ASSESSMENT OF TRANSIENT STABILITY ENHANCEMENT CAPABILITY OF UNIFIED POWER FLOW CONTROLLER IN A MULTI-MACHINE POWER SYSTEM

BY

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DECLARATION

I declare that the work in this thesis entitled “Assessment of Transient Stability Enhancement Capability of Unified Power Flow Controller in a Multi-Machine Power System” has been carried out by me in the Department of Electrical and Computer Engineering. The information derived from the literature has been duly acknowledged in the text and a list of references provided. No part of this thesis was previously presented for another Degree or Diploma at this or any other institution.

Shereefdeen Oladapo SANNI _____ _____

Signature Date

CERTIFICATION

This thesis entitled ASSESSMENT OF TRANSIENT STABILITY ENHANCEMENT CAPABILITY OF UNIFIED POWER FLOW CONTROLLER IN A MULTI-MACHINE POWER SYSTEM by Shereefdeen Oladapo SANNI, meets the regulations governing the award of the degree of Master in Electrical Engineering of the Ahmadu Bello University, and is approved for its contribution to knowledge and literary presentation.

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ABSTRACT

The study of the transient stability enhancement capability of Unified power flow controller (UPFC) in a multi-machine power system is presented. The test system was Nigerian 330kV power system and the focus was on the effect of disturbances on the largest generating unit (Egbin) in the system. The original network was reduced to retain the area of interest (i.e. South West buses including Egbin generator). The UPFC was connected between Egbin and Ikeja-west buses and the analysis was conducted by simulating a 3-phase fault at three locations; on the terminal of the largest generator unit at Egbin bus, the bus with the largest load at Ikeja–west and the bus at Benin. The response of the system for the three cases with and without the device in operation was observed. The dynamic model for the series part of the device was developed in Python programme using the application program interface (API) in Power System Simulation for Engineering (PSS/E) software used for the analysis. Simulation results showed that, with the UPFC in the network, the steady state voltage profiles of some buses were improved by as much as 4.9% especially those close to the point of connection. In addition, the device was able to damp power oscillation and the system transient stability was enhanced. The enhancement is from the critical clearing time of the system which was increased from 380ms to 590ms when the fault was at Egbin generator terminal, from 470ms to 510ms following the fault at Ikeja-west, and from 770ms to 830ms when the fault was at Benin bus.

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ABBREVIATIONS

Abbreviation	Description
AVR	Automatic Voltage Regulator
FACTS	Flexible AC Transmission Systems
GTO	Gate Turn-off Thyristor
IGBT	Insulated Gate Bipolar Transistor
PSS	Power System Stabilizer
PSS/E	Power System Simulation for Engineering
SSSC	Static Synchronous Series Compensator
STATCOM	Static Compensator
SMIB	Single Machine Infinite Bus
TCSC	Thyristor Controlled Series Compensator
UPFC	Unified Power Flow Controller
VSC	Voltage Source Converter

CHAPTER ONE

INTRODUCTION

1.1 Background

Deregulation of power system around the world has brought to the forefront the issue of power system stability. The stability issue stems from new regulatory requirements, economic/environmental factors, and increase demand without a corresponding increase in generation and transmission line reinforcement. All these results in power systems being stressed beyond the capacity they were originally built to handle. Considering that some generators are far from the load centres, the problem of transient stability following a major disturbance will be a threat to the security of supply and utility operators will find it critical to the daily operation of power systems. Power system stability is the ability of synchronous machine to remain in synchronism with one another after disturbances at various locations in the system. It can be broadly divided into Steady-State or Small Signal Stability and Rotor Angle Transient Stability (Padiyar, 2008). The former is the stability of the system under conditions of gradual or relatively slow change in load while the latter refers to the maximum power transfer possible through a point without losing stability with sudden and large changes in the network conditions such as 3-phase bolted faults, or sudden loss of large loads/generating unit(s). Stressed power systems are known to exhibit nonlinear behaviour and the interactions among power systems components results in various modes of oscillations. These oscillations if not properly damped, may be sustained for several minutes affecting power flows and may even increase to cause loss of synchronism between systems and ultimately lead to total or partial system outage.

The system dynamic response to disturbances and the risk of losing stability can be reduced by additional element inserted into the system. Options involve connecting a

Braking Resistor (BR) at the generator or substation terminals. This braking of the accelerating rotor angle influences the rotor motion during disturbances. The switching of the BR is made either trough a mechanical circuit breaker or with a power electronic based devices. Also, Power system stabilizers (PSS) have been one of the fore-most measures used to enhance the damping of power swings. PSS is a device which provides additional control action via the automatic voltage regulator (AVR) system loop. While conventional PSS can be considered an economical option to add damping on critical electromechanical modes it might not be adequate to provide sufficient damping of power swings where the transmission line loading over long distances is quiet high (Kazemi and Mahamnia, 2008). An alternative to PSS are the Flexible AC Transmission System (FACTS) controllers which can be designed to use a variety of control signals and, in principle, can be placed at any location in the transmission system to achieve the best possible damping. Advancement in power electronic devices for high power application indicates that they will continue to find application in electric power transmission and distribution systems. Power electronics provide increased control, and as a result, operation of existing transmission and distribution line close to their thermal limits. FACTS controllers can be series or shunt connected; the Static Synchronous Series Compensator (SSSC) which can be defined as a static synchronous generator is connected in series with a network and acts as a series compensator whose output voltage is fully controllable, independent of line current, with the aim of increasing or decreasing the voltage drop across the line, therefore controlling the power flow.

A Static Var Compensator (SVC) is a shunt connected static var generator/load whose output can be adjusted to exchange capacitive or inductive current with a network where it is located. Primarily SVC is used to improve voltage stability. However,

supplementary control can also provide oscillation damping. Another shunt connected device is the STATic COMpensator (STATCOM) which in many respects resembles a synchronous generator. It acts as a controllable shunt capacitive or inductive reactance, thus allowing regulation of network voltage which is its main function. A supplementary feedback controller can be added in order to enhance damping of system's oscillations. in addition, the Unified Power Flow Controller (UPFC) is another FACTS device which is, technically, the most versatile and effective because, it combines the functionality of a series (SSSC) and shunt (STATCOM) connected device and has the capability of improving transient stability of a power system by controlling the power flow through a transmission line via the series and shunt parameters, hence its choice for this research works.

1.2 Statement of Problem

The Nigerian 330kV transmission network is a very large (but essentially radial) network as shown in Figure 1.1. A section of the network involving the generator at Egbin and the buses in the south west is used for this study. The choice of the study area is based on the fact that Egbin thermal station is the single largest installed electricity generation plant in Nigeria with an installed capacity of 1320 MW and the majority of loads are concentrated in the southwest. Problems like sudden and large changes in the network conditions such as 3-phase bolted faults, or sudden loss of loads/generator unit on this section of the network, would weaken the system security. Hence, the choice to study the response of the network to one of such problems while incorporating a reported corrective device (i.e. UPFC) that is capable of appropriately mitigating such problems.

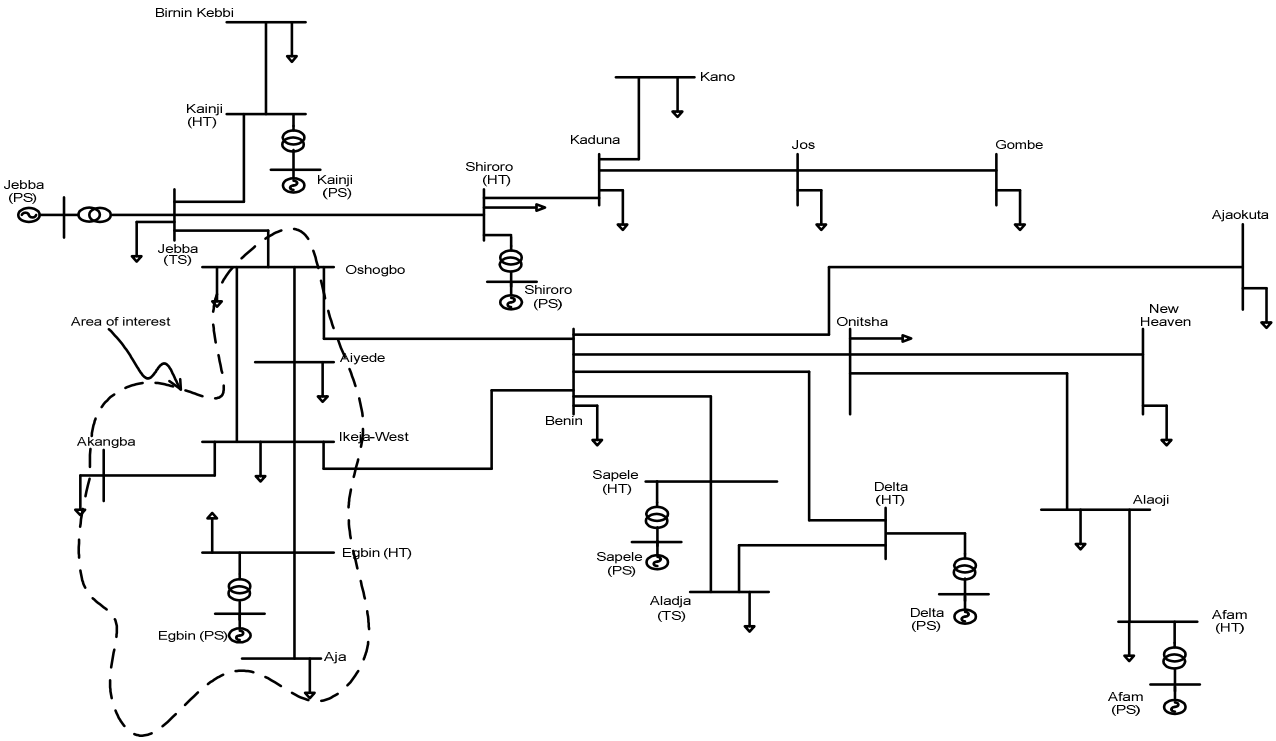

Figure 1.1: The Nigerian 330kV Transmission Network Showing the Area of Interest

1.3 Motivation

Lack of sufficient power to meet immediate and future demand is a problem in some countries (Nigeria inclusive). Consequently there is the need to operate existing infrastructure efficiently. As the power generation is stepped up, most of the transmission corridors are pushed to their operating limits and with delay in building new transmission lines and the associated cost, one problem that arise is the stability of the network. Thus the present facilities on ground have to be optimised for best performance. With the current state of the Nigerian power network where the generation is inadequate to meet the load demand, security of the existing system is very important as the network is increasingly been stressed and vulnerable to instability. The reported stability enhancement capability of UPFC and its application to a multi-machine power system coupled with the state of the study system is the motivation for this study.

1.4 Aim and Objectives

The aim of this project is to assess the transient stability enhancement capability of UPFC in a multi-machine power system subjected to credible transient disturbance.

The research objectives are as follows:

i. Development of a typical multi-machine power system model
ii. Steady-state power flow study of the system leading to network reduction on the study network by retaining the area of interest.
iii. Integration of steady-state and dynamic model of the UPFC in the power flow and dynamic simulation studies.
iv. Transient stability analysis on the reduced multi-machine power system.

1.5 Methodology

The reduced Nigerian 330kV Grid is the test system for this study, and the data will be obtained from the Power Holding Company of Nigeria (PHCN). To achieve the stated objectives, the following research tasks were carried out:

I. Given that the transient stability analysis was conducted on the area including the generator at Egbin and the buses in the south west, the impact of a disturbance in this area on the rest of the network is not of immediate concern thus a network reduction is performed. The network was divided into two sections. An internal network where the impact of the disturbance is of interest, this section of the network is the study system and an external network to be represented by simplified models that still retain its effect on the study system referred to as the dynamic equivalent. This is illustrated as shown in Figure 1.2.

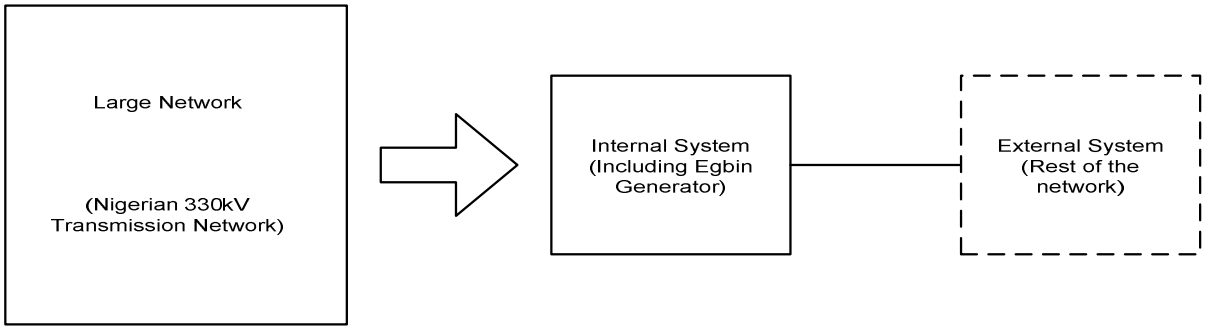

Figure 1.2: Dividing the entire Power System Network into two parts

Dynamic reduction of the network used centred on the coherency-based technique and included the following steps:

i. Identification of coherent generator groups.
ii. Aggregation of generators in the group.
iii. Reduction of the proposed network.

II. A power flow study was performed on the reduced system in order to determine the steady state pre-disturbance condition for the system. The simulation software Power system Simulation for Engineering (PSS/E) will be used to model the system and it components, and then the study is carried out subsequently.

III. Transient stability analysis was conducted on the resulting multi-machine system. The analysis is involved simulating a disturbance on the test system without the UPFC in operation to observe the system behaviour during transients. The UPFC model developed using Python programming is subsequently activated in order to mitigate the resulting disturbances. The system response to the device is examined.

IV. Finally, simulation results produced by the simulation software are presented in order to observe the enhancement capability of the UPFC during this transient condition.

1.6 Significance of Study

The requirement for full control of transmitted power in a deregulated electrical power market is imperative for system operators. This is necessitated because of the increased and variable nature of the loads which usually exhibit non-linear behaviour. One of the effects of this non-linear behaviour is the stability of the network following a severe disturbance. Traditional means of ensuring maximum power transfer e.g. PSS BR etc are increasingly not sufficient for modern power systems during contingencies and FACTS devices have been reported to provide system operators with increased flexibility of control of network parameters to ensure more power is delivered to their consumers. This thesis has investigated the use of UPFC in improving transient stability of a reduced Nigerian 330kV transmission network. The results obtained could assist the system operator in future planning and daily operation of the network.

CHAPTER TWO

LITERATURE REVIEW

2.1 Introduction

In this chapter, the necessary background knowledge into the study is presented. It starts with the illustration of the relevant theories. These include the definition of the stability problems, the various types, and transient stability enhancement methods. The UPFC principle of operation is also been described showing how the network parameters are controlled for improved system performance. Finally, a critical and systemic review of works similar to the study is provided.

2.2 Review of Fundamental Concepts

2.2.1 Power System Stability

The complexity of power systems results from the interconnection of its various components; from generators to loads, the interconnecting transmission lines and other devices associated with power transfer. This interconnection causes dynamic interactions with all these components that could affect the system partly or as a whole. The challenge of a power system operator is making these elements work together irrespective of the system disturbances they are subjected to. The system is said to be stable if it is able to remain in a state of operating equilibrium under normal operating conditions or regain acceptable state of equilibrium after it has been subjected to a disturbance. Power system stability is defined as the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact (Prabha, et al., 2004).The study of power

system stability is classified into three areas, rotor angle stability, frequency stability and voltage stability as illustrated in Figure 2.1.

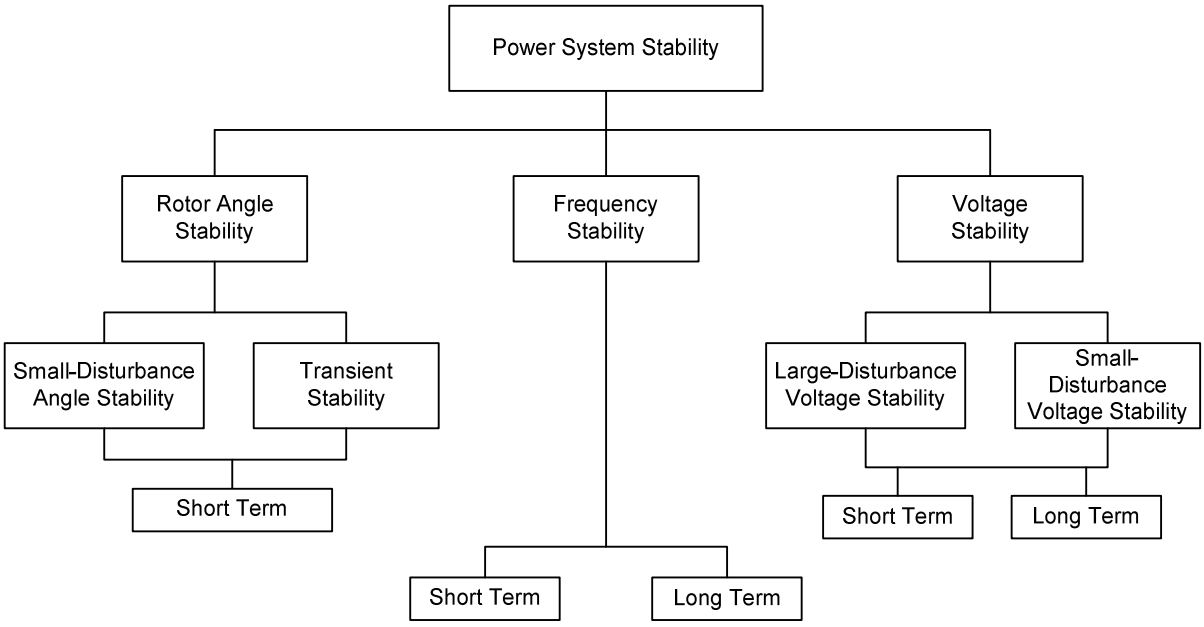

Figure 2.1: Classification of Power System Stability (Prabha, et al., 2004).

2.2.2 Rotor Angle Stability

Rotor angle stability refers to the ability of synchronous machines to maintain synchronism subject to a system disturbance. It depends on the ability of the machine to maintain equilibrium between the electromagnetic torque and mechanical torque. The instability may occur as a result of increasing angular swings of some generators leading to their loss of synchronism with other generators. Rotor angle stability can be categorised as

- Small-disturbance rotor angle stability
- Large-disturbance rotor angle stability

Small-disturbance (or small signal) rotor angle stability is the ability of power system to maintain synchronism when subjected to small disturbance. Large-disturbance rotor angle stability or transient stability as it is commonly known deals with the ability of the power system to maintain synchronism when subjected to a severe disturbance. Transient stability which is the focus of this study depends on the initial operating state of the system and the severity of the disturbance. Transient instability is in the form of aperiodic angular separation due to insufficient synchronizing torque, manifesting itself as first swing stability. The time frame of interest in transient stability studies is usually 3 to 5 seconds following the disturbance. It may be extended to 10–20 seconds for very large systems with dominant inter-area swings (Prabha, et al., 2004). Figure 2.2 shows the classification of power system dynamics with respect to time frame which is closely related to where the dynamics occur within the system.

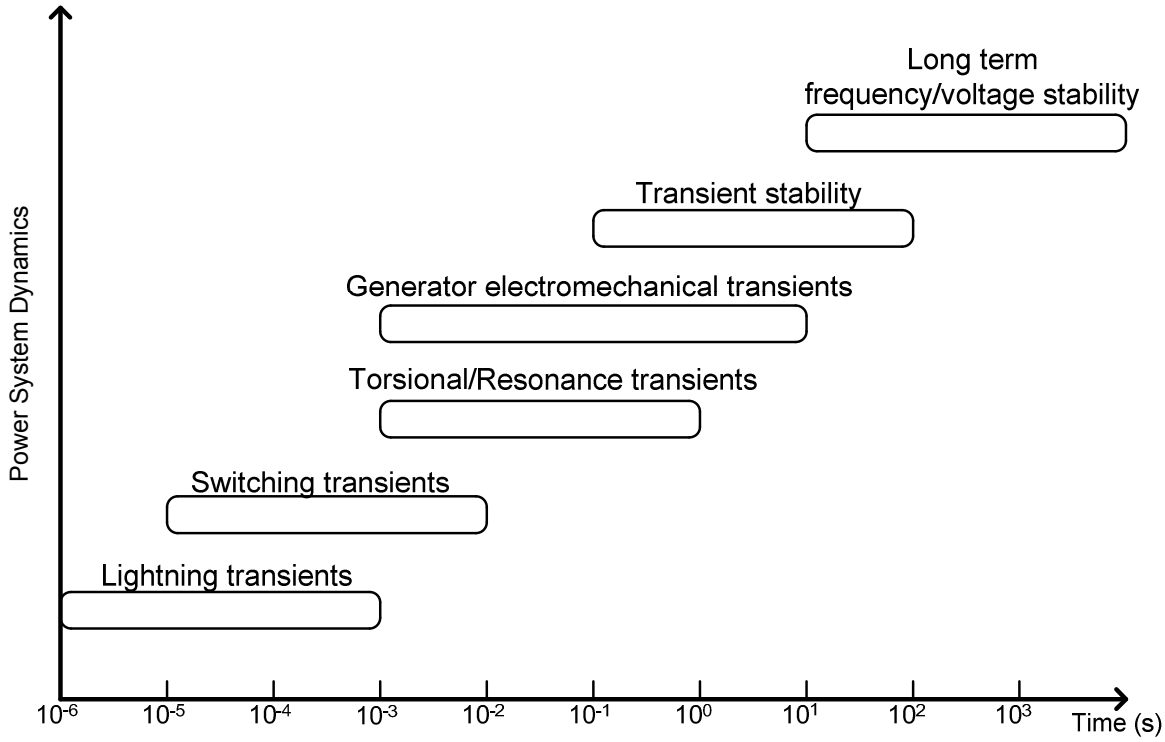

Figure 2.2: Classification of Power System Dynamics

2.2.3 Transient Stability

Transient stability is the ability of power system to remain in synchronism when subjected to large disturbances. Such disturbances which could affect the transient stability of the system include load changes, switching operation and faults that result in subsequent circuit isolation. These disturbances also result in the oscillations of the rotor and by extension the generated power. Figure 2.3 shows the plot of the generator rotor angle (δ) against time. For a generator subject to a system disturbance it can either recover and oscillates around a new equilibrium point with the rest of the system or it can pull away from the rest of the system aperiodically. These curves are also known as the "swing curves".

