APPLICATION OF CONTINGENCY ANALYSIS METHODS FOR POWER SYSTEM SECURITY AND OPTIMIZATION

RAVINDER PAL SINGH SAWHNEY

Application of Contingency Analysis Methods for Power System Security and Optimization

By

Ravinder Pal Singh Sawhney, B.Eng

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Abstract

Static security assessment of a power system deals with analyzing the system steady state performance after disturbances. Security assessment is the process whereby any violation of operating limit is detected. Maintaining power system security is a great challenge as power systems are now operated closer to their security limits. In this thesis, contingencies based on active power flow violations using DC power flow based methods are detected and ranked using performance index. The contingencies causing voltage limit violations are determined using sensitivity analysis based approach. These results are then compared with full AC power flow solution. Network reduction technique is used to reduce a larger power system into a smaller system, so that that particular part of system could be analyzed with sufficient accuracy and less computational burden. Optimization methods are applied to enhance the overall security of the power system. Different case studies are presented throughout the thesis to illustrate the application of the studied methods.

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List of Abbreviations and Symbols

E : Voltage

F : Cost Function

GSF : Generation Shift Factor

LODF : Line Outage Distribution Factor

MW : Mega Watt

OPF : Optimal Power Flow

P : Active Power Flow

Q : Reactive Power Flow

SAM : Sensitivity Analysis Method

SCOPF : Security Constrained Optimal Power Flow

Y : Bus Admittance Matrix

θ : Impedance Angle

$/hr : Dollar per hour

Chapter 1

Introduction

1.1 Motivation

The electric power industry is undergoing changes like deregulation and privatization. The basic function of the industry to produce and to deliver power, safely and reliably has not changed, comparatively little attention has been directed towards the issue of power system security in this market environment. Regardless of the market model chosen, it is still essential to carefully balance the power requirements of the supply side and demand side in the presence of disturbances. It is well known that this balance is required to maintain system voltage, frequency and angle stability of the network. This involves techniques developed to keep the system working when devices fail. For example, when there is a generator outage, the system can make up if there is a sufficient spinning reserve. Key aspects of any security framework are methods to assess security and some type of market dispatch methods to implement security solutions.

Power system security is the ability to maintain the flow of power from the generating station to the customers, especially under disturbed conditions. Since disturbances can be small or large, localized or widespread, the planning and design of the power system must achieve a certain level of security. To secure the system against more severe disturbances obviously requires more expensive designs; hence, the design criteria are chosen to meet an appropriate level of security. In the more developed countries, the customer is often willing to pay more for minimizing the interruption of power, whereas in the less developed countries the scarcity of capital and other reasons keep the level of power system security lower [1]. The measures of power system security are magnitude, duration and frequency of customer outages. Such outages can thus be represented in probabilistic terms, e.g. X hour per year, or 99.9% reliable. Thus the terms reliability and security have been used interchangeably for power systems, although reliability is more often used to refer to the probabilistic measures while security refers to the ability of the system to withstand particular equipment outages without loss of service. One way to withstand equipment outages is to have redundant equipment. Providing redundancy in generators, especially when the economies of scale favored fewer and larger units is an expensive proposition.

Enough generation must be available at all times to meet the load demand. Thus, generator units must be managed in such a way that planned outages of units, as well as forced outages should not result in a shortage of generation. The installed generation capacity has to be greater than the maximum demand and it has to meet specific security criteria.

1.2 System Security

Power System security can be considered as having three major functions that are carried out in an operations control center:

- System monitoring
- Contingency analysis
- Security constrained Optimal power flow

1.2.1 System Monitoring

Monitoring power supply and power quality are critical to ensuring optimal performance of power system. Power providers and users alike are concerned about the reliable power, whether the focus is on interruption and disturbances or extended outages. One of the most critical elements in ensuring reliability is monitoring power system performance. Monitoring can provide information about power flow and demand and help understand the cause of power system disturbances. Effective monitoring programs are important for power reliability assurance for both utilities and customers.

With this in mind, it is clear that monitoring is essential for optimal power system performance and effective energy management, which includes reliable supply of power. Fig. 1.1 shows the basic components of modern power monitoring system [4].

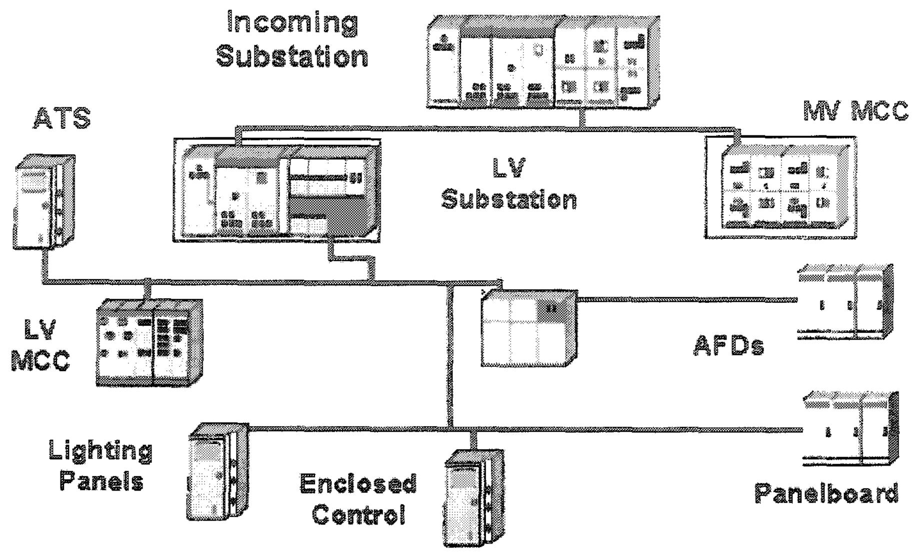

Fig 1.1 Basic components of a power monitoring system [4]

1.2.2 Contingency Analysis

In planning studies, the traditional approach for steady state contingency analysis is to test all contingencies sequentially to evaluate system performance and reliability [5]. Maintaining the security of the power system requires adequate planning and proper operational procedures. A power system can be operated under two security levels: (a) preventive and (b) corrective. A preventive operation requires that for every contingency postulated all system variables are within limits without making any action. A corrective requires that, if any of the contingencies postulated occurs, all variables can be brought within their limits taking appropriate actions. Therefore, a preventive operation is more restrictive than a corrective operation.

Technical constraints can be separated into two types: (1) active power constraints and (2) reactive power constraints. Active power constraints correspond to violations of the branch power flows. Reactive power constraints occur when the bus voltages are not within their admissible ranges. The static security assessment program is thus designed to alert the operator if a particular contingency would cause the system to violate operational limits. The operator, if so alerted must then decide whether to take preventive action right away so that this contingency does not pose a problem or to take no action at the present time but be ready to take corrective action if the contingency does occur. The main use however of the real time power flow solution is the automatic assessment of the static security of the system.

The security analysis program automatically studies hundreds of possible contingencies that could happen on the power system and determines how well the system can withstand them. This is equal to running hundreds of power flow solutions and then checking for line loading or voltage violations to alert the operator and it has to be done within a few minutes for the information to be useful. This is quite a computational burden in terms of both the number of power flow solutions and the data sifting needed for checking violations. Thus much of the development of static security assessment tools in the last two decades has concentrated on making this computation more efficient. Instead of finding full power flow solutions for all hundreds of contingencies, more approximate but fast solutions are obtained to determine which contingencies pose the biggest hazards. This calculation is known as contingency screening.

Most of the time for well-planned systems, single contingencies should not cause any limit violations and the main purpose of the contingency screening is to isolate the very few problem cases from the hundreds of non-threatening contingencies. In addition to running fast approximate solutions, the screening must evaluate these solutions by a severity index to determine which contingencies are the worst. These severity indices must reflect line overloads and voltage violations such that the contingencies can be ranked according to their severity. Once this is done, only the worst contingencies are further studied with accurate power flow solutions and the resulting overloads and under voltages are reported to the operator as alerting messages.

1.2.3 Security Constrained Optimal Power Flow

The security constrained optimal control flow of an electric power system generation- transmission network is an extremely difficulty task. This difficulty tends to increase with growth in size, interconnection and other operating problems. In this operation, a contingency analysis is run in parallel to optimal power flow, which makes changes to the optimal dispatch of generation, as well as other required adjustments, so that when a security analysis is run, no contingencies result in violations. We can divide the whole operation in to four operating states.

- Optimal Dispatch
- Post Contingency
- Secure Dispatch
- Secure post-contingency

Security- constrained scheduling is sometimes applied to the relevant controls throughout an entire interconnected power system. The above states can be explained with an example. It is assumed that the system is in economic dispatch consisting of two generators, a load, and a double circuit line, is to be operated with two generators supplying the load as shown below in fig 1.2 (ignoring losses) [1].

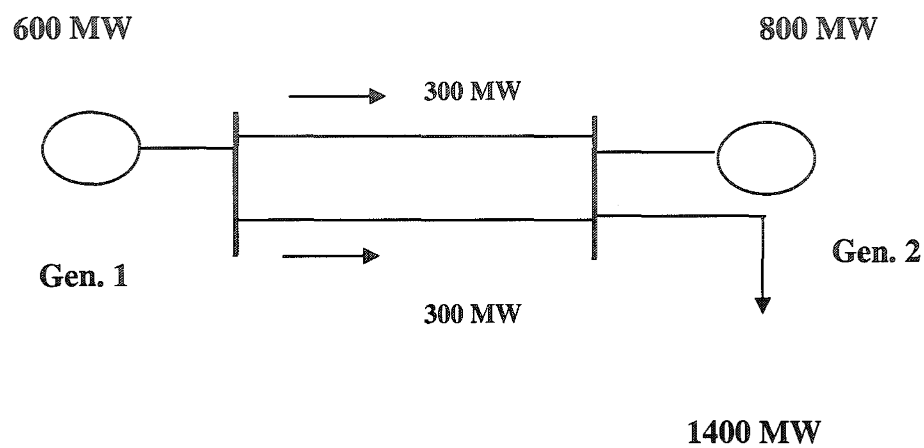

Fig. 1.2 Optimal Dispatch

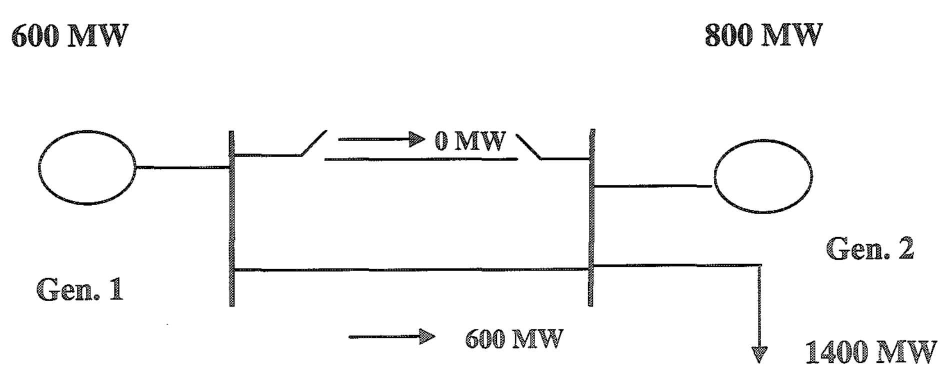

Fig 1.3 Post contingency state

The system shown in fig 1.2 is in economic dispatch, which means 600 MW from generator 1 and the 800 MW is the optimum dispatch. Each circuit can carry a maximum of 500 MW, so there is no loading problem in the base operating condition. If one of the circuits is opened considering a failure and rest of the circuit will be overloaded. This state is called Post Contingency state shown in fig. 1.3. Decreasing the generation on generator 1 and increasing generation on generator 2 can help avoiding this condition. Now, this state is called secure dispatch shown in fig 1.4.

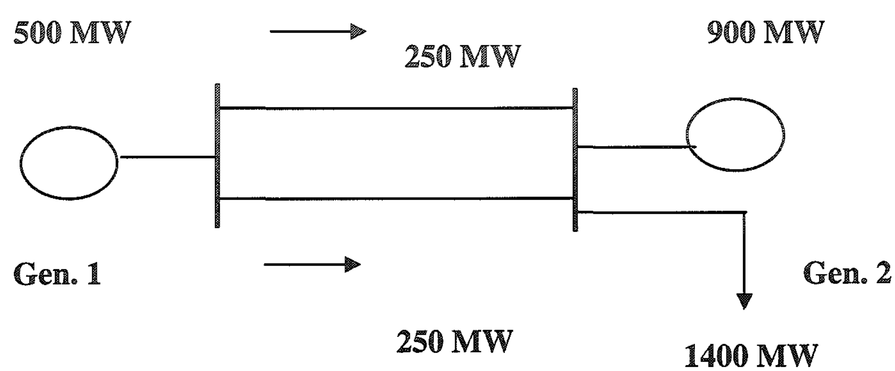

Fig 1.4 Secure Dispatch

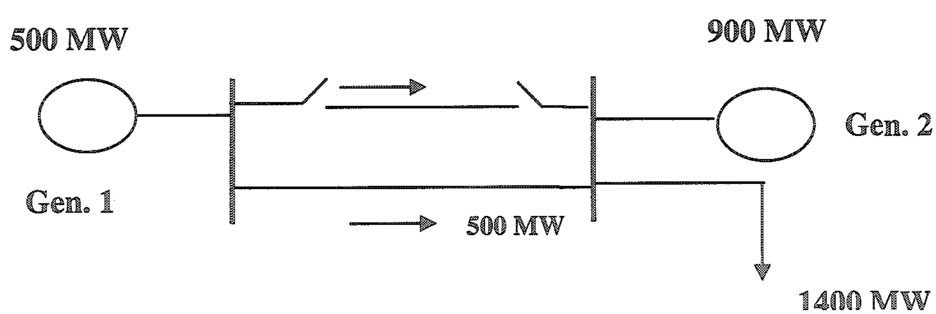

Fig 1.5 Secure post-contingency state

After this measure is taken and a line outage occurs there will be no overloading. This state of the system is called secure post contingency state shown in fig 1.5.

1.3 Methods of Contingency Analysis

The conventional approach followed for contingency analysis is that each contingency is simulated on the base-case model of the power system. Then, the calculated post contingency operating state is checked for operating state violations. In principle, the routine power flow should be run for each each contingency violation. The main motive behind the contingency analysis is to determine severity of the events like: (a) transmission/transformer outages and (b) generator outages. The general approach now adopted is to separate online analysis into three distinct stages: contingency definition, selection and evaluation.

1.3.1 Contingency Definition

This definition is a function that leads to basically selection of cases whose probability of occurrence is deemed sufficiently very high and is specified by the utility company at system level. This list is very large and is automatically translated in to electrical network topological changes: normally injection and or branch outages. Outages occur due to a variety of reasons. It could be due to switching operation or any other kind of over load that trips the circuit breaker. The outages may be of any type but the operators are supposed to know the power flows and voltage conditions in the system. This helps the operator to take preventive measure that he could take before the outage happens. The condition becomes worse in the forced outage case. These outages occur with very low probabilities that are time and weather dependent. Most of the times single -line outages are more probable than double or multiple outages.

1.3.2 Contingency Selection

This area has received the maximum attention. Its function is to select only those cases, which may cause severe violation. It uses an approximate power system model mostly linear with less computational burdened techniques, but limited accuracy results, the contingency cases are ranked in order of severity.

1.3.3 Contingency Evaluation

After the list of cases to be examined is decided, the contingency evaluation using ac power flow is then preferred on the successive individual cases up to the point where no post contingency violations are encountered, or until a maximum number of cases have been covered, or until a specified time has elapsed.

1.4 Organization of the thesis

A discussion of the DC power flow based linear contingency analysis methods is presented in chapter 2. DC load flow and linear sensitivity factors methods are applied to different case studies and the results are compared with full AC power flow solution. contingencies detected on basis of active power flow violations are ranked using performance index.

Chapter 3 focuses on sensitivity analysis based method for detecting voltage violations. The basic concept of sensitivity analysis is discussed and voltage distribution factors are derived. This method is applied to the 39-bus system and Newfoundland & Labrador Hydro system (Reduced equivalent).

Network reduction is introduced in chapter 4. The method of obtaining a reduced equivalent from a larger system is discussed and applied to 39-bus system. Linear contingency analysis method discussed in chapter 2 and 3 are applied to complete Newfoundland Hydro system.

Chapter 5 discusses the application and algorithm of optimal power flow (OPF) and security constrained optimal power flow (SCOPF). The minimum cost problem of OPF and SCOPF is considered as an example to discuss the application of the optimization techniques.

Chapter 6 gives the conclusion of the thesis, highlights the contribution of research and suggestions for future work are given

1.5 Conclusion

The requirement of the present power system security analysis is to look for a trade off between speed and accuracy. The main approach for both contingency selection and evaluation is still direct power flow solution. Major approximations aimed at enhancing computing speeds are still prevalent in the selection process. Unless, some completely different contingency analysis approach emerges, potential for major improvements in the existing analysis seems limited.

Chapter 2

DC Power Flow-Based Methods For Security Analysis

2.1 Introduction

Security monitoring is a fundamental aspect in the operation of the power system. It involves practices designed to maintain system operating when components fail [1]. It is now commonly accepted that for the security assessment of a power system, the most efficient and practical strategy is to deal with the problem in two stages: the first is contingency selection, in which those potentially critical cases are ranked by the severity of their impacts on the system; the second stage is contingency analysis, in which detailed AC power flows are applied only to the most dangerous cases appearing on the top of ranked list.

In the past decade, contingency selection has attracted many intensive studies from which efficient and reliable algorithms have been developed. The two main approaches to contingency selection are direct methods and indirect methods. The main platform on which direct methods are based is DC power flow. Indirect methods calculate a scalar performance index (PI) without calculating the post outage value of monitored quantities, which measures the system stress in terms of circuit overloads and voltage violations. The methods for calculating real power flows have been in use for a long and give fairly accurate results. However, in the field of voltage calculation, little success has been achieved. The methods for real power flow calculations are discussed in the following sections.

2.2 Model For Contingency Analysis

Accurate contingency analysis modeling is the same as in case of normal power flow, in that they both require the iterative solution of non linear equations [2]. In the case of contingency selection, approximations are made to achieve speed and computational efficiency. Among the limits of a power system, the one of concern in present discussions is real power flows.

These operating limits are soft and are neither precise nor to be rigidly enforced. This softness justifies the use of limited accuracy models and solutions. There is no way to quantify the tradeoff between speed and accuracy. The fundamental accurate power flow model is the familiar Newton-Raphson Jacobian matrix equation that represents the linearization of a given operating point [2]:

$$\begin{bmatrix} H & N \\ J & L \end{bmatrix} \begin{bmatrix} \Delta\theta \\ \Delta V \end{bmatrix} = - \begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} \tag{2.1}$$

H, N, J and L are the elements of the Jacobian that relate change in load angle and voltage in response to change in real and reactive power on the buses. More emphasis has been placed on real power flow than on bus voltages. This has given rise to the very extensive use of linearized active power models. One of the models normally considered is [2]

$$B'.\Delta\theta=\Delta P \tag{2.2}$$

Here, matrix B' is a symmetric approximation to the unsymmetrical submatrix H in equation (2.1). The use of an active power model makes the assumption that voltages and reactive flows change very little after a contingency, and that the latter are relatively small. This assumption is most valid for strong high voltage systems, where branch R/X ratios are small.

2.2.1 Methods of Contingency Selection

Direct methods calculate real power flow on an approximate basis. On the basis of approximate post-contingency quantities like real power flows and voltages, the severity of the case can be quantified and ranked [1]. With regard to the applications of these methods to a power system, two power system models are considered: The Newfoundland & Labrador Hydro equivalent system and a 39-bus system.

2.2.2 Newfoundland & Labrador Hydro Equivalent System

The single line diagram for the 9-bus Newfoundland & Labrador Hydro equivalent system is shown in fig 2.1. The single line diagram is a reduced equivalent of the hydro system and the part shown is east of Bay'Despoir.

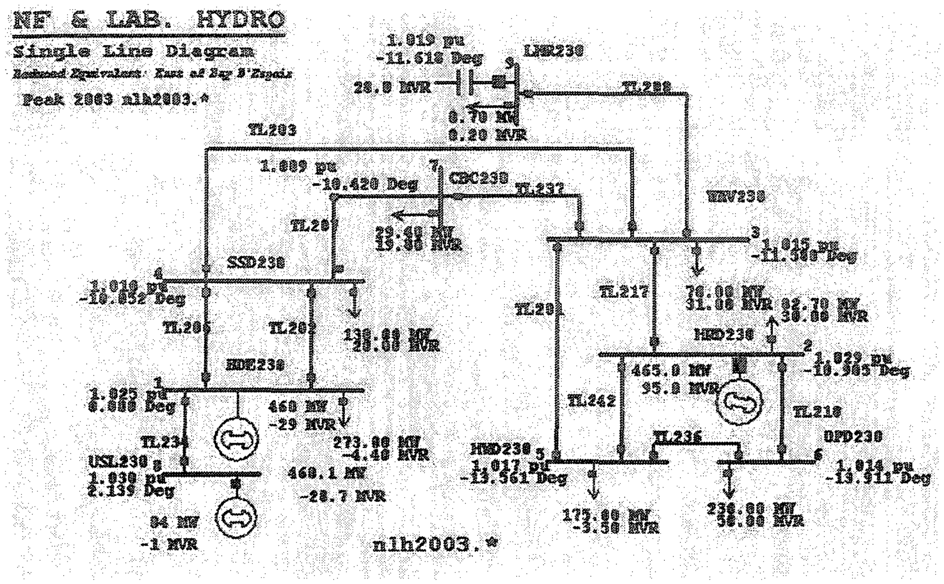

Fig. 2.1 Single line diagram of Newfoundland & Labrador Hydro equivalent system

There are three generating stations located at HolyRood, UpperSalmon and Bay d'Espoir connected to buses 1, 8 and 2 respectively. Table 2.1 gives the component data of the system. Table 2.2 gives the base case load flow summary of this system. In fig. 2.1, the buses have names along with numbers, which are used to show the location of the buses. Mainly the connections between different places are being studied, so, only the high voltage lines are shown in fig. 2.1.

