INTERRUPTED ENERGY ASSESSMENT RATE SENSITIVITY ANALYSIS IN ELECTRIC POWER SYSTEMS

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by

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Dedicated To My

Beloved Mother

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ABSTRACT

Increasing interest in economic optimization approaches in power system planning and expansion have resulted in a higher awareness in reliability worth of electricity supply. The interruption costs incurred by customers due to power supply failures is an important parameter in assessing the worth or benefit associated with a particular level of reliability. Future interruption costs associated with system development of expansion can be predicted using an appropriate customer damage function in association with customer reliability indices. It is also possible to develop an Interrupted Energy Assessment Rate (IEAR) which links the customer interruption costs and the adequacy indices normally used for planning and operating purposes.

This thesis is concerned with the sensitivity of the IEAR at hierarchical level I (HLI), hierarchical level II (HLII) and in the distribution functional zone. Assessment of reliability worth is an extension of quantitative reliability evaluation. The evaluation of an IEAR involves a frequency and duration approach in association with customer damage functions. Sets of IEAR values have been calculated considering the impact of various factors at HLI, HLII and in the distribution functional zone. The IEAR sensitivity studies show that the IEAR is reasonably stable under different operating conditions, which greatly simplifies the predictive reliability worth assessment process.

This thesis also examines the economic optimum service reliability levels at HLI and HLII using a small test system, and shows how this level is affected by unit capacity, peak load and customer damage functions.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF SYMBOLS

CCDF	Composite Customer Damage Function
CDF	Customer Damage Function
EENS	Expected Energy not Supply
ECOST	Expected interruption COST
F&D	Frequency and Duration
FOR	Forced Outage Rate
HLI	Hierarchical Level I
HLII	Hierarchical Level II
HLIII	Hierarchical Level III
IEAR	Interrupted Energy Assessment Rate
kW	kilo Watt
kWh	kilo Watt hour
MTTF	Mean Time To Failure
MTTR	Mean Time To Repair
MW	Mega Watt
MWh	Mega Watt hour
occ	occurrence
RBTS	Roy Billinton Test System
RTS	Reliability Test System
SCDF	Sector Customer Damage Function

CHAPTER 1

INTRODUCTION

1.1 Introduction

The primary function of a modern electric power system is to supply the customer requirements as economically as possible with an acceptable level of reliability and quality. Power system managers, planners, and operators have always been faced with the need to balance the continuity of power supply expected by modern society and the cost involved to sustain this expected high reliability level.

The criteria first used, and still in use today, are based on deterministic techniques with respect to applications in both system planning and operation. Probabilistic considerations and the recognition of random events in the form of equipment failure were not recognized until the 1930's. Reliability evaluation techniques since then have developed rapidly, both in terms of the data available and the required computational techniques [1-8].

Power system reliability can be described as the overall ability of the system to meet its load requirements at any point in time [1, 9, 10, 11]. It can be classified in terms of the two basic aspects of security and adequacy [10, 12]. System security is concerned with the ability of the system to respond to a given contingency and system adequacy evaluation with the system's ability to satisfy the system load requirements under steady state conditions. Figure 1.1 shows this simple categorization. This thesis is focused on adequacy evaluation of electric power systems.

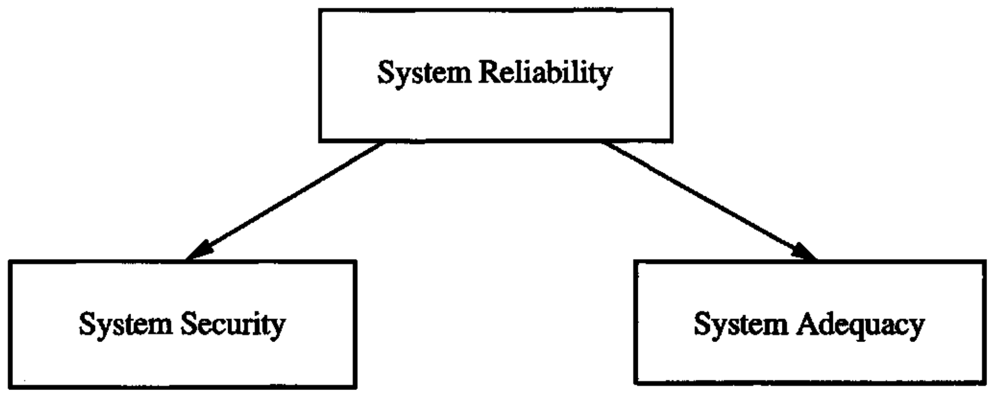

Figure 1.1 Basic aspects of power system reliability evaluation

The traditional approach used by electric power utilities in the decision making process is the implicit cost technique. In this approach, only the investment cost together with the cost of operating and maintaining the system are used to select a particular scheme with the lowest cost from various alternatives. In this analysis, it is assumed that each alternative provides the same reliability level based on a specific deterministic or probabilistic criterion. This approach does not provide any indication of the incremental reliability benefit resulting from the increased expenditure nor does it provide any indication of the optimal system reliability level. Research conducted over the past two decades [14-33] indicates that utilities should have some appreciation of the worth of the existing reliability level as well as the costs associated with maintaining that reliability level. A more comprehensive approach, called the explicit technique, relates the incremental worth or benefit of electric service reliability to the incremental costs associated with providing this reliability [1]. The ability to assess the costs associated with providing reliable service is reasonably well established and accepted. In contrast, the ability to assess the worth of providing reliable service is not well established. Direct worth evaluation of service reliability is an extremely difficult task. Customer interruption costs are widely utilized as a practical alternative and can be used to predict the impacts and monetary losses incurred by customers due to electric power supply failures [29, 33].

