AN APPROACH TO SECURITY EVALUATION OF COMPOSITE POWER SYSTEMS

A Thesis
Submitted to the College of Graduate Studies and Research
in Partial Fulfillment of the Requirements
for the Degree of
Master of Science

in the
Department of Electrical Engineering
University of Saskatchewan

by
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Saskatoon, Saskatchewan
March 1993

"The tears trickle from the eyes, and the heart is full of sorrow, but we say only that which may please our Lord. We are indeed grieved, O Abdulrahman, by the passing away."

Saleh Abdulrahman Aboreshaid

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UNIVERSITY OF SASKATCHEWAN

DEPARTMENT OF ELECTRICAL ENGINEERING

CERTIFICATION OF THESIS WORK

We, the undersigned, certify that Mr. Saleh Aboreshaid, candidate for the Degree of Master of Science in Electrical Engineering, has presented his thesis on the subject An Approach to Security Evaluation of Composite Power Systems that this thesis is acceptable in form and content, and that this student demonstrated a satisfactory knowledge of the field covered by his thesis in an oral examination held on March 26, 1993.

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ACKNOWLEDGEMENTS

The author would like to extend his appreciation, gratitude and sincere thanks to Dr. Roy Billinton, his supervisor, for the guidance and consistent encouragement provided during the course of this research work.

This work was financed by the Government of Saudi Arabia in the form of a scholarship. This financial support is thankfully acknowledged.

Finally, special thanks to my wife, Munerah, my mother, Zainab, my brothers, Soliman, Amro, Faisal and Ahmad, my sisters, Luluah, Jamilah and Manal, and my brothers-in-law, Ibrahim and Ali, for their patience, constant encouragement and moral support during the study.

UNIVERSITY OF SASKATCHEWAN
Electrical Engineering Abstract No. 93A374

AN APPROACH TO SECURITY EVALUATION OF COMPOSITE POWER SYSTEMS

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M.Sc. Thesis Presented to the
College of Graduate Studies and Research

March 1993

ABSTRACT

A bulk electric power system is composed of generating units, transmission lines, transformers and loads. The complexity varies from one system to another, but the associated technical problems are basically the same. It is not uncommon to find power systems which have more than ten thousand buses. As a rule of thumb, about one fourth of these buses will have generators connected to them. A typical planning procedure involves examining the adequacy of the transmission and generating capacities by testing the ability of the system to supply the load demand under specified contingencies. The planner usually studies the stability of the system for a set of disturbances such as a three phase fault near a generation bus. This planning procedure does not account for the probabilistic or stochastic nature of system behavior, of customer demands or of component failure. The need for probabilistic evaluation of system behavior has been recognized for some time and techniques are slowly being developed.

There is a considerable interest in the application of probability techniques in quantitative evaluation of power system reliability. Probability methods are being used extensively in the area of static adequacy assessment, however, their application to power system security evaluation have not received the same degree of attention. In this thesis, an approach to security evaluation of a composite power system is proposed. This approach incorporates both steady state and transient state considerations in the reliability evaluation of composite power systems.

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LIST OF ABBREVIATIONS

ACLF	ac Load Flow
ADLC	Average Duration of Load Curtailment per Load Point
AEC	Average Energy Curtailment Per Load Point
ALC	Average Load Curtailment Per Load Point
ANLC	Average Number of Load Curtailments Per Load Point
ANVV	Average Number of Voltage Violations Per Load Point
BPII	Bulk Power Interruption Index
BPECI	Bulk Power Energy Curtailment Index
BPSAMC	Bulk Power Supply Average MW Curtailed
BPSD	Bulk Power Supply Disturbance
CSOSR	Composite System Operating State Risk
DCLF	dc Load Flow
EDLC	Expected Duration of Load Curtailment
EENS	Expected Energy Not Supplied
ELC	Expected Load Curtailments
ENVV	Expected Number of Voltage Violations
ENLC	Expected Number of Load Curtailments
HLI	Hierarchical Level One
HLII	Hierarchical Level Two
HLIII	Hierarchical Level Three
LOLE	Loss of Load Expectation

MDLC	Maximum Duration of Load Curtailment in Hours
MEC	Maximum Energy Curtailed in MWh
MLC	Maximum Load Curtailed in MW
MSEC	Maximum System Energy Curtailed in MWh
MSLC	Maximum System Load Curtailed in MW
MBPECI	Modified Bulk Power Energy Curtailment Index
MRBTS	Modified Roy Billinton Test System
NF	Network Flow
RBTS	Roy Billinton Test System
SM	Sherman-Morrison

1. POWER SYSTEM RELIABILITY CONCEPTS

1.1. Introduction

The fundamental objective of an electric power system is to supply its customers with electric energy as economically as possible and with a reasonable assurance of continuity and quality. The increased dependence of modern societies on electric energy has led to the recognition of the need for both high reliability of service and for methods of assessing and improving power system reliability. It is impossible to attain a system reliability of one hundred percent, regardless of the amount of time, effort and money spent. Power system designers, planners and scientists have, therefore, always directed their efforts towards achieving the maximum possible system reliability at an affordable cost.

In General, the term *reliability* can be defined as a measure of the overall ability of a system to perform its particular function. The term reliability, however, has a wide range of meaning when applied to power systems. A simple but reasonable subdivision of system reliability is shown in Figure 1.1. This figure represents the two basic aspects of power system reliability, system *adequacy* and system *security* .

System adequacy relates to the existence of sufficient facilities within the system to satisfy the consumer load demand. These include the necessary facilities to generate sufficient energy and the associated facilities to transmit and distribute this energy to the different customer load points. System adequacy, therefore, is associated with the static conditions which do not include system disturbances.

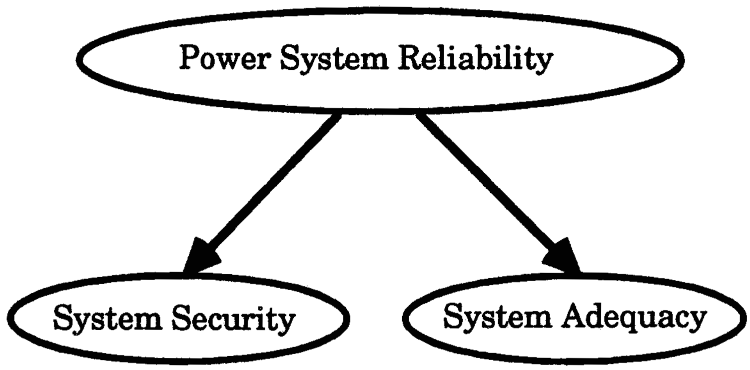

Figure 1.1: Subdivisions of power system reliability

System security, on the other hand, relates to the ability of a system to respond to disturbances and perturbations arising within that system. System security, therefore, involves the dynamic behavior of the system and may require dynamic studies such as transient and voltage stability analysis which involves detailed modeling of the power system control and protection equipment.

It is clear that adequacy assessment and security analysis deal with quite different reliability issues and involve different assessment techniques. It is important to realize that most of the probabilistic techniques presently available are in the domain of adequacy assessment [1-4]. The work described in this thesis is related to the area of power system security analysis.

The evaluation techniques used in reliability analysis of power systems can be categorized in terms of their application to three basic segments of a complete power system. These segments are the functional zones of generation, transmission and distribution. Functional zones can be combined to create *Hierarchical Levels* (HL). The hierarchical levels created can be used in the evaluation of power system reliability. Figure 1.2 shows the different functional zones and the hierarchical level structure.

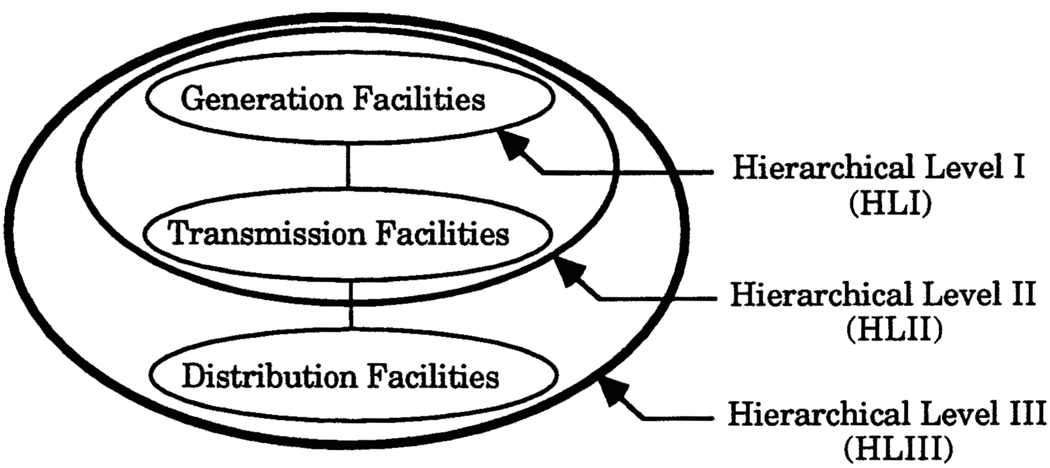

Figure 1.2: Power system functional zones and hierarchical level structure

Hierarchical level I (HLI) is concerned with only the generation facilities. In HLI, the reliability of the transmission and its ability to transfer the energy to different system load points is ignored. The system in this case is represented by a one single bus which has both the total system generation and the total system load connected to it. The objective of HLI evaluation is to the assess of the ability of the total system generation to meet the total system load demand. In HLII studies, the simple generation-load model is extended to include the transmission facilities. The objective of HLII assessment is to evaluate the ability of the composite generation and transmission system to satisfy the load demand at the major load points. HLIII studies are concerned with the overall assessment of the three functional zones. HLIII reliability indices assess the ability of the entire power system to serve the actual customers

1.2. Composite Power System Reliability Assessment

A composite or bulk power system contains two basic component types: generating units and link elements which could be either transformers or transmission lines. Reliability assessment of composite power systems is a complex task and the computation time required in the analysis can be quite significant. This is due to the large number of contingencies which must be considered and the associated computer simulation routines such as load flow and transient stability. The available programs [1-4] for composite power system reliability evaluation are generally based on one of two approaches: the analytical or enumeration technique and the Monte Carlo simulation method. Only the enumeration technique will be considered in this thesis. Irrespective of the approach, the general composite power system evaluation procedure consists of determining:

1. contingencies that cause limit violation(s) and
2. the associated limit violation(s).

Operating power systems can face a wide range of system problems. Figure 1.3 presents the major system problem categories. Circuit overloads and abnormal voltages can be corrected by remedial action(s) such as generation rescheduling and load shedding. These kinds of disturbances contribute to both the adequacy and the security indices. Contingency testing for these categories can be done with steady state analysis tools such as load flow as discussed in Chapter 2. Instability and voltage collapse problems may lead to shutdown of some segments of the system. The outcome of such problems depends on the system dynamic behavior. These types of disturbances contribute only to the security indices.

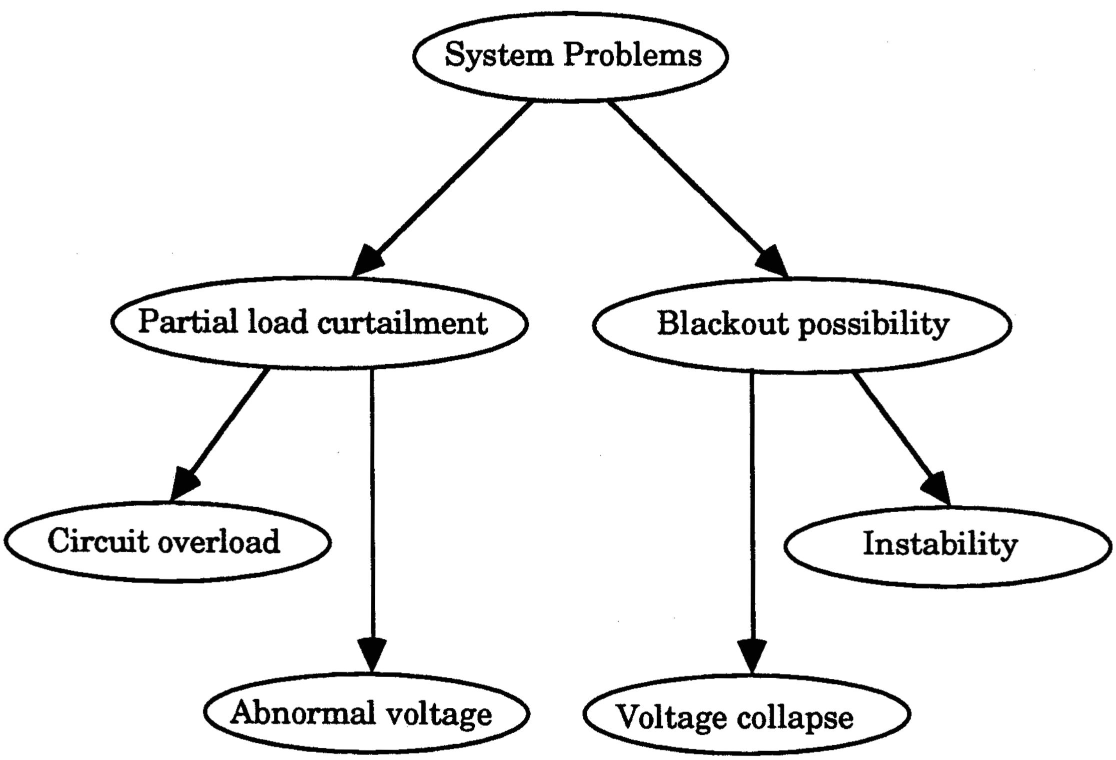

Figure 1.3: Causes and results of system problems

1.3. Composite Power System Security Evaluation

Most of the research done in composite power system reliability evaluation is in the field of adequacy assessment [1-4]. The area of security evaluation has not received the same degree of attention and there is no unanimity in regard to appropriate techniques or criteria. There are two major problems associated with incorporating transient behavior in power system reliability analysis. The first problem is the extensive CPU time required for the analysis. This is due to the large number of stability analyses required in a practical system. The second obstacle is that there are no adequate simplified criteria to decide which situations are transiently dangerous [5,6,7]. Security indices expressed in probabilistic terms are still undeveloped [5,6]. This thesis examines this problem and proposes an approach to incorporating quantitative security assessment into the power system reliability framework.

1.4. Scope and Objective of the Thesis

The work described in this thesis is concerned with composite system (or HLII) security evaluation. This assessment includes testing the ability of a system to respond to disturbances and perturbations arising within that system. This involves examining the steady state performance of the system, and simulating the transient behavior of the system. A direct approach to this problem requires a full ac load flow analysis and a transient stability analysis for each contingency, followed by a check for limit violations. A framework for incorporating security considerations is proposed in Reference [8]. and extended in Reference [9]. In this thesis, the modified framework is extended to include the transient behavior of the system under study.

As noted earlier, the basic approaches in composite system reliability analysis are: the contingency enumeration method and the Monte Carlo method. The contingency enumeration approach, which utilizes a selection algorithm, is used in this thesis to quantify the different system operating states indices. If, in the course of examining each contingency, a line is found to be overloaded, a voltage deviation problem is detected or a transient problem is found, then corrective action is taken without any load curtailment if possible. If load curtailment is needed, linear programming methods are utilized to perform this function.

The basic objective of this research work was to develop a comprehensive technique for quantifying the various system states associated with recognizing power system security considerations in the reliability evaluation of a composite power system.

1.5. Thesis Outline

Following the introduction in Chapter 1, Chapter 2 mainly describes the adequacy evaluation methodology used in a digital computer program COMREL (COMposite systems RELiability evaluation) developed by the Power System Research Group at the University of Saskatchewan. COMREL utilizes the contingency enumeration approach to evaluate the adequacy of composite power systems. Chapter 2 contains a complete detailed review of the network solution techniques, state space modeling of the system components and the adequacy indices. A brief description of the Roy Billinton Test System (RBTS) [10] is presented. The computer program COMREL is utilized to compute the composite system adequacy indices for the RBTS.

Chapter 3 concentrates on studying security constrained adequacy in composite power systems. The security constraint set developed by Billinton and Khan [11] is used to quantify different system operating states. The existing security constraint set [11] contains only steady state constraints. The application of this method is illustrated in this chapter using the RBTS.

In Chapter 4, a review of transient stability solution techniques is briefly presented and the probabilistic aspects of transient stability discussed. In this chapter, the concept of quantifying transient performance in composite power systems is presented and the analytical evaluation procedures proposed by Billinton and Kuruganty [5,6] are implemented. A digital computer program has been developed and used to assess transient performance of electric power systems. This program has been used to evaluate the transient performance of the RBTS and the results are presented in this chapter.

The basic objective of this research work is realized in Chapter 5, in which a new constraint set called the *"transient constraint set"* is developed and used together with the existing steady state constraint set to form an overall security constraint set. The overall constraint set is used in this chapter to detect different system operating states and to evaluate the security of the RBTS.

Chapter 6 illustrates an application of power system expansion planning utilizing a risk index designated as the Composite System Operating State Risk (CSOSR). The CSOSR is assessed in this chapter utilizing the comprehensive security constraint set described in Chapter 5. The application to composite generation and transmission system expansion planning is illustrated in this chapter utilizing the RBTS.

The conclusions of this thesis are presented in Chapter 7.

2. COMPOSITE POWER SYSTEM ADEQUACY EVALUATION

2.1. Introduction

Composite power system adequacy evaluation can be defined as the assessment of the ability of the generation and transmission system to supply sufficient and suitable electric energy to the major system load points. In general, the transmission system which links the generating units and the major load points can not be represented by a simple series/ parallel system and hence can not be reduced using a direct reduction technique. The contingency enumeration approach can be and has been used to evaluate the adequacy of composite power systems [12-14]. The basic procedure involves the selection and evaluation of contingencies, the classification of each contingency according to certain criteria and the accumulation of adequacy indices. The basic steps in the quantitative reliability assessment of a composite power system using the contingency enumeration approach are shown in Figure 2.1. The basic decisions [14] which have to be made regarding the procedure used for a given adequacy study are as follows:

1. selection of an appropriate network solution technique,
2. selection of an appropriate set of corrective actions,

3. selection of appropriate contingency levels for both generating unit and transmission line outages,
4. consideration of station originated and common cause outages and
5. calculation of an appropriate set of adequacy indices.

The first step in the adequacy evaluation is to select an appropriate network solution technique. There are many techniques which can be used in the analysis. The selection of a technique depends mainly on the objective of the adequacy study and the adequacy criteria used.

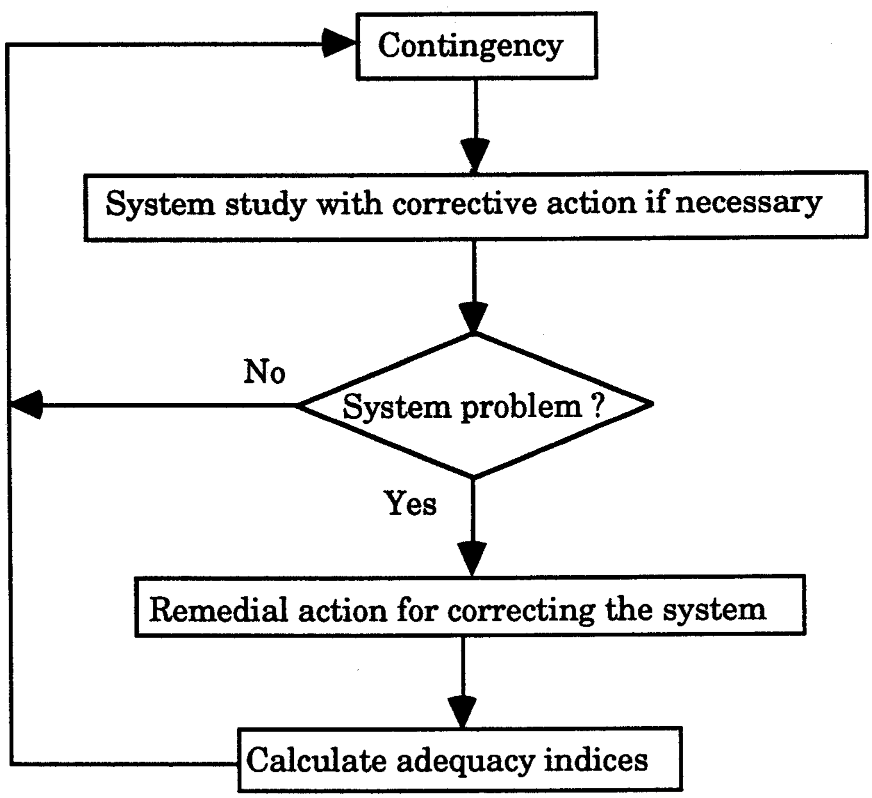

Figure 2.1: Contingency enumeration approach for composite power system adequacy evaluation

After selecting the appropriate network solution technique, it is necessary to determine the appropriate corrective actions which should be utilized. This selection should take into consideration, management, design and planning constraints. The output of the study may also have to be related to consumer expectations, the standard of living and the economic and social consequences associated with electrical supply interruptions.

It is time consuming to consider all possible contingencies in an adequacy evaluation study. In order to limit the number of contingencies, fixed or variable criteria should be considered. Fixed criteria could involve selecting a certain level of contingencies to be considered in the analysis such as second or third level contingencies. The variable criteria could be in the form of cut-off limits for frequency, probability or ranking. This chapter discusses each of the decisions which should be taken during the adequacy evaluation process and illustrates them by application to a test system.

2.2. Network Solution Techniques

The application of the contingency enumeration approach to a practical configuration requires a large number of network solutions. Depending on the adequacy criteria employed and the intent behind the study, various techniques are available to analyze the adequacy of a power system. The three main analytical techniques are:

1. network flow methods,
2. dc load flow methods and
3. ac load flow methods.

The simplest approach is to treat the system as a network flow model [15,16] in order to examine the continuity of power supply at various load centers. Approximate load flow techniques such as dc load flow are simple and fast. The major problem with dc load flow is that it does not provide an estimate of the bus voltages and the reactive power generated. If the bus voltages and/or the reactive power generated by the generating units are important concerns, then an ac load flow should be utilized [17]. The conventional load flow techniques such as Gauss-Seidel, Newton-Raphson, and second order techniques are rarely used in adequacy evaluation because of the large storage and the high computational time that they require. A "fast" ac load flow technique, such as the decoupled load flow, is often used in adequacy assessment because of its limited storage and speed requirements. The following is a brief summary of the three main network solution techniques.

2.2.1. The network flow method

The linear network flow method or transportation model is the simplest network model as the only concern is the movement of a particular commodity from a number of sources to a number of demand centers. The network flow method can be used in certain power system studies. In this case, the generator buses represent network sources and the load buses represent the demand centers (sinks). Continuity of supply at the load points and the limitations on the generated power and the transmission line carrying capabilities are the major points under investigation. The network flow model solution can be formulated either as a maximum flow or minimal cut problem or as a linear programming problem [15]. The mathematical formulation of the network flow method is as follows:

For a certain power network $G = [N ; A]$ which has only one generator bus (source) s and one load bus (sink) t, the mathematical formulation of the network flow is given by Sullivan [16].

Maximize F subject to the following two constraints

$$\sum_{j \in A(i)} f(i,j) - \sum_{j \in B(i)} f(i,j) = \begin{cases} F\ , & i = s \\ 0\ , & i \neq s, i \neq t \\ -F, & i = t \end{cases} \qquad (2.1)$$

and

$$f(i,j) \leq c(i,j) \qquad \text{for all } (i,j) \in A \qquad (2.2)$$

where:

- A is a set of arcs (transmission lines and/or transformers),
- N is a set of nodes (buses),
- $c\,(i,j)$ is the maximum load carrying capacity of the arc between nodes i and j,
- $A(i)$ is a set in which $(j \in N \mid (i\,,j) \in A)$,
- $B(i)$ is a set in which $(j \in N \mid (i\,,j) \in B)$ and
- F is the load flow from s to t.

Equation 2.1 shows that the outgoing net flow from node i is F while the outgoing net flow from node j has the same value but in a negative form and the net flow from any intermediate node is zero. Equation 2.2 shows that the flow in each arc must not exceed the maximum flow that can be carried by the arc.

In practical power systems, there is more than one generator (source) and more than one load bus (sink). The problem in this case can be solved by combining each two nodes repeatedly and finally creating a simple single generator (source) and one sink (load bus) problem. The network flow method is an approximate method that does not satisfy Kirchhoff's voltage law. It is used in certain power system reliability studies [18] because of its computational efficiency.

2.2.2. The dc load flow method

The dc load flow method is one of the most direct approaches that can be applied in power system contingency studies. Bus voltages, VAR effects and system losses are not considered in the analysis. There are three assumptions made in deriving the linear model of the load flow problem. These assumptions are:

1. the voltage magnitude at all buses is equal to unity,
2. the resistance of all lines is neglected and
3. the phase angle difference between any two buses is very small and therefore the cosine of the angle difference is ~~zero~~ 1 while the sine is equal to ~~1~~ 0.