Table 2.1 Newfoundland & Labrador Hydro equivalent system component data

Buses	9
Generators	3
Lines/Transformers	12

Table 2.2 Newfoundland & Labrador Hydro equivalent system base case load flow summary

	Real Power (MW)	Reactive Power (Mvar)
Total generation	1009.1	143.1
Total load	998.1	65.2
Losses	10.16	-49.86
Shunts	0.0	-28.0

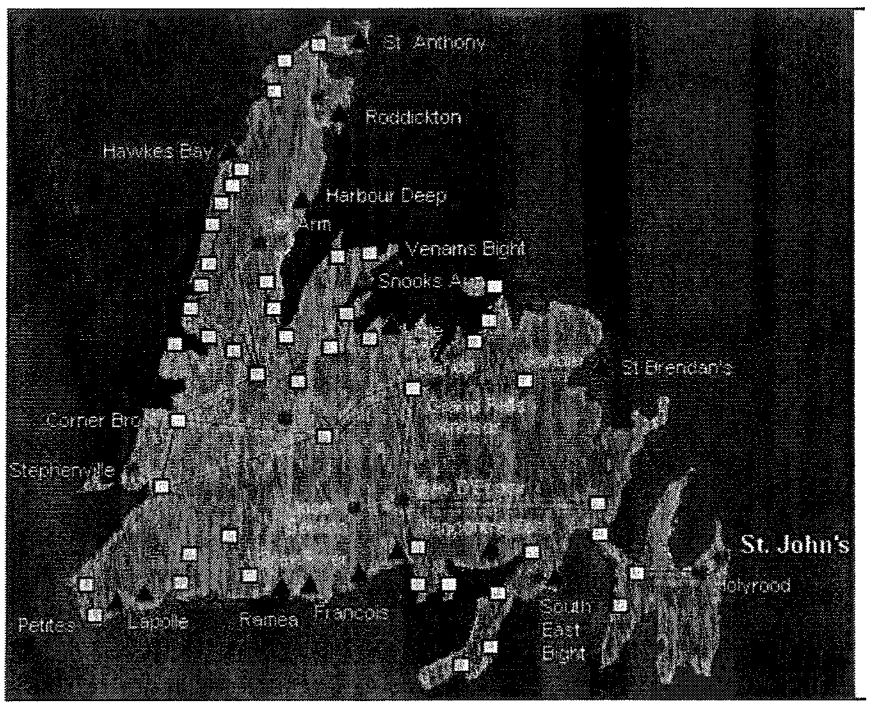

Fig 2.2 Geographic location of Newfoundland & Labrador Hydro transmission network [7]

The headwaters of the Bay d'Espoir begin at Victoria lake at an approximate elevation of 320 m. The seven generating stations at Bay d'Espoir produce an output of 604 MW. Through a man-made array of dams and canals, this water is directed to generating plants at Upper Salmon. The Upper Salmon development utilizes a portion of the residual head between MeelPaeg lake reservoir and Rond Pond within the watershed of the Bay d'Espoir hydro electrical development [7]. The system for study being considered is the eastern part of the island as all the buses shown lie east of Bay d'Espoir.

2.2.3 39 Bus Power System

Fig. 2.3 shows the single line diagram of 39-bus power system, which contains 35 transmission lines, 11 generators and 11 transformers. The system component data is given in Table 2.3. The system base case load flow summary is shown in Table 2.4.

Table 2.3 39 Bus power system component data

Buses	39
Generators	11
Lines/Transformers	46

Table 2.4 39 Bus power system base case load flow summary

	Real Power (MW)	Reactive Power (Mvar)
Total generation	6192.8	1256.3
Total load	6150.1	1408.9
Losses	42.74	-152.56

2.3 Direct Methods

Direct methods have been in use for many years and go under various names like Linear Sensitivity Factors method, DC power flow method etc. The approach works only when an approximate result of the effect of each outage on real power flow is desired. These methods do not take in to consideration any aspect of voltage participation in real power flows.

2.4 DC Power Flow

The Newton power flow is the most robust power flow algorithm used in practice. However, one drawback to its use is the fact that the terms in the Jacobian matrix must be recalculated after each iteration and then the entire set of equations must be resolved each time. Since thousands of power flows are often run for power flow studies, ways to speed up this process have been sought. DC power flow is a linearized version of the load flow problem based on the assumptions discussed ahead. All line conductances are negligible, i.e., $G_{ij} \approx 0$, where G_{ij} is the conductance and B_{ij} is the susceptance of the lines connecting buses i and j. All angular differences are small; within 30^0 range. This implies that $\sin\theta \approx \theta$ where θ is in radians [1]. All voltages remain constant at their nominal values, i.e., at 1 p.u [3]. The implication of these assumptions is that only real power equations are considered with no line losses. Given the above assumptions, the real power injection equation is expressed in equation (2.3) [3]

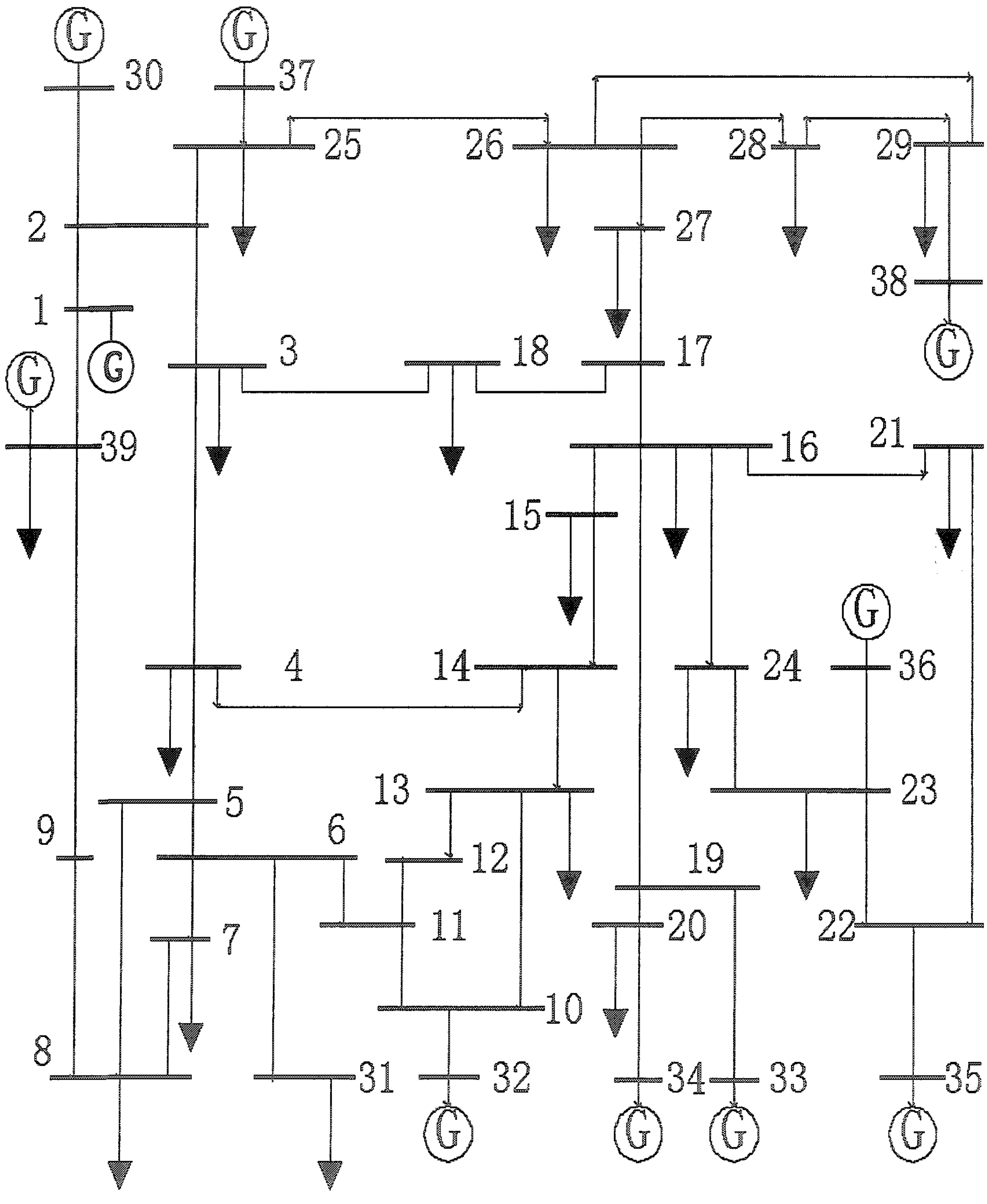

Fig 2.3 Single line diagram of the 39-bus power system

$$P_i=V_i^2G_{ii}-V_i\sum_{j\in k(i)}V_j\left(G_{ij}\cos\left(\theta_i-\theta_j\right)+B_{ij}\sin(\theta_i-\theta_j)\right) \tag{2.3}$$

P_i is the net real power injection. G_{ii} is assumed negligible as mentioned above. Angular differences are small, so $\sin\theta=\theta$.

$$P_i\approx -V_i\sum_{j\in k(i)}V_jB_{ij}(\theta_i-\theta_j) \tag{2.4}$$

These assumptions make P_i approximately equal to the expression on left hand side of equation (2.4).

$$P_i=\sum_{j\in k(i)}\left(-V_iV_jB_{ij}\right)(\theta_i-\theta_j) \tag{2.5}$$

As voltages have been assumed equal to 1 p.u., so this representation of P_i is equivalent to the left hand side expression in equation (2.6)

$$P_i\equiv\sum_{j\in k(i)}\left(-a_{ij}\right)(\theta_i-\theta_j) \tag{2.6}$$

where $a_{ij}=B_{ij}$ for all $i\neq j$. Denoting by a_{ii} the negative sum is given by equation (2.7)

$$a_{ii}=-\sum_{j\in k(i)}a_{ij} \tag{2.7}$$

and the expression is written as $P=A\theta$ (2.8)

Where

$$P=\begin{bmatrix}P_2\\ \vdots\\ P_n\end{bmatrix} \tag{2.9}$$

and $\theta = \begin{bmatrix} \theta_2 \\ : \\ \theta_n \end{bmatrix}$; $[A]_{ij} = a_{ij}$; $i,j \neq 1$. (2.10)

DC power flow is only useful for calculating real power flows on transmission lines. It gives no indication of what happens to voltage magnitudes or reactive power flows. The power flowing on each line using DC power flow is given by

$$P_{iK} = \frac{1}{x_{iK}}(\theta_i - \theta_K) \tag{2.11}$$

and

$$P_i = \sum_{\substack{K=\text{buses} \\ \text{connected} \\ \text{to } i}}^{N} P_K \tag{2.12}$$

As discussed earlier, the use of this method is for calculating real power flows during contingencies. The bar charts have been used for showing comparison between real power flows calculated by AC power flow and DC power flow. The results are shown considering a 39 bus system and the Newfoundland & Labrador Hydro equivalent system. The following are the abbreviations used for the methods:

1. DC : DC Power Flow
2. AC : Full AC Power Flow
3. MW: Mega Watt

These abbreviations are used with the figures to explain which methods are being compared.

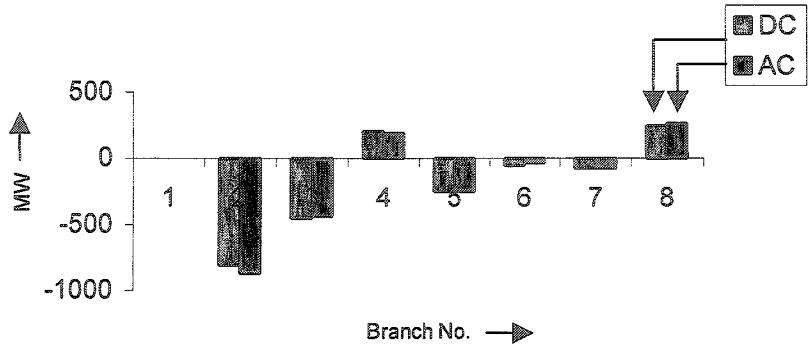

Fig. 2.4 Real power flow comparison with line 1 outaged using 39 bus system

Fig. 2.4 compares the real power flow on branches when line 1(2-1) goes out of service for the 39-bus power system. Real power flow on branch 1 is zero as this branch is out of service. On branch 6, connecting bus 4 and bus 3, the difference is more as compared to rest of the branches. The high difference in such low values of real power flow is not so significant, so the over all results are close to AC power flow. Fig 2.5 compares the real power flow on branches, when line 2(39-1) goes out of service. Real power flow on branch 2 is zero as this branch is out of service.

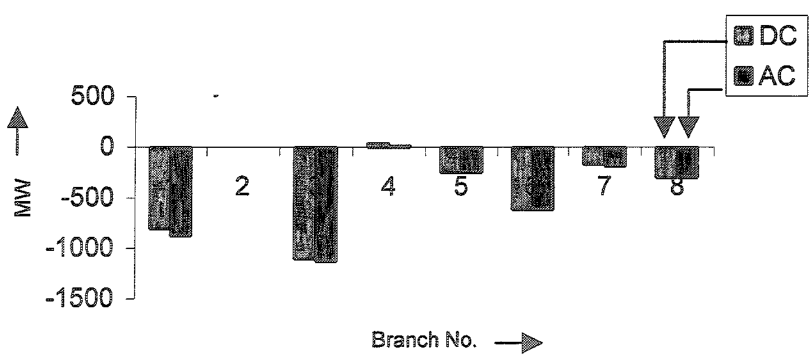

Fig. 2.5 Real power flow comparison with line 2 outaged using 39 bus system

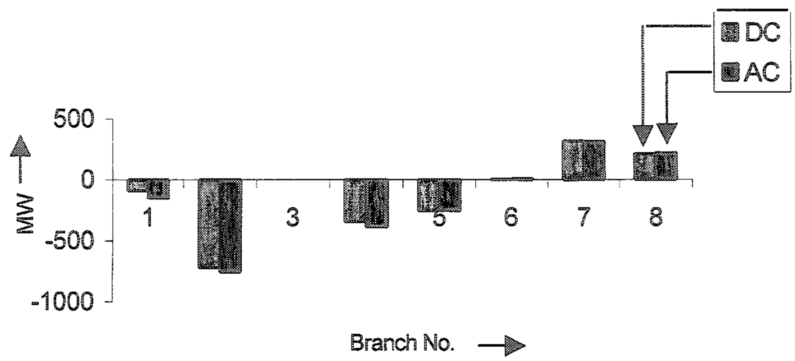

Fig. 2.6 Real power flow comparison with line 3 outaged using 39 bus system

Fig. 2.6 compares the real power flows on branches, when line 3(3-2) goes out of service. In this case, the flows on all the branches are near to the AC power flow. Real power flow on branch 3 is zero as this branch is out of service. Fig. 2.7 compares the real power flows on branches, when line 4(25-2) goes out.

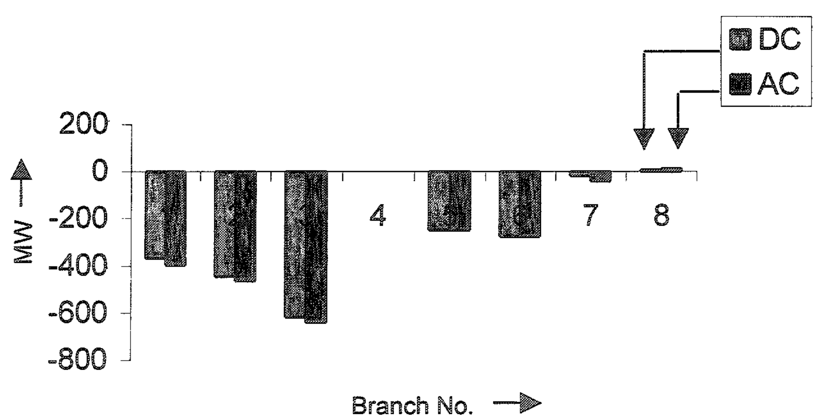

Fig. 2.7 Real power flow comparison with line 4 outaged using 39 bus system

In fig. 2.7, the difference between real power flow on branch 7 calculated by AC power flow and DC power flow is approximately fifty percent. Real power flow on branch 4 is zero as this branch is out of service.

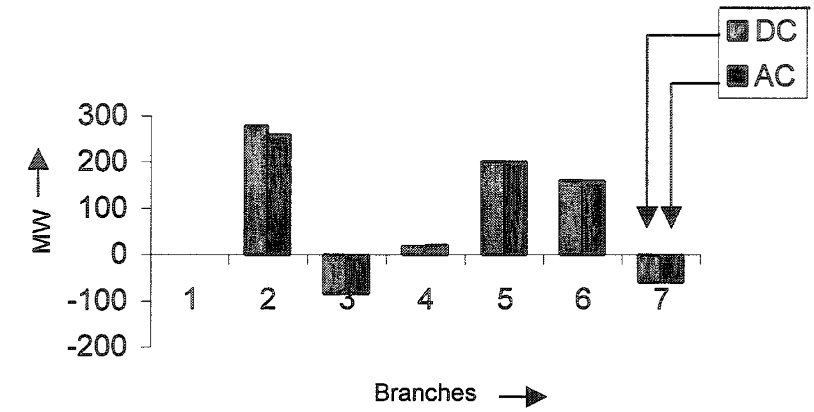

Fig. 2. 8 Real power flow comparison with line 1 outaged using Newfoundland & Labrador Hydro equivalent system

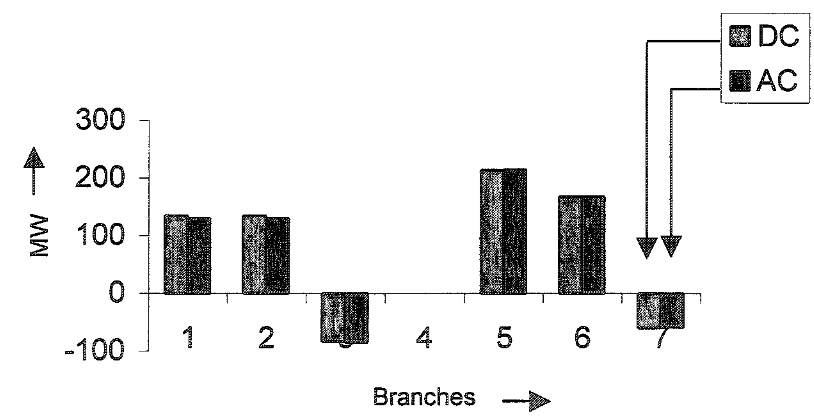

Fig. 2.9 Real power flow comparison with line 4 outaged using Newfoundland & Labrador Hydro equivalent system

Fig. 2.8 compares real power flow using the Newfoundland & Labrador Hydro equivalent system, when line 1 goes out of service connecting Bay d'Espoir and Sunny Side. Flows on all the lines are approximately same. If all the figures discussed above are analyzed carefully, it can be inferred that the results approximately match with AC power flow and can be relied upon. But in some cases the difference also becomes approximately fifty percent between real power flows calculated using AC and DC power flow. Hence, the tradeoff between speed and accuracy can be crucial also in terms of decisions being taken on basis of these calculations.

2.5 Linear Sensitivity Factors

One of the ways to provide a quick calculation of overloads is to use linear sensitivity factors. These factors show the approximate change in line flows for changes in generation during network reconfiguration [1].

These factors are of two types:

1. Generation shift factor
2. Line outage distribution factor

2.5.1 Generation Shift Factor

It is the ratio of change in real power flow on line l, when a change in generation dP_i occurs at bus i. The assumption behind the generation shift factor is when a 1 p.u. power increase is made at bus i, it is compensated by a 1 p.u. decrease in power at the reference bus. The changes in bus phase angles are equal to the derivative of the bus angles with respect to a change in power injection at bus i. The generation shift factor is given in equation (2.13)[2]

$$a_{li}=\frac{df_{li}}{dP_i}=\frac{d}{dP_i}\left[\frac{1}{x_l}\left(\theta_n-\theta_m\right)\right] \tag{2.13}$$

$$a_{li}=\frac{1}{x_l}\left(\frac{d\theta_n}{dP_i}-\frac{d\theta_m}{dP_i}\right)=\frac{1}{x_l}\left(X_{ni}-X_{mi}\right) \tag{2.14}$$

where

$X_{ni}=\dfrac{d\theta_n}{dP_i}=n^{th}$ element from the $\Delta\theta$ vector in equation (2.10)

$X_{mi}=\dfrac{d\theta_m}{dP_i}=m^{th}$ element from the $\Delta\theta$ vector

x_l = Line reactance for line l.

df_{li} = Change in MW flow on line l, when a change in generation occurs at bus i.

dP_i =Change in generation at bus i.

2.5.2 Line Outage Distribution Factor

Linear impact of an outage is determined by modeling the outage as a transfer between the terminals of the line. Thus, setting up a transfer of $\tilde{P}_{nm}$ from bus n to bus m is linearly equivalent to the outaging of the transmission line. This is shown in fig. 2.10

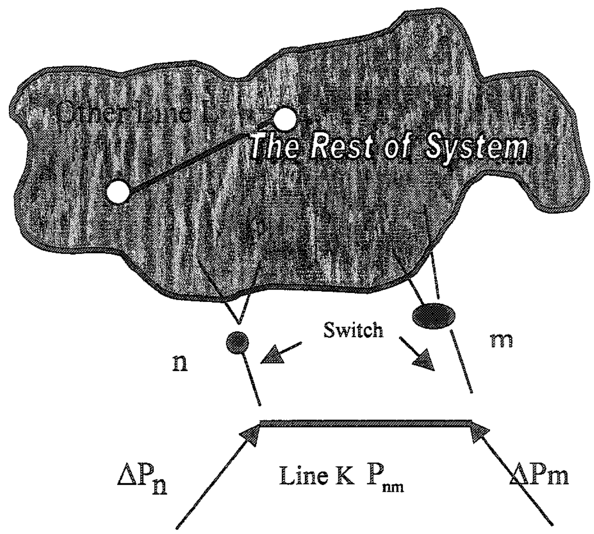

Fig. 2.10 Modeling line outage distribution factor as transfer of power [7]

The line outage model requires that the incremental injections ΔP_n and ΔP_m are equal to the power flowing over the outaged line after the injections are imposed. Let the line reactance be x_k, so $\tilde{P}_{nm} = \Delta P_n = -\Delta P_m$ is the power transfer [2].

where

$$\tilde{P}_{nm} = \frac{1}{x_K}(\tilde{\theta}_n - \tilde{\theta}_m) \tag{2.15}$$

A sensitivity factor δ is defined, which is the ratio of change in phase angle θ, anywhere in the system to the original power flowing over a line nm before it was outaged. That is,

$$\delta_{i,nm} = \frac{\Delta\theta_i}{P_{nm}} \tag{2.16}$$

If one of the outaged buses is reference bus, then injection is made at the other bus. Using the relation between ΔP_n and ΔP_m, the resulting δ factor is

$$\delta_{i,nm} = \frac{\left(X_{in} - X_{im}\right) x_k}{x_k - \left(X_{nn} - X_{mm} - 2X_{nm}\right)} \tag{2.17}$$

If bus i is a reference bus, then $\delta_{i,nm} = 0$ as the reference bus angle is constant.

By definition, the line outage distribution factor is defined as

$$d_{l,k} = \frac{\Delta f_l}{f_k^o} = \frac{\frac{1}{x_l}\left(\Delta\theta_i - \Delta\theta_j\right)}{f_k^o} = \frac{1}{x_l}\left(\frac{\Delta\theta_i}{\tilde{P}_{nm}} - \frac{\Delta\theta_j}{\tilde{P}_{nm}}\right) = \frac{1}{x_l}\left(\delta_{i,nm} - \delta_{j,nm}\right) \tag{2.18}$$

i and j are the buses connecting line k.

Δf_l = Change in MW flow on line l.

f_k^o = Original flow on line k before it was outaged. Substituting equation (2.19) in equation (2.16)

$$d_{l,k} = \frac{\frac{x_k}{x_l}\left(X_{in} - X_{jn} - X_{im} + X_{jm}\right)}{x_k - \left(X_{nn} + X_{mm} - 2X_{nm}\right)} \tag{2.19}$$

If the power on line l and line k is known, the flow on line l with line k out can be determined using "d" factors.

$$\hat{f}_l = f_l^0 + d_{l,K} f_K^0 \tag{2.20}$$

Where

f_l^0, f_K^0 = Pre Outage flows on lines l and k, respectively.

