TRANSMISSION CONGESTION MANAGEMENT IN NIGERIAN 330kV POWER SYSTEM WITH APPLICATION OF FACTS DEVICES AND GENERATOR RESCHEDULING

BY

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IN

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FACULTY OF ENGINEERING

A DISSERTATION SUBMITTED TO THE SCHOOL OF POSTGRADUATE STUDIES IN PARTIAL FULFILMENT OF THE REQUIREMENTS FOR THE AWARD OF DOCTOR OF PHILOSOPHY (Ph.D) IN ELECTRICAL ENGINEERING, NNAMDI AZIKIWE UNIVERSITY, AWKA

FEBRUARY, 2021

CERTIFICATION

This is to certify that I, Ndubisi Mary Ahudiya, a postgraduate (Ph.D) student in the Department of Electrical Engineering with registration number 2013237002P is the original Author of this dissertation (**Transmission Congestion Management in Nigerian 330kV Power System with Application of FACTS devices and Generator Rescheduling**). All sources of information used in this work are duly acknowledged. Also the work embodied in this Dissertation is original and has not been submitted in part or in full for any programme; diploma, degree or certificate in any Institution to the best of my knowledge.

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NDUBISI MARY A. DATE

APPROVAL PAGE

The dissertation titled " Study of Transmission Congestion Management in Nigerian 330kV Power System with Application of FACTS devices and Generator Rescheduling" has been approved having met the requirement in partial fulfilment for the award of the degree of Doctor of Philosophy (Ph,D) in Engineering by the Department of Electrical Engineering, Nnamdi Azikiwe University, Awka

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DEDICATION

I dedicate this work to the Almighty God for His infinite mercy, guidance and direction throughout the period of this programme.

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Thanks to Almighty God for His Divine presence and protection with me all through the period of this programme.

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ABSTRACT

Transmission congestion occurs in a power system when there is insufficient transmission capacity to simultaneously accommodate all requests for transmission service within the network. The modelled 41 Bus 330kV Nigerian power system comprises of 14 generator buses (Egbin is used as the Slack or reference Bus, with 13 other Generators buses), 27 loads buses and 63 Transmission lines, all modelled with data obtained from National Control Centre (NCC) and Transmission Company of Nigeria (TCN) using Power System Analysis Toolbox (PSAT). A load flow simulation of Nigerian 41 Bus 330kV power network (Base case) using Newton Raphson' s iterative method was performed in order to estimate the following unknown variables: generator reactive power, the bus angle, load voltage, line loss and MVA flow. The simulation results show that sixteen voltage profile violations occurred, indicating 39% violations and eleven violated MVA flow transmission lines indicating 15.87% violations hence an unhealthy network. To achieve loss minimization and a healthy network, the output power of the generators were changed through a known optimization technique such as DC optimal power flow. The results reduced the Base case violations to eleven (voltage profile) indicating 26.83% and four (MVA flow) indicating 6.3% violations with the network still unhealthy. In order to get a healthy network, SVC and TCSC were installed separately with the output power of the generators rescheduled. The results obtained could not make the network healthy. In a bid to get a healthy network, combined installation of SVC, TCSC and Generator Rescheduling was also simulated. The simulation results obtained gave a 0% violation on both Bus profile and MVA flow, showing that simultaneous combination of FACTS devices (SVC and TCSC) and generator rescheduling best managed the congestion in the Nigerian Power System.

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LIST OF ABBREVIATIONS AND SYMBOLS

AC:	Alternating Current
AGC:	Automatic generation Control
ATC:	Available Transfer Capability
ATC&C:	Aggregate Technical, Commercial and Collection
CBM:	Capacity Benefit Margin
CM:	Congestion Management
CMS:	Congestion Management System
CPF:	Continuation Power Flow
CRR:	Congestion Revenue Right
DC:	Direct Current
Disco:	Distribution Company
DG:	Distributed Generation
ECN:	Electricity Corporation of Nigeria
EPSR:	Electric Power Sector Reform
ETC:	Existing Transmission Commitments
FACTS:	Flexible AC Transmission Systems
FGR:	Flow Gate Right
FMP:	Federal Ministry of Power
FTR:	Financial Transmission Rights
GACN:	Gas Aggregation Company Nigeria

GAMS:	General Algebraic Modelling Systems
GC:	Generation Cost
Genco:	Generation Company
Gen.Reshd:	Generation Rescheduling
GNE:	Graphical Network Editor
GSF:	Generator Sensitivity Factor
GUI:	Graphical User Interface
GW:	Giga Watt
IPP:	Independent Power Producers
ISO:	Independent System Operator
KM:	Kilo Metre
kV:	kilo Volt
LMP:	Locational Marginal Price
MATLAB:	Mathematics Laboratory
MVA:	Mega Volt Ampere
MVAR:	Mega Volt Ampere Reactive
MW:	Mega Watt
NAPTIN:	National Power Training Institute of Nigeria
NBET:	Nigerian Bulk Electricity Trading
NDPHC:	Niger Delta Power Holding Company
NEPA:	National Electric Power Authority
NELMCO:	Nigeria Electricity Liability Management Company
NEPP:	National Electric Power Policy

NERC: National Electricity Regulatory Commission

NESI: Nigerian Electricity Supply Industry

NIPP: Nigerian Independent Power Producers

Nom: Nominal

NSO: Nigerian System Operator

ONEM: Operator of the Nigerian Electricity Market

OPF: Optimal Power Flow

PF: Power Flow

PHCN: Power Holding Company of Nigeria

PSAT: Power System Analysis Toolbox

PSO: Particle Swarm Optimization

PTDF: Power Transfer Distribution Factor

P.U: Per Unit

REA: Rural Electrification Agency

RED: Relative Electrical Distance

RPLLF: Reactive Power Line Loss Function

SMD: Standard Market Design

SO: System Operator

SSA: Small Signal Stability Analysis

SVC: Static Var Compensators

TCC: Transmission Congestion Contract

TCM: Transmission Congestion Management

TCN: Transmission Company of Nigeria

TCSC: Thyristor Controlled Series Compensator

TD: Time Domain

TLR: Transmission Loading Relief

Transco: Transmission Company

TR: Transmission Rights

TRM: Transmission Reliability Margin

TTC: Total Transfer Capability

UDM: User Defined Model

UPFC: Unified Power Flow Controller

VIU: vertically Integrated Utilities

/V/: Voltage magnitude

δ: Phase angle

G_{ik}: Real Part of the Element

N: Number

P_i: Net Power Injected at Bus *i*

P: Real power or Active power

Q: Reactive Power

Y_{BUS}: Bus Admittance Matrix

Θ: Voltage angle

B: Susceptance

R: Resistance

X: Reactance

₦/MWh: Naira per Mega Watt hour

CHAPTER ONE

INTRODUCTION

1.1 Background of the Study

In a deregulated structure, the market must be modeled so that the market participants (buyers and sellers of energy) engage freely in transactions and play as per market forces, but in a manner that does not threaten the security of the power system. Thus, irrespective of the market structure in place, congestion management has universally become an important activity of power system operators. Universally, the dual objectives of congestion management schemes have been to minimize the interference of the transmission network in the market for electrical energy and to simultaneously ensure secure operation of the power system (Nptel, 2012).

Congestion management has been at the centre of debate over facilitating competition in electricity industry. With difficulties in building new transmission lines due to problem of right-of-the-way and financial crunch and the significant increase in the power transactions associated with the competitive electricity markets, maintaining system security has become one of the main concerns for the market and system operators than ever (Canizares, Chen, Milano, & Singh 2004).

The restructuring of the electric power industry has involved model shifts in the real-time control activities of the power grids. Managing dispatch is one of the important control activities in a power system. Optimal power flow (OPF) has perhaps been the most significant technique for obtaining minimum cost generation patterns in a power system with existing transmission and operational constraints (Lai 2001). The role of an independent system operator in a competitive market environment would be to facilitate the complete dispatch of the power that gets contracted among the market players. With the trend of an increasing number of bilateral contracts being signed for electricity market trades, the possibility of insufficient resources leading to network congestion may be unavoidable. In this scenario, congestion management (within an OPF framework) becomes an important issue. Real-time transmission congestion can be defined as the operating condition in which there is no enough transmission capability to implement all the traded transactions simultaneously due to some unexpected contingencies. It may be alleviated by incorporating line capacity constraints in the dispatch and scheduling process. This may involve re-dispatch of generation or load curtailment. Other possible means for relieving congestion are operation of phase-shifters or FACTS devices (Yamin & Shahidepour 2003).

1.2 Statement of the Problem

The development of deregulated power systems has always resulted in overloading of the transmission networks otherwise known as network congestion. This is because more electricity generation players tend to come into the business with only one corridor (transmission network) to evacuate the generated power. Transmission congestion occurs when transmission networks fail to transfer power based on the load demand. Congestion has serious effects on power systems, including severe system damage. The Nigerian Power System tends to have a peculiar structure with most of the generating facilities located in the South with only one corridor of transmission evacuating bulk of the power to the North. These problems are managed using congestion management methods, which play an important role in deregulated power systems. The introduction of FACTS devices will reduce the loading on the transmission lines after the generators were rescheduled. These will bring stability and reliability to the power system and more importantly, it does not affect the economy of the system,

1.3 Aim and Objectives of the Study

The aim of this work is to proper a technical management approach and development of a model for Transmission Congestion in Nigerian 330kV Power System with application of FACTS devices and Generator Rescheduling.

The specific objectives are:

1. Load flow simulation on the network is carried in order to estimate the unknown variables such as generator reactive power, the bus angle, load voltage, line loss and MVA flow.
2. The output power of the generators was changed through known optimization technique such as dc optimal power flow.
3. To install FACTS devices on the network in order to investigate their effectiveness on the network.
4. To simultaneously combine generator rescheduling and FACTS devices on the network for more efficient results.

1.4 Significance of the Study

Nigeria is strongly on the verge of improved power generation. If the generation is improved, there is need to study about the problems that may arise. One of such problems is congestion of the network. Hence a study of the management of the congestion of the network is necessary in order to avert the consequences that will arise from the improved power generation.

1.5 Scope of the Study

The scope of this dissertation is limited to the application of generator rescheduling and placement of FACTS devices (SVC and TCSC) in transmission congestion management in deregulated Nigerian 330kV power system.

CHAPTER TWO

LITERATURE REVIEW

2.1 Overview of Nigerian Electricity

Electricity is an important facet of any nation’ s development. In Nigeria, electricity is the pillar of its growth and development with roles in the nation’ s production of goods and services in the industrial sector as well as agriculture, health and education (Sambo 2009). Nigeria, a country known as “ the giant of Africa” is blessed with an abundant amount of fossil fuel and renewable energy resources, but the country is battling with an acute epileptic power situation. (Emodi & Samson 2014)

According to the World Bank data; only about 50.9% of Nigerians have access to electricity (World Bank Databank of World Economic Forum on Africa, Abuja, Nigeria. 2014).

The Forum saw an investment boost to the tune of $68 billion from foreign and domestic investors in the service and industrial sectors. Sadly, this investment will meet its “ waterloo” if the Nigerian power situation does not improve. Nigeria’ s poor energy situation results from the national grid network with problems ranging from inefficient power plants which are few in numbers to lack of renewables to support peak load, physical deterioration of the long transmission lines to distribution facilities which are inadequately maintained, lack of communication facilities, illegal electricity connections and outdated meters used by the consumers (Sambo 2009). The overview of Nigerian power sector is to be reviewed in order to address the issues of its poor electricity situation.

The power sector comprises of the Generation, Transmission and Distribution.

In Nigeria, electricity generation rose from few kilowatts that were used in Lagos by the colonial masters when the first generating plant was installed in 1898 (Koledoye, Abdul-Ganiyu & Phillips 2013). By the Act of Parliament in 1951, the Electricity Corporation of Nigeria (ECN) was established. Niger Dams Authority was set up in 1962 to develop hydroelectricity and was merged with ECN to form the National Electric Power Authority (NEPA) in 1972. Despite various effort by NEPA (which operated a monopolized market) to manage the power sector by providing electricity to the increasing population, it became clear that NEPA was losing the battle to meet up with the electricity demand in the 1990s. Hence, in 2001, the National Electric Power Policy (NEPP) was introduced to kick-off the power sector reform and this lead to several other reforms in the past years (KPMG Nigeria, 2013). The NEPP in 2001 created the roadmap for Nigeria' s Power Sector Privatization, but due to government bureaucracy; the policy was not signed into law until 2005. This signed document was the Electric Power Sector Reform (EPSR) Act in 2005 which was expected to level the playing ground for potential investors and improve the wellbeing of its citizens. The EPSR Act led to the incorporation of the Power Holding Company of Nigeria from NEPA, which was later defunct and divided into sub-sectors (Koledoye, Abdul-Ganiyu & Phillips 2013 and KPMG Nigeria, 2013).

The power sector in Nigeria is divided into three major subsectors which are: Generation (GENCO), Transmission (TCN) and Distribution (DISCO).

2.1.1 Generation Company

The total installed capacity of the currently generating plants in Nigeria is 10,396.0 MW, but the available capacity is less than 6,056.3 MW as at December 2013 (Emodi & Samson 2014) and is still on its reduction around 4,465.2 MW as at January 2019. Many of the twenty-three first set of generation stations are over 20 years old and the average daily power generation is lower than the peak forecast for the current existing infrastructure. Through the planned generation capacity projects for a brighter future, the current status of power generation in Nigeria presents challenges, such as inadequate generation availability, delayed maintenance of facilities, insufficient funding of power stations, obsolete equipment, tools, safety facilities and operational vehicles, obsolete communication equipment, lack of exploration to tap all sources of energy morale (Sambo, Garba, Zarma & Gaji 2003 and Patrick, Tolulolope & Sunny 2013).

The splitting of the power sector led to the formation of Nigerian Electricity Supply Industry (NESI) which currently has 23 grid-connected generating plants in operation with a total installed capacity of 10,396 MW and available capacity of 6056 MW. Thermal based installed capacity is 8457.6 MW with available capacity of 4996 MW.

Hydropower from three major plants accounts for 1938 MW of the total installed capacity with 1060 MW as available capacity. The generation segments of the Nigerian power sector are divided into:

- Successor Generation Companies (Gencos): with six successor companies.
- Independent Power Producers (IPPs): they are owned and managed by the private

sector and have three generating facilities.

- National Integrated Power Projects (NIPP): they are owned by the government and are 10 generating facilities (KPMG Nigeria, 2013)

2.1.2 Transmission Company:

The splitting also formed the Transmission Company of Nigeria (TCN) which is a successor of the PHCN. It is made up of two departments namely System Operator and Market Operator. The transmission capacity is made up of about 5523.8 KM of 330kV lines and 6801.49 KM of 132kV lines (KPMG Nigeria, 2013).

The current transmission system in Nigeria comprises 5523.8 km of 330kV, 6801.49 km of 132kV, 32No. 330/132kV Substations with total installed transformation capacity of 7688 MVA. 105No. 132/33/11kV Substations with total installed transformation capacity of 9130 MVA. The average available capacity on 330/132kV is 7364 MVA and 8448MVA on 132/33kV. The Nigeria 330kV transmission grid is characterized by high power losses due to the very long transmission lines. Some of these lines include Benin-Ikeja West (280 km), Oshogbo-Benin (251 km), Oshogbo-Jebba (249 km), Jebba-Shiroro (244 km), Birnin Kebbi-Kainji (310 km), Jos-Gombe (265 km) and Kaduna-Kano (230 km) (Patrick, Tolulolope & Sunny 2013).

Power losses result in lower power availability to the consumers, leading to inadequate power to operate the appliances.

Thus, the high efficiency of the power system is determined by its low power losses. Increased power demand pushes the power transmission and distribution networks to their upper limits and beyond, resulting to shortening of the life span of the network or total collapse

The Nigerian transmission system does not cover every part of the country. It currently has the capacity to transmit a maximum of about 6056 MW and it is technically weak, thus very sensitive to major disturbances. Major problems associated with transmission systems include poor funding by the Federal

Government, it is yet to cover many parts of the country, it' s current maximum electricity wheeling capacity is 6,056.3 MW which is awfully below the required national needs, some sections of the grid are out-dated with inadequate redundancies as opposed to the required mesh arrangement, regular vandalization of the lines, associated with low level of surveillance and security on all electrical infrastructure, technologies used generally deliver very poor voltage stability and profiles, there is a high prevalence of inadequate working tools and vehicles for operating and maintaining the network, there is a serious lack of required modern technologies for communication and monitoring, transformers deployed are overloaded in most service areas, inadequate of spare parts for urgent maintenance, poor technical staff recruitment, capacity building and training programme (Sambo, Garba, Zarma & Gaji 2003 and Patrick, Tolulolope & Sunny 2013).

2.1.3 Distribution and Marketing Company:

The third sub-sector which is the distribution comprises of eleven Electricity Distribution Companies (DISCOS).

The DISCOS are listed below in alphabetical order with their subsidiary companies:

DISCOS	SUBSIDIARY COMPANIES
• Abuja Distribution Company	KANN Utility Company Limited
• Benin Distribution Company	Vigeo Power Limited
• Eko Distribution Company	West Power and Gas Limited
• Enugu Distribution Company	Interstate Electrics Limited
• Ibadan Distribution Company	Integrated Energy Distribution and Marketing Limited.
• Ikeja Distribution Company	Sahara Energy and Koran Electric Power Cooperation (KEPCO)
• Jos Distribution Company	Aura Energy Limited
• Kaduna Distribution Company	Northwest Power Limited
• Kano Distribution Company	Sahelian Power SPV Limited
• Port Harcourt Distribution Company	4 Power Limited
• Yola Distribution Company	Integrated Energy Distribution and Marketing Limited.

(KPMG Nigeria, 2013 and bloomberg.com/Research/stocks/private/snapshot.asp?)

Currently, Nigeria is faced with many electricity problems ranging from generation, transmission to distribution and marketing.

In most regions in Nigeria, the distribution network is poor, the voltage profile is poor and the billing is inaccurate. As the department, which inter-faces with the public, the need to ensure adequate network coverage and provision of quality power supply in addition to efficient marketing and customer service delivery cannot be over emphasized. Some challenges identified are, weak and inadequate network coverage, overloaded transformers and bad feeder pillars, substandard distribution lines, poor billing system, unwholesome practices by staff and very poor customer relations, inadequate logistic facilities such as tools working vehicles, poor and obsolete communication equipment, low staff morale and lack of regular training, insufficient funds for maintenance activities

The total installed capacity of generating plants in Nigeria is 10,390 MW with available capacity less than 6056 MW, but power generation has been below 4500 MW. Using the rule of Thumb, where 1000 MW is for 1,000,000 people and the Nigerian population is 174,567,539 (Nigeria Population, 2014), we should have about 174,508 MW for the Nigerian people but with the power generation that has not exceeded 4500 MW, we can say that Nigeria has a power deficit of 170,008 MW. Surprisingly, Nigerian population is still growing at an amazing 6% - 8% (Nigeria Population, 2014) and the nation is doing so without reasonable increase in power generation (from the national grid) compared to other rapidly growing nations like South Africa with a population of about 50 million people (in real sense, less than a third of the Nigerian population) and still generates over 45,000 MW of electricity.

2.2 Transmission Congestion Management

In an open electricity market system, the functions of the generation, transmission and distribution systems are unbundled. The reasons for this regulation vary from country to country as others seek for more profits while others were as a result of their inability to sustain the supply of power to its citizens. In the traditional electricity utility system also known as a Vertically Integrated Utility (VIU), the generation, transmission and distribution are controlled by one management.

Transmission systems are the link between the generation and distribution systems. The role of the transmission system in a deregulated environment is to regulate the loading activities of the different DISCOs and GENCOs, and settle disputes. In an open market system, transmission line congestion has become more serious and persistent, as compared to conventional regulated power system. The reason is quite simple, different buyers are trying to have access to the transmission line at the same time trying to evacuate cheap power from the generating stations if approved thereby congesting the line.

Transmission congestion is the condition where the desired transmission line flows become more than the available line capacity. Transmission congestion can be defined as the condition that occurs when there is insufficient transmission capacity to simultaneously implement all preferred transactions in electricity markets (Yong-Hua, Xi-Fan 2003). Congestion may occur in power systems due to transmission line outages, generator failures, sudden change in demand and uncoordinated transactions (Shaidepour 2002). Congestion Management is therefore necessary for the security and stability of a power system. Congestion management (CM) can be defined as the actions taken to avoid congestion. CM is a mechanism to prioritize the transactions and commit to such a schedule which would not overload the network. CM occurs in a competitive electricity market which is under a deregulated system. In such market, the System Operator (SO) is responsible for determining the necessary actions to ensure that no violations of the grid constraints occur. Developing necessary congestion management algorithms and successful testing on standard systems are the core aim of this dissertation. Congestion management approaches are based on the orders issued by the SO to various parties to reschedule their contracts, re-dispatch generators, use various control devices, or shed loads in the extreme conditions when other measures are not able to mitigate congestion (Kumar, Scrivastava & Singh 2005).

The management of congestion in the VIU system is simpler than in the deregulated system. In the VIU systems, the generation pattern is determined such that the power flow limits on the transmission lines are not exceeded (Shaidepour

2002). This task is enforced by Energy management team in the transmission system appointed by the VIU Company. In a restructured power system, the market must be modelled so that the market participants or (buyers and sellers of energy) hold freely transactions and play as per market forces but in a manner that does not threaten the security of the power systems (Animesh 2004). This liberty of transactions sometimes leads to disputes hence the need for proper congestion management.

One of the most practiced and an obvious technique of congestion management is rescheduling the power outputs of generators in the system.

Real power generation rescheduling is the most widely used control for network overload alleviation. This is due to the ease of control application and its cost-free requirements. Other models for congestion management are Sensitivity Factors Based Methods, Auction Based Congestion Management, Congestion Cost or Price Based Congestion Management, Re-Dispatch and Willingness-to-pay Methods, Available Transfer Capability Based Congestion Management, OPF Based Congestion Management and FACTS Devices Based Congestion Management.

2.3 Methods of Transmission Congestion Management

2.3.1 Sensitivity Factors Based Methods

In a deregulated electricity market, due to congestion of the transmission corridors, it may always not be possible to dispatch all of the contracted power transactions. The System Operators try to manage congestion, which otherwise increases the cost of the electricity and also threatens the system security and stability. One of the major concerns of system operator (SO) is to ensure that there is free and fair electricity trading while maintaining system security and stability in meeting the pool and contract demands. Achieving a commercially transparent and technically feasible solution during transmission congestion, therefore, poses a great challenge to SO (Kumar, Scrivastava & Singh 2004).

Some Transmission congestion factors have been proposed, one based on sensitivity of ac power flow in the lines due to the unit change in the power injection at the buses by which the congestion zones are identified in order to reschedule the generators and loads in that zone for congestion management, and another approach is based on lines real and reactive power flow sensitivity indexes also called as real and reactive transmission congestion distribution factors (Kumar, Scrivastava, & Singh 2004).

The generators in the most sensitive zones, with strongest and non uniform distribution of sensitivity indexes, are identified for rescheduling their real power output for congestion management. In addition, the impact of optimal rescheduling of reactive power output by generators and capacitors in the most sensitive zones has also been studied. This concept was tested on 41-bus Nigerian super grid system.

Network congestion assessment methodology by introducing congestion cost index is proposed in (Lee, Choi & Shin 2001). Yu et.al 1999, proposed congestion clusters based on DC power transfer distribution factors for an efficient congestion management. Vlachogiannis 2000, proposed formulae to express the contribution of each generator to the power flows, loads, and losses in power systems and these formulae are tested to relieve transmission congestion. Alvarado 1999, proposed power system application data dictionary to implement efficient codes in MATLAB used for congestion management. (Bialek, Germond & Cherkaoui 2000) proposed improvements in National Electricity Regulatory Commission' s (NERC), transmission loading relief (TLR) procedures based on power transfer distribution factors (PTDFs) and congestion management process by allowing multilateral trades. (Overbye, T. J. & Weber, J. D. 2001) discussed assessment of impact of PTDFs in TLR procedures in NERC' s congestion management. (Niimura & Niu 2002) proposed simple and transparent set of indices to represent the level of agreeable load curtailment in congestion conditions.

Kumar, Srivastava & Singh 2003, proposed congestion clusters based on AC load flow approach to manage congestion. Same authors proposed an efficient zonal congestion management approach using real and reactive power rescheduling based on AC transmission congestion distribution factors considering optimal allocation of reactive power resources (Kumar, Srivastava & Singh 2004). Linear sensitivity factors based approaches for congestion management have been presented in (Bialek 1997, Gubina, Grgic & Banic 2000, Audouin, Chaniotis, Tsamasphyrou & Coulondre 2002 and Kumar, Srivastava & Singh 2004). Liu & Gross 2002 and Liu & Gross 2004, provided systematic study on the role and effectiveness of distribution factors in congestion revenue right (CRR) application for congestion management. A statistical method to predict line congestion, which can help ISO to alleviate congestion, is presented in (Deladreue, Brouaye, Bastard & Peligry 2003).

2.3.2 Auction based congestion management

In a deregulated " transparent" markets that run a Central Broker or Market Operator, and where only the participants' bids are used to determine a market clearing price using a simple auction mechanism, without considering system constraints; the results of this auction are passed on to a System Operator who may approve, modify and/or reject the transactions, depending on the market rules and system constraints (Shebl´e 1999).

Under the pool system, electricity prices are calculated using the marginal cost of optimal power flow (OPF) solutions (Schweppe, Caramanis, Tabors, & Bonn 1998).

When there is congestion in a transmission system, prices can be significantly different by location from those of unconstrained optimal solutions. One cause of high locational prices under congested conditions can be attributed to the load slacking price elasticity. Because customers tend to consume a certain amount of electricity, no matter what current prices are, under congested conditions in particular, local suppliers in the downstream area of the congested transmission path can strategically raise the price of electricity (Singh, Hao & Papalexopoulos 1998).

Hogan 1992 proposed a concept of contract network and introduced FTR to hedge the financial risks of congestion induced price variations. Chao & Peck 1996, Chao, Peck, Oren & Wilson 2000 proposed flow gate right (FGR) to price each congested line explicitly. Seeley, Lawarree & Liu 1999 examined integrated auction mechanism to prevent congestion. A combined zonal and FTR scheme has been presented to manage congestion in (Harvey, Hogan & Pope 1996, Harvey, Hogan & Pope 1997, Stoft 1997 and Alomoush & Shahidehpour 1999). Bushnell 1999, discussed the issue of transmission congestion contract (TCC) to manage congestion. Yu, & Ilic 2000, proposed an algorithm for long-term values of transmission rights (TR) to manage congestion. A generalized algorithm for fixed transmission rights auction to manage congestion is proposed in (Alomoush & Shahidehpour 2000).

A decentralized optimization based auction mechanism to manage inter-ISO congestion is presented in (Aguado 2001 and Quintana & Madrigal 2001). Sun 2000 and Sun 2002, presented locational marginal price (LMP) and FTR for congestion management. Transmission rights for congestion management and market power is presented in (Joskow & Jean Tirole 2000). Issues of financial transmission rights to manage congestion are presented in (Lyons, Fraser & Parmesano 2000, Ruff & Flowgates 2001, Yan 2001, and Oren & Ross 2002). Richter, Jayantilal & Kumar 2001 presented FTR options as a new product to manage congestion. Yoon & Ilic 2001 examined secondary markets for transmission rights and compared its performance with TCC and FTR. (Yoon, Collison & Ilic 2001) described market mechanism for inter-regional transmission management. Interruptible physical transmission contracts mechanism to ensure optimal curtailment policy for congestion management is presented in (Raikar, & Ilic 2001). Congestion management options in three south eastern states based on LMP, FTR, and rescheduling of generation resources are presented in (Pope 2001). Analysis of five market based methods are presented and described in (De Vries 2001). Ma, Song, Lu, & Mie 2002 presented necessity of tradable physical flowgate rights for congestion relief across multiple regions. Conejo, Galiana, Arroyo, Gracia-Bertrand, Chua & Huneault 2003 presented an auction-based mechanism for congestion management. Ma, Sun & Ott 2002 and Ma, Sun, & Cheung 2003) presented the developments of LMP based markets, FTR market for congestion hedging, and ancillary services markets evolving towards standard market design (SMD).

Bruno, La Scala, Sbirrizai & Vimercati 2003 introduced financial hedging tools to replicate interruptible load supply contracts in transmission management. The article (Bartholomew, Siddiqui, Marney, & Oren 2003) described empirical analysis of New York ISO's (NYISO) TCC market for hedging congestion risks. O'Neill, Helman, Hobbs, Stewart Jr. & Rothkopf 2001, Liu, & Gross 2002 and O'Neill, Helman, Baldick, Stewart Jr. & Rothkopf 2003, defined contingent financial transmission rights for the future SMD. Liu, & Gross 2004, presented a mathematical framework for design and analysis of congestion revenue rights financial markets for congestion management. A static simulation model is proposed and developed for nodal and zonal dispatching incorporating marginal theory for congestion management system (CMS) under FTR and FGR (Mendez, & Rudnick 2004). Hamoud, G. 2004, described a simple method for determining TCC and LMP. An auction-based model is proposed in (Tuan, Bhattacharya &

Daalder 2005) for the ISO operating in bilateral contract market, for real time selection of interruptible load offers for congestion management.

2.3.3 Pricing Based Congestion Management Methods

Congestion in a transmission system can result in very high locational prices for electricity determined by marginal costs from optimal power flow (OPF) solutions. In heavily congested conditions, physical transmission congestion can be relieved by curtailing a small portion of non-firm transactions. Resultant marginal cost-based electricity prices should drastically decrease. Simple and transparent indices are introduced so that both load and supplier can express their levels of acceptance of the congestion management process, and the system operator can select the most effective and desirable congestion relief measures (Niimura, Niioka & Yokoyam 2003).

Finney, Othman & Rutz 1997, presented a method for decomposition of spot prices to reveal congestion cost component in a pool model. Price area based congestion management in Norway and Buyback method in Sweden is illustrated in (Christie, & Wangensteen 1998). Congestion management based on nodal congestion price signal is presented in (Glavitsch, & Alvarado 1997, Stoft 1998 and Glavitsch & Alavardo 1998). Gedra 1999 provided tutorial review to calculate optimal bus prices and congestion costs using DC load flow based approach. LMP based congestion management for PJM is presented in (Ott 1999 and Balmat & DiCapiro 2002). Hyman 1999 discussed the key issues of transmission pricing and congestion in electricity markets.

Gribik, Angelidis & Kovacs 1999, presented nodal and path based marginal pricing for congestion management. The various congestion management methods are illustrated and evaluated in (Corniere, Martin, Vitet, Hadjsai & Phadke 2000, Christie, Wollenberg & Wangstien 2000, Lo, Yuen &Snider 2000 and Bompard, Correia, Gross & Amelin 2003). Bompard, Carpenato, Chicco & Gross 2000, investigated relationship between real and reactive nodal prices and evaluated the impact of congestion to develop appropriate price signals in the pool paradigm. Chen, Suzuki, Wachi & Shimura 2000, Chen, Suzuki, Wachi & Shimura 2002, presented a method to decompose nodal prices into generation, congestion, and voltage limitations. The impact of load elasticity in congestion management and pricing has been investigated in (Bompard, Carpenato, Chicco, Napoli, & Gross 2000). The influence on social welfare of planned expansion of transmission system and congestion management for network security and reliability is presented in (Okada, Kitimura, Asano, Ishimaru, & Yokoyama 2000).

A congestion cluster pricing method for congestion management formulated as a stochastic optimization problem is described in (Yoon, Ilic, Collison & Arce

2001). An optimization based approach to estimate congestion rent for day-ahead and hour-ahead markets is proposed in (Raikar & Ilic 2001). An OPF based on the two-sided auction market structure reducing nodal price volatility and allows congestion relief is presented in (Marannino, Vilaiti, Zanellini, Bompard & Gross 2001). A multi-agent simulation model, which takes into account the potential impact of congestion management on market prices, is presented in (Watanabe, Okada, Tokoro & Matsui 2002). A new congestion management system based on locational pricing with two new approaches for locational power market screening is presented in (Gan & Bourcier 2002). Pricing signals as shorter-term solution to congestion management has been presented in (Papalexopoulos 2002).

A decomposition method is proposed in the Electric Reliability Council of Texas (ERCOT) portfolio zonal congestion management market to set feasible clearing prices (Yu 2002). A method to manage transmission congestion based on ex ante congestion prices is presented in (Hao & Shirmohammadi 2002). A decentralized approach for congestion management based on the previous work of (Chao & Peck 1996, Wu & Varaiya 1999 and Hogan 2000) is proposed in (Wie, Ni & Wu 2002) to discover the congestion price in spot market. A multi-objective OPF with voltage security constraints considering transmission congestion using LMP is presented in (Milano, Canizares & Invernizzi 2003). An estimation of contribution of market participants to congestion component of nodal prices is presented in

(Stamtsis & Erlich 2004). DC and AC power flow methods are compared for LMP calculation and revealing congestion patterns in (Overbye, Cheng & Sun 2004).

2.3.4 Re-dispatch and willingness-to-pay methods

After the bids are received from the market participants, the market coordinator will select certain bids necessary to facilitate pool market along with the bilateral or multilateral transactions. A transmission market provider finds the solution to this problem by solving the some optimization problems (Kumar, Scrivastava & Singh 2004).

A prioritization for transmission dispatch and related curtailment strategies are developed in (Fang & David 1999) using ' ' willingness to pay' ' factors. The effects of demand elasticity on congestion relief and price volatility are evaluated in (Bompard, Carpenato, Chicco & Gross 2000). Pool and bilateral contract dispatches and the priority arrangements for line congestion and curtailment strategies are discussed in (David & Fang 1997). Srivastava & Kumar 2000 presented an OPF based model for reducing the congestion with minimum curtailment of contracted power. David 1998 developed mathematical model for pool, bilateral and multilateral dispatch coordination including congestion and transmission charges. An overview of short, medium, and long-term scheduling of generators along with congestion management for Norway electricity market is given in (Fosso, Gjejsvik, Haugstad, Mo & Wangensteen 1999). Optimal transmission dispatch methodology considering willingness to pay premium for minimum curtailment strategy is proposed in (Fang & David 1999).

An integrated strategy to manage congestion in a real time operational environment is proposed in (Fang & David 1999, Wang, Song & Lu 2000, Wang & Song 2000, Wang, Song & Lu 2002). Reliability management considering optimal dispatch under transmission congestion is determined in (Niioka & Okada 2000). A simple and efficient algorithm for assessing feasibility of bilateral transactions, which can help system operator (SO) to manage market, is proposed in (Hamoud 2000). Merit order curtailment for managing congestion is presented in (Li & Liu 2000 and Fu & Lamont 2001). An efficient procedure mini1mizing the adjustments in preferred schedules to manage congestion is proposed in (Alomoush & Shahedehpour 2000). Optimal dispatch considering dynamic security constraints is presented in (Singh & David 2000). Optimal dispatch model to manage congestion for the feasible contracts is presented in (Wang, Yu, David, Chung & Se 2000). A Lagrangian relaxation method to congestion management is presented in (Wang & Song 2001, Wang, Song & Lu 2001).

Congestion management based on corrective measures is proposed in (Doll & Verstege 2001). Fast LP algorithm to manage congestion by rescheduling generation in Chinese electricity market is presented in (Lie, Deng, Zhang & Wu 2001). A congestion management problem with ramping constraints for day-ahead and hour-ahead markets is presented in (Lo & Xie 2001). A probabilistic approach for assessing congestion risk associated with the transfers exceeding available transfer capability (ATC) is presented in (Tuglie, Dicorato, La Scala & Bose 2001). AC load flow based OPF maximizing overall satisfaction degree of all participants to manage congestion is presented in (Gomes & Saraiva 2001). A counter-trade congestion management approach and optimal re-dispatch of generation is proposed in (Grgic & Gubina 2001 and Grgic & Gubina 2002). An evolution strategy to manage congestion with minimum corrective dispatch of generation is proposed in (Doll & Verstege 2001). OPF based approach for congestion management and ATC determination is presented in (Khusalani, Khaparde & Suman 2001). Galiana, Ivana & Franco 2002, proposed an OPF to dispatch the pool with bilateral contracts accounting both losses and congestion. Optimal power flow based interruptible load services for congestion relief is presented in (Tuan & Bhattacharya 2002). Bruno et.al 2002 proposed dynamic approach for congestion management through contract curtailment strategy.

Yamina 2002, Yamina & Shahidepour 2003, described a coordination process between Gencos and ISO for congestion management reducing the risk of failure to supply loads. Secure system dispatch solving a minimum load curtailment problem, to manage congestion is proposed in (Karaki, Chahine & Salim2002 and Rodrigues & DaSilva 2003). Padhy, Sood, Moamen, Kumar & Gupta 2002, presented an efficient and practical hybrid model using both real and reactive power transaction to manage congestion. Basic functions of spot and congestion market are described in (Giri & Avila-Rosales 2002). A multi-area congestion management approach through cross border coordinated re-dispatching is presented in (Biskas & Bakirtzis 2002). On line energy trading platform to cater for congestion management using DC load flow is presented in (Yuen & Lo 2002). A congestion management approach using rescheduling of generation and loads considering voltage security constraints is presented in (Phichaisawat, Song & Taylor 2002 and Yamin & Shahidepour 2003). Losi 2002, proposed trade curtailment strategy to maintain transmission security.

A computationally simple method for cost efficient generation rescheduling and load shedding for congestion management is proposed in Talukdar, Sinha, Mukhopadhyay & Bose 2005. (Ivana & Galiana 2002 and Franco, Ivana & Galiana 2002) formulated optimization problem of mixed pool/bilateral coordination with contract curtailment. A new method for decentralized solution of the DC-OPF to manage congestion is presented in (Bakirtzis & Biskas 2003). Congestion influence on the bidding strategies is modelled as a three level optimization problem in (Peng & Tomsovic 2003). A new Bender's decomposition approach using DC-OPF to manage congestion is presented in (Yamin, Al-Tallaq & Shahidepour 2003). AC-OPF based formulation for procuring pricing and settling ancillary services in integrated market system including congestion revenue is presented in (Wu, Rothleder, Alaywan & Papalexopoulos 2004). A problem of inter-regional congestion management using an approach to avoid mismatches between supply and demand considering a sport market is proposed in (Aguado, Quintana, Madrigal & Rosehart 2004). A new technique is suggested in (Canizares, Chen, Milano & Singh 2004) to analyze, manage price transmission congestion based on simple-auction mechanism. The proposed technique is an iterative generation rescheduling and load curtailment technique relying on " online" evaluation of transmission congestion constraints.

2.3.5 Congestion Cost Allocation Methods

In a deregulation Electricity market, there is an increase in competition among generators and this leads to reduction in prices. It has introduced several issues in the market like congestion management and market power. Due to open access all the participants have equal right to access transmission system. However, they have to bear the costs incurred to accommodate their transaction. The cost allocation is still a problem to be tackled efficiently. The prevailing problem is how to allocate the congestion cost among the market participants. Congestion relief cost should be allocated in an equitable manner among all market participants contributing to congestion. An efficient and fair allocation of congestion cost would result in smooth operation of transmission system. It also helps in tackling congestion and market power (Potabattula, Matcha, Kumari & Sydulu 2012).

Many methods for congestion cost allocation have been proposed and implemented in various markets. (Singh, Hao & Papalexopoulos 1998) proposed DC-OPF based approach to compute congestion cost. (Rau 2000) proposed AC-OPF based re-dispatch problem to alleviate congestion along with congestion cost allocation. The concept of nodal pricing was proposed by (Schweppe, Caramanis, Tabors & Bohn 1998) and further developed by (Hogan 1992). (Wu 1996 and Wu & Varaiya 1999) proposed that the surplus collected by the SO from congestion charge in Hogan's method (Hogan 1992) can be shared by generators and consumers as the profit that lead to economic operating point. (Baran, Banunaranan & Garren 2000) investigated bid based congestion management scheme and new method of allocating congestion cost to the bilateral contracts. (Yu & Galvin 2000) proposed a new method to calculate and settle zonal congestion cost for a pool and bilateral model. A load flow based cost allocation concept for congestion management is proposed in (Kawann & Sakulin 2000). (Tao & Gross 2002) proposed a physical flow based congestion management allocation mechanism for multiple transaction mechanism. (Monroy, Kita, Tanaka & Hasegawa 2002) proposed algorithm to determine contribution of each transaction to line congestion and congestion cost allocation of each transaction. (Jung, Hur & Park 2003) proposed a multi-stage method for congestion cost allocation in a pool model. Game theoretic approach for congestion cost allocation is proposed in (Bakirtzis 2001, Da Silva, Marales & De Melo 2001). (Lo, Xie, Senthil, Alaywan & Rothleder 2001) proposed a new congestion management model for inter-scheduling coordinator (SC) trade and introduced a concept of congestion charge compensation between scheduling coordinators.

2.3.6 Available Transfer Capability Based Congestion Management

Congestion is a common condition which creates considerable impact on performance of power system in deregulated environment. Information of Available Transfer Capability (ATC) helps to alleviate problem of congestion by giving power transfer capability available in the system for a particular transaction (Bharat, Bhumit & Dhaval Thesia 2015).

The inter-area tie lines in a vertically integrated market are designed only to address the reliability, system security and system restoration purposes. This integration of various systems becomes a market need in the deregulated era. Thus, inter-area tie lines become means of bulk power transfers on a regular basis from sources of cheap generation to loads. In other words, due to deregulation, the paradigm of grid integration has shifted from regional self-sufficiency to optimal utilization of resources across large geographical areas. Thus, it becomes imperative on the part of system operator to quantify the Available Transfer Capability (ATC) of the network and allocate the same to the market participants in an efficient manner (NPTEL 2012).

Available Transfer Capacity (ATC) is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. Mathematically, ATC is defined as the Total Transfer Capability (TTC) less the Transmission Reliability Margin (TRM), less the sum of existing transmission commitments (which includes retail customer service) and the Capacity Benefit Margin (CBM) (Kushalani, Khaparde & Soman 2001). Therefore:

ATC = TTC - TRM - Existing Transmission Commitments (including CBM)

Total Transfer Capability (TTC) is defined as the amount of electric power that can be transferred over the interconnected transmission network in a reliable manner while meeting all of the specific set of defined pre and post contingency system conditions.

