BULK SYSTEM RELIABILITY EVALUATION IN A DEREGULATED POWER INDUSTRY

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ABSTRACT

The basic function of an electric power system is to supply its customers with electric energy as economically as possible and with a reasonable degree of continuity and quality. Power system reliability evaluation techniques are now highly developed through the work of many researchers and engineers. It is expected that the application of power system reliability evaluation in bulk power systems will continue to increase in the future especially in the newly deregulated power industry. This thesis presents research conducted on the three areas of incorporating multi-state generating unit models, evaluating system performance indices and identifying transmission deficiencies in composite system adequacy assessment. The research was done using a previously developed software package designated as MECORE.

Many generating companies in both the traditionally regulated and newly deregulated electrical power industry have large generating units that can operate in one or more derated states. In this research work, load point and system reliability indices are evaluated using two-state and multi-state generating unit models to examine the impact of incorporating multi-state generating unit models in composite system adequacy assessment.

The intention behind deregulation in the power industry is to increase competition in order to obtain better service quality and lower production costs. This research illustrates how Canadian power systems have performed in the past using data compiled by the Canadian Electricity Association. A procedure to predict similar indices is presented and used to estimate future performance and the effects of system modifications.

The incentives for market participants to invest in new generation and transmission facilities are highly influenced by the market risk in a deregulation environment. An adequate transmission system is a key element in a dynamic competitive market. This thesis presents a procedure to identify transmission deficiencies in composite generation and transmission system.

The research work illustrated in this thesis is focused on the application of probabilistic techniques in composite system adequacy assessment and particularly in

the newly deregulated electric power industry. The conclusions and the techniques presented should prove valuable to those responsible for power system planning.

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LIST OF ABBREVIATIONS

ADLC	Average Duration of Load Curtailment
BC Hydro	a power utility in British Columbia
BPII	Bulk Power-Interruption Index
BECI	Bulk Power/Energy Curtailment Index
BPACI	Bulk Power-supply Average MW Curtailment Index
BES	Bulk Electricity System
CEA	Canadian Electricity Association
DP	Delivery Point
DPUI	Delivery Point Unreliability Index
Disco	Distribution Company
DAFOR	Derating Adjusted Forced Outage Rate
ENLC	Expected Number of Load Curtailments
EDLC	Expected Duration of Load Curtailment
EDNS	Expected Demand Not Supplied
EENS	Expected Energy Not Supplied
EDC	Expected Damage Cost
ELC	Expected Load Curtailed
EEI	Edison Electric Institute
EFOR	Equivalent Forced Outage Rate
FOR	Forced Outage Rate
f/yr	failures per year
Genco	Generation Company
HLI	Hierarchical Level I
HLII	Hierarchical Level II
HLIII	Hierarchical Level III
hr	hour
IEEE	Institute of Electrical and Electronic Engineers
IEEE-RTS	IEEE Reliability Test System
IEAR	Interrupted Energy Assessment Rate
IPP	Independent Power Producer
ISO	Independent System Operator
kW	kilo-Watt
kV	kilo-Volt
k$	kilo-Dollars
kWh	kilo-Watt-hour
km	kilometer
MW	Mega-Watt
MWh	Mega-Watt-hour
MECORE	Monte Carlo simulation and Enumeration Composite System Reliability Evaluation program
MC	Multi-Circuit Supplied Delivery Point

MI	Momentary Interruption
MBECI	Modified Bulk/Energy Curtailment Index
MRTS	Modified IEEE-Reliability Test System
OPF	Optimal Power Flow
occ/yr	occurrences per year
p.u.	per unit
PX	Power Exchange
Resco	Retail Energy Services Company
PBR	Performance-based regulation
PLC	Probability of Load Curtailment
RBTS	Roy Billinton Test System
SI	Severity Index
SC	Single-Circuit Supplied Delivery Point
SI	Sustained Interruption
SAIFI	System Average Interruption Frequency Index
SAIFI-MI	System Average Interruption Frequency Index- Momentary Interruptions
SAIFI-SI	System Average Interruption Frequency Index- Sustained Interruptions
SAIDI	System Average Interruption Duration Index
SARI	System Average Restoration Index
Transco	Transmission Company
yr	year

1. INTRODUCTION

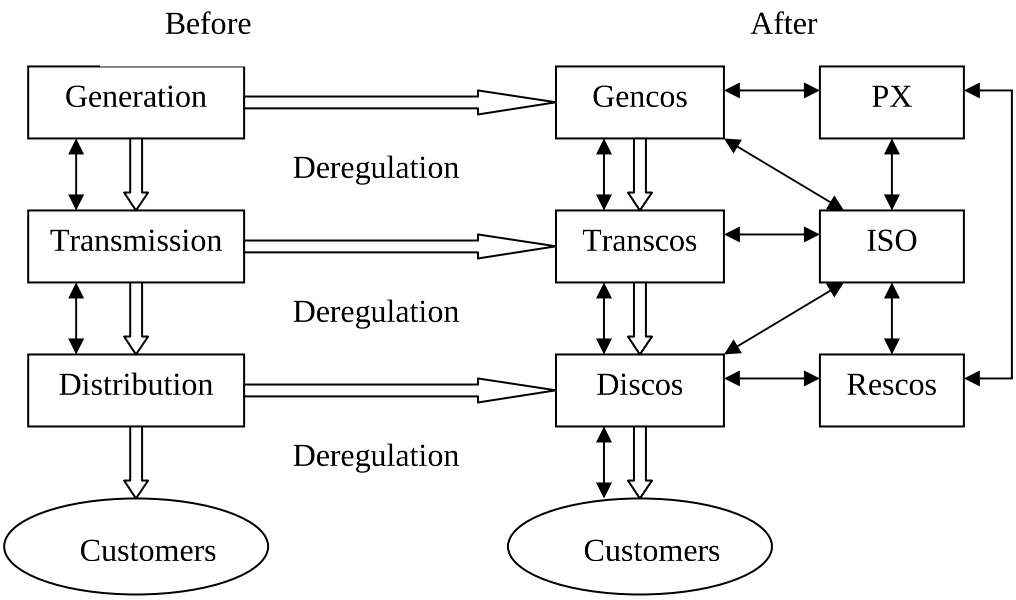
1.1. Introduction

Electricity is a very effective and flexible form of energy. It can be produced in a variety of ways, delivered efficiently, safely and economically, and finally converted to light, heat, power and electronic or other activities. Without it, large-scale industrial equipment or small household electronics would not exist. People in modern societies have difficulty appreciating how life would be without electricity. Recent blackouts in North America and in other parts of the world have, however, focused attention on the need for a highly reliable supply of electrical energy. 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].

In order to resolve the dilemma between the economic and reliability constraints, design, planning, and operating criteria and techniques have been developed and applied in the electric power industry over many years. Most of these criteria are deterministically based and many of them are still in use today [1-4]. It has, however, been recognized that power systems and their components behave stochastically. The basic weakness of deterministic criteria is that they do not respond and reflect the probabilistic or stochastic nature of system behavior, of customer demands, or of component failures [2]. Many engineers and researchers have worked for many years to create quantitative frameworks to reflect the inherent probabilistic or stochastic nature of power systems. There are many publications dealing with the development and application of probabilistic techniques in power system reliability evaluation [5-11]. Reliability evaluation techniques are now highly developed and most power system engineers have a working understanding of probability methods. Probabilistic techniques have been extensively employed in generation planning and distribution system design and some commercial software packages are available. In the field of major transmission planning, more and more utilities are attempting to incorporate probabilistic techniques into their system assessment because of the strategic importance of these facilities [12]. It is expected that the application of reliability concepts in electric power systems will continue to increase in the future.

1.2. Introduction to the Electricity Utility Industry and its Deregulation

Electric utilities are organizations that produce, deliver, distribute or sell electric power. The corresponding functions associated with their actions are generation, transmission, distribution and retail sales. An overall electric power system can be said to be composed of generation, transmission and distribution facilities. Electric utilities can be investor-owned or government-operated entities. Different countries have different power industry structures because of the economic and social differences between the countries, but they generally have some similar characteristics. In a vertically integrated utility, the generation, transmission and distribution facilities are owned by that company, and it manages all the functions of producing, delivering, and selling electric power to the end users [3]. In this type of industry structure, the required revenues are directly related to the cost-of-service based on investment. One of the advantages the traditionally regulated industry has is in the coordination of all the functions required to provide a highly reliable electrical supply. One of the important disadvantages of the traditionally regulated industry is the lack of competition in the created monopoly. This creates losses in efficiency and economic incentives that are important factors in a market-based economy. Traditional regulated industry structures have existed for a long time. In recent years, social, economic, political and technical changes have forced the regulated industry to adapt. Competition has become the key factor driving the deregulation process in the electric power industry, and should benefit both the customers and the participating companies. The key concept behind deregulation in almost every country is that no one company should have a monopoly on either the production, the wholesale, or the retail sale of electricity and electricity-related services. The delivery function associated with transmission and distribution is still a regulated, monopoly business because of its natural characteristics [3]. One of the advantages in the newly deregulated industry is the resulting competition and the benefits that it brings to the customers, utility companies and therefore to society. One of the biggest problems associated with the deregulation process however, is the resulting financial risk caused by the uncertainty existing in the market. There is considerable published material available on power industry deregulation all over the world and its good and bad points [13-23]. Figure 1.1 illustrates some of the changes in the power industry due to the deregulation process.



Gencos — Generation companies
Transcos — Transmission Companies
Discos — Distribution Companies
PX — Power Exchange
ISO — Independent System Operator
Rescos — Retail Energy Services Companies

Figure 1.1: The deregulated power industry

As noted earlier, different countries can have quite different power industry structures, and may be either regulated or deregulated. The industry frameworks however, are all generally similar to that illustrated in Figure 1.1. The left side of the figure shows a general industry structure before deregulation and the right side shows the basic elements existing after deregulation. The single arrows in the figure indicate the flow of electric power and the double arrows indicate the flow of information between the entities. As can be seen, the industry structure before deregulation is comparatively simple. Generation, transmission and distribution are controlled by one system or company and electricity flows from generation to customers directly with the aid of information exchanged between the generation, transmission and distribution divisions. Figure 1.1 shows that in the new deregulated structure, the basic functions of generation, transmission and distribution are performed by a series of new corporate utilities, designated as Gencos, Transcos, Discos, PX, ISO and Rescos.

Gencos (Generation companies) are those organizations in the deregulated power industry that own generating units and produce electric power. Transcos (Transmission companies) are organizations that own transmission lines and move power in bulk quantities from where it is produced to where it is wanted. Discos (Distribution companies) are organizations that deliver electricity locally. There are two basic types, the first is an organization in which the local distribution and retail functions are combined in a single distribution company, and the second case is one in which the distribution company only owns and operates the local distribution system rather than both delivering and selling power. A PX (Power Exchange) is an organization somewhat like a stock exchange where the buyers and sellers of wholesale electricity are allowed to buy and sell electric energy as a commodity. An ISO (Independent System Operator) is a non-partisan organization that actually operates the power system in a region. The duties of the ISO are to operate the system in a reliable and economical manner, and provide equitable treatment to all who need to use the bulk transmission system. This is usually called non-discriminatory open access to the transmission system. Rescos (Retail energy services companies) are retailers of electric power to end customers [3].

Some of the companies such as Gencos, Transcos, Discos, and ISO in the newly deregulated industry were elements of the vertically integrated electric utilities in the regulated industry and are now independent companies responsible for different duties. The PX and Rescos are companies established following deregulation and are important elements in the electricity market. As shown in Figure 1.1, Gencos produce electric power, which Transcos and Discos move to the end customers under the control of the ISO. In this process, the PX and Rescos coordinated the market information and transfer this knowledge to the other entities to facilitate their decision making and operating strategies. All the companies have to work cooperatively to make a power system work smoothly and safely for their common benefit. Under the new industry structure, the revenues of the participating companies are based on their performance rather than on the cost-of-service based on their investment. An ISO is usually a not-for-profit organization. Its activities, however, dramatically impact all the companies because of the key role it plays.

Problems always arise with change, and this is certainly true in the deregulated power industry as the old and comparably simple system is replaced by a more complex industry structure. The power industry is faced with many problems such as how to operate the new power systems economically and reliably, how to minimize production costs, how to attract the new investment required to construct the required generation and transmission facilities under the uncertainty of market competition, etc. Considerable work needs to be done to answer those new and complicated questions. The research described in this thesis is focused on reliability considerations in the deregulated industry domain. Power system reliability evaluation is an important activity in both vertically integrated and unbundled electric power utilities. 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 a power system, the measures of reliability indicate how well the system performs its basic function of supplying electrical energy to its customers [24]. Increased investment in an electric power system will reduce the likelihood of not meeting customer needs, and translates into a higher reliability and a higher customer cost. Cost is a major concern in the newly deregulated power industry due to the competitive framework in which companies operate. The requirements for low cost electrical energy and high levels of reliability are in conflict. How to balance these two aspects is a big challenge to power system managers, planners, designers and operators.

1.3. Introduction to Power System Reliability Evaluation

The term “reliability” when used in a power system context has a very wide range of meaning. In order to be more specific it is usual to divide the term into the two aspects of adequacy and security, as shown in Figure 1.2.

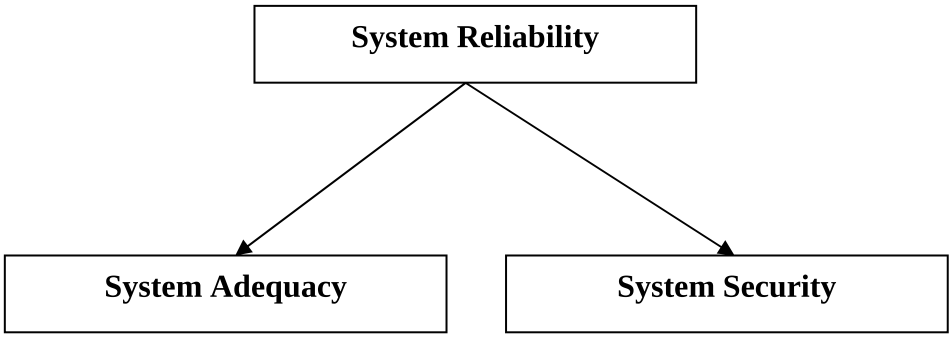


Figure 1.2: Subdivision of system reliability

System adequacy relates to the existence of sufficient facilities within the system to satisfy the consumer load demand or system operational constraints. These include the facilities necessary to generate sufficient energy and the associated transmission and distribution facilities required to transport the energy to the actual consumer load points [2]. System security relates to the ability of the system to respond to disturbances arising within that system. Security is therefore associated with the response of the system to whatever perturbations it is subject to. These include the conditions associated with both local and widespread disturbances and the loss of major generation and / or transmission facilities, which can cause dynamic, transient, or voltage instability of a power system [2]. System adequacy is associated with static conditions, which are long-term analyses. On the contrary, system security is associated with dynamic or transient conditions and associated with short-term analyses. The research work in this thesis is restricted to adequacy evaluation of electric power systems.

An overall power system can be divided into the three basic functional zones of generation, transmission, and distribution, and be organized into the three hierarchical levels (HL) shown in Figure 1.3. Hierarchical Level I (HLI) involves only the generation facilities. Hierarchical Level II (HLII) involves both the generation and transmission facilities. Hierarchical Level III (HLIII) involves all three functional zones.

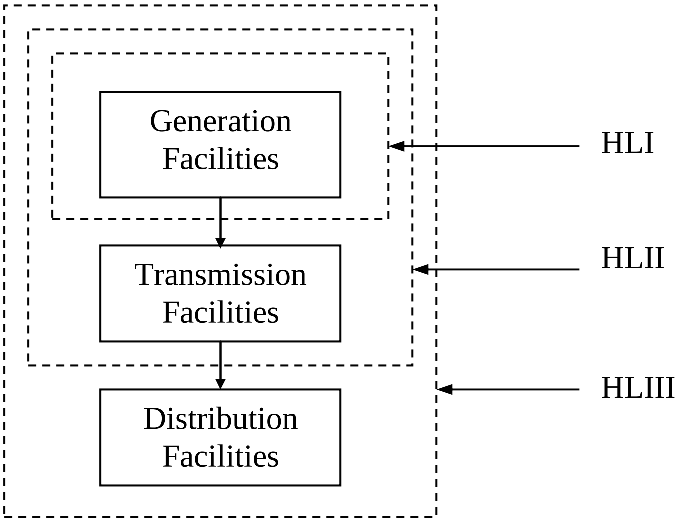


Figure 1.3: Power system hierarchical levels

Adequacy evaluation at HLI is usually termed as generating capacity adequacy evaluation and examines the total system generation in order to determine its adequacy to meet the total system load requirement. The transmission system is not part of the analysis at this level. Adequacy evaluation at HLII is usually termed as composite system or bulk system evaluation because it includes both the generation and the transmission facilities. Technical studies at HLII involve many activities, such as load flow analysis, contingency analysis, overload alleviation, generation rescheduling, load curtailment philosophy, etc. Analytical studies conducted at HLII can be used to assess the adequacy of existing systems and compare the impact of proposed reinforcement alternatives in both the generation and transmission functional zones. Adequacy evaluation at HLIII is concerned with all three functional zones and includes all the associated equipment from the generating sources to the individual consumer load points. In this case, HLII load point indices can be used as input values to the distribution functional zone. In practice, HLIII studies are not usually conducted directly due to the scale of the problem. Analysis is usually performed in the distribution functional zone rather than in all three functional zones [2]. As noted in Section 1.1, probabilistically based evaluation techniques have been used extensively at HLI and in the distribution functional zone. They can, however, be considered to be still in the development phase at HLII. The research described in this thesis is focused on HLII.

1.4. Scope and Objectives of the Thesis

The research described in this thesis is focused on three important considerations in HLII adequacy assessment: incorporating multi-state generating unit models, predicting system performance indices, and identifying transmission deficiencies. All three considerations are important elements in composite system adequacy studies involving both generation and transmission system facilities. The three related areas are discussed in more detail in the following sections. The studies described in the thesis were conducted using a commercial software package known as MECORE. This software is a Monte Carlo simulation based bulk system reliability evaluation tool and is described in detail in Chapter 2.

1.4.1. Incorporating Multi-state Generating Unit Models in Composite System Adequacy Assessment

Many generating companies in both the traditionally regulated and newly deregulated industry have large generating units that can operate in one or more derated states. Two-state generating unit models involving derating adjusted forced outage rates (DAFOR) are usually used to conduct both generating capacity and composite generation and transmission system reliability studies rather than multi-state unit models. Incorporating derated states in large generating unit models can create a considerable increase in the number of generation contingency states and therefore result in a significant increase in the overall solution time when using the enumeration approach [2]. The obvious disadvantage of this simplification is that it produces a slightly pessimistic appraisal of generating capacity adequacy. In the traditionally regulated industry, the additional investment can be returned due to the traditional cost-of-service based rate mechanism. This is not the case in the newly deregulated industry. The objective in examining the effects of incorporating multi-state generating units models in composite system adequacy assessment is to assess the impact of these models on the predictive load point and system reliability, and to draw some conclusions regarding their application in practical system studies.

1.4.2. Evaluating System Performance Indices in Composite System Adequacy Assessment

The intention of deregulation in the power industry is to increase competition in order to obtain better service quality and lower production costs. Deregulation will not only affect the economic and technical framework of the industry, but also the political aspects. A new regulatory approach called performance-based regulation (PBR) has been proposed by policymakers involved in deregulating the industry and in electricity market development. This mechanism attempts to link rewards to desired results or targets. Performance-based regulation is offered as an alternative to more traditional cost-of-service regulatory practices. Bulk electricity system performance indices have the potential to be a key element in this regulatory approach. Bulk electricity system performance indices can be categorized as predictive indices and past performance indices. Predictive indices provide relevant information associated with future system reliability and are normally associated with system planning. On the other hand, past performance indices reflect the actual system reliability and are therefore directly related to the actual operation of the system. The objective of the research conducted in this area is to examine how Canadian power systems have performed in the past using data collected by the Canadian Electricity Association (CEA), and how similar indices can be obtained to predict the future performance of power systems.

1.4.3. Identifying Transmission Deficiencies in Composite Systems

In the traditionally regulated electric power industry, utilities are required to build more generation and transmission facilities to satisfy the growing demands. The traditional cost-of-service based rate mechanism allows utilities to recover the investment with some profit. In a deregulated environment, company revenues are associated with competition in a market filled with risk and uncertainty. This has a negative effect on new investment in transmission facilities. Sufficient transmission is mandatory for a dynamic competitive market. The most efficient use of generating resources cannot be realized without sufficient transmission capacity, and this is the objective of restructuring the power industry. The responsibility of Transcos and ISOs is to see that the required electricity is delivered reliably and economically to the system customers. The objective of the research conducted in this area is to examine the utilization of composite system adequacy assessment to determine the transmission deficiencies in systems where generation resources are decoupled from transmission investment.

1.5. Outline of the Thesis

This thesis is organized into six chapters. Chapter 2 briefly describes relevant reliability indices including both load point and system values. Three Monte Carlo techniques used in power system reliability evaluation, i.e. the state sampling technique, the state transition sampling technique, and the sequential technique are illustrated in this chapter. The composite generation and transmission system reliability evaluation software known as MECORE is introduced in this chapter. The software is based on a combination of Monte Carlo simulation (state sampling) and enumeration techniques. The two test systems used extensively in this thesis are also briefly introduced in Chapter 2. The Roy Billinton Test System (RBTS) is a small educational test system. The IEEE Reliability Test System (IEEE-RTS) is a relatively large system compared with the RBTS. Base cases studies of the two test systems together with the corresponding assumptions are presented in this chapter. The load point and system indices are categorized into annualized and annual values and presented in the base case studies.

Chapter 3 uses the outage data for three types of generating unit provided by the Edison Electric Institute (EEI) together with a procedure called the apportioning method to establish multi-state generating unit models in the two test systems. Both load point and system reliability indices are calculated using two-state and multi-state generating unit models to illustrate the effects of incorporating multi-state generating unit models in composite system adequacy assessment. How multi-state generating unit models should be established and how many derated states are required for an acceptable appraisal are also analyzed in this chapter.

Chapter 4 contains two distinct segments. In the first part, the basic data collected and published by CEA over the period 1993 to 2001 are presented to show how the performance of Canadian power systems has changed with time. A procedure to predict system performance indices similar to those compiled by the CEA is presented in the second part. This procedure is applied to the two test systems.

Chapter 5 presents a procedure to identify transmission deficiencies in composite generation and transmission system adequacy assessment. The proposed procedure includes three parts: base case analysis, factor analysis of the base case, and remedial modifications and their effects. The analyses described in this chapter are conducted using the RBTS and the IEEE-RTS, and modified versions of these test systems, that reflect possible transmission constraints in the new market environment.

Chapter 6 summarizes the research work described in the thesis and presents some general conclusions.

2. COMPOSITE SYSTEM ADEQUACY ASSESSMENT

2.1. Introduction

The basic function of a composite generation and transmission system is to generate the required electricity and deliver it to the major load points. The major objective of composite system adequacy assessment (HLII) is to evaluate the ability of the system to perform this basic function. Composite system adequacy assessment is very complex since it involves not only system analyses but also many practical considerations. The system analyses involved in the assessment include load flow studies, contingency assessment, generation rescheduling, transmission overload alleviation, load curtailment, etc [2].

One of the most basic elements in power system planning is the determination of how much generating capacity is sufficient to satisfy the load requirement. This capacity should be capable of supplying the system requirement under conditions of generating unit forced outages and unforeseen variations in the system load, and also permit preventive maintenance of the generation facilities. Another equally important issue is the development of a suitable transmission network to transfer the energy from the generating system to the customers [26]. Considerable material is available in this area based on the work done by utilities and other associated organizations [1, 2, 5-12].

Composite system adequacy assessment can be conducted using analytical methods or Monte Carlo simulation techniques. Analytical methods represent the system by analytical models and use mathematical methods to evaluate the required reliability indices based on these models. Monte Carlo simulation techniques estimate the reliability indices by simulating the real process and stochastic behavior of the system. In recent years, Monte Carlo simulation techniques have received increasing attention and development because of their advantages when complex operating conditions are incorporated into the assessment. The research work conducted in this thesis is based on Monte Carlo simulation. A detailed introduction to Monte Carlo simulation techniques is presented later in this chapter.

2.2. Reliability Indices in Composite System Adequacy Assessment

Reliability indices are an important outcome of quantitative adequacy assessment of a composite system. Both load point and system indices can be used to measure composite system adequacy. Load point indices indicate the reliability at the individual load buses while system indices provide an overall evaluation of total system reliability and reliability worth [27]. The two sets of indices have different functions but complement each other. Load point indices are usually used when the focus of the adequacy assessment is to find and strengthen unreliable buses in the system. System indices are used when the purpose of the adequacy assessment is to provide a global assessment of the system and to compare different alternatives. There is a wide range of load point and system indices that can be evaluated. Bulk system reliability indices can be divided into the two general categories of predictive and past performance indices. In the first case, the indices are calculated based on component reliability data for the generation and transmission facilities. In the second case, the indices are compiled using statistical methods based on the actual operation of the bulk power system. Most predictive indices are related to adequacy assessment and estimate future system reliability. Past performance indices are normally associated with overall reliability assessment and include both adequacy and security considerations. These indices are usually used to provide general information on the reliability performance of bulk power systems and are discussed in detail in Chapter 4 of this thesis.

As noted above, there is a wide range of possible predictive indices associated with composite system adequacy assessment. A set of basic indices together with some additional IEEE proposed indices are presented in the following [2, 27]. These indices are also used in the research in this thesis.

(a). Basic indices

(1). Probability of Load Curtailment (PLC)

$$\mathrm{PLC} = \sum_{i \in S} p_i \tag{2.1}$$

where p_i is the probability of system state i and S is the set of all system states associated with load curtailments.

(2). Expected Frequency of Load Curtailment (EFLC)

$$\text{EFLC} = \sum_{i \in S} (F_i - f_i) \ \text{occ./yr} \tag{2.2}$$

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.

It is a difficult task in composite system adequacy assessment 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 Curtailments (ENLC) is often used to replace the EFLC index.

$$\text{ENLC} = \sum_{i \in S} F_i \quad \text{occ./yr} \tag{2.3}$$

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 relationship between the frequency and the system state probability p_i:

$$F_i = p_i \sum_{k \in N} \lambda_k \quad \text{occ./yr} \tag{2.4}$$

where λ_k is the departure rate of component corresponding to system state i and N is the set of all possible departure rates corresponding to state i.

(3). Expected Duration of Load Curtailment (EDLC)

$$\text{EDLC} = \text{PLC} \times 8760 \quad \text{hrs/yr} \tag{2.5}$$

(4). Average Duration of Load Curtailment (ADLC)

$$\text{ADLC} = \text{EDLC/EFLC} \quad \text{hrs/disturbance} \tag{2.6}$$

(5). Expected Load Curtailments (ELC)

$$\text{ELC} = \sum_{i \in S} C_i F_i \quad \text{MW/yr} \tag{2.7}$$

where C_i is the load curtailment of system state i.

(6). Expected Demand Not Supplied (EDNS)

$$\text{EDNS} = \sum_{i \in S} C_i p_i \quad \text{MW} \tag{2.8}$$

(7). Expected energy not supplied (EENS)

$$\text{EENS} = \sum_{i\in S} C_i F_i D_i = \sum_{i\in S} 8760 C_i p_i \quad \text{MWh/yr} \tag{2.9}$$

Where D_i is the duration of system state i.

(8). Expected damage cost (EDC)

$$\text{EDC} = \sum_{i\in S} C_i F_i D_i W \quad \text{k\$/yr} \tag{2.10}$$

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.

(b). IEEE proposed indices

(9). Bulk power interruption index (BPII)

$$\text{BPII} = \frac{\sum_{i\in S} C_i F_i}{L} \quad \text{MW/MW-yr} \tag{2.11}$$

where L is the annual system peak load in MW.

(10). Bulk power/energy curtailment index (BPECI)

$$\text{BPECI} = \frac{\text{EENS}}{L} \quad \text{MWh/MW-yr} \tag{2.12}$$

(11). Bulk Power-supply average MW curtailment index (BPACI)

$$\text{BPACI} = \frac{\text{ELC}}{\text{EFLC}} \quad \text{MW/disturbance} \tag{2.13}$$

(12). Modified bulk energy curtailment index (MBECI)

$$\text{MBECI} = \frac{\text{EDNS}}{L} \quad \text{MW/MW} \tag{2.14}$$

(13). Severity Index (SI)

$$\text{SI} = \text{BPECI} \times 60 \quad \text{system min/yr} \tag{2.15}$$

The IEEE indices (9) to (13) are calculated from the basic indices given by Equations 2.1 to 2.10. The IEEE indices can be calculated either at the system peak load and expressed on a one-year basis, or calculated based on the annual load duration curve. The advantage of the IEEE indices is that they can be used to compare the adequacies of systems with different sizes, as they apply to an overall system. The basic indices can be applied to either an overall system or to an individual load point.

2.3. Monte Carlo Simulation

The Monte Carlo method, which is the general designation for stochastic simulation using random numbers, is used in many fields such as complex mathematical calculations, stochastic process simulation, medical statistics, engineering system analysis, and reliability evaluation [2]. The simulation process is used to imitate the system components and their behavior patterns including the random nature of all the system actions including the number of failures, the time between failures, the restoration times, etc during the simulated time. The objective of the simulation process is to estimate the expected or average value of the various reliability parameters and to obtain, if required, the frequency/probability distribution of each parameter [1]. The simulation is achieved by using random numbers and converting them into density functions to represent the behavior of the components and variables under consideration. Random numbers, their generation, and conversion are therefore important and essential parts of Monte Carlo simulation [2]. As previously mentioned, both analytical methods and Monte Carlo simulation can be used to perform power system adequacy evaluation including composite system assessment. Monte Carlo simulation techniques have the advantage compared to analytical methods, when complex operating conditions are incorporated into the assessment process, as they can mimic the actual process and random behavior of the system more accurately. The main advantages of Monte Carlo simulation in power system reliability evaluation are as follows [2]:

- In theory, it can include system effects or processes that may have to be approximated in analytical methods.
- The required number of samples for a given accuracy level is independent of the size of the system and therefore Monte Carlo simulation is suitable for large-scale system evaluation.
- It can simulate the probability distributions associated with component failure and restoration activities. This generally cannot be done using analytical methods.
- It can calculate not only reliability indices in the form of expected values of the random variables, but also the distributions of these indices, which analytical techniques generally cannot do.

- Non-electrical system factors such as reservoir operating conditions in hydro systems, weather effects, etc. can also be simulated.

The two basic Monte Carlo methods used in power system reliability evaluation are generally known as the sequential and non-sequential techniques. The non-sequential techniques sample the states of all components and evaluates the obtained system state without considering system chronology. The non-sequential technique can be divided into the two basic techniques of state sampling and state transition sampling based on their different sampling approaches. The sequential technique simulates the up and down cycles of all the system components chronologically. An entire system operating cycle is then obtained by combining all the component cycles. These methods are briefly described in the following [2].

2.3.1. State Sampling Technique

In the state sampling technique, the states of all components are sampled and the obtained system state is evaluated without considering its chronological characteristics. 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 accordance with the actual conditions. In the case of a two-state component, the component state can be categorized by the component forced outage rate (FOR). The system state can be represented by a vector $S = (S_1, S_2, S_3, \ldots\ldots, S_i, \ldots\ldots, S_m)$, where S_i is the state of the i^{th} component. The vector S of m components includes the state of each element in the system (generators, lines, transformers, etc.) [28]. The steps in evaluating composite system reliability using the state sampling technique are briefly summarized below.

(1). A uniform random number U_i in the range of 0 to 1 is generated for each component i.

(2). The component is deemed to be available or failed using this uniform random number. When the random number $\geq FOR_i$, the component is considered to be available; when the random number $< FOR_i$, the component is considered to be in the failed state.

$$S_i = \begin{cases} 0 \text{ (Normal state)} & \text{if } U_i \geq FOR_i \\ 1 \text{ (Outage state)} & \text{if } U_i < FOR_i \end{cases} \quad (2.16)$$

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

(3). The system state is obtained by repeating Step (2) for all the components.

(4). If S, which represents the system state, is equal to 0, the system is in the normal state and no load curtailment exists. If S is not equal to zero, the system is in a contingency state and load curtailment may occur.

(5). A linear programming minimization model is normally used to reschedule generation, alleviate line overloads and to avoid load curtailment if possible or to minimize the total load curtailment if it is unavoidable [29].

(6). The adequacy indices are accumulated and Steps (1)-(5) are repeated until the coefficient of variation of a designated index such as the Expected Demand Not Served (EDNS) is less than the tolerance error.

2.3.2. State Transition Sampling Technique

The state transition sampling technique focuses on system state transitions, instead of component states or component state processes. In this method, all the state residence times are assumed to be exponentially distributed. The following steps followed briefly describe the procedure used in composite system adequacy assessment [28].

(1). The simulation process starts from the normal system state in which all the generating units and transmission lines are in the up state, which means every component in the system is available.

(2). If the present system state is a contingency state in which at least one component is in the outage state, the minimization model of load curtailment is used to evaluate the adequacy of this system state. Otherwise, proceed to the next step without utilizing the minimization model.

(3). Uniform distributed random numbers are generated to determine the next system state using the state transition sampling procedure. In this procedure, a system state transition sequence is directly created. It can therefore be used to calculate the actual frequency indices of the load points and for the total system, which cannot be done using the state sampling technique [30].

(4). The process is repeated from Step (2) until the selected convergence criterion is satisfied.

2.3.3. Sequential Technique

The sequential technique is based on sampling the probability distribution of the component state duration. In contrast to above two techniques, this approach can simulate the chronological component state transition processes for all components.

This method uses the component state duration distribution functions. In a two-state component representation, these are the operating and down repair duration distribution functions and are usually assumed to be exponential. Other distributions, however, can also be used. The procedure used in composite system adequacy assessment is as follows [2, 28]:

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

(2). Sample the duration of each component state. In the case of an exponential distribution, the sampling value of the state duration is

$$T_i = -\frac{1}{\lambda_i} \ln U_i \tag{2.17}$$

where U_i is a uniformly distributed random number (in the range of 0 to 1) for 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 [31].

(3). Repeat Step (2) and record the sampling values of each state duration for all components. The chronological component state transition processes for each component can be obtained this way.

(4). The chronological system state is obtained by combining the chronological component states of all the components.

(5). System analysis is then conducted for each different system state to obtain the reliability index $F(X_j)$, where X_j is the sequence of system state S in year j and $F(X_j)$ is the reliability index function over the year j.

(6). Steps (1)-(5) are repeated until the coefficient of variation of the chosen index is less than the tolerance error.

The three approaches introduced above have their own advantages and disadvantages.

The basic state sampling technique is relatively simple. It only involves the generation of uniformly distributed random numbers in the range of 0 to 1 instead of sampling a distribution function. Relatively little basic reliability data such as the component-state probabilities are required by the technique. The obvious disadvantage is that the state sampling technique estimates the frequency of load curtailments as the sum of the occurrences of load curtailment states. This is actually an upper boundary of the actual frequency index, not the actual frequency value.

The state transition sampling method can be used to calculate an exact frequency index without sampling the distribution function and storing chronological information as in the sequential technique. The restriction in this technique is that it only applies to exponentially distributed component state durations.

The sequential method can be used to accurately calculate the actual frequency indices and can incorporate any state residence time distribution. Compared to the relatively simple state sampling technique, this method requires considerable CPU time and storage as it has to generate a random variable for each component and to store the chronological component state transition information for a suitably long time span [2].

2.4. Introduction to MECORE

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 electricity systems. The MECORE program was initially developed at the University of Saskatchewan and subsequently enhanced at BC Hydro [27]. This commercial program can be used to provide a wide range of reliability indices at the 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 used to aid in comparing different planning alternatives from a reliability point of view. MECORE is based on a combination of Monte Carlo simulation (state sampling technique) and enumeration techniques. The Monte Carlo method can be used to simulate the 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 curve [27].

- 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

The basic indices include the ENLC, ADLC, EDLC, PLC, EDNS, EENS, EDC, and ELC. The IEEE-proposed indices include the BPII, BPECI, BPACI, MBECI, and SI. The ENLC, ADLC, EDLC, PLC, EDNS, EENS, EDC, BPII, BPECI, BPACI, MBECI, and SI are calculated at the system level, The ENLC, PLC, ELC, EDNS, and EENS are calculated for each individual load point.

- Linear programming optimization model

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 load 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.

2.5. Two Composite Test Systems

Two test systems were used to conduct the research work in this thesis. They are an educational test system designated as the Roy Billinton Test System (RBTS) [32] and the IEEE Reliability Test System (IEEE-RTS) [33]. The single line diagrams of the RBTS and the IEEE-RTS are shown in Figures 2.1 and 2.2 respectively.

The RBTS is a composite system developed at the University of Saskatchewan for educational and research purposes, which is small enough to permit the conduct of a large number of reliability studies with reasonable solution time. The RBTS is a six-bus test system with five load buses. It has eleven generators located at two generator buses and nine transmission lines. The total installed generating capacity is 240 MW and the system peak load is 185 MW. The system voltage level is 230 kV.

The IEEE-RTS was developed by the Subcommittee on the Application of Probability Methods in the IEEE Power Engineering Society to provide a common test system on which different techniques can be developed and the results compared. The IEEE-RTS is a relatively large system compared with the RBTS. The generating system contains 32 units located at 10 generator buses, ranging from 12 to 400 MW. The transmission system has 24 buses, which include 10 generator buses, 10 load buses, and 4 connection buses, connected by 33 transmission lines and 5 autotransformers at two voltage levels: 138kV and 230kV. The total installed capacity of the IEEE-RTS is 3405 MW and the system peak load is 2850 MW.

Both systems have the same per-unit load model [1], which can be used to generate hourly loads for one year on a per unit basis, expressed in chronological fashion so that daily, weekly, and seasonal patterns can be modeled depending on individual study needs.

The data for the two systems, including transmission line, generator and load model information are given in Appendix A.

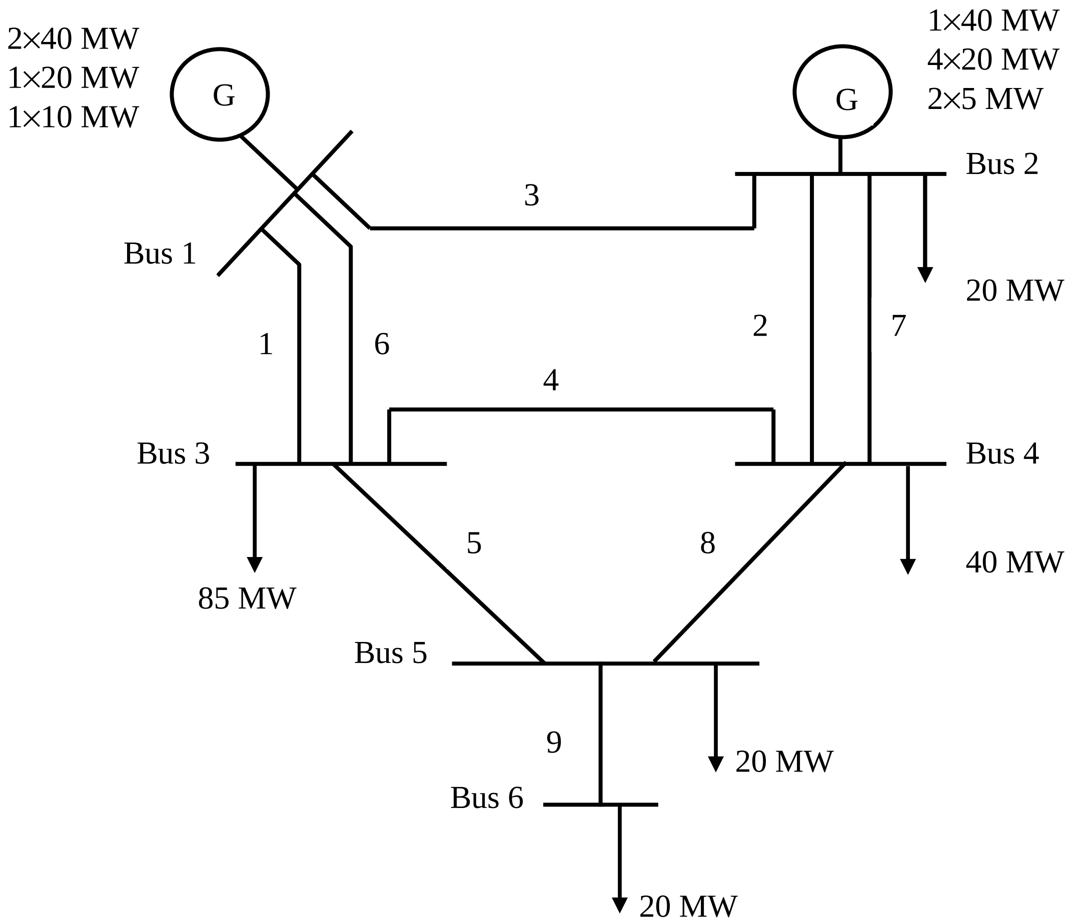


Figure 2.1: Single line diagram of the RBTS

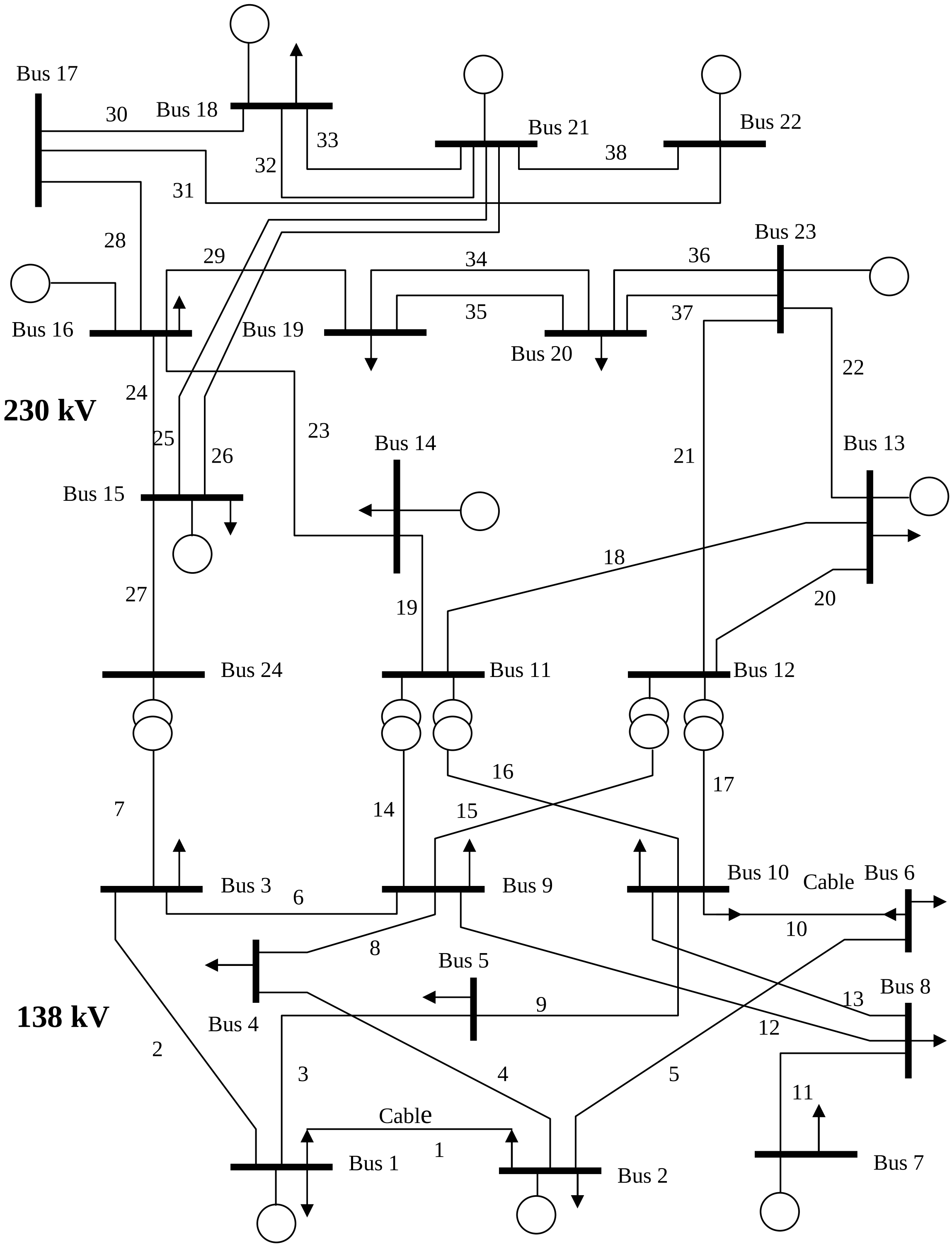


Figure 2.2: Single line diagram of the IEEE-RTS

2.6. Base Case Studies for the RBTS and the IEEE-RTS

Base case analysis provides a benchmark in a general study procedure against which the effects of system modifications and data sensitivity can be assessed. Studies conducted on the original RBTS and IEEE-RTS provide the base case values in this thesis. Many factors such as station configurations, common mode failures of transmission lines, station originated failures and so on, can be included in a composite system assessment [34]. In order to clearly understand the base case results, it is important to appreciate which factors are included and which factors are not considered. In the studies described in this thesis:

- station configurations are not incorporated in the evaluation process,
- the step-down transformers at transformer stations are assumed to be customer-owned and the reliability indices are calculated at the high voltage busbars,
- the economic priority order for load curtailment is utilized,
- transmission line common mode failures are not considered.

2.6.1. Annual and Annualized Indices

There are two ways to calculate the system and load point indices. The first is to calculate the indices under peak load conditions and expressed them on a one-year basis. The indices are then known as annualized indices. The second is to calculate them 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 and reflect the actual load profiles throughout the year. The advantage of annualized indices is that they require less computing time and can be used to roughly reflect the system reliability performance. Both the annualized and annual indices were calculated in the base case studies of the RBTS and the IEEE-RTS presented in this thesis.

2.6.2. Additional Input Data in the Base Case Studies

It is important in a stochastic simulation process to carefully select the number of samples required to obtain meaningful results. Studies conducted earlier [34] show that acceptable accuracy can be obtained when the numbers of samples for the RBTS and the

IEEE-RTS are 2,000,000 and 500,000 respectively. These sample sizes were therefore used in the analyses described in this thesis.

Individual load point indices are highly dependent on the system load curtailment philosophy. In an actual system, some loads are more important than others and therefore, each load bus has a different priority. A load bus priority order should be incorporated in a composite system adequacy assessment in order to implement an agreed load shedding philosophy. The MECORE program has the capability to perform load shedding following a specified priority order. The priority order can be established based on economic factors which recognize the customer costs associated with failure of supply. The most convenient index for this purpose is the Interrupted Energy Assessment Rate (IEAR) [1], which measures the customer monetary loss as a function of the energy not supplied. The unit of the IEAR is $/kWh of unsupplied energy. The priority code of each bus is therefore determined by the corresponding IEAR. The higher the IEAR, the more troublesome is the loss of supply and a higher priority is applied. The IEAR values for the individual load points in the RBTS are shown in Table 2.1 and the corresponding priority order is derived and given in Table 2.2.

Table 2.1: IEAR values at each bus in the RBTS

Bus No.	IEAR ($/kWh)
2	7.41
3	2.69
4	6.78
5	4.82
6	3.63

Table 2.2: Priority order of each bus in the RBTS

Priority Order	Bus No.
1	2
2	4
3	5
4	6
5	3

The IEAR values of each load bus in the IEEE-RTS are given in Table 2.3 and the corresponding priority order is shown in Table 2.4.

Table 2.3: IEAR values at each bus in the IEEE-RTS

Bus No.	IEAR ($/kWh)
1	6.20
2	4.89
3	5.30
4	5.62
5	6.11
6	5.50
7	5.41
8	5.40
9	2.30
10	4.14
13	5.39
14	3.41
15	3.01
16	3.54
18	3.75
19	2.29
20	3.64

Table 2.4: Priority order of each bus in the IEEE-RTS

Priority Order	Bus No.
1	1
2	5
3	4
4	6
5	7
6	8
7	13
8	3
9	2
10	10
11	18
12	20
13	16
14	14
15	15
16	9
17	19

The Expected Damage Cost (EDC) is an important index that can be used to perform economic analysis in composite system adequacy assessment. The MECORE program calculates this index by multiplying the EENS of the overall system by a representative system IEAR that is calculated using the following equation [1].

$$\text{Aggregate system IEAR} = \sum_{k=1}^{NB} \text{IEAR}_k q_k \ \$/\text{kWh} \tag{2.18}$$

In Equation 2.18, NB is the total number of load buses in the system, IEAR_k is the Interrupted Energy Assessment Rate (IEAR) at load bus k, and q_k is the fraction of the system load utilized by the customers at load bus k. The representative system IEAR of the RBTS can be calculated using the data in Table 2.1 and Table A.1, and is 4.42 $/kWh in this case. The representative system IEAR of the IEEE-RTS can be calculated using the data in Table 2.3 and Table A.4, and is 4.22 $/kWh.

The additional input data for the base case studies can be summarized as follows. The number of samples for the RBTS is 2,000,000, the representative system IEAR is 4.42 $/kWh, and the load curtailment priority order is shown in Table 2.2. The corresponding values for the IEEE-RTS are 500,000, 4.22 $/kWh and the priority order is given in Table 2.4.

2.6.3. RBTS Analysis

The annualized and annual load point indices for the RBTS base case are shown in Tables 2.5 and 2.6 respectively. The annualized and annual system indices are given in Table 2.7.

Table 2.5: Annualized load point indices for the RBTS (base case)

Bus No.	PLC	ENLC (1/yr)	ELC (MW/yr)	EDNS (MW)	EENS (MWh/yr)
2	0.00000	0.00150	0.004	0.00000	0.044
3	0.00869	4.08024	48.162	0.09699	849.637
4	0.00003	0.02135	0.142	0.00013	1.113
5	0.00004	0.03020	0.300	0.00033	2.888
6	0.00139	1.30199	24.081	0.02471	216.460

Table 2.6: Annual load point indices for the RBTS (base case)

Bus No.	PLC	ENLC (1/yr)	ELC (MW/yr)	EDNS (MW)	EENS (MWh/yr)
2	0.00000	0.00000	0.000	0.00000	0.000
3	0.00018	0.10162	1.171	0.00201	17.564
4	0.00000	0.00109	0.008	0.00000	0.038
5	0.00000	0.00554	0.059	0.00003	0.296
6	0.00120	1.18265	15.095	0.01535	134.452

Table 2.7: Annualized and annual system indices for the RBTS (base case)

Indices	Annualized	Annual
ENLC (1/yr)	5.25586	1.27965
ADLC (hrs/disturbance)	16.48	9.45
EDLC (hrs/yr)	86.61	12.09
PLC	0.00989	0.00138
EDNS (MW)	0.122	0.017
EENS (MWh/yr)	1070.141	152.3497
EDC (k$/yr)	N/A	673.386
BPII (MW/MW-yr)	0.39292	0.08829
BPECI (MWh/MW-yr)	5.785	0.824
BPACI (MW/disturbance)	13.830	12.764
MBECI (MW/MW)	0.00066	0.00009
SI (system minutes/yr)	347.07	49.41

It can be seen from Tables 2.5 and 2.6 that the EENS values for Buses 3 and 6 are much larger than those of the other buses in the RBTS, which indicates that Buses 3 and 6 are the least reliable load points in the system. It can be seen from Table 2.2 that Bus 3 has the lowest priority among all the load buses. Figure 2.1 shows that Bus 6 is located relatively far away from the generation facilities and is connected to the rest of system by a single radial line. Bus 6 also has the second lowest priority in the system. Both of these factors make Bus 6 a relatively low reliability load point.

2.6.4. IEEE-RTS Analysis

The annualized and annual load point indices for the IEEE-RTS base case are shown in Tables 2.8 and 2.9 respectively. The annualized and annual system indices are given in Table 2.10.

Table 2.8: 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	-	-	-	-	-
2	0.00022	0.21533	7.517	0.00743	65.052
3	0.00012	0.12469	5.997	0.00579	50.685
4	-	-	-	-	-
5	-	-	-	-	-
6	-	-	-	-	-
7	0.00000	0.00327	0.082	0.00005	0.438
8	0.00000	0.00294	0.062	0.00004	0.368
9	0.05080	35.32409	2612.315	3.86918	33894.023
10	0.00056	0.50498	35.025	0.03860	338.171
13	0.00003	0.03218	1.463	0.00126	11.073
14	0.01217	9.29683	639.791	0.81732	7159.724
15	0.03938	25.78817	2481.552	3.48197	30502.036
16	0.00552	4.43487	178.765	0.21584	1890.757
18	0.00237	1.90038	174.843	0.20937	1834.097
19	0.08419	58.09929	4160.457	5.99921	52553.046
20	0.00351	2.93097	153.836	0.18786	1645.678

Table 2.9: 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	-	-	-	-	-
2	0.00000	0.00140	0.049	0.00005	0.397
3	0.00000	0.00082	0.027	0.00002	0.215
4	-	-	-	-	-
5	-	-	-	-	-
6	0.00000	0.00075	0.052	0.00003	0.293
7	0.00000	0.00041	0.004	0.00000	0.021
8	0.00000	0.00004	0.000	0.00000	0.002
9	0.00113	0.87165	53.880	0.06935	607.472
10	0.00001	0.00535	0.295	0.00029	2.541
13	0.00000	0.00013	0.004	0.00000	0.031
14	0.00021	0.17742	10.795	0.01266	110.899
15	0.00067	0.52376	45.318	0.05604	490.941
16	0.00010	0.08251	3.165	0.00362	31.750
18	0.00003	0.03086	2.402	0.00255	22.376
19	0.00201	1.51929	96.376	0.12820	1123.034
20	0.00006	0.05564	2.484	0.00273	23.956

Note: The indices at some buses are too small to be observed by MECORE and are marked with a -.

Table 2.10: Annualized and annual system indices for the IEEE-RTS (base case)

Indices	Annualized	Annual
ENLC (1/yr)	58.10550	1.52049
ADLC (hrs/disturbance)	12.69	11.56
EDLC (hrs/yr)	737.50	17.58
PLC	0.08419	0.00201
EDNS (MW)	14.833	0.276
EENS (MWh/yr)	129932.7	2413.923
EDC (k$/yr)	N/A	10186.755
BPII (MW/MW-yr)	3.66724	0.07539
BPECI (MWh/MW-yr)	45.590	0.847
BPACI (MW/disturbance)	179.873	141.305
MBECI (MW/MW)	0.00520	0.00010
SI (system minutes/yr)	2735.43	50.82

It can be seen from Tables 2.8 and 2.9 that the EENS at Buses 9, 14, 15 and 19 are much larger than those of the other buses in the IEEE-RTS. Table 2.4 shows that these four buses have the lowest four priorities, which has a strong influence on their reliability levels.

It can be seen based on the brief analysis of the base case studies of the two test systems that the load curtailment priority order has a significant impact on the individual load point indices. It can also be seen from Tables 2.5-2.10 that the annual indices are much lower than the annualized values. The annualized indices are obtained on the assumption that the system load resides at the peak level for the whole year and do not incorporate the actual load model in the analysis. All the reliability indices in the following studies in this thesis are annual values.

2.7. Summary

The basic objective of composite generation and transmission system adequacy assessment is to evaluate the ability of the system to generate electricity and deliver it to the major load points. Composite system adequacy assessment can be conducted using either analytical methods or Monte Carlo simulation techniques. Monte Carlo simulation techniques have the advantage when conducting assessments incorporating complex operating conditions.

Both load point and system indices can be used to measure the adequacy of a composite system. The function of the load point indices is to determine the actual adequacy at the connection points to the low voltage distribution systems. System indices are used to provide an overall appraisal of the system adequacy. The MECORE program can be used to calculate both load point and system indices.

The Monte Carlo method is the general designation for stochastic simulation using random numbers. There are three basic Monte Carlo simulation approaches used in power system reliability evaluation. They are designated as the state sampling technique, the state transition sampling technique and the sequential technique. Each method has its own merits and demerits.

The MECORE program is a Monte Carlo based composite generation and transmission system reliability evaluation software designed to perform reliability and reliability worth assessment of bulk electricity systems. It is based on the state sampling technique. All the analyses in this thesis were performed using this software. The concepts and methods illustrated in this thesis are based on analyses of the Roy Billinton Test System (RBTS) and the IEEE Reliability Test System (IEEE-RTS).

Load point and system indices can be categorized into annualized and annual values. Annualized indices are evaluated at the peak load and expressed on a one-year basis. Annual indices are evaluated incorporating the annual load model and provide a practical estimate of the expected annual performance of the system. Both annualized and annual indices are presented in this chapter to establish the base case indices for the RBTS and IEEE-RTS.

3. INCORPORATING MULTI-STATE GENERATING UNIT MODELS IN COMPOSITE SYSTEM ADEQUACY ASSESSMENT

3.1. Introduction

Components are usually represented by two-state models in conventional generating capacity (HLI) and composite generation and transmission system (HLII) reliability studies. Multi-state generating unit models create a significant increase in the number of generation contingency states and can result in a considerable increase in the overall solution time. In order to avoid this problem, the derated states are usually amalgamated with the totally forced out state to create a derating adjusted forced outage rate (DAFOR) [1]. It has been recognized, however, that modeling large generating units in generating capacity adequacy assessment by simple two-state models and DAFOR can yield pessimistic appraisals [1]. Many utilities now use multi-state models instead of two-state representations to assess generating capacity reliability in order to obtain a more accurate appraisal. There is very little published material dealing with the effects of using multi-state generating unit models in composite system adequacy assessment [35]. This issue is becoming more important as Gencos and Transcos work together to minimize their costs and therefore maximize their profits in the new electricity market.

In this chapter, load point and system reliability indices are presented using two-state and multi-state generating unit models to illustrate the impact of incorporating multi-state representations in composite system adequacy assessment. The reliability indices are calculated using different multi-state generating unit models to demonstrate the effect of model variations. Attention is focused on how many derated states should be used in a multi-state model to obtain a reasonably accurate appraisal. All the analyses in this chapter are based on the RBTS and the IEEE-RTS.

3.2. Establishment of Multi-state Generating Unit Models

The multi-state generating unit models used in a composite system adequacy assessment should be based on actual unit performance levels. There is relatively little material available on this issue in the published literature. Generating unit outage statistics including derated state data were collected for some time by the Edison Electric Institute (EEI) and published in their Annual Equipment Availability Report [36]. These profiles together with a technique called the apportioning method [37] were used to create the multi-state generating unit models used in the studies conducted on the two test systems. Generating unit outage statistics collected by EEI were introduced in Section 3.2.1 and the apportioning method is described in Section 3.2.2.

3.2.1. Generating Unit Outage Statistics

The Forced Outage Rate (FOR) for a generating unit is obtained by dividing the number of hours the unit is on forced outage by the total number of hours the unit is exposed to outage. Similarly, the Partial Forced Outage Rate (PFOR) for a given derated state is obtained by dividing the number of hours the unit is operated in the given forced derated state by the total number of hours the unit is exposed to outage. The PFOR are used in the apportioning method to create multi-state generating unit models. The EEI Annual Equipment Availability Reports provide PFOR for generating units of different sizes. The EEI data provide representative profiles based on the actual outage data for different types of generating units. Figure 3.1 shows the PFOR based on ten derated states for 60 ─ 89 MW units, 200 ─ 389 MW units and 390 ─ 599 MW units [36].

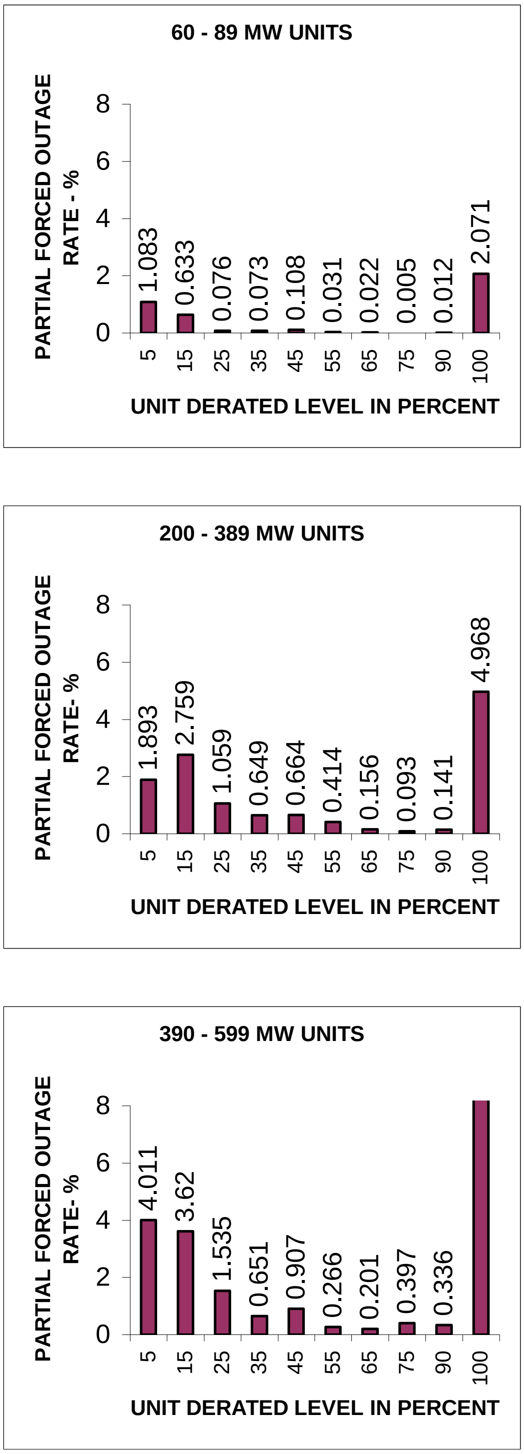


Figure 3.1: PFOR for the unit classifications covered in the Edison Electric Institute Equipment Availability Report

In Figure 3.1, the numbers on the abscissa are the generating unit derated levels in terms of percent capacity on outage. The EEI ranges for the three types of generating unit are 60 to 89 MW, 200 to 389 MW and 390 to 599 MW. The outage data profiles for the three generating units classes were used to build multi-state generating unit models for the 40-MW thermal units in the RBTS, and the 350-MW and the 400-MW generating units in the IEEE-RTS.

