VOLTAGE AND STABILITY ANALYSIS OF DISTRIBUTION NETWORKS WITH NON-CONVENTIONAL ENERGY SOURCES

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Dedicated to Dear Sir,
Prof. Akhtar Kalam.

Abstract

The impact of renewable energy installations connected to the utility grid is an important issue concerning the technical and economic viability of harnessing these emerging energy sources. Distribution networks must be carefully controlled in order to maintain an acceptable power supply quality. The major sources of non-conventional energy are small scale generation and storage from mini hydro, photovoltaic, wind power, fuel cells, battery, flywheel, pump storage and biomass.

The aim of this thesis is to analyse the variation in voltage of the distribution network when renewable energy sources are interconnected to the distribution network, in terms of it's stability. In particular this study analyses the impact of interconnection of small synchronous generators to the utility power grid. Dynamic stability analysis is mainly concerned with analysing the response of electrical power system to small perturbation about a given operating point. These studies are particularly important due to the growing interest in interconnecting small renewable energy sources to large and complex power systems. Simulation studies were carried out in order to find out the transient stability and voltage stability of the non-conventional energy sources under different operating conditions. A 5-second simulation was conducted using explicit numerical integration (Euler method) and an integration time step of 0.002 second. Power System Toolbox was used for analysis.The multimachine power system models used in this thesis are generated in MATLAB code. The load flow is performed on the multimachine power system correponding to the loading condition to be investigated. The machines are represented by the two-axis models, the exciters by IEEE Type-1 models and the loads are modelled as constant impedances. To save programming time, it has become common to limit the machine and exciter representations to some specified models. The network admittance matrix is reduced by retaining only the in-

ternal buses of the generators. The reduced network, machine and exciter data are then combined to form a linearised state-space model representing the entire system.

The simulation studies are applied to a four machine ten bus system. It is clear from the analysis that much care should be taken based on the stability point of view while interconnecting the small renewable energy sources to the utility. The renewable energy sources should be interconnected at a point which provides higher stability margin.The renewable energy sources is a viable option if it is connected to the distribution network with necessary methods of improving transient stability and voltage stability.

Declaration

I declare that, to the best of my knowledge, the research described herein is the result of my own work, except where otherwise stated in the text. It is submitted in fulfilment of the candidature for the degree of Masters by Research in Engineering of Victoria University of Technology, Australia. No part of it has already been submitted for any degree nor is being submitted for any other degree.

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List of Abbreviation

1.	AGC	Automatic Generation Control
2.	BMS	Battery Management System
3.	CAA	Clean Air Act
4.	COP	Current Operational Problems
5.	CPI	Common Price Index
6.	DVR	Dynamic Voltage Regulator
7.	DSG	Dispersed Storage and Generation
8.	EPA	Environmental Protection Agency
9.	EPRI	Electric Power Research Institute
10.	FACTS	Flexible AC Transmission System
11.	FERC	Federal Energy Regulator Commission
12.	FUA	Fuel Use Act
13.	GTO	Gate-turn-off thyristor
14.	IEEE	Institute of Electrical and Electronic Engineers
15.	MOS	Metal Oxide Semi-conductor
16.	NAAQS	National Ambient Air Quality Standards
17.	NEAC	National Energy Advisory Committee
18.	NEPA	National Environment Policy Act
19.	NGPA	Natural Gas Policy Act
20.	NSPS	New Source Performance Standards
21.	PSD	Prevention of Significant Deterioration
22.	PSS	Power System Stabiliser
23.	PURPA	Public Utility Regulatory Policies Act
24.	QF	Qualifying Facilities
25.	SAGASCO	South Australia Gas Company
26.	SEC	State Electricity Commission
27.	SMES	Superconducting Magnetic Energy Storage

28.	STATCON	Static Condenser
29.	SVC	Static Var Compensator
30.	SVS	Static Var System
31.	ULTC	Under-load Tap Changer

Nomenclature

x	State Vector of the system
x_i	State Variable of the system
n	no.of inputs to the system
u	Column vector of input to the system
$\dot{x}$	derivative of the state variable x
y	column vector of outputs
g	vector relating input variables to output variables
Δ	small deviation
λ	eigen values of A
ϕ	eigen vectors of A
ψ_i	left eigen vector
c_i	non zero constant
ε	Perturbation constant
n	dependant variable
t	time
H_a	Magnetizing field intensity

H_m	Magnetic Permeability
H_s	Hysteresis loss
N	turn winding
R_w	total resistance in ohms
R_n	Reluctance
S_m	non linear hysteresis parameter
$f_m(f)$	non-linear function of flux
$f_s(\frac{df}{dt})$	rate of change of flux
L	non linear inductance
R	non linear resistance
i_1	Primary current in transformer
i_2	Secondary current in transformer
$\tan(\delta)$	capacitor loss angle
$f_e(q)$	non linear capacitance as a function of charge
$f_e(q')$	non linear conductance as a function of rate of change charge
p(t)	electronic polarisation
k	integer time step

k_E	exciter constant
v_R	Voltage regulator output
v_{Rmax}	maximum voltage regulator output
v_{Rmin}	minimum voltage regulator output
E_{fd}	machine field voltage
Y_N	network node admittance matrix
OXL	overexcitation limiter
I_{fd}	direct axis field current
I_{LIM}	over excitation limiter current
C_c	Coupling Capacitance
ST3	Statis rectifier
Δw	rotor angular velocity
$\Delta\delta$	rotor angular displacement
b	frequency of oscillation
$\frac{1}{a}$	time constant
SVSs	Static Var Systems
Δx	state vector of dimension n

Δy	output vector of dimension m
Δu	input vector of dimension r
x_l	leakage reactance
r_a	resistance
x_d	d-axis sychronous reactance
x'_d	d-axis transient reactance
x"_d	d-axis subtransient reactance
T'_do	d-axis open-circuit time constant
T"_do	d-axis open-circuit subtransient time constant
x_q	q-axis sychronous reactance
x'_q	q-axis transient reactance
x"_q	q-axis subtransient reactance
T'_qo	q-axis open-circuit time constant
T"_qo	q-axis open circuit subtransient time constant
H	inertia constant
d_o	damping coefficient
d_1	dampling coefficient

Publication

The research that leads to this thesis has also resulted in the following conference paper publications.

[1] G. Ranjan Mohapatra, A.Kalam, A.Zayegh, R.J.Coulter, "Dynamic modelling of DistributionNetwork with Non-conventional Energy Sources", Australiasia Power Engineering Conference (AUPEC-96). October 22 - 24, Melbourne University, Melbourne.

[2] G. Ranjan Mohapatra, A.Kalam, A.Zayegh, R.J.Coulter, "Issues of concern in a Distribution Network with non-conventional energy sources", University Power Engineering Conference (UPEC-96). September 22 - 24, Greece.

[3] R. Nayak, G. Ranjan Mohapatra, A.Kalam, A.Zayegh, "Modern concept of Boiler Management", Australiasia Power Engineering Conference (AUPEC-96). October 22 - 24, Melbourne University, Melbourne.

[4] G. Ranjan Mohapatra, A.Kalam, A.Zayegh, R.J.Coulter, "Voltage Stability Study of Distribution network with Non-conventional Energy sources", Third International Conference on Modelling and Simulation (MS'97), October 29-31, Victoria University of Technology, Melbourne.

[5] G. Ranjan Mohapatra, A.Kalam, A.Zayegh, R.J.Coulter, "Transient Study of Distribution network with non-conventional energy sources", Third International Conference on Modelling and Simulation (MS'97), October 29-31, Victoria University of Technology, Melbourne.

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Introduction and Review

1.1 Introduction

Industrial and commercial customers are adding computer controlled and microprocessor based equipment for automated control, information management and robotics at an ever increasing rate [1]. One of the requirements for these sophisticated devices is the need for high quality power containing minimal voltage variations, because these devices are all susceptible to supply disturbances. The economical and potential safety and environmental impacts of such disturbances can be substantial, compared to residential and typical small commercial loads [2]. The performance of these sophisticated devices can be adversely affected by line voltage sags, surges, transients and harmonic distortions in the power supply. These disturbances can be caused by faults, circuit breaker reclosing, feeder switching actions or switching on capacitor banks. Traditionally, the power supply is from conventional energy sources. The expression conventional energy refers to power generation from coal, large scale hydro, gas and nuclear power. The expression non-conventional energy sources covers COGENERATION, RENEWABLE ENERGY SOURCES, STANDBY GENERATION and ENERGY STORAGE. In practice non-conventional energy sources are connected at the load centre through power electronic controllers. Currently the trend is to use advanced power electronic controllers, such as solid state circuit breakers, Dynamic Voltage Regulators (DVR) and Static Condensers (STATCON). These power electronic controllers are connected along the distribution line [1].

Private owned generating plant has the capacity to make a useful contribution towards meeting the energy demand on the distribution network. COGENERATION is the simultaneous generation of useful heat and electricity from the same primary fuel source. Typically, the heat energy is in the form of process steam, and fuels are either natural gas or process waste gas.

RENEWABLE ENERGY SOURCES are a manifestation of nature's primary energy. Most of the energy captured by the earth comes from the sun in the form of light and heat. The incident solar radiation energy, wind energy, biomass, tidal & wave energy, hydro or water power and geothermal energy are energy sources that do not pollute the atmosphere. Unlike fossil fuel sources these renewable energy sources do not contribute to 'Greenhouse' effect.

Large scale hydro electric plants were the earliest to be harnessed to provide clean energy. Fossil fuel power plants were promoted till the time it was realised that they were one of the main causes of greenhouse gas emissions. With the development of technology, projects that were discarded as being uneconomical are being reviewed taking into account the environmental impact.

STANDBY GENERATION is where customers require a particularly high level of supply reliability and/of availability and they install their own generating plant and security against non-availability of supply authority sources energy because of industrial disputes or supply interruptions. A cogeneration scheme may also fill a stand-by generation role.

ENERGY STORAGE refers to mainly battery, fly wheel, high pressure compress air storage and pump storage.

Integrating Dispersed Sources of Generation (DSG) can provide electric utilities with a technology option that gives high quality, value added power supply suitable for customers' sensitive loads. Connecting DSG has several impacts on the operation and protection of the whole system. This thesis relates to the analysis of dynamic behaviour of the dispersed storage and generation unit interconnected to distribution network in terms of its stability. Simulation studies were carried out to find the transient stability and voltage stability of the non-conventional energy sources under different operating conditions. A 5-second simulation was conducted using explicitly numerical integration (Euler method) and an integration time step of 0.002 second. A synchronous generator, plays the role of a DSG unit which is a common form of renewable energy scheme or cogenerator.

1.2 Dispersed Storage Generation

1.2.1 Introduction

Limited availability of fossil fuels, and the damage its usage causes to the environment has prompted active research into alternative, cleaner energy sources. Energy sources such as wind, solar, tidal, wave, hydro, biomass and geothermal are potential reusable/renewable energy sources. Most of these renewable energy sources are not suitable for producing electric power at a continuous rate as their energy levels fluctuate with time. Currently, these sources of energy are being utilised in small scale production of electric power, mostly in remote areas. In some cases hybrid systems have been tried and proved that utility grade electric power can be produced using these energy sources but still in limited capacity due to practical and economical limitations [3] [4]. In the meantime, to limit the usage of fossil fuels, most governments are encouraging private generators. In large industries and commercial centres where steam is required for processes and/or heating, cogeneration is widely considered as a mean of combined heat and power production to improve energy efficiency.

1.2.1.1 Significance of Cogeneration

Cogeneration, as a mean of energy efficient production of both heat and power, is spreading in large industries and commercial centres in many countries. This trend is due to several practical and economic advantages such as:

- Energy efficiency - more efficient use of fuel with combined production of electricity and steam where steam is required for production processes and/or heating.
- Security of power supply - having an in-house power plant in parallel

operation with utility supply will enhance reliability of supply to vital loads.

- Economy and reduction in environmental damage - availability of waste fuels as a consequence of production process in some industries, such as oil refineries, which can be used for firing in steam generators. This fuel is free, and burning it in the atmosphere could result in emitting more lethal gases into the environment.

- Revenue to cogenerator - opportunity for cogenerators to sell excess power to utility at profitable prices, mainly during peak demand period on the utility system.

- Having dispersed sources of generations, such as cogenerators, connected to utility system will render following advantages to utility systems:

    a. Possibility of meeting short term peak demand on the utility system by buying power from cogenerators and thus avoiding starting peak load plants - Peak lopping.

    b. Maintain a better voltage profile throughout the system.

    c. Availability of more spinning reserve in the system.

    d. Possibility of accommodating more new consumers on the existing utility network without having to augment or construct new transmission and/or distribution network.

Although the effectiveness of above advantages to utilities is case dependent at any one time. On the long run, more and more utilities may begin to realise these benefits as their system demand grows.

The advantages stated above indicate the significance of cogeneration. However, it is to be noted that when a cogenerator is connected to a utility, it becomes part of the utility system. Such a system has several impacts on the utility and on the cogenerator, which are discussed in subsequent sections.

1.2.2 Cogeneration in United States of America

One of the intentions of the Public Utility Regulatory Policies Act (PURPA) of 1978 [5] was to promote the development of small, dispersed generation sources. This has sparked much interest in the American electric utility industry which has now been forced to tackle technical problems associated with the interconnection of Dispersed Storage and Generation (DSG) devices. Under the PURPA, Qualifying Facilities (QFs) may be a unit supplying some or all of an existing or new load, or it may be renewable resources such as wind generation, or geothermal, solar, bio-mass, or mini hydro-electric generation.

Section 210(a) of PURPA also requires that each electric utility offer to sell electric energy to a QF. This obligation to sell power is interpreted as requiring utilities to provide four classes of service to QF's [6][7][8][9]:

(a) "Supplementary Power", which is energy or capacity used by a QF in addition to that which is generated itself;

(b) "Interruptable Power", which is energy or capacity that is subject to interruption by the utility under specified conditions, and is normally provided at a lower rate than non-interruptable service if it enables the utility to reduce peak loads;

(c) "Maintenance Power", which is energy or capacity supplied during scheduled outages of the QF, presumably during periods when the utility's other load is low;

(d) "Backup Power", which is the energy or capacity supplied during unscheduled outages.

A utility may avoid providing any of these four classes of service only if it convinces the Public Service Commission that compliance would impair its ability to render adequate service or would place an undue burden on the electric utility.

Interconnection costs must be assessed on a non-discriminatory basis with respect to non-cogenerating customers with similar load characteristics, and may not duplicate any costs including the avoided costs. Standard or class charges for interconnection may be included in purchase power tariffs for QFs with a design capacity of 100 kW or less, and Public Service Commissions may also determine interconnection costs for larger facilities on either a class or individual basis.

Cogenerators' fuel choice may be influenced by the Fuel Use Act (FUA) prohibitions on oil and gas use and by the allocation and pricing rules of Natural Gas Policy Act of 1978 (NGPA), as well as by the environmental requirements and tax incentives.

A cogenerator may be subject to the FUA prohibitions if it has a fuel heat input rate 100 of million Btu per hour or greater and if it comes within the statutory definition of either a power plant or a major fuel-burning installation. Under FUA, a power plant includes "any stationary electric generating unit", consisting of a boiler, a gas turbine, or a combined-cycle unit that produces electric power for purposes of sale or exchange", but does not include cogeneration facilities if less than half of the annual electric output is sold or exchanged for resale. A major fuel-burning installation is defined as "a stationary unit consisting of a boiler, gas turbine unit, combined cycle unit or internal combustion engine". However, the prohibition against the use of oil and gas in new major fuel-burning installations applies only to boilers.

FUA allows a permanent exemption for cogenerators for if the "economic and other benefits of cogeneration are unobtainable unless petroleum or other gas, or both, are used in such facilities". The Department of Energy interprets the phrase "economic and other benefits" to mean that the oil or gas to be consumed by the cogenerator will be less than that which would otherwise be consumed by the conventional separate electric and thermal energy systems. Alternatively, if the cogenerator can show that the exemption would be in the public interest (e.g., technically innovative facility, or one that would help to maintain employment in an urban area), the Department of Energy will not require a demonstration of oil/gas savings.

Although the permanent exemption for cogeneration is likely to be the preferred route for potential cogenerators subject to the FUA prohibitions. Several other exemptions may be applicable in certain circumstances. First, a permanent exemption is available to petitioners who propose to use a mixture of natural gas or petroleum and alternate fuel. Under this mixtures exemption, the amount of oil or gas to be used cannot exceed the minimum percentage of the total annual Btu heat input of the primary energy source needed to maintain operational reliability of the unit consistent with maintaining a reasonable level of fuel efficiency. Second, a temporary exemption is available to petitioners who plan to use a synthetic fuel (derived from coal or another fuel) by the end of the exemption period. Third, a temporary public interest exemption may be obtained when the petitioner is unable to comply with FUA immediately (but will be able to comply by the end of the exemption). One of the cases where this public interest exemption may be granted is for the use of oil or gas in an existing facility during the ongoing construction of an laternate fuel-fired unit.

Natural Gas Policy Act (NGPA) of 1978 grants an exemption from its incremental pricing provisions to qualify cogeneration facilities under PURPA. Thus, the potential lower gas prices should not affect the relative competitiveness of gas-fired cogeneration significantly. Moreover, plants burning intrastate gas may not realise any savings because the fuel price is often at the same level as the incremental price. In addition, the deregulation could largely remove incremental pricing. These uncertainties mean NGPA probably will not be a major factor in cogeneration investment decisions.

Cogeneration can have significant impacts on air quality, especially in urban areas. Depending on cogenerator's size and location, it may be subject to one or more of the Clean Air Act (CAA) provisions, including New Source Performance Standards (NSPS) and programs for meeting and maintaining the National Ambient Air Quality

Standards (NAAQS) in non-attainment and Prevention significant Deterioration (PSD) areas.

At present, NSPS exist for two types of sources that might be used for cogeneration, and have been proposed for a third. NSPS have been implemented for electric utility steam units of greater than 250-MMBtu/hr. heat input. However, cogeneration facilities in this category are exempt from NSPS if they sell annually less than either 25MW or one-third of their potential capacity. The other promulgated NSPS is for gas turbines of greater than 10 MMBtu/hr. heat input at peak-loads. NSPS have been proposed for nitrogen oxide emissions from both gasoline and diesel stationary engines. As proposed, they would apply to all diesel engines with greater than 560 cubic inch displacement per cylinder. Finally, the Environmental Protection Agency (EPA) is considering NSPS for small fossil fuel boilers. The EPA is reportedly considering lower limits in the range of 50 to 100 MMBtu/hr. heat input.

1.3 Cogeneration in Australia[10]

Cogeneration has existed in Australia since the introduction of electricity. In the early days of electricity, industry often provided its own power (cogeneration where the balance of heat and power was right) and the public system provided domestic and public power.

The 1980's saw an upturn in cogeneration for environmental and economic reasons particularly in Victoria and South Australia. In 1987 the Victorian State Government and State Electricity Commission (SEC) of Victoria introduced a Cogeneration

Incentives Package and about the same time in South Australia, SAGASCO established a cogeneration division.

The 1990's presents an era of great opportunities and challenges for the cogeneration industry as the energy supply industry is transformed by the break-up of vertically integrated utilities (in Victoria) and the introduction of competition between energy supplier and the Grid.

Cogeneration is a smart technical solution to provide heat and power to industry and commerce in a cost effective and environmentally sound manner. Cogeneration exists in a complex competitive and regulatory environment that has capacity to prevent the full development of its contribution to the economy and environment.

1.3.1 Cogeneration data

No authoritative information is available on the extent of non-utility cogeneration and power production.

The best available estimate puts cogeneration capacity in Australia at about 1000 MW, made up as follows:

1.3.2 Victorian support

Within five years, it is conservatively expected that about 500 MW of Victoria's power will be fed into the SEC grid from private and public cogeneration and

Table 1.1 Cogeneration Data

Industry	Capacity(MW)
South Australian Projects	25
Alcoa (Western Australia)	200
Sugar Industry	200
Energy Brix (Victoria)	160
Nabalco (Gove, N. Territory)	115
Queensland Alumina	30
Victorian Projects	200

renewable energy projects, the equivalent to the output from one Loy Yang power station unit.

Already, 100 MW is provided by 15 major natural gas cogenerators. In addition, seven more cogeneration units under construction will provide another 34.4 MW. Further 16 cogeneration projects totalling 138.6 MW and six renewable energy projects totalling 21.2 MW are committed to development.

Table 1.2 Projects operating (Installed prior to 1987)

Organisation	MW Installed	Type
APM, Fairfield and Maryvale	46.0	Steam Turbine
BHP House, Melbourne	6.3	Reciprocating Engine
Cadbury Scheweppes	2.9	Steam Turbine
Kodak, Coburg	1.5	Steam Turbine
MMBW, Carrum	6.0	Reciprocating Engine
TOTAL	**62.7**	

Table 1.3 Projects installed and operational since 1987

Projects	Capacity (MW)	Type
Sirius Biotechnology	1.1	Reciprocating Engine
Nissan Australia, Clayton	5.6	Gas Turbine
Austin Hospital, Heidelberg	3.8	Gas Turbine
APM, Fairfield	7.5	Steam Engine
Sandringham Hospital	0.2	Reciprocating Engine
Ballarat Base Hospital	2.0	Reciprocating Engine
Latrobe University	6.0	Gas Turbine
Unilever	10.0	Gas Turbine
Kyabram Hospital	0.5	Reciprocating Engine
Ringwood Aquatic Centre	0.1	Reciprocating Engine
TOTAL	**36.8**	

Table 1.4 Projects constructed in 1990s

Hospitals	Capacity(MW)	Type
"Big 6" Hospital Project, Dandenong and District	4.2	Gas Turbine
Royal Melbourne	8.4	Gas Turbine
Geelong	4.2	Gas Turbine
Ann Caudle Centre	4.2	Gas Turbine
Alfred Hospital	5.7	Gas Turbine
St.Vincent's	5.7	Gas Turbine
Grace McKellar Centre	2.0	Reciprocating Engine
TOTAL	**34.4**	

1.3.3 SEC Support for cogeneration

Background

Victoria has traditionally relied on its plentiful brown coal resources as a source of base load electricity and on natural gas and hydro for its peak load. It is clear, however, that great potential exists for industry and commerce to contribute economically to electricity production through cogeneration.

The Victorian Government has given cogeneration a high profile and its support for the development of the technology was outlined in the Government Economic Strategy Paper - "Victoria the Next Decade" released in 1984. This was followed by the Government's paper in June 1989 on the Greenhouse Challenge outlined Cogeneration as one of the vehicles to minimise atmospheric emissions of greenhouse gases.

The SEC has adopted the Government's policies in its Cogeneration and Renewable Energy Strategy. This strategy includes:

- encouraging the efficient use of fuel and helping its customers gain the benefits of energy efficiency from cogeneration and renewable energy projects;
- promoting ways of reducing levels of CO_2 emission into the atmosphere by encouraging technology such as cogeneration;

- considering opportunities for joint ventures in potential cogeneration and renewable energy schemes;
- encouraging and promoting commercially viable projects by introducing incentives to stimulate interest in cogeneration and renewable energy projects;
- encouraging the development of a professional and effective cogeneration and renewable energy industry.

To further the commitment in promoting cogeneration in Victoria the following measures are taken:

- providing a market for cogenerated power by enacting a statutory commitment to purchase the power.
- providing reasonable buyback rates for cogenerated power that reward cogenerators but are not subsidised by other customers. This can be done by buying excess power at the SEC's avoided cost, that is, the amount the SEC saves by not generating the power itself.
- making payments to cogenerators who guarantee the availability of future capacity. These payments reflect the amount the SEC saves by the deferral or elimination of the need for some future power stations.
- adopting a new approach to stand-by supplies to remove current discrimination against cogenerators.
- examination of wheeling policies to encourage worthwhile cogen-

eration projects to proceed.

1.3.3.1 Examining fuel policies and prices

- In recognition that a high proportion of potential cogenerators are now burning natural gas to produce process heat or steam, users should be encouraged to convert to cogeneration as a small addition amount of gas burned can yield an overall energy saving.
- Encourage the use of coal in cogeneration systems.
- Examining the pricing structure of natural gas for cogeneration. Evaluation of the merits of a separate cogeneration gas tariff and its effect on the existing Government gas pricing policy.
- Encourage the use of renewable fuels and residues through provision of Government financial incentives.
- Provide financial assistance for feasibility studies for projects that on initial assessment look technically feasible and economically viable.
- Encourage projects to serve as local models and using early studies to evaluate effectiveness of efforts to promote cogeneration.

The key elements of the SEC incentives package for projects smaller than 10 Megawatts are:

- for sites which take SEC power in addition to cogeneration, the stand-by demand charge is waived for three years,

- SEC interconnection costs are repayable over the contract period,
- SEC buyback rates up to 10 MW are tied to the SEC's tariff rate and are linked to CPI increases,
- financial assistance is available for feasibility studies for special projects,
- a 10 year contract period that allows for escalation in buyback rates.

In 1987, the SEC in conjunction with the Victorian Government took the initiative by launching the "Cogeneration and Renewable Energy Incentive Package" to further encourage the smaller potential cogenerators.

1.3.3.2 Encouraging Co-generation in private and public sectors

- Carrying out a detailed examination of cogeneration potential into public facilities e.g., hospitals, universities, libraries, nursing homes etc.
- Installing and promoting the installation of cogeneration plants instead of constructing additional new central power stations.
- Encouraging financing of Private and Public sector projects by outside investors.

1.3.3.3 Undertaking an information and technical assistance program

- Developing a marketing plan to promote the development and wider use of cogeneration.
- Developing publications to promote the awareness of the opportunities

arising from cogeneration in the community, particularly the industrial and commercial sectors.

- Establishing a Cogeneration Advisory Group to help potential cogenerators and provide a consultative service.

Some people are still surprised that the SEC synonyms with what they believe is a power monopoly, should be promoting alternative production. The reasons are not only economically and environmentally sound, but also ensure efficient utilisation of the State's resources. It costs the Commission about $1.3 million to produce one Megawatt of power. Therefore 500 MW of cogeneration power will save it $650 million in capital expenditure. The SEC benefits directly by avoiding capital borrowing, particularly for the construction of new power stations. In 1994 a process for a great deal of change began when the breakdown and privatisation of SEC commenced. The first step towards privatisation of SEC was the break up of the company into separate business groups, such as Generation, Transmission and Distribution. Then each of these groups were further broken up with respect to the area of Distribution. The supply of power throughout Victoria is now the responsibility of five distribution companies. These are United Energy, Eastern Energy, Solaris Power, CitiPower and Powercor Australia.

Cogeneration also creates new electricity supplies much faster than the Commission could plan and build new power stations, which take many years from inception to production. Small generation plants whether cogeneration or renewable also meet environmental licensing requirements more easily than a new central power station. They can also introduce power into the system near to the point of use and reduce system losses.

1.4 Integration of Dispersed Storage Generation

One of the important reasons for parallel operation of a cogenerator with a utility, as mentioned earlier, is to maintain reliable supply to vital local loads. Therefore, it is of paramount importance to secure a cogenerator from tripping, following separation from the utility, for any abnormality on the utility system. A cogenerator separated from the utility may become unstable and trip due to generation - demand mismatch on the cogeneration system. To secure the cogenerator from such an event, proper decision making, and faster, control is necessary on the cogenerator. The control must be fast enough to bring the cogenerator back to stable and normal operating conditions before any protection relay operates. Also, such control is necessary to prevent any damage to cogenerator or any plant supplied by the cogenerator [11].

Over the last decade there has been a growing interest in the installation of small and medium sized generation units which operate in parallel with the local electric utility's power supply defined as Dispersed Storage and Generation (DSG). The utilities' objective has been to ensure that the presence of the DSG unit will not detract from the quality of supply to all customers connected to their system [12].

The major areas of concern are:

1. the adequacy of present protection practices and hardware for electric distribution systems with DSG [2];

2. protection consideration other than surge protection, associated with the connection of small DSGs to the utility distribution lines [13];

3. the issue of the effect of synchronous generators with different kinds of exciter control as well as induction generators and constant extinction angle inverters with or without capacitor compensations on the voltage in the distribution system as load and generated power vary [15];

4. the issue of power constraint of the cogeneration process, control of tie-lines to cogeneration plants, voltage support, energy response and maintenance [14];

5. the issue of technical planning problem associated with system protection, under frequency load shedding and needs for long term operation planning [16];

6. the issues such as outage planning, services restoration, special relay protection under operating problems with cogeneration on distribution systems needs to be considered [17].

For effective operation as part of the utility, a DSG must be integrated. Integration is defined as follows:

1) a DSG connection to a utility system in which provisions are made for protection of the DSG as well as the system.

2) the operation of the DSG as managed part of the total utility supply system.

