بِسۡمِ ٱللَّهِ ٱلرَّحۡمَٰنِ ٱلرَّحِيمِ

قال تعالي : ((قالوا سبحانك لا علم لنا الا ما علمتنا انك انت العليم الحكيم (32))).

سوره البقرة

ACKNOLEDGMENTS

First of all, I would like to express all my thanks to God for his great help in completing this thesis.

I would like to express my sincerest thanks to supervisor Prof. Dr. Yousif Hassan Abdalrahim and to assist supervisor Dr. Abdel Aziz Yousif Mohamed for their useful guidance, keens interest, efforts and help at any time.

My deep thanks to my family for their prayers and patience during my study.

My thanks are also to the staff of load dispatch center for providing the necessary information.

المستخلص

عدم الاستقرارية في الحالة غير العابرة يسبب مشاكل بانظمة القدرة الكهربائية في كل انحاء العالم. وفي كثير من الاحيان لا يتم ملاحظة هذه الحالات بواسطة مهندسي دراسات التخطيط و مهندسي التشغيل حتي يصل النظام الي وضع تنتج منه مشاكل. تنتج عدم الاستقرارية في الحالة غير العابرة من عدة اسباب منها التذبذب الناتج من ربط شبكتين او اكثر, وينتج من ربط الشبكات مع بعضها مشكلة اخري وهي كيفية التحكم في القدرة المنقولة بين الجزر وفق معايير التشغيل و الاستقرارية.

هذه الرسالة تمثل دراسة في تقييم الخط الرابط بين شبكتي السودان و اثيوبيا من حيث التحكم في القدرة المنقولة و مدي صلابة الخط الناقل, وقد تم جمع كافة المعلومات اللازمة لهذه الدراسة و التى تم استعمالها لمراقبة مدي انحراف التردد و معامل الخطا في الشبكة من القيمة المسموح بها. ولقد تم ايضا استعمال المعلومات في حساب مصفوفة الشبكة لحساب متغيرات الشبكة وبالتالي معرفة مدي صلابة الخط الرابط

Abstract

Steady state instabilities cause problems in electrical power system all over the world. Most of the time potential instabilities are undetected by planning and operational engineering studies, until some particular condition develops and creates a problem. One of steady state instabilities problem is inter area oscillation which appear between two or more area. The other problem appears when connects between two areas, how to control the tie line power flow within operating criteria and reliable condition.

This thesis presents a comprehensive approach to evaluate tie line operation control and stiffness for Sudan and Ethiopia network. A data bank for study has been constructed. This has been used to monitoring the deviation from the acceptable limit in the frequency and area control error. Also this data construct Ybus for Sudan and Ethiopia networks to calculate the maximum power which transfer between two areas to identify tie line stiffness.

Table of Contents

Page No

ABSTRACT ……... 4
CONTENTS …… 5
LIST OF FIGURES 8
LIST OF TABLES 9

CHAPTER ONE
Introduction

1.1 Introduction……. 10
1.2 General Concept…… 10
1.3 Power System Stability……..... 13
1.4 Power System Control…… 15
1.5 Interconnected Power System…… 17
1.6 Research Objective……. 18
1.7 Motivation…… 19
1.8 Research Layout……. 19

CHAPTER TWO
Literature Review and Network Grid Data

2.1 Introduction……. 20
2.2 Historical Review of Tie Line Problem……. 21
2.3 Data Survey……. 22
2.4 Generation Power Plants…… 23
2.5 Transmission Lines Representation…….. 23
2.6 Load Representation……..... 24

CHAPTER THREE
Transmission Lines Model and System Elimination

3.1 Introduction……. 27
3.2 Type of Line Model……..... 27
3.3 Transmission Lines Equivalent Data……..... 29
3.4 Convert to Per Unit System…… 30
3.5 YBus Calculate…… 36
3.6 Network Elimination …….. 38

CHAPTER FOUR
Tie Line Power Flow Control

4.1 Introduction……. 45
4.2 Fundamentals of Automatic Generation Control…… 46
4.3 Area Control Error……..... 47
4.4 Frequency Bias Setting …….. 48
4.5 Controller of the Automatic Generation Control…… 48
4.6 Tie Line Power Flow Control……. 50

CHAPTER FIVE
Inter Area Oscillation and Tie Line Evaluation

5.1 Introduction……. 52
5.2 Dynamic System Model…….……. 53
5.3 Power Oscillations in Interconnected Systems ……..... 54
5.4 Tie Line Evaluation …… 55
5.5 Power Flow Analysis…….. 57

CHAPTER SIX
Conclusions and recommandations

6.1 Conclusions ……. 61
6.2 Recommendations …….……. 62
References ……. 63
APPENDIX A Load Flow Program ……..……..... 65
APPENDIX B Transmission Lines Row Data ……... 68
APPENDIX C Buses Data Output ……... 71

LIST OF FIGURES

Figure	Title	Page No.
1.1	The variation of cost with distance for AC and DC transmission……...	11
1.2	Speed governor droops characteristic…….	16
1.3	Two systems connected with tie line…….	18
2.1	Sudan and Ethiopia Network ……...……	26
4.1	Basic generation control loop via telemetry……	46
4.2	Area Control Error calculation……	48
4.3	Frequency Deviation of the System……..……	51
4.4	Area Control Error for Sudan Area……	51
5.1	Load Flow Analysis for Sudan and Ethiopia Network ……..	60

LIST OF TABLES

Tables	Title	Page No.
2.1	Sudan Power Stations Data ……..	23
2.2	Ethiopia Power Stations Data……...…….	23
2.3	Sudan Load Data……	25
2.4	Ethiopia Load Data…….	25
3.1	Sudan Transmission Lines Equivalent Data……	32
3.2	Ethiopia Transmission Lines Equivalent Data……..…..	33
3.3	Sudan Lines Data in Per Unit System……...	34
3.4	Ethiopia Lines Data in Per Unit System ……..	35
3.5	Sudan and Ethiopia inter bus Transformers impedance……	36
3.6	Ybus of the System……..……	37
3.7	(K) matrix ……	40
3.8	Mutual admittances (LT) matrix……..……	41
3.9	Mutual admittances (L) matrix……..	42
3.10	Self and mutual admittances (M) matrix……..	43
3.11	Ybus eliminate……	44
5.1	Sudan Generations Voltage in Per Unit and Power ……	58
5.2	Ethiopia Generations Voltage in Per Unit and Power ……	58

CHAPTER ONE

Introduction

1.1. Introduction:

The purpose of a transmission network is to transfer electric energy from generating units at various locations to the distribution system which ultimately supplies the load. Transmission lines also interconnect neighboring utilities which permits not only economic dispatch of the power within regions during normal conditions, but also transfer of power between regions during emergencies [1].

Conductors for overhead lines are usually stranded, unless they are of small cross section, because the continuous swinging and vibration would otherwise produce mechanical fatigue and hence fracture at the insulator clamps. Because of dirt and oxide films on the surface of each strand, the current flows spirally through the strands rather than axially from strand to strand. The resistance and inductance are therefore slightly higher than those of a solid conductor [1].

The cross sectional area of a distributor is generally determined by the maximum voltage drop which can be tolerated. In the case of feeder and transmission lines, however, voltage drop is less important than the cost of energy loss and the initial cost [1].

1.2. General Concept:

Tie lines have two types to transmit the power from one area to another, AC transmission line and DC transmission line, to take a decision between two types there is some considerations. These considerations are: cost for the transmission lines and substation, technical considerations, and the reliability- availability offered by the transmission. These considerations are necessary to make a planning selection between AC and DC transmission lines [2].

1.2.1. Cost consideration:

Assuming similar insulation requirements for peak voltage levels for both AC and DC lines, a DC line can carry as much power with two conductors (having positive/negative polarities with respect to ground) as an AC line with three conductors of the same size. Therefore for a given power level a DC line requires smaller right of way, simpler and cheaper towers and reduced conductor and insulator costs. There are only two conductors with the same current capacity of AC conductors. The power transmission losses are also reduced about two to three of the comparable AC system. The absence of skin effect with DC is also beneficial in reducing power losses marginally. In additions the dielectric losses in case of power cables is also very much less for DC transmission, beside corona effects tend to be less significant on DC than for AC conductors. The other factors that influence line costs are the costs of compensation and terminal equipment. DC lines do not require reactive power compensation but the terminal equipment costs are increased due to the presence of converters and filters [2].

AC tends to be more economical than DC for distances less than the breakeven distance but is more expensive for longer distances. The breakeven distances can vary between 400km to 700km in overhead line depending on the per unit line costs. With a cable system this breakeven distance lines between 25km to 50km, Figure 1.1 shows that variation of costs of transmission with distance for AC and DC transmission [2].

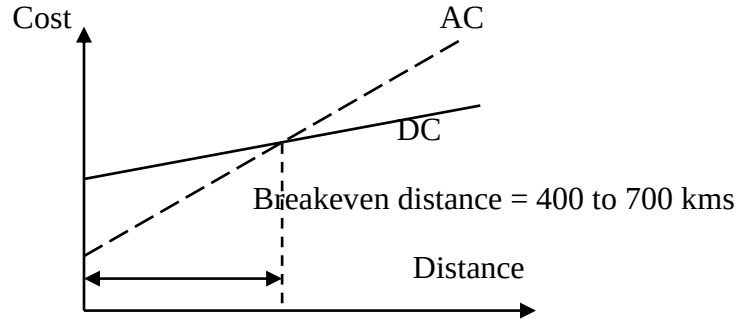

Figure 1.1 the variation of cost with distance for AC and DC transmission

1.2.2. Technical considerations:

Due to its fast controllability, a DC transmission has full control over transmitted power. An ability to enhance transient and dynamic stability in associated AC networks can limit fault currents in the DC lines. Furthermore DC transmission overcomes some of the following problems associated with AC transmission:

- Stability limits:

The maximum power transfer in an AC line is limited by the considerations of steady state and transient stability, and on the angle difference between the voltage phasors which it increases with distance. The power transfer in a DC line is unaffected by distance of transmission [2].

- Voltage control:

The voltage profile in the transmission has two major problems: Line charging (The steady state charging current in AC cables pose serious problems and makes the break even distance for cable transmission around 50kms). Also Voltage drops (the maintenance of constant voltage at the two ends requires reactive power control, the reactive power requirements increase with line length). Although DC converter stations require reactive power related to the power transmitted, the voltage profile varies with the line loading [2].

1.2.3. Reliability and availability cost consideration:

Statistics on the reliability of HVDC link are maintained by CIGRE and IEEE working group. The reliability of DC links has been very good and is comparable with AC system. The availability of DC links is quoted in the upper 90% [2].

1.2.4 Problems of AC And DC Interconnection:

The AC interconnections have many problems:

1. The presence of large power oscillation which can lead to frequent tripping

2. Increases in fault level
3. Transmission of disturbances from one system to the other.

The fast controllability of power flow in DC lines eliminates all of the above problems. Furthermore, the asynchronous interconnection of two power system can only be achieved with use of DC links [2].

The application of DC transmission is limited by many factors such as:

1. High cost of conversion equipment
2. Inability to use transformers to alter voltage levels
3. Generation of harmonics
4. Requirement of reactive power
5. Complexity of control

1.3. Power System Stability:

Power System Stability may be broadly defined as that property of a power system that enables it to remain in a state of operating equilibrium under normal operating conditions and to regain an acceptable state of equilibrium after subjected to a disturbance [3]. The stability problem has been one of maintain synchronous operation. Since power systems rely on synchronous machines for generation of electrical power, a necessary condition for satisfactory system operation is that all synchronous machines remain in synchronism or colloquially, “in step”. This aspect of stability is influenced by the dynamics of generator rotor angles and power-angle relationships [3].

Rotor angle stability is the ability of interconnected synchronous machines of a power system to remain in synchronism [2]. This is termed as the *synchronous operation* of a system. Any disturbance small or large can affect the synchronous operation. There can be a sudden increase in the load or loss of generation. Another type of disturbance is the switching out of a transmission line, which may occur due to overloading or faults [3].

The disturbance can be divided into two categories: small and large. A small disturbance is one for which the system dynamics can be analyzed from linearized equations small signal analysis. The small random changes in the load or generation can be termed as small disturbances. The tripping of a line may be considered as a small disturbance if the initial (pre-disturbance) power flow on that line is not significant.

The faults which result in a sudden dip in the bus voltages are large disturbances and require remedial action in the form of clearing of the fault. The duration of the fault has a critical influence on system stability [2]. Although stability of a system is an integral property of the system, for purposes of the system analysis, it is divided into two broad classes:

1.3.1. Steady-State or Small Signal Stability:

Small signal stability is the ability of the power system to maintain synchronism under small disturbances. The nature of system response to small disturbances depends on a number of factors including the initial operating, the transmission system strength, and the type of generator excitation controls used [3].

