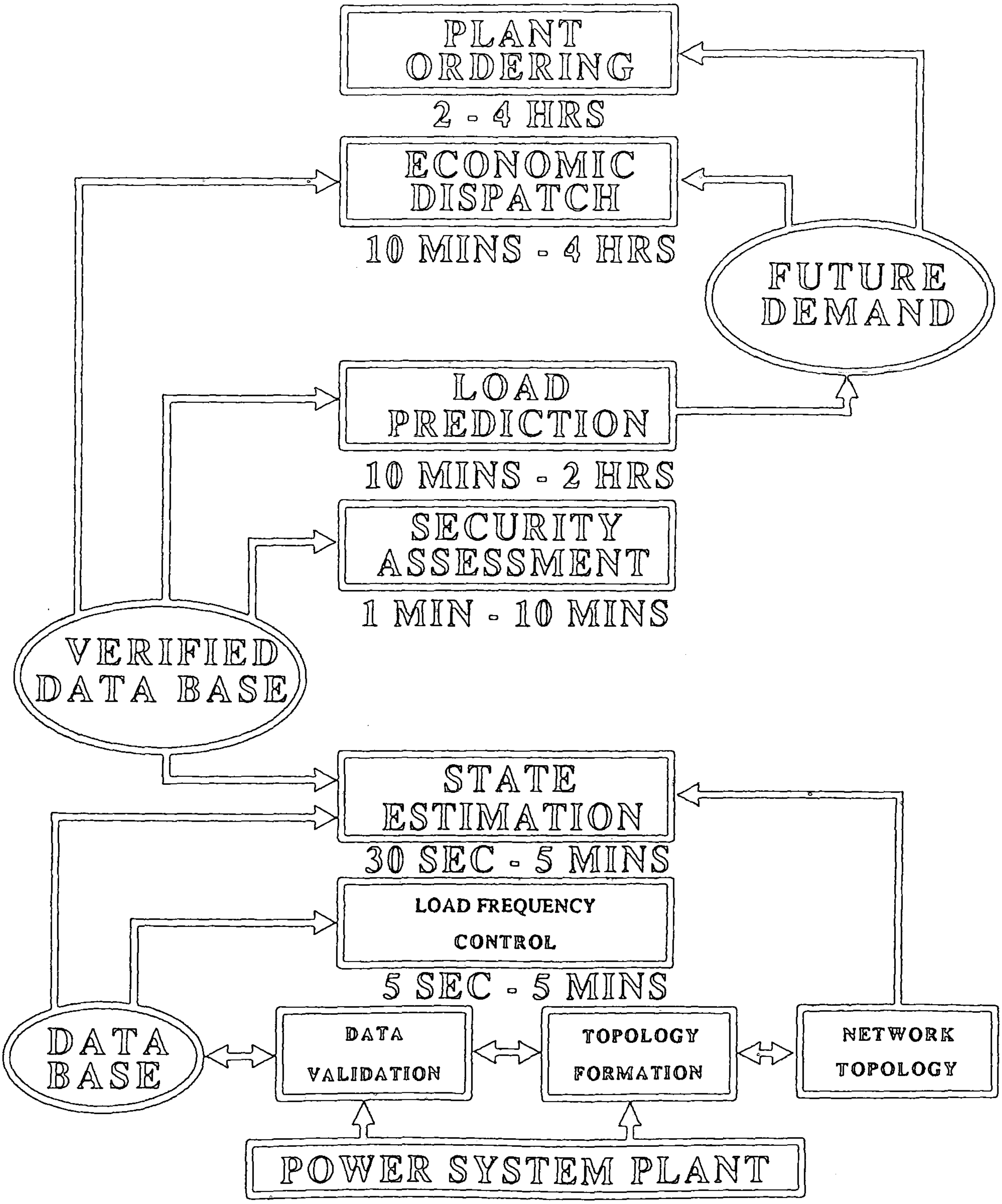
The frequency of the power system provides an easy and direct method of precisely monitoring the balance between the consumer load demand and the power being generated by the system. If the generators are not being supplied with sufficient energy to supply the load demand, then the rotational kinetic energy of the generators decreases, as the load demands more energy. This happens automatically provided the generator remains synchronised with the network. In this case the generator will start to lose kinetic energy and hence, it slows down, thus the system frequency falls. Conversely, if too much energy is being supplied to the generators, the excess energy is seen as an increase in the rotational energy of the system, and hence the system frequency increases.

The control of the power generation throughout the network is a hierarchical process, [200,201] which requires the interaction between many layers of command and will be a differing amount of interaction depending on the time scales.

Manual control will usually be much slower than automatic digital control. With the recent availability of large scale digital computers, has come the ability to implement many of the levels of control automatically, which were previously under manual control. The higher levels of control are generally manually controlled, [119,209] but the shorter time scale activities can be fully automated by on-line computer control. The time scale involved ranges from several hours to less than a second. Diagram 1.3 shows the main elements of the control hierarchy and the approximate time scales in which they operate.

The automatic control activities start with a prediction of the consumer load demand at a central control centre, and ends with closed loop controllers on the turbine-generators themselves. These regulate the amount of energy supplied to the generators in response to variations in the desired and the actual values of frequency and output power. The hierarchical levels in the control sequence

Diagram 1.3 Functional Elements for Power System Control



include control schemes, which require long and short term demand forecasts, and are constrained by economic factors. The long term ordering of which generators need to be synchronised (unit commitment), is based on the long term load forecasts The short term adjustment of the desired levels of generation (economic dispatch) is based on the short term load forecasts. The desired operating frequency is maintained by load frequency control, and finally, the continual adjustment of the local generator regulators is achieved by fast acting closed loop controllers.

The C.E.G.B. divide the unit commitment and economic dispatch problems amongst a National Control Centre and six area control centres. The National Control Centre is responsible for determining the overall operating levels throughout the network, while the area control centres are responsible for implementing the levels. Diagram 1.4 illustrates the location of the control centres of the C.E.G.B.

To supply remote consumer load a transmission system is required, linking the main generation centres to the main load centres, and then to the individual consumers. The transmission network is usually an interconnected system of high voltage transmission lines, with numerous bulk supply points from which the consumers are supplied. The system must also be able to be isolated when fault conditions occur, to allow for periodic maintenance and to maintain the security of supply. The transmission network is operated at high voltages for economic reasons. High voltages reduce the power flow losses in the transmission lines, caused by the line impedance, and also reduce the physical dimensions of the conductors required to transport a given power flow.

The transmission network of the C.E.G.B. is operated at 400 kV, and the lower voltage of 275 kV. Similar operating levels are used both in Europe and America. Trials are in progress to evaluate the use of even higher voltages but this can lead to problems with insulator breakdown. The transmission, or *supergrid* network of the C.E.G.B. consists of approximately 10,000 km of 400 kV lines and 5,000 km of 275 kV lines. Diagram 1.5 illustrates the layout of the *supergrid.*

Diagram 1.4

Area Control Centres

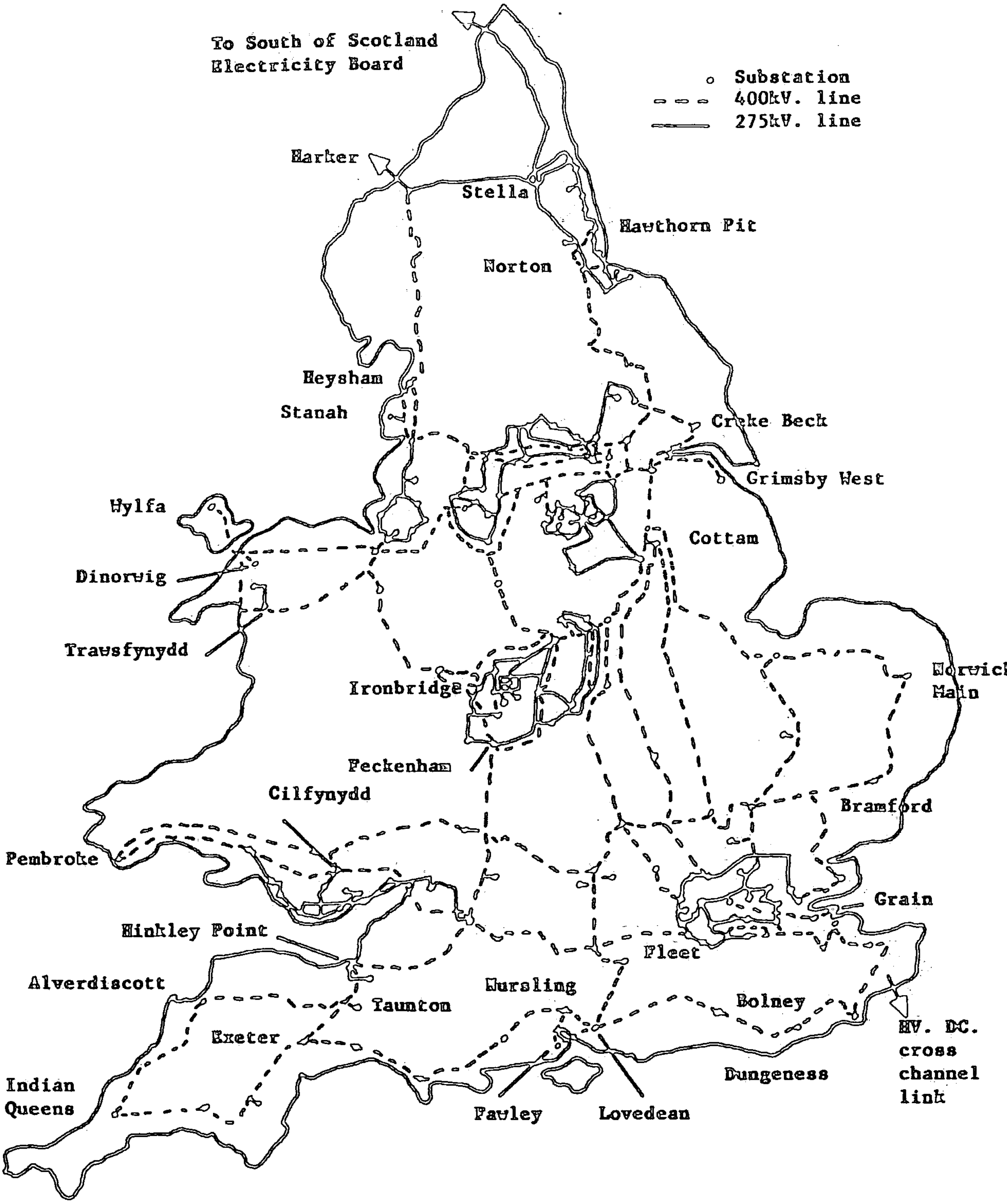


Diagram 1.5

C.E.G.B. Supergrid Network

The supergrid is principally made up from 400 kV, 3-phase, overhead lines, although some underground cables are used. The underground cables are far more expensive than the overhead ones (approximately twenty times), as they are made from copper as opposed to aluminium, and require greater insulation. The network has to be capable of supporting power flows in excess of 9,000 MW from generating stations in the North, to consumer load in the South. To assist with this large power flow, a Channel link was installed, to link Southern England with France. This link was originally a 160 MW, D.C. link, but in 1986 a larger capacity 2000 MW link was installed.

Transformers are used to couple networks of different voltage levels,and these have some form of on-load tap-changing ability in order that the voltage can be controlled. The voltage of the system has a legal requirement to be ± 6% of the rated voltage at the load and so medium voltage tap-changing transformers are used.

Very large industrial complexes are supplied directly from a bulk supply point of the supergrid network, or, alternatively, consumers can be supplied by the distribution network.

The distribution networks are usually supplied by several bulk supply points from the transmission network. The voltage level is transformed to a level of a few tens of kilovolts. The distribution network in England and Wales is maintained by 12 area boards. The boards typically operate transmission lines at 132 kV (for bulk distribution), 66 kV (for industrial users), through to 33 kV, 11 kV, and 415 V, then finally single phase 240 V for the domestic consumer. The method used to convey electricity from the power station to the consumer is shown in diagram 1.6. The design of the distribution network is essentially based on two types. A radial type of network where the lines radiate outwards from the bulk supply points, or a mesh type of network where the lines are connected to the supply points at both ends instead of just one.

The load demand created by the consumers varies enormously from day time to night time and from season to season. Such a power demand changes

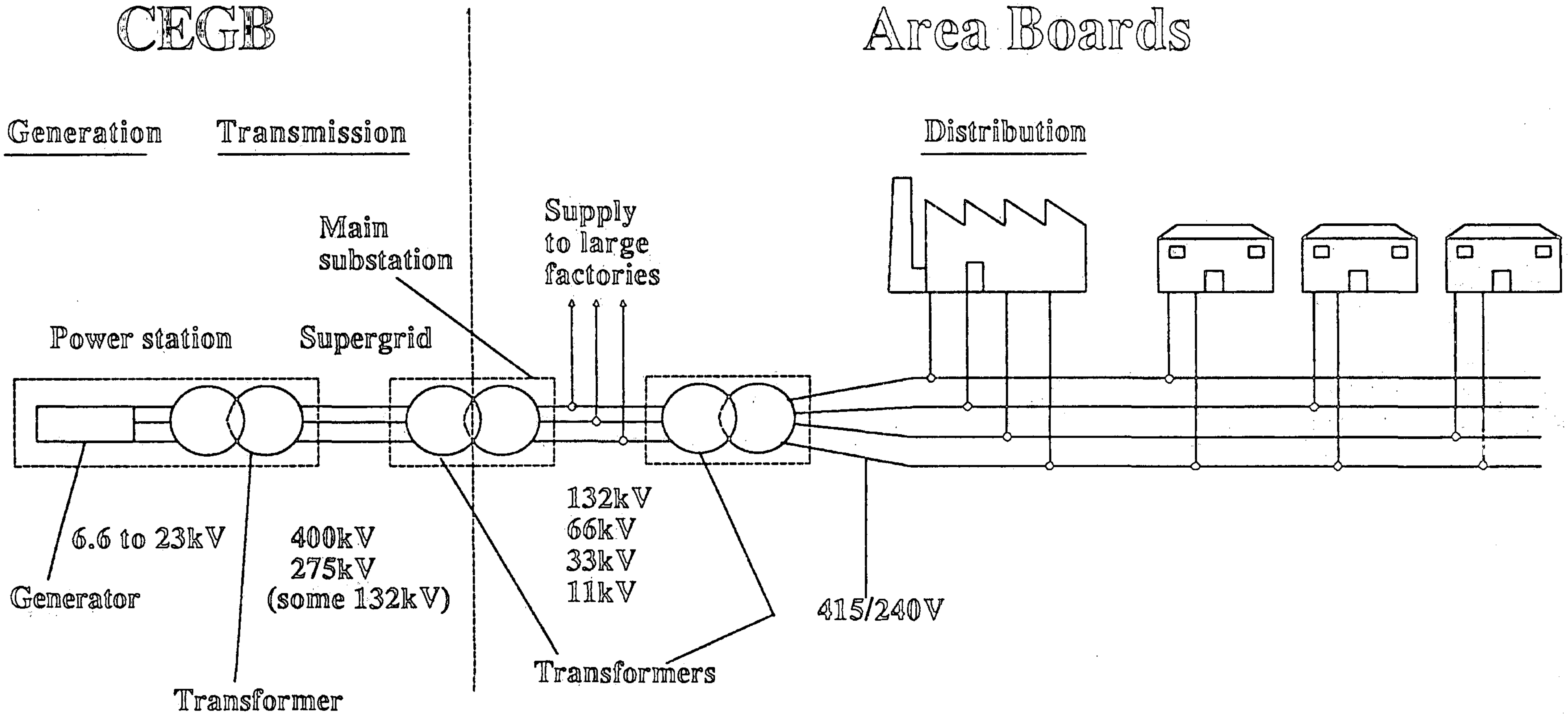


Diagram 1.6

How electricity is conveyed from the power station to the consumer.

continually due to mainly the switching of heating, lighting and motor loads. The power system must be capable of matching the demand, maintaining reliable and safe operating conditions, and keeping the customers supply voltage and frequency within statutory limits. In the U.K. these limits are ±6% variation in voltage level and ±1% variation in the frequency. Ideally the system frequency in the UK should be at 50 Hz, while in other countries the value of 60 Hz is sometimes used. Some power demand variations are cyclical in nature and can be accommodated to a certain extent by planning and scheduling. Load demand varies seasonally, in the U.K. for example the winter load is very much greater than the summer load due to heating requirements. In hot climates the reverse may be true because of the load created by air conditioning. Other cyclic variations occur on a daily basis in general peak loads occur in the morning and early morning, while the lowest loads are during the afternoon and the night. The role of forecasting the load demand is difficult task and is often a matter of judgement based upon the load demand for similar days in the past, weather forecasts and the television schedules.

A standard C.E.G.B. load curve is shown in diagram 1.7. This shows the seasonal variation of the daily load during the summer, winter and autumn. The daily curve shows the typical curve of a low night load, increasing towards a morning peak. The afternoon load flattens off, until the evening peak starts to rise. The late evening load decreases to the overnight plateau. This curve is common for all seasons, but obviously the load peaks are far higher during the winter than in the summer.

The company responsible for the operation of the power system usually has a set of guide lines specifying the operating conditions of the system. These guidelines specify the required level of operation, together with a list of tolerances which should be adhered to under normal and emergency operating conditions. The pressures on the power system operators are forever increasing as the consumers expect, and sometimes demand, a more reliable supply, local and national governing bodies require stricter control of the pollution and nature conservation, and economic pressures force the company to reduce capital expenditure and operating overheads.

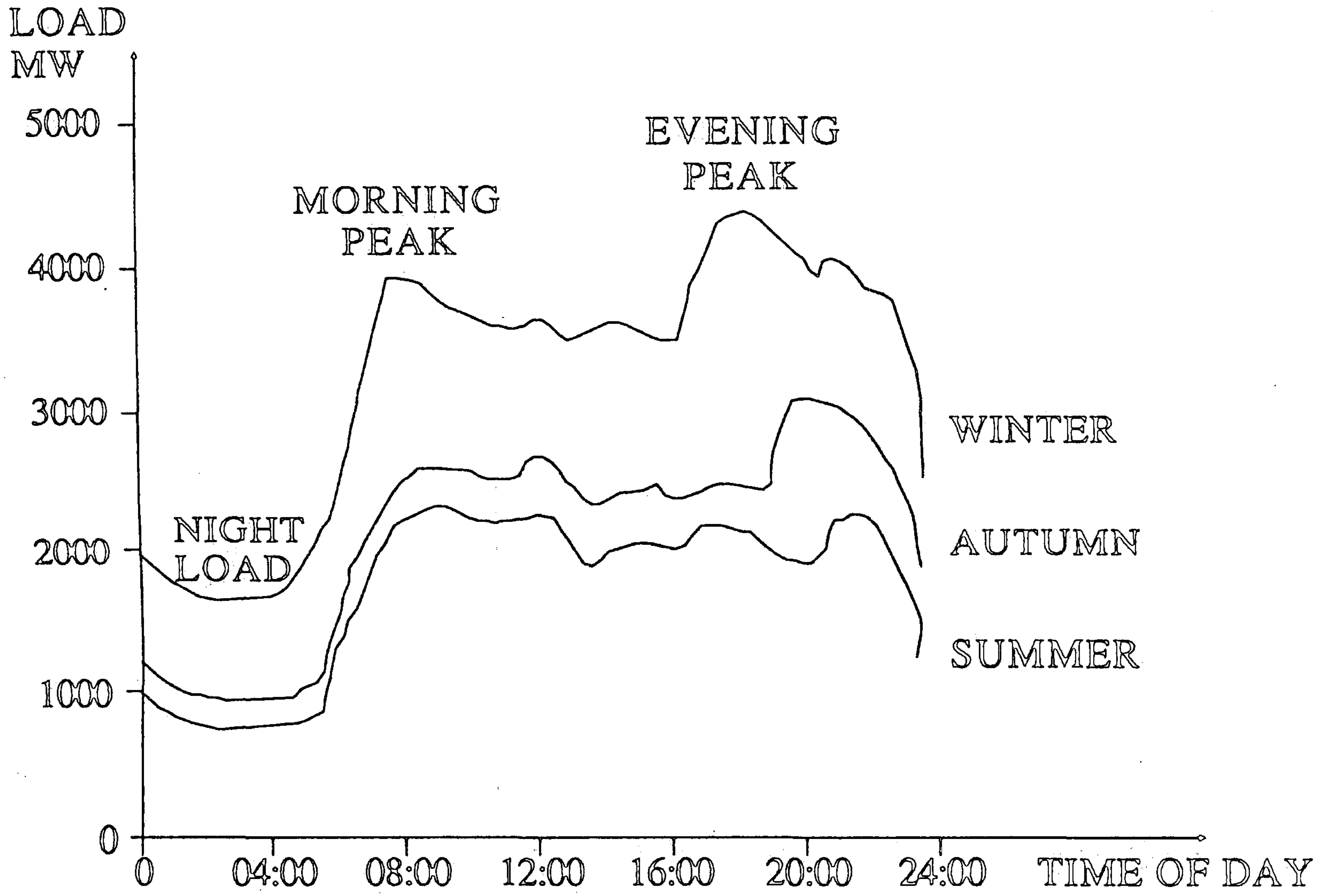


Diagram 1.7 Seasonal Variation of Daily Load Pattern

In order to be able to meet the ever more stringent operating conditions with the ever decreasing levels of equipment redundancy, the operator requires up to date and accurate information about the state of the entire system [202]. The function of supplying the operator with this information and additional information on the security of the system derived by processing the raw measurements, can be provided by on-line digital computer. The computer continuously receives measurements of voltage levels and power flows from selected points in the network. The measurements are then validated to remove those which are in error, and values are then calculated for all the unmeasured points. Additionally the computer is able to notify the operator of any alarms which already exist and perform calculations to advise the operator if an emergency condition would arise from the loss of any single piece of equipment. The computer may also perform calculations to determine the generator output levels required to satisfy the current load in the most economic way.

The installation and development of a computerised control centre is economically justified by the company: by reduction of the capital expenditure, which would otherwise be required to provide the additional equipment needed to maintain a secure supply if such detailed knowledge of the state of the system were not available, by the reduction of manning levels required to operate the system, and by the reduction in fuel costs gained by operating the system more efficiently.

The use of computers in the control of electrical power systems is a rapidly growing area. Energy management systems provide automatic control for the whole, or part of the system, and can be used to great effect by utilities.

The C.E.G.B. use some computer control and prediction to assist in load forecasting. Their objective is to respond to, and anticipate, changes in consumer load demand over all parts of the system, which ensures that it continues to operate economically, securely and safely. To meet the changes, the C.E.G.B. needs to predict continuously, and as accurately as possible, levels of demand over the next 24 hours. They use demand forecasts based on the analysis of past weather observations, past levels of load demand and special occasions. When these are all combined in a computer program, with the latest information about the performance of generating and transmission plant, a generator schedule is produced for the period in question. A small reserve is kept to protect against forecast errors and failures, but this can be kept to a minimum with good accurate prediction.

This thesis is concerned with the control of the active power of the generators which in turn controls the system frequency. This function is termed Load Frequency Control (L.F.C.) or sometimes Automatic Generation Control (A.G.C.). This thesis investigates the methods of system frequency control that have been used in the past by various utilities around the world. Many of these controllers use the idea of a fixed control scheme, which does not enable optimum control action to be taken under all system conditions. One such fixed parameter control scheme is considered and implemented on a real-time power system simulation.

This thesis also investigates the use of adaptive control techniques, which can be used to track a system under study. The controller proposed is able to track the system operating point and use this to calculate optimum control signals. Various problems associated with adaptive control techniques are considered and some solutions are proposed.

The application of the controller is presented operating in several different systems. The first test system was a simulated 30 node network, operating with full Energy Management Software, the second was a multiple area system derived from the 30 node test network. The controller is also presented operating with a C.E.G.B. simulation and compared with the present manual solution. A section of work is presented using the controller operating along side the real C.E.G.B. system using actual system data.

It must be remembered that for a system to make full use of the optimised dispatching of generators a method of control of the generator-turbines is needed. In fact, the control of generator units was the first problem faced by the early power engineers, when designing systems. The methods developed for the control of individual generators and eventually control of large interconnected power systems play a vital role in modern energy control centres. Previous L.F.C. functions have not considered the practical questions of controller interaction with other software used for system management. This thesis investigates the various quantities required by the control scheme and methods of collecting them and verifying them from the system in question. The links between the Dispatching and Unit Commitment functions are investigated and recommendations made for the type of interaction required.

The following section describes in more detail the contents of the thesis.

Chapter 2 introduces the ideas involved in the computer control of large scale power systems. It discusses the various control functions that are required and their relative time scales. The interaction of the various control functions is considered along with their hierarchical relationship with each other. The use of the system frequency as a measure of the imbalance between the system generation and consumer load is introduced and the control of the generator units active power is explained to redress the state of imbalance. The generators are controlled using a Load Frequency Control scheme, which relies on the calculation of an error signal based on the system conditions at any given time. The chapter describes power system variables that are required to be measured and those which are to be minimised. There is a brief discussion of the extensions to the basic algorithm, such as the control of tie–lines and the minimisation of the time error of the system. The inherent problem using the fixed term controllers as described is that any changes in the system are not catered for by the controller. This thesis presents ways in which the controller can track the system it is controlling, and change its control action accordingly.

Chapter 3 explains the use of system modelling as a tool that can be used by the controller. The ideas presented in this chapter can be used to create a mathematical model of the system by collecting the system inputs and outputs. The system under study may be totally unknown or contain unmodelled dynamics. The system modelling enables the systems dynamic behaviour to be accurately modelled. Once the system behaviour has been estimated, the model can be used to predict the future behaviour of the plant. The use of parameter identification is used to form a suitable model for control action to be based upon. The model itself is formed using linear least square estimation which is suitable for a one off estimation for a stationary system. However, power systems are non–stationary, so the method may be expanded to continuously track the system behaviour. This repeated estimation is termed recursive estimation. An improvement of this method is discussed by the addition of forgetting factors which enable the system status to be tracked regardless of the rate at which it is changing.

Chapter 4 follows on from chapter 3 by considering the use of control strategies which can be used in conjunction with the system modelling from the previous chapter. With an updated system model, control actions can be calculated to reduce the system error to zero at a future time step. A control scheme is proposed in this chapter which is designed to minimise the error term at a given time in the future operation of the plant. This control algorithm is termed minimum variance control as it aims to minimise the variance of the system error at the future time interval. Several differing versions of the basic control scheme are discussed, including an expansion to the specific controller to the generalised case. The minimum variance control scheme and the system model estimation may be combined to form what is termed a Self–tuning Regulator. This full control scheme is discussed in a later chapter, with full application details.

Chapter 5 is divided into two separate sections. The first section describes the Real Time Power System Simulator of the University of Durham. The second section describes the application of Load Frequency Control applied to the simulation. The O.C.E.P.S. (Operational Control of Electrical Power Systems) simulator is used for the development of a fully integrated Energy Management System. The frequency controller is developed and tested within the confines of the simulation package. The controller in this earlier case is a standard fixed parameter scheme described in an earlier chapter. This enabled the the subject of frequency control to be reviewed and the interactions between other control functions in the Energy Management Package to be investigated. Results using the developed controller operating under differing system conditions are presented, along with the effect of changing the controllers fixed parameters.

Chapter 6 describes the application of the adaptive control theory from the previous chapters to the application of the frequency control problem. A general discussion of self–tuning regulators is used to establish a proposed L.F.C. strategy. A full adaptive L.F.C. scheme was implemented on the O.C.E.P.S. simulation and results are presented for varying system gains and differing operating conditions. Various methods are considered to improve the numerical stability of the control routine and its control action. The use of different order system models is investigated and the time period of the model. Sample period and control action period are considered and a suitable compromise is made between continuous control of the generators and undue operation. The ability for the self–tuner to track its own performance is considered. This enables consideration to be taken of the *goodness* of the control action, and use of controller *jacketing* is made to guard against controller instability. The problems of controller *blow* up is considered if the system is not sufficiently exciting. The last section of the chapter looks at the different control modes that are available within the frequency controller and the effect that these have on the rest of the system and the generator responses.

Chapter 7 describes the use of the self–tuning regulator applied to a multiple area power system. This test system comprised of the O.C.E.P.S. simulation reconfigured as a two area system. The chapter reviews some of the reasons why electrical power utilities often interconnect their system to a neighbouring system and discusses its advantages and disadvantages. There is a modification proposed for the standard single area frequency controller which enables it to operate fully in this multiple area environment. The use of the inter–area power flows on the tie–lines against the scheduled power interchange is made use of to form the control area error. The self–tuning regulator is required to weight the frequency error and the tie–line error against each other and a variable weighting system is proposed. The latter part of the chapter describes the application of the controller to the test network during different system loadings and operating conditions.

Chapter 8 describes a section of work that was carried out in conjunction with the C.E.G.B. using a simplified system model. The proposed model is designed to model the whole of the C.E.G.B. transmission and generation system. The model was used as a reduced order simulator which could produce satisfactory results of several hours operation in a short time period enabling the effect of control action taken on the system to be seen readily. A simulation of the manual control action used by the C.E.G.B. to control the actual network was designed. This manual control action is compared to that of the automatic control action calculated by the implementation of the adaptive L.F.C. scheme. The results of several simulation runs to compare the manual action with that of the automatic scheme are presented. An investigation into the controller action, number of parameters, changes in consumer load, system constraints and sampling interval are all presented.

Chapter 9 is again concerned with work carried out under the guidance of the C.E.G.B. This chapter describes some work which was carried out in conjunction with the C.E.G.B. Dispatch Project. The aim of the work was to investigate the problems associated with the implementation of a L.F.C. scheme with the existing Dispatching capabilities used by the C.E.G.B. A simulation of the C.E.G.B. system was proposed to be used as a way of closing the control loop for the trials. The trials consisted of using actual system data in conjunction with the control packages developed by C.E.R.L. and the proposed adaptive L.F.C. scheme. Results are presented of the initial testing of the simulation leading to results gained from using on–line system data. The ability to close the loop of the control scheme between the Dispatcher and the L.F.C. is presented during some actual system runs. The requirements for the interaction between the various control levels of such a scheme are considered and are presented in the results section.

This thesis presents several distinct sections of work. A general review of the requirements of L.F.C. is carried out with reference to a fixed parameter type control scheme. Later, the main aim of the thesis, an investigation into adaptive control methods, applied to L.F.C. schemes is presented. With the use of system identification and a review of suitable control methods, a control scheme is developed. The implementation of these methods into an L.F.C. scheme is discussed and results are shown from several different types of system. The ability of the self–tuning regulator to change as the system configuration alters is shown to achieve an optimal control strategy. The results from the operation of such a controller are presented showing the controller is able to operate not only in realistic simulations but also alongside a real system.

CHAPTER TWO

INTRODUCTION TO LOAD FREQUENCY CONTROL

2.1 Introduction

This chapter briefly describes electrical power system networks and their use in transferring electrical energy from its source of generation to the centres of consumer load. The requirement for the control of the system frequency is discussed and a short review is given of the early techniques which were used for the control of the system frequency. The most widely used technique is that of the proportional plus integral control scheme which is described in some detail. These techniques are termed as Load Frequency Control (L.F.C.) or, if used with a full Energy Management system, Automatic Generation Control (A.G.C.).

The use of L.F.C. is required by many utilities to match exactly the power provided by all sources of generation to that demanded by the consumer load. As the electrical energy required to maintain supply to the whole of a grid system is large and there is no easy means by which this energy can be stored, the pattern of generation must follow closely the pattern of consumer load. The L.F.C. function is designed to carry out the short term reallocation of power to keep the system frequency error within a set of predescribed limits. The task of L.F.C. can also include the control of the power flows on transmission lines to neighbouring utilities, such lines are termed tie-lines, and thus the control is termed tie-line control. This enables a system which has a large number of interconnections to honour the agreements which its has with neighbouring utilities without incurring any economic penalties. A review [102,163,207,209] of these general power system ideas may be seen in many publications.

2.2 The Generation of Electricity

An electrical power system [147,215,222] may be thought as a mechanism for transporting energy from one location to another. The energy conversion takes place at the generation station. This is generally thermal energy converted to electrical energy which is then transmitted, via the transmission and distribution network to the centres of consumer load. A diagrammatic representation of this process is shown in diagram 2.1. This process is such that there is only a small amount of energy stored in the system as a whole, compared to that of the total system output. The storage of the energy in the system is stored as steam in the boilers, the inertia of the rotating machines, the electromagnetic energy stored in the transmission lines and perhaps the load itself.

A turbine-generator has a large mass of up to 200 tonnes, which rotates at a typical speed of 3000 rpm. The machine itself has large inertia and can store a significant amount of energy, although this is small compared with the system as a whole. A typical turbine-generator has an inertia constant, H, of approximately four seconds. This means that if all the rotating energy was converted into equivalent generator power output, then the machine would rotate for about four seconds.

The electrical energy stored in the transmission network is stored as electromagnetic energy in the lines themselves. Generally most transmission lines are relatively short and hence their energy storage capacity is low. However this storage element may become significant where the system is weakly interconnected by long transmission lines.

The consumer load will also have some energy storage capacity in the fact that some of the load is made up of rotating machines, which have their own associated inertia.

2.3 System Frequency

The system frequency is a very good indication of the balance between

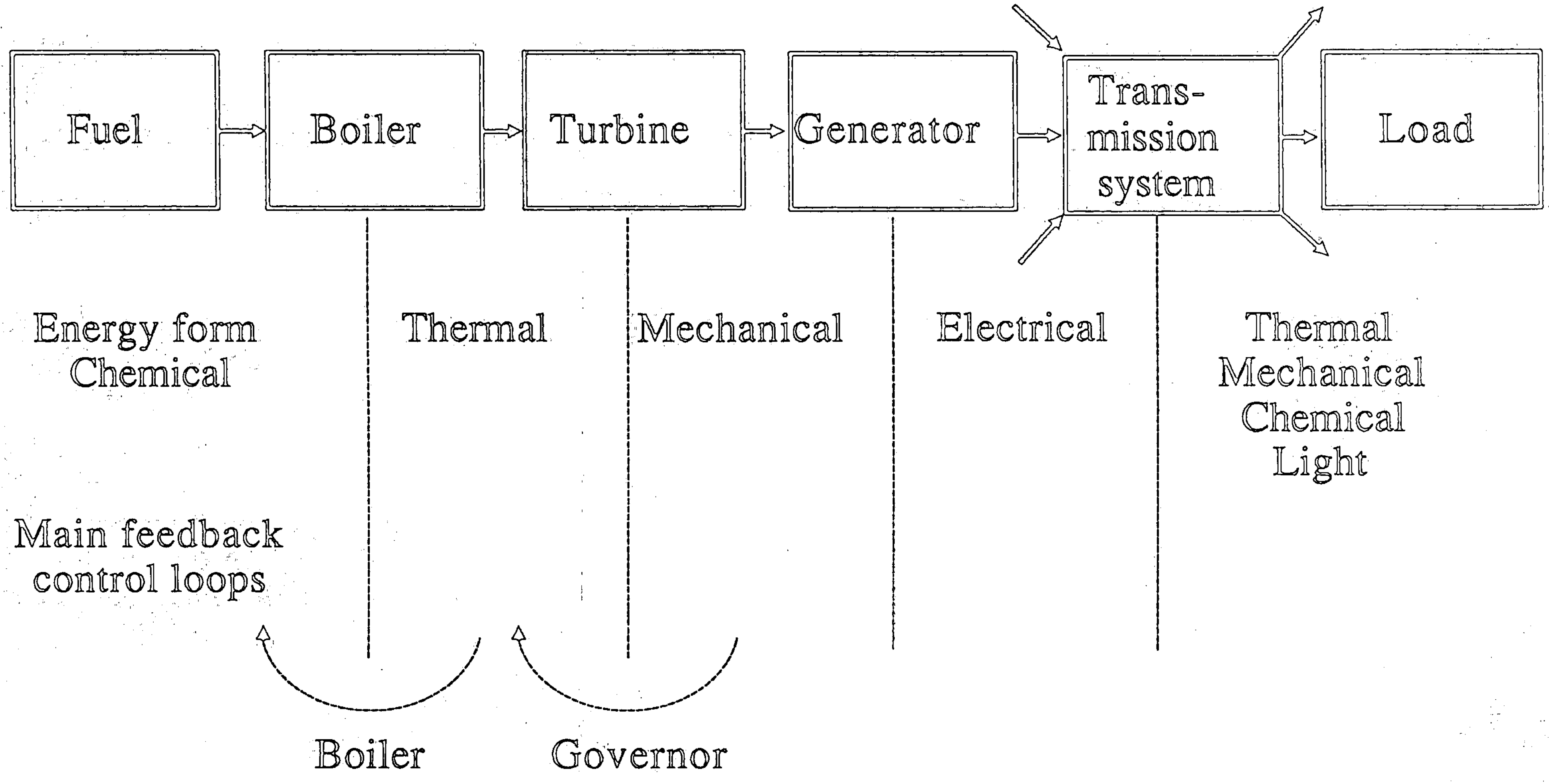


Diagram 2.1 Active-power flow diagram for thermal power generation

consumer load and the system generation [29]. The energy injected into the system must be equal to that demanded by the consumer load otherwise a state of imbalance will occur. If there is an imbalance between the power taken by the load and that generated by the system, then the excess energy must appear elsewhere, it can only go to increase the stored energy of the system. This will result in an increase in the speed of the rotation of the turbine-generators and hence the system frequency will rise. The link between the mechanical energy input to the generator and the electrical energy produced by the generator is shown in diagram 2.2. This is shown by the well known equation, relating the difference between the generated and demanded power, the system inertia and the rate of change of the frequency.

$$\frac{d}{dt}(f) = \frac{1}{K}(\Delta P - \Delta P_G)$$

If the imbalance of power was to continue, then the system frequency would continue to increase as the increasing energy causes the turbine-generators to increase in speed. This in theory could go on indefinitely, if there were no control loops involved in the system (or at least until the protection operated). However this behaviour is not so dominant in practice as many loads are frequency sensitive, and as the frequency increases, so does the amount of power demanded by the load. Also an increase in the voltage will produce an increase in the power demanded by the load.

Different types of load respond in different ways to a change in system frequency and voltage. The common example of a purely resistive load, for example, an electric heater, is unaffected by a change in frequency, but increases as the square of the voltage. A motor load such as a fan will increase load with both system voltage and frequency. It has been found (CEGB) [29] that in general a 1% increase in the system frequency will produce a 1% to 2% increase in load. The system load is made up from a wide range of consumer loads and hence if an imbalance between generated power and that demanded by the consumer load occurs, a frequency drift, away from its nominal value will occur.

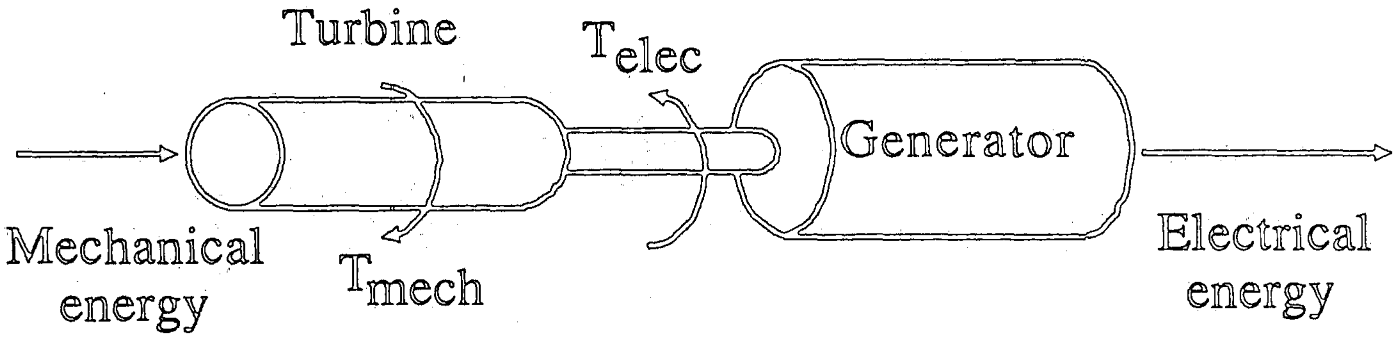


Diagram 2.2 Mechanical and electrical torques in a generating unit

2.4 Turbine Governors

The change in system frequency must be controlled in some way, so a local control loop is fitted to many tubine-generators. The control loop monitors the speed of rotation of the machine and controls it as required, such equipment is termed *speed controllers* or *governors* [69,72,74,211]. These devices constantly monitor the speed of rotation of the turbine against that of its set value. The error signal created from the set point and the actual operating point of the unit can be used as a driving error to alter the governor valve position and hence control the turbine speed. The *droop* is the percentage speed (or frequency) change which results in 100% change in power output of the set. A typical *droop* setting for a turbine generator set is 4%, which implies that if the grid frequency falls by 0.2% due to a system load change, then the power output of the set would be increased by 5% (that is 100/4× 0.2%). Another way of considering this is that an increase of 4% in the rotational speed of a turbine will alter the governor value from the fully closed position to the fully open position. The C.E.G.B. use a typical governor loop setting of twenty–five, or 4% on the majority of their thermal units.

The operation of the governor valve in response to a fall in frequency can only have a short term effect. The additional steam flow which comes from the boiler in response to the change in governor position will decrease over a period of approximately five minutes. The pressure of the steam in the boiler decreases and hence the turbine output will also decrease. The rate of firing of the boiler has to be increased in order to maintain the steam pressure.

2.5 Generation Loss

The rapid loss of a turbine-generator from the system will result in a frequency transient [154]. The typical response is that the frequency falls very suddenly directly after the loss incident. This is due to the rapid decrease in the angular momentum of the system which has been dissipated by the consumer load. The frequency decrease causes the governor valves to open resulting in an increase in the amount of steam flow into the boiler. This will initially increase the power output of the turbine-generator. However, after typically five minutes the stored steam will have been used up, its pressure drops and hence the turbine will begin to slow down. If the lost capacity is relatively small the power loss will almost be restored, but the new frequency will settle out at a value lower than the value before the incident but generally the frequency will continue to decrease. At this point, corrective control action is required to increase the firing rate of the boiler or to take up the generation deficiency using the spare capacity of other plant. This control action may be manual intervention (as in the case of the C.E.G.B.) or if the system is operated using automatic controllers, the L.F.C. will take corrective action. In the long term other generation plant on the system may be required to be synchronised, but this is the task of a longer range control function.

Some turbine-generators are used in a mode, in which the firing is automatically altered by the changes in the turbine output. This mode of operation is termed boiler-follows-turbine. Plant which is unable to respond due to the operation constraints placed on it, such as some fossil fuelled plant and nuclear plant may not have automatic adjustment of the boiler output and the turbine output is fixed by the boiler capacity. The governing of this type of plant must be restored eventually to match the output of the boiler, however it may respond initially to frequency deviations. This mode of operation is termed turbine-follows-boiler.

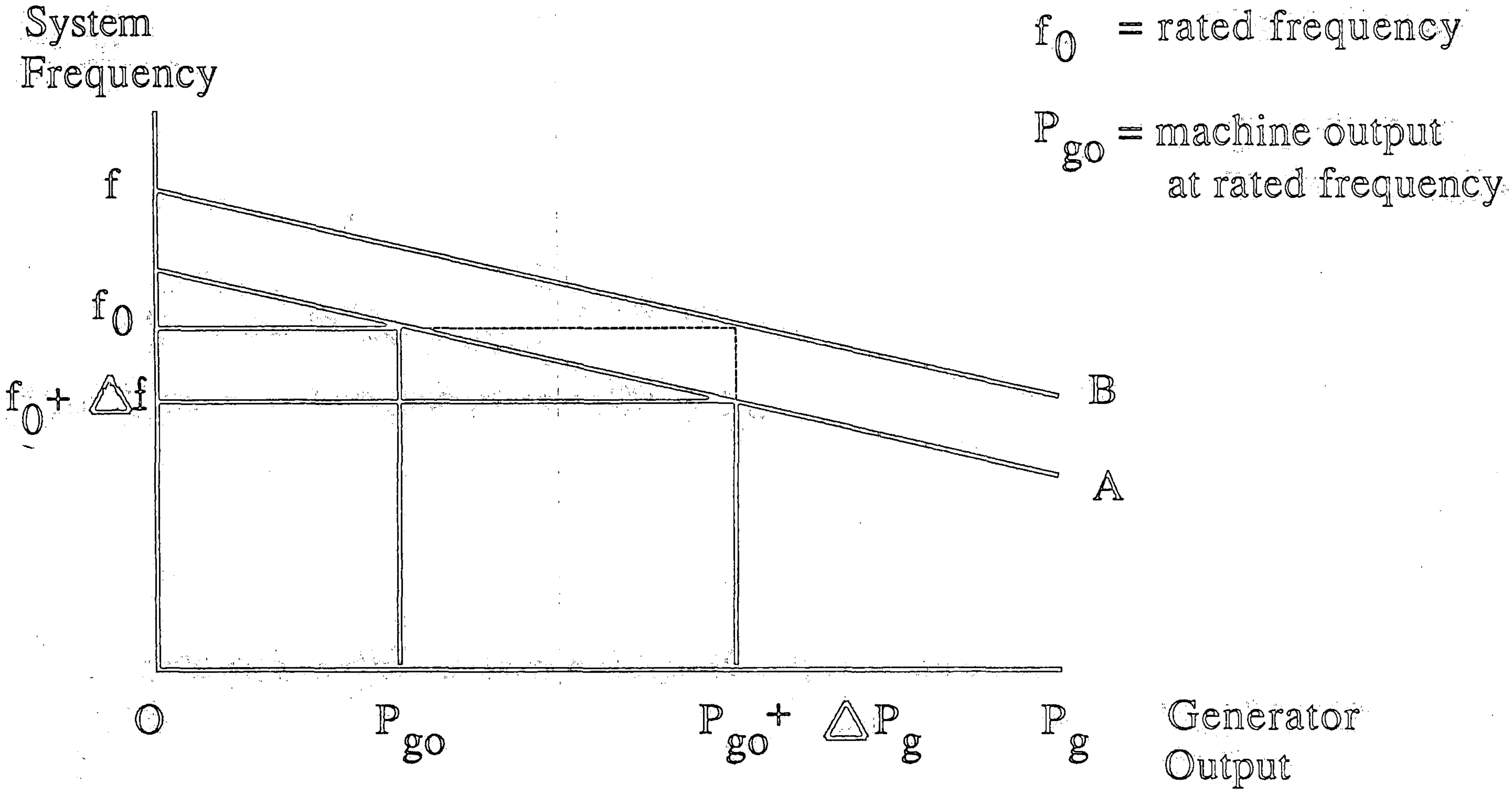
2.6 Real and Reactive Power Control

The primary function of an electric power system is to provide the real and reactive powers demanded by the various loads which make up the system. The power supplied must be continuous and also meet certain minimum requirements regarding the quality of supply such as, constant frequency, constant voltage, and a high reliability. The power in a power system may be represented as a complex quantity but any change in the generator mechanical output will have an affect generally only the system frequency, whereas changes in the excitation will affect generally only the system voltage. Thus it is fairly straight forward to divide the control of a power system into two separate sections; the megawatt frequency control and the megavar voltage control. The control of the real power generator output, in response to the changing system frequency and tie-line transfer, to maintain scheduled system frequency and tie-line interchange is termed Load Frequency Control. The control of the reactive power balance in the system is treated separately and concerns the control of the excitation of the generator units. See diagram 2.3 for details of governor characteristics. The power allocated to each generator in the system is calculated based on data from load prediction calculations [200] which is associated with the Dispatch calculation, which in turn is linked to the L.F.C.

2.7 The Frequency Control Problem

The early attempts to control frequency were by using flywheel governors on the synchronous machines, but this was found to be ineffective for large scale power systems and entirely unsuitable for interconnected systems. The suggestion of a secondary control to be added to the governor led to the ability to control the system frequency. To correct for the changes in the area frequency with changing load, the area can be brought back to the nominal frequency with the use of supplementary control action. The control criterion in a L.F.C. strategy is to; minimise the area control error, inadvertent power interchange, and the time deviation using the minimum of supplementary control. There have been two main approaches to the problem, the classical approach and the optimal approach. The classical control scheme used for this purpose was the standard proportional plus integral (P+I), type algorithm [39,65,66,80,165,167].

A common feature of both approaches is the linearisation of the models under study. The classical approach determines the optimum integrator gain for the area control errors and the frequency bias settings. General this may lead to relatively large overshoots and transient frequency deviations. Also the settling time of the system frequency deviation is relatively long, of the order of 10–20 seconds. The modern state-space approach determines [1,44,90,104,128,175,205,207] an optimal controller using linear optimal control theory. The parameters calculated by the optimal controller are strongly dependent on the coefficients of the quadratic performance index. The main problem with the linear optimal



A - basic machine characteristic
B - modified machine characteristic by alteration of set point to restore rated frequency

Diagram 2.3 Generator Governor Characteristics control approach is the fact that no practical guide lines exist on the selection of the coefficients of the performance index.

The load Frequency Control problem of an interconnected power system is a well defined problem. The system is divided into groups of generators which are interconnected by tie-lines. Each group of generators is called an area, and each area must be able to meet its own load changes and any import or export targets set by the controllers in advance. Each area has its own response characteristics which relate the area frequency and total generation for load changes on the specific area. This curve is the regulation curve of an area and represents the area gain (in MW/Hz). The area gain or regulation is a direct measure of the effects of all the governors on the prime movers within the area, and plays an important part in the steady-state and dynamic performance of the system.

The normal procedure used in the design of L.F.C. functions is to construct a linear system model with fixed parameters. This is obtained by linearising the system around an operating point, however, this approach is not strictly correct as the system response characteristics tend to be non-linear. Power system parameters, are a function of the operating point. Hence, as the operating conditions change, the calculated operating point will no longer be optimal. To keep the system performance near to optimum, a way of tracking the operating conditions of the system is required which will enable the continuous updating of the system parameters. The control signal can then be computed based on an optimal approach using the newly updated parameters.

Load changes in the system are random in magnitude and time. To control the transient response effectively and to take into account the sensitivity problem of L.F.C. in interconnected power systems the use of self-tuning controllers is considered. It seems more appropriate to consider the system as a stochastic system and to improve control performance, design an adaptive stochastic controller than the fixed schemes used previously [8,11,12,14].

2.8 Generator Dynamics

The system frequency as stated earlier is a measure of the imbalance of the system [200]. This system error may be used as an input for a control function which will attempt to reduce the imbalance of the system. So that the system frequency may be controlled, the real power output of the turbine-generators must be continually adjusted to match the consumer load [29,30,41,134,186]. For synchronous machines the real power generated depends on the torque produced by the prime mover. This in turn is dependent on the steam input to the main control valve for the steam turbine, or the water valve of a pump storage scheme. This consists of several involved thermo–dynamic interactions, which mean that there are many factors which effect the dynamic response of the of the steam turbine-generator unit. These factors are: the lag due to the steam between the inlet valves and the first stage of the turbine, and the lag in power output changes of the high and low pressure sections of the turbine. The last lag is mainly due to the storage action of the reheater.

During steady state operation, the mechanical torque produced by the turbine must balance the electrical torque imposed on the generator by the consumer load. The steady-state load frequency response of the system is given by the change of power for a given change in system frequency. This is known as the stiffness, regulating coefficient, or gain of the system. The smaller the change in the system frequency for a given load change, the stiffer the system. The power-frequency characteristic of a particular system is can be approximated to a straight line of slope K, where K is a constant ($\mathrm{PU_{MW}}/\mathrm{PU_{Hz}}$ or MW/Hz) depending on the governor and load characteristics. If there is a sudden increase in the system load ΔP_l, then there will be a change in generation of ΔP_g from the governor action. This results in an imbalance in the power system given by

$$\Delta P = \Delta P_l - \Delta P_g$$

The gain of the system K is given by

$$K = \frac{\Delta P_l}{\Delta f} - \frac{\Delta P_g}{\Delta f}$$

where $\frac{\Delta P_l}{\Delta f}$

represents the effect of the frequency characteristics of the load. ΔP_g is proportional to $(P_c - P_g)$, where P_c is the generation capacity connected to the network and P_g the total generator output. When there is a return to steady-state operating conditions, the load P_l is equal to the generated power P_g, neglecting system losses. Hence

$$K = K_c P_c - K_l P_l$$

where K_c and K_l are the coefficients relating to the turbines and the load respectively.

The K can be determined experimentally by a change in the system loading. For the C.E.G.B. system test have shown that the value of K lies between 2000 and 5500 MW/Hz [69,200,210]. With systems that have large values of K the same frequency control can be achieved by manual control if the necessary types of generation capacity are available (such as pumped storage). However, for systems that have smaller values of K, less than 2000 MW/Hz for example, these require continuous control action to be taken to keep the frequency within the pre–defined limits. The frequency error associated with a given load loss or gain is hence larger. If any inter-area power transfer is to be achieved between interconnected power systems, the two independent areas require local frequency and tie-line power controllers to ensure that the transfers are met, in addition to the local area frequency control.

Normally the electrical connections within a single control area of a multi-area system are strong compared to those which form tie-lines to the neighbouring areas. Each area can then be seen as a single frequency and all generators within the area will change load angle together. However, in practice every bus voltage will vary its load angle at a different rate or frequency, but if the interconnections do not introduce any significant load angle changes between nodes, the approximation is valid.

2.9 Control Objectives

The main objectives of the Automatic Generation Control (A.G.C.) [200] function are

(a) To match the generated power to the load demanded by the consumer

(b) Adjust the system frequency to the reference set frequency

(c) Control the power export to other areas in the interconnected case to keep to scheduled interchange agreements

(d) To control each individual area to share the generation in the most economic way.

The first three objectives are under the control of the L.F.C. and the last involves the use of economic dispatch. The system dynamics must be considered and the complete regulator built up from this start position.

Generally there have been two main types of solutions proposed to the problem of L.F.C., the more conventional solutions which have been used in practice for many years and the more modern ones have only been proposed without any practical implementations.

As mentioned earlier the conventional controllers use the well known and understood proportional plus integral type control schemes. These are based on the theory associated with servomechanisms which was developed in the 1950's. These schemes use what is normally termed unconstrained economic dispatch, that is the control is permitted to carry out any control action it deems necessary without any regard to the economics of this control action.

2.10 Definition of Good Control

The future developments for A.G.C. are based on the definition of how a good L.F.C. function and economic dispatch are capable of acting. This definition is not a well defined quantity, but there are several properties which must be regarded as necessary for the completion of a good frequency controller.

(1) It must be robust in its interaction with other control functions and numerically stable,

it must avoid data complexity,

it must be dencentralised on an area basis.

(2) It must take the system constraints into account, and place extra emphasis on,

system security,

power rate limits and daily dynamic constraints.

(3) It must be able to show some economic improvement in operation,

seen directly through a suitable interface with economic dispatch,

seen indirectly by the reduction of the spinning reserve and regulation plant margins.

(4) It must be able to cope with system transients,

by having large stability margins,

by issuing smooth control commands which improves the economy

by decreasing the wear and tear on the generation units,

the interface between L.F.C. and E.D. must be correctly solved.

2.11 Early Load Frequency Control

The L.F.C. problem has been a major area for research and investigation for both Power System Engineers and academics for several years [22,66,200,210,216,223]. However, many of the proposed solutions have relied on poor modelling and simulation techniques along with reduced order system models leading to uncharacteristic responses of the plant. The control problem has become more significant as the size of the systems has grown and the greater extent to which systems have become interconnected. The growth in such systems has required larger and more powerful computers to both monitor and in many cases control the system as a whole.

2.11.1 Centralised L.F.C.

Much of the early research started using the classical control theory approach [36,39,66,80,165,167] but further research continued due to this relatively simplistic approach in using simple modelling techniques and only two interconnected areas [36,80,185,201] . Many investigations used models which represented nonreheated steam plants and did not represent any nonlinearities such as generator rate constraints, limitations on generator output, or the difference between regulating and non-regulating plant. Some of the ideas used involved the use of large central controllers with system variables being sent to the main control from many out laying stations. This was somewhat impractical due to the large amounts of data which need processing and the in some cases the use of system variables which were not readily measurable.

2.11.2 Non-centralised control

The problems associated with centralised control schemes lead to the investigation of decentralised control of large dynamic systems [28,177,200]. Many of these such solutions were heuristic in design but were successful and worked well in practice. The emphasis of the control schemes became involved not only with the frequency deviation but also with the interaction with other control functions. These control functions tended to be the longer time scale operations to enhance the systems economic operation and security of operation.

2.12 Quality of control action

The question of the quality of control has not been well defined but was covered by Bose and Atiyyah [28]. The quality of system frequency control depends on the quality of service that the utility is expected or required to provide for its customers. This quality of service is most clearly seen in the effect that it has on electric clocks, which will deviate from the actual time if the supply frequency deviates from the actual frequency. To keep the frequency error at zero would be clearly almost impossible, but a zero average time error over a 24 hour period may be acceptable. The quality of control must also take into account the maximum and minimum frequency bounds that a utility would require to stay within, whether it be a legally enforced limit or one defined by the utility.

2.13 Operation Modes

The L.F.C. schemes were originally designed to operate with three separate modes of operation [36]. These were defined to be basic control, emergency action and corrective control.

2.13.1 Basic control

This mode of basic control was designed to maintain the frequency error within a specified error boundary and any power exchanges over inter-area tie-lines to scheduled values. The control was also required to maintain the distribution of generated power between all the generators nominated as regulatory units in an area constant. These generators which are defined to be available for regulation are allocated by the economic dispatch function and hence, the interface between the frequency control and the economic function must be well defined. The L.F.C. objective is to control the generator output by altering the set points of the regulating units in response to changes in system frequency and tie-line interchange values. This power balance is achieved by using units selected for regulation and tracking the set points of the turbine governor. This action is in addition to their primary local control loops, which take action when the locally measured frequency deviates from the reference value. Thus L.F.C. is sometime termed *secondary control* action.

Loading among the regulating units is determined using economic considerations. The use of static and dynamic programs to calculate the economic minimum operating point of each unit gives each turbine generator a base point value and a future output target. This optimisation is termed economic dispatch and has the task of supplying an area consumer load in the most economic manner possible, aiming to find the minimum operating costs for a given set of constraints. The operation and use of an economic control function is often thought of as a tertiary control, as it is one layer above the L.F.C. and governor. Due to the time scales involved, L.F.C. is regarded as a dynamic operation where as the optimisation of the generating cost is regarded as a static operation. The economic dispatching and L.F.C. are both controlled from a longer range control function termed Unit Commitment. This control function is designed to calculate the time of start–up and shut–down of all the plant synchronised to the system and ensure there is sufficient generation available to fully supply the consumer demand. These three control functions are operated very closely and use the same system data, hence integration of these operations is essential for the smooth running of the overall control function.

2.13.2 Emergency Mode

The emergency mode of L.F.C. is entered if there is a large disturbance on the system and the question of system security may become important. In this case the surrounding areas are required to give support to the problem area, as well as the area itself attempting to support the demand. Initially the support from surrounding areas may be able to assist the troubled area, by altering the tie-line interchange, but eventually spinning reserve may need to be allocated or the re-schdeuling of the areas own generators will be required. In extreme circumstances load shedding may be required.

2.13.3 Corrective Control Action

The third standard control mode is that of corrective action. This control action is required during periods of inadvertent power interchange between neighbouring areas, due to non-scheduled power exports or imports of power. The corrective action required is obtained by changing the reference set point of the tie-line interchange and the area frequency. The value of the offset depends on the time predicted for the corrective action and the value of the inadvertent power interchange. The L.F.C. and economic dispatch still operate in their normal modes as previously, but their calculations are based on a new set of reference points. The aim of this corrective action is to return the quantities to their scheduled values.

2.14 Dencentralised Control

Generally the L.F.C. applied to many systems is of the decentralised type, which is carried out in each individual area. Some techniques use the tie-line bias technique, where the control is biased on the tie-line flows rather than the frequency error. This enables the controllers to operate separately in each area and still interact with the other interconnected areas, keeping the economic benefits of the single area calculation. Early developments of the classical control theory showed their ability to solve the L.F.C. problem, and further developments allowed refinements from the earlier work. Work on the control of transient oscillations and reaction to small disturbances of the L.F.C. and its sensitivity to system changes enabled a more practical solution to the problem to be achieved. The integration of L.F.C. and economic dispatch was also investigated.

2.15 Operating Characteristics

The early L.F.C. proposals all had two common themes. Firstly the only mode which was covered in any great detail was the normal operating mode for the steady-state operation. The problems arising from the other modes mentioned earlier have not been provided with any clear solutions.

The second common theme is the design of centralised controllers for the whole of an interconnected network. Several papers have made attempts to use a single system model to simulate various networks. This approach has been used even for the inter–area control problem and also investigation of decentralised control algorithms where separate system models would seem to be more appropriate. A few attempts have been made to apply an area dynamic model to the process of L.F.C. However, the use of a single overall system model to the inter area problem has lead to problems in the computational requirement. The number of variables required for the multiple area calculations is large, and often the data must be gathered from a wide range of transducers and geographic areas. This mass of data must then be solved using a single pass type calculation in real time, which is not possible due to the constraints placed on the data gathering system by the external plant. This problem lead to the development of decentralised design techniques. These techniques use the idea of dividing the multiple area power system into several decomposed subsystems. Each subsystem may then be controlled using a decentralised L.F.C. technique. This system requires the use of decentralised model and area controller.

The practical use of the centralised or decentralised controllers does not appear to be possible at the present time due to the implementation problems of optimisation and system data collection. The theoretical problems encountered are due to the fact that optimal control theory has difficulties coping with the large size and complexity of power systems as well as the data structures required for a well programmed L.F.C. scheme.

2.16 Implementation of Frequency Control

The L.F.C. function is required to carry out the calculation on which the control correction signals are based for the future alteration of the power output levels, of specified generation units on the power system. The control loop required to implement the commands from the L.F.C. function and the associated telemetery is shown in diagram 2.4. Depending on the mode of operation of the L.F.C. computation set by the dispatch operator, the program will operate to control a selection of system frequency, interchange powers, system time and interchange energy as closely as possible to scheduled values.

The main computation for the L.F.C. function is the calculation of the Area Control Error, (A.C.E.) [201,202,203]. This calculation is normally carried out on the known regulating characteristics of the power system together with deviations in system frequency and interchange power levels. These deviations are computed on the basis of telemetered values and target values input from the system. The basic objective of the L.F.C. control function is to control the system frequency within the statutory bounds, in the region of minimum operating cost, and hence there is no requirement to correct for random fluctuations in load provided that the system remains within the specified bounds. Unnecessary control action is undesirable due to the continuous operation and unnecessary use of the speed-changing (governor) equipment of each generation unit. So that the control action is not excessive, the A.C.E. is filtered over several cycles of telemetered data. It is now recognised that improved system performance can be achieved, particularly in the case of slower acting thermal units by varying the gains adaptively to suit different classes

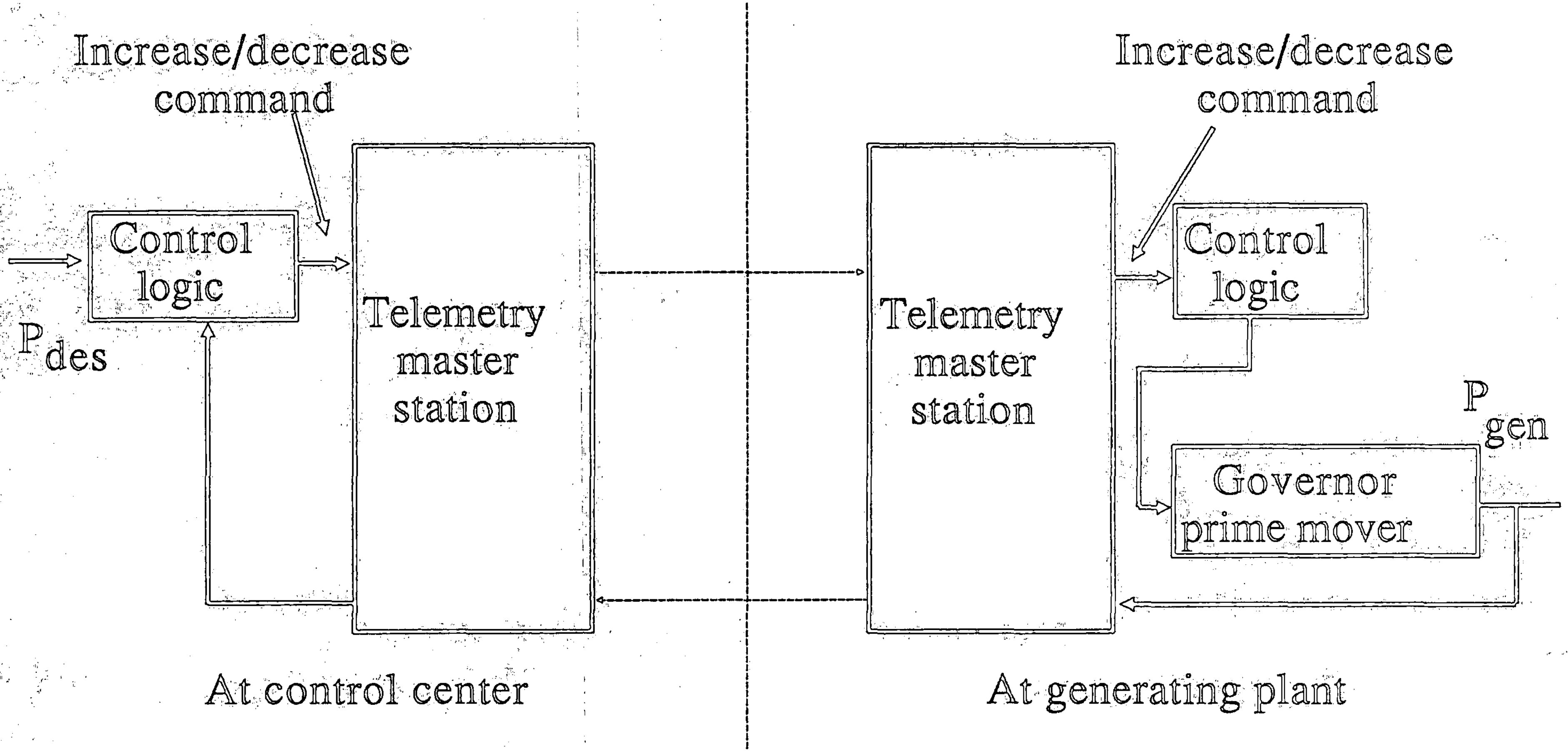


Diagram 2.4 Basic generation control loop via telemetry

of disturbance on the system and different system gains in different operating points.

The L.F.C. function must be capable of supporting the ability of the power system to carry out manual ramping of selected generators, which are not under the control of L.F.C. between pre–determined levels over a specified time period. This facility is required for example to allow the set up of an interchange schedule, or the ramping of a generator to replace one which is going out of merit. So that the L.F.C. may operate while these manual control actions are being carried out, some knowledge of the pre–scheduled ramping must be available to the control function.

The control signals from the L.F.C. function must be allocated between the generators available for regulation, with some emphasis placed on economic operation and rate limits of the system. Two sets of limits are generally specified. Regulating limits apply during normal operation, while sustained limits, situated outside the regulating limits, are used in emergency situations on the network. When the L.F.C. function is used in conjunction with an Economic Dispatch (E.D.) [40] control function, the allocation of power can be decided on using economic data and units constraints. However, if E.D. is not in operation, the power allocation can be carried out as defined by the system operator.

The calculation of the A.C.E. and the allocation of power must be completed taking into account the difference in characteristics between fast acting plant such as hydro–generation and the slower thermal units. Generally the control requirements of the thermal units are more involved due to their slower response. It is important to consider the number of units specified for operation under L.F.C. Clearly, the higher the number of participating units in the system, the faster the response of the actual electrical output to a given control signal. The closed loop response of the system must be examined so that the appropriate values for the gains of the A.C.E. calculation may be estimated. The control outputs to individual generators must not be made at levels below the dispatchable minimum.

The A.C.E. will be checked against a minimum and maximum limits set at the operator interface. If the A.C.E. value is less than the minimum level, then the control output is automatically inhibited. If the upper limit is exceeded then an alarm condition is created and the control status enters emergency mode.

The operation of the L.F.C. within a given area, which is part of an interconnected system, can only carried out correctly if the frequency and tie–line interchange is correctly controlled. This control must be similar to that of the neighbouring areas, and a similar coordinated policy must be initially agreed. If there is a major imbalance between two neighbouring areas, the primary objective becomes one of controlling the system frequency and interchange of power must be allowed to deviate as necessary within line limitations and loading limits. This may be achieved under L.F.C. either by switching modes to exclude interchange power control altogether, or by reducing the weighting factors associated with the interchange power error in the A.C.E. computation.

2.17 Calculation of the Area Control Error

The task of the Load Frequency Control is to regulate the power output of the electrical generators within a given area, in response to changes in the system frequency, tie-line loading or the relation of these to each other [80,119,200,201,204]. This will enable the scheduled system frequency to be maintained and/or the agreed power interchange with other areas to be kept within the pre–defined limits.

So that the control of both the system frequency and the tie-line power interchange, may be controlled as required, the control action is designed to alter the set point of each of the generators regulating on the system. Further corrective action may be required if the frequency, or clock error deviates from a certain band. Each change of the generator set points is a step change in the system power, which itself may introduce an unwanted frequency transient before the control action has chance to carry out its intended action. So that these transients may be avoided, the generators units must be ramped to their new required outputs over a reasonable time interval, and be constrained by their ramp limitations. The automatic computer control schemes that have been proposed [119,204] allow the change in generator set point to control the system frequency error and the tie–line power exchange to be smoothly controlled. To enable the control scheme to operate as required, the control is based on the calculation of the A.C.E. The A.C.E. is calculated based on the equation

$$\text{A.C.E.} = \Delta P_{tie} + K\Delta f$$

where

ΔP_{tie} is the error between the scheduled and actual tie-line power interchange, in MW. Δf is the error between the reference frequency and the actual system frequency.

K is the system stiffness, or gain (MW/Hz).

The control scheme must calculate an A.C.E. before it is due to alter the generator power set points for each unit. At each time interval, the A.C.E. represents the change in generation that must be allocated to various units by the alteration of the individual set points of the regulating generators, taking into account the dynamic limitations of the individual units.

The other quantities which must be taken into account are: The inadvertent power interchange (I.P.I.) which is given by

$$\text{I.P.I.} = \sum_{0}^{t} \Delta P_{tie}$$

The time deviation (T.D.) is given by

$$\text{T.D.} = \sum_{0}^{t} \Delta f \, dt$$

The area supplementary control (A.S.C.) is calculated based on the following criteria. The aim of the control scheme is designed as being to to minimise the area control error (A.C.E.), inadvertent interchange of power (I.^{p}I.), and the time deviation (T.D.) with the minimum area supplementary control (A.S.C.). This may be stated more clearly as

$$\text{A.C.E.} = \Delta P_{tie} + K\Delta f \rightarrow 0$$

$$\text{I.P.I.} = \int \Delta P_{tie} dt \rightarrow 0$$

$$\text{T.D.} = \int \Delta f dt \rightarrow 0$$

while ensuring

$$\text{A.S.E.} = \text{f(A.C.E, I.P.I., T.D.)} \rightarrow \text{minimum}$$

This ensures that unwanted transients in the system and equipment usage are reduced to a minimum.

However, this is only the theoretical value of the power deficiency in an area and not the actual value in practice. The A.C.E. does not give the true value of the generation deficiency, because of the physical limitations of the system,

(a) metering errors which are inherent in fast responding instruments
(b) inaccuracies in the frequency bias K, in both magnitude and phase and
(c) telemetry failures.

Based on the theoretical point of view, the action of the A.S.C. would change generation in such a way so that the A.C.E. is kept to a minimum. However, practically this minimisation is not always physically possible or necessary.

(1) The dynamics of the system combine with the physical limits of the system tend to limit the speed of response of the total system.
(2) The closed-loop gain of the total system varies with the number and characteristics of the controlled generators. A control scheme designed for optimum performance with one set of system parameters may not be optimum for a change in the system parameters and hence a reduction in the control scheme efficiency would be seen.
(3) The maximum permissible rate of change of the generators output in one area is limited by the design of the units and will probably not be linear over the entire operating region.

(4) The mechanical parts especially in the forward loop create dead-zones in the system. The use of a sensitive controller in a closed-mode system can lead to limit cycles.

(5) The aim to control the generation, so that it rapidly follows the time varying load is undesirable. It not only creates undue wear and tear on the valve control systems but the financial cost of such an operation may be substantial. Also the rapid varying of the units output may lead under certain conditions to unwanted and unnecessary transients set up in the system.

The constraints placed on the control by the physical system and the uncertainties in the closed-loop systems can result in deviations from the desired criteria of T.D, I.P.I. and A.C.E. This can lead to the following problems:

(1) A large A.C.E. may be introduced in to the system which can cause problems for the tie-line control.

(2) The required change in generation can lead to oscillations set up in certain control areas.

2.18 Computation of the Area Supplementary Control Signal

The A.S.C. value is calculated using the expression which combines the frequency error, the tie line power error, the time error and the inadvertent power interchange.

$$\begin{aligned}\text{A.S.C.} = & g.B(f_r - f_m) + h.K_1 \int_{j=1}^{n} (P_{sj} - P_{mj})\,dt \\ & + pK_2 \int_0^t \left(1 - \frac{f_m}{f_r}\right) dt \\ & + q.K_3 \int_0^t (P_{sj} - P_{mj}) dt\end{aligned}$$

where

f_r is the reference frequency in Hz,

f_m is the measured frequency in Hz,

B is the area bias parameter in MW/Hz,

P_{sj} is the scheduled interchange of power on tie–line j in MW,

P_{mj} is the measured interchange of power on tie–line j in MW,

n is the number of interconnecting tie-lines

K_1, K_2, K_3 are the weighting factors
K_1 for normal operation
$0 \leq K_1 < 1$ for the operation with major imbalance in neighbouring area.
The parameter B is computed using the sum of the frequency bias parameters $B_1, B_2, B_3, \ldots, B_n$ input as data by the dispatch operator for all n generating units on-line in the area.

g, h, p, q are the logical operators with values of 1 or 0. depending on the mode of operation.

The integration for time and energy errors would be computed from the aggregate of the product of sampled values and time between samples. This operation will itself introduce errors due to the sampling. A preferable technique would be to obtain the time error as a measured value from an installed time error transducer. Similarly, the energy error could be obtained more accurately from the difference between the scheduled value and the telemetered output from a MWHr transducer.

The calculation computational requirement (C.R.), the amount of power to be allocated to the system is then based on a standard proportional plus integral (P+I) controller of the form

$$\text{C.R.} = K_p \times \text{A.S.C.} + \frac{1}{K_i} \int_0^t \text{A.S.C.}\,dt$$

where
K_p is the proportional gain, and
K_i is the integral gain.

These gains represent the dynamic response of the power system to a L.F.C. input command. Typical values of K_p and K_i are given in several references [80,204]

$$K_p - 0.1 \quad \text{to} \quad 1.0$$

$$K_i - 10 \quad \text{to} \quad 30 \quad \text{seconds}$$

These values are only valid for systems which contain only thermal generation units.

2.19 Conclusion

This chapter has introduced the ideas concerned with the frequency control of electrical power systems. It has discussed the generation of power and how the system frequency changes as the consumer load varies. The effect that the loss of a generation unit has been shown along with the characteristic system response. The control of the system frequency and active power has been separated so that each variable can be concentrated on individually. The use of system gain as a measure of the system response to a control signal or to a consumer load increase has been discussed along with the generator dynamics which may vary the system gain. Previous L.F.C. schemes have been investigated based on the linearisation techniques, optimal control theory and classical ideas.

The chapter has considered the definition of good control schemes and their main aims. Centralised control schemes and decentralised techniques have been reviewed based on classical control methods. The calculation of the A.C.E. has been discussed in detail for the isolated system and interconnected power system. Quantities which may be incorporated into the calculation of the A.S.E. have been investigated and the minimisation of this value has been highlighted.

This chapter was designed to introduce the concept of load frequency control, the problems involved with the static control systems which have been used and to investigate the various quantities that may be used to control the frequency of an electrical power system. Later chapters in this thesis use the ideas discussed in this chapter, to propose the design of an L.F.C. scheme, which was then validated against a real-time power system simulator.

CHAPTER 3

SYSTEM MODELLING

3.1 Introduction

The control of a system is made possible if a mathematical model of the system under study is already known. If the system has unmodelled dynamic behaviour, or is totally unknown, then a system model of some form is required. The system model can be calculated fully, or more normally estimated to a given degree. Once a system model has been estimated, it can be used to predict the future behaviour of the plant under study, and hence used as a basis for the calculation of control commands. The type and accuracy of the estimated system model is dependent on the type of system being considered and the required application for the model.

Generally a model of a complex system can be obtained by reducing the system under study into smaller more easily defined blocks. Each block, may then in turn be broken down, and itself modelled as a system, if the internal characteristics of the system are known. The complexity of each model can be decided upon by considering the use to which the model will be put, and the required accuracy of the result. Also, the complexity of the model will have implications on the time taken to calculate the model, and hence this must be considered when time is also a constraint on the modelling process. Often a complete description of a system cannot be achieved because of unknown parameters or variables which cannot, or are not measured. Also, often the system which is to be described by the model is an extremely complicated and detailed process. A general overview of system modelling can be found in the following references (6,11,12,14,15,18,19,20,24,34,37,58,59,70,71,82,161,175).

Any system can be modelled to a given degree by carrying out a set of detailed experiments on the plant. The unknown variables in the model can be determined using an exact mathematical description of the system (if known) and this will then represent the plant under all operating conditions. However, in some cases this can be too precise, as what may actually be required is a general model of the system under study. Also, when the plant is in normal operating mode, it may only be subject to a small proportion of the conditions modelled, and certain operations included in the model may not have any effect in this particular operating range. It is known that for most controller designs, the control is found to be satisfactory, if it is based on a very simple system model which can be obtained over one particular set of operating conditions. The most commonly used approach to find any model is to use the data from the actual plant inputs and outputs, when it is operating dynamically within its normal range. However, this itself causes problems due to the nature of the system. The raw plant data is noisy because of random fluctuations, disturbances and noise introduced by the measuring and telemetry systems used. This process of using data directly gathered from the system under study, including the added noise, to obtain estimates of the parameters of the model of the plant is called *System Identification* [14,17,24,218] .

System identification is therefore, the procedure carried out to model systems mathematically, taking into consideration the external physical interactions which are inherent in the system under study. Factors which must be taken into consideration when modelling a system include; the processing of noisy data [82] , the choice of the model form [89] , the accuracy of the model required, the time allowed to obtain a valid model, and ways of checking the model produced to assess how good a representation it is of the actual system [120,190] .

This chapter considers the different methods available for system identification and how they can be linked together with information which may already have been obtained from the plant. Generally this involves applying statistical tests to the set of plant input-output data in order to estimate both model order and the respective values of the parameters within a model of that order.

3.2 Introduction to System Identification

The identification of any system is generally based on information collected from the system under study, which has been gained during previous on-line operation. This is usually achieved by applying statistical tests to the plant input and monitoring its output. This collected data can then be used to make an estimation of the model of the plant. The estimate will have to include the order of the model required, and then the actual parameters of the model that can be estimated. For a system which is finite, for example a batch process system, the system can be used directly in the identification process, and a system model can be directly based on this.

If the system is such that its parameters vary with time, this static identification method cannot be used. In this case, the time-varying system must be tracked so that the continuously estimated model is always up to date. The tracking of the system is necessary if the system under study is part of an on-line control algorithm, where the estimated model is used as a basis for control signal calculations. The system must also be tracked if the operating point of the process changes significantly. In this case the estimated model must be updated periodically. The estimated model of the plant must include the plant response to past control signals and be updated to show the response of the plant to more recent control action. Depending upon the rate of change in the operating point, more or less of the previous data should be relied on to model the system. The updating of the system model based on its past values is a continually cycling procedure and is hence, termed *recursive identification* or *recursive parameter estimation.* There are many references concerning this complex subject, some of the more useful ones the author has used generally in this section are (64 99,133,137,150,151,168,176,100,101,191,212,219) . This approach of system modelling is useful not only in control structures, but also in the field of signal processing and filtering.

The order and structure of the model of the estimated system is generally predefined, but it is possible to change the model order on-line. However, this may cause problems as the on-line calculation of the estimated model order is very demanding on computer time and this could have a disadvantage in real-time operation. The changing of the model order on-line, however, is not normally required as the system structure does not normally tend to change or *drift* dramatically as time varies. Hence, one predefined model order is usually chosen and kept throughout the control operation.

3.3 Use of Fixed Control Schemes

The design of control systems for dynamic plant depends on the availability of sufficiently accurate plant models in either the time or frequency domain. In process control, the system models are not normally known, to a great enough accuracy so the Proportional plus Integral plus Differential (P.I.D.) controller is normally used [27] . This can give a good response if the coefficients of the equation have been correctly tuned for a given set of operating conditions. The required output level, or set point can calculated using known theory[227], and after some time and effort by the control engineer, the system tuned to give a reasonable response. However, this theory is often difficult to implement in the practical situation, this may be difficult to achieve because of problems encountered with physical systems.

(1) The plant may have complex dynamics with a great deal of phase lag, or large dead times.

(2) Nonlinearities in the plant or the actuator may make the gain of the plant vary according to the set-point. Actuators such as valves generally exhibit dead-bands,hysteresis and saturation.

(3) The dynamics and gain may vary with time and operating point.

(4) Interactions between control loops often mean that they cannot be tightly tuned independently, and hence, many systems are currently designed to minimise this effect leading to less economic operation.

(5) The material input into a process may vary in quantity or there may be environmental disturbances (for example a change in cooling water

temperature). These effects themselves are seen as "load disturbances", which can vary greatly.

(6) The output measurement can also be corrupted by noise and quantisation errors.

Some of the above problems can be solved using the familiar P.I.D. controllers. This type of three-term control as it is termed is simpler and more robust than most so called simple alternatives. It is normally thought that the more conventional P.I.D. regulator is very effective in practice, but its initial tuning and the maintenance of good tuning on a system with many control loops can be a time-consuming activity, especially if the process dynamics are slow. The three gains of the controller system have to be *tuned* manually, and although manual tuning rules and algorithms exist, such as Zielger and Nichols [193], the problem of finding the *best* or optimal set of P.I.D. coefficients can be difficult and time consuming. It can be shown under quite general requirements, such as with quadratic costing or prespecified closed-loop dynamics, that the P.I.D. control is optimal for second-order plant subjected to load-disturbances of a Brownian motion type. This, however, implies that for more complex plant, such as those with dead-time, the P.I.D. algorithm is too simple and would have to be detuned from its optimal values (for example have the gain reduced). With the increasing demands for tighter quality control and good system response it is seen that some of the critical system control loops require controllers with many parameters. The parameters have to be chosen in a more rigorous way. In these cases the automated tuning of P.I.D. controllers, such as those proposed by Åström [13] would not work well. For this type of system more advanced control laws, such as those using self-tuning algorithms can be used as their structure can adapt to changes in the system, and the system operating point can be tracked with respect to time.

3.4 Self-tuning Controllers

The use of self-tuners is one approach to the automatic tuning problem [16,17,125,144,145,146] . It has the advantage that it can be used either as a tuning aid for control laws that are more complex than the standard P.I.D. controller, but which have fixed parameters, or as a means by which a time-varying process can be controlled in an consistent way. Self-tuning algorithms are also ideal for operation in real-time control schemes, as the computational requirements are well defined and known before operation. Although the control is not optimal in the sense of dual control, it can, if properly used, give good tuning and control performance for a wide range of practical systems. Self-tuning algorithms are useful for many applications as they need only a small and easily predictable amount of computing resources. A self-tuning algorithm takes only a small amount of the computational resources of a typical industrial microprocessor-based regulator, and probably has no greater requirements than that of a P.I.D. based system. This increase of performance means that the self-tuning controller could replace more standard controllers even for control operations where there is no need for any form of adaptive capability.

An algorithm is called self-tuning [3,8,95,130,180] if, for constant plant parameters, the controller parameters tend towards those which would have been obtained if the plant parameters were exactly known. A self-tuning controller consists of several basic functions, which can be relatively simple, or can be very sophisticated depending on the type of system under study.

Generally, a self-tuning controller has three main elements [50,51,52]. There is a feedback law of some form, which takes the form of a difference equation. This acts upon a set of values such as the measured output and feedforward signals, the current set-points and other requirements, which produce the new control action. A recursive parameter estimator monitors the system inputs and outputs and computes an estimate of the plant dynamics in terms of a set of parameters in a predefined model. The parameter estimates are fed into a control-design algorithm which then provides a new set of coefficients for the feedback law. The general structure of a self-tuning controller is shown in diagram 6.2. The control design algorithm simply accepts current estimates and ignores their uncertainties (unlike dual control algorithms), this procedure is termed certainty-equivalent. This approach is used because, although there may be poor estimates and hence poor control during the initial tuning phase, the control can be filtered to minimise any potentially incorrect control action. This means that the overall algorithm is much simplified. A further simplification is obtained by removing the control-design stage in an implicit self-tuner. The process model equations are reformulated in this case so that the estimator directly produces the coefficients of the required control law, a self-tuner which includes both an estimator of a *standard* process model and a control design stage is termed explicit.

3.4.1 Implicit and Explicit Self-tuners

Explicit self-tuners [130] identify the system transfer-function directly, using any of the available recursive methods. At each sample interval they perform some algorithmic calculation to resolve the polynomial identity to place closed-loop poles in certain prespecified locations. Implicit [58] self-tuners, on the other hand require no intermediate algorithmic computations as they identify the parameters of the appropriate controller, rather than those of the plant transfer-function.

3.4.2 Modelling Schemes

The recursive parameter estimator (a plant identifier), calculates the system parameters. Then a control design procedure, is used to provide feedback controller coefficients. This means that the manual operator is no longer required to set the values of the P.I.D. constants K,T_i and T_d. The self-tuning algorithm is used to monitor the closed loop performance of the plant and calculate the required control action. The important ability of self-tuning control is that even if the plant model is not known the adaption algorithm is able to continuously monitor and follow the desired closed loop performance by automatically adjusting the controller parameters. For many systems the number of parameters that may be involved could be greater than the three of the P.I.D. form, and so could not practically be manually tuned. However, the proofs of convergence [133,151,178,187,192] for self-tuners to the *true* controller values depend on assumptions about the process such as, (linearity stationary, model order, and so on, which cannot always be justifiable [27,107,108,109,110,224,225,226]. It is clear that the algorithms cannot work directly [115,116,117,127,137,156,194] in a control scheme, so many self-tuner algorithms when used in a practical situation require the use of supporting or 'jacketing' software. They also rely on theoretical convergence considerations.

3.4.3 Early Self-tuning Algorithms

The ideas involved in self-tuning are not new. Kalman [92,137] initially derived the first so called self-tuning algorithm and attempted to implement the algorithm on a special computer. However, theoretical and technological advances were required before this new technique could be compared with the state-space methods being investigated. The theory was revived and extended to cover stochastic aspects by Peterka [179–182], but it was not until Åström and Wittenmark [221] that there was a great deal of work carried out in this area.

Many research papers have been written on the subject of system identification and several practical applications have been investigated [43,73,105,118,168,169]. This led to new theoretical developments as new problems were defined, which enabled the of use of adaptive control techniques to be applied to new areas. New algorithms have been proposed for differing applications. It is relatively easy to derive a new algorithm, or to show if one method is better than another, but the convergence analysis of algorithms is more involved.

3.4.4 Performance Objective

The performance objective of the original self-tuning regulator of Åström and Wittenmark [221] was the minimisation of the variance of the measured process output $y(t)$ at the sampling instants. It is seen to be the stochastic equivalent of the discrete-time *one-step* controller, [13] and shares the same defects. The overall control algorithm takes no account of the control effort required, which may lead to excessive control signals being generated, and in some cases there will be closed loop instability [138]. However, the simplest implicit algorithm normally forms the basis of general self-tuners. The idea of the performance objective was developed for self-tuning controllers by Clarke and Gawthrop [63,94] which were interpreted by Gawthrop [63] and later by [96] to give a wide variety of performance objectives. These implicit algorithms include set-point variations, which enables tracking as well as regulation control, and can be seen for example as minimising a combination of control and output variances. This means that the control effort can be traded against output variations to suit the available actuator characteristics.

3.4.5 Predicitive Modelling

Simple implicit self-tuners are based on predictive control theory which depends on a knowledge of the system time-delay k. However, with explicit methods, although they have a heavier computation requirement, they do not require any knowledge of this delay as it can be estimated as part of the process dynamics. These ideas are seen in Wellstead [217] which are based on his earlier work. In this work the design procedure involves the placement of the closed-loop poles at predescribed locations while the zeros in their closed-loop positions. This has been extended to cover tracking and regulation, by Åström and Wittenmark [19] who have produced a similar design procedure which also places *safe* process zeros in the deterministic servo case. A further extension to these ideas uses state-space methods, in which the estimated model is transformed into its equivalent state-space representation, and the design procedure becomes that used for linear-quadratic-Gaussian control. Early work in this area was carried out by is due to Peterka and Åström [182]. Although the LQG approach requires the most computation, various devices can be used to minimise the computing load [2,3,7,46,78,152] .

An algorithm is called self-tuning if, as the number of input and output samples tends to infinity, the estimated parameters become close to those which would be produced if an accurate system model was directly known. This convergence property depends on various assumptions about the process, such as time-invariant dynamics, and most of the methods have been shown theoretically and experimentally to produce self-tuning behaviour. However, in practice self-tuners are used for more general problems, such as for time-varying processes, and the algorithms are adjusted so that effective control is still produced. Suitable modifications to the basic algorithms, especially their robustness is still an on going research topic [23,93,140].

3.4.6 Recent Developments

Recent developments have been made in the theory corresponding to continuous time-process models which are assumed by the self-tuners, and how the corresponding discrete-time model is obtained, how models operate in the predictive form, and the locations of the discrete-time poles and zeros [218,160]. The derivation from the standard recursive-least-squares parameter estimation algorithm, and its generalisation to cover certain types of correlated noise is also being investigated. Other work includes; the derivation of prototype self-tuning regulators which minimise the process output variance, the generalised self-tuner and interpretations of its performance, and the derivation of explicit self-tuners based on the placement of closed-loop poles in prescribed locations [81,82,112,153,206].

3.5 Dynamic System Modelling

The main aim of identification is to model to the required extent for a given purpose, the dynamic system under study. There are certain structures within the model which must be defined along with an estimation of the parameters contained within each particular model. A good model structure should approximate the system to a reasonable degree and contain all the known relevant information about the system operation. It must also be flexible and lead to simple estimation procedures.

Models may be divided into two main classes, parametric and non-parametric. The type of model considered in this section is parametric because the system order must be specified so that the model estimation is simplified and the associated errors are removed. In non-parametric models, however, this specification is not required, making the estimation more complex and involved.

To apply a self-tuner to the system under study, it assumed that the model used is capable of at least approximating the behaviour of the class of system to which it is applied. Usually the control set point is constrained within an upper and lower limit due to the physical system which remains constant over long periods. So a locally-linearised model is often sufficient to model the plants characteristics over a given time. For the case of a system under discrete-time operation, which is a single input-output system , the output may be expressed in terms of previous inputs and outputs using the standard difference equation [130]

$$y(t) + \sum_{i=1}^{n} a_i y(k-i) = \sum_{i=1}^{n} b_i u(k-i) \tag{3.1}$$

where

$y(t)$ is the system output at time $t = k$,

$y(k-1)$ is the system output at time $t = k-1$

$u(t)$ is the system input at time $t = k$,

$u(k-1)$ is the system input at time $t = k-1$ and so on.

The time period $t = k-1$ to $t = k$ is a measure of one sample period or length of time between each output sample.

This assumes that one time period will have elapsed before the system model will respond to any external influence, which will effect the system output. The model expresses the current output vector as a linear combination of the past outputs and the past inputs. This form of model is termed *Auto Regressive Moving Average* (A.R.M.A.) [92] . The past values of y are the auto regressive components, and the u are the moving average components.

3.6 Prediction Error Models

The most useful class of models for parameter estimation is that of prediction error models. These models use a mathematical representation of the system description such as that in equation (3.1) from which the parameters $a_1, a_2, \ldots, a_n$ and $b_1, b_2, \ldots, b_n$ are estimated. If the same input, $u(t)$ is then applied to both the system and the mathematical model of the system, the outputs of the system and model can be compared. The error involved in the comparison shows how good the parameter estimates are, or the error gives an indication of how close the mathematical representation is to the real system.

One of the most important factors concerning the accuracy or *goodness* of the mathematical model, is the choice and number of the a_i, and b_i parameters. If the model is incorrect, for instance insufficient parameters have been modelled, there will be a large error between the output of the actual plant and that of the model. However, there will also be an error introduced into the system if too many parameters are estimated, that is the system is over modelled.

When considering a practical system, the system output is often corrupted by noise due to disturbances, measurement devices and telemetery. This implies that when considering such system the a_i and b_i parameters, are inappropriate. This is due to the fact that large variations in the system noise many have an effect on the parameters and an inaccurate model may be calculated.

3.6.1 Error Minimisation

The prediction error, $\epsilon(t)$ at time $t = k$ of a system can be used to access the effectiveness of the modelling technique employed. This error can be used to obtain a more exact mathematical model using a revised set of estimates of a_i and b_i. However, trying to minimise the direct error causes problems. The square of the error $\epsilon(k)^2$, instead of the error itself is used in most identification procedures. Generally, the model is formed by collecting a number of samples N from the system input and output. This error signal is squared, and forms the sum of the squares of the errors, which is the basis of the cost function. This function is minimised by estimating the required number of a_i and b_i parameters. This method reduces the effect of system noise.

Many procedures exist for the minimisation of the cost function. The technique discussed in this section is probably one of the more simple methods available, this scheme is termed *linear least squares*.

3.7 System Modelling

The model used to describe the system was defined earlier to be

$$y(t) + \sum_{i=1}^{n} a_i y(t-i) = \sum_{i=1}^{n} b_i u(t-i) \tag{3.2}$$

The discrete time description of the system to be modelled is

$$A(z^{-1})y(t) = B(z^{-1})u(t) + \epsilon(t) \tag{3.3}$$

which may be rewritten as

$$y(t) = z^{-k}\frac{B(z)}{A(z)}u(t) + \epsilon(t) \tag{3.4}$$

where

$y(t)$ is the sequence of output signals form the model
$u(t)$ are the input signals, and
$\epsilon(t)$ is the disturbance signal.
The polynomials $A(z)$ and $B(z)$ are defined as

$$A(z) = 1 + a_1 z^{-1} + \ldots + a_n^{-n_a} \tag{3.5}$$

and

$$B(z) = b_0 + b_1 z^{-1} + \ldots + b_n^{-n_b} \tag{3.6}$$

The delay operator z^{-1} is defined to be $z^{-i}y(t) = y(t-i)$
k is dependent on the delay time of the system.

If the plant being modelled does not have a time delay, then $k = 1$. If the plant does have a time delay $\tau_d = k'T$, where T is the sample period, then $k = k' + 1$ The equation used to describe the system model can be rewritten as

$$y(t) = \frac{B(z^{-1})}{A(z^{-1})}u(t) + \epsilon(t) \tag{3.7}$$

Often when modelling discrete systems, the system is modelled using the more conventional term of the backward difference operator q.

$$A(q)y(t) = q^{-1}B(q)u(t) + \epsilon(t) \tag{3.8}$$

$A(q)$ and $B(q)$ are the same form as above with z replaced by q. By definition $q^{-i}y(t) = y(t-i)$. If the system is subject to a stochastic disturbance, then the previous discrete model can be extended to

$$A(q)y(t) = q^{-1}B(q)u(t) + C(q)\xi(t) \tag{3.9}$$

where $\xi(t)$ is a zero mean uncorrelated random sequence representing the disturbance.

The transfer function $C(q)/A(q)$ relates to the transmittance of the disturbance through the system to the measured output

$C(q)$ is a polynomial having the form

$$C(q) = 1 + c_1 q^{-1} + \ldots + c_{n_c} q^{-n_c} \tag{3.10}$$

Then the equation may be written in the alternative form using

$$y(t) = \theta^T x(t) + \epsilon(t) \tag{3.11}$$

The parameter vector θ^T is

$$\theta^T = (a_1, a_2, \ldots, a_n, b_1, b_2, \ldots, b_n) \tag{3.12}$$

The vector $x(t)$ is known as the regressor vector and is given by

$$x^T(t) = (-y(t-1), -y(t-2), \ldots, -y(t-n), u(t-1), u(t-2), \ldots, u(t-n)) \tag{3.13}$$

The polynomials A and B are considered to be nth order, however, it is more correct to say that the higher order polynomial is of order n, such that the higher order parameter values of the polynomial of order less than n are then equal to zero. The effect of a pure time delay between input and output, is seen in the estimated model by setting the lower order terms of the B polynomial to zero, or by changing the equation (3.2) to involve a time delay k.

$$y(t) + \sum_{i=1}^{n} a_i y(t-i) = \sum_{i=1}^{n} b_i y(t-i-k) \tag{3.14}$$

It is also possible to account for zero mean coloured noise, in the system using

$$\epsilon(t) = Cz^{-1} e(t) \tag{3.15}$$

where

$C(z^{-1})$ is of a similar form to that of Az^{-1}, and

$e(t)$ is a white noise sequence.

A non-zero mean disturbance can also be considered by making

$$\epsilon(t) = C(z^{-1})e(t) + d \tag{3.16}$$

where d is a scalar offset bias level, but this is not often required.

3.8 Linear Least-Squares Estimation

The main aim of the least-squares calculation[51,56,213] is to make the sum of the squares of the differences between the model output and actual system output data a minimum. If this can be achieved then the estimates in the model are as near as possible to that of the actual values. Consider the model of equation (3.14) with $k = 1$, which gives the output of the system at time $t = nT$ as

$$y(t) = -a_1y(t-1)-a_2y(t-2)\ldots-a_ny(t-n)+b_0u(t-1)+b_1u(t-2)\ldots+b_nu(t-n-1) \tag{3.17}$$

The output at following samples $y(n+1),\ldots,y(n+N)$ is given by

$$\begin{aligned} y(t+1) =& - a_1y(t) - a_2y(t-1)\ldots - a_ny(t-n+1) \\ &+ b_0u(t) + b_1u(t-1)\ldots + b_nu(t-n) \qquad (3.18) \\ y(t+N) =& - a_1y(t+N-1) - a_2y(t+N-2)\ldots - a_ny(t+N-n) \\ &+ b_0u(t+N-1) + b_1u(t+N-2)\ldots + b_nu(t+N-n-1) \qquad (3.19) \end{aligned}$$

These equations at the various sample intervals provide a set of simultaneous equations which can be solved to obtain the parameters

$$a_1, a_2, \ldots, a_n, b_0, b_1, \ldots, b_n$$

The equations can be expressed more compactly in the following matrix form

$$Y = X\theta + E$$

where

$$Y = [y(t), y(t+1), \ldots, y(t+N)]^T \tag{3.20}$$

$$X = \left[\begin{matrix} y(t-1) & y(t-2) & \dots & y(t-n) \\ y(t) & y(t-1) & \dots & y(t-n+1) \\ y(t+N-1) & y(t+N-2) & \dots & y(t+N-n) \\ y(t-1) & y(t-2) & \dots & y(t-n) \\ y(t) & y(t-1) & \dots & y(t-n+1) \\ y(t+N-1) & y(t+N-2) & \dots & y(t+N-n) \end{matrix}\right.$$

$$\left.\begin{matrix} u(t-1) & u(t-2) & \dots & u(t-n-1) \\ u(t) & u(t-1) & \dots & u(t-n) \\ u(t+N-1) & u(t+N-1) & \dots & u(t+N-n-1) \end{matrix}\right] \tag{3.21}$$

and

$$\theta = [-a_1, -a_2, \dots, -a_n, b_0, b_1, \dots, \dots, b_n]^T \tag{3.22}$$

and E describes the effect of measurement noise and disturbances affecting the system. The single output measurement taken at time instant t, can be written as

$$y(t) = \sum_{i=1}^{N} \theta_i x_i(t) + e(t) \tag{3.23}$$

Consider now, how an estimate of the parameter vector, $\hat{\theta}$, can be obtained by least squares approach. Using the estimate $\hat{\theta}$, the prediction of the system output $\hat{Y}$ is given by

$$\hat{Y} = X\hat{\theta} \tag{3.24}$$

and the prediction error ϵ by

$$\epsilon = Y - \hat{Y} = Y - X\hat{\theta} = [\epsilon(t), \epsilon(t+1), \dots \epsilon(t+N)]^T \tag{3.25}$$

This is obtained by minimising the cost function

$$\text{Min.} \quad J = \sum_{1}^{N} \epsilon^2(t) \tag{3.26}$$

The predicted value of θ given by $\hat{\theta}$ which minimises the sum of the squares of the errors between $y(k)$ and the predicted output $\hat{y}(t)$, $\hat{\theta}_i x(t)$ summed from $i = 1, \dots, N$, can be written in the vector form

$$S = (Y - X\hat{\theta})^T (Y - X\hat{\theta}) \tag{3.27}$$

This equation must be minimised by selecting a set of system parameters, $\hat{\theta}$ for a given set of input and output data. The value of $\hat{\theta}$ is a minimum when the differential is set to zero hence

$$\hat{\theta} = (X^T X)^{-1} X^T Y \tag{3.28}$$

This is on condition that X^TX is invertable, so that a unique solution may be found. This is the standard least-squares equation, which is derived below. The value of $\hat{\theta}$ which minimises S, the sum of the squares of the errors can be found as follows

$$S = \epsilon^T\epsilon = (Y - X\hat{\theta})^T(Y - X\hat{\theta}) \tag{3.29}$$

$$\frac{dS}{d\hat{\theta}} = 2X^T(X\hat{\theta} - Y) \tag{3.30}$$

Hence S is minimised when

$$2X^T(X\hat{\theta} - Y) = 0 \tag{3.31}$$

that is when

$$\hat{\theta} = (X^TX)^{-1}X^TY$$

An estimate of $\hat{\theta}$ can therefore be obtained provided (X^TX) is non-singular (which it will be if the system is 'persistently excited'). If the system is not excited, then common rows can occur in X, making (X^TX) singular.

If the system is subjected to a stochastic disturbance e giving a model of the form

$$Y = X\hat{\theta} + e$$

then pre-multiplying equation (3.32) by $(X^TX)^{-1}X^T$ gives

$$\hat{\theta} = \theta + (X^TX)^{-1}X^Te$$

This expression indicates that the least-squares estimation will be biased with the bias being given by $E[(X^TX)^{-1}X^Te]$.

If $x(t)$ and $e(t)$ are independent, as assumed, the expected value of $\hat{\theta}(t)$ will depend on the expected value of e. If it is also assumed that the noise has zero mean then $E\{\hat{\theta}(t)\} = \theta(t)$, the true parameters vector, then the estimates are unbiased. If also $e(t)$ is an uncorrelated (white noise) sequence, the least squares estimates can be shown to have minimal variance compared with all the other linear unbiased estimates. The accuracy of which depends on the covariance matrix

$$E\{(\hat{\theta}(t) - \theta(t))(\hat{\theta}(t) - \theta(t))^T = \sigma^2(X(t)^TX(t))^{-1}$$

where σ^2 is the variance of $e(t)$. If $e(t) = \xi(t)$ that is uncorrelated zero mean sequence, then $e(t)$ is uncorrelated with the elements of X^T, which involves only past values of y,these are $y(t-1), y(t-2)\ldots$ and therefore $\xi(t-1), \xi(t-2)\ldots$,consequently $E[(X^TX)^{-1}X^Te] = 0$ and the estimates are unbiased.

A better guide in terms of how good a particular algorithm is, can be found by consideration of statistical confidence regions corresponding to each method. For this purpose the 'residuals' vector $\hat{E}$ must be obtained from

$$\hat{E} = Y - X\hat{\theta}$$

such that the sum of the squares of the residuals is calculated by means of the equation

$$\hat{S} = \sum_{k=1}^{N} \frac{\epsilon(k)^2}{\sigma^2}$$

and this is distributed in the form of $\chi^2(M_N)$ where N is the number of parameters and M is the number of data points. It is , however, fairly straightforward to apply a t distribution if this is preferred to the Chi-square test.

3.9 Recursive Least-Squares

The previously described least-squares approach is suitable only for batch processing, it can be used as an off-line estimator, but if the system model changes slightly or *drifts*, the change in the model can not be detected by the identifier. Thus it is necessary to convert the previous method into a recursive form so that the estimates may be updated when new data has become available. This enables the estimator to track the system on-line enabling real-time identification. This recursive form of the estimator is termed *Recursive Least Squares* [47,85,88,195,199] (R.L.S.) identification.

In common with all recursive methods, the R.L.S. method requires a *window* of the most recent data. This means that only the newer values of the plant input and output are stored, and they are only kept for a certain time. Once the data has been stored for the required time, it is automatically discarded and replaced by new system data. Using this method a known amount of storage is required in the computer and the data is continuously cycled through the defined *window*.

Normally the vector $x(t)$ is used to store plant input data and the vector $y(t)$, all the plant output data. At any time t, the vector will contain the most recent values of y and u, being $y(t)$ and $u(t)$, and the input and output values from n time intervals ago. The system parameters are stored in $\theta(t)$ and then an initial guess, or estimate of the system model is defined as $\hat{\theta}(t)$ for each of the parameters which go to make up the *actual* parameter vector θ.

At time instant $(t-1)$, when a new control input is known, not only is the vector $\hat{\theta}(t)$ known, but also the vector of the previous inputs and outputs.

$$x^T(t) = (-y(t-1), -y(t-2), \ldots, -y(t-n), u(t-1), u(t-2), \ldots, u(t-n))$$

This enables the estimate of the system model to be made, based on the system equation. The estimate of the next output $y(t)$ is then based on this updated data. Hence $\hat{y}$ can be calculated

$$\hat{y}(t) = \hat{\theta}(t-1)x(t) \tag{3.32}$$

The value of $\hat{y}$ is the prediction of the output signal $y(t)$, which is made using the information available at time $(t-1)$. However, when the new actual output signal is measured, the error in the prediction can be found as before using

$$\varepsilon(t) = y(t) - \hat{y}(t)$$

It is obvious that if the noise signal $e(t)$ is relatively small, and if the parameter estimates $\hat{\theta}$ are fairly close to their actual values of θ, then the error $\varepsilon(t)$ should also be small. However, if the estimates of θ are not very accurate, then the value of $\varepsilon(t)$ would be expected to be large. The magnitude of the error $\varepsilon(t)$ can be taken to account and can be used to improve the parameter estimates. The estimates can be improved using

$$\hat{\theta}(t) = \hat{\theta}(t-1) + K(t)\varepsilon(t)$$

From this equation, it is seen that if the value of $\varepsilon(t)$ is small for any value of $K(t)$, then there is very little change made in the estimates, however, if there is a large change in $\varepsilon(t)$ then a large change in the estimates is required. The choice of $K(t)$ is important. Thus a way is required to calculate a useful value of $K(t)$.

Obtaining the recursive calculations required can be very involved, so a simplified version is explained here to demonstrate the basic concepts behind the procedure. One of the benefits of this approach is that a strictly fixed amount of computation is performed for each new piece of data. There is also the advantage that the dimension of X^T is fixed,it does not increase with N. The following definition is made

$$S(t) \triangleq (X(t)^T X(t)) \tag{3.33}$$

where

$X(t)$ is the matrix of known data acquired up to time t. This equation may be written in the partitioned form

$$\begin{bmatrix} Y(t-1) \\ y(t) \end{bmatrix} = \begin{bmatrix} X(t-1) \\ x^T(t) \end{bmatrix} \theta + \begin{bmatrix} \epsilon(t-1) \\ \epsilon(t) \end{bmatrix} \tag{3.34}$$

The estimate for at time T of $\hat{\theta}(t)$ can hence, be given as

$$\hat{\theta}(t) = (X(t)^T X(t))^{-1} X(t)^T Y(t)^T$$

then

$$\hat{\theta}(t) = [X_(t-1)^T X(t)^{-1} + x(t)x^T(t)]^{-1}[(X(t-1)^T Y(t))^{-1} + x(t)^T y(t)] \tag{3.35}$$

or using the S defined as above, more simply

$$\begin{aligned} \theta(t) &= S(t)^{-1}\left[X(t-1)^T Y(t-1) + x(t)y(t)\right] \\ &= S(t)^{-1}\left[S(t-1)\hat{\theta}(t-1) + x(t)y(t)\right] \end{aligned} \tag{3.36}$$

but

$$S(t) = S(t-1) + x(t)x^T(t)$$

$$\hat{\theta} = S(t)^{-1}\left[S(t)\hat{\theta}(t-1) - x(t)x^T(t)\hat{\theta}(t-1) + x(t)y(t)\right] \tag{3.37}$$

$$= \hat{\theta}(t-1) + S(t)^{-1}x(t)\left\{y(t) - x^T(t)\hat{\theta}(t-1)\right\} \tag{3.38}$$

this gives together with (3. 32) the recursive updating of $\hat{\theta}$

$$\hat{\theta}(t) = \hat{\theta}(t-1) + K(t)\left[y(t) - x^T(t)\hat{\theta}(t-1)\right] \tag{3.39}$$

Where $K(t)$ is an n-vector (the Kalman Gain). It is seen that the estimation update for each parameter is of the feedback form

$$\begin{bmatrix}\text{new}\\ \text{estimate}\end{bmatrix} = \begin{bmatrix}\text{old}\\ \text{estimate}\end{bmatrix} + \text{gain} \times \text{(prediction error of old model)}$$

However these equations cause problems for convergence analysis as these equations involve the inverse of $S(t)$ at each stage. A further simplification may be made possible by the use of the well known 'matrix inversion lemma' [53] which involves $P(t)$, the inverse of $S(t)$. This gives

$$P(t) = \left(S(t-1) + xx^T\right)^{-1} = P(t-1) - \frac{P(t-1)\,xx^T P(t-1)}{1 + x^T P(t-1)x}$$

Using this lemma, recursive least squares (R.L.S.) becomes

$$K(t) = \frac{P(t-1)x(t)}{1 + x^T(t)\,P(t-1)x(t)} \tag{3.40}$$

$$P(t) = \left[I - K(t)x^T(t)\right]P(t-1) \tag{3.41}$$

This has the advantage that no matrix inversion is required. However, S^{-1} exists only after n observations have been made, and so a starting value is required for the initialisation of $P(0)$.

The algorithm works as follows

(a) An initial value of $P(0)$ is chosen.
(b) At each time, t, X is obtained using the new data
(c) Equation (3.40) is used to update $K(t)$
(d) Equation (3.41) is used to update $P(t)$
(e) Finally equation (3.39) is used to obtain the parameter estimates $\hat{\theta}(t)$.

Using this method the data storage ($\hat{\theta}, x, P$ and K) and computational requirements stay constant with time.

The form generally used for the starting value of P is a diagonal matrix αI where the value of α is taken to be (10^3) [92,106]. This shows there is little confidence in $\hat{\theta}(0)$ and allows rapid initial changes, so that a reasonable estimate of θ is achieved as $\hat{\theta}(t)$ changes slowly. The covariance matrix of the estimates is given by $\sigma^2 P(t)$ (for large t at least) σ^2 can itself be estimated using the model prediction error $e(t)$. If $P(0) = \alpha I$, where α is large, if the plant is noise-free, if the $X(t)$ vector is 'persistently exciting', and if the plant is accurately modelled by a constant parameter vector θ then

$$\hat{\theta}(t) \rightarrow \theta \qquad \text{exactly in } n \ \text{ steps} \tag{3.42}$$

This is the fastest, possible rate of convergence. For example, if the self-tuner has 5 parameters then 5 samples (after the data vector have been filled up) are sufficient to get good estimates.

However, this is not always the case when practical systems are being investigated. The matrix $S(t) = \sum x(i)x^T(i)$, so that the magnitude of S is *small* initially but tends to infinity, provided that $x(t)$ is 'sufficiently exciting'. The matrix P should be symmetrical and positive definite, but round-off errors may cause P to lose symmetry. If this is the case, then the algorithm will become unstable and the estimates will rapidly diverge. This does not usually happen until about 5000 iterations [58,106,136], which means that the controller has to be used under continuous conditions for a long time under real conditions before it is seen. This action can be prevented with the use of an update factor for $P(t)$. As P is positive, it can always be written as using the UD factorisation, [57,106,130,213,214,217] UDU^T, where U is the upper-triangular matrix with units down to the diagonal and where D is a diagonal matrix. The updating then becomes U and D, and P may be reconstructed using UDU^T

3.10 Forgetting Factors

When P is updated using (3.41), the elements of P tend to reduce in magnitude. This causes the gain matrix K to eventually be reduced to zero, and the estimation of the parameters $\hat{\theta}$, tends to θ. This is only useful if the parameter values are constant with time. This means that the estimation routine is unable to track slowly-varying parameters and hence, cannot be used for the identification of systems which have time varying parameters. Once the gain term becomes negligible, even though the estimation error may be large, the estimated parameter values will not adjust, so the tracking of time varying parameter values is not possible.

The problem may be overcome with the use of a so termed *forgetting factor*. This instead of giving equal weights to the errors in least-squares criterion, gives more weighting to the more recent data preventing $P(t)$ from becoming too large. The speed at which the adaption takes place is determined by the asymptotic memory length described by Clarke and Gawthrop [62]

$$N = \frac{1}{(1 - \lambda)} \tag{3.43}$$

This implies that the information contained in the data storage elements of the algorithm decays with a time constant of N sample intervals. For $\lambda = 1$, the $P(t)$ is the standard covariance matrix described earlier. After the initial tuning phase of the algorithm, the control will become better and hence the elements of $P(t)$ become larger, as they are continually scaled by a factor less than one. This means that if there is little information gathered about the system dynamics due over long periods of steady-state operation, numerical instability may occur as the magnitude of $P(t)$ increases. The regulator becomes very sensitive to any disturbance or a numerical error, which may cause any change in the set point to lead to a temporary unstable system or to total system instability.

Some solutions have been proposed to avoid this problem such as, placing bounds on the diagonal elements of the $P(t)$ matrix, but the exact values for the boundary are difficult to decide upon. A more useful approach is to decide upon the amount of system information that the algorithm stores. Thus a forgetting factor is used to define the amount of system data that is stored. This can prevent the covariance matrix from *blowing-up* but still enables the algorithm to adapt to the system changes.

3.10.1 Variable forgetting factor

To chose the size of the forgetting factor, [106,172] the state of the system must be taken into account. If the error between the actual system output and the calculated output is small then two cases may have caused this: The system may be near the correct set of system parameters, or the estimator is capable of reducing the parameter error. If this is the case, then it would be sensible to keep the maximum amount of system information, thus a forgetting factor close to unity is required. However, if the error is large, the estimator sensitivity may be increased by selecting a lower forgetting factor. This has the effect of shortening the memory length of the algorithm until the errors become smaller. Using this idea it is possible to define a the amount of information which is to be stored about the system as the weighted sum of the squares of the error. This is calculated recursively by

$$\Sigma(t) = \lambda(t)\Sigma(t-1) + \left[1 - y(t-k-1)^T K(t)\right] \xi(t)^T \tag{3.44}$$

This was discussed by Fortescue [89] . The forgetting factor may then be be defined by keeping $\Sigma(t)$ such that

$$\Sigma(t) = \Sigma(t-1) = \ldots = \sigma_0 \tag{3.45}$$

Thus the size of the forgetting factor at each time step corresponds to the amount of new information in the latest data set. This ensures that the estimation is always based on the same amount of system information. Thus

$$\lambda(t) = 1 - \frac{1}{N(t)} \tag{3.46}$$

where

$$N(t) = \frac{\Sigma_0}{(1 - y(t-k-1)^T K(t))\, \xi(t)^2} \tag{3.47}$$

$N(t)$ is the equivalent asymptotic memory length if $\lambda = \lambda(t)$ were to be used throughout the estimation. As Σ_0 is related to the sum of the squares of errors, one possible choice [89] is to express Σ_0 as

$$\Sigma_0 = \sigma_0^2 N_0 \tag{3.48}$$

where

σ_0 is the expected measurement noise variance based on real knowledge of the process. N_0 then, will control the speed of adaption because it corresponds to a nominal asymptotic memory length. It is shown [213,214] that if Σ_0 is chosen this way, then for a stationary process

$$E\{N(t)\} = n_0 \quad \text{as} \quad t \to \infty \tag{3.49}$$

and

$$E\{P(t)\} = P_0 \quad \text{as} \quad t \to \infty \tag{3.50}$$

The sensitivity of the system is controlled by choice of N_0. A small value of N_0 will give a large covariance matrix and a sensitive system, a larger value will give a less sensitive estimator and slower adaption.

