ADEQUACY EVALUATION OF COMPOSITE POWER SYSTEMS

A Thesis

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in Partial Fulfillment of the Requirements
for the Degree of
Master of Science
in the
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University of Saskatchewan

by

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Saskatoon, Saskatchewan

July 1984

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"ADEQUACY EVALUATION OF COMPOSITE POWER SYSTEMS"

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ABSTRACT

There is a growing interest in the power industry in quantitative assessment of composite generation and transmission system adequacy evaluation. This thesis attempts to further the state of the art in adequacy evaluation of a composite system by evaluation, analysis and solution of some specific problem areas. A contingency enumeration approach is utilized in the adequacy evaluation of a system. As the size of the system increases, inclusion of high level outage contingencies, particularly generating unit contingencies, becomes necessary. This, however, increases the computation time tremendously. As a good compromise, contingencies after certain outage level can be included by modifying the indices at the last level. This phenomenon is designated in this thesis as termination of an outage event. The effect of the termination and the inclusion of high level contingencies on the adequacy indices is discussed in this thesis with respect to practical applications.

Some of the problems encountered in a network adequacy evaluation are bus voltage violations and non-convergence A.C. load flow situations. A heuristic algorithm has been developed to solve these problems by rescheduling the generating units in the system and injecting reactive power at voltage violating buses. The capacity deficiency in the system under any outage contingency is alleviated by curtailing the load at appropriate buses. A load curtailment philosophy is developed and discussed in this thesis.

Calculation of both individual load point and overall system indices is necessary in order to assess the adequacy of a load point and of the system as a whole. These indices do not substitute for each other, they complement each other. The thesis stresses that the interpretation of the indices should be done in the domain within which they lie and that it is not valid to draw any conclusion about the adequacy of a load point from the system indices. Two sets of indices, annualized and annual, are described and calculated for the systems discussed in this thesis. The effect of including common cause and station originated outage events on the system adequacy is also analyzed and illustrated by practical examples.

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CHAPTER 1

INTRODUCTION

Electrical energy plays a vital role in the economic, social and geographical development of a region, a province and a country. This responsibility places considerable pressure on power utilities to provide an uninterrupted adequate power supply of acceptable quality to its customers. It is not economical and technically feasible to attempt to design a power system with one hundred percent reliability. Power engineers have, however, always attempted to achieve the highest possible reliability within economic constraints.

The term "reliability" has a wide range of meaning and cannot be associated with a single specific definition. When used in the context of power systems, it is generally defined as the concern regarding the ability of the power system to provide an adequate supply of electrical energy[1]. It is necessary to recognize the extreme generality of the term and therefore to use it to indicate, in a general rather than specific sense, the overall ability of the power system to perform its function. A simple but reasonable subdivision of the concern designated as system reliability can be made by considering two basic and functional aspects of the system, adequacy and security[2, 3].

Adequacy relates to the existence of sufficient facilities within the system to satisfy each consumer load demand. This, therefore, includes the facilities necessary to generate sufficient power and the associated transmission and distribution facilities required to transport the power to the actual consumers load points. Adequacy is therefore related to the static conditions which do not include system disturbances.

Security relates to the ability of the system to respond to disturbances arising within that system. Security is therefore associated with the response of the system to whatever perturbations it is subjected to. These include the conditions associated with local as well as widespread disturbances and the loss of major generation and transmission facilities.

This thesis is concerned with adequacy evaluation of a system. The basic techniques for adequacy assessment can be categorized in terms of their application to segments of a composite power system. These segments are also called functional zones. The three basic functional zones for the purposes of planning, organization, operation and/or analysis are: generation, transmission and distribution. Adequacy studies can be conducted in these three functional zones.

The total problem of adequacy assessment of the generation and the transmission facilities in regard to supplying an adequate, dependable and suitable electrical energy to the major customer load centers is designated as composite system reliability evaluation.

The indices resulting from this assessment then serve as input to calculate the adequacy of the individual consumer's supply. This involves a comprehensive analysis of the distribution facilities in a power network. Attention has been given to the evaluation of distribution facilities and many publications[4, 5, 6] are available, which suggest appropriate reliability indices and their assessment. However, in the area of composite system reliability, very few publications are available that outline the adequacy evaluation techniques required to solve a power network. The size of a practical power system and the complexities involved in analyzing the network are major problems which remain to be solved. As the size of a system increases, it is extremely difficult to analyze the adequacy of a system due to the tremendous increase in the computation time required for the solution of the network using A.C. load flow techniques. Less accurate approaches such as D.C. load flow methods and transportation models[7] can be used to calculate the adequacy of a system but they do not provide any information regarding the quality of the power supply delivered to a load point. The bus voltages and the MVAR limits of the generating units cannot be considered unless A.C. load flow techniques are used.

The selection of an appropriate technique, therefore, is of prime importance and is basically a management decision. The selected technique, however, should be capable of satisfying the intent behind these studies from the management, planning and design point of view. At the same time it should also take into account the consumer expectations, the standard of living and the economic and social consequences associated with an unreliable power supply. In order to obtain an appreciation of the state of the art in the area of composite system reliability, a questionnaire[8] was prepared and sent to those Canadian power utilities active in this area. The questionnaire was also sent to those educational institutes who are engaged in the area of composite power system reliability evaluation. This activity was conducted through the Power System Reliability Subsection of the Engineering and Operating Division of the Canadian Electrical Association (CEA). A list of the participants is as follows:

(1) British Columbia Hydro and Power Authority, Vancouver, B.C., Canada.

(2) Institut de Recherche d' Hydro - Quebec (IREQ), Quebec, Canada.

(3) Ontario Hydro, Toronto, Ontario, Canada.

(4) Shawinigan Consultants Inc., Montreal, Quebec, Canada.

(5) University of Saskatchewan (Power System Research Group), Saskatoon, Saskatchewan, Canada.

(6) Technische Hochschule Darmstadt, West Germany.

A brief description of the questionnaire and the responses of the participants is given in the next sections.

1.1 Description Of Questionnaire

In order to obtain a basic assessment of the primary features of the available digital computer programs and the algorithms used to calculate adequacy indices for a composite power system, a questionnaire was prepared and sent to the participants noted earlier. In the questionnaire, attention was focussed on the following points:

(1) What major disturbances in the system constitute a failure?

(2) What indices are used to express these failures on a quantitative scale?

(3) To what depth (level) are component outages considered and which outages (independent, common cause, failure bunching because of adverse weather etc.) are considered in the adequacy evaluation?

(4) How is an outage contingency solved and what are the corrective actions taken to alleviate system disturbances?

(5) In cases where a contingency results in a failure, how is the contribution of such a contingency taken into account to calculate the adequacy indices?

The questionnaire concludes with an enquiry about the load models used in these studies, the techniques to reduce computation time and the CPU time required to solve the IEEE Reliability Test System (RTS)[9].

1.2 Summary Of The Responses

Table 1-1 shows a comparative summary of the responses from the participants. No attempt has been made to report the CPU time required to solve the IEEE RTS by the various digital computer programs due to the tremendous difference in the intent of the analysis. A brief description of the corrective actions taken in each case is given below. The questionnaire respondent is shown in brackets after each reference to a particular program. The organization responsible for the development of the program is shown in Table 1-1.

Corrective Actions:

(a) Capacity Deficiency:-

In order to meet any capacity deficiency in the system a provision has been made in all the programs to reschedule the generating units to a predetermined capacity level. Program SYREL (B.C. Hydro) and PCAP (Ontario Hydro) also take into account the constraints on the generation capacity imposed by generating unit start-up times.

(b) Line Overloads:-

Line overloads are alleviated by curtailing the load at the appropriate buses. The selection of the appropriate buses, however, varies in each program. In the SYREL program (B.C.Hydro), the appropriate buses are those which result in least cost of load shedding and redispatch[10]. GATOR 2.0 (B.C.Hydro) curtails the load (first interruptable load followed by firm load, if necessary) proportionately at the receiving end buses of the overload line(s) and all those buses which are fed from these receiving end buses. Programs PREFIAPT and FIAPT (Hydro Quebec) utilize an optimization algorithm[11] that curtails the load at the buses so that power limits of the lines are satisfied.

PCAP (Ontario Hydro) curtails the load (first curtailable load followed by firm load) at the buses decided by an upper bounding linear program algorithm[14]. COMREL (University of Saskatchewan) alleviates the line overload by generation rescheduling and load shedding[15].

(c) Voltage Violation, MVAR Limit Violation and Non-Convergent Situations:-

No corrective action is taken by the programs which use a D.C. load flow or a transportation model. A brief description of the corrective actions taken in the programs using an A.C. load flow is given as follows:

(i) SYREL (B.C.Hydro):- Voltage is corrected by transformer tap settings, phase-shifter arrangement and generation rescheduling. Generator MVAR limit violations are not allowed under any outage contingency and if no solution is possible then the entire 'island' is shut down. Non-convergent situations are treated as system failure and are calculated separately.

Table 1-1: A brief summary of the response to the questionnaire on computer program for composite system reliability evaluation

S.No. (1) Name of the Participant	(2) B.C.Hydro (B.C.H)		(3) Hydro Quebec (HQ)	(4) Ontario Hydro (OH)	(5) Shawinigan Consultant Inc. (SCI)	(6) U. of Sask. (U OF S)	(7) Technische Hochachule Darmstadt (THD)
1. Organization who Developed the Program	EPRI (PTI)	Florida Power Corp.	HQ	PTI	SCI	U of S	THD
2. Name of the Program	SYREL	GATOR 2.0	PREFIAPT & FIAPT	PCAP	SYREL	COMREL	ZUBER
3. Program Capability							
(a) Size of the System							
i. Max. # of buses	150	1500	50	375	50	100	120
ii. Max. # of lines/ transformers	350	3000	100	750	100	200	210
iii. Max. # of generators	75	500	N.L.	150	30	100	-
iv. Max. # of phase shifters	20	-	-	40	-	-	-
(b) Maximum Level of Independent Outages							
i. Generator outages	6	1	N.L.	5	2	4	-
ii. Line/transformer outages	6	1	N.L.	5	2	2	N.L.
iii. Gen.- Line outages	6	-	N.L.	5	2	2	-

N.L. = Not Limited

TABLE 1-1 Contd...

S.No.	(1) Name of the Participant	(2) B.C.Hydro (B.C.H)		(3) Hydro Quebec (HQ)	(4) Ontario Hydro (OH)	(5) Shawinigan Consultant Inc. (SCI)	(6) U. of Sask. (U OF S)	(7) Technische Hochachule Darmstadt (THD)
(c)	Dependent Outages							
i.	Common cause line outages	X	-	X	X	-	X	X
ii.	Station originated outages including protection system failures	-	-	-	X	-	X	X
iii.	Failure bunching due to adverse weather	X	-	-	-	-	X	-
4.	Solving a contingency	AC/DC[10] L.F.	AC L.F.	DC[11] L.F.	DC L.F.	DC L.F.	AC/DC[12] L.F.	Transportation[7] Model
5.	Failure Criteria							
i.	Capacity deficiency	X	X	X	X	X	X	X
ii.	Line overload	X	X	X	X	X	X	X
iii.	System separation - load loss	X	X	X	X	X	X	X
iv.	Bus isolation - load loss	X	X	X	X	X	X	-
v.	Voltage collapse	X	-	-	-	-	X	-
vi.	MVAR limits violations	X	-	-	-	-	X	-
vii.	Non-convergent situations	X	-	-	-	-	X	-
6.	Load Model	HPLC	HPLC	HPLC	MSLC	MSLC	HPLC	MSLC

L.F.= Load Flow HPLC = Hourly Peak Load Curve MSLC = Multi Step Load Curve

TABLE 1-1 Contd....

S.No.	(1) Name of the Participant	(2) B.C.Hydro (B.C.H)		(3) Hydro Quebec (HQ)	(4) Ontario Hydro (OH)	(5) Shawinigan Consultant Inc. (SCI)	(6) U. of Sask. (U OF S)	(7) Technische Hochachule Darmstadt (THD)
7.	Adequacy Indices (Systems and Buses)							
(a)	Probability of failure	X	X	X	X	X**	X	X
(b)	Frequency of failure	X	X	X	X	X**	X	X
(c)	Expected load curtailed	X	X	X	X	-	X	X
(d)	Voltage violations	X	-	-	-	-	X	-
(e)	Avg. value of above indices, (a) to (d)	-	-	-	For (a) & (b)	-	X	-
(f)	Max. value of above indices, (a) to (d)	-	-	-	For (c) only	-	X	-
(g)	IEEE indices [13]	-	X	-	-*	-	X	-
8.	Techniques to Reduce CPU Time							
(a)	Ranking of the contingency	X	-	X	X	-	-	-
(b)	Sorting of identical contingency	X	X	-	X	-	X	-
(c)	Probability/ frequency cut-off	X	-	X	X	-	X	X
(d)	Limit on number of contingencies	-	-	X	X	X	-	X

* Instead Load Curtailment Index and Relative Curtailment Index are calculated [10].
** These indices are calculated for the overall system only.

(ii) GATOR 2.0 (B.C.Hydro):- Voltage is corrected by shedding the load (first interruptable load followed by firm load, if required) at the voltage violating buses. Generator MVAR limit violations are not allowed. In those cases where no solution exists, the contingency is simply ignored and no further action is taken. Non-convergent situations are also skipped and are not included in adequacy indices.

(iii) COMREL (U. of Sask.):- Voltage is corrected by injecting reactive power at the voltage violating buses. Generator MVAR limit violations are not allowed under any outage contingency. However, if no solution is possible, it is treated as a system failure. Non-convergent situations are handled by scheduling the generating units and injecting reactive power at the voltage violating buses. If a non-convergent situation still persists, a D.C. load flow is used.

1.3 Scope Of This Thesis

This thesis attempts to further the state of art in composite generation and transmission system adequacy evaluation. Extensive work in this area was done at the University of Saskatchewan by Billinton and Medicherla[16]. A digital computer program for adequacy assessment of a network using a fast decoupled load flow technique was developed. Studies on relatively small systems such as the IEEE 14 bus and the SPC 30 bus system were done using this program. The Saskatchewan Power Corporation (SPC) also carried out reliability studies on their actual system using this program.

In the process of their studies, they provided many suggestions for further modifications that could be incorporated in the program to make it more flexible and to deal with real system problems. Besides integrating some of the major suggestions of SPC, a number of other studies were conducted after developing suitable algorithms and methodologies. A brief description of the fast decoupled load flow technique and the corrective actions that are taken under the outage of an element is discussed in Chapter 2. A list of the adequacy indices calculated on three selected test systems, a 6 bus test system, the IEEE RTS[9] and a Manitoba assisted Saskatchewan Power Corporation (SPC) system, is also discussed in Chapter 2.

Under the outage of the transmission lines, one of the situations encountered is the splitting of a network into smaller networks. If an A.C. load flow is carried out for each separated network, a large memory storage for the Jacobian matrices is needed. The computation time also increases tremendously. An approximate simple algorithm developed to handle these split network situations is also described in Chapter 2.

As the size of a system increases, an examination of the high level simultaneous independent outages, particularly those of the generating units, cannot be ignored. Consideration of high level outages, however, requires tremendously large computation time. The inclusion of high level outages, their solution and the techniques used to reduce computation time are described in Chapter 3. Modified expressions for the probability and the frequency of a Markovian state are also presented in order to include the contribution of higher level outages. The effect of high level outages on the adequacy indices, both individual load point and the system indices, is also demonstrated.

Some of the problems frequently encountered in network adequacy evaluation are low voltage at the system buses and non-convergent A.C. load flow situations. A quantitative treatment of these problems can be easily done by simply treating them as system problems without taking any further corrective action. Such a treatment, however, cannot consider the severity associated with an outage event and no quantitative indices can be produced. A heuristic technique to handle low voltage and non-convergent situations is described in Chapter 4. The technique decides the amount of reactive power (MVAR) to be injected at a voltage violating bus after rescheduling the generating units in the system. A test of the non-convergence of a contingency due to the non-linearity in the mathematical formulations and convergence property of the Newton-Raphson load flow techniques is done before injecting the reactive power. A simple algorithm to check the non-convergence property was integrated into the digital computer program. The effectiveness of these methodologies was tested for the three systems as demonstrated in Chapter 4.

The consequences of the outage of an element on the system performance depends upon a number of factors, such as the relative importance and the location of the component in the network configuration, the corrective action taken and the load curtailment philosophy, etc.. It is, however, desirable that the outage of an element in a particular area should be reflected by the adequacy indices calculated for the area. The load curtailed under a particular outage event may be localized at one bus in a system or may be distributed among a group of buses in the system depending on the load curtailment philosophy. This necessitates the calculation of adequacy indices for each load point as the system overall indices may not provide a correct appreciation of the adequacy of each load center. Relatively little attention has been paid to the examination of the individual bus indices and the tendency among analysts working in this area is to calculate the system indices only. This can be seen from the responses to the questionnaire[8] on composite power system reliability.

A comprehensive analysis for the sensitivity studies performed for the 6 bus test system and the IEEE RTS is discussed in Chapter 5. The effect of the load variation and of the depth of the contingency level on the individual load point indices as well as on the system indices is demonstrated in this chapter. A brief description of the load curtailment philosophy used in this study is also given.

In the adequacy evaluation of a bulk power system, it is normally assumed that the station components such as breakers, isolators, bus-sections, station transformers etc., do not fail and therefore each bus in the system is assumed to be 100% reliable. Attempts have been made to assess the reliability indices for individual station configurations in an isolated manner[17]. This analysis provides a good comparison between two station configurations, but to fully appreciate the selection of a particular station configuration and its role in the overall system, it is necessary that the outages of the individual station components be considered in the system context. The effect of these outage events on the system performance should also be evaluated in quantitative terms. These outage events, termed as station originated outage events, are discussed in detail in Chapter 6. The effect of station originated events on the adequacy indices as a function of system load is also described. The effect of common-cause outages on the system indices, in addition to the station originated outages, is also demonstrated. An attempt is also made to determine the relative contribution of different outage contingencies viz., common cause, station originated, to the adequacy indices in Chapter 6.

There is a growing interest in the power industry in quantitative assessment of composite system reliability evaluation. This activity is being accompanied by intensive data collection procedures[18] for component reliability assessment for virtually all classes of major equipments. This thesis attempts to further the state of art in adequacy evaluation of a composite generation and transmission system by evaluation, analysis and solution of some specific problem areas.

CHAPTER 2

A QUANTITATIVE METHOD FOR ADEQUACY EVALUATION OF A COMPOSITE SYSTEM

2.1 Introduction

The main objective of bulk power system planning is the economic development of the generation and transmission facilities required to satisfy the customer load demands at acceptable levels of quality and availability. Such a requirement invariably dictates the need for quantifying adequacy indices at major distribution points. These indices can then be used to calculate the adequacy of an individual load point. The quantitative evaluation of the adequacy of a composite power system is comprised of the following steps:

(1) Evaluate the performance of the power system without removing any component, or in other words study the performance of the base case system.

(2) Make changes in the network configuration due to the "credible" outage(s) of various components.

(3) Check the adequacy of the modified power system.

(4) Take any corrective action, if necessary, such as rescheduling of the generating units, line overloads alleviation, correction of bus voltages and load curtailment at buses, etc..

(5) Calculate the adequacy indices for the system as a whole and the individual load points.

A performance evaluation of the existing power system is first done to ensure that the base case is satisfactory, because if the base case is unsatisfactory then any further outage(s) of the system components will result in unsatisfactory operation of the system. Such a situation may not warrant any further adequacy studies. On the other hand, if the base case is satisfactory then the effect of removing components from the system is studied. This involves the important task of checking the adequacy of the modified system.

Various techniques, depending upon the adequacy criteria employed and the intent behind the studies, are available in order to analyze the adequacy of a power system. One of the simplest approaches is to treat the system as a transportation model[7, 19, 20] in order to ensure the continuity of power supply at various load centers. Approximate load flow techniques such as D.C. load flow etc. are quite simple and fast but they only provide an estimate of the line power flows, without including any estimate of the bus voltages and the reactive power limits of the generating units, etc.. If the quality of the power supply (proper voltage levels and correct MVAR limits of the generating units) is an important adequacy criterion, then more accurate A.C. load flow methods[21, 22] such as Gauss-Seidel, Newton-Raphson and second order load flow techniques must be employed in order to calculate the adequacy indices. These techniques are not often used because they are computationally more expensive and have large storage requirements. Several computationally faster A.C. load flow techniques which are modifications of the Newton-Raphson load flow approach are available. The fast decoupled load flow technique is one of these methods.

The fast decoupled load flow technique appears to be a good compromise between D.C. and A.C. load flow approaches considering the storage requirements and solution speed. At the same time it can be used to check both continuity as well as quality of a power system thus meeting the two important adequacy requirements. Initial work[16] reported on composite generation and transmission system reliability utilized the fast decoupled load flow algorithm developed by Stott and Alsac[12]. A brief description of the fast decoupled load flow technique is given below.

2.2 The Fast Decoupled Load Flow Technique

The well known polar power mismatch Newton method is a general algorithm for solving non-linear equations, which utilizes successive solutions of the sparse real Jacobian-matrix equation given by

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} H & N \\ J & L \end{bmatrix} \begin{bmatrix} \Delta\theta \\ \Delta V/V \end{bmatrix} . \qquad (2.1)$$

The decoupled load flow algorithm neglects weak couplings between the real power and the voltage magnitudes and the reactive power and the voltage phase angles. The following two separated equations are obtained by neglecting the coupling submatrices [N] and [J] in Equation 2.1.

$$[\Delta P] = [H]\ [\Delta\theta] \tag{2.2}$$

$$[\Delta Q] = [L]\ [\Delta V/V] \tag{2.3}$$

where

$H_{km} = L_{km} = V_k V_m (G_{km} \sin\theta_{km} - B_{km} \cos\theta_{km})$ for $m \neq k$

$H_{kk} = -B_{kk} V_k^2 - Q_k$

and

$L_{kk} = -B_{kk} V_k^2 + Q_k$

In a practical system the following assumptions are always valid:

$$\cos\theta_{km} \approx 1,\ G_{km} \sin\theta_{km} << B_{km},\ Q_k << B_{kk} V_k^2$$

These assumptions simplify Equations 2.2 and 2.3 to

$$[\Delta P] = [VB'V]\ [\Delta\theta] \tag{2.4}$$

$$[\Delta Q] = [VB''V]\ [\Delta V/V] \tag{2.5}$$

The final fast decoupled load flow equations are given below after making further physically-justifiable simplifications[12]:

$$[\Delta P/V] = [B']\ [\Delta\theta] \tag{2.6}$$

$$[\Delta Q/V] = [B'']\ [\Delta V] \tag{2.7}$$

Both matrices $[B']$ and $[B'']$ are real, sparse and contain only network admittances. Since $[B']$ and $[B'']$ are constant, they need be triangulated only once at the beginning of the iterative process. The fast repeat solutions for $[\Delta\theta]$ and $[\Delta V]$ can be obtained using constant triangular factors of $[B']$ and $[B'']$. The magnitude of the voltage at each load bus and the voltage phase angle at each bus except the swing bus are modified as given by Equations 2.8 and 2.9.

$$[\theta]_{new} = [\theta]_{old} + [\Delta\theta] \tag{2.8}$$

$$[V]_{new} = [V]_{old} + [\Delta V] \tag{2.9}$$

Power mismatches $[\Delta P/V]$ and $[\Delta Q/V]$ are calculated for these new values of bus voltage and bus angle. Equations 2.6 and 2.7 are iterated in some defined manner towards an exact solution, i.e. when power mismatches are less than the tolerances.

The solution is adjusted for the generator MVAR limits and the load bus voltage limits once a load flow solution is moderately converged. The correction of the voltage at each violating PV (generator) bus is done by calculating the sensitivity factors as discussed in Appendix 3 of Reference [12].

✱ Based on the above algorithm, a digital computer program[16] for solving load flow for each outage contingency was developed at the University of Saskatchewan. The same A.C. load flow algorithm, after making minor modifications, has been used in this study.

It may be necessary to take corrective actions while solving a contingency using an A.C. load flow. These corrective actions are discussed in the next section.

2.3 Corrective Actions

In the case of generating unit outages, the remaining units in the system are rescheduled so as to meet the generation deficiency created by the removal of the generating units under outage. If the total load of the system is higher than the total available generated power, the load is curtailed at the system buses. The load curtailment philosophy used in this thesis is discussed in Chapter 5. In the case of generator MVAR limit violations, Q-limits of PV buses are corrected by using sensitivity factors[12]. The contingency is treated as a failure event if the Q-limits of the PV buses are still violated.

In the case of line or transformer outages, generating units are rescheduled using a heuristic algorithm described in Chapter 4. Isolation of a bus(es) due to line outages is also recognized. The adequacy indices for isolated bus(es) are calculated depending upon the available generation and the connected load at these buses. An A.C. load flow is conducted on the remaining system and the adequacy of the part system is evaluated. If the outages of the line(s) result in a split network, the adequacy of each network is tested. In order to save storage requirements for calculating admittance matrices for each separated network and the computation time in solving them, a simple and faster but less accurate approach has been used in this study. This approach is discussed in Section 2.10.

The voltage limits at the voltage violating buses are corrected by injecting reactive power at these buses. A heuristic algorithm for voltage violating cases and non-convergent cases has been developed and is described in Chapter 4. The overloads of lines are alleviated by a generation rescheduling and load shedding algorithm[15]. The swing bus overloads arising because of generation deficiency are alleviated by curtailing the load at the appropriate buses. The load curtailment philosophy is described in Chapter 5.

After testing the system adequacy and taking appropriate corrective actions, a quantitative assessment ot a system problem is expressed in terms of a set of adequacy indices. These adequacy indices are as follows.

2.4 Adequacy Indices[2, 16]

The adequacy evaluation of the composite power system can be best expressed by producing indices both for the system and for the individual load points. The response of various organizations to the questionnaire indicates that there is no consensus in the industry as to which reliability indices are the best. Therefore, depending upon the failure criteria, it is appropriate to study a variety of adequacy indices which convey meaningful information regarding the performance of the system and are also suited to making system design/alteration decisions. In this study, the main criteria chosen for defining unacceptable quality of power supply at a load point are:

(i) The load point voltage being less than a specified minimum value and/or

(ii) the inability of the system to supply the load connected to that bus without line overloads. A comprehensive list of the indices considered in this study is given below:

Load Point Indices :

(A) Basic Values:-

(1) Probability of failure = $\sum_{J} P_J . P_{KJ}$

(2) Frequency of failure = $\sum_{J} F_J . P_{KJ}$

Where: J is an outage condition in the network.

P_J is the state probability of outage event J.

F_J is the frequency of occurrence of outage event J.

P_{KJ} is the probability of the load at bus K exceeding the maximum load that can be supplied at that bus during the outage event J. For a fixed load level considered for a specific period of time, P_{KJ} will be equal to zero if the total load at bus K can be supplied without any problem but

P_{KJ} will be unity if there is some problem in supplying the total load at bus K.

(3) Expected number of voltage violations = $\sum_{J\varepsilon V} F_J$.

Where $J\varepsilon V$ includes all contingencies which cause voltage violation at bus K.

(4) Expected number of load curtailments = $\sum_{J\varepsilon X,Y} F_J$.

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

(5) Expected load curtailed = $\sum_{J\varepsilon X,Y} L_{KJ}.F_J$ MW.

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

(6) Expected energy not supplied

$$= \sum_{J\varepsilon X,Y} L_{KJ}.\ D_{KJ}.\ F_J \text{ MWh.}$$
$$= \sum_{J\varepsilon X,Y} L_{KJ}.P_J.\ 8760.0 \text{ MWh.}$$

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

(7) Expected duration of load curtailment

$$= \sum_{J \epsilon X,Y} D_{KJ} \cdot F_J \text{ hours.}$$

$$= \sum_{J \epsilon X,Y} P_J \cdot 8760.0 \text{ hours.}$$

(B) Maximum Values:-

(8) Maximum load curtailed in MW

$$= \text{Max.} \left| L_{K1}, L_{K2}, \ldots . L_{KJ}, \ldots . \right|$$

(9) Maximum energy curtailed in MWh

$$= \text{Max.} \left| L_{K1} D_{K1}, L_{K2} D_{K2}, \ldots . L_{KJ} D_{KJ}, \ldots . \right|$$

(10) Maximum duration of load curtailment in hours

$$= \text{Max.} \left| D_{K1}, D_{K2}, \ldots . D_{KJ}, \ldots . \right|$$

The outage event and its probability and frequency which causes the above maximum values are also reported in this thesis.

(C) Average Values:-

(11) Average load curtailed

$$= \frac{\sum_{J \epsilon X,Y} L_{KJ} \cdot F_J}{\sum_{J \epsilon X,Y} F_J} \text{ MW/ curtailment.}$$

(12) Average energy not supplied

$$= \frac{\sum_{J \epsilon X,Y} L_{KJ} \cdot P_J \cdot 8760.0}{\sum_{J \epsilon X,Y} F_J} \text{ MWh/curtailment.}$$

(13) Average duration of load curtailment

$$= \frac{\sum_{J \epsilon X,Y} D_{KJ} \cdot F_J}{\sum_{J \epsilon X,Y} F_J} \text{ hours/curtailment.}$$

System Indices:[13]

(A) Basic Values:-

(14) Bulk Power Supply Disturbances (BPSD)

$$= \sum_{K} \sum_{J \varepsilon X,Y} F_J$$

(15) Bulk Power Interruption Index (BPII)

$$= \frac{\sum_{K} \sum_{J \varepsilon X,Y} L_{KJ} . F_J}{L_S} \text{ MW.}$$

(16) Bulk Power Supply Average MW Curtailment (BPSAMC)

$$= \frac{\sum_{K} \sum_{J \varepsilon X,Y} L_{KJ} . F_J}{\sum_{J \varepsilon X,Y} F_J} \text{ MW/disturbance.}$$

(17) Bulk Power Energy Curtailment Index (BPECI)

$$= \frac{\sum_{K} \sum_{J \varepsilon X,Y} 60.0 . L_{KJ} . D_{KJ} . F_J}{L_S} \text{ System minutes.}$$

This is also called as Severity Index.

(18) Modified Bulk Power Energy Curtailment Index (MBPECI)

$$= \frac{\sum_{K} \sum_{J \varepsilon X,Y} L_{KJ} . D_{KJ} . F_J}{L_S . 8760.0}$$

Where L_S is the total system load.

(B) Average Values:-

(19) Average number of load curtailments/load point

$$= \sum_{K} \sum_{J \varepsilon X,Y} F_J / C .$$

(20) Average load curtailed/load point

$$= \sum_{K} \sum_{J \varepsilon X,Y} L_{KJ} . F_J / C \text{ MW.}$$

(21) Average load curtailed/load point

Energy

$$= \sum_{K} \sum_{J \varepsilon X,Y} L_{KJ} . D_{KJ} . F_J / C \text{ MWh.}$$

(22) Average duration of load curtailment/load point

$$= \sum_{K} \sum_{J \epsilon X,Y} D_{KJ} / C \text{ Hours.}$$

(23) Average number of voltage violations/load point

$$= \sum_{K} \sum_{J \epsilon V} F_{J} / C .$$

Where C is the total number of load points in the system.

(C) Maximum Values:-

(24) Maximum system load curtailed in MW

$$= \text{Max.} \left| \sum_{K} L_{K1}, \sum_{K} L_{K2}, \ldots, \sum_{K} L_{KJ}, \ldots \right|$$

(25) Maximum system energy curtailed in MWh

$$= \text{Max.} \left| \sum_{K} L_{K1} D_{K1}, \sum_{K} L_{K2} D_{K2}, \ldots, \sum_{K} L_{KJ} D_{KJ}, \ldots \right|$$

These indices are calculated for a single fixed load level over a period of one year and are then referred to as "annualized indices". In practical systems, the load does not remain constant throughout the period and therefore the effect of a variable load level can be included in order to produce more representative "annual" indices. The step modeling of the load for various test systems is explained in Section 2.6 of this chapter.

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

$$\bar{X} = (p_1.x_1 + p_2.x_2 + \ldots\ldots\ldots + p_n.x_n)$$

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

In addition to calculating the above indices, indices such as the total number of voltage violation contingencies, total number of load curtailment contingencies, total number firm load curtailment contingencies, total number of non-convergent contingencies are also calculated. The probability and the frequency of an outage contingency resulting in the load curtailment of curtailable load are also included in this study.

It is important to appreciate that the two sets of load point and system indices do not replace each other but actually complement each other. The load point indices are very useful in system design and in comparing alternative system configurations and system alterations. They also serve as input indices in the reliability evaluation of the distribution systems supplied by the corresponding bulk power supply point. The overall system indices indicate the adequacy of the composite system to meet its total load demand and energy requirements and therefore are quite useful to the system planner. It must be recognized, however, that it may be difficult and sometimes misleading to draw conclusions regarding the adequacy of a particular system load point from the overall system indices or bus average indices. This aspect is emphasized in Chapter 5.

2.5 Test Systems

The adequacy studies are conducted on the following three power systems.

(1) A 6 bus hypothetical test system,

(2) the IEEE Reliability Test System (RTS)[9], and

(3) a 45 bus model of the Manitoba assisted Saskatchewan Power Corporation (SPC) system.

The following is a brief description of these systems.

2.5.1 The 6 Bus Hypothetical Test System

The single line diagram of the 6 bus test system is shown in Figure 2-1. The line data and the generator data of this system are given in Appendix A. The system has 2 generator (PV) buses, 9 lines and 16 generating units. The voltage limits for this system are assumed to be 1.05 and 0.97 p.u.

2.5.2 The IEEE Reliability Test System (RTS)[9]

The single line diagram of the 24 bus IEEE RTS is given in Figure 2-2. The line, transformer and the generator data of this system are included in Appendix B. This system has 10 generator (PV) buses, 10 load (PQ) buses, 33 transmission

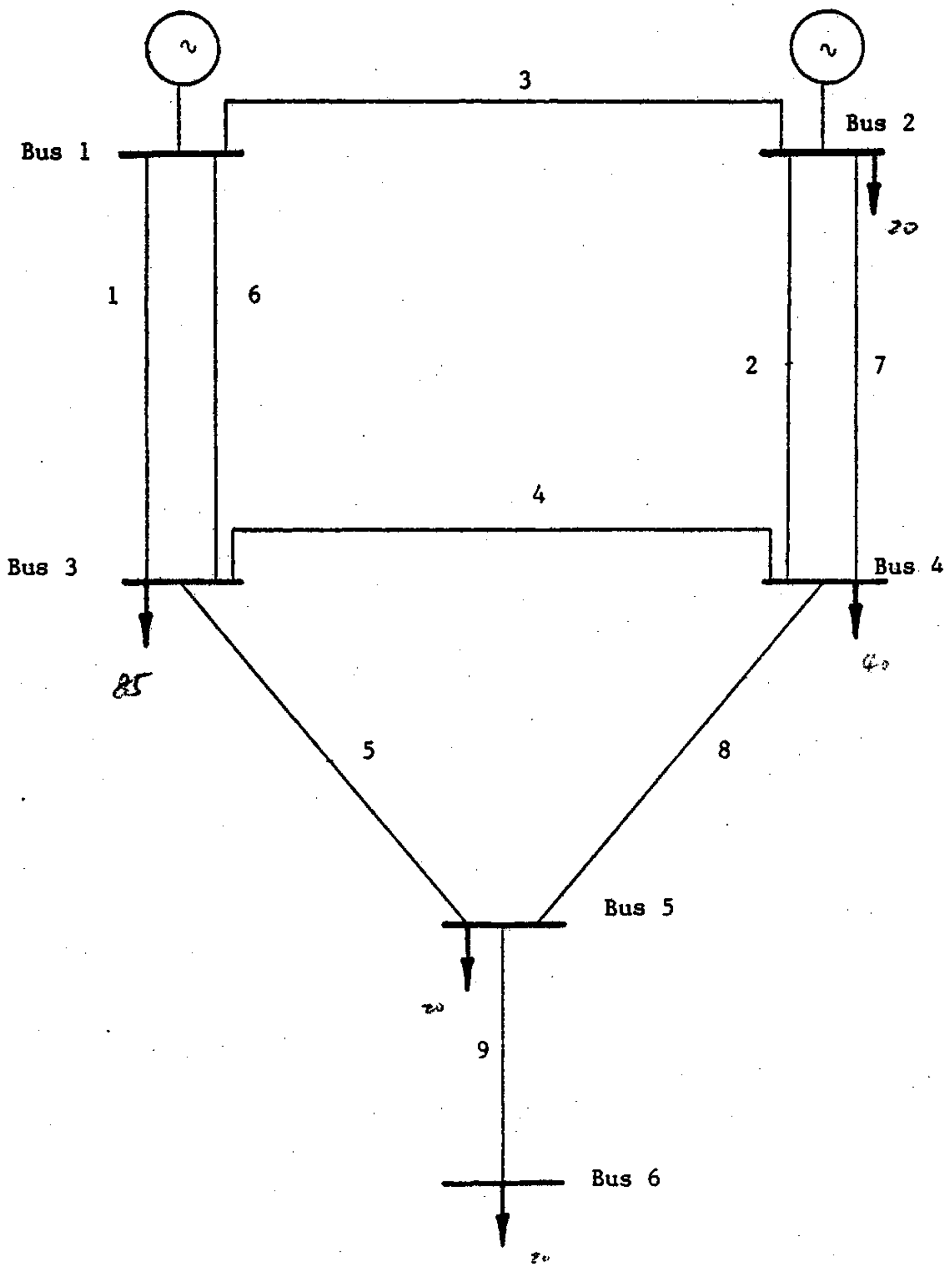

Figure 2-1: Single line diagram of the 6 bus test system

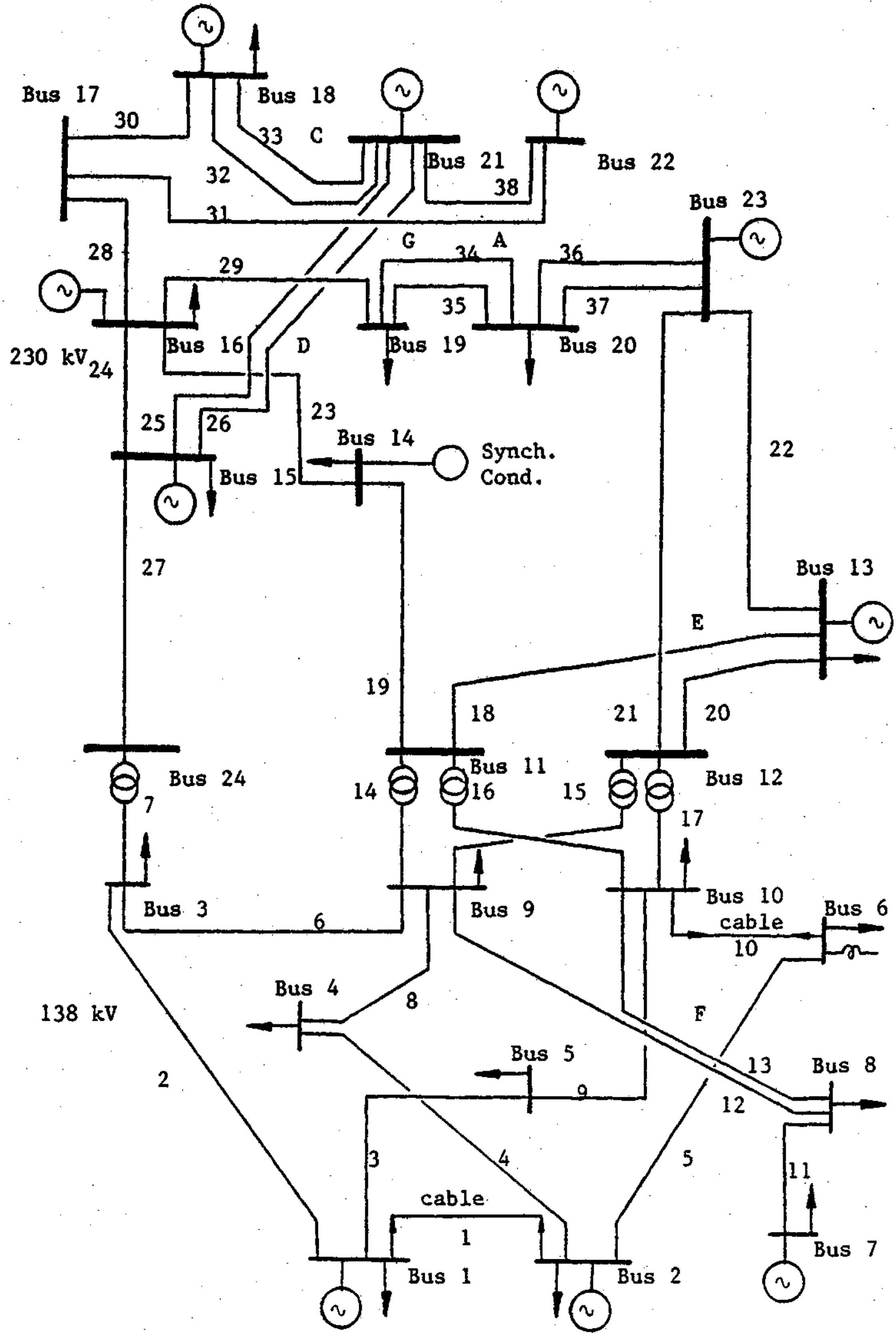

Figure 2-2: Single line diagram of the IEEE Reliability Test System (RTS)

lines and 5 transformers. The total number of generating units is 32. The minimum and the maximum rating of the generating units are 12 MW and 400 MW respectively. The voltage limits for the system buses are assumed to be 1.05 and 0.95 p.u.

2.5.3 The Manitoba Assisted Saskatchewan Power Corporation (SPC) System

The single line diagram of the existing power network of the Manitoba assisted Saskatchewan Power Corporation (SPC) is shown in Figure 2-3. The system has 45 buses in total, of which 4 buses, The Pas, Roblin, Reston and one fictitious bus, are included to represent equivalent assistance from the Manitoba Hydro System. A power import of 300 MW from the Manitoba system is represented by 3 units of 100 MW each at the fictitious bus. The fictitious bus is connected to three buses, The Pas, Reston and Roblin, as shown in Figure 2-4. The fictitious lines and interconnections between the four buses are assumed to be an equivalent power network of the Manitoba system for these reliability studies. The system has 8 generator (PV) buses, 37 load (PQ) buses, 71 transmission lines/transformers and 29 generating units. The line, transformer and the generator data of this system is included in Appendix C. The minimum and the maximum rating of the generating units are 15 MW and 280 MW respectively. The voltage limits for the system buses are assumed to be 1.05 and 0.95 p.u.

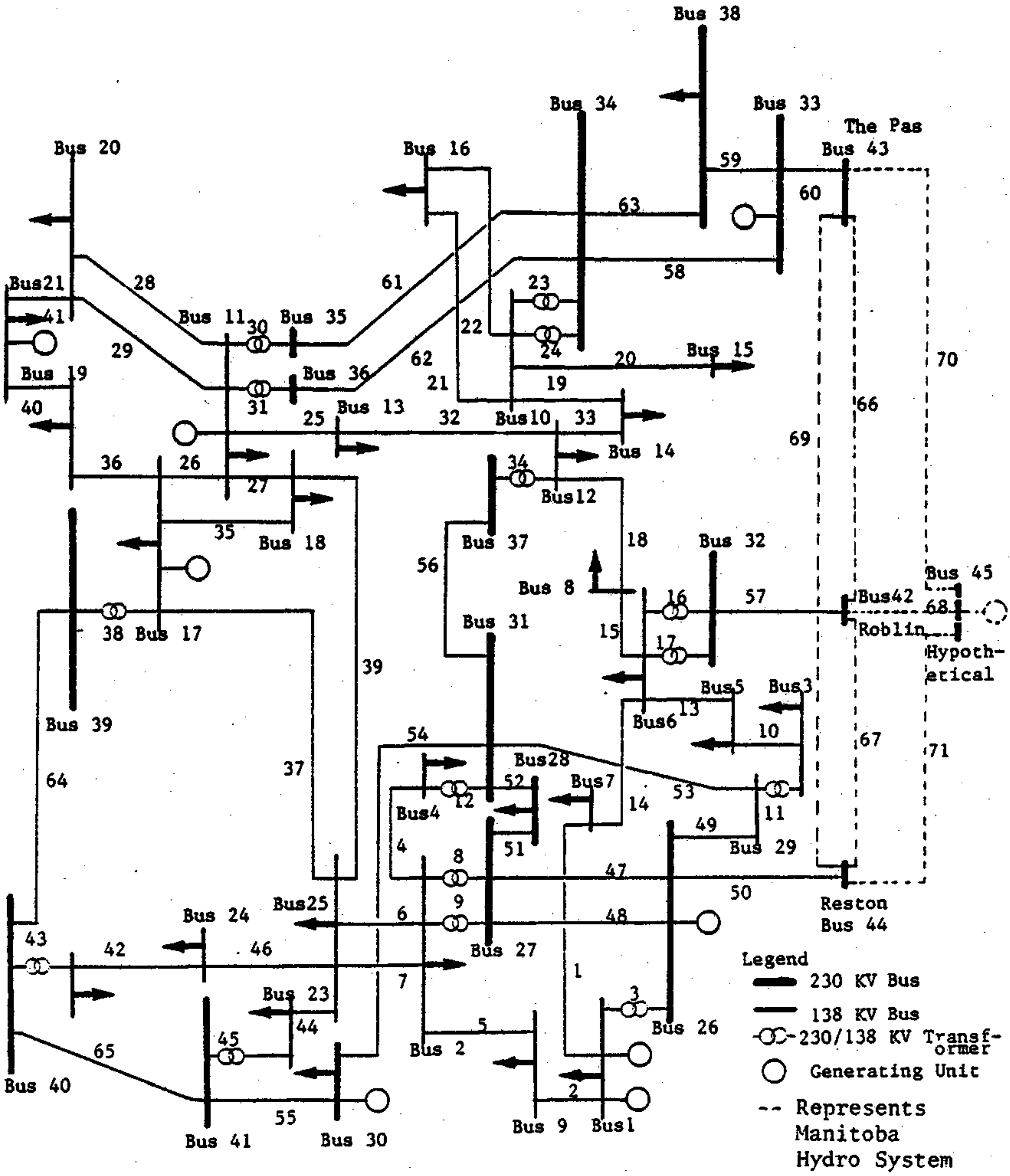

Figure 2-3: Single line diagram of the Manitoba Assisted Saskatchewan Power Corporation (SPC) system

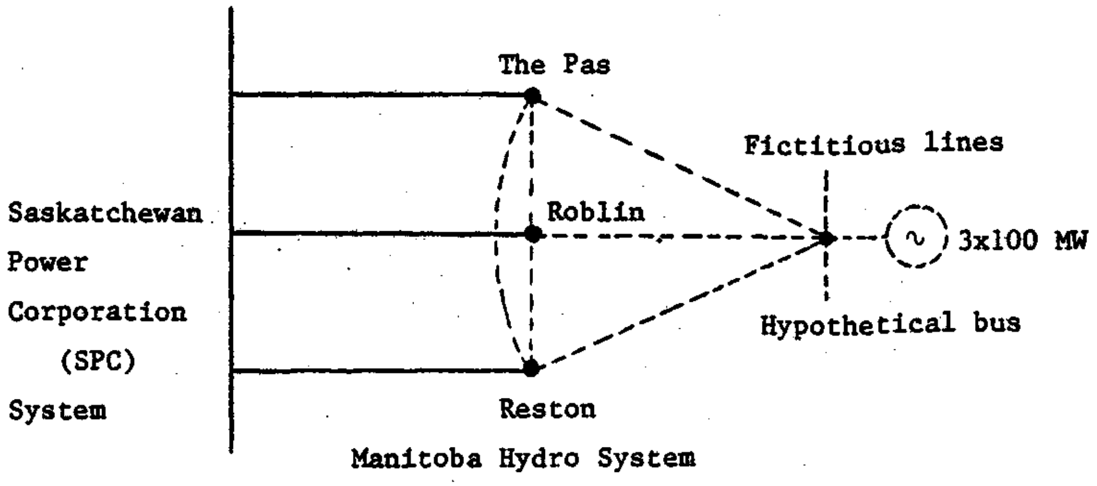

Figure 2-4: Equivalent Manitoba assistance model for the SPC system

2.6 Load Model

The adequacy indices have been calculated considering

(i) a single step peak load model,

(ii) a multistep load model.

A multistep load model is used to study the effect of load variation on both the system and the bus adequacy indices. A single step peak load model has been used to calculate "annualized indices". These indices are discussed in Section 2.4. A brief description of the load models for each test system is given below:

2.6.1 The 6 Bus Test System

(a) The single step peak load model:-

Figure 2-5 shows the single step peak load model for this system. The peak load is assumed to be 185 MW and remains

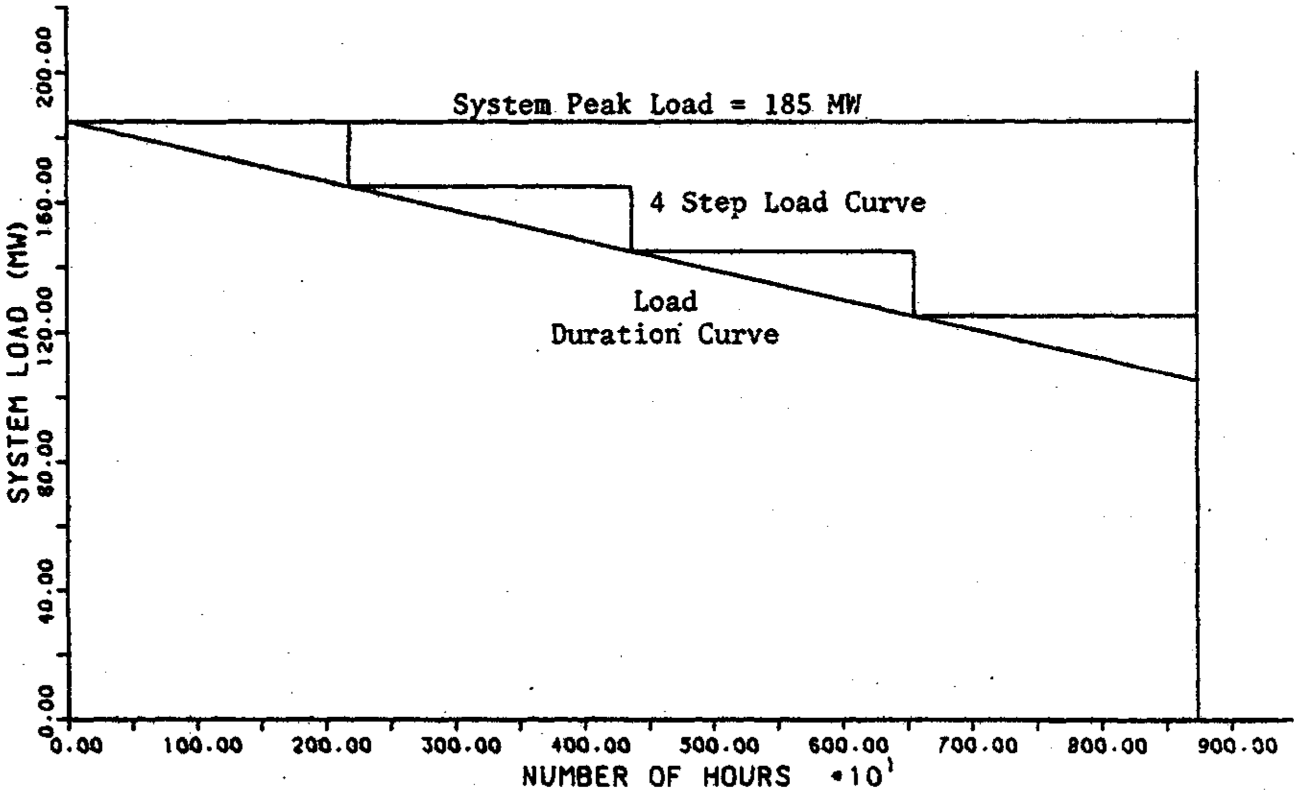

Figure 2-5: Load models for the 6 bus test system

constant throughout the study period of one year.

(b) The multi step load model:-

Figure 2-5 also shows a four step load model for this system. The minimum load is 105 MW (56.8 %) of the peak load and the step size is 20 MW. Table 2-1 shows the number of days when the system load is equal to or less than the corresponding step load but greater than the next lower step load.

Table 2-1: A four step load model for the 6 bus test system

S.No.	Number of steps	Step load(MW)	Number of days	% Days for each step load
1	1	185	91	25
2	2	165	91	25
3	3	145	91	25
4	4	125	91	25
		Total	364	100

i.e. $p_1 = p_2 = p_3 = p_4 = 0.25$

2.6.2 The IEEE RTS

A description of the load model for the RTS is given in Reference [9]. The load data are given for a 364 day period, therefore a year is assumed to consist of 8736 hours. The annual peak load for the test system is 2850 MW. The weekly, daily and hourly load peaking factors are given in Tables 2-2, 2-3 and 2-4 respectively. The load duration curve for a

Table 2-2: Weekly system load peaking factors for the IEEE RTS

Week	Peaking Factor	Week	Peaking Factor	Week	Peaking Factor	Week	Peaking Factor
1	0.862	14	0.750	27	0.755	40	0.724
2	0.900	15	0.721	28	0.816	41	0.743
3	0.878	16	0.800	29	0.801	42	0.744
4	0.834	17	0.754	30	0.880	43	0.800
5	0.880	18	0.837	31	0.722	44	0.881
6	0.841	19	0.870	32	0.776	45	0.885
7	0.832	20	0.880	33	0.800	46	0.909
8	0.806	21	0.856	34	0.729	47	0.940
9	0.740	22	0.811	35	0.726	48	0.890
10	0.737	23	0.900	36	0.705	49	0.942
11	0.715	24	0.887	37	0.780	50	0.970
12	0.727	25	0.896	38	0.695	51	1.000
13	0.704	26	0.861	39	0.724	52	0.952

Table 2-3: Daily system load peaking factors for the IEEE RTS

Day	Peaking Factor
Monday	0.93
Tuesday	1.00
Wednesday	0.98
Thursday	0.96
Friday	0.94
Saturday	0.77
Sunday	0.75

Table 2-4: Hourly system load peaking factors for the IEEE RTS

Hour	Weeks 1-8 & 44-52 Weekday	Weeks 1-8 & 44-52 Weekend	Weeks 18-30 Weekday	Weeks 18-30 Weekend	Weeks 9-17 & 31-43 Weekday	Weeks 9-17 & 31-43 Weekend
1	0.67	0.78	0.64	0.74	0.63	0.75
2	0.63	0.72	0.60	0.70	0.62	0.73
3	0.60	0.68	0.58	0.66	0.60	0.69
4	0.59	0.66	0.56	0.65	0.58	0.66
5	0.59	0.64	0.56	0.64	0.59	0.65
6	0.60	0.65	0.58	0.62	0.65	0.65
7	0.74	0.66	0.64	0.62	0.72	0.68
8	0.86	0.70	0.76	0.66	0.85	0.74
9	0.95	0.80	0.87	0.81	0.95	0.83
10	0.96	0.88	0.95	0.86	0.99	0.89
11	0.96	0.90	0.99	0.91	1.00	0.92
12	0.95	0.91	1.00	0.93	0.99	0.94
13	0.95	0.90	0.99	0.93	0.93	0.91
14	0.95	0.88	1.00	0.92	0.92	0.90
15	0.93	0.87	1.00	0.91	0.90	0.90
16	0.94	0.87	0.97	0.91	0.88	0.86
17	0.99	0.91	0.96	0.92	0.90	0.85
18	1.00	1.00	0.96	0.94	0.92	0.88
19	1.00	0.99	0.93	0.95	0.96	0.92
20	0.96	0.97	0.92	0.95	0.98	1.00
21	0.91	0.94	0.92	1.00	0.96	0.97
22	0.83	0.92	0.93	0.93	0.90	0.95
23	0.73	0.87	0.87	0.88	0.80	0.90
24	0.63	0.81	0.72	0.80	0.70	0.85

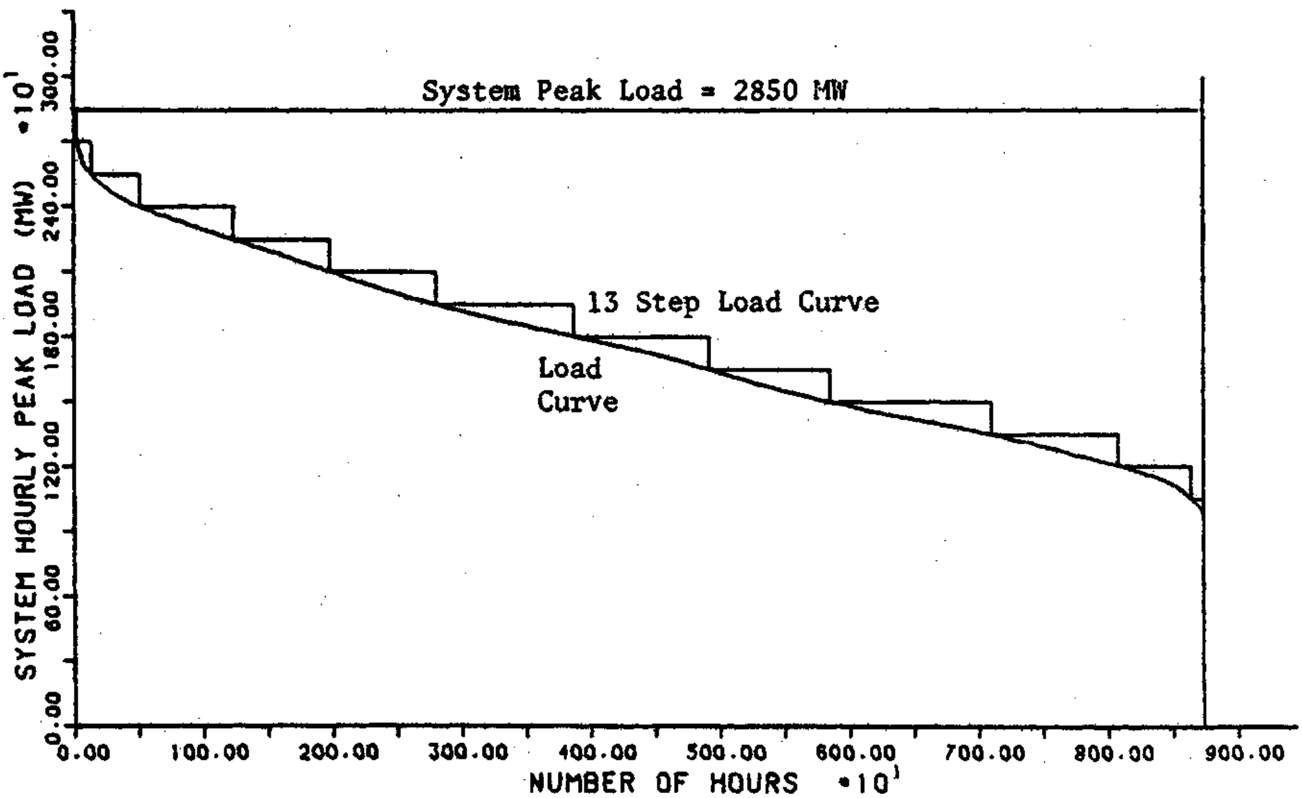

Figure 2-6: Load models for the IEEE RTS

winter peaking system is shown in Figure 2-6. The minimum value of the load is 966 MW (33.88 %) of the peak load. The following is a brief description of load models for this system.

