DETERMINISTIC/PROBABILISTIC EVALUATION IN COMPOSITE SYSTEM PLANNING

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ABSTRACT

The reliability of supply in a bulk electricity system is directly related to the availability of the generation and transmission facilities. In a conventional vertically integrated system these facilities are usually owned and operated by a single company. In the new deregulated utility environment, these facilities could be owned and operated by a number of independent organizations. In this case, the overall system reliability is the responsibility of an independent system operator (ISO).

The load point and system reliabilities are a function of the capacities and availabilities of the generation and transmission facilities and the system topology. This research examines the effect of equipment unavailability on the load point and system reliability of two test systems. The unavailabilities of specific generation and transmission facilities have major impacts on the load point and system reliabilities. These impacts are not uniform throughout the system and are highly dependent on the overall system topology and the operational philosophy of the system.

Contingency evaluation is a basic planning and operating procedure and different contingencies can have quite different system and load point impacts. The risk levels associated with a given contingency cannot be estimated using deterministic criteria. The studies presented in this thesis estimate the risk associated with each case using probability techniques and rank the cases based on the predicted risk levels. This information should assist power system managers and planners to make objective decisions regarding reliability and cost.

Composite system preventive maintenance scheduling is a challenging task. The functional separation of generation and transmission in the new market environment creates operational and scheduling problems related to maintenance. Maintenance schedules must be coordinated through an independent entity (ISO) to assure reliable and economical service. The methods adopted by an ISO to coordinate planned outages are normally based on traditional load flow and stability analysis and deterministic operating criteria. A new method designated as the maintenance coordination technique (MCT) is proposed in this thesis to coordinate maintenance scheduling.

The research work illustrated in this thesis indicates that probabilistic criteria and techniques for composite power system analysis can be effectively utilized in both vertically integrated and deregulated utility systems. The conclusions and the techniques presented in this thesis should prove valuable to those responsible for system planning and maintenance coordination.

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LIST OF ABBREVIATIONS

ADLC	Average Duration of Load Curtailment
BPACI	Bulk Power-supply Average MW Curtailment Index
BPECI	Bulk Power/Energy Curtailment Index
BPII	Bulk Power Interruption Index
CEA	Canadian Electricity Association
CPU	Central Processing Unit
CTU	Combustion Turbine Unit
DISCO	Distribution Company
EDC	Expected Damage Cost
EDLC	Expected Duration of Load Curtailment
EDNS	Expected Demand Not Supplied
EENS	Expected Energy Not Supplied
EFLC	Expected frequency of load curtailment
ELC	Expected Load Curtailment
ENLC	Expected Number of Load Curtailments
FOR	Forced Outage Rate
GENCO	Generation Company
HL	Hierarchical Level
HLI	Hierarchical Level I
HLII	Hierarchical Level II
HLIII	Hierarchical Level III
IEAR	Interrupted Energy Assessment Rate
IEEE-RTS	IEEE-Reliability Test System
II	Impact Index
ISO	Independent System Operator
LOLE	Loss of Load Expected
MBECI	Modified Bulk Energy Curtailment Index
MCT	Maintenance Coordination Technique
MII	Modified Impact Index
MRTS	Modified IEEE-Reliability Test System
MTTR	Mean Time to Repair
NERC	North American Electric Reliability Council
OPF	Optimal Power Flow
PLC	Probability of Load Curtailment
PX	Power Exchange
RBTS	Roy Billinton Test System
RCM	Reliability Centered Maintenance
SI	Severity Index
TRANSCO	Transmission Company

1. INTRODUCTION

1.1 Introduction

Electric power systems are among the most complex and large systems that exist in the world. Broadly speaking, a power system is composed of the three functional zones of generation, transmission, and distribution. The basic function of a power system is to provide electric power to its customers as economically as possible and with an acceptable degree of continuity and quality [1]. Reliability is one of the most important factors considered in power system planning and operation in both vertically integrated and deregulated utility environments.

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 terms of a power system, the measures of reliability indicate how well the system performs its basic function of supplying electrical energy to its customers [2]. The likelihood of customers being disconnected for any reason can be reduced by increased investment during the planning phase and/or the operating phase. Over investment can lead to excessive operating costs. On the other hand, under investment can lead to lower reliability. How to trade-off these two aspects is a major challenge to power system managers, planners, designers, and operators.

In order to resolve the dilemma between the economic and reliability constraints, design, planning, and operating criteria and techniques have been developed and applied over many decades. Most of these criteria are deterministic and many of them are still used today [3]. Deterministic criteria were developed in order to account for randomly occurring failures. Their essential weakness is that they do not and cannot account for the probabilistic or stochastic nature of system behavior, of customer demands, or of component failures. It is well known that power system behavior is stochastic in nature, and therefore it is logical to consider that the analysis of such systems should be based on probabilistic techniques. This has been acknowledged for a long time. There have been a tremendous number of publications dealing with the development and application of probabilistic techniques for power system reliability evaluation [4-10]. Reliability evaluation techniques are now highly developed and most engineers have a working understanding of probability methods. In addition, most utilities have valid and applicable data. Reference [11] indicates that probabilistic techniques have been used by most Canadian utilities in the planning and operation of generating capacity. This is not the case in bulk power systems or distribution systems. It is expected that the application of probability techniques throughout the entire power system industry will continue to increase in the near future.

1.2 Power system reliability evaluation

Power system reliability can be divided into the two aspects of adequacy and security as shown in Figure 1.1. Adequacy relates to the existence of sufficient facilities within the system to satisfy the customer requirements. It is associated with static conditions and long-term analysis. Security relates to the ability of the system to respond to disturbances. It is associated with dynamic conditions and short-term analysis. This thesis is restricted to the adequacy evaluation of power systems.

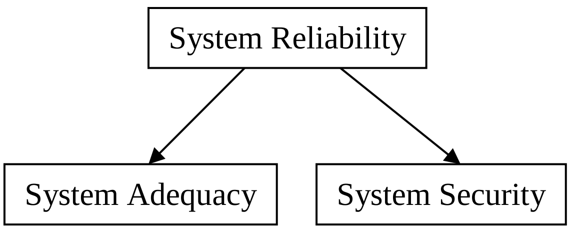


Figure 1.1: Subdivision of system reliability

An overall power system can be divided into the three basic functional zones of generation, transmission, and distribution. These three functional zones can be organized into the three hierarchical levels (HL) shown in Figure 1.2.

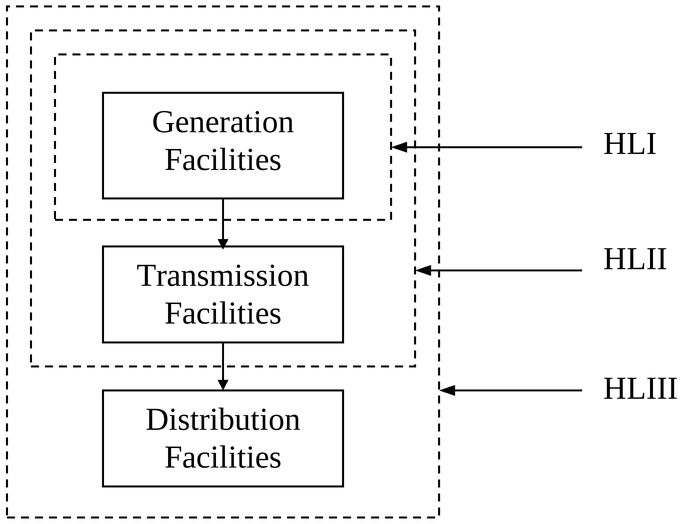


Figure 1.2: Power system hierarchical levels

Reliability assessment at hierarchical level I (HLI) is normally termed as generating capacity adequacy evaluation and is concerned with only the generation facilities. In an HLI study, the total system generation including interconnected assistance is examined to determine its adequacy to meet the total system load demand. The transmission network and the distribution facilities are not part of the analysis at this level. Reliability assessment at hierarchical level II (HLII) is normally referred to as composite system (or bulk system) reliability evaluation and involves the analysis of the combined generation and transmission system in regard to its ability to serve the system load. The reliability of supply at the individual load points in a composite system is a function of the capacities and availabilities of the individual generation, transmission facilities, and the system topology [12]. Reliability assessment at hierarchical level III (HLIII) includes all of the three functional zones and is not easily conducted in a practical system due to the computational complexity and the scale of the assessment. Analyses are usually performed in the distribution functional zone. Load point indices evaluated at HLII can be used as input to these analyses. This thesis is centered on adequacy assessment at HLII. Further discussion on composite system reliability evaluation is presented in Chapter 2 of this thesis.

Power system reliability evaluation can be performed using analytical methods or Monte Carlo simulation. Both techniques have been used successfully in commercial applications. Analytical techniques represent the system by mathematical models and evaluate the reliability indices from these models using numerical solutions. Monte Carlo simulation, however, estimates the reliability indices by simulating the actual process and random behavior of the system. The method therefore treats the problem as a series of experiments. Theoretically, Monte Carlo simulation can include system effects which may have to be approximated in a direct analytical method. The development and utilization of digital computers has led to increasing use of Monte Carlo simulation techniques for power system reliability assessment. The studies presented in this thesis were conducted using the Monte Carlo simulation technique. The basic aspects of Monte Carlo simulation are discussed in Chapter 2 of this thesis.

1.3 Deregulated power industry

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

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

A GENCO is a regulated or non-regulated entity (depending upon the industry structure) that operates and maintains existing generating plants. It may own generating plants or interact on behalf of plant owners with the short-term market (power exchange, power pool, or spot market). GENCO have the opportunity to sell electricity to entities with which they have negotiated sales contracts. They may also opt to sell electricity to the Power Exchange (PX) from which large customers such as DISCO and aggregators may purchase electricity to meet their needs. In addition to real power, GENCO may trade reactive power and operating reserves. GENCO communicate the need for generating unit outages for maintenance to the ISO within a certain time (usually declared by the ISO) prior to the start of the outages. The ISO then informs the GENCO of all approved outages.

A TRANSCO transmits electricity using a high-voltage, bulk transport system from GENCO to DISCO for delivery to the customers. It is composed of an integrated network that is shared by all participants and radial connections that join generating units and large customers to the network. The use of TRANSCO assets is under the control of the regional ISO, although the ownership can continue to be held by the original owners in the vertically integrated structure. TRANSCO are regulated to provide non-discriminatory connections and comparable service for cost recovery. A TRANSCO has the role of building, owning, maintaining, and operating the transmission system in a certain geographical region to provide services for maintaining the overall reliability of the electrical system. The ISO handles the operation and scheduling of TRANSCO facilities. Transmission maintenance and expansion is coordinated between the TRANSCO and the ISO. A TRANSCO advises the ISO of the list of required equipment maintenance outages, or any changes to the scheduled outages, within a certain time (usually declared by the ISO) prior to the start of the outages. The ISO then informs the TRANSCO of all approved outages.

A DISCO is an entity that distributes electricity through its facilities to customers. It constructs and maintains distribution wires connecting the transmission grid to the customers. A DISCO has the responsibility of responding to distribution network outages and power quality concerns. A DISCO coordinates its functions with the TRANSCO and the ISO to ensure the flow of energy. They are responsible for maintenance and ancillary services including coordination with the ISO, and generally perform metering, billing and collection services.

The ISO is a neutral operator responsible for maintaining the instantaneous balance of the system. The ISO performs its function by controlling the dispatch of generation and giving orders to adjust or curtail loads to ensure that loads match available generating resources in the system. Although the ISO's responsibilities differ among restructuring models, in general, the objective is to guarantee a comparable and non-discriminatory access by power suppliers and users to regional electric transmission systems. The ISO should be independent of any participants with commercial interests in the system operation. It has the operational control of the transmission grid components, administers system wide transmission tariffs, maintains and ensures system reliability, coordinates maintenance scheduling, and has a role in coordinating long-term planning.

The ISO should collect all generation and transmission planned outage requests from market participants, i.e., GENCO and TRANSCO. It should review all submissions of planned outages based on operating reliability criteria and the time/date of request for maintenance and then decide whether to permit, deny, or adjust planned outage schedules to preserve the system reliability. The electric utility industry is moving to new planning criteria in the new market environment where broader engineering considerations of transmission access and risks must be explicitly addressed. Specifically, the likelihood of the occurrence of worst possible scenarios must be recognized in the analysis and the acceptable risk levels incorporated in the decision-making process [13]. Intense competition in power markets will result in more complicated facility maintenance scheduling and create additional pressure on the GENCO and the TRANSCO to create optimal maintenance schedules for their facilities. It is imperative to develop efficient decision-making tools for the GENCO, the TRANSCO, and the ISO to create the most appropriate maintenance schedules in a competitive situation.

1.4 Scope and objectives of the thesis

The research presented in this thesis is focused on an examination of the ability to conduct composite system reliability evaluation. The studies described in this thesis were conducted using a commercial software known as MECORE. It is a Monte Carlo simulation based bulk system reliability evaluation tool and is described in Chapter 2. The research is focused on the following three topics: sensitivity analysis, probabilistic and deterministic criteria, and coordination of maintenance scheduling.

1.4.1 Sensitivity analysis

Composite system reliability evaluation involves the analysis of the combined generation and transmission system in regard to its ability to serve the system load. The generating facilities are dispersed throughout the system. The reliability of supply at the individual load points in a composite system is a function of the capacities and unavailabilities of the individual generation and transmission facilities and the system topology [12]. Component unavailability (or forced outage rate (FOR)) is determined by the failure rate λ and repair rate μ (or mean time to repair (MTTR)). The component failure rate is usually affected by variations in the environment and preventive maintenance practices. Similarly, factors, such as manpower, repair strategies, equipment, spare provisions, and so forth, influence the MTTR. In the new power industry environment, some of the factors noted earlier may change due to market forces. The unavailability or FOR of each component in a power system usually varies over its life cycle. The sensitivity of the load point and system reliability to unavailability of the individual facilities is valuable information in the decision-making process associated with reinforcement and maintenance planning. The objectives of the sensitivity studies conducted in this research are to investigate the impacts on the load point and system reliability of changes in the unavailability of selected system facilities.

1.4.2 Probabilistic and deterministic criteria

As noted earlier, most Canadian utilities apply probabilistic technique in the planning and operation of generating capacity. Deterministic criteria are, however, very popular in the planning and operation of composite systems. One possible reason is the lack of suitable analysis tools. The deterministic criterion usually applied in a composite power system is designated as the (n-1) criterion. This means that the system should be able to withstand the removal of any single component. This is obviously a worst-case criterion. If the system can withstand the worst case situation, it can withstand the rest. Here the term “withstand” means, according to the NERC Planning Standards [3], no violations of thermal and voltage limits, the system should remain stable, no loss of demand, and no cascading events. It is obvious that different cases, i.e. removing different elements from the system, usually have different risk or reliability levels.

Unfortunately, it is impossible to estimate the risk levels of each case and determine which case is the worst one using deterministic criteria. The objective of this phase of the research is to demonstrate that it is possible to estimate the risk associated with each case using probabilistic criteria and rank the cases based on the risk levels. This information will help power system managers and planners make objective decision regarding reliability and cost.

1.4.3 Coordination of maintenance scheduling

The basic objective of preventive maintenance is to prevent or forestall future random failures of the system facilities by removing the facilities from service at an appropriate time and conducting diagnostic tests and element replacements. An optimized maintenance schedule can improve system reliability, reduce system operation costs and result in savings in capital investment for new facilities.

Preventive maintenance scheduling of a composite system is a challenging task in both vertically integrated utility and deregulation environments. In a broad sense, there are two kinds of facilities maintenance in bulk power systems: generating unit maintenance and transmission line maintenance. The generating unit maintenance scheduling problem was first proposed when engineers tried to optimize the operational scheduling of a large power system about three decades ago. The transmission line maintenance scheduling problem has a much shorter history and was originally included as a constraint in the solution of generating unit maintenance. Maintenance of generation and transmission facilities is often studied independently. This is true particularly in a restructured power system where the generating units and transmission lines belong to totally different entities in the power market. System constraints such as network flows limits, energy demands and reliability requirements, however, closely tie the two functional zones, and research is required to encourage practical optimization and feasible solutions for the two problems.

In a vertically integrated utility, it is the responsibility of the utility to create maintenance schedules for a variety of facilities. Maintenance schedules for both generation and transmission facilities together with coordination of these schedules are done centrally. The exclusive advantage of this centralized process is that the solution optimizes the reliability and operating cost of the entire system owned by the utility.

The functional separation of generation and transmission in the new market environment creates operational and scheduling problems related to maintenance. For example, the decision when to maintain a generator may be driven by profit motives rather than by the optimal cost of maintenance and repair [14]. Maintenance schedules must be coordinated through an independent entity (i.e., ISO) to assure reliable and economical service.

The methods adopted by an ISO to coordinate planned outages are normally based on the traditional load flow and stability analysis and deterministic operating criteria. The objective of this phase of the research is to examine the ability to use probabilistic techniques to coordinate maintenance scheduling.

1.5 Outline of the thesis

Following the introduction in Chapter 1, Chapter 2 briefly described three Monte Carlo techniques used in power system reliability evaluation, i.e. the state sampling method, the state transition sampling method, and the sequential method. A composite generation and transmission system reliability evaluation tool designated as MECORE is introduced in this chapter. The software MECORE is based on the state sampling technique for Monte Carlo simulation. The load point and system indices used in the MECORE to measure composite system reliability are described in this chapter. These parameters can be expressed as either annualized or annual indices. The two test systems used extensively in this thesis are also briefly introduced in Chapter 2. The RBTS is a small educational test system. The IEEE-RTS is a relatively large system compared with the RBTS. Base cases studies of the two test systems as well as the corresponding assumptions are presented in this chapter.

The unavailability or forced outage rate (FOR) of each component in a composite system is not a constant during its life cycle and can be influenced by many factors. The sensitivity of the load point and system reliability to the unavailability of the individual facilities is valuable information in the decision-making process associated with reinforcement and maintenance planning. Chapter 3 examines the effect of equipment unavailability on the load point and system reliability of the two test systems. A series of studies involving different conditions such as peak load levels for the RBTS, generating station FOR and a modified IEEE-RTS which reflects concerns in the new deregulated environment are described.

The most usual deterministic criterion in a composite system is the (n-1) criterion in which the system should be able to withstand the removal of any single component. The (n-1) criterion, however, cannot identify the difference between the impacts of different contingencies on the load point and system reliability. Chapter 4 describes a series of studies on the two test systems that illustrate how probability techniques can be used to assess the various risks associated with the removal from service of generation and transmission components and ranks the cases based on the risk levels. Two new indices designated as the Impact Index and Modified Impact Index are utilized for comparison purposes.

Chapter 5 presents a new maintenance coordination technique (MCT). The MCT is applied to the two test systems to examine the impact of removing elements for maintenance from the system and to determine if specified planned outages could be conducted during a given time period.

Chapter 6 summarizes the thesis and highlights the conclusions.

2. COMPOSITE SYSTEM RELIABILITY EVALUATION

2.1 Introduction

The function of a composite system is to produce electrical energy at the generating sources and then move this energy to the major load points. The purpose of composite system reliability evaluation is to estimate the ability of the system to perform this function. Assessment of composite system reliability is very complex since it must consider the integrated impacts of generation and transmission. HLII studies include many aspects such as load flow analysis, contingency analysis, generation rescheduling, transmission overload alleviation, load curtailment philosophy, etc. Composite system reliability evaluation can be used to estimate the impacts of many factors on the adequacy of an existing or proposed system such as reinforcement alternatives at both generation and transmission levels [15], maintenance schedules, operating strategies, equipment availability [16], generation modeling, substation configurations etc. In addition, composite system reliability evaluation can be used to coordinate maintenance scheduling, rank system component importance, and so on. There are many power utilities and related organizations doing interesting and innovative work in this area and considerable published materials are available [1, 4-10, 12].

Load point and system indices are used to measure composite system reliability. These two sets of indices complement each other and serve different functions. The load point indices indicate the reliability at the individual buses and are valuable in identifying weak points in the system and in comparing the local impacts of component investment. The load point indices also provide input values to subsequent distribution system adequacy evaluation. The system indices provide valuable information on overall system adequacy and can be used in comparisons of different alternatives in bulk electricity system planning. The load point and system reliability parameters can be expressed as either annualized or annual indices. Annualized indices are calculated using a single load level (normally the system peak load level) and expressed on a one-year basis. Annual indices are calculated considering the detailed load variations that occur throughout a year. Annualized indices provide useful indications when comparing the adequacy of different reinforcement options. Annual indices should be utilized when attempting to calculate the expected annual reliability performance of a system [1]. As noted in Chapter 1, composite system reliability evaluation can be conducted using analytical techniques or Monte Carlo simulation. Considerable work has been done in both areas [4-10]. The basic equations employed to obtain the load point and system indices using the contingency enumeration approach, which is the conventional analytical method, are presented in [12]. The analysis conducted in this research employs Monte Carlo simulation. The basic techniques of Monte Carlo simulation and the required equations for application to HLII evaluation are briefly discussed in this chapter.

2.2 Monte Carlo simulation

As noted in Chapter 1, there are two general approaches for assessing power system reliability: the analytical method and the simulation method. Monte Carlo methods are more flexible when complex operating conditions and system considerations need to be incorporated. A simulation is an imitation of the operation of a system over a period of time. It involves the generation of an artificial history of the system and the observation of that artificial history to draw inferences concerning the characteristics of the real system. There are two fundamental techniques utilized when Monte Carlo methods are applied to power system reliability evaluation. These methods are known as the sequential and non-sequential techniques. The sequential technique simulates the up and down cycles of all components first and then obtains a system state operating cycle by combining all the component cycles. The non-sequential approach involves the two techniques of state sampling and state transition sampling. In a non-sequential technique, the states of all components are sampled and a non-chronological system state is obtained. These three methods [1] are briefly described in the following sections.

2.2.1 State sampling method

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

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

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

$$S_i = \begin{cases} 0 \text{ (up state)} & \text{if } U_i \geq FOR_i \\ 1 \text{ (down state)} & \text{if } U_i < FOR_i \end{cases} \tag{2.1}$$

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

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

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

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

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

2.2.2 State transition sampling method

The state transition sampling method focuses on state transitions of the whole system instead of the component states or the component state transition processes. This method can be explained as follows.

Assume that a system contains n components and that the state duration of each component follows an exponential distribution. The system can experience a system state transition sequence $\{S^{(1)}, S^{(2)}, \ldots, S^{(M)}\} = G$ where G is the system state space. Suppose that the present system state is $S^{(k)}$ and the transition rate of each component relating to $S^{(k)}$ is λ_i (i=1, 2, …, n). The state duration T_i of the i^{th} component corresponding to system state $S^{(k)}$ therefore has the probability density function: $f_i(t) = \lambda_i \exp(-\lambda_i t)$. Transition of the system state depends randomly on the state duration of the component which departs earliest from its present state, i.e., the duration T of the system state $S^{(k)}$ is a random variable which can be expressed by:

$$T = \min_i \{T_i\} \tag{2.2}$$

It can be proved that the state duration of the system T also follows an exponential distribution with following probability density function [1, 17]:

$$f(t) = \sum_{i=1}^{n} \lambda_i \exp\left(-\sum_{i=1}^{n} \lambda_i t \right) \tag{2.3}$$

Starting from system state $S^{(k)}$, the system containing n components has n possible reached states. The probability that the system reaches one of these possible states is expressed by the following equations [1, 17]:

$$P_j = \frac{\lambda_j}{\sum_{i=1}^{n} \lambda_i} \tag{2.4}$$

$$\sum_{j=1}^{n} P_j = 1 \tag{2.5}$$

Therefore, the next system state can be determined by the following simple sampling. The probabilities of n possible reached states are successively placed in the interval [0, 1] as shown in Figure 2.1. Generate a uniform distributed random number U between [0, 1]. If U falls into the segment corresponding to P_j, this means that transition of the j[th] component leads to the next system state. A long system state transition sequence can be obtained by a number of samples and the reliability of each system state can be assessed.

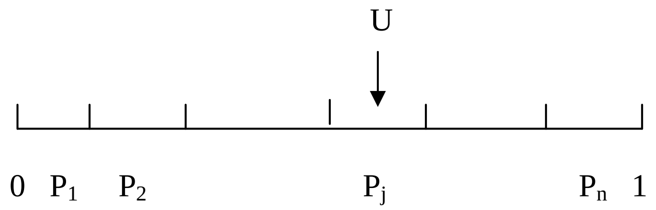


Figure 2.1: Explanation of system state transition sampling

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

(a) The simulation process starts from the normal system state in which all the components are in the up state.

(b) Calculate each P_j ($j = 1, 2, \ldots, n$) using equation (2.4) and generate a uniform distributed random number U between [0, 1], then determine the next system state.

(c) If the present system state is a contingency state in which at least one component is in the outage state, the minimization model [1, 17] of load curtailment is used to evaluate the adequacy of this system state. Otherwise, proceed to the next step without using the minimization model.

(d) The process is repeated until the stopping criterion is reached.

2.2.3 Sequential method

The sequential method is based on sampling the probability distribution of the component state duration. In this approach, chronological component state transition processes for all components are first simulated by sampling. The chronological system state transition process is then created by combination of the chronological component state transition processes [1].

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

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

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

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

$$T_i = -\frac{1}{\lambda_i} \ln U_i \tag{2.6}$$

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

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

(d) The chronological system state transition process in the given time span can be obtained by combining the chronological component state transition processes of all components.

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

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

These three methods described above have their own merits and demerits.

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

The state transition sampling method can be used to calculate an exact frequency index without the need to sample the distribution function and store chronological information as in the sequential method. This technique, however, only applies to exponentially distributed component state durations.

The sequential method can be used to calculate the actual frequency index as well as related indices and can incorporate different state duration distributions. The statistical probability distributions of the adequacy indices can also be assessed in addition to their expected values. This method, however, requires relatively more CPU time and storage.

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

2.2.4 Indices used in Monte Carlo simulation

The following indices [1, 18] are used in this thesis.

(a) Basic indices

Probability of load curtailment (PLC)

$$\text{PLC}= \sum_{i \in S} P_i \tag{2.7}$$

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

Expected frequency of load curtailment (EFLC)

$$\text{EFLC} = \sum_{i \in S} (F_i - f_i) \ \text{occ./yr} \tag{2.8}$$

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

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

$$\text{ENLC} = \sum_{i \in S} F_i \quad \text{occ./yr} \tag{2.9}$$

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

$$F_i = P_i \sum_{k \in N} \lambda_k \quad \text{occ./yr} \tag{2.10}$$

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

Expected duration of load curtailment (EDLC)

$$EDLC = PLC \times 8760 \quad \text{hrs/yr} \tag{2.11}$$

Average duration of load curtailment (ADLC)

$$ADLC = EDLC/EFLC \quad \text{hrs/disturbance} \tag{2.12}$$

Expected load curtailment (ELC)

$$ELC = \sum_{i \in S} C_i F_i \quad \text{MW/yr} \tag{2.13}$$

where C_i is the load curtailment of system state i.

Expected demand not supplied (EDNS)

$$EDNS = \sum_{i \in S} C_i P_i \quad \text{MW} \tag{2.14}$$

Expected energy not supplied (EENS)

$$EENS = \sum_{i \in S} C_i F_i D_i = \sum_{i \in S} 8760 C_i P_i \quad \text{MWh/yr} \tag{2.15}$$

where D_i is the duration of system state i.

Expected damage cost (EDC)

$$EDC = \sum_{i \in S} C_i F_i D_i W \quad \text{k\$/yr} \tag{2.16}$$

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

Bulk power interruption index (BPII)

$$BPII = \frac{\sum_{i \in S} C_i F_i}{L} \quad \text{MW/MW-yr} \tag{2.17}$$

where L is the annual system peak load in MW.

Bulk power/energy curtailment index (BPECI)

$$\text{BPECI} = \frac{\text{EENS}}{\text{L}} \quad \text{MWh/MW-yr} \tag{2.18}$$

Bulk Power-supply average MW curtailment index (BPACI)

$$\text{BPACI} = \frac{\text{ELC}}{\text{EFLC}} \quad \text{MW/disturbance} \tag{2.19}$$

Modified bulk energy curtailment index (MBECI)

$$\text{MBECI} = \frac{\text{EDNS}}{\text{L}} \quad \text{MW/MW} \tag{2.20}$$

Severity Index (SI)

$$\text{SI} = \text{BPECI}\times 60 \quad \text{system min/yr} \tag{2.21}$$

It can be seen that the IEEE proposed indices are calculated from the basic indices by normalization using the system peak load. The advantage of the IEEE proposed indices is that they can be used to compare the adequacy of systems having different sizes. The basic indices can be applied to an overall system or to a single load point, while the IEEE proposed indices only apply to an overall system.

2.3 Introduction to MECORE

The software MECORE 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. It can be used to provide quantitative reliability indices at individual load points and for the overall composite generation and transmission system. It can also be used to provide unreliability cost indices, which reflect reliability worth. The indices produced by the program can be utilized to compare different planning alternatives from a reliability point of view. The MECORE software is based on a combination of Monte Carlo simulation (state sampling technique) and enumeration techniques. The state sampling technique is used to simulate system component states and to calculate annualized indices at the system peak load level. A hybrid method utilizing an enumeration approach for aggregated load states is used to calculate annual indices using an annual load curve [18].

- System size: The program is designed to handle up to 1000 buses and 2000 branches.
- Failure modes:
  - Independent failures of generators, lines and transformers
  - Common cause outages of transmission lines
  - Generating unit derated states
- Failure criteria:
  - Capacity deficiency
  - Line over load
  - System separation-load loss
  - Bus isolation-load loss
- Load model:
  - Annual, seasonal, and monthly load curve
  - Multi-step models
  - Bus load proportional scaling and flat level model
- Probability indices:
  - System and bus indices
  - Annualized and monthly/seasonal/annual indices
  - Basic and IEEE-proposed indices

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

- 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.

2.4 Two test systems

The two test systems used in this thesis are the Roy Billinton Test System (RBTS) [19] and the IEEE Reliability Test System (IEEE-RTS) [20]. The single line diagrams of the RBTS and the IEEE-RTS are shown in Figures 2.2 and 2.3 respectively.

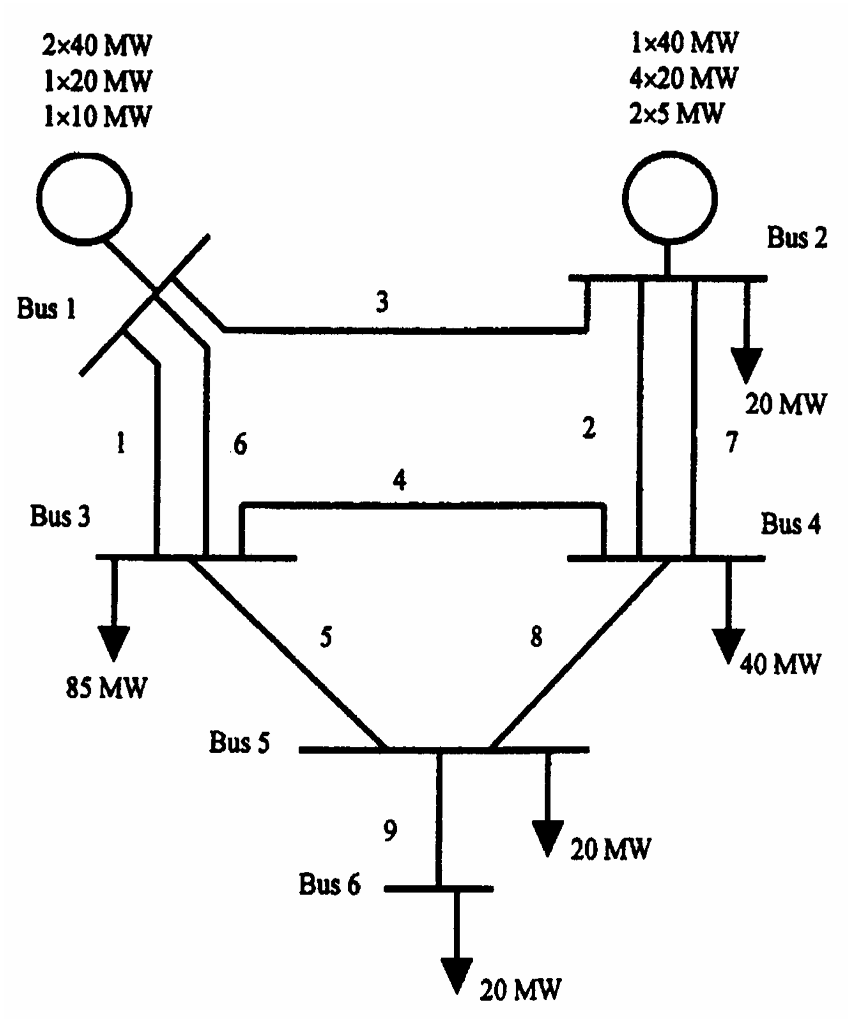


Figure 2.2: The single line diagram of the RBTS

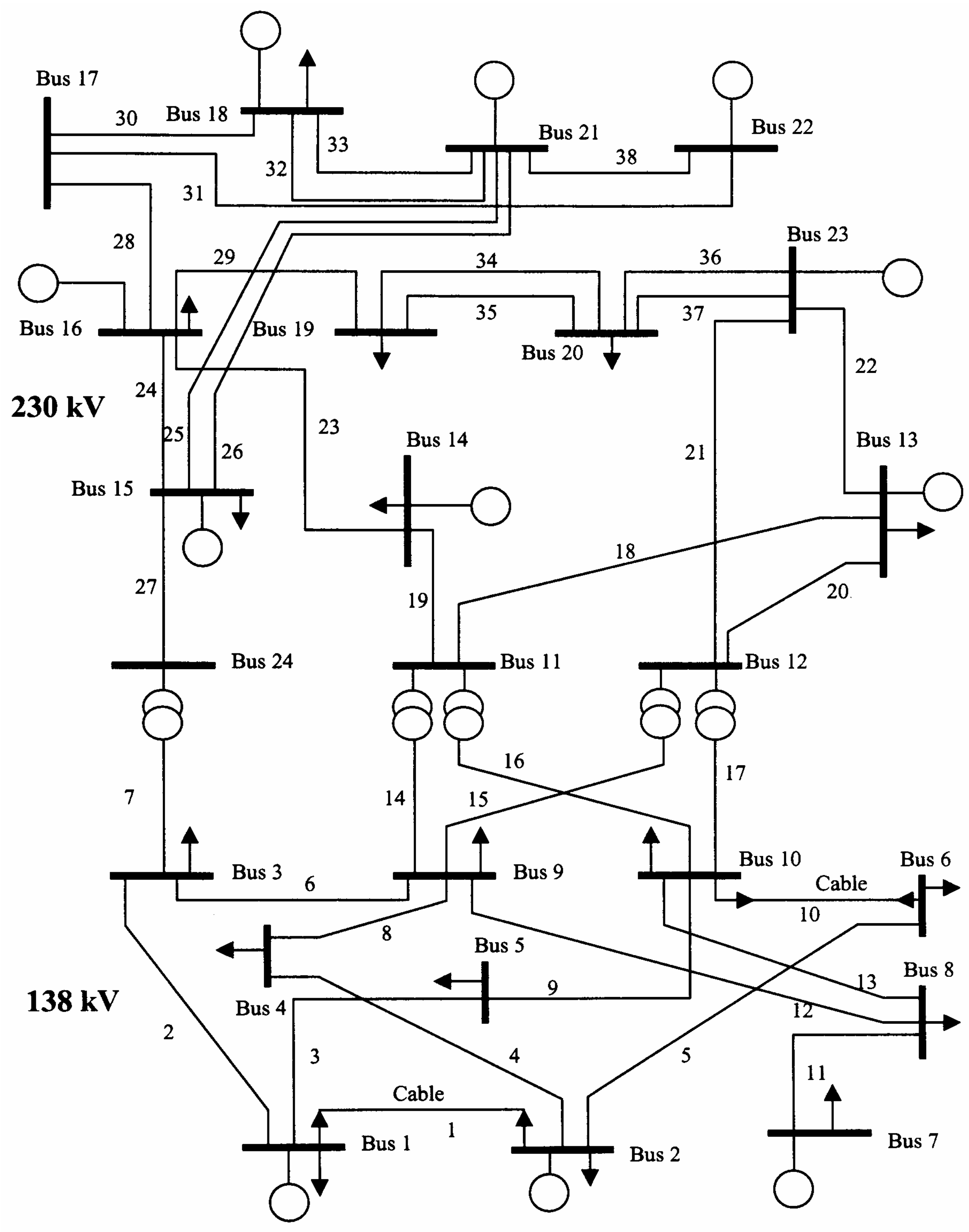


Figure 2.3: The single line diagram of the IEEE-RTS

The RBTS is a small educational test system developed as part of the graduate program in power system reliability evaluation at the University of Saskatchewan. The RBTS is a 6-bus test system with five load buses. It has eleven generators and nine transmission lines. The installed 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 an IEEE Task Force to provide a practical representative bulk power system for research and comparative study purposes. The IEEE-RTS is a relatively large system compared with the RBTS. The generating system contains 32 units, ranging from 12 to 400 MW. The transmission system contains 24 buses, which include 10 generator buses, 10 load buses, and 4 connection buses, connected by 33 lines and 5 autotransformers at two voltage levels: 138kV and 230kV. The total installed capacity of the IEEE-RTS is 3405 MW and the system peak load is 2850 MW.

The RBTS and the IEEE-RTS have the same per-unit load model. The data on weekly peak load in percentage of the annual peak load, daily peak load in percentage of the weekly peak, and hourly peak load in percentage of the daily peak are given in [20]. These data together with the annual peak load define an hourly load model of 8736 hours. A winter peaking system can be adopted by taking Week 1 as January and Monday as the first day of the year. Since the test system provides only 364 daily peak loads in a year, it is assumed that the daily peak load on December 31st is the same as that on January 1st.

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

2.5 Base case studies of the RBTS and the IEEE-RTS

Many factors in bulk power system evaluation, such as multiple generators sharing a single transformer, common model failures of transmission lines, station originated failures, and so forth, are analyzed in [15]. The effects of these factors are a function of the system topology and the operating philosophy. The following conditions were used in the base case analyses of the RBTS and IEEE-RTS in the research described in this thesis.

(a) The station failure events are not included.

(b) The economic priority order is utilized.

(c) Transmission line common mode failures are not considered.

Individual load point indices are highly dependent on the system load curtailment philosophy. In an actual system, each load bus has a different priority. One common method to determine the priority order is based on economic factors which recognize the customer cost associated with failure of supply. The most convenient index for this purpose is the Interrupted Energy Assessment Rate (IEAR) [12], which measures the customer monetary loss as a function of the energy not supplied.

The IEAR values for each load point of the RBTS are given in Table 2.1 [15] and the corresponding priority order is shown in Table 2.2.

Table 2.1: IEAR values of each bus in the RBTS

Bus	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
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 [15] and the corresponding priority order is shown in Table 2.4.

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

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

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

Priority order	Bus	Priority order	Bus	Priority order	Bus
1	1	7	13	13	16
2	5	8	3	14	14
3	4	9	2	15	15
4	6	10	10	16	9
5	7	11	18	17	19
6	8	12	20		

Based on the above assumptions, the base cases of the two test systems were analyzed and the reliability indices are shown in Tables 2.5 to 2.10.

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)	16.47797	9.44535
EDLC (hrs/yr)	86.60575	12.08675
PLC	0.00989	0.00138
EDNS (MW)	0.12216	0.01739
EENS (MWh/yr)	1070.14149	152.34970
EDC (k$/yr)	N/A	673.38568
BPII (MW/MW-yr)	0.39292	0.08829
BPECI (MWh/MW-yr)	5.78455	0.82351
BPACI (MW/disturbance)	13.83016	12.76397
MBECI (MW/MW)	0.00066	0.00009
SI (system minutes/yr)	347.07290	49.41072

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	0	0	0	0	0
2	.00022	.21533	7.517	.00743	65.052
3	.00012	.12469	5.997	.00579	50.685
4	0	0	0	0	0
5	0	0	0	0	0
6	0	0	0	0	0
7	.00000	.00327	.082	.00005	.438
8	.00000	.00294	.062	.00004	.368
9	.05080	35.32409	2612.315	3.86918	33894.020
10	.00056	.50498	35.025	.03860	338.171
13	.00003	.03218	1.463	.00126	11.073
14	.01217	9.29683	639.792	.81732	7159.724
15	.03938	25.78817	2481.552	3.48197	30502.040
16	.00552	4.43487	178.765	.21584	1890.757
18	.00237	1.90038	174.843	.20937	1834.097
19	.08419	58.09929	4160.458	5.99921	52553.040
20	.00351	2.93097	153.836	.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	.00000	.00000	.000	.00000	.000
2	.00000	.00140	.049	.00005	.397
3	.00000	.00082	.027	.00002	.215
4	.00000	.00000	.000	.00000	.000
5	.00000	.00000	.000	.00000	.000
6	.00000	.00075	.052	.00003	.293
7	.00000	.00041	.004	.00000	.021
8	.00000	.00004	.000	.00000	.002
9	.00113	.87165	53.880	.06935	607.472
10	.00001	.00535	.295	.00029	2.541
13	.00000	.00013	.004	.00000	.031
14	.00021	.17742	10.795	.01266	110.899
15	.00067	.52376	45.318	.05604	490.941
16	.00010	.08251	3.165	.00362	31.750
18	.00003	.03086	2.402	.00255	22.376
19	.00201	1.51929	96.376	.12820	1123.035
20	.00006	.05564	2.484	.00273	23.956

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

Indices	Annualized	Annual
ENLC (1/yr)	58.10551	1.52049
ADLC (hrs/disturbance)	12.69111	11.56395
EDLC (hrs/yr)	737.50450	17.58358
PLC	.08419	.00201
EDNS (MW)	14.83250	.27556
EENS (MWh/yr)	129932.7	2413.92300
EDC (k$/yr)	N/A	10186.7600
BPII (MW/MW-yr)	3.66724	.07539
BPECI (MWh/MW-yr)	45.59043	.84699
BPACI (MW/disturbance)	179.87340	141.30460
MBECI (MW/MW)	.00520	.00010
SI (system minutes/yr)	2735.42600	50.81943

It can be seen from the base case results that the annual indices are much lower than the annualized indices due to the fact that the load resides at the peak level for only a short period of time during a year. It can be also seen that the indices of those load points with low priority order are higher, which indicates that the individual load point indices are highly dependent on the load curtailment priority order.

2.6 Conclusions

The purpose of composite system reliability evaluation is to estimate the ability of the system to produce electrical energy at the generation sources and then move this energy to the major load points. This ability can be measured by two sets of parameters: load point indices and system indices. They complement each other and serve different functions. Both load point and system parameters can be evaluated as annualized and annual indices. In general, annualized indices provide satisfactory indications when comparing the adequacy of different reinforcement alternatives. Annual indices should be utilized when attempting to calculate the expected annual performance of a system.

Three Monte Carlo techniques used in power system reliability evaluation are briefly described in this chapter. They are the state sampling method, the state transition sampling method, and the sequential method. Each technique has its own merits and demerits. The state sampling technique is utilized in the MECORE program.

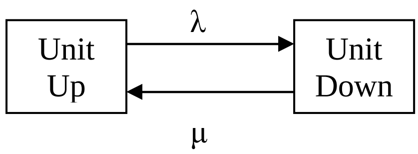
The software MECORE is a Monte Carlo based composite generation and transmission system reliability evaluation tool designed to perform reliability and reliability worth assessment of bulk electricity systems. All the analyses in this thesis are conducted using this tool.

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

3. COMPOSITE SYSTEM RELIABILITY SENSITIVITY ANALYSIS

3.1 Introduction

Composite system reliability evaluation involves the analysis of the combined generation and transmission system in regard to its ability to serve the system load. The generating facilities are dispersed throughout the system. The reliability of supply at the individual load points in a composite system is a function of the capacities and availabilities of the individual generation and transmission facilities and the system topology [12, 16]. The basic two-state reliability model for a power system component is shown in Figure 3.1.



λ = unit failure rate
μ = unit repair rate

Figure 3.1: Basic two-state model

The steady state probabilities of finding the generating or transmission unit in the Up and the Down states are designated as the availability (A) and unavailability (U) respectively and are given by

$$A = \frac{\mu}{\lambda + \mu} \tag{3.1}$$

$$U = \frac{\lambda}{\lambda + \mu} \tag{3.2}$$

The unavailability statistic in the case of a generating unit is commonly known as the forced outage rate (FOR) [12]. This statistic has been collected for many years by electric power utilities throughout the world. The conventional formula used to obtain the FOR is as follows

$$FOR = \frac{\sum DT}{\sum DT + \sum UT} \quad (3.3)$$

where DT = Down or Repair Time,

UT = Up or Operating Time.

The CEA reports [21, 22] contain considerable data on different generating unit types and sizes and different transmission line structures. Tables 3.1 and 3.2 present some overall Canadian reliability data for generating units [21] and transmission lines [22]. The transmission data are divided into the two segments of line related and terminal related statistics. Accurate and consistent collection of data is an important function in a modern power system and a vital component in a probabilistic approach to system development and growth. The strength of the CEA system lies in the ability to collect the required data. This could become more difficult in a future deregulated environment containing a large number of private corporate entities.

Table 3.1: CEA generating unit reliability data

Unit Type	FOR (%)	λ (f/yr)
CTU	7.83*	6.18
Fossil	7.25	10.02
Hydraulic	2.03	2.59
Nuclear	10.44	2.60

* indicates the Utilization Forced Outage Probability [21]

Table 3.2: CEA transmission line reliability data

(a) Line related data

Voltage Classification	Frequency (per 100 km.a)	Mean Duration (h)	Unavailability (%)
Up to 109kV	2.8578	12.1	0.395
110-149 kV	1.2297	29	0.407
150-199 kV	0.6163	9.5	0.067
200-299 kV	0.4209	20.3	0.098
300-399 kV	0.1513	77.2	0.133
500-599 kV	0.2206	13.4	0.034
600-799 kV	0.2056	174.6	0.410

(b) Terminal related data

Voltage Classification	Frequency (per a)	Mean Duration (h)	Unavailability (%)
Up to 109kV	0.1574	46.2	0.083
110-149 kV	0.1208	3.9	0.005
150-199 kV	0.0217	7.6	0.002
200-299 kV	0.1601	11.3	0.210
300-399 kV	0.0354	9.4	0.004
500-599 kV	0.1759	6.5	0.013
600-799 kV	0.1631	17.2	0.032

Equation (3.2) indicates that the component unavailability (or forced outage rate (FOR)) is determined by its failure rate λ and repair rate μ (or mean time to repair (MTTR)). The component failure rate is usually affected by variations in the environment and preventive maintenance practices. Similarly, factors, such as manpower, repair strategies, equipment, spare provisions, and so forth, influence the MTTR. In the new power industry environment, some of these factors may change due to market forces. The sensitivity of the load point and system reliability to the unavailability of the individual facilities is valuable information in the decision-making process associated with reinforcement and maintenance planning. This study examines the effect of equipment availability on the load point and system reliability of the two test systems.

3.2 RBTS analysis

The single line diagram of the RBTS is shown in Figure 2.2. The base case reliability indices for a peak load of 185 MW are shown in Tables 2.5 to 2.7. The reliability of supply in a bulk electricity system is directly related to the availability of the generation and transmission facilities. The objective of this study is to examine the system reliability performance of the RBTS due to variations in component unavailability.