$\hat{f}_l$ = Flow on line l with line k out.

If the line outage distribution factors are precalculated, a very fast procedure can be set up to test all lines in the network for overloads during contingencies.

These factors have the same accuracy as the DC power flow but they are computationally efficient. Here, a comparison is presented using bar charts between the results of AC power flow and Line outage distribution factor method for line outages. The following are the abbreviations used for methods:

1. LODF: Line Outage Distribution Factor

2. GSF : Generation Shift Factor

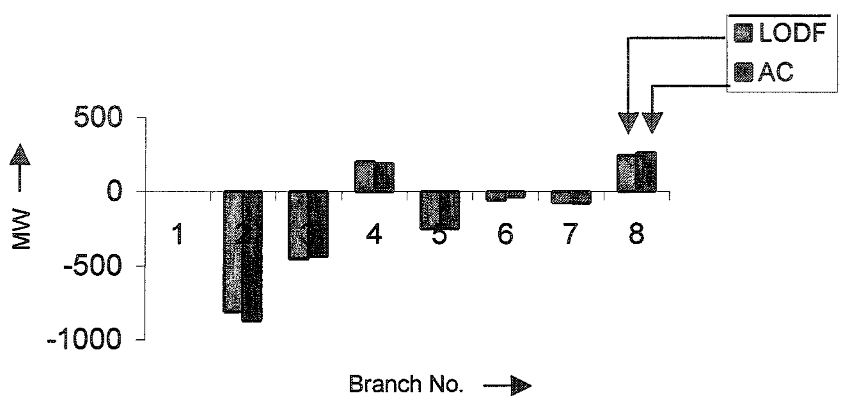

Fig. 2.11 Real power flow comparison during line 1 outaged using 39 bus System

Fig. 2.11 compares the real power flow on branches, when line 1(2-1) goes out of service. Flow on branch 1 is zero as this branch is out of service. The difference between real power flow calculated by AC power flow and DC power flow is more in branch 6 connecting nodes bus 4 and bus 3 than rest of the branches. Fig. 2.12 compares the real power flow on branches, when line 2(39-1) goes out of service.

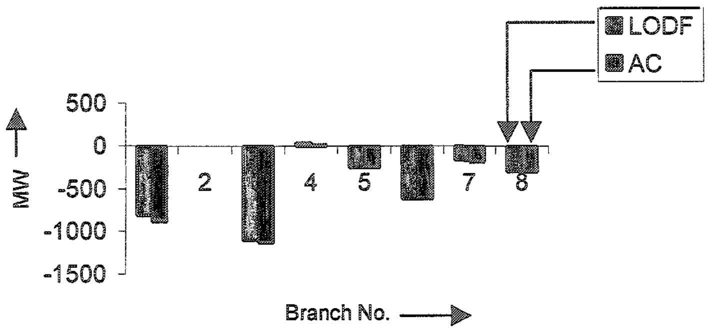

Fig. 2.12 Real power flow comparison during line 2 outaged using 39-bus system

Another application of Linear Sensitivity factors is computing real power flows during generator outages. Fig 2.13 shows real power flows on branches when generator on bus 30 goes out. The real power flow on branch 5 connecting nodes 2 and 30 becomes zero.

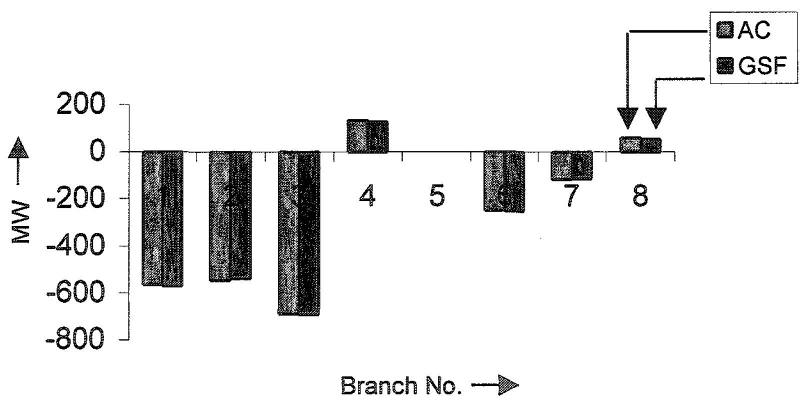

Fig. 2.13 Real power flow comparison during outage of generator on bus 30 using 39-bus system

Fig.2.14 compares real power flows, when generator on bus 32 goes out of service.

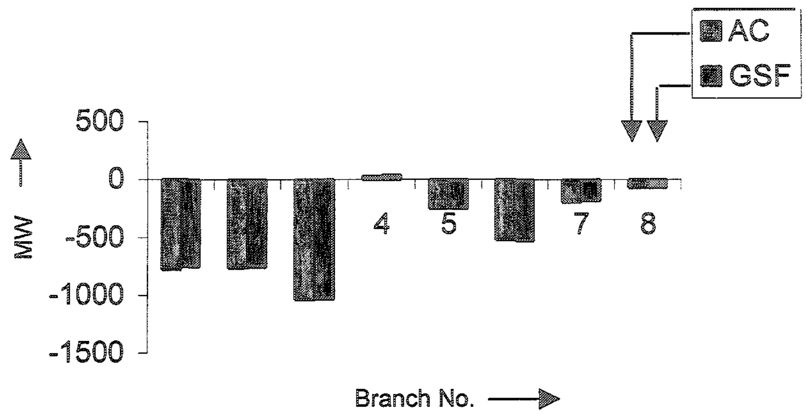

Fig. 2.14 Real power flow comparison during outage of generator on bus 32 using 39-bus system

The real power flows results calculated using Generation Shift Sensitivity factors shown in fig. 2.13 and fig. 2.14 are also close to the near to real power flow calculated using AC power flow.

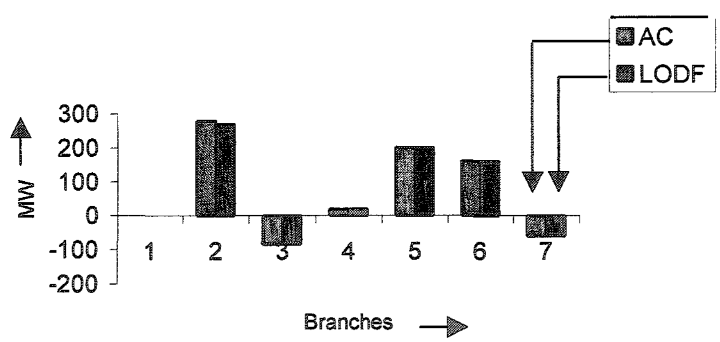

Fig. 2.15 Real power flow comparison during line 1 outaged using Newfoundland & Labrador Hydro equivalent system

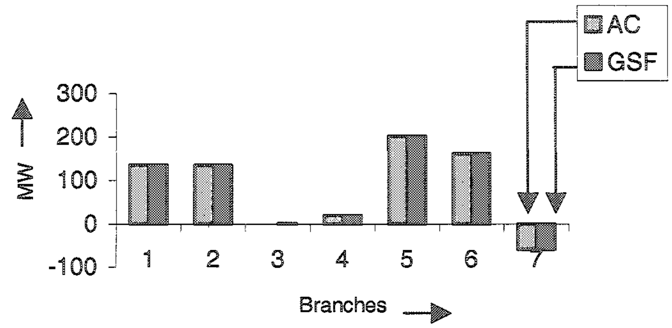

Fig. 2.16 Real Power Flow comparison during outage of generator on bus 8 using Newfoundland & Labrador Hydro equivalent system

Fig 2.15 compares real power flow on branches when line 1(1-4) goes out of service. Flow on line 1 is zero as it is out of service. On rest of the branches, the real power flows calculated by AC power flow and Generation shift factor are in close proximity to each other. Fig 2.16 compares real power flow for generator outage on bus 8 for Newfoundland & Labrador Hydro equivalent system.

2.6 Direct Severity Ranking

If the numerical measure of the flow on each line during contingencies is known, it can be ranked using a severity index. A commonly used definition for the performance index is given in equation (2.21), where L is the number of branches [1].

$$PI=\sum_{\substack{\text{all branches} \\ L}} \left(\frac{P_{flowL}}{P_L^{max}} \right)^{2n} \tag{2.21}$$

If n is a large number, the PI (performance index) will be a small number, if all flows are within limits, and it will be large or if one or more lines are overloaded. The problem then is how to use this performance index.

Many methods have been used to obtain the value of performance index when a branch is taken out. The calculations can be made and a table of performance index values, one for each line in the network, can be calculated quite quickly. The selection procedure then involves ordering the performance index table from largest value to least. The lines corresponding to the top of the list are now used for further analysis. However when n=1, the performance index does not increase in value suddenly, instead, it rises as a quadratic function. A line that is just below its limits contributes to performance index almost equal to one that is just below its limit. Hence, the performance index ability to detect or distinguish bad cases is limited when n=1. Ordering the performance index values when n=1 usually results in a list that is not at all representative of one with the truly bad cases at the top. Many efforts have been tried to develop an algorithm that can calculate quickly when n=2. Performance index is a scalar function of the network variables chosen as a measure of the operating stress of the system [6]. The analysis can be started by executing full AC power flows for the cases at the top of the list. The methods that have been discussed before are compared with AC power flow in terms of severity of performance index for first ten severe outages in table 2.5. The results shown in table 2.5 for DC power flow and Linear sensitivity factors are not same as AC power flow. Other methods are an alternative to AC power flow so accuracy is sacrificed but to a tolerable extent and speed is gained with sacrifice in accuracy.

Table 2.5 Ranking of Performance Index for 39-bus system

AC Load flow		**D.C Load Flow**		**Line Outage Distribution Factor**	
Line No.	P I	Line No.	PI	Line No.	PI
34	20.43	2	21.75	2	21.75
46	18.39	34	20.01	34	20.42
37	18.36	16	18.74	16	18.74
2	18.18	17	18.74	17	18.74
39	17.07	37	18.10	37	18.50
16	16.17	46	17.97	46	18.34
17	15.98	35	17.50	35	17.50
42	15.94	42	17.28	39	17.39
20	15.50	39	17.00	20	17.38
35	14.94	20	16.93	42	17.28

Fig. 2.17 compares performance index calculated using DC power flow and Line Outage Distribution Factor with AC power flow for single line outages.

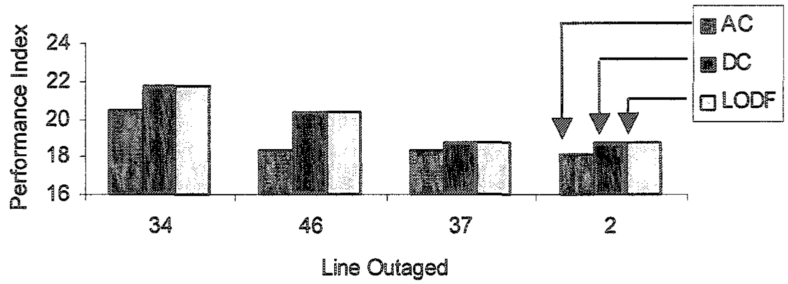

Fig. 2.17 Comparison of Performance Index for 39-bus system

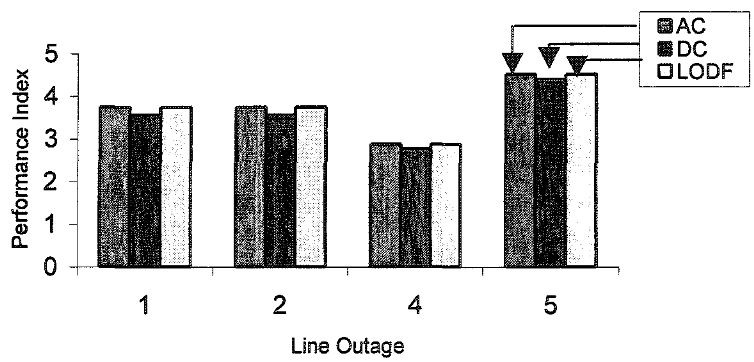

Fig. 2.18 Comparison of Performance Index for the Newfoundland & Labrador Hydro equivalent system

Fig. 2.18 compares the performance index using DC power flow and Line Outage Distribution factor with AC power flow for outage of line 1, 2, 4 and 5 for the Newfoundland & Labrador Hydro equivalent system. Table 2.6 shows the value of performance index calculated by AC power flow, DC power flow and Line Outage Distribution factor.

Table 2.6 Ranking of Performance Index for Newfoundland & Labrador Hydro Equivalent system

AC Load flow		**D.C Load Flow**		**Line Outage Distribution Factor**	
Line No.	P I	Line No.	PI	Line No.	PI
1(1-4)	4.21	1	3.58	1	3.74
2(1-4)	4.21	2	3.58	2	3.74
4(2-3)	3.00	4	2.77	4	2.86
5(2-5)	4.81	5	4.41	5	4.52

The data under the column heading "Line No." means line 1 connecting bus 1 and 4. In Table 2.6, when Performance index is arranged in descending order, the order of the severity of the outage is same as calculated using DC power flow based methods and AC power flow.

2.7 Conclusion

Devising algorithms that are computationally less severe and are approximate in terms of accuracy has always been main consideration in contingency selection. Contingency selection procedure eliminates running an exhaustive list of cases, it decreases the time spend in finding the worst cases. In this sense contingency selector can be thought of a contingency filter in which ranking from all the possible outages filters out specific outages. Finally, each such filtered and index case is then fully simulated with an AC power flow [7]. Results calculated AC power flow and DC power flow based methods are very close to each other. As noticed in some results, the difference in real power flows is higher between DC power flow based methods and AC power flow is higher, so some times the decision should not be made solely taken based on these results. In general it can be inferred that finding real power flow overloads, Linear Sensitivity Factor and DC power flow has proven to be a suitable option that gives us an approximate idea of the severity of outages. Overall the results are quite encouraging.

Chapter 3

Sensitivity Analysis Based-Method For Voltage Security Analysis

3.1 Introduction

One important concern related to voltage security is maintaining acceptable voltage levels. Voltage levels are satisfactory if their values lie within a certain range. Voltages at buses are typically regulated within 5% of nominal values in a transmission system. It is necessary to maintain voltage levels as system conditions change and these changes could be contingencies also. Attention on contingent voltage monitoring is now increasing considerably. Voltage security has assumed greater importance as part of the power system contingency analysis. In order to reduce computational burden, linear modeling is required that provides faster operation. But it is difficult to model the voltage and reactive power relationship as it is inherently a nonlinear phenomena and it is natural to use nonlinear methods. Even if the fast models are developed, they may not be as accurate as AC power flow. Linear methods have been suggested earlier for voltage security analysis, but they are not, in general very accurate [13, 14, 15]. In the following section, a set of distribution factors have been considered which can be used for direct computation of bus voltages following a line or generator outage. These factors are defined in terms of pre-outage real and reactive power flows in the lines and outputs of generators [16]. They are derived by exploiting the sensitivity property of Newton-Raphson Jacobian. Case studies using a 39-bus power system and the Newfoundland & Labrador Hydro equivalent system are presented in this chapter.

3.2 Model For Voltage Contingency Analysis

There is no linear relationship between voltage and reactive power for large disturbances. But, there exists a linear relationship for active power and load angle. The scope for fast approximate modeling in reactive power and voltage is much less than in the active power and load angle. The reactive power flow behavior is nonlinear and voltages are also strongly influenced by reactive power flows. Reactive power flow model analogy to active power flow model is

$$B^{''}.\Delta V = \frac{\Delta Q}{V} \tag{3.1}$$

Where $B^{''}$ is an approximation to the Jacobian sub matrix L [17-20] given in equation (3.2).

$$\begin{bmatrix} H & N \\ J & L \end{bmatrix} \begin{bmatrix} \Delta\theta \\ \Delta V \end{bmatrix} = - \begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} \tag{3.2}$$

It is necessary to calculate ΔQ and possibly B'' using the post-contingency voltage angles obtained from the active power model. The straight approach is to calculate the bus angular changes for the contingency case by an active power screening technique. The updated angles are then used in calculating the voltage normalized reactive mismatches $\frac{\Delta Q}{V}$ in equation (3.1). Equation (3.2) gives the change in voltage due to change in reactive and active power injection. If this expression is explained in terms of sensitiveness of voltage due to change in reactive and active power, then the sensitivity analysis can be used to find the change in voltage.

Sensitivity factors are well known indices in several utilities throughout the world to detect voltage problems and device corrective measures [21]. Sensitivity in this context is defined as a small change in voltage for a small change in active or reactive power injection over a linear operating point.

Sensitivity= $\frac{\partial V_i}{\partial P_i}$ or $\frac{\partial V_i}{\partial Q_i}$

The power flow problem solves the complex matrix equation

$$YV=I=S^*/V^* \tag{3.3}$$

Y is the network nodal admittance matrix, V is the unknown complex voltage vector, I is the nodal current injection, and S=P+jQ is the apparent power nodal injection vector representing specified load and generation at nodes. The most general and reliable algorithm to solve the power flow program is the Newton-Raphson method. It is a multivariable formulation of Newton's method used in calculus [22]. This method involves iteration based on successive linearization using the first terms of a Taylor expansion of the equation to be solved.

$$\overrightarrow{I_K} = \sum_{m=1}^{n} \overrightarrow{Y_{KM}}\,\overrightarrow{V_m} \tag{3.4}$$

$$P_K\text{-}jQ_K=\overrightarrow{V_K^*}\,\overrightarrow{I_K}=\overrightarrow{V_K^*}\sum_{m=1}^{n}\overrightarrow{Y_{KM}}\,\overrightarrow{V_M} \qquad (3.5)$$

The Newton-Raphson method solves the portioned matrix given in equation (3.6)

$$J\begin{bmatrix}\Delta\theta \\ \Delta V\end{bmatrix}=\begin{bmatrix}\Delta P \\ \Delta Q\end{bmatrix} \qquad (3.6)$$

Where ΔP and ΔQ are mismatch vector, ΔV is the unknown voltage magnitude correction vector, and $\Delta\theta$ is the unknown voltage angle correction vector is the Jacobian matrix of partial derivative terms calculated analytically from equation (3.6).

Sensitivity analysis can be used for the design of voltage control and reactive power compensation devices for voltage security. Sensitivity analysis must be used with great caution. The linearized model is only valid for small changes. An increase in loading may cause generator current limiting (PV bus changed to PQ bus) and drastic change in sensitivities.

3.3 Voltage Distribution Factors

These factors are derived using the sensitivity property of Newton-Raphson Jacobian following a line/transformer or generator outages. Voltage distribution factors have been termed as line outage voltage distribution factor for line outage. In case of a generator outage, they are termed as generator outage voltage distribution factor.

3.3.1 Line Outage Voltage Distribution Factor

Consider a line l carrying real power P_L and reactive power Q_L. Fig.3.1 shows line l to be outaged connected between two buses i and j. The transmission line can be represented by two fictious lines L1 and L2 in parallel. Line L1 carrying the real

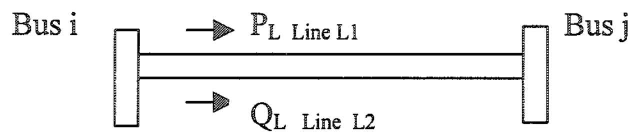

Fig. 3. 1 Schematic diagram of line l

power flow P_L and L2 carrying the reactive power Q_L. Average real power flow over the line is given by

$$P_L = \frac{1}{2}\left(P_{ij} - P_{ji}\right) \tag{3.7}$$

Average reactive power flow over the line is given by

$$Q_L = \frac{1}{2}\left(Q_{ij} - Q_{ji}\right) \tag{3.8}$$

Where P_{ij} is the real power flowing from bus i to bus j and P_{ji} is the real power flowing from bus j to bus i. Q_{ij} is the reactive power flowing from i to j and Q_{ji} is the real power flowing from j to i. During simulation of a line outage, as a line goes out of service, $[Y_{Bus}]$ changes. To include this change in $[Y_{Bus}]$ is a time consuming process which defeats the purpose of this method. The changes like line outages can be simulated by considering two ficticious generators at bus i and bus j and a ficticious line made of two parallel lines L1 and L2 representing the original line. By these assumptions, $[Y_{Bus}]$ does not require a change in values. Fig.3.2 shows the preoutage state of the power flow over the line to be outaged.

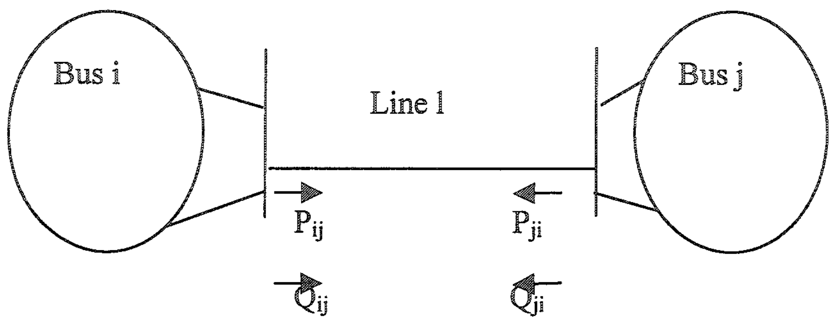

Fig.3.2 Preoutage state of the outaged line

$\overrightarrow{P_{ij}}$ and $\overrightarrow{Q_{ij}}$ are the real and reactive powers flowing from bus i to bus j respectively. $\overrightarrow{P_{ji}}$ and $\overrightarrow{Q_{ij}}$ is the real and reactive powers flowing from bus j to bus i respectively. Post outage conditions can be simulated as shown in fig 3.3.

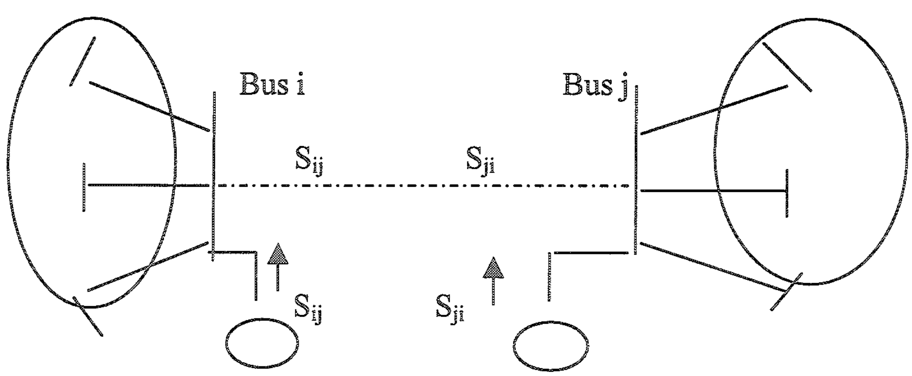

Fig. 3.3 Post outage state of the outaged line

The changes according to fig.3.3 from pre-outage state to post-outage are given in equations (3.9) and (3.10)

$$\Delta P_i = \vec{P}_{ij} \ \& \ \Delta P_j = \vec{P}_{ji} \tag{3.9}$$

$$\Delta Q_i = \vec{Q}_{ij} \& \ \Delta Q_j = \vec{Q}_{ji} \tag{3.10}$$

Suppose, the change in voltage at a bus i is ΔV_i^P due to outage of the line L1 carrying real power P_L and ΔV_i^Q is the change in voltage following the outage of line L2 carrying reactive power Q_L. The net change in voltage at bus i will be the sum of ΔV_i^P and ΔV_i^Q for the line outage. Here an approach utilizing the sensitivity property of Newton-Raphson Jacobian has been suggested to compute the post outage changes in bus voltage magnitudes.