1.3.2. Transient Stability:

Transient Stability is the ability of the power system to maintain synchronism when subjected to a severe transient disturbance. In transient stability studies the study period of interest is usually limited to 3 to 5 seconds following the disturbance, although it may extend to about ten seconds for very large systems with dominant inter area modes of oscillation [3].

Transient stability is a function of both the operating condition and the disturbance. This complicates the analysis of transient stability considerably. Not only system linearization cannot be used, repeated analysis is required for different disturbances that are to be considered [2].

A power system is transiently stable for a particular steady-state operating condition and for a particular large disturbance or sequence of disturbances if, following that or sequence of disturbance it reaches an acceptable steady-state operating condition [2].

1.4. Power System Control:

The frequency of the system is dependent on active power balance. As frequency is a common factor throughout the system, a change in active power demand at one point is reflected throughout the system by a change in frequency [3]. In the network, considerable drop in frequency means the speed of the shaft was dropped and that could result in high magnetizing current in induction motor and transformer. On the other side when the frequency increases means the speed of the shaft was increased [3].

To decrease the deviation of frequency in the network which has many generators supplying power into the system, some means must be provided to allocate change in demand to the generators. A speed governor on each generating unit provides the primary speed control function, while supplementary control (AGC) originating at a central control center allocates generation. In an interconnected system with two or more independently controlled areas, in addition to control the frequency, the generation with each area has to be controlled so as to maintain scheduled power interchange [3]. First review the requirements for primary speed governing and then review the requirements for supplementary control.

1.4.1. Fundamentals of Speed Governing:

Speed droop is a governor function which reduces the governor reference speed as fuel position when the load increases. The basic concept of speed governing is by adjusting the valve in the steam/gas or the gate in the hydraulic by the governor to make a turbine speed within the limit. The simpler mechanical governors have the

droop function built into the control system. More complex hydraulic governor can include temporary droop which is called compensation. Normally, a droop governor lowers the speed reference from 3 to 5 percent of the reference speed over the full range of the governor output [4].

Figure 1.2 illustrate Speed governor droops characteristic, typical speed droops for active governors are in the range of about 5% (which means 5% change in the speed will result in 100% change of the mechanic output power from the prime mover). Initially, the speed governor is operating on curve L_0 and the system is operating at the frequency ω_0 (point A). After the load increase, the system frequency drops to ω_1. The governor will respond by increasing the turbine output from P_{M0} to P_{M1} (point B). By changing the set point of the speed governor, the droop curve will move from L_0 to L_1. Now, the operation point is at C and system frequency has been brought back to ω_0 [5]

Governors should not be paralleled isochronously with any system so big that the governed unit cannot affect the speed of the system. Identical engines can show different characteristics if droop settings are not identical [4]

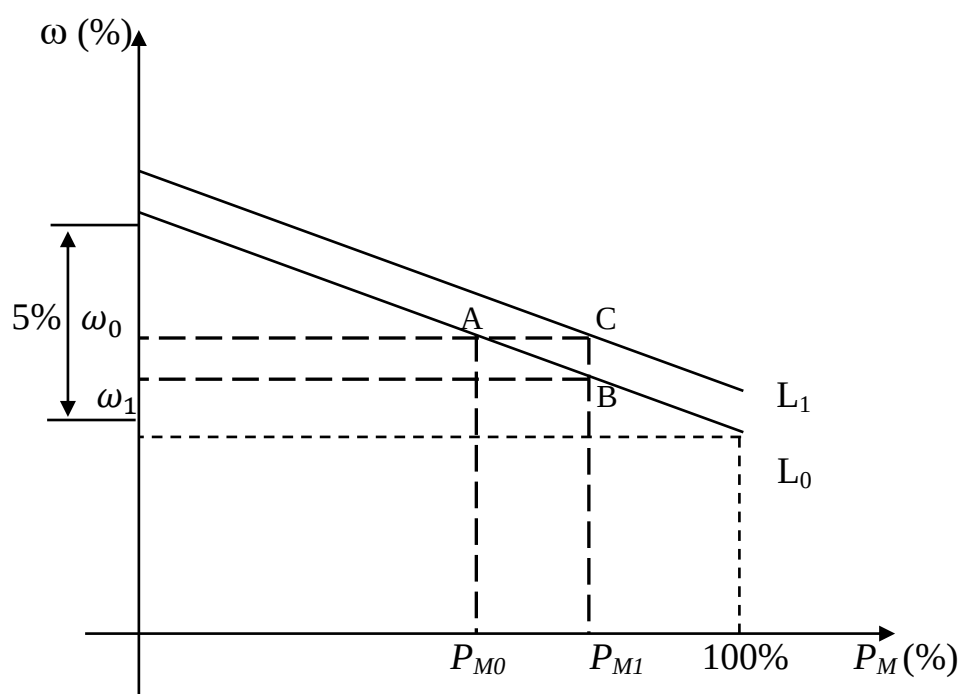

Figure 1.2 Speed governors droops characteristic

Droop causes the governor speed reference to decrease as load increases. This allows the governor to vary the load since the speed cannot change. When paralleled with a bus, the load on an engine is determined by the reference speed setting of the droop governor. Increasing the speed setting cannot cause a change in the speed of the bus, but it will cause a change in the amount of load the engine is carrying [4].

1.4.2. Area Frequency Response Characteristic:

The composite frequency characteristic of a power system thus depends on the combined effect of the droops of all generator speed governors. It also depends on the frequency characteristics of all the loads in the system. The composite frequency response characteristic (β) is normally in [MW/Hz] it is also sometimes referred to as the stiffness of the system. The composite regulating characteristic of the system is equal to ($1/\beta$) [3]. For a system with *n* generators and a composite load damping constant of *D*, the steady state frequency deviation following a load change ΔP_L is given by

$$\Delta f = \frac{-\Delta P_L}{\frac{1}{R_{eq}} + D} \qquad (1.1)$$

$$\beta = \frac{-\Delta P_L}{\Delta f} = \frac{1}{R_{eq}} + D \qquad (1.2)$$

1.5. Interconnected Power System:

The interconnection between areas is used for many reasons:

1. A supplier for specific area (Ethiopian with Djibouti).
2. Economic operations when the sending areas have cheaper electricity generation like hydro (Ethiopian with Sudan).
3. Security operation which makes both networks stronger. When one area losses partial generation both systems try to compensate the lost power. That makes the two areas more reliable.

To make a good visualization for the problem of the power control in the tie line in Figure 1.3, suppose that they are two systems which have the same generation and load characteristics, area 1 sending 100 MW through the tie line to area 2. Assume that area 2 has an increase in load of about 30MW. Both areas experience a 15MW increase by the primary control action to meet the additional load. That means the power in tie line increase from 100 MW to 115 MW [6].

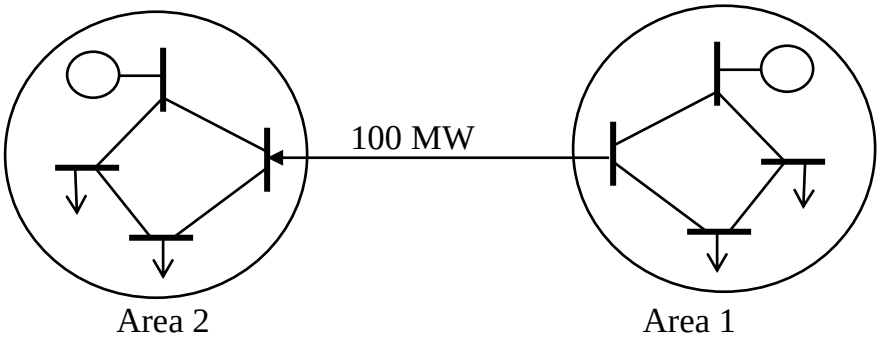

Figure 1.3 Two systems connected with tie line

To solve this problem the machine in both sides must be controlled by the change of frequency and the interchanged power in the same time. The value of generation increase depends on the droop and load damping in each system. There are many scenarios between areas; the two areas can control the tie line power and frequency at the same time. Or one of the two system control frequency and the other system control tie line power. The selection between scenarios depends on the load characteristic and the generation capacity of the two areas [6].

1.6. Research Objective

- This project concentrate on associated with AC tie line with especial enfaces on Sudan and Ethiopia tie line power flow control and inter area oscillation.
- The main objectives of this research are to investigate interconnection power flow control behavior by illustrated AGC controller in Sudan network and by eliminating the networks and calculating load flow parameters for each area

which has effect on the behavior of the tie line power and frequency, thus determining the electrical strength of the tie line.

1.7. Motivation:

- In the first trial of synchronization between Sudanese & Ethiopian power systems the flow of power during the first few moments was in the reverse direction, which is counter to the agreement. Later the direction was corrected to the nominal direction but with uncontrollable flow. In this trial both systems were under primary control.
- In second trial of synchronization, Sudanese national dispatch center operated the AGC was in the flat frequency control while Ethiopian system was still under primary control. The power flow in the tie line continued in dropping to zero.

1.8. Research Layout:

- The research is organized as follows; in chapter 2 a literature review and grid data of interconnection power system is presented.
- Chapter 3 presents transmission line parameters and types of model for all Sudanese and Ethiopia transmission equipment (lines, transformers) in order to calculated Ybus for both network and eliminate Ybus to simplify the model without affecting the results.
- Chapter 4 presents Tie Line Power Flow Control and Exciting AGC in the Grid and illustrates the frequency oscillation and ACE on the tie line.
- Chapter 5 presents evaluation of strength and weaknesses of Inter Area Oscillation and Tie Line. This is followed by conclusions and recommendations in Chapter 6.

CHAPTER TWO

Literature Review and Network Grid Data

2.1. Introduction:

Power system stability may be broadly defined as that property of a power system that enables it to remain in a state of operating equilibrium under normal operating conditions and to regain an acceptable state of equilibrium after being subjected to a disturbance. The system stability can be divided to: Angle stability which is the ability to maintain synchronous torque balance of synchronous machines and Voltage stability which is the ability to maintain steady acceptable voltage [7].

Stable operation of a power system depends on the ability to make a continuous matching of the electrical output of generating units and the electrical load on the system. Consequently, load characteristics have an important influence on system stability [8].

The system modeling of load is complicated because a typical load bus represented in stability studies is composed of a large number of devices such as fluorescent and incandescent lamps, refrigerators, heaters, compressors, motors, furnaces, and so on. The exact composition of load is difficult to estimate. Also, the composition changes depending on many factors including time (hour, day, and season), weather conditions and state of economy [8].

The primary control can't make an accurate action as the agreement for the continually change in power through the tie line; it can be solve this problem by using the secondary control Automatic Generation Control (AGC) [5]. For this thesis the base case data was take form national load dispatch center on 27 July 2013 at 15:00 pm, this period of time in Sudan the load was peaking of year.

2.2. Historical Review Of Tie Line Problem:

As power systems evolved interconnections between independent systems are found to be economically attractive, but the complexity of the system increases stability problems. Systems could no longer be treated as two machine systems. A significant step towards the improvement of stability calculations was the development in 1930 of the network analyzer (or the ac calculating board). A network analyzer is essentially a scaled model of an ac power system with adjustable resistors, reactors and capacitors to represent transmission network and load, voltage sources whose magnitude and angle can be adjusted to represent generators, and meters to measure voltage, currents, and power anywhere in the network. This development permitted power flow analysis of multi machine system; however, the equation of motion or the swing equation still hand to be solved by hand using step by step numerical integration [9].

Improvements to system stability came about by way of faster fault clearing and continuous acting voltage regulators with no dead band. The benefits of an excitation system with a high degree of response for increasing steady state stability were in fact recognized in the early 1920s; however, initially this region of dynamic stability was not recommended for normal operation but was treated as additional margin in determining operating limits. With the increased realization of the potential benefits of faster responding excitation systems in limiting first swing transient instability as well as increasing steady state power transfer limits, their use became more commonplace. However, the use of high response exciters in some cases resulted in decreased damping of power swings. Oscillatory instability thus became a cause for concern, while steady state monotonic instability was virtually eliminated. These trends required better analytical tools. Synchronous machine and excitation system representation had to be more detailed and simulations had to be carried out for longer time periods [10].

2.3. Data Survey:

The survey covered the following items:

1. Data of existing generation power plants
2. The value of interchange power which transfer from Ethiopia to Sudan network.
3. Parameters of the existing transmission lines in both networks (Sudan, Ethiopia). These parameters, such as resistance, reactance and charging MVAR per unit length, should be available in order to determine the equivalent circuit parameters.
4. Systems configuration and load distribution on the network at peak load condition, which is considered an important condition for tie line flow control.