3.2.2. Building Multi-state Generating Unit Models Using the Apportioning Method

The apportioning method is introduced in this section. There are many derated states in which a generating unit can reside in the course of its operating history [37]. The requirement is to represent the generating unit by a specified reduced number of derated states. The state reduction method is based on apportioning the residence times of the actual derated states between the assigned derated state and the up (normal) or down (outage) states. The closer an "absorbed" state is to the assigned state, the more contribution it makes to the probability of the existence of that state. The apportioning method is explained in this section using Figures 3.2-3.4. In these figures, X_N are the original derated states and Y_N are the designated derated states. Y_{dn} (0) and Y_{up} (100) are the full forced out and full capacity states respectively. The percent capacity values shown on the abscissa in Figures 3.2 to 3.4 are the percent capacity in service.

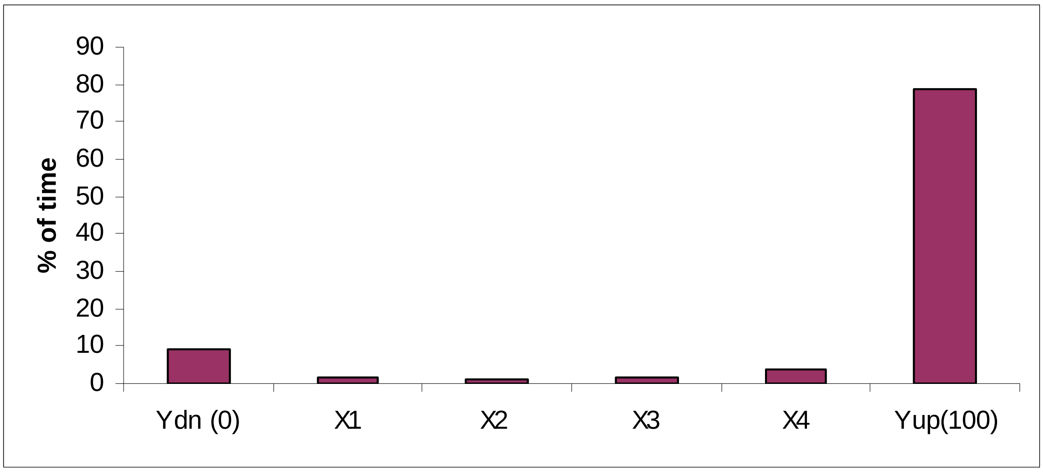


Figure 3.2: The original generating unit model

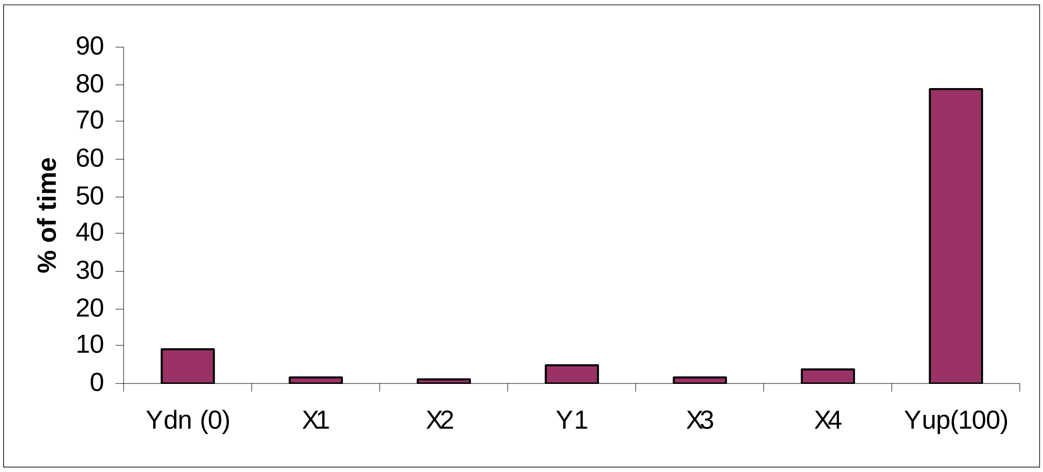


Figure 3.3: The "single-derated state" generating unit model

Figure 3.4: The "two-derated state" generating unit model

Where

X_N = a Nth original derated state capacity in percent of full capacity

Y_N = a Nth designated derated state capacity in percent of full capacity

Y_{dn} (0) = generating unit in the down state

Y_{up} (100) = generating unit in the up state

N =1,2……

Let

n = the number of derated states

$\Delta_X t_N$ = residence time of the original derated state of X_N

$\Delta_X t(Y_1)_N$ = apportioned time of the determined derated state Y_1 from the original derated state of X_N

$\Delta_X t(Y_2)_N$ = apportioned time of the determined derated state Y_2 from the original derated state of X_N

$\Delta_X t(Y_{up})_N$ = apportioned time of the up state from the original derated state of X_N

$\Delta_X t(Y_{dn})_N$ = apportioned time of the down state from the original derated state of X_N

T = total time spent in the up, derated and down states

T_{up} = time spent in the up state

T_{dn} = time spent in the down state

$PFOR_{X_N}$ = partial forced outage rate for a Nth original derated state capacity in percent of full capacity

P_{DN} = Probability of the generating unit in the down state

P_{UP} = Probability of the generating unit in the up state

P_{DEi} = Probability of the generating unit in the ith determined derated state

Note

$$\Delta_X t_N = PFOR_{X_N} \times T \tag{3.1}$$

For the "single-derated state" generating unit model shown in Figure 3.3, the procedure used to establish the model is as follows:

Assume $Y_1 \le X_N \le Y_{up}$

$$\Delta_X t(Y_1)_N = \frac{Y_{up} - X_N}{Y_{up} - Y_1} \Delta_X t_N \tag{3.2}$$

$$\Delta_X t(Y_{up})_N = \frac{X_N - Y_1}{Y_{up} - Y_1} \Delta_X t_N \tag{3.3}$$

And when $X_N \le Y_1 \le Y_{up}$

$$\Delta_X t(Y_1)_N = \frac{X_N - Y_{down}}{Y_1 - Y_{down}} \Delta_X t_N \tag{3.4}$$

$$\Delta_X t(Y_{dn})_N = \frac{Y_1 - X_N}{Y_1 - Y_{down}} \Delta_X t_N \tag{3.5}$$

P_{DN}, P_{UP} and P_{DE} are obtained as follows:

$$P_{DN} = \frac{T_{dn} + \sum_{N=1}^{n} \Delta_X t(Y_{dn})_N}{T} \tag{3.6}$$

$$P_{UP} = \frac{T_{up} + \sum_{N=1}^{n} \Delta_X t(Y_{up})_N}{T} \tag{3.7}$$

$$P_{DE} = \frac{\sum_{N=1}^{n} \Delta_X t(Y_1)_N}{T} \tag{3.8}$$

The procedure to establish the "two-derated state" generating unit model shown in Figure 3.4 is as follows:

Assume $Y_1 \geq Y_2$

When $Y_1 \leq X_N \leq Y_{up}$

$$\Delta_X t(Y_1)_N = \frac{Y_{up} - X_N}{Y_{up} - Y_1} \Delta_X t_N \tag{3.9}$$

$$\Delta_X t(Y_{up})_N = \frac{X_N - Y_1}{Y_{up} - Y_1} \Delta_X t_N \tag{3.10}$$

When $X_N \leq Y_2 \leq Y_{up}$

$$\Delta_X t(Y_2)_N = \frac{X_N - Y_{down}}{Y_2 - Y_{down}} \Delta_X t_N \tag{3.11}$$

$$\Delta_X t(Y_{dn})_N = \frac{Y_2 - X_N}{Y_2 - Y_{down}} \Delta_X t_N \tag{3.12}$$

When $Y_2 \leq X_N \leq Y_1$

$$\Delta_X t(Y_1)_N = \frac{X_N - Y_2}{Y_1 - Y_2} \Delta_X t_N \tag{3.13}$$

$$\Delta_X t(Y_2)_N = \frac{Y_1 - X_N}{Y_1 - Y_2} \Delta_X t_N \tag{3.14}$$

Therefore, P_{DN}, P_{UP} are obtained using Equations 3.6 and 3.7, and P_{DE1}, P_{DE2} are obtained using Equations 3.15 and 3.16:

$$P_{DE1} = \frac{\sum_{N=1}^{n} \Delta_X t(Y_1)_N}{T} \tag{3.15}$$

$$P_{DE2} = \frac{\sum_{N=1}^{n} \Delta_X t(Y_2)_N}{T} \tag{3.16}$$

As previously noted, derating adjusted forced outage rates (DAFOR) are used to replace the forced outage rates of large generating units in most HLI and HLII reliability studies. The term DAFOR is used by Canadian electric power utilities. In the United States, the designation for this statistic is the "equivalent forced outage rate" (EFOR). The EFOR or DAFOR is obtained using the apportioning method. The residence times of the actual derated states are apportioned between the up (normal) and down (outage) states. In this case, there are no assigned derated states. Equations 3.2 and 3.3 can be used to calculate the apportioned times in the down and up states from the original derated states. The DAFOR of a generating unit can be obtained using Equation 3.17.

$$\mathrm{DAFOR} = \frac{T_{dn} + \sum_{N=1}^{n} \Delta_X t(Y_1)_N}{T} \tag{3.17}$$

The two 40-MW thermal units in the RBTS, the two 400-MW generating units and the 350-MW generating unit in the IEEE-RTS were represented by three state models in [32] and [38]. The DAFOR of these three-state generating units are equal to the FOR of the same generating units with two-state representations. Table A.3 shows that the FOR of the two 40-MW thermal units in the RBTS is 0.03. The FOR of the two 400-MW generating units and the 350-MW generating unit in the IEEE-RTS are 0.12 and 0.08 respectively as shown in Table A.6. The FOR of these generating units in the RBTS and IEEE-RTS are not the same as the DAFOR calculated directly from the EEI data in Figures 3.1. The EEI data profiles were scaled down in order to provide the specified DAFOR for the RBTS and IEEE-RTS generating units. As an example, the percentage of time spent in the totally forced outage states in Figure 3.1 will change from 2.071, 4.968 and 8.954 to 2.7119, 6.1751 and 9.3596 respectively.

3.3. RBTS Analysis

The single line diagram of the RBTS is shown in Figure 2.1. The multi-state generating unit models in the RBTS were established using the 60 – 89 MW generating unit data profile in Figure 3.1. The annual indices for the RBTS were calculated using two-state, three-state and four-state generating unit models. Annual indices were also obtained for different model representations. The results of these studies are illustrated in this section.

3.3.1. Multi-state Generating Unit Models

The two 40-MW thermal units in the RBTS were given the optional three-state representation shown in Figure 3.5.

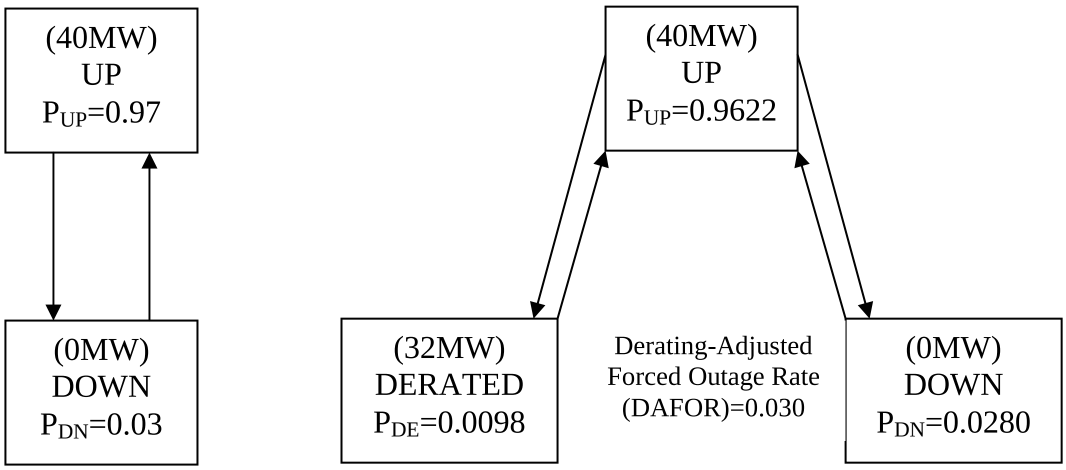


Figure 3.5: The two and three- state models for the 40-MW thermal generating units

The DAFOR in Figure 3.5 is 0.03. A four-state model for the 40 MW units in the RBTS is shown in Figure 3.6. This four-state generating unit model together with the two-state and three-state models are used in this section to illustrate how multi-state generating unit models affect composite system adequacy assessment.

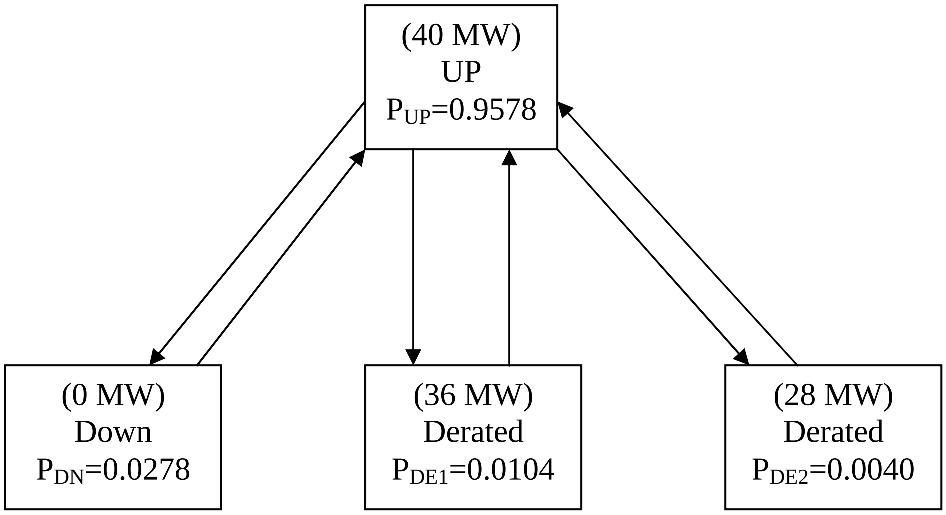


Figure 3.6: The four-state model for the 40-MW thermal generating units

The DAFOR in all three model representations should be equal to 0.03 and be obtained using Equation 3.18.

$$\mathrm{DAFOR} = \mathrm{P_{DN}} + \sum_{i=1}^{n} \frac{\mathrm{Cap.Curi}}{\mathrm{Cap}} \times \mathrm{P_{DEi}} \tag{3.18}$$

Where

DAFOR = Derating-adjusted forced outage rate

P_{DN} = Probability of the generating unit in the down state

Cap.Curi = Curtailed capacity of the generating unit in the ith derated state

Cap = Full capacity of the generating unit

P_{DEi} = Probability of the generating unit in the ith derated state

n = the number of generating unit derated states

3.3.2. Comparison of Annual Indices

The annual indices for the RBTS are compared using two-state and multi-state generating unit models in this section. The generating unit reliability data for the two-state, three-state and four-state models for the 40 MW thermal generating units are shown in Table 3.1.

Table 3.1: Reliability data for the RBTS 40-MW generating units

Model type	Cap (MW)	$Cap.Cur_1$ (MW)	$Cap.Cur_2$ (MW)	P_{DN}	P_{DE1}	P_{DE2}	DAFOR/ FOR
Two-state	40	-	-	0.03	-	-	0.03
Three-state	40	8	-	0.0280	0.0098	-	0.03
Four-state	40	4	12	0.0278	0.0104	0.0040	0.03

The annual system and load bus indices together with the required computing time considering the two-state, three-state and four-state models in Table 3.1 are given in Tables 3.2 and 3.3.

Table 3.2: Annual system indices for the RBTS

Name of indices	Two-state model	Three-state model		Four-state model	
		Indices	Diff. (%)	Indices	Diff. (%)
ENLC (1/yr)	1.27965	1.27230	-0.6	1.27198	-0.6
ADLC (hrs/dist.)	9.44535	9.42601	-0.2	9.42623	-0.2
EDLC (hrs/yr)	12.08675	11.99271	-0.8	11.98995	-0.8
PLC	0.00138	0.00137	-0.7	0.00137	-0.7
EDNS (MW)	0.01739	0.01726	-0.7	0.01724	-0.9
EENS (MWh/yr)	152.34970	151.18742	-0.8	151.01670	-0.9
EDC (k$/yr)	673.38568	668.24841	-0.8	667.49376	-0.9
BPII (MW/MW-yr)	0.08829	0.08778	-0.6	0.08771	-0.7
BECI (MWh/MW-yr)	0.82351	0.81723	-0.8	0.81631	-0.9
BPACI (MW/dist.)	12.76397	12.76372	0	12.75699	-0.1
MBECI (MW/MW)	0.00009	0.00009	0	0.00009	0
SI (sys mins/yr)	49.41072	49.03376	-0.8	48.97839	-0.9
Computing time (sec)	112.097	127.233		130.479	

Table 3.3: Annual load bus indices for the RBTS

Indices	Bus No.	Two-state model	Three-state model		Four-state model	
			Indices	Diff. (%)	Indices	Diff. (%)
PLC	2	0.00000	0.00000	0	0.00000	0
	3	0.00018	0.00017	-5.6	0.00017	-5.6
	4	0.00000	0.00000	0	0.00000	0
	5	0.00000	0.00000	0	0.00000	0
	6	0.00120	0.00120	0	0.00120	0

Table 3.3: (Continued)

Indices	Bus No.	Two-state model	Three-state model		Four-state model	
			Indices	Diff. (%)	Indices	Diff. (%)
ENLC (1/yr)	2	0.00000	0.00000	0	0.00000	0
	3	0.10162	0.09580	-5.7	0.09557	-6.0
	4	0.00109	0.00109	0	0.00109	0
	5	0.00554	0.00554	0	0.00551	-0.5
	6	1.18265	1.18084	-0.2	1.18070	-0.2
ELC (MW/yr)	2	0.000	0.000	0	0.000	0
	3	1.171	1.098	-6.2	1.087	-7.2
	4	0.008	0.008	0	0.008	0
	5	0.059	0.059	0	0.059	0
	6	15.095	15.075	-0.1	15.073	-0.1
EDNS (MW)	2	0.00000	0.00000	0	0.00000	0
	3	0.00201	0.00187	-7.0	0.00186	-7.5
	4	0.00000	0.00000	0	0.00000	0
	5	0.00003	0.00003	0	0.00003	0
	6	0.01535	0.01535	0	0.01535	0
EENS (MWh/yr)	2	0.000	0.000	0	0.000	0
	3	17.564	16.416	-6.5	16.251	-7.5
	4	0.038	0.038	0	0.038	0
	5	0.296	0.294	-0.7	0.293	-1.0
	6	134.452	134.439	-0	134.435	0

The percentage values in Table 3.2 and 3.3 show the difference between the reliability indices calculated using the two-state model, and the three-state and the four-state model. The base indices are those for the two-state model. The computing times are also included in Table 3.2. The computing times in Table 3.2 show that it is possible to use more precise generating unit models to conduct the assessment without taking significantly more computing time. The results in Table 3.2 and 3.3 indicate that reducing the range of derating levels to a two state representation can cause some inaccuracy in the calculated reliability indices. The results obtained using the DAFOR values are also pessimistic. This could result in additional investment in generation or transmission facilities and this is a big issue in the newly deregulated industry. It is therefore necessary to use a more comprehensive generating model when conducting composite system adequacy assessment.

3.3.3. Risk Sensitivity to Derated Capacity Level Selection

In this section, the reliability indices for the RBTS are presented and compared using different three-state and four-state generating unit models. The generating unit reliability data of seven three-state models for the 40 MW thermal generating units are shown in Table 3.4. These seven three-state generating unit models were established using the 60 – 89 MW generating unit data profile in Figure 3.1 and each has a different designated derated capacity level. The corresponding seven locations of Y_1 shown in Figure 3.3 are therefore different in each case. There is no single unique location for Y_i [37]. The set of annual system indices and the load bus indices using the different three-state models for the 40 MW units are given in Tables B.1 and B.2

Table 3.4: Reliability data for the three-state generating unit models of the RBTS 40-MW generating units

Indices	Model No.						
	1	2	3	4	5	6	7
Cap (MW)	40	40	40	40	40	40	40
Cap.Cur (MW)	14	12	10	8	6	4	2
P_{UP}	0.9656	0.9647	0.9636	0.9622	0.9596	0.9578	0.9524
P_{DN}	0.0276	0.0278	0.0279	0.0280	0.0282	0.0287	0.0291
P_{DE}	0.0068	0.0075	0.0085	0.0098	0.0122	0.0135	0.0185
DAFOR/ FOR	0.03	0.03	0.03	0.03	0.03	0.03	0.03

The RBTS base case analysis in Section 2.6.3 shows that the least reliable buses in the system are Bus 3 and Bus 6. The most common index in actual application is the EENS and therefore this index is selected to provide a pictorial representation of the effects of derated state modeling. The following analyses are focused on the EENS at Bus 3 and Bus 6, and for the system in order to illustrate how the different three-state generating unit models affect the calculated indices. These effects are shown in Figures 3.7-3.9.

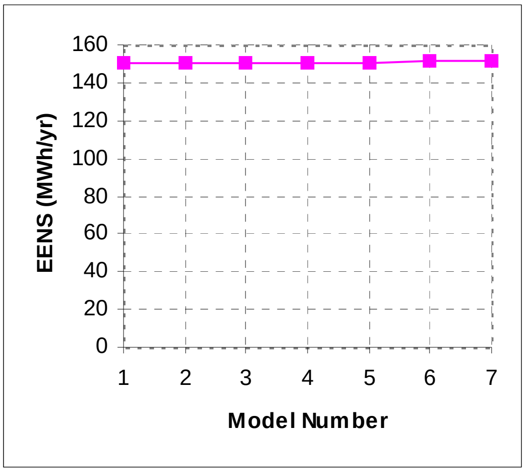


Figure 3.7: RBTS EENS for the seven three-state generating unit models

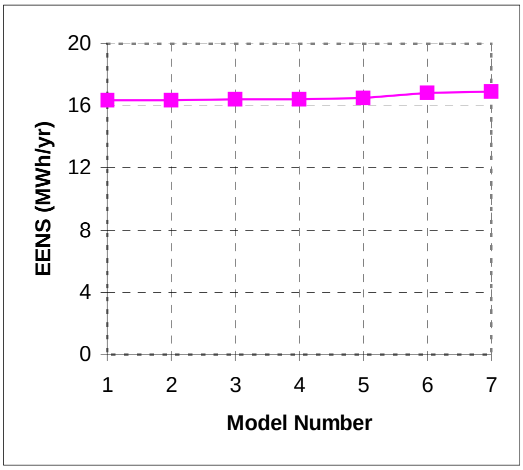


Figure 3.8: EENS at Bus 3 for the seven three-state generating unit models

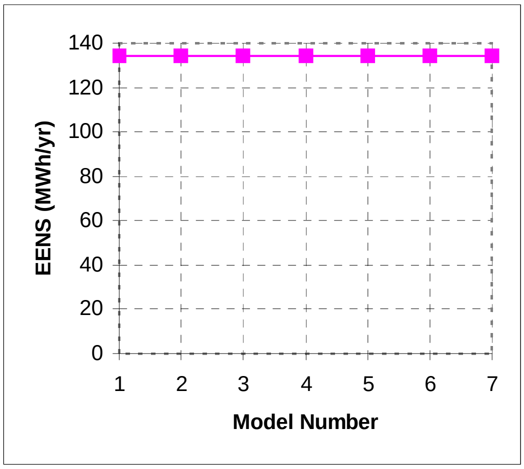


Figure 3.9: EENS at Bus 6 for the seven three-state generating unit models

It can be seen from Figures 3.7-3.9 that the EENS does not change very much with the different three-state models. The maximum variation occurs at Bus 3. The RBTS has a reasonably adequate generating system and therefore is not greatly affected by the model variations. As shown in Figure 2.1, Bus 6 is located away from the generation system and supplied by a single radial line. Its reliability is largely affected by transmission failures and the EENS at Bus 6 does not change significantly with the different three-state unit models. Bus 3 is supplied by four transmission lines and has the lowest load curtailment priority. Its reliability is mainly affected by generation failures and its load will be curtailed when load shedding occurs in the system. The EENS at Bus 3 is therefore directly affected by the different three-state generating unit models. It can be concluded that the effect of different three-state generating unit models on the load bus indices depends on the network topology and the load curtailment philosophy.

A similar analysis was conducted using seven different four-state generating unit models.

The generating unit reliability data for the seven four-state models for the 40 MW thermal generating units are shown in Table 3.5. The seven four-state generating unit models were established using the 60 – 89 MW generating unit data profile in Figure 3.1. and have different designated derated capacity levels. The corresponding locations of Y_1 and Y_2 as shown in Figure 3.4 are therefore different in each case. The annual system indices and the load bus indices using the different four-state models are given in Tables B.3 and B.4.

Table 3.5: Reliability data for the four-state generating unit models of the RBTS 40-MW generating units

Indices	Model No.						
	1	2	3	4	5	6	7
Cap (MW)	40	40	40	40	40	40	40
Cap.Cur1 (MW)	7	6	5	4	3	2	1
Cap.Cur2 (MW)	15	14	13	12	11	10	9
P_{UP}	0.9610	0.9597	0.9589	0.9578	0.9561	0.9524	0.9525
P_{DN}	0.0276	0.0276	0.0277	0.0278	0.0278	0.0279	0.0280

Table 3.5: (Continued)

Indices	Model No.						
	1	2	3	4	5	6	7
P_{DE1}	0.0091	0.0103	0.0102	0.0104	0.0113	0.0140	0.0118
P_{DE2}	0.0023	0.0024	0.0032	0.0040	0.0048	0.0057	0.0077
DAFOR/ FOR	0.03	0.03	0.03	0.03	0.03	0.03	0.03

The effects on the EENS for the system and Bus 3 and 6 due to the seven different four-state generating unit models are shown in Figures 3.10-3.12.

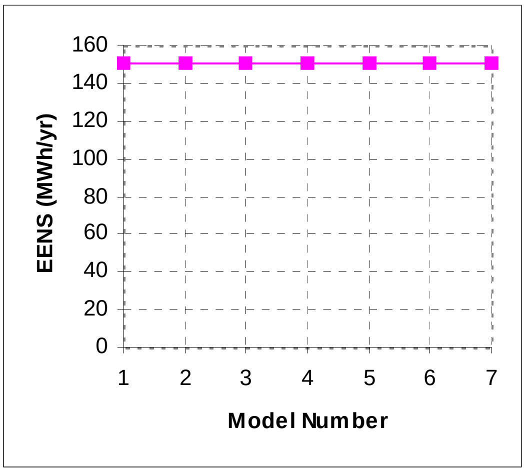


Figure 3.10: RBTS EENS for the seven four-state generating unit models

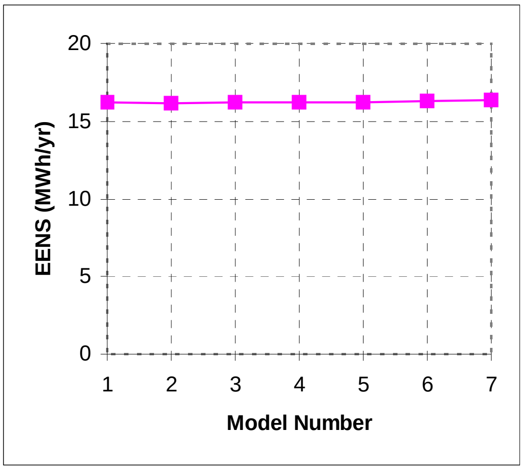


Figure 3.11: EENS at Bus 3 for the seven four-state generating unit models

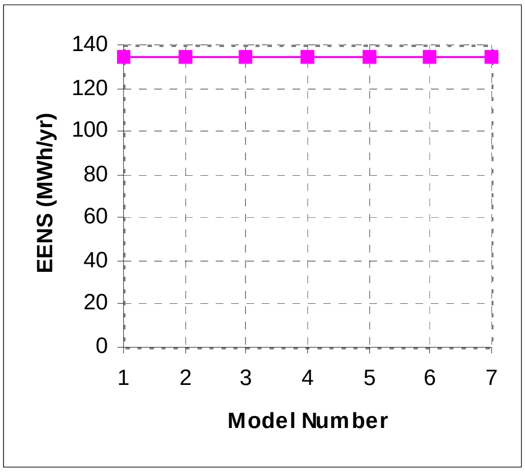


Figure 3.12: EENS at Bus 6 for the seven four-state generating unit models

It can be seen from Figures 3.10-3.12 that the EENS values do not change significantly with the different four-state generating unit models. The conclusion is basically the same as that drawn from the analysis of the three-state generating unit models. The system indices for the RBTS are not significantly affected by the changes in the generating unit models. The effect of the different four-state generating unit models on the load bus indices depends on the network topology and load curtailment philosophy.

These studies show that the selection of the designated derating levels is not very important in an analysis of the RBTS. This conclusion relates directly to the RBTS and cannot be universally applied to all systems. This is illustrated later in regard to the IEEE-RTS. The RBTS can be considered to have a relatively strong generation system at the peak load level of 185 MW.

3.3.4. Comparison of the Two-state, Three-state and Four-state Generating Unit Models

Reference 1 illustrates that the using two-state generating unit models can result in a significant error in the load carrying capacity of a generation system at a specified criterion risk. It also shows [1] that the load carrying capacity is further increased by using more derated states in the analysis. The bulk of the benefit in load carrying capacity occurs when three-state models are used and therefore three-state representations are often used in actual practice. The system and load bus indices calculated using the two-state, three-state and four-state generating unit models can be compared to demonstrate the effects of multi-state generating unit models on the calculated indices. The system load level has a significant effect on the system and load bus indices. The peak load level for the RBTS is assumed to vary from 160 MW to 200 MW in the following analysis. The two-state, three-state and four-state model data for the 40 MW thermal generating units are given in Table 3.1. Table B.5 shows the annual system indices for the three different generating unit models at different peak load levels. The annual load bus indices are shown in Tables B.6 – B.8.

The annual EENS for the system and for Bus 3 and 6 as a function of peak load for the three different generating unit models are shown in Figures 3.13 – 3.15.

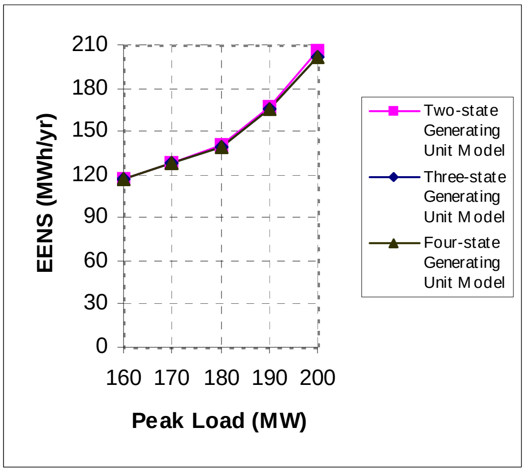


Figure 3.13: RBTS EENS versus peak load for the different generating unit models

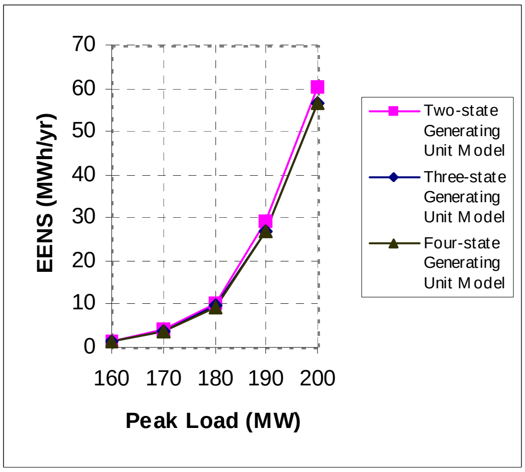


Figure 3.14: EENS at Bus 3 versus peak load for the different generating unit models

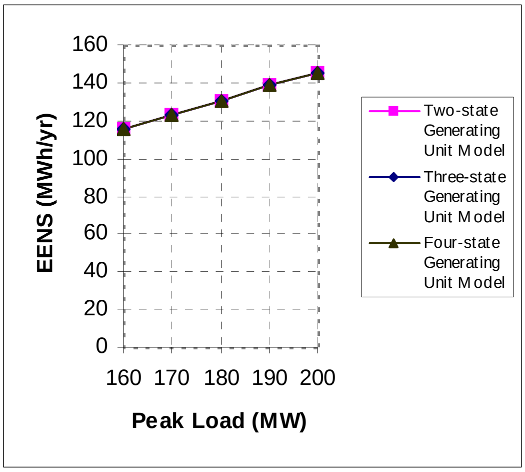


Figure 3.15: EENS at Bus 6 versus peak load for the different generating unit models

It can be seen from Figures 3.13 – 3.15 that as the system peak load increases, the annual system and load bus indices calculated using the three-state and four-state generating unit models decrease relative to those obtained using the traditional two-state generating unit model. This decrease is relatively small in the RBTS analysis and can be seen more clearly from the numerical values in Tables B.5-B.8. As noted in [1] regarding generating capacity assessment, the use of traditional two-state models for large generating units provides a pessimistic appraisal of the system risk. This also applies to the system and load point reliability in a composite system study. The results shown in Tables B.5-B.8 indicate that the bulk of the change in the predicted indices occur by using a three-state representation rather than the traditional DAFOR, and that there is relatively little further change by using a four-state representation. This suggests that from a practical point of view, three-state generating unit models are sufficiently accurate for studies of the RBTS. This is not a universal conclusion and is highly dependent on the studied system composition and load profile. This is illustrated in the following sections by application to the IEEE-RTS.

3.4. IEEE-RTS Analysis

The RBTS was developed for education and research purposes. The IEEE-RTS is a relatively large system compared to the RBTS and is much closer in composition to an actual power system. The single line diagram of the IEEE-RTS is shown in Figure 2.2. In this section, similar studies to those presented in Section 3.3 are presented using the

IEEE-RTS. The multi-state generating unit models for the IEEE-RTS were established using the 200 – 389 MW and 390 – 599 MW generating unit data profiles in Figure 3.1.

3.4.1. Multi-state Generating Unit Models

The two 400-MW generating units and the 350-MW generating unit in the IEEE-RTS were given three-state representations. The three-state representation for the two 400-MW generating units is shown in Figure 3.16.

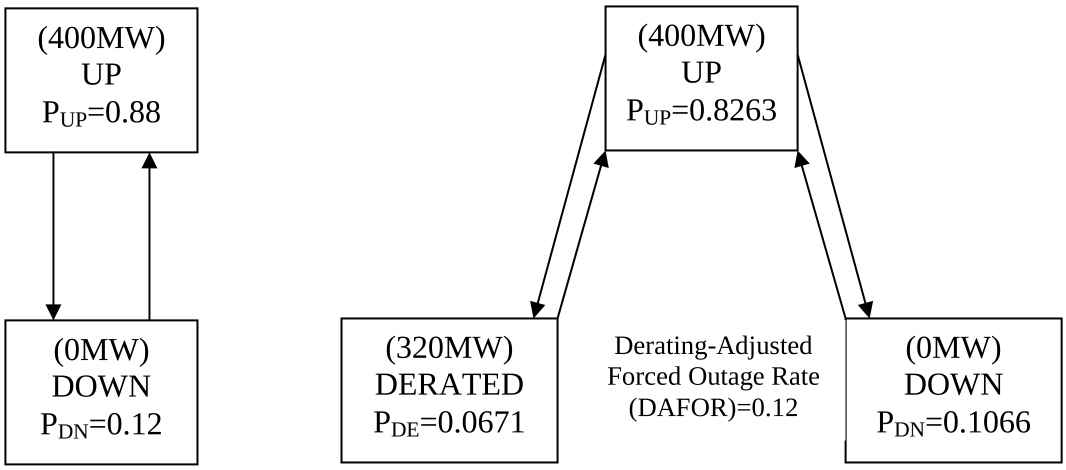


Figure 3.16: The two and three- state models for a 400-MW generating unit

The DAFOR in both of the models shown in Figure 3.16 is 0.12. The four-state model for the 400 MW thermal generating units is shown in Figure 3.17.

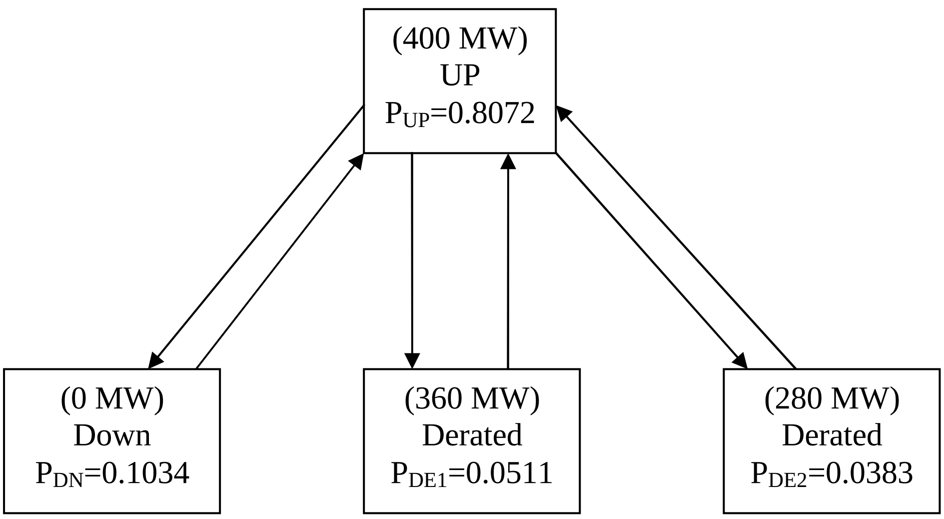


Figure 3.17: The four-state model for a 400-MW generating unit

The DAFOR in the four state model shown in Figure 3.17 is again 0.12, and can be determined using Equation 3.18.

The two-state, three-state and four-state representations of the 350-MW generating unit are shown in Figures 3.18 and 3.19.

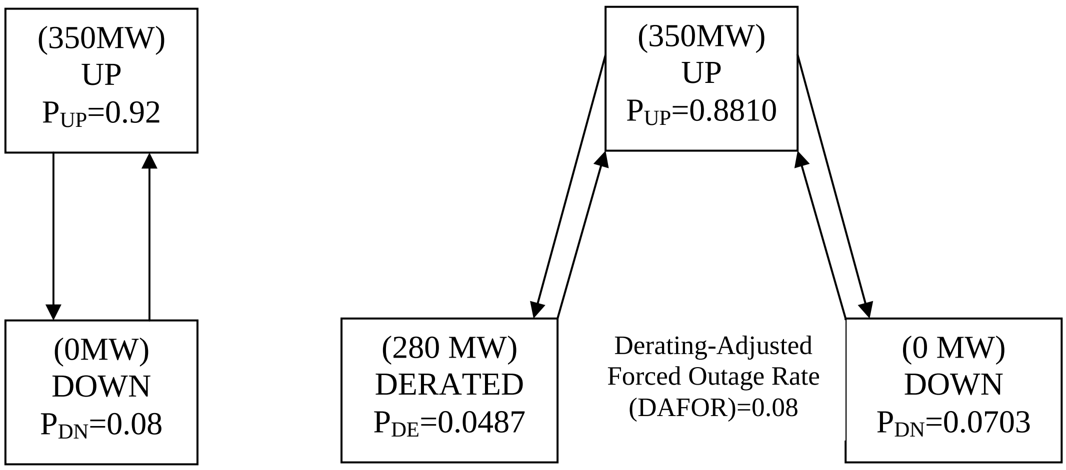


Figure 3.18: The two and three- state models for the 350-MW generating unit

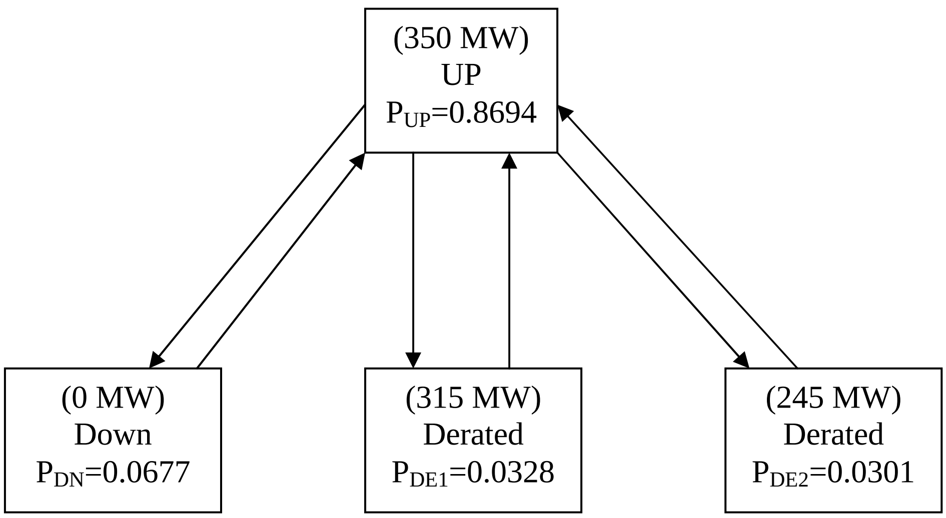


Figure 3.19: The four-state model for the 350-MW generating unit

The DAFOR in Figures 3.18 and 3.19 is 0.08 in each case.

3.4.2. Comparison of Annual Indices

The analysis in this section is quite similar with that presented for the RBTS in Section 3.3.2. The annual indices for the IEEE-RTS are compared using two-state and multi-state generating unit models. The generating unit reliability data of the two-state, three-state and four-state models for the 400 MW and 350 MW generating units are shown in Table 3.6.

Table 3.6: Reliability data for the IEEE-RTS 400-MW and 350-MW generating units

Model type	Cap (MW)	$Cap.Cur_1$ (MW)	$Cap.Cur_2$ (MW)	P_{DN}	P_{DE1}	P_{DE2}	DAFOR/ FOR
Two-state	400	-	-	0.12	-	-	-
	350	-	-	0.08	-	-	-
Three-state	400	80	-	0.1066	0.0671	-	0.12
	350	70	-	0.0703	0.0487	-	0.08
Four-state	400	40	120	0.1034	0.0511	0.0383	0.12
	350	35	105	0.0677	0.0328	0.0301	0.08

The annual system and load bus indices together with the required computing time considering the two-state, three-state and four-state models for the 400 MW and 350 MW generating units in Table 3.6 are given in Tables 3.7 and 3.8.

Table 3.7: Annual system indices for the IEEE-RTS

Indices	Two-state model	Three-state model		Four-state model	
		Indices	Diff. (%)	Indices	Diff. (%)
ENLC (1/yr)	1.52049	1.33277	-12.3	1.28366	-15.6
ADLC (hrs/dist.)	11.56395	11.57540	+0.1	11.55139	-0.11
EDLC (hrs/yr)	17.58358	15.42802	-12.3	14.82872	-15.7
PLC	0.00201	0.00176	-12.4	0.00169	-15.9
EDNS (MW)	0.27556	0.23523	-14.6	0.22477	-18.4
EENS (MWh/yr)	2413.92314	2060.64060	-14.6	1968.99995	-18.4
EDC (k$/yr)	10186.75491	8695.90342	-14.6	8309.17954	-18.4
BPII (MW/MW-yr)	0.07539	0.06452	-14.4	0.06167	-18.2
BECI (MWh/MW-yr)	0.84699	0.72303	-14.6	0.69088	-18.4
BPACI (MW/dist.)	141.30454	137.97528	-2.4	136.91434	-3.1
MBECI (MW/MW)	0.00010	0.00008	-20.0	0.00008	-20.0
SI (sys mins/yr)	50.81941	43.38190	-14.6	41.45263	-18.4
Computing time (sec)	292.809	427.698		463.780	

Table 3.8: Annual load bus indices for the IEEE-RTS

Indices	Bus No.	Two-state model	Three-state model		Four-state model	
			Indices	Diff. (%)	Indices	Diff. (%)
PLC	2	0	0	-	0	-
	3	0	0	-	0	-
	6	0	0	-	0	-
	7	0	0	-	0	-
	8	0	0	-	0	-
	9	0.00113	0.00097	-14.2	0.00093	-17.7
	10	0.00001	0	-100.0	0	-100.0
	13	0	0	-	0	-
	14	0.00021	0.00017	-19.0	0.00016	-23.8
	15	0.00067	0.00056	-16.4	0.00053	-20.9
	16	0.0001	0.00008	-20.0	0.00007	-30.0
	18	0.00003	0.00003	0	0.00003	0
	19	0.00201	0.00176	-12.4	0.00169	-15.9
	20	0.00006	0.00005	-16.7	0.00005	-16.7
ENLC (1/yr)	2	0.0014	0.0013	-7.1	0.00101	-27.9
	3	0.00082	0.00066	-19.5	0.00063	-23.2
	6	0.00075	0.00075	0	0.00075	0
	7	0.00041	0.00041	0	0.00041	0
	8	0.00004	0.00004	0	0.00004	0
	9	0.87165	0.75137	-13.8	0.72435	-16.9
	10	0.00535	0.00425	-20.6	0.00376	-29.7
	13	0.00013	0.00011	-15.4	0.00012	-7.7
	14	0.17742	0.14714	-17.1	0.13707	-22.7
	15	0.52376	0.44337	-15.3	0.42205	-19.4
	16	0.08251	0.06777	-17.9	0.06327	-23.3
	18	0.03086	0.02493	-19.2	0.0228	-26.1
	19	1.51929	1.33158	-12.4	1.28247	-15.6
	20	0.05564	0.04523	-18.7	0.04134	-25.7
ELC (MW/yr)	2	0.049	0.042	-14.3	0.036	-26.5
	3	0.027	0.027	0	0.023	-14.8
	6	0.052	0.052	0	0.052	0
	7	0.004	0.004	0	0.004	0
	8	0	0.001	-	0	-
	9	53.88	46.27	-14.1	44.397	-17.6
	10	0.295	0.234	-20.7	0.216	-26.8
	13	0.004	0.005	+25.0	0.005	+25.0
	14	10.795	8.914	-17.4	8.296	-23.1
	15	45.318	38.248	-15.6	36.219	-20.1
	16	3.165	2.578	-18.5	2.388	-24.5
	18	2.402	1.909	-20.5	1.747	-27.3
	19	96.376	83.616	-13.2	80.554	-16.4
	20	2.484	1.99	-19.9	1.813	-27.0

Table 3.8: (Continued)

Indices	Bus No.	Two-state model	Three-state model		Four-state model	
			Indices	Diff. (%)	Indices	Diff. (%)
EDNS (MW)	2	0.00005	0.00004	-20.0	0.00003	-40.0
	3	0.00002	0.00002	0	0.00002	0
	6	0.00003	0.00003	0	0.00003	0
	7	0	0	-	0	-
	8	0	0	-	0	-
	9	0.06935	0.05938	-14.4	0.05687	-18.0
	10	0.00029	0.00023	-20.7	0.00021	-27.6
	13	0	0	-	0	-
	14	0.01266	0.01044	-17.5	0.0097	-23.4
	15	0.05604	0.04714	-15.9	0.04458	-20.4
	16	0.00362	0.00295	-18.5	0.00272	-24.9
	18	0.00255	0.00204	-20.0	0.00186	-27.1
	19	0.1282	0.11075	-13.6	0.10673	-16.7
	20	0.00273	0.0022	-19.4	0.002	-26.7
EENS (MWh/yr)	2	0.397	0.333	-16.1	0.281	-29.2
	3	0.215	0.209	-2.8	0.179	-16.7
	6	0.293	0.293	0	0.293	0
	7	0.021	0.021	0	0.021	0
	8	0.002	0.004	+100.0	0.003	+50.0
	9	607.472	520.189	-14.4	498.183	-18.0
	10	2.541	2.002	-21.2	1.826	-28.1
	13	0.031	0.04	+29.0	0.033	+6.5
	14	110.899	91.496	-17.5	85.001	-23.4
	15	490.941	412.905	-15.9	390.503	-20.5
	16	31.75	25.841	-18.6	23.869	-24.8
	18	22.376	17.857	-20.2	16.271	-27.3
	19	1123.034	970.144	-13.6	934.991	-16.7
	20	23.956	19.312	-19.4	17.552	-26.7

It can be seen from Tables 3.7 and 3.8 that reducing the number of generating unit states can have a big impact on the system and load bus indices in a relatively large system such as the IEEE-RTS. The computing times shown in Table 3.7 increase considerably when multi-state generating unit models are incorporated in the assessment. It can be seen, however, that traditional two-state generating unit models can provide a pessimistic appraisal and it is possible to use more comprehensive generating unit models to obtain a more accurate appraisal without taking an unreasonable amount of computing time.

3.4.3. Risk Sensitivity to Derated Capacity Level Selection

In this section, the reliability indices for the IEEE-RTS are presented and compared using different three-state and four-state generating unit models. The generating unit reliability data of seven three-state models for the 400 MW and 350 MW generating units are shown in Table 3.9. The seven three-state generating unit models were established using the 200 – 389 MW and 390 – 599 MW generating unit data profiles in Figure 3.1. The set of annual system indices and load bus indices considering the different three-state models are given in Tables B.9 and B.10.

Table 3.9: Reliability data for the three-state models of the IEEE-RTS 400-MW and 350-MW generating units

Model No.	Cap (MW)	Cap.Cur (MW)	P_{UP}	P_{DN}	P_{DE}	DAFOR/ FOR
1	400	140	0.8466	0.1020	0.0514	0.12
	350	70	0.8810	0.0703	0.0487	0.08
2	400	120	0.8412	0.1034	0.0554	0.12
	350	70	0.8810	0.0703	0.0487	0.08
3	400	100	0.8337	0.1046	0.0617	0.12
	350	70	0.8810	0.0703	0.0487	0.08
4	400	80	0.8263	0.1066	0.0671	0.12
	350	70	0.8810	0.0703	0.0487	0.08
5	400	60	0.8139	0.1083	0.0778	0.12
	350	70	0.8810	0.0703	0.0487	0.08
6	400	40	0.8072	0.1119	0.0809	0.12
	350	70	0.8810	0.0703	0.0487	0.08
7	400	20	0.7872	0.1151	0.0977	0.12
	350	70	0.8810	0.0703	0.0487	0.08

The IEEE-RTS is a relatively large system compared to the RBTS and is divided into two regions designated as north and south. It can be seen from the IEEE-RTS base case analysis in Section 2.6.4 that the least reliable buses in the system are Buses 9 (south region), 14, 15 and 19 (north region). The following analyses are therefore focused on the EENS of Buses 9, 14, 15 and 19, and the system EENS in order to illustrate the impact of using three-state generating unit models on the system and load bus indices.

The EENS for the system and for Buses 9, 14, 15 and 19 with the seven different three-state generating unit models are shown in Figures 3.20-3.24.

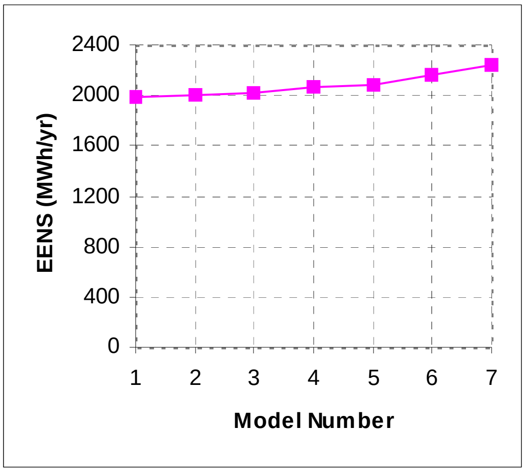


Figure 3.20: IEEE-RTS EENS for the seven three-state generating unit models

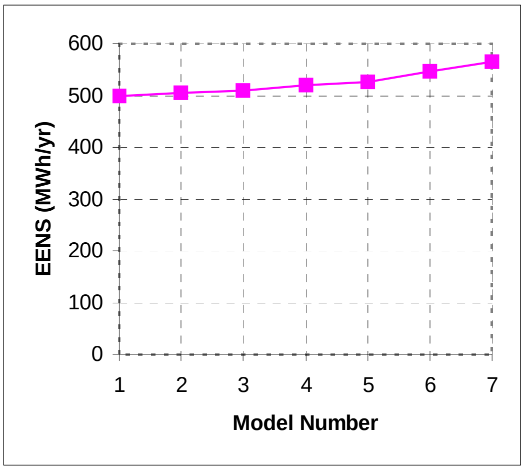


Figure 3.21: EENS at Bus 9 for the seven three-state generating unit models

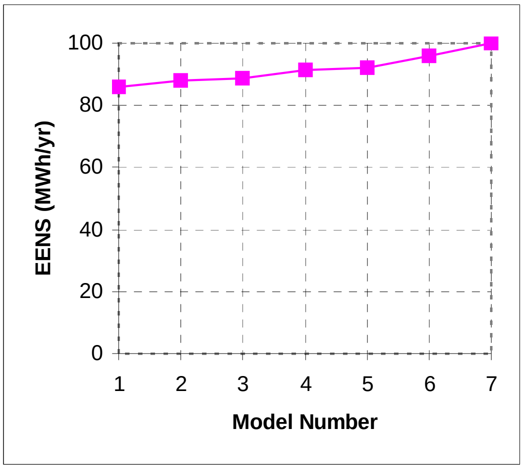


Figure 3.22: EENS at Bus 14 for the seven three-state generating unit models

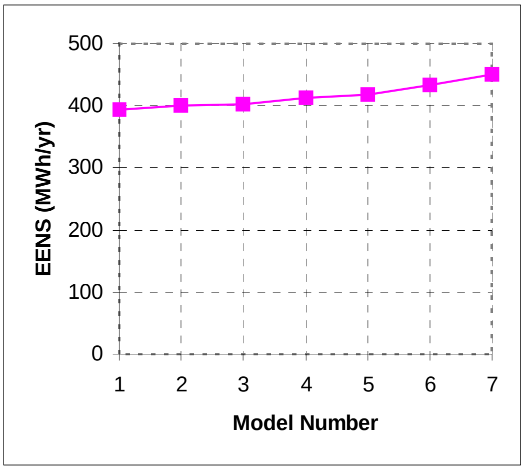


Figure 3.23: EENS at Bus 15 for the seven three-state generating unit models

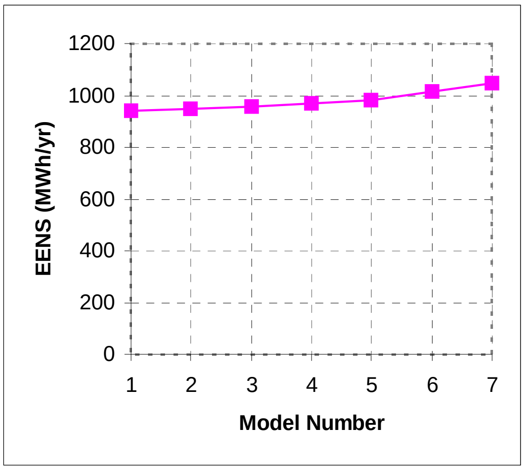


Figure 3.24: EENS at Bus 19 for the seven three-state generating unit models

It can be seen from Figures 3.20-3.24 that the EENS for the overall system and for the load buses are affected significantly by the different three-state generating unit models. In a system like the IEEE-RTS, which is considered to have a relatively strong transmission system, the load bus indices are not greatly influenced by where the load points are located. Bus 14, 15 and 19 are located in the north region where the most of the generating units reside, and Bus 9 resides in the south region that is relatively far removed from the generation center. All these buses, however, have very low load curtailment priorities and therefore their indices are affected by the different three-state generating unit models. The selected derated capacity level in the three-state generating unit models is therefore important in these cases.

The reliability data for the seven four-state models are shown in Table 3.10. The numerical values of the annual system and load bus indices considering the different four-state models are given in Tables B.11 and B.12.

Table 3.10: Reliability data for the four-state models of the IEEE-RTS 400-MW and 350-MW generating units

Model No.	Cap (MW)	Cap.Cur1 (MW)	Cap.Cur2 (MW)	P_{UP}	P_{DN}	P_{DE1}	P_{DE2}	DAFOR/ FOR
1	400	70	150	0.8210	0.1015	0.0529	0.0246	0.12
	350	35	105	0.8694	0.0677	0.0328	0.0301	0.08
2	400	60	140	0.8139	0.1021	0.0572	0.0268	0.12
	350	35	105	0.8694	0.0677	0.0328	0.0301	0.08
3	400	50	130	0.8112	0.1027	0.0535	0.0326	0.12
	350	35	105	0.8694	0.0677	0.0328	0.0301	0.08
4	400	40	120	0.8072	0.1034	0.0511	0.0383	0.12
	350	35	105	0.8694	0.0677	0.0328	0.0301	0.08
5	400	30	110	0.8005	0.1040	0.0513	0.0442	0.12
	350	35	105	0.8694	0.0677	0.0328	0.0301	0.08
6	400	20	100	0.7872	0.1046	0.0582	0.0500	0.12
	350	35	105	0.8694	0.0677	0.0328	0.0301	0.08
7	400	10	90	0.7871	0.1056	0.0487	0.0586	0.12
	350	35	105	0.8694	0.0677	0.0328	0.0301	0.08

The effects on the system EENS and the EENS of Buses 9, 14, 15 and 19 due to the seven different four-state generating unit models are shown in Figures 3.25-3.29.

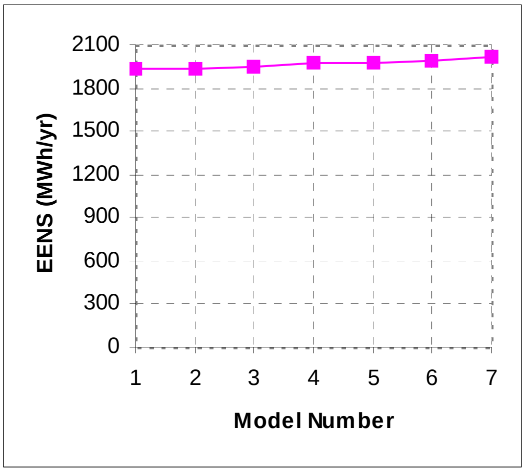


Figure 3.25: IEEE-RTS EENS for the seven four-state generating unit models

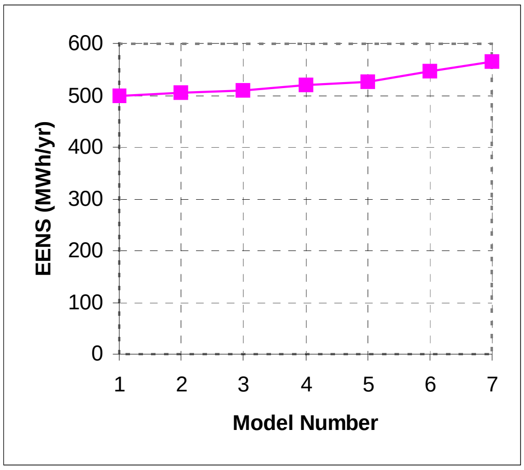


Figure 3.26: EENS at Bus 9 for the seven four-state generating unit models

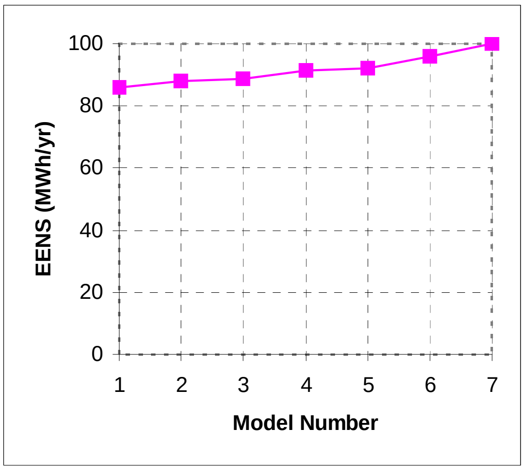


Figure 3.27: EENS at Bus 14 for the seven four-state generating unit models

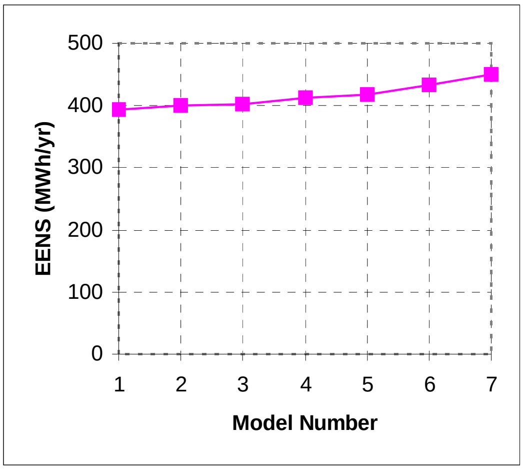


Figure 3.28: EENS at Bus 15 for the seven four-state generating unit models

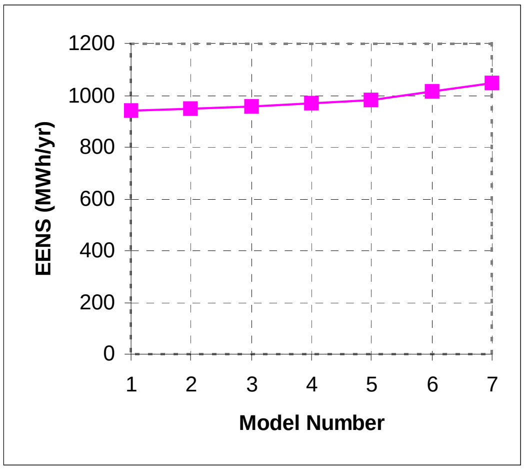


Figure 3.29: EENS at Bus 19 for the seven four-state generating unit models

It can be seen from Figure 3.25-3.29 that the system and load bus indices are significantly affected by the different four-state generating unit models. The conclusion is therefore similar to that shown in Section 3.4.3. The selected derated capacity levels in the four-state generating unit model impact the calculated indices and should be carefully considered.