Typical values of λ are in the range 0.95 (for fast variations) to 0.99 (for slow variations). If the system is not 'persistently exciting', then $P(t)$ can increase indefinitely, which will cause numerical problems in the algorithm. The way this occurs is easily seen if x_t is set to a null vector when

$$P(t) = \frac{1}{\lambda} P(t-1) \tag{3.51}$$

with $\lambda < 1$, $P(t) \to \infty$ as $t \to \infty$. Hence, when the forgetting factor is used, checks should be used and the value of λ adjusted, so that numerical difficulties are avoided.

One advantage of the R.L.S. method is that the matrix $P(t)$ is proportional to the covariance of the parameter estimates, so that a near-singular P indicates that there are badly estimated directions in the parameter space. This could indicate, for example, that the number of parameters is too large or that the data is invalid.

3.11 Conclusion

This chapter has described the use of system modelling for system identification and prediction of the behaviour of unknown systems. The methods discussed enable a mathematical model of the system to be calculated using only the system input and output data, without the need for test signals. Clearly this is very useful for application when modelling industrial processes such as electrical power systems. It allows a reasonable system model to be calculated without disturbance to the system which is required for real-time applications. The use of least-squares estimation has been discussed and shown not to be particularly useful in itself for modelling power systems due to the non-static mode of operation. An extension to enable on line monitoring and calculation of the system model was presented and this type of recursive technique shown to be is useful to track power system dynamics and behaviour, and hence allows suitable control action to be calculated based on the most recent system model. The method of calculating such control signals is discussed in the next chapter.

CHAPTER 4

MINIMUM PREDICTION ERROR CONTROLLERS

4.1 Introduction

The previous chapter discussed the use of mathematical modelling as a tool to produce a representation of a system. This method of modelling a system from its general response without the need to apply artificial test signals is very useful for the control of electrical power systems. It enables the control to be calculated on-line in real-time without disturbing the operation of the system. Based on the updated model a suitable control signal can be calculated using various techniques. This enables the power system to be controlled to the required level without causing economic operating penalties.

The previous model description was capable of providing a way of predicting the future outputs of the system based on the past outputs and present inputs [12,15,50,52]. It would seem reasonable that the modelling process may be reversed and the ideas used in the modelling process may be then used to calculate control action for the system. The aim of the control action is to determine what control at the present time would bring the future output of the system to the required value. This process is especially simple if the future outputs are a linear function of the present control, since then the determination of the control action involves the solution of a set of linear equations.

This chapter discusses the use and equations involved in a control criterion termed *minimum variance control* [106,111,161] and then describes the extension to this technique that enables the control of non-minimum phase systems and reference following. Minimum variance control is the stochastic equivalent of one-step-ahead control which is used in the deterministic case to bring the system output at time $t + k$, $y(t + k)$ to some previously defined required value. Minimum variance control is used because by reducing the variance of a given variable, the controller set point can be kept at a reasonable value for the system while ensuring that the rest of the output meets a given criterion. There are many papers describing design work in this area, much work has been carried out by Clarke, Gawthrop and earlier Åström. There are consequently many references, some of the better ones are (16,17,18,52,53,54,57). Other work is reported in (64,131,141,162,164,189,194,214,217,219,220,221,226).

4.2 Predictive Models

Many self-tuning strategies, particularly implicit methods, are based on predictive control design, where the prediction horizon or time, is the system delay k [4,5,12,15,190,213]. This delay is introduced because the output at time $t+k$, $y(t+k)$ is the first output that can be influenced by the present control $u(t)$. During this time, disturbances will be acting on the system, so if an optimal prediction is to be made at time t, for time $t+k$ [16,51,52,53] the effect of the disturbance on the system at time $t+k$ must be predicted at time t. This enables a control signal, u, to be calculated at time t for time $t+k$. Thus the effect of these disturbances on the system can be removed by the calculation at time t. The effectiveness of this control depends on the accuracy of the predictions, which itself clearly depends on the characteristics of the disturbance and on the prediction interval k.

The system is modelled as described earlier using

$$A(z^{-1})y(t) = z^{-k}B(z^{-1})u(t) + C(z^{-1})\xi(t) \tag{4.1}$$

where

$A(z) = 1 + a_1z^{-1} + a_2z^{-2} + \ldots + a_nz^{-n}$,

$B(z) = b_0 + b_1z^{-1} + b_2z^{-2} + \ldots + b_mz^{-m}$ and

$C(z) = 1 + c_1z^{-1} + c_2z^{-2} + \ldots + c_pz^{-p}$.

The disturbance $\xi(t)$ is taken to be a weakly stationary sequence of uncorrelated random variables with zero mean. The system delay k and the orders of A, B, C are n, m, p respectively and are assumed to be known. The system is such that due to physical constraints, the discrete closed-loop system must contain at least one time delay, hence $k \geq 1$. The delay k is equal to the magnitude of the pole excess of the model $k = n - m$ which appears because of the use of the backward shift operator. The polynomial C is taken not to have roots outside, or on the unit circle in the z-plane, this can be achieved without loss of generality, as is shown in [53].

The input signal $u(t)$, can only change the output signal y, k sample periods ahead of time so the a control scheme is required that aims to make the expected value of the output error, k steps ahead in time equal to zero [130].

A minimum variance controller is proposed in this chapter which is capable of controlling the system output at a given time ahead to a previously defined value. The equation (4.1) can be rewritten using the more normal backward shift operator q as used for discrete systems. The output k samples ahead is given by

$$y(t+k) = \frac{B(q)}{A(q)}u(t) + \frac{C(q)}{A(q)}\xi(t+k) \tag{4.2}$$

By expanding $1/A$ as an infinite series in q, it is seen that the disturbance term has two components. The first is $\xi(t+i)$, where i takes the value from the present time, to the time k steps ahead in the future. The term $\xi(t-j)$ represents the all previous values of ξ up to the present time, that is $-\infty \rightarrow 0$. These past values of $\xi(t)$ can be reconstructed using the above equation and the measured input-output data $u(t), y(t)$, but the future values are unpredictable as ξ is an uncorrelated sequence. This development is shown in [59,106,130,166,181]. The term $C(q)/A(q)$ can be split up into its constituent parts by using the identity

$$\frac{C(q)}{A(q)} \equiv E(q) + q^{-k}\frac{F(q)}{A(q)} \tag{4.3}$$

where

$E(q) = e_0 + e_1 q^{-1} + \ldots + e_{n_e} q^{n_e}$ and

$F(q) = f_0 + f_1 q^{-1} + \ldots + f_{n_f} q^{n_f}$

$E(q)$ and $F(q)$ are both polynomials which can be obtained uniquely by comparing the coefficients of powers of q^{-1} if the degree of $E \leq k-1$. It is seen that if the degree of $e_0 = 1$ then the degree of F is $k-1$, this is shown in the example later. The equation above shows that the order of $E(q)$ is restricted by the order of $C(q)$. The order of C relative to k indicates to what degree the past and future noise will be considered. If C is of a high degree, then past and future noise is considered, but if C is small only future noise is considered. This equation $C(q)/A(q)$ represents two values of noise, the first $E(q)$ accounts for the future noise up to time $(t+k)$, and the second $F(q)$ represents the noise from $-\infty \rightarrow t$, that is from the start of the algorithm to present time. The expansion of $C(q)/A(q)$ is demonstrated using a simple example, where the polynomial in C is simply stated as

$$C = 1 - c_1 q^{-1} - c_2 q^{-2} - c_3 q^{-3} - c_4 q^{-4} - c_5 q^{-5} \tag{4.4}$$

If all the coefficients are set to -1 and $+1$ successively, then the polynomial may be written as

$$C = 1 - q^{-1} + q^{-2} - q^{-3} + q^{-4} - q^{-5} \tag{4.5}$$

The polynomial in A is written as

$$A = 1 - a_1 q^{-1} \tag{4.6}$$

where the coefficients of A are taken to be 1, hence A may be rewritten as

$$A = 1 - q^{-1} \tag{4.7}$$

The value of k in this example is taken to be 3. The division of C by A gives simply

$$\frac{C(q)}{A(q)} = 1 + q^{-2} + q^{-4} \tag{4.8}$$

This is expanded and rewritten as

$$\frac{C(q)}{A(q)} = 1 + q^{-2} + q^{-3}(q^{-1})$$

$$\frac{C(q)}{A(q)} = 1 + q^{-2} + q^{-3}\left[\frac{q^{-1}(1-q^{-1})}{1-q^{-1}}\right]$$

$$\frac{C(q)}{A(q)} = 1 + q^{-2} + q^{-3}\left[\frac{q^{-1}-q^{-2}}{1-q^{-1}}\right] \tag{4.9}$$

This is now compared with the equation

$$\frac{C(q)}{A(q)} \equiv E(q) + q^{-k}\frac{F(q)}{A(q)} \tag{4.10}$$

and clearly shows that

$$E(q) = 1 + q^{-2} \tag{4.11}$$

where, the order of E is less than that of k, and

$$F(q) = q^{-1} - q^{-2} \tag{4.12}$$

Thus as mentioned earlier, $E(q)$ has degree such that $E \leq k - 1$ and the order of $F(q)$ is seen to be $k - 1$. It is seen that the term, has been split into two distinct sections, one represents the quotient and the other the remainder of the term. The first is the noise disturbance predicted for the future, and the second, the noise up to the present time. Equation (4.2) may be rewritten as

$$A(q)y(t+k) = B(q)u(t) + C(q)\xi(t+k) \tag{4.13}$$

and equation (4.3) as

$$C(q) = E(q)A(q) + q^{-k}F(q) \tag{4.14}$$

The equation (4.13) is pre-multiplied by $E(q)$ giving

$$E(q)A(q)y(t+k) = E(q)B(q)u(t) + E(q)C(q)\xi(t+k) \tag{4.15}$$

subsituting for $E(q)A(q)$ from (4.14)

$$C(q)y(t+k) - F(q)y(t) = G(q)u(t) + E(q)C(q)\xi(t+k) \tag{4.16}$$

where

$G(q) \equiv E(q)B(q)$ This is rearranged to give a value of $y(t+k)$

$$y(t+k) = \frac{F(q)y(t) + G(q)u(t)}{C(q)} + E(q)\xi(t+k) \tag{4.17}$$

This equation shows the two sections that are required to make up the prediction for the output at $(t+k)$. The output is a function of the previous inputs and outputs and a noise factor. The first term is deterministic, and concerns the previous outputs and inputs. The second term is probabilistic, and takes into account the noise that will occur up to time $(t+k)$. The future noise term is of length k. The optimum prediction at time $t+k$, made at time t is represented by $(t+k \mid t)$ and is defined to be $y^*(t+k \mid t)$. The error in this prediction at the same time is given by $\tilde{y}(t+k \mid t)$. This means that the equation (4.17) can be rewritten as

$$y(t+k \mid t) = y^*(t+k \mid t) + \tilde{y}(t+k \mid t)$$

This defines the total predicted output at the prediction time $(t+k)$ This equation may be rewritten to show the two term as

$$C(q)^* y(t+k \mid t) = F(q)y(t) + G(q)u(t) \tag{4.18}$$

$$\tilde{y}(t+k \mid t) = E(q)\xi(t+k) \tag{4.19}$$

Hence the prediction depends on the previous values in the data vectors. The order of ξ is k, but the order of the input and output vectors is defined by the size of the *window* of data which is to be kept. Also it is noted that it is necessary for y^* and $\tilde{y}$ to be orthogonal. This is general when considering an optimum predictor. The prediction accuracy can be obtained from [16]

$$\text{Var} \quad \{\tilde{y}\} = \sigma^2(1 + e_1^2 + e_2^2 + \ldots + e_{k-1}^2)$$

This is the variance with k.

4.3 Minimum Variance Control and the Self-Tuning Regulator

As shown, the system model can be written as in the predictive form [4,5,15,16] of

$$C(q)y^*(t+k \mid t) = F(q)y(t) + G(q)u(t) \tag{4.20}$$

or

$$\Big[E(q)A(q) + q^{-1}F(q)\Big]\, y^*(t+k \mid t) = F(q)y(t) + E(q)B(q)u(t) \tag{4.21}$$

and

$$y(t+k) = y^*(t+k \mid t) + \tilde{y}(t+k \mid t) = y^*(t+k \mid t) + E(q)\xi(t+k) \tag{4.22}$$

A control law is used which selects the value of $u(t)$ such that the variance J is minimised. This is shown by the following equation.

$$\text{Min.} \qquad J = E\{y^2(t+k)\} \tag{4.23}$$

Where this is true over the whole of the data range $(-\infty, t)$ and this includes the random processes $\xi(t+i)$ which affects the output after time t. J is chosen as the control target in order to reduce the effect of disturbances on the regulated process output, this enables the process output to be kept within a defined range. This range is a constraint placed on the control system by the physical system itself.

These constraints are defined by the physical system, such as: ramping rates, upper and lower limits, speed of response and the desire for smooth and economic control action. If there are large fluctuations in the control output, the calculated set-point will vary greatly. This will lead to the unsatisfactory operation, such as causing unnecessary operation of the machine, which leads to unnecessary wear and tear on the machine, unnecessary ramping may also lead to unstable system operation. However, the major consideration when varying J rapidly, is that the system would not be operated at its most economic operating point for a particular set of conditions. If these fluctuations in the control commands are minimised, the set-point can be tracked giving the speed of response and quality of control that is required by system operations.

To minimise the variance of the output of the plant [58], the value of J is chosen so that this is achieved by the control system. Several references cover this complex topic, some of the better ones are (16,18,57,59,61,106,110,111,120).

$$\text{Min.} \qquad J = E\{y^2(t+k)\} = E\{(y^*(t+k \mid t) + \tilde{y}(t+k \mid t))^2\} \tag{4.24}$$

$$= (y^*(t+k \mid t))^2 + E\{(\tilde{y}(t+k \mid t))^2\} \tag{4.25}$$

The first term in the above is again seen to be the deterministic element of the equation, and the second, the probabilistic representation. This first term is a prediction of the value of the output k steps ahead of time, and based on information at time t. The second term is a prediction of the future disturbance noise, it is obviously unknown at time t, and it is independent of the control applied to the system. The terms $\tilde{y}$ is concerned with a white noise sequence into the future, while y^* is concerned with the future control commands. Thus $\tilde{y}$ and y^* are orthogonal, and when multiplied the middle term is lost. Also the value of y^* is known at time t. The value of $\tilde{y}$ is thus unaffected by $u(t)$. The minimum value of J is found when the value of y^* is set to zero by choosing a suitable prediction value for y^*, which is made zero. In this case a suitable value of y^* is zero. Hence from (4.20)

$$F(q)y(t) + G(q)u(t) = 0 \tag{4.26}$$

This may be rearranged and expressed as the feedback law

$$u(t) = -\frac{F(q)y(t)}{B(q)E(q)} \tag{4.27}$$

Using this control value, the minimal variance J_{min} can simply be written as being that of the k-step-predictor error $\sigma^2(1 + e_1^2 + \ldots + e_{k-1}^2)$.

The full closed loop equation can hence be stated as

$$\frac{y(t)}{w(t)} = \frac{\dfrac{-F(q)}{B(q)E(q)}\dfrac{q^{-k}B(q)}{A(q)}}{1 + \dfrac{F(q)}{B(q)E(q)}\dfrac{q^{-k}B(q)}{A(q)}} \tag{4.28}$$

The closed loop characteristic equation is thus

$$1 + \frac{F(q)}{B(q)E(q)}\frac{q^{-k}B(q)}{A(q)} = 0 \tag{4.29}$$

or

$$B(q)\left(E(q)A(q) + q^{-k}F(q)\right) = 0 \tag{4.30}$$

which using the identity (4.14) becomes

$$B(q)C(q) = 0 \tag{4.31}$$

If the control law $F(q)y(t) + G(q)u(t) = 0$ is satisfied, at all samples, then

$$y(t+k) = E(q)\xi(t+k) \tag{4.32}$$

Thus for identification, the following equation may then be used from (4.20) and (4.22)

$$y(t+k) = \frac{F(q)y(t) + G(q)u(t)}{C(q)} + E(q)\xi(t+k) \tag{4.33}$$

As E is order of $(k-1)$, $E\xi(t)$ is uncorrelated with $Gu(t-1)+Fy(t-1)$. Thus the least squares estimation algorithm can be used, and the estimates will be unbiased.

As $C(q)$ is a stable polynomial it is seen that the closed-loop stability depends on the sampled-process zeros. However, there are many cases (for example those with fast sampling or large fractional delay) where $B(q)$ may have roots outside the stability region. Hence, minimum-variance control should be used with caution. There are various ways of overcoming this inherent problem.

The original self-tuning regulator designed by Åström and Wittenmark [17,19] used the minimum-variance objective function. If equation (4.17) is considered where $C(q) \neq 1$ and, at time t rather than $t+k$

$$y(t) = \frac{F(q)y(t-k) + G(q)u(t-k)}{C(q)} + E(q)\xi(t) \tag{4.34}$$

$$y(t) = A'(q)y(t-k) + B'(q)u(t-k) + E(q)\xi(t) \tag{4.35}$$

The control that is required to make the predicted value of the output k steps ahead of time equal to zero is given by

$$u(t) = \frac{A'}{B'}y(t) = \frac{F(q)}{B(q)E(q)}y(t) \tag{4.36}$$

Which can be seen to be of the same form as (4.27) It is seen that the controller involves cancellation of system zeros by controller poles. Thus, if the system has non-minimum phase characteristics, the controller will contain unstable poles, and since in practice exact cancellation will not be achieved, an unstable closed-loop system results.

The previous chapter discussed the system model used for identification purposes. The model was shown in the form

$$y(t) = \theta_1 x_1(t) + \theta_2 x_2(t) + \theta_3 x_3(t) + \ldots + \theta_n x_n(t) + \xi(t) \tag{4.37}$$

which can be written more simply as

$$Y(t) = \Theta X(t) + \xi(t) \tag{4.38}$$

If the controller equation (4.36) is compared with (4.38) and it is seen to be in the same form as shown below.

$$\theta^T(t) = (f_0, f_1, \ldots, f_{n-1}, g_0, g_1, \ldots, g_{n+k-}) \tag{4.39}$$

$$x^T(t) = (y(t-k), \ldots, u(t-k), \ldots, u(t-k-n+1)) \tag{4.40}$$

$$\varepsilon(t) = \xi(t) + e_1\xi(t-1) + \ldots + e_{k-1}\xi(t-k+1) \tag{4.41}$$

$$\text{and } y(t) = y(t) \tag{4.42}$$

Here $\varepsilon(t)$ is an autocorrelated process, but is independent of all elements of the *known data* vector $x(t)$. Hence the Recursive Least Squares algorithm described previously can be used to obtain unbiased (though not optimal) estimates of $\hat{\theta}$. These estimates are then used in the certainty-equivalent control law:

$$\hat{F}(q)y(t) + \hat{G}z)u(t) = 0 \tag{4.43}$$

This is an implicit self-tuner, as the required feedback parameters are estimated directly rather than via a control-design calculation.

The estimated parameters in (4.38) are not unique, for this equation may be multiplied by an arbitrary constant without affecting the calculation of $u(t)$. This means that the estimates will lie on a linear manifold *wandering in unison* (52,53) and may lead to excessively large or small values with possible numerical problems developing. A unique estimation can be achieved by *fixing* one parameter, such as $g_0 = b_0$ the first value of the estimated B parameter vector. This can be done in two ways.

(a) The first is to not use g_0 and $u(t-k)$ in θ and x to make $Z = y(t) - \hat{b}_0 u(t-k)$, where $\hat{b}_0$ is the fixed value of g_0.

(b) The second method is to set the corresponding diagonal element in $P(0)$, which would otherwise be αI to zero, indicating that the parameter value was considered to be exactly known.

Although this second method involves slightly more [9] computer time, it has the advantage that the same basic self-tuner software can be used with any chosen parameter fixed. The value of $\hat{b}_0$ does not need to be close to b_0 but the convergence rate depends on the ratio $b_0/\hat{b}_0$ so a *small* value of $\hat{b}_0$ may initially lead to excessive control signals. This can be seen if (4.41) is solved for $u(t)$

$$u(t) = -\frac{1}{\hat{b}_0}(\hat{f}_0 y(t) + \hat{f}_1 y(t-1) + \ldots + \hat{g}_1 u(t-1)) \tag{4.44}$$

A simpler alternative is to ignore the lack of uniqueness in the estimation and not to fix any parameter, although this complicates convergence analysis the self-tuning performance is still effective.

As an example consider what happens when the self-tuner is used with a system where $C(q^-1) \neq 1$ but is a general polynomial. With reference to recursive estimation it may be thought that the Recursive Least Squares method is not sufficient and that Extended Least Squares or Recursive Maximum Likelihood methods should be used, however, this is not the case. This can be seen by expanding $1/C(q)$ as an infinite polynomial

$$C^{-1} = 1 + c_1 q^{-1} + c_2 q^{-2} + \ldots \tag{4.45}$$

The predictor model may be written as

$$\begin{aligned} y(t) =& F(q)y(t-k) + G(q)u(t-k) \\ &+ c_1\left(F(q)y(t-k-1) + G(q)u(t-k-1)\right) + \ldots + E(q)\xi(t) \end{aligned} \tag{4.46}$$

If the algorithm has converged in such away that $\hat{\theta} = \theta$, then the control from (4.41) will set all the terms on the R.H.S. of the equation to zero so that this equation reduces to (4.40) as if $c_i = 0$ and hence as if $C(q) \neq 1$. This implies that $\hat{\theta} = \theta$ is a fixed point of the algorithm, but this in itself does not prove that it is a stable fixed-point, this must be done using alternative methods. In the initial tuning stage, however, $\hat{\theta}$ may be rather different from θ and then c_i

may then have a significant effect on the true convergence rate. The dynamics of $1/C(q)$ and the convergence rate are clearly related.

In practice, the dynamics of the model depend on the certainty equivalent equation (4.41) being satisfied by the control $u(t)$. In many systems there are constraints on the control that can be implemented by the operators, or the physical reality of the plant itself and there may be times when the desired control $u(t)$ cannot be used so that the equation no longer holds. This means that in theory R.L.S. will then fail to give unbiased estimates of $F(q)$ and $G(q)$, but it is found that provided $u(t)$ is not always clipped the algorithm is still effective.

4.4 Generalised minimum-variance self-tuning control

The objective of the self-tuning regulator, in minimising the output variance, is restrictive and may only be applied to a only few industrial situations. The example which is generally quoted is the paper industry, where minimal variance output means that the mean thickness of the paper may be reduced whilst ensuring that only a given percentage of the paper falls below a specified minimum thickness. This criterion is less applicable to process variables such as temperature, flow, pressure and so on. Another drawback with minimum variance control is that no account is taken of the control effort required to achieve this minimal variance, if this is found to be excessive the only variable that can be altered is the sample interval of the controller. Diagram 4.2shows a representation of the generalised minimum-variance controller in block form.

With the self-tuning controller [56] greater flexibility is achieved by defining a *generalised* output $\phi(t)$ of the form

$$\phi(t+k) = P(q^{-1})y(t+k) + Q(q^{-1})u(t) - w(t) \tag{4.47}$$

where

$P(q^{-1})$ and $Q(q^{-1})$ are the transfer functions which can be specified by the control designer to achieve one of the variety of the objectives. The signal $w(t)$ is the set point (this may be pre-filtered to avoid sudden changes) which is available at time t, the use of $w(t)$ allows the self-tuner to be further

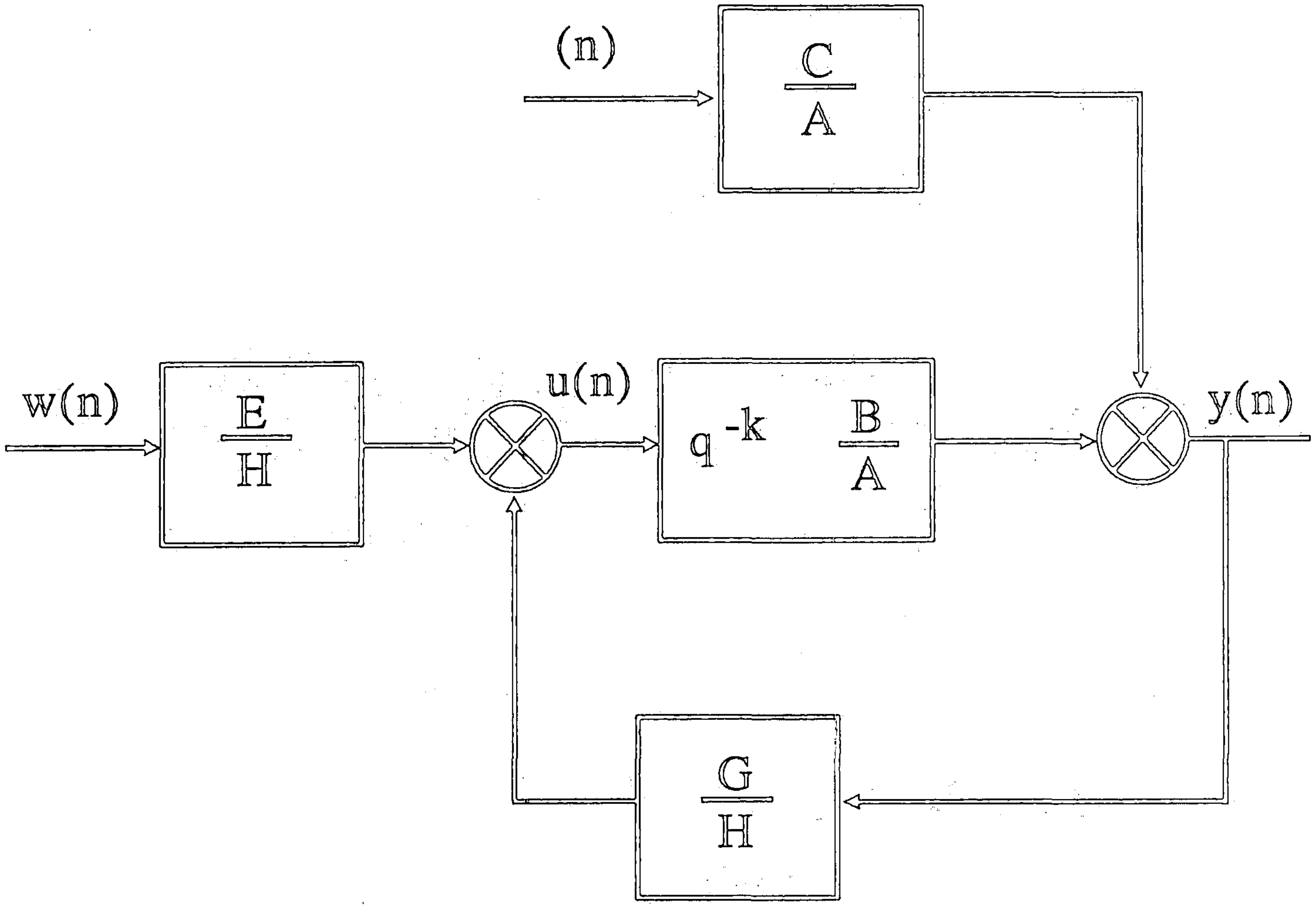


Diagram 4.1 Generalised minimum variance self-tuning control scheme

generalised so that it includes system tracking along with control regulation. The cost-function which is to be minimised (given the known parameters) is the variance of the generalised output

$$\text{Min.} \qquad J = E\{\phi(t+k)\} \tag{4.48}$$

This cost function in conjunction with the equation (4.47) can be used in several ways.

In equation (4.17) the value of $y(t)$ was calculated from the two terms represented in the equation, the deterministic term and the probabilistic one. The variance J was determined using (4.23). In the same way the equivalent cost function for this more general case may be given by

$$\text{Min.} \qquad J = E\{(y(t+k) - w(t+k))^2 + (Qu(t))^2 \mid t)\} \tag{4.49}$$

The minimisation is carried out on the data available up to time t. This means that the first term of the Q vector is equal to the first term of the B vector, that is $q_0 = b_0$. For example, if Q is chosen to be a constant, λ and P is chosen to be one, then the cost function may be written as

$$J = E\{(y(t+k) - w(t))^2 + b_0\lambda u(t)^2 \mid t\} \tag{4.50}$$

This equation is useful as it allows the user to assign a weight to deviations in $y(t)$ from the set point $w(t)$. These are weighted against the minimum variance control of $u(t)$. However, there is a problem involved in this operation because, the weighting is dependent on the fixed parameter b_0 and hence will be system dependent.

Another possibility [50] is to chose Q such that $Q = \lambda(1 - q^{-1})$. This leads to a cost function which depends on changes in the control

$$J = E\{(y(t+k) - w(t))^2 + b_0\lambda(u(t) - u(t-1))^2 \mid t\} \tag{4.51}$$

Other suggestions are made in the literature [50]. If $Q = 0$ then equations (4.17) and (4.47) show that if a control is used such that $\phi^*(t+k) \mid t = 0$, then

$$\phi(t+k) = \tilde{\phi}(t+k \mid t) = P(q^{-1})y(t+k) - w(t) \tag{4.52}$$

which gives

$$y(t+k) = \frac{1}{P(q^{-1})}\left(w(t) + \tilde{\phi}(t+k \mid t)\right) \tag{4.53}$$

The transfer function of P can be chosen to be the inverse M^{-1} of some desired closed loop model M. Thus from (4.53) $y(t+k)$ can be written as

$$y(t+k) = Mw(t) + M\tilde{\phi}(t+k \mid t) \tag{4.54}$$

This corresponds to model reference tracking systems [53]. In this case the disturbance behaviour in closed loop is also prespecified to some extent. If $P(q^{-1}) = 1$ and $Q(q^{-1}) = L^{-1}$, where L is the transfer function for instance of a P.I.D. controller. The control which minimises J and sets ϕ^* to zero is again from equation (4.47). In this case

$$y^*(t+k \mid t) + L^{-1}u(t) - w(t) = 0 \tag{4.55}$$

or

$$u(t) = L(w(t) - y^*(t+k \mid t) \tag{4.56}$$

This form of this equation is that of a classical feedback control law, except that the optimal k step ahead prediction y^* is fed back rather than the current output $y(t)$. This has the effect of removing the phase lag of the process time delay k and allowing for tighter conventional P.I.D. control.

The derivation of this control which minimises the variance of ϕ is relatively straight forward [50] and is shown below. This achieved by substituting equation (4.47) defining ϕ, into the system model given by (4.2). Hence,

$$A(q^{-1})\phi(t+k) = \left(P(q^{-1})B(q^{-1}) + Q(q^{-1})A(q^{-1})\right)u(t) + P(q^{-1})C(q^{-1})\xi(t+k) - A(q^{-1})w(t) \tag{4.57}$$

In this case,the term $-A(q^{-1})w(t)$ is known, so without this term (4.57) gives a model describing equation of

$$A'\phi(t) = B'u(t+k) + C'\xi(t) \tag{4.58}$$

where

$A' = A$,

$B' = P(q^{-1})B(q^{-1}) + Q(q^{-1})A(q^{-1})$ and

$C' = P(q^{-1})C(q^{-1})$

For the somewhat more complicated case, $P(q^{-1})$ and $Q(q^{-1})$ have both numerator and denominator dynamics, rather than just being polynomials. If $P(q^{-1})$ and $Q(q^{-1})$ are to be defined as

$$P(q^{-1}) = \frac{P_n(q^{-1})}{P_d(q^{-1})} \quad \text{and} \quad Q(q^{-1}) = \frac{Q_n(q^{-1})}{Q_d(q^{-1})}$$

then a model like (4.1) is calculated, where
$A' = P_d(q^{-1})Q_d(q^{-1})A(q^{-1})$,
$B' = P_n(q^{-1})B(q^{-1})Q_d(q^{-1}) + Q_n(q^{-1})A(q^{-1}P_d(q^{-1})$ and
$C' = P_n(q^{-1})C(q^{-1})Q_d(q^{-1})$
This equation is in the same form as (4.2), so the derivation of the control signal to minimise $E\{\phi^2(t+k)\}$ follows the previous derivation for the minimisation of $E\{y^2(t+k)\}$. From equation (4.58) it is seen that

$$\phi(t+k) = \frac{P(q^{-1})B(q^{-1}) + Q(q^{-1})A(q^{-1})}{C(q^{-1})}u(t)\frac{P(q^{-1})C(q^{-1})}{A(q^{-1})}\xi(t+k) - w(t) \tag{4.59}$$

The polynomial identity of (4.3) is also altered to become

$$\frac{P_n(q^{-1})C(q^{-1})}{P_d(q^{-1})C(q^{-1})} = E(q^{-1}) + q^{-k}\frac{F(q^{-1})}{P_n(q^{-1})A(q^{-1})} \tag{4.60}$$

This change gives the system model in equation (4.2) that relates $\xi(t)$ to $y(t)$ and $u(t)$. This rather involved equation is

$$\begin{aligned}
\phi(t+k) =& \frac{P(q^{-1})B(q^{-1}) + Q(q^{-1})A(q^{-1})}{A(q^{-1})} + E\xi(t+k) + \\
& \frac{F(q^{-1})}{P_d(q^{-1})A(q^{-1})}\left(\frac{A(q^{-1})y(t+k) - B(q^{-1})u(t-k)}{C(q^{-1})}\right) - w(t) \\
=& \frac{F(q^{-1})}{P_d(q^{-1})C(q^{-1})}y(t) + \frac{P(q^{-1})B(q^{-1}) + Q(q^{-1})A(q^{-1})}{A(q^{-1})}u(t) \\
& - \frac{B(q^{-1})}{C(q^{-1})}\left(\frac{P(q^{-1})C(q^{-1})}{A(q^{-1})} - E(q^{-1})\right)u(t) - w(t) + E(q^{-1}\xi(t+k) \\
=& \frac{F(q^{-1})y(t)}{P_d(q^{-1})C(q^{-1})} + \frac{B(q^{-1})E(q^{-1}) + C(q^{-1})Q(q^{-1})}{C(q^{-1})}u(t) - w(t) + E(q^{-1})\xi(t+k) \\
=& \frac{F(q^{-1})Q_d(q^{-1})y(t)}{P_d(q^{-1})Q_d(q^{-1})C(q^{-1})} \\
& + \frac{P_d(q^{-1})[(B(q^{-1})E(q^{-1})q_d(q^{-1}) + C(q^{-1})Q_n(q^{-1})]u(t)}{P_d(q^{-1})Q_d(q^{-1})C(q^{-1})} \\
& - \frac{P_d(q^{-1})Q_d(q^{-1})C(q^{-1})w(t)}{P_d(q^{-1})Q_d(q^{-1})C(q^{-1})} \\
& + E(q^{-1})\xi(t+k)
\end{aligned} \tag{4.61}$$

It may be simplified to

$$\phi(t+k) = \phi^*(t+k \mid t) + \tilde{\phi}(t+k \mid t)$$

As before, the control which minimises $E\{\phi^2(t+k)\}$ must set $\phi^*(t+k \mid t)$ to zero. This results in the minimised control being given as

$$\begin{aligned} u(t) &= \frac{P_d(q^{-1})Q_d(q^{-1})C(q^{-1})w(t) - F(q^{-1})q_d(q^{-1})y(t)}{P_d(q^{-1})[B(q^{-1})E(q^{-1})Q_d(q^{-1}) + C(q^{-1})Q_n(q^{-1})]} \\ &= \frac{C(q^{-1})w(t) - F(q^{-1})y(t)/P_d(q^{-1})}{B(q^{-1})E(q^{-1}) + C(q^{-1})Q(q^{-1})} \end{aligned} \tag{4.62}$$

When in a closed-loop, this control given by (4.62) shows the following behaviour in terms of the set point $w(t)$ and the disturbances $\xi(t)$.
The Output Signal is given by

$$\begin{aligned} y(t+k) = &\frac{B(q^{-1})P_d(q^{-1})Q_d(q^{-1})}{Q_n(q^{-1})A(q^{-1})P_d(q^{-1}) + P_d(q^{-1})B(q^{-1})Q_n(q^{-1})}w(t) \\ &+ \frac{P_d(q^{-1})Q_d(q^{-1})B(q^{-1})E(q^{-1}) + P_d(q^{-1})Q_n(q^{-1})C(q^{-1})}{Q_n(q^{-1})A(q^{-1})P_d(q^{-1}) + P_n(q^{-1})B(q^{-1})Q_d(q^{-1})}\xi(t \end{aligned} \tag{4.63}$$

The Control Signal is given by

$$\begin{aligned} u(t) = &\frac{A(q^{-1})P_d(q^{-1})Q_d(q^{-1})}{Q_n(q^{-1})A(q^{-1})P_d(q^{-1}) + P_d(q^{-1})B(q^{-1})Q_n(q^{-1})}w(t) \\ &- \frac{Q_d(q^{-1})F(q^{-1})}{Q_n(q^{-1})A(q^{-1})P_d(q^{-1}) + P_n(q^{-1})B(q^{-1})Q_d(q^{-1})}\xi(t) \end{aligned} \tag{4.64}$$

The characteristic equation of the closed loop system is

$$Q_n(q^{-1})A(q^{-1})P_d(q^{-1}) + P_n(q^{-1})B(q^{-1})Q_d(q^{-1}) = 0$$

For the applications when self-tuning regulators are required to minimise $E\{y^2\}$ and also the cases of model reference control, the self-tuning controller has no control weighting, hence, $Q_n = 0$. This gives a characteristic equation whose roots are simply those of $P_n(q^{-1})B(q^{-1})Q_d(q^{-1})$. For stability these roots must lie within the unit-circle, and this implies that the discrete-time model of equation (4.2) must have its zeros within the unit circle [51].

However, this constraint of zeros within the unit circle is an unreasonable restriction in practice, because systems with fractional delay times, or system of high-order with short sampling intervals could have discrete-time models with zeros outside the stability region. To allow such control in these cases of instability, a control weighting is used where $Q = \lambda$ produces a characteristic equation of

$$\lambda A(q^{-1})P_d(q^{-1} + P_n(q^{-1})B(q^{-1}) = 0$$

Thus if the system is open loop stable (that means if the roots of A are in the stability region), and if the design algorithm has chosen P_d correctly, the parameter λ may be varied to enable the closed loop poles to be moved into the stability region. Such a control may be seen as *detuned* model reference control. In such control, the control effort is *traded* off against closeness of model following. If a parameter such as λ is not available in an implicit self-tuner, stability can only be achieved by either increasing the sample time or assumed value of the system's delay k^{50}.

A self-tuning algorithm based on the generalised minimum variance approach can be calculated using the following steps:

(a) Collect value of $y(t)$

(b) Using the most recent controller parameter estimates, calculate the control signal $u(t)$ such that,

$$\left(B(q^{-1})E(q^{-1}) + C(q^{-1})Q(q^{-1})\right) u(t) + F(q^{-1})y(t) - C(q^{-1})w(t) = 0$$

This control command may then be sent out to the system.

(c) Calculate the vector to describe $\phi(t)$

$$\phi(t+k) = P(q^{-1})y(t+k) + Q(q^{-1})u(t) - w(t)$$

(d) Update the controller parameter estimates using a suitable estimation technique (least squares)

$$\phi(t+k) = \left[\left(B(q^{-1})E(q^{-1}) + C(q^{-1})Q(q^{-1})\right) u(t) + F(q^{-1})y(t) - C(q^{-1})w(t)\right]$$

(e) Store the updated parameters and return to (a), to continue the process

In the previous sections it has been shown that the generalised minimum variance approach of self-tuning offers a very flexible method for system stochastic disturbances. With the specification of the auxiliary function, the emphasis of the design criterion is moved away from minimising the system's output variance, to one of providing the closed loop system with a particular closed loop dynamic characteristic. The way in which the dynamic characteristics can be controlled is dependent on the way in which the system is operated.

4.5 Conclusion

This chapter has discussed the control methods that may be used to control systems with known parameters. The control methods surveyed are more advanced than the more usual P.I.D. controller which is implemented in many industrial applications today. The use of the special case of the minimum variance controller was investigated and seen to be useful in industrial applications but has the limitation of the single objective and the fact that no account is taken of the control action which is required. This is a problem when considering the control of power systems, where the magnitude of control as well as the quality of control must be considered.

It has been shown that the control action may be improved using the generalised minimum variance control technique, along with some of the defining equations used in the technique. A brief discussion of the type and order of calculations which are necessary for the implementation of the one of these schemes in a control package has also been presented.

CHAPTER 5

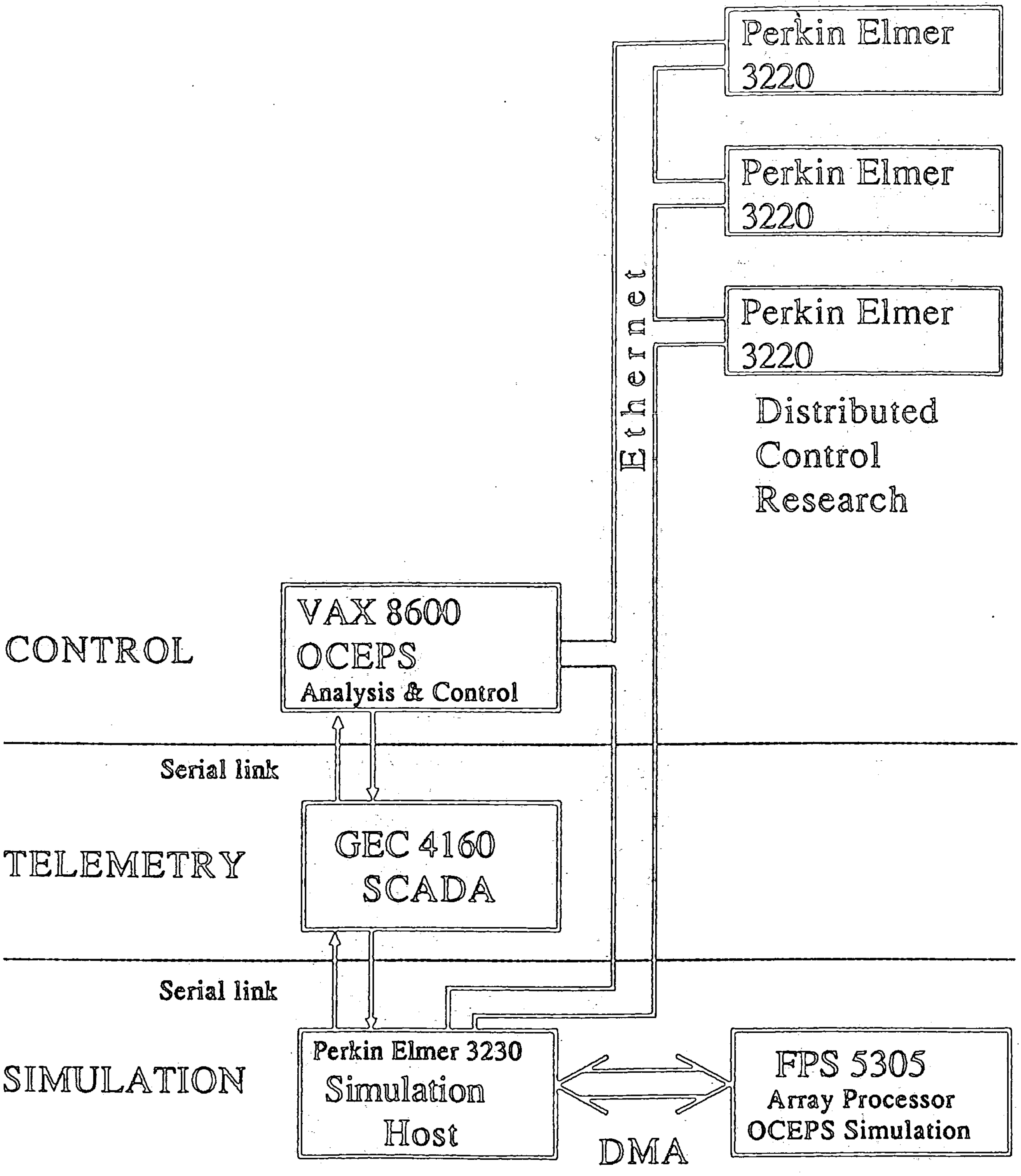
SYSTEM FREQUENCY CONTROL

5.1 Introduction

This chapter is divided into two separate sections. The first section describes the Durham University Power System Simulator and Energy Management software, known as O.C.E.P.S. (Operational Control of Electrical Power Systems). This software suite is a highly integrated system which uses several different computers to simulate and control an Electrical Power System. The simulation and control are both real–time operations and hence require special computing techniques and a large amount of computer hardware. The power system simulation is carried out on an array processor hosted by a Perkin Elmer 3230 minicomputer and the control software is run on a Digital Equipment Corporation, VAX 8600. Diagram 5.1 shows the set–up of the computer facilities used for the O.C.E.P.S. project. The software is mainly written in FORTRAN 77 which supports real–time operation. The simulator is used to execute extensive tests and validation of the control software as well as offer an opportunity to research into simulation techniques.

The second section of this chapter describes the requirements for Load Frequency Controllers, their interaction with other control functions and a standard frequency controller. This frequency controller has been developed and tested within the confines of the O.C.E.P.S. research project and was used to define the problems associated with the introduction of an L.F.C. scheme into an energy management software environment. The results of several simulation runs under differing system conditions, times of day and consumer loads are presented. Also discussed is the effect that changing the controller parameters has on the system response.

Diagram 5.1 O.C.EP.S. Computer System



5.2 Operational Control of Electrical Power Systems

The computer control of electrical power systems generation, transmission and distribution is a complex task, which involves data processing and a high degree of control software interaction.

The Operational Control of Electrical Power Systems [186,200] (O.C.E.P.S.) project at Durham was designed as an integrated package of software programs for the control of electric power systems. Monitoring and control functions are coordinated in a real time package and the verification of software using a real time simulator is made. The configuration of the simulation and control functions is shown in diagram 5.2.

5.3 System Simulation

The use of this real–time approach has several advantages in that a realistic test–bed for control schemes has been created. This scheme means that the generators and other plant, along with the transmission network, may be directly controlled in such a manner that the effect of the calculated control action is seen to have a direct affect on the actual plant [132,185,186,196]. Clearly there is a requirement for highly robust software and a modular structure is required. The start up and shut down of control functions in the simulator transfer control from one mode to another, which leads to problems in data transfer and communications between the algorithms and the simulated system. This requires, that the scheduling of the tasks in overall control scheme synchronised. During emergency conditions when the system is changing rapidly, the control tasks are a heavy load on the computer and require some scheduling of the tasks to be carried out is needed. The functional control, memory occupancy and processor loadings have been considered and an integrated solution has been found.

The simulation used to test the control algorithms is a full dynamic system simulation which will operate in real time, [200,201,203,211] that is one second of simulation time is equal to one second of actual time. The simulation

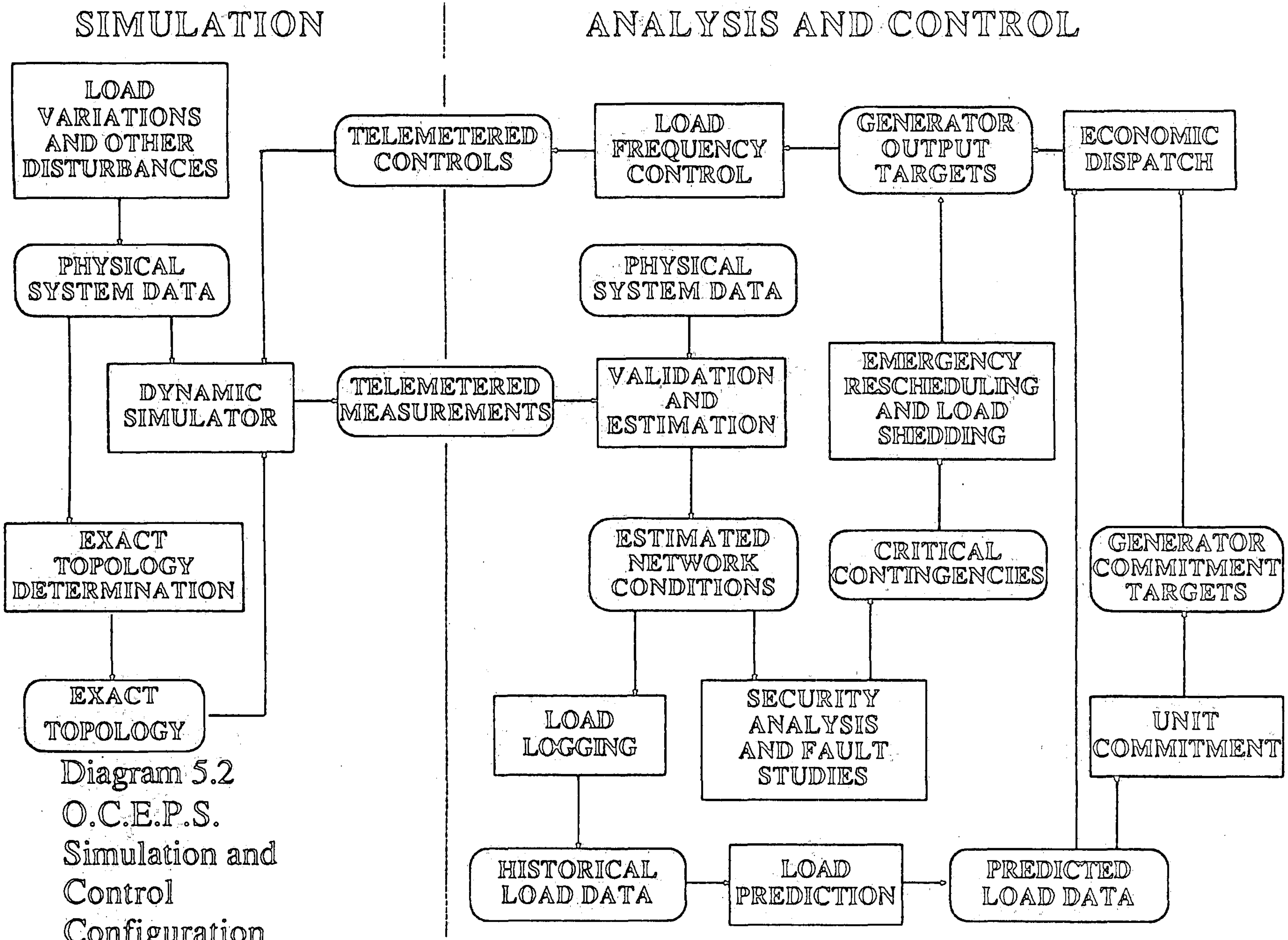


Diagram 5.2
O.C.E.P.S.
Simulation and
Control
Configuration

provides a simplified representation of the elements found in a power system such as, generators, loads, transformers, static compensation and other such elements.

5.3.1 Generator models

The simulation includes a set of generator models which are all based on the same type of units but with slightly different characteristics, along with differing output limitations. Presently the simulation does not provide models for non–thermal units of any kind, for instance pumped storage or gas–turbine.

(a) A set of generator models is used so that the realistic situation of each system generator is modelled. The input and control system is modelled individually for each generator so that the representation is as accurate as possible.

(b) Each unit is provided with an automatic voltage regulator so that the voltage magnitude of the units may be kept near to the set point by variation of the excitation level.

(c) The governor model is used to control the electrical power output of the generator by varying the mechanical power input. This controller is responsible for the very short term control (less than one second) of the turbine–generator unit.

(d) The boiler model used represents the drum type or once through boiler which has an integral boiler–turbine control system.

Turbine models are used to represent the prime mover of the units. These are of the three stage re–heat type and are controlled by the mechanism mentioned above.

5.3.2 Network models

The simulation includes a selection of plant which is found in a typical power system.

(a) Transformers of the fixed type and automatic type are modelled to enable differing voltage levels to be represented by the simulation.

(b) Transmission lines are included so that the effect of the losses involved in such items can effect the simulation. The line parameters vary with system frequency.

(c) Static compensation of the inductive or capacitive are included to correct for the unacceptable high or low voltage conditions in the network.

(d) Consumer loads are modelled as frequency and voltage dependent as well as being of the constant power, constant current and constant impedance type.

5.4 Measurements for Simulation

The effects of measurement corruption and total loss due to faulty transducers and data communication equipment is simulated. Random noise is added directly to the numerical values of the simulator before they are sent to the control systems. This represents both static and dynamic errors, gross errors and component failure can also be simulated. The effect of the noise on the simulation can be removed completely if required so that its effect may be clearly seen on the control algorithms. Part of the aim of the control algorithms is to be able to remove the noise so that its effect is removed from the control action.

5.5 Protection Equipment

Some protection equipment is represented to guard against generator over–speed, under frequency and line overloadings. The time step is accepted to be too great to be able to model accurately protection operation.

5.6 Network Topology

The network topology or connectivity of a system varies during normal operation due to the switching action of the system controllers and the protection. This information of the system configuration may be used by the control algorithms to calculate the which part of the network are energised.

5.7 Electrical Islands

The simulation is capable of splitting the system into multiple independent electrical islands. This is useful for the investigation of emergency conditions should the system reach the undesirable point when it has degraded to such a point that totally independent area of islands are formed. This requires all the control algorithms to have the capability of splitting their control action such that they are able to function on separate islands simultaneously. The resynchronisation of these island is possible through the control of L.F.C., but the control command to start the process must be input manually.

5.8 Simulation Sub–systems

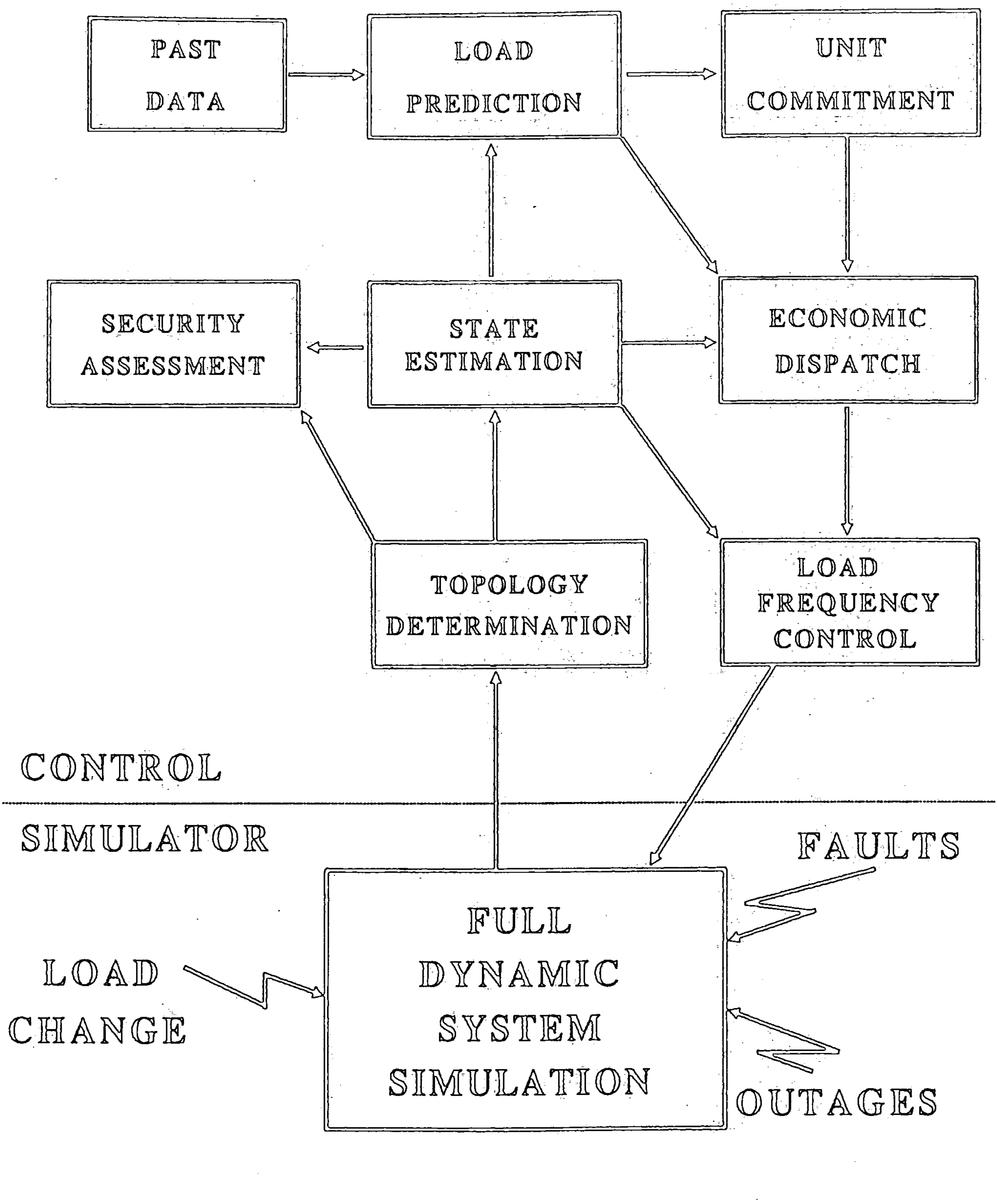
The simulation is made up from several sub–systems which are arranged in a database formation. The physical system data block contains information on the physical state of the network, such as the state of the network, breaker conditions, loading conditions and so on. The link between the connectivity data from the busbar to nodal level is achieved by exact topology determination. The simulation system is shown in diagram 5.3.

The simulator uses non–linear algebraic models of the network in conjunction with a set of low–order differential equations which represent generator dynamics to produce telemetry information. To obtain stable numerical integration at the high solution speeds required, the implicit trapezoidal technique is used with sparse Newton–Raphson techniques.

5.9 System Coordination

The control and simulation software is coordinated into an integrated system. This configuration is similar to a standard automatic control system. The information is monitored via the telemetry system, load–monitoring, topology determination and state–estimation subsystems. Feedback control is

Diagram 5.3 O.C.E.P.S. Overall Scheme



achieved using Load Frequency Control, generation rescheduling and load shedding. Feedforward control is implemented by the use of load-prediction, security analysis, economic dispatch and unit commitment functions.

This system is modular in structure which enables each task to communicate with others through shared memory areas with specified access privileges. The timing of the task execution and their execution is achieved by flags set by each individual task in shared data area. Every task is capable of being started and shut down without affecting the operation of the other functions, or the integrity of the control system as a whole. The coordination of the control sub systems is shown in diagram 5.4.

5.10 Simulated Network

The test system used is an extended version of the 30 node I.E.E.E. standard test network [186]. Each of the nodes in the test system consists of a number of busbars which are connected via links. Each of these links can have one or more circuit breakers, and represents the coupling circuits between busbars of other connection points. The test system used in the simulations is shown in diagram 5.5. A substation may contain more than one node with the number of nodes of each substation depending on the operating conditions. The substations are not fully defined by the I.E.E.E. standard and thus have been designed to allow switching and control action to be carried out in a manner that is probably more complex than in a conventional system.

The system itself represents six generators, the largest capable of producing 200 MW, the smaller ones have a maximum output of 100 MW. The consumer demand is designed to follow a load curve which is based on actual C.E.G.B. data (from 1985) scaled to the appropriate size for the network. A typical load curve for one day is shown in figure 5.1. The lower plot, figure 5.2 shows one day of recorded past load data, along with the prediction for the following day. Also shown is the actual recorded load curve. The error between predicted and actual load is small so the Dispatch calculated values

Diagram 5.4 Coordination of Subsystems

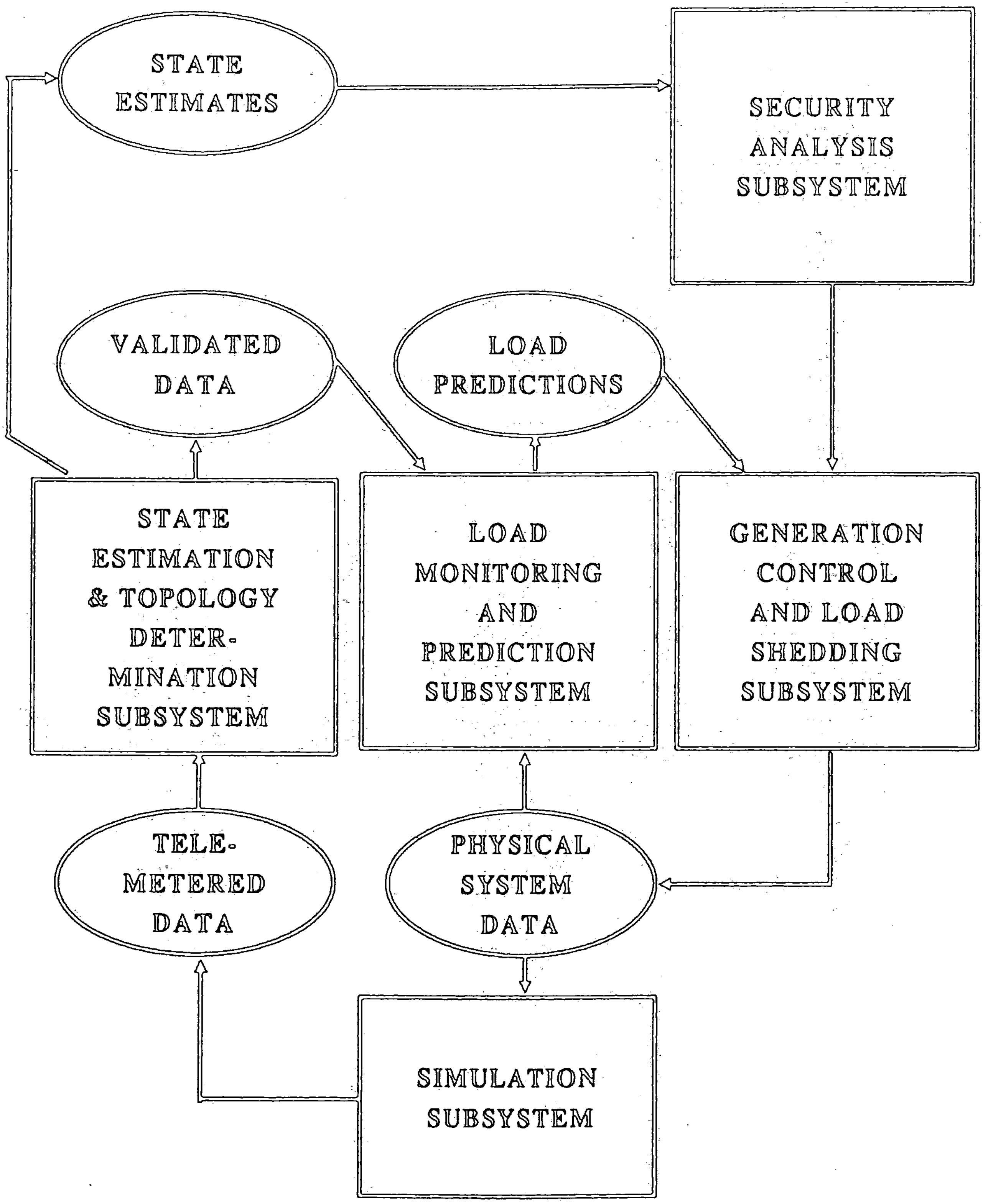
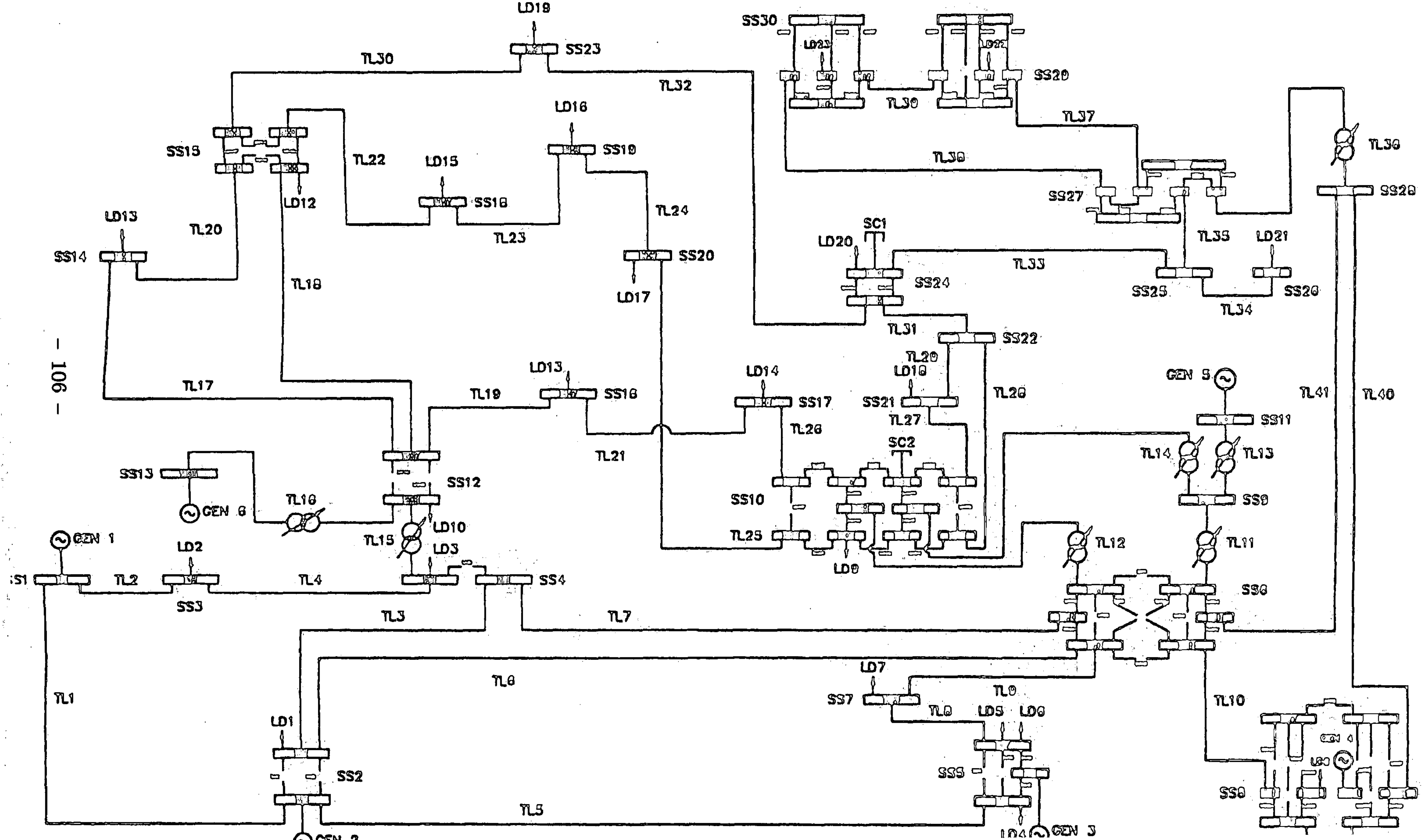


Diagram 5.5 O.C.E.P.S. Projcet thirty substation test system



should satisfy the consumer load without too much alteration by the L.F.C. function.

5.11 Load Frequency Control in O.C.E.P.S.

The following sections describe the basis of the L.F.C. function that has been implemented within the O.C.E.P.S. environment. The earlier sections discuss in general terms the points that should be considered when planning a frequency control scheme and its implementation, further ideas may be found in several references (8,21,36,38,40,49,80,86,98,121,123,124,188 225). An overview of the measurement and control scheme used by the L.F.C. function to collect the required measurements and send out the control commands is shown in diagram 5.6.

The later sections discuss the application of the L.F.C. as an integrated part of the O.C.E.P.S. control hierarchy [200,201,204,216]. These sections describe the problems encountered with the implementation of the control function, the interface with the other existing longer range control schemes and the system limitations which constrain the control scheme. The last section gives some typical plots of the integrated control scheme in action in varying system conditions.

5.12 Load Frequency Requirements

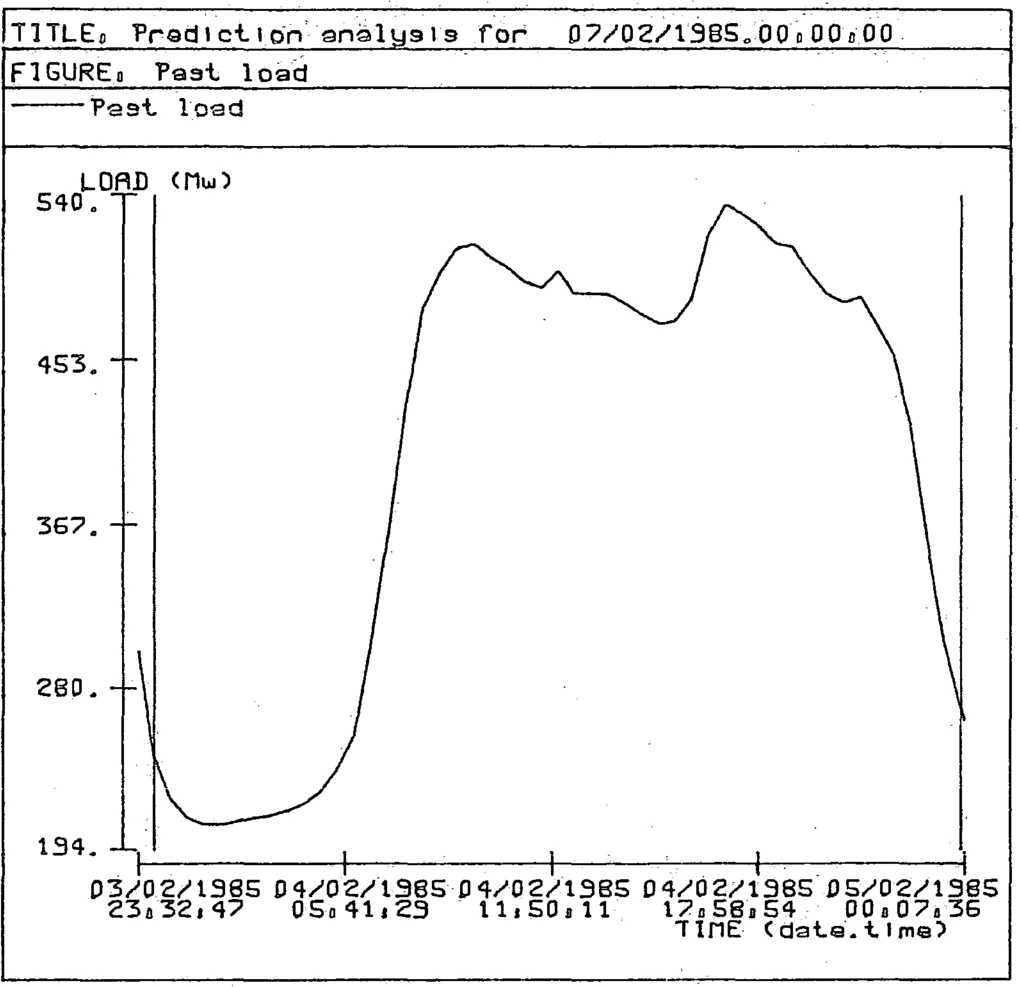
The standard proportional plus integral control equation discussed in the previous chapter is used for the main calculation for the computation requirement (C.R.). Many papers have investigated the use of this control error, some of the better ones are 7,55,141,149,157,184,201,204,214,227. Some of the following section is based on a combination of ideas from this extensive list of references.

$$\text{C.R.} = -\frac{1}{P_r}[\sum K_i(\Delta P_{tie} + K\Delta f)\,dt + K_p(\Delta P_{tie} + K\Delta f)] \qquad (5.1)$$

where

C.R. is a fraction of the system regulating capacity P_r

Figure 5.1



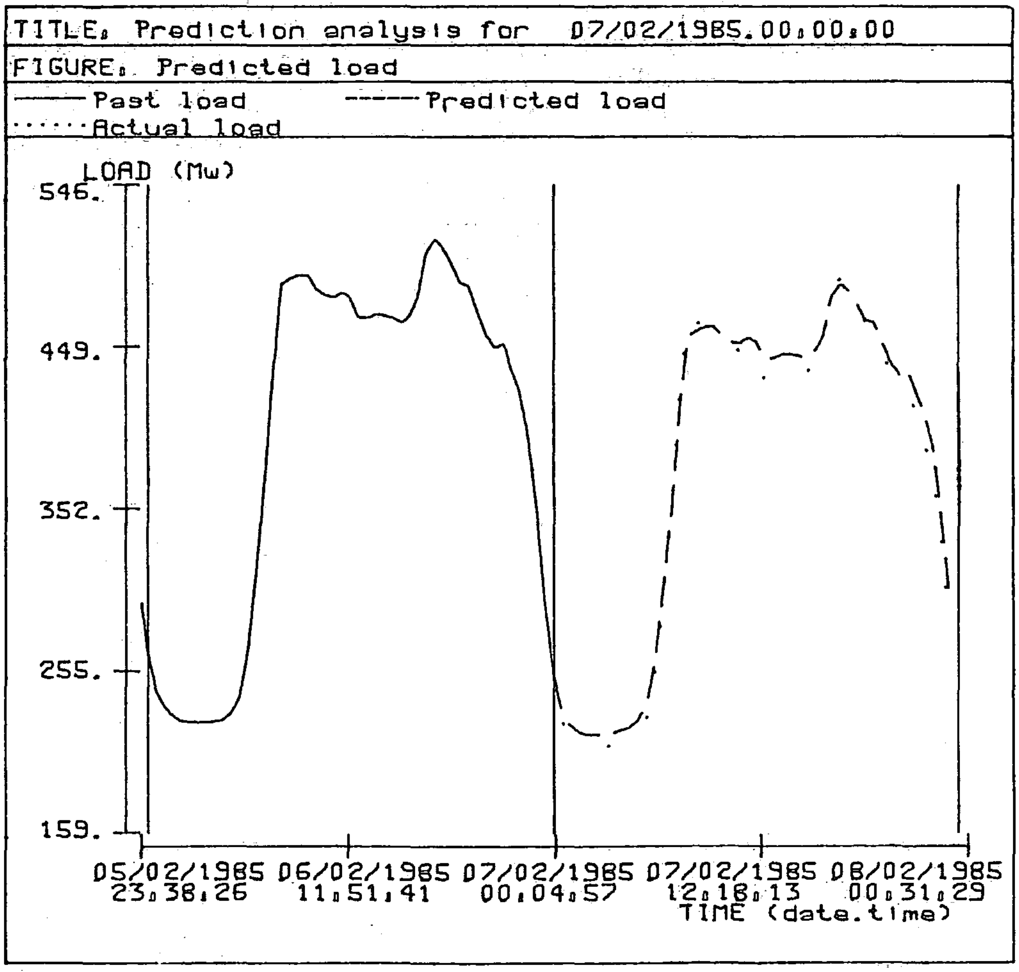


Figure 5.2

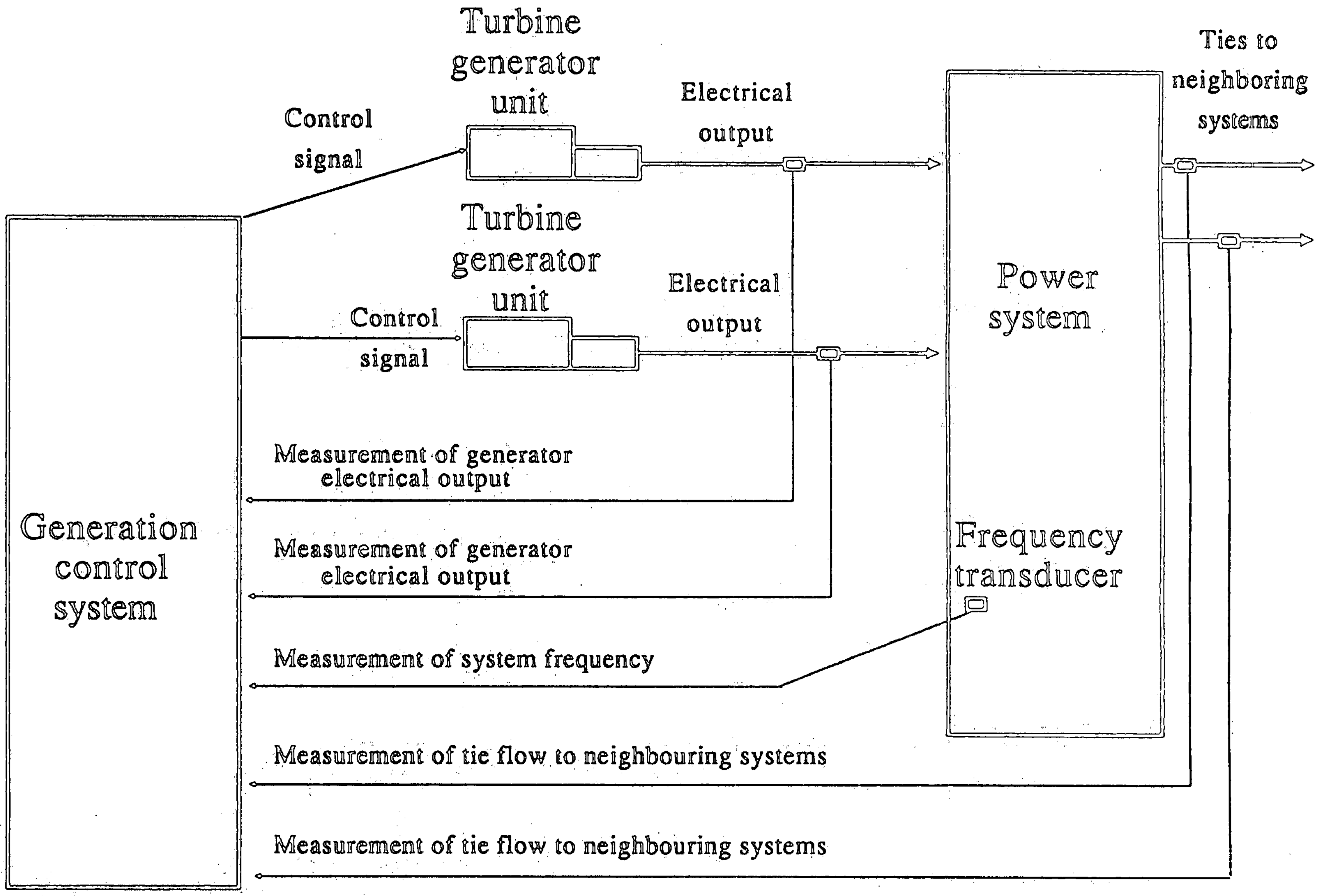


Diagram 5.6 Overview of generation control problem

K_i is the integral action gain, and

K_p is the gain of the proportional action.

This equation does not take into account the inadvertent power interchange or the time error which was added later to the above equation. In theory the C.R. represents the generation deficiencies of a particular area at any given time but in reality this is not actually so. The inherent errors of measuring devices, the system non-linearities and telemetry failures mean that the C.R. in practice does not represent the exact value for the generation deficiency for a given area.

Each generator power set point could be continually altered to keep the value of C.R. close to zero, however, this would take no account of system dynamics, the system gain, the governor characteristics, or the dead bands which occur in all control equipment. Also the unrestricted movement of the power set points may well violate the maximum rates of change of a generator and rapid variation of the set points may cause unnecessary wear and tear on governors. This would lead to uneconomic operation especially in thermal plant. It is thus necessary to consider the implementation of the required power change to satisfy the C.R. for each area.

The total change in system power that is required to satisfy the C.R. can be distributed among the regulating units[200] using

$$P_{sn} = P_{on} + \eta P_{rn}$$

where

P_{on} is the base load or ordered generation for generator n, and

P_{rn} is the required amount of regulation from unit n.

The ordered generation of each unit is calculated manually from load prediction data or automatically using Economic Dispatch programs. If it is decided that a unit should not be used in regulation of the system, then the P_{rn} for that particular unit n is set to zero.

The power set points P_{sn} must be constrained by the maximum and minimum limits P_{Hn} and P_{Ln}. This means that the units output must be within the band specified by

$$P_{Ln} \leq P_{sn} \leq P_{Hn}$$

If the calculation of the C.R. requires the unit to go outside this band, then it is set equal to the limit and the difference between the original value and the limit must be allocated between the other units which have not reached their limits. This iteration of power allocation continues until at one unit is within its limits or all units are limited. For this latter condition, the C.R. cannot be satisfied and hence an alarm condition must be entered. This may require the use of rescheduling or load shedding. In some cases it is permissible to run a unit outside these limits for a given time depending on system conditions and so this must be considered before the other emergency conditions are used.

If there is a large change in system load over a short time period, the units may not be able to respond to the required changes in power set point as calculated by the C.R. because of the speed that these units are permitted to change their power output. The machines are ramp limited in both the increase and decrease of their set points.

$$\frac{\partial P_{sLn}}{\partial t} \leq \frac{\partial P_{sn}}{\partial t} \leq \frac{\partial P_{sHn}}{\partial t}$$

The partial derivative is used to show that the limits depend on unit output. Generally the units often are slower to respond at higher power outputs. This response problem may be solved by using one of two solutions.

Firstly, the generators are arranged so that the faster units take over the load that cannot be generated by the slower units. The slower units then increase their output until they have achieved the required power output, the faster units then gradually reset their set points to lower values.

The second solution requires that the slower units are changed at their maximum rates and no control action is taken on the faster ones.

The first arrangement enables the requirement of the L.F.C. to always be satisfied but has the disadvantage that the faster units are subjected to additional wear. The ramping operation also leads to poor economic operation. The second solution has the effect that to satisfy the L.F.C. commands may take longer and hence, the correction of the error takes longer. A better solution would seem to be to allocate the power to the generation units in a given proportion so unless an emergency condition occurs, the L.F.C. requirement is satisfied by spreading the required change in power over all the regulating units on the system. This allocation of power is discussed later in the chapter, under the implementation of L.F.C. in O.C.E.P.S.

If alteration of the generator power set points from the base loading P_{ok}, frequency set point f_0, or the tie-line power interchange setting P_{t0} is needed, the units must be ramped from one output position to the new position. This ramp action avoids a step change in the C.R. which could result from the proportional term of the controller. This would have a similar effect on the system as a step change in consumer load. The period over which ramping action takes place is dependent on the time scale and the size of the system load fluctuations.

A limit is also imposed on the C.R. so that

$$\frac{\partial \mathrm{C.R.}}{\partial \mathrm{t}} \leq \frac{\partial \mathrm{C.R.}}{\partial \mathrm{t}_{\mathrm{MAX}}} \qquad \text{and } |N|. \leq 1$$

This means that the maximum rate of change of C.R. is restricted to the value of the maximum rate of change of the system load. Also, if $|N|$ exceeds 1, then all the available generator regulating capacity has been taken up. In this case the rescheduling is required or the dispatch calculation must be initiated.

The L.F.C. can operate in three modes which can be integrated into the set of control equations using the integer operators, a and b, which take the values of 0 or 1.

(a) With $a = 0$ and $b = 0$ the A.C.E. is zero and the mode of operation is one of flat frequency

(b) With $a = 1$ and $b = 0$, the A.C.E. represents the change in generation needed for flat tie–line operation.

(c) With $a = 1$ and $b = 1$ the control system will operate biased towards tie–line operation.

$$\text{C.R.} = -\frac{1}{P_r}\left[\int K_i\,(a\Delta P_{tie} + bK\Delta f)dt + K_p(a\Delta P_{tie} + bK\Delta f)\right] \qquad (5.2)$$

The control based on this equation can be easily implemented so long as the integral gain K_i, the proportional gain K_p and the sampling time T_s is known.

The operation of the algorithm is as follows: Consider that the power system is initially in the steady state, that is ΔP, Δf and C.R. are all equal to zero. The sum of the base generation P_{on} will balance the consumer load exactly. Initially both the integral term and proportional term will be at zero. If then the load increases, the system frequency will fall and the tie-line power import will increase. The deviations that this causes will directly affect the C.R. which is seen in the proportional term, this amount depends on the gain K_p. The integral term will take several seconds to rise to a similar level. As the power set points are altered by the control action, the tie-line power and the frequency deviations will begin to return to zero, this leads to a reduction in the control action from the proportional term. However, the integral term will continue to increase, but at a rate slower than before, until ΔP and Δf are zero when the increase will stop. The control action from the proportional term will then be zero and the integral term will be the change in load compared with that of the base generation. However, it is unlikely that the frequency will return exactly to zero, it generally overshoots. In this case, the proportional term will increase leading to a reduction of the C.R. and also the integral will begin to decrease. This action will continue to oppose any variation of ΔP and Δf until the steady-state is achieved. Thus the control action from the integral term is necessary as part of the calculation as it represents the required change from that of the base generation.

The implementation of L.F.C. in an automatic control system for an electrical power system requires sampling of the tie-line power flows and the system frequency, along with the generator power set points of the units. The interval of the control action does not need to be the same as that of the sampling interval. It is better that the two intervals should be different as the integral term would have a reduced and less accurate contribution if it was not the case. A suitable a sampling period would be at least five times shorter than the control period T_p. This is needed to reduce the effect of system and measurement noise and of transmission disturbances.

The input data for the L.F.C. calculation is gathered from the system using the various telemetry channels around the power system. Checks on the data must be carried out to ensure that the data is correct and no corruption has occurred. In energy management situations the incoming data can be checked by or against the values of the state estimator to ensure data integrity. The checked values of Δf and ΔP can then be used to update the values of the C.R. At the mth sampling instant given by

$$C.R._m = -\frac{1}{P_r}\left[\underset{K_i}{\overset{?}{K_p}} \sum_{n=1}^{m} T_{pm}(a\Delta P_{tie_m} + bK\Delta f_m) + \underset{K_p}{K_i}(a\Delta P_{tie_m} + bK\Delta f_m)\right] \quad (5.3)$$

Where T_{pm} = control period

T_{pm} is the actual time between adjacent control samples [201]. It is clear that from the equation above if control action is to be taken less frequently than the sampling interval then the only the last values of ΔP and Δf will be used in the proportional term. This proportional action is susceptible to noise on the measurements, so the situation can be improved if the values of ΔP and Δf since the last control action are averaged before the proportional term is calculated. This does need not be carried out for the integral term as the noise with zero mean will tend to cancel.

Although the straight averaging procedure is a reasonable crude filter, it gives equal weighting to all samples. The more recent values are a more accurate measure of the current state of the system. Exponential smoothing of Δf and ΔP can be used to give results in the presence of noisy measurements where

$$\hat{\Delta} f(m) = exp\left[\frac{-T_s}{T_{sM}}\right]\hat{\Delta} f(m-1) + \left\{1 - exp\left[\frac{-T_s}{T_{sM}}\right]\right\}\Delta f(m) \quad (5.4)$$

and

$$\hat{\Delta} P(m) = exp\left[\frac{-T_s}{T_{sM}}\right]\hat{\Delta} P(m-1) + \left\{1 - exp\left[\frac{-T_s}{T_{sM}}\right]\right\}\Delta P(m) \quad (5.5)$$

$\hat{\Delta} f(m)$ and $\hat{\Delta} f(m)$ are the new smoothed values and directly replace Δf and ΔP in the proportional term of equation above. The effects of telemetry delays inherent in the scanning the various tie-lines flows and the frequency do not usually affect the operation of the control scheme.

5.13 O.C.E.P.S. Frequency Control

The following sections describe the use of the proposed L.F.C. scheme operating as part of the O.C.E.P.S. Energy Management system and its interaction with the other control schemes within the operating environment.

5.14 O.C.E.P.S. Simulator

The subsystems communicate via common blocks and a shared database. All control functions are able to access the database to change the value of variables or just to read their value. To ensure the common block are entered in an orderly fashion and in the correct sequence, a set of flags are used so that once a program has entered the common block, another control function cannot access the data to read it or change it. When the data has been read or altered and is once again consistent, the block is freed and can be accessed by other control functions. Where possible each control function is capable of being started or aborted at any time without unbalancing the system. The algorithms are designed to operate under steady-state and transient conditions and under other unusual conditions such as multiple electrical islanding [200,201,203].

The O.C.E.P.S. package is initialised and loaded after the dynamic simulator has been started. The functions are loaded in a strict sequence so that the system is seen to be as realistic as possible. The control functions start as soon as they have been loaded and require no manual intervention to bring the system on-line.

5.15 Load Frequency Control Function

The L.F.C. control function has been designed to be one part of the integrated control function of the O.C.E.P.S. control package [103,204]. The positioning of the program in the control hierarchy is such that it is the last function before any values are available to control the system. The variables it calculates are directly applicable to the system and are sent directly to control the power set points of the generators. The control function consists of a main section along with four subsections which are used in turn to carry out their individual functions. The main program is concerned with the set up and initialisation of the start–up conditions. Once this has been achieved, the calculation of the Area Supplementary Control (A.S.C.) for each island can be calculated and finally the setting of the power set points required to satisfy the ordered control action. The interaction between the Dispatch function and L.F.C. is important as the Dispatch calculated generator set points are altered by the L.F.C. function. The output from the program is placed in a common block and the appropriate control action is implemented onto the simulator. Diagram 5.7 shows a flow chart on which the L.F.C. control program was based.

The first subsection is concerned with the filtering and validation of the tie–line powers and frequency measurements which is measured throughout the network.

The second subsection calculates the value to which the power set points should be ramped in order to meet the target output and the time set by Dispatch.

The third subsection is concerned with the allocation of the excess power, on top of the Dispatch set targets, which is required to satisfy the A.C.E. and hence keep the frequency within the previously defined limits.

The fourth subsection is used in conjunction with the Reschedule function which removes any emergency conditions and hence is given priority over the control of the frequency at the discretion of the operator. The interaction of the L.F.C. function and the other control and measurements systems is shown in the generation and load control subsystem diagram, 5.8.

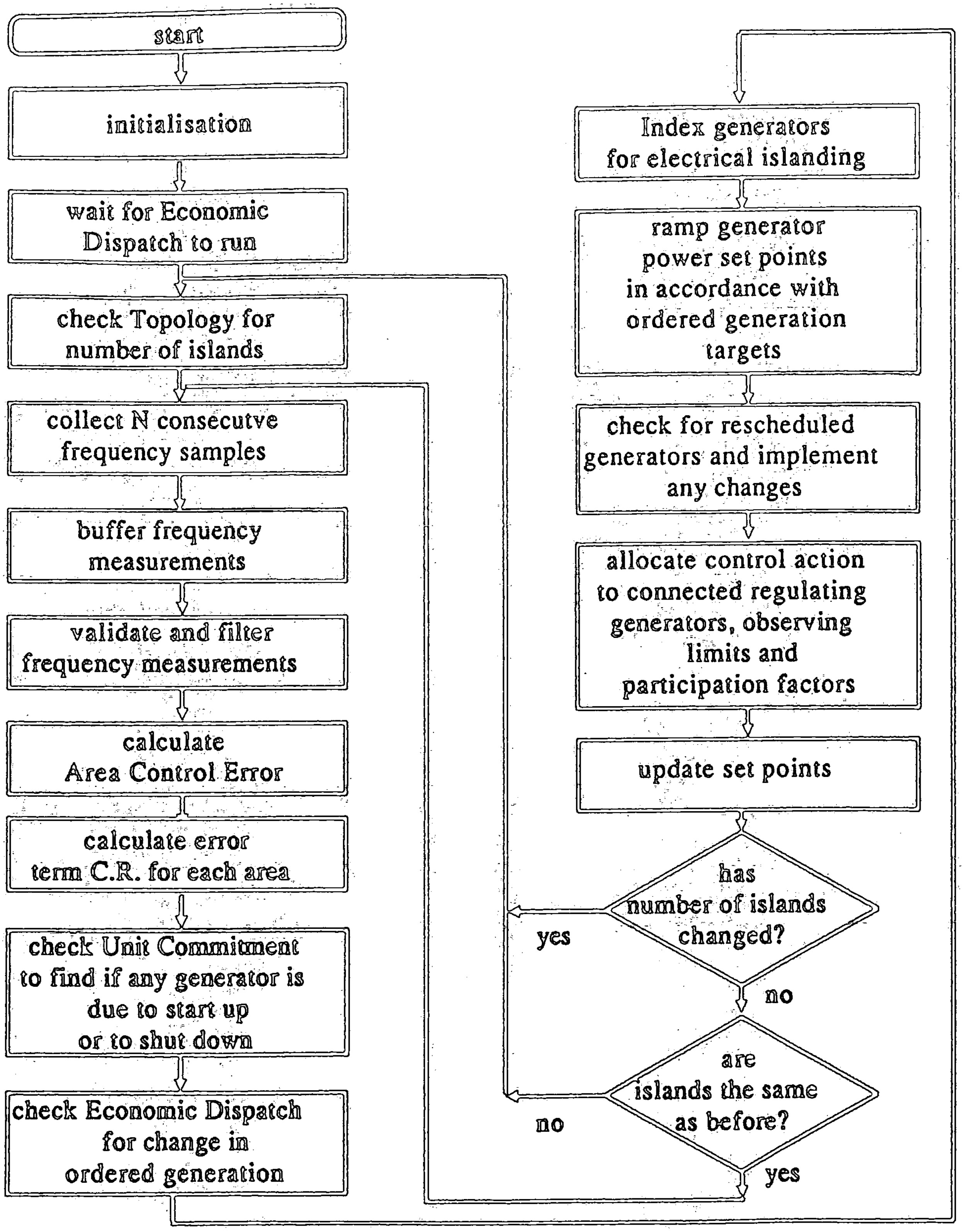


Diagram 5.7 Load Frequency Controller Flow Chart

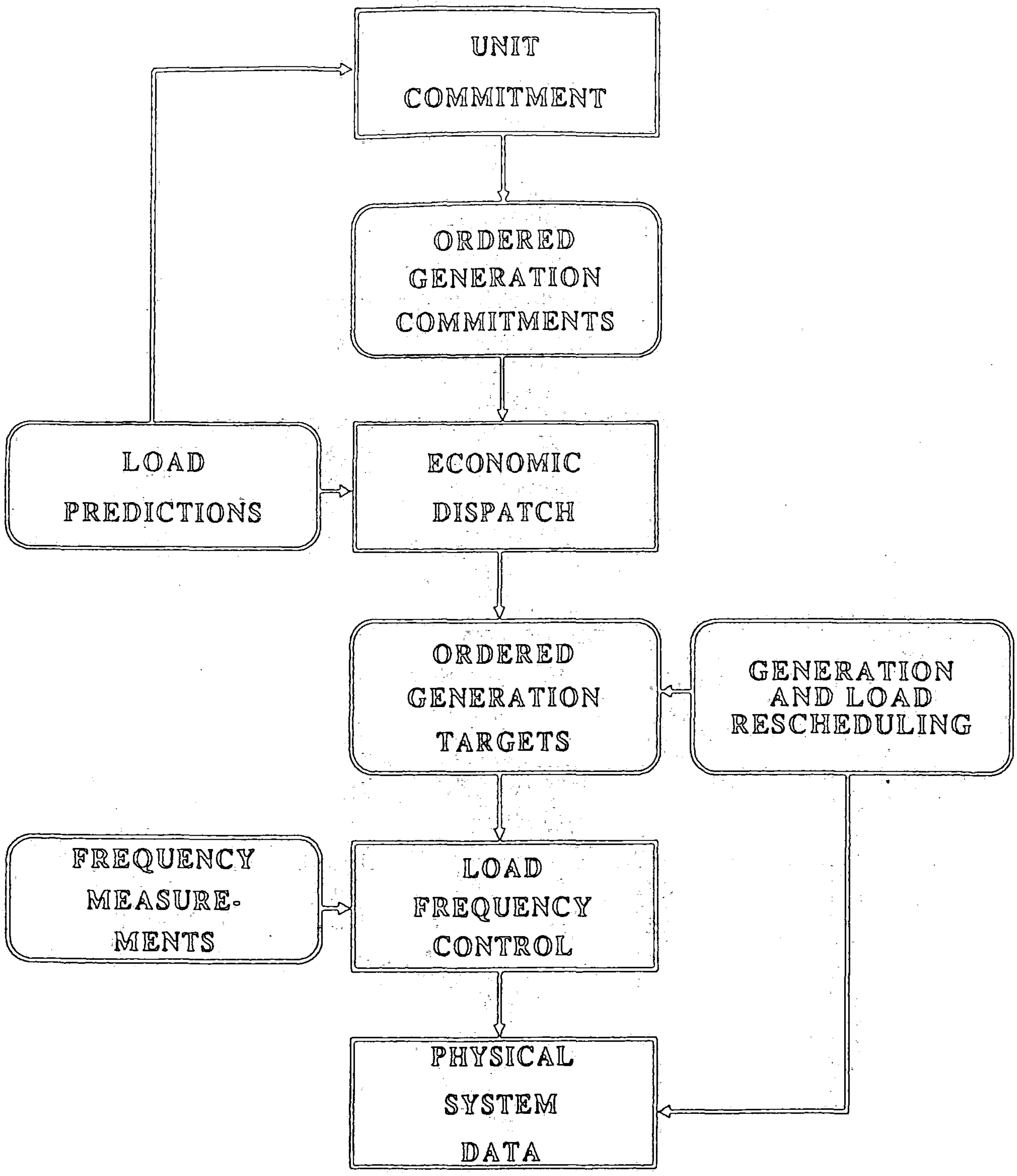


Diagram 5.8 Generation and Load Control Subsystem

5.15.1 Load Frequency Control Set–up

The initial conditions for the controller are set up using the most recent values from the simulator. The starting point for the calculation of the power set points is the most recent value received from the simulator through the communications program. Initially the O.C.E.P.S. package did not posses an interactive Dispatch function, the initial conditions was based on the current generator outputs and a target was set for thirty minutes into the future. This did not take into account any load prediction or change in loading conditions. At the end of the thirty minute period, the next target was set based on the previous target set points. This did not take into account any variation in load, emergency conditions, sudden changes in load, loss of generating units or time of the day. Such occurrences where seen only by the program due to the change in tie–line powers and frequency, but this limited the dynamic response due to the set target values.

If the power system consisted of several islands, the previous targets were still valid and no changes occurred. This lead to the problem that the targets values could be in direct contradiction with the change in frequency and hence the response was not ideal. Dynamic response was improved with the introduction of the Economic Dispatch function. This enables the set points calculated from an economic view point to be used as the starting point for the L.F.C. calculation on the initialisation, and provides an update of each individual generator set point at specified intervals, generally thirty minutes if the system is in steady state. The updates occur as required in emergency situations, or change of network topology.

5.16 Economic Dispatch

As mentioned earlier, the Economic Dispatch has close links with the L.F.C. function [68,201,202]. The Economic Dispatch function is concerned with the allocation of target output powers for generators to satisfy the predicted consumer load at a minimum cost. This requirement would be fairly easy to meet but this minimum must be reached within the system operating constraints. This control function is basically predictive one in which targets are required on a time scale of five minutes and upwards. Each generator is allocated a target output value by Dispatch which it is calculated based on the most recent load prediction and an economic configuration of the generators to satisfy the consumer demand. The target output of each generator is calculated along with a target time for this output to be reached. These values for each generator are the basis for the L.F.C. calculation.

5.17 Corrective Power Error Calculation

The calculation of the A.S.C. signal starts with the tie–line power interchange and the frequency of the interconnected system. The frequency value is taken from the telemetered values from around the system and any tie-line interchanges are monitored. Sufficient values are metered to allow the system to be split into separate islands and ensure that each island has at least one frequency measurement associated with it.

5.17.1 Filtering measurements

The required measurements from the plant are filtered to remove gross errors and noise which has been added by the simulator. Firstly a filter is used to remove the *gross errors* or *bad data.* This requires a robust filtering technique. This is provided by minimising the weighted sum of the absolute errors, a minimum L1 norm estimation technique is used. An upper and lower limit is set for the frequency measurements and any telemetered values which are outside this boundary is rejected. This may be due to corrupted telemetered data of bad data from the measuring device itself. This uses a least modulus estimation and is a non–weighted technique.

With the erroneous data removed, the second level of filtering is carried out using a weighted least squares method. This is less robust than the first technique, and is used to average value of all the frequency measurements which have been collected from the system. With the weighted calculation completed, the validated measurements are returned to the main program.

The standard frequency of the system is that of the normal operating frequency used by the C.E.G.B. of 50Hz. This is used in all frequency calculations as the standard set point, but a facility is available to change this reference point if required. This may be required for the resynchronisation of two islands to reach a common frequency achievable by both islands. This reference value may then be used along with the validated system frequency to form a system frequency error.

The measured power flow on each tie-line is compared against the scheduled power flow and a power error is calculated.

The frequency error and power error are combined to form the Area Control Error which is a measure of the system imbalance. This value is used to calculate the C.R. as described in the earlier chapter.

5.17.2 Area Supplementary Control

The A.C.E. is used in the calculation of the A.S.C. which as described previously uses the standard P+I control technique. The P+I constants were determined by close observation of the generator response and tuned for each individual generator. This tuning process is somewhat iterative and several values were tried before a suitable set of constants were found, for the average operating conditions of the system. The constants, once tuned are not changed and hence must produce a reasonable response for all system operating conditions. These constants must also take into account the amount of participation in regulation that each generator will be required to carry out. Together with the appropriate smoothing factor, the target value for the particular island is calculated, whether it is an increase or decrease in power allocation. This power must be distributed through the system using such a method that it itself does not introduce instability within the system.

5.18 Generation Ramping

The calculation for the ramping of each generator is calculated based on their Dispatch set targets. This enables each generator to be ramped progressively from its previously set Dispatch target to the next Dispatch set target, in the specified time. The target output and time is stored in the common blocks and accessed as required by the L.F.C. function. The ramp rate of each generator is calculated and checked against the ramp rate of each machine. Also the output of the machine is checked against the upper and lower output values to ensure that none of the control commands violate the machine limits. At each period of calculation the new target power set point is calculated with the consideration of the long term Dispatch set targets. However this does not take into account the deviation of the system from the desired frequency.

5.19 L.F.C. and Economic Dispatch

The targets that are calculated by the Dispatch are altered by L.F.C. to take into account the change in the system frequency and the tie–line power interchange. The ramp schedules calculated by Dispatch define the power output of each unit for the end of the Dispatch period. This schedule is used by L.F.C. for the start point of the power allocation to each generator. The power to be allocated is split amongst the participating generator units and this is used to alter the Dispatch set values at each L.F.C. time interval. At the end of the Dispatch period, the new set of targets are calculated based on the L.F.C. controlled targets. Thus the interaction between the two control functions must be well defined to enable the smooth transfer of valid data between the two functions and ensure that the interface is robust.

5.20 Participation factors

The effect of the frequency deviation caused by the imbalance in the system power is removed by the allocation of the excess or deficient power using an allocation section of the control program. This section of the control function allocates the power that has been calculated by the A.S.C. The power allocated to the system could be concentrated on one generator only or split up between the units available for regulation. So that the power was allocated around the whole of the system proportionally, all generators that were participating in control action area allocated an amount of power. Each unit has a participation factor which is fixed by the operator and determined by taking into account the speed of rotation of a machine, its size and ability to react to a control command.

The *free space* of each generator is calculated, that is the change in output of the unit whether it be positive or negative before the upper or lower limit is violated. The generators are then ranked in order of free space, and the power is allocated to them according to their participation factor. If there is excess power remaining after the first pass of the allocation, then a second pass is used to reallocate the generators with more available space. If after this has occurred, the power allocation has still not been fulfilled then it is impossible to satisfy the requirement with the available units. Either more units have to be placed under the control of L.F.C. or emergency action has to be taken, such as rescheduling the generators. However this situation is rarely encountered as the Dispatch in most cases has ensured there is sufficient capacity on the system. The amount of power for each generator to change by has been calculated and so the previously calculated Dispatch set points can now be altered accordingly. Thus the output control signal consists of the Dispatch calculated set points, modified by L.F.C. to suit the system status at any given instant in time.

5.21 Power Set Points

The new power set points for each generator are sent as a control signal to the common areas of the computer memory and are transferred to the simulator by the communications program. This ensures that the correct protocol is followed and the most recent values are always available. It also ensures that variables cannot be changed while they are being accessed by some other control function.

This operation is carried out for each electrical island that is existing within the system. When the calculation has been completed, for the system, it is ensured that there has not been a change in topology. If this is so and a new island has been created, the allocated power is initially split amongst the generators in proportion to their loadings. The accumulated A.S.C. must also be divided up into suitable values to be used in each island. This is done simply again by dividing the value in the proportion of island loading. The Dispatch control function should then be able to reallocate the power for each island configuration and then the L.F.C. can continue with the fine tuning control action.

5.22 Rescheduling of Generators

In emergency situations where there is insufficient generation available to meet the system load, or if there has been an unexpected generation loss incident, it is necessary to be able to rapidly reschedule generation and allocate a degree of load shedding. In this case the L.F.C. is controlled by the Rescheduling function. The target set points for each generator are specified by this emergency function and the L.F.C. must implement these new values in the specified time. Once these values have been reached, then the L.F.C. function can then take over control of the generators again, ensuring that the transition from one control mode to another itself does not cause any transients to occur in the system.

5.23 Load Frequency Controller Results

This section presents some of the results that have been achieved using the L.F.C. function to control the simulated power system. The results are presented in graphical form so that the response of the system variables can be clearly seen with respect to each other. Generally the first graph presented shows the calculated power set point which is sent to each generator in the system. The second plot shows the frequency of the system during the simulation period.

5.24 Standard Loading Conditions

The following sections describe the operation of the power system under normal (steady–state) operating conditions.

5.24.1 Morning peak

These first figures show the system under normal operating conditions, where the only driving force for the system is the consumer load curve. Figure 5.3 shows the response of all six generators on the system during the rise to the morning peak loading conditions. All generators have been ramped to meet the predicted load, with the short range generator short fall being made up by the L.F.C. function control action. Generators four and five are at their maximum output, generator three is ramped to its maximum, followed by generator six. The units one and two are then used to satisfy the continuing load increase. The lower figure 5.4 shows the system frequency over the morning period as the load increases. Clearly the system frequency is stable and controlled well within its limits.

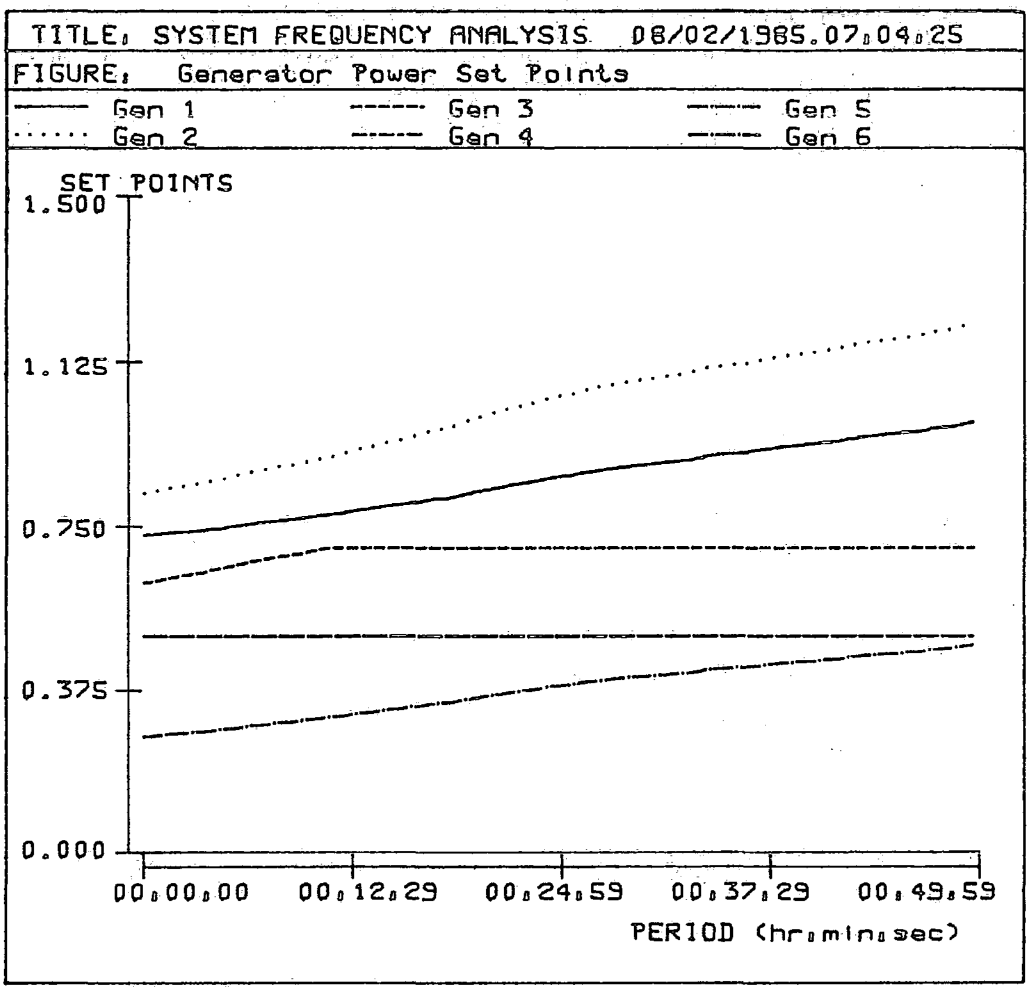
5.24.2 Morning load

The figure 5.5 shows the continuation of the morning load conditions. At this point in time the load has begun to become steady and hence any increase of the generation is not required. There is a small movement of the power set points as dictated by the L.F.C. to follow the load directly, but the amount of movement is small. This shows that the machines are not being controlled to such an extent that they are required to follow every frequency trend, but sufficiently to fine tune the system frequency. The lower figure 5.6 indicates the system frequency over the period of almost constant loading conditions.

5.24.3 Generation loss incident

The figure 5.7 shows the control response to a generation loss incident. During the approach to the evening peak, nearing five o'clock, generator four has been removed from the system. This loss has been initiated manually to simulate a unit tripping under fault conditions. The loss of generation is made up initially using both units one and two. However, after a short time, the second unit reaches its upper output limit and cannot participate in any regulation. The first unit is thus required to increase its output until the

Figure 5.3



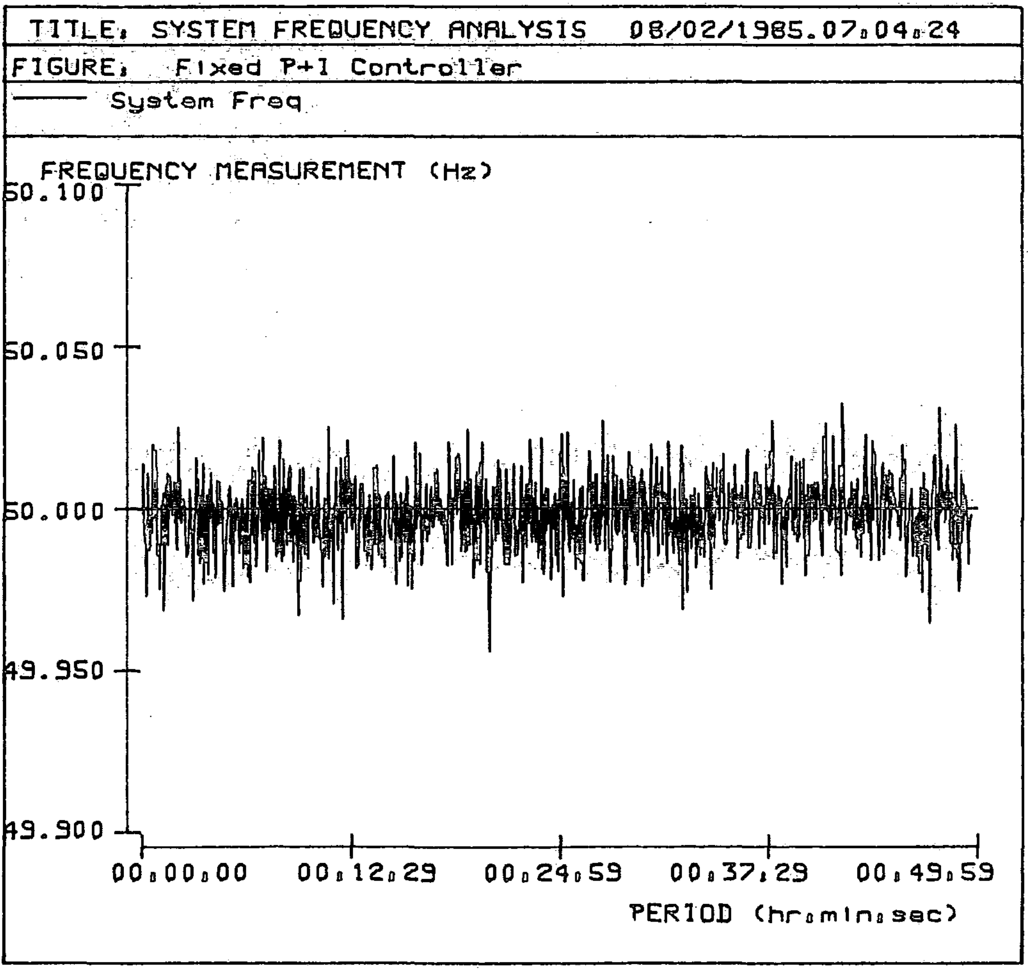
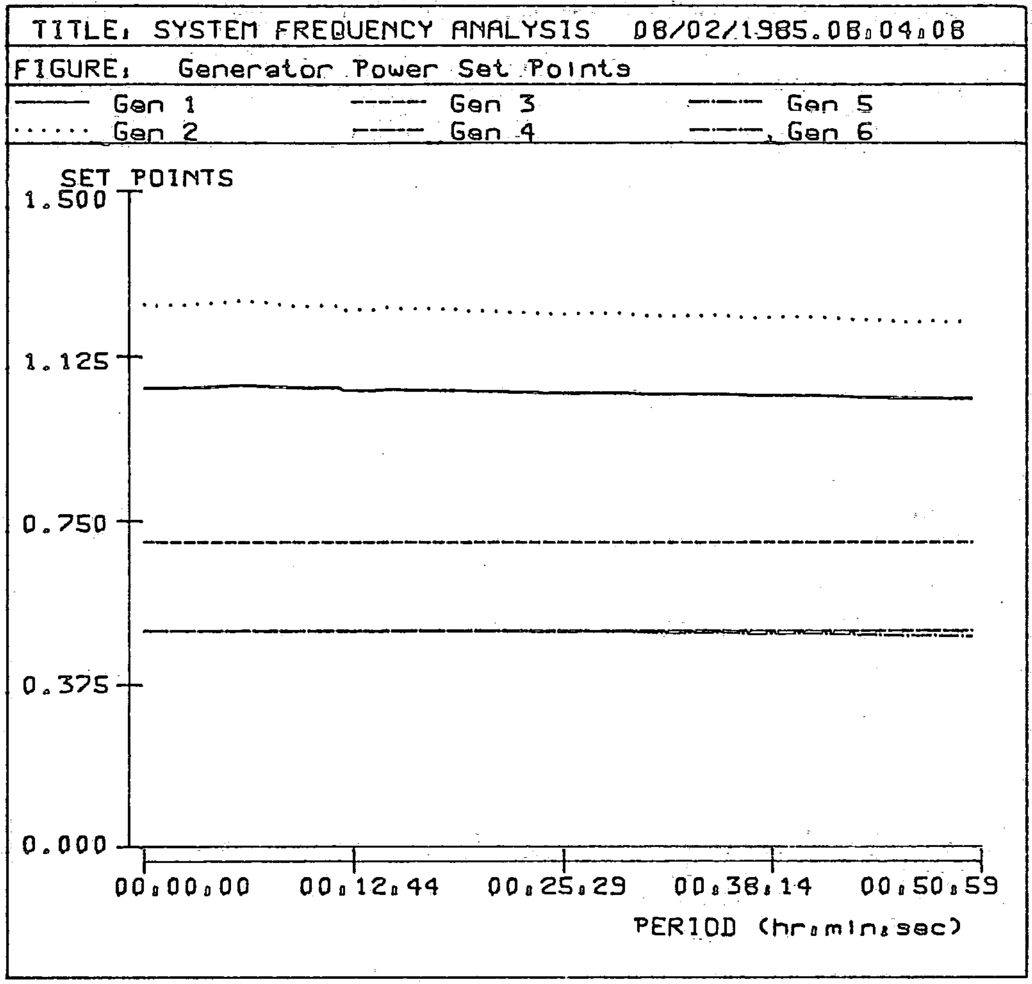


Figure 5.4

Figure 5.5



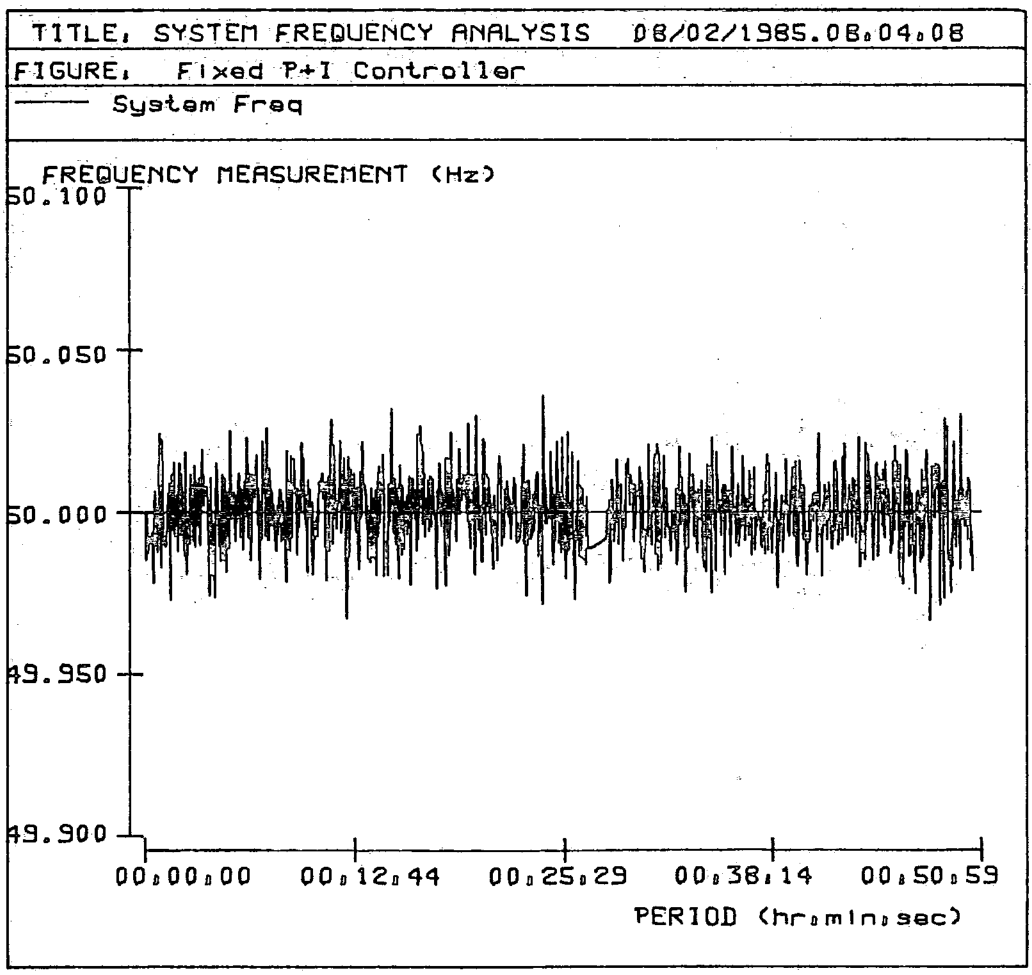


Figure 5.6

frequency error is reduced. The other units on the system have not been allocated any control action as they are at their lower limits.