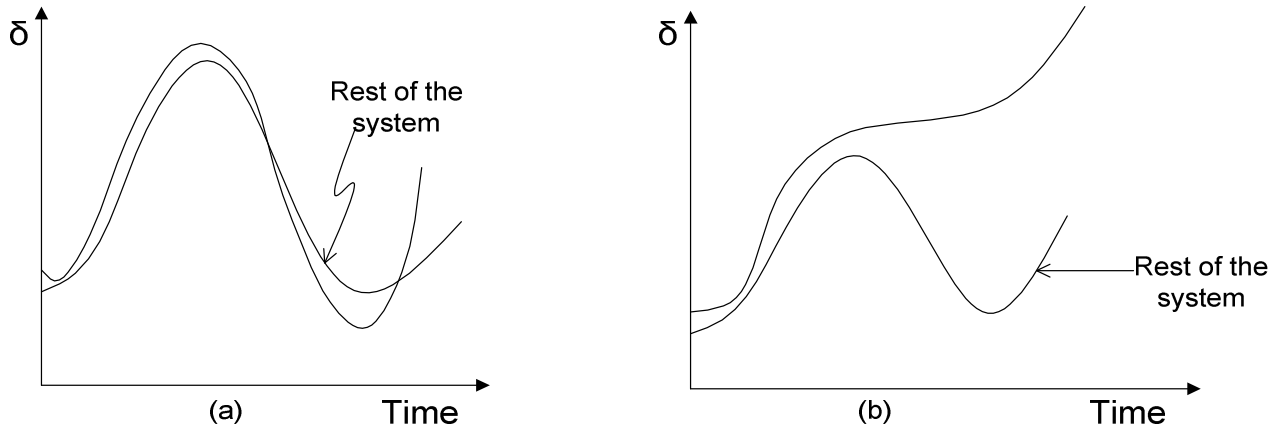

Figure 2.3: Plot of Rotor Angle against Time; a) Stable Case b) Unstable Case

The former case is deemed to be transiently stable while the later is unstable. Equation 2.1 is "the swing equation" which describes the rotor angle swings during disturbances, and the power angle relationship concepts are necessary in transient stability analysis.

$$M\frac{d^2\delta}{dt^2} = (P_m - P_e)MW \tag{2.1}$$

Where M is the inertia constant in MJ-sec/elect-radian, P_m is the mechanical input power, P_e is the Electrical output power.

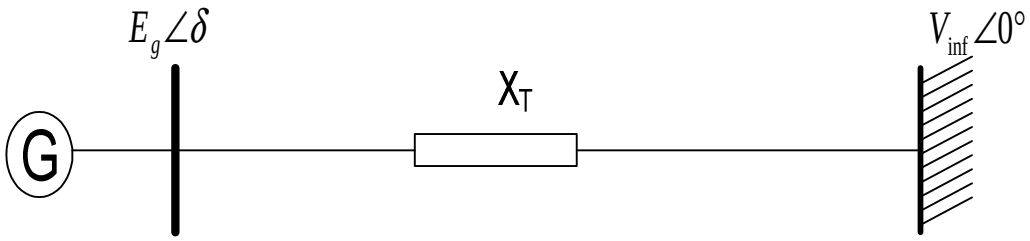

Figure 2.4: Model of a Single Machine Infinite Bus System

In a simple model of as shown in Figure 2.4 where a generator is connected to an infinite bus system, the maximum power that can be transferred to the infinite bus is restricted and the equation relating the generator electrical power P_e and the rotor angle δ of the machine is given by equation 2.2.

$$P_e = \frac{E_g V_{inf}}{X_T} \sin\delta \qquad (2.2)$$

$$= P_{max} \sin\delta$$

where,

$$P_{max} = \frac{E_g V_{inf}}{X_T} \qquad (2.3)$$

Where E_g is the terminal voltage of generator, V_{inf} is the voltage of infinite bus, X_T is the transmission line reactance and δ is the phase angle difference between the buses.

A graphical representation of Equation 2.2 is as shown in Figure 2.5 from which it can be seen that the electrical power initially increases and gets to maximum at 90°. The power decreases above δ=90° until P_e=0 at δ=180°. This power-angle characteristic curve shows the power that can be transmitted as a function of rotor angle.

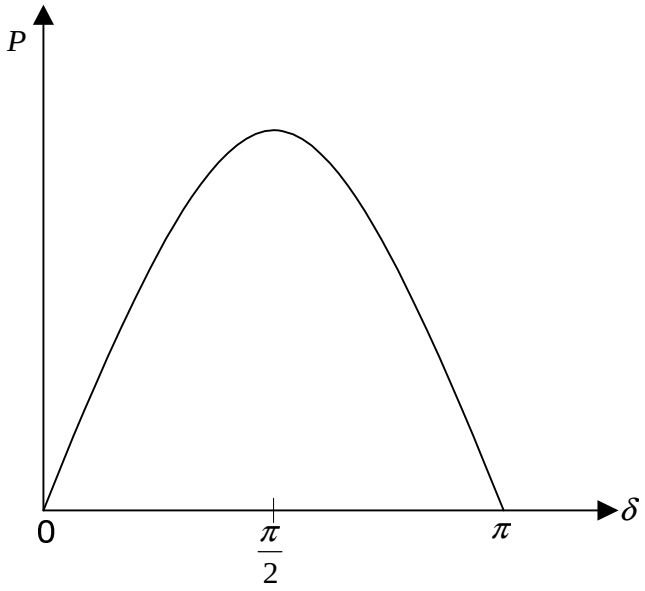

Figure 2.5: Power-angle curve

From equation 2.3 it is apparent that the power flow through a transmission line is a function of the line impedance, voltage magnitude and phase angle of the bus voltages. The power flow through the line can be controlled in a preferred manner if these parameters can be controlled. FACTS devices use power electronics to control the parameters of power system in order to fully utilize the existing transmission capability and improve power system transient stability.

2.2.3.1 Transient Stability Enhancement

The rotor (power) angle stability of a power system can be enhanced, and its dynamic response improved, by correct system design and operation. Some measures that could help in improving system stability include adequate and reliable protective equipment that ensure fast fault clearing, ensuring adequate reserve capability of transmission lines, use of system configuration suitable for a particular operating condition, system wide frequency and voltage control etc. In practice however, financial constraint limits the level to which any of these actions could be implemented and there is always a

compromise between operating a power system close to its stability limits and ensuring excess reserve in generation and transmission. The introduction of some additional elements inserted into the system will help smooth the system dynamic response. These Stability enhancement device/actions are outlined subsequently.

Power System Stabilizers: A power system stabilizer is a device that provides a supplementary control signal to the generator AVR. Though a generator output power is decided by the turbine mechanical torque, a generator output power also can be changed by changing excitation value transiently. A PSS detects the changing of generator output power, controls the excitation value, and reduces the power swing rapidly. PSS are designed to use a variety of control signals. Some commonly used input signals are rotor speed deviation, accelerating power, and frequency deviation.

PSS in their earliest form used a measurement of the speed deviation of the generator shaft.

The main problem with the signal is the measurement noise, and when applied to turbo-generators with long shafts, the measurement position has to be carefully chosen so as to represent actual speed deviation due to their vulnerability to torsional oscillations. For long shafts it is a common practice to measure the speed deviation at a number of points along the shaft and use this information to calculate the average speed deviation (Machowski, et al, 2008).

The measurement of shaft speed can be replaced by a measurement of the generator terminal frequency. A disadvantage of this solution is that the frequency signal often contains power system noise caused by large industrial loads such as arc furnaces. The accuracy of this measured speed signal can be improved by adding the voltage drop across the transient reactance to the generator voltage to obtain the transient emf and its corresponding frequency.

The PSS nowadays receives two signals, the generator current and voltage. Similar to the case of the PSS utilizing the measured shaft speed deviation, the PSS gain is limited by the effect of shaft torsional oscillations. The advantage of this solution compared with other types of stabilizers is that it improves the damping of inter-area oscillations in interconnected power systems.

Due to the simplicity of measuring electrical power and its relationship to shaft speed, it was considered to be a natural candidate as an input signal to early stabilizers. With this arrangement only one input signal is required but can only be used when the mechanical power can be assumed to be constant. If the mechanical power does change, for example due to secondary frequency control, this solution produces transient oscillations in the voltage and reactive power that are unnecessarily forced by the PSS because it sees the change in the mechanical power as a power swing.

Generator Tripping: A disturbance leading to the isolation of loads creates an imbalance between electrical and mechanical torque causing the rest of the generators in the system to over speed. Tripping one or more generators from a group of generators that are operating in parallel on a common bus bar is perhaps the simplest means of rapidly changing the torque balance on the generator rotor. Tripping generators without going through the shutdown procedure instantly reduces the mechanical torque. In the power angle characteristic, this reduces the acceleration area and increases the deceleration areas of the rotor of the remaining units, thereby increasing stability margin. Generator tripping could be Preventive tripping which is when tripping is coordinated with fault clearing to ensure that the remaining generators in operation maintain synchronism or restitutive tripping which is when one, or more, generators are tripped from a group of generators that have already lost synchronism. The objective here is to make resynchronization of the remaining generators easier.

The main disadvantage of generator tripping is that it creates a long-term power imbalance characterized by variations in frequency and power interchange between interconnected systems (Machowski, et al, 2008)**.**

Fast Valving: Fast-valving (or early valving, as it is sometimes referred to) is a technique applicable to thermal unit to assist in maintaining power system transient stability. It involves rapid closing and opening of steam valves in a prescribed manner to reduce the generator accelerating power following the recognition of severe transmission fault. Such fast control is however not possible with hydro turbines due to the large change in pressure and huge torque, necessary to move the control gates.

FACTS: FACTS devices provides power systems with a means to control transmitted power by increasing or decreasing the power flow in a specified transmission line thereby responding almost instantaneously to stability problems. By comparison with other stability enhancement methods the speed of response is the greatest advantage it has. Early FACTS devices were based on silicon controlled rectifier (SCR) and were used as active elements, however, with the advancement in technological developments higher capacity devices based on gate turn off thyristor (GTO), and IGBT in voltage source converters have been introduced. Depending on the system parameter to be controlled various configuration are available for FACTS devices, it could be series, shunt, series-series, or series-shunt connected. Shunt connected FACTS devices are used for voltage compensation at the point of connection. Such devices have also been reported to improve voltage stability and examples include Static var compensation (SVC) and STATic COMpensator (STATCOM). Series device are used primarily for power flow control which indirectly influences bus voltages. Its ability to control power flow also finds application in damping of power oscillations which subsequently increase power system stability limits. The UPFC combines the functionality of the

series and shunt device in damping power oscillation and controlling bus voltages during system disturbance thus allowing for more power transfer. This makes the UPFC the most versatile of all FACTS devices.

2.2.4 UPFC Principle of Operation

The UPFC is conceptually seen as a synchronous voltage source (SVS) at the fundamental frequency. Consider a simple two machine system interconnected by a transmission line in series with a voltage phasor with controllable magnitude V_{pq} ($0 \leq V_{pq} \leq V_{pqmax}$) and angle ρ ($0 \leq \rho \leq 2\pi$) as shown in Figure 2.6 (Hingorani and Gyugyi, 2000). In this functionally unrestricted operation, which clearly includes voltage and angle regulation, the SVS generally exchanges both reactive (Q_{pq}) and real (P_{pq}) power with the transmission system. Since the SVS primarily is able to generate only the reactive power exchange, the real power must be supplied to it, or absorbed from it, by a suitable power supply or sink (Hingorani and Gyugyi, 2000). In the UPFC arrangement the real power exchanged is provided by one of the end buses usually the sending-end bus (V_s), as indicated in Figure 2.6.

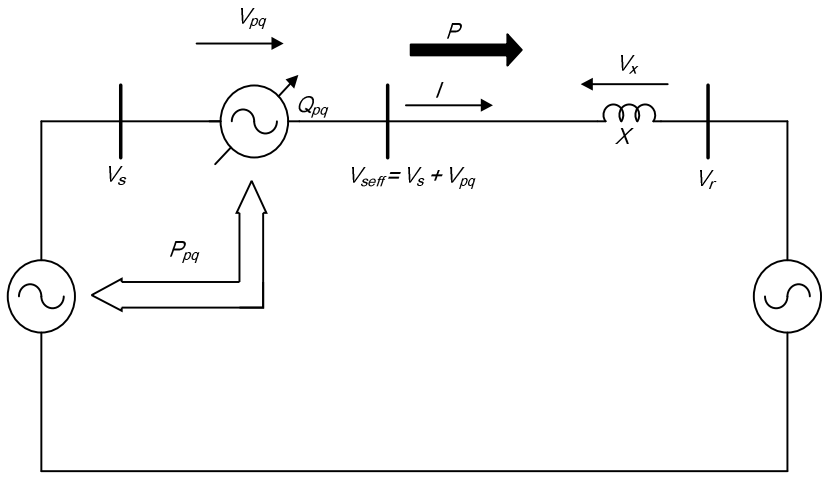

Figure 2.6: Conceptual Representation of the UPFC in a Two-machine Power System.

Figure 2.7 (Nabavi-Naiki, 1996) shows the practical implementation schematic diagram of the power circuit of a UPFC which is composed of an excitation transformer (ET), a boosting transformer (BT), two voltage source converters (VSCs) and a dc link capacitor. The VSC on the side of the boosting transformer (VSC-B) controls the magnitude and phase angle of injected voltage (V_B) by means of amplitude modulation index (m_B) and phase-angle (δ_B) respectively. Figure 2.8 shows the phasor relationship which indicates that depending upon the magnitude and/or phase-angle of V_B, angle δ can be controlled. Thus real and reactive power flow through the line can be regulated. Furthermore, the magnitude of receiving end voltage ($V_{2)}$ could also be controlled by V_B. Therefore; the UPFC can also be used for reactive power flow regulation (voltage control).

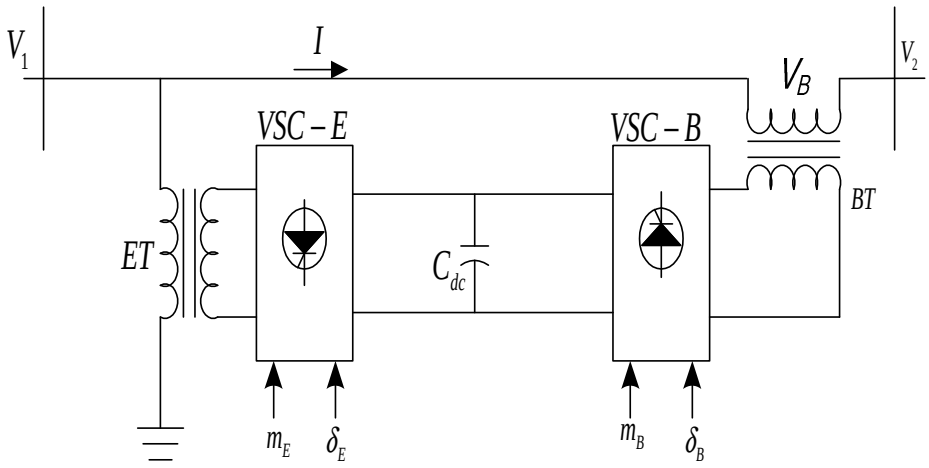

Figure 2.7: UPFC Schematic Diagram

Figure 2.8 also shows that control of the apparent power (S) in the line is accompanied by the exchange of real power ($|V_B||I|\cos\theta$) between the VSC-B and the system. This power exchange results in either the discharge or overcharge of the dc link capacitor. This power exchange is compensated by VSC on the excitation transformer (VSC-E) to maintain the capacitor at the required value, and assure proper operation of the VSCs.

Phase angle of the control signal of VSC-E (δ_E) is used to control the real power exchange between VSC-E and the system so as to control the dc link voltage. Therefore, neglecting losses, the UPFC is neither a source nor a sink of energy (Nabavi-Naiki, 1996).

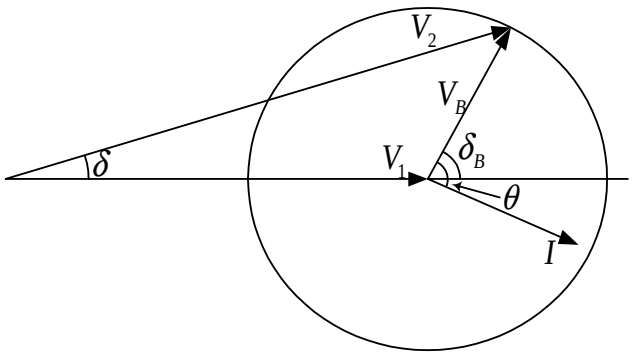

Figure 2.8: Phasor Diagram of UPFC in a System

2.3 Review of Similar Works

The subject of a number of publications has been on how the optimal system performance can be achieved by accurate control of switching instants of network elements that affect system parameters in a transmission network. Such parameter change can be used to damp power swings. This section attempts to describe briefly some reported works carried out on transient stability and UPFC application in power systems.

One of the earliest works carried out on the application of power electronic devices in power systems can traced to Gyugyi, (1992). In the work, the idea of flexible ac transmission concept is described as the real time control of system parameters which affect transmitted power. Furthermore transient (first swing) stability, as well as the damping of the system can be increased by rapidly controlling transmission line power within defined boundaries thereby improving steady-state transmitted power and thus

high utilization of the system. In addition, it was showed that UPFC in it general form can provide simultaneous real time control of power system parameters (transmission voltage, impedance, and phase angle). It was also acknowledge that the control parameters can be changed without any hardware alterations e.g. the function of the controller can be changed from that of a phase-shifter to that of a series line compensator, or vice versa, with or without additional terminal voltage regulation and shunt VAr compensation, to adapt to particular short term contingencies or future system modifications. The novelty of this work actually provided the ground breaking approach to the control of power and the utilization of transmission corridors efficiently using power electronics.

Gyugyi, et al. (1995) described the UPFC as a generalised real and reactive power flow controller that is able to maintain a prescribe P and Q at a given point (bus) on the transmission line. A test was conducted on the Western Area Power Administration (WAPA) power system. Conventional equipments installed on the system included phase angle regulators, two series capacitors, and two static var compensators. A UPFC replaced these components basically for steady-state power flow control and oscillation damping. Computer simulations indicate that the performance of the UPFC compared to the equipments it replaced, under a three-phase fault, shows that the UPFC greatly improves system damping and voltage swings of the bus where it was connected is significantly damped. This shows that the UPFC could replace a combination of phase angle regulators, series capacitors, and static var compensators and is effective in providing equivalent steady-state and superior dynamic system performance.

A UPFC fundamental frequency state-space model under balanced operating conditions is reported by Nabavi-Naiki, (1996). Although this state-space model was used to realize a steady-state power flow model, a small signal (linear) eigen-analysis model,

and a large-signal transient stability model of the UPFC, the work however focused mainly on the technical feasibility of UPFC in damping torsional oscillatory modes which are excited as a result of interaction between a turbine-generator unit and series capacitor compensated transmission system. Results showed that the UPFC mitigates torsional oscillation well both when it is located in series compensated line and in a line parallel to a series compensated line for a relatively simple power system. For a realistic 10-generator power system, he deduced that an open loop UPFC does not affect interarea oscillations while it can significantly change torsional damping, auxiliary control loop to a UPFC can effectively damp out torsional oscillations, and mutual interaction between interarea control and torsional control loop can be prevented by filtering out the undesirable oscillatory modes in each control loop.

Meng and So, (2000) proposed a current injection model for UPFC used in stability studies. Two studied cases were presented; in one of the cases, the input signals to the UPFC controller was the speed deviation and rotor angle deviation while the other case used active power deviation and reactive power deviation as input signals. Even though the speed and rotor angle deviation input signals gives better performance in damping oscillations the choice of input signal means that the location of the device is restricted to a point that allows for such signals to be measured.

Kumar and Nagaraju (2007), using the 10-generator 39-bus New England test system were able to show that the UPFC is more effective when the controller is placed near heavily disturbed generator. UPFC and SVC were used to investigate the transient stability on the system and power oscillations were damped and transient stability was improved by reducing the first swing.

In the works of Omoigui et al. (2007), the Nigerian 330kV was reinforced with two additional generating station and eleven transmission lines. A STATCOM and UPFC

were installed in location with low voltage limit violation following continuation power flow simulations. Results showed that the voltage profiles were improved and stability of the system enhanced with the FACTS devices in operation. Although the UPFC which was located between Kaduna and Kano improved the system wide voltage, the effect of the series device in damping power oscillation was not shown and it is of the view that this functionality could have been better utilised if the device was located at a point farther from the end of the radial line.

Kumkratug,(2009) and Murali, et al. (2010) used the Kundur inter-area power system as a case study. Kumkratug, (2009) was able to demonstrate that transient stability enhancement can be a function of UPFC rating, though the choice of different rating used were limited to two which might not be enough if the inter-area test system was larger. The line power flow between the two areas was used to control the UPFC which was modelled as a variable susceptance and incorporated into the power system model with the device located on the tie line between two areas. Simulation results showed that inter area stability is improved.

Murali, et al. (2010) reported that series devices SSSC and TCSC improved power system stability while the bus voltage where the SVC shunt device was connected was improved. Comparative result revealed that UPFC provided better performance than these other devices during the post fault period. They, however, did not take into consideration the equivalent rating of the device when they were compared.

Nwohu (2011) investigated the use of UPFC to improve the damping of low frequency power oscillations in the Nigerian grid system. Although results obtained showed that the rotor angle of the generator (closest to fault) located at Shiroro was the most affected and the UPFC's (located at Ikeja west) effectiveness in damping power oscillation was shown, the work restricted the fault location to just one bus and the

impact of the fault location and its distance from the UPFC as it relates to the network behaviour was not revealed.

The Western System Coordinating Council (WSCC) was used as a case study in the work of Dube et al, (2012). The network is a 3 machine, 9 bus system studied for voltage stability, small signal stability and transient stability analysis. The voltage stability was enhanced after the critical voltage point was increased following continuation power flow, and Eigen value analysis also shows improvement in small signal stability. Although transient stability enhancement results shows that oscillations were damped effectively, the conclusion based on the results produced was however salient on a key parameter; the critical clearing time for the system when the fault was applied.

A two-machine system was used to investigate the effect of UPFC on transient stability under various fault conditions by Thakur and Ghawghawe, (2012). The four fault condition studied are L-G, L-L, 2L-G and 3L-G. For the various fault conditions the critical clearing time was increased, hence the transient stability; although, the 3L-G fault has the lowest margin. This confirms the use of the 3L-G fault in most stability studies although the test system is small.

Gupta and Sharma, (2013) investigated how proper placement of UPFC can improve static and transient stability of power systems. The IEEE standard 14 bus power system was used as a test system. P-V curve analysis shows that loadability margin was increased by 50% and transient stability was improved when the UPFC was optimally placed. The optimal location of the device was however different in both cases because the problem was looked at separately.

While much effort has been geared towards the capability of UPFC in addressing the various stability issues that arises as a result of disturbance associated with a power

system, not much consideration has been given to how the UPFC responds to the loss/disturbance affecting power supply from a critical generating unit in a network. To this end, there is need to study how a UPFC will respond to such situation. This research studied and investigated the transient stability enhancement capability of UPFC in a typical multi-machine power system. By creating an area of interest including the largest unit in the Nigerian 330kV which is the reference for the study, this research approached the study using a network reduction method that has not been reported for the Nigerian 330kV. In addition the reduced network created can become the basis for researchers who would be interested in other or similar studies for the same area in the future.