Transmission Reliability Margin (TRM) is defined as the amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions

Capacity Benefit Margin (CBM) is defined as the amount of transmission transfer capability reserved by load serving entities to ensure that the interconnected systems do meet generation reliability requirements (NPTEL 2012). Various optimization-based methods for load curtailment and rescheduling of generation have been described for congestion management. (Kumar & Srivastav 2001) presented the congestion cost calculation and allocation of the congestion based approaches for congestion management. Congestion management using Available Transfer capability (ATC) was reported by (Kushalani, Khaparde & Soman 2001). (Makwana, Joshi & Solanki 2014) presented the Assessment of Available Transfer Capability for Congestion Management in Restructured Electrical Power Network for Competent Operation. Available Transfer Capability Calculations was described by (Ejebe, Tong, Waight, Frame, Wang & Tinney 1998). ATC Computational Issues was analysed by (Gravener, Nwankpa & Yeoh 1999). (Shaaban, Ni, & Wu 2000) reported on the Transfer Capability Computation in Deregulated Power Systems. (Kumar & Srivastav 2001) presented Power Transaction Allocation in a Deregulated Market using AC Power Transfer

Distribution Factors. Assessment of Available Transfer Capability of Transmission System was presented by (Hamoud 2000). (Bharat, Bhumit & DhavalThesia 2015) described the Available Transfer Capacity Based Congestion Management in Restructured Power System. (Kumar & Kumar 2011) presented ACPTDF for Multi-transactions and ATC Determination in Deregulated Markets. Available Transfer Capability (ATC) Determination in a Competitive Electricity Market Using AC Distribution Factors was analysed by (Kumar, Srivastava & Singh 2010). Congestion management using open power market environment electricity trading was proposed by (Barbulescu, Kilyeni, Cristian & Jigoria-Oprea 2010). In the paper, the ATC capacity was computed considering the unavailability of the transmission network. The approach was based on Monte Carlo sequential simulation. AC Power Transmission Congestion Distribution factor (PTCDF) was used to calculate the ATC. With the help of ATC calculations, congestion problem can be solved in restructured electrical power network. The proposed PTCDF method is more accurate as compared to the DC power distribution factor.

2.3.7 Distributed Generation (DG)

The distributed generation systems were the earliest power systems that were meant to serve local consumption. They are also suitable for specific applications especially those that require short period of construction and does not require large investment. Due to the increase in electricity demand and the birth of technologies, the use of the DG has shifted to the development of large Centralized Grids connecting generating stations to the load centres. However, the earliest DG still has the advantage of supplying energy to rural settlements and areas with difficult terrain. DG is mostly used for standby or backup power in the event of utility supply interruption. Other applications may include peak shaving, independent generation, net metering, voltage support, combined heat and power etc.

A power system operating under normal conditions may face such contingencies such as loss of transmission lines or line outages, loss of transformer, sudden change in the load. These contingencies are not experienced in such a distributed generation environment.

In terms of power rating, there is no clearly defined classification for the distributed generation. However, the classifications done by Ackermann are quite commendable (Ackermann, Anderson & Soder 2001).According to them, the following classifications on distributed generation capacities are as follows:

- Micro distributed generation – 1 W to <5 kW
- Small distributed generation – 5 kW to < 5 MW
- Medium distributed generation – 5 MW to <50 MW
- Large distributed generation – 50 MW to <300 MW

In Nigerian Power systems, the term DG is defined in terms of large distributed generation where private power generations are encouraged to address the deficiencies in generation sector.

The Electric Power Sector Reform act of 2005 ensured that independent power producers can generate and sell electricity in Nigeria. These reforms have yielded positive results with additional 1099.7MW of power expected to the national grid from the Nigerian Independent Power Producers, (NIPP) (EPSR 2005, www.power.gov.ng).

The three areas of power systems generation, transmission and distribution must work hand in hand for optimal performance. The transmission facilities must be ready to evacuate energy from these NIPP and the existing generating stations to avoid congestion.

Transmission congestion must be managed properly so as to reduce forced outages, improve system security and reliability and then encourage new contracts for DGs (Ackermann, Anderson & Soder 2001).

2.4 RELATED LITERATURE REVIEWED

2.4.1 Generation Rescheduling / Load Curtailment Based Congestion Management

Open market system in power system is a result of restructuring. Congestion in transmission lines (electric grid) occurs frequently if not properly managed. Transmission congestion can be managed by readjusting the real and reactive power outputs of generators. In the competitive electricity market, the ISO may call the real and reactive power rescheduling bids from all the participating generators and determine the optimum generation rescheduling by solving an appropriate optimization problem. Congestion cost method which includes both cost of load shedding and cost of generation rescheduling was considered in (Talukdar, Sinha, Mukhopadhyay & Bose 2005).

Generation Rescheduling for Congestion Management in unbundled power system was presented using particle swarm optimization technique (Puneet, Jyotsna & Sushma 2014). In their presentation, generation rescheduling was done by combining the Generator Sensitivity Factor (GSF), Generation Cost (GC) function and Reactive Power Line Loss Function (RPLLF). By using Particle Swarm Optimization (PSO) technique, all the above mentioned functions were minimized and the net optimized rescheduled generation value is obtained. The Generation Rescheduling for Congestion Management using Relative Electrical Distance was presented by (Kaushik & Nilesh 2012). In Relative Electrical Distance (RED) concept, relative location of the load nodes is found with respect to the generator nodes.

Congestion management using generation rescheduling and/or load shedding in sensitive buses was proposed in (Hazra, Sinha & Phulpin 2009), Multi-objective particle swarm optimization based congestion management using generation rescheduling / load shedding was discussed in (Hazra & Sinha 2007). Congestion Management by Generator Rescheduling in deregulated power systems by PSO was presented by (Harish & Uma 2015). In that presentation, minimizing the line flows is taken as objective function and thus the generators are re-scheduled to elevate congestion in the system. (Yajvender & Ashwani 2014) presented Congestion Management in Hybrid Electricity Market for Hydro-Thermal System using rescheduling. Congestion Management by Generator Rescheduling and FACTS Devices using Multi-Objective Genetic Algorithm was presented by (Sivakumar & Devaraj 2015).In this work Congestion is mitigated by Generator

Rescheduling and implementation of FACTS devices. Minimization of rescheduling costs of the generator and minimization of the cost of deploying FACTS devices are taken as the objectives of the given multi-objective optimization problems. Congestion Management Using Real and Reactive Power Rescheduling Based on Big Bang-Big Crunch Optimization Algorithm was presented by (Farzad, Majid & Mehdi 2014).

2.4.2 FACTS Devices Based Congestion Management

In a deregulated electricity market, it may not always be possible to dispatch all of the contracted power transactions due to congestion of the transmission corridors. The power system restructuring requires an opening of unused potentials of transmission system due to environmental, right-of-way and cost problems which are major hurdles for power transmission network expansion. Flexible AC transmission systems (FACTS) devices can be an alternative to reduce the flows in heavily loaded lines, resulting in an increased loadability, low system loss, improved stability of the network, reduced cost of production and fulfilled contractual requirement by controlling the power flows in the network as presented by (Singh & David 2001). A method to determine the optimal location of thyristor controlled series compensators (TCSCs) was optimised based on real power performance index and reduction of total system VAR power losses.

As the power systems are becoming more complex it requires careful design of the new devices for the operation of controlling the power flow in transmission system, which should be flexible enough to adapt to any momentary system conditions. The operation of an ac power transmission line, is generally constrained by limitations of one or more network parameters and operating variables by using FACTS technology such as STATCON (Static Condenser), Thyristor Controlled Series Capacitor (TCSC), Thyristor controlled Phase angle Regulator (TCPR), UPFC etc., the bus voltages, line impedances, and phase angles in the power system can be regulated rapidly and flexibly. FACTS do not indicate a particular controller but a host of controllers which the system planner can choose based on its benefit analysis.

FACTS devices have a great flexibility that can control the active power, reactive power and voltage simultaneously. SVC and UPFC are two FACTS devices which can relieve the congestion in the transmission lines efficiently. As the FACTS devices are costly hence it is required to find the optimal location for FACTS devices (Singh & Verma 2011).

2.4.3 Thyristor Controlled Series Compensator (TCSC)

Thyristor-Controlled Series Compensator (TCSC) is used in power systems to dynamically control the reactance of a transmission line in order to provide sufficient load compensation. The benefits of TCSC are seen in its ability to control the amount of compensation of a transmission line, and in its ability to operate in different modes. These traits are very desirable since loads are constantly changing and cannot always be predicted.

TCSC designs operate in the same way as Fixed Series Compensation, but provide variable control of the reactance absorbed by the capacitor device (Yu 2009). The basic structure of a TCSC can be seen fig. 2.1 below:

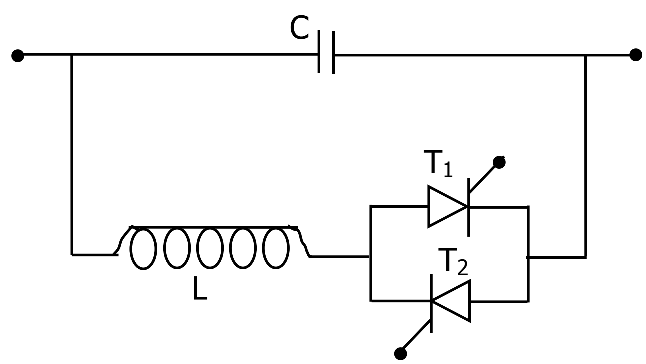


Fig 2.1: Circuit diagram of Thyristor Controlled Series Compensator

A thyristor-controlled series compensator is composed of a series capacitance which has a parallel branch including a thyristor-controlled reactor (Taher 2008).

TCSC operates in different modes depending on when the thyristors for the inductive branch are triggered. The modes of operation are as listed:

- Blocking mode: Thyristor valve is always off, opening inductive branch, and effectively causing the TCSC to operate as FSC
- Bypass mode: Thyristor valve is always on, causing TCSC to operate as capacitor and inductor in parallel, reducing current through TCSC

- Capacitive boost mode: Forward voltage thyristor valve is triggered slightly before capacitor voltage crosses zero to allow current to flow through inductive branch, adding to capacitive current. This effectively increases the observed capacitance of the TCSC without requiring a larger capacitor within the TCSC.

Because of TCSC allowing different operating modes depending on system requirements, TCSC is desired for several reasons. In addition to all of the benefits of FSC, TCSC allows for increased compensation simply by using a different mode of operation, as well as limitation of line current in the event of a fault.

A benefit of using TCSC is the damping of sub synchronous resonance caused by torsional oscillations and inter-area oscillations. The ability to dampen these oscillations is due to the control system controlling the compensator. This results in the ability to transfer more power, and the possibility of connecting the power systems of several areas over long distances (Yu 2009).

To enhance transmission line power transfer capability, FACTS devices are introduced; either in series or in shunt. The series compensation is an economic method of improving power transmission capability of the lines. According to (Taher 2008) Thyristor-Controlled Series Capacitors (TCSC) is a type of series compensator that can provide many benefits for a power system including controlling power flow in the line, damping power oscillations, and mitigating subsynchronous resonance. The TCSC concept is that it uses an extremely simple main circuit. The capacitor is inserted directly in series with the transmission line and the thyristor-controlled inductor is mounted directly in parallel with the capacitor (Acharya & Mithulananthan 2006). Thus no interfacing equipment like high voltage transformers is required. This makes TCSC much more economic than some other competing FACTS technologies. Thus it makes TCSC simple and easy to understand the operation. Series compensation will:

- ✓ Increase power transmission capability.
- ✓ Improve system stability.
- ✓ Reduce system losses.
- ✓ Improve voltage profile of the lines.
- ✓ Optimize power flow between parallel lines.

FACTS devices such as thyristor controlled series compensators and thyristor controlled phase angle regulators, by controlling the power flows in the network, can help to reduce the flows in heavily loaded lines resulting in an increased loadability of the network and reduced cost of production. (Singh & David 2001) presented Congestion management using FACTS devices requires a two-step approach. First, the optimal location of these devices in the network must be ascertained and then, the settings of their control parameters optimised.

A method of utilizing TCSC by adjusting the power flows on the congested lines to reduce the congestion cost was presented by (Lee 2002). It also focused on the optimal siting of TCSC to be installed to reduce the congestion cost. A cost free method for relieving congestion using FACTS devices such as TCSC and UPFC was presented by (Reddy, Padhy & Patel 2006). These FACTS devices are located optimally by considering thermal loading in the lines. In this OPF problem, the objective function being nonlinear, GA technique was used to obtain the global optimal solution. Two new methodologies for the placement of series FACTS devices in deregulated electricity market to reduce congestion was proposed by (Acharya & Mithulananthan 2006). Similar to sensitivity factor based method, the proposed method form a priority list that reduces the solution space. The proposed methodologies were based on the use of LMP differences and congestion rent, respectively. (Phichaisawat, Song, Wang & Wang 2002) described the applications of FACTS devices to deal with combined active and reactive congestion management in a deregulated environment. A Flexible AC transmission system device was used in allocation and transmission pricing (De Oliveri, Lima & Pereira 1999). Determination of the location and amount of series compensation to increase power transfer capability was presented by (Rajaraman, Alvarado, Maniaci, Camfield & Jalali S 1998). The concept of transmission congestion management through DGs was first introduced in (Liu, Salama & Mansour 2005), where DG had been utilized as a powerful tool for managing systems operations. Authors in (Afkousi-Paqaleh, Abbaspour, Rashidinejad & Lee 2010), proposed a new method based on optimal power flow in which DGs were used as a tool for congestion management. In (Shirmohammadi 1998) transmission dispatch and congestion management in the emerging energy market structures was presented. Optimal location of FACTS devices for congestion management was proposed by (Singh & David 2000). Congestion mitigation on high voltage power lines using multiple TCSC & UPFC was proposed by (Anwar & Tanmoy 2015). The proposal uses multiple FACTS devices of similar type and investigates their effect on congestion mitigation in high voltage transmission lines.

2.4.4 Static VAR Compensator (SVC)

Static Var Compensators (SVCs) are shunt connected static Var generators and/or absorbers whose outputs are adjusted to exchange capacitive or inductive current so as to maintain or control specific parameters of the electrical power system (typically bus voltage). The term " static" is used to indicate that SVCs, unlike synchronous compensators, have no moving or rotating components. Thus an SVC consists of static Var generator (SVG) or absorber device and a suitable control device. SVCs are based on thyristor without gate turn-off.

If the power system’ s reactive load is capacitive (leading), the SVC will use thyristor controlled reactors to consume VARs from the system, lowering the system voltage. Under inductive (lagging) conditions, the capacitor banks are automatically switched in, thus providing a higher system voltage.

Static Var Compensators (SVCs) are devices that can quickly and reliably control line voltages. SVCs are used in two main situations:

- Connected to power system, to regulate the transmission voltage (Transmission SVC)
- Connected near large industrial loads, to improve power quality (Industrial SVC)

Types of SVC

The following are the basic types of reactive power control elements which make up all or part of any static var system.

- Saturated reactor
- Thyristor-controlled reactor (TCR)
- Thyristor-switched capacitor (TSC)
- Thyristor-switched reactor (TSR)
- Thyristor-controlled transformer (TCT)
- Self or line commuted converter (SCC/LCC)

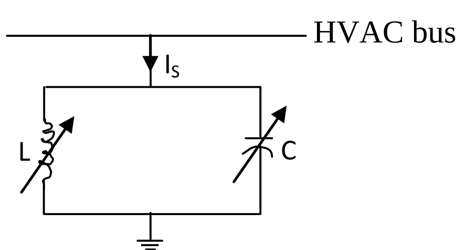


Fig. 2.2: Ideal Static Var System

2.5 Summary of Related Literature Reviewed

The reviewed researchers used different methods under different systems in solving the problems of managing Transmission congestion of a network. Talukdar, Sinha, Mukhopadhyay & Bose 2005, considered congestion cost method of both cost of load shedding and cost of generation rescheduling of a system in their analysis and came up with their result. Puneet, Jyotsna & Sushma 2014 presented generation rescheduling for CM using particle swarm optimization technique where generation rescheduling was done by combining the Generator Sensitivity Factor (GSF), Generation Cost (GC) function and Reactive Power Line Loss Function (RPLLF), minimizing all the above mentioned functions in order to obtain the net optimized rescheduled generation value. Singh & David 2001 presented a method to determine the optimal location of thyristor controlled series compensators (TCSCs) which was optimised based on real power performance index and reduction of total system VAR power losses, this reduce congestion of the network to its minimum. Sivakumar & Devaraj 2015, presented Congestion

Management by Generator Rescheduling and FACTS Devices using Multi-Objective Genetic Algorithm. In their work, Congestion was mitigated by Generator Rescheduling and implementation of FACTS devices. The minimization of rescheduling costs of the generator and minimization of the cost of deploying FACTS devices were taken as the objectives of the given multi-objective optimization problems. Farzad, Majid & Mehdi 2014 presented Congestion Management Using Real and Reactive Power Rescheduling Based on Big Bang-Big Crunch Optimization Algorithm. Liu, Salama & Mansour 2005 introduced the concept of transmission congestion management through DGs, where DG had been utilized as a powerful tool for managing systems operations. Afkousi-Paqaleh, Abbaspour, Rashidinejad & Lee 2010, proposed a new method based on optimal power flow in which DGs were used as a tool for congestion management. Shirmohammadi 1998 presented transmission dispatch and congestion management in the emerging energy market structures. Singh & David 2000, proposed optimal location of FACTS devices for congestion management.

Although the reviewed researchers got results that alleviated congestion management problems but few of the reviewed researchers mitigated transmission congestion by combining generator rescheduling and placement of FACTS technology such STATCON (Static Condenser) but none of these methods was applied in a rigid power system such as Nigerian power system. The peculiar problem in Nigerian power system is the over centralization of power generation. Using single method of reducing congestion will not be enough to create a healthy system due to high concentration of power generation in the southern part of the country and low concentration of power in the northern part which creates an imbalance in power generation. The combination of these methods such as the combined application of TCSC, SVC and generator rescheduling will create a healthy network without violations.

2.6 Research Gaps

Different authors have done extensive work on Transmission Congestion Management using different methods under different systems in solving the problems of managing Transmission Congestion of a power network on flexible transmission systems where generators/facilities are sited at each strategic load centres. The case is different with the Nigerian power system which on the other hand runs an over centralized power system where majority of the generating stations are cited in the southern part with only an overstretched transmission system conveying the loads to the far northern parts. It is safe to say that the proposed solution by other researchers in solving congestion problems was not done in such as an imbalance power generation as in the case of Nigeria power system. That is why the simultaneous application of FACTS devices and Generator Rescheduling is very crucial in solving Nigerian Transmission congestion problem. Therefore this work was able to bridge the above gaps peculiar to Nigerian Power system with very large power network and concentration of power generation in one part of the country.

CHAPTER THREE

METHODOLOGY

The following under listed approaches was adopted in executing the task:

1. Designing the model of 41-bus 330kV network with data obtained from National Control Centre (NCC) and Transmission Company of Nigeria (TCN) using Power System Analysis Toolbox (PSAT).
2. Application of Newton-Raphson technique with PSAT in MATLAB environment to run load flow analysis on the base case in order to estimate the unknown variables such as generator reactive power, the bus angle, load voltage, line loss and MVA flow.
3. Application of DC optimal power flow optimization technique is used to change the output power of the generator.
4. Placement of FACTS devices on the network in order to investigate their effectiveness on the network.

5. Simultaneous combination of generator rescheduling and placement of FACTS devices (SVC and TCSC) on the network for more efficient results.

Excel spreadsheet is used to plot and tabulate the results.

3.1 Power Flow System

In a power flow system, four quantities are associated with each bus. These quantities are;

(i) Voltage magnitude /V/

(ii) Phase angle δ

(iii) Real power or active power P and

(iv) Reactive Power Q

The power system buses are generally classified into three types.

1. **Slack bus:** *Slack or swing bus* (one bus), is taken as a reference where the magnitude and phase angle of the voltage are specified. This bus makes up the difference between the scheduled loads and generated power that are caused by the losses in the network.

2. **Load buses (P-Q bus):** At these buses the active and reactive powers are specified. The magnitude and the phase angle of the bus voltages are known. These buses are called P-Q buses.

3. Generator buses (P-V bus): These buses are the *regulated buses*. There are also known as *voltage-controlled buses.* At these buses, the real power and voltage magnitude are specified. The phase angles of the voltages and the reactive power are to be determined. The limits on the value of the reactive power are also specified. These buses are called P-V buses (Saadat 1999).

	P	**Q**	**V**	**δ**
P-Q bus	known	known	unknown	unknown
P-V bus	known	unknown	known	unknown
Slack bus	unknown	unknown	known	known

Real and reactive powers (i.e. complex power) cannot be fixed. The net complex power flow into the network is not known in advance, and the system power losses are unknown until the study is complete. It is necessary to have one bus (i.e. the slack bus) at which complex power is unspecified so that it supplies the difference in the total system load plus losses and the sum of the complex powers specified at the remaining buses. The slack bus must also be a generator bus. The complex power allocated to this bus is computed as part of the solution. In order for the variations in real and reactive powers of the slack bus to be a small percentage of its generating capacity during the solution process, the bus connected to the largest generating station is normally selected as the slack bus.

The goal of a power-flow study is to obtain complete voltage angle and magnitude information for each bus in a power system for specified load and generator real power and voltage conditions (Grainger & Stevenson 1994). Once this information is known, real and reactive power flow on each branch as well as generator reactive power output can be analytically determined. Due to the nonlinear nature of this problem, numerical methods are employed to obtain a solution that is within an acceptable tolerance.

The power-flow solution problem begins with identifying the known and unknown variables in the system. The known and unknown variables are dependent on the type of bus. A bus without any generators connected to it is called a Load Bus. With one exception, a bus with at least one generator connected to it is called a Generator Bus. The exception is one arbitrarily-selected bus that has a generator. This bus is referred to as the slack bus (Singh 1999).

In the power-flow problem, it is assumed that the real power P_D and reactive power Q_D at each Load Bus are known. For this reason, Load Buses are also known as PQ Buses. For Generator Buses, it is assumed that the real power generated P_G and the voltage magnitude $|V|$ is known. For the Slack Bus, it is assumed that the voltage magnitude $|V|$ and voltage phase Θ are known. Therefore, for each Load Bus, both the voltage magnitude and angle are unknown and must be solved for. For each Generator Bus, the voltage angle must be solved for; there are no variables that must be solved for the Slack Bus. In a system with N buses and R generators, there are then $2(N - 1) - (R - 1)$ unknowns. In order to solve for the $2(N - 1) - (R - 1)$ unknowns, there must be $2(N - 1) - (R - 1)$ equations that do not introduce any new unknown variables.

3.2 Power Flow Study

Load flow studies are one of the most important aspects of power system planning and operation. The load flow gives the sinusoidal steady state of the entire system - voltages, real and reactive power generated and absorbed and line losses. Since the load is a static quantity and it is the power that flows through transmission lines, the purists prefer to call this, **Power Flow Studies** rather than load flow studies. The original nomenclature of load flow is however sticked to.

Through the load flow studies, the voltage magnitudes and angles at each bus in the steady state can be obtained. This is rather important as the magnitudes of the bus voltages are required to be held within a specified limit. Once the bus voltage magnitudes and their angles are computed using the load flow, the real and reactive power flow through each line can be computed. Also based on the difference between power flow in the sending and receiving ends, the losses in a particular line can also be computed. Furthermore, from the line flow, the over and under load conditions can also be determined.

The steady state power and reactive power supplied by a bus in a power network are expressed in terms of nonlinear algebraic equations. We therefore would require iterative methods for solving these equations.

In this dissertation, the mathematical modelling of power flow in Nigerian 330kV 41Bus transmission system will be considered. Also to be obtained is the mathematical modelling of the effects of Flexible AC Transmissions Systems (FACTS) in power system. SVC and TCSC are the FACTS devices considered in this study.

3.3 Elements of Transmission Line

The transmission line transfer electrical energy from the generator bus to the load bus. These transmission lines have parameters which are used in the operation of the Nigeria system. These parameters are given below.

3.3.1 The Impedance

It is the opposition to the flow of an alternating current and represented mathematically as

$$Z = R + JX \qquad (3.1)$$

where R which is the real part; it is the resistance which measures the opposition to the passage of an electric current. X which is the imaginary part; it is the inductive reactance which is the opposition of a circuit element to a change of electric current or voltage due to inductance.

3.3.2 The Admittance

It is the measure of how easily a circuit or device will allow a current to flow. It is the inverse of the impedance

$$Y = Z^{-1} = \frac{1}{Z} \qquad (3.2)$$

The admittance, just like impedance is a complex number, made up of real part and an imaginary part, thus

$$Y = G + JB \qquad (3.3)$$

Where the real is the conductance which is the measure of how easily electricity flows along a certain path and it is the inverse of resistance.

The imaginary part which is the Susceptance is known to be the shunt charging and the inverse of the reactive inductance.

3.4 The Power Flow Problem

The power-flow problem discussed in this section will be presented in terms of the $\mathbf{Y}_{bus}$ matrix whose elements are of the form

$$Y_{ik} = |Y_{ik}|e^{j\theta_{ik}} = |Y_{ik}|\cos\theta_{ik} + j|Y_{ik}|\sin\theta_{ik} = G_{ik} + jB_{ik} \quad (3.4)$$

Fori, k = 1, 2, . . . , N. Let the voltage at bus i be denoted by

$$V_i = |V_i|e^{j\delta_i} = |V_i|(\cos\delta_i + j\sin\delta_i) \quad (3.5)$$

For i = 1, 2, . . . , N.

The net current injected into the network at bus in terms of the elements Y_{ik} of the $\mathbf{Y}_{bus}$ is determined by

$$I_i = Y_{i1}V_1 + Y_{i2}V_2 + \ldots + Y_{iN}V_N = \sum_{k=1}^{n} Y_{ik}\text{ , } i = 1,2..,n \quad (3.6)$$

Let P_i and Q_i denote the net real and reactive power entering the network at bus i. Then the complex conjugate of the power injected at bus i is given by

$$P_i - jQ_i = V_i^*\sum_{k=1}^{n} Y_{ik}V_k = \sum_{k=1}^{n} |Y_{ik} V_i V_k| e^{j(\theta_{ik} + \delta_k + \delta_i)} \quad (3.7)$$

From the preceding equation we obtain the following form of the *power*-flow equations:

$$P_i = \sum_{k=1}^{n} |Y_{ik} V_i V_k| \cos(\theta_{ik} + \delta_k + \delta_i) \quad (3.8)$$

$$Q_i = \sum_{k=1}^{n} |Y_{ik} V_i V_k| \sin(\theta_{ik} + \delta_k + \delta_i) \quad (3.9)$$

The power-flow problem entails the computations of P_i and Q_i for values of the unknown bus voltages which cause the mismatches ΔP_i and ΔQ_i to be equal to zero at each bus. At each bus i two of the four quantities δ_i, $|V_i|$, P_i, and Q_i are specified and the remaining two are calculated. For convenience bus 1 is designated as the *slack bus* and the voltage angle of the slack bus serves as reference for the angles of all other bus voltages. The usual practice is to set $\delta_1 = 0°$.

3.5 Newton Raphson Method

There are several different methods of solving the resulting nonlinear system of equations. The most popular is known as the Newton-Raphson Method which is an iterative technique for solving systems of simultaneous equations in the general form.

To set up the Newton-Raphson numerical method, we employ the power-flow expressions given by Equations (3.8) and (3.9). These equations are more convenient than Equation (3.7) during the computation of the Jacobian matrix, as we will show later.

Let us assume that we have N buses and that all buses, except the slack bus ($i = 1$), are load buses with prescribed demands P_{di} and Q_{di}. Denoting the specified values $|V_1|$ and δ_1 for the slack bus, then each of the remaining buses in the network has the two state variables $|V_i|$ and δ_i to be determined by the power flow solution. The objective of the Newton-Raphson method is to produce values for $|V_i|$ and δ_i that will match the prescribed P_{di} and Q_{di} as determined from Equations (3.8) and (3.9). At each iteration of the method, new estimates of $|V_i|$ and δ_i for the non-slack buses (i = 2, 3, … , N) are generated. At the end of each iteration, the power mismatch is given by

$$\Delta P_i = P_{i,\text{sch}} - P_i, \tag{3.10}$$

$$\Delta Q_i = Q_{i,\text{sch}} - Q_i. \tag{3.11}$$

Expanding equation 3.8 and 3.9 in Taylor's series result in the following set of linear equations given below:

$$\begin{bmatrix} \Delta P_2^k \\ \Delta P_n^k \\ \Delta Q_2^k \\ \Delta Q_n^k \end{bmatrix} = \begin{pmatrix} \frac{\partial P_2}{\partial \delta_2}^k \cdots \frac{\partial P_2}{\partial \delta_n}^k & \frac{\partial P_2}{\partial V_2}^k \cdots & \frac{\partial P_2}{\partial V_n}^k \\ \frac{\partial P_n}{\partial \delta_2}^k \cdots \frac{\partial P_n}{\partial \delta_n}^k & \frac{\partial P_n}{\partial V_2}^k \cdots & \frac{\partial P_n}{\partial V_n}^k \\ \frac{\partial Q_2}{\partial \delta_2}^k \cdots \frac{\partial Q_2}{\partial \delta_n}^k & \frac{\partial Q_2}{\partial V_2}^k \square & \frac{\partial Q_2}{\partial V_n}^k \\ \frac{\partial Q_n}{\partial \delta_2}^k \square \frac{\partial Q_n}{\partial \delta_n}^k & \frac{\partial Q_n}{\partial V_2}^k \square & \frac{\partial Q_n}{\partial V_2}^k \end{pmatrix} \begin{bmatrix} \Delta \delta_2^k \\ \Delta \delta_n^k \\ \Delta V_2^k \\ \Delta V_n^k \end{bmatrix} \tag{3.12}$$

The Jacobian matrix gives the linearized relationship between small changes in voltage angle $\Delta\delta_i^k$ and voltage magnitude ΔV_i^k with small changes in real and reactive power ΔP_i^k and ΔQ_n^k. Elements of the Jacobian matrix are the partial derivatives of equations (3.8) and (3.9), evaluated at $\Delta\delta_i^k$ and ΔV_i^k. In short form, it can be written as

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{matrix} J_1 & J_2 \\ J_3 & J_4 \end{matrix} \begin{bmatrix} \Delta \delta \\ \Delta V \end{bmatrix} \tag{3.13}$$

For the voltage controlled buses, the voltage magnitude are known. Therefore if m buses of the system are voltage controlled, m equations involving ΔQ and ΔV and the corresponding column are eliminated. Accordingly, there are n – 1 real power constraint and n – 1 – m reactive power constraints and the Jacobain matrix is of the order (2n – 2 – m) * (2n – 2 – m). J_1 is the order (n – 1) * (n – 1), J_2, is of the order (n – 1) * (n – 1 – m), J_3 is of the order (n – 1 – m) * (n – 1), and J_4 is of the order (n – 1 – m) * (n – 1 – m)

The diagonal and the off diagonal elements of J_1 are

$$\frac{\partial P_i}{\partial \delta_i} = \sum_{j \neq 1} V_i * V_j * Y_{ij} * \sin(\theta_{ij} - \delta_i + \delta_j)$$

$$\frac{\partial P_i}{\partial \delta_j} = -V_i * V_j * Y_{ij} * \sin(\theta_{ij} - \delta_i + \delta_j)$$

The diagonal and the off diagonal elements of J_2 are

$$\frac{\partial P_i}{\partial V_j} = 2 * V_i * Y_{ij} \cos \theta_{ii} + \sum_{j \neq 1} V_j * Y_{ij} * \cos(\theta_{ij} - \delta_i + \delta_j)$$

$$\frac{\partial P_i}{\partial V_j} = V_i * Y_{ij} * \cos(\theta_{ij} - \delta_i + \delta_j)$$

The diagonal and the off diagonal elements of J_3 are

$$\frac{\partial Q_i}{\partial \delta_i} = \sum_{j\neq 1} V_i * V_j * Y_{ij} * \cos(\theta_{ij} - \delta_i + \delta_j)$$

$$\frac{\partial Q_i}{\partial \delta_j} = -V_i * V_j * Y_{ij} * \cos(\theta_{ij} - \delta_i + \delta_j)$$

The diagonal and the off diagonal elements of J_4 are

$$\frac{\partial P_i}{\partial V_j} = -2 * V_i * Y_{ij} \sin\theta_{ii} - \sum_{j\neq 1} V_j * Y_{ij} * \sin(\theta_{ij} - \delta_i + \delta_j)$$

$$\frac{\partial P_i}{\partial V_j} = -V_i * Y_{ij} * \sin(\theta_{ij} - \delta_i + \delta_j)$$

The approximate errors from (3.12) are added to the initial estimates to produce new estimated values of node voltage magnitude and angle for (i = 1,2,3) and (k = 1,2,……,n).

$$|V_i^{k+1}| = |V_i^k| + \Delta|V_i^k| \quad (3.14)$$

$$|\delta_i^{k+1}| = |\delta_i^k| + \Delta|\delta_i^k| \quad (3.15)$$

3.5.1 Problem Formulation

The optimal power flow is a constrained optimization problem requiring the minimization of:

$$min \sum_{i=1}^{N_g} F_i(P_{geni}) \quad (3.16)$$

Where *i* is an index over the bus and $F_i(P_{geni})$ is the cost function of the generator at bus *i*.

3.5.2 Objective Function

It specifies the relationship between how much heat must be input to the generator and its resulting MW output. In all practical cases, the cost of generator C_i can be represented as:

$$C_i = (a_i + b_i P_i + c_i P_i) * \text{fuel cost} \tag{3.17}$$

Where P_i *is* the real power output of generator i, and a_i, b_i, c_i are the cost coefficients.

3.6 Constraints

Constraints are the operating limits to the problem. In a conventional power flow, equipment limits are normally supplied by the user for monitoring purposes, such as printing out of any violations of circuit flow limits. Only the power flow algorithm enforces a small set of limits, such as, tap limits and generator MVAR limits. In contrast, an OPF enforces all equipment limits input by the user. This may easily lead to problem infeasibility if the limits are too restrictive or inconsistent. Careless input of limits should therefore be avoided. A commercially available OPF normally offers a facility to relax limits in case of unfeasibility. Once a solution is obtained for the relaxed problem, the OPF will provide means to investigate how the original limits had caused convergence difficulties. Such a mechanism may provide valuable information concerning the power system being modelled. For instance, a region which requires relaxation of voltage limits may have implications of requiring new reactive compensation sources. Some OPF programs require users to give them guidance as to which limits can be relaxed and in what sequence. This flexibility in fact places much burden on the users who need to appreciate how an OPF algorithm performs before the preferred strategy for constraint relaxation can be formalized as input to the program.

3.6.1 Types of Constraints.

A. Equality constraint

The equality constraints of the OPF reflect the physics of the power system as well as the desired voltage set points throughout the system. The physics of the power system are enforced through the power flow equations which require that the net injection of real and reactive power at each bus sum to zero. This can be achieved by active and reactive power analysis

The power flow Y matrix equation for each bus i

$$P_{neti} + jQ_{geni} = V_i \left(\sum_{k=1}^{N_g} Y_{ik} V_k\right) \quad (3.18)$$

The bus equation is

$$(P_{geni} - P_{loadi}) - Real\ [V_i(\sum_{k=1}^{N_g} Y_{ik} V_k)] = 0 \quad (3.19)$$

$$(Q_{geni} - Q_{loadi}) - Real\ [V_i(\sum_{k=1}^{N_g} Y_{ik} V_k)] = 0 \quad (3.20)$$

B. Inequality Constraint

In a power system, components and devices have operating limits and these limits are created for security constraints. Thus the required objective function can be minimized by maintaining the network components within the security limits.

3.6.2 Generator Inequality Constraints

$$P_{geni}^{min} \leq P_{geni} \leq P_{geni}^{max}, \text{ for i = 1,2,.....,n} \tag{3.21}$$

$$Q_{geni}^{min} \leq Q_{geni} \leq Q_{geni}^{max}, \text{ for i = 1,2,.....,n} \tag{3.22}$$

3.6.3 Transmission Line Limit

$$\text{MW flow = Real } \{V_i[V_i - V_j]Y_{ij} + V_i^2 + Y_{charging}]\} \leq MW\ flow_{ij}^{max} \tag{3.23}$$

$$\text{MVAR flow = abs } \{V_i[V_i - V_j]Y_{ij} + V_i^2 + Y_{charging}]\} \leq MVAR\ flow_{ij}^{max} \tag{3.24}$$

3.6.4 Voltage Limit

$$V_i^{min} \leq V_i \leq V_i^{max} \tag{3.25}$$

3.7 DC Optimal Power Flow

DC optimal power flow comprises a set of non-linear simultaneous equation which needs a simple linear relation for fast and intuitive analysis. For DC optimal power flow, reactive power is neglected and resistance of the branches is also neglected.

It is assumed that all voltage magnitudes are 1.0 per-unit and the angles are considered small by default. The reason why it is called DC optimal power is due to the fact that the reactance plays the role of a resistance just like the DC circuit, the voltage plays the role of a DC voltage and power plays the role of DC current. By using DC optimal power flow, the formulation is as follows:

$$[B_x]\,\theta = P_{gen} - P_{load} \tag{3.26}$$

where θ is the phase angle and it is equal to $\begin{bmatrix} \theta \\ \vdots \\ \theta_{Ng} \end{bmatrix}$ in radians and $[B_x]$ is known as the B-coefficient and it is in per-unit. And the formula for the B-coefficient is given below.

$$B_{xik} = \left[-\frac{1}{xik}\right] \tag{3.27}$$

$$B_{xkk} = \left[\frac{1}{xkk} + \cdots + \frac{1}{xnn}\right] \tag{3.28}$$

In matrix form, the B-coefficient is written as follows.

$$\begin{bmatrix} B_{xii} & \cdots & B_{xik} \\ \vdots & \ddots & \vdots \\ B_{xik} & \cdots & B_{xin} \end{bmatrix}$$

x_{ik} represents the reactance of the line. From equations 3.27 and 3.28, it is seen that the B-coefficient is dependent on the reactance of the line.

The optimal power flow can be written as the lagrangian as follows

$$\mathscr{L} = \sum_{i=1}^{N_g} F_i(P_{geni}) + \lambda^T(100*[Bx]\,\theta - (P_{geni} - P_{loadi}) + \lambda_{Ng+1}\,(\theta_{ref} - 0) \tag{3.29}$$

(Allen, Bruce, & Gerald, 2015).

In order to force the reference bus phase angle to zero radians including the generator upper and lower limit will result to the following equation

$$\mathcal{L} = \sum_{i=1}^{N_g} F_i(P_{geni}) + \lambda^T (100 * [Bx]\,\theta - (P_{geni} - P_{loadi}) + \lambda_{Ng+1}\,(\theta_{ref} - 0) +$$

$$\lambda_{Ng+1}\,(\theta_{ref} - 0) + \mu^T [P_{gen}, P_{gen}^{min}, P_{gen}^{max}] \qquad (3.30)$$

(Allen, Bruce, & Gerald, 2015)

The langrangian of the DC OPF for *n* number of buses

$$\mathcal{L} = \sum_{i=1}^{N_g} (a_i + b_i P_{geni} + c_i P_{geni}^2) \ldots\ldots.$$

$$+ \lambda_i(100*B_{xii}\theta_i + 100*B_{xik}\theta_k + \ldots\ldots\ldots + 100*B_{xin}\theta_n - P_{geni} - P_{loadi})$$

⋮

⋮

$$+ \lambda_n(100*B_{xnn}\theta_i + 100*B_{xin}\theta_k + \ldots\ldots + 100*B_{xin}\theta_n - P_{genn} - P_{loadn}) \qquad (3.31)$$

The unknown variables are P_{gen}, λ and λ_n. To get the unknown variables we take the derivative of the langrangian with respect to the unknown variables which is given as;

A. For generator output

$$\frac{d\mathcal{L}}{dP_{geni}} = b_i + 2c_i P_{geni} - \lambda_i = 0 \qquad (3.32)$$

⋮

⋮

$$\frac{d\mathcal{L}}{dP_{genn}} = b_n + 2c_n P_{genn} - \lambda_n = 0 \quad (3.33)$$

B. For phase angle

$$\frac{d\mathcal{L}}{d\theta_i} = 100 * B_{xii}\lambda_k + 100*B_{xik}\lambda_k + \square\square\square .. + 100*B_{xin}\lambda_k + \lambda_{ref} \quad (3.34)$$

⋮

⋮

$$\frac{d\mathcal{L}}{d\theta_n} = 100 * B_{xnn}\lambda_k + 100*B_{xnk}\lambda_k + \square\square\square .. + 100*B_{xin}\lambda_k \quad (3.35)$$

C. For the incremental cost

$$\frac{d\mathcal{L}}{d\lambda_i} = 100 * B_{xii}\theta_k + 100 * B_{xik}\theta_k + \cdots + 100 * B_{xin}\theta_n \quad (3.36)$$

⋮

⋮

$$\frac{d\mathcal{L}}{d\lambda_i} = 100 * B_{xii}\theta_k + 100 * B_{xik}\theta_k + \cdots + 100 * B_{xin}\theta_n \quad (3.37)$$

The reason λ_{ref} in equation 3.34 is due to the fact that the slack bus is present.

3.8 Power Flow Multi-control Function with SVC Device

Static Var Compensators (SVCs) control specific parameters of the electrical power system (typically bus voltage). The control strategy with SVC is to keep the transmission bus voltage within a certain narrow limits defined by a controller droop and the firing angle $\propto$ limits ($90^o < \propto < 180^o$). With balanced fundamental frequency operation, an adequate transient stability model can be developed assuming sinusoidal voltages. This model can be represented by the set of p.u. equations;

$$[x_c^{'}, \propto^{'}]^T = f(x_c, \propto, V, V_{ref}) \quad (3.38)$$

$$B_e - \frac{\left(2\propto - sin\propto - \pi\left(2 - \frac{X_L}{X_C}\right)\right)}{\pi X_L} = 0. \quad (3.39)$$

$$I_{SVC} - V_i B_e = 0$$

$$Q_{SVC} - V_i^2 = 0$$

Where $f(x_c, \propto, V, V_{ref})$ stands for the control system variables and equations respectively, V is the controlled bus voltage magnitude, V_i represents the TCR and the fixed capacitor voltage magnitude, V_{ref} is the controller point, X_{SL} is the droop, Q_{SVC} and I_{SVC} are the controller reactive power and current respectively, B_e is the equivalent susceptance of the TCR and the fixed capacitor combination, X_C and X_L corresponds to the fundamental frequency reactance of L and C, respectively.