The following is the linear model used in the approach:

$$[P] = [B][\delta] \tag{2.3}$$

where:

$[P]$	is the vector of bus power injection,
$[B]$	is the system susceptance matrix and
$[\delta]$	is the vector of bus phase angles.

The bus phase angle vector can be obtained by solving Equation 2.3. A rapid solution can be found by factoring the system susceptance matrix and hence the individual branch flow is calculated by:

$$P_{ij} = \frac{\delta_i - \delta_j}{X_{ij}} \tag{2.4}$$

where:

P_{ij}	is the power flow from bus i to bus j,
δ_i, δ_j	is the phase angle at bus i and j respectively and
X_{ij}	is the reactance between bus i and bus j.

A simple fast correction formula called the Sherman-Morrison correction formula [9] is used instead of building and factoring the susceptance matrix for each contingency.

2.2.3. The fast decoupled load flow method

The fast decoupled load flow method is a fast approximate ac load flow solution technique. The fast decoupled load flow algorithm developed by Stott and Alsac [19] is applied in evaluating the adequacy of composite power system reliability in Reference [20].

The general power mismatch for all system buses except the swing bus can be found using the following equation:

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} J_1 & J_2 \\ J_3 & J_4 \end{bmatrix} \begin{bmatrix} \Delta\delta \\ \Delta V / V \end{bmatrix} \tag{2.5}$$

where:

ΔP_i	is the active power mismatch at bus i,
ΔQ_i	is the reactive power mismatch at bus i,
J_1 - J_4	are submatrices of the Jacobian matrix,
$\Delta\delta_i$	is the increment in the phase angle of the voltage at bus i,
ΔV_i	is the increment in the magnitude of the voltage at bus i and
V_i	is the magnitude of the voltage at bus i.

The terms of the Jacobian matrix are the partial derivatives of P and Q with respect to V and δ.

The coupling between changes in real power and voltage magnitude and between changes in the reactive power and phase angle is small and ignored in the decoupled load flow approach. The following are the decoupled equations derived from Equation 2.5 by neglecting the noted weak coupling :

$$[\Delta P] = [J_1][\Delta\delta]. \tag{2.6}$$

Similarly

$$[\Delta Q] = [J_4][\Delta V / V]. \tag{2.7}$$

In practical systems, the following assumptions are valid

$cos\ (\delta_i - \delta_j) \approx 1,$

$g_{ij} \sin\ (\delta_i - \delta_j) << b_{ij}$ and

$Q_i << b_{ii} V_i^2$

where:

$g_{ij} - j\, b_{ij}$	is the series admittance between bus i and bus j,
δ_i and δ_j	are the phase angle of the voltages at bus i and j and
Q_i	is the reactive power at bus i.

Using the above assumptions, Equation 2.6 and Equation 2.7 can be simplified as follows:

$$[\Delta P] = \left[V B' V\right][\Delta\delta] \tag{2.8}$$

and

$$[\Delta Q] = \left[V B'' V\right][\Delta V / V]. \tag{2.9}$$

After making further physical justifications [19], the final decoupled load flow equations are given below:

$$[\Delta P / V] = \left[B'\right][\Delta\delta] \tag{2.10}$$

and

$$[\Delta Q / V] = \left[B''\right][\Delta V]. \tag{2.11}$$

Both matrices $[B']$ and $[B'']$ are real, sparse and contain only network suceptances. Since $[B']$ and $[B'']$ are constant, they need to be factorized only once at the beginning of the iterative process. Both voltage magnitude and phase at all load buses and voltage phase angles at generator buses except the swing bus are modified as shown below:

$$[\delta]_{new} = [\delta]_{old} + [\Delta\delta] \tag{2.12}$$

and

$$[V]_{new} = [V]_{old} + [\Delta V]. \tag{2.13}$$

Both active power mismatch matrix [ΔP] and reactive power mismatch matrix [ΔQ] are calculated for the new values of the voltages and phase angles. Equations 2.8 and 2.9 are iterated in some defined manner towards an exact solution i.e. when power mismatch is less than the tolerance. When a contingency occurs in the system, the Sherman-Morrison formula [40] can also be applied to find the new voltages and bus angles.

2.3. Sherman-Morrison Correction Formula

Instead of rebuilding and factorizing the system admittance matrix for each line and/or generator contingency, a simple fast correction formula is used to adjust the base case solution to effectively represent the line and/or generator outage. This correction formula is called the Sherman-Morrison corrective formula [9]. This formula is applicable to both the dc and the decoupled load flow solution techniques.

Using the original factorized system admittance matrix and the base case solution vector, the correction factors can be computed by one forward and backward substitution. Multiple lines and/or transformers outages can be represented by applying the formula recursively and updating the solution vector at each step.

2.3.1. Application of the correction formula to dc load flow

The base case dc load flow solution given by Equation 2.3 can be rewritten as:

$$[\delta] = [B]^{-1}[P] \tag{2.14}$$

where all the quantities given in the above equation are already defined. The outage of element l (line or transformer) connecting buses i and j can be reflected in the susceptance matrix $[B]$ by:

$$[B]_{new} = [B] + b[m][m]^t \tag{2.15}$$

where:

b is the negative line susceptance and

$[m]$ is a column vector with all elements zero except element i which is (+1) and element j which is (-1).

The Sherman-Morrison corrective formula (SM) is now applied and the following equations obtained:

$$[B]_{new}^{-1} = [B]^{-1} - c[B]^{-1}[m][m]^t[B]^{-1} \tag{2.16}$$

or

$$[B]_{new}^{-1} = [B]^{-1} - c[Z][m]^t[B]^{-1} \tag{2.17}$$

where:

$$
\begin{aligned}
[Z] &= [B]^{-1}[m], \\
c &= \left\{1/b + [m]^t [B]^{-1}[m]\right\}^{-1} \\
&= \left\{1/b + Z_i - Z_j\right\}^{-1}.
\end{aligned}
$$

From Equation 2.14 the solution to the outage problem is

$$
\begin{aligned}
[\delta]_{new} &= \left\{[B]^{-1} - c[Z][m]^t[B]^{-1}\right\}[P] \\
&= [\delta] - c[Z][m]^t[B]^{-1}[P] \\
&= [\delta] - c\left(\delta_i - \delta_j\right)[Z] \\
&= [\delta] + [\Delta\delta].
\end{aligned} \tag{2.18}
$$

Equation 2.18 can be applied recursively for multiple contingencies as follows:

$$
\begin{aligned}
[\delta_1] &= [\delta_0] - c_1[Z_1][m_1]^t[\delta_0], \\
[\delta_2] &= [\delta_1] - c_2[Z_2][m_2]^t[\delta_1], \\
[\delta_3] &= [\delta_2] - c_3[Z_3][m_3]^t[\delta 2].
\end{aligned} \tag{2.19}
$$

Where the subscripts *0,1,2,3* represent the base case, single, double and triple contingency respectively and

$$
\begin{aligned}
[Z_1] &= [B]^{-1}[m_1], \\
[Z_2] &= [B]^{-1}[m_2] - c_1[Z_1][m_1]^t[B]^{-1}[m_2], \\
&= \left\{[I] - c_2[Z_2][m_2]^t\right\}[B]^{-1}[m_2], \\
[Z_3] &= \left\{[I] - c_2[Z_2][m_2]^t\right\}\left\{[I] - c_1[Z_1][m_1]^t\right\}[B]^{-1}[m_3],
\end{aligned} \tag{2.20.a}
$$

The values c_1, c_2 and c_3 can be calculated from the following relations

$$\begin{aligned} c_1 &= \left\{1/b_1 + [m_1]^t [Z_1]\right\}^{-1}, \\ c_2 &= \left\{1/b_2 + [m_2]^t [Z_2]\right\}^{-1}, \\ c_3 &= \left\{1/b_3 + [m_3]^t [Z_3]\right\}^{-1}. \end{aligned} \tag{2.20.b}$$

2.3.2. Application of the correction formula to the decoupled load flow

Both Equations 2.10 and 2.11 can be represented in the base case problem as follows:

$$[X] = [B_0][Y_0]. \tag{2.21}$$

In the above equation, the $[Y_0]$ represents the solution vector which could be either voltage magnitude or phase angle. For a contingency on the element l (line or transformer) that connect buses i and j, the modified susceptance matrix is given by Equation 2.15 as:

$$[B_1] = [B_0] + b[m][m]^t.$$

The iterative process is repeated using the original factorized susceptance matrix with a correction to the solution vector $[Y_0]$ and at the end of each iteration a correction is done using Equation 2.19. The solution in this case is:

$$[X_1] = [X_0] - c[Z][m]^t[Y_0].$$

In the case of multi-contingency situations, the above process can be applied recursively. In a same manner, a set of equations can be derived similar to that of Equations 2.20.

2.4 State Space Models

In order to assess the probability, frequency and duration measures of system reliability, component modeling using state-transition diagrams is required [21]. The following sections illustrate the modeling of single and multiple components. Common cause and station originated outages are also presented.

2.4.1. Single component model

The basic state transition diagram for a single component is shown in Figure 2.2. In this diagram, λ and μ represent the component failure and repair rates, respectively. The usual unit of both λ and μ is $Year^{-1}$.

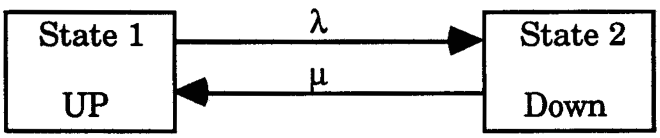

Figure 2.2: Single component two state model

The reliability measures of availability and frequency, for this model are given by [21]:

Availability or the probability of being in state 1:

$$A = \frac{\mu}{\mu + \lambda} = \frac{\mathrm{m}}{\mathrm{m} + \mathrm{r}} = P_1, \tag{2.22}$$

Unavailability or the probability of being in state 2:

$$U = \frac{\lambda}{\mu + \lambda} = \frac{\mathrm{r}}{\mathrm{m} + \mathrm{r}} = P_2, \tag{2.23}$$

Frequency of transfer from state 1 to state 2:

$$f_{12} = A \times \lambda \text{ and} \tag{2.24}$$

Frequency of transfer from state 2 to state 1:

$$f_{21} = U \times \mu, \tag{2.25}$$

where:

m is the mean in-service time and equals to $1/\lambda$,

r is the mean outage duration and equals to $1/\mu$.

The summation of the Availability and the Unavailability must equal 1 and the frequency of transferring from state 1 to state 2 (failure frequency) is equal to the frequency of transferring from state 2 to state 1 (restorative frequency). The failure and repair rates are the basic data needed to model any single component.

2.4.2. Multiple component model - Independent overlapping outages

The main assumptions in the case of independent overlapping outages are:

1- the occurrence of one outage does not affect the probability of occurrence of other outages and

2- the outage duration of any component is not affected by whether other components are in service or on outage.

The state transition diagram for two independent overlapping outages is given in Figure 2.3. Probabilities, frequencies and durations for each of the four states are given by Equations 2.26 and 2.27.

State probabilities:

$$\begin{aligned} P_1 &= A_1 A_2 = \frac{\mu_1 \mu_2}{D} , \\ P_2 &= U_1 A_2 = \frac{\lambda_1 \mu_2}{D} , \\ P_3 &= A_1 U_2 = \frac{\mu_1 \lambda_2}{D} , \\ P_4 &= U_1 U_2 = \frac{\lambda_1 \lambda_2}{D} , \end{aligned} \qquad (2.26)$$

where:

D is equal to $(\lambda_1+\mu_1)(\lambda_2+\mu_2)$,

A_i is the availability of state i and

U_i is the unavailability of state i.

State frequencies and durations:

$$
\begin{aligned}
f_1 &= P_1(\lambda_1+\lambda_2)\,, & r_1 &= \frac{P_1}{f_1} = \frac{1}{(\lambda_1+\lambda_2)}\,, \\
f_2 &= P_2(\mu_1+\lambda_2)\,, & r_2 &= \frac{P_2}{f_2} = \frac{1}{(\mu_1+\lambda_2)}\,, \\
f_3 &= P_3(\lambda_1+\mu_2)\,, & r_3 &= \frac{P_3}{f_3} = \frac{1}{(\lambda_1+\mu_2)}\,, \\
f_4 &= P_4(\mu_1+\mu_2)\,, & r_4 &= \frac{P_4}{f_4} = \frac{1}{(\mu_1+\mu_2)}\,.
\end{aligned}
\qquad (2.27)
$$

This type of model can be extended to three or more components on independent overlapping outage. The state transition diagram shown in Figure 2.3 becomes quite complex for three or more independent overlapping outages. Both Equation 2.26 and 2.27 can be easily generalized to calculate the state probabilities, frequencies and durations for more than two independent overlapping outages.

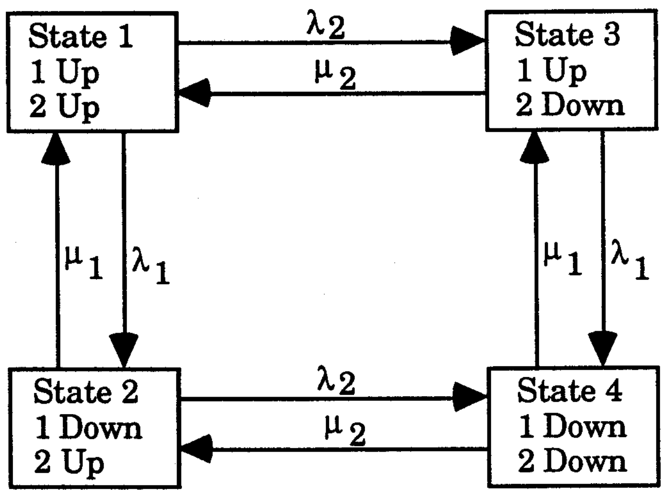

Figure 2.3: Model for two independent overlapping outages

2.4.3. Dependent outages

As the name implies, these outages are dependent on the occurrence of one or more other outages. An example is an independent outage of one line of a double circuit followed by the removal of the second line due to overload. These outages are not normally included in the reliability evaluation of composite power systems and require considerable system data in addition to the individual component data [21].

2.4.4. Common mode outages

A common mode or common cause outage is an event having an external cause with multiple failure effects where the effects are not in consequence of each other [21]. The effect of these outages can be significant compared with the effect of second level outages especially if the probability of independent outages are very low. An example of such outages is the failure of a transmission tower supporting two or more transmission circuits. Figure 2.4 shows how a common mode outage can be included in basic component modeling [21]. In Figure 2.4, λ_C and μ_C represent the common mode failure and repair rates.

2.4.5. Station originated outages

The need to include station originated outages in the evaluation of power system reliability in addition to the inclusion of independent outages of generating units, transmission lines and transformers has been clearly recognized [22,23]. Terminal station related failures such as breaker failures, station transformer failures, bus section failures and protective system failures are a major cause of multiple component outages of major components and can have a significant effect on the adequacy indices.

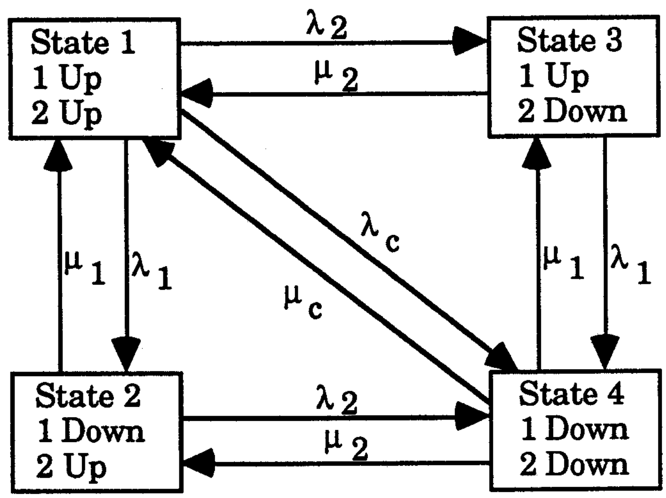

Figure 2.4: Model for common mode outage

Figure 2.5 shows a general model for common mode, independent and station originated outages. Common mode and station originated outages can have a significant effect on the calculated reliability indices. In this thesis only independent outages are considered. The effect of common mode and station originated outages can be considered using approximate methods by modifying the probabilities and frequencies of the appropriate states.

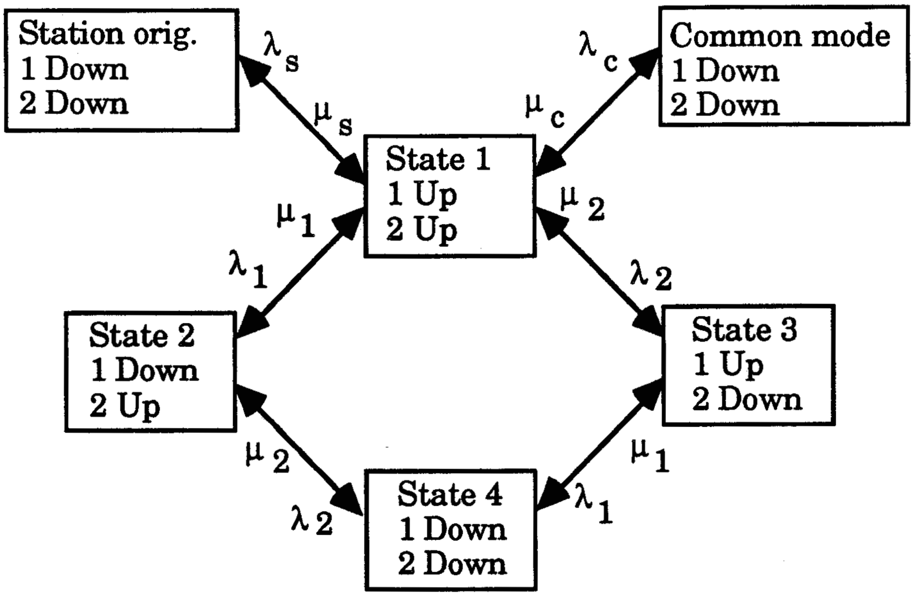

Figure 2.5: A general model for common mode, independent and station originated outages.

2.5. Corrective Actions

The occurrence of any system problem may be recorded as a failure event. However, in many cases successful corrective action can be taken. It is therefore of interest to determine whether it is possible to eliminate a system problem by using proper corrective action(s). There is no consensus among power utilities and other organizations regarding failure criteria, and therefore all organizations do not use the same fundamental solution technique to calculate the reliability for their systems [24,31]. The basic justification for these differences lies in the intent behind the adequacy studies. The experience of one organization with those factors that contribute to system failure in their case may be very different from those of other organizations. Factors such as the meteorological conditions in the region, the configuration of the network, the protection system employed, the system generation and load composition, and the dependent and independent failure and repair rates of components can assume different degrees of importance in different systems. Attention is, therefore, focused primarily on the adequacy evaluation of those outage contingencies which apparently result in failure. The validity of a particular approach may be quite justified for a particular system but may not provide suitable estimates of the adequacy of other systems. It may not therefore be possible to develop a general purpose approach because of the basic differences between power systems. It is important, however, to define a uniform failure criteria for each approach. Table 2.1 shows recommended failure criteria for the three network solution techniques described earlier. The failure criteria of both network flow and dc load flow methods are a sub set of the ac load flow failure criteria.

Table 2.1: Recommended failure criterion for different solution techniques

Network flow DC load flow AC load flow	1- Load curtailment at bus(es) due to capacity deficiency in the system. 2- Load curtailment, if necessary, at isolated bus(es). 3- Load curtailment, if necessary, at bus(es) in the network islands formed due to line outages. 4- Load curtailment at bus(es) due to line/transformer overloads.
AC load flow	5- Voltage collapse at system bus(es). 6- Generating unit MVar limits violation 7- Ill-conditioned network situations.

On the basis of the failure criteria, the broad categories of corrective actions [20,24] that can be employed are as follows:

1. Generation rescheduling in the case of capacity deficiency in the system.
2. Correction of generating unit MVAR limit violations.
3. Bus isolation and system splitting under transmission line(s) and/or transformer(s) outages.
4. Alleviation of line overloads.
5. Correction of a voltage problem at a bus and the solution of ill-conditioned network situations when using AC load flow methods.
6. Load curtailment in the event of a system problem.

A description of corrective actions and load curtailment procedures can be found in Reference [26].

2.6. Adequacy Indices

There are three basic parameters associated with each contingency studied in the calculation of system adequacy indices. These parameters are:

1. event probability,
2. event frequency and
3. event duration.

The relationship between the three parameters noted above is given by Equation 2.28.

Probability = Frequency x Duration. (2.28)

The adequacy of a composite power system can be quantified by evaluating indices for the overall system and for the individual load points [27-29]. These two index sets do not replace each other but complement each other in an overall appraisal of the system.

An outage event may affect a wide area of the system, a small group of buses or perhaps a single bus. This depends upon many factors such as the components under outage, their relative importance and location in the network, the corrective actions taken and the load curtailment strategy. The adequacy indices should focus attention on those portions of the system that are directly affected by the outage event. The total contribution of all possible contingencies should indicate those areas in the system which have low reliability and are prone to disturbances. Overall system indices can not provide such information. High level outages are also not uniformly distributed over the entire system, and therefore, a determination of individual load point indices is necessary. Further reason for having two categories of adequacy indices is that the actual variation in load at all buses may not result in a proportionate variation of the indices at each bus due to the fact that a power system is a nonlinear system. It is important to appreciate that it is not possible to draw conclusions regarding the adequacy of a particular system load point from the overall system indices.

Reference [31] describes the results of a survey which shows that there is no consensus in the industry as to which particular adequacy indices are the best. Depending on the failure criteria, it is appropriate to study a variety of indices which convey meaningful information regarding the performance of the system. A comprehensive list of adequacy indices are presented in Equations 2.29 to 2.54 [27-29].

2.6.1. Load point indices

(a) Basic values:

$$\text{Probability of failure} = \sum_{J} P_J \, P_{KJ} \tag{2.29}$$

and

$$\text{Frequency of failure} = \sum_{J} f_J \, P_{KJ} \tag{2.30}$$

where:

- J is an outage condition in the network,
- P_J is the probability of existence of the outage J,
- f_J is the frequency of occurrence of the outage J and
- P_{KJ} is the probability of the load at bus K exceeding the maximum load that can be supplied to the bus during the outage J.

$$\text{Expected number of voltage violations} = \sum_{J \in V} f_J \tag{2.31}$$

where: $J \in V$ includes all contingencies which cause voltage violation at bus K.

$$\text{Expected number of load curtailments} = \sum_{J \in X,Y} f_J \qquad (2.32)$$

where: $J \in X$ includes all contingencies resulting line overloads which are alleviated by load curtailment at bus K and $J \in Y$ includes all contingencies resulting an isolation of bus K.

$$\text{Expected load curtailments} = \sum_{J \in X,Y} L_{KJ}\, f_J \quad (MW) \qquad (2.33)$$

where: L_{KJ} is the load curtailment, in MW, at bus K to alleviate line overloads or capacity deficiency arising due to the outage J; or the load not supplied at an isolated bus K due to the outage J.

$$\text{Expected energy not supplied} = \sum_{J \in X,Y} L_{KJ}\, D_{KJ}\, f_J \quad (MWh)$$

$$= 8760.0 \sum_{J \in X,Y} L_{KJ}\, P_J \quad (MWh) \qquad (2.34)$$

where: D_{KJ} is the duration, in hours, of the load curtailment arising due to the outage J; or the duration, in hours, of the load curtailment at an isolated bus K due to the outage J.

$$\text{Expected duration of load curtailment} = \sum_{J \in X,Y} D_{KJ}\, f_J \quad (hours)$$

$$= 8760.0 \sum_{J \in X,Y} P_J \quad (hours). \qquad (2.35)$$

(b) Average values:

Average load curtailed

$$= \frac{\sum\limits_{J \in X,Y} L_{KJ}\, f_J}{\sum\limits_{J \in X,Y} f_J} \quad (MW\,/\,curtailment). \tag{2.36}$$

Average energy not supplied

$$= \frac{8760.0 \sum\limits_{J \in X,Y} L_{KJ}\, P_J}{\sum\limits_{J \in X,Y} f_J} \quad (MWh\,/\,curtailment). \tag{2.37}$$

Average duration of load curtailment

$$= \frac{\sum\limits_{J \in X,Y} D_{KJ}\, f_J}{\sum\limits_{J \in X,Y} f_J} \quad (hours\,/\,curtailment). \tag{2.38}$$

(c) Maximum values:

Maximum load curtailed in MW

$$= Max.\ (L_{K1}, L_{K2},\ldots., L_{KJ},\ldots.). \tag{2.39}$$

Maximum energy curtailed in MWh

$$= Max.\ (D_{K1}L_{K1}, D_{K2}L_{K2},\ldots., D_{KJ}L_{KJ},\ldots.). \tag{2.40}$$

Maximum duration of load curtailment in hours

$$= Max.\ (D_{K1}, D_{K2}, \ldots, D_{KJ}, \ldots). \tag{2.41}$$

2.6.2. System indices

(a) Basic values:

Bulk Power Supply Disturbance (BPSD)

$$= \sum_{K} \sum_{J \in X,Y} f_J . \tag{2.42}$$

Bulk Power Interruption Index (BPII)

$$= \frac{\sum_{K} \sum_{J \in X,Y} L_{KJ}\, f_J}{L_S} \quad (MW/MW-Year). \tag{2.43}$$

Bulk Power Supply Average MW Curtailed (BPSAMC)

$$= \frac{\sum_{K} \sum_{J \in X,Y} L_{KJ}\, f_J}{\sum_{K} \sum_{J \in X,Y} f_J} \quad (MW/Disturbance). \tag{2.44}$$

Bulk Power Energy Curtailment Index (BPECI)

$$= \frac{60.0 \sum_{K} \sum_{J \in X,Y} L_{KJ}\, D_{KJ}\, f_J}{L_S} \quad (MW-Min/MW-Year). \tag{2.45}$$

This index is also known as the "Severity Index" and is expressed in system minutes.

