APPLICATION OF THE JOINT DETERMINISTIC-PROBABILISTIC (D-P) CRITERIA TO BULK ELECTRIC SYSTEM PLANNING

A Thesis

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ABSTRACT

Bulk electric system reliability analysis is an important activity in both vertically integrated and unbundled electric power utilities. Conventional deterministic N-1 criterion used to bulk electric system planning does not response to the probabilistic factors that influence the reliability of the system and is a rigid criterion. New planning criteria with the inclusion of traditional deterministic N-1 and probabilistic perspective must be explicitly addressed.

This research work introduces the concept of the joint deterministic-probabilistic (D-P) criteria to bulk electric system planning using a previously developed software package designated as MECORE. The D-P concept presented is a deterministic framework that incorporates the probabilistic criterion. This research examines the application of the conventional deterministic N-1, the basic probabilistic and the D-P criteria to two test systems. The studies show that the D-P approach is driven by the accepted deterministic N-1 criterion and influenced by the probabilistic criterion (Pc). The D-P technique adds additional probabilistic risk information to the traditional deterministic N-1 criterion that is useful when making system reinforcement decisions.

The research work illustrated in this thesis indicates that the D-P criterion and procedures for bulk electric system analysis can be effectively utilized in bulk electric system planning. The conclusions and the techniques presented in this thesis should prove valuable to those responsible for system planning.

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LIST OF ABBREVIATIONS

ADLC	Average Duration of Load Curtailment
BES	Bulk Electric System
BPACI	Bulk Power-supply Average MW Curtailment Index
BPECI	Bulk Power/Energy Curtailment Index
BPII	Bulk Power Interruption Index
CPU	Central Processing Unit
D	Deterministic
DISCO	Distribution Company
D-P	Deterministic-Probabilistic
Dur {H}	Average residence duration in the healthy state (hours/occurrence)
Dur {M}	Average residence duration in the marginal state (hours/occurrence)
Dur {R}	Average residence duration in the at risk state (hours/occurrence)
EDC	Expected Damage Cost
EDLC	Expected Duration of Load Curtailment
EDNS	Expected Demand Not Supplied
EENS	Expected Energy Not Supplied
EFLC	Expected frequency of load curtailment
ELC	Expected Load Curtailment
ENLC	Expected Number of Load Curtailments
FOR	Forced Outage Rate
Freq {H}	Frequency of the healthy state (occurrences/year)
Freq {M}	Frequency of the marginal state (occurrences/year)
Freq {R}	Frequency of the at risk state (occurrences/year)
G	Generation
GENCO	Generation Company
G&T	Generation and Transmission
HL	Hierarchical Level
HLI	Hierarchical Level I
HLII	Hierarchical Level II
HLIII	Hierarchical Level III
IEAR	Interrupted Energy Assessment Rate
IEEE-RTS	IEEE-Reliability Test System
ISO	Independent System Operator
kWh	Kilowatt-hours
LOLD	Loss of Load duration
LOLE	Loss of Load Expectation
LOLF	Loss of Load Frequency
LOLP	Loss of Load Probability
MECORE	Monte Carlo and Enumeration Composite Reliability Evaluation
MRBTS	Modified Roy Billinton Test System
MW	Megawatt
MWh	Megawatt-hours
NERC	North American Electric Reliability Council

OPF	Optimal Power Flow
P	Probabilistic
Pc	Probabilistic criterion
PLC	Probability of Load Curtailment
PLCC	Peak Load Carrying Capability
Prob {H}	Probability of the healthy state (/year)
Prob {M}	Probability of the marginal state (/year)
Prob {R}	Probability of the at risk state (/year)
SI	Severity Index (SM/year)
SM	System Minutes
T	Transmission
TRSCO	Transmission Company
VOLL	Value of Lost Load ($/kWh)
Yr	Year
$	Dollars

1. INTRODUCTION

1.1 Introduction

Electric power systems are among the most complex and largest systems that exist in the world and are undergoing considerable change in regard to structure, operation and regulation. Competition and uncertainty in the new deregulated electric utility industry are serious concerns. Electric power utilities also face increasing uncertainty regarding the political, economic, societal and environmental constraints under which they have to operate existing systems and plan future systems. All these conditions have created new electric utility environments that require extensive justification of new facilities, optimization of system configurations, improvements in system reliability and decreases in construction and operating costs.

The basic function of an electric power system is to supply its customers with electrical energy as economically as possible and with a reasonable degree of continuity and quality [1]. Reliability is one of the most important factors considered in power system planning and operation in both vertically integrated and deregulated utility environments. It is not economical and technically feasible to attempt to design a power system with one hundred percent reliability. Power system engineers, therefore, attempt to achieve an acceptable level of system reliability in their planning, design and operation within the existing economic constraints. In order to resolve the conflict between the economic and reliability constraints, a wide range of techniques and criteria has been developed and used in the system design, planning and operating phases. It is expected that the application of reliability concepts in electric power system planning and operation will continue to increase in the future in both regulated and deregulated utility environments.

1.2 Power System Reliability and Related Concepts

Reliability is an inherent characteristic and a specific measure of any component, device or system which describes its ability to perform its intended function. In the context of power systems, reliability in general terms is related to the ability of the system to supply electric power to its customers under both static and dynamic conditions, with a mutually acceptable assurance of continuity and quality [2]. The term "system reliability" can be subdivided into the two fundamental aspects of system adequacy and system security [1] as shown in Figure 1.1.

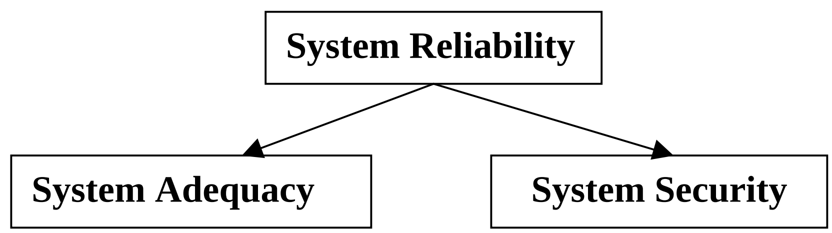

Figure 1.1: Subdivision of system reliability

Adequacy relates to the existence of sufficient facilities within the system to satisfy the customer requirements. It is associated with static conditions and long-term analysis. Security relates to the ability of the system to respond to disturbances. It is associated with dynamic conditions and short-term analysis. This thesis is focused on the adequacy evaluation of power systems.

An overall power system can be divided into functional zones in order to focus on specific problem areas and to simplify the analysis. The three basic functional zones are those of generation, transmission and distribution. Power system adequacy assessment can be conducted in each functional zone and at each hierarchical level [1]. Figure 1.2 shows the three hierarchical levels.

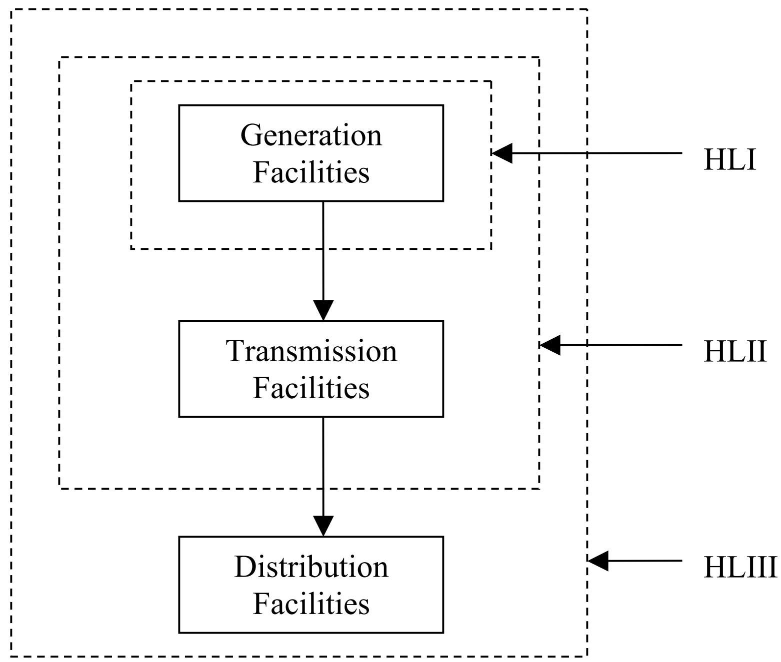

Figure 1.2: Functional zones and hierarchical levels

Reliability assessment at hierarchical level I (HLI) is normally termed as generating capacity adequacy evaluation and is concerned with only the generating facilities [3-7]. In an HLI study, the total system generation including interconnected assistance is examined to determine its adequacy to meet the total system load demand. The transmission network and the distribution facilities are not part of the analysis at this level.

Reliability assessment at hierarchical level II (HLII) is normally referred to as composite system (or bulk system) reliability evaluation and involves the analysis of the combined generation and transmission system in regard to its ability to serve the system load. The function of a composite system is to produce electrical energy at the generating sources and then move this energy to the major load points. The purpose of composite system reliability evaluation is to estimate the ability of the system to perform this function. Assessment of composite system reliability is very complex since it must consider the integrated impacts of generation and transmission. HLII studies include aspects such as load flow analysis, contingency analysis, generation rescheduling, transmission overload alleviation, load curtailment philosophy, etc. Composite system reliability evaluation can be used to estimate the impacts on the adequacy of an existing or proposed system of factors such as reinforcement alternatives at generation and transmission levels [8], maintenance schedules, operating strategies, equipment availability [9], generation modeling, substation configurations etc. In addition, composite system reliability evaluation can be used to coordinate maintenance scheduling, rank system component importance, and so on. The application of quantitative reliability evaluation in electric power systems has now evolved to the point at which most utilities use these techniques in one or more areas of their planning, design and operation [10]. The effect of load growth, configuration changes and facility additions can be studied and the reliability indices can be evaluated for the overall system as well as for the individual buses [10-15].

Considerable effort has been expended during the last two decades in developing techniques and criteria for composite generation and transmission system assessment. The term composite refers to the consideration of both generation and transmission system contingencies, including the modeling of the operating policies necessary in order to dispatch generating units, assess power flows on transmission system components, alleviate network violations, and shed load if required.

Reliability assessment at hierarchical level III (HLIII) includes all of the three functional zones and is not easily conducted in a practical system due to the computational complexity and the scale of the assessment. Analyses are usually performed in the distribution functional zone. Load point indices evaluated at HLII can be used as input to these analyses [16-18]. This thesis is focused on adequacy assessment at HLII. Further discussion on composite system reliability evaluation is presented in Chapter 2 of this thesis.

1.3 Deregulated Power Systems

Electric power systems have traditionally been organized and operated as regulated monopolies. In these cases, an electric power utility or entity owns and operates all the three functional zones of the power system and therefore controls all aspects of system planning, design and operation. The power industry is now undergoing considerable changes due to deregulation. The main aim of restructuring is to let market forces drive the price of electric supply and reduce the net cost through increased competition. Restructuring creates an open market environment by allowing competition in power supply and allowing consumers to choose their supplier of electric energy.

In the new structure, generation companies (GENCO) can be separately owned and compete to sell energy to consumers, and are no longer controlled by the same entities that control the transmission system. Transmission companies (TRANSCO) move energy over high-voltage lines. Distribution companies (DISCO) move energy at the retail level and may aggregate retail loads. These entities must work cooperatively to provide cost-effective and reliable electric power supply. Independent entities designated as Independent System Operators (ISO), coordinate the activities of the GENCO, TRANSCO, and DISCO to achieve the overall goal of serving the customers [19].

1.4 Concept of Bulk Electric System Reliability Analysis

The term "bulk electric system" used in this thesis is equivalent to the term "composite generation and transmission system" introduced in [10], which falls into hierarchical level-II (HL-II) noted earlier. The reliability assessment of composite generation and transmission systems or bulk electric systems is extremely complicated as it is necessary to include detailed modeling of both the generation and transmission facilities to consider multiple levels of component failure. Composite power system reliability evaluation provides an assessment of the ability of an electric power system to satisfy the load and energy requirements at the major load points and for the overall system. The most significant quantitative indices in composite power system reliability evaluation are those that relate to load curtailment. Reliability assessment at HL-II can be performed using analytical methods or Monte Carlo simulation techniques [1].

Analytical methods such as contingency enumeration [20] represent the system by a mathematical model and evaluate the reliability indices from the model using direct numerical solutions. An analytical method will always give the same numerical results for the same system, model and set of input data. These methods tend to provide confidence in the reliability evaluation as the results are obtained by an exact solution using an accepted system model. Significant assumptions, however, are frequently required in order to simplify the problem and to produce an analytical model of the system. This is particularly the case when complex operating procedures have to be modeled. The resulting analysis can therefore sometimes lose some or much of its significance.

This difficulty can be reduced or eliminated by using a simulation approach. Monte Carlo simulation methods estimate the reliability indices by simulating the actual process and random behaviour of the system. The method therefore treats the problem as a series of experiments. There are merits and demerits in both methods. Generally, Monte Carlo simulation requires a large amount of computing time compared to analytical methods. Monte Carlo simulation techniques, however, can theoretically take into account virtually all aspects and contingencies inherent in the planning, design and operation of a power system [1, 21]. These include random events such as outages and repairs of elements represented by general probability distributions and different types of operating policies. On the other hand, numerous assumptions and approximations may be required in an analytical approach to handle complex operations and inherent characteristics. References 22-25 show 145 published papers during the last two decades on the subject of composite generation and transmission system reliability evaluation using analytical or Monte Carlo simulation techniques, or a hybrid of both methods. There is a growing interest and an increasing trend in applying Monte Carlo simulation approaches to bulk electric system reliability analysis due to the development and availability of high speed computation facilities.

Two basic techniques are used when applying Monte Carlo simulation methods to bulk electric system reliability evaluation. These methods are designated as the sequential and non-sequential approaches. Sequential simulation can fully take into account the chronological behaviour of the system, while the non-sequential method involves non-chronological system state considerations.

1.5 Bulk Electric System Planning Criteria

Although most Canadian utilities apply probabilistic technique in the planning and operation of generating capacity, deterministic criteria are very popular in the planning and operation of bulk electric systems (BES). The most common deterministic criterion dictates that specific credible outages will not result in system failure. The traditional deterministic criterion used particularly in bulk electric systems is known as the N-1 security criterion [26, 27] under which the loss of any BES component will not result in system failure. Deterministic techniques, which are also often referred to as engineering judgment, do not include an assessment of the actual system reliability as they do not incorporate the probabilistic or stochastic nature of system behaviour and component failures. These approaches, therefore, are inconsistent [28]. Although deterministic criteria do not consider the stochastic behaviour of system components, they are easier for system planners, designers and operators to understand than a numerical risk index determined using probabilistic techniques.

In contrast, probabilistic methods can respond to the significant factors that affect the reliability of a system. These techniques provide quantitative indices, which can be used to decide if the system performance is acceptable or if changes need to be made. There is, however, considerable reluctance to use probabilistic techniques in many areas due to the difficulty in interpreting the resulting numerical indices.

1.6 Scope and Objectives of the Thesis

The research presented in this thesis is focused on the utilization of deterministic and probabilistic adequacy criteria in long term bulk electric system planning.

The objective of the research is to specifically examine the application of the conventional N-1 criterion and the basic probabilistic approach, and to create a combined approach in which probabilistic criteria are embedded within a deterministic framework.

The combined deterministic and probabilistic criterion incorporates a deterministic consideration, which is a rigid criterion, with a probabilistic assessment to provide a resulting responsive criterion. This concept is designated in this thesis as the joint deterministic and probabilistic (D-P) technique.

1.7 Outline of the Thesis

Chapter 1 provides a brief introduction to the overall area of power system reliability evaluation. A brief introduction to deregulated power system structures and reliability evaluation concepts is given in this chapter.

Chapter 2 briefly discusses the deterministic N-1 criterion and the North American Electric Reliability Council (NERC) Planning Standards. Two Monte Carlo techniques used in bulk electric system reliability evaluation, i.e. the state sampling method and the sequential method are briefly described. A bulk electric system reliability evaluation tool designated as MECORE is introduced in this chapter. The MECORE software is based on the state sampling technique for Monte Carlo simulation. The load point and system indices used in MECORE to measure bulk electric system reliability are described in this chapter and the two test systems used extensively in this thesis are also introduced. Data on these systems are presented in Appendix A. The modified Roy Billinton Test System (MRBTS) is a small educational test system. The IEEE Reliability Test System (IEEE-

RTS) is a relatively large system compared with the MRBTS. Base cases studies of the two test systems, load curtailment priority orders, and annual and annualized indices are discussed.

Chapter 3 discusses the concept of a joint deterministic and probabilistic approach to bulk system reliability evaluation. An existing technique developed at the University of Saskatchewan [29-31] known as the system well-being approach is described. This technique incorporates a deterministic criterion in a probabilistic framework. The new technique developed in this research, which is a probabilistic criterion embedded in a deterministic framework is proposed and illustrated.

Chapter 4 describes a series of studies on the MRBTS system that illustrate how the new joint deterministic-probabilistic (D-P) technique can be used to assess the various risks associated with the removal from service of generation and transmission components. Factor analysis has been conducted and system reinforcement alternatives are discussed.

Chapter 5 illustrates the utilization of the basic concepts applied to the MRBTS in Chapter 4 to the IEEE-RTS, which is a much larger power system, and examines some of the difficulties associated with reliability based bulk electric system planning.

Chapter 6 summarizes the thesis and highlights the conclusions.

2. BULK ELECTRIC SYSTEM EVALUATION

2.1 Introduction

A bulk electric system contains both generation and transmission facilities and is sometimes designated as a composite generation and transmission system (or composite system) [10]. Bulk electric system reliability analysis is concerned with the total problem of assessing the ability of the generation and transmission system to supply reliable electrical energy to the major system load points. These load points are known as bulk supply points or load points. This form of study can also be designated as hierarchical level II (HL-II) reliability analysis [1]. The reliability analysis of a bulk electric system includes many aspects such as load flow analysis, contingency analysis, generation rescheduling, transmission overload alleviation, load curtailment philosophy, etc. Bulk electric system reliability evaluation can be used to estimate the impacts of many factors on the adequacy of an existing or proposed system such as reinforcement alternatives at both generation and transmission levels [8], maintenance schedules, operating strategies, equipment availability [9], generation modeling, substation configurations etc. There are many power utilities and related organizations doing interesting and innovative work in this area and considerable published material is available [1, 21-25].

There is a wide range of adequacy indices that can be calculated at the individual delivery points and for the overall bulk electric system. Individual delivery point indices are useful in identifying weak points in the system and in establishing appropriate system reinforcements. They are also useful as input indices in the reliability analysis of electric distribution systems fed from the relevant bulk supply points. The overall system indices provide an appreciation of the global system adequacy in regard to the ability of the system to satisfy its overall load and energy requirements. These indices are also useful for overall system adequacy management and can be used to compare different alternatives in bulk electric system planning.

The delivery point and system reliability parameters can be expressed as either annualized or annual indices. Annualized indices are calculated using a single load level (normally the system peak load level) and expressed on a one-year basis. Annual indices are calculated considering the detailed load variations that occur throughout a year. Annualized indices provide useful indications when comparing the adequacy of different reinforcement options. Annual indices should be utilized when attempting to calculate the expected annual reliability performance of a system [21]. As noted in Chapter 1, a bulk electric system reliability evaluation can be conducted using analytical techniques or Monte Carlo simulation. The basic equations employed to obtain the delivery point and system indices using the contingency enumeration approach, which is the conventional analytical method, are presented in [1]. The analysis conducted in this research employs Monte Carlo simulation. The basic techniques of Monte Carlo simulation and the required equations for application to HLII evaluation are discussed in this chapter. The deterministic N-1 criterion and the NERC Planning Standards are also briefly discussed.

2.2 Deterministic N-1 Criterion and the NERC Planning Standards

The deterministic criterion usually applied in a bulk electric system is designated as the N-1 criterion, which states that the system should be able to withstand the removal of any single component at all demand levels. This is obviously a worst-case criterion. If the system can withstand the worst case, it can withstand the rest, but is does not consider multiple events. Some utilities are using or considering an N-2 criterion or an N-1-1 criterion, in which it is intended that the system can withstand having any element on maintenance and any other out of service due to a failure [32].

The “traditional deterministic approach”, used by most utilities today, utilizes predetermined constraints on operating parameters (e.g., generation, MW flow, voltage) to determine if the loss of a single circuit or generator is a violation of the operating criteria. This is commonly referred to as an “N-1” criterion (under some conditions, such as when two circuits utilize the same corridor, an “N-2” criterion may also be used). The problem with this practice, is that all resulting limits are hard, i.e. there is no mechanism for adjusting the limit "hardness" as a function of the probability or consequence of the contingency occurring. It is therefore possible for a power system to be planned and operated under constraints imposed by events that have very low probabilities of occurrence. In some cases, the constraints can impose very significant opportunity costs, such as limiting economic interchange between power system participants. Risk is normally computed as the product of the probability of an event resulting in a security violation and the consequence of the violation. The traditional deterministic approach to security assessment can often result in costly operating restrictions that are not justified by the corresponding low level of risk.

The NERC Planning Standards [26] defines a bulk electric system as follows:

"*The bulk electric system is a term commonly applied to that portion of an electric utility system, which encompasses the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100kV or higher*."

The NERC Planning Standards also describes the following system performance requirements following the loss of a single bulk electric system component.

"*The interconnected transmission systems shall be planned, designed, and constructed such that the network can be operated to supply projected customer demands and contracted firm (non-recallable reserved) transmission services, at all demand levels, under the condition specified".*

Transmission systems also should be capable of accommodating planned bulk electric equipment maintenance outages and continue to operate within thermal, voltage, and stability limits under the conditions specified.

Planned or controlled interruption of generators or electrical supply to radial customers or some local network customers connected to or supplied by a faulted component or by an affected area, may occur without impacting the overall security of the interconnected system. In order to prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserve) power transfers. A component in the NERC Planning Standards [26] is considered to be a generator, a transmission circuit, a bulk system transformer, or a single pole (dc) line.

2.3 Bulk Electric System Reliability Evaluation

As noted in Chapter 1, quantitative assessment of bulk electric system adequacy can be performed using analytical methods or Monte Carlo simulation techniques. The following is a brief discussion on the various methodologies with particular emphasis on the techniques used in the software applied in this thesis.

2.3.1 Analytical Techniques

Analytical techniques represent the system by a mathematical model and evaluate the reliability indices from this model using direct numerical solutions. They generally provide expectation indices in a relatively short computing time. As noted in Chapter 1, an analytical method will always give the same numerical results for the same system, model and set of input data. The basic analytical technique applied in bulk electric system evaluation is known as the contingency enumeration approach [1].

The basic procedure of the contingency enumeration approach involves the selection and evaluation of contingencies, the classification of each contingency according to related system failure criteria and the accumulation of the calculated adequacy indices [20]. The analyses conducted in this research were performed using Monte Carlo simulation and therefore no further detail is provided on the available analytical techniques.

2.3.2 Monte Carlo Simulation

The analytical techniques are relatively straightforward and in certain cases may require less computing time to calculate the expected indices. Assumptions are, however, frequently required in order to simplify the problem and produce an analytical model of the system. This is particularly the case when complex systems and complex operating procedures have to be modeled. The resulting analysis can therefore lose some or much of its significance [1]. Simulation techniques are therefore often used in the reliability evaluation in such situations.

Over the last decade, there has been increasing interest in utilizing Monte Carlo simulation in quantitative power system reliability analysis. Monte Carlo simulation is not a new concept and its application has existed for over 50 years. The availability of high speed computation facilities, however, has made Monte Carlo simulation an available and sometimes preferable option for many power system reliability applications. Simulation can be also used to experiment with new situations where there is little or no available information. In addition, simulation can sometimes be valuable in breaking down a complicated system into subsystems, each of which can then be modeled and analyzed separately. The analysis conducted in this research employs Monte Carlo simulation. The basic techniques of Monte Carlo simulation and the required equations for application to HLII evaluation are briefly discussed in this chapter.

There are two types of Monte Carlo methods that can be applied to power system reliability evaluation. They are generally known as the sequential and non-sequential techniques. In the non-sequential (state sampling) approach, the states of all components are sampled and the obtained system states are evaluated. System chronology is not a factor in this evaluation. Sequential simulation considers chronological issues by simulating the up and down cycles of all the system components. The system operating cycle is obtained by combining all the component cycles. The non-sequential approach has been applied to a wide range of power system reliability problems.

State Sampling Method

The state sampling method simulates the system state by sampling the states of all the components. The basic sampling procedure is conducted by assuming that the behavior of each component can be categorized by a uniform distribution under [0, 1]. The component can be represented by a two-state or multi-state model. In the case of a two-state component, the probability of the down state is the component forced outage rate (FOR) or unavailability. It is also assumed that component outages are independent events. The state of the system containing n components including generating units, transmission lines, transformers, etc., can be expressed by the vector $S = (S_1, S_2, \cdots, S_i, \cdots, S_n)$, where S_i is the state of the i^{th} component, when S equals zero, the system is in the normal state. When S is not equal to zero, the system is in a contingency state due to component outage(s). The steps in assessing composite system reliability using the state sampling techniques are briefly summarized below.

(a) For each component i, generate a uniform random number U_i.

(b) Determine the state of component i using following expression:

$$S_i = \begin{cases} 0\,(upstate) & if\ U_i \geq FOR_i \\ 1\,(downstate) & if\ U_i < FOR_i \end{cases} \tag{2.1}$$

Where FOR_i is the i^{th} component's forced outage rate.

(c) The system state S is obtained by applying step (b) to all the components.

(d) Determine the system state condition. If S equals zero, the system is in the normal state. If S is not equal to zero, the system is in a contingency state.

(e) A linear programming optimization model is usually used to reschedule generation, alleviate line overloads and to avoid load curtailment if possible or to minimize the total load curtailment if unavoidable.

The reliability indices for each load point and for the system are accumulated and steps (a) to (e) are repeated until the stopping criterion is reached.

The state sampling technique is relatively simple. It is only necessary to generate uniformly distributed random numbers rather than sample a distribution function. It requires relatively little basic reliability data as only the component-state probabilities are needed. This method, however, estimates the frequency of load curtailment as the sum of the occurrences of the load curtailment states and therefore provides an upper boundary of the actual frequency index.

The state sampling technique is utilized in the MECORE program used to conduct the reliability studies described in this thesis.

Sequential Method

The sequential method is based on sampling the probability distributions of the component state durations. In this approach, chronological component state transition processes for all components are first simulated by sampling. The chronological system state transition history is then created by combing the chronological component state transition histories [21].

This method uses the component state duration distribution functions. In a two-state component representation, these are the up and down state duration distribution functions and are usually assumed to be exponential. Other distributions, however, can be used.

The procedure used in composite system reliability evaluation can be briefly summarized in the following steps:

(a) Specify the initial state of each component. Generally, it is assumed that all components are initially in the up state.

(b) Sample the duration of each component residing in its present state using a conversion method. For example, given an exponential distribution, the sampling value of the state duration is

$$T_i = -\frac{1}{\lambda_i}\ln U_i \quad (2.2)$$

Where U_i is a uniformly distributed random number between [0,1] corresponding to the i^{th} component; if the present state is the up state, λ_i is the failure rate of the i^{th} component; if the present state is the down state, λ_i is the repair rate of the i^{th} component;

(c) Repeat step (b) in the given time span (usually one year) and record the sampling values of each state duration for all components. Chronological component state transition histories in the given time span for each component can be obtained.

(d) The chronological system state transition history in the given time span can be obtained by combing the chronological component state transition histories of all the components.

(e) Conduct system analysis for each system state to obtain the reliability indices [1].

(f) Repeat steps (b) to (e) for the desired number of simulation.

The sequential method is a very powerful technique and can be used to calculate actual frequency indices in addition to other related indices and can incorporate different state duration distributions. The probability distributions of the adequacy indices can also be assessed in addition to their expected values. This method, however, requires considerably more CPU time and storage than does the basic state sampling approach.

2.4 Indices Used in MECORE

The following indices [21, 33] can be computed using the MECORE software and are used in this chapter.

Basic indices

Probability of load curtailment (PLC)

$$\text{PLC}=\sum_{i\in S} P_i \quad (2.3)$$

Where P_i is the probability of system state i and S is the set of all system state associated with load curtailment.

Expected frequency of load curtailment (EFLC)

$$\text{EFLC}=\sum_{i\in S}(F_i - f_i) \quad occ./yr \tag{2.4}$$

Where F_i is the frequency of departing system state i and f_i is the portion of F_i which corresponds to not going through the boundary wall between the loss-of-load state set and the no-loss-of-load state set.

As mentioned earlier, it is a difficult task to calculate the frequency index using the state sampling technique. This is due to the fact that for each load curtailment state i, it is necessary to identify all the no-load-curtailment states which can be reached from state i in one transition. The expected number of load curtailment (ENLC) is often used to replace the EELC index.

$$\text{ENLC}=\sum_{i\in S}F_i \quad \text{occ./yr} \tag{2.5}$$

The ENLC is the sum of the occurrences of the load curtailment states and is therefore an upper boundary of the actual frequency index. The system state frequency F_i can be calculated by the following equation:

$$F_i = P_i\sum_{k\in N}\lambda_k \quad \text{occ./yr} \tag{2.6}$$

Where λ_k is the departure rate of component k and N is the set of all components of the system.

Expected duration of load curtailment (EDLC)

$$\text{EDLC}=\text{PLC}\times 8760 \quad \text{hrs/yr} \tag{2.7}$$

Average duration of load curtailment (ADLC)

$$\text{ADLC}=\text{EDLC/EELC hrs/disturbance} \tag{2.8}$$

Expected load curtailment (ELC)

$$\text{ELC}=\sum_{i\in S}C_iF_i \quad \text{MW/yr} \tag{2.9}$$

Where C_i is the load curtailment of system state i.

Expected demand not supplied (EDNS)

$$\text{EDNS}=\sum_{i\in S} C_i P_i \quad \text{MW} \tag{2.10}$$

Expected energy not supplied (EENS)

$$\text{EENS}=\sum_{i\in S} C_i F_i D_i = \sum_{i\in S} 8760 C_i P_i \quad \text{MWh/yr} \tag{2.11}$$

Where D_i is the duration of system state i.