The figure 5.8 gives a plot of the system frequency during the incident. The characteristic initial drop of frequency is seen immediately as the system losses its inertia. This followed by a smooth return towards the target frequency without any overshoot to continue at the target frequency.

5.24.4 Midnight load response

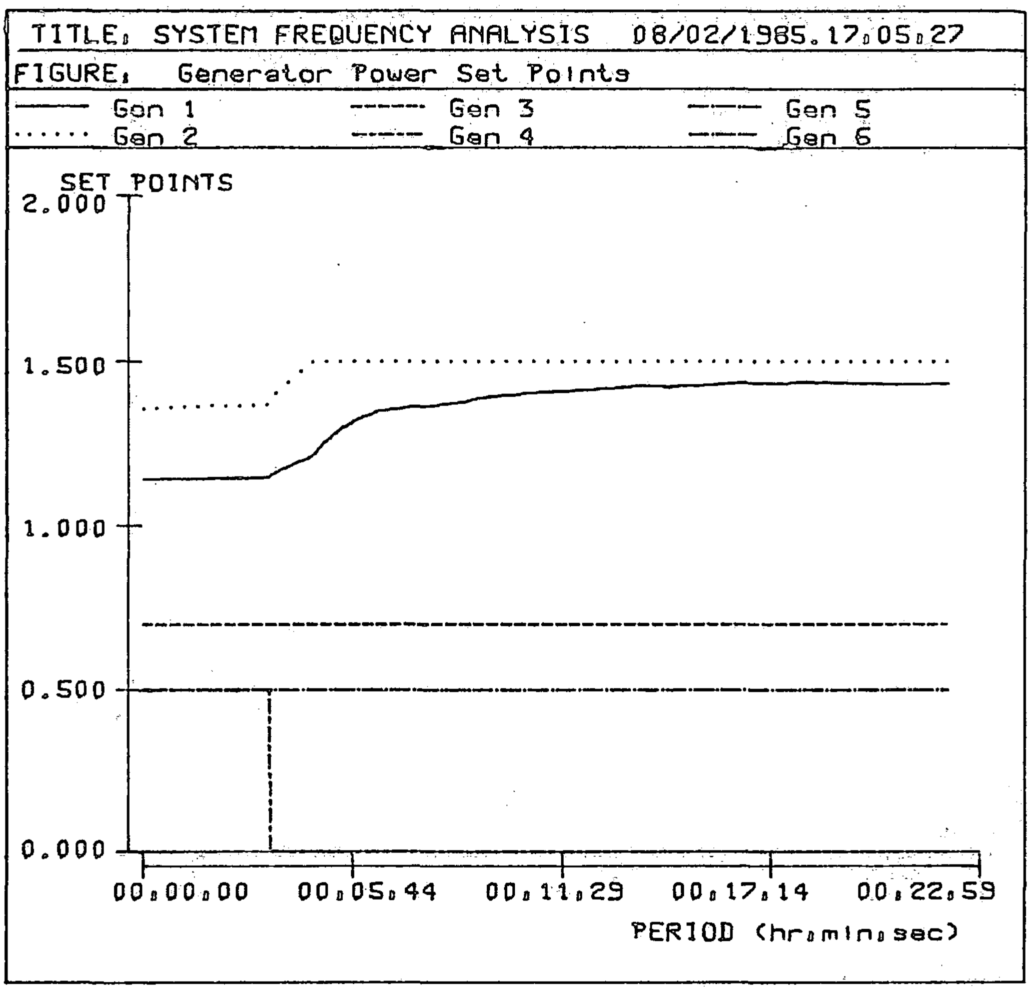
The figure 5.9 shows the system response just after midnight. The system is placed under a heavy transient with a light consumer load. Generator three was on its lower limit as commanded through the Dispatch targets from Unit Commitment. The generator was due to be removed from the system due to the light loading conditions, which through L.F.C. it was desynchronised. This was also due to happen to unit six, which was also on its lower limit. Just before this unit was desynchronised, generator one was removed to simulate a system fault. This unit was supporting a fair proportion of the consumer load and hence requires the generation deficiency to be made up rapidly. Generator two was ramped at its maximum rate along with units four and five. These latter units soon reached their limits requiring generator two to continue increasing. There is some overshoot of the unit as it reaches its new output level.

The figure 5.10 shows the system frequency response to the transient condition. The removal of the first unit is seen by a slight decrease in frequency which is made up, but this is then followed by a large rapid decrease. The recovery assisted by unit two is oscillatory following the control of the generator unit. This indicates that the controller parameters are not optimal for this set of operating conditions. Although this situation is rather extreme, the system response is not ideal.

5.24.5 Early morning system response

This figure 5.11 again shows that the controller parameters are not ideal for all system operating conditions. This plot is during the build up load to the morning peak. Generator six has been synchronised as determined by the

Figure 5.7



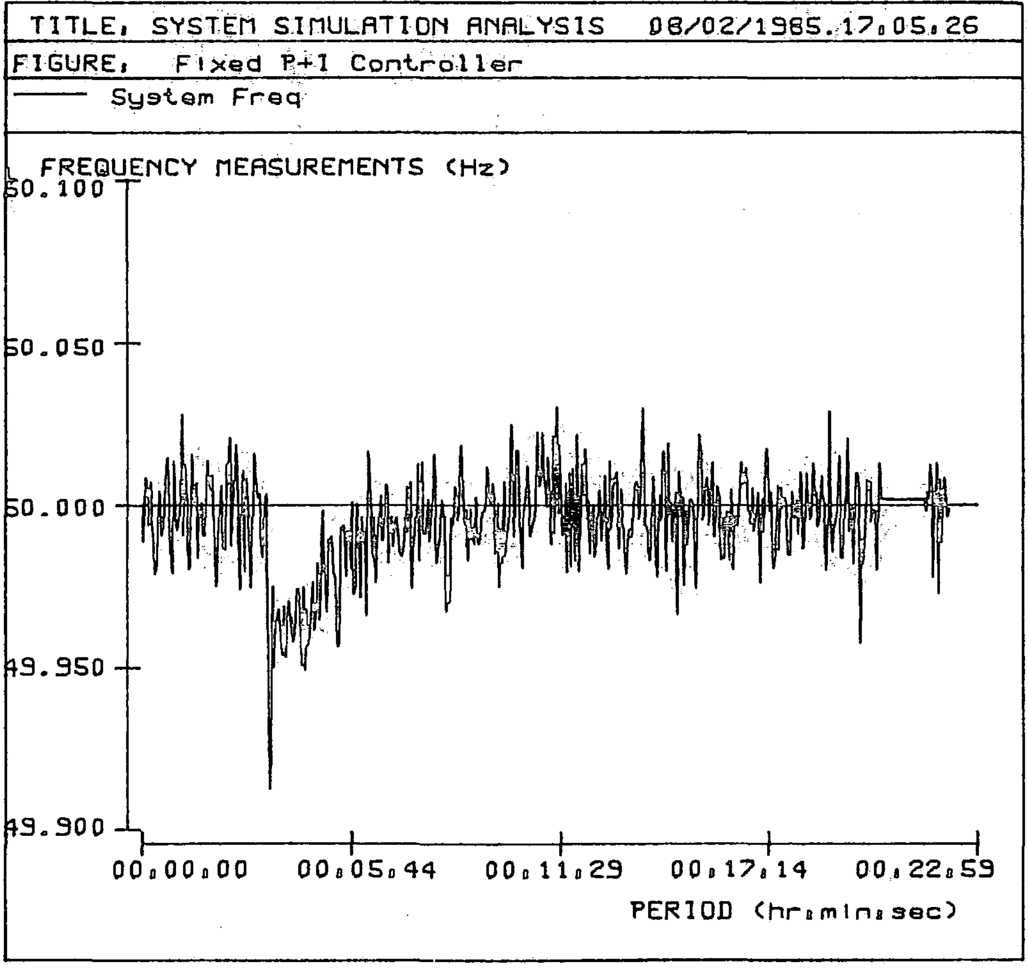
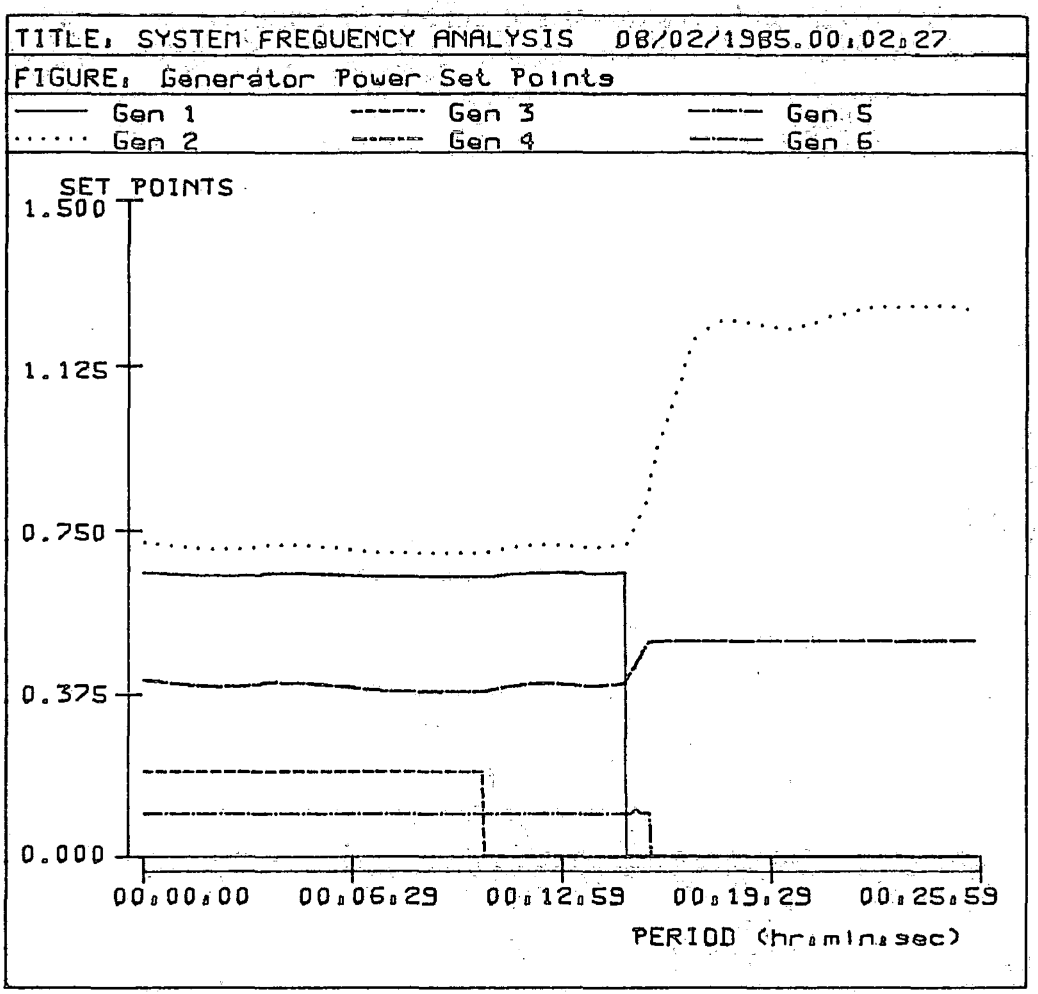


Figure 5.8

Figure 5.9



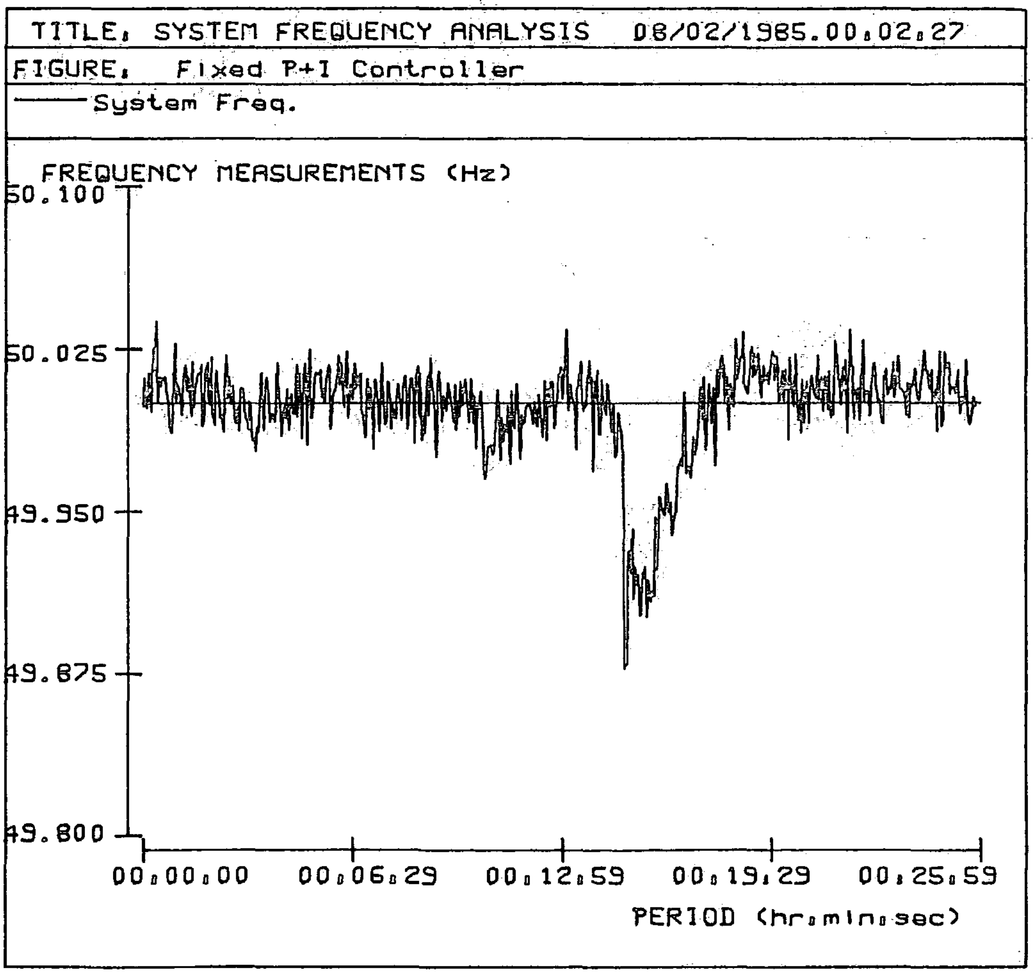


Figure 5.10

Unit Commitment. The units three has reached its upper limit, so the units one and two are required to ramp up to follow the increase in load. With the introduction of unit six the excess generation requires the other units to decrease their output to enable the generated power to be distributed to all the units on the system. Thus there is a marked decrease in the output of units two and to a lesser extent of unit one.

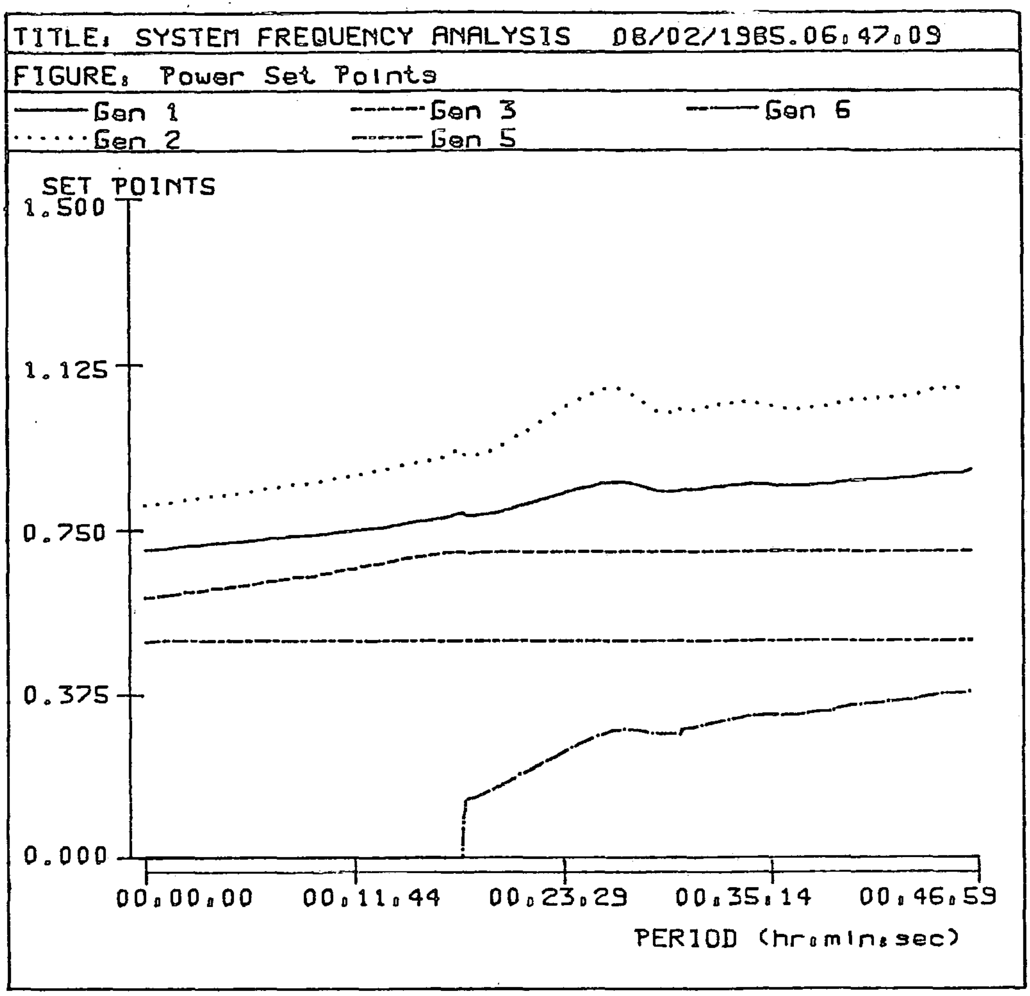
5.24.6 Early morning control parameters

This figure 5.12 shows that the controller parameters are suitable at other operating conditions. In this plot the third unit is synchronised before the morning peak starts to rise. The other units all respond to the increase in system generation by reducing their output in a smooth and controlled manner. The transition of the change of generated power between the available units is clearly seen as the new unit takes over generation from the smaller units to a greater extent than the larger units with higher output. The economic operation of the units requires that the third unit operates in preference to the smaller units under this particular set of operating conditions.

5.24.7 Mid–morning system response

This figure 5.13 shows the system response during the mid–morning load conditions. At this point the load is decreasing from the morning peak, so again the system conditions have changed. A transient is caused by disconnecting generator three from the system. This rapid loss of capacity causes the L.F.C. to increase the available units output. The units four, five and six are on their limits, so the increase of capacity is provided by the units one and two. These increase their output rapidly which causes the frequency to overshoot, consequently the units decrease their outputs which causes the frequency to undershoot. This transient behaviour is unsatisfactory and takes ten minutes to decrease. The frequency plot 5.14 shows the dramatic change in frequency and the continuous oscillatory behaviour of the system. Clearly the response of the controller is not ideal in this case and the controller parameters should be altered to be able to handle the operating conditions.

Figure 5.11



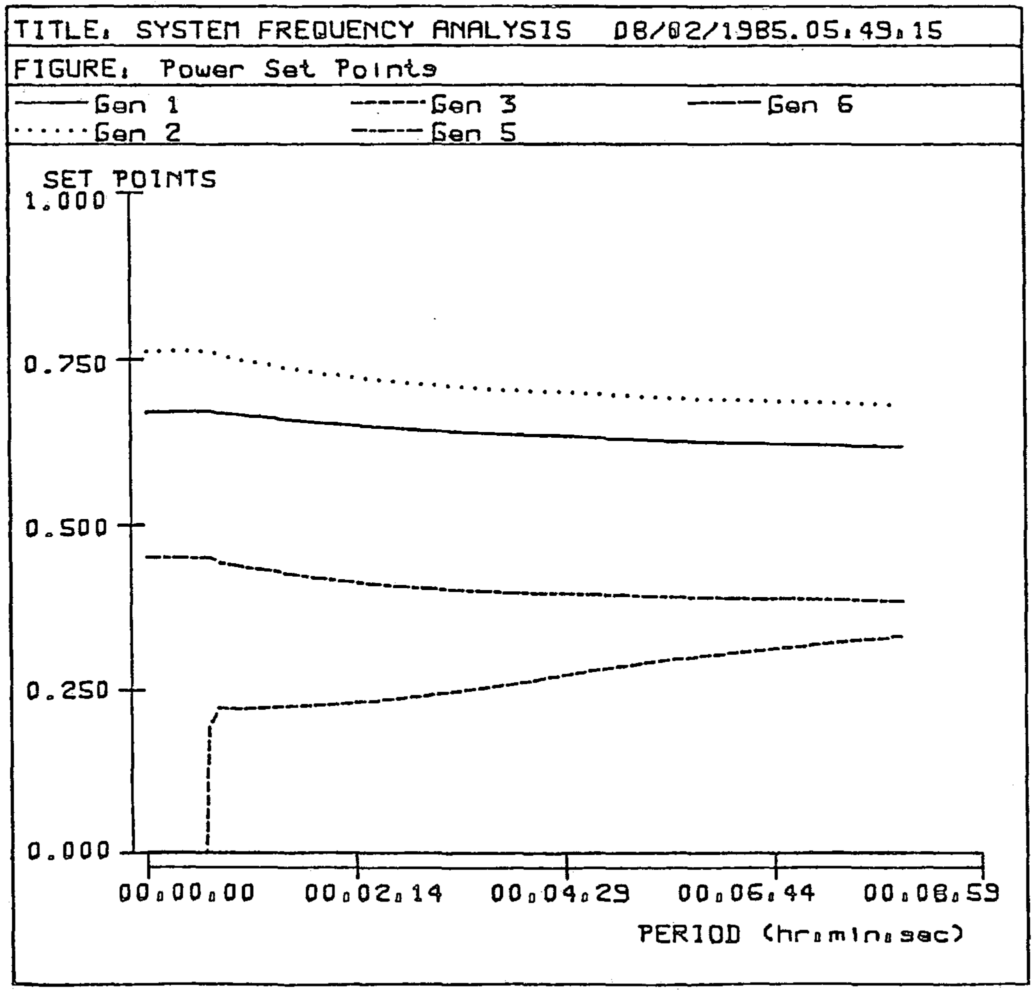
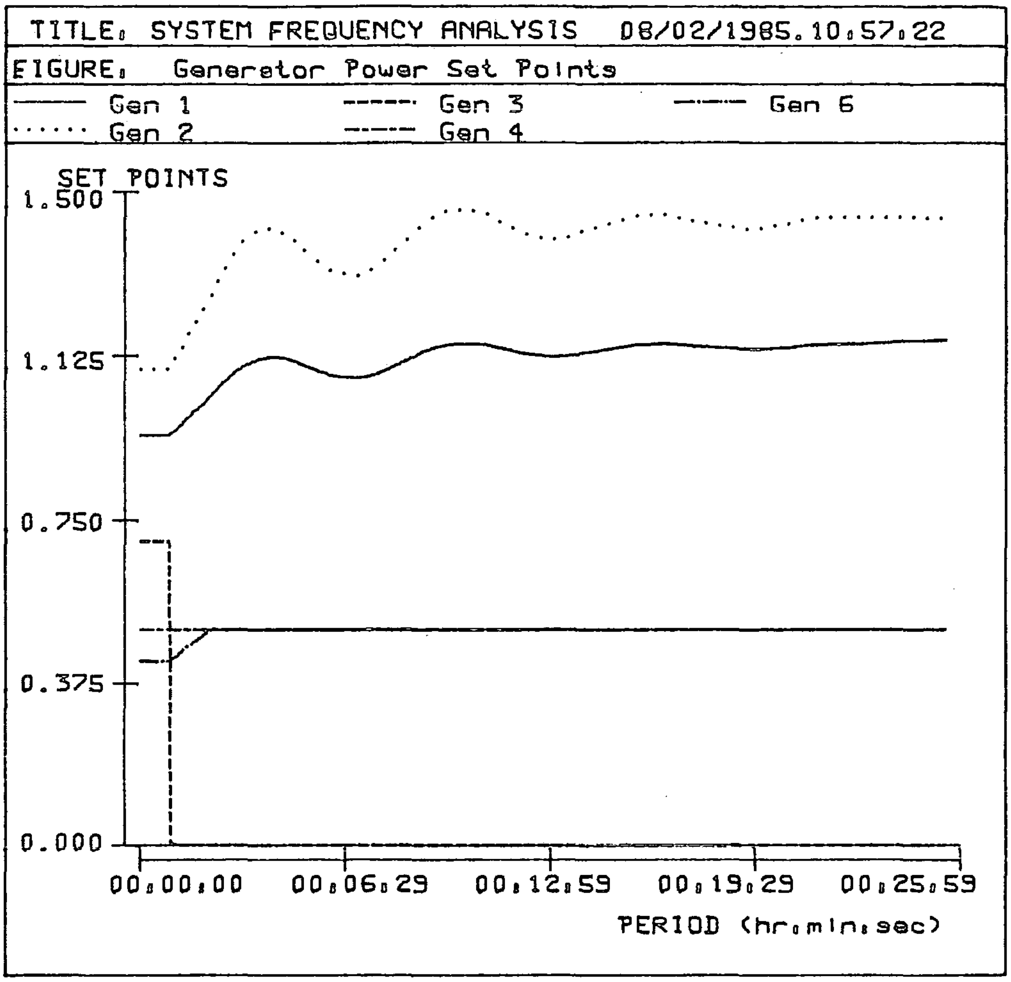


Figure 5.12

Figure 5.13



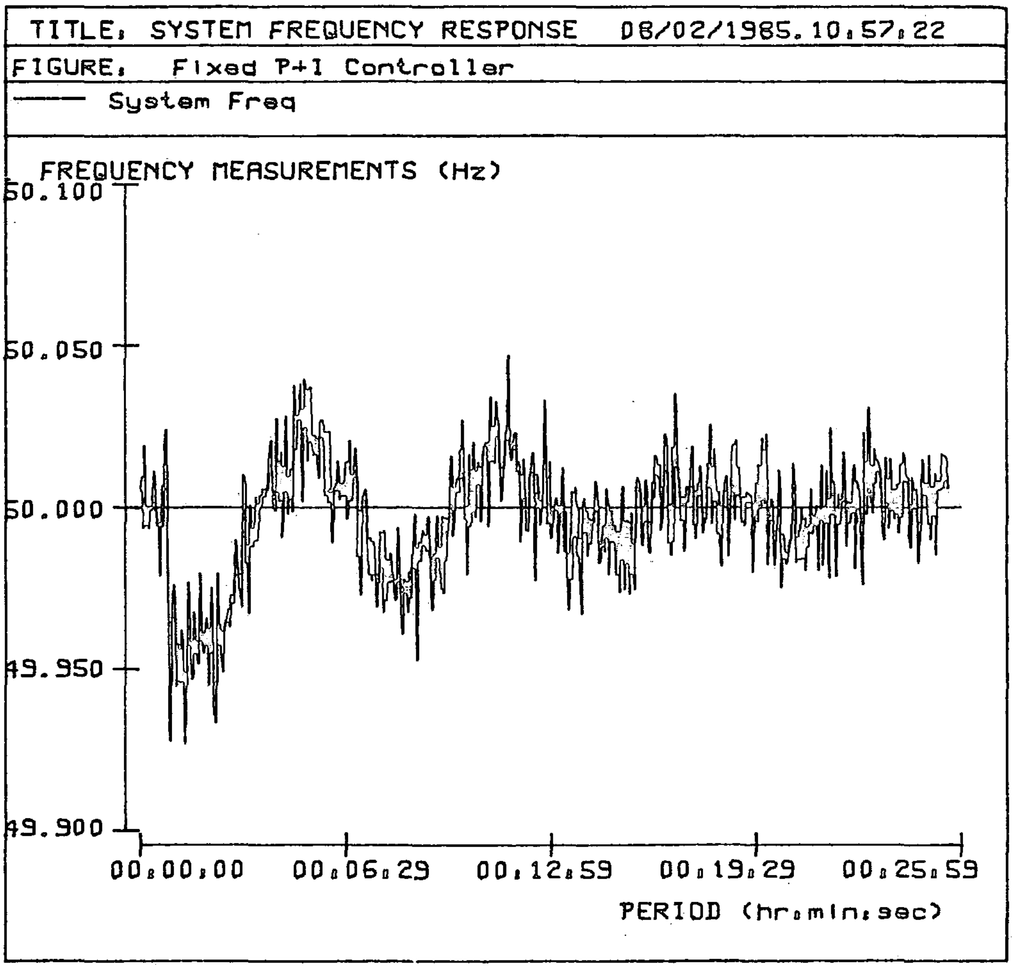


Figure 5.14

5.24.8 Telemetery failure

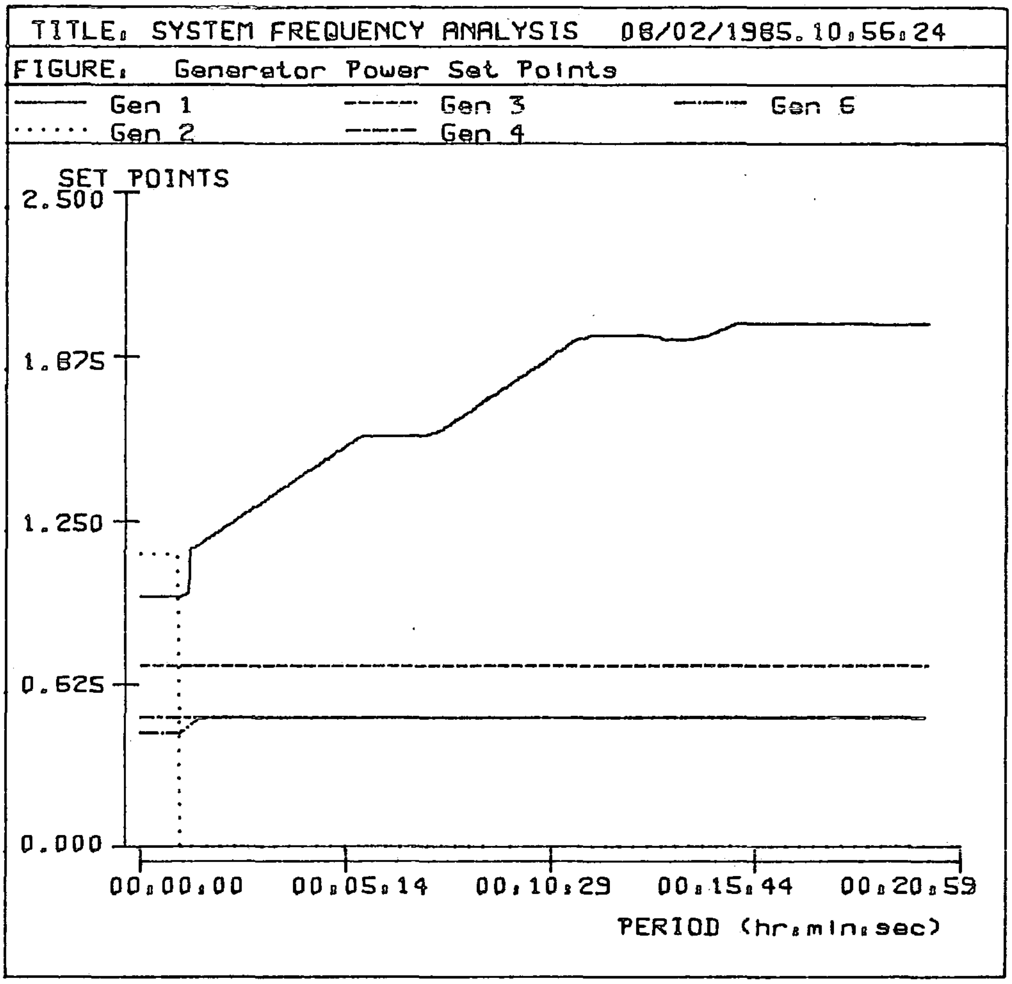
Figure 5.15 shows the problems that are encountered when the telemetered data from the system is stopped for a period due to measurement failure. The time of operation is approximately the same as the previous figure, but in this case the incident is a loss of generator two. This would be expected to have caused a severe transient as shown previously, however, due to the lack of system data the controller does not increase the value of the A.C.E. This consequently means that the control command causes the generator to continue with its previous output. When the system frequency is returned, the controller continues to increase the output of this unit. The transient behaviour that was seen in the previous plot does not occur to such a great extent, but there is some decrease in the system frequency as shown in figure 5.16. The eventual steady–state frequency is achieved some twenty minutes after the initial incident.

5.24.9 Fixed controller parameters

This system incident (figure 5.17) is designed to show the drawbacks of the fixed control scheme. The system is in a state of light load when unit two is removed. This causes a frequency transient which causes the controller to respond by increasing the available units output. Clearly this control action is too severe for the system conditions and there is overshoot of the generator set points. The frequency is returned to is required value after a decrease in the units output, but as this happens the generator which was removed is resynchronised. The frequency is rapidly increased, but the generators do not respond to this increase for several minutes. Their response is seen by the decrease in the set point targets, but there is still a period where the control action takes adequate steps to control the frequency as shown in figure 5.18.

This system incident (figure 5.19) shows that the controller parameters are tuned correctly for the state of the system for this operating point. The loss of generator three is responded to by the increase of output of units one, two and six. This latter unit soon reaches its upper limit and the control action is taken by the larger units. The frequency is returned to it original value by this control action as shown in figure 5.20. The effect of the loss of

Figure 5.15



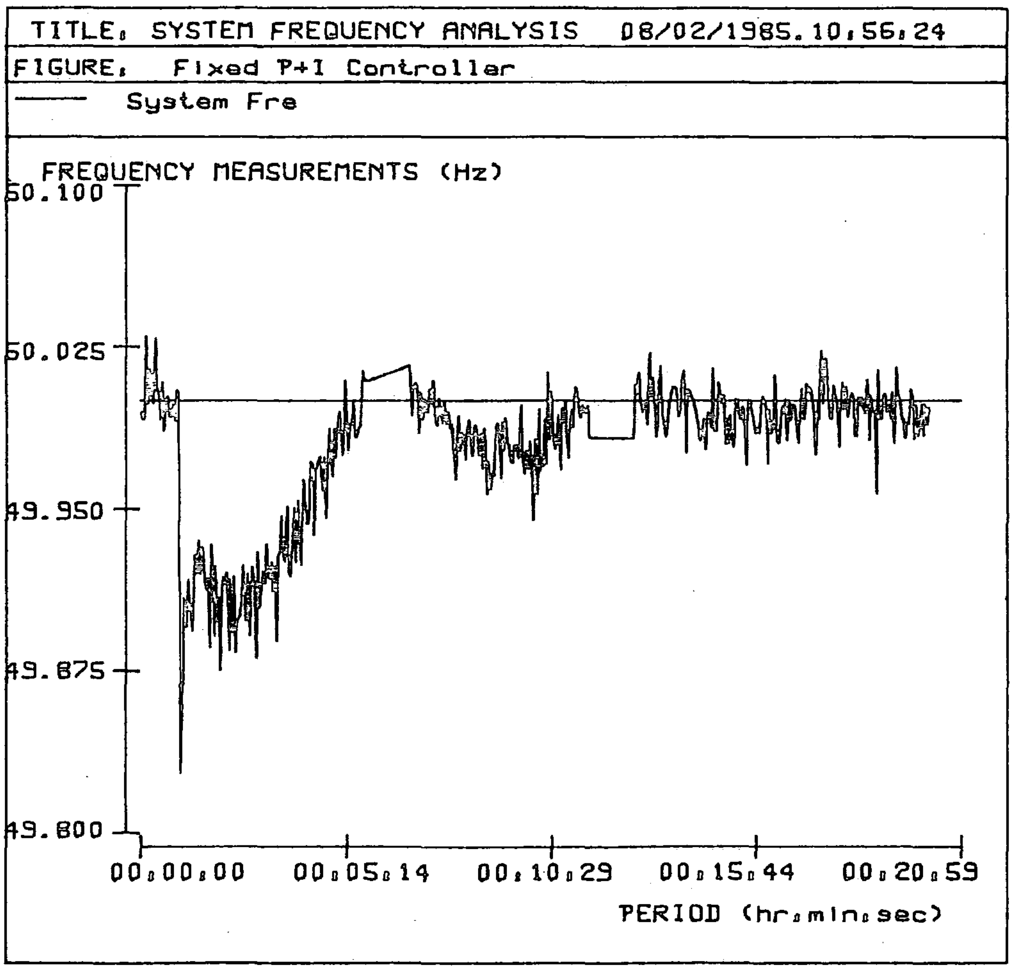
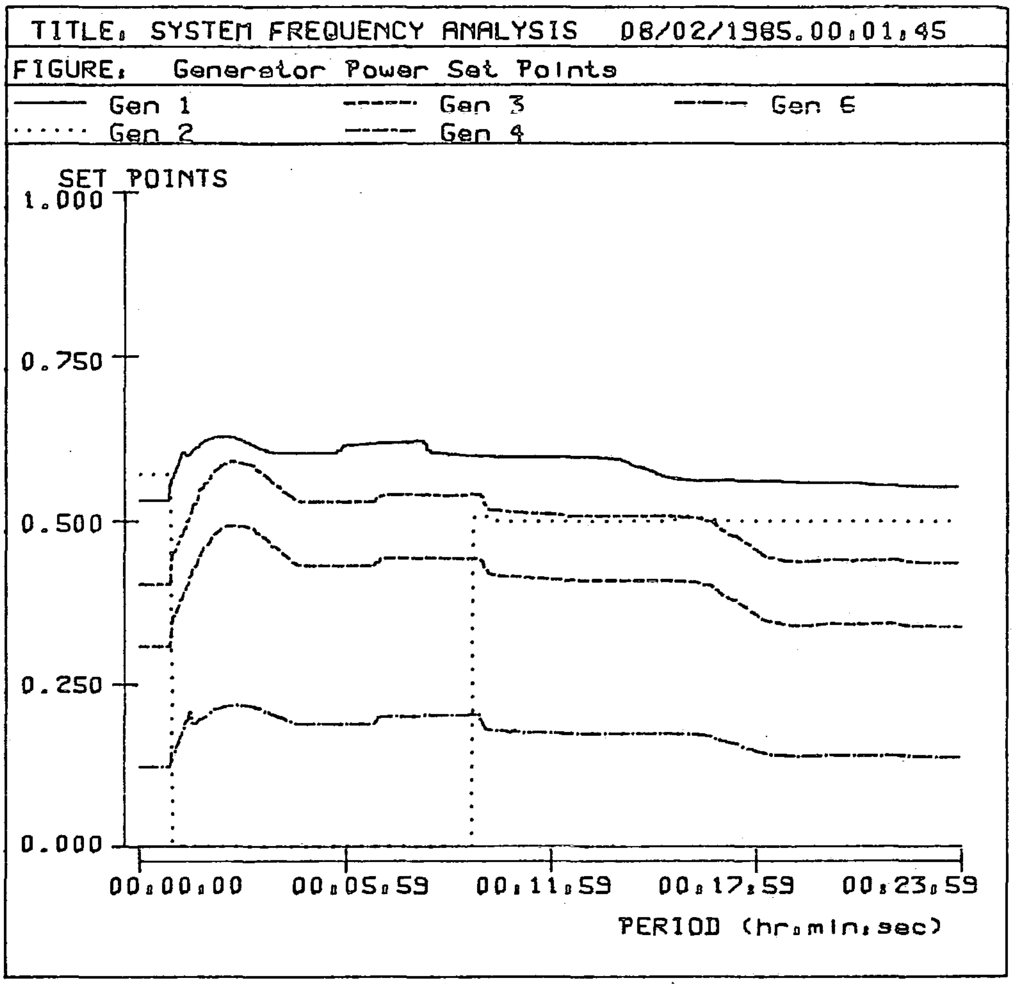


Figure 5.16

Figure 5.17



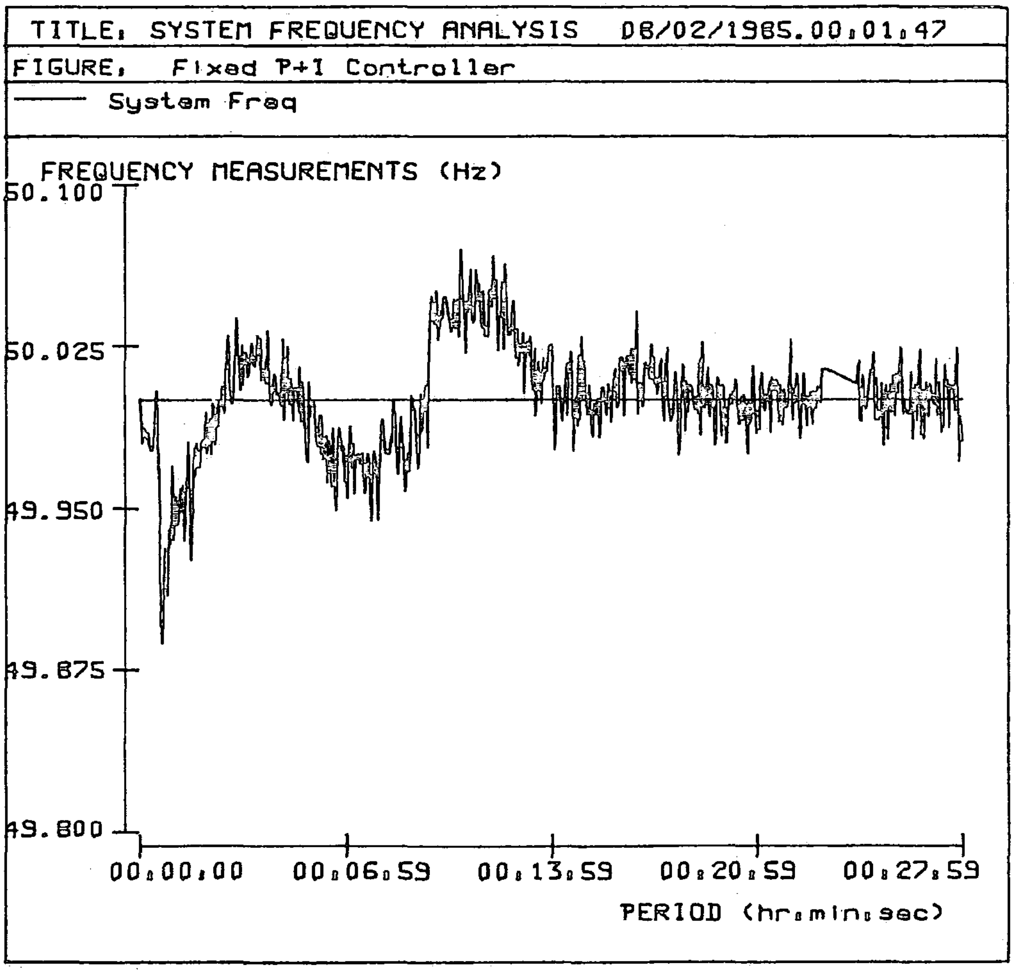


Figure 5.18

the frequency measurement is see again briefly as the set points respond to the lack of data.

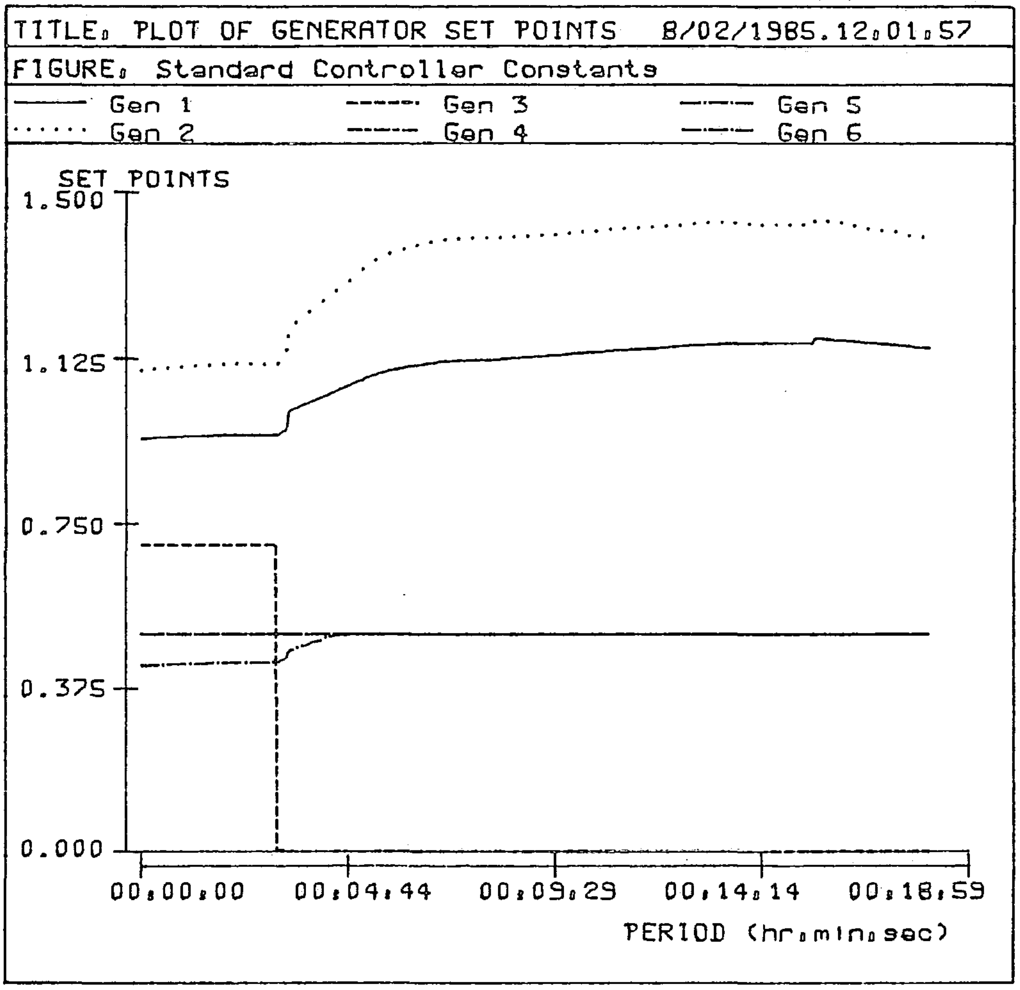
5.24.10 Change of controller parameters

The next set of figures show the effect of changing the controller gain constants for a given system operating point. The first figure 5.21 is the controller response to the loss of generator three with the system conditions as above. The proportional gain has been increased by a factor of two on that used above. This would be expected to have the effect of increasing the speed of response of the unit but could also cause an overshoot if the gain was too great. The initial increase of generator one and two is greater than the previous ramp rate, and unit one overshoots quite noticeably and then drops back to an output value equal to the first case. The frequency plot (figure 5.22) follows the trend of the previous plot although the steady-state frequency is increased from the previous one.

The figure 5.23 shows the system response with the integral gain of generator one increased by a factor of two. The response of the unit is seen to be more rapid after the initial increase than in the first case as the integral action is stronger. The frequency (figure 5.24) is returned to the nominal value more rapidly than in the previous case, but there is no noticeable overshoot.

The figure 5.25 shows the effect of the controller parameters on generator one when the integral action is completely removed and a larger proportional value is used. The speed of response is clearly increased when compared with the first configuration but there is no control action to remove the steady-state error. Thus the frequency response seen in figure 5.26 takes a longer time to return to the average steady-state frequency value. The initial response takes longer to return to the nominal value, but it is also effected by any change in the system as there is no stabilising effect from the integral action, hence the frequency tends oscillate around the nominal value with the proportional action directly responding to the system frequency fluctuations.

Figure 5.19



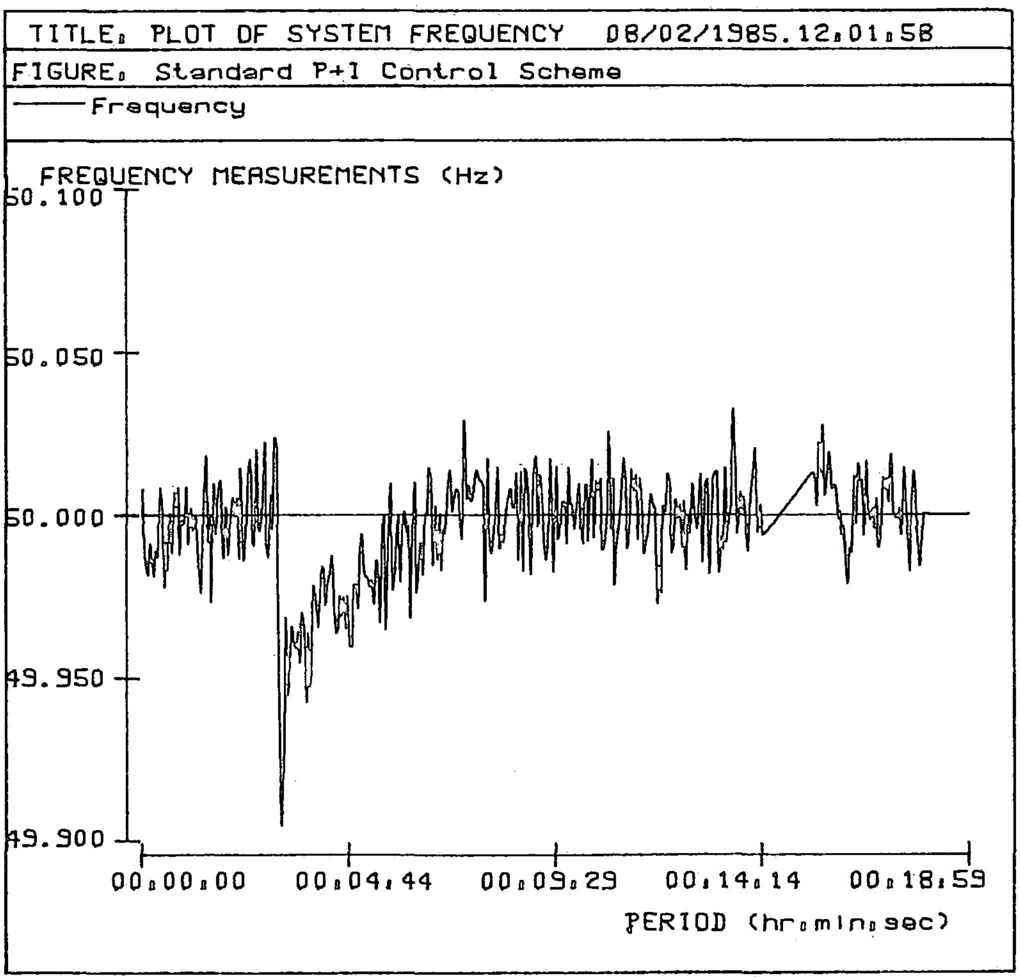
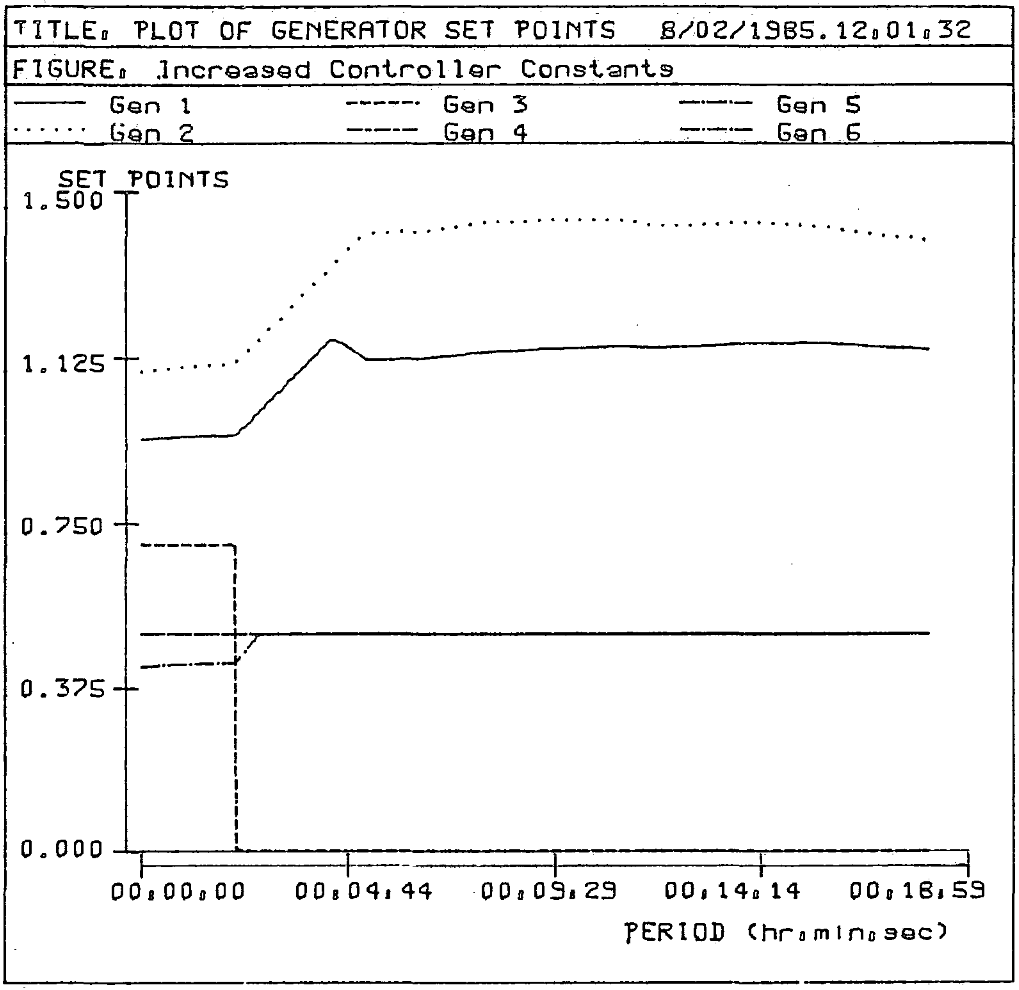


Figure 5.20

Figure 5.21



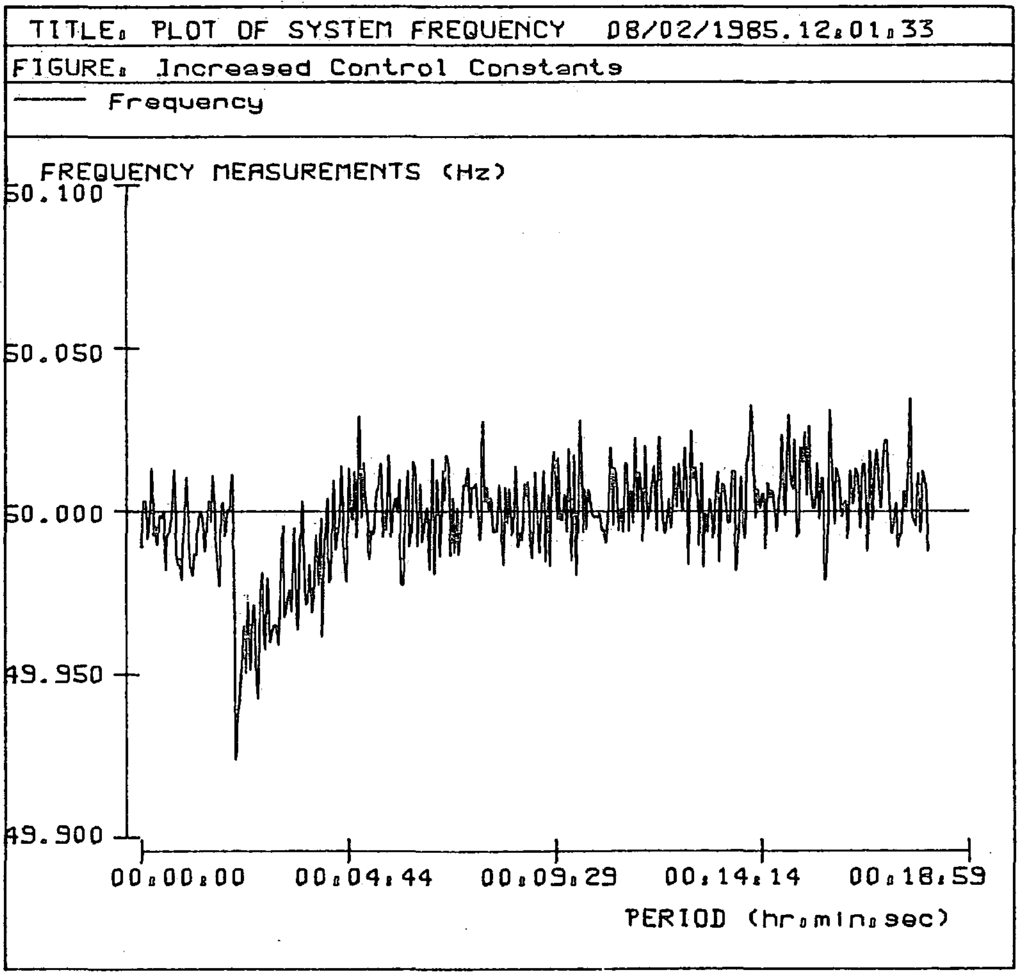
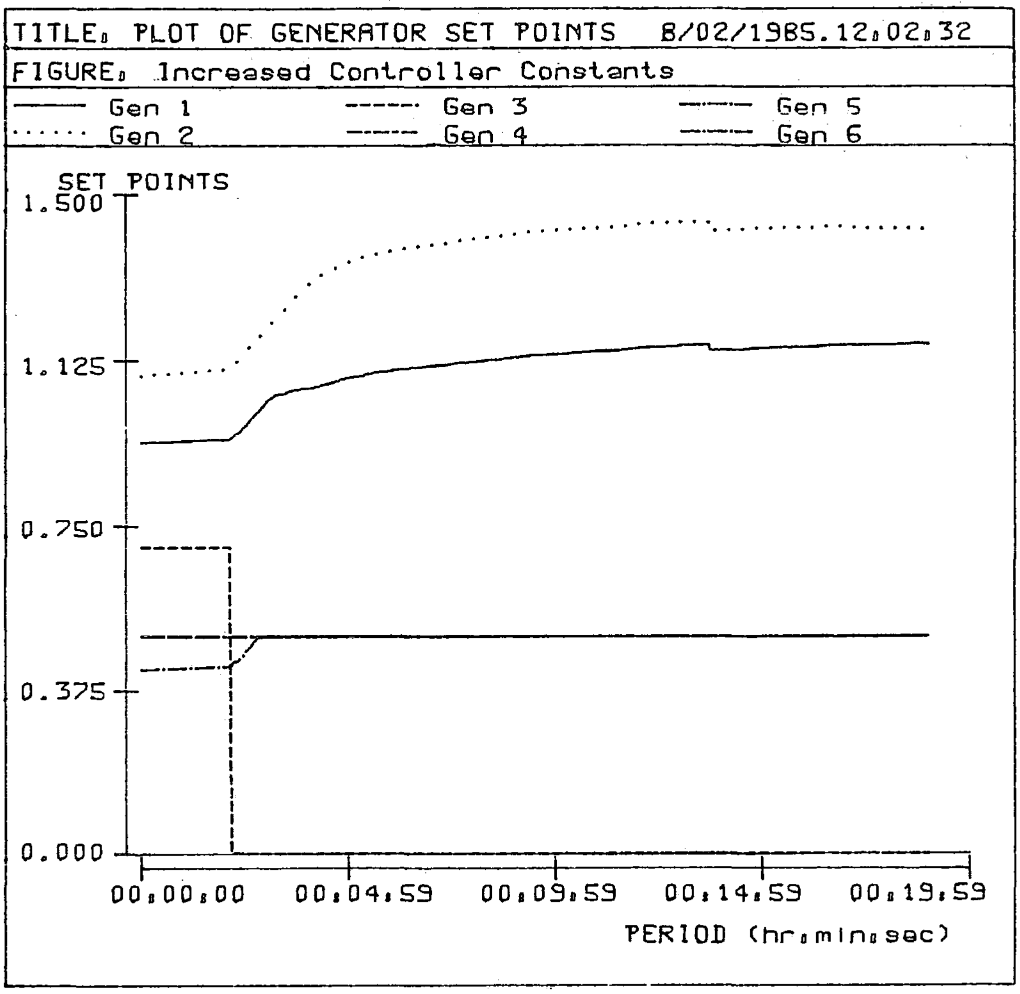


Figure 5.22

Figure 5.23



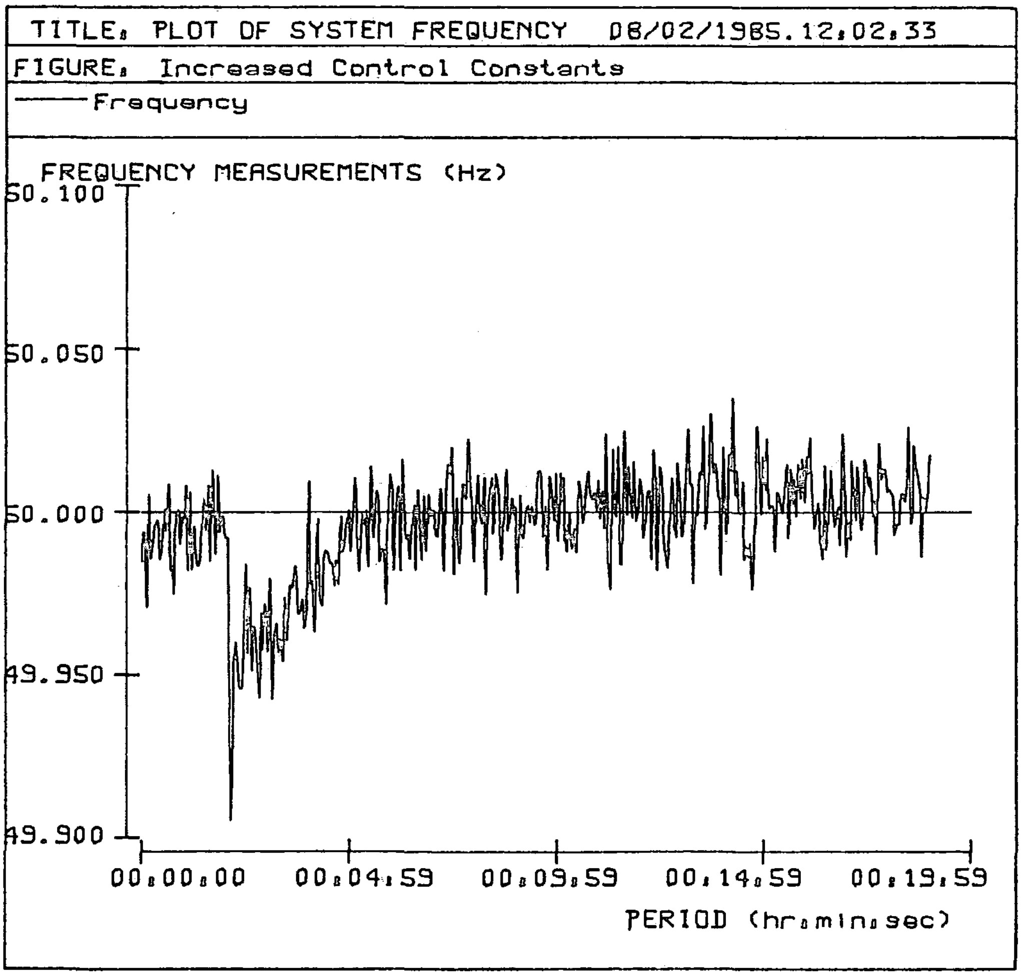
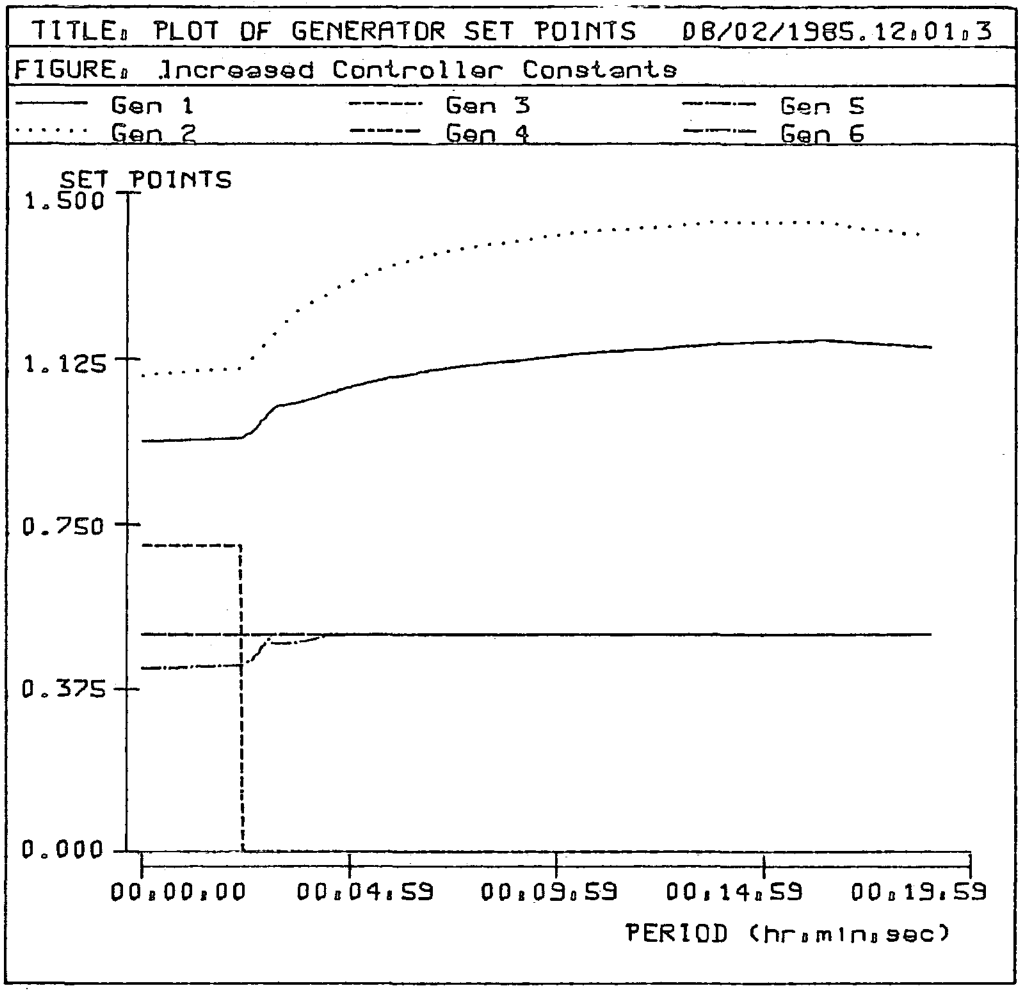


Figure 5.24

Figure 5.25



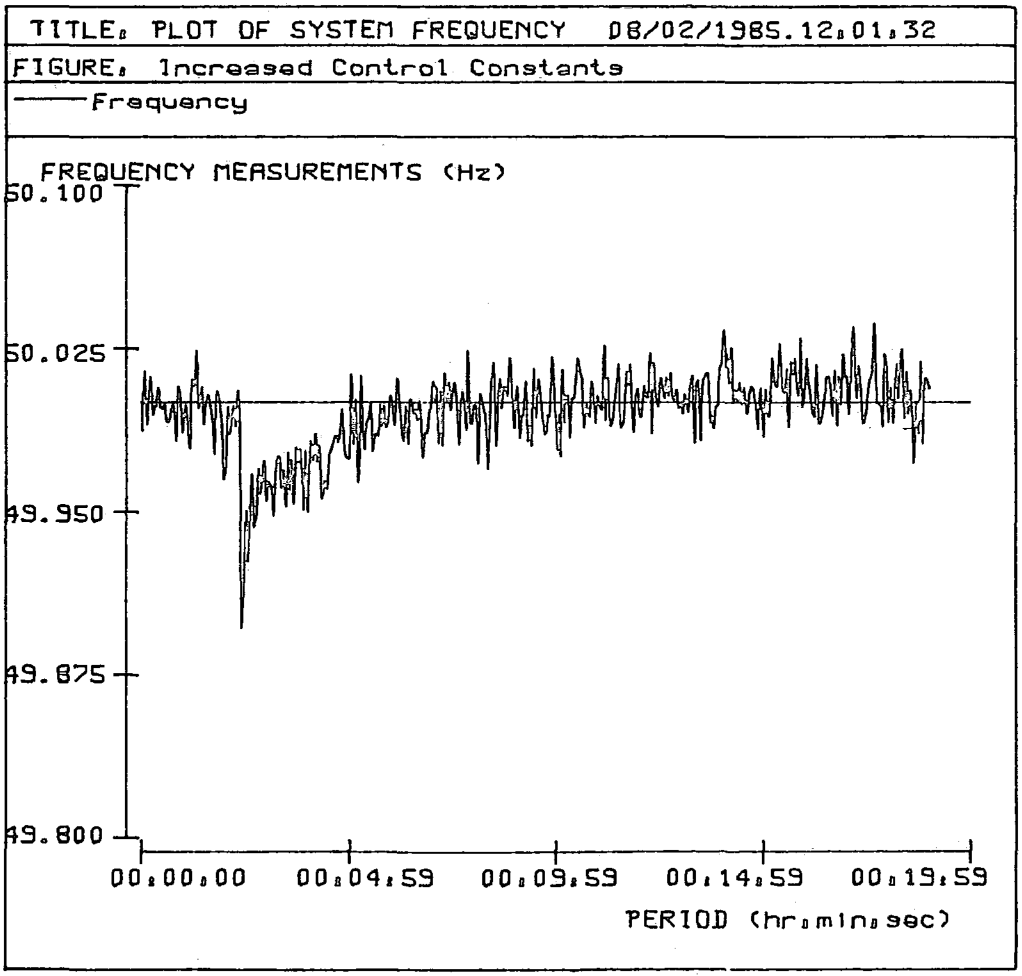


Figure 5.26

The controller was tested against the O.C.E.P.S. standard scenario. The scenario is described in detail in Appendix 1. The result of the controller action is shown in figure 5.27 with the corresponding system frequency (or frequency of island one) in figure 5.28. It is seen that the controller is able to respond to the earlier system faults reasonably well, but when Unit 2 is desynchronised Unit 1 is commanded to increase its output rapidly and over compensates for the loss. Later when the system is islanded, the controller is able to respond to the individual islands, but their individual frequencies are somewhat different. This means that when the synchronisation command is given, the individual islands will not resynchronise. Thus the test finishes with two of the three islands resynchronised but the third one is unable to be synchronised due to the frequency difference.

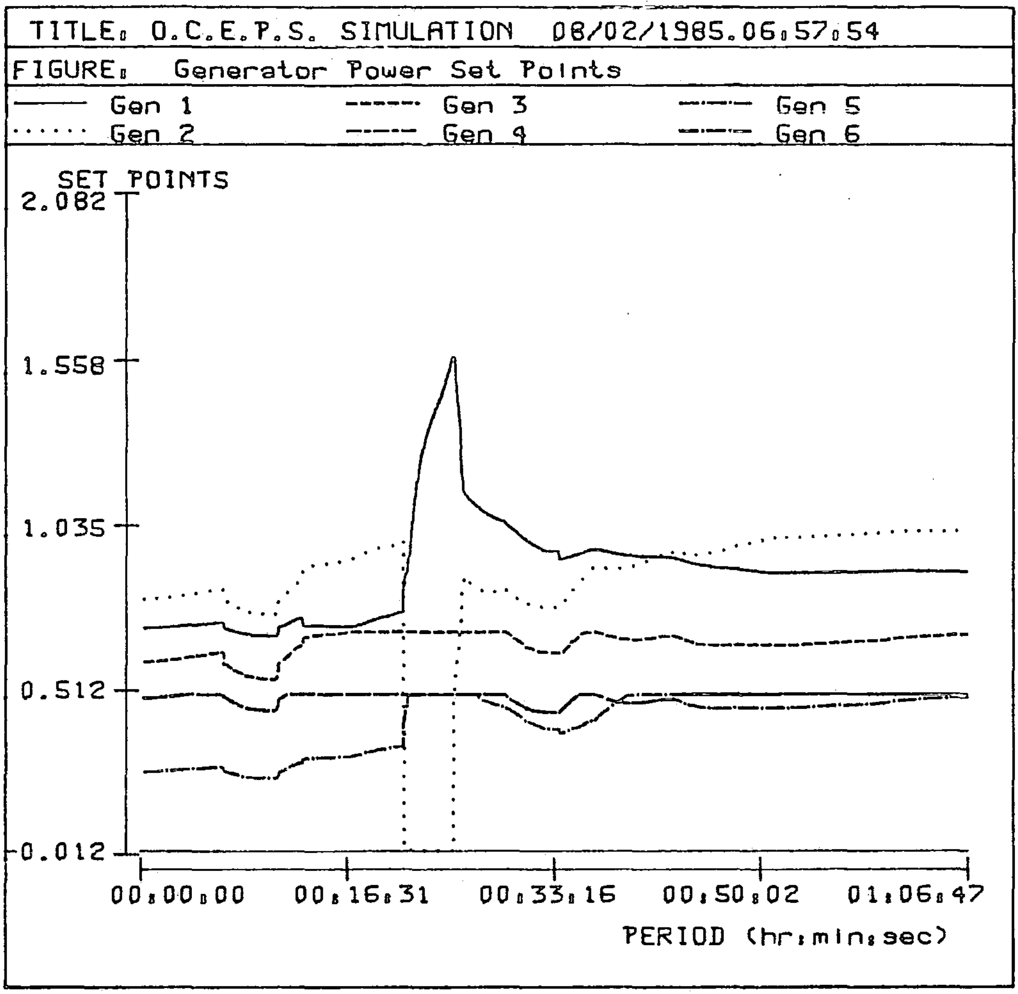
5.25 Conclusion

This chapter described the O.C.E.P.S. simulation and control project as a test facility for power systems software. The first section discussed the types of models used in the simulator, the system simulated, the computer configuration and the energy management software.

The second section described the application of L.F.C. to control the simulated system. The control function must have well established links with the other subsystems in the energy management scheme, especially with Economic Dispatch, Unit Commitment and the Reschedule function. The interface between the L.F.C. has been investigated especially with Economic Dispatch so the control action can be economically based unless security considerations have to be taken into account.

The controller that was implemented was based on a standard P+I control scheme. This control method was chosen initially because it is well known and understood but has the draw back that the parameters of the controller are fixed. Although the controller is robust in its control commands the optimum control action can only be tuned for one operating point. This operating point can change with; the time of day, different days (week days, weekends

Figure 5.27



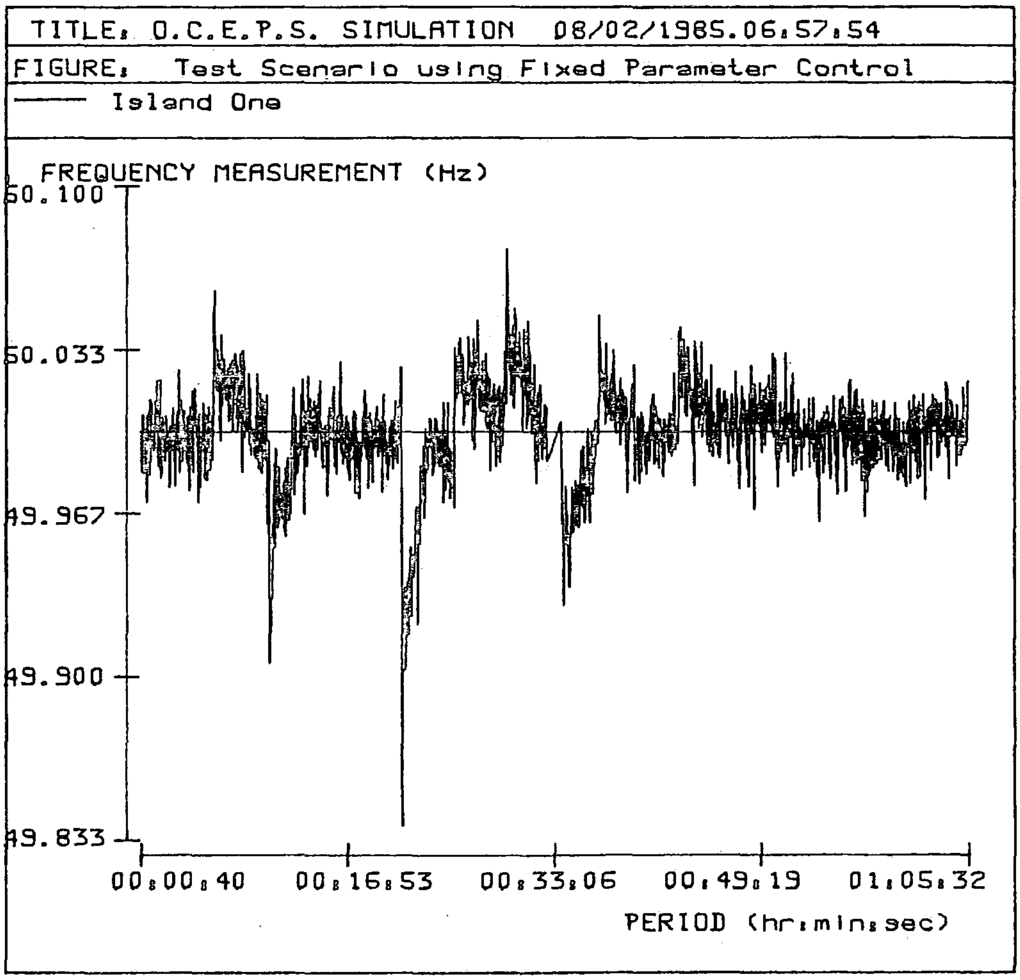


Figure 5.28

or holidays) and the time of year (differing seasons) and is dependent upon the type and amount of regulating plant there is on the system at any given time. This scheme is discussed in detail and results from its implementation are presented in graphical form.

The fixed parameters of the controller are shown to produce suitable control action under certain system conditions. However the parameters were tuned to give an average response for all system operating points and hence this leads to a degrading of the controllers performance during certain times of the day. As the plant on the system changes during the day, the system gain also changes depending the type of generators that are on the system. Thus the controller parameters cannot take into account the change in system gain, the change in tie–line power interchange and cannot account for the change in the generators performance as they become older and less responsive. In emergency conditions, such as the loss of a large generator unit the controller cannot respond as would be required and the control action can under certain circumstances add to the system transient behaviour. This control action is clearly unsuitable for a system where the gain may vary greatly, or where there is a large number of different types of generators which may be used. The stationary nature of the control system must clearly be removed from the control scheme and a scheme that is capable of tracking the power system status be investigated.

The following chapters discuss the methods that are required to implement such a scheme where the system operating point is tracked and updated as the system configuration changes.

CHAPTER 6

ADAPTIVE LOAD FREQUENCY CONTROL

6.1 Introduction

This chapter describes the application of the adaptive control theory discussed in an earlier chapter. The self-tuning control theory is used to form an effective load frequency controller which can be used to replace directly the fixed control scheme described in the previous chapter. The earlier sections briefly discuss the ideas involved in adaptive control and their application to the L.F.C. problem. The later sections give details of the design, construction and testing of a full scale L.F.C. scheme. This was tested and validated in conjunction with the O.C.E.P.S. energy management control software and power system simulator. The use of forgetting factors, more stable numerical calculation methods, order of the system model and system control techniques are also discussed along with their implementation.

6.2 The Need For Adaptive Control

The previous chapters have discussed the use of Load Frequency Control techniques which have been implemented for various systems. These schemes use the standard procedure of creating a linear system model which has by its very nature fixed parameters. These parameters are found from the linearisation of the system about a specific operating point. When considering the control of electrical power systems it must be remembered that due to the physical nature of the system, it is inherently a complex mannerliness system. The parameters of such a system are a function of the system operation point. Thus as the system operating conditions change, so do the system parameters. Hence, any optimal control scheme based on these parameters is no longer optimum. In order that the controller performance is kept optimum, it is proposed to track the operating conditions and hence, continuously update the system model. This should then lead to a control signal which is always optimal for the system under any set of operating conditions [204,208,209]. Diagram 6.1 shows a basic adaptive control configuration to control an industrial process.

6.3 Stochastic Control

Many of the previously used control techniques take the system disturbance as step changes in the consumer load. However, in the real system the load changes are random in nature, both in magnitude and in period. Thus it is proposed to consider the system as a stochastic system and design an adaptive stochastic controller which should lead to better control performance. The adaptive controller combines a parameter estimation algorithm with a control algorithm. The parameter estimation algorithm is used to update the on–line system parameters of a discrete noisy model of the system and the controller is a minimum variance algorithm based on the updated model. The combination of this estimator and controller is termed a self–tuning regulator; it uses a recursive least squares estimation technique and a minimum variance control strategy. Diagram 6.2 shows the arrangement of a typical Self-tuning Regulator scheme.

The use of self–tuning regulators has been successful in various processes, mainly in the chemical industry, although it has been reported controlling voltage and speed regulators for electric generators [43,48,128,219].

The application of self–tuning algorithms for the control of multi–area electrical power systems has been described in [9,135]. However, in the first instance the proposed controller will only be applied to a single area power system. This test system was once again the O.C.E.P.S. simulator and control systems. The choice of the initial single area investigation was made because the O.C.E.P.S. simulation had not previously been operated as a multiple area simulation, which meant that certain modifications were required before simulation of a multiple area system was possible. This also gave an opportunity

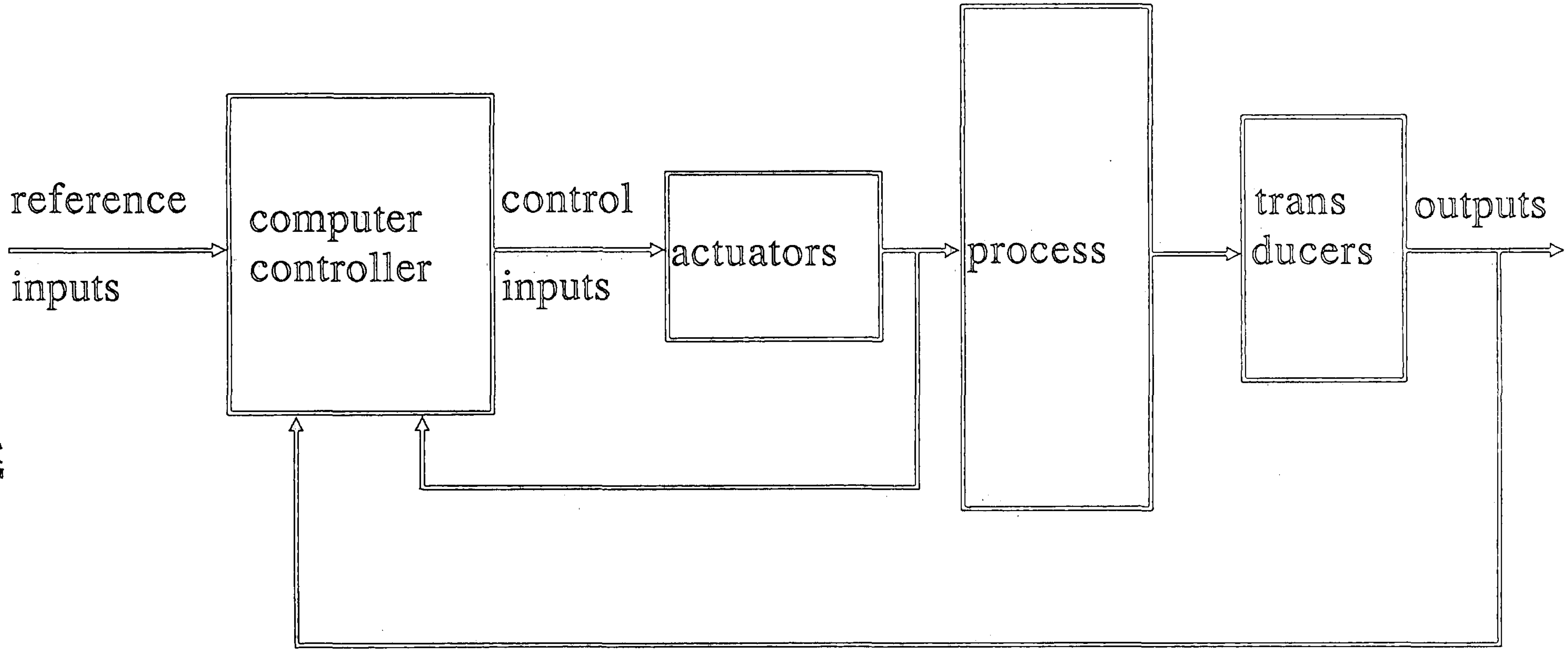


Diagram 6.1 Adaptive control configuration

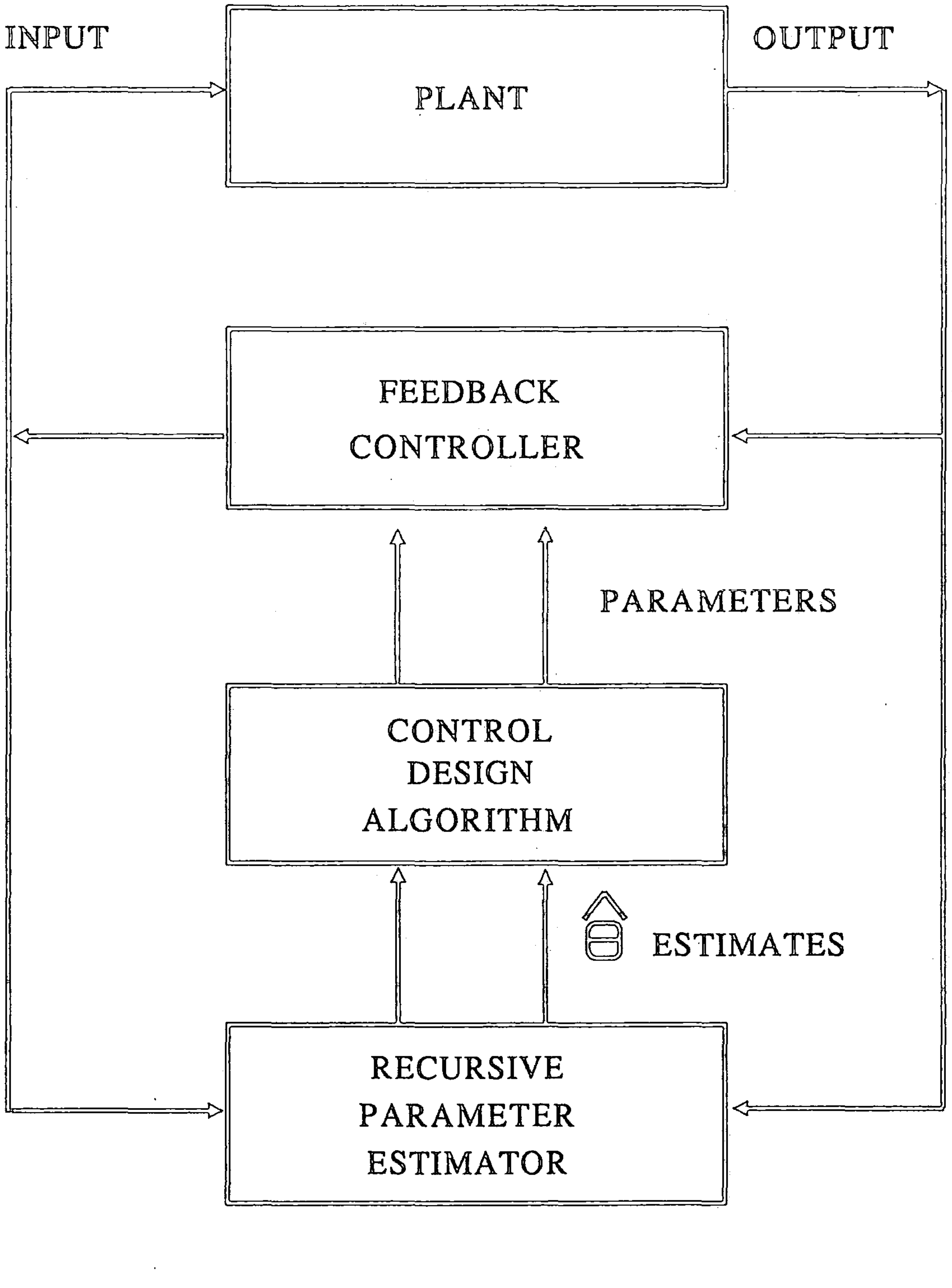


Diagram 6.2 Structure of Self-tuning Regulator

for the new controller to be tested directly against the previously described fixed parameter control scheme. The ideas involved in the control of multiple area power systems are discussed in the following chapter. The next chapter covers the use of tie–line control as a method of controlling an interconnected power system, discusses the algorithms required for the adaptive control of such systems and presents results from the tie–line controller operating within the O.C.E.P.S. environment.

6.4 Formulation of the Area Control Error for Single Area Systems

The A.C.E. of a single area system is formed simply using the weighted sum of the frequency error. This is taken to be the controlled variable. With the simplified single area, the frequency error is the only control measurement available and is independent of all other system variables. Thus if the frequency error can be minimised, minimum variance of the A.C.E. can be achieved [9,25,26].

One of the advantages of using this technique is that the control scheme only requires locally (to the area) available measurements. The frequency error is the only input required for the control scheme. The function of the controller is to control the frequency in the single area and thus easy to implement using a relatively small amount of computing power. The control is such that the scheme is easily implemented on the VAX 8600 control computer and will operate in real–time without incurring any loss of the machines performance. In fact this algorithm is simple to implement and may be used on even relatively limited microprocessors. It is hoped that the performance of this controller set up will be better than that of the more conventional fixed control scheme. The flow chart of the organisation of the proposed control is shown in diagram 6.3.

Previous frequency controllers have used the system frequency error to form the A.C.E. control where the integral of the A.C.E. is fed–back as a control signal. More complex schemes have been considered for both continuous and discrete time control using optimal and sub–optimal approaches. It must be remembered that these techniques do not take into account the dynamic nature of the system under study. These techniques take the parameter values

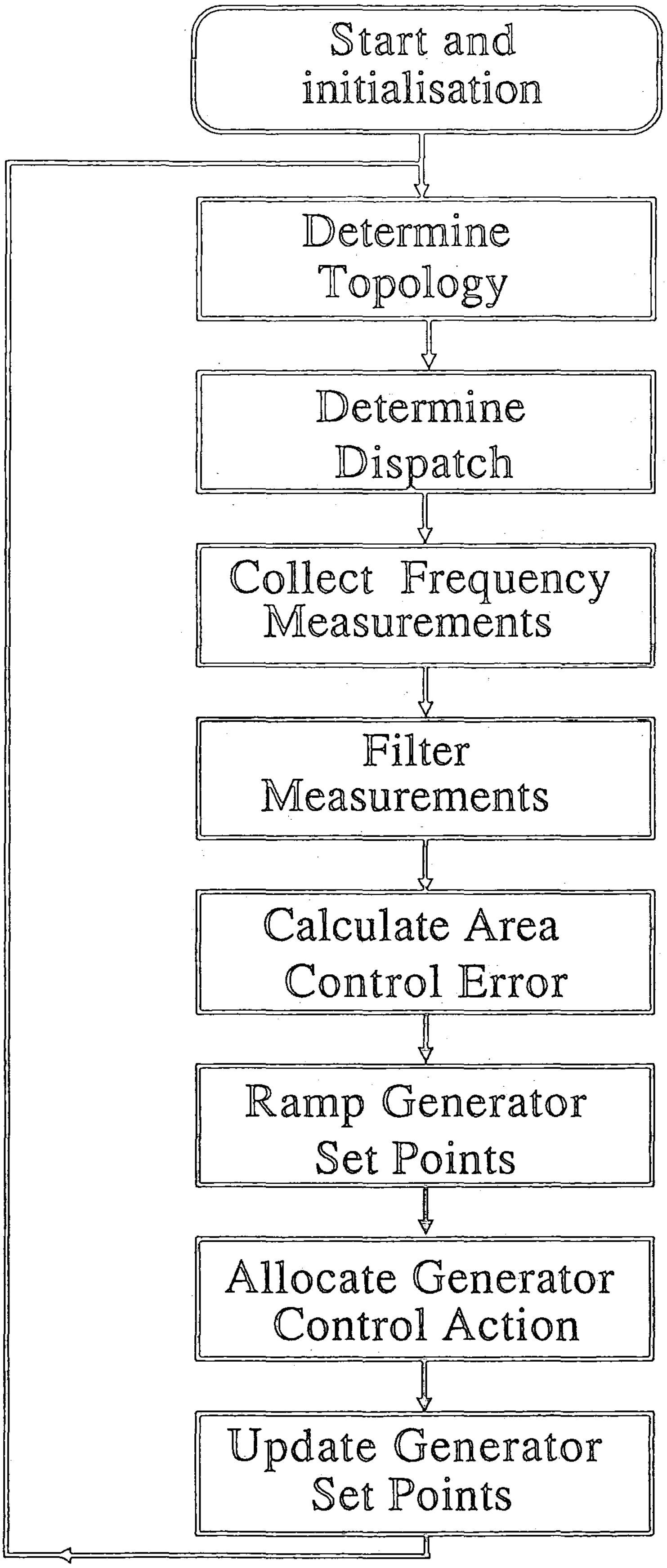


Diagram 6.3 System Frequency Control Flowchart

of the power system to be known and remain constant through its operation, this is not the case. Generator dynamic characteristics change sufficiently with operating conditions, and the equivalent droop characteristics of an area vary widely with percentage loading of the plant due to the changes in the numbers of the turbines performing regulation duty [10]. Thus an adaptive control scheme is required that can evaluate relevant dynamic characteristics during operation and can suitably adjust control parameters when they change.

In self–tuning control, the order of the controller model is determined by the order of the predictive model used to determine the system behaviour. For a single area system using the frequency error and the tie–line power interchange as the control variables, a third to fourth order model has been shown to be suitable [50]. The matter of the model order is investigated for the single area case, and the multiple area case is discussed in the following chapter.

The use of a minimum variance controller involves the cancellation of system zeros by controller poles. Thus if the system has any discrete model zeros outside the unit disc, then stability problems will occur.

6.5 Self–tuning Regulator

The self-tuning regulator is a good alternative to the conventional L.F.C. controller as it offers versatility and the potential for application in real-time control applications. The development of the self-tuning regulator is fairly new, it has been applied to several real time applications. As mentioned in an earlier chapter the general structure of the self-tuning regulator can be split into two separate sections. The first section is the identification process and the second is the control command calculation associated with the identification. The identifier is used to calculate a model of pre-assigned order of the plant at each required time interval. The identifier calculates the system parameters at each required sampling interval. The controller uses the updated parameters and data from the system to calculate a control signal which is sent to the plant. Diagram 6.4 shows the set–up of the adaptive control scheme used in this application. Self–tuning regulators are discussed in many references, the author found the following most useful 9,25,26,87,122,126,129,131,148,159,164,170,171–174,179,183.

6.5.1 The identification routine

Each separate section of a power system is a complicated non-linear system. The identifier within the self-tuning regulator uses the system data available to it to model the system by a linear-discrete finite order model with time varying parameters. The system operating conditions are tracked by the identifier which calculates the model parameters at every sampling period. It uses the actual input and output of the system for the parameter calculation and hence a dynamic model of the plant may be created of a pre-assigned order. A discussion of the implementation of identification routines many be found in 92,93,135,196,197,214.

The task of the identifier is to give unbiased estimates of the values of the parameters. In a real-time control situation, the following recursive computations are performed for the solution of the above problem.

The model is described using the following equation

$$\begin{aligned} &y(t+k+1)+\alpha_1 y(t)+\ldots+\alpha_m y(t-m+1) \\ &\qquad =\beta_0[u(t)+\beta_1 u(t-1)+\ldots\beta_l u(t-l)]+\epsilon(t+k+1) \end{aligned} \tag{6.1}$$

where

$m=n,\ l=n+k-1,$

β_0 is a previously selected constant parameter,

α_j and β_j are the computed model parameters for all $c_j=0$ and

the disturbance $\epsilon(t)$ is a moving average of order k of the driving noise $e(t)$.

To estimate the model parameters, equation (6.1) may rewritten at the instant t, by replacing $(t-k-1)$ in equation (6.1) as follows

$$z(t)=H^T(t)\,\hat{\theta} \tag{6.2}$$

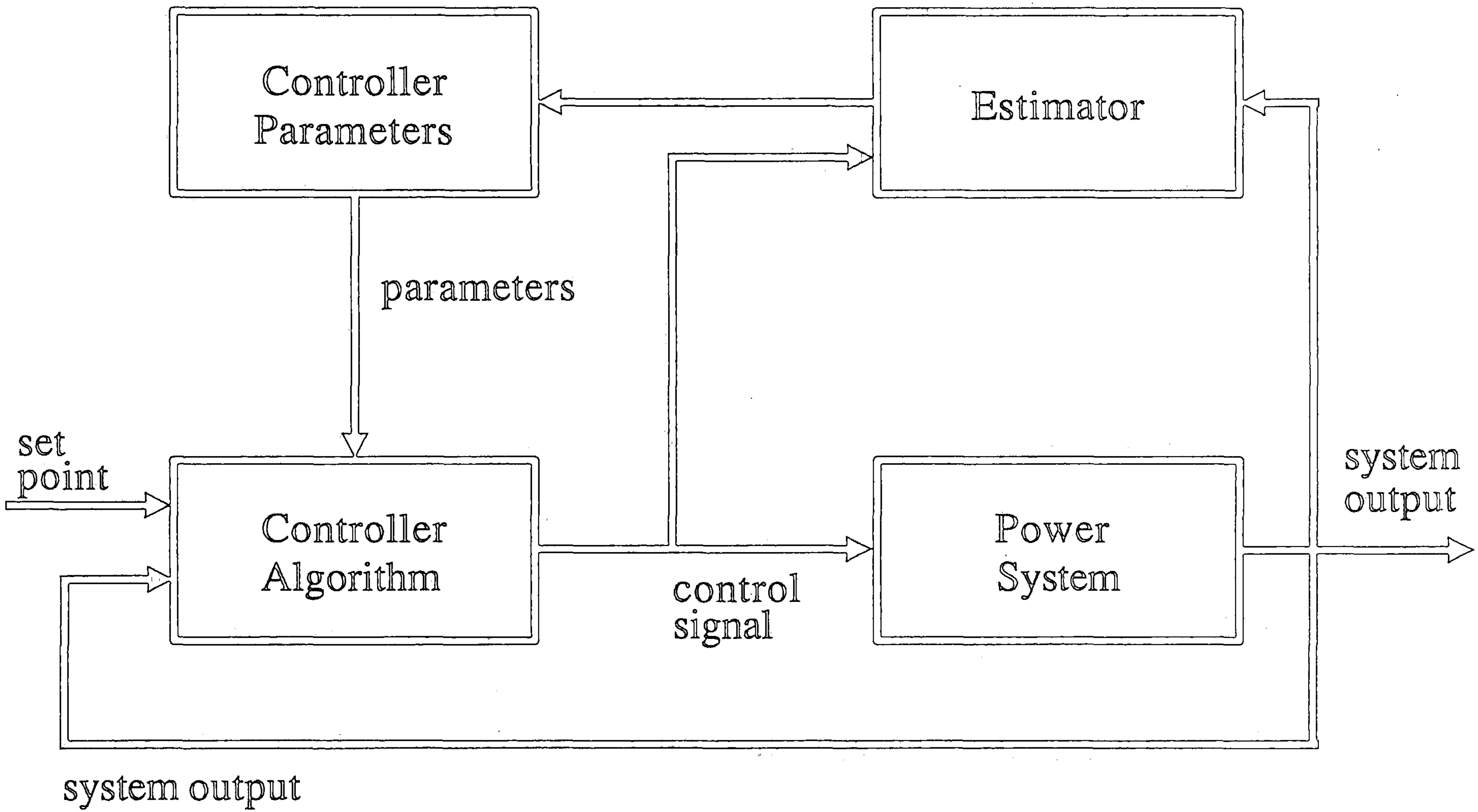


Diagram 6.4 Self-tuning Controller Structure

where

$$z(t) = y(t) - \beta_0 u(t-k-1) \tag{6.3}$$

$$\begin{aligned} H(t) = [&-y(t-k-1), \ldots, -y(t-k-m), \\ &\beta_0 u(t-k), \ldots, \beta u(t-k-l-1)]^T \end{aligned} \tag{6.4}$$

$$\theta = [\alpha, \ldots, \alpha_m, \beta_1, \ldots, \beta_l]^T \tag{6.5}$$

where

$[\ ]^T$ represents the transpose of the matrix.

There are several recursive parameter estimation algorithms which can be used to obtain an estimate, $\hat{\theta}(t)$ for the parameter vector $\hat{\theta}$. One of the more commonly used is the recursive least-squares

$$\hat{\theta}(t) = \hat{\theta}(t-1) + K(t)[z(t) - H^T(t)\hat{\theta}^T(t-1)] \tag{6.6}$$

The correction vector, $K(t)$ can be calculated as

$$K(t) = \frac{P(t-1)H(t)}{1 + H^T(t)P(t-1)H(t)} \tag{6.7}$$

where $P(t)$ is the covariance matrix of estimation error and is found using the recursive equation

$$P(t) = [I - K(t)H^T(t)]P(t-1) \qquad (6.8))$$

The equations (6.6), (6.7) and (6.8) are often referred to as the Kalman filter algorithm, and the vector K is the Kalman gain of the set of equations All the matrices are of the size $2n \times 2n$ and the vectors are of the size $2n$. Where n is the optimum number of estimated parameters (the order of the estimated system). It is clear that the algorithm has to be started with some initial values of $P(t)$ and $\hat{\theta}(t)$, after which the calculations may be repeated.

The initial values are arbitrary, but a good starting point seems to be

$$P(0) = [I] \times v$$

$$\hat{\theta}(0) = [\epsilon\epsilon\epsilon \ldots \epsilon]$$

where ϵ is a small number (can be zero) and I is the unit matrix.

v is a relatively large scalar quantity, and can be calculated using

$$v = (10)\frac{1}{N+1}\sum_{=0}^{N} y^2(i)$$

where $N > 2n$

The algorithm has been shown to give acceptable values of $\hat{\theta}(t)$ within ten samples [92].

The above calculations may be repeated every sample interval but can be repeated recursively and the most recent parameters are passed on to the controller. However, the system model is only required to change when there is a change in the system itself. This can be difficult to define, but the criterion used in these experiments was the rate at which the frequency changed, and when it was outside a pre–defined dead–band.

The identification process is used to calculate the most recent system model. With the updated model the estimate available, the control can be calculated on it. There are several control schemes available which are suitable for real–time operation, but the most widely reported one is that of minimum variance control. This control strategy was discussed in an earlier chapter but is considered here in this specific application. Once$\hat{\theta}(t)$ is obtained, $u(t)$ can be calculated as

$$\begin{aligned} u(t) = & \frac{1}{\beta_0}[\hat{\alpha}_1(t)y(t) + \ldots + \hat{\alpha}_m(t)y_l(t-m+1)] \\ & - \hat{\beta}_1(t)u(t-1) - \ldots - \hat{\beta}_l(t)u(t-l) \end{aligned} \tag{6.9}$$

6.5.2 Minimum variance control scheme

The minimum variance controller was discussed in a previous chapter, but its implementation is briefly discussed here. Further details may be found in a variety of references 28,60,61,97,135,198 but only very basic control schemes are discussed. From previous discussion the single area is modelled as

$$y(t) = -\sum_{j=1}^{n} a_j y(t-j) + \sum_{j=1}^{n} bu(t-k-j) + \psi \sum_{j=0}^{n} ce(t-k) \tag{6.10}$$

where

$u(t)$ is the input to the actual system (the control variable, the A.S.C.)

$y(t)$ is the output of the actual system (the input variable, the frequency error)

and $e(t)$ is the disturbance acting on the actual system.

So long as the system under study behaves in such a way that the input and output are linked by a cause and effect relationship, it is possible to construct a model of the plant. The model plant parameters are

$$a_1, \ldots, a_n;\ b_1, \ldots, b_n;\ \psi\ ; c_1, \ldots, c_n$$

$c_0 = 1$ without loss of generality,
n is the order of the model,
(t-j) represents the time (t-jT), and
T is the sampling period.

The controller chosen to be associated with the identifier is a minimum variance regulator, although more complex control algorithms are available. The minimum variance controller is chosen as it is fairly simple to implement, and has the ability to work in real time with a very satisfactory performance. The criterion for the controller is

$$\text{minimise}\left[V = \sum_{i=1}^{N} y^2(i)\right] \tag{6.11}$$

The controller aims to minimise the square of the deviation of the output from the desired value. The controller is designed to minimise the variance of $y, (k+1)$ sampling periods ahead of time. Then at time $(t+k+1)$ the model given by equation (6.1)

$$\begin{aligned} y(t+k+1) &+ a_1 y(t+k) + \ldots + a_n y(t+k+1-n) \\ &= b_1 u(t) + \ldots + b_n u(t+k) \\ &+ \psi[e(t+k+1) + c_1 e(t+k) + \ldots + c_n e(t+k+1-n) \end{aligned} \tag{6.12}$$

The standard equation (6.1) may be written at times $(t+k), (t+k-1), \ldots, (t+1)$. Then by substituting in equation (6.12) to eliminate $y(t+k), y(t+k-1), \ldots, y(t+1)$, the equation may be modified to

$$\begin{aligned} y(t+k+1) &+ \alpha_1 y(t) + \ldots + \alpha_m y(t-m+1) \\ &= \beta_0[u(t) + \beta_1 u(t-1) + \ldots + \beta_l u(t-l)] + \epsilon(t+k+1) \end{aligned} \tag{6.13}$$

where
$m = n$,

$l = n + k - 1$,

β_0 is a previously selected constant parameter,

α_j and β_j coefficients are computed from the parameters a_j and b_j in equation (6.1) for all $c_j = 0$, and

the disturbance $\epsilon(t)$ is a moving average of order k of the driving noise $e(t)$.

For any system modelled by the equation (6.13), if the parameters of the model are constant and known, the minimum variance strategy can be stated as follows

$$\begin{aligned} u(t) = & \frac{1}{\beta_0}[\alpha_1 y(t) + \ldots + \alpha_m y(t - m + 1)] \\ & - \beta_l u(t-1) - \ldots \beta_l u(t - l) \end{aligned}$$

If the system under study has unknown parameters, then the parameter estimation routine described earlier is used. This estimation may be required at every sampling interval depending upon the system under study.

In the self-tuning regulator the parameters $\alpha_1, \ldots, \alpha_m$ and $\beta_1, \ldots, \beta_l$ which form the assumed model equation (6.13) are estimated on-line at any sampling instant, the estimated values $\hat{\alpha}_1, \ldots \hat{\alpha}_l$ and $\hat{\beta}_1, \ldots, \hat{\beta}_l$ of the parameters are then used to calculate the minimum variance control strategy equation (6.13).

6.6 Forgetting Factor for Adaptive Estimation Controller

With the use of recursive operations in the least squares algorithm, it is clear that more information about the process under study is accumulated as time goes on [67,76,77]. As more system data is collected, the parameter estimates tend to converge and become steadier. The effect of this convergence is seen by the decrease in size of the elements of the Kalman gain vector matrix K. The equation (6.7), the Kalman gain vector controls the size of the update to the system parameter estimates. This convergence is needed for constant parameters systems as the low gain tends to suppress the effect of measurement noise on the estimate of $\hat{\theta}$. However, when the parameters are from a time-varying process it is necessary to stop the continuous alteration to the estimates $\hat{\theta}$. This will allow changes in the system parameters to be followed. However, by not enabling the covariance matrix from decreasing, the random errors in $\hat{\theta}$ are increased, which means that the estimate variance is increased.

In the practical application of these equations there is a trade off between the parameter adaptive capability (which requires the calculated value of K) and the noise suppression feature of the estimation algorithm (which requires small values of K).

This is usually achieved by the use of a *forgetting factor* [91,142,143,155] to control the size of the elements of the covariance matrix of P. The use of the forgetting factor, which is generally a scalar parameter, γ, enables the building of memory attenuation into the recursive least squares algorithm by exponentially weighting past values of the elements of P. This weighting factor is implemented by replacing $P(t-1)$ by $\frac{1}{\gamma}P(t-1)$ in the equations (6.6),(6.7), (6.8). Thus the following equations are formed

$$\hat{\theta}(t) = \hat{\theta}(t-1) + K(t)[z(t) - H^T(t)\theta^T(t-1)] \tag{6.14}$$

$$K(t) = \frac{P(t-1)}{\gamma}H(t)\left[\frac{1}{a} + H^T(t)\frac{P(t-1)}{\gamma}H(t)\right]^{-1} \tag{6.15}$$

$$P(t) = \frac{1}{\gamma}\,[I - K(t)H^T(t)]P(t-1) \tag{6.16}$$

where
$a = 1 - \gamma$ and
$0 < \gamma \leq 1$
When $\gamma = 1$ the normal algorithm of equation (6.8) applies. As γ is decreased the covariance matrix elements are slightly increased at each recursion, which allows the algorithm to 'forget' the old parameter values. This has the effect that there is less emphasis placed on the older values, than the newer ones by the algorithm.

The equation (6.14) shows the formula that is used to *update* the next value of the estimate. This shows that the term $H^T(t-1)\,\hat{\theta}(t-1)$ is the output that is expected at the time t based on the previous data $H(t)$, and the previous estimate, $\hat{\theta}(t-1)$. Hence the next estimate of θ is given by the old estimate corrected by a term linear in the error between the observed output, $y(t)$, and the predicted output, $H^T\hat{\theta}(t-1)$. The gain of the correction, $P(t)$, is given by (6.15) and (6.16). Clearly, there is an advantage using this process in that there is no matrix inversion required, there is only the need for division by

$$\frac{1}{a} + H^T(t)\frac{P(t-1)}{\gamma}H(t)$$

which is a scalar. However, some numerical difficulties are reported to remain [50,91,92] and may effect these recursive calculations. Thus the use of a more stable method of calculating the P matrix was investigated.

6.7 Use of the Square Root Filter

The numerical stability problems can be solved using the upper triangular matrix and its transpose of P, as this matrix is positive and definite. This solution was proposed by Peterka [179]. The P matrix is factorised into $S(t)S(t)^T$ where $S(t)$ is the upper triangular matrix. The updating of this matrix is achieved using

$$S(t)S(t)^T = \frac{1}{\beta}S(t)\left\{1 - \frac{S^T(t-1)x(t-k)x^T(t-k)S(t-1)}{\mu^2}\right\}S(t-1)^T \quad (6.17)$$

where

$\mu^2 = \beta + x^T(t-k)S(t-1)S^T(t-1)x(t-k)$

The vector $f = S^Tx$ is defined and T is an orthogonal matrix so the above equation may be written as

$$S(t)S^T(t) = \frac{1}{\sqrt{\beta}}S(t-1)\begin{bmatrix} I \\ \vdots \\ \frac{jf}{\mu} \end{bmatrix} TT^T \left[I\frac{jf^T}{\mu}\right] S^T(t-1)\frac{1}{\sqrt{\beta}} \quad (6.18)$$

The value of T is chosen such that

$$\left\{I \vdots \frac{jf}{\mu}\right\} T = [H \vdots \tilde{0}]$$

where

H is the upper triangular, and

$\tilde{0}$ is a vector of zeros, then an upper triangular square root of P may be updated as

$$S(t) = \frac{1}{\sqrt{\beta}} S(t-1)H(t)$$

It is seen that the algorithm requires m extractions of the square root, where m is the number of estimated parameters. Clearly this is not a great problem to compute these values.

With the UD factorisation is written as UDU^T where U is the upper triangular with units stored along the diagonal and D is a diagonal matrix corresponding to the variances of the individual parameter estimates.

The square root method involves about $(4m^2+5m)/2$ multiplications plus m square roots per cycle, whereas the UD method uses about $(3m^2+3m)/2$ multiplications per cycle. The advantage of the UC method is that there is a built diagnostic test without the extra computation that would be required for the square root case.

6.8 Factors which Effect the Controller Action

There are several factors which effect the controller operation such as

(1) The order of the model which is used to model the area under observation

(2) the time interval between which control commands are sent out on to the system and,

(3) the sample period of the identifier.

Studies can be carried out to find the optimum value for the above parameters using the integral squares technique described below.

The flow of logic used by the controller is shown in diagram 6.5. It starts with the initialisation procedures, ensures that the support software is active and is then able to carry out the system identification and system control.