The two sets of studies clearly show that in the case of the IEEE-RTS, the derated capacity levels in the multi-state generating unit models should be selected carefully as they significantly affect the system and load bus indices. The impact of multi-state generating unit is larger than that in the RBTS because the IEEE-RTS has a comparably weak generation system.

3.4.4. Comparison of the Two-state, Three-state and Four-state Generating Unit Models

The system and load bus indices calculated using the two-state, three-state and four-state generating unit models are compared in this section,. The peak load level for the IEEE-RTS is assumed to vary from 2500 MW to 3100 MW in the following analysis. The reliability data for the two-state, three-state and four-state models of the 400 MW and 350 MW generating units are shown in Table 3.7. Table B.13 shows the annual system indices with the three different generating unit models at different peak load levels. The annual load bus indices are shown in Tables B.14 to B.16.

The annual system EENS and the EENS of Buses 9, 14, 15 and 19 as a function of the peak load for the three different generating unit models are shown in Figures 3.30-3.34.

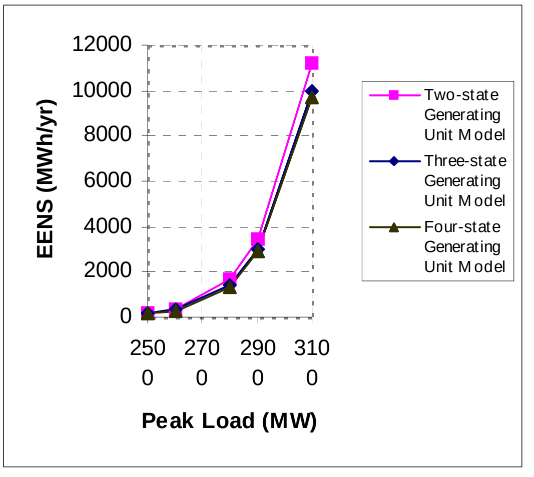


Figure 3.30: IEEE-RTS EENS versus peak load for the different generating unit models

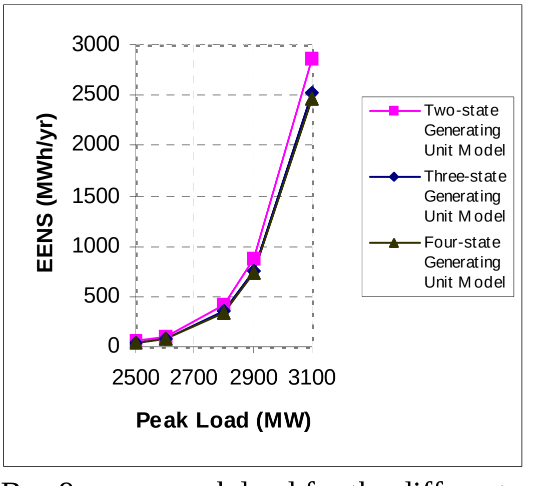


Figure 3.31: EENS at Bus 9 versus peak load for the different generating unit models

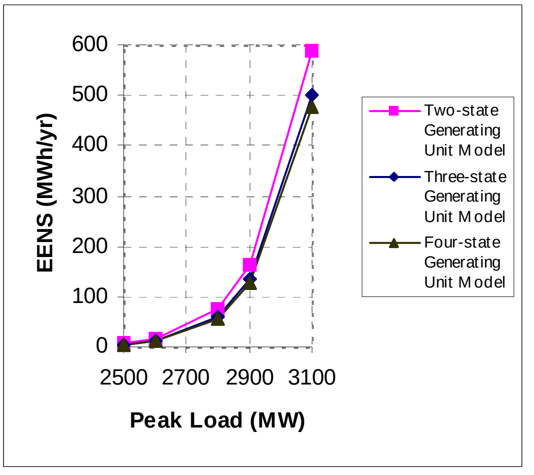


Figure 3.32: EENS at Bus 14 versus peak load for the different generating unit models

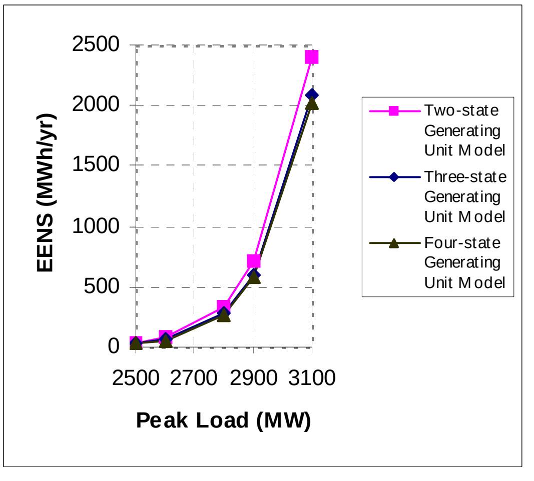


Figure 3.33: EENS at Bus 15 versus peak load for the different generating unit models

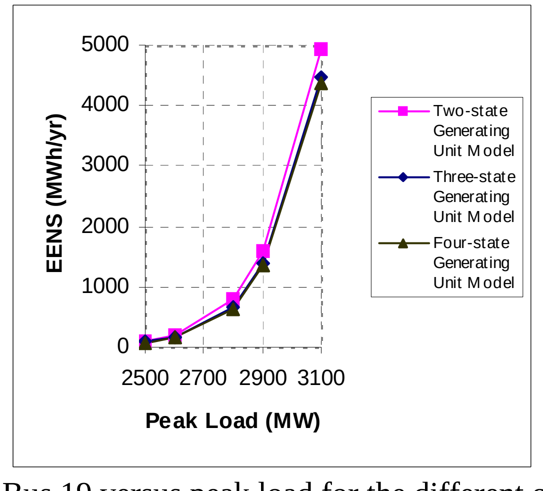


Figure 3.34: EENS at Bus 19 versus peak load for the different generating unit models

Figures 3.30 – 3.34 clearly show that when the system peak load increases, the annual system and load bus indices calculated using the three-state and four-state generating unit models decrease relative to those calculated using the traditional two-state generating unit model. This can also be seen from the numerical data in Tables B.13 to B.16. As in the previous study dealing with the RBTS, the traditional two-state generating unit model creates a pessimistic appraisal of composite system adequacy assessment and at least three states should be used in modeling large generating units.

3.5. Summary

In this chapter, the EEI outage data for three generating unit classes are used with the apportioning method to establish multi-state generating unit models for the RBTS and the IEEE-RTS. Load point and system reliability indices are presented for the two test systems using two-state and multi-state models for selected generating units.

The studies in this chapter show that it is important to incorporate multi-state generating unit models in composite system adequacy assessment and that the traditional two-state generating unit model can lead to pessimistic appraisals. It is also possible to use more comprehensive generating unit models without taking significantly more computing time.

The selection of the designated derated capacity level in a multi-state generating unit model is important in some circumstances and should be done carefully as the system and load bus indices can be significantly affected in these cases. This is especially true in a large system such as the IEEE-RTS, which has a relatively weak generation system.

The composite system analyses conducted on the RBTS and the IEEE-RTS show that there is a significant decrease in the predicted reliability indices by using a three state generating unit representation for the large generating units rather than the traditional DAFOR. The indices decrease further by using more states in the large unit models. This decrease is considerable less than that created using a three-state model. In many cases, the three-state representation will provide a reasonable assessment and can be used in practical system studies. The need to use more states will depend on the size of the largest units relative to the total system capacity and the magnitude of the peak load relative to the total installed capacity.

4. INCORPORATING SYSTEM PERFORMANCE INDICES IN COMPOSITE SYSTEM ADEQUACY ASSESSMENT

4.1. Introduction

There are two basic types of bulk electricity system performance indices. These are predictive indices and past performance indices. Predictive indices provide relevant estimates of future system reliability and are normally associated with system planning. On the other hand, past performance indices reflect the actual system reliability and are therefore related to the actual operation of the system.

Performance-based Regulation (PBR) is a new proposed regulatory approach, which sets rates, or components of rates, for a period of time based on external indices rather than a utility's cost-of-service. The PBR approach is already in the test phase in some electricity distribution industry utilities [25]. In the field of composite generation and transmission systems, PBR is under consideration and bulk electricity system performance indices will be key factors in this regulatory approach. The most common system performance indices in composite ststems are the System Average Interruption Frequency Index (SAIFI), the System Average Interruption Duration Index (SAIDI), the System Average Restoration Index (SARI) and the Delivery Point Unreliability Index (DPUI). This chapter presents some past performance indices that illustrate how Canadian power systems have performed over the last nine years. These data were collected by the participating utilities and compiled by the Canadian Electricity Association (CEA) as part of their Electric Power System Reliability Assessment protocol [39]. This chapter also presents a procedure that can be used to calculate predictive indices to estimate the future performance of power systems. This procedure is illustrated using the RBTS and the IEEE-RTS. The bulk system performance indices used in the analyses are the SAIFI, SAIDI, SARI and DPUI parameters.

4.2. Basic CEA Data Analysis

A comparison of the SAIFI, SAIDI and SARI indices for the 1993−1997, 1994−1998, 1995−1999, 1996−2000 and 1997−2001 periods are presented in this section. These indices were collected and published by the CEA [39]. The purpose of this comparison is to show how the performance has changed with time using the three system performance indices. The time period used to display the basic CEA data is five years, and therefore the SAIFI, SAIDI and SARI indices are rolling five year average values.

The following is a summary of the relevant terms used in the CEA bulk system reliability performance protocol [39].

- Bulk Electricity System (BES)

The Bulk Electricity System (BES) is composed of the power resources, the transmission system that includes buses, switching equipment and circuits of 50 kV and above, all transformers connected to those buses or circuits and low side buses associated with these transformers. It does not include the distribution system.

- Delivery Point (DP)

The delivery point is the point of supply where the energy from the BES is transferred to the distribution system or the retail customer. This point is generally taken as the low voltage busbar at step-down transformer stations (the voltage is stepped down from a transmission or subtransmission voltage, which may cover the range of 50-750 kV to a distribution voltage of under 50 kV but above 2 kV). For customer-owned stations supplied directly from the transmission system, this point is generally taken as the interface between utility-owned equipment and the customer's equipment.

- Single-Circuit Supplied Delivery Point (SC)

A DP supplied from the BES by one circuit whereby the interruption of that circuit will cause an interruption to the Delivery Point.

- Multi-Circuit Supplied Delivery Point (MC)

A DP supplied from the BES by more than one circuit such that the interruption of one circuit does not cause a Delivery Point interruption.

- Delivery Point Primary Supply Voltage

The transmission voltage level before transformation to the Delivery Point. For the purpose of the reporting system, the following four Voltage Classes have been identified.

Voltage Class 1 50- 99kV

Voltage Class 2 100 - 199 kV

Voltage Class 3 200 - 299 kV

Voltage Class 4 300 - 750 kV

- Sustained Interruption (SI)

Any loss of supply voltage to a DP that has a duration of one minute or more. In addition to the Sustained Interruption Frequency, the Interruption Duration of both the BES Supply Voltage and the Customer Load are reported. Generally, the loss of supply voltage to a DP will result in all customer loads to be interrupted since most Canadian utilities have distribution systems that are supplied from a radial DP. However, there may be some situations where customer load is not interrupted or is restored sooner than the BES Supply Voltage, such as where a distribution system is operated as a meshed network or where there is an alternative BES Supply Voltage path. The indices evaluated using MECORE are the sustained interruption indices.

- System Average Interruption Frequency Index- Sustained Interruptions (SAIFI-SI)

A measure of the average number of sustained interruptions that a DP experiences during a given period, usually one year.

$$\text{SAIFI-SI} = \frac{\text{Total No. of Sustained Interruptions}}{\text{Total No. of Delivery Points Monitored}}$$

- System Average Interruption Duration Index (SAIDI)

A measure of the average total interruption duration that a DP experiences during a given period, usually one year.

$$\text{SAIDI} = \frac{\text{Total Duration of all Interruptions}}{\text{Total No. of Delivery Points Monitored}}$$

- System Average Restoration Index (SARI)

A measure of the average duration of a delivery point interruption. In essence, it represents the average restoration time for each delivery point interruption.

$$\text{SARI} = \frac{\text{Total Duration of all Interruptions}}{\text{Total No. of Sustained Interruptions}}$$

- Delivery Point Unreliability Index (DPUI)

A measure of overall BES performance in terms of a composite index of unreliability expressed in System Minutes.

$$\text{DPUI} = \frac{\text{Total Unsupplied Energy (MW - Minutes)}}{\text{System Peak Load (MW)}}$$

4.2.1. Comparison of SAIFI-SI by Voltage Class and Supply Type

Figures 4.1-4.4 show a comparison of the SAIFI-SI excluding the 1998 ice storm over the period 1993-2001 using the 1993-1997, 1994-1998, 1995-1999, 1996-2000 and 1997-2001 data. Tables C.1-C.4 show a comparison of SAIFI-SI by Voltage Class and SAIFI-SI values in total by Supply Type for the 1993-2001 period, excluding and including the 1998 ice storm.

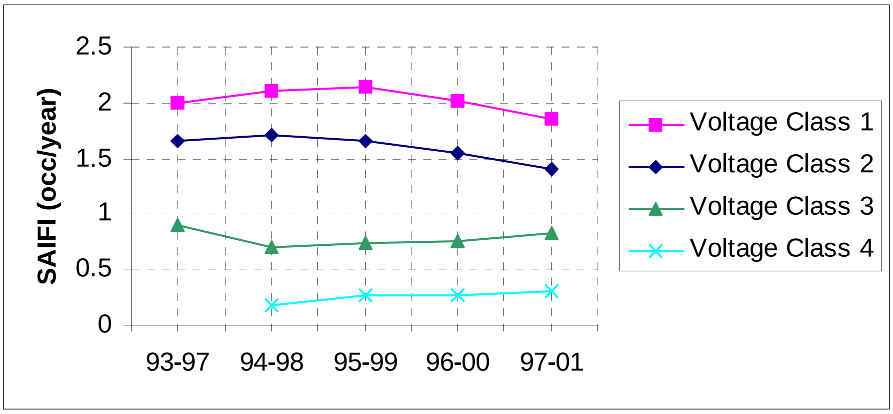


Figure 4.1: SAIFI-SI by Voltage Class for single circuits during the period 1993-2001

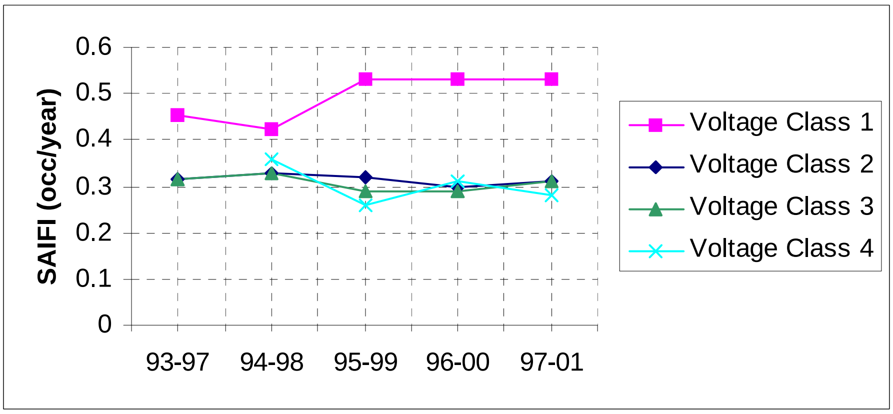


Figure 4.2: SAIFI-SI by Voltage Class for multiple circuits during the period 1993-2001

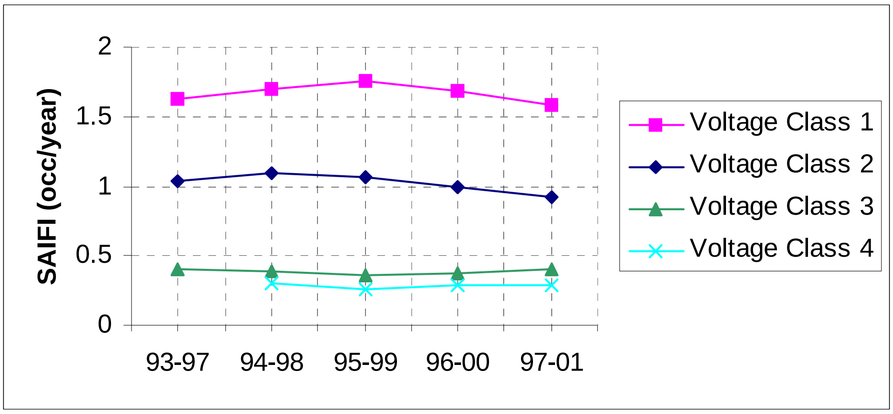


Figure 4.3: SAIFI-SI by Voltage Class for both single circuits and multiple circuits during the period 1993-2001

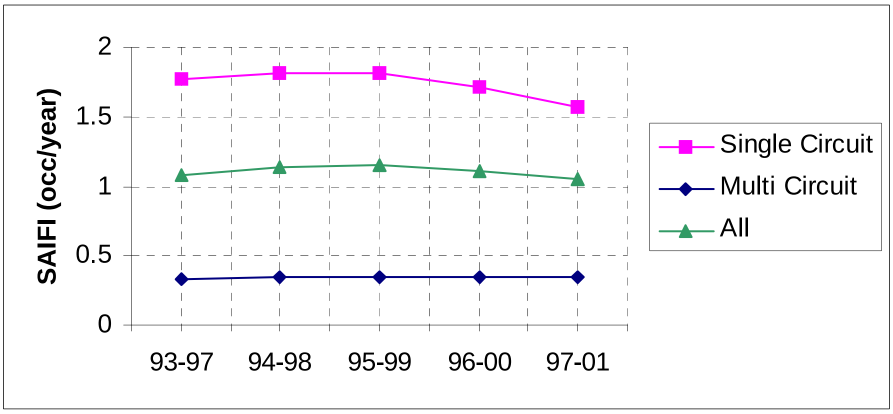


Figure 4.4: SAIFI-SI by Supply Type for all voltage classes during the period 1993-2001

It can be seen from Figure 4.1 that the SAIFI-SI of single circuits at high transmission voltages is much lower than for low transmission voltages. It can be seen from Figure 4.2 that for multiple circuits, the SAIFI-SI for high voltage circuits are not always smaller than those for low voltage circuits because of the more complex configurations of multiple circuits. Figure 4.3 shows that for both single and multiple circuits combined, the values of SAIFI-SI for high voltage circuits are smaller than those for low voltage circuits. The results in this case are dominated by the single circuit values. The values of SAIFI-SI shown in Figure 4.3 increased smoothly over the period of 1994-1998 and decreased smoothly again over the period of 1995-1999. It can be seen from Figure 4.4 that for all transmission voltages, the values of SAIFI-SI for multiple circuits are much smaller than those for single circuits.

The effects of the ice storm in 1998 are not included in Figure 4.1-4.4. Figures C.1-C.4 show a comparison of SAIFI-SI over the same period excluding and including the 1998 ice storm. These figures illustrated the effect of the 1998 ice storm on the SAIFI-SI. In Figures C.1-C.4, the solid curves represent the data excluding the 1998 ice storm and the dashed curves include the 1998 ice storm data.

4.2.2. Comparison of SAIDI by Voltage Class and Supply Type

Figures 4.5-4.8 show the SAIDI excluding the 1998 ice storm over the period 1993-2001 using the 1993-1997, 1994-1998, 1995-1999, 1996-2000 and 1997-2001 data. Tables C.5-C.8 show a comparison of SAIDI by Voltage Class and SAIDI values in total by Supply Type for the 1993-2001 period, which excludes and includes the 1998 ice storm.

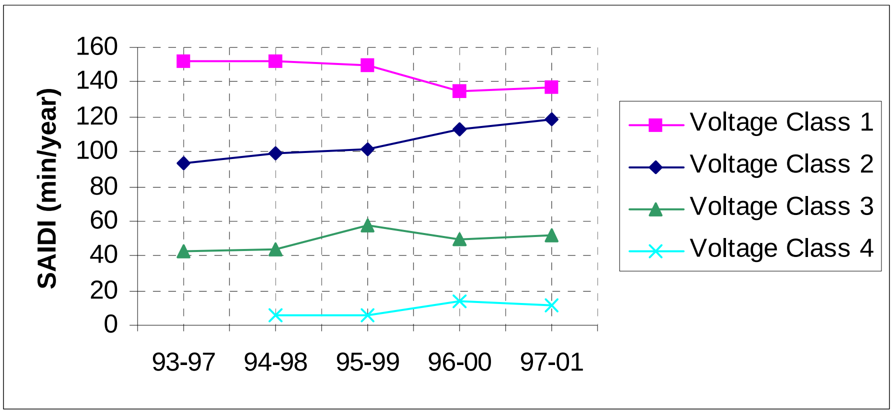


Figure 4.5: SAIDI by Voltage Class for single circuits during the period 1993-2001

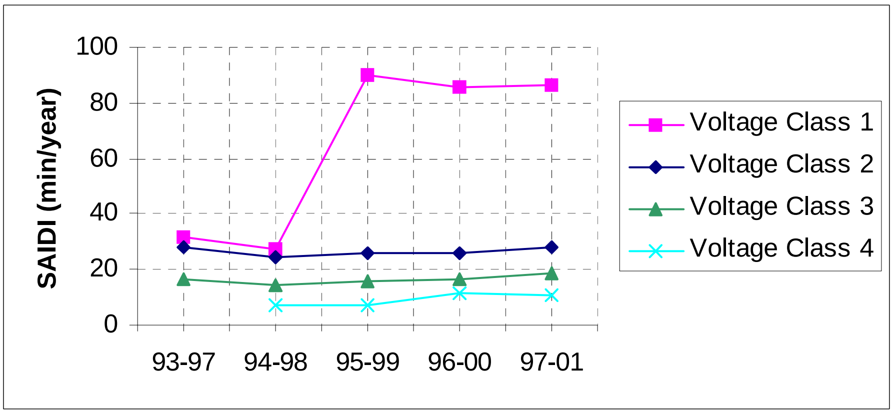


Figure 4.6: SAIDI by Voltage Class for multiple circuits during the period 1993-2001

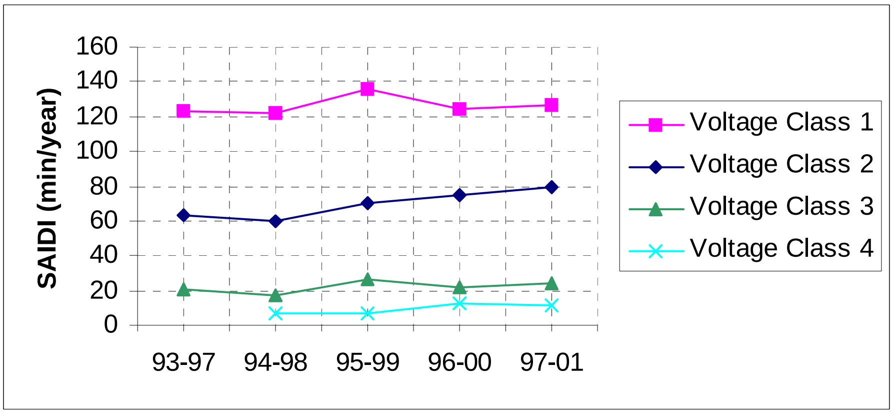


Figure 4.7: SAIDI by Voltage Class for both single and multiple circuits during the period 1993-2001

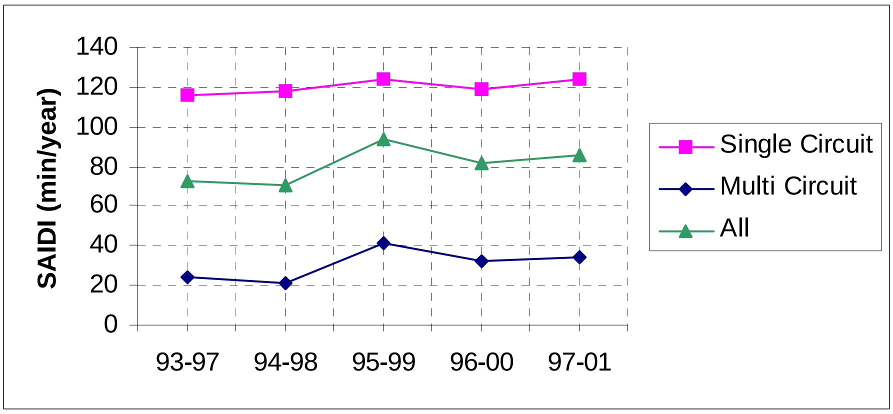


Figure 4.8: SAIDI by Supply Type for all voltage classes during the period 1993-2001

It can be seen from Figures 4.5-4.7 that the values of SAIDI for high voltage circuits are much smaller than those for low voltage circuits. Figure 4.8 shows that the SAIDI for multiple circuits are much smaller than those for single circuits for all transmission voltages.

Figures C.5-C.8 show a comparison of SAIDI excluding and including the 1998 ice storm over the same period.

It can be seen from Figures C.5-C.8 that the two curves for Voltage Class 4 are relatively separate, which indicates that ice storm 98 had a significant impact on SAIDI for Voltage Class 4. It can be seen from Figure C.8 that the ice storm in 1998 had a significant effect on the reliability performance of both single and multi circuits for all voltage classes.

4.2.3. Comparison of SARI by Voltage Class and Supply Type

Figures 4.9-4.12 show a comparison of the SARI excluding the 1998 ice storm over the period 1993-2001 using the 1993-1997, 1994-1998, 1995-1999, 1996- 2000 and 1997- 2001 data. Tables C.9-C.12 show a comparison of the SARI by Voltage Classes and SARI values in total by Supply Type for the 1993-2001 period excluding and including the 1998 ice storm.

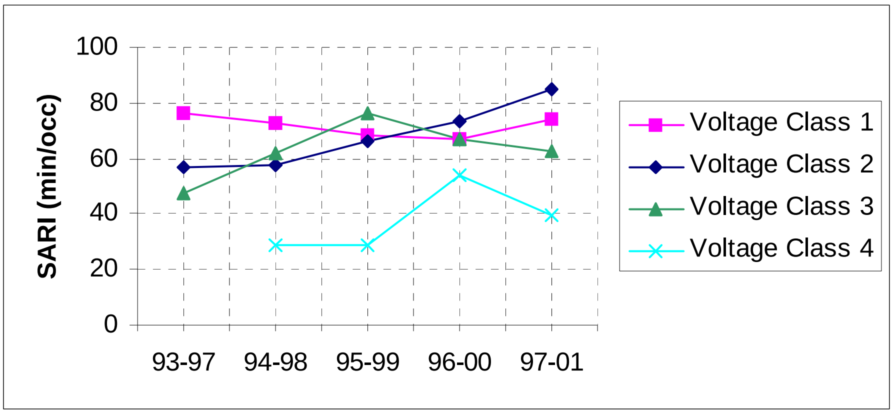


Figure 4.9: SARI by Voltage Class for single circuits during the period 1993-2001

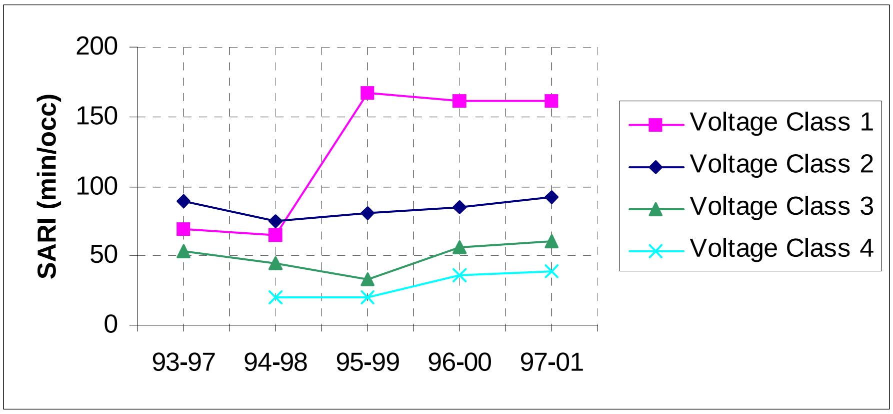


Figure 4.10: SARI by Voltage Class for multiple circuits during the period 1993-2001

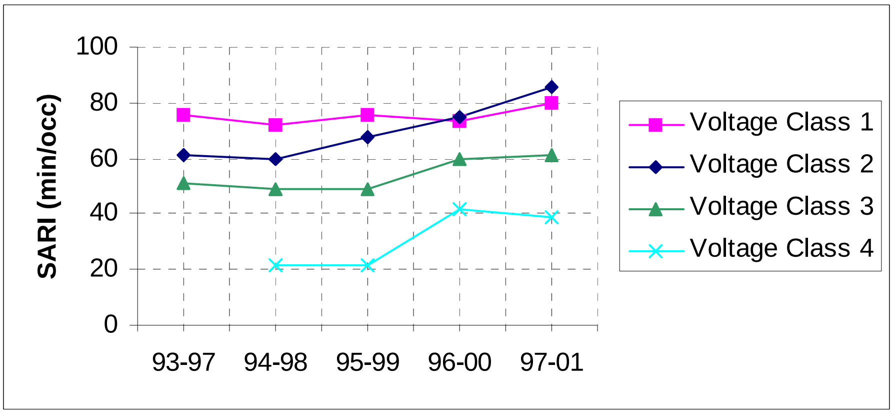


Figure 4.11: SARI by Voltage Class for both single circuits and multiple circuits during the period 1993-2001

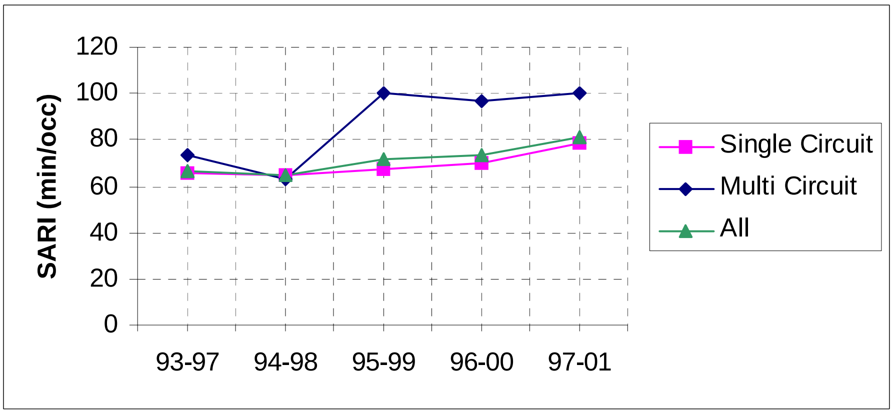


Figure 4.12: SARI by Supply Type for all voltage classes during the period 1993-2001

It can be seen from Figure 4.9 that the SARI for high voltage single circuits are not always smaller than for low voltage single circuits. It can be seen from Figure 4.10 that for multiple circuits the values of SARI at high voltages are usually smaller than those at low voltages. Figure 4.11 shows that for all circuits, the SARI at high voltages are generally smaller than those at low voltages. Figure 4.12 shows that the SARI for multiple circuits are generally larger than those for single circuits for all transmission voltage levels.

Figures C.9-C.12 show the comparison of SARI excluding and including the 1998 ice storm over the repeating period. As with the analysis of SAIDI, Figures C.9-C.12 illustrate that the 1998 ice storm had observable effect on SARI. The CEA system performance indices of SAIFI-SI, SAIDI and SARI shown in Section 4.2 provide a factual illustration of the data used by Canadian electric power utilities to monitor the BES performance of their systems. The actual annual values of SAIFI-SI, SAIDI and

SARI are more variable than the rolling five year average values. The five year values are average values and can be compared with expected values predicted by analysis. The following section illustrates a procedure using the MECORE software to predict the average performance indices for the two test systems.

4.3. Predicting System Performance Indices of Bulk Electricity System Delivery Points

The basic CEA data are presented in Section 4.2 to show how the past system performance indices of SAIFI-SI, SAIDI and SARI vary over a specified period. It is important for utilities to also have the ability to predict how system performance indices may change with time as this is directly related to their revenues and costs. The program MECORE can be used to conduct this task.

A procedure that can be used to transfer the reliability indices calculated by MECORE into a similar form as the CEA past performance indices of SAIFI, SAIDI, SARI and DPUI is presented in the following [34].

The SAIFI is the average number of interruptions per delivery point during time T, usually one year. The ENLC of bus i represents the number of contingencies requiring load to be curtailed at bus i or the isolation of bus i during time T and depends on the probability of load curtailments and the failure rate of the components involved in these load curtailments. The ENLC for each load bus can be calculated using MECORE. The load buses can be categorized by Voltage Class and Supply Type. The SAIFI for a designated category is the arithmetic mean of the ENLC for those buses in the category. The SAIDI represents the average total interruption duration per delivery point during a given time T, usually one year. The PLC of bus i represents the probability of load curtailments at bus i or the isolation of bus i during the given time T. The PLC of bus i multiplied by 8760 is the expected annual interruption duration. The PLC can be converted to the SAIDI in the same manner that the ENLC is converted to the SAIFI. The SARI is the SAIDI divided by the SAIFI. The DPUI is a measure of overall BES performance in terms of a composite index of unreliability in System·Minutes. The DPUI is equal to the composite system reliability index SI calculated by MECORE. Equations 4.1-4.6 can be used to implement the procedure described above.

Equation 4.1 shows the calculation of the SAIFI for the specified Voltage Class and Supply Type using the ENLC of each load bus.

$$\mathrm{SAIFI}=\begin{cases}\dfrac{\sum_{i\in M_j}\mathrm{ENLC}_i}{M_j} & \text{(Single Circuits)}\\[2ex] \dfrac{\sum_{i\in L_j}\mathrm{ENLC}_i}{L_j} & \text{(Multiple Circuits)}\\[2ex] \dfrac{\sum_{i\in M_j}\mathrm{ENLC}_i+\sum_{i\in L_j}\mathrm{ENLC}_i}{N} & \text{(All circuits)}\end{cases}\qquad (4.1)$$

Where

- i: Number of delivery points
- j: Voltage Class number defined by CEA (j=1, 2, 3, 4)
- N: the total number of delivery points
- M_j: the total number of delivery points supplied by single circuits at a specified voltage level j
- L_j: the total number of delivery points supplied by multiple circuits at a specified voltage level j

Equation 4.2 shows the calculation of the SAIDI for the specified Voltage Class and Supply Type using the PLC of each load bus.

$$\mathrm{SAIDI}=\begin{cases}\dfrac{\sum_{i\in M_j}\mathrm{PLC}_i\times 8760}{M_j} & \text{(Single Circuits)}\\[2ex] \dfrac{\sum_{i\in L_j}\mathrm{PLC}_i\times 8760}{L_j} & \text{(Multiple Circuits)}\\[2ex] \dfrac{\sum_{i\in M_j}\mathrm{PLC}_i\times 8760+\sum_{i\in L_j}\mathrm{PLC}_i\times 8760}{N} & \text{(All circuits)}\end{cases}\qquad (4.2)$$

Equation 4.3 shows the calculation of the SAIFI for all the Voltage Classes by Supply Type using the ENLC of each load bus.

$$\mathrm{SAIFI}=\begin{cases}\dfrac{\sum_{j=1}^{4}\sum_{i\in M_j}\mathrm{ENLC}_i}{\sum_{j=1}^{4}M_j} & \text{(Single Circuits)}\\[2ex] \dfrac{\sum_{j=1}^{4}\sum_{i\in L_j}\mathrm{ENLC}_i}{\sum_{j=1}^{4}L_j} & \text{(Multiple Circuits)}\\[2ex] \dfrac{\sum_{j=1}^{4}\sum_{i\in M_j}\mathrm{ENLC}_i+\sum_{j=1}^{4}\sum_{i\in L_j}\mathrm{ENLC}_i}{N} & \text{(All circuits)}\end{cases}\qquad(4.3)$$

Equation 4.4 shows the calculation of the SAIDI for all the Voltage Classes by Supply Type using the PLC of each load bus.

$$\mathrm{SAIDI}=\begin{cases}\dfrac{\sum_{j=1}^{4}\sum_{i\in M_j}\mathrm{PLC}_i\times 8760}{\sum_{j=1}^{4}M_j} & \text{(Single Circuits)}\\[2ex] \dfrac{\sum_{j=1}^{4}\sum_{i\in L_j}\mathrm{PLC}_i\times 8760}{\sum_{j=1}^{4}L_j} & \text{(Multiple Circuits)}\\[2ex] \dfrac{\sum_{j=1}^{4}\sum_{i\in M_j}\mathrm{PLC}_i\times 8760+\sum_{j=1}^{4}\sum_{i\in L_j}\mathrm{PLC}_i\times 8760}{N} & \text{(All circuits)}\end{cases}\qquad(4.4)$$

Equation 4.5 shows the calculation of the SARI based on SAIDI and SAIFI:

$$\mathrm{SARI}=\frac{\mathrm{SAIDI}}{\mathrm{SAIFI}}\qquad(4.5)$$

Equation 4.6 is used to obtain the DPUI:

$$\mathrm{DPUI}=\mathrm{SI}\qquad(4.6)$$

Bulk electricity system delivery point performance can be affected by many variables. Factors such as station transformer configurations, the load curtailment philosophy, system modifications and the system peak load are considered and analyzed in the next section to show they affect the system performance indices. The analyses conducted were done using the RBTS and the IEEE-RTS.

4.4. RBTS Analysis

Five factors that can affect the system performance indices are considered in this section. The five factors are station transformer configurations, station transformer failure rate and outage duration, load curtailment philosophy, system modifications, and system peak load levels. Their impacts on bulk electricity system delivery point performance are analyzed individually.

The RBTS delivery points are classified using the CEA protocol in Table 4.1.

Table 4.1: Classification of the delivery points in the RBTS

Delivery Point	Supply Type		Voltage Class			
	Single	Multiple	1	2	3	4
2		×			×	
3		×			×	
4		×			×	
5		×			×	
6	×				×	

4.4.1. The Effect of Station Transformers

In the following analysis, the step-down transformers are assumed to be utility-owned. The delivery points in this study are the low voltage busbars at the step down transformer stations. The single line diagram of the RBTS with step-down transformer stations is shown in Figure 4.13. As shown in Figure 4.13 there may be one transformer, or two or three redundant transformers in parallel at each transformer station. The following analysis is focused on how the three different transformer station configurations affect the system performance indices.

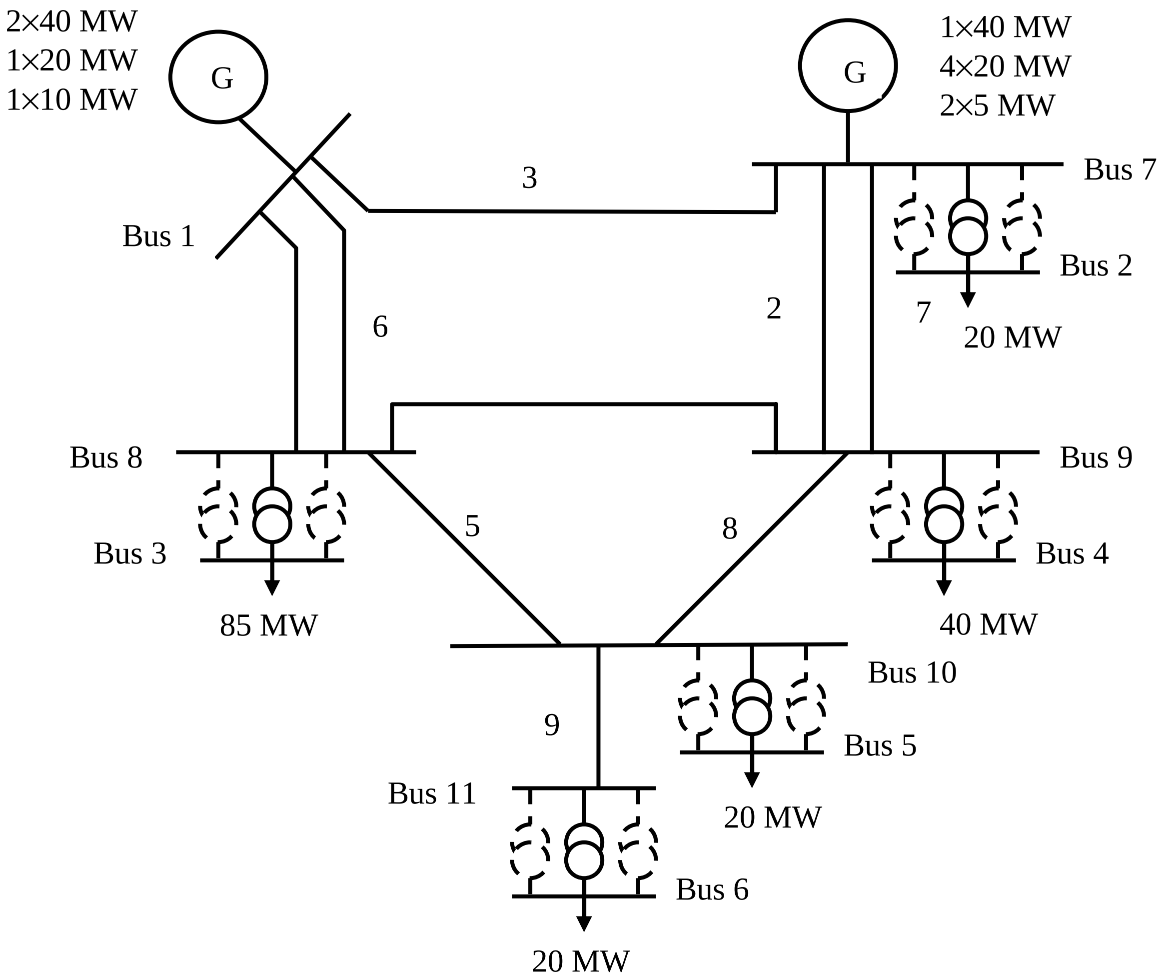


Figure 4.13: Single line diagram of the RBTS with step-down transformers

The three cases in this study are designated as follows: Case 1, only one transformer at every transformer station; Case 2, two redundant transformers are installed in parallel at every transformer station; Case 3, three redundant transformers are installed in parallel at every transformer station. Table 4.2 shows the reliability data for the station transformers.

Table 4.2: The station transformer reliability data

Reliability data	Base case
Failure rate λ (failures/yr)	0.02
Outage duration r (hrs)	768
Repair rate μ (repairs/yr)	11.41
Unavailability U	0.00175

The only transmission voltage in the RBTS is 230KV and therefore only one transmission voltage class (Voltage Class 3) exists.

Figures 4.14-4.16 show the SAIFI and SAIDI by Supply Type and DPUI for the three transformer cases. Tables C.13-C.14 contain the numerical values of SAIFI and SAIDI by Supply Type for the base case and for Cases 1, 2, 3. Table C.15 shows the DPUI for the four cases.

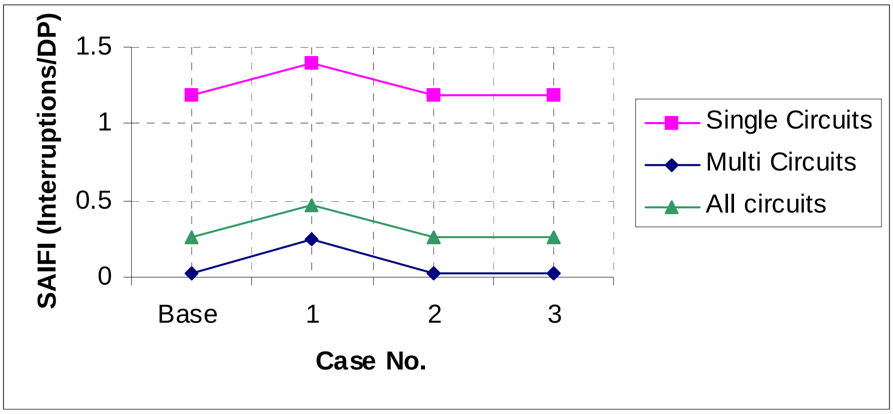


Figure 4.14: SAIFI by Supply Type including the effects of station transformers (MECORE results)

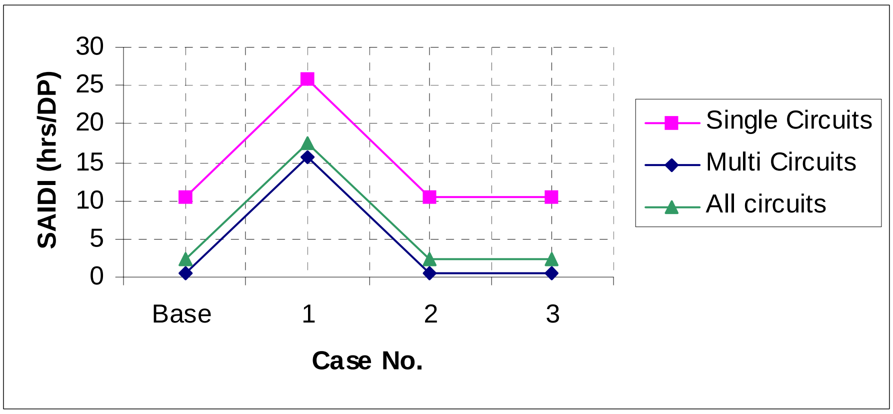


Figure 4.15: SAIDI by Supply Type including the effects of station transformers (MECORE results)

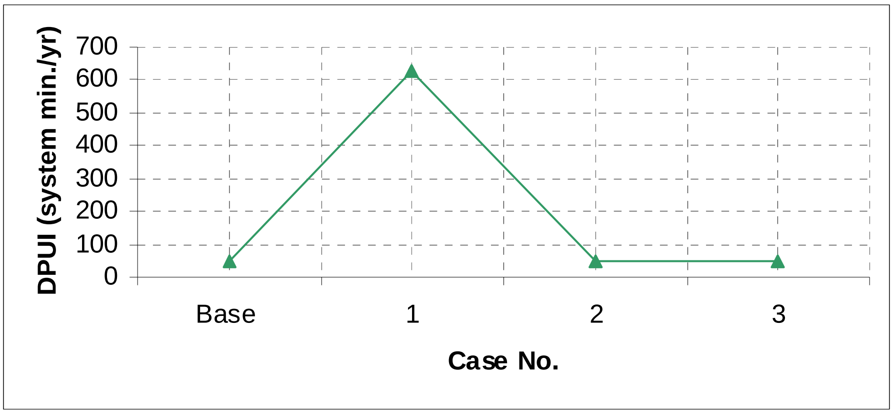


Figure 4.16: DPUI of the system including the effects of station transformers (MECORE results)

In Figure 4.14, the values of SAIFI show a large increase between the base case and Case 1. This is not reasonable, as the failure rate of the utility-owned transformers is only 0.02 failures/yr (Table 4.2), which cannot provide the increase shown. As previously noted, the ENLC is an upper bound on the actual frequency index, when calculated using the state sampling technique. The ENLC obtained by MECORE at a bus supplied by a radial element with a very low failure rate was found to be highly overestimated. This is an obvious disadvantage of the MECORE program. Further development should be done to use the state transition sampling technique or the sequential technique to calculate a more exact frequency index in order to obtain system performance indices such as SAIFI.

The load point failure rate, outage duration and unavailability values at the high voltage buses calculated using the MECORE software can be extended to the low voltage busbars using a simple analytical extension. This hybrid technique was used to obtain the system performance indices at the low voltage busbars. Figures 4.17-4.19 show the SAIFI and SAIDI by Supply Type and the DPUI including the effect of station transformers for the base case and Case 1 and 2. The results for Case 3 are not shown as they are virtually identical to those of Case 2. The numerical values are given in Table C.16 and C.17. Table C.18 shows the DPUI for the three cases.

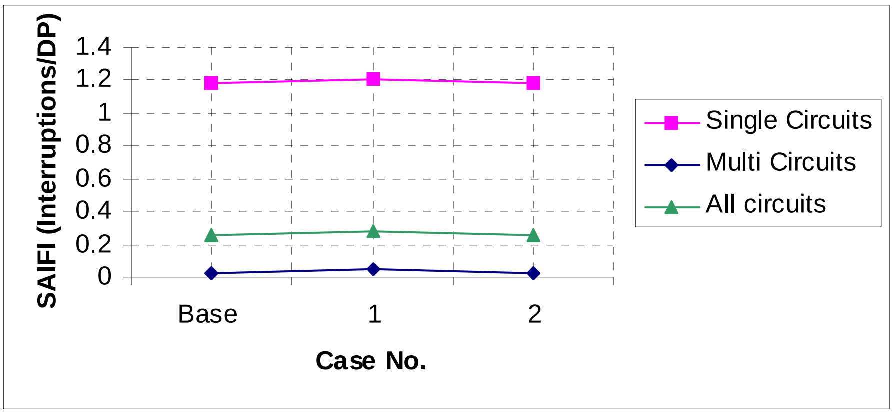


Figure 4.17: SAIFI by Supply Type including the effects of station transformers

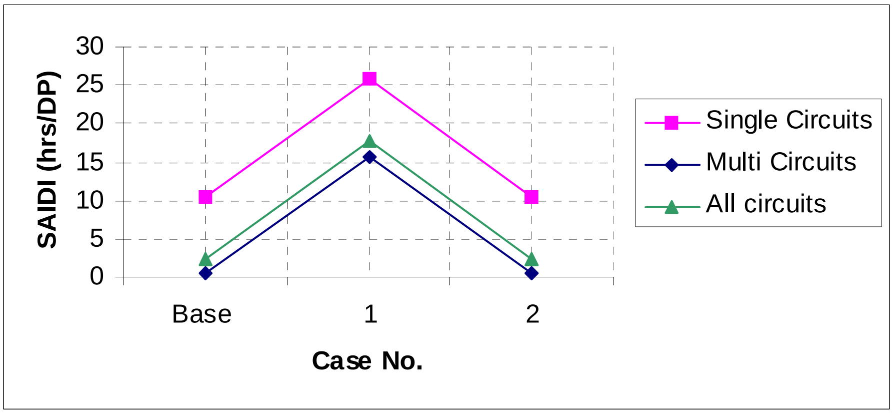


Figure 4.18: SAIDI by Supply Type including the effects of station transformers

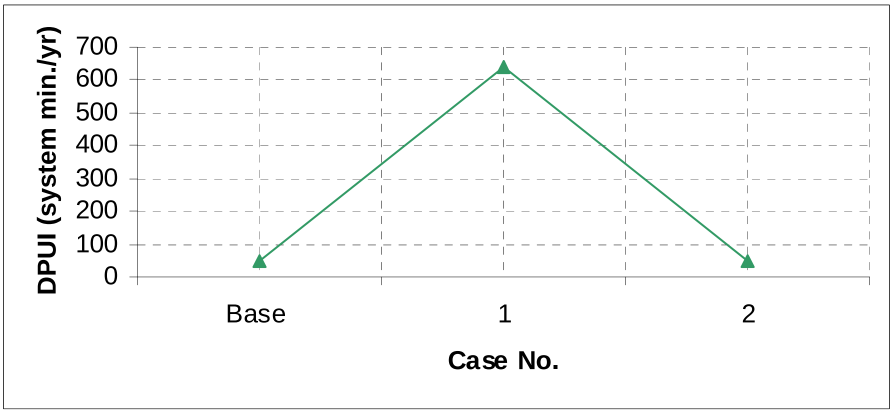


Figure 4.19: DPUI of the system including the effects of station transformers

When the step-down transformers are utility-owned as in Case 1, the values of SAIFI for single, multiple and all circuits increase slightly. In Cases 2 and 3, in which two and three step-down transformers are used, the values of SAIFI for single, multiple and all circuits all decrease to approach the base case level. Redundant transformers in utility-owned transformer stations have a positive impact on the SAIFI. Figures 4.14 and 4.17 show that the ENLC calculated by MECORE leads to a clear overestimation of the frequency based system performance index SAIFI.

Figures 4.15 and 4.18 show that the SAIDI values calculated directly by MECORE and those obtained by the analytical extension of MECORE are very close to each other. The overestimation associated with ENLC does not occur in the PLC. When the step-down transformers are utility-owned as in Case 1, the values of SAIDI for single, multiple and all circuits increase significantly because of the higher probability of load curtailment at each load bus. When two or three redundant transformers are used at a utility-owned transformer station, the values of SAIDI for single, multiple and all circuits approach the base case values. Redundant transformers in utility-owned transformer stations can have a positive impact on the SAIDI.

Figures 4.16 and 4.19 shows that DPUI has similar variations to those of SAIDI as both system performance indices are affected by the probability of load curtailment. It can also be seen from Figures 4.16 and 4.19 that the DPUI calculated by MECORE are very close to those calculated using the analytical extension method.

The analyses conducted also show that three redundant transformers did not provide much benefit over the use of two redundant transformers. The impact of station transformers on the system performance indices is obviously dependant on the transformer failure and repair parameters shown in Table 4.2. The following section illustrates the sensitivity of the system performance indices to selected variations in their parameters.

4.4.2. The Effect of the Station Transformer Failure Rate and Outage Duration on the System Performance Indices

Equipment failure rates tend to increase as equipment age. This can have a negative impact on the reliability of the system. Good maintenance practices and the replacement of aging equipment can have a positive impact on the system reliability. In this section, the analysis is focused on how the station transformer failure rate and outage duration affect the system performance indices. Cases 1 and 2 in Section 4.4.1 are taken as two separate configurations in the following analysis. For each configuration three situations with different station transformer reliability data were analyzed and compared with the corresponding base case. The station transformer reliability data sets designated as A, B and C and the base case data are shown in Table 4.3.

Table 4.3: The station transformer reliability data sets A, B and C and the base case

Reliability data	Base case	A	B	C
Failure rate λ (failures/yr)	0.02	0.03	0.04	0.02
Outage duration r (hrs)	768	768	768	384
Repair rate μ (repairs/yr)	11.41	11.41	11.41	22.81
Unavailability U	0.00175	0.00262	0.00349	0.00088

As it can be seen in Table 4.3, data set B gives the lowest station transformer reliability due to the relatively high failure rate and long average outage duration. Data set C gives the highest station transformer reliability because of the relatively low failure rate and short average outage duration.

The following analysis is based on the three data scenarios and the transformer configurations designated as Cases 1 and 2. Case 1 has one utility-owned step-down transformer at each transformer station. The corresponding studies involving the three data sets are designated as Cases 1A, 1B and 1C. Case 2 has two redundant utility-owned step-down transformers at each station and the subsequent studies are labeled Cases 2A, 2B and 2C.

Figures 4.20-4.21 show the SAIFI by Supply Type for all voltage classes including the station transformers. Figures 4.22-4.23 and Figures 4.24- 4.25 show the results for SAIDI and DPUI respectively. Table C.19-C.24 present the numerical values to support the pictorial results shown in Figures 4.22-4.25.

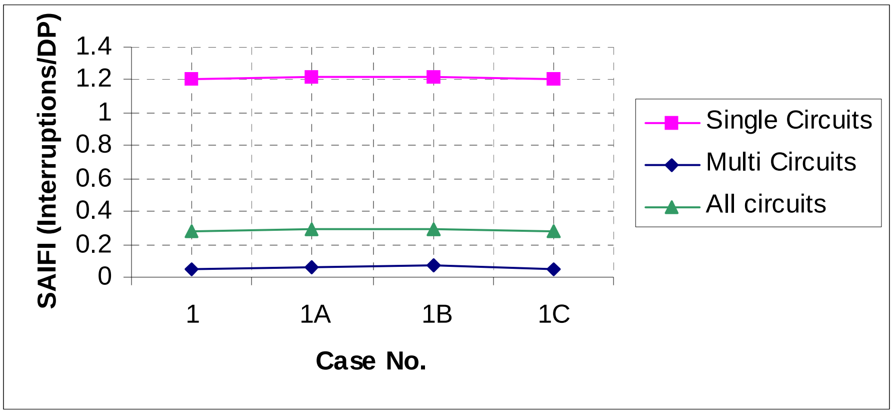


Figure 4.20: SAIFI by Supply Type including station transformer failure rate and outage duration effects (single transformer)

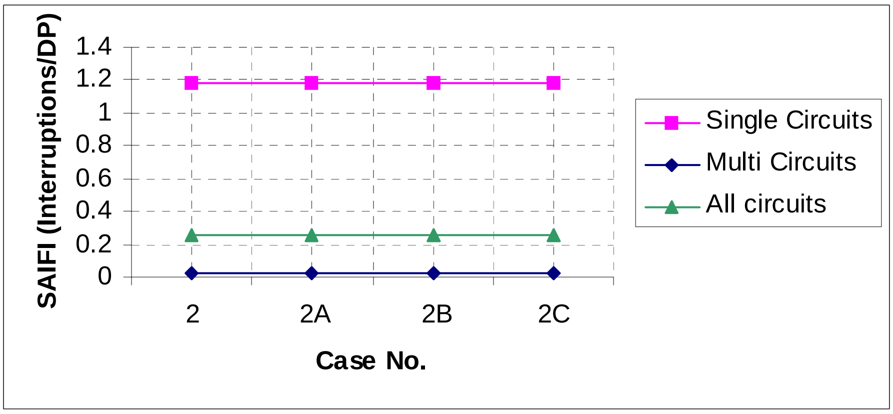


Figure 4.21: SAIFI by Supply Type including station transformer failure rate and outage duration effects (two transformers)

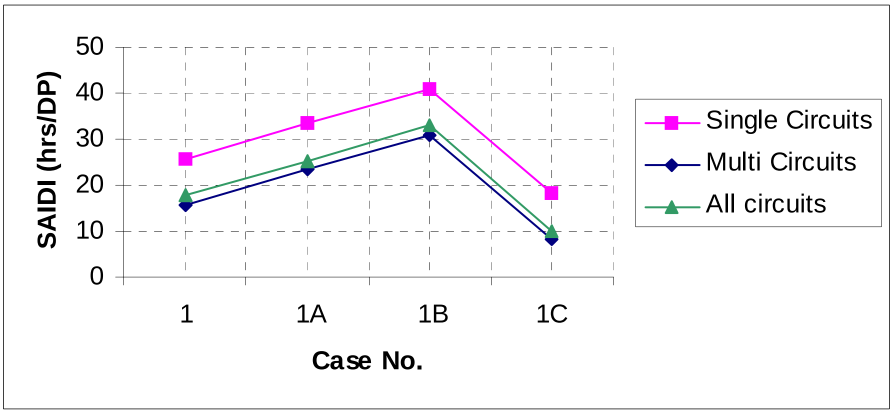


Figure 4.22: SAIDI by Supply Type including station transformer failure rate and outage duration effects (single transformer)

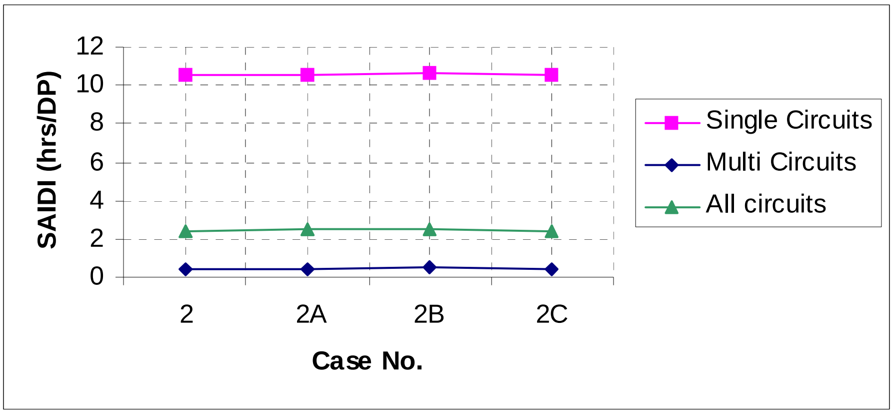


Figure 4.23: SAIDI by Supply Type including station transformer failure rate and outage duration effects (two transformers)

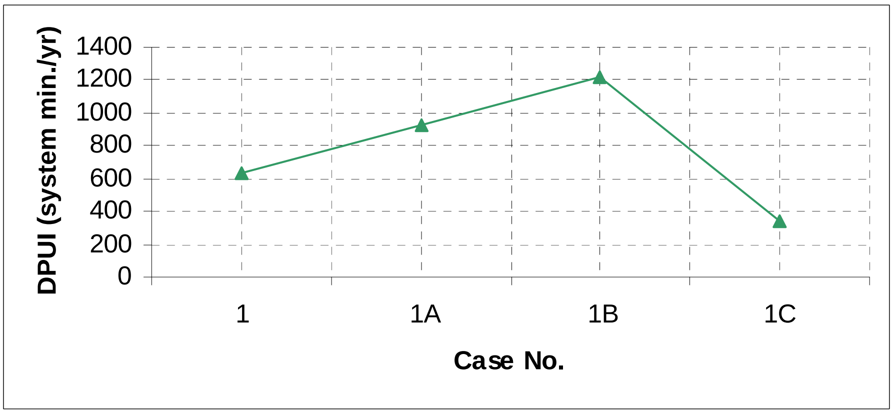


Figure 4.24: DPUI of the system including station transformer failure rate and outage duration effects (single transformer)

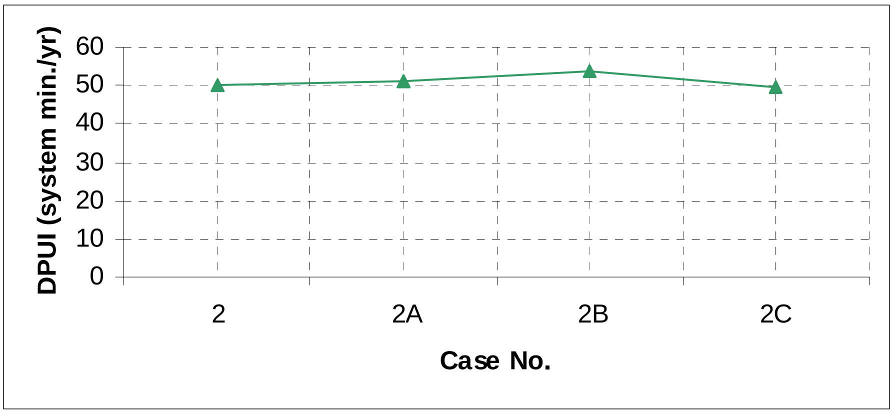


Figure 4.25: DPUI of the system including station transformer failure rate and outage duration effects (two transformers)

It can be seen from Figure 4.20 and Table C.19 that the SAIFI values for single, multiple and all circuits increase only slightly when the station transformer failure rate is increased. The SAIFI values in Figure 4.21 and Table C.22 change even less under these conditions because of the redundancy effect.