3) A single DSG unit of relatively small output, or a number of DSG units of whose aggregate output is small, may be connected to a system without being integrated i.e., they may be connected but not integrated as a managed part of the supply mix. Integrated operations require interaction among the DSGs and the power system, including the electric utility's bulk supply systems.

1.4.1 Operational Problems

Cogeneration has impacted the utility generation due to their base load mode of operation. This base load usually compounds the utility's daily unit commitment problems associated with unit cycling, control reserves, and minimum load. The utility experiences a significant decrease in operating flexibility. Base load cogeneration effectively removes constant load of this utility. The worst case scenario is a cogenerator who sells to the utility only during the off peak, termed off peak dumping. To avoid this undesirable situation, four different types of contracts are advised:

- Firm capacity contracts
- Non-firm energy sales only contract
- Wheeling contracts
- Combination of the above.

The operational problems from cogenerator's point of view are that the basic philosophy behind design of QF generating facilities are much different than that typically used by utilities. Where the utility must design to meet the growing and periodically swinging electrical loads, the QF's concerns lie primarily with meeting thermal demands of manufacturing processes. Design of electrical capabilities then follows, but does not usually constitute the primary design constraint.

It is often difficult to comply with the expectations of and rules imposed by utilities. In some cases, this compliance is realised at significant economic expenses.

IEEE formed a Working Group on Current Operational Problems (COPS) with the goal of focusing attention of the industry on problems faced by those who are involved in actual power. Eight system operational areas are identified:

- operations planning
- normal systems operations
- emergency system operations
- system restoration
- interconnections and pooling
- dispatcher selection and training
- system operations management
- control centre design and maintenance.

The group surveyed, conducted numerous technical sessions and published papers. The mathematical modelling aspects of various types of cogeneration facilities along with the linear program optimisation procedures implemented to arrive at optimum operational schedules have been reported.

The aspects of energy management most impacted by DSG are associated with real time control. Automatic generation control (AGC) can be influenced by the addition of DSGs within the control area. The position of a scheduled DSG is dependent upon considerations of economic dispatch, and will also depend on the resource of the DSG. AGC is affected in two ways by unschedulable DSGs. First, the position in the loading order must be determined, but unlike the case of a scheduled DSG, the addition of a considerable penetration of uncontrollable power sources could influence existing generation.

If a DSG has independent voltage control capability, it can and must be operated cooperatively with any method of DSG voltage control on existing power system. Protection of radial feeders is generally by breakers or reclosures at the distribution substation, tripped by the action of an overcurrent relay. Protection of laterals and transformers is generally by use of fuses, including current limiting types. Intertie protection schemes using undervoltage, overvoltage, underfrequency, overfrequency, voltage-controlled or voltage compensated, batter/DC undervoltage, reverse power are reported by the Power System Relaying Committee of IEEE [13]. The committee has prepared a consumer-utility guide to establish a common understanding amongst those involved in the intertie design.

Some changes in the safety practices and protection hardware are required for low penetration of DSG devices. Additional feeder switches and lock-out disconnect switches at the DSG installations would reduce the size of feeder sections with DSG and prevent the re-energisation of a de-energised feeder section during maintenance. Because of DSG infeed to faults, fuse sizes may need to be increased and reclosure settings delayed to prevent damage to DSG devices operating out of-phase with the utility system following the occurrence of a system disturbance. The placement of capacitors to correct the power factor must take into consideration the possibility of DSG islanding and resonant overvoltage situations.

Automated systems and microprocessor-based protection packages may be a more practical and safer method for controlling the operation of DSG devices and protecting and distribution system.

Also, the small storage and generation systems connected to the distribution system are expected to increase in importance as industrial cogenerators [15]. Home owners with solar arrays or wind turbines and utility with small hydro resources seek to hold down their energy costs. As the amount of generation and storage provided in this way increases, the need to control and monitor them in an integrated fashion will become increasingly evident [16]. While providing economic and environmental benefits, DSGs can create economic, technical, legal and safety concern for the owners, the electric utilities, and other utility customers [16].

Further literature survey indicates that current interest of research on dispersed sources of generation vastly centres on cogeneration systems and their interconnection with power utilities for parallel operation. In that, more focus is given for the protection of a utility inter-tie with a cogeneration facility. The protection requirements on an inter-tie and the complexity in coordinating such protection will depend on the type of connection and operating voltage level [18].

In an industrial power system where a cogenerator is connected to a common high voltage busbar with the utility supply and local distribution feeders, it is important to accurately locate and isolate any fault. Fault can be on the industrial generator, on an industrial distribution circuit, on the utility interconnection, or on some other utility circuit. Fast and dependable fault discrimination technique is important for fast clearance of any fault and at the same time to avoid nuisance tripping of any plant.

Salman and Mollah [19] have presented a technique to detect, locate and identify a fault on such an integrated system. This technique is based on detection of reversal of current flow directions at various locations in the system. The logic used to locate a fault is dependent on the current flow direction on the inter-tie as well. Therefore, it should be noted that, from an exact or near float condition, a small fluctuation of power flow on the inter-tie, possibly due to a sudden change of industrial load, can be interpreted, as per the logic, as a three phase fault on an industrial distribution circuit. Instead of comparing only the signs of the imaginary component of the complex current as suggested by Salman and Mollah [19], a current magnitude check as well may avoid this ambiguity. This method can be easily applied for a simple system configuration. However, for complex cases like a tap off inter-tie and an integrated cogenerator connection, application of this method will require careful analysis.

1.5 Power Electronic Controllers

In the last 30 years, power electronic applications have arisen in electrical power transmission systems primarily in high-voltage direct current transmission. In the last 15 years, however, there has been substantial installation of Static Var Compensators (SVCs) connected to AC transmission lines[17]. Because of the success of these systems the idea of Flexible AC Transmission System (FACTS) evolved. FACTS includes a new generation of systems based on power electronic devices which are capable not only of being switched on but also of being switched off. An example is the Gate-turn-off (GTO) thyristor [20]. The concept of "Custom Power" which focuses on reliability and quality of power flow, has been familiar to a specialised group of distribution engineers since 1988 [1].

Anticipated developments in the utility industry will enlarge the potential for "Custom Power". Superconducting magnetic energy storage was originally proposed for use by utilities to help them meet peak electricity demands. In 1970's feasibility studies in the United States resulted in conceptual design of a large Superconducting Magnetic Energy Storage (SMES) system. In 1988, Superconductivity Inc. began examining applications of smaller SMES units for power qualities uses, which demand rather little in the way of energy storage but quite a lot in the way of power delivery. In 1992, an integrated quench detection and protection system for the SMES was developed at Monash University [21]. In 1993, optimal application of SMES for small-signal stability enhancement in power system was also developed [22].

One of the key components of the distribution network is the power electronic controllers. Improved capabilities and availability of power semiconductor devices and microprocessors have lead to electronic control of distribution systems. Electric Power Research Institute (EPRI), through its Flexible AC Transmission System (FACTS) program which allows a greater control of power flow and a secure loading of transmission lines to levels nearer to their thermal limits, has developed power electronics technology to achieve better control of utility's transmission systems. Further, these devices can reduce distribution system and customer losses. These efforts will prove useful for the development of distribution class controllers [20]. Prototype circuit breakers and static condensers are based on gate turn-off (GTO) thyristor technology and are designed for applications on 15 kV distribution systems. The final version of both controllers are based on advanced metal oxide silicon (MOS) controlled thyristor [1].

1.6 Storage Batteries

Storage batteries represent another key component of the distribution network. Energy storage that could curtail peak demand when the most difficult operational problems occur offers a promising approach. Major developments and the corresponding benefits are as follows:

1. Micro SMES technology has advantages compared to battery, capacitor, flywheel, and other energy storage systems, in terms of its characteristics such as energy density, charge-discharge-cycle efficiency, environmental effects and reliability. Each of the storage technologies is intrinsically better suited to some

applications than others. Some are best suited for charge-discharge times measured in hours, whereas others are best for millisecond cycles. Power-delivery levels can range from a few to thousands of kilowatts [23].

2. Battery management system (BMS) using the latest semiconductor control devices focuses on maximising the discharge and recharge efficiency of an operating battery. This is done by monitoring and controlling individual cell performance at minimum cost. The system can predict battery energy balance by estimating deliverable service capacity at each cycle and it can also estimate capacity returned during regenerative braking in an operating battery [24].

3. While significant progress has been made in obtaining higher performance and longer battery life, the microprocessor based BMS has become a more valuable tool with remote site installations. Instantaneous data retrieval, detailed history data bases, and automated system adjustments without the need of additional personnel are some of the attractive benefits associated with the investment in a BMS [25].

4. The primary benefit obtained by using micro-computer equipment in battery monitoring applications appears to be the reduced need for routine maintenance once such a system is installed [26].

5. The system designer can partition the battery management functions to get many advanced functions presently supported by intelligent battery packs in a system that uses a non-intelligent battery pack with extra features in the power

supply at significant lower system cost [27].

6. One overriding concern pertaining to batteries and power sources in general is the need to avoid a proliferation of battery types. To minimise proliferation, a standard family of batteries, both primary and rechargeable have been identified for future needs. They are:

   - High energy density primary batteries to serve as the next generation of general purpose high energy density batteries, as well as maximum energy density batteries for use in selected applications.
   - Improve rechargeable batteries for use in power equipment for command, control, communications, computer and intelligence uses.
   - Improved reserve/fuse batteries for use in lithium-based and longer life batteries for delivering a few kilowatts for several minutes.
   - Pulse batteries and capacitors for use in mobile applications, which deliver power on the order of several MJ in few milliseconds.
   - Portable fuel cell systems: there is an on-going and increasing need for lighter weight power sources for use in a range of portable applications. Backpack fuel cell "batteries" powered by hydrogen, menthol, or eventually diesel fuel, have the potential to exceed the energy density of a battery, since they can use air as the oxidant.
   - Silent portable power generation which is capable of operating on diesel fuel such as efficient thermophotovoltaic systems [28].

1.7 Further Reviews

Other literature review reveals that placement of variety of controllers can require significant coordination to ensure proper operation under variety of circumstances [29].

Power system studies have been carried out using the network configuration containing a DSG unit to examine the requirements of an islanding, or 'loss of grid', protection and outlines the principal methods used for this type of relaying. A new protection algorithm has been introduced which is based on the rate of change of power as measured at the generator's terminal [30].

Computer modelling has been carried out to verify the PV power system operation and to examine the transient effects [31].

Further literature survey in the subject reveals that significant amount of work has been carried out so far on control of DSG or cogeneration system, operating in parallel with utility [30]. Work on modelling of photovoltaic cell has also been carried out [31]. However, the research to date has not provided enough information on how the system behaves under different operating conditions, when non-conventional energy sources are connected to a system. The proposed research will provide much of the information that is required when non-conventional energy sources are connected to a distribution system.

The strategy of implementing this technology stays on the basic assumption that it provides the lowest cost solution. Surveys [30],[31] have been carried out with the application of a variety of controllers along with the DSGs and how they interact with each other to provide the needed response to attend to the various contingencies. Distribution network with such components has been modelled to find out the voltage drop, transients, fault level and optimisation. Also planning and careful implementation of software control for protection and associated strategies to bring about the smooth and effective operation of various controllers connected in the distribution network has been discussed.

Most of the distribution companies have been concerned about the impact of non-conventional energy on the operation of their distribution systems. The following are some of the advantages of implementing this combined system in the distribution companies:

1. better demand forecasting, particularly at peak periods;

2. planning for new substations, uncertain load growth will be possible;

3. adequacy of distribution alternatives can be tested for different operating conditions;

4. distribution alternatives can be examined on the basis of the contingency analysis considering credible line outage conditions.

5. system capacity can be tested for returning to synchronism after recovery following a major system fault.

6. utilisation of the available distribution corridors in an optimal manner.

1.8 Scope and Objective

The objective of the project is to model a distribution network with dispersed storage and generation (DSG) so as to generate and distribute high quality, value added power to customers in a stable (sustaining small disturbances), viable (currents, voltage, angle and frequencies within tolerances) and optimal supply.

A computer simulation package using Power System Toolbox under MATLAB environment has been developed that has incorporated the above network model and that will provide an inexpensive and reliable method of examining the above system problems. It is envisaged that in future, such concerns as power quality and control optimisation will be addressed using computer models.

The main objectives of this thesis are:

1. To develop a mathematical model to test the responses of the distribution system to the following:

   - voltage stability,
   - transient conditions,
   - fault conditions,

   and to design a network for the future.

2. To use the simulation model to examine phenomena such as voltage drop,

transient effects, short circuit and stability of systems. The analysis will help to determine the ratings of protective devices to study voltage sensitivity of the components of the system, and to establish when cables, transformers and lines are overloaded.

1.9 Originality of Thesis

1. A mathematical model for the configuration has been developed. The formulation of fundamental equations is based on establishing explicit relations between the system dynamic components. The Power System Toolbox package has been used to solve the coupled non-linear fundamental equations for impedance and high frequency losses.

2. The computer simulation is performed as a part of the study to address the adequacy of the electric utility industry's present protection practices on the distribution system with DSGs. Simulation considers phenomena such as voltage drop, transient effects, short circuit effect and sensitivity.

3. The harmonics of the system has been examined by making use of the equations that couple inductance and capacitance. It is planned to optimise these systems to minimise the magnitudes of the harmonics.

4. The model can be used to calculate all necessary momentary, interrupting and relay currents for setting all types of protective devices.

5. System data used for the above studies and their results are documented for analysis and implementation of most appropriate protection algorithm for the configuration.

1.10 Development of Thesis

The development of the subject matter of the investigation reported in the thesis is on the following lines:

Chapter 1: The first chapter explains the issues of Disperse Sources Generation and review of the non-conventional energy sources.

Chapter 2: This chapter explains the mathematical theory on which the models are based and the describe the capabilities of the Power System Toolbox program.

Chapter 3: In this section we will study the small-signal performance of a single synchronous machine which is considered as a non-conventional energy source connected to a large system through distribution lines. Transient stability study of Multi-machine multi bus system also considered.

Chapter 4: The aim of this section is to analyse the variation in voltage of the distribution network when renewable energy sources interconnected to the distribution network, in terms of its stability. In particular this study analyses the impact of interconnection of small synchronous generators to the utility power grid.

Chapter 5: This chapter describes the salient features of the distribution system characteristics. Operational problems like voltage control, harmonics, earthing, reliability etc. are considered. Regulatory and contract issues are also outlined.

Chapter 6: In this section, a review of distribution system protection & control strategies and hardware was carried out to establish 'state-of-the-art' technology currently employed.

Chapter 7: This chapter offers the main conclusions derived from the observed results. Further it points out the direction of future work.

Chapter 2

Mathematical Modelling

2.1 Introduction

The objective of the Distribution network is to generate and to distribute power to its customers in a

- stable (sustaining small disturbances);
- viable (currents, voltages, angles and frequencies within tolerances);
- optimal fashion (economy).

For this operation to be secure, it is also necessary that the system can withstand certain major disturbances such as line faults or sudden loss of equipment without severe consequences. This motivates the notion of dynamic study which is essentially the ability of the system operation to recover a specified set of first contingencies. The system, with suitable degrees of local stability, viability and transient stability, can then be considered to be a secure system [32]. With this assumption as a starting point the connection of the dispersed source of generation and how they interact with the system to provide the needed response to attend to the various contingencies in a distribution network is the major issue of concern. Modelling of the distribution network with these components (as shown in Figure 2.1) to find out the voltage drop, transients, fault level and optimisation along with planning and careful implementation of software control for protection are the strategies to bring about the smooth and effective operation of various controllers connected in the distribution network.

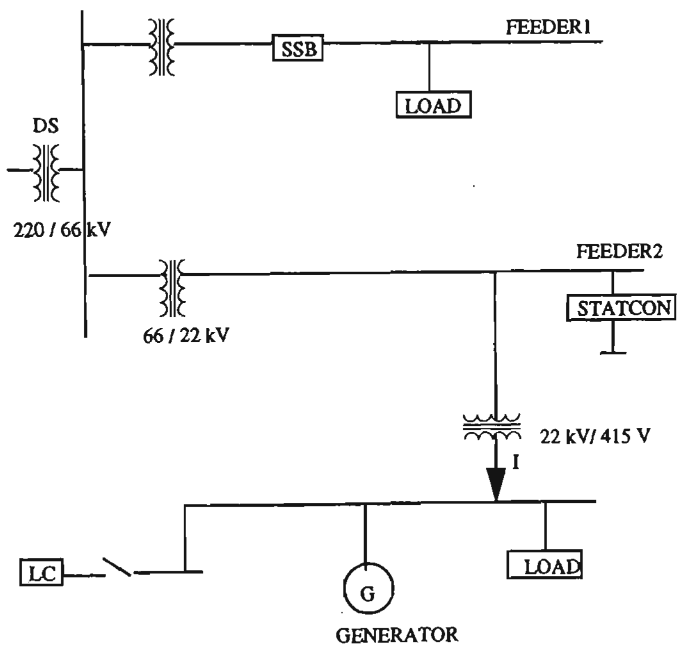


Figure. 2.1 A distribution network connected with a cogenerator

SSB	SOLID STATE CIRCUIT BREAKER
STATCON	STATIC CONDENSOR
LC	INDUCTOR AND CAPACITOR
DS	DISTRIBUTION SUBSTATION

2.1.1 State-Space Representation

The behaviour of a dynamic system, such as a distribution system, may be described by a set of n first order nonlinear ordinary differential equations of the following form:

$$\dot{x}_i = f_i(x_1,x_2,....x_n;\ u_1,u_2,....u_r;\ t) \qquad i = 1,2,....n \tag{2.1}$$

where n is the order of the system and r is the number of inputs. This can be written in the following form by using vector-matrix notation:

$$\dot{x} = f(x,u,t) \tag{2.2}$$

where

$$x = \begin{bmatrix} x1 \\ x2 \\ \cdots \\ xn \end{bmatrix} \qquad u = \begin{bmatrix} u1 \\ u2 \\ \cdots \\ un \end{bmatrix} \qquad f = \begin{bmatrix} f1 \\ f2 \\ \cdots \\ fn \end{bmatrix}$$

The column vector x is referred to as the state vector, and its entries x_i as state variables. The column vector u is the vector of inputs to the system. These are the external signals that influence the performance of the system. Time is denoted by t, and the derivative of a state variable x with respect to time is denoted by $\dot{x}$. If the derivatives of the state variables are not explicit functions of time, the system is said to be autonomous. In this case, above equation simplifies to:

$$\dot{x} = f(x,u) \tag{2.3}$$

The output variables which can be observed on the system, may be expressed in terms of the state variables and the input variables in the following form:

$$y = g(x,u) \tag{2.4}$$

where

$$y = \begin{bmatrix} y1 \\ y2 \\ .. \\ ym \end{bmatrix} \qquad g = \begin{bmatrix} g1 \\ g2 \\ .. \\ gm \end{bmatrix}$$

The column vector y is the vector of outputs, and g is a vector of nonlinear functions relating state and input variables to output variables.

2.1.1.1 The concept of state

The concept of state is fundamental to the state-space approach. The state of a system represents the minimum amount of information about the system at any instant in time t_0 that is necessary so that its future behaviour can be determined without reference to the input before t_0.

Any set of n linearly independent system variables may be used to describe the state of the system. These are referred to as the state variables; they form a minimal set of dynamic variables that, along with the inputs to the system, provide a complete description of the system behaviour. Any other system variables may be determined from a knowledge of the state.

The state variables may be physical quantities in a system such as angle, speed, voltage, or they may be abstract mathematical variables associated with the differential equations describing the dynamics of the system. The choice of the state variables is not unique. This does not mean that the state of the system at any time is not unique; only that the means of representing the state information is not unique. Any set of state variables choosen will provide the same information about the system. The system state may be represented in an n-dimensional Euclidean space called the state space. Whenever the system is not in equilibrium or whenever the input is non-zero, the system state will change with time. The set of points traced by the system state in the state space as the system moves is called the state trajectory.

2.1.1.2 Equilibrium (or singular) point

The equilibrium points are those points where all the derivatives $\dot{x}_1, \dot{x}_2, \ldots, \dot{x}_n$ are simultaneously zero; they define the points on the trajectory with zero velocity. The system is accordingly at rest since all the variables are constant and unvarying with time.

The equilibrium or singular point must therefore satisfy the equation

$$f(x_0) = 0 \tag{2.5}$$

where x_0 is the state vector x at the equilibrium point.

If the functions $f_i(i=1,2,\ldots n)$ in the above equation are linear, then the system is linear. A linear system has only one equilibrium state (if the system matrix is non singular). For a nonlinear system there may be more than one equilibrium point.

The singular points are truly characteristic of the behaviour of the dynamic system, and therefore one can draw conclusions about stability from their nature.

2.1.1.3 Stability of a Dynamic System

The stability of a linear system is entirely independent of the input, and the state of a stable system with zero input will always return to the origin of the state space, independent of the finite initial state.

In contrast, the stability of a nonlinear system depends on the type and magnitude of input, and the initial state. These factors have to be taken into account in defining the stability of a nonlinear system.

In control system theory, it is common practice to classify the stability of a nonlinear system into the following categories, depending on the region of state space in which the state vector ranges:

- Local stability or stability in the small
- Finite stability
- Global stability or stability in the large

Local Stability

The system is said to be locally stable about an equilibrium point if, when subjected to small perturbation. It remains within a small region surrounding the equilibrium point.

If, as t increases, the system returns to the original state, it is said to be asymptotically stable.

It should be noted that the general definition of local stability does not require that the state return to the original state and, therefore includes small limit cycles. In practice, asymptotic stability is of interest.

Local stability (i.e., stability under small disturbance) conditions can be studied by linearising the nonlinear system equations about the equilibrium point in question.

Finite Stability

If the state of a system remains within a finite region R, it is said to be stable within R. If further, the state of the system returns to the original equilibrium point from any point within R, it is asymptotically stable within the finite region R.

Global Stability

The system is said to be globally stable if R includes the entire finite space.

2.1.1.4 Linearisation

This section describes the procedure for linearising equation 2.3. Let x_0 be the initial state vector and u_0 the input vector corresponding to the equilibrium point about which the small-signal performance is to be investigated. Since x_0 and u_0 satisfy equation 2.3, we have

$$\dot{x}_0 = f(x_0, u_0) = 0 \tag{2.6}$$

Let the system be perturb from the above state, by letting

$$x = x_0 + \Delta x \qquad\qquad u = u_0 + \Delta u$$

where the prefix Δ denotes a small deviation.

The new state must satisfy equation 2.3. Hence,

$$\dot{x} = \dot{x}_0 + \Delta\dot{x} = f[(x_0 + \Delta x), (u_0 + \Delta u)] \tag{2.7}$$

As the perturbations are assumed to be small, the nonlinear functions f(x,u) can be expressed in terms of Taylor's series expansion. With terms involving second and higher order powers of Δx and Δu neglected, the above equation can be written as

$$\dot{x} = \dot{x}_{i0} + \Delta\dot{x}_{i0} = f_i[(x_0 + \Delta x), (u_0 + \Delta u)]$$

$$= f_i(x_0, u_0) + \frac{\partial f_i}{\partial x_1}\Delta x_1 + \ldots\ldots + \frac{\partial f_i}{\partial x_n}\Delta x_n + \frac{\partial f_i}{\partial u_1}\Delta u_1 + \ldots\ldots + \frac{\partial f_i}{\partial u_r}\Delta u_r$$

Since $\dot{x}_{i0} = f_i(x_0, u_0)$, Hence

$$\Delta\dot{x}_{i0} = \frac{\partial f_i}{\partial x_1}\Delta x_1 + \ldots\ldots + \frac{\partial f_i}{\partial x_n}\Delta x_n + \frac{\partial f_i}{\partial u_1}\Delta u_1 + \ldots\ldots + \frac{\partial f_i}{\partial u_r}\Delta u_r$$

with $i = 1,2,\ldots,n$.

In a similar manner, from equation 2.4, one can get

$$\Delta y_{j0} = \frac{\partial g_j}{\partial x_1}\Delta x_1 + \ldots\ldots + \frac{\partial g_j}{\partial x_n}\Delta x_n + \frac{\partial g_j}{\partial u_1}\Delta u_1 + \ldots\ldots + \frac{\partial g_j}{\partial u_r}\Delta u_r$$

with $j = 1,2,\ldots\ldots,m$.

Therefore, the linearised forms of equations 2.3 and 2.4 are

$$\Delta\dot{x} = A\Delta x + B\Delta u \qquad (2.8)$$

$$\Delta y = C\Delta x + D\Delta u \qquad (2.9)$$

where

$$A = \begin{bmatrix} \frac{\partial f_1}{\partial x_1} & \cdots & \frac{\partial f_1}{\partial x_n} \\ \cdots & \cdots & \cdots \\ \frac{\partial f_n}{\partial x_1} & \cdots & \frac{\partial f_n}{\partial x_n} \end{bmatrix} \quad B = \begin{bmatrix} \frac{\partial f_1}{\partial u_1} & \cdots & \frac{\partial f_1}{\partial u_r} \\ \cdots & \cdots & \cdots \\ \frac{\partial f_n}{\partial u_1} & \cdots & \frac{\partial f_n}{\partial u_r} \end{bmatrix} \quad C = \begin{bmatrix} \frac{\partial g_1}{\partial x_1} & \cdots & \frac{\partial g_1}{\partial x_n} \\ \cdots & \cdots & \cdots \\ \frac{\partial g_m}{\partial x_1} & \cdots & \frac{\partial g_m}{\partial x_n} \end{bmatrix} \quad D = \begin{bmatrix} \frac{\partial g_1}{\partial u_1} & \cdots & \frac{\partial g_1}{\partial u_r} \\ \cdots & \cdots & \cdots \\ \frac{\partial g_m}{\partial u_1} & \cdots & \frac{\partial g_m}{\partial u_r} \end{bmatrix} \qquad (2.10)$$

The above partial derivatives are evaluated at the equilibrium point about which the small perturbation is being analysed. In equations 2.8 and 2.9,

Δx is the state vector of dimension n

Δy is the output vector of dimension m

Δu is the input vector of dimension r

A is the state or plant matrix of size (n x n)

B is the control or input matrix of size (n x r)

C is the output matrix of size (m x n)

D is the (feedforward) matrix which defines the proportion of input which appears directly in the output, size (m x r)

By taking the Laplace transform of the above equations, the state equations in the frequency domain can be written as follows:

$$s\Delta x(s) - \Delta x(0) = A\Delta x(s) + B\Delta u(s) \tag{2.11}$$
$$\Delta y(s) = C\,\Delta x(s) + D\Delta u(s) \tag{2.12}$$

In representing the transfer function of the system, the initial conditions $\Delta x(0)$ are assumed to be zero.

A formal solution of the state equations can be obtained by solving for $\Delta x(s)$ and evaluating $\Delta y(s)$, as follows:

Rearranging Equation 2.11, the following equation is obtained.

$$(sI - A)\,\Delta x(s) = \Delta x(0) + B\,\Delta u(s)$$

where I = Identity Vector Matrix

Hence,

$$\Delta x(s) = (sI - A)^{-1}\,[\Delta x(0) + B\Delta u(s)] \tag{2.13}$$

$$= \frac{adj(sI - A)}{det(sI - A))}\,[\Delta x(0) + B\Delta u(s)]$$

and correspondingly,

$$\Delta y(s) = C\frac{adj(sI - A)}{det(sI - A))}[\Delta x(0) + B\Delta u(s)] + D\Delta u(s) \tag{2.14}$$

The Laplace transforms of Δx and Δy are seen to have two components, one dependent on the initial conditions and the other on the inputs. These are the Laplace transforms of the free and zero-state components of the state and output vectors. The poles of $\Delta x(s)$ and $\Delta y(s)$ are the roots of the equation

$$\det(sI - A) = 0 \tag{2.15}$$

The values of s which satisfy the above are known as eigenvalues of matrix A, and equation 2.15 is referred to as the characteristic equation of matrix A.

2.1.2 EigenProperties of the State Matrix

2.1.2.1 Eigen Values

The eigen values of a matrix are given by the values of the scalar parameter λ for which there exist non-trivial solutions (i.e., other than $\phi = 0$) to the equation

$$A\phi = \lambda\phi \tag{2.16}$$

where, A is a (nxn) matrix (real for a physical system such as a power system)

ϕ is a (nx1) vector

To find the eigen values, equation 2.16 may be written in the form

$$(A - \lambda I)\phi = 0 \tag{2.17}$$

For a non-trivial solution

$$det(A - \lambda I) = 0 \tag{2.18}$$

Expansion of the determinant gives the characteristic equation. The n solutions of $\lambda = \lambda_1, \lambda_2, \ldots, \lambda_n$ are eigenvalues of A. The eigenvalues may be real or complex. If A is real, complex eigenvalues always occur in conjugate pairs. Similar matrices have identical eigenvalues. It can also be readily shown that a matrix and its transpose have the same eigenvalues.