3.2.1 Reliability as a function of generating unit FOR

The following cases were examined:

(a) Varying the FOR of all the generating units.

(b) Varying the generating unit FOR separately.

(c) Varying the generating station FOR separately.

3.2.1.1 Varying the FOR of all the units

The FOR of all the units in the RBTS were simultaneously varied from –100% to +100% of their base case values. The system indices and load point indices are shown in Tables B.1 to B.4 where Case 5 (FOR unchanged) is the base case. The system indices as a function of the unit FOR are shown pictorially in Figures 3.2 to 3.5. The load point indices as a function of the unit FOR are shown pictorially in Figures 3.6 to 3.10. Two sets of results are shown in Figures 3.2 to 3.10. The annualized indices at the peak load of 185 MW are considerably higher than the annual indices.

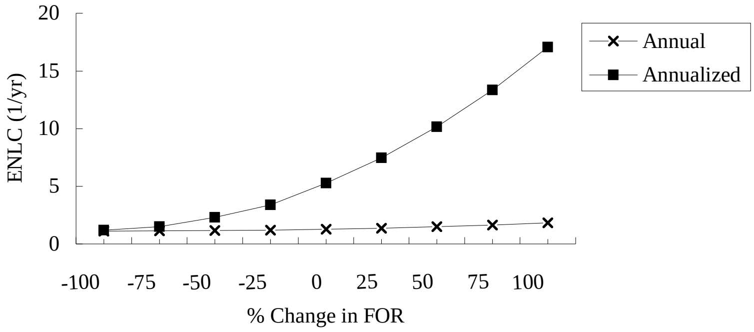


Figure 3.2: System ENLC for the RBTS as a function of the unit FOR

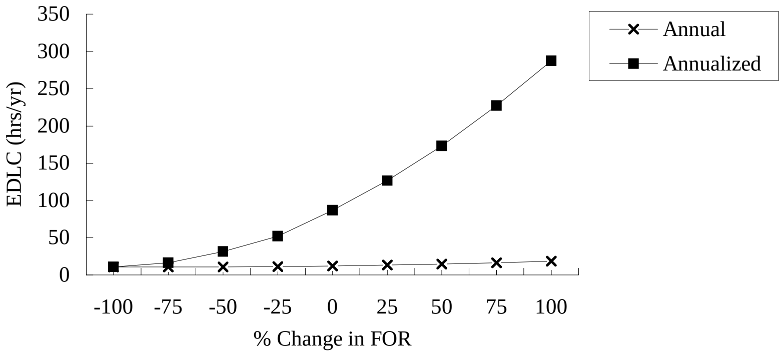


Figure 3.3: System EDLC for the RBTS as a function of the unit FOR

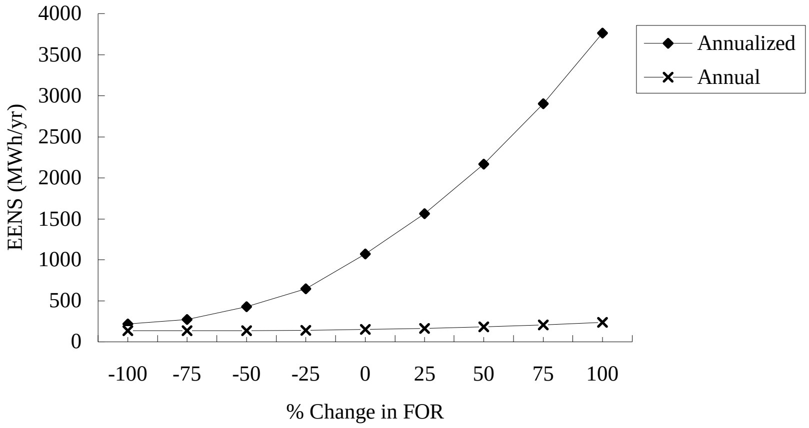


Figure 3.4: System EENS for the RBTS as a function of the unit FOR

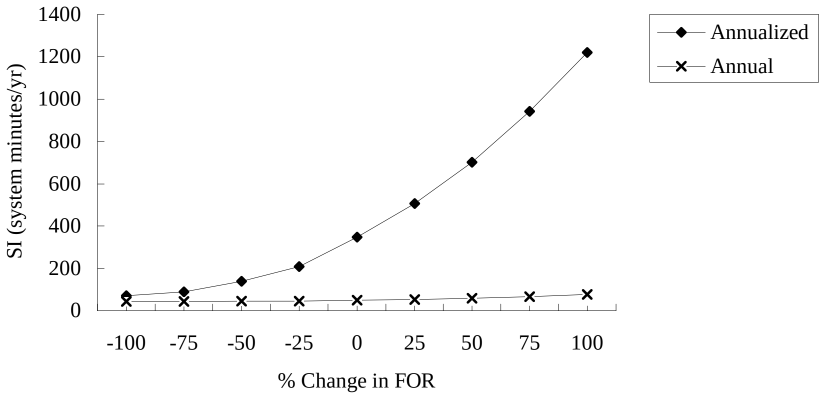


Figure 3.5: System SI for the RBTS as a function of the unit FOR

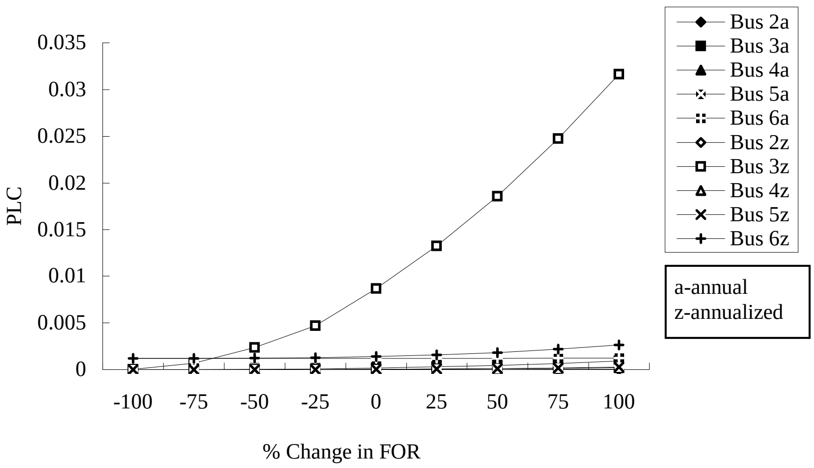


Figure 3.6: Load point PLC for the RBTS as a function of the unit FOR

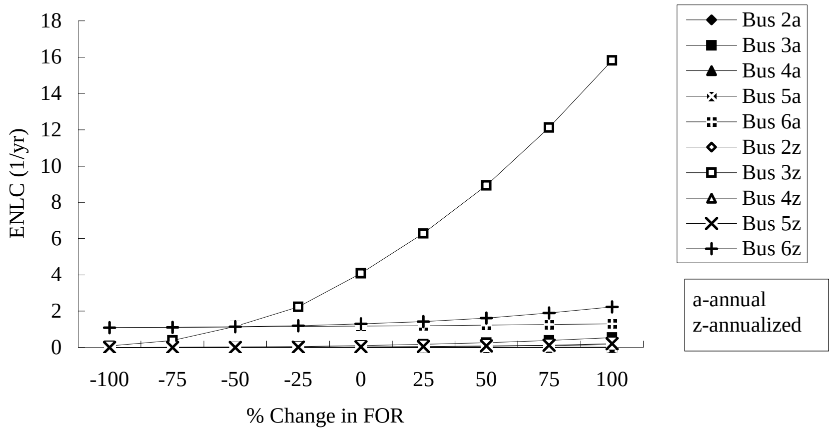


Figure 3.7: Load point ENLC for the RBTS as a function of the unit FOR

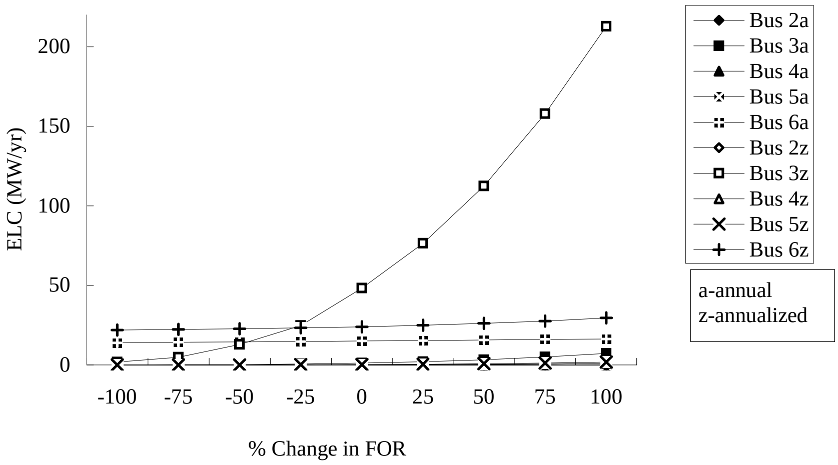


Figure 3.8: Load point ELC for the RBTS as a function of the unit FOR

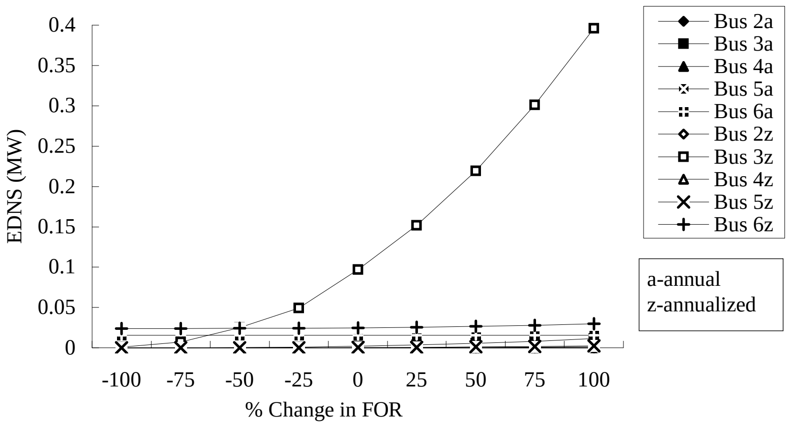


Figure 3.9: Load point EDNS for the RBTS as a function of the unit FOR

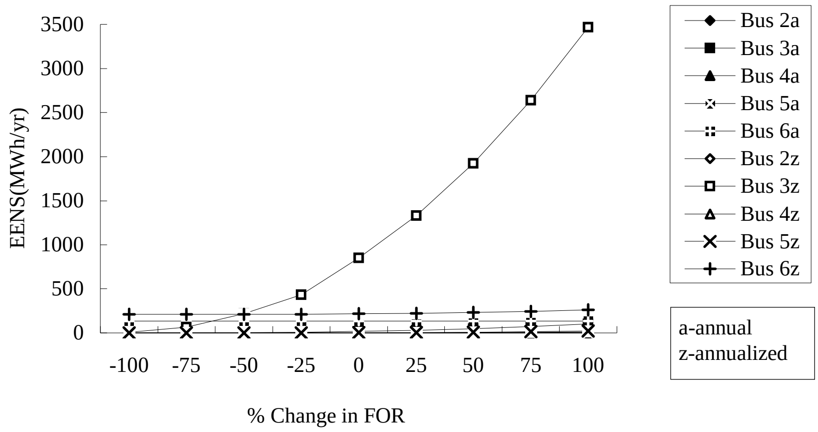


Figure 3.10: Load point EENS for the RBTS as a function of the unit FOR

It can be seen from Figures 3.2 to 3.10 and Tables B.1 to B.4 that the annualized indices (both system and load point) are generally much more sensitive to variations in the FOR than are the annual indices. This is due to the fact that generation outages have a larger impact on the system adequacy at higher load levels than at lower load levels. Under normal circumstances, the load resides at its peak value for only a short period of time. Annual indices incorporate the variations in system load throughout the year and therefore provide a more accurate assessment of the annual adequacy than do the annualized values. This is particularly important when performing economic analysis.

Figures 3.6 to 3.10 clearly show that different load points have different sensitivities to the generating unit FOR. The most sensitive load point is Bus 3 and the least sensitive is Bus 6 in a relative sense.

It should be noted that both the system topology and the system load curtailment philosophy have significant effects on the load point reliability indices. Figures 3.6 to 3.10 indicate that the reliability indices at Bus 3 are dominated by generation failures. The reliability indices of the remaining buses are relatively insensitive to variations in the generating unit FOR.

Figures 3.2 to 3.5 indicate that the different system indices have similar forms. This is also true for the load point indices (see Figures 3.6 to 3.10). The following analyses are focused on the EENS index expressed on an annual basis. The EENS is an important and valuable index. It is a combination of the magnitude of the load curtailment, the duration of load curtailment, and the frequency of load curtailment. It should be noted, however, that the following analyses could be conducted using any of the basic indices.

Figure 3.11 shows the system EENS for two peak load conditions as a function of the generating unit FOR. The numerical values of the system and load point EENS at a peak load of 200 MW are given in Table B.5.

It can be seen from Figure 3.11 that the system EENS is very sensitive to the changes in generating unit FOR and this sensitivity is influenced by the generating reserve margin. This is also the case for Bus 3 (see Figures 3.12 and 3.13) which is dominated by generation failures. Figures 3.12 and 3.13 show the individual load point EENS as a function of the generating unit FOR for the two peak load conditions. The individual load bus indices are highly influenced by the load curtailment priority order. As shown in Table 2.2, Bus 3 has the lowest priority and receives most of its load curtailments due to generating capacity deficiencies. The EENS at Bus 6 is almost entirely due to failures of Line 9.

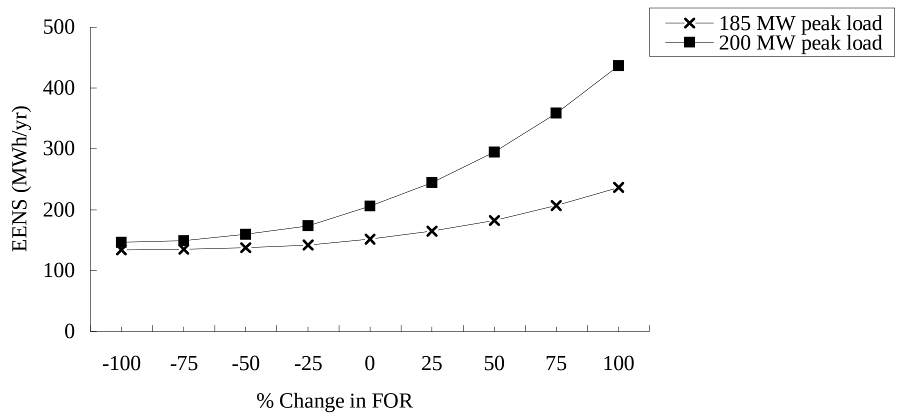


Figure 3.11: System EENS for the RBTS as a function of the unit FOR

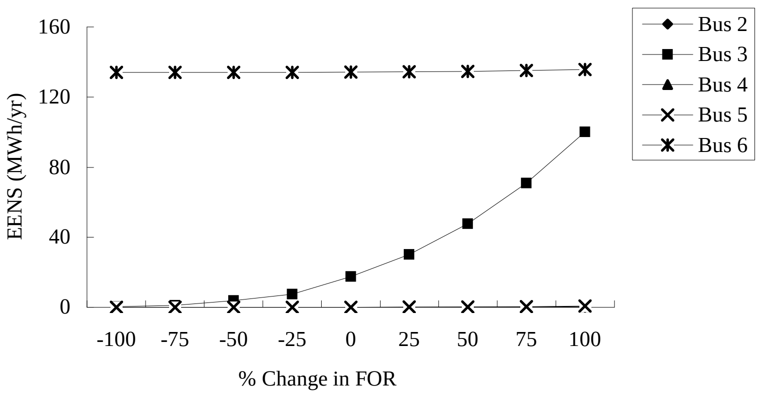


Figure 3.12: Load point EENS for the RBTS as a function of the unit FOR – 185 MW peak load

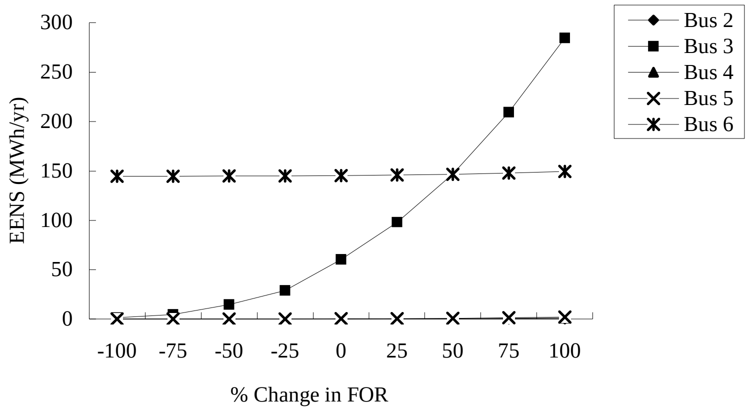


Figure 3.13: Load point EENS for the RBTS as a function of the unit FOR – 200 MW peak load

3.2.1.2 Varying generating unit FOR separately

As noted earlier, each generating unit could be owned by a different company in a deregulated system. The system reliability is sensitive to variations in the FOR of each individual unit. This is illustrated in Figure 3.14 which shows the system EENS as a function of the individual unit FOR for the 185 MW peak load condition. The six cases shown in Figure 3.14 are as follows.

Case A – The FOR of one 40 MW unit at Bus 1 is varied

Case B – The FOR of one 20 MW unit at Bus 1 is varied

Case C – The FOR of one 10 MW unit at Bus 1 is varied

Case D – The FOR of one 40 MW unit at Bus 2 is varied

Case E – The FOR of one 20 MW unit at Bus 2 is varied

Case F – The FOR of one 5 MW unit at Bus 2 is varied

The system and load point EENS for each case at peak loads of 185 MW and 200 MW are shown in Tables B.6 to B.9. Figure 3.14 shows that the system EENS is influenced more by variations in the larger unit FOR than in smaller unit variations. This effect is enhanced at the peak load level of 200 MW as shown in Figure 3.15. Figure 3.16 shows the variation in the EENS at Bus 3 for the six cases. Bus 3 has the lowest priority in the system curtailment order, and the EENS characteristics at Bus 3 for the six cases are very similar in form to those shown for the system in Figure 3.14. The variations in the EENS index are much smaller at Bus 6, as shown in Figure 3.17. Table

B.7 shows that the EENS at load points 2, 4 and 5 are very small for the load curtailment priority order given in Table 2.2. The variations in the EENS at these load points with generating unit FOR variations are negligible.

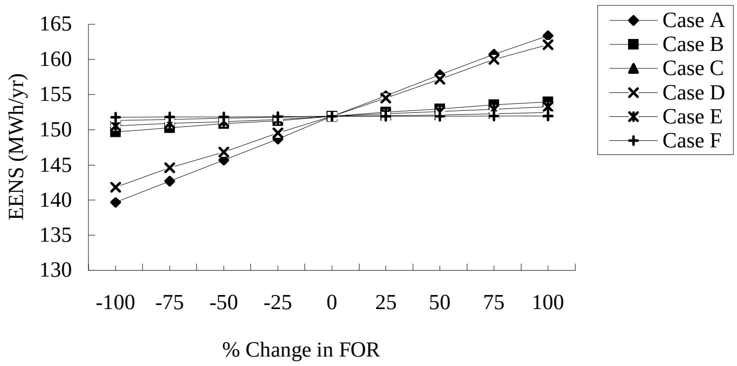


Figure 3.14: System EENS for the RBTS (185 MW peak load) as a function of the unit FOR – Six cases

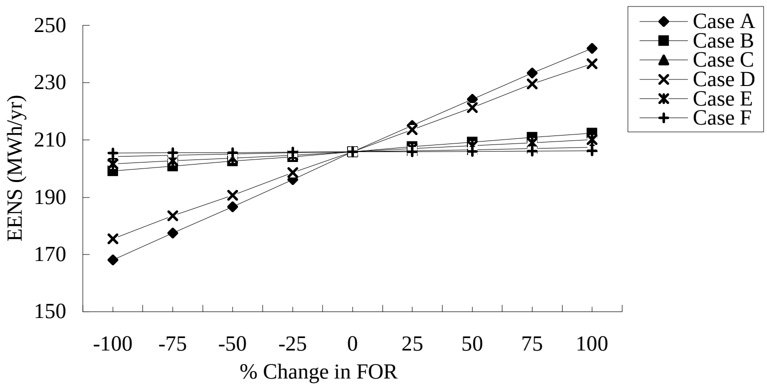


Figure 3.15: System EENS for the RBTS (200 MW peak load) as a function of the unit FOR – Six cases

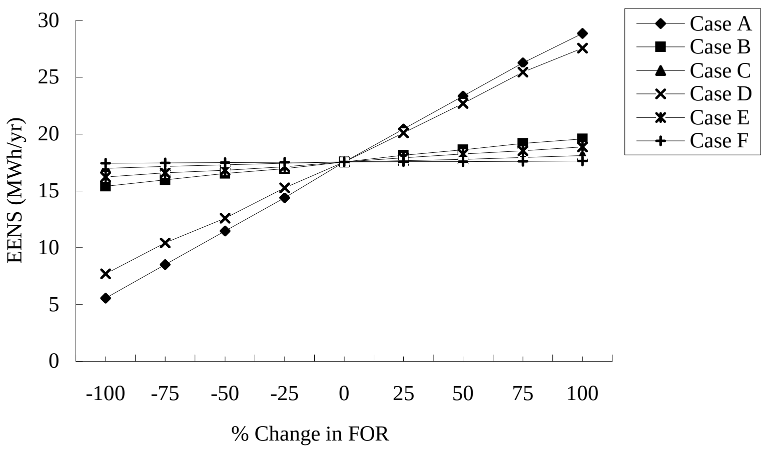


Figure 3.16: Bus 3 EENS for the RBTS as a function of the unit FOR – Six cases (185 MW peak load)

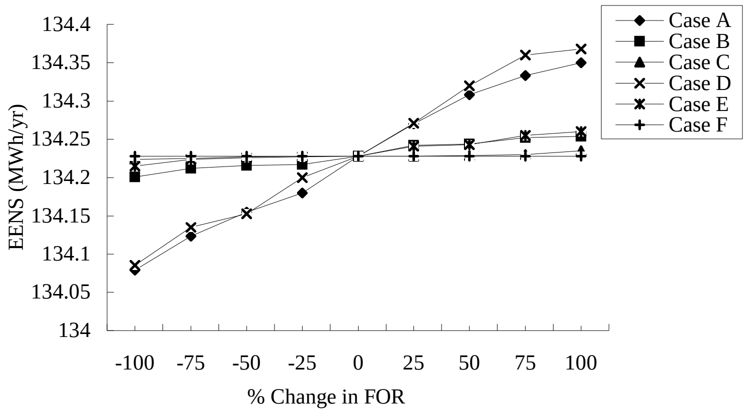


Figure 3.17: Bus 6 EENS for the RBTS as a function of the unit FOR – Six cases (185 MW peak load)

3.2.1.3 Varying generating station FOR separately

In a deregulated environment, it is possible for a company to own a group of units in a particular system. It was assumed that Company A owns all the units at Bus 1 and Company B owns those at Bus 2. The FOR at a station could be influenced by the company philosophy regarding preventive maintenance. Figures 3.18 and 3.19 show the EENS of the system and for Bus 3 for variations in the individual station FOR for the two cases of 185 MW and 200 MW peak load. It can be seen from Figures 3.18 and 3.19 that the EENS of system and Bus 3 are influenced more by variations in the Bus 1 unit FOR than in the Bus 2 unit variations. This effect is enhanced at the peak load level of 200 MW. The variations in the EENS at other load points with generating unit FOR variations are very small and are negligible. The corresponding data are given in Tables B.10 and B.11.

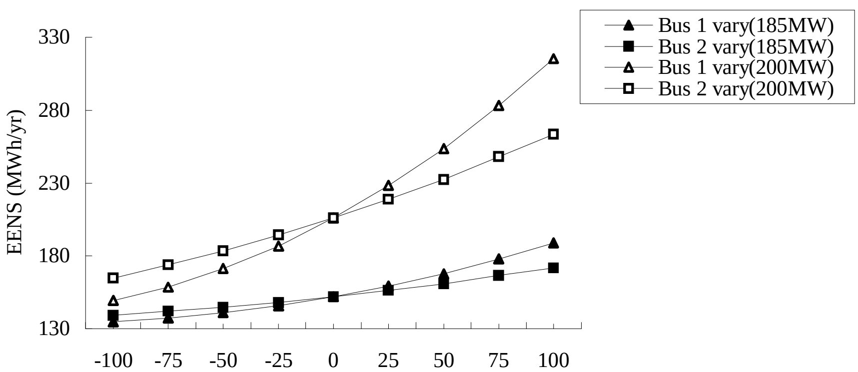


Figure 3.18: System EENS for the RBTS as a function of the generating station FOR

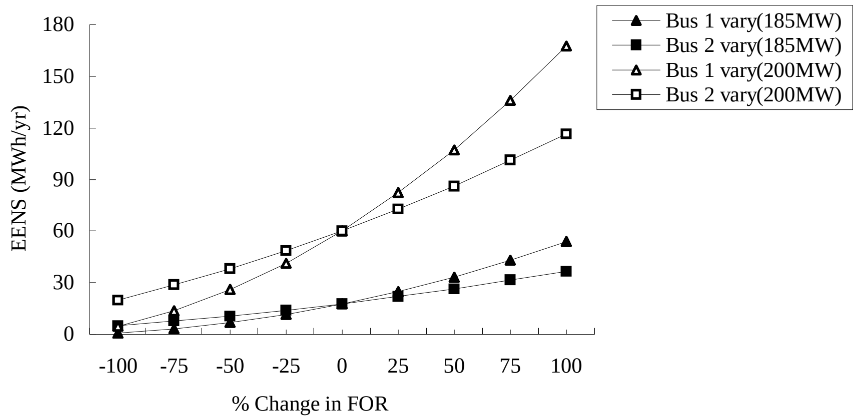


Figure 3.19: Bus 3 EENS for the RBTS as a function of the generating station FOR

3.2.2 Reliability as a function of transmission line unavailability

The objective of this study is to examine load point and system reliability performance due to variations in transmission line unavailability. The following cases were studied:

(a) Varying the unavailability of all transmission lines.

(b) Varying the unavailability of individual transmission lines.

3.2.2.1 Varying the unavailability of all transmission lines

Variation in the system and load point EENS as a function of line unavailability is shown pictorially in Figure 3.20.

Figure 3.20 shows the variations in the system and bus EENS as a function of the transmission line unavailabilities. All the line unavailabilities are changed by the percentage shown. The system and load point EENS values are given in Table B.12. Table 2.6 shows that the bulk of the system EENS comes from the Bus 6 value. This is due to the single line connection to this bus. Figure 3.20 shows that the EENS at this bus and for the system are very sensitive to transmission line unavailability variations. The results of further studies show that these sensitivities are basically due to the unavailability variations in Line 9 and variations in the other line unavailabilities over the range considered have relatively little effect.

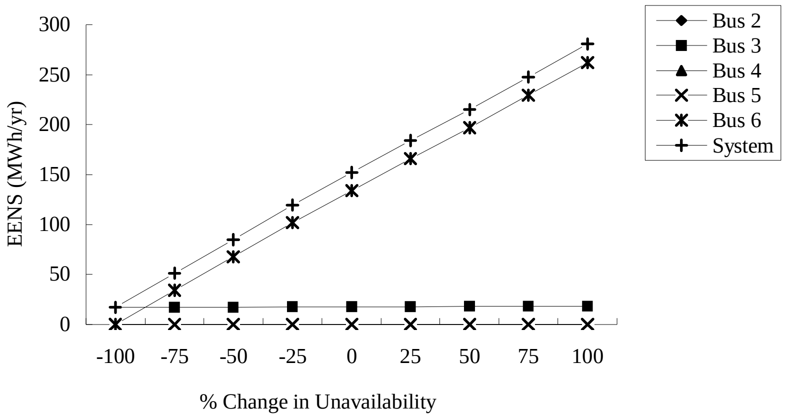


Figure 3.20: System and load point EENS with variations in the transmission line unavailabilities

3.2.2.2 Varying the transmission line unavailability separately

Figure 3.21 shows the system EENS for individual line unavailability variations. The details of the seven cases in Figure 3.21 are as follows.

Case A –The unavailabilities of Line 1 and Line 6 are varied

Case B – The unavailabilities of Line 2 and Line 7 are varied

Case C – The unavailability of Line 3 is varied

Case D – The unavailability of Line 4 is varied

Case E – The unavailability of Line 5 is varied

Case F – The unavailability of Line 8 is varied

Case G – The unavailability of Line 9 is varied

The system and load point EENS of each case with variations in line unavailability are given in Tables B.13 and B.14. Figure 3.21 shows that the system EENS is not significantly influenced by line unavailabilities other than that of Line 9. This is further illustrated in Figure 3.22 for Bus 6.

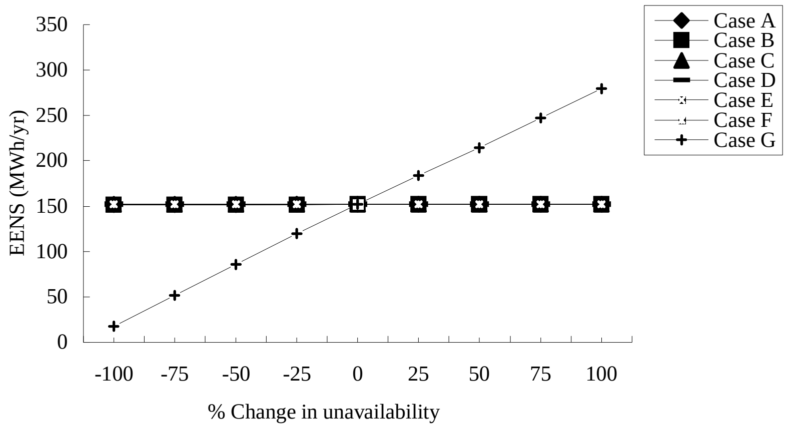


Figure 3.21: System EENS as a function of individual line unavailability variations – Seven cases

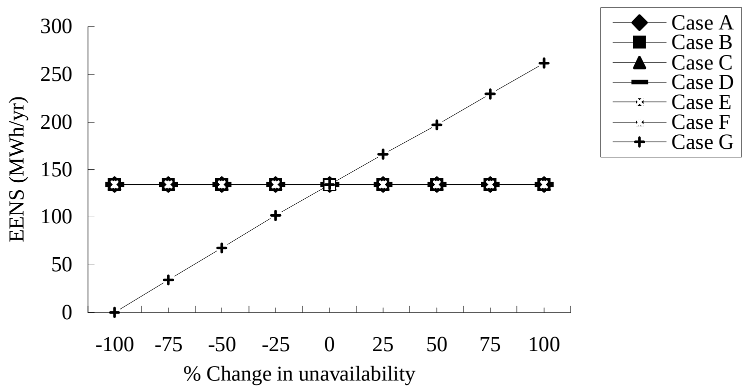


Figure 3.22: Bus 6 EENS as a function of individual line unavailabilities – Seven cases

The topology of the RBTS together with the load curtailment philosophy play a major role in the variations in the system and load point EENS due to changes in the generating unit and transmission line unavailabilities. The most sensitive load point to generating unit FOR variations is Bus 3. The indices at Bus 6 are dominated by the reliability of Line 9 and are relatively insensitive to generating unit FOR variations. The following section shows the results of a series of studies on the IEEE-RTS. This system does not have the designed-in weaknesses of the RBTS and reacts quite differently to element unavailability variations.

3.3 Sensitivity analysis of the IEEE-RTS

The single line diagram of the IEEE-RTS is shown in Figure 2.3. The base case annual reliability indices for a peak load of 2850 MW are shown in Tables 2.9 and 2.10. As mentioned earlier, the IEEE-RTS is relatively large compared to the RBTS. It is not necessary to examine the indices of all the load points as a function of component FOR. Attention can be focused on the least reliable buses, i.e., Buses 19, 9, 15, and 14, as shown in the IEEE-RTS base case studies presented in Chapter 2. These four least reliable buses have significant impact on the system indices and can be used as indicators of load point adequacy. Attention should be concentrated on the larger generating units when examining the impacts of individual unit FOR on the adequacy indices.

3.3.1 Reliability as a function of generating unit FOR

The following cases were studied:

(a) Varying FOR of all generating units.

(b) Varying the large generating unit FOR separately.

3.3.1.1 Varying FOR of all generating units

The FOR of all the units in the IEEE-RTS was assumed to vary from –100% to +100% of the base case values. The numerical values of the system and load points EENS are given in Table B.15. Figure 3.23 shows the system and selected load point EENS as a function of the generating unit FOR. All the unit FOR are changed by the percentage shown. It can be seen from Figure 3.23 that the system and selected load point indices are very sensitive to the variations in generating unit FOR. It is obvious that reinforcement in generation or improvement of generator reliability can effectively increase the reliability of the IEEE-RTS.

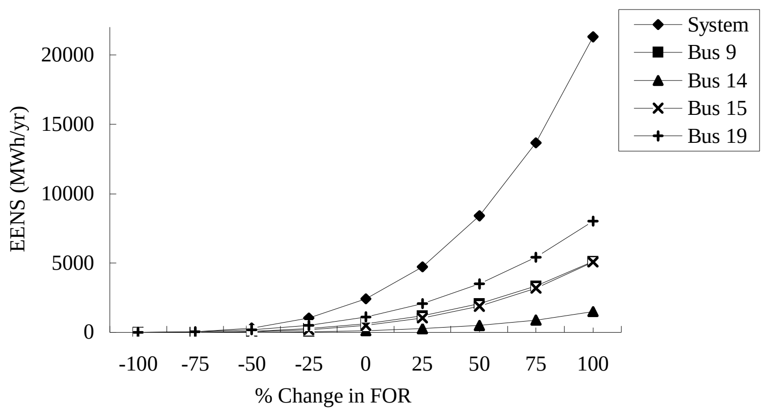


Figure 3.23: System and load point EENS for the IEEE-RTS as a function of the unit FOR

3.3.1.2 Varying the large generating unit FOR separately

The cases studied are as follows:

Case A – The FOR of the 400 MW unit at Bus 18 is varied.

Case B – The FOR of the 400 MW unit at Bus 21 is varied.

Case C – The FOR of the 350 MW unit at Bus 23 is varied.

Case D – The FOR of one 197 MW unit at Bus 13 is varied.

The EENS for the system and the four load points in each case are given in Table B.16 and are shown pictorially in Figures 3.24 to 3.27.

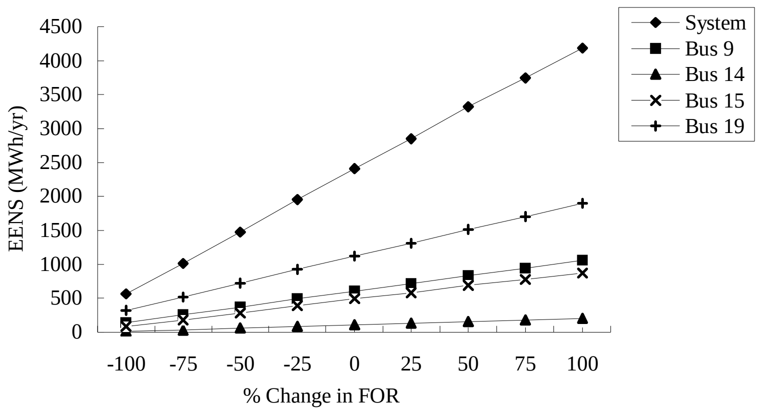


Figure 3.24: System and load point EENS as a function of the FOR of the 400 MW unit at Bus 18

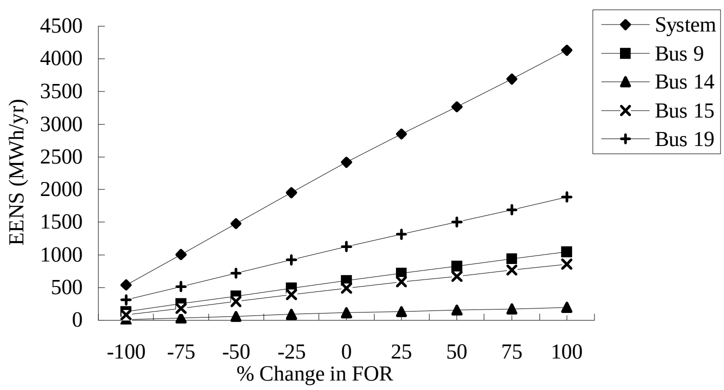


Figure 3.25: System and load point EENS as a function of the FOR of the 400 MW unit at Bus 23

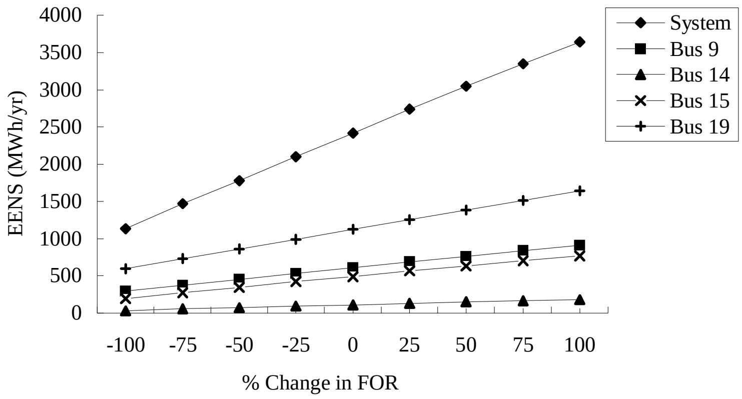


Figure 3.26: System and load point EENS as a function of the FOR of the 350 MW unit at Bus 21

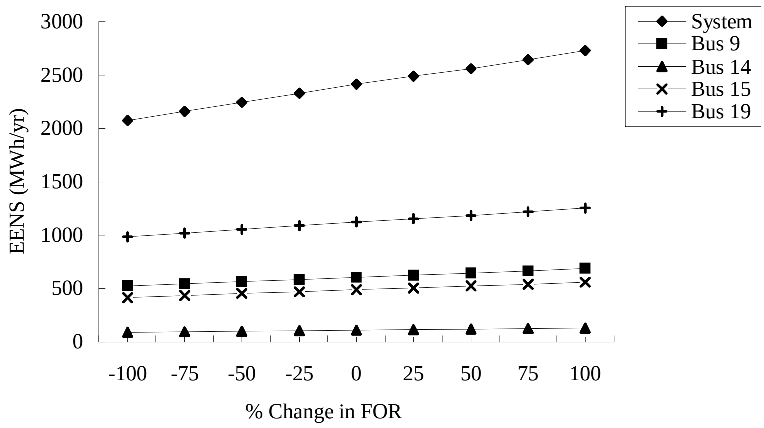


Figure 3.27: System and load point EENS as a function of the FOR of the 197 MW unit at Bus 13

Figure 3.24 shows the EENS values as a function of the FOR of the 400 MW unit at Bus 18. Similar changes occur with FOR variations of the 400 MW unit at Bus 23 and the 350 MW unit at Bus 21, which are shown in Figures 3.25 and 3.26 respectively. Figure 3.27 shows the EENS sensitivity to variations in the FOR of the 197 MW unit at Bus 13. It can be seen from Figures 3.24 to 3.27 that different load points have different sensitivities to the individual generator FOR. The most sensitive load point is Bus 19, followed by Bus 9, Bus 15, and Bus 14. This is mainly determined by the load curtailment philosophy and the actual load at each bus.

The system EENS as a function of FOR variations for the individual unit cases are shown in Figure 3.28. The EENS at Bus 19 is shown in Figure 3.29 for the same conditions. The EENS profiles at Buses 9, 15 and 14 are similar to those shown in Figure 3.29. Figures 3.28 and 3.29 indicate that the larger units contribute more to the system and load point indices.

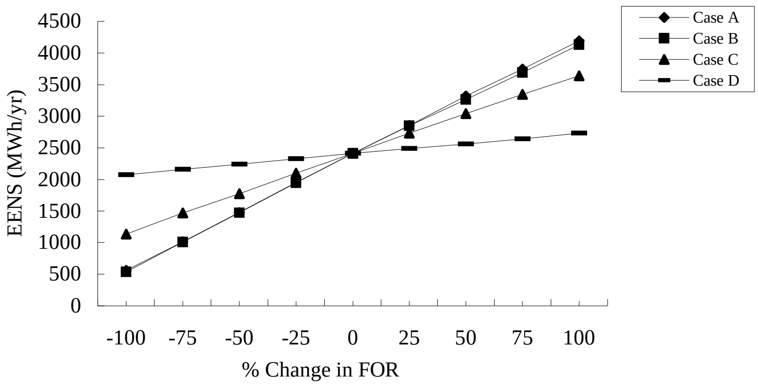


Figure 3.28: System EENS as a function of unit FOR in each case

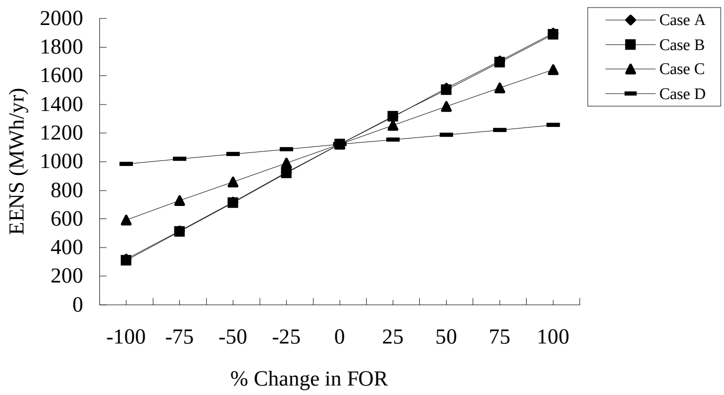


Figure 3.29: EENS at Bus 19 as a function of unit FOR in each case

3.3.2 Reliability as a function of transmission line unavailabilities

The IEEE-RTS has a strong transmission system and therefore the system and load point indices are relatively immune to variations in the transmission line unavailabilities. This is quite different from the RBTS, which has a designed-in weakness at Bus 6. The system and selected bus EENS values as a function of the line unavailabilities are shown in Figure 3.30. The corresponding data are given in Table B17. It can be seen from this figure that transmission line unavailabilities have virtually no impact on the system and load point indices even when the line unavailabilities increase to ten times the original values.

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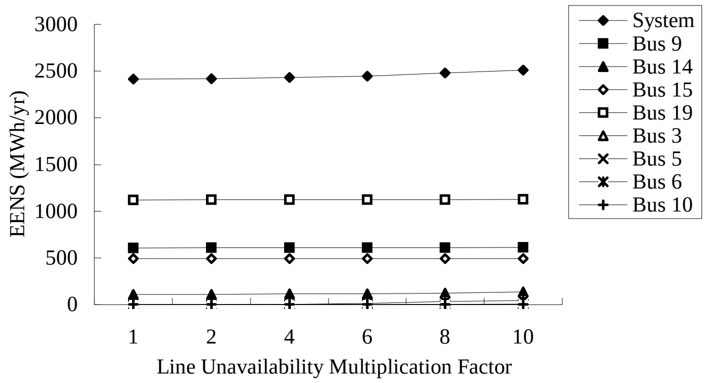

Figure 3.30: System and bus EENS for the IEEE-RTS as a function of the line unavailabilities

3.3.3 Reliability as a function of transmission line unavailabilities for the modified IEEE-RTS (MRTS)

In order to stress the transmission network, the number of generating units in the original IEEE-RTS and the annual load profile were increased by a factor of two with the transmission system unchanged. The total capacity of the modified IEEE-RTS (MRTS) is 6810 MW with a peak load of 5700 MW. Figure 3.31 presents the system and selected bus EENS with variation in the line unavailabilities. Figure 3.32 uses a different scale in order to enlarge Figure 3.31. The corresponding data are given in Table B18.

Figures 3.31 and 3.32 show that the system EENS is now much more sensitive to variation in the line unavailabilities. This is also true for most load points except Buses 15 and 19, which are dominated by generation failures. The EENS at some load points, such as Bus 6 and Bus 14, are sensitive to both generating unit and transmission line unavailabilities. This knowledge is valuable in the decision-making process concerning reinforcement and maintenance planning.

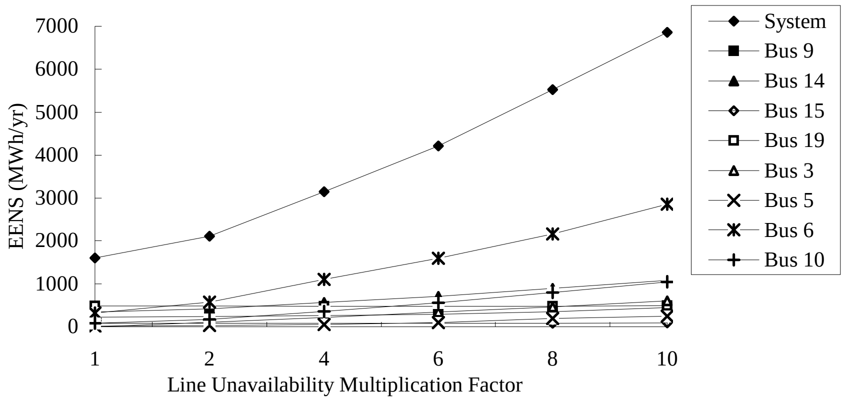

Figure 3.31: Selected load point EENS for the MRTS as a function of line unavailabilities

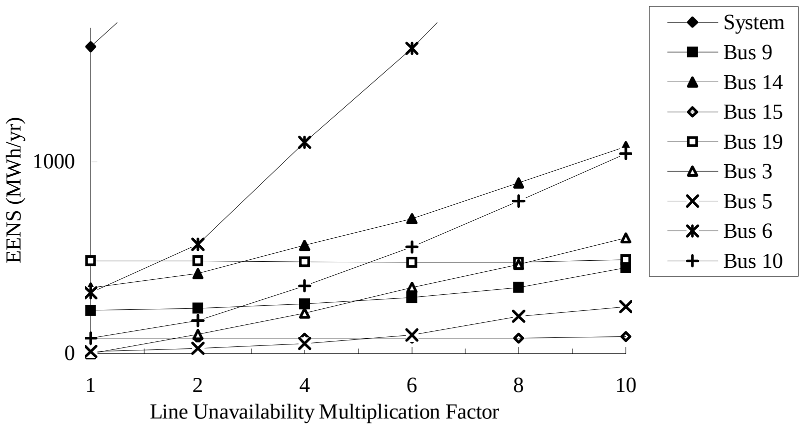

Figure 3.32: Different scale of Figure 3.31

Increasing the size of the IEEE-RTS to create the MRTS reflects a situation that is becoming common in North America. Relatively little transmission is being built or proposed in the near future. Under these circumstances, reliability will degrade as load grows and additional generation is added. The implications of increased line unavailabilities are clearly enhanced under these conditions.

3.4 Conclusions

The effect of equipment availability on the load point and system reliability of two test systems is analyzed using a Monte Carlo simulation approach in this study. The results show that the unavailabilities of specific generation and transmission facilities have major impacts on the load point and system reliabilities. These impacts are not uniform throughout the system and are highly dependent on the load curtailment philosophy and the overall system topology. The system and load point indices are influenced more by variations in the FOR of the larger generating units than in smaller unit variations. Transmission line unavailabilities usually have more local impacts. The indices at some load points are highly influenced by generating unit FOR, while some load points are very sensitive to both generating unit and transmission line unavailabilities, and some buses are influenced only by line unavailabilities. This knowledge is valuable in the decision-making process concerning reinforcement and maintenance planning.