Modified Bulk Power Energy Curtailment Index (MBPECI)

$$= \frac{\sum_{K} \sum_{J \in X,Y} L_{KJ}\, D_{KJ}\, f_J}{8760.0 \times L_S}, \qquad (2.46)$$

where: L_S is the total system load.

(b) Average values:

Average number of load curtailments / load point (ANLC)

$$= \frac{\sum_{K} \sum_{J \in X,Y} f_J}{C}. \qquad (2.47)$$

Average load curtailed / load point (ALC)

$$= \frac{\sum_{K} \sum_{J \in X,Y} L_{KJ}\, f_J}{C} \quad (MW/Year). \qquad (2.48)$$

Average energy curtailed / load point (AEC)

$$= \frac{\sum_{K} \sum_{J \in X,Y} L_{KJ}\, D_{KJ}\, f_J}{C} \quad (MWh/Year). \qquad (2.49)$$

Average duration of load curtailment / load point (ADLC)

$$= \frac{\sum_{K} \sum_{J \in X,Y} D_{KJ}}{C} \quad (hours / Year). \tag{2.50}$$

Average number of voltage violations / load point (ANVV)

$$= \frac{\sum_{K} \sum_{J \in V} f_{J}}{C}, \tag{2.51}$$

where: C is the total number of load points in the system.

(c) Maximum values:

Maximum system load curtailed in MW (MSLC)

$$= Max \left(\sum_{K} L_{K1}, \quad \sum_{K} L_{K2}, \ldots \quad \sum_{K} L_{KJ}, \ldots \right). \tag{2.52}$$

Maximum system energy curtailed in MWh (MSEC)

$$= Max \left(\sum_{K} L_{K1} \; D_{K1}, \quad \sum_{K} L_{K2} \; D_{K2}, \ldots \quad \sum_{K} L_{KJ} \; D_{KJ}, \ldots \right). \tag{2.53}$$

These indices given by Equations 2.29 to 2.53 are called "annualized" indices when calculated for a single fixed load level over a period of one year. In practical systems, the load is not constant throughout the studied period.

The effect of variable load can be included to provide "annual" adequacy indices. This procedure is described in Equation 2.54.

If the values of any index are $x_1, x_2, ..., x_n$ for load levels $l_1, l_2, ..., l_n$, respectively, and the probability of occurrence of the load levels $l_1, l_2, ..., l_n$ are $p_1, p_2, ..., p_n$, respectively, then the annual index $\bar{x}$ is given by:

$$\bar{x} = \left(p_1 x_1 + p_2 x_2 + ... + p_n x_n\right). \tag{2.54}$$

Only the basic and average values will be affected. The maximum values remain unchanged as these represent the maximum value of an index for any load level over the period of study.

2.7. Adequacy Studies for the Roy Billinton Test System

2.7.1. System Description

The Roy Billinton Test System (RBTS) [10] is a small but powerful educational power system. This system was developed for use in the power system reliability research program at the University of Saskatchewan. The aim of designing this system was to conduct a large range of reliability studies with relatively low computational time requirements. The single line diagram for this system is shown in Figure 2.6. The RBTS is a 6 bus system, two of which are generator buses. The system contains eleven high voltage transmission lines. The total installed generation in the system is 240 MW and the total system load is 185 MW. The required data for the system is given in Appendix A.

2.7.2. Adequacy evaluation for the RBTS

The results obtained for the RBTS utilizing the three noted network solution techniques are summarized in Table 2.2 and Figures 2.7 to 2.11. Table 2.2 gives a list of the number of contingencies considered in the analysis. In the case of generator outages, all outages involving four or less than four generating units have been considered. In the case of line outages or line plus generator outages, all outages involving three or less than three lines or generating units plus lines have been considered.

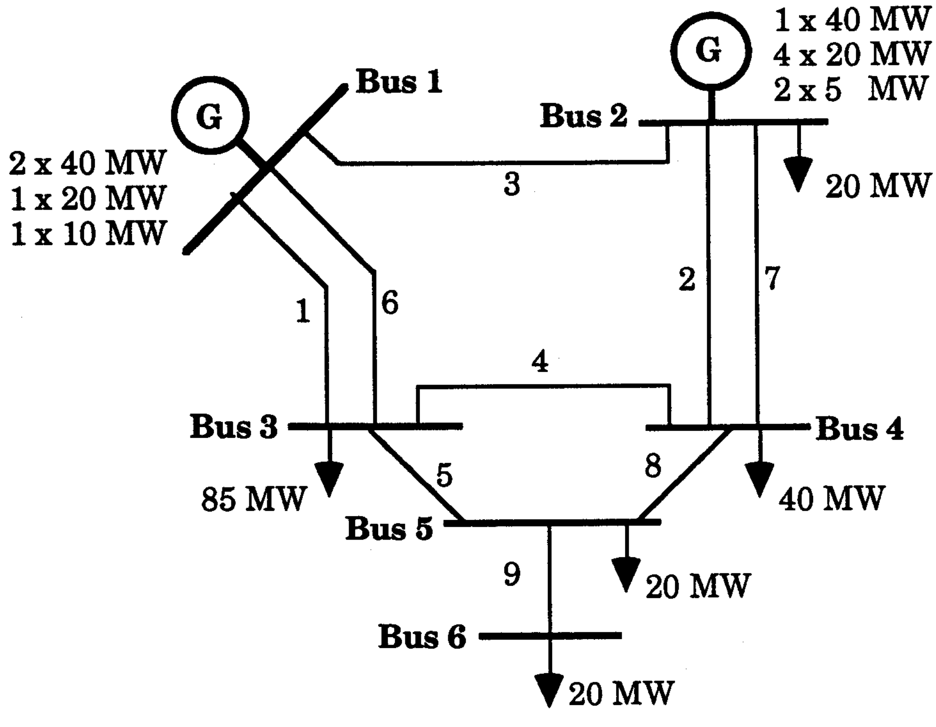

Figure 2.6: Single Line Diagram for RBTS

Figure 2.7 to 2.9 show basic, maximum and average load point adequacy indices for the RBTS. Figures 2.10 and 2.11 show basic, maximum and average system adequacy indices. All the indices are calculated using the three network solution techniques, ac load flow (ACLF), dc load flow (DCLF) and network flow (NF). Figures 2.7 to 2.11 indicate that the dc load flow technique provides, for this system at least, basically similar indices to those obtained by the ac load flow method. The basic problem associated with the dc load flow method is that it does not give an estimation of the voltage violations or the reactive power violations. The network flow method gives results which are significantly different to those obtained by the other methods.

Table 2.2: Total number of different contingencies for the RBTS

	Network solution technique		
Number of	NF	DCLF	ACLF
generator contingencies	561	561	561
line contingencies	129	129	129
generator-line contingencies	990	990	990
voltage violation contingencies	35	0	0
MVAR limit violation contingencies	0	0	0
load curtailment contingencies	1045	1036	879
isolation contingencies	192	192	192
split network contingencies	21	21	18
firm load curtailment contingencies	590	608	354