Expected damage cost (EDC)

$$\text{EDC}=\sum_{i\in S} C_i F_i D_i W \qquad \text{k\$/yr} \tag{2.12}$$

Where C_i is the load curtailment of system state i ; F_i and D_i are the frequency and the duration of system state i ; W is the unit damage cost in \$/kwh.

IEEE proposed indices

Bulk power interruption index (BPII)

$$\text{BPII}=\frac{\sum_{i\in S} C_i F_i}{L} \quad \text{MW/MW-yr} \tag{2.13}$$

Where L is the annual system peak load in MW.

Bulk power/energy curtailment index (BPECI)

$$\text{BPECI}=\frac{EENS}{L} \quad \text{MWh/MW-yr} \tag{2.14}$$

Bulk power-supply average MW curtailment index (BPACI)

$$\text{BPACI}=\frac{ELC}{EFLC} \quad \text{MW/disturbance} \tag{2.15}$$

Modified bulk energy curtailment index (MBECI)

$$\text{MBECI}=\frac{EDNS}{L} \quad \text{MW/MW} \tag{2.16}$$

Severity Index (SI)

$$\text{SI}=\text{BPECI}\times 60 \text{ SM/yr} \tag{2.17}$$

The IEEE proposed indices are calculated from the basic indices by normalizing them using the system peak load. The IEEE proposed indices can be used to compare the adequacy of systems of different sizes. The basic indices can be applied to an overall system or to a single load point, while the IEEE proposed indices only apply to an overall system.

2.5 Introduction to MECORE

The MECORE software is a Monte Carlo based composite generation and transmission reliability evaluation tool designed to perform reliability and reliability worth assessment of bulk electric systems. The MECORE program was initially developed at the University of Saskatchewan and subsequently enhanced at BC Hydro. It can be used to provide quantitative reliability indices at individual load points and for the overall composite generation and transmission system. It can also be used to provide unreliability cost indices, which reflect reliability worth. The indices produced by the program can be utilized to compare different planning alternatives from a reliability viewpoint. The MECORE software is based on a combination of Monte Carlo simulation (state sampling technique) and enumeration techniques. The state sampling technique is used to simulate system component states and to calculate annualized indices at the system peak load level. A hybrid method utilizing an enumeration approach for aggregated load states is used to calculate annual indices using an annual load duration curve [33].

System size: The program is designed to handle up to 1000 buses and 2000 branches.

Failure modes:

- -Independent failures of generators, lines and transformers
- -Common cause outages of transmission lines
- -Generating unit derated states

Failure criteria:

- -Capacity deficiency
- -Line over load
- -System separation-load loss
- -Bus isolation-load loss

Load model:

- -Annual, seasonal, and monthly load curve

-Multi-step models

-Bus load proportional scaling and flat level model

Probability indices:

-System and bus indices

-Annualized and monthly/seasonal/annual indices

-Basic and IEEE-proposed indices

Basic indices include ENLC, ADLC, EDLC, PLC, EDNS, EENS, EDC, and ELC, and IEEE-proposed indices include BPII, BPECI, BPACI, MBECI, and SI.

The MECORE program utilizes a linear programming Optimal Power Flow (OPF) model to reschedule generation (change generation patterns), alleviate line overloads and avoid load curtailments if possible or minimize total curtailments if unavoidable. Load curtailment philosophies in the form of a curtailment priority list can be considered in the minimization model. If the load priority order is not specified using priority codes, the program decides the load curtailment order automatically. The numbers of samples used in the subsequent studies in this thesis for the MRBTS and the IEEE-RTS are 2,000,000 and 500,000 respectively [8].

2.6 Reliability Test Systems

The two basic test systems used in this research are the modified Roy Billinton Test System (MRBTS) [34] and the IEEE Reliability Test System (IEEE-RTS) [35]. The modified RBTS and the IEEE-RTS are briefly described in the following paragraphs.

The single line diagrams of the MRBTS and the IEEE-RTS are shown in Figures 2.1 and 2.2 respectively. The RBTS [34] is a small educational test system developed as part of the graduate program in power system reliability evaluation at the University of Saskatchewan. The original RBTS is modified by adding the load at Bus 6 to that at Bus 5 and removing the radial line from bus 5 to bus 6. The MRBTS is a five bus system with 4 load buses. It has eleven generators located at two generator buses and 8 transmission lines. The total installed generating capacity is 240 MW and the system peak load is 185 MW. The system voltage level is 230kV.

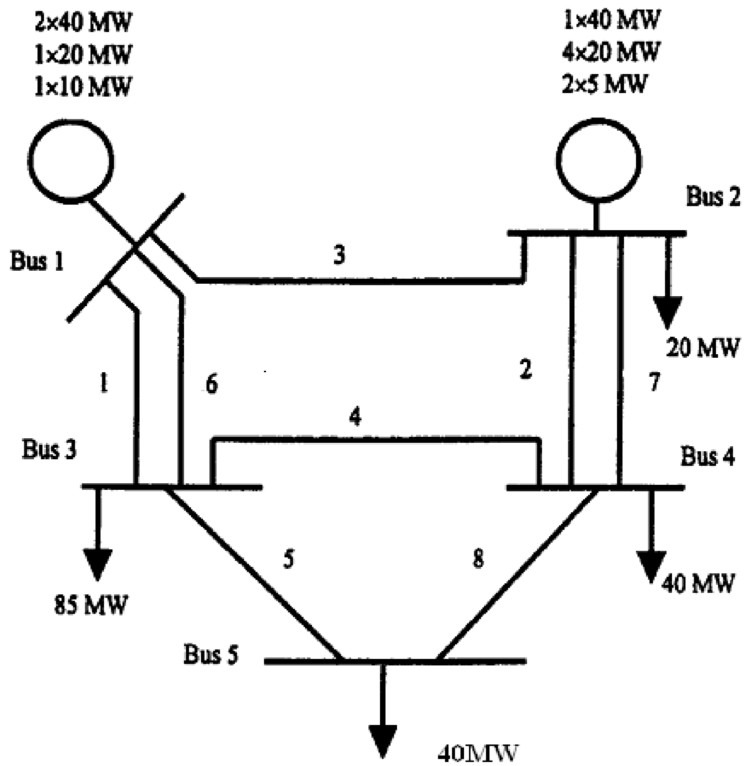

Figure 2.1: The single line diagram of the MRBTS

The IEEE-RTS [35] was developed by an IEEE Task Force to provide a practical representative bulk power system for research and comparative study purposes. The IEEE-RTS is a relatively large system compared to the RBTS. The generating system contains 32 units, ranging from 12 to 400MW. The transmission system contains 24 buses, which includes 10 generator buses, 10 load buses, and 4 connection buses, connected by 33 lines and 5 autotransformers at two voltage levels: 138kV and 230kV. The total installed capacity of the IEEE-RTS is 3405MW and the system peak load is 2850MW.

The MRBTS and IEEE-RTS have the same per-unit load model. The data on the weekly peak loads in percentage of the annual peak load, daily peak loads in percentage of the weekly peak, and hourly peak loads in percentage of the daily peak load are given in [35]. These data together with the annual peak load define the hourly load model consisting of 8736 hours. A winter peaking system can be adopted by taking Week 1 as January and Monday as the first day of the year. The test system provides only 364 daily peak loads in a year, and therefore it is assumed that the daily peak load on December 31st is the same as that on January 1st.

The data for the two test systems, including bus, line, generator, and load model data are given in Appendix 1.

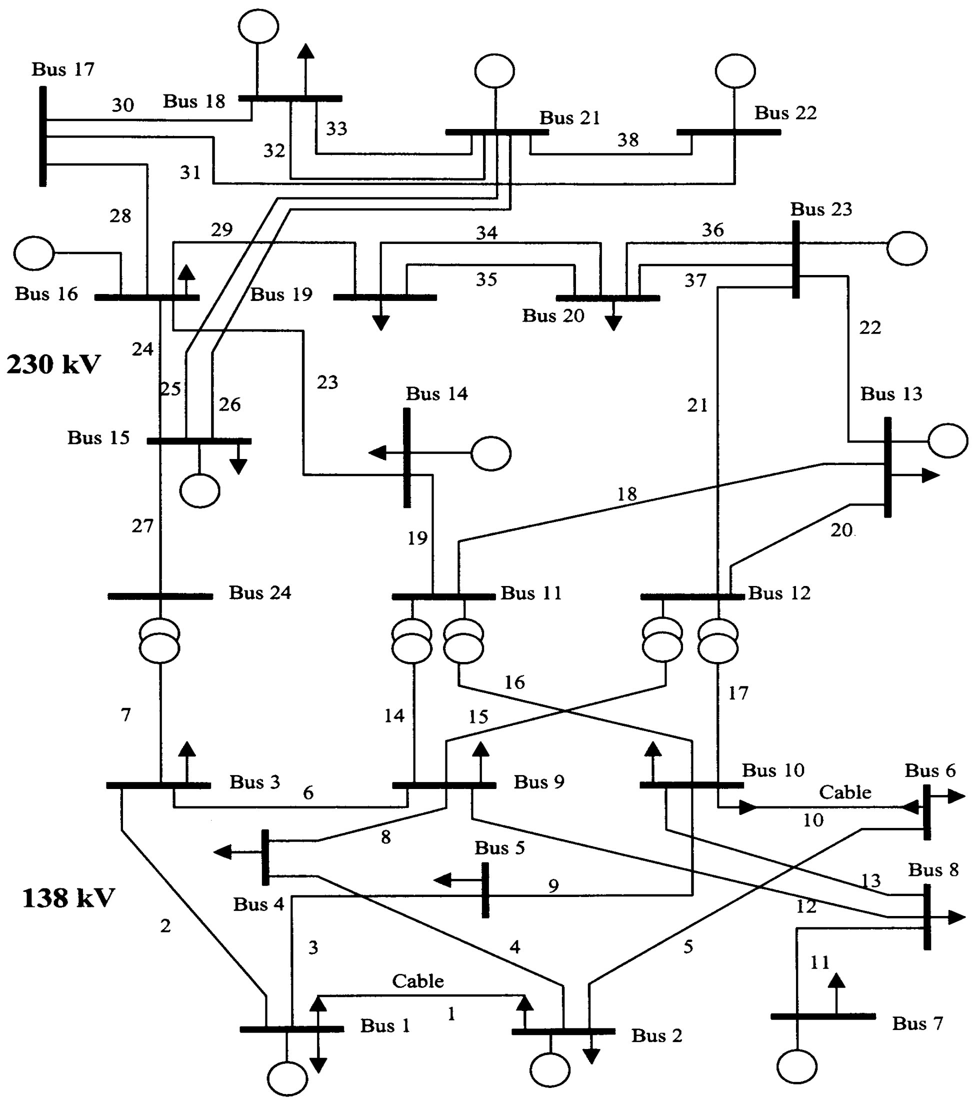

Figure 2.2: The single line diagram of the IEEE-RTS

2.7 Annual and Annualized Indices

System indices can be calculated assuming that the load is constant at the peak load level and expressed on a one-year basis. These indices are known as annualized values. They can also be calculated using the annual load duration curve. In this case, they are known as annual indices. Annual indices are the most useful indices as they incorporate the variations in load level that occur throughout a year. Under normal circumstances, the load resides at the peak value for only a short period of time. The annualized indices are therefore usually much higher than the annual indices.

2.7.1 MRBTS and IEEE-RTS Base Cases Analyses

The effects on bulk system reliability of many factors, such as multiple generators sharing a single transformer, common mode failures of transmission lines, station originated failures, and so forth, are analyzed in [8]. The effects of these factors are a function of the system topology and the operating philosophy. The following conditions were used in the base case analyses of the MRBTS and the IEEE-RTS in the research described in this thesis.

Station failure events are not included.
The economic load curtailment priority order is utilized.
Transmission line common mode failures are not considered.

Individual delivery point indices are highly dependent on the system load curtailment philosophy. The economic priority order philosophy is based on ranking all the bulk delivery points using a reliability worth index such as the interrupted energy assessment rate (IEAR) in $/kWh [1, 36-38]. This parameter is similar to the value of lost load (VOLL) used in the UK [38]. The bulk delivery point that has the highest IEAR will have the highest priority, and the delivery point that has the lowest IEAR will have the lowest priority. When the bulk electric system encounters a severe contingency that requires load curtailments, the delivery point that has the lowest priority will be initially curtailed. This policy minimizes customer interruption costs due to load curtailment.

The IEAR values of each delivery point and the corresponding priority order in the MRBTS are given in Table 2.1 [8].

Table 2.1: IEAR values of each bus and the priority order in the MRBTS

Bus	IEAR ($/kWh)	Priority order
2	7.41	1
3	2.69	4
4	6.78	2
5	4.82	3

The IEAR values of each load point and the corresponding priority order in the IEEE-RTS are given in Table 2.2 [8].

Table 2.2: IEAR values of each bus and the priority order in the IEEE-RTS

Bus	IEAR ($/kWh)	Priority order	Bus	IEAR ($/kWh)	Priority order	Bus	IEAR ($/kWh)	Priority order
1	6.20	1	7	5.41	5	15	3.01	15
2	4.89	9	8	5.40	6	16	3.54	13
3	5.30	8	9	2.30	16	18	3.75	11
4	5.62	3	10	4.14	10	19	2.29	17
5	6.11	2	13	5.39	7	20	3.64	12
6	5.50	4	14	3.41	14			

The base cases of the MRBTS and the IEEE-RTS were analyzed using the noted assumptions. The reliability indices for the load buses and the systems are shown in Tables 2.3 to 2.8.

Table 2.3: Annualized load point indices for the MRBTS (base case)

Bus No.	PLC	ENLC (1/yr)	ELC (MW/yr)	EDNS (MW)	EENS (MWh/yr)
2	0.00	0.00	0.00	0.00	0.04
3	0.01	4.07	48.09	0.10	850.18
4	0.00	0.02	0.14	0.00	1.11
5	0.00	0.12	0.89	0.00	9.81

Table 2.4: Annual load point indices for the MRBTS (base case)

Bus No.	PLC	ENLC (1/yr)	ELC (MW/yr)	EDNS (MW)	EENS (MWh/yr)
2	0.00	0.00	0.00	0.00	0.00
3	0.00	0.10	1.17	0.00	17.57
4	0.00	0.00	0.01	0.00	0.04
5	0.00	0.01	0.13	0.00	0.72

Table 2.5: Annualized and annual system indices for the MRBTS (base case)

Indices	Annualized	Annual
ENLC (1/yr)	4.08	0.11
ADLC (hrs/disturbance)	18.69	15.31
EDLC (hrs/yr)	76.20	1.61
PLC	0.01	0.00
EDNS (MW)	0.10	0.00
EENS (MWh/yr)	861.15	18.33
EDC (k$/yr)	N/A	81.03
BPII (MW/MW-yr)	0.27	0.01
BPECI (MWh/MW-yr)	4.65	0.10
BPACI (MW/disturbance)	12.05	12.45
MBECI (MW/MW)	0.00	0.00
SI (system minutes/yr)	279.29	5.95

Table 2.6: Annualized load point indices for the IEEE-RTS (base case)

Bus No.	PLC	ENLC (1/yr)	ELC (MW/yr)	EDNS (MW)	EENS (MWh/yr)
1	0.00	0.00	0.00	0.00	0.00
2	0.00	0.22	7.52	0.01	65.05
3	0.00	0.12	6.00	0.01	50.69
4	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.08	0.00	0.44
8	0.00	0.00	0.06	0.00	0.37
9	0.05	35.32	2612.32	3.87	33894.02
10	0.00	0.50	35.03	0.04	338.17
13	0.00	0.03	1.46	0.00	11.07
14	0.01	9.30	639.79	0.82	7159.72
15	0.04	25.79	2481.55	3.48	30502.04
16	0.01	4.43	178.77	0.22	1890.76
18	0.00	1.90	174.84	0.21	1834.10
19	0.08	58.10	4160.46	6.00	52553.04
20	0.00	2.93	153.84	0.19	1645.68

Table 2.7: Annual load point indices for the IEEE-RTS (base case)

Bus No.	PLC	ENLC (1/yr)	ELC (MW/yr)	EDNS (MW)	EENS (MWh/yr)
1	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.05	0.00	0.40
3	0.00	0.00	0.03	0.00	0.22
4	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.05	0.00	0.29
7	0.00	0.00	0.00	0.00	0.02
8	0.00	0.00	0.00	0.00	0.00
9	0.00	0.87	53.88	0.07	607.47
10	0.00	0.01	0.30	0.00	2.54
13	0.00	0.00	0.00	0.00	0.03
14	0.00	0.18	10.80	0.01	110.90
15	0.00	0.52	45.32	0.06	490.94
16	0.00	0.08	3.17	0.00	31.75
18	0.00	0.03	2.40	0.00	22.38
19	0.00	1.52	96.38	0.13	1123.04
20	0.00	0.06	2.48	0.00	23.96

Table 2.8: Annualized and annual system indices for the IEEE-RTS (base case)

Indices	Annualized	Annual
ENLC (1/yr)	58.11	1.52
ADLC (hrs/disturbance)	12.69	11.56
EDLC (hrs/yr)	737.50	17.58
PLC	0.08	0.00
EDNS (MW)	14.83	0.28
EENS (MWh/yr)	129932.70	2413.92
EDC (k$/yr)	N/A	10186.76
BPII (MW/MW-yr)	3.67	0.08
BPECI (MWh/MW-yr)	45.59	0.85
BPACI (MW/disturbance)	179.87	141.30
MBECI (MW/MW)	0.01	0.00
SI (system minutes/yr)	2735.43	50.82

It can be seen from Tables 2.3 to 2.8 that the annual indices are much lower than the annualized values. Annual indices incorporate the variations in system load throughout the year and therefore provide a more accurate assessment of the annual adequacy than do the annualized values. This is particularly valuable when performing economic analysis such as calculating the Expected Damage Cost (EDC). The load model is included in all the following studies in this thesis and therefore all the indices are annual values.

Tables 2.3 to 2.8 show that there is a wide range of possible system indices that can be used to measure the adequacy of a bulk electric system. The reliability indices all provide specific information from different points of view. The Expected Energy Not Supplied (EENS) is a very useful index that can be easily appreciated by system planners and engineers. The EENS is a conventional index used in a wide range of applications. The EENS will increase as the system size increases. As noted in Equation 2.14 and 2.17, the EENS can be normalized by dividing it by the peak load, to give the BPECI (2.14). The usual index applied in bulk system studies is the Severity Index given in 2.15. The units in this case are System Minutes (SM) per year. This index is used as the representative index in the studies described later in this thesis. The criterion SI values for the MRBTS and the IEEE-RTS are 6.0 and 50.0 SM/yr respectively.

2.8 Conclusions

There are two basic techniques when applying Monte Carlo simulation methods to bulk electric system reliability evaluation. These methods are designated as the sequential and non-sequential approaches. Sequential simulation can fully take into account the chronological behavior of the system, while the non-sequential method involves non-chronological system state considerations. The two Monte Carlo techniques are briefly described in this chapter. Each technique has its own merits and demerits. The state sampling technique is utilized in the MECORE program.

The MECORE software is a Monte Carlo based composite generation and transmission system reliability evaluation tool designed to perform reliability and reliability worth assessment of bulk electric systems. All the analyses in this thesis are conducted using this tool.

Two test systems are used in this thesis. The modified RBTS is a small educational test system. The IEEE-RTS is a relatively large system compared with the MRBTS. The assumptions used in the base case analyses of the two test systems are utilized in all the subsequent studies in this thesis.

The annualized indices refer to the indices calculated using a single load level (normally the peak load) over a period of one year. In practical systems, the load demand does not remain constant at the peak load level throughout the period and the chronological load model (time varying load) can be used to produce more representative annual indices. The basic annual indices are lower than the annualized indices obtained using peak load levels. The annualized indices give a pessimistic appraisal while the annual indices provide a more representative picture of the system and are utilized in this research.

The Expected Energy Not Supplied (EENS) is used in a wide range of power system reliability studies and can be easily extended to estimate the expected customer outage costs using an interrupted energy assessment rate in $/kWh [1]. The EENS is extended to create the Severity Index (SI) which is used as the basic index in the following studies in this thesis.

3. COMBINED DETERMINISTIC AND PROBABILISTIC TECHNIQUES

3.1 Introduction

Bulk electric system planning is predominantly based on deterministic criteria, such as N-1. Deterministic based approaches generally have very attractive characteristics such as, simple implementation, straightforward understanding, easy assessment by planners in relation to severe conditions involving network outages and the system peak load. Deterministic techniques, however, do not provide an assessment of the actual system reliability as they do not incorporate the probabilistic or stochastic nature of the system behaviour and component failures. These approaches, therefore, are not consistent [32] and do not provide an accurate basis for comparing alternative equipment configurations and performing economic analysis. In contrast, probabilistic methods can respond to the significant factors that affect the reliability of a system. These techniques provide quantitative indices, which can be used to decide if the system performance is acceptable or if changes need to be made. Most of the published papers on reliability assessment of bulk electric systems are based on probabilistic approaches [1, 21, 39, 40]. There is, however, considerable reluctance to use probabilistic technique in many areas due to the difficulty in interpreting the resulting numerical indices.

The perception of many planning engineers that past experience in addition to some known critical situations is enough to assess the system risk is not valid. A proper measure of risk can only be achieved by recognizing the probabilistic nature of the relevant bulk electric system parameters. Methodologies based on probability concepts can be extremely useful in assessing the performance of bulk electric systems [1]. There is a growing interest in combining deterministic considerations with probabilistic assessment in order to evaluate the quantitative system risk and conduct bulk electric system planning. Two bulk electric system planning techniques which combine accepted deterministic and probabilistic criteria are introduced and discussed in this chapter:

- Bulk Electric System Well-Being technique
- Joint Deterministic-Probabilistic (D-P) technique

3.2 System Well-Being Concept

A combination of the basic deterministic and probabilistic concepts can be created using the definitions of a power system's operating states [41, 42]. The concept of quantifying these operating states was introduced in [29, 30] using an analytical approach. This was extended in [31] using a Monte Carlo state sampling technique. The concepts were further extended to large system analysis in [43].

The initiation of the system well-being concept started in 1992 [29]. A survey conducted as part of an EPRI project indicated that many utilities had difficulty in interpreting the expected load curtailment indices as the existing models were based on adequacy analysis and in many cases did not consider realistic operating conditions. These concerns were expressed in response to the survey and were summarized in the project report [42]. This survey also indicated that security considerations are important issues in composite system reliability evaluation. In response to the stated utility concerns, a framework for incorporating security considerations was also proposed in the project report.

In order to recognize security considerations in the evaluation of a composite system, the total power network can be divided into several operating states in terms of the degree to which adequacy and security constraints are satisfied [29].

Figure 3.1 shows a modified system model including security considerations proposed in [29]:

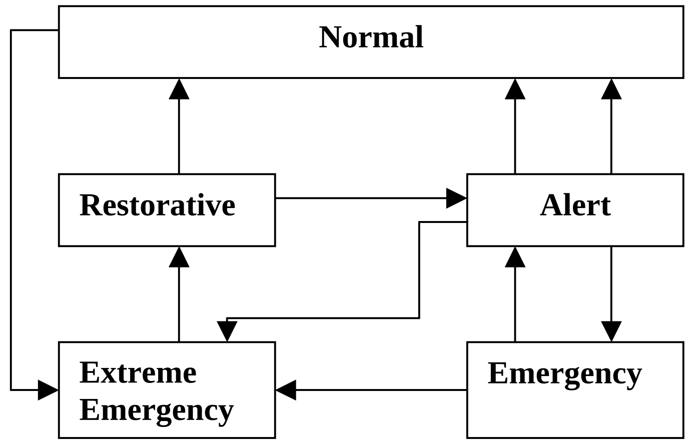

Figure 3.1: System Operating States

Figure 3.1 shows that the overall power system can be divided into several states in terms of the degree to which the adequacy and security constraints are satisfied. The following quotations taken from [42] are the state definitions.

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

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

The emergency state is defined as "*If a contingency occurs or the generation and load changes before corrective action can be (or is) taken, the system will enter the emergency state, no load is curtailed in the emergency state, but equipment or operating constraints have been violated. If control measures are not taken in time to restore the system to the alert state, the system will transfer from the emergency state to the extreme emergency state*". In this state both adequacy and security constraints are violated. This is a temporary state that requires operator action because equipment operating constraints have been violated. The first objective will be to remove the equipment operating constraints without load curtailment, by such means as redispatch or startup of additional generation, voltage sources adjustment, etc. If successful, this could bring the system back to the alert state, where further actions would still be necessary to achieve the normal state.

The extreme emergency state is defined as "*In the extreme emergency state, the equipment and operating constraints are violated and load is not supplied"*. In this state, load has to be curtailed in a specific manner in order to return from this state to another state.

The restorative state is defined as "*To transfer out of the extreme emergency state, the system must enter the restorative state to reconnect load and resynchronize the network. The loop can then be close by either entering the alert state or the normal state*".

The system can be returned to the normal state from the alert state by taking preventive action. Restoration from the emergency state to the alert state can be achieved by taking corrective action. The system can be returned to the restorative state from the extreme emergency state by means of emergency action. The system can return to the alert state or to the normal state from the restorative state by taking the restorative action.

The system operating state structure shown in Figure 3.1 was simplified in [30]. Figure 3.2 shows the simplified system well-being framework [30]. System well-being can be categorized into the three states of healthy, marginal and risk as shown in Figure 3.2.

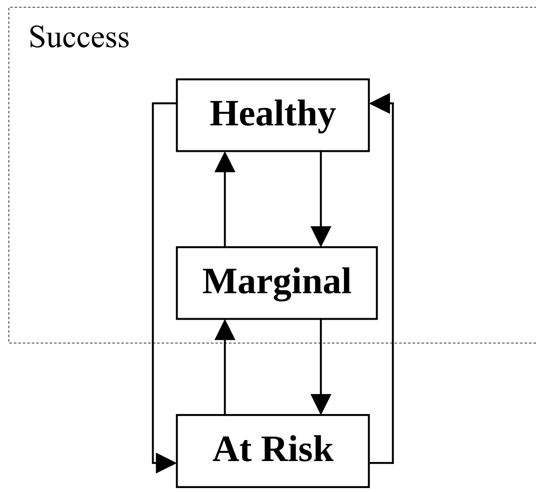

Figure 3.2: System well-being framework

A system operates in *the healthy state* when it has enough generation and transmission capacity to meet a pre-defined deterministic criterion. *In the marginal state*, the system is not in any difficulty but does not have sufficient margin (generation and /or transmission) to meet the specified deterministic criterion. In *the at risk state*, the system load is shed due to generation and/or transmission violations. This model recognizes the concerns of operation planning engineers by introducing the idea of marginal states into composite reliability analysis.

The system well-being concept shown in Figure 3.2 is a probabilistic framework incorporating the simplified operating states associated with the accepted deterministic N-1 criterion [26, 27]. System well-being analysis, therefore, provides a combined framework that incorporates both the deterministic and probabilistic perspectives. The degree of system well-being can be quantified in terms of the probabilities and frequencies of the healthy and marginal states in addition to the traditional risk indices.

System well-being analysis using sequential Monte Carlo simulation is described in [44] together with applications of the technique in bulk electric system planning.

The system well-being indices are the probabilities, frequencies and durations of the healthy, marginal and risk states as shown below:

Prob {H}=Probability of the healthy state (/year)
Prob {M}=Probability of the marginal state (/year)
Prob {R}=Probability of the at risk state (/year)
Freq {H}=Frequency of the healthy state (occurrences/year)
Freq {M}=Frequency of the marginal state (occurrences/year)
Freq{R}= Frequency of the at risk state (occurrence/year)
Dur{H}=Average residence duration in the healthy state (hours/occurrence)
Dur{M}=Average residence duration in the marginal state (hours/occurrenc)
Dur{R}=Average residence duration in the at risk state (hours/occurrence)

The residence duration of each state can be roughly calculated using the ratio of the state probability to the state frequency based on the overall simulation years. The accurate residence duration, however, should be calculated by considering it on an individual simulation year basis.

The probability (Prob), frequency (Freq) and duration (Dur) associated with the H, M, and R states are useful measures for composite systems. The probabilities of health, margin and risk are collectively known as the basic well-being indices. The Prob {R}, Freq{R}, and Dur{R} are, respectively, the traditional Loss of Load Probability (LOLP), LOLF and Loss of load duration (LOLD) indices, Well-being analysis for composite systems is, therefore, a natural extension of composite reliability analysis that allows the qualification of the deterministic criterion on a probabilistic basis. The marginal states must be appropriately identified in order to provide system operators with sufficient time to correct the power system operating trajectory in order to avoid load shedding.

Sequential simulation is used in the system well-being technique described in [44]. Sequential simulation has the following disadvantages.

1. This approach requires considerably more computation time and memory storage than non-sequential simulation methods because it is necessary to generate a random variable following a given distribution function for each component and to store information on the chronological component state transition processes of all the components in a long time span.

2. The sequential simulation approach also requires detailed input data such as chronological load curves at each bus, which some utilities may not have.

As noted in Chapter 1, the basic objective of the research described in this thesis is to develop an alternate approach to the well-being technique, which would also incorporate deterministic and probabilistic considerations in a single risk assessment framework. The developed technique is designated as the joint deterministic-probabilistic (D-P) approach and is described in the following section.

3.3 Joint Deterministic-Probabilistic (D-P) Technique

The deterministic criterion usually applied to a composite system is designated as the N-1 criterion, which means that the system should be able to withstand the removal of any single component at all demand levels. This deterministic criterion is traditionally applied by most utilities as it is relatively easy for planners, electrical engineers and risk managers to interpret and utilize.

The deterministic N-1 criterion does not provide any quantitative reliability risk information and is a rigid criterion. In contrast, probabilistic criteria can be used to assess the variable risks associated with the removal of generation or transmission elements.