The Newton-Raphson load flow equations are used for relating the power mismatch with change in voltage and angles given in equation (3.11)

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = [J] \begin{bmatrix} \Delta \delta \\ \dfrac{\Delta V}{V} \end{bmatrix} \tag{3.11}$$

If reactive power generation limits of the generators are considered then the size of Jacobian will be $(2N - N_q + m - 1)^* \ (2N - N_q + m - 1)$, where m is the number of PV buses converted to PQ type following violations of generator Q-limits. In this method, an extended Jacobian [J*] is considered at the end of base case load flow solution of size (2N-2) * (2N-2) in which all the voltage buses except slack bus are treated as PQ buses.

This can be done by adding $\left(\frac{\partial Q}{\partial \delta}\right)$ and $\left(\frac{\partial Q}{\partial V}\right)$ elements corresponding to all PV buses (except slack bus) in final Jacobian [J]. A sensitivity matrix [S] can be defined as $[S]=[J^*]^{-1}$. This matrix directly provides the sensitivity relationship between bus powers and voltages and can be used to compute changes in bus voltage angles and magnitudes. If the changes in bus power injections are known during line and generator outage, the change in voltage magnitude can be directly computed using equation (3.12).

$$\begin{bmatrix} \Delta\delta \\ \dfrac{\Delta V}{V} \end{bmatrix} = [S] \begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} \tag{3.12}$$

The sensitivity matrix S need not be recomputed utilizing new load flow Jacobian at the end of load flow solution as the Ybus of the system will not change.

The effect of real and reactive power injection can be calculated separately using equation (3.13)

$$\begin{bmatrix} \Delta\delta^P + \Delta\delta^Q \\ \dfrac{\Delta V^P}{V} + \dfrac{\Delta V^Q}{V} \end{bmatrix} = [S]\begin{bmatrix} \Delta P \\ 0 \end{bmatrix} + [S]\begin{bmatrix} 0 \\ \Delta Q \end{bmatrix} \tag{3.13}$$

Where ΔV^P denotes the change in voltage magnitude due to change in real power injection ΔP and ΔV^Q due to change in reactive power injection ΔQ. The equation (3.13) can be divided into two sets.

$$\begin{bmatrix} \Delta\delta^{P} \\ \dfrac{\Delta V^{P}}{V} \end{bmatrix} = [S]\begin{bmatrix} \Delta P \\ 0 \end{bmatrix} \tag{3.14}$$

$$\begin{bmatrix} \Delta\delta^{Q} \\ \dfrac{\Delta V^{Q}}{V} \end{bmatrix} = [S]\begin{bmatrix} 0 \\ \Delta Q \end{bmatrix} \tag{3.15}$$

The total change in bus voltage will be the addition of change in voltage due to active and reactive power. The net change in voltage after contingency will be $\Delta V = \Delta V^{P} + \Delta V^{Q}$. The advantage of this approach is that for each contingency, recalculation of sensitivity matrix is not required.

For outage of line l, all the elements of ΔP vector in equations (3.14) and ΔQ vector in equation (3.15) will be zero except for bus i and bus j. If one of the buses is a slack bus, the slack bus element will be considered zero. The solution of equation (3.14) & (3.15) will provide the change in bus voltage angles from preoutage to postoutage state. During any contingency the slack bus voltage is assumed constant at 1 p.u.

The line outage voltage distribution factor a_{li}^{P} and a_{li}^{Q} corresponding to the outage of ficticious lines L1 and L2 respectively can be defined as

$$a_{li}^{P} = \frac{\Delta V_i^{P}}{P_L} \tag{3.16}$$

$$a_{li}^{Q} = \frac{\Delta V_i^{Q}}{Q_L}\ ,\ i=1,\ldots\ldots, N\ \&\ l=1,\ldots\ldots\ldots, N_l \tag{3.17}$$

In equations (3.16) and (3.17), P_L and Q_L are known, ΔV_i^P and ΔV_i^Q are the changes in voltages on bus i during a line outage.

The set of line outage voltage distribution factors can be used to calculate post outage voltage using equation (3.18).

$$V_i^n = V_i^0 + a_{li}^P P_l + a_{li}^Q Q_l \tag{3.18}$$

V_i^n is the postoutage voltage at bus i after the contingency. Each line outage can be simulated using this algorithm and the post outage values of voltages can be determined. This algorithm can be explained in a step-by-step method given below.

Step 1: Calculate Ybus, $P_{ij}, P_{ji}, Q_{ij}, Q_{ji}$, P_L, Q_L, V_i.

2: Calculate Jacobian and form equation (3.12).

3: Consider a line to be outaged connected to bus i and bus j. Make all elements of ΔP & ΔQ vector in equation (3.13) equal to zero except the elements of the line to be outaged. If one of the buses of the outaged line is a slack bus, assign this element's value zero in ΔP and ΔQ vector.

4: Calculate ΔV^P and ΔV^Q using equation (3.14) & (3.15).

5: Use equation (3.16) & (3.17) to calculate line outage voltage distribution factors.

6: Use equation (3.18) to calculate post outage voltage during outage of line L connecting bus i and bus j.

3.3.2 Generator Outage Voltage Distribution Factor

Consider a generator g generating real power output P_{Gg} and reactive power Q_{Gg}. To simulate the generator outage, it is assumed that generator can be represented by two sources g1 and g2, where g1 is delivering real power with P_{Gg} and $g2$ is delivering reactive power Q_{Gg}. The combined effect of outage of these sources has been used to simulate outage of generator g. During the generator outage, the change in power mismatch from preoutage to post outage is given by equation (3.19) and (3.20)

$$\Delta P_i = -P_{Gg} \tag{3.19}$$

$$\Delta Q_i = -Q_{Gg} \tag{3.20}$$

With these values equated in equations (3.14) and (3.15), the change in ΔV^P and ΔV^Q can be calculated. The generator outage voltage distribution factors can be defined as

$$b_{gi}^P = \frac{\Delta V_i^P}{P_{Gg}} \tag{3.21}$$

$$b_{gi}^Q = \frac{\Delta V_i^Q}{Q_{Gg}} \quad i=1\ldots\ldots,N \quad \& \; g=1,\ldots\ldots\ldots\ldots N_q \tag{3.22}$$

Where N and N_q are the total number of buses and reactive power sources in the system respectively. While simulating a generator outage, it has been assumed that the slack bus generator will meet the real power demand during outage. For a generator outage, the voltage at bus i can be computed as

$$V_i^n = V_i^0 + b_{gi}^P P_{Gg} + b_{ii}^Q Q_{Gg} \qquad i=1,\ldots\ldots\ldots\ldots N \tag{3.23}$$

V_i^n is the post outage voltage at bus i after the contingency. Each generator outage can be simulated using this algorithm and the post outage values of voltages can be determined. This algorithm can be explained in a step-by-step method given below.

Step 1: Calculate Ybus, P_{Gg}, Q_{Gg}, V_i.

2: Calculate Jacobian and form equation (3.12).

3: Consider a generator to be outaged connected to bus i. Make all elements of ΔP & ΔQ vectors in equation (3.13) equal to zero except the element of the bus to which generator is connected

4: Calculate ΔV^P and ΔV^Q using equation (3.14) & (3.15).

5: Use equation (3.21) & (3.22) to calculate line outage voltage distribution factors.

6: Use equation (3.18) to calculate post outage voltage during outage of generator g connected to bus i.

3.4 Application of Distribution Factors To Sample Power Systems

A 39 bus system and the Newfoundland & Labrador Hydro equivalent system is considered in this section. Details of these systems have been discussed in chapter 2.

3.4.1 39 Bus System

Line outage voltage distribution factors and Generator outage voltage distribution factors have been used for calculating the voltages on buses during contingencies like line outages and generator outages. The abbreviations used in the figures for comparison of methods are:

1. AC : AC Power Flow

2 SAM : Sensitivity Analysis Based Method

Fig.3.4 compares the voltages on buses, when line 1 connecting bus 2 and 1 goes out of service. On bus 1, the voltage calculated using AC power flow and the Sensitivity analysis based method would always remain the same, as this is a slack bus. The maximum difference in values of voltages shown in fig.3.4 is on bus 3. On the rest of the buses, the error is not more than 4 percent. Table 3.1 gives the value of percentage error, where percentage error is defined as in equation (3.24), where V_{AC} is the voltage calculated by full AC power flow and V_{SAM} by Sensitivity analysis method.

$$\%Error = \frac{V_{AC} - V_{SAM}}{V_{AC}} * 100 \tag{3.24}$$

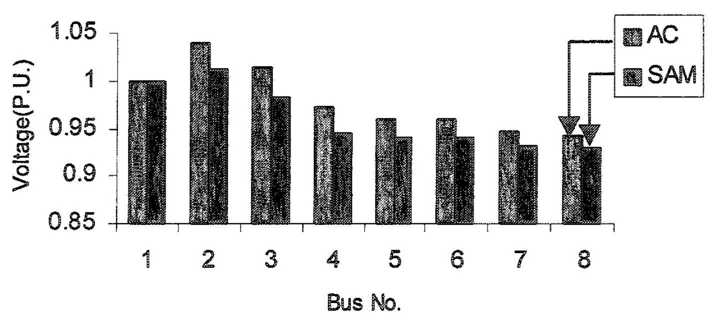

Fig. 3.4 Comparison of voltages on buses during outage of line 1(2-1) of 39-bus system

Table 3.1 Percentage error in voltage for outage of line 1(2-1) of 39-bus system

Bus No.	Voltage		Percentage Error
	V_{AC}	V_{SAM}	
1	1	1	0
2	1.03	1.01	2.67
3	1.01	0.98	3.14
4	0.97	0.94	2.65
5	0.95	0.94	1.99
6	0.96	0.94	2.03
7	0.94	0.93	1.55
8	0.94	0.93	1.30

Fig.3.5 compares the voltages on buses, when line 10 connecting bus 6 and bus 5 goes out of service. The voltage on bus 1 is constant being a slack bus. The values of voltages calculated by the Sensitivity analysis based method are higher than AC power flow method, but the difference between the values calculated by the AC power flow and the Sensitivity analysis method is approximately same as during outage of line 2.

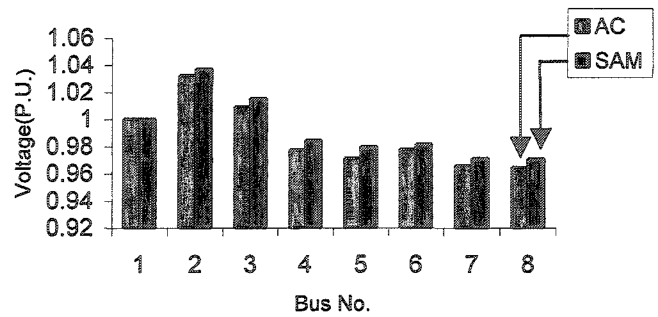

Fig. 3.5 Comparison of voltages at buses during outage of line 10(6-5) of 39-bus system

Table 3.2 Percentage error in voltage for outage of line 10(6-5) of 39-bus system

Bus No.	Voltage		Percentage Error
	V_{AC}	V_{SAM}	
1	1	1	0
2	1.03	1.03	-0.45
3	1.00	1.01	-0.61
4	0.97	0.98	-0.74
5	0.97	0.97	-0.85
6	0.97	0.98	-0.35
7	0.96	0.97	-0.52
8	0.96	0.97	-0.61

Line 10 is carrying fewer loads as compared to line 1 and 2. The values of voltages calculated using AC power flow and the Sensitivity analysis based method in fig. 3.5 are approximately same. Fig. 3.6 compares the voltages on buses when line 20 connecting bus 10 and bus 32 goes out of service.

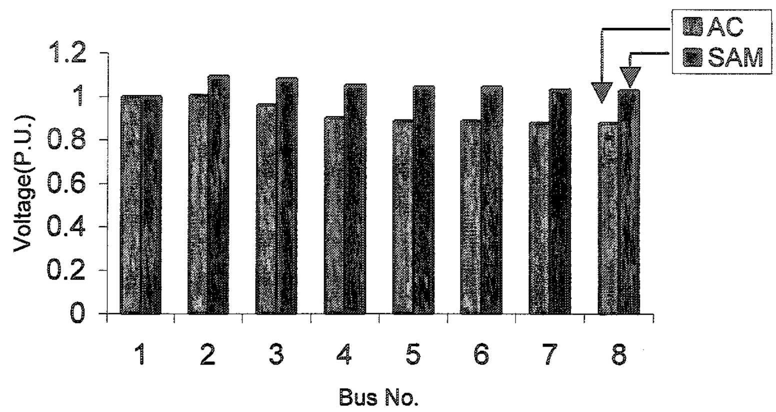

Fig. 3.6 Comparison of voltages on buses during outage of line 20(10-32) of 39-bus system

Table 3.3 Percentage error in voltage for outage of line 20(10-32) of 39-bus system

Bus No.	Voltage		Percentage Error
	V_{AC}	V_{SAM}	
1	1	1	0
2	1.00	1.09	-8.83
3	0.96	1.08	-12.74
4	0.90	1.05	-16.46
5	0.88	1.04	-17.33
6	0.88	1.04	-17.52
7	0.87	1.03	-17.54
8	0.87	1.02	-17.33

The bus 1 being a slack bus, the voltage is constant at 1 p.u. A generator connected to bus 32 also gets disconnected, when line 10 goes out of service. If the difference between the values of voltages calculated by AC power flow and the Sensitivity analysis based method in fig. 3.4 & 3.5 is observed, the difference is maximum in fig. 3.6. The reason that can be attributed to this is that in outage cases discussed earlier, the logic involved was only for line outages, but in this case the line being radial and a generator connected to it makes it completely different from a single line outage case. So this method will not give accurate results in such cases where these kinds of situations arise. The difference in this case between the values is 15 percent, which cannot be considered tolerable.

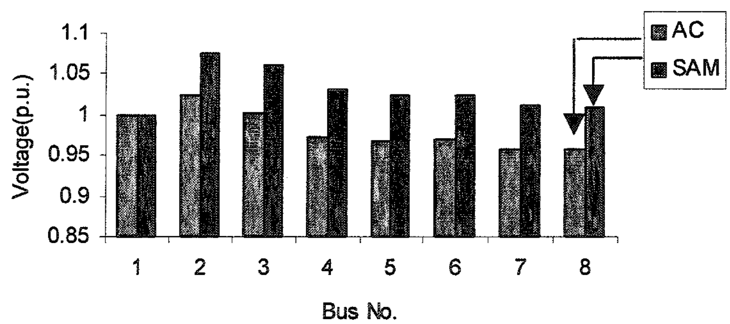

Fig. 3.7 Comparison of voltages on buses during outage of generator on bus 37 for 39-bus system

Fig. 3.7 compares voltages calculated by AC power flow and Sensitivity Analysis based method, when the generator on bus 37 goes out of service. The maximum difference in the values is approximately 6 percent. This small value of difference can be accommodated.

Table 3.4 Percentage error in voltage for outage of generator on bus 37 of 39-bus system

Bus No.	Voltage		Percentage Error
	V_{AC}	V_{SAM}	
1	1	1	0
2	1.00	1.09	-8.83
3	0.96	1.08	-12.74
4	0.90	1.05	-16.46
5	0.88	1.04	-17.33
6	0.88	1.04	-17.52
7	0.87	1.03	-17.54
8	0.87	1.02	-17.33

Fig. 3.8 compares the values of voltages on buses calculated by AC power flow and Sensitivity analysis based method, when the generator on bus 34 goes out of service. The difference in values of voltages in this case is approximately 30 percent. This high difference can be attributed to the high percentage of power delivered by the generator in comparison to the total generation of the system.

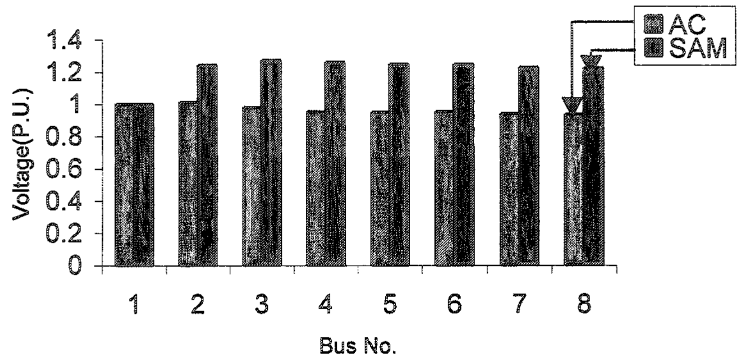

Fig. 3.8 Comparison of voltages on buses during outage of generator on bus 34 of 39-bus system

Table 3.5 Percentage error in voltage for outage of generator on bus 34 of 39-bus system

Bus No.	Voltage		Percentage Error
	V_{AC}	V_{SAM}	
1	1	1	0
2	1.01	1.24	-22.87
3	0.98	1.27	-29.56
4	0.95	1.26	-32.17
5	0.95	1.24	-31.14
6	0.95	1.24	-31.12
7	0.94	1.22	-30.77
8	0.93	1.22	-30.27

3.4.2 Newfoundland & Labrador Hydro Equivalent System

The details of Newfoundland & Labrador Hydro equivalent (NLH) system have been discussed in chapter 2. In this section, voltage distribution factors are applied for calculating voltages during line and generator outages. Fig. 3.9 shows the comparison of voltage on buses calculated by AC power flow and the Sensitivity analysis based method, when line 1 connecting Bay'Despoir and Sunny Side goes out of service. These buses are located on the eastern part of the province.

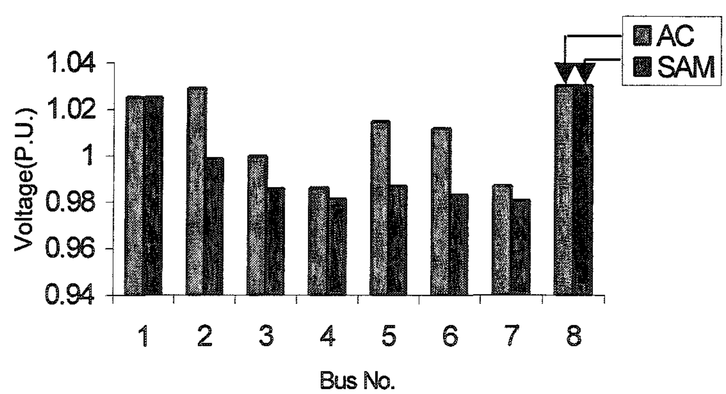

Fig.3.9 Comparison of voltages on buses during outage of line connecting Bay'Despoir and Sunny Side for NLH System.

Table 3.6 Percentage error in voltage during outage of line connecting Bay'Despoir and Sunny Side for NLH System

Bus No.	Voltage		Percentage Error
	V_{AC}	V_{SAM}	
1	1.02	1.02	0
2	1.02	0.99	2.94
3	0.99	0.98	1.39
4	0.98	0.98	0.46
5	1.01	0.98	2.74
6	1.01	0.98	2.83
7	0.98	0.98	0.64
8	1.03	1.03	0

The maximum difference in values shown in fig.3.9 is 2 percent. Fig.3.14 shows the comparison of voltages on buses calculated by AC power flow and the Sensitivity analysis based method.

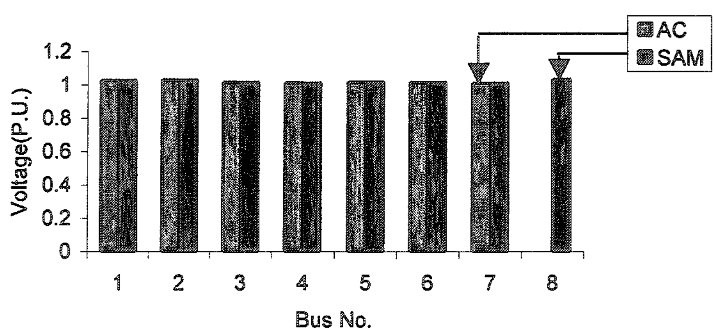

Fig. 3.10 Comparison of voltages on buses during outage of line connecting Bay'Despoir and Upper Salmon for NLH System

Table 3.7 Percentage error in voltage during outage of line connecting Bay'Despoir and Upper Salmon for NLH System

Bus No.	Voltage		Percentage Error
	V_{AC}	V_{SAM}	
1	1.02	1.02	0
2	1.02	1.02	0
3	1.01	1.01	-0.00
4	1.00	1.01	-0.00
5	1.01	1.01	-0.00
6	1.01	1.01	-0.00
7	1.00	1.00	0.00
8	0	1.03	∞

When line 3 connecting bus located at Bay'Despoir and Upper Salmon goes out of service. The value of voltages calculated by both the methods are approximately same except the value of voltage on bus 8 located at Upper Salmon. The value calculated by AC power flow is completely zero, as line connecting bus 1 and bus 8 is radial, so when it is disconnected, it becomes isolated.

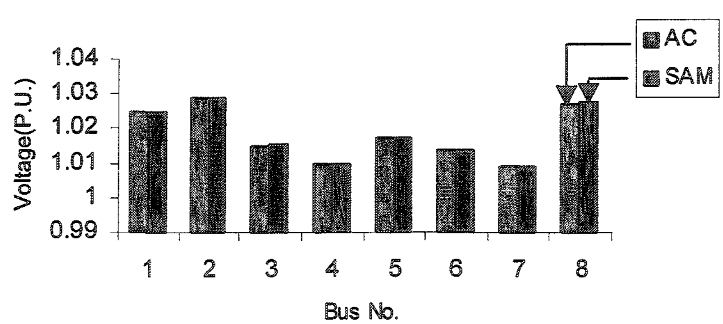

Fig. 3.11 Comparison of voltages on buses during generator on bus 8 goes out of service for NLH system

Table 3.8 Percentage error in voltage during generator on bus 8 out of service for NLH system

Bus No.	Voltage		Percentage Error
	V_{AC}	V_{SAM}	
1	1.02	1.02	0.00
2	1.02	1.02	0.00
3	1.01	1.01	0.00
4	1.00	1.01	-0.00
5	1.01	1.01	-0.00
6	1.01	1.01	-0.00
7	1.00	1.00	-0.00
8	1.02	1.02	0.00

Fig. 3.11 shows the voltage on buses using AC power flow and Sensitivity analysis method, when generator on bus 8 goes out of service. The results calculated using AC power flow and Sensitivity analysis method are same. This generator is delivering no real power, so the reliability of the results can be attributed to the fact that sensitivity analysis method gives better results if the changes are small.

3.5 Conclusion

Sensitivity analysis is used for finding a small change over a linear operating point. The use of Sensitivity analysis should always be narrowed down to small changes for good results. After application of sensitivity analysis based method to the 39 bus system and the Newfoundland & Labrador Hydro equivalent system, a few observations have been made. In case of line outages, the results will be optimistic if the line is carrying a small percentage of its total carrying capacity. The same observation applies to generator outages as well, if the outaged generator is delivering a small percentage of the total generation of the system then the results calculated using Sensitivity analysis based method will be near to AC power flow.