CHAPTER THREE

MATERIALS AND METHODS

3.1 Introduction

The object of this chapter is to present the description of the materials used for this research and the implementation methods applied (i.e. as outlined in section 1.5) in realizing the results thus obtained. These materials included the Nigerian 330kV transmission data and the power system simulation for engineering (PSS/E) software along with the associated documentations to aid its handling.

3.2 Overview of Simulation Package (PSS/E)

As stated in section 3.1, the software used in this study is the professional software package, Power System Simulator for Engineering (PSS/E) developed by Siemens PTI (Power Technologies International) version 32. PSS/E is composed of an all-inclusive set of programs for studies of power system transmission network and generation performance in both steady-state and dynamic conditions. Figure 3.1 shows some component of the user interface. PSS/E can be used for handling a wide range of investigations (Power Technology International (PTI), 2010), including:

a. Data handling, updating, and manipulation
b. Power flow and related network functions
c. Optimal power flow
d. Open network Access and Price calculation
e. Balanced and unbalanced faults analysis
f. Network equivalent construction
g. Dynamic simulation

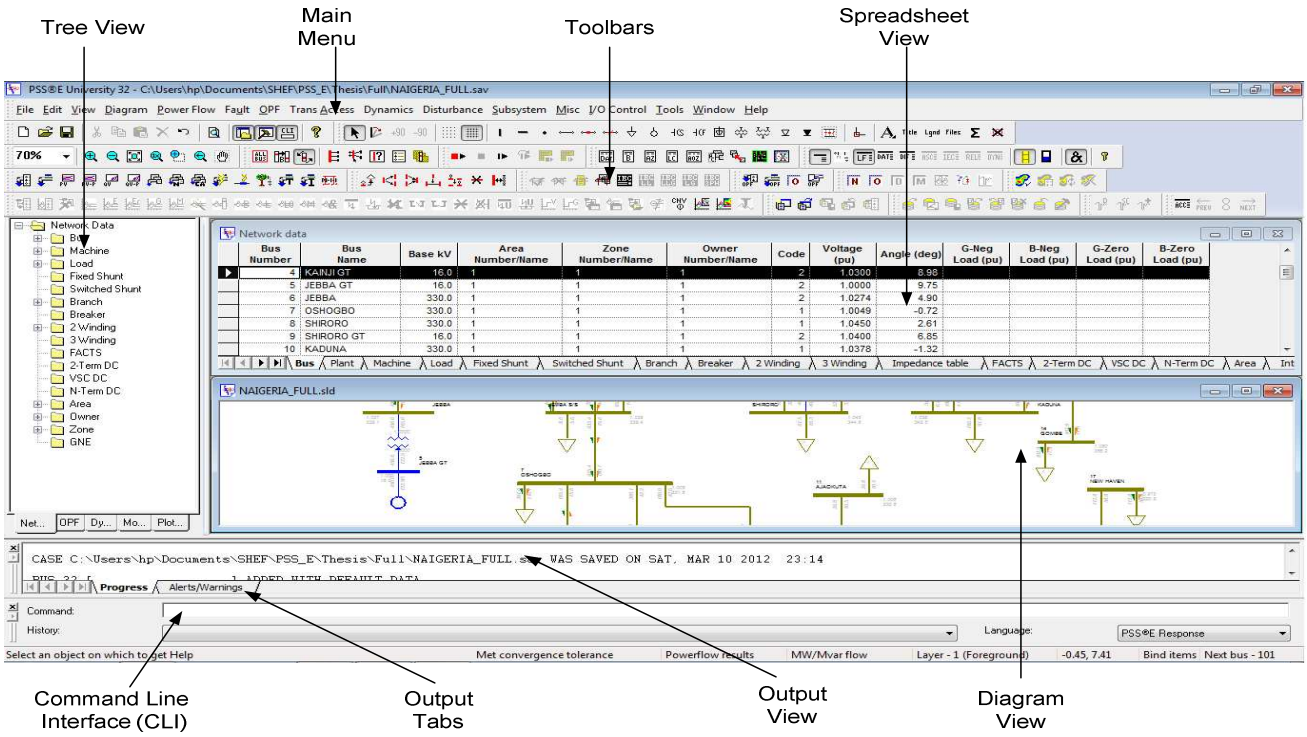

Figure 3.1: Key Elements of PSS/E Interface (Power Technology International (PTI), 2010)

3.3 Power Flow

A power flow study (also known as load-flow study) is an important tool for determining the state of the system. It involves numerical analysis applied to a set of non-linear equations that describe the state of the power systems. Power flow studies are important because they allow for planning and future expansion of existing power systems. A power flow study, also, can be used to determine the best and most effective design of power systems.

The object of power flow study in this work is the determination of bus voltages magnitude and corresponding angle as well as power flows for specified generation and bus conditions. The power flow solution of the network carried out in PSS/E was based on Newton-Raphson's method. The steady state conditions (i.e. bus voltages and transmission line power flows) of the network to be used as the initial condition for

network reduction procedure and in transient stability analysis is determined by the solution of the power flow study. The whole network modelled in PSS/E is shown in Figure 3.2. The result of the power flow solution along with the active and reactive power flowing in the transmission lines as well as the bus voltages is presented in appendix A.

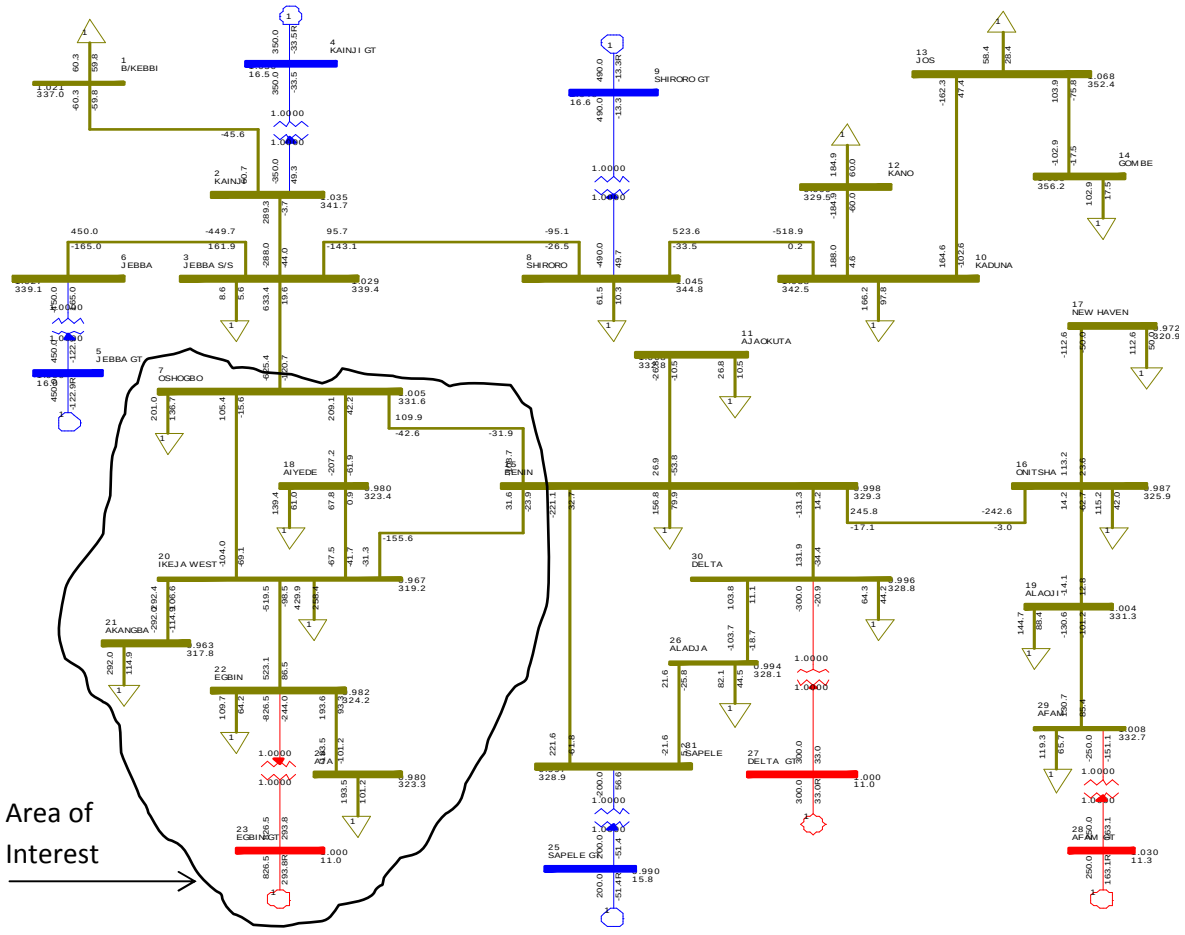

Figure 3.2: The Nigerian 330kV Transmission Network modelled in PSS/E

3.4 Power System Dynamic Equivalent

The literature presents a number of dynamic network reduction techniques which can be achieved using transient simulation. Basically, there are three methods, these are:

1. The modal equivalent
2. The estimation equivalent
3. The coherency-based equivalent

The network reduction techniques are based on the system which divides a network into an internal and external subsystem. A comparison of the three network reduction techniques showing the necessary precondition, suitability and speed of creation are summarised in table 3.1. In the subsequent sub-sections 3.41 to 3.42, the coherency equivalent method as the choice reduction method in this work is discussed in detail along with the implementation on the Nigerian network. The result of the implementation on the Nigerian power system is presented in chapter 4.

Table 3.1: Summary of power system reduction techniques

Reduction techniques	**Precondition**	**Application**	**Speed**	**Reduction result form**
Modal equivalent	Detailed model	Off-line small disturbance	Acceptable	Modal elements
Estimate equivalent	Boundary information only	On-line disturbance	Fast	Experiential equivalent elements
Coherent equivalent	Detail model	Off-line large disturbance	Acceptable	Aggregated equivalent elements

3.4.1 Coherency-based Equivalent Method

The coherency equivalent technique is based on identifying the coherent generators by comparing the generator's rotor angle response during an off-line large disturbance condition. If the swing curves of the generator are similar, the generators can be aggregated as one by modifying the parameters of the generator. This means the reduction degree is mainly dependents on how many coherent generators can be found. Afterwards, the generators are aggregated, and load buses eliminated accordingly. Consequently, the full order power system which contains several buses can be

represented as a reduced power system with reduced number of bus. The result of the reduced system is a number of aggregated real elements with modified parameters.

The procedure to establish dynamic equivalent model used in this study is based on the works of by Yang et al. (2005). The overall procedure can be divided into three stages: identification of coherent generators, aggregation of coherent generators and network reduction. The first two steps are preparatory to the third which is a static equivalent procedure available in PSS/E (Milano and Srivastava, 2009). A description of the technique involved in each of the three steps follows

3.4.1.1 Identification of coherent generators

Coherent generators are identified at this stage and the coherency identification technique is based on the fact that a group of generating units tend to swing together following a disturbance in the multi-machine power system. Two generator buses are to be defined as coherent if the angular difference between them is constant within a certain tolerance over a certain time interval when the power system is perturbed. Mathematically expressed as:

$$\left.\begin{aligned} \frac{\overline{V}_i(t)}{\overline{V}_j(t)} &= \frac{V_i(t)}{V_j(t)} e^{j[\delta_i(t)-\delta_j(t)]} \\ &= \frac{V_i(0)}{V_j(0)} e^{j[\delta_i(0)-\delta_j(0)]} = constant \end{aligned}\right\} \quad (3.1)$$

If the voltage magnitude of the coherent buses is assumed to be constant, the coherency condition of equation 3.1 simplifies to

$$\delta_i(t) - \delta_j(t) = \delta_{ij}(t) = \delta_{ij}(0) = constant \quad (3.2)$$

Where $\delta_i(0)$ and $\delta_{ij}(0) = \delta_i(0) - \delta_j(0)$ are the initial values of the variables calculated for the reduced model. This study identifies coherent generators when a fault is applied in the study system and the swing curves in the external systems are observed and those

generators with the most identical swing curves that satisfy equation 3.2 are classified as coherent.

3.4.1.2 *Dynamic aggregation of generators*

Coherent group of generating units are aggregated into an equivalent generator that exhibits the same speed, voltage and total mechanical and electrical power as the group during any disturbance where the units in the group remain constant. The aggregation of coherent generator buses is based on the Zhukov's method (Machowski, et al. 2008) in which each terminal bus is connected through an ideal transformer with complex turns ratio to the equivalent bus. The voltage of the equivalent bus is defined as the average voltage of the coherent generator buses, which can be mathematically expressed as

$$V_t = \frac{\sum_{k=1}^{n} V_k}{n} \tag{3.3}$$

$$\theta_t = \frac{\sum_{k=1}^{n} \theta_k}{n} \tag{3.4}$$

Where V_t is the voltage of the equivalent bus, V_k is the voltages at coherent buses k and θ_t is the phase angle of the equivalent bus voltage.

The turns ratio of the ideal transformer is given by

$$\bar{a}_k = \frac{\bar{V}_k}{\bar{V}_t} \tag{3.5}$$

The mechanical (P_m^*) and electrical (P_e^*) power of the equivalent generator is the sum of the mechanical and electrical power of all the generators in the same coherent group:

$$P_m^* = \sum_{i=1}^{n} P_{mi} \tag{3.6}$$

$$P_e^* = \sum_{i=1}^{n} P_{ei} \tag{3.7}$$

The equivalent generator is represented by the classical model with constant equivalent transient emf and the swing equation of the rotor given by

$$\left(\sum_{i=1}^{n} M_i\right)\frac{d\omega}{dt} = \sum_{i=1}^{n} P_{mi} - \sum_{i=1}^{n} P_{ei} - \left(\sum_{i=1}^{n} D_i\right)\omega \quad i = 1,2 \ldots \ldots n \tag{3.8}$$

Where ω is the angular frequency of the coherent generator and is assumed to be identical. Hence the inertia (M^*) and damping (D^*) constant of the equivalent generator are given by

$$M^* = \sum_{i=1}^{n} M_i \tag{3.9}$$

$$D^* = \sum_{i=1}^{n} D_i \tag{3.10}$$

The transient reactance$(X_d^{'})$ of the equivalent generator is obtained by parallel combination of the transient reactance of all the coherent generators:

$$X_d^{'} = \frac{1}{\sum_{i=1}^{n} \frac{1}{X_{di}^{'}}} \tag{3.11}$$

3.4.1.3 ***Network reduction***

The network reduction procedure in PSS/E is the topological reduction method. This process involves deleting some load buses in order to reduce the size and complexity of the network. The selected load buses are eliminated by performing Gauss elimination operation on the admittance matrix of the external system.

The admittance matrix equation of the external system can be written in the partitioned form as

$$\begin{bmatrix} I_R \\ I_D \end{bmatrix} = \begin{bmatrix} Y_{RR} & Y_{RD} \\ Y_{DR} & Y_{DD} \end{bmatrix} \begin{bmatrix} V_R \\ V_D \end{bmatrix} \tag{3.12}$$

Where subscript R and D refer to the nodes to be retained and deleted respectively.

The equivalent is obtained by rearranging the second row of Equation 3.12 as

$$V_D = Y_{DD}^{-1}(I_D - Y_{DR}V_R) \tag{3.13}$$

Substituting equation 3.13 into the first row of equation 3.12 to give

$$I_R = Y_R V_R + K_l I_D \tag{3.14}$$

Where

$$Y_R = Y_{RR} - Y_{RD}Y_{DD}^{-1}Y_{DR} \tag{3.15}$$

$$K_l = Y_{RD}Y_{DD}^{-1} \tag{3.16}$$

The admittance matrix Y_R corresponds to a reduced equivalent network that consists of the retained buses and the equivalent branches linking them. The matrix K_l is often referred to as the distribution matrix which passes the node currents from the eliminated buses to the retained buses. The first term of equation 3.15 specifies a set of equivalent branches and static shunt elements connecting the retained nodes, while the second term specifies a set of equivalent currents which must be impressed on the retained nodes to reproduce the effect of load currents at the deleted nodes. These equivalent currents may be translated into equivalent constant real and reactive power loads and added to the original loads at the retained buses.

The algorithm for coherency based network reduction as described in the preceding section is presented in Figure 3.3

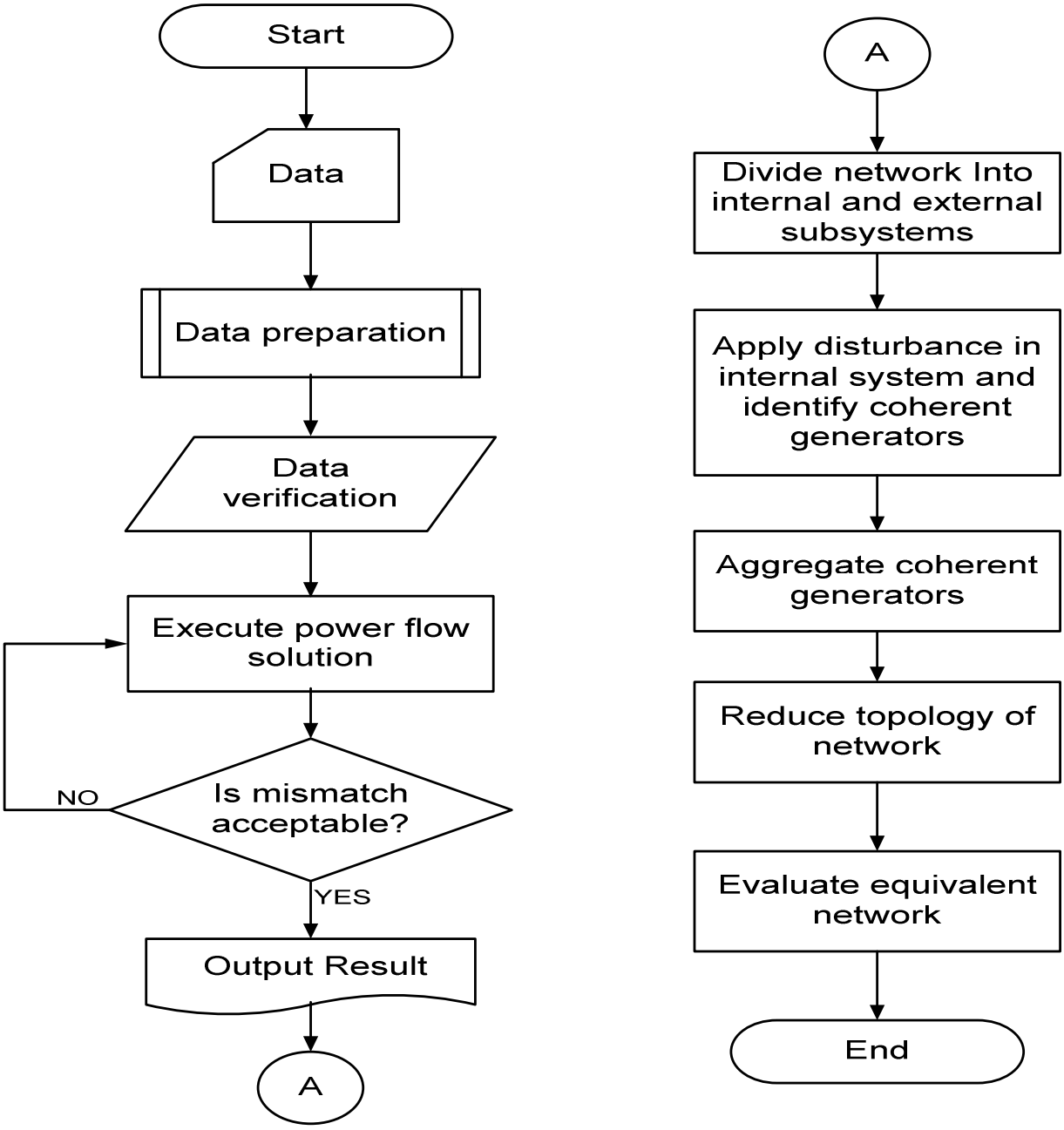

Figure 3.3: Flow chart for the implementation of coherency based network reduction technique

3.4.2 Dynamic Reduction Implementation

The procedure as established in Section 3.4.1 was applied to the Nigerian 330kV network. Since the area of interest is the generator at Egbin and the south west buses, these are identified as the study system. Two other subsystems known as the external systems were created based on the type of generation (i.e. hydro and thermal) and

geographical location. Buses included in the hydro external subsystem are Jebba, Kainji, Shiroro, Birnin kebbi, Kaduna, Kano, Jos and Gombe and the thermal subsystem comprise of Benin, Sapele, Aladja, Delta, Onitsha, Alaoji, Afam, New heaven and Ajaokuta. A three-phase fault was applied in the internal subsystem on the bus at Ikeja west in order to identify the coherent generators. Figure 3.4 shows the response (swing curve) of the generators to this disturbance which was cleared by the tripping of the Ikeja west- Oshogbo line at 0.2 second. The results show that the swing curves of the generators in close proximity to each other are more coherent even though there are more generators within the same area. Two groups of coherent generators were thus identified as shown by the swing curves in Figure 3.4. The groups are: {Jebba, Kainji} and {Delta, Sapele}. Generators at Shiroro and Afam were not included in any of the groups because they were less coherent when compared to the identified groups. The voltage and angle of the equivalent bus for each coherent group of generators was calculated using equations (3.3) and (3.4). The reduced network is shown in Figure 3.5.