A probabilistic criterion is used to state that the system risk shall not exceed a specified value. There is a wide range of reliability indices that can be used as criterion risk values. The most common risk indices are the Loss of Load Expectation (LOLE) used in generating capacity planning and the Expected Energy Not Supplied (EENS) used in composite generation and transmission system planning. The SI is used as the representative probabilistic index in the D-P approach described in this thesis.

The deterministic-probabilistic criterion designated as the D-P criterion that includes both deterministic and probabilistic criteria is defined as follows:

The system is required to satisfy a deterministic criterion (N-1) and also meet an acceptable probabilistic risk criterion under the designated (N-1) outage condition.

The D-P technique combines the well known deterministic N-1 framework with probabilistic analysis. In this thesis, the probabilistic analysis tool is the commercial software known as MECORE, which is a Monte Carlo based composite system reliability analysis tool utilizing the non-sequential sampling technique. The D-P technique provides a bridge between the accepted deterministic and probabilistic methods, as does the system well-being approach. The D-P indices can be useful in practical bulk electric system planning. Specifically, this approach can be very useful in those situations where conventional probabilistic methods have not been well accepted and deterministic techniques are still applied.

The D-P approach incorporates a probabilistic analysis within a deterministic framework in order to recognize the system random behaviour. Figure 3.3 illustrates the system D-P concept. The risk profile in Figure 3.3 is determined under the designated outage condition. The accepted probabilistic criterion is then used to determine the Peak Load Carrying Capability (PLCC) of the bulk electric system. In the studies described in this thesis, the SI is used as the probabilistic criterion index. Similar studies could be performed using the other indices shown in Tables 2.5 and 2.8.

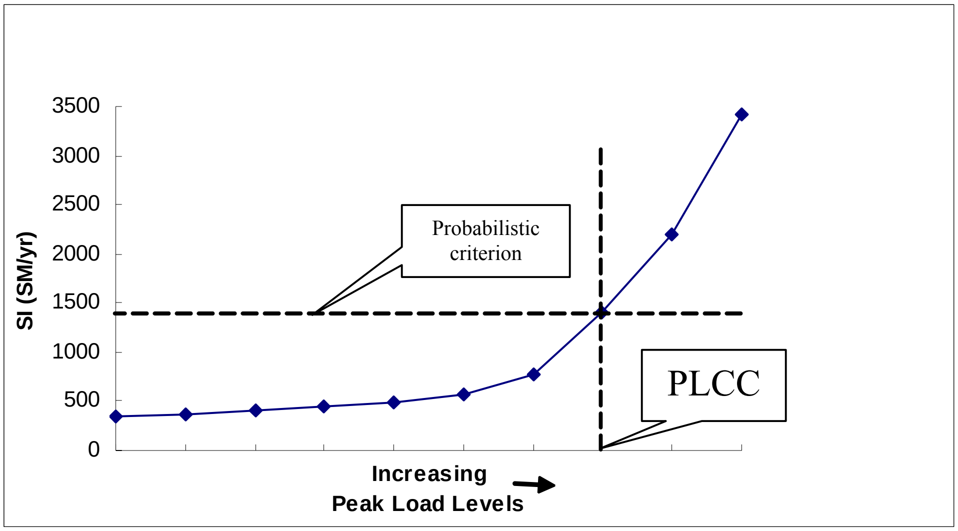

Figure 3.3: System D-P concept

The procedure for D-P analysis of a bulk electric system is briefly illustrated in the following steps. The technique is illustrated by application to the MRBTS and the IEEE-RTS in Chapters 4 and 5.

Step 1:Apply the deterministic N-1 criterion to the given bulk electric system. A pre-established contingency list is used, involving single generating unit or single transmission elements. The purpose of a contingency selection process is to reduce and limit the set of outaged components (contingencies) to be considered. In the case of generation facilities, the largest generating units at different locations in the system are considered. In the case of transmission facilities, the transmission line selections can be done through the power flow analyses. The most severe single contingency can be determined from the contingency analysis list.

Step 2:Probabilistic analysis is then conducted using the MECORE program. The analysis is conducted on the bulk electric system with the element designated as the most severe contingency removed from the system.

Step 3: The SI value under the most severe contingency is then compared with the defined SI criterion.

Step 4: If the determined SI value under the most severe contingency exceeds the defined SI criterion, then system reinforcement planning needs to be conducted.

System planners and operators who are accustomed to a deterministic approach will recognize that the D-P approach utilizes the traditional deterministic concept but extends this to incorporate the variable risk conditions that exist after the most severe contingency has been applied.

D-P analysis provides a bridge between the accepted deterministic and probabilistic methods and provides indices that can be useful in practical power system adequacy assessment.

3.4 Conclusions

There is a growing interest in combining deterministic considerations with probabilistic assessment in order to evaluate the system risk. Two techniques that can be used to combine deterministic and probabilistic considerations in a single framework are illustrated in this chapter. The system well-being approach was initially developed in the late 1980s. The joint deterministic-probabilistic (D-P) approach has been developed in the research described in this thesis.

Well-being analysis provides a combined structure that incorporates deterministic considerations within a probabilistic framework by determining the likelihood of encountering marginal system states in addition to encountering system at risk states. The system well-being concept provides system engineers and risk managers with comprehensive information on the degree of system vulnerability. A complete system well-being analysis can require considerable computing time particularly on large practical electric power systems.

The proposed D-P method is based on a non-sequential Monte Carlo model, which avoids chronological simulations and detailed state clarification requirements and therefore saves computation time. The D-P approach provides a combined structure that incorporates probabilistic considerations within a deterministic framework. It extends the deterministic analysis by providing a risk assessment that is conditional upon the system contingency covered by the traditional deterministic criterion. The application of D-P analysis to practical systems should prove useful in supporting the decision-making processes involved in system planning.

4. APPLICATION OF THE JOINT DETERMINISTIC - PROBABILISTIC (D-P) CRITERION TO BULK ELECTRIC SYSTEM PLANNING

4.1 Introduction

Power system planning is generally divided into the three areas of generation, transmission and distribution. In term of time frames, long term issues are related to system development planning while short term issues are designated as system operation planning. The fundamental task of power system planning is to develop the system as economically as possible and to maintain an acceptable reliability level. This involves the determination and examination of possible reinforcement alternatives.

Most electric power utilities use deterministic techniques such as the traditional N-1 criterion to assess system reliability in transmission system planning. These deterministic techniques do not provide an assessment of the actual system reliability as they do not incorporate the probabilistic or stochastic nature of system behavior and component failures. These approaches, therefore, are not consistent and do not provide an accurate basis for comparing alternative equipment configurations and performing economic analyses [32].

In contrast, probabilistic methods can respond to the significant factors that affect the reliability of a system. These techniques provide quantitative indices, which can be used to decide if the system performance is acceptable or if changes need to be made. There is, however, considerable reluctance to use probabilistic techniques in many areas due to the difficulty in interpreting the resulting numerical indices. Although deterministic criteria do not consider the stochastic behavior of system components, they are easier for regulators, managers, system planners and operators to appreciate than numerical risk indices determined using probabilistic techniques.

This difficulty can be alleviated by incorporating a probabilistic perspective into the accepted deterministic framework. The objective of applying probabilistic analysis is to add an additional dimension in system planning but not to entirely replace the N-1 deterministic principle, which has been accepted by system planners for years. There is no conflict between the N-1 deterministic principle and probabilistic evaluation. The reliability indices calculated with the inclusion of the N-1 deterministic criterion provide additional quantitative system reliability information [45] that can be used to assist in system planning.

This chapter illustrates the application of the three basic techniques listed below in assessing the adequacy of a bulk electric system:

1. Deterministic N-1 criterion (D)
2. Probabilistic criterion (P)
3. Joint deterministic-probabilistic criterion (D-P)

4.2 Study System

The bulk electric system utilized in this chapter is the modified RBTS designated as the MRBTS. This system is described in Section 2.6 of this thesis. The single line diagram shown in Figure 2.1 is repeated in Figure 4.1 for reference purposes.

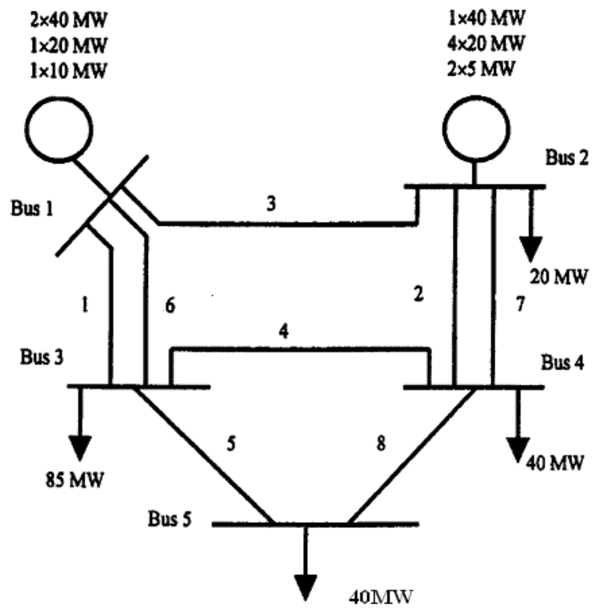

Figure 4.1: Single line diagram of the MRBTS

A series of system planning studies was conducted for the first few years of a possible nine-year time frame. It is assumed that the yearly peak load growth is 5% and that the annual load duration curves for the different years have the same basic shape.

The peak load is 185 MW in the initial year. The yearly peak loads in a nine year planning time frame are shown in Table 4.1 based on a 5% annual load growth:

Table 4.1: Annual peak load (MW)

Year	0	1	2	3	4	5	6	7	8	9
Peak Load	185.00	194.25	204.00	214.20	224.90	236.10	248.00	260.40	273.40	287.10

4.3 Deterministic N-1 Criterion

The deterministic N-1 criterion has been widely used in utility planning practice for many years. The criterion requires that an outage of any single system component does not cause a system failure or load curtailment at all demand levels.

4.3.1 Application of the Deterministic N-1 Criterion

The application of the deterministic N-1 approach involves the determination of the most severe single contingency for the studied system. As noted earlier, this usually involves system load flow analysis that indicates the maximum load that the system can carry under selected contingencies. A range of possible contingencies are presented in order to illustrate the different impacts of various contingencies. The largest generators in the MRBTS have a capacity of 40 MW. Figure 4.1 shows the locations of these units. The designation G1-40 is used in this chapter to indicate the removal of a 40 MW generating unit at Bus 1. Similar designations are applied to the other contingencies.

G1-40 outage
G2-40 outage

The largest load that the system can carry under these conditions is 200 MW. This result does not provide any quantitative information on which generating unit outage is more severe from a reliability point of view.

L1 outage

The largest load that the system can carry in this case is 189 MW, as L6, which is in parallel with L1, is overloaded when the peak load is greater than 189 MW. This comment also applies to L6.

L5 outage
L8 outage

The largest load that the system can carry under these conditions is 239 MW.

The peak load of the MRBTS is 185 MW in year 0, and all the outage situations noted above meet the deterministic N-1 criterion at this peak load level. The largest load that the system can carry is 189 MW under the L1 outage condition, and therefore, L1 is the most severe contingency.

4.3.2 Planning Alternative Analysis

The previous section shows that L1, G1-40, G2-40 are the maximum impact elements in the MRBTS. Reinforcement planning therefore should focus on adding an additional transmission line between Bus 1 and Bus 3 and/or adding generating capacity at selected buses.

Three possible planning alternatives have been considered, and under each alternative, three cases have been studied. The nine scenarios are designated as A1-C1, A1-C2, A1-C3, A2-C1, A2-C2, A2-C3 and A3-C1, A3-C2, A3-C3 and are described in the following.

Alternative 1

Assume that it is only possible to add generating units at the original generating unit locations, e.g. the northern part of the MRBTS.

Alternative 1-Case 1 (A1-C1): Add one 20 MW unit at Bus 1.

Alternative 1-Case 2 (A1-C2): Add one 20 MW unit at Bus 1 and one 10 MW unit at Bus 2.

Alternative 1-Case 3 (A1-C3): Add two 20 MW units at Bus 1 and one 10 MW unit at Bus 2.

Alternative 2

Assume that there are no constraints on added generating units at different locations.

Alternative 2-Case 1 (A2-C1): Add one 20 MW unit at Bus 3.

Alternative 2-Case 2 (A2-C2): Add one 20 MW unit at Bus 3 and one 10 MW unit at Bus 5.

Alternative 2-Case 3 (A2-C3): Add two 20 MW units at Bus 3 and one 10 MW unit at Bus 5.

Alternative 3

Assume that an additional transmission line is considered.

Alternative 3-Case 1 (A3-C1): Add one 20 MW unit at Bus 1 and an additional line between Bus 1 and Bus 3.

Alternative 3-Case 2 (A3-C2): Add one 20 MW unit at Bus 1, one 10 MW unit at Bus 2 and an additional line between Bus 1 and Bus 3.

Alternative 3-Case 3 (A3-C3): Add two 20 MW units at Bus 1, one 10 MW unit at Bus 2 and an additional line between Bus 1 and Bus 3.

In these studies, the forced outage rate (FOR) and repair time for a 20 MW generating unit is 0.025 and 45 hours respectively. The forced outage rate (FOR) and repair time for a 10 MW generating unit is 0.02 and 45 hours respectively.

In Alternatives 1 and 2, the MRBTS is modified to consider situations in which generating units are added at different buses. This scenario creates an increased utilization of the existing transmission networks, which is a common situation under the transmission open access paradigm. The original MRBTS has an adequate transmission system at a peak load level of 185 MW and L1 or L6 is the most severe contingency under a deterministic N-1 criterion, as noted earlier. In the new market environment, generation additions driven by market forces tend not to match the required transmission additions. Under these conditions, systems that previously had adequate transmission facilities can become systems with inadequate transmission facilities as the system load grows. In Alternative 3, one transmission line parallel to L1 and L6 is added between Bus 1 and Bus 3.

The peak load carrying capabilities (PLCC) for each case of the three alternatives have been examined and are presented in the following tables. Similar analyses are presented later in this chapter using the probabilistic (P) and the joint deterministic-probabilistic (D-P) approaches. The PLCC values in the following studies described in this thesis have been expressed as integer values. The objective is to examine the system PLCC under the D, P and D-P criteria rather than conduct a detailed economic analysis of the proposed alternatives. The PLCC values when applied to the load levels shown in Table 4.1 provide an indication of when additional system reinforcements are required to meet the system load. Tables 4.2, 4.3 and 4.4 show the PLCC for each case for the three alternatives.

Case 1 for the Three Alternatives

The system peak load carrying capabilities (PLCC) for the base case, A1-C1, A2-C1 and A3-C1 are shown in Table 4.2.

Table 4.2: The system PLCC for the base case, A1-C1, A2-C1 and A3-C1

Cases	PLCC (MW)
Base Case	189
A1-C1	189
A2-C1	219
A3-C1	219

It can be seen from Table 4.2 that Alternative 1-Case 1 (A1-C1) does not improve the PLCC of the system. However, Alternative 2-Case 1 (A2-C1) and Alternative 3-Case 1 (A3-C1) increases the PLCC of the system from 189 MW to 219 MW.

Case 2 for the Three Alternatives

The system peak load carrying capability (PLCC) for the base case, A1-C2, A2-C2 and A3-C2 are shown in Table 4.3.

Table 4.3: The system PLCC for the base case, A1-C2, A2-C2 and A3-C2

Cases	PLCC (MW)
Base Case	189
A1-C2	196
A2-C2	230
A3-C2	230

It can be seen from Table 4.3 that A1-C2 improves the system PLCC by 7 MW. A2-C2 and A3-C2 increase the PLCC substantially as in Alternative 2 the generators are added directly to the load buses, and in Alternative 3 an additional transmission line is added between Bus 1 and Bus 3.

Case 3 for the Three Alternatives

The system peak load carrying capability (PLCC) for the base case, A1-C3, A2-C3 and A3-C3 are shown in Table 4.4.

Table 4.4: The system PLCC for the base case, A1-C3, A2-C3 and A3-C3

Cases	PLCC (MW)
Base Case	189
A1-C3	196
A2-C3	250
A3-C3	250

It can be seen from Tables 4.2 to 4.4 that Alternative 1 does not solve the transmission deficiency problem because the generating units are added in the northern part of the MRBTS. Alternative 2 adds the generating units in the southern part of the MRBTS, which is the load center. Alternative 3 adds generating units in the northern part of the MRBTS and adds an additional line between Bus 1 and Bus 3. Alternatives 2 and 3 solve the transmission deficiency problem in the MRBTS. It is important to note that a generation location solution is used in Alternative 2 to solve the transmission deficiency problem.

Table 4.5 shows the system PLCC for the three alternatives.

Table 4.5: The system PLCC for the three alternatives using a deterministic N-1 criterion

Cases	PLCC (MW)	Cases	PLCC (MW)	Cases	PLCC (MW)
A1-C1	189	A1-C2	196	A1-C3	196
A2-C1	219	A2-C2	230	A2-C3	250
A3-C1	219	A3-C2	230	A3-C3	250

Table 4.1 shows the forecast peak loads in a nine-year time frame. The PLCC values shown in Table 4.5 can be used to determine in which years the peak load could be carried by the bulk electric system under the different alternatives and cases. This analysis is summarized in Table 4.6.

Table 4.6: Acceptable years using a deterministic N-1 criterion

Cases	Year	Cases	Year	Cases	Year
A1-C1	0	A1-C2	1	A1-C3	1
A2-C1	3	A2-C2	4	A2-C3	6
A3-C1	3	A3-C2	4	A3-C3	6

Table 4.6 clearly illustrates how the proposed facility additions in the three alternatives satisfy the future load growth under the deterministic N-1 criterion. The system is adequate up to Year 6 for both A2-C3 and A3-C3. As noted earlier, A2-C3 provides a generation location solution to a transmission deficiency problem. The actual selection of the optimum reinforcement is obviously based on a detailed economic analysis of the various alternatives available to the system.

4.4 Probabilistic Criterion

The probabilistic criterion states that the system risk shall not exceed a specified criterion value. The actual selection of the criterion value is a management decision and many jurisdictions require regulatory approval. The reference peak load for the RBTS is 185 MW [34]. Table 4.7 shows that the risk at the load level expressed by the Severity Index (SI), is 5.95 System Minutes (SM)/yr. A criterion value of 6.0 SM/yr has been used in the following probabilistic analyses.

4.4.1 MRBTS Base Case Analyses

The load level in a power system has a significant effect on the reliability indices. This section illustrates the variation in the system reliability indices as a function of the peak load. The peak load is assumed to vary from 185 MW to 240 MW.

As illustrated in Chapter 2, there is a wide range of bulk electric system reliability indices. Each index provides specific information. The expected energy not supplied (EENS) is a very useful and popular index, and is used in the following studies. Other indices can also be used if necessary. The EENS estimates the supply unreliability in terms of energy curtailment and provides a valuable overall assessment of the system reliability. The EENS is normalized by the peak load to recognize the changes in system size in the form of the Severity Index expressed in System Minutes/yr.

Table 4.7 and Figure 4.2 show the variation in the SI as a function of the peak load for the MRBTS. The results in Table 4.7 are based on analyses that include both generation and transmission (G & T) element failures.

Table 4.7: Annual SI (SM/yr) as a function of the peak load

Peak Load (MW)	185.00	194.25	204.00	214.20	224.90	236.10	239.00
Total G&T Failures	5.95	13.07	26.86	63.59	145.71	304.33	346.29

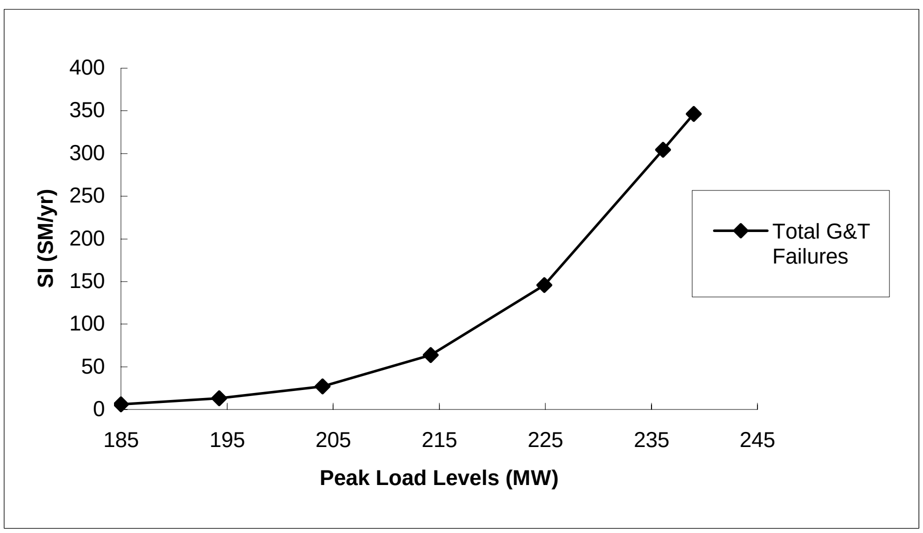

Figure 4.2: Contributions to the MRBTS SI as a function of the peak load

It can be seen in Figure 4.2 that the system SI increases rapidly with peak load growth. The maximum load that the system can carry is 239 MW without any load curtailment with all equipment in service.

4.4.2 Factor Analysis for the MRBTS Base Case

An important step in power system reinforcement planning is to find the weak areas from the viewpoint of composite system reliability [46], and then find out what factor(s) cause the problem. Specified actions can then be taken to cure the problems and strengthen the system. The following studies examine the reliability of the MRBTS when the generation system or the transmission system is assumed to be 100% reliable. The peak load is assumed to vary from 185 MW to 240 MW. Table 4.8 and Figure 4.3 show the changes in the system SI as a function of the peak load for the three element failure conditions (e.g. G, T, G & T failures).

Table 4.8: Annual SI (SM/yr) as a function of the peak load

Peak Load (MW)	185.00	194.25	204.00	214.20	224.90	236.10	239.00
Total G&T Failures	5.95	13.07	26.86	63.59	145.71	304.33	346.29
G failures only	5.59	12.43	25.39	59.59	136.56	286.63	326.93
T failures only	0.28	0.43	0.99	3.10	7.90	16.46	18.18

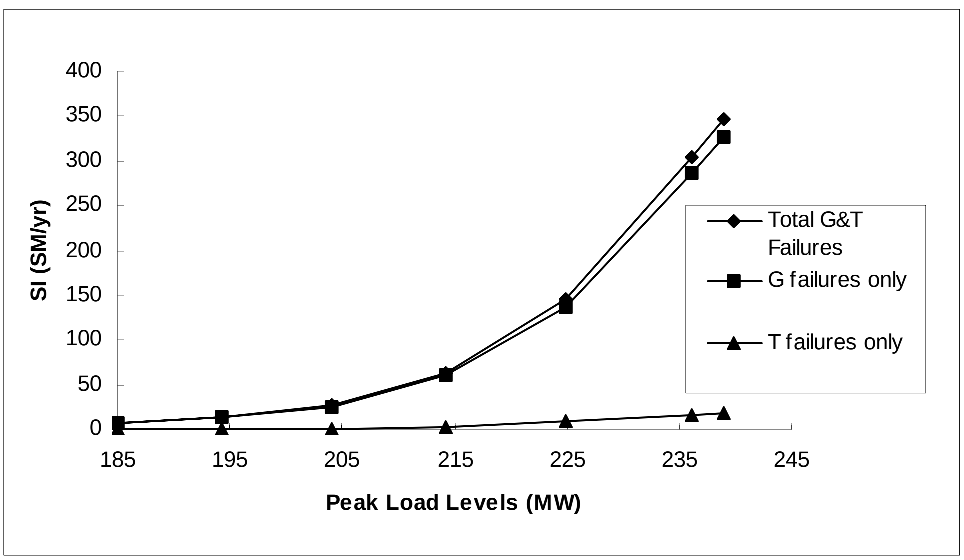

Figure 4.3: Contributions to the MRBTS SI as a function of the peak load

Figure 4.3 graphically illustrates the effect of generation and transmission system failures on the system SI. The effects of generation failures are very dependent on the system load level. Figure 4.3 shows that the SI values increase dramatically with peak load for generation system failures. The system SI values have only relatively small changes with peak load for transmission system failures. This indicates that the MRBTS has a relatively strong transmission system.

The relative contributions of the generation and transmission facilities at the various peak load levels provide indications of what reinforcements are required to improve the overall system reliability. The actual locations of both generation and transmission reinforcement are important considerations. For example, generating units obviously need to be added. One alternative is to add generating units at Bus 3 and Bus 5, as Bus 3 has the biggest system load and Bus 5 is the most remote load bus in the MRBTS.

The following studies focus on the possible planning alternatives introduced earlier and their effects for a range of peak loads.

4.4.3 Planning Alternatives

As noted, the reliability indices of the MRBTS are dominated by generation system failures. The reliability of the system therefore can be improved by adding generating units at different locations.

The three planning alternatives with the three described cases given in Section 4.3.2 have been considered.

Case 1 for the Three Alternatives

Figures 4.4-4.6 respectively show the SI as a function of the peak load for the base case, A1-C1, A2-C1 and A3-C1 considering both generation and transmission failures, generation failures only and transmission failures only. The numerical values for the G&T condition are shown in Table 4.9. The values for the separate G and T analyses are given in Appendix B.

The designation ESC indicates that the system cannot meet this load level, and stands for "Exceeds System Capability". This designation is used in many of the following tables in this thesis.

Table 4.9: Annual SI in SM/yr for the base case, A1-C1, A2-C1 and A3-C1 (Both generation and transmission failures)

Year	Peak Load (MW)	Base Case	A1-C1	A2-C1	A3-C1
0	185.00	5.95	0.86	0.83	0.86
1	194.25	13.07	2.12	1.91	1.87
2	204.00	26.86	5.19	4.31	4.14
3	214.20	63.59	13.91	10.85	10.35
4	224.90	145.71	33.81	26.38	25.04
5	236.10	304.33	76.77	62.50	59.27
6	248.00	ESC	163.29	140.55	133.44
7	260.40	ESC	ESC	ESC	ESC

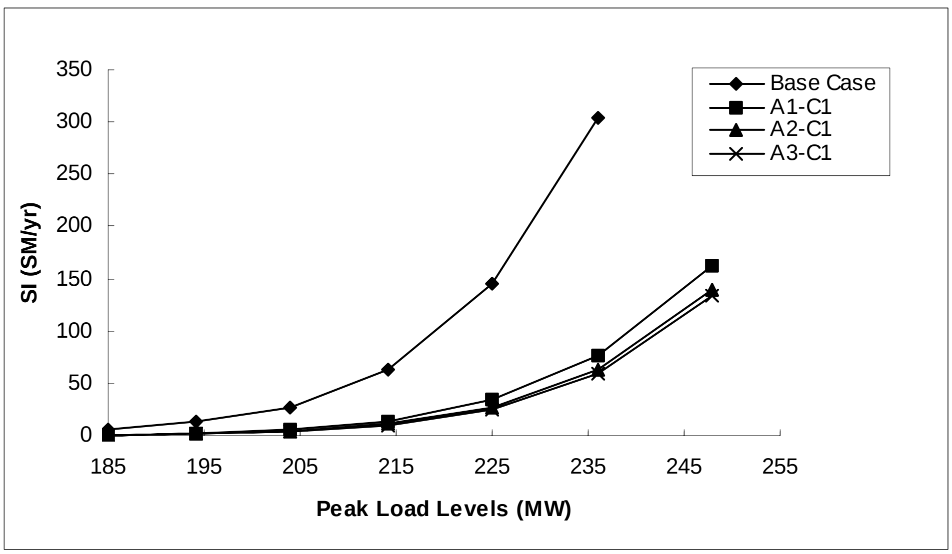

Figure 4.4: Annual SI indices for the base case, A1-C1, A2-C1 and A3-C1 (Both generation and transmission failures)

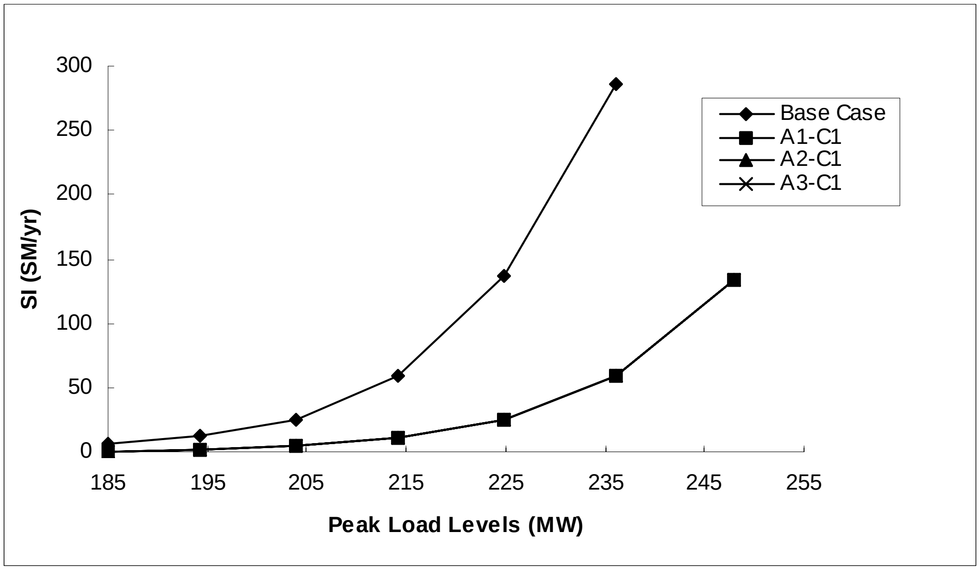

Figure 4.5: Annual SI indices for the base case, A1-C1, A2-C1 and A3-C1 (Generation failures only)

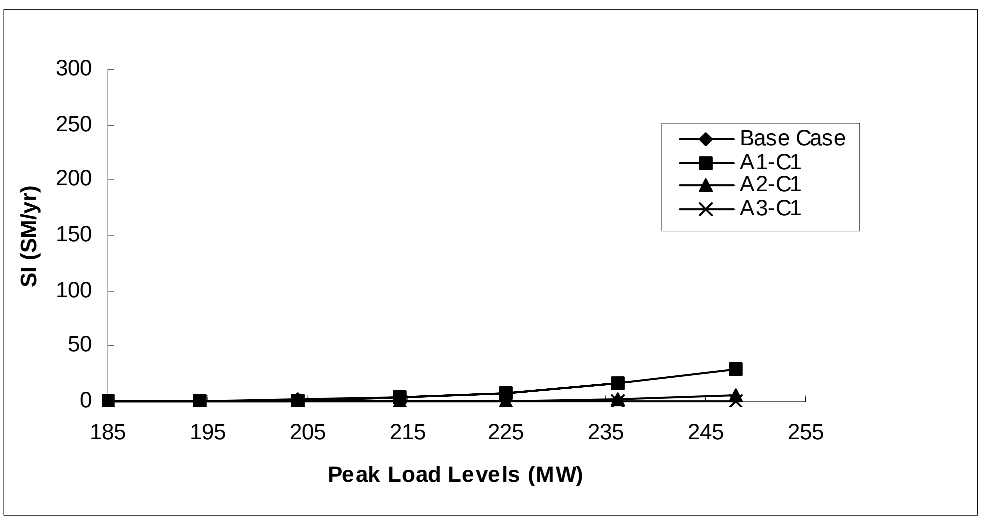

Figure 4.6: Annual SI indices for the base case, A1-C1, A2-C1, A3-C1 (Transmission failures only)

The system peak load carrying capability (PLCC) for the base case and Case 1 for the three alternatives is shown in Table 4.10. Both generation and transmission failures are considered and the SI criterion is 6.0 SM/yr.

