**SUPPLEMENTARY DC CONTROL IN A
TWO AREA AC/DC POWER SYSTEM**

A Thesis submitted to
the College of Graduate Studies and Research
in Partial Fulfilment of the Requirements for
the Degree of
Master of Science
in the
Department of Electrical Engineering
University of Saskatchewan

by

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Saskatoon, Saskatchewan

March 1992

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ACKNOWLEDGEMENTS

The author wishes to express his gratitude to Dr. Ronald J. Fleming for his guidance and assistance during the course of this thesis research. Thanks are also due to various members of the Electrical Engineering Department of the University of Saskatchewan for their valuable suggestions and comments.

The author acknowledges the encouragement provided by his family for the realization of this work. He is also grateful to all those who were helpful in the development of this study.

Financial support provided by the National Research Council of Canada, Research Grant OGPIN 011 and the University of Saskatchewan is thankfully acknowledged.

UNIVERSITY OF SASKATCHEWAN

Electrical Engineering Abstract 92A361

**SUPPLEMENTARY DC CONTROL IN A
TWO AREA AC/DC POWER SYSTEM****Student:** Jose M. Castellanos**Supervisor:** Dr. Ronald J. Fleming

M.Sc. Thesis presented to the College of Graduate Studies and Research.

March 1992

ABSTRACT

In this thesis results of research are reported for a study of the dynamic performance of a two-area power system interconnected by AC and DC tie-lines. The system includes supplementary DC control interacting with the conventional AC area controls. Taking advantage of the fast controllability of DC links, supplementary control utilizing DC power modulation improves system damping, reduces unnecessary governing system operation and reduces inadvertent energy interchange between the two areas. DC power modulation is based on variations of AC system signals such as net power interchange deviation and/or area frequency deviation.

A linear model was used for the power system to study small changes around a base reference state and only the power/ frequency control aspects of the overall power system control problems were considered. The model used and the simulation of it are described in this thesis.

Eigen-structure analysis of the state space model of the power system was used to evaluate system stability, with and without supplementary control. Control optimization was achieved by minimization of a performance index to adjust the values of the controller parameters. The performance index selected is a function of Area Control Error (ACE) and is a good measure of control effectiveness. The results of the eigen-structure analysis and the control optimization are presented.

Computer simulation was used to obtain power system dynamic responses to step load disturbances and to estimate optimal controller parameters. The simulation studies considered various AC and AC/DC interconnection types and control features of the two area interconnected power system. Simulation results are presented in the form of time responses graphs and in summary tables.

It was found that the dynamic performance of the two-area power system could be significantly improved with the aid of the controls in the DC line.

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NOMENCLATURE

P_r	area capacity (power base), MW
f^*	nominal system frequency, Hz
i	subscript referring to area ($i=1,2$)
ΔP_{Gi}	generated power deviation, puMW
ΔP_{12}	net power interchange deviation, puMW
ΔP_{Li}	change in load demand (load disturbance), puMW
Δf_i	frequency deviation, Hz
ΔP_{AC}	AC tie line power deviation, puMW
ΔP_{DC}	DC tie line power deviation, puMW
U_i	AGC control signal
U_3	supplementary control signal
ACE_i	area control error, puMW
T_{Gi}	speed governor time constant, s
R_i	generation regulation characteristic, Hz/puMW
T_{Ti}	steam chest time constant, s
H_i	inertia constant, s
D_i	load frequency characteristic, puMW/Hz ($K_{Pi}=1/D_i$, $T_{Pi}=2H_i/f^*D_i$)
T_{12}	synchronising coefficient, puMW/Hz
B_i	frequency bias constant, puMW/Hz
k_{Pi}	proportional gain of AGC controller
k_{Ii}	integral gain of AGC controller
T_{DC}	DC system time constant, s
k_P	proportional gain of supplementary controller
k_I	integral gain of supplementary controller
s	Laplace operator

1. INTRODUCTION

1.1. General

As interconnected power systems grow in size and complexity, it is necessary to employ various control systems to maintain quality, reliability and economy of operation. Power system control is required to maintain a continuous balance between generation and varying load demand, while system frequency, voltage levels and security are also maintained.

The variable nature of the consumer power demand requires continuous changes of the total generation, therefore the difference between generated and consumed power must be continuously monitored and supervisory control action must be executed to restore the balance following a disturbance.

The research reported in this thesis concerns the performance of supervisory controls associated with high voltage systems interconnected by AC and DC tie-lines. As such these controls are important to successful system operation.

By way of introduction to the studies carried out consider the response of a normal power system interconnected by AC tie-lines with neighbouring power systems. An increment in system load causes a speed reduction and the inertia of the

rotating masses of the generating units provides the energy necessary for a temporary balance. However the speed of the generators determines the system frequency, thus rate of change of frequency represents an indirect measure of the unbalance between consumed and generated power. The speed governing system (primary control) of each controlled generating unit senses the speed change and responds by adjusting its load in proportion to its governing characteristic for the restoration of the system frequency. Subsequently the system reaches a new equilibrium in which the system frequency has decreased slightly and the tie line power interchanges with neighbouring systems have deviated from their previous values.

The requirements for control of frequency and net power interchanges can be implemented by a secondary control, called Automatic Generation Control (AGC). The AGC control provides automatic variation of generation set points on the speed governors to restore system frequency and tie-line power interchanges to scheduled values. The AGC system is an important part of the control hierarchy which helps each control area to operate independently with respect to other control areas in an multiarea interconnected power system.

Due to economic incentives, bulk power interchanges between large, interconnected power systems are desired. The need for dynamic performance analysis of large systems with weak HVAC and HVDC links is increasing.

Power flows in an AC system are related to differences in phase angles across the systems, that means a change in power angle must precede a change in stabilizing power flow. With a DC system, the power flow can be forced on and precede terminal voltage or phase angle changes; so a DC link can be used to reduce power angle changes at its terminals, and if at the same time in parallel with an AC link, to increase the permissible power transfer over that link.

Normally HVDC systems are operated under constant power control in accordance with a fixed scheduled DC power transmission, without assisting the AGC action. The controllability of HVDC links is often cited as an important advantage of DC systems, because of the fast DC power control. This controllability of HVDC links can be valuable in improving the dynamic performance of overall AC/DC interconnected power systems.

Utilizing the fast power control characteristic of HVDC systems with a suitable supplementary controller to modulate the DC power based on control signals derived from the AC system, it is possible to influence favourably the damping of the natural modes of system oscillations. Also, it is possible to minimize the area control error (ACE) to avoid excessive governing system operation and to reduce the inadvertent energy interchange (IEI) between neighbouring areas (control areas) in the multiarea interconnected power system.

In the context of optimal control, an optimization technique based on a performance index can be used as a reference parameter to optimize the controller parameters to achieve the system desired behaviour.

1.2. Background Survey

In this section the terminology of interconnected system controls is discussed along with a brief review of the essential control features of HVDC power lines.

1.2.1. Control Area Structure

A control area is defined¹ as a part of an interconnected power system to which a common generation control scheme is applied. The conventional control strategy for area control is the one based on the "tie line bias" concept, where the main objectives of area control operation are to compensate for the changes in the frequency and the tie line power interchanges with neighbouring control areas.

The conventional method⁴¹ of keeping the system frequency and tie-line power interchanges at preset levels within scheduled limits depends on the hierarchical control structure which includes primary, secondary and tertiary control systems defined as follows:

Primary Control: Speed Governing System

- * Usually analog or digital/analog devices,
- * fast acting, in the order of fraction of a second to a few seconds,

- * regulates about 15% to 30% of total area generation,
- * operates on an individual generating unit in accordance with its regulation characteristic.

Secondary Control: Automatic Generation Control (AGC)

- * Analog or digital devices,
- * slow acting, in the order of a few seconds to a few minutes,
- * system frequency and tie line power flow control tasks.

Tertiary Control: Economic Dispatch Control (EDC)

- * Digital,
- * slow acting, in the order of a few minutes to a few hours,
- * economic generation allocation task.

In a hybrid AC/DC power system, the DC system control is capable of functions at all three hierarchical control levels.

1.2.2. Area Control Error

The tie line bias control strategy for area control is sensitive to changes in the frequency and the tie line power interchange. One of the measures of quality of such a control scheme is the area control error (ACE) signal. ACE is defined¹ as the linear combination of the net power interchange error and the system frequency error. It is the amount of generation required in an area to restore net power

interchange and frequency back to scheduled values. The mathematical expression of ACE is:

$$ACE = \Delta P_{tie} + B \Delta f$$

$$\Delta P_{tie} = P_{tie} - P_s$$

$$\Delta f = f - f_s$$

P_{tie} = actual net power interchange, MW

P_s = scheduled net power interchange, MW

f = actual system frequency, Hz

f_s = scheduled system frequency, Hz

B = area frequency bias setting, MW/Hz

1.2.3. AGC Controller

Usually AGC controllers are designed based on a PI algorithm (proportional plus integral). Under this characteristic, the control signal sent to the participating generators is the sum of the ACE and its time integral as shown in Figure 1.1. The ACE is a function of time, and is very random in nature. The AGC controller output (control signal) takes the form of raise/lower pulses which drive governor speed changers at each generating unit under control. It is uneconomical and technically undesirable to force generation plant outputs to make fast changes, up and down, in an endless sequence of unnecessary control actions. This causes severe stresses in the turbine/generator parts and large control energy expenses.

7

Figure 1.1 Two Area Interconnected Power System via parallel AC and DC Tie-lines.

1.2.4. Area Governing Characteristic

For a control area, the combined effect of all the generating units in operation has a composite governing characteristic ($1/R$), which is an expression of the relationship between generation changes and frequency changes in MW/Hz. It normally has a negative slope (dP/df).

1.2.5. Area Load Frequency Characteristic

This defines the frequency load coefficient of the connected load in an area. In other words, it is the change in the total area load caused by a change in the system frequency. It is expressed in MW/Hz and is designated by "D". It usually has a positive slope (dP/df).

1.2.6. Area Frequency Response Characteristic

The combined effect of the area governing characteristic and the change in area load with frequency is defined¹ as the area frequency response characteristic (β). It is expressed as $\beta = (1/R + D)$ in MW/Hz. It usually has a negative slope (dP/df).

1.2.7. Tie Line Bias Control

In a multiarea interconnected AC system all the areas share in system load changes naturally in proportion to their respective area frequency response characteristics (β). However the automatic generation control supplements the control of generation depending on the bias setting "B" of the AGC control, in an

area in which the load change occurs. The tie line bias control³⁴ can be regarded as having three functions:

- i) it causes each area to absorb its own local load changes,
- ii) it determines the steady state response of an area to a remote load change following the primary governor action,
- iii) it causes each area to share in the system frequency control.

When the controller bias setting (B) is set lower than the area natural frequency response characteristic (β), the area will not respond adequately to take its fair share in the control of the whole interconnected system, resulting in a control burden on the other areas.

When the controller bias setting is greater than the area response characteristic, the area will be over controlled, which will also put an excessive counteracting control burden on the other areas. Therefore, in a control area the bias is normally set close to the area frequency response characteristic ($B \sim \beta$) such that it responds in such a way that the area control error (ACE) is minimized, without imposing an undesired control burden on the other control areas.

1.2.8. HVDC Links

An HVDC transmission link consists of the sending end AC bus, transformer, rectifier, HVDC transmission line, DC to AC converter and receiving end AC bus as shown in Figure 1.2 (a).

The control of HVDC transmission is based on the characteristic of the bridge type converter circuit. These characteristics are illustrated in Figures 1.2 and 1.3.

The HVDC power transmission system depends on continuous operation of two interacting control loops. At the rectifier the direct current level is controlled while at the inverter the direct voltage is controlled either directly or by maintenance of a constant extinction angle. These loops are relatively fast by power system standards, requiring in the order of 20 to 50 milliseconds for completion of a step change. A somewhat slower constant power control is often added which adjusts the set point of the current control according to available DC voltage.

With reference to Figures 1.2 and 1.3 the normal mode of operation is with the rectifier on constant current (C.C.) control and the inverter on constant extinction angle (C.E.A.) control. The operation point is located at the intersection of the rectifier and inverter characteristics. Operation at either (1) or (2) depends on the sign of the margin setting (I_{dm}). A reversal of this sign reverses the direction of DC power flow by reversal of the polarity of the converter voltage.

The current control adjusts the firing delay angle (α) to keep desired current in the DC line. Normally the changes in α are kept small and are utilized to cope with small disturbances. Major changes in DC power transfer are controlled by simultaneous adjustments of the transformer tap changers on the bridges. The VAR consumption at the rectifier is proportional to the firing delay angle (α).

(a)

(b)

(c)

(d)

Figure 1.2 (a) HVDC transmission link, (b) bridge converter, (c) rectifier waveforms, (d) inverter waveforms.

(a)

(b)

Figure 1.3 (a) Operating characteristic with "A" rectifier and "B" inverter; (b) Operating characteristic after power reversal.

The constant extinction angle (γ) control of the inverter adjusts the firing advance angle (β) to maintain a safety range in δ to assure current decay to zero as required for commutation. On the other hand, δ would not be large because the output voltage reduces as β increases resulting in poor utilization of equipment. Also the VAR consumption of the inverter increases when β increases.

One of the common requirements of HVDC transmission schemes is that the DC link should deliver a scheduled level of power. Although constant current control comes near to meeting this requirement if the direct voltage remains reasonably constant, more accurate power control can be obtained by automatically varying the direct current so as to compensate for changes in the DC voltage caused by the variation of the AC network voltage.

Power control could be accomplished in either of two ways. The first way would be to measure the power on either the AC or DC circuit, compare it with the power order, and use the difference (error signal) to advance or retard the ignition of the thyristor valves. In order to keep the advantages of current control (including its speed and the current limits), the power control does not replace the current control but supplements it^{6,7}. Alternatively, the power order and the measured direct voltage are fed in to an analog divider, whose output signal represents the direct current. This becomes the current order (I_{do}), which is one of the input signals to the current control. Other inputs to the current control are a current feedback signal (the DC line current) and a current margin signal (I_{dm}), both are of reverse polarity with

respect to the current order signal. In the event of the inverter taking over the current control, the current controller boosts the current order first to the rectifier and a little later to the inverter by the amount of the current margin, and thus restores the scheduled DC power level in a few tenths of a second.