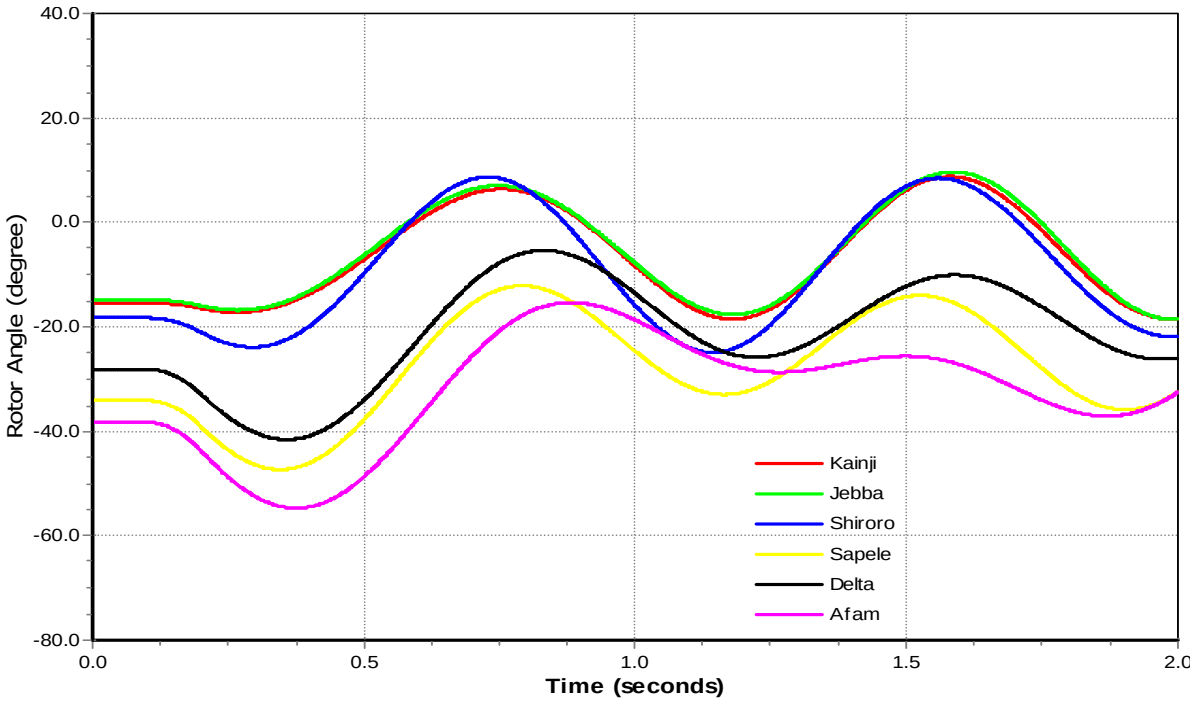

Figure 3.4: Rotor Angle Response of Generators in the External Systems

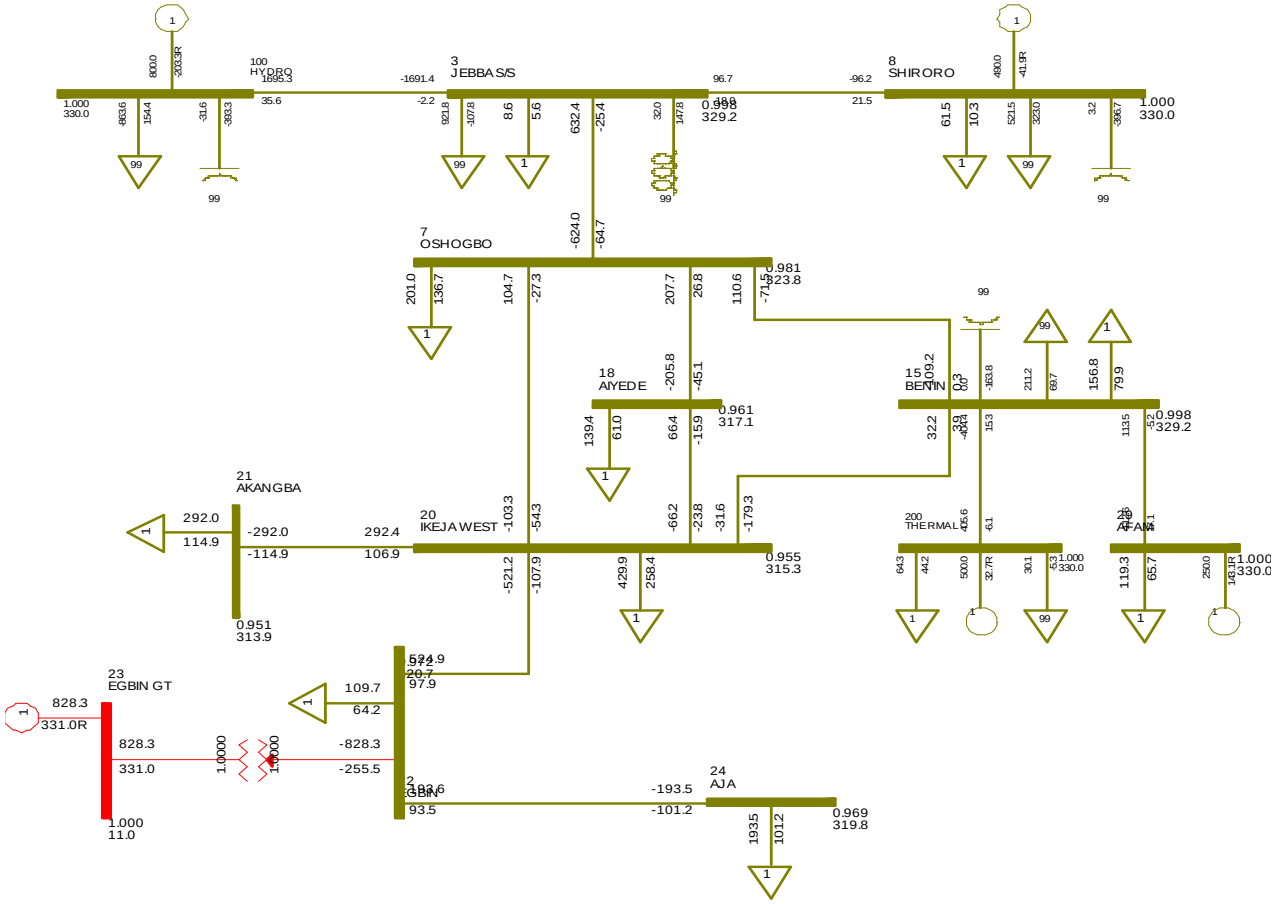

Figure 3.5: The Reduced Nigerian 330kV transmission network

The coherent generators in each group are lumped together to form two equivalent generators called combined hydro (i.e. Kanji and Jebba) and Combined thermal (i.e. Sapele and Delta) while the network was reduced by deleting the load buses using the network reduction module of PSS/E.

The equivalent network thus obtained is reduced to 5 generators, 17 loads, 13 buses and 14 branches. Table 3.2 gives a comparison between the original and reduced system.

Table 3.2: Comparison between the original and reduced system

	Generators	Loads	Buses	Branches
Original	7	21	31	33
Reduced	5	16	13	14
Reduction (%)	29	24	58	58

3.5 Multi-Machine Power System Model

There are many elements affecting the stability of power system that needs to be addressed before studies are conducted, hence the analysis of any stability studies requires appropriate model of each network components. Transient stability analysis requires the appropriate modelling of critical components like generators, transmission lines, loads etc. This section outlines how the multi-machine network is handled during dynamic simulation.

The steady state operation of a power system is determined by solving the initial power flow of the network to determine the initial bus voltages and angles. Equation 3.17 gives the injected currents at the generator buses prior to a disturbance.

$$I_i = \frac{S_i^*}{V_i^*} = \frac{P_i - jQ_i}{V_i^*},\ i = 1,2,\ldots.n \tag{3.17}$$

Where n is the number of generators V_i is the terminal voltage of the i^{th} generator P_i and Q_i are the generator real and reactive powers.

The generator voltage behind transient reactance is obtained from equation 3.18

$$E' = V_i + jX_d' I_i \tag{3.18}$$

Loads are converted to equivalent admittance using equation 3.19

$$y_{j0} = \frac{S_j^*}{|V_j|^2} = \frac{P_j - jQ_j}{|V_j|^2} \tag{3.19}$$

The equivalent network with all load converted to admittances is shown in Figure 3.6.

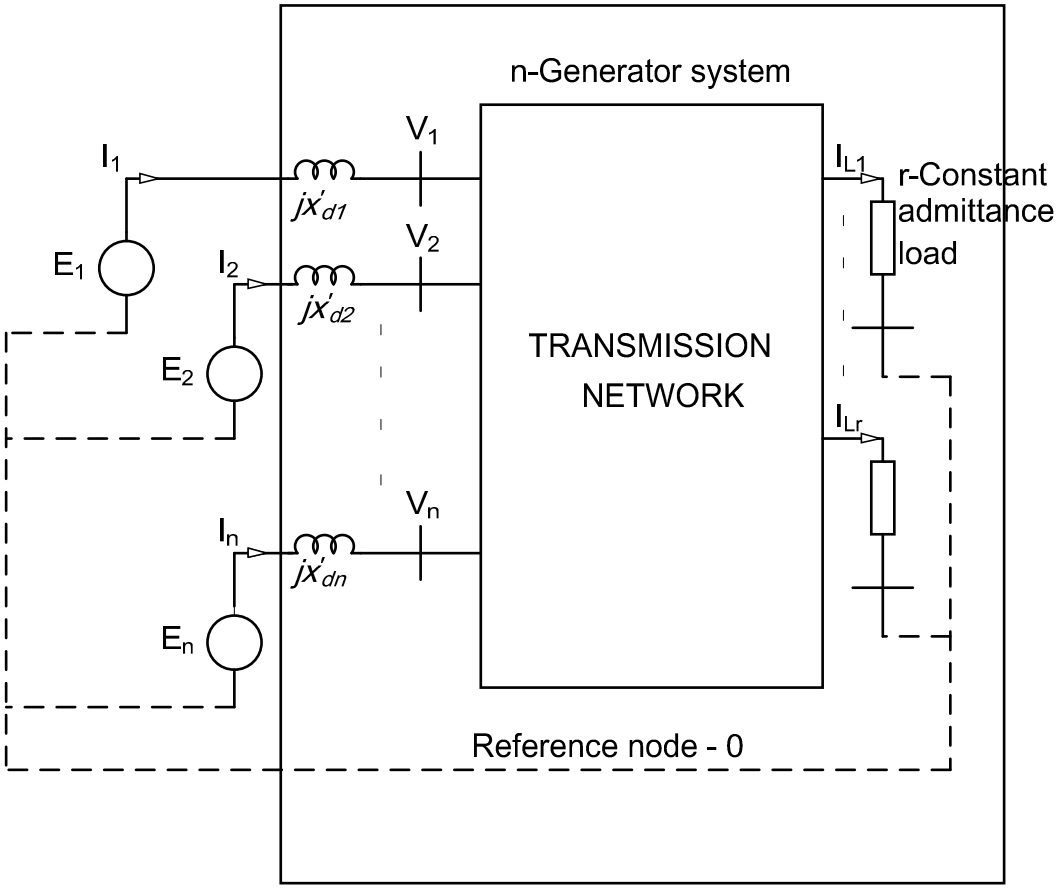

Figure 3.6: Multi-machine system representation

3.5.1 Mathematical Modelling

Once the Y matrix for each network condition (pre-fault, during and after fault) is calculated, all nodes except for the internal generator nodes are eliminated to obtain the Y matrix for the reduced network. The reduction can be achieved by matrix operation bearing in mind that all the nodes have zero injection currents except for the internal generator nodes. In a power system with n generators, the nodal equation can be written as:

$$\begin{bmatrix} I_n \\ 0 \end{bmatrix} = \begin{bmatrix} Y_{nn} & Y_{nr} \\ Y_{rn} & Y_{rr} \end{bmatrix} \begin{bmatrix} V_n \\ V_r \end{bmatrix} \tag{3.20}$$

Where the subscript n represents generator nodes and the subscript r represent all other nodes. Expanding equation (3.20),

$$I_n = Y_{nn}V_n + Y_{nr}V_r \tag{3.21}$$

$$0 = Y_{rn}V_n + Y_{rr}V_r \tag{3.22}$$

Eliminating V_r to find

$$I_n = (Y_{nn} - Y_{nr}Y_{rr}^{-1}Y_{rn})V_n = Y_R V_n \tag{3.23}$$

Thus the reduced matrix can be written as:

$$Y_R = (Y_{nn} - Y_{nr}Y_{rr}^{-1}Y_{rn}) \tag{3.24}$$

The reduced bus admittance matrix has the dimensions (n x n), where n is the number of generators. The network reduction as illustrated by equations 3.20 to 3.24 is a convenient analytical technique that can be used only when the loads are treated as constant impedances. The electrical power output of each machine can now be expressed in terms of the machine's internal voltages. The power into the network at node i which is the electrical power output of the i[th] machine is given by equation 3.25.

$$P_{ei} = \sum_{j=1}^{n} |E_i E_j Y_{ij}| \, cos(\theta_{ij} - \delta_i + \delta_j) \;\; i = 1,2,3 \ldots\ldots, n \tag{3.25}$$

The dynamics of the rotor angle δ and speed ω as described by the swing equations is given as

$$\frac{d\Delta\omega}{dt} = \frac{1}{2H}[T_m - T_e - D\Delta\omega] \tag{3.26}$$

$$\frac{d\delta}{dt} = \omega_0 \Delta\omega \tag{3.27}$$

Where $\Delta\omega = \omega - \omega_0$ is the speed deviation of rotor angular speed from the synchronous speed ω_0, H is the per-unit inertia constant, T_m and T_e are the per-unit mechanical and electrical torque respectively and D is the damping factor.

For the i[th] machine, the swing equation becomes

$$\frac{2H_i}{\omega_0}\frac{d\Delta\omega_i}{dt} + D_i\Delta\omega_i = P_{mi} - \left[\sum_{j=1}^{n}\left|E_iE_jY_{ij}\right|\cos\left(\theta_{ij} - \delta_i + \delta_j\right) \quad i = 1,2,3 \ldots\ldots, n\right] \quad (3.28)$$

$$\frac{d\delta_i}{dt} = \omega_i - \omega_0 \quad i = 1,2, \ldots\ldots, n \quad (3.29)$$

Prior to disturbance, the mechanical input power is at equilibrium with the electrical power output, and we have:

$$P_{mi}^{pf} = \sum_{j=1}^{n}\left|E_iE_jY_{ij}^{pf}\right|\cos\left(\theta_{ij}^{pf} - \delta_i^{pf} + \delta_j^{pf}\right) \quad i = 1,2,3 \ldots\ldots, n \quad (3.30)$$

The superscript pf is used to indicate the pre-transient conditions. As the network changes due to switching during the fault, the corresponding values will be used in the above equations.

The algorithm for the implementation of transient stability analysis is presented in Figure 3.7

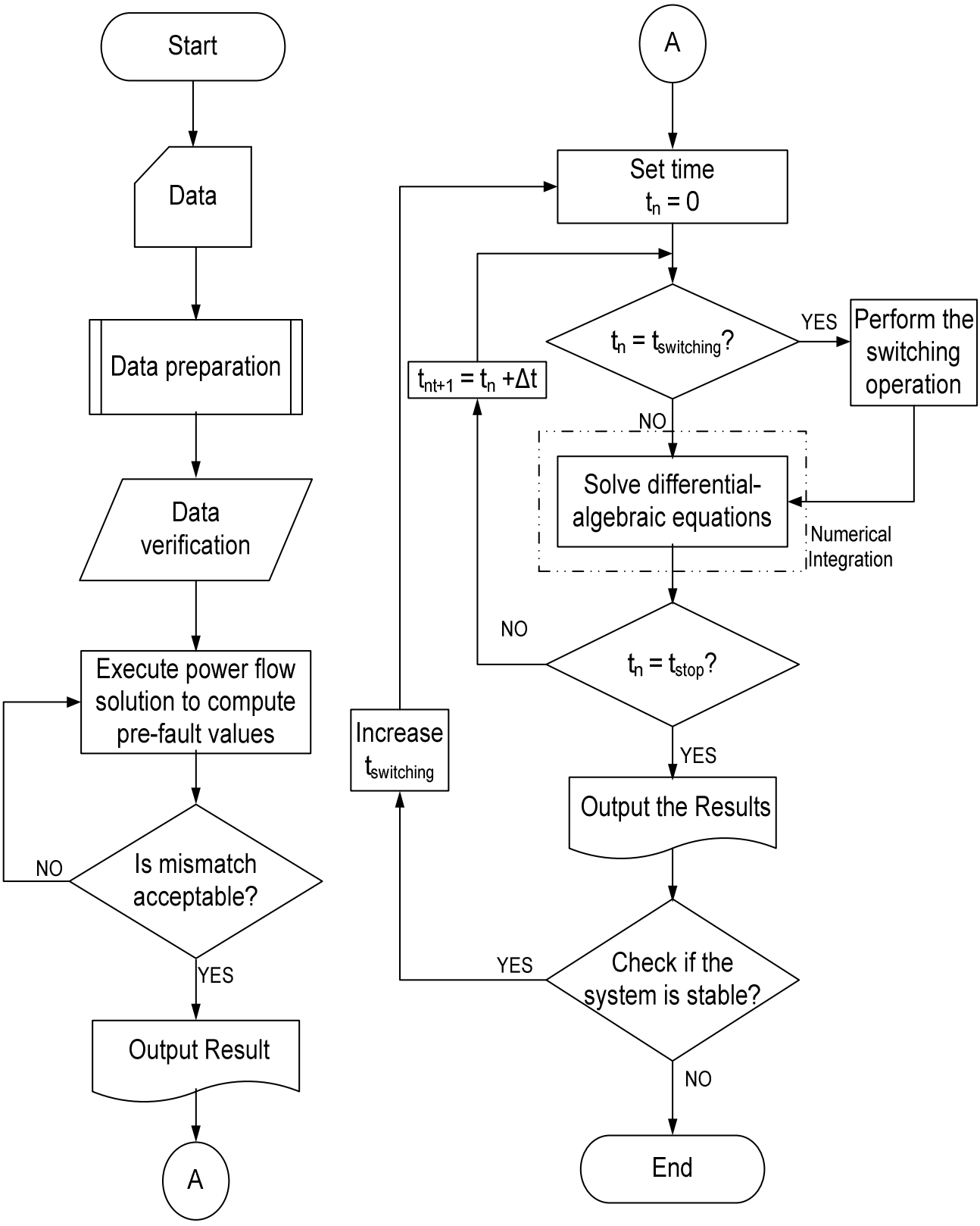

Figure 3.7: Basic procedure for transient stability study

3.6 Transient Stability Studies

The robustness of a system is largely determined by its response to a disturbance such as load switching, short circuits, loss of lines and/or generators, etc. The effects of large disturbances on the system can be investigated by considering the loss of one or more transmission lines, generators or load and faults which may be categorized as one of four types according to their effect on system stability; single line to ground, line to line, double line to ground and balanced three–phase faults. The first three types constitute severe unbalanced operating conditions but the fourth type is the most severe switching action with regard to the transient stability and it is selected to be investigated. An indicator of system stability is given by the rotor angle plot (swing curves) of the machines and the critical clearing time (CCT) of the system before instability occurs. The critical clearing time is the maximum allowable time that a fault can be sustained without the synchronous generator becoming unstable. In the analysis, the generator models selected in PSS/E was the classical model GENCLS, except for the generator at Egbin modelled with a wound rotor model GENROU used for thermal plants. These generator models are able to reflect the characteristics of the actual generators based on the chosen parameters. Since the response of Egbin generator to the device during severe disturbance was of concern, the UPFC in the network was located between the buses at Egbin and Ikeja-west as illustrated in Figure 3.8.

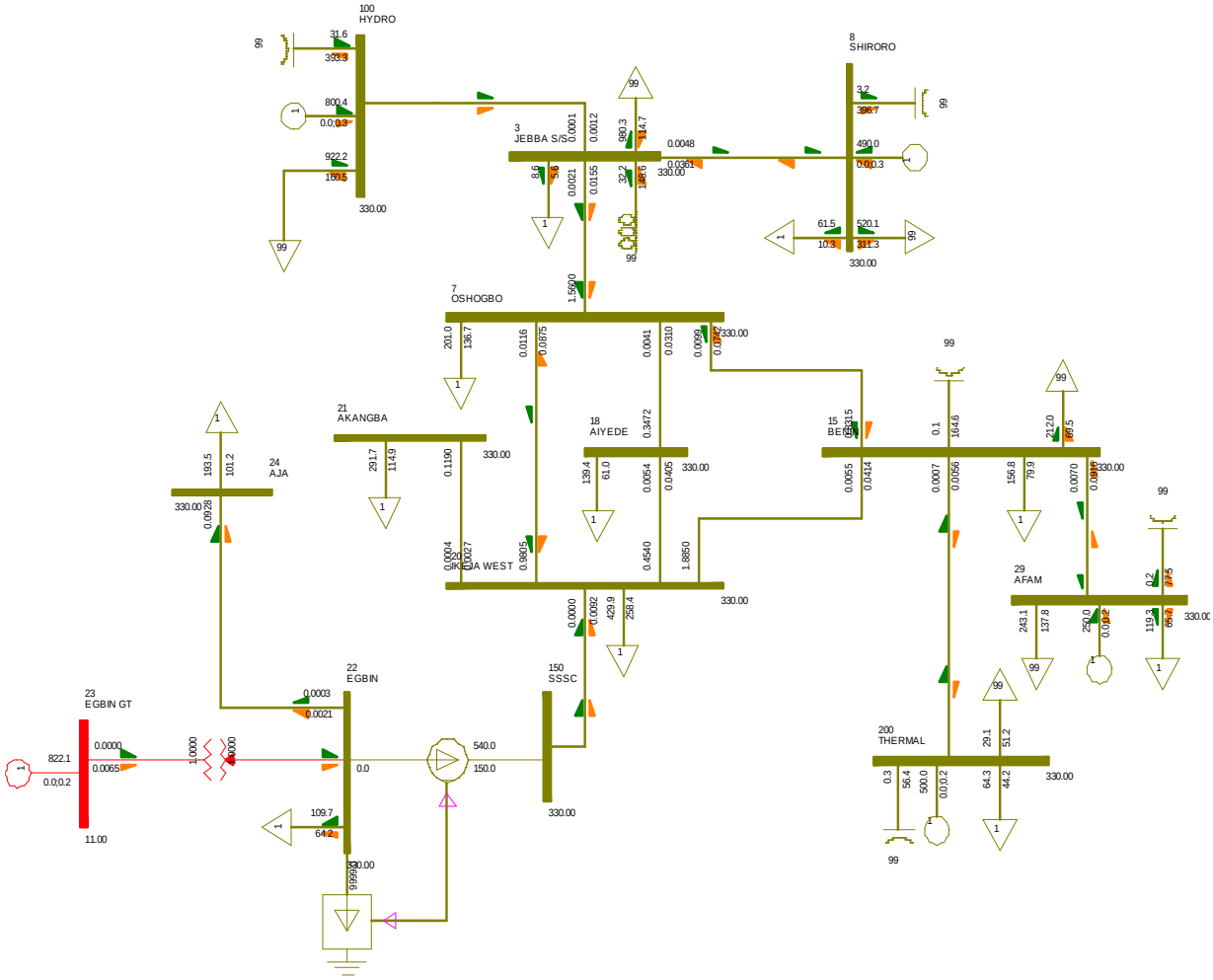

Figure 3.8: The Reduced Nigerian 330kv Transmission Network Including UPFC Modelled in PSS/E

3.6.1 UPFC Model Implementation in PSS/E

It was stated earlier that the simulation study was conducted in the SIEMENS PTI simulation software suite PSS/E. PSS/E is used to model and study power systems in static and dynamic operation and it is the tool of choice by most utility companies around the world. It was, however, discovered that PSS/E model library does not have a dynamic model for the series component of the UPFC to be used in this investigation and a user defined model had to be developed.