The utility cost includes capital investment, operating and maintenance and generally increases as the system reliability level increases. Customer interruption costs generally decrease as the reliability level increases. The total societal cost can be obtained by adding the utility and customer costs. The "optimum" level of reliability can be considered to occur at the point of minimum total cost as shown in Figure 1.2. The concepts illustrated are quite general and can be applied within different segments of an electric power system [30]. The published literature [14-37] clearly illustrates that a considerable amount of work has been done over the past two decades on the assessment of reliability worth.

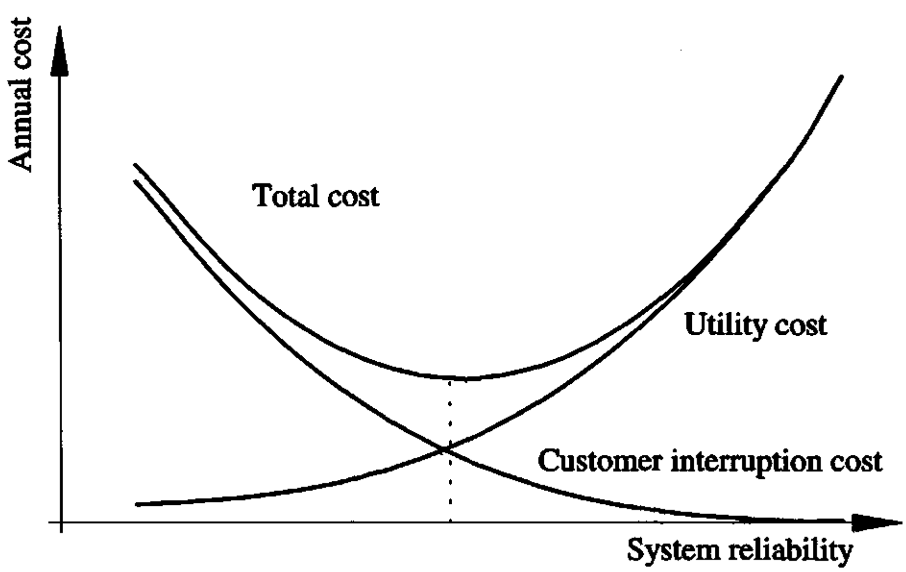

Figure 1.2 System total, utility and customer interruption costs as a function of system reliability

A practical way to quantify the monetary impact of an electric power supply failure on a given customer is to develop customer damage functions (CDF) [19-22]. The required information can be obtained by surveying electrical consumers on a sector basis. Such cost investigations have been made by a number of organizations. The most widely available data are from surveys conducted by the University of Saskatchewan [16-23]. Customer interruption costs as a function of the interruption duration have been obtained from the compiled survey data and are known as sector customer damage functions (SCDF). The sector customer damage functions can be aggregated at any load point in a system to form a composite customer damage function (CCDF) at that load point [38]. In order to use a composite system customer damage function in the predictive assessment of customer interruption costs it is necessary to convert it to an index that can be used with conventional reliability indices. This can be done by expressing the interruption costs in the form of \$ / kWh of unserved energy. This cost factor is designated as the Interrupted Energy Assessment Rate (IEAR) [32]. This index can be used in conjunction with the expected energy not supplied to predict customer interruption costs.

The IEAR is an important parameter in reliability worth evaluation and can be determined for the different segments of an electric power system. The main focus of this thesis is on IEAR determination and its sensitivity to basic power system parameters.

1.2 Hierarchical Levels

An overall power system can be divided into the three basic functional zones of generation, transmission and distribution [10]. These three functional zones can be combined to form hierarchical levels. Adequacy evaluation can be conducted in each functional zone and at each hierarchical level [13]. This division simplifies reliability assessment of electric power systems and creates a formal structure for system expansion analysis. Figure 1.3 shows the hierarchical levels and functional zones of an electric power system.