Table 4.10: The PLCC for the base case, A1-C1, A2-C1 and A3-C1

Cases	PLCC (MW)
Base Case	185
A1-C1	205
A2-C1	207
A3-C1	209

Case 2 for the Three Alternatives

Figures 4.7-4.9 show the SI as a function of the peak load for the base case, A1-C2, A2-C2 and A3-C2 considering both generation and transmission failures, generation failures only and transmission failures only. The numerical values for the G&T condition as shown in Table 4.11. The values for the separate G and T analyses are shown in Appendix B.

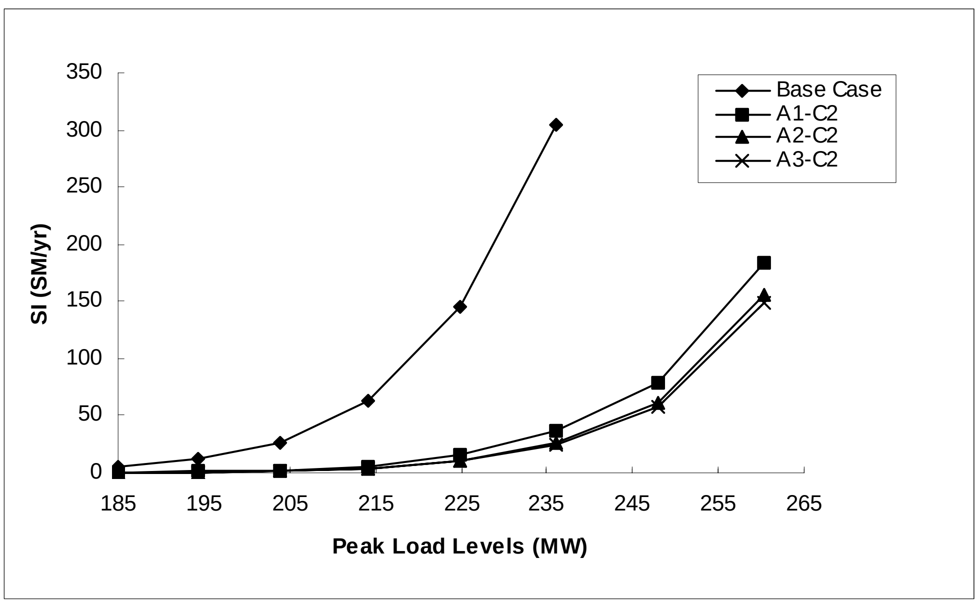

Figure 4.7: Annual SI indices for the base case, A1-C2, A2-C2 and A3-C2
(Both generation and transmission failures)

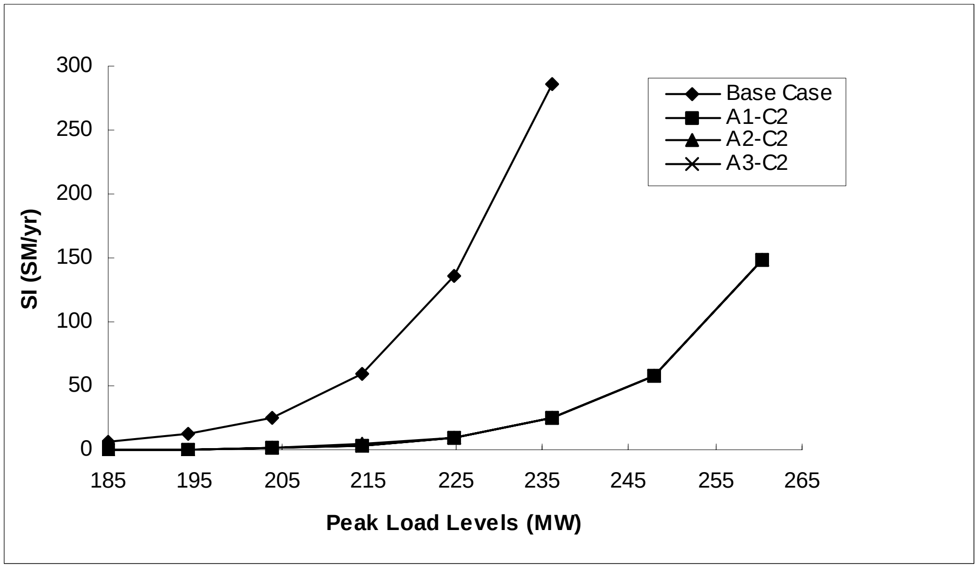

Figure 4.8: Annual SI indices for the base case, A1-C2, A2-C2 and A3-C2 (Generation failures only)

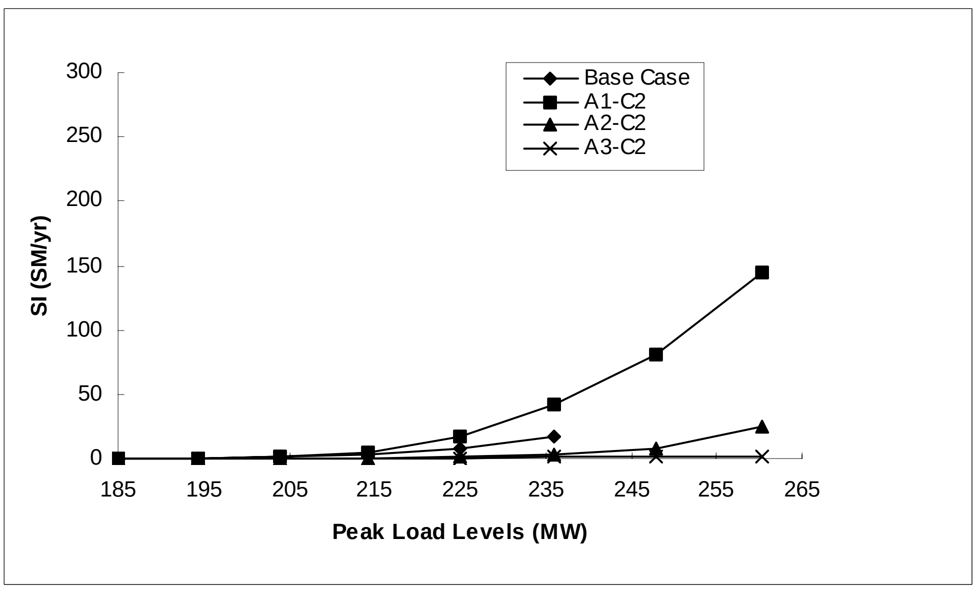

Figure 4.9: Annual SI indices for the base case, A1-C2, A2-C2 andA3-C2 (Transmission failures only)

Table 4.11: Annual SI indices for the base case, A1-C2, A2-C2 and A3-C2
(Both generation and transmission failures)

Year	Peak Load (MW)	Base Case	A1-C2	A2-C2	A3-C2
0	185.00	5.95	0.45	0.35	0.42
1	194.25	13.07	0.89	0.71	0.76
2	204.00	26.86	2.04	1.59	1.57
3	214.20	63.59	5.85	4.22	4.07
4	224.90	145.71	15.31	10.49	10.03
5	236.10	304.33	36.50	25.79	24.53
6	248.00	ESC	79.16	60.80	57.83
7	260.40	ESC	184.09	156.03	148.73
8	273.40	ESC	ESC	ESC	ESC

The system PLCC for the base case and Case 2 for the three alternatives is shown in Table 4.12.

Table 4.12: The system PLCC for the base case, A1-C2, A2-C2 and A3-C2

Cases	PLCC (MW)
Base Case	185
A1-C2	214
A2-C2	219
A3-C2	220

It can be seen from Table 4.12 that the PLCC values of the MRBTS all increase for Case 2 for the three alternatives over the Case 1 values. A1-C2 results in the least improvement on the system PLCC compared to A2-C2 and A3-C2.

Case 3 for the Three Alternatives

Figures 4.10-4.12 show the SI as a function of the peak load for the base case, A1-C3, A2-C3 and A3-C3 considering both generation and transmission failures, generation failures only and transmission failures only. The numerical values for the G&T condition are shown in Table 4.13. The values for the separate G and T analyses are given in Appendix B.

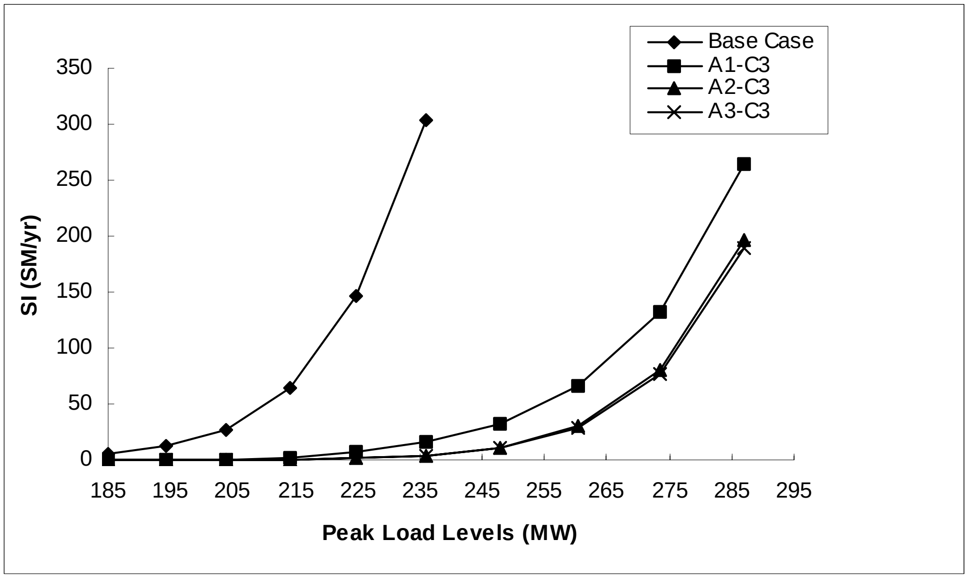

Figure 4.10: Annual SI indices for the base case, A1-C3, A2-C3 and A3-C3 (Both generation and transmission failures)

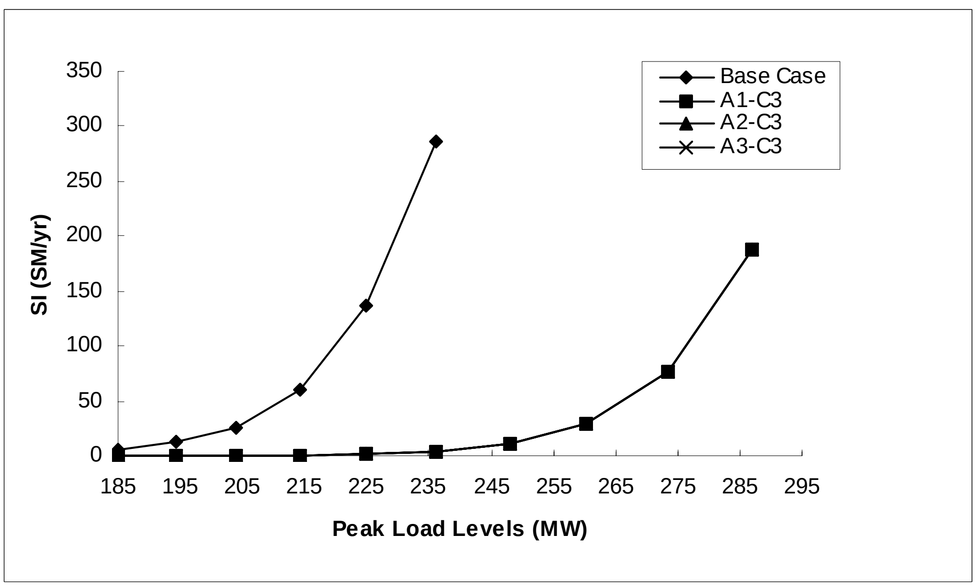

Figure 4.11: Annual SI indices for the base case, A1-C3, A2-C3 and A3-C3 (Generation failures only)

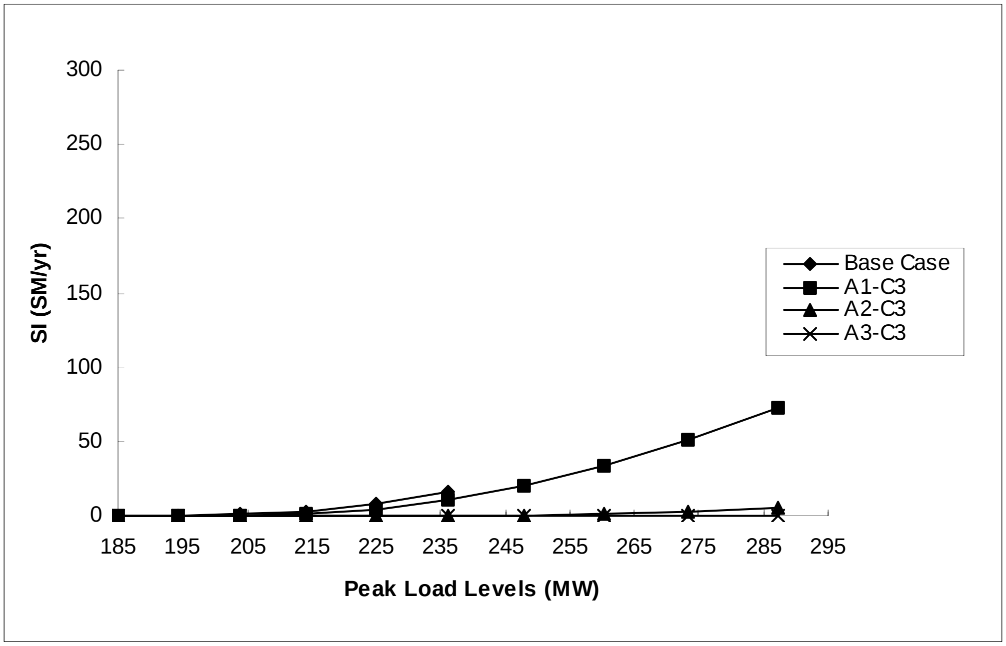

Figure 4.12: Annual SI indices for the base case, A1-C3, A2-C3 and A3-C3 (Transmission failures only)

Table 4.13: Annual SI in SM/yr for the base case, A1-C3, A2-C3, A3-C3 (Both generation and transmission failures)

Year	Peak Load (MW)	Base Case	A1-C3	A2-C3	A3-C3
0	185.00	5.95	0.24	0.13	0.06
1	194.25	13.07	0.37	0.18	0.10
2	204.00	26.86	0.81	0.29	0.21
3	214.20	63.59	2.50	0.66	0.59
4	224.90	145.71	7.06	1.68	1.62
5	236.10	304.33	16.50	4.37	4.29
6	248.00	ESC	32.05	10.55	10.32
7	260.40	ESC	65.49	30.27	29.28
8	273.40	ESC	131.88	80.68	77.66
9	287.10	ESC	263.94	195.56	188.77

Table 4.14 shows the system PLCC for the base case and Case 3 for the three alternatives.

Table 4.14: The PLCC for the base case, A1-C3, A2-C3 and A3-C3

Cases	PLCC (MW)
Base Case	185
A1-C3	223
A2-C3	241
A3-C3	241

Table 4.14 shows that the system PLCC is 223 MW under A1-C3. Figure 4.12 indicates that the transmission failures become more significant with peak load growth in A1-C3. Based on a SI criterion of 6.0 SM/yr, the PLCC is 223 MW under A1-C3. The PLCC is 241 MW under the A2-C3 and A3-C3 conditions.

The system PLCC for the three alternatives are shown in Table 4.15.

Table 4.15: The system PLCC for the three alternatives using a probabilistic criterion (SI=6.0 SM/yr)

Case 1	PLCC (MW)	Case 2	PLCC (MW)	Case 3	PLCC (MW)
A1-C1	205	A1-C2	214	A1-C3	223
A2-C1	207	A2-C2	219	A2-C3	241
A3-C1	209	A3-C2	220	A3-C3	241

The above analyses illustrate the relative differences in the system reliability impacts due to the physical locations of the added elements in the system. The benefits of adding generating units at Bus 3 and Bus 5 are considerably larger than adding units at Bus 1 and Bus 2. Adding a transmission line also reduces the stress on the transmission system. However, it can be seen from the above analyses, that adding one line does not dramatically improve the overall system reliability.

The PLCC values in Table 4.15 can be used to determine in which years the peak load could be carried by the bulk electric system under the different alternatives and cases using a probabilistic criterion. This analysis is summarized in Table 4.16.

Table 4.16: Acceptable years using a probabilistic criterion

Cases	Year	Cases	Year	Cases	Year
A1-C1	2	A1-C2	2	A1-C3	3
A2-C1	2	A2-C2	3	A2-C3	5
A3-C1	2	A3-C2	3	A3-C3	5

Table 4.16 clearly illustrates how the proposed facility additions in the three alternatives satisfy the future load growth using a probabilistic criterion. The acceptable years are quite different in Table 4.16 from those in Table 4.6. Transmission deficiency

is the most severe condition using a deterministic criterion. Generation deficiency however is the most severe condition using the probabilistic criterion.

4.5 Joint Deterministic-Probabilistic (D-P) Criterion

The D-P concept is a deterministic framework incorporating a probabilistic criterion. According to the deterministic N-1 criterion, the system should be able to withstand the loss of any single element without any damage or load curtailment at all demand levels. An acceptable SI value is defined as the probabilistic criterion using a probabilistic approach in this thesis.

4.5.1 Application of the D-P criterion

The D-P criterion used in the following studies is a combination of the deterministic N-1 criterion and a quantitative SI criterion. The SI criterion is designated as Pc in this thesis and provides the probabilistic element in the D-P approach. The Pc value is assumed to be 163 SM/yr. The selection of this value is described in the following.

The following studies show the variation in the SI as a function of the peak load using the joint deterministic-probabilistic (D-P) criterion.

4.5.2 MRBTS Base Case Analysis

The peak load for the MRBTS is assumed to vary from 166.5 MW to 240 MW. The G2-40, G1-40, L1, L5 and L8 outage events have been examined. Table 4.17 and Figure 4.13 show the variation in the SI as a function of the peak load for the studied contingencies. Both generation and transmission failures are considered. The reference peak load for the RBTS is 185 MW [34]. Table 4.17 shows that the risk expressed by the SI of 163.24 SM/yr under the G2-40 contingency. This is the largest contingency risk at the reference peak of 185 MW. A Pc value of 163 SM/yr has therefore been selected as the SI criterion in the following MRBTS D-P studies. As noted earlier, the selection of a particular probabilistic criterion is a management decision.

Table 4.17: Annual SI in SM/yr of the MRBTS for selected outages
(Both generation and transmission failures)

Peak Load (MW)	166.50	175.75	185.00	189.00	194.25	200.00	204.00	214.20	224.90	236.10	239.00
G2-40	33.25	73.33	163.24	209.90	335.91	460.33	ESC	ESC	ESC	ESC	ESC
G1-40	24.95	57.22	131.16	169.12	275.33	378.91	ESC	ESC	ESC	ESC	ESC
L1	5.22	11.57	32.38	52.54	ESC	ESC	ESC	ESC	ESC	ESC	ESC
L5	85.27	86.64	90.00	91.63	97.07	102.36	110.43	144.09	228.05	386.13	427.21
L8	85.36	86.79	90.23	91.95	97.51	103.26	111.52	149.81	234.20	394.42	436.29

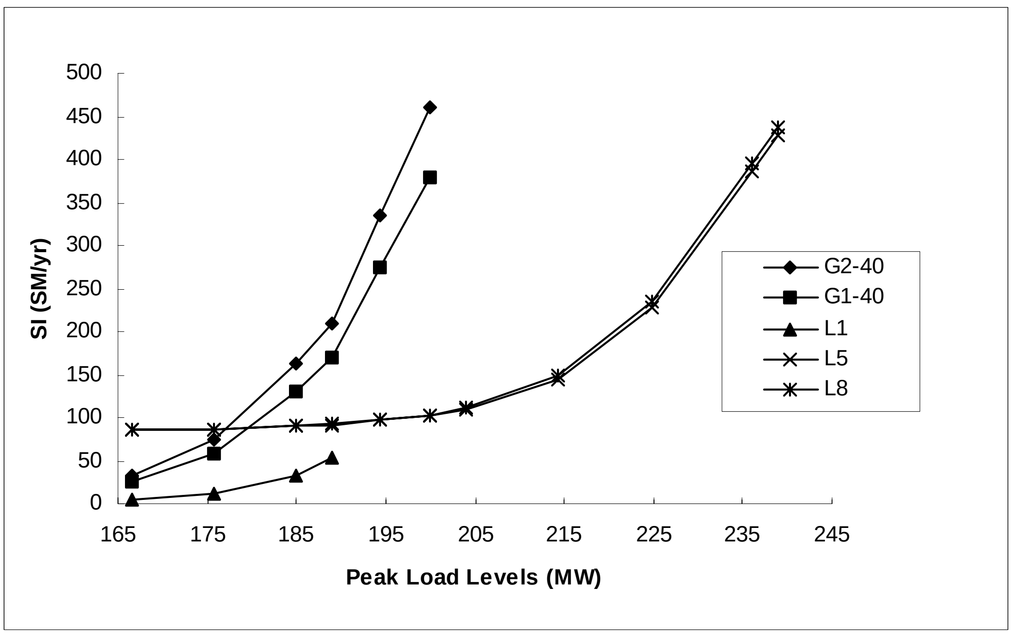

Figure 4.13: Annual SI indices versus the peak load for the selected outages

The MRBTS will experience load curtailment when the peak load is greater than 200 MW for a G1-40 or G2-40 outage. As noted in Section 4.3, the system will have load curtailment for a L1 outage when the peak load is greater than 189 MW, L1 therefore is the weak element in the MRBTS. The utilization of Line #1 and #6 is approximately 85% of the line rating for the system peak load condition, and therefore, losing one of these parallel lines creates an overload on the remaining line during high load periods and results in load curtailment.

The MRBTS system will have load curtailment when the peak load is greater than 239 MW for L5 or L8 outages. It can be seen that L5 and L8 outage conditions are less severe than G2-40, G1-40 and L1 outages, therefore, L5 and L8 outages are not included in the following studies.

The above results are basically the same as those obtained using the deterministic N-1 criterion in Section 4.3. The results in this section, however, provide additional quantitative information under each single element outage condition that is important for managers, planners and engineers when making system expansion planning decisions.

4.5.3 Factor Analyses

The following analyses illustrate the reliability of the MRBTS for the selected contingencies when the generation system or the transmission system is assumed to be 100% reliable. The peak load varies from 166.5 MW to 200 MW.

G2-40 outage

Table 4.18 and Figure 4.14 show the variation in the system SI as a function of the peak load under the G2-40 outage condition.

Table 4.18: Annual SI in SM/yr for the MRBTS (G2-40 outage)

Peak Load (MW)	166.50	175.75	185.00	194.25	200.00
Total G&T Failures	33.25	73.33	163.23	335.91	460.33
G Failures only	33.09	72.71	161.10	330.08	450.22
T Failures only	0.11	0.45	1.74	5.32	9.71

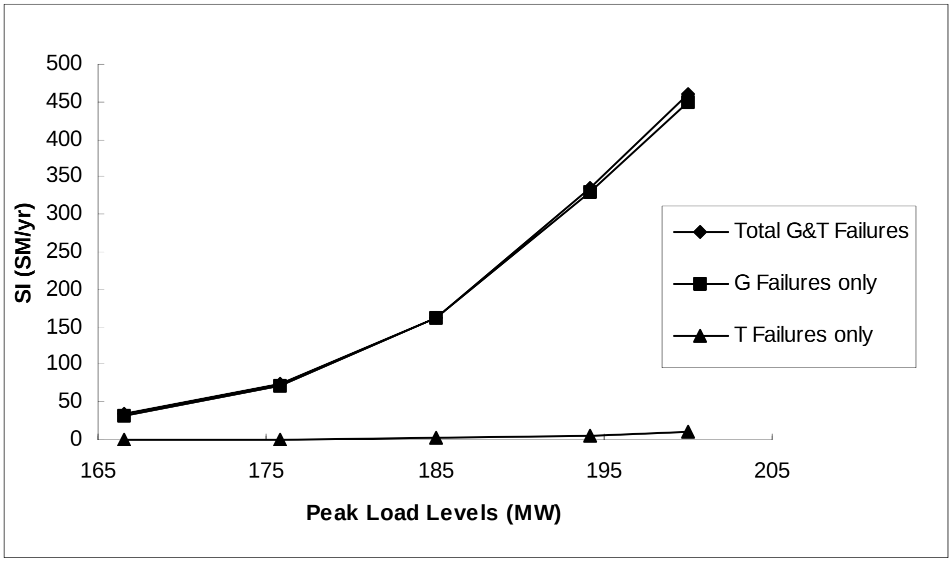

Figure 4.14: Annual SI indices versus the peak load (G2-40 outage)

Table 4.18 and Figure 4.14 show that the SI as a function of the peak load is dominated by generation failures. The PLCC using a Pc of 163 SM/yr is approximately 185 MW.

G1-40 outage

Table 4.19 and Figure 4.15 show the variation in the system SI as a function of the peak load under the G1-40 outage condition.

Figure 4.15 shows that generation failures dominate the system SI values under the G1-40 outage condition.

Table 4.19: Annual SI in SM/yr for the MRBTS (G1-40 outage)

Peak Load (MW)	166.50	175.75	185.00	194.25	200.00
Total G&T	24.95	57.22	131.16	275.33	378.91
G Failures only	24.78	56.98	130.78	274.62	377.89
T Failures only	0.08	0.11	0.22	0.53	0.83

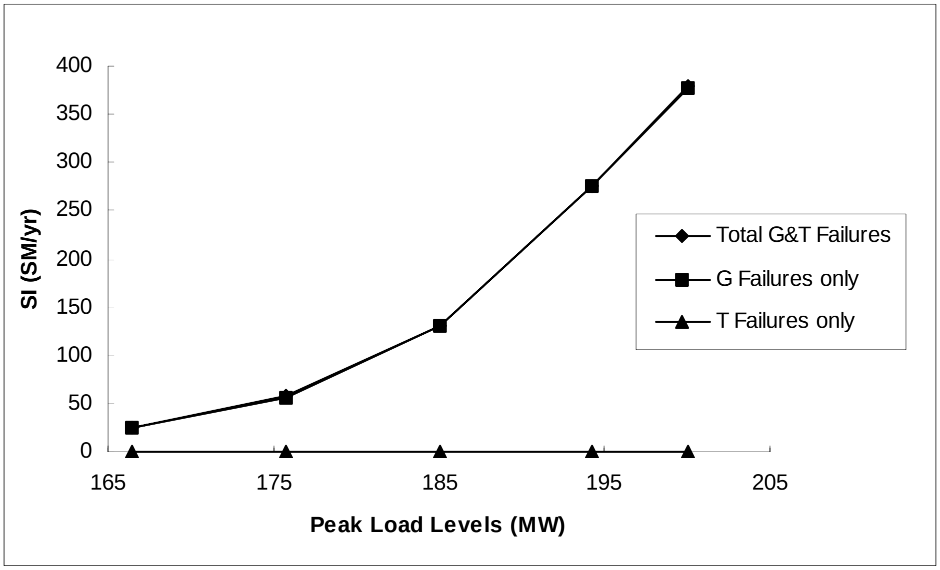

Figure 4.15: Annual SI indices versus the peak load (G1-40 outage)

Table 4.20 and Figure 4.16 show the variations in the system SI as a function of the peak load under the L1 outage condition.