The impact of increasing the failure rate is more significant on the SAIDI values. Figure 4.22 shows the combined effect of increasing the failure rate and the relatively low average outage duration assigned to a transformer. This effect is reduced considerably when the average repair time decreases as shown in Figure 4.22. The effect on the SAIDI of adding a redundant transformer can be seen from Figure 4.23.

The DPUI values are shown in Figure 4.23-4.24 and behave in a similar manner to those for the SAIDI. Both indices are primarily affected by the probability of load curtailment.

4.4.3. The Effect of Load Curtailment Philosophy

The individual load point indices in a composite system adequacy assessment are highly dependent on the load curtailment philosophy. The more important load points are normally assigned a high priority. In the following analysis, the effect on the system performance indices of different load curtailment philosophies in the RBTS is illustrated. Four different priority orders are shown in Table 4.4.

Table 4.4: Four priority orders for the RBTS

Bus No.	Priority order			
	Case 1	Case 2	Case 3	Case 4
2	0	1	1	1
3	0	5	3	2
4	0	2	4	3
5	0	3	2	4
6	0	4	5	5

In Case 1, each load bus is assigned same priority and therefore load curtailment is automatically conducted in the linear programming optimization model rather than decided by a specified priority order. The priority order in Case 2 is that of the base case based on the IEAR of each bus. Case 3 and Case 4 have different assigned priorities. The following analysis is based on the single line diagram shown in Figure 2.1 and therefore station transformers are not considered.

Figures 4.26- 4.28 show the SAIFI and SAIDI by Supply Type and DPUI for the four load curtailment priority orders shown in Table 4.4.

The numerical values of the indices in these studies are given in Tables C.25-C.27.

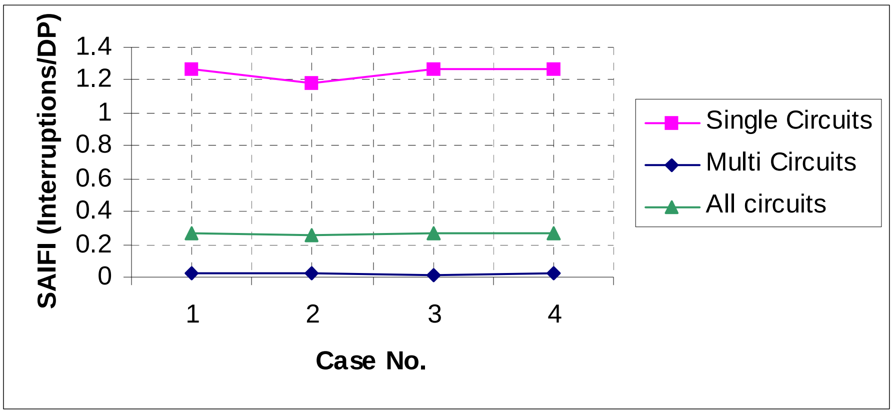


Figure 4.26: SAIFI by Supply Type including the effects of load curtailment philosophy

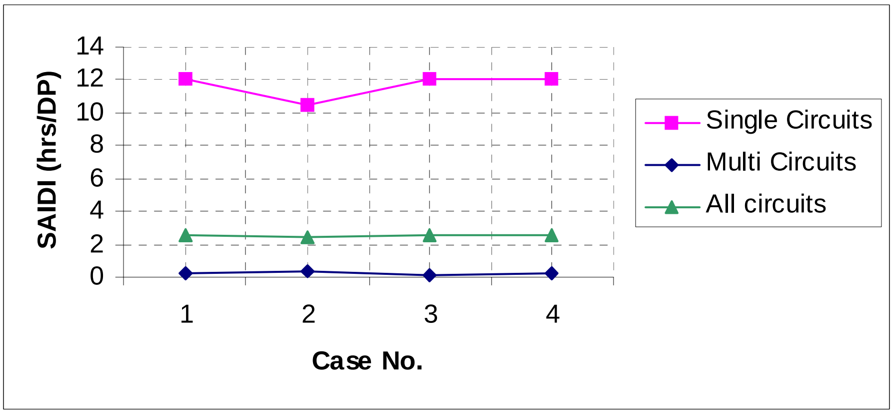


Figure 4.27: SAIDI by Supply Type including the effects of load curtailment philosophy

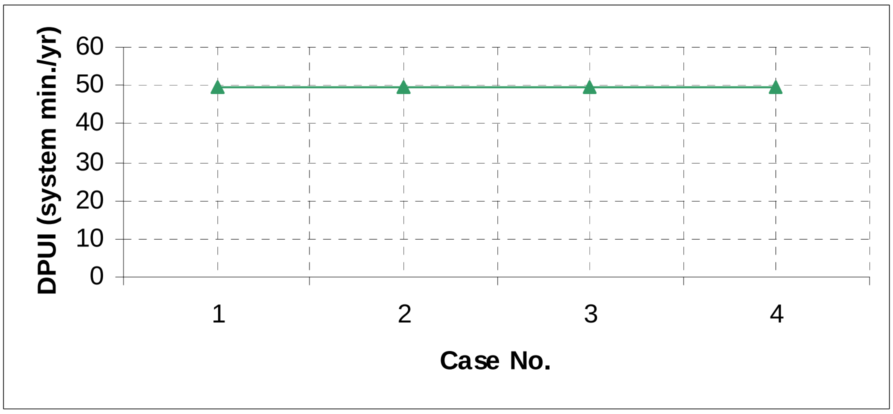


Figure 4.28: DPUI of the system including the effects of load curtailment philosophy

It can be seen from Figures 4.26 and 4.27 that the load curtailment philosophy has some effect on the SAIFI and SAIDI values for single circuits. In the RBTS only Bus 6 is supplied by a single circuit, and in Case 3 and 4, Bus 6 has the lowest economic priority. These two factors increase the probability of load curtailment at Bus 6, which makes the related SAIFI and SAIDI values increase slightly. The SAIFI and SAIDI values are relatively unchanged for the multiple and all circuits cases.

It can be seen from Figure 4.28, that changing the load curtailment priority order has virtually no effect on the system DPUI. The total amount of load curtailments is not dependant on the specific load curtailment philosophy.

4.4.4. The Effect of System Modifications

All modifications made to the system have some effect on the system reliability. The effect may be large or relatively insignificant depending in the modification. A detailed analysis of possible system modifications was conducted in [34]. These studies showed that doubling line 9 and adding 2 × 10MWgenerating units at Bus 3 had a significant effect on the system and load point reliability indices. Figures 4.29-4.31 show that these modifications also have a significant effect on the system performance indices of SAIFI, SAIDI and DPUI. Tables C.28-C.30 show the numerical values obtained in these studies. The station transformers are assumed to be customer owned in this analysis. The modified system has no single circuit supply point and therefore Figures 4.29-4.31 only show multi circuits and all circuit values.

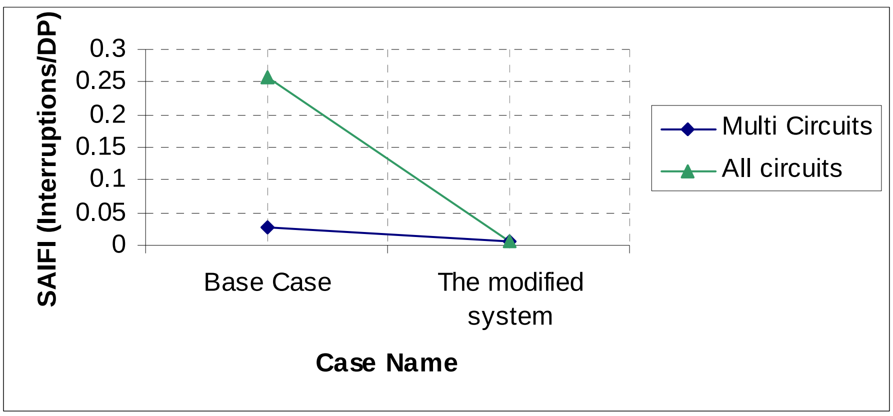


Figure 4.29: SAIFI by Supply Type including the effects of system modifications

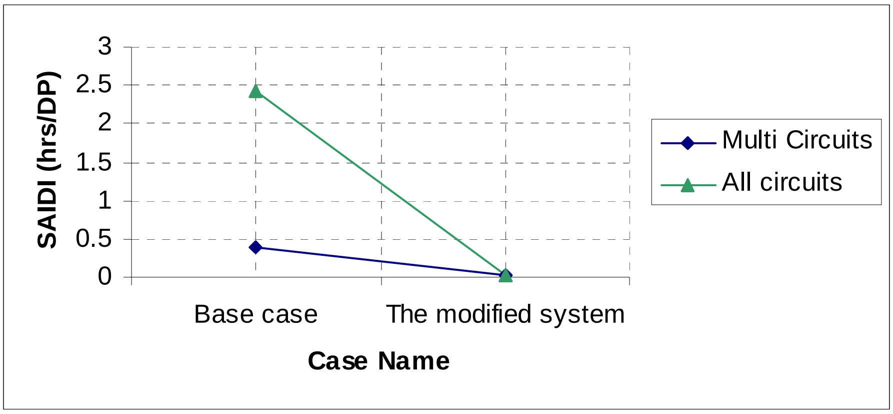


Figure 4.30: SAIDI by Supply Type including the effects of system modifications

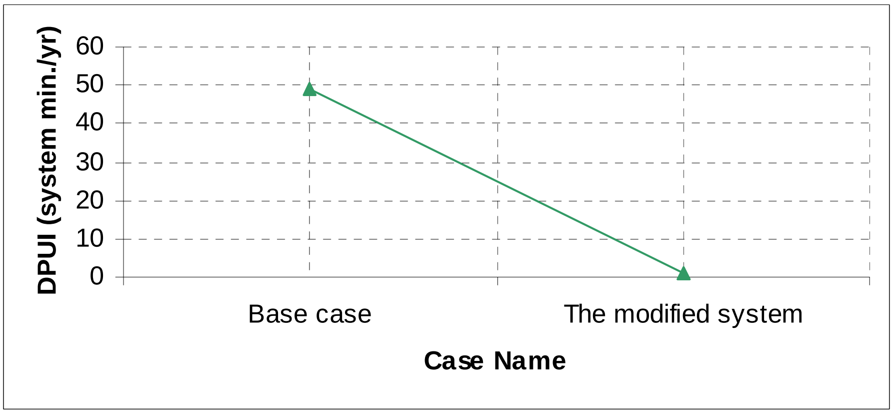


Figure 4.31: DPUI of the system including the effects of system modifications

It can be seen from Figures 4.29-4.30 that the SAIFI, SAIDI and DPUI values decrease dramatically due to the modifications made to the RBTS. These are high impact modifications [34]. Any modification to the system will affect the load point and system reliability indices and can be portrayed in terms of the system performance indices currently used by the Canadian electric power industry.

4.4.5. The Effect of System Peak Load Levels

The magnitude of the system peak load has an important impact on the reliability of an electric power system. The effect of the system peak load on the system performance indices is illustrated in this section. The system peak load was varied from 160 MW to 200 MW in steps of 10 MW. The analysis is based on the single line diagram shown in Figure 2.1, in which the station transformers are assumed to be customer-owned.

Figures 4.32-4.34 show the SAIFI and SAIDI by Supply Type for all voltage classes and DPUI for the different system load levels. The numerical values are given in Tables C.31-C.33.

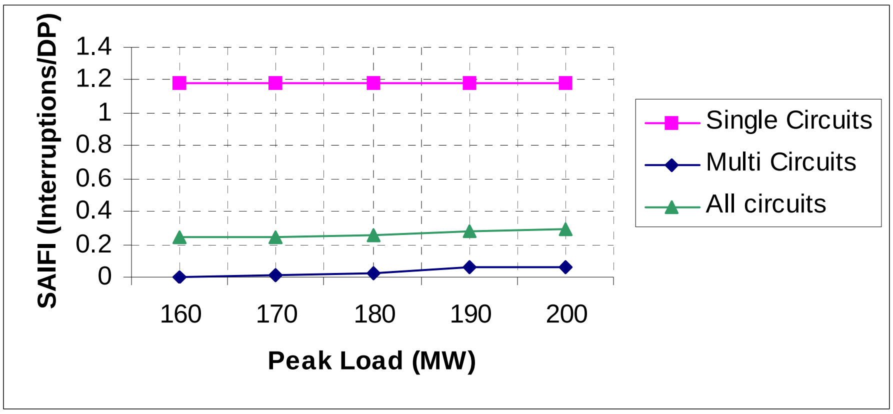


Figure 4.32: SAIFI by Supply Type as a function of the system load level

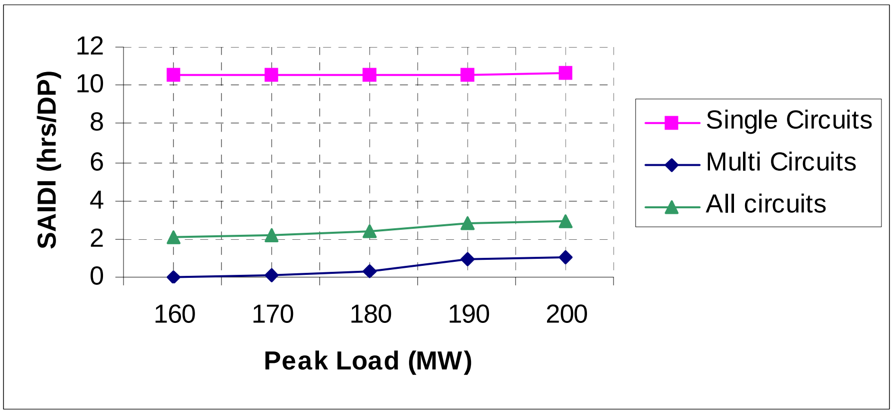


Figure 4.33: SAIDI by Supply Type as a function of the system load level

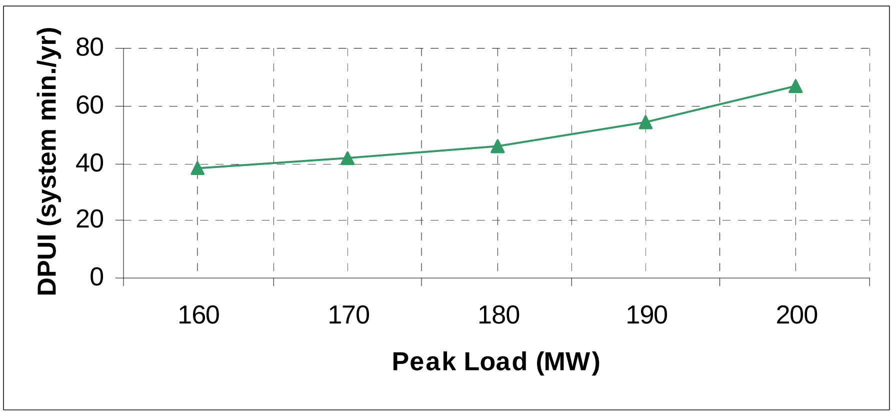


Figure 4.34: DPUI of the system as a function of the system load level

The only single circuit delivery point in the RBTS is Bus 6. The SAIFI and SAIDI values at Bus 6 are dominated by the failure rate of line 9 and are only slightly affected by increases in the system load. This is not the case for the multiple circuit delivery points and their SAIFI and SAIDI values are significantly affected by increases in load. The DPUI is directly related to the system EENS and is highly influenced by increases in the total system load.

4.5. IEEE-RTS Analysis

The previous section illustrated the effect on the system performance indices of several system factors. This analysis was conducted using the RBTS. This section utilizes the same basic factors to examine the sensitivity of the system performance indices in the IEEE-RTS. This system is quite different from the RBTS in regard to the relative strength of the generation and transmission facilities. The classification of the IEEE-RTS delivery points using the CEA categories is shown in Table 4.5.

Table 4.5: Classification of the delivery points in the IEEE-RTS

Delivery Point	Supply Type		Voltage Class			
	Single	Multiple	1	2	3	4
1		×		×		
2		×		×		
3		×		×		
4		×		×		
5		×		×		
6		×		×		
7		×		×		
8		×		×		
9		×		×		
10		×		×		
13		×			×	
14		×			×	
15		×			×	
16		×			×	
18		×			×	
19		×			×	
20		×			×	

4.5.1. The Effect of Station Transformers

A similar analysis to that conducted for the RBTS was performed on the IEEE-RTS. In this analysis, the step-down transformers were assumed to be utility-owned and the delivery points are at the low voltage busbars in the step down transformer stations.

The two cases of one and two transformers in a station were analyzed using the transformer data given in Table 4.2.

The IEEE-RTS has two transmission voltage levels, 138KV and 230KV. As shown in Table 4.5, there are two Voltage Classes, Class 2 and 3. There are no single circuit delivery points in the IEEE-RTS and therefore the system performance indices pertain to multiple or total circuits.

The values of SAIFI and SAIDI by Voltage Class for all circuits were obtained using the hybrid analytical and simulation method. Figures 4.35-4.37 show SAIFI and SAIDI by Voltage Class for all circuits and the DPUI including the effect of station transformers for the base case and for Cases 1, 2. The numerical values are shown in Table C.34-C.36.

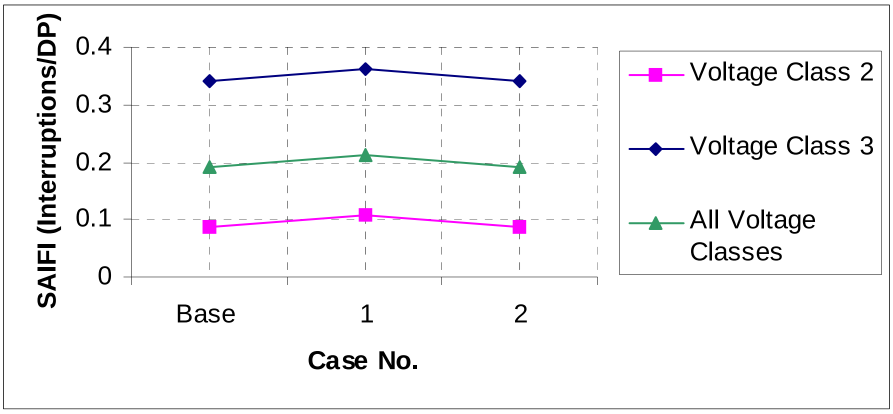


Figure 4.35: SAIFI by Voltage Class including the effects of station transformers

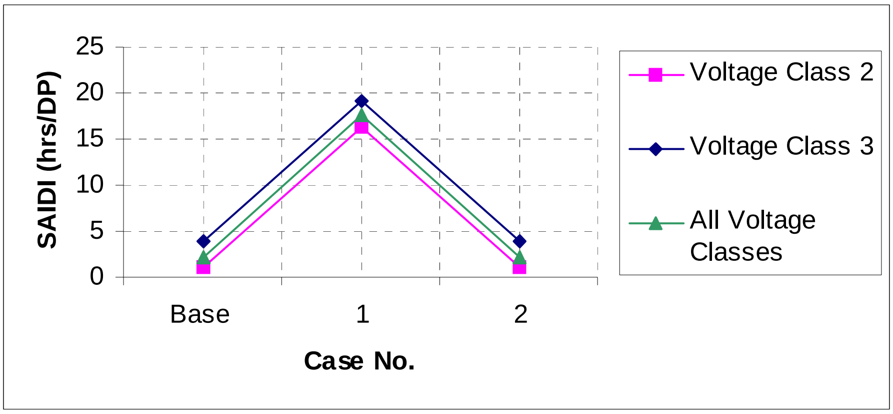


Figure 4.36: SAIDI by Voltage Class including the effects of station transformers

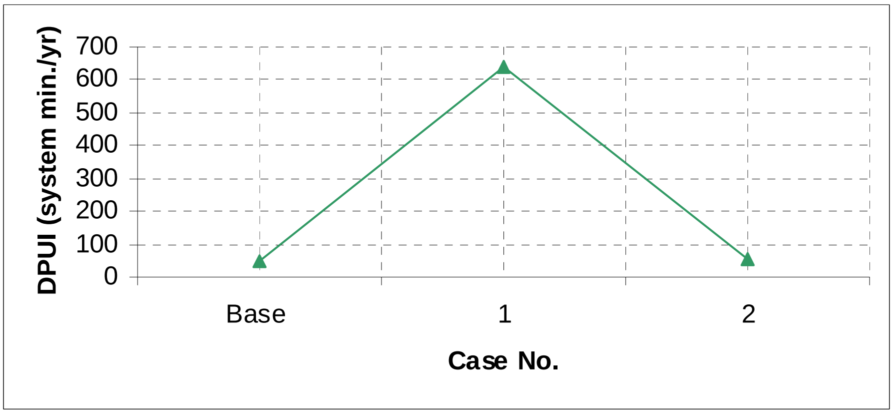


Figure 4.37: DPUI of the system including the effects of station transformers

It is interesting to note that in Figure 4.35, the SAIFI of Voltage Class 2 is smaller than that for Voltage Class 3, which is different from that shown for the CEA data in Section 4.2.1. This is because in the IEEE-RTS, the most unreliable delivery points reside in the north region, in which the transmission voltage is 230KV. Buses 14, 15 and 19 in the north region have the largest contribution to the system performance indices and Bus 9 in the south region, which has a transmission voltage of 138KV, has a comparably smaller contribution. The voltage levels are region based rather than being spread across the entire system. The performance levels in the region are more dependant on the system topology and composition and the load curtailment philosophy. Each system has its own unique characteristics and these factors play an important role in a quantitative reliability assessment.

Figures 4.35-4.37 show the same trends as those illustrated in Figure 4.17-4.19 for the RBTS.

4.5.2. The Effect of the Station Transformer Failure Rate and Outage Duration on the System Performance Indices

The effect on the IEEE-RTS system performance indices of varying the transformer failure rates and average repair times was examined. These studies are similar to those conducted on the RBTS. The transformer reliability parameters are given in Table 4.3.

Figures 4.38-4.39 show the SAIFI by Voltage Class for the two cases of one and two transformers in a station. Figures 4.40-4.41 and Figures 4.42- 4.43 show SAIDI and DPUI respectively. The numerical values are given in Appendix C.

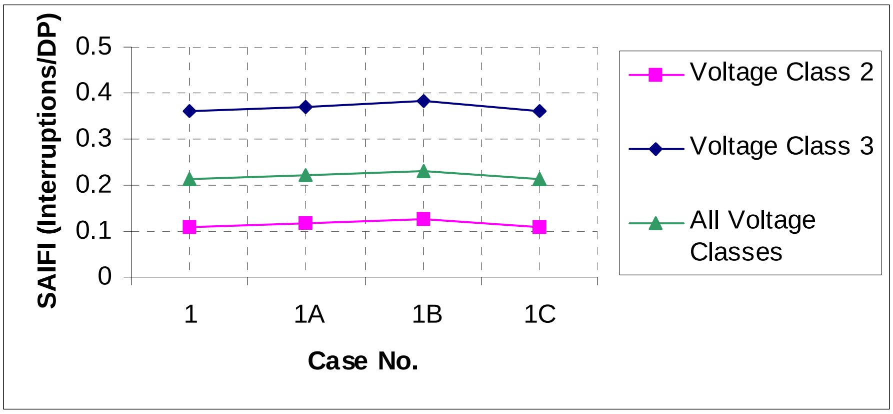


Figure 4.38: SAIFI by Voltage Class including the station transformer failure rate and outage duration effects (one transformer)

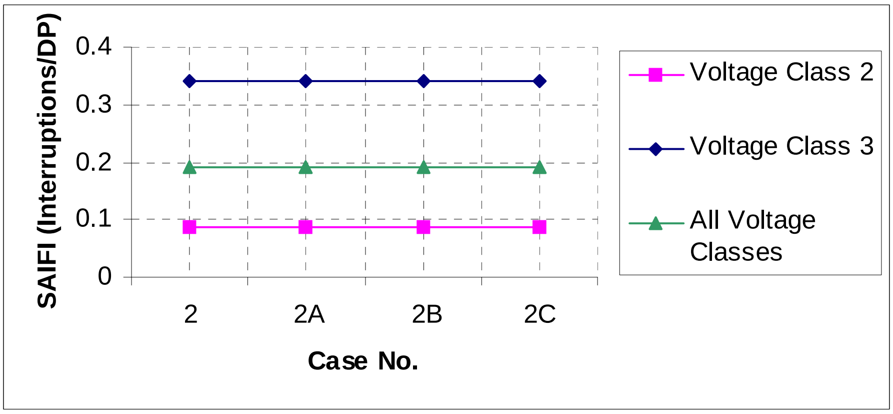


Figure 4.39: SAIFI by Voltage Class including the station transformer failure rate and outage duration effects (two transformers)

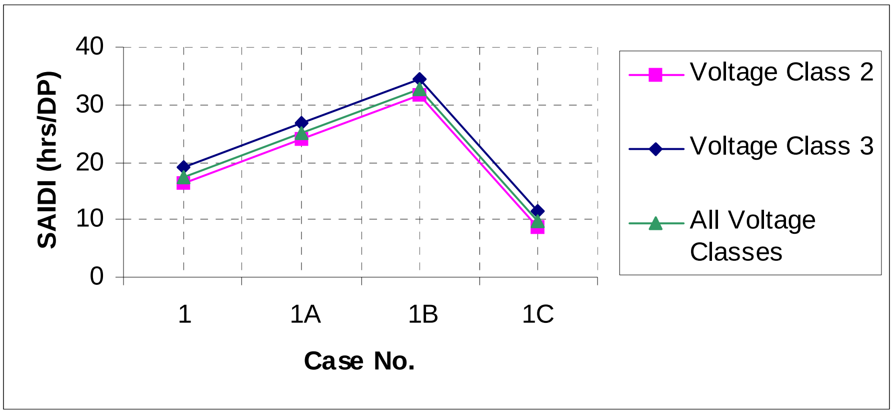


Figure 4.40: SAIDI by Voltage Class including the station transformer failure rate and outage duration effects (one transformer)

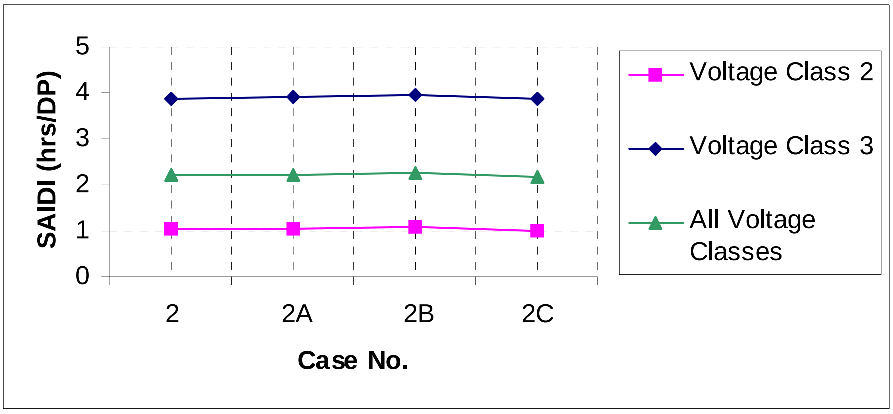


Figure 4.41: SAIFI by Voltage Class including the station transformer failure rate and outage duration effects (two transformers)

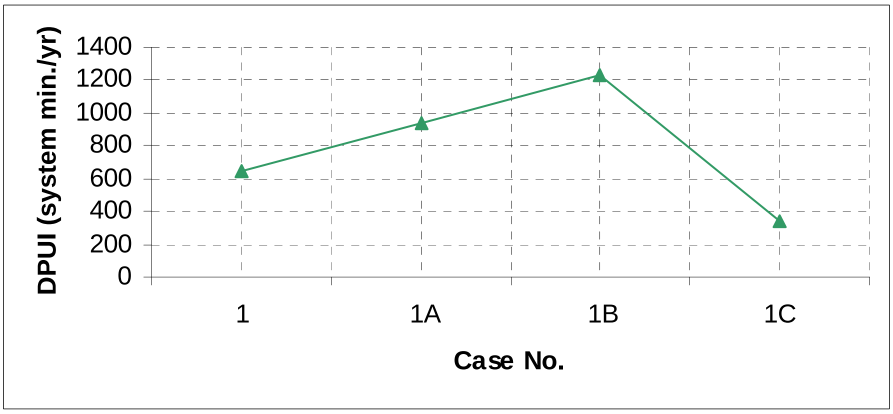


Figure 4.42: DPUI of the system including the station transformer failure rate and outage duration effects (one transformer)

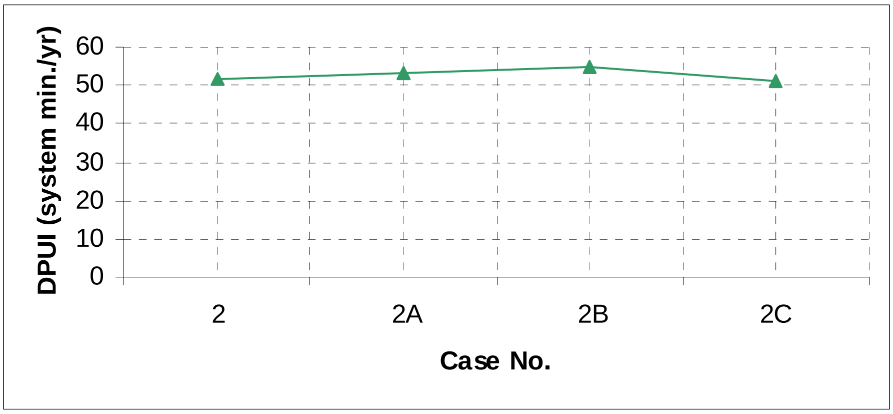


Figure 4.43: DPUI of the system including the station transformer failure rate and outage duration effects (two transformers)

The general conclusions for this study are very similar to those drawn for the RBTS. The actual effect of adding utility owned transformers in the analysis is dependant on the relative reliability of the delivery points without the transformers.

4.5.3. The Effect of Load Curtailment Philosophy

The effect on the system performance indices of different load curtailment priorities is analyzed in this section. Four different priority orders for the IEEE-RTS are shown in Table 4.6. The following analysis is based on the single line diagram in Figure 2.2, in which station transformers are assumed to be customer-owned.

Table 4.6: Four priority orders of each bus in the IEEE-RTS

Bus No.	Priority order			
	Case 1	Case 2	Case 3	Case 4
1	0	1	1	9
2	0	9	5	13
3	0	8	13	4
4	0	3	2	10
5	0	2	10	1
6	0	4	11	2
7	0	5	3	11
8	0	6	12	3
9	0	16	17	8
10	0	10	14	5
13	0	7	4	12
14	0	14	16	7
15	0	15	8	16
16	0	13	7	15

Table 4.6: (Continued)

Bus No.	Priority order			
	Case 1	Case 2	Case 3	Case 4
18	0	11	6	14
19	0	17	9	17
20	0	12	15	6

Figures 4.44-4.46 show the SAIFI and SAIDI by Voltage Class and the DPUI for the different load curtailment cases. The numerical values are given in Appendix C.

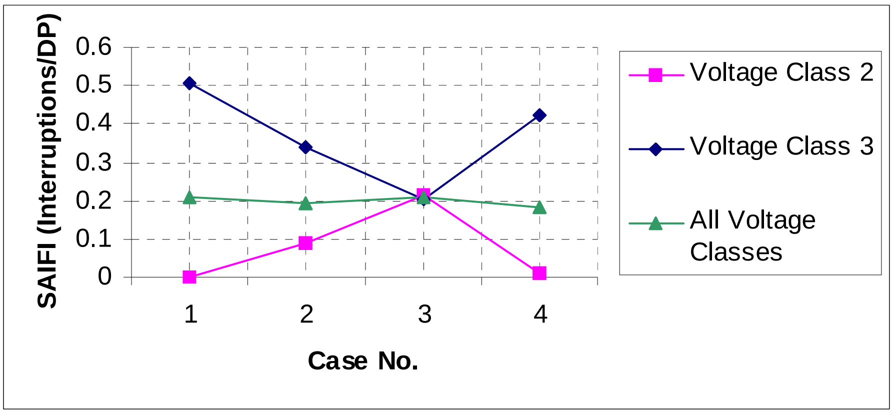


Figure 4.44: SAIFI by Voltage Class including the effects of load curtailment philosophy

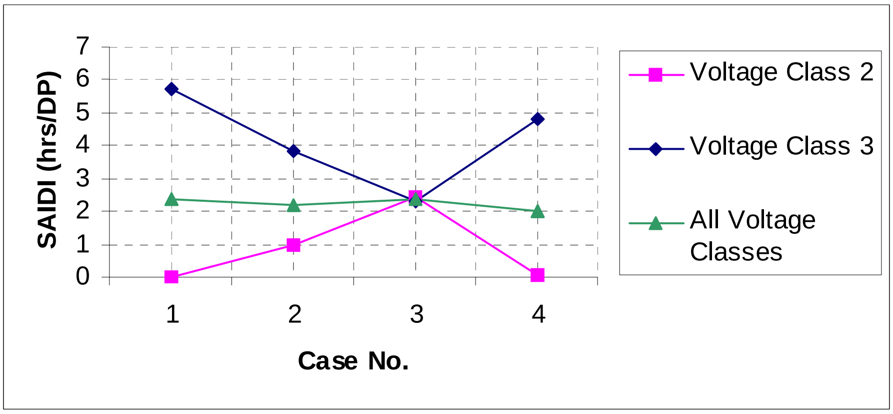


Figure 4.45: SAIDI by Voltage Class including the effects of load curtailment philosophy

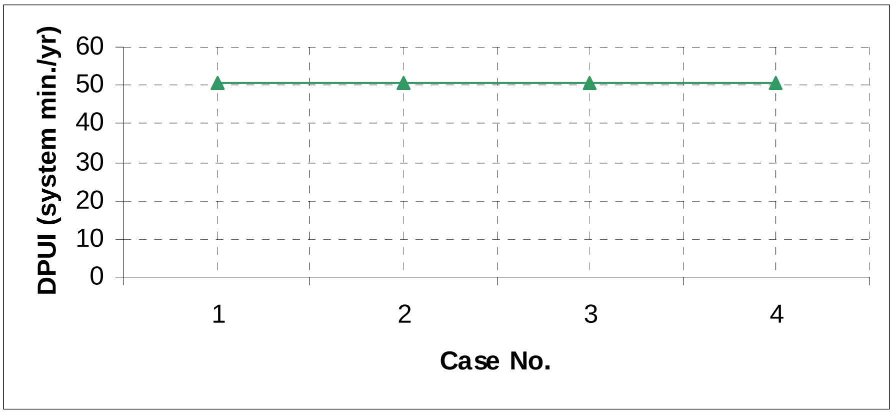


Figure 4.46: DPUI of the system including the effects of load curtailment philosophy

It should again be noted that the Voltage Classes are region specific in the IEEE-RTS. Voltage Class 3 is in the north and Voltage Class 2 is in the south. The bulk of the system generation is in the north together with most of the load. The assignment of low load curtailment priorities has a big impact on the region indices and therefore shows up as a big impact on the Voltage Classes. If the voltage levels were distributed over the regions then the regional effects would not directly relate to the Voltage Classes. The SAIDI and SAIFI values for the all Voltage Class category are not significantly affected by the different load curtailment priority orders. The DPUI is again unaffected as the system EENS is not influenced by the specific load curtailment priority order.

4.5.4. The Effect of System Modifications

The original IEEE-RTS has a relatively strong transmission network. Several modifications were made in [40] to weaken the system for the purpose of conducting transmission planning studies. The Modified IEEE-RTS (MRTS) is as follows.

The system peak load was increased to 125% of the annual peak value of 2850MW. A total of eight generators were added to selected buses (1×76MW at bus 1, 1×76MW at bus 2, 1×197MW at bus 13, 4×50MW at bus 22 and 1×350MW at bus 23). All the additional generators have identical failure and repair data to those of the generators having the same capacity in the original system. In the transmission area, six lines and one transformer branch were removed from the original version and are shown by the dashed lines in Figure 4.47. The six transmission lines are Lines 2, 3, 18, 26, 34 and 36, the one transformer branch is Transformer 14. The following analysis is based on the single line diagram shown in Figure 4.47, in which station transformers are assumed to be customer-owned.

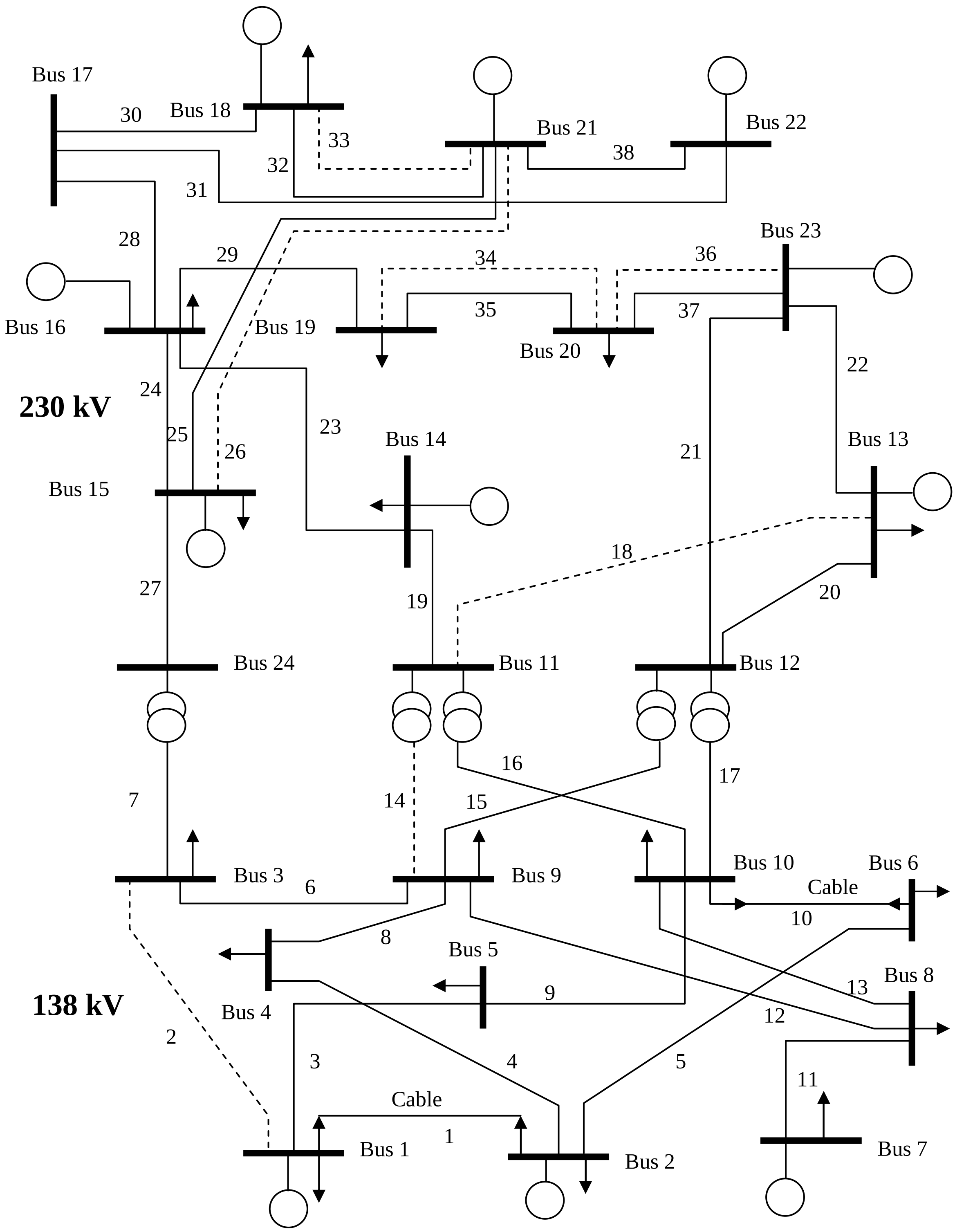


Figure 4.47: Single line diagram of the modified IEEE-RTS

The system performance of the MRTS is compared with that of the base case of the original IEEE-RTS to show the effect of the system modifications noted above.

Figures 4.48-4.50 show the SAIFI and SAIDI by Voltage Class and the DPUI for the original IEEE-RTS and the MRTS. The numerical values are given in Appendix C.

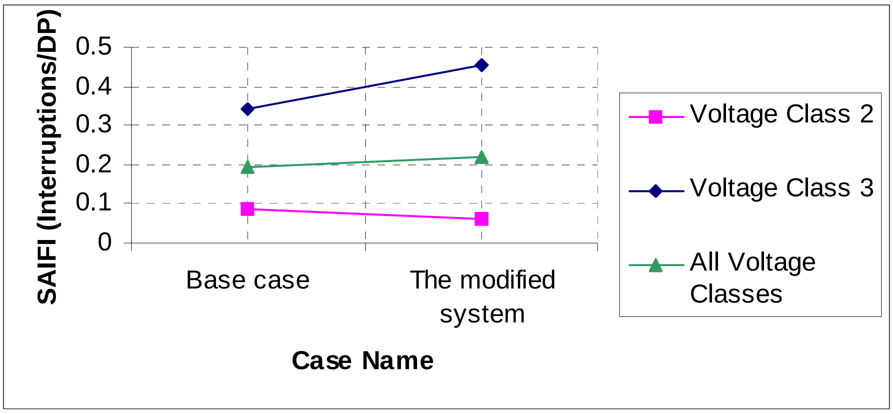


Figure 4.48: SAIFI by Voltage Class including the effects of system modifications

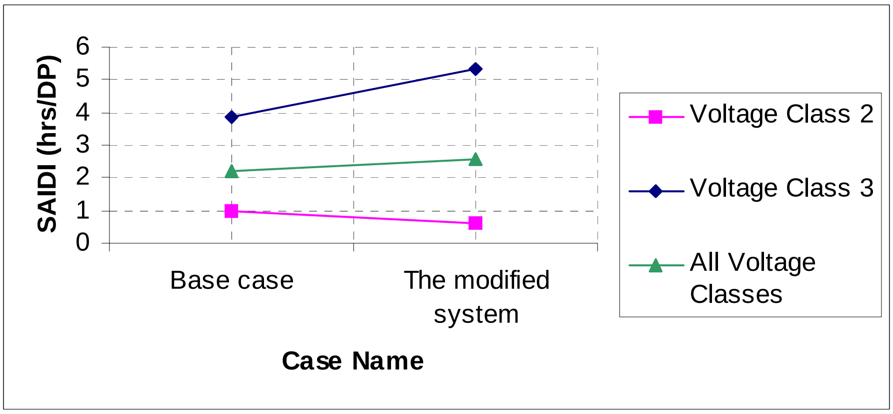


Figure 4.49: SAIDI by Voltage Class including the effects of system modifications

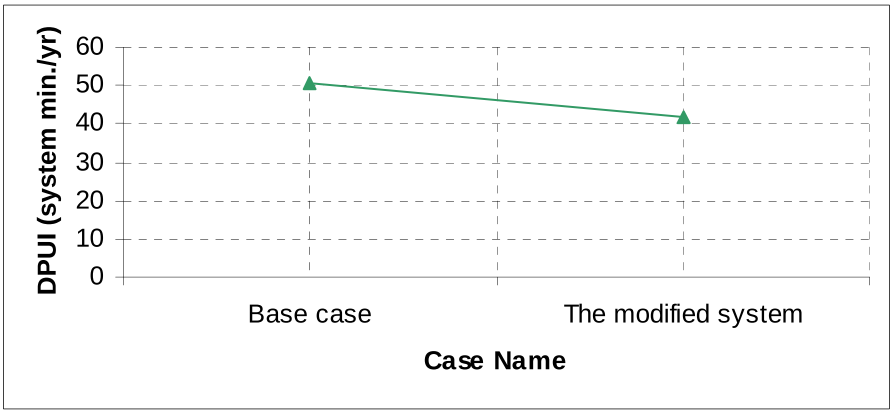


Figure 4.50: DPUI of the system including the effects of system modifications

It can be seen from Figures 4.48-4.49 that the SAIFI and SAIDI values of Voltage Class 2 (south) decrease and those of Voltage Class 3 (north) increase due to the modifications made. The originally strong transmission system in the north region has been weakened by removing some of the transmission facilities in this area, which resulted in a decrease in the load bus reliabilities in this region. The reliability at the load buses in the south is impacted by the added generation and only slightly affected by the removal of one line.

Figure 4.50 shows that the system DPUI decreases due to the modifications. The overall system reliability is improved due to the added installed capacity despite the increase in the system peak load. The effect of weakening the originally strong transmission system is offset by the addition of installed capacity. The predicted system performance indices of SAIFI, SAIDI and DPUI provide important practical indications of the merits and demerits of the proposed system modifications.

4.5.5. The Effect of System Peak Load Levels

The system peak load was varied from 2500 MW to 3100 MW. The analysis is based on the single line diagram shown in Figure 2.2.

Figures 4.51-4.53 show the SAIFI and SAIDI by Voltage Class and the DPUI at the various load levels. The numerical values of the indices at the five load levels are shown in Tables C.49-C.51.

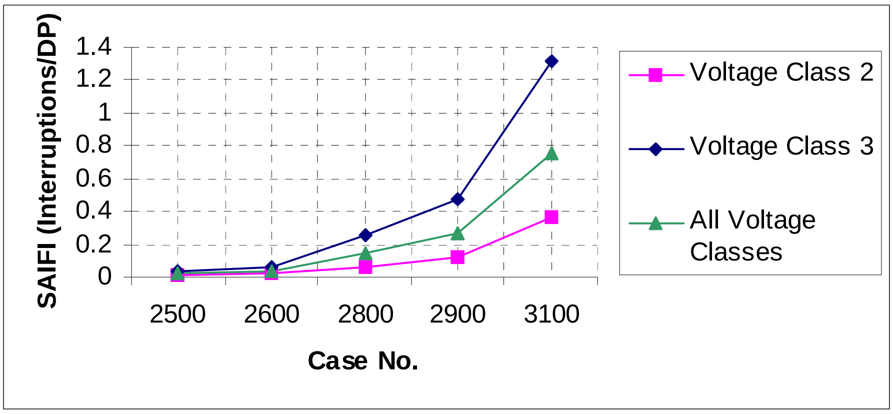


Figure 4.51: SAIFI by Voltage Class as a function of the system load level

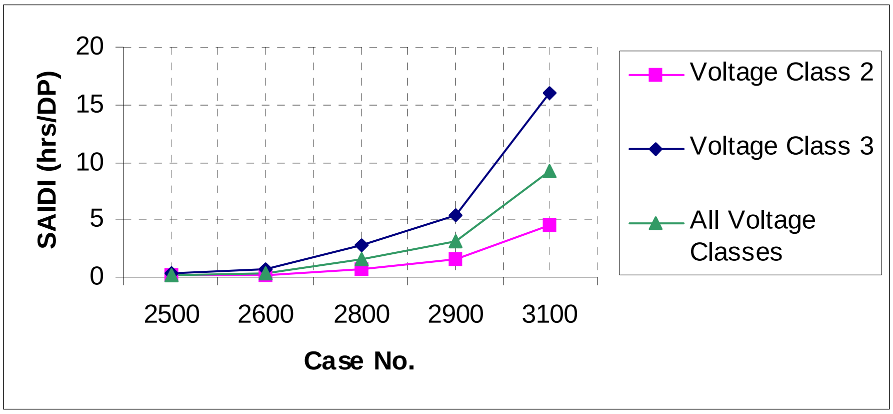


Figure 4.52: SAIDI by Voltage Class as a function of the system load level

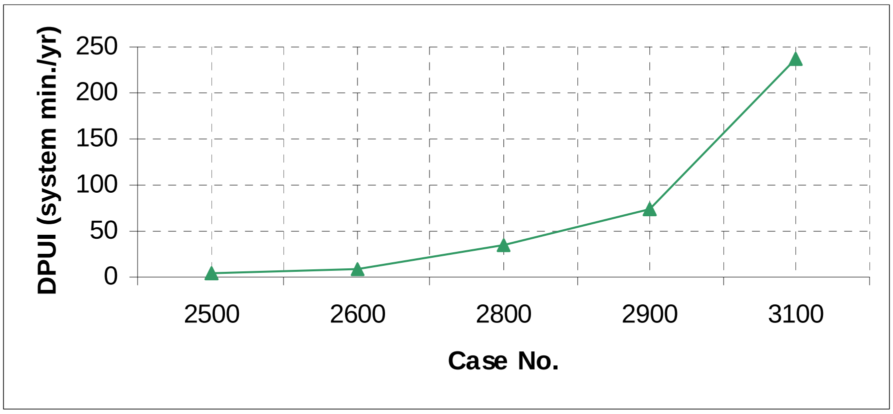


Figure 4.53: DPUI of the system as a function of the system load level

Figures 4.51-4.53 show that the predicted system performance indices increase dramatically as the system peak load increases particularly when it exceeds the base case value of 2850 MW. The system performance indices are valuable indicators of system reliability as they can be compared directly with the past performance of the system.

4.6. Summary

In this chapter, the basic BES data collected and published by CEA over the period 1993 to 2001 are presented to show the BES performance of Canadian electric power utilities over this period. The basic indices used in Canada are the SAIFI, SAIDI, SARI and DPUI. A procedure that can be used to predict similar system performance indices is presented and applied to the RBTS and the IEEE-RTS. Using this approach, the predicted future performance of a power system can be directly compared with its measured past performance.

The system performance indices change with the time due to many factors including the aging of facilities, system growth and operating philosophy and the weather, etc. Multiple circuit supply at a delivery point is more reliable than single circuit supply. The benefit associated with the increased investment can be assessed in terms of the predicted system performance indices. Delivery points served by higher voltage transmission tend to have better service performance indices than those served at lower voltages. The benefits associated with increased voltage levels can be assessed using the estimated system performance indices and considered with the required investment in the decision making process.

Five factors that can influence the system performance indices are examined in this chapter by application to the RBTS and the IEEE-RTS. These are station transformer configurations, station transformer failure rates and outage durations, the load curtailment philosophy, system modifications and the system peak load. The analyses presented show that the system performance indices can be affected by decisions made in planning, designing and operating the system. Increased investment in transformer stations to provide redundancy or reduced repair times and failure rates will result in improved performance indices. The benefits, however, must be compared with the associated costs. The load curtailment philosophy adopted by the system management should be assessed in terms of its impact on the system performance indices, in addition to customer costs associated service disruptions. Modifications proposed and considered in system planning can be assessed in terms of their implications on the BES performance using the same indices created by the electric power industry to assess past performance. This includes the evaluation of facilities required to meet system load growth.

5. IDENTIFYING TRANSMISSION DEFICIENCIES IN COMPOSITE SYSTEMS

5.1. Introduction

Historically, electric power utilities have continually built more generation and transmission facilities to satisfy the growing demands of modern society. The investment in these facilities is recovered through the traditional cost-of-service based rate mechanisms. In the newly deregulated industry, utility revenues are dependant on market competition. The incentives for market participants to invest in new generation and transmission facilities are related to the perceived market risk. An adequate transmission system is a key element in a well-founded competitive market. An important requirement of market participants is an adequate transmission system that meets customer demands and ensures that the competitive power market is healthy. Actions such as the addition of new transmission facilities, the application of new power delivery techniques and distributed generation, etc. can be taken to alleviate transmission congestion and improve the transfer capacity of the transmission system. It is, therefore, important to determine and address possible transmission deficiencies due to the inherent uncertainty and risk associated with operating a competitive market. The uncertainty associated with generation additions in the new competitive market depends on many factors including the load growth and the perceived risk associated with investment in this area. The generation uncertainty directly affects decisions regarding the transmission system. Transmission deficiencies have traditionally been identified by conducting power flows, short-circuit analyses, voltage collapse studies and stability analyses. The possible deficiencies should also be identified based on composite system reliability analysis.

In this chapter, a procedure is presented to identify transmission deficiencies in composite generation and transmission systems. The procedure includes three segments: base case analysis, factor analysis, and remedial modifications and their effects. The analyses presented in this chapter were conducted on the RBTS and the IEEE-RTS, and on a modified version of each of these two systems.

5.2. RBTS Analysis

The transmission deficiencies in the original RBTS are addressed in this section. The least reliable load buses are identified in a base case analysis and those load buses affected by transmission deficiencies are determined using factor analysis. The effects of possible remedial modifications are then examined.

5.2.1. RBTS Base Case Analysis

The variation in the load point and system reliability as a function of the peak load is examined to determine the least reliable load buses in the original RBTS. The peak load for the RBTS is assumed to vary from 160 MW to 200 MW. The analysis is focused on the EENS at the load buses, the system EENS and the BES performance indices of SAIFI and SAIDI. Additional indices can be used if desired.

Figures 5.1-5.4 show the variations in the selected reliability indices as a function of peak load. The actual numerical values are shown in Tables D.1 and D.2.

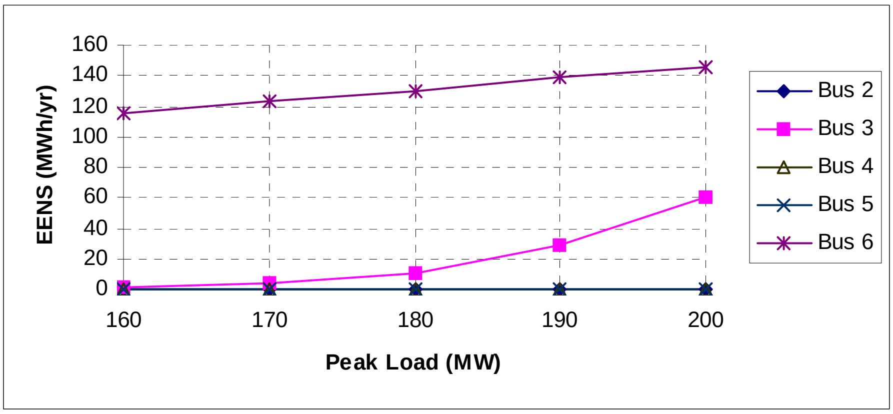


Figure 5.1: EENS of each bus in the RBTS versus peak load

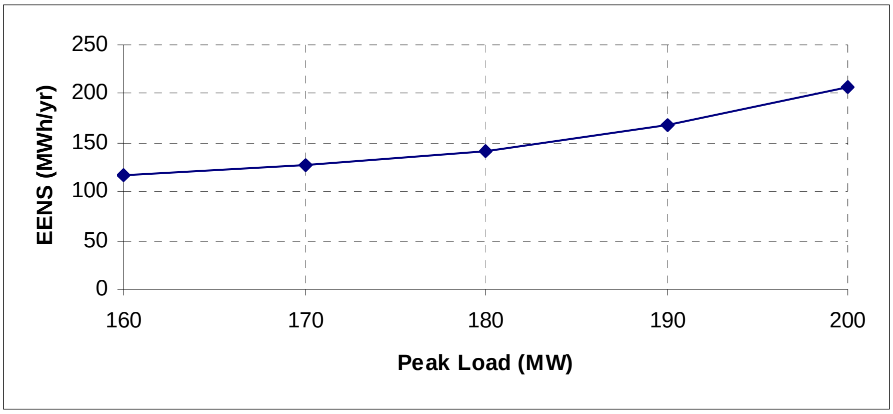


Figure 5.2: RBTS EENS versus peak load

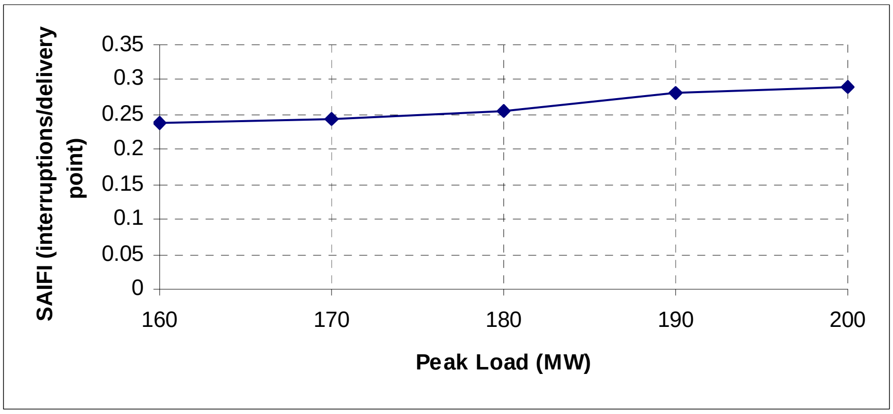


Figure 5.3: SAIFI for the RBTS versus peak load

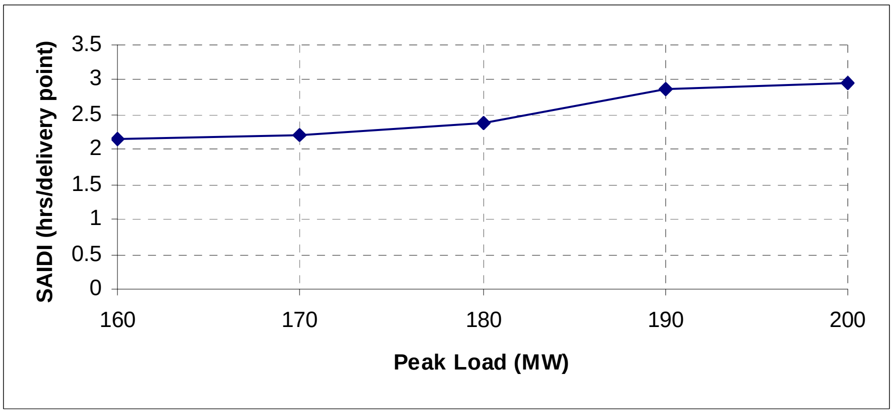


Figure 5.4: SAIDI for the RBTS versus peak load

It can be seen in Figure 5.1, that the EENS at Bus 3 increases with peak load. The EENS at Bus 6 is high at all loads and also increases with peak load. It is obvious that the least reliable load buses are Bus 3 and 6. Figures 5.2-5.4 show that the system EENS, SAIFI and SAIDI increase with peak load.