In a deregulated environment, it is possible for a company to own a group of units in a particular system. The company philosophy regarding preventive maintenance will influence the FOR of the units in a station and therefore will impact the system reliability. It is important to analyze this impact.

The topology of the RBTS together with the load curtailment philosophy play a major role in the variations in the system and load point EENS due to changes in the generating unit and transmission line unavailabilities. The most sensitive load point to generating unit FOR variations is at Bus 3. The indices at Bus 6 are dominated by the reliability of Line 9 and are relatively insensitive to generating unit FOR variations.

The IEEE-RTS is relatively large compared to the RBTS. This system does not have the designed-in weaknesses of the RBTS and reacts quite differently to element unavailability variations. The IEEE-RTS has a strong transmission system and therefore the system and load point indices are relatively immune to variations in the transmission line unavailabilities even if the line unavailabilities increase to ten times their original values.

Increasing the size of the IEEE-RTS to create the MRTS reflects a situation that is becoming common in North America. Relatively little transmission is being built or proposed in the near future. Under these circumstances, reliability will degrade as load grows and additional generation is added. The implications of increased line unavailabilities are clearly enhanced under these conditions.

This study also illustrates the importance of collecting and utilizing generating unit and transmission line unavailability data in the evaluation of bulk system reliability. The considerations presented in this thesis are equally important in both vertically integrated and deregulated utility systems.

4. DETERMINISTIC AND PROBABILISTIC CRITERIA

4.1 Introduction

Power system behavior is stochastic in nature, and therefore it is logical to consider that the analysis of such systems should be based on probabilistic techniques. It is a fact, however, that most of the present planning, design, and operating criteria are based on deterministic techniques which have been utilized by utilities for decades. Although deterministic criteria are developed to account for randomly occurring failures, they are inherently rigid. Their essential weakness is that they do not and cannot recognize the probabilistic or stochastic nature of system behavior, of customer demands, or of component failures [12]. Typical deterministic criteria are as follows [12].

(a) Planning generating capacity — the installed capacity equals the expected maximum demand plus a fixed percentage of the expected maximum demand or the system should be able to withstand the loss of the largest unit.

(b) Operating capacity — the spinning capacity equals the expected load demand plus a reserve equal to one or more of the largest units.

(c) Planning network capacity — construct a minimum number of circuits to a load point such that the system can withstand the loss of any one circuit. This is known as the (n-1) criterion.

In a composite power system, the most usual deterministic criterion is the (n-1) criterion in which the system should be able to withstand the removal of any single component. This is obviously a worst-case criterion. If the system can withstand the worst case, it can withstand the rest, but it does not consider multiple events.

The NERC Planning Standards [3] describe the following system performance requirements following the loss of a single bulk system component.

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

The transmission systems also shall be capable of accommodating planned bulk electric equipment maintenance outages and continuing to operate within thermal, voltage, and stability limits under the conditions specified**.**

Planned or controlled interruption of generators or electric supply to radial customers or some local network customers connected to or supplied by a faulted component or by the affected area, may occur in certain areas without impacting the overall security of the interconnected transmission systems. In order to prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserve) electric power transfers.

Here, the component means a generator, a transmission circuit, a bulk system transformer, or a single pole (dc) line.

It is clear that according to the NERC Planning Standards it is impossible to know how often and how long the interruption of power supply to each load point per year will be. How much demand will not be supplied per year? What is the worst case? Many other concerns exist from a reliability point of view. Which index or indices should be utilized and what risk level should be accepted for the system and for each load point? Do all indices rank the transmission lines and generators in the same order? Is the worst case from a system viewpoint the same as that from an individual bus viewpoint for a specific system? These are important questions which can be answered using probabilistic techniques. This chapter describes a series of studies on the two test systems that illustrate the rigidity of deterministic criteria and how probabilistic techniques can be used to assess the variable risks associated with the removal from service of generation and transmission system elements.

4.2 RBTS studies

The RBTS is a relatively small system and therefore there are only a relatively small number of components that need to be considered. This is not the case in a large composite system. Chapter 3 shows the dominance of the 40 MW units on the system risk and therefore only the 40 MW generating units were considered for removal. This is also in accordance with the common deterministic approach known as the “loss of the largest unit” criterion. All the transmission lines with the exception of Line 9 were considered for removal. Removing Line 9 was not considered due to the fact that its removal will isolate Bus 6. The following cases were therefore considered.

G-1 – the removal of one 40 MW unit at Bus 1

G-2 – the removal of one 40 MW unit at Bus 2

L1 – the removal of Line 1

L2 – the removal of Line 2

L3 – the removal of Line 3

L4 – the removal of Line 4

L5 – the removal of Line 5

L8 – the removal of Line 8

4.2.1 RBTS ranking analysis

As shown in Chapter 2, there is a wide range of possible system and load point indices that can be used to measure the risk in a bulk power system. The probability of load curtailment (PLC), the expected number of load curtailments (ENLC), and the expected energy not supplied (EENS) are utilized in this section. The following studies are all based on the parameters and conditions in the base case studies.

The annualized and annual system indices of the RBTS for each case are listed in Table 4.1. Corresponding indices which only include transmission outages, i.e. all generators are assumed to be fully reliable, are also given in Table 4.1 in order to see which line has the largest impact on the system indices from a purely transmission point of view. This provides important transmission system planning information especially in a deregulated environment. In this case there may be no overall composite system planning as the generating units may have different owners. The transmission system may have different owners but is operated by an independent system operator (ISO) who is responsible for proposing transmission network reinforcements.

The indices in Table 4.1 can be normalized using the base case values for each outage condition for the convenience of comparison. The per-unit indices are called Impact Indices (II) in this research, and are shown in Table 4.2. Table 4.3 shows the rankings of the cases based on the calculated Impact Indices.

Table 4.1: System indices of the RBTS for selected outages

Outage	Case	Annualized			Annual		
		PLC	ENLC (1/yr)	EENS (MWh/yr)	PLC	ENLC (1/yr)	EENS (MWh/yr)
G&T	Base case	.00989	5.25586	1070.14	.00138	1.27965	152.350
	G-1	.12845	34.17316	16169.4	.00500	2.36763	529.208
	G-2	.14017	40.69109	19019.6	.00596	2.89941	628.040
	L1	.09276	33.53828	9237.32	.00317	2.21870	224.892
	L2	.01375	9.01105	1735.33	.00154	1.46346	160.946
	L3	.01047	5.88119	1197.77	.00135	1.26703	149.960
	L4	.00992	5.32655	1065.70	.00131	1.21978	143.819
	L5	.01099	6.36140	1456.57	.00245	2.34380	401.709
	L8	.01103	6.38679	1471.29	.00246	2.35491	402.414
T	Base case	.00125	1.18580	219.142	.00120	1.09937	134.894
	L1	.01426	12.8798	2293.40	.00181	1.68658	160.680
	L2	.00466	4.24481	749.675	.00132	1.22363	137.438
	L3	.00120	1.15824	215.197	.00113	1.04060	127.754
	L4	.00122	1.19978	210.589	.00113	1.03925	126.311
	L5	.00237	2.24209	611.855	.00228	2.08506	384.332
	L8	.00234	2.18659	613.096	.00228	2.09008	384.808

Table 4.2: System Impact Indices (II) of the RBTS for selected outages

Outage	Case	Annualized			Annual		
		PLC	ENLC	EENS	PLC	ENLC	EENS
G&T	Base case	1	1	1	1	1	1
	G-1	12.988	6.502	15.120	3.623	1.850	3.474
	G-2	14.173	7.742	17.773	4.319	2.266	4.122
	L1	9.379	6.381	8.632	2.297	1.734	1.476
	L2	1.390	1.714	1.622	1.116	1.144	1.056
	L3	1.059	1.119	1.119	0.978	0.990	0.984
	L4	1.003	1.013	0.996	0.949	0.953	0.944
	L5	1.111	1.210	1.361	1.775	1.832	2.637
	L8	1.115	1.215	1.375	1.783	1.840	2.641
T	Base case	1	1	1	1	1	1
	L1	11.408	10.862	10.465	1.508	1.534	1.191
	L2	3.728	3.580	3.421	1.100	1.113	1.019
	L3	0.960	0.977	0.982	0.942	0.947	0.947
	L4	0.976	1.012	0.961	0.942	0.945	0.936
	L5	1.896	1.891	2.792	1.900	1.897	2.849
	L8	1.872	1.844	2.780	1.900	1.901	2.853

It can be seen from Table 4.3, when considering both generation and transmission outages, that the worst case from a system perspective is G-2, i.e. removing one 40MW unit at Bus 2. This applies to both the annualized and annual indices. The individual system indices (PLC, ENLC and EENS) do not always result in the same rank order. These are also major differences in the rank orders due to considering annualized and annual indices.

Table 4.3: Ranked system Impact Indices of the RBTS

Outage	Rank Order	Annualized			Annual		
		PLC	ENLC	EENS	PLC	ENLC	EENS
G&T	1	G-2	G-2	G-2	G-2	G-2	G-2
	2	G-1	G-1	G-1	G-1	G-1	G-1
	3	L1	L1	L1	L1	L8	L8
	4	L2	L2	L2	L8	L5	L5
	5	L8	L8	L8	L5	L1	L1
	6	L5	L5	L5	L2	L2	L2
	7	L3	L3	L3	L3	L3	L3
	8	L4	L4	L4	L4	L4	L4
T	1	L1	L1	L1	L8	L8	L8
	2	L2	L2	L2	L5	L5	L5
	3	L5	L5	L5	L1	L1	L1
	4	L8	L8	L8	L2	L2	L2
	5	L4	L4	L3	L3	L3	L3
	6	L3	L3	L4	L4	L4	L4

Similar conclusions can be drawn when considering only transmission outages. In this case, the worst cases are L1 using the annualized Impact Indices and L8 using the annual values.

The annualized and annual load point Impact Indices of the RBTS are given in Tables C.1 to C.5 and corresponding rankings are given in Tables 4.4 to 4.8.

It can be seen from Table 4.4 that the worst case for Bus 2 is G-2, i.e. removing one 40MW unit at Bus 2. This applies to both the annualized and annual values. Transmission failures have no impact on Bus 2 due to the fact that this bus is also a generating bus.

Table 4.4: Ranked Bus 2 Impact Indices

Outage	Rank Order	Annualized			Annual		
		PLC	ENLC	EENS	PLC	ENLC	EENS
G&T	1	G-2	G-2	G-2	-	G-2	G-2
	2	G-1	G-1	G-1	-	G-1	G-1
	3	-	L1*	L1**	-	-	-
	4	-	L3*	L3**	-	-	-
	5	-	L4*	L4**	-	-	-
	6	-	L5*	L5**	-	-	-
	7	-	L8*	L8**	-	-	-
	8	-	L2	L2**	-	-	-
T	1	-	-	-	-	-	-
	2	-	-	-	-	-	-
	3	-	-	-	-	-	-
	4	-	-	-	-	-	-
	5	-	-	-	-	-	-
	6	-	-	-	-	-	-

- The index values of these cases are effectively zero.
* These five cases have the same values.
** These six cases have the same values.

Table 4.5 shows that the worst case for Bus 3 is also G-2 and almost all the Impact Indices rank the cases in the same order. The biggest transmission system effect on Bus 3 is removing line 1. Bus 3 has the largest system load with the lowest priority order and Line 1 connects Bus 3 directly to a generator bus.

Table 4.5: Ranked Bus 3 Impact Indices

Outage	Rank Order	Annualized			Annual		
		PLC	ENLC	EENS	PLC	ENLC	EENS
G&T	1	G-2	G-2	G-2	G-2	G-2	G-2
	2	G-1	G-1	G-1	G-1	G-1	G-1
	3	L1	L1	L1	L1	L1	L1
	4	L2	L2	L2	L2	L2	L2
	5	L3	L3	L3	L3	L3	L3
	6	L4	L4	L8	L8	L8	L8
	7	L8	L8	L4	L4	L4	L4
	8	L5	L5	L5	L5	L5	L5
T	1	L1	L1	L1	L1	L1	L1
	2	L2	L2	L2	L2	L2	L2
	3	L3	L3	L3	L3	L3	L3
	4	L8	L8	L8	L8	L8	L8
	5	L4	L4	L4	L4	L4	L4
	6	L5	L5	L5	L5	L5	L5

Table 4.6 shows the rankings for Bus 4. The rankings of the three annualized Impact Indices are exactly the same. This is not the case for the annual values. The worst cases are G-2 for the annualized Impact Indices and L1 for the annual Impact Indices when generation and transmission outages are considered. L1 is the worst case for all the indices for T outage only.

Table 4.6: Ranked Bus 4 Impact Indices

Outage	Rank Order	Annualized			Annual		
		PLC	ENLC	EENS	PLC	ENLC	EENS
G&T	1	G-2	G-2	G-2	L1	L1	L1
	2	G-1	G-1	G-1	L2	L2	G-2
	3	L1	L1	L1	G-2	G-2	G-1
	4	L2	L2	L2	G-1	G-1	L2
	5	L3	L3	L3	L3	L3	L3
	6	L4	L4	L4	L4	L4	L4
	7	L5	L5	L5	L5	L5	L5
	8	L8	L8	L8	L8	L8	L8
T	1	L1	L1	L1	L1	L1	L1
	2	L2	L2	L2	L2	L2	L2
	3	L4	L4	L4	L4	L4	L4
	4	L5	L5	L5	L5	L5	L5
	5	L8	L8	L8	L8	L8	L8
	6	L3	L3	L3	L3	L3	L3

Table 4.7 shows that the worst case for Bus 5 is L8. Table C.4 shows that L5 has nearly the same impact on Bus 5 for both conditions. When considering generation and transmission outages, almost all the Impact Indices rank the cases in the same order. The annual Impact ENLC is an exception. All the Impact Indices rank the cases in exactly the same order for T outages only.

Table 4.7: Ranked Bus 5 Impact Indices

Outage	Rank Order	Annualized			Annual		
		PLC	ENLC	EENS	PLC	ENLC	EENS
G&T	1	L8	L8	L8	L8	L8	L8
	2	L5	L5	L5	L5	L5	L5
	3	G-2	G-2	G-2	G-2	L1	G-2
	4	G-1	G-1	G-1	G-1	G-2	G-1
	5	L1	L1	L1	L1	L2	L1
	6	L2	L2	L2	L2	G-1	L2
	7	L3	L3	L3	L3	L3	L3

Table 4.7: (Continued)

Outage	Rank Order	Annualized			Annual		
		PLC	ENLC	EENS	PLC	ENLC	EENS
G&T	8	L4	L4	L4	L4	L4	L4
T	1	L8	L8	L8	L8	L8	L8
	2	L5	L5	L5	L5	L5	L5
	3	L1	L1	L1	L1	L1	L1
	4	L2	L2	L2	L2	L2	L2
	5	L3	L3	L3	L3	L3	L3
	6	L4	L4	L4	L4	L4	L4

Table 4.8 shows that the worst case for Bus 6 is L5 using the annual Impact Indices and annualized Impact EENS. The annualized Impact PLC or ENLC shows that the worst case is G-2, while for T outages only, all the Impact Indices rank the cases in the exactly same order and the worst case is L5.

Table 4.8: Ranked Bus 6 Impact Indices

Outage	Rank Order	Annualized			Annual		
		PLC	ENLC	EENS	PLC	ENLC	EENS
G&T	1	G-2	G-2	L5	L5	L5	L5
	2	G-1	G-1	L8	L8	L8	L8
	3	L5	L5	G-2	G-2	G-2	G-2
	4	L8	L8	G-1	G-1	L1	G-1
	5	L2	L2	L2	L1	G-1	L1
	6	L1	L1	L1	L2	L2	L2
	7	L3	L4	L3	L3	L4	L3
	8	L4	L3	L4	L4	L3	L4
T	1	L5	L5	L5	L5	L5	L5
	2	L8	L8	L8	L8	L8	L8
	3	L1	L1	L1	L1	L1	L1
	4	L2	L2	L2	L2	L2	L2
	5	L4	L4	L4	L4	L4	L4
	6	L3	L3	L3	L3	L3	L3

The worst cases from the system and individual bus points of view for each Impact Index are shown in Table 4.9. It can be seen from Table 4.9 that from a system point of view, the worst cases are identical for all the Impact Indices when considering G and T outages. This is also true for Buses 2, 3, and 5. The worst cases for Buses 4 and 6 are different for different Impact Indices. The worst cases at each bus for different Impact Index for T outages only are the same, but for the system the worst cases are different for the different Impact Indices. As a general conclusion, the worst case for the system may not be the worst for each bus, the worst case for one bus may not be the same for others, and the worst case for one index may not be the worst case for another index.

Table 4.9: The worst cases for system and each bus on different Impact Indices

Outage	System or Bus	Annualized			Annual		
		PLC	ENLC	EENS	PLC	ENLC	EENS
G&T	System	G-2	G-2	G-2	G-2	G-2	G-2
	Bus 2	G-2	G-2	G-2	G-2	G-2	G-2
	Bus 3	G-2	G-2	G-2	G-2	G-2	G-2
	Bus 4	G-2	G-2	G-2	L1	L1	L1
	Bus 5	L8	L8	L8	L8	L8	L8
	Bus 6	G-2	G-2	L5	L5	L5	L5
T	System	L1	L1	L1	L5	L8	L8
	Bus 2	N/A	N/A	N/A	N/A	N/A	N/A
	Bus 3	L1	L1	L1	L1	L1	L1
	Bus 4	L1	L1	L1	L1	L1	L1
	Bus 5	L8	L8	L8	L8	L8	L8
	Bus 6	L5	L5	L5	L5	L5	L5

Note: L5 and L8 have basically the same impact on Bus 5 and on Bus 6.

Some conclusions can be drawn based on the analyses conducted.

The utilization of a probabilistic approach to contingency assessment indicates not only which situation is the worst for the system and for each load point, but also the actual impact of each contingency. These results are valuable in system planning and maintenance assessment and cannot be determined by means of deterministic or “rule-of-thumb” techniques.

All contingencies do not have the same impact on the individual load point indices that they have on the system indices.

Different indices can result in different rankings. The selection of the index therefore is important.

The worst contingency for a particular bus may not be the worst case for the system, and the worst case for one bus may not be the worst case for other buses.

The load model used has an impact on the ranking. Ranking using an annualized index is usually different from that obtained using an annual index.

It is worth noting that not all the buses in the RBTS have the same performance. Some buses, such as Bus 3, are dominated by generation. Removing one 40MW unit at

Bus 2 or one 40MW unit at Bus 1 has much more impact on Bus 3 than have other contingency cases. Bus 3 has the largest load and the lowest load curtailment priority. Some buses, such as Bus 5, are dominated by transmission. The removal of Line 5 or Line 8 results in a radial supply to Bus 5 and has a higher impact on Bus 5 than other cases. Some buses, such as Bus 6, are dominated by generation at high load levels or by transmission with all load levels. An appreciation of these impacts is valuable when making system planning and maintenance decisions.

4.2.2 Effects of the load curtailment priority order on contingency ranking

The priority order has a significant impact on the individual load point reliability indices, but has almost negligible effect on the system indices. The effect of the priority order on ranking is investigated in this section. A new priority order is given in Table 4.10 accompanied by the original order. The corresponding system and load point Impact Indices based on EENS are shown in Table C.6 and the related rankings are given in Table 4.11. A comparison of the rankings for the system and the load points for the original and new priority orders are shown in Table 4.12.

Table 4.10: Load curtailment priority order

Priority order	New	Original
1	Bus 2	Bus 2
2	Bus 3	Bus 4
3	Bus 5	Bus 5
4	Bus 6	Bus 6
5	Bus 4	Bus 3

Table 4.11: Ranked system and load point Impact Indices (EENS) with the new priority order

Outage	Ranking	System	Bus 2	Bus 3	Bus 4	Bus 5	Bus 6
G & T	1	G-2	G-2	L1	G-2	L8	L8
	2	G-1	G-1	G-2	G-1	L5	L5
	3	L8	-	G-1	L1	G-2	G-2
	4	L5	-	L2	L2	G-1	G-1
	5	L1	-	L4	L3	L1	L1
	6	L2	-	L3	L4	L2	L2
	7	L3	-	L5	L5	L3	L3
	8	L4	-	L8	L8	L4	L4

Table 4.11: (Continued)

Outage	Ranking	System	Bus 2	Bus 3	Bus 4	Bus 5	Bus 6
T	1	L8	-	L1	L1	L8	L8
	2	L5	-	L2	L2	L5	L5
	3	L1	-	L4	L3	L1	L1
	4	L2	-	L8	L5	L2	L2
	5	L3	-	L5	L4	L3	L3
	6	L4	-	L3	L8	L4	L4

- The index values for these cases are zero.

Table 4.12: A comparison of the ranking for the system and load points with the original and new priority orders

Outage	Rank Order	System		Bus 2		Bus 3	
		Ori.	New	Ori.	New	Ori.	New
G & T	1	G-2	G-2	G-2	G-2	G-2	L1
	2	G-1	G-1	G-1	G-1	G-1	G-2
	3	L8	L8	-	-	L1	G-1
	4	L5	L5	-	-	L2	L2
	5	L1	L1	-	-	L3	L4
	6	L2	L2	-	-	L8	L3
	7	L3	L3	-	-	L4	L5
	8	L4	L4	-	-	L5	L8
T	1	L8	L8	-	-	L1	L1
	2	L5	L5	-	-	L2	L2
	3	L1	L1	-	-	L3	L4
	4	L2	L2	-	-	L8	L8
	5	L3	L3	-	-	L4	L5
	6	L4	L4	-	-	L5	L3

Outage	Rank Order	Bus 4		Bus 5		Bus 6	
		Ori.	New	Ori.	New	Ori.	New
G & T	1	L1	G-2	L8	L8	L5	L8
	2	G-2	G-1	L5	L5	L8	L5
	3	G-1	L1	G-2	G-2	G-2	G-2
	4	L2	L2	G-1	G-1	G-1	G-1
	5	L3	L3	L1	L1	L1	L1
	6	L4	L4	L2	L2	L2	L2
	7	L5	L5	L3	L3	L3	L3
	8	L8	L8	L4	L4	L4	L4
T	1	L1	L1	L8	L8	L5	L8
	2	L2	L2	L5	L5	L8	L5
	3	L4	L3	L1	L1	L1	L1
	4	L5	L5	L2	L2	L2	L2
	5	L8	L4	L3	L3	L3	L3
	6	L3	L8	L4	L4	L4	L4

- The index values for these cases are zero.

It can be seen from Table 4.12 that changing the load curtailment priority order has no effect on the contingency ranking for the system Impact Index. The reason for this is that, as noted earlier, the priority order does not impact the system indices.

Similarly, the rankings for Bus 2 do not change with the new priority order due to the fact that this bus has the highest priority in both the new and original orders. This is not the case for the other buses.

The rankings for Bus 3 change considerably for both the G and T outage and T outage only conditions. L1 becomes the worst case for G and T outages. The impact of the priority order on the rankings is limited for T outages only and the worst two cases do not change. L4 ranks higher for both G and T outage and T outage only conditions.

At Bus 4, G-2 and G-1 become the first and the second worst cases for G and T outages, which implies that Bus 4 is more sensitive to generation deficiencies in the new priority order. The rankings for T outages only do not change at all as L3, L4, L5, and L8 have the same Impact Index value in the original priority order (see Table C.3). In other words, these four cases have the same impact at Bus 4. It can be seen from Table C.6, however, that in the new priority order the Impact Indices for these four cases are different i.e. they have different impacts at Bus 4.

Changing the load curtailment priority order has no effect on the rankings at Bus 5. This is also the case for Bus 6 except that L5 and L8 interchange positions. The differences between the Impact Indices for L5 and L8 are very small.

The effect of the load curtailment priority order on contingency ranking for the system and the load points has been investigated. The load curtailment priority order has no impact on the ranking based on system Impact Indices but can have significant impact on the rankings based on bus Impact Indices. This is due to the fact that the load point indices are highly dependent on the load curtailment priority order.

4.2.3 Impact of contingency likelihood on ranking

The impact on the system and load point reliability indices of removing single components is illustrated in Section 4.2.1. These studies clearly show that not all contingencies have the same impact. This form of analysis provides considerably more information than a deterministic appraisal based on an (n-1) criterion. It should also be appreciated that not all contingencies have the same likelihood. Incorporating the event likelihood into the impact assessment could change the ranking and provide more practical and valuable information.

In this section, a new index called the Modified Impact Index (MII), which considers both the severity and the likelihood of the contingency, is used to incorporate the impact of event likelihood on the ranking. The RBTS component unavailabilities are given in Table 4.13. The Modified Impact Index is calculated using Equation 4.1.

$$MII = II \times U \qquad (4.1)$$

where: MII – The Modified Impact Index,

II – Impact Index,

U – Unavailability.

Table 4.13: RBTS component unavailabilities

Component	Unavailability
G-1	0.03
G-2	0.03
Line 1, 6	0.00171
Line 2, 7	0.00568
Line 3	0.00455
Line 4	0.00114
Line 5	0.00114
Line 8	0.00114
Line 9	0.00114

The system and load point Modified Impact Indices (EENS) of the RBTS are given in Table C.7. The related rankings are shown in Table 4.14. In order to illustrate the impact of incorporating the event likelihood, the rankings obtained using II and MII are both displayed in Table 4.15.

Table 4.14: System and load point contingency ranking based on the Modified Impact Indices (EENS)

Outage	Rank Order	System	Bus 2	Bus 3	Bus 4	Bus 5	Bus 6
G & T	1	G-2	G-2	G-2	G-2	L8	G-2
	2	G-1	G-1	G-1	G-1	L5	G-1
	3	L2	-	L2	L2	G-2	L2
	4	L3	-	L1	L1	G-1	L3

Table 4.14: (Continued)

Outage	Rank Order	System	Bus 2	Bus 3	Bus 4	Bus 5	Bus 6
G & T	5	L8	-	L3	L3	L2	L5
	6	L5	-	L8	L4	L1	L8
	7	L1	-	L4	L5	L3	L1
	8	L4	-	L5	L8	L4	L4
T	1	L2	-	L2	L1	L8	L2
	2	L3	-	L1	L2	L5	L3
	3	L8	-	L3	L3	L2	L5
	4	L5	-	L8	L4	L1	L8
	5	L1	-	L4	L5	L3	L1
	6	L4	-	L5	L8	L4	L4

It can be seen from Table 4.15 that the likelihood of the event has a significant impact on the ranking due to the big differences in the component unavailabilities. Generally, generation receives more weight due to higher unavailability and its ranking is much higher than that based on the Impact Index (II). In regard to the transmission, the ranking of the L2 case also increases for the same reason.

Table 4.15: Comparison of the system and load point contingency rankings based on the Impact Indices (EENS) and the Modified Impact Indices (EENS)

Outage	Rank Order	System		Bus 2		Bus 3	
		II	MII	II	MII	II	MII
G & T	1	G-2	G-2	G-2	G-2	G-2	G-2
	2	G-1	G-1	G-1	G-1	G-1	G-1
	3	L8	L2	-	-	L1	L2
	4	L5	L3	-	-	L2	L1
	5	L1	L8	-	-	L3	L3
	6	L2	L5	-	-	L8	L8
	7	L3	L1	-	-	L4	L4
	8	L4	L4	-	-	L5	L5
T	1	L8	L2	-	-	L1	L2
	2	L5	L3	-	-	L2	L1
	3	L1	L8	-	-	L3	L3
	4	L2	L5	-	-	L8	L8
	5	L3	L1	-	-	L4	L4
	6	L4	L4	-	-	L5	L5
Outage	Rank Order	Bus 4		Bus 5		Bus 6	
		II	MII	II	MII	II	MII
G & T	1	L1	G-2	L8	L8	L5	G-2
	2	G-2	G-1	L5	L5	L8	G-1
	3	G-1	L2	G-2	G-2	G-2	L2

Table 4.15: (Continued)

Outage	Rank Order	Bus 4		Bus 5		Bus 6	
		II	MII	II	MII	II	MII
G & T	4	L2	L1	G-1	G-1	G-1	L3
	5	L3	L3	L1	L2	L1	L5
	6	L4	L4	L2	L1	L2	L8
	7	L5	L5	L3	L3	L3	L1
	8	L8	L8	L4	L4	L4	L4
T	1	L1	L1	L8	L8	L5	L2
	2	L2	L2	L5	L5	L8	L3
	3	L4	L3	L1	L2	L1	L5
	4	L5	L4	L2	L1	L2	L8
	5	L8	L5	L3	L3	L3	L1
	6	L3	L8	L4	L4	L4	L4

- The index values for these cases are zero.

From a system point of view, it can be seen from Table 4.15 that, for G and T outages, the G-2 and G-1 cases rank first and second, i.e. the rankings for these two cases do not change as they have the same likelihood. The rankings of L2 and L3 increase from #6 and #7 using II to #3 and #4 respectively using MII. In the T outages only analysis, the rankings obtained using MII are totally different from those using II. The rankings of L2 and L3 increase from #4 and #5 to #1 and #2.

In regard to the individual load points, it can be seen from Table 4.15 that the event likelihood has almost no effect on the ranking for Bus 3 except that L2 and L1 interchange positions in both the G and T outage and T outage only conditions.

The event likelihood has a major impact on the ranking for Bus 4. In the case of G and T outages, G-2 moves to #1 and G-1 becomes #2, followed by L2 at #3, and L1 at #4. In the case of T outages only, L1 and L2 still rank first and second. As noted before, L3, L4, L5, and L8 have the same Impact Index value (see Table C.3). After incorporating the event likelihood, however, L3 has a greater MII value (see Table C.7) than the other three cases and ranks third.

The contingency likelihood has little impact on the ranking for Bus 5. L2 and L1 interchange positions in the both the G and T outage and T outage only conditions.

At Bus 6, the rankings of G-2, G-1, L2, and L3 move up for G and T outages. G-2 and G-1 replace L5 and L8 and rank first and second. In the case of T outages only, L2 and L3 replace L5 and L8 and become #1 and #2.

The analysis in this section indicates that incorporating the contingency likelihood into the impact assessment has a significant effect on the rankings of the system and load point indices. The Modified Impact Index is a more useful risk indicator than the basic Impact Index.

4.3 IEEE-RTS Studies

A series of contingency ranking studies was conducted using the IEEE-RTS. Single contingency analyses were performed by removing selected generating units and all the transmission lines from service. The removal of Line 11 is not considered as in this case Bus 7 will be isolated. The following cases were examined.

G-7-100 — removing one 100MW unit at Bus 7

G-13-197 — removing one 197MW unit at Bus 13

G-15-155 — removing one 155MW unit at Bus 15

G-16-155 — removing one 155MW unit at Bus 16

G-18-400 — removing one 400MW unit at Bus 18

G-21-400 — removing one 400MW unit at Bus 21

G-23-155 — removing one 155MW unit at Bus 23

G-23-350 — removing one 350MW unit at Bus 23

L1 — removing Line 1

L2 — removing Line 2

L3 — removing Line 3

L4 — removing Line 4

L5 — removing Line 5

L6 — removing Line 6

L7 — removing Line 7

L8 — removing Line 8

L9 — removing Line 9

L10 — removing Line 10

L12 — removing Line 12

L13 — removing Line 13

L14 — removing Line 14

L15 – removing Line 15

L16 – removing Line 16

L17 – removing Line 17

L18 – removing Line 18

L19 – removing Line 19

L20 – removing Line 20

L21 – removing Line 21

L22 – removing Line 22

L23 – removing Line 23

L24 – removing Line 24

L25 – removing Line 25 or 26

L27 – removing Line 27

L28 – removing Line 28

L29 – removing Line 29

L30 – removing Line 30

L31 – removing Line 31

L32 – removing Line 32 or 33

L34 – removing Line 34 or 35

L36 – removing Line 36 or 37

L38 – removing Line 38

4.3.1 Contingency rankings for the IEEE-RTS

The system and load point Impact Indices (EENS) for the IEEE-RTS considering both G and T outages are given in Table C.8 and the corresponding rankings are shown in Table 4.16. The indices obtained for the T outage only condition, are given in Table C.9 and the corresponding rankings are shown in Table 4.17.

Table 4.16: System and load point contingency rankings based on the Impact Indices (EENS) for the IEEE-RTS (G&T)

Rank Order	System	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5
1	G-23-350	SV	G-23-350	G-23-350	L8	L3
2	G-18-400		G-13-197	G-13-197	L4	L9
3	G-21-400		G-18-400	G-18-400	G-23-350	L16
4	G-13-197		G-21-400	G-21-400	G-15-155	L17
5	G-23-155		G-23-155	G-23-155	G-16-155	L13
6	G-15-155		G-15-155	G-15-155	G-18-400	L12
7	G-16-155		G-16-155	G-16-155	G-21-400	SV
8	G-7-100		G-7-100	G-7-100	G-23-155	
9	L5		L8	L6	SV	
10	L23		L1	L2		
11	L19		L10	L27		
12	L10		L29	L7		
13	L8		L23	L30		
14	L4		L31	L23		
15	L3		L27	L16		
16	L9		L28	L17		
17	L12		SV	SV		
18	L13					
19	L31					
20	L38					
21	L7					
22	L28					
23	L29					
24	L1					
25	L2					
26	L6					
27	L24					
28	L25					
29	L27					
30	SV					
Rank Order	Bus 6	Bus 7	Bus 8	Bus 9	Bus 10	Bus 13
1	L5	L12	L12	G-23-350	G-23-350	G-23-350
2	L10	L13	L13	G-18-400	G-18-400	G-18-400
3	G-23-350	G-7-100	L17	G-21-400	G-21-400	G-21-400
4	G-15-155	L16	G-7-100	G-13-197	G-13-197	G-13-197
5	G-16-155	L17	L16	G-23-155	G-23-155	G-15-155
6	G-18-400	L18	G-23-350	G-16-155	G-15-155	G-16-155
7	G-21-400	SV	G-18-400	G-15-155	G-16-155	G-23-155
8	G-23-155		G-21-400	G-7-100	G-7-100	G-7-100
9	G-13-197		G-15-155	L38	L16	L23

Table 4.16: (Continued)

Rank Order	Bus 6	Bus 7	Bus 8	Bus 9	Bus 10	Bus 13
10	G-7-100		G-16-155	L31	L17	L29
11	L1		G-13-197	L29	L29	L28
12	L2		G-23-155	L7	L23	L21
13	L3		L18	L1	L31	L22
14	L4		L1	L23	L27	SV
15	L6		L2	SV	L5	
16	L7		L3		L28	
17	L8		L4		L3	
18	L9		L5		L24	
19	L13		L6		L18	
20	L14		L7		SV	
21	L15		L8			
22	SV		L9			
23			SV			
Rank Order	Bus 14	Bus 15	Bus 16	Bus 18	Bus 19	Bus 20
1	G-23-350	G-23-350	G-23-350	G-23-350	G-23-350	G-23-350
2	G-18-400	G-18-400	G-18-400	G-18-400	G-18-400	G-21-400
3	G-21-400	G-21-400	G-21-400	G-21-400	G-21-400	G-18-400
4	L23	G-13-197	G-13-197	G-13-197	G-13-197	G-13-197
5	L19	G-23-155	G-23-155	G-23-155	G-23-155	G-23-155
6	G-13-197	G-16-155	G-15-155	G-15-155	G-16-155	G-16-155
7	G-23-155	G-15-155	G-16-155	G-16-155	G-15-155	G-15-155
8	G-15-155	G-7-100	G-7-100	G-7-100	G-7-100	G-7-100
9	G-16-155	L31	L28	L31	L38	L36
10	G-7-100	L38	L24	L38	L31	L29
11	L29	L1	L31	SV	L7	L18
12	L28	L9	L38		L23	L31
13	L24	L2	L7		L25	L23
14	L31	L6	L1		SV	L28
15	L7	L7	L2			L38
16	L38	L8	L4			L27
17	L27	L3	L6			L24
18	L6	L10	L8			L7
19	L2	L4	L9			L9
20	L9	L25	L10			L8
21	L1	SV	L5			L6
22	L8		L30			L5
23	L5		SV			L2
24	L22					L10
25	L4					L1
26	L21					SV

Table 4.16: (Continued)

Rank Order	Bus 14	Bus 15	Bus 16	Bus 18	Bus 19	Bus 20
27	L10					
28	L3					
29	L25					
30	SV					

Note: SV indicates that this rank and the following rankings have same value.

Table 4.17: System and load point contingency rankings based on the Impact Indices (EENS) for the IEEE-RTS (T only)

Rank Order	System	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5
1	L5	SV	SV	L2	L8	L3
2	L23			L6	L4	L9
3	L19			L27	SV	L16
4	L10			L7		L17
5	L8			L17		L13
6	L4			L16		L12
7	L3			SV		L5
8	L9					SV
9	L6					
10	L2					
11	L7					
12	L1					
13	L27					
14	SV					
Rank Order	Bus 6*	Bus 7	Bus 8	Bus 9	Bus 10	Bus 13
1	L5	SV	SV	SV	L17	SV
2	L10				L16	
3	L1				L5	
4	L2				L3	
5	L3				SV	
6	L4					
7	L6					
Rank Order	Bus 14	Bus 15	Bus 16	Bus 18	Bus 19	Bus 20
1	L23	SV	SV	SV	SV	SV
2	L19					
3	L15					
4	L18					
5	SV					

Note: SV indicates that this rank and the following rankings have same value.
*: Only the top seven cases are shown for Bus 6.

The following observations can be made from Tables 4.16 and 4.17.

From a system point of view, it can be seen from Table 4.16 that all the considered generating unit contingencies have higher impact than the transmission line contingencies as the IEEE-RTS reliability is dominated by the generation. The worst case is G-23-350 rather than G-18-400, which indicates that the largest unit does not always rank first. The location of a generating unit can be a key factor. The eight transmission lines supplying Buses 4, 5, 6, and 14, rank higher than the other lines. This is also the case when considering T outages only as shown in Table 4.17.

The following comments pertain to the rankings associated with the individual load points. Bus 1 enjoys a high level of reliability and the contingencies considered have no impact on this bus.

It can be seen from Table 4.16 that in the case of Bus 2, the generation contingencies have higher ranking than those of transmission elements, as Bus 2 is dominated by generation. At this bus, G-13-197 ranks in second place and is higher than G-18-400 and G-21-400. The unit location is an important factor from a load point perspective. L8, L1, and L10 have high ranking as their Impact Indices are much higher than those of other lines (Table C.8). Removing Line 1 results in cutting off the supply from Bus 1 and removing Line 8 results in the load at Bus 4 being provided only from Bus 2. The priority order of Bus 4 is also much higher than that of Bus 2. Removing Line 10 has a similar effect as L8. Removing any single line has no effect on Bus 2 when only transmission outages are considered as shown in Table 4.17.

The generation contingencies have the same impact on Bus 3 as they have for Bus 2. As shown in Table 4.16, L6, L2, L27, and L7 rank the top four in the transmission contingencies. Their impact on Bus 3 is much larger than that of other lines for both the G&T and T outage only conditions (Tables C.8 and C.9). The removal of a single line tends to have a local impact on specific buses.

Tables 4.16 and 4.17 (and C.8 and C.9) indicate that Bus 4 is dominated by Lines 8 and 4 and the effect of removing other single components on this bus is negligible compared to these two cases. Bus 4 is connected to the system only through these two lines and has a low load curtailment priority. Buses 5, 6, 7, and 8 have similar reactions. Bus 5 is dominated by Lines 3 and 9, Bus 6 by Lines 5 and 10, Bus 7 and 8 by Lines 12 and 13. When considering T outages only, removing Line 12 or 13 has little or no effect on Buses 7 and 8.

Tables C.8 and 4.16 show that the impact at Bus 9 of generation contingencies are much greater than those of transmission events and removing one transmission line at a time has relatively little effect at this bus. This is because Bus 9 has a high load curtailment priority and a very strong connection to the system. The reliability at Bus 9 is dominated by generation outages. When T outages only are considered, removing any single line has no effect on Bus 9.

Bus 10 has similar effects to those at Bus 9, i.e. the impacts of generation on Bus 10 are much more than those of transmission and removing one transmission line at a time has little effect due to the fact that Bus 10 is also strongly connected to the system. Bus 10 is in the middle of the load curtailment priority order and therefore its base case values are relatively small. In the case of T outages only, although L16 and L17 are the highest ranked, their actual effect on Bus 10 is very small (Table C.9).

It can be seen from Tables 4.16 and C.8 that the impacts of generation contingencies on Bus 13 are larger than those of transmission contingencies when G and T outages are considered. It should be noted that these impacts are not significant due to the low base case values. When considering T outages only, removing one transmission line at a time has no effect on Bus 13.

Bus 14 has a high load curtailment priority and a weak transmission connection (only Lines 19 and 23), which means that Bus 14 will suffer not only from generation deficiencies but also from the removal of Line 19 or Line 23. This is clearly seen from Tables C.8 and 4.16. When considering the G and T outages, L23 and L19 rank higher than some small generation contingencies. In the case of T outages only, L23, L19, L15, and L18 have the top four rankings. It should be noted that L23 and L19 have much larger effects than those of L15 and L18.

Buses 15, 16, 18, 19, and 20 have similar characteristics. They are all generation dominated and the generation contingency rankings at these five buses are identical. The worst case is G-23-350. The effect of removing a transmission line is relatively small and can be neglected when considering G and T outages. There are no effects when removing single transmission lines for T outages only.

The worst contingencies for the system and for each bus are shown in Table 4.18. It can be seen from this table that, from a system point of view, the worst contingency is G-23-350 for G and T outages and L5 for T outages only. From a load point perspective, the worst contingency for G and T outages is G-23-350 other than for some weakly connected buses that are dominated by transmission failures. When considering T outages only, most buses are immune from removing a single line as the IEEE-RTS has a relatively strong transmission system. It should be noted that the impact of L6 on Bus 3 and L16 on Bus 10 is quite small and could be neglected.

Most of the worst contingencies are G-23-350 rather than G-18-400 as might be expected. One reason for this is that the forced outage rate of the 350 MW unit is 0.08 which is lower than that of the 400 MW unit, i.e. 0.12. The difference between the capacities of the two units does not override the difference between their forced outage rates. Another reason is that the 350 MW unit at Bus 23 is closer to the load center in the southern region than the 400 MW units at Bus 18 and Bus 21. The system configuration is an important factor that can impact the ranking.

Table 4.18: The worst contingencies for the system and individual buses in the IEEE-RTS

System and Buses	G&T	T Only
System	G-23-350	L5
Bus 1	N/A	N/A
Bus 2	G-23-350	N/A
Bus 3	G-23-350	L6
Bus 4	L8	L8
Bus 5	L3	L3
Bus 6	L5	L5
Bus 7	L12	N/A
Bus 8	L12	N/A
Bus 9	G-23-350	N/A
Bus 10	G-23-350	L16
Bus 13	G-23-350	N/A
Bus 14	G-23-350	L23
Bus 15	G-23-350	N/A
Bus 16	G-23-350	N/A
Bus 18	G-23-350	N/A
Bus 19	G-23-350	N/A
Bus 20	G-23-350	N/A

The impacts of selected contingencies on the IEEE-RTS are analyzed in this section. As noted earlier, the IEEE-RTS is similar in form to an actual power system. The IEEE-RTS, however, has strong transmission and relatively weak generation systems and does not have the designed-in weaknesses of the RBTS.

It is clear from the analyses conducted that not all contingencies have the same impact on the system and load point indices of the IEEE-RTS. From a system viewpoint, the impacts of generation contingencies are much larger than those of transmission contingencies, which indicates that the IEEE-RTS is dominated by generation. From a load point perspective, the different buses have different responses to the selected contingencies. Some buses are immune to any single contingency, some buses are impacted mainly by generation contingencies, some mainly by transmission contingencies, and some by both generation and transmission events.

It is expected for generation contingencies that the largest unit should be the worst case or have the biggest impact. In the IEEE-RTS, all the worst cases are G-23-350 (the second large unit), not G-18-400 as expected. The forced outage rates and system topology are the key factors.

In a system with strong transmission such as the IEEE-RTS, removing one transmission line at a time usually results in only local impacts at the load points with weak transmission connections.

From a transmission point of view, the rankings under both G&T outage and T outage only conditions provide valuable information for system planning. The G&T outage analyses provide an overall assessment of the actual composite system. In the new market environment, the main responsibility of an ISO is to maintain the system reliability, but the ISO may have relatively little control over the capacity reserve. Under these conditions, the T outage only rankings provide valuable information on possible transmission deficiencies.

4.3.2 Impact of contingency likelihood on the rankings for the IEEE-RTS

The effects of contingency likelihood on the rankings for the IEEE-RTS were examined. The unavailability of each component of the IEEE-RTS is given in Table 4.19. This table shows the large differences exist in the unavailabilities of the generating units, transformers, and transmission lines. The Modified Impact Indices (EENS) are presented in Tables C.10 and C.11. The rankings based on the system and load point Modified Impact Indices and the corresponding rankings based on Impact Indices are shown in Tables 4.20 to 4.23 in order to illustrate the effect of contingency likelihood. Only a limited number of transmission contingencies that have relatively large impact are presented in each bus table.