Constant power control helps to minimize the effect on the AC networks of changes within the HVDC system. Power flow controls can also be designed to vary the DC power interchange in any desired way to satisfy the particular requirements of a HVDC transmission scheme. In addition to the desired DC power and voltage, other signals (supplementary control signals) may be used to modulate the power transmitted over the DC link. DC power modulation can be made in response to various AC system variables such as the phase angle between terminal buses, difference in frequency deviation between control areas^{28,30,37} and deviation of AC power interchange from its scheduled value.

1.2.9. Influence of HVDC Links on AC Systems

HVDC links have been used for various purposes, such as:

- i) Reinforcing the AC system in areas of high load density without increasing the interrupting capacity of circuit breakers, using underground cables (short distance transmission) as in the case of Kingsnorth scheme^{6,9} and Inga Shaba⁹.
- ii) Transmitting of bulk power, long distance, as in the case of the Nelson River scheme^{6,9}.

- iii) Interconnecting AC systems having different frequencies as in the case of Sakuma scheme^{6,9} in Japan and Itaipu scheme⁹ in Brazil/Paraguay. In both cases the DC link interconnects the 50 and 60 Hz systems.
- iv) Sea crossing using submarine cables as in the case of Gotland cross channel^{6,9} and New Zealand^{6,9} schemes.
- v) Back-to-back interconnection of AC systems where loop stability problems exist as in the case of Sakuma and Eel River^{6,9} schemes, where the length of the link is practically zero.

In all the above cases, two AC systems are interconnected only by a DC line which has no inherent problem of synchronous stability. HVDC links are also used to operate in parallel with AC lines as in the case of Vancouver Island³⁷ and Pacific Northwest Southwest intertie^{6,9,16,20} schemes. This type of interconnection combines both economical and technical advantages of HVDC systems, and the possibility of supplying intermediate loads.

A common requirement in all HVDC power systems is that the power transfer over the DC line be maintained within a scheduled range, which is determined by the rectifier and inverter controls within constraints imposed by the AC system voltages and the inherent current limitation of the converters. However, DC power control can be accomplished for the purpose of improving the whole system dynamic performance. In this regard, a variety of DC line control strategies have been suggested^{7,20,21,28,30,31,32,47}.

1.2.10. Dynamic Stability

This denotes the stability of synchronous machines subjected to small and relatively fast disturbances. In normal operation small frequency deviations occur continuously with corresponding variations in the rotor angle differences and generator loadings. These oscillations are associated with changes in generator outputs, bus voltages, line power flows and system loads. If the variations resulting from any initial change decrease with time, the system is said to be dynamically stable. Conversely, if these oscillations increase with time, the system is dynamically unstable. Due to the effects of non linearities, such oscillations may be limited at some magnitudes². In general, these oscillations are in the frequency range of 0.01 to 0.2 Hz, associated with governors, and 0.2 to 3 Hz, associated with exchanges of power between generating plants in the system.

1.3. Review of Literature

In the last three decades several studies have been conducted to emphasize the performance improvements of power systems because of HVDC controllability. Some of this studies are related with development of suitable models for studying hybrid AC/DC systems and a more detailed simulation of power systems. In others, the influence of DC power modulation on the stability of AC/DC power systems for various control schemes has been researched. Some of these studies are reviewed briefly in the following paragraphs to illustrate the extent of past work and to place the present work in context.

Ühlman⁷ has demonstrated analytically the use of a DC link to stabilize an AC transmission line. By using a control signal based on frequency deviations, he showed that any degree of system damping could be obtained with the appropriate control of the DC power and the AC system could be stabilized for large values of phase difference between the AC terminal bus voltages. Ühlman's analysis was developed for a simplified system composed of two machines represented by inertial models, connected by AC and DC lines in parallel. He also assumed constant voltages and negligible time constants for the DC link and the associated control system. In addition he concluded that:

- i) The damping introduced by the DC link control remains satisfactory even under practical current limitations of the DC link.
- ii) Within limits, some time delay in the application of the control signal has no serious effect.
- iii) Reactance common to the power flow over the AC and DC lines has an unfavourable effect on the DC stabilizing action.

Machida and Yoshida^{28,29,30} present a method of automatic frequency ratio control (AFRC) by a DC system. This control also provides a tie line bias control action. The operating principle is that the frequency deviations of the two interconnected AC systems are detected and the controller adjusts the DC power for constant frequency control. They conclude that:

- i) By applying the AFRC device to the random load disturbances in a steady

state, not only are the frequency fluctuations improved (decreased) but the power changes of the regulating power stations in both AC systems are also reduced.

- ii) In order to apply an AFRC device effectively for a random load disturbance with the magnitude of $\pm 1.5\%$ of system capacity, it is necessary to have a controllable DC power margin of 0.7 to 1.0 % of a smaller AC system capacity.

Dougherty and Hillesland⁴⁷ made an evaluation of effectiveness of DC power modulation in improving the steady state and transient stability of power systems. Their work was performed on the Edison Electric Institute (EEI) 700 KW model of a parallel AC/DC power system. The DC power modulation is based on the rate of change of the power angles of machine rotors and its derivative (frequency signal). They conclude that:

- i) The very fast control of power possible on DC transmission can provide strong damping to disturbances within the power system.
- ii) Even if the source of disturbance is a temporary outage of the DC line itself, its dynamic response provides effective damping immediately after restarting the line.
- iii) The DC power modulation based on frequency deviations was the most effective control for the EEI model system.
- iv) Substitution of a dynamically responsive DC line for one of two parallel

AC lines will provide a marked improvement in the transfer capability, using either steady state or transient stability as the criterion.

Cresap and Mittelstadt²⁰ confirmed experimentally the fact that DC power can be modulated to improve the performance of a parallel AC network. The Pacific HVDC intertie control, uses rate of power changes on the AC line as the modulation signal for the DC power transfer. For small perturbations, and assuming constant bus voltages of the intertie, the change in power transmitted is related to power angle. They have also concentrated on the development and implementation of a control algorithm based on the time derivative of the power transmitted over the AC line. The results obtained from both the simulation studies and the field experience have shown that the DC power modulation provides a positive damping for the natural mode of system oscillation. The rating increment of the Pacific AC intertie, from 2100 MW to 2500 MW, resulted from the successful operation of the DC power modulation scheme.

1.4 Purpose of the Thesis

The purpose of the research reported in this thesis was to extend the studies reported above to investigate how HVDC control could be used to simultaneously affect damping of system oscillation modes as well as reduce area control errors (ACE) and inadvertent energy interchange (IEI).

The controllability of HVDC links can be valuable in improving the overall dynamic performance of an AC/DC interconnected power system. Usually HVDC systems are operated with constant power control in accordance with a fixed scheduled DC power transmission; on the other hand, due to load variation (small disturbance) from time to time on the AC systems, automatic generation control action is required to match the generation to power demand, within predefined frequency limits. Utilizing the fast power control characteristic of HVDC systems with a suitable supplementary controller to modulate the DC power transfer, based on an AC system signal (e.g. net power interchange deviation from its scheduled value) it should be possible to reach the following objectives:

- i) improve system dynamic stability providing a positive damping for the natural modes of system oscillations,
- ii) minimize the area control error (ACE) in both AC systems to avoid excessive governing system operation, and
- iii) reduce the inadvertent energy interchange (IEI) between neighbouring power systems (control areas).

Therefore a small signal analysis of two area interconnected power system (TAIPS) via parallel AC/DC tie lines was developed.

A transfer function block diagram representing the power frequency problem of the system under study is presented. The system state space equation and the

eigenvalue analysis of the system is developed to evaluate system stability and the participation factors of each eigenvalue in the system dynamic response.

To evaluate the control system effectiveness, with and without supplementary control, a performance index is used as a reference parameter of system performance improvement. Then a simulation technique is applied to the system model under study to obtain the system dynamic response and also to compute the optimal controller parameters based on the performance index minimization.

From the simulation process an extensive analysis of results is presented including different cases as follows:

- i) effect of AGC controller parameter variation without supplementary control,
- ii) effect of supplementary controller parameter variation,
- iii) effect of supplementary controller parameter variation with DC power limiter,
- iv) optimal supplementary controller parameter for various DC power limiters,
- v) optimal supplementary controller parameter for different step load disturbances.

Also reported in this thesis are the results of simulation studies of dynamic responses in the following cases:

- i) Dynamic response of a TAIPS via two AC tie lines,
- ii) dynamic response of a TAIPS via AC/DC tie lines, without supplementary control,
- iii) dynamic response of a TAIPS via AC/DC tie lines, with supplementary control, and
- iv) dynamic response of a TAIPS via AC/DC tie lines, with supplementary control and DC power limiter.

2. THE SYSTEM MODEL

2.1. General

For any power system dynamic study, a suitable power system model must be chosen to include in the model all significant components relevant to the problem, and to exclude from the model insignificant components irrelevant to the problem.

Typically in studies of power system stability, one is concerned with transients in the range of 0.1 to 20 seconds duration, response characteristics in the range of over 10 Hz usually may be considered instantaneous. In this context, the high frequency dynamics of a DC transmission line and pole controls may be ignored just as the high frequency dynamics of AC transmission lines and transformers are ignored. Then the current control, voltage control, valve firing circuit and DC system (L/R and RC time constants) usually can be considered to respond instantaneously to changes in AC system voltage, desired direct current, desired direct voltage or margin angle.

In AC systems, an unbalance between generated power and load affects primarily the system frequency, leaving bus voltages magnitudes practically unaffected. On the other hand, unbalance in reactive power primarily affects only bus voltages, leaving the system frequency essentially unaffected. Therefore the control

problem can be divided in two decoupled cases. It is emphasized that these characteristics can be considered only when the changes involve only a few percent of normal operating values (i.e. are first order in a mathematical sense). In this study, only the power/frequency control problem is analyzed.

A simplified line diagram of an interconnected power system and its functional control scheme is illustrate in Figure 2.1 . The power system proposed in this thesis is composed of two power system areas interconnected by parallel AC and DC tie lines. Each AC power system is represented by thermal generation (a turbine/generator), area load (P_L) and system interconnection bus. The DC link includes two converter stations, one performing as a rectifier at the sending end, and the other performing as an inverter at the receiving end.

The basic control system includes the speed governing system, the AGC control system and the DC system control. A supplementary controller is added to the basic control scheme to introduce a new control signal (U_3) to the DC system. This control signal is derived from AC system signals and used by the DC system control to modulate the DC power transfer over the DC link.

Since the purpose of this research was to investigate the dynamic performance improvements due to supplementary DC power modulation, the study considered principally the optimization of the AGC controller parameters and supplementary controller parameters to improve control effectiveness.

Figure 2.1 The Two Area Interconnected Power System (TAIPS).

The power frequency control problem required a simplified linearised and time invariant model for low frequency oscillations studies. The linear model was satisfactory because only small changes around a reference state were to be considered.

In the derivation of the model for the two area interconnected power systems, the following assumptions were made:

- i) the electrical interconnections within each individual control area are so strong, at least in relation to the ties with the neighbouring area, that the whole area could be characterized by a single frequency and can be represented by one equivalent machine;
- ii) the voltage magnitudes at the high voltage AC buses were maintained constant by the voltage regulation action;
- iii) incremental mechanical and electrical losses were considered to be negligible, including those of the AC and DC links.

2.2. Frequency Deviation

System frequency serves as an indication of any unbalance between load and generation. Frequency deviation " Δf " is defined¹ as the actual system frequency " f " minus the scheduled frequency " f_s ".

$$\Delta f = f - f_s \quad \text{Hz} \quad (2.1)$$

In general, a negative frequency deviation represents a deficiency of generation while a positive frequency deviation represents an excess of generation.

2.3. Net Power Interchange Deviation

Net power interchange deviation is defined¹ as the algebraic sum of the powers on the area tie lines of a control area. Positive net interchange due to excess of generation is out of the area. Net power interchange deviation " ΔP_{12} " is the actual net interchange minus the scheduled net interchange, from area 1 to area 2.

$$\Delta P_{12} = P_{12} - P_s \quad \text{puMW} \quad (2.2)$$

Since the interconnection between area 1 and area 2 includes two tie lines, one AC link and one DC link, the net power interchange deviation is expressed as

$$\Delta P_{12} = \Delta P_{AC} + \Delta P_{DC} \quad \text{puMW} \quad (2.3)$$

where ΔP_{AC} and ΔP_{DC} are the net power interchange deviations for the AC line and DC line respectively.

2.4. Speed Governing System Model

The real output power in a power system is controlled by controlling the driving torques of the individual turbines of the system. By controlling the position of the control valve, one can exert control over the flow of steam through a turbine. The position of the valve can be affected either directly by the speed changer, by changing the reference power setting (ΔP_{ref}), or indirectly via feedback from changes

in the speed or frequency (Δf) of the generator. Then, an increment in governor output (ΔP_g) results from an increment in ΔP_{ref} and a decrement in Δf .

$$\Delta P_g = \Delta P_{ref} - \frac{1}{R} \Delta f \quad \text{puMW} \quad (2.4)$$

The constant "R" is usually called the generating regulating characteristic or droop, in Hz/puMW. Laplace transformation of Equation 2.4 gives

$$\Delta P_g(s) = \Delta P_{ref}(s) - \frac{1}{R} \Delta f(s) \quad (2.5)$$

In an hydraulic valve actuator, the input position of the valve actuator increases as a result of an increment in governor output (ΔP_g) but decreases due to an increment of valve output (ΔP_v). Thus the relationship for the actuator is

$$\Delta P_v(s) = \frac{1}{1 + T_G s} \Delta P_g(s) \quad (2.6)$$

where T_G is the time constant of the speed governing system, which is depending on the geometric and fluid pressure characteristics of the valve actuator.