The Sensitivity analysis based method can be used without changes also to real time systems. The time taken by this algorithm for computing post outage voltages is very small as compared to full AC power solution but accuracy is comparable. So, this method can be used for online security analysis also.

Chapter 4

Application of Linear Contingency Analysis Methods to Large Power System

4.1 Introduction

This chapter presents, network reduction technique and the application of linear contingency analysis methods to large power system. The 39-bus power system and 95-bus Newfoundland Hydro system are studied after applying the network reduction technique. The main area of investigation in contingency analysis is to look for techniques and methods those could calculate power flow parameters in the shortest interval of time. In the online control and operation context, the system controlled is usually interconnected to other power systems. Normally, a contingency in one's own system will have the highest effects within that system. There are always cases, however, where a contingency in one system is strongly felt in another. For example, the loss of a major generation station may cause power flow limit violations among utilities. The difficulty in predicting the impact of contingency arises from the fact that the external network is not monitored as carefully as the internal network. Through state estimation, all internal system voltage magnitudes and angles, power flows, generations, load and network topology are known online. As far as the external system is concerned, online information available is normally restricted to items such as inter-tie power flows, status of major lines and generators, and possibly individual unit outputs, among a few others. If one is looking for an exact power flow solution for a postulated contingency, then the state of the entire network (internal and external should be known) to establish the pre contingency base case. Since the state of the external network is not fully known, some approximations are required. In the next section, a approach called Network Reduction is discussed. This approach when applied to large power systems under investigation will help analyzing the power system from contingency aspect in a shorter period of time.

4.2 Network Reduction

Consider a power system divided into three portions : internal, external and boundary.

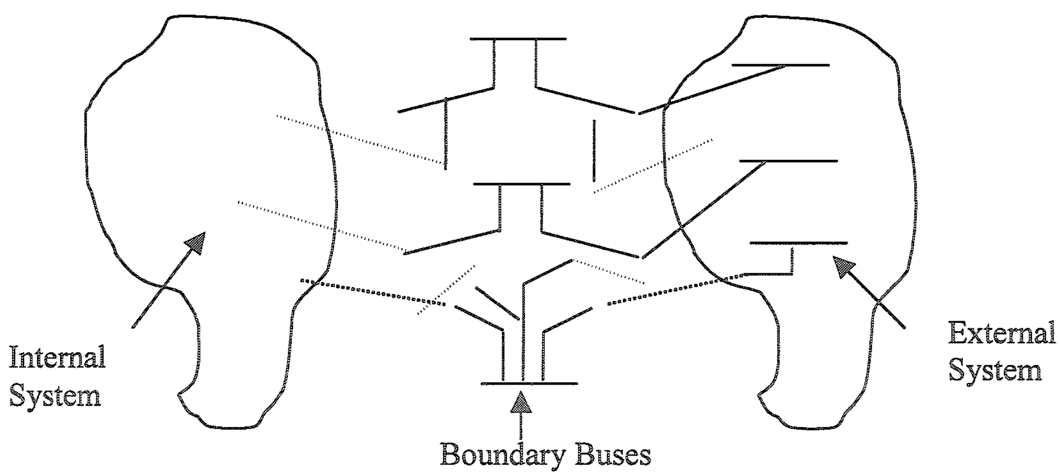

Fig. 4.1 Structure of system decomposition [3]

Fig. 4.1 shows the overall system decomposed into three systems. Boundary buses place a partition between internal and external buses. The Internal buses are not connected to the external buses directly. In the discussion to follow the subscripts I, B, E will correspond to internal, boundary and external bus related parameters [3]. V_I, V_B and V_E are the complex nodal voltages for the internal, boundary, and external systems, respectively. The corresponding notation for complex current, real, and reactive power are (I_I ,I_B, I_E), (P_I,P_B,P_E), and (Q_I,Q_B,Q_E), respectively.

4.2.1 Principle of Network Reduction

The voltage current relationship in terms of bus admittance matrix is given by equation (4.1)

$$\begin{pmatrix} Y_{EE} & Y_{EB} & 0 \\ Y_{BE} & Y_{BB} & Y_{BI} \\ 0 & Y_{IB} & Y_{II} \end{pmatrix} \begin{bmatrix} V_E \\ V_B \\ V_I \end{bmatrix} = \begin{bmatrix} I_E \\ I_B \\ I_I \end{bmatrix} \tag{4.1}$$

Y_{EE} is the admittance matrix for branches connected among external buses. Y_{EB} is the admittance matrix for buses branches connected between external and boundary buses. Y_{BE} is the admittance matrix of branches connected between boundary and external buses. Y_{BB} is the admittance matrix of branches connected among boundary buses. Y_{BI} is the admittance matrix of branches connected between boundary and internal buses. Y_{II} is the admittance matrix of branches connected among internal buses. The complex power vector S in terms of V variables can be obtained by appropriately splitting it into external, boundary, and internal system components. In general, the vector S can be expressed as in equation (4.2) [3]

$$S=V_d I^*=V_d (YV)^* \tag{4.2}$$

Where V_d is the diagonal matrix whose diagonal entries are the corresponding elements of the vector V. Using the notation defined earlier equation (4.2) is expressed as follows

$$\begin{bmatrix} S_E \\ S_B \\ S_I \end{bmatrix} = \begin{pmatrix} (V_E)_d & 0 & 0 \\ 0 & (V_B)_d & 0 \\ 0 & 0 & (V_I)_d \end{pmatrix} \begin{pmatrix} Y^*_{EE} & Y^*_{EB} & 0 \\ Y^*_{BE} & Y^*_{BB} & Y^*_{BI} \\ 0 & Y^*_{IB} & Y^*_{II} \end{pmatrix} \begin{bmatrix} V^*_E \\ V^*_B \\ V^*_I \end{bmatrix} \tag{4.3}$$

Specifically, this last equation will be rewritten as a set of three-vector equations-

$$S_E=(V_E)_d\left[Y_{EE}V_E+Y_{EB}V_B\right]^* \tag{4.4}$$

$$S_B=(V_B)_d\left[Y_{BE}V_E+Y_{BB}V_B+Y_{BI}V_I\right]^* \tag{4.5}$$

$$S_I=(V_I)_d\left[Y_{IB}V_B+Y_{II}V_I\right]^* \tag{4.6}$$

Equation (4.4) is manipulated to yield the equation (4.7)

$$V^*_E=(Y^*_{EE})^{-1}\left[-(Y_{EE}V_B)^*+(V_E)^{-1}{}_d S_E\right] \tag{4.7}$$

The i-th component of $(V_E)^{-1}{}_d S_E$ is given by equation (4.8)

$$S_{Ei}/V_{Ei} = S_{Ei}\,V^*_{Ei}/|V_{Ei}|^2 \tag{4.8}$$

A new vector is defined in equation (4.9)

$$W_E = \begin{bmatrix} S_{Ei} / |V_{Ei}|^2 \\ \vdots \\ \vdots \\ S_{En} / |V_{En}|^2 \end{bmatrix} \tag{4.9}$$

$$(V_E)_d^{-1} S_E = (V_E)_d^{*} W_E = (W_E)_d V_E^{*} \tag{4.10}$$

Equation (4.10) may be re-expressed as in equation (4.11)

$$V_E^{*} = (Y_{EE}^{*})^{-1} \left[-(Y_{EB} V_B)^{*} + (W_E)_d V^{*}_E \right] \tag{4.11}$$

The expression for V_E from equation (4.11) is written as

$$V_E = (Y_{EE} - (W_E)^{*}{}_d)^{-1} Y_{EB} V_B \tag{4.12}$$

Substituting equation (4.12) in to equation (4.5) yields –

$$S_B = \left[\left(Y_{BB} - Y_{BE} \left(Y_{EE} - (W_E)_d^{*} \right)^{-1} Y_{EB} \right)^{*} + (Y_{BI} V_I)^{*} \right] \tag{4.13}$$

The conclusion of this derivation is that the external system is represented by a modification of Y_{BB} matrix given in equation (4.13)

$$Y_{eq} = -Y_{BE} \left[Y_{EE} - (W_E)_d^{*} \right]^{-1} Y_{EB} \tag{4.14}$$

This matrix corresponds to an equivalent network connecting the boundary nodes. If external voltage magnitudes and power injections remain constant, then $(W_E)_d$ is constant. As a result, the external bus nodal injections can be represented by equivalent admittance given by equation (4.15)

$$W_i = \frac{S_i^*}{|V_i|^*},\ i \in \text{(External system)} \tag{4.15}$$

The validity of this system equivalent stays on the requirement that all terms on the right side of equation (4.15) remain constant following a system contingency. This is to be contrasted with the classical approach of representing external load bus injections by means of constant impedances. In the above derivation the external load bus can be represented as admittance, which is a function of the post outage corresponding voltage magnitudes. Thus, if a means is available to estimate external load bus voltage magnitudes and generation bus reactive generation following a postulated contingency, then the above approach will yield very acceptable results.

4.3 Application of Network Reduction to the 39-Bus System

In this section, Network Reduction is applied to the 39-bus system. It is reduced to a 10-bus system. Linear Sensitivity factors method is applied to this reduced system for line outage. The results are then compared with full AC power flow solution to verify that reduced systems are comparable to the complete system.

4.3.1 Case Study of the 39-Bus System

Network Reduction is used to reduce the 39-bus system into a 10-bus system and then this reduced system is simulated for contingencies. The power flow on different transmission lines is compared with full AC power flow during contingencies. Table 4.1

and Table 4.2 give the summary of the new 39-bus system. Table 4.3 and Table 4.4 give the summary of the new 10-bus system.

Table 4.1 39 Bus power system component data

Buses	39
Generators	10
Lines/Transformers	46

Table 4.2 39 Bus power system base case load flow summary

	Real Power (MW)	Reactive Power (Mvar)
Total generation	6192.8	1256.3
Total load	6150.1	1408.9
Losses	42.74	-152.56

Table 4.3 10 Bus system component data

Buses	10
Generators	3
Lines/Transformers	13

Table 4.4 10 Bus system base case load flow summary

	Real Power (MW)	Reactive Power (MVAR)
Total generation	1370	-5.5
Total load	1124	143.3
Losses	10.30	-49.86
Shunts	236.7	-122.5

10-bus system has reduced from 39-bus system making buses internal, external and

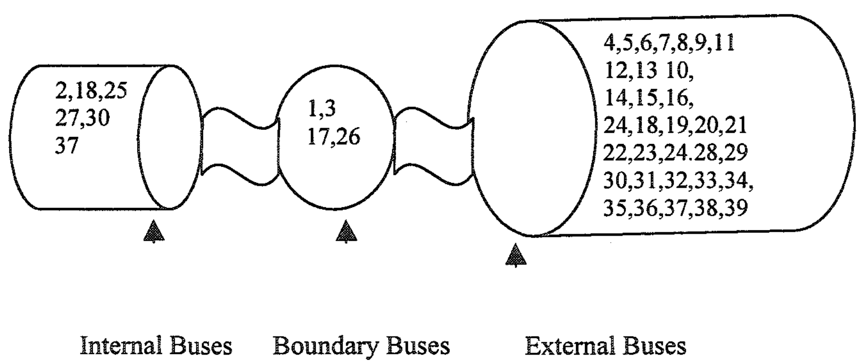

Fig. 4.2 Systems portioned on basis of buses

boundary as shown in fig 4.2. Fig. 4.3 shows the single line diagram of the 39-bus system. Area 1 is made internal and area 2 and area 3 are considered external system. Table 4.5 gives the number of branches and the buses connected to each line.

Table 4.5 Branches and the connected buses of the reduced 10-bus system

Branch No.	To	From
1	2	1
2	1	3
3	1	17
4	3	2
5	25	2
6	2	30
7	3	17
8	18	3
9	18	17
10	27	17
11	26	25
12	25	37
13	27	26

Fig. 4.4 shows the real power flow on transmission lines, when line 1 connecting bus 2 and 1 goes out of service. The real power flow is same as AC power flow on all the branches. The real power flow calculated by Line outage Distribution Factor using complete 39-bus system and reduced 10-bus are equal. This gives an idea that during such kind of reduction, a lot of time is saved and results have the same accuracy as calculated using original system unless and until there is a significant change in the external system configuration. Fig. 4.5 shows the real power flows on branches, when line 2 connecting bus 1 and bus 3 goes out of service. On all the branches except, branch 1 there is a difference in the real power flows calculated by Line Outage Distribution Factor and AC power flow method.

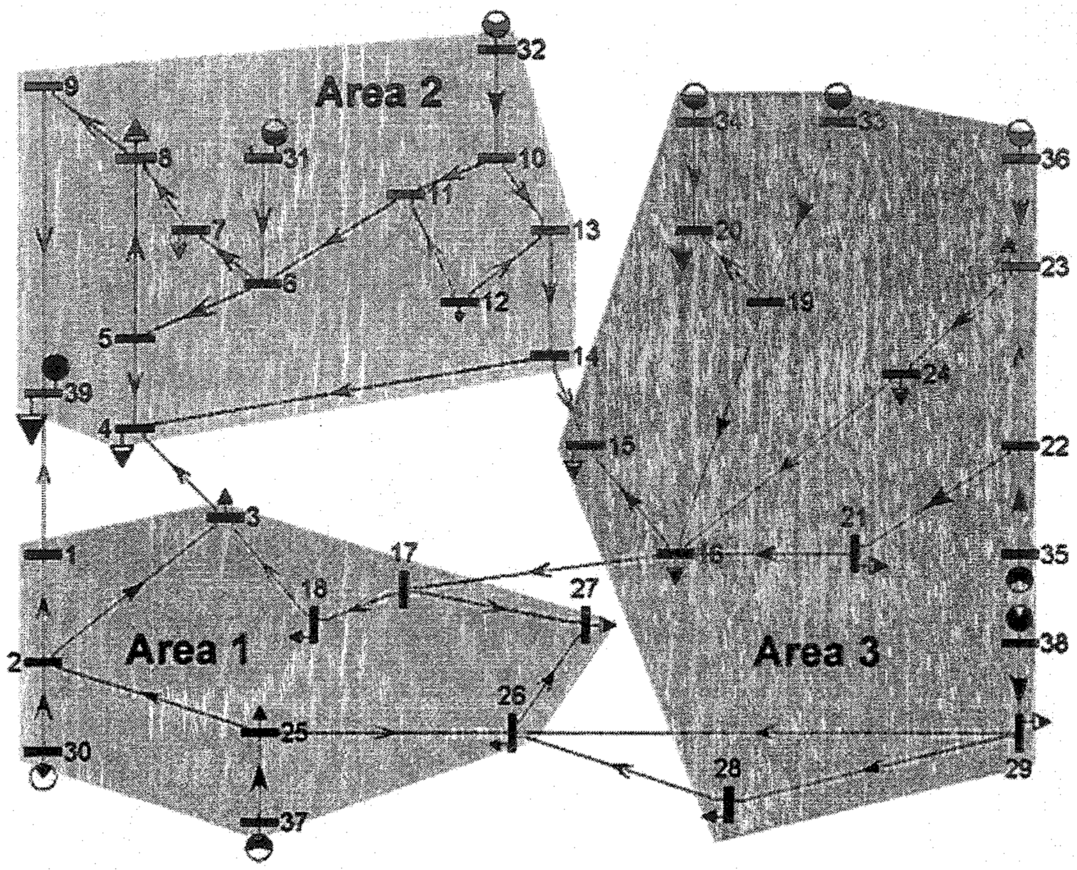

Fig.4.3 Single line diagram of the 39-bus power system

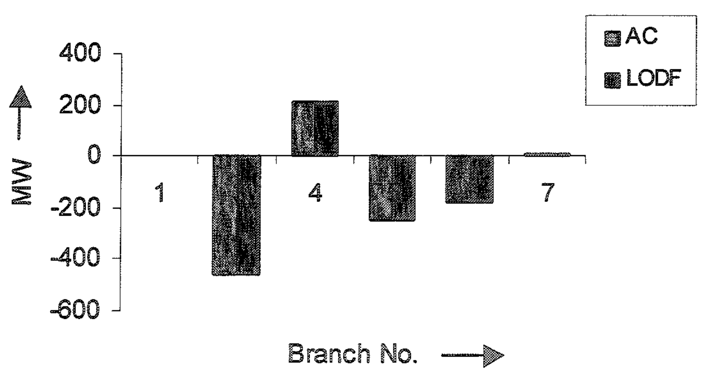

Fig. 4.4 Real power flow comparison with line 1 outaged of the 10-bus system

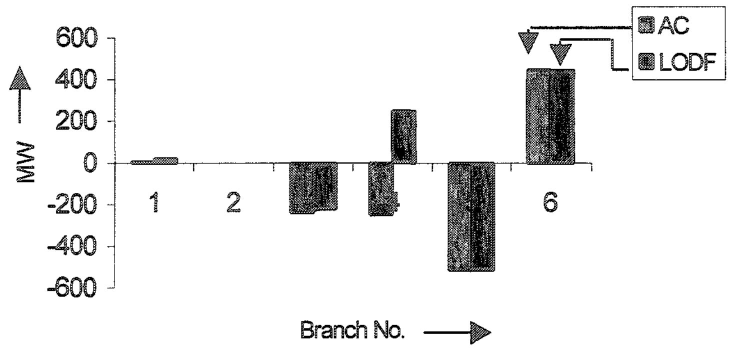

Fig. 4.5 Real power flow comparison with line 2 outaged of the 10-bus system

The observations inferred from Table 4.6. shows that Network reduction is credible means for saving time during contingency analysis for large systems, unless there is big change in the external system configuration. Introduction of concept of Network reduction and its application to 39-bus system is used to emphasize the fact that it could be very useful tool to analyze large interconnected power system. Application of this concept is limited to 39-bus system only in this chapter. In the following section, security analysis of Newfoundland hydro system is studied using linear contingency analysis methods.

4.4 Security Analysis of the Newfoundland Hydro System

Newfoundland Hydro is a 95-bus system owned by the province of Newfoundland and Labrador. The power company generates, transmits and distributes electrical power and energy to utilities, industrial and residential customers throughout the province. It has 9 generating stations. The location of generating stations is shown in

Table 4.6 Real power line flows for 10-bus and 39-bus system for outage of line1

No. of Buses Connected	10-bus System	39-bus System
	MW	MW
2-1	0	0
2-30	-250	-250
25-37	-538.3	-538.3
26-25	-97.5	-99.4
18-3	19.1	18.1

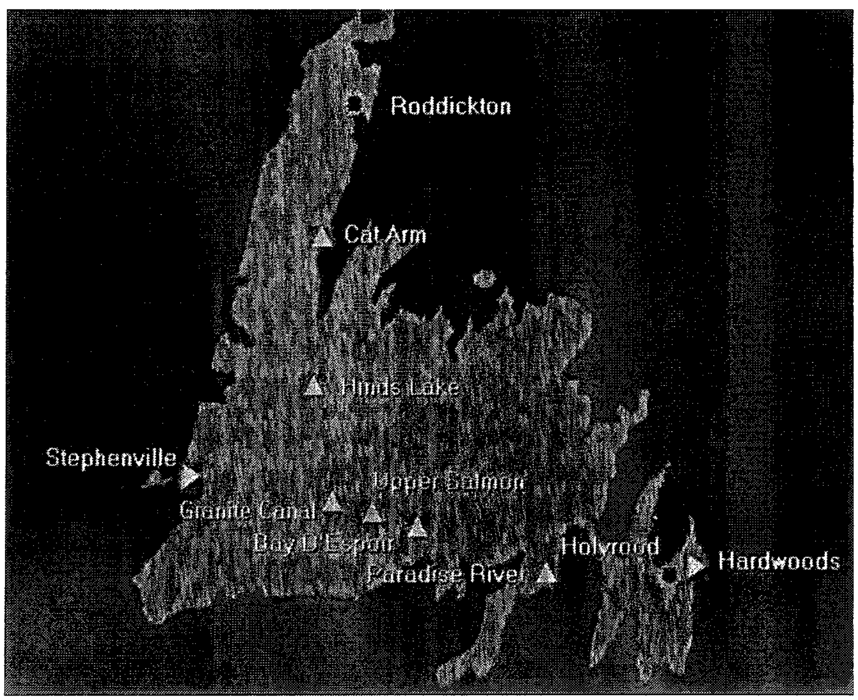

Fig. 4.6 Location of generation plants in Newfoundland Hydro system

fig. 4.6. The total generation of the plants is 1357.2 MW. The details of the system are discussed in Appendix C.

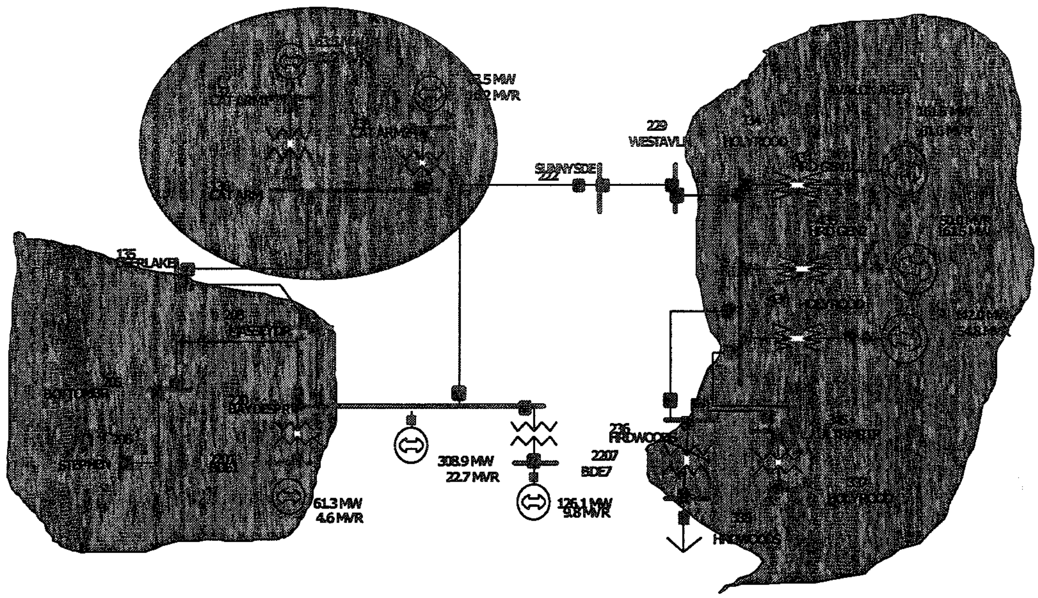

Fig. 4.7 Single line diagram of 95 bus Newfoundland Hydro system

Linear contingency analysis methods are applied on real time 95 bus Newfoundland Hydro system. In fig. 4.7, the single line diagram shows the major transmission lines of the system. DC load flow and Linear Sensitivity Factors method for real power flow calculations and Sensitivity analysis based method have been used for finding voltages on buses during contingencies. The proximity of results to the full AC power flow will support the statement that these methods can be used for real time system also. The results are shown in a serial order, first DC load flow and then Line Outage Distribution Factor and then Sensitivity analysis based method will be applied. Fig. 4.8 shows the real power flow on branches when line 5 connecting CornerBrook and MessyDrive goes out of service. The flow on all the branches is approximately same as AC power flow. If rest of the lines is also observed in the results available, the results are promising except a few lines like line 1 and 2, but this difference can be accommodated, as it is very small.