5.2.2. Factor Analysis of the RBTS Base Case

The first step in strengthening a power system containing weak areas from the viewpoint of composite system reliability, is to find out what factors cause the problems. Specialized actions can then be taken to cure the problems and strengthen the system. The following analyses examine the reliability of the RBTS when the generation system or the transmission system is assumed to be 100% reliable.

Figures 5.5-5.9 show the changes in different load point and system reliability indices as a function of the peak load. The numerical values are shown in Tables D.3 and D.4. In these two tables, the values in the Generation Failures column are the indices based on outages caused only by the generation system with the transmission system 100% reliable. The values in the Transmission Failures column are based on outages caused only by the transmission system with the generation system 100% reliable.

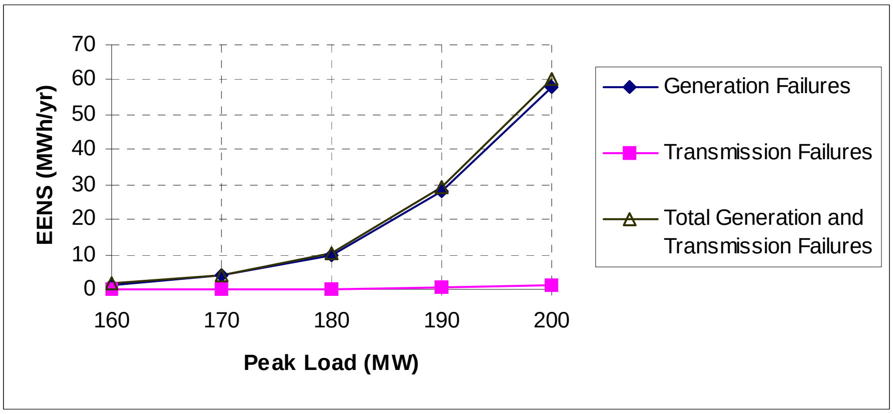


Figure 5.5: Contributions to the EENS at Bus 3 as a function of the peak load (RBTS)

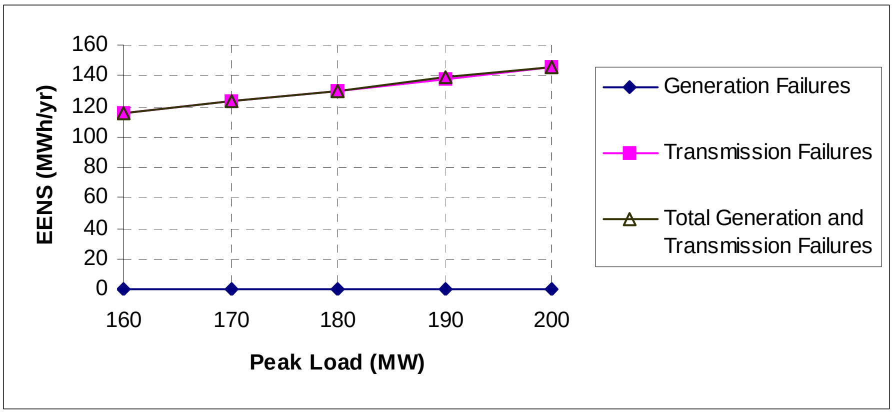


Figure 5.6: Contributions to the EENS at Bus 6 as a function of the peak load (RBTS)

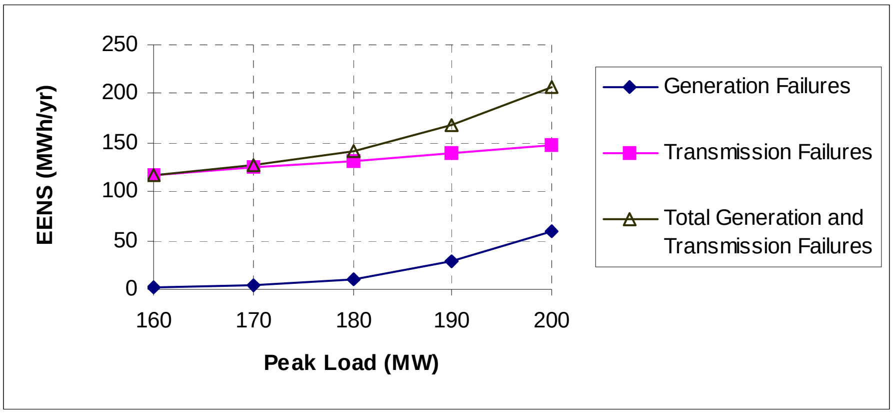


Figure 5.7: Contributions to the RBTS EENS as a function of the peak load

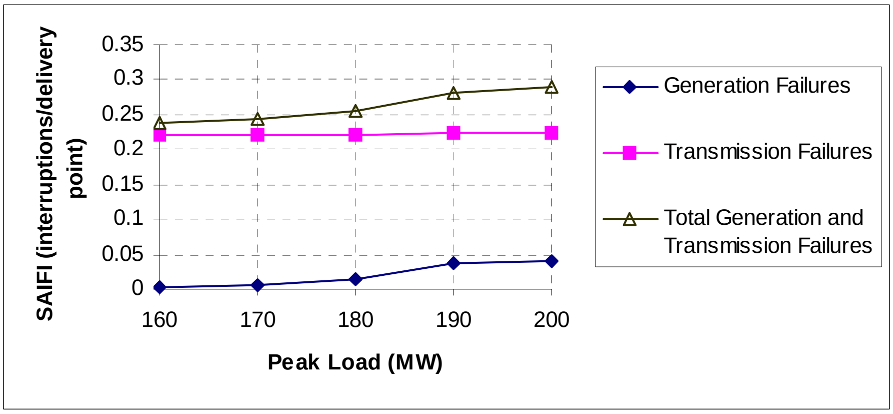


Figure 5.8: Contributions to the SAIFI for the RBTS as a function of the peak load

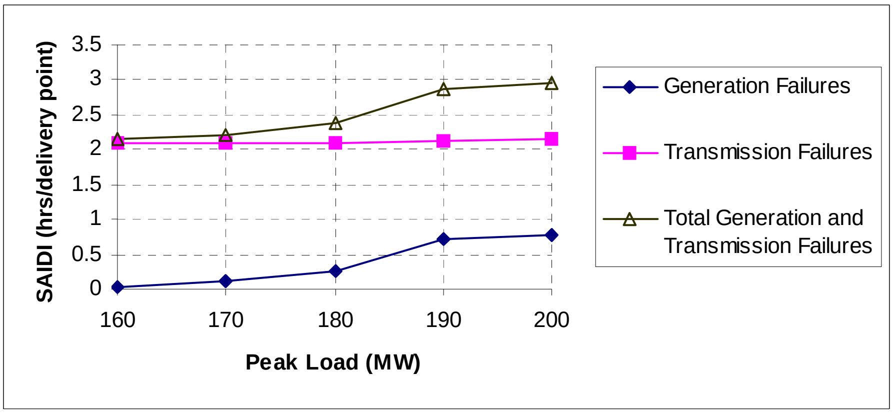


Figure 5.9: Contributions to the SAIDI for the RBTS as a function of the peak load

It can be seen from Figure 5.5 that generation system failures contribute more to the reliability indices for Bus 3 than do transmission failures. As shown in Figure 2.1, Bus 3 is supplied by four lines and is directly connected to generator Bus 1. The reliability performance of this load bus decreases when the load increases and the generation reserve decreases as shown by the increasing EENS. It can be seen from Figure 5.6, that for Bus 6, transmission failures dominate the reliability indices. Bus 6 is located far away from the generation system and is connected to the system by a single radial line.

Figures 5.7-5.9 show that the reliability indices increase with peak load for both generation and transmission system failures. The contribution due to transmission failures, however, is much larger than that due to generation failures. The RBTS is a relatively small system with some designed in weaknesses, one of which is the radial supply to Bus 6. The analysis shows that Buses 3 and 6 are the least reliable load buses in the original RBTS. The system in an overall sense can be considered to have adequate generation and transmission. The focus in the following analysis is on reinforcements that improve both the load bus and system reliability. It is assumed that generation additions are decided by market participants and are not directed by the ISO. Transmission adequacy is a responsibility of the ISO and therefore the focus in these analyses is on possible transmission system reinforcements to maintain an acceptable level of load point and system adequacy.

5.2.3. Remedial Modifications and Their Effects

Four possible transmission additions designated as Cases 1, 2, 3 and 4 are considered. It is assumed that the repair time of a new transmission line is 10 hrs and the failure rate is 0.02 f/yr • km. The four cases are as follows:

1. Double up Line 9;
2. Add a line between Bus 3 and Bus 6;
3. Add a line between Bus 4 and Bus 6;
4. Add a line between Bus 1 and Bus 3.

The data for the new transmission lines are shown in Table 5.1. The obvious purpose of doubling line 9, joining Bus 3 and Bus 6, or joining Bus 4 and Bus 6 is to strengthen the link between Bus 6 and the rest of system. The purpose of adding a line between Bus 1 and Bus 3 is to strengthen the link between Bus 3 and the generation facilities, as the reliability of Bus 3 is affected mostly by the generation system rather than the transmission system.

Table 5.1: The reliability data for the new transmission lines in the RBTS

Case No.	Line No.	From	To	Length (km)	Failure rate (f/yr)	Repair time (hrs)
1	1	5	6	50	1	10
2	1	3	6	100	2	10
3	1	4	6	100	2	10
4	1	1	3	75	1.5	10

Figures 5.10-5.14 show the load point and system reliability indices as a function of the peak load for the base case and the modified systems in Cases 1, 2, 3 and 4. The numerical values are given in Tables D.5-D.12.

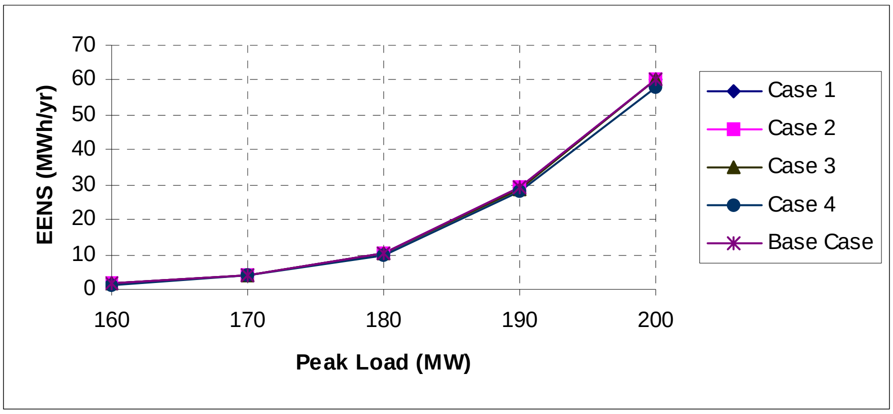


Figure 5.10: EENS at Bus 3 for Cases 1, 2, 3 and 4 and the base case

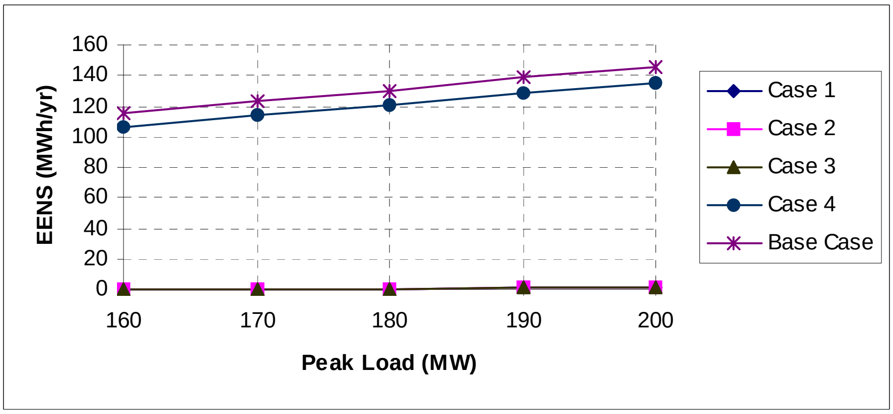


Figure 5.11: EENS at Bus 6 for Cases 1, 2, 3 and 4 and the base case

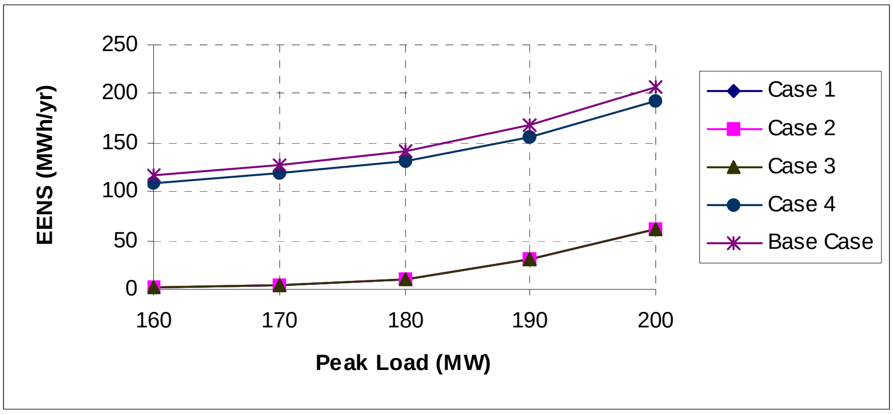


Figure 5.12: RBTS EENS versus peak load for Cases 1, 2, 3 and 4 and the base case

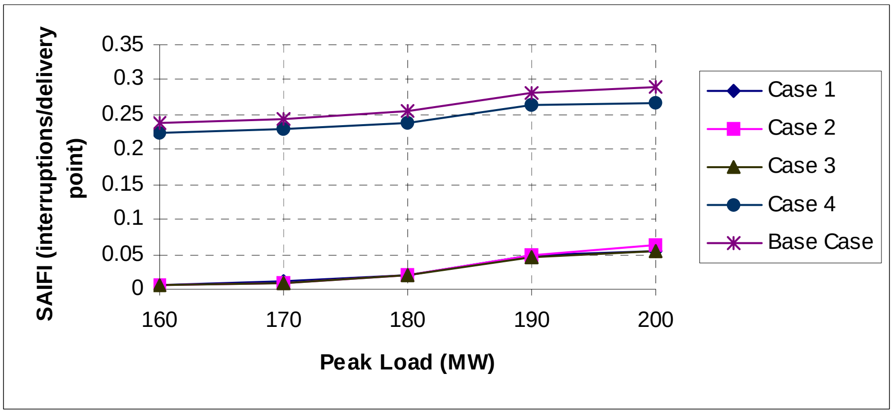


Figure 5.13: SAIFI for the RBTS versus peak load for Cases 1, 2, 3 and 4 and the base case

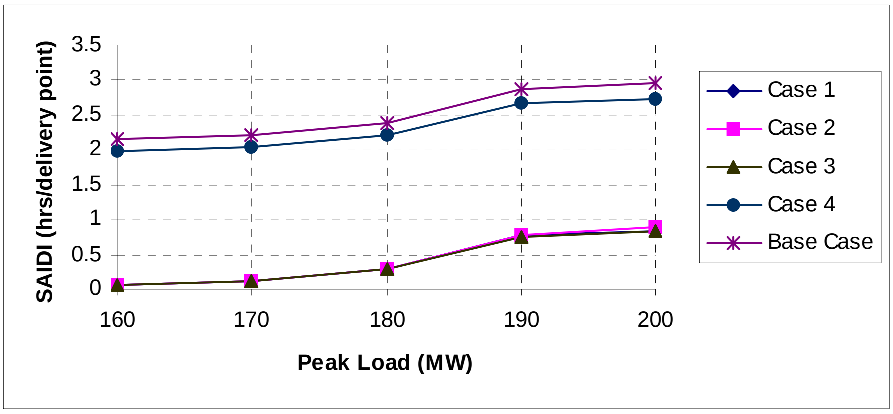


Figure 5.14: SAIDI for the RBTS versus peak load for Cases 1, 2, 3 and 4 and the base case

It can be seen from Figure 5.10 and Tables D.1, D.5, D.7, D.9, D.11 that the EENS at Bus 3 still increases with peak load after the modifications. Figure 5.11 shows that the EENS at Bus 6 improves considerably after the remedial actions taken in Cases 1, 2 and

3. The reliability of Bus 3 is improved very slightly by the transmission addition in Case 4. The factor analysis in Section 5.2.2 shows that the low reliability at Bus 6 is caused by the transmission system but that at Bus 3 is caused by the generation system. Transmission reinforcements only improve the reliability of those load points supplied by inadequate transmission facilities and do not change the reliability of those load points supplied by inadequate generation facilities. Figures 5.12-5.14 show that the overall system reliability is significantly improved by the remedial actions in Cases 1, 2, and 3 and only marginally improved by the action in Case 4. Figures 5.10-5.14 and Tables D.6, D.8, D.10, D.12 show that the three different remedial modifications in Cases 1, 2 and 3 have the same effect on load bus and system reliability. The final conclusion should therefore be based on other considerations including reliability cost and worth [1].

5.3. The Modified RBTS analysis

The original RBTS has adequate generation and transmission other than the supply to Bus 6. As noted earlier, it appears that in the new market environment, generation additions driven by market forces are not being matched by the required transmission additions. Under these conditions, systems which previously had adequate transmission facilities become systems with inadequate transmission facilities as the system load grows. In order to simulate this condition in the RBTS, it is assumed that the transmission system remains the same, but the installed generating capacity is doubled. The same number of generators with the same size as those currently installed was added at each generator bus. It was assumed that the new generators have the same reliability data as the old ones. The peak load level was varied from 260 MW to 340 MW to simulate the increase in demand. The modified RBTS is designated as the MRBTS in the following study.

5.3.1. The Modified RBTS Base Case Analysis

The variation in load point and system reliability as a function of peak load was determined to provide base case analysis and establish the least reliable load buses in the MRBTS.

Figures 5.15-5.18 show the variations in the selected reliability indices as a function of peak load. The numerical values are shown in Tables D.13 and D.14.

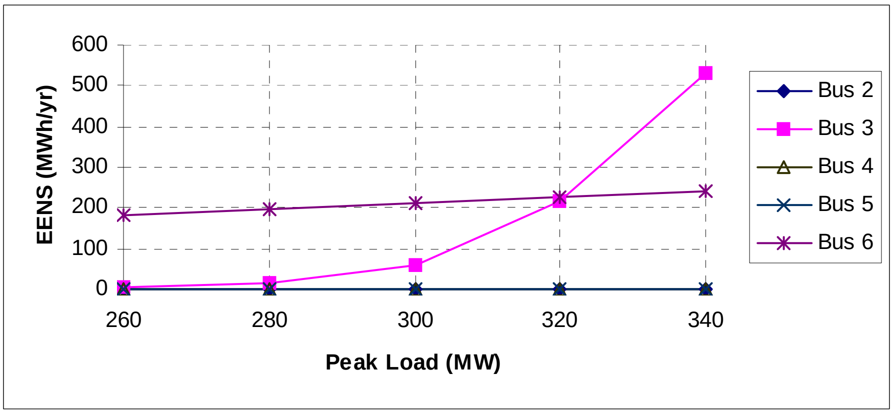


Figure 5.15: EENS of each bus in the MRBTS versus peak load

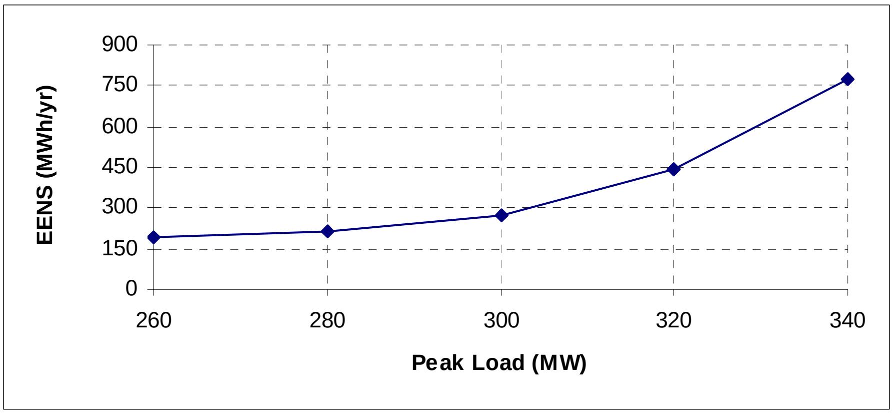


Figure 5.16: MRBTS EENS versus peak load

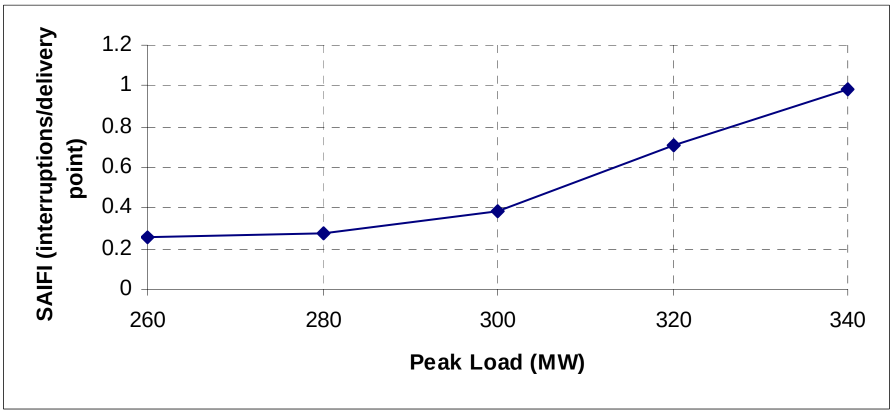


Figure 5.17: SAIFI for the MRBTS versus peak load

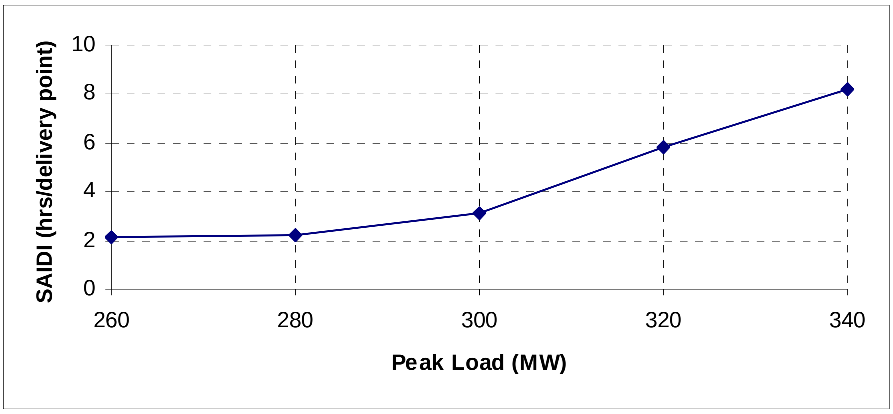


Figure 5.18: SAIDI for the MRBTS versus peak load

Figure 5.15 shows that the EENS at Bus 3 increases significantly with peak load and the initially high EENS at Bus 6 increases slightly. The EENS at Bus 3 increases rapidly when the peak load exceeds 320 MW. It is obvious that the least reliable load buses in the MRBTS are Bus 3 and 6. Figures 5.16-5.18 show how the values of system EENS, SAIFI and SAIDI increase with peak load.

5.3.2. Factor Analysis of the Modified RBTS Base Case

Figures 5.19-5.23 show the contributions to the different load point and system reliability indices as a function of the peak load due to generation and transmission system failures. The numerical values are shown in Tables D.15 and D.16.

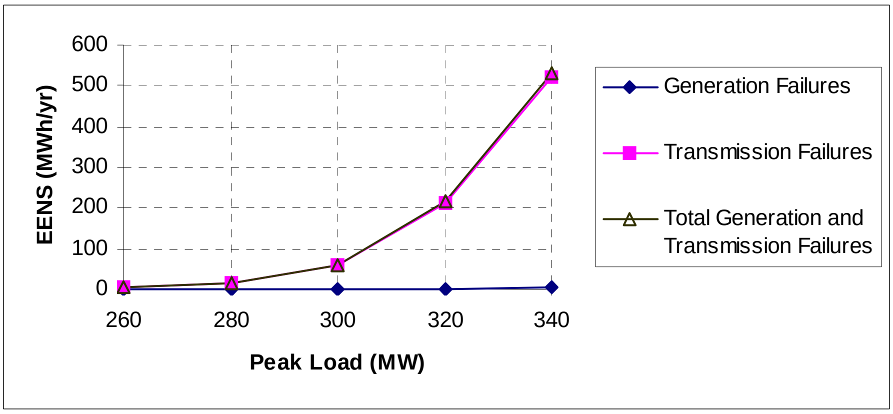


Figure 5.19: Contributions to the EENS at Bus 3 as a function of the peak load (MRBTS)

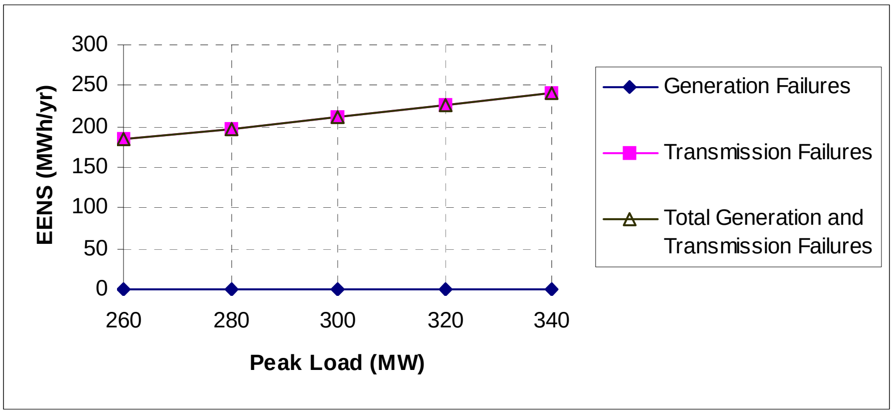


Figure 5.20: Contributions to the EENS at Bus 6 as a function of the peak load (MRBTS)

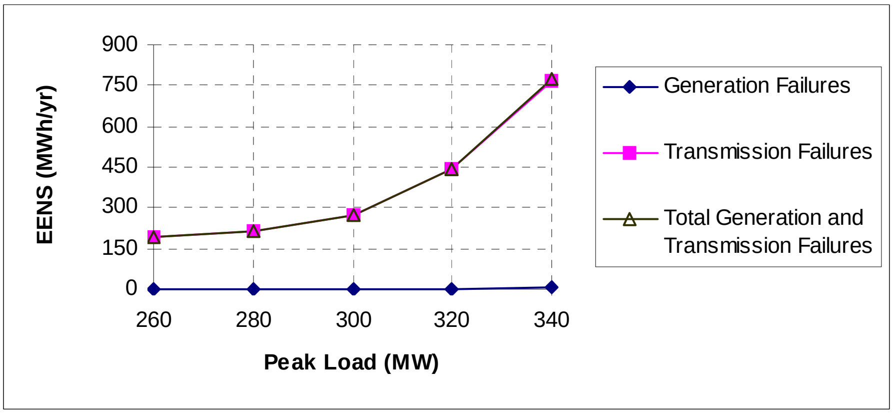


Figure 5.21: Contributions to the MRBTS EENS as a function of the peak load

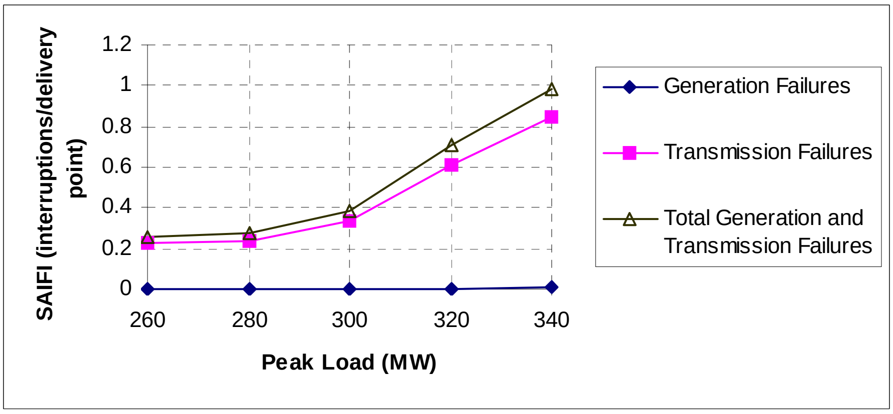


Figure 5.22: Contributions to the SAIFI for the MRBTS as a function of the peak load

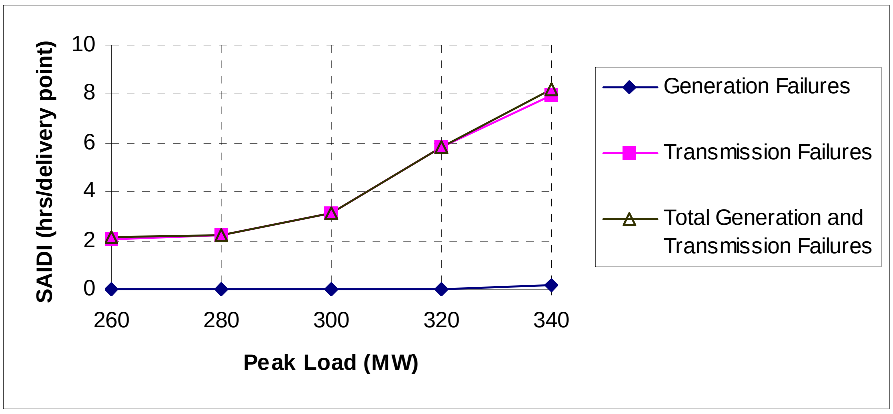


Figure 5.23: Contributions to the SAIDI for the MRBTS as a function of the peak load

Figure 5.19 shows that for Bus 3 in the MRBTS, transmission system failures contribute more to the reliability indices than do generation system failures. This is different from that found in the original RBTS and shows that as generation and load demand increases, transmission deficiencies can occur unless addressed. It can be seen from Figure 5.20 that transmission failures continue to dominate the reliability indices at Bus 6. Figures 5.21-5.23 show that the overall system reliability indices increase with peak load and are dominated by transmission system failures.

The analysis shows that Buses 3 and 6 are the least reliable load buses in the MRBTS, which now can be considered to have an adequate generation system and a weak transmission system.

5.3.3. Remedial Modifications and Their Effects

Two transmission addition actions are analyzed in this section. These are designated as Cases 1 and 2.

1. Add a line between Bus 1 and Bus 3, and double up Line 9;
2. Add a line between Bus 3 and Bus 4, and double up Line 9.

The data for the new transmission lines are shown in Table 5.2. The purpose in adding a line between Bus 1 and Bus 3, or between Bus 3 and Bus 4 is to strengthen the link between Bus 3 and the rest of system, as the reliability of Bus 3 is affected mostly by the transmission system rather than the generation system in the MRBTS. The purpose in doubling Line 9 is to strengthen the link between Bus 6 and the rest of the system as Bus 6 is weakly linked to the system.

Table 5.2: The reliability data for the new transmission lines in the MRBTS

Case No.	Line No.	From	To	Length (km)	Failure rate (f/yr)	Repair time (hrs)
1	1	1	3	75	1.5	10
	2	5	6	50	1	10
2	1	3	4	50	1	10
	2	5	6	50	1	10

Figures 5.24-5.28 show the load point and system reliability indices as a function of the peak load, incorporating the remedial modifications in Cases 1 and 2, and for the base case. The numerical values for these indices are given in Tables D.17-D.20.

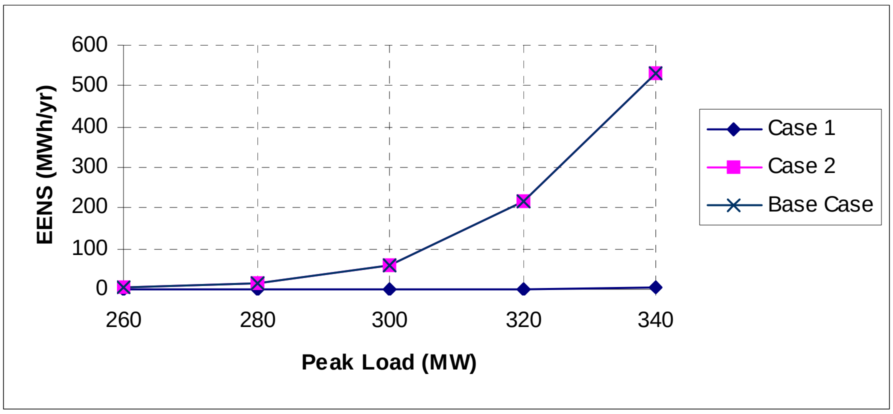


Figure 5.24: EENS at Bus 3 based on Cases 1 and 2 and for the base case

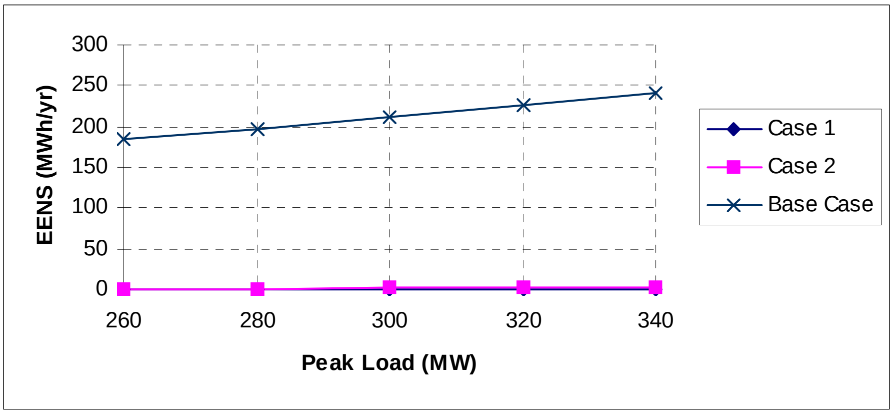


Figure 5.25: EENS at Bus 6 based on Cases 1 and 2 and for the base case

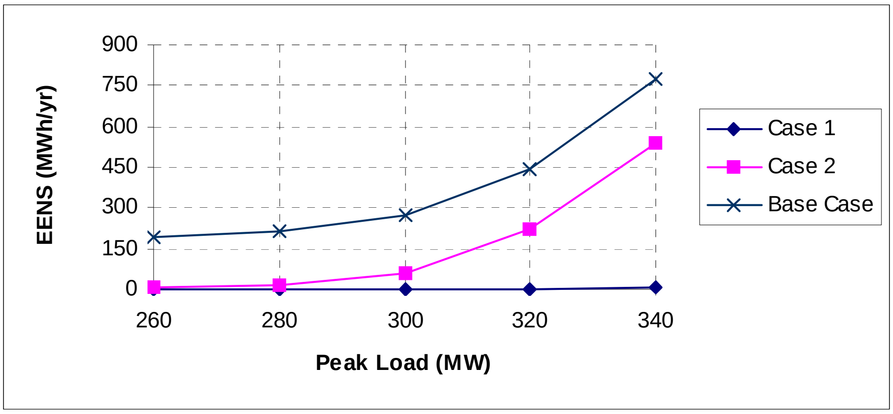


Figure 5.26: MRBTS EENS versus peak load based on Cases 1 and 2 and for the base case

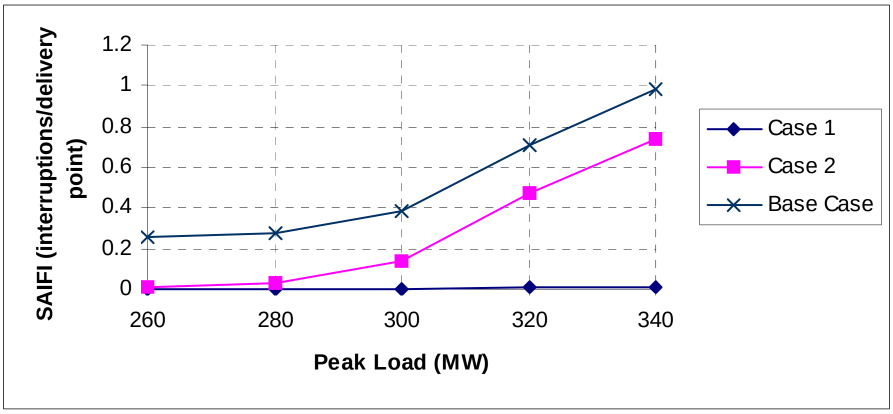


Figure 5.27: SAIFI for the MRBTS versus peak load based on Cases 1 and 2 and for the base case

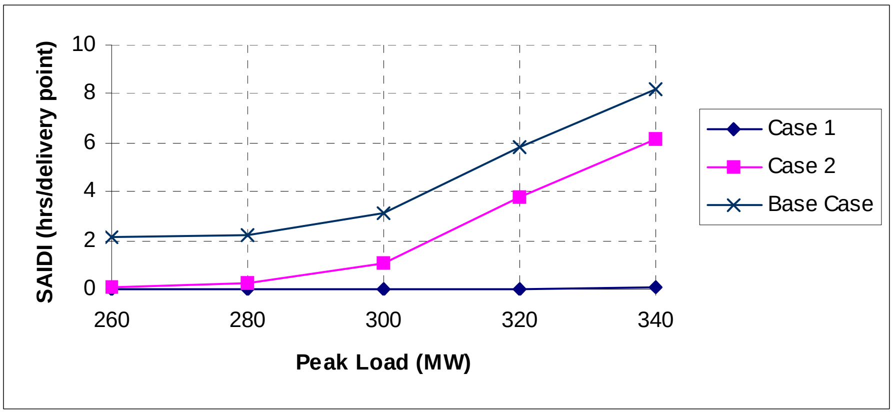


Figure 5.28: SAIDI for the MRBTS versus peak load based on Cases 1 and 2 and for the base case

Figures 5.24-5.25 and Tables D.13, D.17, D.19 show that the EENS values at Bus 3 and Bus 6 remain at a low level as the peak load increases with the remedial modifications in Case 1. The reliabilities of Bus 3 and 6 are improved by adding these new transmission lines. The factor analysis in Section 5.3.2 shows that the poor reliability at both Bus 3 and 6 is caused by an inadequate transmission system. System transmission reinforcements can improve the reliability at load points supplied by an inadequate transmission system. It can be seen from Figure 5.24, however, that the remedial modifications in Case 2 do not improve the reliability of Bus 3, although this transmission addition action strengthens the link between Bus 3 and the rest of the system. Not every system transmission reinforcement action will improve the reliability at a connected load point in a system with inadequate transmission facilities. Figures 5.26-5.28 show that the overall system reliability is improved by the remedial modifications. Figures 5.24-5.28 show that the system reliability is improved more by the actions in Case 1 than by those in Case 2. Different modifications result in different benefits and therefore decision-making should be based on the cost and worth, and other relevant concerns.

5.4. IEEE-RTS Analysis

Transmission deficiency analysis is applied to the IEEE-RTS in this section,.

5.4.1. IEEE-RTS Base Case Analysis

The variations in the load point and system reliability as a function of peak load were determined in order to perform base case analysis and establish the least reliable load buses in the IEEE-RTS. The peak load level for the IEEE-RTS was varied from 2500 MW to 3100 MW. The specified system peak load level for the IEEE-RTS is 2850 MW and the total installed capacity is 3405 MW.

Figures 5.29-5.32 show the variations in the selected reliability indices as a function of peak load. The numerical values are shown in Tables D.21 and D.22.

Table D.21 shows that Bus 9 in the south region and Buses 14, 15 and 19 in the north region have the highest reliability indices of all the load buses. The following analysis is focused on these four load buses.

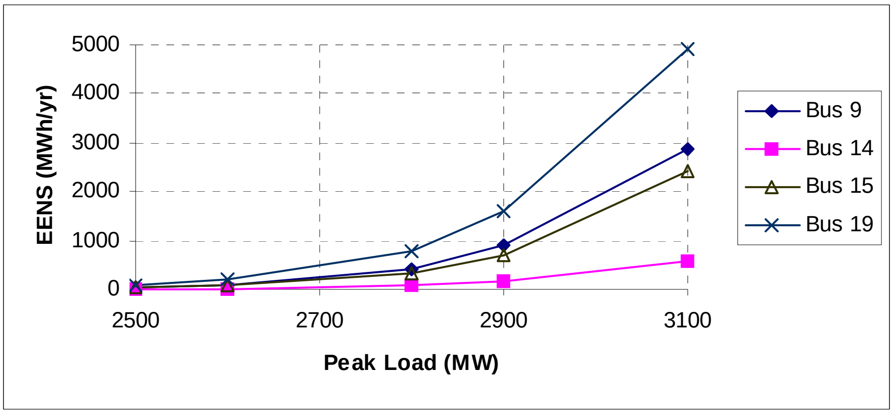


Figure 5.29: EENS of the selected buses in the IEEE-RTS versus peak load

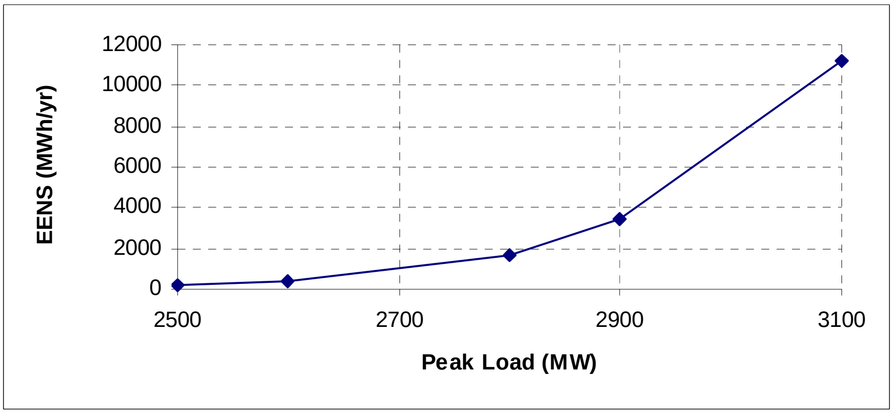


Figure 5.30: IEEE-RTS EENS versus peak load

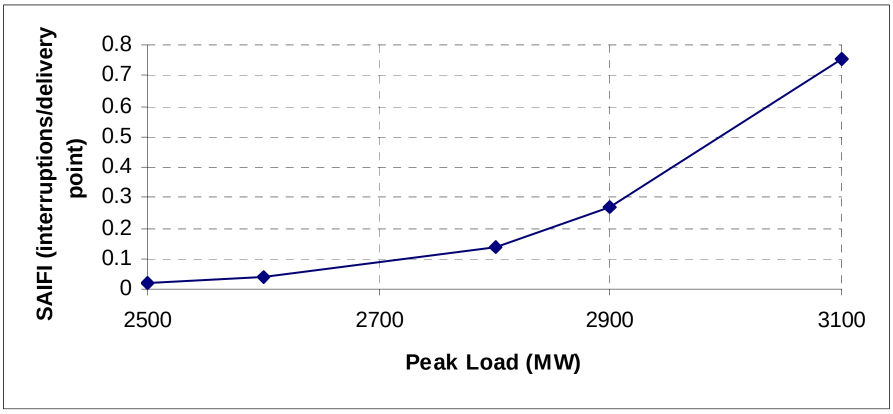


Figure 5.31: SAIFI for the IEEE-RTS versus peak load

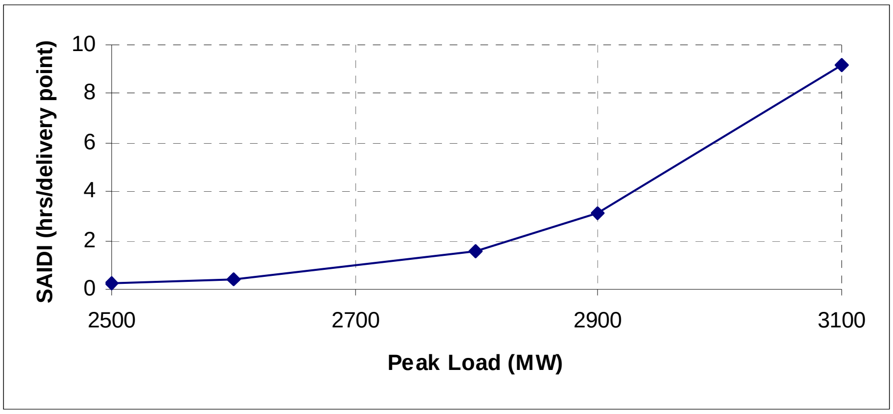


Figure 5.32: SAIDI for the IEEE-RTS versus peak load

It can be seen from Figure 5.29 that the EENS at Buses 9, 14, 15 and 19 increase with increasing peak load. The least reliable load buses in the IEEE-RTS are Buses 9, 14, 15 and 19. Figures 5.30-5.32 show how the overall system EENS, SAIFI and SAIDI increase with peak load.

5.4.2. Factor Analysis of the IEEE-RTS Base Case

The analysis is limited to the least reliable load buses, Buses 9, 14, 15 and 19. Figures 5.33-5.39 show the variations in the different load point and system reliability indices as a function of the peak load. The numerical values are shown in Tables D.23 and D.24.

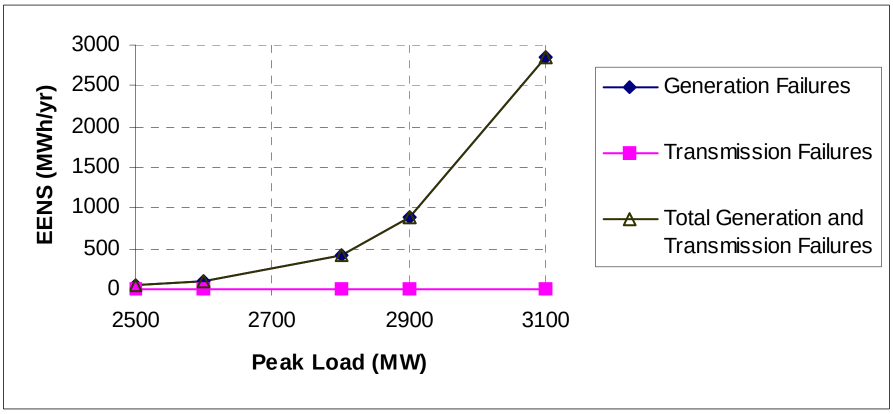


Figure 5.33: Contributions to the EENS at Bus 9 as a function of the peak load

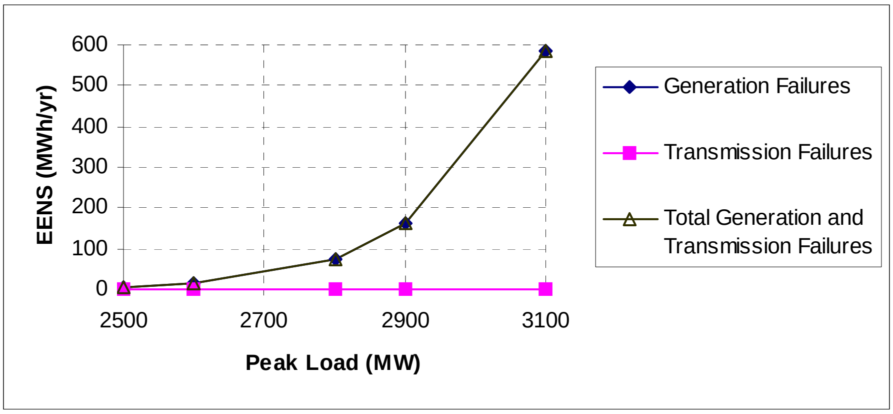


Figure 5.34: Contributions to the EENS at Bus 14 as a function of the peak load

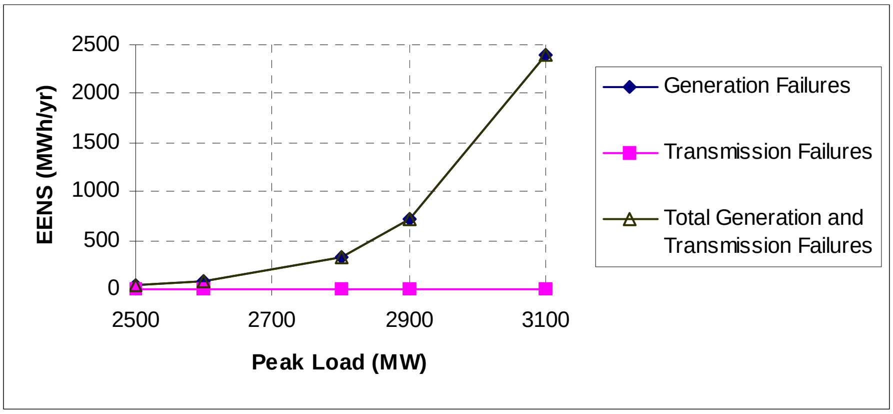


Figure 5.35: Contributions to the EENS at Bus 15 as a function of the peak load

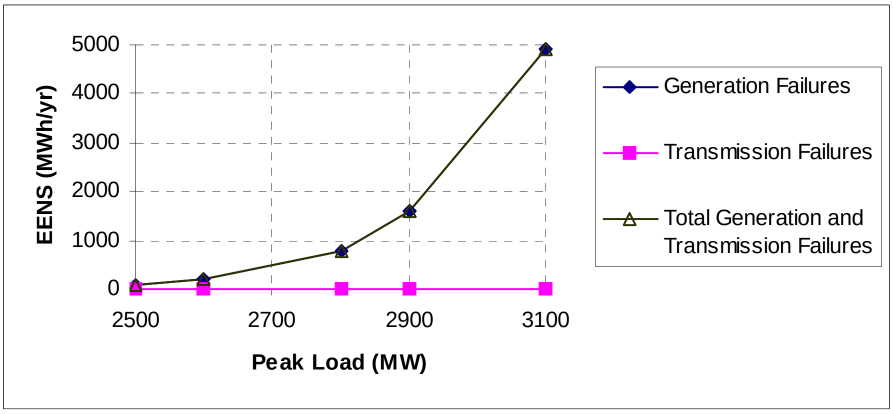


Figure 5.36: Contributions to the EENS at Bus 19 as a function of the peak load

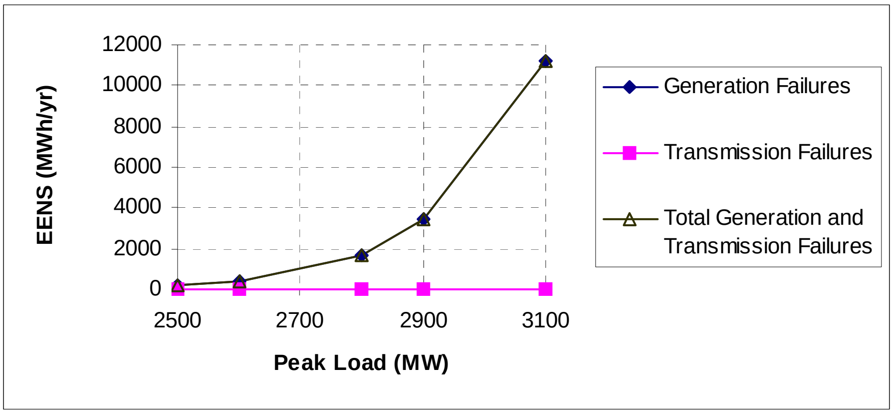


Figure 5.37: Contributions to the IEEE-RTS EENS as a function of the peak load

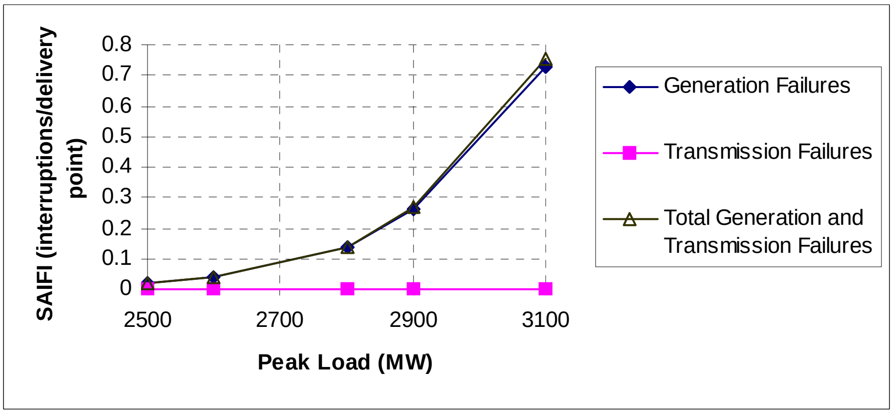


Figure 5.38: Contributions to the SAIFI for the IEEE-RTS as a function of the peak load

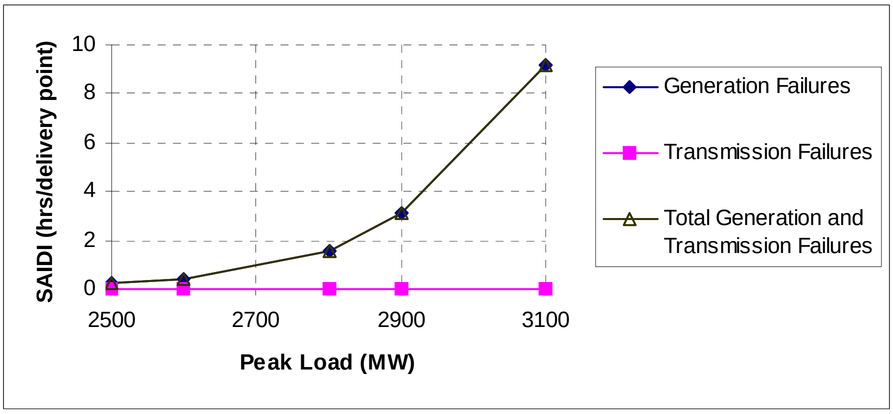


Figure 5.39: Contributions to the SAIDI for the IEEE-RTS as a function of the peak load

It can be seen from Figures 5.33-5.36 that for these load buses, generation system failures are the major contributions to the reliability indices. Figures 5.37-5.39 also show that the system reliability indices are dominated by generation system failures. The

IEEE-RTS is a system with a comparatively strong transmission system and a weak generation system and therefore the generation failures dominate the reliability indices.

5.4.3. Remedial Modifications and Their Effects

The base case analysis indicated that Buses 9, 14, 15 and 19 are the least reliable load points in the system. The factor analysis, however, shows that reliability levels are not due to transmission deficiencies and therefore the addition of new transmission lines will not significantly improve the load bus and system reliability. This point is illustrated in the RBTS study in Section 5.2.3, where adding a line between Bus 1 and Bus 3 does not improve the system reliability as Bus 3 is affected by inadequate generation rather than by insufficient transmission facilities.

5.5. MRTS Analysis

As noted many times, the original IEEE-RTS has inadequate generation and an adequate transmission system. The modified RTS (MRTS) described in Section 5.3 was used in the following analyses.

5.5.1. MRTS Base Case Analysis

The variations in the load point and system reliability as a function of peak load were determined to establish the least reliable load buses in the MRTS. The peak load level was assumed to vary from 4700 MW to 5500 MW. Figures 5.40-5.43 show the variations in the selected reliability indices as a function of peak load. The numerical values are shown in Tables D.25 and D.26.

It can be seen from Table D.25, that Buses 3, 6, 9, 10 in the south region and Buses 14, 15, 16, 19 in the north region have the highest reliability indices of all the load buses. The following analysis is focused on these eight load buses.

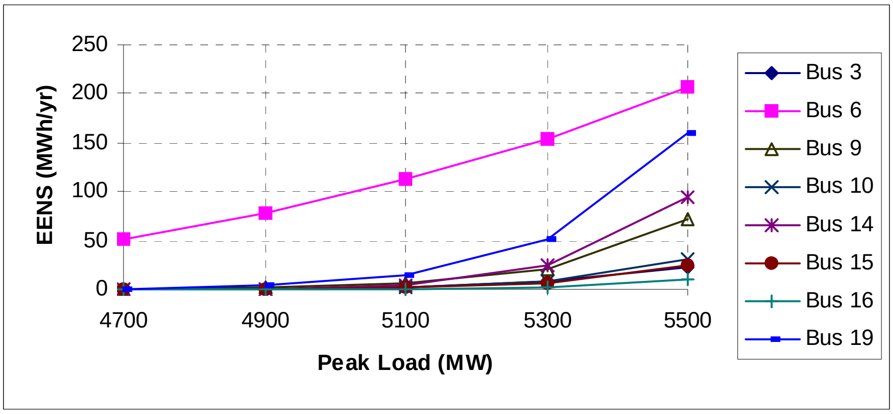


Figure 5.40: EENS of the selected buses in the MRTS versus peak load

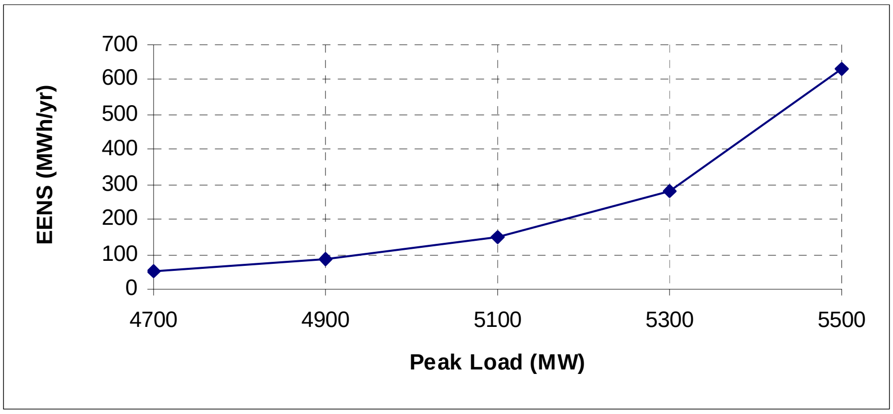


Figure 5.41: MRTS EENS versus peak load

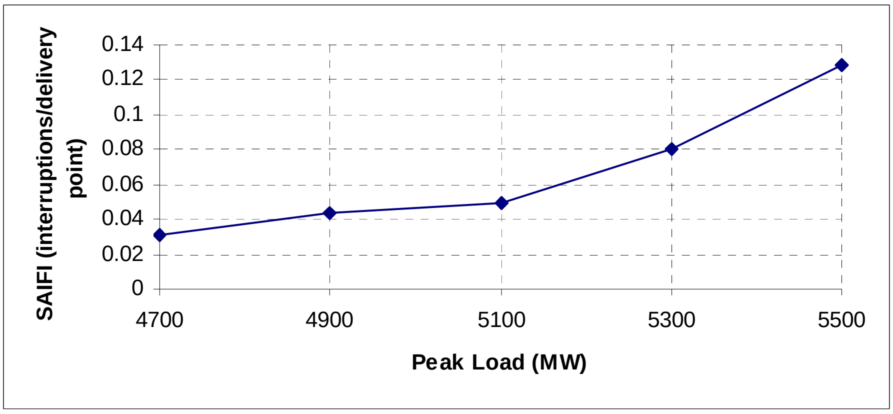


Figure 5.42: SAIFI for the MRTS versus peak load

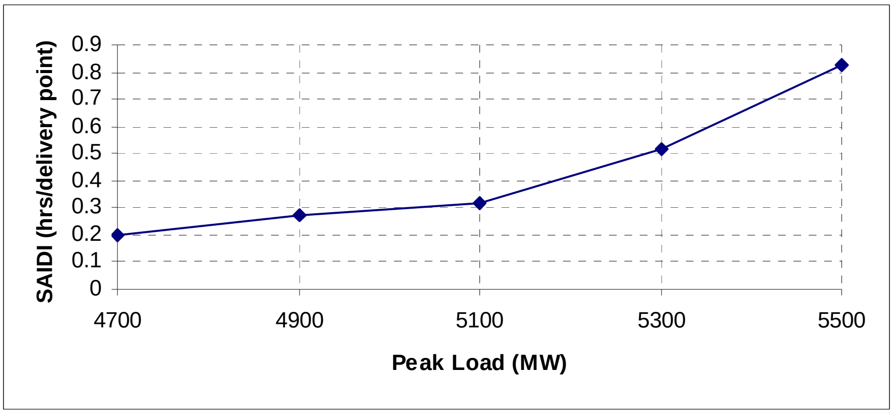


Figure 5.43: SAIDI for the MRTS versus peak load

Figure 5.40 shows how the EENS of Buses 3, 6, 9, 10, 14, 15, 16 and 19 increase with increasing peak load. Figures 5.41-5.43 also show how the system EENS, SAIFI and SAIDI increase with peak load.

5.5.2. Factor Analysis of the MRTS Base Case

The analysis is limited to the eight least reliable load buses.

Figures 5.44-5.54 show the contributions of the generation and transmission system facilities to the load point and system reliability indices as a function of the peak load. The numerical values are shown in Tables D.27 and D.28.