2.1.2.2 Eigenvectors

For any eigenvalue λ_i, the n-column vector ϕ_i which satisfies equation 2.16 is called the right eigenvector of A associated with the eigenvalue λ_i. Therefore,

$$A\,\phi_i = \lambda_i\,\phi_i \quad \text{where} \qquad i = 1,2,......n \tag{2.19}$$

The eigenvector ϕ_i has the form

$$\phi_i = \begin{bmatrix} \phi_{1i} \\ \phi_{2i} \\ \cdots \\ \phi_{ni} \end{bmatrix}$$

Since equation 2.17 is homogeneous, $k\phi_i$ (where k is a scalar) is also a solution. Thus, the eigenvectors are determined only to within a scalar multiplier.

Similarly, the n-row vector ψ_i which satisfies

$$\psi_i A = \lambda_i\,\psi_i \qquad \text{where } i = 1,2,......n \tag{2.20}$$

is called the left eigenvector associated with the eigenvalue λ_i.

The left and right eigenvectors corresponding to different eigenvalues are orthogonal. In otherwords, if λ_i is not equal to λ_j,

$$\psi_j \phi_i = 0 \tag{2.21}$$

However, in cast of eigenvectors corresponding to the same eigenvalue,

$$\psi_i \phi_i = C_i \tag{2.22}$$

where C_i is a non-zero constant.

Since, as noted above, the eigenvectors are determined only to within a scalar multiplier, it is common practice to normalize these vectors so that

$$\psi_i \phi_i = 1 \tag{2.23}$$

The linearisation of electromechanical models in Power System Toolbox have been performed directly using the function svm_em. The steps required to set up a matrix building program are listed as follows:

1. Input the bus and line data of the system, and obtain a solved loadflow using the function loadflow.

2. Specify the input and output variables, and the perturbation constant ε. Typically $\varepsilon = 0.001$.

3. Use the function red_y bus to construct the reduced admittance matrix for the equilibrium configuration.

4. Initialise the state variables by setting flag=0 and set up the proper sequence of calls to the dynamic model functions.

5. Perturb upward sequentially each state variable and each input variable by ε times the nominal value. If the nominal value is zero, set the perturbation to be ε.

6. Perform the network interface computation by setting flag=1 and repeating the same sequence of calls of the dynamic functions.

7. The machine internal voltages are used to compute the current injections.

8. Perform the dynamics computation by setting flag=2 and repeating the same sequence of calls of the dynamic functions.

9. Divide the derivatives of the state variables (those variables with prefix "d") and the output variables by the perturbation. The results form a column of the A matrix and a column of the C matrix if a state variable is perturbed, or a column of the B matrix and a column of the D matrix if an input variable is perturbed.

To be more accurate, a downward perturbation should also be computed. The state matrices would then be calculated as the average of the upward and downward perturbations.

2.2 Numerical Integration Methods

The differential equations to be solved in power system stability analysis are nonlinear ordinary differential equations with known initial values:

$$\frac{\partial x}{\partial t} = f(x,t) \tag{2.24}$$

where x is the state vector of n dependent variables and t is the independent variable (time). The objective is to solve x as a function of t, with the initial values of x and t equal to x_0 and t_0, respectively.

This section provides a general description of numerical integration methods applicable to the solution of equations for the above form. In describing these methods, without loss of generality, equation 2.24 will be treated as if it were a first order differential equation. This simplifies presentation and makes it easier for reader to comprehend the special features of each method.

2.2.1 Euler Method

Consider the first-order differential equation

$$\frac{\partial x}{\partial t} = f(x,t) \tag{2.25}$$

with $x = x_0$ at $t = t_0$. Figure 2.2 illustrates the principle of applying the Euler method.

At $x = x_0$, $t = t_0$ one can approximate the curve representing the true solution by its tangent having a slope

$$\left.\frac{\partial x}{\partial t}\right|_{x = x0} = f(x_0,t_0)$$

Therefore,

$$\Delta x = \left.\frac{\partial x}{\partial t}\right|_{x = x0} . \Delta t$$

The value of x at $t=t_1=t_0+\Delta t$ is given by

$$x_1 = x_0 + \Delta x = x_0 + \left.\frac{\partial x}{\partial t}\right|_{x = x0} . \Delta t \tag{2.26}$$

The Euler method is equivalent to using the first two terms of the Taylor series expansion for x around the point (x_0,t_0):

$$x_1 = x_0 + \Delta t(\dot{x}0) + \frac{\Delta t^2}{2!}(\ddot{x}0) + \frac{\Delta t^3}{3!}(\dddot{x}0) + \ldots\ldots \quad (2.27)$$

After using the Euler technique for determining $x = x_1$ corresponding to $t=t_1$, another short time step Δt can be taken and x_2 is determine corresponding to $t_2 = t_1 + \Delta t$ as follows:

$$x2 = x1 + \left.\frac{\partial x}{\partial t}\right|_{x = x0} . \Delta t \quad (2.28)$$

By applying the technique successively, values of x can be determined corresponding to different values of t.

The method considers only the first derivative of x and is, therefore, referred to as a first-order method. To give sufficient accuracy for each step, Δt has to be small. This will increase round-off errors, and the computational effort required will be very high.

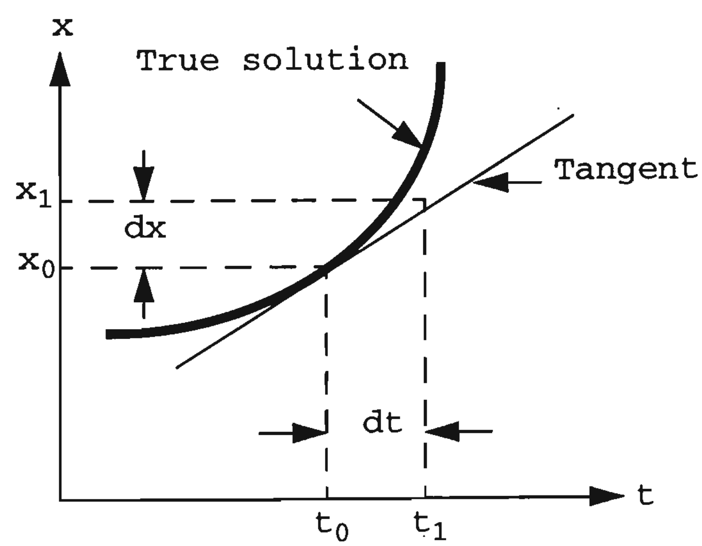


Figure. 2.2. Euler Principle

In the application of numerical integration methods, it is very important to consider the propagation of error, which may cause slight errors made early in the process to be magnified at later steps. Numerical stability depends on the propagation of error. If early errors carry through but cause no significant further errors later, the method is said to be numerically stable. If, on the other hand, early errors cause other large errors later, the method is said to be numerically unstable.

The Euler integration computations in Power System Toolbox have been performed using function eulerint (k,h). This function contains the equation of Euler integration for all the mpc, exciter and svc variables.

Eulerint (k,h) contains the equations of Euler integration for all the machine, exciter and SVC variables. The input variable k is the integer time step of a simulation, and the input variable h is the integration step size. The function eulerint checks for the existence of detailed machine models, excitation systems, power system stabiliser (PSS), turbine-governor models and SVC systems before integration is computed. It can be incorporated as a part of more advanced integration routines.

2.3 Component Modelling

In the design and simulation of power electronics circuits containing energy storage devices, it is desirable to work out lumped circuit models that closely approximate the nonlinearity and the hysteresis loop which usually occurs in devices storing field energy. In this section, efficient and accurate models for nonlinear inductors, capacitors, transformers are presented. The models are based on exhibiting dynamic hysteresis loops from the magnetic and electric field equations; and represent the nonlinear characteristics of the material in terms of stored energy and its rate of change. In addition to hysteresis loss, loss due to increasing operating frequency will be accounted for in the inductor and the transformer models.

2.3.1 Modelling The Inductor

The effects of losses such as core losses, stray capacitance and leakage inductance are very important quantities which must be taken into account whenever a high frequency model of a nonlinear inductor or transformer is desired. With this in mind, useful information can be extracted from the geometry of the hysteresis loop. In Figure 2.3, consider a field point (H_a, B_a) on the hysteresis loop. The magnetizing field intensity H_a is composed of two magnetic field intensities, H_m and H_s, that is,

$$H_a = H_m + H_s = (B_a/m) + (1/s)(dB_a/dt) \tag{2.29}$$

where m denotes the linear magnetic permeability and s is a parameter representing hysteresis loss. In order to ensure proper dynamic modelling, permeability m and the parameter s, in the proposed model is varied with the operating conditions of the circuit.

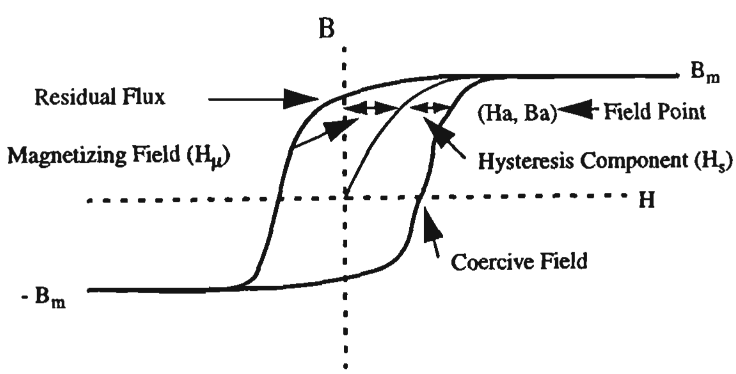


Figure. 2.3. Field point on the hysteresis

The electrical lumped circuit model of the nonlinear inductor is shown in Figure 2.5. The nonlinear inductance L (magnetisation), and the nonlinear resistance R (loss) can be evaluated from the magnetisation curves. Assuming there are N turn windings with a total ohmic resistance R_w, a magnetic path length D, and a cross-sectional area A, a lumped circuit can be used to model the nonlinear inductor. This circuit comprises a winding (electrical circuit) and a nonlinear core (magnetic circuit).

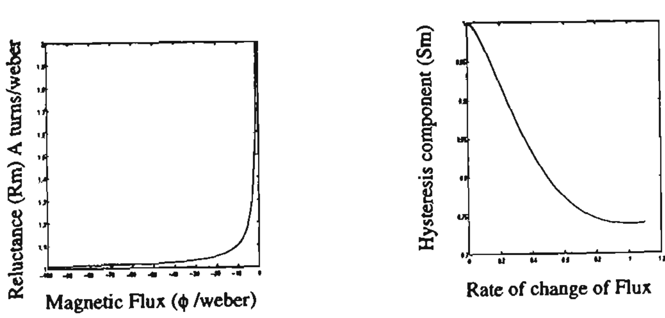
The current i flowing into the winding, is the summation of a magnetising current i_m (flux storage) and a loss current i_s (hysteresis loss). Assuming that the path is normal to the magnetic flux, Ampere's circuital law gives:

$$Ni = N(i_m + i_s) = D(B/m + (1/s)(dB/dt)) \qquad (2.30)$$

By introducing the nonlinear parameters corresponding to magnetisation and loss, nonlinear magnetic resistance (reluctance) R_m, and nonlinear hysteresis parameter S_m can be defined in terms of permeability m and the hysteresis parameters as:

$$R_m = (D/mA) = f_m(f),\ S_m = (D/sA) = f_s\,(df/dt) \qquad (2.31)$$

The two functions $f_m(f)$ and f_s (df/dt) are nonlinear function of flux and rate of change of flux, respectively. These functions are clearly shown in Figure 2.4 and used to evaluate the reluctance R_m and the hysteresis parameter S_m at a particular value of the magnetic field.



(b)

(a)

Figure. 2.4. (a) Nonlinear Relucatance
(b) Nonlinear hysteresis parameter

Mathematically, a system of nonlinear differential equations represents this inductor:

$$Ni = f.\ f_m\ (f) + (df/dt).\ f_s\ (df/dt)$$

$$v = R_w\ i + L_i\ (di/dt) + N(df/dt) \quad (2\ .\ 32)$$

The variables in this model are i, f and df/dt. Therefore, given an initial state, one can

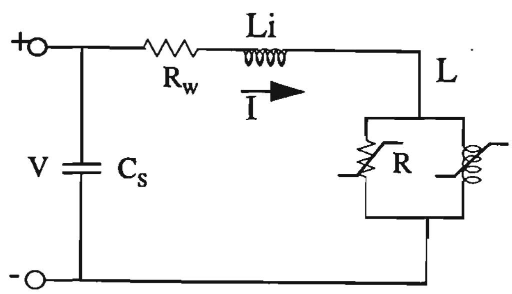


Figure. 2.5. Circuit of Inductor

solve for variables in the time domain keeping in mind that fm(f) and f_s (df/dt) are evaluated at each iteration of the Newton-Raphson algorithm.

2.3.2 Modelling The Transformer

The methodology followed to work out a lumped circuit model for a nonlinear inductor as discussed in section 2.3.1, can be conveniently extended to obtain a lumped circuit model for a nonlinear two winding transformer. A coupling capacitance C_c is connected between the two windings to model the mutual capacitance. The equations describing the model are:

$$v_1 = R_1 i_1 + L_1\ (di_1/dt) + N_1\ (df/dt) \quad (2\ .\ 33)$$

$$v_2 = R_2 i_2 + L_2\ (di_2/dt) + N_2\ (df/dt) \quad (2\ .\ 34)$$

Clearly, one can see that only one variable i_2, had to be added to the inductor model to come up with a model for the transformer. The directions of currents $i_1$and i_2 are assumed to be flowing into the positive terminals of the transformer.The lumped equivalent electric circuit model of the nonlinear transformer is shown in Figure 2.6.

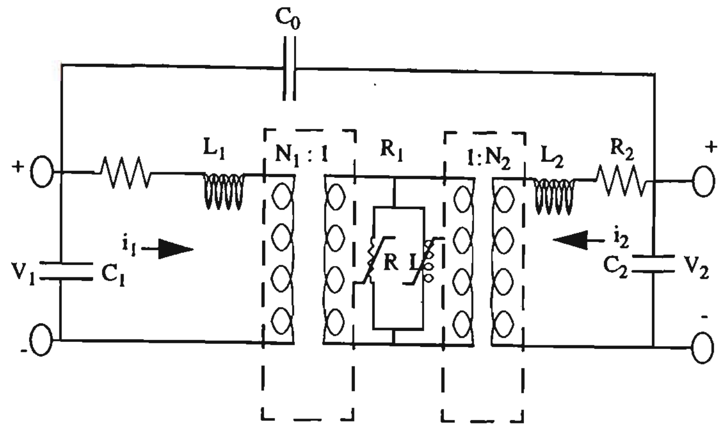


Figure. 2.6. High frequency model of the transformer

2.4 Modelling The Capacitor

The advantageous feature of ferroelectric materials is that they possess a high permittivity and have a very small tan δ. Thus, electric loss can be safely ignored in the model, particularly with the range of frequency considered for power electronics applications.

Two nonlinear functions can be derived from the polarisation characteristics that are shown in Figure 2.7. In equation form, these are

$$C = (ea/l) = f_e(q),$$

$$G_e = (ga/l) = f_g(q') \qquad (2.35)$$

where e and g are the nonlinear permittivity and the hysteresis parameter respectively.

In equation 2.36, $f_e(q)$ is the nonlinear capacitance as a function of charge, and $f_g(q')$ is the nonlinear conductance as a function of the rate of change of charge. These functions are used to evaluate the nonlinear parameters C and G_e at a particular value of an applied electric field. The total charge stored in a parallel plate capacitor of length l and area a, is given by the sum of a prompt free space contribution and the material electronic polarisation P(t) as:

$$D(t) = e_0 E(t) + P(t) = q(t) \tag{2.36}$$

To validate the proposed model some assumptions have to be made. In this case, the

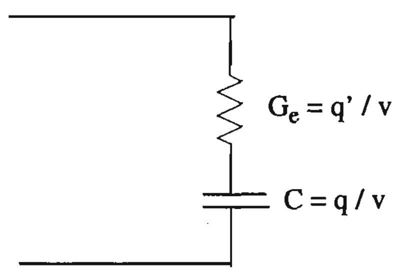


Figure. 2.7. Model of Capacitor

frequency range is assumed to be much lower than that of the relaxation frequency and the temperature never reaches the Curie points of the dielectric.

2.5 Synchronous Machine Modelling

The modelling and analysis of the synchronous machine has always been a challenge. The problem was worked on intensely in the 1920s and 1930s [33][34][35] and has been the subject of several more recent investigations [36][37]. The theory and performance of synchronous machines have also been covered in a number of books [38][39][40][42][45].

In this thesis, POWER SYSTEM TOOLBOX has been used to model the synchronous

Function:

mac_tra

Purpose:

Models a synchronous machine with the voltage behind transient reactance model

Synopsis:

f = mac_tra(i,k,bus,flag)

Description:

mac_tra(i,k,bus,flag) contains the voltage behind the transient reactance model equations for the initialization, network interface and dynamics computation of the i^{th} synchronous machine (block diagram as shown in Figure 2.8). The input k denotes the integer time step of a simulation.

Initialisation is performed when flag=0 and k=1. At initialisation, bus must contain the solved loadflow bus voltages and angles. For flag=1, the machine internal voltage is mapped to the system reference frame to facilitate network solution. For flag=2, the network solution is used to compute the dynamics of the machine. The output f is dummy variable.

The m.file pst_var.m containing all the global variables required for mac_tra should be loaded in the program calling mac_tra. The machine data is contained in the i^{th} row of the matrix variable mac_con. The data format for mac_tra is given in

Appendix B. The definitions of the saturation factors are given in saturation curve diagram (Figure 2.9). It is assumed that there is no saturation for field current less than 0.8 pu. Setting the saturation factors to zero eliminates the saturation effect.

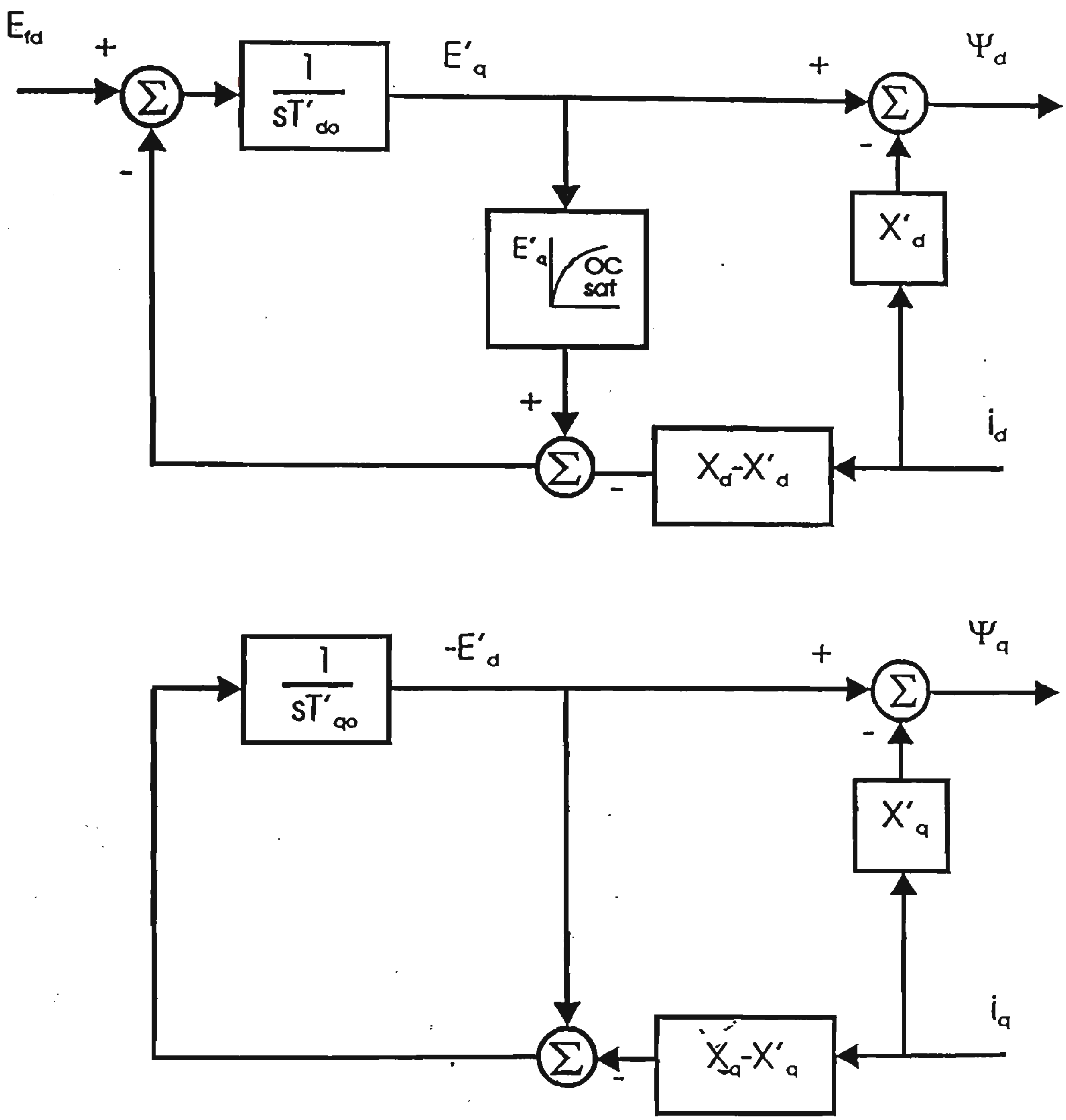


Figure. 2.8. Synchronous Generator Block Diagram (mac_tra)

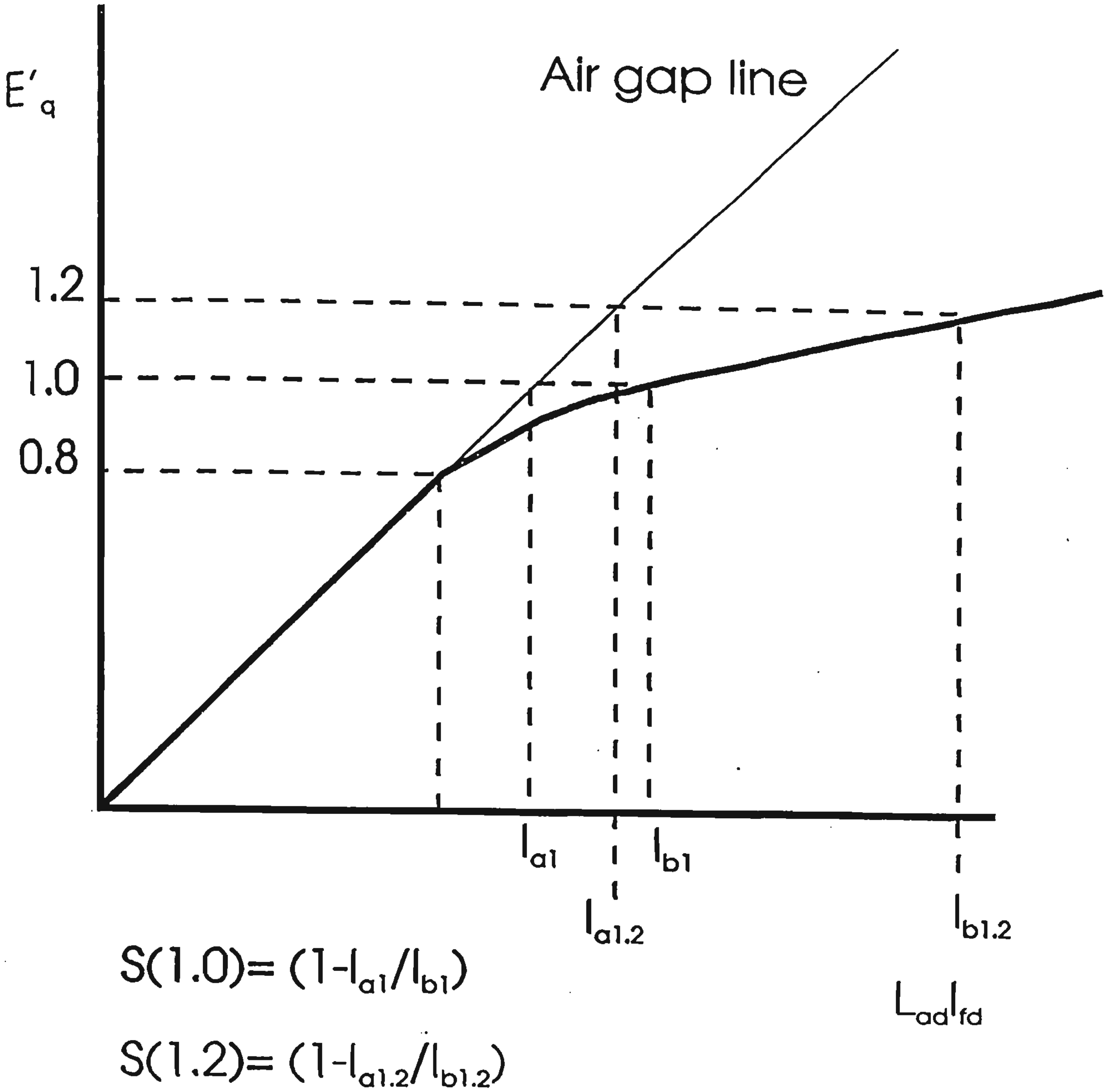


Figure. 2.9. Synchronous Generator Field Saturation characteristics

The function mac_tra can also be used to generate state variable model matrices for detailed machine models by freezing k.

To improve simulation speed, vectorised computation is invoked if i is set to 0. Under this option, all the machines must use the same model. By putting in appropriate parameters, mac_tra can be used to model electromechanical generator models. To neglect flux decay effects, set T_{do}' and T_{qo}' to very large positive numbers [41]. The improvement in computation efficiency would more than offset the additional computations required.

Algorithm:

Based on the machine vector diagram, the initialisation uses the solved loadflow bus voltages and angles to compute the internal voltage and the rotor angle. In the network interface computation, the voltage behind the subtransient reactance on the system reference frame is generated. In the dynamics calculation, the power imbalance and the speed deviation are used to compute the time derivative of the state variables.

This algorithm is implemented in the M-file mac_tra in the POWER SYSTEM TOOLBOX.

2.6 Modelling of Excitation Systems

The basic function of an excitation system is to provide direct current to the synchronous machine field winding. In addition, the excitation system performs control and protective functions essential to the satisfactory performance of the power system by controlling the field voltage and thereby the field current.

The control functions include the control of voltage and reactive power flow, and the enhancement of system stability. The protective functions ensure that the capability limits of the synchronous machine, excitation system, and other equipment are not exceeded.

This section describes the characteristics and modelling of different types of synchronous generator excitation systems. In addition, it discusses dynamic performance criteria and provides definitions of related terms useful in the identification and specification of excitation system requirements. This subject has been covered in several IEEE reports [44]. These serve as useful references to utilities, manufacturers, and system analysts by establishing a common nomenclature, by standardizing models, and by providing guides for specifications and testing. Models and terminologies used in this section largely conform to IEEE publications [44].

2.6.1 Type DC1 exciter model

The type DC1 exciter model represents field-controlled dc commutator exciters, with continuously acting voltage regulators. The exciter may be separately excited or self-excited, the latter type being more common. When self-excited, K_E is selected so that initially $V_R = 0$, representing operator action of tracking the voltage regulator by periodically trimming the shunt field rheostat set point.

Power System Toolbox provides a simplified excitation system model which is described as follows.

Function:

exc_dc12

Purpose:

Model IEEE Type DC1 and DC2 excitation system models

Synopsis:

f = exc_dc12(i,k,bus,flag,h)

Description:

exc_dc12(i,k,bus,flag,h) contains the equations of IEEE Type DC1 excitation system model[44] (Figure 2.10) for the initialisation, machine interface and dynamics computation of the i^{th} excitation system. The input variable k is the integer time step of a simulation, and the input variable h is the integration step size for anti-windup reset. The function is called after the i^{th} machine model function has been computed.

Initialisation is performed when flag=0 and k=1. For proper initialisation, the machine variables must be initialized first. For flag=1, the exciter output voltage is the field voltage of the synchronous machine. For flag=2, the input voltage error signal is used to compute the dynamics of the excitation system. The output f is a dummy variable.

The m.file pst_var.m containing all the global variables required for exc_dc12 should be loaded in the program calling exc_dc12. The exciter data is contained in the i^{th} row of the matrix variable exc_con. The data format for exc_dc12 is shown in Appendix B.