2.4. Generation Power Plants:

In Sudan electricity network there are two type of generation: hydro and thermal plant to meet the demand. There are five hydro power plants: Merowe, Roserse, Sennar, Jebelaulia and Elgirba Dams, and four thermal power plants: Garri, Khartoum north, Obeid, Portsudan Power Plant. Some of these stations have a small capacity of power generation and high consumption of fuel like Obeid and Portsudan. For this reason these stations not working. For simplifying the modeling Sennar, Jebel Aulia and Elgirba station are excluded from the model because the power which deliver by these power plant is very small when compare it with the network demand.

In Ethiopia electricity network all the generation power plants are hydro. The power plants with high capacity have more effect on the network. These are: Beles, Gllgelglbe2, Tekeze, Melkawakena, Finchaa and Amrtneshi.

Each network has independent power plants with different voltage levels. All power plants deliver power to meet the loads consumption. Table 2.1 illustrates type of generations, delivered power form each plants in Sudan power system in

27/7/2013 at 15:00pm, nominal voltages and actual voltage during the case study. Table 2.2 icotains the same equivalent data in Ethiopia network.

Table 2.1 Sudan Power Stations Data

POWER ST.	GENERATION			
	TYPE	NOM. VOLT.	ACTUAL VOLT.	MW
MWP	HYDRO	525	529	806
GAR	GAS	220	225	269
ROS	HYDRO	220	225	100
KHN	STEAM	110	111	186
Summation				1676

Table 2.2 Ethiopia Power Stations Data

POWER ST.	GENERATION			
	TYPE	NOM. VOLT.	ACTUAL VOLT.	MW
BELES	HYDRO	400	415	380
FINCHAA	HYDRO	230	230	125
AMRTNESHI	HYDRO	230	229	115
GLLGELGLBE2	HYDRO	400	410	430
MELKAWAKENA	HYDRO	230	225	123
TEKEZE	HYDRO	230	228	285
GLLGELGLBE 220kv	HYDRO	230	230	195
Summation				1653

2.5. Transmission Lines Representation:

The transmission system consists of the overhead lines in both networks. They connect power plants with substations and substations with substations. The configuration of connection between substations in Sudan network and Ethiopia network is radial system. All load substations in both systems are eliminated and compensated by radial load in the inter bus substations (220kv). The system configuration of the transmission lines with the power plants is given shown in

Figure 2.1. Table 2.3, Table 2.4 include the values of transmission line parameters per km, length of the lines, number of the lines and voltage levels for Sudan network and Ethiopia network.

2.6. Load Representation:

The load models are traditionally classified into two broad categories:

Static load models:

A static load model expresses the characteristics of the load at any instant of time as algebraic functions of the bus voltage magnitude and frequency at that instant [11]. The active power component P and the reactive power component q are considered separately. Traditionally, the voltage dependency of load characteristics has been represented by the exponential model.

Dynamic load models:

The response of most composite loads to voltage and frequency changes is fast, and the steady state of the response is reached very quickly. It is necessary to account dynamics load components in some studies like inter-area oscillations, voltage stability and long term stability often require load dynamics to be modeled.

Loads distribution and load composition changes affect on the dynamic behavior of a power flow through tie line, Load composition changes continually reflecting the customer, lifestyle, the weather, the state of economy, and many other factors. It is important to estimate the load composition at time of critical interest such as under heavy or light load condition [11]. Table 2.5, Table 2.6 contain name of substations, active and reactive power in each area during peak time on 27 July 2013 at 15:00pm with total load in Sudan area mounting to 1776 Mw, and 1553Mw in Ethiopia area.

Table 2.3 Sudan Load Data

	LOAD		
	BUS NO	MW	MVAR
ATB 220KV	5	242	118
IBAB 110KV	6	404	190
KLX	7	190	98
GAD	8	49	21
NHAS	9	76	39
MAR	10	97	36
RBK	11	91	47
JAS	12	162	114
GAM	13	221	148
MHD	14	175	103
GDF	15	69	30
Summation		1776	944

Table 2.4 Ethiopia Load Data

	LOAD		
	BUS NO	MW	MVAR
SEHEDI	23	20	18
GONDER2	24	53	38
B.DAR 220kv	25	86	49
D.MARKOS 220kv	26	87	34
GHEDO	27	204	132
GEFERSA	28	115	62
SEBETA	29	105	45
WELKLTA	30	119	71
KALLTL	31	189	104
LEGETFA	32	107	64
D.DAWA	33	133	64
COMBOLCHA	34	92	59
ALAMATA	35	97	61
MELKELE	36	103	49
Summation		1510	850

Figure.2.1 shows Sudan and Ethiopia 50-Hz areas. These areas consist of many electric power companies. There are some large generators in the areas like Merowe P/S and Beles P/S. The total generation capacity is about 3800MW.

Figure 2.1

CHAPTER THREE

Transmission Lines Models and System Elimination

3.1. Introduction:

In overhead lines the conductors are suspended down the tower by insulators, the number and size of which are determined by the voltage rating of the line. A very important problem in the design and operation of a power system is the maintenance of the voltage within specified limits at various points along system [12]. All transmission lines in a power system exhibit the electrical properties of resistance, inductance, and capacitance. The inductance and capacitance are due to effects of magnetic and electric fields around the conductor. The shunt conductance accounts for leakage currents flowing across insulators and ionized pathways in the air [12].

Transmission lines are represented by an equivalent model with appropriate circuit parameters on a per phase base. The terminal voltages and currents are expressed in per phase values, thus the three phase system is reduced to an equivalent single phase system [12].

3.2. Type of Line Model:

The general equations relating voltage and current on a transmission line recognize the fact that all four of the parameters of a transmission line are uniformly distributed along the line. If an overhead line is classified as short, shunt capacitance is so small that it can be omitted entirely with little loss of accuracy, and we need to consider only the series resistance R and the series inductance L for the total length of the line [12].

A medium length line can be represented sufficiently well by R and L as lumped parameters, with half the capacitance to neutral of the line lumped at each end of the equivalent circuit. Shunt conductance G is usually neglected in overhead power transmission lines when calculating voltage and current [12].

Normally, transmission lines are operated with balanced three phase loads. Although the lines are not spaced equilaterally and not transposed, the resulting dissymmetry is slight and the phases are considered to be balanced. [12]

3.2.1. Short Line Model:

Capacitance may often be ignored without much error if the lines are less than about 80km (50 miles) long. The short line model is obtained by multiplying the series impedance per unit length by the line length [9].

$$Z = (r + j\omega L)\ell \tag{3.1}$$

Where: $r\ and\ L$: are the per-phase resistance and inductance per km.

ℓ : is the line length

3.2.2. Medium Line Model:

As the length of line increases, the line charging current becomes appreciable and the shunt capacitance must be considered. Lines above 80 km and below 250 km in length are termed as medium length line. For medium length lines, half of the shunt capacitance may be considered to be lumped at each end of the line [9]. Z is the total series impedance of the line and Y is the total shunt admittance of the line

$$Z = (r + j\omega L)\ell \tag{3.2}$$

$$Y = (g + j\omega C)\ell \tag{3.3}$$

Where: $g\ and\ C$: is the line to neutral capacitance per km.

ℓ : is the line length

Under normal conditions, the shunt conductance per unit length, which represents the leakage current over the insulators and due to corona, is negligible and g is assumed to be zero.

3.2.3. Long Line Model:

For the short and medium length lines reasonably accurate models were obtained by assuming the line parameters to be lumped. For lines 250 km and longer and for more accurate solution the exact effect of the distributed parameters must be considered [9].

$$Z' = Zc\ \frac{\sinh \gamma\ell}{\gamma\ell} \tag{3.4}$$

$$\frac{Y'}{2} = \frac{1}{Zc}\ \tanh\frac{\gamma\ell}{2} \tag{3.5}$$

$$\gamma = \sqrt{z * y} = \sqrt{(r + j\omega L) * (g + j\omega C)} \tag{3.6}$$

$$Zc = \sqrt{\frac{z}{y}} = \sqrt{\frac{(r+j\omega L)}{(g+j\omega C)}} \tag{3.7}$$

Where:

γ : Known as the propagation constant

Zc : Known as the characteristic impedance

3.3. Transmission Lines Equivalent Data:

The line parameters presented in preceding sections were derived on a per phase basis and where obtained per meter or mile of the line, The row data which given in table 2.3 in chapter two needs to recalculate the equivalent impedance between substations in Sudan and Ethiopia areas by multiply these parameters by the actual line length in order to obtain the total parameter values for the line.

3.3.1. Sudan Transmission Lines Equivalent Data:

In Sudan lines data all impedance of the transmission lines was given by (Ω/Km) while the capacitance was given by (nf/Km), Equation (3.8) to recalculate the equivalent impedance and Equation (3.9) to recalculate the equivalent capacitance for all lines in Sudan. Table 3.1 illustrates the equivalent data in Sudan area.

$$X_L = \frac{x_L * L}{n} \tag{3.8}$$

Where: L is the length of the line, x_L is the line impedance per Km.

n is the number of lines which connected between two substations.

$$X_c = \left(\frac{2*\pi*f*C*L}{10^9}\right) * n \quad (3.9)$$

Where: f is the frequency, L is the length of the line, C is the line to neutral capacitance per Km, n is the number of lines which connected between two substations.

3.3.2. Ethiopia Transmission Lines Equivalent Data:

In Ethiopia lines data all inductance of the transmission lines was given by (Ω) while the capacitance was given by (µf), Equation (3.10) to recalculate the equivalent impedance and Equation (3.11) to recalculate the equivalent capacitance for all lines in Ethiopia. Table 3.2 illustrates the equivalent data in Ethiopia area.

$$X_L = \frac{x_L}{n} \quad (3.10)$$

Where: L is the length of the line.

n is the number of lines which connected between two substations.

$$X_c = \left(\frac{2*\pi*f*C}{10^6}\right) * n \quad (3.11)$$

Where: f is the frequency, L is the length of the line, l is the inductance per Km, C is the line to neutral capacitance per Km, **n** is the number of lines which connected between two substations.

3.4. Convert to Per Unit System:

The solution of an interconnected power system having several different voltage levels requires the cumbersome transformation of all impedances to a single voltage level. In this system the different voltage levels disappear, and a power network involving generators, transformers, and lines (of different voltage levels) reduces to a system of simple impedances. The base power is 1000Mw and the base voltage is 525Kv.

$$\frac{Base\ voltage_{low\ side}}{Base\ voltage_{high\ side}} = \frac{Rated\ voltage_{low\ side}}{Rated\ voltage_{high\ side}} \tag{3.12}$$

The base voltage at 230Kv will be:

$$Base\ voltage_{low\ side} = \frac{525*230}{500} = 241.5kv$$

The base voltage at 110Kv will be:

$$Base\ voltage_{low\ side} = \frac{241.5*110}{230} = 115.5kv$$

The base voltage at 400Kv will be:

$$Base\ voltage_{high\ side} = \frac{241.5*400}{230} = 420kv$$

Then calculate base impedance by:

$$Z_B = \frac{V_B^2}{S_B} \tag{3.13}$$

$$Z_{B(500kv)} = \frac{(525)^2}{1000} = 275.625$$

$$Y_{B(500kv)} = \frac{1}{Z_B} = 0.0036$$

$$Z_B = \frac{(241.5)^2}{1000} = 58.32$$

$$Y_{B(220kv)} = \frac{1}{Z_B} = 0.0171$$

$$Z_B = \frac{(115.5)^2}{1000} = 13.34$$

$$Y_{B(110kv)} = \frac{1}{Z_B} = 0.7496$$

$$Z_B = \frac{(420)^2}{1000} = 176.4$$

$$Y_{B(110kv)} = \frac{1}{Z_B} = 0.0057$$

$$Z_{P.U} = \frac{Z_{Actual}}{Z_B} \tag{3.14}$$

$$Y_{P.U} = \frac{Y_{Actual}}{Y_B} \tag{3.15}$$

Table 3.3 and 3.4 illustrate the equivalent data in per unit system in Sudan and Ethiopia network.