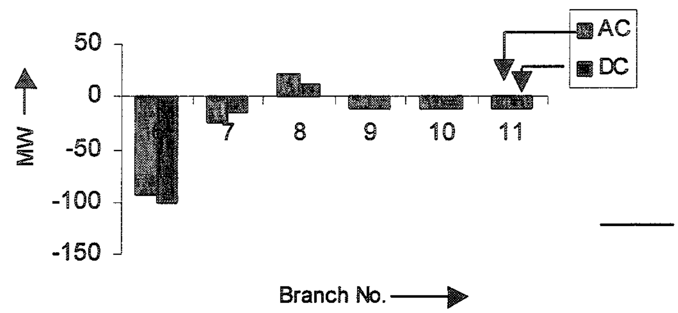

Fig. 4.8 Real power flow comparison with line 5 connecting bus 106 & 152 outaged

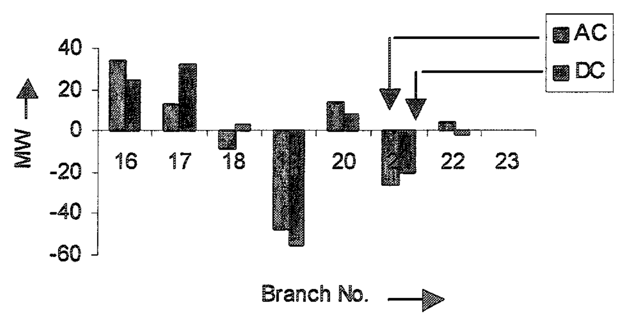

Fig. 4.9 Real power flow comparison with line 23 connecting bus 208 & 115 outaged

Fig. 4.9 shows the real power flow on branches, when line 23 ~~connecting~~ MessyDrive and BottomBrook goes out of service. Real power flow on line 23 is zero both in AC power flow and DC power flow methods. The flow on branch 18 connecting DeerLake 1 and DeerLake 2 calculated using DC load flow and AC power flow is in opposite direction. Fig. 4.10 shows the real power flow on lines, when line 37 connecting Bottom Brook and Buchans goes out of service. In fig. 4.10, lines from 29 to 35 have real power

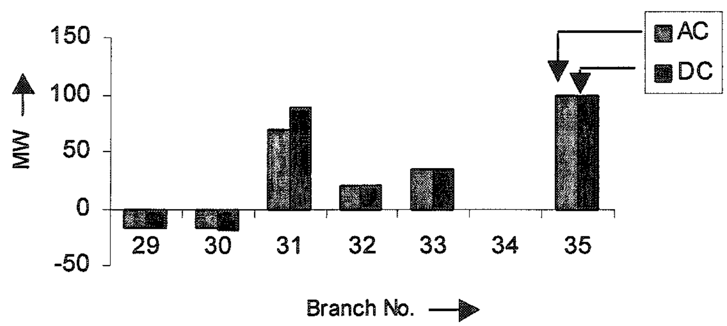

Fig. 4.10 Real power flow comparison with line 37 connecting bus 205 & 215 outaged

flows approximately same as AC power flow. These results make linear contingency analysis methods useful for online security analysis in power system industry.

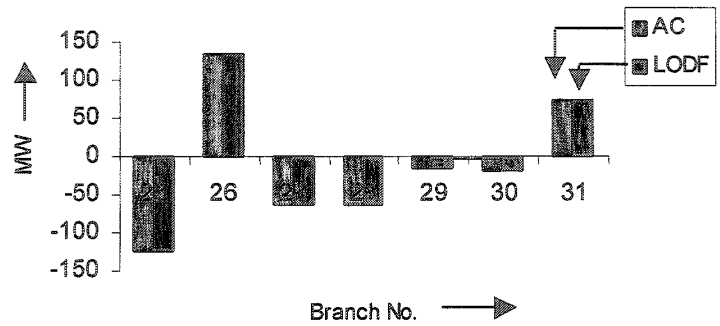

Fig. 4.11 Real power flow comparison with line 101 connecting bus 236 & 238 outaged

Fig. 4.11 shows the flow on transmission lines, when line 101 connecting Hardwoods and OxenPond goes out of service. In fig. 4.11 lines from 25 to 31 are shown and flows are approximately same as AC power flow. Fig. 4.12 shows real power flow on lines from 64 to 70, when line 107 connecting Oxen Pond1 to OxenPond2 goes out of service. The real power flow on all the lines calculated by Line Outage Distribution factor is same as calculated by AC power flow method.

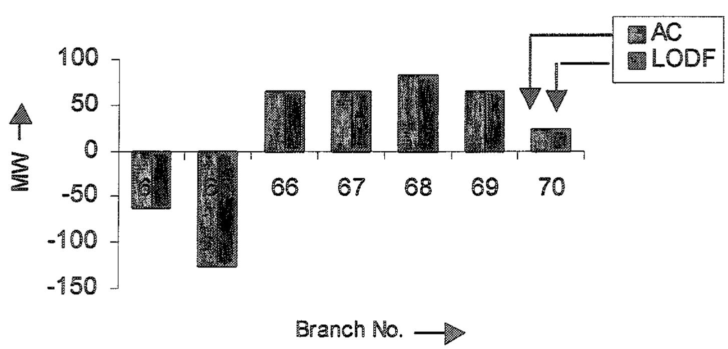

Fig. 4.12 Real power flow comparison with line 107 connecting bus 238 & 334 outaged

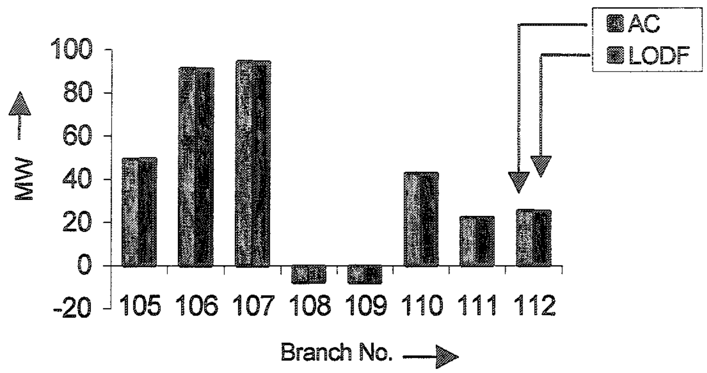

Fig. 4.13 Real power flow comparison with line 125 connecting bus 322 & 863 outaged

Fig. 4.13 shows real power flow on lines, when line 125 connecting PBLANTAP and NWRIVTAP goes out of service. On most of the lines, real power flows calculated by Line Outage Distribution Factor and AC power flow are same. Fig. 4.14 shows the real power flows on transmission lines when generator on bus 105 located in FRC60HZ goes out of service.

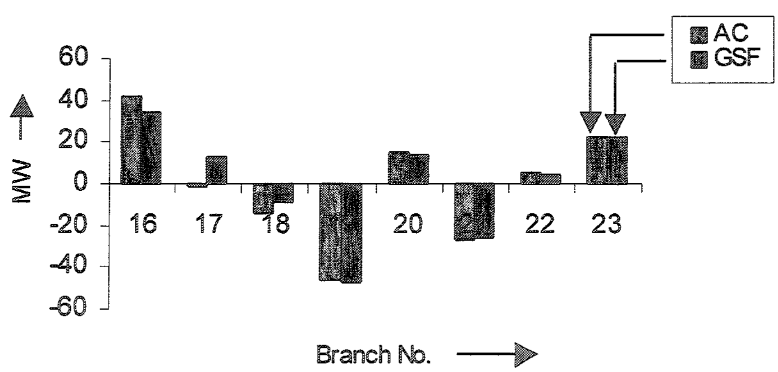

Fig. 4.14 Real power flow comparison with generator on bus 105 outaged

On all the lines from 16 to 23 flows calculated by Generation shift factor and AC power flow are same except on line 17, where the real power flow calculated by AC power flow method is zero but there is real power flow when calculated by Generation Shift Factor. Fig. 4.15 shows the flows on transmission lines, when generator on bus 138 located in CATARM2 goes out of service. The flows in fig. 4.15 are shown for lines from 20 to 25. Real power flow on all the lines calculated by Generation Shift factor is approximately same as AC power flow except on line 25 connecting DeerLake and CATARM.

Fig. 4.15 Real power flow comparison with generator on bus 138 outaged.

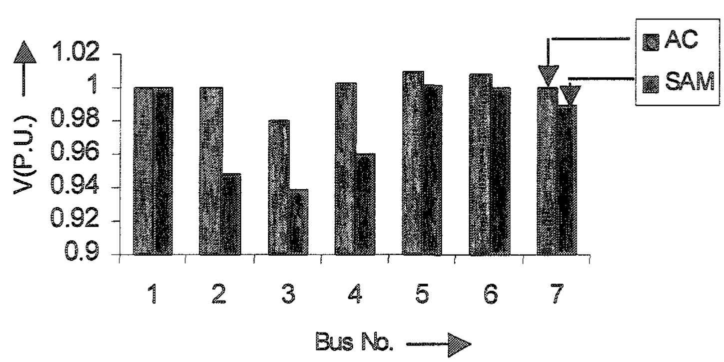

Fig. 4.16 Comparison of voltages on buses during outage of line 5 connecting bus 106 & 152

Fig. 4.16 compares the voltage on buses, when line 10 connecting CornerBrook and DeerLake goes out of service. The voltage on bus 1 is constant being a slack bus. Table 4.7 gives the percentage error of the values of the voltages calculated by full AC power flow and Sensitivity Analysis based method. From table 4.4, it can be inferred the error is within the tolerable range. Fig. 4.17 compares the voltages on buses, when line 23 connecting MassyDrive and MassyDrive (B2B3) goes out of service. Table 4.8 gives the percentage error and the values are very small and the results are promising in this case. In most of the results the error is very small. Fig. 4.18 compares the voltage on buses,

Table 4.7 Percentage error in voltage for outage of line 5

Bus No.	Voltage		Percentage Error
	V_{AC}	V_{SAM}	
1	1	1.00	0.00
2	1	0.94	5.22
3	.97	0.93	4.18
4	1.00	0.96	4.19
5	1.07	1.00	0.90
6	1.00	0.99	0.83
7	1.00	0.98	1.12

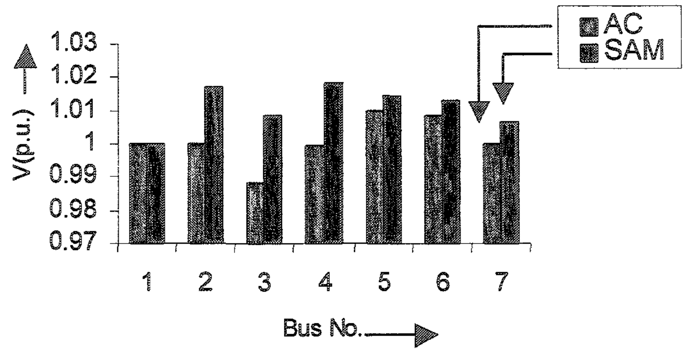

Fig. 4.17 Comparison of voltages on buses during outage of line 23 connecting bus 208 & 115

Table 4.8 Percentage error in voltage for outage of line 23

Bus No.	Voltage		Percentage Error
	V_{AC}	V_{SAM}	
1	1.00	1.00	0.00
2	1.00	1.01	-1.69
3	0.98	1.00	-2.01
4	0.99	1.01	-1.85
5	1.01	1.01	-0.41
6	1.00	1.01	-0.42
7	0.99	1.00	-0.63

when line 37 connecting Bottom Brook and Buchans goes out of service. Table 4.6 gives the percentage error and this value is very less. As discussed in chapter 3, Sensitivity analysis can also be used for finding voltages during generator outages. Here are few results showing application of this method.

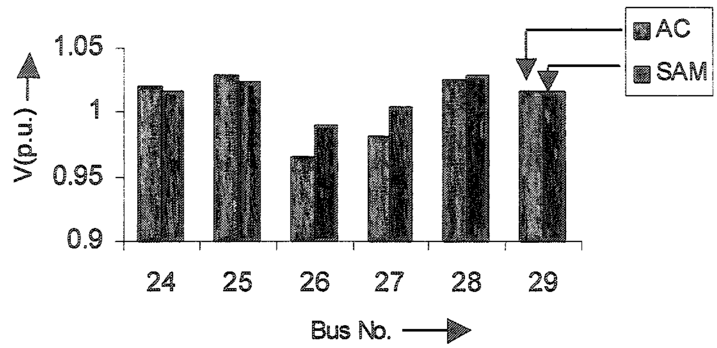

Fig. 4.18 Comparison of voltages on buses during outage of line 37 connecting bus 205 & 215

Table 4.9 Percentage error in voltage for outage of line 37

Bus No.	Voltage		Percentage Error
	V_{AC}	V_{SAM}	
24	1.02	1.01	0.37
25	1.02	1.02	0.40
26	0.96	0.99	-2.61
27	0.98	1.00	-2.31
28	1.02	1.02	-0.31
29	1.01	1.01	-0.01

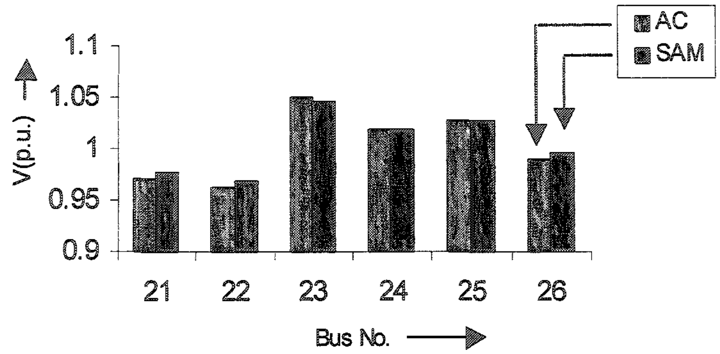

Fig. 4.19 Comparison of voltages on buses during generator on bus 105 out of service

Table 4.10 Percentage error in voltage for outage of generator on bus 105

Bus No.	Voltage		Percentage Error
	V_{AC}	V_{SAM}	
21	0.97	0.97	0
22	0.96	0.96	0
23	1.05	1.04	0.32
24	1.01	1.01	0.00
25	1.02	1.02	1.02
26	0.98	0.99	0.99

Fig. 4.19 compares voltages on different buses, when generator on bus 105 at FRC60HZ goes out of service. Table 4.10 shows the percentage error for the values calculated using full AC power flow and sensitivity analysis based method. The maximum error is 1 percent. The accuracy of results also depends upon the value of the real power supplied by the generator outaged, as the real power supplied by this generator is 18 MW, which is a small value as compared to total generation of system. Hence, the results are more reliable.

4.5 Conclusions

With the tools discussed in chapter 2 and 3, a power system operator can be alerted to the effects of possible contingencies like transmission line or generator outages. Network reduction is used to reduce a larger system into a smaller system and the part of the interest of the system can be studied in a shorter time. When the power system is large, the system can be reduced using Network reduction and the reduced equivalent can be studied using full AC power flow solution. In this chapter, Network reduction is applied to 39-bus system and the results were same as found using the complete system. The observations from the results obtained by applying linear contingency analysis methods to 95 bus Newfoundland Hydro system are very promising both for real power flow and voltage calculations during contingencies. From all the observations made, it can be inferred that the linear contingency analysis methods discussed can be applied to real time power system for online security analysis.

Chapter 5

Security Constrained Optimal Power Flow

5.1 Introduction

The electric power system is defined as the system with the goal to generate and transmit electric power in a optimized way. Optimization, which is the theme of this chapter, is the function in an energy management system that schedules the power system controls in some optimal way, and at the same time is constrained by the power flow network model, and power system operating limits. The term optimal power flow refers to the optimal operation of a power system during normal operation. The optimization during a contingency satisfying all the constraints is called security constrained optimal power flow. This chapter presents the formulations of OPF and Security Constrained Optimal power flow (SCOPF). Matlab optimization toolbox is used to solve these problems. In this chapter optimal power flow and security constrained optimal power flow (during contingencies) are discussed. Case studies using a sample 7-bus power system and the 39-bus power system are presented in detail. In all the cases active power flow limits are considered as part of the constraints. In the final part of this chapter, a summary of the OPF and SCOPF problems is given.

5.2 Optimal Power Flow

The OPF (Optimal Power Flow) was introduced in the early 1960's as an extension of the conventional economic dispatch to determine the optimal settings for control variables in a power network respecting various constraints [27]. OPF is a static constrained nonlinear optimization problem.

Optimal power flow solves a set of non-linear equations, describing optimal and/or secure operation of a power system. Rather then making the adjustments in a random fashion, the system planner will attempt to optimize the adjustments to achieve some objective function. The optimal power flow problem is to formulate the power flow problem to find system voltages and generated powers within the framework of the objective function. In this application, the inputs to the power flow are systematically adjusted to maximize (or minimize) a scalar function of the power flow state variables. The two most common objective functions are minimization of the generating costs and active power losses. The time frame of optimal power flow is on the order of minutes to one hour; therefore it is assumed that the optimization occurs using only those units that are currently online.

In mathematical terms, the optimization problem can be expressed as [28]

$$\text{Minimize} \quad F(x,u) \tag{5.1}$$

Subject to equality constraints:

$$g(x,u)=0 \tag{5.2}$$

and inequality constraints:

$$h(x,u) \leq 0 \tag{5.3}$$

Where g(x,u) represents nonlinear equality constraints (power flow equations), and h(x,u) is the non-linear inequality constraints of vector arguments x and u.

With the variable limitations:

$$U_{min} \leq U \leq U_{max} \tag{5.4}$$

$$X_{min} \leq X \leq X_{max} \tag{5.5}$$

F is a scalar function that represents the power system's optimization goal. X is the vector of dependent variables. U is the vector of control variables. The parameter X contains dependent variables consisting of bus voltage magnitude designated for bus voltage control and fixed parameter such as the reference bus angle, non-controlled generator MW and MVAR output etc. U vector consists of control variables including real and reactive power generation, phase shifter angles, net interchange, load MW and MVAR etc. When both the objective function and the constraints are linear functions of the design variables, the problem is known as a linear programming problem. Quadratic programming concerns the minimization or maximization of a quadratic objective function that is linearly constrained.

5.2.1 Equality Constraints

The loads in a power system are usually assumed to have a constant active part P and a constant reactive part Q. These two values usually cannot be changed by the operator and must not be modified by the normal computation. Thus for every load node where the load cannot be controlled, the two equality constraints must be valid:

$$Q_{scheduled} - Q_i = 0 \qquad (5.6)$$

$$P_{scheduled} - P_i = 0 \qquad (5.7)$$

An additional demand variable could be voltage magnitude of a generator PV node where the voltage is not allowed to move.

5.2.2 Inequality Constraints

The limits on the control and state variables must be modeled correctly in the OPF simulation in order simulation in order to have valid simulation results mathematically, they are formulated in inequality constraints. Inequality constraints must be expressed as functions of vector U and X, which contains all control and state variables.

5.3 Mathematical Algorithm for Optimization

There are primarily two main objectives, which present day electric companies try to achieve and those are reduction of the total cost of the generated power and reduction of active transmission losses.

The objectives function to be minimized is given by the following fuel cost model given in equation (5.8) [29]

$$F(P_g) = \sum_{i=1}^{N} (\alpha_i + \beta_i P_{gi} + \gamma_i P_{gi}^2) \tag{5.8}$$

Subject to equality constraints representing the active and reactive electric network balance,

$$P_i - P_{gi} + P_d = 0 \qquad i=1,............N_b \tag{5.9}$$

$$Q_i - Q_{gi} + Q_d = 0 \qquad i=1,............N_b \tag{5.10}$$

$$P_i = V_i \sum_{j=1}^{N_b} V_j Y_{ij} Cos(\theta_i - \theta_j - \Psi_{ij}) \qquad i = 1,........N_b \tag{5.11}$$

$$Q_i = V_i \sum_{j=1}^{N_b} V_j Y_{ij} Sin(\theta_i - \theta_j - \Psi_{ij}) \qquad i = 1,........N_b \tag{5.12}$$

together with the inequality constraints are

$$V_{imin} \leq V_i \leq V_{imax} \qquad i=1,.....N_b$$
$$P_{gi_{min}} \leq P_{gi} \leq P_{gi_{max}} \qquad i=1,......N_g$$
$$Q_{gi_{min}} \leq Q_{gi} \leq Q_{gi_{max}} \qquad i=1,......N_{gq}$$

Where

$F(P_g)$	Total fuel cost, as a function of Pg
P_{gi}	Active power generation at unit i
$\alpha_i, \beta_i, \gamma_i$	Fuel cost parameters of unit i
N_g	Number of generation units
N_{gq}	Number of generation units and PV buses

N_b Number of buses

N_l Number of lines

V_i, V_j Voltage magnitude at buses i and j

θ_i, θ_j Phase angles at buses i and j

P_i Net active power injections a node i

Q_i Net reactive power injections at node i

Y_{ij} Magnitude of the complex admittance matrix elements at the i^{th} row and j^{th} column

ψ_{ij} Phase angle of the complex admittance matrix element at position i, j

V_{imin}, V_{imax} Lower and upper bound on the voltage magnitude at bus i

Q_{gimin}, Q_{gimax} Lower and upper bounds on the reactive generation at bus i

5.4 Security Constrained Optimal Power Flow

Optimal power flow can also have other constraints. These have to do with the state of the system during a contingency. Such constraints are called security constraints, and allow the system to operate in a secure state. Optimal power flow forces the system to be operated in such a way that if a contingency occurs, the resulting voltages and flows would be still within limits. Contingency constraints are a fundamental part of economic security control. They are intrinsic to security level 1 and 2. Security level 1 means, when operating limits will not be reported in the event of contingencies, there will be no violations. Security level 2 means, there are no limit violations during normal operation. If any violation occurs during a contingency, it can be corrected by appropriate control action without loss of load. If power system is large, the number of constraints could be large in number, the case may include hundreds or thousands of inequalities. Equation (5.13) and (5.14) give the admissible range of variables during a contingency.

$$\left|V_k^-\right| \le \left|V_k\right| (with\ \ line\ nm\ out) \le \left|V_k^+\right| \tag{5.13}$$

Where –ve and +ve sign indicate the value of variable before and after contingency.

$$MVA_{ij}^- \le MVA_{ij}(with\ line\ nm\ \ out) \le MVA_{ij}^+ \tag{5.14}$$

This implies that the optimal power flow would prevent the post contingency voltage on bus k or the post contingency flow on line ij from exceeding the limits for an outage of line nm. This special type of optimal power flow is called security constrained optimal power flow. Only static security assessment is considered in this discussion [30]. The three main steps of security assessment are contingency selection, contingency evaluation and preventive/corrective control action [31]. The order in which outage constraints should be imposed may be used to simplify the security constrained optimal power flow problems. The main goal is to obtain the lowest possible fuel cost while satisfying operating constraints under normal conditions as well as under specified contingencies.

The objective function is the same as in the case of optimal power flow problem and that is given by equation (5.15)

$$F=\sum_{i=1}^{n}\left(\gamma_i+\alpha_i P_{Gi}+\beta_i P_{Gi}{}^2\right) \tag{5.15}$$

Where F is the total fuel cost in dollars per hour

P_{Gi} is the output active power of unit i

α_i , β_i , γ_i are the cost effective coefficients of generators.