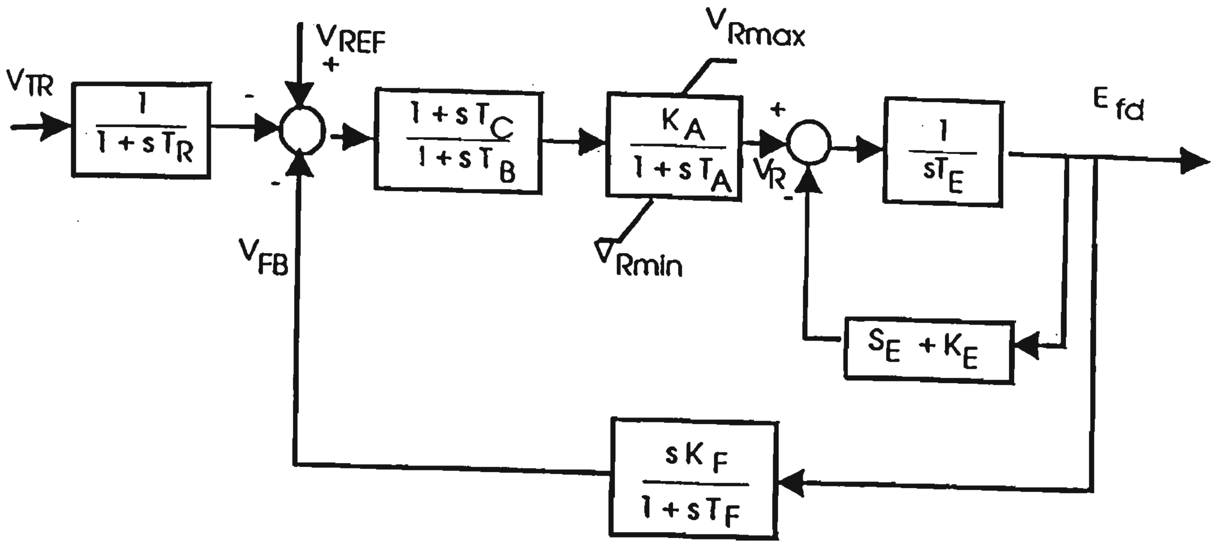


Figure. 2.10. Exciter model DC1 block diagram

A constraint on using exc_dc12 is that $T_F \neq 0$. All other time constants can be set to zero. If T_E is set to zero, then $E_{fd} = V_R$. K_F can be set to zero to model simple first order exciter models. The state VR is prevented from exceeding its limits.

If K_E is set to zero on input, its proper value will be computed during initialization by setting $V_R = 0$. If V_{Rmax} is set to zero on input, the proper values of V_{Rmax} and V_{Rmin} will be computed by assuming that E_2 is the nominal ceiling value of E_{fd}.

The function exc_dc12 can also be used to generate state variable model matrices of the exciter by freezing k. The functions of other models are attached in Appendix A.

2.7 Conclusion

Mathematical models for the distribution network analysis have been presented. These models explicitly represents the interactions between the other dynamic elements within the distribution network. The overall distribution system model within the phasor domain has the following relevant characteristics:

- It is nonlinear and differential-algebraic in the form of constraint differential equations.
- The dimension is very large but the equations are sparse as in the case of the general power system dynamic equations.
- The functions which appear in the set of dynamic and algebraic equations are discontinuous but bounded.

For overall distribution system analysis, the concept of mathematical modelling has been introduced as a tool for tackling a series of problems to the dynamic behaviour of the distribution system. The accuracy of the mathematical models for the distribution network can be tested in two ways:

- by comparing the model with the physical real system;
- by comparing the result with the well proven mathematical model, which already exits.

Chapter 3

Transient Stability

3.1 Introduction

Present trends in the planning and operation of distribution systems have resulted in new kinds of stability problems. Financial and regulatory conditions have caused electric utilities to build distribution systems with less redundancy and operate them closer to transient stability limits. Interconnections are continuing to grow with more use of new technologies such as non-conventional energy sources. More extensive use is being made of power electronics and control technology. Composition and characteristics of loads are changing. These trends have contributed to significant changes in the dynamic characteristics of modern power systems. Modes of instability are becoming increasingly more complex and require a comprehensive consideration of the various aspects of system stability. In particular, small signal instability and low-frequency inter-area oscillations have become greater sources of concern than in the past. Whereas these problems used to occur in isolated situations, they have now become more commonplace. The need for analysing the long-term-dynamic response following major upsets and ensuring proper coordination of protection and control systems is also being recognised.

Transient stability is the ability of the power system to maintain synchronism when subjected to a severe transient perturbation. The resulting system response involves large excursions of generator rotor angles and is influenced by the nonlinear power-angle relationship. Stability depends on both the initial operating state of the system and the severity of the disturbance. Usually, the system is altered so that the post-disturbance steady-state operation differs from that prior to the perturbation.

Perturbations of widely varying degrees of severity can occur on the system. The system is, however, designed and operated so as to be stable for a selected set of contingencies. The contingencies usually considered are short-circuits of different types:

- phase-to-ground,
- phase-to-phase-to-ground,
- three-phase.

They are usually assumed to occur on transmission lines, but occasionally bus or transformer faults are also considered. The fault is assumed to be cleared by the opening of appropriate breakers to isolate the faulted element. In some cases, high-speed reclosure may be assumed.

3.1.1 Small-signal (or small-disturbance) stability

Small-signal stability is the ability of the power system to maintain synchronism under small perturbations. These perturbations occur continually on the system because of small variations in loads and generation. The perturbations are considered sufficiently small for linearisation of system equations to be permissible for purposes of analysis. Instability that may result can be of two forms:

(i) steady increase in rotor angle due to lack of sufficient synchronising torque, or

(ii) rotor oscillations of increasing amplitude due to lack of sufficient damping torque.

The nature of system response to small perturbations depends on a number of factors including the initial operating conditions, the transmission system strength, and the type of generator excitation controls used [43]. For a generator connected radially to a large power system, in the absence of automatic voltage regulators (i.e., with constant field voltage) the instability is due to lack of sufficient synchronising torque. This results in instability through a non-oscillatory mode. With continuously acting voltage regulators, the small-disturbance stability problem is one of ensuring sufficient damping of system oscillations. Instability is normally through oscillations of increasing amplitude. In today's practical distribution systems, small-signal stability is largely a problem of insufficient damping of oscillations. The stability of the following types of oscillations is of concern:

- Local modes or machine-system modes are associated with the swinging of units at a generating station with respect to the rest of the distribution system. The term local is used because the oscillations are localised at one station or a small part of the power system.

- Inter-area modes are associated with the swinging of many machines in one part of the system against machines in other parts. They are caused by two or more groups of closely coupled machines being interconnected by weak ties.

In large distribution systems, transient instability may not always occur as first swing instability. It could be the result of the superposition of several modes of oscillation causing large excursions of rotor angle beyond the first swing.

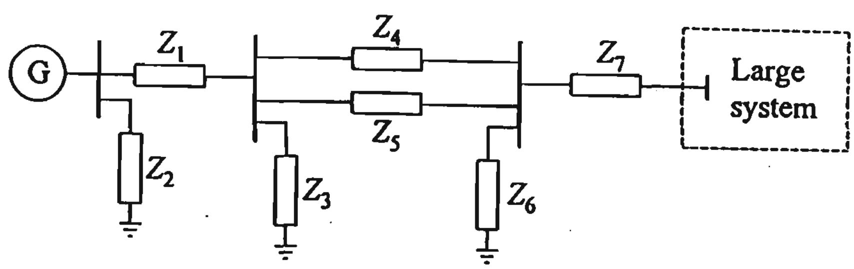
In transient stability studies the study period of interest is usually limited to 3 to 5 seconds following the disturbance, although it may extend to about ten seconds for very large systems with dominant inter-area modes of oscillation.

3.2 Small System Stability of a single machine infinite bus system

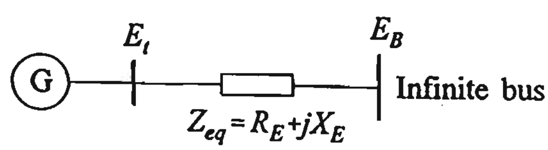
This section deals with the small-signal performance of a single synchronous machine which is considered as a non-conventional energy source connected to a large system through distribution lines. A general system configuration is shown in Figure 3.1(a)

For the purpose of analysis, the system of Figure 3.1(a) may be reduced to the form of Figure 3.1(b) by using Thevenin's equivalent of the transmission network external to the machine and the adjacent transmission. Because of the relative size of the system to which the machine is supplying power, dynamics associated with the machine will cause virtually no change in the voltage and frequency of Thevenin's voltage E_B. Such a voltage source of constant voltage and constant frequency is referred to as an infinite bus. E_t is the terminal voltage of the machine.

Studies are particularly important due to the growing interest in interconnecting small renewable energy sources to large and complex distribution systems [46]. For a small generator connected to a utility distribution system, both the terminal voltage and frequency are fixed by the network and so it has little control over its terminal voltage and none over the system frequency [47]. Synchronous generators are attractive for utility interconnection as they allow independent control of real and reactive power. Single-machine-infinite-bus analysis simulate accurately the behaviour of a real system. A generalised model [48] for dynamic stability analysis of interconnected system which includes the synchronous machines and the exciters have been considered.



(a) General configuration



(b) Equivalent system

Figure. 3.1. Single Machine connected to a large system through transmission lines

To simulate single-machine-infinite bus system for distribution system design the Matlab Power System Toolbox has been used. The machine is modelled with subtransient effect, and the exciter is a static rectifier type (ST3). The system is subject to short-circuit fault on bus 2 and cleared in 3 cycles by tripping one of the line between buses 2 and 3 as shown in the Figure 3.2. Various fault simulation is performed. Euler method is used with a stepsize of 0.002 sec.

3.2.1 The Power System Model

The load flow is performed on the single-machine-infinite-bus power system as shown in Figure 3.2 corresponding to the loading condition to be investigated. The machines are represented by the two-axis models, the exciters by IEEE Type-1 models and the loads are modelled as constant impedances. To save programming time, it has become common [49][50] to limit the machine and exciter representations to some specified models. The network admittance matrix is reduced by retaining only the internal buses of the generators. The reduced network, machine and exciter data are then combined to form a linearised state-space model representing the entire system.

3.2.2 Dynamic Stability Analysis

The initial conditions corresponding to the loading condition of the machines are determined. Using the initial conditions the elements of the A-matrix are obtained where A is the state or plant matrix of size (nx n). The eigen values of the matrix A contains the necessary information on the linearised stability of the system. The system is stable if all the eigen values lie on the left-hand side of the s-plane, i.e. the real parts are all negative. The real eigen values are related to exponential components in the time responses. The complex conjugate pairs of eigen values are associated with the oscillatory modes in the time responses. They have the form l = -a + jb, where b gives the frequency of oscillations in rad/sec and the value of 1/a defines the time constant by which the magnitude of the oscillations decays [51]. Therefore, by inspection of the eigen values the dynamic stability of the system can be confirmed. However, in order to determine whether the small machine is adequately stable, for a perturbation in the state variables of other machines of the utility, the time response of change in rotor angular velocity ($\Delta\omega$) and change in rotor angular displacement ($\Delta\delta$) of the small machine are obtained using Euler integration method.

3.2.3 System Investigated

The distribution system considered here is shown in Figure 3.2. This comprises utility infinite bus and one renewable energy source. It can be seen that the generation capacity of the renewable energy source is very small compared to that of the other machines in the utility.

Line impedances for this system are shown in Table 3.1. The machine and the exciter parameters are shown in Table 3.2. The time responses ($\Delta\delta$) of renewable energy

Table 3.1 Line impedances for single machine infinite bus

Line Section		Impedance		Half-Line charging
From Bus	To Bus	R	X	
1	3	0	0.1	0
2	3	0.0100	0.3999	0
1	3	0.0170	0.1	0

source machine for 10%, 15% and 20% perturbation in load of load bus are given in Figure 3.3-3.5 with time in seconds and $\Delta\delta$ in degrees. It is obvious from Figure 3.3 that with 10% perturbation the damping is poor and with 20% perturbation the rotor angle oscillation of the small machine takes more than 3.5 seconds to settle down. It can be concluded that as we increase the percentage of perturbation the small machine will tend to oscillate more, and may eventually go out of synchronism. Figures 3.3-3.5 illustrate the behaviour of a synchronous machine for different perturbation. In the stable case, the rotor angle increases to a maximum, then

Table 3.2 Machine and Exciter parameters for single machine infinite bus

Parameters	Machine1	Machine 2
r(pu)	0.003	0.002
X_d(pu)	1.1	0.1
Xq(pu)	0.231	0
X'_d(pu)	0.12	0.1
τ'_{do}(s)	0.035	0
τ'_{qo}(s)	0.0351	0
H(s)	4.8765	5

decreases and oscillates with decreasing amplitude until it reaches a steady state. Thus it is clear that though the utility is stiffer, the impact of a small generator is such that it may create instability of the system with medium to large perturbations. So, there is need to provide proper methods for improving the transient stability. When the small generator is unstable it is disconnected from the utility.

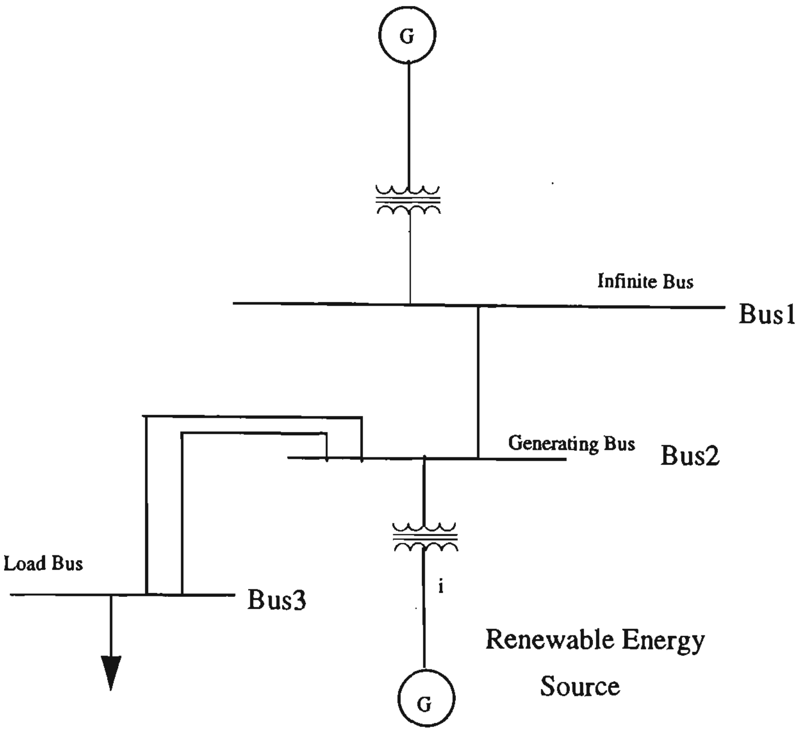


Figure. 3.2. Schematic Representation of single machine infinite bus

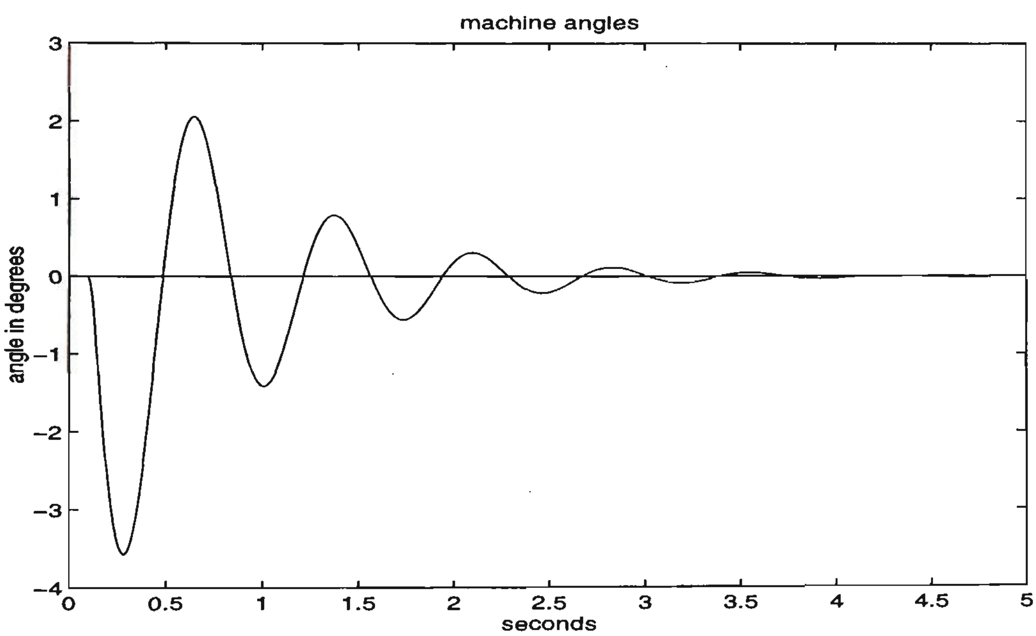


Figure. 3.3. 10% perturbation

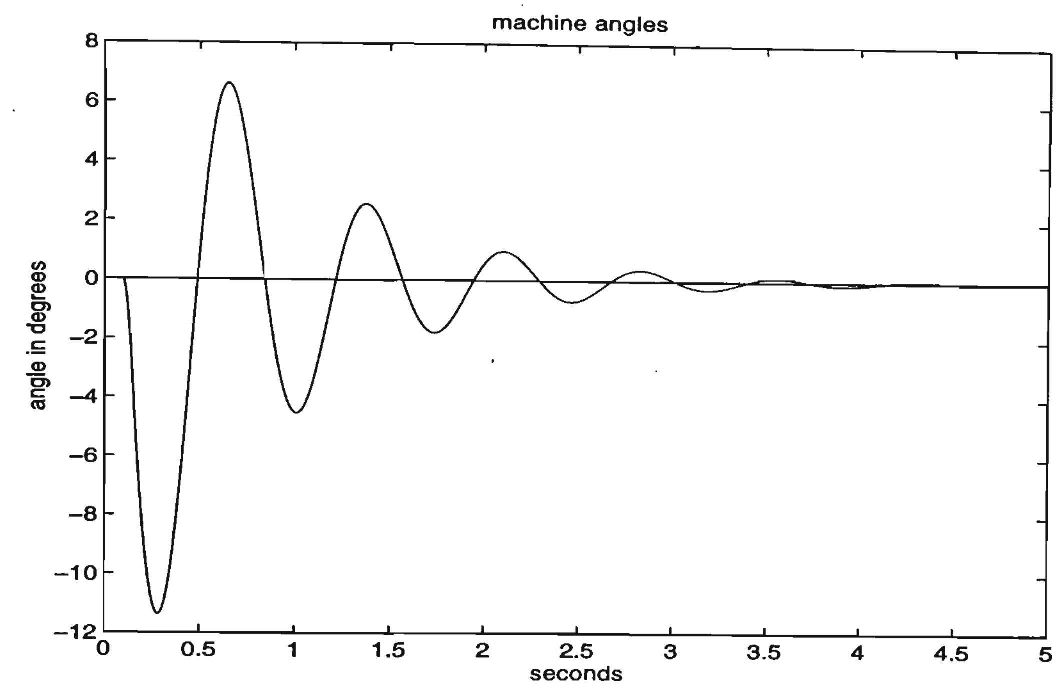


Figure. 3.4. 15% perturbation

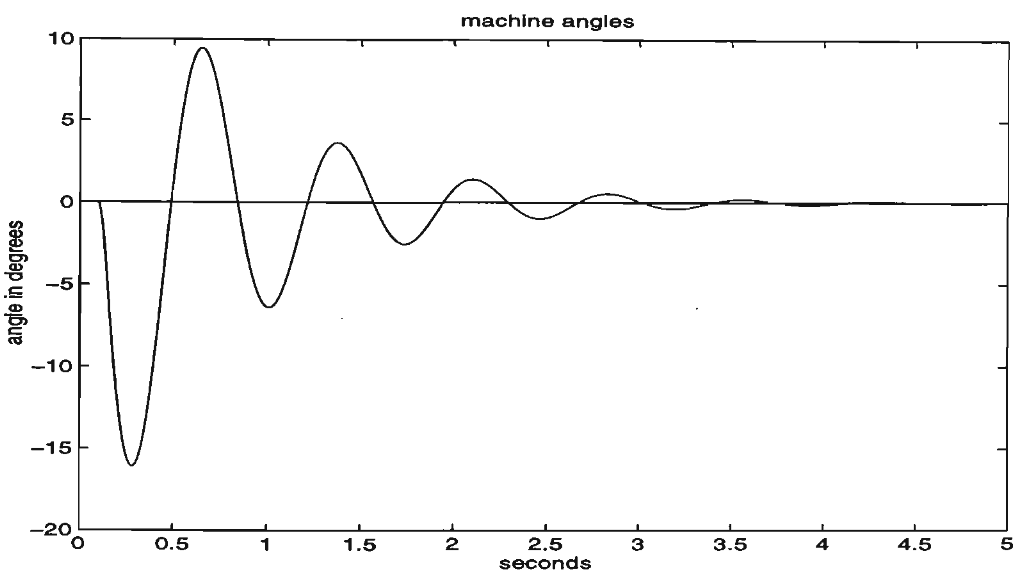


Figure. 3.5. 20% perturbation

3.3 Small Signal Stability of a four machine ten bus system

3.3.1 The Power System Model

The multimachine power system models used in this section are generated using MATLAB code. The load flow is performed on the multimachine power system corresponding to the loading condition to be investigated. The machines are represented by the two-axis models, the exciters by IEEE Type-1 models and the loads are modelled as constant impedances. To save programming time, it has become common [49][50] to limit the machine and exciter representations to some specified models. The network admittance matrix is reduced by retaining only the internal buses of the generators. The reduced network, machine and exciter data are then combined to form a linearised state-space model representing the entire system. Four machine ten bus analysis which simulate accurately the behaviour of the analysed physical system. This section gives a generalised model [48] for transient stability analysis of interconnected system which includes the synchronous machines and the exciters. It discusses the simulation of four machine ten bus system for distribution system using the Matlab Power System Toolbox. The system is subject to short-circuit fault on bus 4 and cleared in 3 cycles by tripping the line between buses 4 and 6 as shown in the Figure 3.10. Predictor-corrector method with a stepsize of 0.01s was used.

3.3.2 System Investigated

The power system considered here is shown in Figure 3.10. This comprises three utility generators and one renewable energy source connected to bus 10. It can be seen that the generation capacity of the renewable energy source is very small compared to that of the other machines in the utility.

Line impedances for this system are shown in Table 3.3, and the generation and load data are in Table 3.4. The machine and the exciter parameters are shown in Table 3.5.

Table 3.3 Line impedances for four machine ten bus system

Line Section		Impedance		Half-Line charging
From Bus	To Bus	R	X	
1	4	0	0.0576	0
4	5	0.0100	0.0850	0.0880
4	6	0.0170	0.0920	0.0790
5	7	0.0320	0.01610	0.1530
6	9	0.0390	0.1700	0.1790
2	7	0	0.0625	0
7	8	0.0085	0.0720	0.0745
8	9	0.0119	0.1008	0.1045
9	3	0.0586	0.0586	0
6	10	0.0596	0.0596	0

The time responses ($\Delta\delta$) of renewable energy source machine for 1%,10%, 15% and 20% perturbation in load of load bus are given in Figures 3.7-3.10 with time in seconds and ($\Delta\delta$) in degrees. It is obvious from the Figure 3.8 that even for 1% change in load of the neighbouring load bus the rotor angle oscillations of the smaller machine takes around 5 seconds to settle down. With 10% perturbation the damping is still poor and with 20% perturbation the rotor angle oscillation of the small machine takes more than 20 seconds to settle down. It can be concluded that as the percentage of perturbation is increased the small machine will tend more to-wards instability as a result of growing oscillation. In the stable case, the rotor angle increases to a maximum, then decreases and oscillates with decreasing amplitude until it reaches a steady state. In large distribution systems, transient instability may

Table 3.4 Generation and Load data for four machine ten bus system

Busbar Number	Generation		Load		Voltage (pu)	
	MW	MVAR	MW	MVAR	Magnitude	Angle
1	51.62	36.20	0	0	1.040	0
2	163.00	9.52	0	0	0.025	10.28
3	85.00	-6.32	0	0	0.025	5.67
4	0	0	0	0	0.020	-1.60
5	0	0	125	50	0.991	-3.27
6	0	0	90	30	1.000	-2.10
7	0	0	0	0	1.024	4.72
8	0	0	100	35	1.014	1.83
9	0	0	0	0	1.029	3.24
10	20.00	-16.50	10	5	0.990	-1.41

Table 3.5 Machine and Exciter parameters for four machine ten bus system

Parameters	Machine 1	Machine 2	Machine 3	Machine 4
r(pu)	0.0014	0.002	0.004	0.0014
X_d(pu)	0.9950	1.651	1.220	1.2500
Xq(pu)	0.5680	1.590	1.160	1.2200
X'_d(pu)	0.1950	0.232	0.174	0.2320
τ'_{do}(s)	9.2000	5.900	8.970	4.7500
τ'_{qo}(s)	0	0.535	0.500	1.5000
H(s)	6.4120	3.302	4.768	5.0160

not always occur as first swing oscillation, it could be the result of the superposition of several modes of oscillation. Thus having a high-ceiling voltage and equipped with a power system stabiliser (PSS) will contributes to the enhancement of the overall system stability.

Thus is clear that through the utility is stiffer the impact of a small generator is such that it may create instability of the system even with medium perturbations. When the small generator is unstable it is disconnected from the utility.