Table 3.1 Sudan Transmission Lines Equivalent Data

No.	Substations	R	X	Y/2
1	MWP-MRK	4.844	47.748	0.002842779
2	MWP-ATB	6.636	65.412	0.000486805
3	MRK-KBA	1.008	9.936	7.39451E-05
4	MRK-GAM	1.273	5.738	0.000155832
5	MRK-MHD	0.7035	3.171	8.61176E-05
6	GAM-JAS	1.273	5.738	0.000155832
7	JAS-GAD	1.2395	5.587	0.000151731
8	GAD-KLX	1.634	8.6645	0.000121788
9	KHN-IBAB	0.402	1.614	4.92101E-05
10	KLX-IBAB	0.469	2.114	5.74118E-05
11	IBAB-KBA	1.005	4.53	0.000123025
12	IBAB-GAR	2.01	9.06	0.00024605
13	KAB-FRZ	0.871	3.926	0.000106622
14	GAR-FRZ	0.1675	0.755	2.05042E-05
15	FRZ-SHN	3.8525	17.365	0.000471597
16	SHN-ATB	4.69	21.14	0.000574118
17	JAS-MSH	4.958	22.348	0.000606924
18	MSH-RBK	3.5845	16.157	0.00043879
19	RBK-RNK	5.4605	24.613	0.000668437
20	RNK-ROS	5.7955	26.123	0.000709445
21	ROS-SNG	6.764	35.867	0.000504146
22	SNG-HWT	3.015	13.59	0.000369076
23	HWT-GDF	3.685	16.61	0.000451092
24	SNG-SNJ	1.9	10.075	0.000141614
25	SNJ-MAR	3.192	16.926	0.000237912
26	MAR-NHS	2.2914	12.15045	0.000170786
27	NHS-GIAD	3.0666	16.26105	0.000228565
28	GDF-SHEHIDE	6.499	29.294	0.000795563

Table 3.2 Ethiopia Transmission Lines Equivalent Data

No.	Substations	R	X	Y/2
29	GONDAR-SHEHIDE	8.411099	53.3761	0.00018347
30	BLS-BDR2	1.784	12.728	0.000188317
31	BDR2-DMK	10.976	78.32	0.00028888
32	DMK-SLU	12.624	90.064	0.00033284
33	G-GIBE-1 - G-GIBE -2	2.464	15.216	0.00007536
34	G-GIBE-2 -SEBETA-2	11.248	70.3264	0.00035325
35	FINCHA - FINCHAA 2	5.19478	37.63835	0.000131739
36	FINCHA-GHEDO	3.35915	20.07555	0.000252424
37	AMRTNESHI-FINCHAA-2	3.66068	12.40505	7.0862E-05
38	FINCHA -DBMRKOS	5.19478	37.63835	0.000131739
39	GHEDO-GEFERSA	4.8139	28.6718	0.000361442
40	GHEDO-GGIBE-1	8.411099	53.3761	0.00018347
41	GEFERSA-SEBATA	0.77763	4.92499	1.69384E-05
42	GEFERSA-SULULTA	0.96807	6.12582	8.49097E-05
43	SEBATA-KALITI1	0.90459	5.75023	1.97537E-05
44	SEBATA-WOLKITE	8.68089	54.55577	0.000189016
45	SEBATA-SEBETA-2	0.642735	4.08388	5.65875E-05
46	KALITI1-KOKA	2.361985	13.09011	0.000180967
47	KALITI1- LEGETOFA	1.372755	4.652555	0.000106298
48	KOKA-M-WAKNA	6.53844	32.9858	0.000448317
49	KOKA-D.DAWA3	12.1141	67.06395	0.00093036
50	D.DAWA3-ADIGALA	5.488375	18.60758	0.000425153
51	DB-MRKOS-MOTA	5.45928	38.82331	0.000135895
52	N.MEW TP - B-DAR-2	12.4844	42.28297	0.000241607
53	B.DAR-2 - GONDAR-2	13.13507	45.01261	0.00025147
54	GASHE-TA - N.MEW TP	9.363298	31.71355	0.000181203
55	ALAMATA-MEKELE	6.451155	21.86357	0.000499558
56	ALAMATA-COMBOL	7.7234	26.16434	0.000597995
57	ALAMATA-GASHE-TA	9.363298	31.71355	0.000181203
58	MEKELE-TEKEZE	4.665781	15.89381	0.000359629
59	TEKEZE-ENDASILA	8.86075	29.9705	0.00068504
60	LEGET - COMBOL	13.45247	45.56806	0.001041532
61	COMBOL-SEMERA	15.55789	52.69898	0.000301123
62	GONDAR-2 -HUMERA	14.29094	48.40615	0.001106376
63	G-GIBE-1 - WOLKITA	6.4009	21.69958	0.000123954
64	MOTA - B-DAR-2	4.62346	32.87735	0.000115093
65	HUMERA-ENDASILA	9.598705	32.51763	0.000743271

Table 3.3 Sudan Lines Data in Per Unit System

PER UNIT				
No.	**Substations**	**R**	**X**	**Y/2**
1	MWP-MRK	0.017575	0.173235	0.789661
2	MWP-ATB	0.024076	0.237322	0.135224
3	MRK-KBA	0.003657	0.036049	0.02054
4	MRK-GAM	0.021827	0.098385	0.009113
5	MRK-MHD	0.012062	0.054371	0.005036
6	GAM-JAS	0.021827	0.098385	0.009113
7	JAS-GAD	0.021253	0.095796	0.008873
8	GAD-KLX	0.028017	0.148563	0.007122
9	KHN-IBAB	0.030135	0.12099	0.000656
10	KLX-IBAB	0.008042	0.036247	0.003357
11	IBAB-KBA	0.017232	0.077672	0.007194
12	IBAB-GAR	0.034464	0.155344	0.014389
13	KAB-FRZ	0.014934	0.067316	0.006235
14	GAR-FRZ	0.002872	0.012945	0.001199
15	FRZ-SHN	0.066056	0.297744	0.027579
16	SHN-ATB	0.080416	0.36247	0.033574
17	JAS-MSH	0.085011	0.383183	0.035493
18	MSH-RBK	0.061461	0.277031	0.02566
19	RBK-RNK	0.093627	0.422019	0.03909
20	RNK-ROS	0.099371	0.44791	0.041488
21	ROS-SNG	0.115977	0.614982	0.029482
22	SNG-HWT	0.051696	0.233017	0.021583
23	HWT-GDF	0.063184	0.284798	0.02638
24	SNG-SNJ	0.032578	0.172748	0.008282
25	SNJ-MAR	0.054731	0.290216	0.013913
26	MAR-NHS	0.039289	0.208334	0.009988
27	NHS-GIAD	0.052581	0.278815	0.013366
28	GDF-SHEHIDE	0.111433	0.50228	0.046524

Table 3.4 Ethiopia Lines Data in Per Unit System

PER UNIT				
No.	**Substations**	**R**	**X**	**Y/2**
29	GONDAR-SHEHIDE	0.144218	0.915197	0.010729
30	BLS-BDR2	0.010113	0.072154	0.033038
31	BDR2-DMK	0.062222	0.443991	0.050681
32	DMK-SLU	0.071565	0.510567	0.058393
33	G-GIBE-1 - G-GIBE -2	0.013968	0.086259	0.013221
34	G-GIBE-2 -SEBETA-2	0.063764	0.398676	0.061974
35	FINCHA - FINCHAA 2	0.089071	0.645354	0.007704
36	FINCHA-GHEDO	0.057597	0.344219	0.014762
37	AMRTNESHI-FINCHAA-2	0.062767	0.212699	0.004144
38	FINCHA -DBMRKOS	0.089071	0.645354	0.007704
39	GHEDO-GEFERSA	0.08254	0.491612	0.021137
40	GHEDO-GGIBE-1	0.144218	0.915197	0.010729
41	GEFERSA-SEBATA	0.013333	0.084445	0.000991
42	GEFERSA-SULULTA	0.016599	0.105034	0.004965
43	SEBATA-KALITI1	0.01551	0.098595	0.001155
44	SEBATA-WOLKITE	0.148844	0.935424	0.011054
45	SEBATA-SEBETA-2	0.01102	0.070023	0.003309
46	KALITI1-KOKA	0.040499	0.224445	0.010583
47	KALITI1- LEGETOFA	0.023538	0.079774	0.006216
48	KOKA-M-WAKNA	0.112109	0.565581	0.026217
49	KOKA-D.DAWA3	0.207711	1.149891	0.054407
50	D.DAWA3-ADIGALA	0.094105	0.319049	0.024863
51	DB-MRKOS-MOTA	0.093606	0.665672	0.007947
52	N.MEW TP - B-DAR-2	0.21406	0.724992	0.014129
53	B.DAR-2 - GONDAR-2	0.225216	0.771795	0.014706
54	GASHE-TA - N.MEW TP	0.160545	0.543767	0.010597
55	ALAMATA-MEKELE	0.110613	0.374877	0.029214
56	ALAMATA-COMBOL	0.132427	0.448619	0.03497
57	ALAMATA-GASHE-TA	0.160545	0.543767	0.010597
58	MEKELE-TEKEZE	0.08	0.272518	0.021031
59	TEKEZE-ENDASILA	0.151928	0.51388	0.040061
60	LEGET - COMBOL	0.048807	0.165326	0.289315
61	COMBOL-SEMERA	0.266759	0.903587	0.01761
62	GONDAR-2 -HUMERA	0.245035	0.829981	0.0647
63	G-GIBE-1 - WOLKITA	0.109751	0.372065	0.007249
64	MOTA - B-DAR-2	0.079275	0.563721	0.006731
65	HUMERA-ENDASILA	0.164581	0.557553	0.043466

3.5. Y Bus Calculate:

In studies of power systems the networks being solved are geographically extensive and often encompass many hundreds of substations, generating plants and load centers. Network equations can be formatted systematically in a verity of forms. However, the node voltage method, which is the most suitable form for many power system analyses, is commonly used. The formulation of the network equations in the nodal admittance form results in complex linear simultaneous algebraic equations in terms of node currents. When node currents are specified, the set of linear equations can be solved for the node voltages. The nodal solution is based upon Kirchhoff's current law. The Y_{bus} matrices of these large networks of thousands of nodes have associated systems of nodal equations to be solved for a correspondingly large number of unknown bus voltages. For such solutions computer based numerical techniques are required to avoid direct matrix inversion, thereby minimizing computational effort and computer storage [11].

In both networks there are step downs transformers which affect on the network impedance, for that its need to add it in Y_{bus} matrix to illustrate the real equivalent impedance of both networks table 3.5 illustrates the impedance of transformers in Sudan and Ethiopia networks. Table 3.6 illustrates Y_{bus} matrices for Sudan and Ethiopia network after calculate the admittance of all lines and transformer.

Table 3.5 Sudan and Ethiopia inter bus transformers impedance

No.	Substations	R	X
1	MRK TR	0	0.060333
2	KBA TR	0	0.0905
3	ATB TR	0	0.0905
4	IBA TR	0	0.031033
5	GILGLBE TR	0	0.0905
6	SEBETA TR	0	0.0905
7	BAHDAR TR	0	0.060333
8	SULUTA TR	0	0.0905
9	DE MARKOS TR	0	0.0905

Y BUS

Table 3.5 Ybus of the System

3.6. Network Elimination:

There are many methods for network elimination, called *Gaussian elimination* and *Korn* reduction, Nodes may be eliminated by matrix manipulation of the standard node equations. However, only these nodes which current does not enter or leave the network can be eliminated [12].

The standard node equations in matrix notation are expressed as:

$$I = Y_{bus} V \tag{3.16}$$

Where: I and V are column matrices and Y_{bus} is a symmetrical square matrix.

The column matrices must be so arranged that elements associated with nodes to be eliminated are in the lower rows of the matrices. Elements of the square admittance matrix are located correspondingly. The columns matrices are partitioned so that the elements associated with nodes to be eliminated are separated from the other elements identified only with nodes to be eliminated are separated from the other elements by horizontal and vertical lines. When partitioned according to these rules the equation (4.1) becomes

$$\begin{bmatrix} I_A \\ I_X \end{bmatrix} = \begin{bmatrix} K & L \\ L^T & M \end{bmatrix} \begin{bmatrix} V_A \\ V_X \end{bmatrix} \tag{3.17}$$

Where I_X the sub matrix is composed of the currents entering the nodes to be eliminated and V_X is the sub matrix composed of the voltages of these nodes. Every elements in I_X is zero, for the nodes could not be eliminated otherwise the self and mutual admittances composing K are those identified only with nodes to be retained. M is composed of the self and mutual admittances identified only with nodes to be eliminated. It is a square matrix whose order is equal to the number of nodes to be eliminated. L and its transpose L^T are composed of only those mutual admittances common to a node to be retained and to one to be eliminated [12].