(a) The single step peak load model:-

The annual peak load curve with a system peak load of 2850 MW is shown in Figure 2-6. This peak load remains constant throughout the study period of one year.

(b) The 13 step load model:-

In this load model, the load variation at each bus is represented by a normalized load duration curve approximated by a multistep load curve as shown in Figure 2-6. A step size of 150 MW was used for the entire system load. Table 2-5 shows the number of hours during which the system load is equal to or less than the corresponding step load but greater than the next lower step load.

2.6.3 The Manitoba Assisted SPC System

The annual peak load for the SPC system was taken as 1802.50 MW. Adequacy studies were only conducted for this single step peak load.

In the case of each test system, bus loads are classified into two curtailment categories , firm load and curtailable load. If possible, a system problem is alleviated by shedding the curtailable load only. Depending on circumstances,

Table 2-5: A 13 step load model for the IEEE RTS

S.No.	Number of steps	Step load(MW)	Number of hours	% days for each step load
1	1	2850	23	0.263
2	2	2700	112	1.282
3	3	2550	381	4.361
4	4	2400	722	8.265
5	5	2250	744	8.517
6	6	2100	824	9.432
7	7	1950	1067	12.214
8	8	1800	1048	11.996
9	9	1650	930	10.646
10	10	1500	1248	14.286
11	11	1350	983	11.252
12	12	1200	559	6.399
13	13	1050	95	1.087
		Total	8736	100

36.84%

curtailable load may represent certain utility loads and loads curtailable by contract etc. The amount of curtailable load at a bus can be decided by the system manager depending upon the relative priority assigned to the bus.

2.7 Outage Model

Outages of generating units, lines and transformers individually or in combination with outages of other generating units, lines and transformers are considered in this study. Treating generating units, lines and transformers as separate elements increases the flexibility of the approach but the number of Markovian states which represent the outage contingencies also increases tremendously. For a system having 9 elements, there is a total of 512 states. As the number of elements increases, the number of Markovian states increases rapidly as shown in Table 2-6, which gives the total number of Markovian states for the three test systems studied in this thesis.

Table 2-6: Total number of possible Markovian states for the three test systems

S.No.	System description	Total number of components	Total number of states
1	6 bus system	25	33554442
2	IEEE RTS	60	$11529215046 \times 10^{8}$
3	SPC system	100	$12676306002 \times 10^{36}$

As seen from Table 2-6, it is quite clear that it is impossible to attempt to calculate the contribution of all states. Since the probability and the frequency of states having many components out are extremely low and as such negligible, it is not really necessary to solve high level contingencies. In order to minimize the number of contingencies which should be calculated, it is appropriate to specify either a probability cut-off or a frequency cut-off limit. This may also be achieved by specifying an appropriate contingency level to which outage contingencies should be considered. The main objective is to recognize "credible" outage contingencies and this can be achieved by employing either of the contingency selection criteria or a combination of both.

A credible outage event at any contingency level is one whose contribution to the adequacy indices is too significant to ignore. A contingency level means the number of situations that result in outages of the component(s) e.g., if two components are out independently, the contingency level is two. However, if two components are out because of a single common cause outage event the contingency level is one. Table 2-7 and Table 2-8 give the number of states for generating unit and line/transformer independent outages respectively for the IEEE RTS for various contingency levels. The probability and the frequency of a contingency at each level is also given for typical values of failure rate (λ) and repair rate (μ).

As can be seen from Tables 2-7 and 2-8, independent outage events beyond the 4th level for generator outages and the 2nd level for line/transformers outages have very low values of probability and frequency and as such their contribution is virtually negligible. The number of states also increases significantly as the number of contingency levels increases. This results in a large computation time if high level outages are considered. In this study, generator outages up to the 4th level and the line/transformer independent outages up to the 2nd level have been considered.

Table 2-7: Probability and frequency of a generating unit outage at various contingency levels

A = 0.9500704

(μ = 175.44 r/yr, λ = 9.22 f/yr.)

S.No.	Contingency level	Total no. of states	~~Probability~~ Unavail. of each state	Frequency of each state
1	I	32	0.0500000000	8.770000
2	II	528	0.0025000000	0.877000
3	III	5488	0.0001250000	0.065800
4	IV	41448	0.0000062500	0.004390
5	V	242824	0.0000003125	0.000274

6.25×10^{-6}

Table 2-8: Probability and frequency of a line outage at various contingency levels

(μ = 876 r/yr, λ = 0.40 f/yr.)

S.No.	Contingency level	Total no. of states	~~Probability~~ Unavail. of each state of Conting. level	Frequency
1	I	38	0.456×10^{-3}	0.400
2	II	741	0.210×10^{-6}	0.365×10^{-3}
3	III	9177	0.950×10^{-10}	0.249×10^{-6}
4	IV	82992	0.434×10^{-13}	0.152×10^{-9}

Common cause events involving outages of three lines have also been included in this study. These outages are discussed in Chapter 6.

Three distinct categories of outage events which are, in fact, forced outage events are recognized and taken into account. The forced outage of a component is defined as the complete outage of the component from the system. The outaged component cannot therefore physically or operationally assist the system in any way.

The three categories of forced outage events considered in this thesis are as follows:

(1) Independent Outage

An independent outage results due to the failure of a component. The cause of an independent outage is neither (a) a direct cause of any other outage nor (b) a consequence of another component outage.

(2) Common Cause Outage

A common cause outage is an outage event having a single external cause with multiple failure effects, where effects are not consequence of each other[23]. Common mode outages resulting from the failure of lines having common right of way or supported at the common structure for at least a part of their length are considered in this study.

(3) Station Originated Outage

This is a dependent outage event that results because of the outage of station components such as breakers, transformers and bus sections. Outages because of the active and passive failure of breakers, bus section faults and forced outages of station transformers have been considered in this thesis.

In addition to the previously noted forced outages, scheduled outages because of planned maintenance of station elements are also considered. A scheduled outage is an outage that results when a component is deliberately taken out of service at a selected time, usually for the purpose of construction, preventive/planned maintenance, or repair.

The digital computer program does not recognize the common cause outage events or station originated outage events automatically. The data for these dependent events have to be given as an input to the digital computer program. The data should provide information regarding components that are removed due to these dependent outages. They should also provide values for the associated failure and repair rates or probability and frequency of down states caused by the outage of these components. In the case of common cause outages, the data are provided together with the outage data of generating units and transmission lines. The data for station originated outages are generated by another digital computer algorithm[24]. These data are then used in the modified digital program for the composite system adequacy evaluation to examine the effect of station originated outage events.

2.8 State Space Models[25]

The probability, frequency and duration indices of a system are computed using Markovian models which provide the transitions between the states. Models for a single component outage, independent overlapping multiple outages for three non-identical components, common mode outages and station related outages are described in the following section.

2.8.1 A Model For A Single Component Outage

The state space diagram for a single component (two states) outage is given in Figure 2-7.

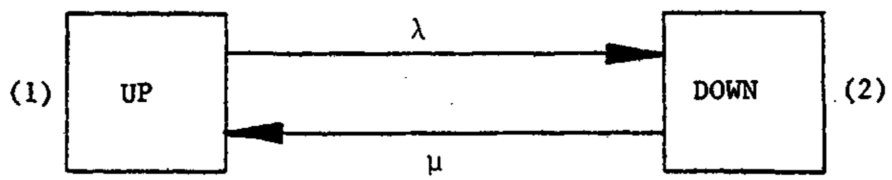

Figure 2-7: Two state model for one component

The probability, availability, unavailability and the frequency for this model are as follows:

$$\text{Availability } A = P_1 = \mu/(\mu + \lambda)$$

$$\text{Unavailability } U = P_2 = \lambda/(\lambda + \mu)$$

Frequency $f = \mu\lambda / (\mu + \lambda)$

2.8.2 A Model For Three Independent Component Outages

The state space diagram for three non-identical independent components is given in Figure 2-8. The expressions for the probability and the frequency for this model are as follows:

$$P_1 = \mu_1\mu_2\mu_3 / D \; ; \quad f_1 = P_1(\lambda_1+\lambda_2+\lambda_3)$$
$$P_2 = \lambda_1\mu_2\mu_3 / D \; ; \quad f_2 = P_2(\mu_1+\lambda_2+\lambda_3)$$
$$P_3 = \mu_1\lambda_2\mu_3 / D \; ; \quad f_3 = P_3(\lambda_1+\mu_2+\lambda_3)$$
$$P_4 = \mu_1\mu_2\lambda_3 / D \; ; \quad f_4 = P_4(\lambda_1+\lambda_2+\mu_3)$$
$$P_5 = \lambda_1\lambda_2\mu_3 / D \; ; \quad f_5 = P_5(\mu_1+\mu_2+\lambda_3)$$
$$P_6 = \lambda_1\mu_2\lambda_3 / D \; ; \quad f_6 = P_6(\mu_1+\lambda_2+\mu_3)$$
$$P_7 = \mu_1\lambda_2\lambda_3 / D \; ; \quad f_7 = P_7(\lambda_1+\mu_2+\mu_3)$$
$$P_8 = \lambda_1\lambda_2\lambda_3 / D \; ; \quad f_8 = P_8(\mu_1+\mu_2+\mu_3)$$

where,

$$D = (\mu_1+\lambda_1)(\mu_2+\lambda_2)(\mu_3+\lambda_3)$$

2.8.3 A Model For Common Cause Outages[26]

Figure 2-9(A) shows a five state model with the common cause failure and repair rates as λ_c and μ_c respectively. The expressions for the probability and the frequency of each state for this model were obtained using a graphical method developed by the author[27]. A flow graph for the Markov model shown in Figure 2-9(A) is indicated in Figure 2-9(B). The expressions for the probability and the frequency of each state are as follows:

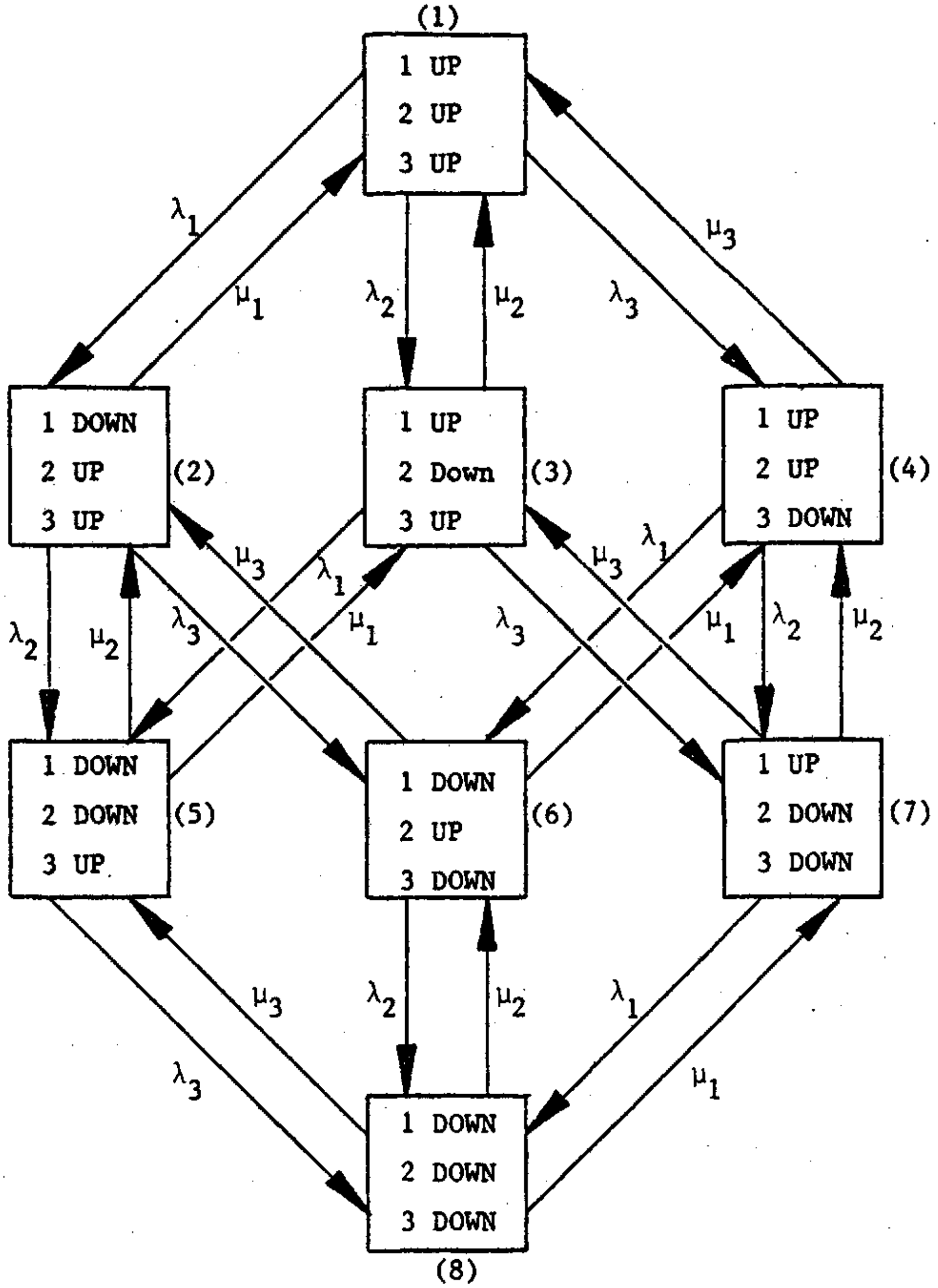

Figure 2-8: Eight state model for three independent overlapping outages

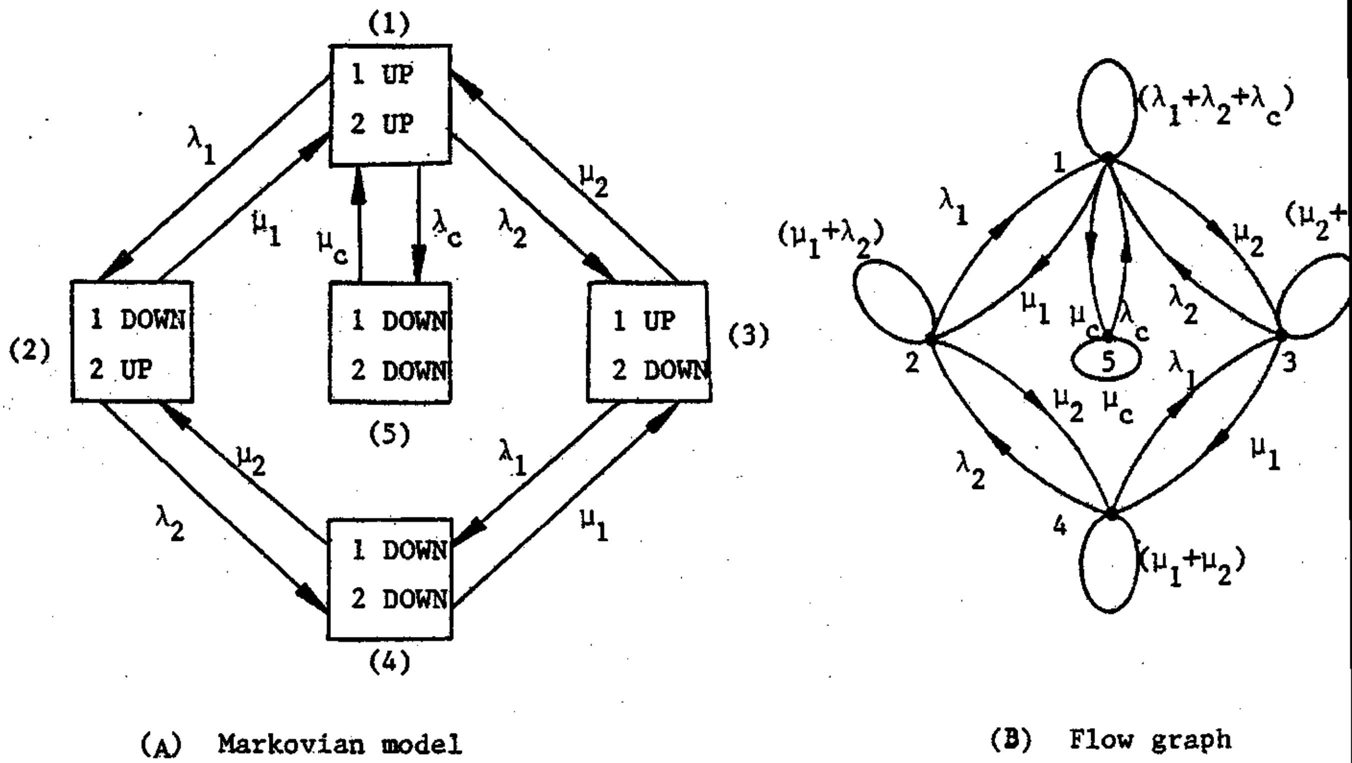

Figure 2-9: Five state common cause model and associated flow graph

$P_1 = \mu_1 \mu_2 \mu_c / D; \quad f_1 = P_1(\lambda_1 + \lambda_2 + \lambda_c)$

$P_2 = \lambda_1 \mu_2 \mu_c / D; \quad f_2 = P_2(\mu_1 + \lambda_2)$

$P_3 = \mu_1 \lambda_2 \mu_c / D; \quad f_3 = P_3(\lambda_1 + \mu_2)$

$P_4 = \lambda_1 \lambda_2 \mu_c / D; \quad f_4 = P_4(\mu_1 + \mu_2)$

$P_5 = \mu_1 \mu_2 \lambda_c / D; \quad f_4 = P_5(\mu_c)$

where,

$$D = \mu_c(\mu_1 + \lambda_1)(\mu_2 + \lambda_2) + \lambda_c \mu_1 \mu_2$$

2.8.4 Station Originated Outages

In addition to independent outages and common mode outages due to common right of way or common structural support, the transmission lines/transformers and/or generating units can be out of service because of station originated causes. Only very few publications[28, 29] are available which consider the inclusion of the station originated outages in the reliability evaluation of a composite system. In this study, emphasis has been placed on the effect of station originated outages on bulk power indices. This phenomenon is described separately in Chapter 6.

2.9 Digital Computer Program For Composite Adequacy Evaluation

A digital computer program[16] using the fast decoupled A.C. load flow was developed at the University of Saskatchewan. *The program as developed can consider up to second level contingencies both for the generating units and transmission lines/transformers. This program has been further modified and utilized to examine the three test systems described in Section 2.5. In the modified version of the program, hitherto called simply as the 'program', minimal changes have been made in the fast decoupled A.C. load flow algorithm or in the line overload alleviation algorithm. The main modifications have been made in the contingency enumeration algorithm, load curtailment philosophy and solution of voltage violating cases. The following is a list of major modification/ alterations in the digital computer program:

1. Inclusion of high level generating unit outage events.
2. Sorting of the identical generating units.
3. Termination of an outage event in order to take into account higher level outages.
4. A quantitative assessment of voltage violating contingencies.
5. Solution of non-convergent and split network situations.

6. Load curtailment philosophy.
7. Inclusion of station originated outages.

A flow chart of the program for the contingency enumeration and the reliability assessment is given in Figure 2-10. Some of the salient features of the digital computer program are as follows:

1. The base case load flow values are used as initial estimates for 1st level outages. Similarly the values for the load flow quantities at an outage level are used as the initial estimates for the next outage level contingencies. This feature results in a faster convergence of the load flow for the outage events.

2. If a bus is isolated due to the outages of the line(s) in the system, an A.C. load flow is carried out for the remaining buses and lines in the system. The adequacy indices, depending upon the availability of the generated power and the connected load at the bus(es), are calculated for the isolated buses.

3. If the outage of a line(s) results in a split network situation, an approximate algorithm is used to test the adequacy of the split networks. This algorithm is discussed in Section 2.10.

4. If the outage of a generating unit connected to a bus, say X, results in the generating capacity being less than the scheduled generation at bus X, then the generation at those

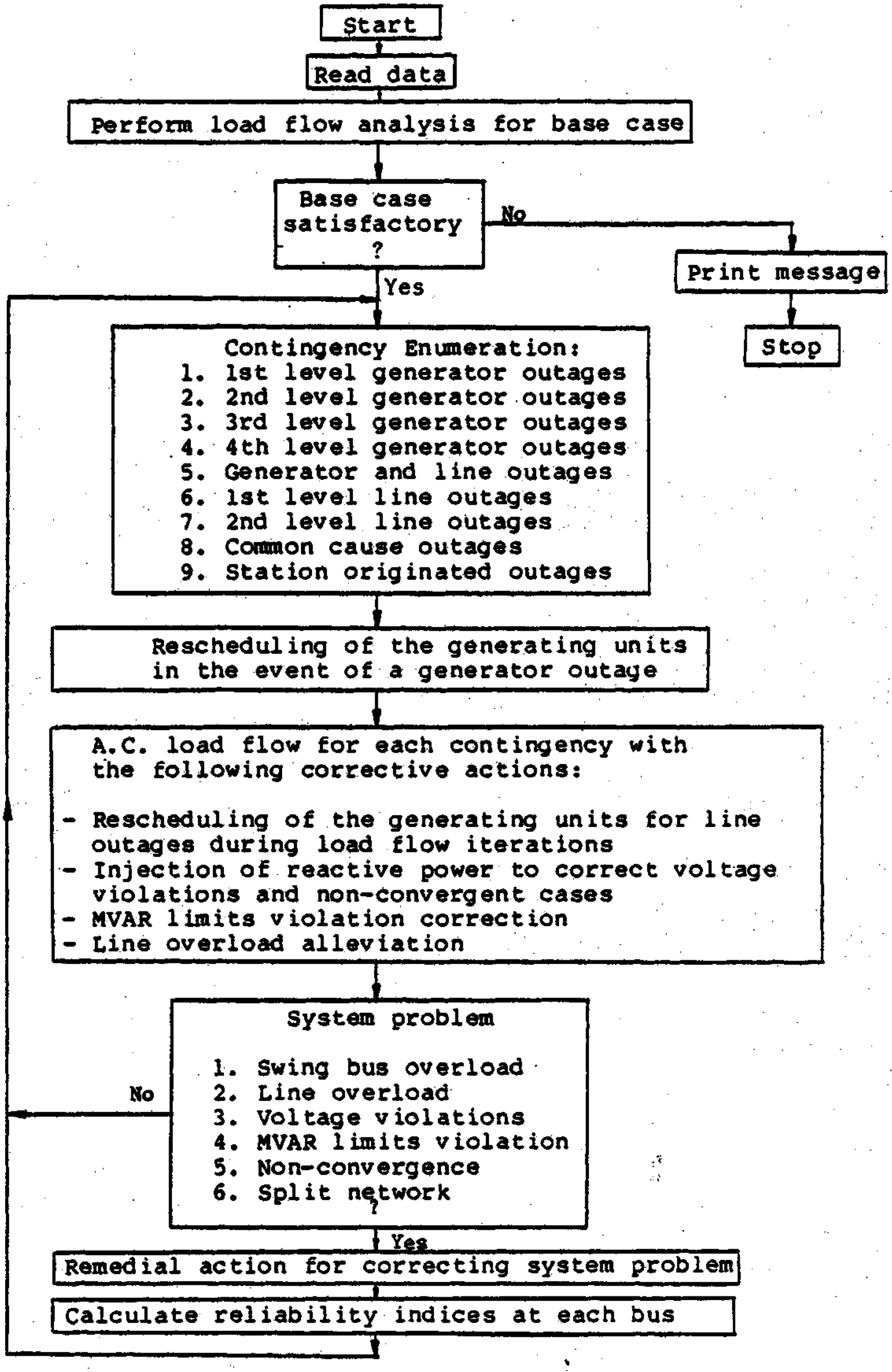

Figure 2-10: Flow chart for contingency enumeration and reliability assessment algorithm

buses which have reserve capacity available is increased in the following proportion:

removing

$$\frac{\text{(Scheduled generation at bus X - Capacity available at bus X after remaining the units.)}}{\text{Sum of the reserve available at all other buses in the system.}}$$

In this study, it is assumed that the total installed capacity at any bus is available for rescheduling under the outage events. Restriction can, however, be imposed on any generating bus after making minor modification in the program.

A similar procedure is adopted for compensating the loss of generation capacity due to the isolation of a generator bus in the case of line outages.

5. Overloads of a line(s) under any outage condition are alleviated by the generation rescheduling and load shedding[15] at the appropriate buses.

6. The swing bus overloads due to generation deficiency are alleviated by curtailing the load at appropriate buses in the system. A load curtailment philosophy for alleviation of swing bus overloads is described in Chapter 5.

7. Voltages at the voltage violating buses are corrected by injecting reactive power. A heuristic algorithm is developed and discussed in Chapter 4.

8. Non-convergent outage contingencies are checked for their divergence by using a heuristic algorithm described in Chapter 4. If a non-convergent situation results due to the

operating conditions, this situation is solved by rescheduling the generating units and injecting reactive power at voltage violating buses. However, if a non-convergent situation persists even after generation rescheduling and reactive power injection, a D.C. load flow is carried out to solve this contingency.

9. In addition to including common cause outages that involve outages of three lines or less, the program also incorporates station originated outages. This is discussed in Chapter 6.

10. In order to reduce the computation time for generating unit outages, identical units are sorted and the outage contribution due to these identical units is determined by calculating the indices for one identical unit only. The contribution of higher level outages (5th level or higher in the case of generator outages and 3rd level or higher in the case of independent line outages) is included by modifying the adequacy indices. This modification is described in the next Chapter.

11. The program can investigate a set of selected or specified generating unit and/or line outages.

2.10 Split Network Situations

2.10.1 Introduction

Changes in the network configuration due to outages of the line(s) and transformer(s) may result in the splitting of a network into two or more than two smaller networks. Each network may consist of PV buses and/or PQ buses and under steady state conditions, they can be treated as independent networks for analysis purposes. Therefore the adequacy evaluation of an outage contingency resulting in a split network involves the study of the adequacy of each network separately. One of the most appropriate techniques to handle these situations is to solve the A.C. load flow for each network after rescheduling the generating units. This proposition does not appear to be feasible because of large computation time and additional storage requirements for the B' and B'' matrices for the separated networks.

It has also been observed that in practical systems, network splitting is caused by outages of at least two or more than two lines. The probability and the frequency of two or more lines being independently out is quite low, therefore their contribution to the adequacy indices is not significant. However, the probability and the frequency of a system separation event could be too high to ignore, if the event is a result of a common cause outage of the line(s). In general, common cause outages involve at least one common terminal and it is, therefore, very seldom that these outage events result in a system separation. Table 2-9 gives a description of system separation cases for the three test systems considered in this thesis. As observed from Table 2-9, the number of outage events resulting in system separation is quite low and no single outage level event results in the splitting of a

Table 2-9: A brief summary of the line contingencies resulting in a split network

S.No.	System Description	2nd Level Contingencies Independent	2nd Level Contingencies Common Cause
1	6 bus test system	Lines 5 & 8 out	-
2	IEEE RTS	Lines 12 & 13 out	Lines 25, 26 & 28 out
3			Lines 29, 36 & 37 out
4	SPC System	Lines 11 & 13 out	Not Considered
5		Lines 36 & 41 out	
6		Lines 43 & 46 out	

network. An approximate but fast and simple approach has therefore been developed to solve these outage events. This approach does not need any additional storage requirements for B' and B'' matrices for each network.

2.10.2 A Simple Algorithm To Solve A Split Network Situation

An approximate algorithm has been developed to take care of situations resulting in system separation. In general, there could be two possibilities when a network is divided into two smaller networks.

(i) one network is a net power exporting area while the other is a net power importing area.

(ii) Both networks are self sufficient and each has more generation than the total load in the area.

These two situations are shown in Figure 2-11 and Figure 2-12 respectively.

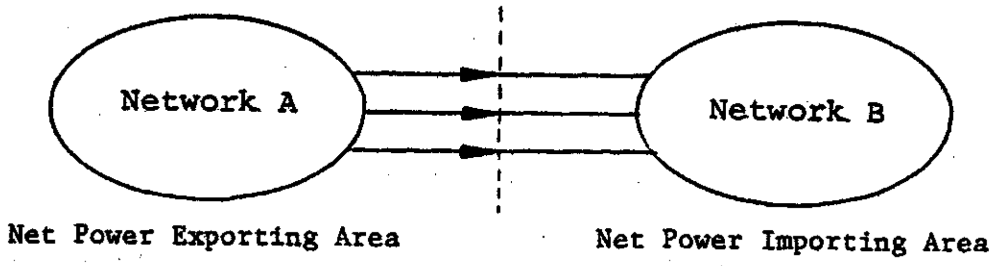

Figure 2-11: Split network situation with net power transport from one area to other area

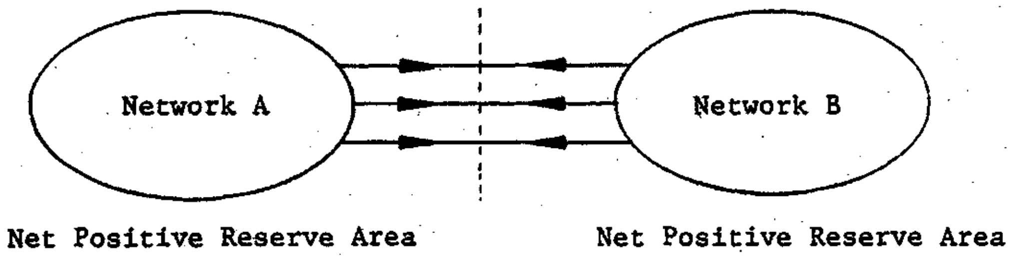

Figure 2-12: Split network situation with adequate reserve in both the areas

Figure 2-11 shows two areas in which area A has net positive reserve available while area B is a net negative reserve area. Under normal circumstances, power flows from area A to area B, thus meeting the deficiency in area B. Figure 2-12 shows both areas having net positive reserve and depending upon the operating conditions, there may or may not be an interchange of power between these two networks. The possibility of both areas having negative reserve is ruled out as it implies unsatisfactory operation of the base case.

The algorithm checks for the net reserve in each area. Line losses in each area are also accounted for by adding them in the system load. It is assumed that all lines in the system have equal line losses which are calculated by dividing the total system losses by the total number of lines in the system. Under the situation represented in Figure 2-11 load is curtailed proportionally from the curtailable load at all buses having load in network B. The total load to be curtailed is equal to the negative reserve in area B. However, if area B still remains generation deficient after curtailing curtailable load at all buses in network B, then the firm load is proportionally curtailed at load buses (PQ buses) after meeting the firm load requirements at PV buses where local generation is greater than the firm load at the bus. Firm load is curtailed only at those PV buses which have local generation less than the firm load. In network A, there is no load curtailment at any bus since it is a power surplus system.

Under the situation shown in Figure 2-12 there is no load curtailment in either network A or network B.

The probability of a line in either of the networks being severely overloaded for both split network situations (Figure

2-11 and Figure 2-12) is unlikely if the base case is quite satisfactory. Therefore in this algorithm no check for line overloads is incorporated. However, there could be voltage violations and/or generator MVAR limit violations but these are not calculated as determination of these violations requires a solution of an A.C. load flow for both networks.

The above algorithm has been successfully employed for the three test systems. A brief description of results is as follows:

2.10.3 Discussion Of Results

(1) The 6 Bus Test system (Figure 2-1)

Only one contingency involving the outage of lines 5 and 8 results in a split network with buses 1, 2, 3 and 4 forming a net positive reserve network and buses 5 and 6 forming a net negative reserve network. Since buses 5 and 6 have no generation available, total load is curtailed at both buses. Other load buses 3 and 4 do not experience any load curtailment as they exist in a net power exporting area.

(2) The IEEE RTS (Figure 2-2)

The outage of lines 12 and 13 results in a split network situation. Buses 7 and 8 form a small network and the remaining other buses from a big network. Both networks have positive reserve so there is no load curtailment at any bus in the system.

Inclusion of common mode outage results in two more split network situations which are as follows:

(1) The outage of lines 25 and 26 on the common right of way with the outage of line 28 results in a split network situation similar to that of Figure 2-11. Buses in the net power exporting area are 17, 18, 21 and 22. These buses will not experience any load curtailment. However, all the load buses in the net power importing area experience a proportional load curtailment. Table 2-10 shows the amount of load curtailment for each load bus in the net power importing region.

Table 2-10: Load curtailment at system buses for outages of lines 25, 26 and 28 in IEEE RTS

Bus No.	Load Curtailed (MW)	Bus No.	Load Curtailed (MW)
1	10.44	9	16.92
2	9.38	10	18.85
3	17.40	13	25.62
4	7.15	14	18.75
5	6.86	15	30.64
6	13.15	16	9.67
7	12.08	19	17.50
8	16.53	20	12.37

(2) The outage of line 29 and that of lines 36 and 37 results in the split network situation shown in Figure 2-11. Two load buses 19 and 20 form a small network and since

neither of them has local generation, each bus experiences a total load curtailment. The remaining buses in the second network do not experience any problem because this network has a positive reserve of 864 MW.

(3) The Manitoba assisted SPC System (Figure 2-3)

As seen from Table 2-9, there are three line contingencies that result in a split network situation. The outage of lines 11 and 13 isolates two load buses 3 and 5 from the rest of the system. These two buses experience total load curtailment since none of them have local generation. The rest of the system does not experience any problem. Similarly, the outage of lines 43 and 46 separates two load buses 22 and 24 which experience total load curtailment. However the outage of lines 36 and 41 does not curtail the load at any bus since isolated buses 19 and 21 have generation greater than the total load of both buses.

2.11 Summary

A digital computer program for calculating load point indices and the overall system indices of a composite generation and transmission system is described in this chapter. The three test systems on which adequacy studies were conducted are also described. Successful application of the program in evaluating the adequacy of the three different systems illustrates the flexibility and the capability of the program to handle a wide range of power networks. The 6 bus test system is relatively simple and hypothetical while the

Manitoba assisted Saskatchewan Power Corporation (SPC) system is complex and is an actual system. The 24 bus IEEE RTS is a standard system used to compare the results generated by different programs created by reliability practitioners in industry, research and consulting organizations.

Two types of indices, "annualized" and "annual", are recognized and discussed. Two sets of indices, bus indices and system indices, for each type are also described. It has been emphasized that these indices supplement each other and their interpretation should be made in a correct perspective. Load models used to calculate the adequacy indices are also discussed in this chapter.

The splitting of a network poses a problem due to the fact that it is necessary to solve an A.C. load flow for separated networks. This requires additional storage for the newly formed $[B']$ and $[B'']$ matrices for the part networks. The computation time to solve a split network event also increases because an A.C. load flow has to be carried out for all networks. In order to avoid additional storage requirements and reduce computation time, a heuristic algorithm was developed and successfully applied to split network situations in all the three test systems.

In the case of generating unit outages, the need to include high level outages is recognized, as the probability and the frequency of these high level outages are too large to ignore. The inclusion of high level generating unit outages is discussed in the next chapter. A discussion of the effect of the high level outages on the adequacy indices is also included in the next chapter.

CHAPTER 3

INCLUSION OF HIGH LEVEL OUTAGES

3.1 Introduction

A primary concern in adequacy studies of a composite generation and transmission system is the selection and testing of outage contingencies which occur frequently and have severe impact on the system performance. In most cases, severity associated with a contingency event is inversely related to the frequency and the probability of its occurrence. In other words, as the number of outage components increases in a contingency both the probability and the frequency of the contingency decrease. In the contingency enumeration approach, a question often raised is whether the analysis is thorough enough such that a sufficient number of outage events have been considered. Hence selection of an 'appropriate' outage level is of fundamental importance in the adequacy evaluation of a composite power system. The main constraint to considering a large number of outage events is the computation time required to solve these contingencies.

Selection of an appropriate outage level is dictated by various factors such as the size of the system, the probabilities and the frequencies of the outage events, the severity associated with an outage event, the purpose of the adequacy studies, the computation time required to evaluate each outage contingency, and the criteria used for determining the system status, i.e. failure/success state. As the outage contingency level increases, computation time increases rapidly, particularly if an A.C. load flow is used for the solution of each contingency. In order to limit the number of contingencies, fixed criteria such as selection of single or double level contingencies and/or variable criteria such as a frequency/probability cut-off limit and/or ranking cut-off limit etc. are presently used. In this study both criteria, fixed and variable, have been employed.

3.2 Contingency Evaluation Cut-Off Criteria

The earlier work[16] done at this university in the area of composite system reliability evaluation considered outages only up to the second level. Recent investigations[10] have indicated that the second level is not an adequate level particularly for a large system, and that higher level outages should be considered. Table 3-1 shows the sum of the probabilities of all independent outage contingencies up to the 2nd level for the three test systems. The sum of the probabilities for all possible outage contingencies in any system is always unity.

As shown in Table 3-1, the sum of the probabilities in the case of line outages for all three systems is close to 1.0, but for both the IEEE RTS and the SPC system, the sum of the probabilities in the case of generator outages is somewhat less than unity. It can therefore be reasonably deduced that as the size of a system increases, the calculation of adequacy

Table 3-1: Sum of the probabilities of all contingencies up to the 2nd level

Contingency Description	6 Bus Test System	IEEE RTS	SPC System
Lines only	0.999999	0.991130	0.999998
Generators only	0.999798	0.841244	0.955439
Both Lines & Generators	0.999529	0.834817	0.954862

other P is 1?

indices involving 1st and 2nd level contingencies, particularly for generator outages, will provide optimistic results. This is due to the fact that as the number of generating units in a system increases, the probability and the frequency of an independent outage event involving three or more components increase to the point at which they cannot be ignored. The testing of higher level independent generator outages is, therefore, necessary when calculating adequacy indices. In this study, independent outages for generating units up to the 4th level and independent outages for transmission lines and transformers up to the 2nd level are considered. The reasons for not considering higher outage levels for transmission lines are as follows:

(1) As shown in Table 3-1, the sum of the probabilities for all transmission line contingencies up to the 2nd level is very close to unity.

(2) The computation time required to solve each line contingency in the IEEE RTS and the SPC system is

approximately 0.25 secs. and 1.25 secs. respectively on the VAX-11/780 digital computer. If the solution of higher level outages involving three and four lines is considered, it is estimated that the required CPU time for the IEEE RTS and the SPC system will be 350 minutes and 350 hours respectively. Computationally these figures are enormously expensive.

(3) Due to the system topology, transmission lines are subjected to common cause failures such as the failure of a transmission tower supporting two or more transmission circuits, failure of two or more than two transmission circuits having common right of way etc.. Transmission lines are also exposed to the vagaries of adverse climatic conditions which cause higher failure rates. The effect of common mode failures and that of 'failure bunching'[2] due to the adverse weather, depending upon the network configuration and meteorological conditions of the region, could be significant and many times larger than that of higher level independent outages. It is therefore not valid to consider the contribution of higher level independent outages for transmission circuits and ignore the contribution of common cause outages and the adverse weather conditions.

In addition to limiting the number of contingencies on the basis of outage level, a frequency cut-off criterion is also used. Those contingencies which have a frequency of occurrence less than 1×10^{-9} are not solved as their contribution is negligible. The inclusion of higher level generator outages is described in the following section.

3.3 Inclusion Of High Level Contingencies

The basic computer program has been extended to include generating unit outages up to the 4th level. Selection of this level is dictated, primarily, by the tremendous increase in the computation time for higher levels and the marginal contribution of these outages to the adequacy indices. Table 3-2 shows the sum of the probabilities for generator outages at different contingency levels for the three test systems.

Table 3-2: Sum of the probabilities for the generator outages

Contingency Level	6 Bus Test System	IEEE RTS	SPC System
Ist	0.993917	0.589915	0.805348
2nd	0.999798	0.841244	0.955439
3rd	0.999996	0.953814	0.992701
4th	0.999999	0.989544	0.999106

As observed from Table 3-2, the sum of the probabilities of contingencies up to the 4th level are 98.95% and 99.91% for the IEEE RTS and the SPC system respectively. The remaining 1.05% and 0.09% are contributed by contingencies beyond the 4th level. The contribution of these higher level outages can be calculated by solving an enormously high number of contingencies, 201376 for the IEEE RTS and 119115 for the SPC system at the expense of excessive CPU time. In order to account for these higher level contingencies, sometimes termed as more-off states, the probability and the frequency of outage events at the 4th level are modified in such a way that they include the effect of successive states. This modification is defined as a 'termination of an outage event' and is discussed in Section 3.3.1. A more-off state at a contingency level is a state in which at least one more component is out of service in addition to those already out at that level, e.g. for 2nd level independent outages, states representing the outage of three or more than three components are designated as more-off states. Conversely, a more-on state is one in which more components are available for operation.

The algorithm modifies the scheduled generation at buses at which generating units under outage are connected and increases the generation at other buses, if required. An A.C. load flow is carried out to test the system adequacy and accordingly suitable adequacy indices are calculated.

In the case of line outages, the probability and the frequency at the 2nd outage level for each line contingency are also modified to take into account the contribution of more-off states. The termination of an outage event is discussed below.

3.3.1 Termination Of An Outage Event

In order to account for the contribution of those higher level contingencies which are not otherwise evaluated, it is necessary to modify the adequacy indices to include the contribution of higher level contingencies but without a significant increase in computation time. As noted earlier, one effective technique is to modify the probability and the frequency of the last level contingencies so that the probability and the frequency are not the individual values for a contingency but the cumulative values for that contingency. In other words, these values are the probability and the frequency of a last level contingency and that of all other more-off states. Consider the case of an n component system. If the 2nd level is chosen as the last level for contingency evaluation, then the modified cumulative probability of components 1 and 2 being out is,

$P_{1,2}$ = Probability of the Markovian state in which components 1 and 2 are out + Probability of all more-off Markovian states in which components 1 and 2 are out in combination with any other component(s).

The severity associated with each more-off state is greater than the last level contingency and therefore the developed adequacy indices are somewhat optimistic. The error involved is negligibly small as these high level contingencies are a very small fraction (1.05% in the case of the IEEE RTS and 0.1% in the case of the SPC system) of the total contingencies. However, ignoring these higher level contingencies altogether results in even more optimistic adequacy indices.

The EPRI report[10] on this subject suggests terminating a state if it is tested as a failure state at any outage level, since all other states are definitely failure states. This technique, depending upon the system load and the generation pattern, may result in too optimistic adequacy indices. This is due to the fact that a more-off state has more severe impact on the system and therefore merging frequently encountered more-off states with less severe states is not justified. In a recent paper, Clements and others[30] presented a method utilizing a binary-tree approach to calculate lower and upper reliability index bounds. One objection[31] to the low level truncation approach or to the upper and lower bounds approach is that both techniques can calculate only two adequacy indices, the probability of failure and the frequency of failure, in a satisfactory manner. Calculation of other indices such as the number of load curtailments, expected load curtailed and expected energy curtailed etc. invariably involves solution of all frequently encountered contingencies. Only those higher level contingencies which have a very low value of frequency of occurrence should be merged. The effect of termination at lower levels for each test system is discussed in Section 3.5.

In the following section modified expressions for the probability and the frequency are developed.

3.3.2 Modified Expressions For The Probability And Frequency

(a) Generator Outages:-

For the outage of generating units NG1, NG2, NG3 and NG4, the modified expressions for the probability (P) is:

$$P = \prod_{\substack{i=1 \\ i\neq NG1,NG2, \\ NG3,NG4}}^{NG4 \to N_G} \frac{\mu_i}{(\mu_i+\lambda_i)} * \prod_{\substack{j=NG1,NG2, \\ NG3,NG4}} \frac{\lambda_j}{(\mu_j+\lambda_j)} *$$

N_G = no. of gen. units

Lalit

(Probability that all lines and transformers are in the UP state.)

The expression for the frequency (f) is:

f = P * (Failure rate of all components - Failure rate of generating units under outage + Repair rate of generating units under outage)

$$= P * \left[\sum_{\substack{i=1 \\ i\neq NG1,NG2,NG3,NG4}}^{N} \lambda_i + \{\mu_{NG1}+\mu_{NG2}+\mu_{NG3}+\mu_{NG4}\} \right]$$

Where N is the total number of generating units, lines and transformers in a system.

(b) Line Outages:-

For the outage of lines L1 and L2, the modified expressions for the probability is:

$$P = \prod_{\substack{i=1 \\ i\neq L1 \\ i\neq L2}}^{NL} \frac{\mu_i}{(\mu_i+\lambda_i)} * \prod_{\substack{j=L1 \\ j=L2}} \frac{\lambda_j}{(\mu_i+\lambda_j)} \left[1+ \sum_{k=L2+1}^{NL} \left\{ \frac{\lambda_k}{\mu_k} + \sum_{m=k+1}^{NL} \left(\frac{\lambda_k \lambda_m}{\mu_k \mu_m} \right) \right\} \right]$$

and the frequency is:

$$f = P * \left[\sum_{\substack{i=1 \\ i\neq L1 \\ i\neq L2}}^{N} \lambda_i + \sum_{\substack{j=L1 \\ j=L2}} \mu_j \right]$$

Where NL is the total number of lines and transformers in a system.

(c) Generator-Line Outages:-

The modified expressions for the probability and frequency for the outage of line L1 and generating unit NG1 are:

$$P = \frac{\lambda_{L1}}{\mu_{L1}} * \frac{\lambda_{NG1}}{\mu_{NG1}} * \prod_{i=1}^{NL} \frac{\mu_i}{(\mu_i+\lambda_i)} * \prod_{m=1}^{NG} \frac{\mu_m}{(\mu_m+\lambda_m)} * \left[1 + \sum_{j=NG1+1}^{NG} \{ \frac{\lambda_j}{\mu_j} + \sum_{k=j+1}^{NG} (\frac{\lambda_j \lambda_k}{\mu_j \mu_k}) \} \right]$$

$$f = P * (\mu_{NG1} + \mu_{L1} + \sum_{\substack{i=1 \\ i \neq L1 \\ i \neq NG1}}^{N} \lambda_i)$$

Where NG is the total number of generating units in a system.

3.4 Effect Of Inclusion Of Higher Level Generator Outages

The three test systems described in Section 2.5 are used to compare the contribution of high level outages to the adequacy indices. The annualized bus and system indices are computed at various outage levels for all the three systems.

3.4.1 The 6 Bus Test System (Figure 2-1)

In a relatively small system, such as the 6 bus test system, lower level outage contingencies provide reasonably accurate results. As seen from Figure 3-1, the 2nd level contingencies contribute the bulk of the adequacy indices. This is due to the fact that the sum of the probabilities up to the 2nd level generator outage contingencies is 0.999798 and the outage of a large generating unit (40 MW) with a

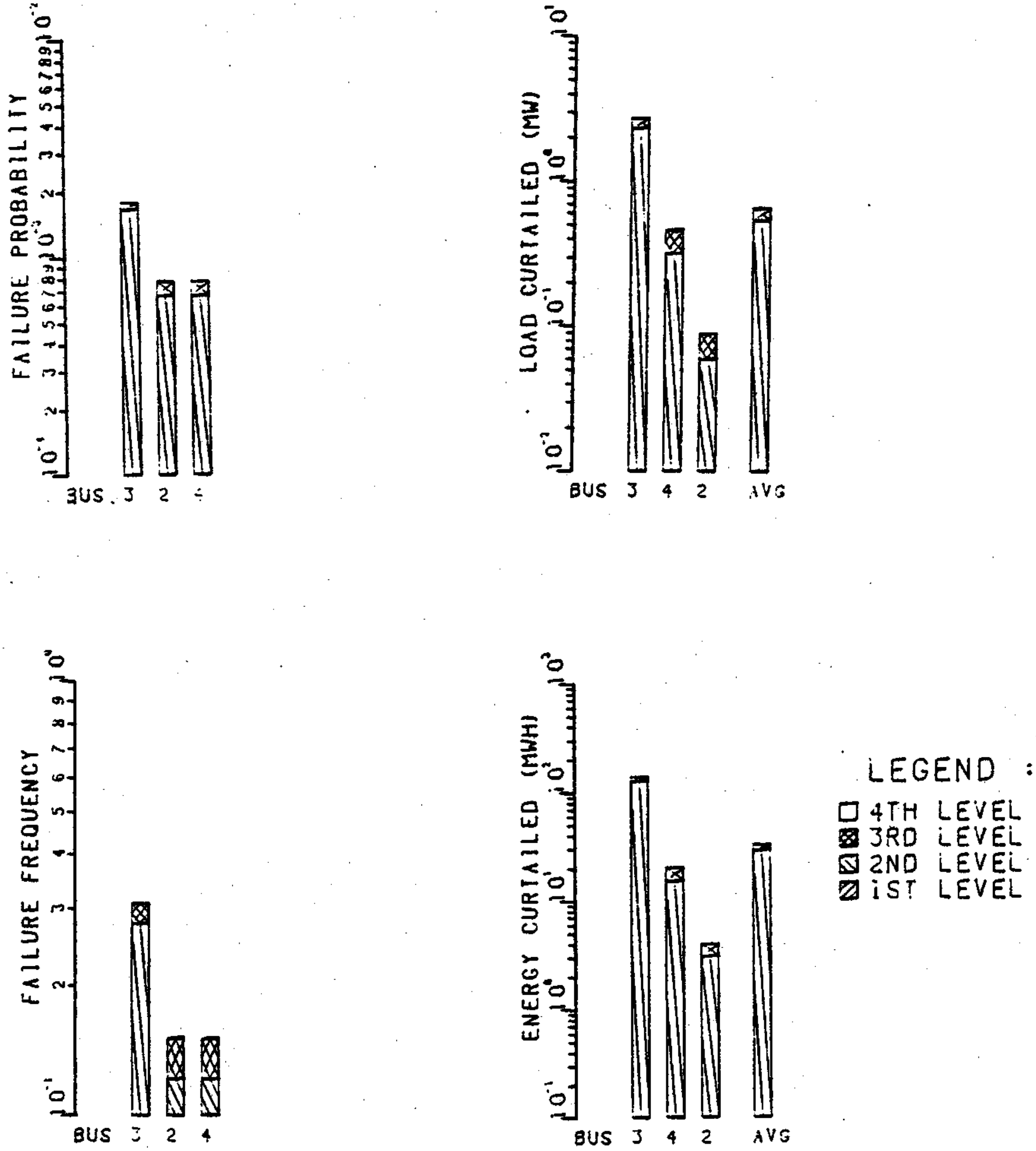

Figure 3-1: Annualized adequacy indices (without termination) for the buses in the 6 bus test system

smaller generating unit results in a generation deficiency in the system. The total reserve in the system is 55 MW. If the reserve in the system is increased or the system load is decreased, the consideration of higher outages becomes necessary. This is discussed in Chapter 5.

Only three buses 2, 3 and 4 experience load curtailment while bus 5 and bus 6 do not encounter any load curtailment problem. The load curtailment at system buses is decided by the load curtailment philosophy discussed in Chapter 5. In the case of generating unit outages, the curtailment of the load is confined to generating unit(s) outage buses and buses which are one line away from these outage buses. Table 3-3 gives a brief summary of the system indices for each outage level. As seen from the Table 3-3 and Figure 3-1, the effect of the 4th level generator outage contingencies is negligible and for this system, the 3rd level provides reasonably accurate results.