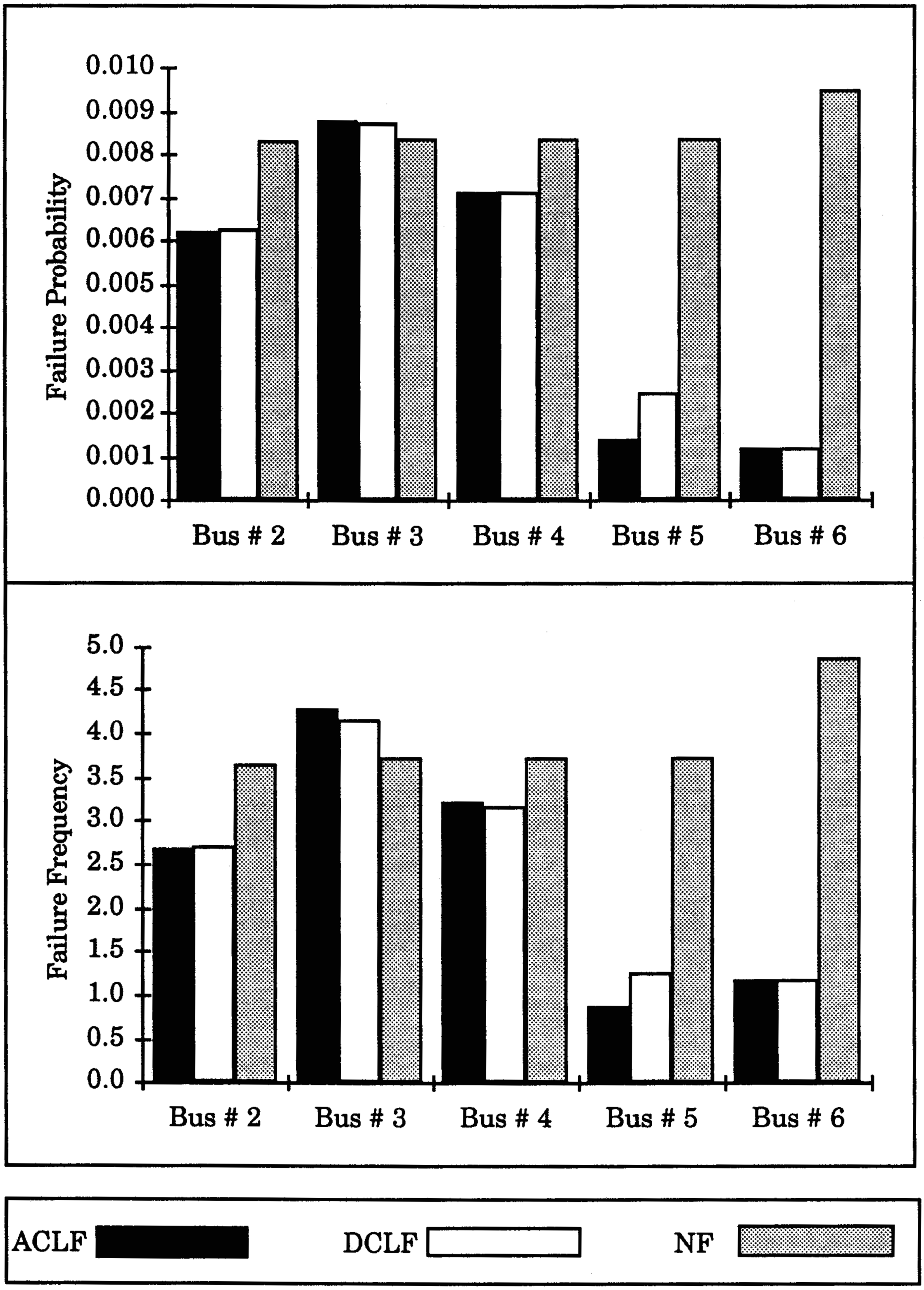

Figure 2.7.a: Load point basic value indices for the RBTS

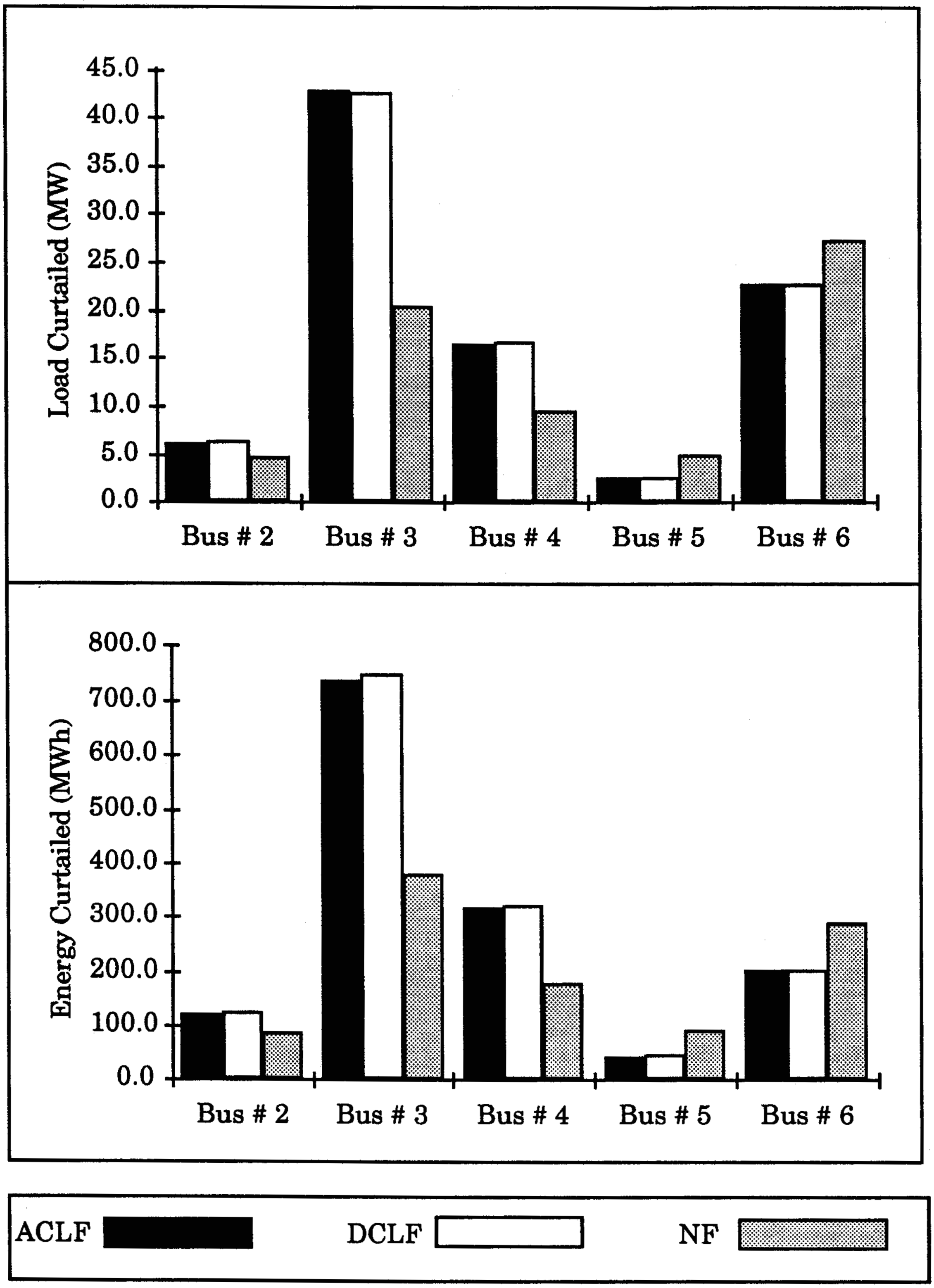

Figure 2.7.b: Load point basic value indices for the RBTS

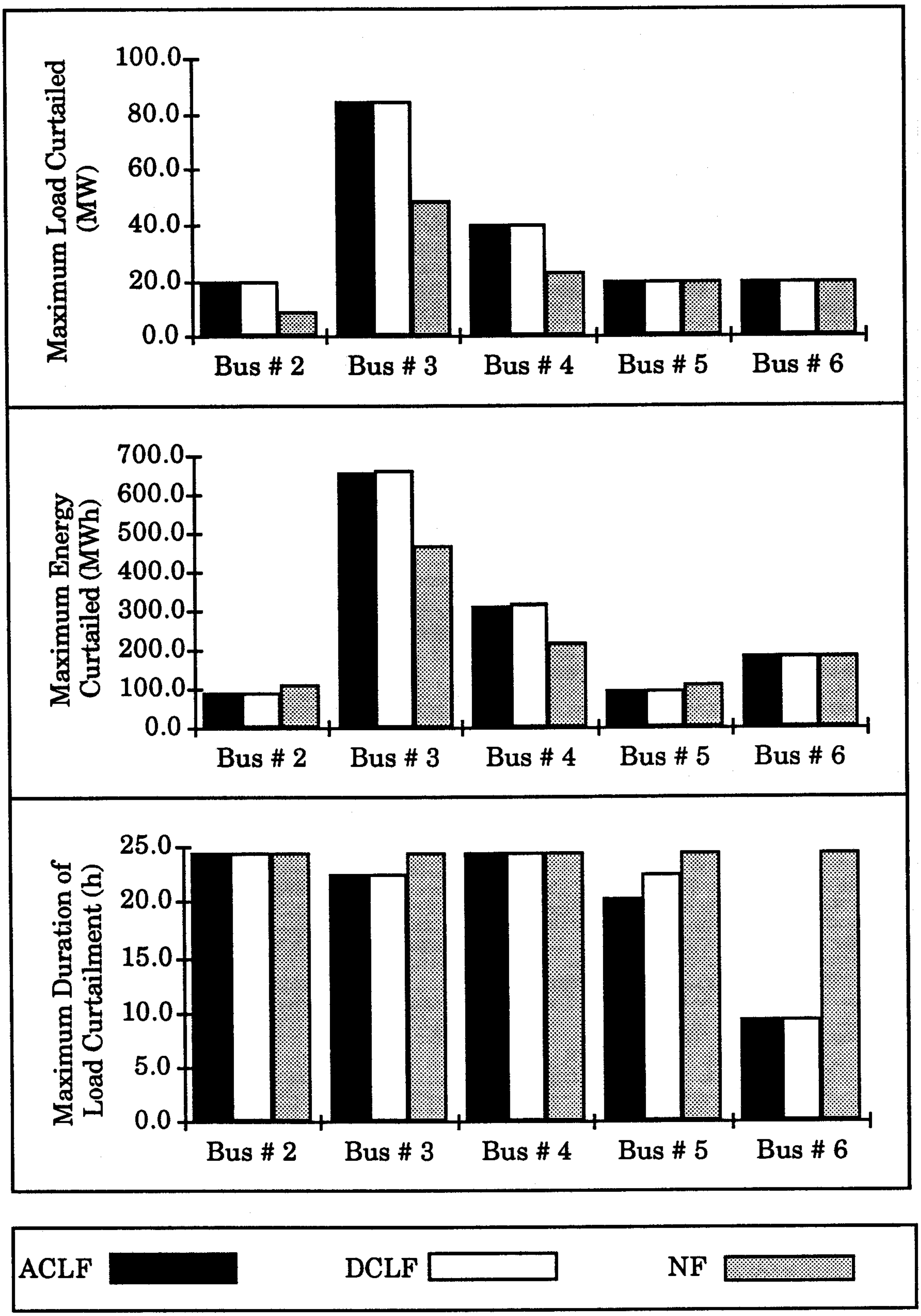

Figure 2.8: Load point maximum value indices for the RBTS

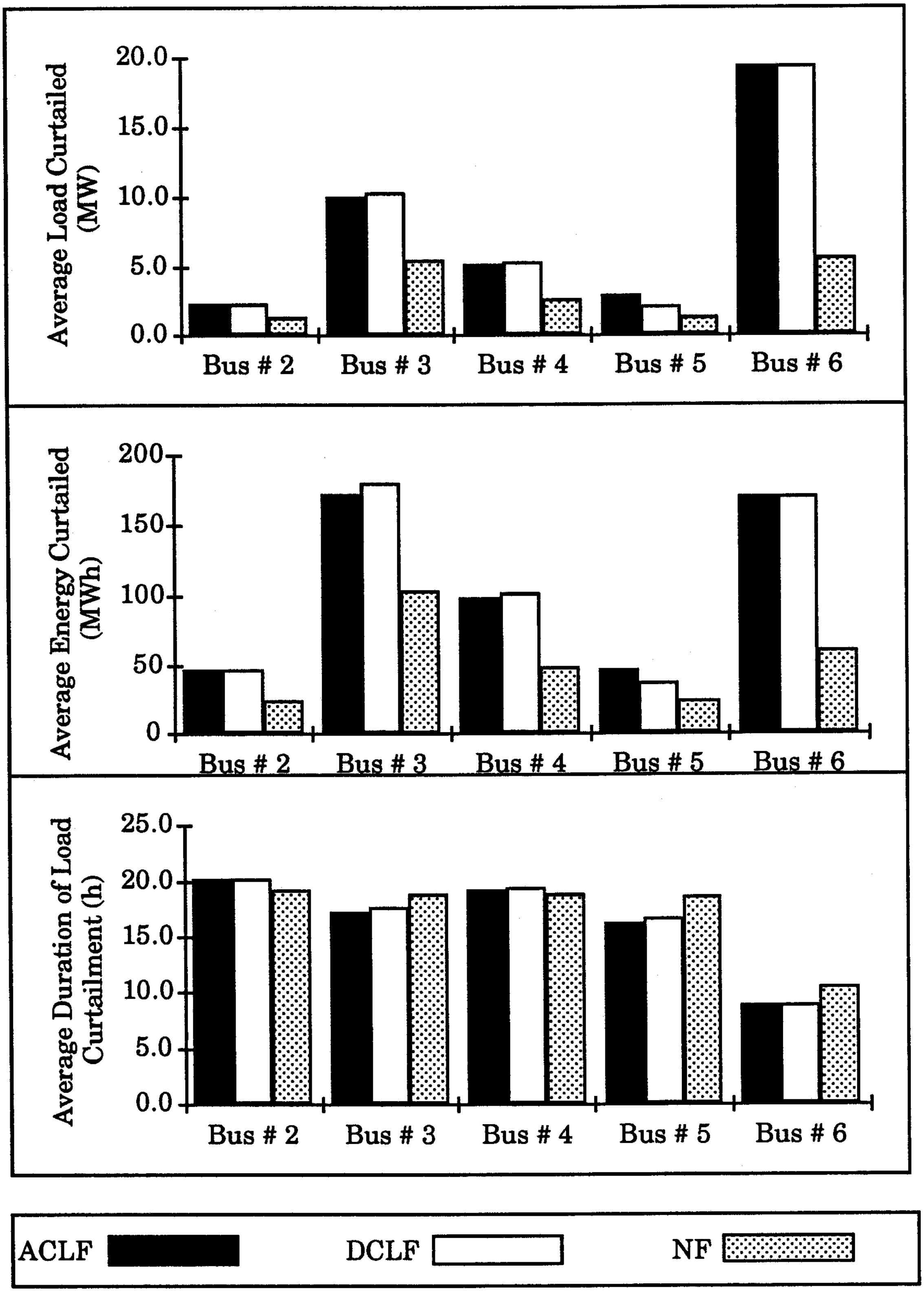

Figure 2.9: Load point average value indices for the RBTS

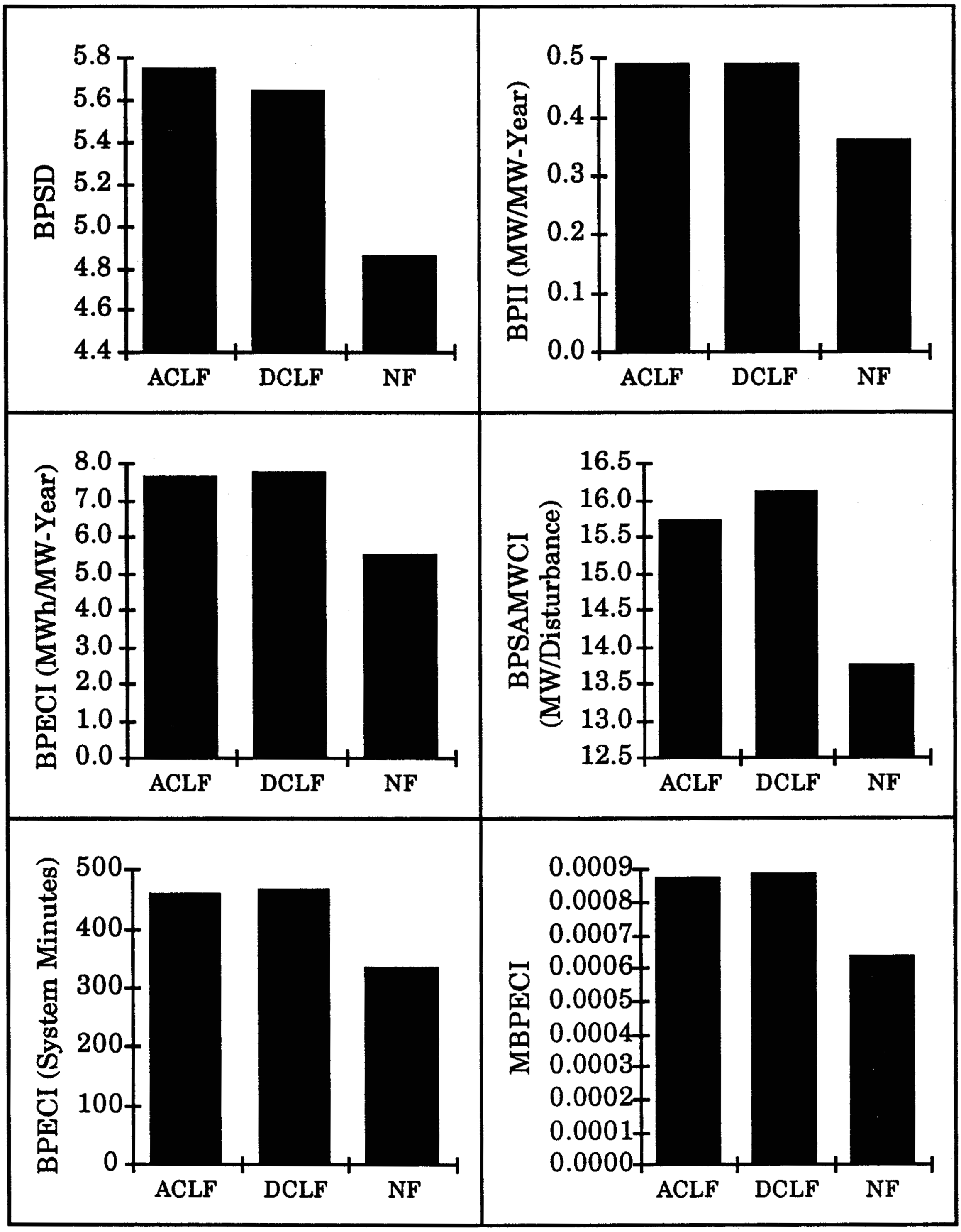

Figure 2.10: System basic indices for the RBTS

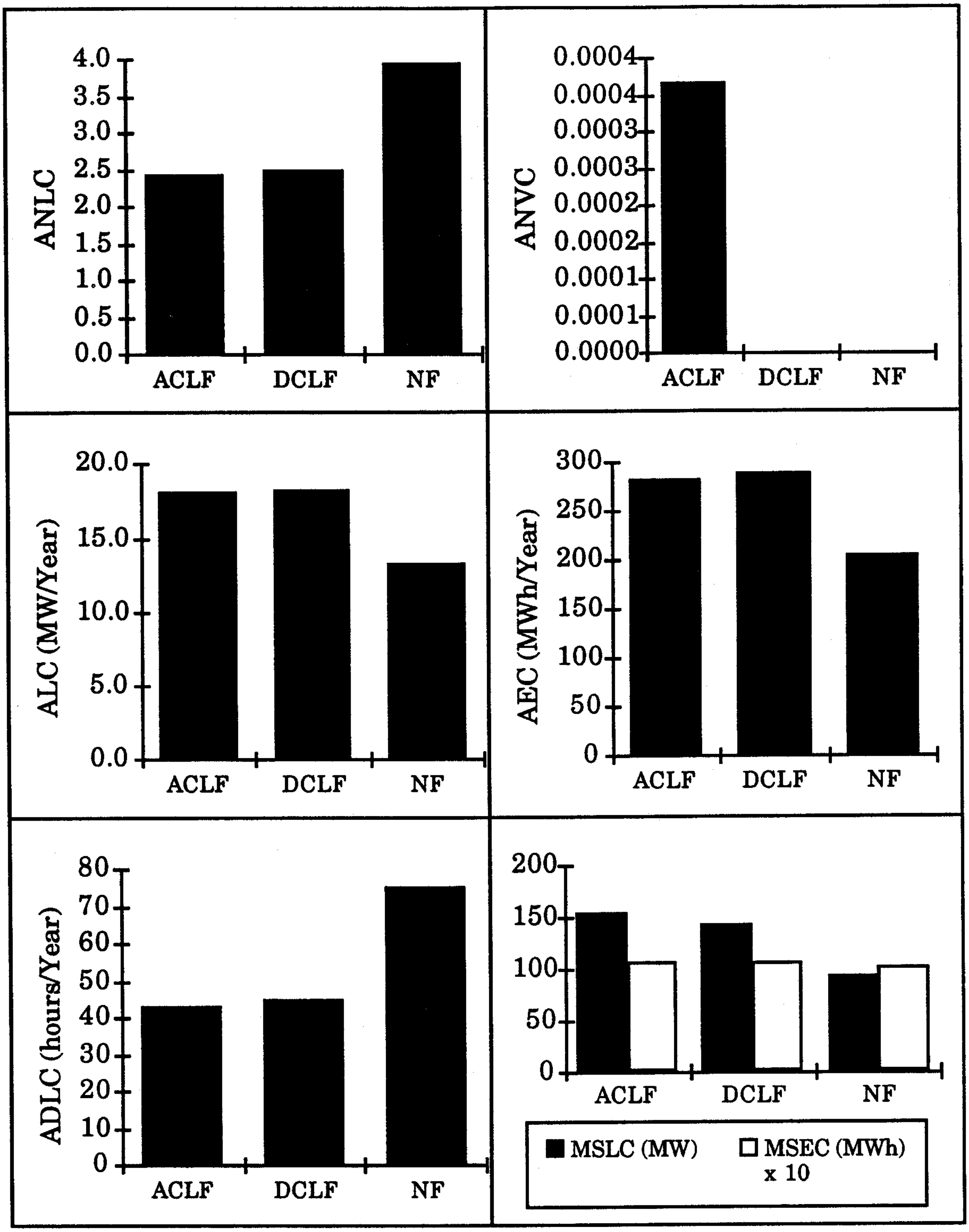

Figure 2.11: System average and maximum value indices for the RBTS

2.8. Summary

The basic concepts associated with composite power system adequacy assessment using the contingency enumeration approach are presented in this chapter. These concepts are utilized in the digital computer program COMREL developed at the University of Saskatchewan. The different network solution techniques used in COMREL are described in this chapter. A composite power adequacy study has been performed for the RBTS using the three solution techniques. It can be seen from the results presented in this chapter that the dc load flow technique provides reasonable results when compared with the ones obtained by the ac load flow method. The results obtained using the network flow approach are far from the ones obtained by the ac or the dc load flow methods. The CPU time required for this method is, however, much less than the CPU time required for the other methods. These conclusions were obtained from the studies conducted on the RBTS. They may not be equally valid for other systems, and therefore, detailed studies should be conducted for specific cases. In all cases, however, the selection of any solution technique depends on the intent behind the adequacy study.

3. COMPOSITE POWER SYSTEM RELIABILITY EVALUATION - SECURITY CONSTRAINED ADEQUACY ASSESSMENT

3.1. Introduction

The primary function of a modern power system is to satisfy the system load demand as economically as possible and with a reasonable assurance of continuity and quality. It is impossible, however, to eliminate the probability of equipment outages or the need to remove equipment from service to perform scheduled maintenance. The consideration of these aspects in the planning, design and operation of a power system is usually designated as "reliability evaluation". Power system reliability can be categorized into the domains of adequacy and security. Billinton and Khan [30] note that virtually all of the available methods for the quantitative reliability evaluation of a bulk power system are in the adequacy domain. System adequacy can be defined as the ability of the system to supply its load taking into consideration system constraints and scheduled and unscheduled outages of both transmission and generation facilities. On the other hand, system security is defined as the ability of the power system to withstand disturbances arising from faults or unscheduled removal of one or more of the element(s) from the system. There are a number of different computer programs available to evaluate the adequacy of composite power systems. These programs are briefly described in References [24,31]. The most significant quantitative indices in composite power system adequacy evaluation are those which relate to load curtailment. Many utilities have difficulty in interpreting the expected load curtailment indices as the existing models are based on adequacy analysis and in many cases do not consider realistic operating conditions in the system under study. This difficulty was found in a survey conducted as part of a project conducted by EPRI [8]. In the project report, a framework for incorporating security considerations was also proposed in response to the stated utility concerns. This framework has been examined and extended by Billinton and Khan [11]. The framework is considered in this chapter and is further extended in the following chapters. The extension includes a new set of power system reliability indices including transient stability constraints in the security evaluation process.

3.2. Security Considerations for Composite Power Systems

3.2.1. System model including security considerations

The operation of a power system can be divided into different operating states namely, normal, alert, emergency and extreme emergency states. These states indicate the degree to which adequacy and security constraints are satisfied. Figure 3.1 shows a possible classification of system operating states [11]. The subsequent quotations are taken from the EPRI report [8].

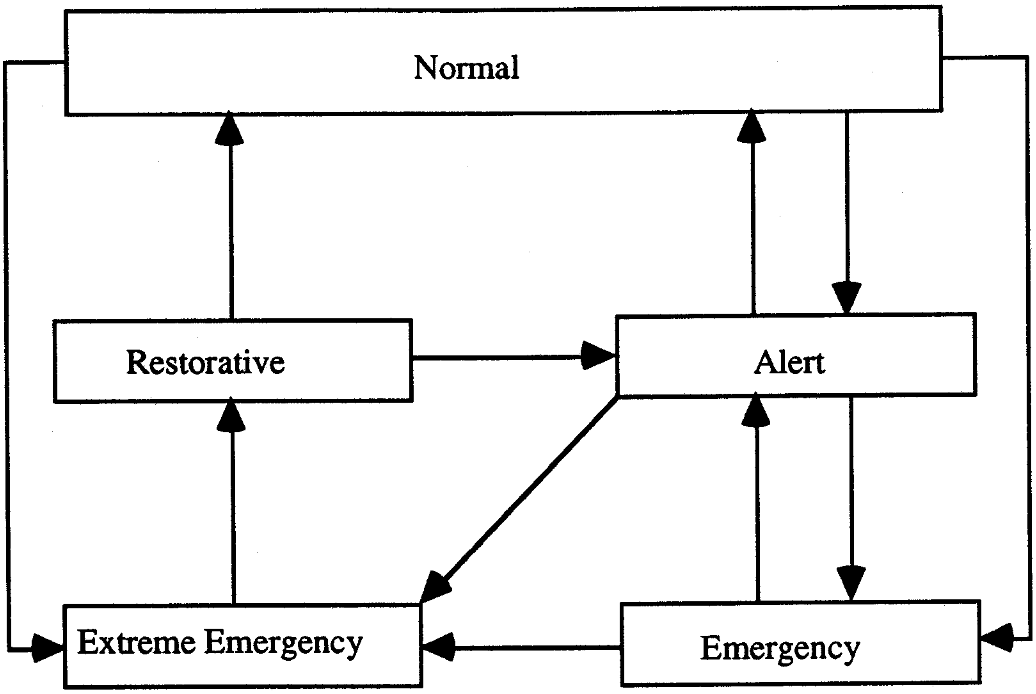

Figure 3.1: System Operating States.

The normal state is defined as [8] :

> " In the normal state, all equipment and operating constraints are within limits, including that the generation is adequate to supply the load (total demand), with no equipment overloaded. In the normal state, there is sufficient margin such that the loss of any element, specified by some criteria, will not result in a limit being violated. The particular criteria, such as all single elements, will depend on planning and operating philosophy of a particular utility."

It is clear from the above definition that the system is both adequate and secure in the normal state.

The alert state is defined as [8] :

> " If a system enters a condition where the loss of some elements covered by the operating criteria will result in a current or voltage violation, then the system is in the alert state. The alert state is similar to the normal state in that all constraints are satisfied, but there is no longer sufficient margin to withstand an outage (disturbance). The system can enter the alert state by the outage of equipment, by a change in generation schedule, or a growth in the system load."

Clearly, in the alert state the system is adequate, but there is no longer sufficient margin to satisfy the security constraints.

The emergency state is defined as [8] :

> " If a contingency occurs or the generation and load changes before corrective action can be (or is) taken, the system will enter the emergency state. No load is curtailed in the emergency state, but equipment or operating constraints have been violated. If control measures are not taken in time to restore the system to the alert state, the system will transfer from the emergency state to the extreme emergency state."

In the emergency state the system is neither adequate nor secure. This state is a temporary state that requires corrective action to be taken. If corrective action is successfully taken without requiring load curtailment, then the system will transfer to the alert state, where further action will still be necessary to transfer again to the normal state. On the other hand, if load must be curtailed then the system will go to the extreme emergency state.

The extreme emergency state is defined as [8] :

> " In the extreme emergency state, the equipment and operating constraints are violated and load is not supplied."

In the extreme emergency state, load should be curtailed following specific criteria to keep the system operating in the alert state or even the normal state.

Composite system reliability assessment including security considerations involves:

1. identifying events that lead to the normal, alert, emergency, extreme emergency states as shown in Figure 3.1 and
2. calculating the reliability indices, state probabilities and state frequencies, for each of the above operating states.

3.2.2. Security constraints

The operating limits which have to be satisfied during the operation of a power system are called security constraints. Security constraints can be divided into two main parts:

1. steady state performance constraints and
2. transient performance constraints.

Steady state performance constraints test the capability of the system to supply the load without violating any equipment operating limits. On the other hand, transient performance constraints test the capability of the system to be operated so that it remains stable when failures occur. In this chapter, only steady state performance constraints are considered. Transient considerations are included in the next chapter. Steady state performance constraints are outlined below.

1. Voltage magnitude constraints:

The voltage magnitude of all system buses should be within specified operating limits. This can be expressed as

$$V^m \le V \le V^M. \tag{3.1}$$

The region inside the limits can be defined by R_v i.e.

$$R_v := \{V : V^m \le V \le V^M\} \tag{3.2}$$

where:

V^m and V^M represent the minimum and the maximum voltage limits.

2. Line flow constraints:

Because of the thermal operating limits of the transmission lines and the transformers, the current flow through them should be limited. This can be expressed as

$$\left|\delta_i - \delta_j\right| \le \theta_k \tag{3.3}$$

where:

δ_i and δ_j	are the phase angle of the voltages at bus i and j,
θ_k	is the maximum phase angle difference between buses i and j, and
k	is the branch connecting buses i and j.

The region that represents all lines is defined as

$$R_\theta := \{\delta : -\theta \le \delta \le \theta\}. \tag{3.4}$$

3. Power generation constraints:

The real and reactive power at a generating (PV) bus should be within specified limits. This can be expressed as

$$P^m \le P \le P^M. \tag{3.5}$$

Similarly,

$$Q^m \leq Q \leq Q^M. \tag{3.6}$$

The region inside the limits can be defined by Rg i.e.

$$R_g := \{P: P^m \leq P \leq P^M\} \cap \{Q: Q^m \leq Q \leq Q^M\} \tag{3.7}$$

where P^m and P^M represent the minimum and the maximum real power generation limits. Similarly, Q^m and Q^M represent the minimum and the maximum reactive power generation limits.

Steady-state security constraint set

The steady-state security constraint set can be formed by any one or a combination of the steady state constraints. The total steady state constraint set is obtained by combining all the steady-state constraints. The power system will be considered to be operating within limits when there is a solution existing in (v, δ)-space which satisfies the following relation:

$$R_{SS} := R_v \cap R_\theta \cap R_g. \tag{3.8}$$

The system is called a steady-state secure system if it satisfies all the steady-state constraints given in Equation 3.8.

3.3. Detection of Different Operating States

A digital computer program has been developed at the University of Saskatchewan to determine the different operating states in a composite power system. The fast decoupled load flow method is used as the network solution technique. The Sherman-Morrison correction formula is also used to correct both voltages and bus angles at each selected contingency. Figure 3.2 shows a flow chart for detecting the operating state for up to second order outages. The same concept can be used to detect higher order operating states.

3.4. The Modified Roy Billinton Test System (MRBTS)

The Roy Billinton Test System (RBTS) has been modified to a 5-bus system having only 8 lines as shown in Figure 3.3, by removing line # 9 and adding the original load at bus # 6 to that at bus # 5. This modification was done because the single outage of line # 9 (single level contingency) will isolate bus # 6 resulting in the 20 MW load having to be curtailed. The normal state probability will therefore be zero in the original configuration.

3.5. Steady State Security Study for the MRBTS

The probabilistic indices for the MRBTS have been calculated. In this analysis, up to fourth level of generator outages, third level line outages and third level of line plus generator outages are considered. The analysis covers more than 99.9975 % of the total sample space. The remaining 0.0025 % consists of higher order contingencies which are not covered in the analysis.

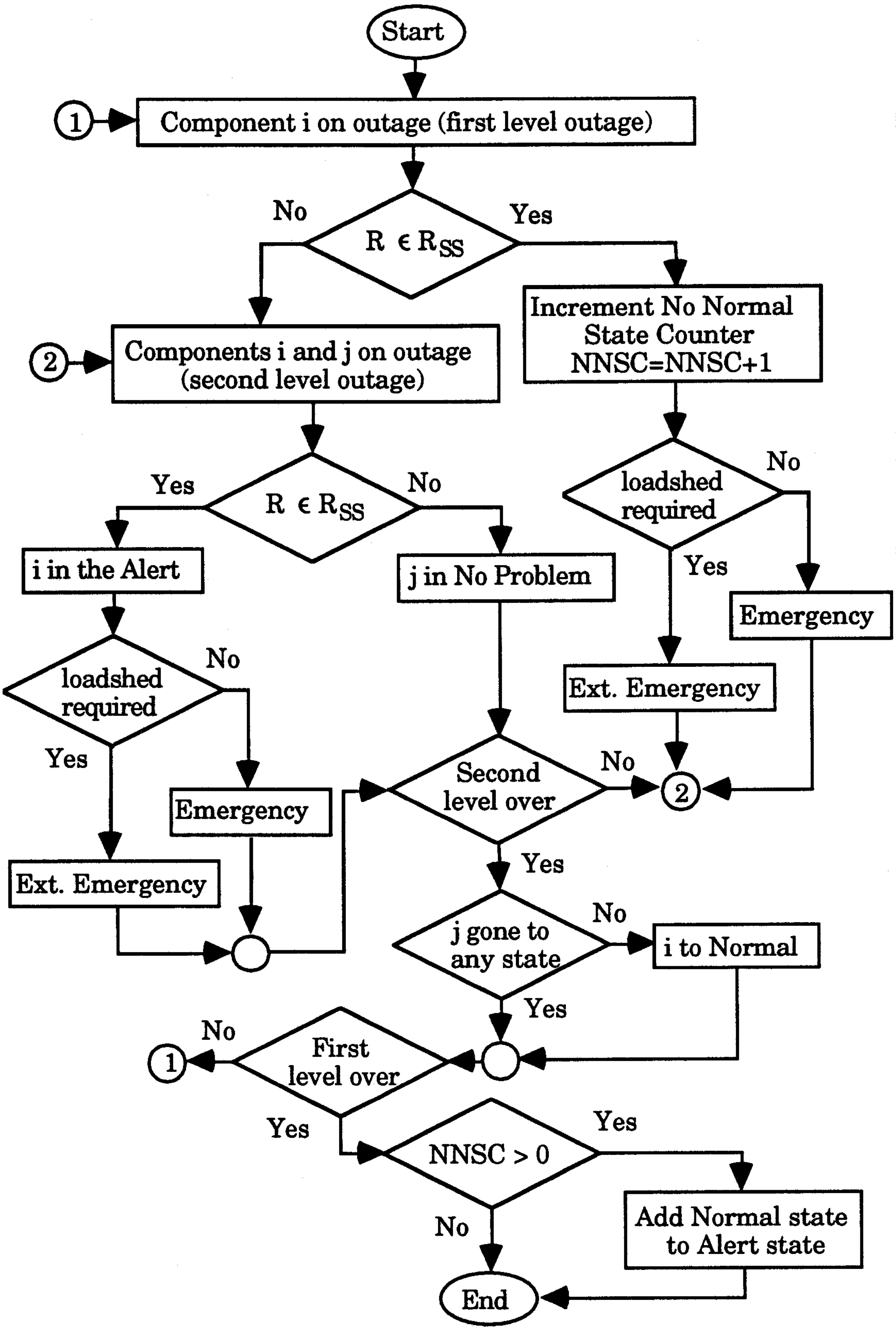

Figure 3.2: Flow chart for detecting different operating states

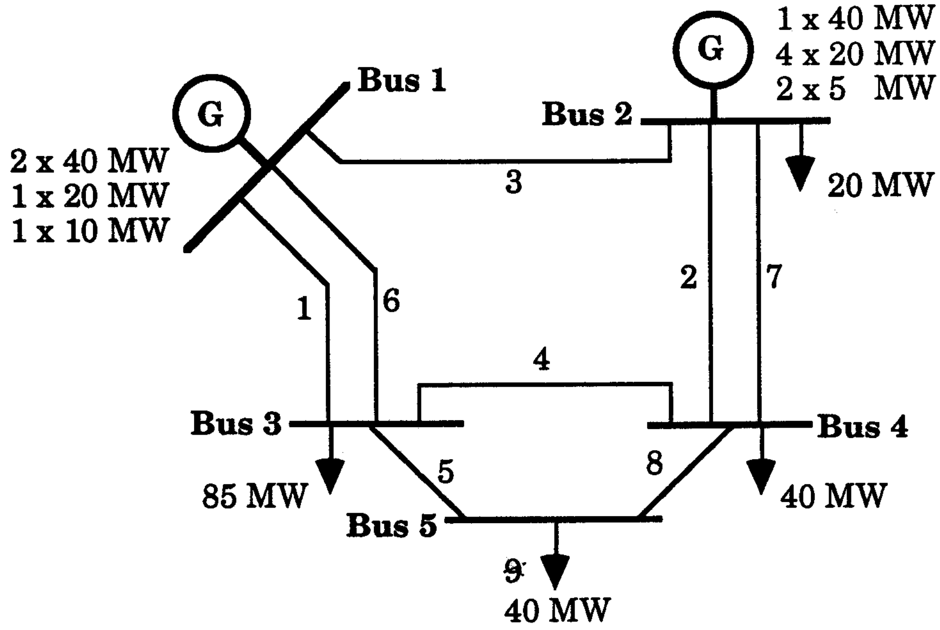

Figure 3.3: Modified RBTS (MRBTS)

The annualized probabilities and frequencies for different operating states at a 185 MW system load are shown in Table 3.1. The use of the peak load as the single system load parameter is, in general, quite pessimistic from a reliability point of view. Annual reliability indices can be obtained by incorporating the annual system load model.

The area of "no problem" is designated for contingencies of third or fourth order that do not violate any constraint but at the same time for which no decision can be made to include them in the normal state or alert state due to the selection criteria. Table 3.1 shows that the probability of curtailing some loads from the system, i.e., the probability of the extreme emergency state, is 0.858 %. The probability of the normal state is greater than zero which means that there are no first level contingencies that violate any of the steady-state performance constraints. The reliability of the system can be ascertained by summing the probabilities of the states that do not violate any security constraint. These are normal, alert and no problem states. The risk, which is designated as the Composite System Operating State Risk (CSOSR), is considered to be the complement of this summation. This can be expressed as:

$$CSOSR = 1.0 - (P_{normal} + P_{alert} + P_{no\ problem}). \quad (3.9)$$

The risk index CSOSR for the MRBTS is 0.008680.

Table 3.1: Probabilities and frequencies of different system operating states

System State	Probability	Frequency
Normal	0.899362	73.494367
Alert	0.091771	35.516125
Emergency	0.000074	0.135088
Extreme Emergency	0.008580	3.982606
No Problem	0.000187	0.249639
Total	0.999975	113.377826

3.6. Effect of Load Variation on Annual Reliability Indices

In practical systems, the load is not constant throughout the year. Assuming that the load stays at the peak value usually gives highly pessimistic reliability values designated as annualized indices. The hourly annual load duration curve for the system can be used to calculate annual indices. The most common system load representation, in reliability studies, is to use multistep modeling as a detailed representation will require considerable computation time. A reduced and therefore approximate load model can be used quite successfully to obtain acceptable annual indices. The number of steps required in the analysis depends on the shape of the load duration curve and the required level of accuracy. In order to calculate the annual indices and to show the effect of multistep load modeling, a "seven-step" load model for the RBTS load duration curve (LDC) is shown in Figure 3.4. The load steps and the associated probabilities are shown in Table 3.2.