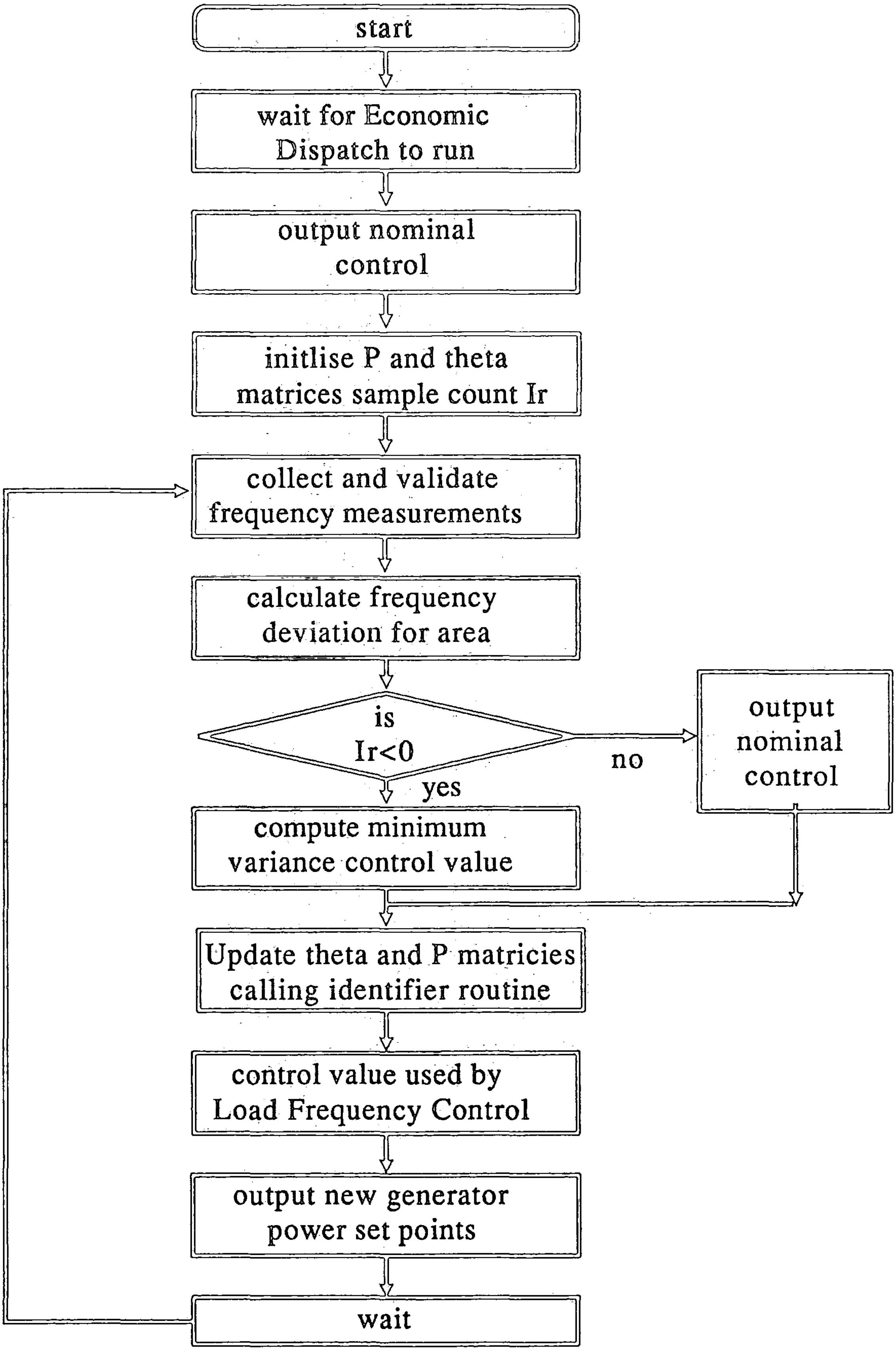


Diagram 6.5 Adaptive L.F.C. Flowchart

The implementation of the proposed control scheme is shown in diagram 6.6. This shows the measurements required by the controller from the system and the interaction between the various elements of the controller.

6.9 Choosing the Correct Model Order

It is possible to fit models of differing order to the data obtained from the system [57,198]. Thus the control action could based on several different model orders. If the wrong order for a model is chosen, this can cause problems with the modelling process and can lead to spurious control commands. Over modelling can lead to problems of redundancy of model terms, and under modelling may not sufficiently model the process under study well enough for the control action to be effective. Thus there is a need for a test which can determine the optimum model order for identification process, a test for the *correct* or *best* model order is needed. Such a suitable test is a sum of squares test, which if applied over a given period of discrete time can be thought of as an integration of the errors.

As the model order increases, the sum of the squares of the residuals will decrease due to the *better* fitting which is being achieved. If this decrease is small between models of increasing order, the order of the use of the higher order model will not significantly reduce the sum of the squares. These index values can be used as a measure of the quality of control (or goodness) of the regulator. The lower the integral value is, the better the quality of the control.

The prediction error term may be defined using

$$\xi(t) = \hat{\alpha}(q^{-1})y(t) - \hat{\beta}(q^{-1})u(t) \tag{6.19}$$

The sum of the squares is then defined as

$$I_n = \sum_k = 1^N \mid \xi(t) \mid^2 \tag{6.20}$$

where

N is the number of data points, and

n is the model order.

Frequency Control Scheme

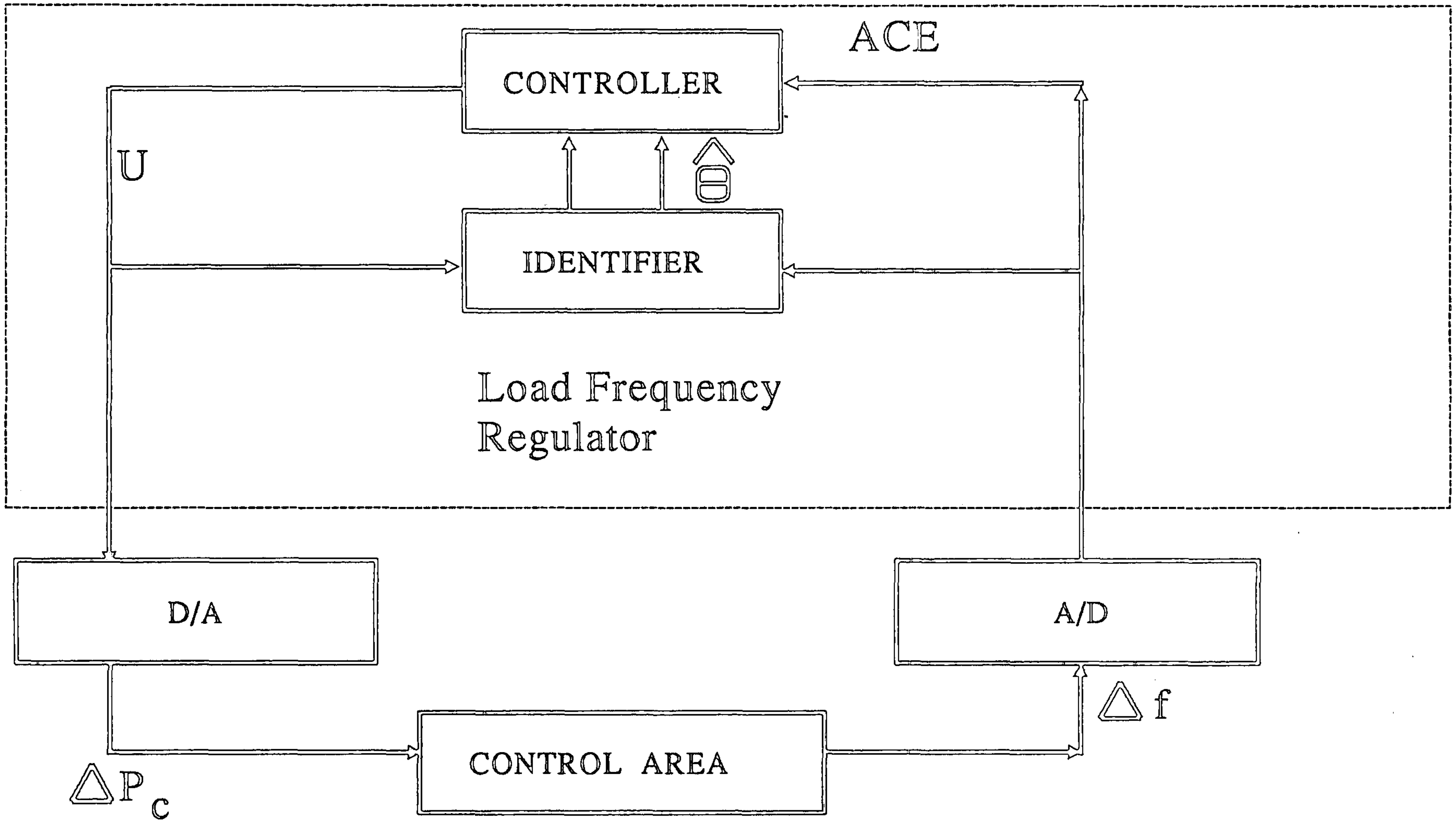


Diagram 6.6 Loaf Frequency Control using a Self-tuning Regulator

For a collected set of data, the coefficients of the polynomials $\hat{\alpha}$ and $\hat{\beta}$ may be found for a given model order using the techniques described earlier. This same procedure may then be carried out using models of different orders. The *best* model order for the system under study is chosen by plotting a graph of I_n against n. By choosing the slope of the graph at a given point, m' say, where the slope of I_n is steep for $n < m'$ and shallow for $n > m'$ the *best* model order may be selected.

The figure 6.1 shows the result of a frequency integral test to determine the optimum model order for the simulated test network. The model order of m=2 or m=3 is seen to be the value required, however, it is difficult to determine which order is best suited to the system model. Thus a continuous integral of squared frequency error test was carried out over a reasonable amount of time see lower figure. It is clearly seen that the model order of m=2 produces the least error. It is also interesting to observe that the models where m=3 and m=4 produce about the same integral error. Thus the majority of control operations were carried out using m=2, with some experiments using m=3 to determine if there was significant improvement in the system control and response.

One such test was carried out to show the response of the controller during the morning increase of consumer load. The initial test carried out was during the steady-state operation of the system. The figure 6.2 shows the controller response using a controller model of m=2, and the figure 6·3 with m=3. There is no obvious difference between the controller response in each case, the frequency is kept constant as the consumer load increases. The Units 1 and 2 are ramped to meet the demand increase, with the other Units on or nearing their upper limits.

The steady-state operation did not really show any differences in the control action calculated by the differing control schemes. The effect of the controller model is more noticeable however, when the system is subjected to a transient. The figures 6.4 and 6.5 shows the system response to change in controller model order from m=2 to m=3 when there is a generation loss

Figure 6.1

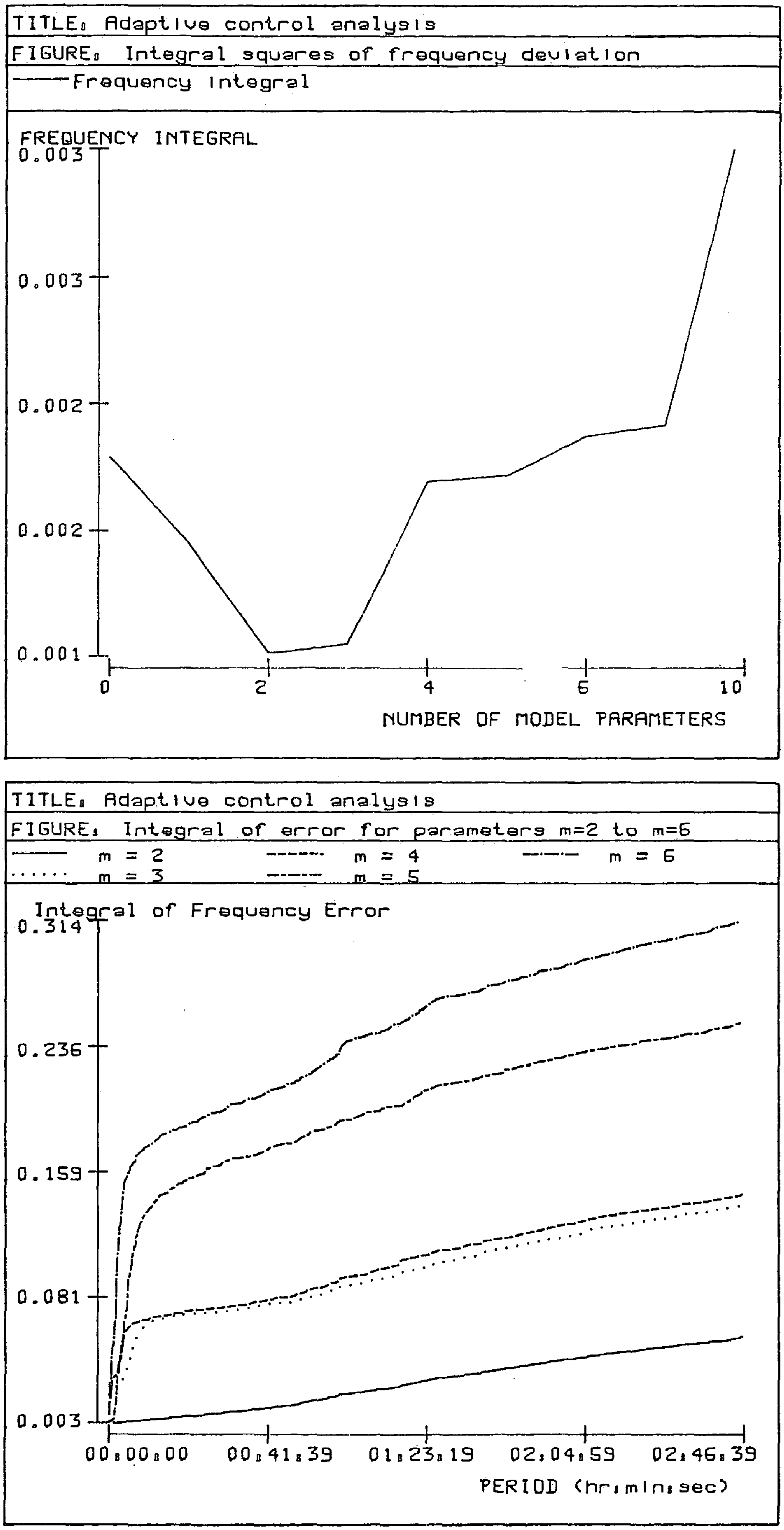
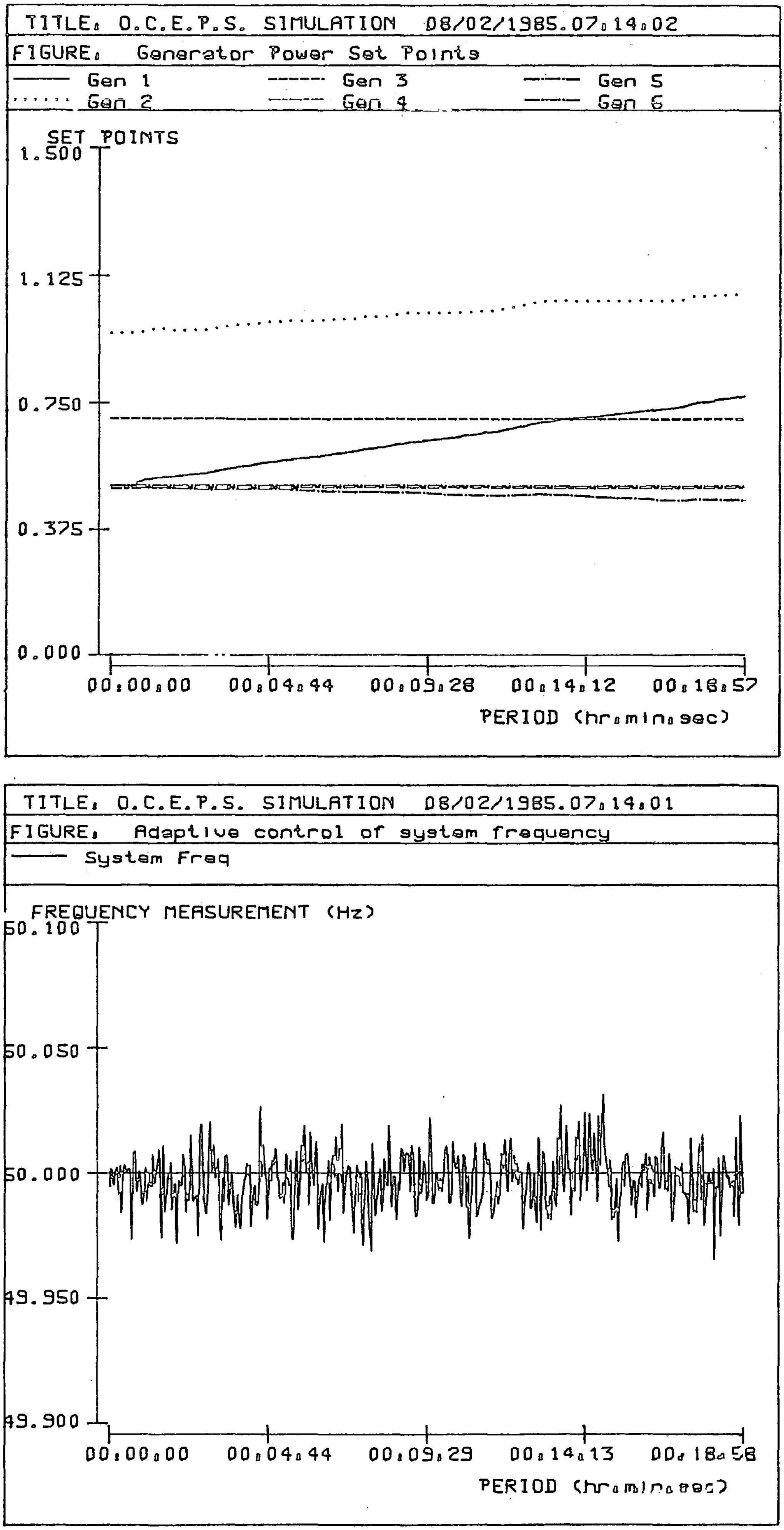

TITLE: Adaptive control analysis
FIGURE: Integral squares of frequency deviation
Frequency integral
FREQUENCY INTEGRAL
0.003
0.003
0.002
0.002
0.001
0
2
4
6
10
NUMBER OF MODEL PARAMETERS
TITLE: Adaptive control analysis
FIGURE: Integral of error for parameters m=2 to m=6
m = 2
m = 3
m = 4
m = 5
m = 6
Integral of Frequency Error
0.314
0.236
0.159
0.081
0.003
00:00:00
00:41:39
01:23:19
02:04:59
02:46:39
PERIOD (hr:min:sec)

Figure 6.2


TITLE: O.C.E.P.S. SIMULATION 08/02/1985.07:14:02
FIGURE: Generator Power Set Points
Gen 1
Gen 2
Gen 3
Gen 4
Gen 5
Gen 6
SET POINTS
1.500
1.125
0.750
0.375
0.000
00:00:00
00:04:44
00:09:28
00:14:12
00:18:57
PERIOD (hr:min:sec)
TITLE: O.C.E.P.S. SIMULATION 08/02/1985.07:14:01
FIGURE: Adaptive control of system frequency
System Freq
FREQUENCY MEASUREMENT (Hz)
50.100
50.050
50.000
49.950
49.900
00:00:00
00:04:44
00:09:29
00:14:13
00:18:58
PERIOD (hr:min:sec)

incident. The first figure shows a steady increase of the Units set points when Unit 3 is removed from the system, followed by the resulting frequency trace. The next figure shows a rapid change in the controller command after the generation loss which eventually is restored and continues to calculate the required control action, the frequency trace is produced below.

6.10 Sample Period

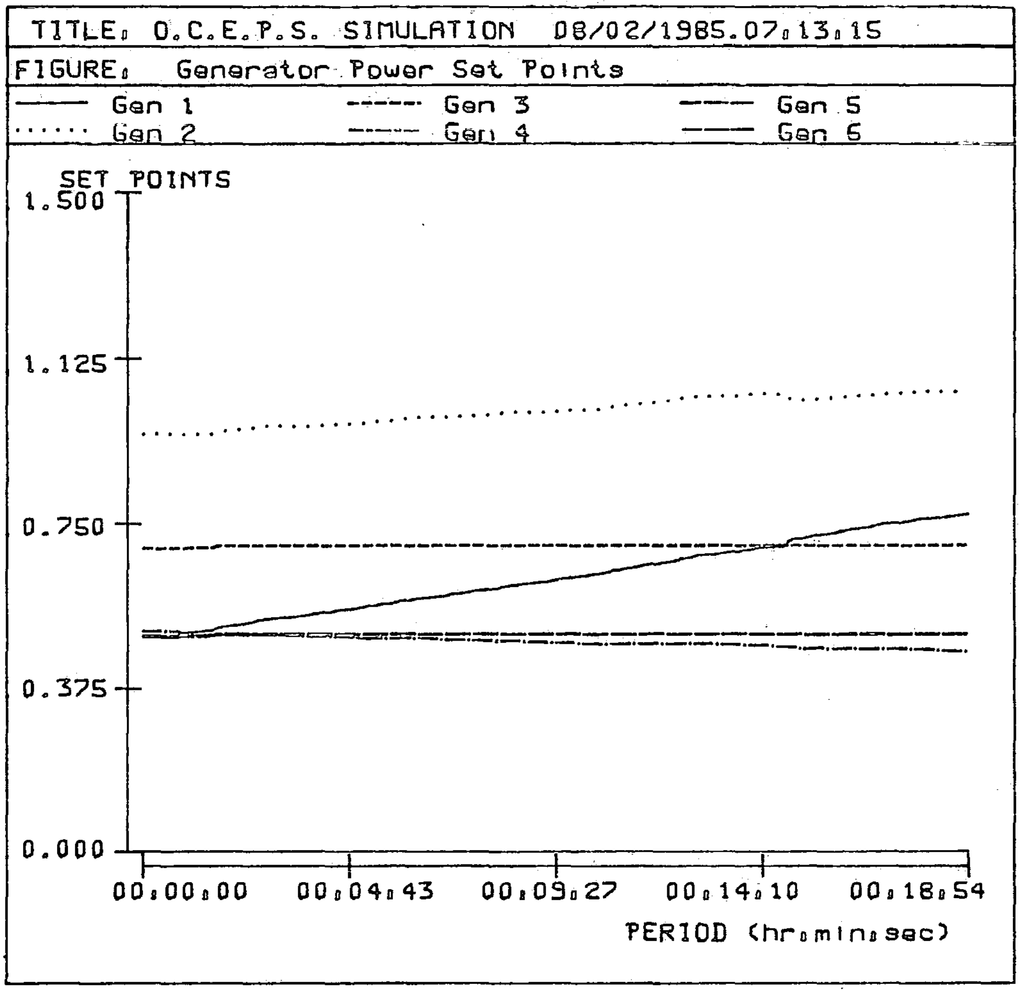
The system model is dependent upon the sample period used for the collection of data used to construct it [57,198] . The time interval represented by the model needs to be sufficiently short to fully model the required time constants in the actual system, but does not need to model the fast acting control such as the almost constant control from the governor control. Thus the model period should be greater than one second so that the faster acting control operation is not represented in the model. The time interval was varied from one second upwards. This was observed that the model time interval did not adversely effect the model construction so long as it was kept to tens of seconds. Thus the time interval used for the modelling period was either 5 or 10 seconds.

A factor which must be taken into account when considering the sample period is the practical limitations due to the taking of measurements from the system. Earlier work [197] has suggested that a suitable interval for the sample period would be 0.6 to 1.5 seconds, however, this interval is really to quick to be practically realised on an actual system. This decreased interval is also nearing the effects of the governor control action and hence was disregarded.

6.11 Control Calculation

The control command as explained is based directly on the most recently updated system model. However, if the system was in steady–state it was unnecessary to alter the model even if the parameters altered slightly. This small alteration in the steady–state operation was due to the noise on the frequency measurements. Thus the model was found to be constantly altering

Figure 6.3


TITLE: O.C.E.P.S. SIMULATION 08/02/1985.07:13:15
FIGURE: Generator Power Set Points
Gen 1
Gen 2
Gen 3
Gen 4
Gen 5
Gen 6
SET POINTS
1.500
1.125
0.750
0.375
0.000
00:00:00
00:04:43
00:09:27
00:14:10
00:18:54
PERIOD (hr:min:sec)

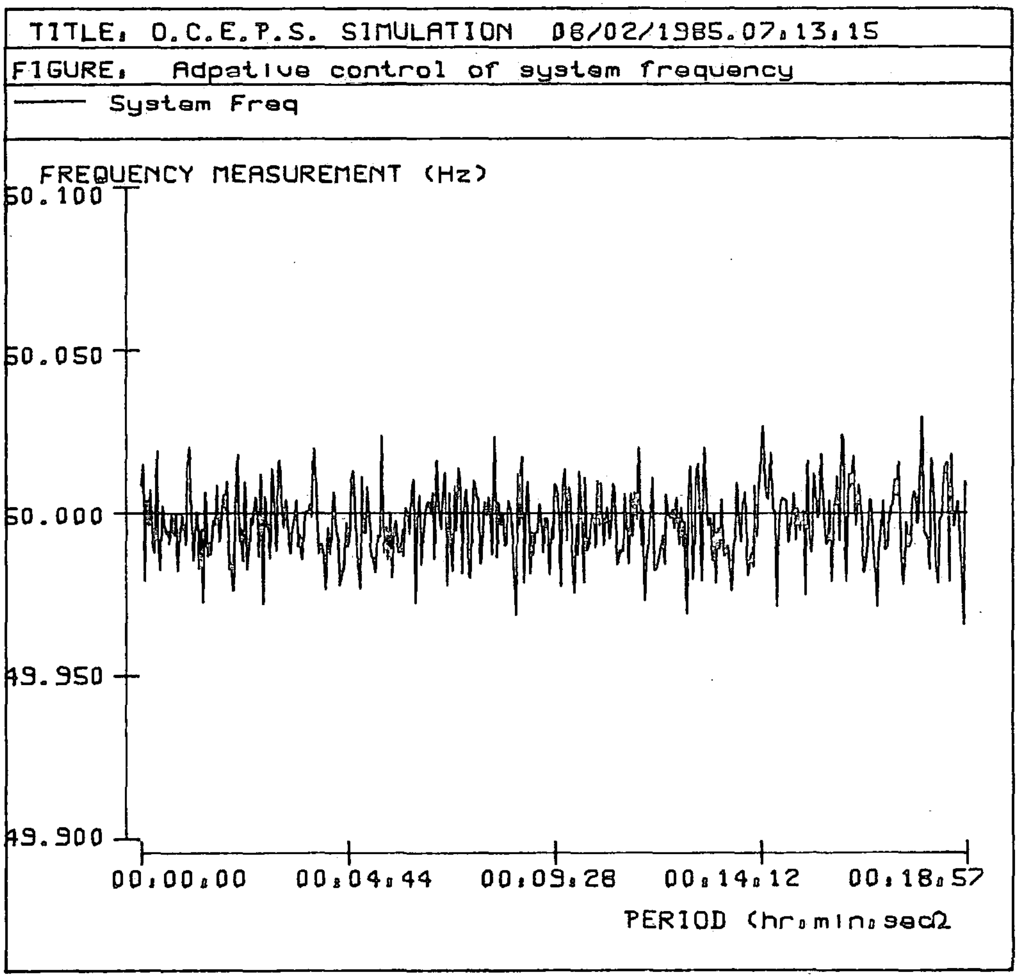
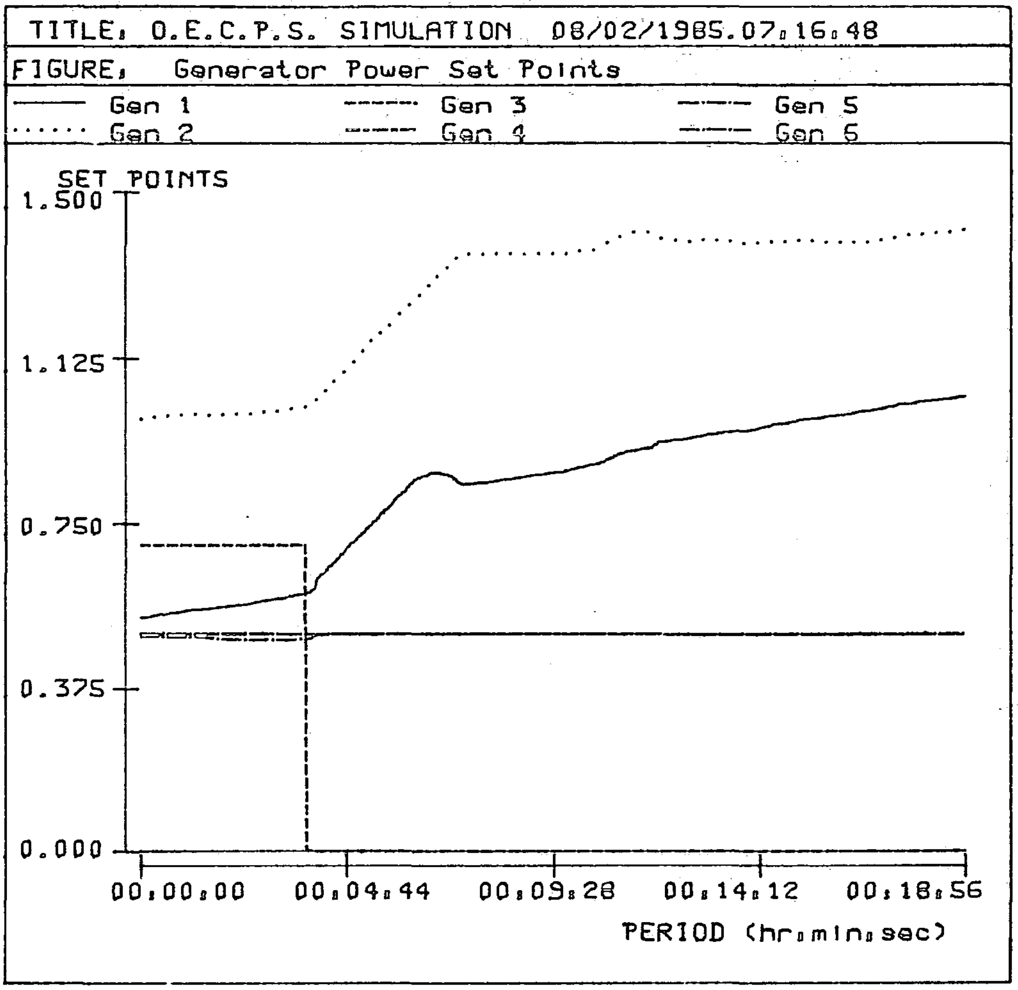
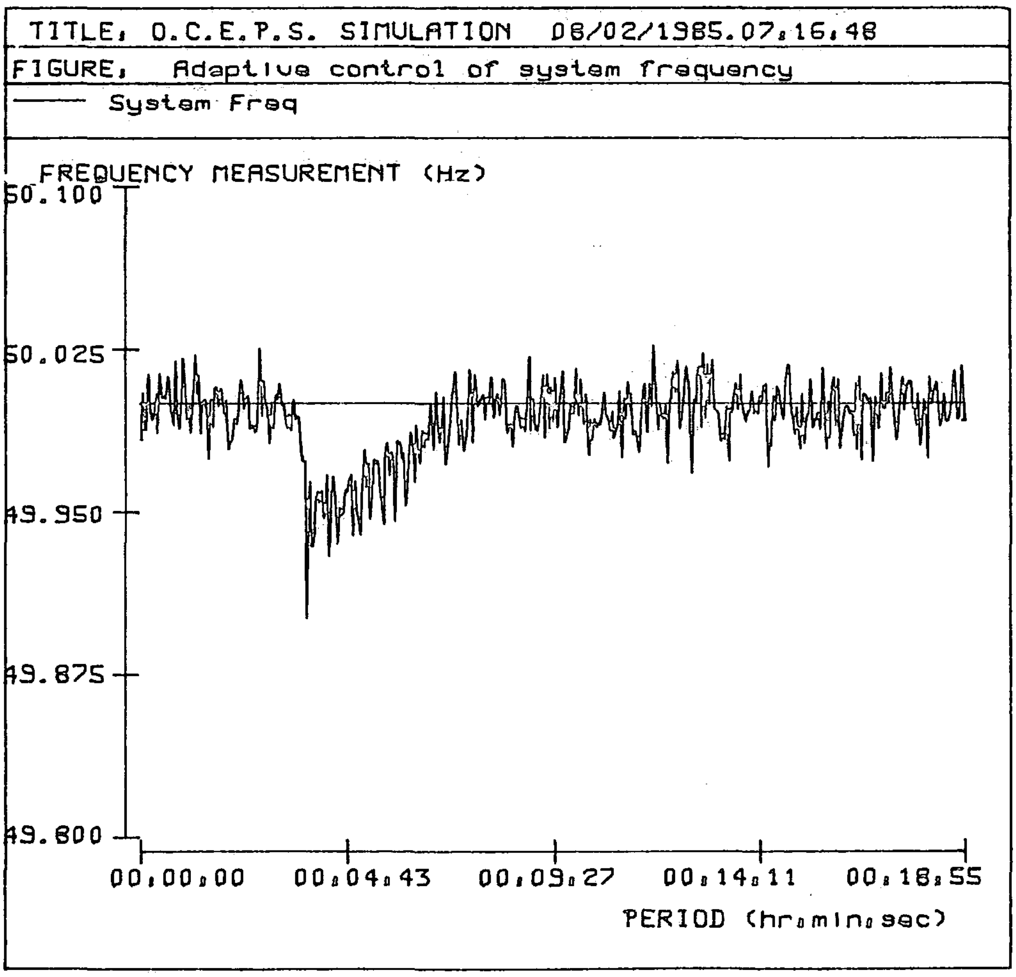

TITLE: O.C.E.P.S. SIMULATION 08/02/1985.07:13:15
FIGURE: Adpative control of system frequency
System Freq
FREQUENCY MEASUREMENT (Hz)
50.100
50.050
50.000
49.950
49.900
00:00:00
00:04:44
00:09:28
00:14:12
00:18:57
PERIOD (hr:min:sec)

Figure 6.4


TITLE: O.E.C.P.S. SIMULATION 08/02/1985.07:16:48
FIGURE: Generator Power Set Points
Gen 1
Gen 2
Gen 3
Gen 4
Gen 5
Gen 6
SET POINTS
1.500
1.125
0.750
0.375
0.000
00:00:00
00:04:44
00:09:28
00:14:12
00:18:56
PERIOD (hr:min:sec)


TITLE: O.C.E.P.S. SIMULATION 08/02/1985.07:16:48
FIGURE: Adaptive control of system frequency
System Freq
FREQUENCY MEASUREMENT (Hz)
50.100
50.025
49.950
49.875
49.800
00:00:00
00:04:43
00:09:27
00:14:11
00:18:55
PERIOD (hr:min:sec)

even though the system was not actually altering itself. A dead-band was imposed on the amount the system parameters were allowed to alter before the new parameters were used in the system model. This removed unnecessary alteration of the model when the system was operating without any changes in operating mode. The model parameters were seen to constantly wander slightly over a short period, but the trend over a longer period (say ten sample periods) was constant. Only when the rate of change of the measured variable (the frequency) exceeded a defined amount, were the new model parameters used to form the model.

This dead-band idea was also used in conjunction with the calculation of the control command. The control command could be refreshed at every sample interval as the adaptive control scheme is designed to do, however, this seems unnecessary if again the system is in steady-state. The control signal was not updated unless it was significantly different from the previous one. This filtering enabled the control signal to be smooth and not require any unnecessary movement of the controlled plant. The filtering of the raw control signal along with the later filtering from the participation calculation leads to a smooth ramping of the controlled participating units.

6.12 Estimated System Frequency Response

One of the many advantages of using the adaptive control scheme over the fixed parameter system is that the self-tuning regulator relies on a recent system model for its calculations. This system model may be used additionally to estimate the system response to a load loss, or gain incident. In this case, the system gain and response remains essentially constant so that the estimated model is valid. However, if the effect of a generation loss incident was to be modelled the system parameters could change slightly, so the estimation would be less valid. The system frequency error can be estimated by using a *snap shot* of the system model parameters and introducing a step change of load to what is essentially the system transfer function. The process would be very useful for application in the security analysis field to answer the "What if ?"type of question. Although the technique is limited only to load changes, the system operators would find the ability to predict the system frequency under emergency conditions useful for the forward planning of Unit Commitment.

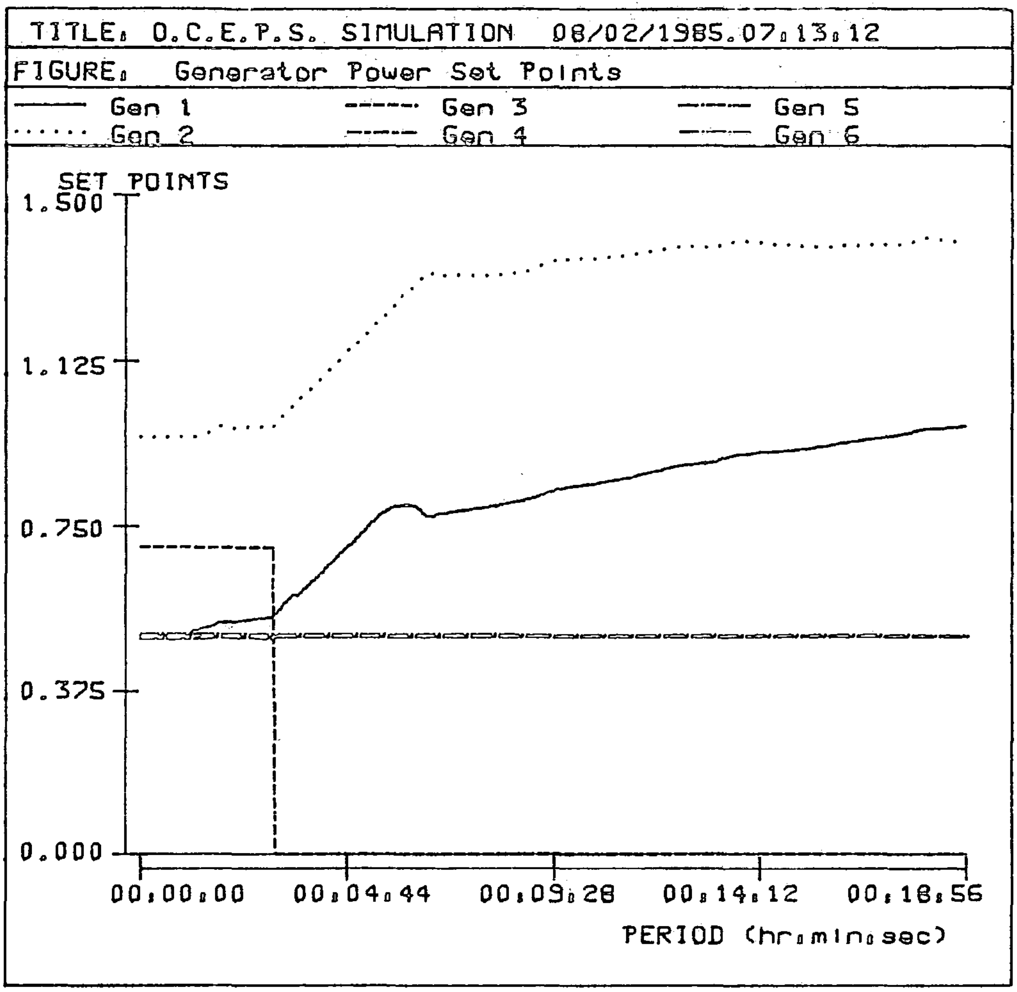
The figures 6.6 and 6.7 show the results of two such estimated frequency calculations. The first response is using a set of standard system parameters collected during the control of the morning peak. The estimated frequency trace is the result of a 0.1 p.u. increase in consumer load. The general shape of the response is that of the typical system response to a step load change. The system gain is calculated to be 0.42 MW/Hz, which is comparable with the values calculated from the simulated system during this operating period.

The second plot shows the estimated system frequency with a 0.2 p.u. load increase. Again the response is seen from a 'snap shot' of the system parameters taken from system operation before the morning demand increase. This trace is slightly longer in time compared with the one above it, and clearly shows the typical system response to a step load change, with several under and over shoots which then settle out to a steady–state frequency error. The gain of the system in this case was calculated to be 0.427 p.u./Hz, which again is close to the calculated value of the simulated system.

6.13 Effect of Forgetting Factor on the Controller Response

The effect of varying the forgetting factor used by the controller was investigated with the system under a rapid change situation. The figure 6.8 shows the system response during the mid–day load along with the controller operating with no forgetting factor operating. The system is changing quite rapidly, but the controller model is unable to calculate control commands which exactly satisfy the system conditions. The frequency plot 6.9 shows that the frequency error is contained and returned to its required value, but it is slightly oscillatory in the steady–state region. In this case the model is not changing sufficiently quickly for the controller to operate to its full effect. In most cases the controller commands are based on an outdated system model which is clearly not suitable for the system in its present state.

Figure 6.5


TITLE: O.C.E.P.S. SIMULATION 08/02/1985.07:13:12
FIGURE: Generator Power Set Points
Gen 1
Gen 2
Gen 3
Gen 4
Gen 5
Gen 6
SET POINTS
1.500
1.125
0.750
0.375
0.000
00:00:00
00:04:44
00:09:28
00:14:12
00:18:56
PERIOD (hr:min:sec)

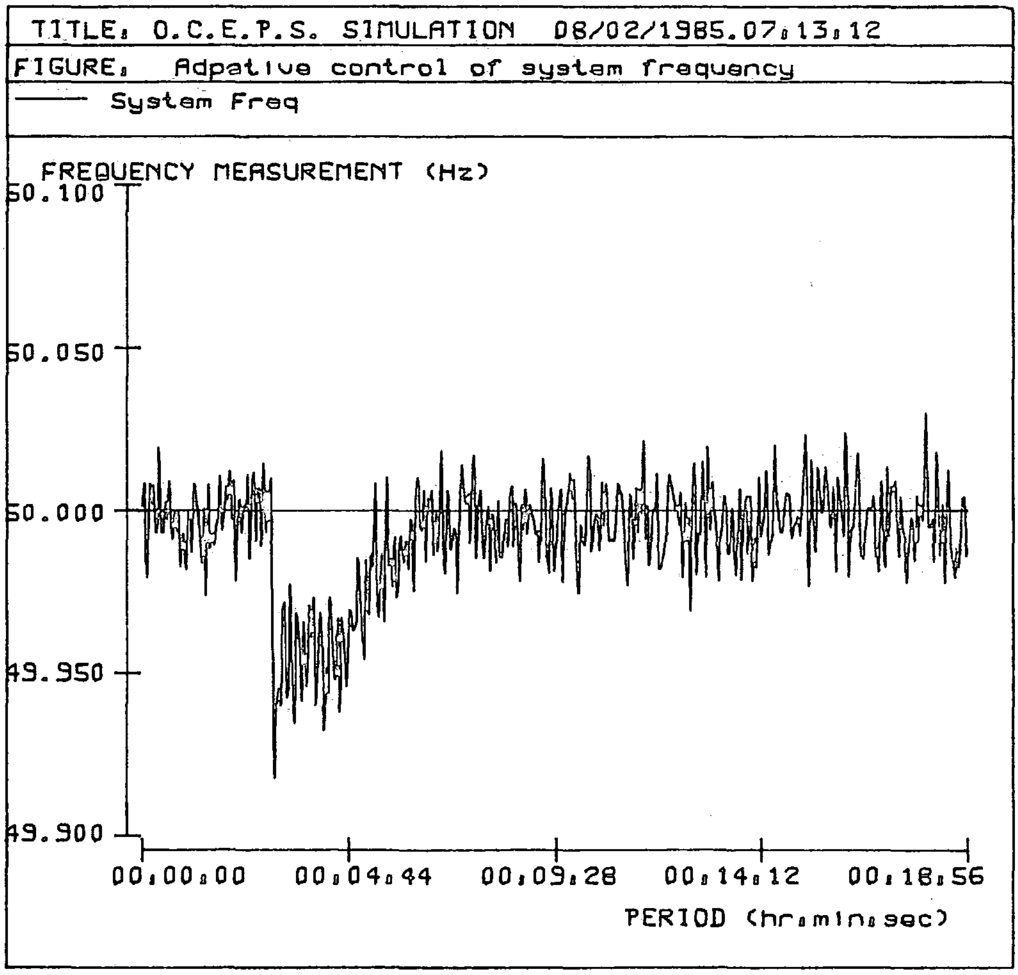

TITLE: O.C.E.P.S. SIMULATION 08/02/1985.07:13:12
FIGURE: Adpative control of system frequency
System Freq
FREQUENCY MEASUREMENT (Hz)
50.100
50.050
50.000
49.950
49.900
00:00:00
00:04:44
00:09:28
00:14:12
00:18:56
PERIOD (hr:min:sec)

Figure 6.6

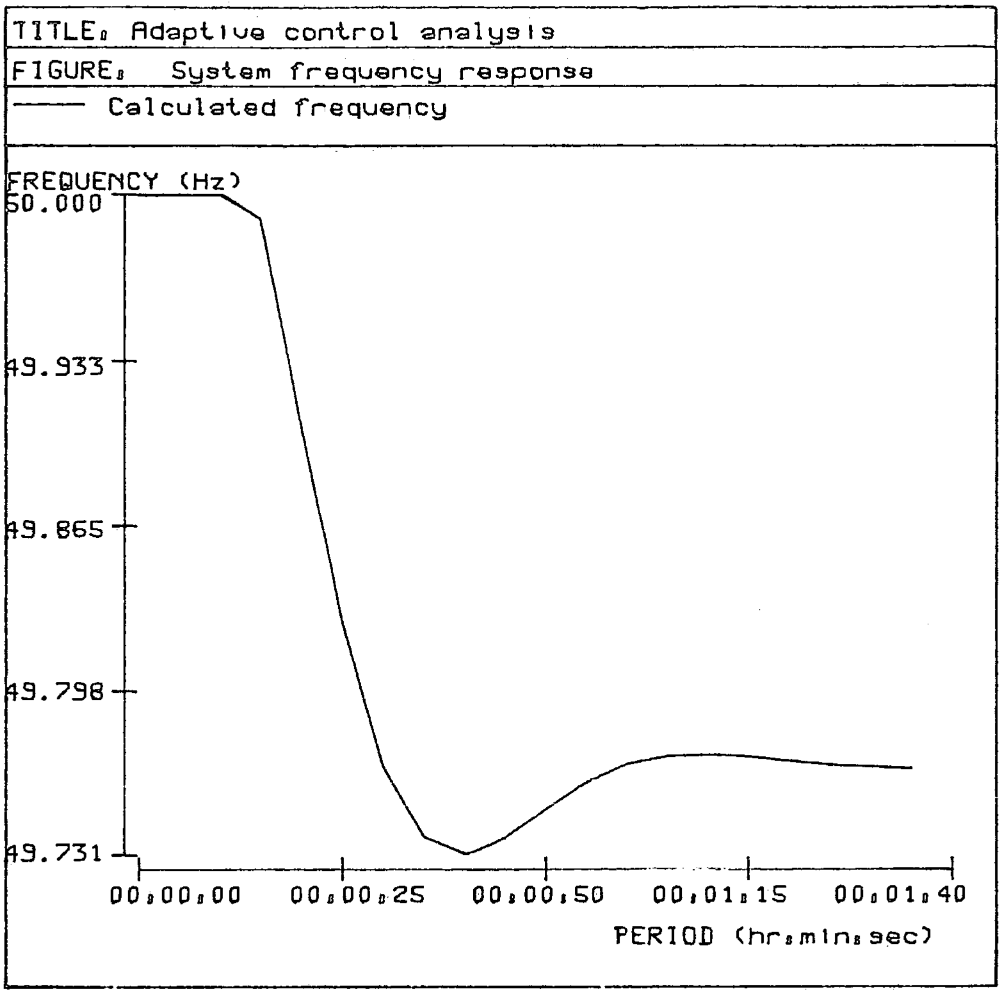

TITLE: Adaptive control analysis

FIGURE: System frequency response

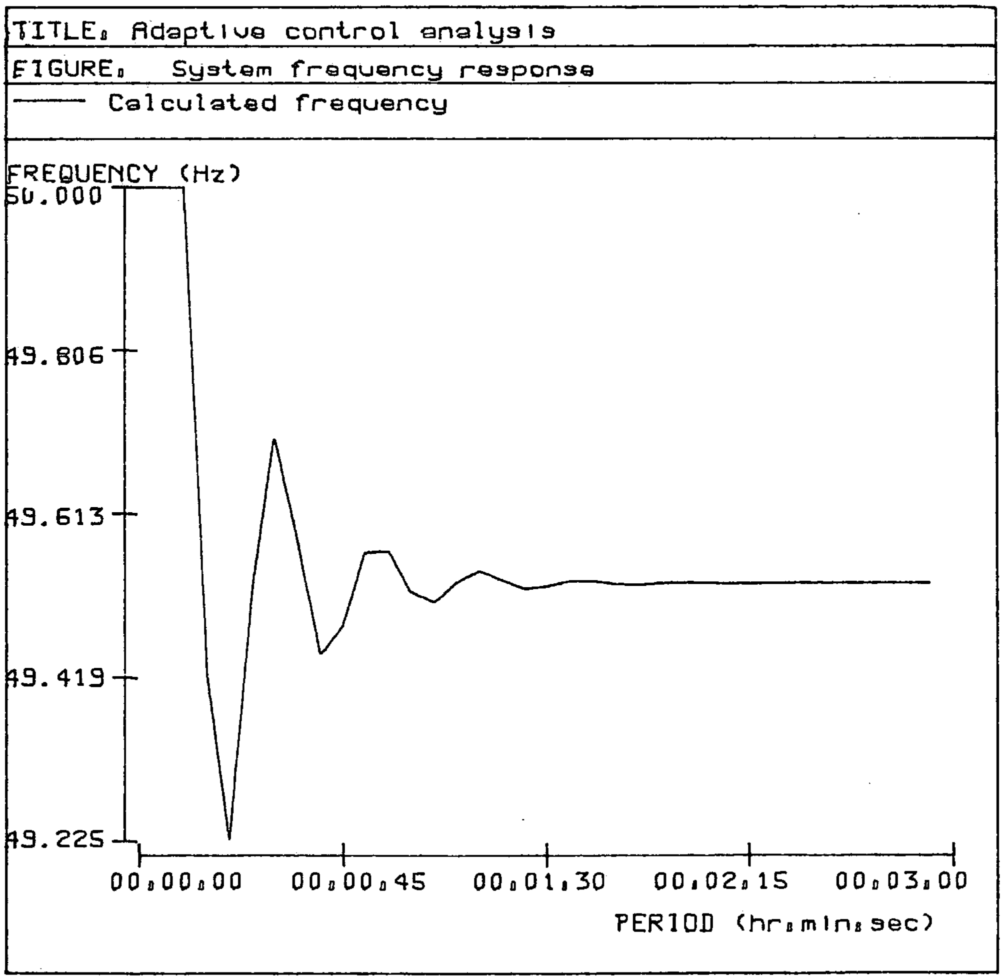

TITLE: Adaptive control analysis

FIGURE: System frequency response

Figure 6.7

The effect of a fixed forgetting factor is shown in 6.10 with the system frequency response due to the control action show in figure 6.11. The forgetting factor was fixed at the value of 0.95. This fixed approach produces a smoother set of control actions compared with the above method but still does not respond with the optimal control. The frequency plot shows that some of the oscillatory action is removed, but it does not produce as smooth a response as is required for system operation.

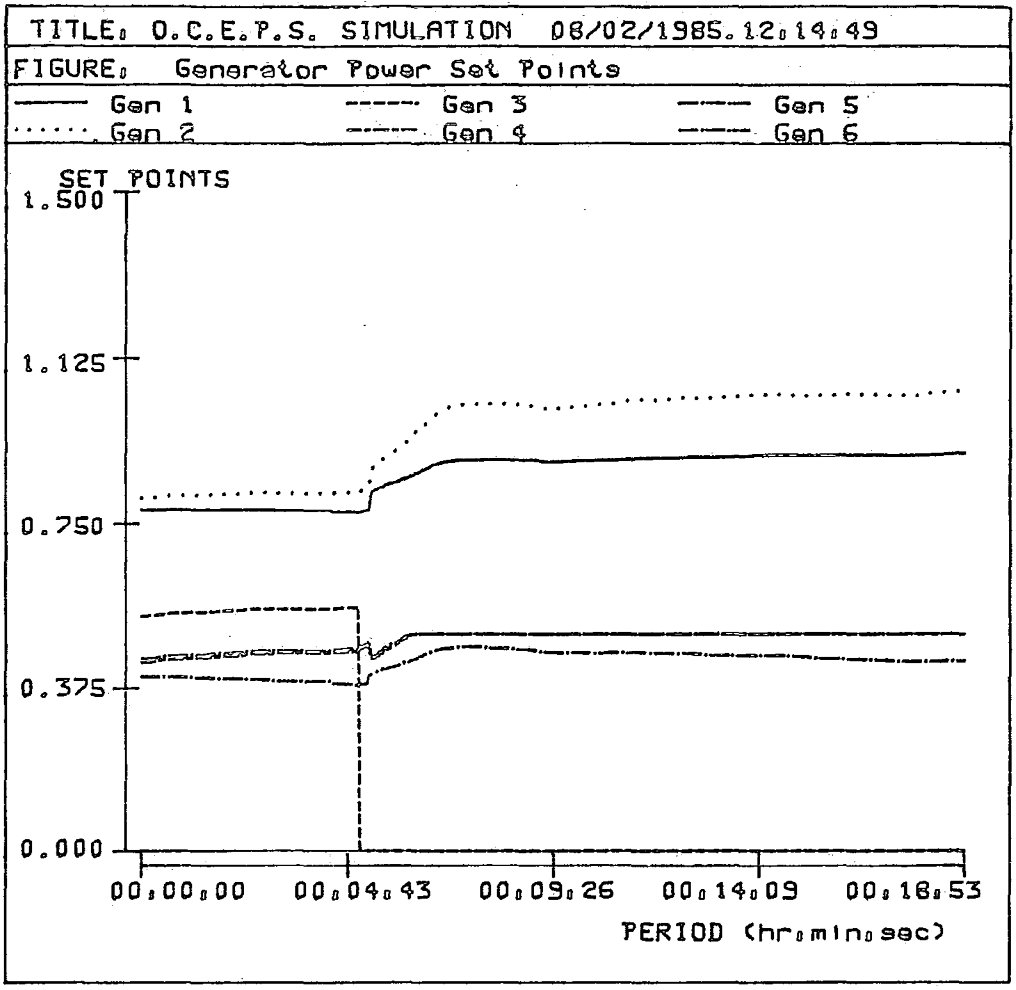
The use of a variable forgetting factor as discussed above is shown in figure 6.12 with the corresponding frequency response in figure 6.13. The ability of the control algorithm to keep the required amount of system information is seen in this test. The control algorithm produces a smooth control action which is sent to the Units on the system. When Unit 2 is lost, the controller model can respond as required and follow the state of the system.

The ability of the controller to respond to changes in system configuration is shown in figure 6.14 along with the corresponding frequency trace in figure 6.15. The Units 4,5 and 6 are all placed in Base mode and hence are not available for direct control from the L.F.C. function. The only Units that are available for control after the loss of Unit 3 are Units 1 and 2. Unit 2 is put to its upper limit, so all the control action must be carried by Unit 1. This unit is able to respond to the control commands from the L.F.C. scheme and is able to restore the frequency trace to its required value.

The same system configuration was used as in the above test to investigate the ability of the controller to respond to differing system conditions. In this case (figure 6.16and 6.17) the system is operating during the mid–evening load conditions. The trace shows the effect of the loss of Unit 3 again, with Unit 1 taking the majority of the control action as Unit 2 reaches its upper limit.

As a comparison, the system response is shown in figure 6.18 and 6.19 of the system operating under normal conditions during the same time period as above. In this case there are no transients created or any loss of load. The driving variable in this case is purely the consumer load. Without the

Figure 6.8



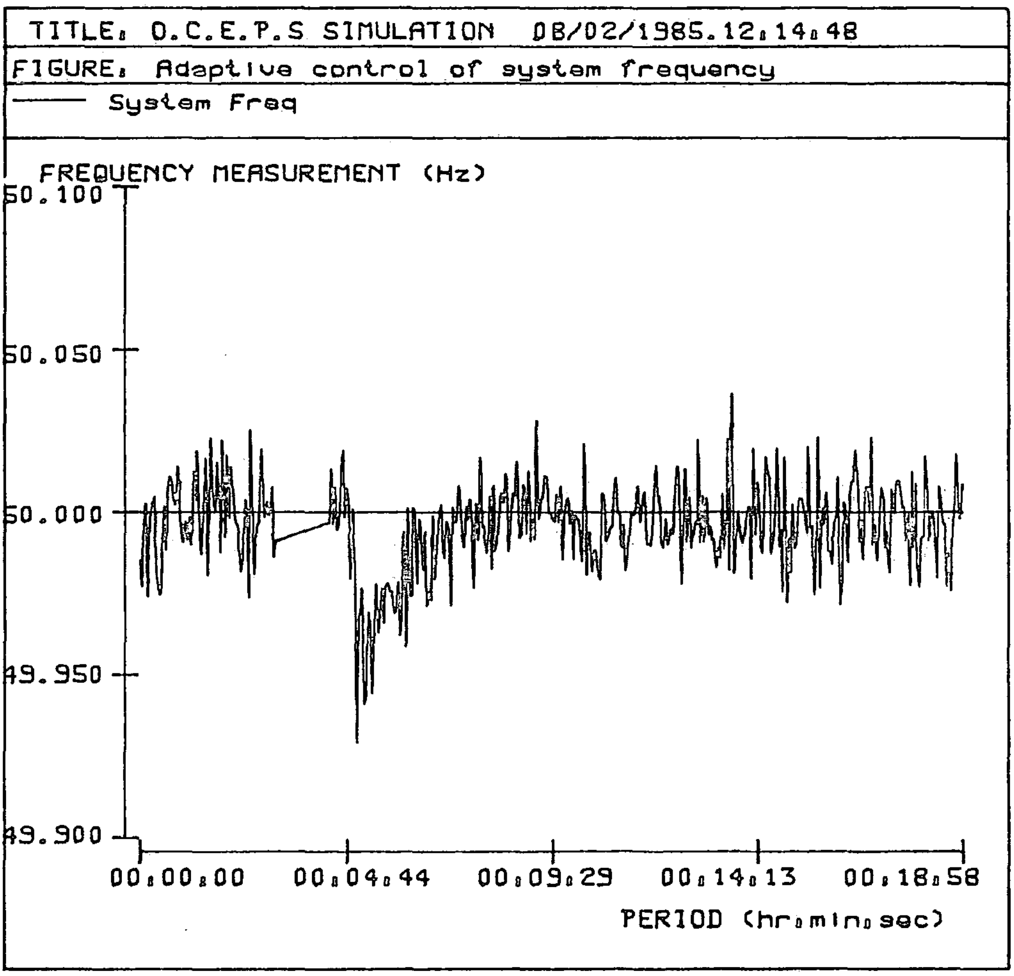
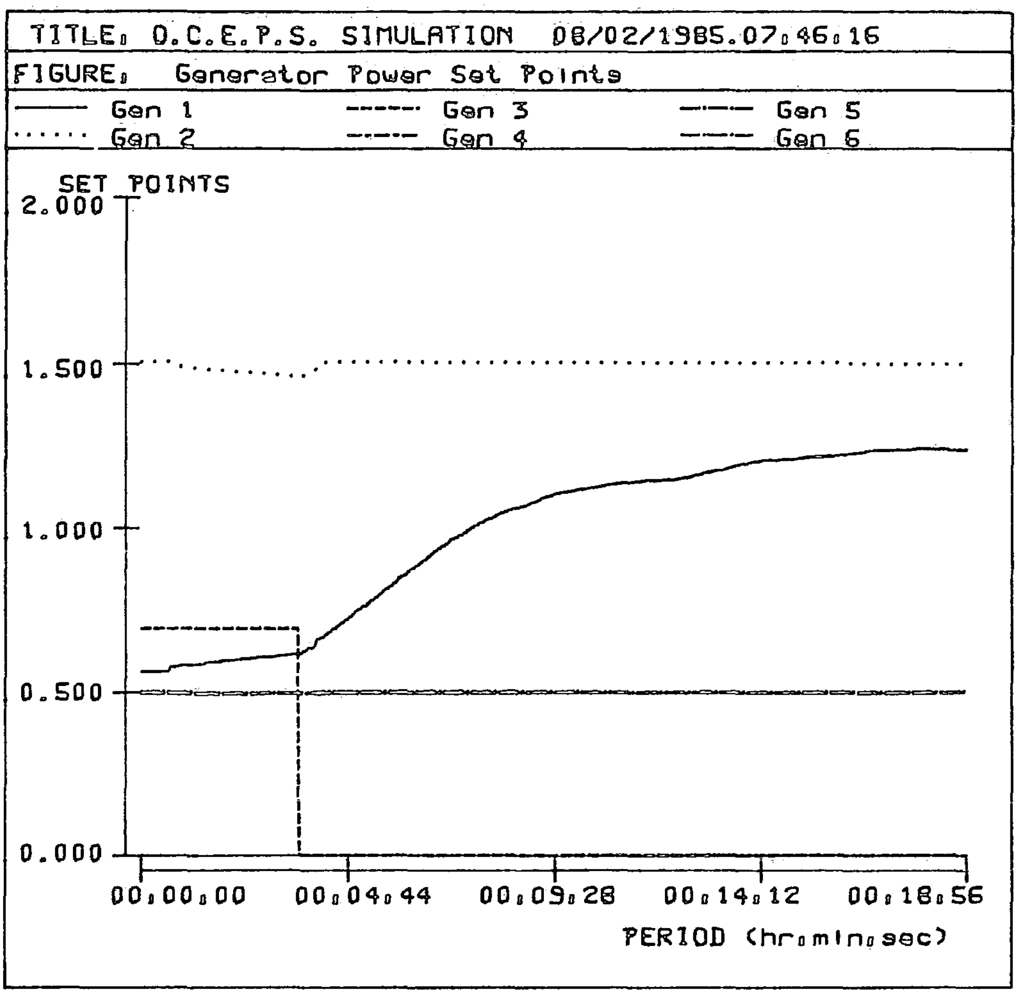


Figure 6.9

Figure 6.10



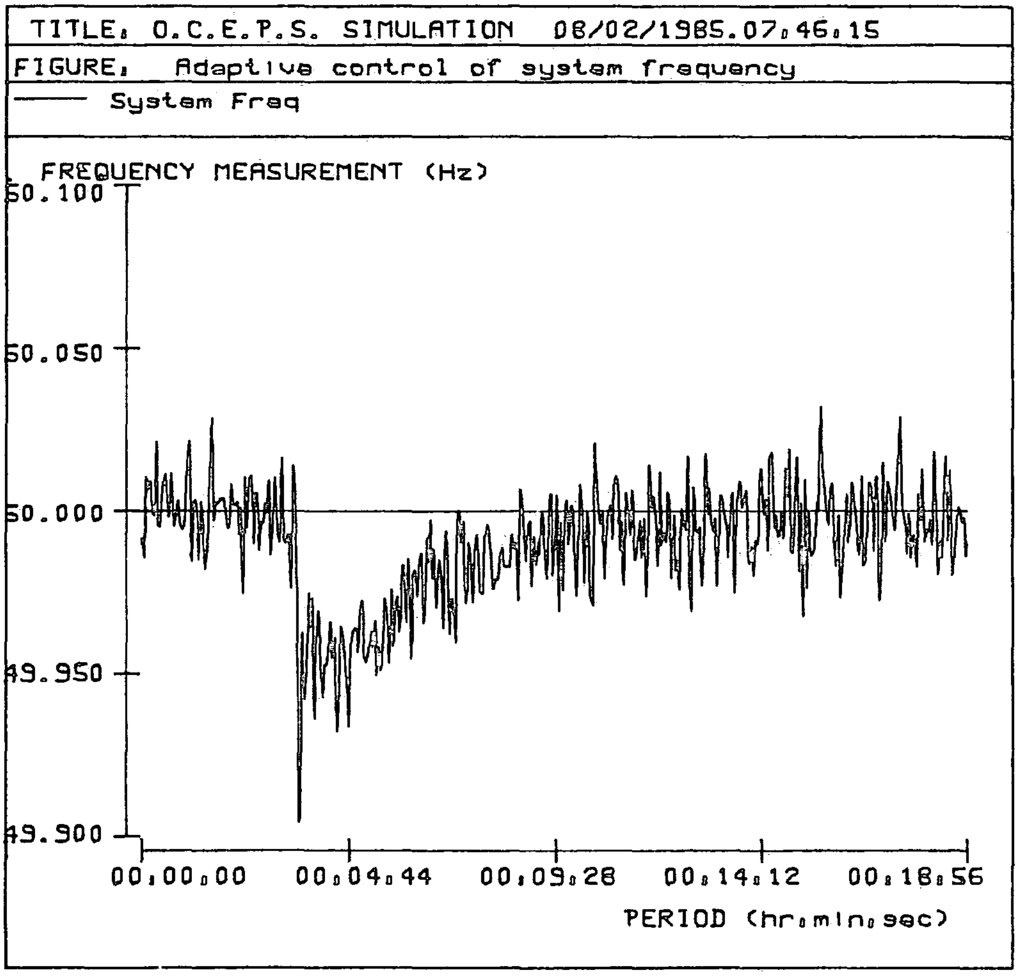
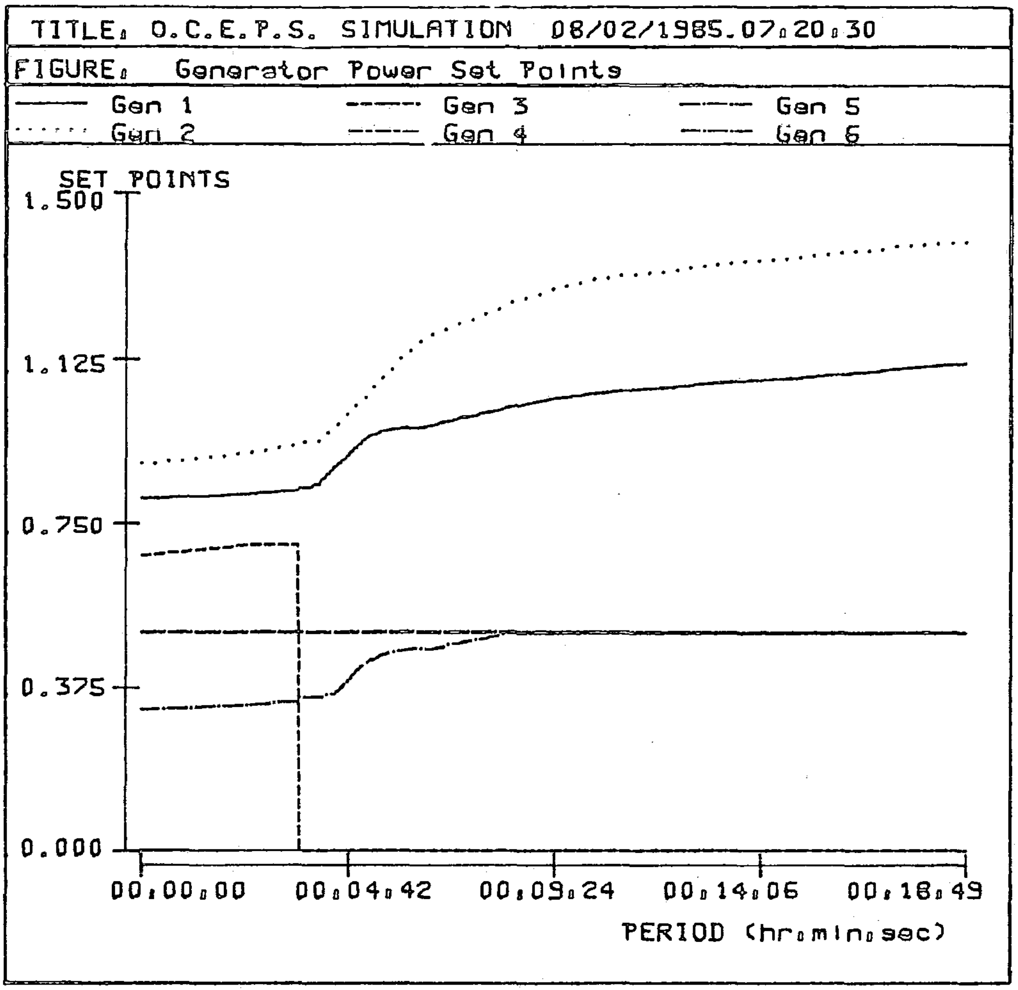


Figure 6.11

Figure 6.12



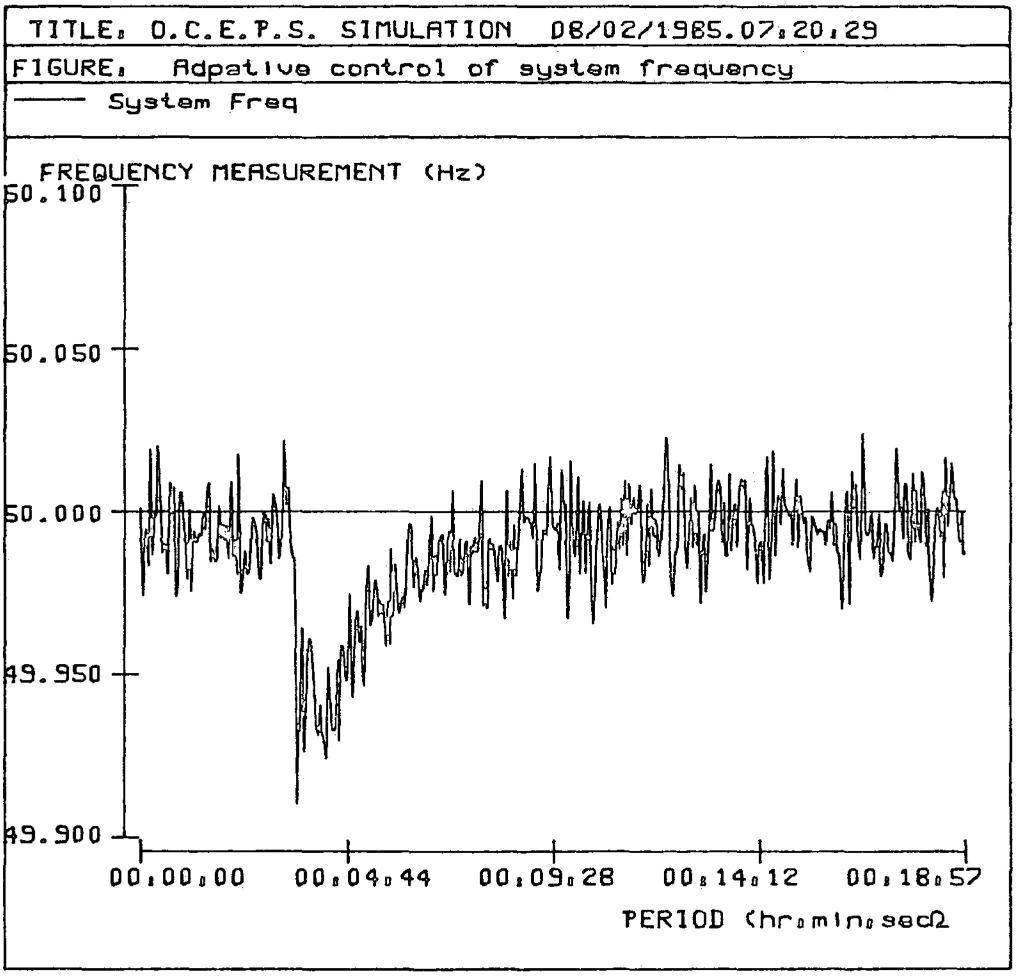
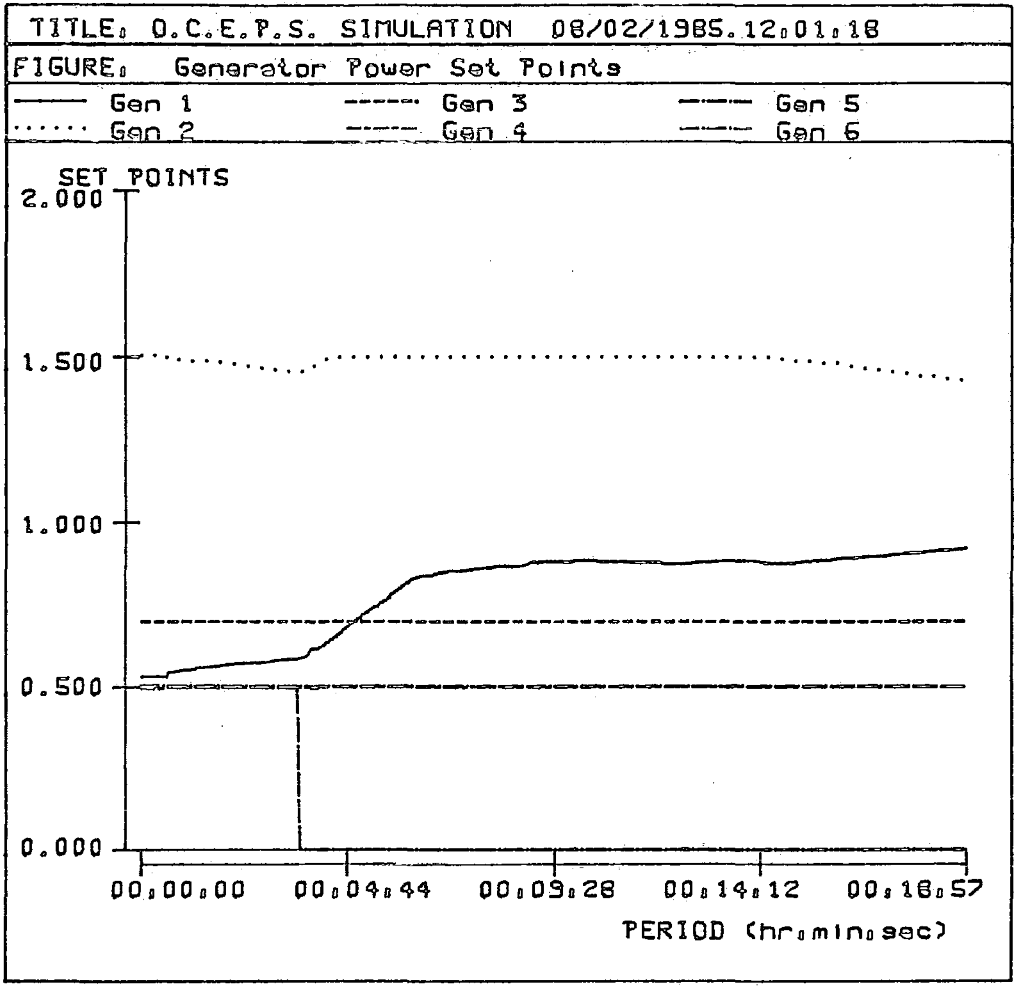


Figure 6.13

Figure 6.14



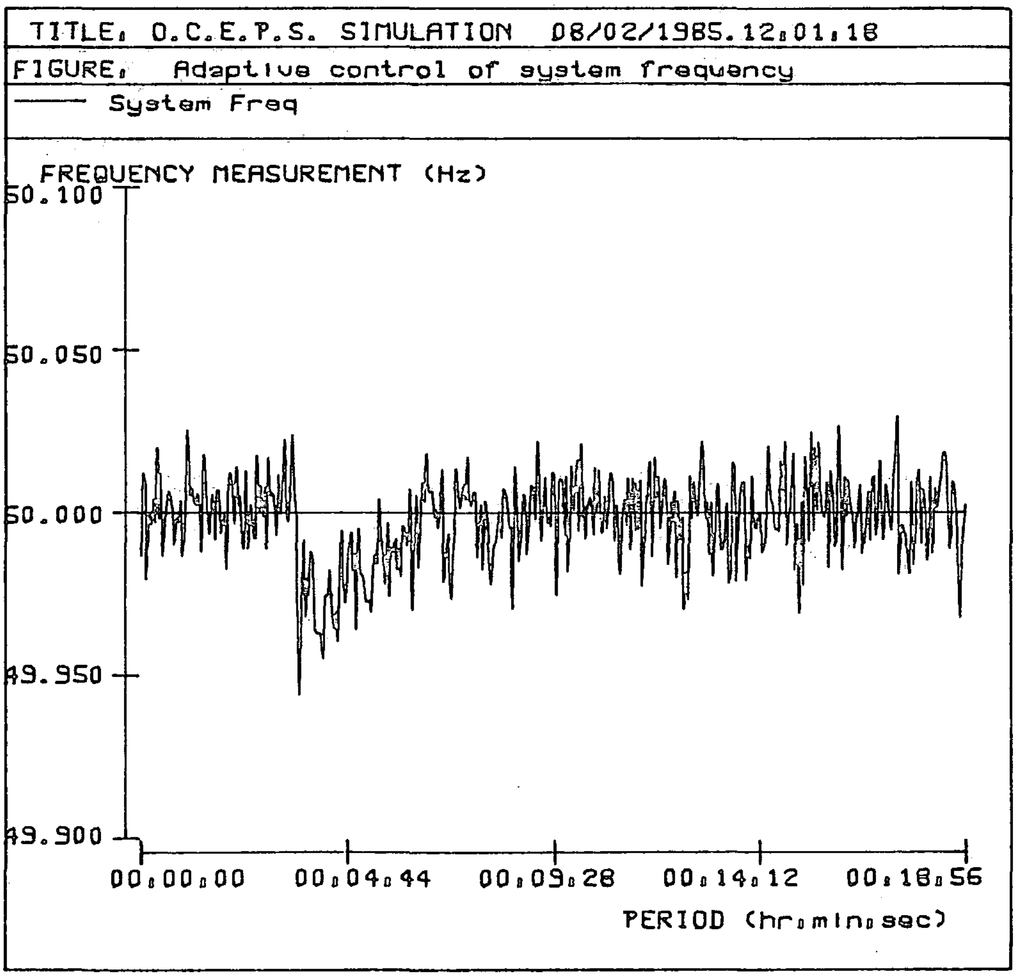


Figure 6.15

loss of Unit 3, the unit 1 is commanded to ramp up its output to replace the generation capacity of Unit 2 which has been commanded to reduce its output by Unit Commitment. The L.F.C. scheme controlled this change in generation pattern without any action which could lead to system transients or instability.

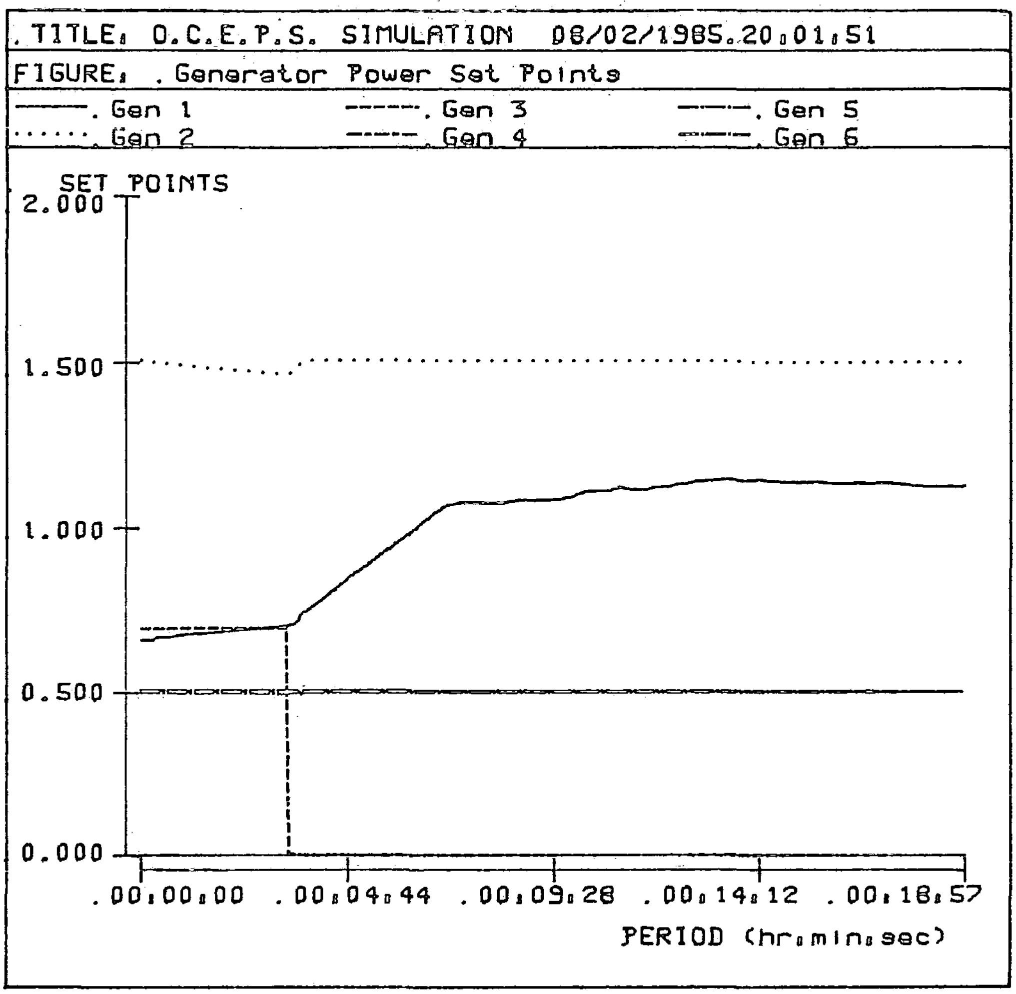
6.14 Irregular Generation Patterns

The L.F.C. scheme was tested to its limits by using an irregular pattern of generation. Figure 6.20 and 6.21 illustrate the loss of two generators (Units 3 and 6). These are lost one after another for test purposes but this is unlikely to occur in actual operation. The remaining units are able to take up the loss of generation as the controller model is able to respond to the state of the system. This test was carried out just after mid–night when the system gain is low. However, the controller is able to respond to the system state and control the available units to reduce the frequency transient to the steady–state.

A further test was carried out on the system by simulating a generation synchronisation of Unit 3 followed by the loss of the Unit. The system response is shown in figure 6.22 along with the frequency trace in figure 6.23. The initial increase generation due to Unit 3 does not effect the system frequency greatly so the controller does not require a great deal of control action for the regulating units. The new unit was required to take up load through the Unit Commitment action as the morning consumer load increases. The loss of the unit as the load increases causes the controller to increase the output of the other available units, which requires the increase of the power set points of Units 1 and 2.

To validate the control scheme for operation on an actual system, the synchronisation of new units on the system as well as the loss of generation units from the system was simulated. The figure 6.24 and 6.25 show the synchronisation of Unit 3 to provide support for the morning peak increase. The use of the variable forgetting factor provides constant monitoring of the system as its state changes, although the system model may take several controller cycles to settle down after a major perturbation. This is seen in

Figure 6.16



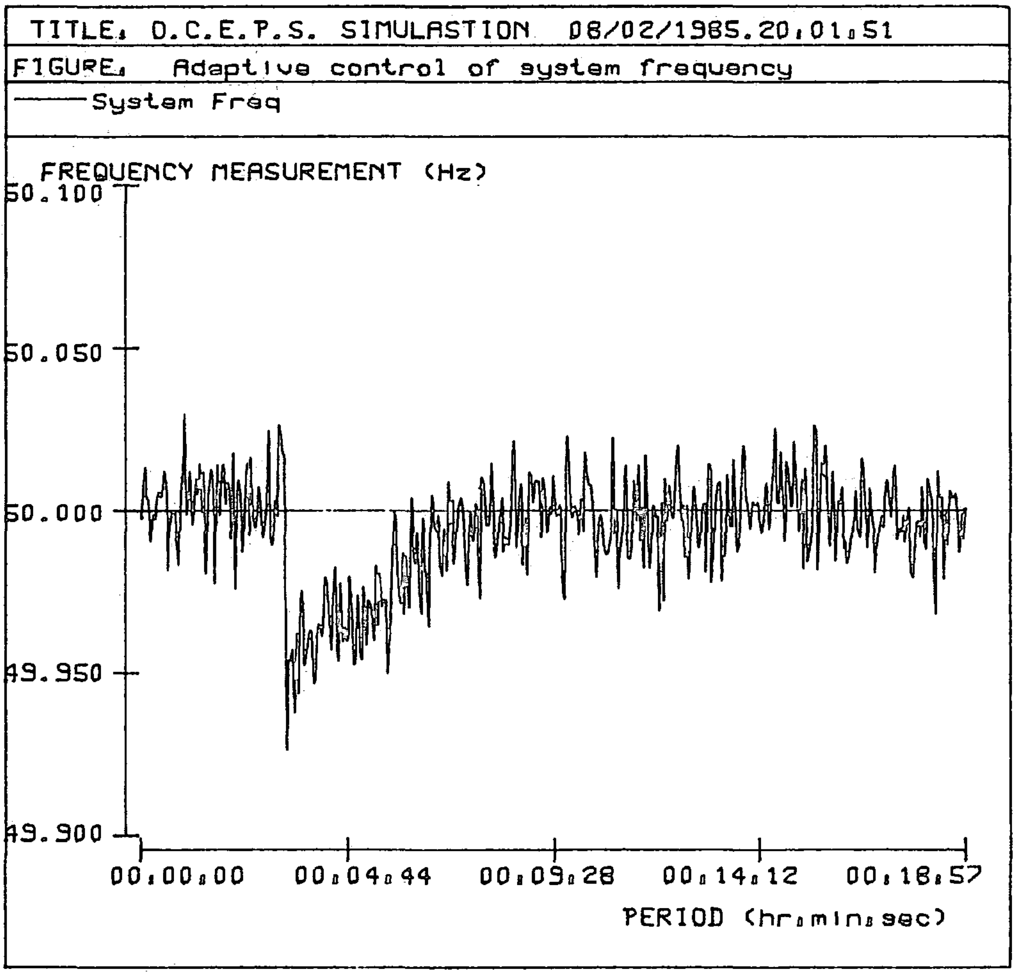
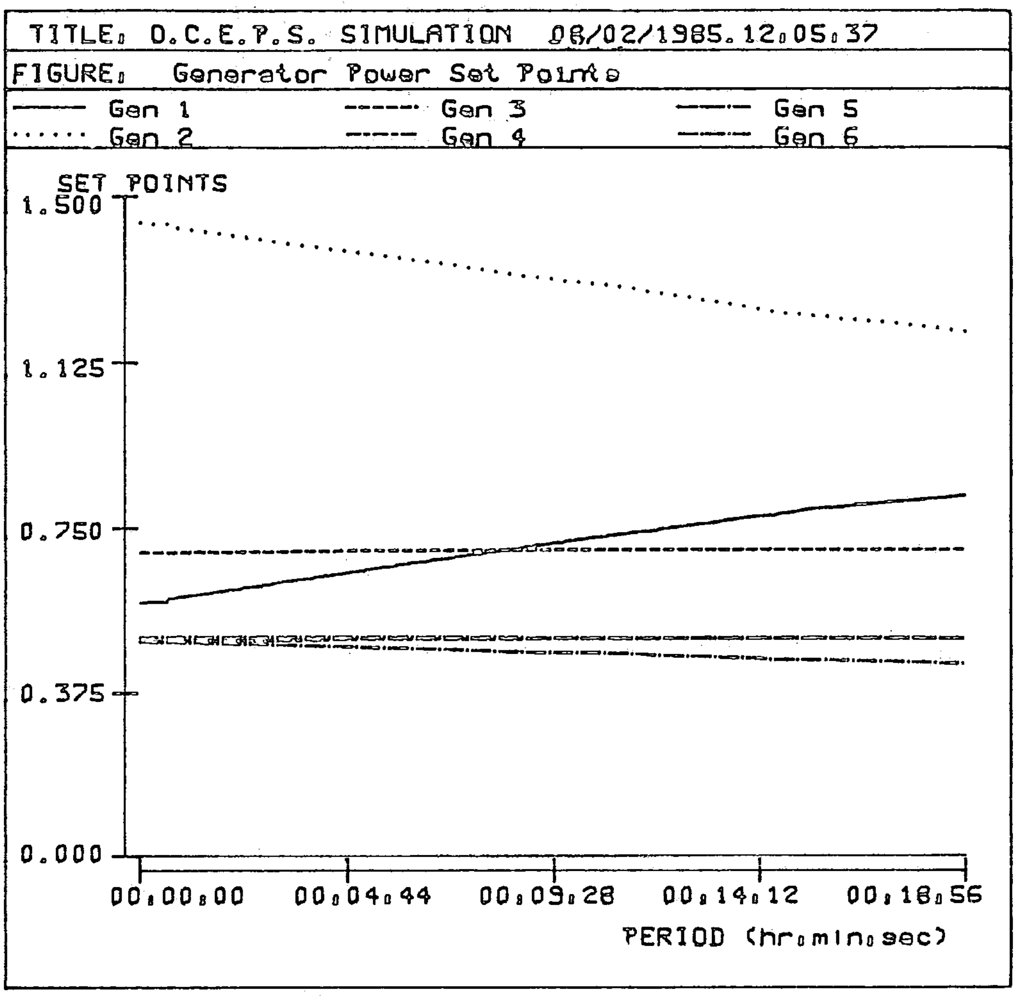


Figure 6.17

Figure 6.18



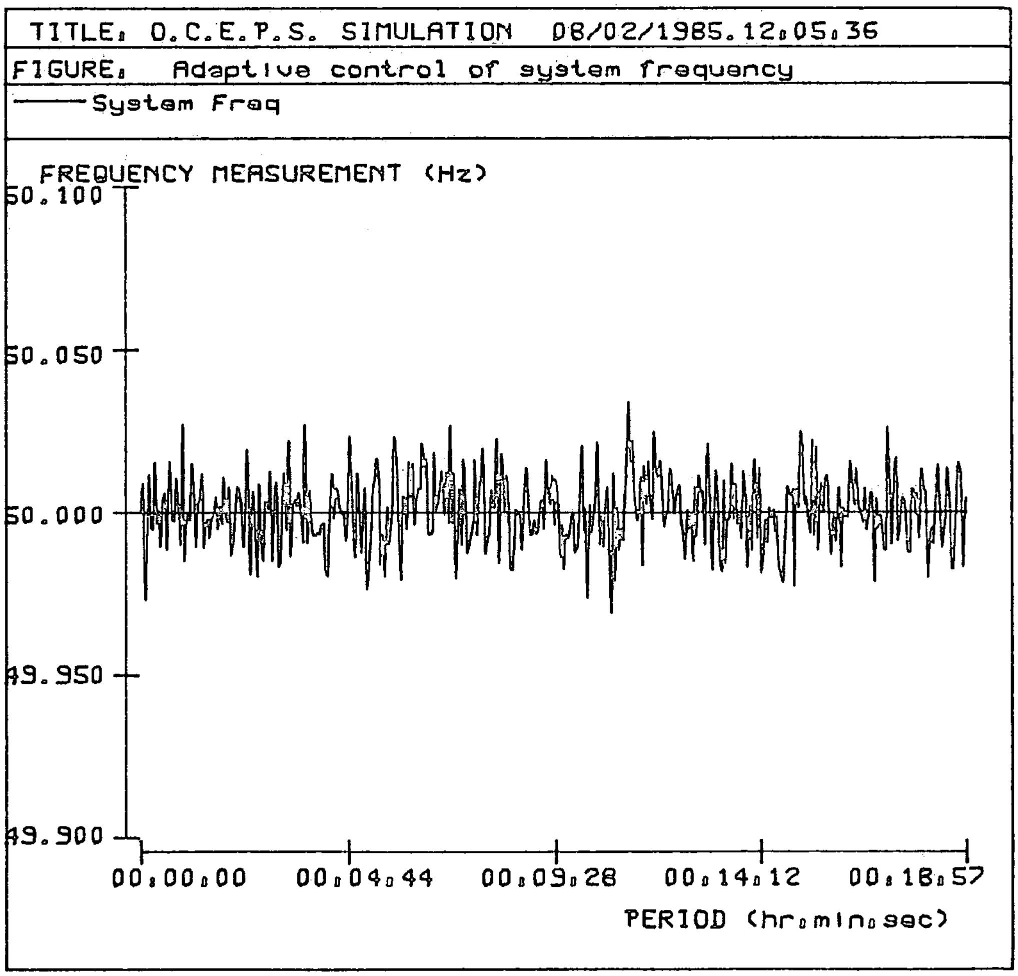
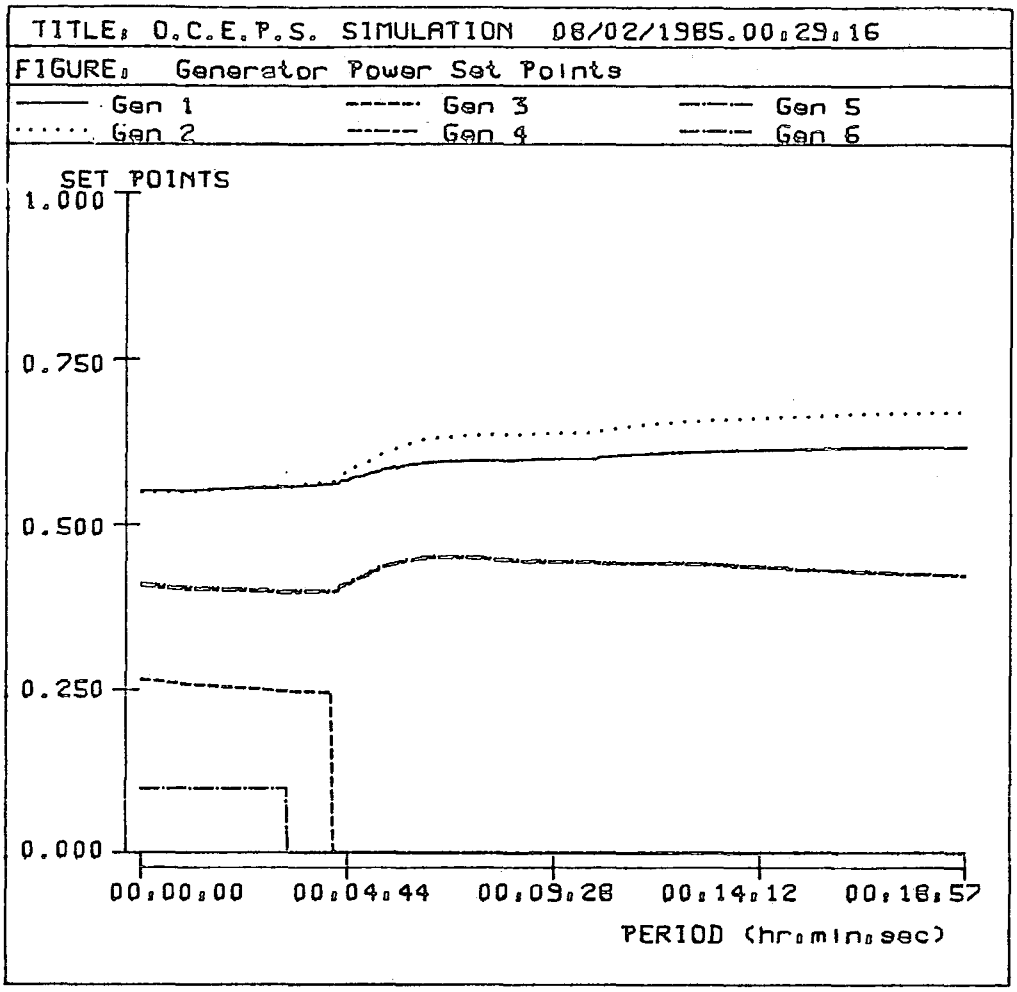


Figure 6.19

Figure 6.20



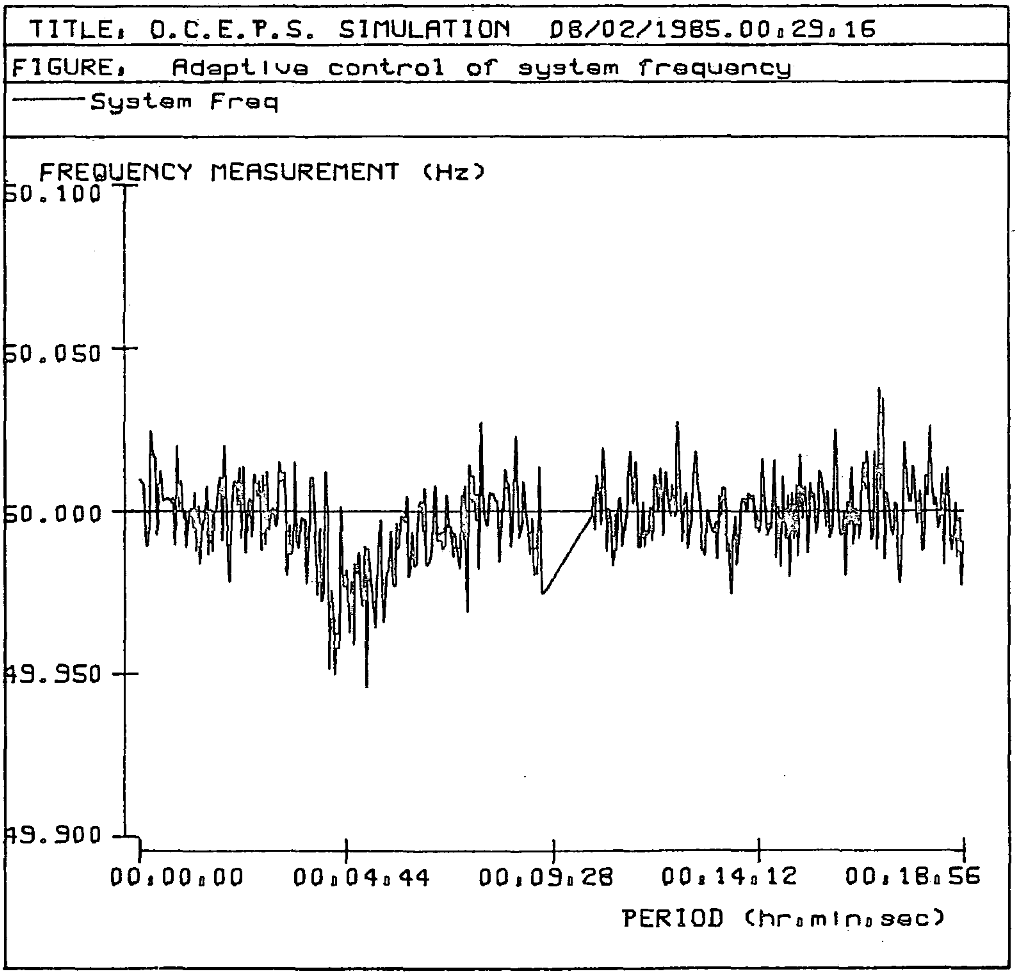


Figure 6.21

this example where after the Units 3 is brought on to the system the control signal to Unit 1 is increased unnecessarily because the model has not changed sufficiently to closely model the system status.

It is seen that the frequency trace losses some data towards the end of the plot. This simulates the loss of data from transducers. The controller has no input data to calculate an updated control signal. The target output level of the Units therefore remains constant. When the data is collected again, the controller continues to calculate the control signals without any abrupt change of Unit power set points.

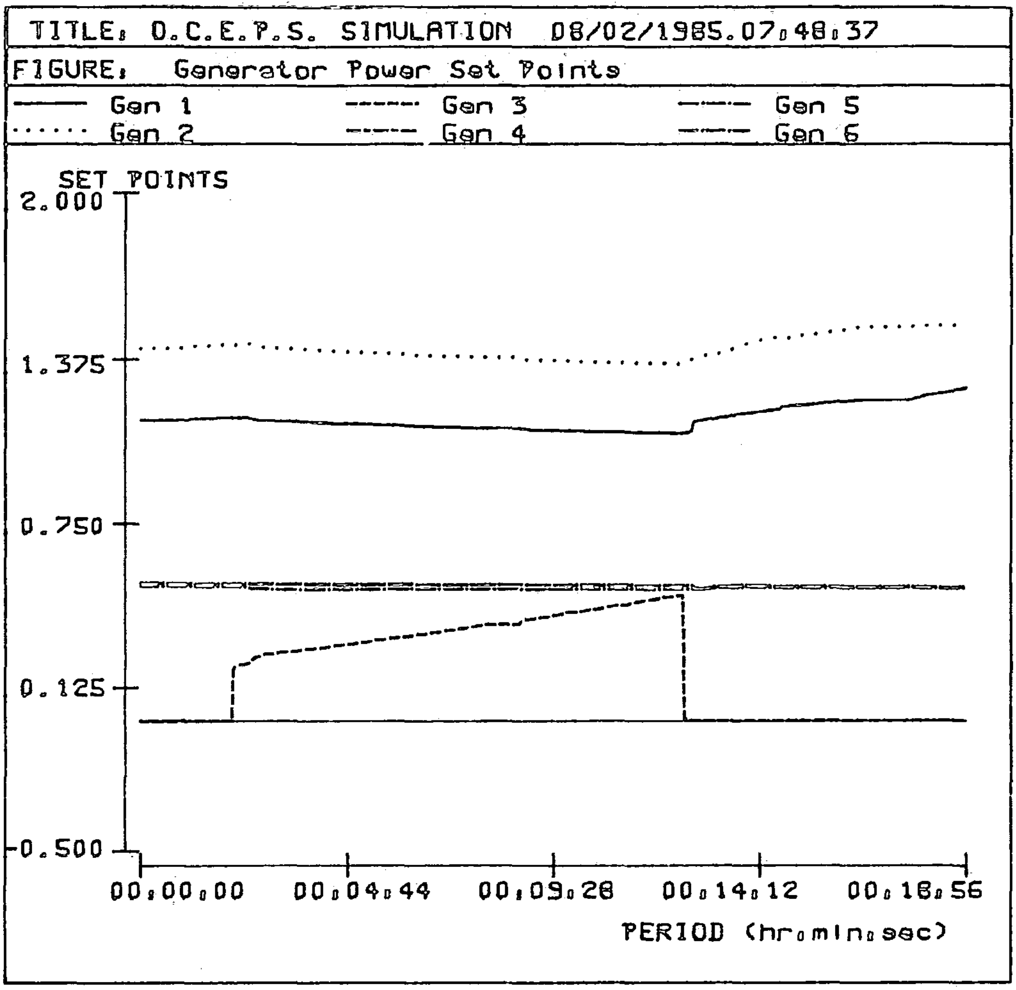
6.15 System Operation in Varying Conditions and Control Modes

One of the advantages of this adaptive control strategy is the ability of the controller to monitor the system status and alter its control action accordingly. In the operation of many power systems, the generator units are often set in generation patterns which are required not to be changed due to economic factors. Often units are placed in Base mode so that the base loading of the system is satisfied without any alteration to the base loaded units.

The figure 6.26 and the frequency plot 6.27, show the operation of the controller when the largest unit, Unit 1 is in Base mode. There is a generation loss incident of Unit 2, the second largest unit on the system which causes a rapid decrease in frequency. This loss is immediately made up using the remaining four units on the system. The controller model is operating so that the control signal matches the system state, but the unit outputs are constrained by rate limits. This leads to an irregular control signal sent to the three smaller units as all system regulation is under their control. The frequency trace shows that the transient is removed and that the lack of controlling units is not directly seen in the frequency error.

To investigate the system response after such a drastic incident as the above, the Unit 2 was synchronised to the system a few minutes later. The figure 6.28 and 6.29 show the system response to this rapid increase in generation

Figure 6.22



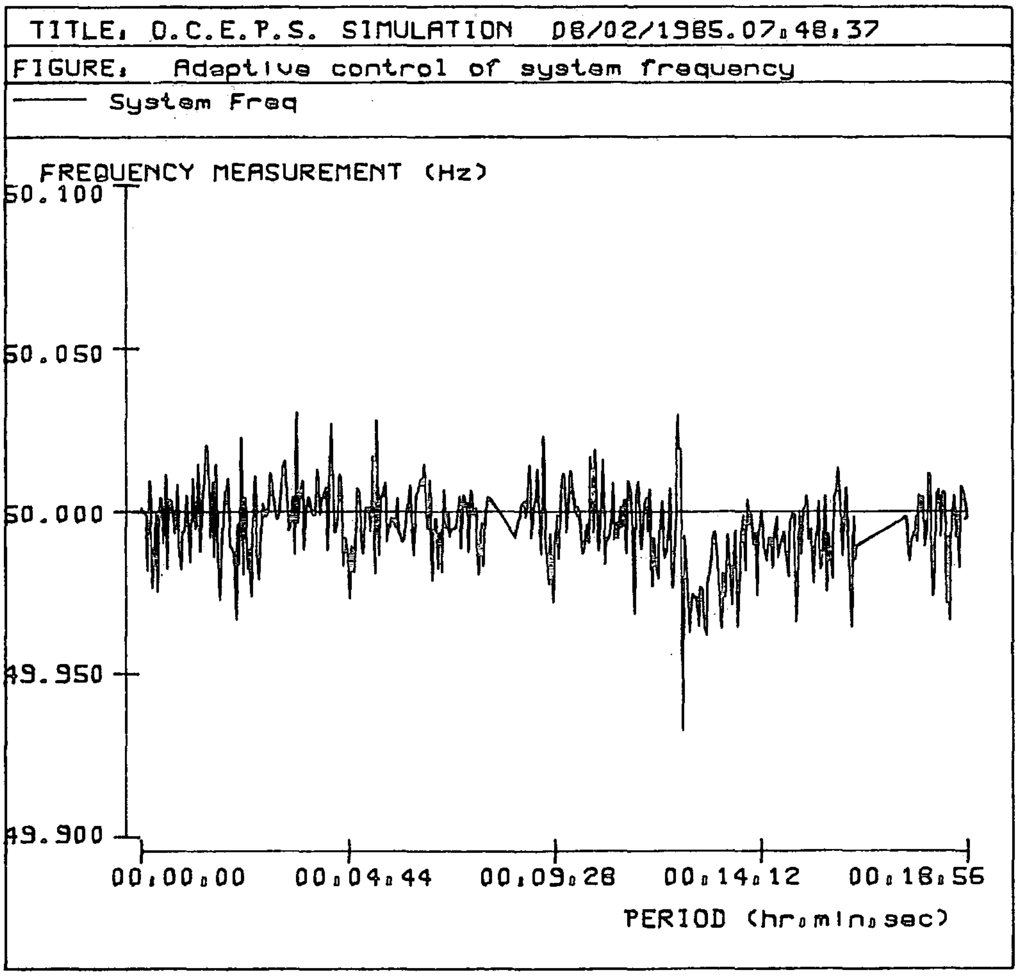
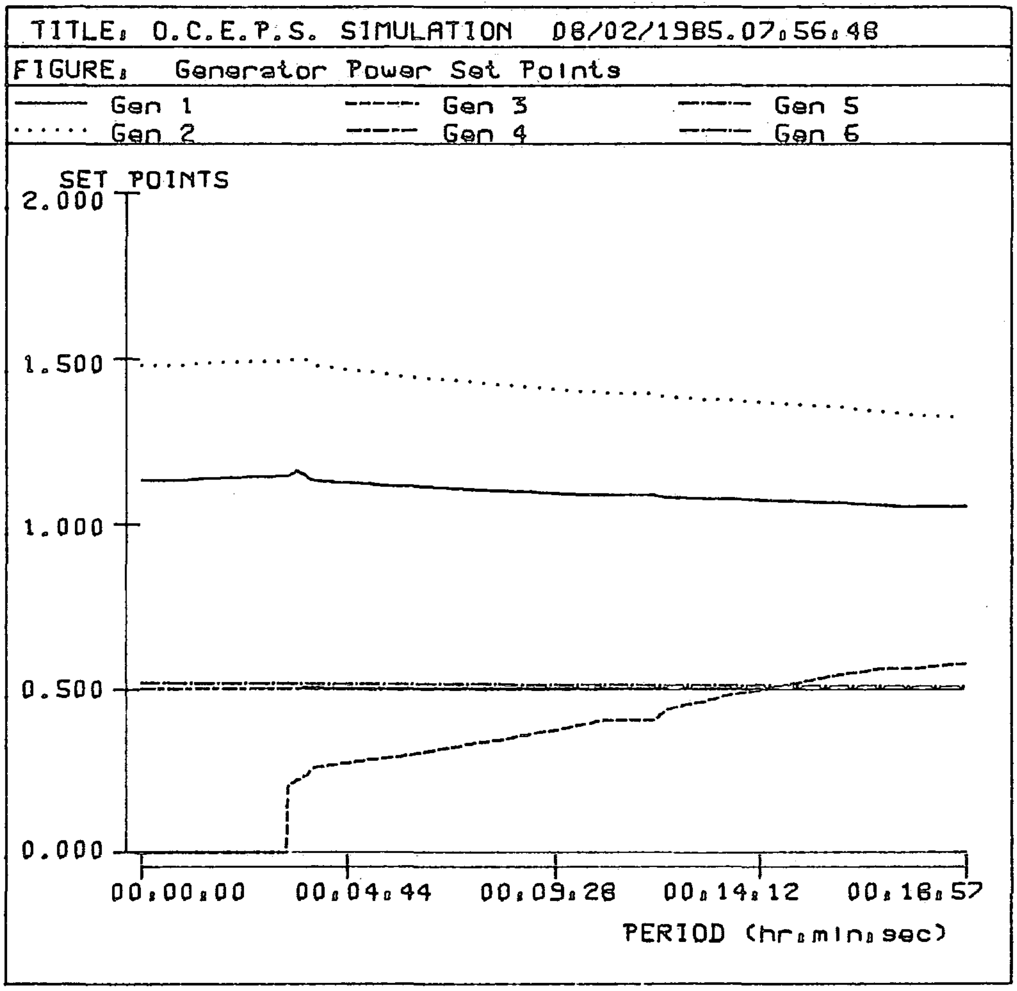


Figure 6.23

Figure 6.24



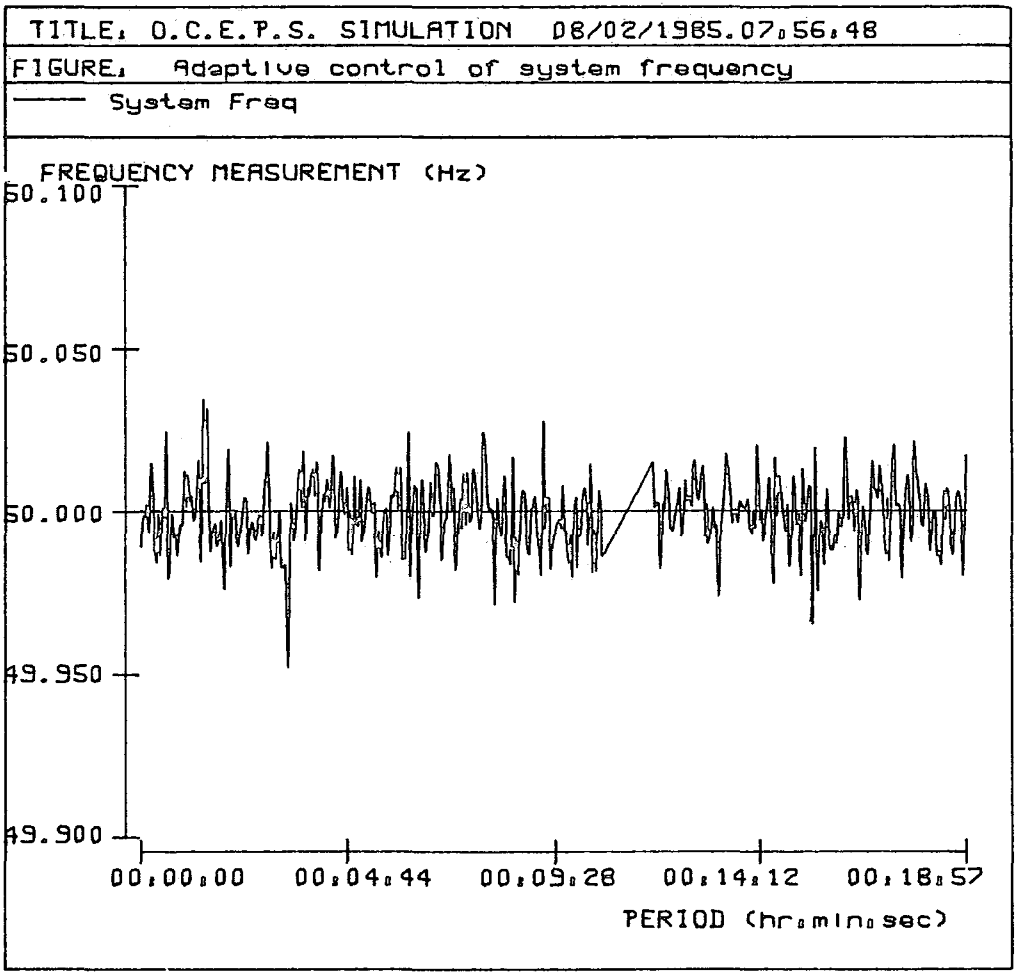


Figure 6.25

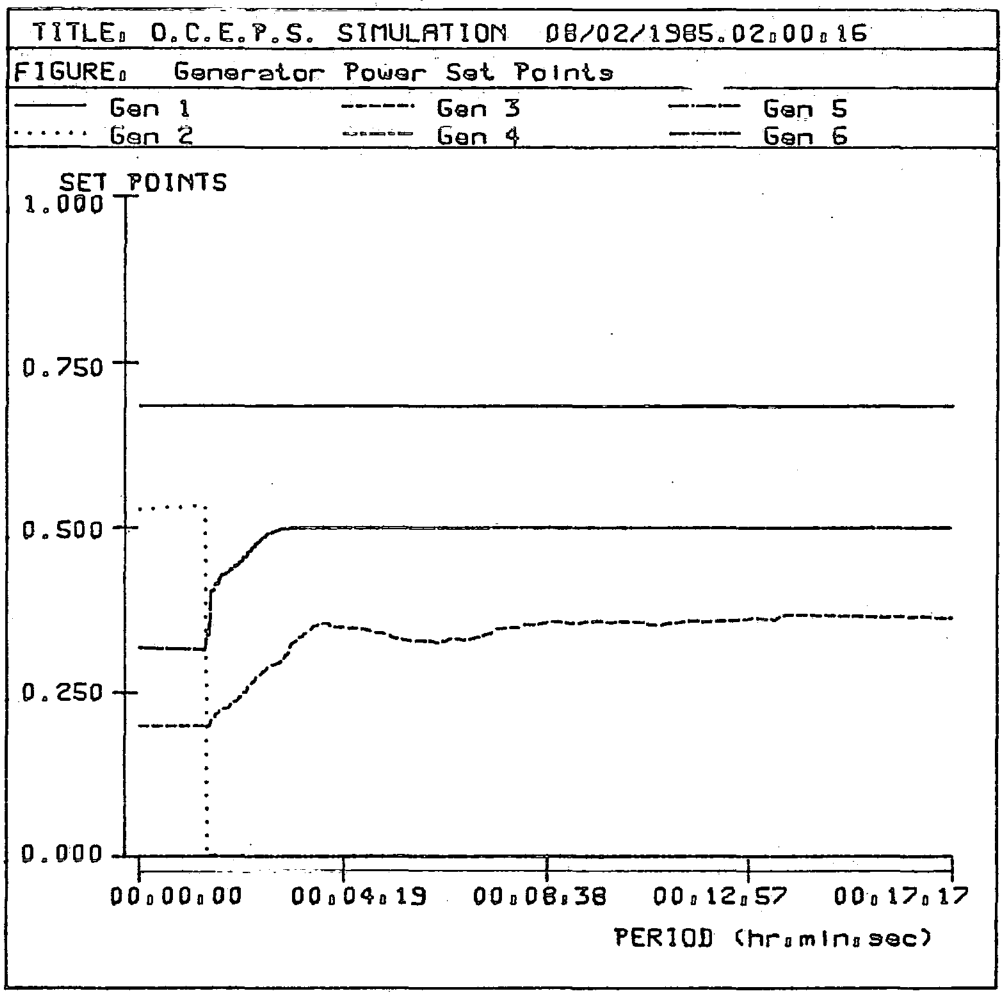
capacity. The slower responding smaller units are immediately commanded to reduce their outputs while the new unit increases its output to replace the lost generation. This causes an overshoot of the unit power set points, due to the fact that the controller model has not been able, in the time available, to remodel the system to a sufficiently accurate degree.

The previous results show the effect of drastic changes on the system. This is unlikely to occur regularly in practice so to provide the controller with a more realistic situation, a test was carried out a period of lighter load. The Unit 3 was synchronised in the early morning with a light load. In this case, the units are able to respond with suitable regulation action. The controller model is able to change to match the simulated system changes, resulting in a controlled decrease in the output of Units 1 and 2, shown in figure 6.30 and a stable system frequency, shown in figure 6.31.

The control of the system frequency with an increase in system generation is seen in figure 6.32 and 6.33. The light loading of the system combined with the availability of many of the system generators for regulation enables the frequency transient caused by the resynchronisation of Unit 2 to be controlled. The Unit 3 was under Base control mode so was unable to respond to the system situation. The smaller units rapidly decrease their outputs, along with Unit 1. Again the lack of frequency measurements is seen for a short period, which causes the generation not to be controlled as would have been desired as the smaller units are required to increase their outputs slightly to match the generation deficiency. The latter part of the plot shows Unit 2 increasing its output while Unit 1 is decreasing its output. This operation is linked with the economic dispatch control function setting the long range targets for each of the available units.