Table 4.19: IEEE-RTS component unavailabilities

Component	Unavailability
G-7-100	0.04
G-13-197	0.05
G-15-155	0.04
G-16-155	0.04
G-18-400	0.12
G-21-400	0.12
G-23-155	0.04
G-23-350	0.08
L1	0.00044
L2	0.00058
L3	0.00038
L4	0.00045
L5	0.00045
L6	0.00055
L7	0.00175
L8	0.00041
L9	0.00039
L10	0.00132
L12	0.00050
L13	0.00050
L14	0.00175
L15	0.00175
L16	0.00175
L17	0.00175
L18	0.00050
L19	0.00049
L20	0.00050
L21	0.00065
L22	0.00062
L23	0.00048
L24	0.00041
L25	0.00051
L27	0.00051

Table 4.19: (Continued)

Component	Unavailability
L28	0.00044
L29	0.00043
L30	0.00040
L31	0.00068
L32	0.00044
L34	0.00048
L36	0.00043
L38	0.00057

Table 4.20: Comparison of the system contingency rankings based on the II (EENS) and the MII (EENS) for the IEEE-RTS (G&T)

Rank Order	II	MII	Rank Order	II	MII	Rank Order	II	MII
1	G-23-350	G-18-400	15	L3	L31	29	L25	L20
2	G-18-400	G-21-400	16	L9	L21	30	L16	L4
3	G-21-400	G-23-350	17	L12	L5	31	L17	L34
4	G-13-197	G-13-197	18	L13	L22	32	L14	L8
5	G-23-155	G-23-155	19	L31	L23	33	L15	L1
6	G-15-155	G-15-155	20	L38	L19	34	L18	L28
7	G-16-155	G-16-155	21	L28	L2	35	L36	L32
8	G-7-100	G-7-100	22	L29	L38	36	L20	L29
9	L5	L7	23	L7	L6	37	L21	L36
10	L23	L16	24	L27	L27	38	L22	L9
11	L19	L17	25	L2	L25	39	L30	L24
12	L10	L14	26	L6	L12	40	L32	L3
13	L8	L15	27	L24	L13	41	L34	L30
14	L4	L10	28	L1	L18			

Table 4.21: Comparison of the load point contingency rankings based on the II (EENS) and the MII (EENS) for the IEEE-RTS (G&T)

Rank Order	Bus 2		Bus 3		Bus 4	
	II	MII	II	MII	II	MII
1	G-23-350	G-23-350	G-23-350	G-23-350	L8	L8
2	G-13-197	G-18-400	G-13-197	G-18-400	L4	L4
3	G-18-400	G-21-400	G-18-400	G-21-400	G-23-350	G-23-350
4	G-21-400	G-13-197	G-21-400	G-13-197	G-15-155	G-18-400
5	G-23-155	G-23-155	G-23-155	G-23-155	G-16-155	G-21-400
6	G-15-155	G-15-155	G-15-155	G-15-155	G-18-400	G-15-155
7	G-16-155	G-16-155	G-16-155	G-16-155	G-21-400	G-16-155
8	G-7-100	G-7-100	G-7-100	G-7-100	G-23-155	G-23-155
9	L8	L7	L6	L7	G-13-197	G-13-197
10	L1	L14	L2	L16	SV	SV
11	L10	L15	L27	L17		

Table 4.21: (Continued)

Rank Order	Bus 2		Bus 3		Bus 4	
	II	MII	II	MII	II	MII
12	L29	L16	L7	L14		
13	L23	L17	L30	L15		
Rank Order	Bus 5		Bus 6		Bus 7	
	II	MII	II	MII	II	MII
1	L3	L9	L5	L10	L12	G-7-100
2	L9	L3	L10	L5	L13	G-23-350
3	L16	L16	G-23-350	G-18-400	G-7-100	G-18-400
4	L17	L17	G-15-155	G-21-400	L16	G-21-400
5	L13	L13	G-16-155	G-23-350	L17	L12
6	L12	L12	G-18-400	G-13-197	L18	L13
7	SV	SV	G-21-400	G-15-155	SV	G-13-197
8			G-23-155	G-16-155		G-15-155
9			G-13-197	G-23-155		G-16-155
10			G-7-100	G-7-100		G-23-155
11			L1	L7		L16
12			L2	L2		L17
13			L3	L6		L14
Rank Order	Bus 8		Bus 9		Bus 10	
	II	MII	II	MII	II	MII
1	L12	G-7-100	G-23-350	G-18-400	G-23-350	G-23-350
2	L13	G-23-350	G-18-400	G-21-400	G-18-400	G-18-400
3	L17	G-18-400	G-21-400	G-23-350	G-21-400	G-21-400
4	G-7-100	G-21-400	G-13-197	G-13-197	G-13-197	G-13-197
5	L16	L12	G-23-155	G-23-155	G-23-155	G-23-155
6	G-23-350	L13	G-16-155	G-15-155	G-15-155	G-15-155
7	G-18-400	G-13-197	G-15-155	G-16-155	G-16-155	G-16-155
8	G-21-400	G-15-155	G-7-100	G-7-100	G-7-100	G-7-100
9	G-15-155	G-16-155	L38	L7	L16	L16
10	G-16-155	G-23-155	L31	L14	L17	L17
11	G-22-50	L17	L29	L16	L29	L15
12	G-13-197	L16	L7	L17	L23	L7
13	L18	L18	L1	L15	L31	L14
Rank Order	Bus 13		Bus 14		Bus 15	
	II	MII	II	MII	II	MII
1	G-23-350	G-23-350	G-23-350	G-18-400	G-23-350	G-18-400
2	G-18-400	G-18-400	G-18-400	G-21-400	G-18-400	G-21-400
3	G-21-400	G-21-400	G-21-400	G-23-350	G-21-400	G-23-350
4	G-13-197	G-13-197	L23	G-13-197	G-13-197	G-13-197
5	G-15-155	G-15-155	L19	G-23-155	G-23-155	G-23-155
6	G-16-155	G-16-155	G-13-197	G-15-155	G-16-155	G-15-155
7	G-23-155	G-23-155	G-23-155	G-16-155	G-15-155	G-16-155
8	G-7-100	G-7-100	G-15-155	G-7-100	G-7-100	G-7-100

Table 4.21: (Continued)

Rank Order	Bus 13		Bus 14		Bus 15	
	II	MII	II	MII	II	MII
9	L23	L7	G-16-155	L23	L31	L7
10	L29	L14	G-7-100	L19	L38	L14
11	L28	L16	L29	L7	L1	L16
12	L21	L17	L28	L14	L9	L17
13	L22	L15	L24	L15	L2	L15

Rank Order	Bus 16		Bus 18		Bus 19	
	II	MII	II	MII	II	MII
1	G-23-350	G-18-400	G-23-350	G-23-350	G-23-350	G-18-400
2	G-18-400	G-21-400	G-18-400	G-18-400	G-18-400	G-21-400
3	G-21-400	G-23-350	G-21-400	G-21-400	G-21-400	G-23-350
4	G-13-197	G-13-197	G-13-197	G-13-197	G-13-197	G-13-197
5	G-23-155	G-23-155	G-23-155	G-23-155	G-23-155	G-23-155
6	G-15-155	G-15-155	G-15-155	G-15-155	G-16-155	G-15-155
7	G-16-155	G-16-155	G-16-155	G-16-155	G-15-155	G-16-155
8	G-7-100	G-7-100	G-7-100	G-7-100	G-7-100	G-7-100
9	L28	L7	L31	L7	L38	L7
10	L24	L14	L38	L14	L31	L14
11	L31	L16	SV	L16	L7	L16
12	L38	L17		L17	L23	L17
13	L7	L15		L15	L25	L15

Rank Order	Bus 20	
	II	MII
1	G-23-350	G-18-400
2	G-18-400	G-21-400
3	G-21-400	G-23-350
4	G-13-197	G-13-197
5	G-23-155	G-23-155
6	G-15-155	G-15-155
7	G-16-155	G-16-155
8	G-7-100	G-7-100
9	L36	L7
10	L29	L14
11	L18	L16
12	L31	L17
13	L23	L15

Table 4.22: Comparison of the system contingency rankings based on the II (EENS) and the MII (EENS) for the IEEE-RTS (T only)

Rank Order	II	MII	Ranking	II	MII
1	L5	L10	18	L32	L21
2	L23	L5	19	L34	L22
3	L19	L23	20	L36	L27
4	L10	L19	21	L38	L38
5	L8	L8	22	L14	L25
6	L4	L4	23	L20	L20
7	L3	L9	24	L21	L18
8	L9	L3	25	L22	L34
9	L6	L7	26	L24	L12
10	L2	L14	27	L25	L28
11	L7	L16	28	L18	L32
12	L1	L17	29	L15	L29
13	L27	L15	30	L16	L36
14	L28	L2	31	L17	L13
15	L29	L6	32	L12	L24
16	L30	L1	33	L13	L30
17	L31	L31			

Table 4.23: Comparison of the load point contingency rankings based on the II (EENS) and the MII (EENS) for the IEEE-RTS (T only)

Rank Order	Bus 3		Bus 4		Bus 5	
	II	MII	II	MII	II	MII
1	L2	L7	L8	L8	L3	L9
2	L6	L2	L4	L4	L9	L3
3	L27	L6	SV	SV	L16	L16
4	L7	L27			L17	L17
5	L17	SV			L13	L13
6	L16				L12	L12
7	SV				L5	SV
					SV	
Rank Order	Bus 6*		Bus 10		Bus 14	
	II	MII	II	MII	II	MII
1	L5	L10	L17	L17	L23	L23
2	L10	L5	L16	L16	L19	L19
3	L1	L7	L5	L5	L15	L15
4	L2	L14	L3	L3	L18	L18
5	L3	L15	SV	SV	SV	SV
6	L4	L16				
7	L6	L17				

Note: SV means that this rank and the following rankings have same values.
*: Only the top seven cases are shown for Bus 6.

From a system viewpoint, it can be seen from Table 4.20 that, for G and T outages, the only change is that G-23-350 drops down to third place and G-18-400 assumes the first place. In regard to transmission elements, the rankings of the five transformers for MII go up significantly. The reason is that the differences among the transmission elements II are relatively small and the unavailability values become the main factor. It can be seen from Table 4.22 for T outages only that incorporating the likelihood of the event does change the ranking. The ranking on the Modified Impact Indices (EENS), however, is still dominated by the eight cases related to the four buses with only two lines (i.e. Buses 4, 5, 6, and 14). The unavailabilities of the five transformers are not large enough to significantly change these rankings.

From a load point perspective, some buses are dominated by generation, some by transmission, some by both, and some by neither of them. The contingency likelihoods have different impacts at different buses.

Ten buses are generation dominated when considering both generation and transmission failures. They are Buses 2, 3, 9, 10, 13, 15, 16, and 18 to 20. It can be seen from Table 4.21 that, after incorporating the likelihood into the assessment, the generation cases still precede those of transmission in the rankings. The rankings of the two largest contingencies G-18-400 and G-23-350 go up for most buses, such as Buses 2, 3, 9, 15, 16, 19, and 20, and G-18-400 becomes the worst contingencies for Buses 9, 15, 16, 19, and 20. In regard to the transmission elements, the five transformer contingencies rank higher than the line contingencies due to their higher forced outage rates.

Buses 4 to 8 are dominated by transmission contingencies in the II rankings. These rankings change differently by incorporating the event likelihood.

It can be seen from Tables C.8 or C.10 that Bus 4 is dominated by Line 8 and Line 4. The impact on Bus 4 of removing a generating unit can be neglected. It can be seen from Table 4.21 that incorporating the likelihood into the assessment has almost no effect on the ranking for Bus 4.

It can be seen from Table 4.21 that the only change for Bus 5 is that L3 and L9 interchange their positions. It should be noted that the MII differences between L3 and L9 are very small. The impact of event likelihood on the ranking on Bus 5 is therefore limited.

Table 4.21 shows that the ranking is changed totally for Bus 6. L5 and L10 interchange positions and L10 becomes the worst case. The eight generation cases rank in their capacity order. The effects of other transmission cases are relatively small and can be neglected.

After incorporating the likelihood into the assessment, Bus 7 changes from being transmission dominated to generation dominated. It can be seen from Table 4.21 that G-7-100 becomes the worst case and other generation contingencies rank higher. L12 and L13 drop from first and second places to the fifth and sixth places respectively. A similar reaction occurs at Bus 8.

As noted earlier, Bus 14 is the only bus dominated by both generation and transmission failures. Table 4.21 indicates that after incorporating the likelihood into the assessment, all eight generation contingencies precede the transmission contingencies in the ranking and L23 and L19 drop to ninth and tenth positions. The transformer contingencies move up the ranking.

Considering T outages only, it can be seen from Table C.11 that there are only six buses with MII values other than zero. Table 4.23 shows that of the six buses only three bus rankings are impacted slightly by incorporating the likelihood into the assessment. At Bus 3, L7 moves to first place from the fourth. At Bus 5, L3 and L9 interchange positions. At Bus 6, L5 and L10 interchange places and the five transformer contingencies are ranked three to seven. The effect of event likelihood on the rankings is very limited when considering T outages only.

4.4 Conclusions

Analyses based on probabilistic concepts can be used to determine the system and load point risk levels in terms of the different indices. Ranking the contingencies considered can prove valuable when making system planning and maintenance decisions and cannot be determined using deterministic or “rule-of-thumb” techniques.

The studies conducted on the two test systems and described in this chapter clearly indicate that not all contingencies have the same impact on the system indices or on the load point indices. The worst contingency for the system may not be the worst for a given bus. The worst contingency for one bus may also not be the worst contingency for other buses. From a generation point of view, removing the largest unit usually has the largest impact. It should be appreciated, however, that the worst contingency for the system and each load point may not always be the largest unit contingency. The generating unit FOR and the system topology are the two important factors. From a transmission point of view, removing a transmission line usually only has local impact on the load point connected to or supplied by the line in question. From a system viewpoint, different systems have different response to the (n-1) criterion. In a system with generation domination, the impacts of generation contingencies are usually much larger than those of transmission contingencies, and vice versa for a system with transmission domination. From the load point perspective, different buses have different responses to a contingency. Some buses are immune to any single contingency, some buses are impacted mainly by generation contingencies, some mainly by transmission contingencies, and some by both generation and transmission contingencies.

In some cases, the use of different Impact Indices results in different rankings. The load model used and the load curtailment priority order selected also have significant impacts on the ranking. Rankings based on annualized impact indices are usually different from those based on the annual impact indices. Load curtailment priority order only impacts the rankings based on load point impact indices.

It is obvious that not all contingencies have the same likelihood. In a composite system, generating units usually have larger unavailabilities, and in turn transformers and transmission lines. In general, incorporating the event likelihood into the assessment can create a significant change in the ranking. These changes depend not only on the differences in the component likelihoods, but on the magnitude of the impact indices. The Modified Impact Index includes both event severity and likelihood and should prove to be a more useful risk index.

In the new market environment, the main responsibility of an ISO is to maintain the system reliability. The ISO, however, may have relatively little control over the capacity reserve. Under these conditions, the T outage only rankings provide valuable information on possible transmission deficiencies.

5. APPLICATION OF PROBABILISTIC TECHNIQUES TO MAINTENANCE SCHEDULING

5.1 Introduction

The basic objective of preventive maintenance is to prevent or forestall future random failures of the system facilities by removing these facilities from service at an appropriate time and conducting diagnostic tests and element replacements. An optimized maintenance schedule can improve system reliability, reduce system operating costs and result in savings in capital investment for new facilities.

Maintenance is an important part of asset management. It is commonly divided into two categories: preventive maintenance and corrective maintenance. The former is also called planned maintenance or scheduled maintenance and deals with scheduled outages. The latter usually includes repair and replacement and deals with forced outages or random failures. As noted earlier, the purpose of preventive maintenance is to extend equipment lifetime. Effective maintenance policies can reduce the frequency of service interruptions and the many undesirable consequences of such interruptions.

The most frequently used maintenance strategies in electric utilities are reviewed in [14] in which it is concluded that maintenance at fixed intervals is the most frequently used approach, often augmented by additional factors. Newer type methods, such as reliability-centered maintenance (RCM), are being increasingly considered for application in North America, but methods based on mathematical models are hardly ever used or even considered.

After determining the individual component maintenance requirements, it is necessary to coordinate all the maintenance requests in terms of their impact on the system. As noted earlier, in a vertically integrated utility it is the responsibility of the utility to coordinate the component maintenance schedules at all three hierarchical levels. Considerable research has been done at HLI [23, 24, and 25]. A deterministic technique designated as the reserve-levelization method for performing preventive maintenance scheduling in power generation systems [23] has been widely used because of its simplicity. This method, however, does not levelize the system reliability, as it ignores the uncertainties in demand and the generating unit availabilities. A quantitative technique designated as the risk-levelization method has been developed, which can recognize the probabilistic effect of the forced outages of the generating units and the variations in the system load. The following four techniques for preventive maintenance scheduling are analyzed and compared in [24].

(a) Health Levelization.

(b) Risk Levelization.

(c) Reserve Levelization.

(d) Loss of the Largest Unit.

The first two techniques are probabilistic approaches. In the health levelization technique, the probability of health P(H) is used as the criterion. This technique was developed further for use in deregulated power systems for both short term and long term applications [25]. In the risk levelization technique, the LOLE is used as the criterion. The other two techniques are deterministic approaches in which, the available capacity reserve in MW and the capacity of the largest unit are used as criteria respectively.

A new probabilistic technique, designated as the dual criteria technique which monitors both the risk and the health of the constructed maintenance schedules and attempts to levelize the probability of health and the loss of load expectation at the same time, is also presented in [24].

No similar studies have been reported in the available literature on HLII maintenance scheduling and coordinating. This is still an interesting and important topic for both vertically integrated and deregulated utility systems.

5.2 Composite system maintenance coordination technique

It is difficult to coordinate all the component maintenance requirements in the new utility environment. The decision when to maintain a generator is determined by the individual GENCO rather than by the optimal cost of maintenance and repair in the overall system. It is important to develop efficient decision-making tools for the ISO to use when receiving all the planned outage submissions and deciding on the most appropriate schedule from a system point of view.

This section presents a procedure to assist in the maintenance scheduling of generation and transmission facilities in a bulk electric system. This approach is designated as the maintenance coordination technique (MCT). The MCT is based on practical procedures used by most ISO. As indicated earlier, an ISO should collect all the generation and transmission planned outage requests from the market participants at an agreed time (usually declared by the ISO) prior to the start of these activities.

The ISO must then determine which of these maintenance activities can proceed as requested without violating the system reliability. In order to do this, the ISO should establish system and load point reliability criteria that can be used to assess the adequacy of the system and load points when specific facilities are removed from service. Most scheduling is done in a weekly basis although longer or shorter intervals can be used if required. The peak load for the week is then assumed to be a constant value over the period. This is forecast in advance of the actual occurrence. The risk criteria are a management decision. The studies described in this thesis use the annualized values of the base case system and load point reliability indices as the criterion values.

The system and load point reliability are a function of the system load level and therefore there will be some periods (weeks) in which certain equipment removals are acceptable and some periods (weeks) in which their removals lead to violation of the risk criteria.

This is illustrated in Figure 5.1 in which there are two designated areas. The one below the criterion risk level is the acceptable area. The other area above the criterion risk level is the unacceptable area. Figure 5.1 shows the variation of the risk with increasing load. The intersection of the criterion risk and the risk profile occurs at the critical load level. Any load higher than this will violate the risk criterion. Any load level less than this has an acceptable risk and therefore the system configuration associated with the risk profile is acceptable at these load levels. The risk profile shown in Figure 5.1 will change as different generation and transmission facilities are removed from service.

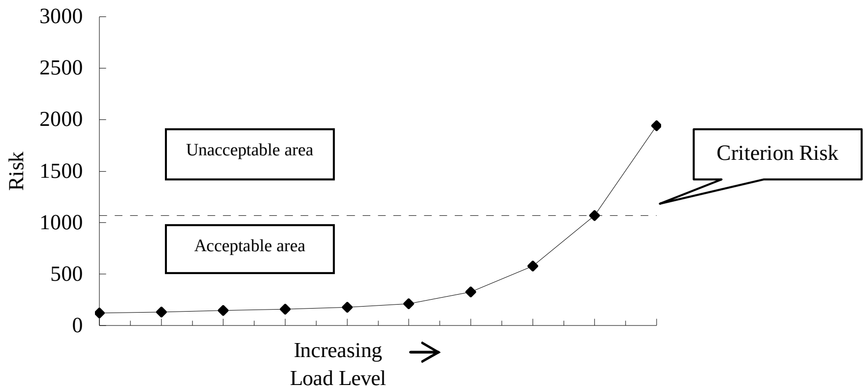

Figure 5.1: An example of the risk variation with increasing peak load

The RBTS and the IEEE-RTS are used to demonstrate this technique in the following sections.

5.3 Application of the MCT to the RBTS

The maintenance coordination technique (MCT) can be used to examine the impact or risk associated with removing elements from the system for maintenance by considering the system indices and the load point indices. This is illustrated by application to the RBTS in this section. The analysis is first conducted by application to the system indices and then to the load point indices.

The system indices are useful to management and to the system planner as they indicate the ability of the system to satisfy the overall load and energy requirements. The load point indices are valuable in system design and in comparing alternative configurations and system additions. They are also useful as input indices in the reliability evaluation of the distribution system which is fed by the relevant bulk supply point. It is possible that a planned outage, which is acceptable based on the system risk, may be unacceptable based on a load point risk. It is therefore necessary to check for unacceptable load point conditions determined by using the system risk.

A number of cases were studied for the RBTS. These cases include all single component removals (except Line 9), some two-generating-unit cases, all possible two-line and three-line cases, and some generating unit and line cases. The designations used to describe a case are shown by the following examples.

G1-40: removing one 40 MW unit at Bus 1 for maintenance

G1-10G2-40: removing one 10 MW unit at Bus 1 and one 40 MW unit at Bus 2 for maintenance

L1: removing Line 1 for maintenance

L1-2: removing Line 1 and Line 2 for maintenance

L1-2-3: removing Line 1, Line 2, and Line 3 for maintenance

G1-20-L1-3: removing one 20 MW unit at Bus 1 and Line 1 and Line 3, etc.

5.3.1 Scheduling based on different system risks

As noted in Chapter 2, the MECORE program produces eleven annualized system indices. Theoretically, any of them can be selected as the system criterion risk. The annualized system EENS, PLC, and ENLC are used as system risks in the following section. The purpose of the following analysis is to indicate the differences in the schedules based on different system indices. The base case values, i.e. 1070 MWh/yr for EENS, 0.00989 for PLC, and 5.26 1/yr for ENLC, are used as the system criterion risks in the following studies.

The system EENS for each of the cases considered, as a function of the system load level, are shown in Table 5.1. The corresponding risk profiles are presented in Figures 5.2 to 5.6.

Table 5.1: System EENS (MWh/yr) of the RBTS as a function of the load level with maintenance removals

Case	Load Level (MW)									
	105	115	125	135	145	155	165	175	185	195
G1-40	114.79	129.75	182.50	254.88	479.48	994.35	3383.2	8533.2	16169	27260
G1-20	112.87	124.32	144.60	168.18	269.93	496.61	868.18	1068.9	5443.4	12010
G1-10	111.95	122.74	136.61	156.08	181.96	313.31	507.37	1060.0	1765.5	5309.3
G2-40	116.51	133.96	205.43	305.71	586.93	1219.9	4075.3	10415	19020	30938
G2-20	113.27	125.26	146.61	170.97	274.31	507.53	919.06	1743.0	5785.5	12498
G2-5	111.93	121.89	135.77	147.64	173.82	217.66	413.39	710.82	1423.0	2451.8
G1-10G2-40	127.49	185.71	302.48	609.25	1084.1	4347.1	9363.3	19426	30691	N/A
G1-10G2-5	116.15	127.67	142.88	169.35	196.73	419.52	619.92	1435.4	2176.0	8884.2
G1-40G2-5	120.53	135.96	220.15	300.78	692.24	1428.1	5653.0	11387	21728	33952
G2-40G2-5	124.55	143.31	257.92	365.27	844.12	1739.1	6797.1	13735	24997	37955
G2-5G2-5	116.09	127.05	141.25	160.98	188.89	321.71	526.78	1088.4	1881.0	5555.2
L1	119.14	133.46	151.85	168.84	193.63	262.83	596.13	3430.9	9237.7	N/A
L2	114.94	127.38	144.61	161.19	185.29	229.19	394.14	956.91	1735.3	2940.4
L3	112.37	122.78	137.70	152.76	175.22	213.27	363.09	662.82	1197.8	2015.0
L4	112.03	122.24	135.73	148.34	167.31	200.29	315.41	569.91	1065.7	2029.4
L5	342.29	372.63	410.27	442.81	481.71	538.41	673.12	948.01	1456.6	2297.2
L8	342.29	372.77	410.58	443.48	482.79	540.30	676.67	955.52	1471.3	2465.8
L1-2	926.93	1478.9	2142.8	2698.4	3307.9	5249.5	10852	N/A	N/A	N/A
L1-3	129.28	151.60	185.46	285.34	450.70	664.76	1044.1	1755.0	4778.8	7972.6
L1-4	129.39	237.57	368.56	539.86	718.32	973.70	1437.2	4714.0	11403	N/A
L1-5	346.22	380.38	422.59	460.41	504.52	586.10	907.05	3230.8	8005.6	N/A
L1-6	2451.2	3424.5	4607.1	5779.7	7140.4	8854.6	N/A	N/A	N/A	N/A
L1-8	350.23	477.82	632.10	827.87	1030.7	1339.1	2109.3	5893.6	13003	N/A
L2-3	197.72	256.91	498.09	990.07	1578.0	2366.8	5870.0	11513	17308	24351
L2-4	122.68	135.82	153.90	171.41	196.40	241.22	419.20	1274.6	2264.7	3528.4
L2-5	343.58	376.14	417.51	454.20	498.35	565.33	758.19	1569.9	2583.7	3870.7
L2-7	460.77	764.37	1277.1	1936.4	2691.3	3680.2	7345.9	13245	19029	N/A

Table 5.1: (Continued)

Case	Load Level (MW)									
	105	115	125	135	145	155	165	175	185	195
L2-8	342.49	374.95	416.21	452.97	497.33	566.87	773.93	1399.3	2196.2	3419.3
L3-4	118.79	133.58	154.49	175.49	204.70	278.71	457.82	810.65	1395.3	2276.2
L3-5	339.14	369.60	408.61	443.79	486.46	549.50	721.92	1050.3	1608.4	2447.8
L3-8	340.94	375.68	420.51	461.33	510.40	607.83	805.18	1181.0	1784.6	2684.4
L4-5	351.31	382.62	421.51	455.37	495.86	557.22	721.45	1480.5	2379.6	3675.2
L4-8	351.87	397.00	453.16	694.05	945.61	1287.8	1690.0	2457.6	3371.3	4569.0
L1-2-3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
L1-2-4	927.40	1478.2	2140.8	2759.6	3423.2	5363.7	11185	N/A	N/A	N/A
L1-2-5	1161.9	1733.4	2420.8	2995.7	3067.3	5253.4	9890.3	N/A	N/A	N/A
L1-2-8	1160.8	1732.2	2419.5	3057.5	3762.6	6185.2	N/A	N/A	N/A	N/A
L1-3-4	129.53	246.39	386.56	566.52	756.25	1026.4	1440.5	2158.3	5201.7	8495.8
L1-3-5	362.62	405.27	463.55	583.70	769.35	1008.5	1410.0	2148.5	5189.4	8439.4
L1-3-8	364.52	501.18	665.04	863.40	1071.5	1362.9	1793.3	2529.3	5587.7	8857.1
L1-4-5	1099.0	1195.8	1313.4	1412.7	1518.6	1658.7	1888.9	2726.7	3691.1	N/A
L1-4-8	1441.6	1538.4	1755.5	N/A	N/A	N/A	N/A	N/A	N/A	N/A
L2-3-4	198.53	261.83	507.73	1003.7	1596.2	2392.2	5908.3	11669	17558	24692
L2-3-5	431.46	511.20	776.80	1288.7	1896.1	2708.8	6227.5	11935	17781	24872
L2-3-8	432.05	515.03	784.47	1299.9	1911.7	2729.9	6262.8	11994	17859	24970
L2-4-5	2628.2	2859.5	3138.4	3372.2	3612.5	3913.8	N/A	N/A	N/A	N/A
L2-4-8	1498.0	1644.7	1822.6	2165.0	2518.1	2982.1	3485.4	4374.0	5387.2	6682.9
G1-20-L1	123.20	138.58	163.60	191.51	298.03	557.35	1097.0	4294.0	12494	N/A
G1-20-L3	120.38	135.53	160.38	188.57	336.45	620.86	1038.7	1835.3	6049.6	13253
G1-20-L4	117.31	129.28	150.34	174.97	277.90	505.81	878.43	1623.5	5461.8	12111
G1-20-L8	339.32	370.80	415.30	459.53	581.95	833.21	1225.9	1993.3	5847.6	12521
G1-40-L1	125.06	143.91	201.19	277.72	506.58	1039.1	3541.2	9649.2	18757	N/A
G1-40-L3	128.47	151.30	237.42	337.96	606.82	1188.9	4151.6	10224	18591	30287
G1-40-L4	119.34	135.20	189.28	263.17	489.13	1010.5	3402.3	8550.1	16188	27365

Table 5.1: (Continued)

Case	Load Level (MW)									
	105	115	125	135	145	155	165	175	185	195
G1-40-L8	341.48	376.84	454.24	547.60	792.83	1337.1	3745.4	8910.4	16559	27753
G2-40-L1	127.81	149.69	226.67	332.62	673.33	2788.6	10719	N/A	N/A	N/A
G2-40-L3	121.56	139.81	213.21	316.70	601.46	1234.1	4095.3	10217	18844	30785
G2-40-L4	120.86	138.83	210.99	312.13	594.03	1228.1	4091.0	10446	19038	30943
G2-40-L8	342.96	380.44	475.98	596.61	897.85	1558.9	4472.7	10859	19473	31398
G1-20-L1-3	127.10	150.28	190.17	299.95	585.82	1039.6	1636.4	2730.9	8190.8	15552
G1-20-L4-8	412.61	461.83	560.13	901.77	1474.6	2223.8	3031.1	4297.4	8504.7	15350
G1-40-L1-3	132.09	163.01	264.42	446.56	852.28	1599.3	4690.9	10910	19395	31202
G1-40-L4-8	486.06	774.61	1178.0	1746.1	2467.8	4427.9	7559.7	12367	19906	31253
G2-40-L1-3	373.85	531.78	773.12	1015.79	1538.7	2687.6	10011	N/A	N/A	N/A
G2-40-L4-8	367.64	421.98	537.60	863.23	1372.5	2275.2	5362.8	11940	20698	32750

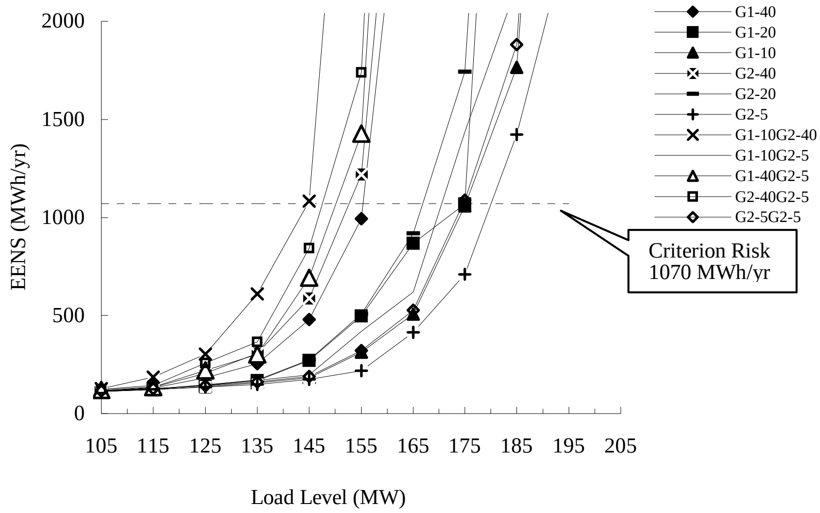

Figure 5.2: System EENS of the RBTS as a function of the load level (remove generation)

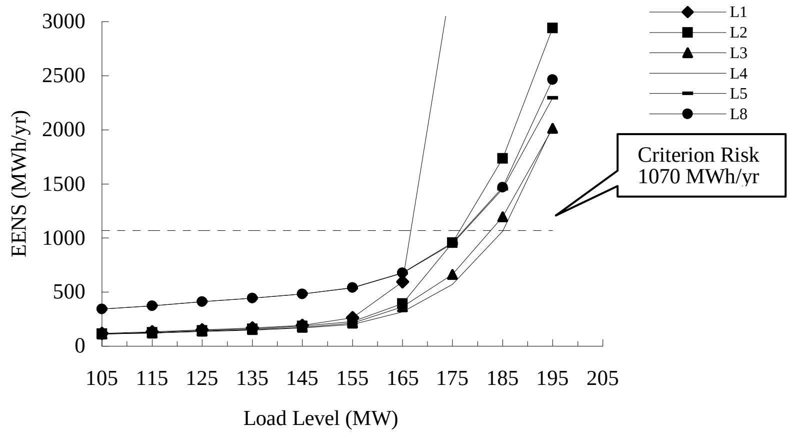

Figure 5.3: System EENS of the RBTS as a function of the load level (remove one line)

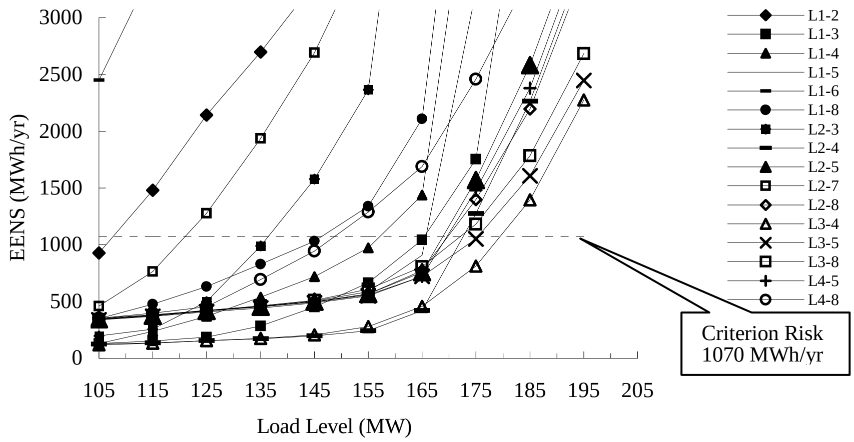

Figure 5.4: System EENS of the RBTS as a function of the load level (remove two lines)

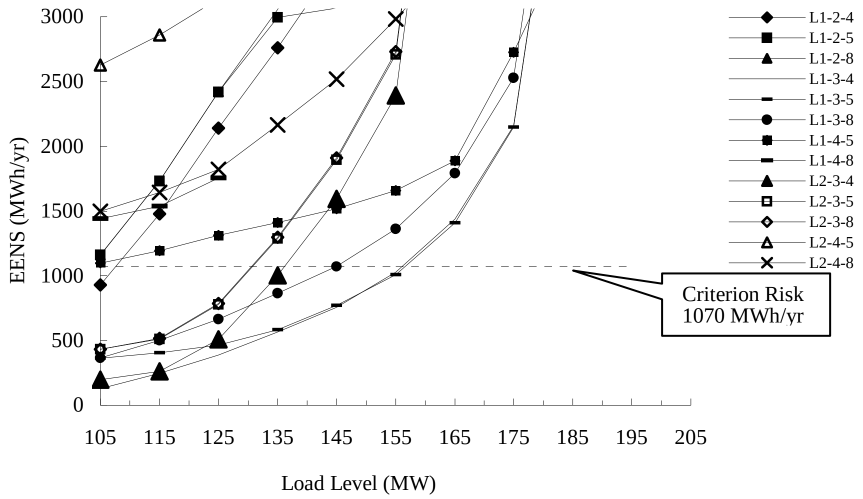

Figure 5.5: System EENS of the RBTS as a function of the load level (remove three lines)

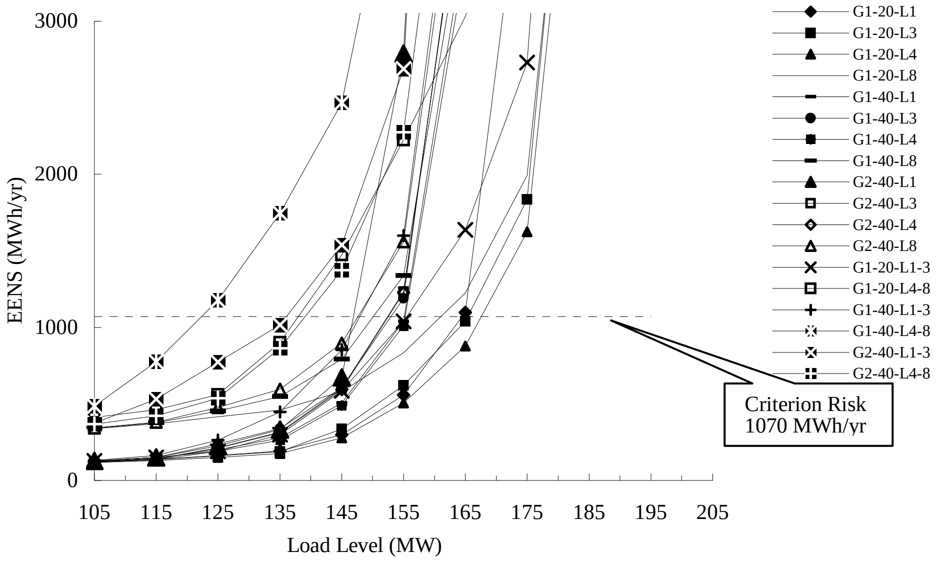

Figure 5.6: System EENS of the RBTS as a function of the load level (remove unit and line(s))

As an example, the case L4-8, i.e. removing Line 4 and Line 8 for maintenance, is analyzed below.

Step 1: Assume that lines 4 and 8 are requested for planned outage during the next week. Assume that this period is week 10 in the RBTS annual load profile shown in Table 5.2.

Step 2: Assume that during week 10, only Line 4 and Line 8 will be off for maintenance.

Step 3: Determine the critical load level for this maintenance outage condition. This is approximately 148 MW as shown in Figure 5.4. This value exceeds the load level of 136.3 MW shown for week 10 in Table 5.2. It is therefore acceptable to remove these lines at this time.

Table 5.2: The weekly peak loads of the RBTS

Week	Peak load (MW)	Week	Peak load (MW)	Week	Peak load (MW)	Week	Peak load (MW)
1	159.5	14	138.8	27	139.7	40	133.9
2	166.5	15	133.4	28	151.0	41	137.5
3	162.4	16	148.0	29	148.2	42	137.6
4	154.3	17	139.5	30	162.8	43	148.0
5	162.8	18	154.8	31	133.6	44	163.0
6	155.6	19	161.0	32	143.6	45	163.7
7	153.9	20	162.8	33	148.0	46	168.2
8	149.1	21	158.4	34	134.9	47	173.9
9	136.9	22	150.0	35	134.3	48	164.7
10	136.3	23	166.5	36	130.4	49	174.3
11	132.3	24	164.1	37	144.3	50	179.5
12	134.5	25	165.8	38	128.6	51	185.0
13	130.2	26	159.3	39	133.9	52	176.1

There may be many periods in a year when it is acceptable to remove these two lines. This also applies to all the maintenance cases considered. This is illustrated in Table 5.3 using several maintenance situations. The different planned outage cases all have different critical load levels as shown in Table 5.3 and therefore different possible time periods in which the required maintenance can be scheduled. A high critical load values indicates that there are many possible periods in which the maintenance can be scheduled.

Table 5.3: Available weeks for selected maintenance outages based on system EENS

Case	Critical Load (MW)	Possible Weeks
L4-8	148	9-17, 27, 31-43
L1-3	166	1, 3-22, 24-45, 48
G2-40	152	8-17, 22, 27-29, 31-43
L1-3-5	157	4, 6-18, 22, 27-29, 31-43

Figures 5.2 to 5.6 show the variation of the risk around the critical load level (gradual or abrupt). This is also important information in decision making. In addition, it

is also possible to estimate the likelihood of accepting additional maintenance requests in the period considered. It also can be seen from Figures 5.2 to 5.6 that removing more components out of service results in the related curves moving to the left. The risk at a particular load level increases and the weeks available for the requested maintenance decrease.

The system PLC of each maintenance case at the given load levels are shown in Table D.1. The results are presented pictorially in Figures 5.7 to 5.11. The four cases given in Table 5.3 were analyzed using the system PLC criterion and the results are listed in Table 5.4.

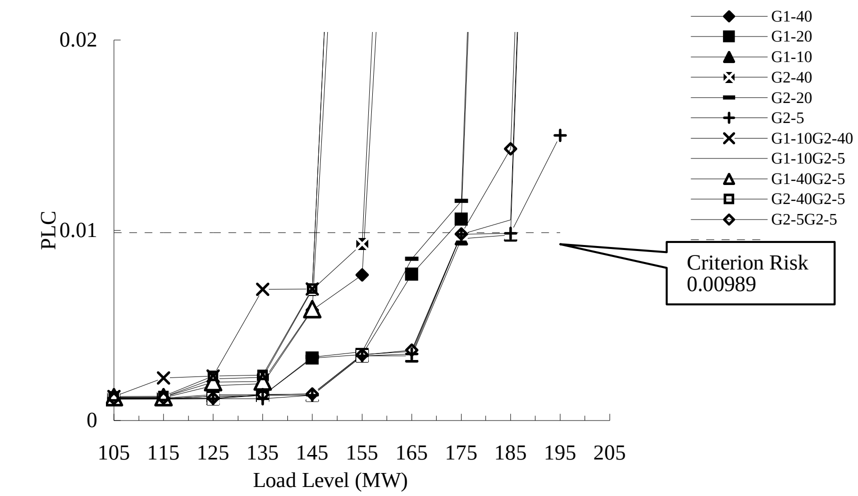

Figure 5.7: System PLC of the RBTS as a function of the load level (remove generation)

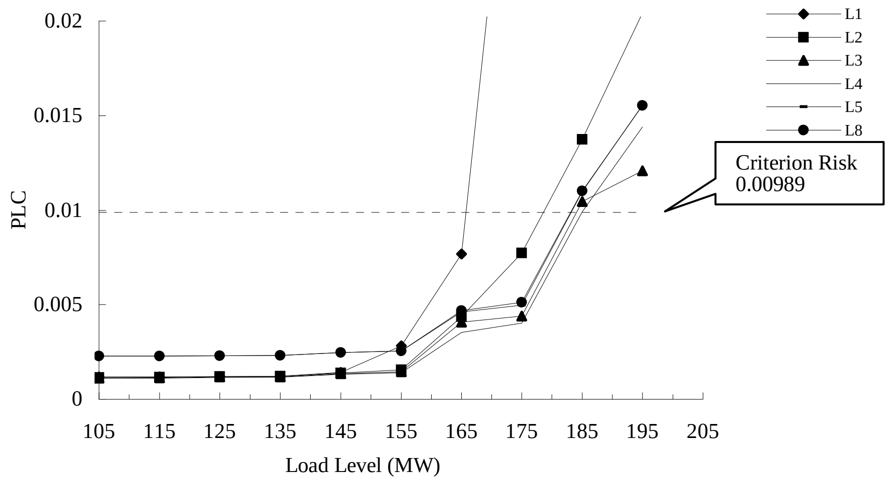

Figure 5.8: System PLC of the RBTS as a function of the load level (remove one line)

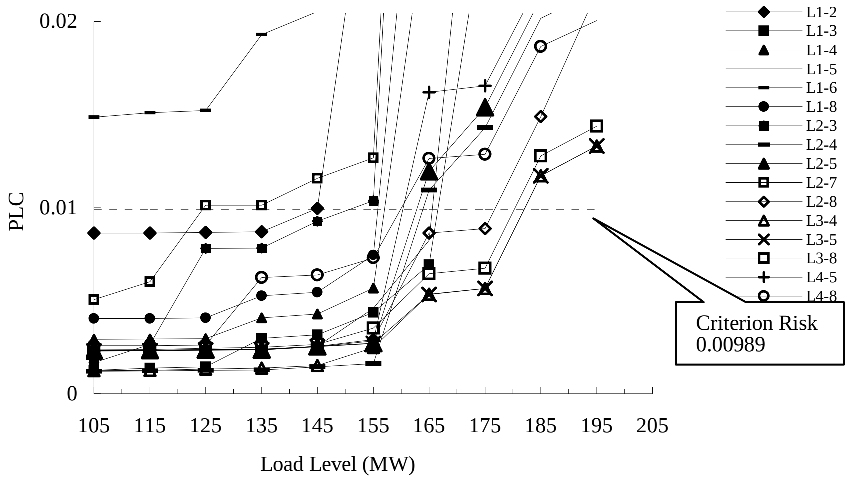

Figure 5.9: System PLC of the RBTS as a function of the load level (remove two lines)

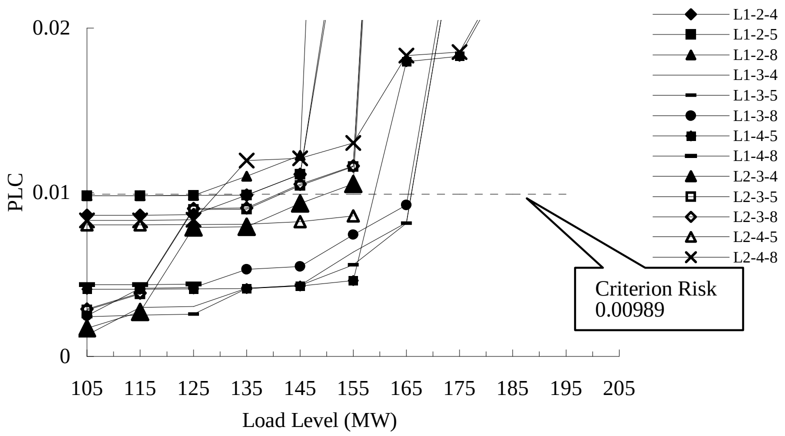

Figure 5.10: System PLC of the RBTS as a function of the load level (remove three lines)

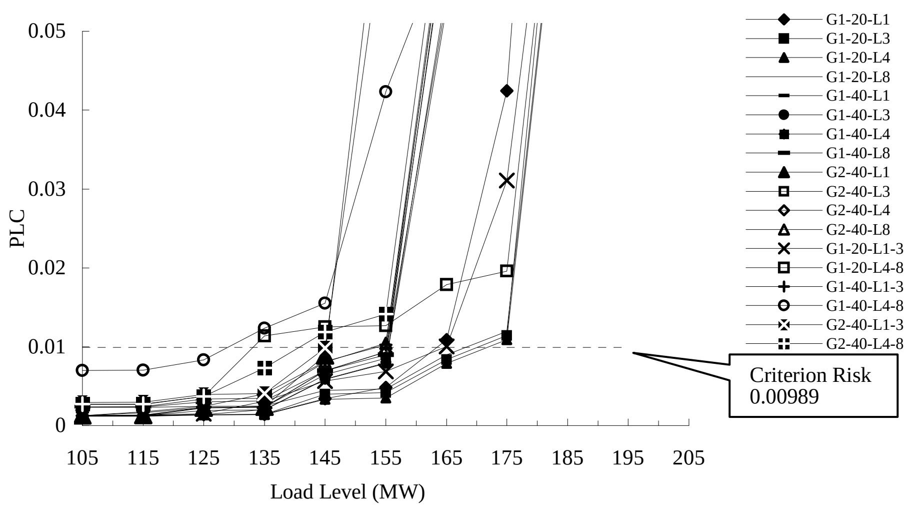

Figure 5.11: System PLC of the RBTS as a function of the load level (remove unit and line(s))

Table 5.4: Available weeks for selected maintenance outages based on system PLC

Case	Critical Load (MW)	Possible Weeks
L4-8	160	1, 4, 6-18, 21-22, 26-29, 31-43
L1-3	166	1, 3-22, 24-45, 48
G2-40	155	4, 7-18, 22, 27-29, 31-43
L1-3-5	166	1, 3-22, 24-45, 48

It can be seen from Table 5.4 that as in Table 5.3, the selected maintenance requests have different critical loads, which result in different opportunities for the planned maintenance. It can be seen from Table 5.4 that amongst these four cases, G2-40 has the lowest critical load from a system PLC viewpoint. Cases L1-3 and L1-3-5 have the same critical load and therefore the same available block of weeks. The reason for this is that these two cases are dominated by L1, i.e. removing Line 1. This can be seen by comparing the L1 (Figure 5.8) with L1-3 (Figure 5.9) and L1-3-5 (Figure 5.10). Removing Line 3, Line 5, and Lines 3 and 5 have relatively small impact on the system PLC.

The system ENLC of each maintenance case at the given load levels are shown in Table D.2 and presented pictorially in Figures 5.12 to 5.16. The four cases given in Table 5.3 were analyzed using the system ENLC criterion and the results are listed in Table 5.5.