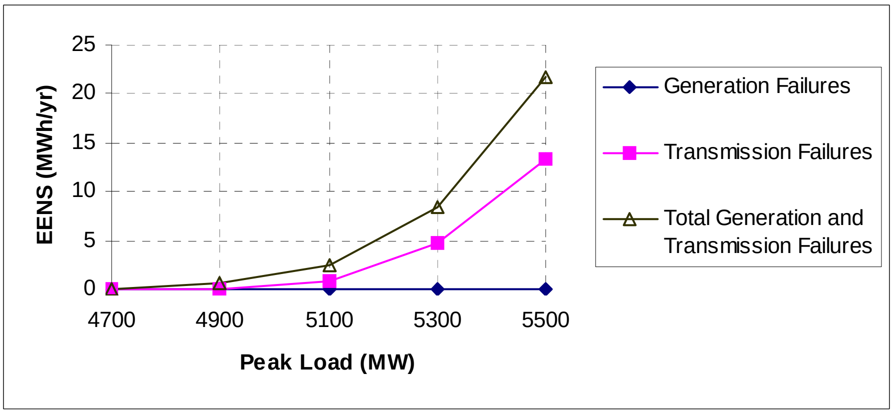


Figure 5.44: Contributions to the EENS at Bus 3 as a function of the peak load

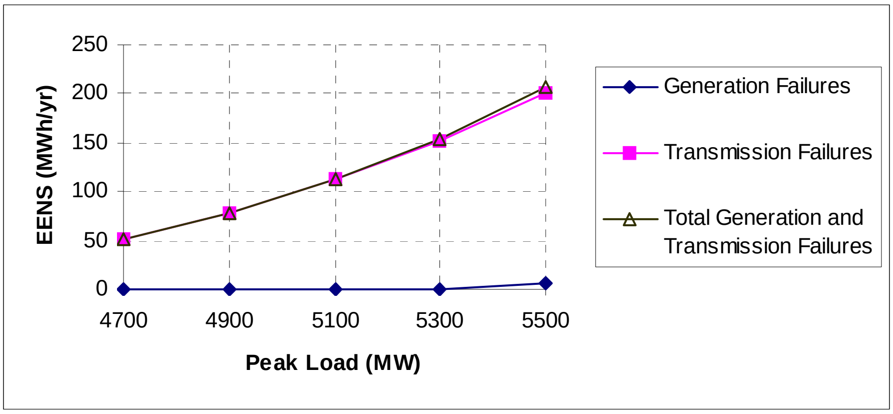


Figure 5.45: Contributions to the EENS at Bus 6 as a function of the peak load

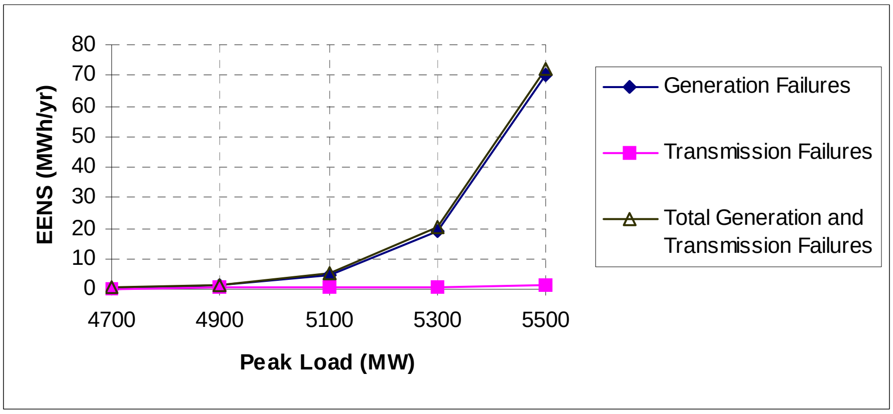


Figure 5.46: Contributions to the EENS at Bus 9 as a function of the peak load

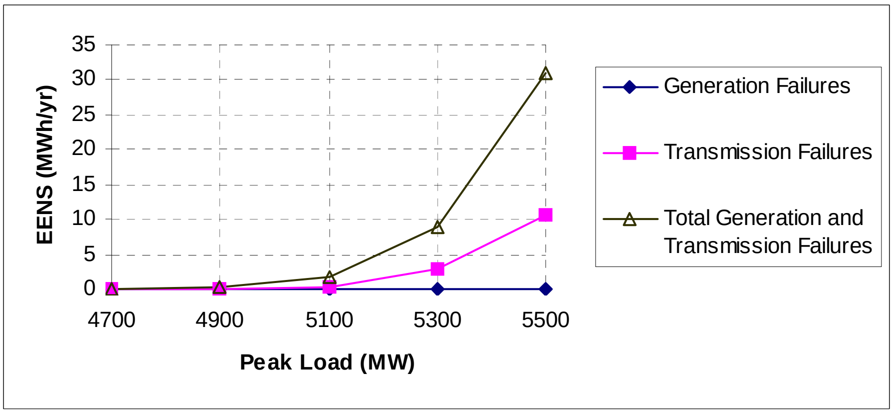


Figure 5.47: Contributions to the EENS at Bus 10 as a function of the peak load

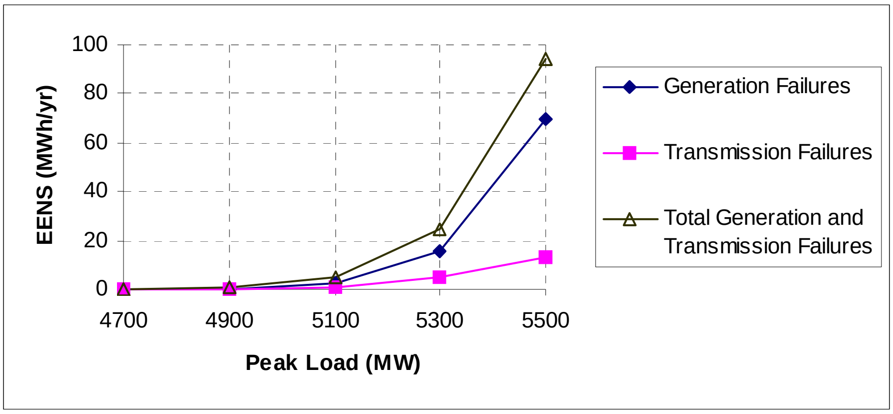


Figure 5.48: Contributions to the EENS at Bus 14 as a function of the peak load

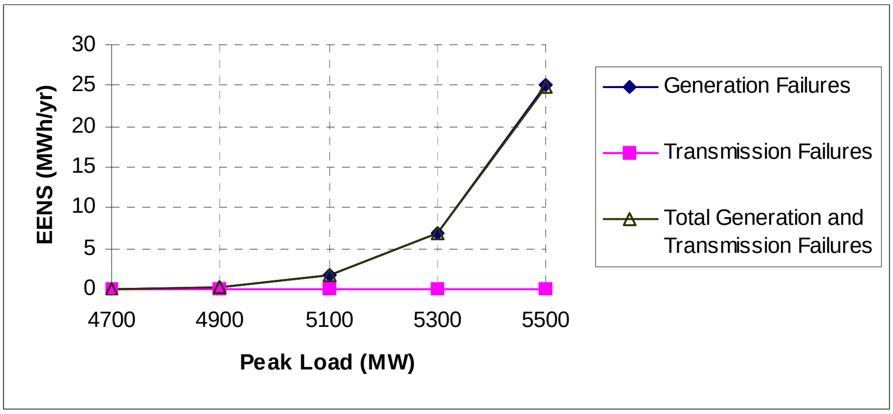


Figure 5.49: Contributions to the EENS at Bus 15 as a function of the peak load

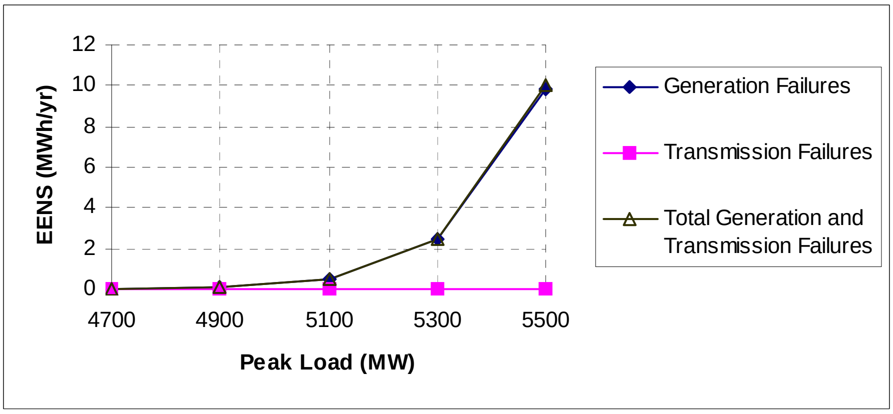


Figure 5.50: Contributions to the EENS at Bus 16 as a function of the peak load

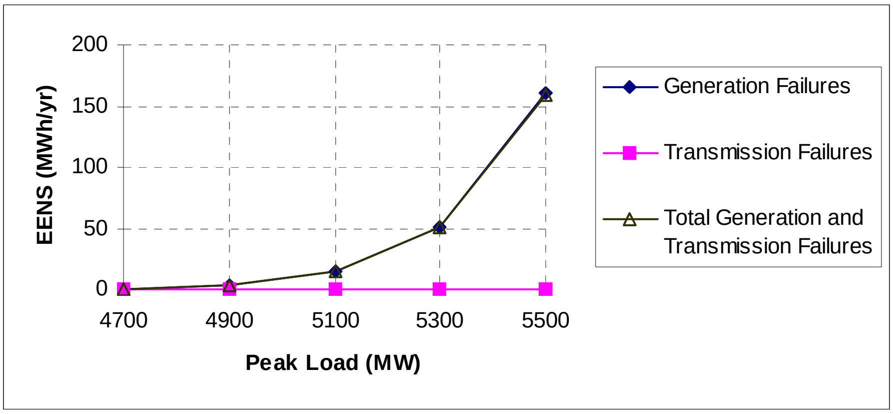


Figure 5.51: Contributions to the EENS at Bus 19 as a function of the peak load

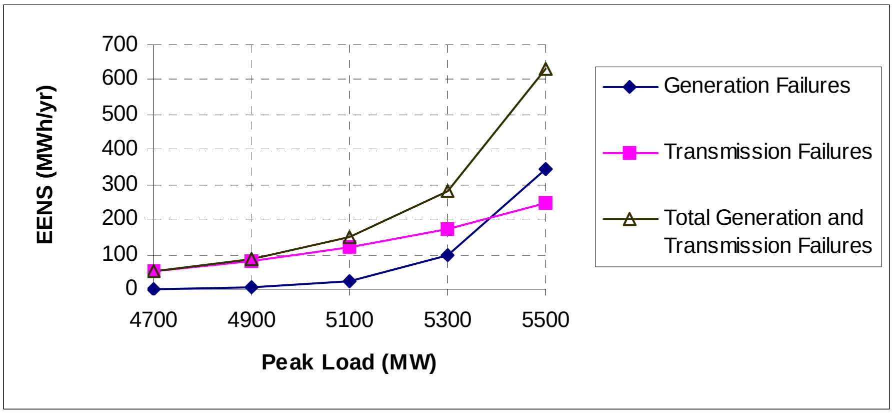


Figure 5.52: Contributions to the MRTS EENS as a function of the peak load

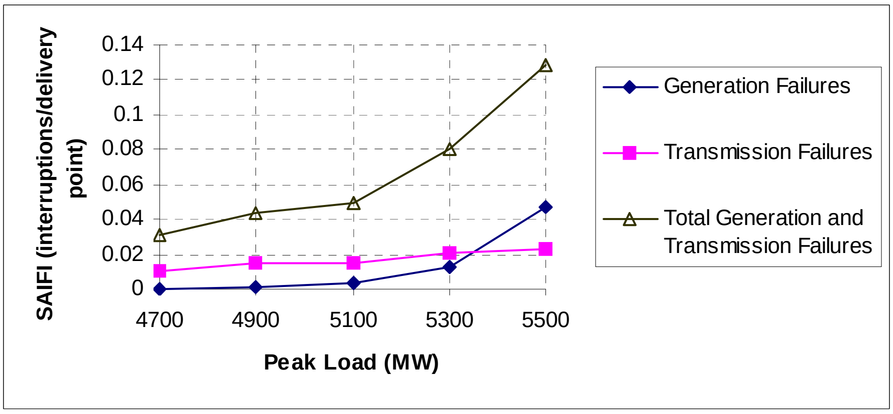


Figure 5.53: Contributions to the SAIFI for the MRTS as a function of the peak load

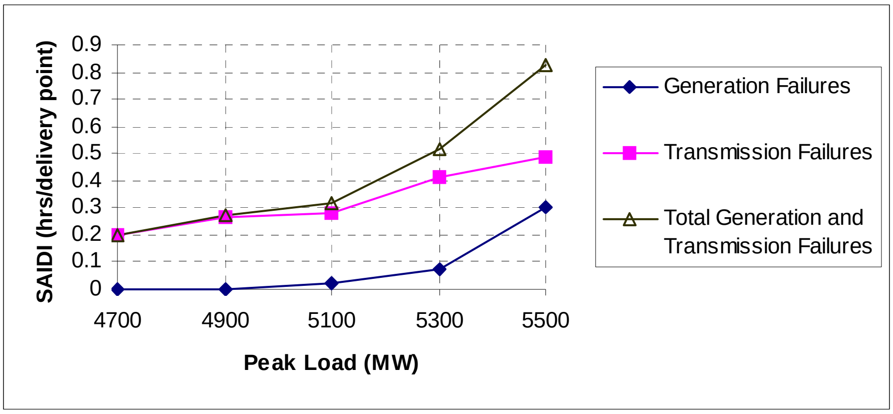


Figure 5.54: Contributions to the SAIDI for the MRTS as a function of the peak load

Figures 5.44-5.51 show that for Bus 3, 6 and 10, transmission system failures contribute more to the reliability indices than does the generation system.

Figures 5.52-5.54 show that the system reliability indices increase with peak load due to both generation and transmission system failures. Transmission failures begin to dominate the reliability indices in the MRTS because the increasing generation and load demands require commensurate transmission capacity to serve the system.

The analysis shows Buses 3, 6 and 10 are the weak points in the MRTS, which can be categorized as having an adequate generation system and an inadequate transmission system.

5.5.3. Remedial Modifications and Their Effects

Two transmission addition actions were considered and are designated as Cases 1 and 2.

1. Double up Lines 7, 10 and 17;
2. Double up Lines 2, 3, 5 and 9.

The data for the new transmission lines are shown in Table 5.3. Buses 3, 6 and 10 are all in the south region, which is relatively remote from the bulk of the generation. Compared to the original IEEE-RTS, the MRTS has a weak transmission system in the south region but not in the whole system. Case 1 strengthens the link between the south region and the north region and this addition should deliver more power from north to south. Case 2 strengthens the link between the least reliable load buses and the generation facilities in the south region.

Table 5.3: The reliability data for the new transmission lines in the MRTS

Case No.	Line No.	From	To	Length (km)	Failure rate (f/yr)	Repair time (hrs)
1	1	3	24	0	0.02	768.0
	2	10	12	0	0.02	768.0
	3	6	10	16	0.33	35.0
2	1	1	3	55	0.51	10.0
	2	1	5	22	0.33	10.0
	3	5	10	23	0.34	10.0
	4	2	6	50	0.48	10.0

Figures 5.55-5.60 show the load point and system reliability indices as a function of peak load based on the remedial modifications in Cases 1 and 2 and for the base case. The numerical values are shown in Tables D.29-D.32.

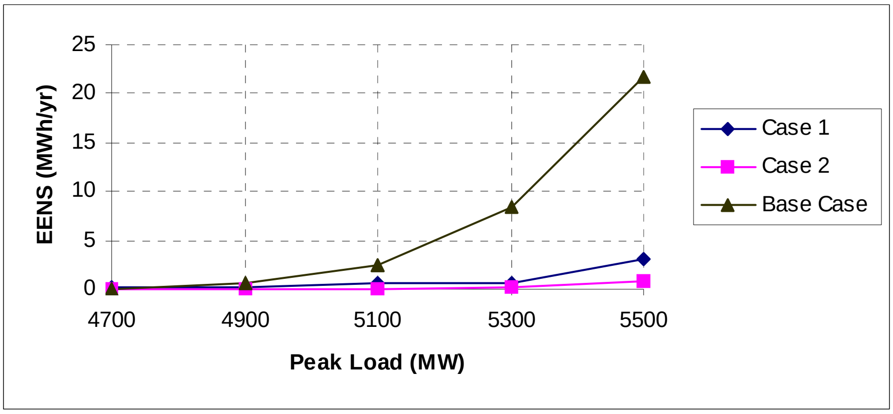


Figure 5.55: EENS at Bus 3 based on Cases 1 and 2 and for the base case

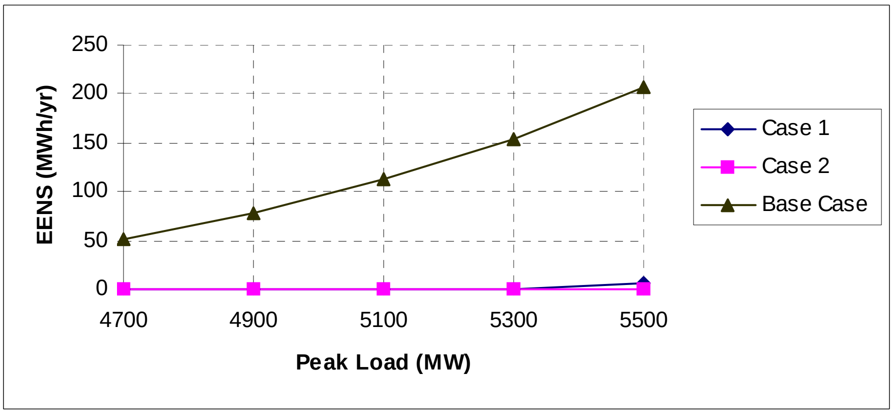


Figure 5.56: EENS at Bus 6 based on Cases 1 and 2 and for the base case

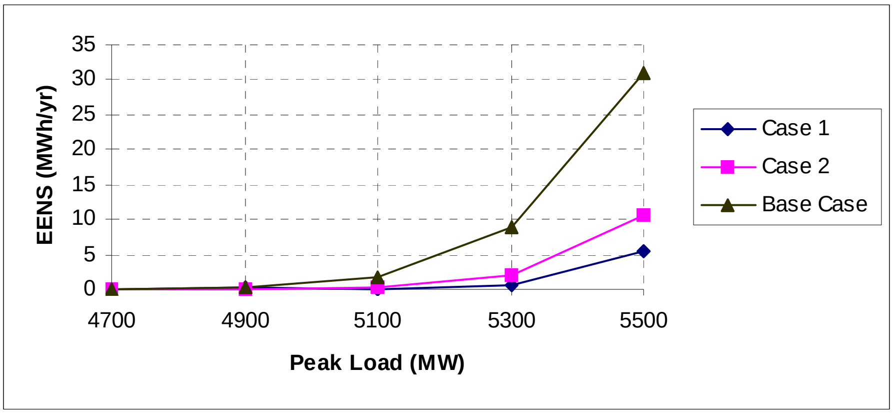


Figure 5.57: EENS at Bus 10 based on Cases 1 and 2 and for the base case

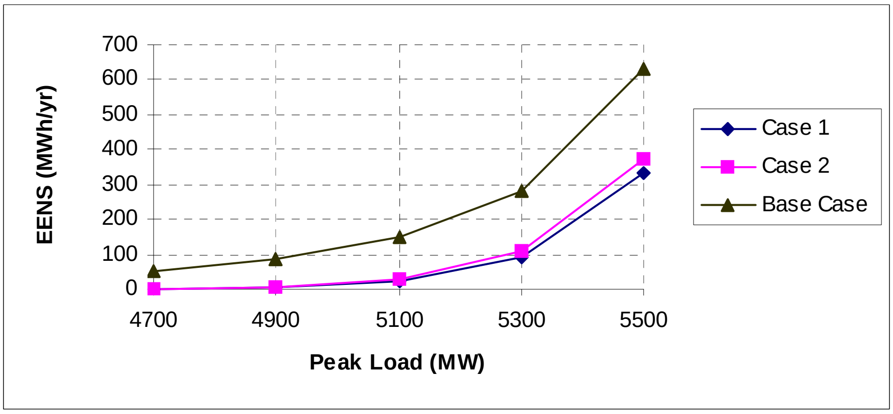


Figure 5.58: MRTS EENS versus peak load based on Cases 1 and 2 and for the base case

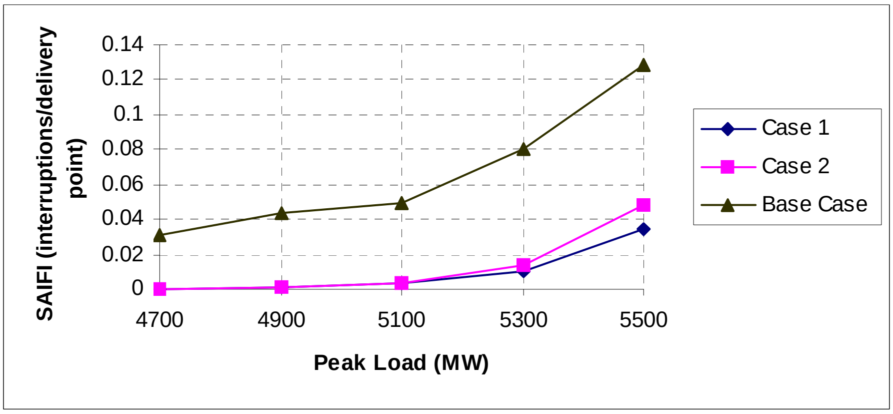


Figure 5.59: SAIFI for the MRTS versus peak load based on Cases 1 and 2 and for the base case

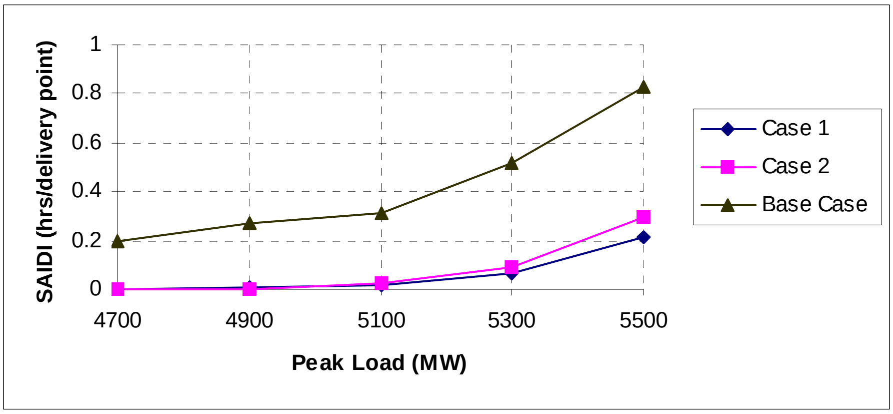


Figure 5.60: SAIDI for the MRTS versus peak load based on Cases 1 and 2 and for the base case

It can be seen from Figures 5.55-5.57 that the EENS at Buses 3, 6 and 10 remain at a relatively low level as the peak load increases. The reliabilities of Buses 3 and 6 are improved by adding the new transmission lines. The factor analysis in Section 5.5.2 shows that the poor reliabilities of Buses 3, 6 and 10 are due to inadequate transmission and that transmission reinforcements can improve the reliability of these load points. Figures 5.58-5.60 show that the overall system reliability is also improved by the remedial modifications. Figures 5.55-5.57 show that Buses 3 and 6 benefit more from the remedial modifications in Case 2 than from those in Case 1, while Bus 10 benefits more from those in Case 1 than from those in Case 2. Figures 5.58-5.60 show that the overall system reliability benefits more from the modifications in Case 1 than from those in Case 2. Different modifications bring different benefits to different points in an overall power system. The final decision regarding which facilities should be constructed should be based on their cost and worth, and on other relevant concerns.

5.6. Summary

This chapter is focused on how to identify transmission deficiencies in composite generation and transmission systems. A procedure that can be employed to implement this task is applied to four test systems. The main steps in the procedure described in this chapter can be summarized as follows:

1. Perform a base case analysis and determine the load point and system reliability indices as a function of the peak load. The combination of the load point indices and the system indices is then used to provide an indication of the system weak points.

2. The individual effects on the load point and system indices of generation and transmission facility failures is then examined. The key factors (generation or transmission) that influence the load point and system reliability indices are then determined.
3. The system is then modified by adding transmission lines in accordance with the information obtained in the previous studies. A range of modifications should be considered and the results compared with those of the base case to determine the benefits associated with the different actions.

Four test systems with different characteristics were used in the studies described in this chapter. They are the original RBTS which is a relatively small system with adequate generation and transmission; the MRBTS with adequate generation and a weak transmission system; the IEEE-RTS which is a comparably larger system with weak generation and adequate transmission; the MRTS with adequate generation and a weak transmission system. The studies shown illustrate that the procedure described above can be used to identify transmission deficiencies in different systems and to determine the reliability benefits associated with different remedial actions.

6. SUMMARY AND CONCLUSIONS

Composite system adequacy assessment involves the analysis of the combined generation and transmission system in regard to its ability to serve the system load. Power system reliability evaluation techniques are now highly developed and it is expected that their application in bulk power systems will continue to increase in the future especially in the newly deregulated power industry. The research described in this thesis was conducted using a Monte Carlo simulation program designated as MECORE. A major objective of the research is to investigate the application of quantitative reliability analysis to composite systems in both the traditionally regulated and newly deregulated electric power industry. This research should assist a system planner to solve reliability related problems in the changing electric power industry. The research presented in this thesis is conducted by application to two well-known reliability test systems.

Chapter 1 provides a brief introduction to the overall area of power system reliability evaluation including deterministic and probabilistic criteria, the concepts of adequacy and security and the three power system hierarchical levels. An introduction to the electricity utility industry and its deregulation is also briefly presented in Chapter 1.

Background information on composite system analysis and the basic adequacy indices including predictive and performance parameters are briefly introduced in Chapter 2. This chapter notes that both analytical and Monte Carlo simulation techniques can be applied to composite system reliability evaluation and that a Monte Carlo approach is used in this research work. Three Monte Carlo simulation methods designated as the state sampling technique, the state transition sampling technique, and the sequential technique together with their advantages, limitations and general procedures are briefly illustrated in this chapter.

The computer program MECORE, which is a Monte Carlo based composite generation and transmission system reliability evaluation tool designed to perform reliability and reliability worth assessment of bulk electricity systems, is also presented in Chapter 2. This program uses the state sampling technique. It was initially developed at the University of Saskatchewan and further enhanced at BC Hydro. It can be used to perform a wide range of composite system studies.

The basic indices and the 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 load point indices and the system indices complement each other and serve different functions. Both load point and system indices can be calculated on an annualized or annual basis. Annualized indices are calculated at the peak load conditions and expressed on a one-year basis. Annual indices are calculated using the annual load duration curve.

The two reliability test systems, i.e. the RBTS and the IEEE-RTS, which are used extensively in this thesis, are introduced in this chapter. The annualized and annual indices for the RBTS and the IEEE-RTS that are used as base case values in the subsequent studies, together with the corresponding assumptions are presented in this chapter. Brief analyses based upon the two system base case studies are also illustrated in Chapter 2.

It has been recognized that modeling large generating units in generating capacity adequacy assessment by simple two-state models using a DAFOR can yield a pessimistic appraisal. A series of studies are conducted in Chapter 3 to investigate the impacts of multi-state generating unit models on the load point and system reliability of the two composite test systems.

The studies in Chapter 3 clearly show that it is important to incorporate multi-state generating unit models in composite system adequacy assessment and that the traditional two-state generating unit model can lead to pessimistic appraisals. It is also possible to use more comprehensive generating unit models without taking significantly more computing time.

The selection of the designated derated capacity level in a multi-state generating unit model is important in some circumstances and should be done carefully, as the system and load bus indices can be significantly affected in these cases. This is illustrated when conducting the analysis on a large system such as the IEEE-RTS, which has a relatively weak generation system.

The composite system analyses conducted on the RBTS and the IEEE-RTS show that in many cases, three state representations will provide an adequate assessment and can be used in practical system studies. The need to use more states will depend on several factors. The most important are the size of the largest units relative to the rest of the system capacity and the magnitude of the peak load relative to the total installed capacity.

Performance-based Regulation (PBR) is a newly proposed regulatory approach in the rapidly changing electric power industry. Bulk electricity system performance indicators including predictive and past performance indices are likely to be key elements in this regulation approach. Chapter 4 presents the past performance indices of SAIFI-SI, SAIDI and SARI and illustrate how Canadian power systems have performed over the last nine years using data collected and compiled by the Canadian Electricity Association (CEA). A procedure that can be used to predict similar system performance indices is presented in Chapter 4 and applied to the RBTS and the IEEE-RTS. The predicted future performance of a power system can be directly compared with its measured past performance using this approach.

The CEA data and the studies conducted in Chapter 4 shows that the system performance indices change with the time due to many factors including the aging of facilities, system growth and operating philosophy and the weather, etc. Multiple circuit supply at a delivery point is more reliable than single circuit supply. The benefits associated with the increased investment can be assessed in terms of the predicted system performance indices. Delivery points served by higher voltage transmission tend to have better service performance indices than those served at lower voltages. The benefits associated with increased voltage levels can be assessed using the estimated system performance indices and considered with the required investment in the decision making process.

Chapter 4 also examines five factors that can influence the system performance indices, by application to the RBTS and the IEEE-RTS. The five factors are station transformer configurations, station transformer failure rates and outage durations, the load curtailment philosophy, system modifications and the system peak load. The analyses show that the system performance indices can be affected by decisions made in planning, designing and operating the system. Increased investment in transmission stations to provide redundancy or reduced repair times and failure rates will result in improved performance indices. The benefits, however, must be compared with the associated costs. The load curtailment philosophy adopted by the system management should be assessed in terms of its impact on the system performance indices in addition to the customer costs associated with service disruptions. Modifications examined and considered in system planning can be assessed in terms of their implications on the BES performance using the same indices created by the electric power industry to assess past performance. The magnitude of the system peak load has a major impact on the bulk electricity system performance indices. This is shown in Chapter 4.

An adequate transmission system is a key element in a well-founded competitive market in the newly deregulated industry. It is very important to determine and address possible transmission deficiencies due to the inherent uncertainty and risk associated with operating in a competitive market. The uncertainty associated with generation additions depends on many factors including the load growth and the perceived risk associated with investment in this area. The generation uncertainty directly affects decisions regarding the transmission system. Transmission deficiencies have traditionally been identified by conducting power flows, short-circuit analyses, voltage collapse studies and stability analyses. The possible deficiencies should also be identified based on composite system reliability analysis. This requirement is illustrated in Chapter 5.

Chapter 5 presents a procedure to identify transmission deficiencies in a composite generation and transmission system. The procedure includes three segments: base case analysis, factor analysis, and remedial modifications and their effects. The main steps in the procedure can be summarized as follows:

1. Perform a base case analysis and determine the load point and system reliability indices as a function of the peak load. The combination of the load point indices and the system indices is then used to provide an indication of the system weak points.
2. The individual effects on the load point and system indices of generation and transmission facility failures is then examined. The key factors (generation or

transmission) that influence the load point and system reliability indices are then determined.

3. The system is then modified by adding transmission lines in accordance with the information obtained in the previous studies. A range of modifications should be considered and the results compared with those of the base case to determine the benefits associated with the different actions.

Four test systems with different characteristics are used in the studies described in Chapter 5. They are the original RBTS, which is a relatively small system with adequate generation and transmission; the MRBTS with adequate generation and a weak transmission system; the IEEE-RTS, which is a comparably larger system with weak generation and adequate transmission; and the MRTS with adequate generation and a weak transmission system. The studies shown illustrate that the proposed procedure can be used to identify transmission deficiencies in different systems and to determine the reliability benefits associated with different remedial actions.

The research work illustrated in this thesis is focused on the application of probabilistic techniques in composite system adequacy assessment in the newly deregulated electric power industry. The research work clearly illustrates the utilization of quantitative composite system reliability evaluation in planning and operating decisions. The three areas examined are important considerations in providing reliable electric power supply in the deregulated electric power industry. They are also equally important in a conventional vertically integrated utility. The conclusions and the techniques presented should prove valuable to those responsible for power system planning.

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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.) Active	Load (p.u.) Reactive	P_g	Q_{max}	Q_{min}	V_0	V_{max}	V_{min}
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 I	Bus J	R	X	B/2	Tap	Current Rating (p.u.)	Failure Rate (occ/yr)	Repair Time (hrs)	Failure Prob.
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 No.	Bus		R	X	B/2	Tap	Current Rating (p.u.)	Failure Rate (occ/yr)	Repair Time (hrs)
	I	J							
1	1	2	0.0260	0.0139	0.2306	1.00	1.93	0.240	16.0
2	1	3	0.0546	0.2112	0.0286	1.00	2.08	0.510	10.0
3	1	5	0.0218	0.0845	0.0115	1.00	2.08	0.330	10.0
4	2	4	0.0328	0.1267	0.0172	1.00	2.08	0.390	10.0
5	2	6	0.0497	0.1920	0.0260	1.00	2.08	0.390	10.0
6	3	9	0.0308	0.1190	0.0161	1.00	2.08	0.480	10.0
7	3	24	0.0023	0.0839	0.0000	1.00	5.10	0.020	768.0
8	4	9	0.0268	0.1037	0.0141	1.00	2.08	0.360	10.0
9	5	10	0.0228	0.0883	0.0120	1.00	2.08	0.340	10.0
10	6	10	0.0139	0.0605	1.2295	1.00	1.93	0.330	35.0
11	7	8	0.0159	0.0614	0.0166	1.00	2.08	0.300	10.0

Table A.5: (Continued)

Line No.	Bus I	Bus J	R	X	B/2	Tap	Current Rating (p.u.)	Failure Rate (occ/yr)	Repair Time (hrs)
12	8	9	0.0427	0.1651	0.0224	1.00	2.08	0.440	10.0
13	8	10	0.0427	0.1651	0.0224	1.00	2.08	0.440	10.0
14	9	11	0.0023	0.0839	0.0000	1.00	6.00	0.020	768.0
15	9	12	0.0023	0.0839	0.0000	1.00	6.00	0.020	768.0
16	10	11	0.0023	0.0839	0.0000	1.00	6.00	0.020	768.0
17	10	12	0.0023	0.0839	0.0000	1.00	6.00	0.020	768.0
18	11	13	0.0061	0.0476	0.0500	1.00	6.00	0.020	768.0
19	11	14	0.0054	0.0418	0.0440	1.00	6.00	0.390	11.0
20	12	13	0.0061	0.0476	0.0500	1.00	6.00	0.400	11.0
21	12	23	0.0124	0.0966	0.1015	1.00	6.00	0.520	11.0
22	13	23	0.0111	0.0865	0.0909	1.00	6.00	0.490	11.0
23	14	16	0.0050	0.0389	0.0409	1.00	6.00	0.380	11.0
24	15	16	0.0022	0.0173	0.0364	1.00	6.00	0.330	11.0
25	15	21	0.0063	0.0490	0.0515	1.00	6.00	0.410	11.0
26	15	21	0.0063	0.0490	0.0515	1.00	6.00	0.410	11.0
27	15	24	0.0067	0.0519	0.0546	1.00	6.00	0.410	11.0
28	16	17	0.0033	0.0259	0.0273	1.00	6.00	0.350	11.0
29	16	19	0.0030	0.0231	0.0243	1.00	6.00	0.340	11.0
30	17	18	0.0018	0.0144	0.0152	1.00	6.00	0.320	11.0
31	17	22	0.0135	0.1053	0.1106	1.00	6.00	0.540	11.0
32	18	21	0.0033	0.0259	0.0273	1.00	6.00	0.350	11.0
33	18	21	0.0033	0.0259	0.0273	1.00	6.00	0.350	11.0
34	19	20	0.0051	0.0396	0.0417	1.00	6.00	0.380	11.0
35	19	20	0.0051	0.0396	0.0417	1.00	6.00	0.380	11.0
36	20	23	0.0028	0.0216	0.0228	1.00	6.00	0.340	11.0
37	20	23	0.0028	0.0216	0.0228	1.00	6.00	0.340	11.0
38	21	22	0.0087	0.0678	0.0712	1.00	6.00	0.450	11.0

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

Table A.6: (Continued)

Unit No.	Bus No.	Rating (MW)	Failure Rate (occ/yr)	Repair Time (hrs)	Failure Prob.
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. THE EFFECT OF MULTI-STATE GENERATING UNIT MODELS ON THE LOAD POINT AND SYSTEM RELIABILITY

Tables B.1-B.8 show the set of annual system indices and the load bus indices using two-state, three-state and four-state models in the RBTS.

Table B.1: RBTS annual system indices for the seven different three-state models

Indices	Model No.						
	1	2	3	4	5	6	7
ENLC (1/yr)	1.26861	1.26749	1.26797	1.26859	1.26992	1.27218	1.27177
ADLC (hrs/dist.)	9.44937	9.43387	9.43642	9.43977	9.44738	9.45467	9.44582
EDLC (hrs/yr)	11.98756	11.95735	11.96507	11.97519	11.99740	12.02808	12.01287
PLC	0.00137	0.00136	0.00137	0.00137	0.00137	0.00137	0.00137
EDNS (MW)	0.01720	0.01720	0.01721	0.01721	0.01721	0.01726	0.01727
EENS (MWh/yr)	150.6461	150.6861	150.7433	150.7420	150.8024	151.1708	151.2674
EDC (k$/yr)	665.8558	666.0325	666.2855	666.2797	666.5466	668.1751	668.6017
BPII (MW/MW-yr)	0.08719	0.08723	0.08726	0.08727	0.08730	0.08745	0.08750
BECI (MWh/MW-yr)	0.81430	0.81452	0.81483	0.81482	0.81515	0.81714	0.81766

Table B.1: (Continued)

Indices	Model No.						
	1	2	3	4	5	6	7
BPACI (MW/dist.)	12.71524	12.73234	12.73145	12.72668	12.71764	12.71711	12.72826
MBECI (MW/MW)	0.00009	0.00009	0.00009	0.00009	0.00009	0.00009	0.00009
SI (sys mins/yr)	48.85819	48.87116	48.88972	48.88929	48.90887	49.02837	49.05967

Table B.2: RBTS annual load bus indices for the seven different three-state models

Indices	Bus No.	Model No.						
		1	2	3	4	5	6	7
PLC	2	0	0	0	0	0	0	0
	3	0.00017	0.00017	0.00017	0.00017	0.00017	0.00018	0.00018
	4	0	0	0	0	0	0	0
	5	0	0	0	0	0	0	0
	6	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012
ENLC (1/yr)	2	0	0	0	0	0	0	0
	3	0.0962	0.0948	0.09523	0.0958	0.09694	0.09896	0.09835
	4	0.00108	0.00108	0.0011	0.00109	0.00109	0.00109	0.00109
	5	0.00179	0.00179	0.00183	0.00183	0.0018	0.00182	0.00182
	6	1.17669	1.17702	1.17707	1.17713	1.17731	1.1777	1.1779
ELC (MW/yr)	2	0	0	0	0	0	0	0
	3	1.089	1.093	1.096	1.098	1.101	1.125	1.132
	4	0.008	0.008	0.008	0.008	0.008	0.008	0.008
	5	0.012	0.012	0.012	0.012	0.012	0.012	0.012
	6	15.022	15.026	15.027	15.027	15.029	15.033	15.036
EDNS (MW)	2	0	0	0	0	0	0	0
	3	0.00186	0.00187	0.00187	0.00187	0.00188	0.00192	0.00193
	4	0	0	0	0	0	0	0
	5	0.00001	0.00001	0.00001	0.00001	0.00001	0.00001	0.00001
	6	0.01532	0.01532	0.01532	0.01532	0.01532	0.01532	0.01532
EENS (MWh/yr)	2	0	0	0	0	0	0	0
	3	16.328	16.367	16.416	16.416	16.479	16.837	16.934
	4	0.038	0.038	0.038	0.038	0.038	0.038	0.038
	5	0.071	0.071	0.074	0.073	0.072	0.074	0.074
	6	134.21	134.21	134.216	134.215	134.213	134.222	134.222

Table B.3: RBTS annual system indices for the seven different four-state models

Indices	Model No.						
	1	2	3	4	5	6	7
ENLC (1/yr)	1.26750	1.26797	1.26832	1.26827	1.26842	1.26758	1.26791
ADLC (hrs/dist.)	9.44168	9.44545	9.44480	9.43999	9.44181	9.43256	9.43580
EDLC (hrs/yr)	11.96731	11.97652	11.97899	11.97243	11.97620	11.95654	11.96373
PLC	0.00137	0.00137	0.00137	0.00137	0.00137	0.00136	0.00137
EDNS (MW)	0.01718	0.01718	0.01719	0.01719	0.01719	0.01719	0.01720
EENS (MWh/yr)	150.5162	150.4928	150.5617	150.5713	150.5436	150.6100	150.6820
EDC (k$/yr)	665.2815	665.1780	665.4825	665.5251	665.4028	665.6964	666.0143
BPII (MW/MW-yr)	0.08716	0.08715	0.08718	0.08720	0.08719	0.08722	0.08724
BECI (MWh/MW-yr)	0.81360	0.81347	0.81385	0.81390	0.81375	0.81411	0.81450
BPACI (MW/dist.)	12.72109	12.71542	12.71690	12.71992	12.71681	12.72923	12.72964
MBECI (MW/MW)	0.00009	0.00009	0.00009	0.00009	0.00009	0.00009	0.00009
SI (sys mins/yr)	48.81605	48.80845	48.83080	48.83392	48.82495	48.84649	48.86982

Table B.4: RBTS annual load bus indices for the seven different four-state models

Indices	Bus No.	Model No.						
		1	2	3	4	5	6	7
PLC	2	0	0	0	0	0	0	0
	3	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017
	4	0	0	0	0	0	0	0
	5	0	0	0	0	0	0	0
	6	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012
ENLC (1/yr)	2	0	0	0	0	0	0	0
	3	0.09509	0.09556	0.09586	0.09557	0.09573	0.09484	0.09512
	4	0.00109	0.00109	0.00109	0.00109	0.00108	0.00108	0.00108
	5	0.0018	0.00179	0.0018	0.0018	0.0018	0.0018	0.00181
	6	1.17669	1.17666	1.17678	1.17699	1.17695	1.17703	1.1771
ELC (MW/yr)	2	0	0	0	0	0	0	0
	3	1.082	1.081	1.086	1.087	1.085	1.089	1.093
	4	0.008	0.008	0.008	0.008	0.008	0.008	0.008
	5	0.012	0.012	0.012	0.012	0.012	0.012	0.012
	6	15.022	15.022	15.023	15.026	15.026	15.026	15.027
EDNS (MW)	2	0	0	0	0	0	0	0
	3	0.00185	0.00185	0.00185	0.00186	0.00185	0.00186	0.00187
	4	0	0	0	0	0	0	0
	5	0.00001	0.00001	0.00001	0.00001	0.00001	0.00001	0.00001
	6	0.01532	0.01532	0.01532	0.01532	0.01532	0.01532	0.01532
EENS (MWh/yr)	2	0	0	0	0	0	0	0
	3	16.197	16.174	16.24	16.251	16.224	16.289	16.361
	4	0.038	0.038	0.038	0.038	0.038	0.038	0.038
	5	0.072	0.072	0.072	0.072	0.072	0.072	0.072
	6	134.21	134.209	134.212	134.211	134.21	134.211	134.212

Table B.5: RBTS annual system indices for the two-state, three-state and four-state generating unit models at different peak load levels

Indices	Model type	Peak Load (MW)				
		160	170	180	190	200
ENLC (1/yr)	2-state	1.18714	1.2102	1.25954	1.3947	1.42452
	3-state	1.18491	1.2066	1.25261	1.37877	1.41067
	4-state	1.1846	1.20591	1.25099	1.37688	1.41437
ADLC (hrs/dist.)	2-state	8.94685	9.09274	9.40944	10.2181	10.1848
	3-state	8.95548	9.09375	9.39006	10.1492	10.1429
	4-state	8.95594	9.09002	9.38154	10.145	10.1916

Table B.5: (Continued)

Indices	Model type	Peak Load (MW)				
		160	170	180	190	200
EDLC (hrs/yr)	2-state	10.6212	11.004	11.8516	14.2511	14.5085
	3-state	10.6114	10.9725	11.7621	13.9934	14.3083
	4-state	10.6093	10.9618	11.7363	13.9685	14.4147
PLC	2-state	0.00121	0.00126	0.00135	0.00163	0.00166
	3-state	0.00121	0.00125	0.00134	0.0016	0.00163
	4-state	0.00121	0.00125	0.00134	0.00159	0.00165
EDNS (MW)	2-state	0.01333	0.01457	0.01603	0.01913	0.0235
	3-state	0.01332	0.01454	0.01595	0.0189	0.02309
	4-state	0.01331	0.01453	0.01595	0.01889	0.02307
EENS (MWh/yr)	2-state	116.751	127.625	140.455	167.543	205.893
	3-state	116.648	127.328	139.742	165.573	202.271
	4-state	116.632	127.289	139.686	165.471	202.091
EDC (k$/yr)	2-state	516.04	564.1	620.809	740.541	910.046
	3-state	515.583	562.79	617.657	731.833	894.038
	4-state	515.511	562.617	617.413	731.382	893.242
BPII (MW/MW-yr)	2-state	0.07069	0.07669	0.08292	0.09399	0.10817
	3-state	0.07056	0.07648	0.08256	0.09322	0.10686
	4-state	0.07055	0.07646	0.08253	0.09316	0.10676
BECI (MWh/MW-yr)	2-state	0.63109	0.68986	0.75921	0.90564	1.11293
	3-state	0.63053	0.68826	0.75536	0.89499	1.09336
	4-state	0.63044	0.68805	0.75506	0.89444	1.09238
BPACI (MW/dist.)	2-state	11.0166	11.7235	12.179	12.467	14.0475
	3-state	11.0168	11.7262	12.1933	12.5085	14.0141
	4-state	11.0176	11.7293	12.2041	12.5177	13.9642
MBECI (MW/MW)	2-state	0.00007	0.00008	0.00009	0.0001	0.00013
	3-state	0.00007	0.00008	0.00009	0.0001	0.00012
	4-state	0.00007	0.00008	0.00009	0.0001	0.00012
SI (sys mins/yr)	2-state	37.8652	41.3917	45.5528	54.3384	66.776
	3-state	37.8317	41.2956	45.3216	53.6993	65.6014
	4-state	37.8264	41.2829	45.3036	53.6662	65.543

Table B.6: RBTS annual load bus indices for the two-state generating unit models at different peak load levels

Bus No.	Indices	Peak Load (MW)				
		160	170	180	190	200
2	PLC	-	-	-	0	0
	ENLC(1/yr)	-	-	-	0.00002	0.00002
	ELC(MW/yr)	-	-	-	0	0
	EDNS (MW)	-	-	-	0	0
	EENS(MWh/yr)	-	-	-	0	0.001
3	PLC	0.00002	0.00006	0.00016	0.00043	0.00046
	ENLC(1/yr)	0.01281	0.03586	0.08521	0.2204	0.25031
	ELC(MW/yr)	0.148	0.347	0.734	1.853	3.686
	EDNS (MW)	0.00016	0.00048	0.00117	0.00331	0.00688
	EENS(MWh/yr)	1.441	4.212	10.237	29.024	60.243
4	PLC	0	0	0	0	0
	ENLC(1/yr)	0.00018	0.00039	0.00071	0.00122	0.00179
	ELC(MW/yr)	0.001	0.003	0.005	0.011	0.017
	EDNS (MW)	0	0	0	0.00001	0.00001
	EENS(MWh/yr)	0.004	0.011	0.024	0.054	0.101
5	PLC	0	0	0	0	0
	ENLC(1/yr)	0.00059	0.00109	0.00161	0.0027	0.00448
	ELC(MW/yr)	0.003	0.006	0.01	0.017	0.026
	EDNS (MW)	0	0	0.00001	0.00001	0.00003
	EENS(MWh/yr)	0.012	0.029	0.055	0.118	0.22
6	PLC	0.0012	0.0012	0.0012	0.0012	0.00121
	ENLC(1/yr)	1.17542	1.17616	1.17722	1.17929	1.18267
	ELC(MW/yr)	12.926	13.832	14.59	15.507	16.281
	EDNS (MW)	0.01316	0.01408	0.01486	0.01579	0.01659
	EENS(MWh/yr)	115.295	123.372	130.139	138.347	145.328

Table B.7: RBTS annual load bus indices for the three-state generating unit models at different peak load levels

Bus No.	Indices	Peak Load (MW)				
		160	170	180	190	200
2	PLC	-	-	-	0	0
	ENLC(1/yr)	-	-	-	0.00002	0.00002
	ELC(MW/yr)	-	-	-	0	0
	EDNS (MW)	-	-	-	0	0
	EENS(MWh/yr)	-	-	-	0	0.001
3	PLC	0.00002	0.00006	0.00015	0.0004	0.00044
	ENLC(1/yr)	0.0121	0.03379	0.0798	0.20599	0.23798
	ELC(MW/yr)	0.141	0.326	0.687	1.734	3.47
	EDNS (MW)	0.00015	0.00045	0.00109	0.00309	0.00647
	EENS(MWh/yr)	1.337	3.917	9.531	27.084	56.685

Table B.7: (Continued)

Bus No.	Indices	Peak Load (MW)				
		160	170	180	190	200
4	PLC	0	0	0	0	0
	ENLC(1/yr)	0.00018	0.00039	0.00071	0.00122	0.00179
	ELC(MW/yr)	0.001	0.003	0.005	0.011	0.017
	EDNS (MW)	0	0	0	0.00001	0.00001
	EENS(MWh/yr)	0.004	0.011	0.024	0.054	0.099
5	PLC	0	0	0	0	0
	ENLC(1/yr)	0.00059	0.00109	0.00159	0.00261	0.0042
	ELC(MW/yr)	0.003	0.006	0.01	0.017	0.025
	EDNS (MW)	0	0	0.00001	0.00001	0.00002
	EENS(MWh/yr)	0.012	0.029	0.054	0.112	0.205
6	PLC	0.0012	0.0012	0.0012	0.0012	0.0012
	ENLC(1/yr)	1.17389	1.17461	1.17559	1.17746	1.1806
	ELC(MW/yr)	12.909	13.814	14.571	15.485	16.256
	EDNS (MW)	0.01316	0.01408	0.01486	0.01579	0.01658
	EENS(MWh/yr)	115.295	123.371	130.132	138.323	145.28

Table B.8: RBTS annual load bus indices for the four-state generating units at different peak load levels

Bus No.	Indices	Peak Load (MW)				
		160	170	180	190	200
2	PLC	-	-	-	0	0
	ENLC(1/yr)	-	-	-	0.00002	0.00002
	ELC(MW/yr)	-	-	-	0	0
	EDNS (MW)	-	-	-	0	0
	EENS(MWh/yr)	-	-	-	0	0.001
3	PLC	0.00002	0.00006	0.00014	0.0004	0.00045
	ENLC(1/yr)	0.01189	0.0332	0.07828	0.2042	0.24178
	ELC(MW/yr)	0.139	0.323	0.683	1.725	3.454
	EDNS (MW)	0.00015	0.00044	0.00108	0.00308	0.00645
	EENS(MWh/yr)	1.321	3.879	9.479	26.986	56.515
4	PLC	0	0	0	0	0
	ENLC(1/yr)	0.00018	0.00039	0.00071	0.00121	0.00176
	ELC(MW/yr)	0.001	0.003	0.005	0.011	0.017
	EDNS (MW)	0	0	0	0.00001	0.00001
	EENS(MWh/yr)	0.004	0.011	0.024	0.054	0.098
5	PLC	0	0	0	0	0
	ENLC(1/yr)	0.00059	0.00108	0.00158	0.00259	0.00415
	ELC(MW/yr)	0.003	0.006	0.01	0.016	0.025
	EDNS (MW)	0	0	0.00001	0.00001	0.00002
	EENS(MWh/yr)	0.012	0.028	0.053	0.11	0.2

Table B.8: (Continued)

Bus No.	Indices	Peak Load (MW)				
		160	170	180	190	200
6	PLC	0.0012	0.0012	0.0012	0.0012	0.0012
	ENLC(1/yr)	1.1738	1.17451	1.1755	1.1774	1.18056
	ELC(MW/yr)	12.908	13.813	14.57	15.484	16.255
	EDNS (MW)	0.01316	0.01408	0.01485	0.01579	0.01658
	EENS(MWh/yr)	115.294	123.37	130.13	138.321	145.276

Tables B.9-B.16 show the set of annual system indices and the load bus indices using two-state, three-state and four-state models in the IEEE-RTS.