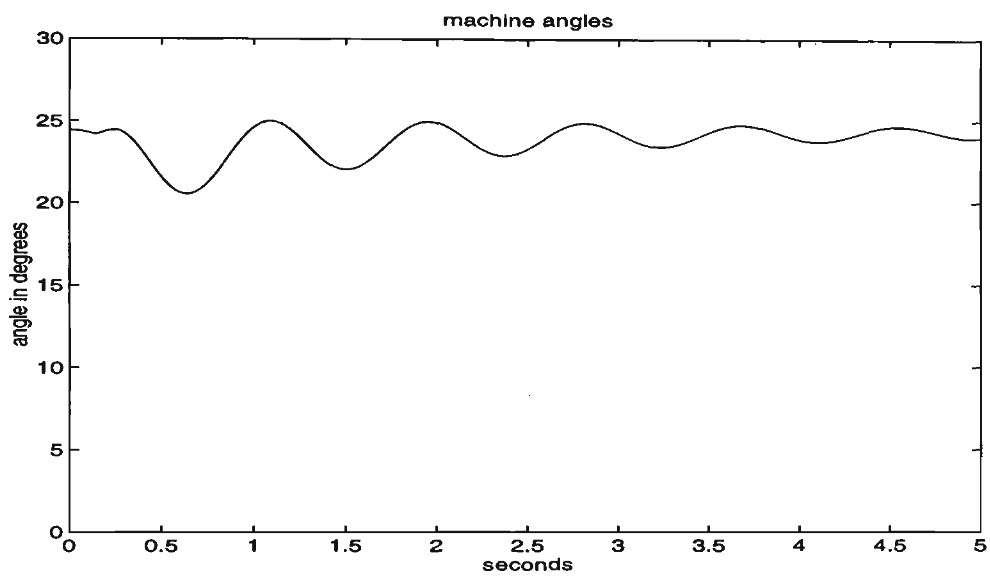


Figure. 3.6. 1% perturbation

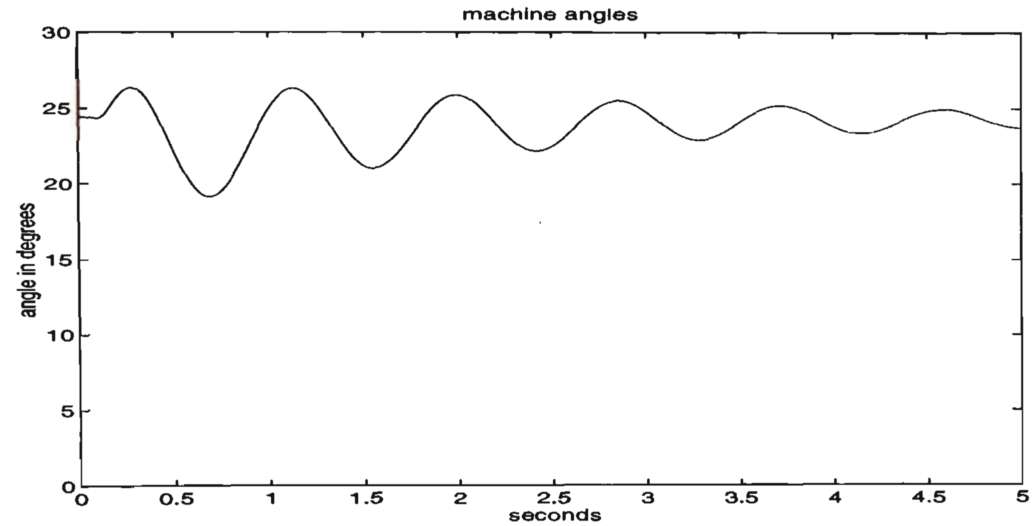


Figure. 3.7. 10% perturbation

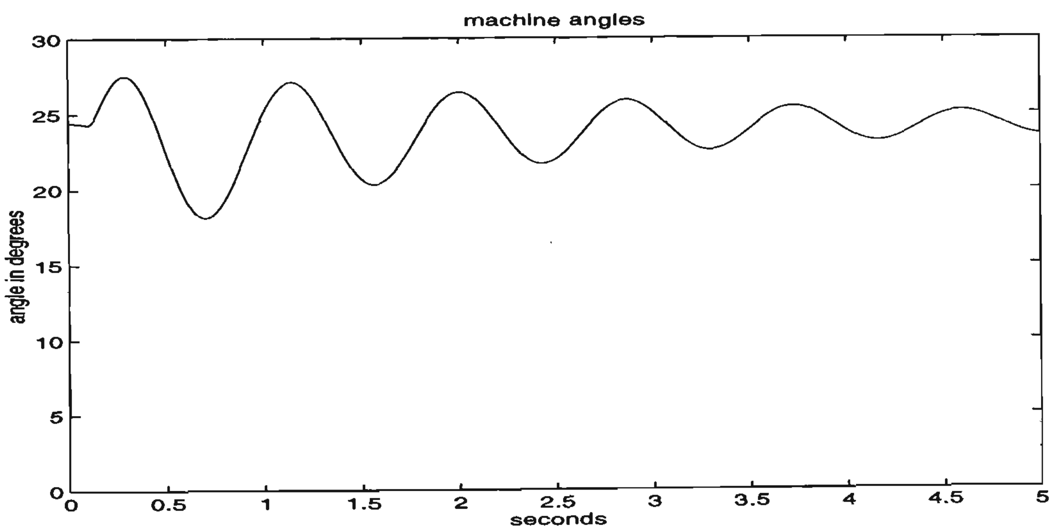


Figure. 3.8. 15% perturbation

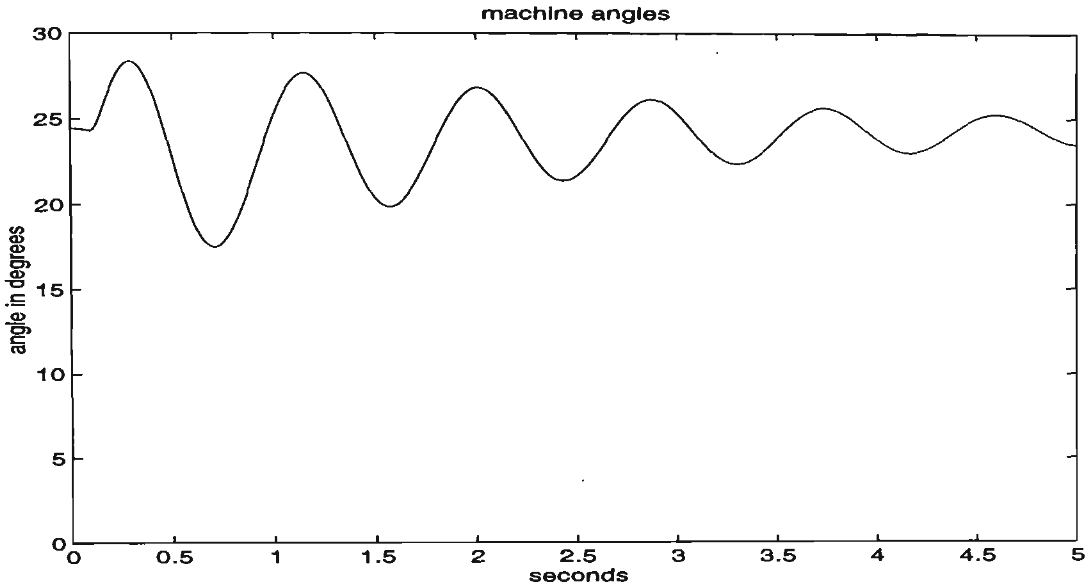


Figure. 3.9. 20% perturbation

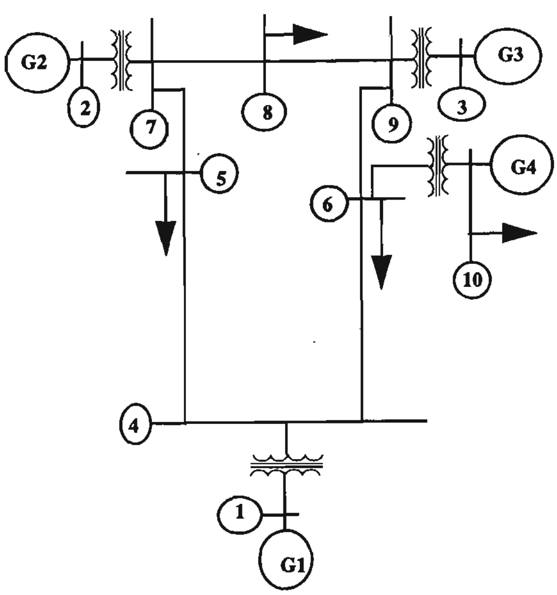


Figure. 3.10. Schematic representation of Four machine ten bus system

3.4 Factors influencing transient stability:

From the above discussions, it is concluded that transient stability of the generator is dependent on the following:

(a) How heavily the generator is loaded.

(b) The generator output during the fault. This depends on the fault location and type.

(c) The fault-clearing time.

(d) The postfault transmission system reactance.

(e) The generator reactance. A lower reactance increases peak power reduces initial rotor angle.

(f) The generator inertia. The higher the inertia, the slower the rate of change in angle. This reduces the kinetic energy gained during fault; i.e., area A_1 is reduced.

(g) The generator internal voltage magnitude (E). This depends on the field excitation.

(h) The infinite bus voltage magnitude E_B.

As a means of introducing basic concepts, the system having a simple configuration and represented by a simple model has been considered. This has enabled the analysis of stability by using a graphical approach. A time-domain simulation was performed in which the nonlinear differential equations are solved by using step-by-step numerical integration techniques.

3.5 Methods of improving stability

This section discusses special methods used for enhancing transient and small-signal stability. These two categories of system stability have received considerable attention since the 1960s, and methods for their improvement are further evolved than those for other categories.

For a given system, any one method of improving stability may not be adequate. The best approach is likely to be a combination of several methods judiciously chosen so as to most effectively assist in maintaining stability for different contingencies and system conditions. In applying these methods to the solution of specific stability problems, it is important to keep in mind the overall performance of the distribution system. Solutions to the stability problem of one category should not be effected at the expense of another category.

Many of the methods for stability enhancement described in this section are options normally available for economic design of the system. With proper design and application they should greatly contribute to the flexibility of system operation without compromising other aspects of system performance.

Some of the methods described are, however, somewhat "heroic" in nature and can be justified only in special situations. While improving system stability, they impose duty on some of the equipment. Their application, therefore, has to be based on a careful assessment of the benefits and costs.

3.5.1 Transient Enhancement Stability

Methods of improving transient stability try to achieve one or more of the following effects:

(a) Reduction in the disturbing influence by minimising the fault severity and duration.

(b) Increase of the restoring synchronising forces.

(c) Reduction of the accelerating torque through control of prime-mover mechanical power.

The following are various methods of achieving the above objectives.

3.5.1.1 High-Speed Fault Clearing

The amount of kinetic energy gained by the generators during a fault is directly proportional to the fault duration; the quicker the fault is cleared, the less disturbance it causes.

Two-cycle breakers, together with high-speed relays and communication, are now widely used in locations where rapid fault clearing is important.

In special circumstances, even faster clearing may be desirable. Combined with a rapid response overcurrent type sensor, which anticipates fault magnitude, nearly one-cycle total fault duration is attained.

3.5.1.2 Reduction of Transmission System Reactance

The series inductive reactance of transmission networks are primary determinants of stability limits. The reduction of reactance of various elements of the distribution network improves transient stability by increasing postfault synchronizing power transfers. Obviously, the most direct way of achieving this is by reducing the reactance of distribution circuits, which are determined by the voltage rating, line and conductor configurations, and number of parallel circuits. The following are additional methods of reducing the network reactance:

(a) Use of transformers with lower leakage reactance.

(b) Series capacitor compensation of distribution lines.

Typically, the per unit transformer leakage reactance ranges between 0.1 and 0.15. For newer transformers, the minimum acceptable leakage reactance that can be achieved within the normal transformer design practices has to be established in consultation with the manufacturer [52]. In many situations, there may be a significant economic advantage in opting for a transformer with the lowest possible reactance.

The maximum power transfer capability of a distribution line may be significantly increased by the use of series capacitor banks. This directly translates into enhancement of transient stability, depending on the facilities provided for bypassing the capacitor during faults and for re-insertion after fault clearing. Speed of re-insertion is an important factor in maintaining transient stability [53]. Early designs of protective gaps and bypass switches limited the benefits achievable by series capacitor compensation. However, with the present trend of using nonlinear resistors of zinc oxide, the re-insertion is practically instantaneous.

One problem with series capacitor compensation is the possibility of subsynchronous resonance with the nearby turbo alternators. This aspect must be analysed carefully and appropriate preventative measures must be taken.

Traditionally, series capacitors have been used to compensate for very long overhead lines. Recently, there has been an increasing recognition of the advantages of compensating shorter, but heavily loaded, lines by using series capacitors.

For transient stability applications, the use of switched series capacitors offers some advantages. Upon detection of a fault or power swing, a series capacitor bank can be switched in and then removed about 0.5 second later. Such a switched bank can be located in a substation where it can serve several lines.

For a given transient stability limit, the aggregate rating of series capacitors required is less if some are switched than if all are unswitched. The scheme with a portion of the capacitors switched reduces the angular swings of the machines, and this in turn reduces fluctuation of loads, particularly those near the electrical centre.

Protective relaying is made more complex when series compensation is used, particularly if the series capacitors are switched.

3.5.1.3 Regulated Shunt Compensation

Shunt compensation capable of maintaining voltages at selected points of the transmission system can improve system stability by increasing the flow of synchronising power among interconnected generators. Synchronous condensers or static var compensators can be used for this purpose.

Regulated shunt compensation increases the maximum power transfer capability of a long transmission line. This clearly enhances transient stability.

3.6 Conclusion

It is clear from the proceeding analysis that much care should be taken based on the stability point of view while interconnecting the small renewable energy sources to the utility. The renewable energy sources should be interconnected at a point which provides a higher stability margin.

The program used shows its capacity as a tool for use in preliminary design stages of future interconnection schemes between the utility distribution feeder and a renewable energy source in order to find a satisfactory solution to problems before they occur in practical situations at significant cost to utilities and customers.

Chapter 4

Voltage Control and Stability

4.1 Introduction

Voltage control and stability problems are not new to the electric utility industry but are now receiving special attention in many systems. Once associated primarily with weak systems and long lines, voltage problems are now also a source of concern in highly developed networks as a result of heavier loadings. In recent years, voltage instability has been responsible for several major network collapses [54][55].

As a consequence, the terms "voltage instability" and "voltage collapse" are appearing more frequently in the literature and in discussions of system planning and operation.

Although low voltages can be associated with the process of rotor angles going out of step, the type of voltage collapse related to voltage instability can occur where "angle stability" is not an issue. The gradual pulling out of step of machines, as rotor angles between two groups of machines approach or exceed 180^0, results in very low voltages at intermediate points in the network. However, in such cases the low voltage is a result of the rotors falling out of step rather than a cause of it.

The emphasis on renewable energy sources for generation is increasing, since they have a lower impact on the environment than conventional energy sources. To be utilised with maximum effectiveness, the new forms of generation based on renewable sources must be managed as part of existing power systems. Connection of small generators to the distribution system can affect the quality of power delivered to loads and the operation of distribution system equipment [54]. However, many of these generators are by their very nature dispersed and small. This raises new problems regarding protection, control and stability. The problem of maintaining voltages within the required limits is complicated by the fact that the power system supplies power to a vast number of loads and is fed from many generating units. For efficient and reliable operation of power systems, the control of voltage and reactive power should satisfy the following objectives:

- Voltages at the terminals of all equipment in the system are within acceptable limits. Both utility equipment and customer equipment are designed to operate at a certain voltage rating. Prolonged operation of the equipment at voltages outside the allowable range could adversely affect their performance and possibly cause them damage.

- System stability is enhanced to maximise utilisation of the distribution system.

- The reactive power flow is minimised so as to reduce RI^2 and XI^2 losses to a practical minimum. This ensures that the transmission system operates efficiently i.e. mainly for active power transfer.

Voltage stability is the ability of a power system to maintain steady acceptable voltages at all buses in the system under normal operating conditions and after being subjected to a disturbance. A system enters a state of voltage instability when a disturbance or perturbation, increase in load demand, or change in system condition causes a progressive and uncontrollable drop in voltage[62]. The main factor causing instability is the inability of the power system to meet the demand for reactive power. The heart of the problem is usually the voltage drop that occurs when active power and reactive power flow through inductive reactance associated with the distribution network.

A criterion for voltage stability is that, at given operating condition for every bus in the system, the bus voltage magnitude increases as the reactive power injection at the same bus is increased. A system is voltage unstable if, for at least one bus in the system, the bus voltage magnitude (V) decreases as the reactive power injection (Q) at the same bus is increased. In other words, a system is voltage stable if V-Q sensitivity is positive for every bus and voltage unstable if V-Q sensitivity is negative for at least one bus. As shown in the Figure 4.1 below bus 1 voltage is unstable as V-Q sensitivity is negative on the left side.

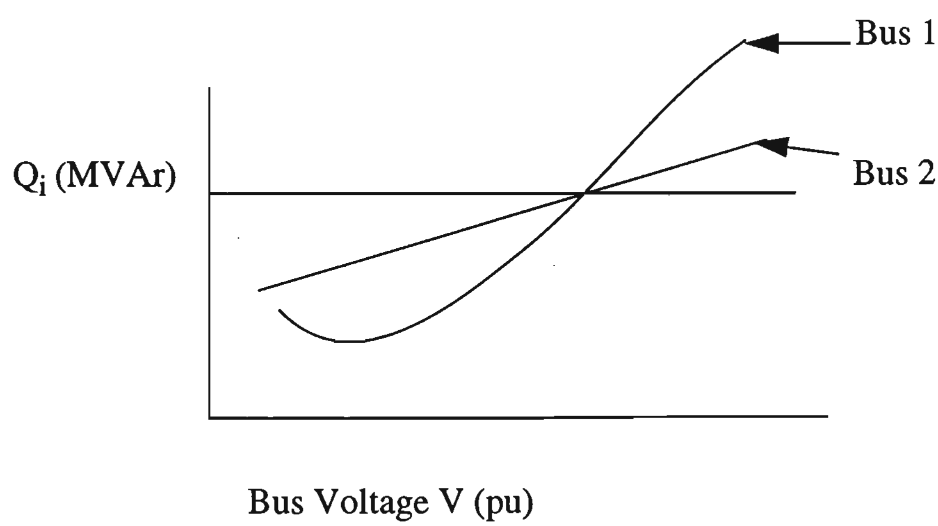


Figure. 4.1. V-Q Sensitivity for the bus

Progressive drop in bus voltages can also be associated with rotor angles going out of step. For example, the gradual loss of synchronism of machines as rotor angles between two groups of machines approach or exceed 180^0 would result in very low voltages at intermediate points in the network. In contrast, the type of sustained fall of voltage that is related to voltage instability occurs where rotor angle stability is not an issue.

Voltage instability is essentially a local phenomenon; however, its consequences may have a widespread impact. Voltage collapse is more complex than simple voltage instability and is usually the result of a sequence of events accompanying voltage instability leading to a low-voltage profile in a significant part of the power system.

The aim of this section is to analyse the variation in voltage of the distribution network when renewable energy sources interconnected to the distribution network, in terms of its stability. In particular this study analyses the impact of interconnection of small synchronous generators to the utility power grid.

It discusses the simulation of four machine ten bus system for distribution system using the Matlab Power System Toolbox. It performs a load flow with the load and generation increased from the starting value by a ratio input by the user. Normally this will be close to the point at which the load flow fails to converge. The multimachine power system models used in this paper are generated in MATLAB code.

4.2 Voltage Stability Analysis

The basic processes contributing to small-disturbance voltage instability are essentially of a steady-state nature. Therefore, static analysis can be effectively used to determine stability margins, identify factors influencing stability, and examine a wide range of system conditions and a large number of post contingency scenarios.

Voltage instability does not always occur in its pure form. Often the angle and voltage instabilities go hand and hand. One may lead to the other and the distinction may not be clear. However, a distinction between angle stability and voltage stability is important for understanding of the underlying causes of the problems in order to develop appropriate design and operating procedures.

4.3 Modelling Requirements

The following are descriptions of models of distribution system elements that have a significant impact on voltage stability:

Loads: Load characteristics could be critical in voltage stability analysis. Unlike in conventional transient stability and power-flow analyses, expanded subtransmission system representation in a voltage-weak area may be necessary. This should include transformer under-load tap changer (ULTC) action, reactive power compensation, and voltage regulators in the subtransmission system.

Generators and their excitation controls: For voltage stability analysis, it may be necessary to account for the droop characteristic of the AVR rather than to assume zero droop. If load (line drop) compensation is provided, its effect should be represented specifically rather than as a fixed value of the maximum reactive power limit.

Static var systems (SVSs): When an SVS is operating within the normal voltage control range, it maintains bus voltage with a slight droop characteristic.

When operating at the reactive power limits, the SVS becomes a simple capacitor or reactor. This could have a very significant effect on voltage stability. These characteristics of SVS should be represented appropriately in voltage stability studies.

Automatic generation control (AGC): For contingencies resulting in a significant mismatch between generation and load, the actions of primary speed control and supplementary tie line bias frequency control can change system generation significantly, sometimes to the detriment of voltage stability. Hence, these functions have to be represented appropriately.

Protection and controls: These include generating unit and transmission network protection and controls. Examples are generator excitation protection, armature over-current protection, transmission line overcurrent protection, capacitor bank controls, phase-shifting regulators, and undervoltage load shedding.

4.4 Dynamic Analysis

The general structure of the system model for voltage stability analysis is similar to that for transient stability analysis. As described, the overall system equations, comprising a set of first-order differential equations, may be expressed in the following general form:

$$\dot{x} = f(x, V) \tag{4.1}$$

and a set of algebraic equations

$$I(x,V) = Y_N V \tag{4.2}$$

with a set of known initial conditions(x_0,V_0) where

x = state vector of the system

V = bus voltage vector

I = current injection vector

Y_N = network node admittance matrix

Since the representation of transformer tap-changer and phase-shift angle controls has been included, the elements of Y_N change as a function of bus voltages and time. The current injection vector I is a function of the system states x and bus voltage vector V, representing the boundary conditions at the terminals of the various devices (generating units, nonlinear static loads, motors, SVSs, etc.). Due to the time-dependent nature of devices such as field current limiters, the relationship between I and x can be a function of time.

Equations 4.1 and 4.2 can be solved in time-domain by using any of the numerical integration methods and network power-flow analysis methods. The study period is typically in the order of several minutes. With the inclusion of special models representing the "slow system dynamics" leading to voltage collapse, the stiffness of the system differential equations is significantly higher than that of transient stability models. Implicit integration methods are ideally suited for such applications. Facilities to automatically change the integration time step, as the solution progresses and fast transients decay, greatly enhance the computational efficiency of such techniques.

4.5 System Investigated

The power system considered here is shown in Figure 4.2. This comprises three utility generators and one renewable energy source connected to bus 10. It can be seen that the generation capacity of the renewable energy source is very small compared to that of the other machines in the utility. Line impedances for this system are shown in Table 4.1, and the generation and load data are in Table 4.2. The machine and the exciter parameters are shown in Table 4.3. The transformer data is

Table 4.1 Line Impedances for Voltage Control and Stability

Line Section		Impedance		Half-Line charging
From Bus	To Bus	R	X	
1	4	0	0.0576	0
4	5	0.0100	0.0850	0.0880
4	6	0.0170	0.0920	0.0790
5	7	0.0320	0.01610	0.1530
6	9	0.0390	0.1700	0.1790
2	7	0	0.0625	0
7	8	0.0085	0.0720	0.0745
8	9	0.0119	0.1008	0.1045
9	3	0.0586	0.0586	0
6	10	0.0596	0.0596	0

shown in Tables 4.4.

Table 4.2 Generation and load data for Voltage Control and Stability

Busbar Number	Generation		Load		Voltage (pu)	
	MW	MVAR	MW	MVAR	Magnitude	Angle
1	51.62	36.20	0	0	1.040	0
2	163.00	9.52	0	0	1.033	10.28
3	85.00	-6.32	0	0	1.0436	5.67
4	0	0	0	0	0.995	-1.60
5	0	0	125	50	0.991	-3.27
6	0	0	90	30	1.000	-2.10
7	0	0	0	0	1.024	4.72
8	0	0	100	35	1.014	1.83
9	0	0	0	0	1.029	3.24
10	20.00	-16.50	10	5	0.990	-1.41

Table 4.3 Machine and Exciter parameters for Voltage Control and Stability

Parameters	G1	G2	G3	G4
r(pu)	0.0014	0.002	0.004	0.0014
X_d(pu)	0.9950	1.651	1.220	1.2500
Xq(pu)	0.5680	1.590	1.160	1.2200
X'_d(pu)	0.1950	0.232	0.174	0.2320
τ'_{do}(s)	9.2000	5.900	8.970	4.7500
τ'_{qo}(s)	0	0.535	0.500	1.5000
H(s)	6.4120	3.302	4.768	5.0160

Table 4.4 Transformer data

Transformer	R	X	Ratio
T1	0.0000	0.0020	0.8857
T2	0.0000	0.0045	0.8857
T3	0.0000	0.0125	0.9024
T4	0.0000	0.0030	1.0664

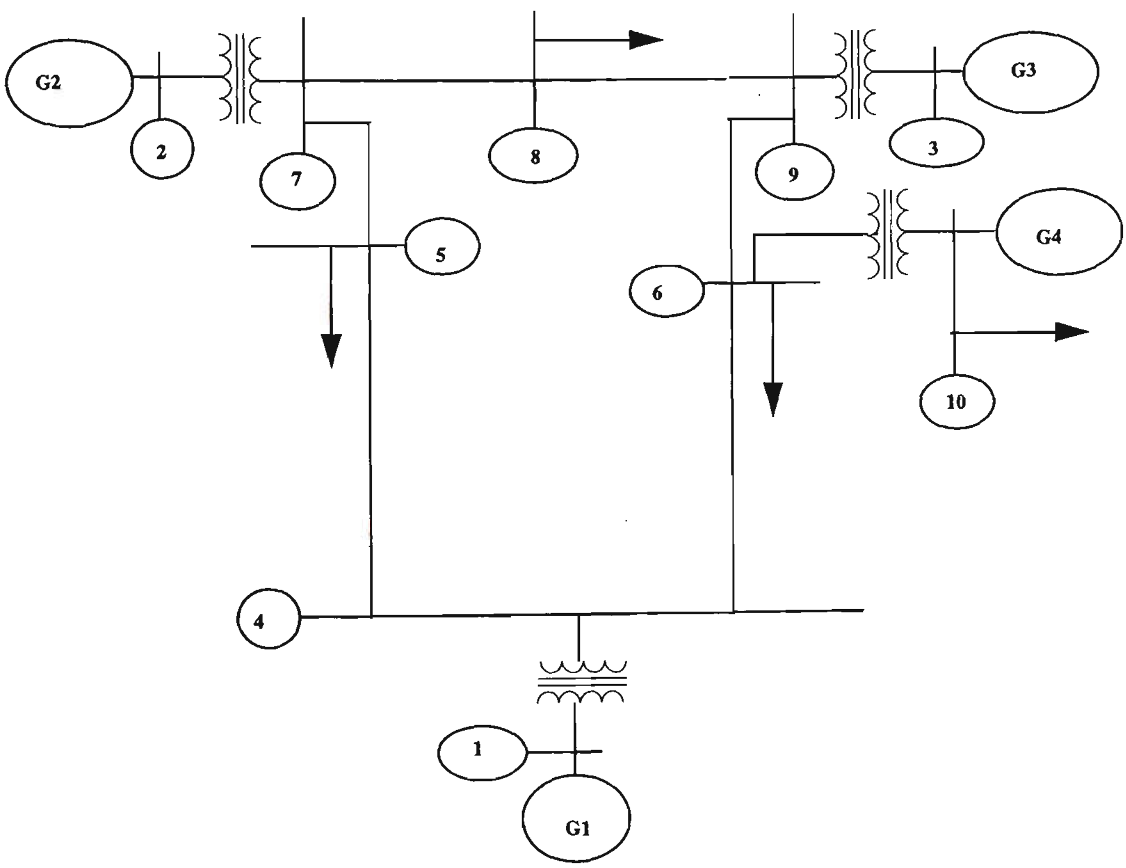


Figure. 4.2. Schematic representation of four machine ten bus system for Voltage Stability study.

4.6 Results: The figures below shows the phase profile, voltage profile and machine reactive power for increase in power by ratio of 1, 1.5 and 2.