This was achieved using the Application Program Interface routines (APIs) developed in Python programming language to control the operation of the program during the dynamic simulation and solving for the SSSC model (see Appendix D3 and E). The

python programme interpreter is an embedded program within PSS/E. The series device model developed is based on the works of Hernández, et al, 2011. Based on the works, VSC switching dynamics can be neglected for the time scale of transient stability analysis, and the SSSC can be represented as a controllable voltage source behind an equivalent transformer reactance. This research uses the same variable impedance model for the SSSC component of the UPFC. In PSS/E it is modelled as a zero impedance line connecting the sending and receiving end bus (i.e. Egbin Sub-station and Ikeja-west). This way, the impedance imposed in series with the transmission line where it is connected varies based on the variation of the power flowing in the line from the steady state value. The flow of control during the dynamic simulation and modelling of series part of the UPFC is illustrated in figure 3.9. However, the available dynamic model in PSS/E was used for the STATCOM component of the UPFC.

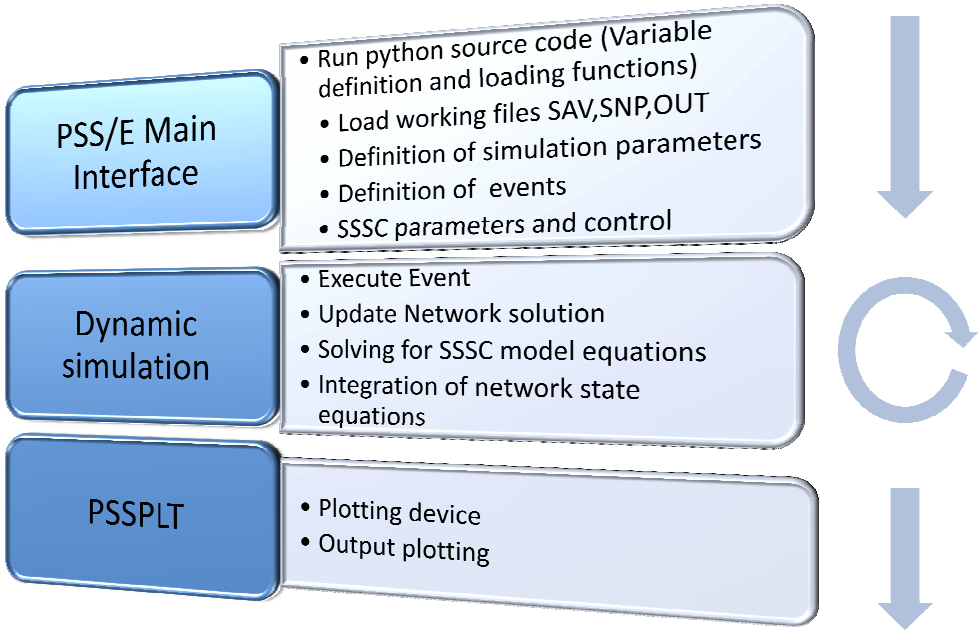

Figure 3.9: Structure of Python code integration within PSS/E (Hernández, et al, 2011)

CHAPTER FOUR

RESULTS AND ANALYSIS

4.1 Introduction

This chapter presents an evaluation of the network reduction implemented in chapter three to determine if the reduced order model can represent the original network. In addition, the developed UPFC dynamic model is incorporated into the reduced network and simulation studies of the transient stability analysis conducted. The results are also presented here.

4.2 Network Reduction Results Evaluation

To assess the accuracy of the equivalent network created in section 3.5.2, a disturbance, by way of sudden loss of load is applied on the bus at Ikeja-west. Simulation is performed on the original and equivalent system respectively for 2Seconds and the results are shown in Figures 4.1 to 4.5.

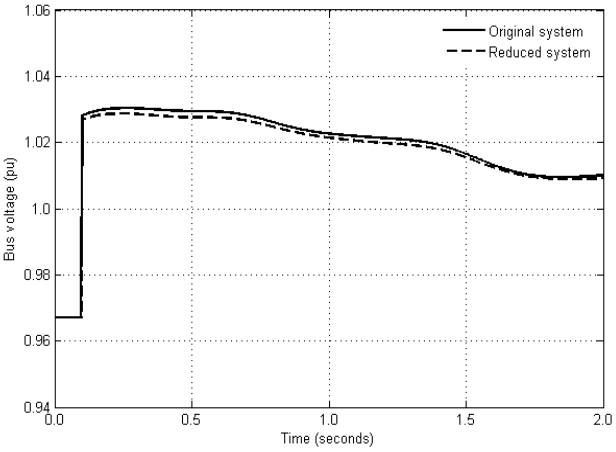

Figure 4.1: Voltage Response of the Ikeja West Bus in the Original and Reduced System

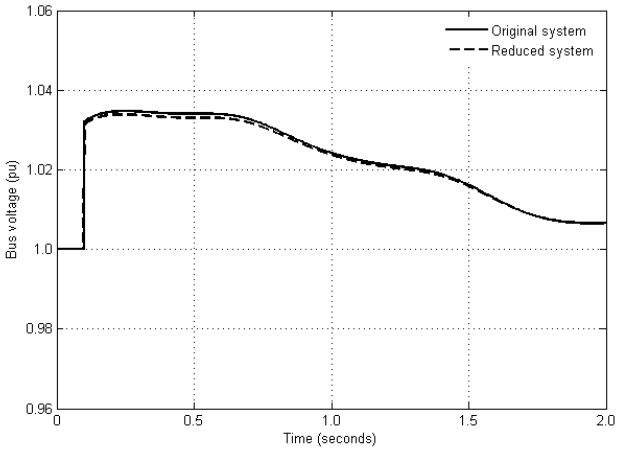

Figure 4.2: Terminal Voltage Response of the Generator at Egbin in the Original and Reduced System

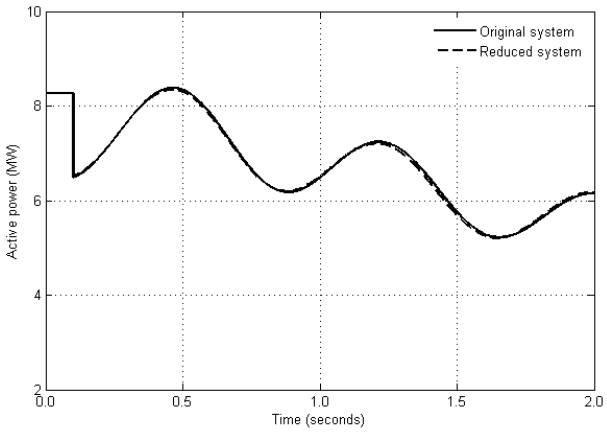

Figure 4.3: Electrical Power Response of Generator at Egbin under a Load Loss Disturbance at Ikeja West in the Original and Reduced System

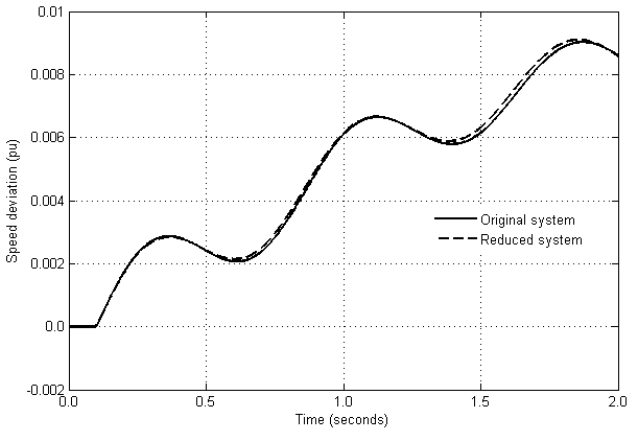

Figure 4.4: Speed Deviation Response of Generator at Egbin under a Load Loss Disturbance at Ikeja West in the Original and Reduced System

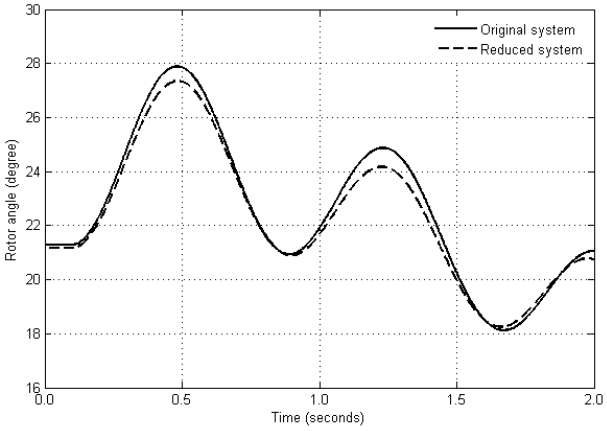

Figure 4.5: Rotor Angle Response of Generator At Egbin under a Load Loss Disturbance at Ikeja-west in the Original and Reduced system

With the sudden loss of load, the voltage at the buses increases and slowly returns to its original value as illustrated in Figures 4.1 and 4.2. Voltage magnitudes of the reduced system reliably reproduce the behaviour of the voltage of the original system. The generator electrical power response of the generator at Egbin is shown in Figure 4.3. The response of the network is reproduced when the network is reduced and when it is full. Rotor angle oscillates after the load loss but has reduced amplitude with time while

the speed deviation of Egbin generator for a reduced and full network is as illustrated in Figures 4.4 and 4.5 respectively.

Based on the responses from the Figures 4.1 to 4.5, the reduced system can adequately represent the original system, and was thus used for the transient stability analysis.

4.3 Transient Stability Results and Analysis

The system was subjected to a three phase fault at:

i. The terminal of the generator at Egbin.
ii. Ikeja-west Bus (as the bus with the largest load)
iii. Benin Bus (as the key bus that links the east with the rest of the network)

In all cases, the system was operating at the steady state and the fault was simulated at 0.1seconds. The fault was cleared after five cycles by the removal of the fault. The evaluation of the system response with and without the UPFC device in the network is described in subsequent sections.

4.3.1 Steady-State Performance of UPFC

When the system was simulated without the UPFC in the network, it was observed that the some buses had low voltages; although, none violated the voltage control policy limit of 330kV+5% and -15% on the 330kV buses (Power Holding Company of Nigeria Plc (PHCN), 2009). But with the introduction of the UPFC, system wide bus voltages were improved even as some of these buses were far away from the point of connection of the device. Table 4.2 gives a comparison of the voltage profiles of some of the buses.

Table 4.1: Comparison of Steady-state Bus Voltage Profiles

Bus Name	Initial Bus Voltage (pu)	Bus Voltage With UPFC (pu)	Improvement (pu)
Aiyede	0.966	0.988	0.022
Ikeja-west	0.944	0.981	0.037
Akangba	0.940	0.977	0.037
Egbin S/S	0.953	1.00	0.047
Egbin GT	0.974	1.00	0.026
Ajah	0.951	0.997	0.046

The improvement was greatest at the point of connection at Egbin sub-station followed by the bus at Ajah which is directly coupled to Egbin. Ikeja-west and Akangba have the same level of improvement even though the bus at Akangba is further away. This is best explained by the value of the impedance between Akangba and Ikeja-west which is 0.00266pu, while between Egbin and Ikeja-west has an impedance of 0.00916pu showing that the effect of the UPFC could be influenced by the electrical distance which is also a function of line impedance.

4.3.2 Fault on Egbin Generator terminal

The response of the system to a three-phase fault on the terminal of the generator at Egbin was considered to examine both transient stability and power oscillation damping capabilities of the UPFC. The swing curves of the 5 generators are shown in figure 4.6 and it is observed that the generator at Egbin was the most severely disturbed considering that it was the faulted bus. Figure 4.7 gives a comparison of the response of the rotor angle for the generator at Egbin when the UPFC operation was activated for the same fault scenario. It could be observed the rotor angle excursion is reduced when the UPFC is in operation. The bus voltages at Egbin, Ikeja-west, Oshogbo, and Benin

dropped to zero, 0.35p.u, 0.67p.u and 0.72p.u respectively during the fault but recovered quickly after the fault was cleared to near the steady state values as illustrated in Figure 4.8. The physical interpretation of these voltage profiles is that during the fault, Egbin generator did not generate electrical power for the fault duration, while the other generators voltage profiles dropped well below the minimum allowable value of 0.95pu albeit just for 5cycles. These voltage profiles, if sustained longer can lead to system collapse. The terminal voltage profiles of the generator at Egbin with and without the UPFC are shown in Figure 4.9, while the voltage returned to pre-fault steady state value at about 5.5 seconds when the UPFC was in the system. Some oscillations could be observed without it, showing the effectiveness of the shunt part of the UPFC in voltage control.

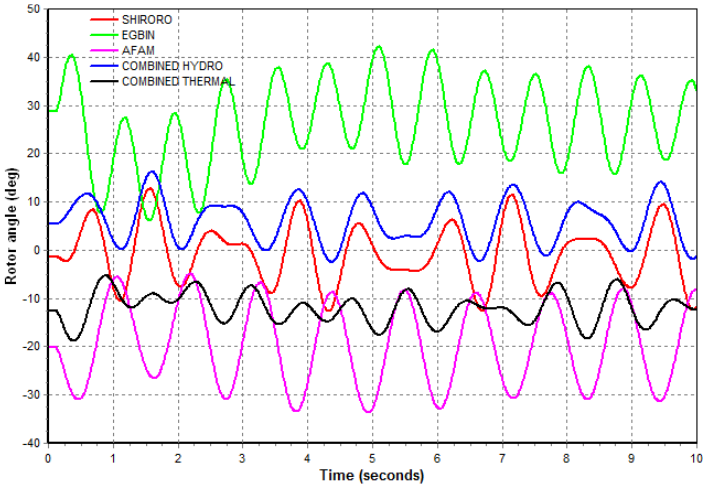

Figure 4.6: Swing Curves of Generators in the Network Following a Three-Phase Fault at Egbin Generator Terminal

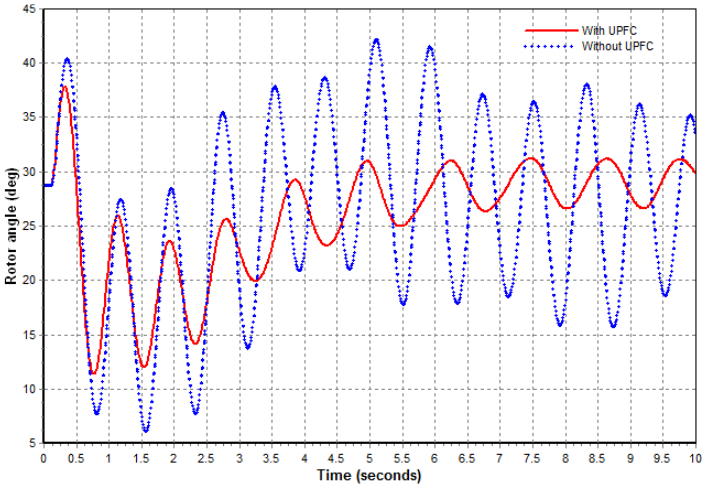

Figure 4.7: Swing Curve of the Generator at Egbin With and Without UPFC in the System Following a Three-Phase Fault at Egbin Generator Terminal

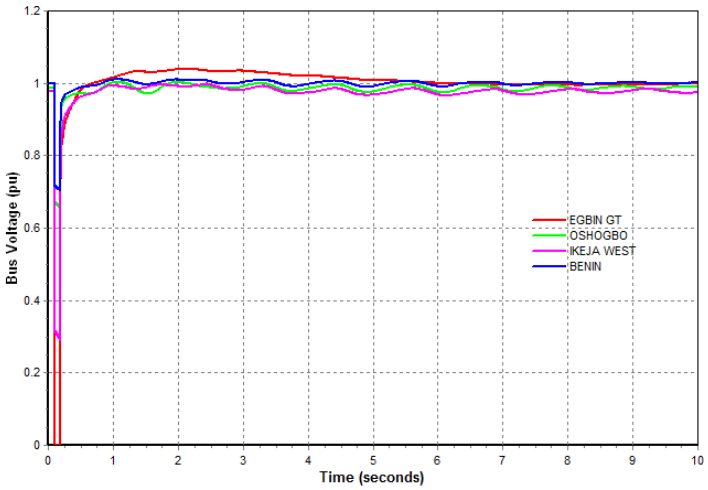

Figure 4.8: Bus Voltages at Benin, Ikeja West, and Egbin Following a Three-Phase Fault at Egbin Generator Terminal Bus.

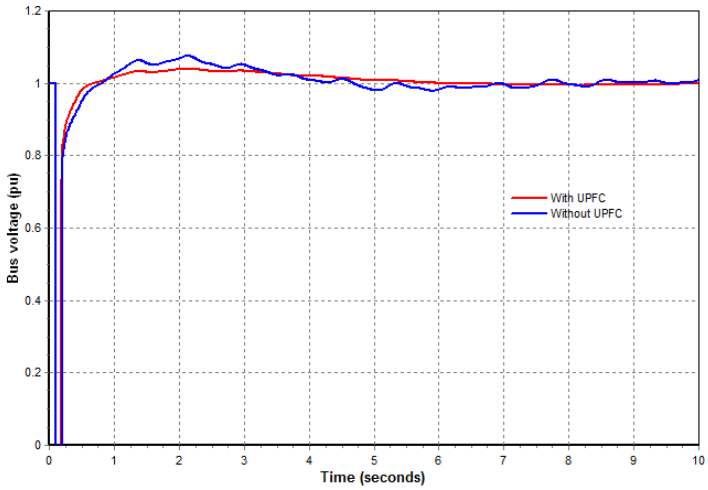

Figure 4.9: Terminal Voltage Response of the Generator at Egbin With and Without UPFC in the System Following a Three-Phase Fault at Egbin Generator Terminal

The effect of the series part of the device can be observed in Figure 4.10 where the oscillation of the power flowing through the Egbin - Ikeja-west line was damped with the UPFC in service. The initial power flowing through the line was 540MVA from Egbin to Ikeja-west. This steady state flow was restored at about 10 seconds after some oscillations that resulted from the applied disturbance. The implication is that more power can be delivered to the load within a short period of time when there is a UPFC in the system. The system was, however, subjected to an extended period of fault clearing time to determine the critical clearing time (CCT) of the system before instability. It was revealed that without the UPFC in operation the critical clearing time of the system was 380ms while it increased to 590ms when the UPFC was in operation. Figure 4.11 is the rotor angle response of the generator at Egbin showing the first swing instability when the CCT was 380ms. The origin of this instability can be traced to the response of the electrical and mechanical power output of the generator as shown in Figures 4.12 and 4.13. Figure 4.13 shows that at the point of instability the synchronising torque in the form of mechanical power generated was insufficient to sustain the electrical power requirement of the available loads leading to instability

without the UPFC device. Conversely, with the UPFC device, the mechanical power output is able to relatively sustain the loads, albeit, oscillating and over time will eventually return to pre steady state value.

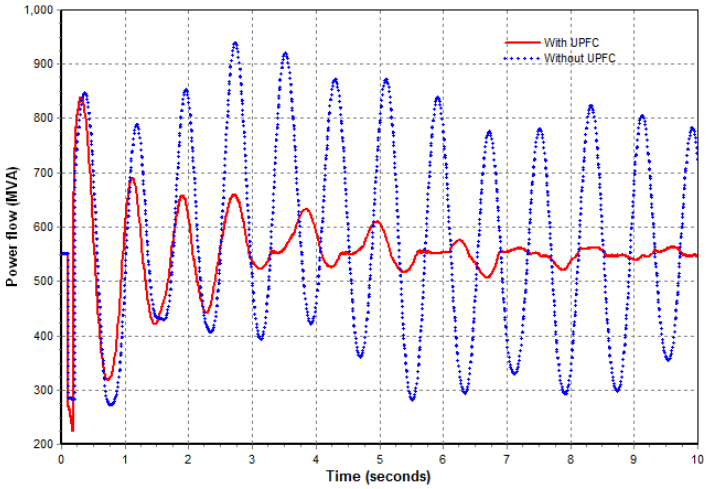

Figure 4.10: Power Flow in the Line between Egbin and Ikeja-West Showing the Oscillation Damping Effect of UPFC Following a Three-Phase Fault at Egbin Generator Terminal

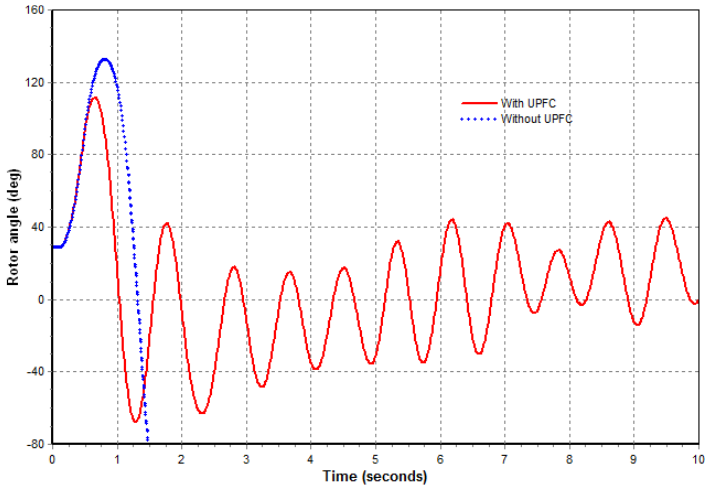

Figure 4.11: Swing Curve of the Generator at Egbin Showing Instability Following a Three-Phase Fault at Egbin Generator Terminal

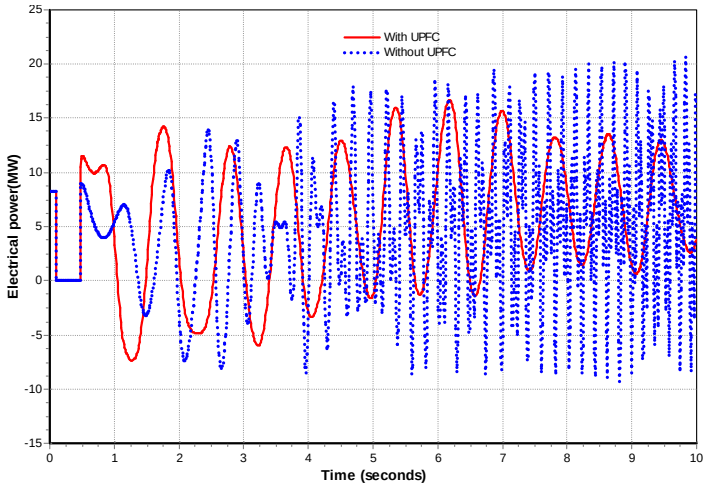

Figure 4.12: Egbin Generator Electrical Power Output During Instability Following a Three-Phase Fault at Egbin Generator Terminal

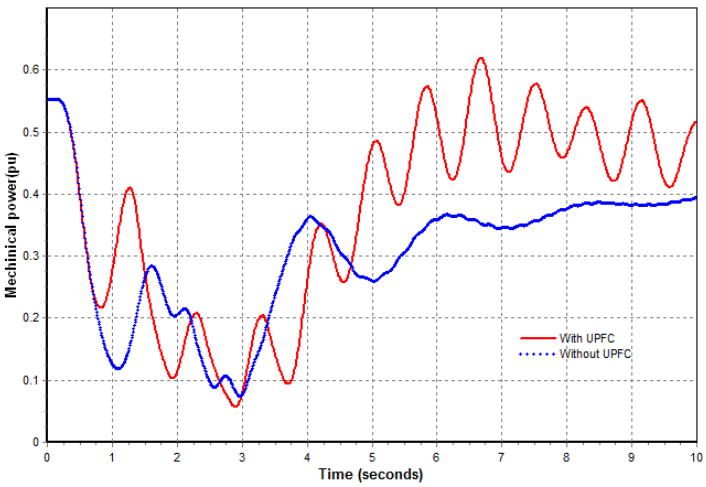

Figure 4.13: Egbin Generator Mechanical Power Output During Instability Following a Three-Phase Fault at Egbin Generator Terminal

4.3.3 Fault on Ikeja-West Bus

For a bus with the largest load of 430MWon the network, the system response to a 3 phase fault on the network was important. The performance of the UPFC during such disturbance was even more critical due to the size of the load on the bus. The swing curves of the 5 generators for fault duration of 5 cycles are shown in Figure 4.14. Figure 4.15 gives a comparison of the response of the rotor angle for the generator at Egbin when the UPFC operation was activated for the same fault scenario. It could be observed the rotor angle oscillation is reduced when the UPFC is in operation. Although, in comparison with when the fault Egbin, the maximum angle in reduced. Being the faulted bus, the voltage of the bus at Ikeja-west falls to zero for the fault duration as shown in Figure 4.16. This means that the largest load on the system momentarily lost power for that duration which could be far-reaching if the loads are critical, emphasizing the need for equipments that will not allow for such fault to be sustained. The bus voltages at Egbin, Oshogbo, and Benin dropped to 0.45p.u, 0.55p.u and 0.6p.u respectively during the fault. The voltage profiles of the buses however returned to near steady state values. As the most significant generator in this study, the terminal voltage of the generator at Egbin with and without the UPFC is shown in Figure 4.17. While some oscillations can be observed without UPFC, the effect of shunt part (STATCOM) of the UPFC in voltage control is shown when the voltage of the Egbin generator returned to pre-fault steady state value at about 6.0 seconds when the UPFC was in the system.