In order words, the power flow equations for SVC are;

$$V - V_{ref} + X_{SL}\ I = 0 \tag{3.40}$$

$$B_e - \frac{\left(2\propto - sin\propto - \pi\left(2 - \frac{X_L}{X_C}\right)\right)}{\pi X_L} = 0 \tag{3.41}$$

$$I_{SVC} - V_i B_e = 0 \tag{3.42}$$

$$Q_{SVC} - V_i^2 = 0 \tag{3.43}$$

For the power flow model to be complete, all SVC controller limits will be adequately represented. SVC limit is the firing angle $\propto$; i.e $\propto \epsilon\ [\propto_m, \propto_M]$; where $\propto_m$ is the minimum firing angle and $\propto_M$ is the maximum firing angle. V_{ref} is fixed at V_{ref}^0 until $\propto$ reaches a limit at which point V_{ref} is allowed to change while $\propto$ is kept at its limit value. Voltage control is regained when V_{ref} returns to V_{ref}^0.

3.9 Power Flow Multi-control Function with TCSC Device

TCSC FACTS controller basically consists of the same TCR and FC combination used in SVC but connected in series with a transmission line. Due to series connection, there is no need in this case for a transformer bank to change the controller voltage. This device is usually designed to directly control line currents, but various other strategies can be used to control line impedance and power flows, damp oscillations, etc.

The limits on the firing angle $\propto$ for the TCSC controller are different from the ones used for the SVC, as there is a resonance region where the controller becomes an open circuit and, hence, it must be avoided in a series connection. Furthermore, the controller is designed to mainly operate in the capacitive region in steady state, to reduce harmonic pollution of the current waveforms. Thus, $\propto_r < \propto < 180^0$, where $\propto_r$ corresponds to the resonant point (this value depends on the ratio (X_C/X_L).

Fundamental frequency operation can be represented by the following set of equations, which includes the control system equations and assumes sinusoidal currents in the controller;

$$[x_c', \propto']^T = f(x_c, \propto, I, I_{ref}) \tag{3.44}$$

$$P + V_k V_m B_e \sin(\delta_k - \delta_m) = 0 \tag{3.45}$$

$$-V_k^2 B_e + V_k V_m B_e \cos(\delta_k - \delta_m) - Q_k = 0 \tag{3.46}$$

$$-V_m^2 B_e + V_k V_m B_e \cos(\delta_k - \delta_m) - Q_m = 0 \tag{3.47}$$

$$B_e - B_e(\propto) = 0 \tag{3.48}$$

$$(P^2 + Q_k^2)^{\frac{1}{2}} - IV_k = 0 \tag{3.49}$$

Where x_c and $f(x_c, \propto, I, I_{ref})$ stand for the internal control system variables and equations, V_k and V_m are the terminal voltages of controller, δ_k and δ_m are the magnitudes of the terminal, Q_k and Q_m are the reactive power injections at both controller terminals, P and I are the active power and current flowing through the controller respectively,

B_e is given as;

$$B_e(\propto) = \pi(k_x^4 - 2k_x^2 + 1)\cos k_x(\pi-\propto) + [X_C(\pi k_x^4 cos k_x(\pi-\propto) - \pi\cos(k_x - \propto) - 2k_x^4 \propto cos k_x(\pi-\propto)$$

(3.50)

where $k_x = \left(\frac{X_C}{X_L}\right)^{\frac{1}{2}}$

It is important to mention that as the controller gets closer to its resonant point, the current deviates from its sinusoidal condition, and hence the model presented should not be used to represent the controller under these conditions.

A steady state model for this TCSC controller can be obtained by replacing the differential equations on equation (3.49) with the corresponding steady state control equations. For an impedance control model with no droop, which yields the simplest set of steady state equations from the numerical point of view, the power flow equations for the TCSC are;

$$B_e - B_{ref} = 0 \tag{3.51}$$

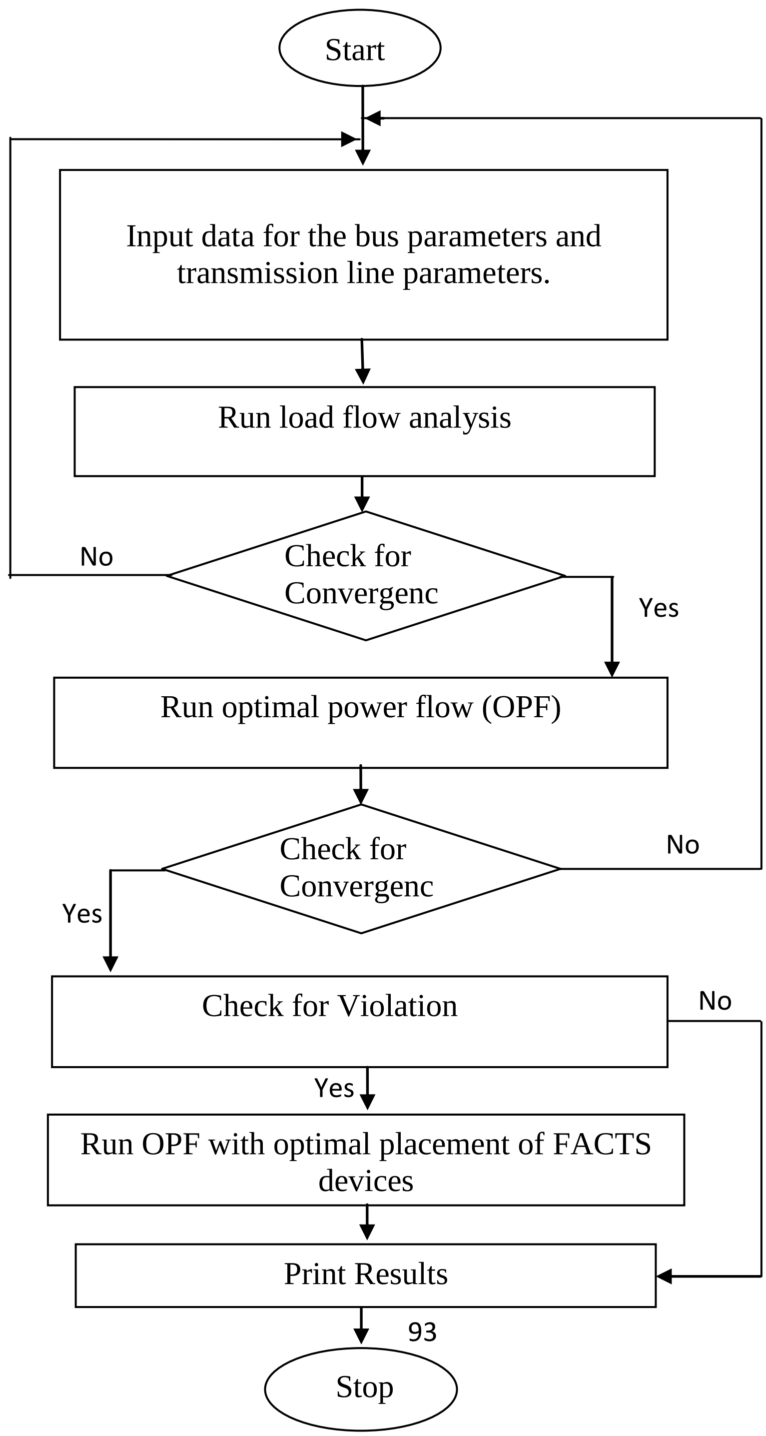
$$P + V_k V_m B_e \sin(\delta_k - \delta_m) = 0 \tag{3.52}$$

$$-V_k^2 B_e + V_k V_m B_e \cos(\delta_k - \delta_m) - Q_k = 0 \tag{3.53}$$

$$B_e - B_e(\propto) = 0 \tag{3.54}$$

$$(P^2 + Q_k^2)^{\frac{1}{2}} - IV_k = 0 \tag{3.55}$$

3.10 Simulation Flow Chart



3.11 Simulation Software Used

The Simulation software used in this dissertation is **Power System Analysis Toolbox (PSAT)**. PSAT is a MATLAB toolbox for electric power system analysis and simulations. PSAT computational engine is purely MATLAB – based and the Simulink environment is used only as graphical tools. It deeply exploits MATLAB vectorized computation and sparse matrix function in order to optimize performance. It also exploits MATLAB classes to be more versatile and to ease maintenance and extensions.

PSAT has high ability to solve Continuation Power Flow (CPF) and Power Flow (PF) problems respectively because it contains interface to UWPFLOW and GAMS. It allows the drawing of electrical schemes by means of pictorial blocks.

PSAT supports a variety of static and dynamic models and this helps it to perform accurate and complete power system analysis. Dynamic models such as non-conventional loads, synchronous machines and controls, regulating transformers, FACTS, wind turbine and fuel cells.

It is provided with a variety of tools such as a set of data conversion functions and the capability of defining user defined models (UDMs) hence ensuring portability and promoting contributions.

PSAT runs on commonest operating systems. It can perform several power system analysis such as:

- ✓ Power Flow (PF)
- ✓ Continuation Power Flow (CPF)
- ✓ Optimal Power Flow (OPF)
- ✓ Small Signal Stability Analysis (SSA)
- ✓ Time Domain simulation (TD)
- ✓ Graphical User Interface (GUI)
- ✓ Graphical Network Editor (GNE) etc.

3.12 Modelling Using PSAT

Launching PSAT

After setting the PSAT folder in the Matlab path, type from the Matlab prompt:

>> psat

After a splash window, the “ Main Graphical User Interface” will appear on the screen

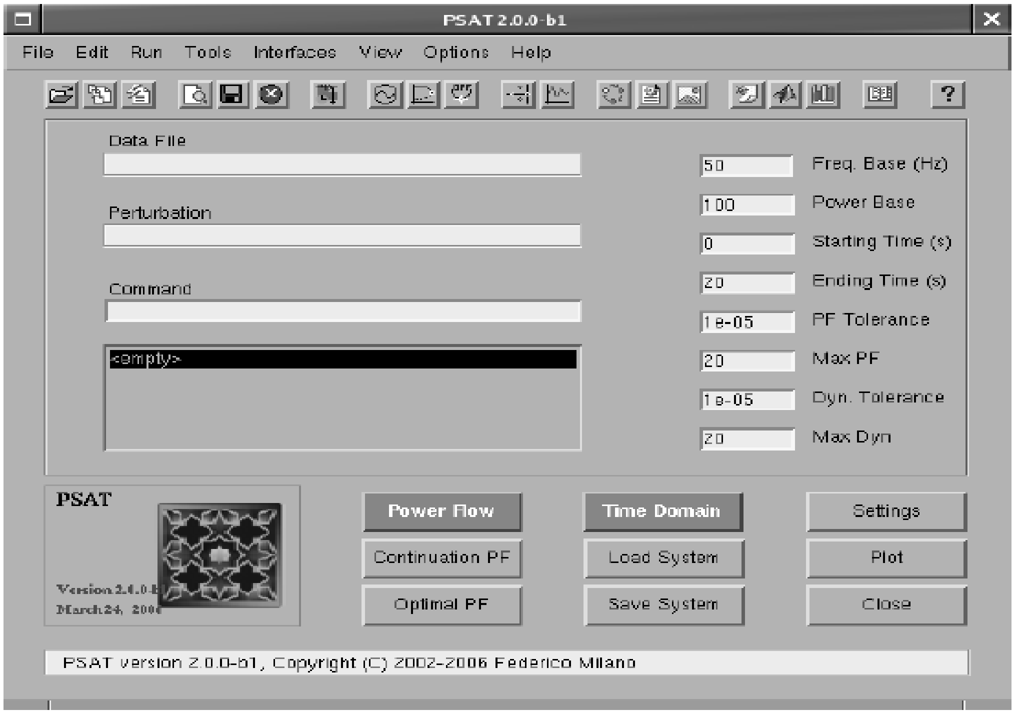


Fig. 3.2: PSAT Main Graphical User Interface

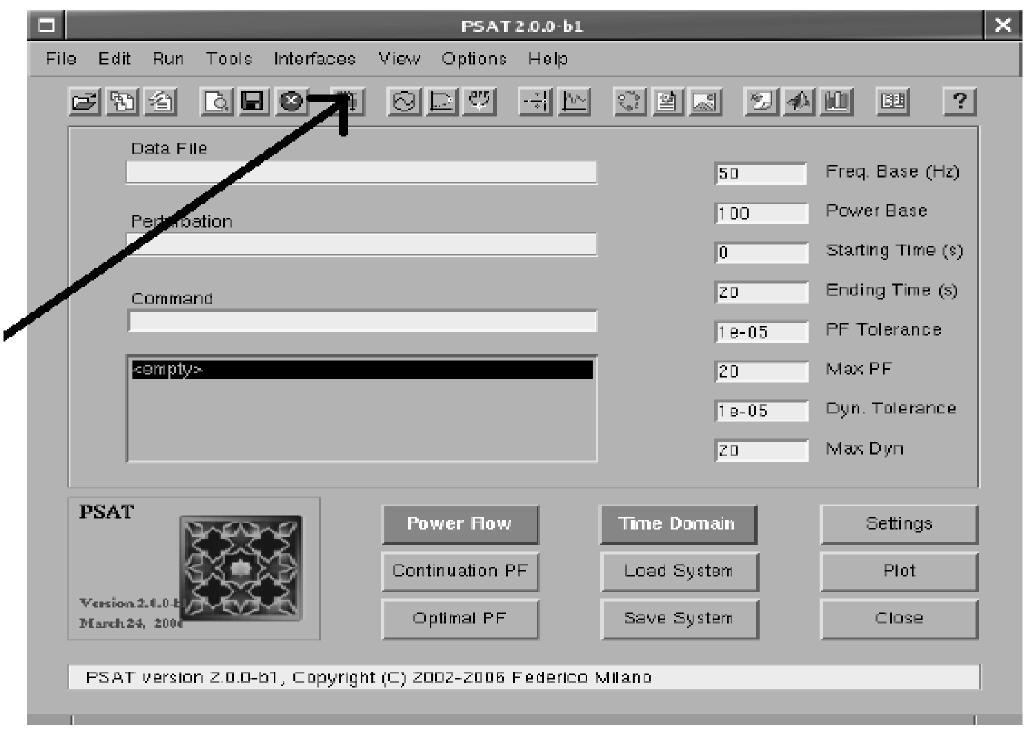


Fig. 3.3: PSAT Main G.U.I-arrow pointing Interface

Launch the PSAT Simulink model library (to set up your one-line diagram)

The PSAT simulink library will appear as shown in figure 3.4.

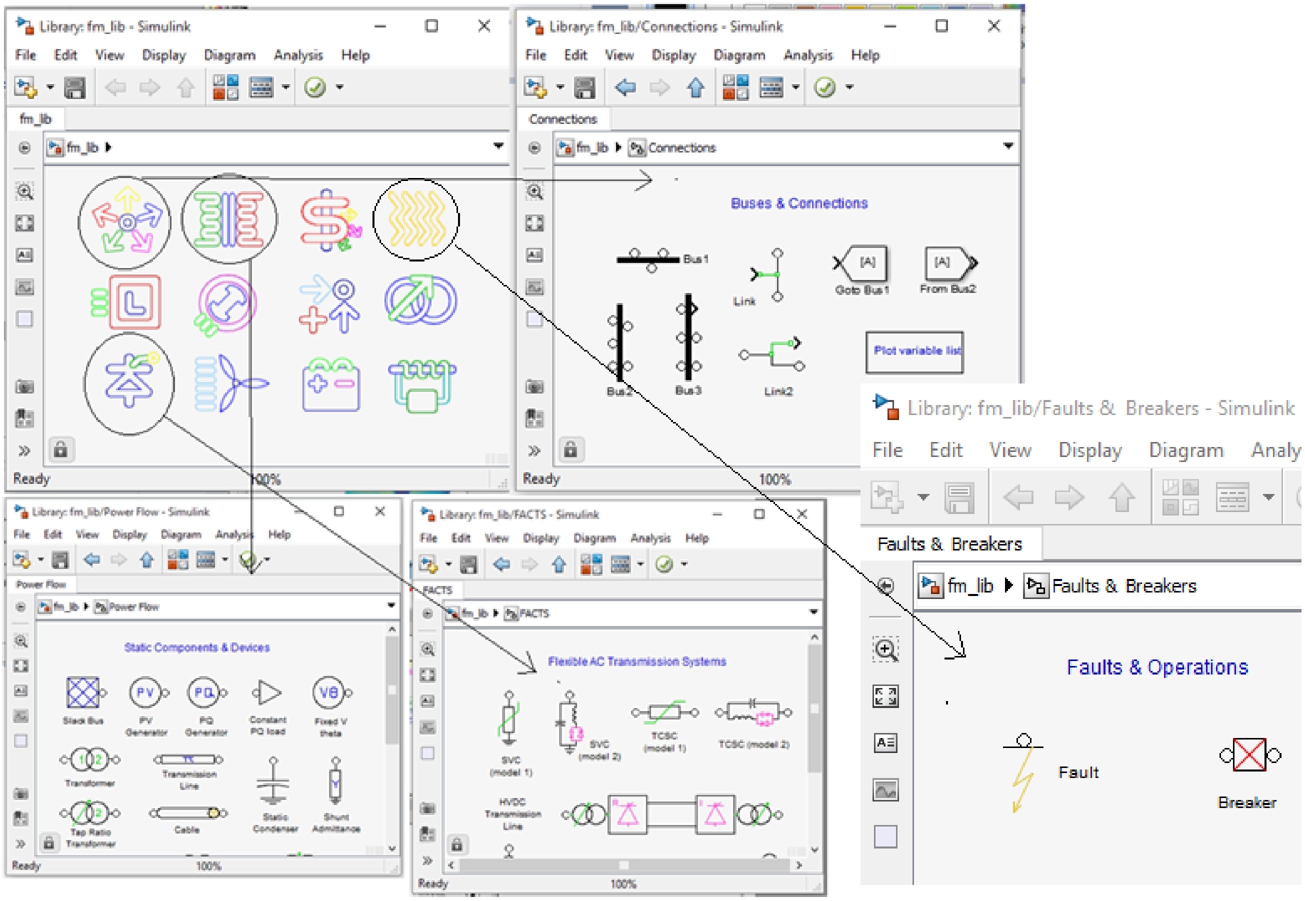


Fig. 3.4: PSAT Simulink model library

From the simulink library, only three sub libraries are required. The libraries used are buses and connection library, static components and devices Library, flexible AC Transmission Systems library. The required components from these libraries are dragged into a blank simulink file to form the Nigerian 41-bus network as shown in figure 3.5 with data obtained from National Control Centre (NCC) and Transmission Company of Nigeria (TCN) (see appendice A).

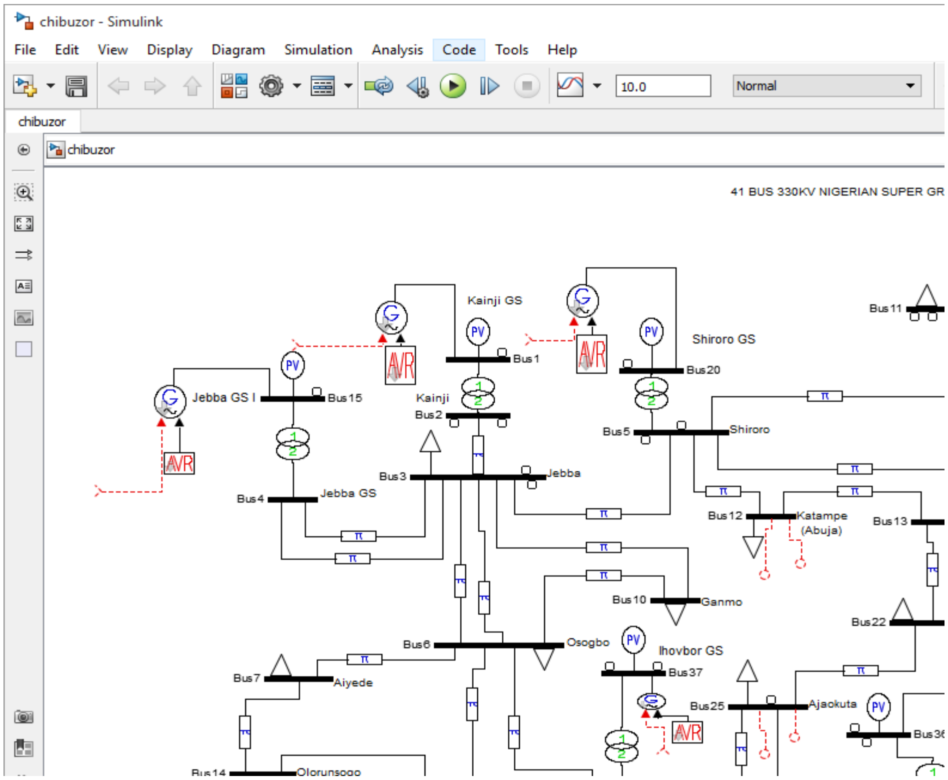


Fig. 3.5: Blank Simulink file for modelling

Modeling of the Network Components

Bus data

When trying to model the network in the software environment, the bus element is always the first. This enables one to know if it is a generator bus when a generator is connected to it, a slack bus when a synchronous generator in bus one is connected to the bus and a load bus when a loads in the network are connected to their respective buses. The fields inputted for the bus are:

Number of inputs: determines the number of connecting pin for input devices.

Number of outputs: determines the number of connecting pin for output devices.

Voltage Rating [kV]: It is the rated or nominal voltage for a particular bus.

Voltage initial guess: Is the initial or assumed state of the generator bus or load bus.

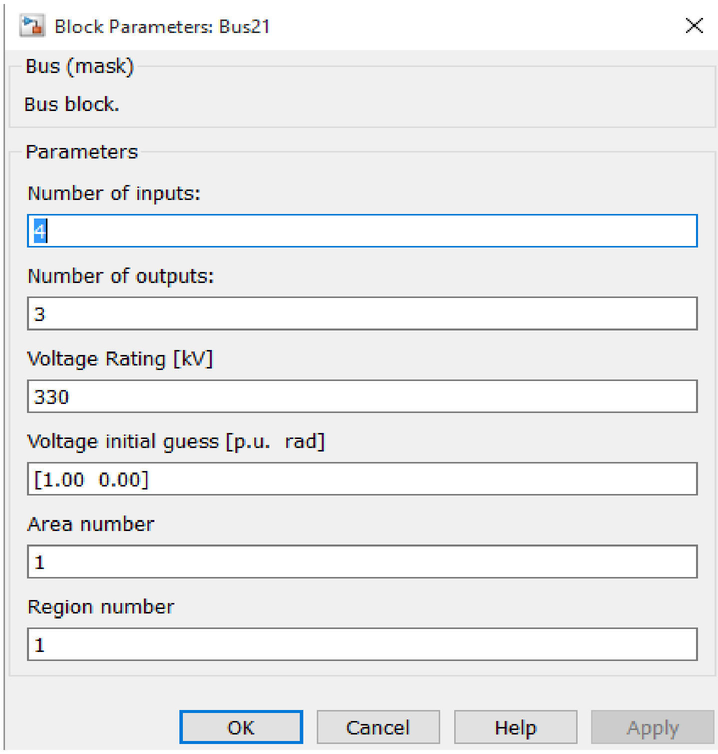


Fig. 3.6: Block parameters - Bus data

After inputting the bus parameters click on **Apply** button and finally on **OK** button to close the dialog box.

Generator Data.

This component allows us to input information or parameters about the generator. The fields associated with the generator are

Power and Voltage Ratings [MVA, kV]: Indicates the base power and voltage.

Active Power [p.u.]: Input the current or known real power of the generator

Voltage Magnitude [p.u.]: Input the current voltage magnitude.

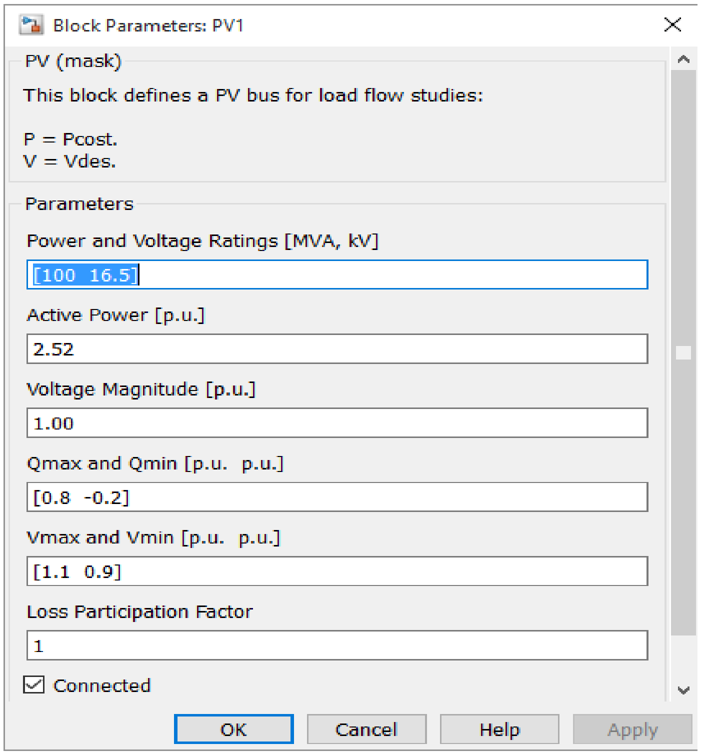


Fig. 3.7: Block parameters - Generator data

After inputting the parameters click on **Apply** button and finally on **OK** button to close the dialog box.

Reference or slack Generator

This component allows one to input information or parameters about the reference/slack generator. The fields associated with this generator are

Power and Voltage Ratings [MVA, kV]: Indicates the base power and voltage.

Voltage Magnitude [p.u.]: Inputs the current voltage magnitude.

Active Power Guess [p.u.]: Computes the initial state of the slack generator which is usually at zero value.

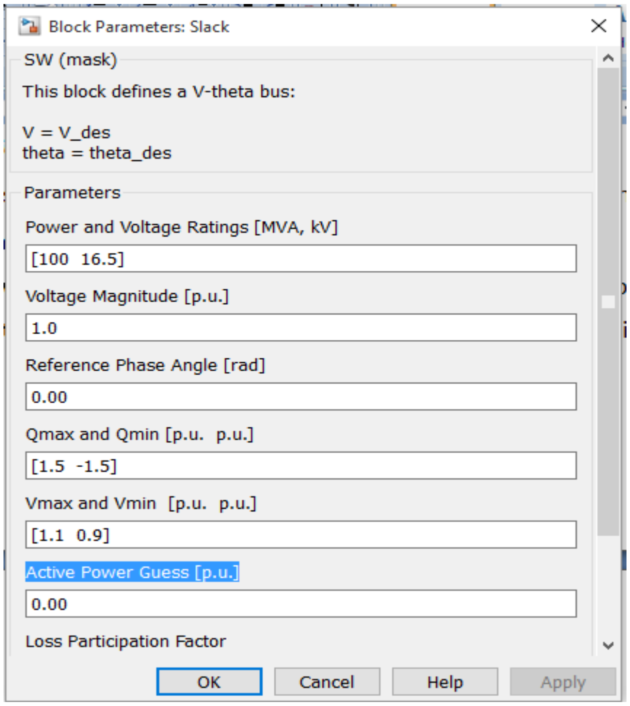


Fig. 3.8: Block parameters – Reference/Slack Generator data

After inputting the parameters click on **Apply** button and finally on **OK** button to close the dialog box.

Load Data

This component allows one to input information or parameters about the load. The field associated with the load bus are

Power and Voltage Ratings [MVA, kV]: Indicates the base power and voltage.

Active and Reactive Powers [p.u. p.u.]: Indicates the known or current value the load' s real and reactive power.

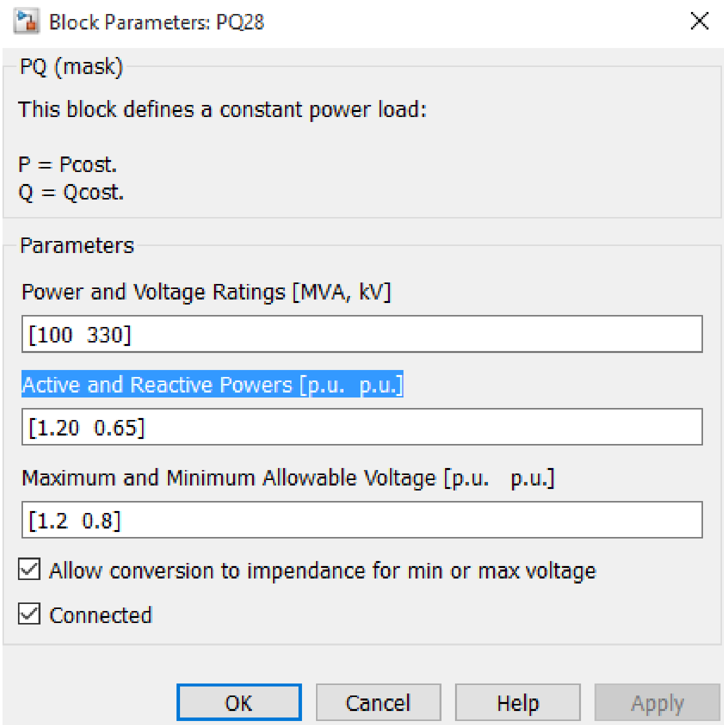


Fig. 3.9: Block parameters – Load data

After inputting the parameters click on **Apply** button and finally on **OK** button to close the dialog box.

Transmission Line Data

The transmission line component creates a link between the generator and the load or between two loads. The fields associated with load bus are:

Power, Voltage and Frequency Ratings [MVA, kV, Hz]: This section is where the base power, the base voltage and the frequency of the overall network is computed.

Length of line [km] (0 for p.u. parameters): This section indicates the distance the transmission line covers, between two components such as distance between the load bus and the generator bus.

Resistance [p.u. (Ohms/km)]: This is where the resistance of the line is computed either in ohms per kilometer that is if the length of the line is computed or in per-unit when the length of the line is zero.

Reactance [p.u. (H/km)]: This is where the inductive reactance of the line is computed in Henri/kilometer that is if the length of the line is computed or in per-unit when the length of the line is zero.

Susceptance [p.u. (F/km)]: This is where the capacitive reactance of the line is computed in Henri/kilometer that is if the length of the line is computed or in per-unit when the length of the line is zero.

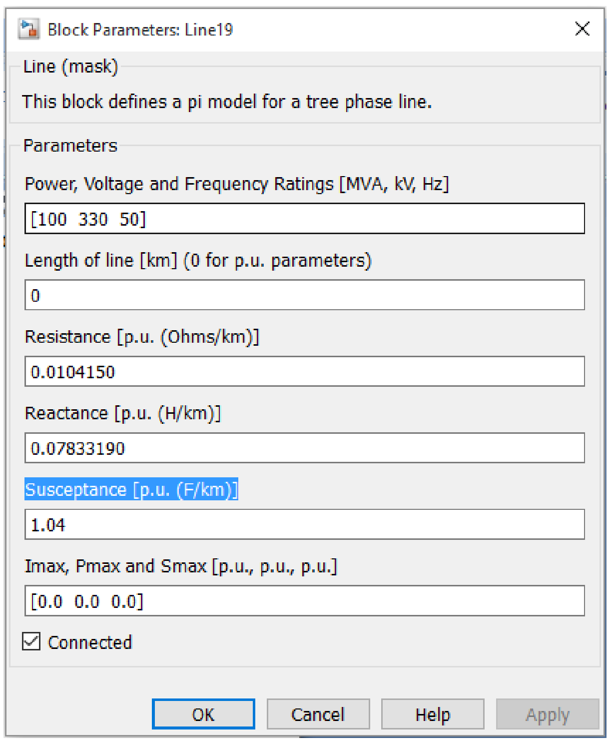


Fig. 3.10: Block parameters – Transmission Line data

After inputting the parameters click on **Apply** button and finally on **OK** button to close the dialog box.

FACTS Devices Data

The SVC and TCSC is comprised of banks of capacitor and reactors, of which at least one of those devices is switched by a thyristor. The SVC is connected only when a bus is not operating within its operating limits and TCSC is connected only when a transmission line is not operating within its operating limits.

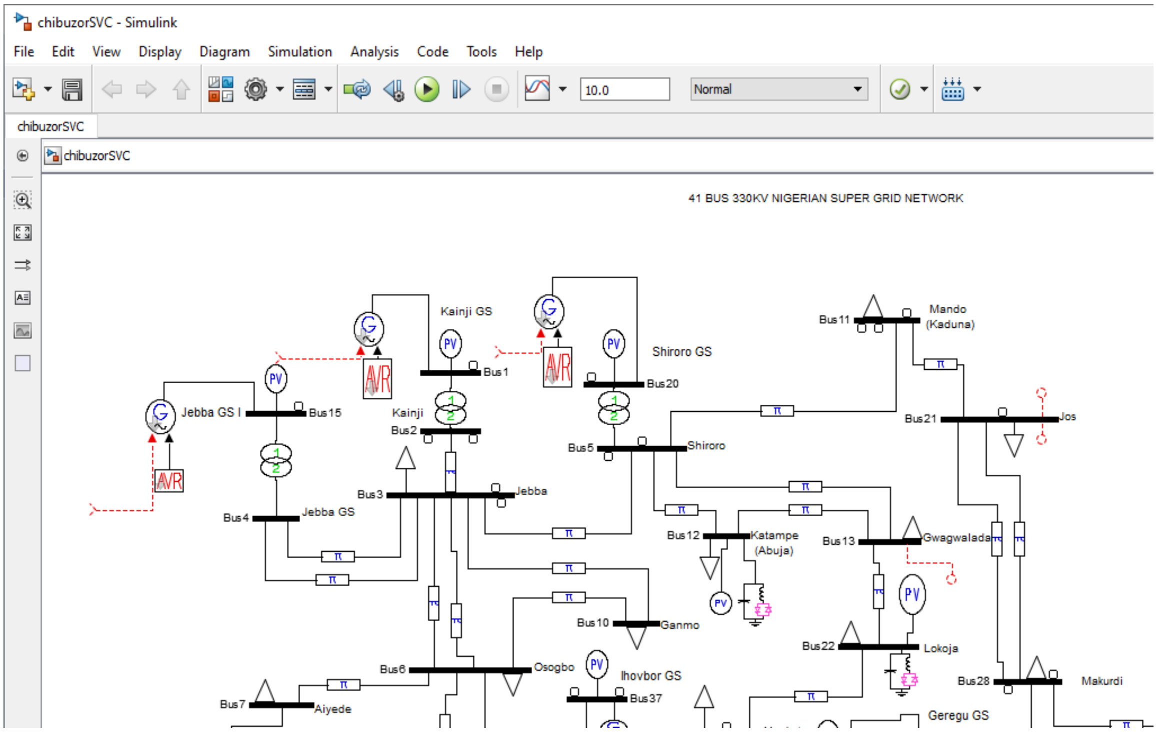


Fig. 3.11: Blank Simulink file for modelling – connection of FACTS devices.

Power, Voltage and Frequency Ratings [MVA, kV, Hz]: this section is where the base power, the base voltage and the frequency of the overall network is computed.

Reference Voltage [p.u.]: It is the regulated voltage. That is the SVC will maintain a voltage of 1PU.

Alpha_max and Alpha_min [rad rad]: It indicates the maximum and minimum firing angle of the thyristor, that is, the operating limit of the thyristor which is based on the size of the capacitor and reactor banks.

Inductive and capacitive reactances Xl and Xc [p.u. p.u.]: This where the inductive reactance and capacitive reactance of each bank is computed.

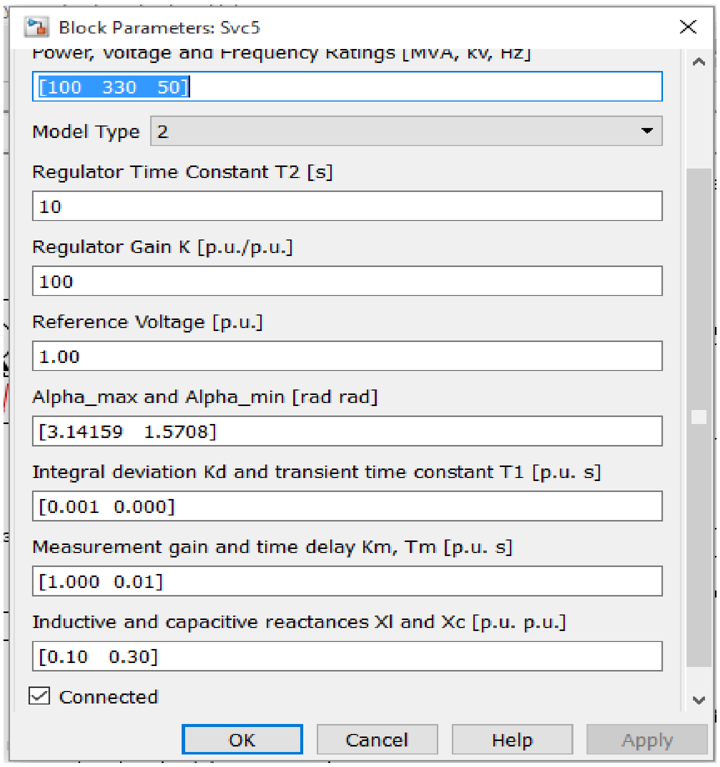


Fig. 3.12: Block parameters – FACTS Devices data

Simulating the Result for Power flow.

After setting up your network, the network is being simulated by clicking on the Power Flow button.

After solving the first power flow, the program is ready for further analysis, such as Continuation Power Flow, Optimal Power Flow, Small Signal Stability Analysis, Time Domain Simulation (transient analysis), PMU placement etc. when you connect the SVC, each of these procedures are repeated.

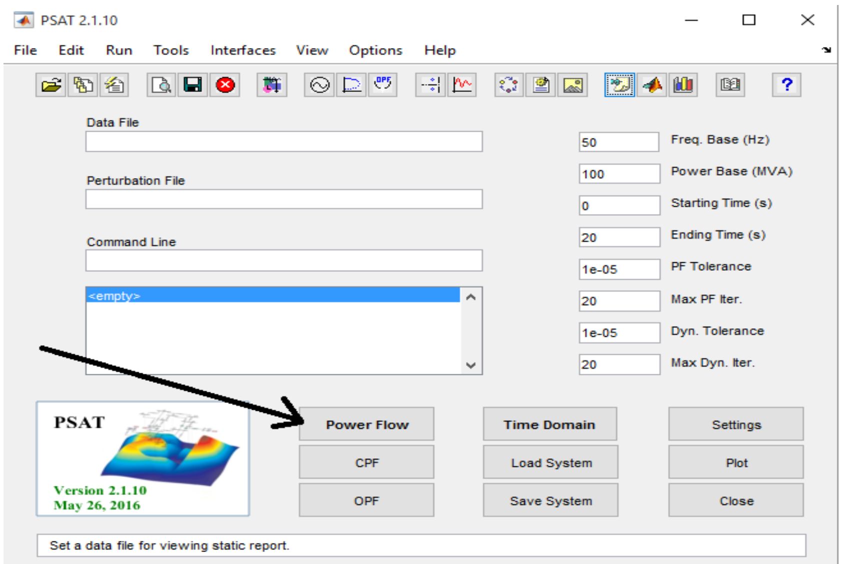


Fig. 3.13: Block parameters – Power flow, CPF and OPF simulation.

Displaying the Result

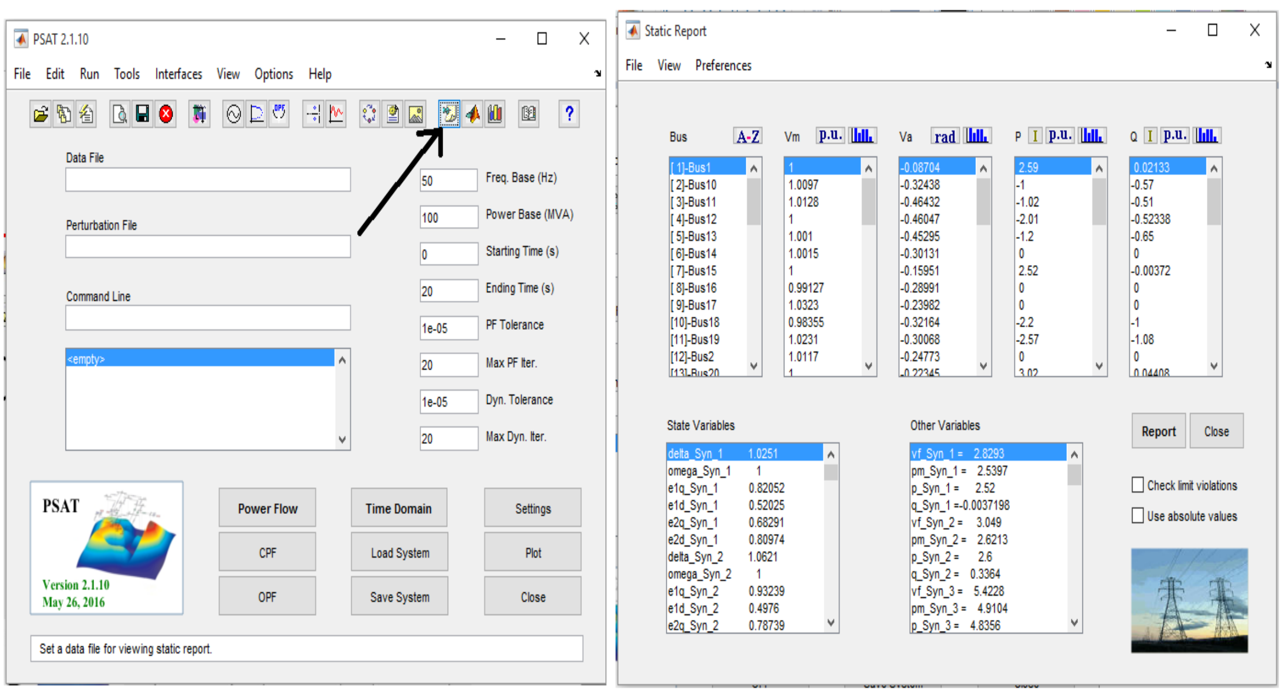


Fig. 3.14: Block parameters – Displaying simulation results.