(a) 1 times increase in power:

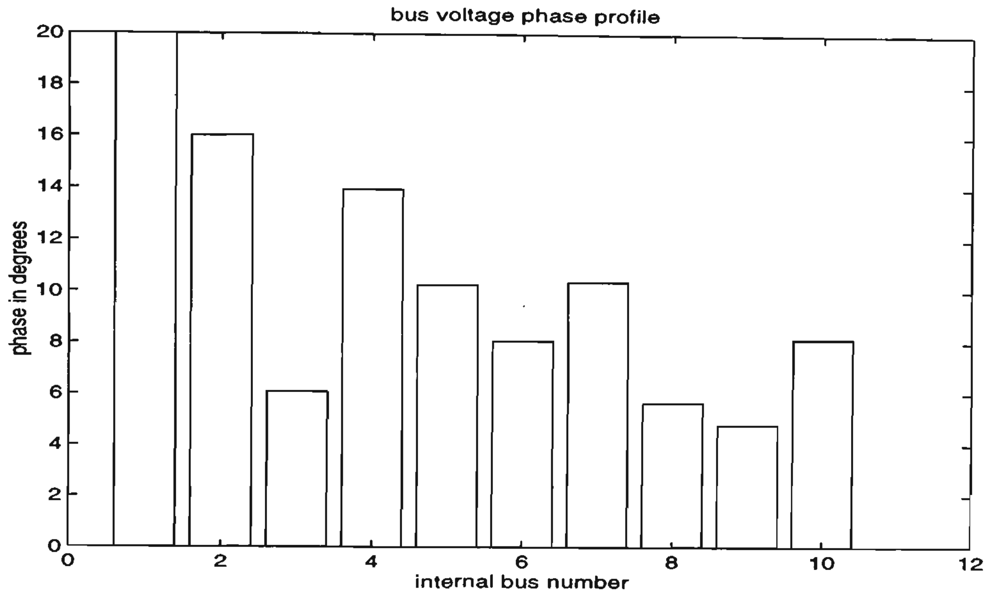


Figure. 4.3. (a) Bus voltage phase profile

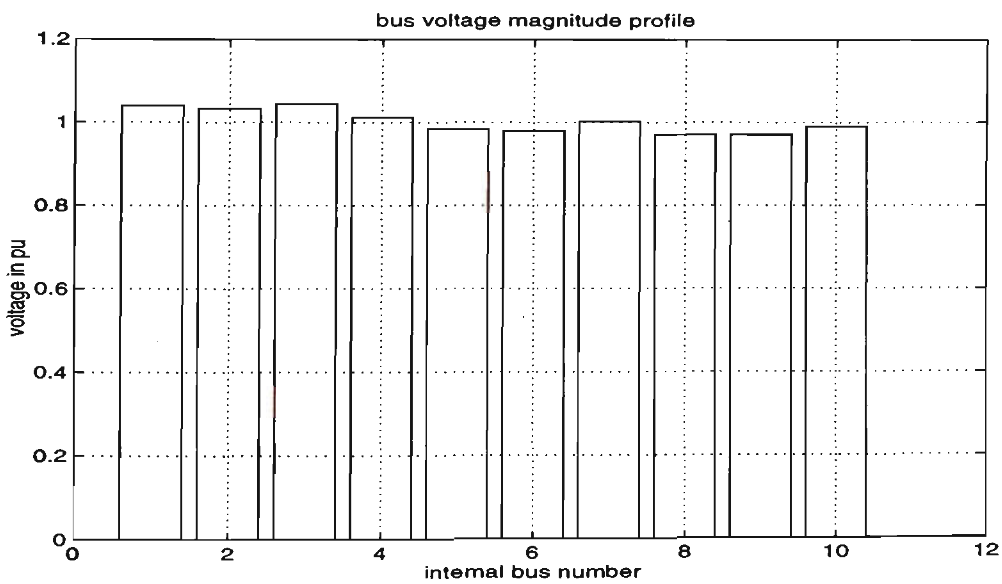


Figure. 4.4. (a) Bus voltage magnitude profile

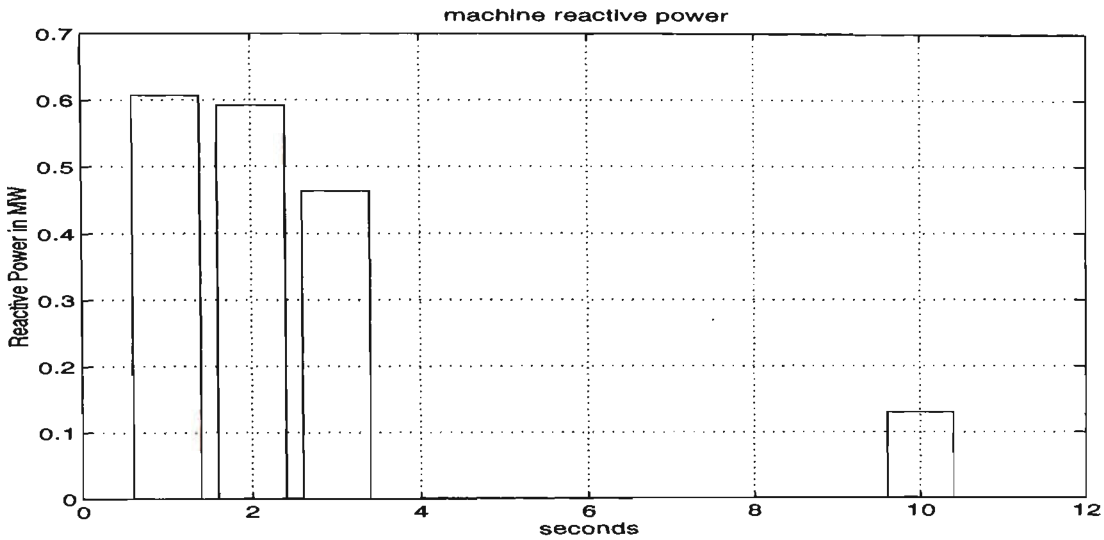


Figure. 4.5. (a) machine reactive power

solved load flow bus solution:

bus_sol =

1.0e+05 *

Columns 1 through 7

0.0000	0.0000	0	-0.0001	0.0004	0	0
0.0000	0.0000	0.9693	-0.0000	-0.0000	0	0
0.0000	0.0000	0.4995	0.0000	0.0002	0	0

0.0000	0.0000	1.3299	0	0	0.0000	-0.0006
0.0001	0.0000	0.6616	0	0	-0.0005	-0.0004
0.0001	0.0000	-0.3006	0	0	-0.0003	-0.0003
0.0001	0.0000	0.9513	0	0	-0.0008	-0.0004
0.0001	0.0000	0.3387	0	0	0.0001	-0.0001
0.0001	0.0000	0.0506	0	0	-0.0002	-0.0002
0.0001	0.0000	0.4033	0.0002	0.0002	0.0000	0.0000

Columns 8 through 10

0	0	0.0000
0	0	0.0000
0	0	0.0000
0	0	0.0000
0	0	0.0000

```
    0         0    0.0000

    0         0    0.0000

    0         0    0.0000

    0         0    0.0000

    0         0    0.0000
```

line flow:

line_flow =

```
  1.0000    1.0000    4.0000   -9.9934   35.9416

  2.0000    4.0000    5.0000   -6.0918   22.5806

  3.0000    4.0000    6.0000   -5.2287    2.1901

  4.0000    5.0000    7.0000   43.4122   25.0992

  5.0000    6.0000    9.0000    5.4662   12.3807

  6.0000    2.0000    7.0000   -2.6764   -2.6523
```

7.0000	7.0000	8.0000	16.4132	7.9983
8.0000	8.0000	9.0000	2.4504	-0.1015
9.0000	9.0000	3.0000	20.7793	4.5598
10.0000	6.0000	10.0000	20.9722	17.0623
1.0000	4.0000	1.0000	9.9934	38.1707
2.0000	5.0000	4.0000	10.6323	15.9247
3.0000	6.0000	4.0000	5.6832	0.1738
4.0000	7.0000	5.0000	56.0526	24.7895
5.0000	9.0000	6.0000	0.5241	13.5145
6.0000	7.0000	2.0000	2.6764	3.7477
7.0000	8.0000	7.0000	-13.9282	11.7910
8.0000	9.0000	8.0000	-2.3908	0.4748
9.0000	3.0000	9.0000	1.2882	17.3580

10.0000 10.0000 6.0000 15.2736 18.9418

(b) 1.5 times increase in power:

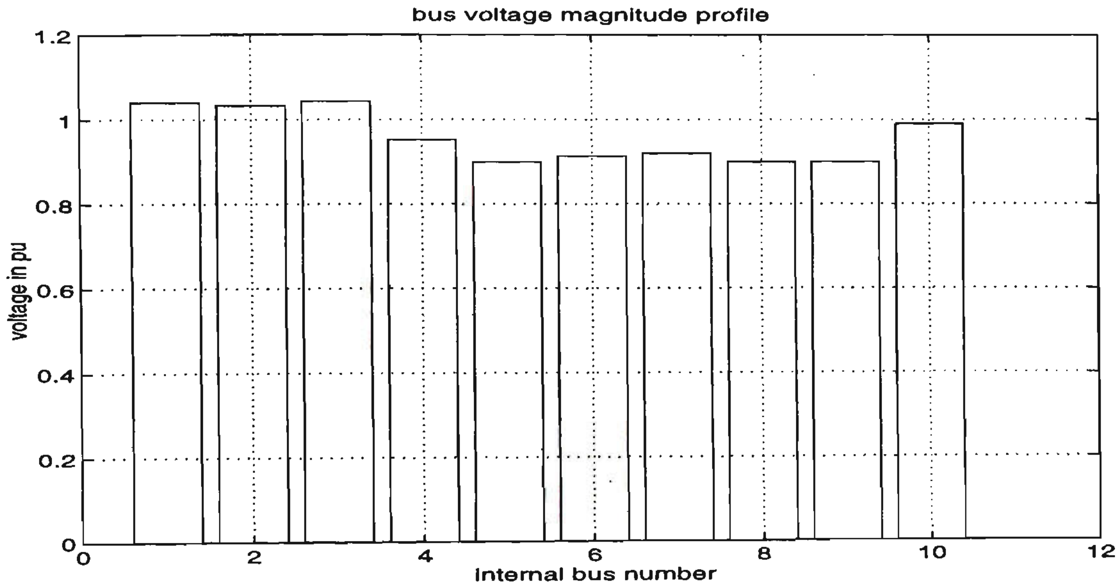


Figure. 4.6. (b) bus voltage magnitude profile

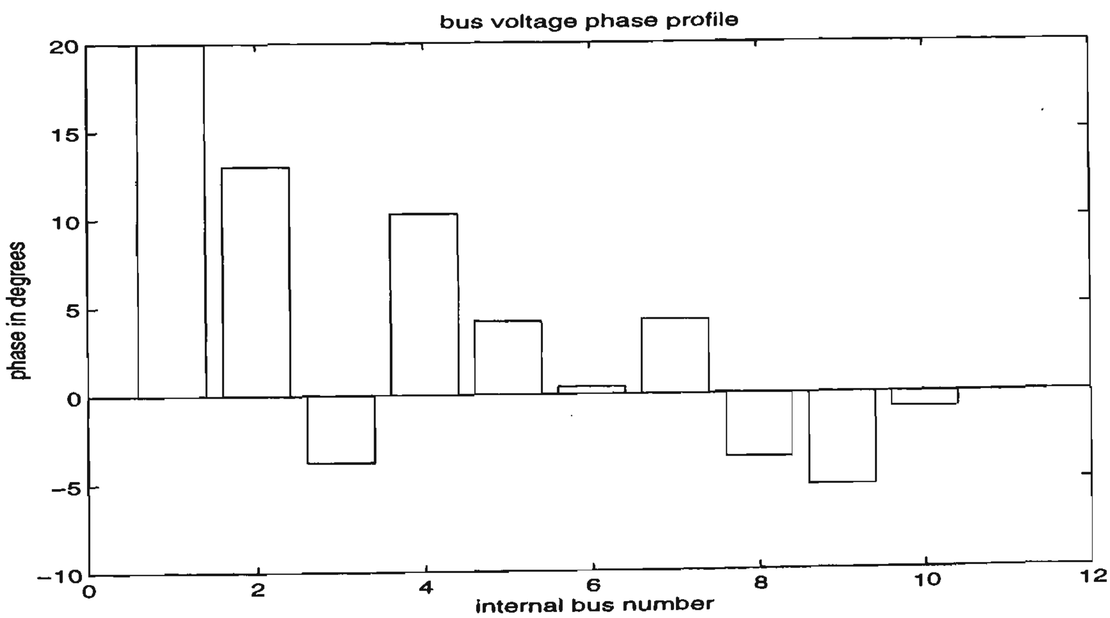


Figure. 4.7. (b) bus voltage phase profile

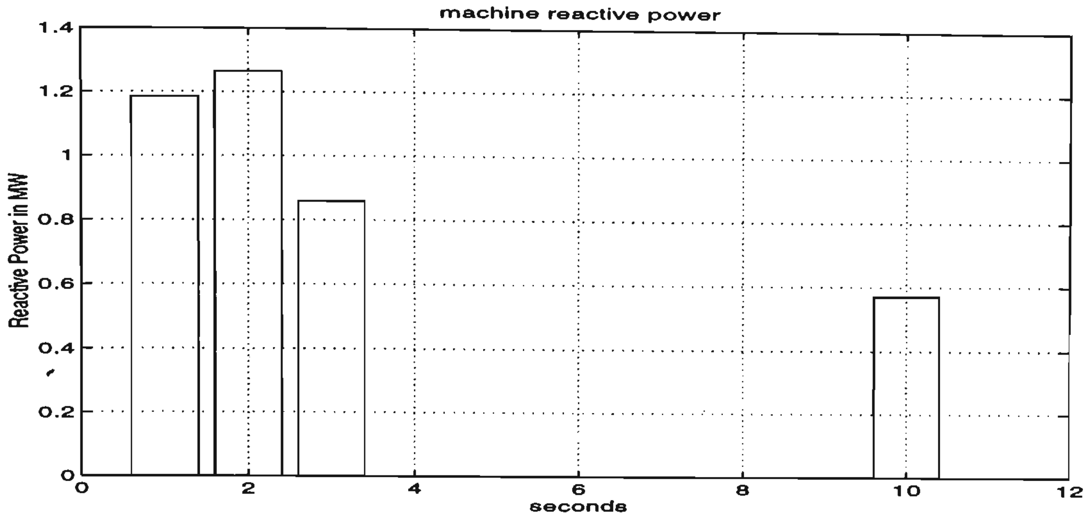


Figure. 4.8. (b)machine reactive power

initial bus data:

solved load flow bus solution:bus_sol =

1.0e+03 *

Columns 1 through 7

0.0010	0.0010	0	0.0116	0.0074	0	0
0.0020	0.0009	-0.1150	0.0010	0.0000	0	0
0.0030	0.0009	5.4232	-0.0002	0.0002	0	0

0.0040	0.0009	-0.0457	0	0	0.0102	-0.0220
0.0050	0.0009	1.8279	0	0	-0.0525	-0.0135
0.0060	0.0009	-5.5667	0	0	-0.0026	-0.0194
0.0070	0.0009	1.6804	0	0	-0.0275	-0.0305
0.0080	0.0009	9.2579	0	0	0.0014	-0.0135
0.0090	0.0009	7.9450	0	0	-0.0092	-0.0208
0.0100	0.0010	-4.8795	-0.0019	0.0061	0.0002	0.0001

Columns 8 through 10

0	0	0.0010
0	0	0.0020
0	0	0.0020
0	0	0.0030
0	0	0.0030

0	0	0.0030
0	0	0.0030
0	0	0.0030
0	0	0.0030
0	0	0.0020

line flow:

line_flow =

1.0000	1.0000	4.0000	11.6206	7.4189
2.0000	4.0000	5.0000	-8.2214	7.7596
3.0000	4.0000	6.0000	9.6782	11.5255
4.0000	5.0000	7.0000	42.6955	7.8164
5.0000	6.0000	9.0000	2.9736	8.6756
6.0000	2.0000	7.0000	1.0364	0.0415

7.0000	7.0000	8.0000	-3.2730	0.9015
8.0000	8.0000	9.0000	-4.8094	13.4106
9.0000	9.0000	3.0000	0.2193	-0.2140
10.0000	6.0000	10.0000	4.5349	-3.5404
1.0000	4.0000	1.0000	-11.6206	2.7037
2.0000	5.0000	4.0000	9.8061	5.6387
3.0000	6.0000	4.0000	-4.9089	14.2210
4.0000	7.0000	5.0000	31.7726	29.5265
5.0000	9.0000	6.0000	1.1369	9.0970
6.0000	7.0000	2.0000	-1.0364	0.0415
7.0000	8.0000	7.0000	3.4017	0.0672
8.0000	9.0000	8.0000	7.8333	11.9055
9.0000	3.0000	9.0000	-0.2125	0.2208

10.0000 10.0000 6.0000 -2.0830 5.9760

(c) 2 times increase in power:

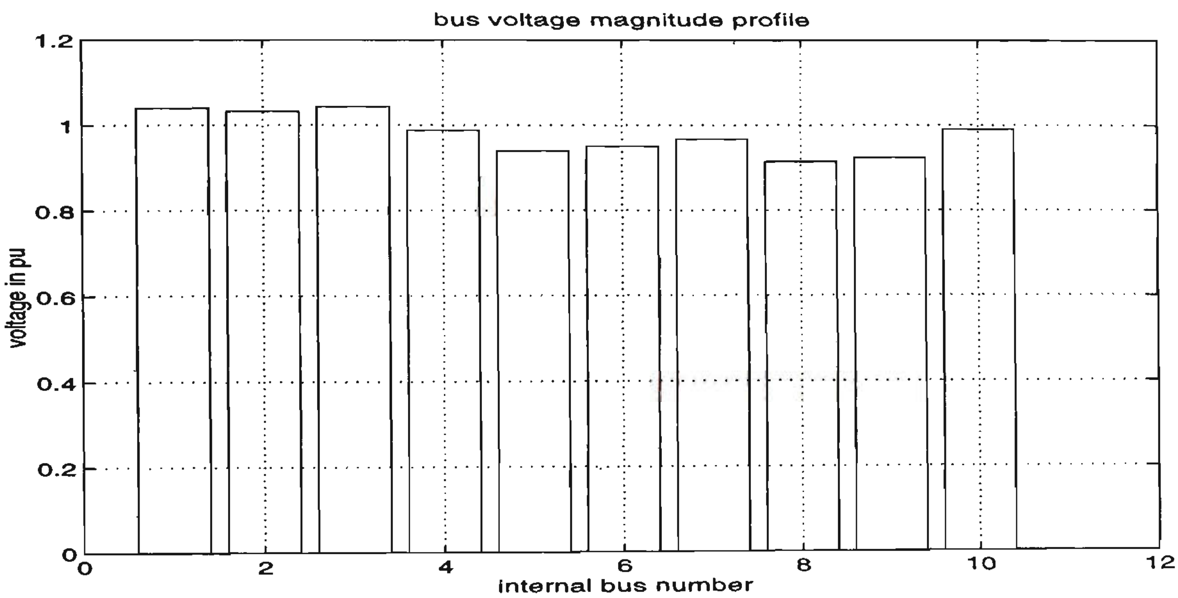


Figure. 4.9. (c) bus voltage magnitude profile

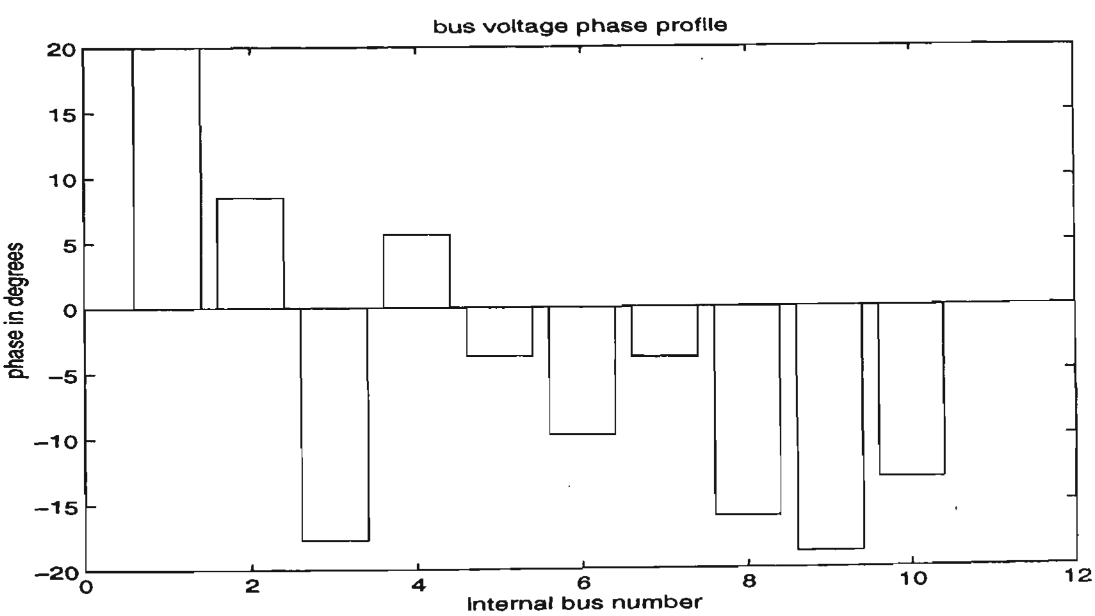


Figure. 4.10. (c) bus voltage phase profile

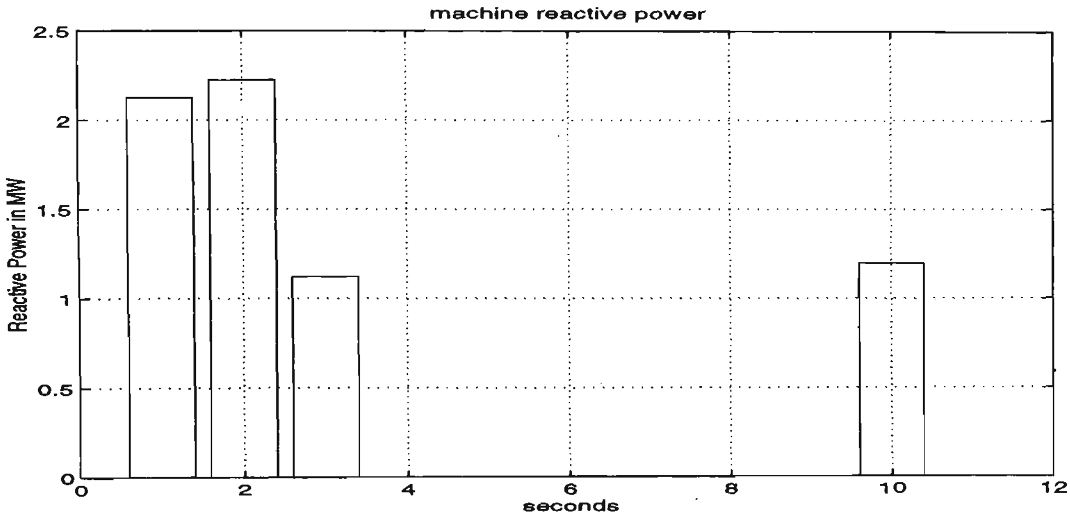


Figure. 4.11. (c) machine reactive power

solved load flow bus solution:

bus_sol =

1.0e+03 *

Columns 1 through 7

0.0010	0.0010	0	0.0196	0.0158	0	0
0.0020	0.0009	-6.6388	-0.0042	0.0252	0	0
0.0030	0.0009	-2.5207	0.0052	-0.0027	0	0

0.0040	0.0011	-2.9613	0	0	0.0254	-0.0251
0.0050	0.0009	-8.3700	0	0	-0.0088	-0.0289
0.0060	0.0011	-3.6401	0	0	-0.0231	-0.0251
0.0070	0.0009	-8.2779	0	0	-0.0371	-0.0377
0.0080	0.0009	-3.7830	0	0	-0.0012	-0.0370
0.0090	0.0009	-6.1556	0	0	-0.0035	-0.0181
0.0100	0.0010	-4.5664	0.0207	0.0124	0.0003	0.0002

Columns 8 through 10

0	0	0.0010
0	0	0.0020
0	0	0.0020
0	0	0.0030
0	0	0.0030

0	0	0.0030
0	0	0.0030
0	0	0.0030
0	0	0.0030
0	0	0.0020

line flow:

line_flow =

1.0000	1.0000	4.0000	19.6321	15.7706
2.0000	4.0000	5.0000	2.0525	2.4274
3.0000	4.0000	6.0000	-7.8010	4.6561
4.0000	5.0000	7.0000	10.7690	30.6523
5.0000	6.0000	9.0000	-0.1412	1.2356

6.0000	2.0000	7.0000	-4.2392	25.2071
7.0000	7.0000	8.0000	1.7763	22.2028
8.0000	8.0000	9.0000	-2.5288	15.0652
9.0000	9.0000	3.0000	-2.6842	5.1878
10.0000	6.0000	10.0000	14.3054	22.2713
1.0000	4.0000	1.0000	-19.6321	17.9998
2.0000	5.0000	4.0000	-1.9668	-1.7881
3.0000	6.0000	4.0000	8.9669	1.5577
4.0000	7.0000	5.0000	31.0815	-9.7203
5.0000	9.0000	6.0000	0.2000	-1.1598
6.0000	7.0000	2.0000	4.2392	25.2071
7.0000	8.0000	7.0000	3.7512	21.9559
8.0000	9.0000	8.0000	6.0050	14.0493

9.0000	3.0000	9.0000	5.1694	-2.7195
10.0000	10.0000	6.0000	20.4379	12.2403

4.6.1 Analysis of the results

The Figure 4.3 (a), 4.4 (a) and 4.5 (a) shows the bus voltage phase profile, bus voltage magnitude profile and machine reactive power respectively for power increased by a ratio of 1. The power was increased by a ratio of 1.5 and 2 from the starting value of 1. Variation in the voltage and the bus angle of all the buses are given in results (a,b,c) with voltage in pu and angle in degree. It is obvious from Figure 4.6 (b) that even for a increase of power by 1.5 there is voltage drop in all the load buses. But the angles are well within 20 degrees (as shown in Figure 4.7 (b)). Figure 4.8 (b) shows incease in machine reactive power. With power increase of 2 the voltages at the buses drop, phase angles increase and machines supplying more reactive power (Figures 4.9 (c), 4.10 (c) and 4.11 (c)) and with 2.6 increase in power it was found that there is clear instability as the bus angles are too high. Thus it is clear that though the utility is stiffer the impact of a small generator is such that it creates instability of the system even with small increase in power. One has to identify the design and operating measures that can be taken to prevent voltage collapse.

4.7 Prevention Of Voltage Collapse

This section identifies system design and operating measures that can be taken to prevent voltage collapse.

4.7.1 System Design Measures

4.7.1.1 Application of reactive power-compensating devices

Adequate stability margins should be ensured by proper selection of compensation schemes. The selection of the sizes, ratings, and locations of the compensation devices should be based on a detailed study covering the most onerous system conditions for which the system is required to operate satisfactorily.

It is important to recognise voltage control areas and weak distribution boundaries in this regard.

4.7.1.2 Control of network voltage and generator reactive output

Load (or line drop) compensation of generator AVR regulates voltage on the high-tension side of, or partway through, the step-up transformer. In many situations this has a beneficial effect on voltage stability by moving the point of constant voltage electrically closer to the loads.

Alternatively, secondary outer loop control of generator excitation may be used to regulate network side voltage. This should be much slower than the normal regulation of generator terminal voltage to minimise adverse interaction of the two controls. A response time of about 10 seconds is usually adequate for the outer loop control.

Several utilities are developing special schemes for control of network voltages and reactive power. For example, French and Italian utilities are developing "secondary voltage control" schemes for centrally controlling network voltages and generator reactive outputs [57][58]. Tokyo Electric Power Company has an adaptive control of reactive power supply [59].

4.7.1.3 Coordination of protections/controls

As identified, one of the causes of voltage collapse is the lack of coordination between equipment protections/controls and distribution system requirements. Adequate coordination should be ensured based on dynamic simulation studies.

Tripping of equipment to prevent an overloaded condition should be the last resort. Wherever possible, adequate control measures (automatic or manual) should be provided for relieving the overload condition before isolating the equipment from the system.

4.7.1.4 Control of transformer tap changers

Tap changers can be controlled, either locally or centrally, so as to reduce the risk of voltage collapse. Where tap changing is detrimental, a simple method is to block tap changing when the source side voltage sags, and unblock when the voltage recovers. Several utilities are using such schemes [60].

There is potential for application of improved under-load tap changer (ULTC) control strategies. Such strategies must be developed based on a knowledge of the load and distribution system characteristics. For example, depressing the distribution voltages in substations which supply predominantly residential loads provides load relief at least temporarily. This will partially offset eventually when the load is increased by the action of automatic or manually controlled devices. Increasing voltage on industrial loads does not materially affect the load supplied, but increases the reactive power supplied by the capacitors associated with such loads.

Microprocessor-based ULTC controls offer virtually unlimited flexibility for implementing ULTC control strategies so as to take advantage of the load characteristics. When dropping the downstream voltage offers relief, the voltages may be reduced to a specific level when the primary voltage drops below a threshold. On the other hand, where secondary voltage is beneficial, normal ULTC controls should be applied. There is even a possibility of actually raising voltages slightly above normal [61].

4.7.1.5 Undervoltage load shedding

To cater for unplanned or extreme situations, it may be necessary to use undervoltage load-shedding schemes. This is analogous to underfrequency load shedding, which has become a common utility practice to cater to extreme situations resulting in generation deficiency and underfrequency. Load shedding provides a low cost means of preventing widespread system collapse. This is particularly true if system conditions and the contingencies leading to voltage instability are of low probability, but would result in serious consequences. The characteristics and locations of the loads to be shed are more important for voltage problems than they are for frequency problems.

Load-shedding schemes should be designed so as to distinguish between faults, transient voltage dips, and low voltage conditions leading to voltage collapse.

4.7.2 System-Operating Measures

4.7.2.1 Stability margin

The system should be operated with an adequate voltage stability margin by the appropriate scheduling of reactive power resources and voltage profile. There are at present no widely accepted guidelines for selection of the degree of margin and the system parameters to be used as indices. These are likely to be system dependent and may have to be established based on the characteristics of the individual system.

If the required margin cannot be met by using available reactive power resources and voltage control facilities, it may be necessary to limit power transfers and to start up additional cogenerator to provide voltage support at critical areas.

4.7.2.2 Spinning reserve

Adequate spinning reactive-power reserve must be ensured by operating generator, if necessary, at moderate or low excitation and switching in shunt capacitors to maintain the desired voltage profile. The required reserve must be identified and maintained within each voltage control area.

4.7.2.3 Operators' action

Operators must be able to recognise voltage stability-related symptoms and take appropriate remedial actions such as voltage and power transfer controls and, possibly as a last resort, load curtailment. Operating strategies that prevent voltage collapse need to be established. On-line monitoring and analysis to identify potential voltage stability problems and possible remedial measures would be invaluable in this regard.

4.8 Conclusion

Voltage stability is essentially a local phenomenon; however, its consequences may have a widespread impact. The heart of the problem is the inability of the small renewable energy sources to supply reactive power demand. Usually, but not always, voltage instability involves system load, or large sudden disturbances such as loss of a generating unit or heavily loaded line.

Chapter 5

Private Generation- Control, Connection and Operational Issue

5.1 Introduction

In Australia, the vast majority of electrical energy generation for distribution through the public network has been owned and operated by electricity supply authorities. This has, meant that generating stations (power stations) have been of large capacity i.e., from about one hundred MW up to several thousand MW, and located nearby to low cost fuel supplies to achieve economies of scale. This bulk generated energy is then delivered to customers via the transmission, subtransmission and distribution networks.

Generally very few organisations outside of electricity supply authorities have owned and operated generating plant except for stand-by purposes. In the last decade this situation has slowly changed with most governments now encouraging customers to install relatively small scale generation i.e., up to about 50MW where it is efficient and appropriate. This concept is referred to as "private generation" or "customer owned generation" to differentiate it from large scale electricity authority owned generating stations.

The introduction of DSG into distribution systems has significantly complicated the previous distribution planning and operating practices. It requires substantially greater data collection and analysis efforts. This chapter describes the salient features of the distribution system characteristics. Operational problems like harmonics, earthing, reliability etc. are considered. Regulatory and contract issues are also outlined.