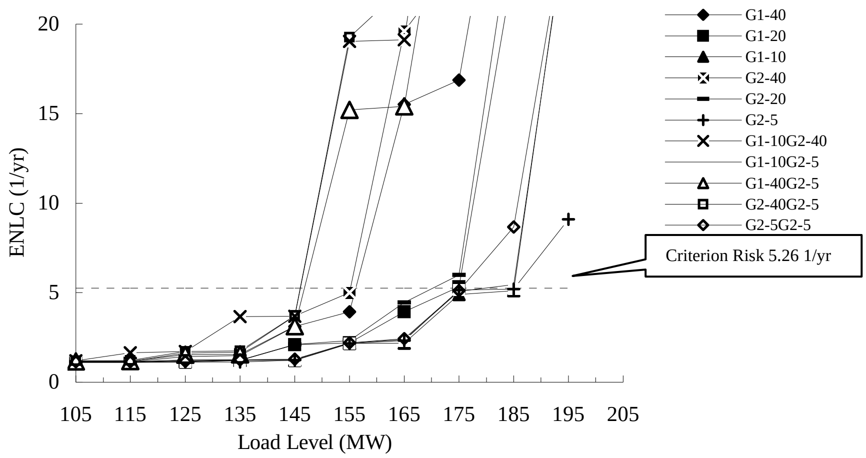

Figure 5.12: System ENLC of the RBTS as a function of the load level (remove generation)

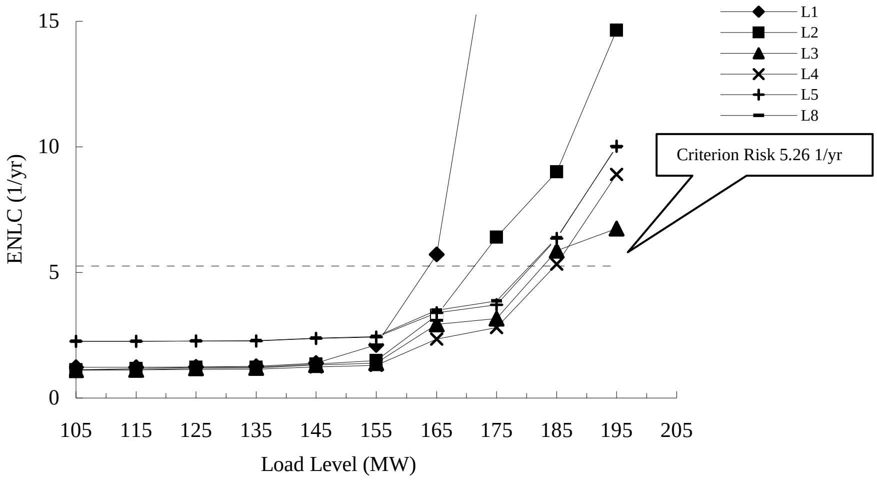

Figure 5.13: System ENLC of the RBTS as a function of the load level (remove one line)

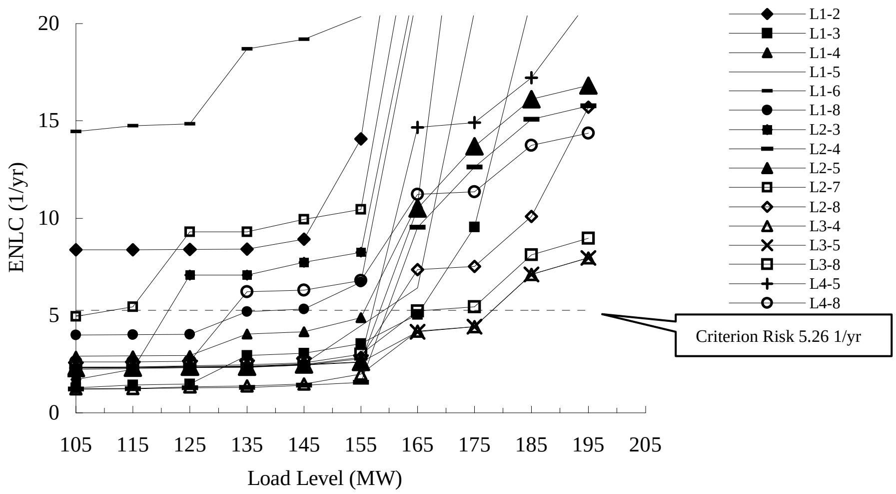

Figure 5.14: System ENLC of the RBTS as a function of the load level (remove two lines)

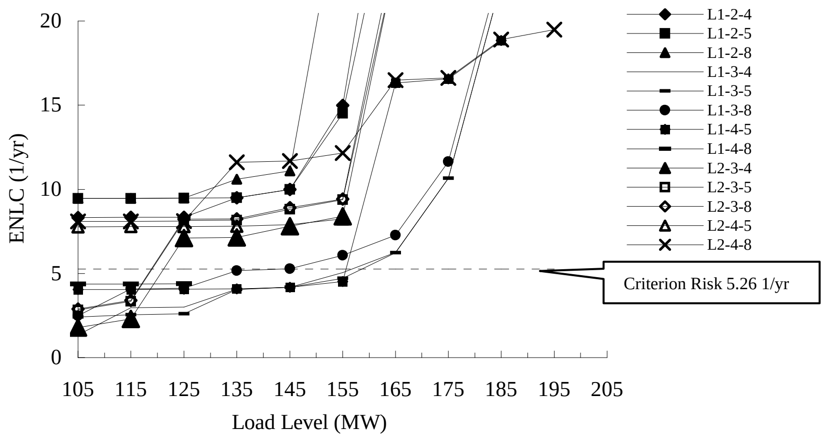

Figure 5.15: System ENLC of the RBTS as a function of the load level (remove three lines)

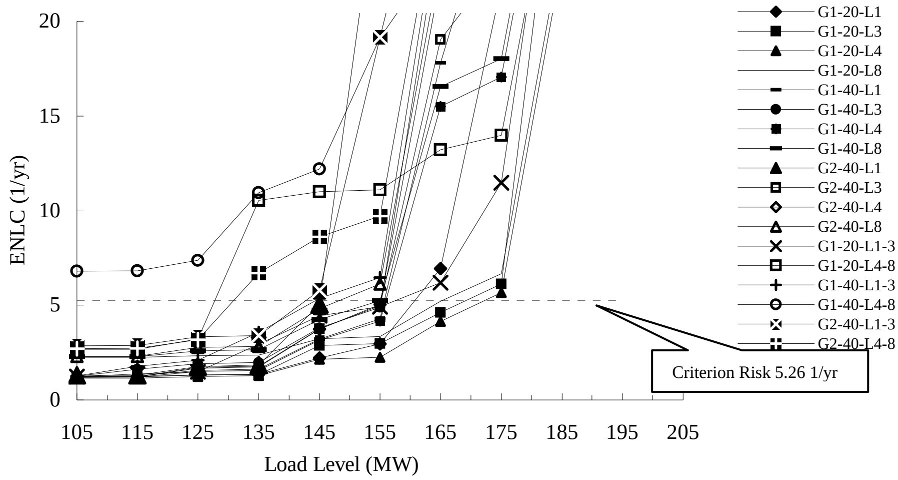

Figure 5.16: System ENLC of the RBTS as a function of the load level (remove unit and line(s))

Table 5.5: Available weeks for selected maintenance outages based on system ENLC

Case	Critical Load (MW)	Possible Weeks
L4-8	132	13, 36, 38
L1-3	166	1, 3-22, 24-45, 48
G2-40	155	4, 6-18, 22, 27-29, 31-43
L1-3-5	158	4, 6-18, 22, 27-29, 31-43

Table 5.5 again indicates that the different maintenance requests have different critical loads, which result in different opportunities for the planned maintenance. From a system ENLC point of view, removing Line 4 and Line 8 results in the lowest critical load level and can only be done in weeks 13, 26, and 38. Although the G2-40 and L1-3-5 have different critical loads, they have the same opportunities for the required maintenance. Case L1-3 has the highest critical load and therefore has the most opportunities for the required maintenance.

The studies conducted in this section are based on three system indices, i.e. EENS, PLC, and ENLC. Tables 5.2, 5.4 and 5.5 show weekly time periods in which certain planned outages could be conducted. The results in Tables 5.2, 5.4 and 5.5 are aggregated in Table 5.6 in order to compare the effects of using different system indices on the available time periods. Table 5.6 shows that for each maintenance case, the different system indices usually provide different critical loads and therefore different weeks during which the requested maintenance can be conducted. There is no common response in all cases. It can be seen from Table 5.6 that the system PLC has the highest critical load for these four cases and the system EENS tends to have the lowest critical load.

Table 5.6: The effects of different system risk indices on the schedules

Case	System Risk	Critical Load (MW)	Possible Weeks
L4-8	EENS	148	9-17, 27, 31-43
	PLC	160	1, 4, 6-18, 21-22, 26-29, 31-43
	ENLC	132	13, 36, 38
L1-3	EENS	166	1, 3-22, 24-45, 48
	PLC	166	1, 3-22, 24-45, 48
	ENLC	166	1, 3-22, 24-45, 48
G2-40	EENS	152	8-17, 22, 27-29, 31-43
	PLC	155	4, 7-18, 22, 27-29, 31-43
	ENLC	155	4, 7-18, 22, 27-29, 31-43
L1-3-5	EENS	157	4, 6-18, 22, 27-29, 31-43
	PLC	166	1, 3-22, 24-45, 48
	ENLC	158	4, 6-18, 22, 27-29, 31-43

As noted earlier, any system index can be selected as the criterion index. The maintenance coordination technique (MCT) presented in this thesis can be used with any of the system indices to determine if a certain planned outage can be scheduled during a given period and also what other periods might be available.

The following studies are based on the EENS index which appears to be the most popular index in system planning. It is a combination of the magnitude of load curtailment, the duration of load curtailment, and the frequency of load curtailment. In addition, it can be seen from Table 5.6 that maintenance schedules based on the system EENS are relatively conservative.

5.3.2 Scheduling based on the load point EENS

As noted earlier, a planned outage, which is acceptable in terms of the system risk, may be unacceptable based on the load point risk. It is therefore necessary from a load point perspective to check for unacceptable conditions created using the system risk. The following analyses are based on the application of the MCT to the load points using the EENS index. Bus 2 has a very high reliability level and is not included in this analysis.

Criterion risk determination is very important in this analysis. It is basically a management decision and is affected by many factors such as customer composition and reliability requirements. In these studies it is assumed that the base case EENS of each load point is used as the criterion risk.

The Bus 3 EENS for each case at various load levels are shown in Table D.3 and presented pictorially in Figures 5.17 to 5.21. The four cases shown in Table 5.3 were analyzed and the results are shown in Table 5.7.

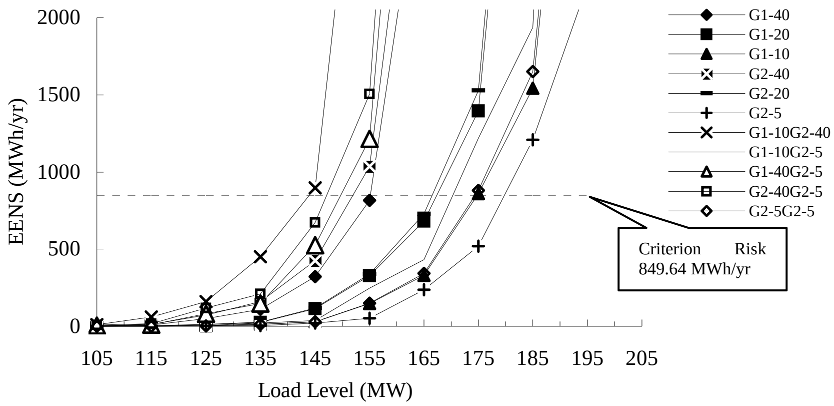

Figure 5.17: Bus 3 EENS of the RBTS as a function of the load level (remove generation)

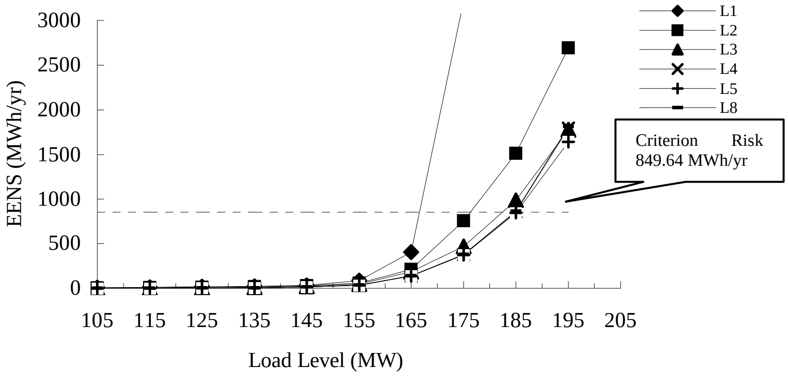

Figure 5.18: Bus 3 EENS of the RBTS as a function of the load level (remove one line)

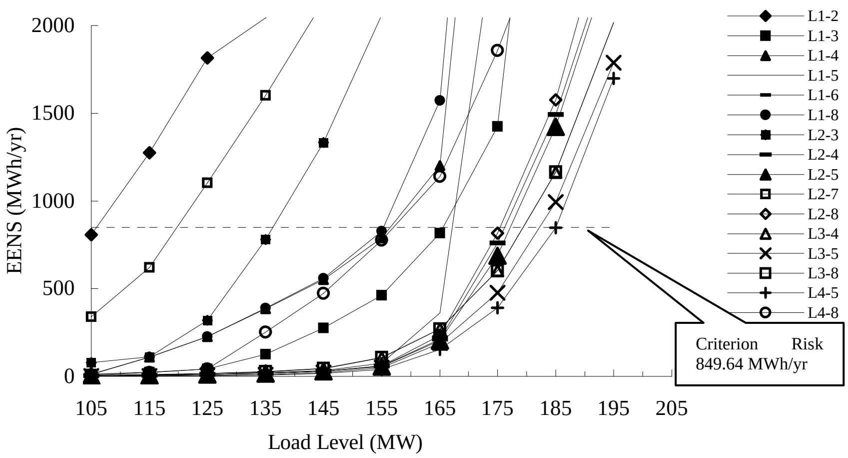

Figure 5.19: Bus 3 EENS of the RBTS as a function of the load level (remove two lines)

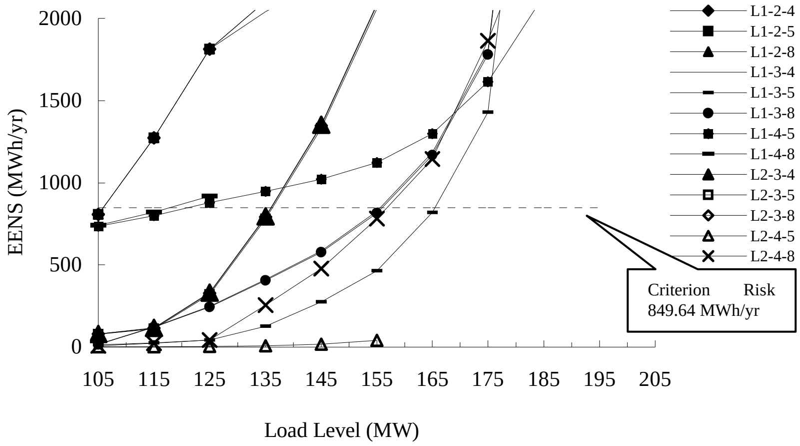

Figure 5.20: Bus 3 EENS of the RBTS as a function of the load level (remove three lines)

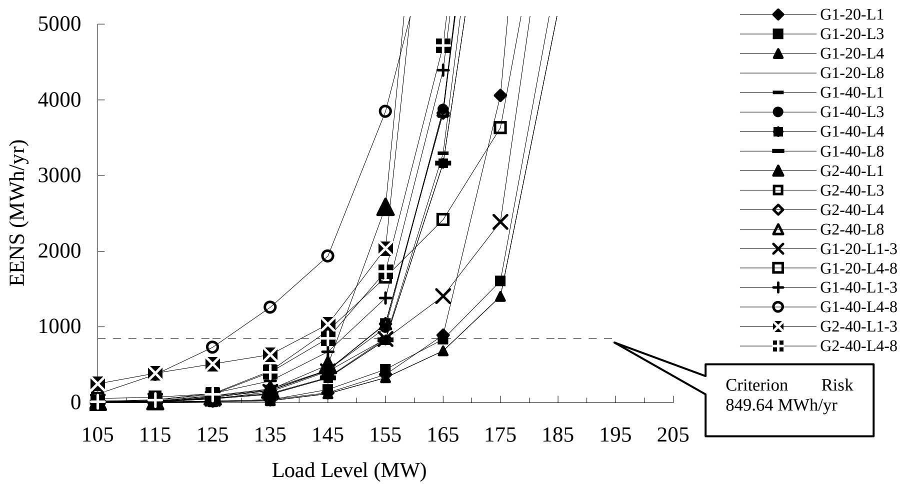

Figure 5.21: Bus 3 EENS of the RBTS as a function of the load level (remove unit and line(s))

Table 5.7: Available weeks for selected maintenance outages based on Bus 3 EENS

Case	Critical Load (MW)	Possible Weeks
L4-8	157	4, 6-18, 22, 27-29, 31-43
L1-3	166	1, 3-22, 24-45, 48
G2-40	151	8-17, 22, 27-29, 31-43
L1-3-5	166	1, 3-22, 24-45, 48

It can be seen from Table 5.7 that the comments made earlier from a system viewpoint are also valid from a load point perspective. The different maintenance requests have different critical loads, which result in different opportunities for the planned maintenance. Case G2-40 has the lowest critical load which means Bus 3 may be more sensitive to generation removals. Cases L1-3 and L1-3-5 have the same critical load and therefore the same possible weeks for maintenance. The reason is that these two cases are dominated by L1, i.e. the removal of Line 1. The four maintenance cases have many available weeks based on the Bus 3 EENS.

The Bus 4 EENS for each case at various load levels are shown in Table D.4 and presented pictorially in Figures 5.22 to 5.26. The four cases considered are listed in Table 5.8.

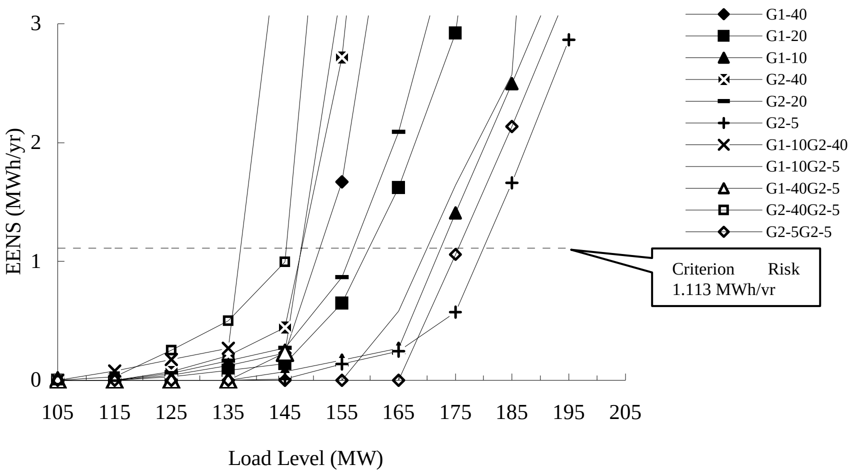

Figure 5.22: Bus 4 EENS of the RBTS as a function of the load level (remove generation)

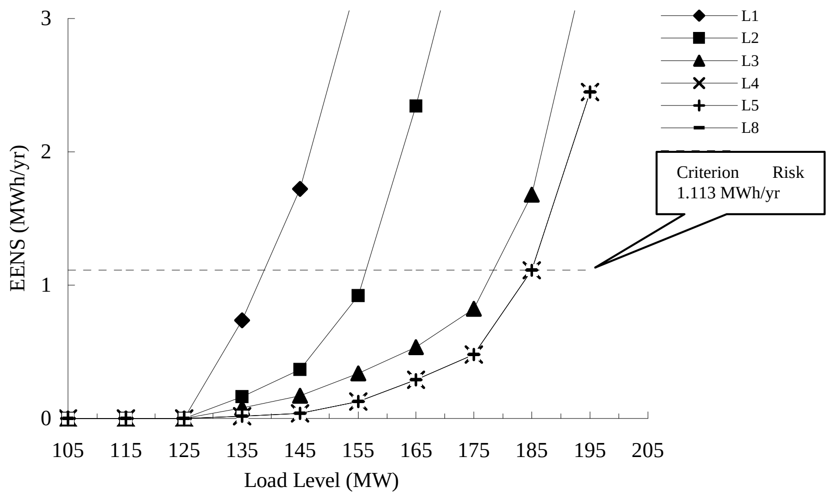

Figure 5.23: Bus 4 EENS of the RBTS as a function of the load level (remove one line)

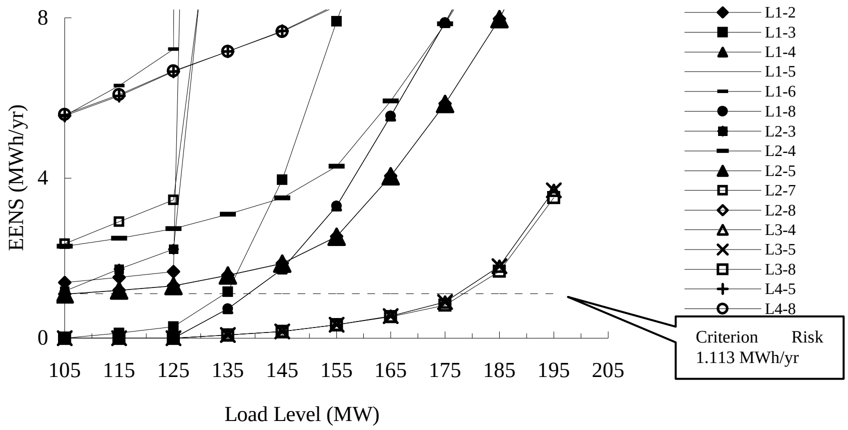

Figure 5.24: Bus 4 EENS of the RBTS as a function of the load level (remove two lines)

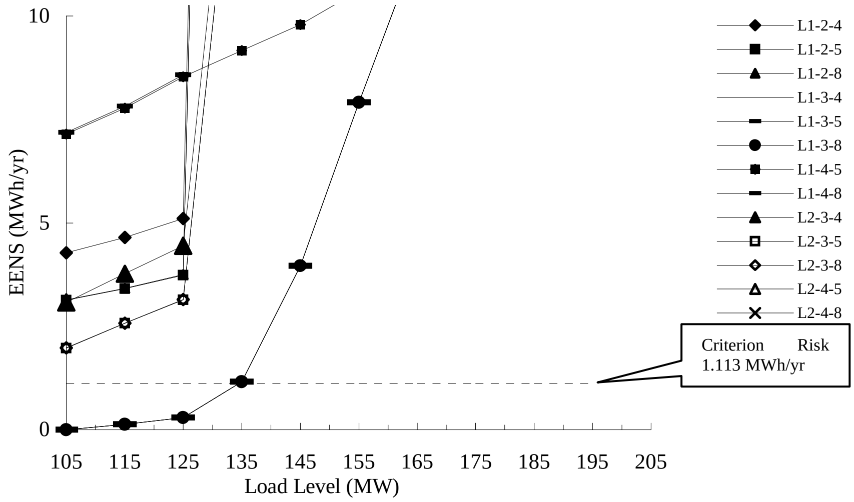

Figure 5.25: Bus 4 EENS of the RBTS as a function of the load level (remove three lines)

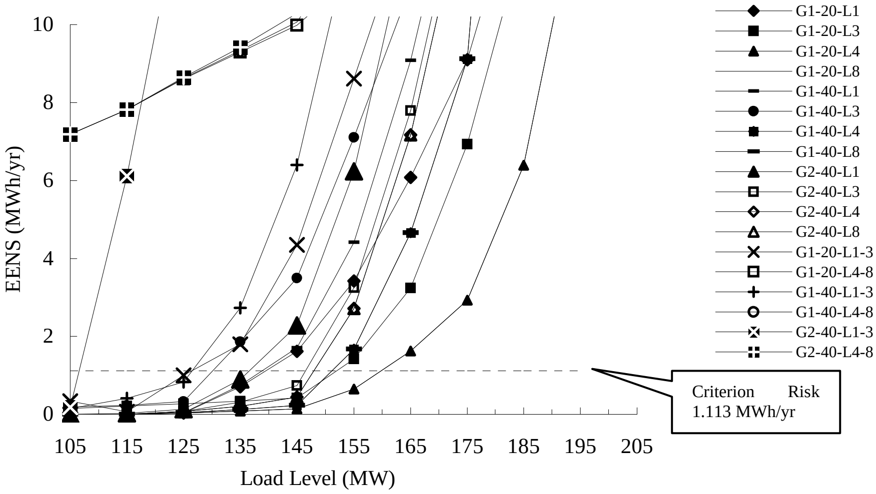

Figure 5.26: Bus 4 EENS of the RBTS as a function of load level (remove unit and line(s))

Table 5.8: The Available weeks for selected maintenance outages based on Bus 4 EENS

Case	Critical Load (MW)	Possible Weeks
L4-8	<105	N/A
L1-3	135	11-13, 15, 31, 34-36, 38-40
G2-40	148	9-17, 27, 31-43
L1-3-5	135	11-13, 15, 31, 34-36, 38-40

It can be seen from Table 5.8 that L4-8 creates an unacceptable condition at Bus 4 for all the weeks. This is also true for many other transmission cases (Figures 5.24 and 5.25). The reason for this is that the criterion risk at Bus 4 is quite low and even a little increase in the EENS will violate the criterion. The selection of the base case EENS at a particular load point may not be acceptable. This again is a management decision. The determination of the load point criterion risk, however, is very important.

The Bus 5 EENS for each case at various load levels are shown in Table D.5 and presented pictorially in Figures 5.27 to 5.31. The four cases considered are listed in Table 5.9.

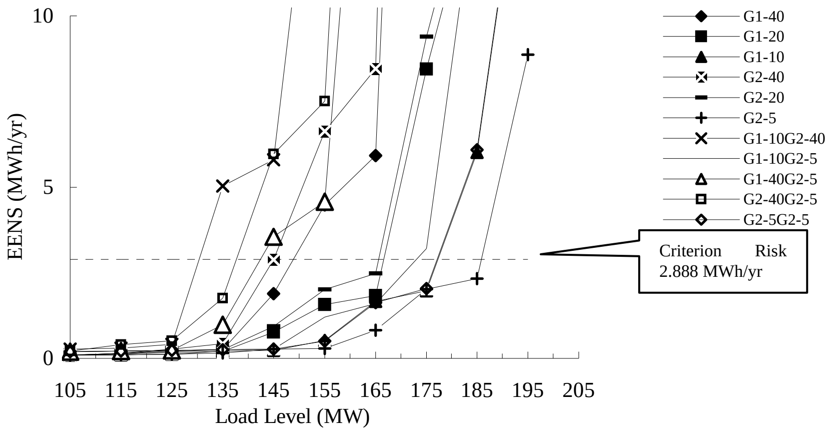

Figure 5.27: Bus 5 EENS of the RBTS as a function of the load level (remove generation)

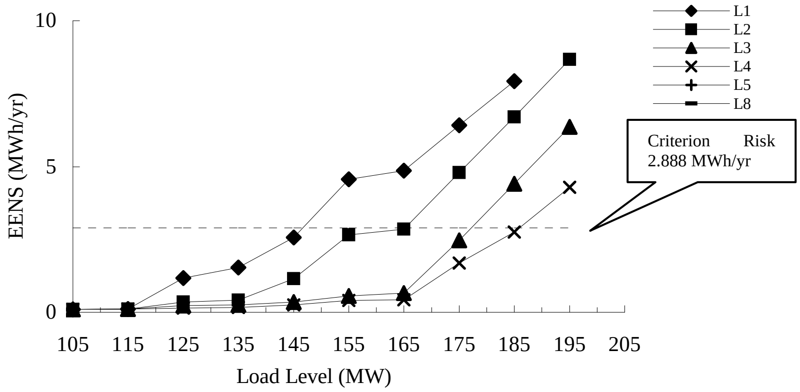

Figure 5.28: Bus 5 EENS of the RBTS as a function of the load level (remove one line)

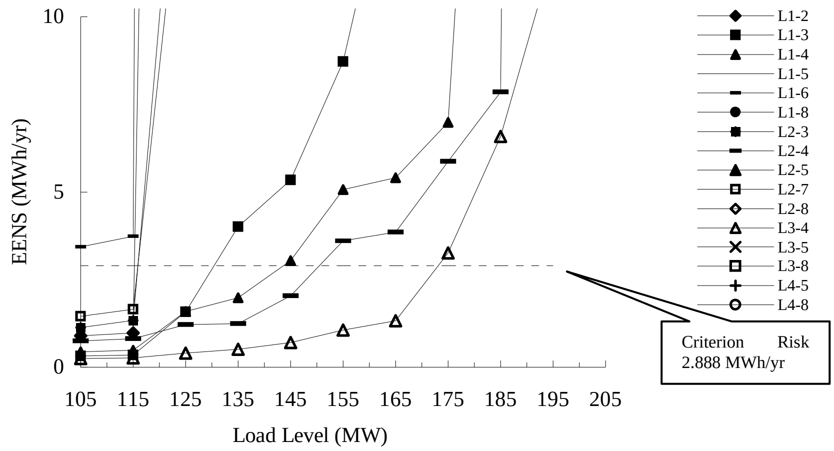

Figure 5.29: Bus 5 EENS of the RBTS as a function of the load level (remove two lines)

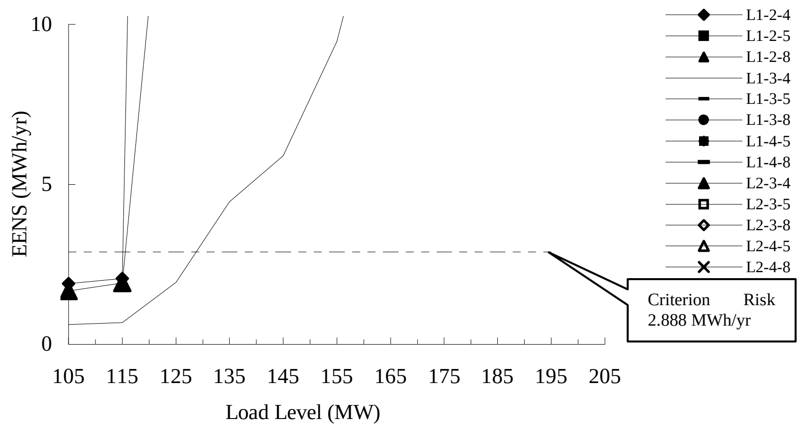

Figure 5.30: Bus 5 EENS of the RBTS as a function of the load level (remove three lines)

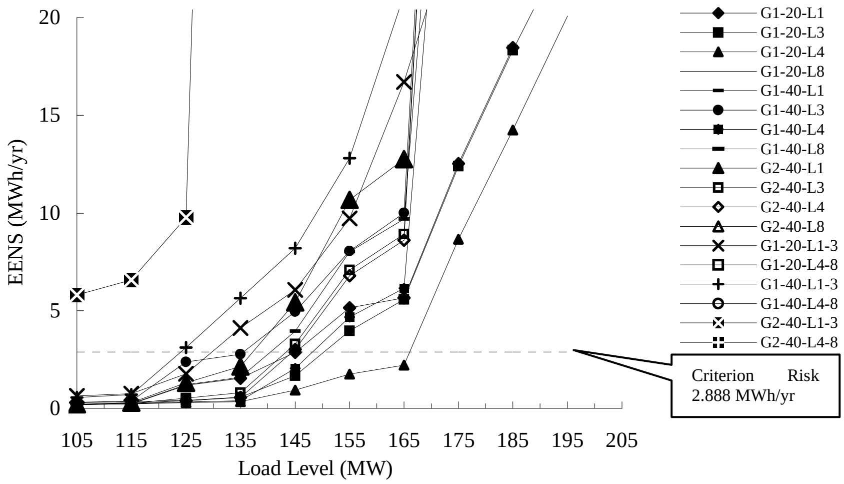

Figure 5.31: Bus 5 EENS of the RBTS as a function of the load level (remove unit and line(s))

Table 5.9: Available weeks for selected maintenance outages based on Bus 5 EENS

Case	Critical Load (MW)	Possible Weeks
L4-8	<105	N/A
L1-3	130	38
G2-40	145	9-15, 17, 27, 31-32, 34-42
L1-3-5	<105	N/A

Table 5.9 shows that L4-8 and L1-3-5 are unacceptable for Bus 5. It can be seen from Figure 5.28 that the risk of removing Line 5 or Line 8 is much higher than the criterion. Many other transmission cases (Figures 5.29 and 5.30) are also unacceptable due to the relatively low criterion risk. Case L1-3 can be done only in week 38. As in the situation at Bus 4, there are more opportunities for generation maintenance requests than for transmission requests.

The Bus 6 EENS of each case at various load levels are shown in Table D.6 and presented pictorially in Figures 5.32 to 5.36. The four cases considered are listed in Table 5.10.

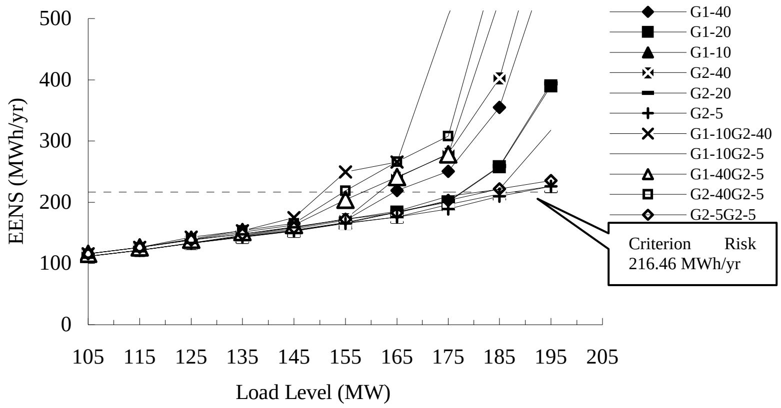

Figure 5.32: Bus 6 EENS of the RBTS as a function of the load level (remove generation)

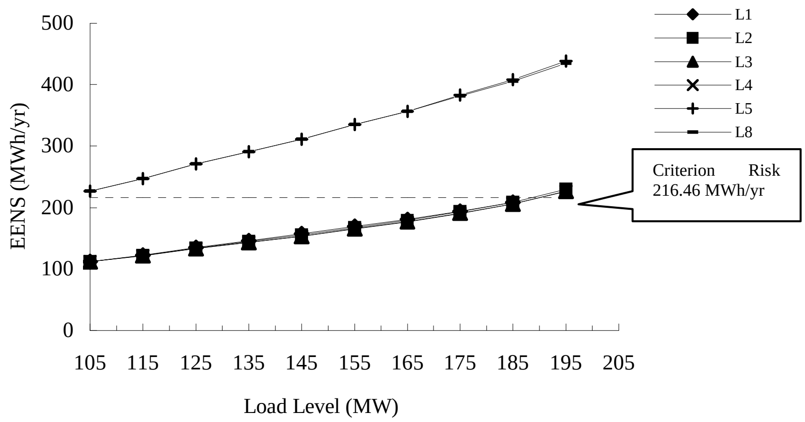

Figure 5.33: Bus 6 EENS of the RBTS as a function of the load level (remove one line)

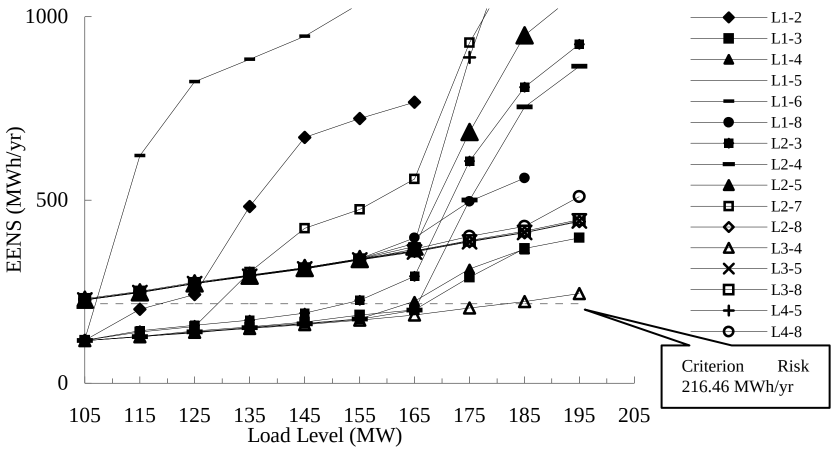

Figure 5.34: Bus 6 EENS of the RBTS as a function of the load level (remove two lines)

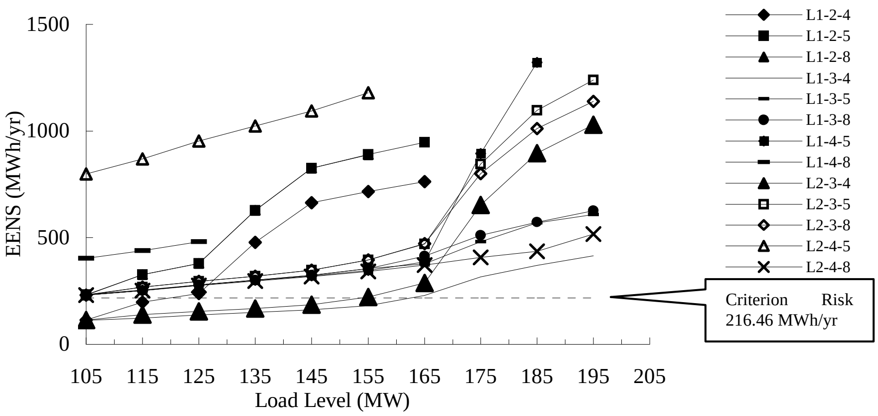

Figure 5.35: Bus 6 EENS of the RBTS as a function of the load level (remove three lines)

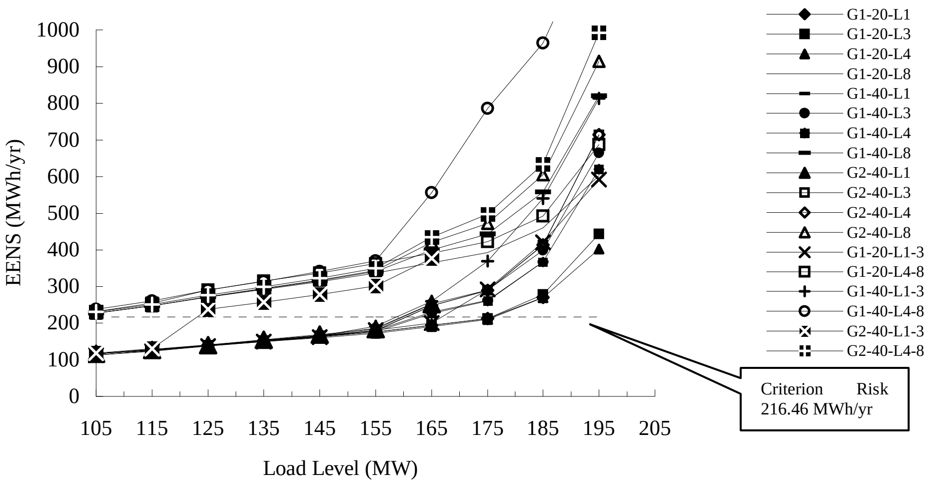

Figure 5.36: Bus 6 EENS of the RBTS as a function of the load level (remove unit and line(s))

Table 5.10: Available weeks for selected maintenance outages based on Bus 6 EENS

Case	Critical Load (MW)	Possible Weeks
L4-8	<105	N/A
L1-3	167	1-45, 48
G2-40	162	1, 4, 6-19, 21-22, 26-29, 31-43
L1-3-5	<105	N/A

Table 5.10 shows that L4-8 and L1-3-5 are unacceptable at Bus 6 as the removal of Line 5 or Line 8 violates the criterion. It should be noted that Bus 6 has a large criterion risk compared to Bus 5. Many generation cases and some transmission cases (not involving Line 5 or Line 8) have larger critical loads and therefore there are many opportunities for planned outages based on the Bus 6 criterion.

The information in Tables 5.3 and 5.7 to 5.10 is aggregated in Table 5.11 in order to compare the difference between the possible schedules based on the load point EENS and the system EENS.

Table 5.11: Comparison of the available periods based on the load point and system EENS

Case	Risk	Critical Load (MW)	Possible Weeks
L4-8	System EENS	148	9-17, 27, 31-43
	Bus 3 EENS	157	4, 6-18, 22, 27-29, 31-43
	Bus 4 EENS	<105	N/A
	Bus 5 EENS	<105	N/A
	Bus 6 EENS	<105	N/A
L1-3	System EENS	136	11-13, 15, 31, 34-36, 38-40
	Bus 3 EENS	166	1, 3-22, 24-45, 48
	Bus 4 EENS	135	11-13, 15, 31, 34-36, 38-40
	Bus 5 EENS	130	38
	Bus 6 EENS	167	1-45, 48
G2-40	System EENS	152	8-17, 22, 27-29, 31-43
	Bus 3 EENS	151	8-17, 22, 27-29, 31-43
	Bus 4 EENS	148	9-17, 27, 31-43
	Bus 5 EENS	145	9-15, 17, 27, 31-32, 34-42
	Bus 6 EENS	167	1-45, 48
L1-3-5	System EENS	157	4, 6-18, 22, 27-29, 31-43
	Bus 3 EENS	166	1, 3-22, 24-45, 48
	Bus 4 EENS	135	11-13, 15, 31, 34-36, 38-40
	Bus 5 EENS	<105	N/A
	Bus 6 EENS	<105	N/A

It can be seen from Table 5.11 that significant differences in the schedules exist. If the load point criteria are applied in addition to the system criterion, then L4-8 and L1-3-5 are unacceptable in any week of the year. Removing Line 1 and Line 3 simultaneously can be done only in week 38, and G2-40 could still be scheduled in many weeks (9-15, 17, 27, 31-32, 34-42).

It should again be noted that the analysis above is based on the assumption that the base case indices are accepted as the criterion risks. Determination of the criterion risk at a load point is a practical management issue. It is important from a load point viewpoint to check for unacceptable conditions created using overall system analysis.

5.3.3 Selected case analyses

The analyses conducted in Sections 5.3.1 and 5.3.2 indicate that different system indices can result in different schedules and a schedule that is acceptable based on the system index may be unacceptable based on the load point indices. Several additional cases are considered in this section. The system EENS of the base case is again used as the criterion risk in these studies.

Figure 5.37 shows the risk as a function of the load level for three cases (G1-40, L1, and G1-40-L1) using the data in Table 5.1. The weeks in which these maintenance removals can be conducted are given in Table 5.12.

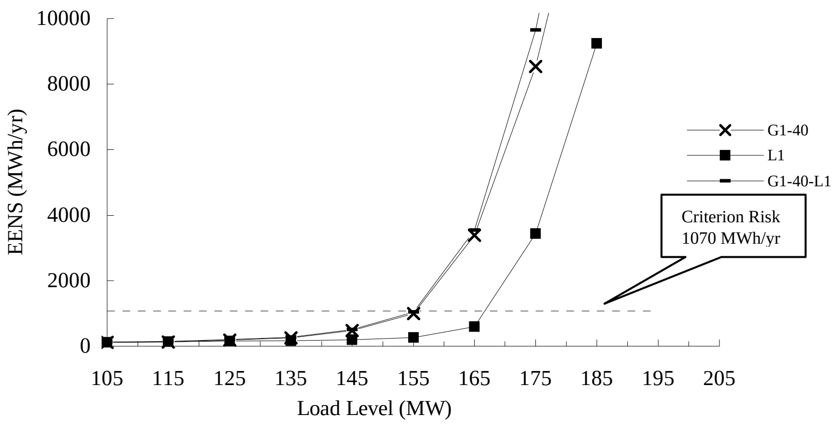

Figure 5.37: System EENS as a function of the load level (cases G1-40, L1, and G1-40-L1)

Table 5.12: Available weeks for selected maintenance outages based on system EENS

Case	Critical Load (MW)	Possible Weeks
G1-40	155	4, 7-18, 22, 27-29, 31-43
L1	167	1-45, 48
G1-40-L1	155	4, 7-18, 22, 27-29, 31-43

It can be seen from Figure 5.37 and Table 5.12 that the risk associated with removing one 40 MW unit at Bus 1 is much higher than that associated with removing Line 1, and therefore there are more opportunities available for maintenance on Line 1. The difference between the risks associated with G1-40 and G1-40-L1 is very small, which indicates that the G1-40-L1 risk is dominated by G1-40. In other words, whenever one 40 MW unit at Bus 1 is removed for maintenance, removing Line 1 does not significantly increase the risk. It should be appreciated that the risk associated with G1-40-L1 cannot be obtained by simply adding the risks associated with G1-40 and L1.

Figure 5.38 shows the risk as a function of load level for the three cases of G1-40, L1-3, and G1-40-L1-3 using the data in Tables 5.1. The weeks in which these maintenance removals can be conducted are given in Table 5.13. The risk associated with G1-40-L1-3 is higher than those of the other two cases and the opportunities for maintenance in these three cases are also different.

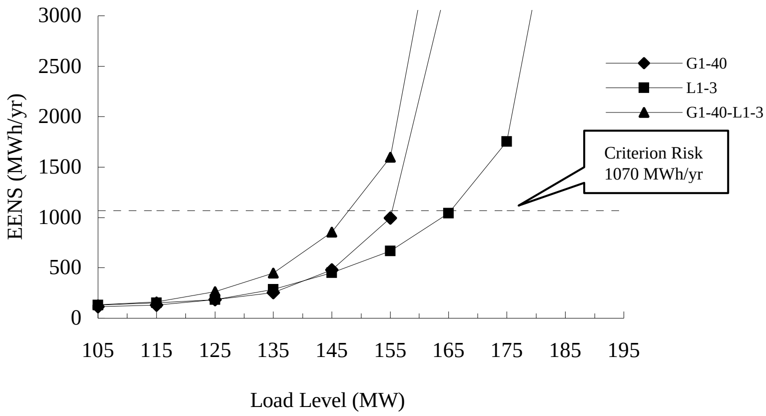

Figure 5.38: System EENS as a function of the load level (cases G1-40, L1-3, and G1-40-L1-3)

Table 5.13: Available weeks for selected maintenance outages based on system EENS

Case	Critical Load (MW)	Possible Weeks
G1-40	155	4, 7-18, 22, 27-29, 31-43
L1-3	165	1, 3-22, 24, 26-45, 48
G1-40-L1-3	148	9-17, 27, 31-43

In practice, it is possible that different generation and transmission element owners may request that different facilities be removed for maintenance in the same time period. From their own perspectives, these removals are acceptable. From a system point of view, however, they may not be acceptable. For instance, it can be seen from Table 5.13 that G1-40 and L1-3 are acceptable in weeks 28 and 29 from an individual point of view, but G1-40-L1-3 is unacceptable during these two weeks from a system viewpoint. This clearly indicates that an overall body such as an ISO should co-ordinate the many possible requests for maintenance removals.

Figure 5.39 shows the risk as a function of load level for another six cases (G1-40, L4, L8 and some of their combination) using the data in Table 5.1. The weeks in which these outages can be done are shown in Table 5.14.