Table B.9: IEEE-RTS annual system indices for the seven different three-state models

Indices	Model No.						
	1	2	3	4	5	6	7
ENLC (1/yr)	1.28736	1.29889	1.30912	1.33277	1.34585	1.38342	1.42176
ADLC (hrs/dist.)	11.56001	11.54504	11.56533	11.57540	11.55111	11.56228	11.60002
EDLC (hrs/yr)	14.88261	14.99637	15.14108	15.42802	15.54678	15.99624	16.49317
PLC	0.00170	0.00171	0.00173	0.00176	0.00177	0.00183	0.00188
EDNS (MW)	0.22598	0.22898	0.23047	0.23523	0.23773	0.24657	0.25495
EENS (MWh/yr)	1979.599	2005.857	2018.886	2060.641	2082.539	2159.979	2233.333
EDC (k$/yr)	8353.908	8464.718	8519.697	8695.906	8788.313	9115.110	9424.665
BPII (MW/MW-yr)	0.06192	0.06283	0.06323	0.06452	0.06517	0.06744	0.06956
BECI (MWh/MW-yr)	0.69460	0.70381	0.70838	0.72303	0.73072	0.75789	0.78363

Table B.9: (Continued)

Indices	Model No.						
	1	2	3	4	5	6	7
BPACI (MW/dist.)	137.0756	137.8522	137.6628	137.9753	138.0087	138.9281	139.4280
MBECI (MW/MW)	0.00008	0.00008	0.00008	0.00008	0.00008	0.00009	0.00009
SI (sys mins/yr)	41.67577	42.22857	42.50285	43.38192	43.84291	45.47323	47.01752

Table B.10: IEEE-RTS Annual load bus indices for the seven different three-state models

Indices	Bus No.	Model No.						
		1	2	3	4	5	6	7
PLC	2	0	0	0	0	0	0	0
	3	0	0	0	0	0	0	0
	6	0	0	0	0	0	0	0
	7	0	0	0	0	0	0	0
	8	0	0	0	0	0	0	0
	9	0.00094	0.00094	0.00095	0.00097	0.00098	0.00102	0.00105
	10	0	0	0	0	0	0	0
	13	0	0	0	0	0	0	0
	14	0.00016	0.00017	0.00017	0.00017	0.00018	0.00018	0.00019
	15	0.00054	0.00055	0.00055	0.00056	0.00057	0.00059	0.00061
	16	0.00007	0.00008	0.00008	0.00008	0.00008	0.00008	0.00009
	18	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003
	19	0.0017	0.00171	0.00173	0.00176	0.00177	0.00183	0.00188
	20	0.00005	0.00005	0.00005	0.00005	0.00005	0.00005	0.00005

Table B.10: (Continued)

Indices	Bus No.	Model No.						
		1	2	3	4	5	6	7
ENLC (1/yr)	2	0.00108	0.00126	0.00128	0.0013	0.00129	0.00135	0.00138
	3	0.00046	0.00063	0.00065	0.00066	0.00066	0.0007	0.00072
	6	0.00075	0.00075	0.00075	0.00075	0.00075	0.00075	0.00075
	7	0.00041	0.00041	0.00041	0.00041	0.00041	0.00041	0.00041
	8	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004
	9	0.72867	0.73467	0.73967	0.75137	0.76064	0.78647	0.81058
	10	0.00355	0.00403	0.00413	0.00425	0.00421	0.00445	0.00464
	13	0.00007	0.00011	0.00011	0.00011	0.00011	0.00012	0.00012
	14	0.13826	0.14125	0.14192	0.14714	0.14793	0.15287	0.15937
	15	0.42356	0.43137	0.43426	0.44337	0.44764	0.46301	0.47974
	16	0.06348	0.06527	0.06572	0.06777	0.06795	0.07083	0.07302
	18	0.023	0.02377	0.02409	0.02493	0.02487	0.02605	0.02685
	19	1.28617	1.2977	1.30793	1.33158	1.34466	1.38223	1.42057
	20	0.04097	0.04296	0.04334	0.04523	0.04498	0.04699	0.04896
ELC (MW/yr)	2	0.033	0.04	0.041	0.042	0.042	0.044	0.046
	3	0.021	0.026	0.027	0.027	0.027	0.028	0.029
	6	0.052	0.052	0.052	0.052	0.052	0.052	0.052
	7	0.004	0.004	0.004	0.004	0.004	0.004	0.004
	8	0.001	0.001	0.001	0.001	0.001	0.001	0.001
	9	44.457	45.052	45.365	46.27	46.82	48.455	49.944
	10	0.195	0.222	0.228	0.234	0.233	0.247	0.256
	13	0.004	0.005	0.005	0.005	0.005	0.006	0.006
	14	8.369	8.563	8.636	8.914	8.969	9.324	9.669
	15	36.418	37.057	37.299	38.248	38.637	40.026	41.427
	16	2.391	2.473	2.495	2.578	2.589	2.684	2.79
	18	1.715	1.822	1.851	1.909	1.907	1.998	2.071
	19	80.979	81.84	82.289	83.616	84.458	87.239	89.775
	20	1.826	1.898	1.923	1.99	1.995	2.088	2.164
EDNS (MW)	2	0.00003	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004
	3	0.00002	0.00002	0.00002	0.00002	0.00002	0.00003	0.00003
	6	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003
	7	0	0	0	0	0	0	0
	8	0	0	0	0	0	0	0
	9	0.05697	0.05774	0.05817	0.05938	0.06012	0.06235	0.06442
	10	0.0002	0.00022	0.00022	0.00023	0.00023	0.00024	0.00025
	13	0	0	0	0	0	0	0
	14	0.00983	0.01003	0.01011	0.01044	0.01051	0.01096	0.0114
	15	0.04489	0.04562	0.04592	0.04714	0.04764	0.04948	0.05137
	16	0.00275	0.00283	0.00285	0.00295	0.00296	0.00308	0.00322
	18	0.00187	0.00195	0.00198	0.00204	0.00204	0.00214	0.00223
	19	0.10734	0.1084	0.10898	0.11075	0.11192	0.11589	0.11954
	20	0.00204	0.0021	0.00213	0.0022	0.00221	0.00232	0.00241

Table B.10: (Continued)

Indices	Bus No.	Model No.						
		1	2	3	4	5	6	7
EENS (MWh/yr)	2	0.275	0.317	0.327	0.333	0.333	0.357	0.369
	3	0.176	0.201	0.206	0.209	0.209	0.222	0.227
	6	0.293	0.293	0.293	0.293	0.293	0.293	0.293
	7	0.021	0.021	0.021	0.021	0.021	0.021	0.021
	8	0.004	0.004	0.004	0.004	0.004	0.004	0.004
	9	499.083	505.772	509.557	520.189	526.654	546.221	564.32
	10	1.741	1.896	1.948	2.002	1.998	2.138	2.217
	13	0.033	0.04	0.04	0.04	0.04	0.042	0.042
	14	86.072	87.842	88.575	91.496	92.092	95.981	99.86
	15	393.26	399.644	402.284	412.905	417.334	433.418	450.008
	16	24.101	24.789	24.985	25.841	25.964	27.022	28.173
	18	16.347	17.052	17.313	17.857	17.848	18.776	19.513
	19	940.325	949.576	954.691	970.144	980.387	1015.18	1047.19
	20	17.874	18.416	18.647	19.312	19.365	20.308	21.105

Table B.11: IEEE-RTS annual system indices for the seven different four-state models

Indices	Model No.						
	1	2	3	4	5	6	7
ENLC (1/yr)	1.26260	1.26740	1.27337	1.28366	1.28811	1.29251	1.30734
ADLC (hrs/dist.)	11.56223	11.56840	11.54449	11.55139	11.56518	11.58613	11.58346
EDLC (hrs/yr)	14.59910	14.66249	14.70107	14.82872	14.89793	14.97591	15.14427
PLC	0.00167	0.00167	0.00168	0.00169	0.00170	0.00171	0.00173
EDNS (MW)	0.22002	0.22062	0.22286	0.22477	0.22582	0.22658	0.22979
EENS (MWh/yr)	1927.343	1932.600	1952.276	1969.001	1978.204	1984.828	2012.955
EDC (k$/yr)	8133.385	8155.570	8238.604	8309.183	8348.022	8375.974	8494.671

Table B.11: (Continued)

Indices	Model No.						
	1	2	3	4	5	6	7
BPII (MW/ MWyr)	0.06027	0.06045	0.06117	0.06167	0.06192	0.06212	0.06300
BECI (MWh/ MW-yr)	0.67626	0.67811	0.68501	0.69088	0.69411	0.69643	0.70630
BPACI (MW/dist.)	136.0450	135.9270	136.9179	136.9144	136.9952	136.9814	137.3453
MBECI (MW/ MW)	0.00008	0.00008	0.00008	0.00008	0.00008	0.00008	0.00008
SI (sys mins/yr)	40.57563	40.68631	41.10054	41.45264	41.64641	41.78584	42.37801

Table B.12: IEEE-RTS Annual load bus indices for the seven different four-state models

Indices	Bus No.	Model No.						
		1	2	3	4	5	6	7
PLC	2	0	0	0	0	0	0	0
	3	0	0	0	0	0	0	0
	6	0	0	0	0	0	0	0
	7	0	0	0	0	0	0	0
	8	0	0	0	0	0	0	0
	9	0.00091	0.00092	0.00092	0.00093	0.00094	0.00094	0.00095
	10	0	0	0	0	0	0	0
	13	0	0	0	0	0	0	0
	14	0.00016	0.00016	0.00016	0.00016	0.00016	0.00016	0.00017
	15	0.00052	0.00052	0.00053	0.00053	0.00053	0.00054	0.00055
	16	0.00007	0.00007	0.00007	0.00007	0.00007	0.00007	0.00007
	18	0.00002	0.00002	0.00002	0.00003	0.00003	0.00003	0.00003
	19	0.00167	0.00167	0.00168	0.00169	0.0017	0.00171	0.00173
	20	0.00004	0.00004	0.00004	0.00005	0.00005	0.00005	0.00005

Table B.12: (Continued)

Indices	Bus No.	Model No.						
		1	2	3	4	5	6	7
ENLC (1/yr)	2	0.00085	0.00085	0.00101	0.00101	0.00101	0.00103	0.00104
	3	0.00046	0.00046	0.00063	0.00063	0.00063	0.00066	0.00066
	6	0.00075	0.00075	0.00075	0.00075	0.00075	0.00075	0.00075
	7	0.00041	0.00041	0.00041	0.00041	0.00041	0.00041	0.00041
	8	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004
	9	0.70934	0.71373	0.71857	0.72435	0.72846	0.72999	0.73989
	10	0.00331	0.0033	0.00375	0.00376	0.00375	0.00385	0.00389
	13	0.00008	0.00008	0.00012	0.00012	0.00012	0.00013	0.00013
	14	0.13384	0.13354	0.13573	0.13707	0.13788	0.13862	0.14145
	15	0.41273	0.41284	0.41841	0.42205	0.42292	0.42462	0.43191
	16	0.06048	0.06047	0.06233	0.06327	0.06349	0.06345	0.06485
	18	0.02148	0.02167	0.02255	0.0228	0.02292	0.02306	0.02351
	19	1.26141	1.26621	1.27218	1.28247	1.28692	1.29132	1.30615
	20	0.03937	0.03944	0.04086	0.04134	0.04145	0.04188	0.04265
ELC (MW/yr)	2	0.029	0.029	0.036	0.036	0.036	0.037	0.038
	3	0.019	0.019	0.023	0.023	0.023	0.024	0.024
	6	0.052	0.052	0.052	0.052	0.052	0.052	0.052
	7	0.004	0.004	0.004	0.004	0.004	0.004	0.004
	8	0	0	0	0	0	0	0
	9	43.428	43.571	44.022	44.397	44.58	44.693	45.363
	10	0.188	0.19	0.216	0.216	0.216	0.222	0.224
	13	0.003	0.003	0.005	0.005	0.005	0.005	0.005
	14	8.002	8.024	8.197	8.296	8.329	8.362	8.525
	15	35.269	35.353	35.852	36.219	36.371	36.49	37.111
	16	2.293	2.297	2.365	2.388	2.397	2.412	2.457
	18	1.623	1.636	1.737	1.747	1.75	1.775	1.802
	19	79.142	79.362	80.039	80.554	80.883	81.141	82.08
	20	1.718	1.732	1.797	1.813	1.818	1.833	1.872
EDNS (MW)	2	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003
	3	0.00002	0.00002	0.00002	0.00002	0.00002	0.00002	0.00002
	6	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003
	7	0	0	0	0	0	0	0
	8	0	0	0	0	0	0	0
	9	0.05568	0.05585	0.05637	0.05687	0.05714	0.0573	0.05817
	10	0.00019	0.00019	0.00021	0.00021	0.00021	0.00021	0.00022
	13	0	0	0	0	0	0	0
	14	0.0094	0.00942	0.00958	0.0097	0.00975	0.00979	0.00997
	15	0.04349	0.04359	0.0441	0.04458	0.04479	0.04494	0.04571
	16	0.00263	0.00264	0.00269	0.00272	0.00274	0.00275	0.00281
	18	0.00176	0.00177	0.00184	0.00186	0.00186	0.00189	0.00191
	19	0.10486	0.10515	0.106	0.10673	0.10723	0.10757	0.10884
	20	0.00192	0.00193	0.00198	0.002	0.00201	0.00203	0.00206

Table B.12: (Continued)

Indices	Bus No.	Model No.						
		1	2	3	4	5	6	7
EENS (MWh/yr)	2	0.241	0.242	0.281	0.281	0.281	0.291	0.293
	3	0.153	0.155	0.179	0.179	0.179	0.185	0.186
	6	0.293	0.293	0.293	0.293	0.293	0.293	0.293
	7	0.021	0.021	0.021	0.021	0.021	0.021	0.021
	8	0.003	0.003	0.003	0.003	0.003	0.003	0.003
	9	487.715	489.224	493.771	498.183	500.559	501.97	509.603
	10	1.664	1.681	1.826	1.826	1.827	1.879	1.897
	13	0.027	0.027	0.033	0.033	0.033	0.033	0.033
	14	82.327	82.486	83.899	85.001	85.38	85.731	87.353
	15	380.989	381.84	386.337	390.503	392.353	393.703	400.454
	16	23.078	23.1	23.604	23.869	23.98	24.133	24.58
	18	15.432	15.517	16.147	16.271	16.317	16.54	16.763
	19	918.595	921.112	928.52	934.991	939.378	942.297	953.398
	20	16.813	16.901	17.368	17.552	17.608	17.755	18.085

Table B.13: IEEE-RTS annual system indices for the two-state, three-state and four-state generating unit models at different peak load levels

Indices	Model type	Peak Load (MW)				
		2500	2600	2800	2900	3100
ENLC (1/yr)	2-state	0.18516	0.31649	1.14723	2.08334	5.5672
	3-state	0.15336	0.26605	0.9861	1.83308	5.06505
	4-state	0.14413	0.25343	0.94337	1.78267	4.96514
ADLC (hrs/dist.)	2-state	10.3801	10.5684	11.7182	11.9745	12.5899
	3-state	10.346	10.5625	11.6356	11.9396	12.6458
	4-state	10.3255	10.5737	11.6086	11.954	12.6404
EDLC (hrs/yr)	2-state	1.92196	3.34482	13.4439	24.9483	70.096
	3-state	1.58668	2.81017	11.4743	21.8874	64.0552
	4-state	1.4882	2.67968	10.9516	21.3112	62.7636
PLC	2-state	0.00022	0.00038	0.00153	0.00285	0.008
	3-state	0.00018	0.00032	0.00131	0.0025	0.00731
	4-state	0.00017	0.00031	0.00125	0.00243	0.00716
EDNS (MW)	2-state	0.02314	0.04507	0.18935	0.39657	1.2842
	3-state	0.01891	0.03734	0.16053	0.34143	1.14039
	4-state	0.01746	0.03485	0.15266	0.32743	1.1066

Table B.13: (Continued)

Indices	Model type	Peak Load (MW)				
		2500	2600	2800	2900	3100
EENS (MWh /yr)	2-state	202.689	394.792	1658.73	3473.91	11249.6
	3-state	165.621	327.138	1406.26	2990.9	9989.85
	4-state	152.926	305.322	1337.32	2868.27	9693.86
EDC (k$/yr)	2-state	855.349	1666.02	6999.85	14659.9	47473.3
	3-state	698.922	1380.52	5934.44	12621.6	42157.1
	4-state	645.348	1288.46	5643.49	12104.1	40908.1
BPII (MW/ MW-yr)	2-state	0.00709	0.01345	0.05275	0.10661	0.32502
	3-state	0.00579	0.01114	0.04482	0.09194	0.2885
	4-state	0.00535	0.01041	0.04266	0.08824	0.2799
BECI (MWh /MW-yr)	2-state	0.07112	0.13852	0.58201	1.21892	3.94722
	3-state	0.05811	0.11479	0.49343	1.04944	3.50521
	4-state	0.05366	0.10713	0.46924	1.00641	3.40135
BPACI (MW/ dist.)	2-state	109.058	121.077	131.041	145.836	166.386
	3-state	107.569	119.357	129.538	142.95	162.335
	4-state	105.862	117.123	128.865	141.07	160.664
MBECI (MW/ MW)	2-state	0.00001	0.00002	0.00007	0.00014	0.00045
	3-state	0.00001	0.00001	0.00006	0.00012	0.0004
	4-state	0.00001	0.00001	0.00005	0.00011	0.00039
SI (sys mins/yr)	2-state	4.26714	8.31142	34.9207	73.135	236.833
	3-state	3.48677	6.88712	29.6056	62.9663	210.313
	4-state	3.2195	6.42782	28.1541	60.3846	204.081

Table B.14: IEEE-RTS annual load bus indices for the two-state generating unit models at different peak load levels

Bus No.	Indices	Peak Load (MW)				
		2500	2600	2800	2900	3100
2	PLC	0	0	0	0	0.00001
	ENLC(1/yr)	0.00001	0.00003	0.00092	0.00239	0.01403
	ELC(MW/yr)	0	0.001	0.025	0.082	0.517
	EDNS (MW)	0	0	0.00002	0.00008	0.00054
	EENS(MWh/yr)	0.001	0.006	0.198	0.695	4.728

Table B.14: (Continued)

Bus No.	Indices	Peak Load (MW)				
		2500	2600	2800	2900	3100
3	PLC	-	0	0	0	0.00001
	ENLC(1/yr)	-	0.00001	0.00026	0.00128	0.00765
	ELC(MW/yr)	-	0	0.013	0.058	0.419
	EDNS (MW)	-	0	0.00001	0.00005	0.00042
	EENS(MWh/yr)	-	0.002	0.098	0.466	3.642
6	PLC	0	0	0	0	0
	ENLC(1/yr)	0.00094	0.00094	0.00075	0.00075	0.0006
	ELC(MW/yr)	0.061	0.063	0.051	0.053	0.044
	EDNS (MW)	0.00004	0.00004	0.00003	0.00003	0.00003
	EENS(MWh/yr)	0.341	0.352	0.287	0.299	0.245
7	PLC	0	0	0	0	0
	ENLC(1/yr)	0.00004	0.00016	0.00041	0.00068	0.00097
	ELC(MW/yr)	0	0.001	0.003	0.005	0.011
	EDNS (MW)	0	0	0	0	0.00001
	EENS(MWh/yr)	0.001	0.004	0.016	0.028	0.061
8	PLC	-	-	0	0	0
	ENLC(1/yr)	-	-	0.00004	0.00005	0.0004
	ELC(MW/yr)	-	-	0	0.001	0.011
	EDNS (MW)	-	-	0	0	0.00001
	EENS(MWh/yr)	-	-	0.001	0.004	0.077
9	PLC	0.00011	0.00022	0.0008	0.00169	0.00504
	ENLC(1/yr)	0.09695	0.18262	0.63685	1.26297	3.53376
	ELC(MW/yr)	5.251	9.883	38.266	76.573	232.816
	EDNS (MW)	0.00604	0.01168	0.04851	0.10079	0.32555
	EENS(MWh/yr)	52.867	102.276	424.933	882.938	2851.79
10	PLC	0	0	0	0.00001	0.00004
	ENLC(1/yr)	0.00012	0.00026	0.00359	0.00874	0.03753
	ELC(MW/yr)	0.003	0.013	0.158	0.492	2.349
	EDNS (MW)	0	0.00001	0.00015	0.00049	0.00254
	EENS(MWh/yr)	0.018	0.095	1.341	4.313	22.285
13	PLC	-	-	0	0	0
	ENLC(1/yr)	-	-	0.00003	0.00022	0.00215
	ELC(MW/yr)	-	-	0.001	0.011	0.12
	EDNS (MW)	-	-	0	0.00001	0.00011
	EENS(MWh/yr)	-	-	0.009	0.08	0.99
14	PLC	0.00002	0.00003	0.00014	0.00029	0.00096
	ENLC(1/yr)	0.01481	0.02957	0.12051	0.24249	0.74876
	ELC(MW/yr)	0.744	1.647	7.363	15.739	52.617
	EDNS (MW)	0.00077	0.00177	0.0085	0.0188	0.06697
	EENS(MWh/yr)	6.773	15.472	74.418	164.652	586.638

Table B.14: (Continued)

Bus No.	Indices	Peak Load (MW)				
		2500	2600	2800	2900	3100
15	PLC	0.00006	0.00011	0.00044	0.00093	0.00285
	ENLC(1/yr)	0.05331	0.09683	0.36335	0.72366	2.08509
	ELC(MW/yr)	3.899	7.738	31.114	64.577	204.955
	EDNS (MW)	0.00427	0.00878	0.03757	0.08121	0.27458
	EENS(MWh/yr)	37.365	76.886	329.154	711.414	2405.289
16	PLC	0.00001	0.00001	0.00007	0.00014	0.00047
	ENLC(1/yr)	0.00569	0.01232	0.05812	0.12035	0.38217
	ELC(MW/yr)	0.19	0.407	2.085	4.502	15.546
	EDNS (MW)	0.00019	0.00043	0.0023	0.00522	0.01903
	EENS(MWh/yr)	1.635	3.733	20.177	45.711	166.734
18	PLC	0	0	0.00002	0.00005	0.0002
	ENLC(1/yr)	0.00128	0.00406	0.02127	0.04557	0.16648
	ELC(MW/yr)	0.074	0.21	1.528	3.716	14.253
	EDNS (MW)	0.00007	0.0002	0.00158	0.00402	0.01641
	EENS(MWh/yr)	0.591	1.772	13.811	35.25	143.711
19	PLC	0.00022	0.00038	0.00153	0.00285	0.008
	ENLC(1/yr)	0.18418	0.31539	1.146	2.08174	5.56525
	ELC(MW/yr)	9.861	18.063	68.098	134.26	389.501
	EDNS (MW)	0.01166	0.02188	0.08888	0.1816	0.56215
	EENS(MWh/yr)	102.142	191.636	778.597	1590.83	4924.455
20	PLC	0	0.00001	0.00004	0.00009	0.00031
	ENLC(1/yr)	0.00318	0.00739	0.03828	0.0815	0.25813
	ELC(MW/yr)	0.111	0.295	1.628	3.755	13.16
	EDNS (MW)	0.00011	0.00029	0.00179	0.00425	0.01587
	EENS(MWh/yr)	0.955	2.561	15.683	37.25	139.001

Table B.15: IEEE-RTS annual load bus indices for the three-state generating unit models at different peak load levels

Bus No.	Indices	Peak Load (MW)				
		2500	2600	2800	2900	3100
2	PLC	0	0	0	0	0.00001
	ENLC(1/yr)	0.00001	0.00005	0.00071	0.00198	0.01105
	ELC(MW/yr)	0	0.002	0.021	0.071	0.41
	EDNS (MW)	0	0	0.00002	0.00007	0.00043
	EENS(MWh/yr)	0.002	0.014	0.166	0.597	3.778
3	PLC	0	0	0	0	0.00001
	ENLC(1/yr)	0	0.00004	0.00028	0.00122	0.00624
	ELC(MW/yr)	0	0.001	0.014	0.05	0.334
	EDNS (MW)	0	0	0.00001	0.00005	0.00033
	EENS(MWh/yr)	0.001	0.005	0.108	0.395	2.896

Table B.15: (Continued)

Bus No.	Indices	Peak Load (MW)				
		2500	2600	2800	2900	3100
6	PLC	0	0	0	0	0
	ENLC(1/yr)	0.00094	0.00094	0.00075	0.0006	0.00061
	ELC(MW/yr)	0.061	0.063	0.051	0.041	0.044
	EDNS (MW)	0.00004	0.00004	0.00003	0.00003	0.00003
	EENS(MWh/yr)	0.341	0.352	0.287	0.228	0.247
7	PLC	0	0	0	0	0
	ENLC(1/yr)	0.00004	0.00016	0.00041	0.00069	0.00099
	ELC(MW/yr)	0	0.001	0.003	0.005	0.012
	EDNS (MW)	0	0	0	0	0.00001
	EENS(MWh/yr)	0.001	0.004	0.016	0.028	0.067
8	PLC	-	-	0	0	0
	ENLC(1/yr)	-	-	0.00004	0.00005	0.00043
	ELC(MW/yr)	-	-	0	0.001	0.012
	EDNS (MW)	-	-	0	0	0.00001
	EENS(MWh/yr)	-	-	0.001	0.007	0.088
9	PLC	0.00009	0.00018	0.00069	0.00145	0.00448
	ENLC(1/yr)	0.0797	0.15188	0.54832	1.09138	3.15564
	ELC(MW/yr)	4.292	8.163	32.533	66.06	206.79
	EDNS (MW)	0.00494	0.00962	0.04105	0.08659	0.28866
	EENS(MWh/yr)	43.277	84.256	359.576	758.509	2528.65
10	PLC	0	0	0	0.00001	0.00003
	ENLC(1/yr)	0.0001	0.00028	0.00298	0.00709	0.03024
	ELC(MW/yr)	0.004	0.014	0.133	0.39	1.878
	EDNS (MW)	0	0.00001	0.00013	0.00039	0.00204
	EENS(MWh/yr)	0.029	0.103	1.114	3.418	17.895
13	PLC	-	0	0	0	0
	ENLC(1/yr)	-	0	0.00005	0.00027	0.0018
	ELC(MW/yr)	-	0	0.003	0.013	0.106
	EDNS (MW)	-	0	0	0.00001	0.0001
	EENS(MWh/yr)	-	0.001	0.021	0.099	0.863
14	PLC	0.00001	0.00003	0.00011	0.00025	0.00082
	ENLC(1/yr)	0.01136	0.02379	0.09926	0.20395	0.64548
	ELC(MW/yr)	0.588	1.299	6.042	13.096	44.957
	EDNS (MW)	0.00061	0.0014	0.00698	0.01559	0.05701
	EENS(MWh/yr)	5.375	12.269	61.143	136.605	499.423
15	PLC	0.00005	0.00009	0.00037	0.00079	0.00251
	ENLC(1/yr)	0.04302	0.07977	0.30774	0.62019	1.83651
	ELC(MW/yr)	3.107	6.286	26.088	54.911	178.836
	EDNS (MW)	0.00342	0.00715	0.03145	0.06885	0.23892
	EENS(MWh/yr)	29.941	62.631	275.49	603.149	2092.944

Table B.15: (Continued)

Bus No.	Indices	Peak Load (MW)				
		2500	2600	2800	2900	3100
16	PLC	0	0.00001	0.00005	0.00011	0.00039
	ENLC(1/yr)	0.0045	0.00961	0.04713	0.09892	0.32275
	ELC(MW/yr)	0.145	0.324	1.67	3.716	13.131
	EDNS (MW)	0.00014	0.00034	0.00185	0.00432	0.01606
	EENS(MWh/yr)	1.248	2.982	16.241	37.815	140.709
18	PLC	0	0	0.00002	0.00004	0.00016
	ENLC(1/yr)	0.00118	0.00321	0.01682	0.03638	0.1378
	ELC(MW/yr)	0.064	0.174	1.2	2.962	11.697
	EDNS (MW)	0.00006	0.00017	0.00124	0.00323	0.01348
	EENS(MWh/yr)	0.504	1.455	10.895	28.259	118.052
19	PLC	0.00018	0.00032	0.00131	0.0025	0.00731
	ENLC(1/yr)	0.15238	0.26495	0.98491	1.83176	5.06336
	ELC(MW/yr)	8.141	15.199	58.672	117.679	353.001
	EDNS (MW)	0.0096	0.01839	0.07632	0.15886	0.51007
	EENS(MWh/yr)	84.109	161.065	668.545	1391.609	4468.184
20	PLC	0	0.00001	0.00003	0.00008	0.00026
	ENLC(1/yr)	0.00259	0.006	0.03055	0.06705	0.21839
	ELC(MW/yr)	0.093	0.231	1.307	3.045	11.03
	EDNS (MW)	0.00009	0.00023	0.00144	0.00345	0.01326
	EENS(MWh/yr)	0.795	2.004	12.649	30.205	116.129

Table B.16: IEEE-RTS annual load bus indices for the four-state generating unit models at different peak load levels

Bus No.	Indices	Peak Load (MW)				
		2500	2600	2800	2900	3100
2	PLC	0	0	0	0	0.00001
	ENLC(1/yr)	0.00001	0.00004	0.0007	0.00196	0.01011
	ELC(MW/yr)	0	0.001	0.021	0.064	0.375
	EDNS (MW)	0	0	0.00002	0.00006	0.00039
	EENS(MWh/yr)	0.002	0.007	0.162	0.529	3.431
3	PLC	0	0	0	0	0.00001
	ENLC(1/yr)	0	0.00001	0.00027	0.00091	0.00568
	ELC(MW/yr)	0	0	0.011	0.046	0.304
	EDNS (MW)	0	0	0.00001	0.00004	0.0003
	EENS(MWh/yr)	0	0.003	0.082	0.354	2.615
6	PLC	0	0	0	0	0
	ENLC(1/yr)	0.00094	0.00094	0.00075	0.00075	0.00061
	ELC(MW/yr)	0.061	0.063	0.051	0.053	0.044
	EDNS (MW)	0.00004	0.00004	0.00003	0.00003	0.00003
	EENS(MWh/yr)	0.341	0.352	0.287	0.299	0.246

Table B.16: (Continued)

Bus No.	Indices	Peak Load (MW)				
		2500	2600	2800	2900	3100
7	PLC	0	0	0	0	0
	ENLC(1/yr)	0.00004	0.00016	0.00041	0.00068	0.00097
	ELC(MW/yr)	0	0.001	0.003	0.005	0.011
	EDNS (MW)	0	0	0	0	0.00001
	EENS(MWh/yr)	0.001	0.004	0.016	0.028	0.062
8	PLC	-	-	0	0	0
	ENLC(1/yr)	-	-	0.00004	0.00005	0.00035
	ELC(MW/yr)	-	-	0	0.001	0.01
	EDNS (MW)	-	-	0	0	0.00001
	EENS(MWh/yr)	-	-	0.001	0.006	0.073
9	PLC	0.00008	0.00017	0.00066	0.0014	0.00435
	ENLC(1/yr)	0.07382	0.14191	0.52464	1.0502	3.06186
	ELC(MW/yr)	3.975	7.59	30.987	63.516	201.086
	EDNS (MW)	0.00457	0.00894	0.03906	0.08319	0.28078
	EENS(MWh/yr)	40.011	78.285	342.207	728.761	2459.589
10	PLC	0	0	0	0.00001	0.00003
	ENLC(1/yr)	0.0001	0.00026	0.00281	0.00655	0.02722
	ELC(MW/yr)	0.003	0.011	0.119	0.355	1.725
	EDNS (MW)	0	0.00001	0.00011	0.00035	0.00187
	EENS(MWh/yr)	0.021	0.076	0.986	3.084	16.362
13	PLC	-	-	0	0	0
	ENLC(1/yr)	-	-	0.00004	0.00017	0.0017
	ELC(MW/yr)	-	-	0.002	0.01	0.094
	EDNS (MW)	-	-	0	0.00001	0.00009
	EENS(MWh/yr)	-	-	0.012	0.069	0.748
14	PLC	0.00001	0.00002	0.00011	0.00023	0.00079
	ENLC(1/yr)	0.01035	0.0217	0.09213	0.1926	0.6187
	ELC(MW/yr)	0.531	1.194	5.616	12.292	42.915
	EDNS (MW)	0.00055	0.00128	0.00647	0.01461	0.05431
	EENS(MWh/yr)	4.832	11.222	56.652	128.001	475.778
15	PLC	0.00004	0.00008	0.00035	0.00076	0.00244
	ENLC(1/yr)	0.03913	0.07391	0.29071	0.59412	1.78434
	ELC(MW/yr)	2.841	5.79	24.6	52.292	172.707
	EDNS (MW)	0.00312	0.00657	0.02961	0.06546	0.23057
	EENS(MWh/yr)	27.289	57.584	259.373	573.424	2019.835
16	PLC	0	0.00001	0.00005	0.00011	0.00037
	ENLC(1/yr)	0.00408	0.00876	0.04306	0.09156	0.30591
	ELC(MW/yr)	0.135	0.294	1.52	3.46	12.458
	EDNS (MW)	0.00013	0.00031	0.00168	0.004	0.01522
	EENS(MWh/yr)	1.143	2.698	14.752	35.079	133.311

Table B.16: (Continued)

Bus No.	Indices	Peak Load (MW)				
		2500	2600	2800	2900	3100
18	PLC	0	0	0.00002	0.00004	0.00015
	ENLC(1/yr)	0.0009	0.003	0.01543	0.03307	0.12775
	ELC(MW/yr)	0.057	0.159	1.095	2.705	10.849
	EDNS (MW)	0.00005	0.00015	0.00113	0.00293	0.01248
	EENS(MWh/yr)	0.439	1.31	9.872	25.707	109.316
19	PLC	0.00017	0.00031	0.00125	0.00243	0.00716
	ENLC(1/yr)	0.14315	0.25233	0.94218	1.7812	4.96349
	ELC(MW/yr)	7.57	14.369	56.341	113.874	344.741
	EDNS (MW)	0.00892	0.01735	0.07321	0.15355	0.49809
	EENS(MWh/yr)	78.139	151.974	641.318	1345.137	4363.295
20	PLC	0	0.00001	0.00003	0.00007	0.00025
	ENLC(1/yr)	0.00249	0.00536	0.02769	0.06255	0.20673
	ELC(MW/yr)	0.084	0.21	1.201	2.811	10.396
	EDNS (MW)	0.00008	0.00021	0.00132	0.00318	0.01246
	EENS(MWh/yr)	0.708	1.809	11.585	27.822	109.174

APPENDIX C. BASIC CEA DATA ANALYSIS AND SYSTEM PERFORMANCE INDICES FOR THE TWO TEST SYSTEMS

Table C.1-C.12 give the CEA performance indices SAIFI-SI, SAIDI and SARI for the period 1993-2001. Figures C.1-C.12 show the comparison of these indices excluding and including the 1998 ice storm over the repeating period.

Table C.1: SAIFI-SI by Voltage Class for single circuits during the period 1993-2001

Voltage Class	SAIFI (Sustained Interruptions)									
	1993-1997		1994-1998		1995-1999		1996- 2000		1997- 2001	
	Ex	In	Ex	In	Ex	In	Ex	In	Ex	In
1	1.996	1.996	2.096	2.12	2.14	2.159	2.02	2.04	1.86	1.876
2	1.658	1.658	1.709	1.807	1.66	1.748	1.54	1.62	1.4	1.478
3	0.9	0.9	0.709	0.735	0.74	0.762	0.75	0.76	0.82	0.842
4	N/A	N/A	0.182	0.818	0.27	0.591	0.27	0.47	0.3	0.457

Table C.2: SAIFI-SI by Voltage Class for multiple circuits during the period 1993-2001

Voltage Class	SAIFI (Sustained Interruptions)									
	1993-1997		1994-1998		1995-1999		1996- 2000		1997- 2001	
	Ex	In	Ex	In	Ex	In	Ex	In	Ex	In
1	0.455	0.455	0.424	0.455	0.533	0.554	0.53	0.56	0.53	0.558
2	0.317	0.317	0.328	0.388	0.321	0.37	0.3	0.35	0.31	0.356
3	0.314	0.314	0.33	0.339	0.29	0.299	0.29	0.3	0.31	0.318
4	N/A	N/A	0.36	1.24	0.26	0.7	0.31	0.6	0.28	0.5

Table C.3: SAIFI-SI by Voltage Class for both single circuits and multiple circuits during the period 1993-2001

Voltage Class	SAIFI (Sustained Interruptions)									
	1993-1997		1994-1998		1995-1999		1996- 2000		1997- 2001	
	Ex	In	Ex	In	Ex	In	Ex	In	Ex	In
1	1.629	1.629	1.693	1.719	1.76	1.785	1.68	1.7	1.58	1.598
2	1.035	1.035	1.087	1.169	1.06	1.138	0.99	1.06	0.92	0.984
3	0.397	0.397	0.39	0.397	0.36	0.371	0.37	0.38	0.4	0.407
4	N/A	N/A	0.306	1.111	0.26	0.667	0.29	0.56	0.29	0.486

Table C.4: SAIFI-SI by Supply Type for all voltage classes during the period 1993-2001

Supply Type	SAIFI (Sustained Interruptions)									
	1993-1997		1994-1998		1995-1999		1996-2000		1997- 2001	
	Ex	In	Ex	In	Ex	In	Ex	In	Ex	In
Single Circuit	1.763	1.763	1.816	1.881	1.81	1.871	1.71	1.76	1.57	1.62
Multi Circuit	0.336	0.336	0.343	0.386	0.34	0.379	0.34	0.38	0.34	0.378
All	1.085	1.085	1.132	1.186	1.15	1.199	1.11	1.15	1.05	1.087

Note: Ex-the results excluding 1998 ice storm, In-the results including 1998 ice storm.

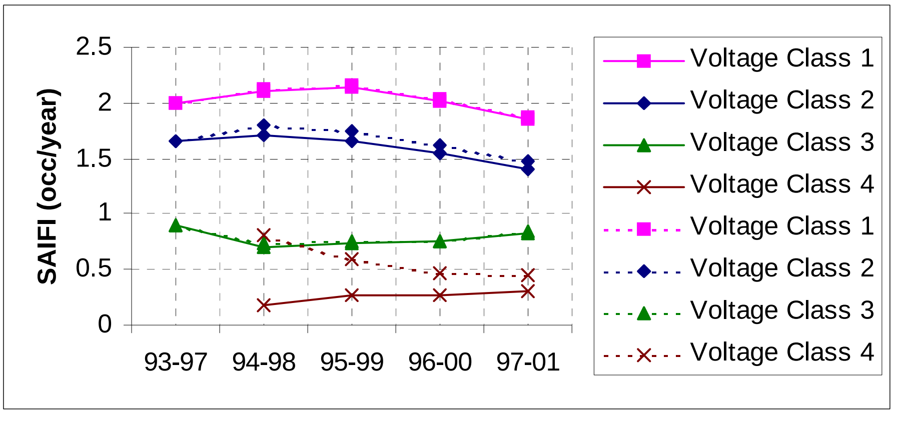

Figure C.1: SAIFI-SI by Voltage Class for single circuits during the period 1993-2001 (including Ice Storm 98 data)

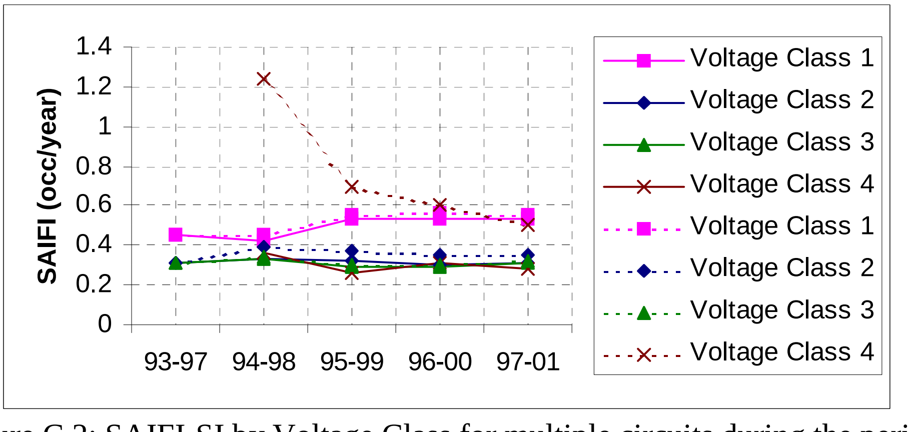

Figure C.2: SAIFI-SI by Voltage Class for multiple circuits during the period 1993-2001(including Ice Storm 98 data)

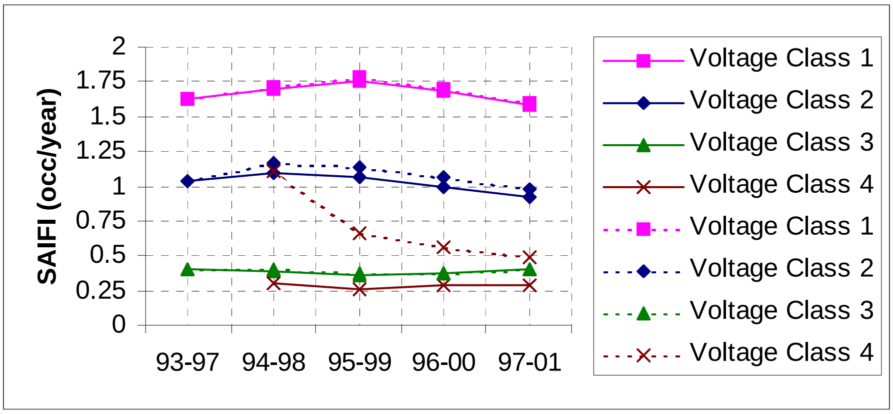

Figure C.3: SAIFI-SI by Voltage Class for both single circuits and multiple circuits during the period 1993-2001 (including Ice Storm 98 data)

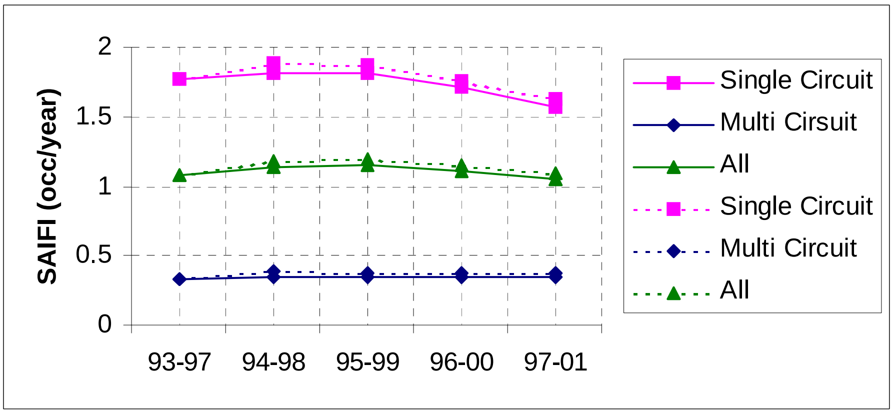

Figure C.4: SAIFI-SI by Supply Type for all voltage classes during the period 1993-2001 (including Ice Storm 98 data)

Note: The dashed lines include Ice Storm 98 data.
The solid lines exclude Ice Storm 98 data.

Table C.5: SAIDI of BES Interruptions by Voltage Class for single circuits during the period 1993-2001

Voltage Class	SAIDI (BES Interruptions)									
	1993-1997		1994-1998		1995-1999		1996- 2000		1997- 2001	
	Ex	In	Ex	In	Ex	In	Ex	In	Ex	In
1	152	152	151.7	204.7	150.1	194.1	134.9	173.8	137.2	172.4
2	93.79	93.79	98.46	225.9	100.8	232.7	112.7	216.1	119	214.7
3	42.88	42.88	43.87	210.8	57.85	202.4	49.94	190	51.69	181
4	N/A	N/A	5.18	1107	5.18	564.5	14.32	370.8	12	275.5

Table C.6: SAIDI of BES Interruptions by Voltage Class for multiple circuits during the period 1993-2001

Voltage Class	SAIDI (BES Interruptions)									
	1993-1997		1994-1998		1995-1999		1996- 2000		1997- 2001	
	Ex	In	Ex	In	Ex	In	Ex	In	Ex	In
1	31.31	31.31	27.15	31.81	89.64	92.09	85.73	89.47	86.21	89.88
2	28.36	28.36	24.66	110.1	25.7	98.54	25.68	97.81	28.21	95
3	16.56	16.56	14.55	24.27	15.89	19.24	16.36	25.61	18.78	27.83
4	N/A	N/A	7.12	586.2	7.12	299.3	11.16	204.2	10.89	155.7

Table C.7: SAIDI of BES Interruptions by Voltage Class for both single circuits and multiple circuits during the period 1993-2001

Voltage Class	SAIDI (BES Interruptions)									
	1993-1997		1994-1998		1995-1999		1996- 2000		1997- 2001	
	Ex	In	Ex	In	Ex	In	Ex	In	Ex	In
1	123.2	123.2	121.7	163.1	135.6	170.3	123.8	154.8	126.5	155
2	63.39	63.39	59.94	173.8	70.56	173.3	74.4	164.1	79.08	162
3	20.28	20.28	17.66	51.51	26.84	47.52	21.82	52.31	24.39	53.96
4	N/A	N/A	6.53	745.3	6.53	380.3	12.15	256.1	11.24	193.4

Table C.8: SAIDI of BES Interruptions by Supply Type for all voltage classes during the period 1993-2001

Supply Type	SAIDI (BES Interruptions)									
	1993-1997		1994-1998		1995-1999		1996- 2000		1997- 2001	
	Ex	In	Ex	In	Ex	In	Ex	In	Ex	In
Single Circuit	116	116	117.7	217.9	124.1	215.8	119.1	197	123.4	194.7
Multi Circuit	24.63	24.63	21.5	71.1	41.2	73.4	32.46	75.34	34.38	74.93
All	72.61	72.61	70.04	149.7	93.48	151.7	81.13	143.7	85.17	143.3

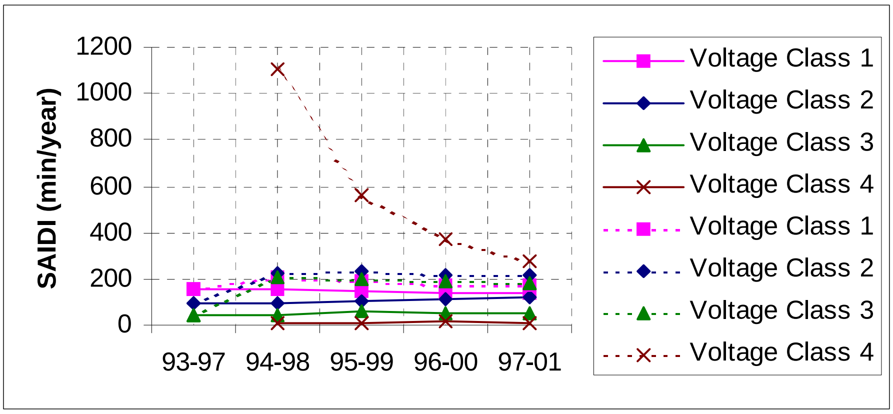

Figure C.5: SAIDI of BES Interruptions by Voltage Class for single circuits during the period 1993-2001 (including Ice Storm 98 data)

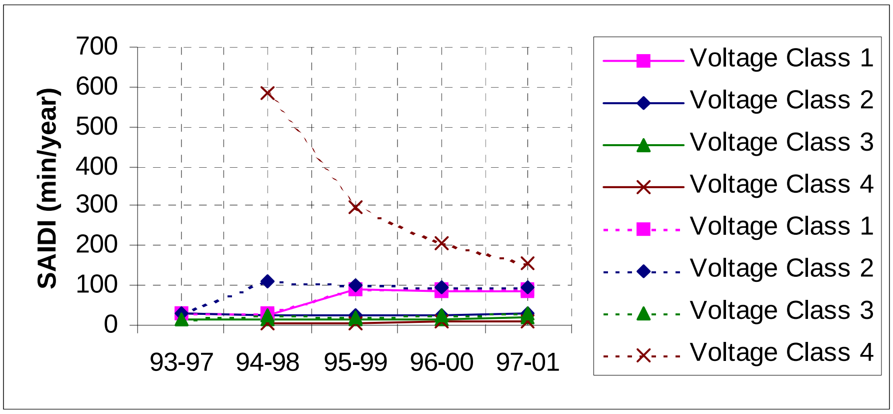

Figure C.6: SAIDI of BES Interruptions by Voltage Class for multiple circuits during the period 1993-2001 (including Ice Storm 98 data)

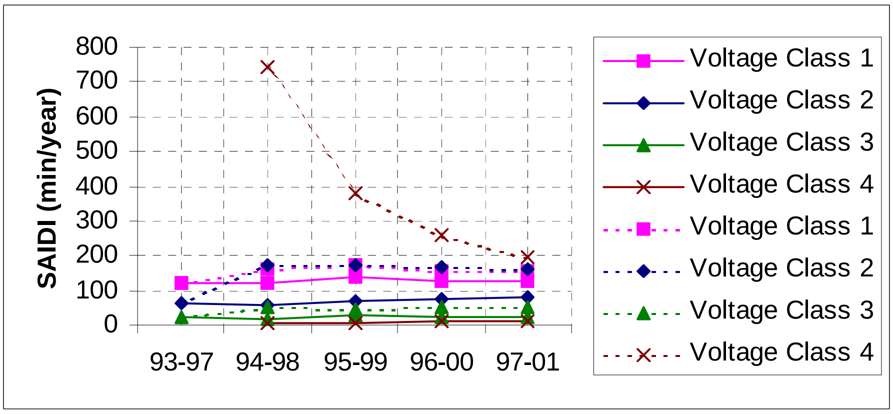

Figure C.7: SAIDI of BES Interruptions by Voltage Class for both single circuits and multiple circuits during the period 1993-2001 (including Ice Storm 98 data)

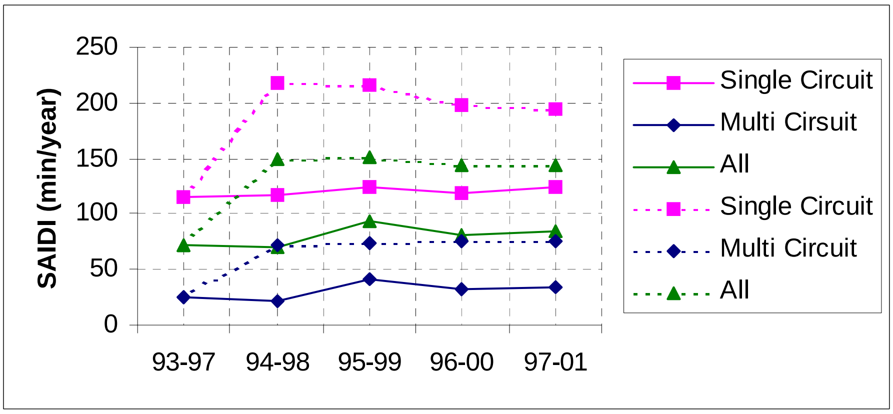

Figure C.8: SAIDI of BES Interruptions by Supply Type for all voltage classes during the period 1993-2001 (including Ice Storm 98 data)

Table C.9: SARI of BES Interruptions by Voltage Class for single circuits during the period 1993-2001

Voltage Class	SARI (BES Interruptions)									
	1993-1997		1994-1998		1995-1999		1996- 2000		1997- 2001	
	Ex	In	Ex	In	Ex	In	Ex	In	Ex	In
1	76.16	76.16	72.39	96.56	68.12	89.89	66.77	85.39	73.79	91.93
2	56.57	56.57	57.62	125	66.21	133.1	73.21	133.6	84.79	145.3
3	47.63	47.63	61.86	286.9	76.48	265.7	66.77	249.6	62.9	215.1
4	N/A	N/A	28.5	1353	28.5	955.2	54.11	787.9	39.43	603.4

Table C.10: SARI of BES Interruptions by Voltage Class for multiple circuits during the period 1993-2001

Voltage Class	SARI (BES Interruptions)									
	1993-1997		1994-1998		1995-1999		1996- 2000		1997- 2001	
	Ex	In	Ex	In	Ex	In	Ex	In	Ex	In
1	68.8	68.8	64.06	69.98	166.8	166.1	161.8	159.1	161.6	161.2
2	89.39	89.39	75.3	283.3	80.19	266	85.37	276.2	91.64	267.2
3	52.75	52.75	44.08	71.63	33.44	64.27	55.88	85.04	60.7	87.64
4	N/A	N/A	19.78	472.7	19.78	427.6	36.39	340.3	38.89	311.3

Table C.11: SARI of BES Interruptions by Voltage Class for both single circuits and multiple circuits during the period 1993-2001

Voltage Class	SARI (BES Interruptions)									
	1993-1997		1994-1998		1995-1999		1996- 2000		1997- 2001	
	Ex	In	Ex	In	Ex	In	Ex	In	Ex	In
1	75.67	75.67	71.89	94.87	75.21	95.41	73.51	90.88	80.05	97.02
2	61.24	61.24	60.02	148.7	67.94	152.3	74.83	154.6	85.8	164.7
3	51.11	51.11	48.86	129.9	48.93	128.2	59.49	139.2	61.48	132.6
4	N/A	N/A	21.36	670.8	21.36	570.5	41.38	457.7	39.07	397.7

Table C.12: SARI of BES Interruptions by Supply Type for all voltage classes during the period 1993-2001

Supply Type	SARI (BES Interruptions)									
	1993-1997		1994-1998		1995-1999		1996- 2000		1997- 2001	
	Ex	In	Ex	In	Ex	In	Ex	In	Ex	In
Single Circuit	65.81	65.81	64.78	115.8	67.56	115.4	69.72	112.2	78.44	120.2
Multi Circuit	73.21	73.21	62.66	184.4	100.2	193.6	96.63	201	99.78	198.1
All	66.9	66.9	64.49	126.2	71.34	126.5	73.3	124.8	81.44	131.8

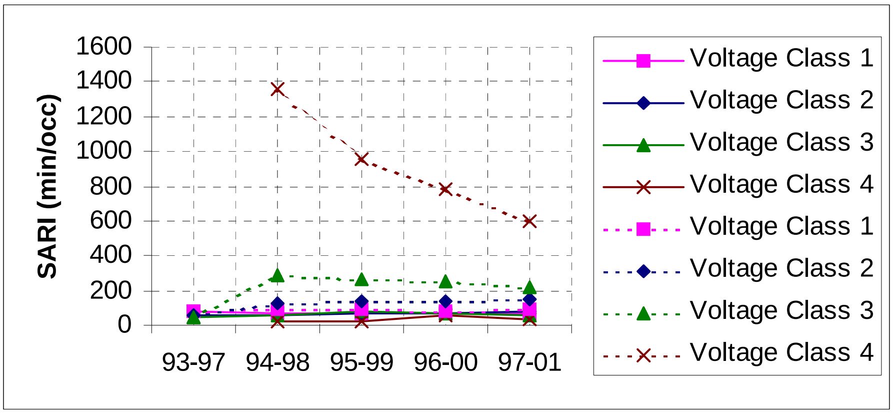

Figure C.9: SARI of BES Interruptions by Voltage Class for single circuits during the period 1993-2001 (including Ice Storm 98 data)

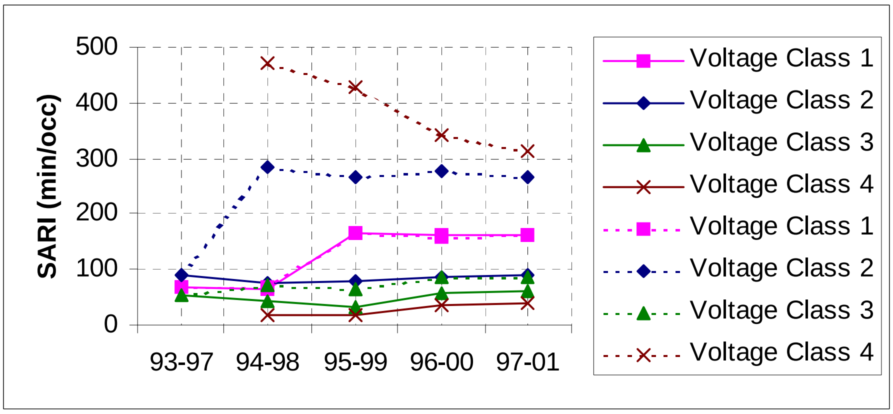

Figure C.10: SARI of BES Interruptions by Voltage Class for multiple circuits during the period 1993-2001 (including Ice Storm 98 data)

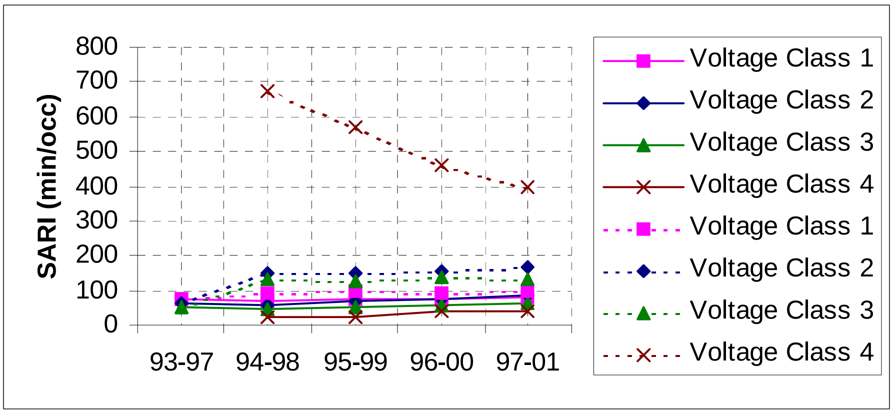

Figure C.11: SARI of BES Interruptions by Voltage Class for both single circuits and multiple circuits during the period 1993-2001 (including Ice Storm 98 data)

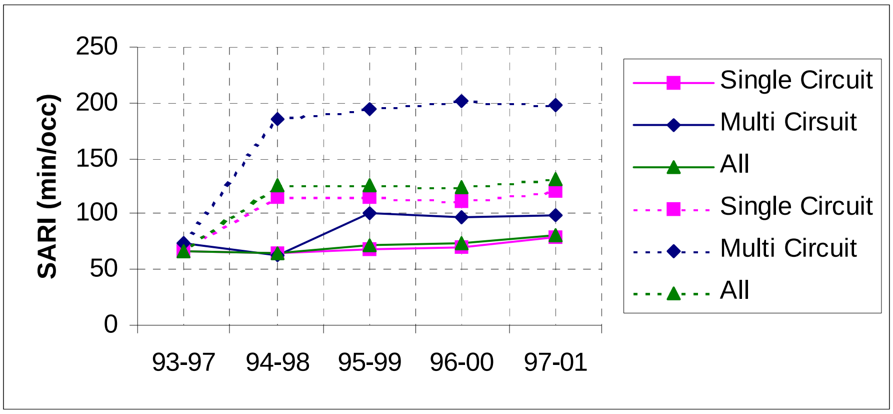

Figure C.12: SARI of BES Interruptions by Supply Type for all voltage classes during the period 1993-2001 (including Ice Storm 98 data)

Tables C.13-C.33 present the predicting system indices SAIFI, SAIDI and DPUI in the RBTS including the effects of the five factors.

Table C.13: SAIFI by Supply Type for the base case and Cases 1, 2, 3 (RBTS)

Supply Type	SIAFI			
	Base case	Case 1	Case 2	Case 3
Single Circuit	1.18265	1.39518	1.18318	1.18351
Multi Circuit	0.02706	0.24617	0.02744	0.02709
All	0.25818	0.47597	0.25858	0.25838

Table C.14: SAIDI by Supply Type for the base case and Cases 1, 2, 3 (RBTS)

Supply Type	SIADI			
	Base case	Case 1	Case 2	Case 3
Single Circuit	10.512	25.7544	10.512	10.512
Multi Circuit	0.3942	15.549	0.438	0.3942
All	2.41776	17.5901	2.4528	2.41776

Table C.15: DPUI of the system for the base case and Cases 1, 2, 3 (RBTS)

Case No.	DPUI
Base case	49.26625
Case 1	626.99926
Case 2	50.10960
Case 3	49.18726

Table C.16: SAIFI by Supply Types for the base case and Cases 1, 2 (RBTS)

Supply Type	SIAFI		
	Base case	Case 1	Case 2
Single Circuit	1.18265	1.20265	1.18272
Multi Circuit	0.02706	0.04706	0.02713
All	0.25818	0.27818	0.25825

Table C.17: SAIDI by Supply Types for the base case and Cases 1, 2 (RBTS)

Supply Type	SIADI		
	Base case	Case 1	Case 2
Single Circuit	10.512	25.842	10.5388
Multi Circuit	0.3942	15.7242	0.42103
All	2.41776	17.7478	2.44459

Table C.18: DPUI of the system for the base case and Cases 1, 2 (RBTS)

Case No.	DPUI
Base case	49.26625
Case 1	637.7451
Case 2	50.4403

Table C.19: SAIFI by Supply Type based on Case 1 and Cases 1A, 1B, 1C (RBTS)

Supply Type	SIAFI			
	Case 1	Case 1A	Case 1B	Case 1C
Single Circuit	1.20265	1.21265	1.22265	1.20265
Multi Circuit	0.04706	0.05706	0.06706	0.04706
All	0.27818	0.28818	0.29818	0.27818

Table C.20: SAIDI by Supply Type based on Case 1 and Cases 1A, 1B, 1C (RBTS)

Supply Type	SIADI			
	Case 1	Case 1A	Case 1B	Case 1C
Single Circuit	25.842	33.4632	41.0844	18.2208
Multi Circuit	15.7242	23.3454	30.9666	8.103
All	17.7478	25.369	32.9902	10.1266

Table C.21: DPUI of the system based on Case 1 and Cases 1A, 1B, 1C (RBTS)

Case No.	DPUI
Case 1	637.745
Case 1A	930.231
Case 1B	1222.72
Case 1C	345.259

Table C.22: SAIFI by Supply Type based on Case 2 and Cases 2A, 2B, 2C (RBTS)

Supply Type	SIAFI			
	Case 2	Case 2A	Case 2B	Case 2C
Single Circuit	1.18272	1.18281	1.18293	1.18272
Multi Circuit	0.02713	0.02722	0.02734	0.02713
All	0.25825	0.25834	0.25846	0.25825

Table C.23: SAIDI by Supply Type based on Case 2 and Cases 2A, 2B, 2C (RBTS)

Supply Type	SIADI			
	Case 2	Case 2A	Case 2B	Case 2C
Single Circuit	10.5388	10.5721	10.6187	10.5188
Multi Circuit	0.42103	0.45432	0.5009	0.40098
All	2.44459	2.47788	2.52446	2.42454

Table C.24: DPUI of the system based on Case 2 and Cases 2A, 2B, 2C (RBTS)

Case No.	DPUI
Case 2	50.4403
Case 2A	51.7185
Case 2B	51.7185
Case 2C	49.6711

Table C.25: SAIFI by Supply Type based on Cases 1, 2, 3 and 4 (RBTS)

Supply Type	SAIFI			
	Case 1	Case 2	Case 3	Case 4
Single Circuit	1.26679	1.18265	1.2705	1.2705
Multi Circuit	0.0205	0.02706	0.01512	0.02013
All	0.26976	0.25818	0.2662	0.2702

Table C.26: SAIDI by Supply Type based on Cases 1, 2, 3 and 4 (RBTS)

Supply Type	SAIDI			
	Case 1	Case 2	Case 3	Case 4
Single Circuit	12.0012	10.512	12.0012	12.0012
Multi Circuit	0.2628	0.3942	0.1752	0.2628
All	2.61048	2.41776	2.5404	2.61048

Table C.27: DPUI of the system based on Cases 1, 2, 3 and 4 (RBTS)

Case No.	DPUI
Case 1	49.41072
Case 2	49.41072
Case 3	49.41072
Case 4	49.41072

Table C.28: SAIFI by Supply Type for the base case and the modified system (RBTS)

Supply Type	SAIFI	
	Base case	The modified system
Single Circuit	1.18265	-
Multi Circuit	0.02706	0.00495
All	0.25818	0.00495

Table C.29: SAIDI by Supply Type for the base case and the modified system (RBTS)

Supply Type	SAIDI	
	Base case	The modified system
Single Circuit	10.512	-
Multi Circuit	0.3942	0.03504
All	2.41776	0.03504

Table C.30: DPUI of the system for the base case and the modified system (RBTS)

Case No.	DPUI
Base case	49.26625
The modified system	0.84557

Table C.31: SAIFI by Supply Type for the base case at five different peak load levels (RBTS)

Supply Type	SAIFI				
	Peak load (MW)				
	160	170	180	190	200
Single Circuit	1.17913	1.17987	1.18094	1.183	1.18638
Multi Circuit	0.00433	0.01026	0.02281	0.05702	0.06508
All	0.23929	0.24418	0.25444	0.28221	0.28934

Table C.32: SAIDI by Supply Type for the base case at five different peak load levels (RBTS)

Supply Type	SAIDI				
	Peak load (MW)				
	160	170	180	190	200
Single Circuit	10.512	10.512	10.512	10.512	10.5996
Multi Circuit	0.0438	0.1314	0.3504	0.9417	1.0293
All	2.13744	2.20752	2.38272	2.85576	2.94336

Table C.33: DPUI of the system for the base case at five different peak load levels (RBTS)

Peak load (MW)	DPUI
160	37.98933
170	41.52457
180	45.69291
190	54.48711
200	66.93175

Tables C.34-C.51 present the predicting system performance indices SAIFI, SAIDI and DPUI in the IEEE-RTS including the effects of the five factors.

Table C.34: SAIFI by Voltage Class for the base case and Cases 1, 2 (IEEE-RTS)

Voltage Class	SIAFI		
	Base case	Case 1	Case 2
2	0.08804	0.108042	0.088112
3	0.34137	0.361373	0.341443
Total	0.19235	0.212355	0.192425

Table C.35: SAIDI by Voltage Class for the base case and Cases 1, 2 (IEEE-RTS)

Voltage Class	SIADI		
	Base case	Case 1	Case 2
2	0.99864	16.32864	1.025466
3	3.8544	19.1844	3.881216
Total	2.17454	17.50454	2.201363

Table C.36: DPUI of the system for the base case and Cases 1, 2 (IEEE-RTS)

Case No.	DPUI
Base case	50.81941
Case 1	639.1539
Case 2	51.84902

Table C.37: SAIFI by Voltage Class based on Case 1 and Cases 1A, 1B, 1C (IEEE-RTS)

Voltage Class	SAIFI			
	Case 1	Case 1A	Case 1B	Case 1C
2	0.10804	0.11804	0.12804	0.10804
3	0.36137	0.37137	0.38137	0.36137
Total	0.21236	0.22236	0.23236	0.21236

Table C.38: SAIDI by Voltage Class based on Case 1 and Cases 1A, 1B, 1C (IEEE-RTS)

Voltage Class	SIADI			
	Case 1	Case 1A	Case 1B	Case 1C
2	16.3286	23.9498	31.571	8.70744
3	19.1844	26.8056	34.4268	11.5632
Total	17.5045	25.1257	32.7469	9.88334

Table C.39: DPUI of the system based on Case 1 and Cases 1A, 1B, 1C (IEEE-RTS)

Case No.	DPUI
Case 1	639.154
Case 1A	931.64
Case 1B	1224.13
Case 1C	346.668

Table C.40: SAIFI by Voltage Class based on base Case 2 and Cases 2A, 2B, 2C (IEEE-RTS)

Voltage Class	SAIFI			
	Case 2	Case 2A	Case 2B	Case 2C
2	0.08811	0.0882	0.08832	0.08811
3	0.34144	0.34153	0.34165	0.34144
Total	0.19243	0.19251	0.19264	0.19243

Table C.41: SAIDI by Voltage Class based on base Case 2 and Cases 2A, 2B, 2C (IEEE-RTS)

Voltage Class	SIADI			
	Case 2	Case 2A	Case 2B	Case 2C
2	1.02547	1.05877	1.10534	1.00542
3	3.88122	3.91451	3.9611	3.86116
Total	2.20136	2.23466	2.28124	2.18131

Table C.42: DPUI of the system based on Case 2 and Cases 2A, 2B, 2C (IEEE-RTS)

Case No.	DPUI
Case 2	51.849
Case 2A	53.1272
Case 2B	54.9143
Case 2C	51.0798

Table C.43: SAIFI by Voltage Class based on Cases 1, 2, 3 and 4 (IEEE-RTS)

Voltage Class	SAIFI			
	Case 1	Case 2	Case 3	Case 4
2	0.00053	0.08804	0.21421	0.00911
3	0.50858	0.34137	0.20313	0.4247
Total	0.20973	0.19235	0.20965	0.18023

Table C.44: SAIDI by Voltage Class based on Cases 1, 2, 3 and 4 (IEEE-RTS)

Voltage Class	SAIDI			
	Case 1	Case 2	Case 3	Case 4
2	0	0.99864	2.41776	0.0876
3	5.74406	3.8544	2.29011	4.80549
Total	2.3652	2.17454	2.3652	2.03026

Table C.45: DPUI of the system based on Cases 1, 2, 3 and 4 (IEEE-RTS)

Case No.	DPUI
Case 1	50.81941
Case 2	50.81941
Case 3	50.81941
Case 4	50.81941

Table C.46: SAIFI by Voltage Class for the base case and the modified system (IEEE-RTS)

Voltage Class	SAIFI	
	Base case	The modified system
2	0.08804	0.0606
3	0.34137	0.45192
Total	0.19235	0.22173

Table C.47: SAIDI by Voltage Class for the base case and the modified system (IEEE-RTS)

Voltage Class	SAIDI	
	Base case	The modified system
2	0.99864	0.6132
3	3.8544	5.35611
Total	2.17454	2.56616

Table C.48: DPUI of the system for the base case and the modified system (IEEE-RTS)

Case No.	DPUI
Base case	50.81941
The modified system	41.72516

Table C.49: SAIFI by Voltage Class for the base case at five different peak load levels (IEEE-RTS)

Voltage Class	SAIFI				
	Peak load (MW)				
	2500	2600	2800	2900	3100
2	0.00981	0.0184	0.06428	0.12769	0.35949
3	0.03749	0.06651	0.24965	0.47079	1.31543
Total	0.02121	0.03821	0.14061	0.26896	0.75312

Table C.50: SAIDI by Voltage Class for the base case at five different peak load levels (IEEE-RTS)

Voltage Class	SAIDI				
	Peak load (MW)				
	2500	2600	2800	2900	3100
2	0.09636	0.19272	0.7008	1.4892	4.4676
3	0.38794	0.67577	2.8032	5.44371	16.0058
Total	0.21642	0.39162	1.56649	3.11753	9.21861

Table C.51: DPUI of the system for the base case at five different peak load levels (IEEE-RTS)

Peak load (MW)	DPUI
2500	4.26714
2600	8.31142
2800	34.92069
2900	73.13497
3100	236.83341

APPENDIX D. ANALYSES RESULTS OF THE RBTS, MRBTS, IEEE-RTS AND MRTS

Tables D.1-D.2 show the load bus and system reliability indices based on the RBTS base case analysis. Tables D.3-D.4 present these reliability indices based on the factor analysis of the RBTS base case. Tables D.5-D.12 give the reliability indices based on four remedial modification actions.