5.1.1 Delivery System Characteristics

5.1.1.1 Distribution reliability

Though the individual equipment has high component reliability, distribution level outages still cause about 95% of all service interruptions to customers, only about 5% is caused by failures in the bulk-supply system [63]. This is due to the large number of components susceptible to outage occurrences caused by natural conditions or human interference. Generally, the cost of service continuity improvement is so high that brief periods of infrequent service interruption to a small number of customers can be tolerated. Usually, distribution outages, compared to bulk supply failures, are significantly more frequent, have shorter duration, and affect a smaller number of customers at one time. Present distribution reliability performance reflects the balance between the value of service continuity to smaller customers and the cost of improvement of these kinds of outages. DSG as an option to improve distribution reliability should be evaluated to the extent it can be useful in these frequent, short-duration and location-specific outages.

5.1.1.2 Distribution Losses

Transmission and distribution systems together lose about 8 to 10% of the energy they deliver, about half of the total loss typically being in the distribution system. Dispersed generation can eliminate transmission losses and reduce distribution losses. Dispersed storage has negligible effect on transmission and distribution losses. To deliver the same amount of energy to end-users, dispersed devices require smaller power and energy capacities.

5.1.1.3 Radial operation

Most distribution systems are radially operated. This avoids the expensive capital investments in additional distribution equipment and reduces operating and protection complexity of loop systems. DSG could be operated to preserve the uni-directional current flow in a network operated radially, avoiding any additional capital investment and planning and operating complexities.

5.1.1.4 Thermal and voltage limitations

Thermally-limited systems require reinforcement to avoid current overloading of equipment. Voltage-limited systems serve areas with lower load density and long primary and secondary lines. Systems can be both thermal and voltage limited. DSG can be used to smooth down the loads higher up the system above the device location in a thermally limited system. It can help to increase the voltage level at the lower part of the system below the device location in a voltage limited system.

5.1.1.5 Power Quality

Utility customers expect electric power to meet certain tolerances so that electric appliances will function efficiently and not be damaged under normal operating conditions. Power supplied to the grid by an interconnected cogenerator also is expected to be within certain tolerances, so that the overall power quality of the utility system remains satisfactory. Electric utilities are concerned about three types of power quality: correcting the power factor to keep the voltage and current in phase, maintaining strict voltage levels, and minimising harmonic distortion.

5.1.1.6 Power Factor Correction

A power factor different from unity means that the voltage and current are out of phase, and can be either leading or lagging. Because the most useful power is delivered when voltage and current are in phase, it is important that the power factor be as closed to unity as possible.

Phase shifts are one consideration in setting the demand component of rate structures. Thus utilities will have one rate for power with a power factor of unity sold to other utilities, another rate for power sold to industrial customer which may have power factors much less than unity and require the utility to install special monitoring devices, and another rate for power sold to residential customers, where power factor is not measured individually.

Synchronous generators have power factors of approximately unity but can be adjusted to slightly leading or lagging while induction generators always have lagging power factors because they have more inductive than capacitive elements. Also, synchronous generators are more efficient than induction generators. These two points can cause synchronous generators to be preferred for units above a certain power level (about 500 kW), although the precise value depends on individual situation.

As the penetration of induction generators increases, more inductive elements are added to a particular distribution substation's circuits, resulting in a more lagging power factor, this creates three potential problems for the utility: the capacity of both transformers and switching equipment in the transmission and the distribution system may have to be increased to handle the out of phase signals; the efficiency of the transmission network may decrease; and equipment and appliance may overheat and may need more frequent overhaul.

Utilities normally improve lagging power factors by using capacitors, which may be sited either at the distribution substation or near the customer's load or generator, depending on the cause of the poor power factors are caused by smaller customers' equipment, utilities usually pay for the correcting capacitors, while large customers often are required to pay for their own power factor correction. Most utilities have guidelines that state the minimum power factor allowed, usually 0.85 lagging. If a customer fails to maintain this minimum, utilities may ask the customer to install and pay for the necessary corrective capacitors. Traditionally, few utilities have leading power factors, because most utility circuits (and most appliances and motors) have more inductive elements than capacitive elements.

Similar policies will apply to cogenerators. Thus many utilities supply capacitors for small cogenerators, while requiring larger ones to pay for their own capacitors under the theory that there will be fewer substations with significant cogenerator penetration. Thus, the avoided substation capacity becomes part of the utilities's avoided cost and is credited to the cogenerator.

5.1.1.7 Earthing

Earthing is necessary for safety, to prevent electric shock and to operate devices which disconnect faulty equipment. Earthing is the process of connecting both the metalwork of electrical apparatus and equipment and, in certain cases, the star or neutral of such apparatus to the general mass of earth in order to ensure that there will be an immediate and safe discharge of energy when necessary.

Where h.v. and l.v. equipment are to be connected to a common earth electrode, its value must not exceed 1 Ω.

For high voltage system neutral earthing, the utility may use solid or resistor methods. The magnitude of the possible earth fault current will vary widely according to which of these methods is used.

The earthing method employed for the cogenerating plant must provide approximately twice the operating current of the earth fault current protection relay.

Arrangement for earthing of the neutral or star point of the generators will be dependent on the number of generators in use and whether they are to be operated in parallel with each other or the utility's system. A generator operating independently at h.v. will normally be connected as a three-phase, three-wire machine with its generator star point earthed.

Where a number of generators are being operated in parallel with one another, the h.v. star point of only one machine should be earthed to avoid the risk of circulating third harmonic currents. Arrangements should be made for the provision of automatic transfer of the generator star point earth to another machine if the selected machine is tripped, so as to ensure that the generator installation remains continuously earthed. This is achieved by connecting an automatic switch to the generator star point so that it is opened automatically when the system is earthed on the utility's system. In the event of the loss of the utility's system, the generator's star point can be arranged to close, thereby maintaining an earth on the cogenerator's system. An arrangement which avoids the need for automatic star point earth switching is the use of a bus bar connected h.v. earthing transformer with all generators connected as three phase, three-wire machines, the star point earth being derived from the earthing transformer.

For l.v. system neutral earthing, the utility uses solid earthing, but variations in possible earth fault current can be expected due to the sizes of the h.v./l.v. distribution transformers and the earthing electrodes employed.

It is essential to ensure that the neutral busbar is continuously connected to a source of supply, or to a balancer, as well as being earthed. The decision to couple the neutrals of l.v. generators operating in parallel will be dependent on the amount of third harmonic circulation current which would result if all the machine neutrals were coupled. With smaller rated sizes of generator, the harmonic problem increases due to laminations in the machine design which result in the production of non-sinusoidal waveform.

The use of static balancer to provide the neutral and earth connection for the l.v. four-wire system will mean that neutral of the four-wire will be maintained and earthed irrespective of the number of generators operating on load. The static balancer must be solidly connected to the l.v. busbar. The generators are then connected as three-wire machines.

Manual or automatic switching of the connection between generator star points is not permitted. In some circumstances, the l.v. secondary of a h.v./l.v. transformer may provide this connection, but there is usually a risk this might become disconnected under fault conditions and result in validates on the neutral which might cause damage to equipment.

5.2 Impacts of Cogeneration

Operating a cogenerator in parallel with a utility has the following impacts on operational and protection aspects of both systems [56].

5.2.1 Control and regulation of voltage and frequency under normal system operating condition

Mostly, a cogeneration system will comprise small to medium size generating plant/s. The automatic response of such plant/s to varying system frequency and voltage will have very little effect on the system due to the high inertia and low source impedance of the utility system. Hence, if the system frequency and voltage are not maintained within specific limits by the utility generators, the cogeneration plant may become unstable by overreacting to such changes. If the conditions exceed any permissible limit, some protection may operate to trip the generator. This is not a desirable situation, as the cogeneration plant shutdown will result in loss of steam production required for processes. Such an abnormality should be detected and rectified to prevent tripping of the cogenerator.

5.2.2 Operating in island mode

While in parallel operation, due to some switching operation or a fault on the utility side, a cogenerator can become separated from the utility system. In such an event, referred to as islanding, the cogenerator may be totally separated from the utility or, separated from the utility generation system, with some utility customers still connected to the cogenerator via the interfacing link. When that happens, with the most probable case of mismatched generation and load on the islanded system, the cogenerator can become unstable and trip. To avoid tripping and at the same time prevent any damage to the generator or turbine, fast acting protection and control systems are necessary on the cogenerator. Utilities also require an islanded cogenerator to be isolated from their inter-tie for the following two reasons:

- when an islanded utility system is to be restored from the utility side, a breaker may be closed to couple two different systems which are not essentially in synchronism. This may cause damage to the circuit breaker as well as to the cogenerator.

- the utility is responsible for the quality of supply to its customers. In island operation, if the cogenerator is the only generating source in the island with some utility customers, utility has no control over the quality of supply to those customers.

Therefore, it is vital to detect an island situation and isolate the cogenerator completely from utility as quickly as possible.

5.2.3 Risk of energising a dead utility/cogenerator inter-tie circuit from the cogenerator's side

To avoid such mishap proper, adequate interlocking must be provided on the inter-tie. The interlock should block closing of the cogenerator end circuit breaker in the event of loss of mains. This also applies in the case of an inter-tie with reclosing facility on the utility side breaker. For a fault on the link, the utility side breaker may open before the cogenerator end breaker. If so, before a reclosing attempt made on the utility breaker, the cogenerator end breaker should trip, and should not be able to close until the supply on the link is established.

5.2.4 Having an unbalanced three phase load to be supplied by a cogenerator during export period

This condition can arise due to an unbalanced three phase load in the utility distribution system that is electrically close to the cogenerator. If such unbalance of load between phases exceeds an acceptable limit the cogenerator should be protected against it.

5.2.5 Unstable condition on a cogenerator following delayed clearance of a fault on the utility system

A sustained fault on a utility feeder could cause severe stability problems on a cogenerator following fault clearance. If a cogenerator is to be connected to an existing utility circuit, it might be necessary to effect changes to existing protection and control systems of the interfacing link. The complexity and costs of such changes may vary depending on the type of interconnection. It may be easier and less expensive if the interconnection is a dedicated line from a utility substation to the cogenerator facility. On the other hand, if the interconnection is a tap off connection from a circuit, with possibly other tap off connections to serve other utility customers, the protection changes required become complicated and costly.

5.3 Regulatory and contract issues [67][68]

5.3.1 Introduction

The technical requirements for private generators are vital for safety and security of personnel and equipment in both the network utility and customers' installations. Appropriate attention to design, manning levels and equipment needs, at an early stage, will ensure smooth commissioning and operation of a private generating installation.

Technical requirements and responsibilities of the customer in relation to parallel operation are framed to ensure safety under both normal and fault conditions, and operation without interference to the continuity or quality of supply to other customers.

For private generation at low voltage, the isolated mode of operation is frequently recommended. This mode enables the customer to receive the benefits of local generation without the need to install additional high cost equipment. The output of the private generator may be completely independent of the public distribution network and used for functions such as water heating or battery charging.

5.3.2 General Requirements

5.3.2.1 Legal Obligations

The electrical installation of private generating plant must comply with the State Regulatory Authority Wiring Regulations (these are based primarily on Australian Standard 3000) and the requirements of all other government and statutory authorities.

Regulations specifically covering the supply of electricity beyond the limits of private premises vary from state to state.

5.3.2.2 Consultation Requirements

Customers should inform the Distribution Network Utility if they are considering the installation of generating plant. This will enable the utility to give guidance on safety, operational aspects, point of connection and terms of supply.

For parallel operation, reinforcement of the utility network may be necessary at the customer's cost. As an example, the installation of a several hundred kW low voltage parallel operating generator would typically require the customer to bear the costs covering:

- Minor extension of high voltage(22 to 6.6 kV) line from a suitable point in the existing network to the customer installation
- Supply and installation of a HV/LV distribution transformer
- Supply and installation of a LV cable from the distribution transformer to customer's generator
- Supply and installation of associated switchgear, protection and metering equipment.

Depending on the extent of any dedicated supply system assets, the distribution network utility may require the customer to meet the utility's costs of operation and maintenance of these assets.

5.3.3 Requirements for Parallel Operation

Parallel connected generating plant virtually becomes part of the distribution network utility system. As the utility network operator must comply with statutory requirements, the privately owned plant must also comply.

5.3.3.1 Safety

It is of paramount importance that parallel operation does not present a hazard to utility staff, public or the customer utilising the generation plant. Consequently, it is necessary for a failure of supply or irregularity in any of the phases of the utility network to which the private generator is connected to result in the complete and automatic disconnection of the private generator from the utility network.

It is also of importance that the generator is automatically disconnected and the prime mover shut down for certain faults on the generator itself and on associated customer installation circuits.

Only persons with adequate electric knowledge should install or work on the generation installation and associated electrical circuits. Unless the equipment is fully automatic, the start-up and operation of the generator may also require specialist knowledge and training.

The customer must provide a suitable switch or circuit breaker to enable total isolation of the distribution utility system form the customer's installation. This device shall be lockable and the isolation visually verifiable.

5.3.4 Technical Aspects

5.3.4.1 Synchronising

Provision by the customer for accurate manual or automatic synchronising is required. Automatic synchronising is preferred and equipment usually must be approved by the distribution network utility.

5.3.4.2 System and Generator Characteristics

The customer's plant must be capable of regulation so that it does not vary its load unnecessarily or continuously with minor changes in the system frequency. To ensure that stability problems do not arise, either of the following requirements must be met:

- Each generating set must have protection equipment to disconnect from the utility system before the set becomes unstable
- Each generating set must prove stable for all loads up to the maximum agreed export rate at minimum permitted power factor while all normal switching operations are carried out in both the customer's and the utility's parts of the system.

The load control system on the governors must be capable of restricting generation to the agreed power export limits.

When the customer's equipment is synchronised to, or operating in parallel with, the Utility network, the power factor measured at the point of common coupling must remain within the nominated limits.

5.3.4.3 Equipment Standards

All of the customer's high voltage equipment shall have an acceptable test certificate. Switchgear, conductors and earthing systems shall have an impulse withstand voltage rating in accordance with Australian Standard AS1824 and an ability to withstand for not less than three seconds, the maximum prospective fault currents which may be imposed on it. The maximum fault level for design purposes shall be to AS2067.

5.3.4.4 Neutral Point Earthing

The customer is to ensure that appropriate neutral point earthing in the event of the continued supply of any part of the high voltage network isolated from the utility network.

The customer is fully liable and shall indemnify the utility against any liability for injury, loss or damage caused by the failure to comply with these provisions.

5.3.4.5 Instrumentation

Each generator should be equipped with a voltmeter, ammeter, power factor indicator, wattmeter and synchronisation monitoring/equipment.

5.3.4.6 Tariff Metering

The customer must provide a suitable space for mounting of the utility's tariff meters. Where export of excess energy has been agreed, export metering will be provided by the utility generally at the customer's expense. Import and export metering will have reverse running stops.

5.3.4.7 Statistical Metering

Statistical metering may be required to:

- Allow correction of source zone substation maximum demands and times of occurrence
- Monitor the customer's maximum real and reactive power flow
- Monitor the customer's export energy

5.3.4.8 Telephone Link

The utility may require, generally at the customer's expense, a dedicated telephone line between the customer's plant control room and the utility network operation control centre.

5.3.4.9 Remote Monitoring

Where energy export is significant, remote monitoring of the customers generation and interconnecting circuit may be required.

5.3.4.10 Auto Reclose and Auto Changeover

It is the customer's responsibility to examine the impact of any automatic reclose or changeover facilities in the distribution network on the customer's plant. If facilities such as live line blocking and synchronism check are required, generally all network costs are required to be met by the customer.

5.3.4.11 Testing and Activation

The utility will inspect and test the installation prior to activation for compliance with the agreements and contracts, Wiring Regulations, etc. If the installation is unsatisfactory, the customer shall disconnect or modify equipment before permanent activation.

5.3.5 Quality of Supply

5.3.5.1 General

The parallel operation of private generators has the potential to degrade quality of supply standards.

They can cause voltage fluctuations in response to prime mover input (i.e. wind turbines) and poorly constructed generators and those coupled through power electronic systems may have distorted output waveforms, with consequent harmonic interference difficulties. Each generator and its associated network connection arrangement must be investigated to ensure that parallel operation does not result in unsatisfactory supply to existing utility customers, caused by voltage unbalance or harmonic distortion.

5.3.5.2 Acceptance Tests

Tests will in general be carried out by the utility before and after connection to check for voltage fluctuation, harmonic distortion and voltage unbalance limits.

5.3.6 Operation

5.3.6.1 High Voltage Operators

Where appropriate (usually above 650 V) high voltage operators, sufficient in number to ensure safe operation of the customer's installation, and interaction with utility network operations, need to be provided by the customer. Prior to authorisation of such operators, a period of initial training at the utility operator training school is required.

5.3.6.2 Operational Procedures

Operational procedures and apparatus must be provided and maintained by the customer. Written safety rules are required to be established and enforced by the customer. High voltage equipment and enclosures must be secure against unauthorised access and a system of access permits established and rigidly controlled.

5.3.6.3 Communication Arrangements

The customer is generally required to nominate a responsible officer to represent it in operational matters at all hours. Day to day operation will be between the high voltage operator and the utility contact officer.

Abnormal events must be promptly notified to the other party.

5.3.6.4 Operation of Parallel Generation

The customer is generally required to provide some days of notice of intention to synchronise shut down or substantially vary the level of parallel generation unless otherwise agreed and to obtain permission to parallel. The customer is to keep a continuous written log on availability, maintenance, operation and unusual events and forward these to the utility as required.

Reduction of export must be prompt when requested by the utility network operations controller for the purposes of network switching or other abnormality.

5.3.7 Operation with Alternative Connection to the Utility System

5.3.7.1 Operational Aspects

No parallel operation with the utility network is generally allowed with this form of connection. The interlocking and methods of changeover must satisfy the utility.

Where a customer intends to use plant for emergency stand-by, extreme care in the allocation of circuits fed by the generator must be exercised to ensure that the hazard from more than one supply being present at any one time in premises is avoided.

Where an automatic mains fail type of generator system is installed, a conspicuous warning notice shall be displayed, for example, "This generator is automatically remotely controlled and work should not be carried out on it until the starting switch is isolated."

5.3.7.2 Technical Aspects

The basic requirements for earthing, protection and instrumentation will apply for this mode of operation as previously described. Precautions must be taken to ensure that an inadvertent parallel connection cannot be made under any circumstances.

The following general methods are possible but each has limitations:

- An electrical interlock between the closing and tripping circuits of the changeover circuit breakers
- A mechanical interlock between the operating mechanisms of the changeover circuit breakers
- An electro-mechanical interlock in the operating mechanisms and in the control circuits of the changeover circuit breakers
- A system of locks with a single transferable key, e.g., Castell Locks.

The devices must be of a "fail safe" design, so that one circuit breaker cannot possibly be closed if the other circuit breaker in the changeover sequence is closed, even if the auxiliary supply to the electro-mechanical devices has failed. In practice, a duplication of interlocking will have advantages.

5.4 Conclusion

Introduction of private generation into the distribution network requires detailed consideration of operational issues and regulatory and contract issues associated with both the customer's installation and supply network to ensure trouble free operation. This section provided an overview of the issues and application aspects as well as some typical arrangements found in practice.

Chapter 6

Private Generation - Protection and Control

6.1 Introduction

The growing number of cogenerators and renewable energy sources and their effects on the performance of distribution networks prompted the public utilities in the U.K. and USA in the late eighties to formulate and recommend certain guidelines for interconnection. Since then, quite a few colloquiums and technical papers have discussed the issue of interconnection keeping in view the protection, control and safety requirements of the generating installations [64].

The guidelines developed by various public utilities in Australia in the recent past for connecting the cogenerators and renewable energy sources reflect predominantly the Engineering recommendations G59 and ET 113 [65][66].

These guidelines essentially dictate the smaller installations to be governed by what appears to be the prerogatives of the larger utility grids. An example of this could be the various protection schemes and the associated relays the installation of which are mandatory for the distributed generation schemes. Except in the cases where fuse protection is generally sufficient, the feasibility of other installations could be in serious jeopardy as the cost of providing discrete protection and control will be significant in relation to capital cost of the planned power generation capacity.

In this section, a review of distribution system protection & control strategies and hardware was carried out to establish 'state-of-the-art' technology currently employed.

The protection and control requirements specified by the utilities in general [67] are as follows:

6.2 Protection Requirements

All the renewable energy sources will have grid interface with the utility distribution network unless the renewable energy source is a stand-alone installation. By their very nature, the renewable energy sources are commonly found to be at or near the end of a distribution network. The typical protection requirements specified by the utilities in general are as follows:

6.2.1 Dispersed Generating Plant

-- Generator unit protection should be included according to the size and importance of the installation.

-- Each generator must have protection to trip the generator circuit breaker. The excitation has to be suppressed and the prime mover shut down if required. The protection should operate for all faults between the generator circuit breaker and the generator windings and act as a back-up protection.

-- For operating generators in parallel, each machine should have reverse power protection to prevent motoring.

-- According to the type of prime mover used, protection should be provided for overspeed, overheating and low lubrication oil pressure.

-- If more than one generator is installed, then under and over voltage relays along with under and over frequency protection should be installed on each machine. This is independent or the overall interconnecting tie protection.

-- Neural displacement protection may have to be provided as per the generator, generator and transformer connection.

-- The customer is responsible for the design, installation, setting and commissioning of all generator protection equipment.

6.2.2 Interconnecting system

-- All faults on the dispersed generator interface with the utility network must be cleared rapidly and automatically from all sources of supply.

-- In case of high voltage faults, back-up protection shall be provided by the utility end protection relays for faults in the dispersed generator end and vice versa.

-- Export limit protection must be installed to prevent energy feed back to utility where there is no buy back agreement. Where there is an energy buy back agreement, the export limit protection will ensure that the level of generation is restricted to the agreed export limit.

-- Neutral displacement protection is necessary if the neutral at the interconnection point is not solidly earthed.

-- Protection scheme must detect 'islanding' i.e.; formation of an isolated combination of dispersed generation and utility system load and positively disconnect the islanded generator. This may require installation of high speed communication link between the utility and the generating plant.

This is due to the fact that current legislation dictate that customers can be supplied power only from the grid. The customers are obliged to pay the cost of this service. This situation is likely to change in the future, as sophisticated energy meters capable of handling complex tariff and billing requirements are installed.

-- The utility must approve all the equipment installed by the customer for the protection of the interconnected generating facilities.

6.2.3 Utility Network

-- Minor or Major modifications to the protection scheme may have to be carried out by the utility to allow parallel operation. Each installation requires detailed analysis to determine the extent of such modifications.

6.2.4 Protection Co-ordination

The conditions for protection Co-ordination has been specified as a general guidance for dispersed generators [68].

-- Generators connected at low voltage (<1kV) must be disconnected from utility in less than 1 second at the maximum system fault level.

-- Generators connected at distribution supply voltage of 6.6kV - 33kV shall be set to disconnect in less than 800ms at the maximum fault level condition.

-- Generation plant connected at 66kV and above shall include duplicate high speed protection capable of disconnecting the system in less than 150ms.

-- Earthing is an important factor. The HV system should be connected with earth at or near the generating source. Earth fault or zero sequence current devices must be well coordinated to avoid damage.

The protection equipment must comply with IEC Standard 255.

6.3 Present State of the Art

At present, to satisfy the protection and control requirements specified by the utility, discrete protection and control equipment are being extensively used. The majority of the projects commissioned during the last decade extensively made use of solid state relays compared to the older installations where electromagnetic relays are still in service. Even though solid state discrete relays have now gained the confidence of the utilities internationally, the changes that are taking place in restricting the utility internationally, the changes that are taking place in restructuring the utility coupled with the increasing number of dispersed generation facilities has posed technological challenge. The challenge is to provide the utilities with a cost effective technology in integrating and controlling the dispersed generation.

6.3.1 Protection and Control - integrated Approach

Considering the growing cost of providing protection & control as specified by the utility, the attention has been oriented towards the development and implementation of integrated protection and control systems. Breakthrough in microprocessor technology and digital communications has encouraged further development in this area. The main attraction is the cost effective solutions that are essential for integrating the dispersed generation into the grid. Further there are immense opportunities to save when refurbishing and replacing the old equipment in the existing power network to interface with the latest technology. Simply replacing analogue electromechanical devices with digital relays is not enough [69][70]. What is required is to fully integrate the protection, control and monitoring functions. The resulting system will be flexible, simpler and allow a subsequent reduction in hardware to achieve higher reliability and efficiency [71].

Recognising the degree of uniformity specified for protection and control of smaller generation installation, the protection and control system must exhibit the following minimum qualities:

* Provide a comprehensive selection of functions to suit the requirements of a wide variety of installations.

* Should be a major contributor to the needs of complex schemes.

* Be easy to install with ease of testing and acceptance as utility grade equipment.

* Exhibit a user interface design that enables the user to adapt quickly to the operating technique.

* Technically sophisticated to execute the multiple requirements for protection, control and operator interaction in real time.

* Provision of serial communication ports to allow remote access to accomplish any function that requires local intervention.

* Data storage capability to allow event recording during occurrence of a fault for post fault analysis.

* Self checking capability.

* Sensitivity, stability, selectivity, economy, reliability and speed.

The remedial measures point in the direction of providing low cost automation and integrated schemes. The good news that the barriers are breaking down and some utilities in Australia are boldly experimenting by installing integrating protection and control systems [72].

On the basis of the above criteria a protection system designed to protect a cogeneration facility should comprise the following modules:

6.3.1.1 Primemover Protection

Primemover overspeed protection.

High engine temperature and bearing temperature.

Low oil pressure (as may be applicable).

6.3.1.2 Generator Protection

Differential Protection.

Overcurrent Protection.

Reverse Power Protection.

Loss of Field Protection.

Over/Under Voltage Protection.

Over/Under frequency Protection.

6.3.1.3 System Electrical Protection

Protection of interfacing circuit with utility.

Loss of mains protection.

6.3.1.4 Metering and Alarms

Metering of required parameters on the power generation and process sides and providing necessary annunciation and /or visual indications.

6.3.1.5 Hazardous situations

This covers the requirements of the gas supply company and Australian standard, and includes ventilation, fuel shut off and purging.

6.3.2 Design of an automatic control system

Design of an automatic control system for a cogeneration facility will include factors such as:

- In a cogeneration system the primary control may depend on what is to be regulated, whether steam or power output. This may be decided based on process and economic requirements and on the opportunity to sell power to utility at profitable price in some cases, where excess generating capacity is available.
- Control of voltage and frequency as a system connected to the utility and during off utility operation. As mentioned earlier, the automatic response of a cogenerator to system frequency and voltage fluctuations should be limited to protect the cogenerator from overloading/overheating.
- Optimising the steam/power output, especially, where there are more than one cogenerating unit is involved.

The control system of a cogenerator will comprise the following modules.

a. Primemover

This includes starting, stopping, and speed regulation during off load and on load.

b. Automatic Synchronising

This covers off bar speed control of the primemover, running up to synchronous speed, field excitation and voltage control, live main checking, synchronising and closing circuit breaker.

c. On load frequency and voltage control and power factor control

d. Process Control

This is relevant to cogenerating systems where it is required to sense and control temperature, and water and steam flow, as required.

There are different combinations of operating conditions a cogeneration system can be engaged into, and within a particular installation the operation strategy may be required to be changed from time to time due to process chances or power export requirements. Hence, it will be desirable to have a cogenerator control system to be as adaptable as possible to any combination of operating requirement.

Cogenerators' concern is to protect their generating plant, and to secure their generation during external disturbances in order to maintain power supplies to their vital loads. Thus, in addition to providing appropriate protection to isolate the cogenerator from the utility, for an external disturbance, it is also necessary to provide fast acting control on the isolated cogenerator. This is vital to secure the local generation and to prevent any damage to the generating plant, or any equipment powered by it, due to under/over voltage and/or over frequency of the separated system.

Since cogenerators, in most cases, are additions to existing power supply systems on the cogenerators' facilities, a protective scheme designed to protect the cogenerator and the inter-tie must suit the system in hand. Design and implementation of such protection system with individual relay for different protective functions is costly. Particularly, in the case of small cogeneration systems this cost forms quite appreciable part of the cost of whole installation. This cost can be as nearly as 25% of the total cost of the cogeneration system in the case of an 800 KW installation and as much as 50% for a 100 KW installation [73]. The utilities require complete range of protection to be provided with any cogeneration system, small or large. This is a limiting factor for facilities with small power generation capability to go into cogeneration and parallel operation with a utility system [79]

The recent development of micro controller based protective relays are cheaper compared to conventional electro - mechanical relays or solid state relays. James H. Harlow in references [18] has discussed about a micro controller based multifunction relay with thirteen protective functions for cogeneration protection application. This multifunction relay using digital signal processing technique is faster, more accurate, includes special features as self - checking and self - calibration, thus more reliable, occupies very little space and costs less. However, it is to be noted that while all the functions in this relay may not be required for a specific cogeneration application, some additional functions may have to be included.