3.4.2 The IEEE RTS (Figure 2-2)

The inclusion of higher level generator outage contingencies is quite justified in this system as seen from Figures 3-2, 3-3, 3-4 and 3-5. Outages of two generating units anywhere in the system do not cause load curtailment in the 138 KV region. Buses in the north (230 KV), however, experience load curtailment in the event of two generating unit outages. Buses in the 138 KV region encounter load curtailment when three or more than three generating units are

Table 3-3: A brief summary of the system indices for the 6 bus test system

Generator Outage Level Ist	2nd	3rd	4th
Number of Load Curtailments			
0	15	231	1295
Number of Firm Load Curtailments (Firm load = 80% of Total Load)			
0	1	15	349
Bulk Power Supply Disturbances			
0.00000	0.27686	0.30864	0.30992
IEEE INDICES			
Bulk Power Interruption Index (MW/MW-Yr.)			
0.00000	0.01463	0.01766	0.01786
Bulk Power Energy Curtailment Index (MWh/Yr.)			
0.00000	0.78216	0.88606	0.89113
Bulk Power Supply Average MW Curtailment Index (MW/Disturbance)			
0.00000	9.77868	10.58738	10.66358
Modified Bulk Power Energy Curtailment Index			
0.00000	0.00009	0.00010	0.00010
Severity Index (System-Minutes)			
0.00000	46.92900	53.16400	53.46800

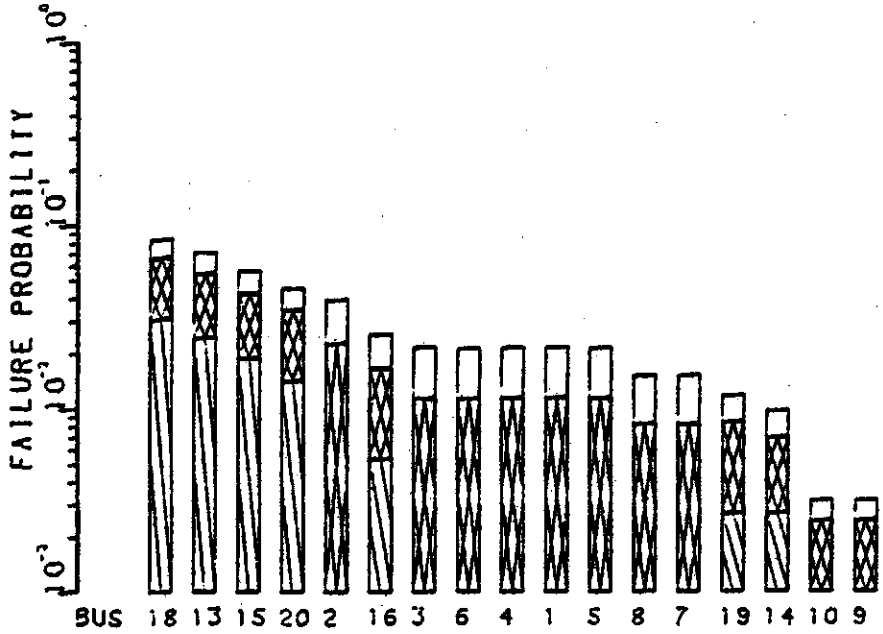

Figure 3-2: Probability of failure (without termination) for the buses in the IEEE RTS

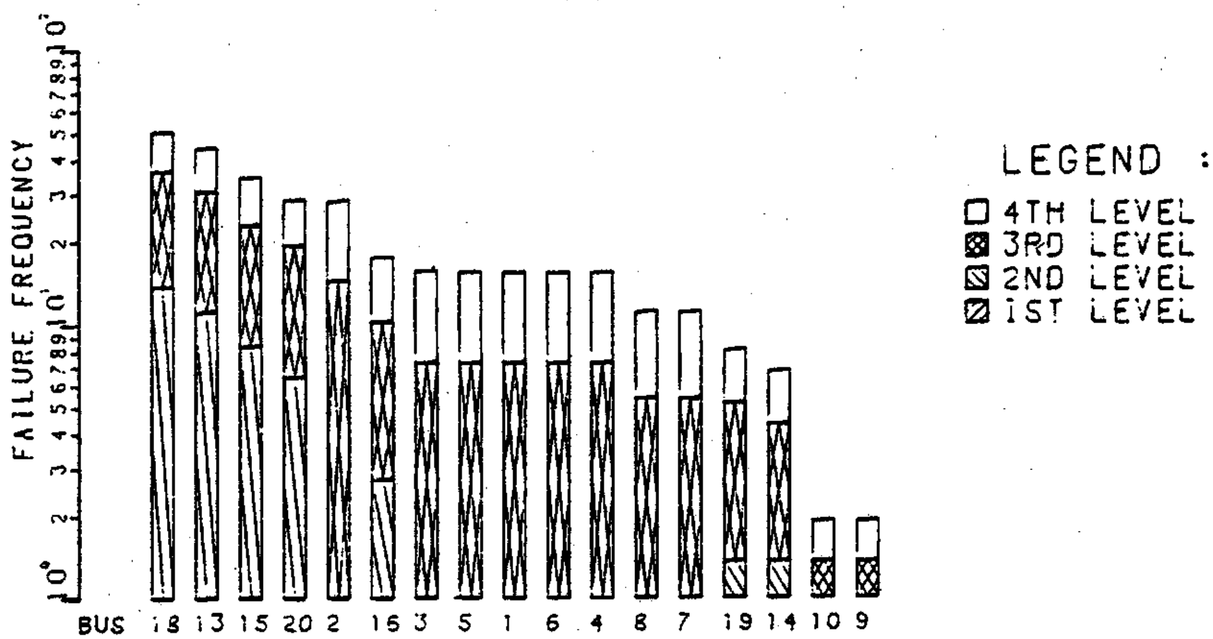

Figure 3-3: Frequency of failure (without termination) for the buses in the IEEE RTS

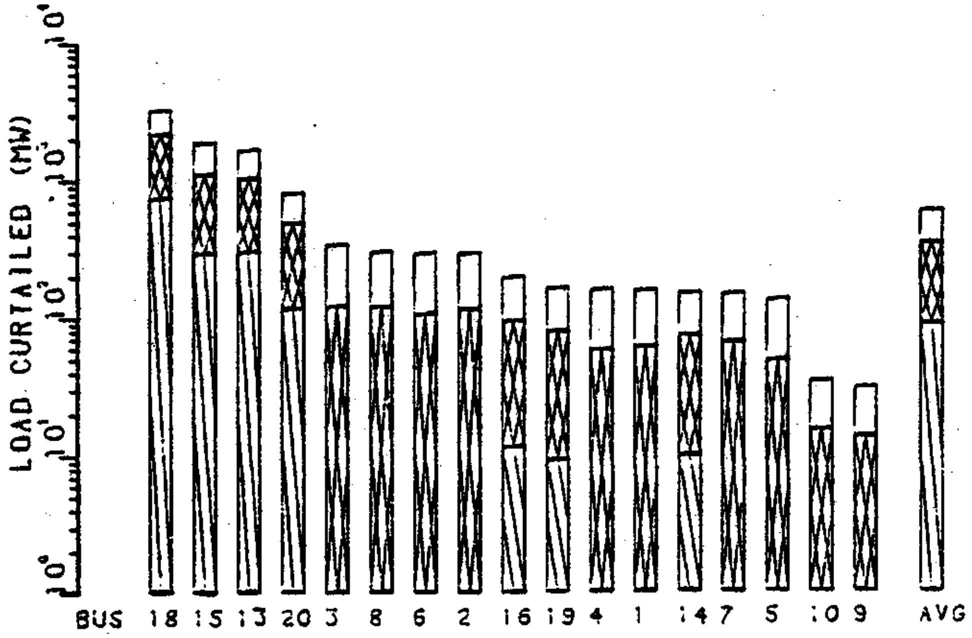

Figure 3-4: Expected load curtailed in MW (without termination) for the buses in the IEEE RTS

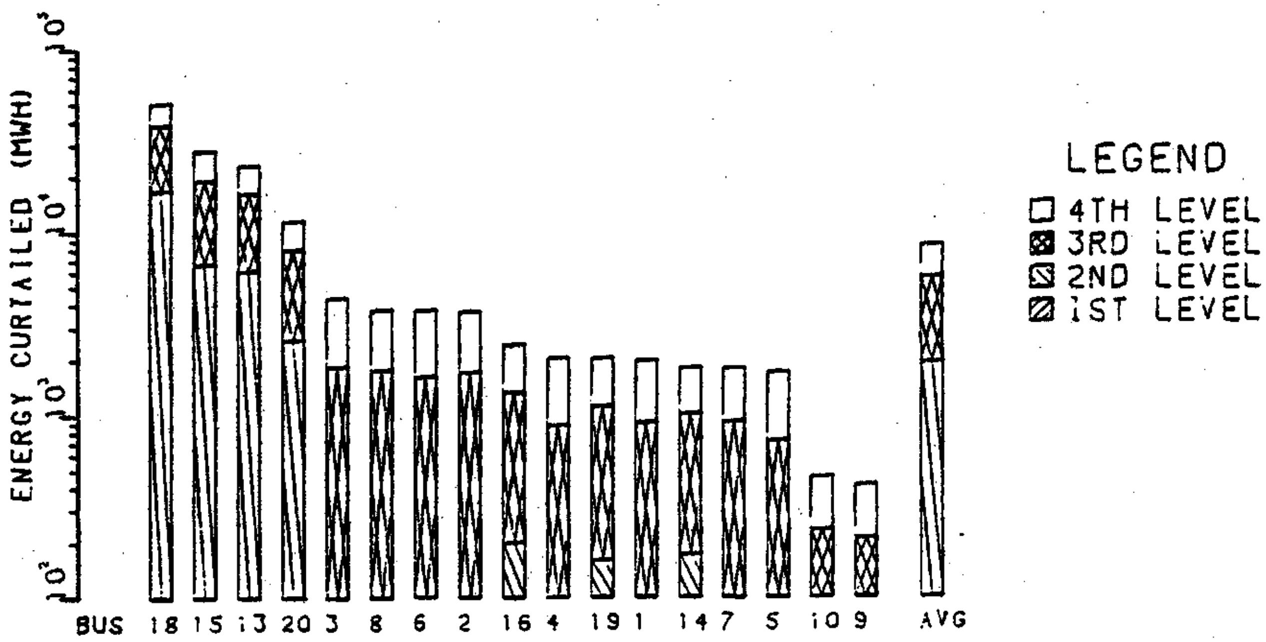

Figure 3-5: Expected energy curtailed in MWh (without termination) for the buses in the IEEE RTS

removed. This is due to the fact that at the 2nd outage level, the system experiences generation deficiency only when a large generator (350 MW or more) is out together with a medium generator (200 MW or more) because the system has a total reserve of 555 MW. Since the maximum rating of any generating unit in the 138 KV region is 100 MW, no bus in this region experiences load curtailment in the event of an outage of two generating units only. As noticed from Figure 3-2 to Figure 3-5, the 3rd and the 4th level contingencies contribute significantly to adequacy indices in the 230 KV region. Table 3-5 gives a summary of system indices at each outage level. Table 3-4 shows the maximum and minimum increment for the 3rd and the 4th level contingencies with respect to the 2nd level contingencies for buses in the 230 KV region.

Table 3-4: Maximum and minimum % increment for the 3rd and the 4th level generator contingencies w.r.t. the 2nd level contingencies for the IEEE RTS

Description of Index	Maximum % Increment w.r.t. 2nd Level		Minimum % Increment w.r.t. 2nd Level	
	3rd	4th	3rd	4th
Failure Probability	316 Bus(19)	478 Bus(16)	215 Bus(18)	272 Bus(18)
Failure Frequency	379 Bus(19)	646 Bus(16)	262 Bus(18)	366 Bus(18)
Total Load Curtailed (MW)	855 Bus(19)	1784 Bus(19)	292 Bus(18)	436 Bus(18)
Total Energy Curtailed (MWh)	696 Bus(19)	1272 Bus(19)	228 Bus(18)	301 Bus(18)

Table 3-5: A brief summary of the system indices for the IEEE RTS

Generator Outage Level Ist	2nd	3rd	4th
Number of Load Curtailments			
0	20	779	11988
Number of Firm Load Curtailments			
0	3	162	3235
Bulk Power Supply Disturbances			
0.00000	15.37400	42.44100	60.49000
IEEE INDICES			
Bulk Power Interruption Index (MW/MW-Yr.)			
0.00000	0.52950	2.05180	3.55340
Bulk Power Energy Curtailment Index (MWh/Yr.)			
0.00000	11.58000	33.99040	50.78830
Bulk Power Supply Average MW Curtailment Index (MW/Disturbance)			
0.00000	98.15080	137.78320	167.41860
Modified Bulk Power Energy Curtailment Index			
0.00000	0.00132	0.00388	0.00580
Severity Index (System-Minutes)			
0.00000	694.80200	2039.42300	3047.29600

3.4.3 The SPC System (Figure 2-3)

The installed capacity of the system is 2530 MW and the peak load is 1802.50 MW. Therefore the system has a static reserve of 727.50 MW, of which 300 MW is the power import from the Manitoba Hydro System. The largest generating unit is 280 MW and there are three units of this capacity. The next unit rating is 142 MW and there are three units of this capacity. The outage of any two generating units in the system does not create any generation deficiency in the system and therefore for this system, calculation of higher level outages is necessary in order to assess the adequacy of the system. Buses 19 and 20 encounter voltage violation problems in the event of two generating unit outages but no bus experiences load curtailment as seen from Figures 3-6, 3-7, 3-8 and 3-9. Load at bus 6 and at bus 38 is curtailed only when four or more than four generating units are removed. Buses which have generators connected to them or buses which are one line away from these buses, experience major load curtailment because of the load curtailment philosophy discussed in Chapter 5. Table 3-6 gives the frequency of failure and the expected load curtailed in MW for both the 3rd and the 4th outage levels at each bus in the system. A brief summary of the system indices at each outage level is shown in Table 3-7.

3.5 Effect Of Termination Of Failure Events At Lower Levels

As discussed in Section 3.3.1, one of the techniques to include the contribution of higher level outages without actually solving these outage contingencies is terminating an

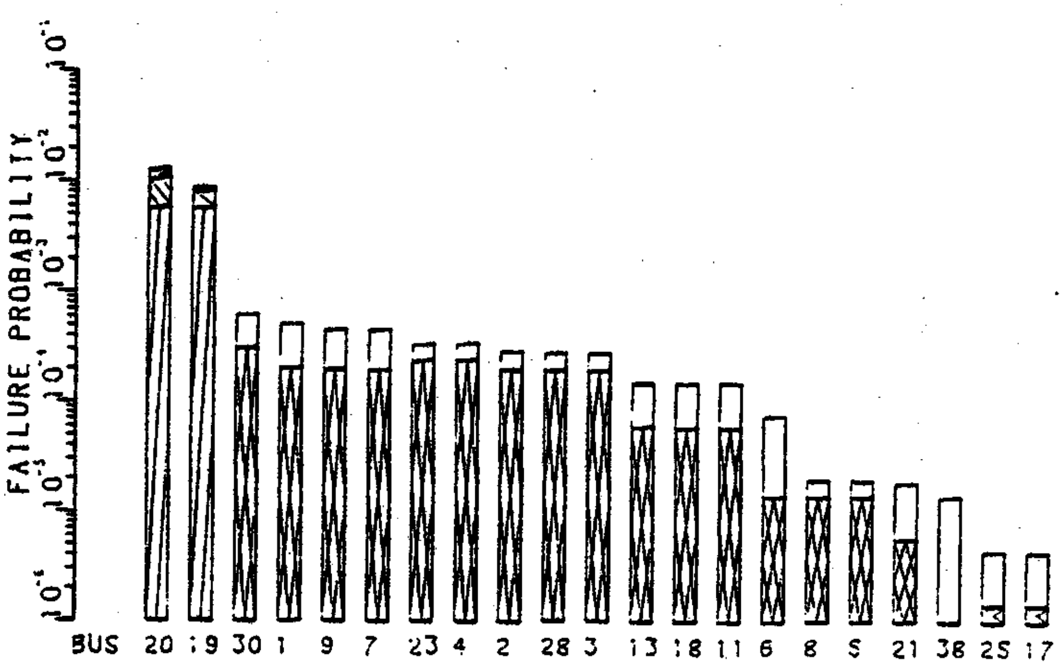

Figure 3-6: Probability of failure (without termination) for the buses in the SPC system

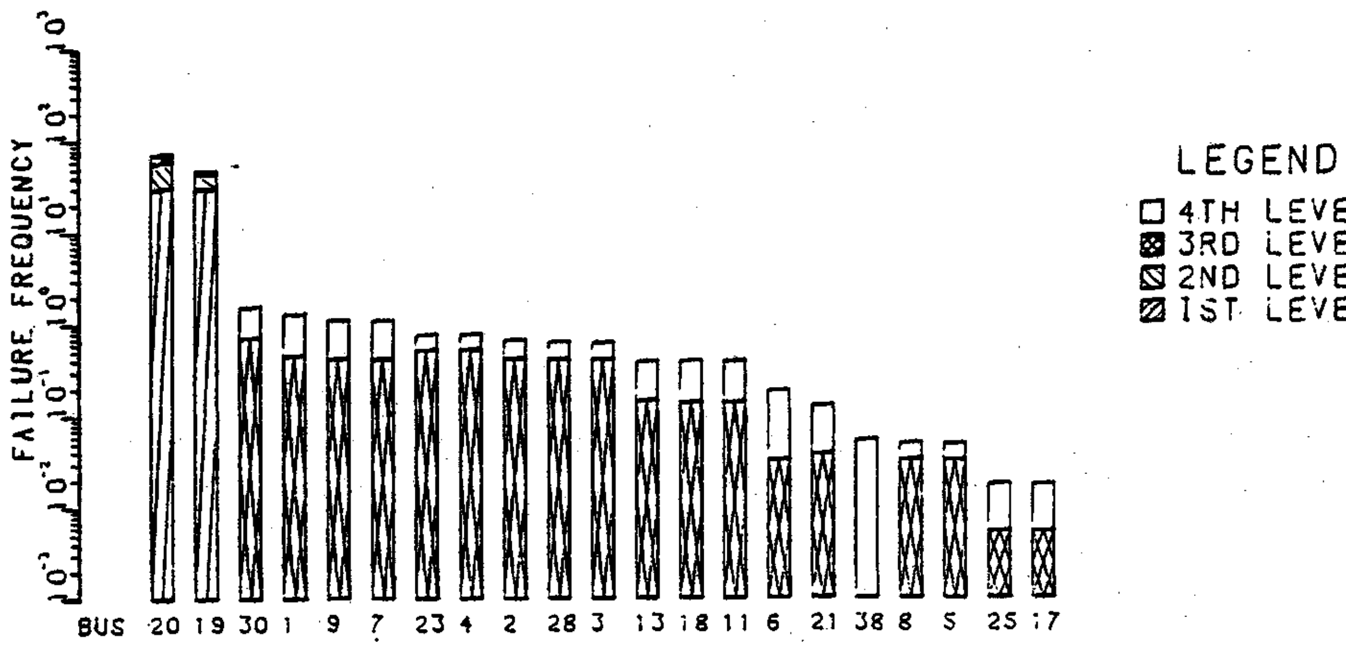

Figure 3-7: Frequency of failure (without termination) for the buses in the SPC system

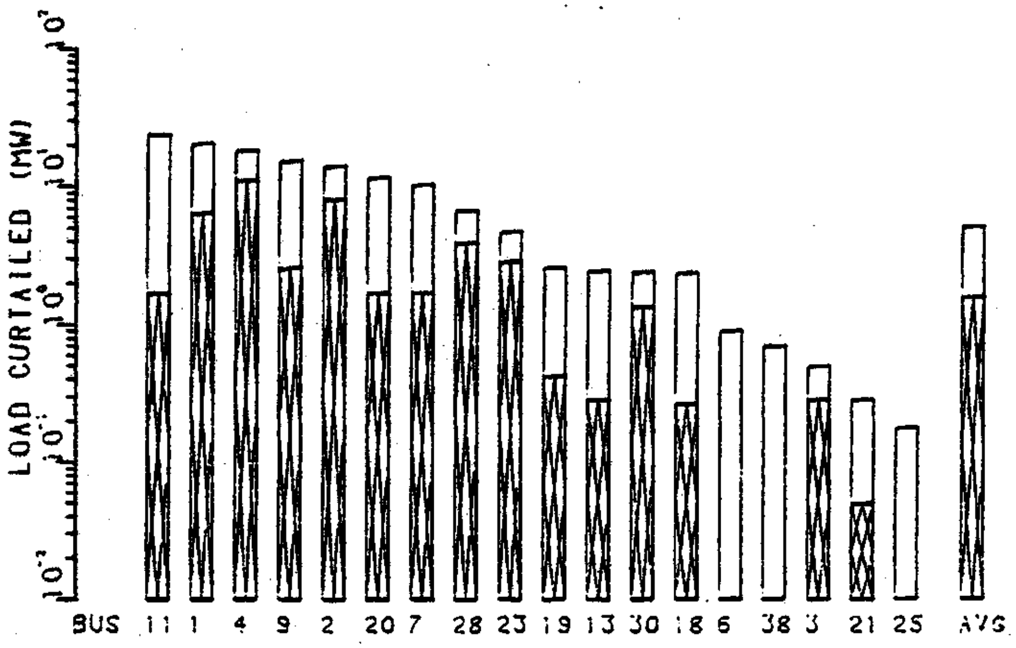

Figure 3-8: Expected load curtailed in MW (without termination) for the buses in the SPC system

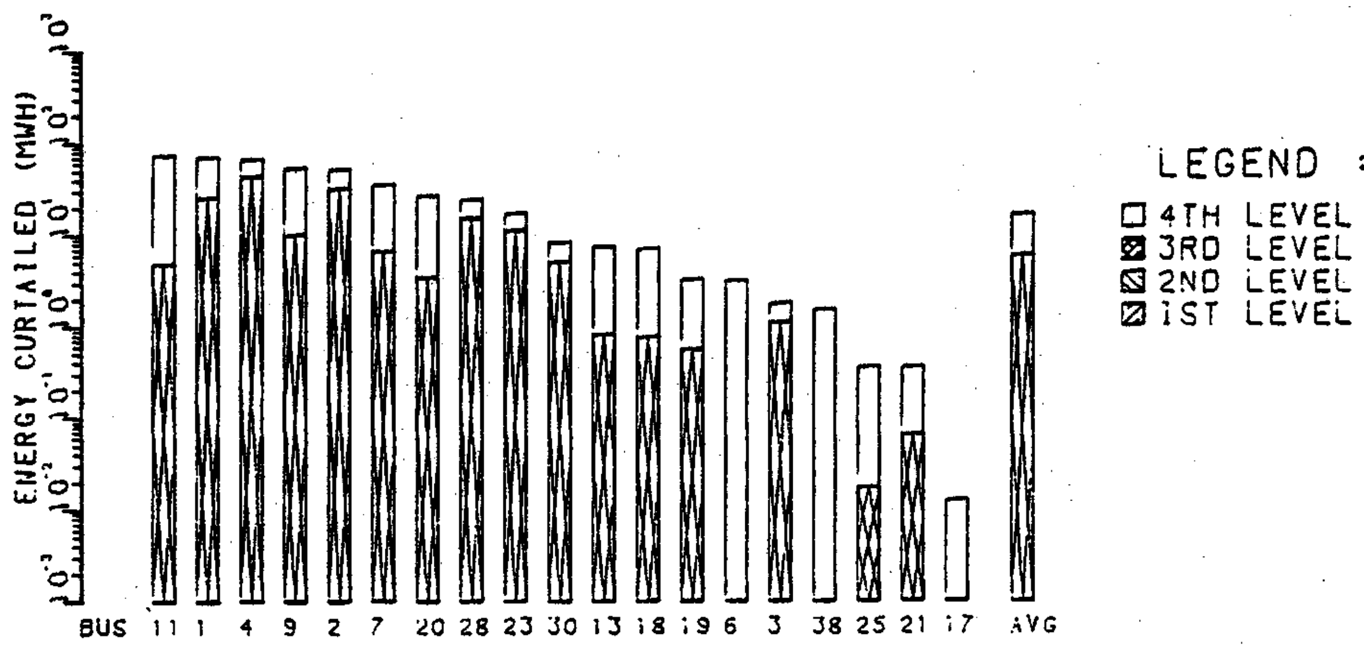

Figure 3-9: Expected energy curtailed in MWh (without termination) for the buses in the SPC system

Table 3-6: Annualized bus indices for the SPC system

BUS	Failure Frequency		Total Load Curtailed (MW)	
	Contingency Level		Contingency Level	
	3rd	4th	3rd	4th
1	0.4533656	1.3041217	6.4600000	20.7700005
2	0.4185923	0.6661793	8.2700005	14.4399996
3	0.4185923	0.6435799	0.2900000	0.5100000
4	0.5245102	0.7771107	11.3199997	18.8199997
5	0.0331406	0.0498841	0.0000000	0.0000000
6	0.0331406	0.1890110	0.0000000	0.9200000
7	0.4185923	1.1017412	1.7300000	10.4899998
8	0.0331406	0.0498841	0.0000000	0.0000000
9	0.4185923	1.1017412	2.5999999	15.7799997
11	0.1434373	0.3991662	1.6900001	24.1200008
13	0.1490662	0.4007158	0.2900000	2.5000000
17	0.0053882	0.0178943	0.0000000	0.0100000
18	0.1434373	0.3991662	0.2700000	2.4200001
19	48.4980392	49.2738075	0.4300000	2.6400001
20	70.4372940	73.7877655	1.7300000	11.9700003
21	0.0381336	0.1298684	0.0500000	0.2900000
23	0.5245102	0.7771107	2.9000001	4.8200002
25	0.0053882	0.0178943	0.0100000	0.1800000
28	0.4185923	0.6435799	3.9700000	6.9099998
30	0.7060811	1.5674913	1.3600000	2.4500000
38	0.0000000	0.0550631	0.0000000	0.7100000

Table 3-7: A brief summary of the system indices for the SPC system

Generator Outage Level			
Ist	2nd	3rd	4th
Number of Load Curtailments			
0	0	22	865
Number of Firm Load Curtailments			
0	0	13	495
Bulk Power Supply Disturbances			
0.00000	0.00000	0.70610	1.59360
IEEE INDICES			
Bulk Power Interruption Index (MW/MW-Yr.)			
0.00000	0.00000	0.02406	0.07808
Bulk Power Energy Curtailment Index (MWh/Yr.)			
0.00000	0.00000	0.09219	0.26151
Bulk Power Supply Average MW Curtailment Index (MW/Disturbance)			
0.00000	0.00000	61.42490	88.17360
Modified Bulk Power Energy Curtailment Index			
0.00000	0.00000	0.00001	0.00003
Severity Index (System-Minutes)			
0.00000	0.00000	5.53200	15.69100

outage event if it is tested as a failure state. The probability and the frequency of this outage event is modified by adding the probability and the frequency of more-off states. Modified expressions at the 4th outage level were presented Section 3.3.2. Similar expressions at other outage levels are used to calculate the probability and the frequency of a terminated event. In this section, the effect of the termination at various outage levels is discussed for the three test systems. Outages of generating units up to the 4th level are considered in each system. Four adequacy indices, the probability of failure, the frequency of failure, the expected load curtailed in MW and the expected energy curtailed in MWh, are represented by histograms for each bus in all the three test systems. Figure 3-10 shows indices for the 6 bus test system, Figures 3-11 to 3-14 give indices for the IEEE RTS, while Figures 3-15 to 3-18 show indices for the SPC system.

The 1st level termination indicates that a contingency is terminated at the 1st outage level if it is tested as a failure contingency at this level. If a contingency is not a failure contingency at the 1st outage level, it is terminated at the next higher level if found to be a failure contingency and so on. The 2nd level termination starts at the 2nd level and no contingency is terminated at the 1st level. In other words, all 1st level outage events are evaluated. If a contingency at the 2nd level is tested as the failure

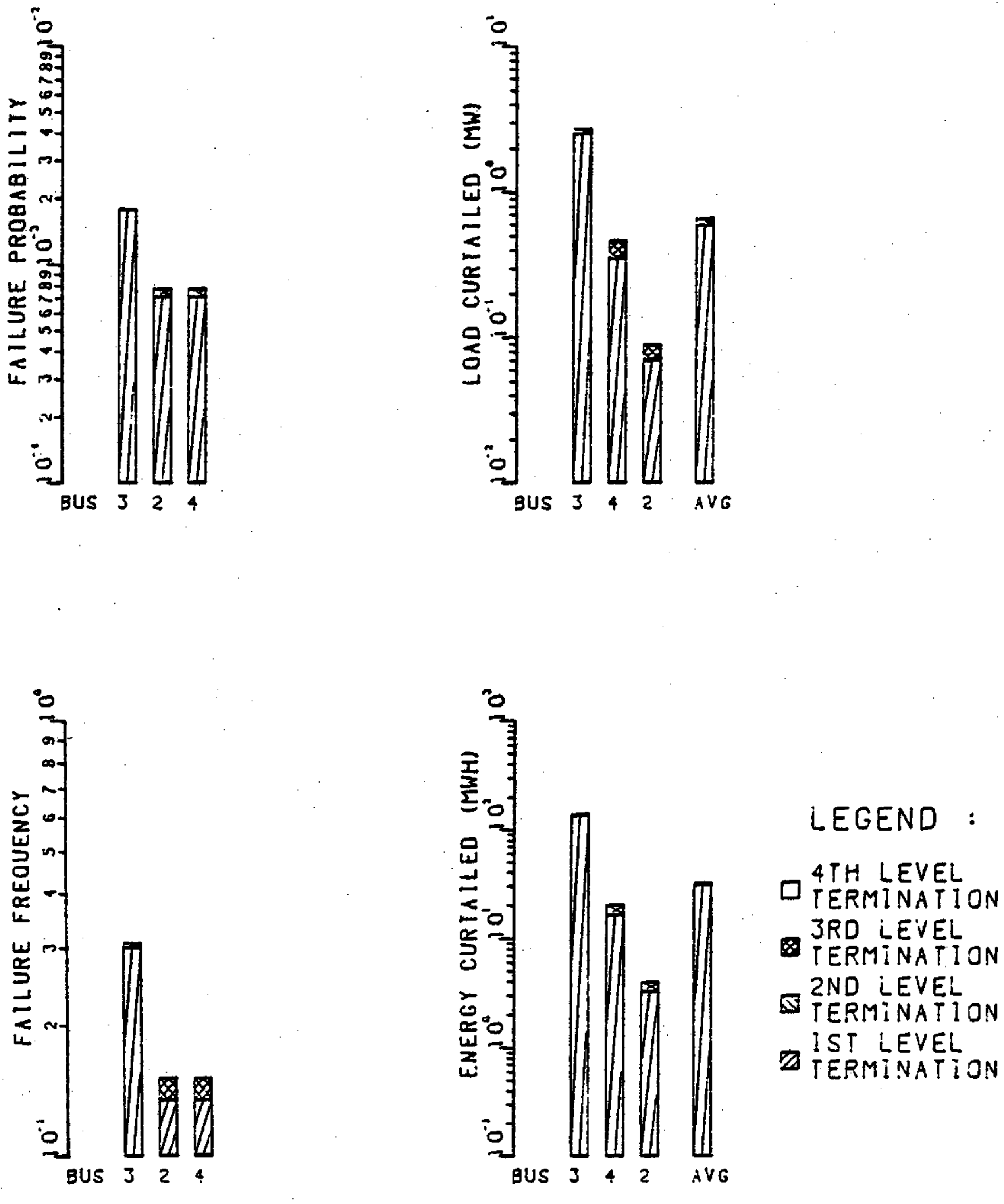

Figure 3-10: Annualized adequacy indices (with termination) for the buses in the 6 bus test system

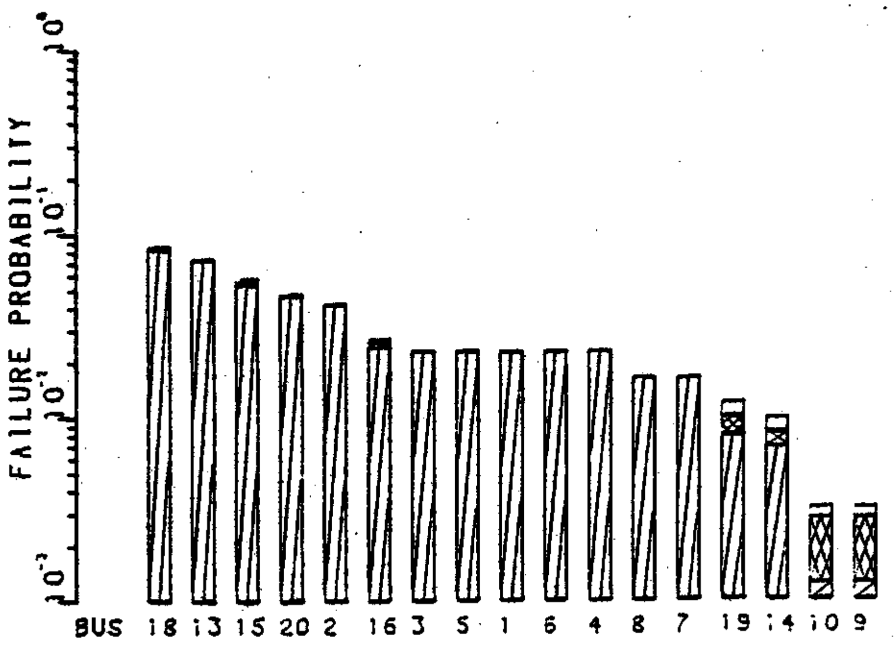

Figure 3-11: Probability of failure (with termination) for the buses in the IEEE RTS

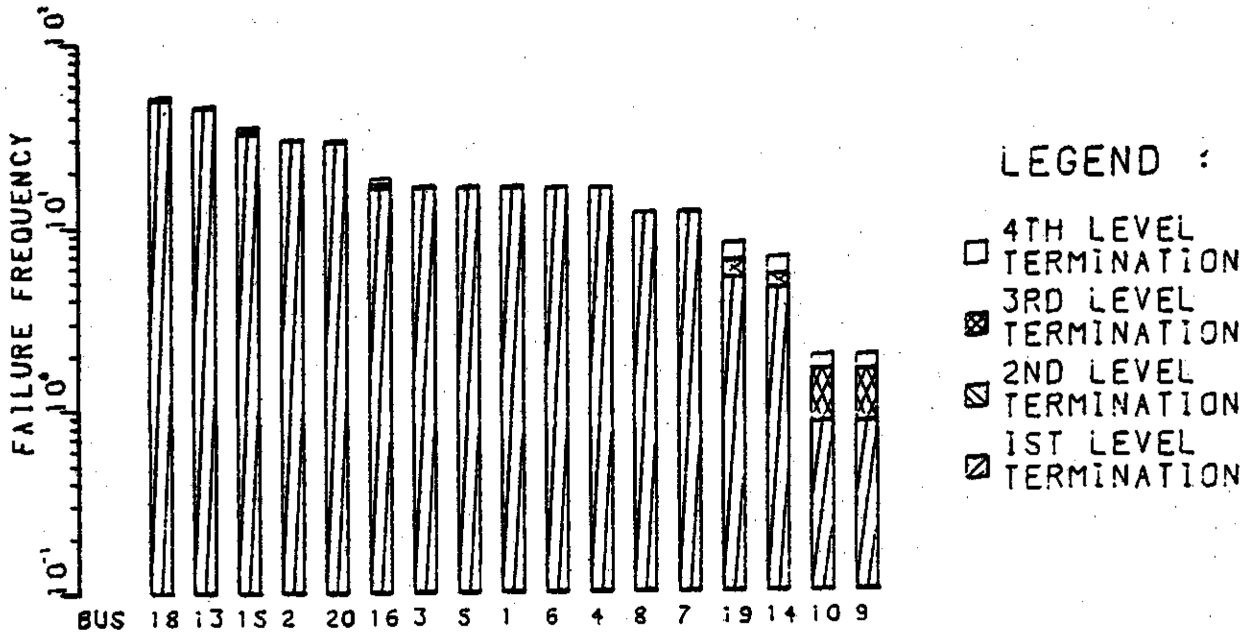

Figure 3-12: Frequency of failure (with termination) for the buses in the IEEE RTS

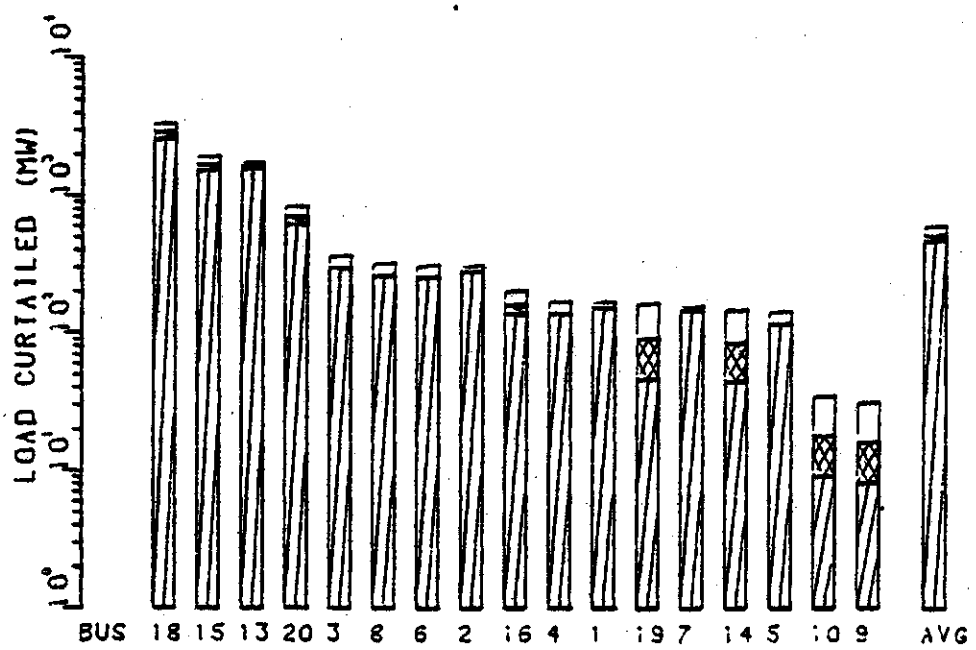

Figure 3-13: Expected load curtailed in MW (with termination) for the buses in the IEEE RTS

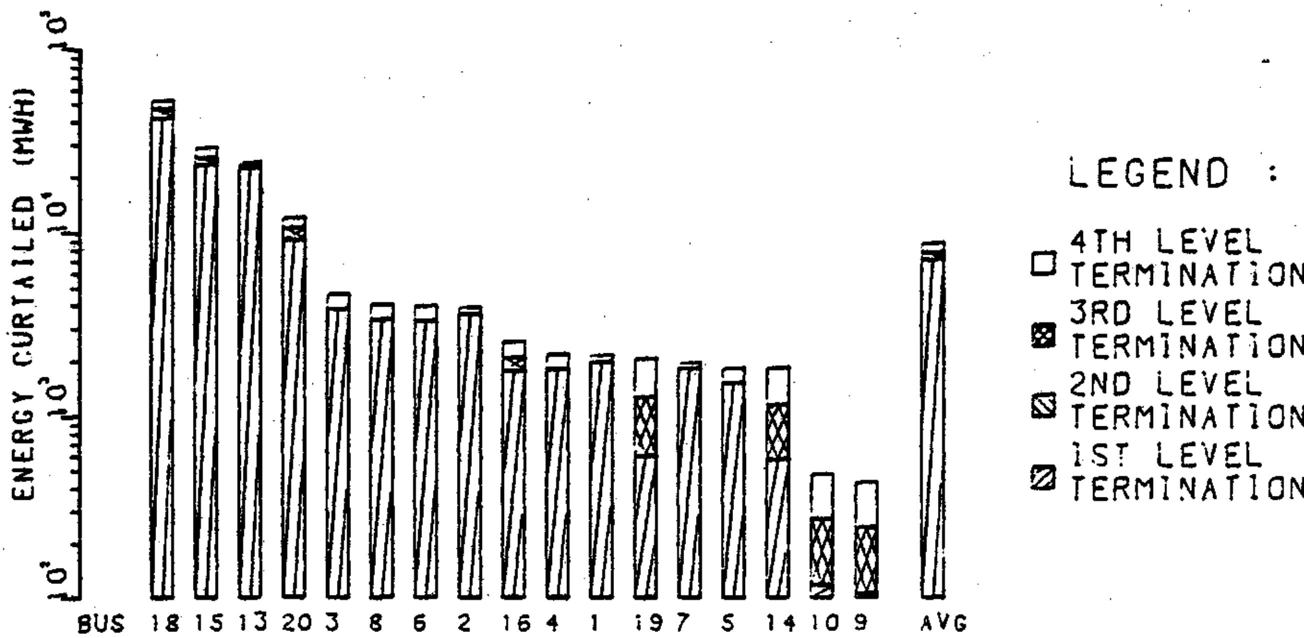

Figure 3-14: Expected energy curtailed in MWh (with termination) for the buses in the IEEE RTS

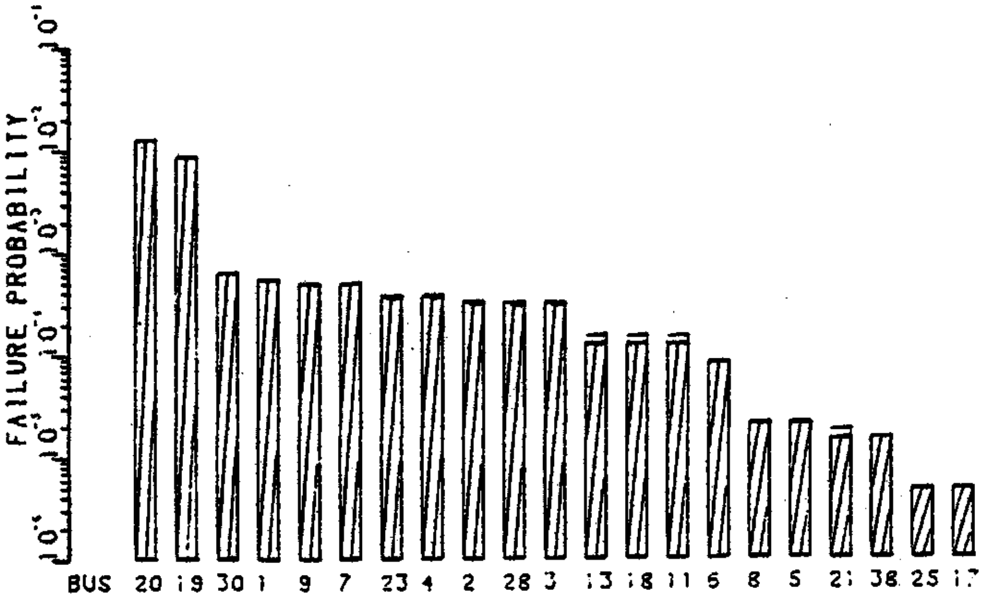

Figure 3-15: Probability of failure (with termination) for the buses in the SPC system

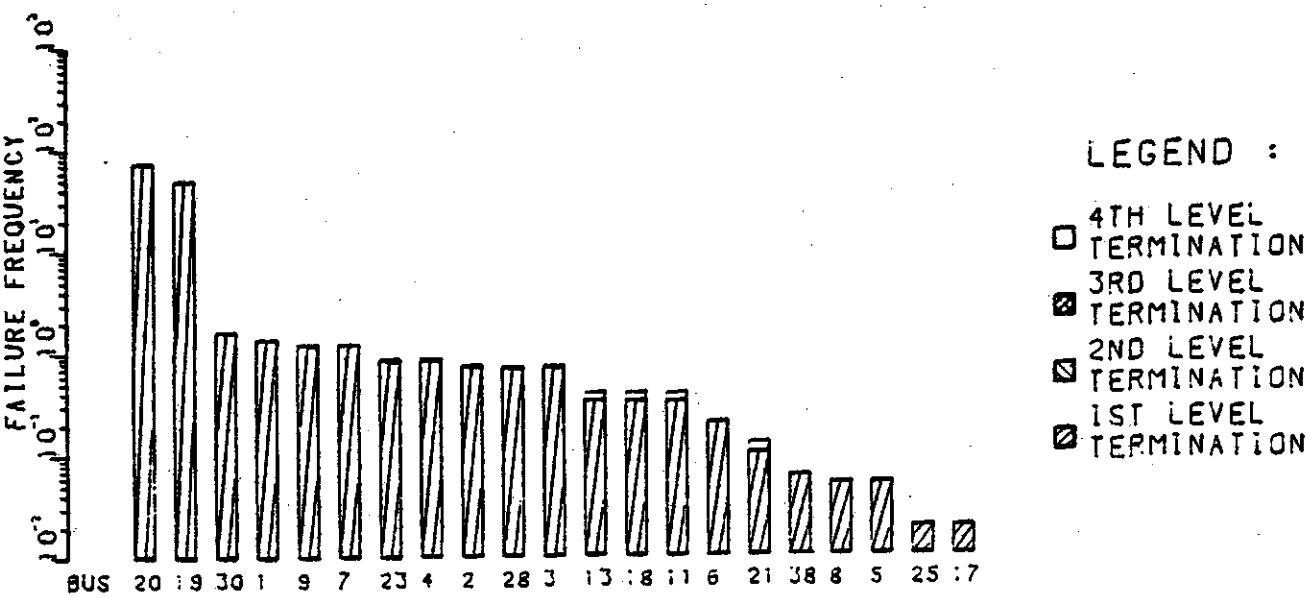

Figure 3-16: Frequency of failure (with termination) for the buses in the SPC system

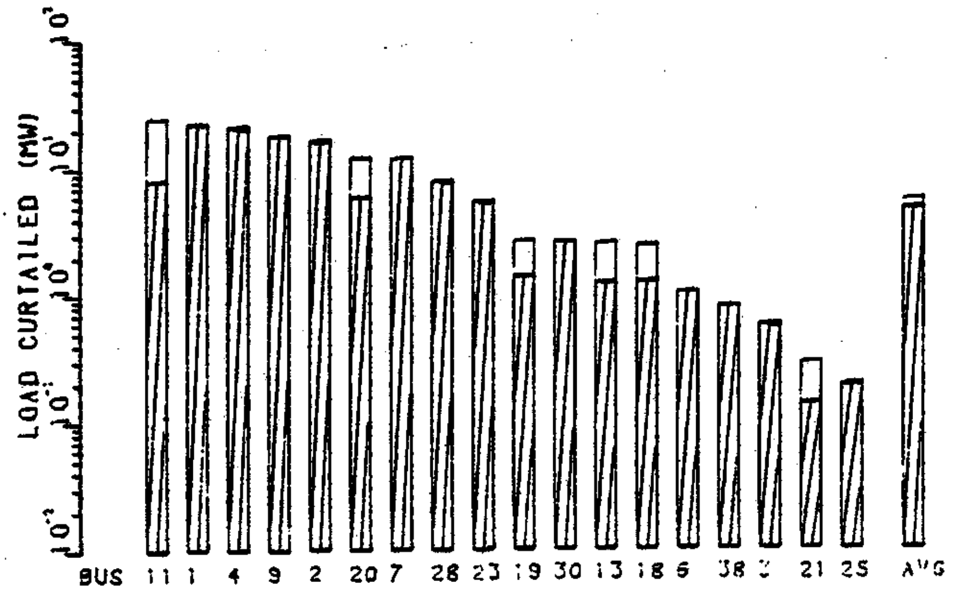

Figure 3-17: Expected load curtailed in MW (with termination) for the buses in the SPC system

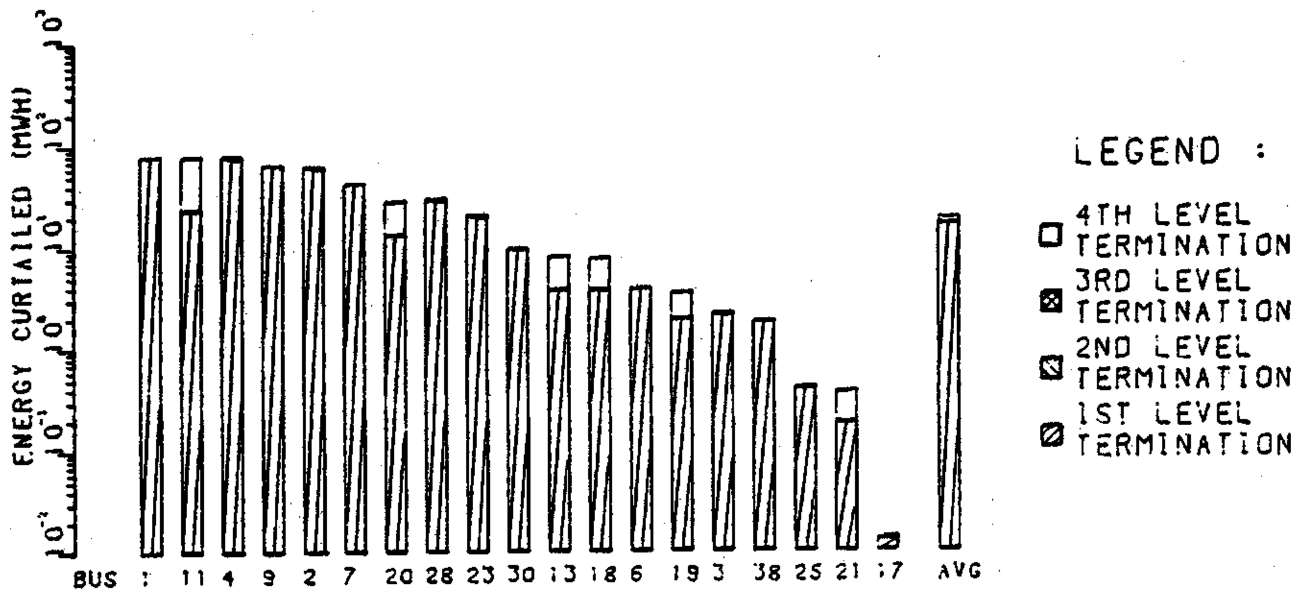

Figure 3-18: Expected energy curtailed in MWh (with termination) for the buses in the SPC system

contingency, no further more-off states involving this outage event are solved. If the outage contingency does not result in a failed state at the 2nd outage level, higher outage contingencies are considered and the contingency is terminated at the 3rd outage level, if it is found in a failure state at this level, otherwise it is terminated at the 4th level. The same approach is followed for the 3rd and the 4th level termination.

The effect of termination varies from one system to another depending upon the size of the system and the total reserve available in the system. The removal of one generating unit does not create any problem in any of the systems considered in this study, therefore no contingency terminates at the Ist level. Quite a few outages of generating units at the 2nd outage level result in a system problem in the case of the 6 bus test system and the IEEE RTS, therefore these outage events are terminated at the 2nd level. However, for the SPC system, outage events start to terminate at the 3rd outage level only, therefore for this system, termination at the Ist level, 2nd level or 3rd level gives the same result as seen in Figures 3-15 to 3-18. The termination at a lower level provides satisfactory results just for two adequacy indices, the probability of failure and the frequency of failure. Except for a few buses, this observation is found to be true for all the three systems discussed in this thesis. The termination of an outage event at lower levels results in optimistic values for the expected load curtailed and the expected energy curtailed. Table 3-8 gives the numerical values for the IEEE RTS at each bus for the the probability of failure and the frequency of failure and Table 3-9 gives the expected load curtailed in MW and the expected energy curtailed in MWh. Table 3-10 gives a summary of the system indices at each termination level for the IEEE RTS. Table 3-11 summarizes various system indices with and without termination at the 4th level for the three test systems.

The saving in the computation time realized by terminating contingencies at lower levels is not significant. It is, therefore, not advisable to terminate a contingency at lower levels for any system under consideration. However, termination at the 4th level in the case of generating unit outages and at the 2nd level in the case of line/transformer outages is recommended to include the effect of more-off states.

3.6 Sorting Of Identical Generating Units

It is shown in Section 3.4 that the inclusion of higher level independent generator outages cannot be ignored in the calculation of more representative adequacy indices. This requirement, however, involves large CPU time and the time increases tremendously as the outage level increases. This is shown in Table 3-12. An effective way to reduce the computation time is to sort out the identical units and calculate the adequacy indices by solving the A.C. load flow,

Table 3-8: Probability of failure and frequency of failure at various levels for the IEEE RTS

BUS	Ist Cont. Actual Value	2nd Cont. Actual Value	3rd Contingency Actual Value	3rd Contingency Incr. w.r.t. 2nd Cont.	4th Contingency Actual Value	4th Contingency Incr. w.r.t. 2nd Cont.
			Failure Probability			
1	0.022957	0.0229575	0.0229575	1.00	0.0230253	1.00
2	0.041936	0.0419363	0.0419363	1.00	0.0420569	1.00
3	0.023011	0.0230111	0.0230111	1.00	0.0232245	1.01
4	0.022920	0.0229196	0.0229196	1.00	0.0229724	1.00
5	0.022957	0.0229575	0.0229575	1.00	0.0230253	1.00
6	0.022920	0.0229196	0.0229196	1.00	0.0229724	1.00
7	0.016333	0.0163330	0.0163330	1.00	0.0163330	1.00
8	0.016365	0.0163646	0.0163646	1.00	0.0163646	1.00
9	0.001242	0.0012419	0.0028145	2.27	0.0032240	2.60
10	0.001242	0.0012419	0.0028145	2.27	0.0032240	2.60
13	0.073105	0.0731047	0.0731047	1.00	0.0731047	1.00
14	0.006896	0.0068956	0.0082148	1.19	0.0098030	1.42
15	0.053701	0.0537008	0.0556561	1.04	0.0579568	1.08
16	0.024188	0.0241880	0.0253938	1.05	0.0266829	1.10
18	0.082841	0.0828413	0.0838206	1.01	0.0855644	1.03
19	0.007843	0.0078433	0.0100167	1.28	0.0119681	1.53
20	0.046594	0.0465938	0.0473121	1.02	0.0473983	1.02
			Failure Frequency			
1	16.511473	16.5114727	16.5114727	1.00	16.7236710	1.01
2	29.833210	29.8332100	29.8332100	1.00	30.2421207	1.01
3	16.551756	16.5517559	16.5517559	1.00	16.8623924	1.02
4	16.475870	16.4758701	16.6738911	1.01	16.6738911	1.01
5	16.511473	16.5114727	16.5114727	1.00	16.7236710	1.01
6	16.475870	16.4758701	16.4758701	1.00	16.6738911	1.01
7	11.968312	11.9683123	11.9683123	1.00	12.0813932	1.01
8	11.994809	11.9948092	11.9948092	1.00	12.1078873	1.01
9	0.841725	0.8417247	1.6296076	1.94	1.9615730	2.33
10	0.841725	0.8417247	1.6296076	1.94	1.9615730	2.33
13	45.292179	45.2921791	45.6301613	1.01	46.0662498	1.02
14	4.548030	4.5480299	5.4111352	1.19	6.7541785	1.49
15	32.495274	32.4952736	33.6597939	1.04	35.5379372	1.09
16	16.460222	16.4602222	17.2757015	1.05	18.4818287	1.12
18	49.156643	49.1566429	50.0207634	1.02	51.7118416	1.05
19	5.197153	5.1971526	6.4788618	1.25	8.1048651	1.56
20	29.171385	29.1713848	29.7537441	1.02	30.1277256	1.03

Incr. = Increment   Cont. = Contingency

Table 3-9: Expected load curtailed in MW and expected energy curtailed in MWh at various levels for the IEEE RTS

BUS	Ist Cont. Actual Value	2nd Cont. Actual Value	3rd Contingency Actual Value	3rd Contingency Incr. w.r.t. 2nd Cont.	4th Contingency Actual Value	4th Contingency Incr. w.r.t. 2nd Cont.
			Total Load Curtailed (MW)			
1	156.4800	156.4800	156.4800	1.00	172.7800	1.10
2	288.2700	288.2700	288.2700	1.00	316.9800	1.10
3	302.3900	302.3900	302.3900	1.00	371.9200	1.23
4	141.8800	141.8800	141.8800	1.00	173.6300	1.22
5	119.2100	119.2100	119.2100	1.00	146.3000	1.23
6	260.7500	260.7500	260.7500	1.00	319.1000	1.22
7	149.5800	149.5800	149.5800	1.00	161.6600	1.08
8	268.2400	268.2399	268.2400	1.00	327.8900	1.22
9	8.3900	8.3900	16.6500	1.98	32.2400	3.84
10	9.3500	9.3500	18.5500	1.98	35.9200	3.84
13	1614.2600	1614.2600	1670.2800	1.03	1778.9600	1.10
14	45.8800	45.8800	86.6300	1.89	151.5700	3.30
15	1548.2100	1548.2100	1687.9399	1.09	1969.3200	1.27
16	140.2100	140.2100	163.7800	1.17	206.4400	1.47
18	2588.9700	2588.9700	2926.3701	1.13	3386.5300	1.31
19	47.9900	47.9900	93.6500	1.95	167.6800	3.49
20	630.9600	630.9600	726.2700	1.15	857.5400	1.36
			Total Energy Curtailed (MWh)			
1	1964.6344	1964.6344	1964.6344	1.00	2140.7991	1.09
2	3617.7581	3617.7581	3617.7581	1.00	3925.8660	1.09
3	3855.3787	3855.3787	3855.3787	1.00	4677.7456	1.21
4	1813.2011	1813.2011	1813.2011	1.00	2187.9658	1.21
5	1519.9813	1519.9813	1519.9813	1.00	1840.2260	1.21
6	3332.3635	3332.3635	3332.3635	1.00	4021.1160	1.21
7	1829.1992	1829.1992	1829.1992	1.00	1954.7832	1.07
8	3373.9417	3373.9417	3373.9417	1.00	4068.5835	1.21
9	105.8127	105.8127	245.3296	2.32	430.0571	4.06
10	117.9055	117.9055	273.3674	2.32	479.2064	4.06
13	22538.1445	22538.1445	23240.7832	1.03	24272.5703	1.08
14	581.3996	581.3996	1147.6532	1.97	1839.6437	3.16
15	23364.7559	23364.7559	25568.0527	1.09	28788.7988	1.23
16	1765.3143	1765.3143	2092.3203	1.19	2542.1453	1.44
18	41740.2109	41740.2109	47002.9688	1.13	52214.4297	1.25
19	606.8278	606.8278	1264.0715	2.08	2069.7351	3.41
20	9135.9209	9135.9209	10643.1416	1.16	12098.2764	1.32

Incr. = Increment Cont. = Contingency

Table 3-10: System indices indices at various contingency levels for the IEEE RTS

Ist Cont. Actual Value	2nd Cont. Actual Value	3rd Contingency Actual Value	3rd Contingency Incr. w.r.t. 2nd Cont.	4th Contingency Actual Value	4th Contingency Incr. w.r.t. 2nd Cont.
Bulk Power Supply Disturbances					
62.125290	62.125290	62.534779	1.01	63.083290	1.02
Bulk Power Interruption Index (MW/MW-Yr.)					
2.919660	2.919660	3.184880	1.09	3.711040	1.27
Bulk Power Energy Curtailment Index (MWh/Yr.)					
42.548328	42.548328	46.590930	1.10	52.474370	
Bulk Power Supply Average MW Curtailment Index (MW/Disturbance)					
133.939377	133.939376	145.149887	1.08	167.658600	1.25
Modified Bulk Power Energy Curtailment Index					
0.004857	0.004857	0.005319	1.10	0.005990	1.23
Severity Index (System-Minutes)					
2552.899902	2552.899902	2795.456054	1.10	3148.461914	1.23
Average Load Curtailed/Load Pt./Year-MW					
489.471924	489.471923	533.936218	1.09	622.144470	1.27
Average Energy Curtailed/Load Pt./Year-MWh					
7133.103027	7133.103027	7810.832520	1.10	8797.174805	1.23

Incr. = Increment
Cont. = Contingency

Table 3-11: A brief summary of the system indices for the three systems

6 Bus System		IEEE RTS		SPC System	
Without Termn.	With Termn.	Without Termn.	With Termn.	Without Termn.	With Termn.
Bulk Power Interruption Index (MW/MW-Yr.)					
0.0179	0.0179	3.5500	3.7100	0.0780	0.0800
Bulk Power Energy Curtailment Index (MWh/Yr.)					
0.8911	0.8912	50.7900	52.4700	0.2600	0.2800
Bulk Power Supply Average MW Curtailment Index (MW/Disturbance)					
10.6636	10.6648	167.4200	167.6600	88.1700	87.9600
Severity Index (System-Minutes)					
53.4680	53.470	3047.300	3148.460	15.6900	16.6500
Average Load Curtailed/Load Pt./Year-MW					
0.6610	0.6611	595.7200	622.1400	5.2100	5.5300
Average Energy Curtailed/Load Pt./Year-MWh					
32.9720	32.9750	8514.500	8797.180	17.4600	18.5300
Total Sum of the Probability of All the Contingencies					
0.999997	0.999998	0.989547	0.992550	0.999105	0.999150

Termn. = Termination

Table 3-12: CPU time in minutes for the generator outages on VAX-11/780 digital computer

Contingency Level	6 Bus Test System	IEEE RTS	SPC System
Up to the 1st level	0.034	0.14	0.37
Up to the 2nd level	0.065	1.42	3.06
Up to the 3rd level	0.274	16.80	34.75
Up to the 4th level	1.044	137.14	268.50

if required, only for one contingency. The contribution of the remaining identical contingencies is calculated by multiplying adequacy indices for this contingency by the number of identical contingencies. Identical generating units are considered to have the same MW rating, equal failure and repair rates and be connected to the same generating station.