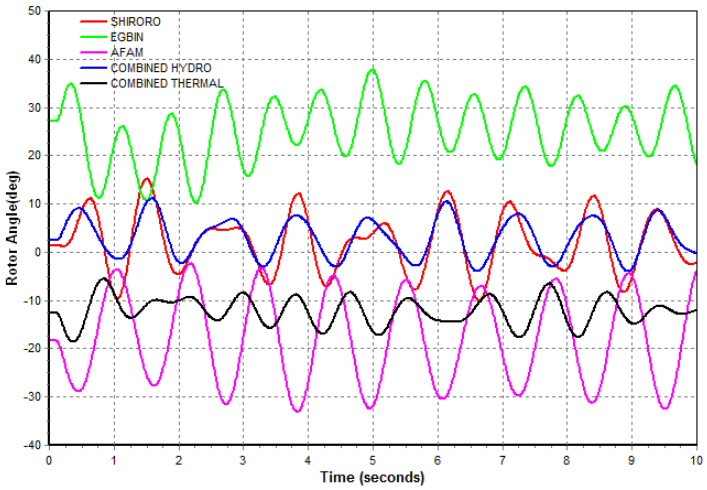

Figure 4.14: Swing Curves of Generators in the Reduced Network Following a Three-Phase Fault at Ikeja-West Bus

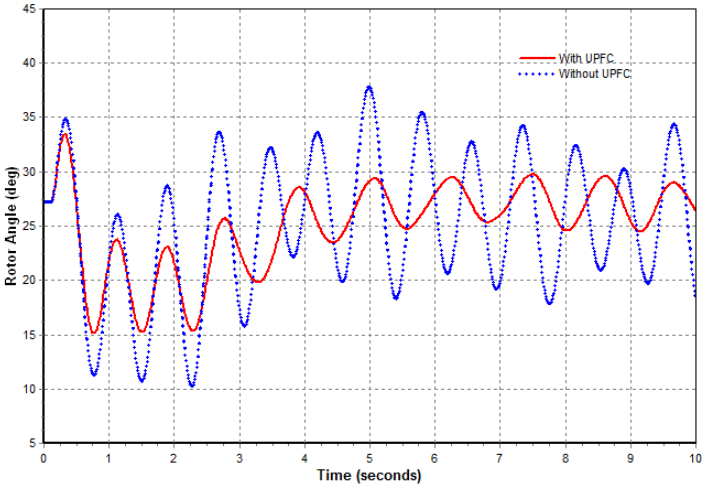

Figure 4.15: Swing Curve of the Generator at Egbin With and Without UPFC in the System Following a Three-Phase Fault at Ikeja-West Bus

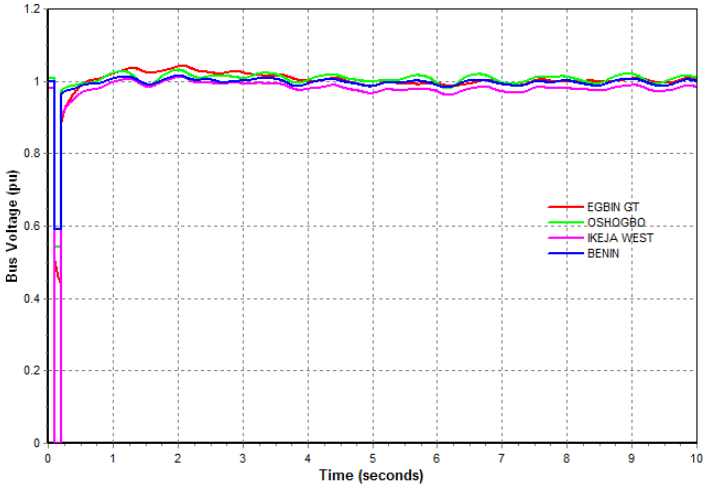

Figure 4.16: Bus Voltages at Benin, Ikeja West, and Egbin Following a Three-Phase Fault at Ikeja-West Bus

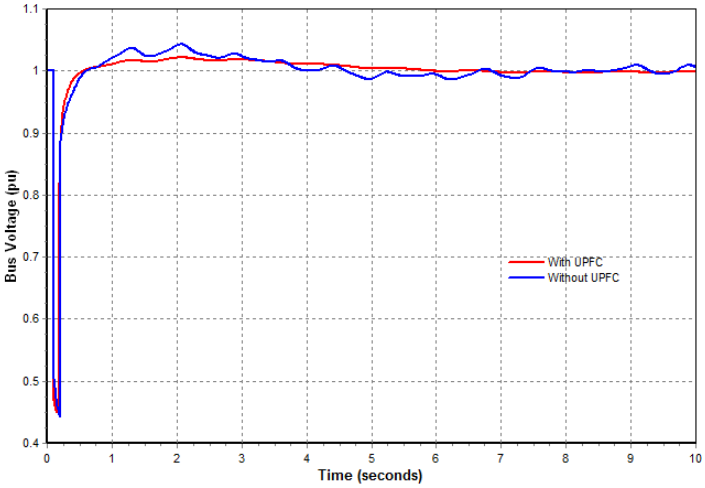

Figure 4.17: Terminal Voltage Response of the Generator at Egbin With and Without UPFC in the System Following a Three-Phase Fault at Ikeja-West Bus

Figure 4.18 shows the power flowing through the transmission line between Egbin and Ikeja-west where the UPFC is connected. There is a marked difference in the power oscillating in the line following the disturbance, showing the effect of the series part (SSSC) of the UPFC. Having subjected the system to a prolonged period of fault

clearing time to determine the CCT of the system before instability, it was discovered that the CCT of the system was increased to 510ms from 470ms with UPFC in the system. Figure 4.19 shows the rotor angle response of the generator at Egbin showing the first swing instability when the CCT was 470ms. During this instability the electrical and mechanical power response is given by Figure 4.20 and 4.21 respectively. It is obvious that the inadequate mechanical power to balance the electrical power output is a factor in the instability that occurred. It can be interpreted that a disturbance on a bus with a large load which is also the receiving end bus of the UPFC could be more severe than the same fault on the largest generating unit.

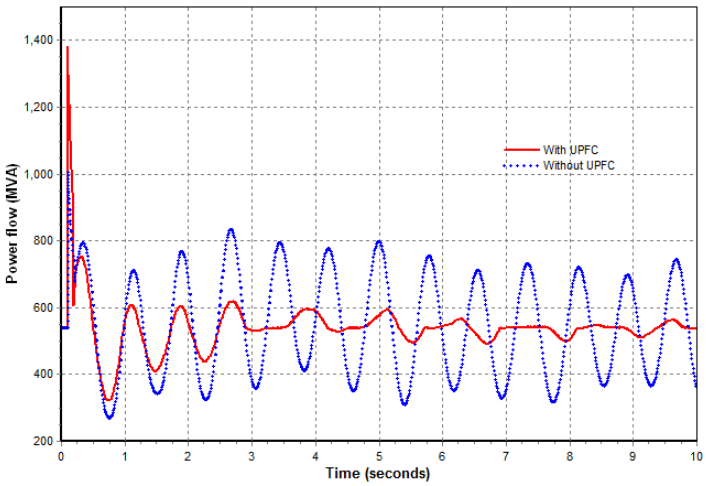

Figure 4.18: Power Flow in the Line between Egbin and Ikeja-West Showing the Oscillation Damping Effect of UPFC Following a Three-Phase Fault at Ikeja-West Bus

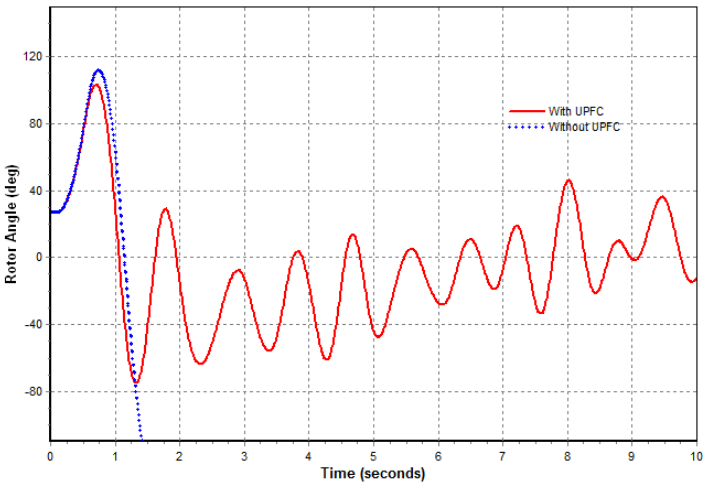

Figure 4.19: Swing Curve of the Generator at Egbin Showing Instability Following a Three-Phase Fault at Ikeja-West Bus

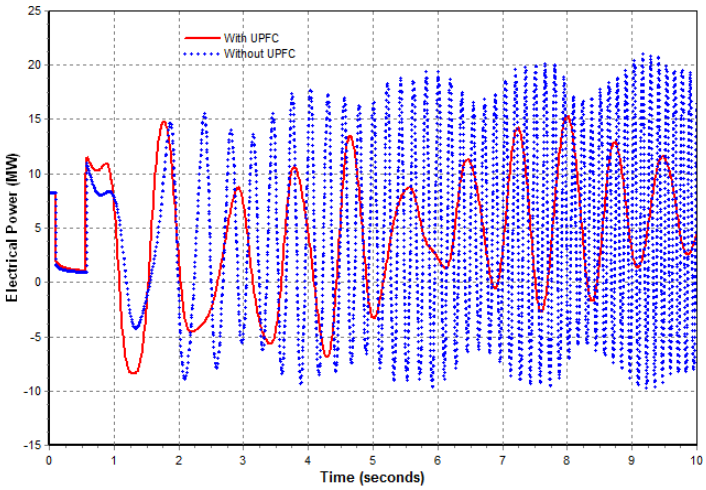

Figure 4.20: Egbin Generator Electrical Power Output During Instability Following a Three-Phase Fault at Ikeja-West Bus

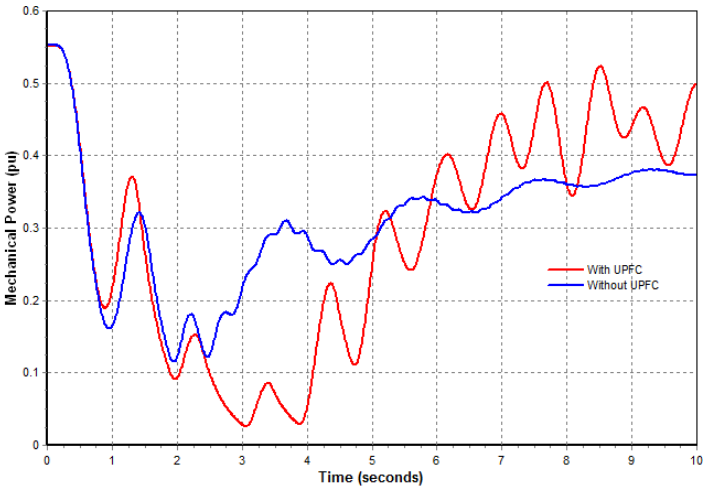

Figure 4.21: Egbin Generator Mechanical Power Output During Instability Following a Three-Phase Fault at Ikeja-West Bus

4.3.4 Fault on Benin Bus

The bus at Benin is a critical bus because it serves as the gateway for the power flowing to and from the east and it is the only point in the network with a relative level of interconnection. A three phase fault was applied on the Benin bus; the system response to such disturbance was investigated to determine the improvement in the CCT with the UPFC in the system. The response of the generators to the fault is illustrated by the simulation result in Figure 4.22. It shows that the Egbin generator is less affected as compared to the first two cases and the generator at Afam has the largest rotor angle excursions. When the UPFC was in the system, the excursion for Egbin was significantly damped as shown in Figure 4.23. Similar to the first two cases, during the fault, the Benin bus voltage dropped to zero while that of Egbin, Ikeja-west, and Oshogbo, dropped to 0.78p.u, 0.55p.u and 0.61p.u respectively during the fault but oscillated around the steady-state value after the fault was cleared as shown in Figure 4.24. The terminal voltage of the generator at Egbin with and without the UPFC is

shown in Figure 4.25; in this case, the pre-fault steady state value is achieved at about 6.5 seconds when the UPFC was in the system.

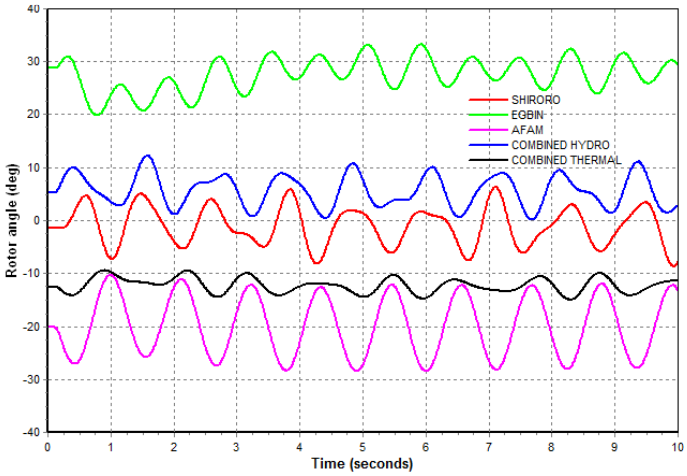

Figure 4.22: Swing Curves of Generators in the Reduced Network Following a Three-Phase Fault at Benin Bus

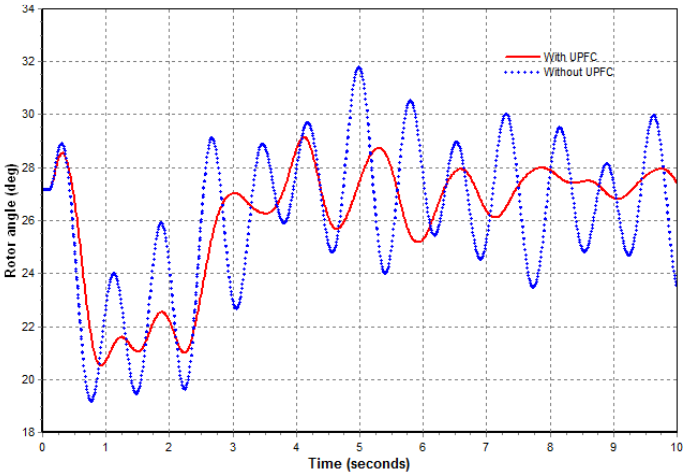

Figure 4.23: Swing Curve of the Generator at Egbin With and Without UPFC in the System Following a Three-Phase Fault at Benin Bus

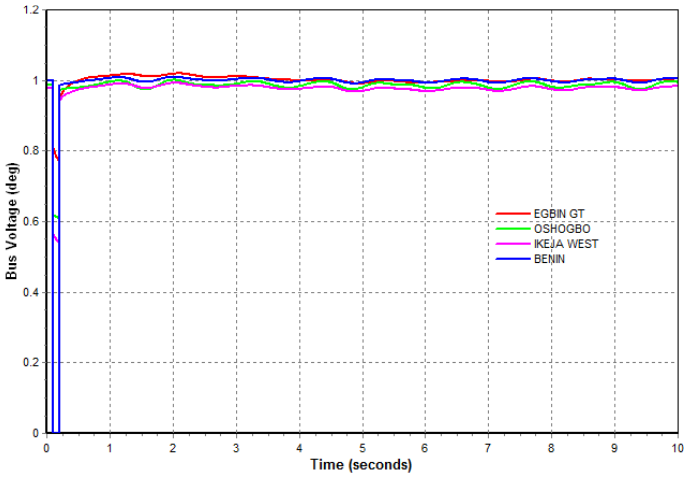

Figure 4.24: Bus Voltages at Benin, Ikeja West, and Egbin Following a Three-Phase Fault at Benin Bus

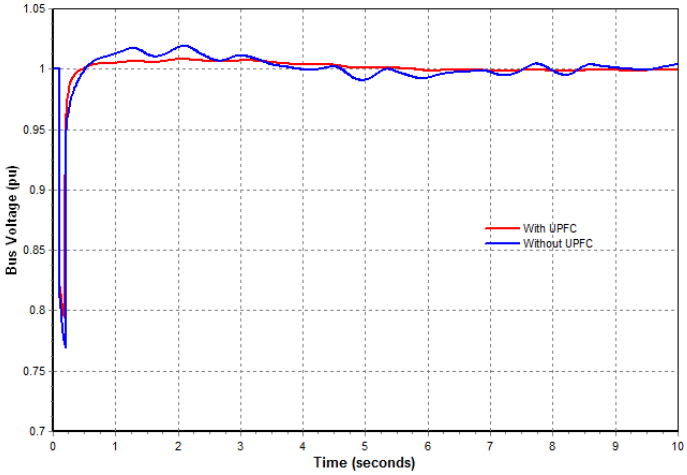

Figure 4.25: Terminal Voltage Response of the Generator at Egbin With and Without UPFC in the System Following a Three-Phase Fault at Benin Bus

The effect of the series part of the device can be observed in Figure 4.26 where the oscillation of the power flowing through the Egbin - Ikeja-west line was damped with the UPFC in service. The initial power flowing through the line was 540MVA from Egbin to Ikeja-west. This steady state flow was restored at about 6.5 seconds after some oscillations that resulted from the applied disturbance. Having subjected the network to increased fault duration, the critical clearing time of the system was 770ms without the UPFC in operation while it increased to 830ms when the UPFC was in operation. Figure 4.27 is the rotor angle response of the generator at Egbin for an unstable condition at 770ms. The electrical and mechanical power output of the generator during this instability is shown in figures 4.28 and 4.29. Although the mechanical power response with the UPFC as shown in figure 4.29 did not in any way stir close to the pre fault value after the fault was cleared, the system was stable. The implication is that the system is marginally stable and any attempt to increase the fault time beyond this time will cause the system to loose stability. This also explains the resulting small stability margin for this case.