Performing the multiplication indicated in equation (4.2) gives

$$I_A = KV_A + LV_X \tag{3.18}$$

And

$$I_X = L^T V_A + MV_X \tag{3.19}$$

Since all elements of I_X are zero, subtracting $L^T V_A$ from both sides of eq. (3.19) and multiplying both sides by the inverse of M (denoted by M^{-1}) yields

$$V_X = -M^{-1} L^T V_A \tag{3.20}$$

This expression for substituted in eq. (3.20) gives

$$I_A = KV_A - LM^{-1} L^T V_A \tag{3.21}$$

Which is a node equation having the admittance matrix

$$Y_{elem.} = K - LM^{-1} L^T \tag{3.22}$$

This admittance matrix enables us to construct the circuit with unwanted nodes eliminated. For Sudan and Ethiopia the matrix (*K)* illustrated in table 3.6, mutual admittances *(L)* illustrated in table 3.7 and its transpose (L^T) illustrated in table 3.8, the self and mutual admittances (*M*) illustrated in table 3.9 and the network after eliminate unwanted node will be 36 row with 36 column as shown in table 3.10.

K

Matrix

LT
Matrix

L

Matrix

M

Matrix

Y

Eliminated

CHAPTER FOUR

Tie Line Power Flow Control

4.1. Introduction:

An electric energy system must be maintained at a desired operating level characterized by nominal frequency, voltage profile, and load flow configuration. It is kept in this nominal state by close control of the real and reactive powers generated in the controllable sources of the system. The total real and reactive power demands PD and QD will slowly change throughout the 24 hours of the day, but during time periods measured in seconds or minutes, they can be considered as essentially constants with superimposed first-order perturbations ΔPD and ΔQD. The perturbations in generated power ΔPG and ΔQG must match the load perturbations if exact nominal state is to be maintained. However, due to the statistical nature of the load fluctuations, this can never be achieved-the best we can hope for is to keep the system within sufficiently small tolerance levels. A mismatch in the real power balance it is more important than mismatch in the reactive power because it is affects primarily the system frequency (f), but leaves the bus voltage magnitudes essentially unaffected [6].

With primary speed control action a change in system load will result in a steady state frequency deviation, depending on the governor droop characteristic and frequency sensitivity of the load. All generating units on speed governing will contribute to the overall change in generation, irrespective of the location of the load change. Restoration of system frequency to nominal value requires supplementary control action which adjusts the load reference set point. Therefore, the basic means of controlling prime mover power to match variations in system load in a desired manner is through control of the load reference set point of selected generating units. As system load is continually changing, it is necessary to

change the output of generators automatically which called automatic generation control [6].

4.2. Fundamentals of Automatic Generation Control:

The methods developed for control of individual generators and eventually control of large interconnections play a vital role in modern energy control centers. The supplementary control adjusts the load reference set point by take the actual value of frequency and the power in tie line and calculation the error between the schedule value and actual value then its send the deviation in power whatever in tie line or in the frequency and compensate this deviation of power by correction the position of turbine valve. This deviation encoded in the bits of a digital word that is transmitted over a digital telemetry channel [5]. Figure 5.1 illustrate basic control loop between the plant and control center.

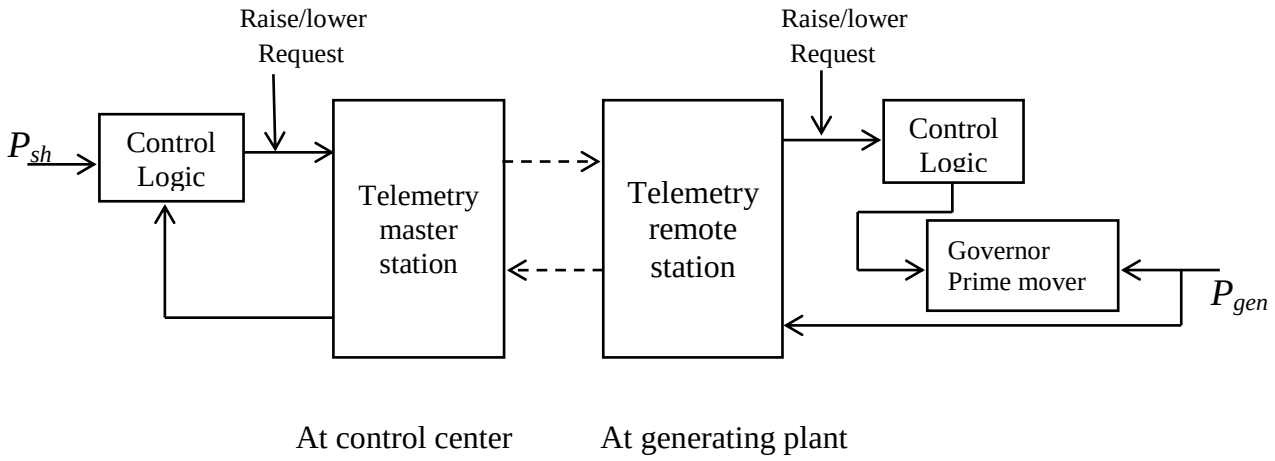

Figure 4.1 basic generation control loop via telemetry

The primary objectives of automatic generation control are to regulate frequency to the specified nominal value and to maintain the interchange power between control areas at the schedules values and to maintain the interchange power generators. A secondary objective is to distribute the required change in generation

among units to minimize operating costs [7]. AGC has three criterions to know that ACG design is good or not: area control error (ACE) is directly influenced by random load variations; this criterion can be treated statistically by saying that the standard deviation of area control error (ACE) should be small. Area control error (ACE) should not be allowed to drift this means that the integral of area control error (ACE) over an appropriate time should be small. Drift in area control error (ACE) has the effect of creating system time errors or what are termed inadvertent interchange errors. The amount of control action called for by AGC should be kept to a minimum [7].

4.3. Area Control Error (ACE):

ACE it measures the deviation between the total generations in specific area from the desired generation whatever raised or lowered the power in that area or in the tie line [7]. Since the tie-line power error integral of the frequency difference between each pair of areas, if the frequency error controlled back to zero, any steady state errors in the frequency of the system would result in tie-line power errors. Therefore tie-line power deviation must be including into the control input [7].

Also the AGC control logic must also be driven by the errors in unit output so as to force the units to obey the economic dispatch. To do this, the sum of the unit output errors is added to ACE to form a composite error signal that drives the entire control system [7]. Figure 5.2 shows all input for area control error and the method to calculate the value of it.

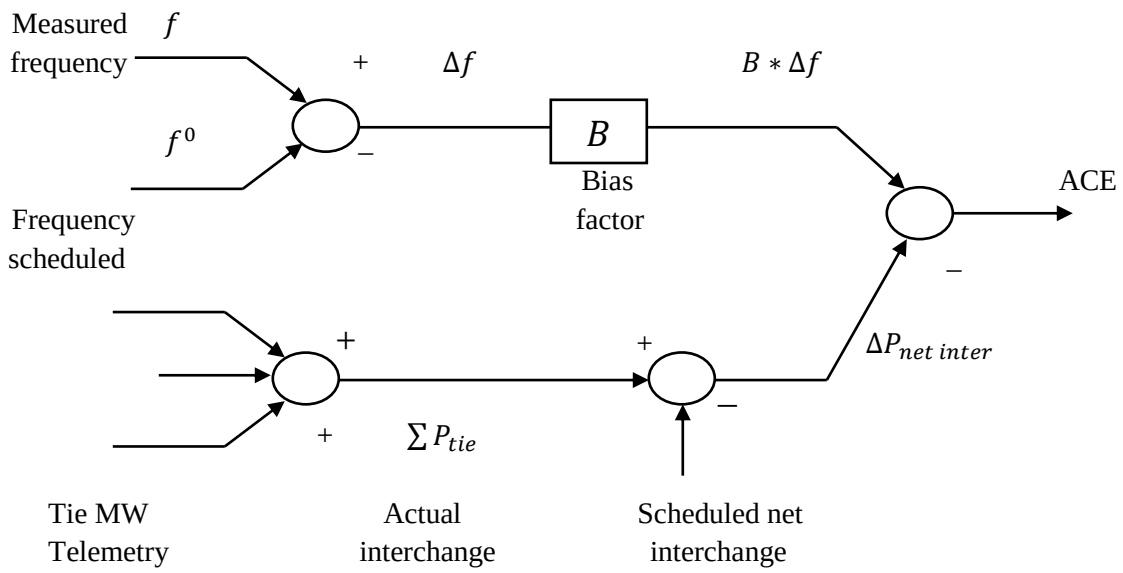

Figure 4.2 ACE calculation

4.4. Frequency Bias Setting:

Frequency Bias Setting is used to convert frequency error [Hz] to a power error [MW]. The units of Frequency Bias Setting may be either [MW/Hz] or [MW/0.1 Hz]. Provisions are made for both entry of Frequency Bias Setting and its calculation. A configuration parameter is provided to select whether the entered or calculated value should be used. The area frequency response characteristic required for establishing the bias factors can be estimated by examination of chart records following a significant disturbance such as a sudden loss of a large unit [5].

4.5. Controller of the Automatic Generation Control:

Many theories was used to find the best controller for the automatic generation control (AGC), in the sense of minimizing the error was defined as the tie line power deviation from scheduled value and the frequency deviation. The controller generalizes the discrepancy between the mathematical model and the real system as a disturbance, and some of these controller: Proportional-integral control (PI),

proportional integral derivative controller (PID), Fuzzy logic control, Neuro Fuzzy, Genetic algorithm (GA), particle swarm optimization (PSO) and active disturbance rejection control [9].

4.5.1. Exciting AGC Control In Sudan Grid:

Is a generic control loop feedback mechanism (controller) widely used in industrial control systems a PID is the most commonly used feedback controller. A PID controller calculates an "error" value as the difference between a measured process variable and a desired set point. The controller attempts to minimize the error by adjusting the process control inputs. The PID controller calculation (algorithm) involves three separate constant parameters, and is accordingly sometimes called three-term control: the proportional, the integral and derivative values, denoted P, I, and D. Heuristically, these values can be interpreted in terms of time: P depends on the present error, I on the accumulation of past errors, and D is a prediction of future errors, based on current rate of change.[9] The weighted sum of these three actions is used to adjust the process via a control element such as the position of a control valve, or the power supplied to a heating element.

National load dispatch center in Sudan was using (PID) controller which was installed by NARI Company, PID controllers can be tuned by using many methods. In all methods an initial guess is made for PID controller parameter settings. Then these parameter settings are improved by fine tuning of the controller. Now a day various simulations software is widely used for this purpose of parameter settings.

PID controller is a powerful controller for improving transient and steady state responses. The goal of AGC is also to maintain zero steady state errors and to maintain transient stability in the system [9].

4.6. Tie Line Power Flow Control:

During the actual situation the slack bus must hold the frequency with in the acceptable limit in all networks and hold interchange power flow within the agreement. The Automatic Generation Control has three modes to work on it: A) just control the frequency. B) Just control tie line power flow. C) Control the frequency and tie line power control at the same time.

Sudan side select the fist mode to control the frequency in both areas which is accounted Merowe power station as a slack bus to control the frequency and Ethiopia side control the tie line power flow by joint control from Beles power station. To know if this mode of control are acceptable for both networks or not, it must be limited the frequency deviation with the acceptable range and hold the tie line power flow within the agreement value which appear in area control error.

The frequency is a very important factors in the network control which reflects the balance between supplier and demand in both networks. For this case average frequency deviation was taken every 1min for 16 hour (960 samples), Figure 4.3 illustrates the deviation of frequency at 27.July.2013 from the nominal value which is 50 HZ the most deviation value is (- 0.15 HZ) and the margin of frequency operation as Sudan grid code is ± 0.5 HZ that mean the system was operate within the acceptable limit.

The tie line power deviation from schedule value will reflects on the area control error. For this case area control error for both network which was taken every 1min for 16 hour (960 samples), Figure 4.4 illustrates the area control error at 27.July.2013, the most calculated value is (- 19.9 MW), the schedule interchange value in the agreement between two areas is (100 MW) and the area control error in Sudan grid code is ± 25 MW that mean the system was operate within the acceptable limit.