Figure 3-19 shows all the possible combinations for a system having 6 generating units. Out of the six units, three units are identical. The total number of contingencies up to the 4th level is 56. If the identical units are sorted out, the generator outages listed inside the box shown in Figure 3-19 are not evaluated. All other contingencies are, however, evaluated. This reduces the number of contingencies which are to be solved from 56 to 26. It can be seen that if the ordering of the generating units is done in such a way that the last three generating units are the identical units, then the number of contingencies that are to be solved reduces to 49 only. It is, therefore, more advantageous to arrange

S.No.	Generators 1st	2nd	3rd	4th	5th	6th
1	G1	G2	G3	G4	G5	G6
2	G1 G2					
3	G1 G2 G3					
4	G1 G2 G3 G4					
5	G1 G2 G3 G5					
6	G1 G2 G3 G6					
7	G1 G2 G4					
8	G1 G2 G4 G5					
9	G1 G2 G4 G6					
10	G1 G2 G5					
11	G1 G2 G5 G6					
12	G1 G2 G6					
13	G1 G3	G2 G3				
14	G1 G3 G4	G2 G3 G4				
15	G1 G3 G4 G5	G2 G3 G4 G5				
16	G1 G3 G4 G6	G2 G3 G4 G6				
17	G1 G3 G5	G2 G3 G5				
18	G1 G3 G5 G6	G2 G3 G5 G6				
19	G1 G3 G6	G2 G3 G6				
20	G1 G4	G2 G4	G3 G4			
21	G1 G4 G5	G2 G4 G5	G3 G4 G5			
22	G1 G4 G5 G6	G2 G4 G5 G6	G3 G4 G5 G6			
23	G1 G4 G6	G2 G4 G6	G3 G4 G6			
24	G1 G5	G2 G5	G3 G5	G4 G5		
25	G1 G5 G6	G2 G5 G6	G3 G5 G6	G4 G5 G6		
26	G1 G6	G2 G6	G3 G6	G4 G6	G5 G6	

Figure 3-19: A list of contingency enumeration for the six generating units up to the 4th outage level

identical generating units in a way so that contingencies involving identical units are evaluated before the contingencies involving non-identical generating units. This is done easily by placing identical units in the beginning of the evaluation list, an input to the digital computer program. Table 3-13 shows the CPU time (in minutes) required for the generator outages, if identical units are sorted out.

Table 3-13: CPU time in minutes for the generator outages (after sorting the identical units) on VAX-11/780 digital computer

Contingency Level	6 Bus Test System	IEEE RTS	SPC System
Up to Ist level	0.03 (90%)	0.12 (86%)	0.22 (60%)
Up to 2nd level	0.04 (66%)	0.45 (32%)	1.25 (41%)
Up to 3rd level	0.06 (22%)	2.27 (14%)	7.43 (21%)
Up to 4th level	0.20 (19%)	14.14 (11%)	48.26 (18%)

A percentile comparison between the two sets of CPU time, with and without sorting identical units, is also shown in Table 3-13 for each case. The quantities inside the brackets are percentage values of CPU time as compared to the CPU time shown in Table 3-12. As seen from Table 3-13, the saving in the CPU time by sorting the identical units is quite significant and as the depth of the contingency level increases, sorting of the identical generating units becomes a very effective way of reducing the CPU time. A further reduction in the CPU time can be achieved by replacing n non-identical units connected at one bus and having equal MW rating but differing slightly in their failure and repair rates (less than 10%) by n identical units with each unit having the worst failure rate and the repair rate, i.e. maximum value of failure rate and minimum value of repair rate among n units. This, however, gives pessimistic results for the system adequacy indices.

3.7 Summary

The inclusion of high level contingencies is necessary when calculating adequacy indices for relatively large power networks. This, however, results in a large computation time because the number of contingencies at higher levels becomes tremendously large. In order to reduce the computation time, it is appropriate to calculate only those credible outage events, whose contribution to the adequacy indices cannot be ignored. Based on the study of the three systems described in this thesis, it was found that in the case of small networks such as the 6 bus test system, generating unit outages up to the 3rd level are sufficient to provide accurate values of the adequacy indices; while for a large network, such as the IEEE RTS and the SPC system, 4th level generating unit outages give satisfactory results. In both small and large networks, independent line outages up to the 2nd level supply reasonably accurate values for the adequacy indices.

In order to account for the contribution of outage events beyond the 4th level in the case of generating units and the

2nd level in the case of lines, indices at the last level are modified such that the contribution of higher level outages is included without actually solving them. This modification, designated as termination, is described in this chapter. The effect of termination at a lower level is also discussed.

A reduction in the computation time for the solution of generator outage contingencies is obtained by sorting the identical units. This approach has resulted in a tremendous saving in computation time, particularly when higher outage levels are considered.

One of the problems resulting from high level generator unit outages or line outages is the creation of an ill-conditioned network situation. The A.C. load flow does not converge and therefore quantitative evaluation of such a situation becomes extremely difficult. These situations and their solution are described in detail in the next chapter.

CHAPTER 4

LOW BUS VOLTAGE AND ILL-CONDITIONED NETWORK SITUATIONS

4.1 Introduction

The assessment of the quality of power supplied to the load centers is done by calculating the voltage level at these points. A good quality of service at a load point is ensured by not allowing deviations in the voltage level at a bus beyond the permissible limits. When solving the outage contingencies using an A.C. load flow, certain outage contingencies, mostly transmission line outages, result in low voltage at some of the buses in the network. The simplest solution to this situation is to allow the system buses to stay at the low voltage and treat the outage event as a system failure due to the bus voltage violation(s). However, this approach does not provide any quantitative measure of the voltage violation problem and also does not give due consideration to the severity of the outage event. These events are treated as failure events regardless of the voltage magnitude at the system buses.

One of the main objections to this assumption is whether low voltage really constitutes a system/bus failure. Many power utilities use D.C. load flow for reliability studies because they do not view low bus voltage as a failure but only as a minor problem which is normally rectified by the transformer tap-settings, the phase-shifter adjustments and/or local reactive power generation. This treatment, however, gives an optimistic assessment because correction of voltage violations may not be possible for all voltage violation contingencies. It also does not permit a quantitative evaluation of the outage contingencies using voltage as an adequacy criterion. The actual situation lies somewhere between the two viewpoints. It is desirable to use voltage as an adequacy criterion but suitable corrective action should be taken when encountering any voltage problem.

A basic bus voltage correction model suitable for use with the Newton-Raphson load flow is developed in Section 4.3.

In addition to the low voltage at some of the system buses, another problem which is also experienced while using an A.C. load flow is a non-convergent load flow situation. These situations pose a major obstacle in system reliability evaluation as it is difficult to quantify the adequacy indices in the event of non-convergence. Most of the non-convergent situations result due to high values of the mismatch in reactive power beyond the permissible tolerance limit. Very few situations result due to high values of the mismatch in active power. A third possibility is that a load flow may not converge although a solution, in fact, does exist. This non-convergence could occur due to numerical problems with the fast decoupled algorithm and/or the characteristics of the numerical formulations used. In order to avoid these non-convergent situations when a solution does exist, an additional algorithm has been included in the digital computer program. This algorithm is discussed in the next section.

If a non-convergence situation still persists, after checking for the non-convergence that may result because of the numerical formulations, it is presumed that it is due to the fact that under given operating conditions of the network, the A.C. load flow does not have a solution. These non-convergence situations as well as the low bus voltage situations described above are solved by an approach discussed in Section 4.3.

4.2 Technique For Preventing A Load Flow From Diverging

When solving an outage contingency using the Newton-Raphson load flow technique, at any point in the iteration process the voltage increment computed on the basis of mismatch powers from the previous iteration may project the voltage solution outside the local neighborhood where the solution exists. The solution range is never encountered and the iterative process diverges. Many approaches are available to prevent the divergence of the Newton-Raphson load flow solution under those situations when a solution does exist. Powel[32] has suggested that the convergence property of the Newton-Raphson load flow can be improved by scaling the solution projection calculated by the load flow algorithm without changing the direction of the projection.

From Equations 2.1, 2.8 and 2.9 in Chapter 2, a set of generalized equations can be written as:

$$\Delta Y(x) = J(x)\ \Delta x \tag{4.1}$$

$$X_{new} = X_{old} + a.\Delta x \tag{4.2}$$

where,

x = Solution vector, voltage magnitude or phase angle.

$\Delta Y(x)$ = Mismatches.

$J(x)$ = Jacobian Matrix.

Δx = Solution vector correction.

a = Scaling factor or acceleration factor.

In an ordinary Newton-Raphson load flow, the scaling factor $a = 1.0$. Powel[32] and recently Iwamoto and Tamura[33] have developed analytical expressions for the scaling factor, such that the sum of the squares of power mismatches is minimized. In a recent report on "Transmission system reliability", EPRI[10] has suggested a heuristic technique to adjust the scaling factor by monitoring the sum of the squares of the power mismatches before and after each voltage magnitude and phase angle correction. This technique is readily adaptable to the fast decoupled load flow approach. Under normal load flow situations, the scaling factor is taken as 1.0, but in the case when the sum of the squares of the power mismatches for the new iterative results exceeds its value calculated from the previous iteration results, the scaling factor is decreased from its initial value of unity by a factor. The value of the factor is arbitrary and it could lie between 0.0 and 1.0. In the studies reported in this thesis, this factor was chosen as 0.5. During one complete load flow cycle, the value of the scaling factor is decreased whenever the sum of the squares of the power mismatches exceeds its previous value. A flow chart of the algorithm is shown in Figure 4-1. The main features of the algorithm are as follows:

(1) The load flow solution progresses in an unmodified way until either the sum of the squares of the real power mismatches SP or the sum of the squares of the reactive power mismatches SQ shows an increase rather than a decrease when the P-θ or Q-V portions of the load flow solution is executed respectively.

(2) At any point during the iteration process, if SP increases from its previous value, the scaling factor a_p is decreased to half of its old value. New values of the phase angles are calculated and again SP is calculated. If SP is still larger than what it was when a_p was unity, then a_p is further halved. This process continues until SP is smaller than its value when a_p was 1.0 or until such time that a_p becomes smaller than a cut-off value. The same procedure is repeated for the Q-V portion of the load flow. The cut-off values of the scale factors for both the portions is chosen as 10^{-4}.

(3) If the load flow has converged, adequacy indices are calculated and the next contingency is solved. In those cases when the load flow does not converge, appropriate corrective actions are employed to handle the non-convergent situation. These corrective actions are discussed in the next section.

After integrating the algorithm into the digital computer program, it was tested for all the three test systems described in this study. Table 4-1 gives a list of the non-convergent outage contingencies before applying the above technique. Even after utilizing the technique, it was found that not a single non-convergent contingency in any test system converged. This implies that for these contingencies there is no solution possible for the operating conditions under which the load flow is solved. This also indicates that the solution for these contingencies does not diverge because of the numerical problems and/or the characteristics of the mathematical formulations used. It is therefore necessary, in order to solve these non-convergent contingencies, to modify the operating conditions so that the load flow converges within the MW and MVAR mismatch tolerance limits. A heuristic algorithm was developed and successfully incorporated into the digital computer program. This algorithm is described below:

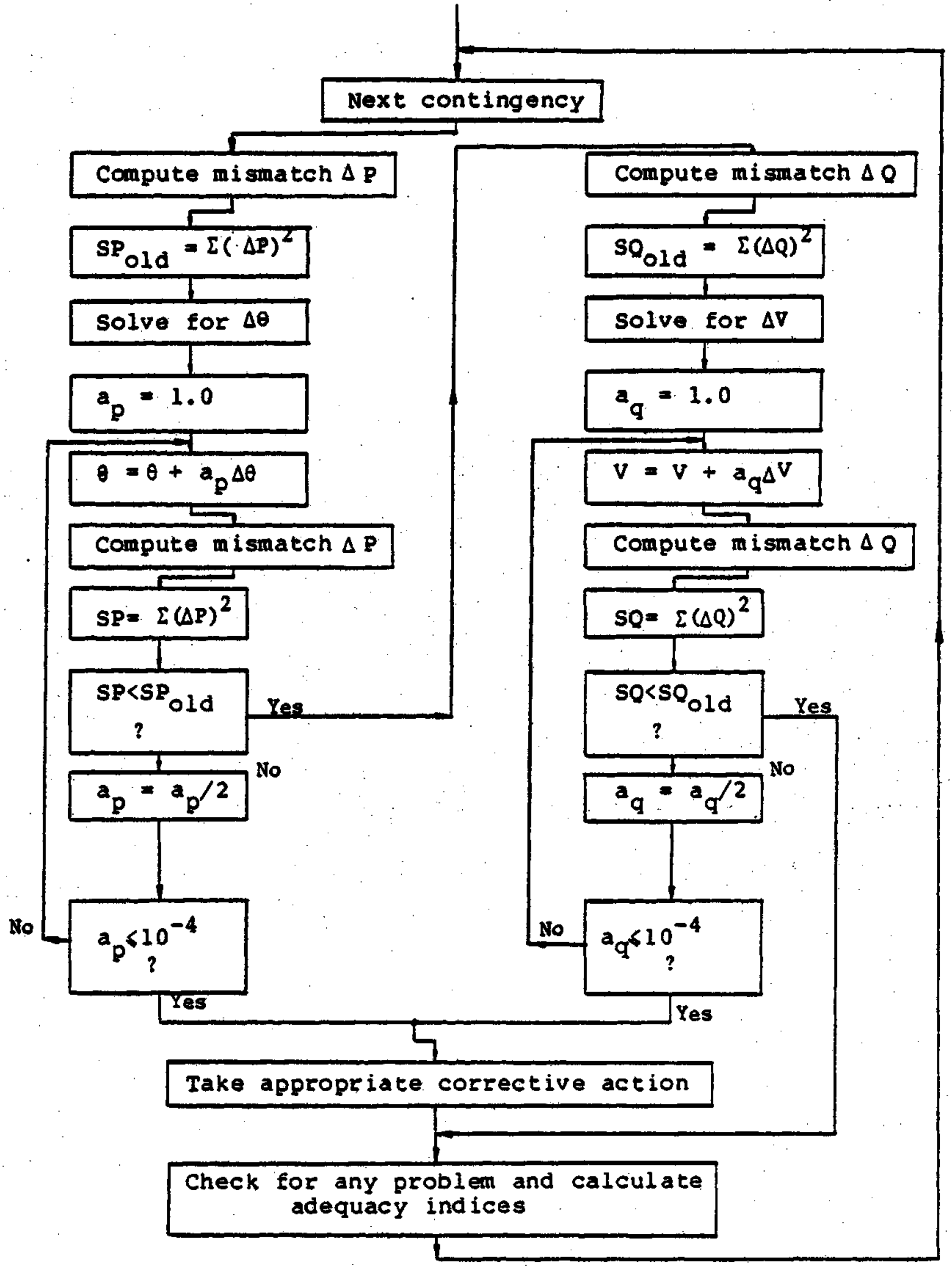

Figure 4-1: Flow chart for the application of scaling factor to prevent divergence of the load flow

Table 4-1: A list of non-convergent outage contingencies for the three test systems

Test system	Line Outage Contingencies	
6 Bus System	Lines 1 and 6 Out	
IEEE RTS	Lines 6 and 7 Out	Lines 6 and 27 Out
	Lines 11 and 13 Out	Lines 23 and 29 Out
	Lines 24 and 28 Out	
SPC System	Lines 1 and 10 Out	Lines 1 and 11 Out
	Lines 1 and 57 Out	Lines 5 and 26 Out
	Lines 10 and 18 Out	Lines 10 and 34 Out
	Lines 10 and 56 Out	Lines 10 and 57 Out
	Lines 10 and 66 Out	Lines 11 and 13 Out
	Lines 11 and 14 Out	Lines 11 and 18 Out
	Lines 11 and 34 Out	Lines 11 and 56 Out
	Lines 11 and 57 Out	Lines 11 and 60 Out
	Lines 11 and 66 Out	Lines 16 and 26 Out
	Lines 17 and 26 Out	Lines 18 and 57 Out
	Lines 23 and 24 Out	Lines 23 and 26 Out
	Lines 24 and 26 Out	Lines 25 and 34 Out
	Lines 25 and 56 Out	Lines 26 and 37 Out
	Lines 26 and 46 Out	Lines 26 and 51 Out
	Lines 26 and 70 Out	Lines 28 and 29 Out
	Lines 28 and 36 Out	Lines 28 and 41 Out
	Lines 29 and 36 Out	Lines 29 and 41 Out
	Lines 36 and 41 Out	Lines 38 and 65 Out
	Lines 54 and 65 Out	Lines 58 and 59 Out
	Lines 58 and 63 Out	Lines 64 and 65 Out
	Outage of line 43 and any line outage combination involving line 43.	

4.3 A Heuristic Algorithm For The Correction Of Voltage Violations And Non-convergent Situations

4.3.1 General

The outage of one or more lines may result in low voltage at some of the system buses and sometimes the A.C. load flow does not converge. The outage of the line(s) in a net power exporting area may result in slightly higher values of the voltages at a few of the system buses in the area and a significant increase in the bus angles at the generation buses. This is caused by the fact that power cannot be transferred from this area to other areas of the system due to the outage of the line(s). Conversely, the outage of the line(s) in a net power importing area may cause lower values of the voltages and a decrease in the bus angles at some of the buses, particularly load buses, in the region.

Outages of lines 23 and 29 and of lines 24 and 28 for the IEEE RTS (Figure 2-2) result in a significant increase in the bus angles at generator buses 18 and 22. These buses are situated in the north (230 KV) region which is a net power exporting area. These outage events also cause a low voltage at bus 3. On the other hand, outages of lines 6 and 7 and of lines 6 and 27 in the net power importing area result in a low voltage at bus 3 and a decrease in the bus angles at generation buses 1 and 2. The outage of lines 11 and 12 and that of lines 11 and 13 result in a low voltage at bus 8.

These non-convergent and low voltage situations are solved by taking the following corrective actions:

(i) Rescheduling of the generating units.

(ii) Injection of reactive power at the voltage violating buses.

While iterating the A.C. load flow, if the absolute value of any bus angle deviates beyond twice its initial estimated value, the generating units are rescheduled as explained in Section 4.3.2. If the magnitude of the voltage at any bus during the load flow iterations is not within the permissible limits even though the load flow has converged, reactive power is injected at the buses as described in Section 4.3.3.

4.3.2 Rescheduling Of The Generating Units

As seen from Equation 2.6, the bus angles are significantly influenced by the real power generation pattern in a network. Therefore outages of lines which are responsible for power transfer from the net power exporting area(s) to the net power importing area(s) cause an increase in the bus angles in the net power exporting region and a decrease in the bus angles in the net power receiving area. This can be seen when lines 23 and 29, and lines 24 and 28 are out in the IEEE RTS.

A heuristic algorithm which monitors the bus angles and adjusts the generation schedule according to deviations in the bus angles was developed and integrated with the digital computer program. The algorithm solves these situations satisfactorily which otherwise result in non-convergent cases. A flow chart for the algorithm is shown in Figure 4-2. The main features of the algorithm are as follows:

(1) If the absolute value of the bus angle $|\theta|$ at any bus increases beyond twice its initial estimated value, the angle deviation $\Delta\theta$ at the generator buses having reserve capacity available are calculated. The average value $\Delta\theta_{avg}$ of these angle deviations is also determined.

(2) The scheduled generation at the generator buses, which have an angle deviation lower than the average value, is increased to the total generation capacity available at those buses. However, a restriction on the reserve available for rescheduling can also be imposed, if required, by slightly modifying the algorithm.

(3) The scheduled generation at the generator buses, which experience angle deviations larger than the average value, is proportionately decreased by an amount which is now available because of augmenting the generation as described in (2).

(4) After rescheduling the generating units, an A.C. load flow is again carried out starting with the initial estimates of the load flow parameters.

4.3.3 Injection Of Reactive Power At The Voltage Violating Buses

The magnitude of the bus voltages are primarily influenced by the reactive power generation pattern in the network. Equation 2.7 explicitly reflects this fact. Therefore

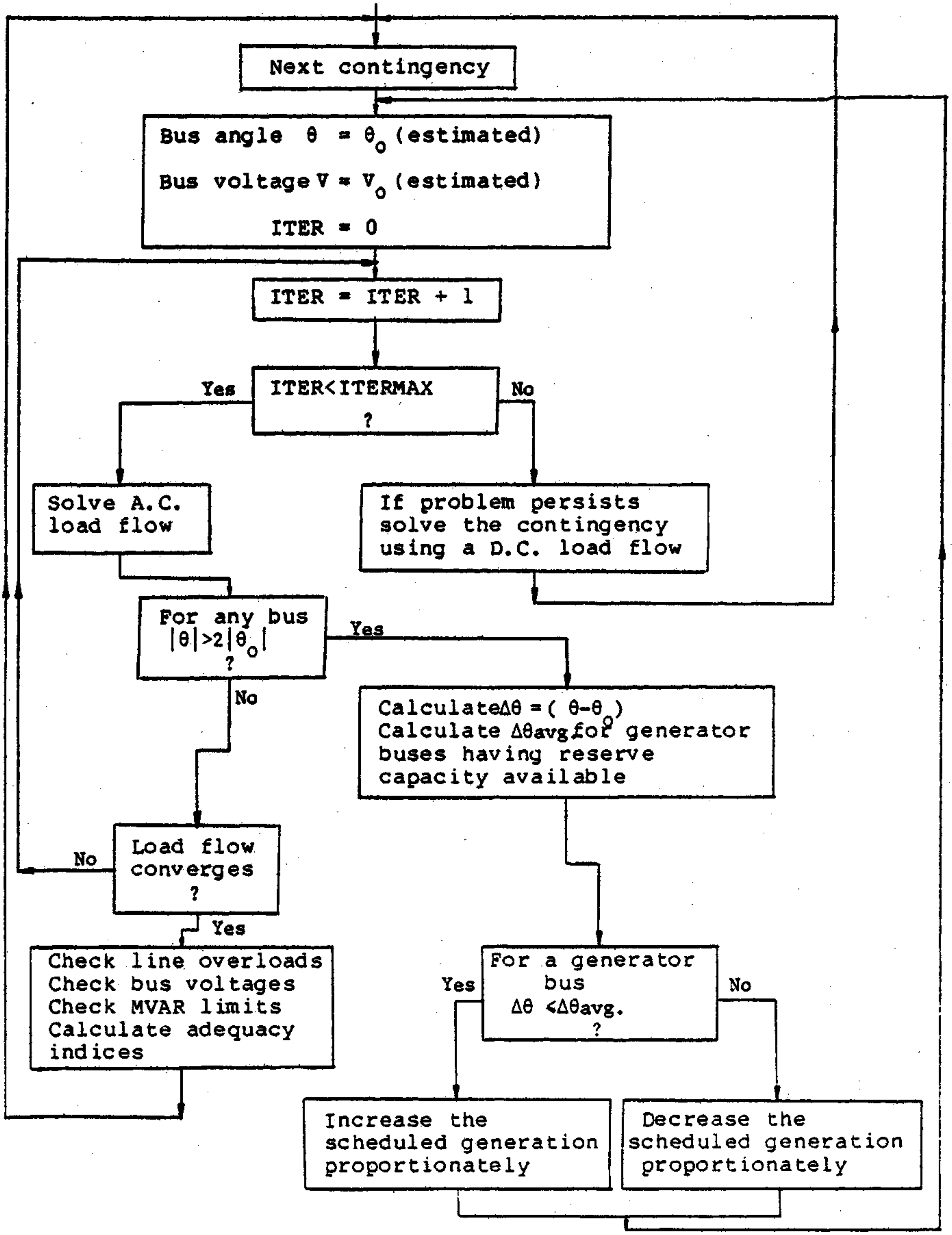

Figure 4-2: Flow chart for rescheduling the generating units for the line outages

injection of a proper amount of MVAR at the voltage violating buses helps in alleviating the voltage violation problem for most outage contingencies. Power factor improvement devices such as synchronous condensers or static capacitor banks could be installed at the appropriate buses. Besides supplying the VAR support under normal circumstances, these devices can improve the quality of the power supply under line outage events. A heuristic algorithm was developed to calculate the reactive power required in order to correct the voltage violations at the system buses for an outage event. A flow chart of the algorithm is shown in Figure 4-3. The main characteristics of the algorithm are as follows:

(1) If the voltage at any load bus decreases to 50% of its initial estimated value (generally 1.0 p.u.) while solving the A.C. load flow or that the load flow has converged but the bus voltages are lower than the permissible voltage limit, the power factor of the load is improved by 10% of its original value. The A.C. load flow is again carried out with the original estimates of voltage magnitude V_0 and bus angle θ_0 as the starting values. If the voltage at all buses is within the specified voltage limits and the load flow converges, the algorithm proceeds to step (3), otherwise to step (2).

(2) If the modified power factor of the load is less than 0.9, it is further improved by 10%, otherwise the net reactive power (local MVAR generation + load MVAR) at a bus is increased to a value which is 20% of the active load. The A.C.

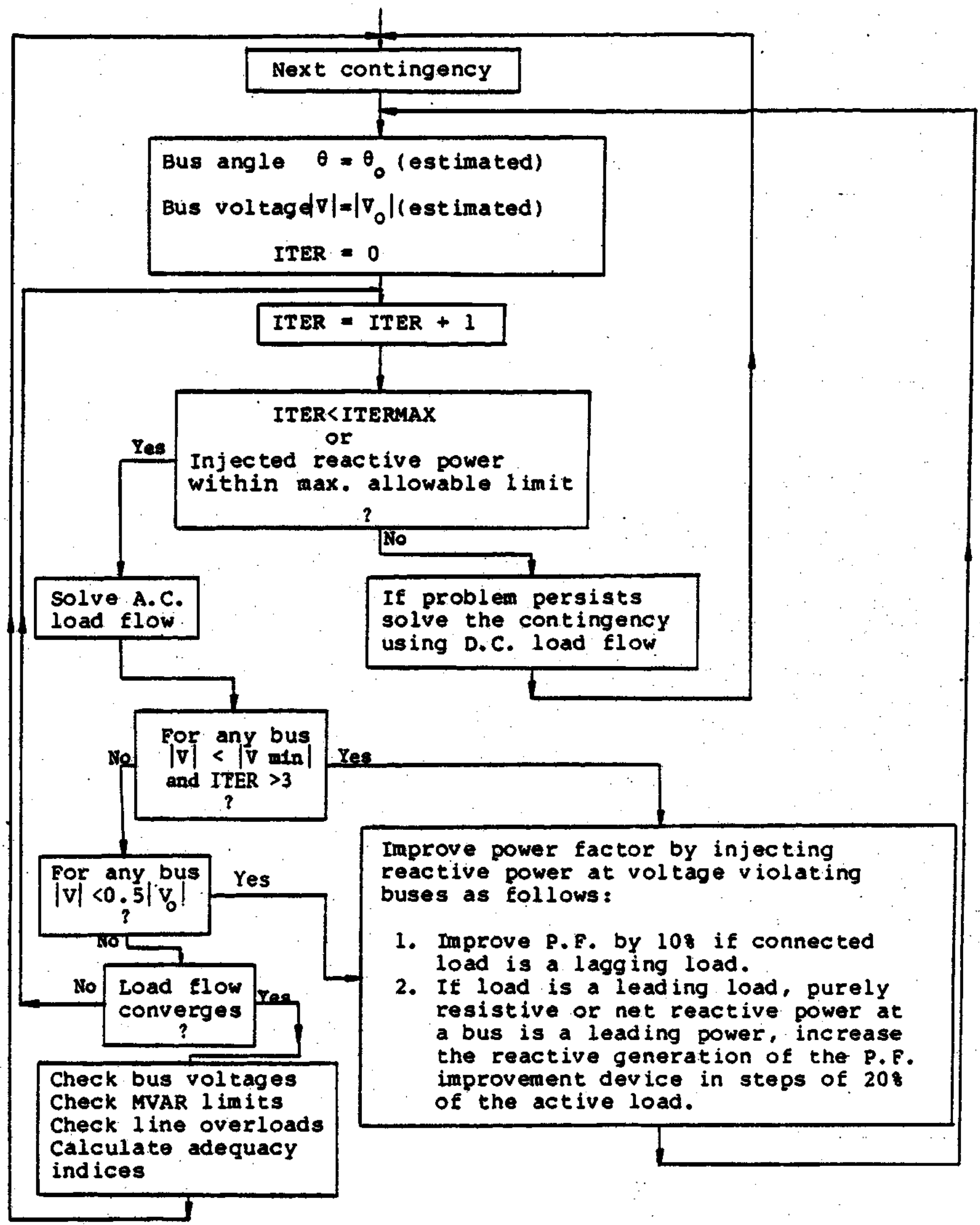

Figure 4-3: Flow chart for correcting the voltage limits by injecting reactive power

load flow is again carried out and the voltage limits are checked. If the voltage at the system buses is still not acceptable, reactive power is further increased by 20% of the active load and so on. The process of injection of reactive power can be stopped after a predetermined value of reactive power is supplied. In these studies, the maximum reactive power that can be injected was taken as 140% of the real load demand at a bus. At this stage, load flow is again carried out. If the load flow diverges, a D.C. load flow is performed and adequacy indices are calculated accordingly.

(3) The line overloads and the generator MVAR limits are then checked. After taking proper corrective action for these problems, if necessary, the adequacy indices are calculated and the next outage contingency is then solved.

4.4 Discussion OF The Results

Table 4-2 shows the total number of voltage violation contingencies for the line outages before employing any corrective actions as described in Section 4.3 for the three test systems. The three voltage levels chosen are 0.95 p.u., 0.90 p.u. and 0.85 p.u. for each bus in each system.

A brief description of the major voltage violation contingencies for each system is as follows:

4.4.1 The 6 Bus Test System (Figure 2-1)

The outage of lines 1 and 6 results in voltage violation at bus 3 for all the three voltage levels.

Table 4-2: Number of voltage violation contingencies for three voltage levels

System description	Permissible minimum voltage limit in p.u. at each bus		
	0.85	0.90	0.95
6 bus test system	1	1	1
IEEE RTS	39	39	144
SPC system	178	334	715

4.4.2 The IEEE RTS (Figure 2-2)

The number of voltage violation contingencies increases significantly if the voltage limit is raised from 0.90 p.u. to 0.95 p.u.. However, the number of voltage violation contingencies remains unchanged if the voltage limit is further relaxed to 0.85 p.u.. The outage of line 10 and all other outage combinations of line 10 with any other line result in low voltage at bus 6 for the voltage limit of 0.85 p.u. or 0.90 p.u.. The most severe contingency is the outage of lines 1 and 10 for which the voltage at bus 6 is 0.56 p.u.. Outages of line 2 and element 7 (transformer) and of lines 2 and 27 result in low voltage (0.81 p.u.) at bus 3. The following is a list of voltage violation contingencies, in addition to the above outages, for the 0.95 p.u. voltage level.

(1) The outage of element 7 (transformer) and all other outage combinations of the transformer with any other

line/transformer result in low voltage at bus 3.

(2) The outage of line 11 together with the outage of any other line/transformer result in low voltage at bus 8.

(3) The outage of line 27 and any other outage combinations involving line 27 result in low voltage at bus 3.

4.4.3 The SPC System (Figure 2-3)

This system is prone to frequent voltage violation problems. The total number of line contingencies tested is 2556. Voltage violation contingencies represent 7%, 13% and 28% of the total line contingencies at three voltage levels of 0.85 p.u., 0.90 p.u. and 0.95 p.u. respectively. A brief summary of the major voltage violation contingencies is as follows:

(a) <u>Voltage limit = 0.85 p.u.:-</u>

(1) The outage of line 10 and any other outage combination with this line results in low voltage at bus 5. Outages of lines 1 and 10, 10 and 18, 10 and 34 (transformer), 10 and 56, and of 10 and 66 result in low voltage at four system buses, namely bus 5, 6, 7 and 8.

(2) The outage of the element 11 (transformer) together with the outage of any other line/transformer results in low voltage at buses 3 and 5.

(3) The outage of line 36 and the outage combination of any other line/transformer with line 36 results in low voltage at bus 19 and bus 20.

(4) Buses 22 and 24 experience low voltage due to the outage of element 43 (transformer) and any other outage combination with the element 43.

(b) Voltage limit = 0.90 p.u.:-

In addition to the above voltage violation contingencies, the outage of line 40 and any other outage combination involving line 40 results in low voltage at bus 19. The outage of line 41 and any other outage combination with line 41 also result in low voltage at bus 20.

(c) Voltage limit = 0.95 p.u.:-

If the bus voltage is increased to 0.95 p.u. from 0.90 p.u., the following additional line outages result in voltage violation contingencies.

(1) The outage of line 25 and any other outage combination with this line result in low voltage at bus 13.

(2) Many outage combinations of line 26 and of line 28 result in low voltage at bus 8 and bus 20 respectively.

(3) The outage of line 29 and any other outage combination with line 29 result in low voltage at bus 20.

(4) Both buses 8 and 12 experience low voltage due to the outage of either element 34 (transformer) or line 56 and any other outage combination involving either of them.

After taking suitable corrective actions as described in

Section 3.3, the voltage violation problem no longer exists in any of the systems. Only 2 contingencies i.e., (i) the outage of transformers 23 and 24 and (ii) the outage of lines 28 and 29 for the SPC system do not converge. The non-convergence of these two contingencies is due to the fact that the iteration limit exceeds the maximum number of iterations which was chosen as 30 in this case. It is worthy of note that prior to employing the corrective actions, the total number of non-convergent contingencies for the SPC system was 112. The maximum MVAR rating of the power factor improvement devices required for the three systems are given in Table 4-3, Table 4-4 and Table 4-5 respectively. The three permissible voltage limits considered are 0.95, 0.90 and 0.85 p.u.. The most severe outage contingency requiring the maximum improvement is also given in each case.

4.5 Summary

A quantitative evaluation of the voltage violation contingencies and non-convergent contingencies in conjunction with the appropriate corrective actions has been presented in this chapter. Two simplified heuristic algorithms, one for rescheduling the generating units and the other for calculating the MVAR rating of a power factor improvement device for each voltage violation contingency were developed and integrated into the fast decoupled A.C. load flow. The

Table 4-3: MVAR rating of a power factor improvement device for the 6 bus test system

Bus	Bus Voltage in p.u. 0.95 MVAR	0.95 Line Contingency	0.90 MVAR	0.90 Line Contingency	0.85 MVAR	0.85 Line Contingency
3	34.0	1 & 6 out	34.0	1 & 6 out	17.0	1 & 6 out
4	16.0	do	16.0	do	8.0	do
5	8.0	do	8.0	do	4.0	do
6	8.0	do	8.0	do	4.0	do

Table 4-4: MVAR rating of a power factor improvement device for the IEEE RTS

Bus	Bus Voltage in p.u. 0.95 MVAR	0.95 Line Contingency	0.90 MVAR	0.90 Line Contingency	0.85 MVAR	0.85 Line Contingency
3	108	6 & 7 out	72	6 & 7 out	72	6 & 7 out
4	15	4 & 7 out				
6	42	9 & 10 out	25	9 & 10 out	25	9 & 10 out
8	103	11 & 13 out	68	11 & 13 out	68	11 & 13 out
9	35	14 & 15 out				

Table 4-5: MVAR rating of a power factor improvement device for the SPC system

Bus	Bus Voltage in p.u. 0.95 MVAR	0.95 Line Contingency	0.90 MVAR	0.90 Line Contingency	0.85 MVAR	0.85 Line Contingency
2	29	43 & 54 out	29	23 & 24 out	29	23 & 24 out
3	4	11 & 57 out	4	11 & 57 out	3	11 & 57 out
4	66	8 & 12 out	33	12 & 43 out	33	12 & 43 out
5	69	10 & 57 out	69	10 & 57 out	52	10 & 57 out
6	76	-do-	76	-do-	76	-do-
7	30	-do-	24	-do-	24	-do-
8	23	-do-	23	-do-	18	-do-
9	9	2 & 12 out	9	2 & 12 out	9	2 & 12 out
12	45	58 & 59 out	45	10 & 57 out	45	10 & 57 out
13	31	25 & 34 out	20	25 & 34 out	20	25 & 34 out
14	12	58 & 59 out	9	58 & 59 out	9	58 & 59 out
15	12	-do-	12	-do-	9	-do-
16	39	-do-	20	-do-	20	-do-
18	9	27 & 35 out				
19	12	20 & 40 out	12	20 & 40 out	12	20 & 40 out
20	109	28 & 36 out	82	28 & 36 out	82	28 & 36 out
22	47	1 & 43 out	47	1 & 43 out	47	1 & 43 out
23	17	43 & 45 out	17	43 & 45 out	17	43 & 45 out
24	9	1 & 43 out	9	1 & 43 out	9	1 & 43 out
25	25	43 & 45 out	13	43 & 45 out	13	43 & 45 out
28	14	47 & 48 out				
38	5	58 & 59 out				

newly incorporated techniques successfully alleviate, for all the three systems, the voltage problems and the non-convergent situations which cause discontinuities in the quantitative evaluation of the system adequacy indices for transmission system reliability.

CHAPTER 5

LOAD POINT AND SYSTEM INDICES

5.1 Introduction

An outage event may affect a wide area of the system or it may affect a small group of buses or perhaps a single bus. This depends upon the components under outage, their relative importance and location in the network configuration, the corrective action taken and the load curtailment philosophy etc.. The adequacy indices should focus attention on those portions of the system that are directly affected by the outage of the element(s). The total contribution of all possible outage contingencies considered should indicate those areas in the system which are less reliable and are prone to disturbances. Calculation of system indices only does not convey this information and therefore it is appropriate to also emphasize individual load point indices. This aspect has not received much attention up to the present time and very few publications[2] available stress this aspect.

The need for considering the individual load point indices is also necessitated by the fact that the effect of considering higher level outages is not uniformly distributed over the entire system. At some of the system buses, Ist and 2nd level contingencies may be sufficient to provide adequacy indices with a reasonable accuracy. At other buses, higher level contingencies must be considered before any significant problem is experienced. In the case of the overall system indices, an appropriate choice of the outage level is dictated by the relative contribution of the adequacy indices for the two general categories of buses noted earlier.

In a similar manner, varying the load at each bus in equal proportion may not result in a proportionate variation of the indices at each bus. This is due to the fact that load flow studies involve the solution of non-linear simultaneous equations. The effect of load variation may not therefore be uniform at each bus, depending upon the network configuration and the system component parameters.

The variation in system average indices due either to the inclusion of high level outages or to the variation in load level does not necessarily result in the same variation pattern at each bus in the system. Sensitivity studies are very important for an individual load point assessment. Drawing conclusions about the adequacy of any load point from the system indices may be both misleading and far from reality. The effects on the adequacy indices of varying the depth of the outage events and variation in the system load are discussed in detail in Sections 5.3 and 5.4 respectively.

The curtailment of load at system buses in the event of a deficiency in the generation capacity can be decided in a number of ways depending upon the relative priority given to each major load center. A brief description of the load curtailment philosophy used in this study is given below:

5.2 Load Curtailment Philosophy

A capacity deficiency in the system under any contingency condition is alleviated by curtailing the load at the appropriate buses. As indicated earlier in Chapter 2, the load at each bus has been classified into two types:

(1) Firm Load.

(2) Curtailable Load.

Based on individual load point requirements, curtailable load may represent some percentage of the total load at the bus. In the case of a deficiency in the generation capacity, curtailable load is interrupted first, followed by the curtailment of firm load, if necessary. The effect of a system disturbance that results in swing bus overload, (a capacity deficiency in the system) can be confined to a small area or to a large region of the system. If the relative importance of the load at a bus in the system is such that the firm load at the bus will not be curtailed unless it is unavoidable, it is obvious that more buses in the system will experience load curtailment. On the other hand, if the system design warrants that a disturbance in one region should not be felt in another region of the system, then the number of buses that experience load curtailment will be less but under many outage contingencies firm load may have to be curtailed. This provision has been made in the load curtailment philosophy algorithm by defining the number of load curtailment passes. A brief description of the load curtailment under each pass is as follows:

5.2.1 Load Curtailment Pass 1

In the case of generator outages, pass 1 covers those buses at which the generators under outage are physically connected and are one line away and receiving power from these generator buses. In the case of line outages, pass 1 covers the receiving end bus(es) of lines under outage and buses which are one line away and receiving power from these receiving end buses. In the event of both generator and line outages, pass 1 covers those buses at which the generator under outage is physically connected and the receiving end bus of the line under outage and those buses which are one line away from the receiving end buses and are receiving power from them. The swing bus overload is alleviated by proportional interruption of the curtailable load at buses covered under pass 1.

If the swing bus is still overloaded after removing the curtailable load from the buses mentioned earlier, the firm load is curtailed proportionally at these buses. However, at those buses which have load as well as local generation, only that amount of firm load is curtailed which is in excess of its local generation. In other words, these buses do not experience any firm load curtailment if the generation is more than the firm load. If generation is less than the firm load, the excess firm load is interrupted proportionately. If the swing bus is overloaded even after curtailing the total load at the load buses, the load is removed from those buses which are covered under load curtailment pass 2 as described below:

5.2.2 Load Curtailment Pass 2

In load curtailment pass 2, the buses covered are as noted for pass 1 and all those buses which are two lines away from the generator outage buses and/or receiving end buses for a line outage and are being directly supplied from the buses covered under pass 1. The load curtailment philosophy remains the same as described above, i.e. proportional curtailment of the curtailable load followed by proportional curtailment of the firm load, if necessary. If the swing bus is still overloaded after removing the total load from the buses covered under pass 2, the load is curtailed at the other buses covered under pass 3.

5.2.3 Load Curtailment Pass 3

This pass covers all buses that are covered under pass 2 and those additional buses which are three lines away from the generator outage buses and/or receiving end buses for a line outage and are being fed from the buses which are two lines away and covered under pass 2. The load curtailment philosophy remains the same as explained for pass 1.

If the swing bus is still overloaded after curtailing the total load at all buses covered under 3 passes, a message is printed to this effect and the the load is curtailed proportionately at all system buses. However, this possibility is very remote and is hardly ever experienced even for a large power system.

As noted earlier, the number of the buses at which curtailable load is to be interrupted increases as the number of load curtailment passes increases. The number of passes can be specified depending upon the system requirements and the operation philosophy. The effect of the number of load curtailment passes on the adequacy indices is discussed below.

5.3 Effect of Load Curtailment Passes on Adequacy Indices

5.3.1 The 6 Bus Test System (Figure 2-1)

Table 5-1 gives the curtailable load in percentage of the total load at each bus for the 6 bus test system. These values

Table 5-1: Curtailable load in MW at each bus of the 6 bus test system

S.No.	Bus No.	Total Load MW	Curtailable Load	
			% of Total Load	In MW
1	2	20	10	2.0
2	3	85	25	21.25
3	4	40	25	10.0
4	5	20	20	4.0
5	6	20	20	4.0
	System Load =	185	System Curtailable Load	41.25

have been chosen arbitrarily. In this system, bus 3 and bus 4 are one line away from the generator buses 1 and 2 respectively. If load curtailment pass 1 is chosen, these buses experience load interruption whenever the generating units are out at their respective one line away generating stations. Buses 5 and 6 do not experience any load curtailment for the generator outage contingencies because the total load at buses 2 and 3 exceeds the capacity deficiency in the system under the outage of four of the largest generators. Buses 5 and 6 experience load curtailment for line outage events only. However, if the load curtailment pass is increased to 2, bus 5, which is two lines away from both the generating stations, also encounters load interruption. The probability of failure and the frequency of failure of bus 5 increase sharply as shown in Figure 5-1. The expected values of load curtailed in MW and energy curtailed in MWh at bus 5 also increase while at bus 3 these values decrease.

The net effect of increasing the load curtailment pass from 1 to 2 is that now the system problem is shared by three buses, buses 3, 4 and 5 instead of bus 3 and bus 4 only. As seen from Table 5-2, if the pass is further increased to 3, bus 6 also shares the load interruption in the event of generating unit outages. Table 5-2 gives the annualized adequacy indices at each bus for the three load curtailment passes. As seen from Figure 5-1, the variation in the adequacy indices at each bus is not uniform and as such it is greatly

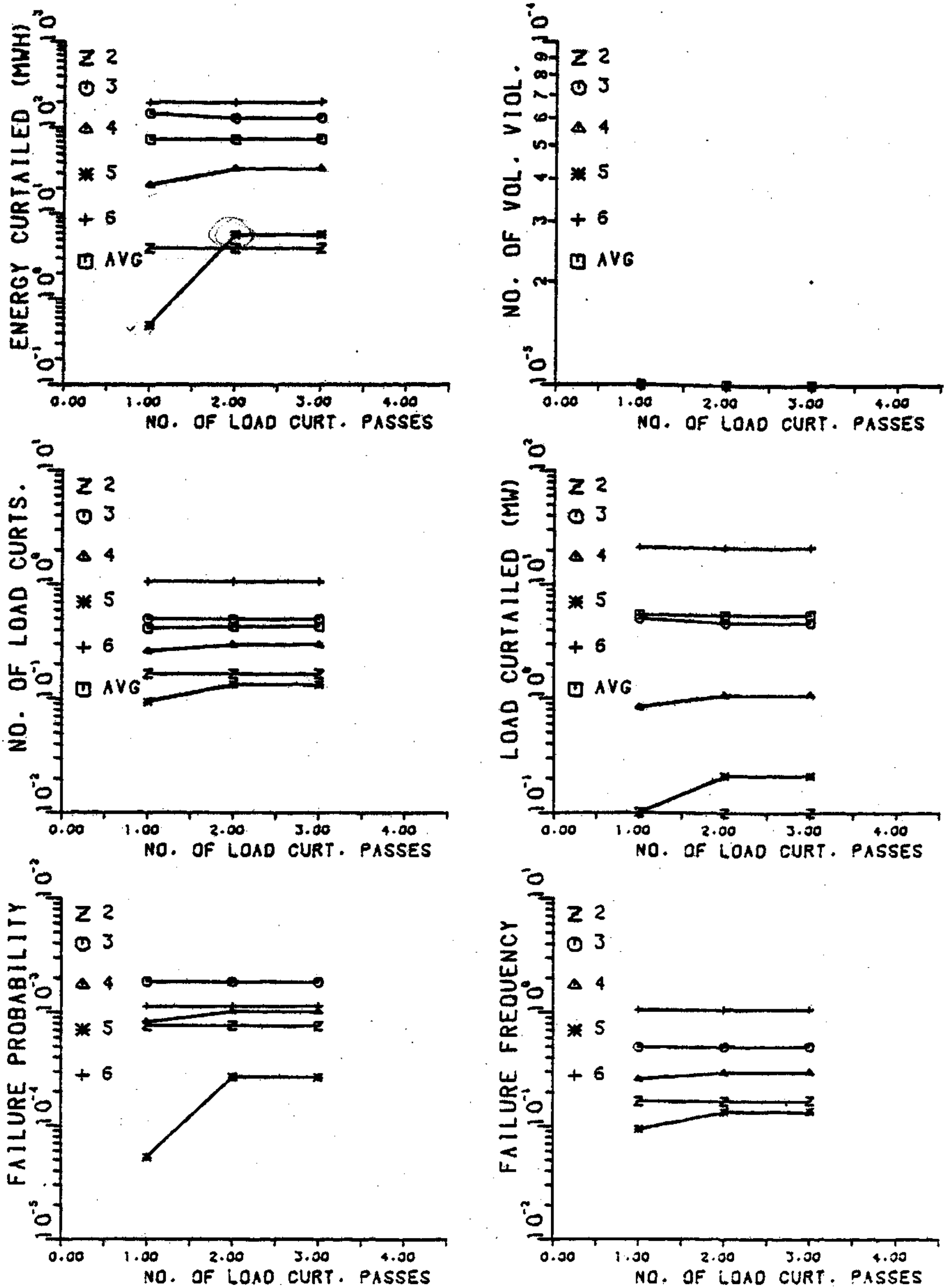

Figure 5-1: Annualized bus indices vs. number of load curtailment passes for the 6 bus test system

Table 5-2: Annualized bus indices for the 6 bus test system at various load curtailment passes

BUS	Load Curtailment Pass Ist Actual Value	2nd Actual Value	2nd Incr. w.r.t. Ist Pass	3rd Actual Value	3rd Incr. w.r.t. Ist Pass
			Failure Probability		
2	0.0007627	0.0007627	1.00	0.0007627	1.00
3	0.0018466	0.0018466	1.00	0.0018466	1.00
4	0.0008167	0.0010194	1.25	0.0010194	1.25
5	0.0000524	0.0002684	5.12	0.0002684	5.12
6	0.0011280	0.0011280	1.00	0.0011399	1.01
			Failure Frequency		
2	0.1642844	0.1642844	1.00	0.1642844	1.00
3	0.4982281	0.4982360	1.00	0.4982360	1.00
4	0.2602414	0.2961859	1.14	0.2961859	1.14
5	0.0930924	0.1328363	1.43	0.1328363	1.43
6	1.0567538	1.0567538	1.00	1.0599492	1.00
		Total Load Curtailed (MW)			
2	0.1000000	0.1000000	1.00	0.1000000	1.00
3	5.0000000	4.6500001	0.93	4.6399999	0.93
4	0.8400000	1.0800000	1.29	1.0800000	1.29
5	0.1000000	0.2100000	2.10	0.2100000	2.10
6	21.1399994	21.1399994	1.00	21.1499996	1.00
		Total Energy Curtailed (MWh)			
2	3.9164000	3.9164000	1.00	3.9164000	1.00
3	146.9962006	129.8780975	0.88	129.5301971	0.88
4	21.4964008	33.4525986	1.56	33.3874016	1.55
5	0.4880000	5.6521001	11.58	5.6521001	11.58
6	197.6300964	197.6300964	1.00	198.0471954	1.00

Incr. = Increment

influenced by the values of the two constituents of the load, i.e. the firm load and the curtailable load.

As the number of the load passes increases for a given load composition, the number of contingencies that results in the curtailment of firm load at any bus decreases. The number of contingencies resulting in the curtailment of the firm load also decreases if the limit of the curtailable load at each bus is increased for a specified number of load curtailment passes. Table 5-3 gives the number of outage contingencies resulting in firm load curtailment for various values of curtailable load. The total number of load curtailment contingencies in each case is 1327.

Table 5-3: Number of the firm load curtailment contingencies for the 6 bus test system

S.No.	Curtailable Load at Each Bus (% of Total Load)	No. of Load Passes		
		Ist	2nd	3rd
1	15	561	513	513
2	30	149	122	122
3	45	40	36	36
4	60	27	26	26

If the curtailable load is increased beyond 60%, the number of contingencies that result in firm load curtailment remains at 26, because these 26 contingencies result in the interruption of total load at bus 6. Whenever line 9 itself or in combination with any other line or generating unit is out, bus 6 is isolated. Bus 6 and bus 5 are also isolated if lines 5 and 8 are out.

5.3.2 The IEEE RTS (figure 2-2)

In this system, there are 17 buses which have loads connected at them. The remaining buses are either free buses or PV (generator) buses without connected load. Adequacy indices have been calculated for these 17 buses. In order to facilitate a better comparison of the adequacy indices for these buses, they are classified into 6 categories depending upon their type, voltage level and location relative to a generating station. This classification helps not only in comparing the adequacy indices of buses falling into one class with the adequacy indices of buses falling into other classes, but also in achieving a better pictorial representation of the adequacy indices. Figure 5-2 shows the classification of buses for this system. The buses in the six categories are as follows:

(a) 138 KV Buses (South Region):-

(1) Buses having local generation : Buses 1, 2 and 7.

(2) One line away buses with two lines connected to them: Buses 4, 5 and 6.

(3) One line away buses with three or more lines connected to them: Buses 3 and 8.

(4) Two lines away buses: Buses 9 and 10.

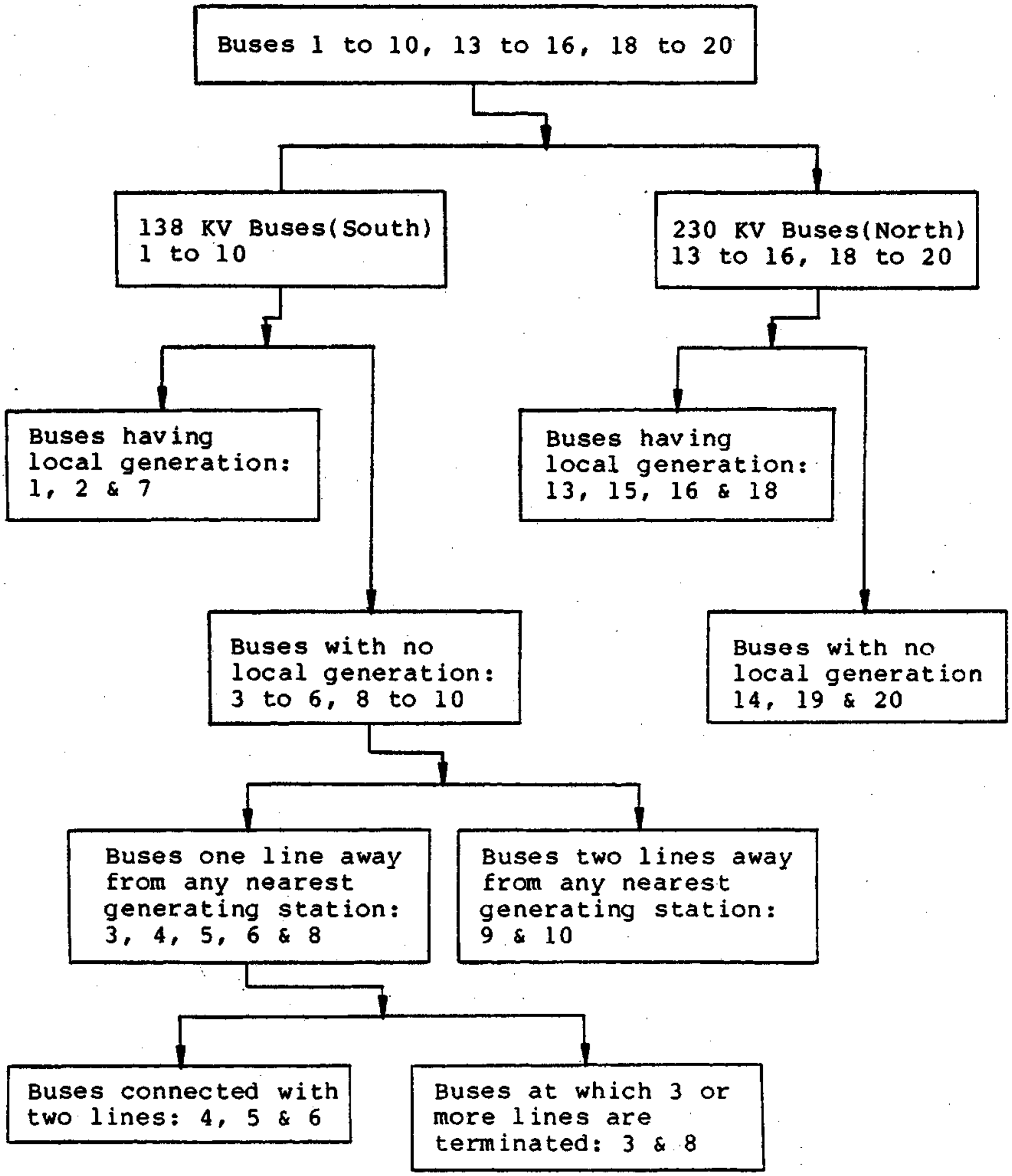

Figure 5-2: Bus classification for the IEEE RTS

(b) 230 KV Buses (North Region):-

(5) Buses having local generation : Buses 13, 15, 16 and 18.

(6) Buses having no local generation : Buses 14, 19 and 20.

On the basis of above classification, the variation in the adequacy indices namely, the probability of failure, the frequency of failure, the number of load curtailments, the expected load curtailed in MW, the expected energy curtailed in MWh and the total number of voltage violations, as a function of the number of load curtailment passes are shown in Figures 5-3, 5-4, 5-5, 5-6, 5-7 and 5-8 respectively. There are 6 sets of graphs in each figure. The number of graphs in each set is not equal but depends upon the number of buses in each class. The number mentioned adjacent to the graph symbol represents the bus number. 'Avg' represents the average value of the load point indices. The scale on both the horizontal and vertical axes are the same for all the six sets of graphs in each figure. This facilitates a quick comparison of the adequacy indices of buses in one class to those of buses in another class. This graphical representation of the adequacy indices has also been followed in all the further studies presented in this thesis.