Table D.1: RBTS load bus reliability indices at different peak load levels

Bus No.	Indices	Peak Load (MW)				
		160	170	180	190	200
2	PLC	-	-	-	0	0
	ENLC(1/yr)	-	-	-	0.00002	0.00002
	ELC(MW/yr)	-	-	-	0	0
	EDNS (MW)	-	-	-	0	0
	EENS(MWh/yr)	-	-	-	0	0.001
3	PLC	0.00002	0.00006	0.00016	0.00043	0.00046
	ENLC(1/yr)	0.01281	0.03586	0.08521	0.2204	0.25031
	ELC(MW/yr)	0.148	0.347	0.734	1.853	3.686
	EDNS (MW)	0.00016	0.00048	0.00117	0.00331	0.00688
	EENS(MWh/yr)	1.441	4.212	10.237	29.024	60.242
4	PLC	0	0	0	0	0
	ENLC(1/yr)	0.00018	0.00039	0.00071	0.00122	0.00179
	ELC(MW/yr)	0.001	0.003	0.005	0.011	0.017
	EDNS (MW)	0	0	0	0.00001	0.00001
	EENS(MWh/yr)	0.004	0.011	0.024	0.054	0.101
5	PLC	0	0	0	0	0.00001
	ENLC(1/yr)	0.00431	0.0048	0.00533	0.00642	0.00819
	ELC(MW/yr)	0.043	0.049	0.055	0.065	0.077
	EDNS (MW)	0.00002	0.00003	0.00003	0.00004	0.00005
	EENS(MWh/yr)	0.202	0.232	0.269	0.346	0.459
6	PLC	0.0012	0.0012	0.0012	0.0012	0.00121
	ENLC(1/yr)	1.17913	1.17987	1.18094	1.183	1.18638
	ELC(MW/yr)	12.967	13.876	14.637	15.556	16.332
	EDNS (MW)	0.01318	0.01411	0.01488	0.01582	0.01662
	EENS(MWh/yr)	115.487	123.579	130.356	138.578	145.57

Table D.2: System reliability indices for the RBTS at different peak load levels

System Indices	Peak Load (MW)				
	160	170	180	190	200
EENS (MWh/yr)	117.134	128.034	140.886	168.002	206.373
SAIFI (interruptions /delivery point)	0.23929	0.24418	0.25444	0.28221	0.28934
SAIDI (hrs/delivery point)	2.13744	2.20752	2.38272	2.85576	2.94336

Table D.3: RBTS load bus reliability indices (factor analysis)

Bus No.	Peak Load (MW)	Generation Failures			Transmission Failures		
		PLC	ENLC	EENS	PLC	ENLC	EENS
2	160	-	-	-	-	-	-
	170	-	-	-	-	-	-
	180	-	-	-	-	-	-
	190	0	0.00002	0	-	-	-
	200	0	0.00002	0.001	-	-	-
3	160	0.00002	0.00914	1.26	0	0.00261	0.164
	170	0.00006	0.02946	3.959	0	0.00302	0.211
	180	0.00015	0.07137	9.842	0	0.00456	0.275
	190	0.00041	0.17996	28.075	0.00001	0.01465	0.48
	200	0.00043	0.18664	57.704	0.00002	0.0221	1.366
4	160	0	0	0	0	0.00017	0.003
	170	0	0.00007	0.003	0	0.00031	0.008
	180	0	0.00018	0.009	0	0.00051	0.015
	190	0	0.00033	0.027	0	0.00086	0.027
	200	0	0.0005	0.06	0	0.00124	0.04
5	160	0	0.00007	0.004	0	0.00405	0.198
	170	0	0.00021	0.013	0	0.0044	0.219
	180	0	0.00049	0.031	0	0.00462	0.238
	190	0	0.00112	0.083	0	0.005	0.261
	200	0	0.00258	0.177	0	0.00512	0.28
6	160	0	0.00021	0.013	0.0012	1.0926	115.474
	170	0	0.0005	0.039	0.0012	1.09298	123.539
	180	0	0.00117	0.095	0.0012	1.09333	130.26
	190	0	0.00274	0.249	0.0012	1.09362	138.325
	200	0.00001	0.00534	0.517	0.0012	1.09409	145.046

Table D.3: RBTS load bus reliability indices (factor analysis) (continued)

Bus No.	Peak Load (MW)	Total Generation and Transmission Failures			Overlapping Generation and Transmission Failures		
		PLC	ENLC	EENS	PLC	ENLC	EENS
2	160	-	-	-	0	0	0
	170	-	-	-	0	0	0
	180	-	-	-	0	0	0
	190	0	0.00002	0	0	0	0
	200	0	0.00002	0.001	0	0	0
3	160	0.00002	0.01281	1.441	0	0.00106	0.017
	170	0.00006	0.03586	4.212	0	0.00338	0.042
	180	0.00016	0.08521	10.237	0.00001	0.00928	0.12
	190	0.00043	0.2204	29.024	0.00001	0.02579	0.469
	200	0.00046	0.25031	60.242	0.00001	0.04157	1.172
4	160	0	0.00018	0.004	0	0.00001	0.001
	170	0	0.00039	0.011	0	0.00001	0
	180	0	0.00071	0.024	0	0.00002	0
	190	0	0.00122	0.054	0	0.00003	0
	200	0	0.00179	0.101	0	0.00005	0.001
5	160	0	0.00431	0.202	0	0.00019	0
	170	0	0.0048	0.232	0	0.00019	0
	180	0	0.00533	0.269	0	0.00022	0
	190	0	0.00642	0.346	0	0.0003	0.002
	200	0.00001	0.00819	0.459	0.00001	0.00049	0.002
6	160	0.0012	1.17913	115.487	0	0.08632	0
	170	0.0012	1.17987	123.579	0	0.08639	0.001
	180	0.0012	1.18094	130.356	0	0.08644	0.001
	190	0.0012	1.183	138.578	0	0.08664	0.004
	200	0.00121	1.18638	145.57	0	0.08695	0.007

Table D.4: System reliability indices for the RBTS (factor analysis)

Peak Load (MW)	Generation Failures			Transmission Failures		
	EENS	SAIFI	SAIDI	EENS	SAIFI	SAIDI
160	1.27722	0.002	0.04	115.84	0.22	2.1
170	4.01399	0.006	0.11	123.977	0.22	2.1
180	9.97625	0.015	0.26	130.788	0.221	2.1
190	28.4342	0.037	0.72	139.093	0.223	2.1
200	58.4599	0.039	0.77	146.732	0.225	2.1

Table D.4: System reliability indices for the RBTS (factor analysis) (continued)

Peak Load (MW)	Total Generation and Transmission Failures			Overlapping Generation and Transmission Failures		
	EENS	SAIFI	SAIDI	EENS	SAIFI	SAIDI
160	117.134	0.2393	2.14	0.01658	0.018	0
170	128.034	0.2442	2.21	0.04286	0.018	0
180	140.886	0.2544	2.38	0.12218	0.019	0.02
190	168.002	0.2822	2.86	0.47453	0.023	0.02
200	206.373	0.2893	2.94	1.18134	0.026	0.04

Table D.5: RBTS load bus reliability indices at different peak load levels (Case 1)

Bus No.	Indices	Peak Load (MW)				
		160	170	180	190	200
2	PLC	-	-	-	0	0
	ENLC(1/yr)	-	-	-	0.00002	0.00002
	ELC(MW/yr)	-	-	-	0	0
	EDNS (MW)	-	-	-	0	0
	EENS(MWh/yr)	-	-	-	0	0.001
3	PLC	0.00002	0.00006	0.00016	0.00043	0.00046
	ENLC(1/yr)	0.01285	0.03605	0.0857	0.22179	0.25175
	ELC(MW/yr)	0.149	0.348	0.738	1.864	3.708
	EDNS (MW)	0.00016	0.00048	0.00117	0.00331	0.00688
	EENS(MWh/yr)	1.441	4.213	10.241	29.039	60.277
4	PLC	0	0	0	0	0
	ENLC(1/yr)	0.00018	0.00039	0.00071	0.00122	0.00179
	ELC(MW/yr)	0.001	0.003	0.005	0.011	0.017
	EDNS (MW)	0	0	0	0.00001	0.00001
	EENS(MWh/yr)	0.004	0.011	0.024	0.054	0.101
5	PLC	0	0	0	0	0.00001
	ENLC(1/yr)	0.00475	0.00524	0.00577	0.00686	0.00863
	ELC(MW/yr)	0.048	0.054	0.061	0.071	0.083
	EDNS (MW)	0.00002	0.00003	0.00003	0.00004	0.00005
	EENS(MWh/yr)	0.202	0.232	0.269	0.346	0.459
6	PLC	0.00001	0.00001	0.00001	0.00001	0.00001
	ENLC(1/yr)	0.00977	0.0105	0.01157	0.01364	0.01703
	ELC(MW/yr)	0.102	0.113	0.126	0.148	0.176
	EDNS (MW)	0.00005	0.00006	0.00007	0.00009	0.00013
	EENS(MWh/yr)	0.464	0.53	0.62	0.817	1.122

Table D.6: System reliability indices for the RBTS at different peak load levels (Case 1)

System Indices	Peak Load (MW)				
	160	170	180	190	200
EENS (MWh/yr)	2.11023	4.98643	11.15442	30.25634	61.95989
SAIFI (interruptions /delivery point)	0.00551	0.01044	0.02075	0.04871	0.05584
SAIDI (hrs/delivery point)	0.05256	0.12264	0.29784	0.77088	0.84096

Table D.7: RBTS load bus reliability indices at different peak load levels (Case 2)

Bus No.	Indices	Peak Load (MW)				
		160	170	180	190	200
2	PLC	-	-	-	0	0
	ENLC(1/yr)	-	-	-	0.00002	0.00002
	ELC(MW/yr)	-	-	-	0	0
	EDNS (MW)	-	-	-	0	0
	EENS(MWh/yr)	-	-	-	0	0.001
3	PLC	0.00002	0.00006	0.00016	0.00043	0.00049
	ENLC(1/yr)	0.01287	0.03617	0.08595	0.2225	0.28472
	ELC(MW/yr)	0.149	0.349	0.741	1.88	3.75
	EDNS (MW)	0.00016	0.00048	0.00117	0.00332	0.00691
	EENS(MWh/yr)	1.441	4.215	10.252	29.12	60.521
4	PLC	0	0	0	0	0
	ENLC(1/yr)	0.00018	0.00039	0.00071	0.00122	0.00179
	ELC(MW/yr)	0.001	0.003	0.005	0.011	0.017
	EDNS (MW)	0	0	0	0.00001	0.00001
	EENS(MWh/yr)	0.004	0.011	0.024	0.054	0.101
5	PLC	0	0	0	0	0.00001
	ENLC(1/yr)	0.00203	0.00253	0.00305	0.00415	0.00593
	ELC(MW/yr)	0.019	0.023	0.028	0.036	0.046
	EDNS (MW)	0.00001	0.00001	0.00001	0.00002	0.00003
	EENS(MWh/yr)	0.06	0.08	0.109	0.175	0.281
6	PLC	0.00001	0.00001	0.00001	0.00001	0.00001
	ENLC(1/yr)	0.00986	0.0106	0.01167	0.01374	0.01713
	ELC(MW/yr)	0.102	0.114	0.127	0.149	0.177
	EDNS (MW)	0.00005	0.00006	0.00007	0.00009	0.00013
	EENS(MWh/yr)	0.463	0.529	0.619	0.816	1.12

Table D.8: System reliability indices for the RBTS at different peak load levels (Case 2)

System Indices	Peak Load (MW)				
	160	170	180	190	200
EENS (MWh/yr)	1.96751	4.83533	11.00439	30.16553	62.02446
SAIFI (interruptions /delivery point)	0.00499	0.00994	0.02028	0.04833	0.06192
SAIDI (hrs/delivery point)	0.05256	0.12264	0.29784	0.77088	0.89352

Table D.9: RBTS load bus reliability indices at different peak load levels (Case 3)

Bus No.	Indices	Peak Load (MW)				
		160	170	180	190	200
2	PLC	-	-	-	0	0
	ENLC(1/yr)	-	-	-	0.00002	0.00002
	ELC(MW/yr)	-	-	-	0	0
	EDNS (MW)	-	-	-	0	0
	EENS(MWh/yr)	-	-	-	0	0.001
3	PLC	0.00002	0.00006	0.00016	0.00042	0.00046
	ENLC(1/yr)	0.01286	0.03613	0.08595	0.21612	0.25243
	ELC(MW/yr)	0.149	0.348	0.737	1.859	3.691
	EDNS (MW)	0.00016	0.00048	0.00117	0.00331	0.00686
	EENS(MWh/yr)	1.441	4.211	10.228	28.965	60.071
4	PLC	0	0	0	0	0
	ENLC(1/yr)	0.00018	0.00039	0.00071	0.00122	0.00179
	ELC(MW/yr)	0.001	0.003	0.005	0.011	0.017
	EDNS (MW)	0	0	0	0.00001	0.00001
	EENS(MWh/yr)	0.004	0.011	0.024	0.054	0.101
5	PLC	0	0	0	0	0.00001
	ENLC(1/yr)	0.00203	0.00253	0.00305	0.00415	0.00593
	ELC(MW/yr)	0.018	0.022	0.027	0.036	0.046
	EDNS (MW)	0.00001	0.00001	0.00001	0.00002	0.00003
	EENS(MWh/yr)	0.059	0.079	0.108	0.174	0.28
6	PLC	0.00001	0.00001	0.00001	0.00001	0.00001
	ENLC(1/yr)	0.00986	0.0106	0.01167	0.01374	0.01713
	ELC(MW/yr)	0.103	0.115	0.127	0.149	0.178
	EDNS (MW)	0.00005	0.00006	0.00007	0.00009	0.00013
	EENS(MWh/yr)	0.464	0.53	0.62	0.817	1.122

Table D.10: System reliability indices for the RBTS at different peak load levels (Case 3)

System Indices	Peak Load (MW)				
	160	170	180	190	200
EENS (MWh/yr)	1.96735	4.83165	10.98032	30.01048	61.57405
SAIFI (interruptions /delivery point)	0.00499	0.00993	0.02028	0.04705	0.05546
SAIDI (hrs/delivery point)	0.05256	0.12264	0.29784	0.75336	0.84096

Table D.11: RBTS load bus reliability indices at different peak load levels (Case 4)

Bus No.	Indices	Peak Load (MW)				
		160	170	180	190	200
2	PLC	-	-	-	0	0
	ENLC(1/yr)	-	-	-	0.00002	0.00002
	ELC(MW/yr)	-	-	-	0	0
	EDNS (MW)	-	-	-	0	0
	EENS(MWh/yr)	-	-	-	0	0.001
3	PLC	0.00002	0.00006	0.00015	0.00041	0.00043
	ENLC(1/yr)	0.01016	0.03255	0.0788	0.19915	0.2071
	ELC(MW/yr)	0.099	0.282	0.645	1.68	3.296
	EDNS (MW)	0.00015	0.00045	0.00113	0.00321	0.00659
	EENS(MWh/yr)	1.273	3.978	9.861	28.093	57.717
4	PLC	0	0	0	0	0
	ENLC(1/yr)	0	0.00007	0.00019	0.00035	0.00053
	ELC(MW/yr)	0	0	0.001	0.002	0.005
	EDNS (MW)	0	0	0	0	0.00001
	EENS(MWh/yr)	0	0.003	0.009	0.027	0.061
5	PLC	0	0	0	0	0.00001
	ENLC(1/yr)	0.00289	0.00303	0.00333	0.00405	0.0057
	ELC(MW/yr)	0.031	0.034	0.037	0.043	0.053
	EDNS (MW)	0.00002	0.00002	0.00002	0.00003	0.00004
	EENS(MWh/yr)	0.146	0.165	0.192	0.255	0.359
6	PLC	0.00111	0.00111	0.00111	0.00111	0.00112
	ENLC(1/yr)	1.10839	1.10875	1.10946	1.11124	1.11415
	ELC(MW/yr)	12.193	13.046	13.759	14.622	15.351
	EDNS (MW)	0.01219	0.01304	0.01375	0.01462	0.01536
	EENS(MWh/yr)	106.749	114.222	120.484	128.088	134.563

Table D.12: System reliability indices for the RBTS at different peak load levels (Case 4)

System Indices	Peak Load (MW)				
	160	170	180	190	200
EENS (MWh/yr)	108.1684	118.3680	130.5457	156.4631	192.7009
SAIFI (interruptions /delivery point)	0.22429	0.22888	0.23836	0.26296	0.2655
SAIDI (hrs/delivery point)	1.97976	2.04984	2.20752	2.66304	2.73312

Tables D.13-D.14 show the load bus and system reliability indices based on the MRBTS base case analysis. Tables D.15-D.16 present these reliability indices based on the factor analysis of the MRBTS base case. Tables D.17-D.20 give the reliability indices based on two remedial modification actions.

Table D.13: MRBTS load bus reliability indices at different peak load levels

Bus No.	Indices	Peak Load (MW)				
		260	280	300	320	340
2	PLC	-	-	-	-	-
	ENLC(1/yr)	-	-	-	-	-
	ELC(MW/yr)	-	-	-	-	-
	EDNS (MW)	-	-	-	-	-
	EENS(MWh/yr)	-	-	-	-	-
3	PLC	0.00004	0.00011	0.00061	0.00214	0.00346
	ENLC(1/yr)	0.0634	0.15002	0.67712	2.27907	3.59401
	ELC(MW/yr)	1.356	2.85	8.553	27.651	65.213
	EDNS (MW)	0.00073	0.00183	0.00688	0.02475	0.06057
	EENS(MWh/yr)	6.365	16.024	60.271	216.775	530.599
4	PLC	0	0	0	0	0.00001
	ENLC(1/yr)	0.00002	0.00013	0.0015	0.00515	0.01248
	ELC(MW/yr)	0	0.001	0.009	0.044	0.136
	EDNS (MW)	0	0	0	0.00002	0.00007
	EENS(MWh/yr)	0	0.005	0.042	0.206	0.635
5	PLC	0	0	0	0.00001	0.00001
	ENLC(1/yr)	0.00051	0.00187	0.00602	0.0146	0.02656
	ELC(MW/yr)	0.001	0.012	0.056	0.161	0.327
	EDNS (MW)	0	0.00001	0.00003	0.00008	0.00017
	EENS(MWh/yr)	0.007	0.055	0.251	0.732	1.485
6	PLC	0.00116	0.00117	0.00117	0.00118	0.00119
	ENLC(1/yr)	1.23148	1.24131	1.25057	1.26239	1.28307
	ELC(MW/yr)	22.193	23.821	25.683	27.59	29.532
	EDNS (MW)	0.02094	0.02245	0.02416	0.02588	0.02763
	EENS(MWh/yr)	183.445	196.699	211.6	226.715	242.052

Table D.14: System reliability indices for the MRBTS at different peak load levels

System Indices	Peak Load (MW)				
	260	280	300	320	340
EENS (MWh/yr)	189.816	212.782	272.164	444.428	774.771
SAIFI (interruptions /delivery point)	0.25908	0.27867	0.38704	0.71224	0.98322
SAIDI (hrs/delivery point)	2.1024	2.24256	3.11856	5.83416	8.18184

Table D.15: MRBTS load bus reliability indices (factor analysis)

Bus No.	Peak Load (MW)	Generation Failures			Transmission Failures		
		PLC	ENLC	EENS	PLC	ENLC	EENS
2	260	-	-	-	-	-	-
	280	-	-	-	-	-	-
	300	-	-	-	-	-	-
	320	-	-	-	-	-	-
	340	-	-	-	-	-	-
3	260	0	0	0	0.00003	0.05535	6.248
	280	0	0	0	0.0001	0.12649	15.419
	300	0	0.00002	0.002	0.00061	0.58615	58.481
	320	0	0.00111	0.122	0.00213	1.963	213.707
	340	0.00011	0.03603	4.974	0.00335	3.0614	521.641
4	260	-	-	-	0	0.00001	0
	280	-	-	-	0	0.00008	0.003
	300	-	-	-	0	0.00124	0.029
	320	-	-	-	0	0.00439	0.164
	340	0	0.00001	0.001	0.00001	0.01091	0.549
5	260	-	-	-	0	0.00046	0.007
	280	-	-	-	0	0.00171	0.055
	300	-	-	-	0.00001	0.01344	0.731
	320	-	-	-	0	0.00553	0.251
	340	-	-	-	0.00001	0.02437	1.48
6	260	-	-	-	0.00116	1.06347	183.445
	280	-	-	-	0.00117	1.07254	196.699
	300	-	-	-	0.00117	1.08109	211.599
	320	0	0	0	0.00118	1.09188	226.708
	340	0	0.00001	0.001	0.00119	1.1098	241.983

Table D.15: MRBTS load bus reliability indices (factor analysis) (continued)

Bus No.	Peak Load (MW)	Generation Failures			Transmission Failures		
		PLC	ENLC	EENS	PLC	ENLC	EENS
2	260	-	-	-	-	-	-
	280	-	-	-	-	-	-
	300	-	-	-	-	-	-
	320	-	-	-	-	-	-
	340	-	-	-	-	-	-
3	260	0.00004	0.0634	6.365	0.00001	0.00805	0.117
	280	0.00011	0.15002	16.024	0.00001	0.02353	0.605
	300	0.00061	0.67712	60.271	0	0.09095	1.788
	320	0.00214	2.27907	216.775	0.00001	0.31496	2.946
	340	0.00346	3.59401	530.599	0	0.49658	3.984
4	260	0	0.00002	0	-	-	-
	280	0	0.00013	0.005	-	-	-
	300	0	0.0015	0.042	-	-	-
	320	0	0.00515	0.206	-	-	-
	340	0.00001	0.01248	0.635	0	0.00156	0.085
5	260	0	0.00051	0.007	-	-	-
	280	0	0.00187	0.055	-	-	-
	300	0	0.00602	0.251	-	-	-
	320	0.00001	0.0146	0.732	-	-	-
	340	0.00001	0.02656	1.485	-	-	-
6	260	0.00116	1.23148	183.445	-	-	-
	280	0.00117	1.24131	196.699	-	-	-
	300	0.00117	1.25057	211.6	-	-	-
	320	0.00118	1.26239	226.715	0	0.17051	0.007
	340	0.00119	1.28307	242.052	0	0.17326	0.068

Table D.16: System reliability indices for the MRBTS (factor analysis)

Peak Load (MW)	Generation Failures			Transmission Failures		
	EENS	SAIFI	SAIDI	EENS	SAIFI	SAIDI
260	0	0	0	189.699	0.22	2.08
280	0.00015	0	0	212.174	0.24	2.23
300	0.00158	0	0	270.361	0.33	3.12
320	0.12177	0	0	441.309	0.61	5.82
340	4.97549	0.01	0.2	765.652	0.84	7.99

Table D.16: System reliability indices for the MRBTS (factor analysis) (continued)

Peak Load (MW)	Total Generation and Transmission Failures			Overlapping Generation and Transmission Failures		
	EENS	SAIFI	SAIDI	EENS	SAIFI	SAIDI
260	189.816	0.259	2.1	0.11695	0.035	0.02
280	212.782	0.279	2.24	0.60786	0.039	0.02
300	272.164	0.387	3.12	1.80209	0.052	0
320	444.428	0.712	5.83	2.99684	0.097	0.02
340	774.771	0.983	8.18	4.14289	0.135	0

Table D.17: MRBTS load bus reliability indices at different peak load levels (Case 1)

Bus No.	Indices	Peak Load (MW)				
		260	280	300	320	340
2	PLC	-	-	-	-	-
	ENLC(1/yr)	-	-	-	-	-
	ELC(MW/yr)	-	-	-	-	-
	EDNS (MW)	-	-	-	-	-
	EENS(MWh/yr)	-	-	-	-	-
3	PLC	0	0	0	0.00001	0.00002
	ENLC(1/yr)	0.00005	0.00051	0.00395	0.02111	0.0387
	ELC(MW/yr)	0	0.005	0.041	0.206	0.593
	EDNS (MW)	0	0	0.00002	0.00011	0.00031
	EENS(MWh/yr)	0.001	0.022	0.188	0.937	2.718
4	PLC	-	0	0	0	0
	ENLC(1/yr)	-	0.00001	0.00028	0.00173	0.00648
	ELC(MW/yr)	-	0	0.002	0.012	0.056
	EDNS (MW)	-	0	0	0.00001	0.00004
	EENS(MWh/yr)	-	0.001	0.009	0.066	0.329
5	PLC	0	0	0	0	0
	ENLC(1/yr)	0.00185	0.00185	0.00185	0.00185	0.00186
	ELC(MW/yr)	0.033	0.035	0.038	0.041	0.043
	EDNS (MW)	0.00002	0.00002	0.00002	0.00002	0.00002
	EENS(MWh/yr)	0.156	0.168	0.18	0.192	0.205
6	PLC	0	0	0	0	0.00001
	ENLC(1/yr)	0.00378	0.00378	0.00378	0.00379	0.00949
	ELC(MW/yr)	0.068	0.073	0.078	0.084	0.105
	EDNS (MW)	0.00004	0.00004	0.00004	0.00004	0.00006
	EENS(MWh/yr)	0.316	0.338	0.363	0.388	0.538

Table D.18: System reliability indices for the MRBTS at different peak load levels (Case 1)

System Indices	Peak Load (MW)				
	260	280	300	320	340
EENS (MWh/yr)	0.47363	0.52901	0.74056	1.58369	3.79003
SAIFI (interruptions /delivery point)	0.00114	0.00123	0.00197	0.0057	0.01131
SAIDI (hrs/delivery point)	0	0	0	0.01752	0.05256

Table D.19: MRBTS load bus reliability indices at different peak load levels (Case 2)

Bus No.	Indices	Peak Load (MW)				
		260	280	300	320	340
2	PLC	-	-	-	-	-
	ENLC(1/yr)	-	-	-	-	-
	ELC(MW/yr)	-	-	-	-	-
	EDNS (MW)	-	-	-	-	-
	EENS(MWh/yr)	-	-	-	-	-
3	PLC	0.00004	0.00011	0.00061	0.00214	0.00346
	ENLC(1/yr)	0.06282	0.14908	0.67861	2.28992	3.61012
	ELC(MW/yr)	1.349	2.826	8.521	27.695	65.412
	EDNS (MW)	0.00072	0.00181	0.00684	0.02471	0.06048
	EENS(MWh/yr)	6.308	15.845	59.921	216.43	529.837
4	PLC	0	0	0	0	0.00001
	ENLC(1/yr)	0.00002	0.00013	0.0015	0.00516	0.01254
	ELC(MW/yr)	0	0.001	0.009	0.044	0.137
	EDNS (MW)	0	0	0	0.00002	0.00007
	EENS(MWh/yr)	0	0.005	0.042	0.206	0.637
5	PLC	0	0	0	0.00001	0.00001
	ENLC(1/yr)	0.00235	0.00372	0.00788	0.01647	0.02844
	ELC(MW/yr)	0.035	0.048	0.094	0.202	0.37
	EDNS (MW)	0.00002	0.00003	0.00005	0.00011	0.00019
	EENS(MWh/yr)	0.163	0.222	0.431	0.924	1.689
6	PLC	0	0.00001	0.00001	0.00002	0.00003
	ENLC(1/yr)	0.00578	0.01561	0.02489	0.03672	0.05741
	ELC(MW/yr)	0.085	0.144	0.281	0.464	0.68
	EDNS (MW)	0.00004	0.00008	0.00015	0.00024	0.00036
	EENS(MWh/yr)	0.39	0.661	1.282	2.116	3.167

Table D.20: System reliability indices for the MRBTS at different peak load levels (Case 2)

System Indices	Peak Load (MW)				
	260	280	300	320	340
EENS (MWh/yr)	6.86124	16.73355	61.67561	219.6756	535.3304
SAIFI (interruptions /delivery point)	0.01419	0.03371	0.14258	0.46965	0.7417
SAIDI (hrs/delivery point)	0.07008	0.21024	1.08624	3.80184	6.14952

Tables D.21-D.22 show the load bus and system reliability indices based on the IEEE-RTS base case analysis. Tables D.23-D.24 present these reliability indices based on the factor analysis of the IEEE-RTS base case.

Table D.21: IEEE-RTS load bus reliability indices at different peak load levels

Bus No.	Indices	Peak Load (MW)				
		2500	2600	2800	2900	3100
1	PLC	-	-	-	-	-
	ENLC(1/yr)	-	-	-	-	-
	ELC(MW/yr)	-	-	-	-	-
	EDNS (MW)	-	-	-	-	-
	EENS(MWh/yr)	-	-	-	-	-
2	PLC	0	0	0	0	0.00001
	ENLC(1/yr)	0.00001	0.00003	0.00092	0.00239	0.01403
	ELC(MW/yr)	0	0.001	0.025	0.082	0.517
	EDNS (MW)	0	0	0.00002	0.00008	0.00054
	EENS(MWh/yr)	0.001	0.006	0.198	0.695	4.728
3	PLC	-	0	0	0	0.00001
	ENLC(1/yr)	-	0.00001	0.00026	0.00128	0.00765
	ELC(MW/yr)	-	0	0.013	0.058	0.419
	EDNS (MW)	-	0	0.00001	0.00005	0.00042
	EENS(MWh/yr)	-	0.002	0.098	0.466	3.642
4	PLC	-	-	-	-	-
	ENLC(1/yr)	-	-	-	-	-
	ELC(MW/yr)	-	-	-	-	-
	EDNS (MW)	-	-	-	-	-
	EENS(MWh/yr)	-	-	-	-	-
5	PLC	-	-	-	-	-
	ENLC(1/yr)	-	-	-	-	-
	ELC(MW/yr)	-	-	-	-	-
	EDNS (MW)	-	-	-	-	-
	EENS(MWh/yr)	-	-	-	-	-

Table D.21: (Continued)

Bus No.	Indices	Peak Load (MW)				
		2500	2600	2800	2900	3100
6	PLC	0	0	0	0	0
	ENLC(1/yr)	0.00094	0.00094	0.00075	0.00075	0.0006
	ELC(MW/yr)	0.061	0.063	0.051	0.053	0.044
	EDNS (MW)	0.00004	0.00004	0.00003	0.00003	0.00003
	EENS(MWh/yr)	0.341	0.352	0.287	0.299	0.245
7	PLC	0	0	0	0	0
	ENLC(1/yr)	0.00004	0.00016	0.00041	0.00068	0.00097
	ELC(MW/yr)	0	0.001	0.003	0.005	0.011
	EDNS (MW)	0	0	0	0	0.00001
	EENS(MWh/yr)	0.001	0.004	0.016	0.028	0.061
8	PLC	-	-	0	0	0
	ENLC(1/yr)	-	-	0.00004	0.00005	0.0004
	ELC(MW/yr)	-	-	0	0.001	0.011
	EDNS (MW)	-	-	0	0	0.00001
	EENS(MWh/yr)	-	-	0.001	0.004	0.077
9	PLC	0.00011	0.00022	0.0008	0.00169	0.00504
	ENLC(1/yr)	0.09695	0.18262	0.63685	1.26297	3.53376
	ELC(MW/yr)	5.251	9.883	38.266	76.573	232.816
	EDNS (MW)	0.00604	0.01168	0.04851	0.10079	0.32555
	EENS(MWh/yr)	52.867	102.276	424.933	882.938	2851.79
10	PLC	0	0	0	0.00001	0.00004
	ENLC(1/yr)	0.00012	0.00026	0.00359	0.00874	0.03753
	ELC(MW/yr)	0.003	0.013	0.158	0.492	2.349
	EDNS (MW)	0	0.00001	0.00015	0.00049	0.00254
	EENS(MWh/yr)	0.018	0.095	1.341	4.313	22.285
13	PLC	-	-	0	0	0
	ENLC(1/yr)	-	-	0.00003	0.00022	0.00215
	ELC(MW/yr)	-	-	0.001	0.011	0.12
	EDNS (MW)	-	-	0	0.00001	0.00011
	EENS(MWh/yr)	-	-	0.009	0.08	0.99
14	PLC	0.00002	0.00003	0.00014	0.00029	0.00096
	ENLC(1/yr)	0.01481	0.02957	0.12051	0.24249	0.74876
	ELC(MW/yr)	0.744	1.647	7.363	15.739	52.617
	EDNS (MW)	0.00077	0.00177	0.0085	0.0188	0.06697
	EENS(MWh/yr)	6.773	15.472	74.418	164.652	586.638
15	PLC	0.00006	0.00011	0.00044	0.00093	0.00285
	ENLC(1/yr)	0.05331	0.09683	0.36335	0.72366	2.08509
	ELC(MW/yr)	3.899	7.738	31.114	64.577	204.955
	EDNS (MW)	0.00427	0.00878	0.03757	0.08121	0.27458
	EENS(MWh/yr)	37.365	76.886	329.154	711.414	2405.29

Table D.21: (Continued)

Bus No.	Indices	Peak Load (MW)				
		2500	2600	2800	2900	3100
16	PLC	0.00001	0.00001	0.00007	0.00014	0.00047
	ENLC(1/yr)	0.00569	0.01232	0.05812	0.12035	0.38217
	ELC(MW/yr)	0.19	0.407	2.085	4.502	15.546
	EDNS (MW)	0.00019	0.00043	0.0023	0.00522	0.01903
	EENS(MWh/yr)	1.635	3.733	20.177	45.711	166.734
18	PLC	0	0	0.00002	0.00005	0.0002
	ENLC(1/yr)	0.00128	0.00406	0.02127	0.04557	0.16648
	ELC(MW/yr)	0.074	0.21	1.528	3.716	14.253
	EDNS (MW)	0.00007	0.0002	0.00158	0.00402	0.01641
	EENS(MWh/yr)	0.591	1.772	13.811	35.25	143.711
19	PLC	0.00022	0.00038	0.00153	0.00285	0.008
	ENLC(1/yr)	0.18418	0.31539	1.146	2.08174	5.56525
	ELC(MW/yr)	9.861	18.063	68.098	134.26	389.501
	EDNS (MW)	0.01166	0.02188	0.08888	0.1816	0.56215
	EENS(MWh/yr)	102.142	191.636	778.597	1590.83	4924.46
20	PLC	0	0.00001	0.00004	0.00009	0.00031
	ENLC(1/yr)	0.00318	0.00739	0.03828	0.0815	0.25813
	ELC(MW/yr)	0.111	0.295	1.628	3.755	13.16
	EDNS (MW)	0.00011	0.00029	0.00179	0.00425	0.01587
	EENS(MWh/yr)	0.955	2.561	15.683	37.25	139.001

Table D.22: System reliability indices for the IEEE-RTS at different peak load levels

System Indices	Peak Load (MW)				
	2500	2600	2800	2900	3100
EENS (MWh/yr)	202.689	394.792	1658.73	3473.91	11249.6
SAIFI (interruptions /delivery point)	0.02121	0.03821	0.14061	0.26896	0.75312
SAIDI (hrs/delivery point)	0.21642	0.39162	1.56649	3.11753	9.21861

Table D.23: IEEE-RTS load bus reliability indices (factor analysis)

Bus No.	Peak Load (MW)	Generation Failures			Transmission Failures		
		PLC	ENLC	EENS	PLC	ENLC	EENS
9	2500	0.00011	0.09389	52.837	-	-	-
	2600	0.00022	0.17669	102.194	-	-	-
	2800	0.0008	0.61521	424.644	-	-	-
	2900	0.00169	1.21779	882.432	-	-	-
	3100	0.00503	3.4003	2850.386	-	-	-

Table D.23: (Continued)

Bus No.	Peak Load (MW)	Generation Failures			Transmission Failures		
		PLC	ENLC	EENS	PLC	ENLC	EENS
14	2500	0.00002	0.01437	6.773	-	-	-
	2600	0.00003	0.0286	15.467	-	-	-
	2800	0.00014	0.11653	74.366	-	-	-
	2900	0.00029	0.2344	164.512	-	-	-
	3100	0.00096	0.72274	586.217	-	-	-
15	2500	0.00006	0.05169	37.35	-	-	-
	2600	0.00011	0.09376	76.845	-	-	-
	2800	0.00044	0.35119	328.922	-	-	-
	2900	0.00093	0.69859	710.964	-	-	-
	3100	0.00285	2.00884	2404.127	-	-	-
19	2500	0.00022	0.17803	102.06	-	-	-
	2600	0.00038	0.30509	191.513	-	-	-
	2800	0.00153	1.10561	778.156	-	-	-
	2900	0.00285	2.00564	1590.093	-	-	-
	3100	0.008	5.3516	4922.242	-	-	-

Table D.23: IEEE-RTS load bus reliability indices (factor analysis) (continued)

Bus No.	Peak Load (MW)	Total Generation and Transmission Failures			Overlapping Generation and Transmission Failures		
		PLC	ENLC	EENS	PLC	ENLC	EENS
9	2500	0.00011	0.09695	52.867	-	-	-
	2600	0.00022	0.18262	102.276	-	-	-
	2800	0.0008	0.63685	424.933	-	-	-
	2900	0.00169	1.26297	882.938	-	-	-
	3100	0.00504	3.53376	2851.79	-	-	-
14	2500	0.00002	0.01481	6.773	-	-	-
	2600	0.00003	0.02957	15.472	-	-	-
	2800	0.00014	0.12051	74.418	-	-	-
	2900	0.00029	0.24249	164.652	-	-	-
	3100	0.00096	0.74876	586.638	-	-	-
15	2500	0.00006	0.05331	37.365	-	-	-
	2600	0.00011	0.09683	76.886	-	-	-
	2800	0.00044	0.36335	329.154	-	-	-
	2900	0.00093	0.72366	711.414	-	-	-
	3100	0.00285	2.08509	2405.29	-	-	-
19	2500	0.00022	0.18418	102.142	-	-	-
	2600	0.00038	0.31539	191.636	-	-	-
	2800	0.00153	1.146	778.597	-	-	-
	2900	0.00285	2.08174	1590.83	-	-	-
	3100	0.008	5.56525	4924.46	-	-	-

Table D.24: System reliability indices for the IEEE-RTS (factor analysis)

Peak Load (MW)	Generation Failures			Transmission Failures		
	EENS	SAIFI	SAIDI	EENS	SAIFI	SAIDI
2500	202.219	0.02	0.22	0.67059	0	0
2600	394.185	0.037	0.39	0.69345	0	0
2800	1657.4	0.136	1.57	0.74685	0	0
2900	3471.69	0.259	3.12	0.7776	0	0
3100	11243.8	0.725	9.21	0.83502	0	0

Table D.24: System reliability indices for the IEEE-RTS (factor analysis) (continued)

Peak Load (MW)	Total Generation and Transmission Failures			Overlapping Generation and Transmission Failures		
	EENS	SAIFI	SAIDI	EENS	SAIFI	SAIDI
2500	202.689	0.0212	0.22	0	0.0007	0
2600	394.792	0.0382	0.39	0	0.001	0
2800	1658.73	0.1406	1.57	0.588	0.005	0
2900	3473.91	0.269	3.12	1.44208	0.01	0
3100	11249.6	0.7531	9.22	4.96972	0.028	0.01

Tables D.25-D.26 show the load bus and system reliability indices based on the MRTS base case analysis. Tables D.27-D.28 present these reliability indices based on the factor analysis of the MRTS base case. Tables D.29-D.32 give the reliability indices based on two remedial modification actions.

Table D.25: The MRTS load bus reliability indices at different peak load levels

Bus No.	Indices	Peak Load (MW)				
		4700	4900	5100	5300	5500
1	PLC	-	-	-	-	-
	ENLC(1/yr)	-	-	-	-	-
	ELC(MW/yr)	-	-	-	-	-
	EDNS (MW)	-	-	-	-	-
	EENS(MWh/yr)	-	-	-	-	-
2	PLC	-	-	-	0	0
	ENLC(1/yr)	-	-	-	0.00003	0.0002
	ELC(MW/yr)	-	-	-	0.002	0.006
	EDNS (MW)	-	-	-	0	0
	EENS(MWh/yr)	-	-	-	0.009	0.034
3	PLC	0	0.00001	0.00002	0.00005	0.00013
	ENLC(1/yr)	0.00132	0.00897	0.02941	0.05639	0.15275
	ELC(MW/yr)	0.011	0.092	0.347	1.154	2.967
	EDNS (MW)	0.00001	0.00008	0.00028	0.00095	0.00248
	EENS(MWh/yr)	0.068	0.661	2.433	8.327	21.684

Table D.25: (Continued)

Bus No.	Indices	Peak Load (MW)				
		4700	4900	5100	5300	5500
4	PLC	0	0	0	0	0
	ENLC(1/yr)	0.00005	0.0002	0.00051	0.00051	0.00086
	ELC(MW/yr)	0.002	0.007	0.016	0.028	0.048
	EDNS (MW)	0	0	0.00001	0.00001	0.00002
	EENS(MWh/yr)	0.009	0.031	0.067	0.12	0.207
5	PLC	0	0	0.00001	0.00003	0.00002
	ENLC(1/yr)	0.00138	0.00239	0.00727	0.02789	0.01942
	ELC(MW/yr)	0.083	0.12	0.207	0.346	0.505
	EDNS (MW)	0.00009	0.00012	0.00021	0.00035	0.00053
	EENS(MWh/yr)	0.765	1.085	1.845	3.069	4.685
6	PLC	0.00038	0.00052	0.00053	0.00074	0.00082
	ENLC(1/yr)	0.51841	0.71509	0.72444	1.01775	1.13428
	ELC(MW/yr)	8.028	12.204	17.923	24.257	32.728
	EDNS (MW)	0.00577	0.00881	0.01294	0.01752	0.02365
	EENS(MWh/yr)	50.564	77.169	113.388	153.513	207.158
7	PLC	-	-	-	-	-
	ENLC(1/yr)	-	-	-	-	-
	ELC(MW/yr)	-	-	-	-	-
	EDNS (MW)	-	-	-	-	-
	EENS(MWh/yr)	-	-	-	-	-
8	PLC	0	0	0	0	0
	ENLC(1/yr)	0.0007	0.00086	0.002	0.00275	0.00539
	ELC(MW/yr)	0.016	0.036	0.069	0.114	0.205
	EDNS (MW)	0.00002	0.00003	0.00006	0.00009	0.00015
	EENS(MWh/yr)	0.137	0.294	0.526	0.821	1.348
9	PLC	0	0	0.00001	0.00002	0.00009
	ENLC(1/yr)	0.00142	0.0039	0.01129	0.03435	0.1156
	ELC(MW/yr)	0.093	0.29	0.941	3.347	11.296
	EDNS (MW)	0.00005	0.00018	0.00062	0.00229	0.00824
	EENS(MWh/yr)	0.45	1.618	5.398	20.031	72.153
10	PLC	0	0	0.00001	0.00002	0.00008
	ENLC(1/yr)	0.00026	0.00204	0.00761	0.02757	0.08778
	ELC(MW/yr)	0.01	0.056	0.273	1.233	4.085
	EDNS (MW)	0.00001	0.00004	0.0002	0.00103	0.00354
	EENS(MWh/yr)	0.046	0.318	1.779	8.986	31.032
13	PLC	-	-	0	0	0
	ENLC(1/yr)	-	-	0.00004	0.00021	0.00137
	ELC(MW/yr)	-	-	0.001	0.013	0.098
	EDNS (MW)	-	-	0	0.00001	0.00006
	EENS(MWh/yr)	-	-	0.006	0.061	0.498

Table D.25: (Continued)

Bus No.	Indices	Peak Load (MW)				
		4700	4900	5100	5300	5500
14	PLC	0	0	0.00001	0.00006	0.00025
	ENLC(1/yr)	0.00059	0.00382	0.02228	0.0911	0.35847
	ELC(MW/yr)	0.021	0.157	0.956	4.507	16.395
	EDNS (MW)	0.00001	0.00009	0.00057	0.00285	0.0108
	EENS(MWh/yr)	0.105	0.78	4.957	24.952	94.639
15	PLC	0	0	0	0.00001	0.00002
	ENLC(1/yr)	0.00008	0.00058	0.00313	0.01054	0.03206
	ELC(MW/yr)	0.009	0.065	0.309	1.183	4.113
	EDNS (MW)	0.00001	0.00004	0.0002	0.00079	0.00284
	EENS(MWh/yr)	0.052	0.363	1.747	6.94	24.907
16	PLC	0	0	0	0.00001	0.00002
	ENLC(1/yr)	0.00003	0.00033	0.00219	0.00891	0.03301
	ELC(MW/yr)	0.001	0.015	0.097	0.441	1.699
	EDNS (MW)	0	0.00001	0.00006	0.00028	0.00114
	EENS(MWh/yr)	0.005	0.077	0.522	2.462	10.008
18	PLC			0	0	0
	ENLC(1/yr)			0.00001	0.00002	0.00012
	ELC(MW/yr)			0	0.002	0.011
	EDNS (MW)			0	0	0.00001
	EENS(MWh/yr)			0.001	0.009	0.061
19	PLC	0	0	0.00002	0.00006	0.00018
	ENLC(1/yr)	0.00177	0.00719	0.02624	0.08582	0.24097
	ELC(MW/yr)	0.138	0.628	2.507	8.197	24.642
	EDNS (MW)	0.00009	0.00042	0.00171	0.00586	0.01823
	EENS(MWh/yr)	0.788	3.653	15.021	51.294	159.699
20	PLC	0	0	0	0	0
	ENLC(1/yr)	0.00003	0.0001	0.00049	0.00127	0.00314
	ELC(MW/yr)	0.001	0.007	0.052	0.087	0.238
	EDNS (MW)	0	0	0.00003	0.00004	0.00013
	EENS(MWh/yr)	0.003	0.029	0.256	0.391	1.119

Table D.26: System reliability indices for the MRTS at different peak load levels

System Indices	Peak Load (MW)				
	4700	4900	5100	5300	5500
EENS (MWh/yr)	52.9923	86.0771	147.947	280.985	629.232
SAIFI (interruptions /delivery point)	0.03094	0.04385	0.04923	0.0803	0.12855
SAIDI (hrs/delivery point)	0.19581	0.27311	0.31433	0.51529	0.82962

Table D.27: MRTS load bus reliability indices (factor analysis)

Bus No.	Peak Load (MW)	Generation Failures			Transmission Failures		
		PLC	ENLC	EENS	PLC	ENLC	EENS
3	4700	-	-	-	0	0	0.004
	4900	-	-	-	0	0.00104	0.056
	5100	-	-	-	0.00001	0.00107	0.895
	5300	-	-	-	0.00003	0.00637	4.683
	5500	0	0.00002	0.001	0.00011	0.02355	13.302
6	4700	0	0.00001	0	0.00038	0.17647	50.563
	4900	0	0.00011	0.004	0.00052	0.24501	77.587
	5100	0	0.0015	0.047	0.00052	0.24531	113.286
	5300	0.00001	0.01731	0.59	0.00072	0.33765	152.592
	5500	0.00008	0.11694	5.543	0.00073	0.33897	200.193
9	4700	0	0.00053	0.226	0	0.00038	0.216
	4900	0	0.00231	1.102	0	0.00056	0.33
	5100	0.00001	0.00923	4.801	0	0.00058	0.465
	5300	0.00002	0.0313	19.01	0	0.00088	0.736
	5500	0.00008	0.10867	70.262	0	0.00138	1.205
10	4700	-	-	-	0	0.00004	0.03
	4900	-	-	-	0	0.00016	0.113
	5100	-	-	-	0	0.00044	0.322
	5300	0	0.00004	0.01	0.00001	0.00084	2.957
	5500	0	0.0001	0.033	0.00005	0.00324	10.475
14	4700	0	0.0002	0.035	0	0.00009	0.033
	4900	0	0.00188	0.371	0	0.00015	0.117
	5100	0.00001	0.01202	2.566	0	0.00226	1.118
	5300	0.00004	0.05572	15.871	0.00001	0.0116	4.527
	5500	0.00021	0.27593	69.914	0.00001	0.01192	13
15	4700	0	0.00008	0.052	-	-	-
	4900	0	0.00058	0.365	-	-	-
	5100	0	0.00309	1.755	-	-	-
	5300	0.00001	0.01041	6.999	-	-	-
	5500	0.00002	0.03184	25.146	-	-	-
16	4700	0	0.00003	0.005	-	-	-
	4900	0	0.00032	0.075	-	-	-
	5100	0	0.00208	0.517	-	-	-
	5300	0.00001	0.00887	2.446	-	-	-
	5500	0.00002	0.03206	9.855	-	-	-
19	4700	0	0.00176	0.794	-	-	-
	4900	0	0.00711	3.693	-	-	-
	5100	0.00002	0.02602	15.128	-	-	-
	5300	0.00006	0.0844	51.588	-	-	-
	5500	0.00018	0.23695	160.686	-	-	-

Table D.27: MRTS load bus reliability indices (factor analysis) (continued)

Bus No.	Peak Load (MW)	Total Generation and Transmission Failures			Overlapping Generation and Transmission Failures		
		PLC	ENLC	EENS	PLC	ENLC	EENS
3	4700	0	0.00132	0.068	-	-	-
	4900	0.00001	0.00897	0.661	-	-	-
	5100	0.00002	0.02941	2.433	-	-	-
	5300	0.00005	0.05639	8.327	-	-	-
	5500	0.00013	0.15275	21.684	0.00002	0.12918	8.381
6	4700	0.00038	0.51841	50.564	0	0.34193	0.001
	4900	0.00052	0.71509	77.169	0	0.46997	-0.422
	5100	0.00053	0.72444	113.388	0.00001	0.47763	0.055
	5300	0.00074	1.01775	153.513	0.00001	0.66279	0.331
	5500	0.00082	1.13428	207.158	0.00001	0.67837	1.422
9	4700	0	0.00142	0.45	0	0.00051	0.008
	4900	0	0.0039	1.618	0	0.00103	0.186
	5100	0.00001	0.01129	5.398	0	0.00148	0.132
	5300	0.00002	0.03435	20.031	0	0.00217	0.285
	5500	0.00009	0.1156	72.153	0.00001	0.00555	0.686
10	4700	0	0.00026	0.046	-	-	-
	4900	0	0.00204	0.318	-	-	-
	5100	0.00001	0.00761	1.779	-	-	-
	5300	0.00002	0.02757	8.986	0.00001	0.02669	6.019
	5500	0.00008	0.08778	31.032	0.00003	0.08444	20.524
14	4700	0	0.00059	0.105	0	0.0003	0.037
	4900	0	0.00382	0.78	0	0.00179	0.292
	5100	0.00001	0.02228	4.957	0	0.008	1.273
	5300	0.00006	0.0911	24.952	0.00001	0.02378	4.554
	5500	0.00025	0.35847	94.639	0.00003	0.07062	11.725
15	4700	0	0.00008	0.052	-	-	-
	4900	0	0.00058	0.363	-	-	-
	5100	0	0.00313	1.747	-	-	-
	5300	0.00001	0.01054	6.94	-	-	-
	5500	0.00002	0.03206	24.907	-	-	-
16	4700	0	0.00003	0.005	-	-	-
	4900	0	0.00033	0.077	-	-	-
	5100	0	0.00219	0.522	-	-	-
	5300	0.00001	0.00891	2.462	-	-	-
	5500	0.00002	0.03301	10.008	-	-	-
19	4700	0	0.00177	0.788	-	-	-
	4900	0	0.00719	3.653	-	-	-
	5100	0.00002	0.02624	15.021	-	-	-
	5300	0.00006	0.08582	51.294	-	-	-
	5500	0.00018	0.24097	159.699	-	-	-

Table D.28: System reliability indices for the MRTS (factor analysis)

Peak Load (MW)	Generation Failures			Transmission Failures		
	EENS	SAIFI	SAIDI	EENS	SAIFI	SAIDI
4700	1.12801	0.0002	0	51.7414	0.01	0.2
4900	5.66044	0.0007	0	79.4955	0.015	0.27
5100	24.9456	0.003	0.02	118.692	0.015	0.28
5300	96.8427	0.012	0.08	169.919	0.021	0.41
5500	342.638	0.047	0.3	249.435	0.023	0.48

Table D.28: System reliability indices for the MRTS (factor analysis) (continued)

Peak Load (MW)	Total Generation and Transmission Failures			Overlapping Generation and Transmission Failures		
	EENS	SAIFI	SAIDI	EENS	SAIFI	SAIDI
4700	52.9923	0.031	0.2	0.12295	0.02	0
4900	86.0771	0.044	0.27	0.92116	0.029	0.01
5100	147.947	0.049	0.31	4.30926	0.031	0.02
5300	280.985	0.08	0.52	14.2236	0.047	0.03
5500	629.232	0.129	0.83	37.1588	0.059	0.04

Table D.29: MRTS load bus reliability indices at different peak load levels (Case 1)

Bus No.	Indices	Peak Load (MW)				
		4700	4900	5100	5300	5500
3	PLC	0	0	0	0	0.00001
	ENLC(1/yr)	0.002	0.00243	0.00932	0.00766	0.02455
	ELC(MW/yr)	0.046	0.05	0.129	0.152	0.595
	EDNS (MW)	0.00002	0.00002	0.00006	0.00008	0.00035
	EENS(MWh/yr)	0.175	0.186	0.562	0.671	3.058
6	PLC	0	0	0	0	0.00001
	ENLC(1/yr)	0.00252	0.00276	0.00314	0.00408	0.01042
	ELC(MW/yr)	0.081	0.045	0.093	0.095	1.109
	EDNS (MW)	0.00005	0.00003	0.00006	0.00006	0.00073
	EENS(MWh/yr)	0.429	0.25	0.496	0.52	6.404
9	PLC	0	0	0.00001	0.00002	0.00008
	ENLC(1/yr)	0.00056	0.00267	0.00937	0.03148	0.10505
	ELC(MW/yr)	0.042	0.204	0.814	3.102	10.183
	EDNS (MW)	0.00003	0.00013	0.00054	0.00213	0.00725
	EENS(MWh/yr)	0.228	1.156	4.77	18.646	63.516
10	PLC	0	0	0	0	0.00001
	ENLC(1/yr)	0.00001	0.0006	0.00027	0.00111	0.00892
	ELC(MW/yr)	0.001	0.052	0.011	0.108	1.014
	EDNS (MW)	0	0.00003	0	0.00006	0.00063
	EENS(MWh/yr)	0.002	0.267	0.041	0.533	5.537

Table D.29: (Continued)

Bus No.	Indices	Peak Load (MW)				
		4700	4900	5100	5300	5500
14	PLC	0	0	0	0.00001	0.00006
	ENLC(1/yr)	0.00006	0.00063	0.00464	0.02202	0.09022
	ELC(MW/yr)	0.002	0.021	0.161	0.887	4.503
	EDNS (MW)	0	0.00001	0.00009	0.00053	0.0029
	EENS(MWh/yr)	0.008	0.105	0.827	4.676	25.437
15	PLC	0	0	0	0.00001	0.00003
	ENLC(1/yr)	0.00008	0.00059	0.00316	0.01079	0.0385
	ELC(MW/yr)	0.009	0.066	0.313	1.213	6.532
	EDNS (MW)	0.00001	0.00004	0.0002	0.00081	0.00445
	EENS(MWh/yr)	0.052	0.365	1.765	7.108	38.991
16	PLC	0	0	0	0.00001	0.00002
	ENLC(1/yr)	0.00002	0.00031	0.00232	0.00878	0.03249
	ELC(MW/yr)	0.001	0.017	0.106	0.479	1.887
	EDNS (MW)	0	0.00001	0.00007	0.00031	0.00128
	EENS(MWh/yr)	0.004	0.088	0.573	2.728	11.176
19	PLC	0	0.00001	0.00002	0.00007	0.00019
	ENLC(1/yr)	0.00183	0.00736	0.02709	0.09103	0.259
	ELC(MW/yr)	0.14	0.642	2.593	8.705	26.975
	EDNS (MW)	0.00009	0.00043	0.00178	0.00622	0.02005
	EENS(MWh/yr)	0.797	3.727	15.557	54.456	175.633

Table D.30: System reliability indices for the MRTS at different peak load levels (Case 1)

System Indices	Peak Load (MW)				
	4700	4900	5100	5300	5500
EENS (MWh/yr)	1.71035	6.38566	24.7577	89.6787	333.74
SAIFI (interruptions /delivery point)	0.00046	0.00109	0.00355	0.01053	0.03405
SAIDI (hrs/delivery point)	0	0.00515	0.01546	0.06184	0.21127

Table D.31: MRTS load bus reliability indices at different peak load levels (Case 2)

Bus No.	Indices	Peak Load (MW)				
		4700	4900	5100	5300	5500
3	PLC	-	0	0	0	0.00001
	ENLC(1/yr)	-	0.00017	0.00026	0.00181	0.0106
	ELC(MW/yr)	-	0.006	0.004	0.027	0.144
	EDNS (MW)	-	0	0	0.00002	0.0001
	EENS(MWh/yr)	-	0.032	0.021	0.149	0.849

Table D.31: (Continued)

Bus No.	Indices	Peak Load (MW)				
		4700	4900	5100	5300	5500
6	PLC	0	0	0	0	0
	ENLC(1/yr)	0.00029	0.00031	0.00027	0.00148	0.00536
	ELC(MW/yr)	0.003	0.002	0.002	0.013	0.061
	EDNS (MW)	0	0	0	0.00001	0.00004
	EENS(MWh/yr)	0.014	0.009	0.01	0.062	0.326
9	PLC	0	0	0.00001	0.00002	0.00008
	ENLC(1/yr)	0.00057	0.00257	0.00987	0.03326	0.11342
	ELC(MW/yr)	0.041	0.202	0.835	3.235	11.149
	EDNS (MW)	0.00003	0.00013	0.00056	0.00221	0.00812
	EENS(MWh/yr)	0.228	1.135	4.866	19.39	71.093
10	PLC	0	0	0	0.00001	0.00003
	ENLC(1/yr)	0.00003	0.00029	0.0016	0.00904	0.03109
	ELC(MW/yr)	0.001	0.007	0.047	0.306	1.463
	EDNS (MW)	0	0	0.00003	0.00023	0.00122
	EENS(MWh/yr)	0.005	0.037	0.278	2.023	10.672
14	PLC	0	0	0.00001	0.00006	0.00023
	ENLC(1/yr)	0.00052	0.00365	0.01935	0.08779	0.33421
	ELC(MW/yr)	0.015	0.131	0.856	4.202	15.463
	EDNS (MW)	0.00001	0.00008	0.00052	0.00268	0.01018
	EENS(MWh/yr)	0.08	0.67	4.525	23.478	89.158
15	PLC	0	0	0	0.00001	0.00002
	ENLC(1/yr)	0.00009	0.00059	0.00315	0.01064	0.03263
	ELC(MW/yr)	0.009	0.066	0.312	1.204	4.192
	EDNS (MW)	0.00001	0.00004	0.0002	0.0008	0.00288
	EENS(MWh/yr)	0.052	0.365	1.757	7.016	25.212
16	PLC	0	0	0	0.00001	0.00002
	ENLC(1/yr)	0.00004	0.00036	0.00221	0.00893	0.03362
	ELC(MW/yr)	0.001	0.016	0.103	0.448	1.737
	EDNS (MW)	0	0.00001	0.00006	0.00028	0.00117
	EENS(MWh/yr)	0.006	0.08	0.547	2.49	10.208
19	PLC	0	0	0.00002	0.00006	0.00018
	ENLC(1/yr)	0.0018	0.00735	0.02676	0.0872	0.24439
	ELC(MW/yr)	0.14	0.641	2.545	8.31	24.973
	EDNS (MW)	0.00009	0.00042	0.00173	0.0059	0.01838
	EENS(MWh/yr)	0.794	3.698	15.156	51.707	161.05

Table D.32: System reliability indices for the MRTS at different peak load levels (Case 2)

System Indices	Peak Load (MW)				
	4700	4900	5100	5300	5500
EENS (MWh/yr)	1.19595	6.10424	27.3781	106.99	370.615
SAIFI (interruptions /delivery point)	0.00021	0.00094	0.00382	0.01428	0.04788
SAIDI (hrs/delivery point)	0	0	0.02061	0.0876	0.29372
SARI (hrs/interruption)	0	0	5.39824	6.13471	6.13423