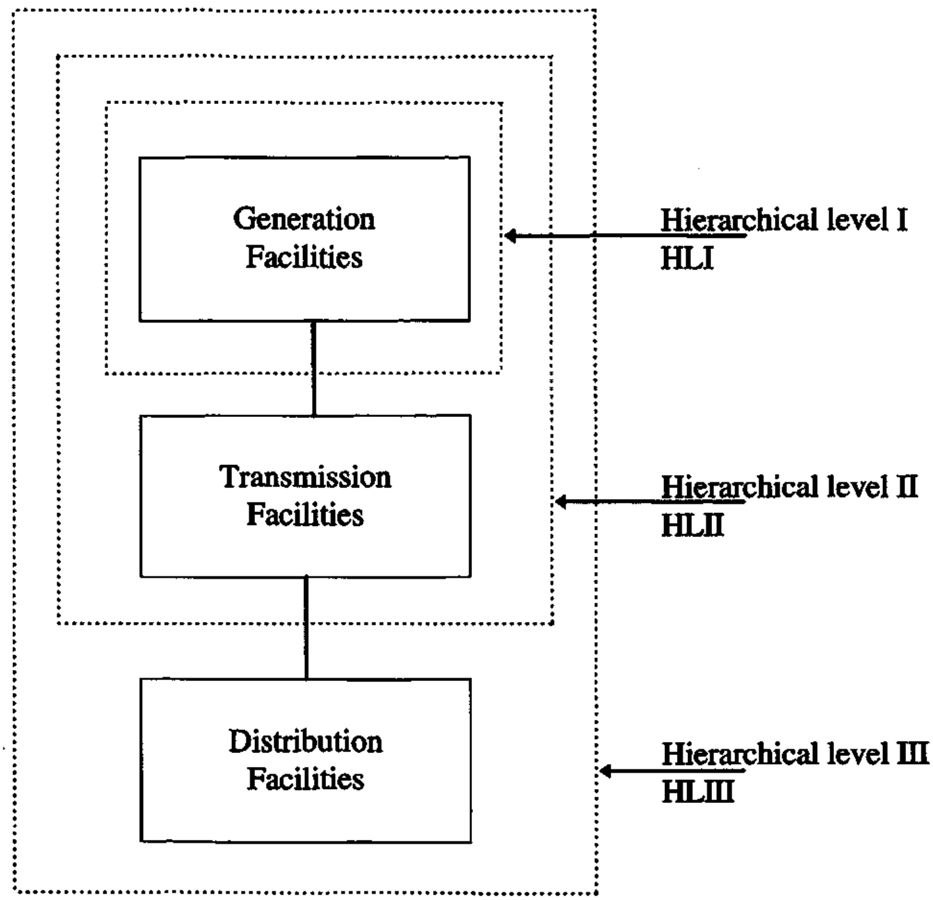

Figure 1.3 Hierarchical levels and functional zones

Hierarchical Level I (HLI) is concerned only with the generation facilities. The objective in an HLI analysis is to determine the ability of the generation facilities to meet the total load demand. Considerable work has been done at HLI and most electric power utilities routinely utilize and apply quantitative reliability assessment at this level. Hierarchical level II (HLII) includes both generation and transmission facilities. The objective in an HLII analysis is to determine the ability of the bulk system to serve the major load points. There has been considerable work done in developing quantitative assessment procedures at HLII, but electric power utilities in general do not routinely use these procedures at the present time. Hierarchical Level III (HLIII) includes all three functional zones in an assessment of customer load point adequacy. This thesis is concerned with adequacy worth assessment at HLI, HLII and in the distribution functional zone.

1.3 Objectives and Scope of Work

The research work described in this thesis is in the area of IEAR evaluation and its sensitivity to various system parameters at HLI, HLII and in the distribution functional zone. Economic optimization considerations for power system planning and expansion at HLI and HLII are also examined.

The thesis consists of five chapters. Following the introduction in Chapter 1, Chapters 2, 3 and 4 utilize basic quantitative reliability worth concepts to conduct IEAR sensitivity studies at HLI, HLII and in the distribution functional zone respectively. Many important factors were considered to examine their impact upon IEAR values at the different hierarchical levels and functional zones. In addition to the IEAR sensitivity studies, Chapters 2 and 3 also conduct economic optimization analysis at HLI and HLII respectively. Chapter 5 presents the conclusions of the research. The concepts are illustrated using two reliability test systems; the Roy Billinton Test System (RBTS) [40, 42, 43] and the IEEE Reliability Test System (RTS) [41].

Assessment of IEAR at HLI involves a frequency and duration approach (F & D) [1] and a composite customer damage function. In order to perform this analysis, a computer program designated as HLIW was developed. The program also includes the application of the IEAR in optimal system capacity reserve margin analysis [1, 33]. The HLII IEAR evaluation uses the contingency enumeration approach in association with appropriate customer damage functions [1, 34, 35, 39]. The composite system adequacy evaluation software COMREL developed at the University of Saskatchewan was modified and extended to create a composite system worth evaluation software. The modified software has been designated as COMRELW. In order to extend the basic contingency enumeration concepts to distribution system reliability worth evaluation, a new program designated as DISTRNW was developed [1, 36]. Sector customer damage functions are utilized instead of the composite customer damage functions used at HLII.

The IEAR is a basic parameter in power system reliability worth evaluation as it provides valuable information on the customer costs associated with deficiencies in electric power system supply. The expected energy not supplied (EENS) is a relatively easy parameter to estimate and is used in a wide variety of digital computer program. The product of the EENS and the IEAR gives the expected costs associated with power supply deficiencies. This thesis examines the sensitivity of the IEAR to changes in basic system parameters and operating policies.

CHAPTER 2

IEAR SENSITIVITY ANALYSIS AT HLI

2.1 Introduction

The main objectives of the research described in this chapter were to investigate the sensitivity of the IEAR at HLI. The IEAR sensitivity analysis examines the variability of the calculated IEAR with changes in specific major system parameters. A relatively constant IEAR, which can be used in a wide range of system studies, will greatly simplify reliability worth assessment in practical power system planning. The following factors were considered in the IEAR sensitivity study:

1. System peak load.
2. The generating unit failure and repair rates with constant Forced Outage Rates (FOR).
3. The generating unit FOR.
4. The shape of the system load model.

This chapter also illustrates the utilization of the explicit cost approach to reliability worth assessment to determine an optimum level of reliability at HLI for the RBTS [40] and RTS [41]. The basic concepts associated with the explicit cost approach to reliability worth assessment are briefly introduced in Chapter 1 and shown in Figure 1.2.

Estimation of the IEAR at HLI involves a basic frequency and duration (F&D) method [1] and the system composite customer damage function (CCDF). The F&D approach provides expected or average system performance indices such as the probability, frequency and duration of each load loss event. These indices can be used in association with the CCDF to develop the expected interruption cost for each considered contingency. Reference 1 provides a detailed description of the F&D method and its extension to obtain the IEAR at HLI. The system composite customer damage function (CCDF) is an important parameter in estimating the IEAR. The system CCDF is obtained by weighting the respective sector customer damage functions (SCDF). The SCDF are usually obtained from surveys of the sector customers [16-24]. The development of the CCDF is discussed in detail later in this chapter. This chapter briefly presents the concepts of IEAR estimation at HLI and the three basic models required for the evaluation.