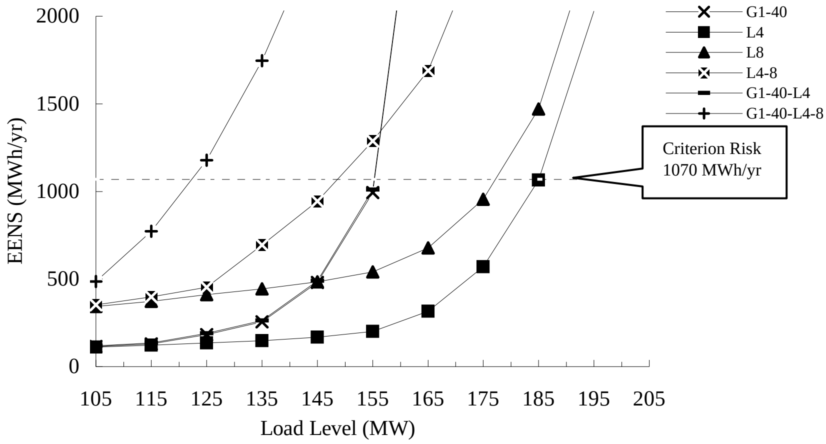

Figure 5.39: System EENS as a function of the load level for the six cases

It can be seen from Figure 5.39 and Table 5.14 that L4 can be done at any time of the year. Cases G1-40 and G1-40-L4 have almost the same response to the load variation and therefore the same opportunities for planned outage. When one 40 MW unit at Bus 1 is removed for maintenance, the removal of Line 4 minimally increases the system risk. This is not the case for L4-8. Case G1-40-L4-8 is quite different from either G1-40 or L4-8. Figure 5.39 and Table 5.14 show that G1-40-L4-8 is unacceptable at any time. This reinforces the point made earlier that the risk associated with two maintenance requests cannot be assessed by simply summing the risks associated with each individual request.

Table 5.14: Available weeks for selected maintenance outages based on system EENS

Case	Critical Load (MW)	Possible Weeks
G1-40	155	4, 7-18, 22, 27-29, 31-43
L4	185	1-52
L8	178	1-49, 52
L4-8	149	9-17, 27, 29, 31-43
G1-40-L4	155	4, 7-18, 22, 27-29, 31-43
G1-40-L4-8	122	N/A

5.4 Application of the MCT to the IEEE-RTS

The RBTS is a relatively small system and many factors constrain removing elements for maintenance. The IEEE-RTS is relatively large compared to the RBTS. As noted earlier, the IEEE-RTS has a strong transmission network and a weak generation system. It has more room for removing elements, especially transmission lines, from the system for maintenance than does the RBTS. It is unnecessary and impossible to analyze all the possible element removal cases for the IEEE-RTS. The following cases were studied and are discussed in this section to illustrate the application of the MCT to the IEEE-RTS.

G18-400: removing one 400 MW unit at Bus 18

G23-350: removing one 350 MW unit at Bus 23

G18-400-13-197: removing one 400 MW unit at Bus 18 and one 197 MW unit at Bus 13

G23-350-13-197: removing one 350 MW unit at Bus 23 and one 197 MW unit at Bus 13

L5: removing Line 5

L23: removing Line 23

L15-16: removing Lines 15 and 16

L1-6-21-31: removing Lines 1, 6, 21, and 31

L2-13-30-36: removing Lines 2, 13, 30, and 36

L2-8-9-12: removing Lines 2, 8, 9, and 12

G18-400-13-197 -L2-8-9-12: removing one 400 MW unit at Bus 18 and one 197 MW unit at Bus 13 as well as Lines 2, 8, 9, and 12

G23-350-13-197 -L2-8-9-12: removing one 350 MW unit at Bus 23 and one 197 MW unit at Bus 13 as well as Lines 2, 8, 9, and 12

As concluded from the studies of the RBTS, any system index or load point index can be used as the criterion risk. The system EENS is used in the following studies. The weekly peak loads of the IEEE-RTS are given in Table 5.15. The annual peak load is 2,850 MW. The base case system EENS is 129,933 MWh/yr and is used as the criterion risk.

Table 5.15: The weekly peak loads of the IEEE-RTS

Week	Peak load (MW)	Week	Peak load (MW)	Week	Peak load (MW)	Week	Peak load (MW)
1	2457	14	2138	27	2152	40	2063
2	2565	15	2055	28	2326	41	2118
3	2502	16	2280	29	2283	42	2120
4	2377	17	2149	30	2508	43	2280
5	2508	18	2385	31	2058	44	2511
6	2397	19	2480	32	2212	45	2522
7	2371	20	2508	33	2280	46	2591
8	2297	21	2440	34	2078	47	2679
9	2109	22	2311	35	2069	48	2537
10	2100	23	2565	36	2009	49	2685
11	2038	24	2528	37	2223	50	2765
12	2072	25	2554	38	1981	51	2850
13	2006	26	2454	39	2063	52	2713

The system EENS for each case of at different load levels are shown in Table 5.16. The corresponding risk profiles are presented in Figure 5.40. The weeks in which these maintenance outages can be done are given in Table 5.17.

Table 5.16: System EENS (MWh/yr) of the IEEE-RTS as a function of the load level with maintenance removals

Case	Load Levels (MW)					
	1900	2100	2300	2500	2700	2900
G18-400	241.95	2902.9	19476	88899	348999	915022
G23-350	444.6	4463.1	25650	95858	347766	872636
G18-400-13-197	2442.8	17045	77919	330374	854714	N/A
G23-350-13-197	3453.6	22453	84576	331087	824741	N/A
L5	1025.8	1560.0	4071.5	14945	59593	183544
L23	616.88	1109.1	3586.9	14413	59078	183207

Table 5.16: (Continued)

Case	Load Levels (MW)					
	1900	2100	2300	2500	2700	2900
L15-16	27.077	457.03	2863.7	13636	58234	182346
L1-6-21-31	30.585	466.1	2881.7	13713	58418	182842
L2-13-30-36	46.906	498.32	2929.6	13729	58549	183128
L2-8-9-12	395.93	931.17	3669.5	15358	61821	198180
G18-400-13-197 -L2-8-9-12	2827.7	17545	78743	331845	855908	N/A
G23-350-13-197 -L2-8-9-12	3845.0	22956	85387	332536	826766	N/A

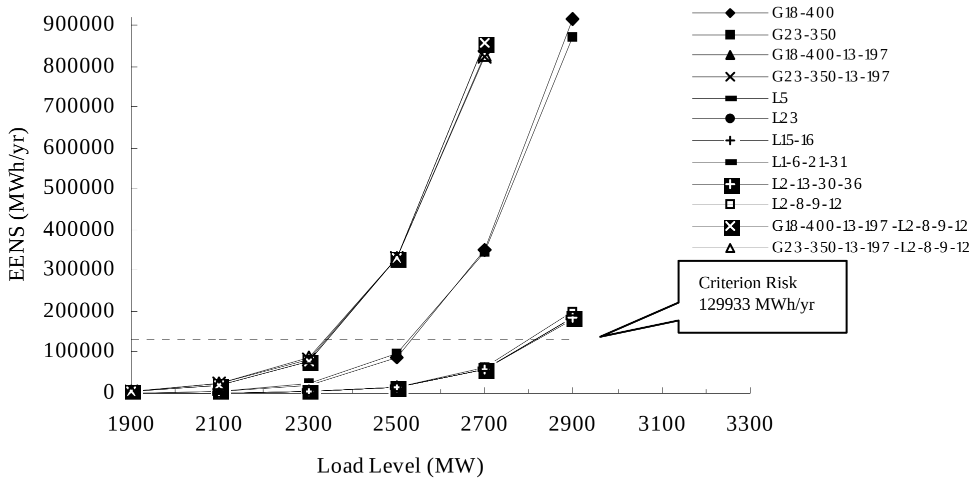

Figure 5.40: System EENS of the IEEE-RTS as a function of the load level

Table 5.17: Available weeks for selected maintenance outages based on system EENS of the IEEE-RTS

Case	Critical Load (MW)	Possible Weeks
G18-400	2560	1, 3-22, 24-45, 48
G23-350	2550	1, 3-22, 24, 26-45, 48
G18-400-13-197	2370	8-17, 22, 27-29, 31-43
G23-350-13-197	2365	8-17, 22, 27-29, 31-43
L5	2815	1-50, 52
L23	2815	1-50, 52
L15-16	2815	1-50, 52
L1-6-21-31	2815	1-50, 52
L2-13-30-36	2815	1-50, 52
L2-8-9-12	2800	1-50, 52
G18-400-13-197 –L2-8-9-12	2365	8-17, 22, 27-29, 31-43
G23-350-13-197 –L2-8-9-12	2365	8-17, 22, 27-29, 31-43

It can be seen from Tables 5.16 and 5.17, and Figure 5.40 that the six cases involving removing transmission have little impact on the system EENS and can be done in any week of the year except week 51. This again indicates that the IEEE-RTS has a very strong transmission network. Cases G18-400 and G23-350 are sensitive to the load level and there are fewer opportunities than for the six transmission cases. Cases G18-400-13-197 and G23-350-13-197 are more sensitive to the load level than G18-400 and G23-350 and the impact of removing an additional 197 MW unit is significant. The impact of removing transmission elements in addition to generating units is seen in G18-400-13-197-L2-8-9-12. This condition has a similar critical load to G18-400-13-197 and the same possible weeks for maintenance. This is also the case for G23-350-13-197-L2-8-9-12 and G23-350-13-197.

In order to stress the transmission network, the original IEEE-RTS generating units and load profile were doubled with the transmission system unchanged. The total capacity of the modified IEEE-RTS (MRTS) is 6,810 MW with a peak load of 5,700 MW. The weekly peak loads of the MRTS are given in Table 5.18. The system EENS of each case for the MRTS at the different load levels are shown in Table 5.19. The corresponding curves are presented in Figure 5.41. The base case system EENS is 209,402 MWh/yr and is used as the criterion risk. The weeks in which these maintenance outages can be done are given in Table 5.20.

Table 5.18: The weekly peak loads of the MRTS

Week	Peak load (MW)	Week	Peak load (MW)	Week	Peak load (MW)	Week	Peak load (MW)
1	4914	14	4276	27	4304	40	4126
2	5130	15	4110	28	4652	41	4236
3	5004	16	4560	29	4566	42	4240
4	4754	17	4298	30	5016	43	4560
5	5016	18	4770	31	4116	44	5022
6	4794	19	4960	32	4424	45	5044
7	4742	20	5016	33	4560	46	5182
8	4594	21	4880	34	4156	47	5358
9	4218	22	4622	35	4138	48	5074
10	4200	23	5130	36	4018	49	5370
11	4076	24	5056	37	4446	50	5530
12	4144	25	5108	38	3962	51	5700
13	4012	26	4908	39	4126	52	5426

Table 5.19: System EENS (MWh/yr) of the MRTS as a function of the load level with maintenance removals

Case	Load Levels (MW)				
	3500	4000	4500	5000	5500
G18-400	2.7016	252.21	1072.4	14593	229266
G23-350	2.7016	252.21	1087.6	17808	294547
G18-400-13-197	2.3600	281.58	2398.1	42713	541950
G23-350-13-197	4.6209	347.37	2852.8	59624	799686
L5	1832.8	N/A	N/A	N/A	N/A
L23	857.03	1264.2	6635.7	N/A	N/A
L15-16	893.87	2773.8	18108	N/A	N/A
L1-6-21-31	930.80	1820.6	4121.7	20657	420377
L2-13-30-36	1064.6	2065.6	3809.4	17660	157746
L2-8-9-12	1769.7	2936.1	6544.0	29386	289188
G18-400-13-197 -L2-8-9-12	1741.1	2921.4	8373.8	66760	701979
G23-350-13-197 -L2-8-9-12	1756.4	2996.5	8967.0	83027	923741

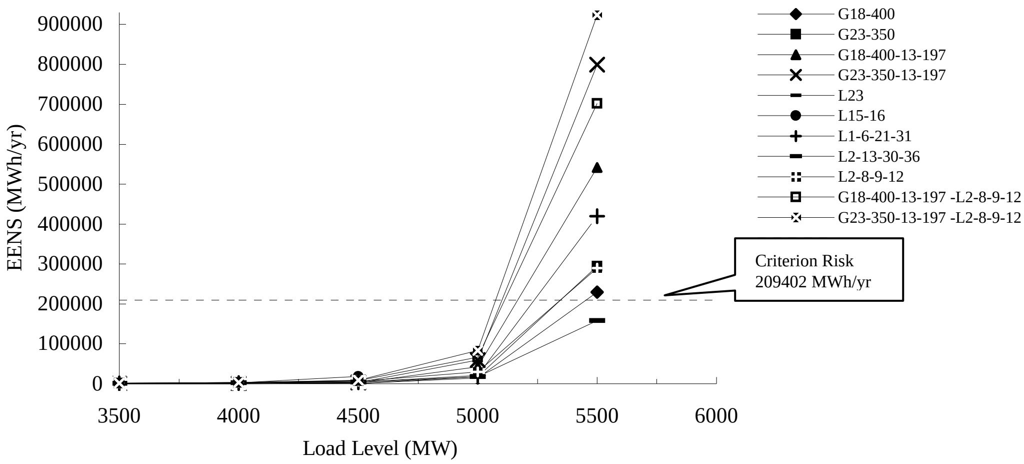

Figure 5.41: System EENS of the MRTS as a function of load level

Table 5.20: Available weeks for selected maintenance outages based on system EENS of the MRTS

Cases	Critical Load (MW)	Possible Weeks
G18-400	5450	1-49, 52
G23-350	5350	1-46, 48
G18-400-13-197	5150	1-45, 48
G23-350-13-197	5100	1, 3-22, 24, 26-45, 48
L5	<4000	None
L23	>4500	At least 9-15, 17, 27, 31-32, 34-42
L15-16	>4500	At least 9-15, 17, 27, 31-32, 34-42
L1-6-21-31	5250	1-46, 48

Table 5.20: (Continued)

Cases	Critical Load (MW)	Possible Weeks
L2-13-30-36	>5500	At least 1-49, 52
L2-8-9-12	5350	1-46, 48
G18-400-13-197 -L2-8-9-12	5100	1, 3-22, 24, 26-45, 48
G23-350-13-197 -L2-8-9-12	5080	1, 3-22, 24, 26-45, 48

It can be seen from Table 5.20 that the transmission system of the MRTS is stressed significantly and some line removals are restricted. For example, removing Line 5 is unacceptable when the load is greater than or equal to 4,000 MW. Similarly, L23 and L15-16 cannot be conducted when the load is greater than or equal to 5,000 MW.

Figure 5.41 indicates that the risk associated with L1-6-21-31 is higher than that of G18-400 or G23-350. The system EENS for G18-400-13-197-L2-8-9-12 is much larger than that of the G18-400-13-197, particularly at high loads. This is also the case for G23-350-13-197-L2-8-9-12 and G23-350-13-197. As shown earlier, this is not the case for the IEEE-RTS, where removing the same transmission lines has very little impact on the system EENS. Although the MRTS has 1,110 MW of reserve capacity, which is almost three times the largest unit, the risk when removing generating units is still very sensitive to the load growth. This can be seen by comparing the two generating cases G18-400 and G18-400-13-197 in Figure 5.41.

Table 5.20 shows that L5 has the lowest critical load and this maintenance cannot be done in any week of the year. The critical loads for L23 and L15-16 are lower than those of the other cases and these maintenance activities have relatively few opportunities. The difference between the critical loads of G18-400-13-197 and G18-400-13-197-L2-8-9-12 (or G23-350-13-197 and G23-350-13-197-L2-8-9-12) is relatively small due to the criterion value and load model. The MRTS cannot be considered to have a strong transmission network and removing transmission lines has a significant impact on the system reliability.

5.5 Conclusions

Removing system elements for maintenance can create significant increases in the system risk. It is important to develop efficient decision-making tools that the ISO can use to coordinate the maintenance schedules. The maintenance coordination technique (MCT) proposed in this thesis was applied to the two test systems to examine the impact of removing elements for maintenance. The object is to determine if a certain planned outage could be conducted during a designated period.

The analysis described in this thesis indicates that different cases have different critical loads, which result in different opportunities for the planned maintenance. Some cases can be done in any week during the year. Some cases cannot be done at any time. In certain cases, if one element is removed for maintenance, another element can be removed simultaneously without significantly increasing the risk. Generally, removing more components from service results in the related curves moving to the left, which means that the corresponding risks increase and the weeks available for the maintenance decrease.

Different system indices can result in different critical loads and periods in which a specified maintenance outage can be permitted. There are no general rules followed by all cases.

Planned maintenance outages, which are acceptable based on the system risk, may be unacceptable based on load point risks. Determination of the criterion risks, particularly for load points, is a practical management issue and can have a large impact on maintenance scheduling decisions. It is important to appreciate that it is necessary from a load point perspective to check for unacceptable conditions created by using system risk criteria.

6. SUMMARY AND CONCLUSIONS

Composite system reliability evaluation involves the analysis of the combined generation and transmission system in regard to its ability to serve the system load. The reliability of supply at the individual load points in a composite system is a function of the capacities and availabilities of the individual generation and transmission facilities and the system topology. Quantitative evaluation of the impacts of forced and planned outages of the generation and transmission facilities is an extremely valuable tool in both vertically integrated and deregulated utility systems. These analyses can provide input to reinforcement decisions, maintenance scheduling, operating strategies, and reliability worth assessment.

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, the three power system hierarchical levels, and the merits and demerits of analytical techniques and Monte Carlo simulation. An introduction to deregulated power system structures is also presented in Chapter 1.

A series of studies on composite system reliability evaluation utilizing Monte Carlo simulation is described in this thesis. Some of the basic concepts associated with Monte Carlo simulation are introduced in Chapter 2. Three simulation techniques designated as the state sampling method, the state transition sampling method, and the sequential method together with their advantages, limitations and basic procedures are briefly described in this chapter. The state sampling technique is applied in the MECORE program that was utilized for all analyses presented in this thesis.

The software 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 was initially developed at the University of Saskatchewan and further enhanced at BC Hydro. It can be utilized to conduct a wide variety of composite system studies.

The basic indices and IEEE proposed indices used in MECORE are presented in Chapter 2. The basic indices can be determined for an entire system or for a single load point. The IEEE proposed indices are applicable to an overall system. It should be noted that the load point indices and the system indices complement each other and serve different functions. Both load point and system indices can be categorized on an annualized or annual basis. Annualized indices are calculated using a single load level (normally the system peak load level) and expressed on a one-year basis. Annual indices are calculated considering the detailed load variations throughout a year.

The two 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, which are used as base case values in the following studies, are also presented. It should be appreciated that the assumptions used in the base case studies of the two test systems are utilized in all the studies described in this thesis.

Component unavailability is one of the key factors affecting system and load point reliability in a composite system. A series of studies are conducted in Chapter 3 to investigate the impacts of variations in component unavailability on the load point and system reliability of the two test systems.

The topology of the RBTS together with the load curtailment philosophy plays a major role in the variations in the system and load point indices due to changes in the generating unit and transmission line unavailabilities. The most sensitive load point to generating unit FOR variations is Bus 3. The indices at Bus 6 are dominated by the reliability of Line 9 and are relatively insensitive to generating unit FOR variations.

The IEEE-RTS is relatively large compared to the RBTS. This system does not have the designed-in weaknesses of the RBTS and reacts quite differently to element unavailability variations. The IEEE-RTS has a strong transmission system and therefore the system and load point indices are relatively immune to variations in the transmission line unavailabilities.

The analyses conducted in this chapter clearly indicate that the impacts of component unavailabilities on the load point and system reliability are not uniform throughout the system and are highly dependent on the load curtailment philosophy and the overall system topology. The system and load point indices are influenced more by variations in the larger generating unit FOR than in smaller unit variations. The indices at some load points are highly influenced by the generating unit FOR, some load points are very sensitive to both generating unit and transmission line unavailabilities, and some buses are influenced only by transmission line unavailabilities. This knowledge is valuable in the decision-making process associated with reinforcement and maintenance planning.

Increasing the size of the IEEE-RTS to create the MRTS reflects a situation that is becoming common in North America. Relatively little transmission is being built or proposed in the near future. Under these circumstances, reliability will degrade as load grows and additional generation is added. The implications of increased line unavailabilities are clearly enhanced under these conditions.

Although the probabilistic criteria and techniques at each hierarchical level are well developed and have been used in practical applications, many composite systems are still designed according to deterministic standards. The primary weakness of deterministic criteria and techniques is that they cannot reflect the stochastic nature of power system behavior. Using an (n-1) criterion does not provide information on the actual impacts of the different contingencies on the load point and system reliability. This procedure cannot be used to determine which contingency case is the worst. The impacts of different (n-1) contingencies on composite system reliability are fully investigated in Chapter 4. A new parameter designated as the Impact Index is utilized to rank the various contingencies.

The studies conducted on the two test systems and described in this chapter clearly indicate that not all contingencies have the same impact on the system indices or on the load point indices. The worst contingency for the system may not be the worst for a given bus. The worst contingency for one bus may also not be the worst contingency for other buses. From a generation point of view, removing the largest unit usually has the largest impact. It should be appreciated, however, that the worst contingency for the system and for each load point may not always be the largest unit contingency. The generating unit FOR and the system topology are the two most important factors. From a transmission point of view, removing a transmission line usually only has local impact on the load point connected to or supplied by the line in question. From a system viewpoint, different systems have different responses to the (n-1) criterion. In a system that is generation dominated, the impacts of generation contingencies are usually much larger than those of transmission contingencies, and vice versa for a system that is transmission dominated. From the load point perspective, different buses have different responses to a contingency. Some buses are immune to any single contingency, some buses are impacted mainly by generation contingencies, some mainly by transmission contingencies, and some by both generation and transmission contingencies.

In some cases, the use of different impact indices results in different contingency rankings. The load model used and the load curtailment priority order selected also have significant impacts on the contingency ranking. Rankings based on annualized impact indices are usually different from those based on the annual impact indices. The load curtailment priority order only impacts the contingency rankings associated with load points.

It is obvious that not all contingencies have the same likelihood. In a composite system, generating units usually have large unavailabilities, followed by those of transformers and transmission lines. In general, incorporating the event likelihood into the assessment can create a significant change in the ranking. These changes depend not only on the differences in the component likelihoods, but on the magnitude of the impact indices. The Modified Impact Index developed in this research includes both event severity and likelihood and should prove to be a more useful risk index.

In the new market environment, the main responsibility of an ISO is to maintain the system reliability. The ISO, however, may have relatively little control over the capacity reserve. Under these conditions, the T outage only rankings provide valuable information on possible transmission deficiencies.

Preventive maintenance scheduling and coordinating of a composite system is a challenging task in both vertically integrated and deregulated systems. Removing elements from a system for maintenance can significantly increase the system risk. Chapter 4 clearly shows that not all single element removals have the same impact on the system and load point indices. These impacts are even more diverse when removing multiple elements for maintenance.

A maintenance coordination technique (MCT) is proposed in Chapter 5. The MCT was applied to the two test systems to examine the impact of removing elements for maintenance. The object is to determine if a certain planned outage could be conducted during a designated period.

The basic concept in the MCT is the determination of the relationship between the calculated risk indices and the variation in the system peak load. The risk indices are then compared with predetermined criteria to see if the requested maintenance can be done during a specific period.

The analyses conducted in this chapter indicate that different maintenance removal cases have different critical loads, which result in different opportunities to schedule the planned maintenance. Some maintenance can be done in any week during the year. Some cannot be done at any time. In certain cases, if one element is removed for maintenance another element can be removed simultaneously without significantly increasing the risk. Generally, removing more components from service results in the related risk profiles moving to the left, which means that the corresponding risks increase and the weeks available for the maintenance decrease.

Different system indices can result in different critical loads and time periods in which a specified maintenance outage can be permitted.

Planned maintenance outages, which are acceptable based on the system risk, may be unacceptable based on load point risks. Determination of the criterion risks particularly for load points is a practical management issue and can have a large impact on maintenance scheduling decisions. It is important to appreciate that it is necessary from a load point perspective to check for unacceptable conditions created by using system risk criteria.

The research work illustrated in this thesis indicates that the probabilistic criteria and techniques for composite power system analysis can be effectively utilized in both vertically integrated and deregulated utility systems. The conclusions and the techniques presented in this thesis should prove valuable to those responsible for system planning and maintenance coordination.

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

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

Table A.1: Bus data for the RBTS

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

Table A.2: Line data for the RBTS

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

Table A.3: Generator data for the RBTS

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

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

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

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

Line	Bus I	Bus J	R	X	B/2	Tap	Current Rating (p.u.)	Failure Rate (occ/yr)	Repair Time (hrs)	Failure Prob.
1	1	2	0.0260	0.0139	0.2306	1.0	1.75	0.24	16	0.00044
2	1	3	0.0546	0.2112	0.0286	1.0	1.75	0.51	10	0.00058
3	1	5	0.0218	0.0845	0.0115	1.0	1.75	0.33	10	0.00038
4	2	4	0.0328	0.1267	0.0172	1.0	1.75	0.39	10	0.00045
5	2	6	0.0497	0.1920	0.0260	1.0	1.75	0.39	10	0.00045
6	3	9	0.0308	0.1190	0.0161	1.0	1.75	0.48	10	0.00055
7	3	24	0.0023	0.0839	0.0000	1.0	4.00	0.02	768	0.00175
8	4	9	0.0268	0.1037	0.0141	1.0	1.75	0.36	10	0.00041
9	5	10	0.0228	0.0883	0.0120	1.0	1.75	0.34	10	0.00039
10	6	10	0.0139	0.0605	1.2295	1.0	1.75	0.33	35	0.00132
11	7	8	0.0159	0.0614	0.0166	1.0	1.75	0.30	10	0.00034
12	8	9	0.0427	0.1651	0.0224	1.0	1.75	0.44	10	0.00050
13	8	10	0.0427	0.1651	0.0224	1.0	1.75	0.44	10	0.00050
14	9	11	0.0023	0.0839	0.0000	1.0	4.00	0.02	768	0.00175
15	9	12	0.0023	0.0839	0.0000	1.0	4.00	0.02	768	0.00175

Table A.5: (Continued)

Line	Bus		R	X	B/2	Tap	Current Rating (p.u.)	Failure Rate (occ/yr)	Repair Time (hrs)	Failure Prob.
	I	J								
16	10	11	0.0023	0.0839	0.0000	1.0	4.00	0.02	768	0.00175
17	10	12	0.0023	0.0839	0.0000	1.0	4.00	0.02	768	0.00175
18	11	13	0.0061	0.0476	0.0500	1.0	5.00	0.02	11	0.00050
19	11	14	0.0054	0.0418	0.0440	1.0	5.00	0.39	11	0.00049
20	12	13	0.0061	0.0476	0.0500	1.0	5.00	0.40	11	0.00050
21	12	23	0.0124	0.0966	0.1015	1.0	5.00	0.52	11	0.00065
22	13	23	0.0111	0.0865	0.0909	1.0	5.00	0.49	11	0.00062
23	14	16	0.0050	0.0389	0.0409	1.0	5.00	0.38	11	0.00048
24	15	16	0.0022	0.0173	0.0364	1.0	5.00	0.33	11	0.00041
25	15	21	0.0063	0.0490	0.0515	1.0	5.00	0.41	11	0.00051
26	15	21	0.0063	0.0490	0.0515	1.0	5.00	0.41	11	0.00051
27	15	24	0.0067	0.0519	0.0546	1.0	5.00	0.41	11	0.00051
28	16	17	0.0033	0.0259	0.0273	1.0	5.00	0.35	11	0.00044
29	16	19	0.0030	0.0231	0.0243	1.0	5.00	0.34	11	0.00043
30	17	18	0.0018	0.0144	0.0152	1.0	5.00	0.32	11	0.00040
31	17	22	0.0135	0.1053	0.1106	1.0	5.00	0.54	11	0.00068
32	18	21	0.0033	0.0259	0.0273	1.0	5.00	0.35	11	0.00044
33	18	21	0.0033	0.0259	0.0273	1.0	5.00	0.35	11	0.00044
34	19	20	0.0051	0.0396	0.0417	1.0	5.00	0.38	11	0.00048
35	19	20	0.0051	0.0396	0.0417	1.0	5.00	0.38	11	0.00048
36	20	23	0.0028	0.0216	0.0228	1.0	5.00	0.34	11	0.00043
37	20	23	0.0028	0.0216	0.0228	1.0	5.00	0.34	11	0.00043
38	21	22	0.0087	0.0678	0.0712	1.0	5.00	0.45	11	0.00057

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

Unit No.	Bus No.	Rating (MW)	Failure Rate (occ/yr)	Repair Time (hrs)	Failure Prob.
1	22	50	4.42	20	0.01
2	22	50	4.42	20	0.01
3	22	50	4.42	20	0.01
4	22	50	4.42	20	0.01
5	22	50	4.42	20	0.01
6	22	50	4.42	20	0.01
7	15	12	2.98	60	0.02
8	15	12	2.98	60	0.02
9	15	12	2.98	60	0.02
10	15	12	2.98	60	0.02
11	15	12	2.98	60	0.02
12	15	155	9.13	40	0.04
13	7	100	7.30	50	0.04
14	7	100	7.30	50	0.04
15	7	100	7.30	50	0.04
16	13	197	9.22	50	0.05

Table A.6: (Continued)

Unit No.	Bus No.	Rating (MW)	Failure Rate (occ/yr)	Repair Time (hrs)	Failure Prob.
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 EQUIPMENT UNAVAILABILITY ON THE LOAD POINT AND SYSTEM RELIABILITY

This appendix contains numerical indices and data on the studies described in Chapter 3.

Table B.1: Annualized system indices for the RBTS as a function of the unit FOR

Case	Change in FOR (%)	Annualized Indices			
		ENLC (1/yr)	EDLC (hrs/yr)	EENS (MWh/yr)	SI (system minutes/yr)
1	-100	1.2	10.9	218.4	70.8
2	-75	1.5	16.5	273.9	88.8
3	-50	2.3	31.3	429.4	139.3
4	-25	3.4	51.7	644.0	208.9
5	0	5.3	86.6	1069.4	346.8
6	+25	7.5	126.6	1562.6	506.8
7	+50	10.2	173.3	2167.3	702.9
8	+75	13.4	227.2	2903.6	941.7
9	+100	17.1	287.4	3762.4	1220.2

Table B.2: Annual system indices for the RBTS as a function of the unit FOR

Case	Change in FOR (%)	Annual Indices			
		ENLC (1/yr)	EDLC (hrs/yr)	EENS (MWh/yr)	SI (system minutes/yr)
1	-100	1.1	10.5	134.4	43.6
2	-75	1.1	10.6	135.2	43.8
3	-50	1.2	10.9	137.9	44.7
4	-25	1.2	11.2	141.7	45.9
5	0	1.3	12.1	151.9	49.3
6	+25	1.4	13.1	164.8	53.4
7	+50	1.5	14.5	182.6	59.2
8	+75	1.6	16.3	206.7	67.0
9	+100	1.8	18.5	237.0	76.9

Table B.3: Annualized load point indices for the RBTS as a function of the unit FOR

Bus No.	Change in FOR (%)	PLC	ENLC (1/yr)	ELC (MW/yr)	EDNS (MW)	EENS (MWh/yr)
2	-100	.00000	.00000	.00000	.00000	.00000
	-75	.00000	.00000	.00000	.00000	.00000
	-50	.00000	.00000	.00000	.00000	.00000
	-25	.00000	.00000	.00000	.00000	.00000
	0	.00000	.00150	.004	.00000	.044
	+25	.00000	.00392	.010	.00001	.099
	+50	.00001	.00700	.018	.00002	.186
	+75	.00002	.01398	.049	.00006	.504
	+100	.00003	.02410	.089	.00010	.887
3	-100	.00005	.09406	1.8	.00096	8.4
	-75	.00069	.39426	4.8	.00727	63.7
	-50	.00238	1.2	12.9	.02488	218.0
	-25	.00471	2.2	24.7	.04919	430.9
	0	.00869	4.1	48.1	.09699	849.6
	+25	.01326	6.3	76.6	.15217	1333.0
	+50	.01859	8.9	112.5	.21951	1922.9
	+75	.02474	12.1	157.9	.30120	2638.5
	+100	.03163	15.8	212.7	.39594	3468.4
4	-100	.00000	.00396	.073	.00003	.241
	-75	.00000	.00425	.074	.00003	.252
	-50	.00001	.00698	.081	.00004	.339
	-25	.00001	.01071	.089	.00005	.434
	0	.00003	.02135	.142	.00013	1.11
	+25	.00006	.04200	.243	.00025	2.19
	+50	.00009	.06833	.371	.00043	3.74
	+75	.00015	.10553	.628	.00075	6.57
	+100	.00022	.16460	1.021	.00121	10.64
5	-100	.00000	.00396	.040	.00002	.13
	-75	.00000	.00425	.043	.00002	.18
	-50	.00001	.00698	.070	.00006	.53
	-25	.00001	.01238	.111	.00011	.95
	0	.00003	.02649	.226	.00029	2.54
	+25	.00007	.05109	.443	.00059	5.15
	+50	.00011	.08564	.734	.00101	8.83
	+75	.00018	.13173	1.128	.00155	13.6
	+100	.00027	.20737	1.770	.00238	20.9

Table B.3: (Continued)

Bus No.	Change in FOR (%)	PLC	ENLC (1/yr)	ELC (MW/yr)	EDNS (MW)	EENS (MWh/yr)
6	-100	.00120	1.09216	21.8	.02394	209.7
	-75	.00120	1.11529	22.2	.02395	209.8
	-50	.00122	1.15199	22.8	.02404	210.6
	-25	.00126	1.19444	23.2	.02417	211.7
	0	.00139	1.29828	24.0	.02467	216.1
	+25	.00156	1.42936	24.9	.02536	222.1
	+50	.00183	1.62738	26.1	.02645	231.7
	+75	.00220	1.89457	27.6	.02791	244.5
	+100	.00265	2.22879	29.5	.02986	261.5

Table B.4: Annual load point indices for the RBTS as a function of the unit FOR

Bus No.	Change in FOR (%)	PLC	ENLC (1/yr)	ELC (MW/yr)	EDNS (MW)	EENS (MWh/yr)
2	-100	.00000	.00000	.000	.00000	.000
	-75	.00000	.00000	.000	.00000	.000
	-50	.00000	.00000	.000	.00000	.000
	-25	.00000	.00000	.000	.00000	.000
	0	.00000	.00000	.000	.00000	.000
	+25	.00000	.00001	.000	.00000	.000
	+50	.00000	.00002	.000	.00000	.000
	+75	.00000	.00034	.002	.00000	.017
	+100	.00000	.00074	.004	.00000	.036
3	-100	.00000	.00763	.093	.00004	.332
	-75	.00001	.01241	.134	.00012	1.1
	-50	.00004	.02700	.289	.00043	3.8
	-25	.00008	.04866	.531	.00086	7.5
	0	.00018	.10162	1.171	.00201	17.6
	+25	.00030	.17023	2.037	.00344	30.2
	+50	.00046	.26340	3.258	.00543	47.6
	+75	.00066	.38940	4.961	.00810	70.9
	+100	.00091	.55000	7.197	.01143	100.1
4	-100	.00000	.00086	.006	.00000	.021
	-75	.00000	.00086	.006	.00000	.021
	-50	.00000	.00087	.006	.00000	.021
	-25	.00000	.00088	.006	.00000	.021
	0	.00000	.00109	.008	.00000	.038
	+25	.00000	.00146	.010	.00001	.059
	+50	.00000	.00193	.013	.00001	.093
	+75	.00000	.00349	.027	.00003	.231
	+100	.00001	.00567	.045	.00005	.399

Table B.4: (Continued)

Bus No.	Change in FOR (%)	PLC	ENLC (1/yr)	ELC (MW/yr)	EDNS (MW)	EENS (MWh/yr)
5	-100	.00000	.00124	.008	.00000	.028
	-75	.00000	.00125	.009	.00000	.028
	-50	.00000	.00129	.009	.00000	.032
	-25	.00000	.00138	.009	.00000	.035
	0	.00000	.00183	.012	.00001	.074
	+25	.00000	.00265	.018	.00002	.132
	+50	.00000	.00372	.026	.00003	.220
	+75	.00001	.00656	.045	.00005	.427
	+100	.00001	.01064	.073	.00008	.706
6	-100	.00120	1.09007	13.9	.01530	134.1
	-75	.00120	1.11170	14.2	.01530	134.1
	-50	.00120	1.13476	14.5	.01531	134.1
	-25	.00120	1.15514	14.8	.01531	134.1
	0	.00120	1.17894	15.0	.01532	134.2
	+25	.00121	1.20487	15.4	.01534	134.4
	+50	.00121	1.23321	15.7	.01537	134.7
	+75	.00122	1.26281	16.0	.01543	135.1
	+100	.00123	1.29736	16.4	.01550	135.8

Table B.5: System and load point EENS (MWh/yr) for the RBTS as a function of the unit FOR at peak load 200 MW

Change in FOR (%)	System	Bus 2	Bus 3	Bus 4	Bus 5	Bus 6
-100	146.3	0	1.4	.040	.040	144.8
-75	149.5	0	4.6	.041	.043	144.8
-50	159.7	0	14.7	.044	.064	144.9
-25	173.7	0	28.6	.047	.090	145.0
0	205.9	.001	60.2	.101	.220	145.3
+25	244.4	.003	97.9	.177	.424	145.9
+50	294.5	.006	146.8	.294	.722	146.7
+75	359.0	.042	209.3	.604	1.227	147.9
+100	437.1	.084	284.5	1.010	1.949	149.5

Table B.6: System EENS (MWh/yr) for the RBTS as a function of the unit FOR in each case at peak load 185 MW

Change in FOR (%)	Case A	Case B	Case C	Case D	Case E	Case F
-100	139.7	149.7	151.3	141.8	150.6	151.8
-75	142.7	150.3	151.5	144.6	150.9	151.8
-50	145.7	150.9	151.7	146.8	151.2	151.8
-25	148.7	151.3	151.8	149.6	151.5	151.9
0	151.9	151.9	151.9	151.9	151.9	151.9
+25	154.8	152.5	152.0	154.5	152.3	151.9
+50	157.8	153.0	152.1	157.2	152.6	151.9
+75	160.7	153.6	152.3	160.0	152.9	152.0
+100	163.4	154.0	152.5	162.1	153.3	152.0

Table B.7: Load point EENS (MWh/yr) for the RBTS as a function of the unit FOR in each case at peak load 185 MW

Bus No.	Change in FOR (%)	Case A	Case B	Case C	Case D	Case E	Case F
2	-100	.000	.000	.000	.000	.000	.000
	-75	.000	.000	.000	.000	.000	.000
	-50	.000	.000	.000	.000	.000	.000
	-25	.000	.000	.000	.000	.000	.000
	0	.000	.000	.000	.000	.000	.000
	+25	.000	.000	.000	.000	.000	.000
	+50	.000	.000	.000	.000	.000	.000
	+75	.000	.000	.000	.000	.005	.000
	+100	.000	.000	.000	.000	.005	.000
3	-100	5.6	15.4	17.0	7.7	16.2	17.5
	-75	8.5	16.0	17.2	10.4	16.6	17.5
	-50	11.5	16.5	17.3	12.6	16.8	17.5
	-25	14.4	17.0	17.5	15.3	17.1	17.5
	0	17.6	17.6	17.6	17.6	17.6	17.6
	+25	20.4	18.2	17.7	20.1	17.9	17.6
	+50	23.4	18.6	17.8	22.7	18.3	17.6
	+75	26.3	19.2	18.0	25.5	18.5	17.6
	+100	28.9	19.6	18.1	27.6	18.9	17.6
4	-100	.021	.030	.038	.021	.038	.038
	-75	.029	.034	.038	.025	.038	.038
	-50	.029	.034	.038	.026	.038	.038
	-25	.030	.034	.038	.034	.038	.038
	0	.038	.038	.038	.038	.038	.038

Table B.7: (Continued)

Bus No.	Change in FOR (%)	Case A	Case B	Case C	Case D	Case E	Case F
4	+25	.046	.042	.038	.042	.038	.038
	+50	.050	.042	.038	.047	.038	.038
	+75	.050	.042	.038	.055	.057	.038
	+100	.051	.042	.038	.055	.057	.038
5	-100	.029	.060	.074	.030	.072	.074
	-75	.047	.067	.074	.044	.074	.074
	-50	.052	.067	.074	.047	.074	.074
	-25	.056	.067	.074	.065	.074	.074
	0	.074	.074	.074	.074	.074	.074
	+25	.092	.082	.074	.087	.078	.074
	+50	.103	.082	.074	.102	.079	.074
	+75	.107	.083	.075	.119	.089	.074
	+100	.110	.084	.077	.120	.090	.074
6	-100	134.1	134.2	134.2	134.1	134.2	134.2
	-75	134.1	134.2	134.2	134.1	134.2	134.2
	-50	134.2	134.2	134.2	134.2	134.2	134.2
	-25	134.2	134.2	134.2	134.2	134.2	134.2
	0	134.2	134.2	134.2	134.2	134.2	134.2
	+25	134.3	134.2	134.2	134.3	134.2	134.2
	+50	134.3	134.2	134.2	134.3	134.2	134.2
	+75	134.3	134.3	134.2	134.4	134.3	134.2
	+100	134.4	134.3	134.2	134.4	134.3	134.2

Table B.8: System EENS (MWh/yr) for the RBTS as a function of the unit FOR in each case at peak load 200 MW

Change in FOR (%)	Case A	Case B	Case C	Case D	Case E	Case F
-100	168.1	199.2	204.2	175.5	201.7	205.4
-75	177.4	200.9	204.7	183.5	202.8	205.5
-50	186.7	202.6	205.1	190.7	203.7	205.6
-25	196.2	204.1	205.5	198.7	204.7	205.8
0	205.9	205.9	205.9	205.9	205.9	205.9
+25	215.1	207.7	206.2	213.6	207.0	206.0
+50	224.2	209.3	206.6	221.3	208.0	206.1
+75	233.4	211.0	207.1	229.5	209.1	206.2
+100	241.9	212.4	207.5	236.6	210.1	206.3

Table B.9: Load point EENS (MWh/yr) for the RBTS as a function of the unit FOR in each case at peak load 200 MW

Bus No.	Change in FOR (%)	Case A	Case B	Case C	Case D	Case E	Case F
2	-100		.001	.001		.001	.001
	-75	.001	.001	.001	.000	.001	.001
	-50	.001	.001	.001	.000	.001	.001
	-25	.001	.001	.001	.001	.001	.001
	0	.001	.001	.001	.001	.001	.001
	+25	.002	.002	.001	.002	.001	.001
	+50	.002	.002	.001	.002	.001	.001
	+75	.002	.002	.001	.003	.010	.001
	+100	.002	.002	.001	.003	.010	.001
3	-100	23.1	53.7	58.6	30.4	56.1	59.8
	-75	32.3	55.3	59.0	38.3	57.2	59.9
	-50	41.4	57.0	59.5	45.4	58.1	60.0
	-25	50.8	58.5	59.9	53.2	59.1	60.1
	0	60.2	60.2	60.2	60.2	60.2	60.2
	+25	69.2	62.0	60.6	67.7	61.3	60.3
	+50	78.2	63.6	61.0	75.3	62.3	60.4
	+75	87.2	65.2	61.4	83.3	63.3	60.5
	+100	95.7	66.7	61.9	90.4	64.3	60.6
4	-100	.041	.079	.100	.042	.099	.101
	-75	.066	.090	.101	.059	.100	.101
	-50	.072	.090	.101	.062	.101	.101
	-25	.075	.090	.101	.088	.101	.101
	0	.101	. 101	.101	.101	.101	.101
	+25	.125	.112	.101	.117	.105	.101
	+50	.140	.112	.101	.136	.105	.101
	+75	.144	.113	.101	.160	.127	.101
	+100	.147	.114	.104	.161	.128	.101
5	-100	.053	.190	.216	.060	.205	.220
	-75	.102	.202	.217	.115	.215	.220
	-50	.139	.207	.219	.137	.218	.220
	-25	.167	.208	.220	.189	.219	.220
	0	.220	.220	.220	.220	.220	.220
	+25	.267	.235	.220	.268	.234	.220
	+50	.310	.238	.221	.323	.237	.220
	+75	.338	.246	.222	.367	.250	.220
	+100	.357	.250	.227	.377	.255	.220
6	-100	144.9	145.2	145.3	144.9	145.3	145.3
	-75	145.0	145.3	145.3	145.1	145.3	145.3
	-50	145.1	145.3	145.3	145.1	145.3	145.3
	-25	145.2	145.3	145.3	145.2	145.3	145.3
	0	145.3	145.3	145.3	145.3	145.3	145.3

Table B.9: (Continued)

Bus No.	Change in FOR (%)	Case A	Case B	Case C	Case D	Case E	Case F
6	+25	145.4	145.4	145.3	145.5	145.4	145.3
	+50	145.6	145.4	145.3	145.6	145.4	145.3
	+75	145.6	145.4	145.3	145.7	145.4	145.3
	+100	145.7	145.4	145.3	145.7	145.4	145.3

Table B.10: System EENS for the RBTS as a function of the generating station FOR

Change in FOR (%)	Bus 1 vary (185MW)	Bus 2 vary (185MW)	Bus 1 vary (200MW)	Bus 2 vary (200MW)
-100	139.7	149.7	149.4	164.9
-75	142.7	150.3	158.6	174.0
-50	145.7	150.9	171.3	183.3
-25	148.7	151.3	186.5	194.2
0	151.9	151.9	205.9	205.9
+25	154.8	152.5	228.4	218.9
+50	157.8	153.0	253.7	232.4
+75	160.7	153.6	283.2	248.2
+100	163.4	154.0	315.5	263.6

Table B.11: Bus EENS for the RBTS as a function of the generating station FOR

Bus No.	Change in FOR (%)	Bus 1 vary (185MW)	Bus 2 vary (185MW)	Bus 1 vary (200MW)	Bus 2 vary (200MW)
2	-100	.000	.000	.000	.000
	-75	.000	.000	.000	.000
	-50	.000	.000	.000	.000
	-25	.000	.000	.000	.001
	0	.000	.000	.001	.001
	+25	.000	.000	.003	.002
	+50	.000	.000	.004	.003
	+75	.000	.005	.005	.014
	+100	.000	.005	.005	.015
3	-100	0.7	5.0	4.6	20.0
	-75	3.2	7.8	13.6	28.8
	-50	6.9	10.5	26.1	38.1
	-25	11.4	13.8	41.3	48.7
	0	17.6	17.6	60.2	60.2
	+25	24.8	21.9	82.4	72.9
	+50	33.0	26.3	107.1	86.1
	+75	43.1	31.7	136.0	101.4
	+100	53.8	36.7	167.7	116.5

Table B.11: (Continued)

Bus No.	Change in FOR (%)	Bus 1 vary (185MW)	Bus 2 vary (185MW)	Bus 1 vary (200MW)	Bus 2 vary (200MW)
4	-100	.021	.021	0.04	0.04
	-75	.025	.025	0.052	0.057
	-50	.025	.025	0.058	0.06
	-25	.026	.030	0.062	0.077
	0	.038	.038	0.101	0.101
	+25	.054	.043	0.153	0.123
	+50	.067	.056	0.199	0.165
	+75	.076	.102	0.237	0.264
	+100	.078	.107	0.26	0.286
5	-100	.028	.029	0.04	0.045
	-75	.037	.042	0.063	0.099
	-50	.042	.045	0.101	0.121
	-25	.046	.057	0.132	0.172
	0	.074	.074	0.22	0.22
	+25	.112	.093	0.331	0.3
	+50	.147	.123	0.453	0.387
	+75	.178	.187	0.589	0.51
	+100	.199	.205	0.713	0.572
6	-100	134.1	134.1	144.8	144.8
	-75	134.1	134.1	144.9	145.0
	-50	134.1	134.1	145.0	145.0
	-25	134.2	134.2	145.1	145.2
	0	134.2	134.2	145.3	145.3
	+25	134.3	134.3	145.6	145.5
	+50	134.4	134.4	145.9	145.8
	+75	134.6	134.5	146.3	146.0
	+100	134.7	134.5	146.7	146.2