6.4 Conclusion

Utilities are concerned about safety, security and quality of the power supply to their customers, and the safety of their personnel working on their system. Hence, for a cogenerator to operate in parallel with a utility, it is necessary to satisfy the utility's stringent requirements of protection, control and interlocking systems on the interconnection.

Integrated protection and control coupled with the advances in communication engineering will pave the way for distribution automation. This will result in savings that help in offsetting the capital cost of the dispersed renewable energy sources.

Given the nature of dispersed generation and the need for accurate fault detection, it appears that a combination of discrete and fuzzy logic algorithms on an integrated platform will provide reliable protection and control readily adaptable to Distribution Automation. This approach is expected to meet the complex requirements of the integrated renewable energy and utility power grid sectors in the years to come.

Chapter 7

Conclusion

7.1 Introduction

This chapter offers the main conclusions derived from the observed results. Further it points out the direction of future work.

7.2 Transient Stability

Simulation studies were carried out in Chapter 3 to find out the transient stability of the non-conventional energy sources under different operating conditions. A 5-second simulation was conducted using explicitly numerical integration (Euler method) and an integration time step of 0.002 second.

Transients are caused by faults on the feeders and switching actions of the generators. Figures 3.6-3.9 shows the absolute rotor angle plots for renewable energy source generator (G4). Absolute angle is measured relative to the synchronous rotating reference frame, and it is clear from plots that the remaining generating unit has less oscillation while the unit G4 has more oscillation as the perturbation increases. If G4 becomes unstable, the rest of the system becomes generation deficient, and hence the

absolute angles of all machines in the system drifts
slightly. In this regard, using relative angles rather than absolute angles is often a better choice since it permits one to easily observe the relative motion of rotors between machines. The fault results in the loss of one double circuit line, leaving the entire plant connected to the system through a significantly weaker (i.e., higher impedance) path. The plant is unable to transfer full output through this path, and the resulting accelerating power may lead to instability.

7.3 Voltage Stability

Simulation studies were carried out in Chapter 4 to find out the voltage stability of the non-conventional energy sources under different operating conditions. A 5-second simulation was conducted using explicitly numerical integration (Euler method) and an integration time step of 0.002 second.

Figure 4.6 (b)shows with load level 1.5, the voltage of bus 10 is restored to nearly its reference value in about 40 seconds as in the case of load level 1. However, the reactive power demand on the generators is now higher (as shown in Figure 4.8 (b) and the field current of generator G4 exceeds its limit. This in turn triggers the following chain of events:

- The terminal voltage of G3, which is no longer being controlled by the AVR, remains stable.
- Voltages at buses 4,5,6,7,8,9 drop.
- The demand for reactive power on the generators increases.
- Voltage at the transmission level (bus 8) drops and this causes further reduc-

tion of bus 9 voltage.

With load level 2.6, the demand for reactive power is higher. Consequently, the field current of G4 reaches its limit at about 50 seconds. With loss of voltage control by G4, the voltages at the transmission level and at bus 9 drops. The voltage of bus 9 settles at nearly 0.84 pu.

In another case the active power component of load at bus 8 is represented as an induction motor. Only load level 2 is considered. The motor stalls at about 65 seconds. This results in a decrease in active power absorbed by the motor. However, the reactive power drawn by the motor increases rapidly. This causes voltage drops as depicted in results (a,b,c) in chapter 4.

7.4 Ratings of Protective Devices

The results of the line flow and bus solution found in chapter 4 can be utilised in distribution system design to select, set and coordinate protective equipment such as circuit breakers, fuses, relay and instrument transformer. The results will also establise when cables, transformers and lines are overloaded.

It is usually necessary to calculate only symmetrical fault current at a system location, and then select a breaker with a symmetrical interrupting capability equal to or above the calculated current. The breaker has the additional capability to interrupt the asymmetrical (or total) fault current if the dc offset is not too large.

Power circuit breakers with a 2-cycle rated interruption time are designed for an asymmetrical interrupting capability up to 1.4 times their symmetrical interrupting capability, whereas slower circuit breakers have a lower asymmetrical interrupting capability.

For low-voltage applications, moulded case circuit breakers with dual trip capability are available. There is a magnetic instantaneous trip for large fault currents above a specified threshold, and a thermal trip with time delay for smaller fault currents.

LC circuit connected close to the customer, can act as an active filter mode as well as storage mode. This is perhaps the best strategy for harmonic mitigation is to eliminate the harmonics as close to the source as possible.

System data used for the above studies and their results are documented for analysis and implementation of most appropriate protection algorithm for the configuration.

7.5 Advantages

Most of the distribution companies have been concerned about the impact of non-conventional energy on the operation of their distribution systems. The following are some of the advantages of implementing this combined system in the distribution companies:

1. There will be a better demand forecasting, particularly at peak periods.

2. Planning for new substations, uncertain load growth will be possible.

3. The adequacy of the distribution alternatives can be tested for different operating conditions.

4. Distribution alternatives can be examined on the basis of the contingency analysis considering credible line outage conditions.

5. The system capacity can be tested for returning to synchronism after recovery from a major system fault.

6. The Utilisation of the available distribution corridors in an optimal manner.

7.5.1 Transmission Grid Benefits

When sufficient battery storage and non-conventional energy sources are installed to curtail daily peak periods they can

1. Eliminate the high demand periods when the grid is more vulnerable to disturbances.

2. Easier control of transmission grid.

3. Maintain steadier loadings on lines and transformers and avoid the abrupt variations of losses.

7.5.2 Generating Organisation Benefits

The generating bodies can also have following advantage:

1. Simplify generator scheduling,

2. Reduce the need for peaking generators,

3. Operate generators at steady, high and more efficient outputs,

4. Reduce maintenance of generators.

7.6 Utility Option

In spite of the many significant accomplishments in recent years in the application of the direct methods, modelling limitations and unreliability of computation techniques continue to be major impediments to their widespread practical use. The direct methods are vulnerable to numerical problems when one is solving stressed systems. The use of sophisticated and robust computer solution techniques usually imposes a heavy computational burden, making the method slower than the time-domain simulation.

The best course appears to be the use of a hybrid approach in which the transient energy calculation is incorporated into the conventional time-domain simulation. This enhances the capability of time-domain simulations by computing the stability margin and minimising the effort required in determining the stability limits.

It is clear from the proceeding analysis that much care should be taken based on the stability point of view while interconnecting the small renewable energy sources to the utility. The renewable energy sources should be interconnected at a point which provides a higher stability margin. The renewable energy sources is a viable option if it is connected to the distribution network with necessary methods of improving transient stability and voltage stability.

7.7 Future work:

Currently the trend is to use advanced power electronic controllers, such as solid state circuit breakers, Dynamic Voltage Regulators (DVR) and Static Condensers (STATCON) along the distribution line. Future work is to integrate these power electronic controllers with non-conventional energy sources which are connected through power electronic controllers to the distribution network [Figure 7.1]. Integrating such a system can provide electric utilities with a technology option that gives high quality, value added power supply suitable for customers' sensitive loads. Connecting dispersed sources of generation and storage battery through power electronic controllers combined with solid state circuit breakers, STATCON and DVR has several impacts on the operation and protection of the whole system.

The placement of a variety of controllers at the load centre will require significant coordination to insure proper operation under a variety of circumstances. Safety, protection of equipment, detection of faults, restoration of services, quality of services, and cost all need to be considered when connecting all these equipment with a distribution network.

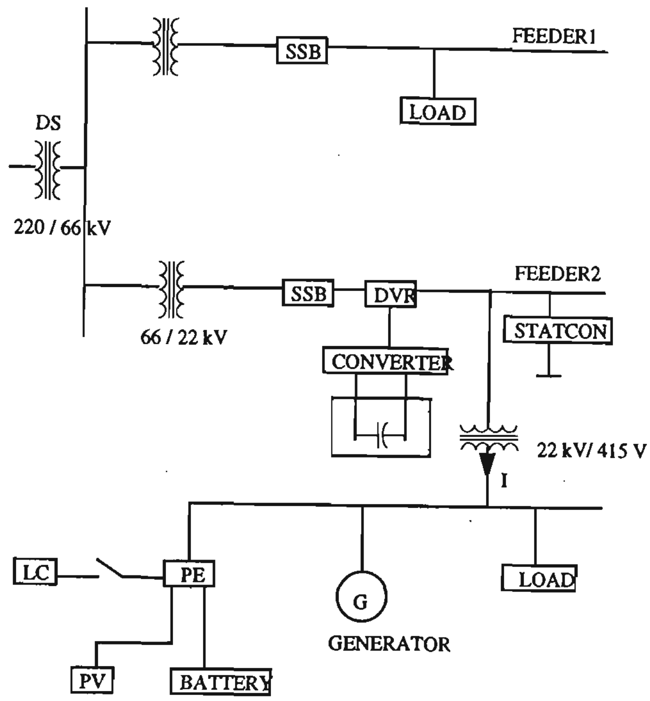


Figure. 7.1. A distribution network utilising variety of controllers

SSB	SOLID STATE CIRCUIT BREAKER
DVR	DYNAMIC VOLTAGE REGULATOR
STATCON	STATIC CONDENSOR
PE	POWER ELECTRONICS
PV	PHOTO VOLTAIC
LC	INDUCTOR AND CAPACITOR
DS	DISTRIBUTION SUBSTATION

In many parts of the distribution network, actual short circuit levels are close to the design maximum short circuit level and hence the rating of equipment, in particular switchgear. As the amount of generation and storage provided in this way increases, the need to control and monitor them in an integrated fashion will become increasingly evident.

The addition of any reasonable capacity generation in these areas can increase the short circuit level above equipment ratings unless special actions are taken. Other factors like the generator may be on a feeder that is also supplying other customers and the voltage level supplied to these customers must be kept within limits regardless of the real and reactive loading of the generator.

In order to fully exploit the capabilities of solid state circuit breakers the realities of the system characteristics must be considered Voltage sags can be caused by either insufficient VAR support or high short circuit currents due to a line-to-ground fault. The appropriate action would be dependent on the nature of the problem. It is clear that the VAR support can easily be provided from a STATCON. However, if the voltage sag is caused by a line-to-ground fault not only the location of the fault but all the sources feeding into the fault must be determined and then current limiting devices must operate to minimise the current feeding into the fault.

The STATCON device can also be used to operate in an active filter mode to cancel harmonics. Now depending upon the relative location of STATCON with regard to the source of harmonics it may or may not solve the problem faced by the customer's neighbouring the one that generates the harmonics. So, LC circuit connected close to the customer, can act as an active filter mode as well as storage mode. This is perhaps the best strategy for harmonic mitigation is to eliminate the harmonics as close to the source as possible.

Thus, in principle the LC circuit is a siting of the reactive-power generators. At this point of view (of generating reactive-power more or less independently of active power), it is usually found that an incidental benefit in most of our generation is operating at or near unity power factor (i.e., zero reactive-power output) and so it is available as a reactive-power reserved in case of need.

Moreover, to get the maximum transfer capability of the network, part of the reactive-power generation (or shunt compensation) must be controlled. The job of the system planner is then to optimise the different types of network and operation conditions, i.e., fixed capacitor (or inductors), switched capacitors and continuously controlled static or synchronous compensation, as well as the appropriate utilisation of reactive power reserved in the generators. Another common way of controlling load voltage is by transformer tap changer. Good control of down stream voltage requires a strong network upstream. So operation may be misguided and often should be suppressed when the overall network has been weakened by a disturbance.

The strategy of implementing this technology stays on the basic assumption that it provides the lowest cost solution. With this assumption as a starting point the application of a variety of controllers along with the DSGs and how they interact with each other to provide the needed response to attend to the various contingencies. Modelling of the distribution network with these components to find out the voltage drop, transients, fault level and optimisation along with planning and careful implementation of software control for protection are the strategies to bring about the smooth and effective operation of various controllers connected in the distribution network.

7.8 Conclusion

Implementation of "custom power" concept would directly result in a reduction in system losses. So, the customers who depend on sensitive microprocessor-based systems would prefer to purchase "custom power" from their local utilities rather than attempt to mitigate power quality problems on their own. This service will probably be offered to large commercial and industrial customers with direct distribution feeder connection. Smaller customers may be able to obtain this service in special industrial parks, where all the buildings would be provided with "custom power" from a central utility distribution feeder. By offering this new class of value-added power, utilities will help ensure that their customers can make the most of their investments in advanced microprocessor-based equipment.

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Appendix A

The purpose of the PST dynamic models is to provide models of machines and control systems for performing transient stability simulations of a power system, and for building state variable models in small signal analysis and damping controller design. These dynamic models are coded as functions. By following a set of rules, the user can assemble customized applications. The remainder of this section will discuss how these functions have been used to set up a simulation and to build system matrices.

Data Requirements

Before using the dynamic models, a user must first set up the bus and line data of a power system and obtain a solved load flow solution. For each dynamic model, the user must supply the model parameters. They are the machine data in the matrix mac_con, the excitation system data in exc_con, the power system stabilizer data in pss_con, the turbine-governor data in tg_con and the non-conforming load data in load_con. The format of these matrices are explained in the function documentation. These matrix names are declared as Matlab global variables in the function pst_var. The use of global variables eliminates the need to include them as input arguments to the dynamic model declared inside the function. The user must use these variable names; otherwise, the model functions would not know where to look up the data. The function documentation of pst_var lists the meaning of all the global variables.

The meaning of most of the variables are transparent to the user. For example, the variable mac_ang is a vector of δ, the machine angle, and dmac_ang is $\frac{d\delta}{dt}$.

Dynamic Model Functions

The models of PST include:

1. Machine models

(a) mac_tra -- model including transient effect

2. Excitation system models

(a) exc_dc12 -- IEEE type DC1 and DC2 models

3. Power system stabilizer model -- pss

4. Static VAR control system model -- svc

5. Simplified turbine-governor model -- tg

6. Non-conforming load model -- nc_load

7. Line flow function -- line_pq

The user can expand this repertoire of models by including additional models. To code a model as a function, start with a block diagram of the model and determine the number of state variables required. For example, to add a new exciter model, the user can examine the exciter variables that are already defined in pst_var, and add to it additional ones that are required. To add a completely new model, like a thyristor-controlled series compensation device, it would be necessary to add a complete set of variables for that class of device in pst_var.

Each model function consists of 3 parts -- the first part (flag=0) is the initialization of the state variables, the second part (flag=1) is the network interface computation, and the third part (flag=2) is the computation of the dynamics of the models. In general, there are 4 input variables to a function, namely, i (the device number), k (time step), bus and flag. In models containing anti-wind-up features, the integration step size is input as the fifth variable.

When identical machine and control system models are used for all the machines in a system, the computation can be accelerated by using vectorized computations. In most functions, if the device number i is set to 0, the functions will compute the same variables for all the devices in vector form. For example, this option can be used in the simulation of a system with electromechanical models.

In creating a function for a new model, it would be useful to simply edit an existing function of a similar model. All functions created for new models should include the option of vectorized computation.

Transient Stability Simulation Program

A power system simulation model consists of a set of differential equations determined by the dynamic models and a set of algebraic equations determined by the power network. The dynamic models provide the machine internal node voltages for the network. The network uses these voltages to compute the appropriate current injections. (This step is commonly called the network solution). The current injections then form the inputs to the dynamic models. A simulation involves repeated sequential solutions of the algebraic part and the differential part.

The steps required to set up a transient stability simulation program of a power system are listed as follows:

1. Input the bus and line data of the system, and obtain a solved load flow using the function loadflow.

2. Specify the integration step size and the switching times in which the network disturbances and discrete control actions occur. The switching time should be a multiple of the integration step size, unless a variable step size integration routine is used.

3. Specify the network disturbances and create reduced admittance matrices using the function red_ybus for each system network configuration. For example, for a short circuit fault on a particular bus, set the active power load on that bus to be a very large number, like 10^{10}. To remove a line, either eliminate the line

from the matrix line, or set the line reactance to a very large number and the other parameters to zero. Alternatively, a line with parameters that are negative of the removed line can be added to the end of the array line, which effectively cancels the removed line when the network admittance matrix is built. PST eliminates the buses with constant impedance loads to form a reduced admittance matrix Y_{red}. Buses with non-conforming loads listed in load_con will not be eliminated.

4. Initialize the state variables by setting flag=0 and set up the proper sequence of calls to the dynamic model functions. In general, the machine functions should be called first, as they provide the variables (such as field voltage and mechanical power) to initialize the other models. It is a good practice to let the simulation run for a short time without any disturbance. If the initialization is done properly, all the state variables should remain at their equilibrium values.

5. Perform the network interface computation by setting flag=1 and repeating the same sequence of calls of the dynamic functions. For the machines, this interface computes the projections of the machine internal voltages on the machine dq-axis to the system dq-axis.

6. The machine internal voltages (the variables psi_re and psi_im) are used to compute the current injections cur_re and cur_im using the reduced admittance matrix Y_red.

For networks with non-conforming loads, the function nc_load should be used to iteratively solved for the network solution.

7. Perform the dynamics computation by setting flag=2 and repeating the same sequence of calls of the dynamic functions. It is necessary to set some of the input variables such as pmech and exc_sig to appropriate values if they are not computed by the dynamic models. This step yields the derivatives on the state variables. The variable name of the derivative of a state variable starts with the prefix d followed by the variable name of the state variable.

8. Integrate the system dynamics using the derivatives. PST provides the function eulerint for the Euler method. However, the Euler method requires a small step size. It is usually desirable to use a first order technique such as the modified Euler method (a predictor-corrector method) to allow for a larger step size and better accuracy. Code for such integration techniques can be assembled quite readily.

Function:

nc_load

Purpose:

Solves the complex voltages at non-conforming load buses

Synopsis:

[V] = nc_load(bus,flag,Y22, Y21,psi,Vo,tol)

[V] = nc_load(bus,flag,Y22,Y21,psi,Vo,tol,k)

Description:

[V] = nc_load(bus,flag,Y22, Y21,psi,Vo,tol) uses the voltage source psi(ψ), the Y matrix Y22 of the non-conforming loads, and the mutual Y matrix Y21 of the source nodes to the non-conforming loads to compute the complex voltage V at the non-conforming load buses. The matrices Y21 and Y22 are output variables of the function red_ybus. Vo provides the initial guess of the bus voltage and tol is the tolerance for the convergence of the Newton solution.

The last input variable k denoting integer time is needed only if static VAR control systems and/or FACTS devices are present. For example, buses having svc's must be declared as non-conforming load buses in load_con, and the function svc is called to compute the susceptance at the svc buses. The output susceptance at time k is used to adjust the entries of the Y22 matrix before solving the network equation. This function is automatically performed in nc_load.

The m.file pst_var.m containing all the global variables required for nc_load should be loaded in the program calling nc_load. The non-conforming load data is contained in the i^{th} row of the matrix variable load_con.

Algorithm:

The constant impedance components are included in Y22 (which is computed in the function red_ybus). Sensitivities of these injections with respect to the voltage is used to formulate a Newton's algorithm to solve this nonlinear equation. The initial guess Vo is typically the bus solution at the previous time step.

This algorithm is implemented in the M-file nc_load in the POWER SYSTEM TOOLBOX.

Function:

pss

Purpose:

Models power system stabilizers

Synopsis:

f = pss(i,k,bus,flag)

Description:

pss(i,k,bus,flag) contains the equations of a power system stabilizer (pss) model in

Figure 1 for the initialization, machine interface and dynamics computation of the i^{th} excitation system. The input variable k is the integer time step of a simulation. The function is called after the i^{th} machine model function has been computed, but before the exciter model function is called. Note that this model does not include an equivalent model of torsional filters for subsynchronous oscillation mitigation. The filter equivalent model can be modelled as a simple transfer function.

Initialization is performed when flag=0 and k=1. For proper initialization, the machine variables must be initialized first. For flag=1, the output exc_sig of the pss as a function of the state variables is computed. For flag=2, the input variable, which can be either a machine speed or an electrical power, is used to compute the dynamics of the pss. The output f is a dummy variable.

The m.file pst_var.m containing all the global variables required for pss should be loaded in the program calling pss. The pss data is contained in the i^{th} row of the matrix variable pss_con.

A constraint on using pss is that $T \neq 0$ and $T_2 \neq 0$. The output of the power system stabilizer is limited by an upper and a lower limit. The lower limit is set to be the negative of the upper limit.

The function pss can also be used to generate state variable model matrices of the pss by freezing k.

Algorithm:

Based on the pss block diagram, all the state variables are initialized to zero. In the network interface computation, the pss output signals are made ready for use by the exciters. In the dynamics calculation, the input machine speed or electrical power is used to drive the pass dynamics.

This algorithm is implemented in the M-file pss in the POWER SYSTEM TOOLBOX.

Appendix B

```
% A 4-machine 10-bus system f

% data4m10b.m

% bus data format

% bus: number, voltage(pu), angle(degree), p_gen(pu), q_gen(pu),

%     p_load(pu), q_load(pu),G shunt,B shunt, bus_type

%     bus_type - 1, swing bus % bus_type - 2, generator bus (PV bus)

% bus_type - 3, load bus (PQ bus)

bus = [ 1 1.04   0.00   0.00   0.00  0.00  0.00  0.00  0.00 1;

2 0.02533 10.28   1.63   .952  0.00  0.00  0.00  0.00 2;

3 0.02536 5.67   .85   -.632  0.00  0.00  0.00  0.00 2;

4 0.02   -1.60   0.00   0.00  0.00  0.00  0.00  0.00 3;

5 0.991   -3.27   0.00   0.00  1.25   .50  0.00  0.00 3;

  6 1.00   -2.10   0.00   0.00  .90 .30  0.00  0.00 3;
```

```
  7 1.024   4.72  0.00   0.00  0.00  0.00  0.00  0.00 3;
8 1.014   1.83   0.00   0.00  1.00  0.35  0.00  0.00 3;
9 1.029   3.24  0.00   0.00  1.25  0.50  0.00  0.00 3;
10 0.99  -1.41   .20  -.165  .1   .05   0.0   0.0 2];
% line data format
% line: from bus, to bus, resistance(pu), reactance(pu),
%       line charging(pu), tap ratio
line = [1 4  0.00    0.0576  0.000    1. 0. ;
  4 5  0.010   0.0850  0.088   1. 0. ;
  4 6  0.017  0.0920   0.079   1. 0. ;
  5 7  0.032  0.0161   0.153   1. 0. ;
  6 9  0.039  0.1700   0.179   1. 0. ;
  2 7  0.000  0.0625  0.000   1. 0. ;
  7 8  0.009  0.0720  0.075  1. 0. ;
  8 9  0.012  0.1008  0.105  1. 0. ;
```

```
9 3  0.059  0.0586  0.0    1. 0.;

6 10 0.060  0.0596  0.0    1. 0.];

% Machine data format

% Machine data format

%      1. machine number,

%      2. bus number,

%      3. base mva,

%      4. leakage reactance x_l(pu),

%      5. resistance r_a(pu),

%      6. d-axis sychronous reactance x_d(pu),

%      7. d-axis transient reactance x'_d(pu),

%      8. d-axis subtransient reactance x"_d(pu),

%      9. d-axis open-circuit time constant T'_do(sec),

%      10. d-axis open-circuit subtransient time constant

%             T"_do(sec),

%      11. q-axis sychronous reactance x_q(pu),
```

```
%    12. q-axis transient reactance x'_q(pu),
%    13. q-axis subtransient reactance x"_q(pu),
%    14. q-axis open-circuit time constant T'_qo(sec),
%    15. q-axis open circuit subtransient time constant
%          T"_qo(sec),
%    16. inertia constant H(sec),
%    17. damping coefficient d_o(pu),
%    18. dampling coefficient d_1(pu),
%    19. bus number
mac_tra = [ ...
1 1 100 0.000  0.0014  0.995  0.1950  0 9.2  0 0 0 0 0 0  6.412  9.6 0  1 0 0;
2 2 100 0.000  0.002  1.651  0.323  0 5.9  0 1.59 0 0 .535 0 3.302   0 0  2 0 0;
3 3 100 0.000  0.004  1.22  0.174  0 8.97  0 1.16 0 0 .5 0  4.768  0 0  3 0 0;
4 10 100 0.00  0.0014  1.25  .232  0 4.75  0 1.22 0 0 1.5 0 5.016 0 0 10 0 0];
% Exciter data format
% exciter:  1. exciter type - 3 for ST3
```

% 2. machine number

% 3. input filter time constant T_R

% 4. voltage regulator gain K_A

% 5. voltage regulator time constant T_A

% 6. voltage regulator time constant T_B

% 7. voltage regulator time constant T_C

% 8. maximum voltage regulator output V_Rmax

% 9. minimum voltage regulator output V_Rmin

% 10. maximum internal signal V_Imax

% 11. minimum internal signal V_Imin

% 12. first stage regulator gain K_J

% 13. potential circuit gain coefficient K_p

% 14. potential circuit phase angle theta_p

% 15. current circuit gain coefficient K_I

% 16. potential source reactance X_L

% 17. rectifier loading factor K_C

```
%        18. maximum field voltage E_fdmax

%        19. inner loop feedback constant K_G

%        20. maximum inner loop voltage feedback V_Gmax

exc_con = [

3 1 0 7.04 0.4 6.67 1.0 7.57 0 0.2 -0.2 200 4.365 20 ...

4.83 0.091 1.096 146.53 1 6.53];


%exciter data dc12 model

%    1 - exciter type (1 for DC1, 2 for DC2)

%    2 - machine number

%    3 - input filter time constant T_R

%    4 - voltage regulator gain K_A

%    5 - voltage regulator time constant T_A

%    6 - voltage regulator time constant T_B

%    7 - voltage regulator time constant T_C
```

```
%    8 - maximum voltage regulator output V_Rmax

%    9 - minimum voltage regulator output V_Rmin

%   10 - exciter constant K_E

%   11 - exciter time constant T_E

%   12 - E_1

%   13 - saturation function S_E(E_1)

%   14 - E_2

%   15 - saturation function S_E(E_2)

%   16 - stabilizer gain K_F

%   17 - stabilizer time constant T_F

exc_con1 = [...

1 1 0 5.0 0.06 0 0 1.0  -1.0  -0.0485 0.25 3.5461 0.080 4.7281 0.260 0.040 1.0;

1 2 0 6.2 0.05 0 0 1.0  -1.0  -0.0633 .405 0.9183 0.660 1.2244 0.880 0.057 0.5;

1 3 0 5.0 0.06 0 0 1.0  -1.0  -.0198 0.50 2.3423 0.130 3.1230 0.340 0.080 1.0;

1 4 0 5.0 0.06 0 0 1.0  -1.0  -.0525 0.50 2.8681 0.080 3.8241 0.314 0.080 1.0;

1 5 0 40. 0.02 0 0 10.  -10.  1.0    .785 3.9267 0.070 5.2356 0.910 0.030 1.0;
```

```
1 6 0 5.0 0.02 0 0 1.0  -1.0  -.0419 .471 3.5868 0.064 4.7824 0.251 .0754 1.246;

1 7 0 40. 0.02 0 0 6.5  -6.5  1.0   .730 2.8017 0.530 3.7356 0.740 0.030 1.0;

1 8 0 5.0 0.02 0 0 1.0  -1.0  -0.047 .528 3.1915 0.072 4.2553 0.282 .0854 1.26;

1 9 0 40. 0.02 0 0 10.5 -10.5 1.0   1.40 4.2568 0.620 5.6757 0.850 0.030 1.0 ];

%st3 exciter model on all generators

exc_con = [...

3 1 0.01 7.04  1.0  6.67  1.0  10.0  -10.0 ...

0.2  -0.2  200.0 4.37  20  4.83  0.09  1.1   8.63 1.0 6.53;

3 1 0.01 7.04  1.0  6.67  1.0  10.0  -10.0 ...

0.2  -0.2  200.0 4.37  20  4.83  0.09  1.1   8.63 1.0 6.53;

3 1 0.01 7.04  1.0  6.67  1.0  10.0  -10.0 ...

0.2  -0.2  200.0 4.37  20  4.83  0.09  1.1   8.63 1.0 6.53;

3 1 0.01 7.04  1.0  6.67  1.0  10.0  -10.0 ...

0.2  -0.2  200.0 4.37  20  4.83  0.09  1.1   8.63 1.0 6.53];

% governor model on all generators

tg_con = [...
```

1 1 1 1.0 25.0 0.1 0.5 0.0 1.25 5.0;

1 2 1 1.0 25.0 0.1 0.5 0.0 1.25 5.0;

1 3 1 1.0 25.0 0.1 0.5 0.0 1.25 5.0;

1 4 1 1.0 25.0 0.1 0.5 0.0 1.25 5.0];