2.2 Basic HLI Model

HLI reliability worth evaluation can be conducted by extending the basic system reliability concepts used at HLI. The basic assumption at HLI is that the total system generation is connected directly to the total system load as shown in Figure 2.1. The basic objective is to assess the ability of the total generating capacity to meet the total system demand and to extend this to determine the corresponding reliability worth or the cost of system inadequacy.

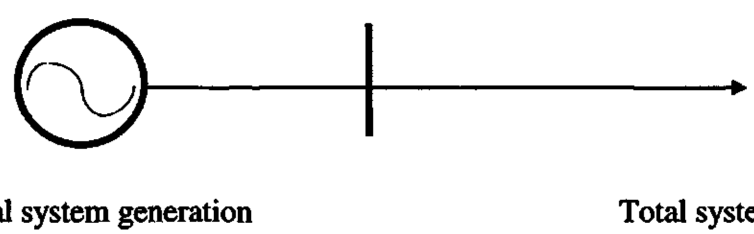

Figure 2.1 Basic HLI system model

Estimation of the IEAR at HLI involves three models. They are the system generation model, the system load model and the system cost model. These factors are discussed in detail in Subsections 2.2.1, 2.2.2 and 2.2.3.

2.2.1 Generation Model

The generation model used in this research is designated as a capacity outage probability and frequency table. It consists of an array of capacity levels with the associated probabilities of existence and the frequency of encountering these levels. It is developed from the basic generating unit data. Reference 1 describes in detail the process for creating the capacity model.

Generating units can be characterized by their capacities, forced outage rates, failure rates, repair rates, Mean Times to Failure (MTTF) and Mean Times to Repair (MTTR). The generating unit ratings and reliability data for the RBTS are given in Reference 40, and for the IEEE - RTS in Reference 41. These data are also shown in Appendix A and B respectively of this thesis.

2.2.2 Load Model

The annual peak load for the RBTS [40] is 185 MW, and for the IEEE - RTS [41] is 2850 MW. The data on weekly peak loads in percent of the annual peak load, daily peak load in percent of the weekly peak, and hourly peak load in percent of the daily peak are given in Tables 1, 2 and 3 of the IEEE Reliability Test System [41]. The total number of data points used to define the daily peak load curve is 364 days. In the case of the hourly peak load curve or the load duration curve, 8736 points are required. These data are given in Appendix B of this thesis and can be used to create an annual chronological load model.

2.2.3 Cost Model

Reliability worth, in the form of customer interruption costs due to power supply failure can be determined by utilizing actual or perceived costs of interruptions. Investigations of power interruption costs have been conducted using a variety of approaches. The customer survey method [16-24] is considered to be the most acceptable approach to assess the service interruption costs. Sector customer damage functions (SCDF) can be created from the data provided by customer surveys. The following seven sector types have been identified [31].

1. Large Industrial users (peak demand > 5 MW) (Large users),
2. Small Industrial users (peak demand < 5 MW) (Small users),
3. Commercial users (Comm.),
4. Agricultural or Farm users (Farm),
5. Residential users (Residential)
6. Government & Institutional users (Govt. & Inst.),
7. Office Space & Building users (Office & Bldg.).

Table 2.1 shows sector interruption cost estimates expressed in $/kW of annual peak demand. A composite customer damage function (CCDF) can be determined by combining the individual SCDF. This is done by proportionally weighting the individual

Table 2.1 Interruption cost data in $/kW of annual peak demand

User sector	Interruption duration				
	1 min.	20 min.	1 hr.	4 hr.	8 hr.
Large users	1.005	1.508	2.225	3.968	8.240
Small users	1.625	3.868	9.085	25.163	55.808
Comm.	0.381	2.969	8.552	31.317	83.008
Farm	0.060	0.343	0.649	2.064	4.120
Residential	0.001	0.093	0.482	4.914	15.690
Govt. & Inst.	0.044	0.369	1.492	6.558	26.040
Office&Bldg.	4.778	9.878	21.065	68.830	119.160

SCDF by the peak demand composition for short duration interruptions and by the energy consumption composition for interruption durations longer than one - half hour [38]. Table 2.2 shows the assumed distribution of energy consumption and peak demand. The CCDF is shown in Table 2.3.

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Table 2.2 Distribution of energy consumption and peak demand

User sector	Sector peak (%)	Sector energy (%)
Large users	30.0	31.0
Industrial	14.0	19.0
Commercial	10.0	9.0
Agricultural	4.0	2.5
Residential	34.0	31.0
Govt. & Inst.	6.0	5.5
Office & bldg.	2.0	2.0
Total	100.0	100.0

Table 2.3 System CCDF ($/kW)calculated from the SCDF

	Interruption duration				
	1 min.	20 min.	2 hr.	4 hr.	8 hr.
CCDF	0.67	1.56	3.85	12.14	29.41

2.3 Basic Evaluation Methods

Estimating the IEAR at HLI involves the generation of a capacity margin model which indicates the severity, frequency and duration of the expected negative margin states. This model is then used in conjunction with the CCDF for the given service area to estimate the IEAR. The generation model is developed from the capacities, forced outage rates, failure rates and repair rates of the generating units. The corresponding cost for each load loss duration is obtained from the composite customer damage function.

The 8736 data point hourly load model can be combined with an exact - state capacity model to yield the frequency and duration associated with each load loss event. The total Expected Energy Not Supplied (EENS) within the considered period for all the load loss events is given by:

$$\text{Total EENS} = \sum_{i=1}^{N} m_i f_i d_i \,, \qquad (\text{kWh/year}) \qquad (2.1)$$

where:

m_i = margin state in kW of load loss event i,

f_i = frequency in occ./year of load loss event i,

d_i = duration in hours of load loss event i,

N = the total number of load loss events.