To view the result, click on the static report button to display the result. To view the excel format click on the report button and it will generate a report.

CHAPTER FOUR

RESULTS AND DISCUSSION

4.1 Modelled 41 Bus 330kV Nigerian Super Grid – Base Case

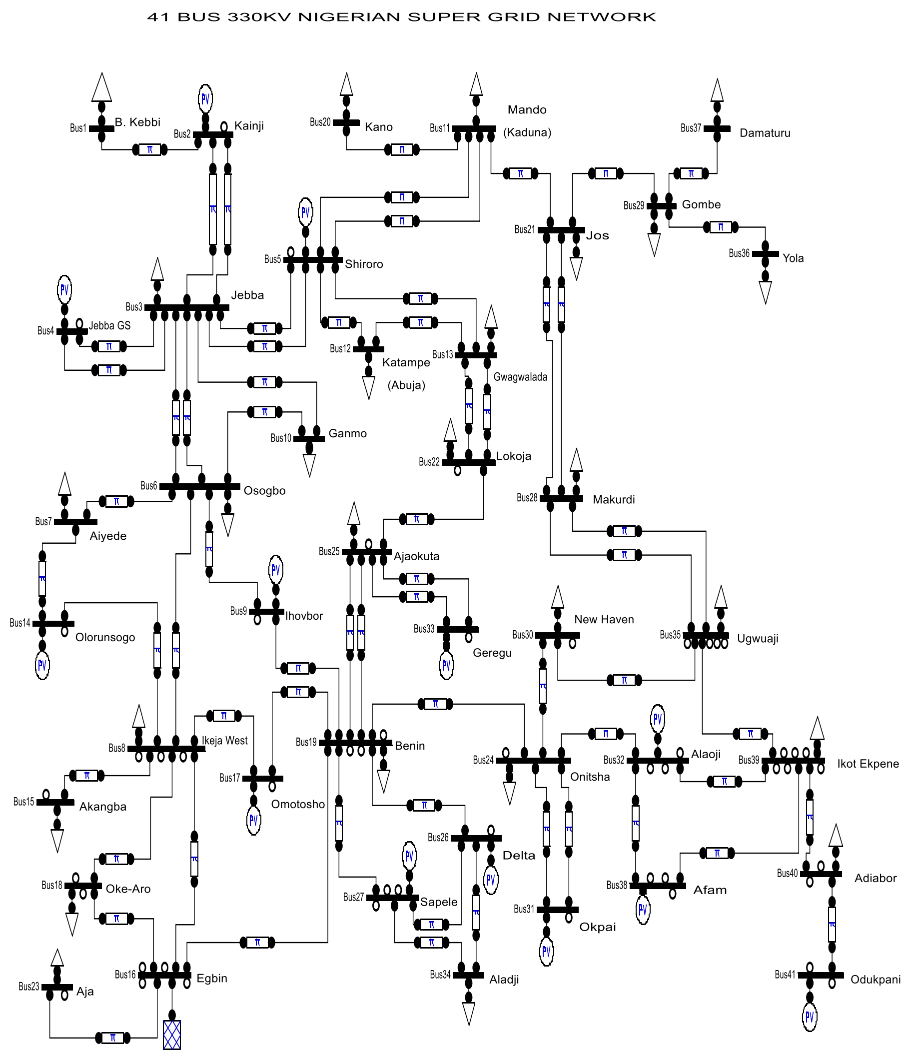


Fig. 4.1: Modelled 41 Bus 330kv Nigerian Super Grid – Base Case

The above modeled 41 Bus 330kV Nigerian power network comprises of its current Transmission system of Nigeria.

In the above network, Egbin is used as the Slack or reference Bus, with 13 other Generators buses, 27 loads buses and 63 Transmission lines, all modelled with data obtained from National Control Centre (NCC) and Transmission Company of Nigeria (TCN) using Power System Analysis Toolbox (PSAT).

4.2 Load Flow Analysis of the Network

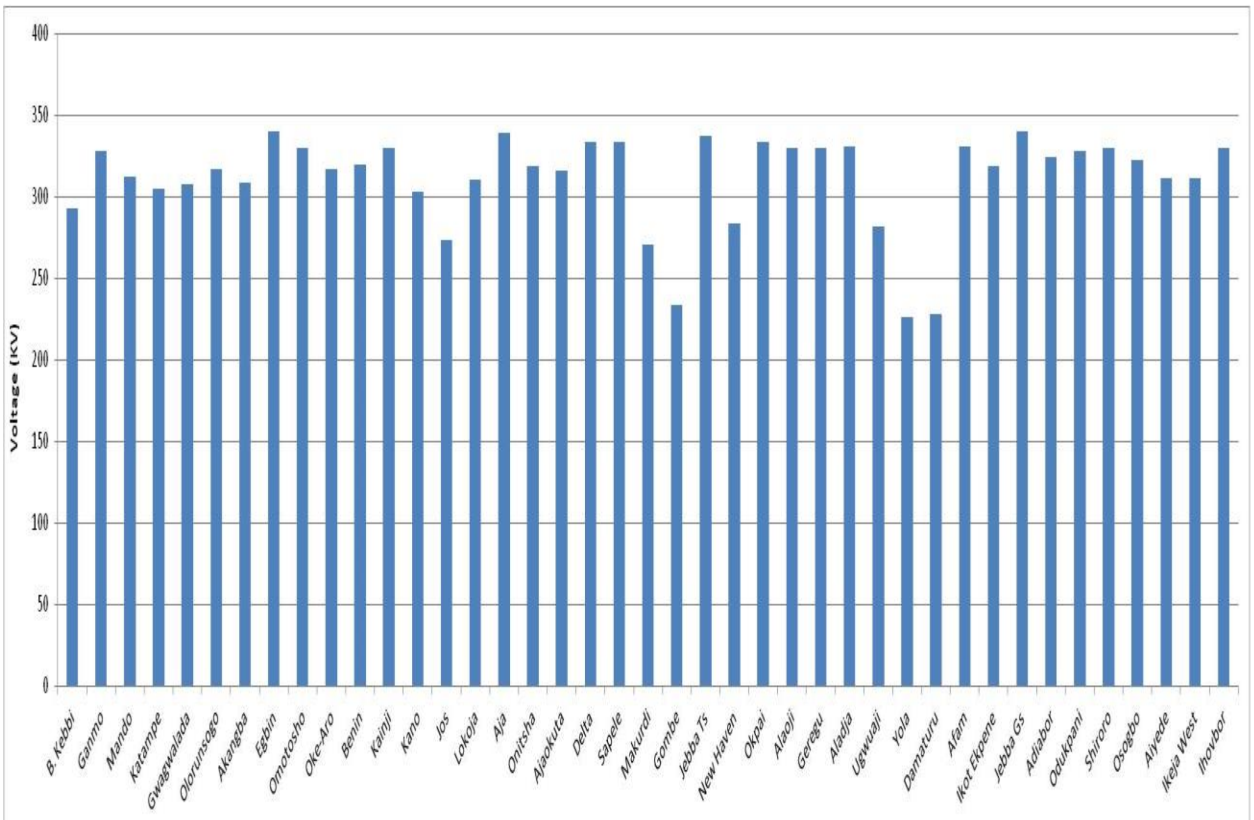


Fig.4.2: PSAT Result of Load Flow Analysis of the Network- Base Case

Figure 4.2 shows the voltage profile of the network of the Base case. The standard operating range of voltages is between 0.95PU – 1.05PU (313.5kV – 346.5kV). If the bus value falls below 0.95PU, it is known as under-voltage violation while the bus that has a value higher than 1.05PU is known as over-voltage violation. The buses that fall below or above the standard operating range of voltages is shown in table 4.1.

Table 4.1: Bus Violations of the Base Case

S/Number	Bus Name	Voltage (kV)	Bus Violation type
1	B. Kebbi	293.2535545	under voltage
2	Mando	312.4498136	under voltage
3	Katampe	305.3221285	under voltage
4	Gwagwalada	307.8620548	under voltage
5	Akangba	308.4239716	under voltage
6	Kano	303.0401725	under voltage
7	Jos	273.7928104	under voltage
8	Lokoja	310.7697535	under voltage
9	Makurdi	270.7862923	under voltage
10	Gombe	234.0070032	under voltage
11	New Haven	284.0169595	under voltage
12	Ugwuaji	282.2990359	under voltage
13	Yola	226.5181473	under voltage
14	Damaturu	228.0053515	under voltage
15	Aiyede	311.6840354	under voltage
16	Ikeja West	311.7644693	under voltage

Table 4.1 shows that the total number of violation is sixteen. Majority of the bus violations are under voltage violations. The northern part of the network had about 81.25% of the bus violation.

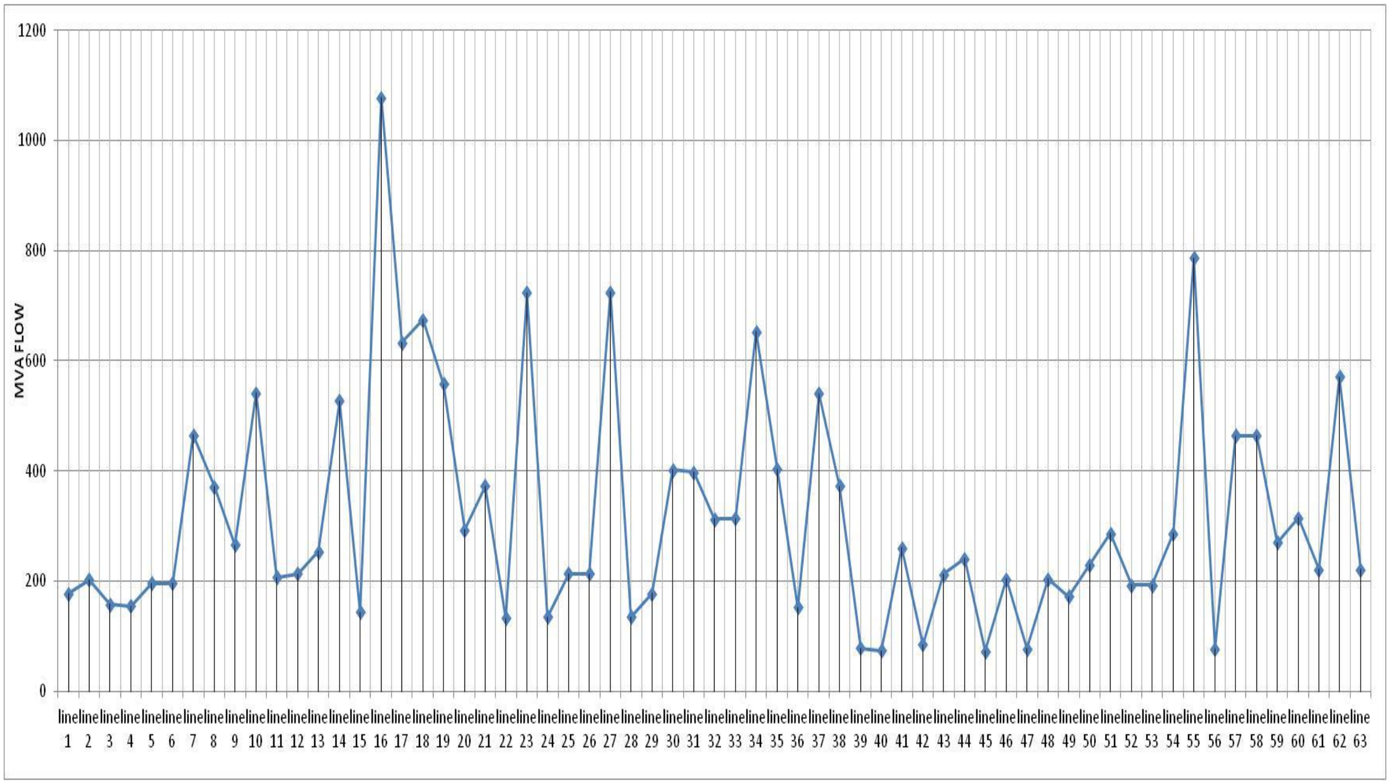


Fig.4.3: MVA Flow of the Lines- Base Case

Figure 4.3 shows the MVA flow of the line. The limit of the transmission line is pegged at 70% of 777.3MVA which is equal to 544.1MVA. 777.3MVA is the standard value for Nigeria’ s 330kV transmission line. The transmission line that met the criteria as violation; that is above the operating limit is shown in table 4.2.

Table 4.2: MVA Flow of Line Violations of the Base Case

S/N	Bus Name	Bus connection	MVA Flow
1	Line 16	Egbin – Benin	1077.48657
2	Line 23	Benin – Onitsha	723.480437
3	Line 17	IKeja West – Oke-Aro	632.880749
4	Line 18	Oke-Aro – Egbin	674.917357
5	Line 19	Ikeja West – Omotosho	557.603784
6	Line 27	Benin– Sapele	724.429967
7	Line 34	Onitsha– Alaoji	652.743581
8	Line 55	Ikot Ekpene– Ugwaji	787.038531
9	Line 62	Adiabor– Odukpani	570.866823
10	Line 14	Egbin – Ikeja West	547.694941

From the above table, it is observed that most of the congestion occurred in the southern part of the country.

4.3 Generator Rescheduling By Optimization Technique

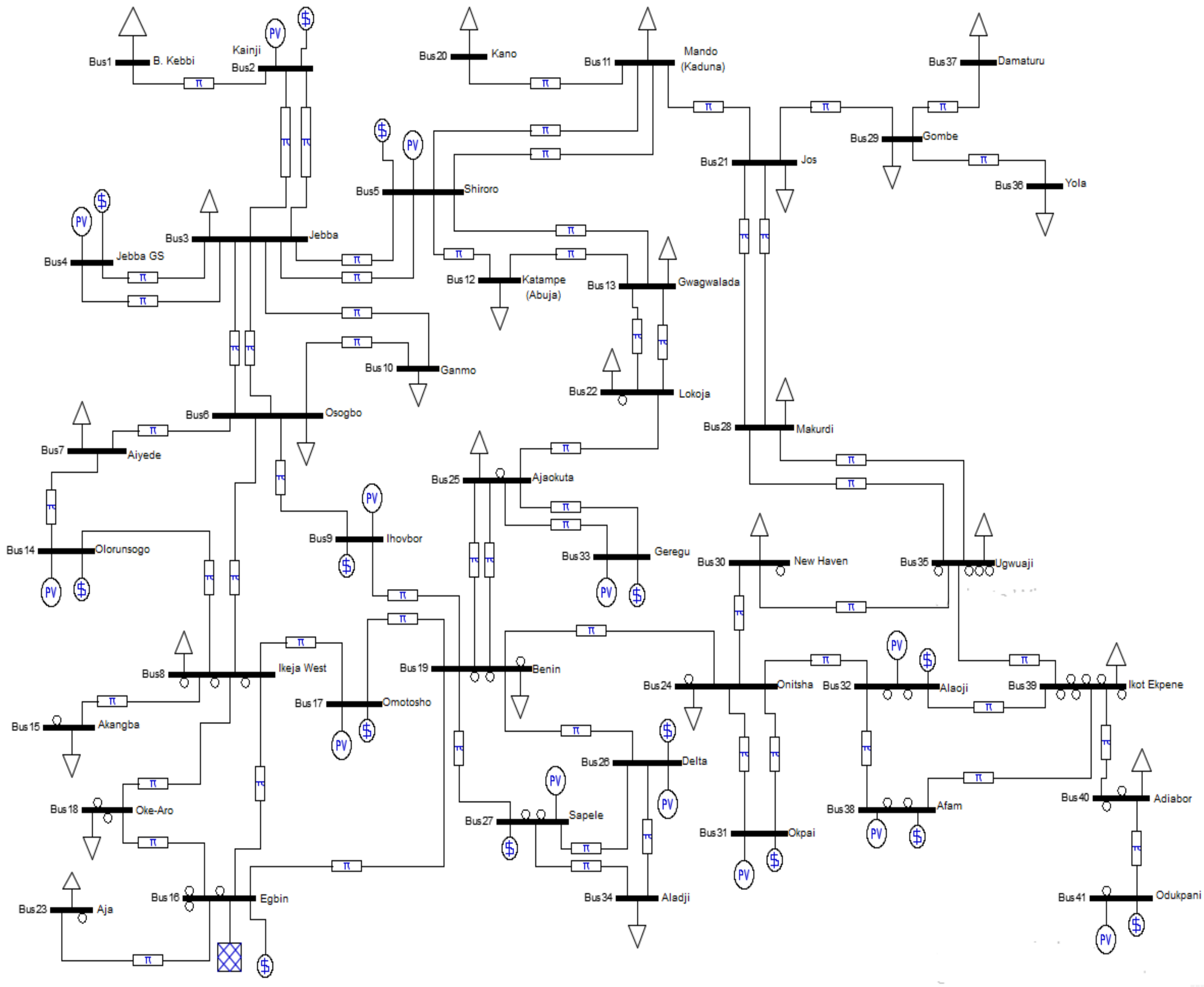


Fig. 4.4: Modelled 41 Bus 330kV Nigerian Super Grid - Generator Rescheduled.

The idea of generator rescheduling in managing congestion is to increase and decrease the active power output of the generators. Congestion in transmission lines (electric network) occurs frequently if not properly managed. The amount of active power output of the generators is obtained through an optimization technique.

To reschedule the generators, the following assumptions were made,

- The Generators are at Automatic generation Control (AGC)
- The reactive Power Interaction is neglected
- The effect of valve point loading is neglected
- Voltage operating outside 0.95PU – 1.05PU (313.5kV – 346.5kV) is considered violation.
- The system loads are Fixed
- %MVA Loading above 70% is considered as a violation

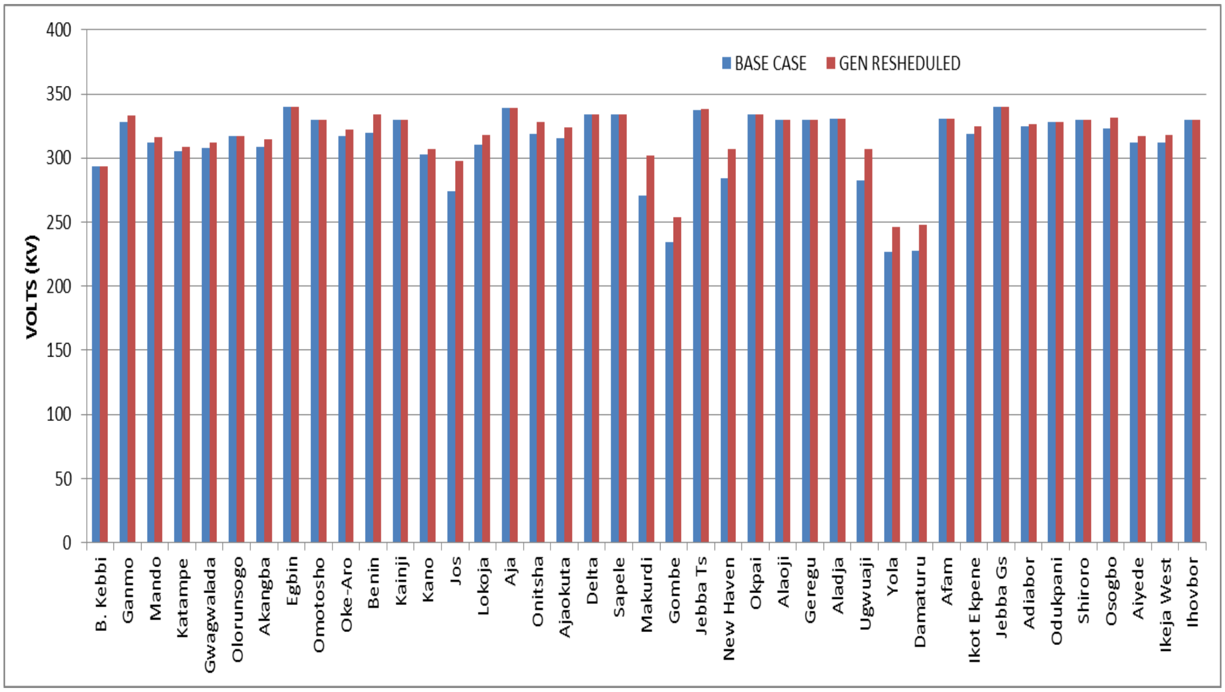


Fig.4.5: Bus Voltage after rescheduling the Generators.

Figure 4.5 shows the voltage profile of the network after the generators have been rescheduled. There was a general improvement in the voltages at the load buses.

Table 4.3: Voltage profile after Rescheduling

S/Number	Bus name	Base Case Voltage (kV)	Gen. Reshd Voltage (kV)	Bus Violation type
1	B. Kebbi	293.253555	293.253555	under voltage
2	Mando	312.449814	316.468348	operating voltage
3	Katampe	305.322129	308.899350	under voltage
4	Gwagwalada	307.862055	312.142781	under voltage
5	Akangba	308.423972	314.607544	operating voltage
6	Kano	303.040173	307.216388	under voltage
7	Jos	273.792810	297.460821	under voltage
8	Lokoja	310.769754	318.053107	operating voltage
9	Makurdi	270.786292	302.060773	under voltage
10	Gombe	234.007003	254.235731	under voltage
11	New Haven	284.016960	306.984327	under voltage
12	Ugwuaji	282.2990360	306.631360	under voltage
13	Yola	226.518147	246.099501	under voltage
14	Damaturu	228.005352	247.7152664	under voltage
15	Aiyede	311.684035	316.995160	operating voltage
16	Ikeja West	311.764469	317.880042	operating voltage

Table 4.3 shows that five buses are operating at it operating voltage, the buses are Mando (Kaduna), Akangba, Lokoja, Aiyede and Ikeja West. The rest of the buses that were violated during load flow experienced increased voltage after rescheduling, but the increase had no significant effect on the affected load buses.

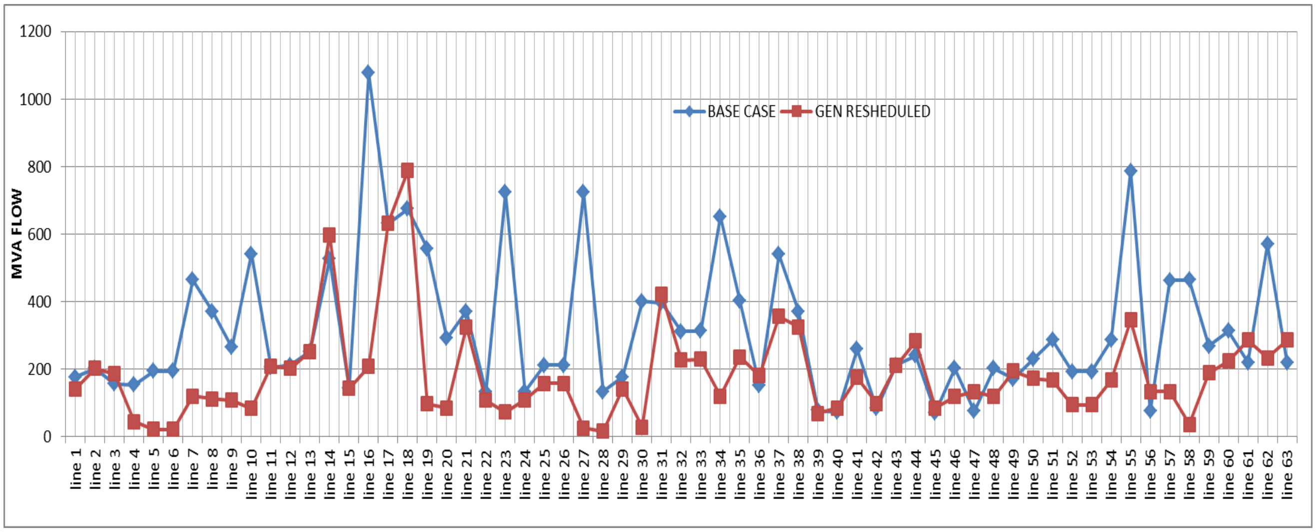


Fig.4.6: MVA Flow after rescheduling the Generators.

Figure 4.6 shows the MVA flow on the transmission lines after the generators have been rescheduled.

Table 4. 4: MVA Flow of the Violated Transmission Lines after Generator Rescheduling

S/N	Line Name	Bus Connection	Base Case MVA FLOW	Gen. Resched MVA FLOW
1	Line 16	Egbin – Benini	1077.486573	598.5455
2	Line 23	Benin – Onitsha	723.4804368	73.3666
3	Line 17	IKeja West – Oke-Aro	632.8807493	633.3464
4	Line 18	Oke-Aro – Egbin	674.9173576	788.5279
5	Line 19	Ikeja West – Omotosho	557.6037835	97.7532
6	Line 27	Benin – Sapele	724.4299672	26.6236
7	Line 34	Onitsha – Alaoji	652.7435806	121.031
8	Line 55	IkotEkpene – Ugwaji	787.0385312	346.5156
9	Line 62	Adiabor – Odukpani	570.8668234	234.7489
10	Line 14	Egbin – Ikeja West	547.6949407	598.5455

From table 4.4, it is observed that out of the ten violations that occurred, only four transmission lines which are lines16, 17, 18, and 14, exceeded their line limits after the generators were rescheduled. The other six transmission lines were set to operating limit.

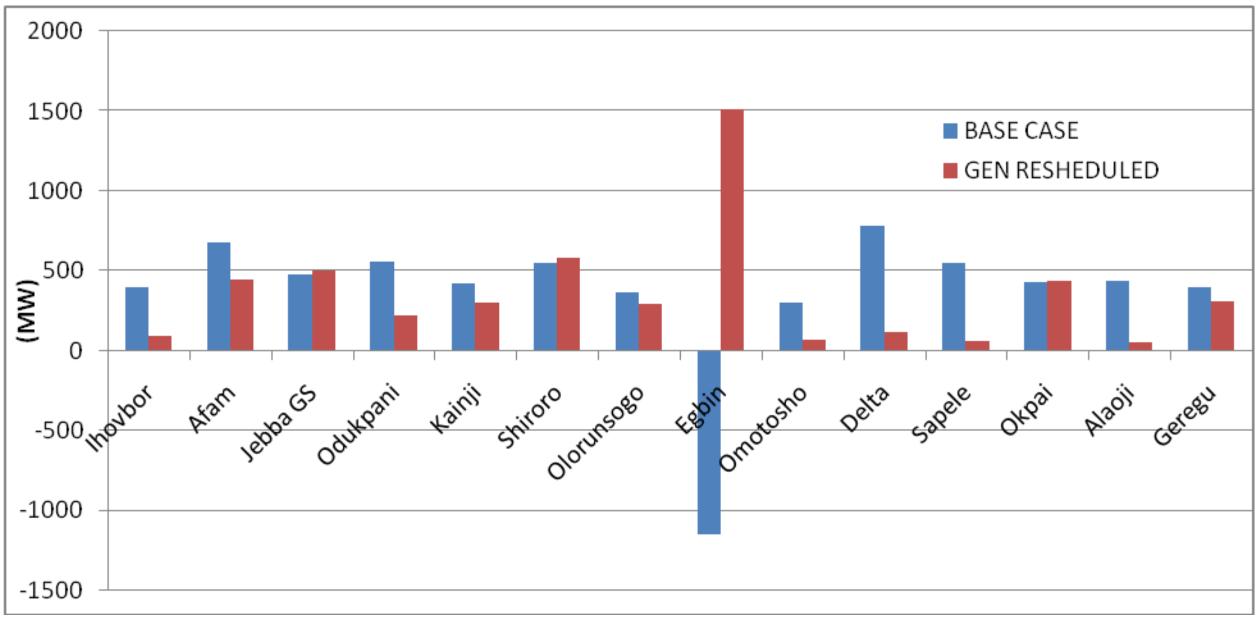


Fig. 4.7: Power Generation Profile (MW) after Rescheduling.

Figure 4.7 shows the generation profile of the network (MW). The blue colour represent the base case which is the initial data gotten from the National Control Centre, Oshogbo while the red colour is the rescheduled data obtained after optimization. Before rescheduling, the generator at Egbin was generating below capacity, after rescheduling Egbin generated above capacity which led to congestion around its area as seen in figure 4.1 and table 4.4.

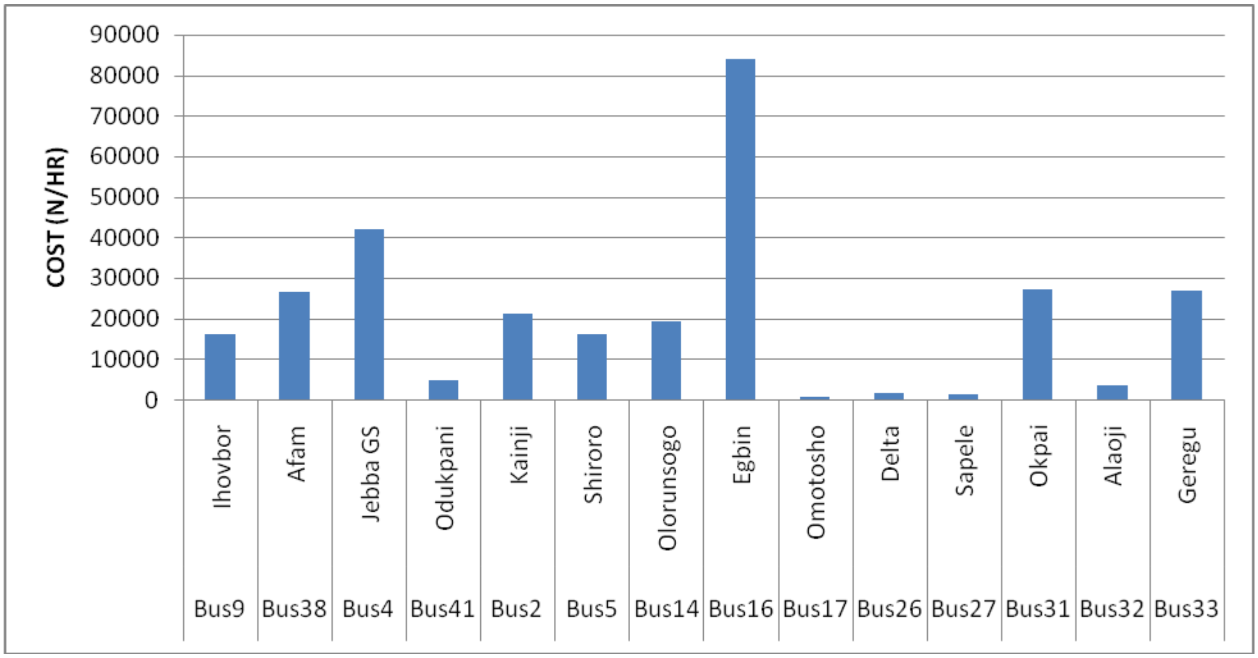


Fig. 4.8: Cost Profile of Generators (N/HR) after Rescheduling.

Figure 4.8 shows the cost profile of the generators after rescheduling. The generator at Egbin has the highest cost 84069.74507N/Hr while Omotosho has the lowest cost 745.54601N/Hr.

4.4 Placement of SVC

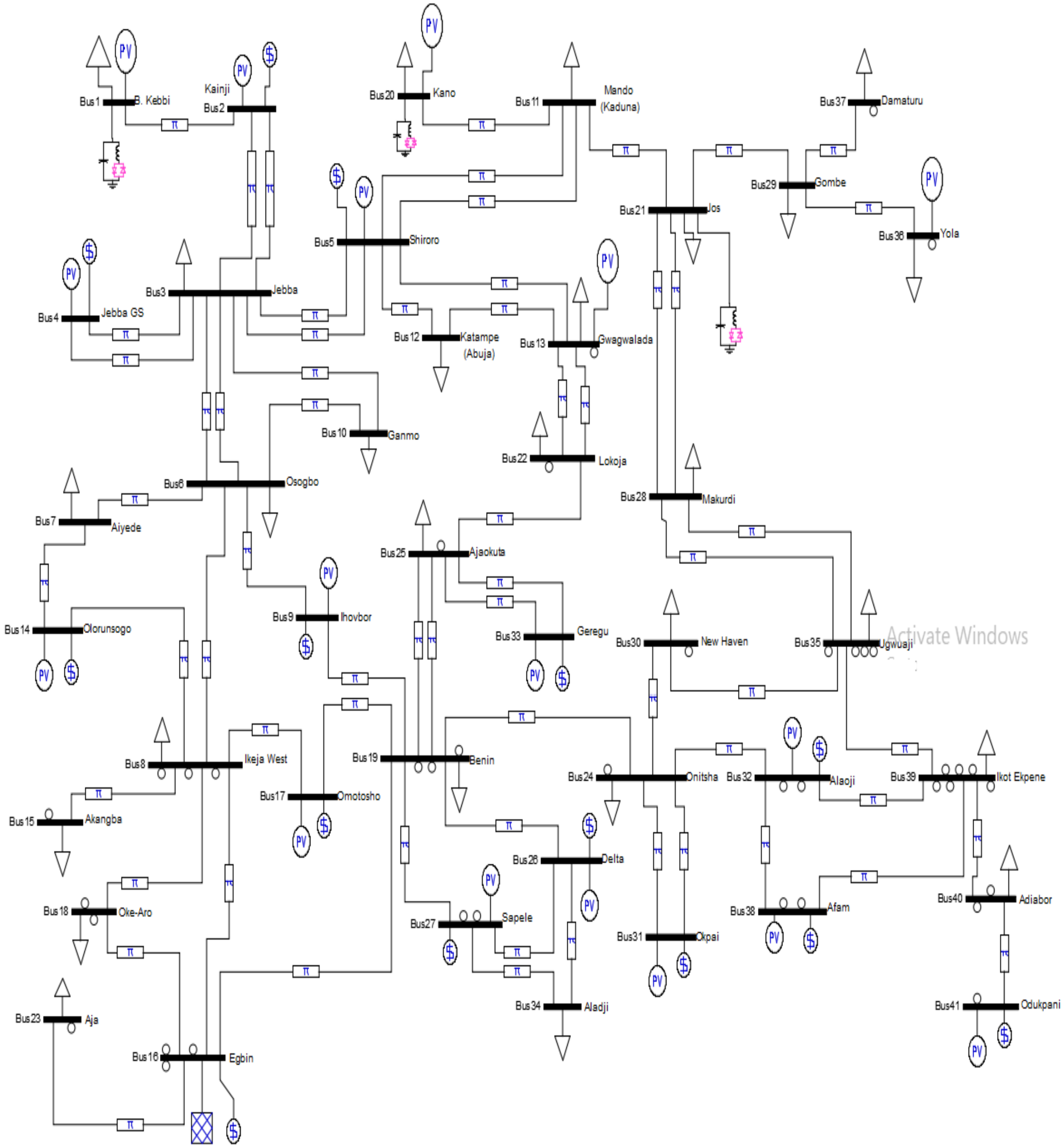


Fig. 4.9: Modelled 41 Bus 330kv Nigerian Power System - Placement of SVC.

Flexible Alternate Current Transmission System (FACTS) devices such as Static Var Compensators (SVCs) is a device that can quickly and reliably control bus voltages. SVC devices will typically regulate and control the voltage to the required set point under normal steady state and thereby provide dynamic, fast response to reactive power following system violation such as under voltage or over voltage. The major areas where the SVCs where optimally installed are Birni-Kebbi, Kano and Jos.

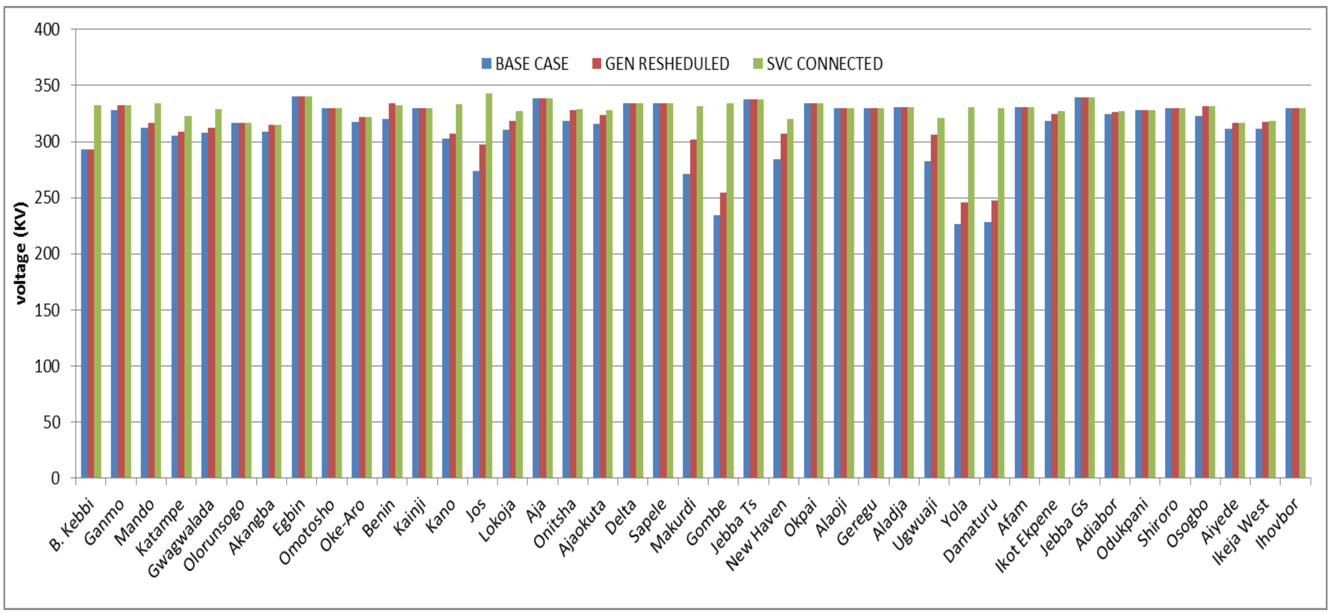


Fig.4.10: Bus Voltage after Placement of SVC.

Figure 4.10 shows the voltage profile of the network (kV) after the SVCs where installed at Birni-Kebbi, Kano and Jos. The blue colour represent the base case which is the initial data gotten from the National Control Centre Oshogbo, the red colour is the rescheduled data obtained after optimization while the green colour is voltage profile when the SVC was installed to the network after the generators were rescheduled. From the above figure, it has shown that there was an improved voltage on those buses that were below the operating voltage as can be seen in table 4.5

Table 4.5: Voltage Profile Comparison after Placement of SVC

S/N	Bus name	Base Case voltage (kV)	Gen. Resched. voltage (kV)	FACTS voltage (kV)
1	B. Kebbi	293.2535545	293.2535545	332.150312
2	Mando	312.4498136	316.4683475	334.30509
3	Katampe	305.3221285	308.8993499	323.177229
4	Gwagwalada	307.8620548	312.1427811	329.048118
5	Akangba	308.4239716	314.6075441	314.778754
6	Kano	303.0401725	307.2163877	333.057674
7	Jos	273.7928104	297.4608205	342.731554
8	Lokoja	310.7697535	318.0531074	327.168601
9	Makurdi	270.7862923	302.0607729	332.020369
10	Gombe	234.0070032	254.2357306	333.958029
11	New Haven	284.0169595	306.9843271	320.249962
12	Ugwuaji	282.2990359	306.6313599	321.181084
13	Yola	226.5181473	246.0995008	330.31192
14	Damaturu	228.0053515	247.7152664	329.841823
15	Aiyede	311.6840354	316.9951596	317.098603
16	Ikeja West	311.7644693	317.8800417	318.049407

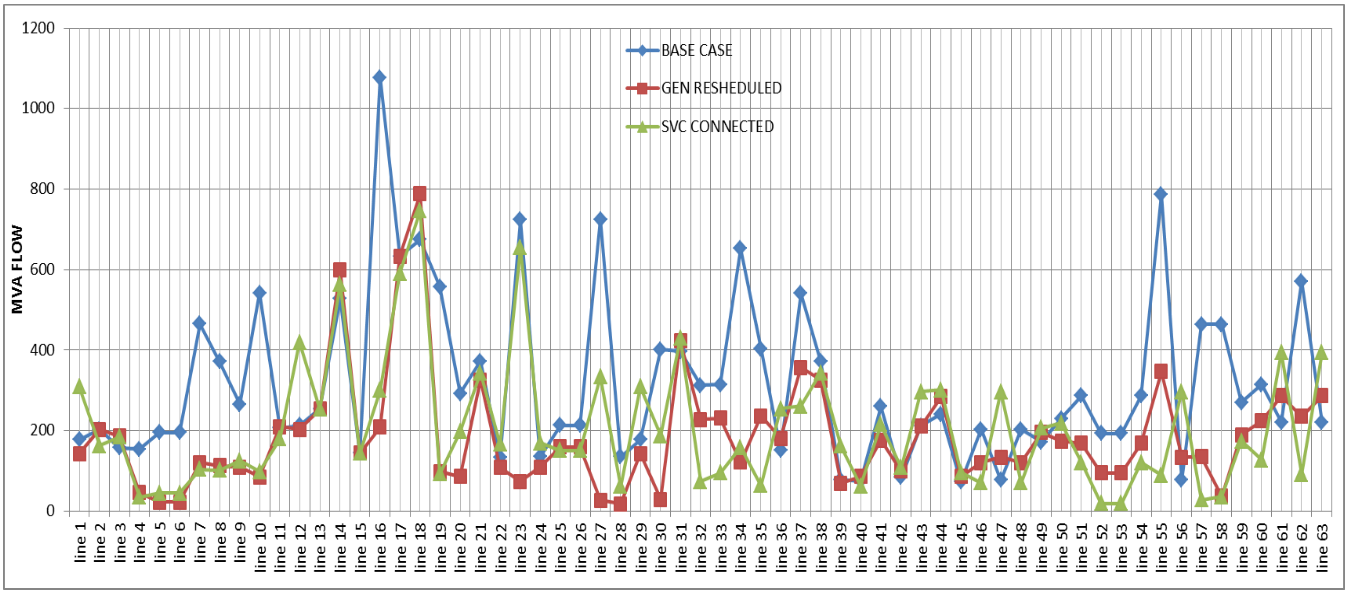


Fig.4.11: MVA flow of the Transmission Lines after Placement of SVC.