The transfer function block diagram of the speed governing system is shown in Figure 2.2. Further information about detailed models may be found in references 3,5,8,10,14 and 17.

Figure 2.3 Turbine generator block diagram.

2.6. Power System Model

To obtain a mathematical relation between generated power deviation (ΔP_G) and frequency deviation (Δf) it is necessary to make reasonable assumptions about area behaviour. The system is originally in power balance, that is, generated power equals area load plus net power interchange ($P_G = P_L + P_{12}$), and the system frequency is at scheduled value (f_s). All rotating equipment provide a total kinetic energy of W_s [MW $\times$ s]. If the area load is increased by ΔP_L the speed or frequency in the area will decrease and the power unbalance will be initially compensated by the kinetic energy. Then, as the kinetic energy is proportional to the square of the speed, the area kinetic energy is

$$W = W_s \left(\frac{f}{f_s} \right)^2 \quad \text{MWs} \quad (2.8)$$

The area load has a frequency dependency $\partial P_L / \partial f$ that is usually called the mechanical damping coefficient or area load frequency characteristic (D). Area power balance requires that the increase in turbine power equals the sum of total

area load plus the rate of change of kinetic energy and the change in net power interchange with the neighbouring area; so, the area power balance is

$$\Delta P_G - \Delta P_L - \Delta P_{12} = \frac{2W_s}{f^*} \frac{d}{dt}(\Delta f) + D \Delta f \quad \text{MW} \quad (2.9)^*$$

Dividing Equation 2.9 by the generator rating and introducing the per unit inertia constant

$$H = \frac{W_s}{P_r} \quad \text{MWs/MW} \quad (2.10)$$

Equation 2.9 becomes

$$\Delta P_G - \Delta P_L - \Delta P_{12} = \frac{2H}{f^*} \frac{d}{dt}(\Delta f) + D \Delta f \quad \text{puMW} \quad (2.11)$$

and by Laplace transformation

$$\Delta P_G(s) - \Delta P_L(s) - \Delta P_{12}(s) = \frac{2H}{f^*} s \Delta f(s) + D \Delta f(s) \quad (2.12)$$

equation (2.12) can be written in the form

$$\Delta f(s) = \frac{K_p}{1 + T_p s} [\Delta P_G(s) - \Delta P_L(s) - \Delta P_{12}(s)] \quad (2.13)$$

$$T_p = \frac{2H}{f^* D} \quad s \quad (\text{power system time constant}) \quad (2.14)$$

*Note: in Equation (2.9) P_G , P_L and P_{12} have units of MW, but in Equation (2.11) they are in per unit.

$$K_p = \frac{1}{D} \quad \text{Hz/puMW} \quad (2.15)$$

The transfer function block diagram of the power system is shown in Figure 2.4. Further detailed information on power system models may be obtained from references 3,5,8,10 and 14.

Figure 2.4 Power system block diagram.

2.7. The AC Link Model

In a single area case the frequency deviation is represented by the single variable Δf . In the present case, of a two area interconnected power system, it is assumed that each area is individually strong and the two areas are interconnected by a weak tie line. Then the frequency deviations in the two areas can be represented by two variables Δf_1 and Δf_2 for area 1 and area 2 respectively.

Under normal operation the AC net power interchange between areas can be

represented as

$$P_{AC} = \frac{V_1 V_2}{X} \sin(\delta_1 - \delta_2) \quad \text{puMW} \quad (2.16)$$

where δ_1 and δ_2 are the phase angles of the voltages V_1 and V_2 respectively relative to a common reference and X is the reactance of the AC link.

Small deviations of the net power interchange due to deviations in the δ angles are obtained from $\partial P_{AC}/\partial \delta$. So the net power interchange deviation can be expressed as

$$\Delta P_{AC} = P_{AC \max} \cos(\delta_1 - \delta_2)(\Delta \delta_1 - \Delta \delta_2) \quad \text{puMW} \quad (2.17)$$

where $P_{AC \max} = V_1 V_2 / X$.

The synchronizing coefficient of the link is defined as

$$T_{12} = 2\pi P_{AC \max} \cos(\delta_1 - \delta_2) \quad \text{puMW/Hz} \quad (2.18)$$

and the frequency deviation Δf is related to the reference angle by

$$\Delta \delta = 2\pi \int \Delta f \, dt \quad \text{rad} \quad (2.19)$$

By expressing the net power interchange in terms of T_{12} and Δf one obtains

$$\Delta P_{AC} = T_{12} \left(\int \Delta f_1 \, dt - \int \Delta f_2 \, dt \right) \quad \text{puMW} \quad (2.20)$$

and by Laplace transformation

$$\Delta P_{AC} = \frac{T_{12}}{s} [\Delta f_1(s) - \Delta f_2(s)] \quad (2.21)$$

The transfer function block diagram of the AC link is shown in Figure 2.5. A more detailed information about modelling AC tie lines may be found it in references 3,5,7,8,14 and 33.

Figure 2.5 The AC link block diagram.

2.8. The DC Link Model

The transfer function of a constant DC power control system including the DC line, is generally represented by a second order control system²⁹. Since the dynamic response of automatic generation control in the AC power system is slow (i.e. of the order of a few seconds) the DC converter can be safely represented as a first order control system.

A DC transmission line has many natural modes of oscillation, generally the

first resonant frequency is between 10 to 100 Hz ⁶ and the remaining resonant frequencies are greater. However in this research interest is in the power frequency interactions under 3 Hz, much smaller than the DC line resonance frequency; therefore the dynamics in the DC link are neglected and the variation of DC link power is treated as a control input which is applied at the DC terminal bus. This is justified in view of the fast response of modern converters with thyristor valves.

The DC link is represented by a simplified model shown in Figure 2.6, where T_{DC} is the time constant of DC power control system, s is the Laplace operator, ΔP_{DC} is the deviation in DC power transfer from its scheduled value, and U_3 is the modulation signal for the DC power control. Further information may be obtained from references 6,7,9,29,31,38,39 and 42.

Figure 2.6 Simplified model of a DC link.

2.9. Automatic Generation Control Model

The AGC control regulates the area generated power in response to changes in area load, system frequency, net power interchange, or the relation of these to

each other so as to maintain these variables within scheduled limits.

The conventional AGC approach employs a system controller which is usually implemented as a proportional plus integral action based on the area control error (ACE). The area control error results from a linear combination of the contribution from both the frequency deviation and the net power interchange deviation.

$$ACE = \Delta P_{12} + B \Delta f \quad \text{puMW} \quad (2.22)$$

The bias setting B , in puMW/Hz, determines the control contribution of an area to maintain the scheduled frequency in the interconnected system. The ACE signal represents the amount of generation required in the area to restore system frequency and net power interchange back to scheduled values.

The AGC control senses frequency deviation and net power interchange deviation to compute the ACE signal, which is processed by the AGC controller to provide the control signal (reference) to the speed governing system. The AGC controller output is a control signal U , that includes a component that is proportional to, plus one that is the time integral of, the ACE signal.

$$U = k_p ACE + k_i \int ACE dt \quad (2.23)$$

By Laplace transformation

$$U(s) = \left[k_p + \frac{k_i}{s} \right] ACE(s) \quad (2.24)$$

where k_p and k_i are the proportional and integral gain respectively.

A block diagram of the AGC controller model is shown in Figure 2.7. Further information may be obtained from references 3,5,14,34 and 41.

Figure 2.7 AGC controller block diagram.

2.10. Supplementary Control Model

A supplementary controller is added to the conventional control scheme, to improve overall dynamic performance of the two areas interconnected power system (TAIPS). This supplementary PI controller (proportional plus integral control) provides a new control signal U_3 (reference) to the constant DC power system control to modulate the DC power transfer based on AC system signals. The modulation signals from the AC system, can be net power interchange deviation ΔP_{12} and/or difference in frequency deviation from both areas $(\Delta f_1 - \Delta f_2)$. A block diagram

of the supplementary controller is shown in Figure 2.8, where k_p and k_i are the proportional and integral gain, and K_f is the frequency sensitivity of the controller.

Figure 2.8 Supplementary controller block diagram.

2.11. Block Diagram of Two Area Interconnected Power System.

A small perturbation transfer function block diagram of a two area thermal system, interconnected via AC and DC tie lines is shown in Figure 2.9. The subsystems discussed above have been combined in a suitable way to constitute the main model to satisfy the objectives of this research.

Automatic generation control (AGC) of interconnected power systems is centred around tie line frequency bias control strategy. A supplementary controller is implemented to regulate DC power transfer according to changes in net power interchange and/or difference in area frequencies. The fast supplementary control interacts with the conventional AGC controller to restore system frequency and net power interchange to scheduled values (zero steady state area control error).

Figure 2.9 Transfer function block diagram of two area thermal system interconnected by AC and DC tie-lines.

Nomenclature:

- P_r Area capacity (power base), MW
 f^* nominal system frequency, Hz
 i subscript referring to area ($i=1,2$)
 ΔP_{Gi} generated power deviation, puMW
 ΔP_{12} net power interchange deviation, puMW
 ΔP_{Li} change in load demand (load disturbance), puMW
 Δf_i frequency deviation, Hz
 ΔP_{AC} AC tie line power deviation, puMW
 ΔP_{DC} DC tie line power deviation, puMW
 U_i AGC control signal
 U_3 supplementary control signal
 ACE_i area control error, puMW
 T_{Gi} speed governor time constant, s
 R_i generation regulation characteristic, Hz/puMW
 T_{Ti} steam chest time constant, s
 H_i inertia constant, s
 D_i load frequency characteristic, puMW/Hz
 $(K_{Pi} = 1/D_i, T_{Pi} = 2H_i/f^* D_i)$
 T_{12} synchronising coefficient, puMW/Hz
 B_i frequency bias constant, puMW/Hz
 k_{Pi} proportional gain of AGC controller
 k_{Ti} integral gain of AGC controller

T_{DC} DC system time constant, s

k_p proportional gain of supplementary controller

k_i integral gain of supplementary controller

s Laplace operator

2.12. Power System Parameters

For the purpose of this study both area power systems have the same characteristics. So it is assumed that both areas have equal system parameters (equal time constants and gain coefficients). The nominal system parameters are:

$$P_{base} = 2000 \text{ MW}$$

$$f = 60 \text{ Hz}$$

$$P_n = 2000 \text{ MW}$$

$$H_i = 5 \text{ MWs/MW}$$

$$D_i = 8.33 \times 10^3 \text{ puMW/Hz}$$

$$R_i = 2.4 \text{ Hz/puMW}$$

$$T_{Gi} = 0.08 \text{ s}$$

$$T_{Ti} = 0.3 \text{ s}$$

$$T_{Pi} = 20 \text{ s}$$

$$K_{Pi} = 120 \text{ Hz/puMW}$$

$$T_{DC} = 0.05 \text{ s}$$

The AC and DC tie lines have a capacity of 10% of area capacity, and the AC system is operating at a power angle (δ) of 30° . Then the synchronising torque

coefficient is: $T_{12} = 0.544 \text{ puMW/Hz}$

The frequency bias constant (B_1) is set equal to the area frequency response (β_1) to minimize the control action in the control area where no disturbance occurs.

Then the bias constant is: $B_1 = 0.544 \text{ puMW/Hz}$

The PI controller parameters will be chosen to optimize the control effectiveness. To evaluate the control effectiveness a performance index is computed, which is related to the control error (ACE) in both control areas.

3. STATE SPACE NOTATION

3.1. General

A mathematical model of a system can be obtained from the structure of the system and the properties of individual elements of the system. A suitable model is a compromise between the mathematical complexity attached to complicated equations and the desired accuracy in the results. Equations describing the system dynamics can often be approximated by ordinary differential equations of order "n" with time "t" as the independent variable, or a set of "n" first order ordinary differential equations. The difficulty of analyzing and solving a system depends on the type of differential equations which describe it. Usually a system described by linear and time invariant differential equations is easier to study, but unfortunately, in constructing models for physical systems one arrives more often at a nonlinear system of equations. However the power frequency control problem studied in this research required a simplified linear and time invariant model. The linear and time invariant characteristics are adequate because small changes around a reference state and slow changes in the system's characteristics are considered.

3.2. State Space Representation

The state of a system is defined¹³ as the minimum set of numbers or variables, the state variables, which contain sufficient information about the past history of the

system to permit us to compute all future states of the system, assuming known all future inputs (control forces) and equations describing the system.

For a multiple input multiple output (MIMO) system the block diagram representation including optimal control feedback is shown in Figure 3.1.

Figure 3.1 Block diagram of a MIMO system.

The state space equations are:

$$\dot{X} = AX + BU + FV \quad (3.1)$$

$$U = KX \quad (3.2)$$

$$Y = CX \quad (3.3)$$

then the state space equation can be rewritten as:

$$\dot{X} = [A + BK]X + FV \quad (3.4)$$

$$Y = CX \quad (3.5)$$

X :[n×1] state vector

U :[r×1] control vector

V :[p×1] disturbance vector

Y :[m×1] output vector

A :[n×n] state coefficient matrix

B :[n×r] control coefficient matrix

C :[m×n] state output coefficient matrix

K :[r×n] optimal feedback coefficient matrix

F :[n×p] disturbance coefficient matrix.

3.3. State Space Representation of the AC System

For a two area interconnected power system (TAIPS) interconnected by AC link only, the state space equations can be obtained from the transfer function block diagram shown in Figure 3.2.

Figure 3.2 Block diagram of an AC TAIPS.