The controller was tested directly against the standard O.C.E.P.S. test scenario, the results are shown in figure 6.34 with the corresponding frequency trace in figure 6.35 (see Appendix 1 for scenario details). It is difficult to make direct comparisons with the previous fixed controller response to this test, but it can be seen that the maximum output of Unit 1 is less than in the previous case.

Figure 6.26



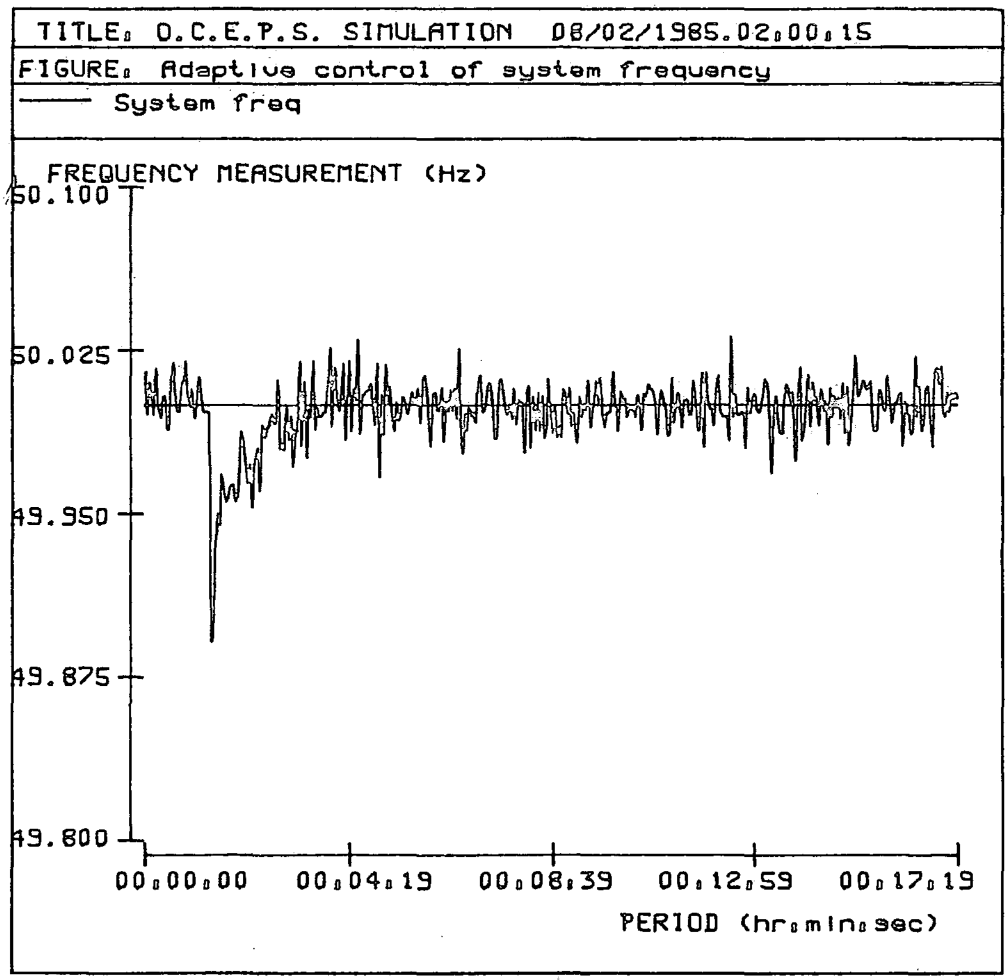
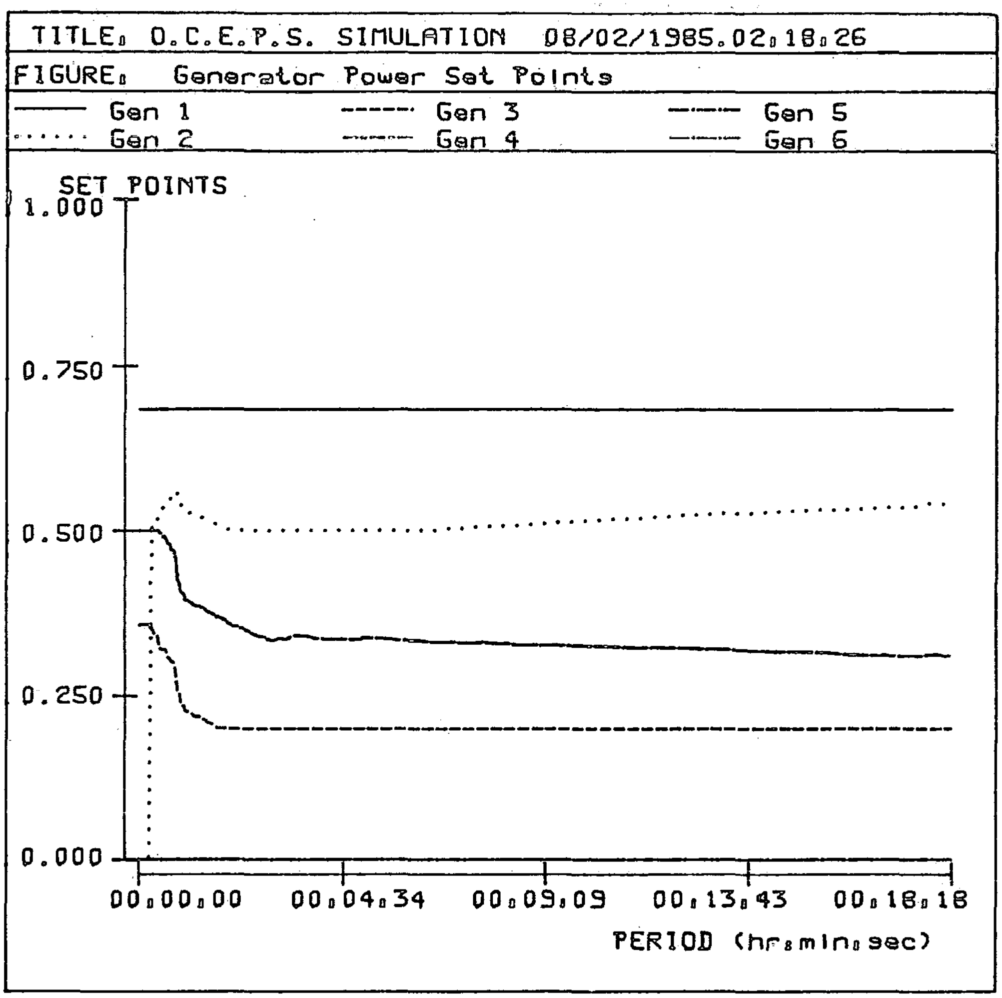


Figure 6.27

Figure 6.28



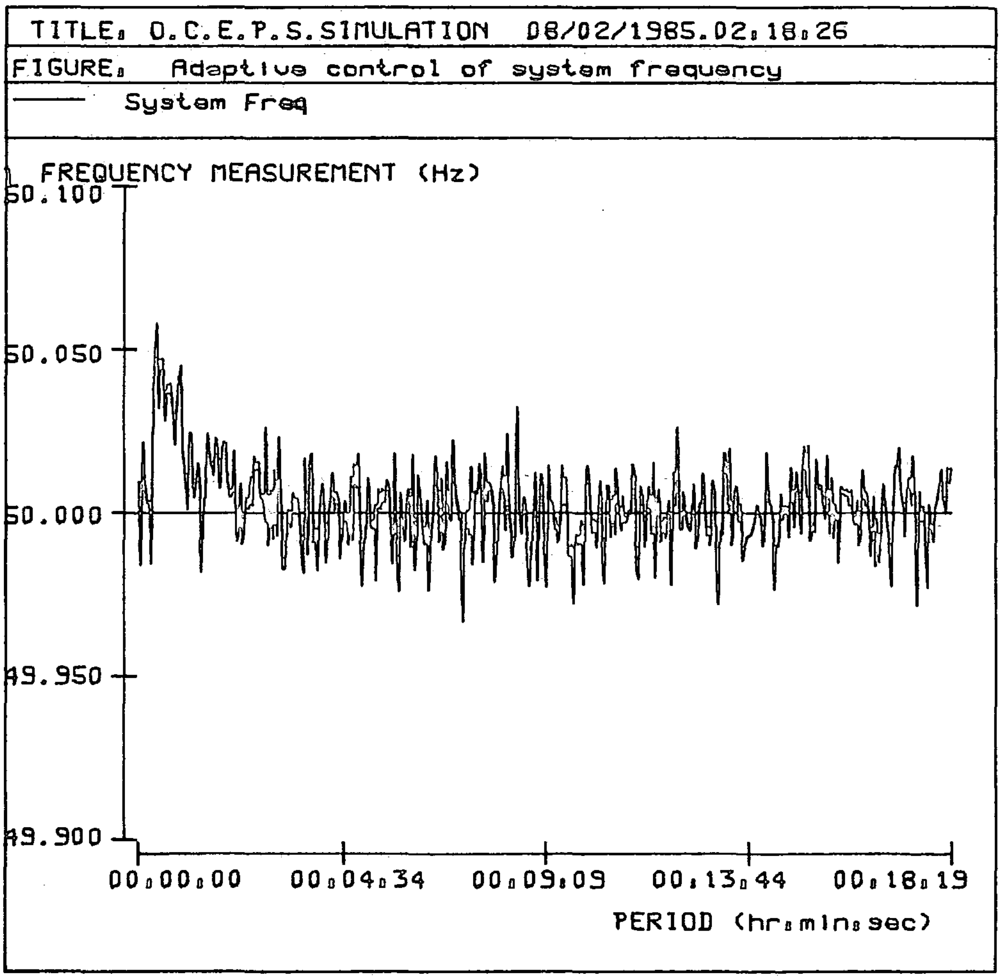
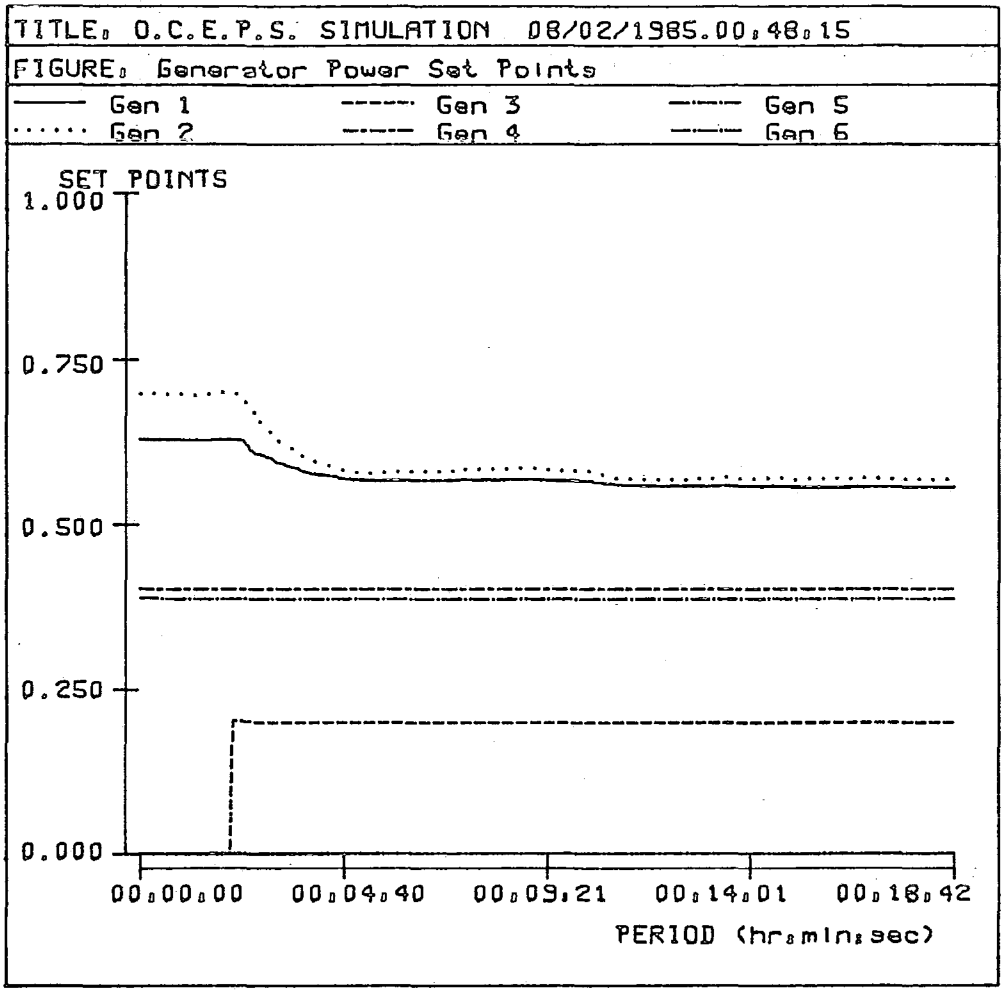


Figure 6.29

Figure 6.30



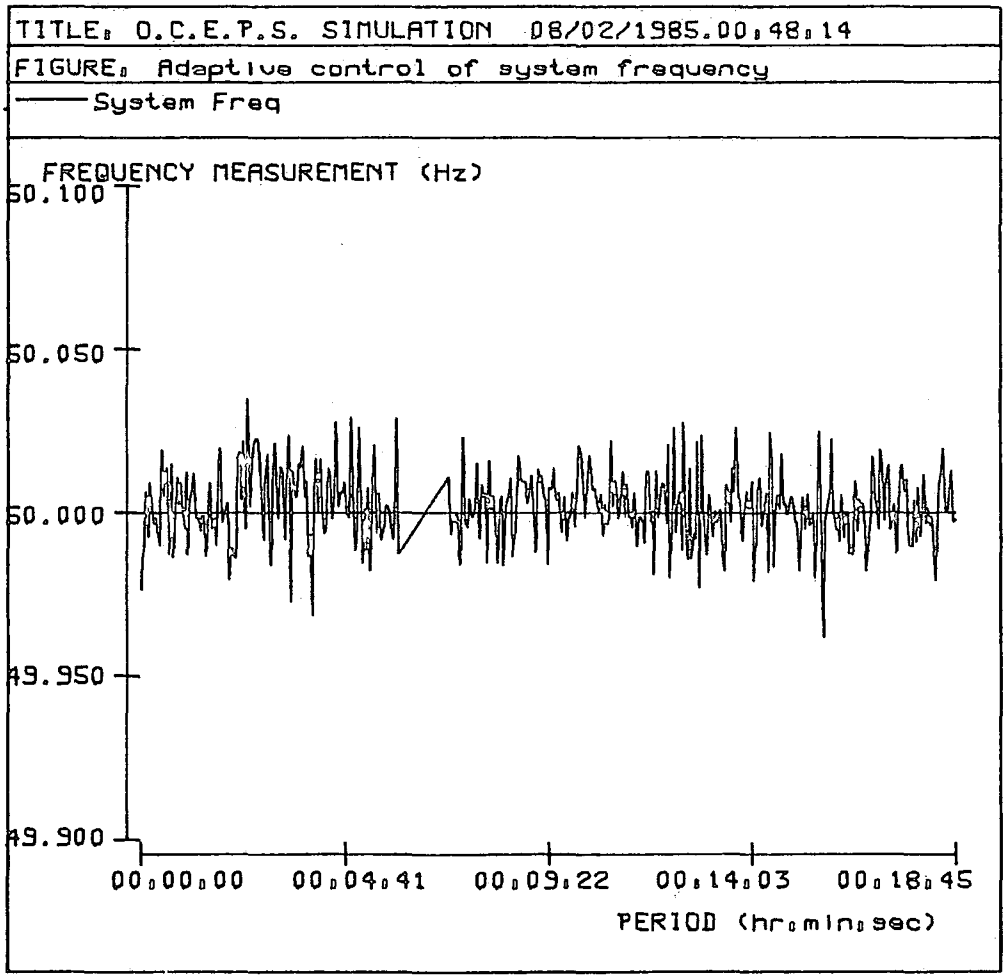


Figure 6.31

There is little difference between the frequency deviations, but the adaptive controller requires less generation control to achieve the same deviation. One condition that must be noted is that all the islands were resynchronised by the adaptive controller and the test ends with a single system unlike the previous case.

6.16 Conclusion

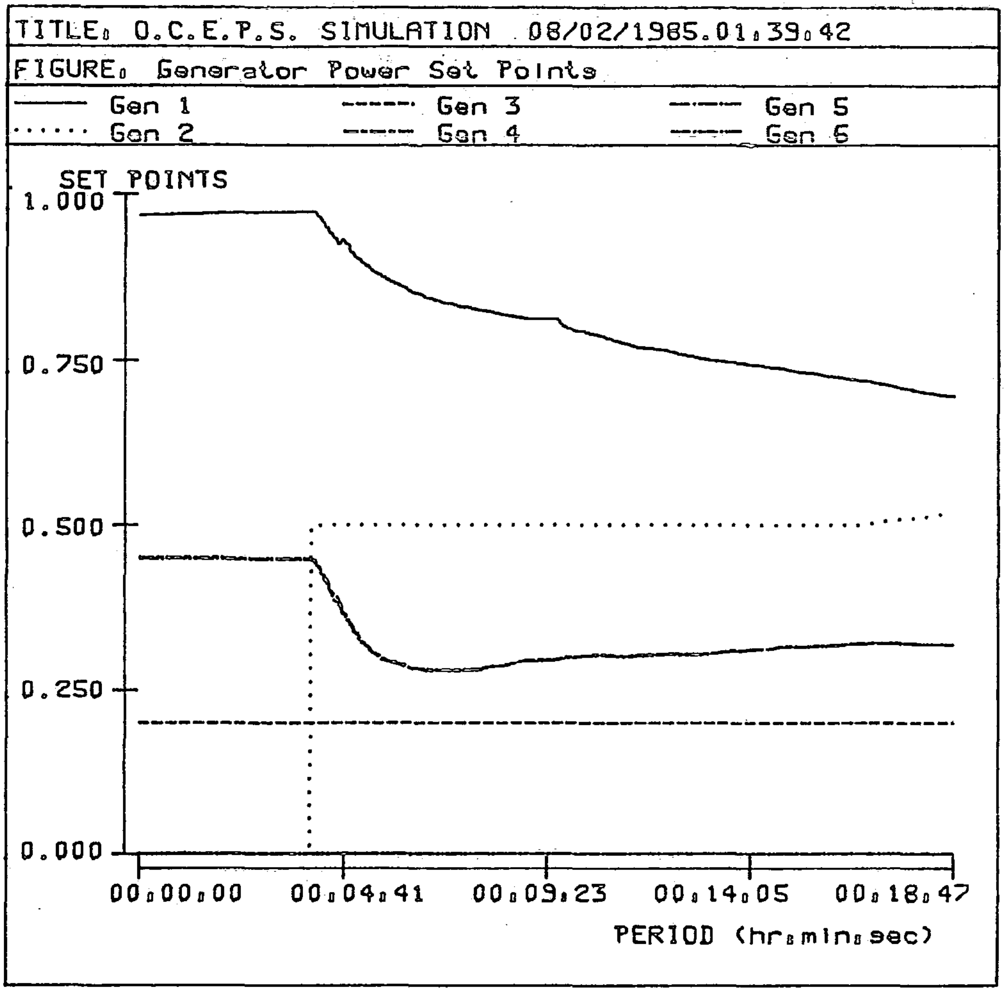
This chapter has discussed the use of adaptive control and its potential application in the field of L.F.C. The early sections discussed the techniques required to build a system identification process and a suitable control scheme. The use of the self–tuning regulator for this purpose was investigated and found to be suitable with some modifications. Basing the control calculations on a system model was shown to be reliable if the correct model order was used.

The use of the minimum variance control scheme based on the updated system model was investigated for many system configurations and types of operation. The modelling technique is capable of producing a valid model quickly so that the control algorithm may effectively use the investigated technique.

The basic controller was enhanced using forgetting factors to alter the speed of the construction of the controller model. It is shown that the use of the forgetting factors can improve the control commands even during major frequency transients.

Differing control modes were used for the generation units to effectively change the system gain and response time for different system conditions. The results have shown that the controller has the ability to track the system status and calculate suitable controls in situations where the fixed parameter schemes would be unsuitable. However the control scheme has not been tested under multi–area conditions where the use of inter–area tie–lines cause many control problems. This problem is discussed and a suitable control scheme is proposed in the next chapter.

Figure 6.32



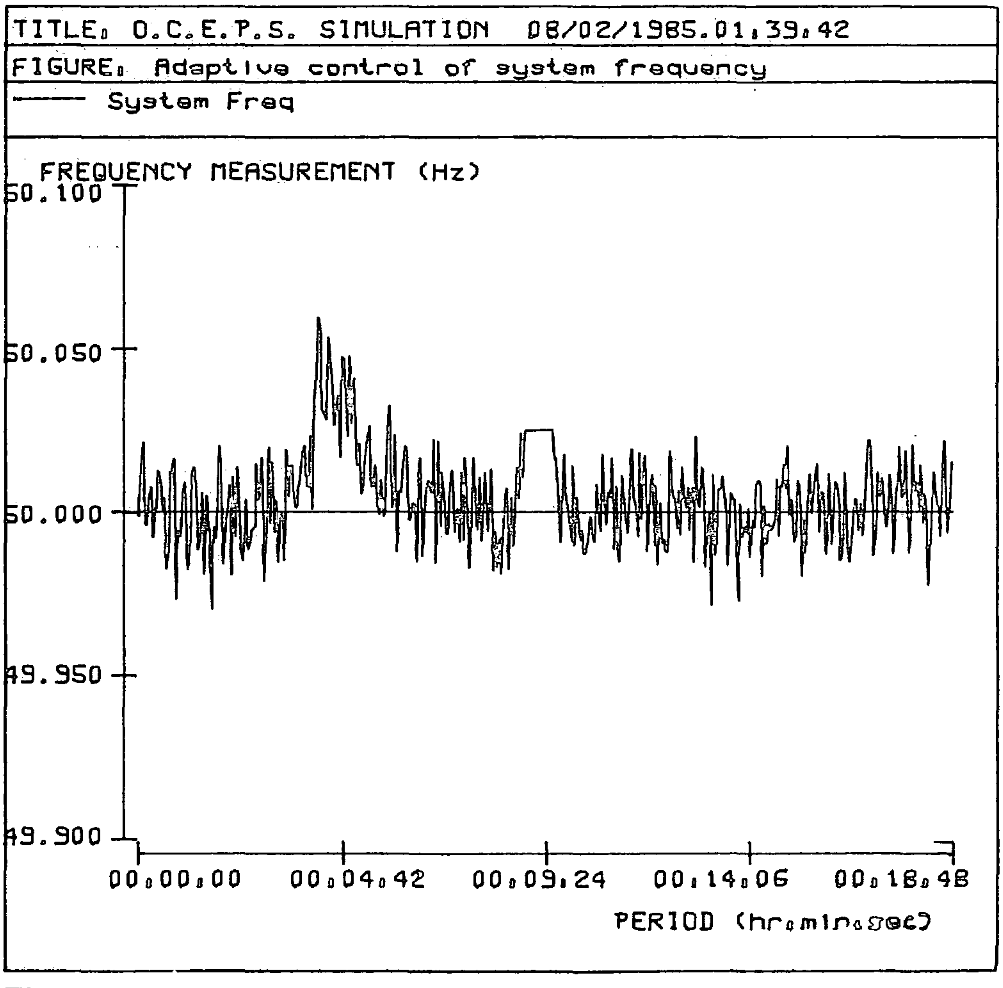
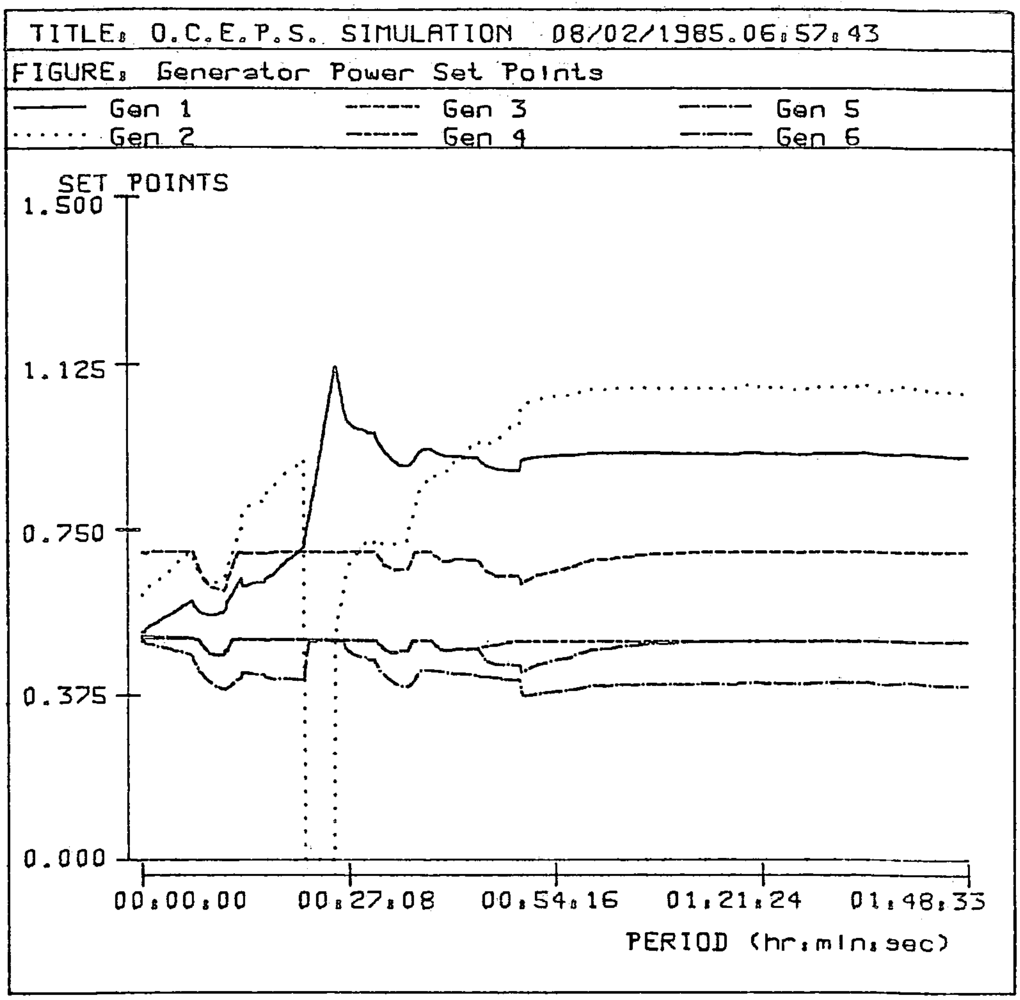


Figure 6.33

Figure 6.34



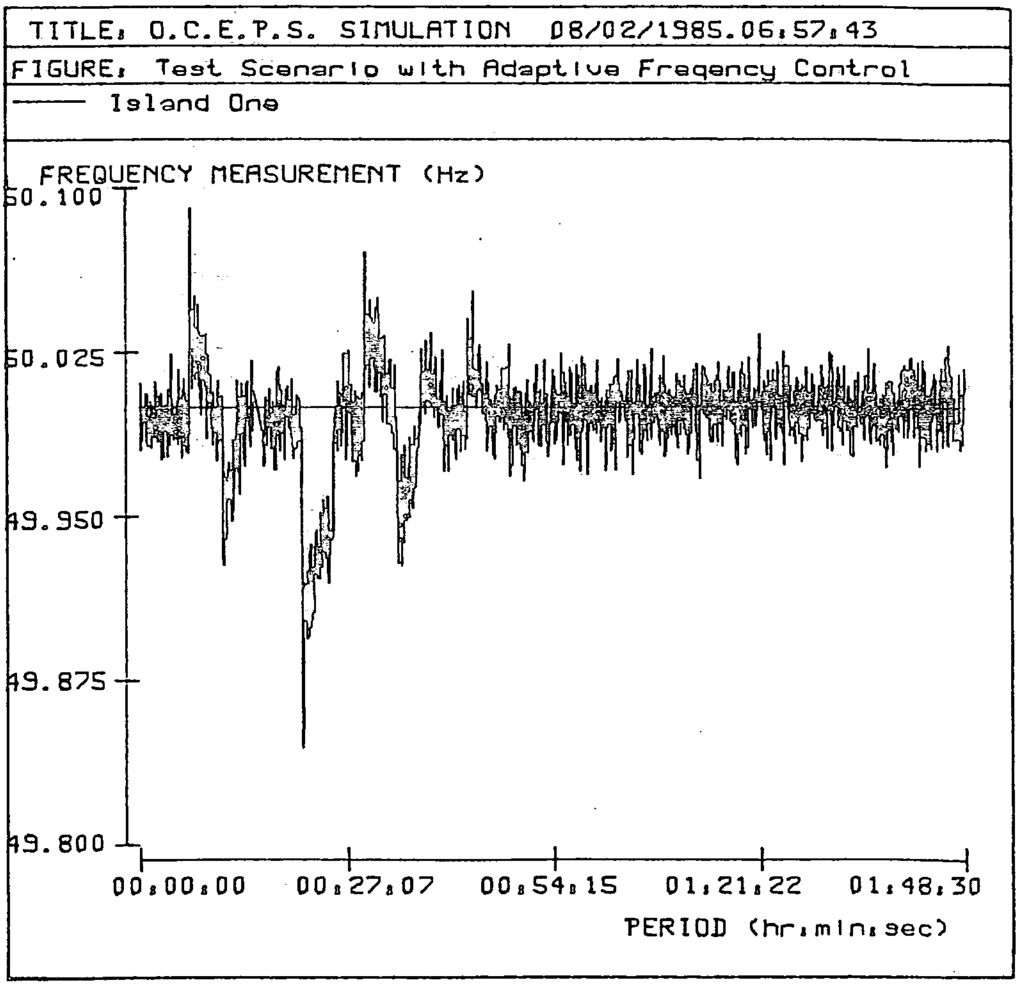


Figure 6.35

CHAPTER 7

Control of Interconnected Power Systems

7.1 Introduction

The previous chapter discussed the use of adaptive control techniques for the control of the system frequency. The use of the self-tuning regulator was developed for a single area utility without any connections to other power systems. This chapter considers and reviews some of the reasons why electrical power utilities often connect their power system to that of neighbouring power systems, and the problems that this causes with the frequency control of the interconnected system. A modification is proposed to the frequency control method described in the previous chapter for the single area problem, which is capable of controlling multiple area systems. This algorithm uses the inter–area power flows, along with the individual area frequencies for the system control. With the use of adaptive control the inter–area dynamics can be tracked directly and suitable control action taken.

The latter part of the chapter describes the application of this adaptive algorithm used for the control of the O.C.E.P.S. simulator, which was split into two interconnected areas. There is a discussion of the additional variables that are required for control purposes and the use that the algorithm makes of them.

7.2 Interconnected Power Systems

There are some power systems in the world that are single entireties, but the majority of systems are connected to other utilities for one reason or another. The C.E.G.B. system is often thought of as a single system, but there are links to Scotland and the cross Channel D.C. link with E.D.F. in France, although the system does not rely on these links for control action. There are many reasons why one utility should connect with another one, such as geographical or political reasons. Many utilities, throughout the world connect their system to that of their neighbours because of mainly economic and security considerations. Some of the more interesting references available on the subject are (113,201,204,205,207,209,210,215,222).

The advantages of the interconnection of electrical power systems are that: it ensures reliability, makes the individual system more secure, and enables the systems to be operated at a cost less than that if left in its separate parts. Interconnected power systems have better regulating characteristics in response to consumer load changes in any of the systems. This is because the load change is responded to by all units in the interconnection, not just the units in the control area where the consumer load change has occurred. This fact also makes interconnections more reliable as the loss of a generating unit in one area can be made up from spinning reserve of the other units linked by the interconnection. Thus, if a unit is lost in one control area, control action from units in all connected areas will increase the generation to make up the deficit, until stand–by units can be brought on–line, although an economic penalty may be paid. If a power system were to be run isolated and lose a large unit, the chance of the other units in the isolated system being able to make up the deficit are greatly reduced. Extra units would have to be run as spinning reserve, and this would mean a less economic operation. There is also the advantage that one area will generally require a smaller installed generation capacity if it is planned as part of an interconnected power system.

7.3 Economic Operation of Interconnected Power Systems

One of the main arguments for interconnecting systems is the economic one. Better economic operation can be attained when the systems are interconnected [139,201,222] This chance to improve the operating economics of an area is due to the fact that the two power systems have differing incremental costs.

Consider the following example

(1) Utility A is generating at a lower incremental cost than B

(2) If the Utility B were to buy the next Megawatt of power for its load from utility A at a price less than if it generated that Megawatt from its own generation, it would save money in supplying the increment in consumer load.

(3) Utility A would also benefit economically from selling power to Utility B so along as Utility B was willing to pay a price that was greater than the cost to Utility A for generating that block of power.

The problem is to achieve a so termed mutually beneficial transaction and to establish a *fair* price for the cost of the interchange sale.

There are other, longer term transactions that are economically advantageous to interconnected utilities. One system may have a surplus of power and energy and may wish to sell if to an interconnected company on a long–term, firm supply basis. It may, under other conditions wish to arrange to sell this excess only on a *when, and if available* basis. The purchaser would probably agree to pay more for a firm supply (in the first case) than for the interruptable supply of the second case.

In all cases of power interchange the question of a *fair and equitable price* must be considered. In many cases the economy of interchange is such that they are all based on an equal division of the operating costs that are saved by the utilities involved in the interchange. This is not always the case since *fair and equatable* is very subjective depending on the utilities own view point. What is fair and equatable to one partner may be totally unfair and inequitable to the other. A 50–50 share of the costs of the interchange is often used in the U.S.A. as in *normal operation* it appears to be the fairest mode of operation. Pricing arrangements for long–term interchange can vary widely and can become very involved including so termed *take-or-pay* split savings, or fixed price contracts.

7.4 Energy-interchange

There are often other reasons for the interchange of power than simply obtaining economic benefits. Interchange arrangements are made between power utilities for a variety of reasons, however the major reason is clearly economic. The following sections briefly describe some of these other reasons.

7.4.1 Capacity Interchange

In normal operation, a power utility will ensure that it has sufficient generation available so that the capacity of its normal units is equal to that of its predicted load plus a reserve to cover unit outages. If for some reason this criterion cannot be met, the system may enter into a capacity agreement with a neighbouring system. So long as the neighbouring system has a surplus capacity greater than what it needs to supply its own peak load and maintain its own reserves this operation is feasible. When selling capacity, the system that has a surplus agrees to cover the reserve need of the other system. This may require running extra units during certain hours, which represents a cost to the selling system. The advantage of such agreements is that each system is able to schedule increased generation at increased time periods by buying capacity when it is short, and selling capacity when a large unit has just been brought on-line and it has a surplus.

7.4.2 Diversity Interchange

Daily diversity arrangements may be made between two large systems covering operating areas that span different time zones. Under such circumstances one system may experience its peak load at a different time of day to the other system, because the second system is 1 hour behind. If the two systems experience such a set of conditions, they can help each other by interchanging power during the peak. The system that peaked first would be able to buy power from the other and then pay it back when the other system reached its peak load.

This type of interchange can also occur between systems that peak at different seasons of the year. Typically, one system will peak in the summer due to air–conditioning load and the other will peak in winter due to winter heating load. The winter peaking system would buy power during the winter months from the summer peaking system, whose system load would be lower at that time of the year. Then in the summer, the situation would be reversed and the summer peaking system would buy power from the winter peaking system.

7.4.3 Energy Banking

Energy–banking agreements usually occur between a system which has mainly hydro units and is interconnected to a system which has mainly thermal units. During high water runoff periods, the hydro system may have energy to spare and will be able to sell it to the thermal system. Conversely, the hydro system may also need to import energy during periods of low runoff.

7.4.4 Emergency Power Interchange

It is possible that during future operation a power system would have a series of generation failures. This may require a single system to load shed. However, if the systems are interconnected, one system would be able to import power rather than load shed. Under such emergencies it is very useful to have agreements with neighbouring systems to supply power so that there will be time to shed load. This may occur at times that are not convenient or economical from the incremental cost point of view. Therefore, such agreements often require that emergency power be priced very high.

7.4.5 Inadvertent Power Interchange

The A.G.C. that utilities use can sometimes fail to control the tie–line power flows to the required values. This has the result that over periods of time a significant amount of energy may be accumulated by one area. This is known as *inadvertent interchange.* Under normal circumstances, the system operators would *pay back* the accumulated inadvertent power interchange over periods during the next week of operation. However, with the use of more advanced A.G.C. functions these interchange errors may be greatly reduced.

7.4.6 Energy Trading

Energy trading is a method used to enable the scheduled interchange power to be monitored and any deviation made up at some future time. The power interchange is monitored and averaged over a five minute or half-hour period, at the end of which the schedule may be altered to account for any change from the scheduled interchange. In some the cases the deficit of power may be made up at a later time depending how the agreement is made up.

7.5 Inter-area Economic Power Interchange

Power systems are able to operate in a more economic manner if they operate in an interconnected mode rather than alone. The problem that this creates is that a Dispatch for all the units in the interconnected system has to be carried out. This implies that all the information required by the Dispatch algorithm, such as input-output curves, fuel-costs, unit-limits, unit status, and so on, are available in one location and that the calculation for an overall dispatch is carried out as if the areas were part of the same system. However, unless the two power systems have formed a power pool or communicate the required information to each other, or to a third party who will arrange the transactions, this assumption is incorrect. Generally the system operations within each of the control areas communicate with each other. It is assumed that one area has the data and the ability to perform an Economic Dispatch calculation for its own system and that all information about the neighbouring systems has to come over a communications link.

The simplest way of carrying out an Economic Dispatch for the interconnected system is to Dispatch as if someone was carrying out an economic dispatch calculation for both systems combined, the most economic way to operate would require the incremental cost to be the same at each generating plant assuming losses are ignored. The two control centres are able to achieve the same result by

(1) Assuming there is no interchange of power being transmitted between the two systems.

(2) Each system control centre runs an Economic Dispatch calculation for its own system.

(3) Predetermine which system has the lower incremental cost. The control centre in the system with lower incremental cost then runs a series of economic calculations each one having a greater total demand. Similarly, the system operations in the system having the higher incremental cost runs a series of economic dispatch calculations each having a lower total demand.

(4) Each increase of consumer demand on the system with lower incremental cost will tend to cause a raise in its incremental cost, and each decrease in demand on the high incremental cost system will tend to lower its incremental cost. By running the economic dispatch steps the two control centres can determine the level of interchange of energy that will bring the two systems toward the most economic operation.

Under the idealised *free market* conditions, both utilities attempt to minimise their respective operating costs and if they assume no physical limitations on the transfer, their power negotiations will lead to the same economic results as a pool dispatch performed on a single area basis. These assumptions are however, critical. In many practical situations there are physical and local constraints that prevent interconnected utility systems from achieving the optimum economic dispatch.

7.6 Tie–line Model

Consider an interconnected power system which has been broken into two areas which each have one generator as in diagram 7.1. The areas are connected by a single transmission line. The power flow over the transmission line will appear to be a positive load to one area and an equal but negative load to the other area, depending on the direction of flow. The direction of flow will be dictated by the relative phase angle between the areas, which is determined by the relative speed deviations in the areas. If a two area system is considered, the power flow is defined as going from Area 1 to Area 2, the flow appears as a load to Area 1 and a power source (negative load) to Area

2. If it is assumed that mechanical powers are constant, the rotating masses and tie–lines exhibit damped oscillatory characteristics known as synchronising oscillations.

It is interesting to analyse the steady–state frequency deviation, tie–line flow deviation, and generator outputs for an interconnected area after a load change occurs. Consider a load change ΔP_L, in Area 1. In the steady–state, after all synchronising oscillations have been damped out, the frequency will be constant and will be the same value in both areas. Then

$$\Delta\omega_1 = \Delta\omega_2 = \Delta\omega \qquad \text{and} \qquad \frac{d(\Delta\omega_1)}{dt} = \frac{d(\Delta\omega_2)}{dt} = 0 \tag{7.1}$$

and

$$\Delta P_{mech_1} - \Delta P_{tie} - \Delta P_{L_1} = \Delta\omega K_1 \tag{7.2}$$

$$\Delta P_{mech_2} + \Delta P_{tie} = \Delta\omega K_2 \tag{7.3}$$

$$\Delta P_{mech_1} = \frac{-\Delta\omega}{R_1} \tag{7.4}$$

$$\Delta P_{mech_2} = \frac{-\Delta\omega}{R_2} \tag{7.5}$$

by making the appropriate substitutions in equation (7.2, 7.3)

$$-\Delta P_{tie} - \Delta P_{L_1} = \Delta\omega\left(\frac{1}{R_1} + K_1\right) \tag{7.6}$$

$$\Delta P_{tie} = \Delta\omega\left(\frac{1}{R_2} + K_2\right) \tag{7.7}$$

or finally

$$\Delta\omega = \frac{-\Delta P_{L_1}}{\frac{1}{R_1} + \frac{1}{R_2} + K_1 + K_2}$$

form which it is possible to derive the change in tie-line power flow

$$\Delta P_{tie} = \frac{-\Delta P_{L_1}\left(\frac{1}{R_1} + K_2\right)}{\frac{1}{R_1} + \frac{1}{R_2} + K_1 + K_2} \tag{7.8}$$

It must be remembered that for the conditions described in equations (7.7) to (7.8) are the new steady–state conditions after the load change. The new tie flow is determined by the net change in load and generation in each area. It is not necessary to know the tie stiffness to determine this new tie flow, although

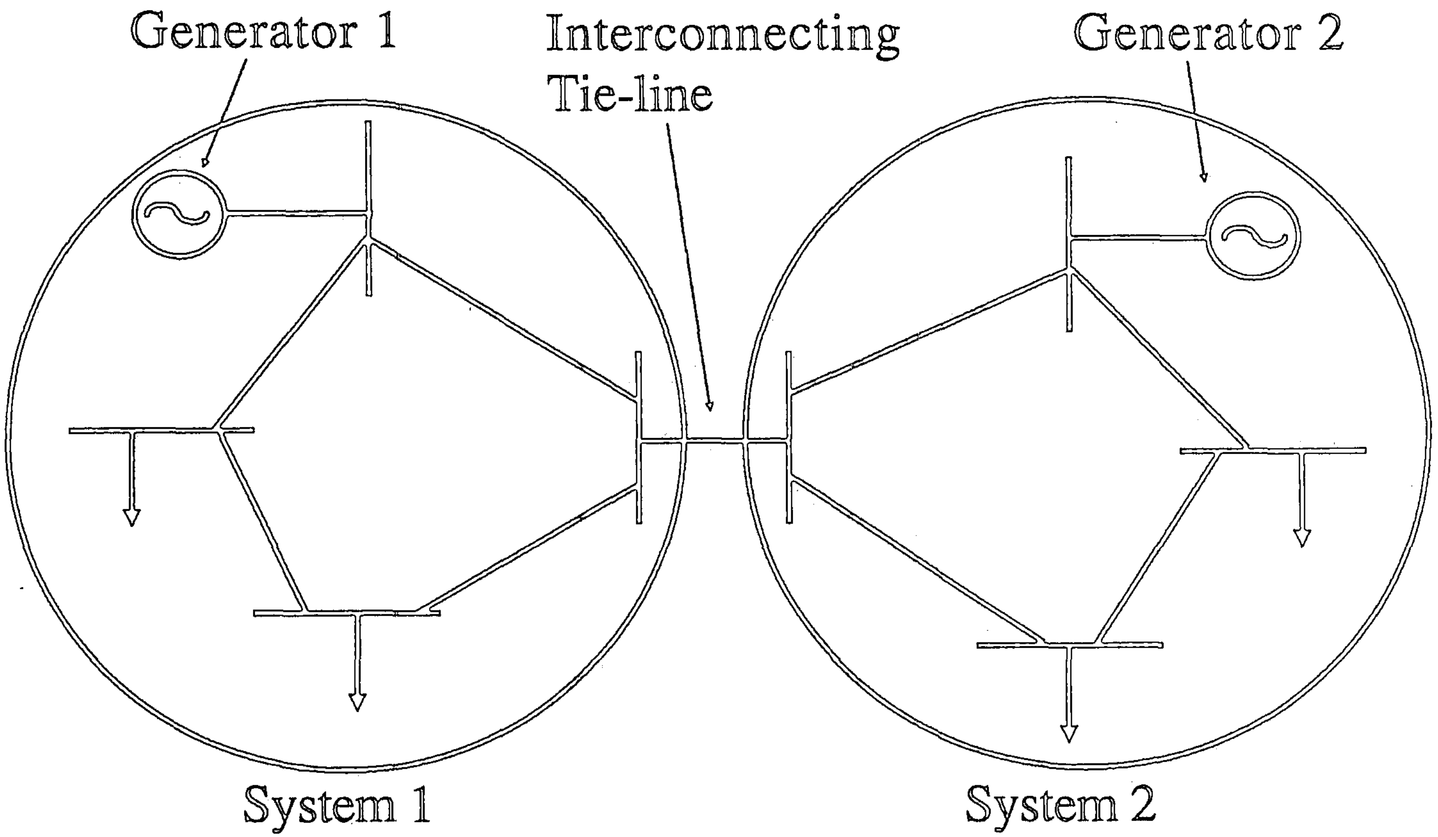


Diagram 7.1 Two-area system

the tie stiffness will determine how much difference in phase angle across the tie will result from the new tie flow.

7.7 Tie–Line Control

When two utilities interconnect their systems, they do so for a number of reasons. One is to be able to buy and sell power with neighbouring systems whose operating costs make such transactions profitable. Also, even if no power is being transmitted over ties to neighbouring systems, if one system has a sudden loss of generating plant, the units throughout the whole interconnected system will experience a change in frequency and can assist in the restoration of the frequency deviation.

Interconnection presents problems when controlling the allocation of the generation to meet the consumer load. As an example assume there are two systems that have similar generation and load characteristics. ($R_1 = R_1, K_1 = K_2$) and assume Area 1 is sending 100 MW to Area 2 under an interchange agreement made between the two operators of each system. Area 2 experiences a sudden load increase of 30 MW. Since both units have an equal generation characteristics, they will both experience a 15 MW increase, and the tie–line will experience an increase in flow from 100 MW to 115 MW. Thus the 30 MW load increase in Area 2 will have been satisfied by a 15 MW increase in the generation in Area 2 plus 15 MW increase in its flow into Area 2. This would be allowable however, Area 1 has contracted to sell only 100 MW to Area 2, and not 115 MW. The generating costs of Area 1 have just gone up without anyone to charge the extra cost to. What is needed at this point is a control scheme that recognises the fact that the 30 MW load increase occurred in system 2 and, therefore, would increase the generation in Area 2 by 30 MW while restoring the frequency to the nominal value. It would also restore the generation in Area 1 to its output before the load increase occurred.

Such a system must use two pieces of information: the system frequency and the net power flowing in or out over the tie–lines.

Such a control scheme would need to recognise the following

(1) If the frequency decreased and net power interchange power leaving the system increased, a load increase has occurred outside the system.

(2) If frequency decreased and net interchange power leaving the system decreased, a load increase has occurred inside the system.

A control area is defined to be part of an interconnected system within which the load and generation will be controlled [135]. The control area's boundary is simply the tie–line points where power flow is metered. All tie–lines crossing the boundary must be metered so that the total control area net interchange power can be calculated. Diagram 7.2 shows two small systems that may be typically interconnected.

The change of generating level from one interconnected set to another is difficult. The system inertia is large compared with the torque output of one of the units and no easily detectable speed change occurs. However, if a speed change occurs on the system, it is detected by all the units, and their combined torque change affects the speed rapidly. If the governor speed droop of one unit is increased, the rate of response of the units is increased to a change of consumer load with no apparent effect upon the system speed. Hence, with the exception of slow speed response to a set point change on one unit of a system, the function of speed governing can be implemented by the same governor characteristics which are optimum for isolated operation, even when the units are operating in parallel.

7.8 Control of interconnected systems

The interconnection of power systems which can provide security of supply, economic operation and reduce capital costs of the system introduces more complex control problems [200,201]. In an interconnected system, system frequency is no longer a suitable measure of the system imbalance. As an example, consider two interconnected systems. If system B experiences an increase in load then the following events occur.

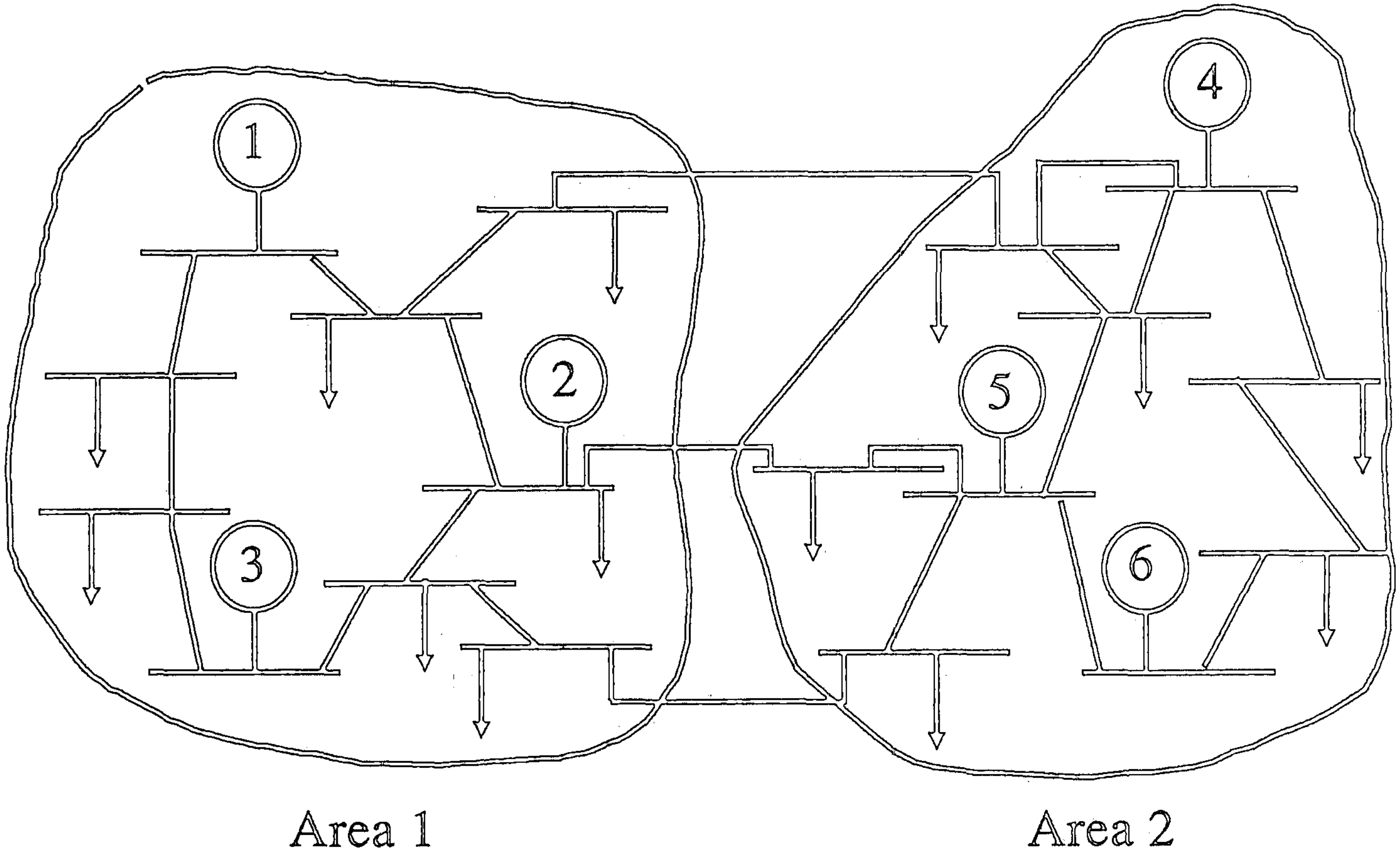


Diagram 7.2 Interconnected areas

(1) The speed of Area B will begin to fall as the increased demand is supplied from kinetic energy in the rotating masses.

(2) The phase angle on the tie–line increases and more power flows into B.

(3) The speed of Area A begins to fall due to the increased load out on the tie–line to B.

(4) The governors on both systems will detect the change in speed and each system will respond in proportion to its regulating characteristic.

(5) The two system will settles out at a new frequency common to both systems and a new tie–line load.

All this takes place in few seconds and is taken to be completed before the other system control functions respond.

Consider the change in power transferred from A to B when a change of consumer load results in an out of balance power ΔP in Area B. This change in power is defined to be ΔP_t and is positive when power is transferred from A to B. The change in frequency in Area B due to an extra load ΔP and an extra input of ΔP_t from A is $-(\Delta P - \Delta P_t)/K_B$, where the negative sign indicates a fall in frequency. The drop in frequency in A due to the extra load ΔP_t is $-\Delta P_t/K_A$, but the change in frequency in each system must eventually be equal. Hence

$$\frac{-(\Delta P - \Delta P_t)}{K_B} = -\frac{\Delta P_t}{K_a}$$

hence

$$\Delta P_t = \frac{K_a}{K_a + K_B}\Delta P$$

The dynamics of a tie–line interconnection as opposed to the steady state analysis can be derived as follows

Consider an area i which is radially connected with neighbouring areas $j, k \ldots$. The total power flow exported from area i, P_{ti}, equals the sum of all out–flowing line powers P_{tin} in the lines connecting area i with areas $j, k \ldots$ Thus

$$P_{ti} = \sum_n P_{tin}$$

Where the summation extends over all n lines that terminate in area i.

If the line losses are neglected, the individual line powers can be written in the form

$$P_{tin} = \frac{|V_i||V_n|}{X_{in}P_{ri}}\sin(\delta_i - \delta_n)$$
$$\approx P_{tMax}\sin(\delta_i - \delta_n)$$

where $V_i = |V_i|e^{j\delta_i}$ and $V_n = |V_n|e^{j\delta_n}$

are the terminal bus voltages of the line, and X_{in} its reactance. P_{tMax} represents the maximum real power, expressed in per unit of area P_{ri}, that can be transmitted via the line. The tie–line is termed *weak* if $P_{tMax} \ll P_{ri}$

This steady–state example suggests that the tie–line load change and frequency change should be combined to define an amount of power for each area necessary for it to reduce the total power error, this is area requirement for an interconnected system. The computational requirement derived earlier may thus be redefined to incorporate the effect of the tie–line power interchange.

$$C.R. \quad \text{for area} \quad i = \Delta P_{ti} + K\Delta f_i$$

where

ΔP_{ti} is the net change in the tie–line power flow out of area i and

Δf_i is the frequency deviation in area i.

The $C.R.$ is thus positive when the load increases within area i.

If the system control is to control the generators in its area on the idea of keeping the area requirement at zero, then changes in generation must match changes in demand. If this is so, the equation must be solved continuously by the controller. The tie–line and frequency deviations ΔP_{ti} and Δf_i can be obtained by comparison of actual telemetered tie–line load with the scheduled value and actual frequency with scheduled frequency.

System regulation based on the equation is generally termed *tie–line bias control*, since it can be considered as a form of tie–line control biased by frequency error. Sometimes control of only tie–line load is acceptable if the system is small and tied radially to a much larger system.

7.9 Supplementary Control for Multiple Area Systems

Clearly, the use of adaptive control techniques applied to interconnected systems has a great advantage over the use of the fixed parameter type schemes mentioned in earlier sections. The adaptive scheme may adapt to the state of the whole interconnected system without having to have prior knowledge of the system configuration [147,198]. This means that none of the complicated tuning for fixed parameter schemes is required and the system may change configuration as dictated by the economics of the situation (to follow previously agreed power transfers) rather than constraints placed on it by the control system. The overall gain of the interconnected system will change more rapidly than that of a single area as each utility will plan the utilisation of each of their generator units. Thus the gain of the interconnected system would be more difficult to estimate than that of a single system, if each single area did not know the configuration of their neighbours. The problem which must be considered is that of the measurements required for the control calculation, but this occurs for standard fixed parameter control schemes.

7.9.1 Controller Algorithm

The modelling equations discussed earlier may be expanded to account for interconnected area operation [9,25,26,28,173] The ith area is modelled as

$$y_i(t) = -\sum_{j=1}^{n_i} a_{ij} y_i(t-j) + \sum_{j=1}^{n_i} b_i u_i(t-k_i-j) + \psi_i \sum_{j=0}^{n_i} c_i e_i(t-k_i) \qquad (7.9)$$

where

$y_i(t)$ is the output of the system at various time intervals (the A.C.E. in this case)

$u_i(t)$ is the control input to the plant of the ith area

$e_i(t)$ is the disturbance in the ith area acting on the plant.

For any system modelled by the equation (7.9), if the parameters of the model are constant and known, the minimum variance strategy can be written for interconnected systems as

$$\begin{aligned} u_i(t) =& \frac{1}{\beta_{i0}}[\alpha_{i1} y_i(t) + \ldots + \alpha_{im_i} y_i(t - m_i + 1)] \\ & - \beta_{il} u_i(t-1) - \ldots \beta_{il_i} u_i(t - l_i) \end{aligned} \tag{7.10}$$

7.9.2 Identifier Algorithm

The identification routine discussed in the earlier chapter may be expanded for interconnected operation [9,135,214]. There follows a brief summary of the equations from the previous chapter that are required to identify a system model for multiple areas.

To estimate the model parameters, equation (7.9) may rewritten at the instant t, by replacing $(t - k_i - 1)$ in equation (7.9) as follows

$$z_i(t) = H_i^T(t)\,\theta_i \tag{7.11}$$

where

$$\begin{aligned} z_i(t) =& y_i(t) - \beta_{i0} u_i(t - k_i - 1) \\ H_i(t) =& [-y_i(t - k_i - 1), \ldots, -y_i(t - k_i - m_i), \\ & \beta_{i0} u_i(t - k_{i_2}), \ldots, \beta u_i(t - k_i - l_i - 1)]^T \\ \theta_i =& [\alpha_i, \ldots, \alpha_{im_i}, \beta_{i1}, \ldots, \beta_{il_i}]^T \end{aligned}$$

where $[\;]^T$ indicates the transpose of the matrix. There are several recursive parameter estimation algorithms which can be used to obtain an estimate, $\hat{\theta}_i(t)$ for the parameter vector $\hat{\theta}$.

The recursive parameter least–squares technique is rewritten and reformulated as

$$\hat{\theta}_i(t) = \hat{\theta}_i(t-1) + K_i(t)[z_i(t) - H_i^T(t)\theta_i^T(t-1)] \tag{7.12}$$

The correction vector, $K_i(t)$ can be calculated as

$$K_i(t) = \frac{P_i(t-1)}{\gamma_i} H_i(t) \left[\frac{1}{w_i} + H_i^T(t) \frac{P_i(t-1)}{\gamma_i} H_i(t)\right]^{-1} \tag{7.13}$$

where $P_i(t)$ is the covariance matrix of estimation error and is found using the recursive equation

$$P_i(t) = \frac{1}{\gamma}\left[I - K_i(t)H_i^T(t)\right]P_i(t-1) \tag{7.14}$$

The equations (7.12),(7.13),(7.14) are seen to form the Kalman filter type algorithm as before, with the vector K_i being the Kalman gain of the set of equations.

7.10 Formulation of the Area Control Error

The extension to the single area control scheme must also take account of the changes required to calculate an A.C.E. This is based on the inter–area power flows along with the area frequency error, some method of combining the two errors was required so that a single A.C.E. could be calculated for the whole interconnected system.

The A.C.E. is formed using the weighted sum of the frequency error and the deviation of the total tie–line power. The control criteria was to minimise the variances of the frequency error and deviation of the tie–line power individually. Clearly there must be some division between the error from the frequency measurements and those of the tie–line power measurements to enable a suitable A.C.E. to be calculated. To achieve this aim of the controller in the system, weighting factors may be used to proportion the effect that each set of measurements has on the control action. A fixed weighting scheme could be used to control this apportioning of the control effort, but in a time varying system such as interconnected power systems it is proposed to use a weighting factor which alters dynamically as the system conditions alter. Thus the area control error, $y_i(t)$, of area i is be defined to be

$$y_i(t) = (1 - \rho_i)\Delta P_{tie\,i}(t) + \rho_i \Delta f_i(t) \tag{7.15}$$

where

$\Delta P_{tie\,i}$ is the deviation in the ith tie–line power,

Δf_i is the area ith frequency error, and

ρ_i is the calculated weight for Δf_i.

The aim of the controller is to determine the control action, which will minimise the individual variances of Δf_i and $\Delta P_{tie\,i}$.

The variance of the $y_i(t)$ using the new formulation of the A.C.E. is defined to be V_{yi}, and is given by

$$\begin{aligned} V_{yi} =& E\{y_i^2(t)\} \\ =& (1-\rho_i)^2 V_{\Delta P_{tie\,i}} + \rho_i^2 V_{\Delta f_i} \\ &+ 2(1-\rho_i)\rho_i E\left\{\Delta P_{tie\,i}(t) + \Delta f_i(t)\right\} \end{aligned} \tag{7.16}$$

Once again the S.T.R. uses $y_i(t)$ as the input from the system, and its aim is to calculate a control signal that minimises the variance of $y_i(t)$. In the previous case, when there was only one variable, this minimisation was requirement was straight forward. However, in this case there are now two non-independent variables that each need to be minimised. The third term in equation (7.16) does not disappear as $\Delta P_{tie\,i}$ and Δf_i are not independent. This means that to minimise the variance of $y_i(t)$, does not lead to the minimum variance of $\Delta P_{tie\,i}$ and Δf_i individually. To minimise the variances of $\Delta P_{tie\,i}$ and Δf_i individually the use a time-varying relative weight factor is used. The weighting factor is calculated based on the following criteria

(1) Initially a nominal value of ρ_i is taken at the start according to the system requirements under steady state conditions.

(2) The value of ρ_i is altered dynamically according to the variances of frequency and tie-line power deviation.

Changing the weight factors will change dynamically the value of the A.C.E. To be near minimum variance of a variable, the corresponding weight has to be increased as the variance increases. Hence ρ_i can be considered as a relative value related to the integral of the weighted frequency error and the integral of the weighted tie-line power deviation.

The weighted integral of tie-line power deviation and frequency error respectively is calculated using the sum of the squares of the error term, this is shown below.

$$E_{\Delta P_{tie\,i}}(t) = \sum_{j=0}^{t} [\Delta P_{tie}\,(j)]^2 p^{t-j} \tag{7.17}$$

$$E_{\Delta f_i}(t) = \sum_{j=0}^{t} [\Delta f_i(j)]^2 p^{t-J} \tag{7.18}$$

where

The discount factor p is given the value so that $0 < p \leq 1$.

The weighting function, p^{t-j}, will assign a weight equal to 1 to the latest value at time t and an exponentially decreasing weight to the earlier values of the error squared. For the special case when all the weights are the same, $p = 1$ may be used.

The variables in equation (7.17) and equation (7.18) are calculated using the recursive operations

$$E_{\Delta P_{tie\,i}}(t) = pE_{\Delta P_{tie\,i}}(t-1) + [\Delta P_{tie\,i}(t)]^2 \tag{7.19}$$

and

$$E_{\Delta f_i(t)} = pE_{\Delta f_i}(t-1) + [\Delta f_i(t)]^2 \tag{7.20}$$

The weight factor $\rho_i(t)$ may be calculated using

$$\rho_i(t) = \frac{E_{\Delta f_i}(t)}{E_{\Delta f_i}(t) + \lambda_i E_{\Delta P_{tie\,i}}(t)} \tag{7.21}$$

where

λ_i, is a constant that determines the relative importance of $\Delta P_{tie\,i}$ and Δf_i. The parameter λ_i enables one of the variances to be closer to the minimum than the other. The value of this parameter may take a wide range of values, although there are methods of calculating the optimum value of λ_i ^{198}. Thus the control problem may be defined as determining a control signal $u_i(t)$ which will enable the minimise variance value of $y_i(t)$ to be achieved. The minimisation of

$$y_i(t) = [1 - \rho_i(t)]\Delta P_{tie\,i}(t) + \rho_i(t)\Delta f_i(t) \tag{7.22}$$

must be calculated using a value of $\rho_i(t)$ from equation (7.21). The combination of the above calculations enabled the frequency controller proposed in the previous chapter to be expanded to control multiple areas. A diagrammatic representation of this control scheme is shown in diagram 7.3.

7.11 The O.C.E.P.S. Network as an Interconnected Power System

The O.C.E.P.S. simulation was initially designed to be a single area test network which had the ability of forming individual electrical islands, but there was no requirement to operate the network as an interconnected system. Clearly for the investigation of tie–line control the system had to be split into separate areas connected by several lines. As it was very difficult to change the system topology radically, it was decided to leave the whole system very much the same and to define a system split that could enable the system to operate as two interconnected areas. Thus several lines of the system were taken to be tie–lines which now connected two areas together. The lines chosen to split the system into two viable areas were 5, 6, 7, 21, 25 and 32. The normal operation of inter–area control is to monitor the power flow on these lines and to ensure that the power flow is kept to the scheduled values decided before operation for the transfer of power. In this case, the schedules were taken to be the normal operating power flows on the transmission lines. These values obviously change as the system requirements change, so in order to simulate a table of scheduled tie–line interchanges, the power flow was monitored on that set of lines for several days of operation. The following simulations were the only carried out for these specified days. The tie–line schedule was arranged so that for all operating times and conditions, each area controller was able to scan through the look–up table and choose the appropriate scheduled power flow for each line. Thus the overall power interchange could be achieved by considering all the individual power flows on the connecting lines. The diagram 7.4 shows the two areas into which the system was split. Generator units 1, 2 and 6 were in area one, with Units 3, 4 and 5 in area two.

7.12 Multiple Area L.F.C.

The L.F.C. function was altered to enable it operate in the multiple area environment [5,9,25,26,135]. The generator units available in each area were

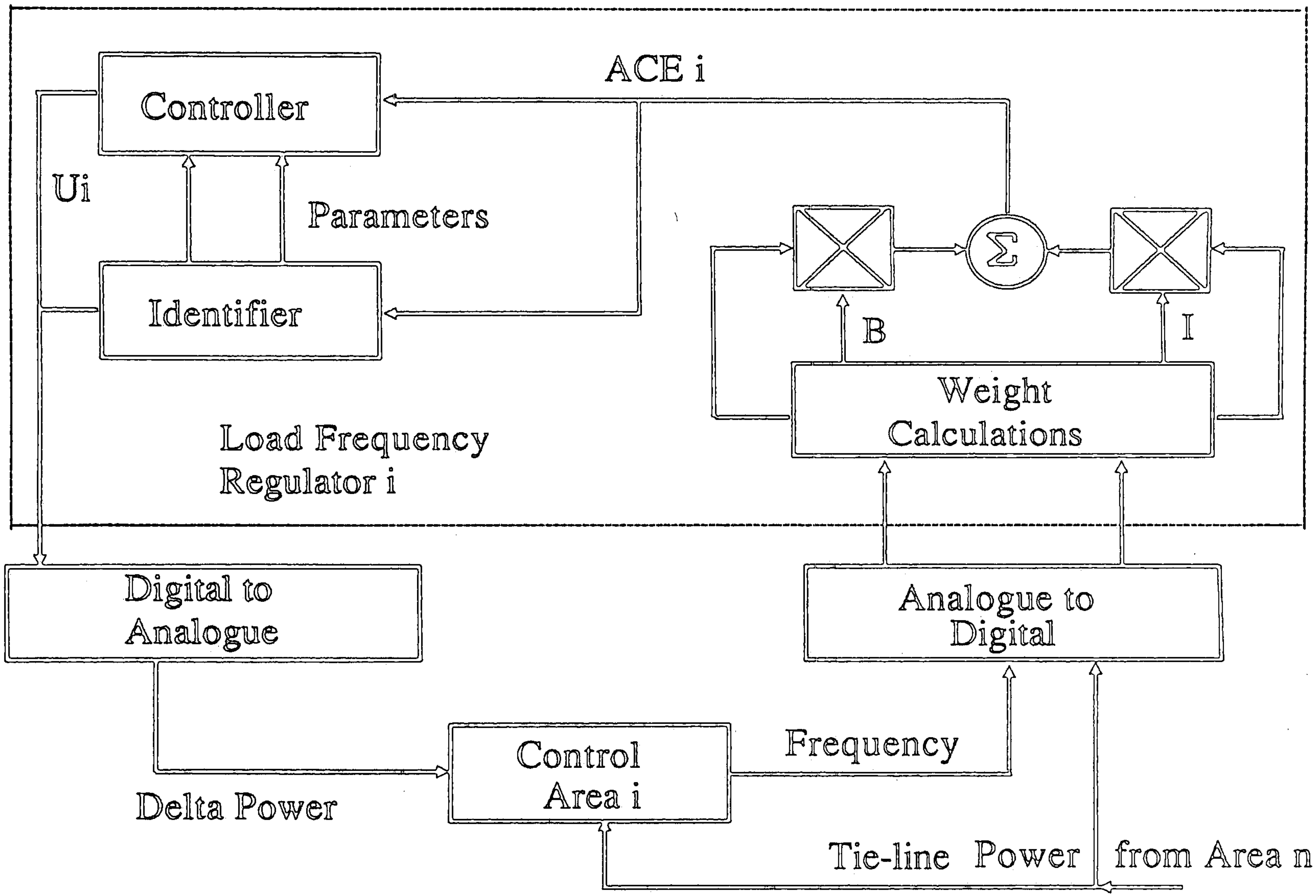
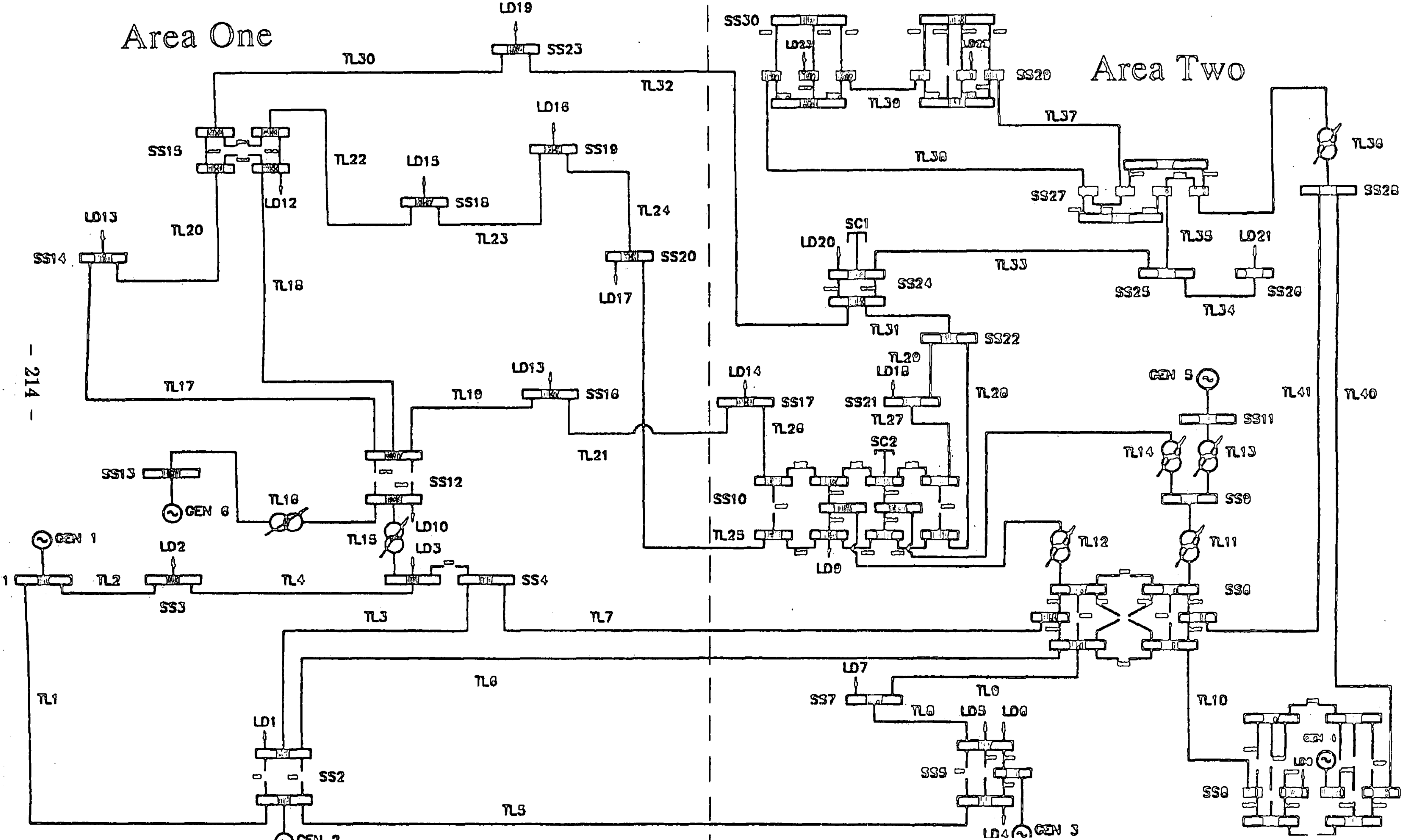


Diagram 7.3 Control Area i with Self-tuning Regulator

Diagram 7.4 O.C.E.P.S. Projcet thirty substation test system



assigned to a controller. For this case, the L.F.C. requirement was such that each area needed its own controller totally separate from that of the other area. In the actual case of operation it is unlikely that each utility would have any knowledge of the neighbouring areas operating conditions, so two separate controllers were required. A suitable frequency value for each area was measured in each area so that each area could operate as a totally independent island if the tie–line links were removed. The active power flows on the tie-lines was also measured and filtered as described previously for the frequency measurements. Together with the frequency error for each area, they were used to calculate the *C.R.* for each area, and used in the equations described previously.

7.13 Adaptive Control

This type of split operation is suitable for adaptive control techniques to be applied to as there is no requirement for the controller to know the state or make up of the system. This means that there does not have to be a set of predetermined controller constants. Clearly as the system to be controlled has changed quite considerably from the previous case, the adaptive properties of the controller enable it to control the individual areas and overall power flows in an optimal manner regardless of the changes to the system.

7.14 Interconnected Area Tests

The initial tests of the controller were carried out using steady–state operation of the system. To test the control action, based entirely on the tie–line error, a simulation run was carried out using purely the power error between that measured on the tie–lines and that scheduled. The results of this simulation are shown in figure 7.1 and 7.2. The tie–line error clearly has an effect on the control of all units in both areas. The alteration in the output of the units can be seen in the control signals of Units 1, 2 and 6. All these Units are in Area 1. The other Units in Area 2 are at full output and are hence unavailable to carry out control action. This method of control is suitable for the system frequency in the steady–state as shown in the frequency plot, but has undesirable effects on the generation units. The control action clearly needs to be calculated based on both the frequency error and the tie–line error. The following examples highlight the application of the previously discussed frequency controller as applied to an interconnected system.

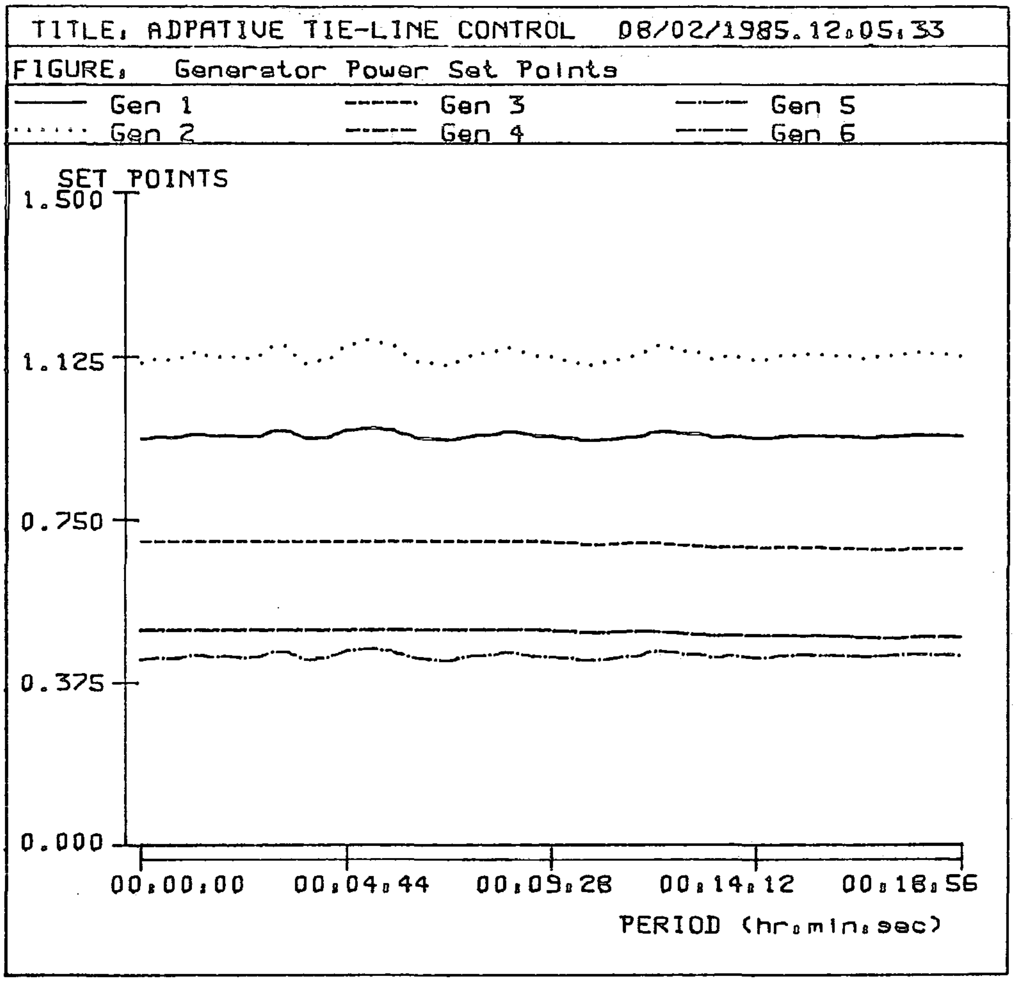
7.15 Steady–state tie-line operation

The controller was operated with a fixed set of frequency and tie–line weighting factors. Figure 7.3 shows the controller operation just after midnight. The output of the Units is low with the consumer load decreasing. The output of Unit 3 has been decreased over the period of the plot to match the change in consumer loading and to match the tie–line transfer constraints due to the two area operation. The lower figure, Figure 7.4 shows the frequency of Area 1 during the change in generation of Unit 3. The system frequency remains constant throughout the operating period. In this case, the frequency weighting was greater than that for the tie–line, so the tie–line power error has a proportionally smaller effect on the control action.

7.16 Generation Loss Incidents

The controller was tested under transient conditions to consider the effects of frequency and tie–line variable weighting and also the effect of changes in consumer loadings. Initially the frequency weighting factor was kept constant at a value calculated using the previously discussed equation (equation 7.21). Figure 7.5 and 7.6 show the overall system response to the loss of Unit 3 due to a fault condition. With the control effort weighted in favour of the frequency error, the error is reduced by the increase of generation in Area 1, although the loss occurred in Area 2. The response of the Controller is slower than it was in the single area case as part of the control error is obtained from the tie–line schedules, which are in effect operating in a sense opposite to that of the frequency error. This fixed biasing scheme is useful in some circumstances depending on the mode of operation of the interconnected system. If there are large penalties for incorrect tie–line operation clearly the weighting should reflect this, but if the frequency error is more important in the operation then

Figure 7.1



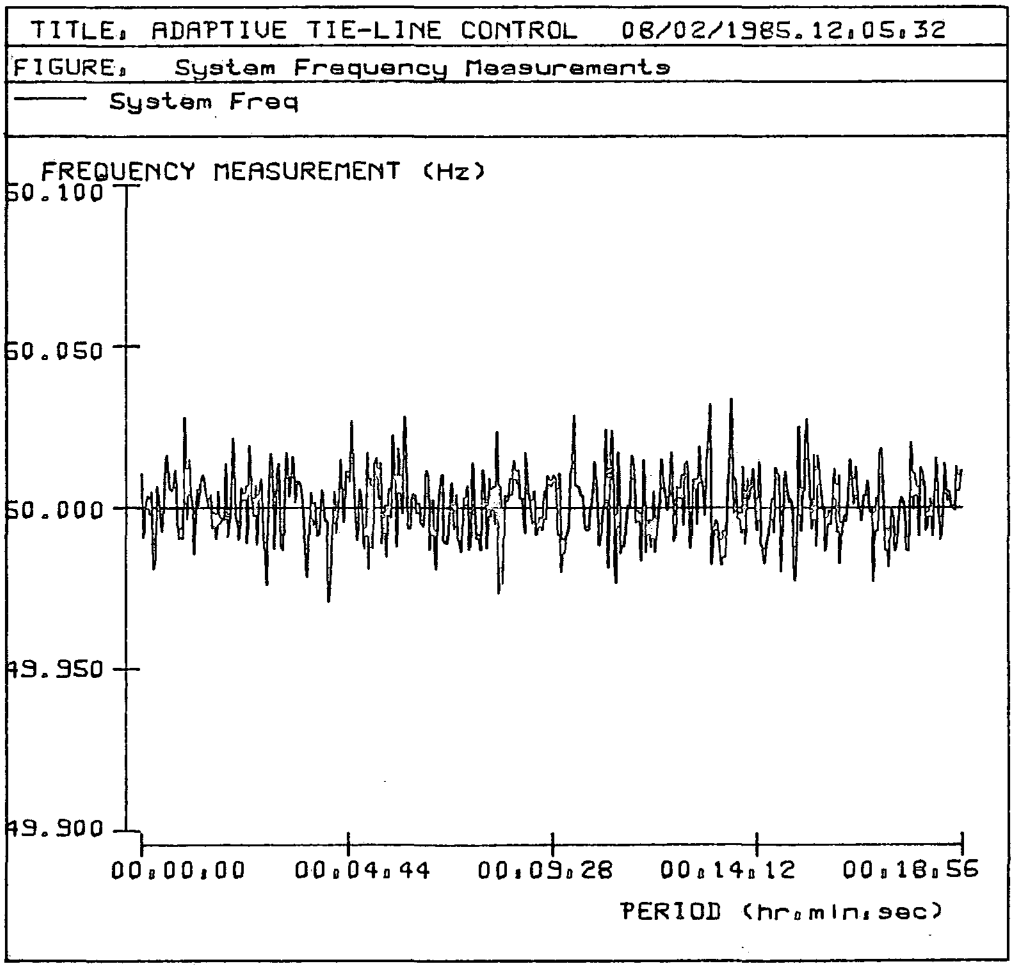
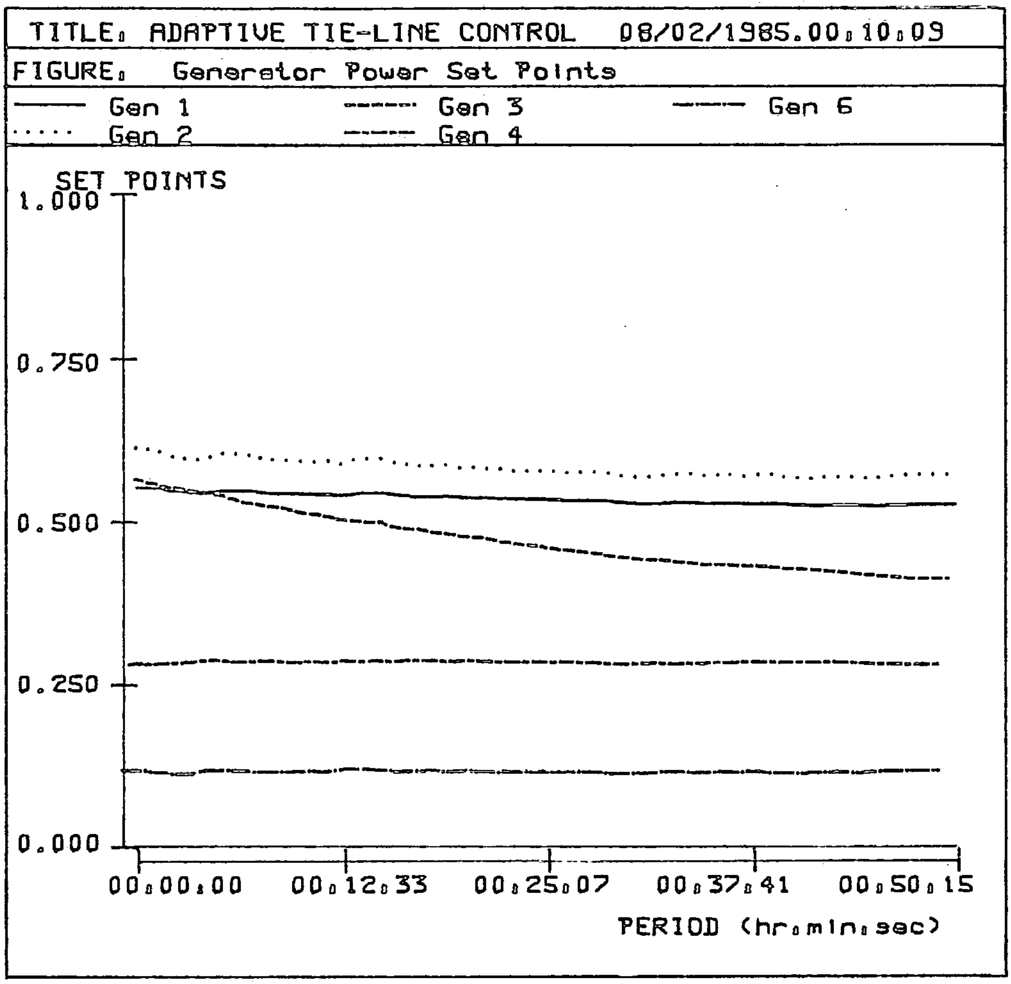


Figure 7.2

Figure 7.3



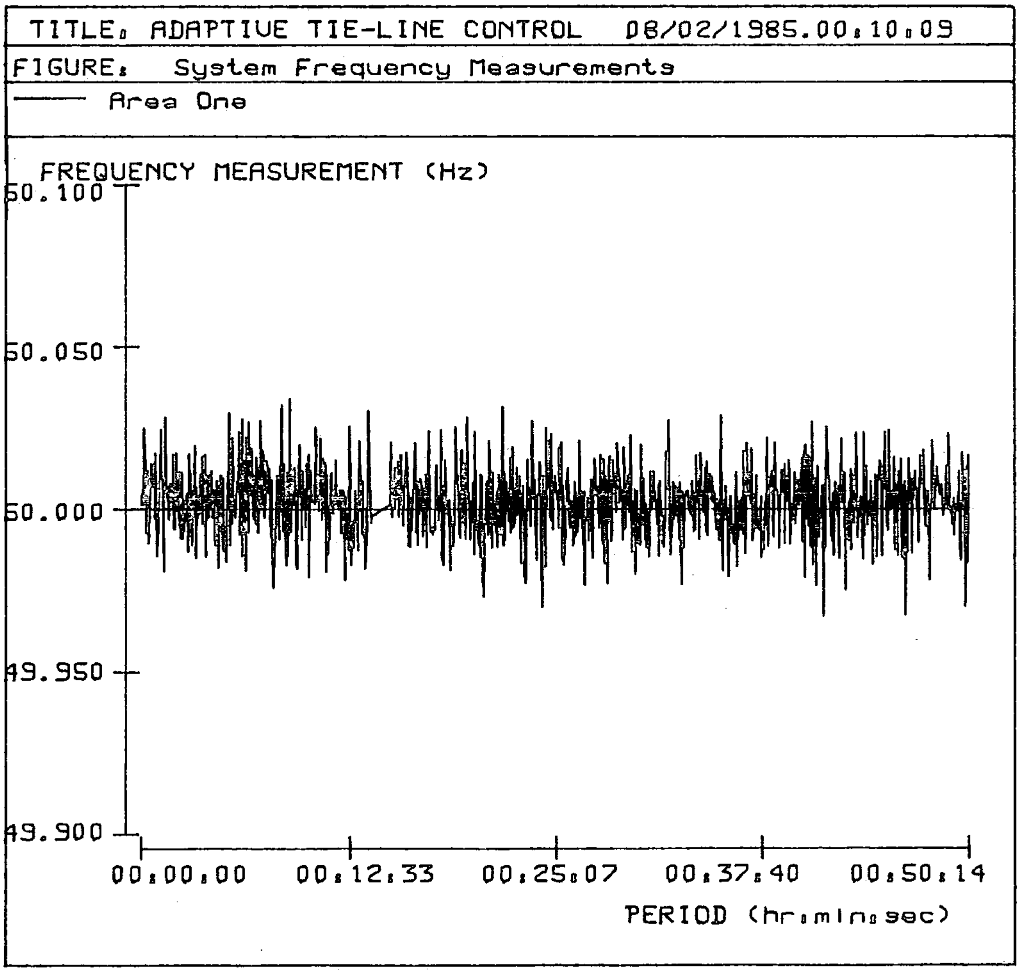


Figure 7.4

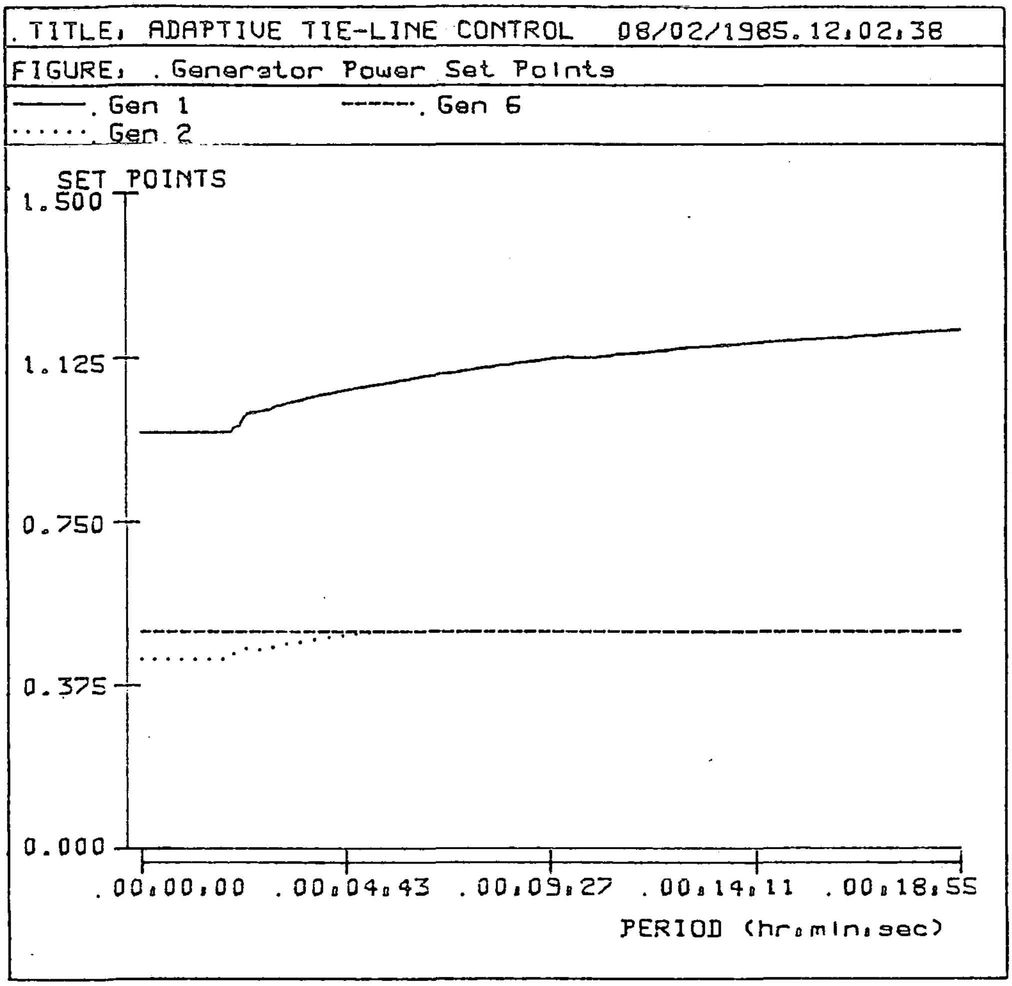
the weighting factor should reflect this also. The type of operation is dependent on the utilities within the interconnected system.

The effect of frequency biased weighting factors is shown in figure Figure 7.7. The figure show the effect on the interconnected areas of the synchronisation of Unit 3 in Area 2. The overall active power of the system exceeds that demanded by the consumer load and hence the output of the largest unit, Unit 1 is reduced. With the reallocation of power in the system the line flows change to accommodate the change in generation. The figure 7.8 shows the change in the power flow of line 5, which actually decreases because of the introduction of Unit 3. The line power flows are taken to be negative if power is flowing out of the node, thus in the figure, the power flow on line 5 actually decreases. The import of power into Area 2 has decreased on this line as dictated by the frequency error of the interconnected system, but the tie–line scheduled values are only effecting the power flows to a small extent. The level of the flows on the other tie–lines remains essentially unchanged.

Biasing the controller in favour of the tie–line scheduled values is shown in figure 7.9 and 7.10. The frequency error has less of an effect on the controller in this case. The effect of the tie–line error causes an overshoot of the allocated power shown by the response of Unit 1, which is then compensated for, and its output is decreased due to the frequency error. There is a steady–state frequency error after the incident because of the tie–line power biasing which clearly is not acceptable for standard frequency control but may be tolerated for tie–line operation.

The above incident is rather severe and rather unfair for the controller in such a small system, where the amount of generating capacity is limited in each area. The figure 7.11 and 7.12 shows a more realistic loss of a smaller unit, Unit 6. The control error is again weighted in the favour of the tie–line operation. The power flow on line 5 is changed after the loss of Unit 6, but as this unit is in the same area as Unit 1, the response rate of this unit is capable of making up the generation loss along with Unit 2. The Unit 4 responds in a similar fashion, to redress the loss of imported power as it is in Area 2. The

Figure 7.5



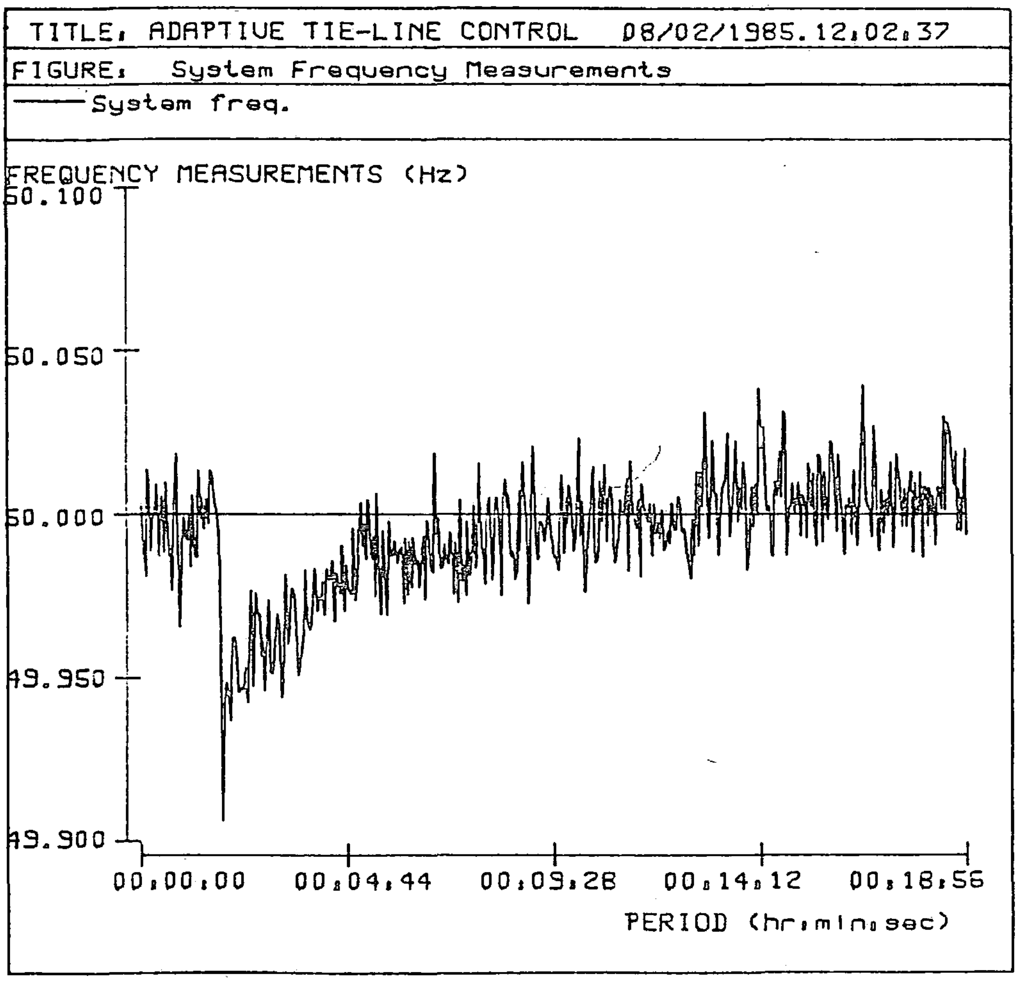
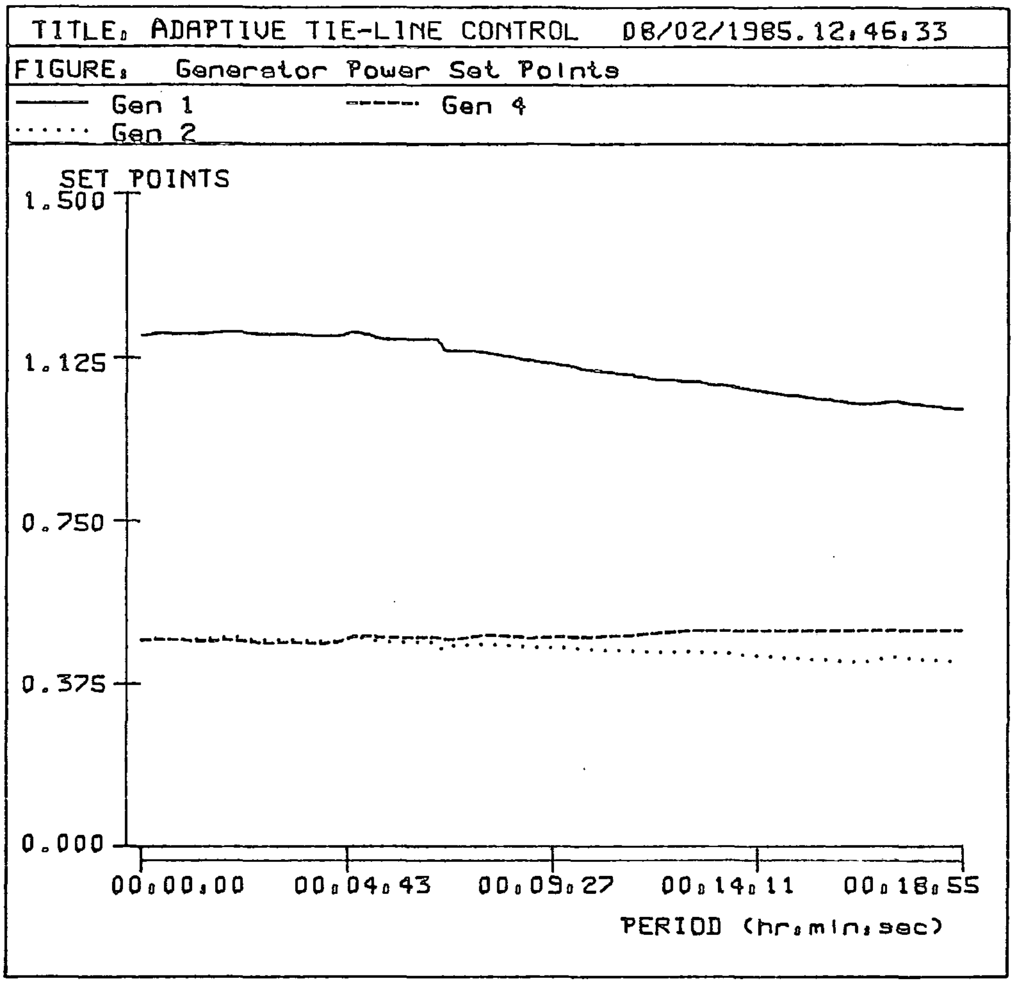


Figure 7.6

Figure 7.7



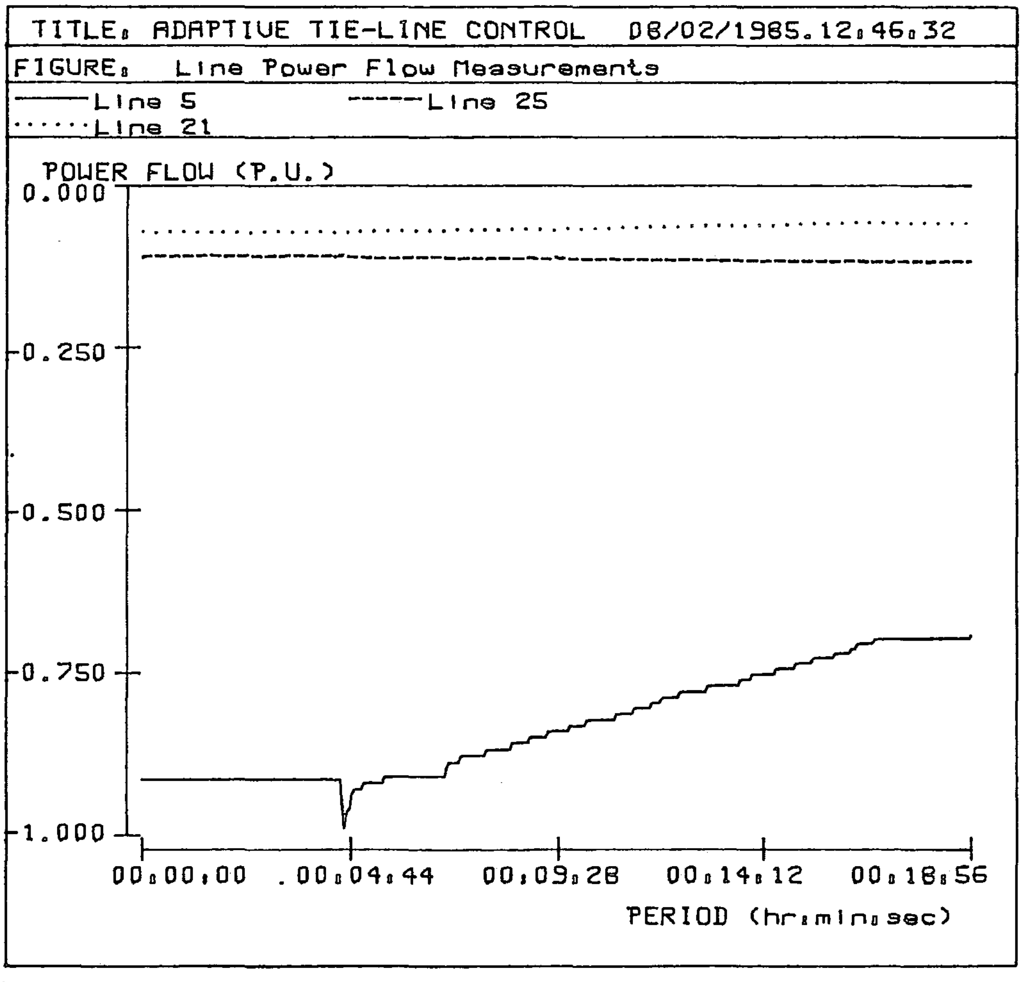
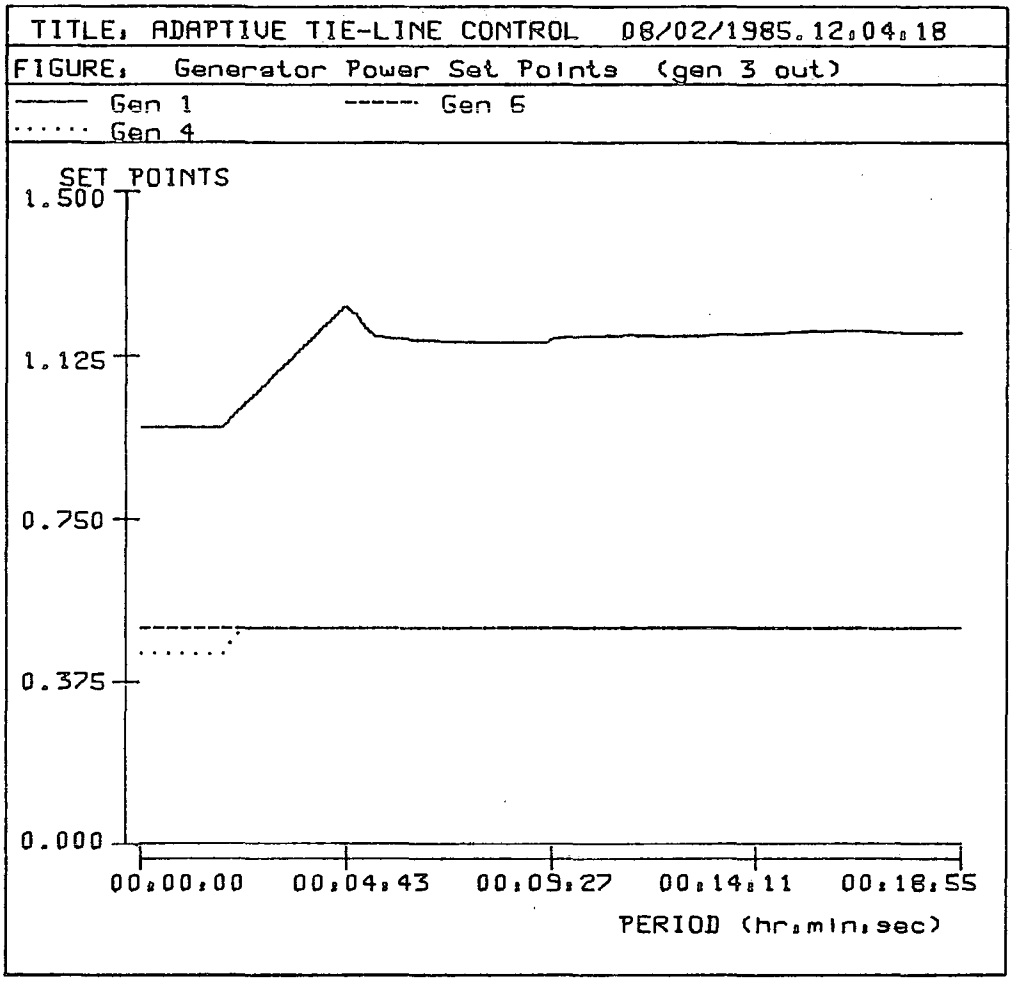


Figure 7.8

Figure 7.9



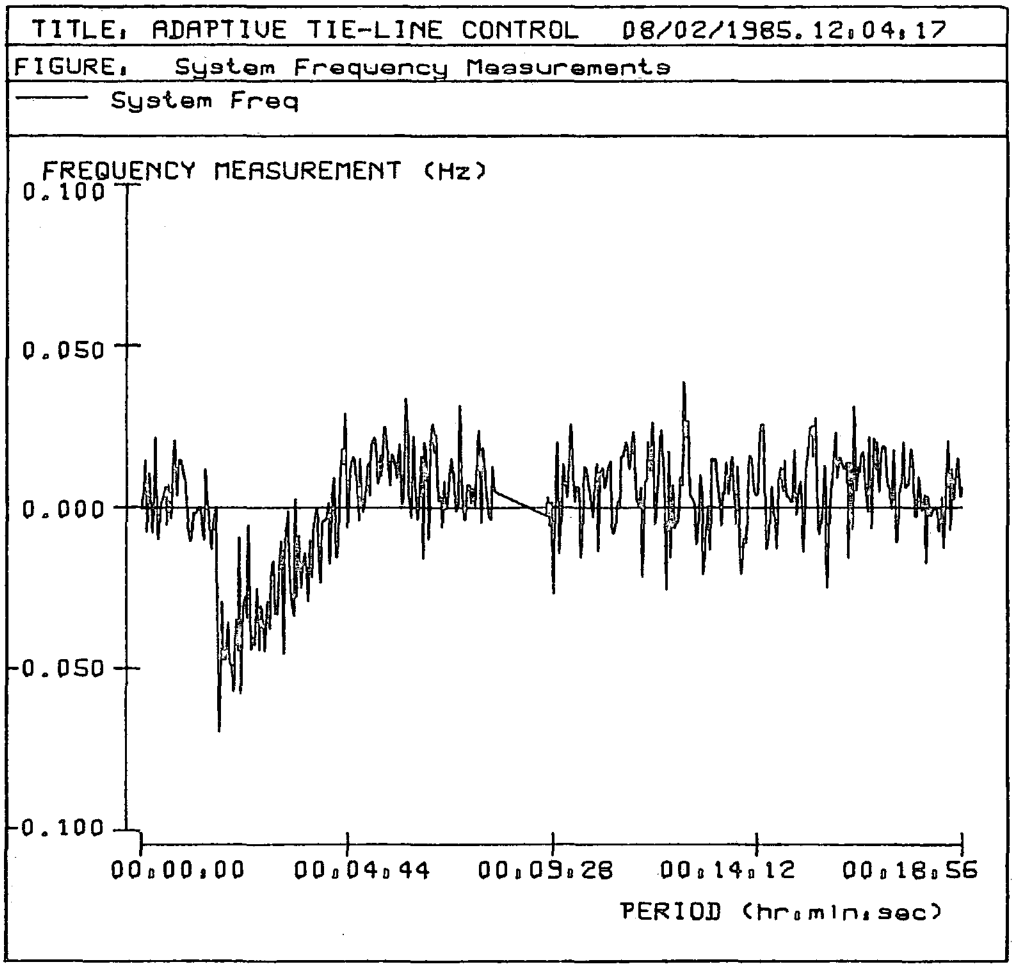


Figure 7.10

power flow on the line 5 is corrected after the initial change in flow and is returned to a steady-state operating position.

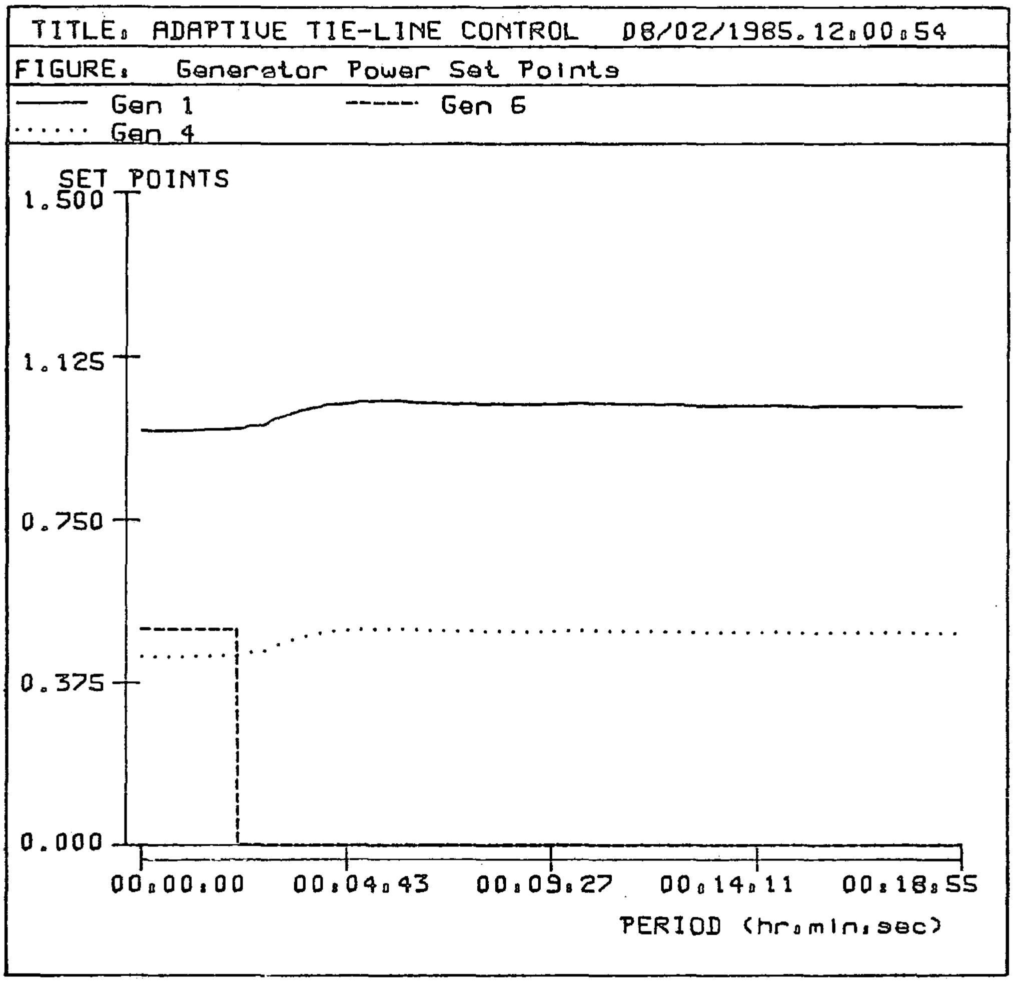
The synchronisation of a unit to an interconnected area can also cause problems for the control regime. Figure 7.13 and 7.14 show the effect of connecting Unit 3 to the system just after mid-day. Initially the frequency was above the average value due to a previous system incident. The controller was taking some action to reduce the frequency error, but a more severe transient was introduced on the system with the resynchronisation of Unit 3. The frequency of the system is reduced as the output of Unit 3 is increased by increasing targets from Economic Dispatch. The output from all the other units on the system is decreased to account for the increase in generation above that required by the consumer load.

7.17 Variable Weighting Factors

The use of fixed weighting factors has been discussed above. It is shown to be useful in certain circumstances where the control of one of the variables is more important than the other. However, in many interconnected areas the minimisation of both of the errors is required for standard operation. Earlier, the use of variable "forgetting factors" was discussed to enable the weighting scheme to change dynamically in an effort to reduce the error of both of the independent variables.

Figure 7.15 and 7.16 show the effect of the use of the variable weighting factors on the interconnected system. The figures show the effect of the increasing the load in Area 1. The frequency of the interconnected system immediately decreases as the system inertia is insufficient for the consumer load. Clearly, the tie-line interchanges must increase to accommodate the new operating conditions and this was allowed for in the tie-line schedule look-up tables. As determined previously, as the load increased suddenly, the tie-line flows were altered to match the required new set of power flows. System frequency recovers due to the control action from all the available generators, as both the frequency error increases and the tie-line target values change.