Bus voltage and angle are the main state variables. Control variables are generator's generation and voltage etc. The equality constraints consist of load flow equations during normal operation and during contingency. Equations from (5.16)-(5.19) give the equality constraints.

$$\sum_{i=1}^{m} P_i = 0 \tag{5.16}$$

$$\sum_{i=1}^{m} Q_i = 0 \tag{5.17}$$

$$\sum_{i=1}^{m} P_i^{"} = 0 \tag{5.18}$$

$$\sum_{i=1}^{m} Q_i^{"} = 0 \tag{5.19}$$

Where P_i and Q_i is the power flow at bus i during normal operation.

$P_i^{"}$ and $Q_i^{"}$ is the power flow at bus i in contingency states.

m is the number of buses.

In regard to inequality constraints, these constraints don't let the system operate with violations after contingencies also. The following are the inequality constraints from equation (5.19)-(5.23)

$$P_{Gimin} \leq P_{Gi} \leq P_{Gimax} \qquad i=1,2,3\ldots\ldots\ldots\ldots,n \tag{5.20}$$

$$P_{ijmin} \leq P_{ij} \leq P_{ijmax} \qquad i,j=1,2,3\ldots\ldots\ldots\ldots,m \tag{5.21}$$

$$Q_{ijmin} \le Q_{ij} \le Q_{ijmax} \qquad i,j=1,2,3..........,m \tag{5.22}$$

$$V_{imin} \le V_i \le V_{imax} \qquad i=1,2,3..........,m \tag{5.23}$$

$$C_{imin} \le C_i \le C_{imax} \qquad i=1,2,3..........,K \tag{5.24}$$

When it comes to contingency, there is change in values of the variables but the limits still remain same. The inequality contingency constraints are given from equation (5.25)-(5.29).

$$P_{GSlackmin} \le P''_{GSlack} \le P_{GSlackmax} \tag{5.25}$$

$$P_{ijmin} \le P''_{ij} \le P_{ijmax} \qquad i,j=1,2,3..........,m \tag{5.26}$$

$$Q_{ijmin} \le Q''_{ij} \le Q_{ijmax} \qquad i,j=1,2,3..........,m \tag{5.27}$$

$$V_{imin} \le V''_i \le V_{i\,max} \qquad i=1,2,3..........,m \tag{5.28}$$

$$C_{imin} \le C''_i \le C_{i\,max} \qquad i=1,2,3..........,K \tag{5.29}$$

Where P_{Gi} is the generation at bus i during normal conditions

P''_{GSlack} is a generation power of slack bus in contingency condition

V_i is the voltage at bus i in contingency condition

P_{ij} and Q_{ij} are the power flow between bus i and j in normal condition

P''_{ij} and Q''_{ij} are the power flow between bus i and j in contingency condition

C_i is the control variable in normal condition

C''_i is the control variables in contingency condition

n and m are the number of generators and buses respectively

The explanation of security constrained optimal power flow in terms of optimal power flow can be explained as the objective function minimization as in normal optimal power flow but satisfying both the equality and inequality constraints during the contingency.

5.5 Case Study of a the 7-Bus System

Fig. 5.1 shows the single line diagram of a 7-bus system, which contains 11 transmission lines, 5 generators. Table 5.1 gives the component data. Table 5.2

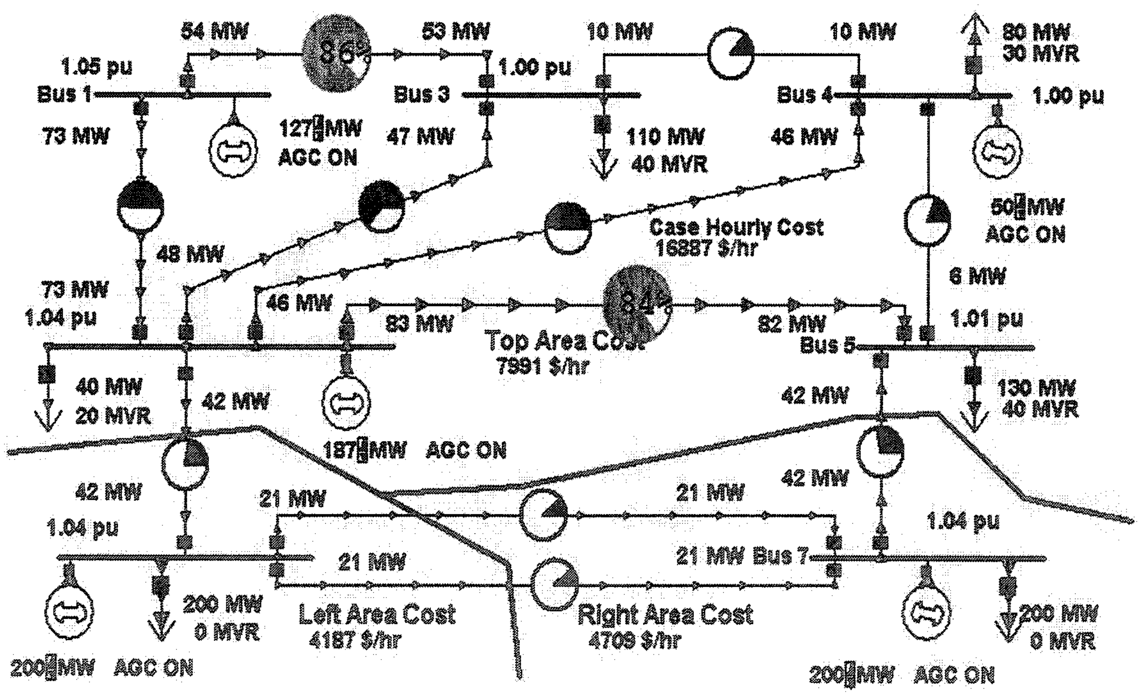

Fig. 5.1 Single line diagram of a 7-bus system

Table 5.1 7 Bus power system component data

Buses	7
Generators	5
Lines/Transformers	11

Table 5.2 7 Bus power system base case load flow summary

	Real Power (MW)	Reactive Power (Mvar)
Total generation	765.2	110.7
Total load	760.0	130.0
Losses	5.24	-19.32

gives the base case load flow summary of the system. The main concern in this discussion is optimal power flow. The details in regard to generators are provided in Table 5.3.

Table 5.3 Cost coefficients of generators in the 7-bus power system

Cost Coefficients	Gen. 1*	Gen.2*	Gen.4*	Gen.6*	Gen.7*
α_i	373.5	403.6	253.24	388.9	194.2
β_i	7.62	7.51	7.57	7.57	7.7
γ_i	.002	.001	.001	.001	.001
Fuel Cost**	2807.3	3835.6	1357	4186.5	4694

* MW

** $/Hr.

The 7-bus power system is divided into three areas. Each area has its own set of generators. Generators are using cubic cost model for this study. To calculate the optimal power flow, a single area should be chosen which would comprise of all the areas together and can be called as super area. There is a single cost objective function given in equation (5.30)

$$\begin{aligned}F(SA)=&2.04*\left(373.5+7.62*G_1+.002*G_1^2\right)+2.06*\left(403.61+7.519*G_2+.0014*G_2^2\right)\\&+2.09*\left(253.24+7.836*G_4+.0013*G_4^2\right)+2.14*\left(388.9+7.53*G_6+.001*G_6^2\right)\\&+2.57*\left(194.28+7.71*G_7+.0019*G_7^2\right)\end{aligned} \tag{5.30}$$

G_1, G_2, G_4, G_6, G_7 are the output of generators in MW. SA means super area.

Table 5.4 gives the hourly cost of the five generators in the 7-bus power system.

Table 5.4 Hourly cost of the 7-bus power system

Case	Gen.1*	Gen.2*	Gen.4*	Gen.6*	Gen.7*	Cost ($/hr)
Base Case	127.5	187.1	50	200.2	200.5	16887
OPF	100	150	183.06	220	112.77	16548

* MW

Fig. 5.2 shows the 7-bus system with optimal power flow including line flow constraints. The cost in base case is more than the optimized generation case but line 2-5 has reached maximum power carrying capacity limit. Now in this case, single line outages will be studied including their impact on total hourly cost and overloading of lines. Three lines 6,8 and 9 have been selected for contingency studies. These have been selected on random basis as the system is small and if desired, all contingencies could also be studied with not much effort. Outage of line 6 and 8 will be studied and for rest of the outages only results will be given.

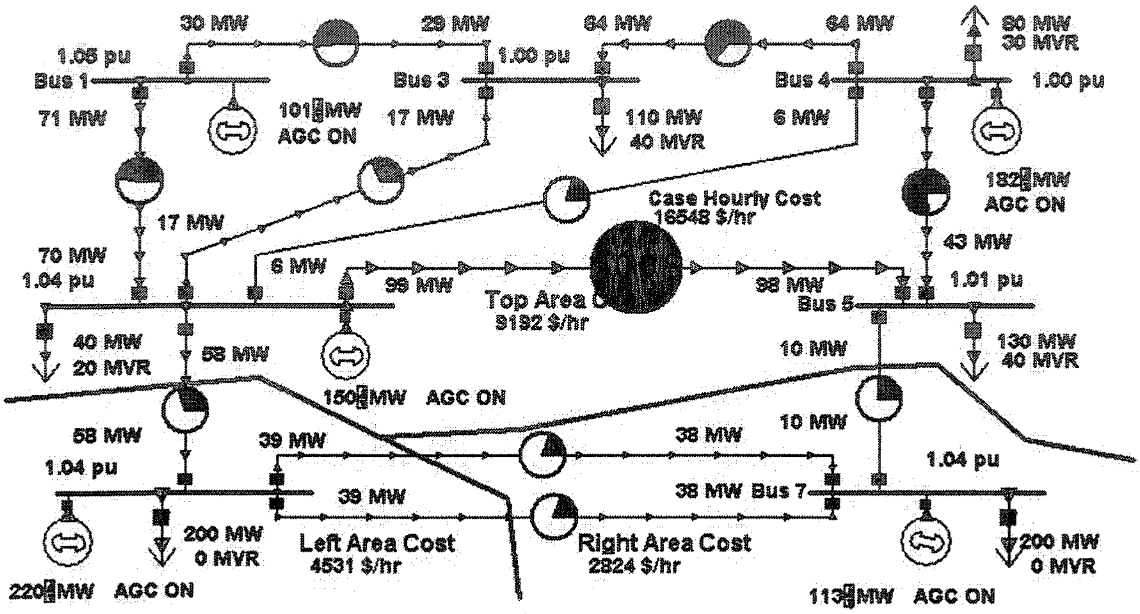

Fig. 5.2 Single line diagram with OPF results

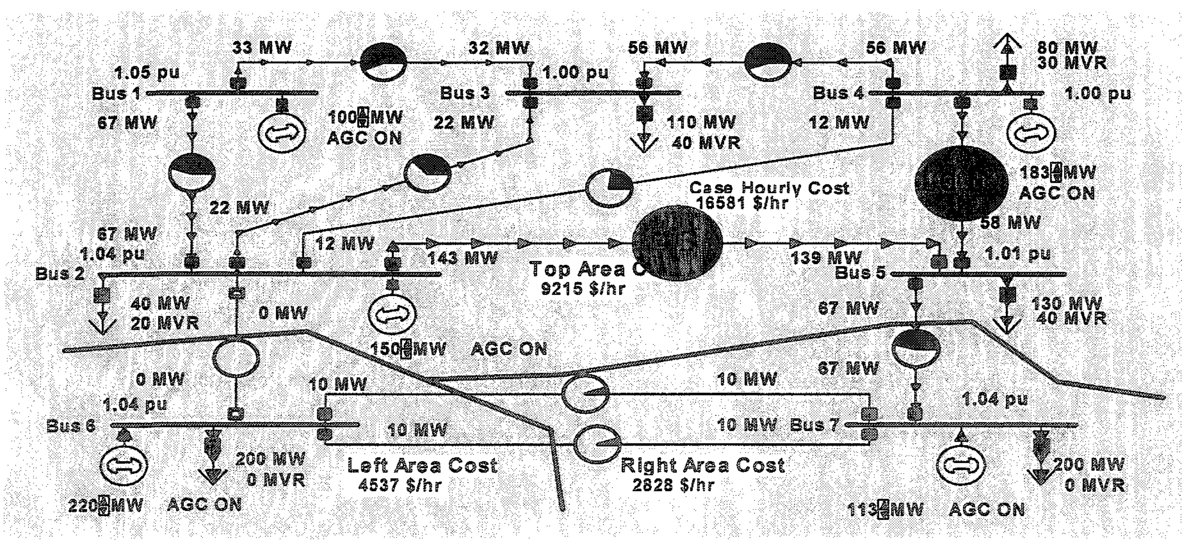

Fig. 5.3 Single line diagram with line (2-6) outaged

Table 5.5 has two rows marked for each outage. The row without the suffix SCOPF gives the output of generators, when the line goes out and the system is not secure. The second row with suffix SCOPF gives the generation, when system is secure for that particular contingency. When line 6 connecting bus 2 and 6 goes out of service, line 5 connecting bus 2 and 5 gets overloaded by 143 percent and line 8 connecting buses 4 and 5 get overloaded to 101 percent as shown in fig 5.3 and the price increased from 16548 $/hr to 16581 $/hr. When the generation was rescheduled to make the violations disappear, the total hourly cost increased from 16548 $/hr to 16583 $/hr, and the loading of line (2-5) became 100 percent as shown in fig. 5.4. Normally, fuel cost is greater in secure power system than non-secure one.

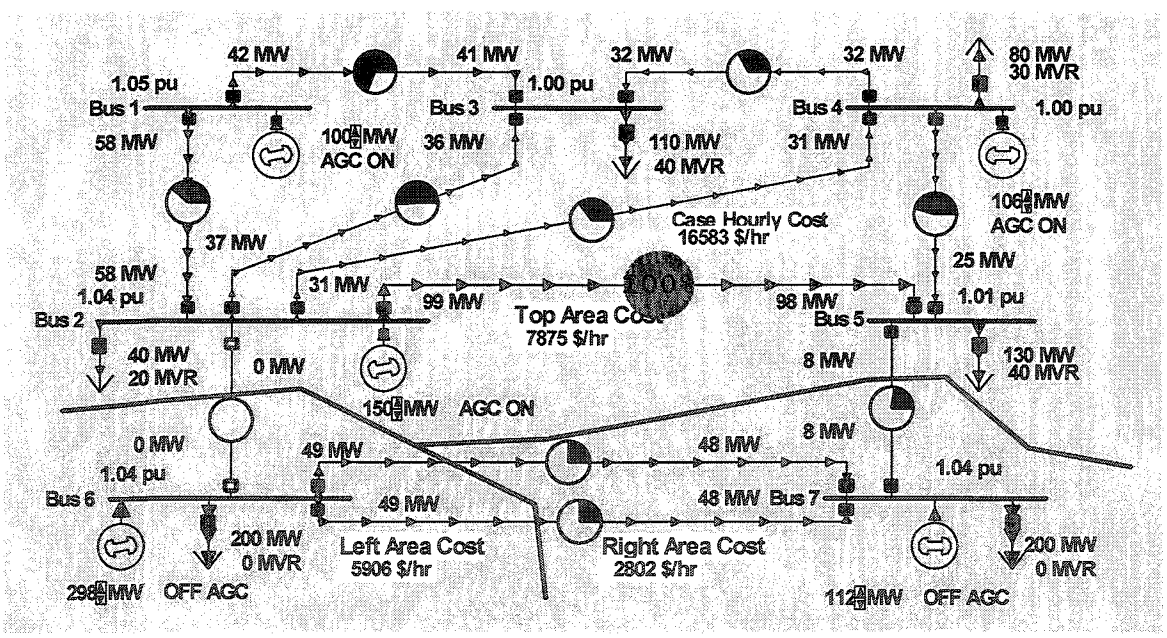

Fig. 5.4 Single line diagram with SCOPF implemented for line (2-6) outaged

When line 8 connecting bus 4 and 5 goes out of service, line 5 connecting bus 2 and 5 gets overloaded by 129 percent as shown in fig 5.5. When the generation was rescheduled to make system secure, the fuel cost was increased from 16570 \$/hr to 16724 \$/hr and the loading of line (2-5) reduces to 99 percentage as shown in fig 5.6. This shows that the fuel cost increases, if the power system is made secure from the contingency aspect.

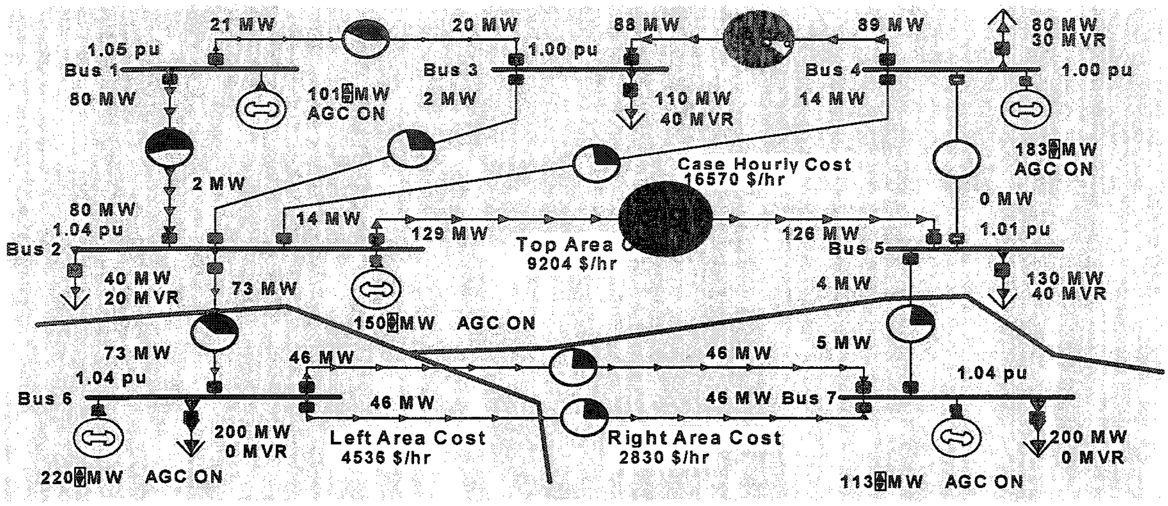

Fig. 5.5 Single line diagram with line (4-5) outaged

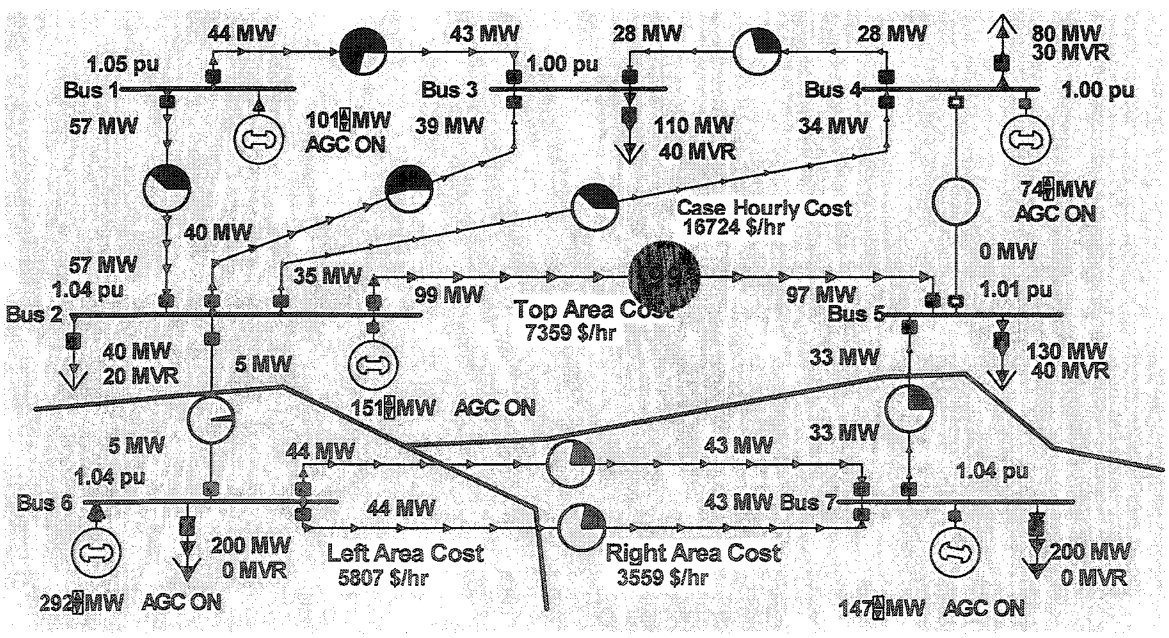

Fig. 5.6 Single line diagram with SCOPF implemented for line (4-3) outaged

Table 5.5 Contingency constrained generations for single line outages of 7bus system

Line Outages	G1 (MW)	G2 (MW)	G4 (MW)	G6 (MW)	G7 (MW)	Percentage Violation in Lines	Cost ($/hr)
2-6	100	150.35	183.41	220.31	113.20	Line 2-5: 143 % Line 4-5:101 %	16581
2-6(SCOPF)	100	150	106.26	297.9	111.9	None	16583
5-7	100	150	183.05	220	112.97	Line 4-7: 102 %	16551
5-7(SCOPF)	100	150	195.08	207.9	112.9	None	16556
4-5	100.24	150.24	183.30	220.24	113.03	Line 2-5:129%	16570
4-5(SCOPF)	100	151.2	73.6	292.32	147.46	None	16724

When line 9 connecting bus 5 and 7 goes out of service, line (4-7) gets loaded to 102 percent. When the generation is securely constrained, the loading of line (4-7) reduces to 100 percent and the cost increases from 16570 $/hr to 16724 $/hr. All the results indicate a trend that there is always increase in fuel cost when the system is made secure from a contingency.

5.6 Case Study of the 39-bus System

This 39-bus power system has 10 generators and slack bus is located at bus 31. The Generators are using cubic cost model for this study and the cost coefficients are given in Table 5.6.