Table 4.20: Annual SI in SM/yr for the MRBTS (L1 outage)

Peak Load (MW)	166.50	175.75	185.00	189.00	194.25
Total G&T	5.22	11.57	32.38	52.54	ESC
G Failures only	1.31	5.19	19.23	32.97	ESC
T Failures only	3.66	5.63	11.52	17.51	ESC

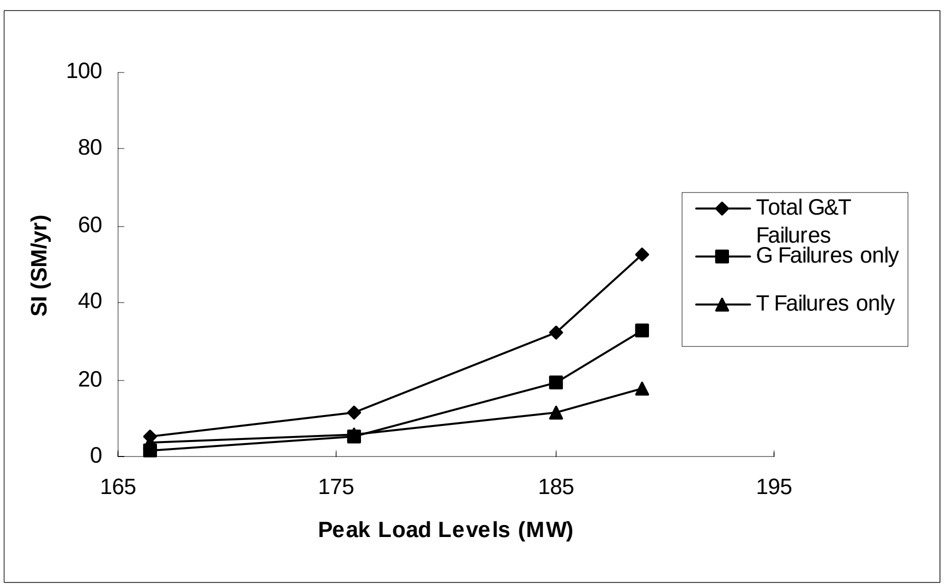

Figure 4.16: Annual SI indices versus the peak load (L1 outage)

It is interesting to note that at peak load levels less than 189 MW, the G2-40 and G1-40 outage conditions are more severe than the L1 outage condition. An L1 outage condition, however, violates the deterministic N-1 criterion when the peak load exceeds 189 MW. At this peak load level, the SI is 52.54 SM/yr, which is less than the Pc value of 163 SM/yr.

4.5.4 Planning Alternatives

The studies in Section 4.4 using a probabilistic criterion clearly show that generation insufficiency is the major problem in the MRBTS. The deterministic approach used in Section 4.3 states that the system should be able to withstand any single element out without any damage or load curtailment. Under this condition, the system will therefore have load curtailment due to a L1 outage when the peak load is higher than 189 MW. The D and P approaches therefore offer quite conflicting conclusions.

The three alternatives described earlier have been analyzed using the joint deterministic-probabilistic (D-P) criterion.

Case 1 for the Three Alternatives

The annual SI indices for the base case, A1-C1, A2-C1 and A3-C1 are shown in Tables 4.21-4.23. A comparison of the results is also shown in Figures 4.17-4.19 under the G2-40, G1-40 and L1 outage conditions.

G2-40 outage

Table 4.21: Annual SI in SM/yr for the base case, A1-C1, A2-C1 and A3-C1 with G2-40 on outage (Both generation and transmission failures)

Year	Peak Load (MW)	Base case	A1-C1	A2-C1	A3-C1
0	185.00	163.24	26.59	24.60	24.24
1	194.25	335.91	61.30	55.69	54.97
2	204.00	ESC	130.94	118.62	116.84
3	214.20	ESC	292.44	270.50	265.62
4	224.90	ESC	ESC	ESC	ESC
5	236.10	ESC	ESC	ESC	ESC
6	248.00	ESC	ESC	ESC	ESC

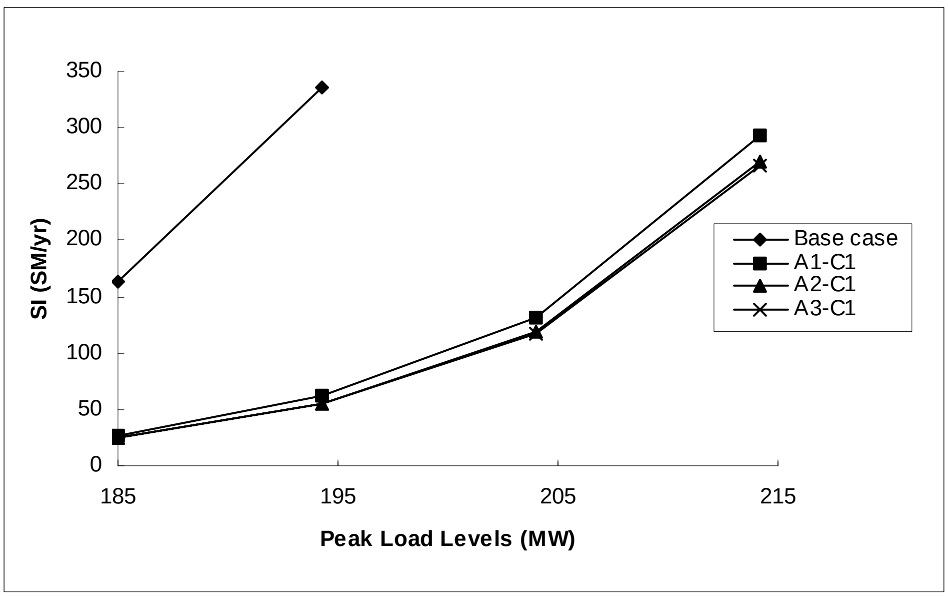

Figure 4.17: Annual SI indices for the base case, A1-C1, A2-C1 and A3-C1 with G2-40 on outage (Both generation and transmission failures)

G1-40 outage

Table 4.22: Annual SI in SM/yr for the base case, A1-C1, A2-C1 and A3-C1 with G1-40 on outage (Both generation and transmission failures)

Year	Peak Load (MW)	Base case	A1-C1	A2-C1	A3-C1
0	185.00	131.16	18.82	18.80	18.60
1	194.25	275.33	44.23	43.90	43.77
2	204.00	ESC	96.86	95.72	95.67
3	214.20	ESC	226.93	223.57	223.48
4	224.90	ESC	ESC	ESC	ESC
5	236.10	ESC	ESC	ESC	ESC
6	248.00	ESC	ESC	ESC	ESC

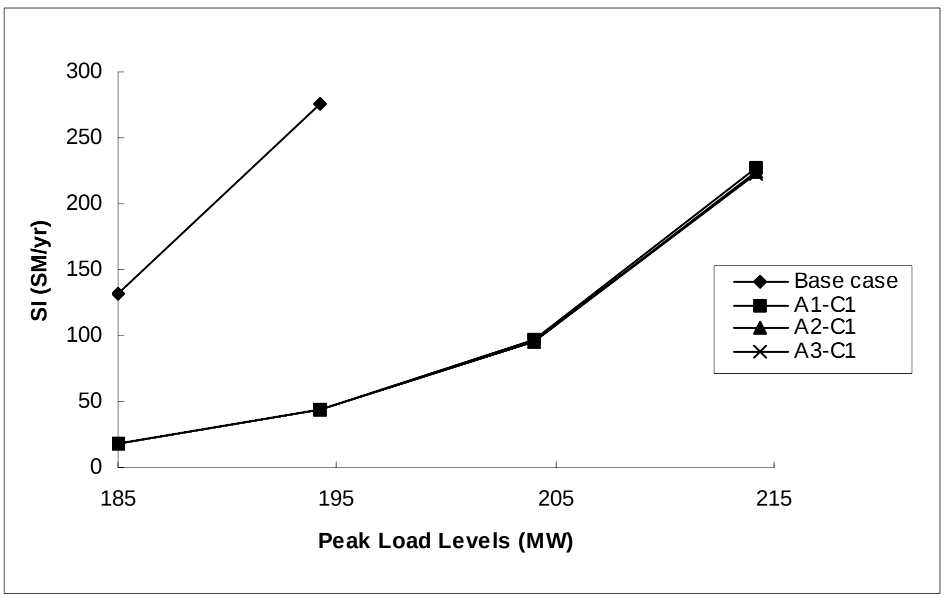

Figure 4.18: Annual SI indices for the base case, A1-C1, A2-C1 and A3-C1 with G1-40 on outage (Both generation and transmission failures)

L1 outage

Table 4.23: Annual SI in SM/yr for the base case, A1-C1, A2-C1 and A3-C1 when L1 on outage (Both generation and transmission failures)

Year	Peak Load (MW)	Base case	A1-C1	A2-C1	A3-C1
0	185.00	32.38	27.79	3.68	0.86
1	194.25	ESC	ESC	8.81	2.12
2	204.00	ESC	ESC	26.01	5.19
3	214.20	ESC	ESC	ESC	13.91
4	224.90	ESC	ESC	ESC	33.81
5	236.10	ESC	ESC	ESC	76.77
6	248.00	ESC	ESC	ESC	163.29
7	260.40	ESC	ESC	ESC	ESC

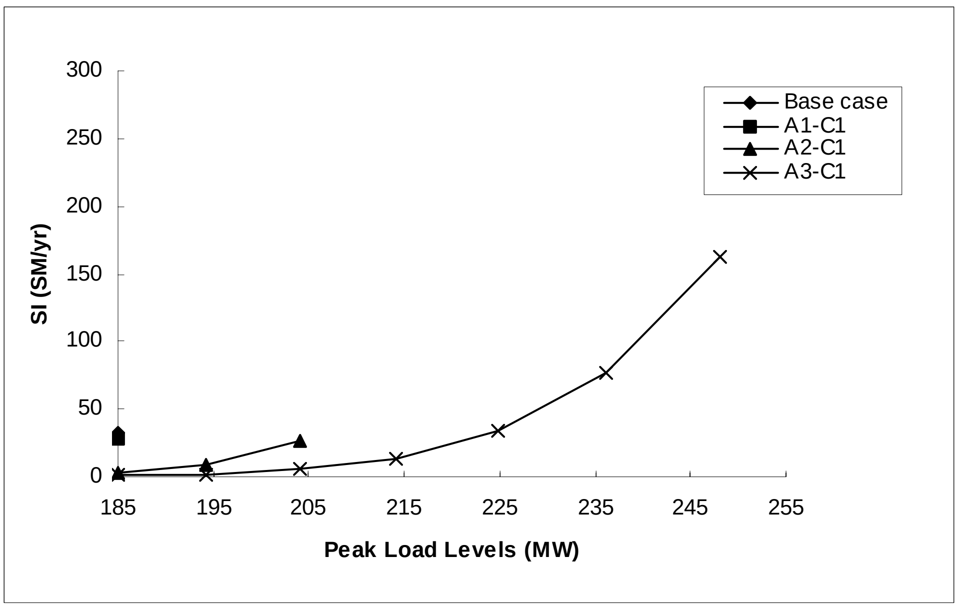

Figure 4.19: Annual SI indices for the base case, A1-C1, A2-C1 and A3-C1 with L1 on outage (Both generation and transmission failures)

It can be seen from Figures 4.17 and 4.18 that under the G2-40 or G1-40 outage conditions, Alternatives 1, 2 and 3 have similar impacts on the system SI values. It is shown in Figure 4.19 that under the L1 outage condition, Alternative 3 solves the transmission deficiency problem as an additional transmission line is added between Bus 1 and Bus 3.

Table 4.24 shows the system PLCC for the base case, A1-C1, A2-C1 and A3-C1 using the D-P criterion.

Table 4.24: The system PLCC for the base case, A1-C1, A2-C1 and A3-C1

Cases	PLCC (MW)
Base Case	189
A1-C1	189
A2-C1	208
A3-C1	208

Case 2 for the Three Alternatives

The annual SI indices for the base case, A1-C2, A2-C2 and A3-C2 are listed in Tables 4.25-4.27. A comparison of the results is also shown in Figures 4.20-4.22 under the G2-40, G1-40 and L1 outage conditions.

G2-40 outage

Table 4.25: Annual SI in SM/yr for the base case, A1-C2, A2-C2 and A3-C2 with G2-40 on outage (Both generation and transmission failures)

Year	Peak Load (MW)	Base case	A1-C2	A2-C2	A3-C2
0	185.00	163.24	9.83	8.94	8.92
1	194.25	335.91	23.68	20.63	20.52
2	204.00	ESC	52.91	45.79	45.39
3	214.20	ESC	129.44	113.93	112.45
4	224.90	ESC	282.45	256.19	251.92
5	236.10	ESC	ESC	ESC	ESC

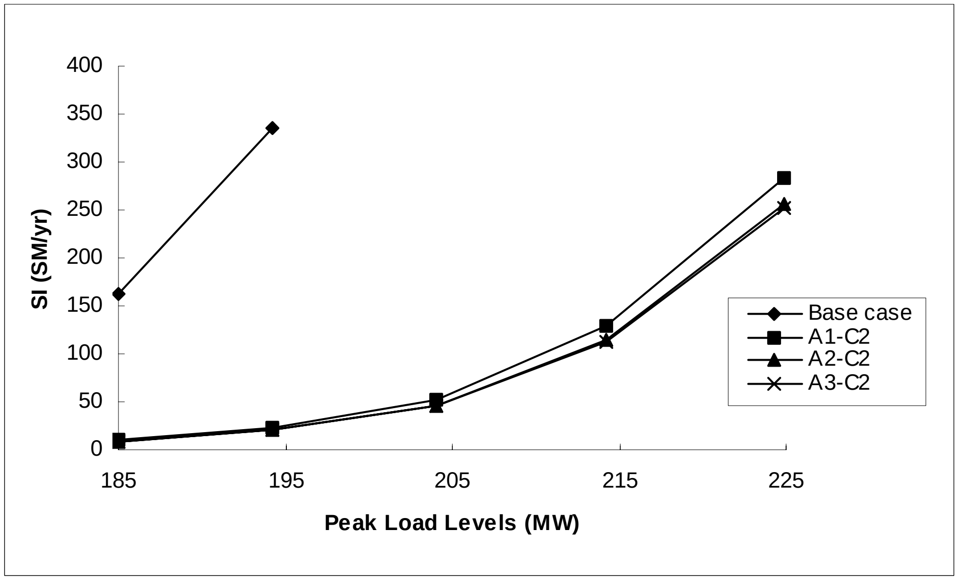

Figure 4.20: Annual SI indices for the base case, A1-C2, A2-C2 and A3-C2 with G2-40 on outage (Both generation and transmission failures)

G1-40 outage

Table 4.26: Annual SI in SM/yr for the base case, A1-C2, A2-C2 and A3-C2 with G1-40 on outage (Both generation and transmission failures)

Year	Peak Load (MW)	Base case	A1-C2	A2-C2	A3-C2
0	185.00	131.16	6.61	6.64	6.65
1	194.25	275.33	15.88	15.77	15.83
2	204.00	ESC	36.58	36.06	36.23
3	214.20	ESC	94.24	92.36	92.69
4	224.90	ESC	217.83	212.66	213.07
5	236.10	ESC	ESC	ESC	ESC

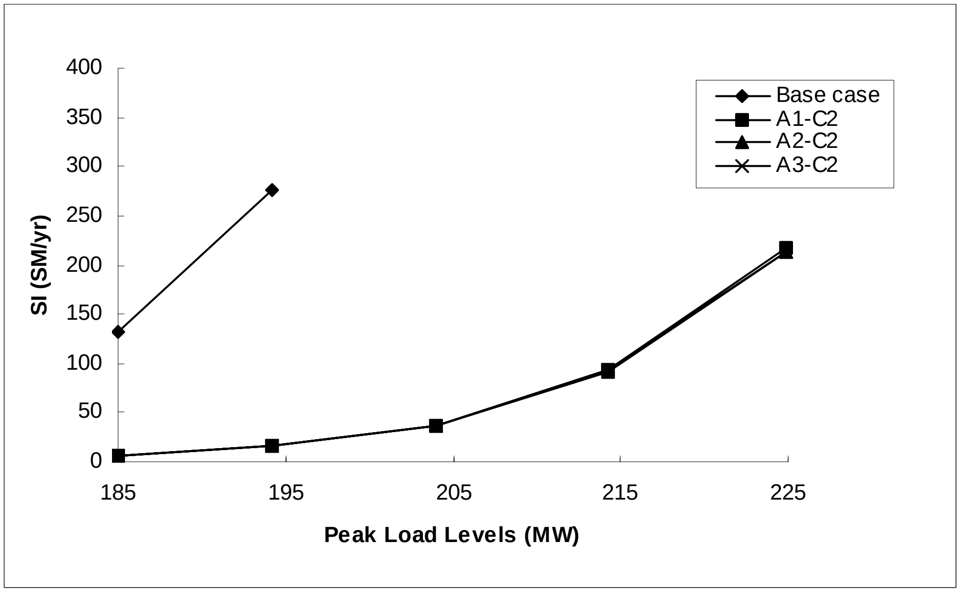

Figure 4.21: Annual SI indices for the base case, A1-C2, A2-C2 and A3-C2 with G1-40 on outage (Both generation and transmission failures)

L1 outage

Table 4.27: Annual SI in SM/yr for the base case, A1-C2, A2-C2 and A3-C2 with L1 on outage (Both generation and transmission failures)

Year	Peak Load (MW)	Base case	A1-C2	A2-C2	A3-C2
0	185.00	32.38	15.73	1.59	0.45
1	194.25	ESC	45.74	2.85	0.88
2	204.00	ESC	ESC	7.05	2.04
3	214.20	ESC	ESC	25.73	5.84
4	224.90	ESC	ESC	ESC	15.31
5	236.10	ESC	ESC	ESC	36.50
6	248.00	ESC	ESC	ESC	79.16
7	260.40	ESC	ESC	ESC	184.09

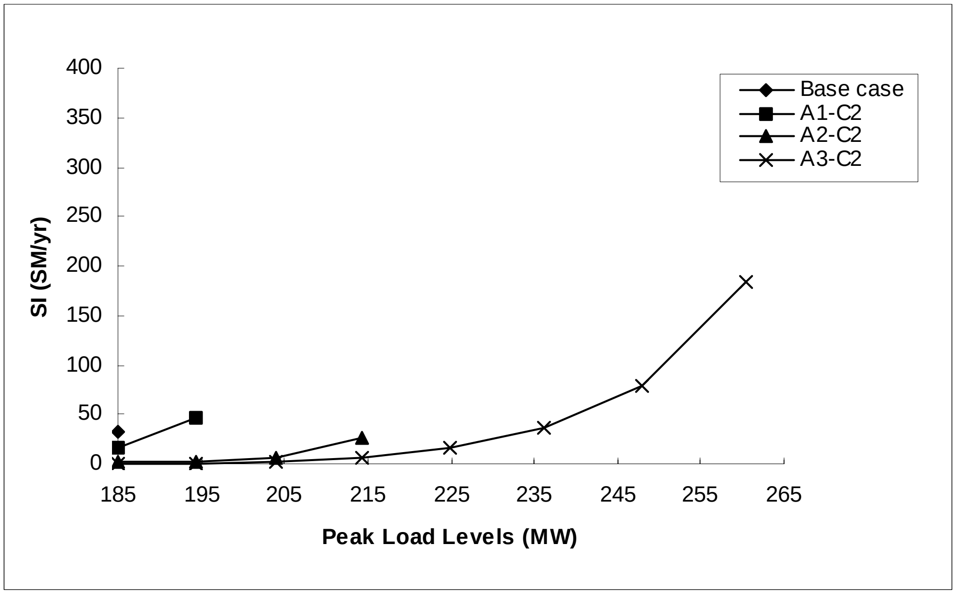

Figure 4.22: Annual SI indices for the base case, A1-C2, A2-C2 and A3-C2 with L1 on outage (Both generation and transmission failures)

Table 4.28 shows the system PLCC for the base case, A1-C2, A2-C2 and A3-C2 using the D-P criterion.

Table 4.28: The system PLCC for the base case, A1-C2, A2-C2 and A3-C2

Cases	PLCC (MW)
Base Case	189
A1-C2	196
A2-C2	219
A3-C2	220

It can be seen from Table 4.28 that the PLCC of the system under A1-C2 is 196 MW using the D-P criterion. This is the value obtained using the deterministic N-1 criterion in Section 4.3. The reason is that the D-P approach is predicated on the deterministic N-1 criterion with an added probabilistic perspective. The deterministic N-1 criterion is the pre-condition before applying the probabilistic criterion.

Case 3 for the Three Alternatives

The annual SI indices for the base case, A1-C3, A2-C3 and A3-C3 are listed in Tables 4.29-4.31. A comparison of the results is also shown in Figures 4.23-4.25 under the G2-40, G1-40 and L1 outage conditions.

G2-40 outage

Table 4.29: Annual SI in SM/yr for the base case, A1-C3, A2-C3 and A3-C3 with G2-40 on outage (Both generation and transmission failures)

Year	Peak Load (MW)	Base case	A1-C3	A2-C3	A3-C3
0	185.00	163.24	2.22	1.20	1.21
1	194.25	335.91	6.25	2.95	2.96
2	204.00	ESC	14.52	6.80	6.82
3	214.20	ESC	35.43	18.13	18.14
4	224.90	ESC	77.40	46.54	46.31
5	236.10	ESC	168.26	112.26	111.12
6	248.00	ESC	302.99	242.40	239.11

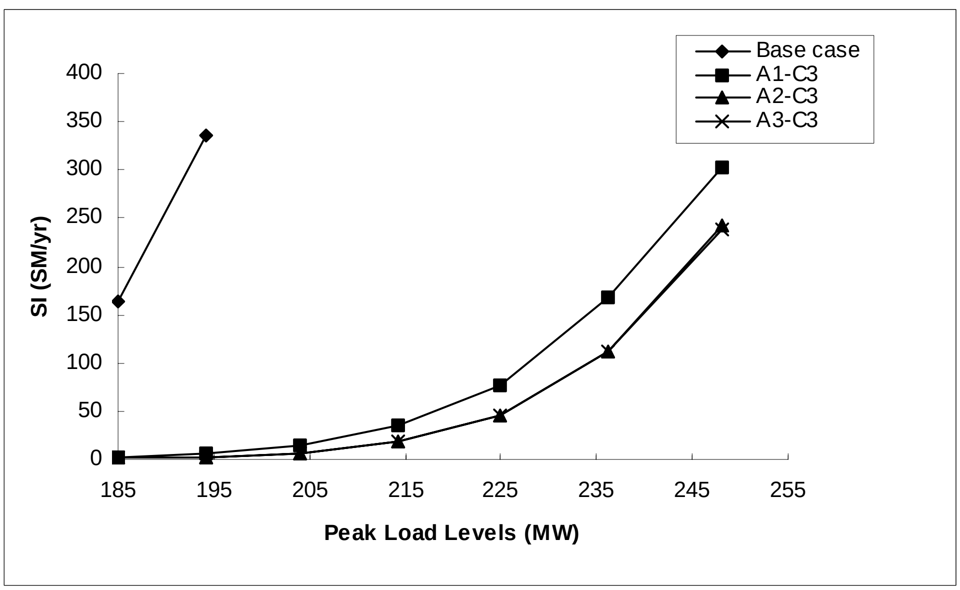

Figure 4.23: Annual SI indices for the base case, A1-C3, A2-C3 and A3-C3 with G2-40 on outage (Both generation and transmission failures)

G1-40 outage

Table 4.30: Annual SI in SM/yr for the base case, A1-C3, A2-C3 and A3-C3 with on outage (Both generation and transmission failures)

Year	Peak Load (MW)	Base case	A1-C3	A2-C3	A3-C3
0	185.00	131.16	0.95	0.90	0.91
1	194.25	275.33	2.29	2.20	2.16
2	204.00	ESC	5.51	5.14	5.05
3	214.20	ESC	15.74	14.09	13.98
4	224.90	ESC	42.34	37.26	37.14
5	236.10	ESC	103.92	92.29	92.20
6	248.00	ESC	225.05	204.41	204.30

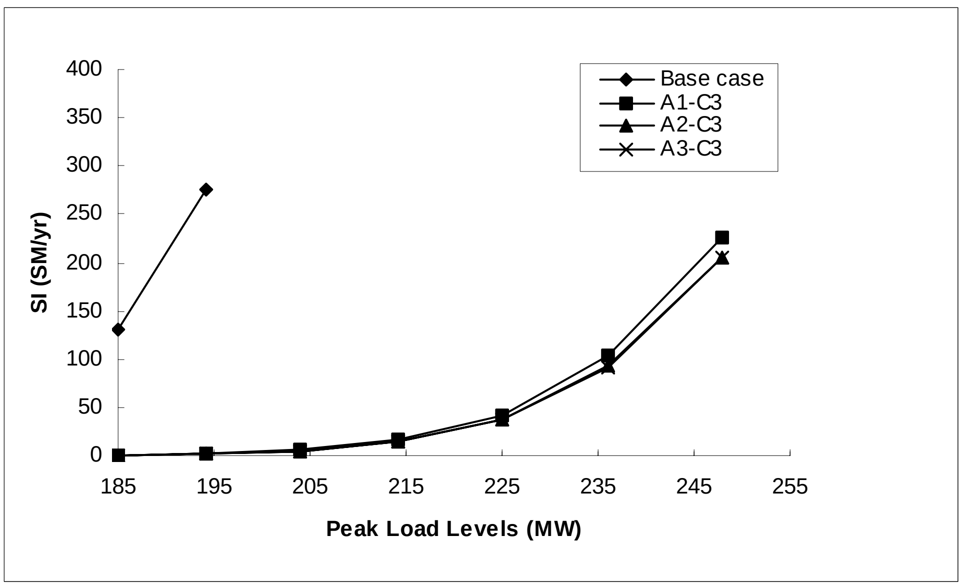

Figure 4.24: Annual SI indices for the base case, A1-C3, A2-C3 and A3-C3 with G1-40 on outage (Both generation and transmission failures)

L1 outage

Table 4.31: Annual SI in SM/yr for the base case, A1-C3, A2-C3 and A3-C3 with L1 on outage (Both generation and transmission failures)

Year	Peak Load (MW)	Base case	A1-C3	A2-C3	A3-C3
0	185.00	32.38	16.14	0.54	0.73
1	194.25	ESC	46.17	0.81	0.37
2	204.00	ESC	ESC	1.28	0.81
3	214.20	ESC	ESC	2.73	2.50
4	224.90	ESC	ESC	8.35	7.06
5	236.10	ESC	ESC	28.84	16.50
6	248.00	ESC	ESC	ESC	32.05
7	260.40	ESC	ESC	ESC	65.49
8	273.40	ESC	ESC	ESC	131.88
9	287.10	ESC	ESC	ESC	263.94

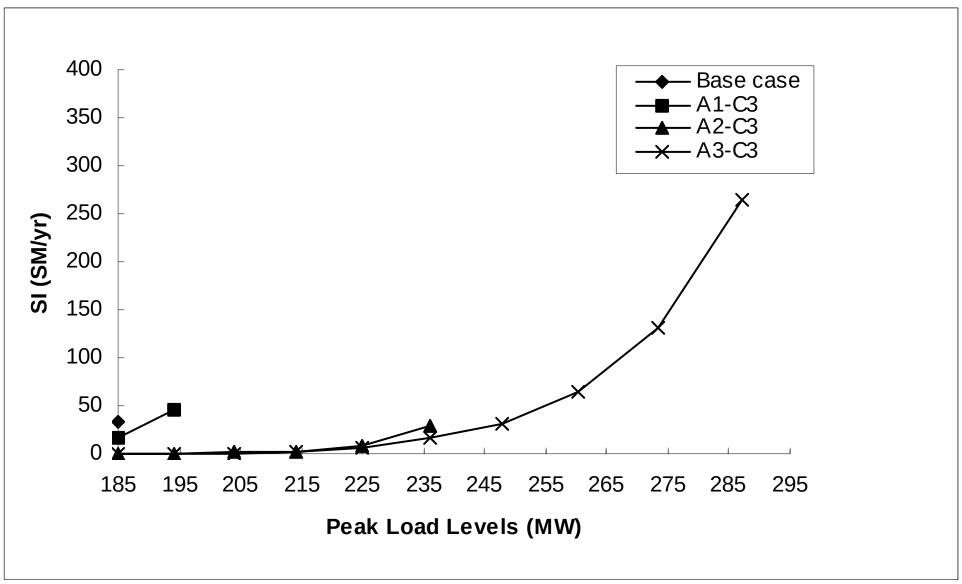

Figure 4.25: Annual SI indices for the base case, A1-C3, A2-C3 and A3-C3 with L1 on outage (Both generation and transmission failures)

It can be seen from Figures 4.23 and 4.24 that Alternatives 1, 2 and 3 all improve the system SI under both the G2-40 and G1-40 outage conditions. Figure 4.25, however, shows that under the L1 outage condition, A1-C3 does not solve the transmission deficiency problem as generators are added to the northern part of the MRBTS.

Table 4.32 shows the system PLCC for the base case, A1-C3, A2-C3 and A3-C3 using the D-P criterion.

Table 4.32: The system PLCC for the base case, A1-C3, A2-C3 and A3-C3

Cases	PLCC (MW)
Base Case	189
A1-C3	196
A2-C3	242
A3-C3	242

Table 4.33 shows the system PLCC for the three alternatives using the D-P criterion.

Table 4.33: The system PLCC for the three alternatives using the D-P criterion

Cases	PLCC (MW)	Cases	PLCC (MW)	Cases	PLCC (MW)
A1-C1	189	A1-C2	196	A1-C3	196
A2-C1	208	A2-C2	219	A2-C3	242
A3-C1	208	A3-C2	220	A3-C3	242

The PLCC values in Table 4.33 can be used to determine in which years the peak load could be carried by the bulk electric system under the different alternatives and cases. This analysis is summarized in Table 4.34.

Table 4.34: Acceptable years using the D-P criterion

Cases	Year	Cases	Year	Cases	Year
A1-C1	0	A1-C2	1	A1-C3	1
A2-C1	2	A2-C2	3	A2-C3	5
A3-C1	2	A3-C2	3	A3-C3	5

Table 4.34 shows how the proposed facility additions in the three alternatives satisfy the future load growth using the D-P criterion. The system is adequate up to Year 5 for both A2-C3 and A3-C3. The system is adequate up to Year 1 for both A1-C2 and A1-C3 which are as same as those shown in Table 4.6. The reason is that the deterministic N-1 criterion is the pre-condition before applying the probabilistic criterion.

As noted earlier, adding generating units at the northern part of the MRBTS does not solve the transmission deficiency problem.

4.6 Impact on the System PLCC of Changing the Probabilistic Criterion and the D-P Criterion Values

4.6.1 System Risk Profile

According to the D-P criterion discussed earlier, the system should withstand any single element out without load curtailment and the system should meet the SI criterion under the most critical single element outage condition. The actual risk profile is dependent on the particular element on outage. The acceptable load carrying capability is then dependent on the Pc value. The acceptable and unacceptable domains are shown in Figure 4.26.