Table B.12: System and load point EENS (MWh/yr) for the RBTS with variations in the transmission line unavailability

Change in unavailability (%)	System	Bus 2	Bus 3	Bus 4	Bus 5	Bus 6
-100	17.2	.000	17.0	.017	.046	.157
-75	51.1	.000	17.1	.017	.046	33.9
-50	85.0	.000	17.1	.017	.046	67.8
-25	119.5	.000	17.4	.035	.067	102.1
0	151.9	.000	17.6	.038	.074	134.2
+25	184.0	.000	17.8	.040	.081	166.1
+50	214.9	.000	17.9	.040	.081	196.8
+75	247.7	.017	18.1	.043	.088	229.4
+100	280.7	.036	18.4	.043	.088	262.2

Table B.13: System EENS (MWh/yr) for the RBTS with variations in the transmission line unavailability in each case

Change in unavailability (%)	Case A	Case B	Case C	Case D	Case E	Case F	Case G
-100	151.3	151.4	151.8	151.9	151.9	151.9	17.9
-75	151.4	151.4	151.8	151.9	151.9	151.9	51.7
-50	151.4	151.6	151.9	151.9	151.9	151.9	85.6
-25	151.8	151.7	151.9	151.9	151.9	151.9	119.7
0	151.9	151.9	151.9	151.9	151.9	151.9	151.9
+25	152.0	152.0	152.0	151.9	151.9	151.9	183.7
+50	152.0	152.1	152.0	151.9	151.9	151.9	214.5
+75	152.1	152.2	152.0	151.9	151.9	151.9	247.0
+100	152.2	152.3	152.0	151.9	151.9	151.9	279.8

Table B.14: Load point EENS (MWh/yr) for the RBTS with variations in the transmission line unavailability in each case

Bus No.	Change in unavailability (%)	Case A	Case B	Case C	Case D	Case E	Case F	Case G
2	-100	.000	.000	.000	.000	.000	.000	.000
	-75	.000	.000	.000	.000	.000	.000	.000
	-50	.000	.000	.000	.000	.000	.000	.000
	-25	.000	.000	.000	.000	.000	.000	.000
	0	.000	.000	.000	.000	.000	.000	.000
	+25	.000	.000	.000	.000	.000	.000	.000
	+50	.000	.000	.000	.000	.000	.000	.000
	+75	.000	.000	.000	.000	.000	.000	.000
	+100	.000	.000	.000	.000	.000	.000	.000
3	-100	17.1	17.2	17.5	17.6	17.6	17.6	17.6
	-75	17.1	17.2	17.5	17.6	17.6	17.6	17.6
	-50	17.2	17.3	17.6	17.6	17.6	17.6	17.6
	-25	17.5	17.4	17.6	17.6	17.6	17.6	17.6
	0	17.6	17.6	17.6	17.6	17.6	17.6	17.6
	+25	17.6	17.7	17.6	17.6	17.6	17.6	17.6
	+50	17.7	17.7	17.6	17.6	17.6	17.6	17.6
	+75	17.8	17.8	17.6	17.6	17.6	17.6	17.6
	+100	17.8	17.9	17.7	17.6	17.6	17.6	17.6
4	-100	.017	.017	.038	.038	.038	.038	.038
	-75	.017	.017	.038	.038	.038	.038	.038
	-50	.017	.019	.038	.038	.038	.038	.038
	-25	.038	.035	.038	.038	.038	.038	.038
	0	.038	.038	.038	.038	.038	.038	.038
	+25	.038	.040	.038	.038	.038	.038	.038
	+50	.038	.040	.038	.038	.038	.038	.038

Table B.14: (Continued)

Bus No.	Change in unavailability (%)	Case A	Case B	Case C	Case D	Case E	Case F	Case G
4	+75	.038	.043	.038	.038	.038	.038	.038
	+100	.038	.043	.038	.038	.038	.038	.038
5	-100	.046	.046	.074	.074	.074	.074	.074
	-75	.046	.046	.074	.074	.074	.074	.074
	-50	.046	.052	.074	.074	.074	.074	.074
	-25	.074	.067	.074	.074	.074	.074	.074
	0	.074	.074	.074	.074	.074	.074	.074
	+25	.074	.081	.075	.074	.074	.074	.074
	+50	.074	.081	.075	.074	.074	.074	.074
	+75	.074	.088	.075	.074	.074	.074	.074
	+100	.074	.088	.075	.074	.074	.074	.074
6	-100	134.2	134.2	134.2	134.2	134.2	134.2	0.2
	-75	134.2	134.2	134.2	134.2	134.2	134.2	34.0
	-50	134.2	134.2	134.2	134.2	134.2	134.2	67.9
	-25	134.2	134.2	134.2	134.2	134.2	134.2	102.1
	0	134.2	134.2	134.2	134.2	134.2	134.2	134.2
	+25	134.2	134.2	134.2	134.2	134.2	134.2	166.1
	+50	134.2	134.2	134.2	134.2	134.2	134.2	196.8
	+75	134.2	134.3	134.2	134.2	134.2	134.2	229.4
	+100	134.2	134.3	134.2	134.2	134.2	134.2	262.1

Table B.15: System and four load point EENS (MWh/yr) for the IEEE-RTS as a function of unit FOR

Change in FOR (%)	System	Bus 9	Bus 14	Bus 15	Bus 19
-100	0.8	0.0	0.0	0.0	0.0
-75	50.0	11.9	0.8	6.1	30.3
-50	318.9	80.2	8.5	51.3	174.3
-25	1019.5	258.1	37.8	190.1	509.7
0	2413.9	607.5	110.9	490.9	1123.0
+25	4741.3	1184.2	249.8	1017.6	2081.4
+50	8397.3	2081.9	490.4	1879.9	3497.1
+75	13685.3	3352.0	875.5	3171.1	5425.5
+100	21290.7	5123.8	1486.2	5079.0	8023.0

Table B.16: System and four load point EENS (MWh/yr) for the IEEE-RTS as a function of unit FOR in the four cases

Cases	Change in FOR (%)	System	Bus 9	Bus 14	Bus 15	Bus 19
Case A	-100	563.7	140.9	12.5	86.2	319.0
	-75	1012.2	255.4	35.3	183.6	516.5
	-50	1478.7	372.8	60.1	286.6	719.1
	-25	1956.4	492.4	86.0	391.1	925.7
	0	2413.9	607.5	110.9	490.9	1123.0
	+25	2852.4	716.7	134.4	585.0	1312.4
	+50	3322.1	835.4	159.9	687.9	1513.8
	+75	3747.0	943.7	180.7	778.0	1703.5
	+100	4189.6	1056.6	203.0	872.5	1898.3
Case B	-100	537.7	133.6	10.4	78.8	311.2
	-75	1006.8	251.3	36.4	181.7	511.6
	-50	1474.2	370.4	60.9	283.8	715.3
	-25	1949.6	490.5	86.5	389.0	921.3
	0	2413.9	607.5	110.9	490.9	1123.0
	+25	2848.7	718.8	132.8	585.1	1316.6
	+50	3263.8	825.7	152.6	672.7	1502.9
	+75	3691.5	935.4	173.4	764.3	1694.0
	+100	4130.3	1047.4	195.3	858.8	1888.8
Case C	-100	1131.4	295.1	31.7	196.2	592.6
	-75	1468.5	376.1	53.8	274.7	728.9
	-50	1775.5	452.0	71.6	344.8	859.5
	-25	2100.7	530.2	92.1	419.5	991.9
	0	2413.9	607.5	110.9	490.9	1123.0
	+25	2735.7	686.3	130.6	564.5	1255.2
	+50	3044.4	763.1	148.1	633.7	1385.5
	+75	3345.6	838.2	164.4	701.3	1515.4
	+100	3639.0	910.9	181.0	767.0	1641.7
Case D	-100	2075.1	523.3	90.5	413.6	984.0
	-75	2162.0	544.5	95.7	433.7	1019.8
	-50	2244.7	565.2	100.8	452.7	1054.1
	-25	2329.1	586.5	105.9	471.9	1087.9
	0	2413.9	607.5	110.9	490.9	1123.0
	+25	2488.3	626.3	115.2	507.1	1154.6
	+50	2562.4	645.5	119.1	523.2	1186.7
	+75	2644.8	666.4	123.6	541.9	1221.8
	+100	2732.1	688.5	128.9	562.2	1257.1

Table B.17: System and selected bus EENS for the IEEE-RTS as a function of the line unavailabilities

Multiplication Factor	System	Bus 9	Bus 14	Bus 15	Bus 19	Bus 3	Bus 5	Bus 6	Bus 10
1	2414	607	111	491	1123	0.215	0.000	0.293	2.541
2	2417	608	111	491	1124	0.216	0.153	1.172	2.541
4	2431	609	115	492	1125	0.219	1.628	4.572	2.541
6	2447	609	118	492	1126	0.225	1.629	15.24	2.562
8	2479	610	122	493	1127	0.233	4.051	35.05	2.566
10	2512	611	137	494	1129	0.244	6.439	44.2	2.566

Table B.18: System and selected bus EENS for the MRTS as a function of the line unavailabilities

Multiplication Factor	System	Bus 9	Bus 14	Bus 15	Bus 19	Bus 3	Bus 5	Bus 6	Bus 10
1	1601.4	225.6	341.4	80.8	485.7	0.1	12.0	318.8	81.1
2	2110.5	236.6	416.9	81.1	484.5	100.8	28.6	571.3	172.7
4	3147.4	257.8	565.5	80.6	480.3	212.5	53.1	1104.3	353.8
6	4216.5	292.8	705.6	80.3	476.4	345.4	97.8	1592.9	557.2
8	5525.8	346.5	892.3	79.8	477.9	464.3	195.7	2160.9	797.4
10	6861.0	448.6	1081.4	89.9	489.6	606.1	245.0	2862.3	1045.3

APPENDIX C. THE IMPACT INDICES AND MODIFIED IMPACT INDICES FOR THE TWO TEST SYSTEMS

This appendix contains numerical indices and data on the studies described in Chapter 4.

Table C.1: Bus 2 Impact Indices (II) of the RBTS for selected outages

Outage	Case	Annualized			Annual		
		PLC	ENLC	EENS	PLC	ENLC	EENS
G&T	Base case	0(N/A)	1	1	0(N/A)	0(N/A)	0(N/A)
	G-1	.00006	21.727	30.864	0	.00031	.018
	G-2	.00009	36.900	50.773	0	.00060	.033
	L1	0	1	1	0	0	0
	L2	0	0.993	1	0	0	0
	L3	0	1	1	0	0	0
	L4	0	1	1	0	0	0
	L5	0	1	1	0	0	0
	L8	0	1	1	0	0	0
T	Base case	0	0	0	0	0	0
	L1	0	0	0	0	0	0
	L2	0	0	0	0	0	0
	L3	0	0	0	0	0	0
	L4	0	0	0	0	0	0
	L5	0	0	0	0	0	0
	L8	0	0	0	0	0	0

Table C.2: Bus 3 Impact Indices (II) of the RBTS for selected outages

Outage	Case	Annualized			Annual		
		PLC	ENLC	EENS	PLC	ENLC	EENS
G&T	Base case	1	1	1	1	1	1
	G-1	14.661	8.123	18.502	21.556	12.515	22.616
	G-2	16.009	9.721	21.750	26.889	17.692	28.066
	L1	10.547	7.951	10.605	11.389	10.938	5.447
	L2	1.453	1.935	1.781	2.333	3.576	1.918
	L3	1.077	1.173	1.160	1.278	1.638	1.365
	L4	1.008	1.018	1.007	1.056	1.080	1.029
	L5	0.999	0.993	0.992	1.000	0.945	0.995
	L8	1.008	1.016	1.012	1.056	1.089	1.037
T	Base case	1	1	1	0(N/A)	1	1
	L1	263.000	126.087	247.169	.00069	86.890	95.464
	L2	70.400	34.081	64.312	.00020	27.145	32.069
	L3	1.600	1.503	1.835	.00001	3.106	6.747
	L4	1.200	1.122	1.261	.00001	1.688	2.349

Table C.2: (Continued)

Outage	Case	Annualized			Annual		
		PLC	ENLC	EENS	PLC	ENLC	EENS
T	L5	1.000	0.999	0.904	0	0.641	0.964
	L8	1.200	1.169	1.401	.00001	1.758	2.500

Table C.3: Bus 4 Impact Indices (II) of the RBTS for selected outages

Outage	Case	Annualized			Annual		
		PLC	ENLC	EENS	PLC	ENLC	EENS
G&T	Base case	1	1	1	0(N/A)	1	1
	G-1	24.333	15.716	23.795	.00001	5.294	14.737
	G-2	35.667	24.629	34.788	.00001	8.670	23.053
	L1	2.667	5.821	9.248	.00001	22.982	23.605
	L2	2.333	4.277	5.475	.00001	9.229	8.026
	L3	1.333	1.914	1.509	0	2.248	2.421
	L4	1.000	0.999	1.000	0	1.000	1.000
	L5	1.000	0.999	1.000	0	1.000	1.000
	L8	1.000	0.999	1.000	0	1.000	1.000
T	Base case	0(N/A)	1	1	0(N/A)	1	1
	L1	.00006	26.149	38.892	.00001	27.837	41.905
	L2	.00003	13.568	19.357	0	9.593	11.190
	L3	0	0.997	1.000	0	0.988	1.000
	L4	0	1.000	1.000	0	1.000	1.000
	L5	0	1.000	1.000	0	1.000	1.000
	L8	0	1.000	1.000	0	1.000	1.000

Table C.4: Bus 5 Impact Indices (II) of the RBTS for selected outages

Outage	Case	Annualized			Annual		
		PLC	ENLC	EENS	PLC	ENLC	EENS
G&T	Base case	1	1	1	0(N/A)	1	1
	G-1	20.250	12.967	22.730	.00002	2.720	5.206
	G-2	29.000	19.477	33.142	.00004	4.051	7.557
	L1	2.500	5.063	2.745	.00002	6.848	4.361
	L2	2.250	4.347	2.322	.00001	3.323	2.250
	L3	1.750	3.145	1.530	0	1.159	0.851
	L4	1.000	1.091	0.951	0	0.675	0.625
	L5	29.750	38.736	70.911	.00116	206.715	436.422
	L8	29.750	38.888	70.922	.00116	206.717	436.422
T	Base case	0(N/A)	1	1	0(N/A)	1	1
	L1	.00006	16.987	11.497	.00002	7.523	4.992
	L2	.00005	12.441	6.833	.00001	3.103	2.241
	L3	.00003	7.684	1.985	0	0.653	0.562
	L4	0	1.353	0.706	0	0.632	0.558
	L5	.00116	141.743	422.507	.00116	221.831	518.614
	L8	.00116	142.332	422.576	.00116	221.833	518.614

Table C.5: Bus 6 Impact Indices (II) of the RBTS for selected outages

Outage	Case	Annualized			Annual		
		PLC	ENLC	EENS	PLC	ENLC	EENS
G&T	Base case	1	1	1	1	1	1
	G-1	4.165	2.383	1.640	1.025	0.973	0.966
	G-2	4.942	2.833	1.858	1.067	1.003	0.981
	L1	0.993	1.045	0.963	0.958	0.983	0.945
	L2	1.007	1.049	0.965	0.950	0.957	0.939
	L3	0.978	1.003	0.952	0.942	0.940	0.935
	L4	0.971	1.005	0.951	0.933	0.943	0.934
	L5	1.806	1.876	1.885	1.900	1.905	1.897
	L8	1.777	1.822	1.871	1.900	1.902	1.896
T	Base case	1	1	1	1	1	1
	L1	0.992	1.049	0.962	0.958	0.982	0.945
	L2	0.983	1.032	0.959	0.942	0.952	0.938
	L3	0.958	0.979	0.946	0.933	0.934	0.933
	L4	0.967	1.006	0.950	0.933	0.940	0.934
	L5	1.933	1.964	1.912	1.900	1.904	1.898
	L8	1.900	1.903	1.898	1.892	1.901	1.898

Table C.6: System and load point Impact Indices (EENS) of the RBTS for selected outages with the new priority order

Outage	Case	System	Bus 2	Bus 3	Bus 4	Bus 5	Bus 6
G&T	Base case	1	0(N/A)	1	1	1	1
	G-1	3.474	.018	14.084	22.745	17.695	1.189
	G-2	4.122	.033	30.483	27.516	24.477	1.268
	L1	1.476	0	104.194	1.757	3.508	0.954
	L2	1.056	0	13.028	1.463	2.450	0.947
	L3	0.984	0	1.199	1.348	1.419	0.940
	L4	0.944	0	1.322	1.000	1.036	0.935
	L5	2.637	0	0.916	1.000	159.921	1.888
	L8	2.641	0	0.858	0.997	160.191	1.892
T	Base case	1	0(N/A)	1	1	1	1
	L1	1.191	0	113.463	83.041	8.377	0.953
	L2	1.019	0	36.806	24.480	4.451	0.943
	L3	0.947	0	0.969	10.014	1.341	0.936
	L4	0.936	0	1.925	1.196	1.084	0.935
	L5	2.849	0	0.975	1.216	473.110	1.897
	L8	2.853	0	1.444	0.932	473.681	1.899

Table C.7: System and load point Modified Impact Indices (EENS) of the RBTS for selected outages

Outage	Case	System	Bus 2	Bus 3	Bus 4	Bus 5	Bus 6
G&T	G-1	0.10422	0.00054	0.67848	0.44211	0.15618	0.02898
	G-2	0.12366	0.00099	0.84198	0.69159	0.22671	0.02943
	L1	0.00252	0	0.00931	0.04036	0.00746	0.00162
	L2	0.00600	0	0.01089	0.04559	0.01278	0.00533
	L3	0.00448	0	0.00621	0.01102	0.00387	0.00425
	L4	0.00108	0	0.00117	0.00114	0.00071	0.00106
	L5	0.00301	0	0.00113	0.00114	0.49752	0.00216
	L8	0.00301	0	0.00118	0.00114	0.49752	0.00216
	L1	0.00204	0	0.16324	0.07166	0.00854	0.00533
	L2	0.00579	0	0.18215	0.06356	0.01273	0.00425
	L3	0.00431	0	0.03070	0.00455	0.00256	0.00216
	L4	0.00107	0	0.00268	0.00114	0.00064	0.00216
	L5	0.00325	0	0.00110	0.00114	0.59122	0.00162
	L8	0.00325	0	0.00285	0.00114	0.59122	0.00106

Table C.8: System and load point Impact Indices (EENS) of the IEEE-RTS for selected outages (G&T)

Case	System	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5
Base case	1	0(N/A)	1	1	0(N/A)	0(N/A)
G-7-100	1.760	0	3.615	5.488	0	0
G-13-197	3.439	0	9.967	16.298	0	0
G-15-155	2.705	0	7.048	10.879	.002	0
G-16-155	2.705	0	7.048	10.879	.002	0
G-18-400	6.279	0	9.413	14.651	.001	0
G-21-400	6.279	0	9.413	14.651	.001	0
G-23-155	2.766	0	7.935	11.707	.001	0
G-23-350	6.826	0	17.637	27.135	.002	0
L1	1.001	0	1.179	1.000	0	0
L2	1.001	0	1.000	2.009	0	0
L3	1.059	0	1.000	1.000	0	140.8
L4	1.067	0	1.000	1.000	159.2	0
L5	1.396	0	1.000	1.000	0	0
L6	1.001	0	1.000	2.009	0	0
L7	1.002	0	1.000	1.451	0	0
L8	1.074	0	1.212	1.000	175.0	0
L9	1.058	0	1.000	1.000	0	137.6
L10	1.178	0	1.073	1.000	0	0
L12	1.007	0	1.000	0.991	0	0.034
L13	1.007	0	1.000	0.991	0	0.092
L14	1.000	0	1.000	1.000	0	0
L15	1.000	0	1.000	1.000	0	0
L16	1.000	0	1.000	1.005	0	0.109

Table C.8: (Continued)

Case	System	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5
L17	1.000	0	1.000	1.005	0	0.109
L18	1.000	0	1.000	1.000	0	0
L19	1.186	0	0.987	0.991	0	0
L20	1.000	0	1.000	1.000	0	0
L21	1.000	0	1.000	1.000	0	0
L22	1.000	0	1.000	1.000	0	0
L23	1.235	0	1.005	1.005	0	0
L24	1.001	0	1.000	1.000	0	0
L25	1.001	0	1.000	1.000	0	0
L27	1.001	0	1.005	1.460	0	0
L28	1.002	0	1.003	1.000	0	0
L29	1.002	0	1.025	1.000	0	0
L30	1.000	0	1.000	1.014	0	0
L31	1.004	0	1.005	1.000	0	0
L32	1.000	0	1.000	1.000	0	0
L34	1.000	0	1.000	1.000	0	0
L36	1.000	0	1.000	1.000	0	0
L38	1.003	0	1.000	1.000	0	0
Case	Bus 6	Bus 7	Bus 8	Bus 9	Bus 10	Bus 13
Base case	1	1	1	1	1	1
G-7-100	5.205	11.905	272.000	1.764	2.649	11.806
G-13-197	5.222	0.238	51.500	3.457	7.216	38.065
G-15-155	5.246	0.143	54.000	2.705	4.912	29.613
G-16-155	5.246	0.143	54.000	2.705	4.912	29.613
G-18-400	5.242	0.476	66.000	6.361	7.594	38.097
G-21-400	5.242	0.476	66.000	6.361	7.594	38.097
G-23-155	5.235	0.095	42.500	2.764	5.548	27.129
G-23-350	5.273	1	121.500	6.671	12.981	70.161
L1	5.201	0	3.000	1.001	1.000	1.000
L2	5.201	0	3.000	1.001	1.000	1.000
L3	5.201	0	3.000	1.000	1.005	1.000
L4	5.201	0	3.000	1.000	1.000	1.000
L5	3261.4	0	3.000	1.000	1.006	1.000
L6	5.201	0	3.000	1.001	1.000	1.000
L7	5.201	0	3.000	1.001	1.001	1.000
L8	5.201	0	3.000	1.000	1.000	1.000
L9	5.201	0	3.000	1.001	1.000	1.000
L10	1461.7	0	3.000	1.000	1.000	1.000
L12	0.765	32.048	9015.500	1.000	0.998	0.968
L13	5.201	32.048	9015.500	1.000	0.998	0.968
L14	1.014	1	1	1.000	1.000	1.000
L15	1.014	1	1	1.000	1.000	1.000
L16	1	1.286	269.500	1.000	1.068	1.000

Table C.8: (Continued)

Case	Bus 6	Bus 7	Bus 8	Bus 9	Bus 10	Bus 13
L17	1	1.286	296.000	1.000	1.068	1.000
L18	1	1.286	18.500	1.000	1.001	1.000
L19	0	1	1	1.000	0.993	1.000
L20	1	1	1	1.000	1.000	1.000
L21	1	1	1	1.000	1.000	1.355
L22	1	1	1	1.000	1.000	1.323
L23	0	1	1	1.001	1.014	2.355
L24	1	1	1	1.000	1.002	1.000
L25	1	1	1	1.001	1.001	1.000
L27	1	1	1	1.001	1.006	1.000
L28	1	1	1	1.000	1.005	1.355
L29	1	1	1	1.002	1.020	2.323
L30	1	1	1	1.000	1.000	1.000
L31	1	1	1	1.003	1.008	1.000
L32	1	1	1	1.000	1.000	1.000
L34	1	1	1	1.000	1.000	1.000
L36	1	1	1	1.000	1.000	1.000
L38	1	1	1	1.004	1.000	1.000
Case	Bus 14	Bus 15	Bus 16	Bus 18	Bus 19	Bus 20
Base case	1	1	1	1	1	1
G-7-100	1.834	1.825	1.828	2.066	1.715	1.942
G-13-197	4.011	3.668	4.043	5.028	3.190	4.401
G-15-155	3.062	2.847	3.017	3.576	2.559	3.316
G-16-155	3.062	2.847	3.017	3.576	2.559	3.316
G-18-400	6.666	6.553	6.619	6.722	6.045	6.556
G-21-400	6.666	6.553	6.619	6.722	6.045	6.556
G-23-155	3.160	2.916	3.127	3.882	2.604	3.491
G-23-350	8.433	7.440	8.956	10.234	6.279	9.257
L1	1.001	1.001	1.001	1.000	1.000	1.001
L2	1.001	1.001	1.001	1.000	1.000	1.001
L3	1.001	1.001	1.000	0.999	1.000	1.000
L4	1.001	1.001	1.001	1.000	1.000	1.000
L5	1.001	1.000	1.001	1.000	1.000	1.001
L6	1.001	1.001	1.001	1.000	1.000	1.001
L7	1.003	1.001	1.001	1.000	1.001	1.001
L8	1.001	1.001	1.001	1.000	1.000	1.001
L9	1.001	1.001	1.001	1.000	1.000	1.001
L10	1.001	1.001	1.001	1.000	1.000	1.001
L12	1.000	0.999	0.999	0.999	0.999	0.999
L13	1.000	0.999	0.999	0.999	0.999	0.999
L14	1.000	1.000	1.000	1.000	1.000	1.000
L15	1.000	1.000	1.000	1.000	1.000	1.000
L16	1.000	1.000	1.000	1.000	1.000	1.000

Table C.8: (Continued)

Case	Bus 14	Bus 15	Bus 16	Bus 18	Bus 19	Bus 20
L17	1.000	1.000	1.000	1.000	1.000	1.000
L18	0.992	1.000	1.000	1.000	1.000	1.007
L19	5.055	1.000	0.998	0.995	1.000	0.999
L20	1.000	1.000	1.000	1.000	1.000	1.000
L21	1.001	1.000	1.000	1.000	1.000	1.000
L22	1.001	1.000	1.000	1.000	1.000	1.000
L23	6.101	0.999	1.000	1.000	1.001	1.003
L24	1.006	0.999	1.051	1.000	1.000	1.002
L25	1.001	1.001	1.000	1.000	1.001	1.000
L27	1.002	1.000	1.000	1.000	1.001	1.002
L28	1.011	0.999	1.118	1.000	1.000	1.003
L29	1.035	1.000	1.000	1.000	1.000	1.007
L30	1.000	1.000	1.001	1.000	1.000	1.000
L31	1.005	1.004	1.006	1.008	1.003	1.006
L32	1.000	1.000	1.000	1.000	1.000	1.000
L34	1.000	1.000	1.000	1.000	1.000	1.000
L36	1.000	1.000	1.000	1.000	1.000	1.018
L38	1.003	1.003	1.002	1.001	1.003	1.002

Table C.9: System and load point Impact Indices (EENS) of the IEEE-RTS for selected outages (T only)

Case	System	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5
Base case	1	0(N/A)	0(N/A)	0(N/A)	0(N/A)	0(N/A)
L1	1.999	0	0	0	0	0
L2	2.285	0	0	0.217	0	0
L3	186.8	0	0	0	0	140.8
L4	210.9	0	0	0	159.2	0
L5	1253.7	0	0	0	0	0
L6	2.285	0	0	0.217	0	0
L7	2.127	0	0	0.097	0	0
L8	231.6	0	0	0	175.0	0
L9	182.6	0	0	0	0	137.6
L10	561.9	0	0	0	0	0
L12	0.874	0	0	0	0	0.034
L13	0.846	0	0	0	0	0.092
L14	0.997	0	0	0	0	0
L15	0.985	0	0	0	0	0
L16	0.981	0	0	0.001	0	0.067
L17	0.981	0	0	0.001	0	0.067
L18	0.989	0	0	0	0	0
L19	590.4	0	0	0	0	0
L20	0.997	0	0	0	0	0
L21	0.997	0	0	0	0	0

Table C.9: (Continued)

Case	System	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5
L22	0.997	0	0	0	0	0
L23	741.6	0	0	0	0	0
L24	0.997	0	0	0	0	0
L25	0.997	0	0	0	0	0
L27	1.127	0	0	0.1	0	0
L28	1.000	0	0	0	0	0
L29	1.000	0	0	0	0	0
L30	1.000	0	0	0	0	0
L31	1.000	0	0	0	0	0
L32	1.000	0	0	0	0	0
L34	1.000	0	0	0	0	0
L36	1.000	0	0	0	0	0
L38	1.000	0	0	0	0	0
Case	Bus 6	Bus 7	Bus 8	Bus 9	Bus 10	Bus 13
Base case	1	0(N/A)	0(N/A)	0(N/A)	0(N/A)	0(N/A)
L1	1.524	0	0	0	0	0
L2	1.524	0	0	0	0	0
L3	1.524	0	0	0	0.016	0
L4	1.524	0	0	0	0	0
L5	1254.1	0	0	0	0.016	0
L6	1.524	0	0	0	0	0
L7	1.524	0	0	0	0	0
L8	1.524	0	0	0	0	0
L9	1.524	0	0	0	0	0
L10	562.0	0	0	0	0	0
L12	0.831	0	0	0	0	0
L13	0.724	0	0	0	0	0
L14	0.997	0	0	0	0	0
L15	0.980	0	0	0	0	0
L16	0.831	0	0	0	0.047	0
L17	0.831	0	0	0	0.047	0
L18	0.980	0	0	0	0	0
L19	0	0	0	0	0	0
L20	0.996	0	0	0	0	0
L21	0.996	0	0	0	0	0
L22	0.996	0	0	0	0	0
L23	0	0	0	0	0	0
L24	0.996	0	0	0	0	0
L25	0.996	0	0	0	0	0
L27	0.997	0	0	0	0	0
L28	1	0	0	0	0	0
L29	1	0	0	0	0	0
L30	1	0	0	0	0	0

Table C.9: (Continued)

Case	Bus 6	Bus 7	Bus 8	Bus 9	Bus 10	Bus 13
L31	1	0	0	0	0	0
L32	1	0	0	0	0	0
L34	1	0	0	0	0	0
L36	1	0	0	0	0	0
L38	1	0	0	0	0	0
Case	Bus 14	Bus 15	Bus 16	Bus 18	Bus 19	Bus 20
Base case	0(N/A)	0(N/A)	0(N/A)	0(N/A)	0(N/A)	0(N/A)
L1	0	0	0	0	0	0
L2	0	0	0	0	0	0
L3	0	0	0	0	0	0
L4	0	0	0	0	0	0
L5	0	0	0	0	0	0
L6	0	0	0	0	0	0
L7	0	0	0	0	0	0
L8	0	0	0	0	0	0
L9	0	0	0	0	0	0
L10	0	0	0	0	0	0
L12	0	0	0	0	0	0
L13	0	0	0	0	0	0
L14	0	0	0	0	0	0
L15	0.003	0	0	0	0	0
L16	0	0	0	0	0	0
L17	0	0	0	0	0	0
L18	0.003	0	0	0	0	0
L19	450.0	0	0	0	0	0
L20	0	0	0	0	0	0
L21	0	0	0	0	0	0
L22	0	0	0	0	0	0
L23	565.3	0	0	0	0	0
L24	0	0	0	0	0	0
L25	0	0	0	0	0	0
L27	0	0	0	0	0	0
L28	0	0	0	0	0	0
L29	0	0	0	0	0	0
L30	0	0	0	0	0	0
L31	0	0	0	0	0	0
L32	0	0	0	0	0	0
L34	0	0	0	0	0	0
L36	0	0	0	0	0	0
L38	0	0	0	0	0	0

Table C.10: System and load point Modified Impact Indices (EENS) of the IEEE-RTS for selected outages (G&T)

Case	System	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5
G-7-100	0.07040	0.00000	0.14460	0.21952	0.00000	0.00000
G-13-197	0.17195	0.00000	0.49835	0.81490	0.00000	0.00000
G-15-155	0.10820	0.00000	0.28192	0.43516	0.00008	0.00000
G-16-155	0.10820	0.00000	0.28192	0.43516	0.00008	0.00000
G-18-400	0.75348	0.00000	1.12956	1.75812	0.00012	0.00000
G-21-400	0.75348	0.00000	1.12956	1.75812	0.00012	0.00000
G-23-155	0.11064	0.00000	0.31740	0.46828	0.00004	0.00000
G-23-350	0.54608	0.00000	1.41096	2.17080	0.00016	0.00000
L1	0.00044	0.00000	0.00052	0.00044	0.00000	0.00000
L2	0.00058	0.00000	0.00058	0.00117	0.00000	0.00000
L3	0.00040	0.00000	0.00038	0.00038	0.00000	0.05350
L4	0.00048	0.00000	0.00045	0.00045	0.07164	0.00000
L5	0.00063	0.00000	0.00045	0.00045	0.00000	0.00000
L6	0.00055	0.00000	0.00055	0.00110	0.00000	0.00000
L7	0.00175	0.00000	0.00175	0.00254	0.00000	0.00000
L8	0.00044	0.00000	0.00050	0.00041	0.07175	0.00000
L9	0.00041	0.00000	0.00039	0.00039	0.00000	0.05366
L10	0.00155	0.00000	0.00142	0.00132	0.00000	0.00000
L12	0.00050	0.00000	0.00050	0.00050	0.00000	0.00002
L13	0.00050	0.00000	0.00050	0.00050	0.00000	0.00005
L14	0.00175	0.00000	0.00175	0.00175	0.00000	0.00000
L15	0.00175	0.00000	0.00175	0.00175	0.00000	0.00000
L16	0.00175	0.00000	0.00175	0.00176	0.00000	0.00019
L17	0.00175	0.00000	0.00175	0.00176	0.00000	0.00019
L18	0.00050	0.00000	0.00050	0.00050	0.00000	0.00000
L19	0.00058	0.00000	0.00048	0.00049	0.00000	0.00000
L20	0.00050	0.00000	0.00050	0.00050	0.00000	0.00000
L21	0.00065	0.00000	0.00065	0.00065	0.00000	0.00000
L22	0.00062	0.00000	0.00062	0.00062	0.00000	0.00000
L23	0.00059	0.00000	0.00048	0.00048	0.00000	0.00000
L24	0.00041	0.00000	0.00041	0.00041	0.00000	0.00000
L25	0.00051	0.00000	0.00051	0.00051	0.00000	0.00000
L27	0.00051	0.00000	0.00051	0.00074	0.00000	0.00000
L28	0.00044	0.00000	0.00044	0.00044	0.00000	0.00000
L29	0.00043	0.00000	0.00044	0.00043	0.00000	0.00000
L30	0.00040	0.00000	0.00040	0.00041	0.00000	0.00000
L31	0.00068	0.00000	0.00068	0.00068	0.00000	0.00000
L32	0.00044	0.00000	0.00044	0.00044	0.00000	0.00000
L34	0.00048	0.00000	0.00048	0.00048	0.00000	0.00000
L36	0.00043	0.00000	0.00043	0.00043	0.00000	0.00000
L38	0.00057	0.00000	0.00057	0.00057	0.00000	0.00000

Table C.10: (Continued)

Case	Bus 6	Bus 7	Bus 8	Bus 9	Bus 10	Bus 13
G-7-100	0.20820	0.47620	10.88000	0.07056	0.10596	0.47224
G-13-197	0.26110	0.01190	2.57500	0.17285	0.36080	1.90325
G-15-155	0.20984	0.00572	2.16000	0.10820	0.19648	1.18452
G-16-155	0.20984	0.00572	2.16000	0.10820	0.19648	1.18452
G-18-400	0.62904	0.05712	7.92000	0.76332	0.91128	4.57164
G-21-400	0.62904	0.05712	7.92000	0.76332	0.91128	4.57164
G-23-155	0.20940	0.00380	1.70000	0.11056	0.22192	1.08516
G-23-350	0.42184	0.08000	9.72000	0.53368	1.03848	5.61288
L1	0.00229	0.00000	0.00132	0.00044	0.00044	0.00044
L2	0.00302	0.00000	0.00174	0.00058	0.00058	0.00058
L3	0.00198	0.00000	0.00114	0.00038	0.00038	0.00038
L4	0.00234	0.00000	0.00135	0.00045	0.00045	0.00045
L5	1.46763	0.00000	0.00135	0.00045	0.00045	0.00045
L6	0.00286	0.00000	0.00165	0.00055	0.00055	0.00055
L7	0.00910	0.00000	0.00525	0.00175	0.00175	0.00175
L8	0.00213	0.00000	0.00123	0.00041	0.00041	0.00041
L9	0.00203	0.00000	0.00117	0.00039	0.00039	0.00039
L10	1.92944	0.00000	0.00396	0.00132	0.00132	0.00132
L12	0.00038	0.01602	4.50775	0.00050	0.00050	0.00048
L13	0.00260	0.01602	4.50775	0.00050	0.00050	0.00048
L14	0.00177	0.00175	0.00175	0.00175	0.00175	0.00175
L15	0.00177	0.00175	0.00175	0.00175	0.00175	0.00175
L16	0.00175	0.00225	0.47163	0.00175	0.00187	0.00175
L17	0.00175	0.00225	0.51800	0.00175	0.00187	0.00175
L18	0.00050	0.00064	0.00925	0.00050	0.00050	0.00050
L19	0.00000	0.00049	0.00049	0.00049	0.00049	0.00049
L20	0.00050	0.00050	0.00050	0.00050	0.00050	0.00050
L21	0.00065	0.00065	0.00065	0.00065	0.00065	0.00088
L22	0.00062	0.00062	0.00062	0.00062	0.00062	0.00082
L23	0.00000	0.00048	0.00048	0.00048	0.00049	0.00113
L24	0.00041	0.00041	0.00041	0.00041	0.00041	0.00041
L25	0.00051	0.00051	0.00051	0.00051	0.00051	0.00051
L27	0.00051	0.00051	0.00051	0.00051	0.00051	0.00051
L28	0.00044	0.00044	0.00044	0.00044	0.00044	0.00060
L29	0.00043	0.00043	0.00043	0.00043	0.00044	0.00100
L30	0.00040	0.00040	0.00040	0.00040	0.00040	0.00040
L31	0.00068	0.00068	0.00068	0.00068	0.00069	0.00068
L32	0.00044	0.00044	0.00044	0.00044	0.00044	0.00044
L34	0.00048	0.00048	0.00048	0.00048	0.00048	0.00048
L36	0.00043	0.00043	0.00043	0.00043	0.00043	0.00043
L38	0.00057	0.00057	0.00057	0.00057	0.00057	0.00057

Table C.10: (Continued)

Case	Bus 14	Bus 15	Bus 16	Bus 18	Bus 19	Bus 20
G-7-100	0.07336	0.07300	0.07312	0.08264	0.06860	0.07768
G-13-197	0.20055	0.18340	0.20215	0.25140	0.15950	0.22005
G-15-155	0.12248	0.11388	0.12068	0.14304	0.10236	0.13264
G-16-155	0.12248	0.11388	0.12068	0.14304	0.10236	0.13264
G-18-400	0.79992	0.78636	0.79428	0.80664	0.72540	0.78672
G-21-400	0.79992	0.78636	0.79428	0.80664	0.72540	0.78672
G-23-155	0.12640	0.11664	0.12508	0.15528	0.10416	0.13964
G-23-350	0.67464	0.59520	0.71648	0.81872	0.50232	0.74056
L1	0.00044	0.00044	0.00044	0.00044	0.00044	0.00044
L2	0.00058	0.00058	0.00058	0.00058	0.00058	0.00058
L3	0.00038	0.00038	0.00038	0.00038	0.00038	0.00038
L4	0.00045	0.00045	0.00045	0.00045	0.00045	0.00045
L5	0.00045	0.00045	0.00045	0.00045	0.00045	0.00045
L6	0.00055	0.00055	0.00055	0.00055	0.00055	0.00055
L7	0.00176	0.00175	0.00175	0.00175	0.00175	0.00175
L8	0.00041	0.00041	0.00041	0.00041	0.00041	0.00041
L9	0.00039	0.00039	0.00039	0.00039	0.00039	0.00039
L10	0.00132	0.00132	0.00132	0.00132	0.00132	0.00132
L12	0.00050	0.00050	0.00050	0.00050	0.00050	0.00050
L13	0.00050	0.00050	0.00050	0.00050	0.00050	0.00050
L14	0.00175	0.00175	0.00175	0.00175	0.00175	0.00175
L15	0.00175	0.00175	0.00175	0.00175	0.00175	0.00175
L16	0.00175	0.00175	0.00175	0.00175	0.00175	0.00175
L17	0.00175	0.00175	0.00175	0.00175	0.00175	0.00175
L18	0.00050	0.00050	0.00050	0.00050	0.00050	0.00050
L19	0.00248	0.00049	0.00049	0.00049	0.00049	0.00049
L20	0.00050	0.00050	0.00050	0.00050	0.00050	0.00050
L21	0.00065	0.00065	0.00065	0.00065	0.00065	0.00065
L22	0.00062	0.00062	0.00062	0.00062	0.00062	0.00062
L23	0.00293	0.00048	0.00048	0.00048	0.00048	0.00048
L24	0.00041	0.00041	0.00043	0.00041	0.00041	0.00041
L25	0.00051	0.00051	0.00051	0.00051	0.00051	0.00051
L27	0.00051	0.00051	0.00051	0.00051	0.00051	0.00051
L28	0.00044	0.00044	0.00049	0.00044	0.00044	0.00044
L29	0.00045	0.00043	0.00043	0.00043	0.00043	0.00043
L30	0.00040	0.00040	0.00040	0.00040	0.00040	0.00040
L31	0.00068	0.00068	0.00068	0.00069	0.00068	0.00068
L32	0.00044	0.00044	0.00044	0.00044	0.00044	0.00044
L34	0.00048	0.00048	0.00048	0.00048	0.00048	0.00048
L36	0.00043	0.00043	0.00043	0.00043	0.00043	0.00044
L38	0.00057	0.00057	0.00057	0.00057	0.00057	0.00057

Table C.11: System and load point Modified Impact Indices (EENS) of the IEEE-RTS for selected outages (T only)

Case	System	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5
L1	0.00088	0.00000	0.00000	0.00000	0.00000	0.00000
L2	0.00133	0.00000	0.00000	0.00013	0.00000	0.00000
L3	0.07098	0.00000	0.00000	0.00000	0.00000	0.05350
L4	0.09491	0.00000	0.00000	0.00000	0.07164	0.00000
L5	0.56417	0.00000	0.00000	0.00000	0.00000	0.00000
L6	0.00126	0.00000	0.00000	0.00012	0.00000	0.00000
L7	0.00372	0.00000	0.00000	0.00017	0.00000	0.00000
L8	0.09496	0.00000	0.00000	0.00000	0.07175	0.00000
L9	0.07121	0.00000	0.00000	0.00000	0.00000	0.05366
L10	0.74171	0.00000	0.00000	0.00000	0.00000	0.00000
L12	0.00044	0.00000	0.00000	0.00000	0.00000	0.00002
L13	0.00042	0.00000	0.00000	0.00000	0.00000	0.00005
L14	0.00174	0.00000	0.00000	0.00000	0.00000	0.00000
L15	0.00172	0.00000	0.00000	0.00000	0.00000	0.00000
L16	0.00172	0.00000	0.00000	0.00000	0.00000	0.00012
L17	0.00172	0.00000	0.00000	0.00000	0.00000	0.00012
L18	0.00049	0.00000	0.00000	0.00000	0.00000	0.00000
L19	0.28930	0.00000	0.00000	0.00000	0.00000	0.00000
L20	0.00050	0.00000	0.00000	0.00000	0.00000	0.00000
L21	0.00065	0.00000	0.00000	0.00000	0.00000	0.00000
L22	0.00062	0.00000	0.00000	0.00000	0.00000	0.00000
L23	0.35597	0.00000	0.00000	0.00000	0.00000	0.00000
L24	0.00041	0.00000	0.00000	0.00000	0.00000	0.00000
L25	0.00051	0.00000	0.00000	0.00000	0.00000	0.00000
L27	0.00057	0.00000	0.00000	0.00005	0.00000	0.00000
L28	0.00044	0.00000	0.00000	0.00000	0.00000	0.00000
L29	0.00043	0.00000	0.00000	0.00000	0.00000	0.00000
L30	0.00040	0.00000	0.00000	0.00000	0.00000	0.00000
L31	0.00068	0.00000	0.00000	0.00000	0.00000	0.00000
L32	0.00044	0.00000	0.00000	0.00000	0.00000	0.00000
L34	0.00048	0.00000	0.00000	0.00000	0.00000	0.00000
L36	0.00043	0.00000	0.00000	0.00000	0.00000	0.00000
L38	0.00057	0.00000	0.00000	0.00000	0.00000	0.00000
Case	Bus 6	Bus 7	Bus 8	Bus 9	Bus 10	Bus 13
L1	0.00067	0.00000	0.00000	0.00000	0.00000	0.00000
L2	0.00088	0.00000	0.00000	0.00000	0.00000	0.00000
L3	0.00058	0.00000	0.00000	0.00000	0.00001	0.00000
L4	0.00069	0.00000	0.00000	0.00000	0.00000	0.00000
L5	0.56435	0.00000	0.00000	0.00000	0.00001	0.00000
L6	0.00084	0.00000	0.00000	0.00000	0.00000	0.00000
L7	0.00267	0.00000	0.00000	0.00000	0.00000	0.00000
L8	0.00062	0.00000	0.00000	0.00000	0.00000	0.00000

Table C.11: (Continued)

Case	Bus 6	Bus 7	Bus 8	Bus 9	Bus 10	Bus 13
L9	0.00059	0.00000	0.00000	0.00000	0.00000	0.00000
L10	0.74184	0.00000	0.00000	0.00000	0.00000	0.00000
L12	0.00042	0.00000	0.00000	0.00000	0.00000	0.00000
L13	0.00036	0.00000	0.00000	0.00000	0.00000	0.00000
L14	0.00174	0.00000	0.00000	0.00000	0.00000	0.00000
L15	0.00172	0.00000	0.00000	0.00000	0.00000	0.00000
L16	0.00145	0.00000	0.00000	0.00000	0.00008	0.00000
L17	0.00145	0.00000	0.00000	0.00000	0.00008	0.00000
L18	0.00049	0.00000	0.00000	0.00000	0.00000	0.00000
L19	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L20	0.00050	0.00000	0.00000	0.00000	0.00000	0.00000
L21	0.00065	0.00000	0.00000	0.00000	0.00000	0.00000
L22	0.00062	0.00000	0.00000	0.00000	0.00000	0.00000
L23	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L24	0.00041	0.00000	0.00000	0.00000	0.00000	0.00000
L25	0.00051	0.00000	0.00000	0.00000	0.00000	0.00000
L27	0.00051	0.00000	0.00000	0.00000	0.00000	0.00000
L28	0.00044	0.00000	0.00000	0.00000	0.00000	0.00000
L29	0.00043	0.00000	0.00000	0.00000	0.00000	0.00000
L30	0.00040	0.00000	0.00000	0.00000	0.00000	0.00000
L31	0.00068	0.00000	0.00000	0.00000	0.00000	0.00000
L32	0.00044	0.00000	0.00000	0.00000	0.00000	0.00000
L34	0.00048	0.00000	0.00000	0.00000	0.00000	0.00000
L36	0.00043	0.00000	0.00000	0.00000	0.00000	0.00000
L38	0.00057	0.00000	0.00000	0.00000	0.00000	0.00000
Case	Bus 14	Bus 15	Bus 16	Bus 18	Bus 19	Bus 20
L1	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L2	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L3	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L4	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L5	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L6	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L7	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L8	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L9	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L10	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L12	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L13	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L14	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L15	0.00001	0.00000	0.00000	0.00000	0.00000	0.00000
L16	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L17	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L18	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000

Table C.11: (Continued)

Case	Bus 14	Bus 15	Bus 16	Bus 18	Bus 19	Bus 20
L19	0.22050	0.00000	0.00000	0.00000	0.00000	0.00000
L20	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L21	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L22	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L23	0.27134	0.00000	0.00000	0.00000	0.00000	0.00000
L24	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L25	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L27	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L28	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L29	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L30	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L31	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L32	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L34	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L36	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
L38	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000

APPENDIX D. THE RISKS ASSOCIATED WITH THE REMOVAL OF GENERATION AND TRANSMISSION FACILITIES FROM SERVICE AT VARIOUS LOAD LEVELS

This appendix contains numerical indices and data on the studies described in Chapter 5.