Figure 7.11



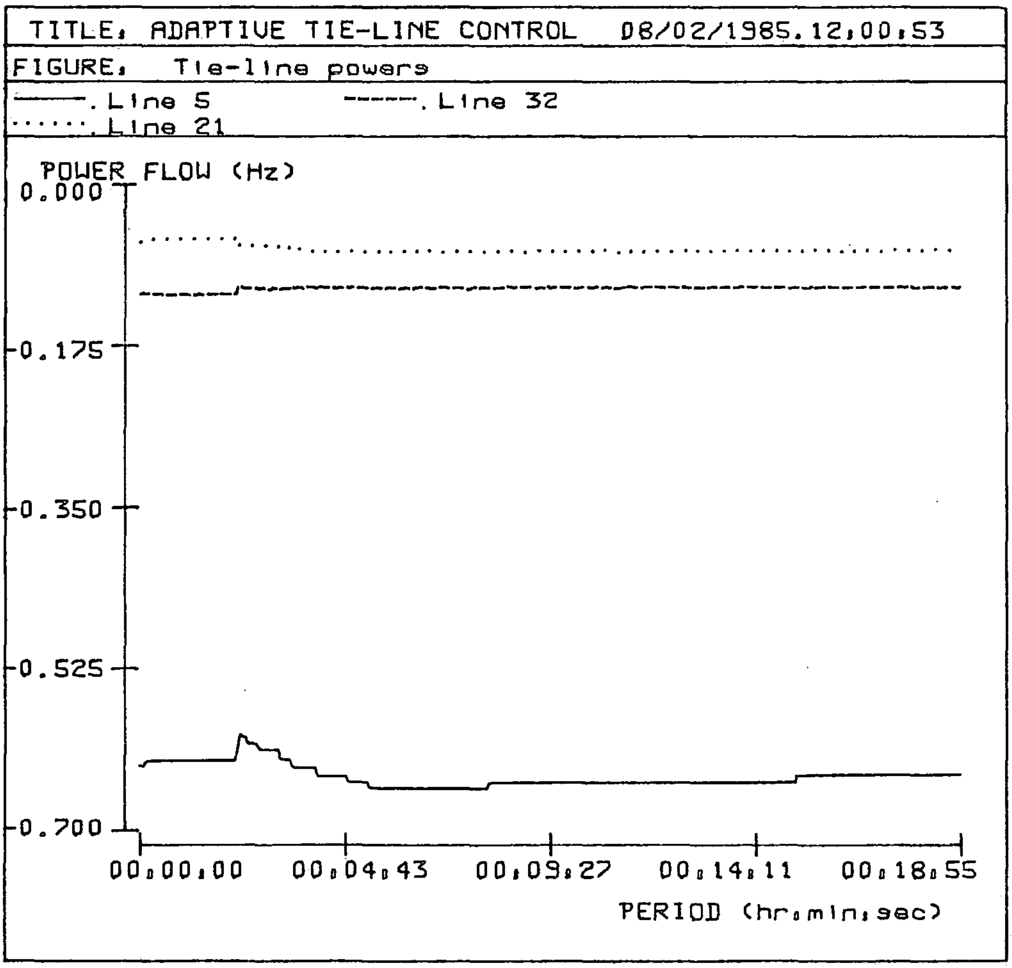
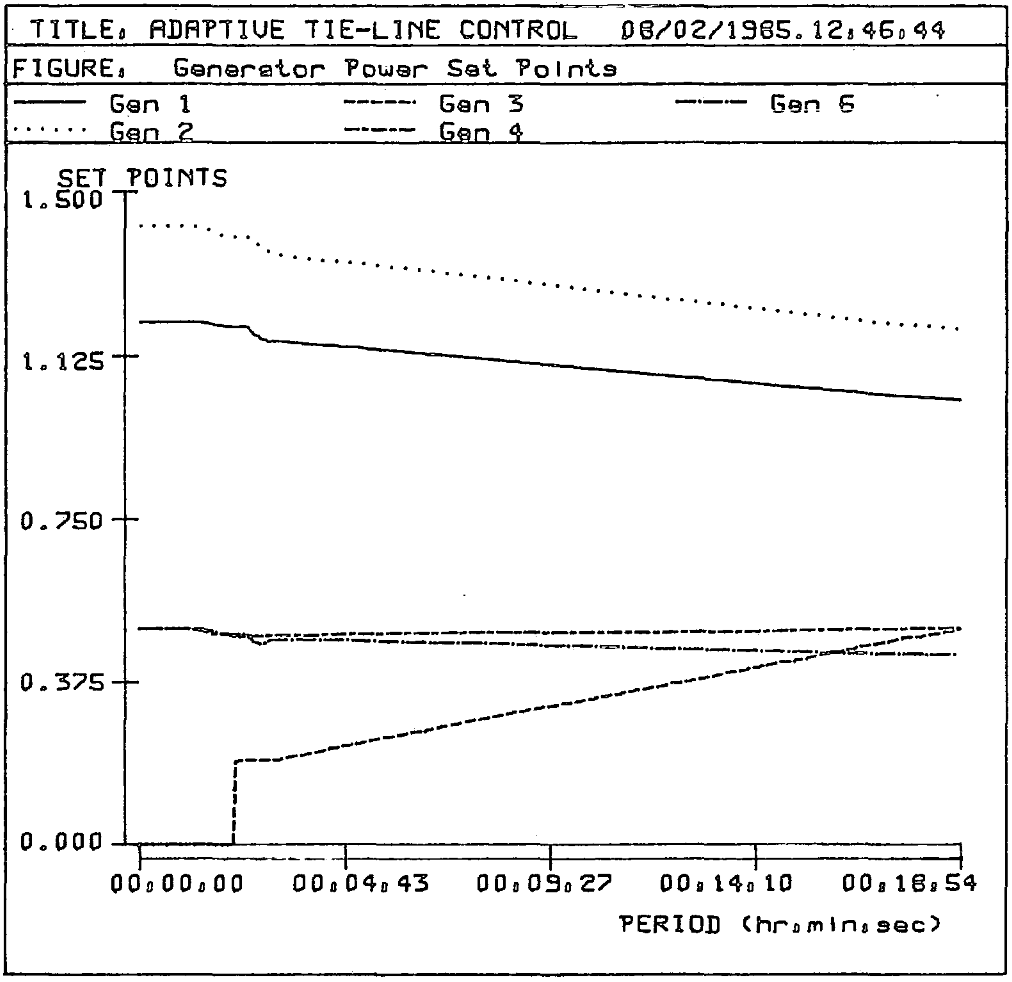


Figure 7.12

Figure 7.13



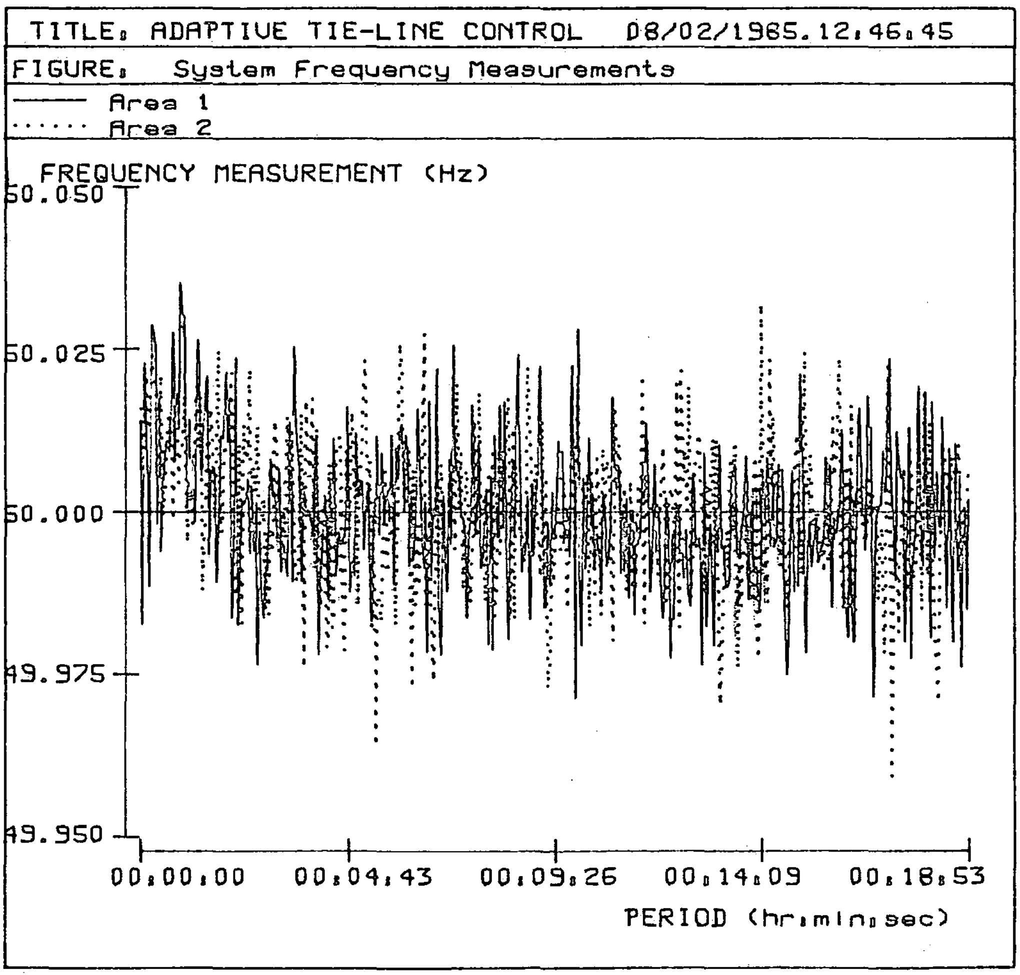


Figure 7.14

Again the frequency is retuned to its nominal value in a a suitable time period due to the change in weighting and the change in the power flow targets.

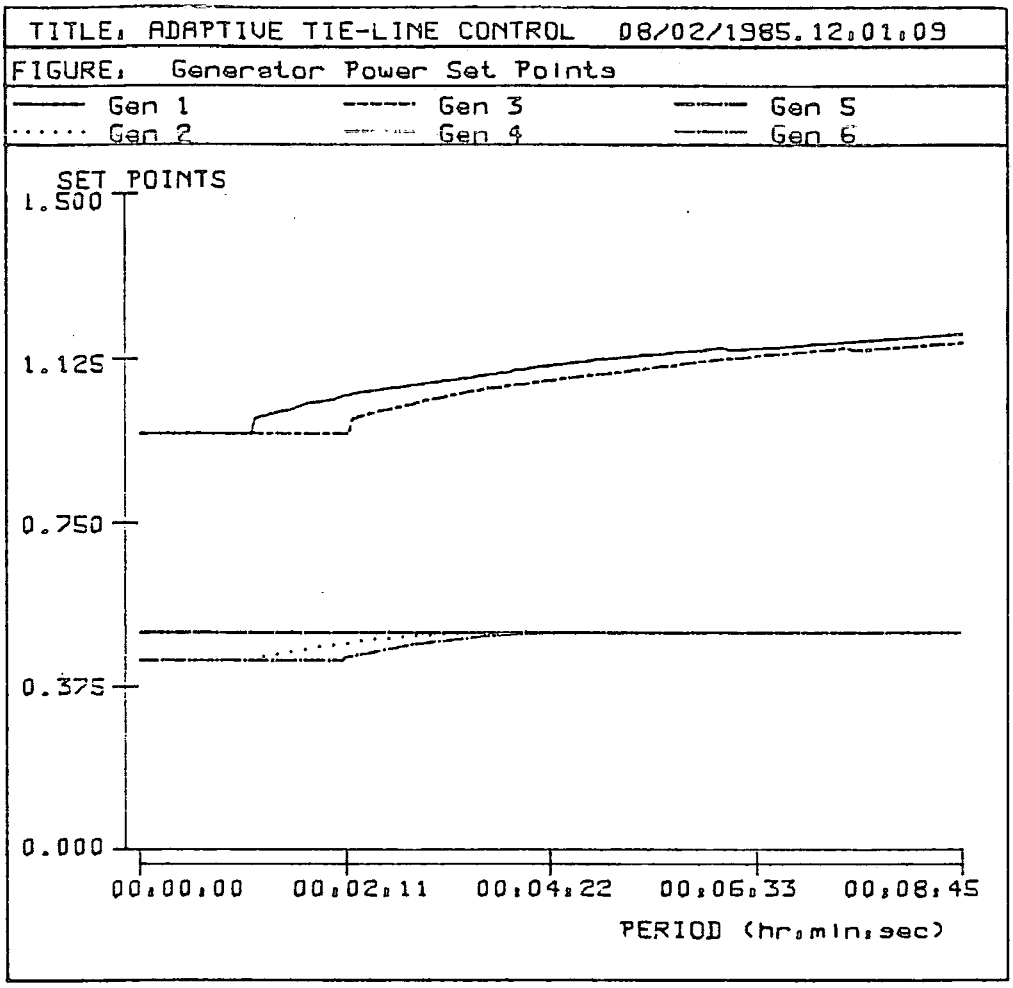
The problem of changing the tie–line schedule on–line could cause problems on the system, if the change was carried out abruptly. In fact a sudden change in the schedule power flow values could have the same effect as the loss of a medium size generator of change in system load. Thus, the scheduled values for the tie–line interchange were altered progressively between differing operating levels. Figure 7.17 and 7.18 show the effect of this gradual change. It was scheduled that the Units in Area 1 should increase their power outputs to simulate a change in generation pattern of the interconnected system. The top figure shows the increase in output of the Units in Area 1, with a corresponding decrease of the outputs in Area 2. The frequency trace over the same period shows that the transition of the change in generation was successfully completed without causing any undue transients on the system.

The effect of the loss of a medium size generating unit along with variable frequency weighting factor was investigated by the manual tripping of Unit 5. During the mid–day load cycle, Unit 5 was removed form the system. The figures 7.19 and 7.20 show the effect that this generation loss incident had on the system. The power flow on line 21 decreased, with the change in power being moved to line 6. The flow on line 21 remains essentially the same after the incident as before the loss with a period of change due to the change in the pattern of generation. The set points of the units in Area 1 clearly must increase to replace the loss of Unit 5. In this case the other units in Area 2 are at their maximum outputs, so are unavailable to take any control action.

7.18 Conclusion

This chapter has considered the use of a self–tuning A.G.C. scheme for interconnected power systems. A review of the reasons why utilities may wish to connect their power system to a neighbouring one was followed by a discussion of the problems of controlling such a set–up. The use of adaptive control techniques for the control of the inter–area frequency and tie–lines was

Figure 7.15



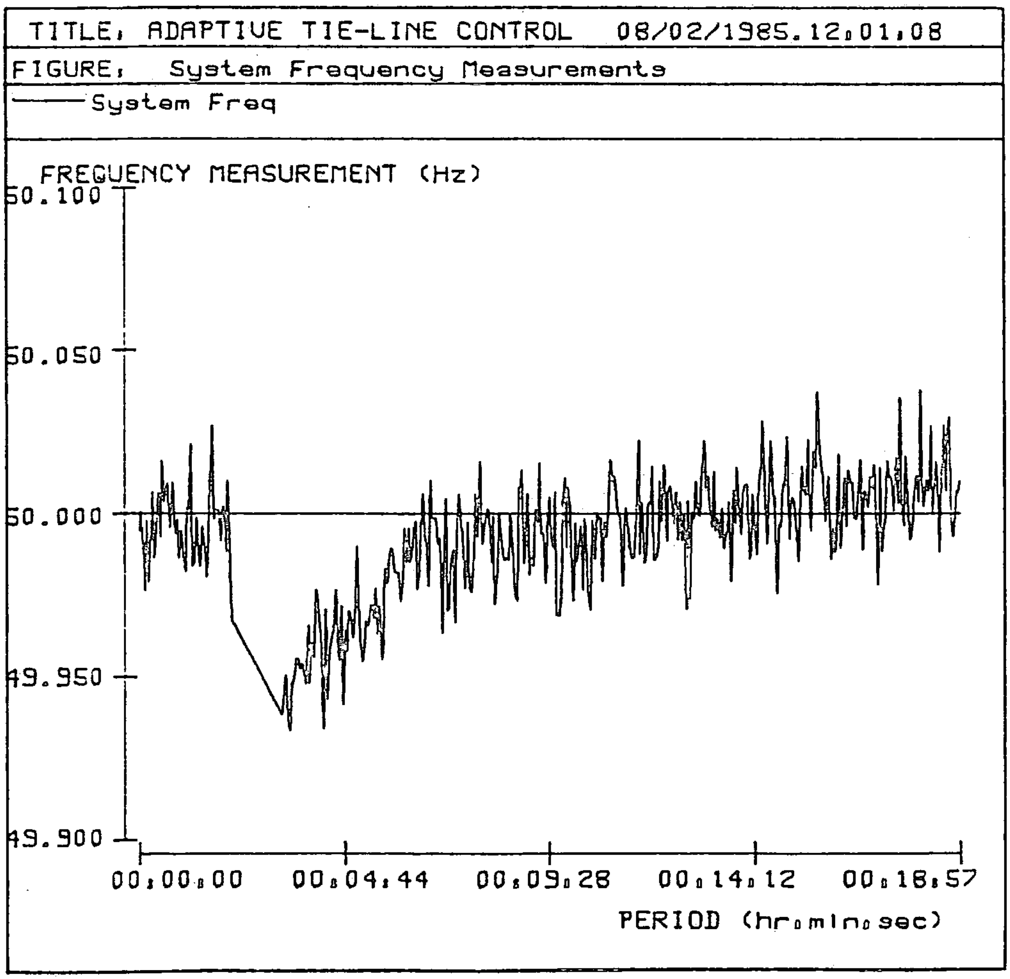
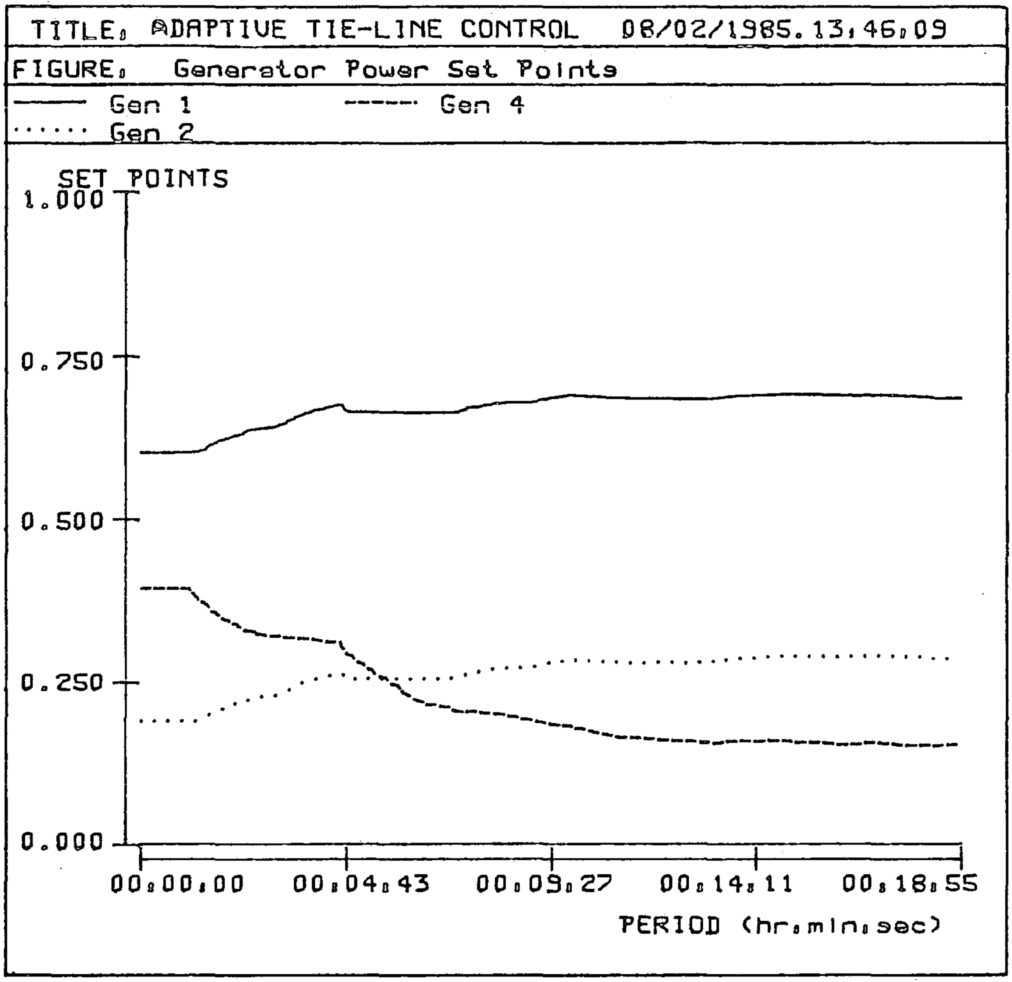


Figure 7.16

Figure 7.17



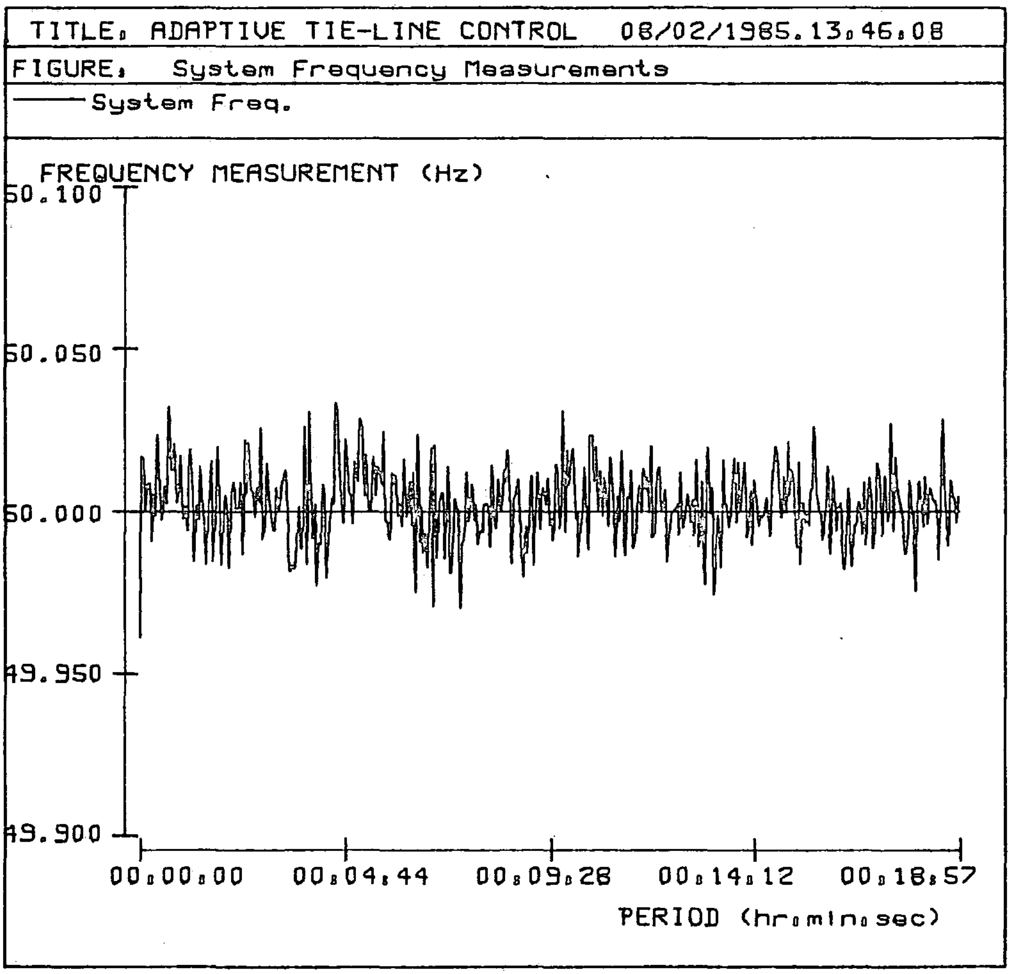
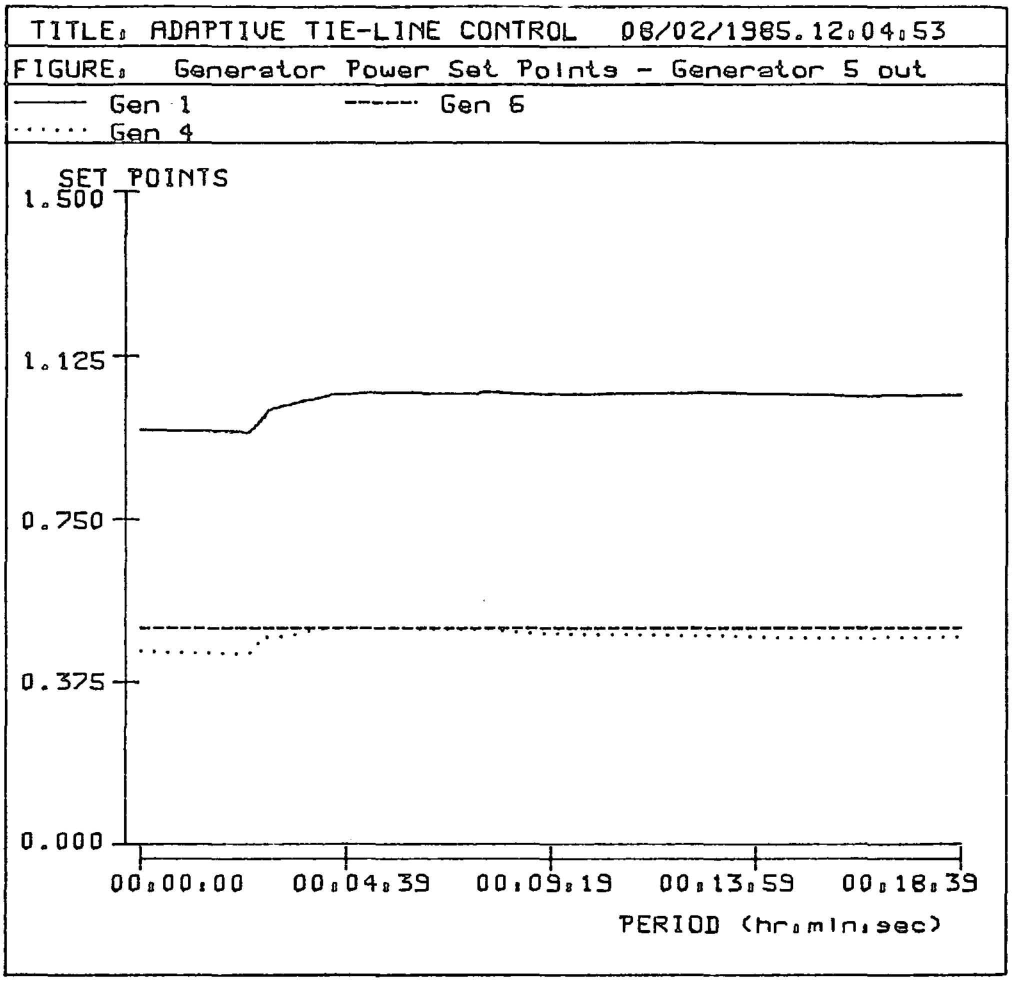


Figure 7.18

Figure 7.19



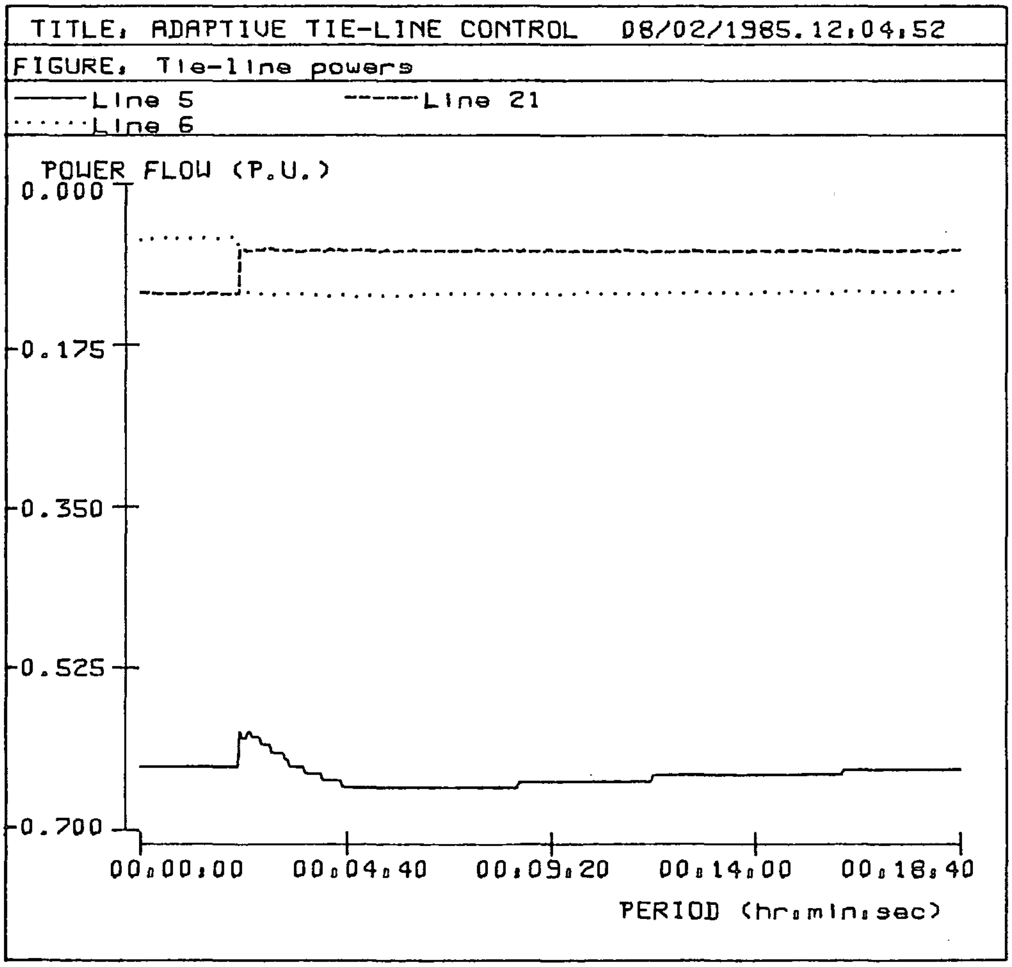


Figure 7.20

discussed in detail, based on the ideas presented in the previous chapter for single area operation. The alteration of the single area controller to enable it to interact with other such controllers in neighbouring areas was discussed, along with its implementation.

The proposed controller was implemented within the O.C.E.P.S. control scheme. Using the simulator to create two separate areas numerous tests were completed to investigate differing control strategies. The use of fixed frequency weighting factors, variable weighting factors and tie–line scheduling was investigated. The results were presented of the controller action along with the effect of this action on the system indicated by the joint system frequency or the change in the tie–line power flows.

It is seen that using a controller with a variable frequency weighting factor in neighbouring areas suitable inter–area control can be achieved. The changes in configuration of either area are accommodated for by the ability of the controller to adapt to the system operating conditions at any given time. This enables the controller to be used without the need for pre–tuning, or the manual alteration during its operation. The control of the tie–line power flow and the frequency error can be minimised with respect to each other using the described techniques, leading to a optimal and robust control scheme which is able to respond to a variety of system incidents.

CHAPTER 8

MODEL FOR POWER SYSTEM SIMULATION

8.1 Introduction

A simple power system model is proposed in this section, using as a basis equations suggested to the author by the Central Electricity Research Laboratories. The model was designed to give a reasonable representation of the response of the whole of the Central Electricity Generating Board's generating system. The model was constructed to represent the response of the generation system and consumer load, but was not designed to represent any of the transmission network, which is not required in the description of a model to be used for the testing of Load Frequency Control techniques. This would only lead to more complexities in the model which are unnecessary. For this reason, the model of the generators used is greatly reduced when compared with that, used by the Operational Control of Electrical Power Systems (O.C.E.P.S.) simulator for example. The model presents a fair response of the system in question without having to use complicated and time consuming mathematical models and methods. Hence, the model can run in an off-line sense, enabling several hours of real-time operation to be simulated in several seconds.

The simplicity of the model allows test routines to be run repeatedly and quickly with the same start-up conditions and parameters. As this system is simplified, it does not require any of the lengthy and complicated setup, or involved control and monitoring procedures which are used in advanced simulation and energy management systems, such as the O.C.E.P.S. simulator and control package [186]. The model also enables the effect of the command signals calculated by the control algorithm under test to be seen directly. The signals are not filtered by other command and control procedures which could influence the calculated control signal, and in some cases totally remove its effect. The simulation was initially designed to simulate 240 minutes running time, which was felt to be a good compromise between the execution time of the computer and the amount of data produced.

8.2 The System Model

The model is designed to give a response that closely follows the total system output response of the entire C.E.G.B. [10,41,193,223] generation system. Although this reduced model does not allow for the more advanced control techniques, such as the introduction of Economic Dispatch and Unit Commitment to be studied, and their interaction to form a fully integrated energy management system with Load Frequency Control, the model is suitable for the purpose for which it is designed. This simplified model represents all the essential elements in the actual system, to such an extent that the response of the model to a disturbance closely follows that of the actual system. The model is made up from a number of transfer functions which model different parts of the system in question. Clearly the generators must be represented to a suitable degree of accuracy, along with the change of the consumer load, and its response to change in generation. The model also represents the response of generators which are not available in the O.C.E.P.S. simulation, such as pumped storage units. The representation of these units are essential if the C.E.G.B. system is to be modelled to any degree of accuracy. The model itself consists of

(a) a load change to drive the simulation,
(b) a transfer function to represent the inertia of the system,
(c) the response of the consumer load to the change in generation,
(d) the response of the generators to a change in system frequency, and
(e) a simulation of the manual dispatch which is presently used by the C.E.G.B. while running the system.

The size of the system which is simulated by this simulation program is 50 GVA, a true representation of the actual system. The generator response is made up from two main types of generators. Their responses are sustained and non-sustained, which gives the characteristic frequency response to a step load change, this being a rapid decrease in frequency and then a recovery, and then a slow decrease again. The decrease is governed by the proportion of plant which has sustained and non-sustained responses. Later a pumped-storage model was introduced so that its effect could be seen on system operation. The system model is designed to simulate the perturbation of the output about the normal steady-state operating conditions, hence, long range dispatching is assumed to have been carried out, and the load disturbance is due to the error of the load prediction, rather than that of the total system load. The frequency error produced by the simulation is that error from the standard operating point, that is, the deviation from 50 Hz.

The various model elements of the simulation are now considered, along with a discussion of the mathematical techniques used to solve the equations.

8.3 Load Change

The model is intended to give the predictive error of the load, and not the total load variation. This predictive error is based on work carried out at C.E.R.L. to simulate actual system loadings. The error on the prediction, (the load error) is represented by a random walk given by

$$\text{load error} = \text{power system size} \times 200\ \text{MW}^2 \quad \text{per minute}$$

This random walk is limited at 30 minutes to

$$\text{power system size} \times 6000\ \text{MW}^2$$

The sample interval is 12 seconds, which enables the computer code to be somewhat simplified. The prediction error is limited for practical reasons rather than theoretical ones. The dynamic range of interest of the simulation is, for example, 1 to 30 minutes, and if the variation is not limited, the load prediction error becomes increasingly large. The prediction errors are stored in a ring buffer arrangement, so they are continuously circulated through the buffer, and used as and when required by the program.

The random walk is generated by the addition of normally distributed random variables. The random variable function is generated using 10 evenly distributed random numbers and removing the mean. This value is then scaled to give the 200 × random variable MW^2 per minute which is required for the 50 GVA system. The load randomness is assumed to increase linearly with the system size. The load error once calculated, becomes the driving error for the simulation.

8.4 Numerical Integration Techniques

The system model is represented by a set of differential equations, which must be solved simultaneously to sufficiently describe the physical system. The solution of differential equations involves the process of integration. This process must be carried out in the computer by replacing the analytical integration by some numerical method which calculates an approximation to the true analytical solution [35,193].

Consider a continuous signal $x(t)$. This may be represented by a series of values $x_0, x_1, x_2, \ldots, x_n$, which define the signal amplitude at corresponding times $t_0, t_1, t_2, \ldots, t_n$. These sample values are usually equally spaced time intervals, and if the sampling interval is chosen to be small enough, then none of the information about the signal is lost. Usually a sample frequency of at least twice that of the signal under study is required to stop effects such as aliasing. Clearly the smaller the sample used, the more faithful the reproduction of the original signal will be. This is also true for the solving of the equations. The smaller the time step used, the more accurate the end result will be. This value varies depending on the application but is always when the calculated values were made available to the control algorithm. The sample interval for this simulation was chosen to be a twentieth of the time interval that was being simulated. Using this discrete representation of the continuous signal, differential equations are converted to difference equations and integration may be carried out in a stepwise fashion. The solution of difference equations requires the integration of a signal, $\dot{x}(t)$, which itself is a function of $x(t)$. As an example of this, consider the first order differential equation

$$\dot{x}(t) = ax(t) + bu(t) \tag{8.1}$$

If the value of $x(t)$ is known at time t, the value of x at time $t + \Delta t$ is given by

$$x(t + \Delta t) = x(t) + \int_{t}^{t+\Delta t} \dot{x}(t)\Delta t \tag{8.2}$$

However to evaluate this integral, it is necessary to know $x(t + \Delta t)$. There are many intergration routines to choose from, which will enable the next value of $x(t)$ to be estimated. To solve a differential equation, the unknown trajectory $x_1, x_2, x_3, \ldots, x_n$ is built up progressively, one integration time step at a time, starting from a known value of x_0.

One of the simplest integration algorithms is the Euler Method, which assumes that the function to be integrated and the derivative function, remains unchanged from t to $t + \Delta t$, with the value which it has at time t, that is $\dot{x}(t)$. Thus $\dot{x}(t)$ may be found using

$$x(t + \Delta t) = x(t) + \Delta t \dot{x}(t) \tag{8.3}$$

This shows that the values $x(t)$ and $\dot{x}(t)$ are used to estimate $x(t + \Delta t)$. For a specified input function $u(t)$, starting at a known initial output value $x(0)$, equations (8.2) and (8.2) can be alternatively and repeatedly applied to calculate successive values of the output functions.

$$\begin{aligned}
x(\Delta t) &= x(0) + \Delta t\{ax(0) + bu(0)\} \\
x(2\Delta t) &= x(\Delta t) + \Delta t\{ax(\Delta t) + bu(\Delta t)\} \\
x(3\Delta t) &= x(2\Delta t) + \Delta t\{ax(2\Delta t) + bu(2\Delta t)\}
\end{aligned} \tag{8.4}$$

and so on to complete the time interval.

The Euler Method is useful to understand the use of numerical integration routines, but it is not often used in practice as it uses a poor estimate of the mean value of the derivative function for the time interval Δt. For better accuracy of a given integration step size, multiple stage algorithms are used. The Euler Method may be improved by using a two stage process, this is termed Improved Euler Method. The Improved Euler Method uses the original Euler Method to estimate a first value of the next point. The derivative at this point is calculated from this estimated point, and compared with the derivative at the start of the time step. The average of these two derivatives is calculated, and then used to calculate the value of next point.

There is a further extension to Euler Method, known as the Modified Euler Method. This again uses a two stage calculation, firstly an estimate of the midpoint between the present point and the next point is obtained. The midpoint derivative is calculated and this is used to calculate the value of the next point. This more complex and accurate method was used to solve the differential equations for the generator models in the system simulation. This calculation is repeated for the number of times the simulation time interval has been sub-divided into, and hence, accurate answers at the end of each simulation time interval can be found.

More complex methods are available, such as methods that only use the current value to estimate the next value, but estimates three, or more, usually four derivatives to do this. This method is called the Runge-Kutta Method. A more advanced class of integration algorithm uses predictor-corrector methods, which make use of both present and past values to predict the next value and then correct the predicted value by an appropriate algorithm, the prediction and the correction sometimes being done iteratively. However, these methods are far more complex than required for the accuracy of this simulation. The integration routine used in the simulation was the Modified Euler Method, using a time step of one twentieth of the time interval. This does not pose great overheads in the computational time, and produces accurate answers.

8.5 Inertia Model

The inertia of the system represents the total of all the rotating masses in the system as described earlier. This is modelled using the following transfer function.

$$\Delta f = \frac{\Delta P}{T_s s} \qquad (8.5)$$

where

Δf is the system frequency error, in Hz, the driving error for the generators and the control functions,

ΔP is the power error, in MW, that is, the difference in power between that demanded by the load and the mechanical power that is supplied by the turbines, and

T_s is the system time constant. This is given by

$$T_s = PS \times H_s \times 0.667 \tag{8.6}$$

where

PS is the power system size in GVA,

H_s is the specific system inertia and is assumed to be 10 MW sec/MVA. The factor of 0.667 is introduced to describe the response of the load, in response to the change in system voltage. If system voltage decreases, this is followed by a reduction in the consumer load. If the factor is not introduced, then the typical response curve is not followed exactly as predicted by the equations.

8.6 Load Response

There is a change in the response of the consumer load in response to a change in system frequency. This is due to frequency sensitive loads, such as induction motors which and are included in the model. The load response is assumed to be 2% per Hz. The change in the consumer load is taken to be

$$U_l = \Delta f \times PS \times 20 \text{ MW} \tag{8.7}$$

where

U_l is the load response, in MW,

PS is the power system size, in GVA, and

Δf is the frequency error, in Hz.

8.7 Generation Response

Turbine generators are extremely complicated, large systems in their own right. The terms non-sustained and sustained response are introduced in an attempt to reduce these systems into a form that may be approximated by simple mathematical equations. These equations are used to describe the response of the whole turbine generator system, both thermal and electrical.

The turbine generator as explained in an earlier chapter is made up of a boiler, turbine and electrical generator, along with the support equipment. Hence, when they are designed initially, it is very difficult to determine the exact response characteristics, as their response is a combination of many different factors.

Consider a machine which is on part load. If the valve is opened further, the initial inflow of steam to the turbine will enable the unit's output to be increased. After a given time period, the boiler will not be able to support this amount of output as its reserves are drained, hence, the power output of the machine will decrease, unless the boiler firing rate can be changed quickly enough. Consider the movement of the steam from the boiler which is saturated, then superheated, and then loses its energy in the turbine and becomes non-saturated. This is clearly a very complex process in which different thermodynamic laws operate at each stage in the transfer from wet steam in the boiler to dry steam in the turbine.

If a turbine generator is considered at full load, with the governor fully open, a drop in system frequency will require an increase in the unit's output. The governor demands more output from the electrical generator, and inturn the output of the turbine must be increased. This implies that the boiler is able to produce more steam, but this is governed by the steam path. The efficiency decreases as the speed increases, and if no more fuel is fed into the boiler, the reserve in the boiler will be depleted. Hence, while the unit's output will initially increase as the boiler loses its steam reserves, these are not replaced, so the unit's output will then begin to decrease, and may decrease to a level below that at which it was operating previously. This is termed as non-sustained generation, as there is no mechanism of sustaining the unit's output from its reserves. A sustained unit, as its name suggests, is capable of sustaining its change in response for a longer period of time. In this case, the unit is less constrained than in the previous example, has fewer steam losses and its boiler reserves cannot be depleted so easily or quickly. Hence, it can continue to operate at a particular increased output level for longer, before decreasing its output.

Generally the more modern the machine, the more capable it is of operating above its design limits. For example, the 500 MW machines were generally not capable of operating over their limits, but the more modern 660 MW machines may have some spare capacity. These machines may be capable of operating at 690 MW for extended periods, peaking at 720 MW.

The response of the unit is dependent on the operating position of the unit at any given time. If a unit is operating in the middle of its range, then it will be more capable of increasing its output more rapidly, than for example, one which is at its upper limit.

The time period of response also has a bearing on the response of the unit. If the time scale for governor operation is being considered, the reserve energy in the system will be more capable of responding to and supporting a change in demand than it would for a longer time scale control. For the period involved in considering Load Frequency Control, the boiler dynamics tend to dominate the response, but really the mill response time should also be taken into account. There are no control schemes at the present time which place the control of the boiler under that of an automatic generation control scheme.

The generators in the model represent all the system generators lumped together as one unit, and hence could be described by one transfer function. However, the representation of the units is split up to give two types of response, as described, sustained and non-sustained, in an attempt to produce a realistic response. The mechanisms involved are clearly very complex and cannot be modelled exactly using the techniques explained in this section, of lumped parameters. However, the overall response of the simulation is an adequate representation of the system as a whole. The system is shown in diagram 8.1.

8.7.1 Sustained generation

The response of the sustained generation is given by the following transfer function

$$P_s = K_s \Delta f \tag{8.8}$$

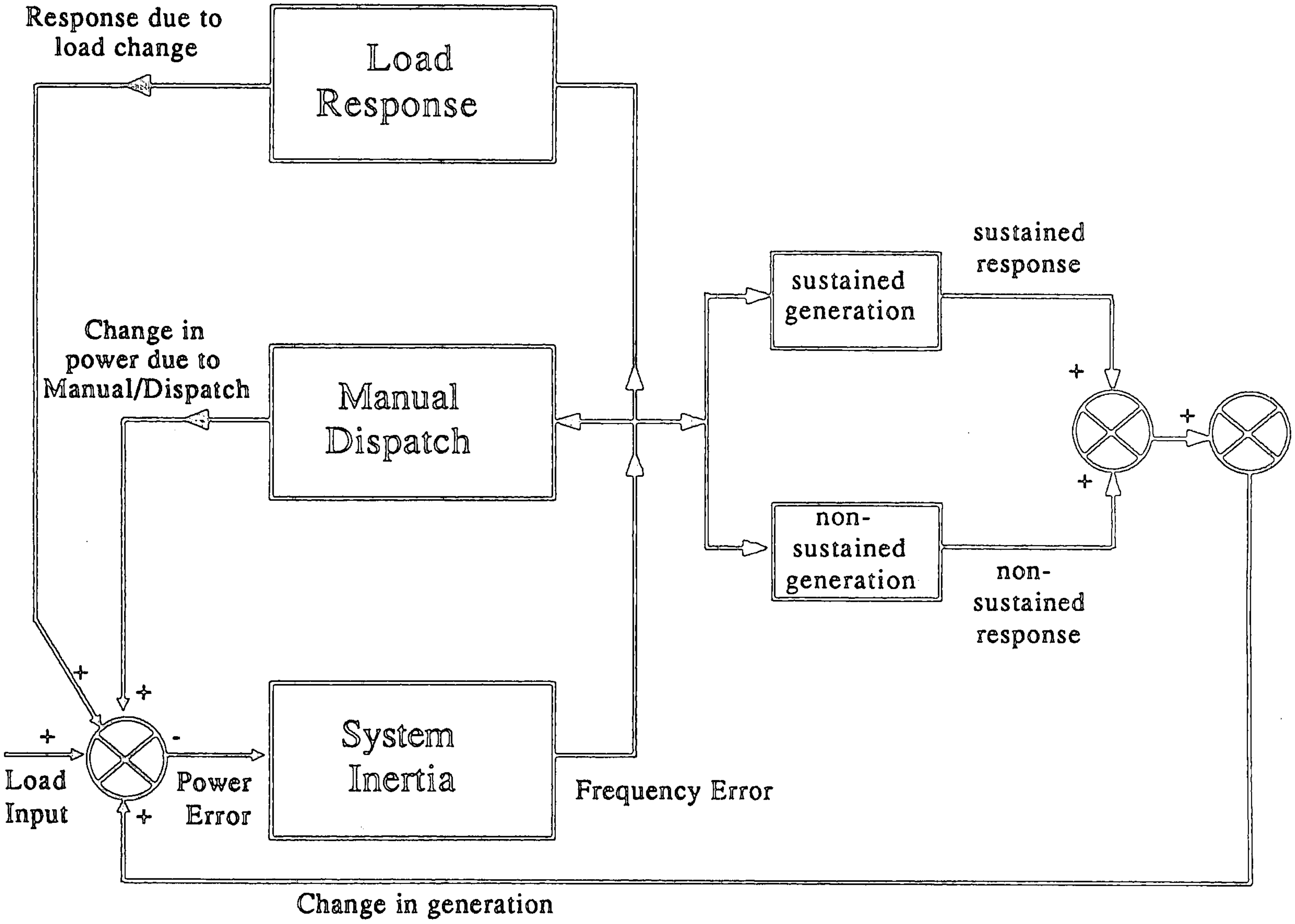


Diagram 8.1 Model for power system simulation

where

P_s is the sustained output in GW,

Δf is the frequency error in Hz, and

K_s is the sustained gain, which is assumed to be 5 GW/Hz.

The sustained response equation is obtained by combining the above equation with the system inertia equation given earlier. This gives

$$P_s = \frac{K_s}{sT_s}\Delta f \tag{8.9}$$

8.7.2 Non-sustained generation

The response of this type of generator is given by the following transfer function

$$P_n = K_n\frac{sT_n}{1+sT_n}\Delta f \tag{8.10}$$

where

P_n is the non-sustained output in GW,

K_n is the non-sustained gain, which is assumed to be 1 GW/Hz, and

T_n is the non-sustained plant boiler time constant, assumed to be 180 seconds.

Again as above the non-sustained response equation is obtained by combining the above equation with the system inertia equation. This gives

$$P_n = \frac{K_n}{sT_s}\frac{sT_n}{1+sT_n}\Delta f \tag{8.11}$$

So that the accuracy of the response of the model could be increased, a term to represent further turbine generator dynamics was added. This transfer function represented the turbines of the units, and took the form

$$\left(\frac{0.5}{1+sT_l}+\frac{0.5}{1+sT_h}\right) \tag{8.12}$$

where

T_l is the time constant which represents the delay of the low pressure steam, taken to be 0.05 minutes, and

T_h is the time constant which represents the delay of the high pressure steam, taken to be 0.025 minutes.

Clearly the response is split equally between the two terms. This is slightly incorrect as under steady-state conditions, three quarters of the output comes from the low pressure turbine, but under transient conditions the split becomes more equal between the two terms. The transfer functions for the sustained and non-sustained response were changed accordingly, to become, respectively

$$P_s = \frac{K_s}{sT_s}\left(\frac{0.5}{1+sT_l} + \frac{0.5}{1+sT_h}\right)\Delta f \tag{8.13}$$

and

$$P_n = \frac{K_n}{sT_s}\frac{sT_n}{1+sT_n}\left(\frac{0.5}{1+sT_l} + \frac{0.5}{1+sT_h}\right)\Delta f \tag{8.14}$$

To run the model to give reasonable accuracy at one second time intervals as intended, it was necessary to include this generator transient model. The model cannot have time steps much smaller than this because the much faster generator transients are not included in the model.

8.8 System Modelling

The use of transfer functions is a well known tool in the modelling and analysis of linear control systems. The approach is based on Laplace transformation, which enables the system performance to be predicted without actually solving for the roots of the characteristic equation. However, with the advancement of digital computers, a method using state-space representation is widely used. This representation enables the use of mathematical techniques that lead to a more systematic design process than is possible using transfer functions. The state-space method involves transforming a single nth order differential equation into a set of n first order simultaneous differential equations, which are generally written in a matrix form. This method requires the use of additional variables, termed state-variables. The number of state-variables required to define a system completely is equal to the order of the system. These variables are not unique and are chosen to suit the particular application. The use of matrices is useful in this approach, as the A and B matrix specify the dynamic characteristics of the particular linear system under study, and so the dynamic properties of the system can be studied by investigating the properties of the matrices.

To enable the model equations to be solved using the described integration routines, the equations are reformulated into the state-space (canonical) form. The transfer function can be treated as an algebraic expression. The numerator and denominator of equations (8.13) and (8.14) are divided by the highest power of s to replace all the differentiating terms by integrating terms. The state variable diagram for the sustained and non-sustained cases are shown in diagrams 8.2 and 8.3. The variable $V(s)$ is introduced to avoid the need for differentiation. The state variable diagram is formed by integrating $V(s)$ three times and combining the signals required. This form of the equations can now be easily solved using the Modified Euler Method.

8.8.1 Sustained response

Again from the diagram 8.2 by inspection it is seen that the state equations are

$$\begin{aligned} \dot{x}_1(t) &= x_2(t) \\ \dot{x}_2(t) &= x_3(t) \\ \dot{x}_3(t) &= \frac{K_s.\Delta f}{2T_lT_h} - \frac{1}{T_lT_h}x_2 - \left(\frac{T_l+T_h}{T_lT_h}\right)x_3 \end{aligned}$$

The matrix form of these equations is

$$\begin{Bmatrix} \dot{x}_1 \\ \dot{x}_2 \\ \dot{x}_3 \end{Bmatrix} = \begin{bmatrix} 0 & 1 & 0 \\ 0 & 0 & 1 \\ -\dfrac{1}{T_lT_h} & -\dfrac{T_l+T_h}{T_lT_h} & 0 \end{bmatrix} \times \begin{Bmatrix} x_1 \\ x_2 \\ x_3 \end{Bmatrix} + \begin{bmatrix} 0 & 0 & \dfrac{K_s}{2T_lT_hT_s} \end{bmatrix} (\Delta f)$$

This takes the familiar form of

$$\{\dot{x}(t)\} = A\{x(t)\} + Bu(t)$$

Also

$$P_s = 2x_1(t) + x_2(t)(T_l + T_h) \tag{8.15}$$

The values of $\dot{x}_n(t)$ are solved using the Modified Euler Method, and then the output of the generators are calculated using the above matrix equation.

8.8.2 Non-sustained response

From the diagram 8.3, by inspection it is seen that the state equations

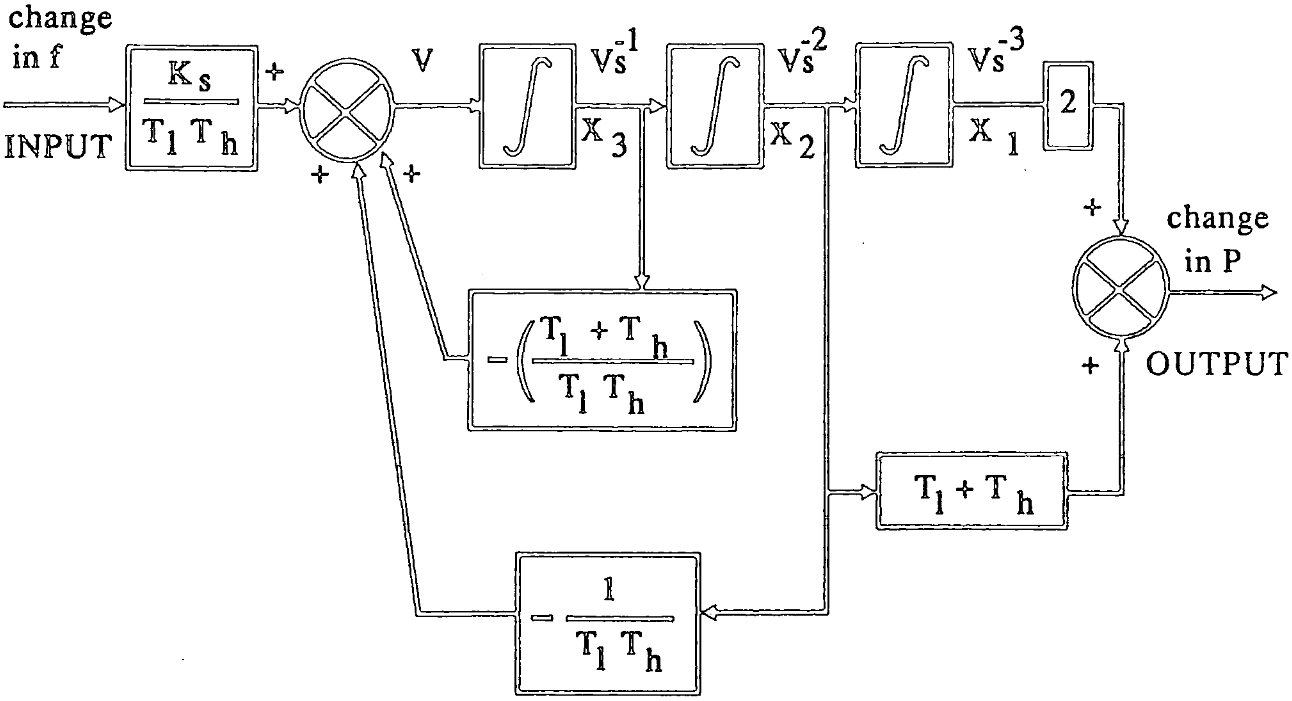


Diagram 8.2 State variable diagram for sustained response

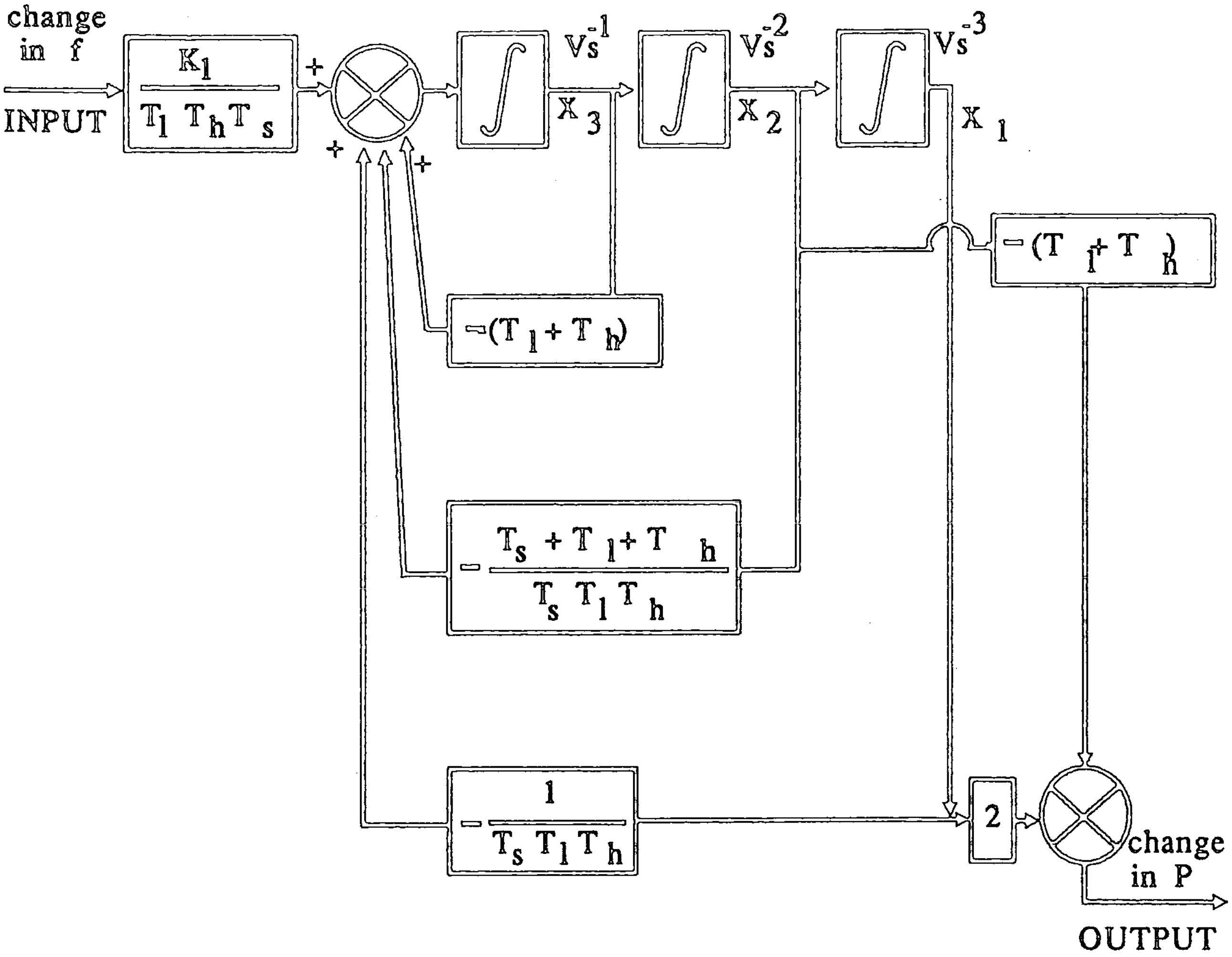


Diagram 8.3 State variable diagram for non-sustained response

are

$$\dot{x}_1(t) = x_2(t)$$
$$\dot{x}_2(t) = x_3(t)$$
$$\dot{x}_3(t) = \frac{K_n \Delta f}{2T_l T_h T_s} - \frac{1}{T_l T_h T_s} x_1 - \left(\frac{T_l + T_h + T_s}{T_l T_h T_s}\right) x_2 - (T_l + T_h) x_3$$

These can be written using the matrix notation

$$\begin{Bmatrix} \dot{x}_1 \\ \dot{x}_2 \\ \dot{x}_3 \end{Bmatrix} = \begin{bmatrix} 0 & 1 & 0 \\ 0 & 0 & 1 \\ -\frac{1}{T_l T_h T_n} & -\frac{T_l + T_h + T_n}{T_l T_h T_n} & -(T_l + T_h) \end{bmatrix} \times \begin{Bmatrix} x_1 \\ x_2 \\ x_3 \end{Bmatrix} + \begin{bmatrix} 0 & 0 & \frac{K_n}{2T_l T_h T_s} \end{bmatrix} (\Delta f)$$

The output can also be obtained by inspection from diagram 8.3, and is seen to be

$$P_n = 2x_1(t) + x_2(t)(T_l + T_h) \tag{8.16}$$

8.9 Manual Dispatch

The dispatch algorithm was designed to model the manual action which is carried out by the system control engineers at National Control. Useful discussions of this may be found in (41,75,79,83,132,157,209,210,223) .The allocation of generation is carried out such that the frequency error is kept to a minimum, sampling the frequency at minute intervals. The dispatch is defined as a linear ramp over a given number of minutes, assumed to be five in this case, which means that any newly set target by dispatch will be reached in five minutes from the present time. A dispatch dead-band of 0.1 Hz was assumed, so that until the frequency moved outside this band no manual control action was taken. The gain for the dispatch control was taken to be 5 GW/Hz, which represents a change in generation of 5 GW for each 1 Hz change in frequency. This is a typical value for such a system. The rate of change of frequency for the dispatch calculation was taken to be 1 GW Hz/minute. The dispatch itself was carried out at minute intervals, in line with the frequency error measurements.

8.10 Description of Operation

The diagrammatic representation of the simulation model developed is shown in diagram 8.4. The simulation is driven using the load input as a random variable, as described earlier. The summing block defines the power error, to which the system responds. This power error is made up from:

(a) the change in the load response due to the change in frequency, ΔU_l

(b) the change in generation due to that ordered by the manual dispatch calculation, ΔU_d,

(c) the change in generation due to the response of the generators acting on the frequency error. This value is made up from the two components described earlier, that of the sustained response and the non-sustained response of the turbine generators, $\Delta(P_s + P_n)$.

Hence the power error is given by

$$\Delta P = \Delta U_l + \Delta U_d + \Delta(P_s + P_n) \tag{8.17}$$

The frequency error is calculated by the system inertia term shown earlier. This then becomes the driving error for the other model components and hence the loop is completed. The starting point for the simulation is taken to be that of the steady-state, with no power or frequency error. The load input then follows a random walk, and this produces a frequency error, to which the other components will react.

The initial test of the simulation was carried out using the basic simulation model, without including the turbine representation. The turbine model was then added to the working simulation with some differences noted.

8.11 Pumped Storage

The use of pumped storage units is well known and was briefly described in a previous chapter. The C.E.G.B. system has several pumped storage units which should be included in the model if it is to simulate the whole system as required. It must be remembered that the use of pump storage, is as its

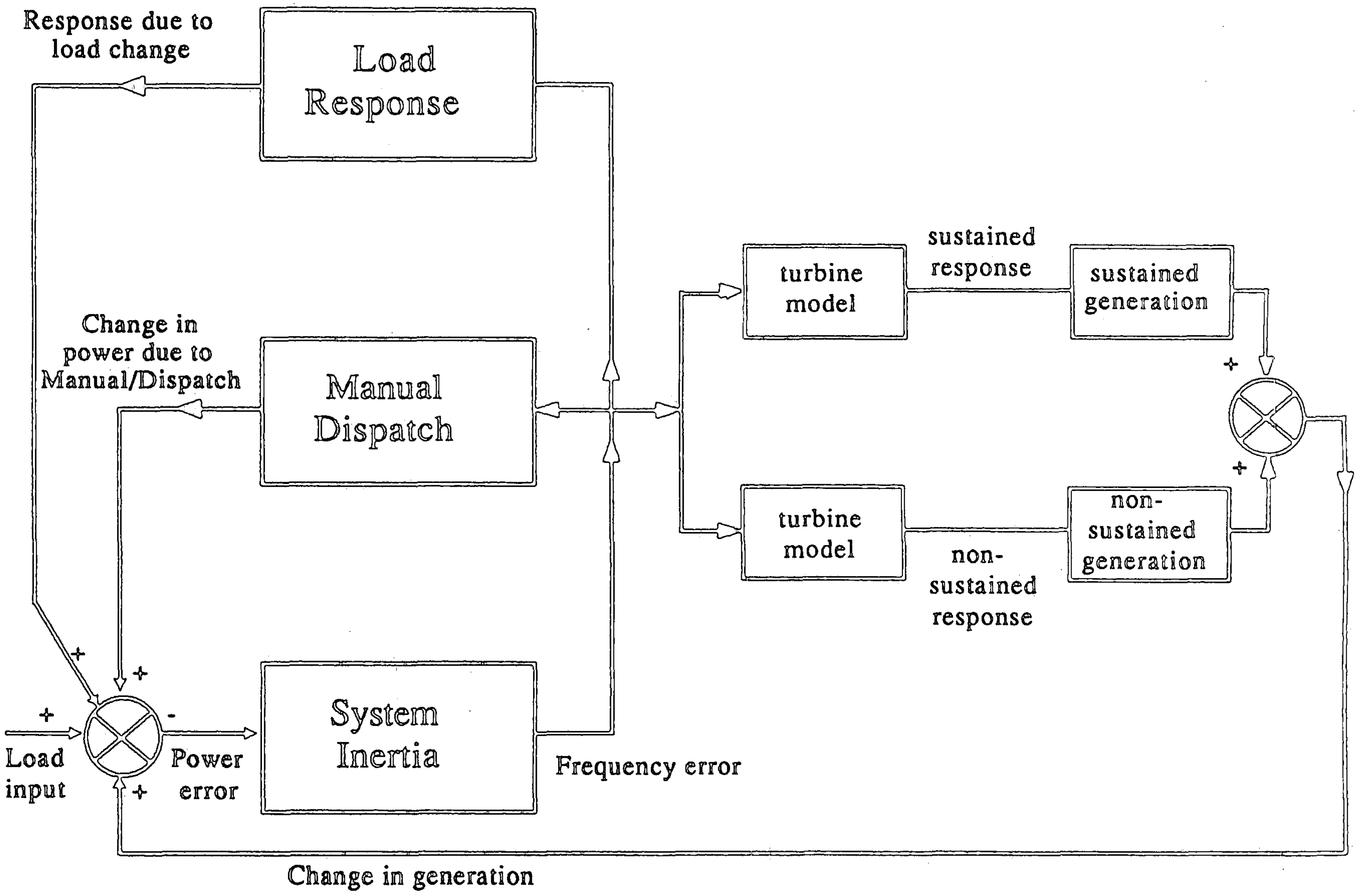


Diagram 8.4 Model for power system simulation including turbine model

name indicates, a method of storing energy and not of primary generation. Thus, strictly the model should include some representation of the reverse pump action, which is required to refill the storage reservoir during periods of light consumer load. This restoring action is usually carried out overnight when the consumer load is decreased, and there is spare generation capacity on the system. However, to simulate this fully would make the model more complex than required, and is unnecessary because as described earlier, the simulation is designed to represent the error of the prediction, rather than the complete system load. The Unit Commitment and Economic Dispatch is assumed, so the allocation of the power for reversing the pumps is assumed to have been available and used as required. Thus, the energy from the pump storage units can be used as and when required by the generation control method employed at the time. The simulation model was further expanded improved by the addition of the pumped storage model, which is now described.

8.12 Pumped Storage Model

The pumped storage transfer function is of a similar form to those models used for the sustained and non-sustained generation. The model clearly does not need the representation of the steam turbine and hence acts directly on the frequency error. The response to the frequency error is given by

$$P_{ps} = K_{ps} \frac{T_{ps}}{1 + sT_{ps}} \Delta f \qquad (8.18)$$

where

P_{ps} is the pumped storage output in GW/Hz,

K_{ps} is the pumped storage gain, which is assumed to be 3.6 GW/Hz, and

T_{ps} is the pumped storage time constant, assumed to be 180 seconds.

The pumped storage response is given for the whole system by the combination with the inertia equation shown earlier. This gives

$$P_{ps} = \frac{K_{ps}}{sT_{ps}} \frac{T_{ps}}{1 + sT_{ps}} \Delta f \qquad (8.19)$$

The state-space diagram for the pumped storage model is shown in diagram 8.5.

From inspection of the diagram 8.5 it is seen that the state equations are

$$\dot{x}_1(t) = x_2(t)$$

$$\dot{x}_2(t) = \frac{K_{ps}\Delta f}{T_{ps}T_s} - T_s x_1$$

These can be written using the matrix notation

$$\begin{Bmatrix} \dot{x}_1 \\ \dot{x}_2 \end{Bmatrix} = \begin{bmatrix} 0 & 1 \\ -T_s & 0 \end{bmatrix} \times \begin{Bmatrix} x_1 \\ x_2 \end{Bmatrix} + \begin{bmatrix} 0 & \frac{K_{ps}}{T_{ps}T_s} \end{bmatrix} (\Delta f) \qquad (8.20)$$

The output of the units is obtained by inspection of diagram 8.5 and is seen to be

$$P_{ps} = x_1 \qquad (8.21)$$

With the addition of this new element in the simulation, the power error can now be written as

$$\Delta P = \Delta U_l + \Delta U_d + \Delta(P_s + P_n + P_{ps}) \qquad (8.22)$$

The complete diagram of the simulation system is shown in diagram 8.6.

8.13 Simulation Results

This section describes and comments on the use of the system simulation, using both the simulated Manual Dispatch technique and the Adaptive Load Frequency Control technique discussed earlier.

8.13.1 System response to a step input

Figure 8.1 shows the response of the system to a single step input. The single step is provided by the prediction error, which is suddenly changed to a new constant value. The variables which are plotted may be described as follows:

(a) Power Error

The power error at the summing junction immediately reacts to this load change and abruptly changes. The error in the power is reduced by the intervention

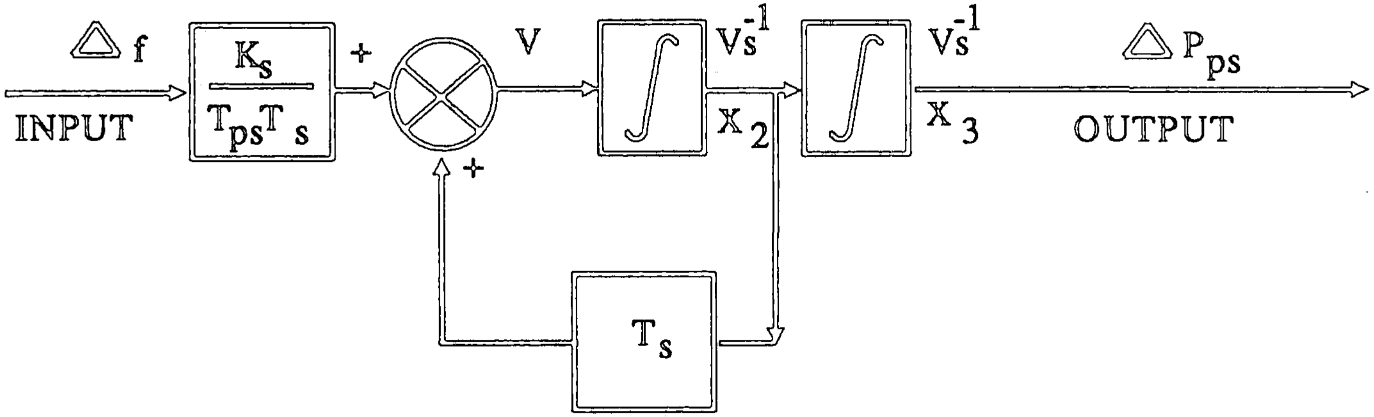


Diagram 8.5 State variable diagram for pumped storage model

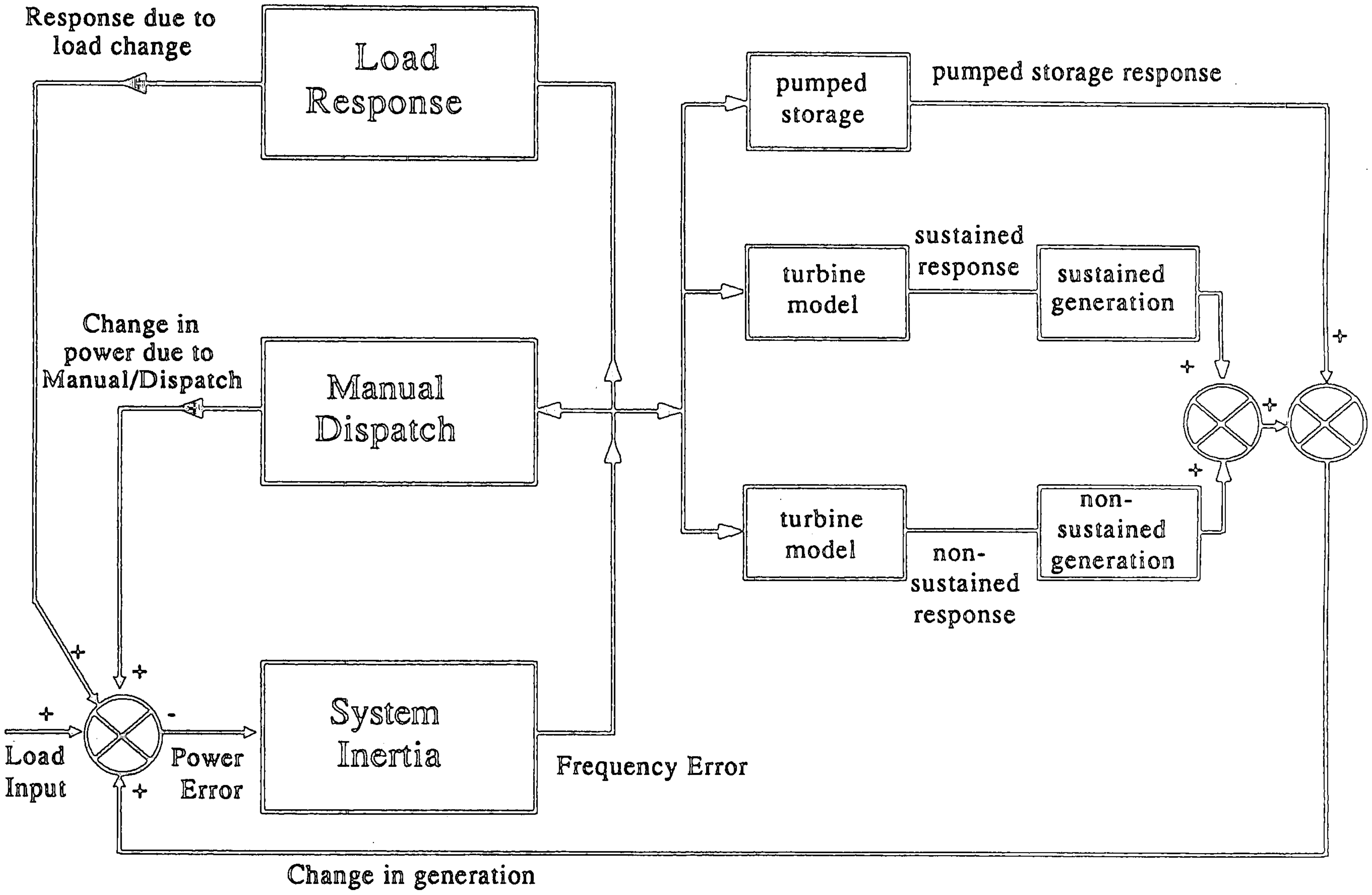


Diagram 8.6 Full model for power system simulation including pumped storage

of the manual dispatching technique, which changes the power allocated to the generator units. In this case, the load change is actually negative, that is a decrease in load, but it is seen as a positive prediction error.

(b) Dispatched Power

The same is true for the dispatched power, in that the dispatched value of power changes, and this is seen as a decrease in allocated power at the summing junction. Thus the allocated power and the power demanded by the consumer load is almost equal once again. The power error decreases, but is not zero reflecting the fact that the allocated power and demanded power is not exactly matched. This is seen in the error in the frequency, which has not returned to zero, as it would if the dispatch had exactly allocated the required amount of power. This power error continues as the frequency error is less than the dispatch dead band, and hence the power allocation to the generator units is not changed.

(c) Frequency Error

The frequency follows, a pattern which characterises the operation of the C.E.G.B. system. There is an initial increase in frequency as the load on the generator units is decreased. The units are still being provided with the same amount of energy as before the incident, so the excess energy in the system is seen as a rise in frequency. This initial rapid change in frequency is in direct response to the load change, and would continue to increase if no control action was taken. The dispatch provides the required control action, with the decrease in generation which causes the frequency to increase. The overshoot of the frequency is reduced by the redispatching of the generators, meaning that the decrease in load and change in generation is almost matched, calculated by the change in frequency. There is still a small difference between the dispatched power and the consumer load and hence a small frequency error is seen on the system. This frequency error cannot be removed from the system in its present state because the error is inside the controller dead-band.

8.13.2 Manual dispatch

Figure 8.2 shows the simulation controlled by the manual dispatching technique. The simulation run represents 4 hours actual time. The Dispatch gain was taken to be 5 GW/Hz, a value which was felt to be correct for the size of system under study. The effect of the dispatching technique can be clearly seen. There is a delay between the change in consumer load and the reallocation of generator power. It is clear that the dispatch tends to allocate the required power at a time later than the load change, and the actual amount of power allocated does not match the load change. The power error is kept fairly small over the operating time, although it is quite random. The frequency error scale has been enlarged to enable a trace to be seen on the graph, although it is still rather small. The dead-band in control is seen when the frequency error is small and the generated power and consumer load do not match. The mean frequency error is –0.004 Hz, it has a standard deviation of 0.0871 and the sum of the frequency error squared is 1.8168.

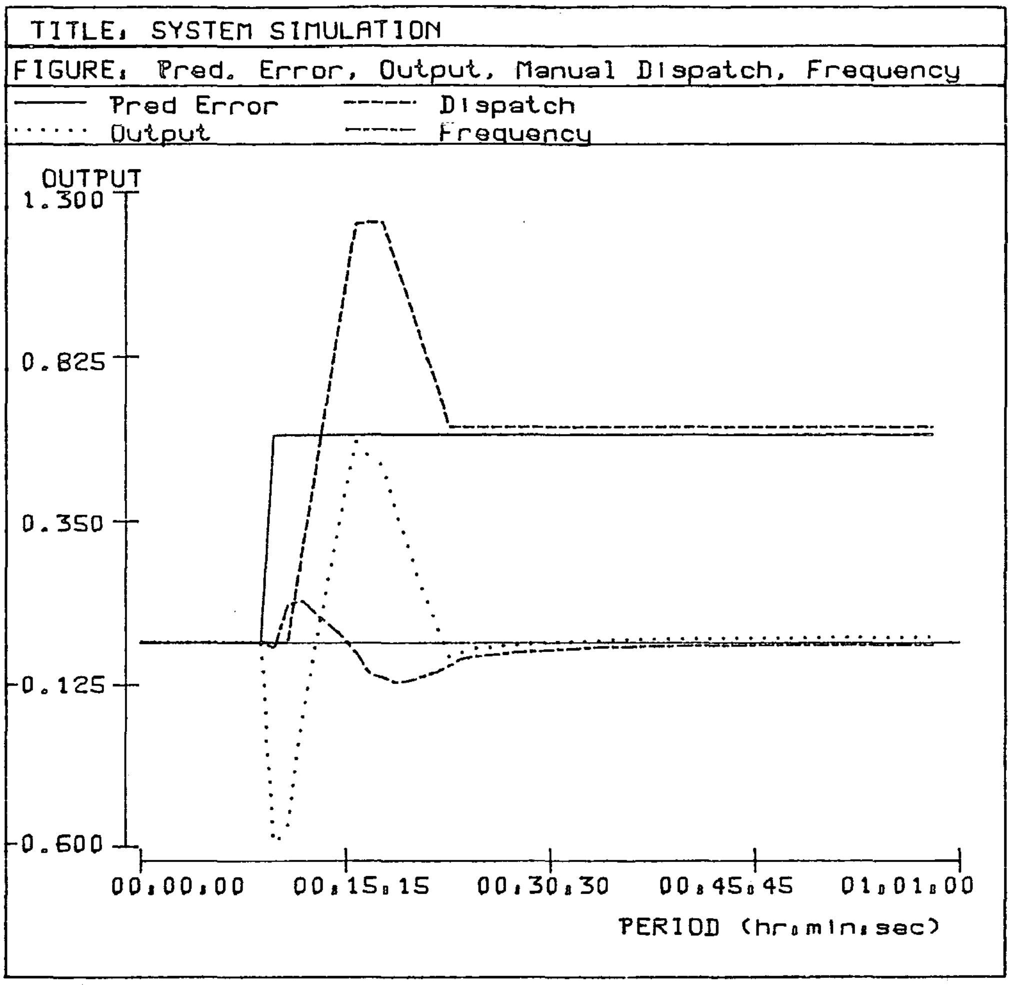
8.13.3 Altered dispatch gain

Figure 8.3 shows the simulation following the same (4 hour) load profile (load error) as the previous figure, although the dispatch gain has been increased to 6 GW/Hz, a value which was felt to be slightly high for the system model used.

8.13.4 Frequency response to dispatch

Figure 8.4 shows the frequency associated with the simulation on a greater scale than the previous figure. It is seen that the frequency initially starts to decrease as the load increases, the dispatch responds to the frequency error after several minutes and reallocates generator power. A large amount of power is called for by the dispatch which causes the error frequency to increase and change sign. This process continues for the duration of the simulation, with a large deviation in frequency approaching 49.70 Hz. This is corrected by a large increase in the allocated power, greatly in excess to that required by the load. The reallocation of power is greater than in the previous example, as the sum of the square of the frequency error is 1.86760, the mean frequency error is –0.007 Hz and the standard deviation of this is 0.0882. The control action in this case is increased due to the increased gain, but this causes more overshoots and increases the system frequency error.

Figure 8.1



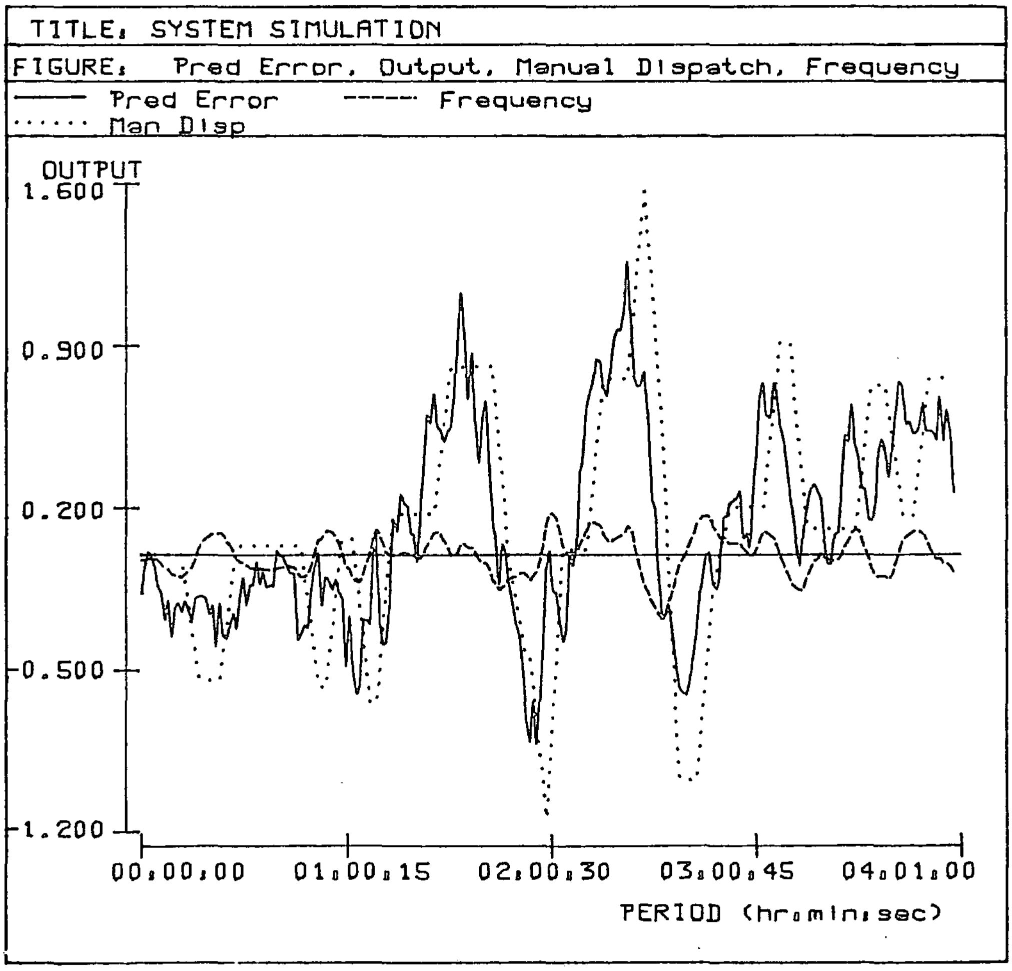


Figure 8.2

8.13.5 System response to manual dispatch

Figure 8.5 shows the simulation following the same load curve as before, but with the conditions as used in figure (8.2). All the appropriate values are plotted on the same graph to give an idea of the overall operation of the system and the response of the dispatch to the frequency error.

8.13.6 Prediction error

Figure 8.6 shows the demand change of the consumer load (in GW) in greater detail, this is the error in the load prediction.

8.13.7 Frequency response to lower gain dispatch

Figure 8.7 is the frequency error trace associated with this particular run of the simulator. It is included to show in greater detail the frequency error which drives the dispatch calculation. With the decrease in the dispatch gain, the sum of the squares of the frequency error has decreased to 1.3590, showing that the initial value of the gain set at 5 GW/Hz was a better value for this particular simulation than the lower value.

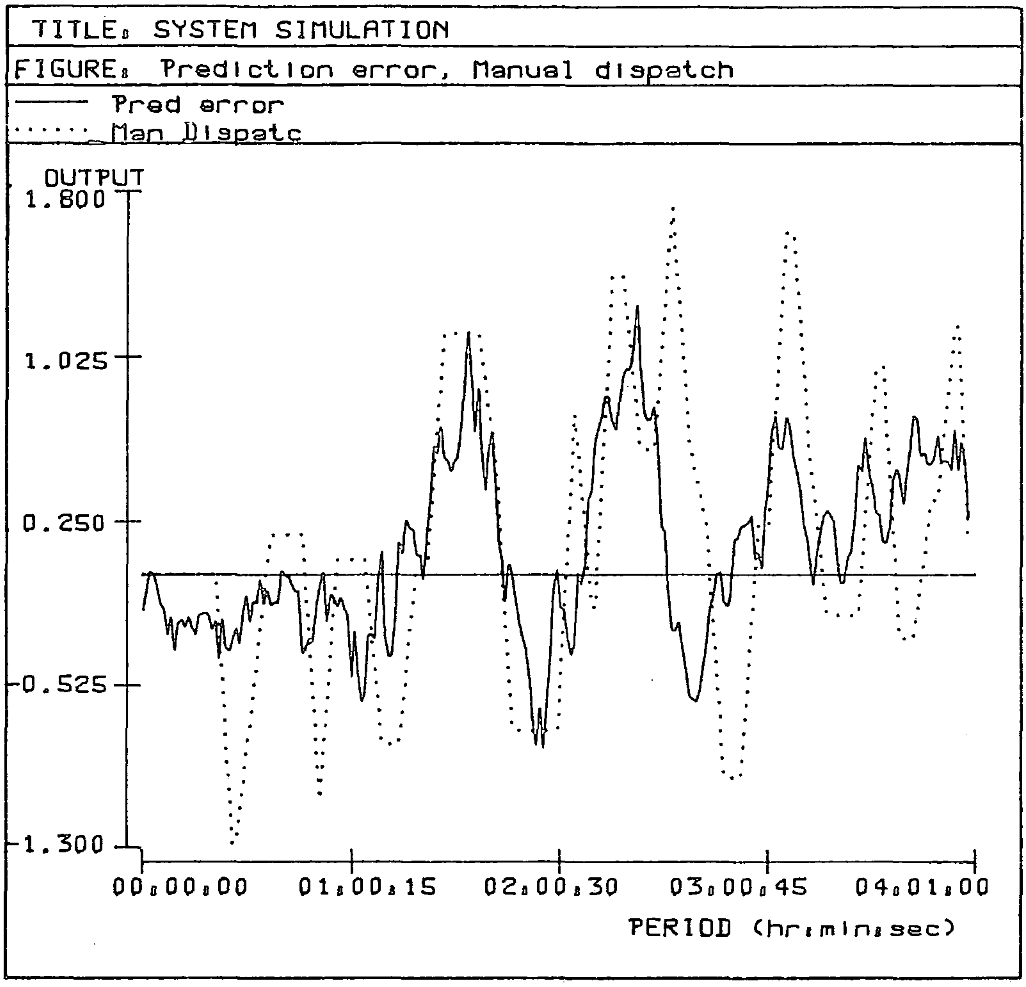
8.13.8 Manual dispatched power

Figure 8.8 shows the associated manual dispatch plot in more detail. This enables the amount of power allocated to be compared with the change in the consumer demand. The sum of the squares of the consumer load (seen in figure (8.5)) is 46.3025, whereas the sum of the squares of the manual dispatched power is 67.4221. This shows that the frequency control method used is not as accurate as could be used, and this will lead to periods of operation which are not as economic as they might be. Unnecessary power is allocated in this case and the frequency is not kept under tight control.

8.13.9 Sytem response to manual dispatch

Figure 8.9 shows the simulation following the same load curve as the previous cases, with a different manual dispatch due to the fact that the dispatch period started slightly later than the start of the simulation. The results of the dispatch are quite different and it is interesting to note that the mean frequency error is worse than the previous value of –0.004 Hz, the value

Figure 8.3



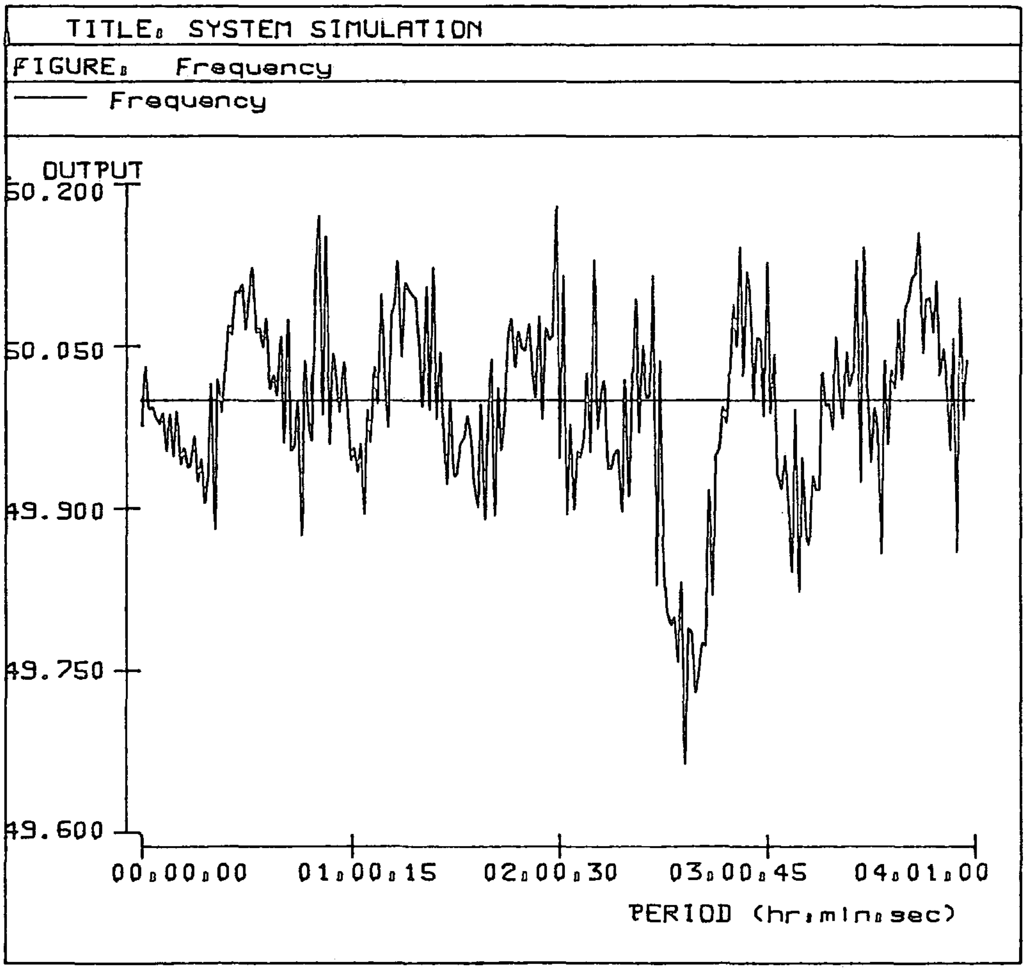
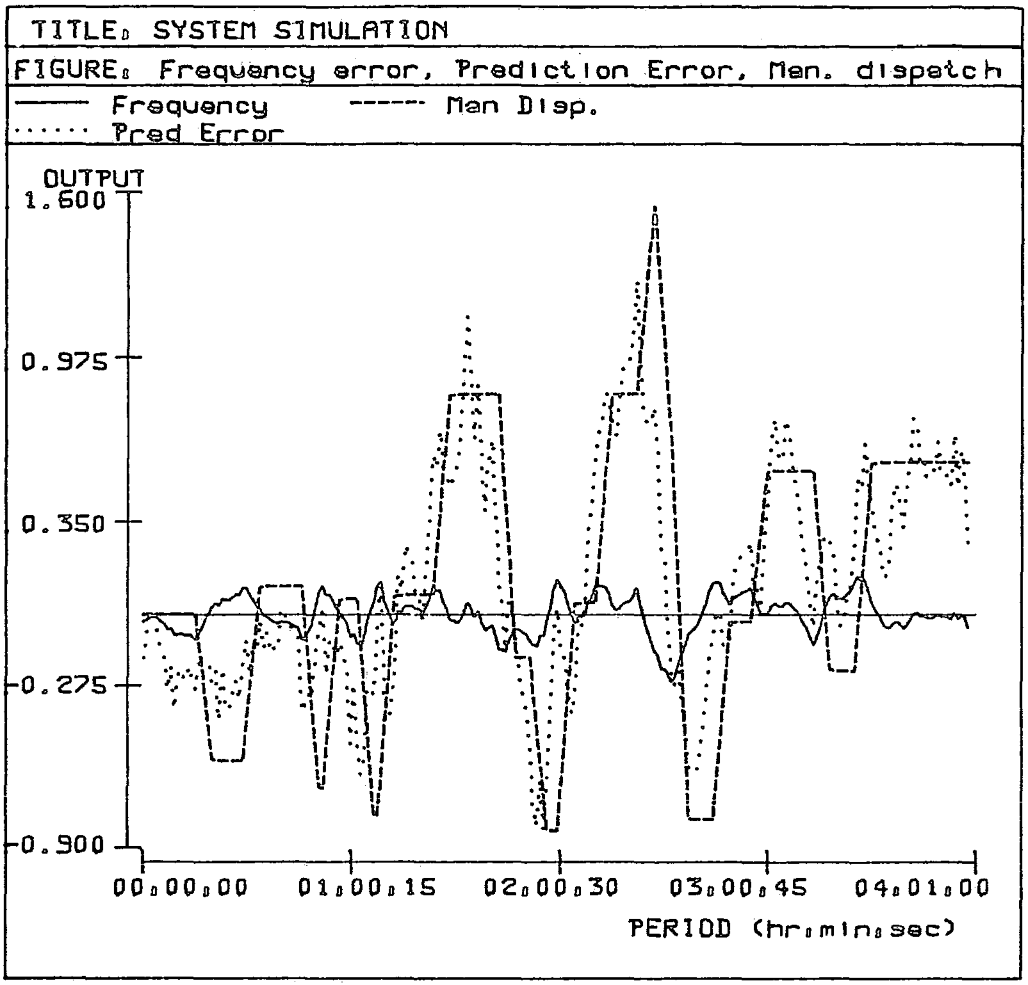


Figure 8.4

Figure 8.5



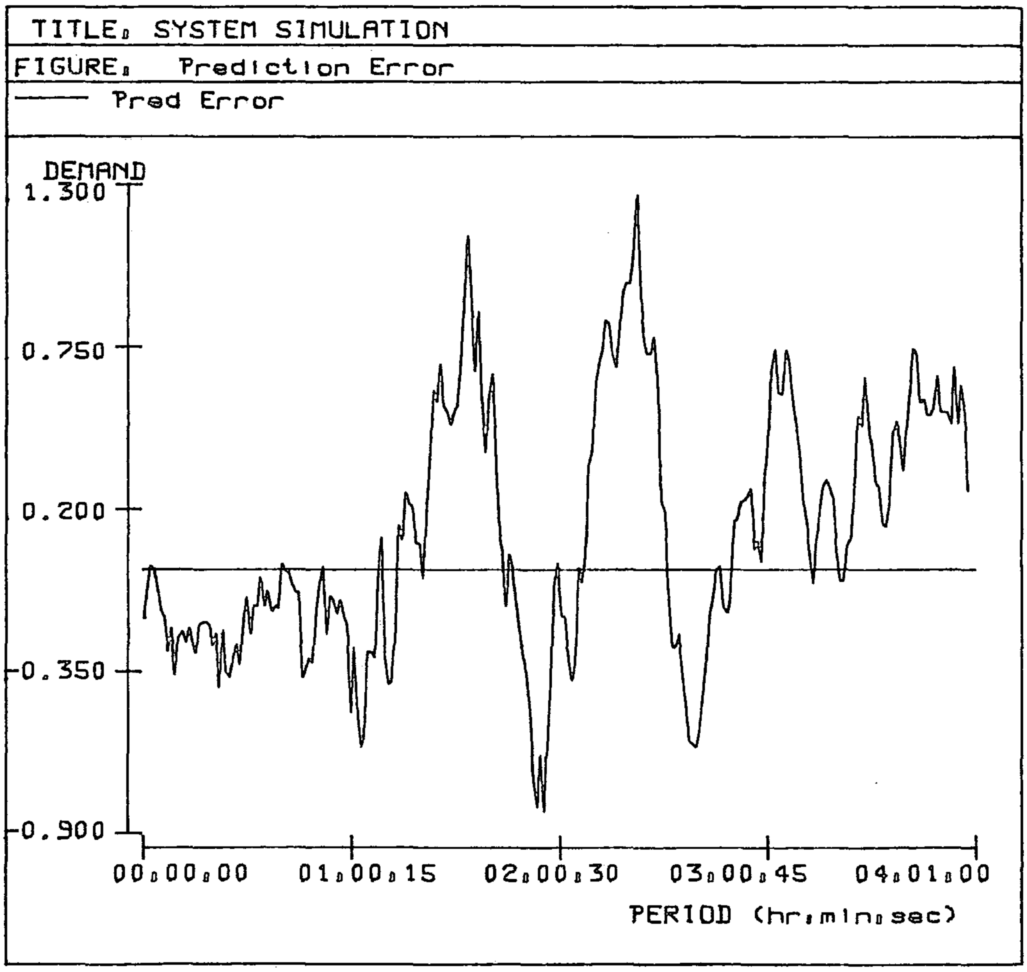
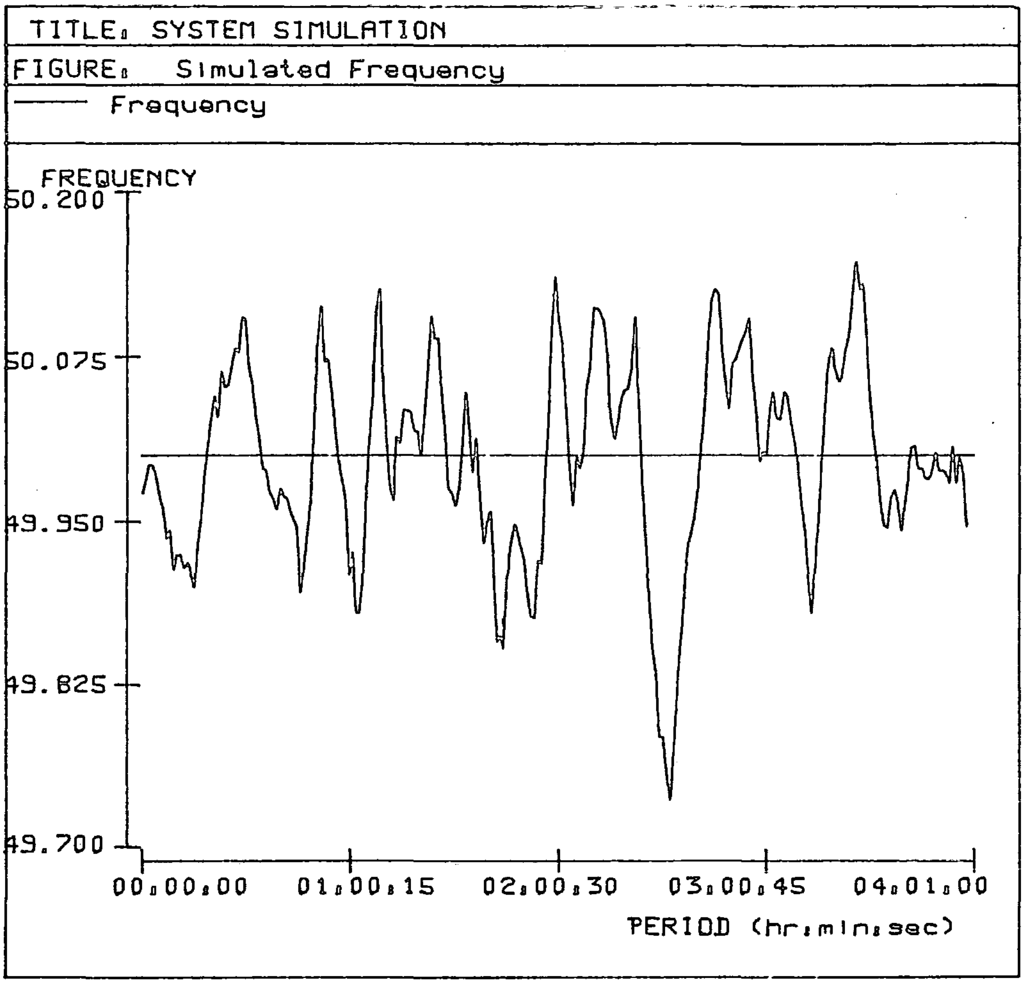


Figure 8.6

Figure 8.7



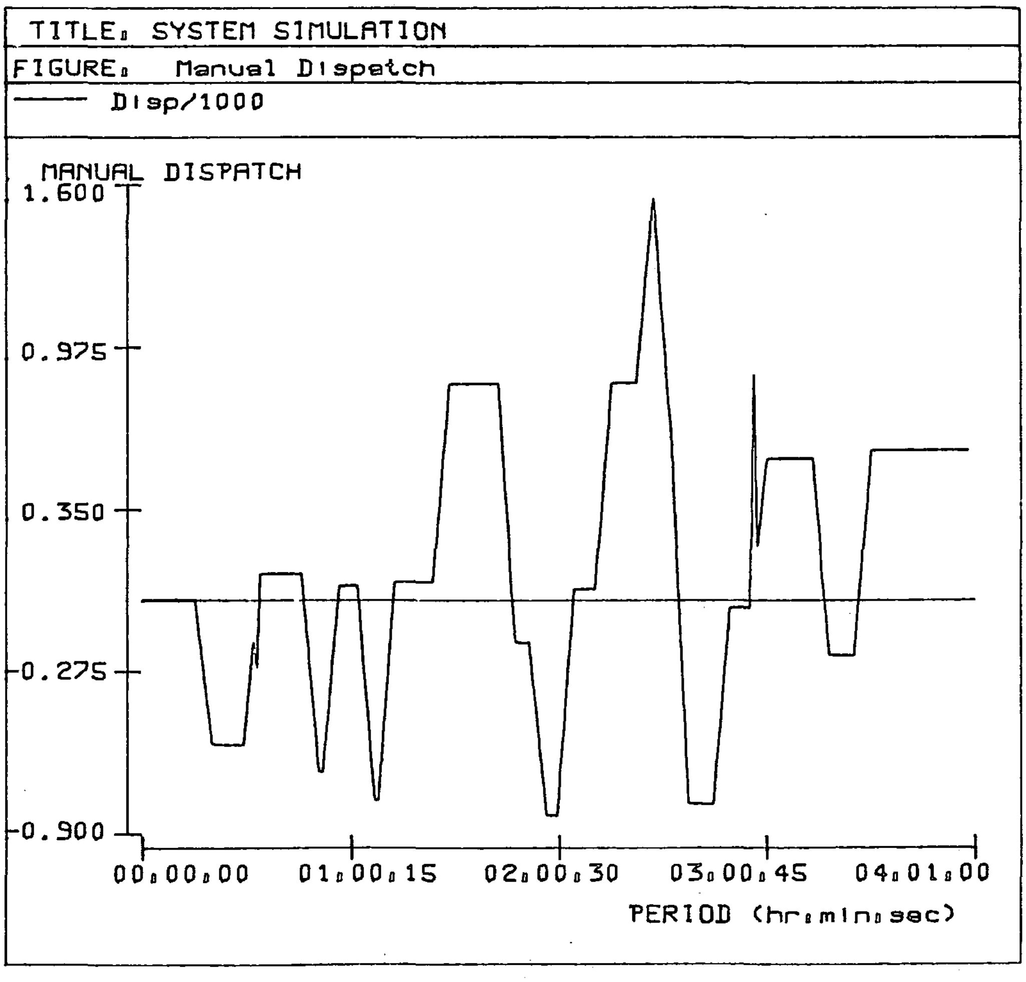


Figure 8.8

in this case is –0.008 Hz, with the sum of the squares of the frequency error being slightly greater than the last simulation. In this case the sum of the squares of the frequency error was 1.1469, previously it was 1.3590. Hence, it is clear that the quality of the frequency control can vary greatly using the same technique applied at a different time. The delays in the system cause problems for the manual dispatching techniques, along with the speed of response of the control. In some cases the control makes the a greater error because of the way in which the control responds and the application of any previous knowledge of the system state.

8.13.10 System response with pumped storage model

Figure 8.10 shows the simulation following the same load curve as before, only in this case the model contains the pumped storage model, allowing the system to respond to the consumer load more quickly than before. Figure 8.11 shows the corresponding load curve for direct comparison with figure (8.10).

Figure 8.12 shows the simulated frequency of the system, which if compared with figure (8.7) is seen to have a smaller frequency error due the faster response of the pumped storage units. Figure 8.13 show the corresponding manual dispatch for the simulation, showing that less power is needed to be reallocated as the available power is able to react more quickly than in the previous case. Thus overall less allocation is required to give the frequency control required. The mean frequency in this case was found to be –0.007 Hz, with a standard deviation of 0.0685. The sum of the squares of the frequency error was calculated to be 1.1280.

This simulation provides a good testing ground for the application of frequency control techniques, without the complication of economic considerations which will be considered elsewhere. The dispatch technique used in the simulation is obviously not the most effective way of controlling the system frequency. However, it provides a good indication of the advances that can be achieved, if an automatic frequency control technique is used, instead of a manual technique. The adaptive frequency control technique described earlier was applied to the simulation so a comparison could be made with the manual

Figure 8.9

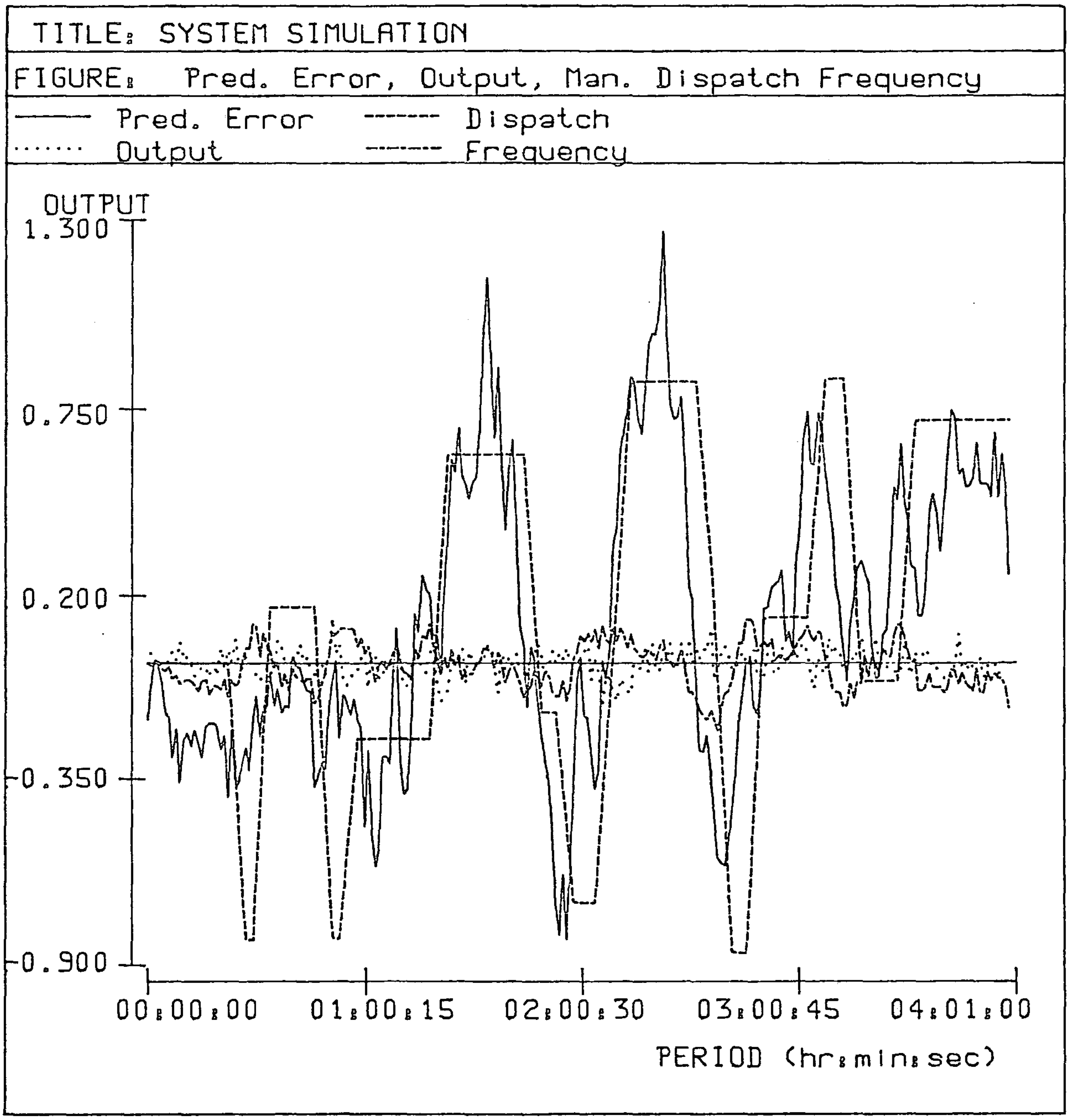
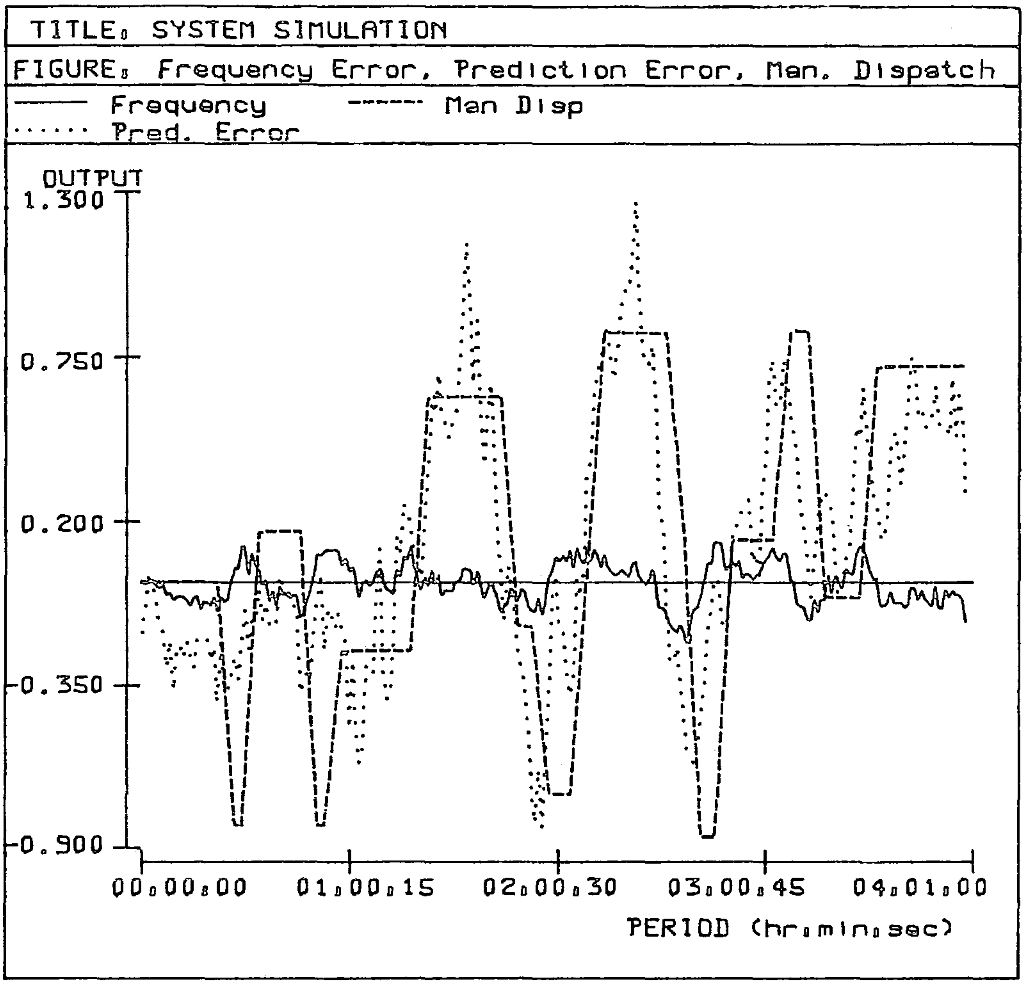

TITLE: SYSTEM SIMULATION
FIGURE: Pred. Error, Output, Man. Dispatch Frequency
Pred. Error
Dispatch
Output
Frequency
OUTPUT
1.300
0.750
0.200
-0.350
-0.900
00:00:00
01:00:15
02:00:30
03:00:45
04:01:00
PERIOD (hr:min:sec)

Figure 8.10



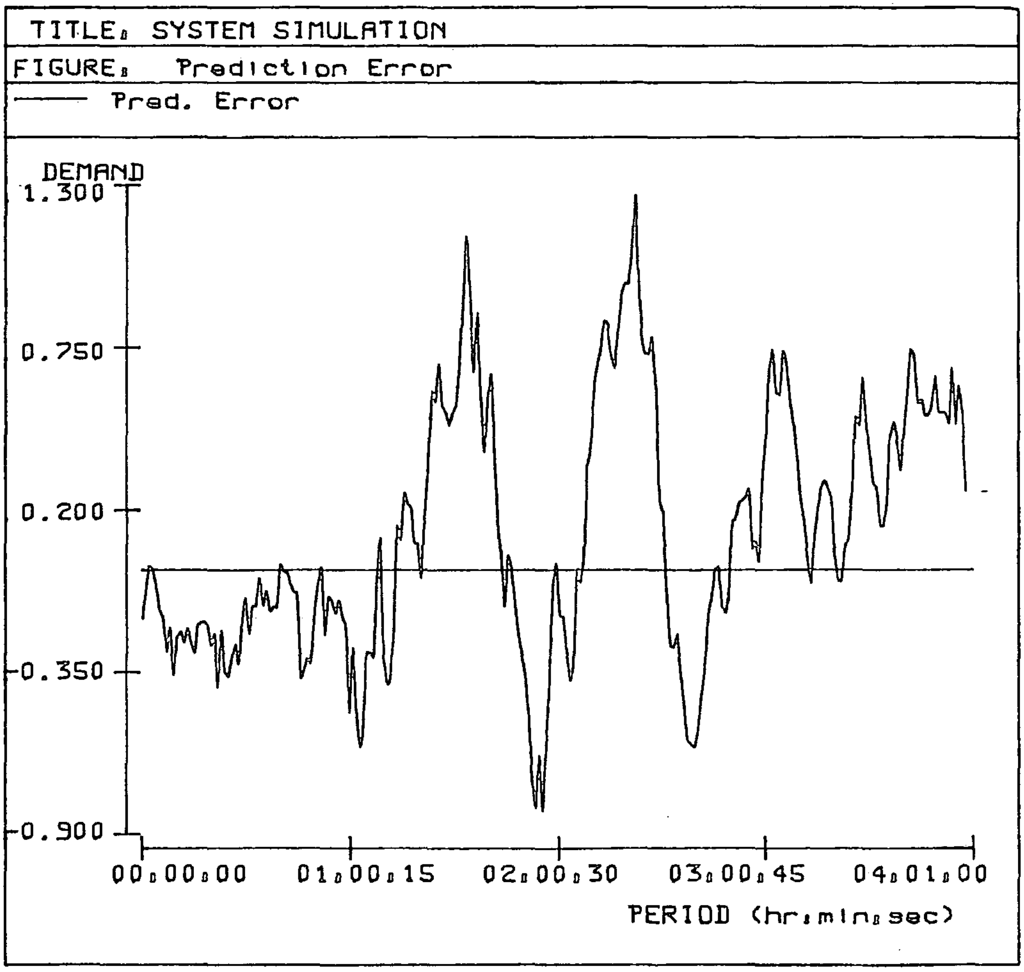
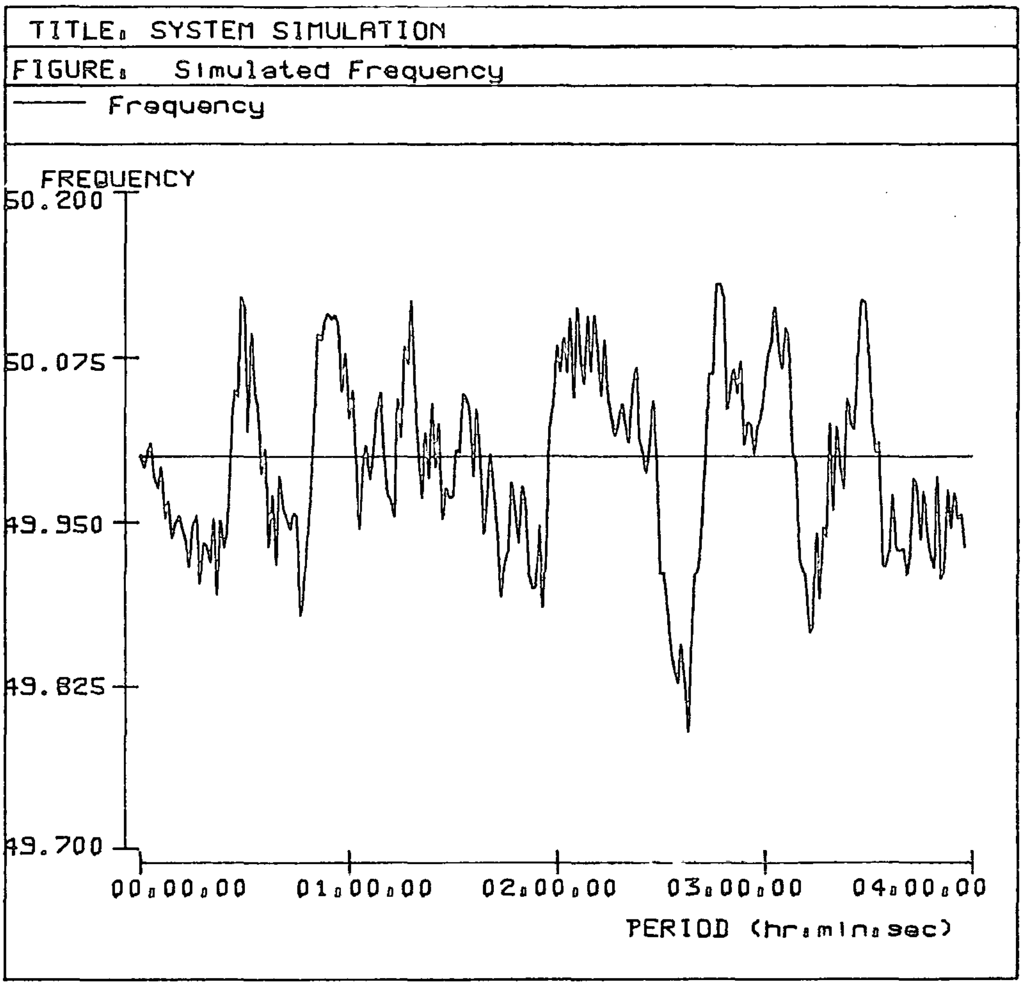


Figure 8.11

Figure 8.12



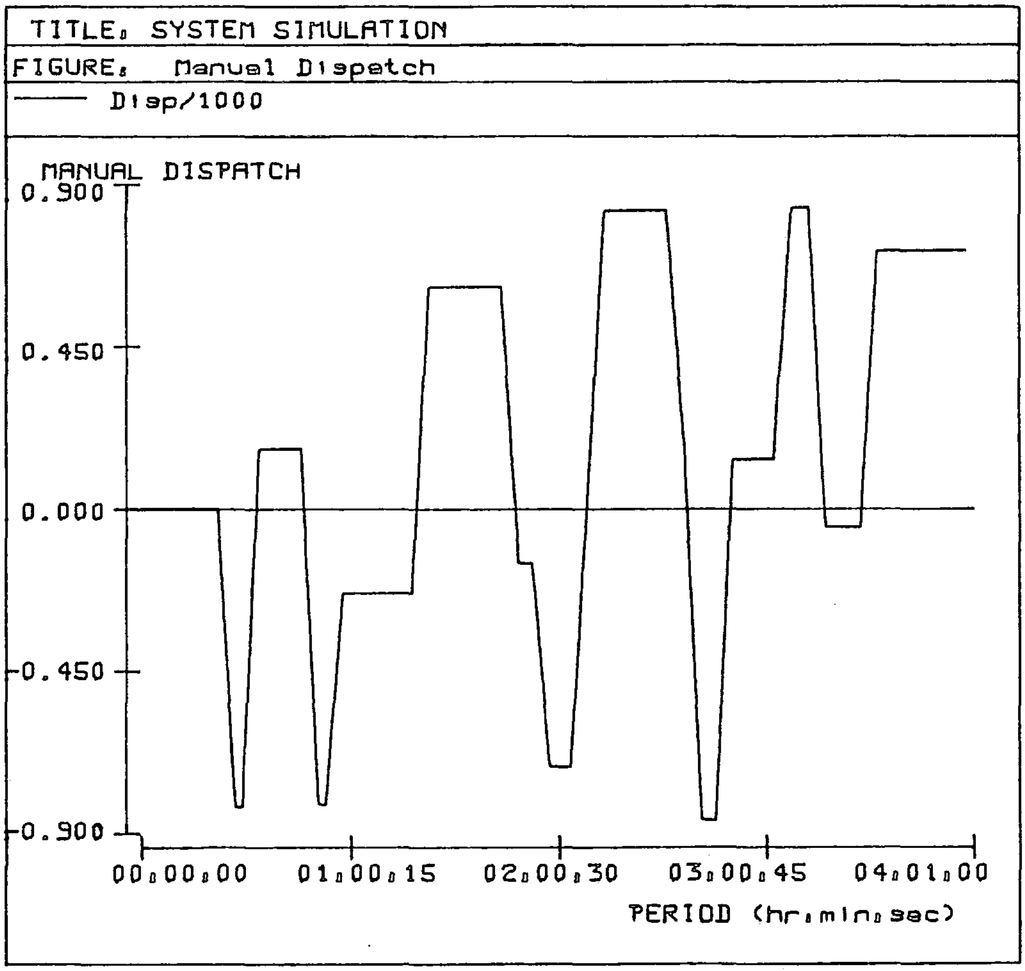


Figure 8.13

approach. The technique used the same modelling algorithm and minimum variance control technique as described previously in Chapter 6. The driving error for the controller again came directly from the system frequency error. In this case there was no noise on the driving error variable, so the filtering on the input to the controller was reduced. There was no possibility of the frequency error being out of bounds or corrupted by communication failure, so the removal of the filtering techniques was felt to be justified.