The failure probability (Figure 5-3) and the failure frequency (Figure 5-4) for buses having local generation do not change as the number of passes increases. The most notable

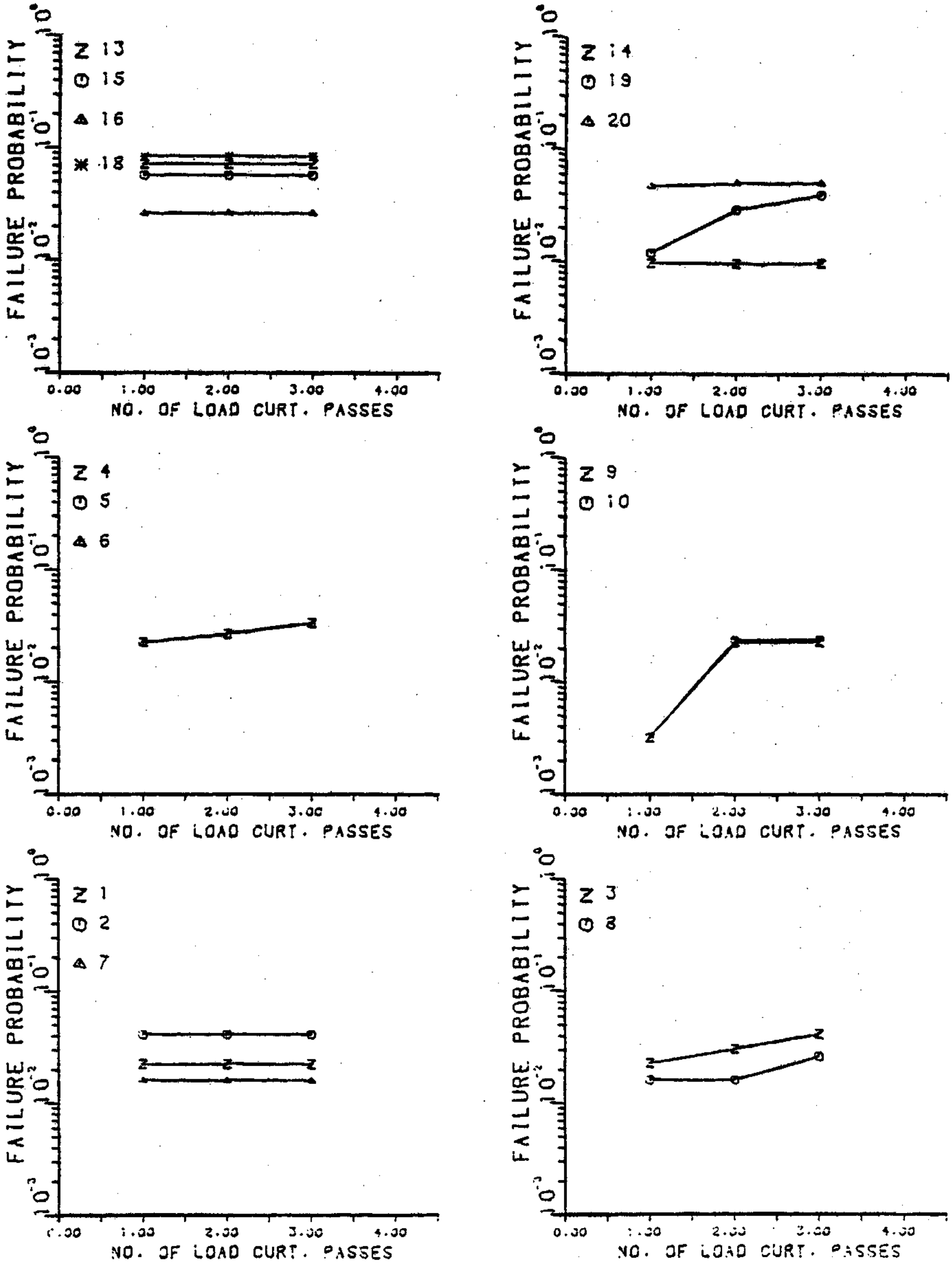

Figure 5-3: Probability of failure vs. number of load curtailment passes for the IEEE RTS

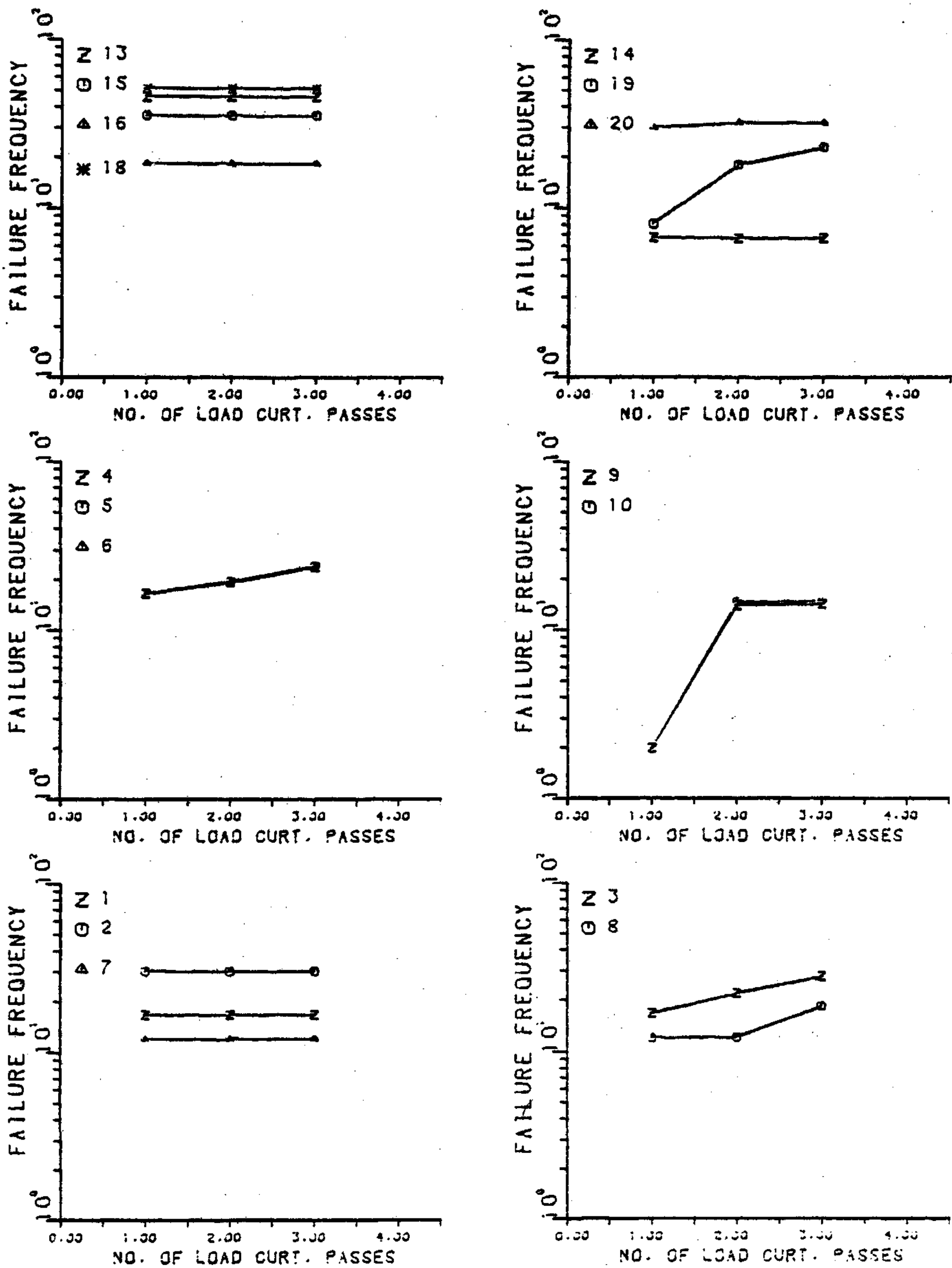

Figure 5-4: Frequency of failure vs. number of load curtailment passes for the IEEE RTS

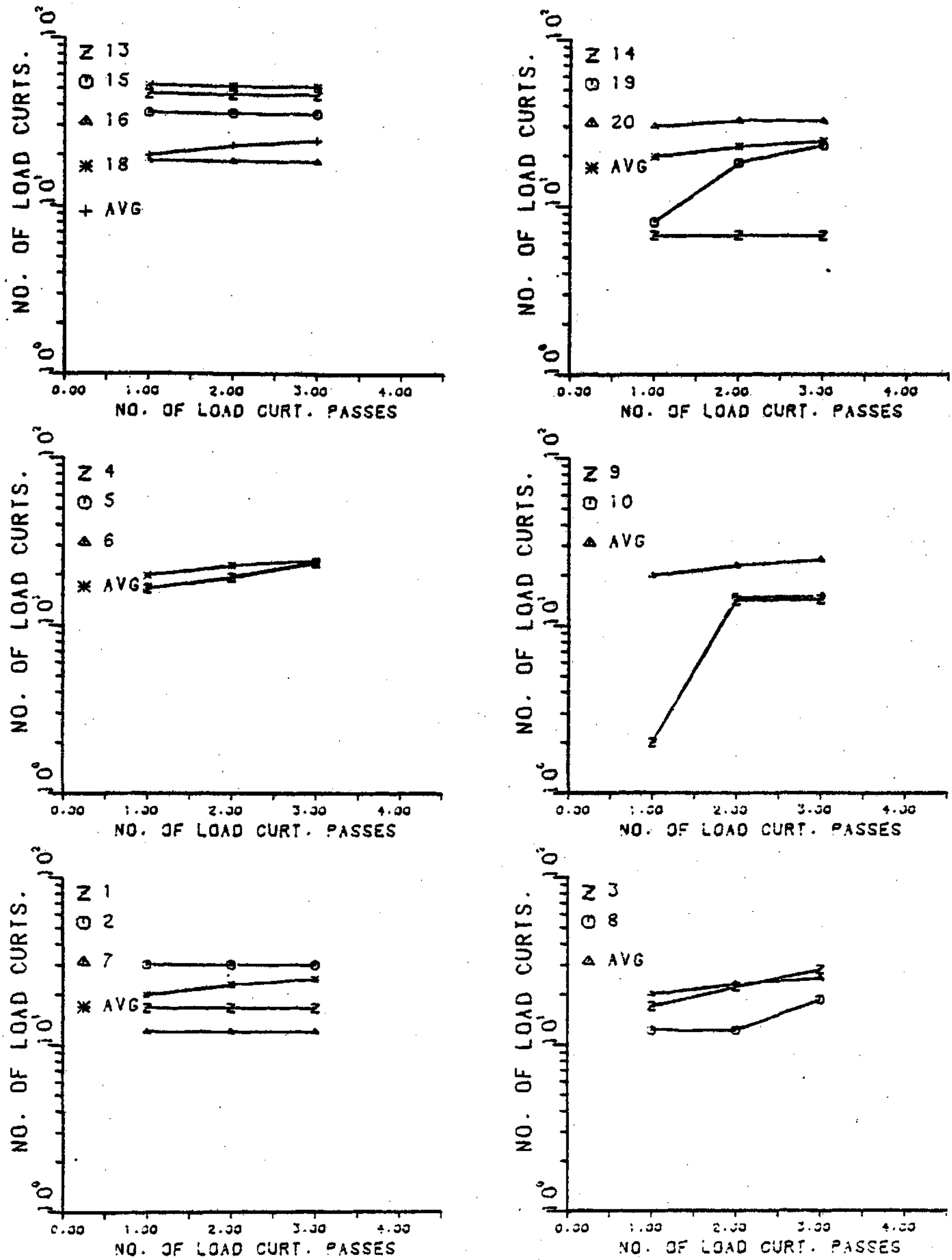

Figure 5-5: Number of load curtailments vs. number of load curtailment passes for the IEEE RTS

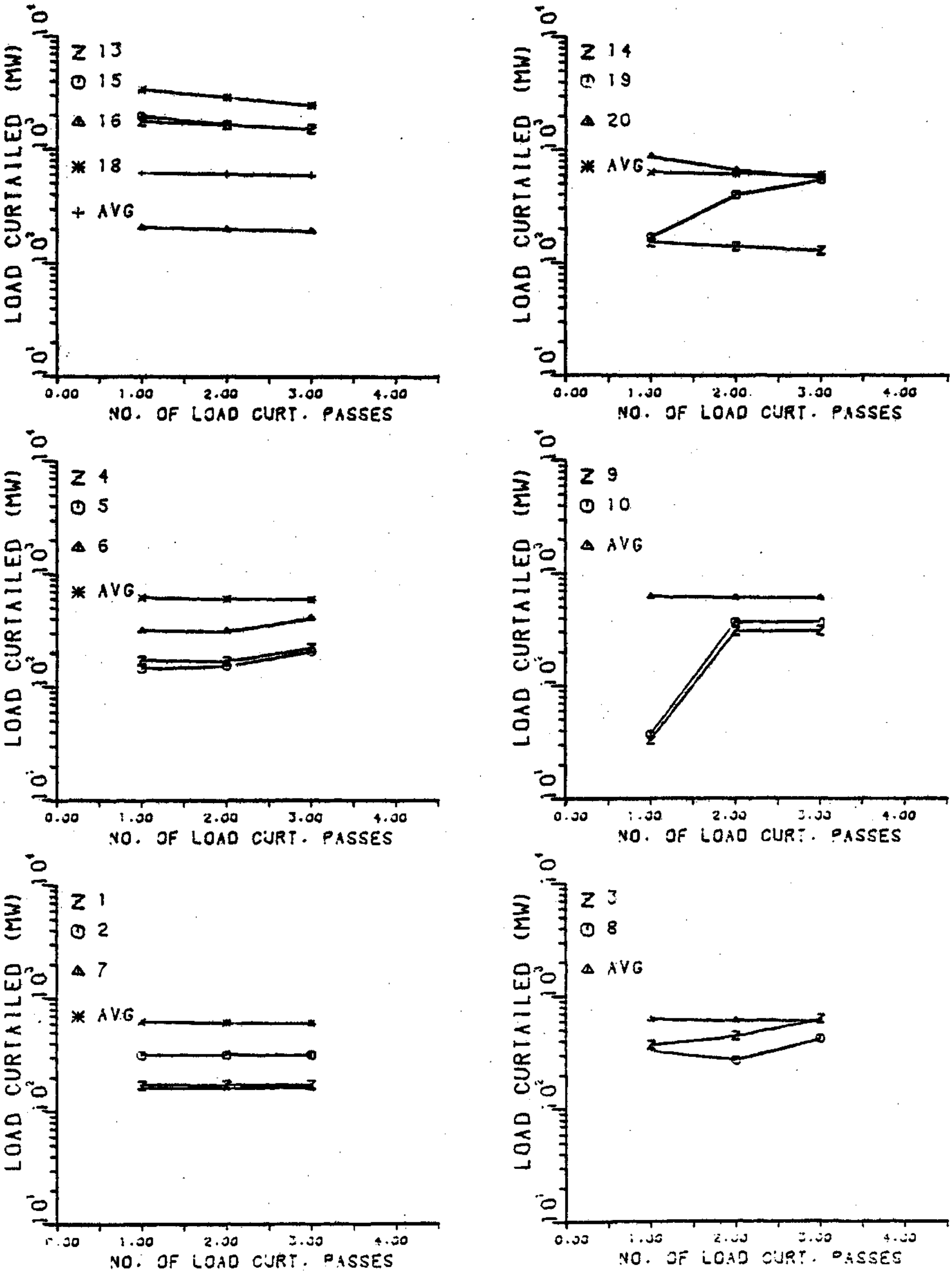

Figure 5-6: Expected load curtailed in MW vs. number of load curtailment passes for the IEEE RTS

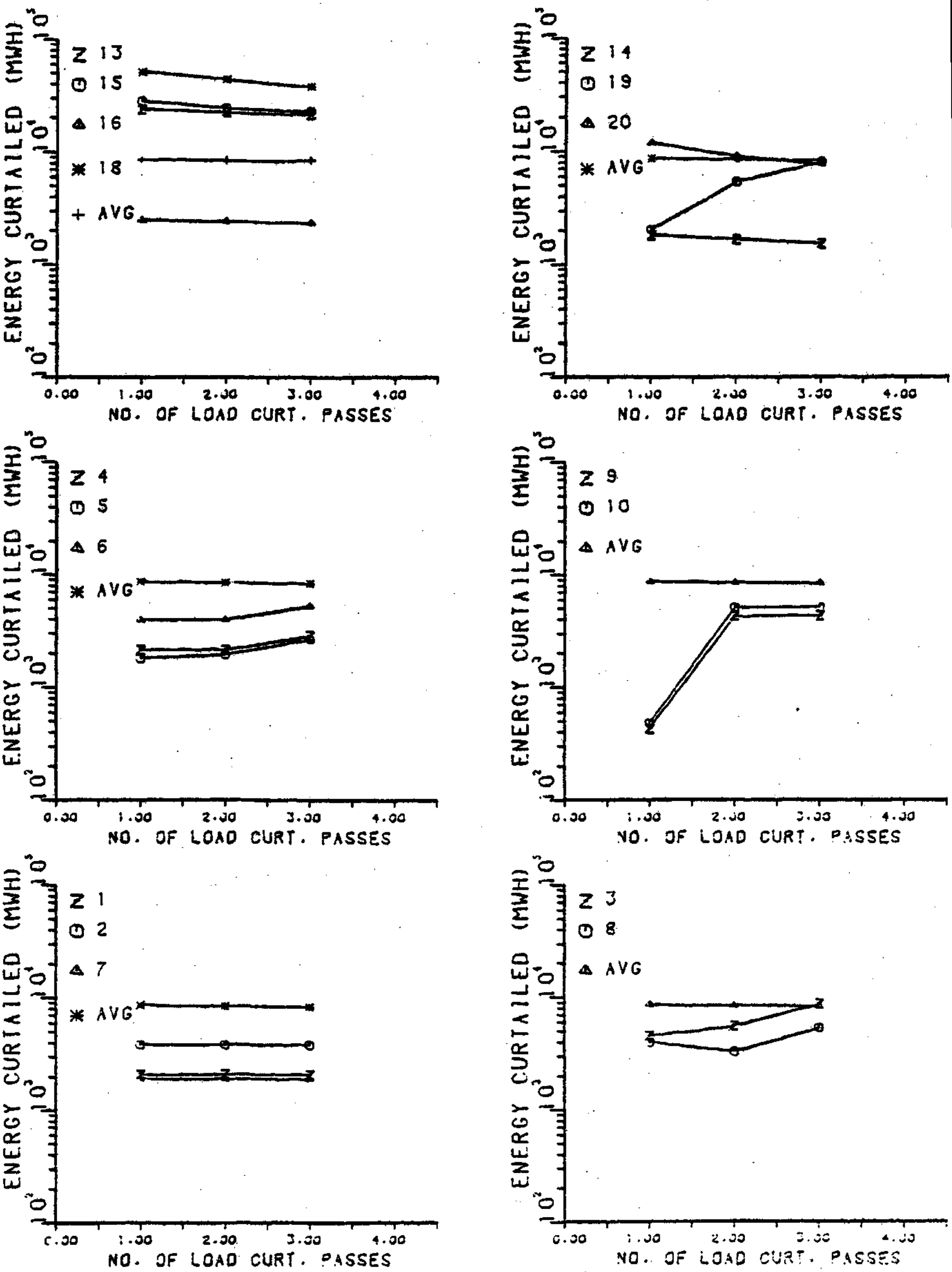

Figure 5-7: Expected energy curtailed in MWh vs. number of load curtailment passes for the IEEE RTS

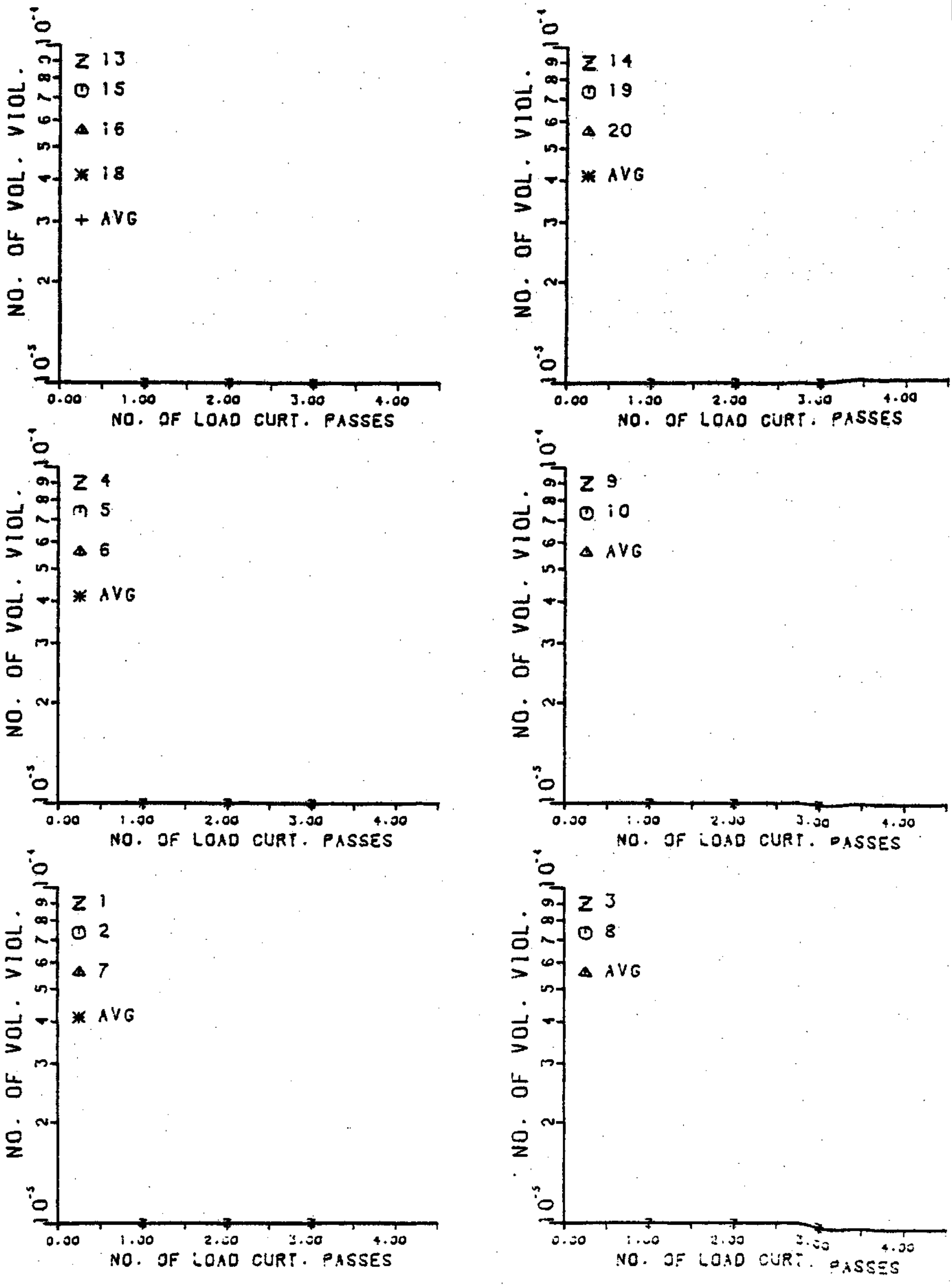

Figure 5-8: Total number of voltage violations vs. number of load curtailment passes for the IEEE RTS

increase in indices is for buses 9 and 10 as the number of load curtailment passes increases from 1 to 2. These buses are two lines away from generator bus 13 and bus 23. An outage of a 197 MW unit at bus 13, or the outage of a unit at bus 23 with the outage of other big generating units therefore results in the load interruption at these two buses. The net effect is that these two buses also share the capacity deficiency. This reduces the amount of the load curtailment and the energy curtailment at buses falling in the 230 KV region with the exception of bus 19 as seen from Figure 5-6 and Figure 5-7. In fact, bus 19 shares more of a capacity deficiency at pass 2, because it is two lines away from bus 23 which has large generating units (1 unit of 350 MW and 2 units of 155 MW each).

One interesting feature is that the expected load curtailed at buses 4, 6 and 8 decreases as the load curtailment pass is increased from 1 to 2, but if the load curtailment pass is further increased from 2 to 3, the expected load curtailed increases. This is quite clear from Table 5-4 which gives the expected load curtailed in MW at each bus for the three passes and associated variation (in per unit) as a function of the expected load curtailed for pass 1. This is due to the fact that at load curtailment pass 2, bus 9 and 10 share the load curtailment of these buses whenever a generating unit is out either at bus 2 or at bus 7. However, at load curtailment pass 3, buses 4, 6 and 8 start sharing the

Table 5-4: Expected load curtailed in MW for the IEEE RTS at various load curtailment passes

BUS	Load Curtailment Pass				
	Ist	2nd		3rd	
	Value	Value	Variation w.r.t. Ist Pass	Value	Variation w.r.t. Ist Pass
1	171.50	171.23	1.0	171.22	1.0
2	314.64	314.37	1.0	314.32	1.0
3	369.29	439.81	1.2	625.05	1.7
4	172.44	169.55	1.0	223.50	1.3
5	145.29	154.43	1.1	208.11	1.4
6	317.00	311.68	1.0	410.85	1.3
7	160.41	160.36	1.0	160.33	1.0
8	326.33	268.70	0.8	417.43	1.3
9	32.90	305.75	9.3	308.03	9.4
10	36.66	364.99	10.0	366.89	10.0
13	1769.22	1638.36	0.9	1534.73	0.9
14	150.49	138.60	0.9	127.89	0.8
15	1961.79	1662.60	0.8	1548.42	0.8
16	204.90	198.50	1.0	192.92	0.9
18	3377.93	2887.15	0.9	2481.43	0.7
19	166.44	396.46	2.4	543.14	3.3
20	853.40	652.54	0.8	558.44	0.7

load curtailment whenever a generating unit is removed from bus 13 or bus 23 with other generating units. The expected load curtailed at buses 13, 14, 15, 16, 18 and 20 further decreases because at pass 3, buses in the south and bus 19 share the load curtailment of these buses.

As indicated earlier in Chapter 4, the application of an heuristic approach to handle voltage violation situations alleviates the voltage problems in the system. This is shown in Figure 5-8. The voltage violation situation does not change with the number of load curtailment passes.

5.4 Effect of the Contingency Level on the Adequacy Indices

The necessity of including high level generator outages was emphasized in Chapter 3. As indicated earlier, the selection of an appropriate outage level for a system is not only dictated by the marginal contribution of higher level contingencies to the system indices but also by the marginal contribution of these contingencies to the load point indices. The effect of higher level outage contingencies may not be uniform throughout the system as indices at some buses may increase tremendously, while at other buses it may change slightly. The effect of contingency level both on the system and on the load points has been studied for the 6 bus test system and the IEEE RTS and reported in this section. These studies have been carried out using load curtailment pass 1. Component outages up to the 4th level have been considered.

The Ist level contingency outages include the outage of one component only. The 2nd level contingency outages include outages of two generating units and/or outages of two lines and/or outages of one generating unit and one line. In the case of a third level contingency, removal of three generating units and/or removal of two lines and/or removal of one generating unit and one line are considered. The 4th outage level includes outages of four generating units and/or outages of two lines and/or outages of one generator and that of one line. The independent outages of three or more lines are not considered since the contribution of these outages is extremely small and the computation time to solve these contingencies is tremendously large. This has been discussed in Chapter 3. In order to account for the contribution of high level outage contingencies, each last level contingency at all the four outage levels is terminated. The effect of common cause events is not considered in this study. A brief description of the effect of contingency level on the adequacy indices for the 6 bus test system and the IEEE RTS is as follows:

5.4.1 The 6 Bus Test System (Figure 2-1)

Figure 5-9 shows the variation of selected adequacy indices with the contingency level. The numerical values of the bus indices and the system indices are given in Table 5-5 and Table 5-6 respectively. Maximum values and the average values of the bus indices are shown in Table 5-7 to Table 5-10. As seen from Figure 5-9 and the above referenced tables, bus 6, which is radially fed from bus 5, experiences total load curtailment at the single outage level because of the removal of line 9. The effect of higher level outages on this bus is negligible. It can, therefore, be inferred that in calculating the indices at load point 6, the first outage level contingency provides reasonably accurate values. In the case of the other buses, the solution of higher contingencies is extremely important as none of these buses experiences any problem in the case of a single component outage. Bus 5 does not experience any problem due to the outages of the

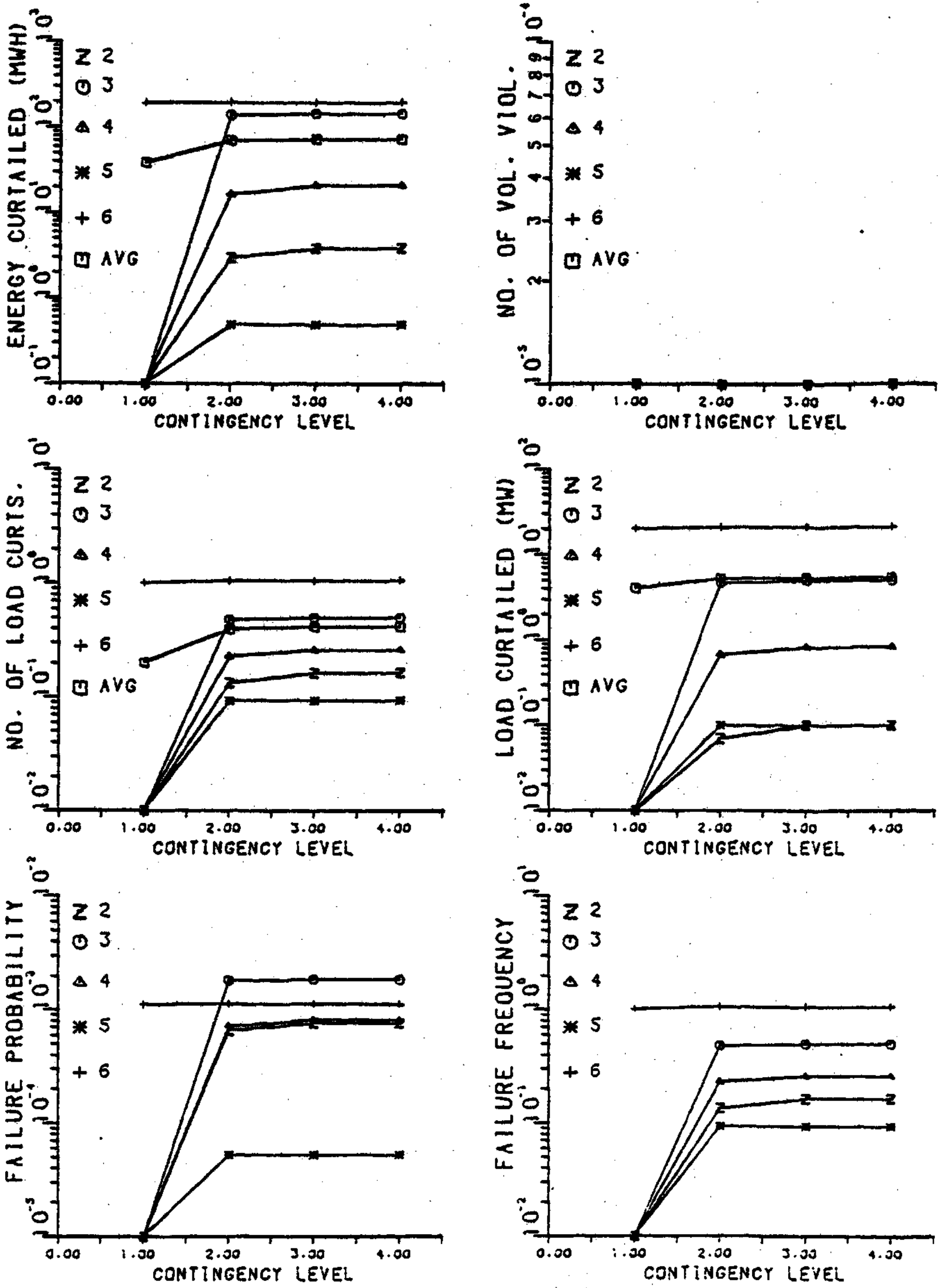

Figure 5-9: Annualized bus indices vs. contingency level for the 6 bus test system

Table 5-5: Annualized bus indices for the 6 bus test system at various contingency levels

Bus	Ist Cont. Actual Value	2nd Cont. Actual Value	3rd Cont. Actual Value	3rd Cont. Incr. w.r.t. 2nd Cont.	4th Cont. Actual Value	4th Cont. Incr. w.r.t. 2nd Cont.
			Failure Probability			
2	0.000000	0.000659	0.000761	1.16	0.000762	1.16
3	0.000000	0.001805	0.001846	1.02	0.001846	1.02
4	0.000000	0.000713	0.000815	1.14	0.000817	1.15
5	0.000000	0.000052	0.000052	1.00	0.000052	1.00
6	0.001113	0.001128	0.001128	1.00	0.001128	1.00
			Failure Frequency			
2	0.000000	0.133698	0.163625	1.22	0.164284	1.23
3	0.000000	0.477914	0.497763	1.04	0.498228	1.04
4	0.000000	0.229655	0.259582	1.13	0.260241	1.13
5	0.000000	0.093092	0.093092	1.00	0.093092	1.00
6	1.010229	1.056753	1.056753	1.00	1.056753	1.00
			Total Load Curtailed (MW)			
2	0.000000	0.070000	0.100000	1.43	0.100000	1.43
3	0.000000	4.719999	4.989999	1.06	5.000000	1.06
4	0.000000	0.680000	0.830000	1.22	0.840000	1.24
5	0.000000	0.100000	0.100000	1.00	0.100000	1.00
6	20.200001	21.139999	21.139999	1.00	21.139999	1.00
			Total Energy Curtailed (MWh)			
2	0.000000	3.024200	3.887800	1.29	3.916400	1.30
3	0.000000	140.895294	146.807495	1.04	146.996200	1.04
4	0.000000	16.732200	21.307399	1.27	21.496400	1.28
5	0.000000	0.488000	0.488000	1.00	0.488000	1.00
6	195.012695	197.630096	197.630096	1.00	197.630096	1.00

Cont. = Contingency
Incr. = Increment

Table 5-6: System indices for the 6 bus test system at various contingency levels

Ist Cont. Actual Value	2nd Cont. Actual Value	3rd Cont. Actual Value	3rd Cont. Incr. w.r.t. 2nd Cont.	4th Cont. Actual Value	4th Cont. Incr. w.r.t. 2nd Cont.
Bulk Power Supply Disturbances					
1.010230	1.537530	1.557740	1.01	1.558220	1.01
Total Probability					
0.994059	0.999637	0.999753	1.00	0.999753	1.00
IEEE INDICES					
Bulk Power Interruption Index (MW/MW-Yr.)					
0.109210	0.144320	0.146730	1.02	0.146860	1.02
Bulk Power Energy Curtailment Index (MWh/Yr.)					
1.054120	1.939299	2.000649	1.03	2.002850	1.03
Bulk Power Supply Average MW Curtailment Index (MW/Disturbance)					
20.000000	17.364419	17.426319	1.00	17.435979	1.00
Modified Bulk Power Energy Curtailment Index					
0.000120	0.000221	0.000228	1.03	0.000228	1.03
Severity Index (System-Minutes)					
63.247002	116.358001	120.039001	1.03	120.170997	1.03
AVERAGE INDICES					
Av. No. of Hrs of Load Curtailment/Load Pt./Year					
1.950130	7.631979	8.061380	1.06	8.066129	1.06
Av. No. of Load Curtailments/Load Pt./Year					
0.202050	0.398220	0.414520	1.04	0.414520	1.04
Av. Load Curtailed/Load Pt./Year-MW					
4.040920	5.339670	5.429140	1.02	5.433829	1.02
Av. Energy Curtailed/Load Pt./Year-MWh					
39.002541	71.753967	74.024147	1.03	74.105423	1.03

Cont. = Contingency   Incr. = Increment   Av. = Average

Table 5-7: Maximum load curtailed in MW for the 6 bus test system at various contingency levels

Bus	MLC MW	G1	G2	G3	G4	L1	L2	L3	IB	Probability	Frequency
		Contingency Description: Components Out — Generators				Lines			Bus		
Contingency Level = Ist											
6	20.0000	0	0	0	0	9	0	0	6	0.0011131	1.0102291
Contingency Level = 2nd											
2	0.5809	1	12	0	0	0	0	0	0	0.0000666	0.0135035
3	30.6257	1	2	0	0	0	0	0	0	0.0002152	0.0377013
4	37.5866	0	0	0	0	1	6	0	0	0.0000029	0.0051306
5	0.5929	0	0	0	0	2	3	0	0	0.0000257	0.0456317
6	20.0000	0	0	0	0	9	0	0	6	0.0009875	0.8962790
Contingency Level = 3rd											
2	2.0000	1	2	11	0	0	0	0	0	0.0000010	0.0002770
3	50.6257	1	2	4	0	0	0	0	0	0.0000031	0.0007777
4	37.5866	0	0	0	0	1	6	0	0	0.0000029	0.0051306
5	0.5929	0	0	0	0	2	3	0	0	0.0000257	0.0456317
6	20.0000	0	0	0	0	9	0	0	6	0.0009875	0.8962790
Contingency Level = 4th											
2	2.0001	1	2	10	16	0	0	0	0	0.0000000	0.0000018
3	60.8481	1	2	3	4	0	0	0	0	0.0000000	0.0000151
4	37.5866	0	0	0	0	1	6	0	0	0.0000029	0.0051306
5	0.5929	0	0	0	0	2	3	0	0	0.0000257	0.0456317
6	20.0000	0	0	0	0	9	0	0	6	0.0009875	0.8962790

IB = Isolated Bus
MLC = Maximum Load Curtailed

Table 5-8: Maximum energy curtailed in MWh for the 6 bus test system at various contingency levels

Bus	MEC MWh	G1	G2	G3	G4	L1	L2	L3	IB	Probability	Frequency
		Contingency Description									
		Components Out									
		Generators				Lines			Bus		
		Contingency Level = Ist									
6	193.0381	0	0	0	0	9	0	0	6	0.0011131	1.0102291
		Contingency Level = 2nd									
2	25.0931	1	12	0	0	0	0	0	0	0.0000666	0.0135035
3	1531.4121	1	2	0	0	0	0	0	0	0.0002152	0.0377013
4	184.6878	0	0	0	0	1	6	0	0	0.0000029	0.0051306
5	2.9232	0	0	0	0	2	3	0	0	0.0000257	0.0456317
6	193.0381	0	0	0	0	9	0	0	6	0.0009875	0.8962790
		Contingency Level = 3rd									
2	63.7821	1	2	11	0	0	0	0	0	0.0000010	0.0002770
3	1794.9017	1	2	4	0	0	0	0	0	0.0000031	0.0007777
4	486.3508	1	2	14	0	0	0	0	0	0.0000010	0.0002729
5	2.9232	0	0	0	0	2	3	0	0	0.0000257	0.0456317
6	193.0381	0	0	0	0	9	0	0	6	0.0009875	0.8962790
		Contingency Level = 4th									
2	63.7821	1	2	16	0	0	0	0	0	0.0000010	0.0002702
3	1794.9026	1	2	4	0	0	0	0	0	0.0000030	0.0007325
4	547.2288	1	2	4	12	0	0	0	0	0.0000000	0.0000052
5	2.9232	0	0	0	0	2	3	0	0	0.0000257	0.0456317
6	193.0381	0	0	0	0	9	0	0	6	0.0009875	0.8962790

IB = Isolated Bus
MEC = Maximum Energy Curtailed

Table 5-9: Maximum duration of load curtailment in hours for the 6 bus test system at various contingency levels

Bus	MDLC hrs	Contingency Description: Components Out: Generators G1	G2	G3	G4	Lines L1	L2	L3	Bus IB	Probability	Frequency
	Contingency Level = Ist										
6	9.6519	0	0	0	0	9	0	0	6	0.0011131	1.0102291
	Contingency Level = 2nd										
2	43.1968	1	16	0	0	0	0	0	0	0.0000653	0.0132368
3	50.0042	1	4	0	0	0	0	0	0	0.0002089	0.0365902
4	43.1968	1	16	0	0	0	0	0	0	0.0000653	0.0132368
5	4.9303	0	0	0	0	2	3	0	0	0.0000257	0.0456317
6	9.6519	0	0	0	0	9	0	0	6	0.0009875	0.8962790
	Contingency Level = 3rd										
2	43.1968	1	12	0	0	0	0	0	0	0.0000653	0.0132368
3	50.0042	1	2	0	0	0	0	0	0	0.0001967	0.0344645
4	43.1968	1	12	0	0	0	0	0	0	0.0000653	0.0132368
5	4.9303	0	0	0	0	2	3	0	0	0.0000257	0.0456317
6	9.6519	0	0	0	0	9	0	0	6	0.0009875	0.8962790
	Contingency Level = 4th										
2	43.1968	1	12	0	0	0	0	0	0	0.0000653	0.0132368
3	50.0042	1	2	0	0	0	0	0	0	0.0001967	0.0344645
4	43.1968	1	12	0	0	0	0	0	0	0.0000653	0.0132368
5	4.9303	0	0	0	0	2	3	0	0	0.0000257	0.0456317
6	9.6519	0	0	0	0	9	0	0	6	0.0009875	0.8962790

IB = Isolated Bus
MDLC = Maximum Duration Of Load Curtailment

Table 5-10: Average value of bus indices for the 6 bus test system at various contingency levels

BUS	Load Curtailed MW	Energy Curtailed MWh	Duration of Load Curtailment hrs
Contingency Level = Ist			
6	20.000	193.038	9.652
Contingency Level = 2nd			
2	0.524	22.620	43.197
3	9.869	294.813	29.872
4	2.950	72.858	24.698
5	1.065	5.242	4.921
6	20.000	187.016	9.351
Contingency Level = 3rd			
2	0.601	23.761	39.561
3	10.017	294.934	29.442
4	3.185	82.083	25.769
5	1.065	5.242	4.921
6	20.000	187.016	9.351
Contingency Level = 4th			
2	0.607	23.839	39.291
3	10.034	295.038	29.403
4	3.212	82.602	25.720
5	1.065	5.242	4.921
6	20.000	187.016	9.351

generating units as load curtailment pass 1 was utilized. Bus 5 experiences load interruption due to the line(s) outages only.

The marginal increment of the indices on buses 2 and 4, when the contingency level is increased from 2 to 3, is more pronounced as compared to that on bus 3. This is due to the fact that generating station 2 (bus 2) has smaller generating units (maximum rating is 20 MW), while generating station 1 (bus 1) has two larger units (40 MW each). Therefore buses that are affected by the outages of generators at generating station 2 alone, experience a system problem when 3 or more generators at bus 2 are out. The effect of the 4th level outage contingency is negligibly small at all system buses.

As seen from Table 5-6, system indices vary greatly from contingency level one to contingency level two, but from two to three the variation is relatively small. The variation in the system indices from the 3rd level to the 4th level is negligible as is the case with bus indices. It could, therefore, be concluded that from the system indices point of view, the 2nd contingency level is sufficient. On the other hand for indices of load points 2 and 4, the solution of 3rd contingency outages is required. This is also true for the average values of the bus indices as seen from Table 5-10. However, if the indices of interest are the maximum values, then the calculation of 4th level outage contingencies is recommended as noted from Table 5-7 to Table 5-9.

5.4.2 The IEEE RTS (Figure 2-2)

Figures 5-10, 5-11, 5-12, 5-13, 5-14 and 5-15 show various bus indices at different contingency levels for this system. No bus in the system experiences a problem if only one component is out of service. Even if two components are out, buses 1, 2, 3 and 7 do not experience any load interruption as seen from Figures 5-12 and 5-13. The remaining buses, however, experience load curtailment when two components are out of service. Buses 4, 5 and 6 experience total load curtailment whenever both the lines terminated at these buses are out of operation. Since the probability and the frequency of two lines being out of service are quite small, values of the expected load curtailed or the energy curtailed are also small.

Buses 1 and 7 do not experience any load curtailment due to the outages of two generating units anywhere in the system. However, buses in the north (230 KV region) experience load interruption when two large generating units are removed from the system. Since all the large generators are concentrated in the north region and because of the load curtailment philosophy described in Section 5.2, buses 13, 14, 15, 16, 18, 19 and 20 experience load curtailment. The amount of load curtailment is proportional to the load connected at each bus. Table 5-11 gives the number of load curtailments and the expected load curtailed in MW at each bus. As seen from Table

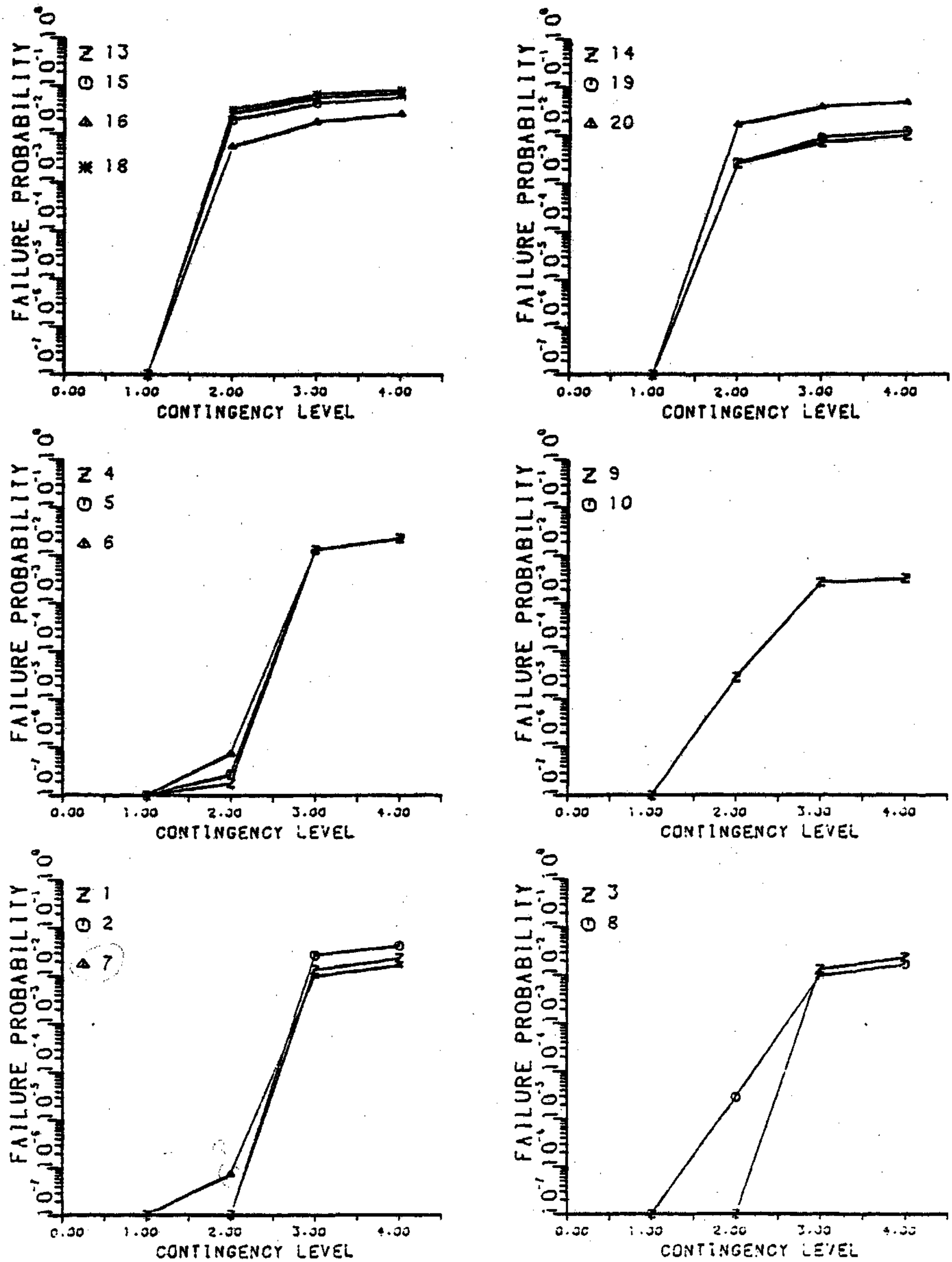

Figure 5-10: Probability of failure vs. contingency level
for the IEEE RTS

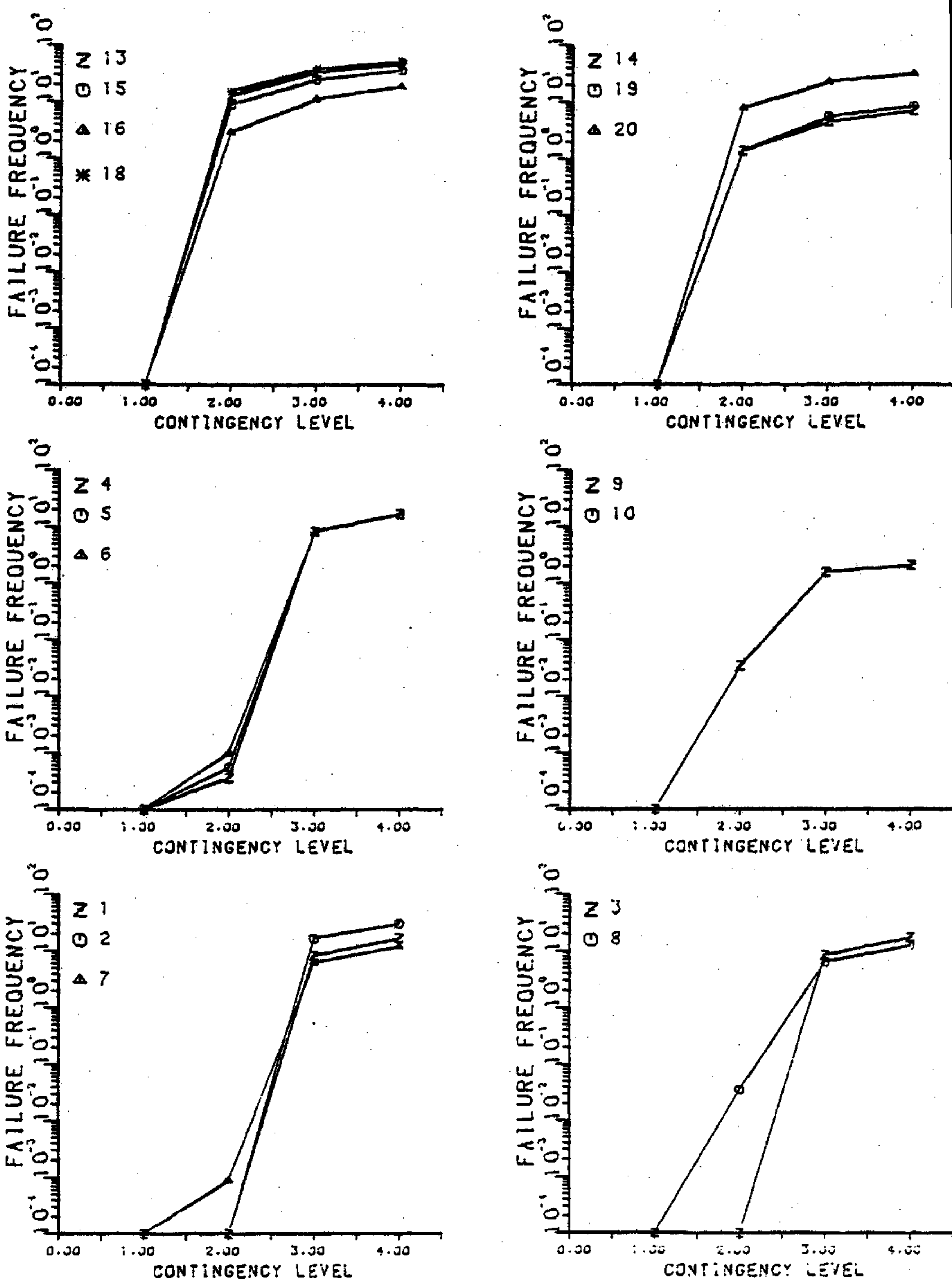

Figure 5-11: Frequency of failure vs. contingency level for the IEEE RTS

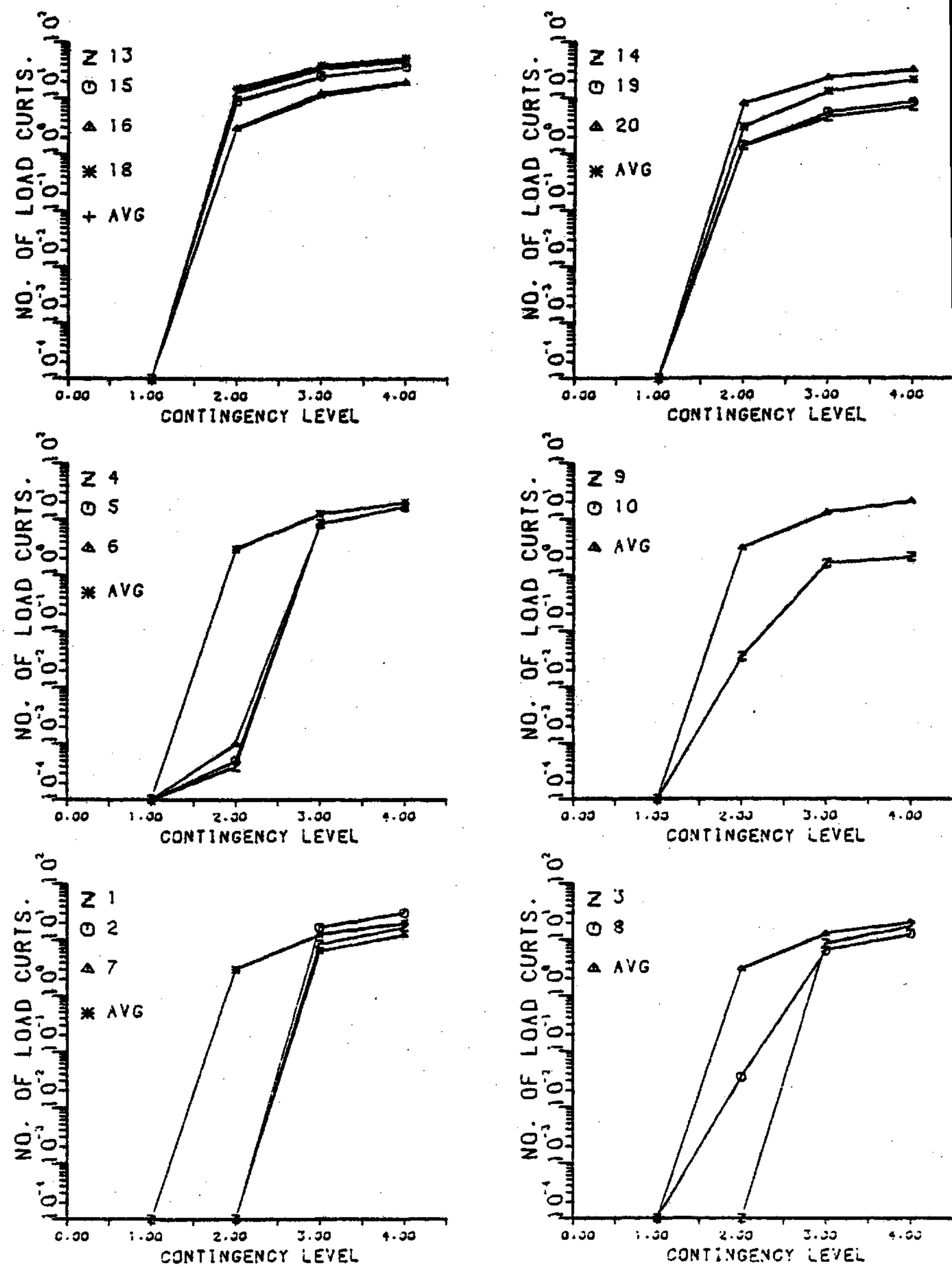

Figure 5-12: Number of load curtailments vs. contingency level for the IEEE RTS

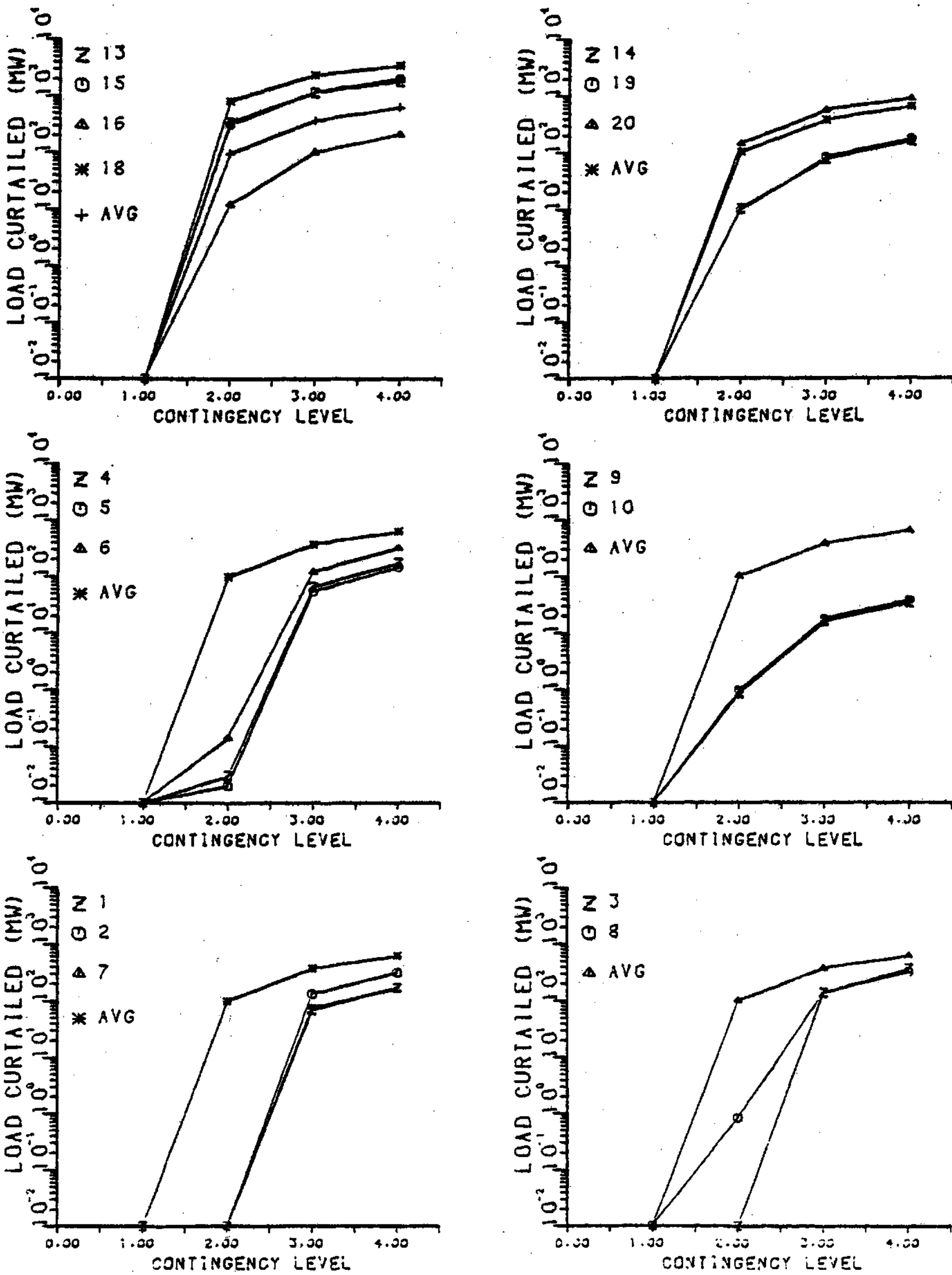

Figure 5-13: Expected load curtailed in MW vs. contingency level for the IEEE RTS