Table D.1: System PLC of the RBTS as a function of the load level with maintenance removals

Cases	Load Levels (MW)									
	105	115	125	135	145	155	165	175	185	195
G1-40	.00118	.00119	.00184	.00193	.00579	.00765	.05304	.05605	.12845	.14882
G1-20	.00114	.00114	.00127	.00131	.00328	.00346	.00768	.01059	.08036	.08434
G1-10	.00112	.00114	.00114	.00132	.00132	.00339	.00340	.00957	.00977	.08458
G2-40	.00120	.00122	.00219	.00227	.00687	.00930	.06296	.06884	.14017	.15739
G2-20	.00114	.00115	.00128	.00131	.00333	.00361	.00850	.01155	.08352	.08479
G2-5	.00112	.00112	.00114	.00114	.00132	.00339	.00350	.00979	.00985	.01499
G1-10G2-40	.00126	.00223	.00233	.00689	.00690	.06294	.06301	.14019	.14028	N/A
G1-10G2-5	.00118	.00118	.00136	.00136	.00139	.00346	.00363	.00980	.01056	.08473
G1-40G2-5	.00122	.00123	.00201	.00205	.00585	.05312	.05324	.12852	.12873	.15722
G2-40G2-5	.00126	.00127	.00233	.00238	.00693	.06294	.06593	.14011	.14029	.16573
G2-5G2-5	.00116	.00118	.00118	.00136	.00140	.00345	.00369	.00981	.01429	.08470
L1	.00118	.00118	.00120	.00122	.00142	.00282	.00770	.03743	.09276	N/A
L2	.00115	.00116	.00120	.00121	.00139	.00155	.00437	.00774	.01375	.02043
L3	.00112	.00113	.00118	.00119	.00136	.00146	.00407	.00439	.01047	.01208
L4	.00112	.00112	.00115	.00116	.00132	.00140	.00353	.00402	.00992	.01441
L5	.00228	.00228	.00230	.00231	.00247	.00255	.00461	.00497	.01099	.01555
L8	.00228	.00228	.00230	.00231	.00247	.00256	.00469	.00513	.01103	.01554

Table D.1: (Continued)

Cases	Load Levels (MW)									
	105	115	125	135	145	155	165	175	185	195
L1-2	.00865	.00865	.00868	.00871	.00997	.03089	.10542	N/A	N/A	N/A
L1-3	.00126	.00138	.00144	.00297	.00317	.00436	.00692	.02589	.04069	.04275
L1-4	.00292	.00293	.00295	.00407	.00427	.00567	.02686	.09232	.11158	N/A
L1-5	.00234	.00234	.00236	.00238	.00255	.00459	.00824	.03738	.09362	N/A
L1-6	.01486	.01511	.01523	.01929	.02054	.02178	N/A	N/A	N/A	N/A
L1-8	.00403	.00404	.00407	.00526	.00545	.00746	.03828	.09349	.11275	N/A
L2-3	.00167	.00265	.00782	.00783	.00927	.01038	.06553	.06930	.09304	.11111
L2-4	.00121	.00122	.00126	.00127	.00145	.00161	.01094	.01430	.02017	.02164
L2-5	.00232	.00233	.00237	.00237	.00255	.00271	.01196	.01539	.02126	.02273
L2-7	.00506	.00602	.01014	.01014	.01158	.01268	.06985	.07038	.09408	N/A
L2-8	.00232	.00233	.00237	.00238	.00255	.00291	.00864	.00889	.01489	.02157
L3-4	.00124	.00125	.00132	.00137	.00152	.00248	.00535	.00566	.01172	.01332
L3-5	.00228	.00230	.00234	.00236	.00253	.00270	.00532	.00566	.01172	.01332
L3-8	.00236	.00237	.00244	.00249	.00264	.00353	.00644	.00673	.01279	.01439
L4-5	.00231	.00232	.00234	.00236	.00252	.00284	.01620	.01654	.02228	.02707
L4-8	.00257	.00257	.00262	.00623	.00637	.00731	.01265	.01287	.01866	.02005
L1-2-3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
L1-2-4	.00861	.00861	.00864	.00984	.01111	.03191	.10651	N/A	N/A	N/A
L1-2-5	.00979	.00979	.00981	.00984	.01110	.03081	.08850	N/A	N/A	N/A
L1-2-8	.00979	.00979	.00981	.01098	.01224	.08740	N/A	N/A	N/A	N/A
L1-3-4	.00130	.00298	.00303	.00415	.00433	.00634	.00816	.02706	.04183	.04494
L1-3-5	.00241	.00252	.00258	.00412	.00432	.00556	.00813	.02706	.04183	.04494
L1-3-8	.00247	.00415	.00419	.00529	.00547	.00742	.00923	.02811	.04288	.04494
L1-4-5	.00408	.00408	.00411	.00412	.00428	.00462	.01796	.01829	.02403	N/A
L1-4-8	.00436	.00436	.00440	N/A	N/A	N/A	N/A	N/A	N/A	N/A
L2-3-4	.00172	.00270	.00786	.00790	.00933	.01052	.06659	.07143	.09512	.11315

Table D.1: (Continued)

Cases	Load Levels (MW)									
	105	115	125	135	145	155	165	175	185	195
L2-3-5	.00282	.00380	.00896	.00897	.01041	.01157	.06659	.07143	.09512	.11315
L2-3-8	.00288	.00386	.00902	.00905	.01049	.01161	.06767	.07143	.09512	.11315
L2-4-5	.00802	.00803	.00805	.00807	.00822	.00856	N/A	N/A	N/A	N/A
L2-4-8	.00830	.00830	.00834	.01193	.01207	.01300	.01832	.01853	.02429	.02567
G1-20-L1	.00123	.00123	.00136	.00141	.00339	.00482	.01086	.04247	.14409	N/A
G1-20-L3	.00123	.00123	.00137	.00141	.00399	.00416	.00835	.01140	.09064	.09170
G1-20-L4	.00118	.00118	.00132	.00137	.00334	.00351	.00786	.01089	.08047	.08439
G1-20-L8	.00230	.00230	.00243	.00248	.00445	.00463	.00895	.01194	.08148	.08539
G1-40-L1	.00127	.00128	.00139	.00203	.00589	.00797	.05549	.06840	.13990	N/A
G1-40-L3	.00127	.00161	.00227	.00236	.00644	.00854	.06384	.06678	.13839	.15572
G1-40-L4	.00123	.00124	.00190	.00200	.00585	.00786	.05311	.05631	.12858	.14889
G1-40-L8	.00234	.00236	.00302	.00311	.00696	.00897	.05417	.05733	.12953	.14981
G2-40-L1	.00130	.00132	.00229	.00240	.00889	.07467	.14595	N/A	N/A	N/A
G2-40-L3	.00125	.00128	.00227	.00236	.00695	.00934	.06292	.06891	.14024	.15744
G2-40-L4	.00125	.00127	.00223	.00233	.00692	.00935	.06594	.06893	.14026	.15746
G2-40-L8	.00236	.00238	.00335	.00344	.00803	.01045	.06694	.06992	.14117	.15838
G1-20-L1-3	.00123	.00135	.00151	.00307	.00565	.00686	.01001	.03108	.09207	.09414
G1-20-L4-8	.00266	.00266	.00370	.01135	.01248	.01265	.01786	.01960	.08851	.08957
G1-40-L1-3	.00127	.00174	.00242	.00402	.00810	.01021	.06531	.06824	.13973	.15702
G1-40-L4-8	.00700	.00702	.00831	.01233	.01550	.04232	.06210	.06461	.13635	.15371
G2-40-L1-3	.00294	.00297	.00394	.00405	.00982	.06564	.11669	N/A	N/A	N/A
G2-40-L4-8	.00271	.00273	.00369	.00731	.01186	.01411	.07129	.07423	.14517	.16225

Table D.2: System ENLC (1/yr) of the RBTS as a function of the load level with maintenance removals

Cases	Load Levels (MW)									
	105	115	125	135	145	155	165	175	185	195
G1-40	1.1313	1.1442	1.4336	1.4859	3.1030	3.9379	15.516	16.866	34.173	41.510
G1-20	1.1105	1.1124	1.1888	1.2135	2.0847	2.1967	3.9301	5.3266	23.218	26.406
G1-10	1.1029	1.1146	1.1173	1.2228	1.2228	2.1615	2.1726	4.8893	5.1107	26.666
G2-40	1.1586	1.1704	1.6306	1.6861	3.6947	5.0066	19.602	23.654	40.691	45.397
G2-20	1.1198	1.1237	1.2025	1.2256	2.1155	2.3265	4.4570	5.9866	26.340	27.006
G2-5	1.1068	1.1068	1.1219	1.1219	1.2291	2.1694	2.3252	5.1417	5.2092	9.1013
G1-10G2-40	1.1976	1.6467	1.7135	3.6647	3.6812	19.034	19.120	39.564	39.605	N/A
G1-10G2-5	1.1439	1.1439	1.2563	1.2563	1.2715	2.1944	2.3705	5.0804	5.4500	26.361
G1-40G2-5	1.1649	1.1761	1.5336	1.5565	3.1216	15.202	15.403	33.649	33.771	43.055
G2-40G2-5	1.2013	1.2073	1.7187	1.7536	3.7185	19.275	22.088	40.079	40.159	46.857
G2-5G2-5	1.1381	1.1499	1.1532	1.2587	1.2896	2.1934	2.4240	5.1135	8.6740	26.600
L1	1.2205	1.2215	1.2372	1.2597	1.3859	2.1134	5.7233	20.210	33.538	N/A
L2	1.1210	1.1758	1.2238	1.2285	1.3464	1.4897	3.2878	6.4066	9.0111	14.638
L3	1.1111	1.1268	1.1858	1.1937	1.3063	1.3838	2.9341	3.1641	5.8812	6.7481
L4	1.1167	1.1178	1.1325	1.1442	1.2407	1.3003	2.3454	2.7996	5.3266	8.9129
L5	2.2499	2.2510	2.2657	2.2708	2.3674	2.4208	3.3957	3.7087	6.3614	10.024
L8	2.2545	2.2556	2.2703	2.2846	2.3812	2.4437	3.4954	3.8667	6.3868	10.009
L1-2	8.3796	8.3835	8.3989	8.4192	8.9279	14.074	33.002	N/A	N/A	N/A
L1-3	1.2865	1.4223	1.4787	2.9369	3.0617	3.5425	5.0512	9.5451	21.259	22.153
L1-4	2.9030	2.9214	2.9361	4.0356	4.1587	4.8764	10.735	33.552	39.035	N/A
L1-5	2.3547	2.3557	2.3714	2.3939	2.5086	4.4674	6.4117	20.633	34.204	N/A
L1-6	14.448	14.737	14.845	18.694	19.188	20.361	N/A	N/A	N/A	N/A
L1-8	3.9964	4.0148	4.0295	5.1984	5.3215	6.7086	21.560	34.690	40.162	N/A
L2-3	1.7110	2.2278	7.0701	7.0717	7.7304	8.2420	22.618	25.952	32.167	36.862
L2-4	1.2198	1.2346	1.2825	1.2944	1.4125	1.5568	9.5280	12.627	15.066	15.767
L2-5	2.2975	2.3122	2.3602	2.3648	2.4829	2.6204	10.507	13.683	16.110	16.807

Table D.2: (Continued)

Cases	Load Levels (MW)									
	105	115	125	135	145	155	165	175	185	195
L2-7	4.9538	5.4397	9.2953	9.2968	9.9467	10.446	26.604	26.845	32.976	N/A
L2-8	2.2975	2.3122	2.3602	2.3703	2.4884	2.8464	7.3506	7.5072	10.085	15.693
L3-4	1.2311	1.2537	1.3254	1.3742	1.4741	1.9815	4.1850	4.4192	7.0994	7.9566
L3-5	2.2426	2.2616	2.3198	2.3322	2.4449	2.5983	4.1646	4.4192	7.0994	7.9566
L3-8	2.3298	2.3491	2.4207	2.4656	2.5655	3.0033	5.2285	5.4370	8.1172	8.9689
L4-5	2.3073	2.3178	2.3318	2.3557	2.4510	2.7767	14.653	14.908	17.230	21.136
L4-8	2.6101	2.6101	2.6403	6.2078	6.2894	6.7802	11.218	11.352	13.732	14.356
L1-2-3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
L1-2-4	8.3251	8.3290	8.3443	9.4959	9.9980	14.982	33.837	N/A	N/A	N/A
L1-2-5	9.4607	9.4646	9.4792	9.4959	9.9968	14.520	29.083	N/A	N/A	N/A
L1-2-8	9.4607	9.4646	9.4792	10.589	11.091	28.447	N/A	N/A	N/A	N/A
L1-3-4	1.3477	2.9644	2.9932	4.0699	4.1818	5.0463	6.2509	10.655	22.284	24.155
L1-3-5	2.4087	2.5393	2.5948	4.0500	4.1746	4.7103	6.2313	10.655	22.284	24.155
L1-3-8	2.4797	4.0926	4.1207	5.1702	5.2820	6.0823	7.2659	11.649	23.278	24.155
L1-4-5	4.0417	4.0501	4.0648	4.0842	4.1780	4.5279	16.319	16.555	18.847	N/A
L1-4-8	4.3636	4.3636	4.3930	N/A	N/A	N/A	N/A	N/A	N/A	N/A
L2-3-4	1.7766	2.2916	7.1110	7.1504	7.7975	8.3959	23.499	27.832	33.946	38.549
L2-3-5	2.8229	3.3379	8.1566	8.1619	8.8090	9.3763	23.499	27.832	33.946	38.549
L2-3-8	2.8924	3.4036	8.2222	8.2526	8.8996	9.4291	24.522	27.832	33.946	38.549
L2-4-5	7.7698	7.7783	7.7929	7.8122	7.9029	8.2463	N/A	N/A	N/A	N/A
L2-4-8	8.0862	8.0862	8.1154	11.597	11.674	12.149	16.495	16.622	18.901	19.496
G1-20-L1	1.2362	1.2395	1.3136	1.3528	2.2224	2.9543	6.9383	21.880	45.446	N/A
G1-20-L3	1.2184	1.2203	1.3115	1.3416	2.8678	2.9731	4.6212	6.1279	32.146	32.586
G1-20-L4	1.1535	1.1554	1.2379	1.2807	2.1432	2.2544	4.1405	5.6614	23.197	26.307
G1-20-L8	2.2443	2.2462	2.3294	2.3744	3.2336	3.3453	5.1996	6.6552	24.156	27.256
G1-40-L1	1.2555	1.2668	1.5520	1.6174	3.2145	4.2816	17.795	28.346	44.363	N/A

Table D.2: (Continued)

Cases	Load Levels (MW)									
	105	115	125	135	145	155	165	175	185	195
G1-40-L3	1.2483	1.6272	1.9182	1.9726	3.8001	4.8812	25.245	26.467	42.324	46.652
G1-40-L4	1.1859	1.2007	1.4987	1.5621	3.1600	4.1661	15.506	17.051	34.069	41.293
G1-40-L8	2.2750	2.2879	2.5840	2.6503	4.2410	5.2404	16.547	18.026	34.956	42.152
G2-40-L1	1.2944	1.3062	1.7650	1.8411	5.0456	28.252	48.667	N/A	N/A	N/A
G2-40-L3	1.1938	1.2182	1.7220	1.7752	3.7462	4.9752	19.031	23.183	39.650	44.120
G2-40-L4	1.2011	1.2129	1.6721	1.7348	3.7341	5.0415	22.321	23.648	40.538	45.122
G2-40-L8	2.2958	2.3076	2.7655	2.8304	4.8220	6.1224	23.250	24.562	41.368	45.986
G1-20-L1-3	1.2383	1.3680	1.4909	2.9357	4.4520	4.9274	6.1798	11.482	33.218	34.054
G1-20-L4-8	2.6700	2.6711	3.2160	10.549	11.011	11.110	13.228	13.980	30.579	31.022
G1-40-L1-3	1.2662	1.7777	2.0949	3.5619	5.3630	6.4551	26.448	27.652	43.133	47.371
G1-40-L4-8	6.8026	6.8092	7.3775	10.950	12.206	19.131	23.716	24.766	41.048	45.472
G2-40-L1-3	2.8590	2.8808	3.3271	3.3966	5.7777	19.159	32.008	N/A	N/A	N/A
G2-40-L4-8	2.7120	2.7238	3.1764	6.6984	8.6286	9.7140	27.308	28.559	44.877	49.298

Table D.3: Bus 3 EENS (MWh/yr) of the RBTS as a function of the load level with maintenance removals

Cases	Load Levels (MW)									
	105	115	125	135	145	155	165	175	185	195
G1-40	3.025	8.094	48.926	109.45	320.56	817.67	3153.2	8232.9	15721	26509
G1-20	1.115	2.695	11.122	24.181	114.92	328.18	681.10	1397.0	5164.9	11587
G1-10	.207	1.192	3.211	12.777	28.518	146.50	329.38	860.21	1543.5	5063.2
G2-40	4.734	12.227	71.599	158.91	424.80	1037.7	3819.2	10062	18481	30029
G2-20	1.499	3.565	12.998	26.643	118.60	337.75	729.89	1528.3	5503.2	12068
G2-5	.183	.345	2.423	4.364	20.622	51.723	236.22	519.40	1209.2	2213.9
G1-10G2-40	11.250	59.134	158.74	450.27	899.02	4069.9	9007.7	18756	29655	NA
G1-10G2-5	.065	1.402	4.387	20.674	36.980	246.32	432.47	1220.7	1938.0	8538.4
G1-40G2-5	4.441	9.687	80.859	148.31	525.85	1216.3	5382.6	11026	21065	32949

Table D.3: (Continued)

Cases	Load Levels (MW)									
	105	115	125	135	145	155	165	175	185	195
G2-40G2-5	8.266	16.579	117.29	209.24	671.67	1506.7	6486.1	13307	24200	36747
G2-5G2-5	0	.782	2.757	12.307	29.841	149.01	342.57	882.06	1651.2	5300.0
L1	7.396	10.954	16.173	20.706	32.451	85.971	405.21	3222.6	9010.5	N/A
L2	3.193	5.624	10.804	16.222	28.651	58.366	209.76	754.40	1513.7	2692.8
L3	.627	1.127	4.157	9.197	21.515	47.181	184.91	468.37	985.62	1778.3
L4	.281	.673	2.367	5.035	13.995	34.962	138.53	377.14	855.95	1796.3
L5	.276	.530	2.060	4.400	13.031	33.400	136.35	371.15	842.55	1639.7
L8	.281	.673	2.367	5.073	14.114	35.291	139.91	380.27	860.22	1812.5
L1-2	808.05	1274.7	1814.9	2044.2	2241.7	3688.8	8914.7	N/A	N/A	N/A
L1-3	12.950	23.853	41.638	126.32	274.84	462.12	817.23	1424.9	4322.6	7384.5
L1-4	12.807	109.80	227.11	385.53	550.52	789.71	1202.5	4387.6	10997	N/A
L1-5	8.027	11.505	16.626	22.076	33.214	75.200	362.19	2644.3	7380.4	N/A
L1-6	2323.0	2793.1	3226.2	3772.8	4504.5	5448.4	N/A	N/A	N/A	N/A
L1-8	11.743	108.62	225.78	389.15	558.95	827.78	1572.8	5197.4	12207	N/A
L2-3	78.495	111.01	319.26	781.78	1333.6	2060.9	5483.3	10743	16162	22771
L2-4	3.198	5.656	10.869	16.533	29.181	59.001	210.82	760.80	1492.4	2491.4
L2-5	3.193	5.624	10.804	16.222	28.582	57.232	204.52	687.51	1423.5	2426.3
L2-7	339.74	619.80	1103.5	1602.1	2138.9	2848.7	6247.0	11505	16710	N/A
L2-8	3.193	5.624	10.804	16.386	29.061	60.387	233.90	817.64	1575.9	2753.4
L3-4	2.600	7.072	15.522	25.977	44.388	105.27	269.84	601.41	1164.1	2016.1
L3-5	.949	1.581	4.786	9.988	22.527	49.188	189.51	475.97	994.80	1788.1
L3-8	2.544	7.423	16.318	27.083	45.909	106.88	269.97	602.43	1165.9	2018.5
L4-5	1.932	2.521	4.531	7.439	16.803	40.831	152.63	389.67	849.43	1699.5
L4-8	7.136	21.894	41.343	251.56	472.10	777.28	1140.0	1857.9	2726.7	3823.4
L1-2-3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
L1-2-4	807.68	1273.4	1812.5	2105.8	2358.3	3805.4	9248.7	N/A	N/A	N/A

Table D.3: (Continued)

Cases	Load Levels (MW)									
	105	115	125	135	145	155	165	175	185	195
L1-2-5	807.53	1273.2	1812.4	2041.1	2220.9	3348.9	7586.7	N/A	N/A	N/A
L1-2-8	807.53	1273.2	1812.4	2104.3	2377.7	4282.3	N/A	N/A	N/A	N/A
L1-3-4	16.645	122.37	246.72	411.65	584.63	828.16	1183.7	1800.1	4740.8	7884.5
L1-3-5	14.091	24.891	42.582	127.05	275.39	463.16	820.12	1429.7	4323.0	7419.6
L1-3-8	15.436	120.18	243.26	405.83	576.41	816.43	1168.0	1779.6	4716.4	7816.9
L1-4-5	736.34	801.34	880.62	947.89	1021.6	1123.0	1299.6	1614.1	2138.1	N/A
L1-4-8	741.42	821.52	919.41	N/A	N/A	N/A	N/A	N/A	N/A	N/A
L2-3-4	80.398	117.13	330.14	796.61	1353.0	2087.3	5520.5	10846	16317	22976
L2-3-5	78.483	111.01	319.04	780.93	1331.6	2058.0	5475.4	10727	16136	22734
L2-3-8	79.825	115.63	327.43	792.83	1347.9	2079.9	5509.9	10831	16299	22955
L2-4-5	2.093	2.684	4.673	7.536	16.750	40.758	N/A	N/A	N/A	N/A
L2-4-8	7.174	22.896	43.533	254.77	476.40	782.82	1145.6	1863.2	2730.3	3823.9
G1-20-L1	7.105	11.433	22.921	37.836	130.46	372.87	891.25	4060.3	12191	N/A
G1-20-L3	3.933	8.750	21.029	37.714	171.98	439.64	836.14	1604.0	5740.5	12764
G1-20-L4	1.212	2.925	11.655	25.361	116.88	330.90	684.37	1402.0	5171.5	11674
G1-20-L8	1.120	2.809	11.546	25.324	116.80	330.74	684.79	1403.4	5171.1	11679
G1-40-L1	8.957	16.721	60.426	122.65	335.16	846.45	3292.8	9327.6	18284	N/A
G1-40-L3	11.934	22.666	94.018	180.05	432.50	987.77	3877.7	9856.0	18053	29416
G1-40-L4	3.232	8.812	50.495	112.13	324.18	827.29	3165.1	8239.9	15728	26600
G1-40-L8	3.271	8.796	50.337	111.87	323.65	826.26	3161.1	8231.6	15712	26584
G2-40-L1	11.641	22.357	85.160	175.25	497.37	2588.5	10442	N/A	N/A	N/A
G2-40-L3	5.448	13.241	73.823	163.73	432.56	1044.1	3830.9	9853.3	18292	29860
G2-40-L4	4.743	12.373	71.986	159.76	425.97	1039.5	3827.9	10083	18486	30019
G2-40-L8	4.738	12.340	71.869	159.59	425.60	1042.6	3862.5	10128	18536	30072
G1-20-L1-3	13.816	25.843	50.125	144.68	413.41	839.72	1406.0	2388.3	7665.9	14743
G1-20-L4-8	55.803	70.775	119.43	419.11	949.45	1653.3	2417.9	3630.7	7746.2	14372

Table D.3: (Continued)

Cases	Load Levels (MW)									
	105	115	125	135	145	155	165	175	185	195
G1-40-L1-3	19.114	37.660	121.79	286.92	672.77	1382.1	4391.3	10433	18643	30014
G1-40-L4-8	115.54	370.24	729.57	1259.0	1937.5	3846.6	6773.6	11295	18509	29330
G2-40-L1-3	250.18	389.06	512.58	634.68	1036.5	2040.4	9186.3	N/A	N/A	N/A
G2-40-L4-8	11.290	34.088	111.51	402.47	847.54	1731.0	4715.3	11159	19700	31304

Table D.4: Bus 4 EENS (MWh/yr) of the RBTS as a function of the load level with maintenance removals

Cases	Load Levels (MW)									
	105	115	125	135	145	155	165	175	185	195
G1-40	0	0	.043	.124	.229	1.671	4.661	9.121	26.484	62.845
G1-20	0	0	.029	.083	.141	.648	1.623	2.923	6.395	13.461
G1-10	0	0	0	0	.073	.170	.269	1.410	2.497	3.623
G2-40	0	0	.072	.206	.445	2.717	7.171	13.579	38.719	92.167
G2-20	0	0	.058	.165	.272	.866	2.091	3.870	7.796	15.254
G2-5	0	0	0	0	.010	.138	.246	.574	1.664	2.866
G1-10G2-40	0	.078	.175	.269	4.158	9.273	13.388	69.514	123.18	N/A
G1-10G2-5	0	0	0	0	0	0	.582	1.644	2.573	8.982
G1-40G2-5	0	0	0	0	.231	3.322	6.320	17.844	55.906	96.879
G2-40G2-5	0	.029	.254	.500	.995	6.168	11.041	27.747	81.512	138.01
G2-5G2-5	0	0	0	0	0	0	0	1.061	2.135	3.289
L1	0	0	0	.736	1.724	3.307	5.552	7.879	10.293	N/A
L2	0	0	0	.164	.366	.919	2.343	4.027	6.049	8.711
L3	0	0	0	.080	.170	.338	.535	.821	1.680	3.549
L4	0	0	0	.017	.039	.127	.291	.479	1.113	2.448
L5	0	0	0	.017	.039	.127	.291	.479	1.113	2.448
L8	0	0	0	.017	.039	.127	.291	.479	1.113	2.448
L1-2	1.391	1.514	1.661	59.661	137.33	286.05	585.49	N/A	N/A	N/A

Table D.4: (Continued)

Cases	Load Levels (MW)									
	105	115	125	135	145	155	165	175	185	195
L1-3	0	.130	.291	1.161	3.964	7.911	11.655	20.110	28.492	38.500
L1-4	0	0	0	.736	1.724	3.307	5.552	7.879	10.293	N/A
L1-5	0	0	0	.736	1.724	3.307	5.552	7.879	10.293	N/A
L1-6	5.558	6.309	7.22	387.78	901.51	1519.9	N/A	N/A	N/A	N/A
L1-8	0	0	0	.736	1.724	3.307	5.552	7.879	10.293	N/A
L2-3	1.177	1.723	2.220	15.330	29.046	47.031	55.508	69.005	93.966	148.32
L2-4	2.291	2.492	2.733	3.098	3.501	4.296	5.922	7.848	10.071	12.934
L2-5	1.092	1.188	1.304	1.563	1.862	2.530	4.051	5.851	7.968	10.727
L2-7	2.357	2.918	3.455	14.029	25.071	73.200	236.40	435.22	612.28	N/A
L2-8	1.099	1.195	1.310	1.570	1.869	2.538	4.058	5.858	7.976	10.734
L3-4	0	0	0	.080	.170	.338	.550	.899	1.799	3.695
L3-5	0	0	0	.080	.170	.338	.550	.899	1.799	3.695
L3-8	0	0	0	.080	.170	.338	.535	.821	1.669	3.512
L4-5	5.558	6.048	6.656	7.164	7.672	8.331	8.993	9.968	11.240	13.197
L4-8	5.592	6.083	6.672	7.162	7.653	8.294	8.905	9.638	10.709	12.464
L1-2-3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
L1-2-4	4.278	4.654	5.106	63.174	140.86	289.53	588.52	N/A	N/A	N/A
L1-2-5	3.129	3.405	3.736	61.704	139.29	287.84	586.73	N/A	N/A	N/A
L1-2-8	3.139	3.415	3.746	61.714	139.30	287.85	N/A	N/A	N/A	N/A
L1-3-4	0	.130	.291	1.161	3.964	7.911	11.669	20.160	28.557	38.564
L1-3-5	0	.130	.291	1.161	3.964	7.911	11.669	20.160	28.557	38.564
L1-3-8	0	.130	.291	1.161	3.964	7.911	11.655	20.082	28.426	38.381
L1-4-5	7.145	7.776	8.533	9.164	9.794	10.611	11.411	12.507	13.881	N/A
L1-4-8	7.190	7.821	8.578	N/A	N/A	N/A	N/A	N/A	N/A	N/A
L2-3-4	3.072	3.769	4.452	17.706	31.590	49.788	58.449	72.174	97.287	151.72
L2-3-5	1.973	2.574	3.141	16.299	30.087	48.169	56.734	70.343	95.360	149.70

Table D.4: (Continued)

Cases	Load Levels (MW)									
	105	115	125	135	145	155	165	175	185	195
L2-3-8	1.975	2.576	3.144	16.301	30.090	48.171	56.721	70.267	95.232	149.52
L2-4-5	1138.0	1238.1	1358.3	1458.4	1558.6	1678.8	N/A	N/A	N/A	N/A
L2-4-8	1141.5	1241.7	1361.8	1462.0	1562.1	1682.3	1782.6	1902.9	2003.6	2105.0
G1-20-L1	0	0	0.029	0.702	1.615	3.416	6.085	9.095	13.994	N/A
G1-20-L3	0.148	0.217	0.267	0.338	0.414	1.416	3.239	6.931	12.231	20.873
G1-20-L4	0	0	0.029	0.083	0.141	0.648	1.623	2.923	6.395	13.461
G1-20-L8	0	0	0.029	0.083	0.141	0.648	1.623	2.923	6.395	13.461
G1-40-L1	0	0	0.043	0.743	1.703	4.417	9.079	15.221	33.965	N/A
G1-40-L3	0.187	0.233	0.324	1.860	3.490	7.109	10.965	16.580	39.057	90.648
G1-40-L4	0	0	0.043	0.124	0.229	1.671	4.661	9.121	26.473	62.807
G1-40-L8	0	0	0.043	0.124	0.229	1.671	4.661	9.121	26.462	62.770
G2-40-L1	0	0.026	0.131	0.890	2.279	6.237	12.647	N/A	N/A	N/A
G2-40-L3	0	0	0.072	0.310	0.738	3.242	7.795	14.244	39.464	93.050
G2-40-L4	0	0	0.072	0.206	0.445	2.717	7.171	13.579	38.752	92.280
G2-40-L8	0	0	0.072	0.206	0.445	2.717	7.171	13.579	38.730	92.205
G1-20-L1-3	.332	.0671	1.001	1.798	4.355	8.615	12.907	22.604	33.737	48.787
G1-20-L4-8	7.190	7.821	8.607	9.291	9.980	11.246	12.857	14.937	18.987	26.536
G1-40-L1-3	.150	.408	.828	2.726	6.398	12.654	18.287	30.404	59.073	117.81
G1-40-L4-8	7.190	7.821	8.621	9.332	10.068	12.234	15.818	20.992	38.817	75.411
G2-40-L1-3	.184	6.112	13.463	16.906	95.933	202.01	275.63	N/A	N/A	N/A
G2-40-L4-8	7.190	7.821	8.650	9.415	10.284	13.278	18.400	25.609	51.385	105.40

Table D.5: Bus 5 EENS (MWh/yr) of the RBTS as a function of the load level with maintenance removals

Cases	Load Levels (MW)									
	105	115	125	135	145	155	165	175	185	195
G1-40	.099	.136	.207	.257	1.886	4.490	5.923	40.283	65.644	76.725
G1-20	.098	.126	.177	.206	.771	1.572	1.835	8.453	14.004	18.713
G1-10	.098	.107	.118	.215	.238	.528	1.668	1.970	6.017	16.324
G2-40	.098	.154	.267	.427	2.878	6.636	8.458	58.863	95.713	109.30
G2-20	.098	.145	.237	.254	.932	2.005	2.476	9.390	14.967	19.222
G2-5	.098	.107	.118	.157	.272	.293	.823	2.023	2.331	8.870
G1-10G2-40	.270	.296	.414	5.042	5.805	18.428	75.293	90.024	200.58	N/A
G1-10G2-5	.197	.214	.235	.253	.270	1.202	1.595	3.205	13.959	18.853
G1-40G2-5	.197	.215	.236	.979	3.550	4.583	22.988	63.573	73.450	218.59
G2-40G2-5	.213	.404	.511	1.759	5.976	7.510	33.466	90.307	101.89	275.69
G2-5G2-5	.197	.214	.235	.253	.270	.508	1.628	2.040	6.096	16.451
L1	.099	.107	1.177	1.533	2.564	4.567	4.867	6.413	7.927	N/A
L2	.098	.107	.347	.414	1.152	2.650	2.845	4.795	6.707	8.679
L3	.098	.107	.227	.254	.354	.559	.658	2.464	4.418	6.359
L4	.099	.107	.142	.159	.252	.403	.428	1.692	2.747	4.299
L5	114.97	125.12	137.32	147.48	157.71	170.03	180.20	193.63	204.79	216.40
L8	114.97	125.12	137.32	147.48	157.71	170.03	180.20	193.63	204.82	215.63
L1-2	.896	.975	84.287	111.62	257.96	552.10	585.32	N/A	N/A	N/A
L1-3	.318	.350	1.580	4.012	5.350	8.722	15.178	19.137	57.038	149.35
L1-4	.441	.483	1.589	1.976	3.038	5.077	5.409	6.991	30.798	N/A
L1-5	110.95	120.75	133.56	143.70	154.52	168.26	178.35	191.63	202.90	N/A
L1-6	3.434	3.743	550.51	735.27	786.57	850.34	N/A	N/A	N/A	N/A
L1-8	111.10	120.91	133.74	143.89	154.72	168.48	178.58	191.88	225.45	N/A
L2-3	1.131	1.328	18.589	21.149	24.576	33.129	40.152	94.490	244.37	505.92
L2-4	.746	.812	1.212	1.244	2.039	3.606	3.858	5.875	7.855	159.08
L2-5	111.50	121.34	133.38	143.28	153.85	167.15	177.18	190.93	202.55	363.66

Table D.5: (Continued)

Cases	Load Levels (MW)									
	105	115	125	135	145	155	165	175	185	195
L2-7	1.452	1.654	15.472	17.564	104.30	283.59	304.85	375.65	515.41	N/A
L2-8	110.95	120.75	132.73	142.43	153.10	166.34	176.32	190.02	201.71	213.17
L3-4	.247	.269	.405	.508	.702	1.057	1.320	3.255	6.591	11.797
L3-5	110.95	120.75	132.61	142.42	152.31	164.33	174.25	187.79	199.55	212.57
L3-8	111.05	120.86	132.73	142.61	152.59	164.60	174.57	188.19	201.46	215.47
L4-5	113.76	123.81	135.87	145.91	156.01	168.43	178.66	191.94	203.04	466.63
L4-8	111.42	121.26	133.06	143.10	153.24	165.33	175.48	188.84	205.00	223.27
L1-2-3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
L1-2-4	1.893	2.060	85.211	112.60	258.72	552.24	585.45	N/A	N/A	N/A
L1-2-5	119.55	130.10	225.71	263.48	419.99	725.98	769.56	N/A	N/A	N/A
L1-2-8	119.00	129.50	225.06	262.78	419.24	725.17	N/A	N/A	N/A	N/A
L1-3-4	.616	.675	1.937	4.457	5.903	9.472	16.000	20.055	59.401	154.77
L1-3-5	118.17	128.61	142.32	155.15	166.90	182.82	199.69	216.11	264.29	367.76
L1-3-8	118.44	128.90	142.65	15.58	167.44	183.38	200.29	216.80	266.24	370.52
L1-4-5	121.65	132.38	145.26	156.00	166.82	180.02	190.90	205.01	216.79	N/A
L1-4-8	289.90	315.51	346.24	N/A	N/A	N/A	N/A	N/A	N/A	N/A
L2-3-4	1.662	1.913	19.215	21.905	25.471	34.170	41.327	95.713	246.93	534.98
L2-3-5	119.37	130.01	159.78	172.79	186.67	207.78	225.25	292.01	452.07	748.25
L2-3-8	118.99	129.60	159.33	172.39	186.32	207.38	224.84	291.63	452.89	726.23
L2-4-5	688.27	748.71	821.24	881.68	942.21	1015.0	N/A	N/A	N/A	N/A
L2-4-8	118.57	129.04	141.60	152.22	162.96	175.76	186.49	200.54	217.72	237.23
G1-20-L1	0.197	0.233	1.186	1.545	2.867	5.146	5.650	12.529	18.466	N/A
G1-20-L3	0.297	0.342	0.414	0.568	1.668	3.958	5.576	12.398	18.323	23.856
G1-20-L4	0.197	0.234	0.295	0.345	0.935	1.755	2.207	8.658	14.247	20.082
G1-20-L8	110.95	120.77	132.56	142.37	152.72	165.27	175.31	193.67	209.04	223.58
G1-40-L1	0.197	0.243	1.216	1.591	3.953	8.026	9.699	44.215	69.898	N/A

Table D.5: (Continued)

Cases	Load Levels (MW)									
	105	115	125	135	145	155	165	175	185	195
G1-40-L3	0.315	0.378	2.381	2.764	4.940	8.051	10.015	61.304	98.753	111.85
G1-40-L4	0.197	0.241	0.324	0.395	2.049	4.675	6.136	40.503	66.026	78.399
G1-40-L8	110.95	120.78	132.59	142.45	153.89	168.26	179.48	225.54	260.80	281.90
G2-40-L1	0.221	0.289	1.305	2.151	5.418	10.682	12.758	N/A	N/A	N/A
G2-40-L3	0.197	0.261	0.520	0.801	3.287	7.076	8.925	59.469	97.134	112.51
G2-40-L4	0.197	0.262	0.385	0.554	3.014	6.783	8.612	59.105	96.042	110.95
G2-40-L8	110.95	120.79	132.65	142.59	154.83	170.33	181.94	244.11	290.76	314.11
G1-20-L1-3	.640	.747	1.774	4.118	6.066	9.736	16.711	25.508	66.939	162.55
G1-20-L4-8	118.55	129.25	141.95	159.25	178.91	196.87	208.82	229.30	246.41	262.78
G1-40-L1-3	.563	.703	3.111	5.640	8.199	12.806	21.163	74.552	147.57	250.05
G1-40-L4-8	125.46	136.68	150.08	163.93	180.06	198.37	214.00	264.98	392.93	550.79
G2-40-L1-3	5.792	6.569	9.783	102.38	120.73	134.72	144.51	N/A	N/A	N/A
G2-40-L4-8	118.47	128.98	141.63	152.40	165.45	181.84	194.33	257.35	310.20	342.53

Table D.6: Bus 6 EENS (MWh/yr) of the RBTS as a function of the load level with maintenance removals

Cases	Load Levels (MW)									
	105	115	125	135	145	155	165	175	185	195
G1-40	111.66	121.52	133.32	145.05	156.81	170.44	219.33	250.78	355.03	607.30
G1-20	111.66	121.50	133.27	143.72	154.11	166.16	183.54	200.46	257.62	389.94
G1-10	111.65	121.44	133.29	143.08	153.13	166.12	176.04	196.28	213.26	225.95
G2-40	111.68	121.58	133.49	146.18	158.80	172.79	240.29	279.47	402.16	701.52
G2-20	111.67	121.55	133.31	143.91	154.51	166.81	184.45	201.22	258.83	394.04
G2-5	111.65	121.44	133.23	143.12	152.92	165.50	176.10	188.78	209.65	226.04
G1-10G2-40	115.97	126.20	143.15	153.60	175.00	249.34	265.85	505.19	705.22	N/A
G1-10G2-5	115.89	126.06	138.26	148.42	159.48	172.00	185.28	209.88	221.44	317.61
G1-40G2-5	115.89	126.06	139.06	151.49	162.60	203.86	241.11	278.00	530.39	682.36

Table D.6: (Continued)

Cases	Load Levels (MW)									
	105	115	125	135	145	155	165	175	185	195
G2-40G2-5	116.07	126.29	139.86	153.76	165.33	218.49	266.10	307.83	607.96	786.88
G2-5G2-5	115.89	126.06	138.26	148.42	158.78	172.19	182.59	203.25	221.63	235.43
L1	111.65	122.40	134.51	145.86	156.89	168.99	180.51	194.00	208.55	N/A
L2	111.65	121.65	133.46	144.39	155.12	167.26	179.19	193.69	208.86	230.03
L3	111.65	121.54	133.31	143.23	153.18	165.20	176.99	191.17	206.01	226.67
L4	111.65	121.46	133.22	143.13	153.02	164.80	176.17	190.60	205.85	226.23
L5	227.04	246.98	270.89	290.91	310.93	334.85	356.29	382.76	408.07	438.51
L8	227.04	246.98	270.89	290.91	310.93	334.85	356.27	381.14	405.10	435.07
L1-2	116.59	201.72	241.965	482.86	670.84	722.50	767.07	N/A	N/A	N/A
L1-3	116.02	127.27	141.95	153.75	166.37	185.82	199.47	288.41	367.04	396.64
L1-4	116.14	127.28	136.87	151.62	163.04	175.61	223.72	311.60	365.71	N/A
L1-5	227.24	248.13	272.40	293.90	315.07	339.33	360.97	387.01	412.04	N/A
L1-6	119.14	621.33	823.07	883.58	946.99	1035.6	N/A	N/A	N/A	N/A
L1-8	227.39	248.29	272.58	294.09	315.27	339.55	397.39	496.48	560.03	N/A
L2-3	116.92	142.85	158.02	171.80	190.72	225.79	291.12	606.50	807.69	925.38
L2-4	116.44	126.86	139.18	150.53	161.68	174.32	198.59	500.08	754.25	864.81
L2-5	227.79	247.98	272.02	293.14	314.05	338.41	372.44	685.62	949.55	1069.8
L2-7	117.22	140.00	154.66	302.73	422.97	474.77	557.67	929.21	1191.3	N/A
L2-8	227.24	247.38	271.36	292.43	313.30	337.60	359.66	385.76	410.64	441.88
L3-4	115.94	126.24	138.57	148.93	159.44	172.04	186.11	205.09	222.76	244.51
L3-5	227.24	247.27	271.21	291.30	311.46	335.65	357.61	385.64	412.18	443.33
L3-8	227.34	247.41	271.46	291.56	311.74	336.02	360.10	389.54	415.57	446.80
L4-5	230.06	250.24	274.46	294.87	315.37	339.63	381.15	888.87	1315.8	1495.8
L4-8	227.72	247.77	272.08	292.23	312.61	336.94	365.61	401.15	428.83	509.74
L1-2-3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
L1-2-4	113.55	198.16	238.00	478.07	665.34	716.57	762.78	N/A	N/A	N/A

Table D.6: (Continued)

Cases	Load Levels (MW)									
	105	115	125	135	145	155	165	175	185	195
L1-2-5	231.73	326.72	379.00	629.43	827.08	890.75	947.29	N/A	N/A	N/A
L1-2-8	231.19	326.12	378.35	628.73	826.33	889.94	N/A	N/A	N/A	N/A
L1-3-4	112.27	123.22	137.62	149.15	161.59	180.71	228.50	315.59	369.66	414.27
L1-3-5	230.36	251.64	278.36	300.22	322.94	354.40	377.98	480.09	570.21	609.78
L1-3-8	230.64	251.97	278.85	300.73	323.47	355.03	412.77	510.34	573.27	627.59
L1-4-5	233.83	254.34	278.97	299.69	320.46	345.11	386.95	895.08	1322.2	N/A
L1-4-8	403.13	438.55	481.27	N/A	N/A	N/A	N/A	N/A	N/A	N/A
L2-3-4	113.40	139.02	153.92	167.46	186.17	220.89	287.96	654.70	896.39	1029.2
L2-3-5	231.64	267.61	294.85	318.73	347.73	394.80	470.14	846.23	1097.2	1240.0
L2-3-8	231.26	267.23	294.56	318.41	347.37	394.47	471.40	800.73	1012.4	1139.9
L2-4-5	799.86	870.02	954.23	1024.6	1095.0	1179.3	N/A	N/A	N/A	N/A
L2-4-8	230.76	251.06	275.64	296.03	316.62	341.21	370.70	407.39	435.57	516.66
G1-20-L1	115.90	126.91	139.47	151.43	163.10	175.87	193.90	211.92	269.96	N/A
G1-20-L3	116.00	126.22	138.67	149.95	162.40	175.80	193.70	211.88	277.99	443.37
G1-20-L4	115.90	126.12	138.36	149.18	159.95	172.45	190.33	209.80	269.07	402.39
G1-20-L8	227.25	247.23	271.17	291.76	312.28	336.50	364.07	393.24	460.55	603.02
G1-40-L1	115.91	126.94	139.51	152.74	165.77	180.10	229.51	262.04	367.11	N/A
G1-40-L3	116.03	128.02	140.69	153.28	165.89	185.91	252.81	289.53	398.72	664.96
G1-40-L4	115.91	126.14	138.41	150.52	162.67	176.77	226.30	260.45	366.84	620.15
G1-40-L8	227.26	247.27	271.28	293.16	315.06	340.86	400.04	443.96	558.28	820.40
G2-40-L1	115.94	127.02	140.08	154.31	168.23	182.97	251.31	N/A	N/A	N/A
G2-40-L3	115.92	126.31	138.79	151.87	164.88	179.50	247.47	289.05	413.44	713.23
G2-40-L4	115.92	126.19	138.55	151.60	164.61	179.05	247.17	289.24	414.30	714.61
G2-40-L8	227.27	247.31	271.39	294.21	316.98	343.14	420.85	472.30	605.04	914.24
G1-20-L1-3	112.31	123.02	137.27	149.21	161.74	181.19	199.99	291.91	420.53	592.47
G1-20-L4-8	231.07	253.99	290.15	314.12	336.21	362.30	391.46	422.30	492.55	687.51

Table D.6: (Continued)

Cases	Load Levels (MW)									
	105	115	125	135	145	155	165	175	185	195
G1-40-L1-3	112.26	124.24	138.70	151.13	164.66	191.39	259.30	369.59	540.47	813.38
G1-40-L4-8	237.88	259.88	289.72	313.85	340.18	370.65	556.21	786.10	964.43	1293.6
G2-40-L1-3	117.65	129.98	237.15	256.92	277.80	301.55	377.11	N/A	N/A	N/A
G2-40-L4-8	230.69	251.09	275.81	298.95	322.23	349.03	434.57	497.70	634.17	991.91