Table 5.6 Cost coefficients of generators in 39-bus power system

Cost Coefficients	Gen. 30	Gen. 31	Gen. 32	Gen. 33	Gen. 34	Gen. 35	Gen. 36	Gen. 37	Gen. 38	Gen. 39
α_i	0	0	0	0	0	0	0	0	0	0
β_i	6.9	3.7	2.8	4.7	7.7	2.8	3.7	4.8	3.6	3.7
γ_i	.0193	.011	.0104	.0088	.0128	.009	.009	.011	.007	.006
Fuel Cost**	2767	5551	5958	6612	4917	6536	5952	5398	8597	9517

** \$/hr.

The cost function of generators for each area is given by equations below.

$$F=\sum_{i=1}^{n}\left(\gamma_i+\alpha_i P_{Gi}+\beta_i P_{Gi}^{2}\right) \tag{5.31}$$

Table 5.7 Hourly cost of 39-bus power system

Case	Gen.* 30	Gen*. 31	Gen.* 32	Gen.* 33	Gen.* 34	Gen.* 35	Gen.* 36	Gen.* 37	Gen.* 38	Gen.* 39	Cost \$/Hr.
Base	237	557	637	645	518	657	569	551	870	950	61813
OPF	240	559	634	640	520	660	570	550	870	952	61810

*MW

Table 5.8 Overloading of lines for a single line outage

Line Outage	Percentage Violation in Lines
14-4	Line 13-16:110.5 %
14-4 (SCOPF)	None
13-10	Line 11-16:113 % Line 11-10: 107%
13-10 (SCOPF)	None
14-3	Line 11-16:130 % Line 11-10: 101%
13-10(SCOPF)	None
21-16	Line 24-23:117%
21-16(SCOPF)	None

Table 5.9 has two rows marked for each outage. The row without the suffix SCOPF gives the output of generators, when the line goes out and the system is not secure. The second row with suffix SCOPF gives the generation, when system is secure for that particular contingency. Line 9 connecting bus 14 and 4 is considered for a line outage. When line 9 goes out of service, line 13 connecting bus 11 and 6 gets overloaded to 110.5 percent. After the system is made secure from this outage, then if the same outage takes place, there will be no over loading. The overloading in line 13 has reduced from 110 percent to 100 percent and the fuel cost increased from 61857 $hr to 61898 $/hr as given in Table 5.9. During outage of line 19 connecting bus 13 and 10, loading of line 13 connecting bus 11 and 6 and line 18 connecting bus 11 and 6 becomes 113 and 107 percent respectively. After the system is made secure from this contingency, the loading of line 13 and line 18 reduces to 100 and 95.2 percent respectively and the fuel cost increases from 61846 $/hr to 61846 $/hr as given in Table 5.9. During outage of line 23 connecting

bus 14 and 13, line 13 and 18 gets overloaded to 130 and 101 percent respectively, after generation is rescheduled to make the system secure the loading on line 13 and 18 becomes 100 and 78 percent respectively. During outage of line 28 connecting buses 21 and 16, line 38 gets overloaded to 117.9 percent. When the line 23 connecting bus 14 and 13 goes out of service, the price in the non-secure contingency case increases from 61857 \$/hr to 62115 \$/hr for a secure contingency case. The results are obtained using Matlab and later on verified using PowerWorld Simulator. Table 5.8 gives the overloading of lines of every single line outage discussed earlier.

Table 5.9 Contingency constrained generation for single line outages of 39-bus system

Line Outage	G^*_{30}	G^*_{31}	G^*_{32}	G^*_{33}	G^*_{34}	G^*_{35}	G^*_{36}	G^*_{37}	G^*_{38}	G^*_{39}	Total Cost**
14-4	240	562	634	640	520	660	570	550	870	952	61857
14-4 (SCOPF)	240	590	582	632	510	650	560	560	880	991	61898
13-10	240	562	634	640	520	660	570	550	870	952	61846
13-10(SCOPF)	240	578	559	650	520	660	576	560	880	971	61924
14-13	240	562	634	640	520	660	570	550	870	952	61857
14-13(SCOPF)	250	569	487	660	530	670	590	570	890	981	62115
21-16	240	565	634	640	520	660	570	550	870	952	61907
21-16(SCOPF)	245	567	651	660	530	602	520	560	890	971	61939

** \$/hr.
* MW

5.7 Conclusion

The chapter has discussed the optimal power flow and security constrained optimal power flow application to 7-bus and 39-bus power system. A nonlinear programming based optimization technique has been used to solve OPF and SCOPF problems. During OPF operation, the fuel cost of the power system is greater than during Economic Dispatch settings. Thermal limits may be violated in economic dispatch but these limits are enforced during OPF operation. During SCOPF settings, the fuel cost is even greater than OPF operation, as the power system is secure, if a contingency occurs. SCOPF forces the system to operate in both economic and secure state. SCOPF problems pose more computational burden than OPF and Economic Dispatch applications. The time taken for optimizing the system from security constrained generation aspect using Matlab as a programming tool depends upon the size of the system and may take from few minutes to hours. In this study, the 39-bus system took approximately 2 hours on a 1.7 GHz processor; this was one of the reasons for limiting the study up to 39-bus system only.

Chapter 6

Conclusion and Future Work

6.1 Summary of the Research and Contribution of the Thesis

Application of DC power flow based methods for calculating the severity of the outage during a contingency is considered in this thesis. DC load flow and Linear Sensitivity factors method are evaluated from the aspect of real power flow violations and the results obtained are compared with complete AC power flow solution. Performance index is calculated using AC power flow solution and then compared with performance index calculated using DC power flow based methods. The results show that DC power flow bases methods can be used to estimate the severity of an outage in a power system with less computational burden.

A sensitivity analysis based approach is used to calculate voltages during contingences and the results are compared with those calculated using full AC power flow solution. Time is a very important factor during contingency analysis and DC power flow and sensitivity analysis based methods can be very helpful in predicting contingency results in a shorter time. Due to practical limitations involving analysis of large power system, only a part of the system called the internal system is considered and the remainder of the system called external system is represented by a network equivalent of that part of the system. This technique is called network reduction and is used to analyze the part of interest in a power system with reasonable accuracy and computational efficiency.

Application of optimization techniques to reschedule the generation to minimize the system cost while ensuring security is implemented and presented in this thesis. The optimization method presented in this thesis has been successful in achieving generation from security aspect. The optimization methods enable the power system to be operated in such a way that a single line outage does not cause any violation.

All the applications discussed above can be helpful for a power system utility in real time operation for taking a corrective action to avoid violations. Linear contingency analysis methods can be used for predicting thermal overloads and sensitivity analysis method can be used for detecting voltage violations. SCOPF can be used to reschedule the generation to make the system secure, if a contingency takes place.

6.2 Scope of the Future Work

Optimal power flow in all its forms has enormous scope and potential for online applications. Parallel developments are occurring in the operation and planning fields. Online optimal power flow is the application area, where a lot of work needs to be done in terms of reducing the computational burden and improving efficiency. The active power problem, which is discussed in this thesis, is still tractable but the reactive power problem related to voltage magnitude is still a great challenge. Voltage/VAR constraints are especially important because they still restrict the economic transmission of active power.

The other major issue is, how effectively security constrained OPF can be applied to the interconnected power system, like an individual utility or a sub-area of the utility. Substantial progress has been made in modeling operational and security considerations in a realistic manner but a great deal of more work is needed in implementing OPF based modeling that will lead to specific stand alone OPF packages.

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Appendix A :Data of the 7-Bus Power System

Appendix A contains the information of the 7-bus power system used as a case study in the thesis. The generation and line characteristics are shown in Table A.1 and Table A.2 respectively. Single line diagram of the 7-bus system is shown in fig. A.1.

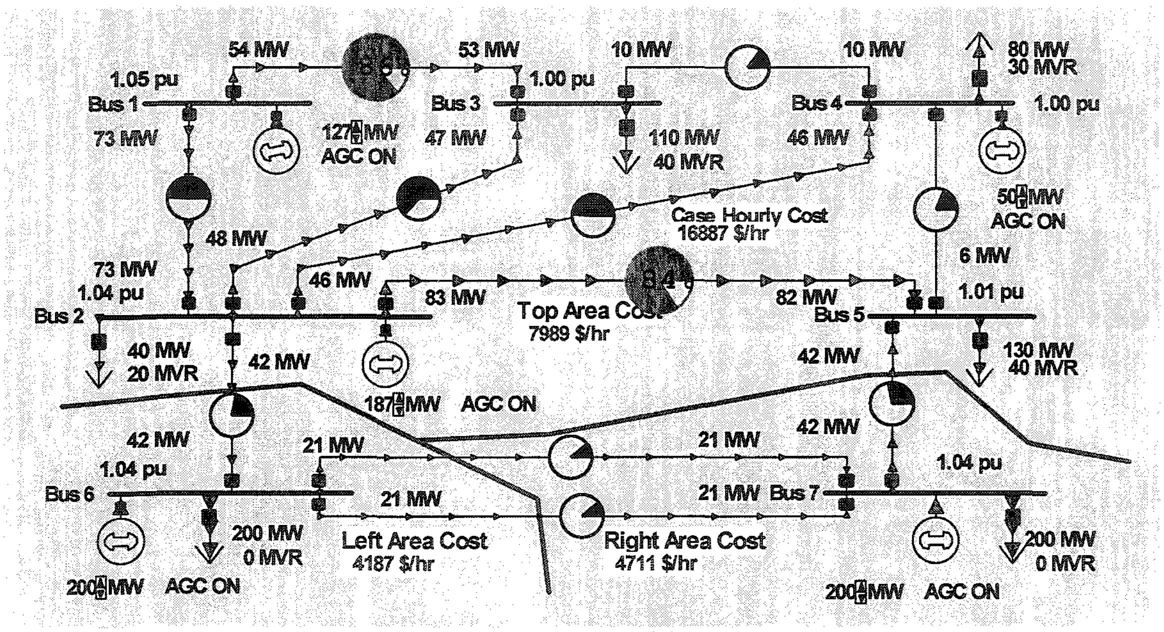

Fig. A.1 Single line diagram of the 7-bus system

Table A.1 Generation details of the 7-bus system

Bus	Generation		Limits (MW)	
			Min.	Max.
1	127.48 MW	18.02 Mvar	100	400
2	187 MW	46 Mvar	150	500
4	50 MW	14 Mvar	50	200
6	200 MW	-6 Mvar	150	500
7	200 MW	38 Mvar	0	600

Table A.2 Line characteristics of the 7-bus power system

Line No.	From Bus	To Bus	Resistance (p.u.)	Reactance (p.u.)	Line Charging (p.u)	Line Limit (MVA)
1	1	2	0.01000	0.06000	0.06000	150.0
2	1	3	0.04000	0.24000	0.05000	65.0
3	2	3	0.03000	0.18000	0.04000	80.0
4	2	4	0.03000	0.18000	0.04000	100.0
5	2	5	0.02000	0.12000	0.03000	100.0
6	2	6	0.01000	0.06000	0.05000	200.0
7	3	4	0.00500	0.03000	0.02000	100.0
8	4	5	0.04000	0.24000	0.05000	60.0
9	7	5	0.01000	0.06000	0.04000	200.0
10	6	7	0.04000	0.24000	0.05000	200.0
11	6	7	0.04000	0.24000	0.05000	200.0

Appendix B: Data of the 39-bus Power System

Appendix B contains the data of the 39-bus power system. The generation and line characteristics of the system are given in Table B.1 and Table B.2 respectively.

Table B.1 Generation details of the 39-bus power system

Bus	Generation		Limits	
	MW	Mvar	Min.(MW)	Max.(MW)
1	0.27	-281.53	0.00	10000.00
30	250	192.38	0.00	10000.00
31	572	212.55	0.00	10000.00
32	650	211.98	0.00	10000.00
33	632	113.43	0.00	10000.00
34	508	169.07	0.00	10000.00
35	650	216.16	0.00	10000.00
36	560	103.30	0.00	10000.00
37	540	25.15	0.00	10000.00
38	830	30.22	0.00	10000.00
39	1000	286.53	0.00	10000.00

Table B.2 Line characteristics of the 39-bus power system

Line No.	From Bus	To Bus	Resistance (p.u.)	Reactance (p.u.)	Line Charging (p.u)	Line Limit (MVA)
1	2	1	0.0035	0.0411	0.6987	600
2	39	1	0.0010	0.0250	0.7500	1000
3	3	2	0.0013	0.0151	0.2572	500
4	25	2	0.0070	0.0086	0.1460	500
5	2	30	0.0000	0.0181	0.0000	500
6	4	3	0.0013	0.0213	0.2214	500
7	18	3	0.0011	0.0133	0.2138	500
8	5	4	0.0008	0.0128	0.1342	600
9	14	4	0.0008	0.0129	0.1382	500
10	6	5	0.0002	0.0026	0.0434	1200
11	8	5	0.0008	0.0112	0.1476	900
12	7	6	0.0006	0.0092	0.1130	900
13	11	6	0.0007	0.0082	0.1389	480
14	6	31	0.0000	0.0250	0.0000	2500
15	8	7	0.0004	0.0046	0.0780	900
16	9	8	0.0023	0.0363	0.3804	900
17	39	9	0.0010	0.0250	1.2000	900
18	11	10	0.0004	0.0043	0.0729	600
19	13	10	0.0004	0.0043	0.0729	600
20	10	32	0.0000	0.0200	0.0000	2500
21	12	11	0.0016	0.0435	0.0000	500
22	12	13	0.0016	0.0435	0.0000	500
23	14	13	0.0009	0.0101	0.1723	600
24	15	14	0.0018	0.0217	0.3660	600
25	16	15	0.0009	0.0094	0.1710	600
26	17	16	0.0007	0.0089	0.1342	600
27	19	16	0.0016	0.0195	0.3040	2500
28	21	16	0.0008	0.0135	0.2548	600
29	24	16	0.0003	0.0059	0.0680	600
30	18	17	0.0007	0.0082	0.1319	600
31	27	17	0.0013	0.0173	0.3216	600
32	19	20	0.0007	0.0138	0.0000	2500
33	19	33	0.0007	0.0142	0.0000	2500
34	20	34	0.0009	0.0180	0.0000	2500
35	22	21	0.0008	0.0140	0.2565	900
36	23	22	0.0006	0.0096	0.1846	600
37	22	35	0.0000	0.0143	0.0000	2500

38	24	23	0.0022	0.0350	0.3610	600
39	23	36	0.0005	0.0272	0.0000	2500
40	26	25	0.0032	0.0323	0.5130	600
41	25	37	0.0006	0.0232	0.0000	1000
42	27	26	0.0014	0.0147	0.2396	600
43	28	26	0.0040	0.0474	0.7802	600
44	29	26	0.0057	0.0625	1.0290	600
45	29	28	0.0014	0.0151	0.2490	600
46	29	38	0.0008	0.0156	0.0000	2500

Appendix C : Data of the Newfoundland Hydro System

Appendix C contains the data of the 95-bus Newfoundland Hydro system used in thesis. Table C.1 gives the generation details and Table C.2 gives the lines characteristics of the system.

Table C.1 Generation details of the Newfoundland Hydro system

Bus	Generation		Limits	
	MW	Mvar	Min.(MW)	Max.(MW)
103	0.73	-39.36	0.00	10000.00
105	18.0	2.53	0.00	10000.00
109	79.10	27.97	0.00	10000.00
137	63.50	16.19	0.00	10000.00
138	63.50	16.21	0.00	10000.00
209	0.00	23.78	0.00	10000.00
220	308.9	22.70	0.00	10000.00
237	0.00	28.00	0.00	10000.00
250	75.00	6.97	0.00	10000.00
284	8.00	2.94	0.00	10000.00
406	84.00	7.46	0.00	10000.00
434	161.50	61.56	0.00	10000.00
435	161.50	49.97	0.00	10000.00
436	142.00	54.81	0.00	10000.00
871	17.86	-2.39	0.00	10000.00
2201	61.34	4.60	0.00	10000.00
2207	126.09	9.81	0.00	10000.00

Table C.2 Line characteristics of the Newfoundland Hydro system

Line No.	From Bus	To Bus	Resistance (p.u.)	Reactance (p.u.)	Line Charging (p.u)	Line Limit (MVA)
1	0111	103	0.01257	0.32976	0.00000	42.0
2	103	319	0.00689	0.01445	0.00022	30.0
3	106	105	0.02203	0.30100	0.00000	28.0
4	106	110	0.14048	0.50430	0.00910	42.0
5	106	152	0.00696	0.04899	0.00079	61.0
6	106	152	0.00696	0.04899	0.00079	61.0
7	108	114	0.04757	0.17582	0.00318	42.0
8	108	152	0.01874	0.06726	0.00122	42.0
9	110	109	0.00100	0.73520	0.00000	13.0
10	110	109	0.00100	0.73520	0.00000	13.0
11	110	109	0.00100	0.73520	0.00000	13.0
12	110	109	0.00100	0.73520	0.00000	13.0
13	110	109	0.00100	0.73520	0.00000	13.0
14	110	109	0.00100	0.73520	0.00000	13.0
15	110	109	0.00100	0.73520	0.00000	13.0
16	110	114	0.05970	0.21130	0.00290	42.0
17	110	319	0.00773	0.01622	0.00025	30.0
18	135	111	0.00440	0.14504	0.00000	75.0
19	111	212	0.02930	0.06812	0.01645	63.0
20	112	113	0.03384	0.08697	0.01898	52.0
21	112	212	0.06591	0.17612	0.03621	52.0
22	113	219	0.02062	0.04880	0.01138	63.0
23	208	115	0.00830	0.20780	0.00000	67.0
24	208	115	0.00300	0.11730	0.00000	125.0
25	135	136	0.01180	0.11304	0.22178	247.0
26	135	208	0.00533	0.05086	0.09929	247.0
27	136	137	0.00527	0.16320	0.00000	80.0
28	136	138	0.00522	0.16325	0.00000	80.0
29	215	151	0.00643	0.22270	0.00000	67.0
30	151	870	0.21967	0.49235	0.00671	30.0
31	208	152	0.00210	0.12130	0.00000	125.0
32	205	203	0.01059	0.21975	0.00000	42.0
33	206	204	0.00696	0.22440	0.00000	67.0
34	204	209	0.00839	0.21673	0.00000	75.0
35	205	206	0.00289	0.01973	0.03736	199.0
36	205	208	0.00947	0.05345	0.09554	175.0
37	205	215	0.01853	0.12665	0.24123	199.0

38	205	603	0.00742	0.21907	0.00000	42.0
39	206	260	0.00012	0.00080	0.00147	199.0
40	208	215	0.01843	0.08287	0.14611	154.0
41	212	213	0.00952	0.03840	0.00972	89.0
42	213	250	0.00612	0.14830	0.00000	69.0
43	213	250	0.00599	0.14970	0.00000	69.0
44	215	216	0.01422	0.08037	0.14392	175.0
45	215	216	0.00787	0.07653	0.15456	249.0
46	216	217	0.00200	0.07370	0.00000	125.0
47	216	217	0.00190	0.07460	0.00000	125.0
48	216	221	0.00979	0.09615	0.18920	249.0
49	216	221	0.00981	0.09642	0.18972	249.0
50	216	261	0.00011	0.00062	0.00103	175.0
51	217	219	0.08914	0.21141	0.04943	63.0
52	217	296	0.04619	0.15817	0.03923	80.0
53	217	326	0.00804	0.02647	0.00678	140.0
54	217	341	0.01234	0.04111	0.01025	140.0
55	221	220	0.00466	0.16710	0.00000	88.0
56	221	220	0.00455	0.16447	0.00000	88.0
57	221	220	0.00527	0.16976	0.00000	88.0
58	221	220	0.00461	0.16634	0.00000	88.0
59	221	220	0.00451	0.16230	0.00000	88.0
60	221	222	0.01946	0.13391	0.24752	199.0
61	221	222	0.01948	0.13407	0.24781	199.0
62	240	221	0.02689	0.63613	0.00000	25.0
63	240	221	0.02373	0.64087	0.00000	25.0
64	221	405	0.00482	0.04713	0.09394	249.0
65	221	2201	0.00450	0.16713	0.00000	88.0
66	221	2207	0.00196	0.08130	0.00000	172.0
67	222	223	0.00198	0.07437	0.00000	125.0
68	222	223	0.00200	0.07438	0.00000	125.0
69	222	227	0.00092	0.00632	0.01165	356.0
70	222	229	0.00850	0.04238	0.07761	154.0
71	223	232	0.06478	0.15548	0.03518	63.0
72	223	301	0.01228	0.04093	0.01021	140.0
73	223	306	0.02646	0.08819	0.02200	140.0
74	223	371	0.09737	0.39585	0.10089	89.0
75	224	225	0.03688	0.08916	0.01989	63.0
76	224	232	0.05391	0.13015	0.02915	63.0
77	225	359	0.00411	0.01369	0.00342	140.0
78	227	228	0.01034	0.28310	0.00000	50.0
79	227	229	0.00748	0.04282	0.07818	356.0
80	227	428	0.01056	0.28300	0.00000	50.0
81	229	230	0.00202	0.01391	0.02568	199.0

82	229	234	0.01077	0.07231	0.13327	199.0
83	229	236	0.01346	0.07696	0.14065	175.0
84	229	311	0.01067	0.21855	0.00000	42.0
85	229	311	0.01053	0.21975	0.00000	42.0
86	229	311	0.00164	0.07505	0.00000	125.0
87	229	336	0.02853	0.54993	0.00000	25.0
88	229	336	0.02928	0.53990	0.00000	25.0
89	230	231	0.00491	0.17613	0.00000	83.0
90	232	282	0.07662	0.76615	0.00000	15.0
91	234	236	0.00215	0.02441	0.05052	275.0
92	234	238	0.00513	0.03480	0.06605	199.0
93	337	234	0.02440	0.61620	0.00000	25.0
94	337	234	0.02373	0.63287	0.00000	25.0
95	234	338	0.01181	0.21837	0.00000	42.0
96	234	338	0.01053	0.21975	0.00000	42.0
97	234	338	0.00163	0.07492	0.00000	125.0
98	234	434	0.00130	0.07443	0.00000	180.0
99	234	435	0.00191	0.08389	0.00000	190.0
100	234	436	0.00229	0.07997	0.00000	170.0
101	236	238	0.00145	0.00955	0.01929	199.0
102	236	335	0.00790	0.20730	0.00000	67.0
103	236	335	0.00730	0.22800	0.00000	67.0
104	236	335	0.00824	0.21110	0.00000	67.0
105	236	335	0.00310	0.11729	0.00000	125.0
106	335	237	0.00867	0.22094	0.00000	75.0
107	238	334	0.00650	0.22120	0.00000	67.0
108	238	334	0.00175	0.12026	0.00000	125.0
109	238	334	0.00313	0.11636	0.00000	125.0
110	282	283	0.32998	1.03550	0.00047	16.0
112	283	284	0.05022	0.85686	0.00000	10.0
113	296	315	0.01808	0.06206	0.01525	80.0
114	301	306	0.01395	0.04647	0.01159	140.0
115	304	305	0.03146	0.10485	0.02615	112.0
116	304	315	0.00462	0.01556	0.00380	140.0
117	305	320	0.01357	0.04522	0.01128	140.0
118	306	860	0.01769	0.05895	0.01471	140.0
119	310	311	0.01066	0.03512	0.00896	140.0
120	310	357	0.01943	0.06406	0.01634	140.0
121	315	341	0.06206	0.20681	0.05159	140.0
122	320	321	0.01509	0.05028	0.01254	140.0
123	321	863	0.00736	0.02453	0.00612	140.0
124	322	323	0.00265	0.00884	0.00221	140.0
125	322	860	0.00769	0.02562	0.00639	140.0
126	322	863	0.00491	0.01635	0.00408	140.0

127	326	341	0.01073	0.03546	0.00901	140.0
128	335	349	0.02624	0.07728	0.00145	60.0
129	335	349	0.02240	0.08061	0.00148	74.0
130	337	345	0.00268	0.00750	0.00014	67.0
131	338	340	0.00925	0.03084	0.00769	140.0
132	340	354	0.01120	0.03710	0.00937	140.0
133	345	347	0.02760	0.03046	0.00043	33.0
134	347	348	0.02310	0.07895	0.00143	74.0
135	348	349	0.02852	0.09744	0.00176	74.0
136	353	354	0.00514	0.01696	0.00433	140.0
137	353	357	0.00652	0.02148	0.00548	140.0
138	359	371	0.00971	0.03234	0.00807	140.0
139	405	406	0.00318	0.15270	0.00000	88.0
140	870	871	0.01570	0.34690	0.00000	17.0