The total expected cost for all the system load loss events is given by the following equation:

$$\text{Total expected cost} = \sum_{i=1}^{N} m_i f_i C_i(d_i)\,, \qquad (\$/\text{year}) \qquad (2.2)$$

where:

$C_i(d_i)$ = the interruption cost in \$/kW for a duration d_i in hours of a load loss event i.

$$\text{Estimated IEAR} = \frac{\sum_{i=1}^{N} m_i f_i C_i(d_i)}{\sum_{i=1}^{N} m_i f_i d_i}\,. \qquad (\$/\text{kWh}) \qquad (2.3)$$

The calculation of m_i, f_i, d_i proceeds as follows:

For the given load model, suppose:

m_k = the maximum value of kW shortage during each load loss event k,

b_k = duration in hours of load loss event k,

λ_k = departure rate (include upward and downward load) of load loss event k,

p_k = the probability of load loss event k.

Then:

$\lambda_k = 8736 / b_k$,

$p_k = b_k / 8736$.

For a given generation model,

a_j = the available system capacity level,

p_j = the probability that the system has capacity a_j, and

λ_j = the departure rate (include upward capacity and downward capacity) of a_j.

The discrete levels of available capacity and the discrete hourly system load levels can be combined to create a set of discrete capacity margins m_i. A negative margin represents a state in which the system load exceeds the available capacity and constitutes a system failure event.

$m_i = m_k$,

$p_i = p_j \times p_k$,

$\lambda_i = \lambda_j + \lambda_k$,

$f_i = p_i \times \lambda_i$,

$d_i = 8736 / \lambda_i$.

The calculated values of m_i, f_i, and d_i are used in Equation 2.3.

2.4 Application to the Test Systems

As indicated at the beginning of this chapter, the objective was to determine the sensitivity of the IEAR to various major system parameters. The first study involves the system peak load.

2.4.1 Impact of Peak Load

Table 2.4 and Figure 2.2 show a set of IEAR values corresponding to peak load levels varying from 165 MW to 205 MW for the RBTS [40]. It can be observed that the estimated IEAR for the given system generation capacity and CCDF do not vary significantly with peak load. The IEAR does, however, tend to increase as the peak load increases.

Table 2.4 Variation in the IEAR with peak load for the RBTS

Peak Load (MW)	IEAR ($/kWh)
165.0	5.2668
170.0	5.1964
175.0	5.3159
180.0	5.4519
185.0	5.5657
190.0	5.4469
195.0	5.4858
200.0	5.5528
205.0	5.4945

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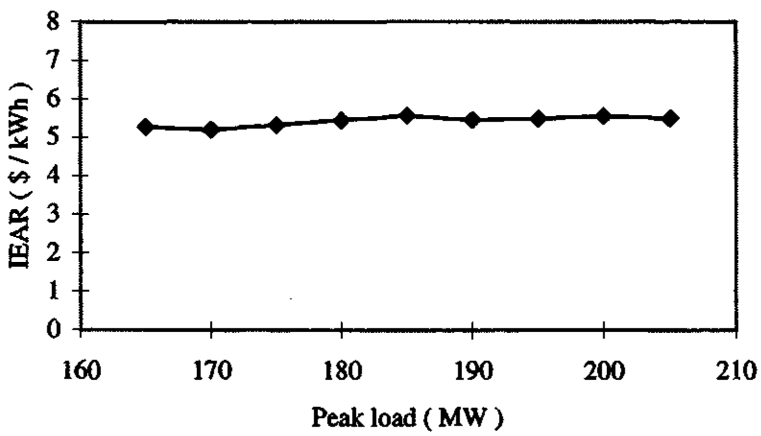


Figure 2.2 Variation in the IEAR with peak load for the RBTS

In the case of the RTS, Table 2.5 and Figure 2.3 show a set of IEAR values corresponding to peak load levels varying from 2650 MW to 3050 MW for the RTS [41]. The results show that there is very little change in the IEAR with variation in the peak load.

Table 2.5 Variation in the IEAR with peak load for the RTS

Peak Load (MW)	IEAR ($/kWh)
2650	5.2478
2700	5.2601
2750	5.2528
2800	5.2498
2850	5.2680
2900	5.2883
2950	5.3036
3000	5.2917
3050	5.3034

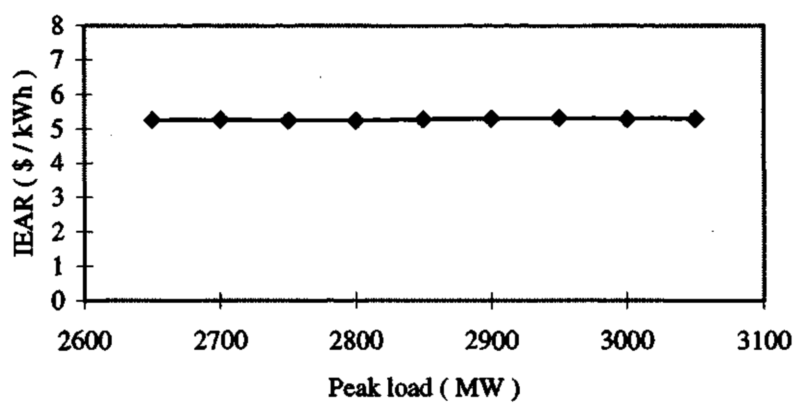


Figure 2.3 Variation in the IEAR with peak load for the RTS

The numerical IEAR values, as shown in Tables 2.4 and 2.5, for the remaining studies in this chapter are shown in Appendix D. The IEAR variations are illustrated pictorially, as shown by Figures 2.2 and 2.3.