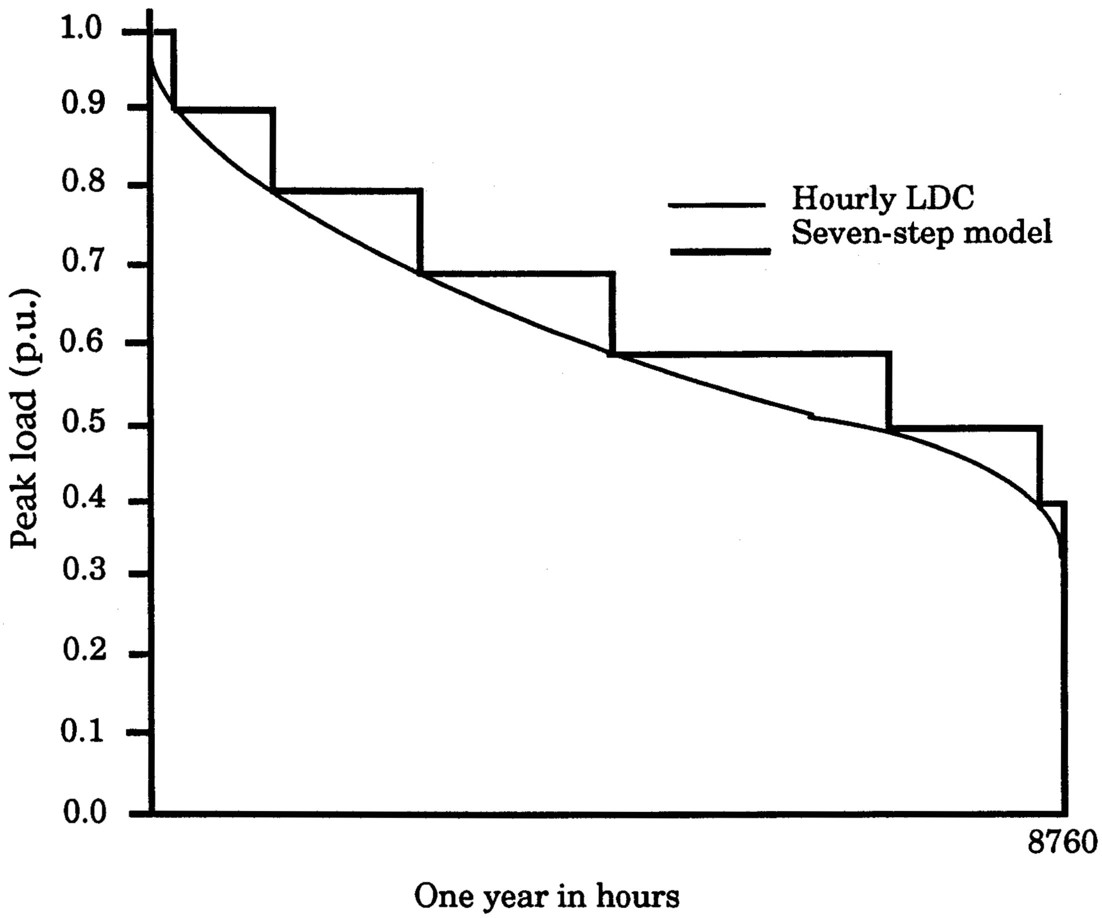

Figure 3.4: Multi-step load model

Table 3.2: Probability of different load levels

Load Step	% Load	Probability
1	40	0.03651557
2	50	0.22630495
3	60	0.21554486
4	70	0.23202839
5	80	0.16540751
6	90	0.11103480
7	100	0.01316392

It is assumed in the analysis that the loads at different buses vary in proportion to the total system load. The real load at any bus can be calculated as:

$$P_{Load}(i) = P_{Load}(0) \times \frac{\%Load}{100} \qquad (3.10)$$

where:

$P_{Load}(i)$ is the active load at step i and

$P_{Load}(0)$ is the active peak load.

Table 3.3: Bus loads in MW for the seven step load model - MRBTS

Bus Number	Step Number 1	2	3	4	5	6	7
2	8.0	10.0	12.0	14.0	16.0	18.0	20.0
3	34.0	42.5	51.0	59.5	68.0	76.5	85.0
4	16.0	20.0	24.0	28.0	32.0	36.0	40.0
5	16.0	20.1	24.1	28.1	32.1	36.1	40.1
Total	74.0	92.6	111.1	129.6	148.1	166.6	185.1

The effect of the load variations on different probability and frequency indices are shown in Table 3.4. and Table 3.5 respectively. Figures 3.5 and 3.6 show the effect on the security indices of considering a more realistic load model.

Table 3.4: Effect of load variation on probability of different states

Load	No Violation Zone			Violation Zone		
Step %	Normal	Alert	No Prob.	Emerg.	Ext. Em.	Risk
40	0.997500	0.002050	0.000424	0.000000	0.000001	0.000027
50	0.997490	0.002060	0.000424	0.000000	0.000001	0.000027
60	0.997402	0.002148	0.000422	0.000000	0.000003	0.000028
70	0.982800	0.016667	0.000409	0.000075	0.000024	0.000124
80	0.976996	0.022320	0.000393	0.000080	0.000186	0.000291
90	0.950189	0.047044	0.000324	0.000077	0.002341	0.002443
100	0.899362	0.091772	0.000187	0.000074	0.008580	0.008680
Annual	0.984129	0.014995	0.000401	0.000040	0.000415	0.000475

Table 3.5 : Effect of load variation on frequency of different states

Load Step %	No Violation Zone			Violation Zone		
	Normal	Alert	No Prob.	Emerg.	Ext. Em.	CSOSR
40	110.83903	1.98460	0.55148	0.00000	0.00270	0.00270
50	110.82082	2.00282	0.55141	0.00000	0.00277	0.00277
60	110.75807	2.06557	0.54994	0.00000	0.00425	0.00425
70	97.40158	15.29219	0.53035	0.13672	0.01727	0.15398
80	94.80286	17.80348	0.51451	0.14487	0.11210	0.25697
90	85.03237	26.63838	0.42397	0.13953	1.14357	1.28310
100	73.49436	35.51613	0.24964	0.13509	3.98261	4.11769
Annual	101.69005	10.88931	0.52198	0.07296	0.20359	0.27655

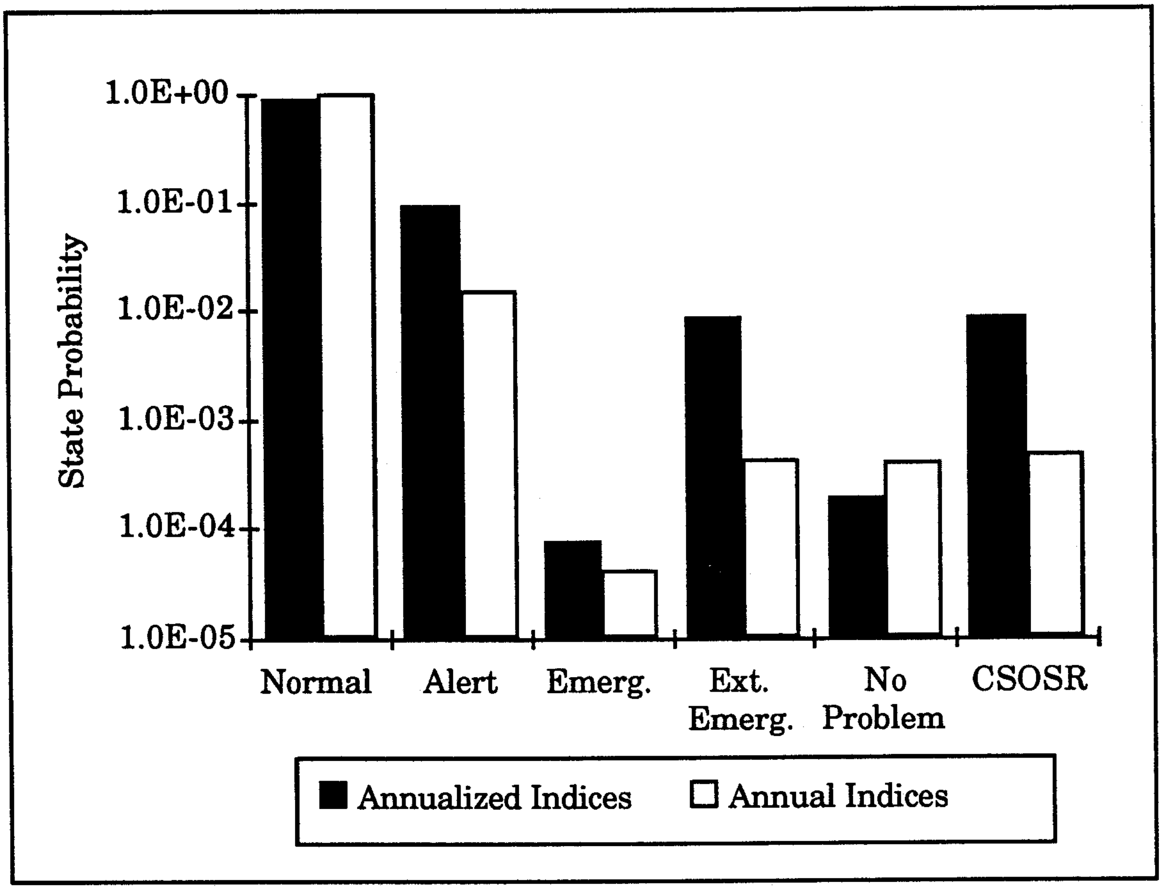

Figure 3.5: Effect of load variation on the probability of different states

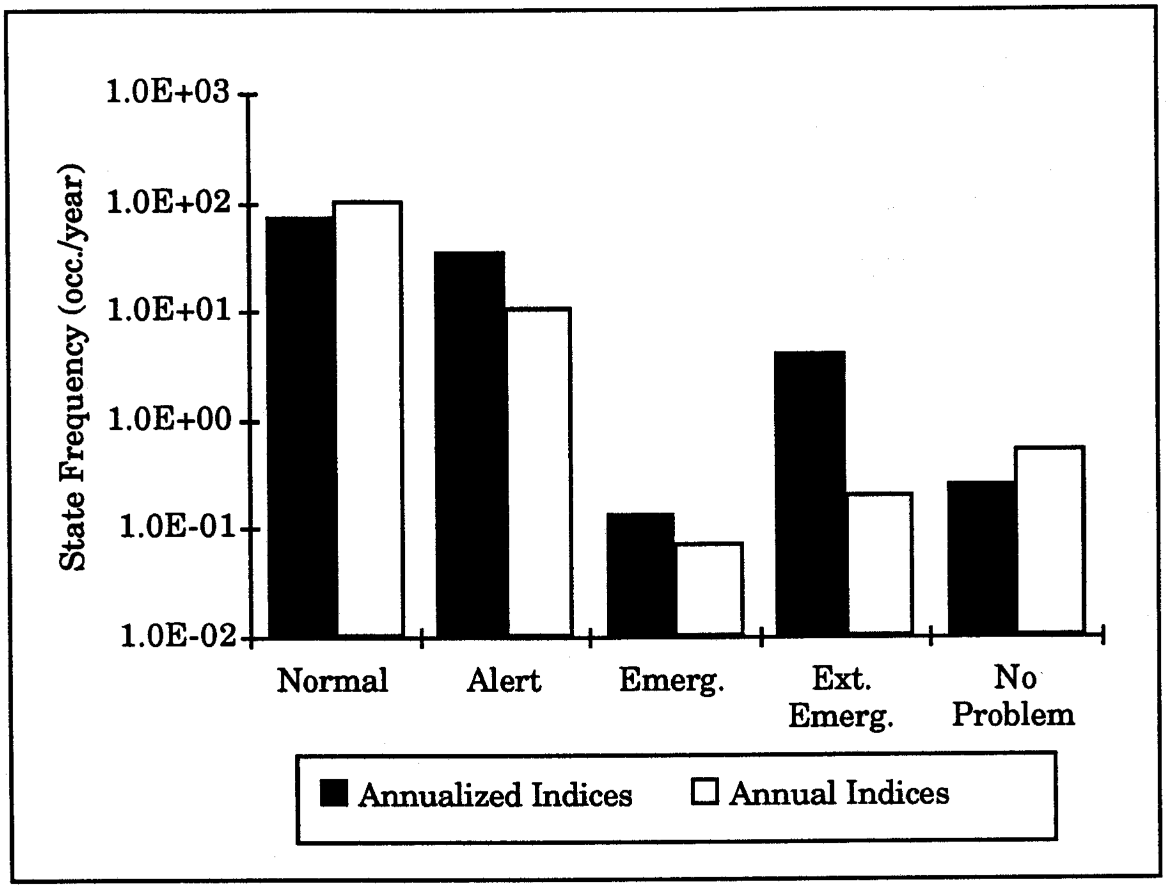

Figure 3.6: Effect of load variation on the frequency of different states

It can clearly be seen from Figure 3.5 that the annual CSOSR is considerably smaller than the annualized value obtained at the system peak load. The normal state probability increases and the extreme emergency state probability decreases when annual values are calculated rather than annualized parameters.

3.7. Summary

In this chapter, a power system which is composed of transmission and generation facilities has been classified by different operating states which provide a framework for including steady state security considerations in system reliability evaluation.

The framework developed by Billinton and Khan [11] has been used to evaluate the steady state security indices. The probabilistic indices for different operating states of the MRBTS are shown considering the constraint set given in Reference [11]. Both annual and annualized indices are presented in this chapter.

The steady state analysis and results presented in this chapter provide the basic framework and general procedure for incorporating transient considerations in the following chapters.

4. COMPOSITE POWER SYSTEM RELIABILITY EVALUATION - SECURITY ASSESSMENT

4.1. Introduction

As the system load increases, additional system components such as generators, transmission lines and transformers must be installed to maintain an acceptable level of system reliability. The characteristics of these components are basically nonlinear and ,therefore, a power system is a large nonlinear system. A common problem in designing or planning any non-linear system is its stability. Stability in a power system is a problem generally associated with the parallel operation of synchronous generators. The following definition for power system stability is taken from Kimbark [32]

" Power system stability is a term applied to alternating current electric power systems, denoting a condition in which the various synchronous machines in the system remain in synchronism, or 'in-step' with each other."

In power systems studies, there are two types of basic stability problems, namely steady state and transient stability. Steady state stability evaluation considers the ability of the system to operate under stable conditions when subject to small or gradual changes in the system. On the other hand, transient stability studies consider the ability of the system to operate successfully under large or sudden perturbations. This chapter deals only with transient stability analysis.

There are many perturbations that may cause a power system to be transiently unstable. Some of these are:

1. a loss of one or more generator due to sudden forced outage,
2. a sudden loss of a large load,
3. a sudden removal of one or more lines or
4. a line fault, particularly one occurring on a heavily loaded line or near a generator bus.

It is impossible to design a system that is stable for all possible perturbations. A basic and practical approach is used by planning engineers to ensure that the system remains stable under certain specified contingencies such as:

1. the tripping of interconnections,
2. a sudden increase in the system load,
3. the loss of a large generator or a group of generators or
4. certain system faults such as three phase faults near generator buses.

The published literature in the area of transient stability is extensive and contains many descriptions of simulation techniques. There are a number of text books [32-35] devoted entirely or in part to transient stability analysis and there are many available methods. Some of these are discussed briefly [32-37] below.

1- Equal Area Criterion Method:

This classical method is illustrated in most power system analysis books and is used to study a simple two machine system. It is based on a comparison of energies during and after the fault periods. The acceleration energy originated during the fault must be equal to or less than the post fault deceleration energy for system stability. This can be represented and checked from the power angle diagram which shows the two energy areas. The time at which the two areas are equal is called the *Critical Clearing Time* (CCT). This basic method is easy to appreciate and has been studied extensively in regard to its application to larger systems. Xue et al [36] consider a new approach to include more than two machines in the equal area criterion method.

2. Direct Method of Lyapunov:

In this method, the stability behavior of the system can be determined without obtaining the time domain solution. Stability information is obtained from the general properties of a function which describes the state of the system in the neighborhood of the equilibrium point. The method was applied by El-Abiad and Nagappan [37] in 1966 to evaluate the critical clearing time in a power system stability problem. Since then, there has been considerable research activity in this area. Pai [35] discusses this method in a comprehensive manner.

3. Numerical Integration Method:

The stability problem basically consists of obtaining a solution for a set of nonlinear differential equations. A number of numerical integration techniques can be used to solve these equations. The most commonly used approach is the classical *step by step* method [32]. The nonlinear equations that represent the machine response can be solved by step by a step integration procedure for the period starting from after the fault occurrence up to its clearing time. A time domain solution for the machine angles is obtained and the system is considered stable if the machine angles are approaching each other at the end of the integration period. The numerical integration method is used in the analysis of the transient stability problem in this chapter and in the following chapters.

This chapter illustrates the probabilistic nature of transient stability. The procedures proposed by Billinton and Kuruganty [5,6] are implemented and extended for use in composite power system security evaluation.

4.2. Probabilistic Aspects of Transient Stability Evaluation

The traditional design of a power system includes testing the stability of the system under specified basic contingencies such as a three phase fault near generator buses or on particular transmission lines. This "worst case" approach has been used widely and successfully by most power utilities. It is obvious that a wide range of contingencies are possible at any location in the system. This introduces the realization that a stochastic approach could be used in the analysis to include the probabilities associated with all possible contingencies in order to obtain a more realistic appraisal of the system stability. There are several uncertainties that have considerable effect in the probabilistic assessment of transient stability. Some of these are:

1. types of faults,
2. location of faults,
3. fault clearing phenomena and
4. system parameters and operating conditions.

1. Type of faults:

There are two basic fault types that occur in power system operation, open circuit faults and short circuit faults. The second type is more common and has in general, a more severe impact on the system. Short circuit faults that affect transient stability can be classified into four categories :

a. single phase to ground faults,

b. phase to phase faults ,

b. phase to phase to ground faults and

d. three phase faults.

The probability of occurrence of each of these can vary significantly from one system to another as it depends highly on the system configuration, weather, and the geographical location of the system. In general the probability of occurrence decreases from (a) to (d) .

2. Location of faults:

The resulting severity of a given fault tends to diminish as the distance between the fault location and the generating units increases. Faults near generator buses are the most severe faults in the system. The location of the fault is probabilistic, and can be represented by the probability distribution of fault occurrence. The probability distribution for fault location will be different for each line in the system and from one system to another and can be determined only from statistical data on the system.

3. Fault clearing phenomena:

Fault clearing time is the most important factor affecting transient stability. The more quickly a fault is cleared, the more likely the system is to be stable. On the other hand, if a fault remains on the system for a long time before it is cleared, the system may experience transient stability problems. The operating time of the breakers required to clear a fault is a combination of the main protection time, the backup protection time and the signaling time. This combination can be used to create the probability distribution of clearing time [5,6].

4. System parameters and operating conditions:

System stability is affected by all of the physical elements in the system. Some of the principal factors that affect system stability are:

a. actual transmission topology and associated impedances and admittances,
b. switching and protection elements,
c. operating conditions at the time of the fault and
d. the system load.

The actual physical system parameters are non-probabilistic. The system operation at some time in future, however, is probabilistic in nature and affects the system stability.

4.3. Deterministic Aspects of Stability Evaluation

The deterministic aspects of stability evaluation include the modeling of the network components such as generators, transmission lines, transformers, and loads. Deterministic evaluation includes performing load flow analysis, forming sequence matrices for different types of faults and locations, and finding the system response by solving the associated differential equations.

4.3.1. Network solution and initial operating conditions

The steady state pre-fault conditions must be known before conducting transient stability analysis. The power output, angle and voltage of each synchronous machine can be found through system load flow analysis. There are many available methods to perform load flow analysis. The most common techniques are Gauss-Seidel, Newton-Raphson and fast decoupled load flow methods. The network solution techniques are briefly discussed in Chapter 2. In this chapter, the Newton-Raphson technique [17,33] is used. After calculating the bus voltages and powers, the internal machine voltages are evaluated using synchronous machine models.

The synchronous machine is an inherently complicated device. A complete mathematical model is quite involved and requires a lengthy development if it is required to be properly understood. Experience [33,34] has shown that certain simplifying assumptions can greatly reduce the model's complexity without seriously affecting the accuracy of the transient stability calculations. The usual assumptions have been made in this analysis such as the representation of the machine by a constant voltage behind the transient reactance and constant machine input, etc. The mathematical relation between the internal machine voltage and the bus voltage is given by:

$$\overline{E}' = \overline{V} + jX_d' \,\overline{I} \tag{4.1}$$

where:

$\overline{E}'$ is the voltage behind the transient reactance,

$\overline{V}$ is the terminal voltage,

X'_d is the direct axis transient reactance and

$\overline{I}$ is the machine current.

The generator equivalent circuit representing the above equation is shown in Figure 4.1. This simplified model is used for the analysis in this chapter.

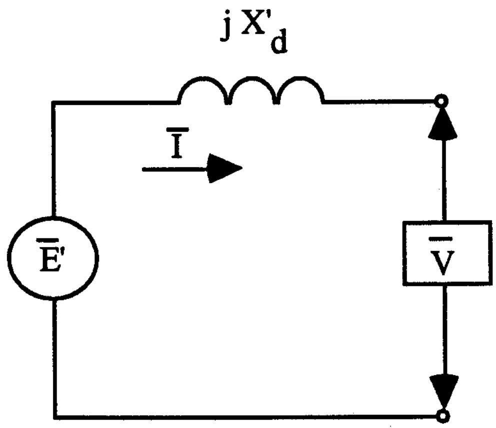

Figure 4.1: Equivalent circuit of a synchronous machine

4.3.2. Sequence matrices and matrix reduction

1. Sequence Matrices:

The positive sequence network matrix can be used if the simulated fault is a balanced three phase fault. For unbalanced system faults, both negative and zero sequence matrices must be included in the analysis.

The positive sequence network includes the generator voltages and the impedances of the generators, transformers, and transmission lines. The negative sequence network is almost exactly the same as that of the positive sequence except that the generator voltages are not included and the negative sequence reactances of the synchronous machines may be different from the positive sequence values. The zero sequence network is basically similar to that of the negative sequence but requires special consideration for both transformers and generators depending on the type of connection and grounding used. The three sequence networks are connected differently for each fault type . Table 4.1 shows the required connection for different types of short circuit faults.

Table 4.1: Connections of Sequence network for different types of faults

Type of fault	Connection
three phase	positive sequence only
phase to phase to ground	the three sequences in parallel
phase to phase	positive and negative sequences in parallel
single phase to ground	the three sequences in series

2. Matrix reduction:

In transient stability analysis, the admittance matrices can be reduced to show only the generator buses. The power distribution in the network branches is not particularly important. The reduction will simplify the solution and decrease the required computation time. The application of this technique requires that all loads be represented by constant impedances. If the load can not be represented as a constant impedance then its bus can not be eliminated. The network current-voltage relation is given by the following equation:

$$\begin{bmatrix} [I_G] \\ [I_L] \end{bmatrix} = \begin{bmatrix} [Y_1] & | & [Y_2] \\ --- & - & --- \\ [Y_3] & | & [Y_4] \end{bmatrix} \begin{bmatrix} [E_G] \\ [E_L] \end{bmatrix} \tag{4.2}$$

where:

$[Y_1]$	is an NG x NG matrix,
$[Y_2]$	is an NG x NL matrix,
$[Y_3]$	is an NL x NG matrix,
$[Y_4]$	is an NG x NG matrix,
NG	is the no. of generator buses and
NL	is the no. of load buses.

From Equation 4.2, the following equations are obtained:

$$[I_G] = [Y_1][[E_G] + [Y_2][E_L] \quad (4.3)$$

and

$$[I_L] = [Y_3][[E_G] + [Y_4][E_L]. \quad (4.4)$$

The current injected at a load bus is zero, i.e. $[I_L] = 0$. Equation 4.4 then becomes:

$$[E_L] = -[Y_3][E_G][Y_4]^{-1}. \quad (4.5)$$

Substituting the matrix $[E_L]$ from Equation 4.5 in Equation 4.3 gives:

$$[I_G] = \left[[Y_1] - [Y_2][Y_3][Y_4]^{-1}\right][E_G] \quad (4.6)$$

4.4.3. The swing equations and their solution

A synchronous generator is a device that converts mechanical energy into electrical energy. The difference between the input mechanical energy and the output electrical energy is the kinetic energy of the machine components. The machine will not rotate at synchronous speed if there is a mismatch between the input mechanical energy and the output electrical energy of the machine. This can be formed mathematically by the following equation:

$$M \frac{d^2\delta}{dt^2} = P_m - P_e \quad (4.7)$$

where:

M	is the angular momentum,
δ	is the torque angle,
Pm	is the mechanical power input corrected for rotational losses and
Pe	is the electrical power output corrected for electrical losses.