Figure 4.11 shows the MVA flow of the transmission lines after SVCs were installed at the buses at Birni-Kebbi, Kano and Jos. The blue colour represent the base case which is the initial data gotten from the National Control Centre, Oshogbo, the red colour is the rescheduled data obtained after optimization while the green colour is voltage profile when the SVCs were installed to the network after the generators were rescheduled.

The introduction of SVC slightly reduced the loading on the transmission lines after the generators were rescheduled as shown in table 4.6.

Table 4.6: MVA Flow Comparison after Placement of SVC

S/N	Line Name	Bus Connections	Base Case MVA FLOW	Gen. Resched MVA FLOW	SVC MVA FLOW
1	Line 16	Egbin ☐ Benin	1077.486573	598.5455	299.3829
2	Line 23	Benin ☐ Onitsha	723.4804368	73.3666	654.6983
3	Line 17	IKeja West ☐ Oke-Aro	632.8807493	633.3464	591.046
4	Line 18	Oke-Aro ☐ Egbin	674.9173576	788.5279	746.1466
5	Line 19	Ikeja West ☐ Omotosho	557.6037835	97.7532	92.98644
6	Line 27	Benin ☐ Sapele	724.4299672	26.6236	333.0255
7	Line 34	Onitsha ☐ Alaoji	652.7435806	121.031	158.273
8	Line 55	Ikot Ekpene ☐ Ugwaji	787.0385312	346.5156	88.88702
9	Line 62	Adiabor ☐ Odukpani	570.8668234	234.7489	90.9088
10	Line 14	Egbin ☐ Ikeja West	527.6949407	598.5455	563.63

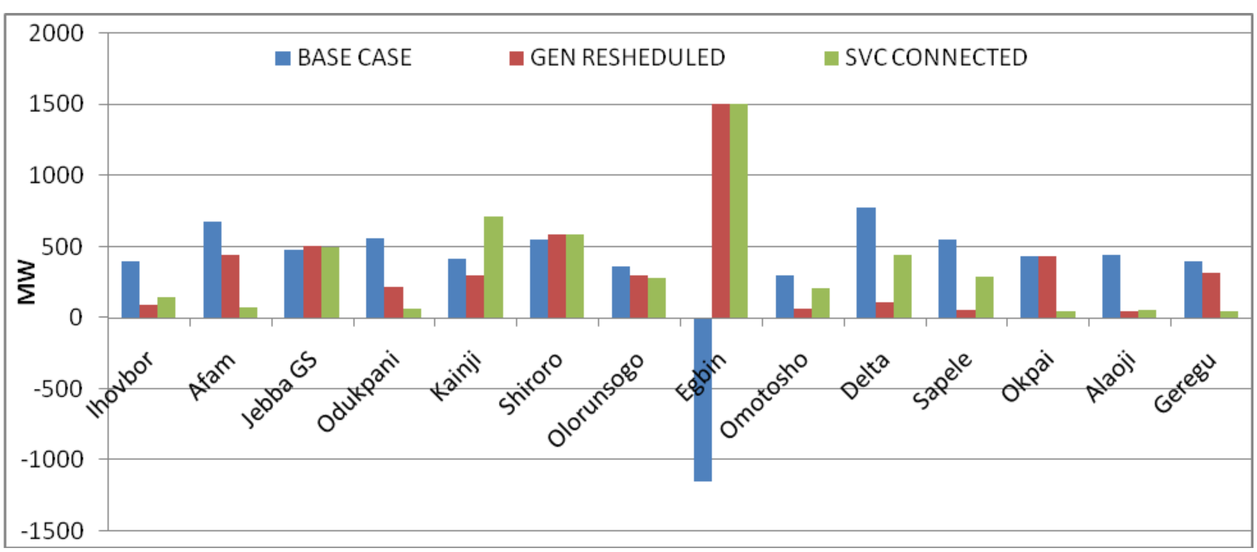


Fig. 4.12: Power Generation Profile (MW) after Placement of SVC.

Figure 4.12 shows the generation profile of the network (MW) after installation of SVCs. The blue colour represent the base case which is the initial data gotten from the National Control Centre, Oshogbo, the red colour is the rescheduled data obtained after optimization while the green colour represents the data obtained when SVCs were installed to the network. Looking at figure 4.12, the generators at Jebba, Kainji, Shirror and Egbin were called-up because they had the least cost coefficient. The generator at Egbin was generating above its capacity which resulted in high congestion around the bus close to it.

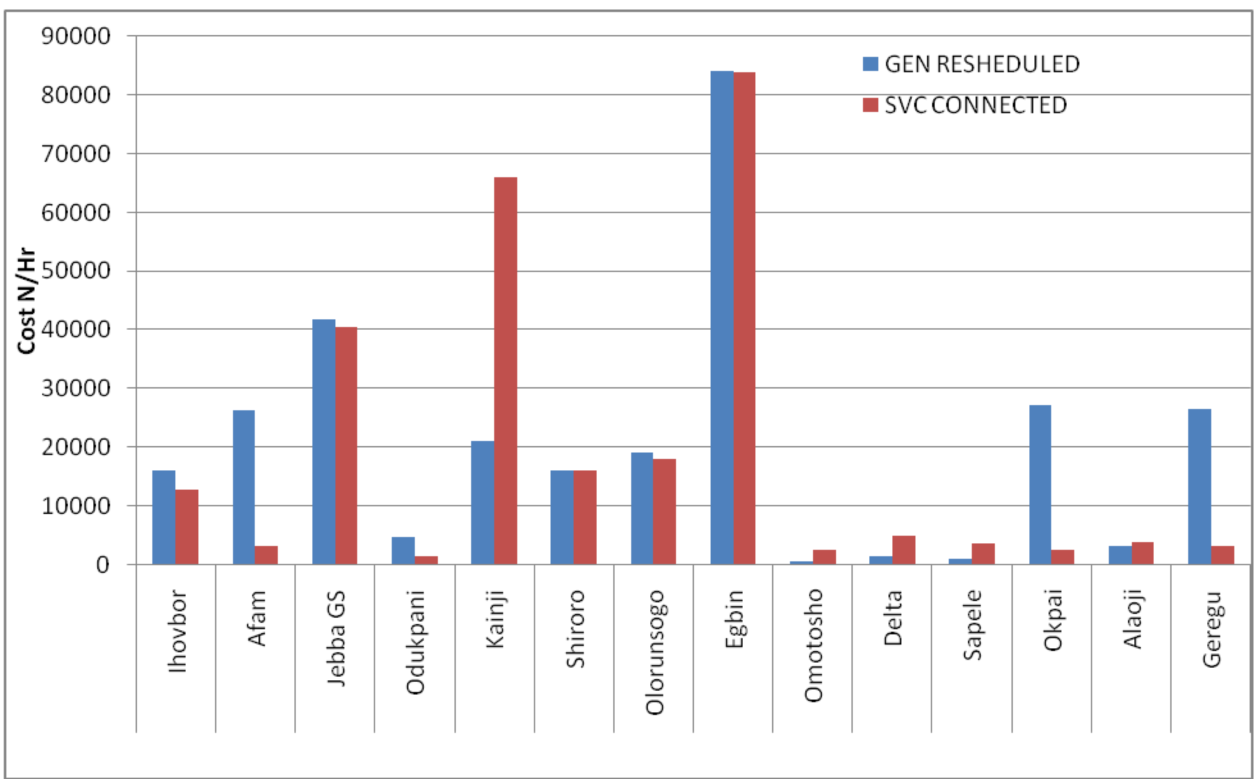


Fig. 4.13: Cost Profile of Generators (N/HR) after Placement of SVC.

Figure 4.13 shows the cost profile of the generators after installation of SVCs. The blue colour represents the base case which is the total cost after the generators were rescheduled. The red colour represents the total cost after SVC were installed. The generator at Egbin still has the highest cost 8385.51074₦/Hr as against 84069.74507₦/Hr when the generators where rescheduled. Odukpani has the lowest cost 1538.598351₦/Hr.

4.5 Placement of TCSC

Thyristor Controlled Series Compensator (TCSC) is a device that can quickly and reliably control bus voltages and transmission line flow. In addition, a TCSC device can also increase transfer capability, reduce losses and mitigate active power oscillations.

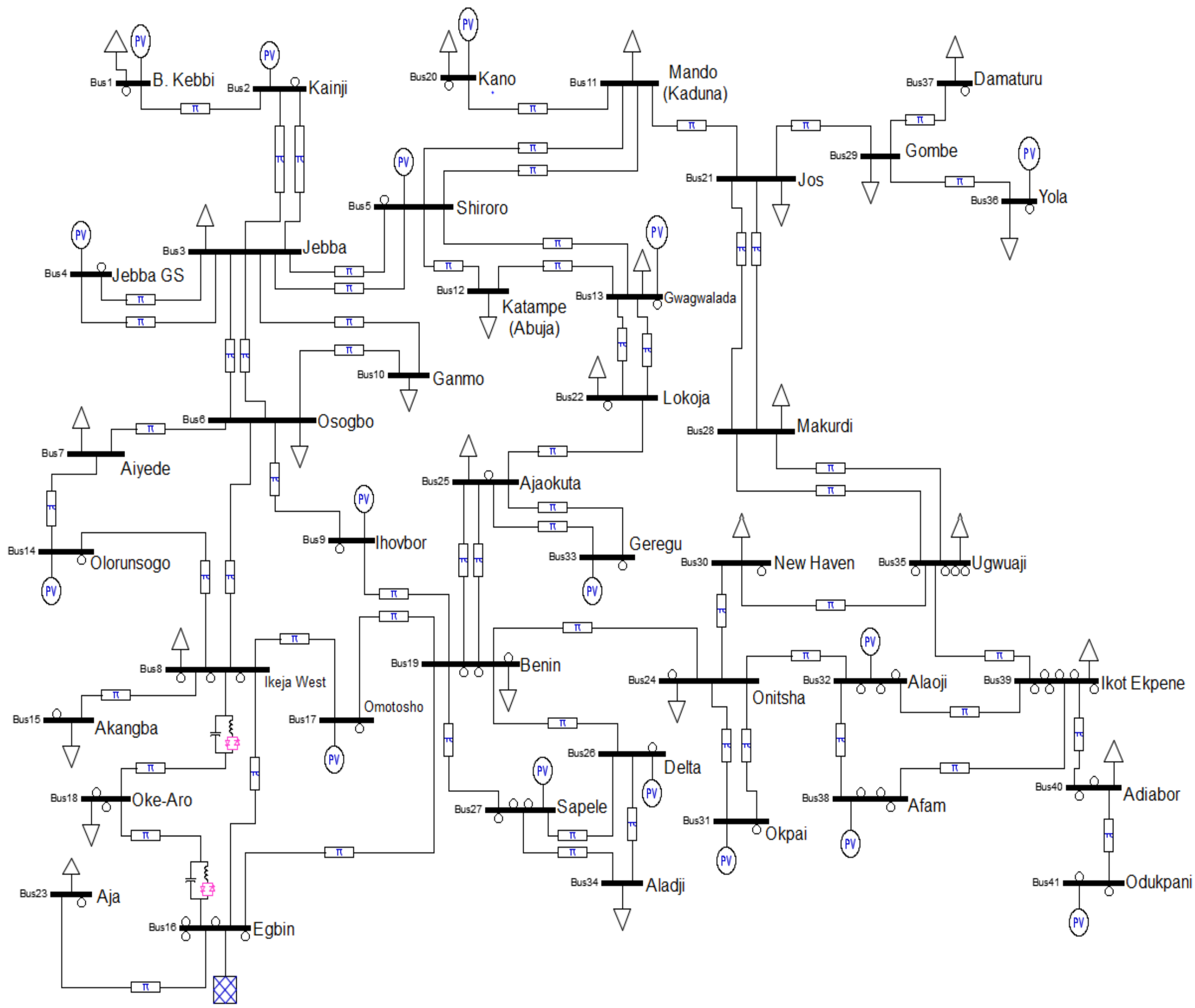


Fig. 4.14: Modelled 41 Bus 330kv Nigerian Super Grid Network - Placement of TCSC.

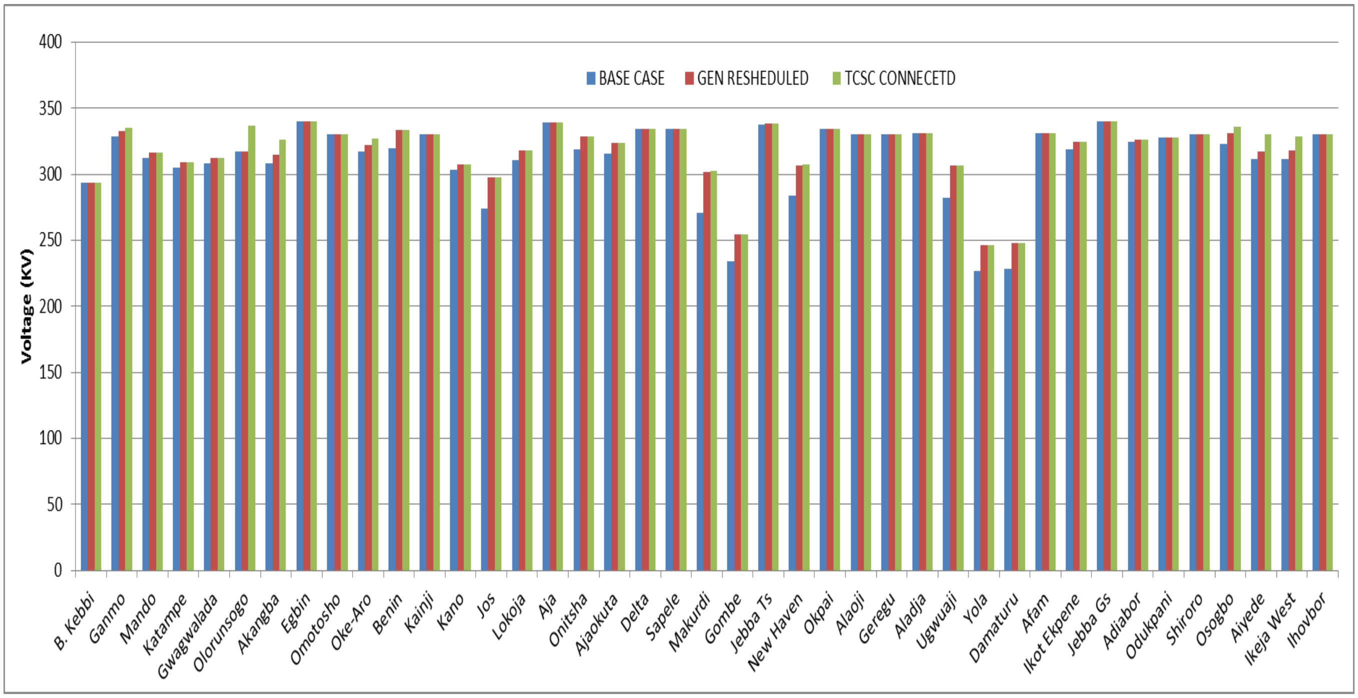


Fig.4.15: Bus Voltage after Placement of TCSC.

Figure 4.15 shows the voltage profile of the network (kV) after installing TCSCs optimally at the transmission lines between the buses at Ikeja West and Oke-Aro and also between the buses at Egbin and Oke-Aro. The blue colour represent the base case which is the initial data gotten from the National Control Centre, Oshogbo, the red colour is the rescheduled data obtained after optimization while the green colour is voltage profile when the TCSCs were installed to the network after the generators were rescheduled. Figure 4.15 has shown that there was slight improvement of voltage on those buses that were below the operating voltage as shown in table 4.7.

Table 4.7: Voltage Profile Comparison after Placement of TCSC

S/N	Bus name	Base Case	Gen. Resched	TCSC
1	B. Kebbi	293.2535545	293.2535545	293.254
2	Mando	312.4498136	316.4683475	316.438
3	Katampe	305.3221285	308.8993499	308.809
4	Gwagwalada	307.8620548	312.1427811	312.023
5	Akangba	308.4239716	314.6075441	325.823
6	Kano	303.0401725	307.2163877	307.185
7	Jos	273.7928104	297.4608205	297.601
8	Lokoja	310.7697535	318.0531074	317.849
9	Makurdi	270.7862923	302.0607729	302.061
10	Gombe	234.0070032	254.2357306	254.356
11	New Haven	284.0169595	306.9843271	307.204
12	Ugwuaji	282.2990359	306.6313599	306.889
13	Yola	226.5181473	246.0995008	246.216
14	Damaturu	228.0053515	247.7152664	247.832
15	Aiyede	311.6840354	316.9951596	330.238
16	Ikeja West	311.7644693	317.8800417	330.238

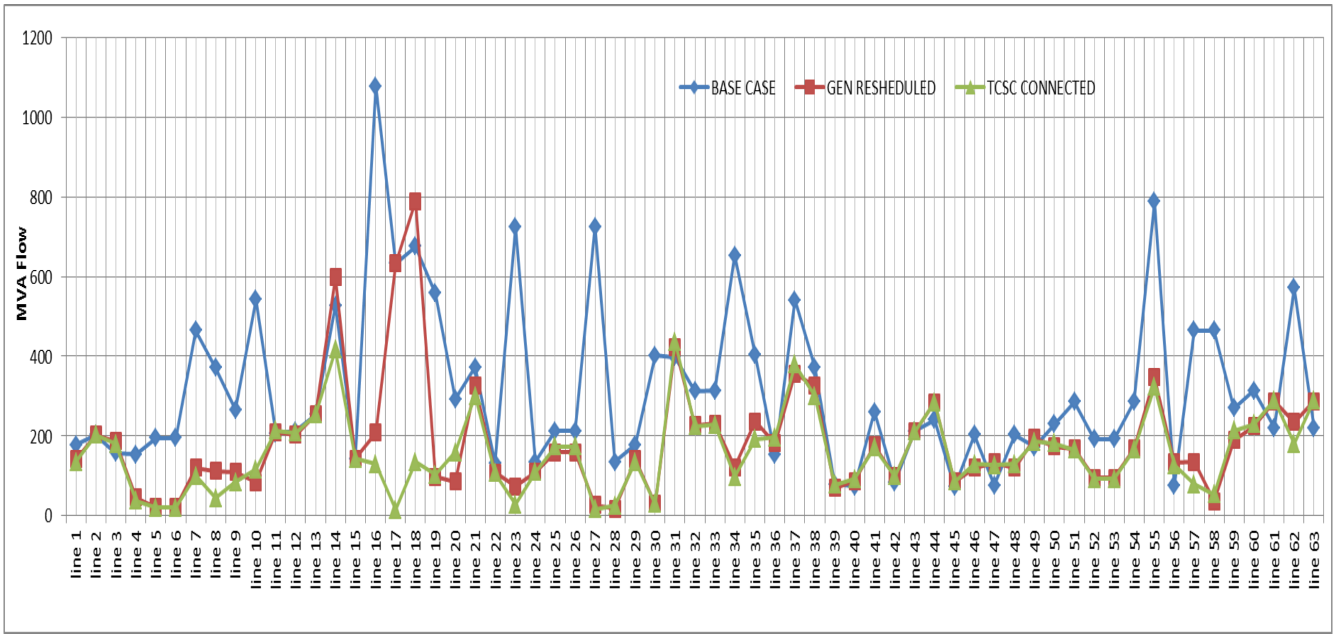


Fig. 4.16: MVA flow of the Transmission Lines after Placement of TCSC.

Figure 4.16 shows the MVA flow of the network after installing TCSCs at the transmission lines between the buses at Ikeja West and Oke-Aro and also between the buses at Egbin and Oke-Aro. The blue colour represent the base case which is the initial data gotten from the National Control Centre Oshogbo, the red colour is the rescheduled data obtained after optimization while the green colour is MVA flow when TCSCs were installed to the network after the generators were rescheduled. Figure 4.16 has shown also that there was a major reduction on the MVA loading on the line as shown in table 4.8.

Table 4.8: MVA Flow Comparison after Placement of TCSC

S/N	Line Name	Bus Connections	Base Case MVA FLOW	Gen. Resched. MVA FLOW	TCSC MVA FLOW
1	Line 16	Egbin – Benin	1077.48657	598.5455	129.264933
2	Line 23	Benin – Onitsha	723.480437	73.3666	27.5620873
3	Line 17	IKeja West – Oke-Aro	632.880749	633.3464	15.286018
4	Line 18	Oke-Aro – Egbin	674.917358	788.5279	134.829308
5	Line 19	Ikeja West – Omotosho	557.603784	97.7532	102.596478
6	Line 27	Benin – Sapele	724.429967	26.6236	16.7986228
7	Line 34	Onitsha – Alaoji	652.743581	121.031	97.5768357
8	Line 55	IkotEkpene – Ugwaji	787.038531	346.5156	323.461262
9	Line 62	Adiabor – Odukpani	570.866823	234.7489	180.180329
10	Line 14	Egbin – Ikeja West	527.694941	598.5455	416.257446

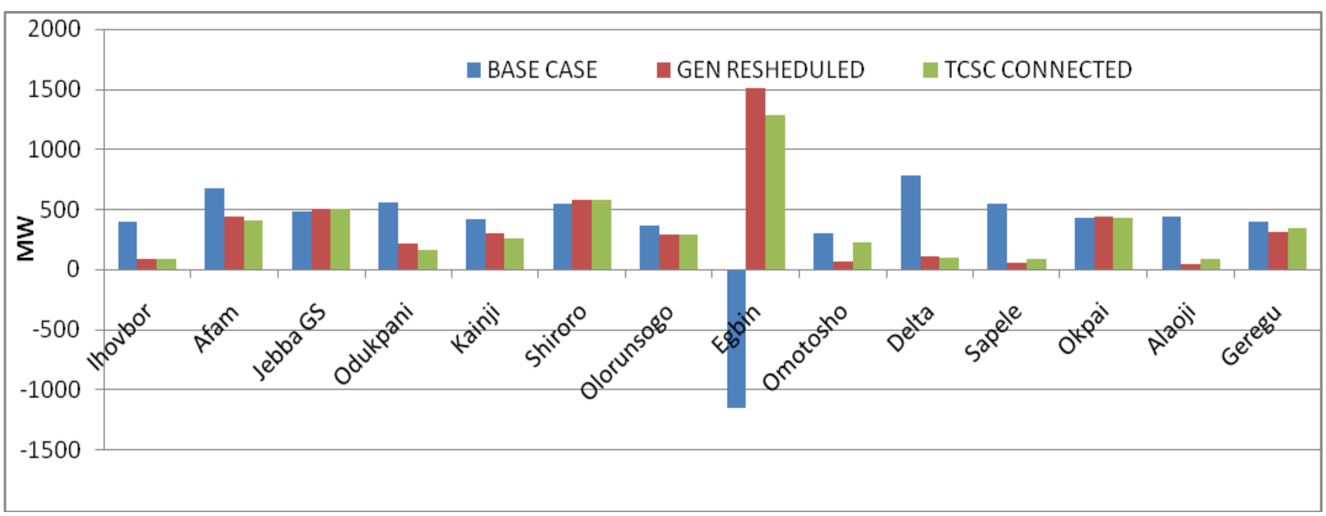


Fig. 4.17: Power Generator Profile (MW) after Placement of TCSC.

Figure 4.17 shows the generator profile of the network (MW) after installation of TCSCs. The blue colour represent the base case which is the initial data gotten from the National Control Centre Oshogbo, the red colour is the rescheduled data obtained after optimization while the green colour represents the data obtained when TCSCs were connected to the network. Looking at figure 4.17, the generators at Jebba, Kainji, Shirror, Egbin and Omotosho were called-up. The generator at Egbin had the highest power generation and the installation of TCSC made it to operate within its limit, which led to the calling-up of the generator at Omotosho.

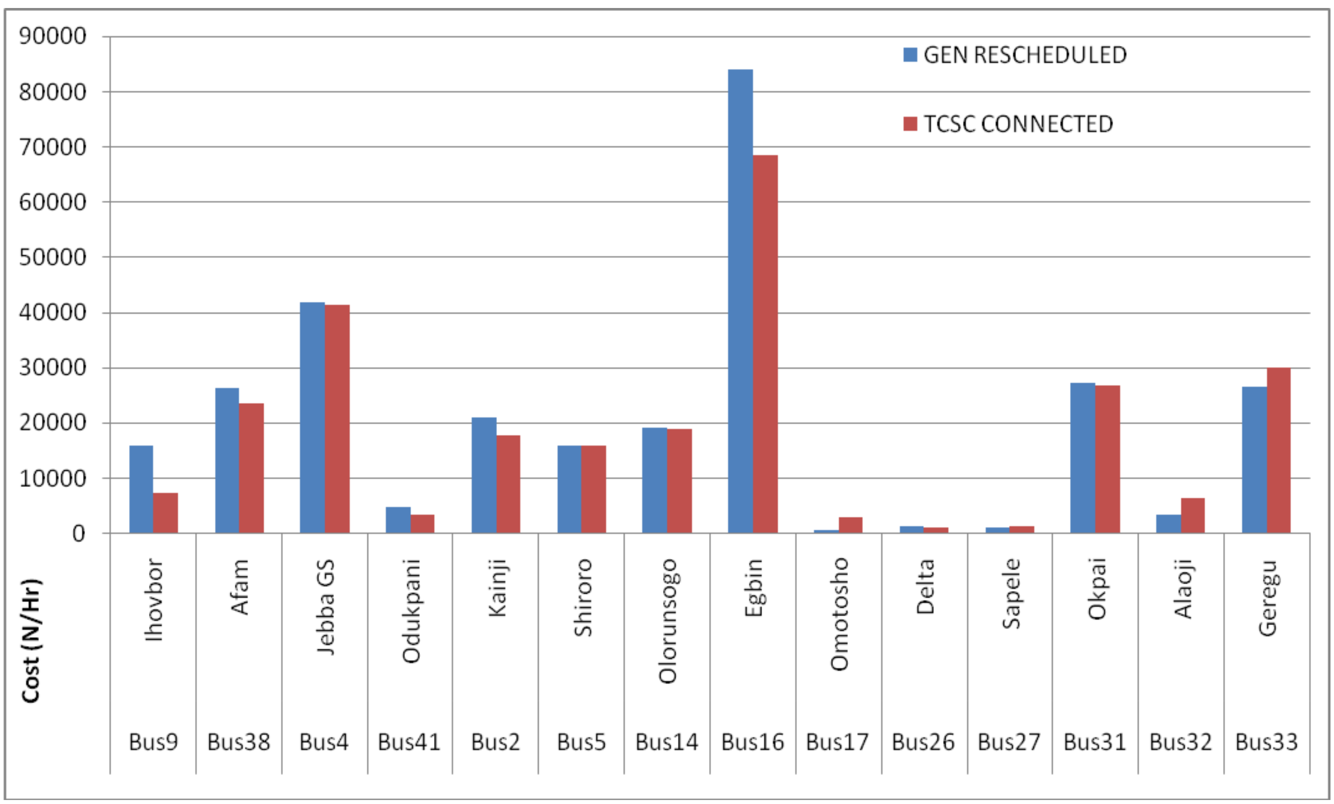


Fig. 4.18: Cost Profile of Generators (N/HR) after placement of TCSC.

Figure 4.18 shows the cost profile of the generators after installation of TCSCs. The blue colour represents the base case which is the total cost after the generators were rescheduled. The red colour represents the total cost after TCSCs were installed. The generator at Egbin still has the highest cost 68407.20431₦/Hr as against 84069.74507₦/Hr when the generators where rescheduled. Delta has the lowest cost 1256.850471₦/Hr.

4.6 Combined Placement of SVC and TCSC and Generator Rescheduling

The combination of Flexible Alternate Current Transmission System (FACTS) devices such as Static Var Compensators (SVCs) and Thyristor Controlled Series Compensator (TCSC) can quickly and reliably control bus voltages and transmission line flow. SVC devices will typically regulate and control the voltage to the required set point under normal steady state and thereby provide dynamic, fast response to reactive power following system violation such as under voltage or over voltage. In addition, TCSC device can also increase transfer capability, reduce losses and mitigate active power oscillations.

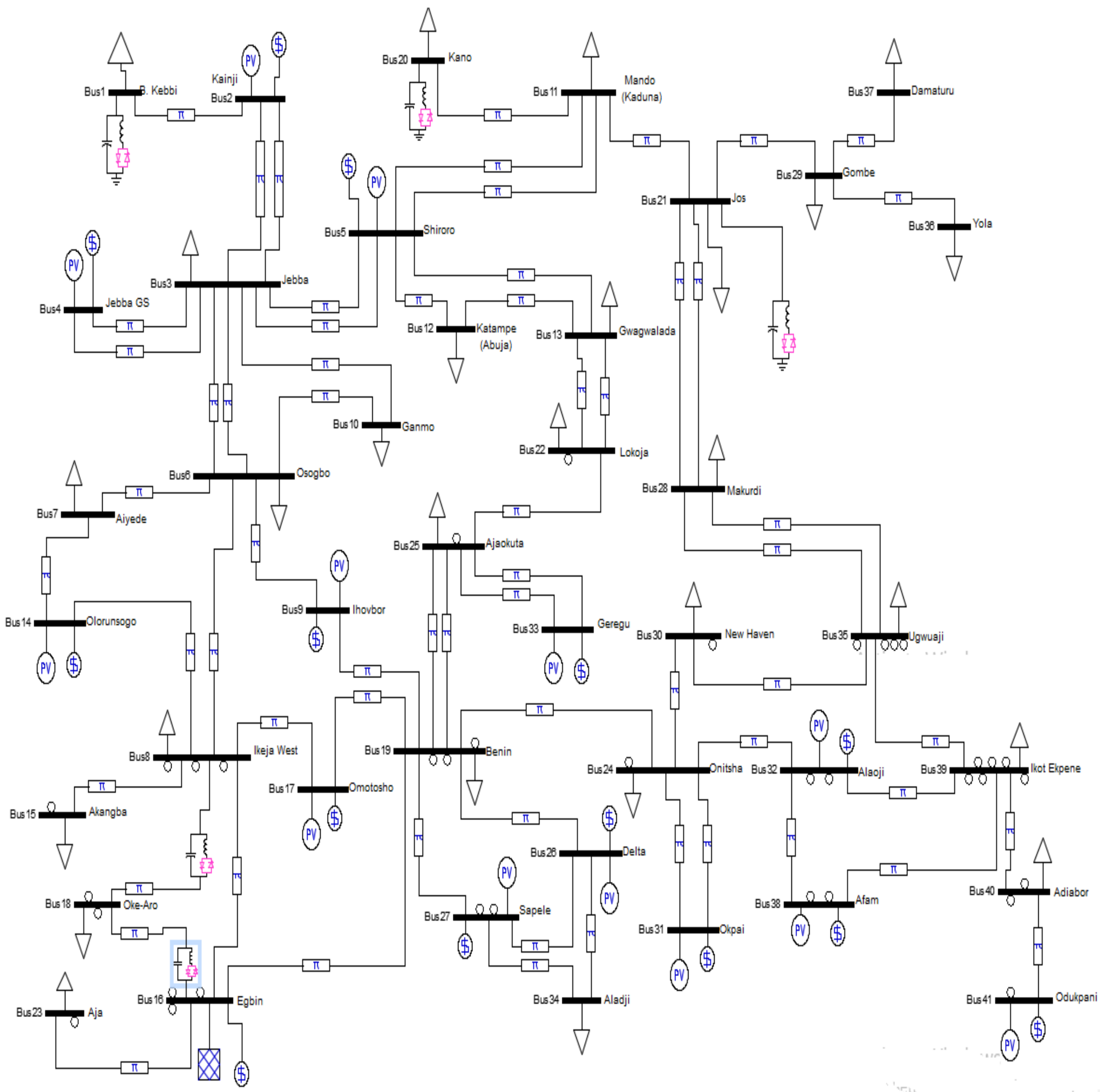


Fig. 4.19: Modelled 41 Bus 330kV Nigerian Power System, combined Placement of SVC and TCSC and Generator Rescheduling

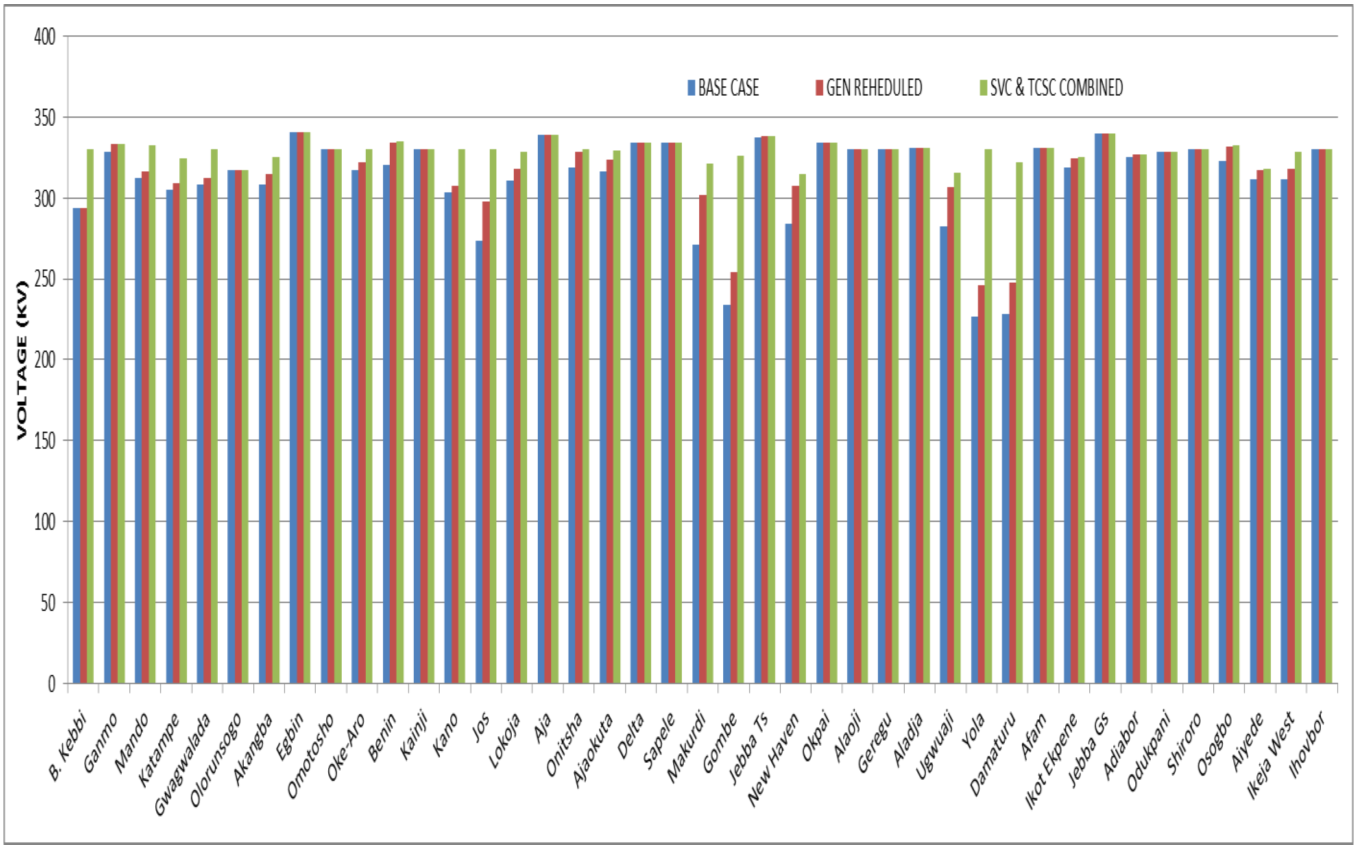


Figure 4.20: Bus Voltage after combined placement of SVC and TCSC and Generator Rescheduling

Figure 4.20 shows the voltage profile of the network during load flow, when the generator was rescheduled and when the static var compensator and thyristor controlled series compensator were installed. Figure 4.20 has shown that there was an improved voltage on those buses that were below the operating voltage as shown in table 4.9.

Table 4.9: Voltage Profile Comparison after combined Placement of SVC and TCSC and Generator Rescheduling

S/N	Bus Name	Base Case voltage (kV)	Gen. Resched. voltage (kV)	SVC & TCSC & Gen. Resched. voltage (kV)
1	B. Kebbi	293.2535545	293.2535545	330
2	Mando	312.4498136	316.4683475	332.4491881
3	Katampe	305.3221285	308.8993499	324.0368409
4	Gwagwalada	307.8620548	312.1427811	330
5	Akangba	308.4239716	314.6075441	325.1721058
6	Kano	303.0401725	307.2163877	330
7	Jos	273.7928104	297.4608205	330.0016629
8	Lokoja	310.7697535	318.0531074	328.3512355
9	Makurdi	270.7862923	302.0607729	321.4711432
10	Gombe	234.0070032	254.2357306	326.2967569
11	New Haven	284.0169595	306.9843271	315.0116659
12	Ugwuaji	282.2990359	306.6313599	315.2720685
13	Yola	226.5181473	246.0995008	330
14	Damaturu	228.0053515	247.7152664	321.887724
15	Aiyede	311.6840354	316.9951596	317.772856
16	Ikeja West	311.7644693	317.8800417	328.3344263

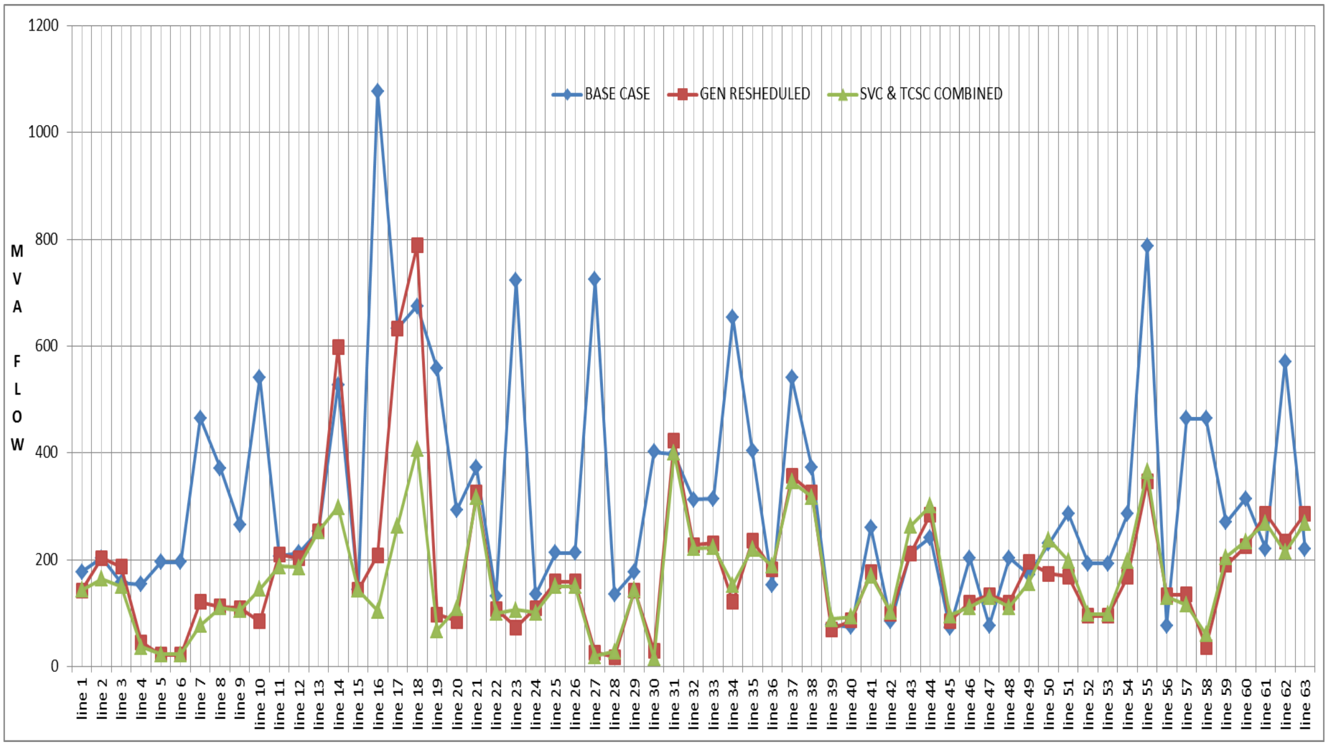


Fig. 4.21: MVA flow of the Transmission Lines after combined placement of SVC and TCSC and Generator Rescheduling

Figure 4.21 shows the MVA flow of the transmission lines after the combined installation of SVC and TCSC and Generator Rescheduling. The combined connection of SVC and TCSC (FACTS devices) and Generator Rescheduling helped to drastically reduce the high loading on the transmission lines as seen in table 4.10.