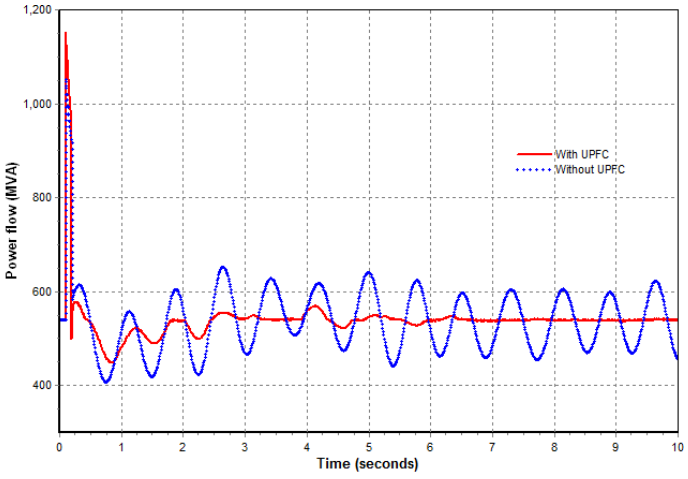

Figure 4.26: Power Flow in the Line Between Egbin and Ikeja-West Showing the Oscillation Damping Effect Of UPFC Following a Three-Phase Fault at Benin Bus

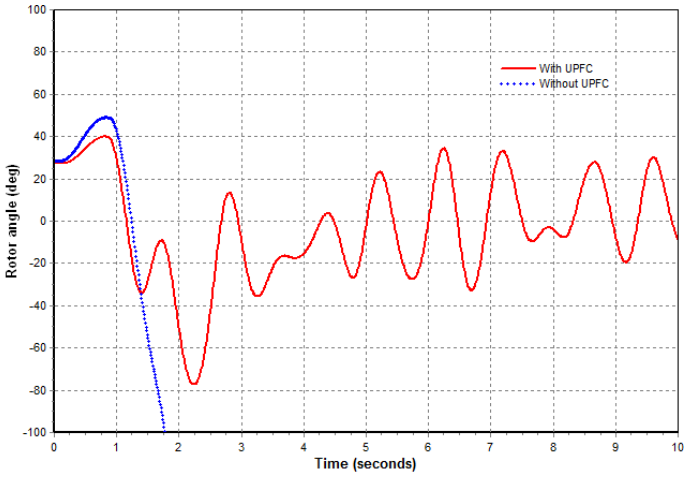

Figure 4.27: Swing Curve of the Generator at Egbin Showing Instability Following a Three-Phase Fault at Benin Bus

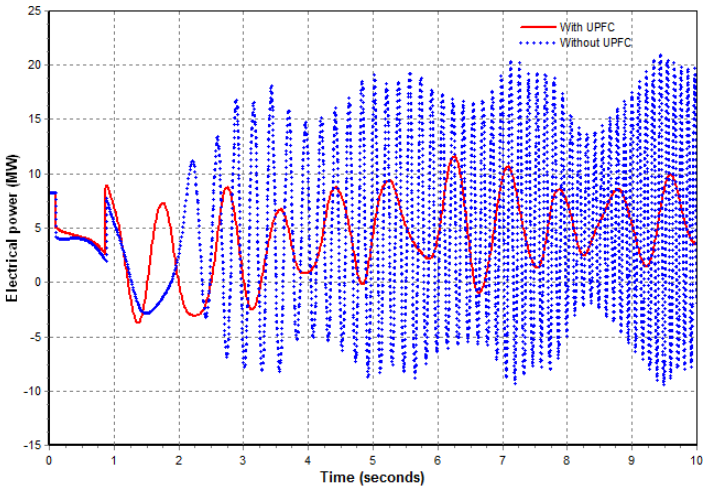

Figure 4.28: Egbin Generator Electrical Power Output During Instability Following a Three-Phase Fault at Benin Bus

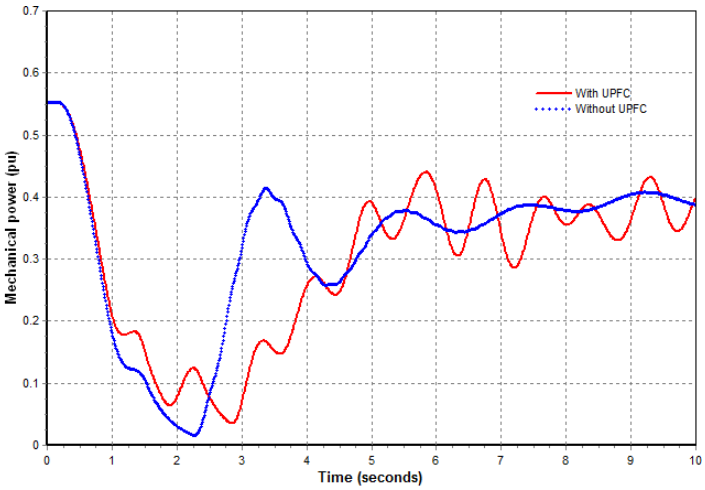

Figure 4.29: Egbin Generator Mechanical Power Output During Instability Following a Three-Phase Fault at Benin Bus

CHAPTER FIVE

SUMMARY, CONCLUSIONS AND RECOMMENDATION

5.1 Summary

The main purpose of this thesis was to asses the transient stability of a typical multi-machine power system. The test system was a reduced Nigerian 330kV system that included the largest unit in the network (i.e. Egbin generator). A key contribution along the line was the development and incorporation of dynamic model for the UPFC series component in PSS/E Software. Perceived limitations are highlighted, conclusions are also drawn in accordance with the results obtained and recommendations were made for future works.

5.2 Limitations of Study

This study is not without some limitations. One of such is the network reduction procedure in which, the classical generator models were used for the machines in the external system. In aggregating the coherent generators, the equivalent system could have taken into consideration the equivalent AVRs and turbine-governor of the equivalent generators. Another limitation is on the developed model for the series part of the UPFC within PSS/E program. A validation of the developed model with other series FACTS device may be required by Siemens.

5.3 Conclusions

In this research, an investigation of the capability of UPFC in enhancing the transient stability of a reduced Nigerian 330kV network is presented. The power oscillation damping capability of UPFC was also examined. In order to achieve the set aim, the first goal was to create a dynamic equivalent model of the original network used as a case study in the PSS/E program. The result of this procedure produced two coherent groups of generators which reduced the network to a 5 generator, 14 transmission lines

and 13 bus systems. The responses obtained with a disturbance simulated on the equivalent system and the original system respectively shows that the developed equivalent system gives a good approximation of the original network. The developed equivalent model was then used for the transient stability analysis assessment of the retained part of the network.

For the transient stability analysis, a three-phase fault was simulated at the terminal of the largest generator unit in the system located at Egbin, at Ikeja-west and at Benin buses. The dynamics of the system were compared with and without the presence of UPFC in the system in the time immediately following the disturbance. It was revealed that in all cases, the UPFC was able to damp the resulting power oscillations and by extension increased the system stability by means of increase in the critical clearing time for the system before instability. The Modelling and simulation of the network including the UPFC was implemented in PSS/E using python programming trough the application program interface. With the fault at Egbin the critical clearing time was extended by 210ms, at Ikeja-west it was 40ms while the margin of stability was 60ms when the fault was located at Benin. These margins show that having the UPFC close to the largest unit will be more effective when such unit experiences a major disturbance. In addition, a disturbance on the bus with the largest load could be more severe than that on the largest generating unit especially if that bus is the receiving end of the UPFC as the case of Ikeja-west bus. Furthermore, a fault father from the largest generating unit could not guarantee a better stability margin and this is basically because of the non-linear nature of power systems. It is believed that the Nigerian power system can benefit significantly from the utilization of FACTS technologies to solve some of the problems associated with it.

5.2 Recommendations for Further Work

Based on the results of this study, possibilities for future work include:

i. The study of multiple consecutive faults in the network and how the UPFC responds to such situation.

ii. A comprehensive study into the possibility of including multiple UPFC devices in the system. This can include the addition of other FACTS devices in the system. In addition, the adequate coordination control of these multiple devices within the system and their influence on system stability should be examined.

iii. Improvements in the model developed for the series part of the controller. Although the model showed promising performance as implemented in PSS/E, some improvements can still be made. In a future implementation it would be interesting to look at how the controller response is affected by the using Meta-heuristic techniques in tuning some of the parameters of the UPFC. Some of these techniques could include particle swamp optimisation technique, genetic algorithm, bacteria foraging technique etc.

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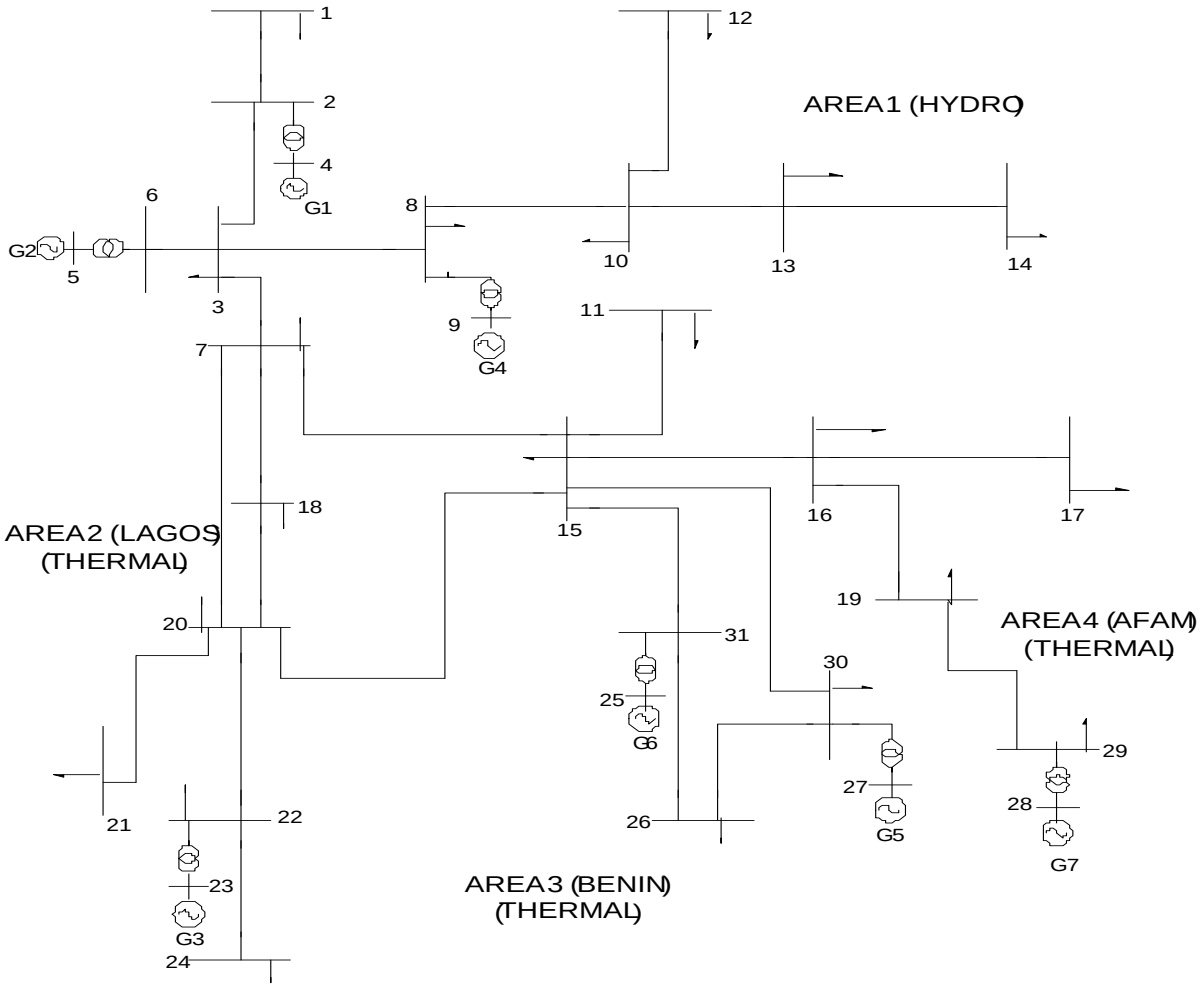
APPENDIX A- Nigerian 330kV Power System Data



330kV Nigerian Grid System

Table 1: Transmission Line Data in Per Unit on 100 MVA Base for 330 kV Nigerian Grid System

LINE NO.	FROM BUS i	TO BUS j	LINE PARAMETERS (P.U.) R	X	B	TAP	PHASE
1	1	2	0.01218	0.09163	1.0269		
2	2	3	0.00159	0.01197	0.5366		
3	2	4	0	0.01351	0	1	0
4	3	6	0.00016	0.00118	0.053		
5	3	7	0.00206	0.01547	1.56		
6	3	8	0.0048	0.03606	1.6165		
7	5	6	0	0.01932	0	1	0
8	7	15	0.00987	0.07419	0.8315		
9	7	18	0.00412	0.03098	0.3472		
10	7	20	0.01163	0.0875	0.9805		
11	8	9	0	0.01638	0	1	0
12	8	10	0.00189	0.01419	0.636		
13	10	12	0.00904	0.06799	0.7619		
14	10	13	0.00774	0.05832	0.6526		
15	11	15	0.00766	0.05764	0.646		
16	13	14	0.01042	0.07833	0.8778		
17	15	16	0.00538	0.0405	0.4538		
18	15	20	0.0055	0.04139	1.885		
19	15	30	0.00287	0.02158	0.2418		
20	15	31	0.00098	0.00739	0.3313		
21	16	17	0.00377	0.02838	0.318		
22	16	19	0.00605	0.04552	0.5101		
23	18	20	0.00538	0.0405	0.454		
24	19	29	0.00049	0.00369	0.1656		
25	20	21	0.00036	0.00266	0.119		
26	20	22	0.00122	0.00916	0.4108		
27	22	23	0	0.00648	0	1	0
28	22	24	0.00028	0.00207	0.0928		
29	25	31	0	0.01204	0	1	0
30	26	30	0.00102	0.00769	0.08613		
31	26	31	0.00248	0.01862	0.2087		
32	27	30	0	0.01333	0	1	0
33	28	29	0	0.01422	0	1	0

Source (PHCN)

Table 2: Generator Data Nigerian Grid System (330kV)

Gen.	MVA	H	x_d	x'_d	x''_d	x_q	x'_q	x''_q	T'_{do}	T''_{do}	T'_{qo}	T''_{qo}	x_l	R
m/c 1	450	3.34	0.75	0.28	0.21	0.53	-	0.21	6.0	0.04	-	0.16	0.16	0.004
m/c 2	600	3.39	0.65	0.26	0.24	0.44	-	0.24	5.2	0.06	-	0.24	0.14	0.0037
m/c 3	1500	3.09	1.87	0.262	0.23	1.87	0.45	0.22	7.1	0.063	1.0	0.11	0.18	0.004
m/c 4	700	3.24	0.8	0.3	0.2	0.49	-	0.24	5.57	0.05	-	0.34	0.16	0.004
m/c 5	440	8.91	2.17	0.25	0.18	1.92	-	0.18	8.8	0.05	-	0.20	0.13	0.004
m/c 6	550	6.70	2.16	0.234	0.17	2.16	-	0.16	8.6	0.05	-	0.20	0.12	0.002
m/c 7	330	9.01	2.09	0.20	0.15	1.89	-	0.15	6.93	0.05	-	0.20	0.11	0.003

Source (PHCN)

Table 3: Data for Hydro-Turbine/Governor Nigeria Grid System

Description	Kainji (m/c 1)	Jebba (m/c 2)	Shiroro (m/c 4)
Deadband value	0.0	0.0	0.0
Permanent Droop (R_p)	0.055	0.05	0.04
Maximum Gate Position (G_{max})	1.05	1.5	1.5
Minimum Gate Position (G_{min})	0.0	0.0	0.0
Maximum Gate Opening Rate (MXGTOP)	0.2/min	0.8	0.8
Maximum Gate Closing Rate (MXGTCG)	-0.2/min	-6.0	-6.0
Pilot Valve Servomotor Time Constant (T_p)	0.04secs	0.035	0.03
Servo Gain (Q)	1.0	1.0	1.0
Main Servo Time Constant (Tg)	0.3	0.25	0.2
Temporary Droop (δ)	0.6	0.6	0.6
Reset Dashpot Time Constant (T_R)	8.0	8.0	8.0
Water Starting Time Constant (T_w)	1.6	1.6	1.6
Penstock Head Loss Coefficient (f_p)	0.1	0.025	0.05
Turbine Damping Coefficient	0.15	0.15	0.25

Source (PHCN)

Table 4: Data for Steam-Turbine/Governor Nigerian Grid System

Description	Egbin (m/c 3)	Delta (m/c 5)	Sapele (m/c 6)	Afam (m/c 7)
Deadband value	0.0	0.0	0.0	0.0
(K)Inverse of Droop (Kg)	25	25	25	25
Speed relay Time Constant	0.25	0.1	0.2	0.2
(T_3)Gate servo Time Constant	0.1sec	0.1	0.1	0.1
(U_o)Maximum Opening rate	0.1pu/sec	0.4	0.1	-
(U_c)Maximum Closing rate	1.0pu/sec	-0.5	-1.0	-
(V_{MAX})Maximum Servo Position	1.25 pu	1.05	1.05	1.05
(V_{MIN})Minimum Servo Position	0.0	0.0	0.0	0.0
(K_1)HP ratio (K_1)	0.26	1.0	1.0	1.0
(K_3)IP ratio (K_3)	0.3	0.0	0.0	0.0
(K_5)LP ratio (K_5)	0.44	0.0	0.0	0.0
(T_4)Steam chest Time Constant (T_4)	0.4 sec	0.7	5.0	0.7
(T_5,)Reheater Time Constant (T_5)	8.0 sec	0.0	0.0	0.0
(T_6)Reheater/Crossover Time Constant (T_6)	0.5 sec	0.0	0.0	0.0
(T_7)Cross-over Time Constant (T_7)	0.35 sec	0.0	0.0	0.0

Source (PHCN)

Table 5: Data for Excitation System Nigerian Grid System

Description	Jebba (m/c 2)	Egbin (m/c 3)	Kainji (m/c 1) & Shiroro (m/c 4)	Afam (m/c 7), Delta (m/c 5) & Sapele (m/c 6)
Lead Time Constant (T_C)	0.0 sec	0.0 sec	-	--
Lag Time Constant (T_B)	0.04 sec	0.04 sec	-	-
Regulator Gain	125	125	-	0.04
Regulator Time Constant (T_A)	0.04 sec	0.04 sec	0.5	1.2
V_{max}	1.5	1.5	1.2	0.0
V_{min}	0.0	0.0	0.0	200
K_A	125	150	256	-
K_{pmax}	3	7	-	-
K_{pmin}	2.6	5.6	-	0.03
K_F	0.002	0.003	0.03	1.0
T_F	0.22 sec	0.22 sec	0.98	-
K_D	0.0	0.0	-	-
K_C	0.0	0.0	-	0.06
T_1	-	-	0.02	1.0
K_1	-	-	1.0	0.04
T_E	-	-	3.7	0.016
K_E	-	-	0.1	0.0
A	-	-	0.0	0.0
B^F	-	-	0.0	8.0
V_{rmax}	-	-	2.6	-7.0
V_{rmin}	-	-	0.0	6.22
E_{fmax}	-	-	3.0	-5.0
E_{fmin}	-	-	-5.0	

Source (PHCN)

APPENDIX B- Power flow result for the full network

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E UniversityWED, JUN 20 2012 22:29
NIGERIA 330KV TRANSMISSION NETWORK %MVA FOR TRANSFORMERS
BASKV: 330kV SYSTEMBASE: 100MVA % I FOR NON-TRANSFORMER BRANCHES

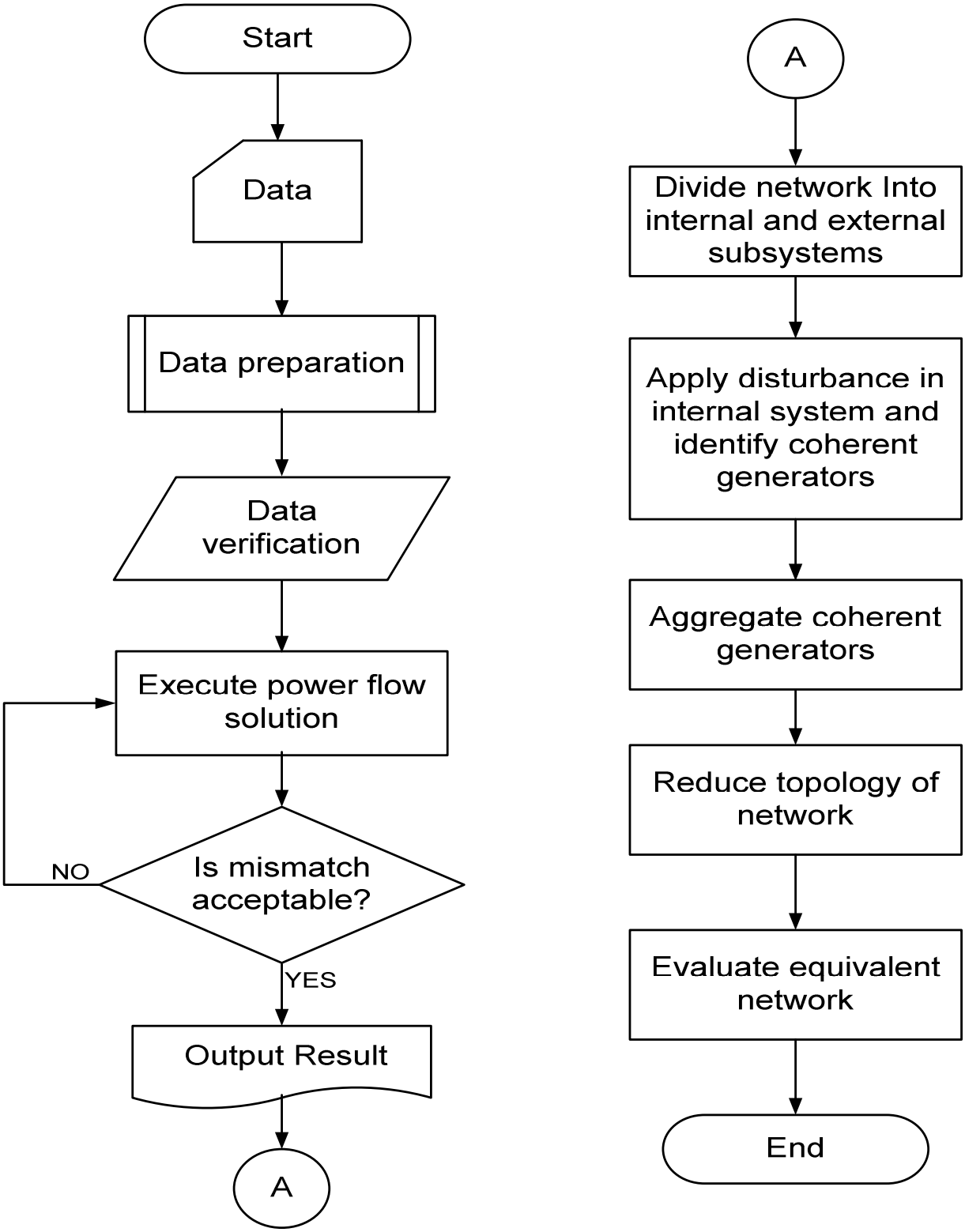
FROM BUS BUS#	NAME	BASKV	AREA ZONE	VOLT PU/KV	ANGLE	GEN MW/MVAR	LOAD MW/MVAR	SHUNT MW/MVAR	TO BUS BUS#	NAME	BASKV	AREA	CKT	MW	MVAR	TRANSFORMER RATIO	ANGLE	RATING %	SET A
1	B/KEBBI	330.00	1	1.0212	3.5	0.0	60.3	0.0											
			1	337.01		0.0	59.8	0.0	2	KAINJI	330.00	1	1	-60.3	-59.8			11	760
2	KAINJI	330.00	1	1.0354	6.4	0.0	0.0	0.0											
			1	341.69		0.0	0.0	0.0	1	B/KEBBI	330.00	1	1	60.7	-45.6			10	760
									3	JEBBA S/S	330.00	1	1	289.3	-3.7			18	1520
									4	KAINJI GT	16.000	1	1	-350.0	49.3	1.000LK			
3	JEBBA S/S	330.00	1	1.0286	4.6	0.0	8.6	0.0											
			1	339.44		0.0	5.6	0.0	2	KAINJI	330.00	1	1	-288.0	-44.0			19	1520
									6	JEBBA	330.00	1	1	-449.7	161.9			31	1520
									7	OSHOGBO	330.00	1	1	633.4	19.6			27	2280
									8	SHIRORO	330.00	1	1	95.7	-143.1			11	1520
4	KAINJI GT	16.000	1	1.0300	9.0	350.0	0.0	0.0											
			1	16.480		-33.5R	0.0	0.0	2	KAINJI	330.00	1	1	350.0	-33.5	1.000UN			
5	JEBBA GT	16.000	1	1.0000	9.8	450.0	0.0	0.0											
			1	16.000		-122.9R	0.0	0.0	6	JEBBA	330.00	1	1	450.0	-122.9	1.000LK			
6	JEBBA	330.00	1	1.0274	4.9	0.0	0.0	0.0											
			1	339.05		0.0	0.0	0.0	3	JEBBA S/S	330.00	1	1	450.0	-165.0			31	1520
									5	JEBBA GT	16.000	1	1	-450.0	165.0	1.000UN			
7	OSHOGBO	330.00	1	1.0049	-0.7	0.0	201.0	0.0											
			1	331.62		0.0	136.7	0.0	3	JEBBA S/S	330.00	1	1	-625.4	-120.7			28	2280
									15	BENIN	330.00	1	1	109.9	-42.6			15	760
									18	AIYEDE	330.00	1	1	209.1	42.2			28	760
									20	IKEJA WEST	330.00	1	1	105.4	-15.6			14	760
8	SHIRORO	330.00	1	1.0449	2.6	0.0	61.5	0.0											
			1	344.83		0.0	10.3	0.0	3	JEBBA S/S	330.00	1	1	-95.1	-26.5			6	1520
									9	SHIRORO GT	16.000	1	1	-490.0	49.7	1.000LK			
									10	KADUNA	330.00	1	1	523.6	-33.5			33	1520
9	SHIRORO GT	16.000	1	1.0400	6.8	490.0	0.0	0.0											
			1	16.640		-13.3R	0.0	0.0	8	SHIRORO	330.00	1	1	490.0	-13.3	1.000UN			
10	KADUNA	330.00	1	1.0378	-1.3	0.0	166.2	0.0											
			1	342.46		0.0	97.8	0.0	8	SHIRORO	330.00	1	1	-518.9	0.2			33	1520
									12	KANO	330.00	1	1	188.0	4.6			24	760
									13	JOS	330.00	1	1	164.6	-102.6			25	760
11	AJAOKUTA	330.00	1	1.0085	-6.4	0.0	26.8	0.0											