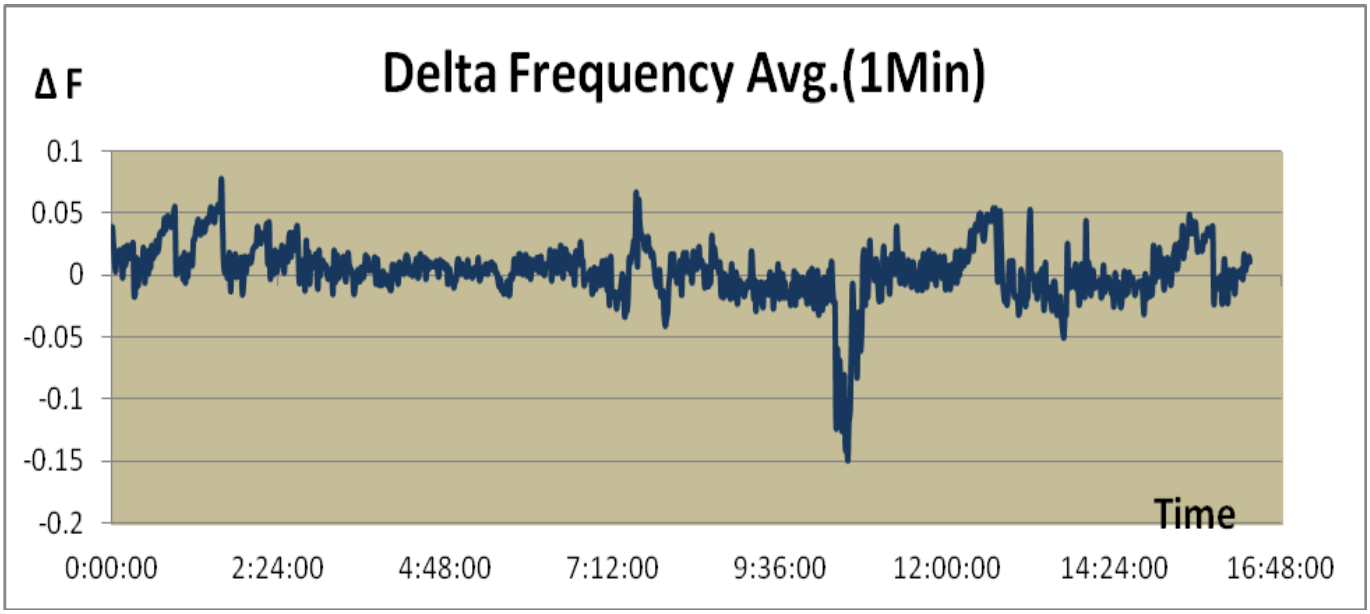

Fig 4.3 Frequency Deviation of the System

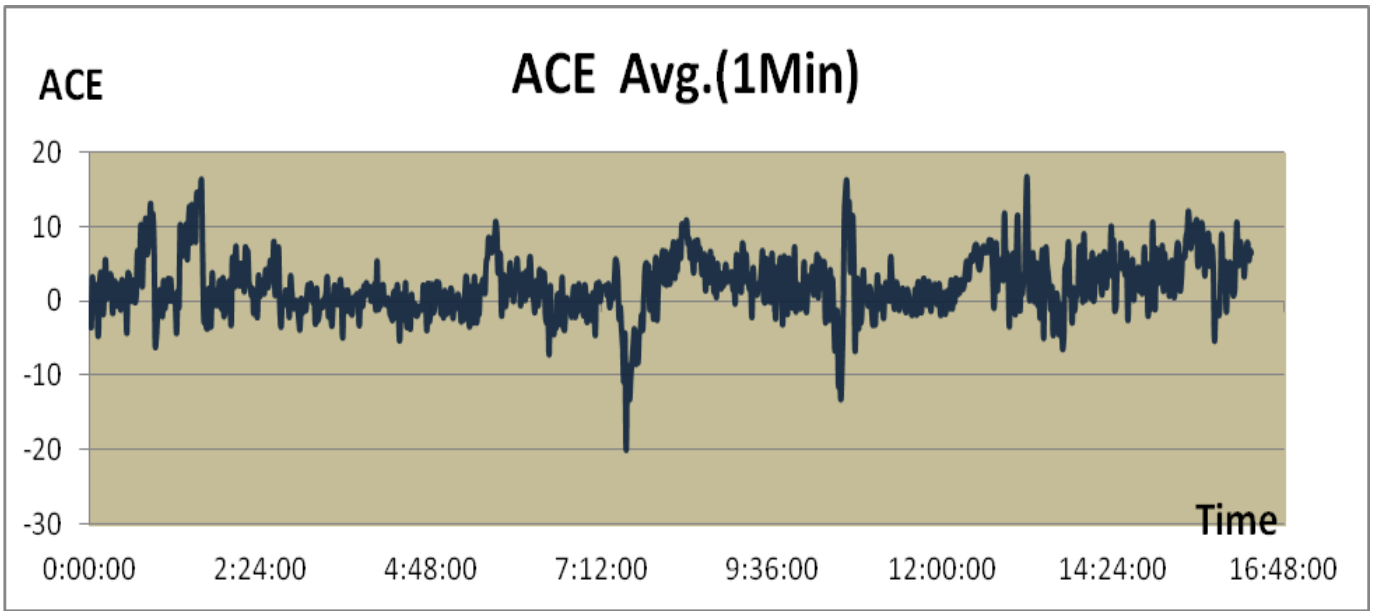

Fig 4.4 Area Control Error for Sudan Area

CHAPTER FIVE

Inter Area Oscillation and Tie Line Evaluation

5.1. Introduction:

Small signal stability is the ability of the power system to maintain synchronism under small disturbance. Such disturbance occurs continually on the system because of small variations in load and generation. Instability that may result can be of two forms the first one is Steady increase in rotor angle due to lack of sufficient synchronizing torque [13]. Rotor oscillations of increasing amplitude due to lack of sufficient damping torque. It is largely problem of insufficient damping of oscillations. The stability of the following types of oscillations is of concern:

- Local modes: Machine system modes are associated with the swinging of units at a generating station with respect to the rest of the power system. The oscillation are localized at one station or a small part of the power system. Oscillations occurred only to the small part of the power system. Typically, the frequency range is 1-2 Hz.
- Control modes: Are associated with generating units and other controls. Poorly tuned exciters, speed governors, HVDC converters and static VAR compensators are the usually causes of instability of these mode.
- Torsional modes: Are associated with the turbine generator shaft system rotational components. Instability of torsional modes may be caused by interaction with excitation controls, speed governors, HVDC controls, and series capacitor compensated lines.
- Inter-area modes: Are associated with the swinging of many machines in one part of the system against machines in other parts. They are caused by two or more group of closely coupled machines being interconnected by weak ties.

It generally occurs in weak interconnected power systems through long tie lines. Typically frequency range is 0.1-1 Hz.

5.2. Dynamic System Model

When the system deviates from the constant nominal frequency, every bus voltage will experience its own angular velocity or frequency. The assumption made means that all generators belonging to an area will swing in unison. Should this assumption not be permissible (and one must be careful in the case of an individual area covering a wide territory), then one must subdivide the area into subareas. The theory that follows will still apply. The net power surplus in the area following a disturbance ΔP_D equals $\Delta P_G - \Delta P_D$ MW, and this power will be absorbed by the system in three ways:

1) by increasing the area kinetic energy W_{kin}. at the rate

$$\frac{d}{dt} W_{kin} = \frac{d}{dt}\left[W_{kin} * \left(\frac{f}{f^*}\right)^2\right] \tag{5.1}$$

$$\triangleq \frac{d}{dt}\left[W_{kin} * \left(1 + 2\frac{\Delta f}{f^*}\right)\right] \tag{5.2}$$

$$= 2\frac{{W_{kin}}^*}{f^*}\frac{d}{dt}(\Delta f) \tag{5.3}$$

2) by an increased load consumption: All typical loads (because of the dominance of motor load) experience an increase $D \triangleq \frac{\partial P_D}{\partial f}$ MW/Hz with speed or frequency. This D parameter can be found empirically;

3) by increasing the export of power, via tie lines, with the total amount ΔP_{tie} MW defined positive out from the area. In summary, the following power equilibrium equation applies to area i:

$$\Delta P_G - \Delta P_D = (2\frac{{W_{kin}}^*}{f^*}\frac{d}{dt}(\Delta f)) + D\Delta f + \Delta P_{tie} \tag{5.4}$$

From the above equation is entirely different from that of maintaining a scheduled power interchange over the tie line, control equipment can be provided to perform this function. These controllers are usually too slow to interfere with the dynamic oscillations mentioned above [14]. To alter these oscillations, the dynamic response of the components of the overall interconnected system must be considered. Thus the tie line under study may in effect be connecting two huge systems. In this case the smallest oscillatory adjustments in the large systems are reflected as sizable power oscillations in the tie line [15]. The problem is not only in the tie line itself but also in the two systems it connects and in the sensitivity of control in these systems.

5.3. Power Oscillations In Interconnected Systems:

The phenomenon of small signal stability is related to small changes of system quantities such as power and machine angles. The free response of -machine power system is derived from the linearized version of the well-known swing equation of motion of an ideal unregulated machine [16]. The small signal stability of large power systems is characterized by a number of complex Eigen values for each oscillating mode. Each mode is associated with a single Eigen frequency and a damping factor. Successful damping of power oscillations indicates a stable system that is able to return to an acceptable steady-state situation after being exposed to a disturbance. A damping factor of 3%–5% is accepted as reasonable for damping of inter area modes [14].

Inter area power oscillations are dependent on the power system response to small disturbances such as change in scheduled generation or small increase in system load after the system has been perturbed from a steady-state condition [14]. In general, electromechanical oscillations in interconnected power systems are manifested by an exchange in mechanical kinetic energy between groups of generators as electric power flows through the transmission system. Analysis of inter area oscillations in large interconnected power systems requires

comprehensive offline studies, such as Eigen value analysis and dynamic simulations using a detailed model of the entire system, including a wide range of nonlinear devices.

Most widely used methodology for low frequency oscillation study, Eigen value analysis is presented in details in the methodology section. Measures for oscillation damping can be classified in two broad categories:

a) Oscillation damping at operational level:

Approaches for power system oscillation damping include re-tuning excitation control system and PSS. Re-dispatching of generators and adjusting of load changers can also be considered. At the operational level, load shedding can also be used as the last line of defense to damp low frequency of oscillation [14].

b) Oscillation damping at planning level:

At planning stage a number of damping controllers can be considered for implementation. New PSS, FACTS controllers, Superconducting Magnetic Energy Storage (SMES) and fly wheel are some of them [14].

In general, computation of Eigen values in large power systems is a complex task, since it involves a systematic procedure for simultaneous solution of differential equations representing synchronous machines with associated prime movers, excitation systems, and power system stabilizers (PSS), extensive transmission networks, load dynamics, power electronic devices (such as HVDC links, SVC).

In general, the dynamics of power oscillations in large systems are related to the power flow in a tie-line where the line reactance is, and are the magnitudes and angles of the voltages at the line terminals. The power oscillations are dependent on the rated system frequency (rad), the inertia constant for machine, and the synchronizing power coefficient, which is related to the change in electrical power in machine due to angle change between machines and, with all other machine angles held constant[17].

5.4. Tie Line Evaluation:

The situation in a tie line is different in one sense since it connects one group of machines to another. These two groups are in continuous oscillation with respect to each other, and this is reflected in the power flow over the tie line. The electrical strength (admittance) or capacity of the tie cannot be divorced from this problem. For example, a 40 MW oscillation on a 400 MW tie is a much less serious problem than the same oscillation on a 100 MW tie. The oscillation frequency has an effect on the damping characteristics of prime movers, exciters; therefore, there is a minimum size of tie that can be effectively made for the stability [17].

The situation may be further complicated by the fact that each machine group in turn is connected to other groups. Thus the tie line under study may in effect be connecting two huge systems. In this case the smallest oscillatory adjustments in the large systems are reflected as sizable power oscillations in the tie line. The question then becomes, to what degree these oscillations can be tolerated to say this tie line is week or strong [16]. To answer this question, the detailed information about the tie line, the impedance path of the tie-lines, and the transmission corridors (transmission stiffness between areas) is the key issue for determination tie line stiffness.

The power system in Figure1 shows a two-area model of major generation, load areas connected by a tie-line. In general, the dynamics of power oscillations in large systems is related to the active power flow in a tie-line if the line losses are neglected, the individual line powers can be written in the form as follows:

$$P_{tie\ iv} = \frac{|V_i||V_v|}{X_{iv}P_{ri}}\sin(\delta_i - \delta_v) \tag{5.6}$$

$$\cong P_{tie\ max\ iv} * \sin(\delta_i - \delta_v) \tag{5.7}$$

$$P_{tie\ \max iv} = \frac{|V_i||V_v|}{X_{iv}} \tag{5.8}$$

Where:

V_i V_v are the terminal bus voltages of the line, and X_{iv} its reactance.

The maximum value $P_{tie\,\max iv}$ represents the maximum real power (here expressed in per unit of area power P_{ri}) that can be transmitted via the line. The tie line is termed "weak" if [15]:

$$P_{tie\,\max iv} \ll P_{ri} \tag{5.9}$$

To know the tie line stiffness ranges first its need the voltage between two sides to calculate the maximum power by using load flow solution.