Table 4.10: MVA Flow Comparison after combined placement of SVC and TCSC and Generator Rescheduling

S/N	Line Name	Bus Connection	Base Case	Gen. Resched.	SVC & TCSC & Gen. Resched.
			MVA FLOW	MVA FLOW	MVA FLOW
1	Line 16	Egbin – Benini	1077.486573	598.5455	104.6424372
2	Line 23	Benin – Onitsha	723.4804368	73.3666	105.6822123
3	Line 17	IKeja West – Oke-Aro	632.8807493	633.3464	264.0969342
4	Line 18	Oke-Aro – Egbin	674.9173576	788.5279	406.5200116
5	Line 19	Ikeja West – Omotosho	557.6037835	97.7532	108.3188987
6	Line 27	Benin – Sapele	724.4299672	26.6236	19.01750252
7	Line 34	Onitsha – Alaoji	652.7435806	121.031	152.5807091
8	Line 55	IkotEkpene – Ugwaji	787.0385312	346.5156	365.4121653
9	Line 62	Adiabor – Odukpani	570.8668234	234.7489	214.2305696
10	Line 14	Egbin – Ikeja West	527.6949407	598.5455	298.3894481

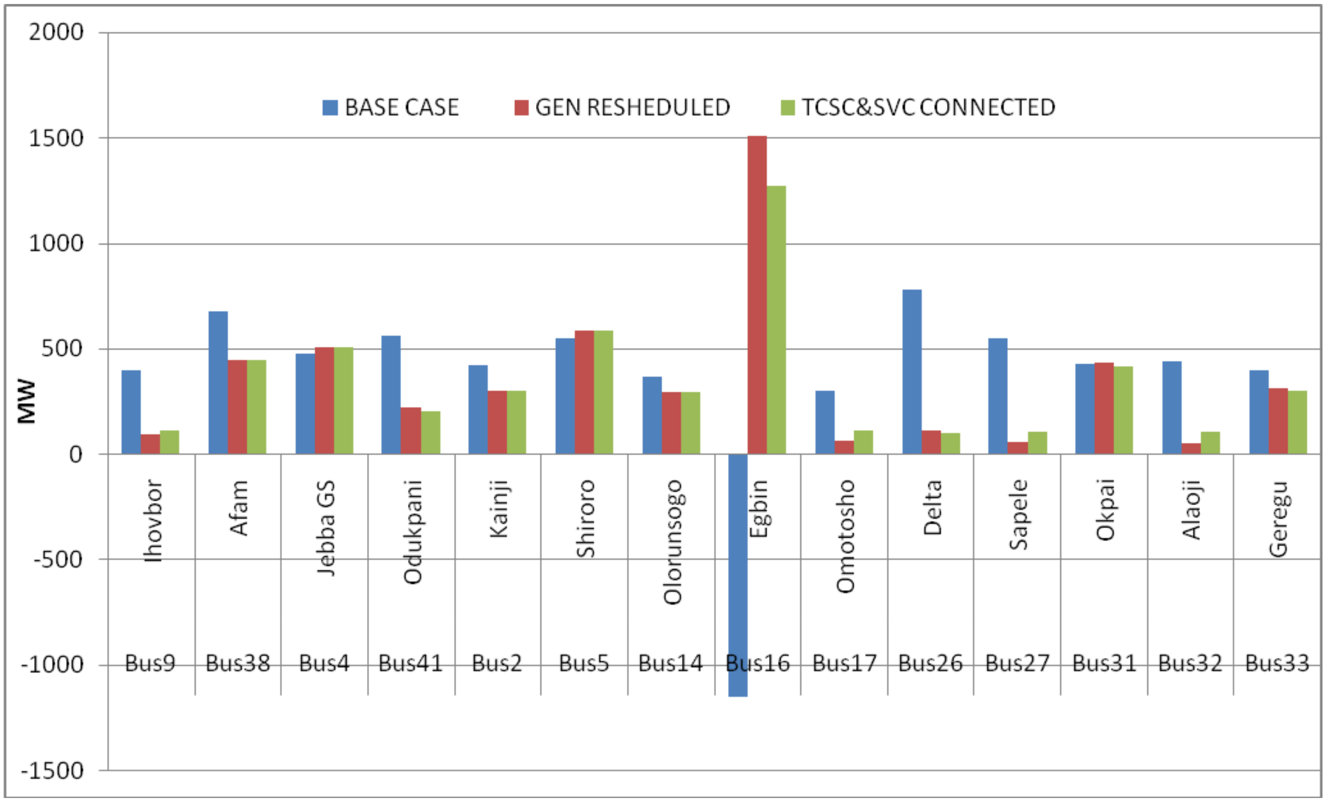


Fig. 4.22: Power Generator Profile (MW) after combined placement of SVC and TCSC

Figure 4.22 shows the generator profile of the network (MW) after combined installation of SVC and TCSC. The blue colour represent the base case which is the initial data gotten from the National Control Centre, Oshogbo, the red colour is the rescheduled data obtained after optimization while the green colour represents the data obtained when there was combined installation of SVC and TCSC to the network. Looking at this figure, the generators at Jebba, Shirror and Egbin were called-up. The generator at Egbin had the highest power generation and the combined installation of SVC and TCSC made it to operate within its limit.

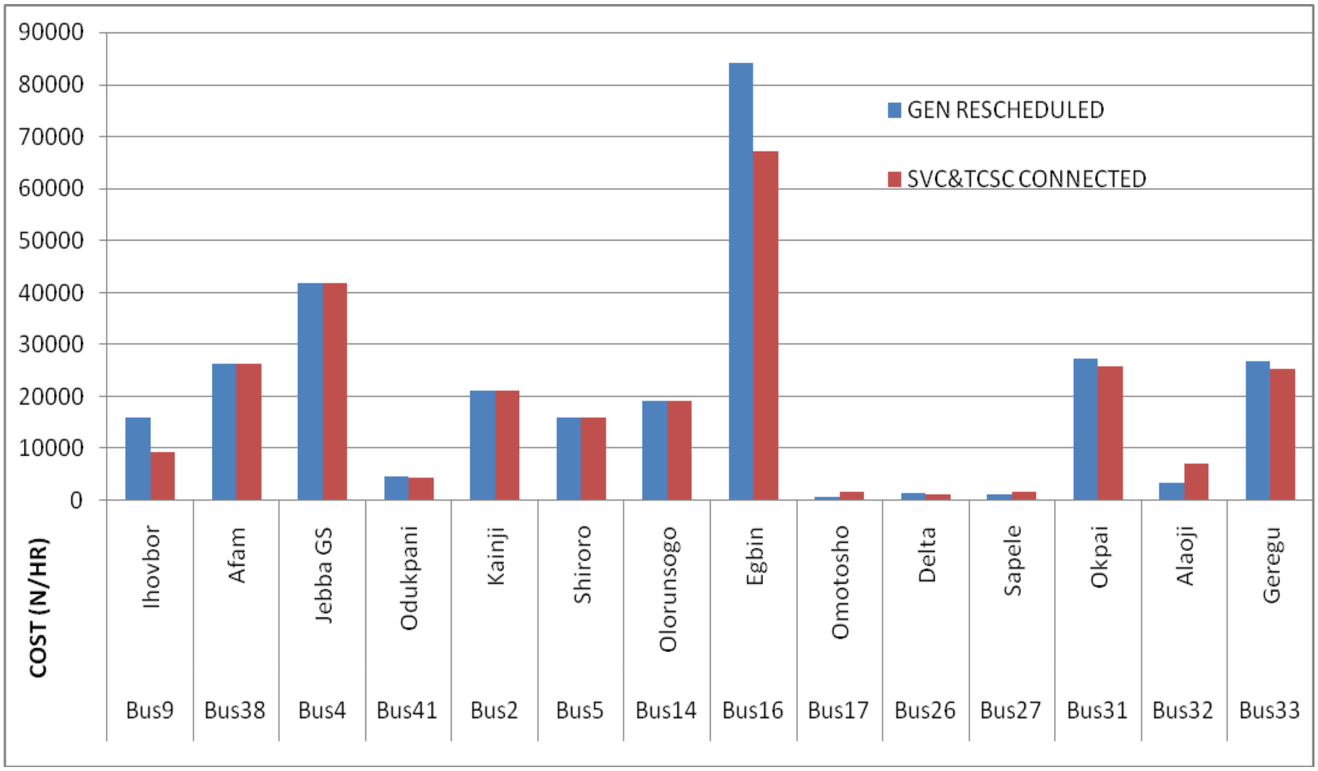


Fig. 4.23: Cost Profile of Generators (N/HR) after combined placement of SVC and TCSC.

Figure 4.23 shows the cost profile of the generators after combined installation of SVC and TCSC. The blue colour represents the base case which is the total cost after the generators were rescheduled. The red colour represents the total cost after combined installation of SVC and TCSC to the Network. The generator at Egbin still has the highest cost 67220.42983₦/Hr as against 84069.74507₦/Hr when the generators where rescheduled. Delta has the lowest cost 1292.415749₦/Hr.

CHAPTER FIVE

CONCLUSION AND RECOMMENDATIONS

5.1 CONCLUSION

Transmission congestion management is an important issue in a deregulated power system.

This dissertation focuses on congestion management within an OPF frame work in Nigerian 41-Bus super grid scenario. The operational aspects of power systems pose some of the most challenging problems encountered in managing the congestion in the network.

This work promotes the simultaneous placement of FACTS devices and generator rescheduling to alleviate congestion. The optimal locations for placement of these devices were necessary in consideration of the costs of FACTS devices.

The simulation results obtained from the methods used in this dissertation as tabulated in Table 4.10 shows that simultaneous combination of FACTS devices (SVC and TCSC) and generator rescheduling best managed the congestion in the Nigerian power system, reducing 39% voltage profile violations and 15.87% MVA flow violations of the base case to 0% violation, thus improving system efficiency.

5.2 RECOMMENDATIONS

The transmission system needs to be continually free from congestion. This is very important for the Nigerian Power systems undergoing reforms and restructuring to put the transmission system ready for increased generation as a result of this restructuring.

1. It is recommended that a robust plan in managing congestion in Nigeria should be a priority. The national electricity regulatory commission (NERC) and various stake holders in the electricity industry should come with a policy in improving power transmission in the grid.
2. It is proven that the introduction of the FACTS devices has shown more effectiveness in reducing congestion than the conventional load shedding and transmission line expansion methods. However more complex analyses are recommended as an extension of the work.
3. More research should be done on the economic merits of combining these methods of managing congestion such as operational cost of the generation, the nodal pricing and market bidding.
4. For cost reduction in application of FACTS devices, it is recommendation that Distributed generation can be introduced at the Northern part of the country for Transmission Congestion management.

5.3 CONTRIBUTION TO KNOWLEDGE

Different methods of reducing congestion are crucial in the overall operation of the Nigerian power system. The overwhelming problem emanated from the over-centralization of generating facilities in one area with only one corridor of transmission to evacuating the bulk of the power to the other areas made it impossible to use a single method to totally alleviate its congestion.

The researcher reviewed that combined introduction of series and shunt FACTS devices and rescheduling of the generators in Nigerian Power system helped in reducing congestion on the network for a more reliable system. This combination also helped in reducing the cost of installing FACTS devices in a fast deregulated economy.

The survey presented in this dissertation will be very informative and useful to research scholars, utility engineers, and academicians. Periodic update on this topic will be useful as the deregulated electric industry continues to evolve in Nigeria.

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APPENDICES

APPENDICE A

INPUT DATA

A1. Generation Data1

Generation Data 1 for the 14 Power Generation Stations

S/N	Gen. Name	Bus No.	Operating Gen. Capability Gen. MW	Voltage Mag.	Installed Gen. Capacity	
					Min. MW	Max. MW
1	Kainji	2	292	1	76	760
2	Jebba	4	460	1.030	54	540
3	Shiroro	5	450	1	60	600
4	Ihovbor	9	337	1	42	420
5	Olorunsogo	14	266	0.961	30	304
6	Egbin	16	722	1.012	132	1320
7	Omotosho	17	280	1	30	304
8	Delta	26	480	1.012	90	900
9	Sapele	27	240	1.012	72	720
10	Okpai	31	400	1.012	45	450
11	Alaoji	32	240	1	50	504
12	Geregu	33	385	1	41	414

13	Afam	38	580	1.003	73	726
14	Odukpani	41	360	0.994	63	625

Generation Data 2 for the 14 Power Generation Stations

S/N	Gen. Name	Bus No.	Operating Gen. Capability Gen. MW	Voltage Mag.	Mvar Limits	
					Min.	Max.
1	Kainji	2	292	1	14	143
2	Jebba	4	460	1.030	23	225
3	Shiroro	5	450	1	22	220
4	Ihovbor	9	337	1	17	165
5	Olorunsogo	14	266	0.961	13	130
6	Egbin	16	0	1.012	0	0
7	Omotosho	17	280	1	15	149
8	Delta	26	480	1.012	24	235
9	Sapele	27	240	1.012	12	117
10	Okpai	31	400	1.012	22	220
11	Alaoji	32	240	1	12	117
12	Geregu	33	385	1	19	188
13	Afam	38	580	1.003	28	284
14	Odukpani	41	360	0.994	18	176

Generator Fuel Cost Data for the 14 Power Generation Stations

S/N	Generator	Cost Coefficient		
		a(₦/MWh)	b(₦/MWh)	c(₦/MWh)
1	Kainji	0	0	0.014
2	Jebba	0	0	0.012
3	Shiroro	0	0	0.013
4	Ihovbor	525.7	61.3	0.012
5	Olorunsogo	237.87	48	0.031
6	Egbin	497	52.3	0.058
7	Omotosho	229.8	56	0.092
8	Delta	192.76	40.32	0.042
9	Sapele	197.87	33	0.098
10	Okpai	127	15	0.020
11	Alaoji	179	20.4	0.012
12	Geregu	692.9	78.55	0.031
13	Afam	117.76	37.55	0.012
14	Odukpani	155	51.7	0.056

A2. Bus Data.

Bus Data for the 41-Bus System

S/N	Bus Name	Nom. kV	Volt. Mag. PU	Actual Volt (kV)	Angle (Deg)	Load		Generation	
						MW	Mvar	MW	Mvar
1	B. Kebbi	330	1	322	0	162	122	-	-
2	Kainji	330	1	330	0	89	67	292	143
3	JebbaTs	330	1	339	0	260	195	-	-
4	JebbaGs	330	1.030	340	0	-	-	460	225
5	Shiroro	330	1	330	0	328	246	450	220
6	Osogbo	330	1	337	0	127	95	-	-
7	Aiyede	330	1	320	0	174	131	-	-
8	Ikeja West	330	1	325	0	847	635	-	-
9	Ihovbor	330	1	330	0	-	-	337	165
10	Ganmo	330	1	332	0	100	75	-	-
11	Mando	330	1	316	0	142	107	-	-
12	Katampe	330	1	319	0	303	227	-	-
13	Gwagwalada	330	1	326	0	220	165	-	-
14	Olorunsogo	330	0.961	317	0	157	117	266	130
15	Akangba	330	1	311	0	203	152	-	-
16	Egbin	330	1.012	334	0	-	-	0	0
17	Omotosho	330	1	330	0	262	196	304	149
18	Oke-Aro	330	1	320	0	120	90	-	-

19	Benin	330	1	333	0	144	108	-	-
20	Kano	330	1	305	0	194	146	-	-
21	Jos	330	1	324	0	72	54	-	-
22	Lokoja	330	1	320	0	120	90	-	-
23	Aja	330	1	318	0	115	86	-	-
24	Onitsha	330	1	329	0	100	75	-	-
25	Ajaokuta	330	1	320	0	120	90	-	-
26	Delta	330	1.012	334	0	-	-	480	235
27	Sapele	330	1.012	334	0	128	96	240	117
28	Makurdi	330	1	326	0	160	120	-	-
29	Gombe	330	1	302	0	68	51	-	-
30	New Haven	330	1	328	0	196	147	-	-
31	Okpai	330	1.012	334	0	-	-	400	196
32	Alaoji	330	1	330	0	227	170	240	117
33	Geregu	330	1	330	0	200	150	385	188
34	Aladja	330	1	330	0	210	158	-	-
35	Ugwuaji	330	1	328	0	175	131	-	-
36	Yola	330	1	302	0	26	20	-	-
37	Damaturu	330	1	302	0	24	18	-	-
38	Afam	330	1.003	331	0	534	401	580	284
39	Ikot Ekpene	330	1	328	0	165	124	-	-
40	Adiabor	330	1	328	0	90	68	-	-
41	Odukpani	330	0.994	328	0	-	-	360	176

A3. Line Data

Line Data for 63 Transmission Lines of the Network

S/N	Bus No.	Bus No.	R, p.u	X, p.u	½B, p.u
1	1	2	0.0121836	0.09183360	1.21
2	2	3	0.0031834	0.02394290	0.31
3	2	3	0.0031834	0.02394290	0.31
4	3	4	0.0003144	0.01883550	0.00
5	3	4	0.0003144	0.01883550	0.00
6	3	5	0.0095897	0.07212450	0.05
7	3	5	0.0095897	0.07212450	0.05
8	3	6	0.0061704	0.36964720	0.07
9	3	6	0.0061704	0.36964720	0.07
10	3	10	0.0227603	0.20001260	0.03
11	5	11	0.0037730	0.02837080	0.37
12	5	11	0.0037730	0.02837080	0.37
13	5	12	0.0061704	0.36964720	0.07
14	5	13	0.0061704	0.36964720	0.07
15	6	7	0.0053843	0.04049610	0.53
16	6	8	0.1163340	0.08749530	1.16
17	6	9	0.0098648	0.07419360	0.98
18	6	10	0.0001704	0.04610790	0.61
19	7	14	0.0788326	0.15700510	1.08

20	8	14	0.0053843	0.04049610	0.45
21	8	15	0.0007074	0.00532060	0.05
22	8	16	0.0024367	0.01832670	0.20
23	8	17	0.0110045	0.08276580	1.09
24	8	18	0.0411811	0.08236230	0.05
25	9	19	0.0098648	0.07419360	0.98
26	11	20	0.0090394	0.00798620	0.90
27	11	21	0.0077425	0.05823100	0.77
28	12	13	0.0099770	0.12478530	0.02
29	13	22	0.0184481	0.23073520	0.04
30	13	22	0.0184481	0.23073520	0.04
31	16	18	0.0411811	0.08236230	0.05
32	16	19	0.0098648	0.0719360	0.98
33	16	23	0.0005502	0.00413820	0.04
34	17	19	0.0110045	0.08276580	1.09
35	19	24	0.0053843	0.04049610	0.63
36	19	25	0.0076639	0.05764040	0.76
37	19	25	0.0076639	0.05764040	0.76
38	19	26	0.0676425	0.21681980	0.04
39	19	27	0.0019651	0.01477960	0.19
40	21	28	0.0104150	0.07833190	1.04
41	21	28	0.0104150	0.07833190	1.04
42	21	29	0.0104150	0.07833190	1.04
43	22	25	0.0135537	0.18051970	0.03
44	24	30	0.0037730	0.02837680	0.37
45	24	31	0.0103535	0.12949420	0.02
46	24	31	0.0103535	0.12949420	0.02

47	24	32	0.0060525	0.04552120	0.60
48	25	33	0.0043296	0.05415210	0.01
49	25	33	0.0043296	0.05415210	0.01
50	26	27	0.0024760	0.01862230	0.24
51	26	34	0.0010218	0.00768530	0.10
52	27	34	0.0024760	0.01862230	0.24
53	28	35	0.0300841	0.38377380	0.08
54	28	35	0.0300841	0.38377380	0.08
55	29	36	0.0606942	0.53336700	0.10
56	29	37	0.0342607	0.42850820	0.08
57	30	35	0.0042254	0.01354410	0.10
58	32	38	0.0009825	0.00738980	0.09
59	32	39	0.0112947	0.14126640	0.20
60	35	39	0.0060525	0.04552120	0.60
61	38	39	0.0135537	0.16951970	0.03
62	39	40	0.0135537	0.16951970	0.03
63	40	41	0.0122359	0.15303860	0.03

APPENDICE B

B1. MATLAB CODE - LOAD FLOW ANALYSIS

```
% This programme evaluates the power flow in a system of any No. of buses
% To run this code, excel tables of line admittances (table1.xlsx)and
% bus parameters (table2.xlsx) must be saved in the Matlab working folder(i.e current directory
% in older versions or current folder in more recent versions)


clear  % To clear the workspace
clc    % To clear the command window
A=xlsread('table1.xlsx');  % Loading table of line admittances
fb=A(:,2);   % identifying the from buses
tb=A(:,3);   % identifying the buses
if max(fb)>max(tb)  % identifying the number of buses
    nb=max(fb);
else nb=max(tb);
end
y=zeros(nb,nb);  %initializing the line admittance
Ybus=zeros(nb,nb); %initializing the Ybus matrix
teeta=zeros(nb,nb); %initializing the angle of Ybus matrix elements

% Evaluating the line admittances from the line impedances
  for i=1:length(fb)
      if fb(i)~=tb(i)
          y(fb(i),tb(i))=(A(i,4)+A(i,5)*1j)\1; % yi,k=1/(r+jx)
           y(tb(i),fb(i))=(A(i,4)+A(i,5)*1j)\1; % yk,i=yi,k
      end
  end
% Evaluating the Ybus admittances from the line admittances
  for i=1:nb
      for k=1:nb
          if k==i
              for m=1:nb
                  Ybus(i,k)=Ybus(i,k)+y(i,m); %Diagonal elements of the Ybus
              end
```

```
        else Ybus(i,k)=-y(i,k);   %off Diagonal elements of the Ybus
        end
      end
   end
% Evaluating angles of the Ybus admittances
   for k=1:nb
      for n=1:nb
      teeta(k,n)= angle(Ybus(k,n));
      end
   end
% Loading table of bus parameters
B=xlsread('table2.xlsx'); % loading table of bus parameters
v=B(:,3);      %extracting voltage values from table of bus parameters
del=B(:,5);    %extracting voltage angles from table of bus parameters
pd=B(:,10);    %extracting bus real load  from table of bus parameters
qd=B(:,11);    %extracting bus reactive load from table of bus parameters
pg=B(:,12);    %extracting bus real generation from table of bus parameters
qg=B(:,13);    %extracting bus reactive generation from table of bus parameters
nb= length(del);    % Identifying number of buses
Psch=zeros(nb,1);   % Initializing Psch-vector
Qsch=zeros(nb,1);   % Initializing Qsch-vector
for n=1:nb
    Psch(n)=pg(n)-pd(n);  %obtaining bus real power
    Qsch(n)=qg(n)-qd(n);  %obtaining bus reactive power
end
slb=input('enter the bus number of the desired slack bus __');
iter=0;   % Initializing the iteration counter
t=0.001;  % The convergence test criterion

%  EVALUATION OF THE JACOBIAN
P=zeros(nb,1);  % Initializing bus real power
Q=zeros(nb,1);  % Initializing bus reactive power
delP=zeros(nb,1); % Initializing the change in bus real power
delQ=zeros(nb,1); % Initializing the change in bus reactive power
DP_DQ=ones(2*(nb-1),1); %Initializing the column matrix for change in P & Q with exception
of the slack bus.
delP_fj=zeros(nb-1,1);
delQ_fj=zeros(nb-1,1);
delv_fj=zeros(nb-1,1);
del_del_fj=zeros(nb-1,1);
Ddel_Dv=ones(nb-1,1);

% Iteration begins
while abs(DP_DQ)> t & iter < 20  % checking for convergence
    for m=1:nb
       if m~=slb
```

```
            for n=1:nb
                    P(m)= P(m)+(abs(v(m))*abs(v(n))*abs(Ybus(m,n))*cos(teeta(m,n)-del(m)+del(n)));
                    Q(m)= Q(m)-(abs(v(m))*abs(v(n))*abs(Ybus(m,n))*sin(teeta(m,n)-del(m)+del(n)));
            end
        end
    end
for m=1:nb
    if m ~= slb
    delP(m)=Psch(m)-P(m); % Change in P
    delQ(m)=Qsch(m)-Q(m); % Change in Q
    end
end
for m=1:nb-1
    if m<slb
      delP_fj(m)= delP(m);
      delQ_fj(m)=delQ(m);
    else
      delP_fj(m)= delP(m+1);
      delQ_fj(m)=delQ(m+1);
    end
end
%Initializing the Jacobian matrix
J1=zeros(nb-1,nb-1);
J2=zeros(nb-1,nb-1);
J3=zeros(nb-1,nb-1);
J4=zeros(nb-1,nb-1);
J=ones(2*(nb-1),2*(nb-1));

%evaluating J1 = d(Pi)/d(deli)
for n=1:(nb-1)
    for m=1:(nb-1)
        if n<slb
            if n == m
             for k=1:(nb-1)
                 if k~=n
                     if k<slb
                         J1(n,m)=J1(n,m)+(abs(v(n))*abs(v(k))*abs(Ybus(n,k))*sin(teeta(n,k)-
del(n)+del(k)));
                     else  J1(n,m)=J1(n,m)+(abs(v(n))*abs(v(k+1))*abs(Ybus(n,k+1))*sin(teeta(n,k+1)-
del(n)+del(k+1)));
                     end
                 end
             end
            elseif m<slb
                J1(n,m)=-(abs(v(n))*abs(v(m))*abs(Ybus(n,m))*sin(teeta(n,m)-del(n)+del(m)));
```

```
        else  J1(n,m)=-(abs(v(n))*abs(v(m+1))*abs(Ybus(n,m+1))*sin(teeta(n,m+1)-
del(n)+del(m+1)));
        end
    else
        if n == m
         for k=1:(nb-1)
            if k~=n
                if k<slb
                    J1(n,m)=J1(n,m)+(abs(v(n+1))*abs(v(k))*abs(Ybus(n+1,k))*sin(teeta(n+1,k)-
del(n+1)+del(k)));
                else
J1(n,m)=J1(n,m)+(abs(v(n+1))*abs(v(k+1))*abs(Ybus(n+1,k+1))*sin(teeta(n+1,k+1)-
del(n+1)+del(k+1)));
                end
            end
         end
                  elseif m<slb
           J1(n,m)=-(abs(v(n+1))*abs(v(m))*abs(Ybus(n+1,m))*sin(teeta(n+1,m)-
del(n+1)+del(m)));
        else J1(n,m)=-(abs(v(n+1))*abs(v(m+1))*abs(Ybus(n+1,m+1))*sin(teeta(n+1,m+1)-
del(n+1)+del(m+1)));
        end
    end

   end
end
%evaluating J2 = d(Pi)/d(Vi)
for n=1:nb-1
   for m=1:nb-1
      if n<slb
        if n == m
           J2(n,m)= 2*abs(v(n))*abs(Ybus(n,n))*cos(teeta(n,n));
         for k=1:nb-1
            if k~=n
                if k<slb
                    J2(n,m)=J2(n,m)+(abs(v(k))*abs(Ybus(n,k))*cos(teeta(n,k)-del(n)+del(k)));
                else J2(n,m)=J2(n,m)+(abs(v(k+1))*abs(Ybus(n,k+1))*cos(teeta(n,k+1)-
del(n)+del(k+1)));
                end
            end
         end
        elseif m<slb
            J2(n,m)=(abs(v(n))*abs(Ybus(n,m))*cos(teeta(n,m)-del(n)+del(m)));
        else J2(n,m)=(abs(v(n))*abs(Ybus(n,m+1))*cos(teeta(n,m+1)-del(n)+del(m+1)));
        end
    else
```

```
            if n == m
               J2(n,m)= 2*abs(v(n+1))*abs(Ybus(n+1,n+1))*cos(teeta(n+1,n+1));
            for k=1:(nb-1)
               if k~=n
                  if k<slb
                     J2(n,m)=J2(n,m)+(abs(v(k))*abs(Ybus(n,k))*cos(teeta(n+1,k)-del(n+1)+del(k)));
                  else  J2(n,m)=J2(n,m)+(abs(v(k+1))*abs(Ybus(n,k+1))*cos(teeta(n+1,k+1)-
del(n+1)+del(k+1)));
                  end
               end
            end
         elseif m<slb
               J2(n,m)=(abs(v(n+1))*abs(Ybus(n+1,m))*cos(teeta(n+1,m)-del(n+1)+del(m)));
         else J2(n,m)=(abs(v(n+1))*abs(Ybus(n+1,m+1))*cos(teeta(n+1,m+1)-
del(n+1)+del(m+1)));
                  end
      end
   end
end
%evaluating J3 = d(Qi)/d(deli)
for n=1:(nb-1)
   for m=1:(nb-1)
      if n<slb
         if n == m
            for k=1:(nb-1)
               if k~=n
                  if k<slb
                     J3(n,m)=J3(n,m)+(abs(v(n))*abs(v(k))*abs(Ybus(n,k))*cos(teeta(n,k)-
del(n)+del(k)));
                  else J3(n,m)=J3(n,m)+(abs(v(n))*abs(v(k+1))*abs(Ybus(n,k+1))*cos(teeta(n,k+1)-
del(n)+del(k+1)));
                  end
               end
            end
         elseif m<slb
               J3(n,m)=-(abs(v(n))*abs(v(m))*abs(Ybus(n,m))*cos(teeta(n,m)-del(n)+del(m)));
               J3(n,m)=-(abs(v(n))*abs(v(m+1))*abs(Ybus(n,m+1))*cos(teeta(n,m+1)-
del(n)+del(m+1)));
         end
      else
         if n == m
            for k=1:(nb-1)
               if k~=n
                  if k<slb
                     J3(n,m)=J3(n,m)+(abs(v(n+1))*abs(v(k))*abs(Ybus(n+1,k))*cos(teeta(n+1,k)-
del(n+1)+del(k)));
```

```
                else
J3(n,m)=J3(n,m)+(abs(v(n+1))*abs(v(k+1))*abs(Ybus(n+1,k+1))*cos(teeta(n+1,k+1)-
del(n+1)+del(k+1)));
                end
             end
          end
         elseif  m<slb
            J3(n,m)=-(abs(v(n+1))*abs(v(m))*abs(Ybus(n+1,m))*cos(teeta(n+1,m)-
del(n+1)+del(m)));
         else J3(n,m)=-(abs(v(n+1))*abs(v(m+1))*abs(Ybus(n+1,m+1))*cos(teeta(n+1,m+1)-
del(n+1)+del(m+1)));
         end
      end
   end
end
%evaluating J4 = d(Qi)/d(Vi)
for n=1:nb-1
   for m=1:nb-1
      if n<slb
         if n == m
           J4(n,m)= -2*abs(v(n))*abs(Ybus(n,n))*sin(teeta(n,n));
          for k=1:nb-1
             if k~=n
                if k<slb
                   J4(n,m)=J4(n,m)-(abs(v(k))*abs(Ybus(n,k))*sin(teeta(n,k)-del(n)+del(k)));
                else J4(n,m)=J4(n,m)-(abs(v(k+1))*abs(Ybus(n,k+1))*sin(teeta(n,k+1)-
del(n)+del(k+1)));
                end
             end
          end
         elseif m<slb
            J4(n,m)=-(abs(v(n))*abs(Ybus(n,m))*sin(teeta(n,m)-del(n)+del(m)));
         else J4(n,m)=-(abs(v(n))*abs(Ybus(n,m+1))*sin(teeta(n,m+1)-del(n)+del(m+1)));
         end
      else
         if n == m
            J4(n,m)= -2*abs(v(n+1))*abs(Ybus(n+1,n+1))*sin(teeta(n+1,n+1));
          for k=1:(nb-1)
             if k~=n
                if k<slb
                   J4(n,m)=J4(n,m)-(abs(v(k))*abs(Ybus(n,k))*sin(teeta(n+1,k)-del(n+1)+del(k)));
                else  J4(n,m)=J4(n,m)-(abs(v(k+1))*abs(Ybus(n,k+1))*sin(teeta(n+1,k+1)-
del(n+1)+del(k+1)));
                end
             end
          end
```

```
          elseif m<slb
             J4(n,m)=-(abs(v(n+1))*abs(Ybus(n+1,m))*cos(teeta(n+1,m)-del(n+1)+del(m)));
          else J4(n,m)=-(abs(v(n+1))*abs(Ybus(n+1,m+1))*cos(teeta(n+1,m+1)-
del(n+1)+del(m+1)));
          end
       end
   end
end
J=[J1 J2;J3 J4];
DP_DQ=[delP_fj;delQ_fj]; % Updating change in P & Q
Ddel_Dv=J\DP_DQ;     % Updating change in del & v

% Updating del and v.
for k=1:2*nb
   if k<slb
      del(k)=del(k)+Ddel_Dv(k);
   elseif k==slb
             del(k)=del(k);
   elseif k<nb+1
      del(k)=del(k)+Ddel_Dv(k-1);
   elseif k<(nb+slb)
      v(k-nb)=v(k-nb)+Ddel_Dv(k-1);
   elseif k==(nb+slb)
      v(k-nb)=v(k-nb);
   else v(k-nb)=v(k-nb)+Ddel_Dv(k-2);
   end
end
iter=iter+1;
end
BN=[1:nb]';  %Bus numbers
   C_R=[BN P Q v del];  %Concatation of results for display
   disp('      bus     P        Q        V        Del');
   disp(C_R);
```

B2. MATLAB CODE – GENERATOR RESCHEDULING

```
% This programme evaluates the change in Generator output in a system of any No. of buses


% formation of Y bus
j=sqrt(-1);
nl = linedata(:,1); nr = linedata(:,2); R = linedata(:,3);
X = linedata(:,4); Bc = j*linedata(:,5); a = linedata(:, 6);
nbr=length(linedata(:,1)); nbus = max(max(nl), max(nr));
Z = R + j*X; y= ones(nbr,1)./Z;       %branch admittance
for n = 1:nbr
if a(n) <= 0  a(n) = 1; else end
Ybus=zeros(nbus,nbus);     % initialize Ybus to zero
% formation of the off diagonal elements
for k=1:nbr;
       Ybus(nl(k),nr(k))=Ybus(nl(k),nr(k))-y(k)/a(k);
       Ybus(nr(k),nl(k))=Ybus(nl(k),nr(k));
    end
end
% formation of the diagonal elements
for  n=1:nbus
     for k=1:nbr
         if nl(k)==n
         Ybus(n,n) = Ybus(n,n)+y(k)/(a(k)^2) + Bc(k);
         elseif nr(k)==n
         Ybus(n,n) = Ybus(n,n)+y(k) +Bc(k);
         else, end
     end
end
  nn1=length(gencost(:,1));
  for ii=1:nn1-1
      if x(ii)>1
          x(ii)=1;
      else
      end
     y1(ii)=gencost(ii+1,5)+x(ii)*(gencost(ii+1,6)-gencost(ii+1,5));
```

```
  end

       for i=1:nn1-1;
      xx=gencost(i+1,1);
      busdata(xx,7)=y1(i);
    end
basemva = 100;  accuracy = 0.002; maxiter =5;
ns=0; ng=0; Vm=0; delta=0; yload=0; deltad=0;
nbus = length(busdata(:,1));
for k=1:nbus
n=busdata(k,1);
kb(n)=busdata(k,2); Vm(n)=busdata(k,3); delta(n)=busdata(k, 4);
Pd(n)=busdata(k,5); Qd(n)=busdata(k,6); Pg(n)=busdata(k,7); Qg(n) = busdata(k,8);
Qmin(n)=busdata(k, 9); Qmax(n)=busdata(k, 10);
Qsh(n)=busdata(k, 11);
    if Vm(n) <= 0  Vm(n) = 1.0; V(n) = 1 + j*0;
    else delta(n) = pi/180*delta(n);
         V(n) = Vm(n)*(cos(delta(n)) + j*sin(delta(n)));
         P(n)=(Pg(n)-Pd(n))/basemva;
         Q(n)=(Qg(n)-Qd(n)+ Qsh(n))/basemva;
         S(n) = P(n) + j*Q(n);
    end
end
for k=1:nbus
if kb(k) == 1, ns = ns+1; else, end
if kb(k) == 2 ng = ng+1; else, end
ngs(k) = ng;
nss(k) = ns;
end
Ym=abs(Ybus); t = angle(Ybus);
m=2*nbus-ng-2*ns;
maxerror = 1; converge=1;
iter = 0;
% Start of iterations
clear A  DC   J  DX
while maxerror >= accuracy & iter <= maxiter % Test for max. power mismatch
for i=1:m
for k=1:m
   A(i,k)=0;      %Initializing Jacobian matrix
end, end
iter = iter+1;
for n=1:nbus
nn=n-nss(n);
lm=nbus+n-ngs(n)-nss(n)-ns;
J11=0; J22=0; J33=0; J44=0;
   for i=1:nbr
```

```
  if nl(i) == n | nr(i) == n
    if nl(i) == n,  l = nr(i); end
    if nr(i) == n,  l = nl(i); end
    J11=J11+ Vm(n)*Vm(l)*Ym(n,l)*sin(t(n,l)- delta(n) + delta(l));
    J33=J33+ Vm(n)*Vm(l)*Ym(n,l)*cos(t(n,l)- delta(n) + delta(l));
    if kb(n)~=1
    J22=J22+ Vm(l)*Ym(n,l)*cos(t(n,l)- delta(n) + delta(l));
    J44=J44+ Vm(l)*Ym(n,l)*sin(t(n,l)- delta(n) + delta(l));
    else, end
    if kb(n) ~= 1  & kb(l) ~=1
    lk = nbus+l-ngs(l)-nss(l)-ns;
    ll = l -nss(l);
   % off diagonal elements of J1
    A(nn, ll) =-Vm(n)*Vm(l)*Ym(n,l)*sin(t(n,l)- delta(n) + delta(l));
          if kb(l) == 0  % off diagonal elements of J2
          A(nn, lk) =Vm(n)*Ym(n,l)*cos(t(n,l)- delta(n) + delta(l));end
          if kb(n) == 0  % off diagonal elements of J3
          A(lm, ll) =-Vm(n)*Vm(l)*Ym(n,l)*cos(t(n,l)- delta(n)+delta(l)); end
          if kb(n) == 0 & kb(l) == 0  % off diagonal elements of  J4
          A(lm, lk) =-Vm(n)*Ym(n,l)*sin(t(n,l)- delta(n) + delta(l));end
    else end
  else , end
end
Pk = Vm(n)^2*Ym(n,n)*cos(t(n,n))+J33;
Qk = -Vm(n)^2*Ym(n,n)*sin(t(n,n))-J11;
if kb(n) == 1 P(n)=Pk; Q(n) = Qk; end   % Swing bus P
  if kb(n) == 2  Q(n)=Qk;
      if Qmax(n) ~= 0
        Qgc = Q(n)*basemva + Qd(n) - Qsh(n);
        if iter <= 7                  % Between the 2th & 6th iterations
          if iter > 2                % the Mvar of generator buses are
            if Qgc  < Qmin(n),       % tested. If not within limits Vm(n)
            Vm(n) = Vm(n) + 0.01;    % is changed in steps of 0.01 pu to
            elseif Qgc  > Qmax(n),   % bring the generator Mvar within
            Vm(n) = Vm(n) - 0.01;end % the specified limits.
          else, end
        else,end
      else,end
  end
if kb(n) ~= 1
  A(nn,nn) = J11;  %diagonal elements of J1
  DC(nn) = P(n)-Pk;
end
if kb(n) == 0
  A(nn,lm) = 2*Vm(n)*Ym(n,n)*cos(t(n,n))+J22;  %diagonal elements of J2
  A(lm,nn)= J33;       %diagonal elements of J3
```

```
     A(lm,lm) =-2*Vm(n)*Ym(n,n)*sin(t(n,n))-J44;  %diagonal of elements of J4
     DC(lm) = Q(n)-Qk;
   end
end
DX=A\DC';
for n=1:nbus
  nn=n-nss(n);
  lm=nbus+n-ngs(n)-nss(n)-ns;
    if kb(n) ~= 1
    delta(n) = delta(n)+DX(nn); end
    if kb(n) == 0
    Vm(n)=Vm(n)+DX(lm); end
 end
  maxerror=max(abs(DC));
end
V = Vm.*cos(delta)+j*Vm.*sin(delta);
deltad=180/pi*delta;
i=sqrt(-1);
k=0;
for n = 1:nbus
     if kb(n) == 1
     k=k+1;
     S(n)= P(n)+j*Q(n);
     Pg(n) = P(n)*basemva + Pd(n);
     Qg(n) = Q(n)*basemva + Qd(n) - Qsh(n);
     Pgg(k)=Pg(n);
     Qgg(k)=Qg(n);
     elseif  kb(n) ==2
     k=k+1;
     S(n)=P(n)+j*Q(n);
     Qg(n) = Q(n)*basemva + Qd(n) - Qsh(n);
     Pgg(k)=Pg(n);
     Qgg(k)=Qg(n);
  end
yload(n) = (Pd(n)- j*Qd(n)+j*Qsh(n))/(basemva*Vm(n)^2);
end
busdata(:,3)=Vm'; busdata(:,4)=deltad';
Pgt = sum(Pg);  Qgt = sum(Qg); Pdt = sum(Pd); Qdt = sum(Qd); Qsht = sum(Qsh);
if Pgg(1)>gencost(1,6);
    Pgg(1)=gencost(1,6);
else
end
% Pdt=283.4;
 TL=basemva*sum(P);
 Pgg=abs(Pgg);
 lam=100*abs(sum(Pgg)-TL-Pdt);
```

```
P1=Pgg;
a1=gencost(:,2);
b1=gencost(:,3);
c1=gencost(:,4);
 F1=(Pgg.*Pgg)*a1+Pgg*b1+sum(c1)+lam;
   vv=abs(V);
```

B3. MATLAB CODE – Static Var Compensator

```
% This function computes the shunt capacitor compensation required
% for a specified receiving-end voltage.



function shntcomp(ABCD)
global resp model par1 par2 linelngt freq
diary off
if exist('ABCD')~=1
A = input('Enter the complex line constant A = ');
B = input('Enter the complex line constant B = ');
C = input('Enter the complex line constant C = ');
D = A; ABCD=[A B; C D]; end
Vsm = input('Enter sending end line-line voltage kV = ');
Vrm = input('Enter desired receiving end line-line voltage kV = ');
dr = input('Enter receiving end voltage phase angleø (for Ref. enter 0 ) = ');
drrad=dr*pi/180;
Vr = Vrm*(cos(drrad) +j*sin(drrad))/sqrt(3);   % Rec.-end phase voltage
Pr = input('Enter receiving end 3-phase real power MW = ');
%r = input('Enter receiving end 3-phase reactive power (+ for lagging & - for leading  power
factor ) Mvar = ');
fprintf(' Enter receiving end 3-phase reactive power')
Qload = input('(+ for lagging & - for leading power factor) Mvar = ');
Sload = Pr +j*Qload;
ba = angle( ABCD(1,2) )- angle(ABCD(1,1));
S1 = Vsm*Vrm/abs(ABCD(1,2)); S2 = abs(ABCD(1,1))*Vrm^2/abs(ABCD(1,2));
bd = acos( (Pr + S2*cos(ba))/S1 );
Qr = S1*sin(bd) - S2*sin(ba);
Qc = Qr - Qload;
Sr = Pr + j*Qr;
Xc = Vrm^2/abs(Qc); Cap = 1000000/(2*pi*60*Xc)
Ir = conj(Sr)/(3*conj(Vr));  % Rec. end current  kA
Irm = abs(Ir)*1000;
angIr = angle(Ir); pfr = cos(drrad - angIr); angIr = angIr*180/pi;
Iload = conj(Sload)/(3*conj(Vr));  % Rec. end current  kA
```

```
Iloadm = abs(Iload)*1000;
angIl = angle(Iload); pfl = cos(drrad - angIl); angIl = angIl*180/pi;
Ic = Ir - Iload;
Icm = abs(Ic)*1000;
angIc= angle(Ic)*180/pi;
VsIs = ABCD*[Vr; Ir];
Vs = VsIs(1);  Is = VsIs(2);
Vsm = abs(Vs)*sqrt(3);
ds = angle(Vs); dsdg = ds*180/pi;
Ism = abs(Is)*1000;
angIs = angle(Is); pfs = cos(ds - angIs ); angIs = angIs*180/pi;
Ss = 3*Vs*conj(Is);  Ps = real(Ss); Qs = imag(Ss);
Sl = Ss - Sr;  Pl = real(Sl); Ql = imag(Sl);
Reg = 100*(Vsm/abs(ABCD(1,1)) - Vrm)/Vrm;
Eff = Pr/Ps*100;
clc
fprintf(' \n')
fprintf(' Shunt capacitive compensation \n')
fprintf(' ----------------------------- \n')
fprintf(' Vs = %g kV (L-L)', Vsm), fprintf('  at %gø \n', dsdg)
fprintf(' Vr = %g kV (L-L)', Vrm), fprintf('  at %gø \n', dr)
fprintf(' Pload = %g MW', Pr), fprintf('   Qload = %g Mvar \n', Qload)
fprintf(' Load current = %g A', Iloadm), fprintf('  at %gø', angIl), fprintf('  PFl = %g', pfl)
if Qload > 0, fprintf(' lagging \n'),elseif Qload < 0 fprintf(' leading \n'), end
fprintf(' Required shunt capcitor: %g ohm,', Xc)
fprintf('  %g micro F,',Cap), fprintf('  %g Mvar \n', abs(Qc))
fprintf(' Shunt capacitor current = %g A', Icm), fprintf('  at %gø \n', angIc)
fprintf(' Pr = %-10.3f MW', Pr), fprintf('   Qr = %-10.3f Mvar \n', Qr)
fprintf(' Ir = %g A', Irm), fprintf('  at %gø', angIr), fprintf('  PFr = %g', pfr)
if abs(Qr) >0.01 & Qr > 0, fprintf(' lagging '),end
if abs(Qr) >0.01 & Qr < 0, fprintf(' leading '),end
fprintf(' \n')
fprintf(' Is = %g A', Ism), fprintf('  at %gø', angIs), fprintf('  PFs = %g', pfs)
if abs(Qs) >0.01 & Qs > 0, fprintf(' lagging '),end
if abs(Qs) >0.01 & Qs < 0, fprintf(' leading '),end
fprintf(' \n')
fprintf(' Ps = %-10.3f MW', Ps), fprintf('   Qs = %-10.3f Mvar \n', Qs)
fprintf(' PL = %-10.3f MW', Pl), fprintf('   QL = %-10.3f Mvar \n', Ql)
fprintf(' Percent Voltage Regulation   = %g \n', Reg)
fprintf(' Transmission line efficiency = %g \n', Eff)
fprintf(' \n Hit return to continue \n')
pause
```