2.4.2 Impact of Generating Unit Failure and Repair Rates

The sensitivity of the IEAR is examined in this section with variation in the failure and the repair rates of the generating units. In this analysis, the FOR of each unit within the system remains unchanged. The RBTS results as shown in Table 2.6 are a function of the increase in the failure and repair rate over the base case value. The multiplication factor is as follows.

$$\text{Multiplication Factor} = \frac{\lambda\,(\,\mu\,)}{\text{Base } \lambda\,(\,\mu\,) \text{ of each unit}}$$

When the multiplication factor is greater than 1.0, the unit fails more often and is repaired more quickly. The number of system failures increase but the duration of the failures decrease. The actual interruption cost per event will decrease as well as the unsupplied energy due to the event.

Figure 2.4 shows the variation in the IEAR with the RBTS. In this case, there is an initial decrease followed by relatively little change in the IEAR values with variation in the unit failure and repair rates, when the unit FOR remain unchanged.

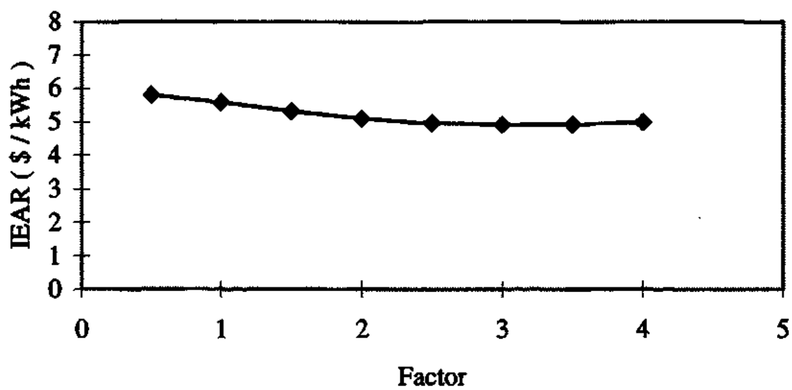
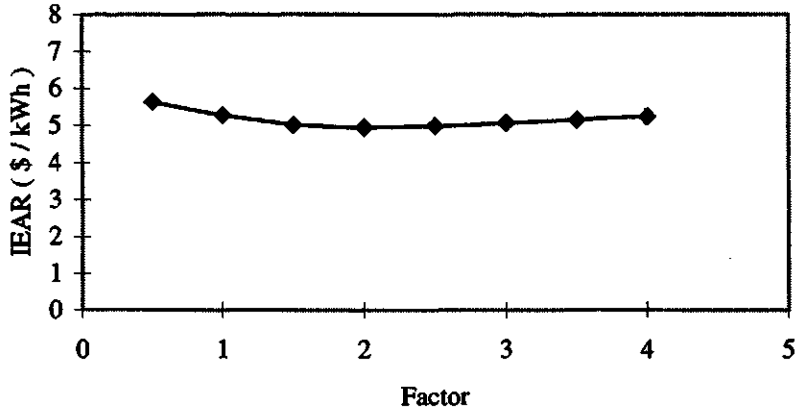


Figure 2.4 Variation in the IEAR with changes in the unit failure and repair rates (fixed FOR) for the RBTS

Figure 2.5 shows the variation in the IEAR for the RTS. The change in the IEAR profile is similar to that for the RBTS.



* λ, μ (FOR unchange
* FOR (λ ↗)

Figure 2.5 Variation in the IEAR with changes in the unit failure and repair rates (fixed FOR) for the RTS

2.4.3 Impact of the Generating Forced Outage Rates

In this case, the following multiplication factor was applied:

$$\text{Multiplication Factor} = \frac{\text{FOR}}{\text{Base FOR of each unit}}$$

The change in the FOR was achieved by modifying the generating unit failure rates. The repair rate was held constant at the base value. In most cases, the repair rate is much larger than the failure rate. The change in the unit failure rate is therefore almost proportional to the change of the FOR.

Figure 2.6 shows the variation in the IEAR with FOR for the RBTS. The IEAR shows relatively little change with variation in the unit FOR but tends to decrease as the multiplication factor increases. ?

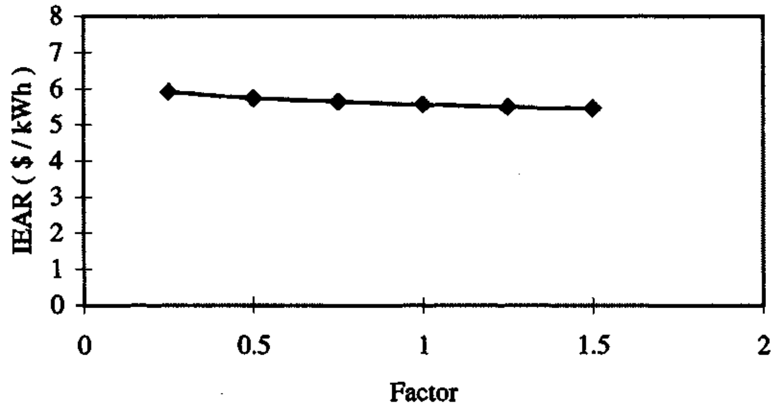


Figure 2.6 Variation in the IEAR with unit FOR for the RBTS

Figure 2.7 shows the variation in the IEAR with FOR for the RTS system. There is again relatively little change in the IEAR with variation in the multiplication factor.