		1 332.79		0.0	10.5	0.0	15 BENIN	330.00	1	1	-26.8	-10.5		2	1520
12 KANO	330.00	1 0.9986	-8.2	0.0	184.9	0.0									
		1 329.54		0.0	60.0	0.0	10 KADUNA	330.00	1	1	-184.9	-60.0		26	760
13 JOS	330.00	1 1.0679	-6.6	0.0	58.4	0.0									
		1 352.40		0.0	28.4	0.0	10 KADUNA	330.00	1	1	-162.3	47.4		21	760
							14 GOMBE	330.00	1	1	103.9	-75.8		16	760
14 GOMBE	330.00	1 1.0795	-10.7	0.0	102.9	0.0									
		1 356.24		0.0	17.5	0.0	13 JOS	330.00	1	1	-102.9	-17.5		13	760
15 BENIN	330.00	1 0.9979	-5.4	0.0	156.8	0.0									
		1 329.30		0.0	79.9	0.0	7 OSHOGBO	330.00	1	1	-108.7	-31.9		15	760
							11 AJAOKUTA	330.00	1	1	26.9	-53.8		4	1520
							16 ONITSHA	330.00	1	1	245.8	-17.1		32	760
							20 IKEJA WEST	330.00	1	1	31.6	-23.9		3	1520
							30 DELTA	330.00	1	1	-131.3	14.2		17	760
							31 SAPELE	330.00	1	1	-221.1	32.7		15	1520
16 ONITSHA	330.00	1 0.9874	-11.2	0.0	115.2	0.0									
		1 325.85		0.0	42.0	0.0	15 BENIN	330.00	1	1	-242.6	-3.0		32	760
							17 NEW HAVEN	330.00	1	1	113.2	23.6		15	760
							19 ALAOJI	330.00	1	1	14.2	-62.7		9	760
17 NEW HAVEN	330.00	1 0.9724	-13.0	0.0	112.6	0.0									
		1 320.88		0.0	50.0	0.0	16 ONITSHA	330.00	1	1	-112.6	-50.0		17	760
18 AIYEDE	330.00	1 0.9799	-4.4	0.0	139.4	0.0									
		1 323.36		0.0	61.0	0.0	7 OSHOGBO	330.00	1	1	-207.2	-61.9		29	760
							20 IKEJA WEST	330.00	1	1	67.8	0.9		9	760
19 ALAOJI	330.00	1 1.0040	-11.7	0.0	144.7	0.0									
		1 331.33		0.0	88.4	0.0	16 ONITSHA	330.00	1	1	-14.1	12.8		3	760
							29 AFAM	330.00	1	1	-130.6	-101.2		11	1520
20 IKEJA WEST	330.00	1 0.9672	-5.9	0.0	429.9	0.0									
		1 319.17		0.0	258.4	0.0	7 OSHOGBO	330.00	1	1	-104.0	-69.1		17	760
							15 BENIN	330.00	1	1	-31.3	-155.6		11	1520
							18 AIYEDE	330.00	1	1	-67.5	-41.7		11	760
							21 AKANGBA	330.00	1	1	292.4	106.6		21	1520
							22 EGBIN	330.00	1	1	-519.5	-98.5		36	1520
21 AKANGBA	330.00	1 0.9630	-6.4	0.0	292.0	0.0									
		1 317.80		0.0	114.9	0.0	20 IKEJA WEST	330.00	1	1	-292.0	-114.9		21	1520
22 EGBIN	330.00	1 0.9824	-3.1	0.0	109.7	0.0									
		1 324.20		0.0	64.2	0.0	20 IKEJA WEST	330.00	1	1	523.1	86.5		36	1520
							23 EGBIN GT	11.000	1	1	-826.5	-244.0	1.000LK		
							24 AJA	330.00	1	1	193.6	93.3		14	1520
23 EGBIN GT	11.000	1 1.0000	0.0	826.5	0.0	0.0									
		1 11.000		293.8R	0.0	0.0	22 EGBIN	330.00	1	1	826.5	293.8	1.000UN		
24 AJA	330.00	1 0.9798	-3.3	0.0	193.5	0.0									
		1 323.34		0.0	101.2	0.0	22 EGBIN	330.00	1	1	-193.5	-101.2		15	1520

```
25 SAPELE GT   16.000    1 0.9900   -3.0   200.0      0.0     0.0 ---------------------------------------------------------------------------
                         1 15.840          -51.4R     0.0     0.0     31 SAPELE      330.00    1  1    200.0   -51.4  1.000LK

26 ALADJA      330.00    1 0.9942   -4.2     0.0     82.1     0.0 ---------------------------------------------------------------------------
                         1 328.08           0.0     44.5     0.0     30 DELTA       330.00    1  1   -103.7   -18.7                    14   760
                                                                     31 SAPELE      330.00    1  1     21.6   -25.8                     4   760
27 DELTA  GT   11.000    1 1.0000   -1.4   300.0      0.0     0.0 ---------------------------------------------------------------------------
                         1 11.000           33.0R      0.0     0.0     30 DELTA       330.00    1  1    300.0    33.0  1.000LK

28 AFAM GT     11.000    1 1.0300   -9.5   250.0      0.0     0.0 ---------------------------------------------------------------------------
                         1 11.330          163.1R      0.0     0.0     29 AFAM        330.00    1  1    250.0   163.1  1.000LK

29 AFAM        330.00    1 1.0081  -11.4     0.0    119.3     0.0 ---------------------------------------------------------------------------
                         1 332.67           0.0     65.7     0.0     19 ALAOJI      330.00    1  1    130.7    85.4                    10  1520
                                                                     28 AFAM GT     11.000    1  1   -250.0  -151.1  1.000UN
30 DELTA       330.00    1 0.9964   -3.7     0.0     64.3     0.0 ---------------------------------------------------------------------------
                         1 328.81           0.0     44.2     0.0     15 BENIN       330.00    1  1    131.9   -34.4                    18   760
                                                                     26 ALADJA      330.00    1  1    103.8    11.1                    14   760
                                                                     27 DELTA  GT   11.000    1  1   -300.0   -20.9  1.000UN
31 SAPELE      330.00    1 0.9965   -4.4     0.0      0.0     0.0 ---------------------------------------------------------------------------
                         1 328.86           0.0      0.0     0.0     15 BENIN       330.00    1  1    221.6   -61.8                    15  1520
                                                                     25 SAPELE GT   16.000    1  1   -200.0    56.6  1.000UN
                                                                     26 ALADJA      330.00    1  1    -21.6     5.2                     3   760
```

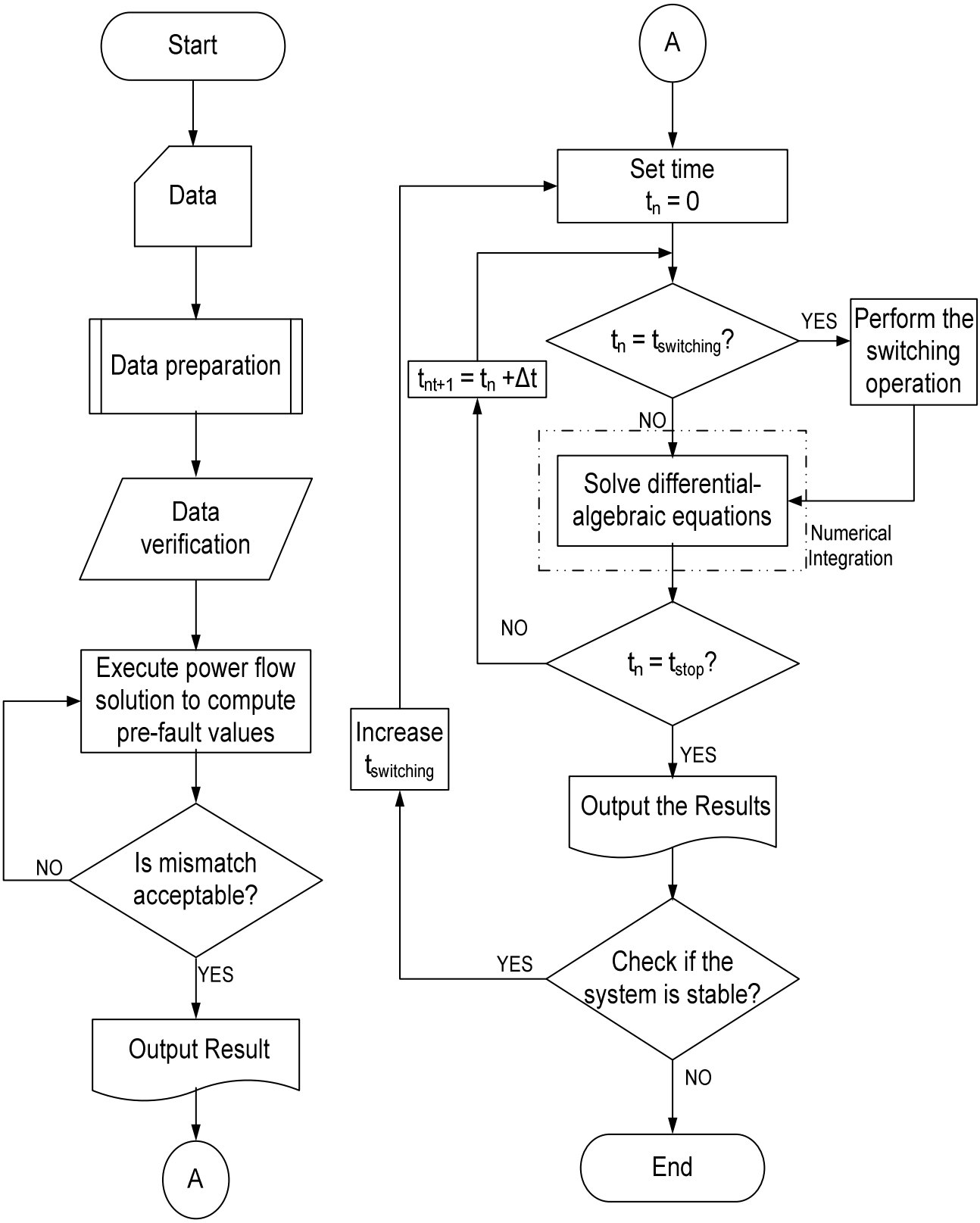
APPENDIX C – Implementation flow charts

C1: Network reduction algorithm



Flow chart for network reduction implementation in PSS/E

C2: Transient stability analysis algorithm



Basic procedure for transient stability study

APPENDIX D -UPFC Parameters

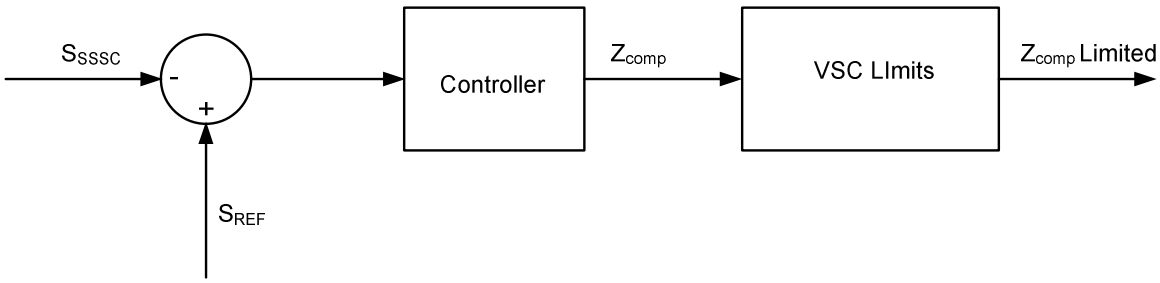
D1. Parameters of the STATCOM

Parameter	Value
T1 [s]	0.2
T2 [s]	0.2
T3 [s]	0.2
T4 [s]	0.2
K	100
Droop [pu]	0.03
Vmax	999
Vmin	-999
Icmax [pu]	1.25
ILmax [pu]	1.25
Vcutout [pu]	0.2
Elimit [pu] 1,2	1.2
Xt [pu]	0.1
Acc	0.5
STBASE [MVAr]	400

D2. Parameters of the SSSC

Parameter	Value
PI proportional constant (Kp)	10
Transformer ratio	1.48
Additional reactance (Xad)	7 Ω pri
Static reactance (Xest)	10 Ω pri
VSC voltage limit	± 6650 V
VSC voltage ramp limit	6650 V/s
VSC current limit	1450 A
Power rating	18.95MVA

D3. SSSC Variable Impedance Dynamic Model



APPENDIX E -Python Script for the Stability Analysis including SSSC implementation in PSS/E

```
#PSS/E  SSSC Implementation in Python


import math

# Working files: Network, Snapshot, Output and Progress
# Very Important for the reuse of the code with other file names

networkcasefile =r"""C:\Users\SHEREEFDEEN SANNI\Documents\PSS_E\Thesis
\NAIGERIA_REDUCE_STAT_CONVERTED.sav"""
snapfile=r"""C:\Users\SHEREEFDEEN SANNI\Documents\PSS_E\Thesis\Reduced_Analysis_With
UPFC\NAIGERIA_REDUCE_BENIN_UPFC.snp"""
outputfile=r"""C:\Users\SHEREEFDEEN SANNI\Documents\PSS_E\Thesis\Reduced_Analysis_With
UPFC\NAIGERIA_REDUCE_BENIN_UPFC.out"""
outputfilenoextension=r"""NAIGERIA_REDUCE_BENIN_UPFC"""
progressfile=r"""C:\Users\SHEREEFDEEN
SANNI\Documents\PSS_E\Thesis\Reduced_Analysis_With UPFC\progress_Benin_UPFC.txt"""

# Redirect progress window to file
# This is useful to speed execution of the script
psspy.progress_output(2,progressfile,0)

# Load Network and Initial Snapshot files
psspy.case(networkcasefile)
psspy.rstr(snapfile)


# Simulation parameters: Start time, Stop time, Integration step
# Here is the definition of when the simulation starts and stops and the integration
step (DELT)
# This information is stored in a variable named t
# t is a vector with all the simulation steps
tstart=0 # simulation start time in s
tstop=30 # simulation stop time in s
delta_t=0.01 # integration step time in s (Must be equal to DELT value in Dynamic
Simulation Options)
steps=(tstop-tstart)/delta_t # total numeber of integration steps
t=range(tstart,steps,1) # vector with all the integration steps of the simulation


# Definition of events
# Definition of the time associated with an event and the value of the variable that
changes in case of a control event
# In case of a network event (a line trip, a fault...) only the time is defined. There
is no restriction to the number of events
# Except that the time of the event must be between tstart and tstop

tstop_1=0.1 # time associated with the first event to simulate

tstop_2=0.2 # time associated with the second event to simulate

tstop_3=1.0 # time associated with the third event to simulate


# SSSC parameters
# Here you define the parameters of your model
From_Bus=22
To_Bus=20
X_max=7 # maximum impedance in Primary Ohms
X_min=-7 # minimum impedance in Primary Ohms


# SSSC control parameters
# Control mode: Constant line MVA flow
Kp=10 # proportional gain
Ramp=7 # maximum ramp ohms/s

# Initial Steady State. Initialization of SSSC control
ierr,Vbase = psspy.busdat(To_Bus,'BASE') # Primary voltage of SSSC (kV)
Sbase = psspy.sysmva() # System MVA base (MVA)
Zbase = (Vbase*Vbase)/Sbase # Impedance base (Ohm)
ierr,init_flow=psspy.brnflo(From_Bus,To_Bus,'1') #Initial MVA flow through the SSSC
(MVA)
Sref=abs(init_flow) # Initial power referece for SSSC control (MVA)
ierr,init_current=psspy.brnmsc(From_Bus,To_Bus,'1','AMPS') #Initial Current through
SSSC in A
Isssc_ref=init_current
Xsteppu=Ramp*delta_t/Zbase # ramp change in pu/time step
X_max_pu=X_max/Zbase # maximum impedance in pu
X_min_pu=X_min/Zbase # minimum impedance in pu
```

```
# Initialize simulation(solve from - 2*DELT to Start Time)
psspy.strt(0,outputfile)
psspy.run(0, tstop_1,1,1,0)

# Solve the simulation and run the SSSC model
# Here the simulation is solved for every time step defined in variable t
# The SSSC model is executed every time step
# If the simulation time is equal to the time of an event previously defined
# the event is executed prior to the execution of the SSSC model
for j in t:
    # Checking if time is equal to an event time
    if j*delta_t==tstop_1: # first event
          psspy.dist_bus_fault(15,1, 330.0,[0.0,-0.2E+10])

    if j*delta_t==tstop_2: # second event
          psspy.dist_clear_fault(1)
          psspy.dist_branch_trip(15,20,r"""1""")

    if j*delta_t==tstop_3: # third event
          psspy.dist_branch_close(15,20,r"""1""")



    # SSSC state monitoring
    ierr,V_from=psspy.busdat(From_Bus,'PU') # Actual SSSC From Bus voltage in p.u.
    ierr,angle_from=psspy.busdat(From_Bus,'ANGLE') # Actual SSSC From Bus voltage angle
in radians
    ierr,V_to=psspy.busdat(To_Bus,'PU') # Actual SSSC To Bus voltage in p.u.
    ierr,angle_to=psspy.busdat(To_Bus,'ANGLE') # Actual SSSC To Bus voltage angle in
radians
    Vsssc_pu=(V_to*math.cos(angle_to)-
V_from*math.cos(angle_from))+1j*(V_to*math.sin(angle_to)-V_from*math.sin(angle_from)) #
Serial SSSC voltage in p.u.
    vsssc.append(Vsssc_pu)
    Vsssc=Vsssc_pu*Vbase # Serial SSSC voltage in kV
    ierr,Isssc=psspy.brnmsc(From_Bus,To_Bus,'1','AMPS') # Current through SSSC in A
    ierr,now_flow=psspy.brnflo(From_Bus,To_Bus,'1') #current MVA flow through the SSSC
(MVA)
    Ssssc=abs(now_flow)
    ierr,Zsssc = psspy.brndt2(From_Bus,To_Bus,'1','RX')
    Xsssc=Zsssc.imag # Actual SSSC reactance during simulation in pu
    Xsssc_pri=Xsssc*Zbase # Actual SSSC reactance in Ohm
    Zsssc_pri=Zsssc*Zbase # Actual SSSC Impedance in Ohm


    # SSSC Control Loop
    # Proportional control output
    error = Sref - Ssssc # Power flow error in MVA
    errorpu = error/Zbase
    x_P = -1*Kp * errorpu # PI controller proportional response
    Xcomppu = x_P #SSSC new reactance value in pu

    # Ramp limit
    if (Xsssc - Xcomppu) > Xsteppu:
        Xcomppu = Xsssc - Xsteppu
    if (Xsssc - Xcomppu) < -1*Xsteppu:
        Xcomppu = Xsssc + Xsteppu
    # Max/Min reactance limit
    if Xcomppu > X_max_pu:
        Xcomppu = X_max_pu
    if Xcomppu < X_min_pu:
        Xcomppu = X_min_pu

    # New compensating reactance. Modify SSSC equivalent branch impedance to the new
value

psspy.branch_data(From_Bus,To_Bus,'1',[_i,_i,_i,_i,_i,_i],[_f,Xcomppu,_f,_f,_f,_f,_f,_f
,_f,_f,_f,_f,_f,_f,_f,_f])

    injected_volt=Isssc*Xcomppu*Zbase



    # Solve next iteration
    psspy.run(0,j*delta_t,1,1,1)

# Return progress output from file to window
psspy.progress_output(1,progressfile,1)



pssplot.newplotbook()
pssplot.setselectedpage(0)
pssplot.openchandatafile(outputfile)
pssplot.setselectedpage(1)
```

```
pssplot.insertpage()
pssplot.setselectedpage(2)
pssplot.insertpage()
pssplot.setselectedpage(3)
pssplot.insertpage()
pssplot.setselectedpage(4)
pssplot.insertpage()
pssplot.setselectedpage(5)
pssplot.insertpage()
pssplot.setselectedpage(6)
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330.00]1""")
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11.000]1""")
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330.00]1""")
pssplot.dragdropplotdata(outputfilenoextension,r"""4 - ANGL   100[HYDRO
330.00]1""")
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330.00]1""")
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330.00]1""")
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11.000]1""")
pssplot.dragdropplotdata(outputfilenoextension,r"""18 - ETRM    29[AFAM
330.00]1""")
pssplot.dragdropplotdata(outputfilenoextension,r"""18 - ETRM    29[AFAM
330.00]1""")
pssplot.dragdropplotdata(outputfilenoextension,r"""19 - ETRM   100[HYDRO
330.00]1""")
pssplot.dragdropplotdata(outputfilenoextension,r"""20 - ETRM   200[THERMAL
330.00]1""")
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11.000]1""")
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'""")
pssplot.setselectedpage(4)
pssplot.dragdropplotdata(outputfilenoextension,r"""114 - POWR     22 TO    20 CKT '1
'""")
pssplot.setselectedpage(5)
pssplot.dragdropplotdata(outputfilenoextension,r"""115 - VARS     22 TO    20 CKT '1
'""")
pssplot.setselectedpage(6)
pssplot.dragdropplotdata(outputfilenoextension,r"""2 - ANGL    23[EGBIN GT
11.000]1""")
pssplot.setselectedplot(0)
```