Equation 4.7 is called the "Swing Equation". Such an equation can be written to express the dynamic behavior of each machine in the system. For an N machine system, N swing equations similar to Equation 4.7 can be formulated

$$
\begin{aligned}
M_1 \frac{d^2 \delta_1}{dt^2} &= P_{m1} - P_{e1}(\delta_1, \delta_2, \ldots, \delta_{N,} \frac{d\delta_1}{dt}, \frac{d\delta_2}{dt}, \ldots, \frac{d\delta_N}{dt}) \\
M_2 \frac{d^2 \delta_2}{dt^2} &= P_{m2} - P_{e2}(\delta_1, \delta_2, \ldots, \delta_{N,} \frac{d\delta_1}{dt}, \frac{d\delta_2}{dt}, \ldots, \frac{d\delta_N}{dt}) \\
&\vdots \\
M_N \frac{d^2 \delta_N}{dt^2} &= P_{mN} - P_{eN}(\delta_1, \delta_2, \ldots, \delta_{N,} \frac{d\delta_1}{dt}, \frac{d\delta_2}{dt}, \ldots, \frac{d\delta_N}{dt}).
\end{aligned}
\tag{4.8}
$$

It is clear that solving the above swing equation requires the use of one of the available techniques for solving non-linear differential equations. There are several methods that can be used for this purpose. In the developed computer program used in the analysis, step by step integration is used [32]. The change in the torque angle is given by the expression [32]

$$\begin{aligned}\Delta\delta_n &= \Delta\delta_{n-1} + \frac{(\Delta t)^2}{M}(P_{m(n-1)} - P_{e(n-1)}) \\ &= \Delta\delta_{n-1} + \frac{(\Delta t)^2}{M} P_{a(n-1)}\end{aligned} \tag{4.9}$$

where $P_{a(n-1)}$ is the accelerating power $(P_{m(n-1)} - P_{e(n-1)})$.

Equation 4.9 gives the incremental change in the rotor angle at any time. It is very important to include the discontinuity in the accelerating power (P_a) which will happen at time zero. In order to cover the discontinuity in the calculations, Equation 4.9 is modified to be

$$\Delta\delta_n = \Delta\delta_{n-1} + \frac{(\Delta t)^2}{2M}(P_{a(n-1)} + P_{a(n-2)}). \tag{4.10}$$

4.4. Differences Between Deterministic and Stochastic Approaches

The main difference between the deterministic and stochastic methods for evaluating the transient performance of a power system is the introduction of the probability distributions for different system parameters in the stochastic approach. Figure 4.2.a. shows the basic procedure for deterministic transient stability evaluation while Figure 4.2.b. presents a procedure for probabilistic transient stability evaluation.

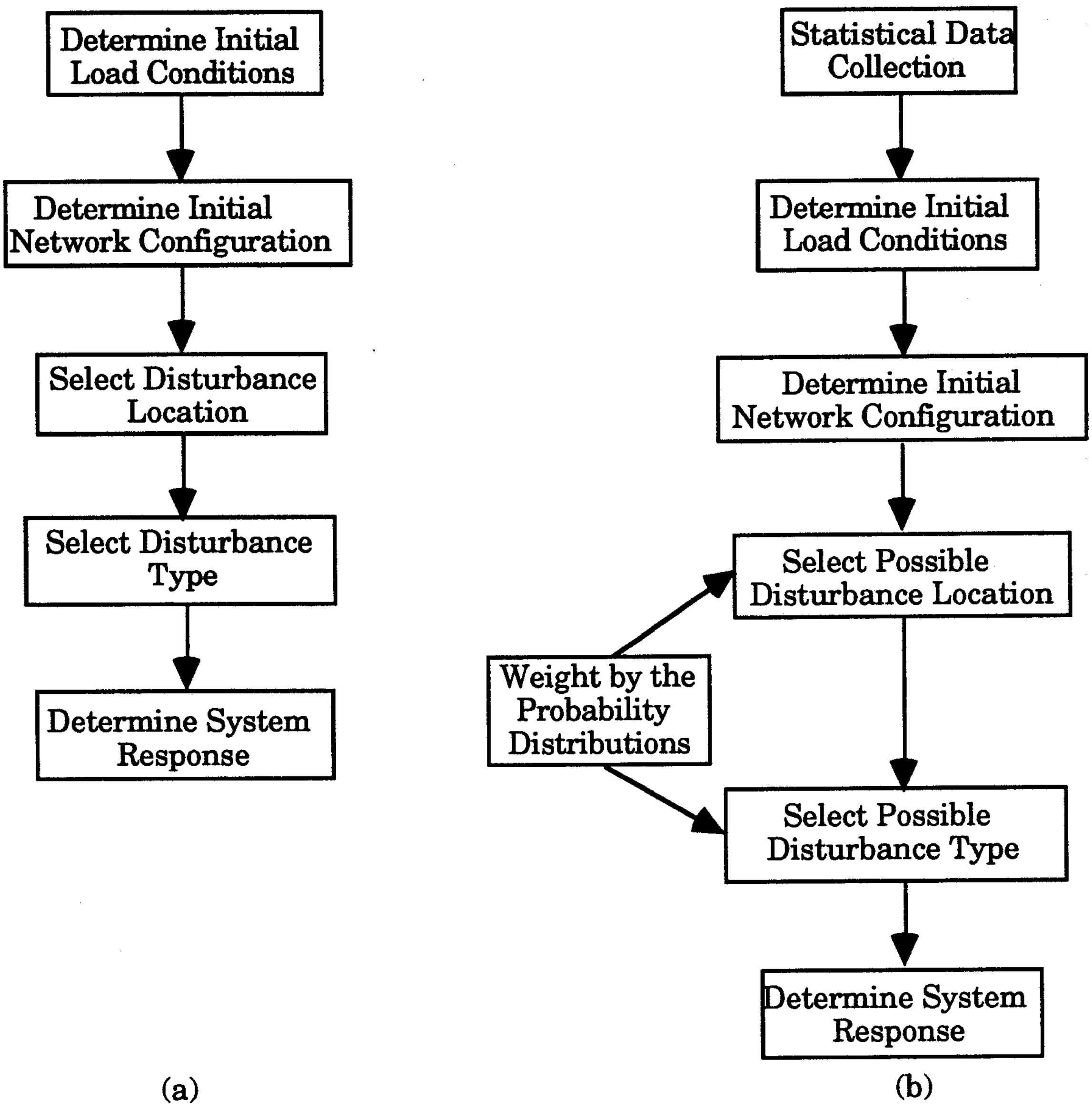

Figure 4.2: (a) Deterministic transient stability procedure
(b) Probabilistic transient stability procedure

One of the important, basic factors that affect probabilistic transient stability assessment is the statistical data collection required to determine the probability density function for the fault location, type and clearing time. After that, transient stability analysis is done at all possible locations and for all possible types of faults. The results are weighted by the probability density function of each parameter using the conditional probability approach. On the other hand, the deterministic approach does not require any statistical data. The analysis is usually done only at certain locations and for certain fault types (usually the worst case).

Generally speaking, the probabilistic approach does not eliminate the need for the deterministic approach. Rather, it includes both the deterministic and the probabilistic procedures and combines the results to obtain the required system indices.

4.5. A Probabilistic Index for Transient Stability

Section 4.2 proposed that probabilistic factors should be included in the evaluation of power system stability. The first and the most difficult step in the probabilistic approach is to collect statistical data on system faults such as fault types, locations, and clearing times. Each of these three factors are mutually exclusive and therefore the conditional probability approach can be used to assess system transient stability.

Figure 4.3 shows the probability density function for the fault clearing time. If the critical clearing time (CCT) is the maximum time in which the fault must be cleared, then the shaded area in this figure represents the probability of stability P_{ijk} for a fault type i at a location j of line k. Using the conditional probability approach, the probability of stability (PST) for all fault types (I) at all possible locations (J) of all lines (K) is given by the following equation:

$$PST = \sum_{K=1}^{K} \sum_{j=1}^{J} \sum_{i=1}^{I} P_{ijk}\, P_i\, P_j\, P_k \tag{4.12}$$

where:

P_{ijk} is the probability of stability if a fault of type i is occurring at location j of line k,

P_i is the probability of having a fault of type i occurring at location j of line k,

P_j is the probability of having a fault at location j of line k and

P_k is the probability of having a fault at location k.

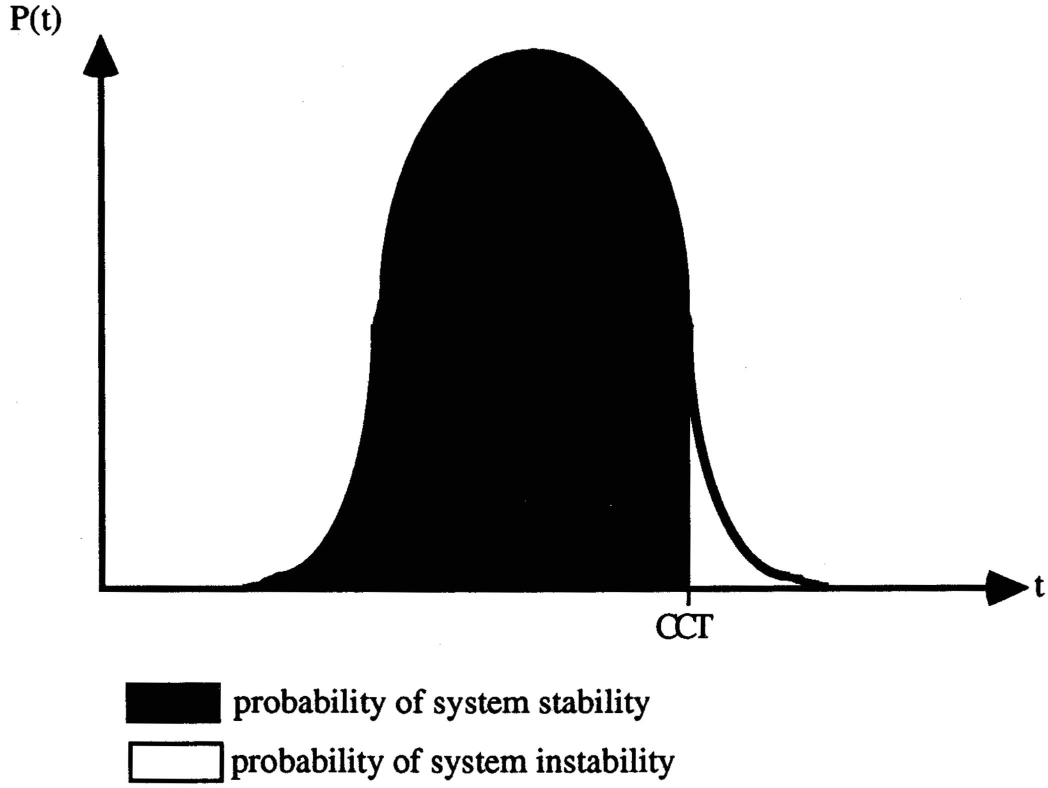

Figure 4.3: Probability density function for the fault clearing time

4.6. Description for the Developed Probabilistic Transient Stability Program

A digital computer program called PTSE (Probabilistic Transient Stability Evaluation) has been developed to simulate the probable faults at possible system locations and, hence, calculate the probability of stability indices for the system. In the program, all the indicated simplifications to reduce the complexity of the power system were utilized. The general flow chart of the developed program is given in Figure 4.4.

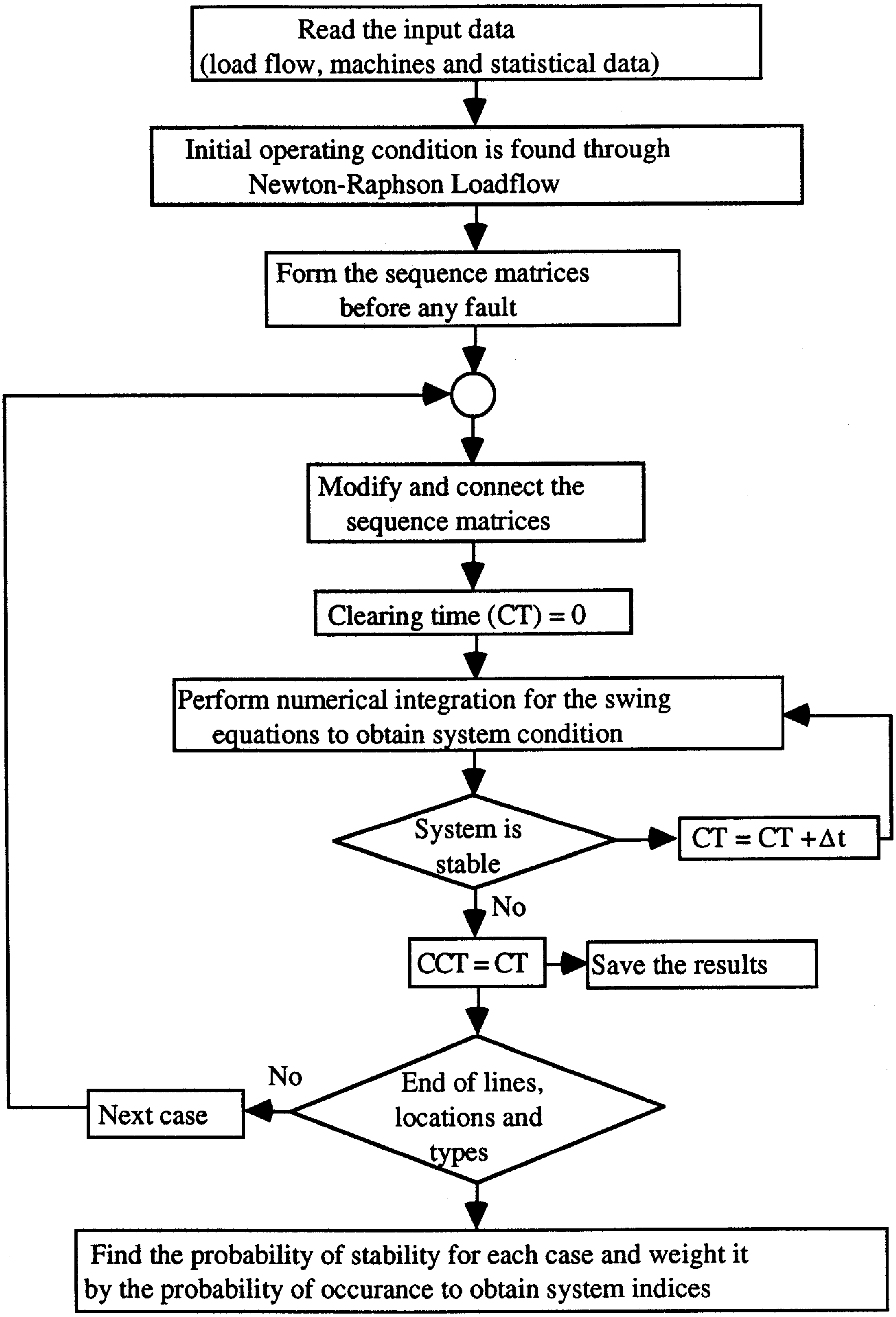

Figure 4.4: General flow diagram for the PTSE program

The functions of the main parts of the program are as follows:

1. Reading the load flow, stability and statistical data.
2. Performing initial load flow for the system using the Newton-Raphson technique.
3. Calculating the initial conditions for the system before the fault.
4. Forming the sequence matrices for the system before any fault.
5. Simulating the specified fault by doing the following steps:
    a. modifying and connecting the sequence matrices.
    b. Performing step-by-step integration and finding the critical clearing time.
    c. Calculating the probability of stability.
6. Repeating Step 5 for all possible fault types and locations.
7. Weighting all fault types and locations by their occurrence probabilities to obtain the system indices.

4.7. Probabilistic Transient Stability Evaluation for the RBTS

4.7.1. Including transient stability data in the RBTS

The published RBTS does not include the data required to conduct transient stability studies. The required extension includes the following data:

1. zero and negative sequence resistances and reactances of transmission lines,
2. probability distribution for fault clearing times.
3. probability distribution for fault types
4. probability distribution for the fault locations.
5. positive, negative and zero sequence resistances and reactances for the synchronous machines.
6. inertia constants for the machines.

The required additional data are presented in Appendix A.

4.7.2. Application of Probabilistic Transient Stability Assessment to the RBTS

The basic configuration of the system shown in Chapter 2 is used in this study. The system deterministic and stochastic data (bus, line, and generator data) are given in Appendix A. The fault clearing times are assumed to be normally distributed and it is assumed that faults occur at the ends of a transmission line with a 0.5 probability of occurrence at each location.

Figure 4.5 shows the weighted probability of stability for all the RBTS transmission lines and also the overall probability of stability for the system. It is clear from this figure that three phase faults and double line to ground faults have the lowest probability of stability while single phase and phase to phase faults have a probability of stability of unity as the system is stable for any single line or two line fault occurring at any system location. Figure 4.5 also shows that Lines 2,3 and 7 are the most critical lines in the system. This is due to the fact that these lines are connected to the major generator bus #2.

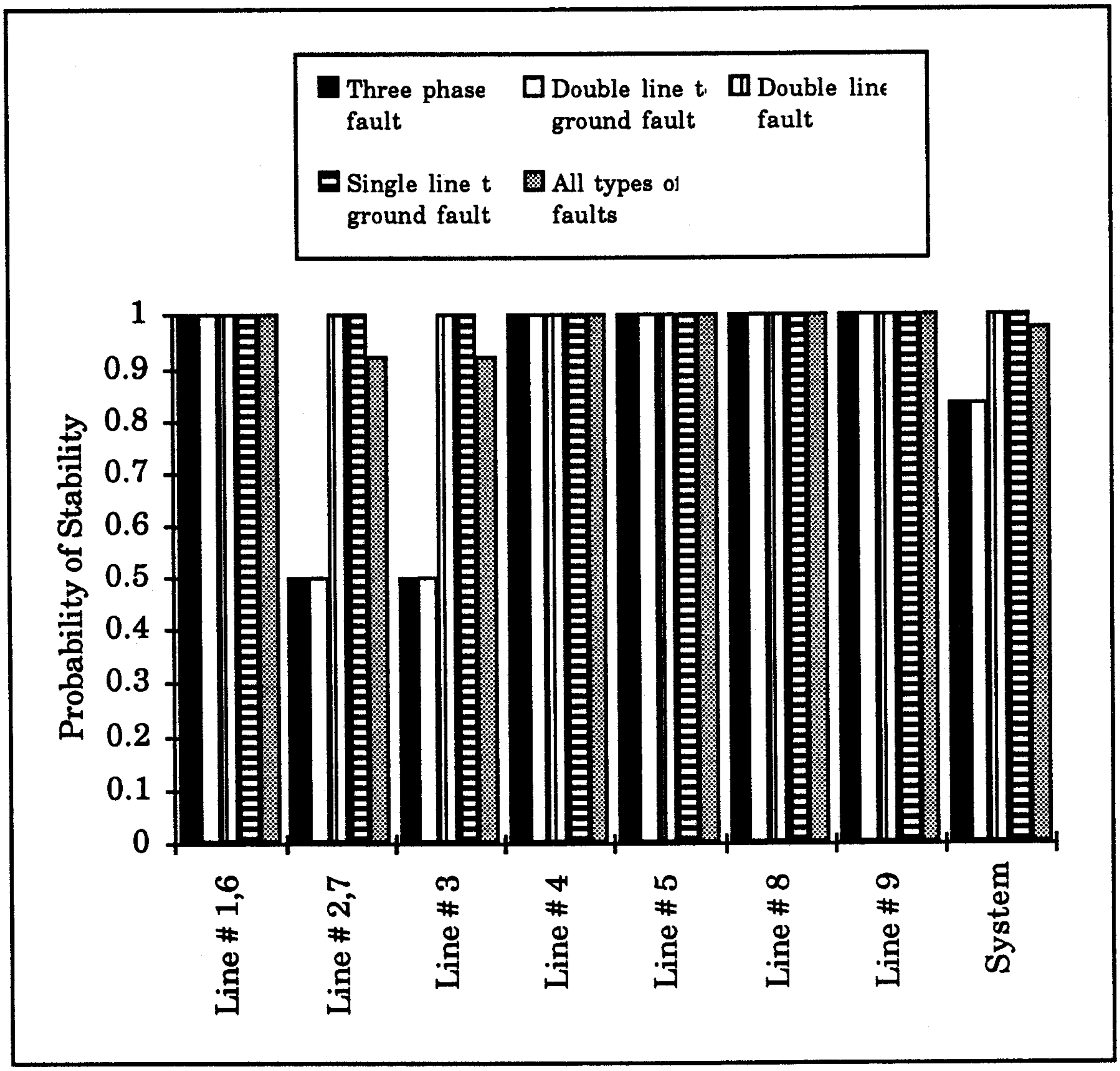

Figure 4.5: Weighted probability of stability for the RBTS and its transmission lines

4.8. Summary

This chapter describes the basic differences between the deterministic approach and a stochastic approach to transient stability evaluation. The swing equations which describe the motion of synchronous machines and their solution using step by step integration are presented. A probabilistic approach to transient stability evaluation is discussed. A digital computer program called Probabilistic Transient Stability Evaluation (PTSE) has been developed to apply stochastic concepts to the transient stability problem. The stochastic technique is illustrated in this chapter by application to the RBTS utilizing the developed program (PTSE). The stability indices evaluated for the RBTS are presented graphically in Figure 4.5. Stability indices in this form are practical and realistic and should prove useful in system planning, control and design.

5. AN APPROACH TO SECURITY EVALUATION OF COMPOSITE POWER SYSTEMS

5.1. Introduction

There are three fundamental reliability related design considerations in system planning, namely:

1. *Adequacy evaluation:* this relates to whether the installed generation and transmission capacities are sufficient to meet the total system load requirements.

2. *Security constrained adequacy evaluation:* this relates to whether the amount of generation and transmission reserve is sufficient to avoid load curtailment under failure events.

3. *Security evaluation:* this considers the capability of the system to operate under stable conditions when a major change in the system occurs.

The first consideration is referred to as *adequacy evaluation* and Chapter 2 of this thesis presents a description of adequacy evaluation in composite power systems. Studies that take the first two noted considerations into account are referred to as *security constrained adequacy analyses* and an example study is presented in Chapter 3. The concepts associated with transient performance evaluation are presented in Chapter 4. The inclusion of these concepts in the security constrained adequacy evaluation leads to the ability to perform *overall reliability evaluation* which includes both adequacy and security.

In this chapter, the steady state security constraint set presented in Chapter 3 is extended by adding a transient performance constraint set to form an overall security constraint set.

5.2. A Security Constraint Set for Composite Power System Reliability Evaluation

Security constraints can be divided into two main parts: *steady state performance constraints* and *transient performance constraints*. Transient performance constraints test the capability of a system to be operated in such a way that it remains stable when faults occur. Steady state performance constraints test the capability of a system to supply the load without violating equipment operating limits. The steady state performance constraints set is discussed in Chapter 3. The transient performance constraints set is derived from the concept presented in Chapter 4.

5.2.1. The transient performance constraints

A power system is usually designed to ensure that synchronism will be maintained under specified system failures such as a three phase fault at particular system buses or transmission lines. This "worst case" approach has been widely used by utilities. It was noted in Chapter 4 that many other contingencies in different locations are also probable and might have higher probabilities than the occurrence of three phase faults near generation buses. At the same time, different system faults do not have the same impact on the system. A stochastic approach is therefore the most suitable way to obtain a realistic appraisal of the expected transient performance of the system. This can be expressed as:

$$PST_i \geq PST_i^m \tag{5.1}$$

where PST_i^m is the minimum probability of stability for line i.

The corresponding region that represents all lines is defined as

$$R_{TS} := \{PST : PST_i \geq PST_i^m\}. \tag{5.2}$$

5.2.2. The security constraint set

The total security constraints set R_T can be found by combining both steady state and transient security constraint sets. The power system is considered to be operating within limits when there exists a solution in (v, δ, t) - space which satisfies the following relation:

$$R_T := R_{SS} \cap R_{TS}. \tag{5.3}$$

The flow chart used for detecting different operating states in Figure 3.2 and discussed in Chapter 3 can be used here for an overall security evaluation. In this case, the total constraint set R_T is utilized instead of the steady state constraint set R_{SS}.

5.3. A Security Study for the MRBTS

The probabilistic indices for the MRBTS have been calculated using the comprehensive constraint set. In this analysis, up to the fourth level of generator outages, third level line outages and third level of line plus generator outages are considered. The analysis covers more than 99.997 % of the total sample space. The remaining 0.003 % consists of higher order contingencies which are not covered in the analysis.

The annualized probabilities and frequencies for different operating states at 185 MW system load are shown in Table 5.1 and Figure 5.1. The selected minimum probability of stability is 70%. This selection was done to ensure that the system will remain stable at least under the highly probable faults (single line to ground faults). The probability of the normal state in Table 5.1 and Figure 5.1.a is greater than zero which means that there is no first level contingency that violates any of the transient performance constraints. It can be seen from both Table 5.1 and Figure 5.1 that the probability of the extreme emergency state when the transient performance constraints are included is equal to that obtained without including the transient performance constraints. This is due to the fact that no decision is made on load curtailment when the system is considered to be at risk. The probability of the emergency state increases considerably by recognizing the transient constraint set. There is an increase of more than 12% in the CSOSR due to the consideration of the transient performance constraints.