5.5. Power Flow Analysis:

To get buses data for evaluation of the transmission line stiffness it is needed to make a power flow calculations to get bus bar voltage. The method which used in this calculation is Newton-Raphson method. The Newton–Raphson method has a very good convergence rate. The computation time increases only linearly with system size. This method has convergence problems when the initial voltages are significantly different from their true values: it is therefore not suited for a flat voltage start. Once the voltage solution is near the true solution, however the convergence is very rapid. The Newton-Raphson method is therefore particularly suited for applications involving large systems requiring very accurate solutions [4].

To get real load flow case as exact as possible, the initial conditions for the generations and load are based on actual data which illustrated in chapter two, the data was get from generation dispatch and transfers from substation to national load dispatch center, which are captured by a limited amount of Supervisory Control and Data Acquisition System (SCADA). Table 5.1 illustrated the voltage in per unit and active power for regulated bus in Sudan area, Table 5.2 illustrated the voltage in per unit and active power for regulated bus in Ethiopia area, the load for both areas was already illustrated in chapter two and the slack bus for both areas is Beles power station in Ethiopia area to compensate the power in tie line.

Table 5.1 Sudan Generations Voltage in Per Unit and Power

POWER ST.	GENERATION		
	BASE. VOLT.	ACTUAL VOLT.	MW
MWP	525	1.008	806
GAR	241.5	0.932	269
ROS	241.5	0.932	100
KHN	115.5	0.961	186
Summation			1676

Table 5.2 Ethiopia Generations Voltage in Per Unit and Power

POWER ST.	GENERATION		
	BASE. VOLT.	NOM. VOLT.	MW
BELES	420	0.988	380
FINCHAA	241.5	0.952	125
AMRTNESHI	241.5	0.948	115
GLLGELGLBE2	420	0.976	430
MELKAWAKENA	241.5	0.932	123
TEKEZE	241.5	0.944	285
GLLGELGLBE 220kv	241.5	0.952	195
Summation			1653

After load flow calculation the power flow through tie line is 128Mw with voltage magnitude 224.4Kv at GADARIF substation and with 226.3Kv at SHIEDI substation, to know the strength of tie line $P_{tie\,\max iv}$ must be calculated. The voltage at GADARIF substation is $V_i = 224.4\ kv$ and at SHIEDI substation is $V_v = 226.3\ kv$, the reactance of the line is $X_{tie} = 0.302\ \Omega/km$ and total length of the tie line is 194Km then the reactance of the line will be:

$$X_{tie} = 0.302 * 194 = j58.59\Omega \tag{5.10}$$

The maximum value of real power at tie line

$$P_{tie\,\max(3\phi)} = \frac{224.4*226.3}{58.59} = 866.7Mw \quad (5.11)$$

The base power of Sudan area $P_{rSudan} = 1000\ Mw$

When comparison between maximum real power in the tie line and the base of power in Sudan area illustrate that the different between them is not large and that mean the tie line is strong during peaking time with this situation and configuration.

Figure 5.1

CHAPTER SIX

Conclusions and Recommendations

6.1 Conclusions:

This thesis presents tie line control and oscillation between Sudan and Ethiopia network, and demonstrates the importance of tie line monitoring and stability studies analysis for recently developing power systems especially all countries try to connect to each other for more security and reliability. The importance of data availability and accuracy regarding system configuration as well as system physical apparatuses for constructing appropriate computer models has been highlighted.

The tie line power flow was controlled by National load dispatch center and maintains the power as the schedule by using automatic generation control. To detect this operation operates within acceptable limit or not there are two criteria.

The first criteria by detect the frequency deviation from nominal value the deviation was taken for every 1minute for 16hour and monitoring the value of it and comparison with maximum deviation range for national grid code of Sudan.

The second criteria by detect area control error value; the (ACE) value was taken for every 1minute for 16hour and monitoring the value of it and comparison with maximum value of ACE for national grid code of Sudan.

The tie line oscillation is a serious problem especially when the power oscillation will be a measure value from the power transfers. The transmission stiffness between the inertias is the key issue for determination tie line oscillation is a serious problem or not. To know the tie line stiffness ranges first its need the voltage between two sides to calculate the maximum power transfers by using load flow solution.

To simplify the model of networks; ybus was eliminated from 74 buses to 36 buses to simplified network model. The load data has collected from national load dispatch center, and then calculate load flow to determine the voltage of the system

for peak load condition then calculate the maximum power transfers to measure tie line strength range, which appear that the tie line under this condition was strong.

6.2 Recommendations:

This thesis concern on the tie line power flow control and oscillation just during peak time between Sudan and Ethiopia but for safety of both network the study must be done in several condition of load - off peak for day and year- and several networks configuration for both areas to know at any range the tie line will be save for operate and at any time will be weak.

To full control the tie line power facts must be construct and many study must be done to select the suitable size for Sudan and Ethiopia case.

To transfer more power between these two area DC tie line will be a good choice more than AC in many point like reliability and stability which need more study to determine the suitable parameter for these case.

REFERENCES

1. J. Duncan Glover, Mulukutla S. Sarma And Thomas J. Overbye, "Power System Analysis And Design", Global Engineering: Christopher M. Shortt, Stamford, U.S.A, 2008.

2. Vijay k. Sood, "HVDC and FACTS Controllers Applications of Static Converters In Power Systems", Kluwer Academic, Boston, U.S.A, 2004.

3. K. R. Padiyar, "Power system dynamics stability and control", BS Publications, Hyderabad, India, 2008

4. Woodward Governor Company, "Speed Droop and Power Generation", Application Note 01302, 1991.

5. Liu Xin, Nan Jing and Yang Jia , "Design and Implementation of AGC in Gas Ultrasonic Flow meter", Electronic Measurement and Instruments, Vol. No. , 2007, Pages 534.

6. Allen J. Wood and Bruce F. Wollenberg, "Power system operation and control", John Wiley & Sons, New York, U.S.A, 1996.

7. P.Kundur, "Power system stability and control", McGraw-Hill, Inc. New York, U.S.A, 1994.

8. OLLE I. ELGERD and CHARLES E. FOSHA, JR "Optimum Megawatt-Frequency Control of Multi area Electric Energy Systems", IEEE Transactions On Power Apparatus And Systems, Vol. Pas-89, No. 4, April 1970, Page 556.

9. HADI SAADAT, "Power System Analysis", McGraw Hill, Singapore, 2004.

10. Naoto Kakimoto and Katsuyuki Tomiyama, "Monitoring of Inter-area Oscillation Mode by Synchronized Phasor Measurement", IEEE

TRANSACTIONS ON POWER SYSTEMS, VOL. 21, NO. 1, FEBRUARY 2006, Page 260.

11. Abdel Aziz Yousif Mohamed, “Steady State Stability of National Grid for Electricity”, Sudan University of Science and Technology, 2002.

12. William D. Stevenson, Jr. “Elements of Power System Analysis”, McGraw-Hill, New Delhi, 1982.

13. M. Klein, G.J. Rogers and P. Kundur, “ A Fundamental Study of Inter-Area Oscillations in Power Systems”, Transactions on Power Systems, VOL.6, No. 3 August 1991, Page 914.

14. Joana Rasmussen and Preben Jorgensen, “Synchronized Phasor Measurements of a Power System Event in Eastern Denmark”, IEEE TRANSACTIONS ON POWER SYSTEMS, VOL. 21, NO. 1, FEBRUARY 2006, Page 278.

15. OLLE I. ELGERD, “Electric Energy Systems Theory: An introduction”, McGraw-Hill, New Delihi, 1978.

16. CHARLES E. FOSHA, JR. and OLLE I. ELGERD, “The Megawatt-Frequency Control Problem: A New Approach via Optimal Control Theory”, IEEE Transactions On Power Apparatus And Systems, Vol. Pas-89, No. 4, Page 564.

17. P. M. Anderson and A. A. Fouad, “Power System Control and Stability”, the Iowa State University Press, Ames, Iowa, U.S.A., 1977.

APPENDIX (A)

MATLAB Program

```
ns=0; ng=0; Vm=0; delta=0; yload=0; deltad=0;
nbus = length(busdata(:,1));
kb=[];Vm=[];delta=[];Pd=[];Qd=[];Pg=[];Qg=[];Qmin=[];Qmax=[];%Added(6-8-
00)
Pk=[]; P=[]; Qk=[]; Q=[]; S=[]; V=[]; % Added (6-8-00)
for k=1:nbus
n=busdata(k,1);
kb(n)=busdata(k,2); Vm(n)=busdata(k,3); delta(n)=busdata(k, 4);
Pd(n)=busdata(k,5); Qd(n)=busdata(k,6); Pg(n)=busdata(k,7); Qg(n) =
busdata(k,8);
Qmin(n)=busdata(k, 9); Qmax(n)=busdata(k, 10);
Qsh(n)=busdata(k, 11);
    if Vm(n) <= 0  Vm(n) = 1.0; V(n) = 1 + j*0;
    else delta(n) = pi/180*delta(n);
         V(n) = Vm(n)*(cos(delta(n)) + j*sin(delta(n)));
         P(n)=(Pg(n)-Pd(n))/basemva;
         Q(n)=(Qg(n)-Qd(n)+ Qsh(n))/basemva;
         S(n) = P(n) + j*Q(n);
    end
end
for k=1:nbus
if kb(k) == 1, ns = ns+1; else, end
if kb(k) == 2 ng = ng+1; else, end
ngs(k) = ng;
nss(k) = ns;
end
Ym=abs(Ybus); t = angle(Ybus);
m=2*nbus-ng-2*ns;
maxerror = 1; converge=1;
iter = 0;
%%%% added for parallel lines (Aug. 99)
mline=ones(nbr,1);
for k=1:nbr
      for m=k+1:nbr
         if((nl(k)==nl(m)) & (nr(k)==nr(m)));
            mline(m)=2;
         elseif ((nl(k)==nr(m)) & (nr(k)==nl(m)));
         mline(m)=2;
         else, end
      end
   end
%%%   end of statements for parallel lines (Aug. 99)
```

```
 % Start of iterations
clear A  DC   J  DX
while maxerror >= accuracy & iter <= maxiter % Test for max. power
mismatch
for ii=1:m
for k=1:m
   A(ii,k)=0;      %Initializing Jacobian matrix
end, end
iter = iter+1;
for n=1:nbus
nn=n-nss(n);
lm=nbus+n-ngs(n)-nss(n)-ns;
J11=0; J22=0; J33=0; J44=0;
   for ii=1:nbr
    if mline(ii)==1   % Added to include parallel lines (Aug. 99)
        if nl(ii) == n | nr(ii) == n
            if nl(ii) == n ,  l = nr(ii); end
            if nr(ii) == n , l = nl(ii); end
         J11=J11+ Vm(n)*Vm(l)*Ym(n,l)*sin(t(n,l)- delta(n) + delta(l));
         J33=J33+ Vm(n)*Vm(l)*Ym(n,l)*cos(t(n,l)- delta(n) + delta(l));
                if kb(n)~=1
                J22=J22+ Vm(l)*Ym(n,l)*cos(t(n,l)- delta(n) + delta(l));
                J44=J44+ Vm(l)*Ym(n,l)*sin(t(n,l)- delta(n) + delta(l));
                else, end
                if kb(n) ~= 1  & kb(l) ~=1
                    lk = nbus+l-ngs(l)-nss(l)-ns;
                    ll = l -nss(l);
                % off diagonalelements of J1
        A(nn, ll) =-Vm(n)*Vm(l)*Ym(n,l)*sin(t(n,l)- delta(n) + delta(l));
                    if kb(l) == 0  % off diagonal elements of J2
        A(nn, lk) =Vm(n)*Ym(n,l)*cos(t(n,l)- delta(n) + delta(l));
end
                    if kb(n) == 0  % off diagonal elements of J3
        A(lm, ll) =-Vm(n)*Vm(l)*Ym(n,l)*cos(t(n,l)- delta(n)+delta(l));
end
               if kb(n) == 0 & kb(l) == 0  % off diagonal elements of  J4
        A(lm, lk) =-Vm(n)*Ym(n,l)*sin(t(n,l)- delta(n) + delta(l));
end
               else end
            else , end
      else, end
   end
   Pk = Vm(n)^2*Ym(n,n)*cos(t(n,n))+J33;
   Qk = -Vm(n)^2*Ym(n,n)*sin(t(n,n))-J11;
   if kb(n) == 1 P(n)=Pk; Q(n) = Qk; end   % Swing bus P
     if kb(n) == 2  Q(n)=Qk;
         if Qmax(n) ~= 0
           Qgc = Q(n)*basemva + Qd(n) - Qsh(n);
         if iter <= 7                  % Between the 2th & 6th iterations
             if iter > 2                 % the Mvar of generator buses are
            if Qgc  < Qmin(n),       % tested. If not within limits Vm(n)
             Vm(n) = Vm(n) + 0.01;    % is changed in steps of 0.01 pu to
               elseif Qgc  > Qmax(n),   % bring the generator Mvar within
                Vm(n) = Vm(n) - 0.01;end % the specified limits.
              else, end
           else,end
         else,end
```

```
     end
   if kb(n) ~= 1
     A(nn,nn) = J11;  %diagonal elements of J1
     DC(nn) = P(n)-Pk;
   end
   if kb(n) == 0
    A(nn,lm) = 2*Vm(n)*Ym(n,n)*cos(t(n,n))+J22;  %diagonal elements of J2
     A(lm,nn)= J33;        %diagonal elements of J3
 A(lm,lm) =-2*Vm(n)*Ym(n,n)*sin(t(n,n))-J44;  %diagonal of elements of J4
     DC(lm) = Q(n)-Qk;
   end
end
DX=A\DC';
for n=1:nbus
  nn=n-nss(n);
  lm=nbus+n-ngs(n)-nss(n)-ns;
    if kb(n) ~= 1
    delta(n) = delta(n)+DX(nn); end
    if kb(n) == 0
    Vm(n)=Vm(n)+DX(lm); end
 end
  maxerror=max(abs(DC));
     if iter == maxiter & maxerror > accuracy
   fprintf('\nWARNING: Iterative solution did not converged after ')
   fprintf('%g', iter), fprintf(' iterations.\n\n')
 fprintf('Press Enter to terminate the iterations and print the results
\n')
   converge = 0; pause, else, end

end

if converge ~= 1
   tech= ('                      ITERATIVE SOLUTION DID NOT CONVERGE');
else,
   tech=('                 Power Flow Solution by Newton-Raphson Method');
end
V = Vm.*cos(delta)+j*Vm.*sin(delta);
deltad=180/pi*delta;
i=sqrt(-1);
k=0;
for n = 1:nbus
     if kb(n) == 1
     k=k+1;
     S(n)= P(n)+j*Q(n);
     Pg(n) = P(n)*basemva + Pd(n);
     Qg(n) = Q(n)*basemva + Qd(n) - Qsh(n);
     Pgg(k)=Pg(n);
     Qgg(k)=Qg(n);     %june 97
     elseif  kb(n) ==2
     k=k+1;
     S(n)=P(n)+j*Q(n);
     Qg(n) = Q(n)*basemva + Qd(n) - Qsh(n);
     Pgg(k)=Pg(n);
     Qgg(k)=Qg(n);  % June 1997
  end
yload(n) = (Pd(n)- j*Qd(n)+j*Qsh(n))/(basemva*Vm(n)^2);
```

```
end
busdata(:,3)=Vm'; busdata(:,4)=deltad';
Pgt = sum(Pg);  Qgt = sum(Qg); Pdt = sum(Pd); Qdt = sum(Qd); Qsht =
sum(Qsh)
```