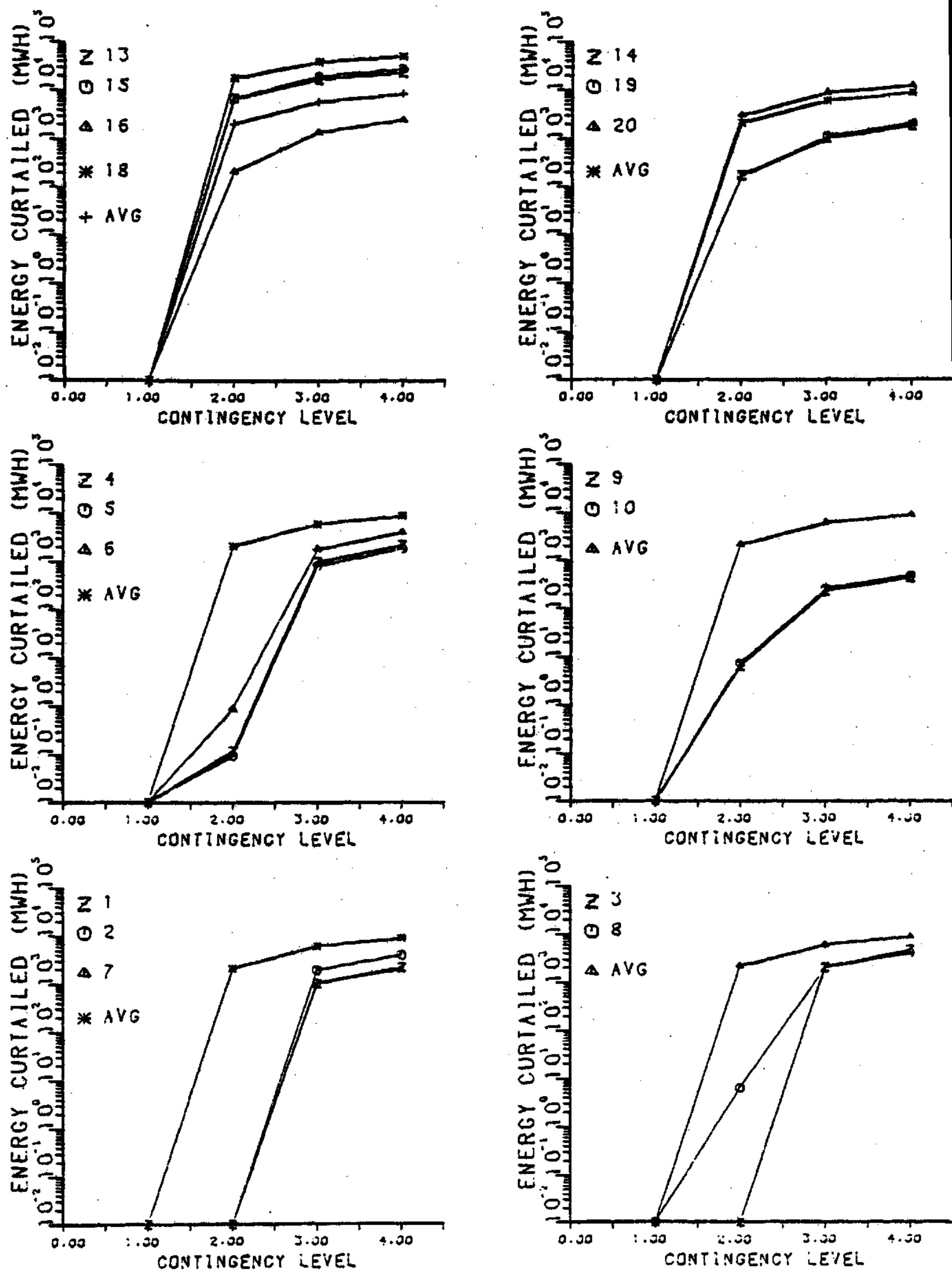

Figure 5-14: Expected energy curtailed in MWh vs. contingency level for the IEEE RTS

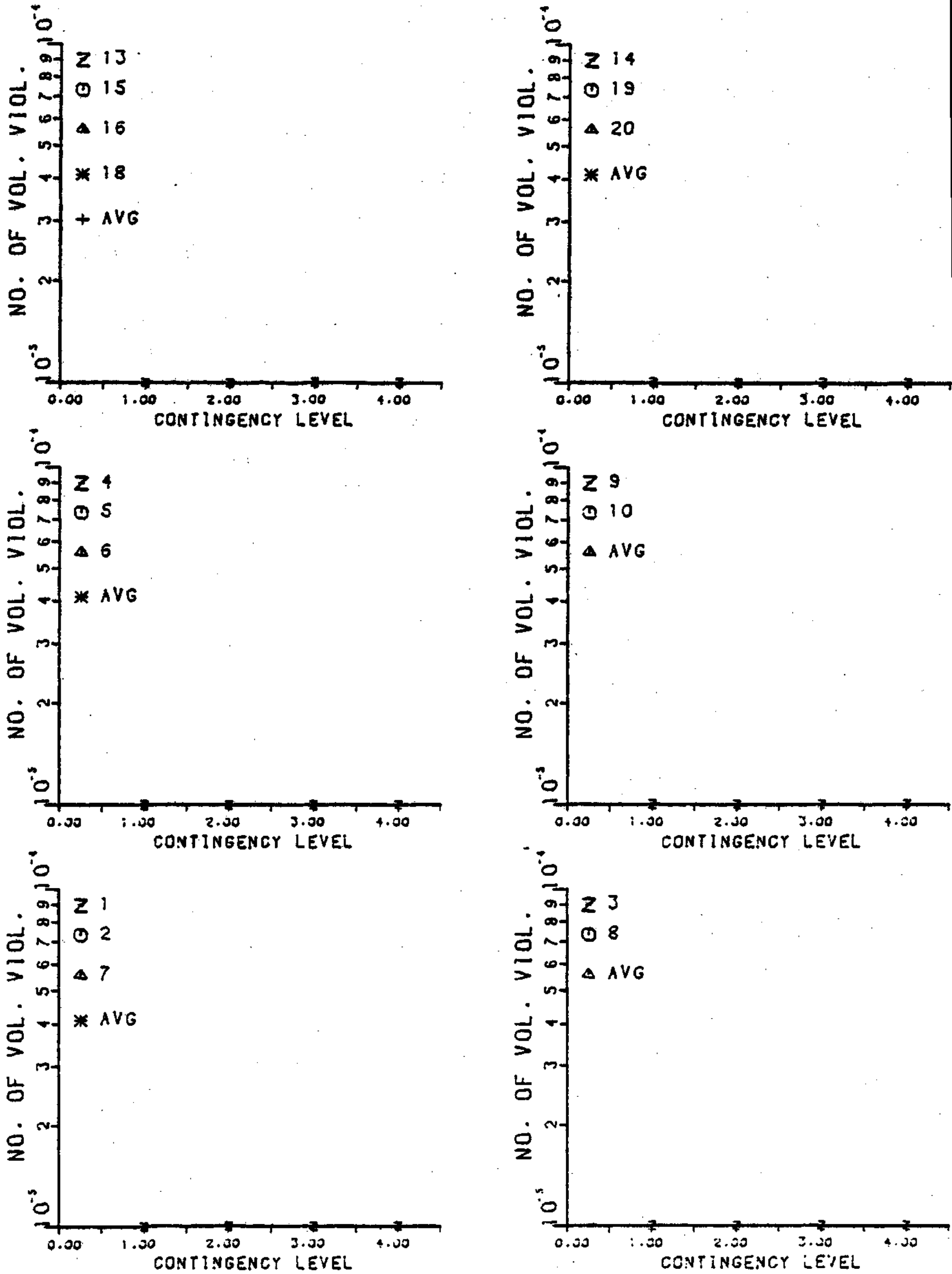

Figure 5-15: Number of voltage violations vs. contingency level for the IEEE RTS

Table 5-11: Annualized bus indices for the IEEE RTS at various contingency levels

Bus	Ist Cont. Actual Value	2nd Cont. Actual Value	3rd Cont. Actual Value	3rd Cont. Incr. w.r.t. 2nd Cont.	4th Cont. Actual Value	4th Cont. Incr. w.r.t. 2nd Cont.
Number of Load Curtailments						
1	0.0000	0.0000	8.2191		16.5930	
2	0.0000	0.0000	16.3514		30.0112	
3	0.0000	0.0000	8.2191		16.7308	
4	0.0000	0.0004	8.2194	20548.5	16.5443	41360.8
5	0.0000	0.0005	8.2195	16439.2	16.5935	33187.2
6	0.0000	0.0010	8.2201	8220.1	16.5449	16544.9
7	0.0000	0.0000	6.1201		11.9833	
8	0.0000	0.0340	6.1540	181.0	12.0172	353.5
9	0.0000	0.0340	1.5422	45.4	1.9868	58.4
10	0.0000	0.0340	1.5422	45.4	1.9868	58.4
13	0.0000	12.7885	33.3278	2.6	45.8370	3.6
14	0.0000	1.3643	4.3085	3.2	6.7082	4.9
15	0.0000	8.7939	24.1961	2.7	35.3866	4.0
16	0.0000	2.8818	10.9981	3.8	18.3530	6.4
18	0.0000	15.1452	38.2298	2.5	51.5144	3.4
19	0.0000	1.3639	5.2735	3.9	8.0516	5.9
20	0.0000	7.5523	21.6245	2.9	29.9752	4.0
Total Load Curtailed (MW)						
1	0.0000	0.0000	69.2099		171.5099	
2	0.0000	0.0000	130.1699		314.6499	
3	0.0000	0.0000	135.4799		369.2900	
4	0.0000	0.0300	65.0000	2166.7	172.4400	5748.0
5	0.0000	0.0200	53.4599	2673.0	145.2899	7264.5
6	0.0000	0.1400	119.5500	853.9	317.0000	2264.3
7	0.0000	0.0000	75.6900		160.4100	
8	0.0000	0.8300	137.1100	165.2	326.3299	393.2
9	0.0000	0.8500	15.4099	18.1	32.9000	38.7
10	0.0000	0.9500	17.1800	18.1	36.6599	38.6
13	0.0000	349.8500	1145.0300	3.3	1769.2199	5.1
14	0.0000	10.0699	74.0299	7.4	150.4900	14.9
15	0.0000	316.9200	1184.2600	3.7	1961.7900	6.2
16	0.0000	12.3199	100.6399	8.2	204.8999	16.6
18	0.0000	830.9699	2337.3400	2.8	3377.9299	4.1
19	0.0000	9.3199	80.3000	8.6	166.4400	17.9
20	0.0000	137.7500	550.2999	4.0	853.4099	6.2

Incr. = Increment   Cont. = Contingency

5-11, the values of the expected load curtailed are many times higher for buses in the north as compared to those in the south. Buses in the north experience load curtailment in the event of two generating unit outages while buses in the south experience load curtailment only when either three generating units are out or at least one line in combination with other component(s) is out. The load curtailment at buses 8, 9 and 10 for the 2nd outage level is due to the outage of line 11 in combination with the outage of any large (>350 MW) generating unit in the system. Whenever three generating units involving at least one unit from the south region are out of operation, buses in the south also encounter load interruption. At the same time, the amount of load curtailed at buses in the north also increases by at least 200% over its value at the 2nd outage contingency level.

The increment in the adequacy indices for buses in the south is tremendously high as seen from Table 5-11. This non-uniform trend in the variation of the adequacy indices also continues at the 4th outage level. It is quite clear from a study of Figures 5-10 to 5-15 and Table 5-11 that for this system, the calculation of the 4th level outage contingencies is necessary for both the bus indices and the system indices. Table 5-12 gives the system indices and the corresponding increment with respect to the 2nd outage level contingencies for this system. As observed from Table 5-12, the value of the severity index at the 4th outage level is approximately four

Table 5-12: System indices for the IEEE RTS at various contingency levels

Ist Cont.	2nd Cont.	3rd Cont.		4th Cont.	
Actual Value	Actual Value	Actual Value	Incr. w.r.t. 2nd Cont.	Actual Value	Incr. w.r.t. 2nd Cont.
Bulk Power Supply Disturbances					
0.000000	17.300449	46.026939	2.7	62.805328	3.6
Total Probability					
0.600226	0.838691	0.949944	1.1	0.982296	1.2
IEEE INDICES					
Bulk Power Interruption Index (MW/MW-Yr.)					
0.000000	0.585970	2.207070	3.8	3.694970	6.3
Bulk Power Energy Curtailment Index (MWh/Yr.)					
0.000000	12.348200	35.305061	2.9	51.167850	4.1
Bulk Power Supply Average MW Curtailment Index (MW/Disturbance)					
0.000000	96.530472	136.662155	1.4	167.671295	1.7
Modified Bulk Power Energy Curtailment Index					
0.000000	0.001410	0.004030	2.9	0.005841	4.1
Severity Index (System-Minutes)					
0.000000	740.892029	2118.303955	2.9	3070.071045	4.1
AVERAGE INDICES					
Av. No. of Hrs of Load Curtailment/Load Pt./Year					
0.000000	54.900379	181.011261	3.3	255.690826	4.7
Av. No. of Load Curtailments/Load Pt./Year					
0.000000	2.940810	12.397990	4.2	19.812851	6.7
Av. Load Curtailed/Load Pt./Year-MW					
0.000000	98.236504	370.008270	3.8	619.450073	6.3
Av. Energy Curtailed/Load Pt./Year-MWh					
0.000000	2070.139404	5918.790039	2.9	8578.140625	4.1

Incr. = Increment   Cont. = Contingency

times higher than the value at the 2nd outage level, while the value of the average load curtailed for each load point per year is more than six times the value at the 2nd outage level. This is due to the fact that the number of load curtailment contingencies increases tremendously as the outage level increases. This is shown in Table 5-13 which gives the actual number of contingencies for different outage events.

Table 5-13: Number of the contingencies for the IEEE RTS at various contingency levels

Description	Contingency Level Ist	2nd	3rd	4th
No. of generator contingencies	32	528	5488	41448
No. of line contingencies	38	741	741	741
No. of G-L contingencies considered	0	1178	1178	1178
No. of voltage violation contingencies	0	0	0	0
No. of MVAR limit violation contingencies	1	79	586	6281
No. of no-convergence contingencies	0	1	1	1
No. of load curtailment contingencies	0	28	787	11996
No. of bus isolation contingencies	1	75	75	75
No. of split network contingencies	0	1	1	1
No. of firm load curtailment contingencies	0	8	166	3240

The average values of the bus indices at different contingency levels are mainly influenced by the indices of the buses in the north (230 KV) region. The marginal increment of the average values of the adequacy indices may, therefore, give some idea about the behavior of the bus indices for buses in the north region but drawing any conclusion about the indices for buses in the south from the average values is highly misleading as seen from Figures 5-10 to 5-15. This is also the case with the system indices. Approximately 80% of the contribution to the system indices comes from buses in the north area. This reinforces the observation made earlier that it may be erroneous to draw conclusions about the bus indices from either system indices or average values of the bus indices.

5.5 Effect of the Load Variation on the Adequacy Indices

5.5.1 Introduction

In an actual system, the load does not stay at its peak value throughout a year. An evaluation of the system performance assuming a peak load model may therefore give highly pessimistic values for the adequacy indices. These indices, referred to as annualized indices, are useful for comparing the performance of two or more systems but do not convey accurate information about the absolute quantitative evaluation of a power system itself. Modeling the system load as a multistep load does provide more accurate results than the single step load model, however evaluation of the adequacy indices at various load levels increases the CPU time. Depending upon the number of steps, the CPU time could increase as many times as the number of steps.

A proper selection of the number of steps is primarily dictated by the shape of the load curve, the size of each step, the contribution of the lowest step load to the adequacy indices and the period for which the lowest step load exists.

This is due to the fact that even if the contribution of the lowest step load is quite low as compared to the highest step load but depending upon the duration for which each step load exists, the contribution of each step load to the annual indices may be comparable. Multistep load models for the 6 bus test system and for the IEEE RTS are discussed in Section 2.6. The effect of varying load on the system indices and on the individual load point indices is discussed in this section. An attempt has been made to determine the proper number of load steps that are required to calculate the system adequacy for both systems.

While assigning values of the active and reactive load at each bus for each step system load, it has been assumed that the load at each bus varies in proportion to the system load. If the system peak load is X and the corresponding peak loads at buses i and j are X_i and X_j then for a step system load of Y, the corresponding step load at bus i is,

$$Y_i = X_i(Y/X)$$

and

$$\text{reactive load} = Y_i \tan \phi_i$$

where ϕ_i is load power factor angle at bus i.

and at bus j, the real load is

$$Y_j = X_j(Y/X)$$

and

$$\text{reactive load} = Y_j \tan \phi_j$$

where ϕ_j is load power factor angle at bus j.

Numerical values of the active load at each bus are shown in Table 5-14 and Table 5-15 for the 6 bus test system and the IEEE RTS respectively. In practical situations this load correlation may not exist and in fact there could be many ways in which the system load is shared between the system buses. In such cases, if the load pattern at each individual bus is known, adequacy indices can be evaluated for the specific values of real and reactive loads. The effect of the load variation on the 6 bus test system and on the IEEE RTS is discussed in the following sections.

5.5.2 The 6 Bus Test System

Table 5-14 gives values of the real load in MW at each bus in the system. A four step load model was used to study the effect of load variation on this system as noted in Section 2.6. Figure 5-16 shows the variation in the adequacy indices with the system load. Numerical values of these bus indices and the corresponding decrement in their values with respect to the values at the system peak load (185 MW) are given in Table 5-16. The adequacy indices for buses 2, 3 and 4 decrease sharply as the load decreases. Bus 5 and bus 6 indices are mainly due to the isolation of the respective buses because of transmission line outages, while indices of buses 2, 3 and 4 are heavily influenced by the generating unit outages. As the system load decreases, the capacity deficiency in the system due to the generator outages also decreases, therefore the system problem can be alleviated by curtailing a smaller amount of load at buses. On the other hand, in the

Table 5-14: Bus loads in MW for the four step load model of the 6 bus test system

Bus	Step Number			
	Ist	2nd	3rd	4th
2	20.0	17.8	15.7	13.5
3	85.0	75.8	66.6	57.5
4	40.0	35.7	31.4	27.0
5	20.0	17.8	15.7	13.5
6	20.0	17.9	15.6	13.5
Total	185.0	165.0	145.0	125.0

Table 5-15: Bus loads in MW for the 13 step load model of the IEEE RTS

	Step Number												
Bus	Ist	2nd	3rd	4th	5th	6th	7th	8th	9th	10th	11th	12th	13th
1	108	100	95	90	85	80	75	70	65	60	55	45	40
2	97	95	90	85	75	70	65	60	55	50	45	40	35
3	180	170	160	150	140	130	125	115	105	95	85	75	65
4	74	70	65	60	60	55	50	45	40	35	35	35	30
5	71	65	65	60	55	50	50	45	40	35	35	30	30
6	136	130	120	110	105	100	95	85	80	75	65	55	50
7	125	120	110	100	100	95	85	80	75	70	60	55	45
8	171	160	150	145	135	125	115	110	100	90	80	70	65
9	175	165	155	145	140	130	120	110	100	90	80	75	65
10	195	185	175	160	155	145	135	125	115	105	95	85	70
13	265	255	240	225	210	195	180	165	150	135	125	110	100
14	194	185	175	165	155	145	130	120	110	100	90	80	70
15	317	300	285	275	250	235	215	200	185	170	150	135	115
16	100	95	90	85	80	75	70	65	60	55	50	45	40
18	333	315	300	285	265	245	225	210	190	175	160	140	125
19	181	170	160	150	140	130	125	115	105	95	85	75	65
20	128	120	115	110	100	95	90	80	75	65	60	55	50
Total	2850	2700	2550	2400	2250	2100	1950	1800	1650	1500	1350	1200	1050

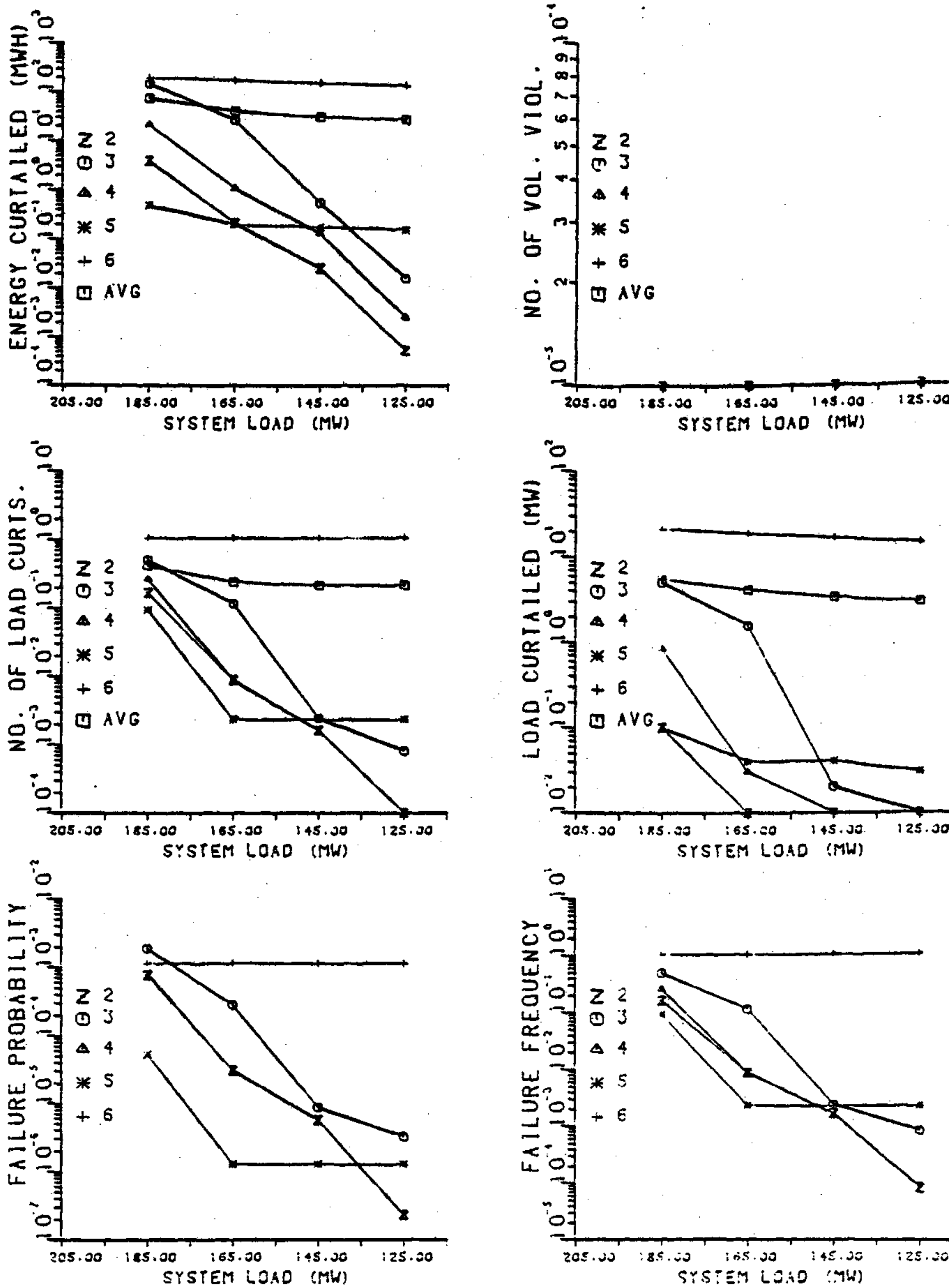

Figure 5-16: Adequacy indices vs. system load
for the 6 bus test system

Table 5-16: Bus indices for the 6 bus test system at various load levels

Bus	185 (1) Actual Value	165 (2) Actual Value	Decr. w.r.t. (1)	145 (3) Actual Value	Decr. w.r.t. (1)	125 (4) Actual Value	Decr. w.r.t. (1)
	Failure Probability						
2	0.000763	0.000030	0.04	0.000005	0.01	0.000000	0.00
3	0.001847	0.000277	0.15	0.000008	0.00	0.000003	0.00
4	0.000817	0.000030	0.04	0.000005	0.01	0.000000	0.00
5	0.000052	0.000001	0.02	0.000001	0.02	0.000001	0.02
6	0.001128	0.001128	1.00	0.001128	1.00	0.001128	1.00
	Failure Frequency						
2	0.164284	0.008716	0.05	0.001611	0.01	0.000081	0.00
3	0.498228	0.114349	0.23	0.002359	0.00	0.000814	0.00
4	0.260241	0.008716	0.03	0.001611	0.01	0.000081	0.00
5	0.093092	0.002266	0.02	0.002266	0.02	0.002266	0.02
6	1.056754	1.056753	1.00	1.056753	1.00	1.056753	1.00
	Total Load Curtailed (MW)						
2	0.10000	0.01000	0.10	0.00000	0.00	0.00000	0.00
3	5.00000	1.55999	0.31	0.02000	0.00	0.00000	0.00
4	0.84000	0.03000	0.04	0.00000	0.00	0.00000	0.00
5	0.10000	0.04000	0.40	0.04000	0.40	0.03000	0.30
6	21.13999	18.92000	0.89	16.48999	0.78	14.27000	0.68
	Total Energy Curtailed (MWh)						
2	3.91640	0.21090	0.05	0.02540	0.01	0.00050	0.00
3	146.99620	26.62019	0.18	0.53810	0.00	0.01520	0.00
4	21.49640	1.06890	0.05	0.12770	0.01	0.00240	0.00
5	0.48800	0.19810	0.41	0.17470	0.36	0.15020	0.31
6	197.63009	176.87899	0.90	154.15150	0.78	133.40029	0.67

Decr. = Decrement

case of line outages, an isolated bus experiences total load curtailment unless there is local generation at the isolated bus. In a system which frequently encounters line overloads, the adequacy indices decrease as the system load is reduced. The 6 bus test system under study, however, does not frequently involve line overload situations.

The decrement in the amounts of load interrupted for buses 2, 3 and 4 is not uniform. The amount of load curtailed at buses 2 and 4 for a system peak load of 165 MW is approximately 10% and 4% respectively of the amount curtailed when the system peak load is 185 MW. In the case of bus 3 this value is 31%. If the system peak load is further reduced to 145 MW, the amount of load curtailed at these buses is less than 0.5% of the amount curtailed when the system peak load is 185 MW. Therefore, the decrement in the amount of load interrupted for buses 2 and 4 is faster than for bus 3, if the system peak load is reduced to 165 MW from 185 MW. In the case of the next load step reduction (165 MW to 145 MW), the situation reverses. This is due to the fact that buses 2 and 4 do not encounter load curtailment due to the outages of only two generating units anywhere in the system when the system peak load is 165 MW. However at this system peak load, bus 3 does experience load curtailment because of the outages of 2 generating units of 40 MW each connected at bus 1. Bus 3 does not encounter load curtailment due to outages of two units alone if the system load is 145 MW. At 125 MW of system load, the load curtailed or the energy curtailed at buses 2, 3 and 4 is negligibly small as seen from Figure 5-16 and Table 5-16.

Table 5-17 gives the system indices at different load levels. Bus average indices (Figure 5-16) and the system indices shown in Table 5-17 also decrease as system load decreases but the variation pattern of these indices as compared to the bus indices is entirely different and as such no meaningful information can be obtained about bus indices by merely studying the system or average indices.

Adequacy indices, discussed so far, have been calculated by assuming the system load to remain constant for the entire period of study of one year. A more representative set of indices, known as annual indices were discussed in Chapter 2, and have been calculated for the four step load model. Table 5-18 shows the bus indices, their average values and the system indices for this system. Except for bus 5 and bus 6, the annual bus indices are greatly reduced as compared to the annualized indices calculated at the system peak load of 185 MW. The average bus indices and the system indices are also reduced. A comparative study of the annualized and the annual indices is shown in Table 5-19. The quantities in brackets represent the percentile annual indices in terms of the annualized indices. For the three buses 2, 3 and 4, whose indices are mainly due to the outages of the generating units, the annual indices are approximately 30% of the respective

Table 5-17: System indices for the 6 bus test system at various load levels

System Load In MW						
185 (1) Actual Value	165 (2) Actual Value	Decr. w.r.t. (1)	145 (3) Actual Value	Decr. w.r.t. (1)	125 (4) Actual Value	Decr. w.r.t. (1)
Bulk Power Supply Disturbances						
1.558220	1.168840	0.75	1.056850	0.68	1.055300	0.68
Total Probability						
0.999752	0.999752	1.00	0.999752	1.00	0.999752	1.00
IEEE INDICES						
Bulk Power Interruption Index (MW/MW-Yr.)						
0.146860	0.124570	0.85	0.114090	0.78	0.114380	0.78
Bulk Power Energy Curtailment Index (MWh/Yr.)						
2.002850	1.242290	0.62	1.069090	0.53	1.068550	0.53
Bulk Power Supply Average MW Curtailment Index (MW/Disturbance)						
17.435980	17.435980	1.00	15.652839	0.90	13.548130	0.78
Modified Bulk Power Energy Curtailment Index						
0.000229	0.000141	0.62	0.000122	0.53	0.000122	0.53
Severity Index (System-Minutes)						
120.170998	74.537002	0.62	64.144996	0.53	64.112999	0.53
AVERAGE INDICES						
Av. No. of Hrs of Load Curtailment/Load Pt./Year						
8.066130	2.566220	0.32	2.008990	0.25	1.980490	0.25
Av. No. of Load Curtailments/Load Pt./Year						
0.414520	0.238160	0.57	0.212920	0.51	0.212000	0.51
Av. Load Curtailed/Load Pt./Year-MW						
5.433830	4.110930	0.76	3.308530	0.61	2.859469	0.53
Av. Energy Curtailed/Load Pt./Year-MWh						
74.105423	40.995418	0.55	31.003480	0.42	26.713720	0.36

Decr. = Decrement

Table 5-18: Annual indices for the 6 bus test system ~~at various load levels~~

Bus	Failure Probability	Failure Frequency	No. of Load Curts.	Load Curtailed (MW)	Energy Curtailed (MWh)	Duration of Load Curts. (Hrs)
2	0.00019973	0.0436734	0.0437	0.03	1.0383	1.7497
3	0.00053394	0.1539378	0.1539	1.64	43.5424	4.6774
4	0.00021323	0.0676626	0.0676	0.22	5.6739	1.8679
5	0.00001405	0.0249726	0.0250	0.05	0.2528	0.1231
6	0.00112803	1.0567536	1.0568	17.71	165.5152	9.8815

BUS INDICES AVERAGES

Bus	Load Curtailed MW	Energy Curtailed MWh	Duration of Load Hrs
2	0.630	23.773	37.756
3	10.687	282.881	26.470
4	3.215	83.871	26.087
5	2.100	10.110	4.814
6	16.753	156.619	9.349

S Y S T E M I N D I C E S

Bulk Power Supply Disturbances = 1.20980

IEEE INDICES

0.124975
1.345695

Bulk Power Interruption Index = 0.10620 MW/MW-Yr
Bulk Power Energy Curtailment Index = 1.16769 MWh/Yr
Bulk Power Supply Average MW Curt. Index = 16.24026 MW/Dist. 16.0182
Modified Bulk Power Energy Curt. Index = 0.00013330
Severity Index = 70.061 System-Min.

80.7415

SYSTEM INDICES AVERAGES

Av. No. of Load Curtailments/Load Pt./Year = 0.26941
Av. No. of Voltage Violations/Load Pt./Year = 0.00000 3.9782
Av. Load Curtailed/Load Pt./Year = 3.92950 MW
Av. Energy Curtailed/Load Pt./Year = 43.20451 MWh
Av. No. of Hrs of Load Curt./Load Pt./Year = 3.65991 Hrs

Curt. = Curtailment Av. = Average

Table 5-19: Annual & annualized indices for the 6 bus test system - a comparative analysis

	No. of Load Curtailments		Expected Load Curtailed (MW)	
Bus No.	Annualized Indices	Annual Indices	Annualized Indices	Annual Indices
2	0.1643	0.0437 (26.6%)	0.1000	0.030 (30.0%)
3	0.4982	0.1539 (30.9%)	5.0000	1.640 (32.8%)
4	0.2602	0.0676 (26.0%)	0.8400	0.220 (26.2%)
5	0.0931	0.0250 (26.9%)	0.1000	0.050 (50.0%)
6	1.0568	1.0568 (100.0%)	21.1399	17.710 (83.8%)

annualized indices at the the system peak load of 185 MW. The annual and the annualized number of load curtailments for bus 6 are equal. Bus 6 encounters total load interruption irrespective of the system load level, whenever line 9 is removed. The calculation of the annual indices is computationally expensive, but in absolute terms these indices do provide more accurate information regarding the performance of a system.

5.5.3 The IEEE RTS (Figure 2-2)

The 13 step load model discussed in Section 2.6 was used to study the effect of load variation for this system. Numerical values of bus loads in MW are given in Table 5-15. Figures 5-17 to 5-22 show the variation in the bus adequacy indices for different system load levels. It is obvious that the bus indices, in general, decrease as the system load decreases. The decrement in indices, however, is not uniform for all buses in the system.

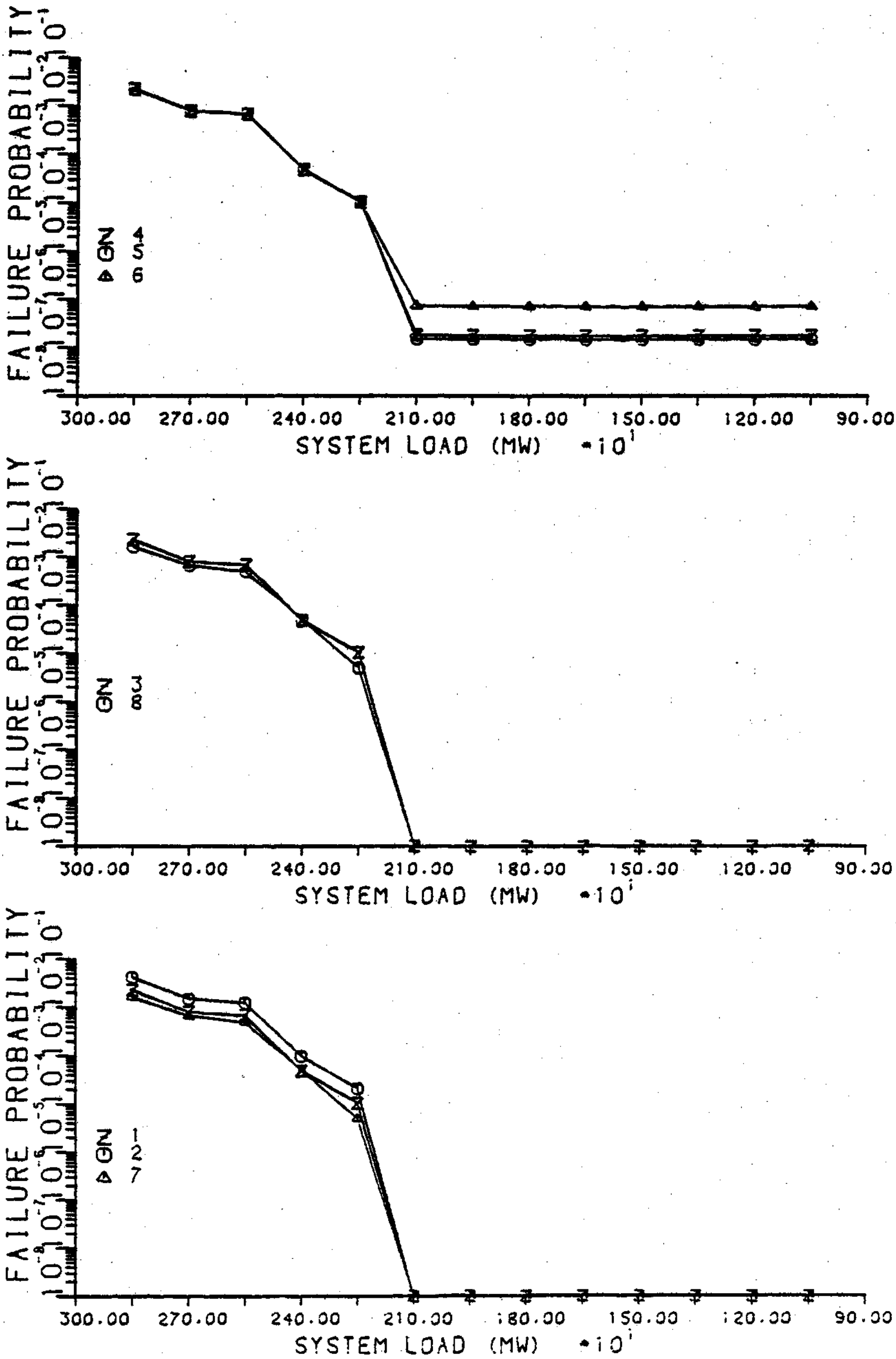

Figure 5-17: Probability of failure vs. system load for the IEEE RTS

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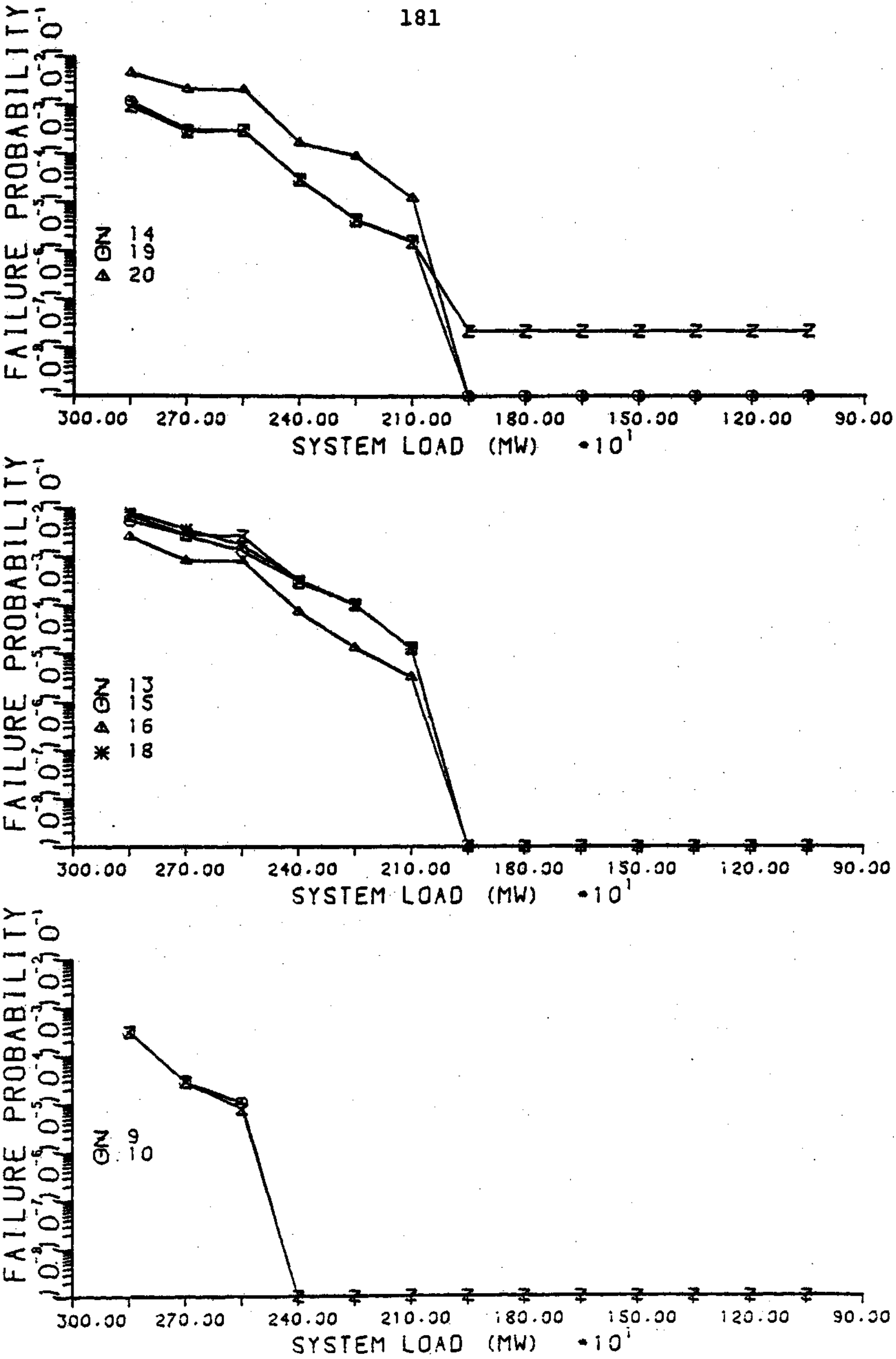

Figure 5-17: Probability of failure vs. system load for the IEEE RTS

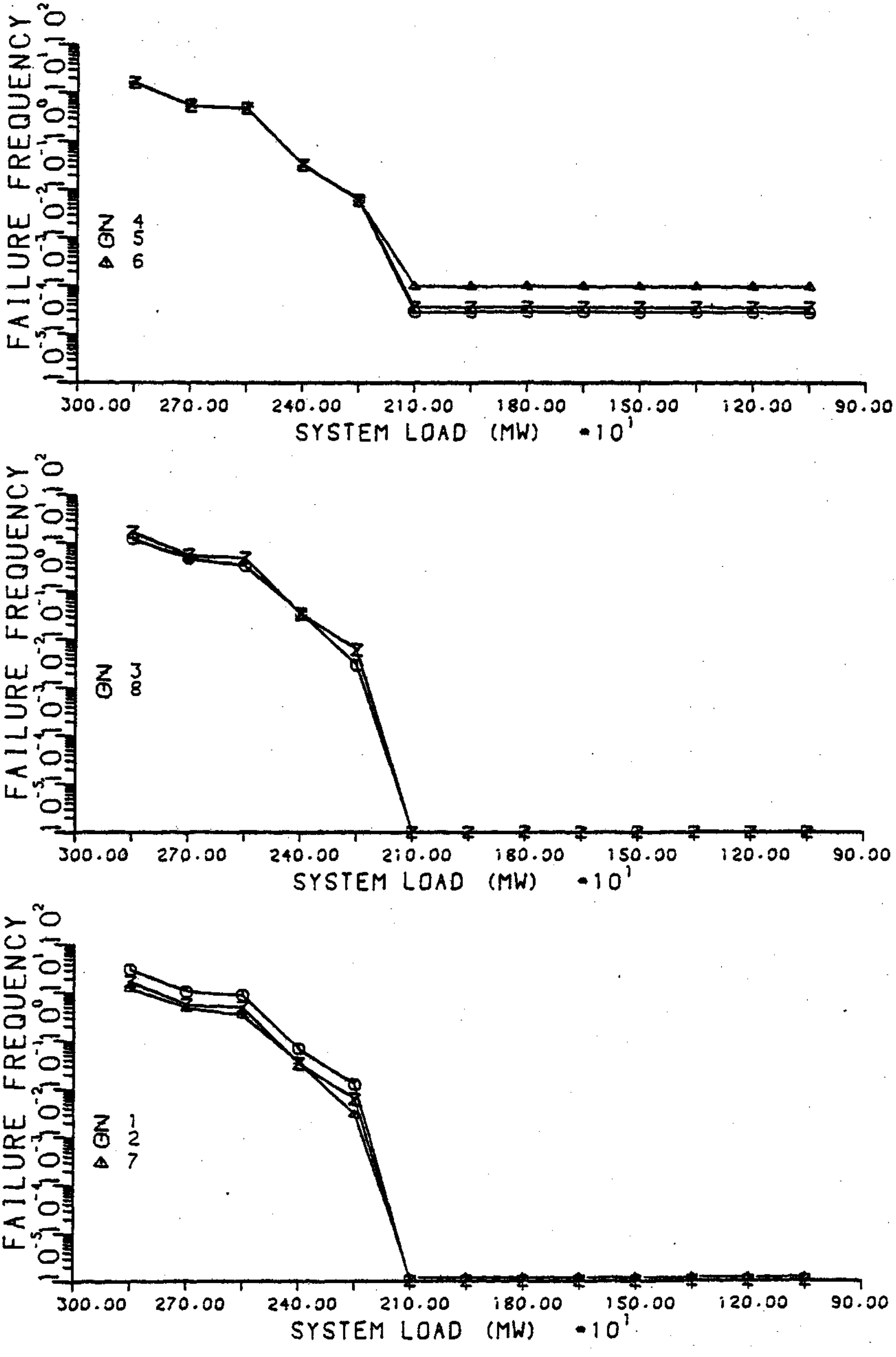

Figure 5-18: Frequency of failure vs. system load
for the IEEE RTS

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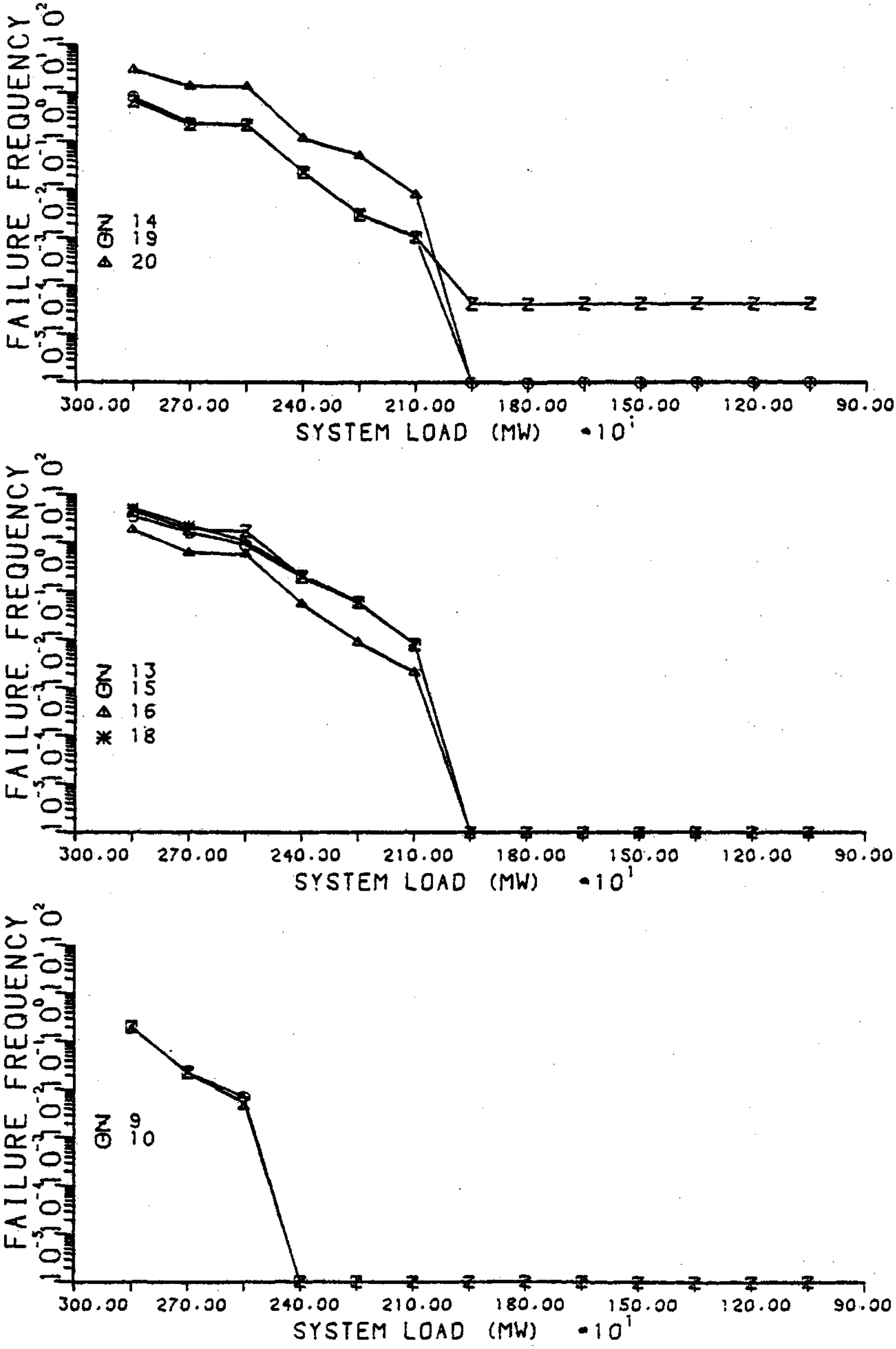