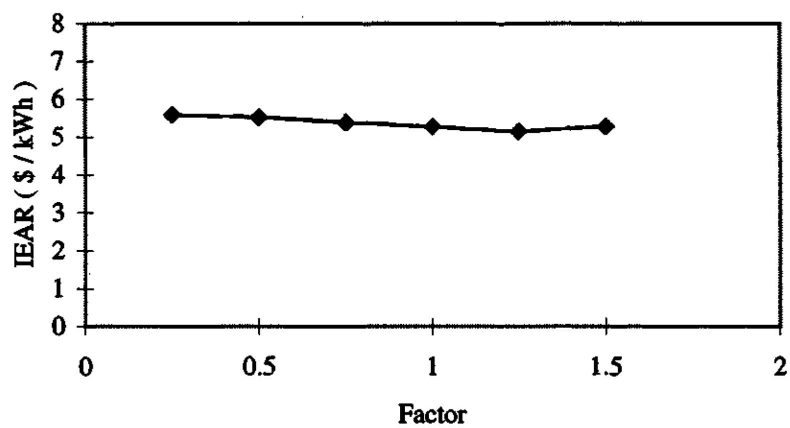


Figure 2.7 Variation in IEAR with unit FOR for the RTS

2.4.4 Impact of the Shape of the Daily Peak Load Curve

A set of different daily peak load curves was obtained by modifying the data shown in Table B.2 in the Appendix. The weekly peak load values other than the annual peak shown as 100 % in Table B.2 were modified by a given percentage change. These percentages ranged from - 3 % to + 3 % in 1 % steps. The resulting seven daily peak load curves are shown in Figure 2.8. The individual daily peak values are related to the weekly peak values as shown in Table B.3. The individual hourly values will also change as they are related to the daily peak values using the factors in Table B.4.

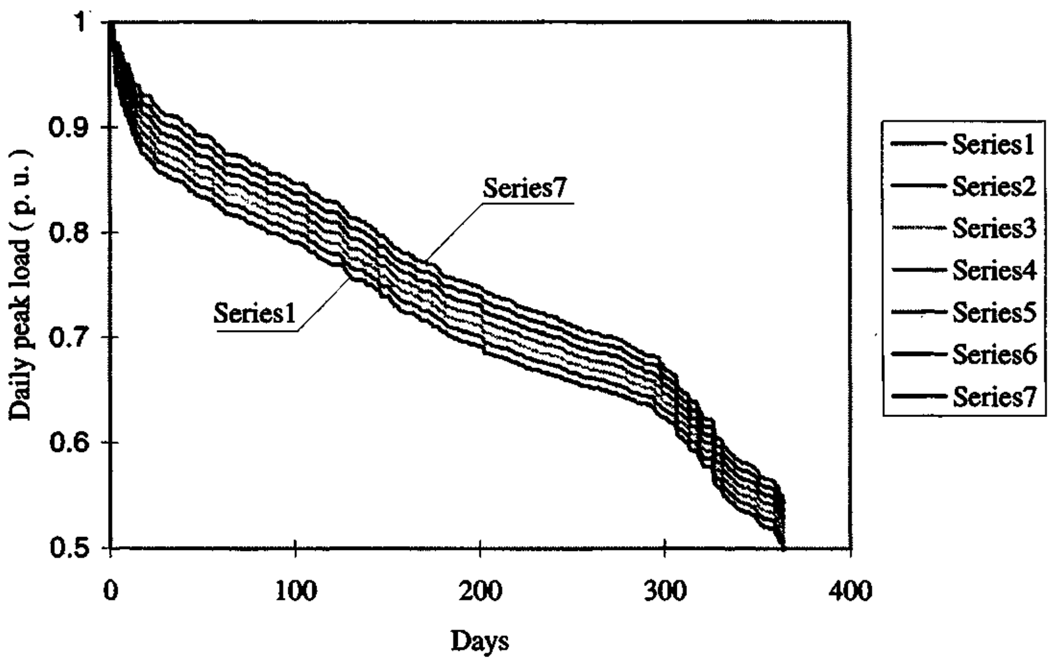


Figure 2.8 Daily peak load profiles

Table 2.6 shows the variation in the IEAR, for both the RBTS and the RTS, for the different daily peak load curves. It can be seen that the IEAR is not particularly sensitive to these changes in the peak load parameter.

Table 2.6 Variation in the IEAR for the different load curves

Daily Peak Load Curve	IEAR ($/kWh)	
	RBTS	RTS
Series 1	5.5205	5.3117
Series 2	5.5170	5.2966
Series 3	5.5813	5.2811
Series 4 (Base case)	5.5657	5.2680
Series 5	5.5084	5.2612
Series 6	5.5218	5.2607
Series 7	5.5139	5.2690

2.5 Application of the IEAR in HLI Reliability Cost / Worth Evaluation

This section illustrates the application of the IEAR in reliability worth evaluation at HLI using the RBTS and the RTS. It was assumed in this studies that the additional capacity is in the form of 10 MW gas turbine units for the RBTS, and 50 MW gas turbine units for the RTS. The annual fixed cost of the added units is 50 $/kW. The annual fixed costs associated with the original systems are not included in the analysis, as it is assumed that no decisions can be made regarding the existing capacity.

In these studies, the IEAR was assumed to be constant at 5.57 $/kWh and 5.27 $/kWh for the RBTS and RTS respectively.

2.5.1 Applications in the RBTS

Case 1 — Base System Analysis

Table 2.7 shows the EENS and ECOST for the RBTS with the subsequent addition of 10 MW units. The results given in Table 2.7 are also shown graphically in Figure 2.9. It can be seen that the customer costs decrease and the fixed costs increase as additional capacity is added to the system. The least cost reserve occurs for the original system with a reserve of 29.73 %.