The controller was used to directly replace the manual dispatch as used in the previous section, which was removed completely. The diagram of the simulation model used is shown in diagram 8.7. The simulation was run using the previous load curve to allow a direct comparison could be made with manual dispatching technique. The interval for the operation of the controller was chosen to be 10 seconds, and an investigation into this time interval is discussed later.

8.13.11 Controller without forgetting factors

Figure 8.14 shows the system output using the load frequency controller directly without any forgetting factors, based on a model using three parameters. On this scale the frequency error cannot be distinguished clearly, but has been included to indicate that no significant deviations are observed. The mean frequency error is 0.001 Hz, with a standard deviation of 0.0072. The sum of the squares of the frequency error is 0.0105. The frequency error is greatly reduced over the whole of the operating time.

8.13.12 Controller using forgetting factors

Figure 8.15 shows the system output using the load frequency controller with a forgetting factor of 0.98. This was running under the same conditions as the example shown in figure (8.10), but the sum of the squares of the frequency error has decreased to 0.0079. Although it is difficult to see this directly on the plots, it indicates that if the input data is weighted in favour of the more recent data, the results achieved by the controller can be improved. In both examples the controller has very nearly matched the reallocation of the generator power, with that of the change in consumer load, giving a mean frequency error of 0.001 Hz.

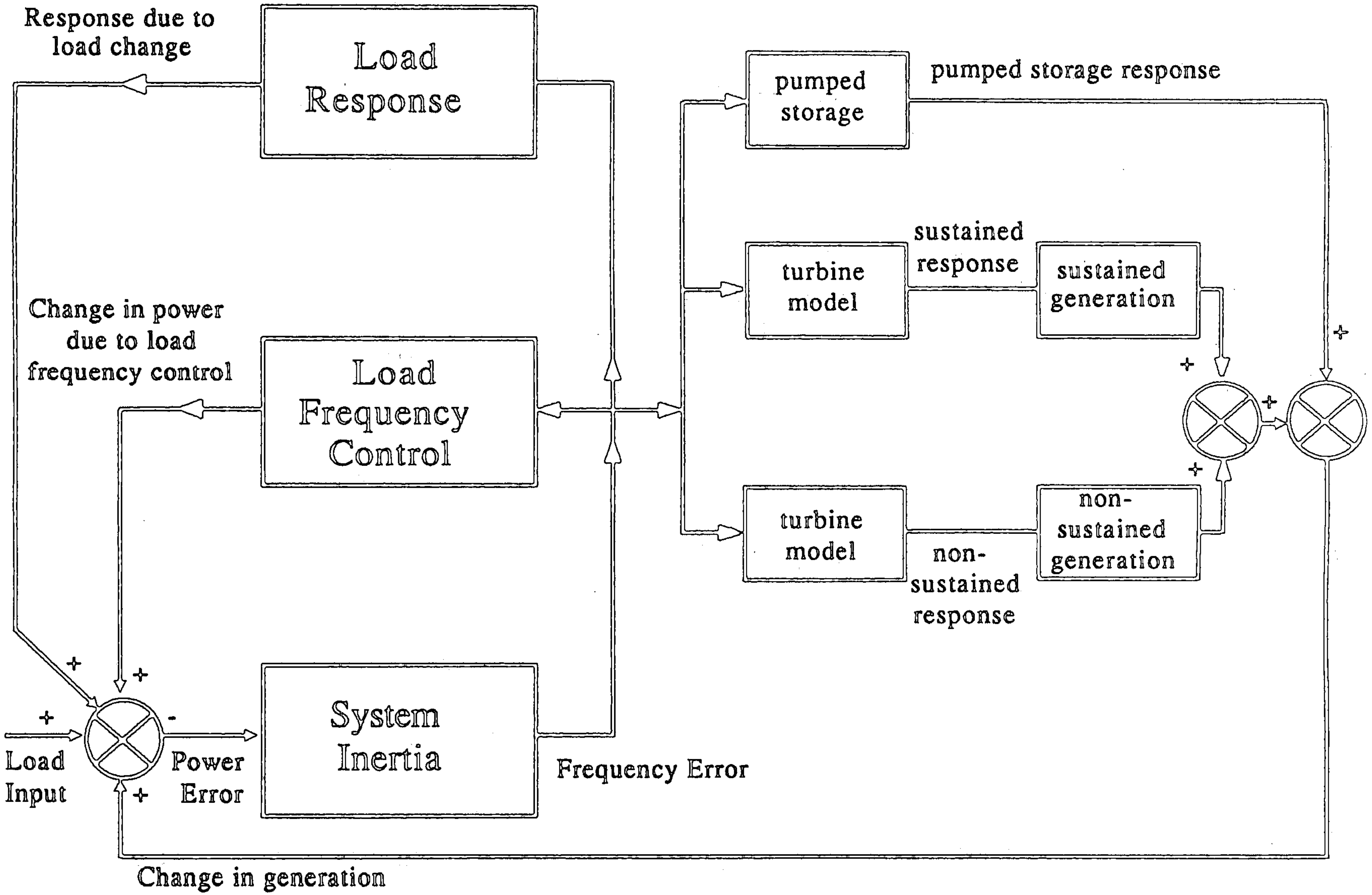
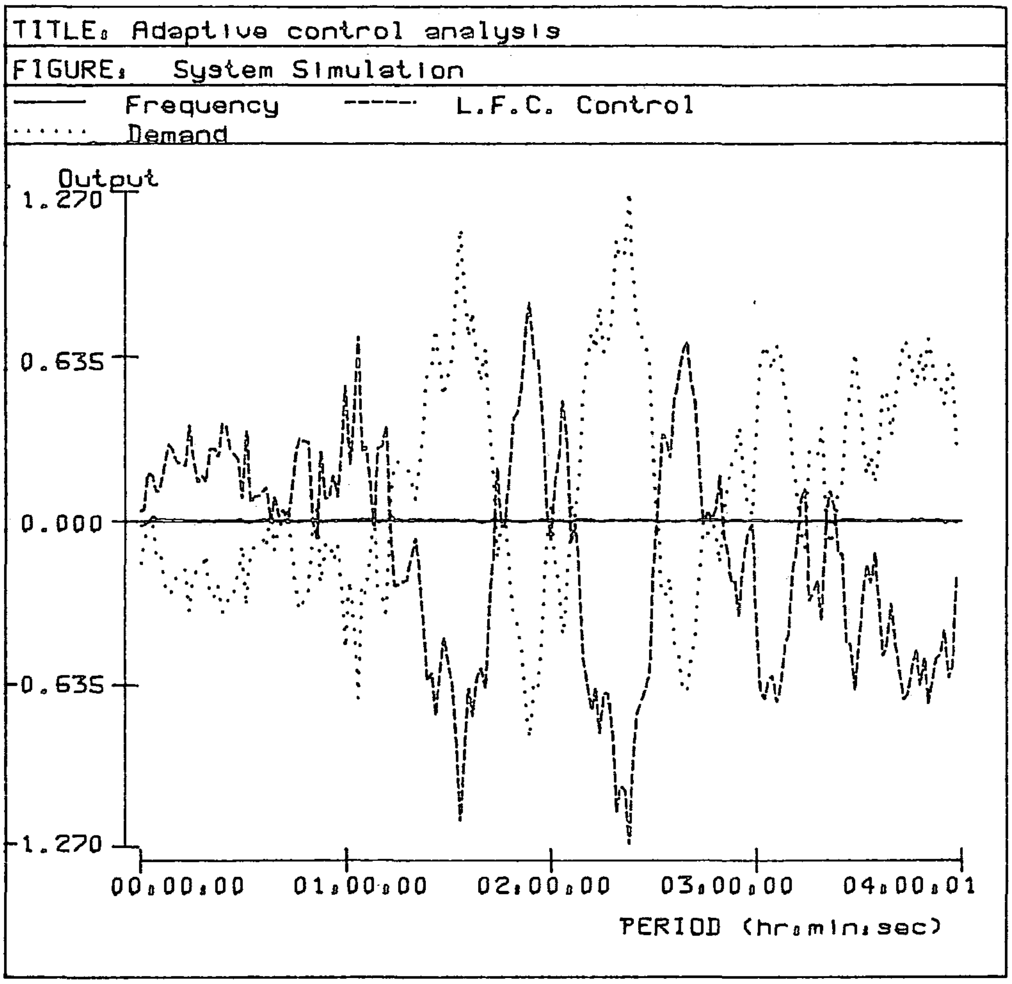


Diagram 8.7 Full model for power system simulation including load frequency control

Figure 8.14



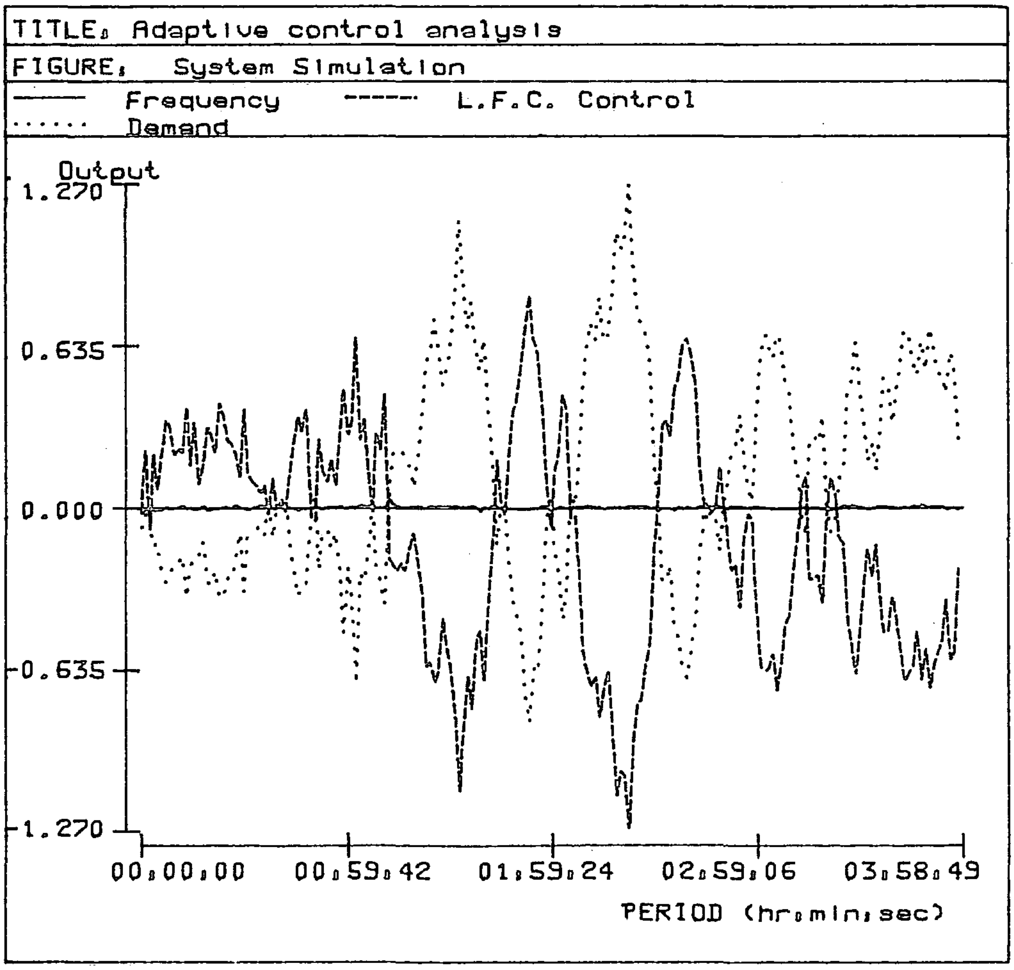


Figure 8.15

8.13.13 Control model based on three parameters

Figure 8.16 shows the system output using the load frequency controller, with the control based on a model of three estimated parameters. The scale has been altered in comparison to the previous figure so that the frequency error is slightly more clearer.

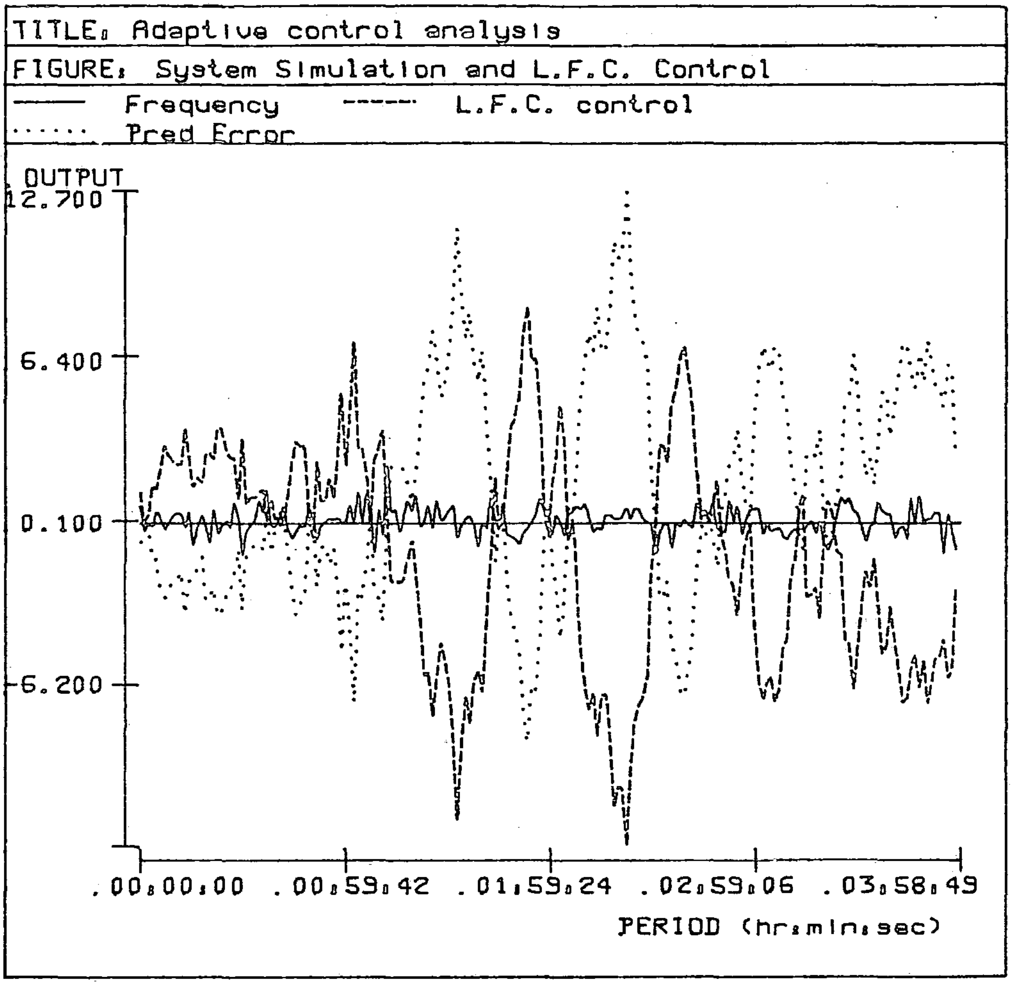
8.13.14 Model system parameters

Figure 8.17 shows the estimated parameters used in the system model to calculate the load frequency control action from. It is seen that the parameters take some minutes to reach a steady-state. The initial guess of the adaptive model is based on the starting values of the algorithm. These are chosen arbitrarily, as they are soon replaced by valid parameters. The actual parameters are approached from the start point and converge well to the final continuous value. The plot has been stopped after the time shown as the detail at the beginning is far more important than the steady-state operation, once this has been achieved. The initial adaption of the model parameters could cause the system to become unstable if the control action was calculated on the nonconverged parameters. So for the first couple of iterations the control action is kept constant at a predefined starting value. The control is then calculated on the model produced as the parameters start to converge, even though they have not reached their final value. This control action helps to increase the speed of adaption, as the model parameters begin to react to the control commands issued. This method of control is acceptable if the control command is filtered to ensure it is not outside the required range.

8.13.15 Controller using five estimated parameters

Figure 8.18 shows the system response to an estimated model using 5 estimated parameters. The estimated model converges at approximately the same speed as the 3 parameters model and the control action causes a slightly greater sum of the squares of the frequency error to be calculated. Thus it would appear that the optimum number of parameters to model for this model was 3 parameters. The parameter adaption is shown in figure 8.19.

Figure 8.16



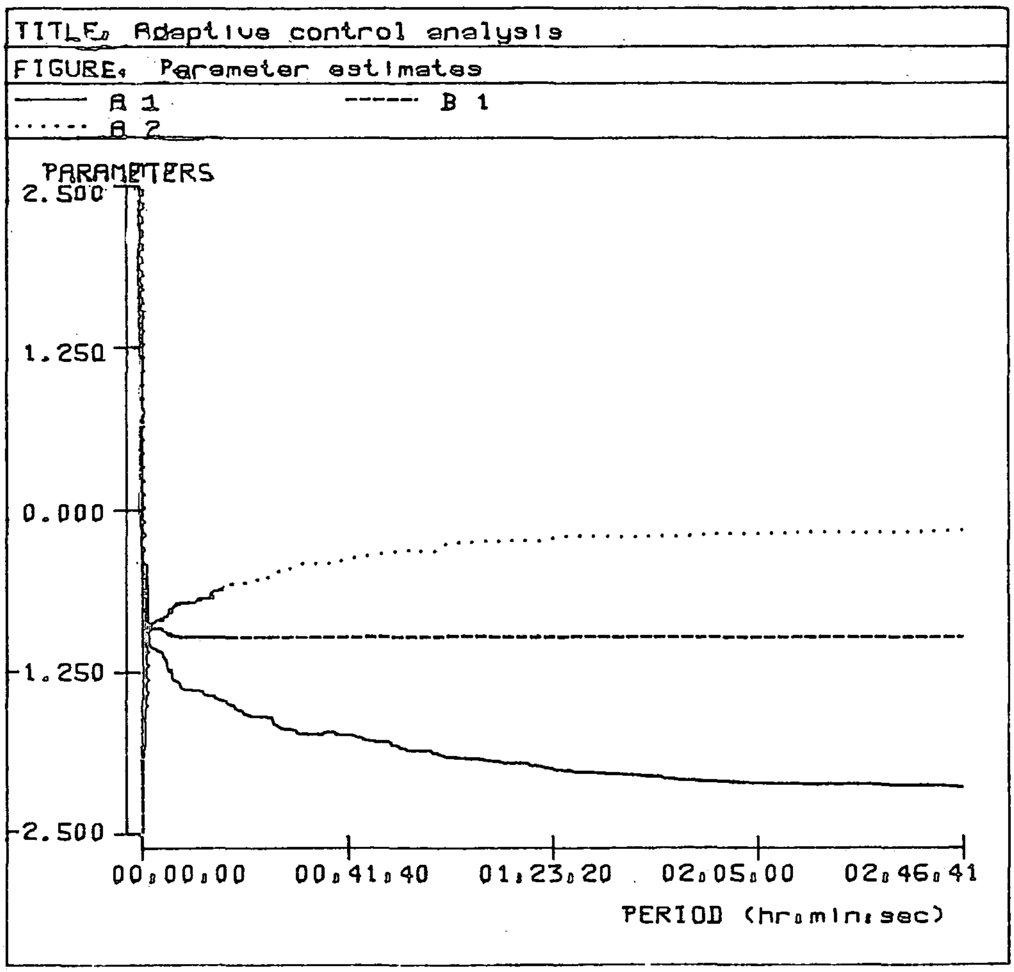
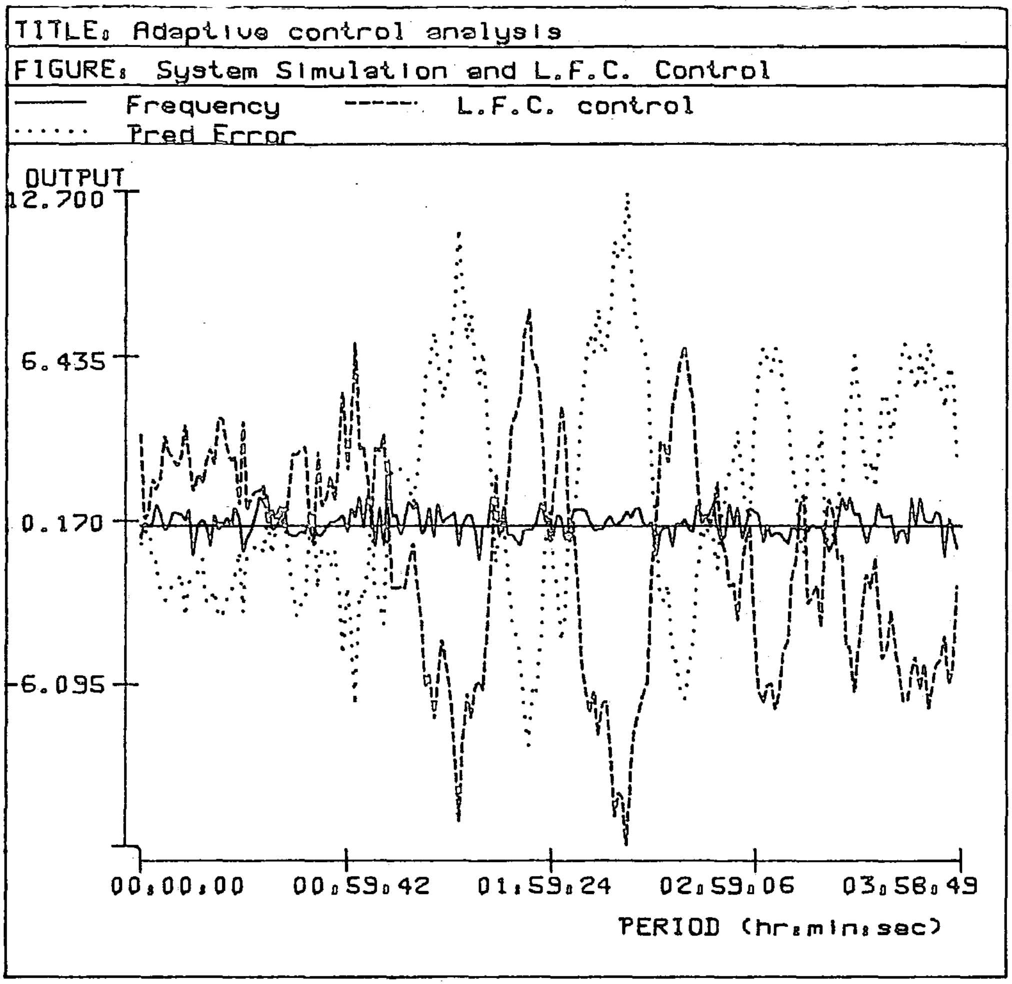


Figure 8.17

Figure 8.18



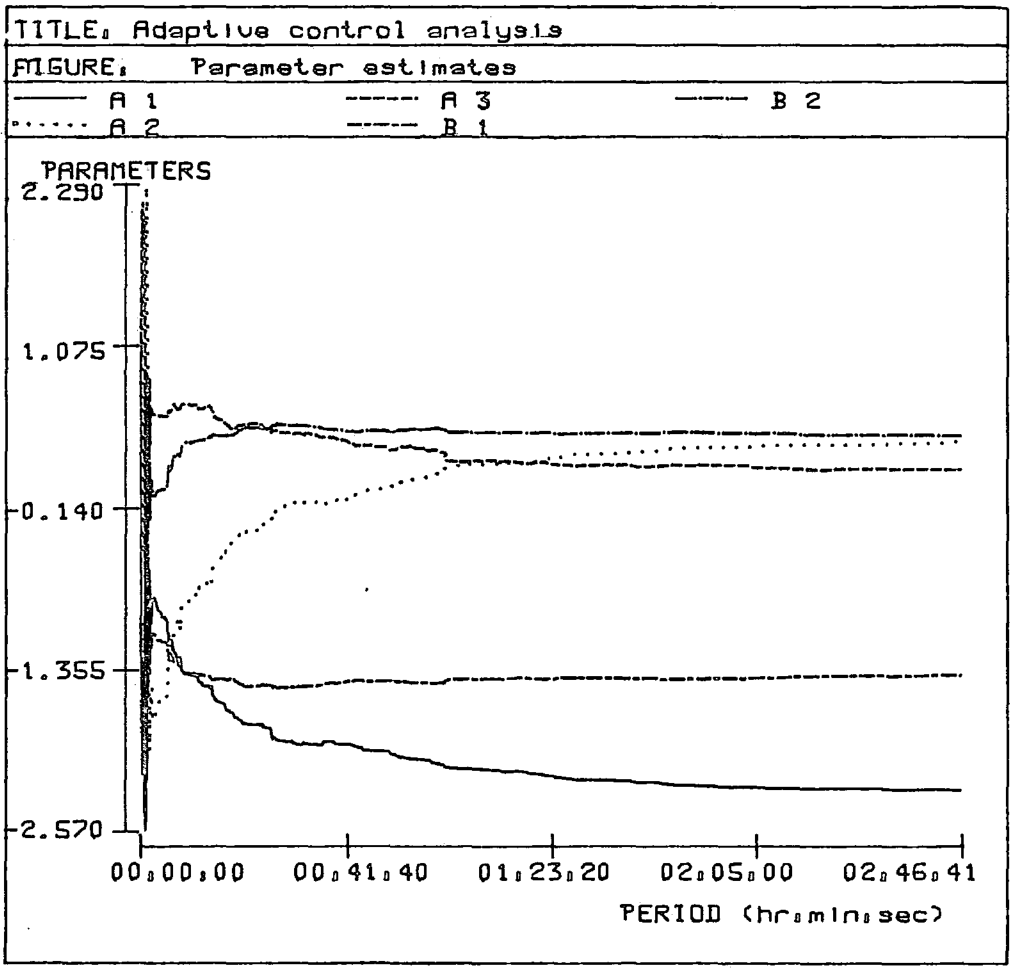


Figure 8.19

8.13.16 Sum of the squares of the frequency error

The number of parameters that were required for the model to be optimum was unknown at this stage. To decide upon the optimum number of parameters to be used in the estimated model, a sum of squares of the frequency error was calculated. This calculation was repeated for estimated numbers of parameters from 2 to 9. The experiment was carried out following the same load curve, over the same time and using the same operating conditions. The results are shown in figure 8.20.

Number of A parameters N	Sum of squares of frequency error Δf^2
2	0.5474
3	0.5635
4	2.2529
5	6.9441
6	0.8797
7	0.6546
8	0.6546
9	0.6044

Figure (8.20)

Sum of squares of frequency error for different numbers of estimated parameters Thus the number of parameters that were chosen for the parameter estimation was three. Although the square error using two parameters was slightly smaller the effect of one more parameter did not degrade the controllers performance. It was felt that the three parameter controller could track the system slightly better than the two parameter version due to the time constants it could identify. The use of one parameter was felt to be insufficient to model the system to a sufficient degree of accuracy. The use of four and five parameters causes massive control action to be taken which is totally unnecessary but still within the system capabilities. These control schemes estimate system models where the corresponding *a* and *b* parameters actually cancel themselves out. More than five parameters shows a decreasing sum of squares of the error, this is because the control action calculated from these models tends to swamp the system under control. This leads to over modelling and calculated control action which is excessive and unstable. Thus following the idea of the minimum number of parameters to model a system sufficiently, a three estimated parameters model was chosen to base the control calculation on.

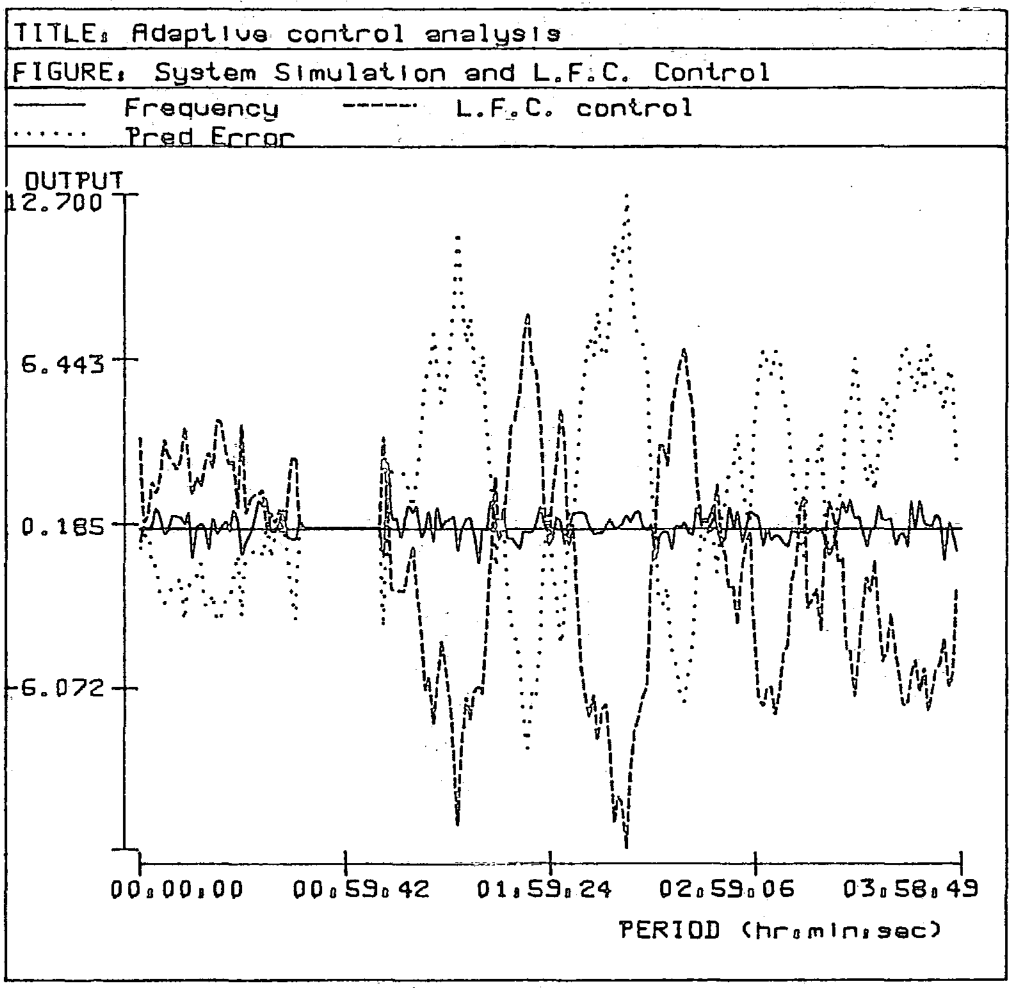
8.13.17 Persistently exciting systems

A standard problem in the field of adaptive control is ensuring that the system under study is 'persistently exciting', that is the driving error for the modelling provides sufficient information for the model to represent the actual system. In some cases (references) the lack of a suitable input to the identifier causes the parameters to drift and become unrepresentative of the system being modelled. To observe the effect of no input to the controller, the load error was reduced to zero for twenty minutes and then continued. The result of this simulation run is seen in figure 8.21 , along with the corresponding parameters in figure 8.22. The parameter estimation is stopped when the load error is reduced to zero and the values are kept at those calculated before the interruption, until the input data returns to its non-zero value. This does not adversely effect the parameter estimation, nor does it slow down the adaption process. The plot of the system outputs shows that the controller continues the control action after the loss of data with the same effect as it did before the incident. Thus the safeguards built in to the controller program are able to handle the lack of relevant data without losing track of the system state.

8.13.18 Faster sampling interval

Although the controller is cycling at 10 second intervals, for the sake of clarity, the system outputs are only recorded every minute. Thus it was possible that under some circumstances some of the faster system responses may be lost by the slower sampling interval. To check for the faster system response, the simulation was executed with a data collection time of 10 seconds. The result of this simulation is shown in figure 8.23. It is shown that the sampling interval used previously of 1 minute is suitable and no faster transients are lost

Figure 8.21



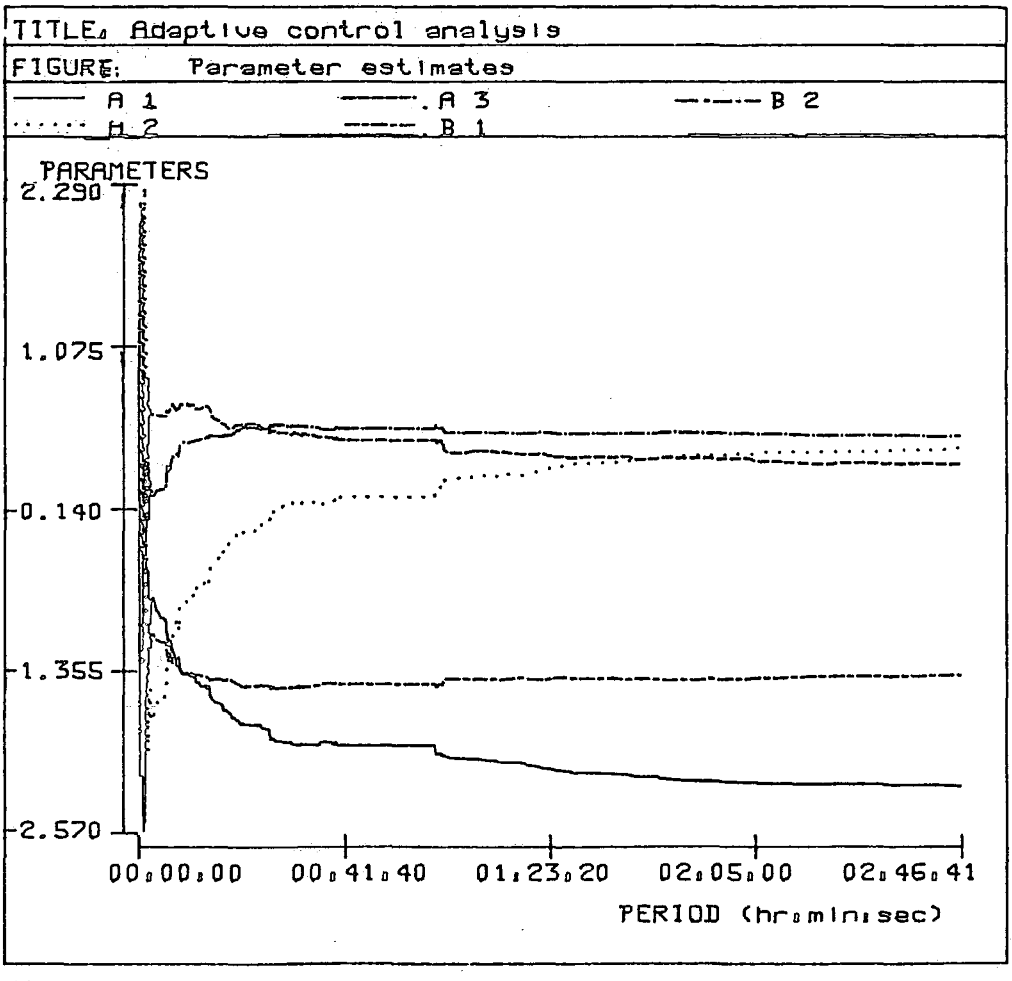


Figure 8.22

using this time interval. The advantage of the slower sampling interval lies in the fact that the data recorded and stored is greatly reduced.

8.13.19 System constraints

The initial simulation runs using the load frequency controller were carried in such a way that the change in power required by the controller was allocated as and when required. This is not the case in actual system, where the turbine-generators have limits associated with them, such as ramping limits and upper and lower output limits. The simulation was made more realistic by limiting the allocation of the requested power by the controller to the system generators. The output of the generators is clearly much smoother than in the case when it was following directly the load change without any constraints. The small perturbations are followed well by the controller, as this does not violate any of the system limits, but the larger load changes require a longer time period for the system to respond due to the constraints. The result of the system constraints is seen in figure 8.24.

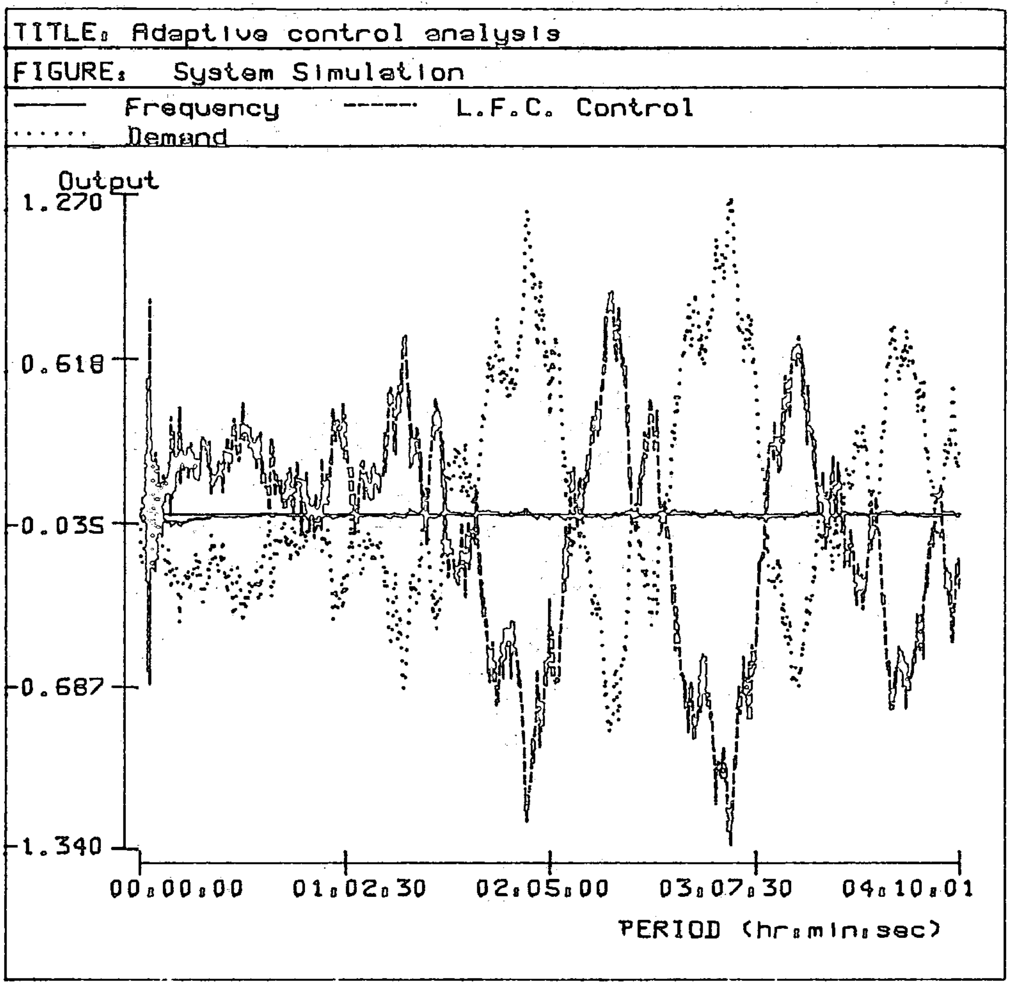
8.13.20 Change in system loading conditions

Figure 8.25 shows the system response to a different set of load changes to determine the controllers ability to track differing loading conditions. The associated parameters are shown in figure 8.26. In this case the mean frequency deviation was found to be 0.001 Hz, with a standard deviation of 0.0055, the sum of the squares of the frequency error was calculated to be 0.0073.

8.13.21 Constrained system output

Figure 8.27 shows the system response to the same set of load changes as for the previous figure, but in this case the output was constrained. The output is much smoother than the driving error and the frequency error is somewhat worse than the previous case, but this is only to be expected due to the system constraints. The figure 8.28 shows the parameters of the model used in the controller for the simulation. The system constraints stop the model parameters from wandering greatly as would be expected, and are brought to a steady-state value more quickly than before. However, this converged value is not as continuous as in the previous case. The mean frequency in this case

Figure 8.23



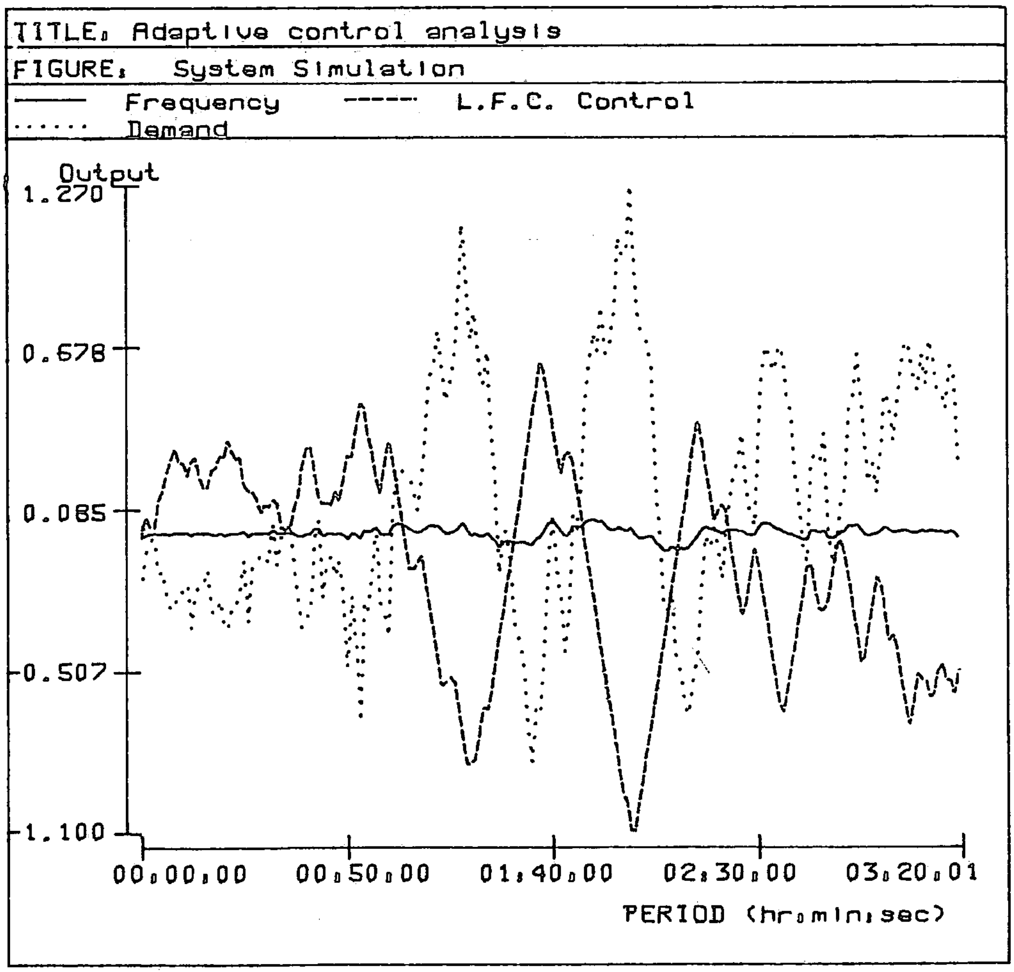
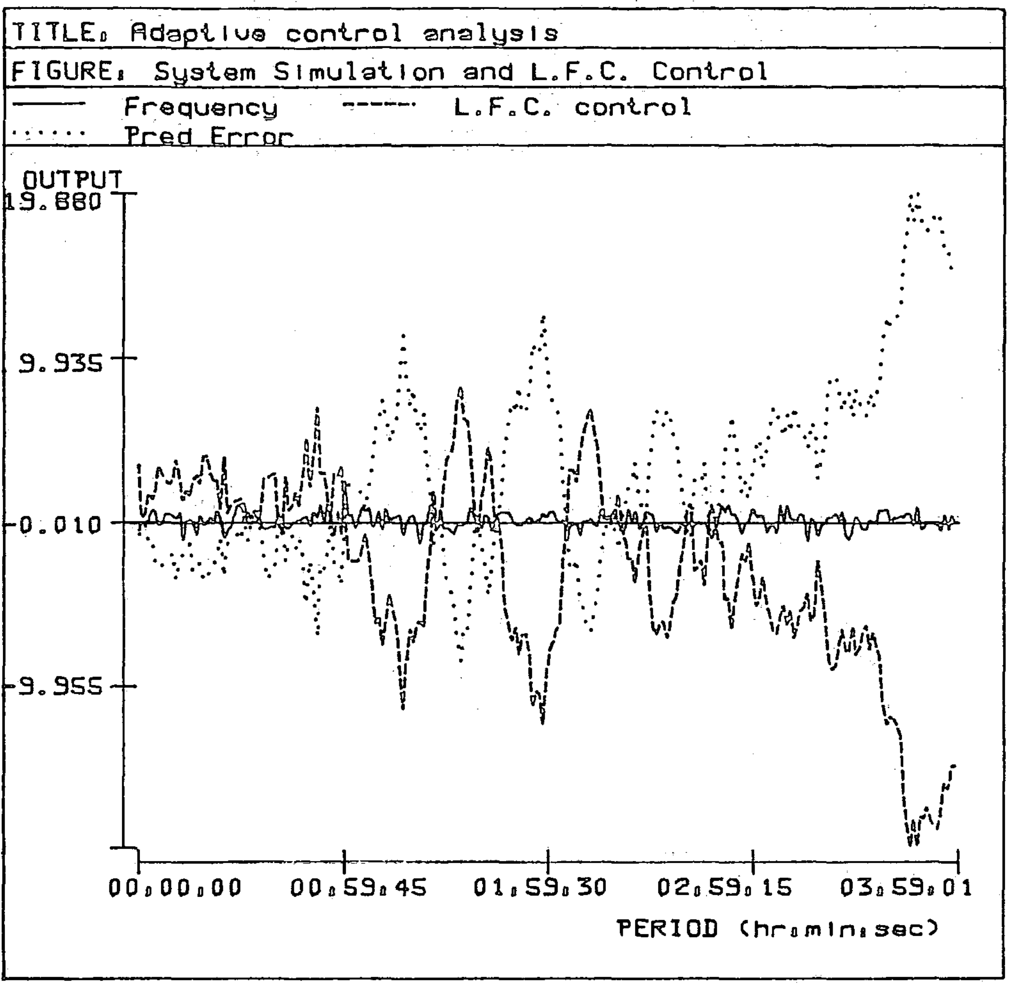


Figure 8.24

Figure 8.25



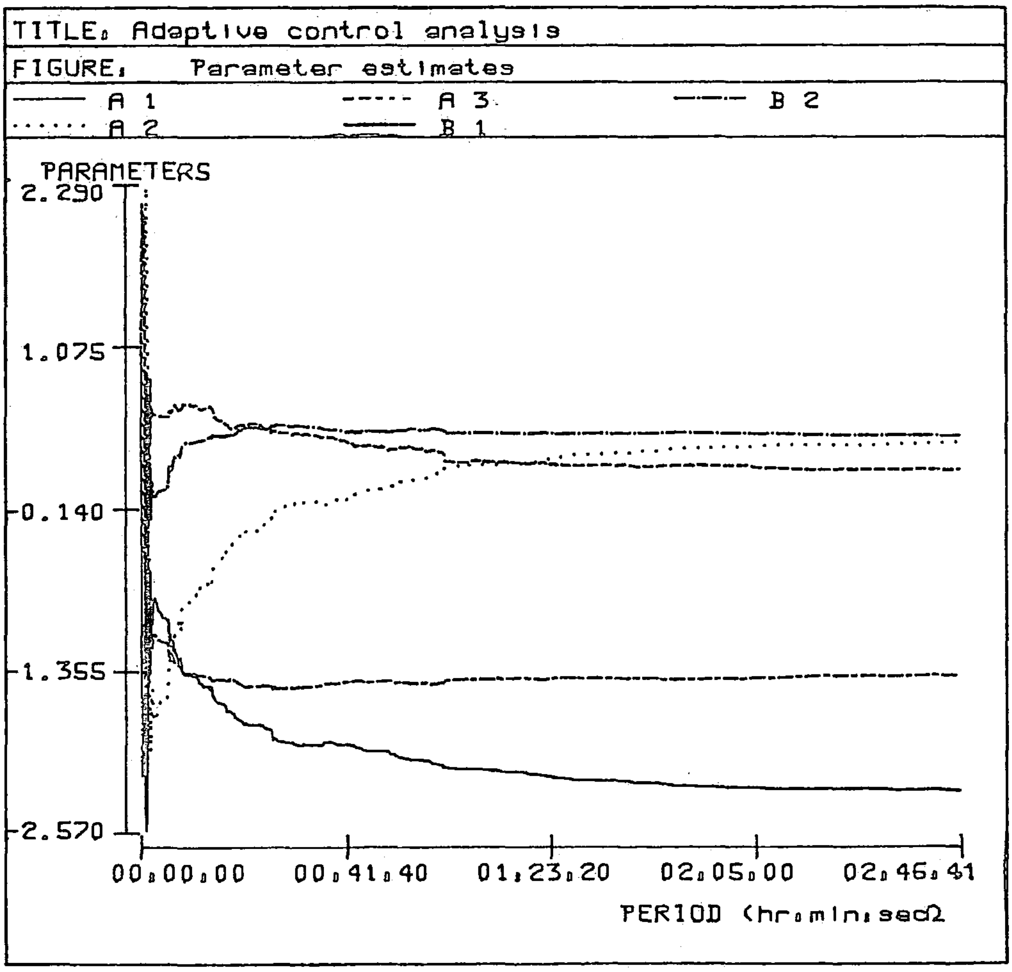


Figure 8.26

is 0.002 Hz with a standard deviation of 0.002. The sum of the squares of the frequency error is 0.01.

8.14 Conclusion

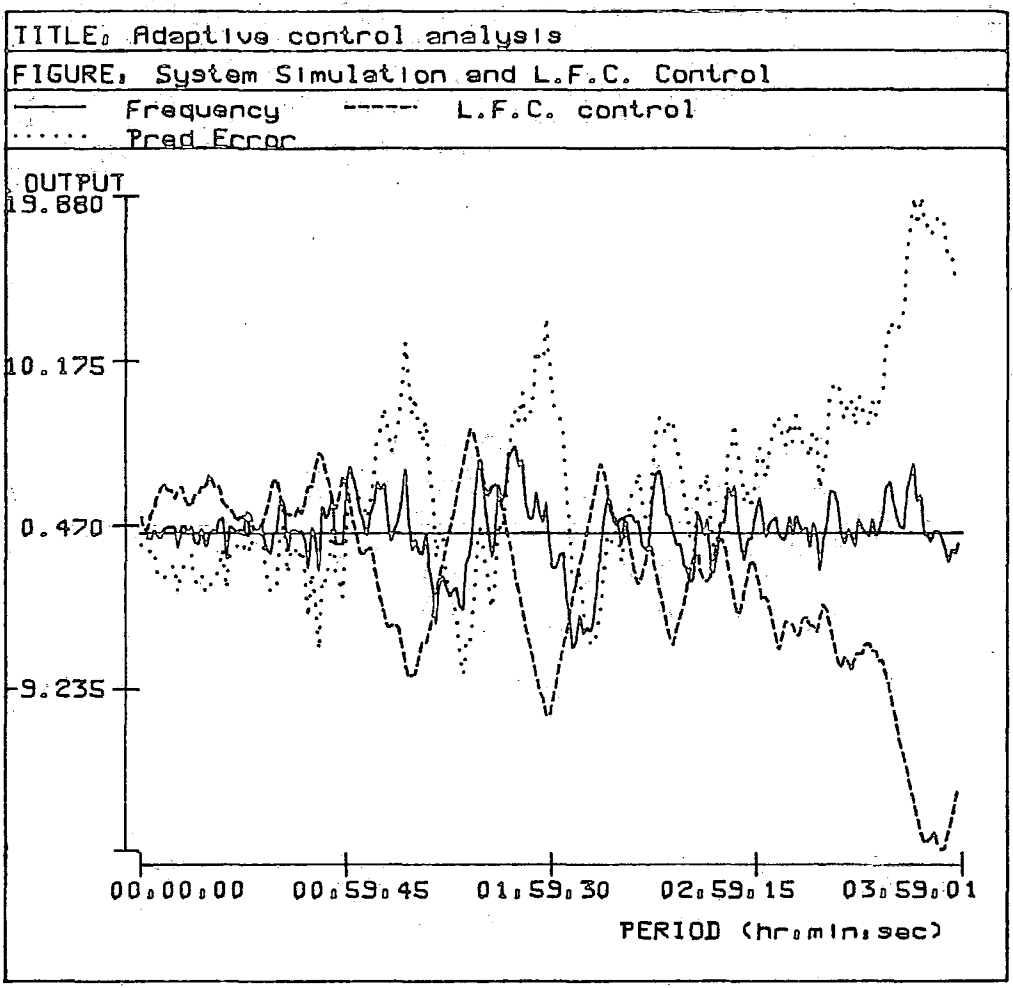
This simulation is shown to be an accurate representation of the system that it set out to be modelled. The use of different generator representation, along with pumped storage models enhances the simulation. The manual dispatch techniques used are shown to be adequate for the control of the system frequency. However, it must be remembered that the long range control functions of Unit Commitment and Economic Dispatch were assumed to have been carried out. Hence, none of the interaction between the higher level control functions have been modelled.

The simulation model along with the simulated Manual Dispatch produced results that are very similar to current operating practices of the C.E.G.B. The C.E.G.B. standard deviation of frequency variation is around 0.08 Hz, which agrees well with the simulated value. The model has shown that without any automatic frequency control it is not possible to improve the frequency control of the C.E.G.B.

The use of adaptive control has been shown to produce tight frequency control, taking in account the system constraints and limits. The ability of the controller to keep the model parameters constant when invalid data or not 'sufficiently exciting' data is presented to it has been demonstrated. The identification of the number of parameters for the model has been carried out and the model obtained from these parameters is shown to be adequate for the control of the system frequency.

The implementation of automatic control on the system has shown that the frequency error can be greatly reduced by almost an order of magnitude in some cases. This is a useful result as it shows that some type of dedicated frequency control would improve the operation of the U.K. network. However, this simulation was operated without any interaction with any sort of Unit

Figure 8.27



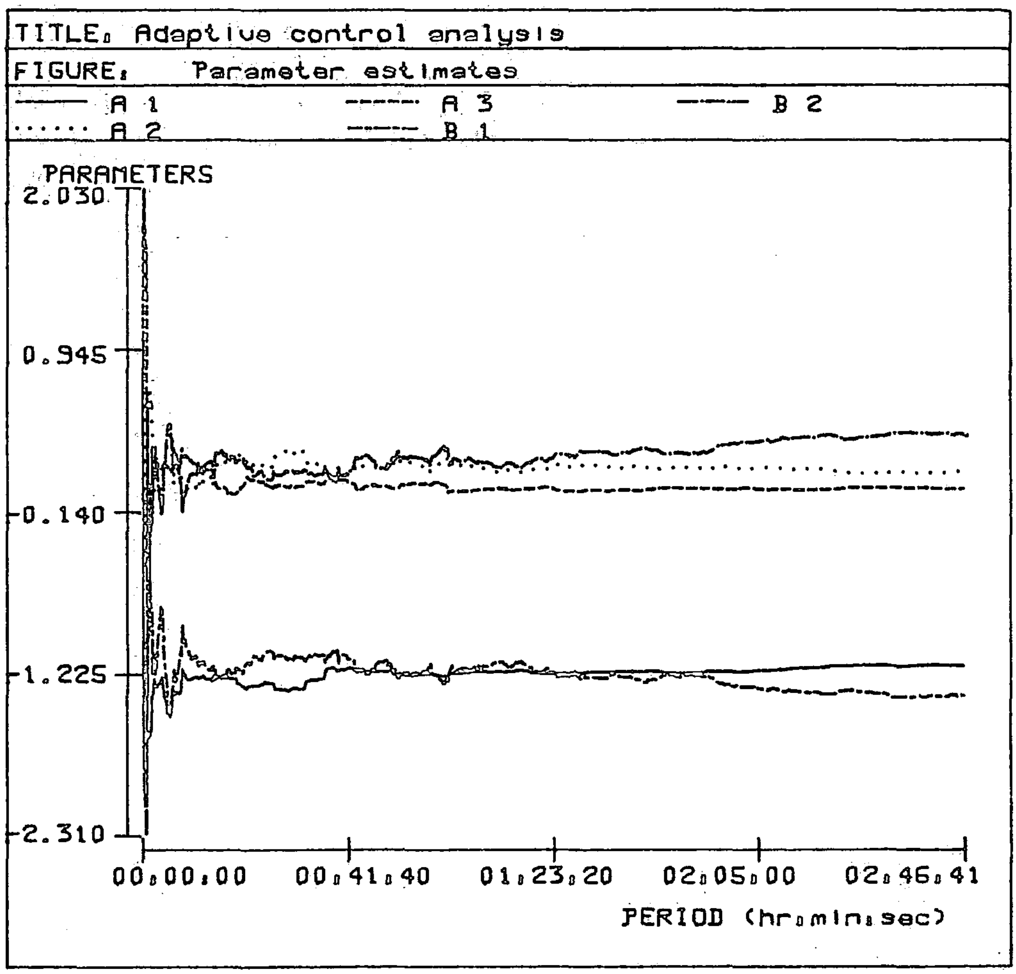


Figure 8.28

Commitment, plant ordering or economic consideration. Thus it is probable that in the event of automatic frequency control being used by the C.E.G.B. that such a great improvement over the frequency error would not be achieved. It must also be remembered that the tests were carried out using a fixed set of operating constraints and over a fixed period of time. Clearly further work would be required to investigate the effect of prolonged frequency control on the network and during periods of large changes in the consumer load.

CHAPTER 9

ON-LINE SYSTEM CONTROL

9.1 Introduction

This chapter describes work which was carried out in conjunction with the Central Electricity Research Laboratories (C.E.R.L.), Leatherhead. The aim of the research was to investigate the requirements for the interface between the C.E.G.B. dispatching project and load frequency control. A further aim was to implement the adaptive load frequency controller developed on the Operational Control of Electrical Power Systems Simulator at Durham into the dispatching controller. The dispatching project developed by the C.E.G.B. has been under development for a number of years at C.E.R.L. and a brief description follows.

9.2 Dispatch Project

The C.E.G.B. system is one of the largest systems under single management compared with other utilities. It is controlled as a single entity, with little emphasis on tie-line flows. The system operation is characterised by slow ramping, due to the capabilities of the thermal plant, mainly coal-fired generators. There is also some pumped storage plant available , but this reserve is valuable and is dispatched regarding the economics of operation. The short term frequency control is achieved by each unit's governor on the thermal plant, backed up by automatic start-up facilities on the pumped storage units and gas turbines [29,30,193]. The pumped storage and gas turbines plant can be started up manually if required to control the system frequency. There is also another option which can be used to control the system frequency but this is not used often as it involves removing the consumer load. In extreme emergencies frequency sensitive protection will load shed, this is very rarely invoked.

The time scale of this control action is a few minutes onwards. The control of the real power of the system is entirely by that of manual action, although there are numerous off-line computer aids available to the dispatch controller. The metering on the system and control equipment is designed for mainly manual operation. The use of automatic control must take this limitation into consideration and the requirement of a continuous supply delivered to the consumer.

9.2.1 Inter Area Transfer system

The manual control of such a large system would very difficult indeed if it were based centrally. To reduce the difficulty of the control problem, the system is split up into six areas, each with their own Area Control Centre, which are co-ordinated by a central control at the National Control Centre. This system of reducing the network into several smaller area is called the *Inter Area Transfer System.* The National Control Centre defines an amount of export or import power for each area and the area control centres adhere to this centrally calculated amount. The power transfers are calculated off-line several hours in advance, and updated using the most recent information of each areas incremental and decremental generation costs along with the limitations imposed on the system by the transmission network. In this way the large dispatching problem is broken down into six smaller ones, each of which can be handled by the control engineer in each area. The targets can be biased in proportion to the system frequency, to assist the effect of the unit's governors.

The advantages of the Inter Area Transfer System are

(a) The smaller dispatch problems can be handled by one or two control engineers; this would be very difficult for the whole system.

(b) The task of National Control is eased by the fact that the sum of the transfers of all areas is zero.

(c) The transfers are selected to avoid overloading the Inter-Area transmission lines, and the local Area engineer can avoid the overloading of local lines.

(d) If the transfer calculation is not updated, then the system can still continue to operate, although it would be less economic.

(e) The errors in demand prediction and target following can be accommodated and reduced by inter-area transfer.

(f) The system has been operated in this mode for many years and the characteristics of the operation are well known.

The Inter-Area Transfer system worked well in the past, but developments in the system, computational techniques and the desire for more economic operation required an updating of the dispatching for the system. The generation of the system became concentrated into a smaller number of larger units and hence, the concept of central control became feasible. The increase in computer power enabled the benefits of centralised dispatch linked with a degree of automation to be considered. The benefits of centralised dispatch are

(a) Centralised dispatch has the ability to use on-line information that can be regularly updated. This enables optimisation to be performed more frequently and hence, the optimal point for system operation can be followed.

(b) The short term variations from the load prediction can be satisfied from the whole system rather than by the local control area.

(c) The pumped storage capacity can be treated as a system resource and used under certain circumstances..

(d) Repeatedly calculated central dispatch calculations potentially provide an economic benefit by reducing the system requirement for spinning reserve.

(e) The use of computer based dispatch techniques provides a basis for future developments such as optimisation with respect to consideration of transmission losses. These transmission losses are incorporated into the calculation at present by assigning each loss a penalty factor.

9.2.2 Dispatch function

The Dispatch Project[83,84] was set up in 1981 to review dispatch procedures in the C.E.G.B. and investigate the advantages of centralised dispatching techniques for the allocation of real power generation[32,33,45,79,158,223]. The use of computers has enabled the Dispatch Project to be implemented as an off-line advisory control function, both in the National Control Centre and in Area Control Centres.

The dispatch calculation was performed every five minutes to ensure that is was up to date, but the results were implemented manually as thought necessary typically every 15–30 minutes. Dispatch targets are set for each generator in time steps ranging from ten minutes to two hours, including pumped storage units. Generator costs are modelled as picewise-linear using upto three segments for each generator, and are used to calculate the individual targets. The start-up and shut-down times for each unit, are used by a separate program known as Generating Ordering and Loading (G.O.A.L.) which provides input data for the dispatch. The dispatch calculation does not attempt to carry out any frequency control as the cycling period of five minutes was not sufficiently fast.

9.3 Load Frequency Control and Dispatch

The aim of the work carried out with C.E.R.L. as described was to investigate the interface between the Dispatch Project and that of Load Frequency Control, with a view of linking the adaptive L.F.C. into the dispatch calculation. Clearly this control function requires a completely closed loop system for operation. The mechanism for closing this loop is not available, and if it were available extensive testing would have to be carried out before the loop could be closed in reality. A way in which the controller could be tested out on-line was required, so a way of closing the loop had to be found.

The L.F.C. function was to be interfaced with the off-line version of the Dispatch Project which is used for development work. The data base that the off-line Dispatch software works from is updated as is the on-line version, but the off-line version can be altered as required with the addition of new variables for test purpose without affecting the on-line version. This interface would enable the L.F.C. to run in such an environment that it was reacting to on-line data from the actual system updated in real-time in conjunction with the Dispatch calculations.

The control loop for the L.F.C. was to be closed using a simulated system which could operate along with the actual system, and react as the actual system. The input data for the simulation would be a combination of *live* data from the data base and data calculated by the L.F.C. and the dispatch set values. The dispatch set values were calculated from *live* data from the system data base, including ramping rates, start-up and shut-down costs and other system constraints to produce an economically determined set of generator target set points. The configuration of the data base, dispatch software and the frequency controller is shown in 9.1.

Later it was possible to close the loop completely such that the Dispatch was reacting to the values calculated from the L.F.C. itself and then reacting to values from the simulation, rather than the actual system itself. Clearly it was not at all possible to feed control signals from the L.F.C. back to the real system. The data was still taken from the live data base, so the real system status still affected the off-line calculation. If was felt that the duration of the simulation was not long enough for the simulation and the actual system to deviate to any great extent, so the data from the actual system could still be used on the system without the loss of any validity. The modified system with the feedback to the Dispatch function is shown in diagram 9.2. The model used for the simulation of the system and its requirements are discussed below. This is followed by a presentation of the results of both the off-line and on-line studies, along with discussion of the L.F.C. function.

9.4 Simulation Model for Frequency Control Investigation

The L.F.C. function is designed to interact in real-time with the Dispatch control function and so the model must be capable of reproducing the response of the system to a reasonable degree. This model is required to be simple so that it does take up too much of the main computing resource, yet realistic enough so that the Dispatch function can fully function along with the L.F.C. and associated control functions. A discussion of the work carried out at C.E.R.L. follows including: the simulation model used, the use of the on-line

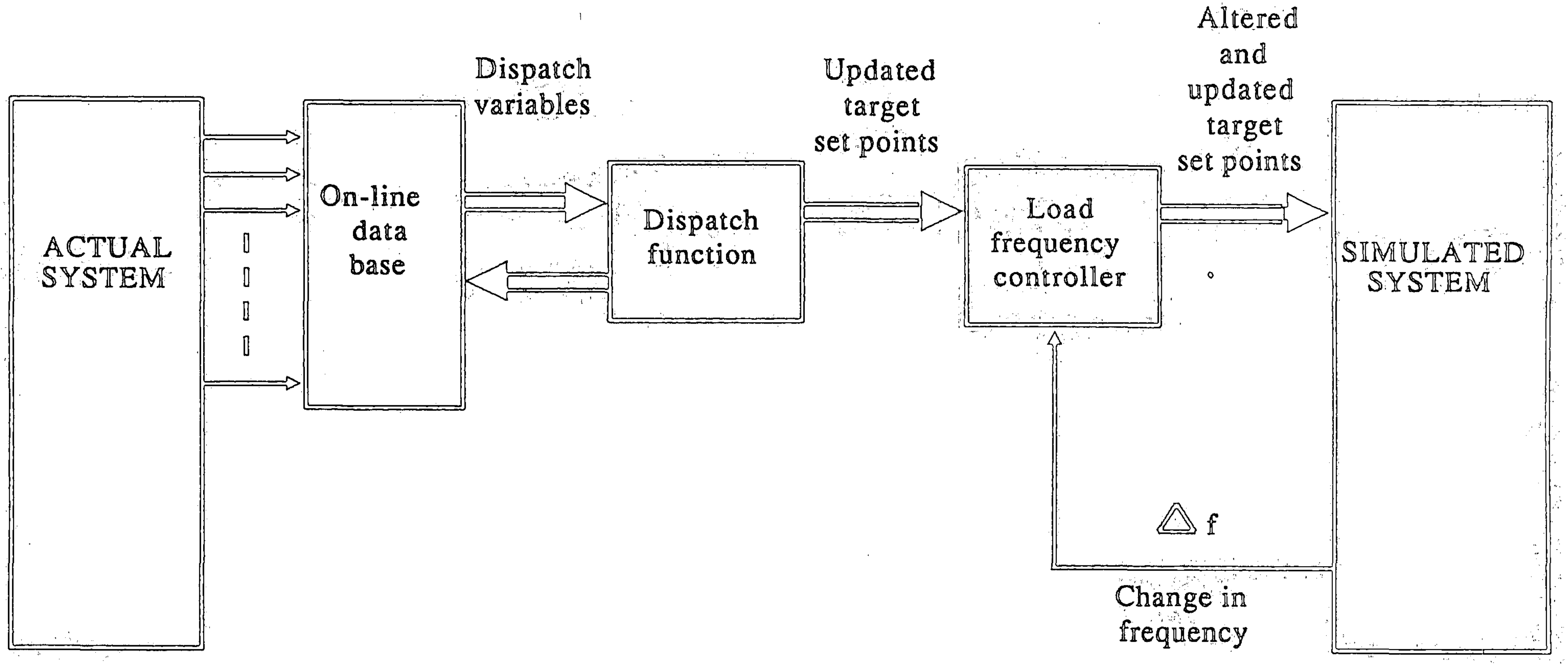


Diagram 9.1 Actual System and Simulated System

Path of data flow between

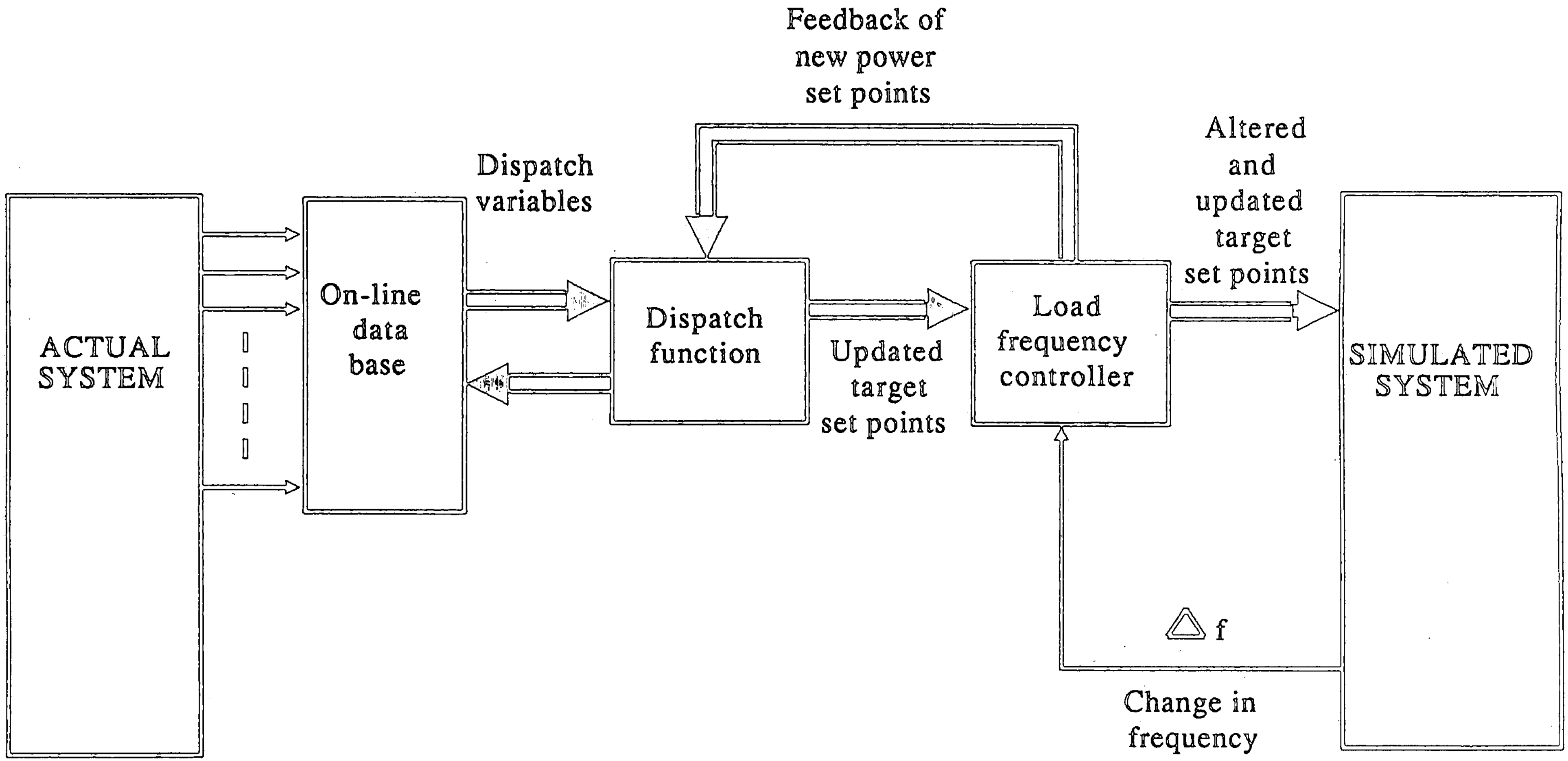


Diagram 9.2 Actual System and Simulated System with feedback power set points

data base, the operation of Dispatch, the use of L.F.C., the generator unit's response and the results obtained from the real system data.

9.5 Dispatch

The Dispatch produces a sequence of target values for every generator in the system and cycles at every five minute interval. The new set point for each generator is made available to the database, although the value is not sent to the generator unit. The new set point is only taken as advisory and must be implemented manually at present. The simulation assumes that each set point is directly sent to the generator unit as it would be in a fully automatic control system. Most of the set points of the generators are kept constant in the actual system as they are run at their most economic operating point, with only a few generally available for control purposes. The dispatch calculated set points for each generator are denoted by U.

9.6 Load Frequency Control

The Load Frequency Control function cycles every few seconds and produces a modified total additional megawatt signal $\Sigma\Delta U$. This is the total amount of power which needs to be allocated to the generators for the frequency error to be reduced to zero in the next time period. The value ΔU is the amount of power which is to be allocated to each individual generator, and this is found by a partitioning algorithm. A value for ΔU is found only for a small subset of the generators (typically 12). This is because only certain generators are allowed to participate in control action for load frequency control. The generators which are allowed to contribute are decided upon through several factors

(a) Does the unit have a suitable governor.

(b) Is the unit operating near its maximum or minimum limit, and if so can it run over these limits for a given period.

(c) Does the unit have to go through any breakpoints. For example does a coal mill have to be started in order to sustain a power increase.

(d) What is the unit's increase, or, decrease rate, and what is the unit's turn around time, that is what is the time for the unit's to change its ramping direction.

(e) What are the plant characteristics, does the unit have local computer control?, is the generator flexible enough for change of output (for example a nuclear station will operate at one point continuously).

(f) Is the generator unit well instrumented, can control commands and outputs be monitored, are there enough communication channels.

(g) Does the increase in generation of one generation station violate the transmission line limitations.

The units which are capable of participation in the control of frequency in this case are selected by the Dispatch function and made available to the L.F.C. function through the data base facility.

At any time there is a *combined target* for all generators. This is U for most of the units, but for the proportion which are able to participate, it becomes $U + \Delta U$.

9.7 Generator Response

The generator units respond to the target signal which has been calculated by the dispatch and altered by the L.F.C. of $U + \Delta U$ and also to the frequency error Δf. Ideally the output should be

$$(U + \Delta U) - K\Delta f \tag{9.1}$$

Hence their output is the sum of the dispatch set targets, altered if necessary by the L.F.C. and the contribution of the governors response to the frequency error. The governors short term response ensures that the instantaneous frequency error is reduced.

9.8 Response to Dispatch Set Targets

It is reasonable to assume that generators will follow their dispatch set targets fairly well, since these are premeditated and calculated using the most recent system data. Hence, all the values calculated by the dispatch should be capable of being reached by the generators. However, complete and true response of all the generator units to the dispatch commands would be an unrealistic situation to assume [29,30,79,83,84]. To add some variation to the generator response, it was decided to alter the dispatched set point sent to the generator, by a random amount based on the output of the particular unit five minutes ago. Hence

$$P(U) = P_{old} + R \times (U - P_{old}) \tag{9.2}$$

where

P_{old} is the output five minutes ago, and

R is a random number between 0.7 and 1.1

9.9 Response to Load Frequency Control Set Targets

The response of the generator units to the targets altered by L.F.C. is less predictable as it does not take into account the ability of the machine to respond to the command issued. The new target to be reached will also be subject to a firing delay. This unpredictability of the response of the generator unit is reflected in the way the simulated plant respond to the control signal.

The ability of the machine to respond depends on the type of generator, so the following criterion was proposed for the plant response.

(a) Oil Plant is certain to respond directly if ΔU is in the opposite sense to $(U - P_{old})$ and,
has a probability of 0.6 of responding as ordered if it is in the same sense as $(U - P_{old})$ or, if $U = P_{old}$.

(b) Coal plant is the same as above but with probabilities of 0.7 and 0.3.

(c) Nuclear plant, ΔU is not permitted .

(d) Pumped storage responds directly to system frequency.

Time response to the control command is very variable, depending on whether mill or burners have to be started.

Thus the following transfer function was proposed to model the delay in a unit responding to a control command.

$$\Delta P_{LFC} = \frac{1}{1 + T_{LFC} s \Delta f} \tag{9.3}$$

The value of T_{LFC} was determined as approximately one minute, thus $T_{LFC} = 1$ minute. The configuration of the L.F.C. function is shown in diagram 9.3.

9.10 System Response to Change in frequency

The generators output respond to a change in frequency due to the governor action. This is usually quoted as

$$\text{Change in generation due to change in frequency } = K\Delta f \tag{9.4}$$

However in this case the simulation model must be included in this term as the model represents the change in the system output in response to the frequency. Thus the response is re-written as

$$\text{Change in generation due to change in frequency } = KG(s)\Delta f \tag{9.5}$$

where

$G(s)$ is the system transfer function, and

K is the total gain of the system, made up from the sum of all the generators distributed about the system. The value of K is taken such that $\Sigma K \approx 5000$ MW/Hz

It is noted that the system becomes harder to control as ΣK reduces, as it is less responsive to the control action.

9.11 Simple Simulation Model

The system is modelled using a transfer function which describes the system in a fairly simple way, but models the reaction of the system to an input effectively. The simplified representation of $G(s)$ was taken to be

$$\text{Power output } = \left(\frac{1}{1 + T_1 s}\right)\left(1 - \frac{1}{1 + T_2 s}\right)\Delta f \tag{9.6}$$

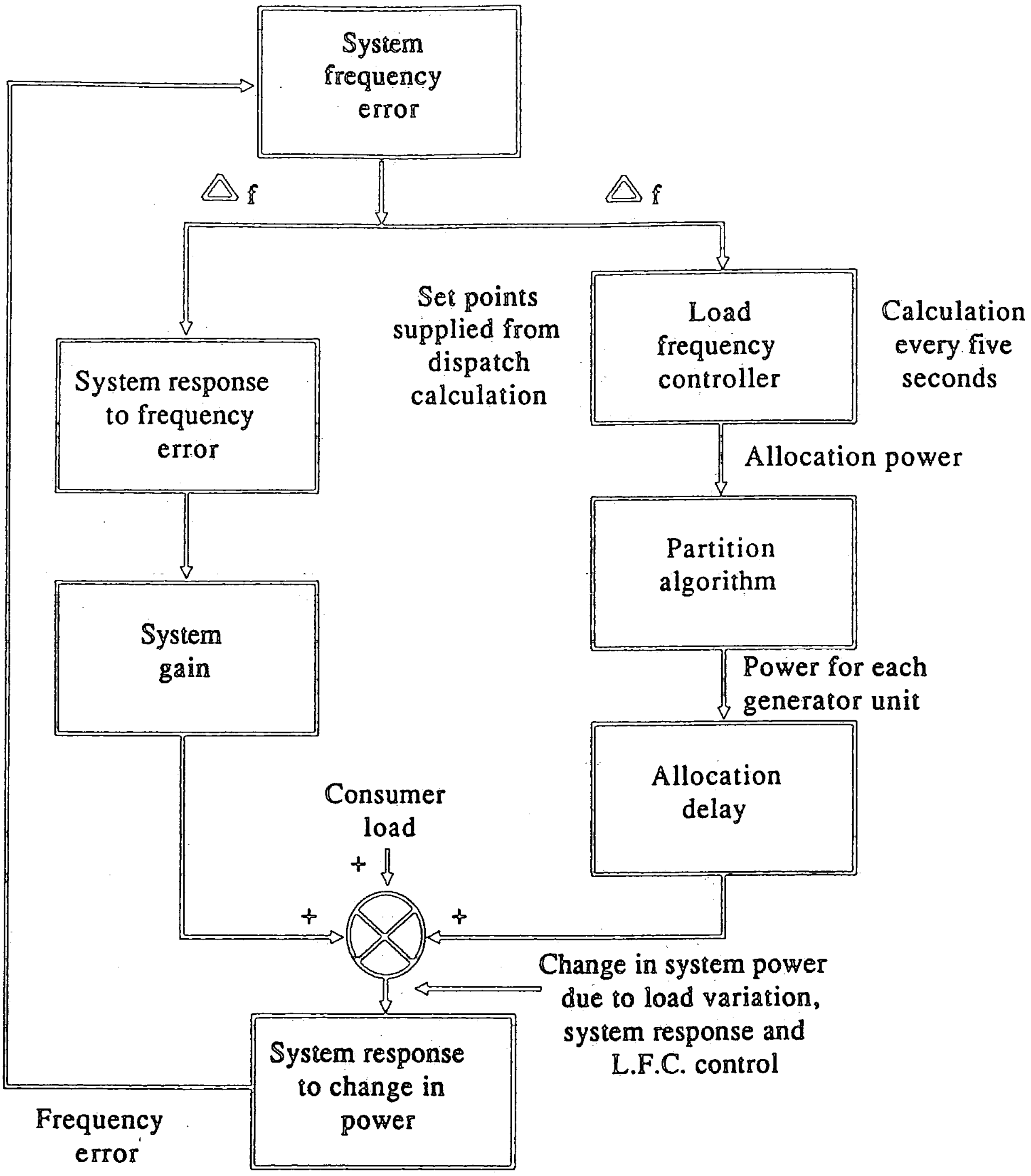


Diagram 9.3 Load frequency control interfaced to system simulation

where

T_1 is the rise time constant, taken to be 10 seconds, and

T_2 is the decay time constant taken to be 180 seconds.

This is a suitable representation for a system which contains units whose response is non-sustained (see previous chapter), but if some of the units in the system have a sustained response, then the term becomes

$$\text{Power output} = \left(\frac{1}{1+T_1 s}\right)\left(1-\frac{p}{1+T_2 s}\right)\Delta f \tag{9.7}$$

where

the value of $p < 1$ (a typical value would be 0.95).

This situation makes it easier for to control the system using L.F.C., as the control function can rely on some support from the sustained response units.

9.12 Complete Simulated System Response

Clearly, the generators cannot respond directly and immediately to the control commands. The response of the generators to the control signal $(U+\Delta U)$ is strictly limited by the physical constraints, such as the unit's minimum and maximum output. It is also limited by the individual generators ramp rates, but the declared ramp rates for the units are conservative, as they are defined to specify long sustained ramps, not short control ramps as required by the L.F.C.

Thus the ramp rates of the generator units could be defined from the values residing in the data base. It was assumed that the response to the control command U was constrained by the declared ramp rates (as it actually was, as the long range ramp rates are declared to dispatch). It was also decided that the total response of the generators to the error signal $U + \Delta U - K\Delta f$ should be constrained to within a practical limit. Thus, constraints were placed on the ramping rates such that the units were restricted to 2% above that of the maximum ramp rate and 5% below that of the minimum ramp rate. Also, the ramp rates should not be exceeded by more than 10% of the unit maximum ramp rate. The system simulation, along with the L.F.C. and the Dispatch was shown in diagram 9.4.

9.13 The Generation of the System Frequency

The system frequency was calculated using the standard equation of the error between the demanded power by the load, and that supplied by the generators, taking into account the system inertia. This is given by

$$\frac{d}{dt}(\Delta f) = \frac{1}{K_I}(\Sigma P - D) \tag{9.8}$$

where

ΣP is the sum of all the generator outputs at time t,
D is the total consumer demand at time t, and
Δf is the system frequency
K_I is the system inertia and was given the value of 50000 MW.Hz.s.

In this model there was no need for a $-K'\Delta f$ term because this is included in the frequency response of the plant.

9.14 Solving the Model Equations

The system simulation as defined, using the transfer functions described implies a differential equation description for each generator. To simplify the programming of the simulation and reduce the number and type of generators represented in the network, it was decided that the generators could be 'lumped' together. This enables one transfer function to be used to represent all the generators in the system. This implies that all the generators in this system have the same time constants, and are of the same type. Clearly, this is untrue as there are many different types of generators in the system. However, the approximation enables a realistic system response to be obtained without the use and complexity of many different generator models and types.

When responding to a change in power of ΔU, it must be remembered that the power at time t,is only influenced by ΔU at $(t - \Delta t)$. To solve the

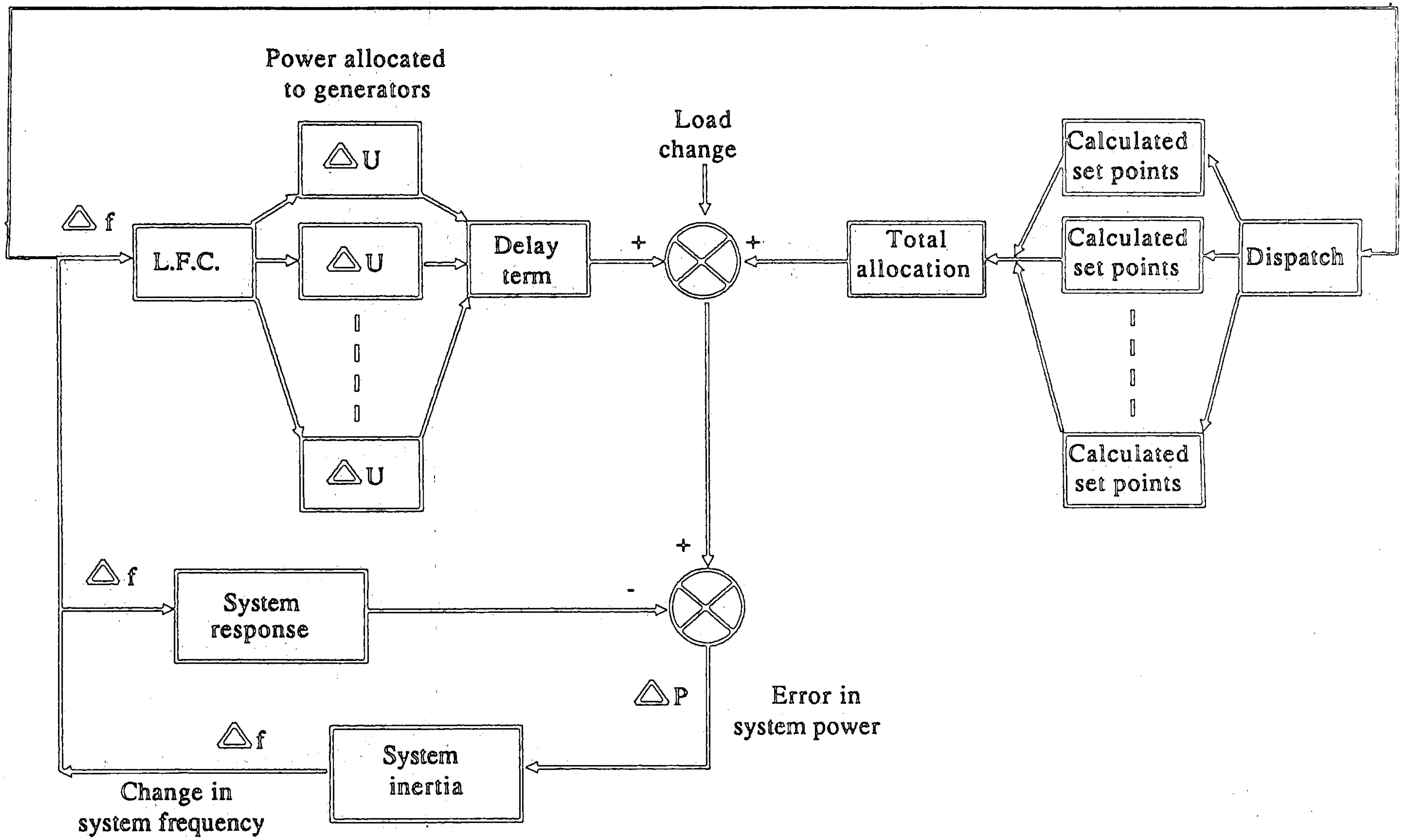


Diagram 9.4 Proposed combination of L.F.C. and dispatch functions for simulation

differential equations, it was decided to use Euler Integration, as this is a simple and easy to implement method.

The equations were solved using the Modified Euler Method described in an earlier chapter and so were converted into the state-space form. The state variable diagram for the system response is shown in diagram 9.5.

Again, as in the previous chapter the variable $V(s)$ is introduced to avoid the need for differentiation. The state variable diagram is formed by integrating $V(s)$ twice and combining the signals required. In this form, the initial differential equation may easily be solved using the Modified Euler Method. By inspection of diagram 9.5, the state equations are

$$\dot{x}_1(t) = x_2(t) \tag{9.9}$$

$$\dot{x}_2(t) = \frac{\Delta f}{T_1 T_2} - \frac{1}{T_1 T_2} x_1 - \frac{T_1 + T_2}{T_1 T_2} x_2 \tag{9.10}$$

These can be written using the matrix notation

$$\begin{Bmatrix} \dot{x}_1 \\ \dot{x}_2 \end{Bmatrix} = \begin{bmatrix} 0 & 1 \\ -\frac{1}{T_1 T_2} & -\frac{T_1 + T_2}{T_1 T_2} \end{bmatrix} \times \begin{Bmatrix} x_1 \\ x_2 \end{Bmatrix} + \begin{bmatrix} 0 \\ \frac{1}{T_1 T_2} \end{bmatrix} (\Delta f) \tag{9.11}$$

This takes the form of

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

The output (change in power) can also be obtained from the diagram 9.5 and can be seen to be

$$\text{Output } = x_2 T_2 K$$

. The equation to calculate the frequency

$$\frac{d}{dt}(\Delta f) = \frac{1}{K_I}(\Sigma P - D) \tag{9.12}$$

is treated in the same way and gives

$$\dot{x}_2(t) = \frac{\Delta f}{T_{ps}} - \frac{1}{T_{ps}} x_1 \tag{9.13}$$

These can be written using the matrix notation

$$\dot{x}_1 = \left[-\frac{1}{T_{ps}} \right] \times x_1 + \left[\frac{1}{T_{ps}} \right] (\Delta f) \tag{9.14}$$

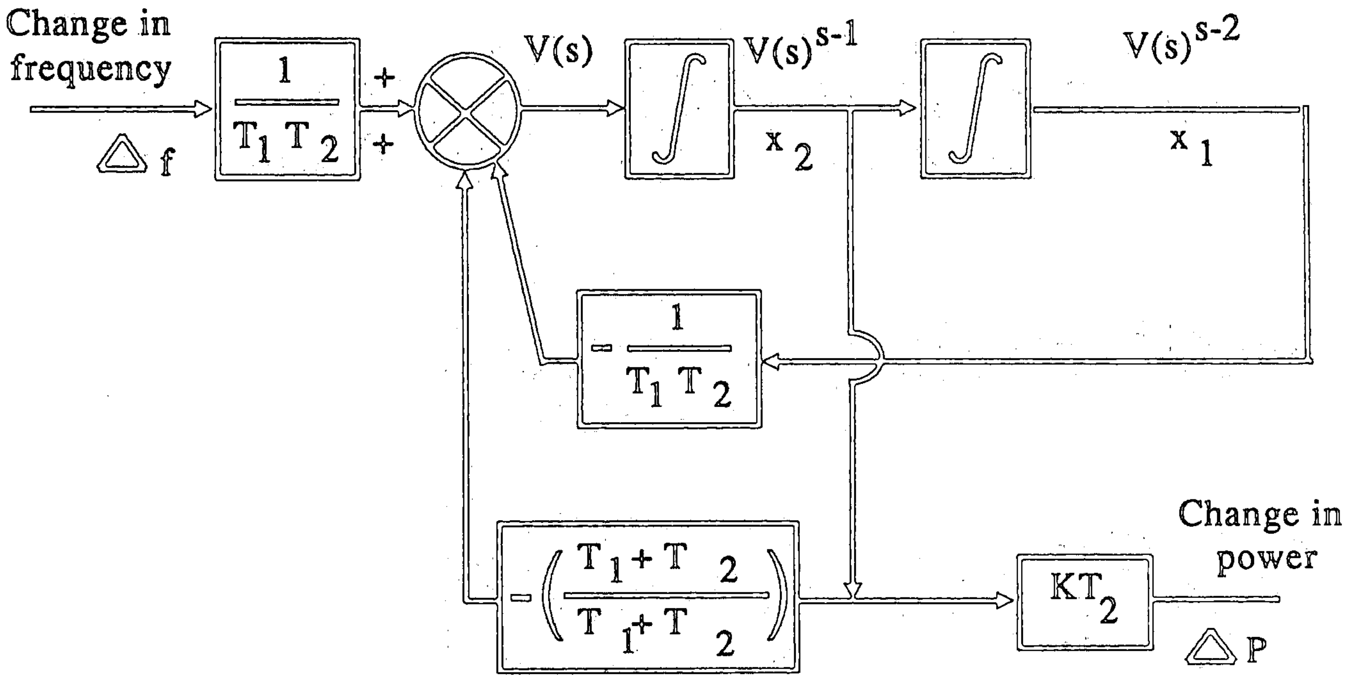


Diagram 9.5 State variable diagram
for simulated system

9.15 Simulation Demand Modelling

The total system demand varies with a change in frequency according to

$$D = D_0 + K_D \times \Delta f \tag{9.15}$$

where

K_D represents the change in the consumer load of the frequency sensitive load which is approximately 2%/Hz

Thus the equation (9.17) becomes

$$D = D_0(1 + 0.02\Delta f) \tag{9.16}$$

where

D_0 is the consumer load at nominal frequency the change in frequency. The total system inertia is generally proportional to the total of the plant synchronised to the system, and hence to the demand. Thus

$$K_I \approx 1.7 \times D \tag{9.17}$$

However as this model is to be used as a test for L.F.C. it does not enter directly into the dynamics. It must be remembered that the data and parameters given are only estimates and that a further enhancement to the model would involve revising the transfer functions for the individual generators. However, this model is good enough to provide a valid test of L.F.C. The values used in the simulation are a reasonable approximation for a realistic simulation although individual generator units are not modelled. The model could be made more exact by incorporating several different generator types.

9.16 Pumped Storage

To enhance the simulation, it was felt that a representation of the pumped storage generators available on the system should be included as they can be selected by the dispatch function.

9.16.1 Selection of Pump Storage

If they are available, but not selected, they should trip in on low frequency. The pumped storage units are organised in a cascade arrangement such that if the frequency reaches 49.9 Hz,

(a) one Dinorwig set at a nominal 200 MW is tripped in with a nominal rise time of 10 seconds If the frequency reaches 49.85 Hz,

(b) two Ffestiniog sets, with a total of 180 MW and a rise time of 60 seconds are tripped in.

(c) If the frequency reaches 49.8 Hz, a second Dinorwig set is tripped in as above.

If the Dinorwig sets are spinning in air the rise time is ten seconds, otherwise it is 120 seconds. In normal operation, the first unit is spinning in air, the second one is not. Eventually Dispatch will select whether the set is spinning, depending on the distribution of the other reserves. To simplify the situation, the two reaction times were averaged, and the reaction time taken was 60 seconds.

The two Ffestiniog sets, which can produce a total of 180 MW, and are tripped in when the frequency drops below 49.9 Hz. These Ffestiniog sets are only capable of generating at nominal output and hence, are not capable of regulation.

9.16.2 Pumped storage response

The Dinorwig sets respond to Δf much more strongly than the thermal units so this was reflected in the transfer function used to describe their response. As for the other generators represented by the model, the factor used was

$$\text{Power output } = K_{ps} \times G(s) \times \Delta f \tag{9.18}$$

clearly showing that the response of the units is sustained.
where $G(s)$ has the transfer function

$$G(s) = \frac{1}{1 + T_{ps}s} \tag{9.19}$$

where

T_{ps} is the pumped storage rise time, and takes the value of 10 seconds, and
K_{ps} is the pumped storage gain and has the value 600 MW/Hz per running

set, whether started by Dispatched or on auto start However, the response is limited by an upper and lower limit of 320 MW and 140 MW, these units have a sustained output of 300MW.

The response to ΔU is the same as that to U and hence is given by the transfer function

$$G(s) = \frac{1}{1 + T_{ps} s} \tag{9.20}$$

The units will respond to the control command with essentially 100% certainty, but its response is limited to $U + \Delta U \leq 300$ MW.

In normal system operation units which come on in this auto start mode are switched off manually when the system has settled down. Thus a simple criterion for this was used to simulate this switching action.

If the frequency has been above 49.99 Hz for greater than ten minutes *and* 10 minutes has elapsed since the last switch-off, *then* the last block of auto–start pumped storage that was switched on, is switched off. The term block is used to indicate one unit at Dinorwig or two units at Ffestiniog.

9.17 Pumping Mode

The level of the reservoir for the pumped storage units is clearly maintained by pumping water back into the lake above the generation station. This is seen in the system as a consumer load, and is generally carried out at times of light consumer load. At the same frequencies as above (49.9, 49.85 and 49.8 Hz) any of the generators which are in pumping mode, will trip off, thus relieving the system of 300 MW per set of Dinorwig and 75 MW per set at Ffestiniog. These trippings are taken to be instantaneous at the staggered frequencies. The pumped storage units cannot offer any frequency regulation in pumping mode.

9.18 Gas Turbines and Load Disconnection

If the pumped storage auto-start facilities described earlier are insufficient, a number of gas turbines have auto-start capability with a rise time of five minutes. If the frequency falls further and there are no more units available then the consumer load is disconnected progressively. The engineers will also start other unused pumped storage and gas turbine plant at their discretion. Time constants of these activities are likely to be in the range of five to fifteen minutes. Load disconnection is designed to cater for local deficiencies in generation, rather than the system shortfall as a whole.

Clearly, these situations are not concerned with the normal running of the system and hence it seemed inappropriate to model these more extreme features until the more basic features were validated.

9.19 System Transfer Function Response

The effect of the system transfer function was investigated with the use of a commercially available control package. The transfer functions used to describe the system as a whole were combined so that their total response could be observed.

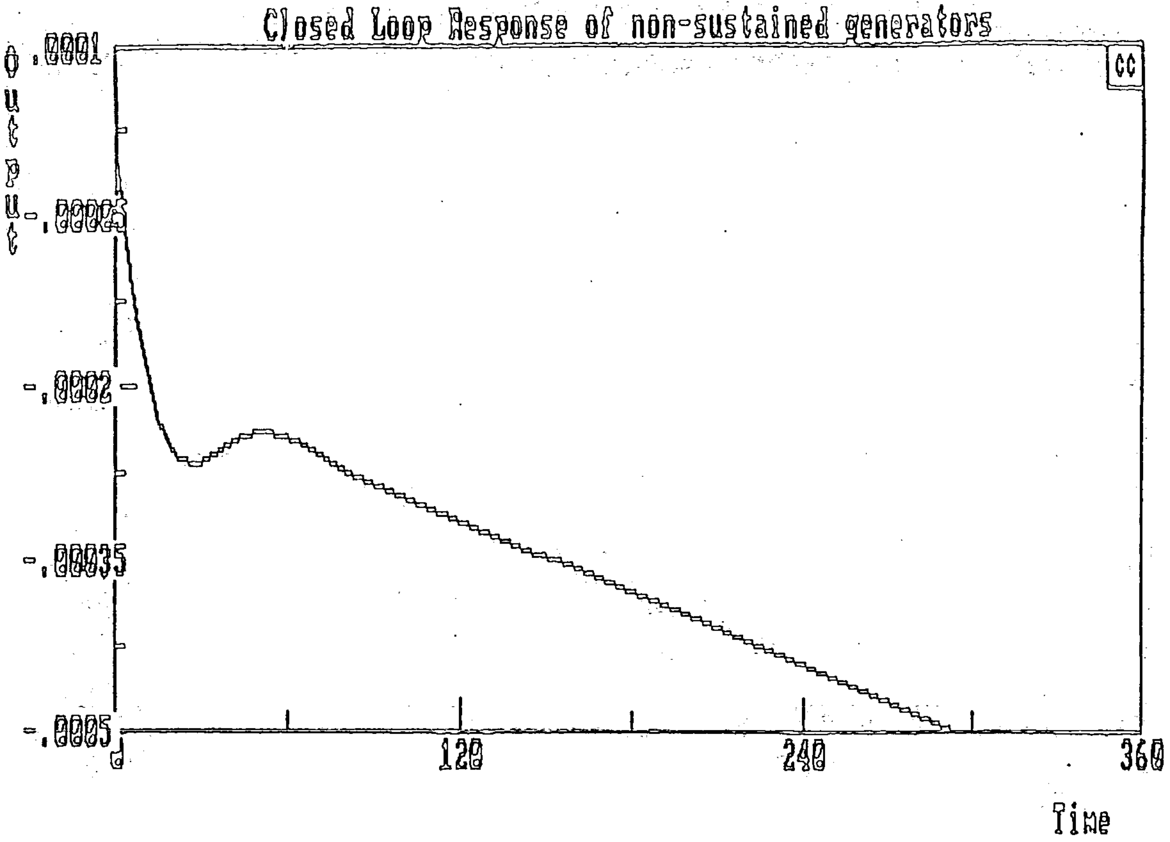
9.19.1 Non-sustained response

Figure 9.1 shows the response of the system to a step change in consumer load. This gives the response of a non-sustained system, as described by equation (9.6). This response consists of the required and familiar rapid decrease in the system frequency, followed by a short term recovery, then a continuous decrease.

9.19.2 Sustained response

Figure 9.2 shows the response of the system which contains a proportion of sustained plant. This models the system as described in equation (9.7). The usual test of applying a step change in consumer load was carried out and the resulting change in system frequency noted. This response is typical of such a system which has a certain amount of plant which is capable of sustained operation.

Figure 9.1



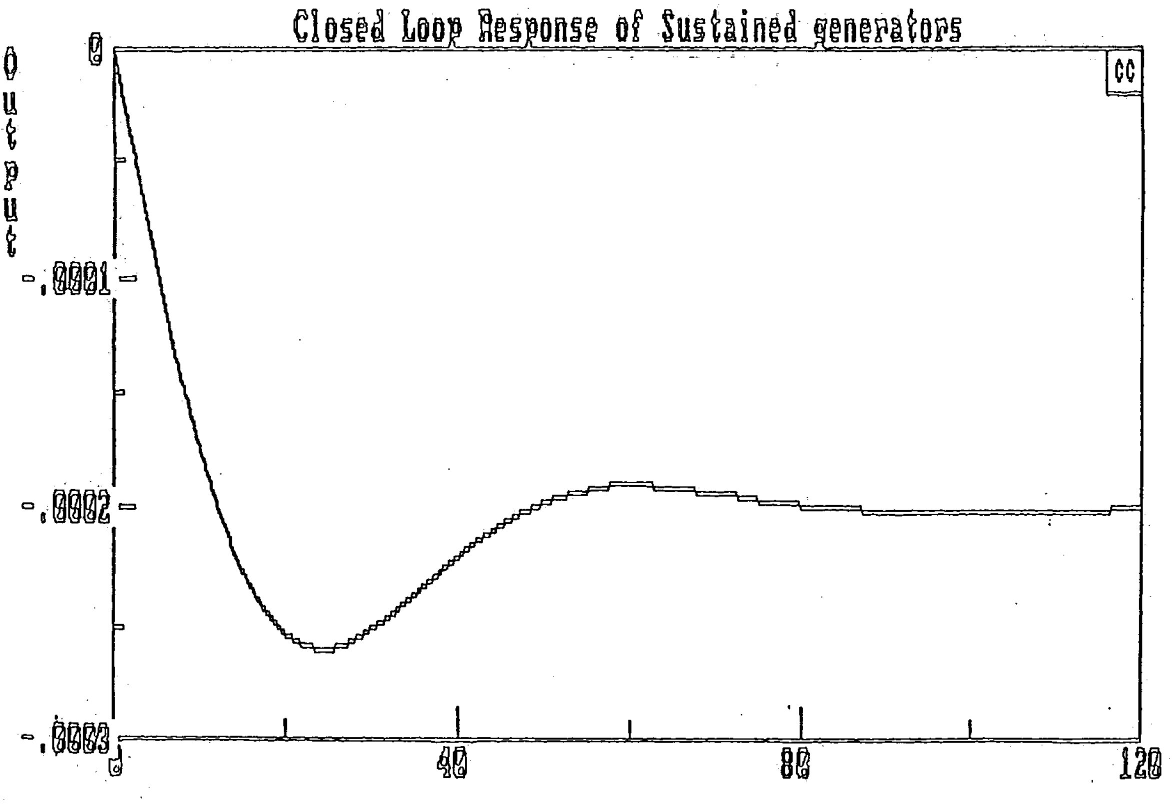


Figure 9.2

Having determined that the proposed system model responded as required, the system model was then programmed in the main simulation program.

9.20 Participation Factors

The power error of the system is calculated by the L.F.C. and is allocated amongst the participating generator units by altering their Dispatch calculated set points by an appropriate amount. The amount of power allocated to each unit can be partitioned in many different ways. The Dispatch calculation calculates the amount of available capacity on each unit and the power can then be allocated between the controlling units.

The way in which the power is allocated was taken to be as simple as possible, as this was only a test of the requirements of the interfacing and interaction, rather than a complete economic calculation. Clearly, economic factors play their part in the allocation of the additional power for the system, but in this case it was felt sufficient to use the order calculated in the Dispatch calculation.

The Dispatch function calculates the list of available units based on economic running at every five minute calculation period, which was felt to be sufficient for this task. This function provides a ranked list of all the units on the system and their available spare capacity. The top of the list is dominated by the pumped storage units, but it was felt better not too allocate these in preference to other units, as the reverse pump action could not be taken into account. The pump storage units were modelled in the simulation as described and operated as discussed, but they were not placed directly under the command of the L.F.C.

Thus the required system power was allocated according to the availability of each unit, typically the first twelve units were chosen for regulation. This number was decided upon as it provided sufficient capacity for the allocation to be effective and yet it left unaltered units which were not to be used in regulation. Thus at every cycle of the L.F.C. function the first twelve generators in the list were available for power set point alteration. It was also found that as the power was allocated in such a way as to take up the available slack on each unit then only about ten of the available units were ever re-allocated.

9.21 Off-line Simulation Testing

The simulation was tested initially in an off-line sense. This work was carried out to ensure that the simulation programme operated as required and that problems encountered with the computer code could be solved before the simulation was installed at C.E.R.L. The simulation testing was carried out using a variety of forcing functions, which represented the change in consumer load. These included

(a) Transfer function analysis,

(b) single step changes, to investigate the system response to a sudden generation loss incident,

(c) multiple step changes to follow the response to continuous level changes,

(d) sinusoidal inputs to follow the system response to slow repeatable changes in load, and

(e) random load inputs to follow the system response to actual operating conditions.

With the use of the features in the model it was possible to simulate a number of system incidents such as

(a) the loss of a 500 MW generation unit

(b) the increase or decrease of load of a 500 MW demand step

(c) step changes in system gain, inertia and loss of regulating capacity. The off–line testing procedures are described below. The following sections describe the off–line testing procedures used to test the model and some of the results achieved from the testing.

9.22 Simulation Studies using Sine Wave Inputs

Many of the results that follow show the adaptive controller at the beginning of its operation. Clearly, during the initial operation, the controller has no in built knowledge of the system. This means that the initial tuning transients are seen in the results. In practice these tuning transients would be filtered out of the control action, or the controller would be started with a rough system model. This would lead to control action calculated on a standardised system model that could be used for all tests of a particular system in a particular configuration. The use of the tuning transients indicates the speed at which the estimator can adapt to system about which it has no prior knowledge.

For off-line testing purposes, the first forcing function (or driving error) used was that of a low frequency sine wave. The sine wave was used directly as the driving error, along with a small proportion of noise on the directly calculated wave form. The effect of this 'load error' is shown in figure 9.3.

The calculated control signal initially is very oscillatory. This rapid increase and decrease is due to initialisation of the parameter estimation routine. The oscillatory nature is shown to illustrate the effect of the initial parameter tuning, starting from a completely undefined system. This command control signal would clearly not be allowed to be sent on to the system generators themselves, as this is only required for the parameter tuning and would cause great instability in the system and unnecessary wear and tear on the machines themselves. Clearly this type of control action is not required on the system. Once the parameter adaption has taken place the control commands follow directly the forcing function. In this initial case there were no lags introduced into the system and so that direct control action could be taken, but not of a practical nature. The frequency error due to the load change is controlled tightly as would be expected with the direct method of control. The noise on the load error is seen directly on the control action through the noise generated in the frequency. This noise is filtered somewhat by the plotting technique used. This simulation was carried out taking the calculated data every twenty seconds as the input to the L.F.C. routine. The number of estimated parameters used in parameter estimation routine was two parameters, which is seen to model the simulated system well.