B4. MATLAB CODE – Thyristor Controlled Series Compensator

```
% This function determines the line performance for a given
% series capacitor compensation.


function sercomp(ABCD)
global resp model par1 par2 linelngt freq
if exist('ABCD')~=1
A = input('Enter the complex line constant A = ');
B = input('Enter the complex line constant B = ');
C = input('Enter the complex line constant C = ');
D = A; ABCD=[A B; C D]; end
if exist('freq')~=1
f = input('Enter frequency in Hz = '); else, f = freq; end
Z = ABCD(1,2); Y = 2*ABCD(2,1)/(ABCD(1,1)+1);
Vrm = input('Enter receiving end line-line voltage kV = ');
dr = input('Enter receiving end voltage phase angleø (for Ref. enter 0 ) = ');
drrad=dr*pi/180;
Vr = Vrm*(cos(drrad) +j*sin(drrad))/sqrt(3);   % Rec.-end phase voltage
Pr = input('Enter receiving end 3-phase real power MW = ');

fprintf(' Enter receiving end 3-phase reactive power')
Qr = input('(+ for lagging & - for leading power factor) Mvar = ');

fprintf(' Enter percent compensation for series capacitor')
kc= input('(recommnded range 25 to 75% of the line reactance) = ');
Xc = -j*kc*imag(Z)/100;  caps = 1000000/(2*pi*60*abs(Xc));
Z2 = Z + Xc;
ssrf=f*sqrt(abs(Xc)/imag(Z));
ABCDnu = [1+Z2*Y/2  Z2; Y*(1+Z2*Y/4) 1+Z2*Y/2];
Sr = Pr +j*Qr;
Ir = conj(Sr)/(3*conj(Vr));  % Rec. end current  kA
Irm = abs(Ir)*1000;
angIr = angle(Ir); pfr = cos(drrad - angIr); angIr = angIr*180/pi;
VsIs = ABCDnu*[Vr; Ir];
Vs = VsIs(1);  Is = VsIs(2);
Vsm = abs(Vs)*sqrt(3);
ds = angle(Vs); dsdg = ds*180/pi;
```

```
Ism = abs(Is)*1000;
angIs = angle(Is); pfs = cos(ds - angIs ); angIs = angIs*180/pi;
Ss = 3*Vs*conj(Is);  Ps = real(Ss); Qs = imag(Ss);
Sl = Ss - Sr;  Pl = real(Sl); Ql = imag(Sl);
Iline = Ir + Y/2*Vr;
Qcap =  abs(Xc)*(abs(Iline))^2;
Reg = 100*(Vsm/abs(ABCDnu(1,1)) - Vrm)/Vrm;
Eff = Pr/Ps*100;
clc
fprintf(' \n')
fprintf(' Series capacitor compensation \n')
fprintf(' ---------------------------- \n')
fprintf(' Vr = %g kV (L-L)', Vrm), fprintf('  at %gø \n', dr)
fprintf(' Pr = %g MW', Pr), fprintf('   Qr = %g Mvar \n', Qr)
fprintf(' Required series capacitor:  %g ohm,', abs(Xc))
fprintf('   %g micro F,', caps), fprintf('   %g Mvar \n', Qcap)
fprintf(' Subsynchronous resonant frequency = %g Hz \n', ssrf)
fprintf(' Ir = %g A', Irm), fprintf('  at %gø', angIr), fprintf('  PFr = %g', pfr)
if abs(Qr) >0.01 & Qr > 0, fprintf(' lagging '),end
if abs(Qr) >0.01 & Qr < 0, fprintf(' leading '),end
fprintf(' \n')
fprintf(' Vs = %g kV (L-L)', Vsm), fprintf('  at %gø \n', dsdg)
fprintf(' Is = %g A', Ism), fprintf('  at %gø', angIs), fprintf('  PFs = %g', pfs)
if abs(Qs) >0.01 & Qs > 0, fprintf(' lagging '),end
if abs(Qs) >0.01 & Qs < 0, fprintf(' leading '),end
fprintf(' \n')
fprintf(' Ps = %-10.3f MW', Ps), fprintf('   Qs = %-10.3f Mvar \n', Qs)
fprintf(' PL = %-10.3f MW', Pl), fprintf('   QL = %-10.3f Mvar \n', Ql)
fprintf(' Percent Voltage Regulation   = %g \n', Reg)
fprintf(' Transmission line efficiency = %g \n', Eff)
fprintf(' \n Hit return to continue \n')
pause
```

APPENDICE C

POWER FLOW REPORT

C1: BASE CASE

POWER FLOW REPORT

P S A T 2.1.9

NETWORK STATISTICS

Buses:	41
Lines:	63
Generators:	14
Loads:	27

SOLUTION STATISTICS

Number of Iterations:	6
Maximum P mismatch [MW]	5.52E-08
Maximum Q mismatch [MVar]	1.65E-08

POWER FLOW RESULTS

Bus	V	phase	P gen	Q gen	P load	Q load
	[kV]	[rad]	[MW]	[MVar]	[MW]	[MVar]
Bus1	293.2536	0.401615	4.44E-14	2.22E-14	162	122
Bus10	328.4145	0.478112	-1.4E-12	4.97E-12	100	75

Bus11	312.4498	0.55023	3.37E-09	1.2E-10	142	107
Bus12	305.3221	0.555346	-8.4E-13	6.66E-13	303	227
Bus13	307.8621	0.578315	2.66E-13	1.27E-12	220	165
Bus14	317.13	0.242507	366	83.29847	0	0
Bus15	308.424	0.032671	1.33E-13	1.07E-12	203	152
Bus16	340.23	0	-1149.7	1852.372	0	0
Bus17	330	0.564134	300	145.3292	0	0
Bus18	317.2985	0.030322	1.28E-11	4.41E-12	120	90
Bus19	319.9261	0.824383	1.56E-10	5.01E-10	144	108
Bus2	330	0.559507	420	-197.973	0	0
Bus20	303.0402	0.543645	5.06E-11	2.76E-11	194	146
Bus21	273.7928	0.621801	-1.6E-08	1.04E-09	72	54
Bus22	310.7698	0.677233	6.22E-13	-5E-13	120	90
Bus23	338.9084	-0.00406	3.11E-13	2.04E-12	115	86
Bus24	318.6193	1.144462	2.74E-10	4.7E-10	100	75
Bus25	315.8683	0.744575	6.28E-12	1.65E-12	120	90
Bus26	333.96	0.953045	780	147.0594	0	0
Bus27	333.96	0.928072	550	271.6954	0	0
Bus28	270.7863	0.853309	1.86E-10	3.92E-10	160	120
Bus29	234.007	0.327583	-5.5E-08	1.65E-08	82.49719	45.56988
Bus3	337.4519	0.526482	-1.2E-11	4.63E-11	260	195
Bus30	284.017	1.076341	5.3E-10	1.32E-10	196	147
Bus31	333.96	1.179076	430	452.1409	0	0
Bus32	330	1.461973	440	280.6242	0	0
Bus33	330	0.85461	400	145.5965	0	0
Bus34	330.8982	0.935495	-3.1E-13	1.2E-12	210	158
Bus35	282.299	1.07542	1.47E-10	2.33E-10	175	131
Bus36	226.5181	0.269809	4.34E-08	3.58E-09	73.6204	40.49122
Bus37	228.0054	0.269538	3.75E-08	1.96E-09	70.86076	32.81972
Bus38	330.99	1.491862	680	139.7099	0	0
Bus39	318.783	1.440183	4.58E-11	2.01E-11	165	127
Bus4	339.9	0.531241	480	569.6151	0	0
Bus40	324.8986	1.530246	2.65E-12	6.08E-12	90	68
Bus41	328.02	1.557449	560	130.451	0	0
Bus5	330	0.58469	550	435.9399	0	0
Bus6	322.8285	0.441018	-1.7E-11	6.98E-11	127	95
Bus7	311.684	0.30532	1.25E-11	2.13E-11	174	131
Bus8	311.7645	0.043703	4.87E-11	9.49E-11	847	635
Bus9	330	0.758873	400	17.26171	0	0

LINE FLOWS

From Bus	To Bus	Line	P Flow	Q Flow	S Flow	P Loss	Q Loss
			[MW]	[MVar]	[MVA]	[MW]	[MVar]

Bus2	Bus3	1	126.5505	-124.311	177.3932	0.886735	-25.0386
Bus1	Bus2	2	-162	-122	202.8004	4.898956	-71.3507
Bus5	Bus12	3	81.41753	134.6191	157.3249	1.698601	-38.0557
Bus6	Bus10	4	-141.869	-59.8084	153.9601	0.715468	-27.1715
Bus3	Bus6	5	189.3163	48.61759	195.4593	2.259665	-42.5549
Bus3	Bus6	6	189.3163	48.61759	195.4593	2.259665	-42.5549
Bus8	Bus6	7	-460.23	63.50688	464.5907	22.04291	99.30884
Bus6	Bus7	8	367.4867	54.28455	371.4744	6.035333	9.541692
Bus10	Bus3	9	-242.584	-107.637	265.3916	1.712041	-13.4331
Bus8	Bus14	10	-539.141	52.66063	541.7071	12.77338	70.8628
Bus7	Bus14	11	187.4513	-86.2571	206.3451	1.536499	-21.1608
Bus21	Bus11	12	73.43792	-199.717	212.7912	3.981322	-31.0724
Bus8	Bus15	13	203.5155	151.4621	253.6914	0.515492	-0.53792
Bus16	Bus8	14	-164.103	501.5299	527.6949	6.630384	30.31292
Bus23	Bus16	15	-115	-86	143.6001	0.105701	-3.44035
Bus16	Bus19	16	-904.161	586.0641	1077.487	113.6619	756.7174
Bus8	Bus18	17	324.356	-543.444	632.8807	1.647855	10.31297
Bus18	Bus16	18	202.7082	-643.757	674.9174	6.168062	38.4611
Bus8	Bus17	19	-546.233	112.0312	557.6038	39.97062	197.4793
Bus17	Bus19	20	-286.204	59.88113	292.4013	10.45381	-27.0993
Bus4	Bus3	21	240	284.8075	372.4451	0.377832	-0.1041
Bus25	Bus19	22	-128.115	-33.0758	132.3159	1.37324	-60.2023
Bus19	Bus24	23	-698.063	190.0837	723.4804	30.6805	171.7816
Bus25	Bus19	24	-130.867	-32.6636	134.8822	1.433	-59.984
Bus33	Bus25	25	200	72.79824	212.837	1.967513	22.72986
Bus33	Bus25	26	200	72.79824	212.837	1.967513	22.72986
Bus19	Bus27	27	-706.937	-158.238	724.43	10.9151	63.43469
Bus27	Bus26	28	-134.714	7.336468	134.9138	0.448062	-21.2095
Bus2	Bus3	29	126.5505	-124.311	177.3932	0.886735	-25.0386
Bus19	Bus26	30	-394.477	-75.4002	401.6187	6.445499	13.54892
Bus24	Bus30	31	243.3674	313.9563	397.2358	6.836886	20.47083
Bus31	Bus24	32	215	226.0704	311.9821	2.139774	-4.6809
Bus24	Bus31	33	-212.86	-230.751	313.9358	2.139774	-4.6809
Bus24	Bus32	34	-646.391	90.84851	652.7436	28.04398	152.9539
Bus32	Bus38	35	-403.076	14.5558	403.3383	1.599835	3.005998
Bus30	Bus35	36	40.53048	146.4855	151.9892	0.109833	-1.85633
Bus25	Bus22	37	535.0476	75.87616	540.4009	4.354246	23.50599
Bus4	Bus3	38	240	284.8075	372.4451	0.377832	-0.1041
Bus9	Bus19	39	-78.3116	5.36019	78.49479	0.896487	-88.3115
Bus34	Bus27	40	33.23729	-66.2924	74.15793	0.099618	-23.6059
Bus34	Bus26	41	-243.237	-91.7076	259.9513	0.67762	-5.05137
Bus36	Bus29	42	-73.6204	-40.4912	84.02084	0.620399	-19.9757
Bus11	Bus20	43	199.2858	72.38145	212.0234	5.285835	-73.6186

Bus29	Bus21	44	-228.152	-77.2349	240.8708	9.734361	23.43165
Bus29	Bus37	45	71.41438	11.14946	72.27949	0.55362	-21.6703
Bus13	Bus22	46	-202.977	-9.3467	203.1917	2.370077	-28.1616
Bus3	Bus5	47	-76.1783	-7.58055	76.55456	0.623386	-93.1055
Bus13	Bus22	48	-202.977	-9.3467	203.1917	2.370077	-28.1616
Bus5	Bus13	49	39.50869	167.1345	171.7407	1.524204	-28.9092
Bus12	Bus13	50	-223.281	-54.3252	229.7948	0.65658	-4.58812
Bus35	Bus28	51	285.178	25.20302	286.2895	7.443044	12.86377
Bus21	Bus28	52	-191.662	22.52534	192.9814	6.072587	-25.1354
Bus21	Bus28	53	-191.662	22.52534	192.9814	6.072587	-25.1354
Bus35	Bus28	54	285.178	25.20302	286.2895	7.443044	12.86377
Bus39	Bus35	55	738.3634	272.4869	787.0385	33.42815	239.4227
Bus3	Bus5	56	-76.1783	-7.58055	76.55456	0.623386	-93.1055
Bus39	Bus40	57	-463.027	-32.2807	464.151	5.037298	19.94002
Bus6	Bus9	58	-460.778	57.06681	464.298	17.53395	68.96833
Bus39	Bus32	59	-167.362	-211.415	269.6413	1.2786	-7.45182
Bus39	Bus38	60	-272.974	-155.791	314.3018	2.350768	-4.53163
Bus11	Bus5	61	-135.915	-174.013	220.8016	1.820563	-21.3949
Bus40	Bus41	62	-558.064	-120.221	570.8668	1.93557	10.23032
Bus11	Bus5	63	-135.915	-174.013	220.8016	1.820563	-21.3949

LINE FLOWS

From Bus	To Bus	Line	P Flow [MW]	Q Flow [MVar]	P Loss [MW]	Q Loss [MVar]
Bus3	Bus2	1	-125.664	99.27273	0.886735	-25.0386
Bus2	Bus1	2	166.899	50.64929	4.898956	-71.3507
Bus12	Bus5	3	-79.7189	-172.675	1.698601	-38.0557
Bus10	Bus6	4	142.584	32.63687	0.715468	-27.1715
Bus6	Bus3	5	-187.057	-91.1725	2.259665	-42.5549
Bus6	Bus3	6	-187.057	-91.1725	2.259665	-42.5549
Bus6	Bus8	7	482.2727	35.80196	22.04291	99.30884
Bus7	Bus6	8	-361.451	-44.7429	6.035333	9.541692
Bus3	Bus10	9	244.296	94.20374	1.712041	-13.4331
Bus14	Bus8	10	551.9148	18.20217	12.77338	70.8628
Bus14	Bus7	11	-185.915	65.09631	1.536499	-21.1608
Bus11	Bus21	12	-69.4566	168.6448	3.981322	-31.0724
Bus15	Bus8	13	-203	-152	0.515492	-0.53792
Bus8	Bus16	14	170.7331	-471.217	6.630384	30.31292
Bus16	Bus23	15	115.1057	82.55965	0.105701	-3.44035
Bus19	Bus16	16	1017.822	170.6533	113.6619	756.7174
Bus18	Bus8	17	-322.708	553.7568	1.647855	10.31297
Bus16	Bus18	18	-196.54	682.2179	6.168062	38.4611
Bus17	Bus8	19	586.2041	85.4481	39.97062	197.4793

Bus19	Bus17	20	296.6579	-86.9804	10.45381	-27.0993
Bus3	Bus4	21	-239.622	-284.912	0.377832	-0.1041
Bus19	Bus25	22	129.4884	-27.1266	1.37324	-60.2023
Bus24	Bus19	23	728.7436	-18.3022	30.6805	171.7816
Bus19	Bus25	24	132.3005	-27.3204	1.433	-59.984
Bus25	Bus33	25	-198.032	-50.0684	1.967513	22.72986
Bus25	Bus33	26	-198.032	-50.0684	1.967513	22.72986
Bus27	Bus19	27	717.8519	221.6725	10.9151	63.43469
Bus26	Bus27	28	135.1622	-28.546	0.448062	-21.2095
Bus3	Bus2	29	-125.664	99.27273	0.886735	-25.0386
Bus26	Bus19	30	400.9228	88.94913	6.445499	13.54892
Bus30	Bus24	31	-236.53	-293.486	6.836886	20.47083
Bus24	Bus31	32	-212.86	-230.751	2.139774	-4.6809
Bus31	Bus24	33	215	226.0704	2.139774	-4.6809
Bus32	Bus24	34	674.4345	62.10537	28.04398	152.9539
Bus38	Bus32	35	404.6754	-11.5498	1.599835	3.005998
Bus35	Bus30	36	-40.4207	-148.342	0.109833	-1.85633
Bus22	Bus25	37	-530.693	-52.3702	4.354246	23.50599
Bus3	Bus4	38	-239.622	-284.912	0.377832	-0.1041
Bus19	Bus9	39	79.20805	-93.6717	0.896487	-88.3115
Bus27	Bus34	40	-33.1377	42.68649	0.099618	-23.6059
Bus26	Bus34	41	243.9149	86.65624	0.67762	-5.05137
Bus29	Bus36	42	74.2408	20.51552	0.620399	-19.9757
Bus20	Bus11	43	-194	-146	5.285835	-73.6186
Bus21	Bus29	44	237.8867	100.6665	9.734361	23.43165
Bus37	Bus29	45	-70.8608	-32.8197	0.55362	-21.6703
Bus22	Bus13	46	205.3467	-18.8149	2.370077	-28.1616
Bus5	Bus3	47	76.80171	-85.525	0.623386	-93.1055
Bus22	Bus13	48	205.3467	-18.8149	2.370077	-28.1616
Bus13	Bus5	49	-37.9845	-196.044	1.524204	-28.9092
Bus13	Bus12	50	223.9376	49.73706	0.65658	-4.58812
Bus28	Bus35	51	-277.735	-12.3393	7.443044	12.86377
Bus28	Bus21	52	197.7349	-47.6607	6.072587	-25.1354
Bus28	Bus21	53	197.7349	-47.6607	6.072587	-25.1354
Bus28	Bus35	54	-277.735	-12.3393	7.443044	12.86377
Bus35	Bus39	55	-704.935	-33.0642	33.42815	239.4227
Bus5	Bus3	56	76.80171	-85.525	0.623386	-93.1055
Bus40	Bus39	57	468.0644	52.22072	5.037298	19.94002
Bus9	Bus6	58	478.3116	11.90152	17.53395	68.96833
Bus32	Bus39	59	168.6411	203.9631	1.2786	-7.45182
Bus38	Bus39	60	275.3246	151.2597	2.350768	-4.53163
Bus5	Bus11	61	137.7352	152.6182	1.820563	-21.3949
Bus41	Bus40	62	560	130.451	1.93557	10.23032

Bus5	Bus11	63	137.7352	152.6182	1.820563	-21.3949

GLOBAL SUMMARY REPORT

TOTAL GENERATION	
REAL POWER [MW]	5206.302
REACTIVE POWER [MVar]	4473.12
TOTAL LOAD	
REAL POWER [MW]	4745.978
REACTIVE POWER [MVar]	3512.881
TOTAL LOSSES	
REAL POWER [MW]	460.324
REACTIVE POWER [MVar]	960.239

C2: GENERATOR RESCHEDULING

POWER FLOW REPORT

P S A T 2.1.9

NETWORK STATISTICS

Buses:	41
Lines:	63
Generators:	14
Loads:	27

SOLUTION STATISTICS

Number of Iterations:	5
Maximum P mismatch [MW]	1.59E-09
Maximum Q mismatch [MVar]	5.62E-10

POWER FLOW RESULTS

Bus	V	Phase	P gen	Q gen	P load	Q load
	[kV]	[rad]	[MW]	[MVar]	[MW]	[MVar]
Bus1	293.2536	-0.2719	-2.2E-14	1.11E-13	162	122
Bus10	332.8977	-0.1469	4.44E-13	7.11E-13	100	75
Bus11	316.4683	-0.2993	8.56E-11	1.22E-11	142	107
Bus12	308.8993	-0.2896	1.78E-13	-8.9E-14	303	227
Bus13	312.1428	-0.2750	6.22E-13	1.78E-12	220	165
Bus14	317.13	-0.0543	296	-68.2167	0	0
Bus15	314.6075	-0.0955	-1.3E-13	-5.9E-12	203	152
Bus16	340.23	0	1508.127	830.5189	0	0
Bus17	330	-0.1073	24	-80.5982	0	0
Bus18	321.9001	-0.0677	-4.9E-13	3.44E-13	120	90
Bus19	333.8093	-0.1451	9.1E-12	1.14E-11	144	108
Bus2	330	-0.1140	300	-200.678	0	0

Bus20	307.2164	-0.3059	3.29E-12	3.02E-12	194	146
Bus21	297.4608	-0.4185	-1.6E-09	1.61E-10	72	54
Bus22	318.0531	-0.2255	-2.4E-13	8.33E-13	120	90
Bus23	338.9084	-0.0041	-4.2E-13	-3.8E-12	115	86
Bus24	328.3519	-0.1139	1.82E-11	1.01E-11	100	75
Bus25	323.5701	-0.1853	-1.1E-13	1.78E-12	120	90
Bus26	333.96	-0.1503	115	68.95275	0	0
Bus27	333.96	-0.1483	58	11.58603	0	0
Bus28	302.0608	-0.3383	1.67E-11	2.6E-11	160	120
Bus29	254.2357	-0.7129	9.9E-10	1.18E-10	97.3766	53.78898
Bus3	338.0659	-0.1330	-6.1E-12	1.2E-11	260	195
Bus30	306.9843	-0.2238	2.17E-11	7.22E-12	196	147
Bus31	333.96	-0.0761	438	122.6279	0	0
Bus32	330	-0.0589	45	45.05463	0	0
Bus33	330	-0.1001	313	58.11483	0	0
Bus34	330.9199	-0.1600	-8E-13	-1.3E-12	210	158
Bus35	306.6314	-0.2299	1.78E-11	3.13E-12	175	131
Bus36	246.0995	-0.7705	9.81E-10	5.62E-10	86.89877	47.79432
Bus37	247.7153	-0.7708	3.98E-10	3.94E-10	83.6414	38.73917
Bus38	330.99	-0.0415	446	75.42918	0	0
Bus39	324.4247	-0.0812	4.62E-12	-4.5E-12	165	127
Bus4	339.9	-0.1277	506	409.0962	0	0
Bus40	326.4105	-0.0562	6.33E-13	5.92E-12	90	68
Bus41	328.02	-0.0456	223	70.83549	0	0
Bus5	330	-0.2248	584	303.0307	0	0
Bus6	331.3148	-0.1398	1.38E-12	4.77E-12	127	95
Bus7	316.9952	-0.1217	2.22E-13	1.47E-12	174	131
Bus8	317.88	-0.0849	5.33E-13	5.33E-12	847	635
Bus9	330	-0.1298	33	-116.038	0	0

LINE FLOWS

From Bus	To Bus	Line	P Flow [MW]	Q Flow [MVar]	S Flow [MVA]	P Loss [MW]	Q Loss [MVar]
Bus2	Bus3	1	66.55052	-125.663	142.198	0.527329	-27.8008
Bus1	Bus2	2	-162	-122	202.8004	4.898956	-71.3507
Bus5	Bus12	3	154.5312	104.7428	186.6841	2.129237	-34.9612
Bus6	Bus10	4	24.62589	-38.2518	45.4932	0.032374	-34.3058
Bus3	Bus6	5	19.79119	9.475038	21.9424	0.113898	-62.5228
Bus3	Bus6	6	19.79119	9.475038	21.9424	0.113898	-62.5228
Bus8	Bus6	7	63.46514	-102.415	120.4847	0.694412	-88.1593
Bus6	Bus7	8	-34.9539	106.7793	112.3548	0.73259	-37.3671
Bus10	Bus3	9	-75.4065	-78.946	109.1724	0.24388	-26.3167
Bus8	Bus14	10	-84.3356	-1.30173	84.3457	0.308857	-35.7589

Bus7	Bus14	11	-209.686	13.14643	210.0982	1.669048	-20.613
Bus21	Bus11	12	-183.662	-85.4982	202.5873	3.494407	-40.4079
Bus8	Bus15	13	203.4952	151.1328	253.4786	0.495221	-0.86723
Bus16	Bus8	14	503.9763	322.9004	598.5455	8.372523	43.06215
Bus23	Bus16	15	-115	-86	143.6001	0.105701	-3.44035
Bus16	Bus19	16	205.1695	-37.557	208.5787	3.926167	-72.694
Bus8	Bus18	17	-554.025	-306.894	633.3464	1.590623	9.701405
Bus18	Bus16	18	-675.616	-406.595	788.5279	8.25985	56.02077
Bus8	Bus17	19	20.00423	-95.6845	97.7532	0.288838	-102.898
Bus17	Bus19	20	43.71539	-73.3849	85.4188	0.249546	-108.389
Bus4	Bus3	21	253	204.5481	325.3443	0.288197	-0.86931
Bus25	Bus19	22	-74.676	-77.9954	107.9804	0.581568	-71.042
Bus19	Bus24	23	-70.6762	19.68578	73.3666	0.404684	-60.3739
Bus25	Bus19	24	-76.4045	-78.6693	109.6655	0.606877	-70.9495
Bus33	Bus25	25	156.5	29.05741	159.1747	1.099481	11.8287
Bus33	Bus25	26	156.5	29.05741	159.1747	1.099481	11.8287
Bus19	Bus27	27	21.52245	-15.6717	26.6236	0.009576	-19.3779
Bus27	Bus26	28	10.59166	-13.6874	17.3069	0.002759	-24.5587
Bus2	Bus3	29	66.55052	-125.663	142.198	0.527329	-27.8008
Bus19	Bus26	30	15.96175	-24.7477	29.4487	0.0099	-42.9132
Bus24	Bus30	31	383.8117	177.3751	422.816	7.073405	18.87409
Bus31	Bus24	32	219	61.31394	227.4212	1.109157	-14.1073
Bus24	Bus31	33	-217.891	-75.4212	230.5749	1.109157	-14.1073
Bus24	Bus32	34	-119.111	-21.473	121.031	0.871474	-53.1467
Bus32	Bus38	35	-236.032	-11.6793	236.3207	0.547868	-4.90629
Bus30	Bus35	36	180.7383	11.50103	181.1039	0.131299	-2.15939
Bus25	Bus22	37	341.8815	101.1221	356.523	1.820625	1.359823
Bus4	Bus3	38	253	204.5481	325.3443	0.288197	-0.86931
Bus9	Bus19	39	18.43266	-66.8505	69.3451	0.06495	-98.6493
Bus34	Bus27	40	-68.7652	-52.163	86.3112	0.156017	-23.1833
Bus34	Bus26	41	-141.235	-105.837	176.4901	0.305953	-7.84746
Bus36	Bus29	42	-86.8988	-47.7943	99.1751	0.732296	-23.5786
Bus11	Bus20	43	199.1195	70.137	211.1108	5.119482	-75.863
Bus29	Bus21	44	-269.303	-91.1651	284.3149	11.49008	27.65784
Bus29	Bus37	45	84.29487	13.16041	85.316	0.653472	-25.5788
Bus13	Bus22	46	-109.332	-49.0916	119.8473	0.698843	-44.2105
Bus3	Bus5	47	131.1186	-25.7349	133.6203	1.449435	-86.2015
Bus13	Bus22	48	-109.332	-49.0916	119.8473	0.698843	-44.2105
Bus5	Bus13	49	154.0803	119.5126	194.9974	1.784387	-27.2437
Bus12	Bus13	50	-150.598	-87.296	174.07	0.361034	-7.35642
Bus35	Bus28	51	167.6042	-18.5384	168.6263	2.121934	-43.2786
Bus21	Bus28	52	-84.5654	-43.6624	95.172	0.916924	-78.9222
Bus21	Bus28	53	-84.5654	-43.6624	95.172	0.916924	-78.9222

Bus35	Bus28	54	167.6042	-18.5384	168.6263	2.121934	-43.2786
Bus39	Bus35	55	335.9771	84.80807	346.5156	6.375736	4.545215
Bus3	Bus5	56	131.1186	-25.7349	133.6203	1.449435	-86.2015
Bus39	Bus40	57	-132.277	-26.2345	134.8532	0.400961	-19.9262
Bus6	Bus9	58	-14.5467	-33.7871	36.7855	0.020643	-82.975
Bus39	Bus32	59	-160.436	-101.819	190.0176	0.61373	-13.4111
Bus39	Bus38	60	-208.265	-83.7549	224.4751	1.155523	-15.0987
Bus11	Bus5	61	-264.138	-111.114	286.5573	3.225574	-11.2594
Bus40	Bus41	62	-222.678	-74.3083	234.7489	0.32235	-3.47284
Bus11	Bus5	63	-264.138	-111.114	286.5573	3.225574	-11.2594

LINE FLOWS

From Bus	To Bus	Line	P Flow [MW]	Q Flow [MVar]	P Loss [MW]	Q Loss [MVar]
Bus3	Bus2	1	-66.0232	97.86263	0.527329	-27.8008
Bus2	Bus1	2	166.899	50.64929	4.898956	-71.3507
Bus12	Bus5	3	-152.402	-139.704	2.129237	-34.9612
Bus10	Bus6	4	-24.5935	3.946006	0.032374	-34.3058
Bus6	Bus3	5	-19.6773	-71.9979	0.113898	-62.5228
Bus6	Bus3	6	-19.6773	-71.9979	0.113898	-62.5228
Bus6	Bus8	7	-62.7707	14.25532	0.694412	-88.1593
Bus7	Bus6	8	35.68648	-144.146	0.73259	-37.3671
Bus3	Bus10	9	75.65036	52.62932	0.24388	-26.3167
Bus14	Bus8	10	84.64447	-34.4572	0.308857	-35.7589
Bus14	Bus7	11	211.3555	-33.7595	1.669048	-20.613
Bus11	Bus21	12	187.1563	45.09027	3.494407	-40.4079
Bus15	Bus8	13	-203	-152	0.495221	-0.86723
Bus8	Bus16	14	-495.604	-279.838	8.372523	43.06215
Bus16	Bus23	15	115.1057	82.55965	0.105701	-3.44035
Bus19	Bus16	16	-201.243	-35.137	3.926167	-72.694
Bus18	Bus8	17	555.6159	316.5951	1.590623	9.701405
Bus16	Bus18	18	683.8757	462.6158	8.25985	56.02077
Bus17	Bus8	19	-19.7154	-7.21336	0.288838	-102.898
Bus19	Bus17	20	-43.4658	-35.0038	0.249546	-108.389
Bus3	Bus4	21	-252.712	-205.417	0.288197	-0.86931
Bus19	Bus25	22	75.25755	6.953383	0.581568	-71.042
Bus24	Bus19	23	71.08091	-80.0597	0.404684	-60.3739
Bus19	Bus25	24	77.01137	7.719822	0.606877	-70.9495
Bus25	Bus33	25	-155.401	-17.2287	1.099481	11.8287
Bus25	Bus33	26	-155.401	-17.2287	1.099481	11.8287
Bus27	Bus19	27	-21.5129	-3.70622	0.009576	-19.3779
Bus26	Bus27	28	-10.5889	-10.8713	0.002759	-24.5587
Bus3	Bus2	29	-66.0232	97.86263	0.527329	-27.8008

Bus26	Bus19	30	-15.9519	-18.1655	0.0099	-42.9132
Bus30	Bus24	31	-376.738	-158.501	7.073405	18.87409
Bus24	Bus31	32	-217.891	-75.4212	1.109157	-14.1073
Bus31	Bus24	33	219	61.31394	1.109157	-14.1073
Bus32	Bus24	34	119.9824	-31.6737	0.871474	-53.1467
Bus38	Bus32	35	236.5798	6.773025	0.547868	-4.90629
Bus35	Bus30	36	-180.607	-13.6604	0.131299	-2.15939
Bus22	Bus25	37	-340.061	-99.7623	1.820625	1.359823
Bus3	Bus4	38	-252.712	-205.417	0.288197	-0.86931
Bus19	Bus9	39	-18.3677	-31.7988	0.06495	-98.6493
Bus27	Bus34	40	68.92122	28.97967	0.156017	-23.1833
Bus26	Bus34	41	141.5408	97.98958	0.305953	-7.84746
Bus29	Bus36	42	87.63106	24.21575	0.732296	-23.5786
Bus20	Bus11	43	-194	-146	5.119482	-75.863
Bus21	Bus29	44	280.7926	118.823	11.49008	27.65784
Bus37	Bus29	45	-83.6414	-38.7392	0.653472	-25.5788
Bus22	Bus13	46	110.0304	4.881152	0.698843	-44.2105
Bus5	Bus3	47	-129.669	-60.4666	1.449435	-86.2015
Bus22	Bus13	48	110.0304	4.881152	0.698843	-44.2105
Bus13	Bus5	49	-152.296	-146.756	1.784387	-27.2437
Bus13	Bus12	50	150.9591	79.93958	0.361034	-7.35642
Bus28	Bus35	51	-165.482	-24.7402	2.121934	-43.2786
Bus28	Bus21	52	85.48228	-35.2598	0.916924	-78.9222
Bus28	Bus21	53	85.48228	-35.2598	0.916924	-78.9222
Bus28	Bus35	54	-165.482	-24.7402	2.121934	-43.2786
Bus35	Bus39	55	-329.601	-80.2629	6.375736	4.545215
Bus5	Bus3	56	-129.669	-60.4666	1.449435	-86.2015
Bus40	Bus39	57	132.6777	6.308329	0.400961	-19.9262
Bus9	Bus6	58	14.56734	-49.1879	0.020643	-82.975
Bus32	Bus39	59	161.0495	88.40761	0.61373	-13.4111
Bus38	Bus39	60	209.4202	68.65615	1.155523	-15.0987
Bus5	Bus11	61	267.3635	99.85425	3.225574	-11.2594
Bus41	Bus40	62	223	70.83549	0.32235	-3.47284
Bus5	Bus11	63	267.3635	99.85425	3.225574	-11.2594

GLOBAL SUMMARY REPORT

TOTAL GENERATION	
REAL POWER [MW]	4889.127
REACTIVE POWER [MVar]	1529.716
TOTAL LOAD	
REAL POWER [MW]	4786.917
REACTIVE POWER [MVar]	3534.322
TOTAL LOSSES	
REAL POWER [MW]	102.2104
REACTIVE POWER [MVar]	-2004.61

C3: CONNECTION OF SVC

POWER FLOW REPORT

P S A T 2.1.10

NETWORK STATISTICS

Buses:	41
Lines:	63
Generators:	14
Loads:	27

SOLUTION STATISTICS

Number of Iterations:	7
Maximum P mismatch [MW]	5.91E-12
Maximum Q mismatch [MVar]	6.48E-12

POWER FLOW RESULTS

Bus	V	phase	P gen	Q gen	P load	Q load	MARG COST
	[kV]	[rad]	[MW]	[MVar]	[MW]	[MVar]	N/HR
Bus1	332.1503	-0.17277	6.66E-14	2.66E-13	162	19.78077	
Bus10	332.7176	-0.10661	-6.20E-13	-3.40E-12	100	75	
Bus11	334.3051	-0.4093	3.55E-13	7.55E-13	142	107	
Bus12	323.1772	-0.37836	-1.10E-12	-4.40E-14	303	227	
Bus13	329.0481	-0.36903	-1.80E-13	-1.70E-12	220	-166.082	
Bus14	317.13	-0.0415	279.3323	-70.2497	0	0	18091.3
Bus15	314.7788	-0.08781	-8.90E-14	-5.50E-12	203	152	
Bus16	340.23	0	1505.194	838.8762	0	0	83853.51
Bus17	330	-0.05852	211.0813	-86.7921	0	0	2669.134

Bus18	322.0683	-0.06178	-4.40E-13	1.03E-12	120	90	
Bus19	332.1977	-0.21234	-3.80E-13	-2.00E-12	144	108	
Bus2	330	-0.01934	715.0358	-358.662	0	0	66104.12
Bus20	333.0577	-0.44019	-5.30E-13	-5.80E-13	194	-132.082	
Bus21	342.7316	-0.64693	-3.40E-13	6.44E-13	72	-59.2582	
Bus22	327.1686	-0.33799	5.11E-13	2.39E-12	120	90	
Bus23	338.9084	-0.00406	3.11E-13	2.04E-12	115	86	
Bus24	328.997	-0.47832	-1.80E-13	-1.60E-12	100	75	
Bus25	328.0298	-0.30736	3.33E-13	-1.10E-12	120	90	
Bus26	333.96	-0.15232	442.1674	50.5474	0	0	4936.704
Bus27	333.96	-0.1637	291.9116	22.10184	0	0	3603.441
Bus28	332.0204	-0.65195	-2.20E-14	1.02E-12	160	120	
Bus29	333.958	-0.87167	6.44E-13	-6.10E-14	105	32.3967	
Bus3	337.8151	-0.08758	-3.10E-13	-9.10E-13	260	195	
Bus30	320.25	-0.6015	5.91E-12	-7.30E-13	196	147	
Bus31	333.96	-0.47597	45.41442	139.0638	0	0	2539.022
Bus32	330	-0.54807	56.40804	-9.76113	0	0	4019.343
Bus33	330	-0.29411	50.10074	16.4059	0	0	3183.32
Bus34	330.9155	-0.1659	1.33E-12	4.11E-12	210	158	
Bus35	321.1811	-0.60889	-3.90E-12	-6.50E-12	175	131	
Bus36	330.3119	-0.9105	9.55E-13	2.44E-13	100	39.97163	
Bus37	329.8418	-0.90982	2.22E-13	-1.20E-13	95	44	
Bus38	330.99	-0.55134	72.47316	81.57621	0	0	3210.623
Bus39	326.8155	-0.5719	6.66E-13	-2.90E-12	165	127	
Bus4	339.9	-0.08251	495.8591	474.6231	0	0	40513.57
Bus40	326.9451	-0.57629	-2.50E-12	-3.60E-12	90	68	
Bus41	328.02	-0.57329	67.41773	55.21505	0	0	1538.598
Bus5	330	0.29808	584	-245.626	0	0	16047.9
Bus6	331.2555	-0.10599	3.11E-13	3.18E-12	127	95	
Bus7	317.0986	-0.09904	-1.60E-13	-1.60E-12	174	131	
Bus8	318.0494	-0.07721	3.55E-13	-2.00E-12	847	635	
Bus9	330	-0.10266	150.2476	-117.005	0	0	12803.46
			4966.643				263114

STATE VARIABLES

alpha_Svc_1	2.507241
vm_Svc_1	1
alpha_Svc_2	2.275053
vm_Svc_2	1
alpha_Svc_3	3.14159
vm_Svc_3	1
alpha_Svc_4	2.241206

vm_Svc_4	1

OTHER ALGEBRAIC VARIABLES

vref_Svc_1	1.000025
q_Svc_1	2.333878
vref_Svc_2	1.000023
q_Svc_2	0.95805
vref_Svc_3	1.000034
q_Svc_3	3.333333
vref_Svc_4	1.000022
q_Svc_4	0.70059