APPENDIX (B)

Transmission Lines Raw Data

Sudan Transmission Lines Raw Data

Substations Name	Voltage Level	No. of Line	Length (Km)	Total Resistance (Ω/Km)	Total Reactance (Ω/Km)	Total Susceptance (nf/Km)
MWP-MRK	500KV	2	346	0.028	0.276	13.083
MWP-ATB	500KV	1	237	0.028	0.276	13.083
MRK-KBA	500KV	1	36	0.028	0.276	13.083
MRK-GAM	220KV	2	38	0.067	0.302	13.06
MRK-MHD	220KV	2	21	0.067	0.302	13.06
GAM-JAS	220KV	2	38	0.067	0.302	13.06
JAS-GAD	220KV	2	37	0.067	0.302	13.06
GAD-KLX	220KV	2	43	0.076	0.403	9.02
KHN-IBAB	110KV	2	12	0.067	0.269	13.06
KLX-IBAB	220KV	2	14	0.067	0.302	13.06
IBAB-KBA	220KV	2	30	0.067	0.302	13.06
IBAB-GAR	220KV	2	60	0.067	0.302	13.06
KAB-FRZ	220KV	2	26	0.067	0.302	13.06
GAR-FRZ	220KV	2	5	0.067	0.302	13.06
FRZ-SHN	220KV	2	115	0.067	0.302	13.06
SHN-ATB	220KV	2	140	0.067	0.302	13.06
JAS-MSH	220KV	2	148	0.067	0.302	13.06
MSH-RBK	220KV	2	107	0.067	0.302	13.06
RBK-RNK	220KV	2	163	0.067	0.302	13.06
RNK-ROS	220KV	2	173	0.067	0.302	13.06
ROS-SNG	220KV	2	178	0.076	0.403	9.02
SNG-HWT	220KV	2	90	0.067	0.302	13.06
HWT-GDF	220KV	2	110	0.067	0.302	13.06
SNG-SNJ	220KV	2	50	0.076	0.403	9.02
SNJ-MAR	220KV	2	84	0.076	0.403	9.02
MAR-NHS	220KV	2	60.3	0.076	0.403	9.02

NHS-GIAD	220KV	2	80.7	0.076	0.403	9.02
GDF-SHEHIDE	220KV	2	194	0.067	0.302	13.06

Ethiopia Transmission Lines Raw Data

Substations Name	Voltage Level	No. of Line	Length (Km)	Total Resistance (Ω)	Total Reactance (Ω)	Total Susceptance (µf)
GONDAR-SHEHIDE	230KV	1	130	8.411099	53.3761	1.1686
BLS-BDR2	400KV	2	65	3.568	25.456	0.599736
BDR2-DMK	400KV	1	200	10.976	78.32	1.84
DMK-SLU	400KV	1	230	12.624	90.064	2.12
G-GIBE-1 - G-GIBE -2	400KV	1	45	2.464	15.216	0.48
G-GIBE-2 -SEBETA-2	400KV	1	210	11.248	70.3264	2.25
FINCHA - FINCHAA 2	230KV	1	95	5.19478	37.63835	0.839099
FINCHA-GHEDO	230KV	2	94	6.7183	40.1511	0.803898
AMRTNSH-FINCHAA-2	230KV	1	40	3.66068	12.40505	0.45135
FINCHA -DBMRKOS	230KV	1	95	5.19478	37.63835	0.839099
GHEDO-GEFERSA	230KV	2	134	9.6278	57.3436	1.15109
GHEDO-GGIBE-1	230KV	1	130	8.411099	53.3761	1.1686
GEFERSA-SEBATA	230KV	1	12	0.77763	4.92499	0.107888
GEFERSA-SULULTA	230KV	2	30	1.93614	12.25164	0.270413
SEBATA-KALITI1	230KV	1	14	0.90459	5.75023	0.12582
SEBATA-WOLKITE	230KV	1	133	8.68089	54.55577	1.203921
SEBATA-SEBETA-2	230KV	2	20	1.28547	8.16776	0.180215
KALITI1-KOKA	230KV	2	66	4.72397	26.18021	0.576327
KALITI1- LEGETOFA	230KV	2	30	2.74551	9.30511	0.338528
KOKA-M-WAKNA	230KV	2	164	13.07688	65.97159	1.427761
KOKA-D.DAWA3	230KV	2	337	24.2282	134.1279	2.962929
D.DAWA3-ADIGALA	230KV	2	120	10.97675	37.21515	1.35399
DB-MRKOS-MOTA	230KV	1	98	5.45928	38.82331	0.865574
N.MEW TP - B-DAR-2	230KV	1	136.4	12.4844	42.28297	1.538899
B.DAR-2 - GONDAR-2	230KV	1	143	13.13507	45.01261	1.601718
GASHE-TA - N.MEW TP	230KV	1	102	9.363298	31.71355	1.154159
ALAMATA-MEKELE	230KV	2	141	12.90231	43.72714	1.590948

Ethiopia Transmission Lines Raw Data

Substations Name	Voltage Level	No. of Line	Length (Km)	Total Resistance (Ω)	Total Reactance (Ω)	Total Susceptance (μf)
ALAMATA-COMBOL	230KV	2	168.8	15.4468	52.32868	1.904444
ALAMATA-GASHE-TA	230KV	1	102.3	9.363298	31.71355	1.154159
MEKELE-TEKEZE	230KV	2	105	9.331561	31.78761	1.145314
TEKEZE-ENDASILA	230KV	2	249	17.7215	59.94099	2.181656
LEGET - COMBOL	230KV	2	294	26.90494	91.13612	3.316982
COMBOL-SEMERA	230KV	1	170	15.55789	52.69898	1.917982
GONDAR-2 -HUMERA	230KV	2	280	28.58187	96.81229	3.523492
G-GIBE-1 - WOLKITA	230KV	1	70	6.4009	21.69958	0.789517
MOTA - B-DAR-2	230KV	1	83	4.62346	32.87735	0.733075
HUMERA-ENDASILA	230KV	2	285	19.19741	65.03526	2.367106

APPENDIX (C)

Buses Data Output

Bus	Voltage	Angle	------Load------		---Generation---		Injected
No.	Mag.	Degree	MW	Mvar	MW	Mvar	Mvar
1	1.008	-21.736	0	0	806	-307.662	-250
2	0.999	-27.159	0	0	0	0	-125
3	0.979	-25.106	0	0	0	0	-125
4	0.989	-27.225	0	0	0	0	0
5	0.978	-28.874	0	0	0	0	0
6	0.946	-30.421	221	148	0	0	0
7	0.97	-29.377	175	103	0	0	0
8	0.934	-30.818	162	114	0	0	0
9	0.93	-30.445	49	21	0	0	0
10	0.934	-29.182	190	98	0	0	-30
11	0.941	-28.491	0	0	0	0	0
12	0.938	-28.707	404	190	0	0	0
13	0.961	-26.615	0	0	300	111.316	0
14	0.96	-27.558	0	0	0	0	0
15	0.952	-26.555	0	0	360	-198.859	0
16	0.954	-26.724	0	0	0	0	0
17	0.971	-26.744	0	0	0	0	0
18	0.971	-26.486	242	118	0	0	0
19	0.944	-30.175	0	0	0	0	-15
20	0.941	-29.556	91	47	0	0	-30
21	0.954	-26.287	0	0	0	0	-30
22	0.952	-22.585	0	0	210	-82.975	0
23	0.937	-25.892	0	0	0	0	-30
24	0.939	-24.974	0	0	0	0	0
25	0.929	-23.667	69	30	0	0	-60
26	0.937	-19.273	20	18	0	0	-60
27	0.991	-10.891	53	38	0	0	-30
28	0.997	-3.338	86	49	0	0	0
29	0.994	-2.111	0	0	0	0	0
30	0.988	0	0	0	482.421	-165.233	0
31	0.992	-5.467	0	0	0	0	0
32	0.987	-8.881	0	0	0	0	0
33	0.995	-4.376	0	0	0	0	0
34	0.984	-5.539	87	34	0	0	-30
35	0.952	-3.588	0	0	120	-22.776	0

Bus	Voltage	Angle	------Load------		---Generation---		Injected
No.	Mag.	Degree	MW	Mvar	MW	Mvar	Mvar
36	0.932	-7.381	204	132	0	0	-30
37	0.948	0.579	0	0	0	0	0
38	0.948	2.036	0	0	100	1.093	-30
39	0.976	-10.141	115	62	0	0	-30
40	0.962	-1.395	0	0	180	-29.909	0
41	0.985	-10.587	105	45	0	0	0
42	0.983	-9.483	0	0	0	0	0
43	1.007	-12.735	189	104	0	0	-30
44	0.929	-5.795	119	71	0	0	-30
45	0.986	-9.316	0	0	0	0	0
46	0.983	-7.698	0	0	0	0	0
47	0.976	-0.145	0	0	430	-56.005	0
48	0.969	-0.724	0	0	0	0	0
49	1.004	-12.971	0	0	0	0	0
50	1.036	-13.802	107	64	0	0	-30
51	0.952	-8.183	0	0	120	-80.909	0
52	1.013	-22.135	133	64	0	0	0
53	1.021	-22.27	0	0	0	0	0
54	1.02	-6.952	0	0	0	0	0
55	1.026	-9.359	0	0	0	0	0
56	1.022	-11.565	97	61	0	0	-15
57	1.067	-14.407	92	59	0	0	-15
58	1.084	-14.68	0	0	0	0	0
59	0.995	-8.524	103	49	0	0	-30
60	0.994	-4.76	0	0	280	-180.956	0
61	1.05	-7.466	0	0	0	0	0
62	1.064	-9.427	0	0	0	0	0
63	0.928	-27.484	0	0	0	0	-15
64	0.914	-30.21	97	36	0	0	0
65	0.912	-30.854	76	39	0	0	-30