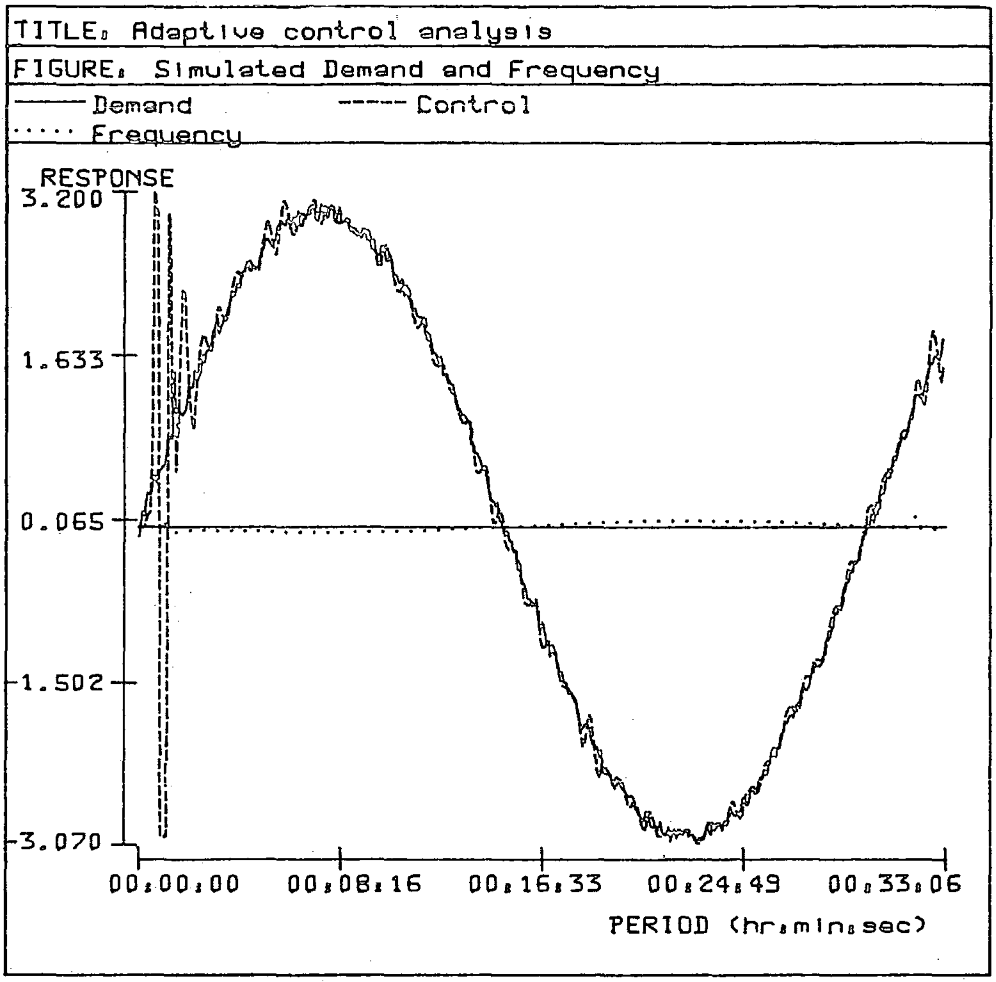
The effect of higher order estimated parameter models is seen in figure 9.4. The number of estimated parameters used in the modelling process in this simulation was four. It is clear that the system is over modelled. The control action based on the model is excessive and sometimes unstable. This control action is obviously following the load error but is over reacting to the frequency error. The load error pattern is followed tightly by the control action, but clearly the control effort is too great. The frequency error is of the same order as the previous figure, but in the previous figure, the control effort was greatly reduced.

9.23 Simulation Studies Using Step Inputs

The simulation was subjected to a number of step inputs to simulate generation loss incidents or sudden increases in consumer load. The system response was tested without using any control effort to take corrective action, this is shown in figure 9.5. The frequency response shows a rapid decrease, as the load change occurs. This is followed by a small increase, then a drop back to a continuous steady-state error. This plot simulates a system with a large proportion of sustained response, in that the frequency deviation recovers after its initial decrease, and then stabilises out at a continuous error. This is a typical plot of a system which has a controller that contributes no integral effort to the control action. The consumer load is a step of 300 MW and the final steady state frequency error is –0.006 Hz, giving a system gain of 5000 MW/Hz, as defined in the specification.

The simulation responds as required in the previous test, but it was felt that this was somewhat unrealistic as the system it was designed to model does not have a large proportion of machines which are capable of giving a sustained response. Thus the system simulation was altered in such a way as to decrease the proportion of sustained response machines represented in the simulation. This was carried out by altering the transfer function as described earlier. The factor used on the top of the transfer function was set to 0.95, representing the fact only 5% of the machines in the simulated system were capable of giving a sustained response. The effect on the frequency error is shown in figure 9.6.

Figure 9.3



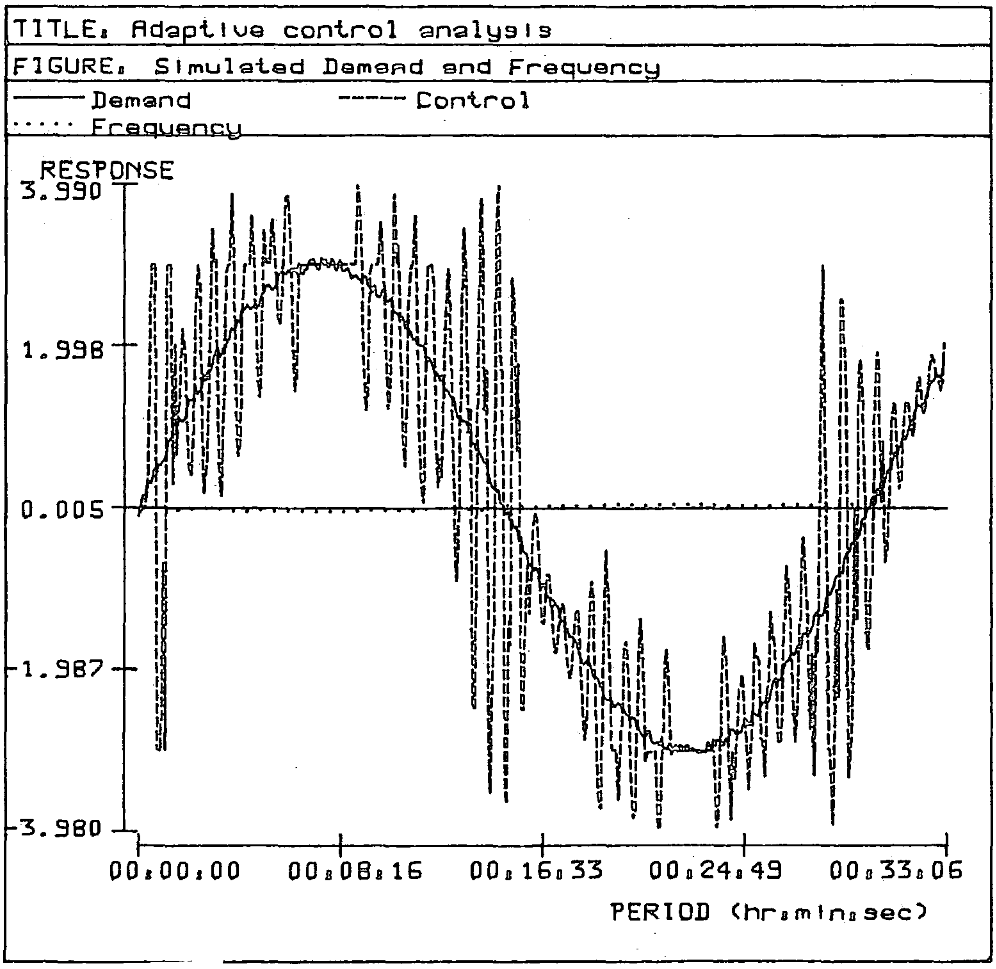


Figure 9.4

Again the change in load is as before, but in this case the frequency error recovers only slightly and then begins to fall away, characterising the system response of the actual system under study. In this case the system does not have sufficient reserves to support the load change and the system frequency decreases. The frequency would continue to decrease until the pumped storage units came in under frequency relay control or more drastically other consumer load was removed from the system.

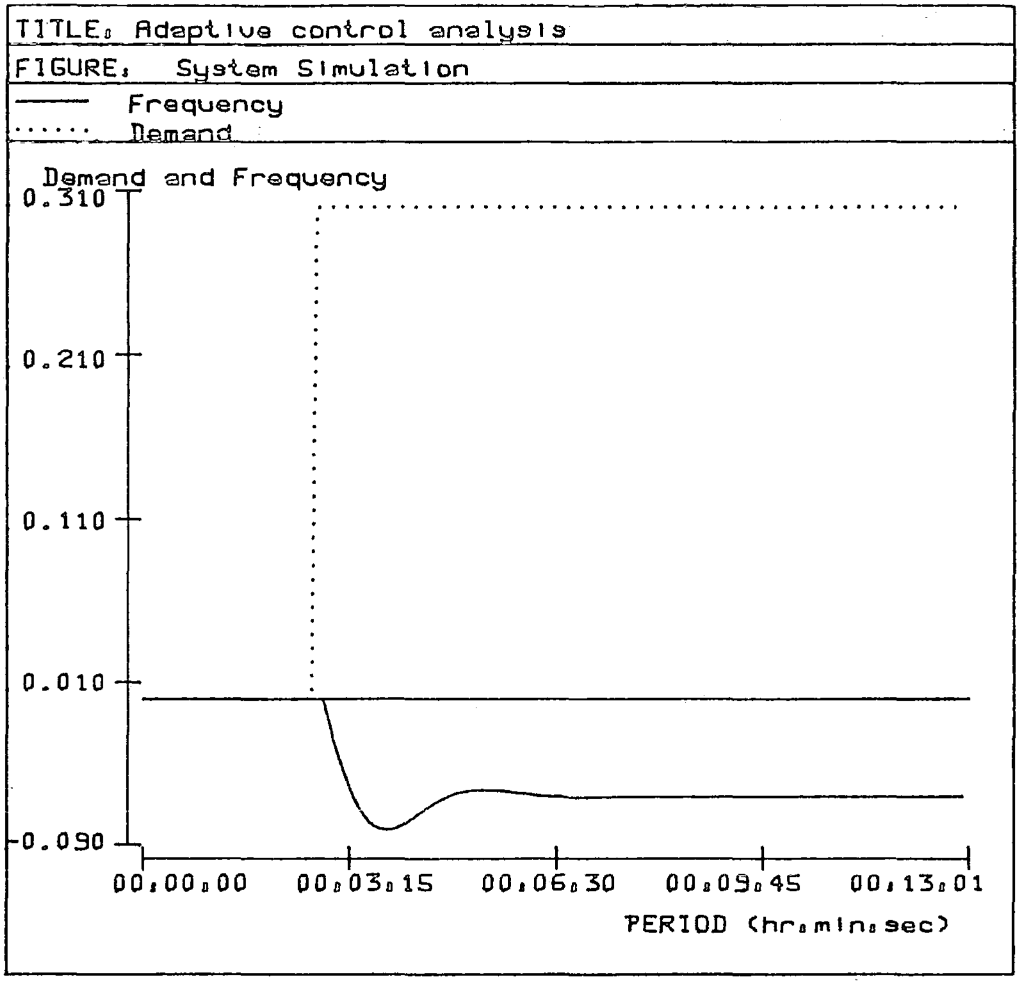
9.23.1 System gain test

Figure 9.7 shows the response of the system to a typical system gain test. The system is operated in a mode such that there are no external control functions operating, the only control in the system are the individual generator governors. The step load change is applied to the system and corresponding change in frequency noted. In the steady state, the constant frequency error is measured and used to calculate the gain of the system. An unrealistically large load was used to illustrate the decrease in frequency for plotting purposes. The change in frequency is seen to be 0.1 Hz, this is a very large change in system frequency, and produces a gain of 5000MW/Hz, the programmed system gain. The figure also illustrates the problems encountered sampling the output of the simulation at minute intervals. The sampling frequency is such that the overall shape of the response is shown, but the actual detail of the response may be missed. In this case the recovery of the frequency after its initial rapid decrease is not captured, but is known to exist by studying the previous figures.

9.23.2 Delay of load frequency control signal

Figure 9.8 shows the system responding to a sinusoidal disturbance, with the L.F.C. function responding to the frequency deviation. In this case the excess power allocated by the L.F.C. is delayed using the delayed function described earlier. This simulates the inherent delay that would be seen by the L.F.C. commands as they are sent to the system, and before they are implemented on the system. This system delay would be modelled in the estimated model calculated by the controller as the control action is seen to affect the simulated system after a finite time. Again noise has been superimposed on the driving error to simulate noise that would be picked up

Figure 9.5



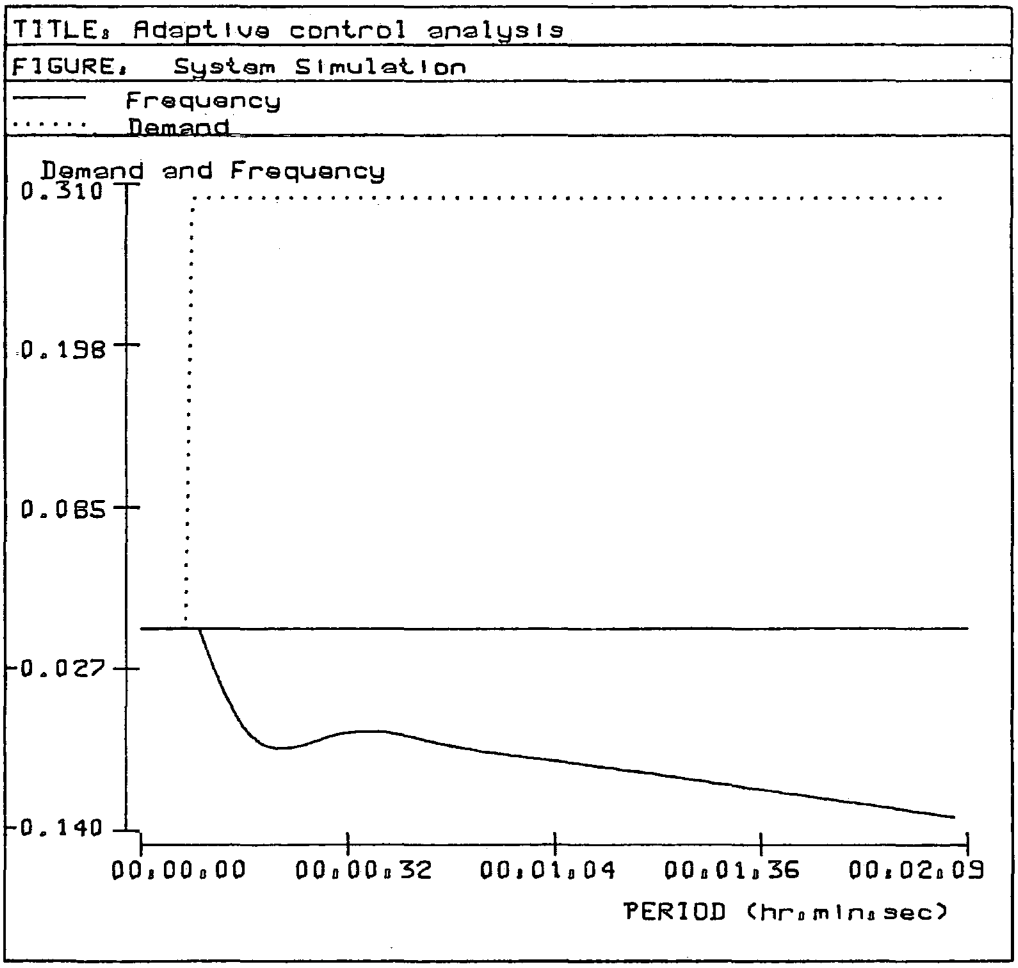


Figure 9.6

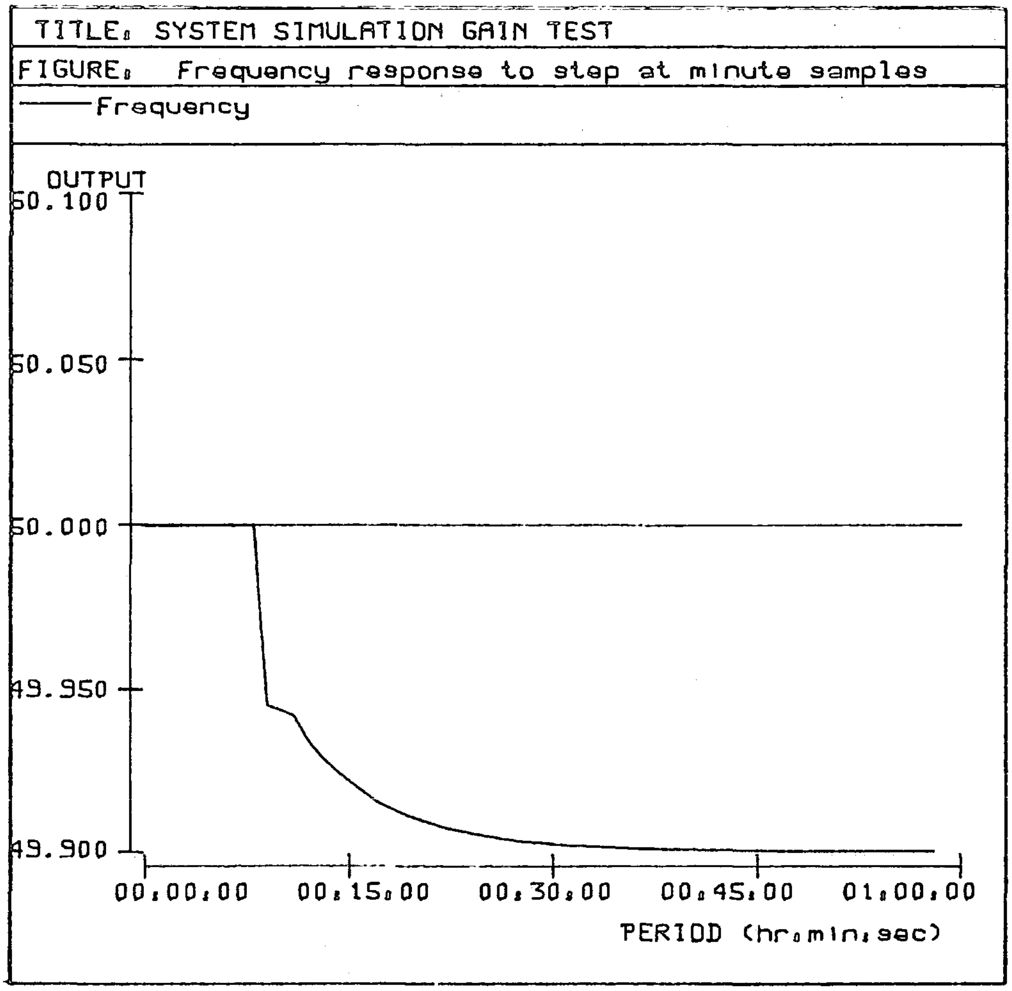
in the system operation. There is some noise seen on the control action, but has been greatly reduced by a simple averaging procedure used to filter the input. It is seen that the adaption routine is affected by the system noise and this can lead to incorrect control action being calculated, hence, filtering of the input variables is essential.

Figure 9.9 shows the system response to a step change in load, and the response of the L.F.C. reacting to the frequency deviation. The L.F.C. response has been limited to avoid rapid change in power and overshoot from the step input. The L.F.C. estimation routine has started from an unknown system and hence needs to adapt as the disturbance is seen through the system. The initial change in the control action is influenced by the adaption of the parameter estimation rather than the load disturbance. Once the estimator has adjusted to the system it is modelling, the control action becomes dependent on the driving error rather than the estimation routine. There is a slight frequency error which persists in the system, and this is the driving error for the controller. The control action is increasing to remove the error totally from the system, which it would achieve given time, once the estimation routine has produced valid model parameters. If the system model is known before–hand from previous runs of the simulator, clearly the initial adaption is not required, and the control action is directly relevant to the system disturbance. The control action during the parameter tuning phase of operation would clearly not be sent to the system to be implemented.

9.23.3 Delayed control action

Figure 9.10 shows the effect of the delay term in the simulation acting on the calculated control action. The figure shows the amount of power allocated by the L.F.C. function for the control of the system frequency and the power actually allocated to the system at any given time. The power that is actually allocated to the system lags behind that scheduled for allocation by the control function and there is clearly a deficit of power allocation to the system. The allocation of power is, however, greatly filtered by the system and hence, the actual allocation of power is far smoother than it would have been if directly

Figure 9.7



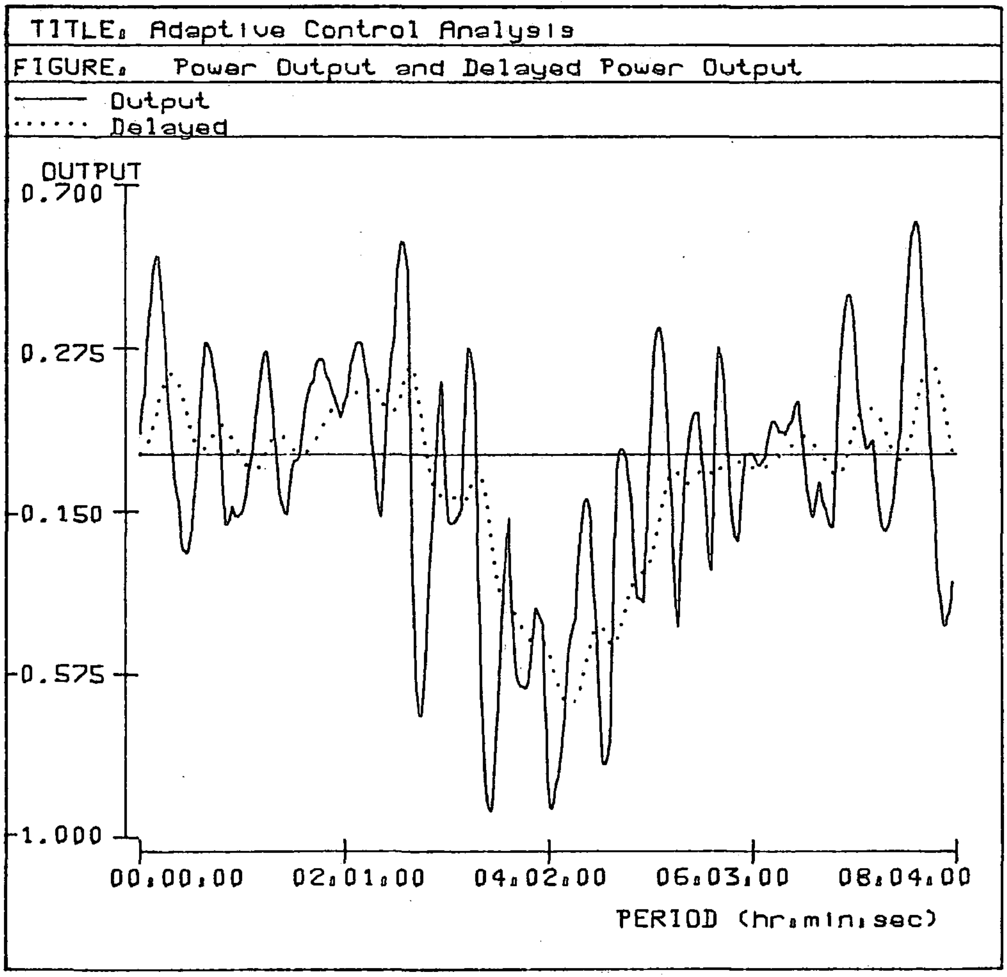


Figure 9.8

applied to the system. The controller signal would require filtering before being sent to the generator units, as this signal is exceptionally noisy.

9.23.4 Parameter identification

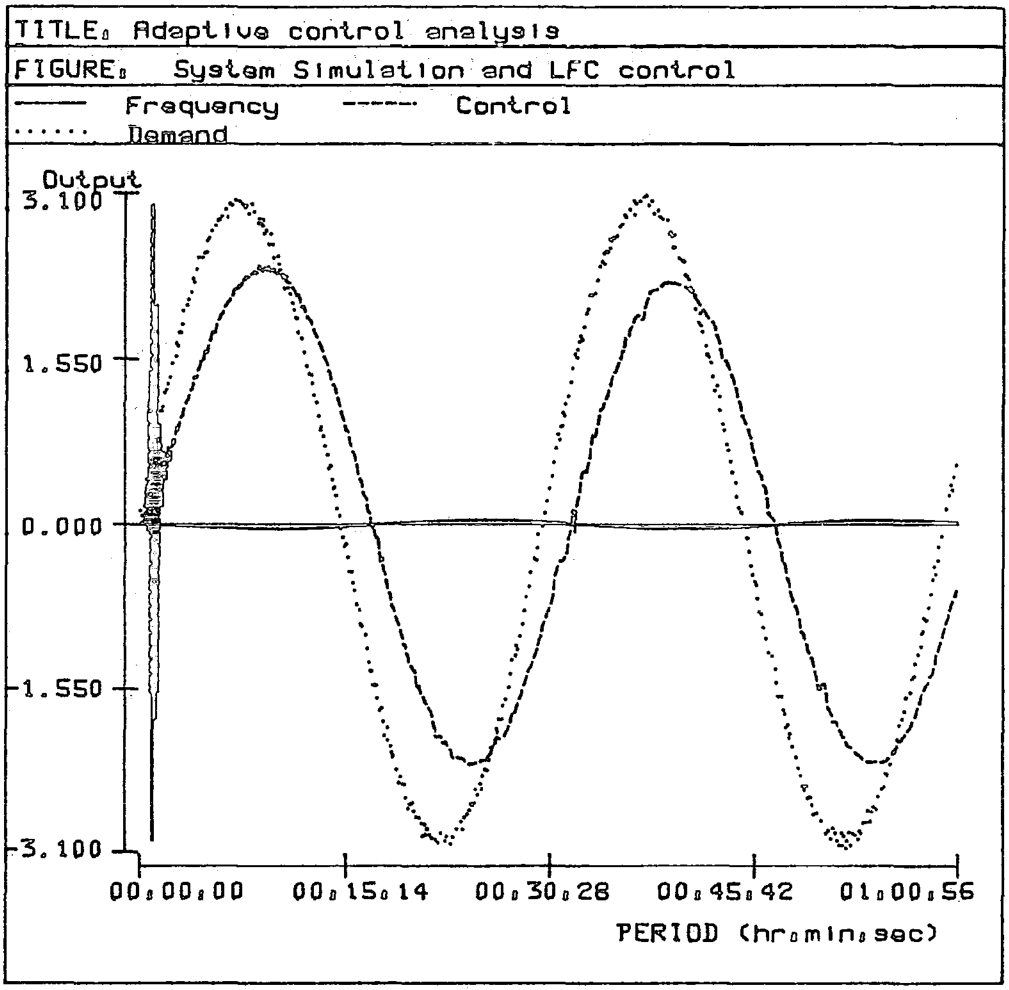
Figure 9.11 shows the estimated parameters for the system model in response to a step response. The L.F.C. function was working in a monitoring mode only in this case. This mode of operation enabled the parameter adaption part of the control function to be studied, without the interaction of any control action. Initially the parameters for the system model are unknown, and hence, the step input is the first of the system information to be collected by the estimation routine. The estimated parameters converge to constant values for several tens of minutes, but then they begin to diverge. This movement of estimated parameters is due to the system input not being 'persistently exciting', and after a period of no new system information, the estimated parameters begin to wander away from their previous values. The lower figure, figure 9.12 shows the decrease of the system frequency as there is no control action to respond to the change in consumer load.

9.23.5 Step input with noise

Figure 9.13 and figure 9.14 show the parameter adaption for the model estimation for the simulated system, and the consumer load change. There are two parameters estimated for the system model, which converge to steady state values after the step disturbance. The parameter estimation, initially has no prior information of the system and hence, the first estimations are required to start to converge on the system model parameters.

There is, initially only noise on the measurements, as the system is in steady state. The parameter adaption routine start to converge to a set of parameters with little system information to which to respond. The step input in demand enables the controller to begin the modelling process, which is clearly seen as an increase in the control command signal. The control ramps up rapidly, as the controller responds to the demand change, with values based on the previous estimated parameters. The step information provides extra information for the estimation routine to react to, but by this time there has

Figure 9.9



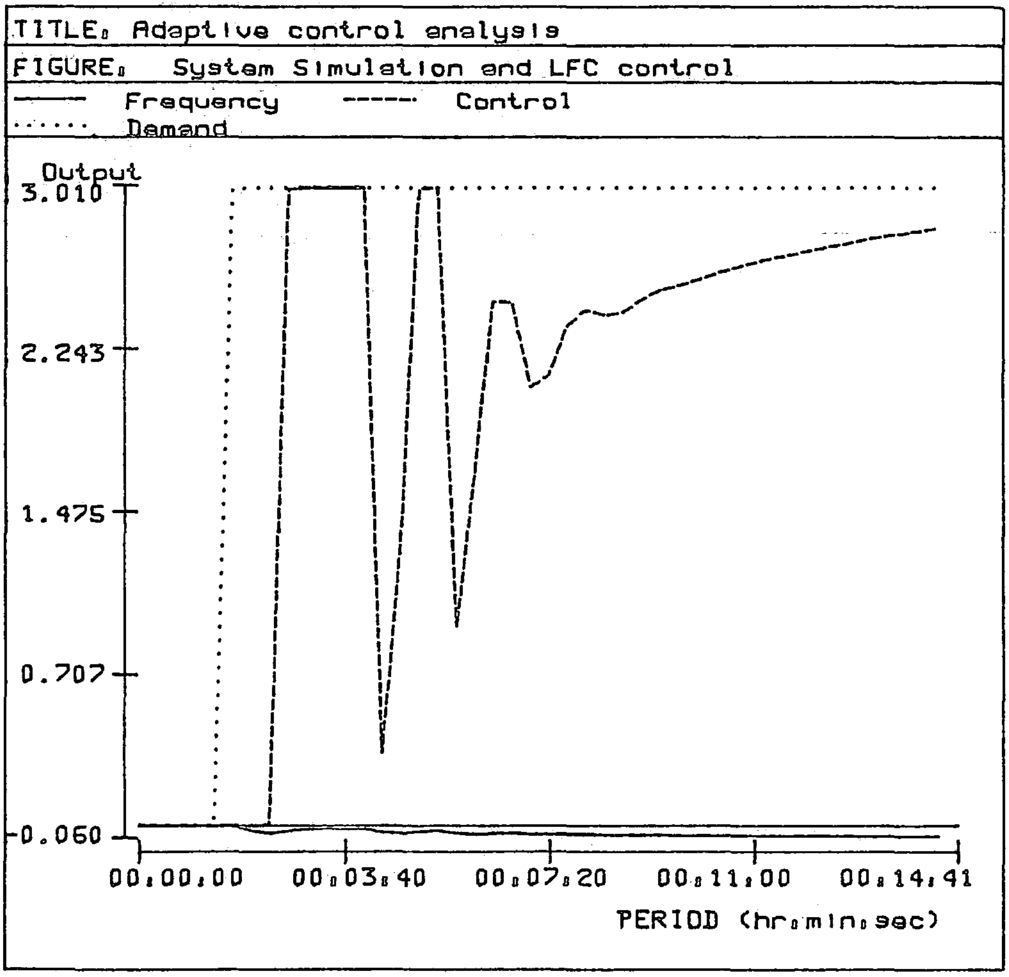
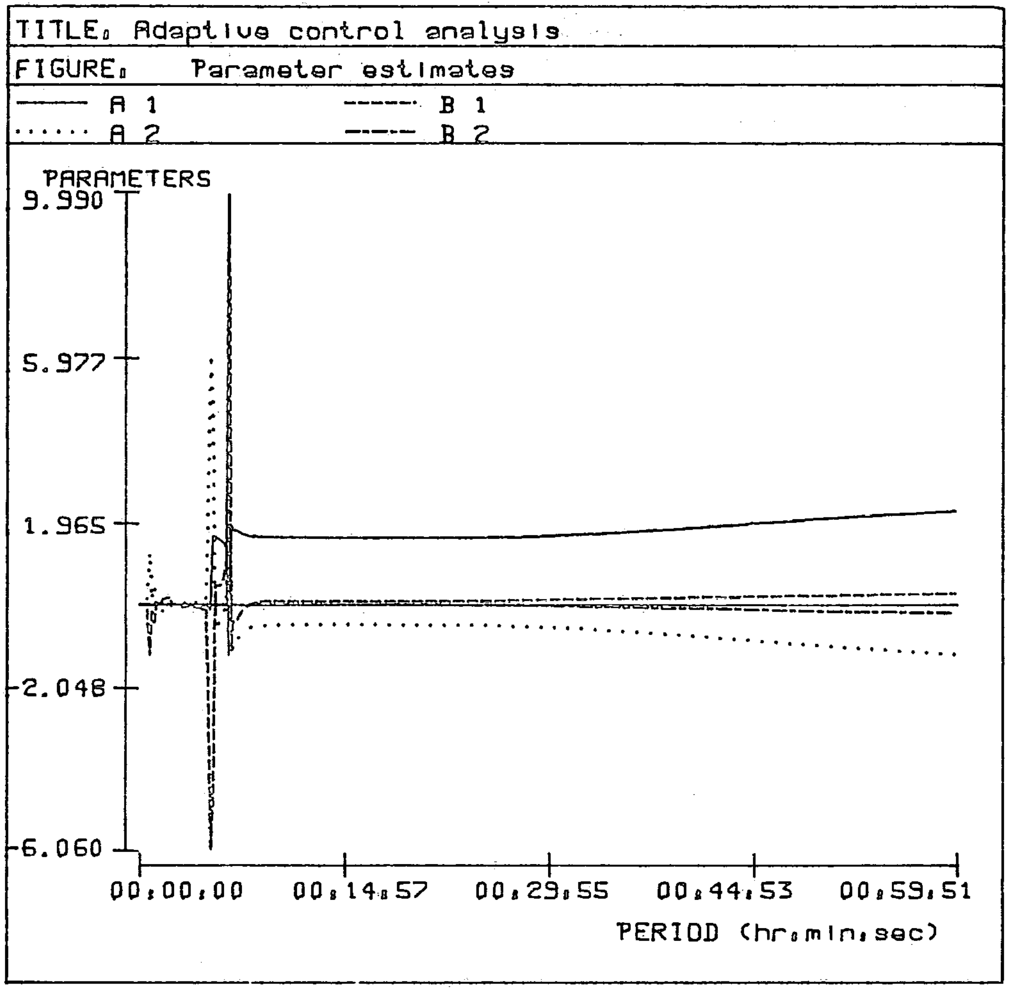


Figure 9.10

Figure 9.11



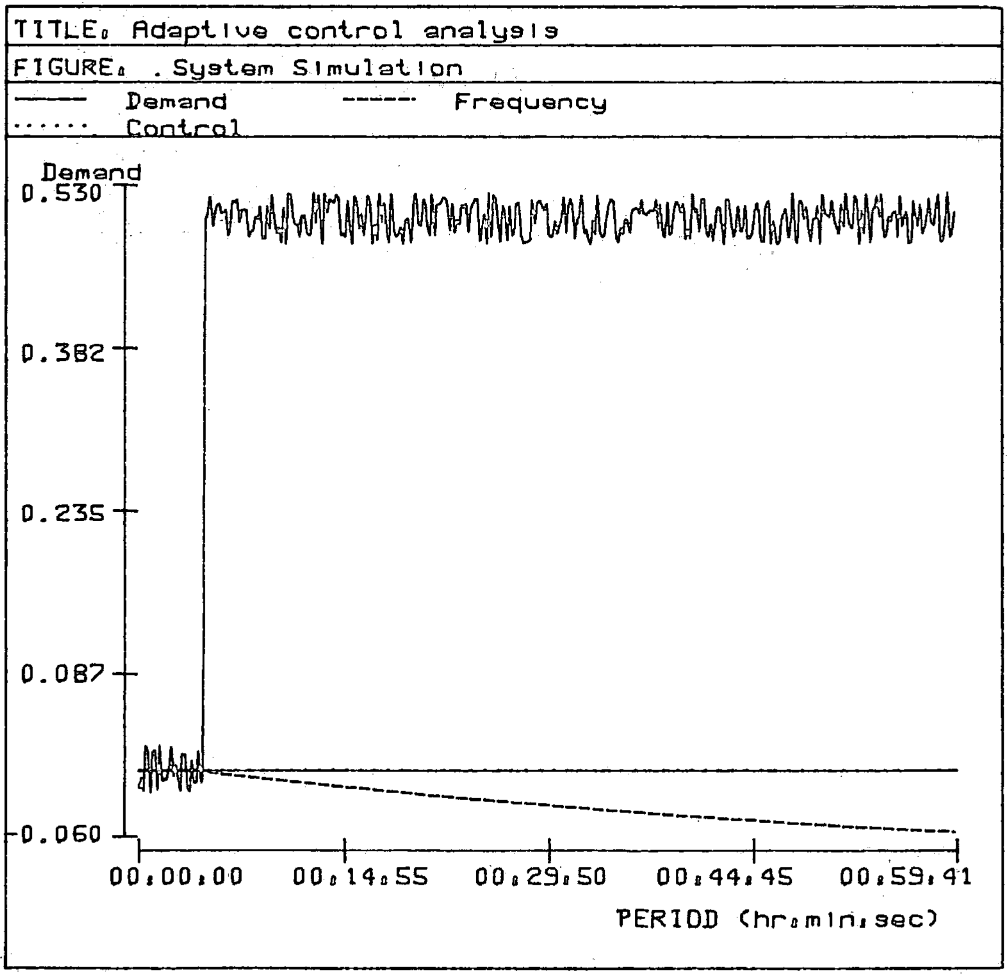
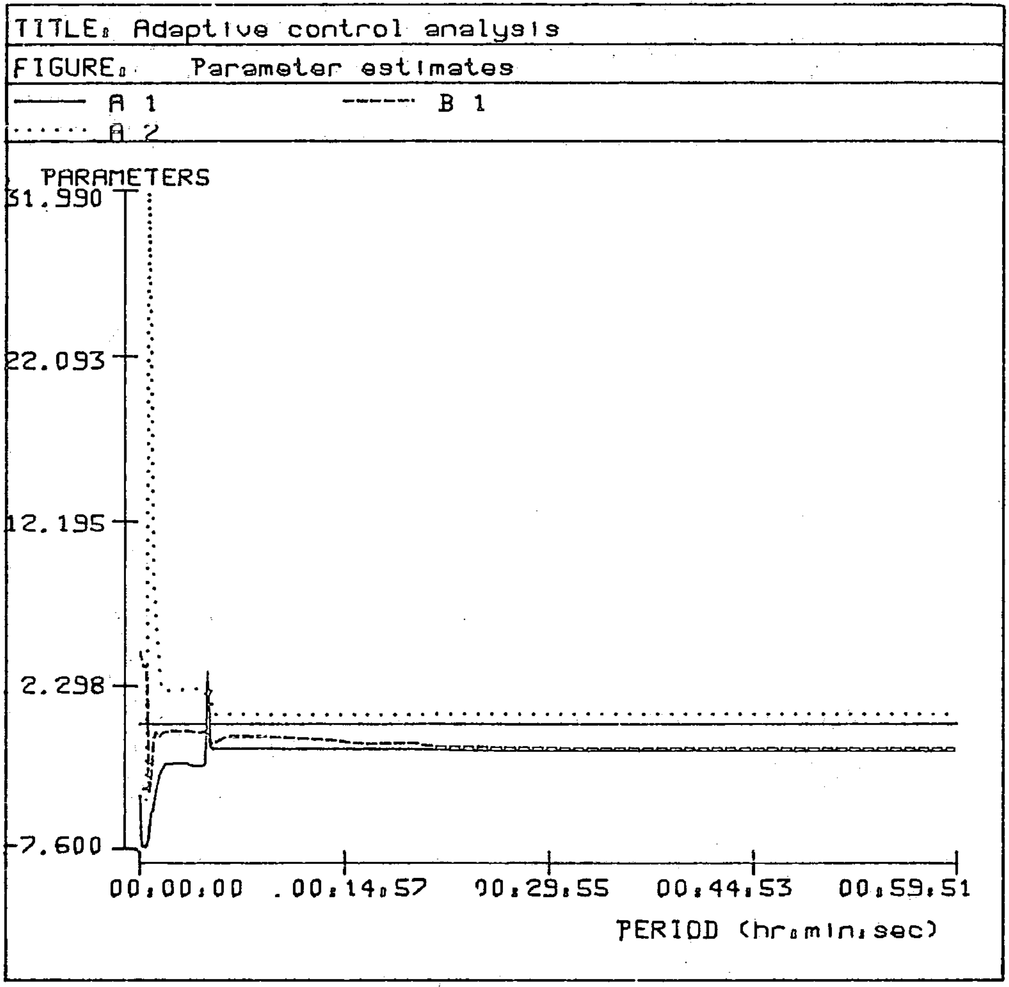


Figure 9.12

Figure 9.13



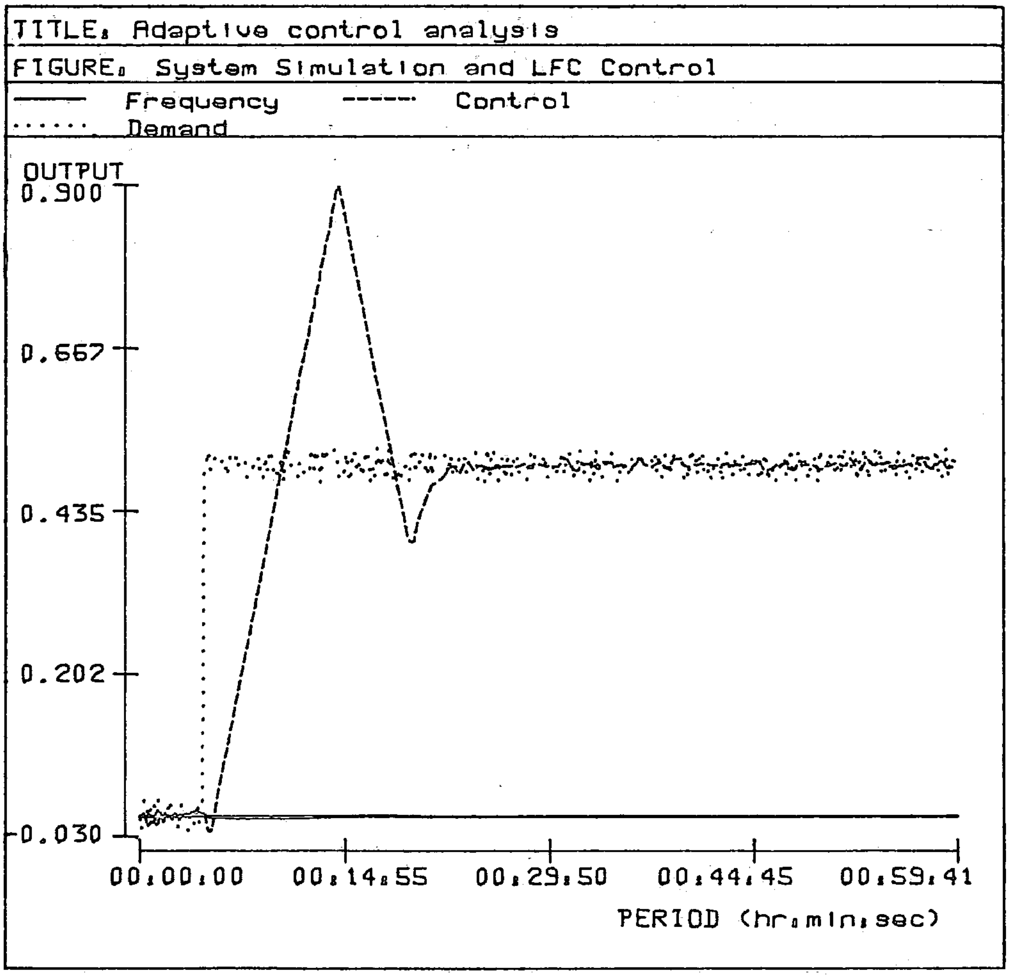


Figure 9.14

been an overshoot of the control action. The control action is restored by a rapid ramping down of the power set points and settles to a value exactly matching the disturbance. The parameters of the model have converged rapidly to the new system model, and this assists the control action to be restored to its correct course.

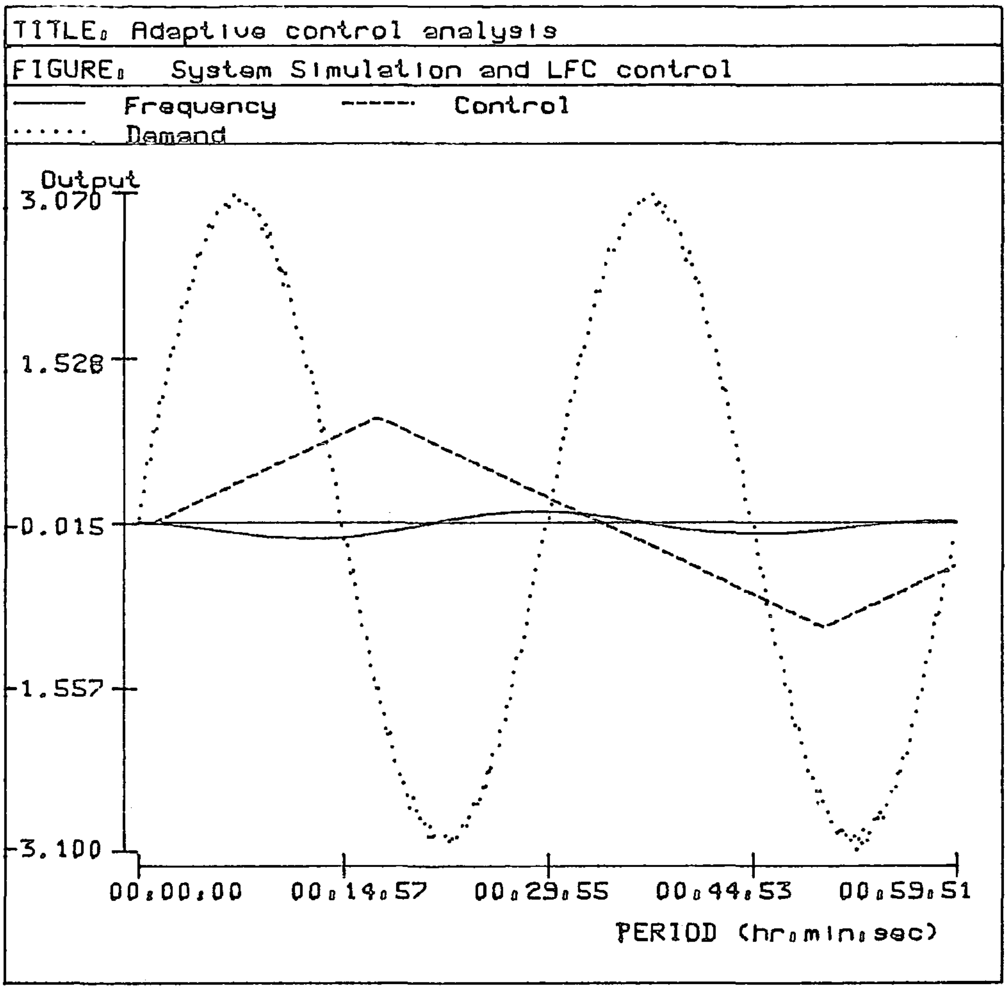
9.23.6 Constrained system output

Figure 9.15 shows the control calculated for the system when a sinusoidal input was used to describe the system load. The output of the L.F.C. function was heavily constrained by the ramp limits placed on it. These ramp values were deliberately chosen so that the calculated control commands could not be executed as required. The effect of these constraints on the controller is shown to produce a triangular shaped waveform as expected. This shows the problems encountered when control action is required that cannot be delivered by the system in question. The system frequency is seen to follow a sinusoidal form, dictated by the input driving error, and the lack of ability of the control action to be allocated as desired by the values calculated by the control function.

9.23.7 Controller with previously known parameters

Figure 9.16 shows the effect of the system responding to a step change in load, controlled by a controller that has prior knowledge of the system. The parameter estimation results of a previous simulation are used as a basis for the parameter estimation of the next simulation. The data arrays used in the controller do not need to be filled up with valid system data in this case as the initialisation of the controller uses previous valid data. The step change in consumer load is directly followed by a change in generation, which settles to its required value without any overshoot or oscillations. The system frequency is seen to have a small offset, which is due to the problem of 'persistently exciting' inputs. The step input does not contain any other change level, so the set of estimated parameters used to model the system are in fact incomplete, and another disturbance would be required to completely describe the system and hence enable the the estimated parameters to fully model the system.

Figure 9.15



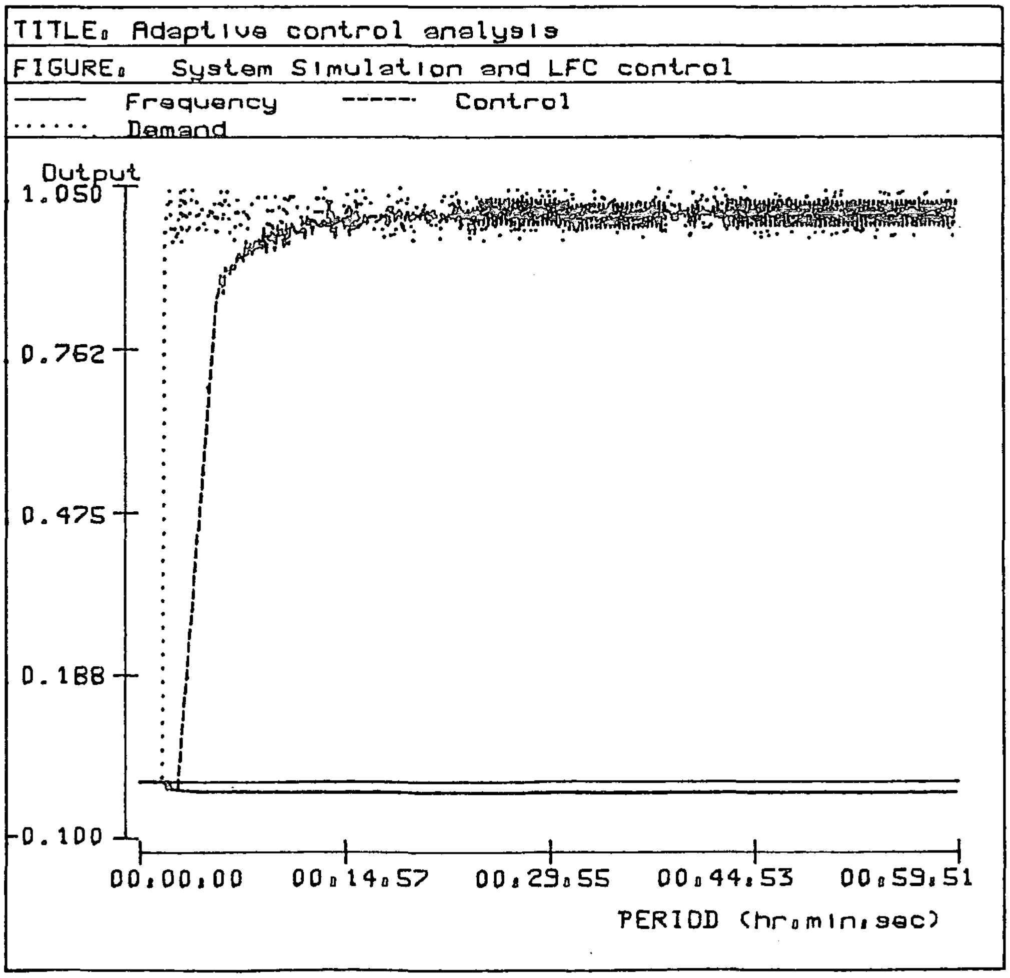


Figure 9.16

9.23.8 Steady-state parameters

Figures 9.17 and 9.18 shown the system response to a step change in consumer demand and the corresponding estimated parameters calculated by the controller. The system is known to the controller by storing the system state as described earlier. The parameters converge rapidly after the system disturbance, and are unchanged as time progresses. The same problem as above is seen again as the input remains at a constant after the change, which lead to a small steady-state frequency error. This error will remain on the system until the model can be updated by the system reacting to another disturbance.

9.23.9 System response to square-wave inputs

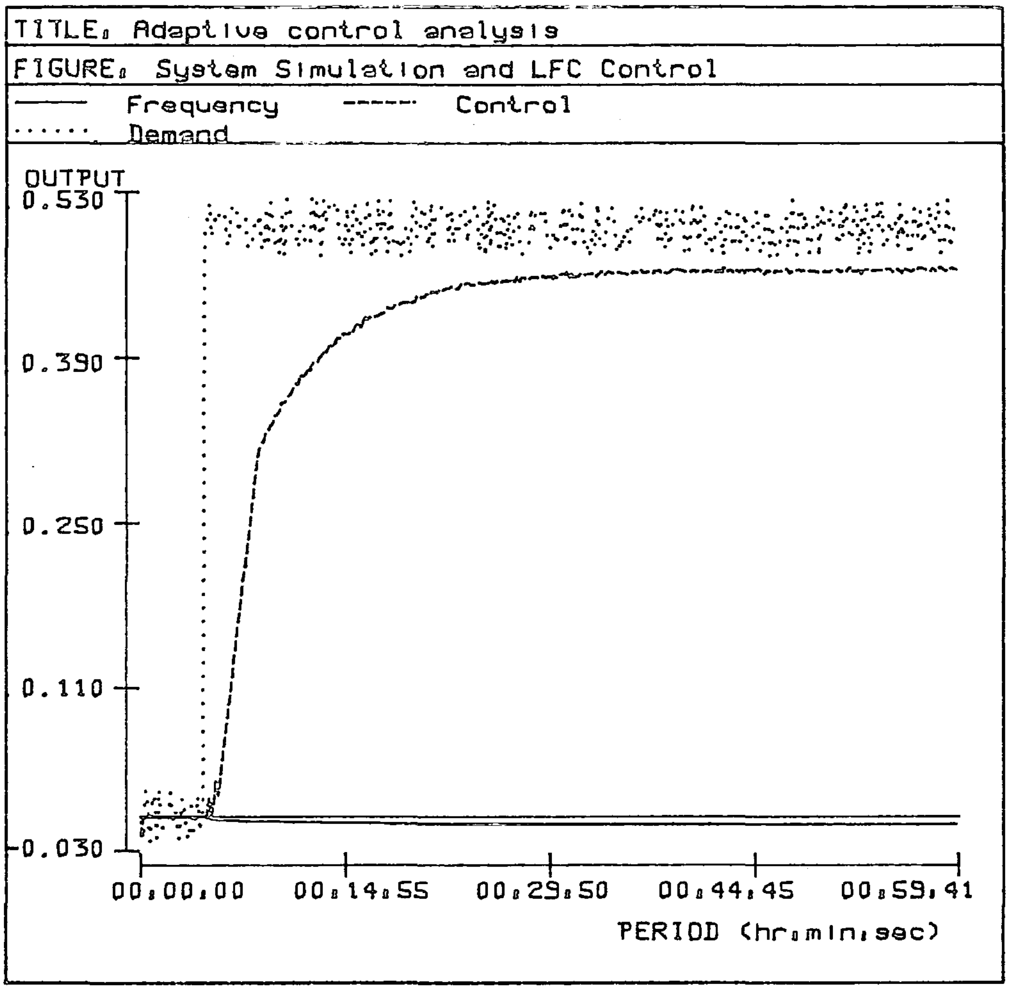
Figure 9.19 and 9.20 shown the system response to square-wave inputs. They both show the initial parameter adaption phase, with the excessive control action. This is then replaced by control based on a known system model as the estimated parameters converge. The system error frequency is greatly reduced, and no steady state error is observed as the system is fully modelled by the estimated parameters.

The figure (9.19) shows the controller response to a load change which is always greater than zero. Figure (9.20) shows the controller response to a positive and negative load change, along with periods of constant load. The estimator tracks the disturbances in such a way as to enable the controller ensure that the frequency error never exceeds ± 0.02 Hz. Hence, the controller has been shown to be able to track quite drastic changes in system load and continue to produce suitable control signals.

9.24 Controller Model Response

The simulation was operated several times using a step change in load as a driving error. The corrective action from the adaptive controller has been shown in several of the previous figures. The estimated model parameters used by the controller to calculate the corrective action were also recorded. These parameters are able to model the system themselves, so a check for the accuracy of the model estimation was carried out. The control and simulation package

Figure 9.17



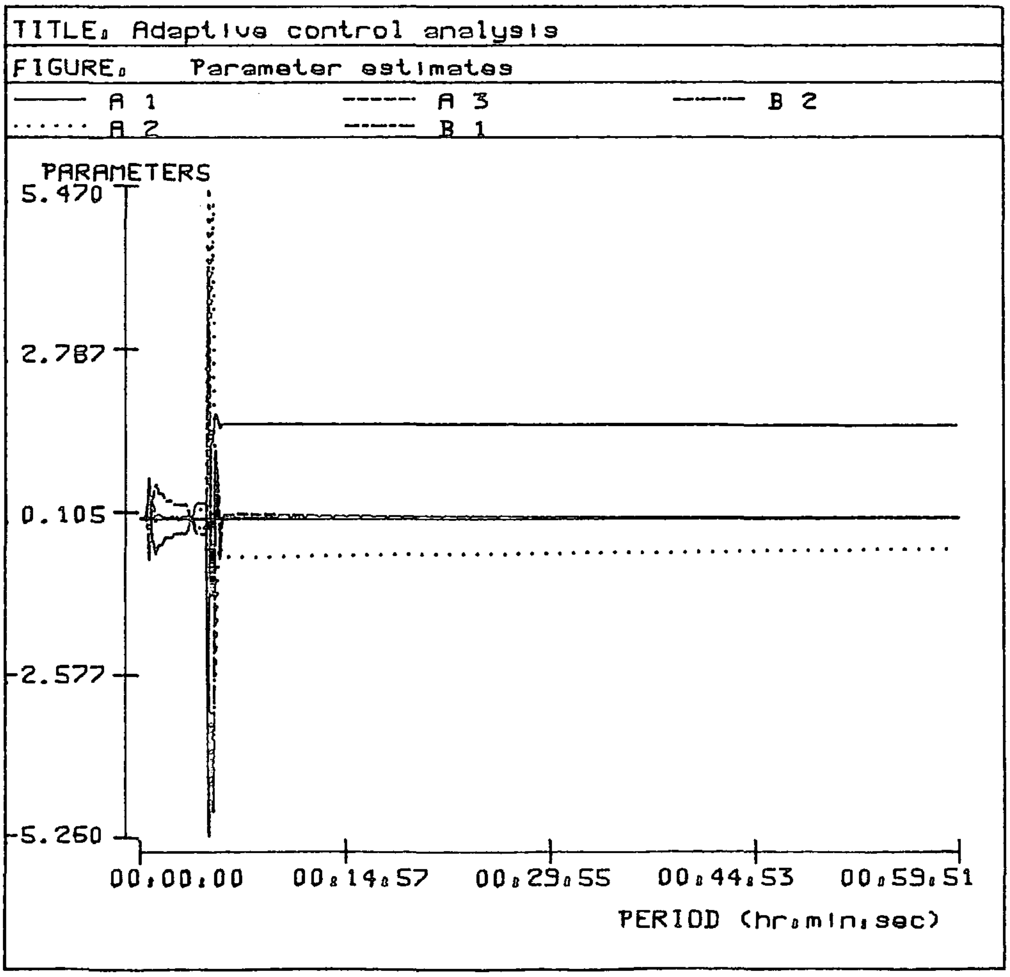
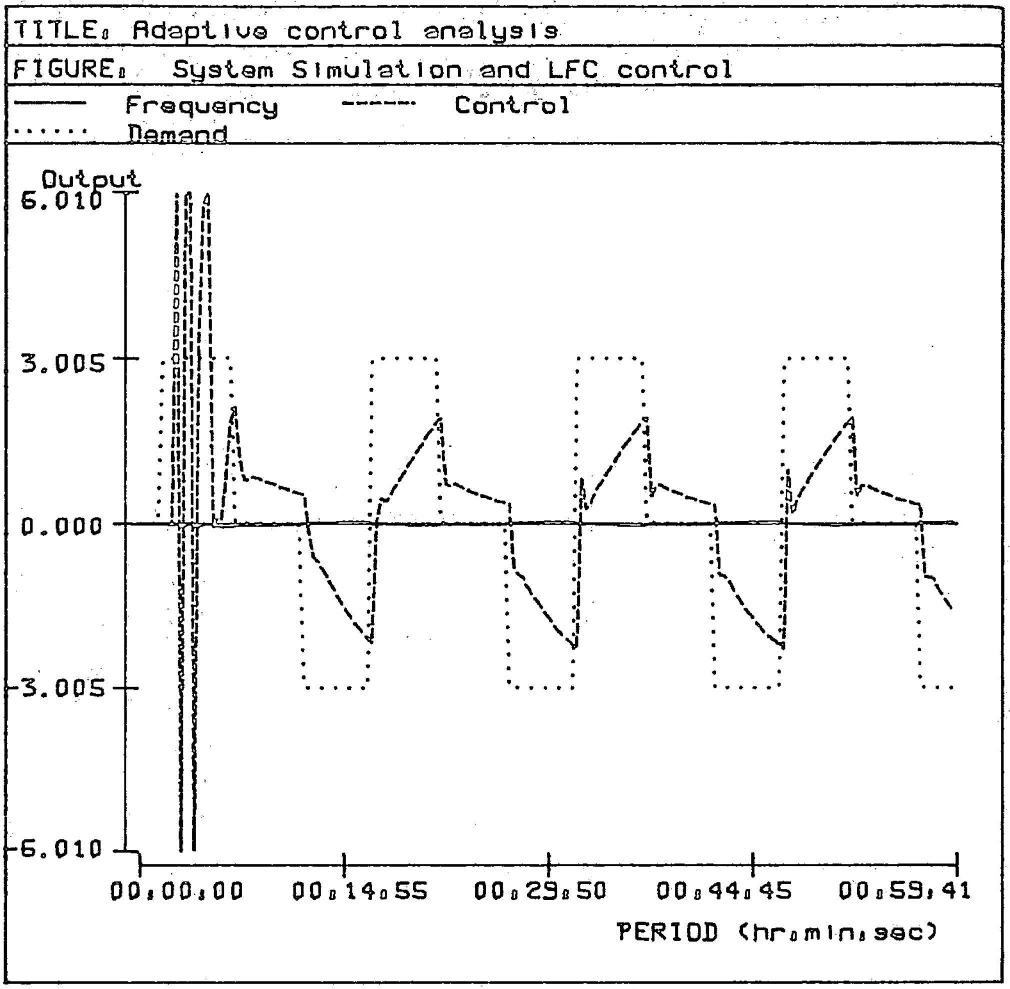


Figure 9.18

Figure 9.19



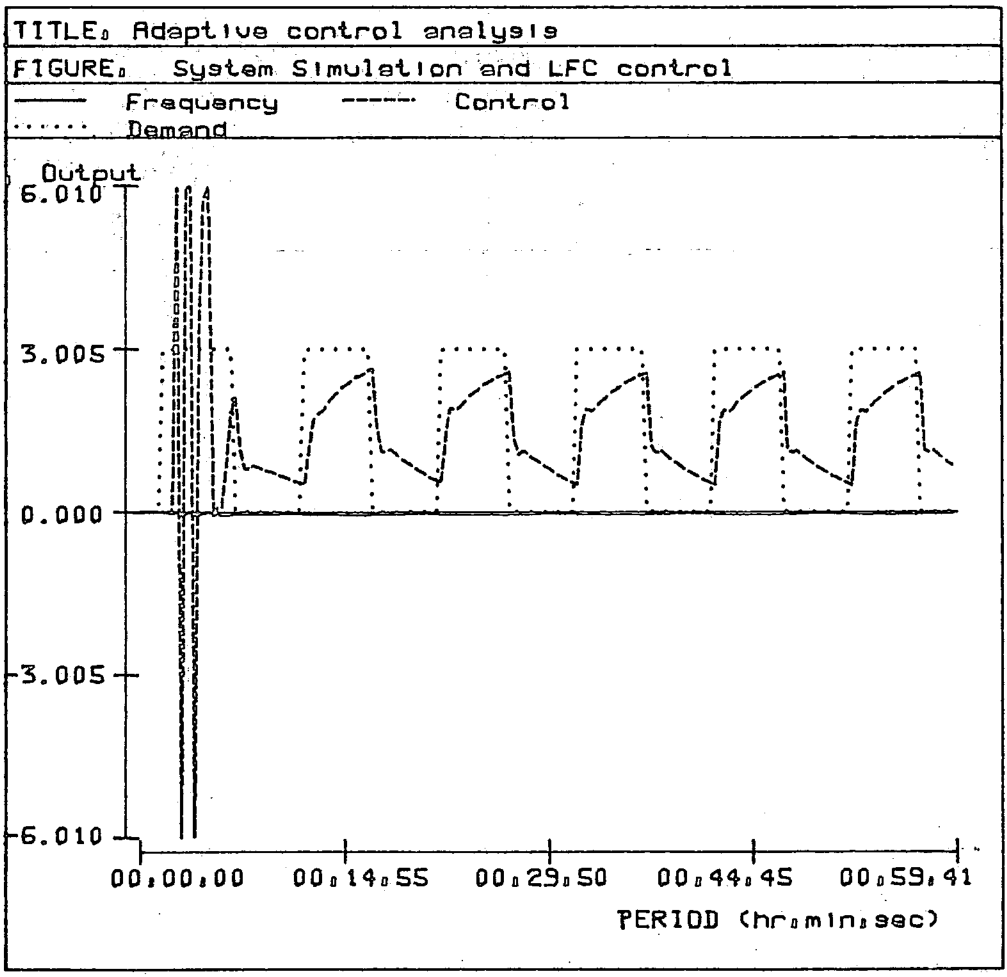


Figure 9.20

mentioned earlier was again used to investigate the nature of the estimated model. The estimated parameters were arranged to form a transfer function which represented the system response. This transfer function could then be subjected to step inputs, just as the simulated system.

These discrete transfer functions were programmed using the package. The estimated model was then subjected to rather drastic load changes so a significant response could be seen. The response of the model to the change in load is shown in figures 9.21 9.22 9.23 and 9.24. The value of n shown in the top figure in each case is equal to 10. Hence, the time scales of the upper and lower plots are the same. The lower figure in each case is a plot of the continuous time representation of the response.

The first figure is the response using two 'A'-parameters, the second is the response using three A parameters. There is little difference between the shape of two responses, except the first one has a slightly greater maximum frequency deviation and a greater steady-state frequency error. From the calculated figures, the system gain for the first case was calculated to be approximately 5000 MW/Hz, from a load change of 660 MW to simulated the loss of a large modern generator unit. The second case produced a gain of approximately 4888 MW/Hz, about the same value, only slightly less than the simulation programmed gain. Thus it is seen that the model estimation is good enough to model the simulated system. This model produces a good estimation of the system parameters such that the control commands that are calculated based on the model are valid.

9.25 Implementation of the Control Scheme

The L.F.C. function was interfaced to the C.E.R.L. Dispatch function and on-line database, as shown in earlier in diagram 9.1. This was achieved by incorporating the appropriate link commands and required variables into the L.F.C. function. This interaction was complex as the database entry was strictly defined. The interaction between Dispatch and L.F.C. was designed along the lines of that proposed in the O.C.E.P.S. simulation work. The

Figure 9.21

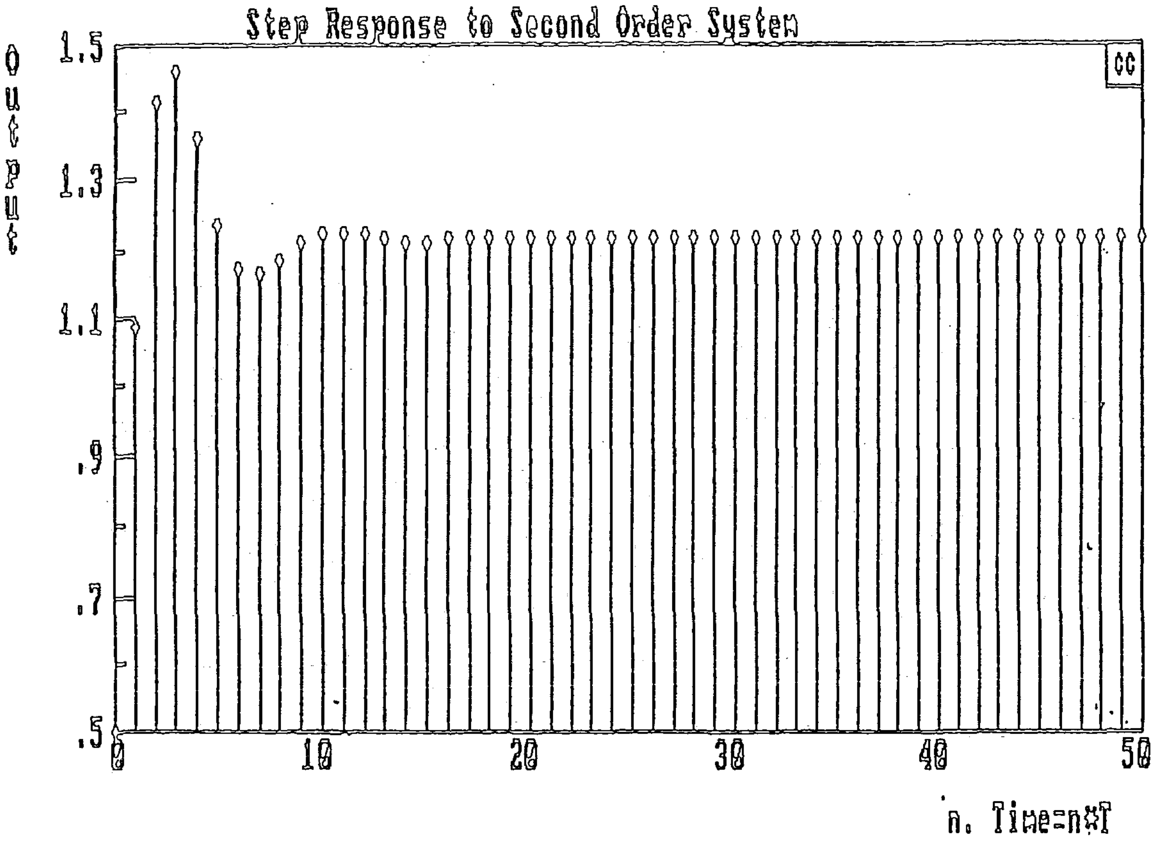


Figure 9.22

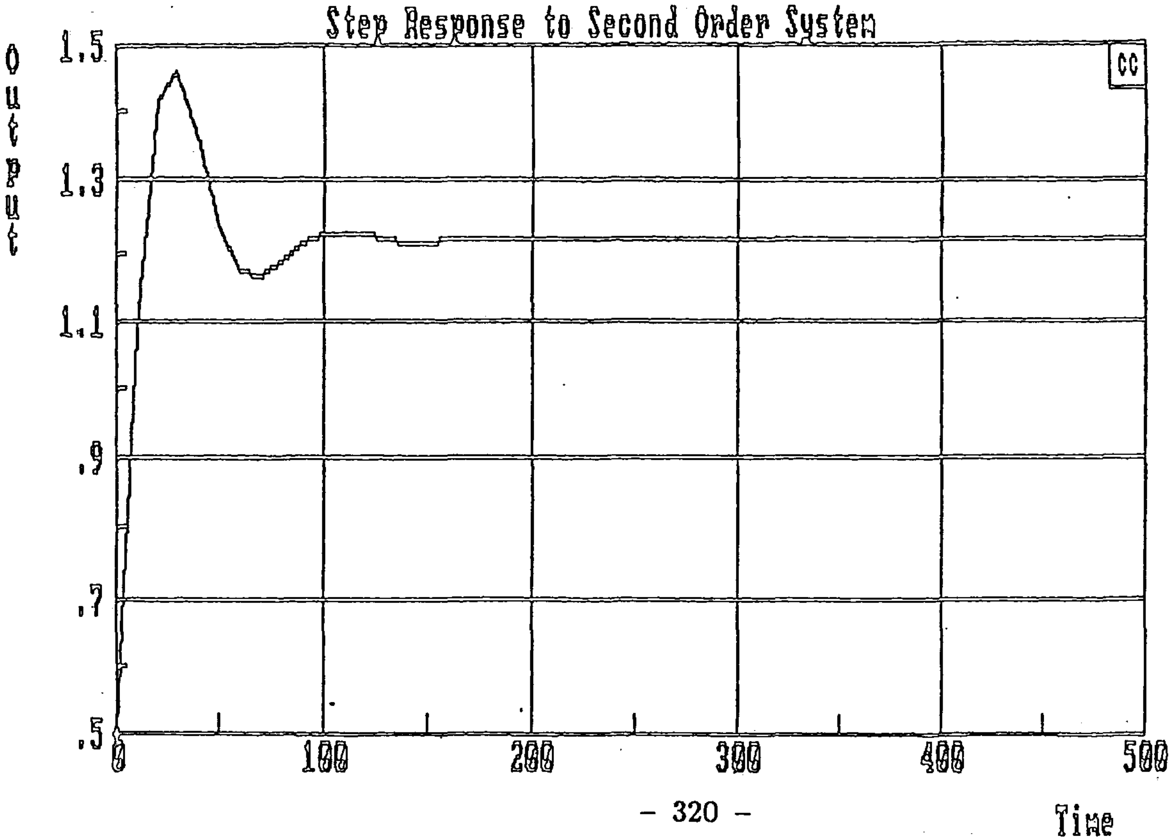


Figure 9.23

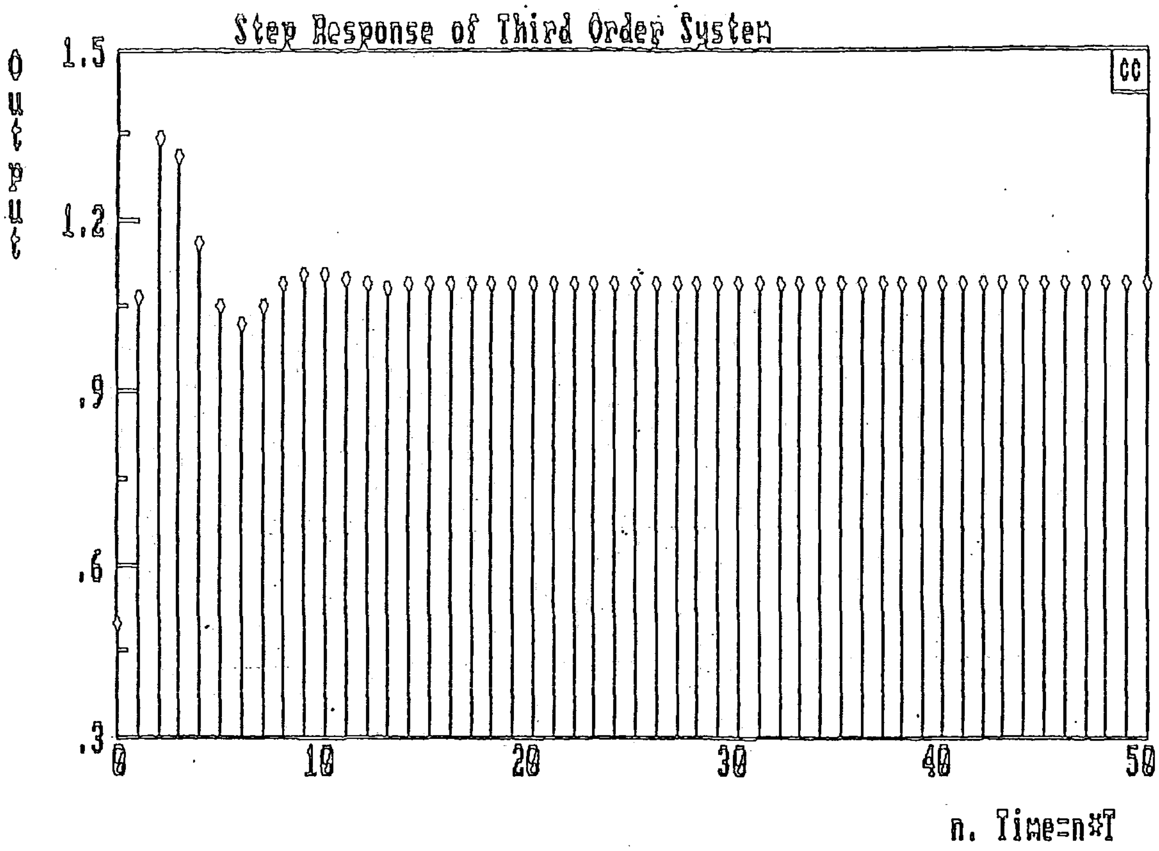
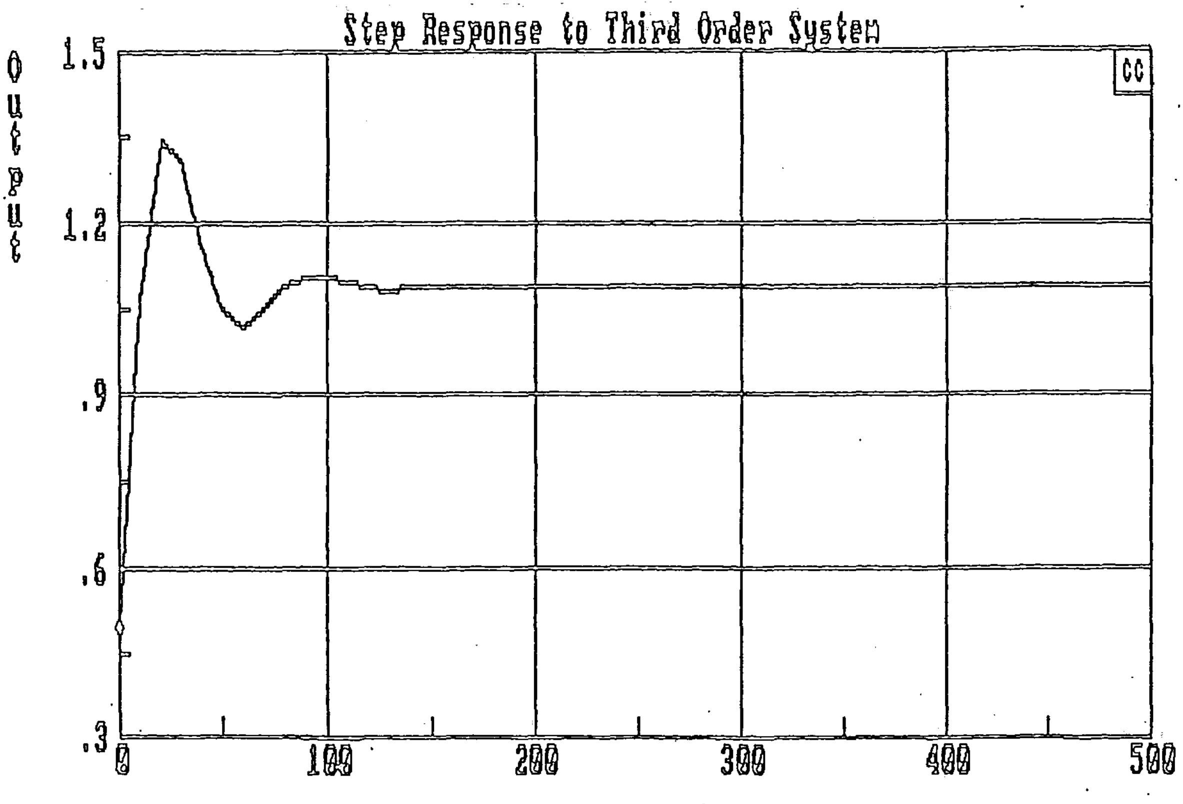


Figure 9.24



controller programs were operated from a single timing and scheduler controller. This enabled the use of the D.E.C. V.A.X. hibernation command, which enables a task to be active for a given amount of time to allow it to perform it specific operations. After its operation has been completed, the task becomes dormant until it is scheduled to come out of hibernation. The use of this scheme enabled the required information flow between the two controllers to be synchronised without undue loading on the computer that was used to run the controllers. The hibernation controller is clearly the key to the smooth running of this combined control action and may aspects of its operation had not previously been considered.

The variables supplied from the database and Dispatch are as follows

(a) the maximum number of generators,
(b) the number of generator real power measurements,
(c) the generator status (connected, or disconnected),
(d) the system frequency measurement,
(e) the present time in seconds,
(f) the power set point of each generator, at the present time,
(g) each generator's lowest power output,
(h) each generator's maximum power output,
(i) each generator's maximum ramping up rate, at each output level,
(j) each generator's maximum ramping down rate, at each output level,
(k) each generator's dispatch calculated participation factor
(l) the dispatch set point target for each generator,
(m) the total system output,
(n) the total system load

9.25.1 Off– line simulation testing

The simulation was initially tested using an off–line load curve to investigate the system operation and the problems involved with the database interfacing. When these problems had been solved, the simulation was driven from the system load updated from the data base. The L.F.C. was fully operational at this stage. The simulated frequency from the system model for two simulation runs is shown in figure 9.25 and 9.26.

9.25.2 Actual system frequency response

The actual system frequency was not available at this time for a direct comparison, but it is known that the system was in its normal steady-state without any significant perturbations. Later, the actual system frequency was made available from the database. This enabled the actual system frequency to be monitored for periods of time. A plot of the recorded system frequency at minute intervals, over a fifteen hour period is shown in figure 9.27.

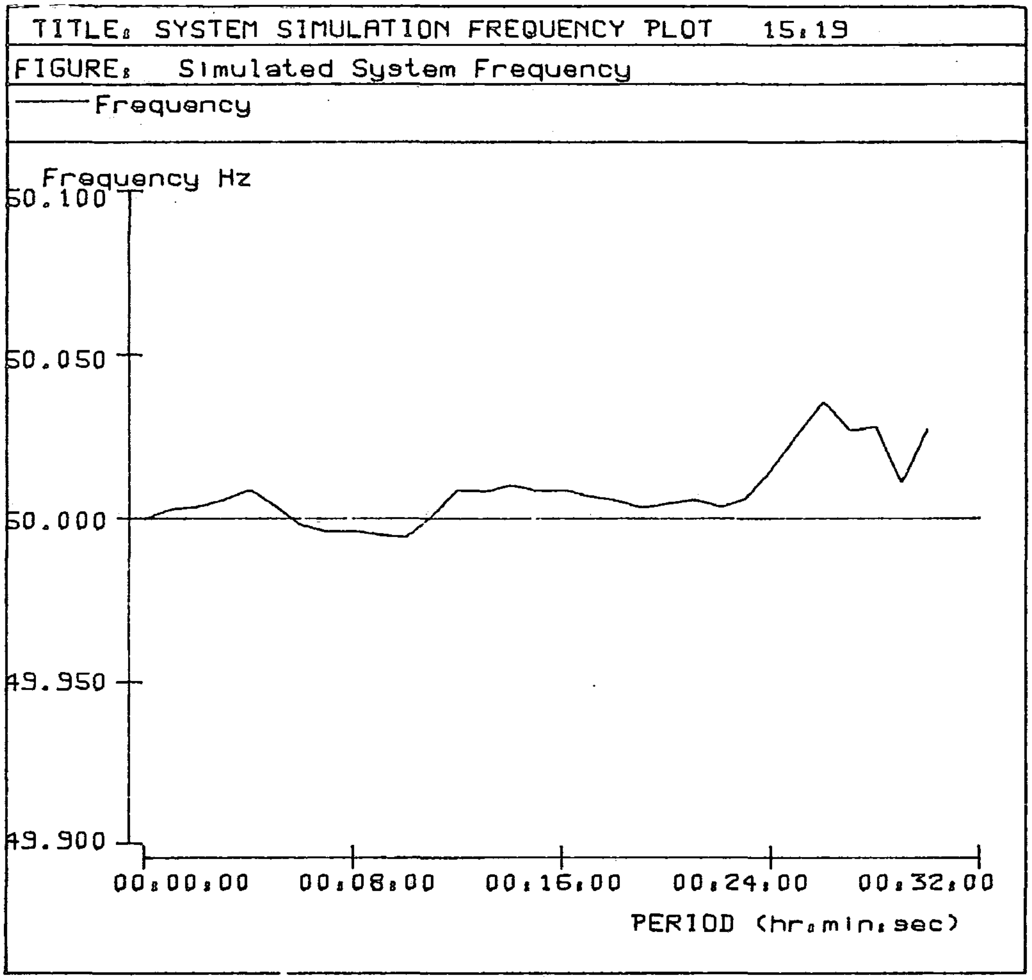
9.26 Comparison of Simulated and Actual Frequency Responses

With the availability of the on–line frequency at minute intervals, if was possible to compare the actual system frequency with that of the simulation. The simulation was run for periods of approximately thirty minutes and suitable data recorded. This time period was used so that the amount of data collected from the system and simulation did not become to great. A plot of the recorded system frequency and the system simulated frequency, over a twenty-eight minute period is shown in figure 9.28. The system frequency is greatly smoothed by the frequency of the collection of the data, but it gives a general trend of the system behaviour.

The simulated frequency deviates from zero, as the simulation has to start from the steady-state unlike the actual system which is always in a state of change. After the initial start it then begins to follow the trend of the system frequency. The simulated frequency is also greatly smoothed due to the data collection interval of a minute. The simulation was again run to simulate 20 second time periods, but because of the overheads involved, the L.F.C. function could only be operated every minute interval.

This figure shows the first closed loop operation of the controller, simulator and the on–line data. This is the fist time that such an operation has been carried out using *live* data from the C.E.G.B. system. The results obtained

Figure 9.25



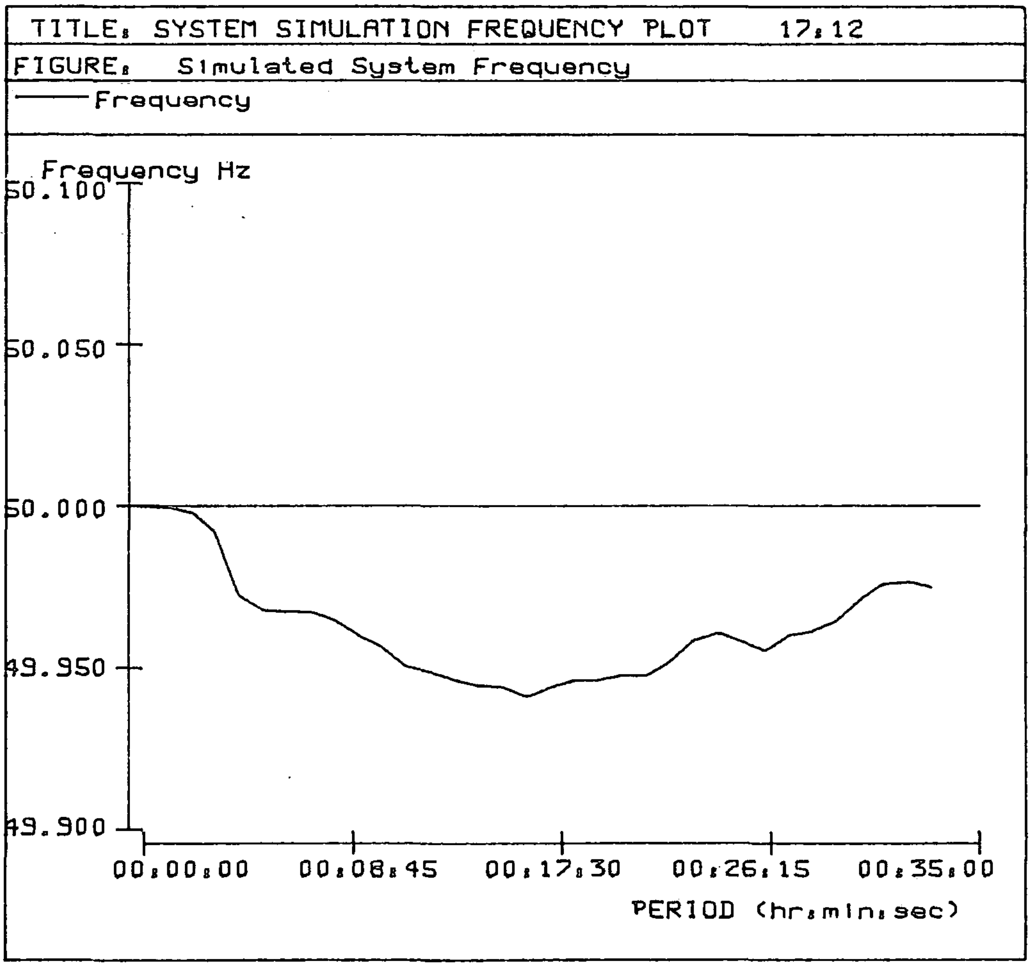
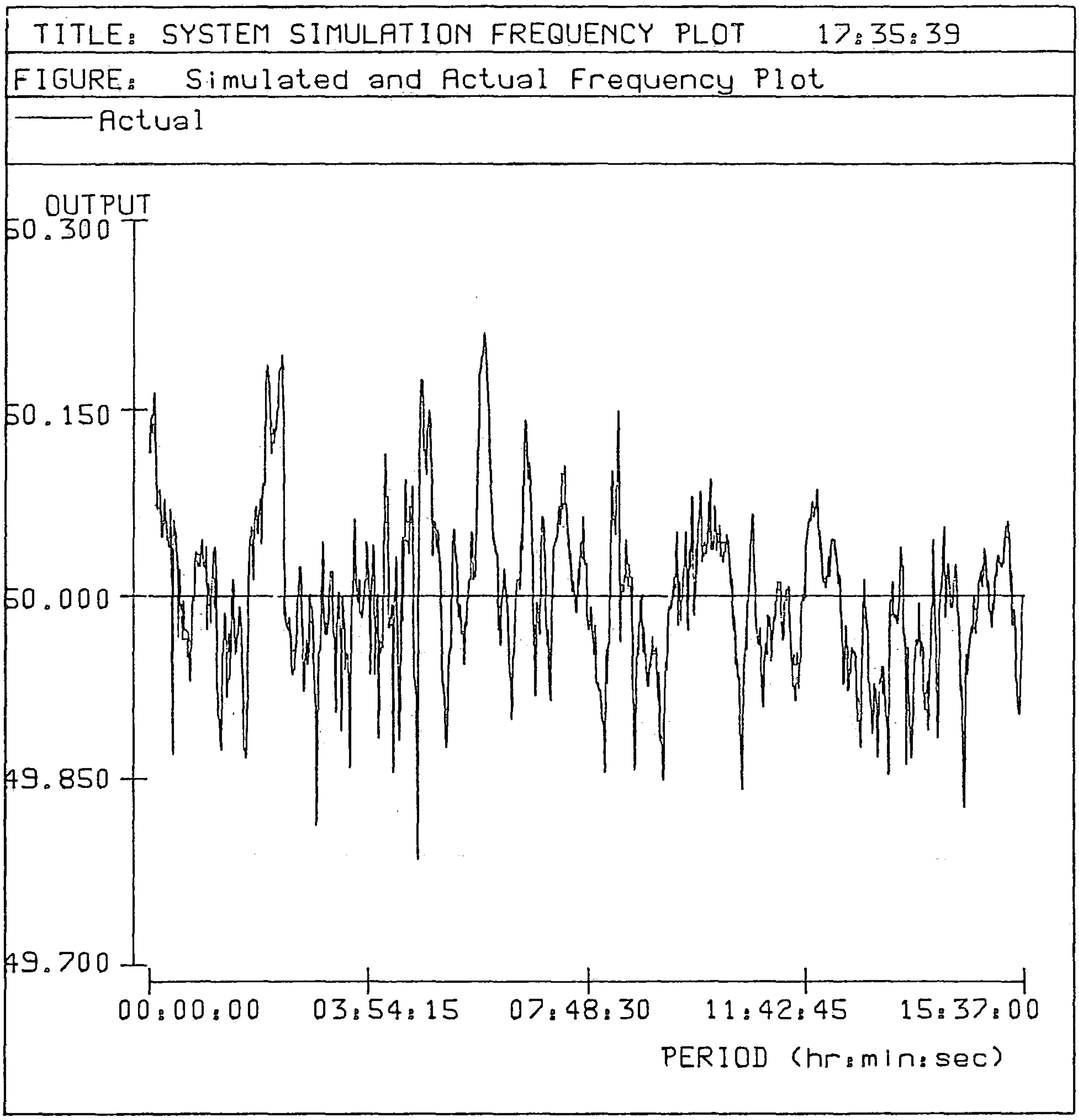


Figure 9.26

Figure 9.27

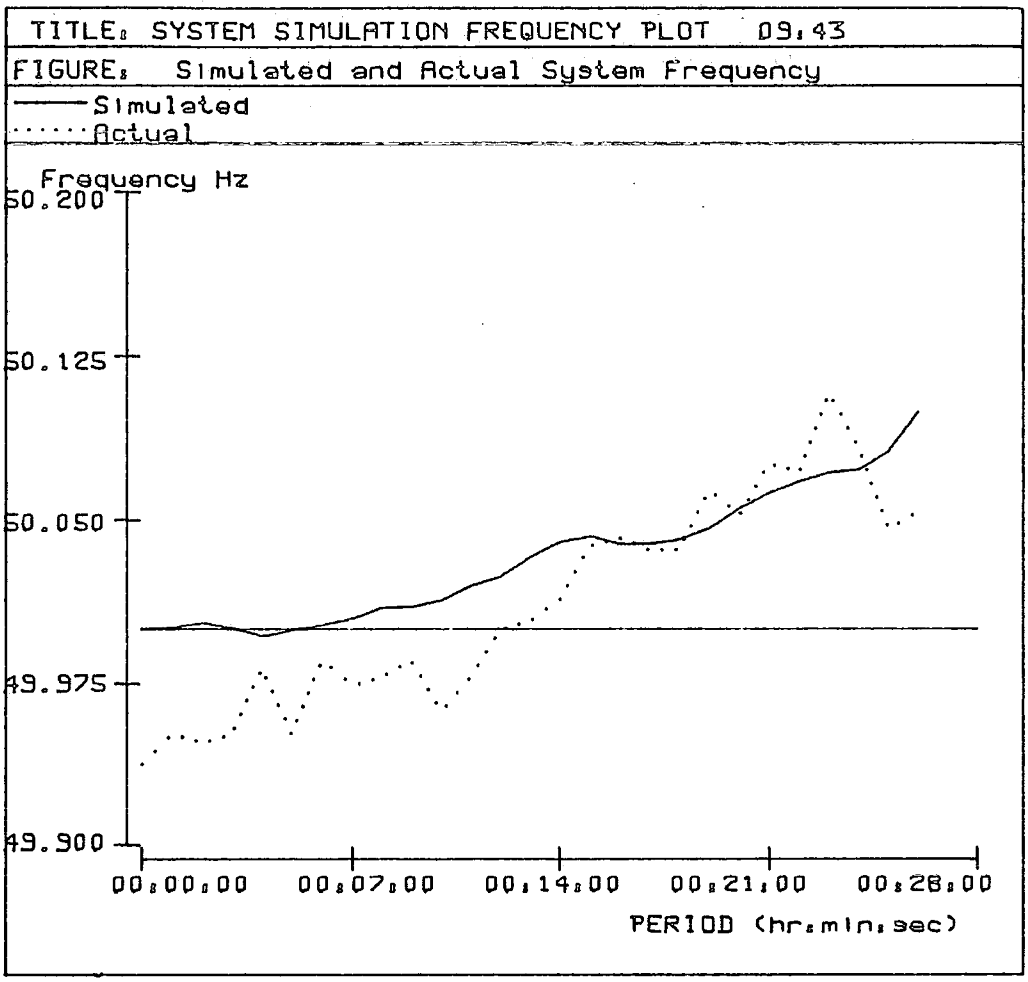

TITLE: SYSTEM SIMULATION FREQUENCY PLOT 17:35:39
FIGURE: Simulated and Actual Frequency Plot
Actual
OUTPUT
50.300
50.150
50.000
49.850
49.700
00:00:00
03:54:15
07:48:30
11:42:45
15:37:00
PERIOD (hr:min:sec)

from this successful test show that closing the loop on the controller does not cause any instability within the loop. The control loop is stable within the confines of the simulation. Although the simulation is crude, it does contain details such as implementation delay of the control action and the fact that the generators have only a limited probability of responding to the calculated control action. Thus the limited implementation of this control scheme initially shows promising results.

The Dispatch function up to this point had been providing values for the L.F.C. calculation directly from the database, there was no feedback from the frequency controller itself. The links between the L.F.C. and Dispatch are shown in diagram 9.2. With the links between the database, Dispatch and L.F.C. operating as required, it was decided to further integrate the control functions. The generator power set points from the Dispatch function were passed to L.F.C. and altered as required. These set points were used by the simulation as an input but were not fedback to the Dispatch. The data flow was re-arranged so that the altered generator set points were sent to the system simulation, and to the Dispatch function. This enabled the Dispatch to calculate the new set points based on the previous L.F.C. target set points, rather than the values from the system. The result of this interaction is shown in figure 9.29. The simulated and actual frequencies are shown for a period of twenty seven minutes. The simulated frequency again starts from the no error and proceeds downwards following the general trend of the system frequency. The system frequency and simulated frequency are not as close as in the previous example as the Dispatch calculation is based on the simulation response, rather than that of the actual system.

This plot shows that the controller loop is still stable even when introducing the Dispatch function to the complete loop. The ability of the simulation to follow the general trend of the actual system frequency should be noted. The simulation frequency error should not be as great as that of the actual due to the fact of the control scheme in operation. This is in fact so but only over a limited period of time. Due to operational difficulties periods of longer testing could not be carried out.

Figure 9.28



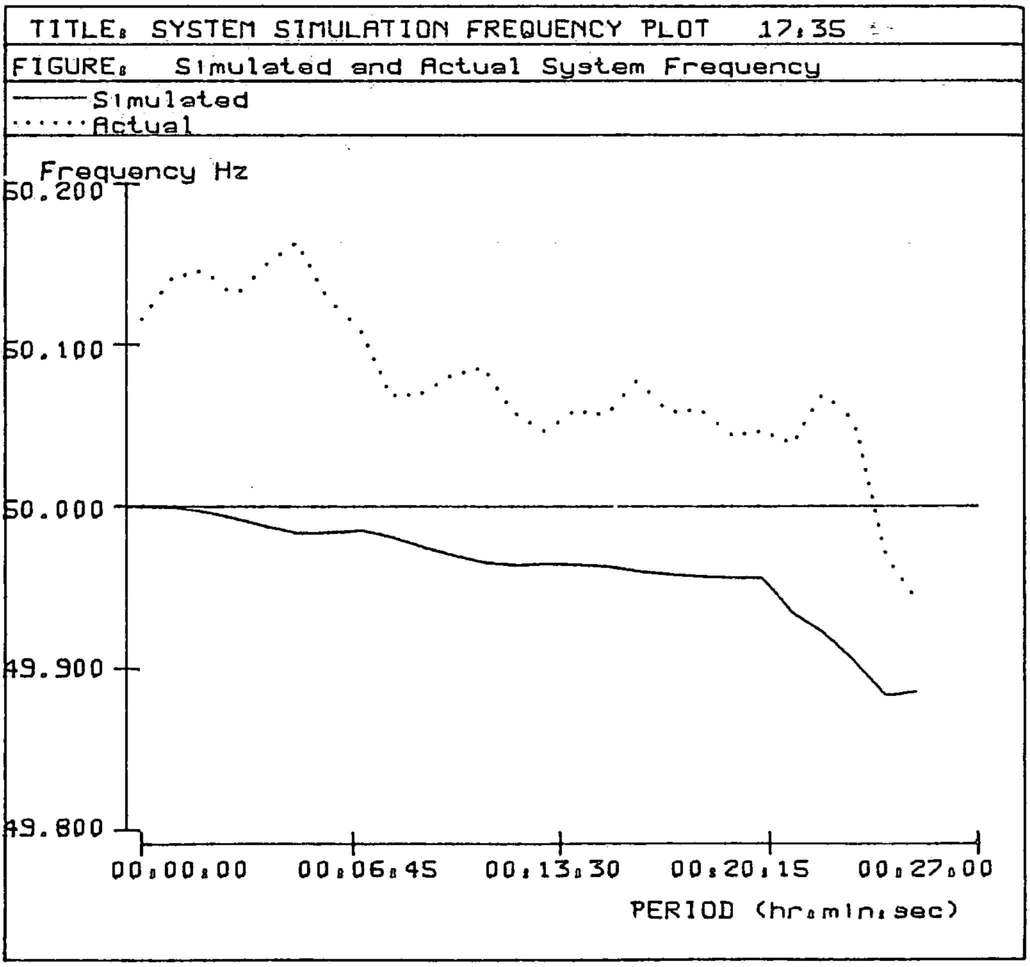


Figure 9.29

9.27 Conclusion

This chapter has described the work carried out in preparation to test the L.F.C. function operating in an actual system. The work included an investigation into the variables required to form the interface between the controller and the external system and the requirements to operate along side a real-time data base. The links between the controller and the Dispatch function have been investigated along with the reaction of the Dispatch to control commands calculated by the L.F.C.

The use of system simulation was considered to enable the L.F.C. function to operate with the Dispatch system, and hence form a closed system. The system was designed to model the action of the whole of the C.E.G.B. generation system in a general way. This aim was achieved and proved by comparing the simulation system output with that of a typical C.E.G.B. system output.

The simulation was shown to respond well within the limitations of the rather crude modelling approach. There are the required similarities between the actual system and the simulation which make the simulation sufficiently accurate to use in the further tests. The model satisfied the engineers at C.E.R.L. that the response was the correct shape to simulate the actual system to a reasonable degree of accuracy.

Some of the most interesting results from the tests were achieved when a square wave was used as the driving error for the simulation. In these cases the controller was *sufficiently excited* and responded well. The actual system has enough noise and general changing of recorded values that the problems of having non–stationary values for long periods of time is small. Various safe guards may be built into the controller to remove this problem.

The parameter model that is calculated by the L.F.C. function was used to create a model of the simulated system to check the accuracy of the estimation procedure. The result of this has shown the modelling process to estimate an accurate model of the system under study.

The plots presented in the latter part of the chapter were constrained to a short time period due to operation difficulties with the on–line data collection and recording. The time period of the plots shows that the system was in fairly steady–state operation. In this case the manual operation of the system from National Control is possible without the need for a great deal of manual controller interaction. It is seen that in this state, the automatic controller is able to react as well as the manual approach. It would be interesting to observe the prolonged effect of the described control scheme on such a system. The data presented was from the system in steady–state. Unfortunately there were no *System Incidents* while the data was being recorded or minor problems on the system. The effect of a so termed *interesting* event would be useful to access the controllers reaction to that of a change in the system status. An instability on the system is not seen too often so prolonged data acquisition would be required to record any meaningful results.

Although the simulation is only a crude representation of the system is does include some the important factors seen in the actual system. The integrated control scheme remains stable in closed loop operation, and the simulation follows the trend of the actual system. This project has given some insight into the problems of placing an advanced control scheme on a system that previously had little automatic control. It has enabled the system response to automatic control action to be observed, from a simulation of the actual system, using actual system data. The results are promising but due to time constraints, the project was unable to continue. However, it considered some of the implementation problems that would be associated if any sort of frequency control scheme were to be used on the C.E.G.B. system.

CHAPTER 10

CONCLUSION

This thesis has presented the results of a study of power system control with special emphasis on the integrated control of the system frequency. This has been achieved by direct automatic control of the turbine–generators in the system to establish what is termed Load Frequency Control (L.F.C.). The use of L.F.C. schemes to balance the energy demanded by the system load and that produced by the system generators has been studied in great detail. The original algorithms for L.F.C. were developed using fixed parameter type control schemes, much work has been published in this particular area. However, the use of non–dynamic controllers led to non–optimal control of power systems. Clearly, there was a need for optimal controllers that could alter their control action depending on the state of the system and operate within economic constraints.

The general trend in power systems control has been towards centralised control rooms were Energy Management Systems are used to control networks with greater speed and efficiency than with the traditional manual approach. This has led to more economic operation of the system and has had a dramatic effect on long system operation and planning. Computer assistance may be used in long term system planning as well as in hour by hour, down to the second by second operation of the system. The use of Energy Management systems has enabled power systems to be operated in a more economic manner and with increased security of supply to the customer.

Initially, the type of controller investigated was of the fixed parameter type. This served two purposes, firstly it helped to define the problems faced when implementing an L.F.C. scheme in an Energy Management system, and secondly general experience was gained in the area of system control. The controller chosen for this application was a fixed parameter controller, using a well known and understood P+I control scheme. Although this scheme produces numerically robust control action, it can only calculate an optimal response for a defined set of operating conditions. In the case of power systems, this leads to periods of non–optimal control action as the system can change its gain, and hence its operating point as system conditions alter. Thus the fixed control scheme is not ideal for use with dynamically changing systems. The requirement for a non–static controller was realised early on in the project.

Before using adaptive control techniques, it was necessary to decide the type of control required. The two questions, what is adaptive control, and is it useful in this application, were initially considered. Clearly there was a requirement for a control scheme that was able to change its control action depending on the response and the state of the system at any given time. The use of stochastic control theory cannot directly solve a non–linear problem, however, the problem may be linearised and then a theoretical solution may be calculated. With the repeated use of stochastic control schemes it has been shown possible to control a non–linear system. One problem that can occur is that the due to modelling errors, a sub–optimal solution for the assumed process may be calculated. Also, if the assumed model is incorrect compared with the actual plant, errors from the control action can become significant. It has been shown that the reduced modelling process proposed in this thesis is able to model a system sufficiently accurately for these errors to be reduced.

The use of adaptive control to produce a self–tuning regulator was investigated. The regulator may be split into two distinct sections. Firstly there is the system identification function, followed by the calculation of the control action. Various methods were reviewed for these operations. The methods finally used were hybrids of those reported in the literature. Many of the methods use the same basic ideas with some alteration to suit a particular set of constraints. The controller proposed in this thesis is a combination of several versions of the basic controller, to enable it to track rapid changes in the system and also follow periods with little change. This thesis has considered adaptive control schemes which enable the control action to be calculated, based on the current system status and operating conditions.

The estimation scheme used for the controller was a recursive least squares type of calculation. This is useful for dealing with systems that vary slowly with time. Modifications are required to the basic algorithm if the system under consideration varies more rapidly with time. The effect of swamping the algorithm with data may be seen under some circumstances. For this reason, an exponential window is used to control the data flow. The old data is removed exponentially as the new data replaces it. It is also possible to make the adaptive algorithm more robust to enable it to cope with plant non–lineararities and sudden parameter changes. The estimator must be able to respond quickly to changes in system conditions, this can be achieved or assisted by the use of a variable forgetting factor.

The use of a self–tuning regulator was considered so that the changes in the system conditions could be tracked and allowed for by the controller. The ability of the self–tuning regulator to produce robust control commands in real–time is a great advantage for the on–line control of a power system. The regulator requires an estimated model of reduced order of the system under study. This model must be sufficiently accurate to estimate the system status to a reasonable degree, without causing errors by over modelling.

The use of variable forgetting factors in the estimated system model has been proposed for frequency control. These forgetting factors allow for the fact that the system changes status at differing rates. The data accumulated by the estimator may be weighted in favour of the newer data points if the system is undergoing a period of change, or it can be stabilised if the system is in steady–state.

The proposed controller uses the updated estimated system model as a basis to calculate the control action. The controller is designed to minimise the variance of the system error whether it is a single system or an interconnected system. The basic controller may be extended so that it can be used to control an interconnected system as well as a single network. The frequency error and the tie–line power flows can be both used as control variables as required. The use of weighting factors in the calculation enables the required minimum to be reached depending on the method of operation either frequency error, tie–line error, or a combination of both. It is not possible to minimise against both of the variables as they are totally independent.

This control scheme is able to react to all system operating conditions. It is able to track the system and offer optimum control action for large abrupt changes in consumer load or generation, or slower smaller changes. The scheme is two way adaptive in that it uses an on–line continuously updated model for the regulator, and the weighting assigned to the frequency error and tie–line error. The use of this controller improves the frequency response of the system tested. It is beneficial in system operation in both steady–state and transient conditions because of its ability to change the control action as the system conditions change. This also makes it useful for direct on–line applications.

The current trend of linking power systems to their neighbours has helped to reduce their operating overheads. This method requires less plant for for system regulation, less spinning reserve and has increased system security. However, this trend has also increased the demands placed on the control functions of the system. Well defined models of the neighbouring systems are required to allow the meaningful control of power interchange to be achieved. This has effected all the control functions in the energy management of the system and all control schemes should now be capable of considering the effect of influences outside the original system. This is especially true for the L.F.C. strategy.

The use of generator control modes was introduced to the controller to interact with the simulation. This enabled the generators to be controlled in a more realistic way. The introduction of Base mode and Ramp mode provided the opportunity to simulate differing control modes in the system. It enabled part manual control and part automatic control of the generator units which could not previously be achieved. This placed more constraints on the L.F.C. function as the system characteristics could be changed even more dramatically.

The operation of the adaptive controller was unaffected by these manual control operations and continued to operate with meaningful control action. The ability of the system to track the control state of the generators enabled the other long range controller functions to take account of the manual interaction and integrate this into the automatic control scheme. The control states of the generators allowed the operator to see directly the system operating state. If the data from the system became invalid either by telemetery fault or failure the control state could be changed and indicated to the operator. Appropriate action could then be taken either automatically or manually. Once the data became valid once again the control state could be changed and the unit incorporated into the control scheme once again. This type of change on the system clearly would have caused problems to the fixed control scheme investigated in the early stages of the project. The enforced partial control of only some of the areas generators would clearly have caused the controllers response to be non-ideal. However, using the adaptive control techniques proposed in the thesis the controller was able to change its system model to reflect changes in the actual system and hence, the control action it calculated.

The thesis also presents an investigation into the types of support software which is required in an L.F.C. scheme to assist the adaptive controller. This important subject was carried out in two separate sections. Firstly, there is the interface between the L.F.C. function and the other command functions in the controller hierarchy. Secondly there is the support software required by the adaptive controller itself within the L.F.C. function. The interface between the other command functions is important because there needs to be a well defined exchange of information within the controller hierarchy for the optimal control of the system to occur. The support software around the adaptive routines themselves is important for the robustness of the controller. Little work had been carried out previously in this important area which is required to ensure that the controller is numerically stable, protected by invalid data values and continues to operate when the data is not sufficiently exciting.

The work into the interface requirements was continued when the controller was tested as part of the software used by the C.E.G.B. This work allowed the controller to be tested on *live* data from an actual system. Due to the constraints placed on the testing, only a simulated system could be controlled. However, the control loop was able to be closed by linking the L.F.C. function to Dispatch function also running alongside the simulation, yet receiving its data directly from the *live* system.

The controller has been validated against the O.C.E.P.S. simulator, which has been in turn validated by the C.E.G.B. The controller has also been operated inconjunction with a C.E.G.B. proposed simulation model. This model was a reduced order system model giving a realistic response with out the buffering effect of any complicated Energy Management software. It enabled a direct comparison to be made of the proposed automatic control action and a simulation of the currently used C.E.G.B. manual control and dispatching techniques.

The project has enabled the problems of interfacing L.F.C. techniques with Dispatching and other software. The use of on–line database operation and definition has also been investigated. The controller has been used directly with a Dispatching technique employed by the C.E.G.B. at National Control. This showed that the controller was able to function well with action based on real–time live data as well as defining the interface between the control functions. The closed loop operation between the L.F.C. and Dispatching function along with the system simulation and live data showed that the proposed system could well work to control the frequency of the C.E.G.B. system, although clearly there is far more work to be carried out.

With the ever expanding size and complexity of both power systems and their control centres there is an increasing need for L.F.C. schemes. External pressures both economical and political require the control of the C.E.G.B. network to be altered in such a way that computer control will be required to carry out much of the day to day operation. Previously, systems which have relied on manual frequency control will, through external circumstances require tighter control over system frequency. There may even be a requirement for economic operation using interconnecting lines to other utilities, perhaps in other countries. The subject of an integrated power system control strategy is clearly important from an operational and economical view point and should continue to be investigated.

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Appendix 1

O.C.E.P.S. Scenario

The standard test for all software within the O.C.E.P.S. package is an hour long scenario. This test is designed to create difficult control situations for the automatic control functions in the O.C.E.P.S. environment. It creates a set of system conditions to simulate those operating conditions which would be met by an actual system. The test is designed to simulate the steady–state running of a system and severe emergency conditions, to the limit where the system actually becomes separate sections. It ranges from the standard loss of consumer load, the loss of a generator unit and loss of transmission lines to the more severe condition of system islanding when the system forms separate electrical islands. This test causes severe transients on the system as well as splitting the system into separate self–supporting networks. The last test in the scenario requires the resynchronisation of the separate electrical islands. Clearly all the control software must be capable of not only controlling the system during these severe transients but also under islanding conditions.

The scenario itself is presented at the end of this section. There follows a brief description of the various commands that are used to drive the scenario. It initially starts with the loss of consumer loads, a transmission line and then a generator.

The scenario starts at 07:00

(1) after 4 minutes load 4 is disconnected,
(2) 4 minutes later load 4 is reconnected,
(3) 2 minutes later the breaker on the sending end of line 1 is opened,
(4) 4 minutes later line 1 is reconnected,
(5) 4 minutes later generator 2 is disconnected from the system,
(6) 4 minutes later generator 2 is resynchronised to the system.

At this point the network is split into an active section and a non–active region which are then recombined.

(7) 4 minutes later 3 lines and 2 links are opened to form a passive region of the network,

(8) 4 minutes later the region is re-energised.

The network is now split into islands

(9) 3 minutes later the network is split into 2 separate electrical islands,

(10) 6 minutes later the system is split into 3 separate electrical islands,

(11) after 5 minutes of split operation, there is an attempt to resynchronise part of the network to form 2 islands.

(12) after 10 minutes of split operation there is an attempt to resynchronise both islands to reform the complete network.

```
* SCENARIO   OCEPS SIMULATION OFFICIAL DEMO
*
* REVISION   3.00.00
*
* DATE   24.02.87
*
#TITLE OCEPS SIMULATION OFFICIAL DEMO R3.00.00
*
$TIME 8/2/1985.7:0:0              ;* wait until required date and time
*
$WAIT 0.0:4:0                     ;* wait for 4 minutes
  $OPEN LOAD,4                    ;* disconnect load number 4
*
$WAIT 0.0:4:0
  $CLOSE LOAD,4                   ;* reconnect load number 4
*
$WAIT 0.0:2:0
  $OPEN LINE SEND,1               ;* disconnect line number 1 at sending end
*
$WAIT 0.0:4:0
  $CLOSE LINE SEND,1              ;* reconnect line number 1
*
$WAIT 0.0:4:0
  $OPEN GEN,2                     ;* disconnect generator number 2
*
$WAIT 0.0:4:0
  $CLOSE GEN,2                    ;* reconnect generator number 2
*
$WAIT 0.0:4:0
  $OPEN LINE SEND,32              ;* disconnect line number 32 at sending end
  $OPEN LINE SEND,24              ;* disconnect line number 24 at sending end
  $OPEN LINE SEND,19              ;* disconnect line number 19 at sending end
  $OPEN LINK,42                   ;* disconnect link number 42
  $OPEN LINK,43                   ;* disconnect link number 43
*                                  * a region of the network is now de-energised
*
$WAIT 0.0:4:0
  $CLOSE LINK,42                  ;* reconnect link number 42
  $CLOSE LINK,43                  ;* reconnect link number 43
*                                  * the region is now re-energised
*
$WAIT 0.0:3:0
  $OPEN LINE SEND,15              ;* network now split into two islands
*
$WAIT 0.0:4:0
  $OPEN LINE SEND,10
  $OPEN LINE SEND,41
*
$WAIT 0.0:2:0
  $OPEN LINE SEND,33              ;* network now split into three islands
*
$WAIT 0.0:5:0
  $SYNC LINE SEND,32,0.0:7:0      ;* request synchronisation of islands land 2
*
$WAIT 0.0:7:0
  $CLOSE LINE SEND,19
  $CLOSE LINE SEND,24
  $CLOSE LINE SEND,15
*
$WAIT 0.0:3:0
  $SYNC LINE SEND,33,0.0:7:0      ;* request synchronisation of remaining island
*
$WAIT 0.0:7:0
  $CLOSE LINE SEND,41
  $CLOSE LINE SEND,10
*
$EXIT
```

Appendix 2

Recursive Least Squares Algorithm

```
1) Select the values of $a$, $\gamma$ $b_0$ and $m$.
2) Using the fact that $a = \gamma = 1$ is the ordinary least squares; $a = 1 - \gamma$ and $0 < \gamma < 1$ is exponentially weighted least squares.
3) Select initials values for $P(m)$ and $\hat{\theta}(m)$.
4) Collect $y(0), \ldots, y(m)$ and $u(0), \ldots, u(m)$ and form $H^T(m+1)$
5) Let $t \leftarrow m$.
6) $K(t) = \frac{P(t-1)}{\gamma} H(t) \left[ \frac{1}{a} + H^T(t) \frac{P(t-1)}{\gamma} H(t) \right]^{-1}$
7) Collect $y(t)$ and $u(t)$
8) $\hat{\theta}(t) \leftarrow \hat{\theta}(t-1) + K(t) \Big[ (z(t) - \theta^T(t) \hat{\theta}(t-1) \Big]$
   $z(t) = y(t) - b_0 u(t)$
9) $P(t) \leftarrow \frac{1}{\gamma} \left[ I - K(t) H^T(t) \right] P(t)$
10) Form $H(t+1)$.
11) Let $t \leftarrow t + 1$.
12) Goto step 6.
```