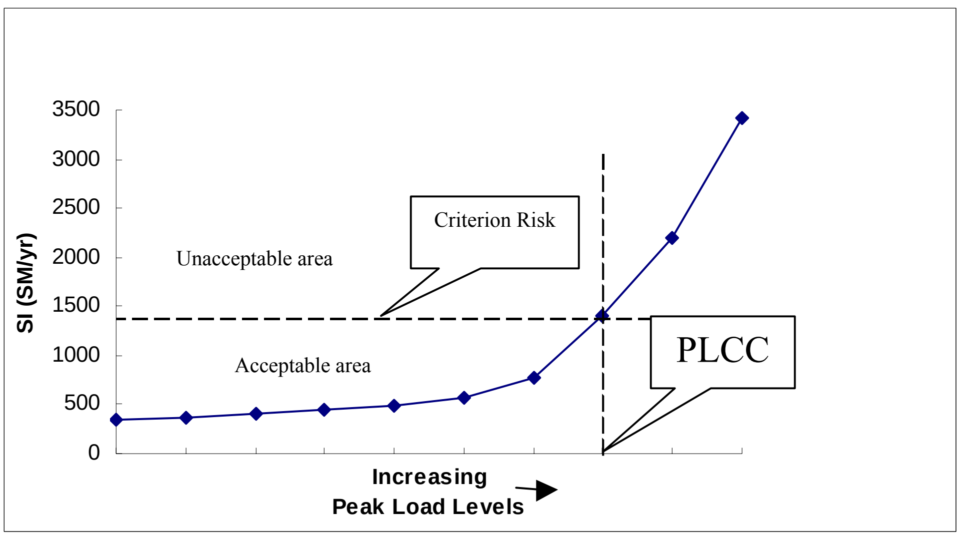

Figure 4.26: An example of the risk variation with increasing peak load

Figure 4.26 shows the variation of the risk with increasing load. The intersection of the criterion risk and the risk profile occurs at the critical load level (e.g. PLCC). Any load level higher than this will violate the risk criterion. Any load level less than this has an acceptable risk and therefore the system configuration associated with the risk profile is adequate at these load levels [47].

4.6.2 Impact on the System PLCC of Changing the Criterion Values

The three planning alternatives described in Section 4.3 have been examined under the following conditions. The SI criterion has been changed from 6.0 SM/yr to 9.0 SM/yr in the probabilistic approach and the Pc in the D-P approach has been changed from 163 SM/yr to 244.5 SM/yr.

As noted earlier in this chapter, the deterministic N-1 criterion does not provide any quantitative information on each contingency, and therefore, it is not possible to compare the risk associated with different contingencies. The system PLCC for the three alternatives using a deterministic N-1 criterion are shown in Table 4.5 in Section 4.3 and are listed below in Table 4.35 for comparison purposes.

Table 4.35: The system PLCC for the three alternatives using a deterministic N-1 criterion

Case 1	PLCC (MW)	Case 2	PLCC (MW)	Case 3	PLCC (MW)
A1-C1	189	A1-C2	196	A1-C3	196
A2-C1	219	A2-C2	230	A2-C3	250
A3-C1	219	A3-C2	230	A3-C3	250

The SI criterion in the probabilistic approach was changed from 6.0 SM/yr to 9.0 SM/yr and the PLCC for the three alternatives are shown in Table 4.36.

Table 4.36: The system PLCC for the three alternatives using a probabilistic criterion (SI=9.0 SM/yr)

Case 1	PLCC (MW)	Case 2	PLCC (MW)	Case 3	PLCC (MW)
A1-C1	211	A1-C2	220	A1-C3	230
A2-C1	212	A2-C2	223	A2-C3	246
A3-C1	213	A3-C2	224	A3-C3	246

The Pc in the D-P criterion was changed from 163 SM/yr to 244.5 SM/yr and the system PLCC of the three alternatives are shown in Table 4.37.

Table 4.37: The system PLCC for the three alternatives using the D-P criterion (Pc=244.5 SM/yr)

Case 1	PLCC (MW)	Case 2	PLCC (MW)	Case 3	PLCC (MW)
A1-C1	189	A1-C2	196	A1-C3	196
A2-C1	213	A2-C2	224	A2-C3	248
A3-C1	213	A3-C2	224	A3-C3	248

The system PLCC shown in Table 4.35 based on the deterministic criterion (N-1) do not respond the probabilistic factors that influence the reliability of the system or the ability of management to accept a particular level of system risk.

It can be seen by comparing Table 4.36 with Table 4.15 that the PLCC increase if the management is prepared to accept a higher level of risk. The criterion risk value is therefore a very important parameter and influences the planning and operating philosophy of the company. This is not a decision that management has to make when it uses the basic deterministic N-1 approach.

A similar situation exists when comparing Table 4.37 with Table 4.33. In this case, Pc is increased from 163 SM/yr to 244.5 SM/yr. There is no change in the PLCC values for Alternative 1 where the removal of L1 dominates the situation, but the PLCC values increase for Alternative 2 and 3 where generating units are added in the southern part of the MRBTS or a line in parallel with L1 is added.

4.7 Technique Analysis

The PLCC values shown in Tables 4.5, 4.15 and 4.33 obtained using the three techniques are repeated in Table 4.38 for comparison purposes.

Table 4.38: The system PLCC (MW) for the three alternatives using the three techniques

Case	Technique		
	D	P	D-P
A1-C1	189	205	189
A2-C1	219	207	208
A3-C1	219	209	208
A1-C2	196	214	196
A2-C2	230	219	219
A3-C2	230	220	220
A1-C3	196	223	196
A2-C3	250	241	242
A3-C3	250	241	242

Table 4.38 shows that there are considerable differences in the PLCC values obtained using the three techniques. The results in Table 4.38 have been rounded off to the nearest MW. The three alternatives and their three cases are described in Section 4.3.2. Table 4.39 presents a brief summary of the conditions for the nine cases in order to facilitate a comparison between the PLCC values in Table 4.38.

Table 4.39: A summary of the conditions for the nine cases

Cases	Additions to the MRBTS
A1-C1	20 MW unit at Bus 1
A2-C1	20 MW unit at Bus 3
A3-C1	20 MW unit at Bus 1, line between Bus 1 and 3
A1-C2	20 MW unit at Bus 1, 10 MW unit at Bus 2
A2-C2	20 MW unit at Bus 3, 10 MW unit at Bus 5
A3-C2	20 MW unit at Bus 1, 10 MW unit at Bus 2, line between Bus 1 and 3
A1-C3	2-20 MW units at Bus 1, 10 MW unit at Bus 2
A2-C3	2-20 MW units at Bus 3, 10 MW unit at Bus 5
A3-C3	2-20 MW units at Bus 1, 10 MW unit at Bus 2, line between Bus 1 and 3

In A1-C1, the 20 MW unit is added in the northern part of the system and the PLCC determined by the D and D-P approaches is limited by the L1 (L6) contingency. The PLCC determined using the P technique is higher due to the relatively low probability of losing one of the lines between Bus 1 and Bus 3.

In A2-C1, the 20 MW is added in the southern portion of the system and therefore the impact of losing L1 (L6) is diminished in the D analysis. The PLCC under the D criterion is the largest of the three values. The P and D-P PLCC values are very similar.

The PLCC values for the D approach in A3-C1 is the same as in A2-C2 as the line addition provide no further benefit. The addition of the line does provide a small additional benefit under the P approach and a negligible contribution for the D-P technique.

Additional capacity is added under the Case 2 condition. In the D approach, the L1 (L6) contingency still dominates the PLCC value for A1-C2. This value is higher than the A1-C1 value due to the fact that the additional 10 MW unit is added at Bus 2. The D and D-P PLCC values are the same for this condition. The PLCC value for the P criterion is the highest of the three alternatives for this condition.

In A2-C2, the addition capacity is located in the southern portion of the system. The most critical contingency in the D approach is the loss of the largest unit and transmission line outages are not a factor. The combined effects of both transmission and generation outages are included in the P and D-P analyses and the PLCC in both these cases are lower than in the D approach. The PLCC values in the A3-C2 studies are similar to those in A2-C2 as the additional line provides no significant further benefit.

The L1 (L6) outage condition dictates the PLCC for A1-C3 and there is no benefit from the additional capacity over the PLCC in A1-C2 for the D and D-P approaches. The addition of a 20 MW unit at Bus 1 in A1-C3 results an increase in the PLCC of only 9 MW over the PLCC in A1-C2 for the P approach.

The addition of a 20 MW unit in the southern portion of the system increases the PLCC by 20 MW in the D approach and results in similar increases for the P and D-P applications. Transmission constraints are not a problem in A2-C3 and A3-C3 and the results in these two situations are very similar.

It is interesting and important to note that none of the three techniques produce the highest or lowest PLCC in all cases. The D approach results in the highest and lowest values in some cases. The D criterion is a hard limit approach. The P approach recognizes the likelihood of element failures and provides a much softer limit that is influenced by the relative risks. The D-P approach is driven by the hard D criterion and influenced by recognizing the resulting relative risks.

The years into the future, for which the determined PLCC are acceptable for the three techniques, are shown in Tables 4.6, 4.16, 4.34 and are repeated in Table 4.40 for comparison purposes.

Table 4.40: Acceptable years for the three alternatives using the three techniques

Case	Technique		
	D	P	D-P
A1-C1	0	2	0
A2-C1	3	2	2
A3-C1	3	2	2
A1-C2	1	2	1
A2-C2	4	3	3
A3-C2	4	3	3
A1-C3	1	3	1
A2-C3	6	5	5
A3-C3	6	5	5

Table 4.40 indicates that the D-P criterion is more stringent than the D criterion as it combines both the deterministic and probabilistic perspectives. The D-P criterion incorporates the likelihood of element failures and therefore provides quantitative reliability risk information, which responses to the factors that do actually influence the system reliability.

The decision to select a particular system reinforcement option over other options involves a detailed economic analysis of the relevant costs in each case. The relative benefits of each option in terms of PLCC can be compared by conducting the relevant reliability studies. The focus in the research described in this thesis is on the deterministic and probabilistic techniques and the combination of these methods to produce the joint deterministic-probabilistic approach. The analyses have not been extended by conducting the economic studies required to select the optimum reinforcement alternatives.

The reliability evaluation technique and the applied criteria are both key elements in determining the PLCC for a particular reinforcement option. Table 4.38 and 4.40 clearly indicate that in the case of the MRBTS there are definite differences in the perceived need to add generation and/or transmission facilities in the future to meet the expected load growth under the different reliability evaluation methodologies.

4.8 Conclusion

This chapter presents the application of the deterministic (D), probabilistic (P) and joint deterministic-probabilistic (D-P) techniques to MRBTS planning. Three possible system reinforcement planning alternatives are examined using the D, P and D-P approaches and the system PLCC is determined using the D, P and D-P criteria.

The application of the deterministic N-1 technique to MRBTS reinforcement planning shows that the deterministic criterion does not response to the probabilistic factors that influence the reliability of the system and is a rigid criterion.

The results obtained by applying the probabilistic technique to the MRBTS show that the probabilistic approach responds to the significant factors that influence the reliability of the system and provide reliability risk information that is valuable when making system reinforcement decisions. The actual selection of the probabilistic criterion value is a management decision based on the planning and operating philosophy of the company. This is not a decision that management has to make when the basic deterministic N-1 criterion is used.

The proposed D-P approach combines the probabilistic criterion in a deterministic framework which incorporates both the deterministic and probabilistic perspectives. The studies show that the D-P approach is driven by the deterministic N-1 criterion and influenced by the probabilistic criterion (Pc). The D-P technique adds additional probabilistic risk information to the traditional accepted deterministic N-1 criterion that is useful when making system reinforcement decisions.

The specific numerical values and therefore the conclusions in this chapter are based on the MRBTS. The conclusions may be different for other systems. The following chapter presents a similar analysis based on the IEEE-RTS.

5. APPLICATION OF THE JOINT DETERMINISTIC- PROBABILISTIC (D-P) CRITERION TO THE IEEE-RTS

5.1 Introduction

Chapter 4 illustrates the application of the deterministic N-1, probabilistic and joint deterministic-probabilistic criteria to the MRBTS. The MRBTS is a relatively small system and therefore it is relatively easy to locate the system weak points and to conduct system reinforcement planning. It is much more difficult to determine where to add generators or transmission lines if the studied system is large. This chapter applies the techniques used in Chapter 4 to the IEEE-RTS and shows that some of the general conclusions reached based on the MRBTS may not applicable in other systems, such as the IEEE-RTS.

5.2 Study System

The IEEE-RTS described in Section 2.6 is used in this study. The IEEE-RTS is a relatively large system compared with the MRBTS. The total installed capacity is 3405 MW and the system peak load is 2850 MW. The MRBTS and the IEEE-RTS have the same per-unit load model. The single line diagram shown in Figure 2.2 is repeated in Figure 5.1 for reference purposes.

5.3 Application of the Deterministic N-1 Criterion to the IEEE-RTS

The application of the deterministic N-1 approach involves the determination of the most severe single contingency for the studied system. A series of contingency studies was conducted on the IEEE-RTS. The following analysis shows the maximum loads that the system can carry under selected contingencies. The largest generating unit in this system is 400 MW and the following single component outages are the most severe contingencies [47]. The designation G23-350 is used to indicate the removal of a

350 MW generating unit at Bus 23. Similar designations are applied to the other contingencies. The locations of these generating units and transmission lines are shown in Figure 5.1.

G23-350

G18-400

G21-400

G13-197

L5

L23

L19

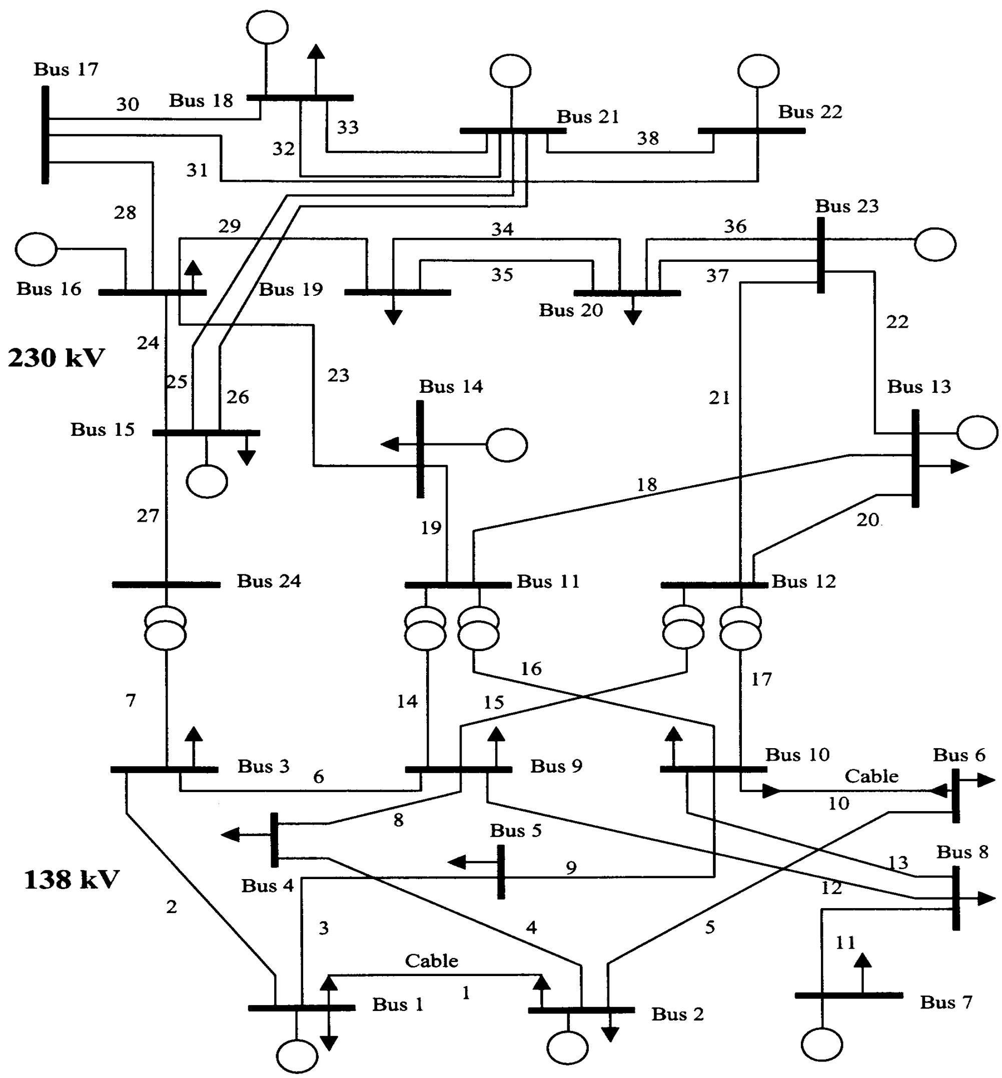

Figure 5.1: Single line diagram of the IEEE-RTS

The system peak load carrying capabilities (PLCC) for the IEEE-RTS using a deterministic N-1 criterion under each selected contingency are given in Table 5.1.

Table 5.1: The system PLCC using a deterministic N-1 criterion

Single element on outage	PLCC (MW)
G23-350	3055
G18-400	3005
G21-400	3005
G13-197	3208
L5	3405
L23	3405
L19	3405

It can be seen from Table 5.1 that the PLCC of the IEEE-RTS is 3005 MW using a deterministic N-1 criterion as the largest generators in the IEEE-RTS have a capacity of 400 MW. It is noted in Table 5.1 that the PLCC is 3405 MW under each single transmission line outage condition. The IEEE-RTS has a relatively strong transmission system and a weak generation system.

5.3.1 Planning Alternative Analysis

The previous section indicates that the IEEE-RTS has a relatively weak generation system and therefore reinforcement planning should be focused on adding generating capacity at selected buses.

Three possible planning alternatives have been considered, and two cases have been studied under each alternative. These cases are designated as A1-C1, A1-C2, A2-C1, A2-C2, A3-C1 and A3-C2 and are described in the following:

Alternative 1

Adding generating units in the northern part of the IEEE-RTS.

Alternative 1-Case 1 (A1-C1): Add one 200 MW unit at Bus 15.

Alternative 1-Case 2 (A1-C2): Add two 200 MW units at Bus 15.

Alternative 2

Adding generating units in the southern part of the IEEE-RTS.

Alternative 2-Case 1 (A2-C1): Add one 200 MW unit at Bus 2.

Alternative 2-Case 2 (A2-C2): Add two 200 MW units at Bus 2.

Alternative 3

Alternative 3-Case 1 (A3-C1): Add one 400 MW unit at Bus 15.

Alternative 3-Case 2 (A3-C2): Add one 400 MW unit at Bus 2.

The forced outage rate (FOR) and repair time for a 200 MW generating unit is 0.05 and 50 hours. The forced outage rate (FOR) and repair time for a 400 MW generating unit is 0.12 and 150 hours respectively in these studies.

In the three alternatives, the generating units are only added to the existing generation buses. In Alternative 1, the generating units are added in the northern part of the IEEE-RTS. In Alternative 2, the generating units are added in the southern portion of the system. In Alternative 3, the IEEE-RTS is modified to consider adding a 400 MW generating unit at either northern or southern location in the IEEE-RTS.

The peak load carrying capabilities (PLCC) for each case of the three alternatives have been examined and are presented in the following studies. Similar analyses are presented later in this chapter using the probabilistic (P) and the joint deterministic-probabilistic (D-P) approaches. The PLCC values in the following studies described in this thesis have been expressed as integer values. Tables 5.2, 5.3 show the PLCC values for each case for the three alternatives using the deterministic N-1 criterion.

Case 1 for Alternatives 1 and 2

The system peak load carrying capabilities (PLCC) for the base case, A1-C1, A2C1 are shown in Table 5.2.

Table 5.2: The system PLCC for the base case, A1-C1 and A2-C1

Cases	PLCC (MW)
Base Case	3005
A1-C1	3205
A2-C1	3205

Case 2 for Alternatives 1 and 2 and Cases 1 and 2 for Alternative 3

The system peak load carrying capabilities (PLCC) for the base case, A1-C2, A2-C2, A3-C1 and A3-C2 are shown in Table 5.3.

Table 5.3: The system PLCC for the base case, A1-C2, A2-C2, A3-C1 and A3-C2

Cases	PLCC (MW)
Base Case	3005
A1-C2	3405
A2-C2	3405
A3-C1	3405
A3-C2	3405

It can be seen from Tables 5.2 and 5.3 that the system peak load carrying capabilities (PLCC) are determined by the single generating unit outage.

The system PLCC for the three alternatives using a deterministic N-1 criterion is summarized in Table 5.4.

Table 5.4: The system PLCC for the three alternatives using a deterministic N-1 criterion

Cases	PLCC (MW)	Cases	PLCC (MW)
A1-C1	3205	A1-C2	3405
A2-C1	3205	A2-C2	3405
A3-C1	3405	A3-C2	3405

In this analysis the system PLCC is simply determined by subtracting the capacity of the largest unit from the total installed capacity.

This result is different from that obtained for Alternative 1 of the MRBTS in Chapter 4. Section 4.3 shows that removing L1 dominates the system PLCC of the MRBTS using a deterministic N-1 criterion.

5.4 Application of the Probabilistic Criterion to the IEEE-RTS

The probabilistic criterion states that the system risk shall not exceed a specified criterion value. The SI criterion is considered to be 50 SM/yr in the following studies.

5.4.1 IEEE-RTS Base Case Analysis

This section illustrates the variation in the system SI as a function of the peak load. The peak load is assumed to vary from 2850 MW to 3405 MW.

Table 5.5 and Figure 5.2 show the variation in the SI as a function of the peak load for the IEEE-RTS. The results in Table 5.5 include both generation and transmission (G & T) element failures.

Table 5.5: Annual SI (SM/yr) as a function of the peak load

Peak Load (MW)	2850	2950	3050	3150	3250	3350	3405
Total G&T failures	50.82	84.13	160.72	292.65	446.97	651.96	850.15

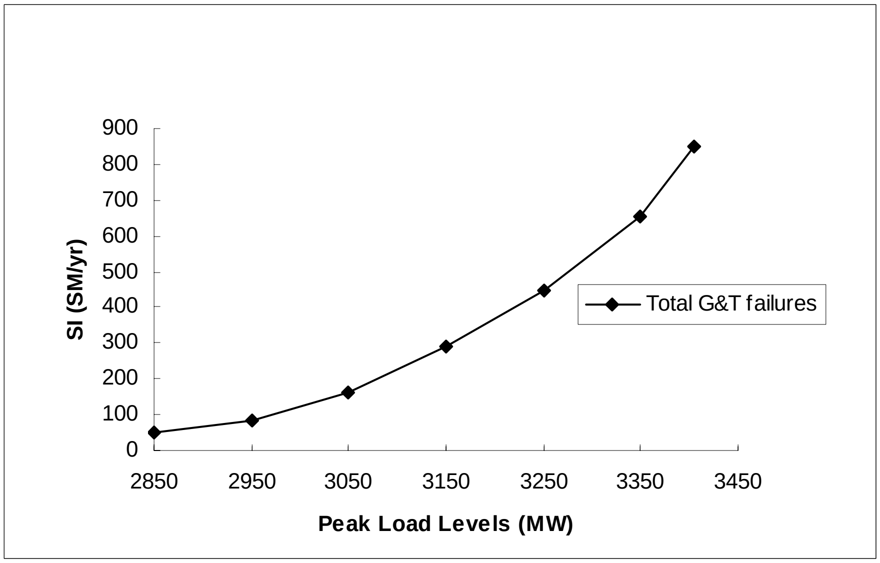

Figure 5.2: Contributions to the IEEE-RTS SI as a function of the peak load

Figure 5.2 shows that the system SI increases dramatically as the peak load increases. The total installed capacity is 3405 MW and therefore this is the maximum load that the IEEE-RTS can carry without any load curtailment with all equipment in service.

5.4.2 Factor Analysis of the IEEE-RTS

The factor analysis approach described in Section 4.4 can be applied to the IEEE-RTS. The following analyses focus on the reliability of the IEEE-RTS when either the generation system or the transmission system is assumed to be 100% reliable. The peak load is assumed to vary from 2850 MW to 3405 MW.

Table 5.6 and Figure 5.3 show the annual SI as a function of the peak load for the three element failure conditions (e.g. G, T, G&T failures).

Table 5.6: Annual SI (SM/yr) as a function of the peak load

Peak load (MW)	2850	2950	3050	3150	3250	3350	3405
Total G&T failures	50.82	84.13	160.72	292.65	446.97	651.96	850.15
G failures only	50.78	84.08	160.63	292.50	446.76	651.69	849.81
T Failures only	0.02	0.02	0.02	0.02	0.02	0.03	0.03

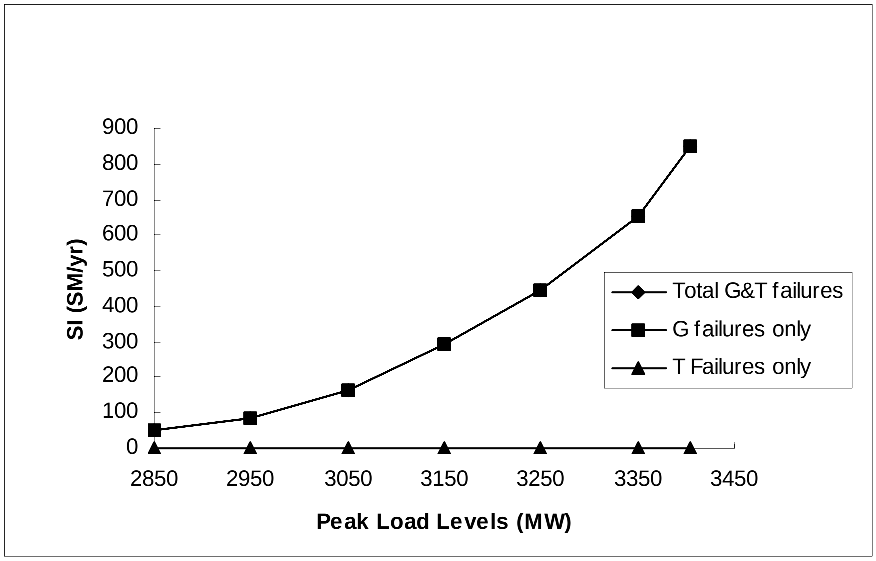

Figure 5.3: Contributions to the IEEE-RTS SI as a function of the peak load

Figure 5.3 shows the relative contributions of the generation and transmission failures to the SI. Generation deficiencies have a significant adverse effect on the SI in this case. Figure 5.3 also clearly shows that the IEEE-RTS has a strong transmission system at these load levels. In a system with strong transmission such as the IEEE-RTS, transmission line failures usually result in only local impacts at the load points with relatively weak transmission connections.

5.4.3 Planning Alternatives

As noted earlier, the reliability indices of the IEEE-RTS are dominated by generation system failures. The reliability of the system therefore can be improved by adding generating units at different locations. The three planning alternatives and cases given in Section 5.3 have been examined.

Case 1 for Alternatives 1 and 2

Figures 5.4-5.6 show the SI as a function of the peak load for the base case, A1-C1 and A2-C1 considering both generation and transmission failures, generation failures only and transmission failures only. The numerical values for the G & T condition are shown in Table 5.7. The values for the separate G and T analyses are given in Appendix C.