Figure 5-18: Frequency of failure vs. system load for the IEEE RTS

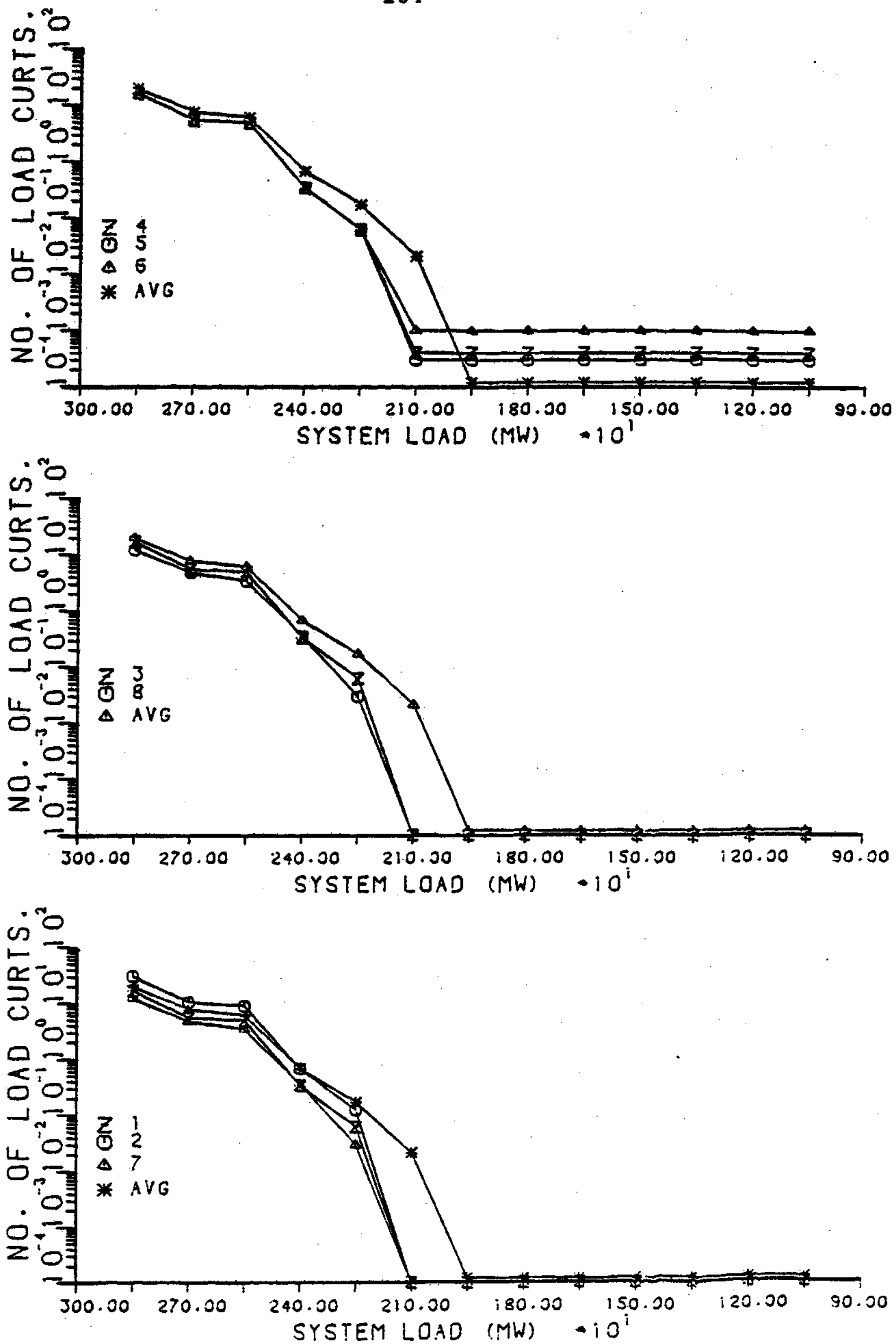

Figure 5-19: Number of load curtailments vs. system load for the IEEE RTS

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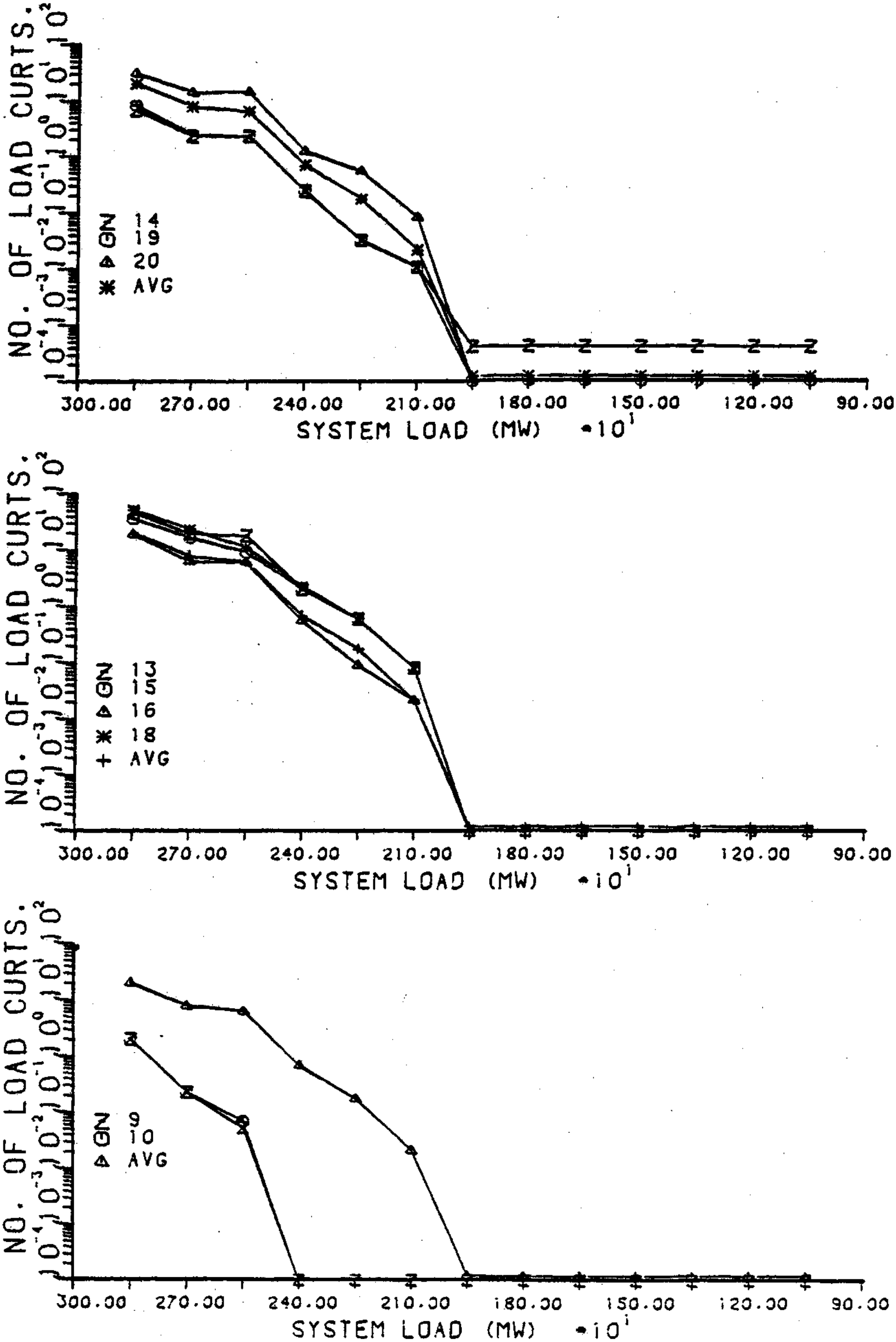
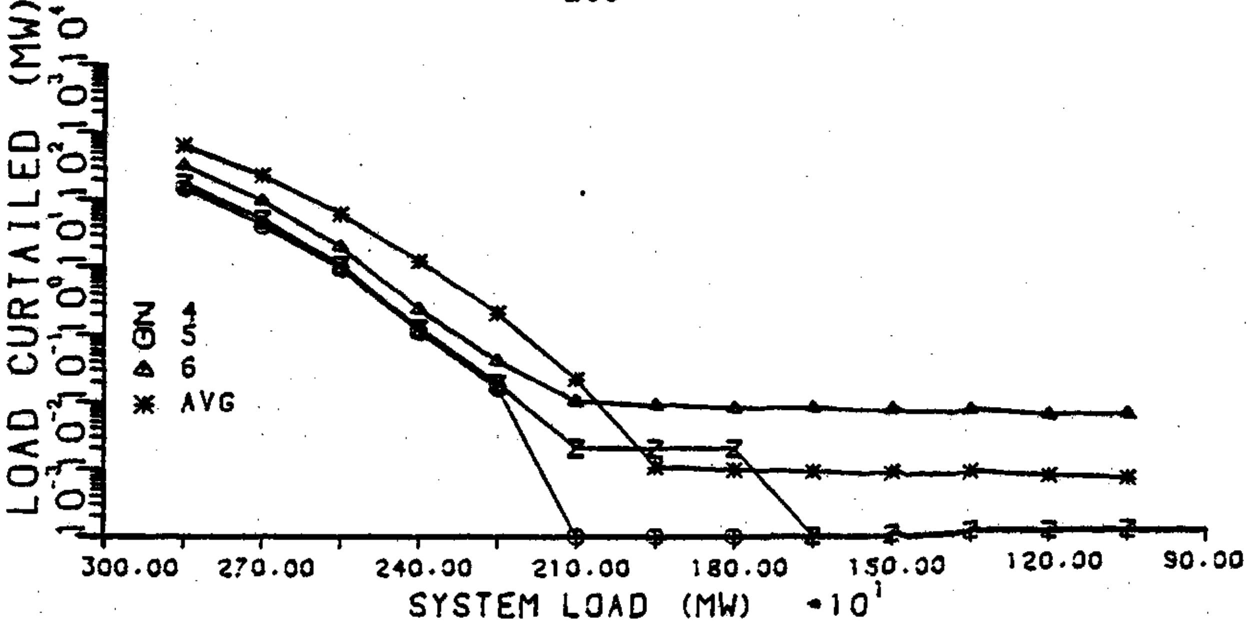
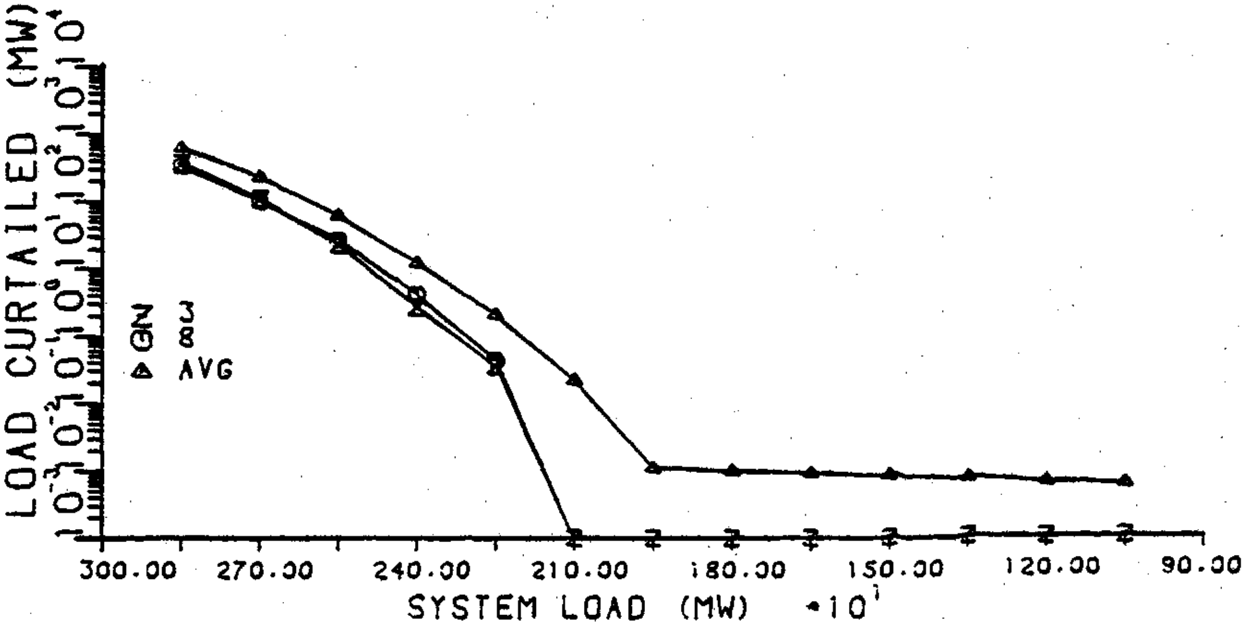


Figure 5-19: Number of load curtailments vs. system load for the IEEE RTS





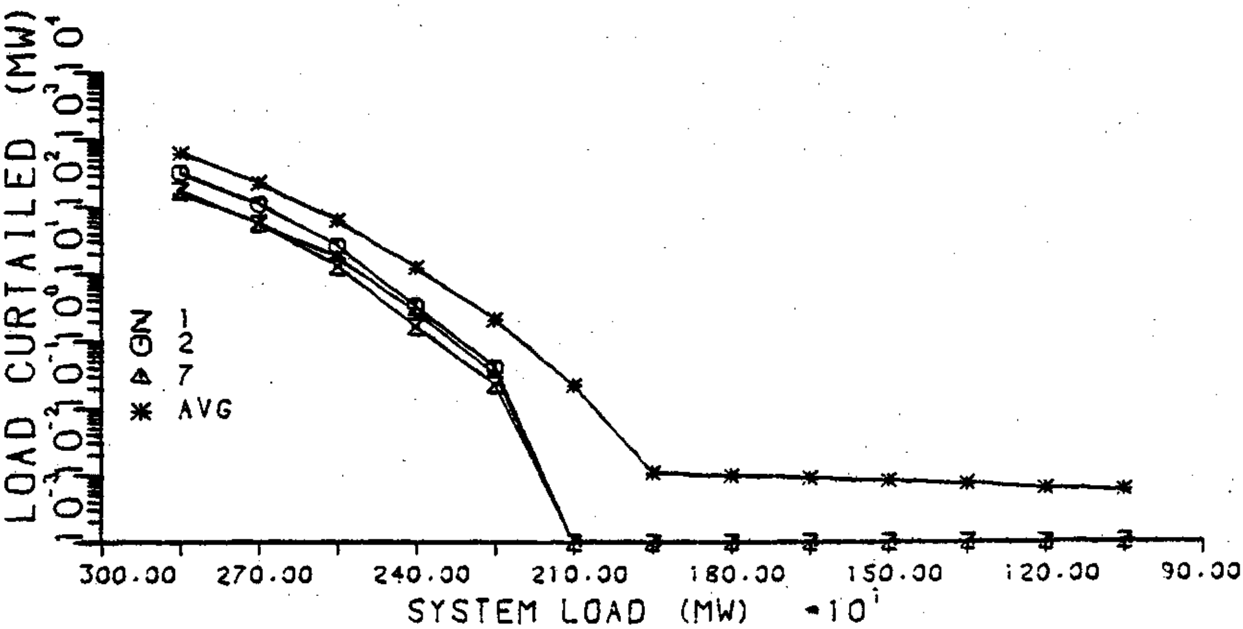


Figure 5-20: Expected load curtailed in MW
vs. system load for the IEEE RTS Contd.

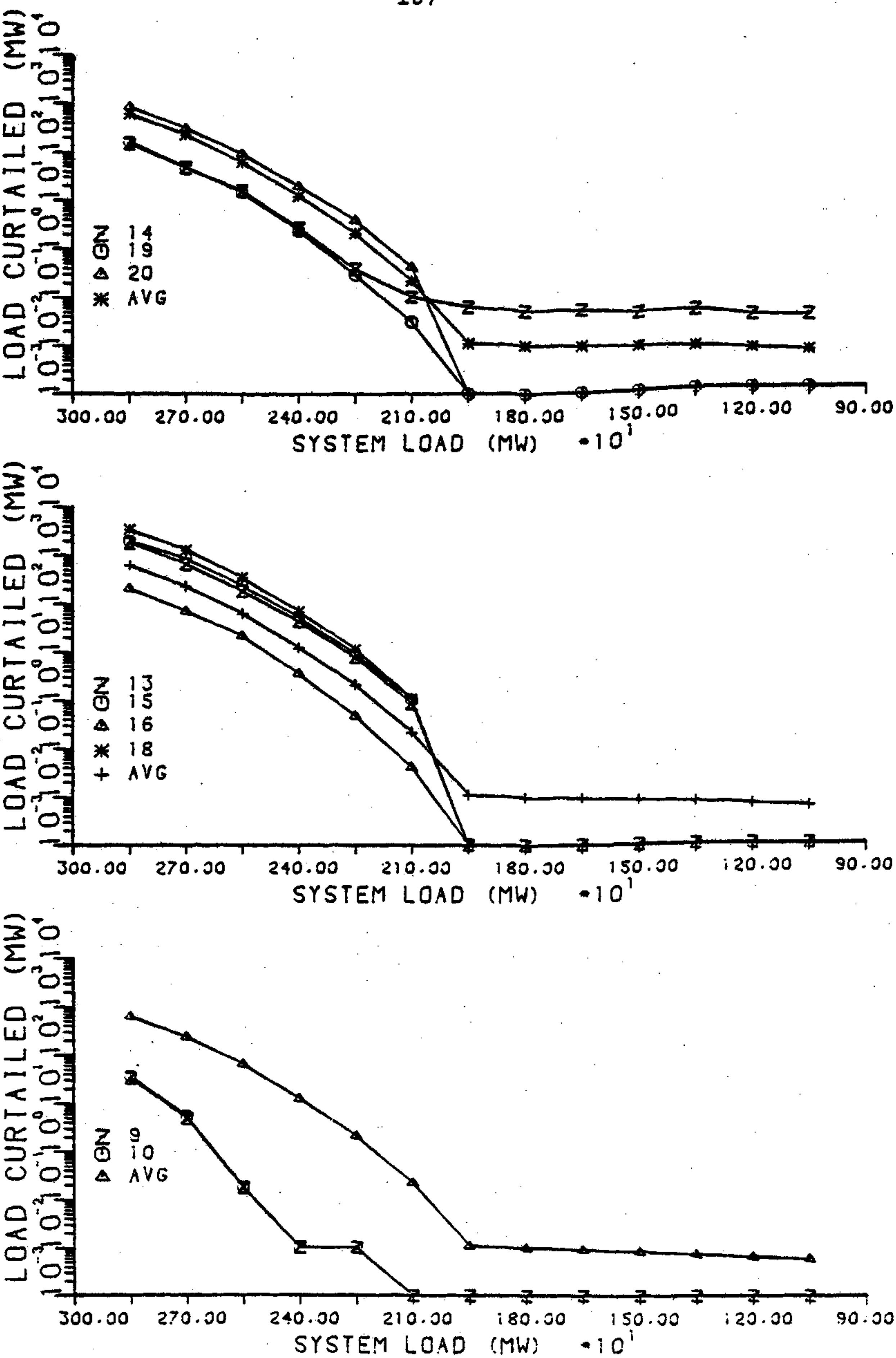
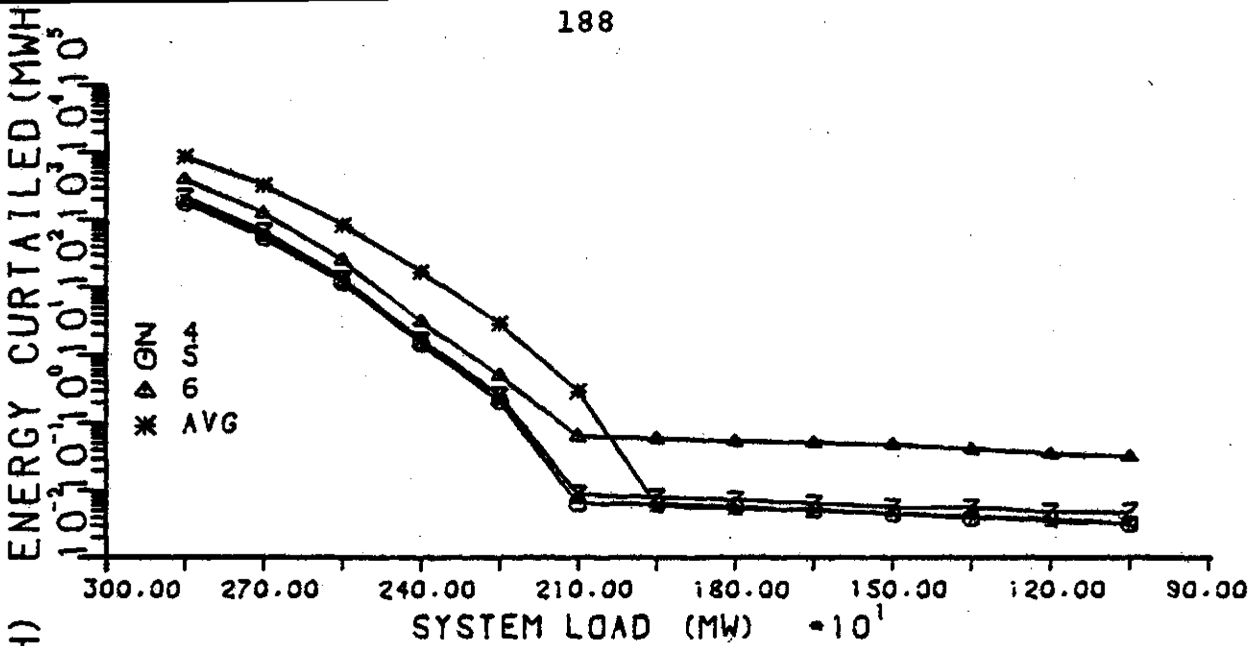
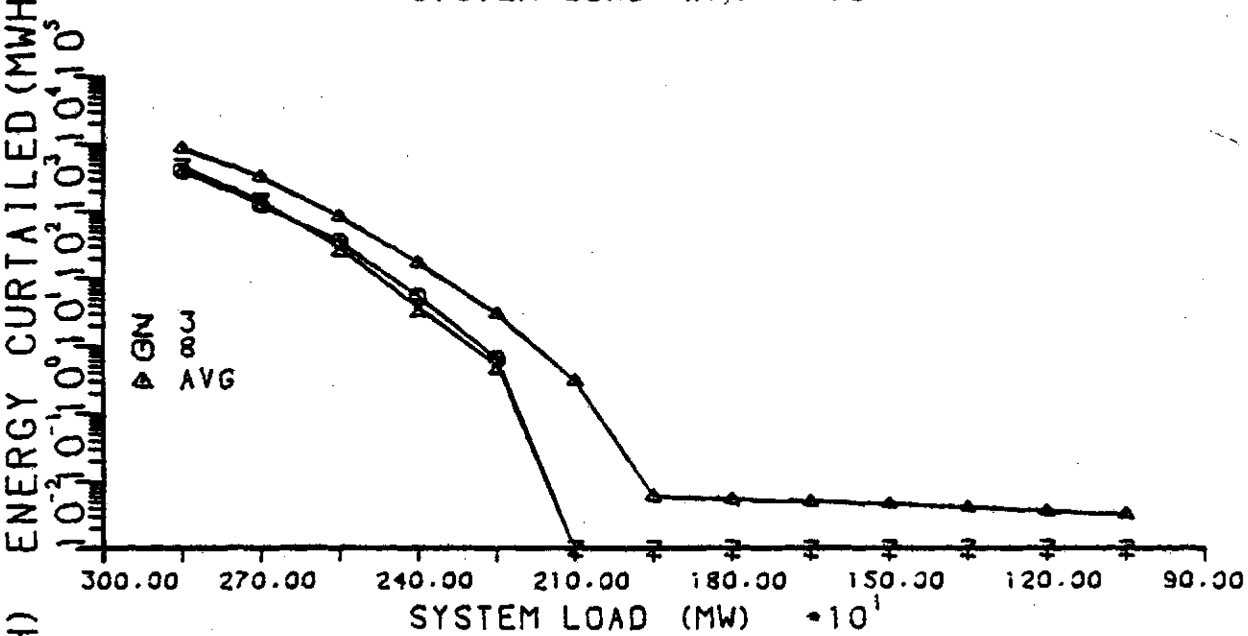


Figure 5-20: Expected load curtailed in MW
vs. system load for the IEEE RTS





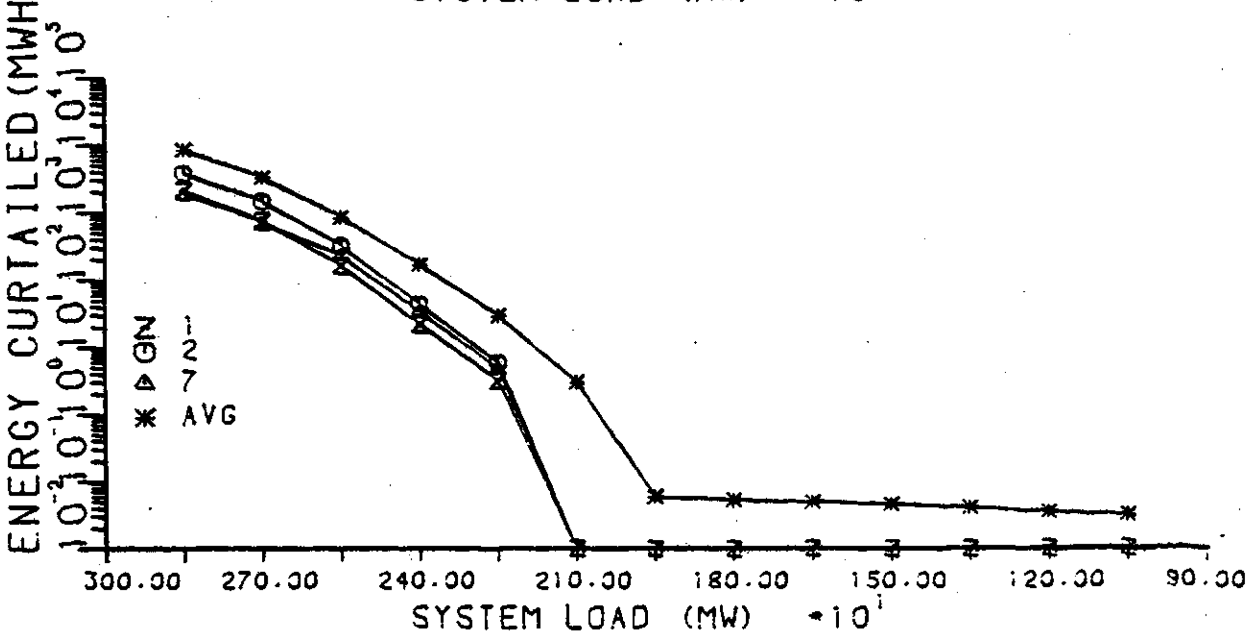


Figure 5-21: Expected energy curtailed in MWh
vs. system load for the IEEE RTS

Contd.

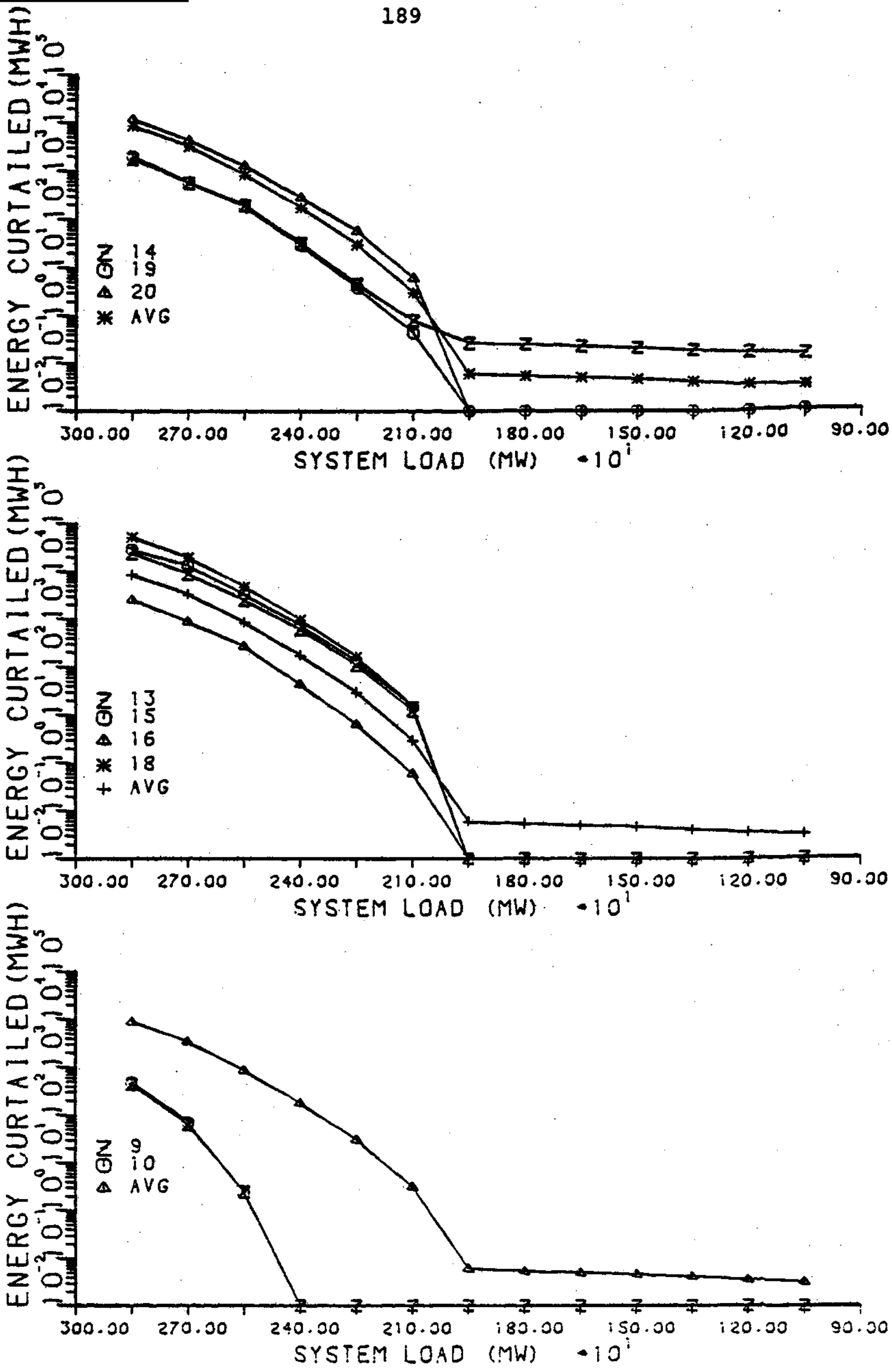


Figure 5-21: Expected energy curtailed in MWh vs. system load for the IEEE RTS

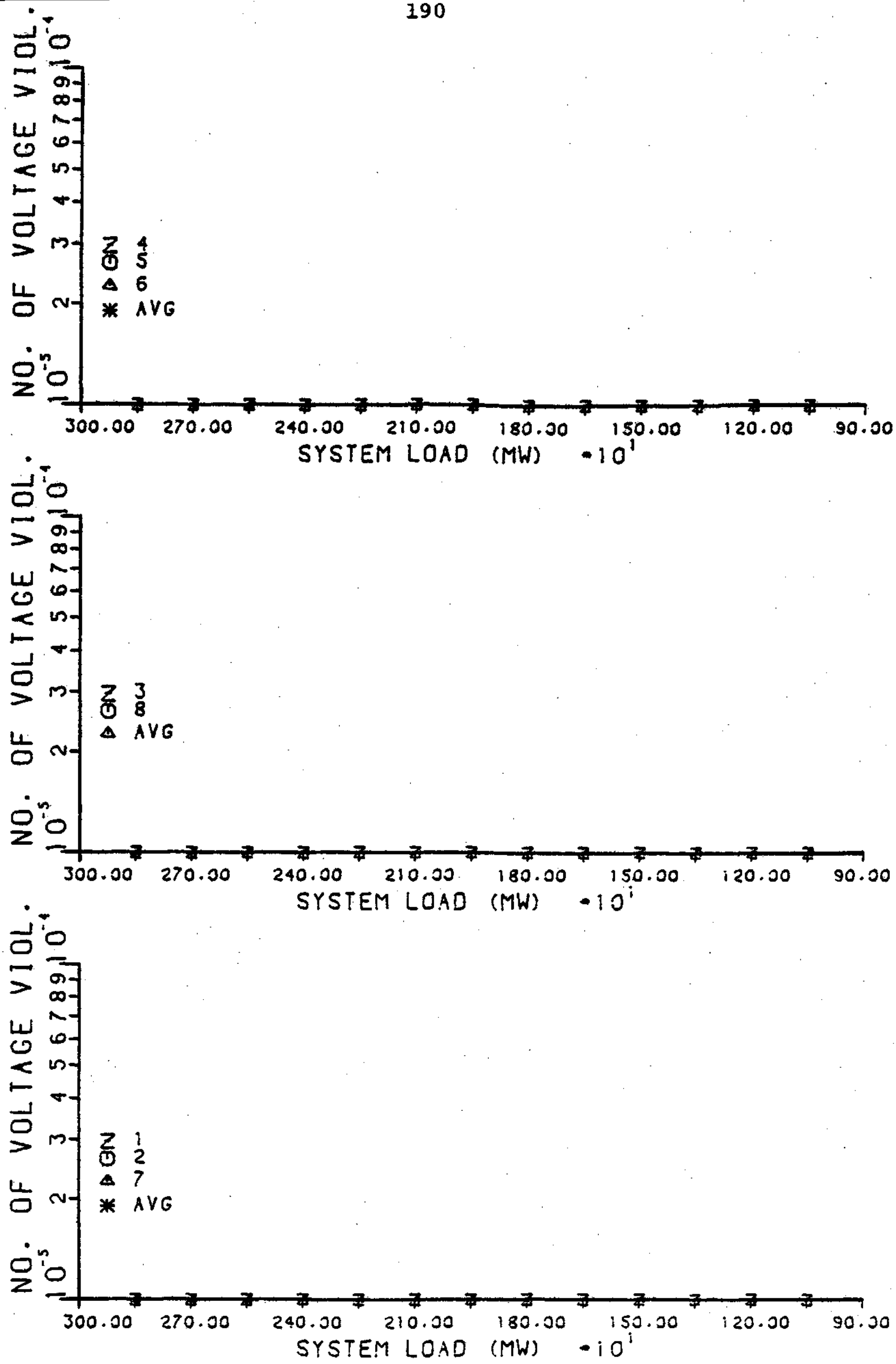


Figure 5-22: Number of voltage violations vs. system load for the IEEE RTS

Contd.

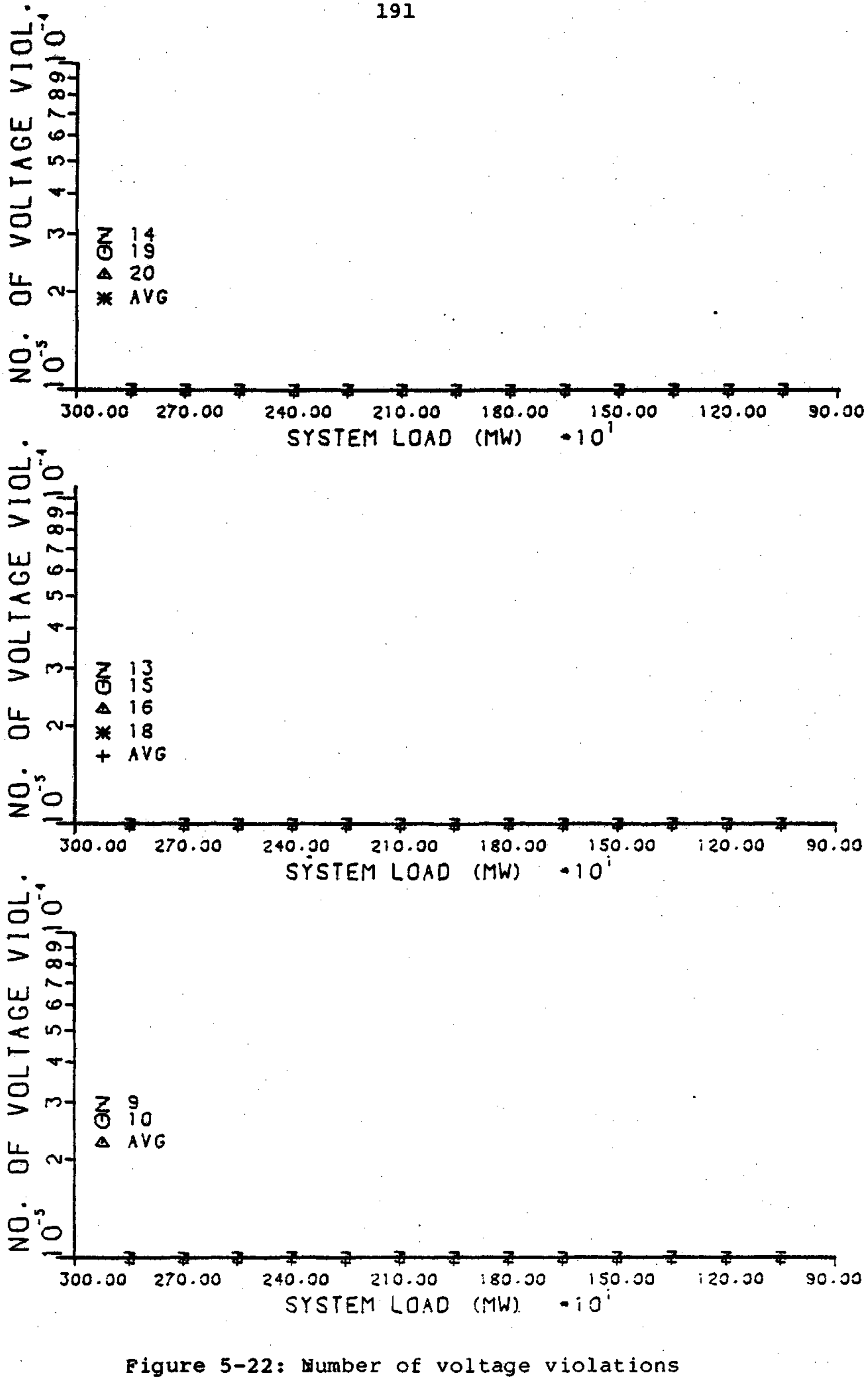


Figure 5-22: Number of voltage violations vs. system load for the IEEE RTS

One of the most obvious observations that can be made from Figures 5-17 to 5-22 is that the indices for all system buses except buses 4, 5, 6 and 14 are quite small if the system load drops to 1950 MW. As seen from the single line diagram of the IEEE RTS (Figure 2-2), all these four buses are connected by two lines to other buses in the system. Therefore whenever those two lines are out of service, these buses experience total load interruption as none of them have local generation. It can, therefore, be inferred that as the system load decreases, the outage of transmission lines/transformers becomes the major causes of the system problems. These system problems are mostly caused by the isolation of the bus(es) or the separation of the network into two networks.

The outage of generating units does not really affect the adequacy indices, if the total reserve available in the system is higher than the sum of total MW capacities of several large generating units. In the case of the IEEE RTS, the sum of the four largest units for this system is 1347 MW (2*400 + 350 + 197 MW) and the total installed capacity is 3405 MW. After taking into account the losses in the transmission lines, if the system load is below 2000 MW, the outage of generating units in this case does not materially affect the adequacy indices. A study of Table 5-20 illustrates this fact. Table 5-20 lists the maximum load curtailment indices, the maximum energy curtailment indices and the maximum duration of load curtailment indices for system buses at two load levels, 2100

Table 5-20: Maximum values of bus indices for the IEEE RTS at two load levels

Bus	Max. Value for System Load (MW) 2100	1950	Contingency Description: Components Out: Generators G1	G2	G3	G4	Lines L1	L2	Probability
	Maximum Load Curtailed (MW)								
4	55.00	50.00	0	0	0	0	4	8	0.0000002
5	50.00	50.00	0	0	0	0	3	9	0.0000001
6	100.00	95.00	0	0	0	0	5	10	0.0000007
13	16.49		16	29	30	31	0	0	0.0000203
14	145.00	130.00	0	0	0	0	19	23	0.0000002
15	19.88		16	29	30	31	0	0	0.0000203
16	2.43		12	29	30	31	0	0	0.0000162
18	20.72		16	29	30	31	0	0	0.0000203
19	3.11		29	30	31	32	0	0	0.0000156
20	8.04		16	29	30	31	0	0	0.0000203
	Maximum Energy Curtailed (MWh)								
4	239.30	217.55	0	0	0	0	4	8	0.0000002
5	217.54	217.54	0	0	0	0	3	9	0.0000001
6	631.99	600.39	0	0	0	0	5	10	0.0000007
13	238.00		16	29	30	31	0	0	0.0000203
14	687.99	616.82	0	0	0	0	19	23	0.0000002
15	286.82		16	29	30	31	0	0	0.0000203
16	32.74		12	29	30	31	0	0	0.0000162
18	299.02		16	29	30	31	0	0	0.0000203
19	41.97		29	30	31	32	0	0	0.0000156
20	115.94		16	29	30	31	0	0	0.0000203
	Maximum Duration Of Load Curtailment (Hrs.)								
4	4.35	4.35	0	0	0	0	4	8	0.0000002
5	4.35	4.35	0	0	0	0	3	9	0.0000001
6	6.32	6.32	0	0	0	0	5	10	0.0000007
13	14.43		16	29	30	31	0	0	0.0000203
14	13.50	4.75	29	30	31	32	0	0	0.0000156
15	14.43		16	29	30	31	0	0	0.0000203
16	13.50		12	29	30	31	0	0	0.0000162
18	14.43		16	29	30	31	0	0	0.0000203
19	13.50		29	30	31	32	0	0	0.0000156
20	14.43		16	29	30	31	0	0	0.0000203

MW and 1950 MW. At 2100 MW system load, the outage of three large generating units (2 of 400 MW and 1 of 350 MW) with the outage of another big unit causes load curtailment at buses 13, 15, 16, 18, 19 and 20. If the system load is reduced to 1950 MW then these buses do not encounter load interruption as seen from Table 5-20.

All buses except 4, 5 and 6 in the south region (138 KV) do not experience any load interruption, if the system load drops to 2100 MW. On the other hand, buses in the north region (230 KV) except bus 14 do not encounter load curtailment if the system load drops to 1950 MW. The difference in these two 'threshold values' of the load for two regions is due to the fact that in addition to three largest units, other large units are also concentrated in the north. The largest unit in the south is 100 MW at bus 7. Therefore outage of 100 MW at bus 7 or outage of 76 MW at bus 1 or bus 2 in combination with three largest units in the system does not create any problem if the system load drops to 2100 MW as the system has a reserve of more than 50 MW (excluding losses in the transmission lines) at this load level. On the other hand the outage of the fourth (197 MW) or of the fifth largest unit (155 MW) in the north with the outage of the three largest units would cause negative static reserve when system load is 2100 MW. However, for a system load of 1950 MW, outages of these units do not cause generation deficiency in the system and therefore no load shedding at this system load.

Buses 9 and 10 do not experience load interruption even if the system load is as high as 2400 MW. This is due to the load curtailment philosophy used in this study. If a load curtailment pass of 1 is used, bus 9 and/or bus 10 experience load interruption only when generator outages are confined to either bus 13 or bus 23 or both. The combined capacity outage of four largest units at these two buses is 941 MW, therefore the system has a reserve of 64 MW (excluding line losses) at a system load of 2400 MW.

The contribution of the northern region bus indices to the bus average indices is quite significant. As seen from Figures 5-19 to 5-21, adequacy indices for buses in the south (138 KV region) are always lower than the average values. This suggests that the southern region of the IEEE RTS is more reliable than the northern region, although the southern area is importing net power from the north through five transformer links. This interpretation requires a correct appreciation of the load curtailment philosophy. The fact that load is interrupted in the neighborhood of a bus(es) at which generating units are removed makes the northern region of the system apparently less reliable as compared to the southern region, because all the large generating units are concentrated in the north (230 KV). However if the load curtailment philosophy is formulated in such a way that in the case of an outage in an area, the load demands of the area are met first before supplying any surplus power to neighboring areas, the northern area buses will encounter less load curtailment than those in the southern area. This can, however, be achieved by increasing the number of load curtailment passes to three and decreasing the value of curtailable load at buses in the northern region.

The annual indices for the IEEE RTS have been calculated using the 13 step load model discussed in Section 2.4. In order to facilitate a comparison between the annual bus indices and the annualized bus indices, these results at seven system load levels, 2850 MW, 2700 MW, 2550 MW, 2400 MW, 2250 MW, 2100 MW and 1950 MW, are given in Tables 5-21 and 5-22. The annual indices are expressed in percent in column 10 of each table taking the indices at a system load of 2850 MW as the base. As observed from the tables, the maximum percentile annual index for any bus is less than 3.5%.

The annual indices, in general, are closest to the annualized indices for a system load of 2400 MW and are higher than the annualized indices for a system load of 2250 MW. The system average load is 1826.60 MW for the 13 step load model using energy equivalence approach. The actual value of the system average load will be lower than 1826.60 MW. This implies that the annual indices are greatly affected by the indices at higher load levels. If a 7 step load model is used instead of a 13 step load model, the adequacy indices for these two load models are almost equal. A 7 step load model

Table 5-21: Probability x10000 of failure and frequency of failure for the IEEE RTS at various load levels

	Annualized Indices for System Load (MW)							Annual Indices		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Bus	2850	2700	2550	2400	2250	2100	1950	13 Step Value	% Of (2)	7 Step
Probability x(10000) Of Failure										
1	224.46	78.32	67.38	4.77	1.01	0.00	0.00	5.01	2.23	5.01
2	409.99	146.91	121.89	9.54	2.03	0.00	0.00	9.24	2.25	9.24
3	226.40	78.32	67.83	4.77	1.01	0.00	0.00	5.03	2.22	5.03
4	223.94	78.31	67.38	4.77	1.01	0.00	0.00	5.01	2.23	5.01
5	224.46	78.32	67.73	4.77	1.01	0.00	0.00	5.03	2.24	5.03
6	223.95	78.32	68.00	4.78	1.02	0.00	0.00	5.04	2.25	5.04
7	159.22	64.20	47.62	4.93	0.48	0.00	0.00	3.76	2.36	3.76
8	159.50	64.53	47.96	4.93	0.48	0.00	0.00	3.78	2.37	3.78
9	31.71	2.83	0.78	0.00	0.00	0.00	0.00	0.15	0.48	0.15
10	31.71	2.83	1.05	0.00	0.00	0.00	0.00	0.16	0.52	0.16
13	712.73	292.34	272.07	30.82	10.13	1.25	0.00	21.01	2.94	21.01
14	95.56	29.18	29.18	3.06	0.44	0.15	0.00	2.20	2.30	2.20
15	565.09	272.12	132.63	30.49	9.86	1.25	0.00	14.23	2.51	14.23
16	260.11	83.27	83.27	7.25	1.29	0.31	0.00	6.12	2.35	6.12
18	834.33	375.12	173.29	33.73	10.13	1.25	0.00	18.33	2.19	18.33
19	116.67	31.30	31.30	3.05	0.43	0.15	0.00	2.37	2.03	2.37
20	462.13	220.54	220.54	17.35	9.18	1.25	0.00	15.99	3.46	15.99
Frequency Of Failure Indices										
1	16.59	5.51	4.92	0.33	0.06	0.00	0.00	0.36	2.18	0.36
2	30.01	10.31	8.83	0.67	0.12	0.00	0.00	0.66	2.20	0.66
3	16.73	5.51	4.95	0.33	0.06	0.00	0.00	0.36	2.17	0.36
4	16.54	5.51	4.92	0.33	0.06	0.00	0.00	0.36	2.19	0.36
5	16.59	5.51	4.93	0.33	0.06	0.00	0.00	0.36	2.18	0.36
6	16.54	5.51	4.95	0.33	0.06	0.00	0.00	0.36	2.20	0.36
7	11.98	4.68	3.38	0.35	0.02	0.00	0.00	0.27	2.26	0.27
8	12.01	4.72	3.39	0.35	0.02	0.00	0.00	0.27	2.26	0.27
9	1.98	0.22	0.05	0.00	0.00	0.00	0.00	0.01	0.52	0.01
10	1.98	0.22	0.06	0.00	0.00	0.00	0.00	0.01	0.55	0.01
13	45.83	18.88	17.39	1.99	0.58	0.07	0.00	1.34	2.93	1.34
14	6.70	2.25	2.22	0.23	0.03	0.01	0.00	0.16	2.48	0.16
15	35.38	16.20	8.91	1.96	0.56	0.07	0.00	0.90	2.56	0.90
16	18.35	6.13	5.83	0.53	0.08	0.02	0.00	0.43	2.37	0.43
18	51.51	22.52	10.68	2.21	0.58	0.07	0.00	1.13	2.19	1.13
19	8.05	2.41	2.23	0.23	0.03	0.01	0.00	0.17	2.14	0.17
20	29.97	13.64	13.64	1.16	0.51	0.07	0.00	0.99	3.32	0.99

Table 5-22: Expected load curtailed in MW and expected energy curtailed in MWh for the IEEE RTS at various load levels

	Annualized Indices for System Load (MW)							Annual Indices		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Bus	2850	2700	2550	2400	2250	2100	1950	13 Value	Step % Of (2)	7 Step
				Expected Load Curtailed (MW)						
1	171.5	56.3	13.0	1.6	0.2	0.0	0.0	1.9	1.1	1.9
2	314.6	110.0	25.9	3.2	0.4	0.0	0.0	3.7	1.1	3.7
3	369.2	108.3	23.4	2.7	0.3	0.0	0.0	3.6	1.0	3.6
4	172.4	50.7	10.7	1.2	0.1	0.0	0.0	1.7	1.0	1.7
5	145.2	41.4	9.5	1.1	0.1	0.0	0.0	1.4	1.0	1.4
6	317.0	94.3	19.9	2.3	0.4	0.1	0.1	3.2	1.0	3.2
7	160.4	54.2	17.6	2.6	0.3	0.0	0.0	2.1	1.3	2.1
8	326.3	98.5	27.3	4.1	0.4	0.0	0.0	3.7	1.1	3.7
9	32.9	4.8	0.2	0.0	0.0	0.0	0.0	0.2	0.5	0.2
10	36.6	5.3	0.2	0.0	0.0	0.0	0.0	0.2	0.5	0.2
13	1769.2	652.6	179.1	41.8	7.5	0.8	0.0	25.0	1.4	25.0
14	150.4	47.9	15.6	2.6	0.4	0.1	0.1	1.9	1.3	1.9
15	1961.7	848.4	237.1	50.3	8.8	1.0	0.0	31.4	1.6	31.4
16	204.9	67.9	21.0	3.4	0.4	0.0	0.0	2.6	1.2	2.6
18	3377.9	1275.1	341.3	67.1	11.1	1.0	0.0	46.7	1.3	46.7
19	166.4	48.1	14.4	2.3	0.3	0.0	0.0	1.9	1.1	1.9
20	853.4	308.3	92.5	19.1	3.8	0.4	0.0	12.1	1.4	12.1
				Expected Energy Curtailed (MWh)						
1	2086	725	160	21	3.1	0.0	0.0	23	1.1	23
2	3827	1420	318	43	5.7	0.0	0.0	46	1.2	46
3	4560	1394	290	36	5.1	0.0	0.0	45	1.0	45
4	2133	653	133	16	2.5	0.0	0.1	21	1.0	21
5	1794	533	117	14	2.0	0.0	0.0	18	1.0	18
6	3920	1213	246	30	4.9	0.6	0.6	39	1.0	39
7	1905	683	225	33	4.6	0.0	0.0	26	1.4	26
8	3972	1252	352	53	6.2	0.0	0.0	46	1.1	46
9	425	60	2	0	0.0	0.0	0.0	1	0.4	1
10	474	67	2	0	0.0	0.0	0.0	2	0.4	2
13	23662	8663	2407	585	108.0	12.0	0.0	337	1.4	337
14	1793	570	192	30	4.4	0.7	0.3	23	1.3	23
15	28069	12736	3211	708	126.9	14.5	0.0	447	1.5	447
16	2478	840	261	41	6.1	0.5	0.0	32	1.3	32
18	50912	18971	4665	928	158.8	15.1	0.0	672	1.3	672
19	2017	576	177	27	3.7	0.4	0.0	23	1.1	23
20	11794	4281	1260	272	55.3	5.9	0.0	168	1.4	168

used in this study is shown in Figure 5-23. The difference between the 7 step load model and the 13 step load model is that the minimum system load is assumed to be 1950 MW. The load is assumed to stay at this minimum value as long as the actual system load is equal to or less than 1950 MW. The advantage of using such a load model is that it saves computation time. Adequacy indices are now calculated at only 7 load levels instead of 13 load levels.

The difference in the annual indices obtained by these two load models is negligibly small as can be seen from columns 9 and 11 of Tables 5-21 to 5-22. The adequacy indices for buses 4, 5, 6 and 14 are slightly different in the two cases. The expected load curtailed and energy curtailed indices for the 7 step load model are higher than those for the 13 step load model. The probability of failure and the frequency of failure are exactly equal for both load models. The computation time to determine the annual indices using the 13 step load model is 1.85 times higher than that required using the 7 step load model.

The system does not encounter any voltage violation problems at any load level if the heuristic algorithms to prevent voltage violating situations are employed.

The system adequacy indices for the IEEE RTS are shown in Table 5-23. The annualized indices for seven load levels are

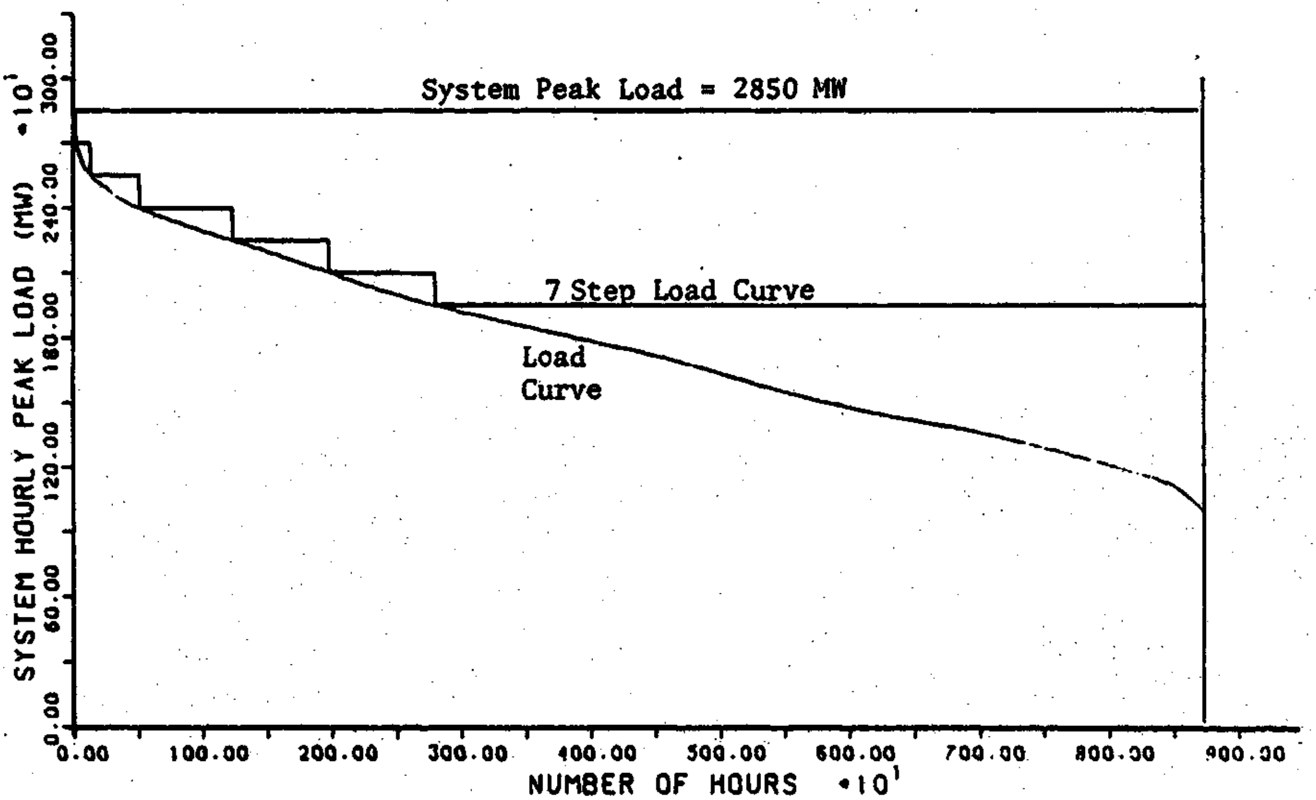


Figure 5-23: A 7 step load model for the IEEE RTS

Table 5-23: System indices for the IEEE RTS at various load levels

Annualized Indices for System Load (MW)							Annual Indices		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
2850	2700	2550	2400	2250	2100	1950	13 Step Value	% Of (1)	7 Step
IEEE INDICES									
Bulk Power Supply Disturbances									
62.80	24.37	19.50	2.21	0.58	0.08	0.0	1.57	2.5	1.57
Bulk Power Interruption Index (MW/MW-Yr.)									
3.69	1.43	0.41	0.08	0.02	0.00	0.0	0.05	1.3	0.05
Bulk Power Energy Curtailment Index (MWh/Yr.)									
51.16	20.23	5.50	1.18	0.22	0.02	0.0	0.69	1.3	0.69
Modified Bulk Power Energy Curtailment Index									
0.01	0.00	0.00	0.00	0.00	0.00	0.0	0.00	1.3	0.00
Severity Index (System-Minutes)									
3070.07	1214.34	330.01	71.10	13.28	1.43	0.0	41.65	1.3	41.65
AVERAGE INDICES									
Av. No. of Hrs of Load Curtailment/Load Pt./Year									
19.81	7.63	6.11	0.67	0.17	0.02	0.0	0.48	2.4	0.48
Av. No. of Load Curtailments/Load Pt./Year									
0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00	0.0	0.00
Av. Load Curtailed/Load Pt./Year-MW									
619.45	227.80	61.72	12.11	2.06	0.21	0.0	8.44	1.3	8.44
Av. Energy Curtailed/Load Pt./Year-MWh									
8578.14	3214.44	825.04	167.30	29.29	2.95	0.1	116.4	1.3	116.38

shown and the annual indices using both the 13 step load model and the 7 step load model are also given in the Table 5-23. The 13 step load annual indices are also expressed in terms of the annualized indices for the system load of 2850.0 MW. System annual indices, in general, are higher for the 7 step load model but the difference is quite small. The severity index for the IEEE RTS using the 13 step load model is 41.65 system - minutes which is 1.35% of its value if the system load remains at 2850 MW for the entire year.

A large difference between the annualized indices and the annual indices suggests that the system performance in absolute terms should not be judged on the basis of annualized indices only. The annual indices provide a better measure of performance evaluation for a system. The annualized indices can, however, be used to compare the performance of two networks at a particular load level. These indices can also be used to compare the adequacy of two alternative designs for a power system.

The annualized and annual indices provide information regarding the number of load curtailments and the total load curtailed at each bus in the system and for the overall system. From these indices, it is difficult to find out how many times a particular amount of load at each bus is curtailed. As noted in the discussion on load curtailment philosophy , bus loads are classified into two curtailment categories, curtailable load and firm load. Depending upon the circumstances, curtailable load at a bus may represent certain utility loads, loads curtailable by contract, load reduction obtainable by voltage reduction, etc.. It is intended that the firm load would not be interrupted until and unless it is necessary to do so while attempting to adjust for capacity deficiency in the system. The amount of curtailable load at any bus may vary from one system to another system. This amount may even be different in a given system at different periods of the year. It is, therefore, desirable to calculate probability and frequency indices for a system as a function of MW load curtailed. These indices are discussed in the next section.

5.6 Load Curtailment Indices

The variation of probability and frequency indices at each bus for the 6 bus test and the IEEE RTS as a function of MW load curtailed at each bus is discussed in the following sections.

5.6.1 The 6 Bus Test System (Figure2-1)

The probability and frequency indices for the firm load curtailment and the load curtailed in steps of 10% of the total bus load are shown in Table 5-24. These indices for each bus decrease or remain constant as the amount of load curtailment at each bus increases. Buses 5 and 6 experience total load curtailment due to transmission line outages. Bus 4 experiences 90% (36 MW) load curtailment because of the outage

Table 5-24: Probability and frequency of load curtailment for the 6 bus test system

Probability x1000 Of Firm Load Curtailment And Load Curtailed (MW) In Step Of 10% Each

		Load Curtailed (In % of Total Load)									
Bus	>Firm Load	⩾10	⩾20	⩾30	⩾40	⩾50	⩾60	⩾70	⩾80	⩾90	100
2	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.25	0.71	0.27	0.20	0.01	0.00	0.00	0.00	0.00	0.00	0.00
4	0.02	0.08	0.03	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.05

Frequency x1000 Of Firm Load Curtailment And Load Curtailed In Step Of 10% Each

		Load Curtailed (In % of Total Load)									
Bus	>Firm Load	⩾10	⩾20	⩾30	⩾40	⩾50	⩾60	⩾70	⩾80	⩾90	100
2	3	3	0	0	0	0	0	0	0	0	0
3	108	195	112	37	2	0	0	0	0	0	0
4	8	26	12	7	5	5	5	5	5	5	0
5	2	2	2	2	2	2	2	2	2	2	2
6	1057	1057	1057	1057	1057	1057	1057	1057	1057	1057	985

of lines 1 and 6. Buses 3 and 6 have a frequency of load curtailment exceeding 0.1 failures per year. The least reliable bus is bus 6 with a frequency of load curtailment of 1.05 failures per year. This is due to the fact that bus 6 is radially fed from bus 5 and the outage of line 9 itself or with other lines in the system always isolates bus 6. Bus 5 is the most reliable bus because it encounters a minimum number of load curtailments, 0.00022 per year. The frequency of firm load curtailment is also minimum for bus 5 as seen from Table 5-24.