The state variables are:

$$x_1 = \Delta f_1 \quad : \text{frequency deviation, area 1}$$
 $x_2 = \Delta P_{G1}$: deviation in generated power, area 1

x_3 : deviation in governor position, area 1

$x_4 = \Delta f_2$: frequency deviation, area 2

 $x_5 = \Delta P_{G2}$: deviation in generated power, area 2

x_6 : deviation in governor position, area 2

$x_7 = \Delta P_{12}$: net power interchange deviation

u_1 : control signal area 1

u_2 : control signal area 2

$$v_1 = \Delta P_{L1} : \text{change in load (disturbance), area 1}$$

$v_2 = \Delta P_{L2}$: change in load (disturbance), area 2

then $X = [x_1 \ x_2 \ \dots \ x_7]^T$, $U = [u_1 \ u_2]^T$ and $V = [v_1 \ v_2]^T$. Translating the transfer functions which use Laplace notation into the state space form, the model can be described by a set of first order differential equations as follows:

$$\text{block 1: } \dot{x}_1 = -\frac{1}{T_{P1}} x_1 + \frac{K_{P1}}{T_{P1}} x_2 - \frac{K_{P1}}{T_{P1}} x_7 - \frac{K_{P1}}{T_{P1}} v_1 \quad (3.6)$$

$$\text{block 2: } \dot{x}_2 = -\frac{1}{T_{T1}} x_2 + \frac{1}{T_{T1}} x_3 \quad (3.7)$$

$$\text{block 3: } \dot{x}_3 = -\frac{1}{R_1 T_{G1}} x_1 - \frac{1}{T_{G1}} x_3 - \frac{1}{T_{G1}} u_1 \quad (3.8)$$

$$\text{block 4: } \dot{x}_4 = -\frac{1}{T_{P2}} x_4 + \frac{K_{P2}}{T_{P2}} x_5 + \frac{K_{P2}}{T_{P2}} x_7 - \frac{K_{P2}}{T_{P2}} v_2 \quad (3.9)$$

$$\text{block 5: } \dot{x}_5 = -\frac{1}{T_{T2}} x_5 + \frac{1}{T_{T2}} x_6 \quad (3.10)$$

$$\text{block 6: } \dot{x}_6 = -\frac{1}{T_{T2}} x_5 + \frac{1}{T_{T2}} x_6 \quad (3.11)$$

$$\text{block 7: } \dot{x}_7 = T_{12} x_1 - T_{12} x_4 \quad (3.12)$$

$$\text{block 8: } u_1 = B_1 \left(k_{P1} + \frac{k_{I1}}{s} \right) x_1 + \left(k_{P1} + \frac{k_{I1}}{s} \right) x_7 \quad (3.13)$$

$$\text{block 9: } u_2 = B_2 \left(k_{P2} + \frac{k_{I2}}{s} \right) x_4 - \left(k_{P2} + \frac{k_{I2}}{s} \right) x_7 \quad (3.14)$$

where $p=d/dt$. Then the state space vector equations are:

$$\dot{X} = (A + BK)X + FV \quad (3.15)$$

$$Y = CX \quad (3.16)$$

The coefficient matrices are:

$$A = \begin{bmatrix} -\frac{1}{T_{P1}} & \frac{K_{P1}}{T_{P1}} & 0 & 0 & 0 & 0 & -\frac{K_{P1}}{T_{P1}} \\ 0 & -\frac{1}{T_{T1}} & \frac{1}{T_{T1}} & 0 & 0 & 0 & 0 \\ -\frac{1}{R_1 T_{G1}} & 0 & -\frac{1}{T_{G1}} & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & -\frac{1}{T_{P2}} & \frac{K_{P2}}{T_{P2}} & 0 & \frac{K_{P2}}{T_{P2}} \\ 0 & 0 & 0 & 0 & -\frac{1}{T_{T2}} & \frac{1}{T_{T2}} & 0 \\ 0 & 0 & 0 & -\frac{1}{R_2 T_{G2}} & 0 & -\frac{1}{T_{G2}} & 0 \\ T_{12} & 0 & 0 & -T_{12} & 0 & 0 & 0 \end{bmatrix} \quad (3.17)$$

$$B = \begin{bmatrix} 0 & 0 \\ 0 & 0 \\ -\frac{1}{T_{G1}} & 0 \\ 0 & 0 \\ 0 & 0 \\ 0 & -\frac{1}{T_{G2}} \\ 0 & 0 \end{bmatrix} \quad F = \begin{bmatrix} \frac{K_{P1}}{T_{P1}} & 0 \\ 0 & 0 \\ 0 & 0 \\ 0 & -\frac{K_{P2}}{T_{P2}} \\ 0 & 0 \\ 0 & 0 \\ 0 & 0 \end{bmatrix} \quad C = I \text{ (identity)} \quad (3.18)$$

$$K = \begin{bmatrix} B_1(k_{P1} + \frac{k_{I1}}{p}) & 0 & 0 & 0 & 0 & 0 & k_{P1} + \frac{k_{I1}}{p} \\ 0 & 0 & 0 & B_2(k_{P2} + \frac{k_{I2}}{p}) & 0 & 0 & -(k_{P2} + \frac{k_{I2}}{p}) \end{bmatrix} \quad (3.19)$$

The K matrix has some elements dependent on time because of the integral component in the feedback control loop; therefore the $[A+BK]$ matrix also is dependent on time, and this renders it impossible to do eigenvalue computation for stability analysis. However if we consider the augmented system, where the control signals are considered as state variables ($u_1=x_8$ and $u_2=x_9$), the vector state space equation is increased by two differential equations.

$$\text{block 8: } \dot{x}_8 = k_{P1}B_1\dot{x}_1 + k_{P1}\dot{x}_7 + k_{I1}B_1x_1 + k_{I1}x_7 \quad (3.20)$$

replacing Equations (3.6) and (3.12) in Equation (3.20)

$$\begin{aligned} \dot{x}_8 = & \left(\frac{-k_{P1}B_1}{T_{P1}} + k_{P1}T_{12} + k_{I1}B_1 \right) x_1 + \frac{k_{P1}B_1K_{P1}}{T_{P1}} x_2 - k_{P1}T_{12}x_4 \\ & + \left(\frac{-k_{P1}B_1K_{P1}}{T_{P1}} + k_{I1} \right) x_7 - \frac{k_{P1}B_1K_{P1}}{T_{P1}} v_1 \end{aligned} \quad (3.21)$$

$$\text{block 9: } \dot{x}_9 = k_{P2}B_2\dot{x}_4 - k_{P2}\dot{x}_7 + k_{I2}B_2x_4 - k_{I2}x_7 \quad (3.22)$$

replacing Equations (3.9) and (3.12) in Equation (3.22)

$$\begin{aligned} \dot{x}_9 = & -k_{P2}T_{12}x_1 + \left(\frac{-k_{P2}B_2}{T_{P2}} + k_{P2}T_{12} + k_{I2}B_2 \right) x_4 + \frac{k_{P2}B_2K_{P2}}{T_{P2}} x_5 \\ & + \left(\frac{k_{P2}B_2K_{P2}}{T_{P2}} - k_{I2} \right) x_7 - \frac{k_{P2}B_2K_{P2}}{T_{P2}} v_2 \end{aligned} \quad (3.23)$$

then the augmented matrices are:

$$A_1 = \begin{bmatrix} & \vdots & \\ [A] & \vdots & [B] \\ & \vdots & \\ \cdots & \vdots & \cdots \\ [D] & \vdots & [0] \\ & \vdots & \end{bmatrix} \quad F_1 = \begin{bmatrix} -\frac{K_{P1}}{T_{P1}} & 0 \\ 0 & 0 \\ 0 & 0 \\ 0 & -\frac{K_{P2}}{T_{P2}} \\ 0 & 0 \\ 0 & 0 \\ 0 & 0 \\ \frac{-k_{P1}B_1K_{P1}}{T_{P1}} & 0 \\ 0 & \frac{-k_{P2}B_2K_{P2}}{T_{P2}} \end{bmatrix} \quad (3.24)$$

$$D = \begin{bmatrix} k_{P1}(T_{12} - \frac{B_1}{T_{P1}}) + k_{11}B_1 & -k_{P2}T_{12} \\ \frac{k_{P1}B_1K_{P1}}{T_{P1}} & 0 \\ 0 & 0 \\ -k_{P1}T_{12} & k_{P2}(T_{12} - \frac{B_2}{T_{P2}}) + k_{12}B_2 \\ 0 & \frac{k_{P2}B_2K_{P2}}{T_{P2}} \\ 0 & 0 \\ \frac{-k_{P1}B_1K_{P1}}{T_{P1}} + k_{11} & \frac{k_{P2}B_2K_{P2}}{T_{P2}} - k_{12} \end{bmatrix}^T \quad (3.25)$$

The matrix A_1 is shown in Figure 3.3 and the augmented state space equation is

$$\dot{X} = A_1X + F_1V \quad (3.26)$$

$$A_1 = \begin{bmatrix} -\frac{1}{T_{P1}} & \frac{K_{P1}}{T_{P1}} & 0 & 0 & 0 & 0 & -\frac{K_{P1}}{T_{P1}} & 0 & 0 \\ 0 & -\frac{1}{T_{T1}} & \frac{1}{T_{T1}} & 0 & 0 & 0 & 0 & 0 & 0 \\ -\frac{1}{R_1 T_{G1}} & 0 & -\frac{1}{T_{G1}} & 0 & 0 & 0 & 0 & -\frac{1}{T_{G1}} & 0 \\ 0 & 0 & 0 & -\frac{1}{T_{P2}} & \frac{K_{P2}}{T_{P2}} & 0 & \frac{K_{P2}}{T_{P2}} & 0 & 0 \\ 0 & 0 & 0 & 0 & -\frac{1}{T_{T2}} & \frac{1}{T_{T2}} & 0 & 0 & 0 \\ 0 & 0 & 0 & -\frac{1}{R_2 T_{G2}} & 0 & -\frac{1}{T_{G2}} & 0 & 0 & -\frac{1}{T_{G2}} \\ T_{12} & 0 & 0 & -T_{12} & 0 & 0 & 0 & 0 & 0 \\ k_{P1}(T_{12} - \frac{B_1}{T_{P1}}) + k_{I1} B_1 & \frac{k_{P1} B_1 K_{P1}}{T_{P1}} & 0 & -k_{P1} T_{12} & 0 & 0 & \frac{-k_{P1} B_1 K_{P1}}{T_{P1}} + k_{I1} & 0 & 0 \\ -k_{P2} T_{12} & 0 & 0 & k_{P2}(T_{12} - \frac{B_2}{T_{P2}}) + k_{I2} B_2 & \frac{k_{P2} B_2 K_{P2}}{T_{P2}} & 0 & \frac{k_{P2} B_2 K_{P2}}{T_{P2}} - k_{I2} & 0 & 0 \end{bmatrix}$$

Figure 3.3 State coefficient matrix A_1 .

3.4. State Space Representation of the AC/DC System

The state space equations of a two areas power system (TAIPS) interconnected via parallel AC and DC links can be derived from the dynamic model shown in Figure 3.4.

Figure 3.4 Block diagram of an AC/DC TAIPS.

The state variables are:

$x_1 = \Delta f_1$: frequency deviation, area 1

$x_2 = \Delta P_{G1}$: deviation in generated power, area 1

x_3 : deviation in governor position, area 1

$x_4 = \Delta f_2$: frequency deviation, area 2

$x_5 = \Delta P_{G2}$: deviation in generated power, area 2

x_6 : deviation in governor position, area 2

$x_7 = \Delta P_{AC}$: AC power interchange deviation

$x_8 = \Delta P_{DC}$: DC power interchange deviation

$x_9 = u_1$: control signal, area 1

$x_{10} = u_2$: control signal, area 2

$x_{11} = u_3$: control signal DC system

Then $X = [x_1 \dots x_{11}]^T$ (state vector) and $V = [v_1 \ v_2]^T$ (disturbance vector). Applying a similar procedure as in Section 3.3, the set of differential equations is :

$$\text{block 1: } \dot{x}_1 = -\frac{1}{T_{P1}} x_1 + \frac{K_{P1}}{T_{P1}} x_2 - \frac{K_{P1}}{T_{P1}} x_7 - \frac{K_{P1}}{T_{P1}} x_8 - \frac{K_{P1}}{T_P} v_1 \quad (3.27)$$

$$\text{block 2: } \dot{x}_2 = -\frac{1}{T_{T1}} x_2 + \frac{1}{T_{T1}} x_3 \quad (3.28)$$

$$\text{block 3: } \dot{x}_3 = -\frac{1}{R_1 T_{G1}} x_1 - \frac{1}{T_{G1}} x_3 - \frac{1}{T_{G1}} x_9 \quad (3.29)$$

$$\text{block 4: } \dot{x}_4 = -\frac{1}{T_{P2}} x_4 + \frac{K_{P2}}{T_{P2}} x_5 + \frac{K_{P2}}{T_{P2}} x_7 + \frac{K_{P2}}{T_{P2}} x_8 - \frac{K_{P2}}{T_{P2}} v_2 \quad (3.30)$$

$$\text{block 5: } \dot{x}_5 = -\frac{1}{T_{T2}} x_5 + \frac{1}{T_{T2}} x_6 \quad (3.31)$$

$$\text{block 6: } \dot{x}_6 = -\frac{1}{R_2 T_{G2}} x_4 - \frac{1}{T_{G2}} x_6 - \frac{1}{T_{G2}} x_{10} \quad (3.32)$$

$$\text{block 7: } \dot{x}_7 = T_{12} x_1 - T_{12} x_4 \quad (3.33)$$

$$\text{block 8: } \dot{x}_8 = -\frac{1}{T_{DC}} x_8 - \frac{1}{T_{DC}} x_{11} \quad (3.34)$$

$$\begin{aligned} \text{block 9: } \dot{x}_9 = & [k_{P1}(T_{12} - \frac{B_1}{T_{P1}}) + k_{11} B_1] x_1 + \frac{k_{P1} B_1 K_{P1}}{T_{P1}} x_2 - k_{P1} T_{12} x_4 \\ & + (\frac{-k_{P1} B_1 K_{P1}}{T_{P1}} + k_{11}) x_7 + [-k_{P1}(\frac{B_1 K_{P1}}{T_{P1}} + \frac{1}{T_{DC}}) + k_{11}] x_8 \\ & - \frac{k_{P1}}{T_{DC}} x_{11} - \frac{k_{P1} B_1 K_{P1}}{T_{P1}} v_1 \end{aligned} \quad (3.35)$$

$$\begin{aligned} \text{block 10: } \dot{x}_{10} = & -k_{P2} T_{12} x_1 + [k_{P2}(T_{12} - \frac{B_2}{T_{P2}}) + k_{12} B_2] x_4 + \frac{k_{P2} B_2 K_{P2}}{T_{P2}} x_5 \\ & + (\frac{k_{P2} B_2 K_{P2}}{T_{P2}} - k_{12}) x_7 + [k_{P2}(\frac{B_2 K_{P2}}{T_{P2}} + \frac{1}{T_{DC}}) - k_{12}] x_8 \\ & + \frac{k_{P2}}{T_{DC}} x_{11} - \frac{k_{P2} B_2 K_{P2}}{T_{P2}} v_2 \end{aligned} \quad (3.36)$$

$$\begin{aligned} \text{block 11: } \dot{x}_{11} = & [k_P(T_{12} + \frac{K_f}{T_{P1}}) - k_1 K_f] x_1 - \frac{k_P K_f K_{P1}}{T_{P1}} x_2 + [-k_P(T_{12} + \frac{K_f}{T_{P2}}) + k_1 K_f] x_4 \\ & + \frac{k_P K_f K_{P2}}{T_{P2}} x_5 + [k_P K_f(\frac{K_{P1}}{T_{P1}} + \frac{K_{P2}}{T_{P2}}) + k_1] x_7 + [k_P K_f(\frac{K_{P1}}{T_{P1}} + \frac{K_{P2}}{T_{P2}}) - \frac{k_P}{T_{DC}} + k_1] x_8 \\ & - \frac{k_P}{T_{DC}} x_{11} + \frac{k_P K_f K_{P1}}{T_{P1}} v_1 - \frac{k_P K_f K_{P2}}{T_{P2}} v_2 \end{aligned} \quad (3.37)$$