Table 5.1: Probabilities and frequencies of different operating states

System State	Excluding Transient Performance Constraints $PST^m = 0.0$ %		Including Transient Performance Constraints $PST^m = 70.0$ %		% Change in the system states	
	Probability	Frequency	Probability	Frequency	Prob.	Freq.
Normal	0.899362	73.494368	0.845798	59.821520	6	19
Alert	0.091772	35.516126	0.144317	48.062565	57	35
Emergency	0.000074	0.135088	0.001127	1.309558	1422	869
Ext. Emerg.	0.008580	3.982606	0.008580	3.982606	0	0
No Problem	0.000187	0.249639	0.000153	0.201578	18	19
CSOSR	0.008680	4.117694	0.009733	5.292164	12	28
Total	0.999975	113.37783	0.999975	113.37783		

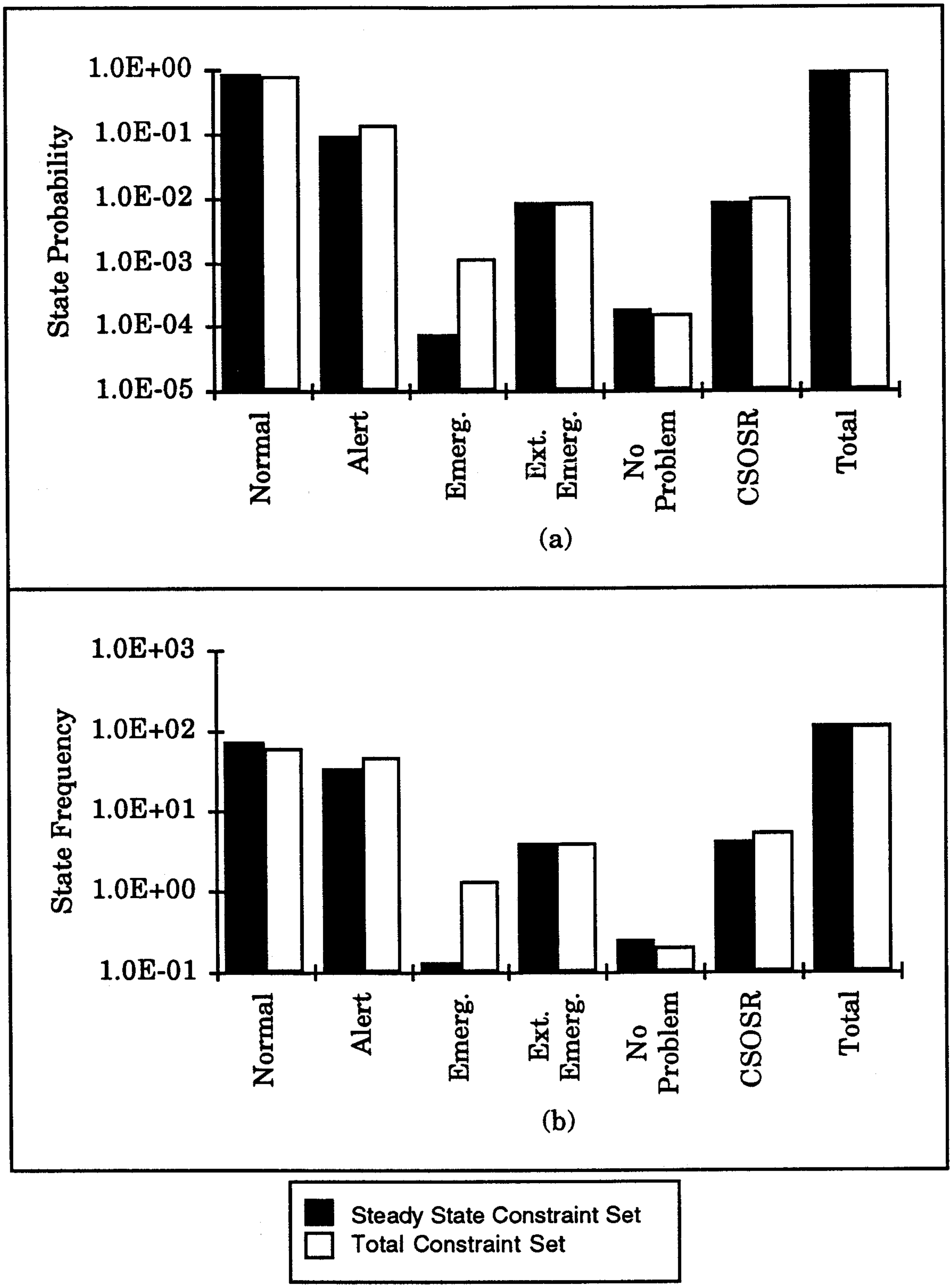

Figure 5.1: (a) Probabilities of different operating states
(b) Frequencies of different operating states

5.4. Effect of Changing the Transient Performance Constraints

The effect of changing the transient performance constraints by changing the minimum acceptable limit for the probability of stability (PST^{m}) is shown in Figure 5.2 and Figure 5.3. Figure 5.2 shows the effect of increasing the minimum probability of stability on the probability of different operating states. It can be seen that the emergency and the composite system operating state risk (CSOSR) probabilities increase when the minimum probability of stability criterion is increased. The normal state and no problem probabilities decrease as the required stability criterion increases. The alert state probability increases initially when some of the normal probability transfers to the alert state. After that it will decrease slightly with the increase in the required stability criterion. Similar observations are apparent in Figure 5.3 which shows state frequencies instead of probabilities.

5.5. Effect of Load Variation and Annual Indices

The annual indices are calculated using the seven step load model described in Chapter 3. The effect of load variation on the different operating states probabilities is shown in Figure 5.4. Figure 5.5 shows the effect of different load levels on the frequency of the different operating states. These figures also shows the annual results using the seven step load model. It can clearly be seen that the annual CSOSR is considerably smaller than the CSOSR calculated at the system peak load.

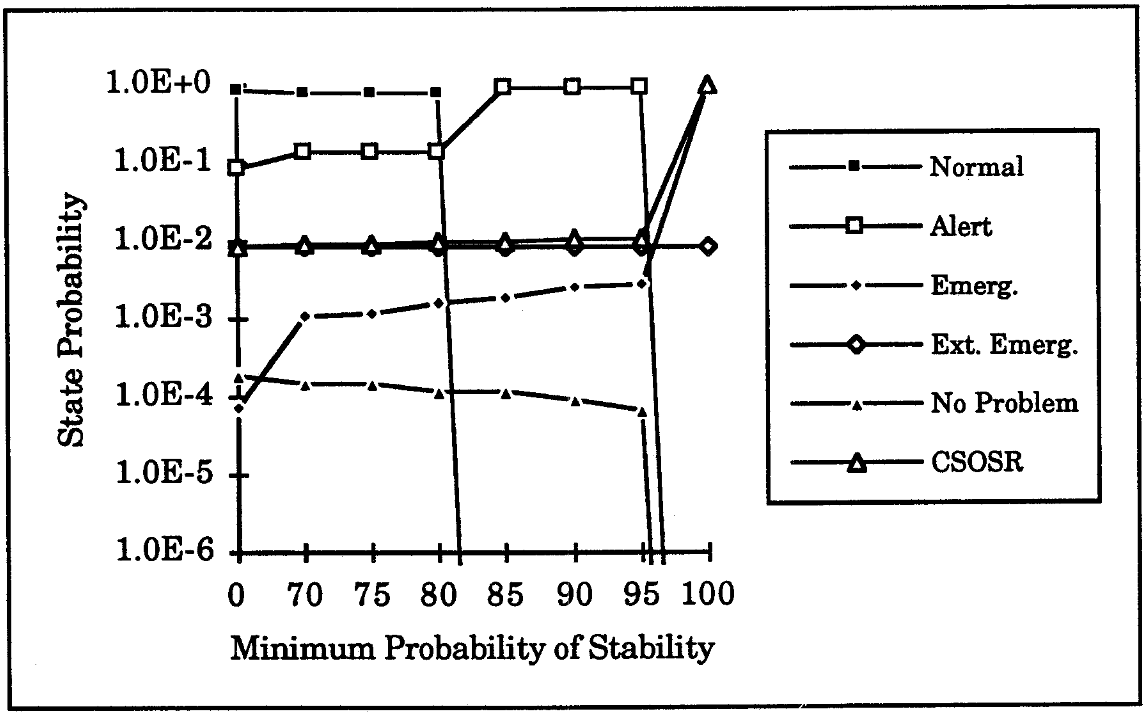

Figure 5.2: Effect of changing PST^{m} on the probability of different operating states

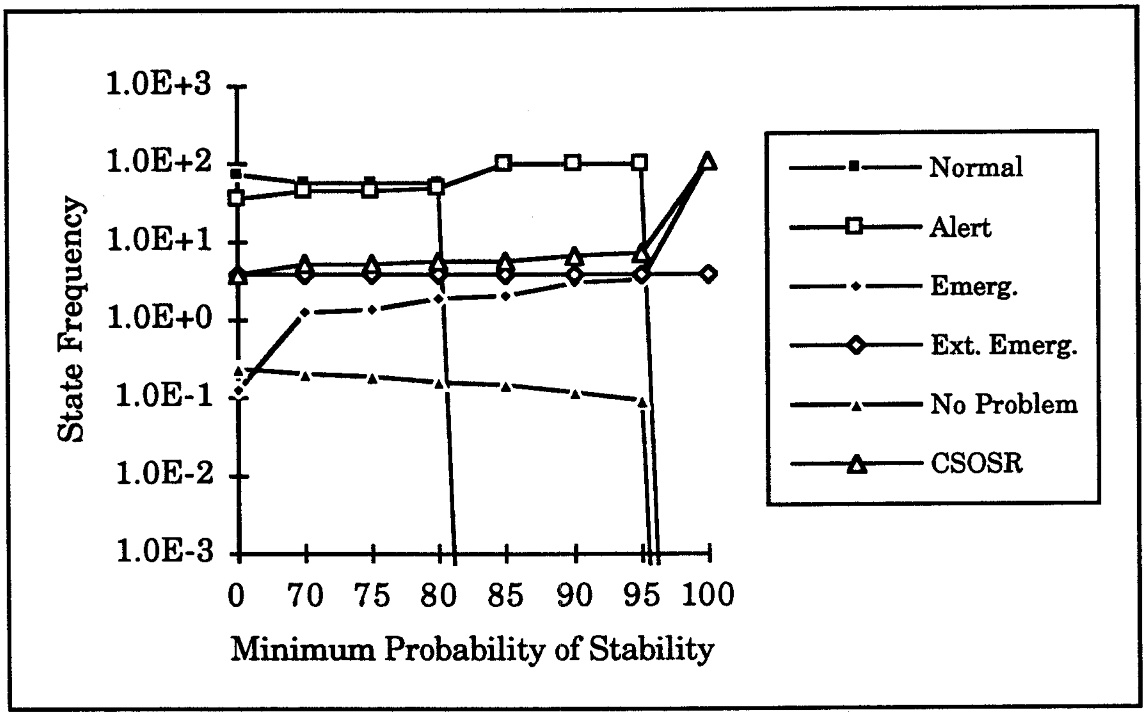

Figure 5.3: Effect of changing PST^{m} on the frequency of different operating states

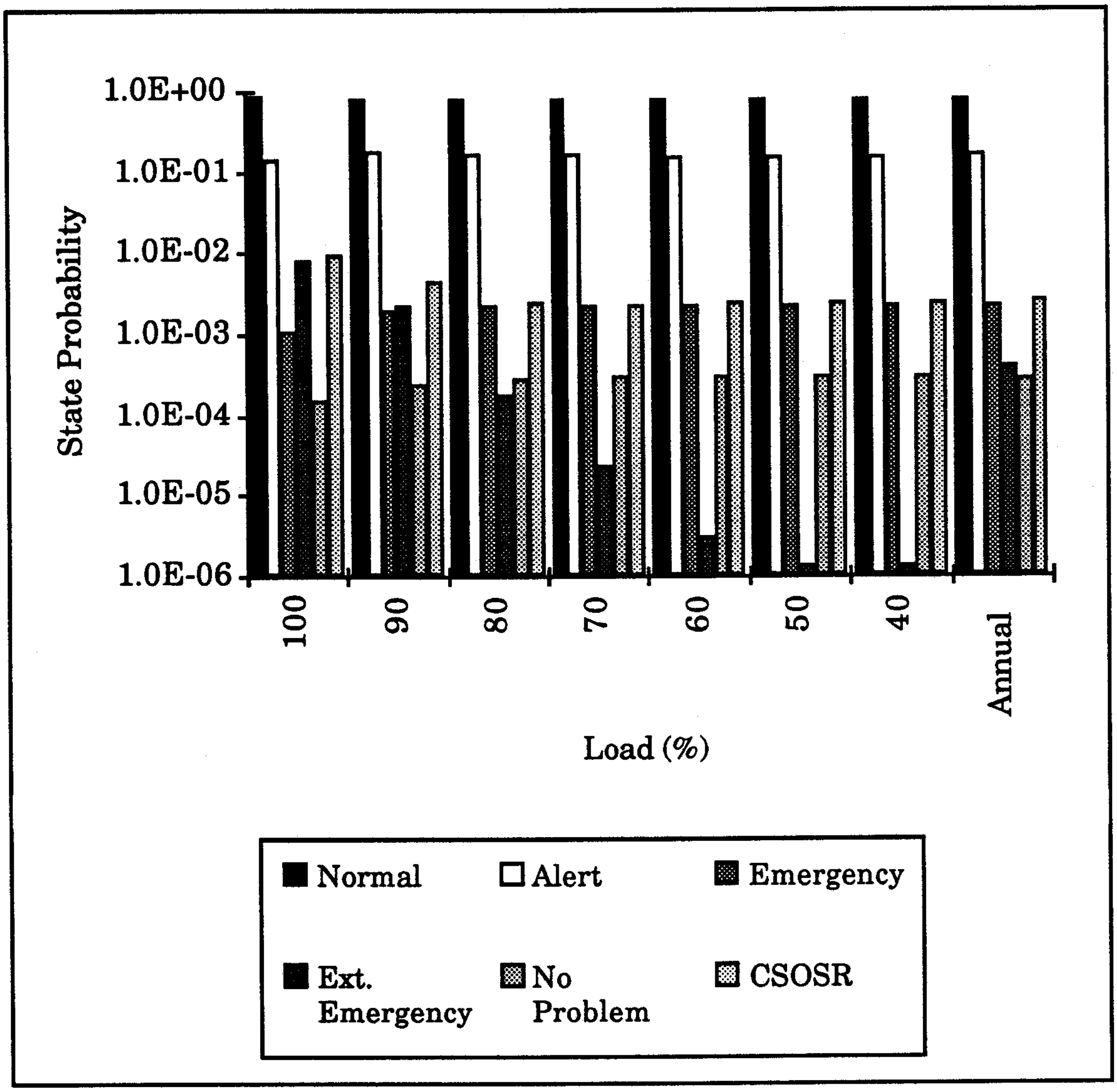

Figure 5.4: Effect of varying the load on different operating states probabilities and the annual probability indices

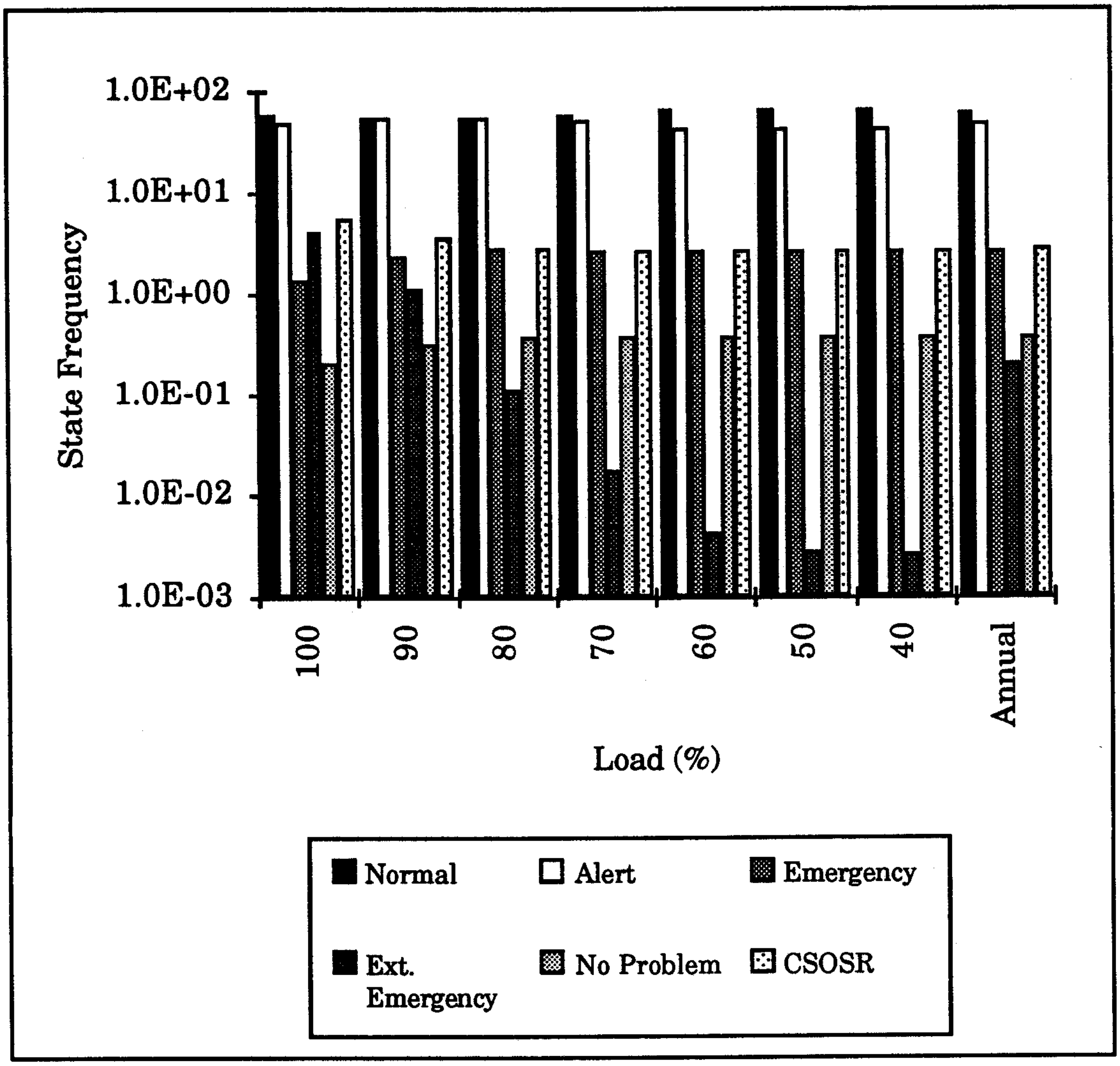

Figure 5.5: Effect of varying the load on different operating states frequencies and the annual frequency indices

5.6. SUMMARY

In this chapter, the framework developed by Billinton and Khan [11] has been extended by incorporating the transient behavior of the system to form a realistic security constraint set.

The new constraint set is utilized to obtain security indices for the MRBTS. The probabilistic indices for different operating states have been calculated considering the constraint set given in Reference [11] and the new security constraint set. The effect of varying the transient performance constraint demonstrates the importance of taking the effect of system dynamics into consideration. The minimum acceptable probability of stability of 70% used in this study is approximately equal to the occurrence probability of single line to ground faults which implies that the system must be stable for at least all single line to ground faults. It is noted that for the example considered the effect of considering the transient behavior of the system has a significant effect on the risk indices. Both annual and annualized indices are presented in this chapter using the developed constraint set.

6. UTILIZATION OF THE SECURITY EVALUATION CONCEPT IN POWER SYSTEM PLANNING

6.1. Introduction

Power system planning usually starts with the load forecasting process as an accurate estimation of both future demand and energy are essential. The forecast demand and energy requirements are used in planning the generation, transmission and distribution systems. There is no one particular method or approach to load forecasting that works for all power utilities and it appears that there are as many valid forecasting methods as utilities [26]. In the studies described in this chapter, expansion planning is done based on a total increase in the load of 10% in steps of 2%. No attempt has been made to relate this to a particular time in the future.

The domain of power system operation has been divided into four operating states namely, normal, alert, emergency and extreme emergency. The mathematical model for these states is described in the previous chapters. The system does not violate any steady state and/or transient constraints if it is working in the normal or alert states. The main objective of system planning is to design a system that operates most of the time in these two states or, in other words, to operate with a high probability of being in these two states. The risk index (CSOSR) is defined in the previous chapters as the probability of not operating in the normal or alert states. This risk index is used in this chapter as a criterion for composite power system expansion planning.

6.2. Expansion Planning in the MRBTS

System expansion planning at HLII is performed by adding appropriate generation facilities in order to satisfy the total system load at an acceptable level of reliability. The pre-specified risk may be associated with a deterministic or a probabilistic criterion. The most common deterministic criterion is the loss of the largest unit or some percentage of the peak demand [40]. LOLE [40] is the most common probabilistic risk index. The transmission facilities are not included in the analysis at HLI.

In this section, expansion planning for the RBTS is done utilizing the Composite System Operating State Risk (CSOSR). As noted earlier, the system does not violate any steady state or transient constraints in the normal or alert states. System planners, therefore, would like to have the systems reside with a high probability in these states. The no problem area represents states that belong to neither normal or alert states. The summation of normal, alert and no problem probabilities gives the probability that the system is operating in a favorable condition. The complement of this summation, which represents the risk index (CSOSR), gives the probability of unfavorable operating conditions. The risk index (CSOSR) is utilized in this chapter to justify the addition of generation and transmission facilities under system load growth. An acceptable CSOSR of 0.0125 is used for expansion planning of the MRBTS. This means that the system is considered to be reliable if its CSOSR is equal to or less than 0.0125.

6.2.1. Generation expansion planning in the RBTS

The objective of this study is to determine at which load level an additional generating unit must be added to satisfy the specified risk level. Table 6.1 shows the parameters of additional generating units. It is assumed that generating units can be added to any system bus in the analysis. In order to find which bus is the most suitable for generating unit additions, generators are added sequentially to each bus and the study conducted in steps up to a 10 % increase in the peak load. Figure 6.1 shows that without violating the specified risk level, the system can only carry up to a 3% increase in peak load without requiring expansion of the existing generation and transmission facilities. Figure 6.2 shows the effect of adding generation at different system buses. It can be seen from Figure 6.2 with an addition of one generator at bus 2, the system can serve up to an 8% increase in the peak load at a specified risk level of 0.0125. If the peak load increases by more than 8%, extra generating units must be added. When the units are added to Bus #1, the system can carry up to a 9.5% increase in the peak load by adding two generating units. It can be seen from Figure 6.2 that the two additional generating units are not enough to supply an increase of 10% in the system peak load regardless at which bus the units are added. More generating units must be added or an expansion of the existing transmission facilities must be conducted in order to meet such a load increase.