5.6.2 The IEEE RTS (Figure 2-2)

Table 5-25 shows the probability and the frequency of load curtailment at specific buses. The firm load at any bus is assumed to be 80% of its total connected load. Eight of ten 138 KV buses in the IEEE RTS have a frequency of load curtailment exceeding 1 failure per year. The least reliable bus is bus 18. This is due to the fact that an outage of a 400 MW unit at bus 18 together with the outage of other big generating units in the system results in load curtailment at bus 18. Buses 4, 5, 6 and 14 experience total load curtailment due to their isolation from the system when lines terminated at them are out of service. Buses 13, 15, 18 and 20 experience total load curtailment due to outages of generating units. Table 5-26 shows the maximum load curtailed at each bus and the component involved in the outage event resulting in the maximum load curtailment. All buses except 7, 9 and 10 encounter a load curtailment of more than half of their

Table 5-25: Probability and frequency of the load curtailment for the IEEE RTS

Probability x1000 Of Firm Load (F.L.) Curtailment And Load Curtailed (MW) In Step Of 10% Each

		Load Curtailed (In % of Total Load)									
Bus	>F.L.	≥10	≥20	≥30	≥40	≥50	≥60	≥70	≥80	≥90	100
1	1.8	8.8	1.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	4.3	19.6	4.3	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	4.5	8.8	4.5	2.8	1.2	0.4	0.1	0.0	0.0	0.0	0.0
4	4.7	10.3	4.7	3.3	2.5	1.0	0.4	0.1	0.0	0.0	0.0
5	4.5	8.8	4.5	2.8	1.2	0.4	0.1	0.0	0.0	0.0	0.0
6	4.7	10.3	4.7	3.3	2.5	1.0	0.4	0.1	0.0	0.0	0.0
7	1.6	8.6	1.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	4.0	8.6	4.0	2.8	1.6	1.2	0.6	0.4	0.2	0.1	0.0
9	0.2	0.9	0.2	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0
10	0.2	0.9	0.2	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0
13	8.1	39.8	13.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	0.2
14	1.5	3.3	1.5	0.8	0.4	0.1	0.0	0.0	0.0	0.0	0.0
15	21.5	29.2	21.5	6.4	3.9	3.0	2.7	2.6	2.1	0.9	0.0
16	3.4	9.9	4.2	1.1	0.4	0.2	0.1	0.0	0.0	0.0	0.0
18	28.1	47.3	28.1	19.1	13.3	10.5	8.7	3.2	2.2	1.6	1.0
19	1.7	4.1	1.7	1.0	0.5	0.1	0.0	0.0	0.0	0.0	0.0
20	18.2	24.9	18.2	11.7	6.2	5.1	4.3	3.3	2.7	2.2	1.0

Frequency x1000 Of Firm Load Curtailment And Load Curtailed In Step Of 10% Each

		Load Curtailed (In % of Total Load)									
Bus	>F.L.	≥10	≥20	≥30	≥40	≥50	≥60	≥70	≥80	≥90	100
1	1.2	6.3	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	3.1	14.2	3.1	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	2.9	6.3	2.9	1.8	0.9	0.3	0.0	0.0	0.0	0.0	0.0
4	3.2	7.3	3.2	2.2	1.6	0.7	0.3	0.0	0.0	0.0	0.0
5	2.9	6.3	2.9	1.8	0.9	0.3	0.0	0.0	0.0	0.0	0.0
6	3.2	7.3	3.2	2.2	1.6	0.7	0.3	0.0	0.0	0.0	0.0
7	1.1	6.3	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	2.7	6.3	2.7	1.9	1.1	0.8	0.4	0.3	0.2	0.0	0.0
9	0.2	0.6	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
10	0.2	0.6	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
13	5.8	25.7	7.9	1.2	1.2	1.2	1.2	1.2	1.2	1.2	0.1
14	1.1	2.5	1.1	0.6	0.3	0.1	0.0	0.0	0.0	0.0	0.0
15	12.0	17.9	12.0	4.2	2.6	2.0	1.7	1.6	1.3	0.6	0.0
16	2.4	7.5	3.0	0.7	0.3	0.1	0.0	0.0	0.0	0.0	0.0
18	15.7	28.7	15.7	10.3	7.3	5.4	4.3	2.0	1.3	0.9	0.6
19	1.2	3.1	1.2	0.7	0.3	0.1	0.0	0.0	0.0	0.0	0.0
20	10.8	16.0	10.8	7.2	4.3	3.4	2.8	2.1	1.7	1.4	0.7

Table 5-26: Maximum value of load curtailment in MW for the IEEE RTS

BUS	MLC (MW) for System Load (MW) 2100	Contingency Description Components Out Generators G1	G2	G3	G4	Lines L1	L2	Probability
1	81.2044	21	22	30	31	0	0	0.0000019
2	78.7756	25	26	30	31	0	0	0.0000019
3	135.7733	21	29	30	31	0	0	0.0000079
4	74.0000	0	0	0	0	4	8	0.0000002
5	71.0000	0	0	0	0	3	9	0.0000001
6	136.0000	0	0	0	0	5	10	0.0000007
7	42.7415	13	14	15	30	0	0	0.0000027
8	163.6479	13	16	29	31	0	0	0.0000062
9	84.8676	16	17	29	31	0	0	0.0000078
10	94.5668	16	17	29	31	0	0	0.0000078
13	265.0000	16	17	31	0	0	0	0.0000865
14	194.0000	0	0	0	0	19	23	0.0000002
15	317.0000	12	29	30	31	0	0	0.0000162
16	81.8471	12	30	31	32	0	0	0.0000075
18	333.0000	29	30	31	0	0	0	0.0003703
19	128.6227	29	30	31	32	0	0	0.0000156
20	128.0000	29	30	31	0	0	0	0.0003703

connected load. All buses in the system experience firm load interruption. Buses 9 and 10 are the most reliable buses in the system as both of them have the minimum frequency of load curtailment of 0.63 failures per year. The frequency of firm load curtailment is also minimum for these buses as seen from Table 5-25.

5.7 Summary

A comprehensive study of the effect of contingency level and load variation on the adequacy indices has been presented in this chapter. It has been stressed that calculation of two sets of indices, individual load point indices and overall system indices, is necessary and that one cannot substitute for the other. Drawing any conclusions about the adequacy of any load point from the system indices may give erroneous results.

The individual load point indices are very dependent on the selection of a load curtailment philosophy. Depending upon the relative priority given to the buses in a system, the load can be curtailed accordingly, whenever there is a capacity deficiency in the system. The selection of a particular load curtailment philosophy is a management decision. The interpretation of the individual load point indices should be done in conjunction with the load curtailment philosophy used in the algorithm.

The load curtailment philosophy discussed in this chapter is quite flexible. The load interruption can be localized in the neighborhood of a disturbance or it can be distributed throughout the system by assigning a proper load curtailment pass.

The effect of the contingency level on load point indices and overall system indices has been discussed for the 6 bus test system and the IEEE RTS. It has been observed that the effect of higher level outage contingencies is not uniform at all the system buses. In the case of the 6 bus test system, calculation of the Ist level contingency provides reasonably accurate results for load point 6 but for other load points, calculation of higher level contingencies (up to the 3rd level) is necessary. On the other hand in the case of the IEEE RTS, calculation of the 4th level outage contingencies is necessary for both bus indices and system indices. The variation in the adequacy indices from one contingency level to other contingency level is also non-uniform for each bus. This depends upon the load curtailment philosophy and the relative location of a bus in the system.

Similarly, it can be seen that the effect of load variation on the adequacy indices for the 6 bus test system and the IEEE RTS is not uniform. Obviously, as the system load decreases, the indices also decrease. The two sets of indices, the annualized and the annual indices, are presented for both the systems. The annualized indices calculated at the system peak load do not convey accurate information regarding the absolute quantitative evaluation of a power system. In this case, the calculation of annual indices is necessary. The proper selection of a load step in the modeling of the load curve is quite important while calculating the annual indices. In the case of the 6 bus test system, the four step load model provides reasonably accurate indices while in the case of the IEEE RTS, it is not really necessary to consider a thirteen step load model. The seven step load model gives accurate indices. This is due to the fact that the contribution of lower system load steps is negligibly small.

The probability and the frequency of curtailing the load at a bus in a system decreases as the amount of load curtailment increases. As the number of components under outage in a contingency increases, so does the severity of the contingency. The probability and the frequency of the contingency, however, decrease. In this chapter, a brief description of the variation in probability of failure and the frequency of failure as a function of MW load curtailed at each bus is also presented.

The studies presented do not consider common cause outages or station originated outages. Calculation of common cause outages and station originated outages is necessary prior to considering further higher level outages. The contribution of common cause outages and station originated outages is quite significant. The computation time involved in incorporating these outages is also less than the time required to solve higher level independent outage contingencies. Moreover the calculation of higher level independent outage contingencies is not significant as compared to that of common cause and station originated outages. This is discussed in the next chapter.

CHAPTER 6

STATION ORIGINATED AND COMMON CAUSE OUTAGE EVENTS

6.1 Introduction

The reliability evaluation of a bulk power system normally considers outages of generating units, transformers and transmission lines only. Station originated outages can, however, also contribute significantly to the adequacy indices. Recent attention by power utilities and educational institutions[10, 28, 29, 34, 35] to the role of protection schemes in system disturbances supports the idea of considering component outages of the bulk system due to disturbances in switching stations and sub-stations etc.. Sub-station failures such as breaker failures, station transformer failures, bus-section failures and protective system failures are a major cause of multiple component outages.

Landgren and Anderson[36] calculated that over 40% of the multiple line outages are caused by terminal related disturbances in the Commonwealth Edison Company's 345 KV power system. It is, therefore, imperative to consider station originated outages in the adequacy evaluation of a composite power system. This reinforces an earlier observation made in Chapter 3 that it is not advisable to consider higher level independent line outages and ignore common cause or multiple outages due to station disturbances. Consideration of common mode failures and station originated outages may obviate the need to examine higher level independent line outages, thus saving computation time.

In the past, reliability experts have not devoted much attention to station originated outages in a composite power system due to the lack of data on station originated outages and because of the complexities involved in the analysis. The contribution of these outages, however, have been considered by two distinct approaches:

(1) A comparative reliability evaluation[17] of various substations and switching stations by solving failure events resulting from the station elements only. The total failure rate and the outage duration for a particular station configuration is calculated assuming continuity of the power supply to the load center as a success criterion.

(2) By simply increasing the failure rates of lines and/or generating units affected by the outages of the station components[28]. The increment in the failure rates is to reflect the outage effects of terminal station components.

Both approaches do not include the full implications of the station originated outages in a composite power system. The first approach does not normally consider outages in the generating stations. It neither considers the alternative means available to satisfy the load in the case of a fault in a substation, nor checks the quality of the power supply at a load center. The second approach is correct if the outage of a terminal station component results in the outage of one element (transmission line or generating unit etc.) of a system. However, when two or more elements in a system are unavailable, which is a frequently encountered situation in a practical system, the approach assumes an unrealistic independence between these system element outages.

The correct approach is to regard the terminal components as separate elements of the system and by considering outages of these components, evaluate the adequacy of the system using an A.C. load flow for each outage contingency.

This approach is, however, not feasible as the CPU time required to solve all the contingencies is enormously large as the number of station components is large in a power network. A numerical evaluation of the station originated outages using Markovian models suitable for including the effects of these outages in the adequacy analysis of a composite generation and transmission system is described in Reference [24]. This approach calculates the probability of an outage event arising due to station disturbances. The approach, however, does not decide whether an event is a failure event or a success event and therefore, by itself cannot calculate other adequacy indices such as the expected load curtailed, expected energy curtailed and total number of voltage violations etc..

This chapter presents a practical approach to including station originated effects in composite system adequacy evaluation. The digital computer program for composite power system reliability evaluation has been extended to calculate the effects of the station disturbances on the adequacy indices. The effect of the outage levels with and without common cause line outages, and of the load variation on the station originated outages for the 6 bus test system and for the IEEE RTS is also studied.

6.2 Station Originated Outage Models

The outage of a breaker, bus-section, station transformer or a fault in the protective scheme may result in outages of a generating unit(s), transformer(s), line(s) and the isolation of load feeders in a network. The adequacy evaluation of a contingency resulting due to the station disturbances invariably involves an assessment of its effect, i.e. outage of the generating units, lines, transformers and/or load feeders. Outages of the generating units, lines and transformers may, therefore, arise because of any of the following causes:

(1) Independent and/or common cause failures of the components.

(2) Outages due to the failure of station elements.

which is not correct

It has been assumed that these two events are independent and mutually exclusive, therefore the total probability of an outage contingency is the total sum of the probabilities of each cause, i.e.,

P(Components X and Y are out) = P(Components X and Y are out due to their own internal failure given that all the station elements are operating)
+ P(Components X and Y are out due to the outages of appropriate station elements given that all other system components are operating)

The frequency of the outage contingency is calculated by adding the frequencies of these two events.

As noted earlier, the probability and the frequency of components X and Y being out due to their own internal failure are calculated using the Markov models discussed in Chapter 2. The probability and the frequency of components X and Y being out because of station originated outages are calculated using the models discussed in Reference [24]. A list of the outage events considered in this study is as follows:

(1) Active and passive failures of the breakers.

(2) Failures of the station transformers.

(3) Failures of the Bus-sections.

(4) Failure of a station transformer overlapping the failure of any other station component.

(5) Failure of a bus-section overlapping the failure of any other station component.

(6) Failure (passive or active) of a breaker overlapping the failure of any other station component.

(7) Failure (passive or active) of a breaker or failure of a transformer or bus-section overlapping the maintenance of any station component.

The active failure of a breaker is an event that results in the removal of certain other healthy station components from service. Active failures include component faults which cause operation of circuit breakers or disconnect switches. All component outages which do not remove any healthy components from service are classified as passive failures. These include undetected open failures and components out for repair etc..

The maintenance outage of a component is the removal of the component from service for preventive maintenance only. The maintenance outage rate is the average number of times in a year that a component is taken out of operation for preventive maintenance.

The following assumptions were made in developing the Markovian models for the outage events noted earlier in this section.

(1) Probability of a stuck breaker when called upon to operate is assumed to be zero.

(2) Probability of overlapping outages for three or more components is assumed to be zero, as this probability is quite small.

(3) A component is not taken out of service for preventive maintenance if it results in the outage of a current carrying component.

(4) Failure bunching effects due to adverse weather are not considered in the study.

After developing the Markov models, the probability and the frequency of a station outage event is calculated. The effect of this outage event on the operation of system components, i.e. generating units, transformers and transmission lines, is examined. A list of outages of the system components and the associated probability and frequency of these events is prepared. This output serves as input to the composite system reliability program. A general list of the combination of system components removed from service due to station disturbances is as follows:

(1) One generating unit is out.

(2) Two generating units are out.

(3) Three generating units are out.

(4) Four generating units are out.

(5) One line/transformer is out.

(6) Two line(s)/transformer(s) are out.

(7) Three line(s)/transformer(s) are out.

(8) One generating unit and one line/transformer are out.

(9) Two generating units and one line/transformer are out.

(10) Load feeder(s) is isolated.

The contribution of the above contingencies except for the outage of three lines (No. 7), the outage of the two generating units and one line (No. 9) and the isolation of the load feeder (No. 10) is taken into account by adding the probabilities and the frequencies to the probability and the frequency of the respective contingencies resulting from the independent failure of these components. The remaining three outages are calculated separately. The digital computer program for composite reliability evaluation has been modified to calculate all the previously noted outage contingencies. In the following section, the effect of station originated outages and the effect of common cause outages on the adequacy indices are studied. The effect of the load variation on the station originated outages is discussed in Section 6.4.

6.3 Study Of The Effect Of Common Cause And Station Originated Outages

A comparative study of the contribution of common cause outage events and station originated outage contingencies to the adequacy indices has been made in this section. Independent outages of the generating units up to the 4th level and of the transmission lines up to the 2nd level are considered. The failure events were terminated at the 4th level in the case of generating units and at the 2nd level in the case of lines. The four cases studied to compare the indices are as follows:

(1) Independent outages only.

(2) Independent outages and common cause outages.

(3) Independent outages and station originated outages.

(4) Independent outages, common cause outages and station originated outages.

The common cause outage data for both the 6 bus test system and the IEEE RTS are given in Appendix D. A five state common cause outage model discussed in Section 2.8 was utilized for these studies. The station configurations at each bus for both the systems are described in Reference[24].

The following is a brief description of the study on the 6 bus test system and on the IEEE RTS.

6.3.1 The 6 Bus Test System (Figure 2-1)

Adequacy studies were conducted for a system load of 165 MW. The individual bus loads at this system load are given in Chapter 5. The selection basis for this system load is that that for the four step load model discussed in Section 2.5, the system load of 165 MW gives the annualized indices which are close to the annual indices for this system. Table 6-1 gives system indices for the four cases described earlier. Common cause outages of lines 1 and 6 and of lines 2 and 7 are considered in this study. The increment of the indices in each case with respect to case (1) is also shown in Table 6-1. The effect of common cause events is less pronounced when compared to that of the station originated outage events. The tremendous increase in the indices after including station originated outages is due to the contingencies resulting from

Table 6-1: System indices for the 6 bus test system with/without common cause and station originated outage events

Case (1) Independent Outages	(2) C.C. Outages		(3) S.O. Outages		(4) C.C. and S.O. Outages	
Actual Value	Actual Value	Incr. w.r.t. (1)	Actual Value	Incr. w.r.t. (1)	Actual Value	Incr. w.r.t. (1)
IEEE INDICES						
Bulk Power Interruption Index (MW/MW-Yr.)						
0.11736	0.12620	1.08	0.36053	3.07	0.36858	3.14
Bulk Power Energy Curtailment Index (MWh/Yr.)						
1.20329	1.26357	1.05	4.16697	3.46	4.21948	3.51
Bulk Power Supply Average MW Curtailment Index (MW/Disturbance)						
17.58381	18.38408	1.05	23.84413	1.36	24.07452	1.37
Modified Bulk Power Energy Curtailment Index						
0.00014	0.00014	1.05	0.00048	3.46	0.00048	3.51
Severity Index (System-Minutes)						
72.19699	75.81400	1.05	250.01800	3.46	253.16901	3.51
AVERAGE INDICES						
Av. No. of Hrs of Load Curtailment/Load Pt./Year						
2.49905	2.65902	1.06	6.09219	2.44	6.24859	2.50
Av. No. of Load Curtailments/Load Pt./Year						
0.22452	0.24156	1.08	0.51442	2.29	0.53108	2.37
Av. Load Curtailed/Load Pt./Year-MW						
3.87060	4.16461	1.08	11.89744	3.07	12.16327	3.14
Av. Energy Curtailed/Load Pt./Year-MWh						
39.68430	41.69795	1.05	137.51009	3.47	139.24295	3.51

Incr. = Increment
C.C. = Common Cause
S.O. = Station Originated
Av. = Average
Pt. = Point

the isolation of a load because of a fault in the station components. The probability and the frequency of a load isolation is relatively high as compared to that of a higher level independent outage contingency. Moreover, in the case of a load isolation contingency, the entire load is curtailed.

6.3.2 The IEEE RTS (Figure 2-2)

As seen from Chapter 5, for this system the annualized indices at the system load of 2400 MW are close to the annual indices for the load model discussed in Section 2.5. These studies have, therefore, been conducted using 2400 MW as the system peak load. The individual bus loads for this system load are given in Chapter 5. A list[9] of the circuits exposed to common cause outages is as follows:

(1) Lines 12 and 13

(2) Lines 18 and 20

(3) Lines 25 and 26

(4) Lines 31 and 38

(5) Lines 32 and 33

(6) Lines 34 and 35

(7) Lines 36 and 37

Table 6-2 shows system indices for the four cases noted earlier in this chapter. The increment in the system indices in each case with respect to case (1) is also given in Table 6-2. The effect of the station originated outage events is more pronounced as compared to that of common cause outage events as seen from Table 6-2. The major contribution of the

Table 6-2: System indices for the IEEE RTS with/without common cause and station originated outage events

Case	(1) Independent Outages	(2) C.C. Outages		(3) S.O. Outages		(4) C.C. and S.O. Outages	
	Actual Value	Actual Value	Incr. w.r.t. (1)	Actual Value	Incr. w.r.t. (1)	Actual Value	Incr. w.r.t. (1)
IEEE INDICES							
Bulk Power Interruption Index (MW/MW-Yr.)	0.08579	0.10308	1.20	0.13666	1.59	0.15803	1.84
Bulk Power Energy Curtailment Index (MWh/Yr.)	1.18503	1.30798	1.10	2.05153	1.73	2.24482	1.89
Bulk Power Supply Average MW Curtailment Index (MW/Disturbance)	92.81903	100.34611	1.08	104.54426	1.13	110.09784	1.19
Modified Bulk Power Energy Curtailment Index	0.00014	0.00015	1.10	0.00023	1.73	0.00026	1.89
Severity Index (System-Minutes)	71.10200	78.47900	1.10	123.09200	1.73	134.68900	1.89
AVERAGE INDICES							
Av. No. of Hrs of Load Curtailment/Load Pt./Year	8.71335	9.14968	1.05	9.56775	1.10	10.19681	1.17
Av. No. of Load Curtailments/Load Pt./Year	0.67052	0.73267	1.09	0.72322	1.08	0.79649	1.19
Av. Load Curtailed/Load Pt./Year-MW	12.11181	14.55229	1.20	19.29249	1.59	22.31119	1.84
Av. Energy Curtailed/Load Pt./Year-MWh	167.29817	184.65901	1.10	289.62839	1.73	316.92191	1.89

Incr. = Increment
C.C. = Common Cause
S.O. = Station Originated
Av. = Average
Pt. = Point

station originated outages comes from the contingencies resulting either from the isolation of a load or from the removal of two or more large generating units because of a fault in the station components. The inclusion of common cause outages results in two more split network situations:

(1) Outage of lines 36, 37 and 29 curtails total load at bus 19 and 20.

(2) Outage of lines 25, 26 and 28 creates capacity deficiency in the separated network having buses 1 to 16 and buses 19, 20 and 23. Most of the buses in the network experience load curtailment. The amount of the load curtailed (MW) at each system bus is shown in Table 2-10 in Chapter 2.

The number of load curtailment contingencies increases from 365 to 414 when common cause outages are considered. The combined effect of common cause and station originated outages is quite large. The severity index is approximately 1.9 times its the value for independent outage events.

It can be concluded both for the 6 bus test system and for the IEEE RTS that the effect of station originated outages is quite significant. This indicates that before considering computationally expensive higher level independent outage contingencies, calculation of common cause outages and station originated outages is highly recommended. The effect of the station originated outages and of the common cause outages on the adequacy indices is not uniform when the system load is varied. This is discussed in the next section.

6.4 Effect Of The Load Variation On The Adequacy Indices

In Section 5.5, the effect of load variation on the adequacy indices due to the independent outages was discussed in detail. In this section the effect of the load variation on the system indices due to the independent outages, common cause outages and station originated outages is described for both the 6 bus test system and the IEEE RTS. The independent outages for the generating units up to the 4th level and for the lines up to the 2nd level are considered. The contingencies at the last level are terminated. A brief description of the effect of the load variation for each system is as given below:

6.4.1 The 6 Bus Test System (Figure 2-1)

Table 6-3 gives the system indices at four system peak loads, 185 MW, 165 MW, 145 MW and 125 MW. The absolute value of the system indices is increased at each load when compared to the respective values given in Table 5-17 in Chapter 5. This is due to the inclusion of station originated outages and common cause outages. As seen from Table 6-3 and Table 5-17, the decrement in the indices with a decrease in the system load with common cause events and station originated events is not as large as it is when only independent outages are considered. This is due to the fact that at lower loads the contribution of the independent outages decreases rapidly. However, the contribution of the station originated outage

Table 6-3: System indices for the 6 bus test system at various load levels including common cause and station originated outage events

(1)	(2)		(3)		(4)	
System Load in MW						
185.0	165.0		145.0		125.0	
Actual Value	Actual Value	Decr. w.r.t. (1)	Actual Value	Decr. w.r.t. (1)	Actual Value	Decr. w.r.t. (1)
IEEE INDICES						
Bulk Power Interruption Index (MW/MW-Yr.)						
0.43591	0.36858	0.85	0.36089	0.83	0.35914	0.82
Bulk Power Energy Curtailment Index (MWh/Yr.)						
5.54343	4.21948	0.76	4.04635	0.73	4.03523	0.73
Bulk Power Supply Average MW Curtailment Index (MW/Disturbance)						
25.44570	24.07452	0.95	21.49544	0.84	18.47754	0.73
Modified Bulk Power Energy Curtailment Index						
0.00063	0.00048	0.76	0.00046	0.73	0.00046	0.73
Severity Index (System-Minutes)						
332.60599	253.16900	0.76	242.78100	0.73	242.11399	0.73
AVERAGE INDICES						
Av. No. of Hrs of Load Curtailment/Load Pt./Year						
12.39566	6.24859	0.50	5.49044	0.44	5.45832	0.44
Av. No. of Load Curtailments/Load Pt./Year						
0.76177	0.53108	0.70	0.49304	0.65	0.49217	0.65
Av. Load Curtailed/Load Pt./Year-MW						
16.12859	12.16327	0.75	10.46573	0.65	8.97856	0.56
Av. Energy Curtailed/Load Pt./Year-MWh						
205.10701	139.24295	0.68	117.34430	0.57	100.88081	0.49

Decr. = Decrement
S.O. = Station Originated
Pt. = Point
C.C. = Common Cause
Av. = Average

events and of the common cause outage events does not diminish as quickly. The main contribution of the station originated events, as noted earlier, comes from the isolation of a load, therefore irrespective of the system load level the entire load is curtailed.

6.4.2 The IEEE RTS (Figure 2-2)

Table 6-4 gives the system indices after including the effect of station originated and common cause outages at four system loads, 2850 MW, 2700 MW, 2550 MW and 2400 MW. Table 6-5 gives the system indices at these loads for the independent outage events without including the effect of station originated outages and common cause outages. As seen from Tables 6-4 and 6-5, the absolute value of the indices with the station originated and common cause outages increases at each system load level. As is the case with the 6 bus test system, the decrement in the indices with a decrease in the load when considering common cause and station originated outages is not as large as it is when only independent outages are considered. This is due to the fact that as the load decreases, the contribution to the adequacy indices comes mainly from the isolation of a load. Faults in the station components are largely responsible for the isolation of a load. However, load is also isolated when lines terminated at a load bus are removed. No system bus experiences total load curtailment for the outage of one line only. The number of bus isolation contingencies with the inclusion of common cause and station originated outage events has increased from 48 to 104.

Table 6-4: System indices for the IEEE RTS at various load levels including common cause and station originated outage events

(1)	(2)		(3)		(4)	
System Load in MW						
2850.0	2700.0		2550.0		2400.0	
Actual Value	Actual Value	Decr. w.r.t. (1)	Actual Value	Decr. w.r.t. (1)	Actual Value	Decr. w.r.t. (1)
IEEE INDICES						
Bulk Power Interruption Index (MW/MW-Yr.)						
3.71753	1.47203	0.40	0.46006	0.12	0.13666	0.04
Bulk Power Energy Curtailment Index (MWh/Yr.)						
51.57207	20.87945	0.40	6.32895	0.12	2.05153	0.04
Bulk Power Supply Average MW Curtailment Index (MW/Disturbance)						
168.41957	158.73817	0.94	58.05872	0.34	58.05872	0.34
Modified Bulk Power Energy Curtailment Index						
0.00589	0.00238	0.40	0.00072	0.12	0.00023	0.04
Severity Index (System-Minutes)						
3094.32398	1252.76697	0.40	379.73700	0.12	123.09200	0.04
AVERAGE INDICES						
Av. No. of Hrs of Load Curtailment/Load Pt./Year						
258.24514	101.67792	0.39	79.23013	0.31	9.56775	0.04
Av. No. of Load Curtailments/Load Pt./Year						
19.95304	7.62601	0.38	6.11028	0.31	0.72322	0.04
Av. Load Curtailed/Load Pt./Year-MW						
623.23340	233.79334	0.38	69.00830	0.11	19.29249	0.03
Av. Energy Curtailed/Load Pt./Year-MWh						
8645.90723	3316.14795	0.38	949.34283	0.11	289.62839	0.03

Decr. = Decrement
C.C. = Common Cause
S.O. = Station Originated
Av. = Average
Pt. = Point

Table 6-5: System indices for the IEEE RTS at various load levels without including common cause and station originated outage events

(1)	(2)		(3)		(4)	
System Load in MW						
2850.0	2700.0		2550.0		2400.0	
Actual Value	Actual Value	Decr. w.r.t. (1)	Actual Value	Decr. w.r.t. (1)	Actual Value	Decr. w.r.t. (1)
IEEE INDICES						
Bulk Power Interruption Index (MW/MW-Yr.)						
3.69497	1.43433	0.39	0.41150	0.11	0.08579	0.02
Bulk Power Energy Curtailment Index (MWh/Yr.)						
51.16785	20.23907	0.40	5.50024	0.11	1.18503	0.02
Bulk Power Supply Average MW Curtailment Index (MW/Disturbance)						
167.67130	158.89359	0.95	53.80362	0.32	92.81903	0.55
Modified Bulk Power Energy Curtailment Index						
0.00584	0.00231	0.40	0.00062	0.11	0.00014	0.02
Severity Index (System-Minutes)						
3070.07105	1214.34399	0.40	330.01401	0.11	71.10200	0.02
Average Indices						
Av. No. of Hrs of Load Curtailment/Load Pt./Year						
255.69083	101.86563	0.40	79.20758	0.31	8.71335	0.03
Av. No. of Load Curtailments/Load Pt./Year						
19.81285	7.63679	0.39	6.11366	0.31	0.67052	0.03
Av. Load Curtailed/Load Pt./Year-MW						
619.45007	227.80481	0.37	61.72573	0.10	12.11181	0.02
Av. Energy Curtailed/Load Pt./Year-MWh						
8578.14062	3214.4409	0.37	825.0358	0.10	167.29817	0.02

Decr. = Decrement
C.C. = Common Cause
S.O. = Station Originated
Av. = Average
Pt. = Point

The probability and the frequency of the isolation of a bus due to a fault in the station components is higher than the values due to the removal of the associated transmission lines. Therefore, the contribution to the adequacy indices of the bus isolation contingencies when common cause and station originated outages are considered is quite significant.

6.5 Summary

The inclusion of common cause outage events and station originated events significantly increases the adequacy indices as shown in this chapter. It is, therefore, necessary to examine the common cause and station originated outage events prior to considering the inclusion of higher level independent outage events. The total computation time does not increase very much with the addition of station originated outages and common cause outages but can increase tremendously with the addition of high level independent outages. The probability and the frequency of an outage event decreases as the depth of a contingency level increases. The contribution of the contingency to the adequacy indices also decreases, although the severity associated with the contingency increases. It has been demonstrated in both the 6 bus test system and the IEEE RTS, that the relative contribution of common cause and station originated outage events as compared to the independent outages is more pronounced as the system load decreases.

CHAPTER 7

CONCLUSION

Composite system reliability evaluation in a real power network is a complex problem and is computationally quite expensive. The inclusion of station originated outages makes it further complicated. It may not be worth attempting to solve very large networks with the present available techniques. The solution of a large network either in parts or of an equivalent smaller network can, however, always be done with the techniques described in this thesis. The only limitation to the solution of large power networks is the enormously high computation time and storage requirements. The basic algorithm can be used to solve a system of any size.

A contingency enumeration approach is used to assess the adequacy of a composite generation and transmission system. The outage models and the state space models for the component outages are also reviewed in Chapter 2. Split network situations are solved by using a simple algorithm without occupying any additional memory storage for the Jacobian matrices. This algorithm was successfully used to solve the split network situations in all three test systems described in the thesis.

It has been emphasized in Chapter 3 that as the size of a system increases, consideration of high level outages, particularly generating unit outages, cannot be ignored. It is also desirable to consider high level transmission line outage contingencies. It is shown, however, in Chapter 3 that it is not worth attempting to include high level independent line outages and to ignore common cause and station originated outages. This phenomenon is also explained in Chapter 6. The contribution of those high level outage contingencies which are not solved is included by terminating a last level contingency. It is pointed out in Chapter 3 that the termination of a contingency at lower levels may not provide accurate results and should not be attempted as a general rule. In order to reduce computation time for large networks, sorting of identical generating units is a very effective procedure. The percentage saving in the computation time due to sorting of the identical units increases, as the depth of the contingency level increases.

Bus voltage violation and non-convergence A.C. load flow situations are few of the major problems encountered in the adequacy evaluation of a composite system. These situations, however, can be alleviated by rescheduling the generating units and injecting reactive power (MVAR) at the voltage violating buses. A heuristic simple algorithm for determining the maximum rating of the VAR supplying device at a bus is described in Chapter 4. The technique is found to be effective in removing voltage violations and non-convergent problems from a system. A quantitative evaluation of these situations gives an estimate of the severity of an outage event from a voltage violation point of view.

Individual load point indices are necessary to identify the weak points in a system and to help establish optimum response of the system under steady state conditions to equipment investment. These indices also serve as infeed values for determining the adequacy of a distribution system. Overall system indices provide a measure of global adequacy which is useful in the comparison of one system's performance with that of another system. These global indices are more appealing to a system manager, while individual load point indices are more useful for a system designer. In Chapter 5, both indices are discussed in detail and the effects of the load curtailment passes, system load variation and the contingency level on these indices are discussed. One of the most outstanding conclusions from this chapter is that the interpretation of the indices should be done in the domain within which they lie. It is not valid to draw any conclusion about the adequacy of a system or of different parts of a system without a correct interpretation of the load curtailment philosophy. Both sets of indices are valuable and they do not replace each other. The judgement of the adequacy of a load point should not be done simply from the overall system indices.

In real situations, the load at each bus and hence the system load does not remain at a constant value throughout the year. Calculation of the annualized indices by assuming that the peak load of a system remains constant for the entire period of study gives inflated values of the system unreliability. These indices can be useful when comparing the relative performance of two systems or when studying the effect of alterations in a system. Calculation of the annual indices is highly desirable in order to obtain an appreciation of the absolute performance of a system. This, however, involves large computation time. The time can be reduced by properly selecting the optimum number of load steps used to model the load curve. In the case of the 6 bus test system and the IEEE RTS, the contribution of low system loads to the adequacy indices is negligible. As shown in Chapter 5, the annual adequacy indices for the IEEE RTS using the seven step load model are almost equal to the indices calculated using the thirteen step load model. The appropriate number of load steps may, however, be different for each particular system under study.

The effect of common cause outages and station originated outages is comparable to that of high level independent generating unit outages at the 3rd and 4th level both for the 6 bus test system and the IEEE RTS. This, therefore, suggests that it is advisable to examine common cause and station originated outages prior to considering further higher level independent outages. As noted in Chapter 3, inclusion of independent outages for the generating units beyond the 4th level involves tremendously high CPU time for a practical network. The contribution of these independent outages may not be significant as observed in Section 3.3. The inclusion of station originated outages and common cause outages, however, does not increase the computation time to a great extent.

The effect of system load variation on the system indices with common cause and station originated outages is non-uniform. It is observed in Chapter 6 that as the system load decreases, the relative contribution of these outages becomes more pronounced as compared to that of independent outages. This, therefore, necessitates the examination of common cause and station originated outages when calculating either annualized indices at low values of system load or annual indices to assess the system performance in absolute terms.

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APPENDICES

I Appendix A - Data of the 6 bus test system

Base MVA = 100

Table A-1: Line data

Line No.	Buses I	Buses J	R	X	B/2	Tap	Current Rating (p.u.)	Failures per Year	Repair Time (hours)
1	1	3	0.0342	0.1800	0.0106	1.00	0.85	1.500	10.00
2	2	4	0.1140	0.6000	0.0352	1.00	0.71	5.000	10.00
3	1	2	0.0912	0.4800	0.0282	1.00	0.71	4.000	10.00
4	3	4	0.0228	0.1200	0.0071	1.00	0.71	1.000	10.00
5	3	5	0.0228	0.1200	0.0071	1.00	0.71	1.000	10.00
6	1	3	0.0342	0.1800	0.0106	1.00	0.85	1.500	10.00
7	2	4	0.1140	0.6000	0.0352	1.00	0.71	5.000	10.00
8	4	5	0.0228	0.1200	0.0071	1.00	0.71	1.000	10.00
9	5	6	0.0228	0.1200	0.0071	1.00	0.71	1.000	10.00

$\mu = 876$

Table A-2: Bus data

Bus	Load (p.u.) Active	Load (p.u.) Reactive	P_G	Q_{Max}	Q_{Min}	V_0	V_{Max}	V_{Min}
1	0.000	0.000	1.000	0.40	-0.30	1.05	1.05	0.97
2	0.200	0.000	1.200	0.50	-0.40	1.05	1.05	0.97
3	0.850	0.000	0.000	0.00	0.00	1.00	1.05	0.97
4	0.400	0.000	0.000	0.00	0.00	1.00	1.05	0.97
5	0.200	0.000	0.000	0.00	0.00	1.00	1.05	0.97
6	0.200	0.000	0.000	0.00	0.00	1.00	1.05	0.97

Table A-3: Generator data

Unit No.	Bus No.	Rating (MW)	Failures per Year	Repair Time (Hrs)
1	1	40.00	1.10000	120.00
2	1	40.00	1.10000	120.00
3	1	10.00	1.10000	120.00
4	1	20.00	1.10000	120.00
5	2	5.00	0.50000	87.60
6	2	5.00	0.50000	87.60
7	2	5.00	0.50000	87.60
8	2	5.00	0.50000	87.60
9	2	5.00	0.50000	87.60
10	2	5.00	0.50000	87.60
11	2	5.00	0.50000	87.60
12	2	15.00	0.50000	87.60
13	2	20.00	0.50000	87.60
14	2	20.00	0.50000	87.60
15	2	20.00	0.50000	87.60
16	2	20.00	0.50000	87.60

$\mu=73$ Yrs = 0.01370

$\mu=100$ $\rightarrow$ = 0.0100

II Appendix B - Data of the IEEE RTS

Base MVA = 100

Table B-1: Line data

Line No.	Buses I	J	R	X	B/2	Tap	Current Rating (p.u.)	Failures per Year	Repair Time (hours)
1	1	2	0.0026	0.0139	0.2306	1.00	1.93	0.240	16.00
2	1	3	0.0546	0.2112	0.0286	1.00	2.08	0.510	10.00
3	1	5	0.0218	0.0845	0.0115	1.00	2.08	0.330	10.00
4	2	4	0.0328	0.1267	0.0172	1.00	2.08	0.390	10.00
5	2	6	0.0497	0.1920	0.0260	1.00	2.08	0.480	10.00
6	3	9	0.0308	0.1190	0.0161	1.00	2.08	0.380	10.00
7	3	24	0.0023	0.0839	0.0000	1.00	5.10	0.020	768.00
8	4	9	0.0268	0.1037	0.0141	1.00	2.08	0.360	10.00
9	5	10	0.0228	0.0883	0.0120	1.00	2.08	0.340	10.00
10	6	10	0.0139	0.0605	1.2295	1.00	1.93	0.330	35.00
11	7	8	0.0159	0.0614	0.0166	1.00	2.08	0.300	10.00
12	8	9	0.0427	0.1651	0.0224	1.00	2.08	0.440	10.00
13	8	10	0.0427	0.1651	0.0224	1.00	2.08	0.440	10.00
14	9	11	0.0023	0.0839	0.0000	1.00	6.00	0.020	768.00
15	9	12	0.0023	0.0839	0.0000	1.00	6.00	0.020	768.00
16	10	11	0.0023	0.0839	0.0000	1.00	6.00	0.020	768.00
17	10	12	0.0023	0.0839	0.0000	1.00	6.00	0.020	768.00
18	11	13	0.0061	0.0476	0.0500	1.00	6.00	0.400	11.00
19	11	14	0.0054	0.0418	0.0440	1.00	6.00	0.390	11.00
20	12	13	0.0061	0.0476	0.0500	1.00	6.00	0.400	11.00
21	12	23	0.0124	0.0966	0.1015	1.00	6.00	0.520	11.00
22	13	23	0.0111	0.0865	0.0909	1.00	6.00	0.490	11.00
23	14	16	0.0050	0.0389	0.0409	1.00	6.00	0.380	11.00
24	15	16	0.0022	0.0173	0.0364	1.00	6.00	0.330	11.00
25	15	21	0.0063	0.0490	0.0515	1.00	6.00	0.410	11.00
26	15	21	0.0063	0.0490	0.0515	1.00	6.00	0.410	11.00
27	15	24	0.0067	0.0519	0.0546	01.00	6.00	0.410	11.00
28	16	17	0.0033	0.0259	0.0273	1.00	6.00	0.350	11.00
29	16	19	0.0030	0.0231	0.0243	1.00	6.00	0.340	11.00
30	17	18	0.0018	0.0144	0.0152	1.00	6.00	0.320	11.00
31	17	22	0.0135	0.1053	0.1106	1.00	6.00	0.540	11.00
32	18	21	0.0033	0.0259	0.0273	1.00	6.00	0.350	11.00
33	18	21	0.0033	0.0259	0.0273	1.00	6.00	0.350	11.00
34	19	20	0.0051	0.0396	0.0417	1.00	6.00	0.380	11.00
35	19	20	0.0051	0.0396	0.0417	1.00	6.00	0.380	11.00
36	20	23	0.0028	0.0216	0.0228	1.00	6.00	0.340	11.00
37	20	23	0.0028	0.0216	0.0228	1.00	6.00	0.340	11.00
38	21	22	0.0087	0.0678	0.0712	1.00	6.00	0.450	11.00

Table B-2: Bus data

Bus	Load (p.u.) Active	Load (p.u.) Reactive	P_G	Q_{Max}	Q_{Min}	V_0	V_{Max}	V_{Min}
1	1.080	0.220	1.720	1.20	-0.75	1.00	1.05	0.95
2	0.970	0.200	1.720	1.20	-0.75	1.00	1.05	0.95
3	1.800	0.370	0.000	0.00	0.00	1.00	1.05	0.95
4	0.740	0.150	0.000	0.00	0.00	1.00	1.05	0.95
5	0.710	0.140	0.000	0.00	0.00	1.00	1.05	0.95
6	1.360	0.280	0.000	0.00	0.00	1.00	1.05	0.95
7	1.250	0.250	3.000	2.70	0.00	1.00	1.05	0.95
8	1.710	0.350	0.000	0.00	0.00	1.00	1.05	0.95
9	1.750	0.360	0.000	0.00	0.00	1.00	1.05	0.95
10	1.950	0.400	0.000	0.00	0.00	1.00	1.05	0.95
11	0.000	0.000	0.000	0.00	0.00	1.00	1.05	0.95
12	0.000	0.000	0.000	0.00	0.00	1.00	1.05	0.95
13	2.650	0.540	5.500	3.60	0.00	1.00	1.05	0.95
14	1.940	0.390	0.000	3.00	-0.75	1.00	1.05	0.95
15	3.170	0.640	2.100	1.65	-0.75	1.00	1.05	0.95
16	1.000	0.200	1.450	1.20	-0.75	1.00	1.05	0.95
17	0.000	0.000	0.000	0.00	0.00	1.00	1.05	0.95
18	3.330	0.680	4.000	3.00	-0.75	1.00	1.05	0.95
19	1.810	0.370	0.000	0.00	0.00	1.00	1.05	0.95
20	1.280	0.260	0.000	0.00	0.00	1.00	1.05	0.95
21	0.000	0.000	3.500	3.00	-0.75	1.00	1.05	0.95
22	0.000	0.000	2.500	1.45	-0.90	1.00	1.05	0.95
23	0.000	0.000	6.600	4.50	-1.75	1.00	1.05	0.95
24	0.000	0.000	0.000	0.00	0.00	1.00	1.05	0.95

Table B-3: Generator data

Unit No.	Bus No.	Rating (MW)	Failures per Year	Repair Time (Hrs)
1	22	50.00	4.42000	20.00
2	22	50.00	4.42000	20.00
3	22	50.00	4.42000	20.00
4	22	50.00	4.42000	20.00
5	22	50.00	4.42000	20.00
6	22	50.00	4.42000	20.00
7	15	12.00	2.98000	60.00
8	15	12.00	2.98000	60.00
9	15	12.00	2.98000	60.00
10	15	12.00	2.98000	60.00
11	15	12.00	2.98000	60.00
12	15	155.00	9.13000	40.00
13	7	100.00	7.30000	50.00
14	7	100.00	7.30000	50.00
15	7	100.00	7.30000	50.00
16	13	197.00	9.22000	50.00
17	13	197.00	9.22000	50.00
18	13	197.00	9.22000	50.00
19	1	20.00	19.47000	50.00
20	1	20.00	19.47000	50.00
21	1	76.00	4.47000	40.00
22	1	76.00	4.47000	40.00
23	2	20.00	19.47000	50.00
24	2	20.00	19.47000	50.00
25	2	76.00	4.47000	40.00
26	2	76.00	4.47000	40.00
27	23	155.00	9.13000	40.00
28	23	155.00	9.13000	40.00
29	23	350.00	7.62000	100.00
30	18	400.00	7.96000	150.00
31	21	400.00	7.96000	150.00
32	16	155.00	9.13000	40.00

III Appendix C - Data of the SPC system

Base MVA = 100

Table C-1: Line data

Line No.	Buses I	Buses J	R	X	B/2	Tap	Current Rating (p.u.)	Failures per Year	Repair Time (hours)
1	1	7	0.07360	0.28380	0.03835	1.0	1.300	0.51000	2.50
2	1	9	0.06110	0.23540	0.03175	1.0	1.640	0.51000	2.50
3	1	26	0.00000	0.03050	0.00000	1.0	1.600	0.08800	12.50
4	2	4	0.01890	0.06960	0.01010	1.0	1.230	0.51000	2.50
5	2	9	0.06217	0.23956	0.00000	1.0	1.650	0.51000	2.50
6	2	25	0.04020	0.15220	0.02095	1.0	1.900	0.51000	2.50
7	2	25	0.04014	0.15209	0.00000	1.0	1.900	0.51000	2.50
8	2	27	0.00000	0.02970	0.00000	1.0	2.160	0.08800	12.50
9	2	27	0.00000	0.02940	0.00000	1.0	2.160	0.08800	12.50
10	3	5	0.02880	0.18690	0.02420	1.0	2.160	0.51000	2.50
11	3	29	0.00000	0.04040	0.00000	1.0	1.760	0.08800	12.50
12	4	31	0.00000	0.03270	0.00000	1.0	3.000	0.08800	12.50
13	5	6	0.05170	0.19860	0.02670	1.0	1.200	0.51000	2.50
14	6	7	0.08640	0.33380	0.04520	1.0	1.430	0.51000	2.50
15	6	8	0.06770	0.26080	0.03530	1.0	1.070	0.51000	2.50
16	6	32	0.00000	0.03710	0.00000	1.0	2.650	0.08800	12.50
17	6	32	0.00000	0.03710	0.00000	1.0	2.650	0.08800	12.50
18	8	12	0.07230	0.27860	0.03770	1.0	1.070	0.51000	2.50
19	10	14	0.10510	0.23820	0.02940	1.0	0.860	0.51000	2.50
20	10	15	0.03830	0.14710	0.01970	1.0	1.160	0.51000	2.50
21	10	16	0.03970	0.15880	0.01965	1.0	0.870	0.51000	2.50
22	10	16	0.03970	0.15880	0.01965	1.0	0.870	0.51000	2.50
23	10	34	0.00000	0.03000	0.00000	1.0	1.600	0.08800	12.50
24	10	34	0.00000	0.03030	0.00000	1.0	1.600	0.08800	12.50
25	11	13	0.05400	0.12170	0.01495	1.0	1.300	0.51000	2.50
26	11	17	0.06140	0.23060	0.03180	1.0	1.350	0.51000	2.50
27	11	18	0.05150	0.19810	0.02670	1.0	1.400	0.51000	2.50
28	11	20	0.08700	0.35200	0.04335	1.0	1.900	0.51000	2.50
29	11	20	0.08700	0.35200	0.04335	1.0	1.900	0.51000	2.50
30	11	35	0.00000	0.02650	0.00000	1.0	1.600	0.08800	12.50
31	11	36	0.00000	0.02650	0.00000	1.0	1.600	0.08800	12.50
32	12	13	0.03730	0.14340	0.01930	1.0	1.610	0.51000	2.50
33	12	14	0.04380	0.09930	0.01225	1.0	0.860	0.51000	2.50
34	12	37	0.00000	0.04000	0.00000	1.0	2.370	0.08800	12.50
35	17	18	0.01550	0.05960	0.00795	1.0	1.550	0.51000	2.50

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Line No.	Buses I	J	R	X	B/2	Tap	Current rating (p.u.)	Failures per Year	Repair Time (hours)
36	17	19	0.09213	0.42315	0.00000	1.0	0.950	0.51000	2.50
37	17	25	0.09120	0.35210	0.04760	1.0	1.490	0.51000	2.50
38	17	39	0.00000	0.04100	0.00000	1.0	2.370	0.08800	12.50
39	18	25	0.09191	0.35478	0.00000	1.0	1.640	0.51000	2.50
40	19	21	0.03660	0.14070	0.01885	1.0	1.330	0.51000	2.50
41	20	21	0.07610	0.17170	0.02105	1.0	1.300	0.51000	2.50
42	22	24	0.08690	0.24290	0.03095	1.0	0.910	0.51000	2.50
43	22	40	0.00000	0.04100	0.00000	1.0	2.370	0.08800	12.50
44	23	25	0.06870	0.26480	0.03570	1.0	1.640	0.51000	2.50
45	23	41	0.00000	0.04000	0.00000	1.0	2.370	0.08800	12.50
46	24	25	0.08500	0.23760	0.03030	1.0	0.910	0.51000	2.50
47	26	27	0.02100	0.12140	0.22530	1.0	3.380	0.66000	3.75
48	26	27	0.02100	0.12140	0.22530	1.0	3.350	0.66000	3.75
49	26	29	0.01690	0.10960	0.11000	1.0	3.330	0.66000	3.75
50	26	44	0.02630	0.16990	0.16935	1.0	2.450	0.66000	3.75
51	27	28	0.00190	0.01200	0.01205	1.0	2.990	0.66000	3.75
52	28	31	0.00360	0.02360	0.02365	1.0	2.990	0.66000	3.75
53	29	31	0.02490	0.16220	0.16860	1.0	3.100	0.66000	3.75
54	30	31	0.01510	0.11340	0.21885	1.0	4.290	0.66000	3.75
55	30	41	0.00650	0.04880	0.09360	1.0	7.100	0.66000	3.75
56	31	37	0.01730	0.14300	0.14550	1.0	2.720	0.66000	3.75
57	32	42	0.01070	0.07160	0.07035	1.0	2.500	0.66000	3.75
58	33	34	0.01490	0.12090	0.13095	1.0	4.500	0.66000	3.75
59	33	38	0.00660	0.05360	0.05805	1.0	4.500	0.66000	3.75
60	33	43	0.02330	0.15600	0.15050	1.0	3.100	0.66000	3.75
61	34	35	0.01730	0.13990	0.15215	1.0	1.600	0.66000	3.75
62	34	36	0.01730	0.13990	0.15215	1.0	1.600	0.66000	3.75
63	34	38	0.00830	0.06730	0.07290	1.0	4.500	0.66000	3.75
64	39	40	0.02540	0.13490	0.13175	1.0	2.370	0.66000	3.75
65	40	41	0.01430	0.10740	0.20690	1.0	4.000	0.66000	3.75
66	42	43	0.02087	0.10776	0.00000	1.0	9.990	0.66000	1.00
67	42	44	0.26979	1.40478	0.00000	1.0	9.990	0.66000	1.00
68	42	45	0.20143	1.00157	0.00000	1.0	9.990	0.66000	1.00
69	43	44	0.01400	0.15905	0.00000	1.0	9.990	0.66000	1.00
70	43	45	0.07479	0.60670	0.00000	1.0	9.990	0.66000	1.00
71	44	45	0.03195	0.27886	0.00000	1.0	9.990	0.66000	1.00

Table C-2: Bus data

Bus	Load (p.u.) P_L	Q_L	P_G	Q_{Max}	Q_{Min}	V_0	V_{Max}	V_{Min}	Name
1	0.760	0.105	1.500	2.000	-1.250	1.05	1.050	0.950	BD 138
2	1.452	0.413	0.000	0.000	0.000	1.00	1.050	0.950	REGIN138
3	0.051	0.005	0.000	0.000	0.000	1.00	1.050	0.950	KENNE138
4	1.655	0.351	0.000	0.000	0.000	1.00	1.050	0.950	CONDI138
5	0.860	0.061	0.000	0.000	0.000	1.00	1.050	0.950	TANTA138
6	0.950	0.060	0.000	0.000	0.000	1.00	1.050	0.950	YORKT138
7	0.303	0.037	0.000	0.000	0.000	1.00	1.050	0.950	PEEBL138
8	0.293	0.008	0.000	0.000	0.000	1.00	1.050	0.950	BANKE138
9	0.456	0.072	0.000	0.000	0.000	1.00	1.050	0.950	WEYBU138
10	0.000	0.000	0.000	0.000	0.000	1.00	1.050	0.950	BEATT138
11	2.940	0.873	0.800	2.300	-2.500	1.05	1.050	0.950	QE 138
12	0.565	0.217	0.000	0.000	0.000	1.05	1.050	0.950	WOLVE138
13	0.509	0.120	0.000	0.000	0.000	1.00	1.050	0.950	ELSTO138
14	0.142	0.028	0.000	0.000	0.000	1.00	1.050	0.950	HUMBO138
15	0.579	0.092	0.000	0.000	0.000	1.00	1.050	0.950	TISDA138
16	0.980	0.251	0.000	0.000	0.000	1.00	1.050	0.950	PA 138
17	0.035	0.015	1.890	1.600	-2.000	1.05	1.050	0.950	CC 138
18	0.468	0.076	0.000	0.000	0.000	1.00	1.050	0.950	HAWAR138
19	0.598	0.115	0.000	0.000	0.000	1.00	1.050	0.950	ERMIN138
20	1.358	0.357	0.000	0.000	0.000	1.00	1.050	0.950	NB 138
21	0.071	0.010	0.000	0.750	-0.750	1.05	1.050	0.950	LANDI138
22	0.789	0.064	0.000	0.000	0.000	1.00	1.050	0.950	SC 138
23	0.424	0.086	0.000	0.000	0.000	1.00	1.050	0.950	ASSIN138
24	0.141	0.013	0.000	0.000	0.000	1.00	1.050	0.950	CHAPL138
25	0.638	0.059	0.000	0.000	0.000	1.00	1.050	0.950	PASQU138
26	0.000	0.000	6.000	5.000	-4.000	1.05	1.050	0.950	BD 230
27	0.000	0.000	0.000	0.000	0.000	1.00	1.050	0.950	REGIN230
28	0.697	0.237	0.000	0.000	0.000	1.00	1.050	0.950	FS 230
29	0.000	0.000	0.000	0.000	0.000	1.00	1.050	0.950	KENNE230
30	0.041	0.000	5.600	4.000	-4.000	1.05	1.050	0.950	PR 230
31	0.000	0.000	0.000	0.000	0.000	1.00	1.050	0.950	CONDI230
32	0.000	0.000	0.000	0.000	0.000	1.00	1.050	0.950	YORKT230
33	0.000	0.000	2.400	2.500	-4.000	1.05	1.050	0.950	SR 230
34	0.000	0.000	0.000	0.000	0.000	1.00	1.050	0.950	BEATT230
35	0.000	0.000	0.000	0.000	0.000	1.00	1.050	0.950	QE A 230
36	0.000	0.000	0.000	0.000	0.000	1.00	1.050	0.950	QE B 230
37	0.000	0.000	0.000	0.000	0.000	1.00	1.050	0.950	WOLVE230
38	0.270	0.039	0.000	0.000	0.000	1.00	1.050	0.950	CODET230
39	0.000	0.000	0.000	0.000	0.000	1.00	1.050	0.950	CC 230
40	0.000	0.000	0.000	0.000	0.000	1.00	1.050	0.950	SC 230
41	0.000	0.000	0.000	0.000	0.000	1.00	1.050	0.950	ASSIN230
42	0.000	0.000	0.000	0.000	0.000	1.00	1.050	0.950	ROBLN230
43	0.000	0.000	0.000	0.000	0.000	1.00	1.050	0.950	TPAS 230
44	0.000	0.000	0.000	2.000	-4.000	1.00	1.050	0.950	RESTO
45	0.000	0.000	2.500	3.000	-3.000	1.00	1.050	0.950	HYP 110

Table C-3: Generator data

Unit No.	Bus No.	Rating (MW)	Failures per Year	Repair Time (Hrs)
1	33	34.0000	2.50000	2.50
2	33	34.0000	2.50000	2.50
3	33	34.0000	2.50000	2.50
4	33	34.0000	2.50000	2.50
5	33	34.0000	2.50000	2.50
6	33	34.0000	2.50000	2.50
7	33	42.0000	8.40000	7.00
8	33	42.0000	8.40000	7.00
9	17	63.0000	2.20000	4.50
10	17	63.0000	2.20000	4.50
11	17	63.0000	2.20000	4.50
12	45	100.0000	20.60000	15.00
13	45	100.0000	20.60000	15.00
14	45	100.0000	20.60000	15.00
15	26	142.0000	17.90000	20.00
16	26	142.0000	17.90000	20.00
17	26	142.0000	18.90000	26.00
18	26	280.0000	21.20000	13.00
19	1	66.0000	29.70000	28.00
20	1	66.0000	29.70000	28.00
21	1	15.0000	21.00000	26.00
22	1	20.0000	21.00000	26.00
23	1	30.0000	21.00000	26.00
24	30	280.0000	21.20000	13.00
25	30	280.0000	21.20000	13.00
26	11	62.0000	5.10000	13.00
27	11	62.0000	14.80000	56.00
28	11	96.0000	23.60000	3.50
29	21	70.0000	65.40000	1.75

IV Appendix D - Common cause data

Table D-1: Common cause data for the 6 bus test system and the IEEE RTS

Lines Exposed To C.C.		Common Cause(C.C.) Failure Rate	Repair Time (hours)
		6 Bus Test System	
1	6	0.150	16.00
2	7	0.500	16.00
		IEEE RTS	
12	13	0.500	16.00
18	24	0.500	16.00
25	26	0.150	16.00
31	38	0.500	16.00
32	33	0.500	16.00
34	35	0.500	16.00
36	37	0.500	16.00