Therefore the system shown in Figure 3.4 can be represented by the vector equation:

$$\dot{X} = A_2 X + F_2 V \quad (3.38)$$

where A_2 is a $[11 \times 11]$ matrix and F_2 is a $[11 \times 2]$ matrix whose coefficients are obtained from the state space equations. The above state space equation developed from the transfer function blocks, includes a DC power modulation in accordance with a linear combination of net power interchange deviation and the difference of power systems frequency deviation ($\Delta P_{12} - K_f[\Delta f_1 - \Delta f_2]$). However, in this research a particular case was studied in more detail, regarding a DC power modulation based only on net power interchange deviation (ΔP_{12}). The transfer function block diagram is shown in Figure 3.5.

Figure 3.5 Block diagram of an AC/DC TAIPS, with ΔP_{12} as input of the DC system controller.

In this case, the state variable # 11 is defined as:

$$x_{11} = (k_p + \frac{k_I}{s})(x_7 + x_8) \quad (3.39)$$

$$\dot{x}_{11} = k_p T_{12} x_1 - k_p T_{12} x_4 + k_I x_7 + (-\frac{k_p}{T_{DC}} + k_I) x_8 - \frac{k_p}{T_{DC}} x_{11} \quad (3.40)$$

Therefore the state coefficient matrix A_3 is similar to matrix A_2 with exception of the row 11, and the disturbance coefficient matrix F_3 is equal to F_2 . Then the system dynamics are represented by the state space equation:

$$\dot{X} = A_3 X + F_3 V \quad (3.41)$$

The state coefficient matrix A_3 is shown in detail in Figure 3.6.

$A_3 =$

$-\frac{1}{T_{P1}}$	$\frac{K_{P1}}{T_{P1}}$	0	0	0	0	$-\frac{K_{P1}}{T_{P1}}$	$-\frac{K_{P1}}{T_{P1}}$	0	0	0
0	$-\frac{1}{T_{T1}}$	$\frac{1}{T_{T1}}$	0	0	0	0	0	0	0	0
$-\frac{1}{R_1 T_{G1}}$	0	$-\frac{1}{T_{G1}}$	0	0	0	0	0	$-\frac{1}{T_{G1}}$	0	0
0	0	0	$-\frac{1}{T_{P2}}$	$\frac{K_{P2}}{T_{P2}}$	0	$\frac{K_{P2}}{T_{P2}}$	$\frac{K_{P2}}{T_{P2}}$	0	0	0
0	0	0	0	$-\frac{1}{T_{T2}}$	$\frac{1}{T_{T2}}$	0	0	0	0	0
0	0	0	$-\frac{1}{R_2 T_{G2}}$	0	$-\frac{1}{T_{G2}}$	0	0	0	$-\frac{1}{T_{G2}}$	0
T_{12}	0	0	$-T_{12}$	0	0	0	0	0	0	0
0	0	0	0	0	0	0	$-\frac{1}{T_{DC}}$	0	0	$-\frac{1}{T_{DC}}$
$k_{P1}(T_{12} - \frac{B_1}{T_{P1}}) + k_{I1}B_1$	$\frac{k_{P1}B_1K_{P1}}{T_{P1}}$	0	$-k_{P1}T_{12}$	0	0	$\frac{-k_{P1}B_1K_{P1} + k_{I1}}{T_{P1}}$	$-k_{P1}(\frac{B_1K_{P1}}{T_{P1}} + \frac{1}{T_{DC}}) + k_{I1}$	0	0	$-\frac{k_{P1}}{T_{DC}}$
$-k_{P2}T_{12}$	0	0	$k_{P2}(T_{12} - \frac{B_2}{T_{P2}}) + k_{I2}B_2$	$\frac{k_{P2}B_2K_{P2}}{T_{P2}}$	0	$\frac{k_{P2}B_2K_{P2}}{T_{P2}} - k_{I2}$	$k_{P2}(\frac{B_2K_{P2}}{T_{P2}} + \frac{1}{T_{DC}}) - k_{I2}$	0	0	$\frac{k_{P2}}{T_{DC}}$
$k_P T_{12}$	0	0	$-k_P T_{12}$	0	0	k_I	$-\frac{k_P}{T_{DC}} + k_I$	0	0	$-\frac{k_P}{T_{DC}}$

Figure 3.6 State coefficient matrix A_3 .

4. SYSTEM STABILITY

4.1. General

The stability of an interconnected power system is measured in terms of its capability to return to normal or stable operation after having been subjected to some kind of disturbance. On the other hand, if the machines fall out of step after a disturbance the system is unstable. Generally power system stability problems are classified into three basic types¹⁰:

- i) Steady state stability is basically concerned with the determination of the upper limit of machine loadings before losing synchronism provided the loading is increasing gradually.
- ii) Dynamic stability refers to the stability of a power system subject to a relatively small and sudden or periodic disturbance, including the effect of automatic control devices.
- iii) Transient stability refers to the stability of a power system subject to a sudden and large disturbance beyond the capability of the basic controls. The system may lose its stability at the first or subsequent swings unless an effective countermeasure is taken.

In normal power system operation, small disturbances are continually occurring (variations in loading, changes in turbine speeds, etc.), which are small

enough not to cause the system to lose synchronism but can excite natural oscillations. Therefore, one of the important features that describes the behaviour of a power system is its dynamic response capability.

This chapter presents the effects of various controller parameters on the system stability by describing their influences on the eigenvalues of the system, especially those of the critical modes of oscillation. The critical modes of oscillation of the power system are defined by the eigenvalues which determine the system instability as a result of a variation in any of the system parameters.

4.2. Stability in the Complex Plane

The system characteristic stability is a property of the system itself and does not depend on the input or driving function of the system. The stability of a linear closed loop system can be determined from the location of the closed loop poles in the s plane. If all closed loop poles lie to the left of the $j\omega$ axis, any transient response eventually reaches equilibrium. This represents a stable system. Closed loop poles lying on the $j\omega$ axis will yield oscillations, the amplitudes of which neither decay nor grow with time. This represents a critically stable system. On the other hand, if the transient response oscillates with increasing amplitude, this represents an unstable system. The fact that all closed loop poles lie in the left half of the s plane does not guarantee satisfactory dynamic response characteristics. If dominant complex poles are located close to the $j\omega$ axis, the dynamic response may show excessive oscillations or a long settling time.

4.3. Eigenstructure

It is known that the eigenvalues of the state space coefficient matrix are the closed loop poles of the model system. For the system represented by the state equation :

$$\dot{X} = AX + FV \quad (4.1)$$

the eigenvalue spectrum is the set of roots of the characteristic equation :

$$|\lambda I - A| = 0 \quad (4.2)$$

The right eigenvector μ_i and the left eigenvector e_i associated with an eigenvalue λ_i (i^{th} mode) are obtained from the equations :

$$[\lambda_i I - A] \mu_i = 0 \quad (4.3)$$

$$e_i^T [\lambda_i I - A] = 0 \quad (4.4)$$

such that for normalized values of e and μ

$$e_i^T \mu_j = \begin{cases} 1 & \text{for } i=j \\ 0 & \text{for } i \neq j \end{cases} \quad (4.5)$$

The homogeneous solution part of Equation (4.1) is independent of the input V and depends only upon the initial state $X(0)$. The particular solution part (forced solution) is independent of $X(0)$ but depends upon the input V throughout the whole control period.

The homogeneous solution (transient response) of Equation (4.1) can be written

$$X(t) = \sum_{i=1}^n \mu_i e^{\lambda_i t} e_i^T X(0) \quad (4.6)$$

for i^{th} mode λ_i

$$X_i(t) = C_i e^{\lambda_i t} \begin{bmatrix} \mu_{i1} \\ \vdots \\ \mu_{in} \end{bmatrix} \quad (4.7)$$

$$C_i = \sum_{j=1}^n e_{ij} x_j(0) \quad (4.8)$$

Then the transient response of the system is a linear combination of n exponential functions which describe the dynamical modes of the system. The shape of a mode is determined by the right eigenvector μ_i , and its time domain characteristic is determined by the eigenvalue λ_i . The right eigenvector μ_i measures the activity of state variables in participating in the i^{th} mode dynamics. The left eigenvector e_i weighs the contribution of state variables $X(t)$ to the future response of the i^{th} mode. Another index defined as participation factor⁴⁵ may be obtained as follows

$$P_{ik} = e_{ik} \mu_{ik} \quad (4.9)$$

P_{ik} represents the participation factor of state variable x_k corresponding to i^{th} mode λ_i . Therefore, the participation factors provide a measure of the participation of each state variable in each oscillation mode.

In this research, eigen-analysis was performed to evaluate the effects of variation of controller parameters on system stability. The eigenvalues and eigenvectors were computed using subroutines EVLRG and EVCRG of the IMSL MATH/LIBRARY on a VAX computer system at the University of Saskatchewan. The reference parameters of the system controllers utilized in the eigen analysis are optimal. The optimization of controller parameters is described in Chapter 5.

4.4. AC System Stability

The stability analysis of the two area interconnected power system via an AC link was based on the eigenvalue analysis of its state space model.

The state space equation of the AC system is

$$\dot{X} = A_1 X + F_1 V \quad (4.10)$$

The state space coefficient matrix A_1 as a function of the system parameters is given in Figure 3.3 and the optimal controller parameters in both AC areas are:

$$* \quad k_{P1} = k_{P2} = 0.3; \quad k_{I1} = k_{I2} = 0.6$$

The remainder of the system parameters are provided in Chapter 3. The state space

A_1 matrix of constant coefficients is

$$A_1 = \begin{bmatrix} -0.05 & 6 & 0 & 0 & 0 & 0 & -6 & 0 & 0 \\ 0 & -3.333 & 3.333 & 0 & 0 & 0 & 0 & 0 & 0 \\ -5.208 & 0 & -12.5 & 0 & 0 & 0 & 0 & -12.5 & 0 \\ 0 & 0 & 0 & -0.05 & 6 & 0 & 6 & 0 & 0 \\ 0 & 0 & 0 & 0 & -3.333 & 3.333 & 0 & 0 & 0 \\ 0 & 0 & 0 & -5.208 & 0 & -12.5 & 0 & 0 & -12.5 \\ 0.544 & 0 & 0 & -0.544 & 0 & 0 & 0 & 0 & 0 \\ 0.412 & 0.765 & 0 & -0.163 & 0 & 0 & -0.165 & 0 & 0 \\ -0.163 & 0 & 0 & 0.412 & 0.765 & 0 & 0.165 & 0 & 0 \end{bmatrix} \quad (4.11)$$

and the eigenvalues of A_1 are shown in Table 4.1.

Table 4.1 Eigenvalues of the AC system.

λ_1	$-13.47 + j0.00$
λ_2	$-13.40 + j0.00$
λ_3	$-1.57 + j0.00$
λ_4	$-0.94 - j2.88$
λ_5	$-0.94 + j2.88$
λ_6	$-0.55 + j0.00$
λ_7	$-0.53 + j0.00$
λ_8	$-0.18 - j3.76$
λ_9	$-0.18 + j3.76$

All the eigenvalues lie in the left side of the complex plane indicating a stable system.

4.4.1. Effect of AGC Controller Gain Variations.

The effect of variation of proportional gain of the AC controllers on the system stability is shown in Figures 4.1, 4.2, 4.3 and 4.4. Those Figures show that the dominant poles move to the right in the complex plane as the proportional gain is increased. The oscillation frequency rises and damping is decreased. Therefore the system is less stable when the proportional gain of the controllers is higher, reaching a critical stability limit for $k_{p1}=k_{p2}=0.9$.

Figure 4.1 Eigenvalue locations for various k_{p1} and k_{p2} .

Figure 4.2 Detail of Figure 4.1 for modes λ_1 and λ_2 .

Figure 4.3 Detail of Figure 4.1 for modes λ_3 , λ_6 and λ_7 .

Figure 4.4 Detail of Figure 4.1 for modes λ_5 and λ_9 .

The effect of variation of integral gain of the AC controllers on the system stability is shown in Figures 4.5, 4.6 and 4.7. Figures 4.5 to 4.7 show that dominant poles move to the right in the complex plane as the integral gain is increased. The oscillation frequency tends to decrease slightly as well as the damping. Therefore the system is less stable for higher integral gain, reaching a critical stability limit for $k_{i1} = k_{i2} = 1.2$.

Figure 4.5 Eigenvalue locations for various k_{11} and k_{12} .