Table 5.7: Annual SI in SM/yr for the base case, A1-C1 and A2-C1
(Both generation and transmission failures)

Peak Load (MW)	Base Case	A1-C1	A2-C1
2850	50.82	11.32	11.38
2950	84.13	20.47	20.54
3050	160.72	43.43	43.53
3150	292.65	86.24	86.31
3250	446.97	141.58	141.63
3350	651.96	219.67	219.66
3405	850.15	297.82	297.80
3450	ESC	399.11	399.01
3550	ESC	663.64	663.44
3605	ESC	753.64	753.45

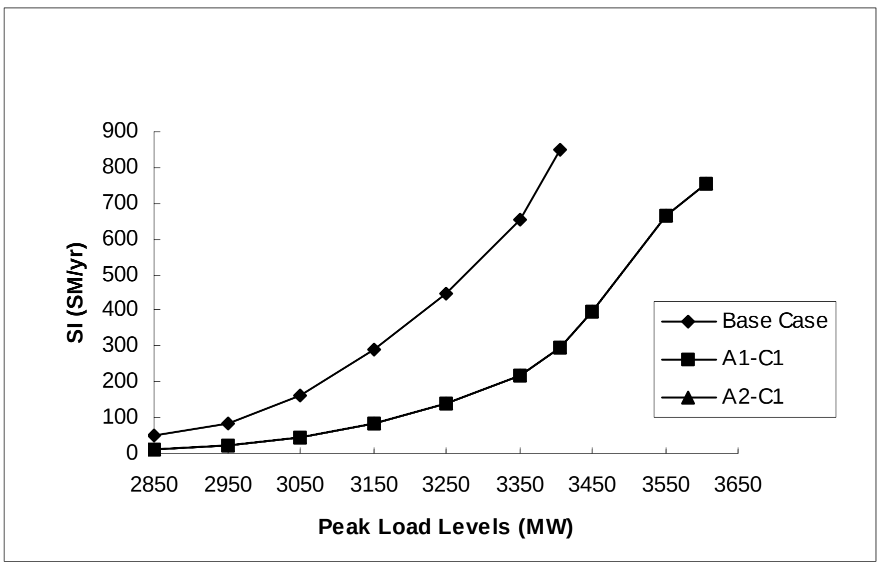

Figure 5.4: Annual SI indices for the base case, A1-C1 and A2-C1
(Both generation and transmission failures)

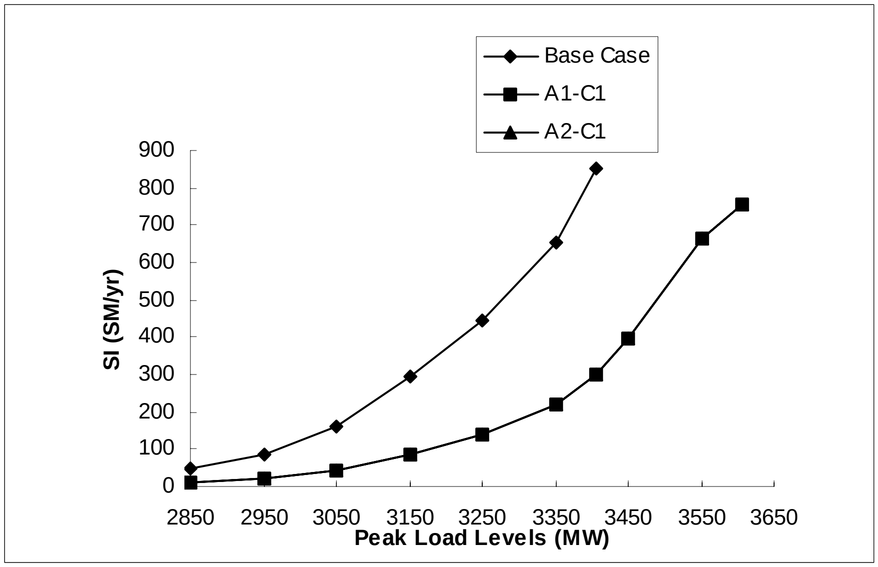

Figure 5.5: Annual SI indices for the base case, A1-C1 and A2-C1 (Generation failures only)

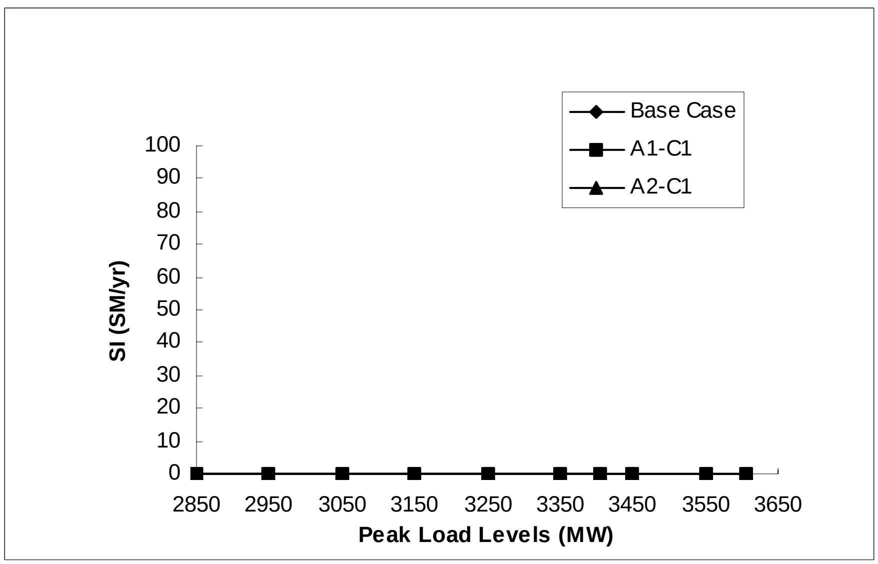

Figure 5.6: Annual SI indices for the base case, A1-C1 and A2-C1 (Transmission failures only)

The system peak load carrying capability for the base case and Case 1 for the two alternatives is shown in Table 5.8. Both generation and transmission failures are considered and the SI criterion is 50 SM/year.

Table 5.8: The system PLCC for the base case, A1-C1 and A2-C1

Cases	PLCC (MW)
Base Case	2850
A1-C1	3090
A2-C1	3090

Case 2 for Alternatives 1 and 2 and Cases 1 and 2 for Alternative 3

Figures 5.7-5.9 show the SI as a function of the peak load for the base case, A1-C2, A2-C2, A3-C1 and A3-C2 considering both generation and transmission failures, generation failures only and transmission failures only. The numerical values for the G & T condition are shown in Table 5.9. The values for the separate G and T analyses are given in Appendix C.

Table 5.9: Annual SI in SM/yr for the base case, A1-C2, A2-C2, A3-C1 and A3-C2 (Both generation and transmission failures)

Peak Load (MW)	Base Case	A1-C2	A2-C2	A3-C1	A3-C2
2850	50.82	2.28	2.76	7.06	7.65
2950	84.13	4.40	5.26	12.31	13.31
3050	160.72	10.35	11.89	25.27	27.00
3150	292.65	22.56	25.51	49.27	52.39
3250	446.97	39.79	43.43	79.68	83.41
3350	651.96	65.45	71.80	122.41	128.60
3405	850.15	91.90	100.59	165.01	173.33
3450	ESC	129.60	137.42	255.87	228.93
3550	ESC	231.83	250.40	370.44	387.74
3650	ESC	362.47	377.85	547.66	561.53
3750	ESC	598.51	ESC	854.06	ESC

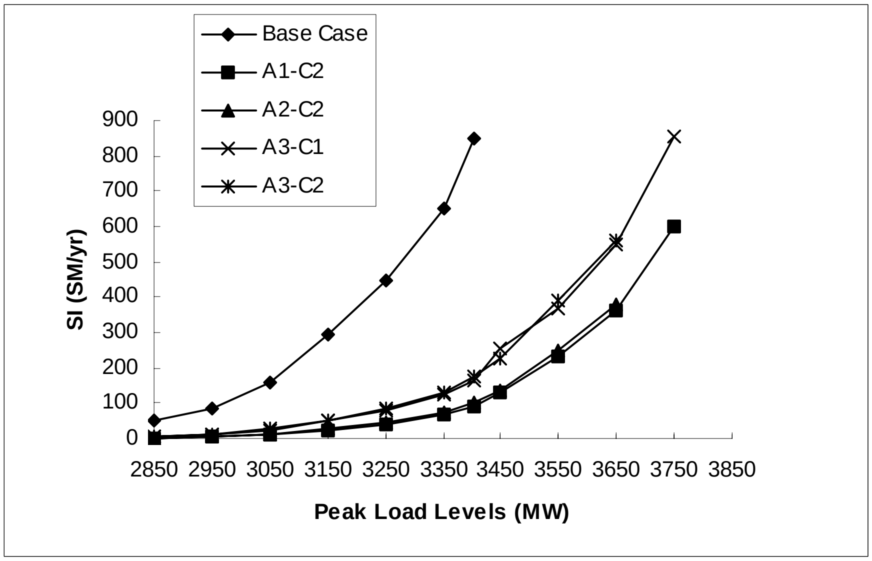

Figure 5.7: Annual SI indices for the base case, A1-C2, A2-C2, A3-C1 and A3-C2 (Both generation and transmission failures)

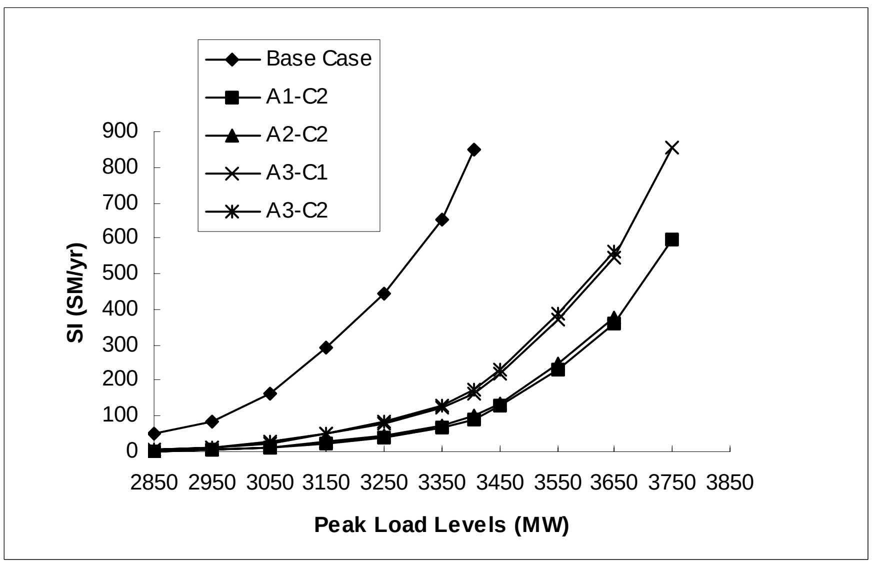

Figure 5.8: Annual SI indices for the base case, A1-C2, A2-C2, A3-C1 and A3-C2 (Generation failures only)

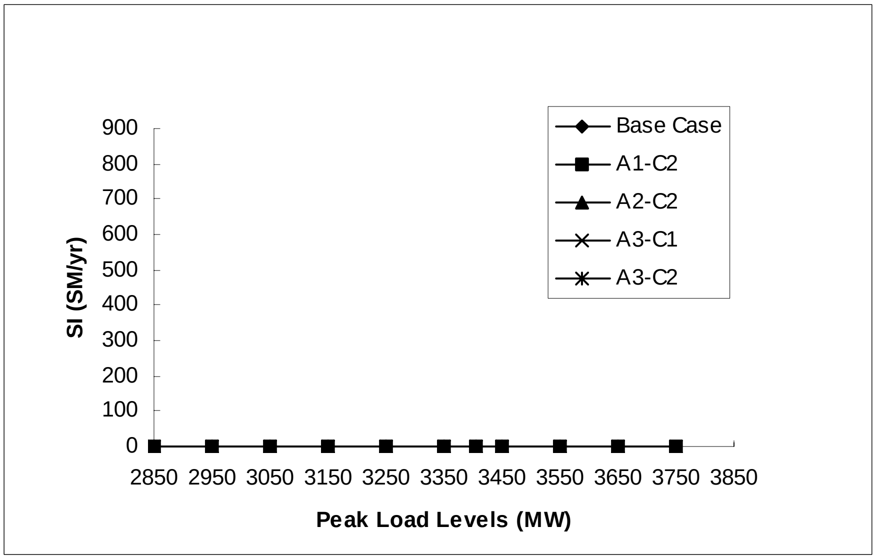

Figure 5.9: Annual SI indices for the base case, A1-C2, A2-C2, A3-C1 and A3-C2 (Transmission failures only)

The system PLCC for the base case, Case 2 for Alternatives 1 and 2 and Cases 1 and 2 for Alternative 3 are shown in Table 5.10.

Table 5.10: The PLCC for the base case, A1-C2, A2-C2, A3-C1 and A3-C2

Cases	PLCC (MW)
Base Case	2850
A1-C2	3290
A2-C2	3290
A3-C1	3150
A3-C2	3150

The system PLCC for the three alternatives using the probabilistic criterion is shown in Table 5.11.

Table 5.11: The system PLCC for the two alternatives using the probabilistic criterion (SI=50 SM/yr)

Cases	PLCC (MW)	Cases	PLCC (MW)
A1-C1	3090	A1-C2	3290
A2-C1	3090	A2-C2	3290
A3-C1	3150	A3-C2	3150

The generating capacity is added in the northern region in Alternative 1 and in the southern region of the system in Alternative 2. It can be seen that generating adding locations do not have significant effect on the system PLCC values using a probabilistic criterion.

The generating unit is added in the northern region of the system in A3-C1 and in the southern region in A3-C2. The PLCC values are similar in A3-C1 and A3-C2. Table 5.11 also shows that the PLCC values in A1-C2 and A2-C2 are higher than those in A3-C1 and A3-C2.

5.5 Application of the Joint Deterministic-Probabilistic Criterion to the IEEE-RTS

The D-P criterion used in the following studies is a combination of the deterministic N-1 criterion and a quantitative SI criterion (Pc). The Pc value is assumed to be 350 SM/yr in the following studies.

5.5.1 The IEEE-RTS Base Case Analysis

The peak load for the IEEE-RTS is assumed to vary from 2850 MW to 3150 MW. The G18-400, G23-350, G21-400, G13-197, L5, L23 and L19 outage events have been examined. Table 5.12 and Figure 5.10 show the variation in the SI as a function of the peak load for the selected contingencies.

Table 5.12: Annual SI in SM/yr of the IEEE-RTS for the selected contingencies

Peak Load (MW)	2850	2950	3005	3055	3150	3250	3350	3405
G23-350	346.89	533.18	714.28	930.31	ESC	ESC	ESC	ESC
G18-400	319.07	512.51	690.95	ESC	ESC	ESC	ESC	ESC
G21-400	319.07	512.51	690.95	ESC	ESC	ESC	ESC	ESC
G13-197	174.78	274.97	369.13	488.52	833.18	ESC	ESC	ESC
L5	70.93	104.14	136.95	180.49	312.72	466.84	671.63	869.69
L23	62.75	96.03	128.86	172.45	304.81	459.20	664.30	862.64
L19	60.26	93.51	126.32	169.85	302.06	456.30	661.20	859.33

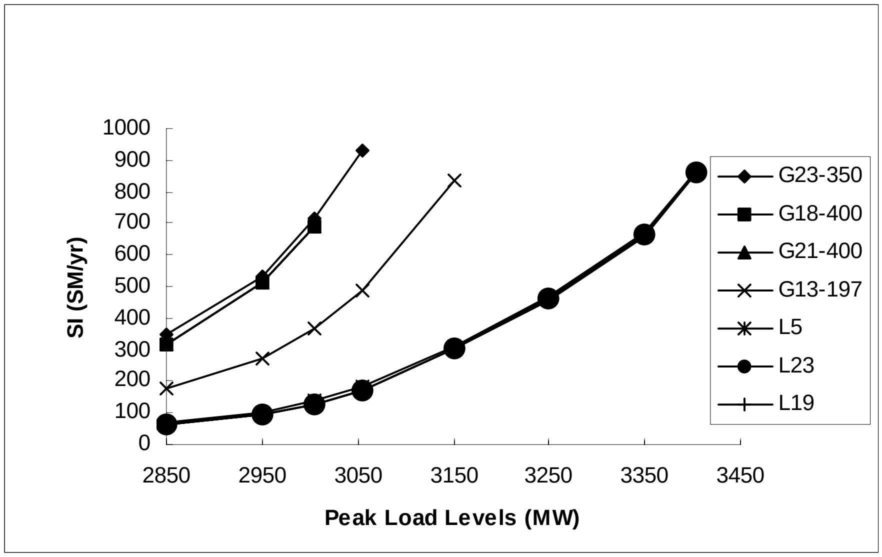

Figure 5.10: Annual SI indices versus peak load for selected contingencies

It can be seen from Figure 5.10 that the G23-350 outage condition creates the highest SI values compared to the other single element outage events. This is due to the physical location of the 350 MW unit. G18-400 and G21-400 outages have similar impacts on the system SI. L5, L23 and L19 have lower but similar impacts on the system SI. As noted earlier, the IEEE-RTS has a strong transmission system and therefore transmission outages have less impact on the system reliability indices comparing to generation outages.

The G23-350 and G18-400 outage events are examined in the following studies. A G21-400 outage event has similar effects to a G18-400 outage. The L5, L23 and L19 outages are much less severe than G23-350 and G18-400 outage events and are not studied further.

5.5.2 Factor Analysis

Table 5.13 and Figure 5.11 show the variation in the system SI as a function of the peak load under the G23-350 outage condition.

Table 5.13: Annual SI in SM/yr for the IEEE-RTS (G23-350 outage)

Peak Load	2850	2950	3005	3055	3150
Total G&T Failures	346.89	533.18	714.28	930.31	ESC
G Failures Only	346.57	532.76	713.79	929.72	ESC
T Failures Only	0.03	0.04	0.05	0.06	ESC

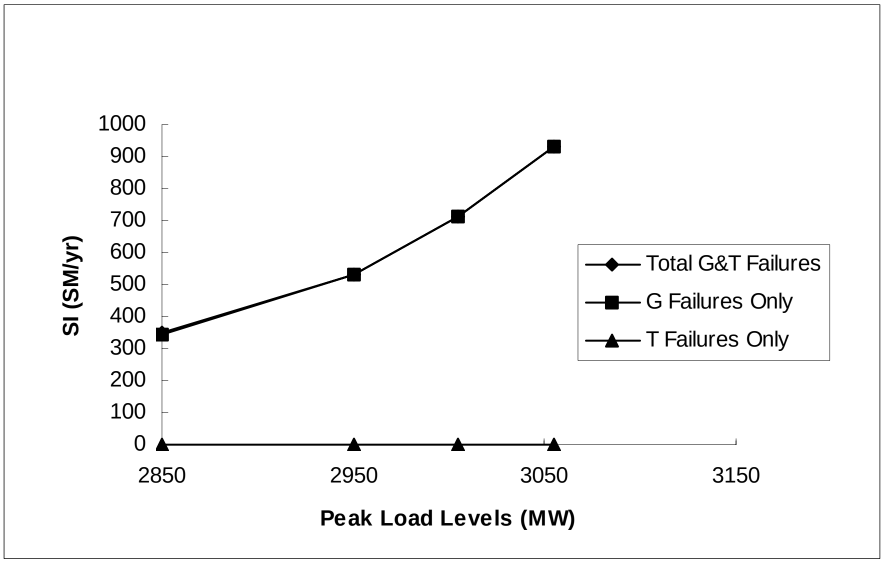

Figure 5.11: Annual SI indices versus the peak load (G23-350 outage)

Table 5.13 and Figure 5.11 show that the SI values are dominated by generation failures. The system PLCC using a Pc of 350 SM/yr is approximately 2850 MW.

Table 5.14 and Figure 5.12 show the variation of the system SI as a function of the peak load under the G18-400 outage condition.

Table 5.14: Annual SI in SM/yr for the IEEE-RTS (G18-400 outage)

Peak Load	2850	2950	3005	3050
Total G&T Failures	319.07	512.51	690.95	ESC
G Failures Only	318.75	512.08	690.43	ESC
T Failures Only	0.03	0.04	0.06	ESC

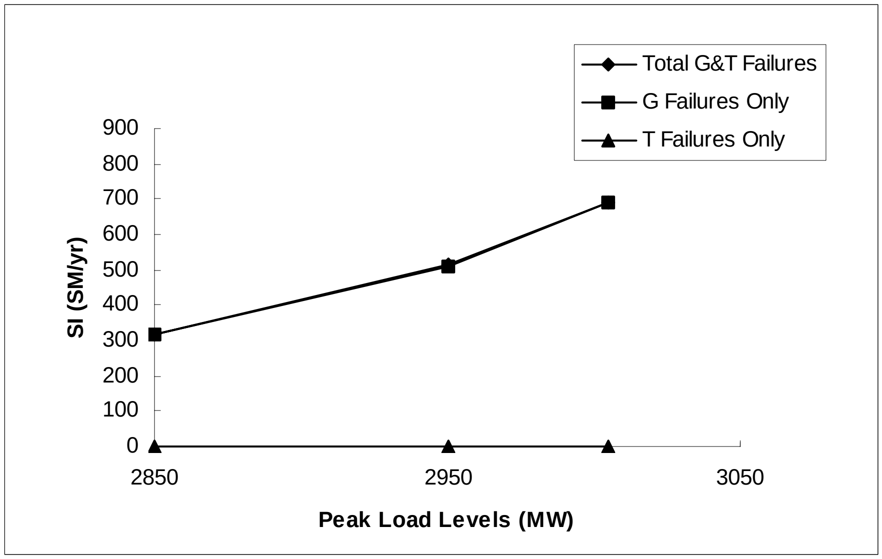

Figure 5.12: Annual SI indices versus the peak load (G18-400 outage)

Table 5.14 and Figure 5.12 show that the SI values are dominated by generation failures. A comparison of Table 5.13 with Table 5.14 shows that the G18-400 outage is less severe than the G23-350 outage.

5.5.3 Planning Alternatives

The three alternatives described earlier were analyzed using the joint deterministic-probabilistic (D-P) criterion.

Case 1 for Alternatives 1 and 2

The annual SI indices of the base case, A1-C1 and A2-C1 are shown in Tables 5.15-5.16. A comparison of the results is also shown in Figures 5.13-5.14 under G23-350 and G18-400 outage conditions.

G23-350 Outage

Table 5.15: Annual SI in SM/yr for the base case, A1-C1 and A2-C1 with G23-350 on outage (Both generation and transmission failures)

Peak Load (MW)	Base Case	A1-C1	A2-C1
2850	346.89	93.20	92.99
2950	533.18	156.38	156.12
3005	714.28	215.64	215.38
3050	931.84	298.65	298.33
3150	ESC	532.48	532.07
3250	ESC	809.99	809.50

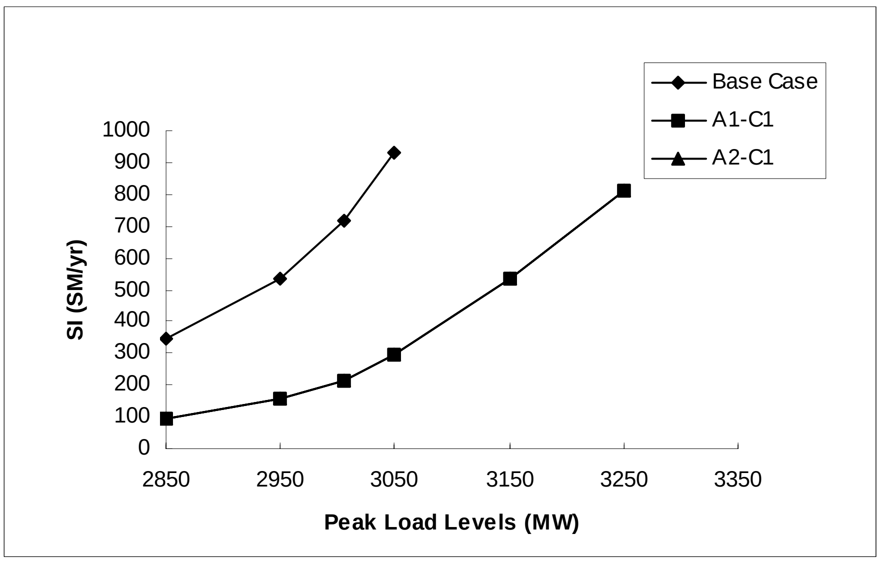

Figure 5.13: Annual SI indices for the base case, A1-C1 and A2-C1 with G23-350 on outage (Both generation and transmission failures)

G18-400 Outage

Table 5.16: Annual SI in SM/yr for the base case, A1-C1 and A2-C1 with G18-400 on outage (Both generation and transmission failures)

Peak Load (MW)	Base Case	A1-C1	A2-C1
2850	319.07	82.44	82.21
2950	512.51	142.35	142.07
3005	690.95	201.77	201.57
3050	ESC	281.73	281.57
3150	ESC	525.12	525.00
3205	ESC	606.21	606.14

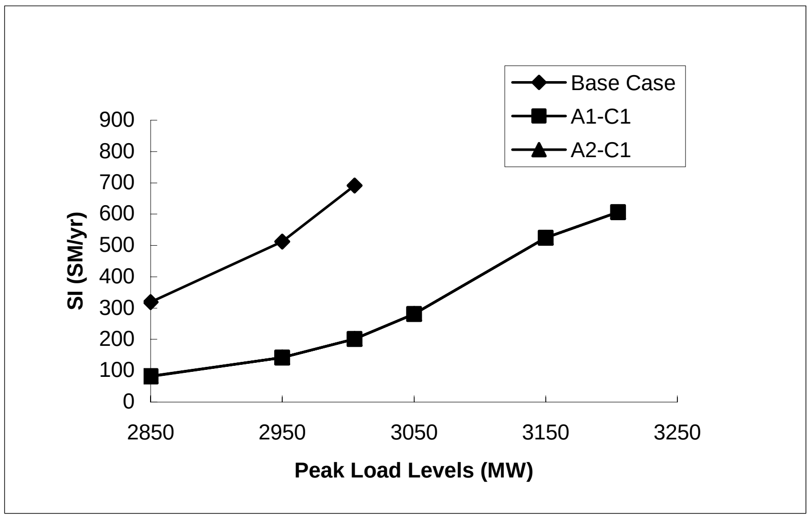

Figure 5.14: Annual SI indices for the base case, A1-C1 and A2-C1 with G18-400 on outage (Both generation and transmission failures)

Table 5.17 shows the system PLCC for the base case, A1-C1 and A2-C1 using the D-P criterion.

Table 5.17: The system PLCC for the base case, A1-C1 and A2-C1

Cases	PLCC (MW)
Base Case	2850
A1-C1	3090
A2-C1	3090

Case 2 for Alternatives 1 and 2 and Cases 1 and 2 for Alternative 3

The annual SI indices for the base case, A1-C2, A2-C2, A3-C1 and A3-C2 are listed in Tables 5.18-5.19. A comparison of the results is also shown in Figures 5.15-5.16 under the G23-350 and G18-400 outage conditions.

G23-350 Outage

Table 5.18: Annual SI in SM/yr for the base case, A1-C2, A2-C2, A3-C1, A3-C2 with G23-350 on outage (Both generation and transmission failures)

Peak Load (MW)	Base Case	A1-C2	A2-C2	A3-C1	A3-C2
2850	346.89	21.63	25.31	54.60	57.32
2950	533.18	38.99	44.90	88.41	92.91
3050	931.84	82.19	92.48	165.80	174.03
3150	ESC	162.46	178.43	296.90	309.89
3250	ESC	264.20	284.17	446.22	462.73
3350	ESC	406.41	433.16	645.78	668.56
3450	ESC	717.59	ESC	1055.67	ESC

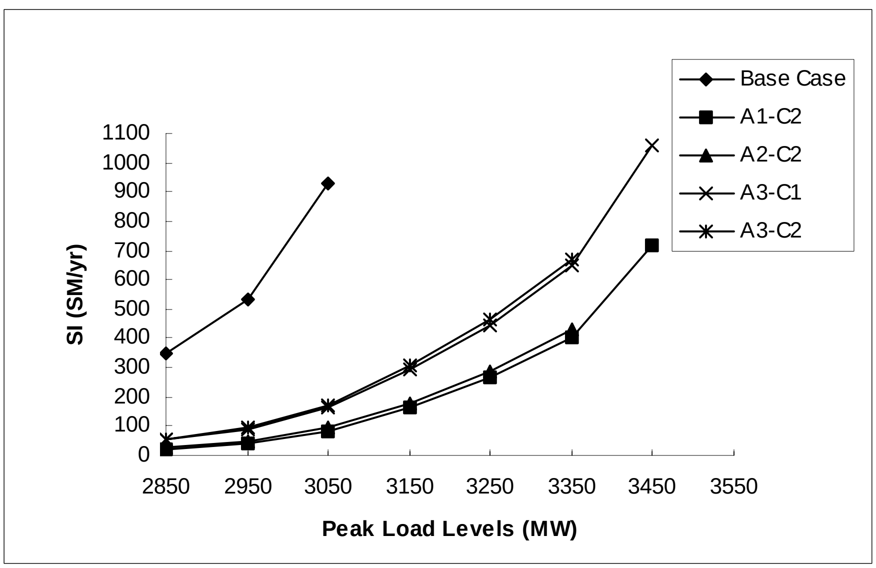

Figure 5.15: Annual SI indices for the base case, A1-C2, A2-C2, A3-C1 and A3-C2 with G18-350 on outage (Both generation and transmission failures)

G18-400 Outage

Table 5.19: Annual SI in SM/yr for the base case, A1-C2, A2-C2, A3-C1 and A3-C2 with G18-400 on outage (Both generation and transmission failures)

Peak Load (MW)	Base Case	A1-C2	A2-C2	A3-C1	A3-C2
2850	319.07	17.48	21.17	49.71	51.54
2950	512.51	32.76	39.27	82.70	86.73
3005	690.95	49.56	57.77	115.21	120.67
3050	ESC	73.58	84.24	158.64	166.27
3150	ESC	151.61	171.70	289.58	305.84
3250	ESC	253.53	276.72	442.97	462.11
3350	ESC	396.36	437.33	646.89	682.95
3405	ESC	540.27	ESC	844.32	ESC

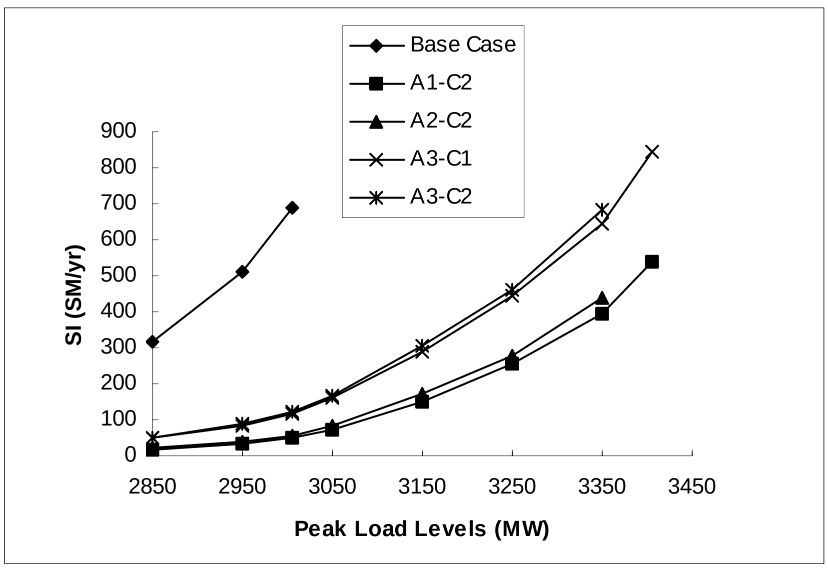

Figure 5.16: Annual SI indices for the base case, A1-C2, A2-C2, A3-C1 and A3-C2 with G18-400 on outage (Both generation and transmission failures)

Table 5.20 shows the system PLCC for the base case, A1-C2, A2-C2, A3-C1 and A3-C2 using the D-P criterion.

Table 5.20: The PLCC for the base case, A1-C1, A2-C1, A3-C1 and A3-C2

Cases	PLCC (MW)
Base Case	2850
A1-C2	3310
A2-C2	3290
A3-C1	3200
A3-C2	3180

The system PLCC for the three alternatives using the D-P criterion is shown in Table 5.21.