LINE FLOWS

From Bus	To Bus	Line	P Flow [MW]	Q Flow [MVar]	S Flow [MVA]	P Loss [MW]	Q Loss [MVar]
Bus2	Bus3	1	274.8362	-141.002	308.8955	2.905987	-9.88641
Bus1	Bus2	2	-162	-19.7808	163.2032	3.363424	-96.4393
Bus5	Bus12	3	184.0483	4.751522	184.1096	1.790596	-40.1883
Bus6	Bus10	4	0.41379	-34.0947	34.09717	0.008813	-34.4809
Bus3	Bus6	5	44.30333	5.677023	44.66558	0.181306	-61.8895
Bus3	Bus6	6	44.30333	5.677023	44.66558	0.181306	-61.8895
Bus8	Bus6	7	30.49697	-99.1636	103.7472	0.364927	-91.0183
Bus6	Bus7	8	-4.62573	101.3876	101.493	0.62822	-38.2596
Bus10	Bus3	9	-99.595	-74.6138	124.4443	0.335092	-25.5063
Bus8	Bus14	10	-98.438	2.332886	98.46566	0.421496	-34.8225
Bus7	Bus14	11	-179.254	8.647123	179.4624	1.218829	-24.4472
Bus21	Bus11	12	-405.35	108.6841	419.6675	13.41361	19.8441
Bus8	Bus15	13	203.4947	151.1237	253.4728	0.494677	-0.87627
Bus16	Bus8	14	462.4862	322.1573	563.63	7.441964	36.05342
Bus23	Bus16	15	-115	-86	143.6001	0.105701	-3.44035
Bus16	Bus19	16	298.2083	-26.4938	299.3829	8.31375	-39.2118
Bus8	Bus18	17	-500.631	-314.172	591.046	1.38307	7.936298
Bus18	Bus16	18	-622.014	-412.108	746.1466	7.379538	48.54464
Bus8	Bus17	19	-26.8786	-89.017	92.98644	0.260216	-103.167
Bus17	Bus19	20	183.9425	-72.642	197.7668	3.759575	-81.4522
Bus4	Bus3	21	247.9296	237.3115	343.1994	0.320784	-0.59084
Bus25	Bus19	22	-163.672	-29.735	166.3514	2.082525	-60.3927
Bus19	Bus24	23	654.653	-7.70307	654.6983	22.80238	108.2702
Bus25	Bus19	24	-167.172	-29.0882	169.684	2.173152	-60.0617
Bus33	Bus25	25	25.05037	8.20295	26.35924	0.03082	-1.56364

Bus33	Bus25	26	25.05037	8.20295	26.35924	0.03082	-1.56364
Bus19	Bus27	27	-332.964	6.419884	333.0255	2.154867	-3.14948
Bus27	Bus26	28	-61.4965	-3.75658	61.61114	0.093191	-23.8786
Bus2	Bus3	29	274.8362	-141.002	308.8955	2.905987	-9.88641
Bus19	Bus26	30	-187.019	-10.1969	187.2971	1.322065	-31.5509
Bus24	Bus30	31	427.1593	43.77183	429.3961	7.073118	17.38637
Bus31	Bus24	32	22.70721	69.53188	73.14574	0.148847	-22.3068
Bus24	Bus31	33	-22.5584	-91.8387	94.56865	0.148847	-22.3068
Bus24	Bus32	34	149.808	-51.0677	158.273	1.394121	-49.3327
Bus32	Bus38	35	38.2735	-50.1127	63.05665	0.034833	-8.76504
Bus30	Bus35	36	224.0862	-120.615	254.4847	0.236361	-1.57166
Bus25	Bus22	37	260.8837	-11.6437	261.1434	0.937713	-6.7323
Bus4	Bus3	38	247.9296	237.3115	343.1994	0.320784	-0.59084
Bus9	Bus19	39	145.8311	-69.2126	161.4221	2.13822	-82.5732
Bus34	Bus27	40	-18.2265	-59.3093	62.04678	0.063136	-23.8815
Bus34	Bus26	41	-191.773	-98.6907	215.6778	0.462856	-6.6672
Bus36	Bus29	42	-100	-39.9716	107.6928	0.478301	-48.4602
Bus11	Bus20	43	200.1491	-218.669	296.4388	6.149069	-86.5869
Bus29	Bus21	44	-300.933	-17.328	301.4315	8.010547	-37.4335
Bus29	Bus37	45	95.45477	-6.58015	95.68131	0.454774	-50.5801
Bus13	Bus22	46	-69.7037	-4.63365	69.85757	0.269253	-52.0893
Bus3	Bus5	47	295.2706	-20.9438	296.0124	7.178462	-36.9729
Bus13	Bus22	48	-69.7037	-4.63365	69.85757	0.269253	-52.0893
Bus5	Bus13	49	203.5348	-30.7295	205.8414	1.687646	-30.2936
Bus12	Bus13	50	-120.742	-182.06	218.4596	0.51226	-7.1471
Bus35	Bus28	51	68.58021	-98.2892	119.85	0.603259	-65.5756
Bus21	Bus28	52	12.20316	-14.6602	19.07453	0.180108	-107.374
Bus21	Bus28	53	12.20316	-14.6602	19.07453	0.180108	-107.374
Bus35	Bus28	54	68.58021	-98.2892	119.85	0.603259	-65.5756
Bus39	Bus35	55	88.75564	4.830948	88.88702	0.445026	-48.6335
Bus3	Bus5	56	295.2706	-20.9438	296.0124	7.178462	-36.9729
Bus39	Bus40	57	22.64061	-16.4757	28.0008	0.01193	-23.4387
Bus6	Bus9	58	-4.41197	-35.3052	35.5798	0.00456	-83.0977
Bus39	Bus32	59	-166.029	-52.9647	174.2726	0.519274	-14.3482
Bus39	Bus38	60	-110.367	-62.3906	126.7812	0.344735	-22.162
Bus11	Bus5	61	-380.456	100.2547	393.4438	5.844281	6.459928
Bus40	Bus41	62	-67.3713	-61.037	90.9088	0.046415	-5.82195
Bus11	Bus5	63	-380.456	100.2547	393.4438	5.844281	6.459928

LINE FLOWS

From Bus	To Bus	Line	P Flow	Q Flow	P Loss	Q Loss
			[MW]	[MVar]	[MW]	[MVar]
Bus3	Bus2	1	-271.93	131.1154	2.905987	-9.88641

Bus2	Bus1	2	165.3634	-76.6585	3.363424	-96.4393
Bus12	Bus5	3	-182.258	-44.9398	1.790596	-40.1883
Bus10	Bus6	4	-0.40498	-0.38619	0.008813	-34.4809
Bus6	Bus3	5	-44.122	-67.5665	0.181306	-61.8895
Bus6	Bus3	6	-44.122	-67.5665	0.181306	-61.8895
Bus6	Bus8	7	-30.132	8.145272	0.364927	-91.0183
Bus7	Bus6	8	5.253951	-139.647	0.62822	-38.2596
Bus3	Bus10	9	99.93012	49.10755	0.335092	-25.5063
Bus14	Bus8	10	98.85952	-37.1554	0.421496	-34.8225
Bus14	Bus7	11	180.4728	-33.0943	1.218829	-24.4472
Bus11	Bus21	12	418.7635	-88.84	13.41361	19.8441
Bus15	Bus8	13	-203	-152	0.494677	-0.87627
Bus8	Bus16	14	-455.044	-286.104	7.441964	36.05342
Bus16	Bus23	15	115.1057	82.55965	0.105701	-3.44035
Bus19	Bus16	16	-289.895	-12.718	8.31375	-39.2118
Bus18	Bus8	17	502.0139	322.1084	1.38307	7.936298
Bus16	Bus18	18	629.3935	460.6531	7.379538	48.54464
Bus17	Bus8	19	27.13878	-14.1501	0.260216	-103.167
Bus19	Bus17	20	-180.183	-8.8102	3.759575	-81.4522
Bus3	Bus4	21	-247.609	-237.902	0.320784	-0.59084
Bus19	Bus25	22	165.7549	-30.6577	2.082525	-60.3927
Bus24	Bus19	23	-631.851	115.9733	22.80238	108.2702
Bus19	Bus25	24	169.3454	-30.9735	2.173152	-60.0617
Bus25	Bus33	25	-25.0195	-9.76659	0.03082	-1.56364
Bus25	Bus33	26	-25.0195	-9.76659	0.03082	-1.56364
Bus27	Bus19	27	335.1184	-9.56936	2.154867	-3.14948
Bus26	Bus27	28	61.5897	-20.122	0.093191	-23.8786
Bus3	Bus2	29	-271.93	131.1154	2.905987	-9.88641
Bus26	Bus19	30	188.3414	-21.3541	1.322065	-31.5509
Bus30	Bus24	31	-420.086	-26.3855	7.073118	17.38637
Bus24	Bus31	32	-22.5584	-91.8387	0.148847	-22.3068
Bus31	Bus24	33	22.70721	69.53188	0.148847	-22.3068
Bus32	Bus24	34	-148.414	1.735063	1.394121	-49.3327
Bus38	Bus32	35	-38.2387	41.34763	0.034833	-8.76504
Bus35	Bus30	36	-223.85	119.0429	0.236361	-1.57166
Bus22	Bus25	37	-259.946	4.911356	0.937713	-6.7323
Bus3	Bus4	38	-247.609	-237.902	0.320784	-0.59084
Bus19	Bus9	39	-143.693	-13.3605	2.13822	-82.5732
Bus27	Bus34	40	18.28967	35.42778	0.063136	-23.8815
Bus26	Bus34	41	192.2363	92.02347	0.462856	-6.6672
Bus29	Bus36	42	100.4783	-8.48856	0.478301	-48.4602
Bus20	Bus11	43	-194	132.0825	6.149069	-86.5869
Bus21	Bus29	44	308.9436	-20.1055	8.010547	-37.4335

Bus37	Bus29	45	-95	-44	0.454774	-50.5801
Bus22	Bus13	46	69.97297	-47.4557	0.269253	-52.0893
Bus5	Bus3	47	-288.092	-16.029	7.178462	-36.9729
Bus22	Bus13	48	69.97297	-47.4557	0.269253	-52.0893
Bus13	Bus5	49	-201.847	0.435915	1.687646	-30.2936
Bus13	Bus12	50	121.2545	174.9131	0.51226	-7.1471
Bus28	Bus35	51	-67.977	32.71365	0.603259	-65.5756
Bus28	Bus21	52	-12.023	-92.7137	0.180108	-107.374
Bus28	Bus21	53	-12.023	-92.7137	0.180108	-107.374
Bus28	Bus35	54	-67.977	32.71365	0.603259	-65.5756
Bus35	Bus39	55	-88.3106	-53.4644	0.445026	-48.6335
Bus5	Bus3	56	-288.092	-16.029	7.178462	-36.9729
Bus40	Bus39	57	-22.6287	-6.96299	0.01193	-23.4387
Bus9	Bus6	58	4.416528	-47.7925	0.00456	-83.0977
Bus32	Bus39	59	166.5484	38.61648	0.519274	-14.3482
Bus38	Bus39	60	110.7118	40.22858	0.344735	-22.162
Bus5	Bus11	61	386.3006	-93.7948	5.844281	6.459928
Bus41	Bus40	62	67.41773	55.21505	0.046415	-5.82195
Bus5	Bus11	63	386.3006	-93.7948	5.844281	6.459928

GLOBAL SUMMARY REPORT

TOTAL GENERATION	
REAL POWER [MW]	4966.643
REACTIVE POWER [MVar]	790.3136
TOTAL LOAD	
REAL POWER [MW]	4819
REACTIVE POWER [MVar]	2685.727
TOTAL LOSSES	
REAL POWER [MW]	147.6428
REACTIVE POWER [MVar]	-1895.41

C4: CONNECTION OF TCSC

POWER FLOW REPORT

P S A T 2.1.10

NETWORK STATISTICS

Buses:	41
Lines:	63
Generators:	14
Loads:	27

SOLUTION STATISTICS

Number of Iterations:	5
Maximum P mismatch [MW]	5.80E-12
Maximum Q mismatch [MVar]	4.79E-12

POWER FLOW RESULTS

Bus	V	Phase	P gen	Q gen	P load	Q load	MARGINAL COST
	[kV]	[rad]	[MW]	[MVar]	[MW]	[MVar]	N/Hr
Bus1	293.2536	-0.23553	4.44E-14	2E-13	162	122	
Bus10	335.1755	-0.10446	6.44E-13	4.6E-12	100	75	
Bus11	316.438	-0.25476	7.22E-11	1.4E-11	142	107	
Bus12	308.8094	-0.23951	4.44E-13	-3.1E-13	303	227	
Bus13	312.0225	-0.22402	8.88E-14	2E-12	220	165	
Bus14	336.6	-0.02499	293.2683	70.54408	0	0	19041.33
Bus15	325.8231	-0.0601	3.11E-13	9.1E-13	203	152	
Bus16	340.23	0	1287.843	793.9987	0	0	68407.2
Bus17	330	0.029118	232.9808	-138.296	0	0	2899.799

Bus18	326.7937	-0.05513	2.22E-14	2.11E-13	120	90	
Bus19	333.8389	-0.08686	6.04E-12	1.51E-11	144	108	
Bus2	330	-0.07764	260.5209	-203.825	0	0	17775.02
Bus20	307.1849	-0.26128	1.67E-12	1.55E-12	194	146	
Bus21	297.6014	-0.37877	-1.3E-09	1.31E-10	72	54	
Bus22	317.8489	-0.16884	-5.3E-13	-1.9E-12	120	90	
Bus23	338.9084	-0.00406	-4.2E-13	-3.8E-12	115	86	
Bus24	328.4063	-0.07457	1.59E-11	1.02E-11	100	75	
Bus25	323.4154	-0.12561	4.44E-14	8.99E-13	120	90	
Bus26	333.96	-0.09226	96.52544	71.09866	0	0	1256.851
Bus27	333.96	-0.08837	87.35862	7.169173	0	0	1464.814
Bus28	302.3597	-0.30201	1.48E-11	2.11E-11	160	120	
Bus29	254.3558	-0.67299	8.72E-10	8.34E-11	97.46863	53.83982	
Bus3	338.3718	-0.09204	-7.4E-12	-4.7E-11	260	195	
Bus30	307.2043	-0.18943	1.97E-11	5.37E-12	196	147	
Bus31	333.96	-0.03724	432.7234	121.2101	0	0	26870.65
Bus32	330	-0.03125	95.13999	35.14666	0	0	6385.47
Bus33	330	-0.0323	342.2104	60.11788	0	0	30084.47
Bus34	330.9195	-0.10138	5.33E-13	4.06E-12	210	158	
Bus35	306.8895	-0.19605	1.45E-11	1.24E-11	175	131	
Bus36	246.2158	-0.73076	7.75E-10	4.68E-10	86.9809	47.83949	
Bus37	247.8323	-0.73103	2.92E-10	3.29E-10	83.72045	38.77579	
Bus38	330.99	-0.01728	407.8517	78.54251	0	0	23498.89
Bus39	324.529	-0.05825	5.11E-12	4.42E-12	165	127	
Bus4	339.9	-0.08671	502.6455	330.9735	0	0	41401.59
Bus40	326.455	-0.04507	-1.1E-12	-1.8E-12	90	68	
Bus41	328.02	-0.03747	161.9578	74.73767	0	0	3390.403
Bus5	330	-0.17917	579.8938	301.2955	0	0	15906.78
Bus6	335.9687	-0.09576	6.66E-13	5.48E-12	127	95	
Bus7	330.2384	-0.08262	6.66E-14	1.44E-12	174	131	
Bus8	328.9789	-0.0502	8.88E-13	1.31E-11	847	635	
Bus9	330	-0.05928	88.42177	-143.351	0	0	7489.605
			4869.342				265872.9

STATE VARIABLES

x1_Tcsc_1	3.14159
x1_Tcsc_2	1

OTHER ALGEBRAIC VARIABLES

x0_Tcsc_1	3.14159
pref_Tcsc_1	-2.00331
x0_Tcsc_2	1
pref_Tcsc_2	-3.09355

LINE FLOWS

From Bus	To Bus	Line	P Flow [MW]	Q Flow [MVar]	S Flow [MVA]	P Loss [MW]	Q Loss [MVar]
Bus2	Bus3	1	46.81097	-127.237	135.5747	0.467209	-28.2825
Bus1	Bus2	2	-162	-122	202.8004	4.898956	-71.3507
Bus5	Bus12	3	145.2356	105.8714	179.7279	2.001983	-36.0299
Bus6	Bus10	4	34.6959	-12.3646	36.83327	0.036972	-34.9921
Bus3	Bus6	5	9.884783	-17.8666	20.41874	0.016451	-64.2915
Bus3	Bus6	6	9.884783	-17.8666	20.41874	0.016451	-64.2915
Bus8	Bus6	7	57.23297	-81.5032	99.59107	0.388128	-95.3804
Bus6	Bus7	8	-31.9587	31.32214	44.7486	0.158942	-44.6633
Bus10	Bus3	9	-65.3411	-52.3725	83.73969	0.139118	-27.4236
Bus8	Bus14	10	-85.2326	-79.8847	116.8169	0.418109	-38.6206
Bus7	Bus14	11	-206.118	-55.0146	213.3333	1.499866	-25.7346
Bus21	Bus11	12	-190.558	-82.9711	207.8379	3.711022	-38.8015
Bus8	Bus15	13	203.4614	150.5484	253.1034	0.461356	-1.45165
Bus16	Bus8	14	339.9367	240.2359	416.2574	0	24.72952
Bus23	Bus16	15	-115	-86	143.6001	0.105701	-3.44035
Bus16	Bus19	16	124.0442	-36.3658	129.2649	1.450917	-91.3194
Bus8	Bus18	17	9.303458	12.12881	15.28602	-1.8E-15	-0.89575
Bus18	Bus16	18	-110.697	-76.9754	134.8293	0	7.939464
Bus8	Bus17	19	-93.7681	-41.6362	102.5965	0.990959	-101.21
Bus17	Bus19	20	138.2217	-78.7219	159.0672	2.167	-93.9772
Bus4	Bus3	21	251.3228	165.4867	300.9136	0.246455	-1.22586
Bus25	Bus19	22	-72.3269	-79.2967	107.3273	0.563555	-71.1494
Bus19	Bus24	23	-24.6394	12.35182	27.56209	0.136542	-62.4067
Bus25	Bus19	24	-74.0088	-80.0063	108.9876	0.58808	-71.0598
Bus33	Bus25	25	171.1052	30.05894	173.7254	1.30929	14.45376
Bus33	Bus25	26	171.1052	30.05894	173.7254	1.30929	14.45376
Bus19	Bus27	27	9.934063	-13.5465	16.79862	0.002176	-19.4353
Bus27	Bus26	28	21.03474	-15.0448	25.86131	0.010881	-24.4976
Bus2	Bus3	29	46.81097	-127.237	135.5747	0.467209	-28.2825
Bus19	Bus26	30	16.67337	-24.5518	29.67817	0.010718	-42.9101
Bus24	Bus30	31	399.912	175.3357	436.6603	7.521615	22.21606
Bus31	Bus24	32	216.3617	60.60505	224.6895	1.083118	-14.3322
Bus24	Bus31	33	-215.279	-74.9373	227.9484	1.083118	-14.3322
Bus24	Bus32	34	-94.1308	-25.7027	97.57684	0.542488	-55.6309
Bus32	Bus38	35	-191.482	-18.3133	192.356	0.362113	-6.30344
Bus30	Bus35	36	196.3904	6.119668	196.4857	0.154229	-1.96998

Bus25	Bus22	37	365.9275	100.5133	379.481	2.061653	3.420491
Bus4	Bus3	38	251.3228	165.4867	300.9136	0.246455	-1.22586
Bus9	Bus19	39	34.96671	-68.81	77.1848	0.159327	-97.9484
Bus34	Bus27	40	-76.0757	-51.1055	91.64764	0.180029	-23.0027
Bus34	Bus26	41	-133.924	-106.895	171.3539	0.287692	-7.9848
Bus36	Bus29	42	-86.9809	-47.8395	99.26879	0.732988	-23.6009
Bus11	Bus20	43	199.1207	70.15401	211.1176	5.120711	-75.846
Bus29	Bus21	44	-269.557	-91.2513	284.5836	11.50094	27.68398
Bus29	Bus37	45	84.37454	13.17285	85.39665	0.65409	-25.6029
Bus13	Bus22	46	-121.089	-46.4732	129.7011	0.843611	-42.9268
Bus3	Bus5	47	124.7952	-24.3497	127.1485	1.321446	-87.3911
Bus13	Bus22	48	-121.089	-46.4732	129.7011	0.843611	-42.9268
Bus5	Bus13	49	139.6151	121.5708	185.1265	1.635533	-28.4932
Bus12	Bus13	50	-159.766	-85.0988	181.0168	0.39181	-7.08838
Bus35	Bus28	51	164.1278	-18.7601	165.1965	2.031574	-44.1628
Bus21	Bus28	52	-81.2499	-44.9821	92.87056	0.84633	-79.5793
Bus21	Bus28	53	-81.2499	-44.9821	92.87056	0.84633	-79.5793
Bus35	Bus28	54	164.1278	-18.7601	165.1965	2.031574	-44.1628
Bus39	Bus35	55	312.6009	83.11363	323.4613	5.58136	-2.27657
Bus3	Bus5	56	124.7952	-24.3497	127.1485	1.321446	-87.3911
Bus39	Bus40	57	-71.6421	-33.6071	79.13303	0.127075	-22.2619
Bus6	Bus9	58	-53.1557	-7.23049	53.64517	0.299397	-81.7711
Bus39	Bus32	59	-191.163	-95.3456	213.6216	0.785667	-11.9575
Bus39	Bus38	60	-214.795	-81.1609	229.6175	1.211869	-14.6283
Bus11	Bus5	61	-267.695	-110.662	289.6664	3.300361	-10.6938
Bus40	Bus41	62	-161.769	-79.3453	180.1803	0.18858	-4.60759
Bus11	Bus5	63	-267.695	-110.662	289.6664	3.300361	-10.6938

LINE FLOWS

From Bus	To Bus	Line	P Flow [MW]	Q Flow [MVar]	P Loss [MW]	Q Loss [MVar]
Bus3	Bus2	1	-46.3438	98.95448	0.467209	-28.2825
Bus2	Bus1	2	166.899	50.64929	4.898956	-71.3507
Bus12	Bus5	3	-143.234	-141.901	2.001983	-36.0299
Bus10	Bus6	4	-34.6589	-22.6275	0.036972	-34.9921
Bus6	Bus3	5	-9.86833	-46.4249	0.016451	-64.2915
Bus6	Bus3	6	-9.86833	-46.4249	0.016451	-64.2915
Bus6	Bus8	7	-56.8448	-13.8772	0.388128	-95.3804
Bus7	Bus6	8	32.11768	-75.9854	0.158942	-44.6633
Bus3	Bus10	9	65.48019	24.94894	0.139118	-27.4236
Bus14	Bus8	10	85.65076	41.26411	0.418109	-38.6206
Bus14	Bus7	11	207.6175	29.27997	1.499866	-25.7346
Bus11	Bus21	12	194.2691	44.16959	3.711022	-38.8015

Bus15	Bus8	13	-203	-152	0.461356	-1.45165
Bus8	Bus16	14	-339.937	-215.506	0	24.72952
Bus16	Bus23	15	115.1057	82.55965	0.105701	-3.44035
Bus19	Bus16	16	-122.593	-54.9536	1.450917	-91.3194
Bus18	Bus8	17	-9.30346	-13.0246	-1.8E-15	-0.89575
Bus16	Bus18	18	110.6965	84.9149	0	7.939464
Bus17	Bus8	19	94.7591	-59.574	0.990959	-101.21
Bus19	Bus17	20	-136.055	-15.2552	2.167	-93.9772
Bus3	Bus4	21	-251.076	-166.713	0.246455	-1.22586
Bus19	Bus25	22	72.89046	8.147241	0.563555	-71.1494
Bus24	Bus19	23	24.77596	-74.7585	0.136542	-62.4067
Bus19	Bus25	24	74.59685	8.946447	0.58808	-71.0598
Bus25	Bus33	25	-169.796	-15.6052	1.30929	14.45376
Bus25	Bus33	26	-169.796	-15.6052	1.30929	14.45376
Bus27	Bus19	27	-9.93189	-5.8888	0.002176	-19.4353
Bus26	Bus27	28	-21.0239	-9.45278	0.010881	-24.4976
Bus3	Bus2	29	-46.3438	98.95448	0.467209	-28.2825
Bus26	Bus19	30	-16.6627	-18.3583	0.010718	-42.9101
Bus30	Bus24	31	-392.39	-153.12	7.521615	22.21606
Bus24	Bus31	32	-215.279	-74.9373	1.083118	-14.3322
Bus31	Bus24	33	216.3617	60.60505	1.083118	-14.3322
Bus32	Bus24	34	94.6733	-29.9282	0.542488	-55.6309
Bus38	Bus32	35	191.8444	12.00984	0.362113	-6.30344
Bus35	Bus30	36	-196.236	-8.08965	0.154229	-1.96998
Bus22	Bus25	37	-363.866	-97.0928	2.061653	3.420491
Bus3	Bus4	38	-251.076	-166.713	0.246455	-1.22586
Bus19	Bus9	39	-34.8074	-29.1383	0.159327	-97.9484
Bus27	Bus34	40	76.25577	28.10282	0.180029	-23.0027
Bus26	Bus34	41	134.212	98.90971	0.287692	-7.9848
Bus29	Bus36	42	87.71388	24.23864	0.732988	-23.6009
Bus20	Bus11	43	-194	-146	5.120711	-75.846
Bus21	Bus29	44	281.058	118.9353	11.50094	27.68398
Bus37	Bus29	45	-83.7205	-38.7758	0.65409	-25.6029
Bus22	Bus13	46	121.9329	3.546403	0.843611	-42.9268
Bus5	Bus3	47	-123.474	-63.0414	1.321446	-87.3911
Bus22	Bus13	48	121.9329	3.546403	0.843611	-42.9268
Bus13	Bus5	49	-137.98	-150.064	1.635533	-28.4932
Bus13	Bus12	50	160.1582	78.01037	0.39181	-7.08838
Bus28	Bus35	51	-162.096	-25.4027	2.031574	-44.1628
Bus28	Bus21	52	82.09627	-34.5973	0.84633	-79.5793
Bus28	Bus21	53	82.09627	-34.5973	0.84633	-79.5793
Bus28	Bus35	54	-162.096	-25.4027	2.031574	-44.1628
Bus35	Bus39	55	-307.02	-85.3902	5.58136	-2.27657

Bus5	Bus3	56	-123.474	-63.0414	1.321446	-87.3911
Bus40	Bus39	57	71.76922	11.34526	0.127075	-22.2619
Bus9	Bus6	58	53.45506	-74.5406	0.299397	-81.7711
Bus32	Bus39	59	191.9489	83.38809	0.785667	-11.9575
Bus38	Bus39	60	216.0073	66.53267	1.211869	-14.6283
Bus5	Bus11	61	270.9953	99.96803	3.300361	-10.6938
Bus41	Bus40	62	161.9578	74.73767	0.18858	-4.60759
Bus5	Bus11	63	270.9953	99.96803	3.300361	-10.6938

GLOBAL SUMMARY REPORT

TOTAL GENERATION	
REAL POWER [MW]	4869.342
REACTIVE POWER [MVar]	1459.363
TOTAL LOAD	
REAL POWER [MW]	4787.17
REACTIVE POWER [MVar]	3534.455
REAL POWER [MW]	82.17183
REACTIVE POWER [MVar]	-2075.09

C5: COMBINED CONNECTION OF SVC AND TCSC

POWER FLOW REPORT

P S A T 2.1.10

NETWORK STATISTICS

Buses:	41
Lines:	63
Generators:	14
Loads:	27

SOLUTION STATISTICS

Number of Iterations:	4
Maximum P mismatch [MW]	4.89E-12
Maximum Q mismatch [MVar]	4.21E-12

POWER FLOW RESULTS

Bus	V	phase	P gen	Q gen	P load	Q load	MARGINAL COST
	[kV]	[rad]	[MW]	[MVar]	[MW]	[MVar]	N/Hr
Bus1	330	-0.19455	-8.9E-14	95.80499	162	122	
Bus10	333.599	-0.0749	2.52E-11	6.51E-11	100	75	
Bus11	332.4492	-0.2266	-1.3E-08	5.25E-09	142	107	
Bus12	324.0368	-0.21485	4.44E-12	2.81E-11	303	227	
Bus13	330	-0.20252	6.31E-11	339.8609	220	165	
Bus14	317.13	0.001006	295	-169.23	0	0	19159.71
Bus15	325.1721	-0.0504	0	-2.8E-12	203	152	
Bus16	340.23	0	1270.455	944.3745	0	0	67220.43
Bus17	330	-0.00569	114	-134.143	0	0	1660.45

Bus18	330.1863	-0.03396	-4.9E-12	1.1E-10	120	90	
Bus19	335.227	-0.06728	-2.2E-10	9.7E-10	144	108	
Bus2	330	-0.041	300	-323.485	0	0	21055.3
Bus20	330	-0.25377	1.39E-09	232.3055	194	146	
Bus21	330.0017	-0.33524	-1.5E-08	3.5E-08	72	54	
Bus22	328.3512	-0.15355	6.92E-11	1.35E-10	120	90	
Bus23	338.9084	-0.00406	-1.2E-12	-6.7E-12	115	86	
Bus24	329.9507	-0.02323	-4.9E-09	1.03E-09	100	75	
Bus25	329.5588	-0.11328	7.1E-11	1.79E-10	120	90	
Bus26	333.96	-0.06997	100	57.58957	0	0	1292.416
Bus27	333.96	-0.06571	107	-24.3466	0	0	1665.809
Bus28	321.4711	-0.25054	3.01E-08	1.25E-08	160	120	
Bus29	326.2968	-0.57666	3.24E-08	1.11E-08	105	58	
Bus3	338.1593	-0.0602	8.25E-11	6.31E-10	260	195	
Bus30	315.0117	-0.13275	-8.8E-09	5.23E-09	196	147	
Bus31	333.96	0.014953	418	68.60983	0	0	25775.64
Bus32	330	0.047813	105	5.826538	0	0	7015.604
Bus33	330	-0.03171	300	-8.744	0	0	25226.75
Bus34	330.9194	-0.07898	-2.2E-13	-9.5E-13	210	158	
Bus35	315.2721	-0.1388	-1.4E-08	1.08E-08	175	131	
Bus36	330	-0.61911	3.65E-09	71.12325	100	55	
Bus37	321.8877	-0.61661	4.07E-09	4.04E-10	95	44	
Bus38	330.99	0.063903	445	60.2379	0	0	26327.36
Bus39	325.4482	0.020744	-3.4E-09	3.1E-10	165	127	
Bus4	339.9	-0.0549	506	385.1352	0	0	41843.87
Bus40	326.632	0.042424	3.67E-11	-1.1E-12	90	68	
Bus41	328.02	0.05225	205	59.14662	0	0	4351.929
Bus5	330	-0.14944	584	-298.261	0	0	16047.9
Bus6	332.7522	-0.06888	1.05E-10	6.39E-10	127	95	
Bus7	317.7729	-0.05901	-9.5E-13	1.84E-10	174	131	
Bus8	328.3344	-0.04046	3.91E-11	5.94E-10	847	635	
Bus9	330	-0.03098	111	-135.398	0	0	9402.705
			4860.455				268045.9

STATE VARIABLES

alpha_Svc_1	2.504828
vm_Svc_1	1
alpha_Svc_2	2.275053
vm_Svc_2	1
alpha_Svc_3	3.14159
vm_Svc_3	1
alpha_Svc_4	2.242569
vm_Svc_4	1

x1_Tcsc_1	3.14159
x1_Tcsc_2	1

OTHER ALGEBRAIC VARIABLES

vref_Svc_1	1.000025
q_Svc_1	2.323055
vref_Svc_2	1.000023
q_Svc_2	0.95805
vref_Svc_3	1.000034
q_Svc_3	3.333333
vref_Svc_4	1.000022
q_Svc_4	0.711233
x0_Tcsc_1	3.14159
pref_Tcsc_1	-2.00331
x0_Tcsc_2	1
pref_Tcsc_2	-3.09355

LINE FLOWS

From Bus	To Bus	Line	P Flow [MW]	Q Flow [MVar]	P Loss [MW]	Q Loss [MVar]
Bus2	Bus3	1	67.32958	-126.931	0.53959	-27.7176
Bus1	Bus2	2	-162	-26.195	3.340845	-95.8185
Bus5	Bus12	3	150.6084	0.286481	1.203419	-45.3307
Bus6	Bus10	4	21.78506	-29.6528	0.019141	-34.641
Bus3	Bus6	5	22.7366	0.365388	0.084461	-63.062
Bus3	Bus6	6	22.7366	0.365388	0.084461	-63.062
Bus8	Bus6	7	35.21099	-69.3012	0.150281	-96.2728
Bus6	Bus7	8	-11.8498	109.8678	0.717434	-37.7962
Bus10	Bus3	9	-78.2341	-70.0117	0.226842	-26.5282
Bus8	Bus14	10	-107.111	97.74793	0.991492	-31.2459
Bus7	Bus14	11	-186.567	16.664	1.330634	-23.5719
Bus21	Bus11	12	-184.646	-16.4879	2.677233	-57.4386
Bus8	Bus15	13	203.4632	150.5819	0.463227	-1.41813
Bus16	Bus8	14	249.5693	163.5586	2.123339	-4.55904
Bus23	Bus16	15	-115	-86	0.105701	-3.44035
Bus16	Bus19	16	96.42644	-40.6446	0.875052	-96.0683
Bus8	Bus18	17	-200.331	-172.089	0	2.277299
Bus18	Bus16	18	-309.355	-263.738	-5.7E-14	18.68795
Bus8	Bus17	19	-41.7644	-53.739	0.193905	-106.993
Bus17	Bus19	20	72.04173	-80.8886	0.647766	-105.868
Bus4	Bus3	21	253	192.5676	0.275219	-0.98015
Bus25	Bus19	22	-83.1668	-54.738	0.553301	-72.9504

Bus19	Bus24	23	-102.984	23.72759	0.718369	-58.5934
Bus25	Bus19	24	-85.0061	-54.8572	0.57738	-72.8624
Bus33	Bus25	25	150	-4.372	0.974658	10.23227
Bus33	Bus25	26	150	-4.372	0.974658	10.23227
Bus19	Bus27	27	-7.29351	17.56332	0.015275	-19.4178
Bus27	Bus26	28	23.03241	-15.3022	0.013045	-24.4813
Bus2	Bus3	29	67.32958	-126.931	0.53959	-27.7176
Bus19	Bus26	30	9.799015	-10.7943	0.007928	-43.1129
Bus24	Bus30	31	384.7278	110.0122	6.209551	11.35001
Bus31	Bus24	32	219	34.30492	1.042006	-14.7904
Bus24	Bus31	33	-217.958	-49.0953	1.042006	-14.7904
Bus24	Bus32	34	-152.514	-4.5007	1.447608	-49.1035
Bus32	Bus38	35	-219.656	-14.1356	0.474957	-5.45468
Bus30	Bus35	36	182.5183	-48.3378	0.134742	-2.31042
Bus25	Bus22	37	346.2235	-9.61339	1.635877	-0.9308
Bus4	Bus3	38	253	192.5676	0.275219	-0.98015
Bus9	Bus19	39	46.15946	-75.5838	0.279903	-97.4594
Bus34	Bus27	40	-77.4739	-50.9026	0.184926	-22.9658
Bus34	Bus26	41	-132.526	-107.097	0.284327	-8.0101
Bus36	Bus29	42	-100	16.12325	0.553107	-46.5705
Bus11	Bus20	43	198.9606	-172.593	4.960563	-86.2878
Bus29	Bus21	44	-301.033	8.529242	8.595194	-26.0913
Bus29	Bus37	45	95.47986	-3.83551	0.479859	-47.8355
Bus13	Bus22	46	-111.635	0.214535	0.65902	-49.1268
Bus3	Bus5	47	127.5477	-25.2727	1.375482	-86.8639
Bus13	Bus22	48	-111.635	0.214535	0.65902	-49.1268
Bus5	Bus13	49	151.8786	-36.1802	0.945882	-36.7258
Bus12	Bus13	50	-153.595	-181.383	0.607254	-6.4055
Bus35	Bus28	51	182.2606	-76.2011	2.493166	-45.8999
Bus21	Bus28	52	-98.491	-1.44577	1.276477	-91.7469
Bus21	Bus28	53	-98.491	-1.44577	1.276477	-91.7469
Bus35	Bus28	54	182.2606	-76.2011	2.493166	-45.8999
Bus39	Bus35	55	364.0145	31.92938	6.87673	7.3042
Bus3	Bus5	56	127.5477	-25.2727	1.375482	-86.8639
Bus39	Bus40	57	-114.437	-15.9985	0.295029	-20.9146
Bus6	Bus9	58	-56.5703	-21.3887	0.270214	-81.2028
Bus39	Bus32	59	-189.971	-77.1055	0.723088	-12.5406
Bus39	Bus38	60	-224.606	-65.8254	1.262429	-14.2684
Bus11	Bus5	61	-264.142	53.27202	2.786791	-16.3205
Bus40	Bus41	62	-204.732	-63.0838	0.268061	-3.93722
Bus11	Bus5	63	-264.142	53.27202	2.786791	-16.3205

LINE FLOWS

From Bus	To Bus	Line	P Flow [MW]	Q Flow [MVar]	P Loss [MW]	Q Loss [MVar]
Bus3	Bus2	1	-66.79	99.21327	0.53959	-27.7176
Bus2	Bus1	2	165.3408	-69.6235	3.340845	-95.8185
Bus12	Bus5	3	-149.405	-45.6171	1.203419	-45.3307
Bus10	Bus6	4	-21.7659	-4.98825	0.019141	-34.641
Bus6	Bus3	5	-22.6521	-63.4274	0.084461	-63.062
Bus6	Bus3	6	-22.6521	-63.4274	0.084461	-63.062
Bus6	Bus8	7	-35.0607	-26.9716	0.150281	-96.2728
Bus7	Bus6	8	12.56719	-147.664	0.717434	-37.7962
Bus3	Bus10	9	78.46092	43.48359	0.226842	-26.5282
Bus14	Bus8	10	108.1022	-128.994	0.991492	-31.2459
Bus14	Bus7	11	187.8978	-40.2359	1.330634	-23.5719
Bus11	Bus21	12	187.3234	-40.9507	2.677233	-57.4386
Bus15	Bus8	13	-203	-152	0.463227	-1.41813
Bus8	Bus16	14	-247.446	-168.118	2.123339	-4.55904
Bus16	Bus23	15	115.1057	82.55965	0.105701	-3.44035
Bus19	Bus16	16	-95.5514	-55.4237	0.875052	-96.0683
Bus18	Bus8	17	200.3309	174.3666	0	2.277299
Bus16	Bus18	18	309.355	282.4264	-5.7E-14	18.68795
Bus17	Bus8	19	41.95827	-53.2539	0.193905	-106.993
Bus19	Bus17	20	-71.394	-24.9796	0.647766	-105.868
Bus3	Bus4	21	-252.725	-193.548	0.275219	-0.98015
Bus19	Bus25	22	83.72011	-18.2124	0.553301	-72.9504
Bus24	Bus19	23	103.7025	-82.321	0.718369	-58.5934
Bus19	Bus25	24	85.58344	-18.0053	0.57738	-72.8624
Bus25	Bus33	25	-149.025	14.60427	0.974658	10.23227
Bus25	Bus33	26	-149.025	14.60427	0.974658	10.23227
Bus27	Bus19	27	7.308789	-36.9811	0.015275	-19.4178
Bus26	Bus27	28	-23.0194	-9.17918	0.013045	-24.4813
Bus3	Bus2	29	-66.79	99.21327	0.53959	-27.7176
Bus26	Bus19	30	-9.79109	-32.3186	0.007928	-43.1129
Bus30	Bus24	31	-378.518	-98.6622	6.209551	11.35001
Bus24	Bus31	32	-217.958	-49.0953	1.042006	-14.7904
Bus31	Bus24	33	219	34.30492	1.042006	-14.7904
Bus32	Bus24	34	153.9619	-44.6028	1.447608	-49.1035
Bus38	Bus32	35	220.1312	8.680879	0.474957	-5.45468
Bus35	Bus30	36	-182.384	46.02735	0.134742	-2.31042
Bus22	Bus25	37	-344.588	8.682592	1.635877	-0.9308

Bus3	Bus4	38	-252.725	-193.548	0.275219	-0.98015
Bus19	Bus9	39	-45.8796	-21.8755	0.279903	-97.4594
Bus27	Bus34	40	77.6588	27.93673	0.184926	-22.9658
Bus26	Bus34	41	132.8105	99.08733	0.284327	-8.0101
Bus29	Bus36	42	100.5531	-62.6937	0.553107	-46.5705
Bus20	Bus11	43	-194	86.30546	4.960563	-86.2878
Bus21	Bus29	44	309.6282	-34.6206	8.595194	-26.0913
Bus37	Bus29	45	-95	-44	0.479859	-47.8355
Bus22	Bus13	46	112.2938	-49.3413	0.65902	-49.1268
Bus5	Bus3	47	-126.172	-61.5912	1.375482	-86.8639
Bus22	Bus13	48	112.2938	-49.3413	0.65902	-49.1268
Bus13	Bus5	49	-150.933	-0.54558	0.945882	-36.7258
Bus13	Bus12	50	154.2023	174.9774	0.607254	-6.4055
Bus28	Bus35	51	-179.767	30.30114	2.493166	-45.8999
Bus28	Bus21	52	99.76748	-90.3011	1.276477	-91.7469
Bus28	Bus21	53	99.76748	-90.3011	1.276477	-91.7469
Bus28	Bus35	54	-179.767	30.30114	2.493166	-45.8999
Bus35	Bus39	55	-357.138	-24.6252	6.87673	7.3042
Bus5	Bus3	56	-126.172	-61.5912	1.375482	-86.8639
Bus40	Bus39	57	114.7319	-4.91617	0.295029	-20.9146
Bus9	Bus6	58	56.84054	-59.8141	0.270214	-81.2028
Bus32	Bus39	59	190.6944	64.5649	0.723088	-12.5406
Bus38	Bus39	60	225.8688	51.55702	1.262429	-14.2684
Bus5	Bus11	61	266.9288	-69.5925	2.786791	-16.3205
Bus41	Bus40	62	205	59.14662	0.268061	-3.93722
Bus5	Bus11	63	266.9288	-69.5925	2.786791	-16.3205

GLOBAL SUMMARY REPORT

TOTAL GENERATION	
REAL POWER [MW]	4895.455
REACTIVE POWER [MVar]	1226.407
TOTAL LOAD	
REAL POWER [MW]	4819
REACTIVE POWER [MVar]	3551
TOTAL LOSSES	
REAL POWER [MW]	76.45465
REACTIVE POWER [MVar]	-2324.59