Figure 4.6 Detail of Figure 4.5 for modes λ_1 and λ_2 .

Figure 4.7 Detail of Figure 4.5 for modes λ_3 , λ_5 , λ_6 , λ_7 and λ_9 .

4.5. AC/DC System Stability

The stability of the two area power system interconnected via parallel AC and DC links was evaluated by eigenvalue analysis of its state space model.

The state space equation of the AC/DC system is

$$\dot{X} = A_3 X + F_3 V \quad (4.12)$$

The state space coefficient matrix A_3 as a function of the system parameters is given in Figure 3.6. The parameters of the AC controllers are kept constant, and the computed optimal parameters for the DC controller are:

$$* \quad k_p = 0 ; k_i = 12$$

The remainder of the system parameters are the same as in Section 4.4. The state space matrix of constant coefficients is as follows

$$A_3 = \begin{bmatrix} -0.05 & 6 & 0 & 0 & 0 & 0 & -6 & -6 & 0 & 0 & 0 \\ 0 & -3.333 & 3.333 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\ -5.208 & 0 & -12.5 & 0 & 0 & 0 & 0 & 0 & -12.5 & 0 & 0 \\ 0 & 0 & 0 & -0.05 & 6 & 0 & 6 & 6 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & -3.333 & 3.333 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & -5.208 & 0 & -12.5 & 0 & 0 & 0 & -12.5 & 0 \\ 0.544 & 0 & 0 & -0.544 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & -20 & 0 & 0 & -20 \\ 0.412 & 0.765 & 0 & -0.163 & 0 & 0 & -0.165 & -6.165 & 0 & 0 & -6 \\ -0.163 & 0 & 0 & 0.412 & 0.765 & 0 & 0.165 & 6.165 & 0 & 0 & 6 \\ 0 & 0 & 0 & 0 & 0 & 0 & 12 & 12 & 0 & 0 & 0 \end{bmatrix} \quad (4.13)$$

Table 4.2 Eigenvalues of the AC/DC system.

λ_1	$-13.47 + j0.00$
λ_2	$-9.75 - j11.88$
λ_3	$-9.75 + j11.88$
λ_4	$-0.94 - j2.83$
λ_5	$-0.94 + j2.83$
λ_6	$-0.53 + j0.00$
λ_7	$-0.53 + j0.00$
λ_8	$-1.17 - j3.09$
λ_9	$-1.17 + j3.09$
λ_{10}	$-13.50 + j0.00$
λ_{11}	$0.00 + j0.00$

The eigenvalues of matrix A_3 are shown in Table 4.2. The eigenvalue λ_{11} , located at the origin of the complex plane, represents a critical stability condition. In order to evaluate the incidence of λ_{11} in the transient response of the system, an eigenvalue computation for various values of system parameters was carried out. This analysis included variations of all system parameters and their effects on eigenvalue λ_{11} . The eigenvalue λ_{11} did not show any change for variations of any of the system parameters. Since the λ_{11} mode is not sensitive to any system parameter variation, this mode can be considered neutral. It represents a steady state offset in state variables. Therefore the dynamic stability of the system is not affected by the neutral mode λ_{11} . In addition, participation factors for the λ_{11} mode is shown in Table 4.3.

Table 4.3 Participation Factors
corresponding to mode λ_{11} .

State Variable	Participation Factors
x_1	0
x_2	0
x_3	0
x_4	0
x_5	0
x_6	0
x_7	-1
x_8	0.561
x_9	0
x_{10}	0
x_{11}	-0.094

As we can see from Table 4.3, only the state variables x_7 (AC power interchange deviation), x_8 (DC power interchange deviation) and x_{11} (supplementary control signal) have some degree of participation in the mode λ_{11} and are thus subject to steady state offsets following a system disturbance.

4.5.1. Effect of Supplementary controller Gain Variation

The effect of variation of proportional gain of the supplementary controller on the system stability is shown in Figures 4.8, 4.9, 4.10 and 4.11. These figures show that dominant poles (λ_8, λ_9) move to the left side in the s plane as proportional gain is increased. The damping is increased and the oscillation frequency is decreased, and system stability is improved. λ_6 moves to the right in the s plane, and it is slightly sensitive to proportional gain variation.

The effect of integral gain variation of the supplementary controller on the system stability is shown in Figures 4.12, 4.13 and 4.14. These figures show that dominant poles (λ_8, λ_9) moves to the left in the s plane as integral gain is increased. For low values of gain, oscillation frequency is increased slightly and after that it decreases faster around the optimal gain. The damping is continuously increased until the gain is a little less than optimal gain, after that starts to decrease slowly. The pole λ_6 moves to the right in the s plane with little sensitivity as the integral gain is increased. Therefore the system stability is improved in a range close to the optimal gain.

Figure 4.8 Eigenvalue locations for various k_p .

Figure 4.9 Detail of Figure 4.8 for modes λ_1 and λ_2 .

Figure 4.10 Detail of Figure 4.8 for modes λ_3 , λ_6 and λ_7 .

Figure 4.11 Detail of Figure 4.8 for modes λ_5 and λ_9 .

Figure 4.12 Eigenvalue locations for various k_I . Figure 4.13 Detail of Figure 4.12 for modes λ_5 and λ_9 .

Figure 4.14 Detail of Figure 4.12 for modes λ_6 and λ_7 .

4.6. Conclusions

In this Chapter stability analysis of the AC and AC/DC systems, based on their eigenstructure is reported. The eigenvalue computation of the state coefficient matrix of the system for various AGC and supplementary controller parameters carried out to evaluate system stability are described. The following general observations are based on the location and movements of dominant poles in the complex plane.

The variation of AGC controller parameters on the system stability show system responses with increasing oscillation frequency and reduction of damping as the proportional gain increases. Similar effects, but in smaller degree, occur as the

integral gain increases.

The variation of supplementary controller parameters on system stability show improvements in system damping and oscillation frequency reduction as proportional gain is increased and the integral gain is set in a range close to its optimal value. It appears that the system stability could be improved by action of the supplementary DC control.

5. SIMULATION STUDIES

5.1. General

Simulation studies can be used to analyze and evaluate the dynamic performance of a system. Computer simulation is often the only feasible technique to determine system dynamic performance over a range of operating conditions.

In this research the computer simulation process was carried out using a computer program called TUTSIM⁴⁹. It is an interactive program which simulates the dynamics of systems. The TUTSIM system accepts models in the form of block diagrams. It simulates these models and allows one to change system parameters interactively and compare resulting changes in system responses. This feature make it possible to optimize a system easily and quickly. In the research reported here the model input to the TUTSIM system was based on the transfer function block diagram of the Two Area Interconnected Power System (TAIPS) representation. Through this simulation program the dynamic response of the system was obtained for a specific input disturbance. The model structure developed for this study is shown in Appendix A.

The simulation studies presented in this chapter include mainly two cases as follows:

- i) Simulation of a two area power system interconnected by an AC tie line, with AGC control. For the purposes of system response studies from the control system point of view, this system is equivalent to a two area power system interconnected by parallel AC and DC tie lines, with AGC control and constant DC power control. Constant DC power control does not affect the dynamic responses of the AC interconnected power system when an area load change occurs.
- ii) Simulation of a two area power system interconnected by parallel AC and DC tie lines, with AGC and supplementary DC control.

The simulated system responses were obtained for the two-area power system model assuming it had been subjected to a step load disturbance in one of the system areas. It was assumed that each area was working independently with no mutual assistance of power transfer scheduled through the link except following a disturbance. Initially the power system was in steady state condition determined by normal system operation. That means there were no state variable deviations from scheduled values, in other words all the state variables of the system model were zero. Subsequently the area load was increased by a step (ΔP_L) in one of the control areas, so the system model responses oscillated until they were settled down by the action of the AGC and supplementary DC controls. The AGC control was based on the Tie-line Bias concept described in Chapter 1. The supplementary DC control, the main object of this research work, imposed power modulation of the DC link based

on the deviation of the power interchange (ΔP_{12}) between the individual power system areas.

The inadvertent energy interchange (IEI) which is represented by the time integral of the net power interchange, was also computed in the simulation process. Furthermore the simulation process was used for the optimization of controller parameters (proportional and integral gains) of the AGC and supplementary DC controls.

Since the smallest time constant of the system model utilized is $T_{DC} = 0.05$ seconds (DC system time constant) the simulation time step chosen is 0.01 seconds, which is small enough so as not to compromise the accuracy of system responses. The time period of the simulation was determined by the reset time of the slowest system response examined. In this research work the time period of the simulation was 20 seconds.

5.2. Control Optimization

In the design of a control system, the system must satisfy given performance specifications. Since control systems are dynamic, the performance specifications may be given in terms of either the transient response behaviour to specific inputs or in terms of a performance index. In this case the latter approach was used.

A desired performance index was selected, and using that a unique system

design was obtained. This system is called "optimal control" in terms of the defined performance index.

5.2.1. Performance Index

A performance index is a quantitative measure of the performance of a system and it is chosen such that the important system specifications are emphasized. The performance index can be used to determine the nature of the resulting control system. The system is considered to be an optimum control system when the system parameters are adjusted so that the index reaches an extreme value, usually a minimum value. The "optimal" values of the parameters depend directly on the performance index selected.

5.2.2. Control Optimization of the Two Area Interconnected Power System

The formal optimal control approach includes all system state variables in the optimal feedback control; however, in this study, it is not feasible to include all the system state variables in the feedback loop because of the actual characteristic of a power system. Moreover, the configuration of the system controllers is predetermined (proportional plus integral control). Therefore a pseudo optimal control was utilized in this research, based only on the optimization of the controller parameters to minimize a selected performance index which includes a subset of the state variables.

The performance criterion chosen must lead to the minimisation of the Area Control Error (ACE) in both control areas. The performance index selected is

represented by the time integral of the sum of the square of control error (ISACE) in Area 1 and the square of control error in Area 2, averaged over a time period T.

The mathematical representation of the performance index ISACE is

$$\text{ISACE} = \frac{1}{T} \int_0^T [(ACE_1)^2 + (ACE_2)^2] dt \quad (5.1)$$

The performance index of Equation (5.1) is based directly on generation requirements in both control areas, which represents a good measure of control effectiveness.

The performance index minimisation was carried out by a sub routine called Parameter Estimation⁴⁹ of the TUTSIM program. It is an implementation of the SIMPLEX METHOD⁵⁰ by Nelder and Mead. This subroutine minimizes the ISACE function by adjusting the controller parameters. In the computation of the optimal parameters a constraint of system frequency deviation was also included. The peak value of the first swing of the system frequency deviation was not allowed to exceed 0.025 Hz. This is an arbitrary limit based on accepted North American practice.

5.3. AC System with AGC Control

The simulation tests for a two area power system interconnected by an AC tie line with AGC control was based on the transfer function block diagram shown in Figure 3.2. The parameters associated with the system are shown in Section 2.12.

The AC link had a capacity of 10 % (200 MW) of area capacity, and the power system was operating at a power angle of 30° between the two areas of the system. Then from equation (2.16) the power interchange in steady state condition was $P_{12} = 100$ MW, and from equation (2.17) the synchronizing torque coefficient was $T_{12} = 0.544$ puMW/Hz.

The performance of the system was examined for a step load increase in Area 1 of 1 % (20 MW) of area capacity.

The simulation tests were carried out such that, initially (before disturbance) the system was in steady state condition. The step load change in Area 1 represented a situation of lack of generation, resulting in a decrease of power interchange from Area 1 to Area 2. This imbalance between generation and load in area 1 caused a decrease of frequency in both areas. Thereafter, by action of the governors and AGC controllers the system was restored to normal steady state condition, such that system frequency and power interchange came back to their scheduled values.

A series of simulation tests were carried out to compute the optimal AGC controller parameters to minimize the ISACE. The optimal parameters were found to be:

- * $k_{p1} = k_{p2} = 0.3$ (proportional gain)
- * $k_{i1} = k_{i2} = 0.6$ (integral gain)

The simulation results illustrated in Figures 5.1 to 5.10 and Table 5.1 show the effects of changes of the AGC controller parameters on the dynamic responses of the system. Two modes of response are evident; one under damped mode about 0.3 Hz and the other, a relatively over damped mode. The higher frequency mode is not affected significantly by governor operation; however, the other mode is.

Figure 5.1 illustrates the frequency deviation dynamic response in Area 1 for various values of proportional gain of the AGC control. The frequency oscillation of the response increases and the system damping decreases as k_{p1} and k_{p2} increase; so the area system frequency came back to scheduled value more quickly for small values of proportional gain.

In Figure 5.2 the frequency deviation responses in Area 1 for various values of integral gain of the AGC control show practically the same oscillation frequency in all the cases. Smaller k_{i1} and k_{i2} provide an over damped response, and larger k_{i1} and k_{i2} provide a poor damping response, compared with the optimal parameters. Therefore the area system frequency is seen to settle down faster with optimal AGC controller parameters.

Figures 5.3 and 5.4 illustrate the frequency deviation responses in Area 2 for various values of AGC proportional gain and AGC integral gain respectively. The curves shown similar characteristics to Figures 5.1 and 5.2, respectively, with the exception of the size of the first swing of the responses (Δf_{1max} , Δf_{2max}). Since the

change in load was in Area 1, the disturbance affected mainly the transient response in this area.

In Figure 5.5 the power interchange deviation responses show a higher oscillation frequency and less damping as k_{P1} and k_{P2} increase. The response settled down faster for smaller proportional gain, but the first swing increased.

In Figure 5.6, with smaller values of k_{I1} and k_{I2} the power interchange deviation response was over damped, with a larger swing. Conversely larger values of k_{I1} and k_{I2} provided a response with poor damping and smaller first swing. Optimal integral gain provide a well damped response with the smallest reset time.

Figures 5.7 and 5.8 illustrate the effect of changes in proportional gain and integral gain, respectively, on the performance index value. The performance index (ISACE) was found to be more sensitive to changes of k_{I1} and k_{I2} than to changes of k_{P1} and k_{P2} , reaching a minimum value with the optimal controllers parameters.