Table 6.1: Parameters of the additional generating unit for the MRBTS

				Pos. Seq.		Neg. Seq.		Zero seq.	
Rating (MW)	MTTF (Hours)	MTTR (Hours)	H p.u	R p.u	X p.u	R p.u	X p.u	R p.u	X p.u
10	550	75	3.0	0.00	0.20	0.00	0.10	0.00	0.05

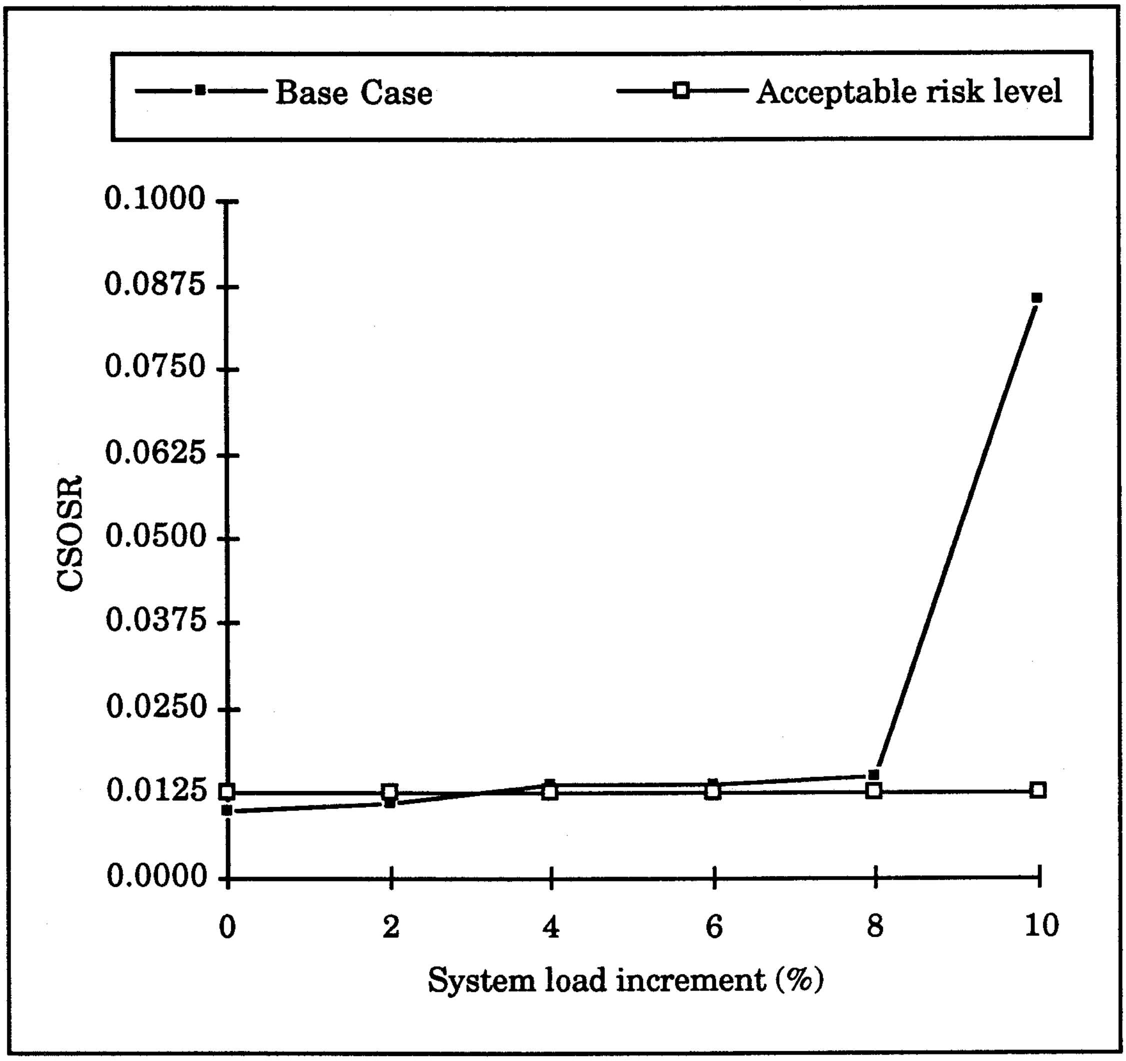

Figure 6.1: CSOSR variation with peak load increment

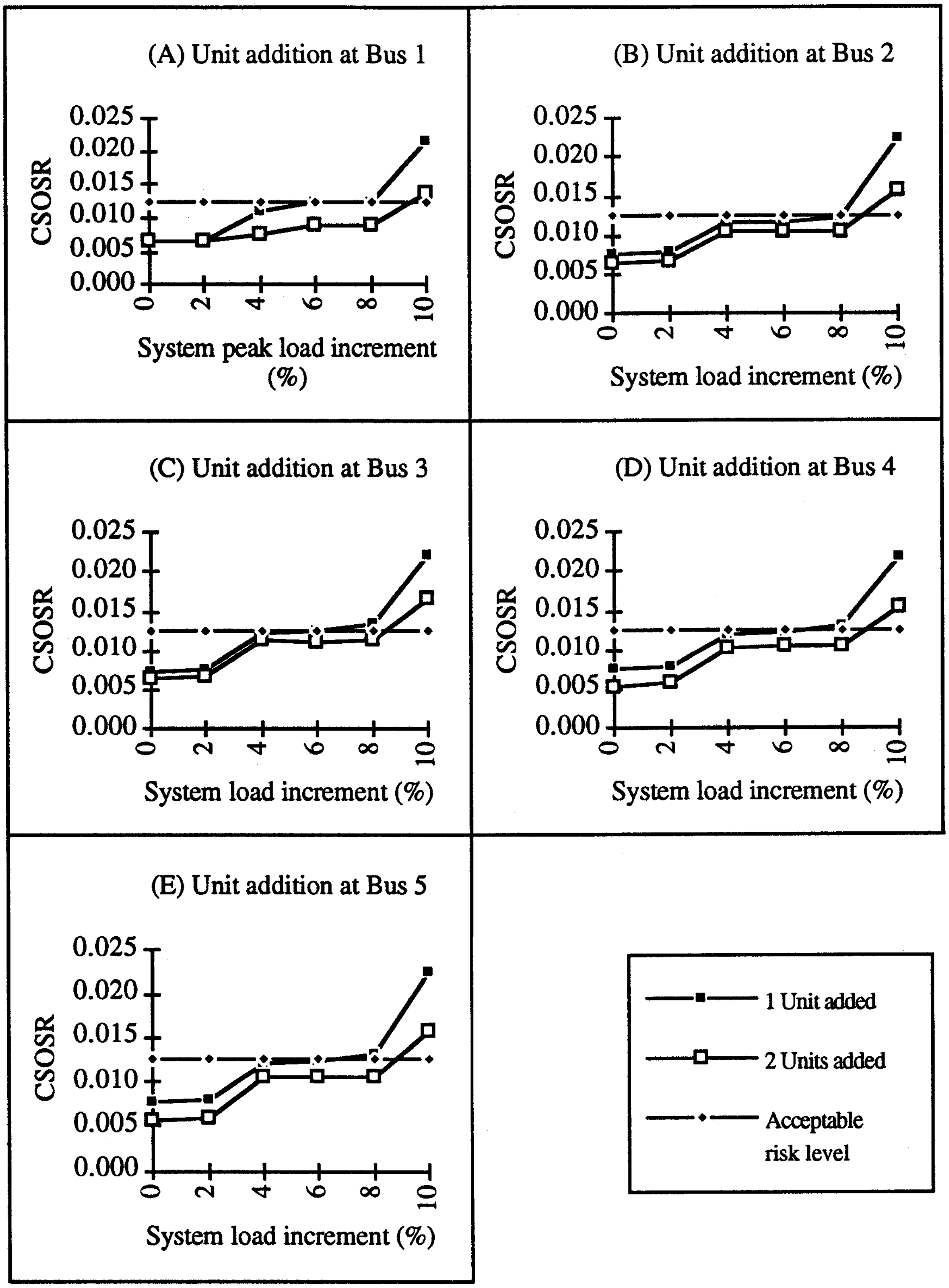

Figure 6.2: CSOSR variation with addition of generation at different buses

6.2.2. Transmission expansion planning in the RBTS

In the previous section, only extra generating units ~~only~~ are added to the system to reduce the CSOSR. Some of the reliability violations, however, occur due to limitations in the capability of the transmission facilities where weaknesses in the transmission configuration cause the transient limits to be violated. Expansion analysis of the transmission facilities, therefore, must be conducted. In order to illustrate the effect of additional transmission facilities, selected additions were analyzed. Lines were added to the system one at a time. It is also assumed that one new transmission line between any two buses has the same parameters as the original line connecting these two buses. The following line additions were considered in the analysis:

Case	Addition
1.	line between bus 1 and 2 similar to line 1 or 6,
2.	line between bus 1 and 3 similar to line 2 or 7,
3.	line between bus 2 and 4 similar to line 3,
4.	line between bus 3 and 4 similar to line 4,
5.	line between bus 3 and 5 similar to line 5 and
6.	line between bus 4 and 5 similar to line 8.

Figure 6.3 shows the effect of adding lines (each of the above cases) on the CSOSR.

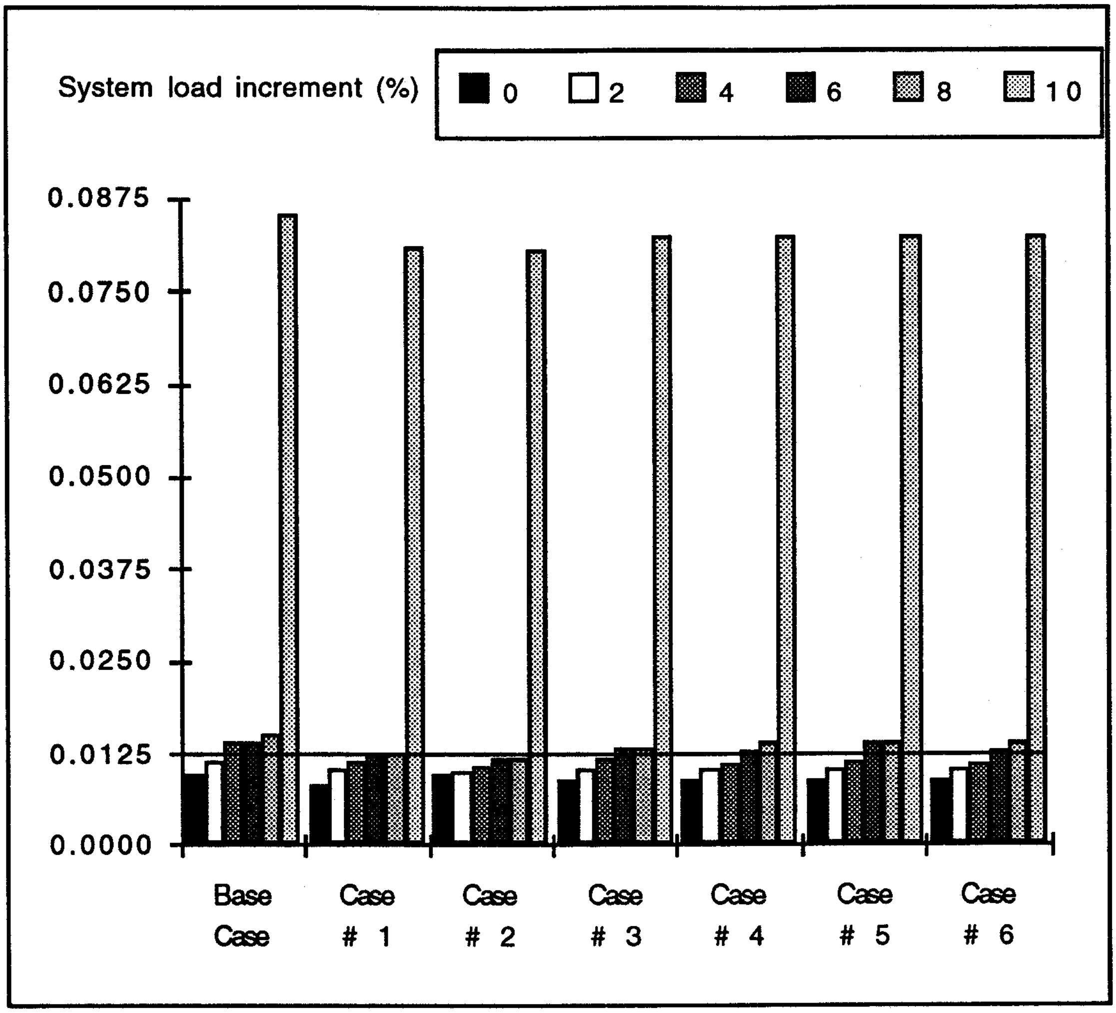

Figure 6.3: Effect of transmission expansion on the CSOSR

It can be seen from Figure 6.3 that transmission expansion can reduce the CSOSR. The figure shows that with the addition of a line between bus 1 and 3 (Case # 2), the system can carry up to an 8% increase in the total system peak load without violating the steady state or transient performance constraints. If there is more than an 8% increase in the system peak load, a single transmission line addition cannot satisfy the specified load level and extra transmission and/or generation facilities must be added.

6.2.3. Improving the protection system

In this section, no transmission or generation facilities are added but the circuit breakers that isolate the faulted transmission lines are improved. The improvements considered are:

1. the tripping time of the circuit breakers is reduced by 50% and
2. the standard deviation of the tripping time probability distribution is reduced by 50%.

Figure 6.4 shows how the CSOSR is affected by the above improvements. It can be seen from Figure 6.4 that the system can carry up to an increase of 5% of the system peak load by improving the system protection.

The addition of generating units, the addition of transmission lines or improving the protection system all lead to a reduction in the CSOSR. The addition of generating units alone to the system may lead to a situation in which the addition of more units does not significantly improve the CSOSR either because of a weakness in the protection system or a capacity limitation of the transmission facilities. The addition of only transmission lines to the system may also not be a good planning decision if the existing transmission system is capable of carrying the energy from the generating stations to the major load points. Also, improving the existing protection system may not be a good planning decision if the existing protection system is capable of isolating the faulted lines before creating any stability problems.

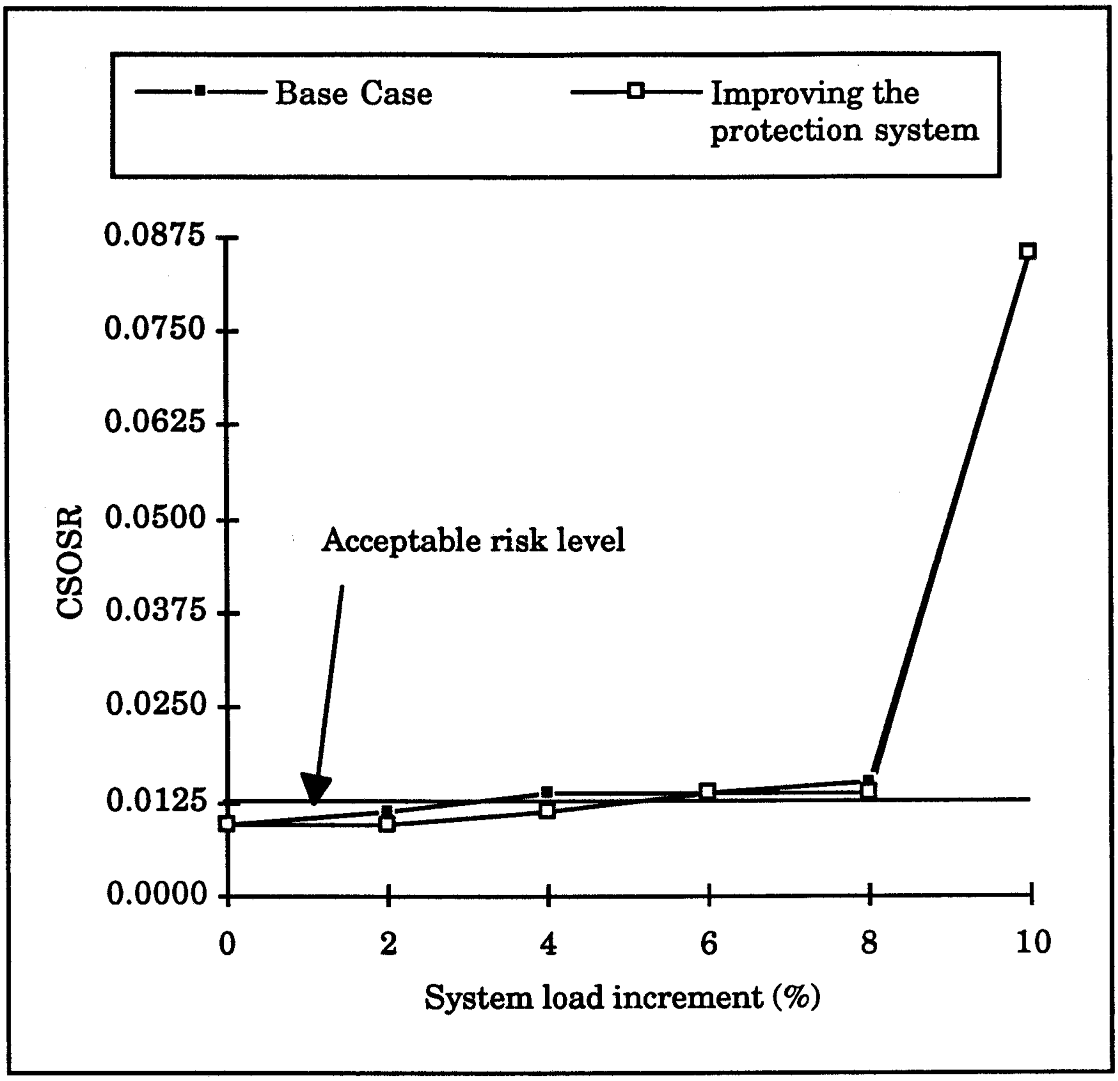

Figure 6.4: Effect of improving the protection system

Table 6.2 summarizes the best alternatives arising in the three previous sections and presents a typical planning problem. Valid and practical decisions can not be taken by considering isolated reinforcements in the generation facilities, transmission facilities or protection systems. Planning must be undertaken which considers all possible combinations of the three facilities studied and must include consideration of the economics of each alternative in addition to the technical considerations. There are many possible combinations of generation and transmission additions which could be considered. No attempt has been made in this research work to optimize the system investments. The objective was to examine the incorporation of security constraints in the evaluation of a system risk index and to illustrate its use in facility addition analysis.

Table 6.2: Comparison between different expansion alternatives

Facility Addition/Improved	Maximum percentage increase in the load
Base Case	3.0 %
One line is added between busses 1 and 3	8.0 %
One generator is added at bus 1	8.0 %
Two generators are added at bus 1	9.5 %
Protection system is improved	5.0 %

6.3. Summary

The Composite System Operating State Risk (CSOSR) is defined in Chapter 5 as the probability of residing in an undesirable system operating state. This index is used as a planning criterion and its utilization in the planning procedure is illustrated by application to the RBTS. The selection of an appropriate location for new generating units as well as the addition of new transmission lines is an important aspect of HLII expansion planning. The studies conducted in this research work show that the addition of new facilities (generating units or transmission lines) are important considerations and proper selection and location of these facilities can make the system more reliable.

The expansion planning examples considered in this chapter are simplistic. There are many other expansion considerations which must be included in actual expansion planning studies.

7. SUMMARY AND CONCLUSIONS

Composite power system reliability evaluation involves assessment of the ability of the combined generation and transmission facilities to supply adequate, dependable and suitable electric energy to the major system load points. The objective of this thesis is to develop a new technique to evaluate the security of composite power systems. This technique takes into account both the steady state performance and the transient performance of the system. The technique developed in this thesis is illustrated by application to the Roy Billinton Test System (RBTS).

The contingency enumeration approach is the most basic technique for composite power system reliability evaluation. The technique involves the selection of contingencies, the evaluation of each contingency and the assessment of the reliability indices. There are several solution techniques that can be used to evaluate contingencies. In Chapter 2, adequacy indices are calculated using three network solution techniques: network flow, dc load flow and ac load flow methods. The selection of the solution technique depends on the intent behind the reliability study and the utilized failure criteria. It is noted in this chapter that more comprehensive information on the system is provided when ac load flow is used as the network solution technique.

To simplify the approach used in quantifying the security problem, the system performance is divided into steady state performance and transient performance. In Chapter 3, a steady state constraint set is proposed and illustrated utilizing the RBTS. The system operating states are calculated utilizing the steady state constraint set. The system operating states can be categorized into two zones. The first zone can be called the no violation zone, in which the system is either secure or adequate. The second zone can be called the violation zone, in which the system is not adequate and hence not secure. The Composite System Operating State Risk (CSOSR) represents the probability of the system being in the violation zone.

The second type of system performance, system transient performance, is discussed in Chapter 4. A worst case study such as a three phase fault or phase to phase to ground fault near the generator buses is normally performed to ensure that the system remains stable after clearing the fault. The probabilities associated with different types of faults are , however, quite different, and it is not realistic to invest money in building a system that is capable of handling faults that rarely occur. The best approach is therefore to include the probabilities associated with the influential factors. The probability of stability (PST) is a realistic and relatively simple index that can be used for this purpose. A digital computer program was developed to calculate the system probability of stability indices and has been utilized to assess the indices for the RBTS.

A new constraint set has been developed to quantify the transient performance of the system. This constraint set based on the PST index is discussed in Chapter 4. The system, in a certain configuration, is considered to be stable if its probability of stability is less than a threshold value. This value can be found from the probability distributions of different types of system faults. In order to include the transient performance in the analysis, an ac load flow must be used as a network solution technique. The transient performance constraint set is combined with the steady state performance constraint set to form an overall constraint set that can be used in quantifying the security of composite power systems. This concept is introduced and illustrated in Chapter 5 when the RBTS is again used as the test system. The reliability indices for different operating states are evaluated. It was found that considering the transient performance of the system provides a realistic approach and that this inclusion has a significant effect on the overall reliability indices.

A system operates without violating any of the steady state or transient constraints in both the normal and alert states. Therefore, the system operation objective should be to operate the system with a high probability of being in these two system operating states. The utilization of the complement of these two states , CSOSR, as a simple expansion planning criterion to meet future load growth is illustrated in Chapter 6 using the RBTS as a test system. It was shown that the selection of new generating units or transmission lines is very important. The CSOSR can be used to assist in selecting the location which gives the highest reliability margin. The expansion planning illustrated in this chapter is simple, as the intention was to demonstrate the utilization of the new CSOSR as a planning tool. There are many other considerations which must be included in actual expansion planning.

In conclusion, the inclusion of the transient performance of the system is only the initial phase of the development of a quantitative assessment of system security. Much work has yet to be done in the area of data collection and the incorporation of reliability worth concepts. Finally, it is expected that the stability indices and the procedure presented in this thesis will serve as a stepping stone to further development in the area of power system security evaluation.

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APPENDIX A. Data of the 6-bus RBTS

Base MVA = 100

Table A.1: Line data

Line No.	Buses I	J	R p.u.	X p.u	B/2 p.u	I-rat. p.u	λ F/y	r Hrs
1	1	3	0.0342	0.1800	0.0106	0.85	1.5	10
2	2	4	0.1140	0.6000	0.0352	0.71	5.0	10
3	1	2	0.0912	0.4800	0.0282	0.71	4.0	10
4	3	4	0.0228	0.1200	0.0071	0.71	1.0	10
5	3	5	0.0228	0.1200	0.0071	0.71	1.0	10
6	1	3	0.0342	0.1800	0.0106	0.85	1.5	10
7	2	4	0.1140	0.6000	0.0352	0.71	5.0	10
8	4	5	0.0228	0.1200	0.0071	0.71	1.0	10
9	5	6	0.0228	0.1200	0.0071	0.71	1.0	10

Table A.2: Bus data (pu)

Bus	P_{load}	Q_{load}	$P_{gen.}$	Q_{max}	Q_{min}	V	V_{max}	V_{min}
1	0.000	0.000	1.000	0.500	-0.40	1.05	1.05	0.97
2	0.200	0.000	1.200	0.750	-0.40	1.05	1.05	0.97
3	0.850	0.000	0.000	0.000	0.000	1.00	1.05	0.97
4	0.400	0.000	0.000	0.000	0.000	1.00	1.05	0.97
5	0.200	0.000	0.000	0.000	0.000	1.00	1.05	0.97
6	0.200	0.000	0.000	0.000	0.000	1.00	1.05	0.97

Table A.3: Generator data

Unit No.	Bus No.	Rating MW	λ F/y	r Hrs
1	1	40.0	6.0	45.0
2	1	40.0	6.0	45.0
3	1	10.0	4.0	45.0
4	1	20.0	5.0	45.0
5	2	5.0	2.0	45.0
6	2	5.0	2.0	45.0
7	2	40.0	3.0	60.0
8	2	20.0	2.4	55.0
9	2	20.0	2.4	55.0
10	2	20.0	2.4	55.0
11	2	20.0	2.4	55.0

Table A.4: Additional line data

Line No.	Buses I	J	R* p.u.	X* p.u	Fault Prob.	CLR T - s	Sdv s	Fault type prob. 3-L	L-g	2L	2L-g
1	1	3	0.0342	0.1800	1/9	0.3	0.03	.05	.70	.15	.10
2	2	4	0.1140	0.6000	1/9	0.4	0.04	.05	.70	.15	.10
3	1	2	0.0912	0.4800	1/9	0.4	0.04	.05	.70	.15	.10
4	3	4	0.0228	0.1200	1/9	0.2	0.02	.05	.70	.15	.10
5	3	5	0.0228	0.1200	1/9	0.2	0.02	.05	.70	.15	.10
6	1	3	0.0342	0.1800	1/9	0.3	0.03	.05	.70	.15	.10
7	2	4	0.1140	0.6000	1/9	0.4	0.04	.05	.70	.15	.10
8	4	5	0.0228	0.1200	1/9	0.2	0.02	.05	.70	.15	.10
9	5	6	0.0228	0.1200	1/9	0.2	0.02	.05	.70	.15	.10

* This is the negative sequence value. The zero sequence value is three times the negative sequence one.

Table A.5: Additional generator data

		Positive Seq.		Negative Seq.		Zero seq.		
Unit No.	Bus No.	R p.u	X p.u	R p.u	X p.u	R p.u	X p.u	H sec.
1	1	0.00	0.20	0.00	0.10	0.00	0.08	5.0
2	1	0.00	0.20	0.00	0.10	0.00	0.08	5.0
3	1	0.00	0.10	0.00	0.05	0.00	0.03	3.0
4	1	0.00	0.15	0.00	0.10	0.00	0.05	4.0
5	2	0.00	0.10	0.00	0.05	0.00	0.03	1.0
6	2	0.00	0.10	0.00	0.05	0.00	0.03	1.0
7	2	0.00	0.20	0.00	0.10	0.00	0.08	5.0
8	2	0.00	0.15	0.00	0.10	0.00	0.05	4.0
9	2	0.00	0.15	0.00	0.10	0.00	0.05	4.0
10	2	0.00	0.15	0.00	0.10	0.00	0.05	4.0
11	2	0.00	0.15	0.00	0.10	0.00	0.05	4.0