Table 5.21: The system PLCC for the three alternatives using the D-P criterion (SI=350 SM/yr)

Cases	PLCC (MW)	Cases	PLCC (MW)
A1-C1	3090	A1-C2	3310
A2-C1	3090	A2-C2	3290
A3-C1	3200	A3-C2	3180

The PLCC values obtained using the three techniques shown in Table 5.4, 5.11, 5.21 are repeated in Table 5.22 for comparison purposes.

Table 5.22: The system PLCC for the three alternatives using the three techniques

Case	Technique		
	D	P	D-P
A1-C1	3205	3090	3090
A2-C1	3205	3090	3090
A1-C2	3405	3290	3310
A2-C2	3405	3290	3290
A3-C1	3405	3150	3200
A3-C2	3405	3150	3180

Table 5.22 shows the PLCC values obtained using the three techniques. The results in Table 5.22 have been rounded off to the nearest MW. The three alternatives and two cases are described in Section 5.3.1. Table 5.23 presents a brief summary of the conditions for the 6 cases in order to facilitate a comparison between the PLCC values in Table 5.22.

Table 5.23: A summary of the conditions for the six cases

Cases	Additions to the IEEE-RTS
A1-C1	200 MW unit at Bus 15
A2-C1	200 MW unit at Bus 2
A1-C2	2-200 MW units at Bus 15
A2-C2	2-200 MW units at Bus 2
A3-C1	400 MW unit at Bus 15
A3-C2	400 MW unit at Bus 2

Table 5.22 shows that the PLCC values determined by subtracting one of the largest generating units from the system in the D approach. The D approach produces the highest PLCC values in all the cases. This result is different from that obtained in Chapter 4.

In A1-C1, the 200 MW unit is added in the northern region and in A2-C1, the 200 MW unit is added in the southern region of the system. The PLCC values are similar for the P and D-P approaches using the SI criterion of 50 SM/yr and Pc of 350 SM/yr respectively in these cases. The generating addition locations however do not create significant impacts on the system PLCC in A1-C1 and A2-C1.

In A1-C2, the two 200 MW units are added in the northern region of the system. The PLCC value using the D-P technique is higher than the value obtained using the P approach. The PLCC values are similar for the P and D-P approaches in A2-C2. The PLCC value in A2-C2 is lower than in A1-C2 as the two 200 MW units are added in the southern region of the system which overloads cable 1 between Bus 1 and Bus 2 when the peak load is equal to or greater than 3750 MW. It is noted, therefore, that when a total of 400 MW is added to the system, the generating unit addition locations impact the system PLCC.

It is interesting to note that the PLCC values in A2-C2 are similar using the P and D-P approaches. The PLCC is higher in A1-C2 using the D-P technique than for the P approach. This is due to the generating unit addition locations.

The 400 MW unit is added in the northern region of the system in A3-C1 and in A3-C2, the 400 MW unit is added in the southern region. The PLCC value for the P approach is lower than the D-P approach in both cases. The PLCC value in A3-C1 is higher than that in A3-C2 due to the generating unit addition location.

Table 5.22 shows that the PLCC values are higher when adding two 200 MW units than those obtained by adding one 400 MW unit. This is due to the combined effect of unit size and forced outage rate (FOR). The forced outage rate (FOR) of the 200 MW unit is smaller than that of the 400 MW unit. The system reliability improves by adding two 200 MW units rather than one 400 MW unit.

5.6 Conclusions

This chapter presents the application of the deterministic (D), probabilistic (P) and joint deterministic-probabilistic (D-P) techniques to IEEE-RTS planning. Three possible system planning alternatives are examined using the D, P and D-P approaches and the system PLCC is determined using the D, P and D-P criteria.

The IEEE-RTS has a relatively strong transmission system and a weak generation system. The application of the deterministic N-1 technique to the IEEE-RTS shows that the system PLCC values are directly related to the largest single generating unit outage and the added generating unit capacities. The D criterion is the least stringent one among the three criteria in this system.

The results obtained by applying the P technique to the IEEE-RTS show that the probabilistic approach responds to the significant factors that influence the reliability of the system. Generating unit addition locations however have less impact on the overall system reliability indices compared to those obtained in Chapter 4 due to the strong transmission system in the IEEE-RTS.

The D-P criterion is more stringent than the deterministic N-1 criterion because the D-P technique is driven by the deterministic N-1 criterion and supplemented by the additional probabilistic risk constraint. The PLCC of the system is influenced by the Pc value. The actual selection of the Pc value is a management decision based on the planning and operating philosophy of the company.

6. SUMMARY AND CONCLUSIONS

Electric power utilities are facing increasing uncertainty regarding the political, economic, societal and environmental constraints under which they have to operate existing systems and plan future systems. Practical methods capable of analyzing the reliability of the existing bulk electric systems and planning the future systems are much more needed today than in the past. This research work is focused on the utilization of deterministic and probabilistic adequacy criteria in long term bulk electric system planning.

Chapter 1 provide a brief introduction to the overall area of bulk electric system reliability evaluation including the concepts of adequacy and security, the three power system hierarchical levels, the bulk electric system reliability analysis methods and the planning criteria. A brief introduction to deregulated power system structures is also given in this chapter.

A series of studies on bulk electric system reliability evaluation utilizing Monte Carlo simulation is described in this thesis. There are two basic techniques when applying Monte Carlo simulation methods to bulk electric system reliability evaluation. These methods are designated as the sequential and non-sequential approaches. Sequential simulation can fully take into account the chronological behavior of the system, while non-sequential method involves non-chronological system state considerations. The two techniques are briefly described in Chapter 2. Each technique has its own merits and demerits. The state sampling technique is applied in the MECORE program that was utilized for all analyses presented in this thesis.

The MECORE software, which is a Monte Carlo based composite generation and transmission system reliability evaluation tool designated to perform reliability and reliability worth assessment of bulk electric systems, is also presented in Chapter 2. This program was initially developed at the University of Saskatchewan and further enhanced at BC Hydro. It can be utilized to conduct a wide variety of bulk electric system studies.

The basic indices and IEEE proposed indices used in MECORE are presented in Chapter 2. The basic indices can be determined for an entire system or for a single load point. The IEEE proposed indices are applicable to an overall system. The annualized indices refer to the indices calculated using a single load level (normally peak load) over a period of one year. In practical systems, the load demand does not remain constant at the peak load level throughout the period and the chronological load model (time varying load) can be used to produce more representative annual indices. The basic annual indices are lower than the annualized indices obtained using peak load levels. The annualized indices give a pessimistic appraisal while the annual indices provide a more representative picture of the system and are utilized in this research.

The two test systems are used in this thesis and introduced in Chapter 2. The modified RBTS is a small educational test system. The IEEE-RTS is a relatively large system compared with the MRBTS. The assumptions used in the base case analyses of the two test systems are utilized in all the subsequent studies in this thesis.

There is a growing interest in combining deterministic considerations with probabilistic assessment in order to evaluate the system risk. Two techniques that can be used to combine deterministic and probabilistic considerations in a single framework are illustrated in Chapter 3. The system well-being approach was initially developed in the late 1980s. The joint deterministic-probabilistic (D-P) approach has been developed in this research and described in this chapter.

Well-being analysis provides a combined structure that incorporates deterministic considerations within a probabilistic framework by determining the likelihood of encountering marginal system states in addition to encountering system at risk states. The system well-being concept provides system engineers and risk managers with comprehensive information on the degree of system vulnerability. A complete system well-being analysis can require considerable computing time particularly on large practical electric power systems.

The proposed D-P method is based on a non-sequential Monte Carlo model, which avoids chronological simulations and detail state clarification requirement and therefore saves computation time. The D-P approach provides a combined structure that incorporates probabilistic consideration within a deterministic framework. It extends the deterministic analysis by providing a risk assessment that is conditional upon the system contingency covered by the traditional deterministic criterion. The application of D-P analysis to practical systems should prove useful in supporting the decision-making processes involved in system planning.

Chapter 4 presents the application of the deterministic (D), probabilistic (P) and joint deterministic-probabilistic (D-P) techniques to MRBTS planning. Three possible system planning alternatives are examined using the D, P and D-P approaches and the system PLCC is determined using the D, P and D-P criteria.

The application of the deterministic N-1 technique to the MRBTS reinforcement planning shows that the deterministic criterion does not response to the probabilistic factors that influence the reliability of the system and is rigid criterion.

The results obtained by applying the probabilistic technique to the MRBTS show that the probabilistic approach responds to the significant factors that influence the reliability of the system and provide reliability risk information that is valuable when making system reinforcement decisions. The actual selection of the probabilistic criterion value is a management decision based on the planning and operating philosophy of the company. This is not a decision that management has to make when the basic deterministic N-1 criterion is used.

The proposed D-P approach combines the probabilistic criterion in a deterministic framework that incorporates both the deterministic and probabilistic perspectives. The studies show that the D-P approach is driven by the deterministic N-1 criterion and influenced by the probabilistic criterion (Pc). The D-P technique adds additional probabilistic risk information to the traditional accepted deterministic N-1 criterion that is useful when making system reinforcement decisions.

Chapter 5 focuses on applications of the deterministic (D), probabilistic (P) and joint deterministic-probabilistic (D-P) techniques to the IEEE-RTS. The steps used to examine the IEEE-RTS are similar to those used for the MRBTS in Chapter 4. The IEEE-RTS has a weak generation and strong transmission system. The studies show that adding generators at various locations have different impacts on the overall system adequacy indices. The benefits associated with alternatives at different locations are important information in system reinforcement planning. The numerical values and the conclusions obtained in Chapter 4 and 5 are based on the MRBTS and the IEEE-RTS respectively. The conclusions may be different for other systems.

The research work described in this thesis clearly illustrated that a software such as MECORE can be effectively used to provide valuable information to bulk electric system reinforcement planning. The conclusions and techniques presented should prove valuable to those responsible for bulk electric system planning. The focus in this research is on the deterministic and probabilistic techniques and a combination of these methods to produce the joint deterministic-probabilistic approach. The analyses have not been extended by conducting the economic studies required to select the optimum reinforcement alternatives. This is therefore an existing area for future research.

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APPENDIX A. BASIC DATA FOR THE RBTS AND THE IEEE-RTS

Tables A.1-A.3 and A.4-A.6 present the bus, line and generator data for the RBTS and the IEEE-RTS respectively.

Table A.1: Bus data for the RBTS

Bus No.	Load (p.u.)		P_g	Q_{max}	Q_{min}	V_0	V_{max}	V_{min}
	Active	Reactive						
1	0.00	0.0	1.0	0.50	-0.40	1.05	1.05	0.97
2	0.20	0.0	1.2	0.75	-0.40	1.05	1.05	0.97
3	0.85	0.0	0.0	0.00	0.00	1.00	1.05	0.97
4	0.40	0.0	0.0	0.00	0.00	1.00	1.05	0.97
5	0.20	0.0	0.0	0.00	0.00	1.00	1.05	0.97
6	0.20	0.0	0.0	0.00	0.00	1.00	1.05	0.97

Table A.2: Line data for the RBTS

Line	Bus		R	X	B/2	Tap	Current Rating (p.u.)	Failure Rate (occ/yr)	Repair Time (hrs)	Failure Prob.
	I	J								
1,6	1	3	0.0342	0.18	0.0106	1.0	0.85	1.50	10.0	0.00171
2,7	2	4	0.1140	0.60	0.0352	1.0	0.71	5.00	10.0	0.00568
3	1	2	0.0912	0.48	0.0282	1.0	0.71	4.00	10.0	0.00455
4	3	4	0.0228	0.12	0.0071	1.0	0.71	1.00	10.0	0.00114
5	3	5	0.0228	0.12	0.0071	1.0	0.71	1.00	10.0	0.00114
8	4	5	0.0228	0.12	0.0071	1.0	0.71	1.00	10.0	0.00114
9	5	6	0.0228	0.12	0.0071	1.0	0.71	1.00	10.0	0.00114

Table A.3: Generator data for the RBTS

Unit No.	Bus No.	Rating (MW)	Failure Rate (occ/yr)	Repair Time (hrs)	Failure Prob.
1	1	40.0	6.0	45.0	0.03
2	1	40.0	6.0	45.0	0.03
3	1	10.0	4.0	45.0	0.02
4	1	20.0	5.0	45.0	0.025
5	2	5.0	2.0	45.0	0.01
6	2	5.0	2.0	45.0	0.01
7	2	40.0	3.0	60.0	0.02
8	2	20.0	2.4	55.0	0.015
9	2	20.0	2.4	55.0	0.015
10	2	20.0	2.4	55.0	0.015
11	2	20.0	2.4	55.0	0.015

Table A.4: Bus data for the IEEE-RTS

Bus No.	Load (p.u.)		P_g	Q_{max}	Q_{min}	V_0	V_{max}	V_{min}
	Active	Reactive						
1	1.08	0.22	1.92	1.20	-0.75	1.00	1.05	0.95
2	0.97	0.20	1.92	1.20	-0.75	1.00	1.05	0.95
3	1.80	0.37	0.00	0.00	0.00	1.00	1.05	0.95
4	0.74	0.15	0.00	0.00	0.00	1.00	1.05	0.95
5	0.71	0.14	0.00	0.00	0.00	1.00	1.05	0.95
6	1.36	0.28	0.00	0.00	0.00	1.00	1.05	0.95
7	1.25	0.25	3.00	2.70	0.00	1.00	1.05	0.95
8	1.71	0.35	0.00	0.00	0.00	1.00	1.05	0.95
9	1.75	0.36	0.00	0.00	0.00	1.00	1.05	0.95
10	1.95	0.40	0.00	0.00	0.00	1.00	1.05	0.95
11	0.00	0.00	0.00	0.00	0.00	1.00	1.05	0.95
12	0.00	0.00	0.00	0.00	0.00	1.00	1.05	0.95
13	2.65	0.54	5.91	3.60	0.00	1.00	1.05	0.95
14	1.94	0.39	0.00	3.00	-0.75	1.00	1.05	0.95
15	3.17	0.64	2.15	1.65	-0.75	1.00	1.05	0.95
16	1.00	0.20	1.55	1.20	-0.75	1.00	1.05	0.95
17	0.00	0.00	0.00	0.00	0.00	1.00	1.05	0.95
18	3.33	0.68	4.00	3.00	-0.75	1.00	1.05	0.95
19	1.81	0.37	0.00	0.00	0.00	1.00	1.05	0.95
20	1.28	0.26	0.00	0.00	0.00	1.00	1.05	0.95
21	0.00	0.00	4.00	3.00	-0.75	1.00	1.05	0.95
22	0.00	0.00	3.00	1.45	-0.90	1.00	1.05	0.95
23	0.00	0.00	6.60	4.50	-0.75	1.00	1.05	0.95
24	0.00	0.00	0.00	0.00	0.00	1.00	1.05	0.95

Table A.5: Line data for the IEEE-RTS

Line	Bus I	Bus J	R	X	B/2	Tap	Current Rating (p.u.)	Failure Rate (occ/yr)	Repair Time (hrs)	Failure Prob.
1	1	2	0.0260	0.0139	0.2306	1.0	1.75	0.24	16	0.00044
2	1	3	0.0546	0.2112	0.0286	1.0	1.75	0.51	10	0.00058
3	1	5	0.0218	0.0845	0.0115	1.0	1.75	0.33	10	0.00038
4	2	4	0.0328	0.1267	0.0172	1.0	1.75	0.39	10	0.00045
5	2	6	0.0497	0.1920	0.0260	1.0	1.75	0.39	10	0.00045
6	3	9	0.0308	0.1190	0.0161	1.0	1.75	0.48	10	0.00055
7	3	24	0.0023	0.0839	0.0000	1.0	4.00	0.02	768	0.00175
8	4	9	0.0268	0.1037	0.0141	1.0	1.75	0.36	10	0.00041
9	5	10	0.0228	0.0883	0.0120	1.0	1.75	0.34	10	0.00039
10	6	10	0.0139	0.0605	1.2295	1.0	1.75	0.33	35	0.00132
11	7	8	0.0159	0.0614	0.0166	1.0	1.75	0.30	10	0.00034
12	8	9	0.0427	0.1651	0.0224	1.0	1.75	0.44	10	0.00050
13	8	10	0.0427	0.1651	0.0224	1.0	1.75	0.44	10	0.00050
14	9	11	0.0023	0.0839	0.0000	1.0	4.00	0.02	768	0.00175
15	9	12	0.0023	0.0839	0.0000	1.0	4.00	0.02	768	0.00175
16	10	11	0.0023	0.0839	0.0000	1.0	4.00	0.02	768	0.00175
17	10	12	0.0023	0.0839	0.0000	1.0	4.00	0.02	768	0.00175
18	11	13	0.0061	0.0476	0.0500	1.0	5.00	0.02	11	0.00050
19	11	14	0.0054	0.0418	0.0440	1.0	5.00	0.39	11	0.00049
20	12	13	0.0061	0.0476	0.0500	1.0	5.00	0.40	11	0.00050
21	12	23	0.0124	0.0966	0.1015	1.0	5.00	0.52	11	0.00065
22	13	23	0.0111	0.0865	0.0909	1.0	5.00	0.49	11	0.00062
23	14	16	0.0050	0.0389	0.0409	1.0	5.00	0.38	11	0.00048
24	15	16	0.0022	0.0173	0.0364	1.0	5.00	0.33	11	0.00041
25	15	21	0.0063	0.0490	0.0515	1.0	5.00	0.41	11	0.00051
26	15	21	0.0063	0.0490	0.0515	1.0	5.00	0.41	11	0.00051
27	15	24	0.0067	0.0519	0.0546	1.0	5.00	0.41	11	0.00051
28	16	17	0.0033	0.0259	0.0273	1.0	5.00	0.35	11	0.00044
29	16	19	0.0030	0.0231	0.0243	1.0	5.00	0.34	11	0.00043
30	17	18	0.0018	0.0144	0.0152	1.0	5.00	0.32	11	0.00040
31	17	22	0.0135	0.1053	0.1106	1.0	5.00	0.54	11	0.00068
32	18	21	0.0033	0.0259	0.0273	1.0	5.00	0.35	11	0.00044
33	18	21	0.0033	0.0259	0.0273	1.0	5.00	0.35	11	0.00044
34	19	20	0.0051	0.0396	0.0417	1.0	5.00	0.38	11	0.00048
35	19	20	0.0051	0.0396	0.0417	1.0	5.00	0.38	11	0.00048
36	20	23	0.0028	0.0216	0.0228	1.0	5.00	0.34	11	0.00043
37	20	23	0.0028	0.0216	0.0228	1.0	5.00	0.34	11	0.00043
38	21	22	0.0087	0.0678	0.0712	1.0	5.00	0.45	11	0.00057

Table A.6: Generator data for the IEEE-RTS

Unit No.	Bus No.	Rating (MW)	Failure Rate (occ/yr)	Repair Time (hrs)	Failure Prob.
1	22	50	4.42	20	0.01
2	22	50	4.42	20	0.01
3	22	50	4.42	20	0.01
4	22	50	4.42	20	0.01
5	22	50	4.42	20	0.01
6	22	50	4.42	20	0.01
7	15	12	2.98	60	0.02
8	15	12	2.98	60	0.02
9	15	12	2.98	60	0.02
10	15	12	2.98	60	0.02
11	15	12	2.98	60	0.02
12	15	155	9.13	40	0.04
13	7	100	7.30	50	0.04
14	7	100	7.30	50	0.04
15	7	100	7.30	50	0.04
16	13	197	9.22	50	0.05
17	13	197	9.22	50	0.05
18	13	197	9.22	50	0.05
19	1	20	19.47	50	0.01
20	1	20	19.47	50	0.01
21	1	76	4.47	40	0.02
22	1	76	4.47	40	0.02
23	2	20	9.13	50	0.01
24	2	20	9.13	50	0.01
25	2	76	4.47	40	0.02
26	2	76	4.47	40	0.02
27	23	155	9.13	40	0.04
28	23	155	9.13	40	0.04
29	23	350	7.62	100	0.08
30	18	400	7.96	150	0.12
31	21	400	7.96	150	0.12
32	16	155	9.13	40	0.04

Tables A.7-A.9 give the per-unit load model for both the RBTS and IEEE-RTS.

Table A.7: The weekly peak load as a percent of annual peak

Week	Peak load	Week	Peak load	Week	Peak load	Week	Peak load
1	86.2	14	75.0	27	75.5	40	72.4
2	90.0	15	72.1	28	81.6	41	74.3
3	87.8	16	80.0	29	80.1	42	74.4
4	83.4	17	75.4	30	88.0	43	80.0
5	88.0	18	83.7	31	72.2	44	88.1
6	84.1	19	87.0	32	77.6	45	88.5
7	83.2	20	88.0	33	80.0	46	90.9
8	80.6	21	85.6	34	72.9	47	94.0
9	74.0	22	81.1	35	72.6	48	89.0
10	73.7	23	90.0	36	70.5	49	94.2
11	71.5	24	88.7	37	78.0	50	97.0
12	72.7	25	89.6	38	69.5	51	100.0
13	70.4	26	86.1	39	72.4	52	95.2

Table A.8: Daily peak load as a percentage of weekly load

Day	Peak Load
Monday	93
Tuesday	100
Wednesday	98
Thursday	96
Friday	94
Saturday	77
Sunday	75

Table A.9: Hourly peak load as a percentage of daily peak

Hour	Winter Weeks 1-8&44-52		Summer Weeks 18-30		Spring/Fall Weeks 9-17&31-43	
	Wkdy	Wknd	Wkdy	Wknd	Wkdy	Wknd
12-1am	67	78	64	74	63	75
1-2	63	72	60	70	62	73
2-3	60	68	58	66	60	69
3-4	59	66	56	65	58	66
4-5	59	64	56	64	59	65
5-6	60	65	58	62	65	65
6-7	74	66	64	62	72	68
7-8	86	70	76	66	85	74
8-9	95	80	87	81	95	83
9-10	96	88	95	86	99	89
10-11	96	90	99	91	100	92
11-noon	95	91	100	93	99	94
Noon-1pm	95	90	99	93	93	91
1-2	95	88	100	92	92	90
2-3	93	87	100	91	90	90
3-4	94	87	97	91	88	86
4-5	99	91	96	92	90	85
5-6	100	100	96	94	92	88
6-7	100	99	93	95	96	92
7-8	96	97	92	95	98	100
8-9	91	94	92	100	96	97
9-10	83	92	93	93	90	95
10-11	73	87	87	88	80	90
11-12	63	81	72	80	70	85

Note: Wkdy-Weekday, Wknd-Weekend.

APPENDIX B. MRBTS ANALYSIS RESULTS

Case 1 for the Three Alternatives Using the Probabilistic Technique

Table B.1-B.2 show the SI as a function of the peak load for the base case, A1-C1, A2-C1 and A3-C1 for generation failures only and transmission failures only.

Table B.1: Annual SI in SM/yr for the base case, A1-C1, A2-C1 and A3-C1 (Generation failures only)

Year	Peak Load (MW)	Base Case	A1-C1	A2-C1	A3-C1
0	185.00	5.59	0.67	0.71	0.67
1	194.25	12.43	1.68	1.78	1.68
2	204.00	25.39	3.95	4.12	3.95
3	214.20	59.50	10.15	10.42	10.15
4	224.90	136.56	24.81	25.20	24.81
5	236.10	286.63	58.99	59.48	58.99
6	248.00	ESC	133.10	133.63	133.10

Table B.2: Annual SI in SM/yr for the base case, A1-C1, A2-C1 and A3-C1 (Transmission failures only)

Year	Peak Load (MW)	Base Case	A1-C1	A2-C1	A3-C1
0	185.00	0.28	0.13	0.11	0.18
1	194.25	0.43	0.24	0.11	0.18
2	204.00	0.99	0.76	0.12	0.19
3	214.20	3.10	2.79	0.19	0.19
4	224.90	7.90	7.47	0.64	0.20
5	236.10	16.46	15.86	2.03	0.22
6	248.00	ESC	28.10	5.44	0.27

Case 2 for the Three Alternatives Using the Probabilistic Technique

Table B.3-B.4 show the SI as a function of the peak load for the base case, A1-C2, A2-C2 and A3-C2 for generation failures only and transmission failures only.

Table B.3: Annual SI in SM/yr for the base case, A1-C2, A2-C2 and A3-C2 (Generation failures only)

Year	Peak Load (MW)	Base Case	A1-C2	A2-C2	A3-C2
0	185.00	5.59	0.23	0.24	0.42
1	194.25	12.43	0.57	0.60	0.57
2	204.00	25.39	1.39	1.46	1.39
3	214.20	59.50	3.87	4.03	3.87
4	224.90	136.56	9.80	10.06	9.80
5	236.10	286.63	24.25	24.62	24.25
6	248.00	ESC	57.48	57.94	57.48
7	260.40	ESC	148.24	148.77	148.24

Table B.4: Annual SI in SM/yr for the base case, A1-C2, A2-C2 and A3-C2 (Transmission failures only)

Year	Peak Load level (MW)	Base Case	A1-C2	A2-C2	A3-C2
0	185.00	0.28	0.60	0.34	0.56
1	194.25	0.43	0.74	0.37	0.59
2	204.00	0.99	1.43	0.40	0.62
3	214.20	3.10	4.92	0.46	0.67
4	224.90	7.90	16.34	0.81	0.74
5	236.10	16.46	41.49	2.59	0.88
6	248.00	ESC	80.77	7.79	1.13
7	260.40	ESC	145.24	24.63	1.69

Case 3 for the Three Alternatives Using the Probabilistic Technique

Table B.5-B.6 show the SI as a function of the peak load for the base case, A1-C3, A2-C3 and A3-C3 for generation failures only and transmission failures only.

Table B.5: Annual SI in SM/yr for the base case, A1-C3, A2-C3 and A3-C3 (Generation failures only)

Year	Peak Load (MW)	Base Case	A1-C3	A2-C3	A3-C3
0	185.00	5.59	0.02	0.02	0.02
1	194.25	12.43	0.06	0.07	0.06
2	204.00	25.39	0.17	0.18	0.17
3	214.20	59.50	0.54	0.54	0.54
4	224.90	136.56	1.56	1.54	1.56
5	236.10	286.63	4.20	4.16	4.20
6	248.00	ESC	10.17	10.12	10.17
7	260.40	ESC	29.06	28.98	29.06
8	273.40	ESC	77.32	77.19	77.32
9	287.10	ESC	188.27	188.05	188.27

Table B.6: Annual SI in SM/yr for the base case, A1-C3, A2-C3, A3-C3 (Transmission failures only)

Year	Peak Load (MW)	Base Case	A1-C3	A2-C3	A3-C3
0	185.00	0.28	0.20	0.11	0.04
1	194.25	0.43	0.23	0.11	0.04
2	204.00	0.99	0.43	0.12	0.04
3	214.20	3.10	1.40	0.12	0.04
4	224.90	7.90	4.42	0.13	0.05
5	236.10	16.46	10.69	0.13	0.08
6	248.00	ESC	19.80	0.22	0.11
7	260.40	ESC	33.89	0.73	0.17
8	273.40	ESC	51.72	2.36	0.26
9	287.10	ESC	72.96	5.82	0.41

APPENDIX C. IEEE-RTS ANALYSIS RESULTS

Case 1 for Alternatives 1 and 2 Using the Probabilistic Technique

Table C.1: Annual SI in SM/yr for the base case, A1-C1 and A2-C1 (Generation failures only)

Peak Load (MW)	Base Case	A1-C1	A2-C1
2850	50.78	11.29	11.34
2950	84.08	20.42	20.50
3050	160.63	43.37	43.45
3150	292.50	86.15	86.22
3250	446.76	141.46	141.53
3350	651.69	219.52	219.52
3405	849.81	297.63	297.63
3450	ESC	398.88	398.80
3550	ESC	663.31	663.15
3605	ESC	753.29	753.15

Table C.2: Annual SI in SM/yr for the base case, A1-C1 and A2-C1 (Transmission failures only)

Peak Load (MW)	Base Case	A1-C1	A2-C1
2850	0.02	0.03	0.03
2950	0.02	0.03	0.03
3050	0.02	0.03	0.03
3150	0.02	0.04	0.04
3250	0.02	0.04	0.04
3350	0.03	0.04	0.04
3405	0.03	0.04	0.04
3450	ESC	0.04	0.04
3550	ESC	0.05	0.05
3605	ESC	0.05	0.05

Case 2 for Alternatives 1 and 2 and Cases 1 and 2 for Alternative 3 Using the Probabilistic Technique

Table C.3: Annual SI in SM/yr for the base case, A1-C2, A2-C2, A3-C1 and A3-C2 (Generation failures only)

Peak Load (MW)	Base Case	A1-C2	A2-C2	A3-C1	A3-C2
2850	50.78	2.23	2.70	7.02	7.61
2950	84.08	4.34	5.18	12.26	13.26
3050	160.63	10.29	11.78	25.21	26.92
3150	292.50	22.47	25.36	49.19	52.27
3250	446.76	39.68	43.22	79.57	83.24
3350	651.69	65.29	71.47	122.27	128.36
3405	849.81	91.71	100.28	164.84	173.04
3450	ESC	129.36	137.02	221.39	228.55
3550	ESC	231.48	249.83	370.11	387.17
3650	ESC	361.97	377.07	547.21	560.75
3750	ESC	597.76	ESC	853.35	ESC

Table C.4: Annual SI in SM/yr for the base case, A1-C2, A2-C2, A3-C1 and A3-C2 (Transmission failures only)

Peak Load (MW)	Base Case	A1-C2	A2-C2	A3-C1	A3-C2
2850	0.02	0.05	0.05	0.03	0.03
2950	0.02	0.05	0.05	0.03	0.03
3050	0.02	0.05	0.05	0.03	0.03
3150	0.02	0.05	0.05	0.03	0.03
3250	0.02	0.05	0.05	0.03	0.03
3350	0.03	0.05	0.05	0.03	0.03
3405	0.03	0.05	0.05	0.03	0.03
3450	ESC	0.05	0.05	0.03	0.03
3550	ESC	0.05	0.05	0.03	0.03
3650	ESC	0.07	0.05	0.05	0.04
3750	ESC	0.13	ESC	0.11	ESC