Figures 5.9 and 5.10 show the inadvertent energy interchange (IEI) for various values of proportional gain and integral gain respectively. The IEI was found to be practically insensitive to changes of proportional gain but very sensitive to changes of integral gain. The IEI was minimized as the k_{I1} and k_{I2} increase.

Table 5.1 summarizes the effects of changes of AGC controller parameters on

system performance, supplying relevant numeric information as obtained from the dynamic simulation.

Other system dynamic responses such as area control error (ACE), deviation in generated power and control signals are shown in Appendix B.

Additionally a set of simulation tests were carried out to verify how well the optimal control worked for different sizes of step load disturbances. Whenever the performance index was varied as a consequence of size changes of the step load disturbance, the optimal controller parameters were found to keep the same values. Therefore, the optimal values of AGC controller parameters were found to be independent of step load size variations.

Figure 5.1 Frequency deviation responses in Area 1 for various AGC proportional gain.

Figure 5.2 Frequency deviation responses in Area 1 for various AGC integral gain.

Figure 5.3 Frequency deviation responses in Area 2 for various AGC proportional gain.

Figure 5.4 Frequency deviation responses in Area 2 for various AGC integral gain.

Figure 5.5 Power interchange deviation responses for various AGC proportional gain.

Figure 5.6 Power interchange deviation responses for various AGC integral gain.

Figure 5.7 Performance index for various AGC proportional gain.

Figure 5.8 Performance index for various AGC integral gain.

Figure 5.9 Inadvertent energy interchange for various AGC proportional gain.

Figure 5.10 Inadvertent energy interchange for various AGC integral gain.

Table 5.1 Effects of changes of AGC parameters on system performance

AGC k_{P1}, k_{P2}	AGC k_{I1}, k_{I2}	ISACE 10^{-7}	IEI KWh	$\Delta f_1 \text{max}$ Hz	$\Delta f_2 \text{max}$ Hz	$\Delta P_{12} \text{max}$ puMW
0.3	0.6	71.36	4.636	0.0199	0.0150	0.00502
0.1	0.6	76.10	4.627	0.0210	0.0163	0.00555
0.5	0.6	76.55	4.646	0.0190	0.0139	0.00461
0.3	0.2	121.82	13.307	0.0202	0.0153	0.00523
0.3	1.0	111.26	2.882	0.0197	0.0147	0.00486

5.4. AC/DC System with AGC and Supplementary DC Controls

The simulation tests for a two area power system interconnected by parallel AC and DC tie lines, with AGC and supplementary DC control (SC), were based in the transfer function block diagram shown in Figure 3.5. The parameter values for this system are shown in Section 2.12.

The characteristics of the AC link and its normal steady state condition were assumed to be the same as were described in Section 5.3. The DC link was assigned a capacity of 10% (200 MW) of area capacity. It was assumed that the DC link was in normal steady state operation, such that the DC power interchange deviation, from

its scheduled value, was zero. For the simulation, conditions for the system were assumed to be in normal steady state condition before it was subjected to a step load increase of 20 MW in Area 1. The imbalance between generation and area load was corrected by the control system comprised of governors, AGC control and the DC system control. The supplementary DC control (SC), part of the DC system control, interacting with the AGC helped to stabilize the dynamic system responses faster than without the supplementary DC control.

A set of simulation tests were executed to estimate the optimal parameters of the SC controller maintaining the optimal AGC controller parameters constant as computed in the previous section. The optimal SC controller parameters were:

- * $k_p = 0.0$ (proportional gain)
- * $k_i = 12.0$ (integral gain)

The simulation results illustrated in Figures 5.11 to 5.20 and Table 5.2 show the effects of changes of the SC controller parameters on the system dynamic responses.

Figures 5.11 and 5.12 illustrate the effects of changes in proportional gain and integral gain, respectively, of the SC controller on the frequency deviation responses in Area 1. In general, the shapes of the curves are very similar with minor differences in the amplitudes of the swings. The amplitude of the swing increases as the k_p and/or k_i of the SC controller increases. The frequency responses are well damped

coming back to scheduled values in about 10 seconds. The fast response of the DC control make it possible to drop the high frequency oscillation effectively (compare Figures 5.1 and 5.11).

Figures 5.13 shows that the frequency deviation responses in Area 2 remain practically the same as the k_p of the SC controller is varied. Figure 5.14 shows that the swing of the frequency deviation response in Area 2 increases significantly as the k_i decreases.

Figures 5.15 and 5.16 illustrate power interchange effects. The power interchange deviation responses are slightly sensitive to changes of k_p (Figure 5.15); but very sensitive to changes of k_i (Figure 5.16). As k_i increases the swing of the power interchange settles down faster.

Figures 5.17 and 5.18 show that the performance index is only slightly affected by variations of k_p or k_i around their optimal values.

Figures 5.19 and 5.20 show that the inadvertent energy interchange (IEI) maintains the same value for different values of k_p (figure 5.19). However, it shows large changes as k_i is varied. The IEI decreases as k_i increases.

Table 5.2 illustrates the system performance for various values of the parameters of the supplementary DC controller.

Figure 5.11 Frequency deviation responses in Area 1 for various SC controller proportional gain.

Figure 5.12 Frequency deviation responses in Area 1 for various SC controller integral gain.

Figure 5.13 Frequency deviation responses in Area 2 for various SC controller proportional gain.

Figure 5.14 Frequency deviation responses in Area 2 for various SC controller integral gain.

Figure 5.15 Power interchange deviation responses for various SC controller proportional gain.

Figure 5.16 Power interchange deviation responses for various SC controller integral gain.

Figure 5.17 Performance index for various SC controller proportional gain.

Figure 5.18 Performance index for various SC controller integral gain.

Figure 5.19 Inadvertent energy interchange for various SC controller proportional gain.

Figure 5.20 Inadvertent energy interchange for various SC controller integral gain.

Table 5.2 Effects of changes of SC controller parameters on system performance.

SC k_p	SC k_i	ISACE 10^{-7}	IEI KWh	Δf_1 max Hz	Δf_2 max Hz	ΔP_{12} max puMW
0.0	12.0	48.12	0.8142	0.0230	0.0029	0.00096
4.0	12.0	48.09	0.8142	0.0240	0.0025	0.00079
0.0	3.0	49.82	2.1318	0.0210	0.0077	0.00259
0.0	20.0	48.22	0.5255	0.0237	0.0019	0.00061

The dynamic responses of other variables such as area control error, deviation in generated power, AC power interchange deviation, DC power interchange deviation and control signals for various parameters of the supplementary DC controller are illustrated in Appendix C.

The system frequency and net power interchange come back to scheduled values in less than 10 seconds, because of the system control action. However, the power transfers in the AC link and DC link reach new steady state values of operation. The changes in DC power (positive) and AC power (negative) are about 1.8 times the change in area load.

5.5. AC/DC System with AGC and SC Controls, Including DC Power Limiter

Usually, if the DC control is fully utilized, it is possible to achieve full power changes at very fast rates (20 to 50 ms). However, when long distance communication is involved due to the distance between converter stations, the possibility of false signals causing very large power changes must be considered. Also large steady state deviation of power interchange on the AC and DC links would cause problems of operation. To avoid such occurrences, it is desirable to limit the DC power interchange to fixed step changes. The selection of the size of DC power step change is a compromise between reliability and fast response.

For the simulation purposes reported in this research, it was assumed that the DC power limiter maintained a single limit level during the simulation period. This is expressed as a percentage of DC link capacity.

5.5.1. System Dynamic Responses for Various DC Power Limiter Settings

A series of simulation tests was carried out to examine the effects of changes of the DC power limiter (DCPL) on power system responses. The disturbance applied to the system was an area load step change of 1% (20 MW) of area capacity. The selected levels of DC power limiter were 3%, 5% and 10% of DC link capacity, and the related optimal parameters of the SC control were:

- * $k_p = 0$, $k_I = 1.5$; DCPL = 3% (6 MW)
- * $k_p = 0$, $k_I = 2.8$; DCPL = 5% (10 MW)
- * $k_p = 0$, $k_I = 9.6$; DCPL = 10% (20 MW)

As the dynamic changes of the DC power were limited to a smaller range the optimal integral gain of the SC controller was found to be smaller.

Figures 5.21 to 5.27 and Table 5.3 illustrate the effects of changes of DC power limiter settings on system responses. The main aspect observed from the simulation results is the time required for the system responses to settle down to steady state condition. System frequency (Figures 5.21 and 5.22) and power interchange (Figure 5.23) come back to scheduled values faster as the permissible DC power change is larger. In addition the AC power deviation response (Figure 5.25) is stabilized faster for larger DCPL. The swings of the responses are larger as the range of DC power changes is limited to smaller amounts. The performance index (Figure 5.27) and the inadvertent energy interchange (Figure 5.24) are smaller as the DCPL is increased.

Figure 5.21 Frequency deviation responses in Area 1 for various DC power limiter.

Figure 5.22 Frequency deviation responses in area 2 for various DC power limiter.

Figure 5.23 Power interchange deviation responses for various DC power limiter.

Figure 5.24 Inadvertent energy interchange for various DC power limiter.

Figure 5.25 AC power interchange deviation responses for various DC power limiter.

Figure 5.26 DC power interchange deviation responses for various DC power limiter.

Figure 5.27 Performance index for various DC power limiter settings.

Table 5.3 Effects of changes of DC power limiters on system performance.

DCPL %	SC k_p	SC k_i	ISACE 10^{-7}	IEI KWh	Δf_1 max Hz	Δf_2 max Hz	ΔP_{12} max puMW
3	0.0	1.5	55.59	3.9827	0.0204	0.0104	0.00346
5	0.0	2.8	50.68	3.5473	0.0208	0.0079	0.00268
10	0.0	9.6	48.06	2.4597	0.0226	0.0035	0.00116

5.5.2. System Dynamic Responses for various Step Load Disturbances

A set of simulations was carried out to evaluate the effects of change in the amount of load disturbance on the power system responses. The DC power limiter utilized in these tests was 10% (20 MW) of DC link capacity. The selected step load disturbances (ΔP_L) applied to area 1, expressed in percentage of area capacity, and the associated optimal parameters of the supplementary DC controller were:

- * $k_p = 0, k_i = 11.8 ; \Delta P_{L1} = 0.5\% (10 \text{ MW})$
- * $k_p = 0, k_i = 9.6 ; \Delta P_{L1} = 1.0\% (20 \text{ MW})$
- * $k_p = 0, k_i = 2.7 ; \Delta P_{L1} = 2.0\% (40 \text{ MW})$

The optimal integral gain of the supplementary controller decreases as the step load disturbance increases.

Figures 5.28 to 5.34 and Table 5.4 illustrate the effects of changes of step load disturbances on system dynamic responses. In general, as the step load disturbance is increased, the swing of the system responses increase and the dynamic response settles down more slowly. Performance index and inadvertent energy interchange decrease as the step load disturbance applied to the system is decreased.

Figure 5.28 Frequency deviation responses in Area 1 for various step load disturbances in area 1.

Figure 5.29 Frequency deviation responses in Area 2 for various step load disturbances in area 1.

Figure 5.30 Power interchange deviation responses for various step load disturbances in Area 1.

Figure 5.31 Inadvertent energy interchange for various step load disturbances in Area 1.

Figure 5.32 AC power interchange deviation responses for various step load disturbances in Area 1.

Figure 5.33 DC power interchange deviation responses for various step load disturbances in Area 1.

Figure 5.34 Performance index for various step load disturbances in Area 1.

Table 5.4 Effects of changes of step load disturbance in Area 1 on power system performance.

ΔP_{L1} %	SC k_p	SC k_i	ISACE 10^{-7}	IEI KWh	$\Delta f_{1,max}$ Hz	$\Delta f_{2,max}$ Hz	$\Delta P_{12,max}$ puMW
0.5	0.0	2.7	12.02	0.4127	0.0115	0.0015	0.00049
1.0	0.0	9.6	48.06	2.4597	0.0226	0.0035	0.00116
2.0	0.0	11.8	202.65	7.0942	0.0417	0.0161	0.00546

5.6. Simulation Results for Various Interconnection Types and Control Systems of the Two Area Power System

In this section, a set of simulation results is presented for different interconnection types and control system characteristics of the two area power system. These simulation tests were carried out to compare system dynamic responses under similar operation conditions of the power system. The following cases were considered in the simulation process:

- i) Two area power system interconnected by two AC tie lines, with AGC control.
- ii) Two area power system interconnected by AC and DC tie lines, with AGC and constant DC power controls.
- iii) a) Two area power system interconnected by a AC and DC tie lines, with AGC and Supplementary DC controls.
- b) Two area power system interconnected by AC and DC tie lines, with AGC control and supplementary DC control including DC power limiter.

AC and DC links were set to have the same capacity (10% of area capacity). The interconnected power system was operating at a power angle of 30° between system areas and the power transfer between areas was 200 MW (10% of area capacity). Therefore the synchronizing torque coefficient T_{12} was equal to 1.088 puMW/Hz for the two area power system interconnected by two AC lines. T_{12} was set at 0.544 puMW/Hz for the remainder of the cases described above.

The step load disturbance applied to the model system in Area 1 was 1% (20 MW) of area capacity for all the cases. The DC power limiter of the DC control system, included in the third case, was 10% (20 MW) of DC link capacity.

The parameters of the AGC and SC controllers were optimal. These values are given in the previous section with the exception of the system which included two AC tie lines. The optimal parameters of the AGC controller for a two area power system interconnected by two AC tie lines are:

$$* \quad k_{P1} = k_{P2} = 0 ; k_{I1} = k_{I2} = 0.5$$

Figures 5.35 to 5.41 and Table 5.5 illustrate the system dynamic responses for various interconnection types and control systems of the TAIPS, under the operating conditions described above.

In the systems where no supplementary DC control is included, the system dynamic responses have practically the same settling down times in both cases. The oscillation frequency of the system responses is higher for the TAIPS interconnected by two AC lines with AGC control than the TAIPS interconnected by AC and DC lines with AGC and constant DC power control.

Figure 5.35 shows the frequency deviation responses in Area 1. By the action of SC control the frequency deviation response is damped faster, so the system frequency comes back to scheduled values in about 10 seconds or less. The first swing

of the frequency deviation in Area 1 is larger for the TAIPS which includes SC control.

Figure 5.36 shows the frequency deviation responses in Area 2. The SC control action increases the damping of the dynamic frequency deviation response significantly. Moreover the first swing of frequency deviation in Area 2 is largely reduced. Therefore the dynamic frequency changes are very small in the system area which is not subjected to load disturbance.

Figure 5.37 shows that the power interchange deviation responses experience a significant damping improvement because of the SC control action. The dynamic response settles down in about 10 s for the SC control which include DCPL, and in about 7 s for the SC control without DCPL.

Figure 5.38 illustrates that the inadvertent energy interchange is drastically reduced by the action of the SC control, reaching a minimum value for the system without DCPL.

Figures 5.39 and 5.40 show the area control error dynamics in Area 1 and Area 2 respectively. In both control areas the control error signal is reduced (mainly in Area 2) and quickly stabilized by the action of SC control. Therefore the governing system operation in both areas would be minimized because of the control error minimization. Since the system damping is mainly provided by the faster SC

control, Area 2 has very low sensitivity, to load changes in Area 1.

Figure 5.41 illustrates the performance of the TAIPS measured by the performance index ISACE. By the action of the SC control the ISACE is minimized, so the control effectiveness is increased such that the dynamic performance of the TAIPS is improved.

Table 5.5 summarizes some of the main characteristics of the system performance for the different cases examined in this section. The reduction of the values of ISACE and IEI are significant, because of the SC control. The DCPL causes a very small change in the ISACE, but it causes an increase in the IEI.

Figure 5.35 Frequency deviation responses in Area 1 for various interconnection types and control systems of the TAIPS.

Figure 5.36 Frequency deviation responses in Area 2 for various interconnection types and control systems of the TAIPS.

Figure 5.37 Power interchange deviation for various interconnection types and control systems of the TAIPS.

Figure 5.38 Inadvertent energy interchange for various interconnection types and control systems of the TAIPS.

Figure 5.39 Control error of Area 1 for various interconnection types and control systems of the TAIPS.

Figure 5.40 Control error of Area 2 for various interconnection types and control systems of the TAIPS.

Figure 5.41 Performance index for various interconnection types and control systems of the TAIPS.

Table 5.5

System performance for various interconnection types and control systems of the TAIPS.

TAIPS characteristics	AGC k_P	AGC k_I	SC k_P	SC k_I	ISACE 10^{-7}	IEI KWh	$\Delta f_1^{\max}$ Hz	$\Delta f_2^{\max}$ Hz	$\Delta P_{12}^{\max}$ puMW
Two AC tie lines, AGC control	0.0	0.5	--	--	104.91	5.5724	0.0185	0.0199	0.00736
AC-DC tie lines, AGC and constant DC power control	0.3	0.6	--	--	71.36	4.6351	0.0200	0.0150	0.00502
AC-DC tie lines, AGC and SC controls	0.3	0.6	0.0	12.0	48.12	0.8142	0.0230	0.0029	0.00096
AC-DC tie lines, AGC and SC controls with DCPL	0.3	0.6	0.0	9.6	48.06	2.4597	0.0226	0.0035	0.00116

5.7. Conclusions

The simulation results reported in this Chapter illustrate, mainly, the effect of supplementary DC control action on the dynamic performance of the two area interconnected power system following a step load disturbance.

The fast supplementary DC control (SC), based on net power interchange variations, interacts with the conventional AC controls providing a positive damping to the system dynamic responses. The responses settle down faster, reaching a steady state condition in about 10 s. Furthermore, the optimization of the AGC and SC controller parameters, based on the minimization of the performance index ISACE, has a marked effect on system dynamic performance. The area control error is reduced, avoiding unnecessary governing operations. The inadvertent energy interchange (IEI) is also reduced by action of the SC control, reaching smaller values as the integral gain increases. ISACE and IEI have low sensitivities to variations of the SC controller proportional gain.

The DC power limiter (DCPL) has a significant effect on the IEI value, and less influence on the ISACE value.

The calculated optimal values of the SC controller parameters are different for different sizes of area load disturbances and for different DCPL. This attests to the non-linear behaviour of the power control system.

6. SUMMARY AND CONCLUSIONS

6.1. Summary

In this thesis research the dynamic performance of a two area AC/DC power system, with supplementary DC control interacting with the conventional AC controls is described. Emphasis is on the power/frequency control aspects of the overall power system control problem.

The control structure, terminology of interconnected system controls and the general background of HVDC control features are discussed in Chapter 1. The influence of HVDC links on AC systems and a brief review of previously reported studies are also included.

A linear model of a two area power system interconnected by AC and DC tie-lines including conventional controls (primary governing system, AGC control and constant DC power control) and supplementary DC control is presented in Chapter 2. The linear model was satisfactory for these studies because only small changes around a base reference state were considered. The simplified dynamic model developed involves only the power-frequency interactions.

The vector state space equations of the two area power system interconnected by an AC tie-line with AGC control, and by parallel AC and DC tie-lines with AGC and supplementary controls, are presented in Chapter 3. The system state space equations were derived from transfer function block diagrams of the power system.

The results of stability studies of the two-area interconnected power systems are reported in Chapter 4. The stability analysis was carried out by identification of the eigen-structure of the state space models developed in Chapter 3. The system eigen-structure was obtained from the constant coefficient matrix of the state space vector equation.

Simulation studies to evaluate power system dynamic responses under step load changes and to compute optimal controller parameters are discussed in Chapter 5. Control optimization used to adjust the controller parameters was achieved by minimization of a performance index. The performance index (ISACE) chosen is a function of the control error in both control areas and thus is a measure of control effectiveness. The simulation results illustrate the effects of, variation of controller parameters around the optimal values, variation of the size of step load disturbance and variation of DC power limiter settings, on the dynamic responses of the system. Furthermore, graphical results are presented to illustrate the dynamic performance of the various interconnection types and control features of the interconnected power system under operating conditions which are similar with respect to net power transfer between the two areas for all cases.

6.2. Conclusions

It was found that the stability of the two area power system interconnected by AC and DC tie-lines was significantly improved using DC power modulation with supplementary control. In the S plane, the dominant complex poles (natural oscillation modes λ_8 and λ_9) move from $(-0.18 \pm j 3.76)$ to $(-1.17 \pm j 3.09)$ because of the implementation of the optimal supplementary control. The system damping is increased and the oscillation frequency of the system responses is reduced. Thus the dynamic stability of the system is improved.

The responses of the power system subjected to a step load disturbance in one of the control areas, obtained from the simulation results, illustrate a significant dynamic performance improvement overall for the two area interconnected power system with the supplementary control. The fast DC power modulation, based on the time integral of the net power interchange deviation, interacting with the AGC control makes it possible to restore net power interchange and system frequency back to scheduled values in less than 10 seconds following a disturbance. Furthermore, the control optimization, carried out by minimization of the performance index ISACE, minimizes the area control errors and reduces the inadvertent energy interchange. Since the system damping is provided mainly by the faster supplementary control, the control area which is not subjected to load disturbance is practically insensitive to load changes in the neighbouring control area.

Summarizing, the optimal supplementary control provides a positive damping to the system dynamic responses. Following a disturbance the system settles down faster, the inadvertent energy interchange is reduced and the system governing operations are reduced. Thus the control effectiveness is improved.

The effects of the DC power limiter on system responses show a small influence on the performance index value, but it causes an increase of the inadvertent energy interchange. It increases the mutual assistance between the individual power systems through the AC tie-line and hence demands larger angle swings between areas.

The integral action of the supplementary control causes a significant steady state deviation of the power transfer over the AC and DC links; one increases while the other decreases. Further research is required on this problem to devise a suitable means to compensate for or avoid it. It is suggested that the addition of a relatively slow "wash-out" action to the supplementary controller would accomplish this.

The values of optimal parameters of the supplementary controller depend on the size of the step load disturbance and of the value of the DC power limiter setting. This is due to the basic non-linear characteristic of the system and on-line tuning of such parameters would be required to maintain optimal performance over a wide range of operation. This area requires further study.

As real power systems have non linear characteristics, it is recommended that a more detailed TAIPS model including such non-linearities be developed in order to extend the studies for a wider range of disturbances.

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APPENDIX A

Simulation Model Structure

TUTSIM Block number	TUTSIM Block type	TUTSIM Block inputs	TUTSIM Block parameters						Output variables
			P	K	T	I _c	Min	Max	
1	SUM	11,44	-	-	-	-	-	-	(-ACE ₁)
2	GAI	1	k _{P1}	-	-	-	-	-	
3	GAI	1	k _{I1}	-	-	-	-	-	
4	INT	3	-	-	-	0	-	-	
5	SUM	-10,-2,-4	-	-	-	-	-	-	
6	FIO	5	-	1	T _{G1}	0	-	-	x ₃
7	FIO	6	-	1	T _{T1}	0	-	-	x ₂ , (ΔP _{G1})
8	SUM	-19,7,-44	-	-	-	-	-	-	
9	FIO	8	-	K _{P1}	T _{P1}	0	-	-	x ₁ , (Δf ₁)
10	ATT	9	R ₁	-	-	-	-	-	
11	GAI	9	B ₁	-	-	-	-	-	
12	SUM	9,-29	-	-	-	-	-	-	
13	GAI	12	T ₁₂	-	-	-	-	-	
14	INT	13	-	-	-	0	-	-	x ₇ , (ΔP _{AC})
15	MUL	1,1	-	-	-	-	-	-	
16	SUM	15,32	-	-	-	-	-	-	
17	LMI	16	-	-	-	0	0	T	
18	TIM	-	-	-	-	-	-	-	
19	CON	-	ΔP _{L1}	-	-	-	-	-	(ΔP _{L1})
21	SUM	31,-44	-	-	-	-	-	-	(-ACE ₂)
22	GAI	21	k _{P2}	-	-	-	-	-	
23	GAI	21	k _{I2}	-	-	-	-	-	

24	INT	23	-	-	-	0	-	-	
25	SUM	-30,-22,-24	-	-	-	-	-	-	
26	FIO	25	-	1	T_{G2}	0	-	-	x_6
27	FIO	26	-	1	T_{T2}	0	-	-	$x_5, (\Delta P_{G2})$
28	SUM	44,27	-	-	-	-	-	-	
29	FIO	28	-	K_{P2}	T_{P2}	0	-	-	$x_4, (\Delta f_2)$
30	ATT	29	R_2	-	-	-	-	-	
31	GAI	29	B_2	-	-	-	-	-	
32	MUL	21,21	-	-	-	-	-	-	
40	GAI	44	k_P	-	-	-	-	-	
41	GAI	44	k_I	-	-	-	-	-	
42	INT	41	-	-	-	0	-	-	
43	FIO	-40,-42	-	1	T_{DC}	0	-	-	
44	SUM	14,90	-	-	-	-	-	-	$x_{11}, (\Delta P_{12})$
49	LIM	18	-	-	-	0	ΔT	T	
50	DIV	17,49	-	-	-	-	-	-	(ISACE)
60	INT	44	-	-	-	0	-	-	
61	ATT	60	1.8	-	-	-	-	-	(IEI)
80	SUM	-2,-4	-	-	-	-	-	-	x_9
81	SUM	-22,-24	-	-	-	-	-	-	x_{10}
90	LIM	43	-	-	-	-	-DCPL	+DCPL	$x_8, (\Delta P_{DC})$

The above simulation model structure, developed for the TUTSIM program, is based on the transfer function block diagram of the AC/DC Two Area Interconnected Power System shown in Figure 3.5.

Note:

- T : simulation time period
- ΔT : simulation time step

APPENDIX B

AC System Dynamic Responses for Various AGC Controller Parameters

Figure B.1 Control error in Area 1 for various AGC proportional gain.

Figure B.2 Control error in Area 1 for various AGC integral gain.

Figure B.3 Control error in Area 2 for various AGC proportional gain.

Figure B.4 Control error in Area 2 for various AGC integral gain.

Figure B.5 Generated power deviation in Area 1 for various AGC proportional gain.

Figure B.6 Generated power deviation in Area 1 for various AGC integral gain.

Figure B.7 Generated power deviation in Area 2 for various AGC proportional gain.

Figure B.8 Generated power deviation in Area 2 for various AGC integral gain.

Figure B.9 Control signal in Area 1 for various AGC proportional gain.

Figure B.10 Control signal in Area 1 for various AGC integral gain.

Figure B.11 Control signal in Area 2 for various AGC proportional gain.

Figure B.12 Control signal in Area 2 for various AGC integral gain.

APPENDIX C

AC/DC System Dynamic Responses for Various Supplementary Controller Parameters

Figure C.1 Control error in Area 1 for various SC controller proportional gain.

Figure C.2 Control error in Area 1 for various SC controller integral gain.

Figure C.3 Control error in Area 2 for various SC controller proportional gain.

Figure C.4 Control error in Area 2 for various SC controller integral gain.

Figure C.5 Generated power deviation in Area 1 for various SC controller proportional gain.

Figure C.6 Generated power deviation in Area 1 for various SC controller integral gain.

Figure C.7 Generated power deviation in Area 2 for various SC controller proportional gain.

Figure C.8 Generated power deviation in Area 2 for various SC controller integral gain.

Figure C.9 Control signal in Area 1 for various SC controller proportional gain.

Figure C.10 Control signal in Area 1 for various SC controller integral gain.

Figure C.11 Control signal in Area 2 for various SC controller proportional gain.

Figure C.12 Control signal in Area 2 for various SC controller integral gain.

Figure C.13 Control signal DC system for various SC controller proportional gain.

Figure C.14 Control signal DC system for various SC controller integral gain.

Figure C.15 AC power deviation for various SC controller proportional gain.

Figure C.16 AC power deviation for various SC controller integral gain.

Figure C.17 DC power deviation for various SC controller proportional gain.

Figure C.18 DC power deviation for various SC controller integral gain.