Table 2.7 Case 1 analysis for the RBTS

Situation	Total capacity (MW)	Reserve margin (%)	EENS (MWh/yr)	ECOST (M$/yr)	Fixed cost (M$/yr)	Total cost (M$/yr)
original	240.0	29.73	9.9335	0.0553	0.0000	0.0553
+1×10	250.0	35.14	3.3060	0.0184	0.5000	0.5184
+2×10	260.0	40.50	1.0499	0.0058	1.0000	1.0058
+3×10	270.0	45.95	0.3305	0.0018	1.5000	1.5018
+4×10	280.0	51.35	0.0924	0.0005	2.0000	2.0005
+5×10	290.0	56.76	0.0222	0.0001	2.5000	2.5001
+6×10	300.0	62.16	0.0039	0.0000	3.0000	3.0000
+7×10	310.0	67.57	0.0005	0.0000	3.5000	3.5000

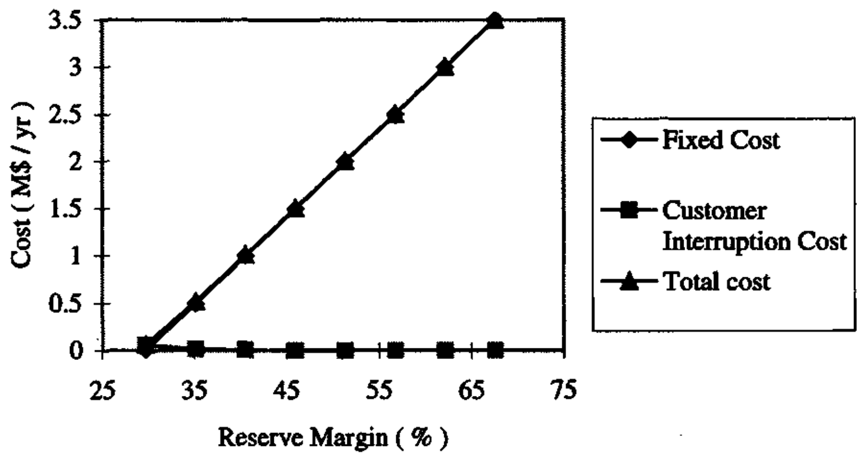


Figure 2.9 Case 1: Change in fixed, customer, and total costs with reserve margin (Base case) for the RBTS

Case 2 — IEAR Increased By a Factor of 2 ?

In this case, the IEAR was increased from the original value of 5.57 $/kW to a value of 11.14 $/kW. Table 2.8 and Figure 2.10 show the cost variation with additional capacity for this case. Both the numerical values and the pictorial representation of the fixed, customer and total costs are shown in each case to clearly illustrate the relative magnitudes and the variations with reserve margin. As in Case 1, the least cost reserve occurs for the original system at a reserve of 29.73 %.

Table 2.8 Case 2 analysis for RBTS

Situation	Total capacity (MW)	Reserve margin (%)	EENS (MWh/yr)	ECOST (M$/yr)	Fixed cost (M$/yr)	Total cost (M$/yr)
original	240.0	29.73	9.9335	0.1106	0.0000	0.1106
+1×10	250.0	35.14	3.3060	0.0368	0.5000	0.5368
+2×10	260.0	40.50	1.0499	0.0117	1.0000	1.0117
+3×10	270.0	45.95	0.3305	0.0037	1.5000	1.5037
+4×10	280.0	51.35	0.0924	0.0010	2.0000	2.0010
+5×10	290.0	56.76	0.0222	0.0002	2.5000	2.5002
+6×10	300.0	62.16	0.0039	0.0000	3.0000	3.0000
+7×10	310.0	67.57	0.0005	0.0000	3.5000	3.5000

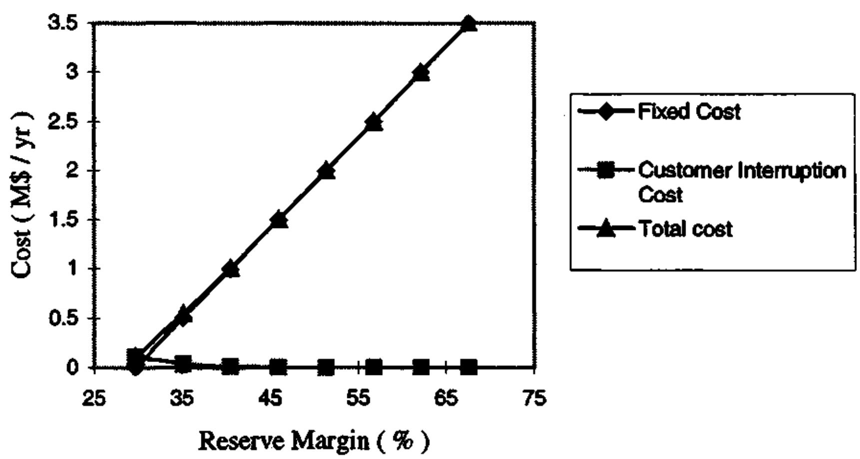


Figure 2.10 Case 2: Change in fixed, customer, and total costs with reserve margin (IEAR doubled) for the RBTS

Case 3 — Additional Unit Costs Decreased By a Factor of 2

Table 2.9 and Figure 2.11 show the variation in costs when the additional unit fixed costs are halved. As in the previous cases, the original system provides the optimum reserve and the optimum reserve margin is 29.73 %.

Table 2.9 Case 3 analysis for the RBTS

Situation	Total capacity (MW)	Reserve margin (%)	EENS (MWh/yr)	ECOST (M$/yr)	Fixed cost (M$/yr)	Total cost (M$/yr)
original	240.0	29.73	9.9335	0.0553	0.0000	0.0553
+1×10	250.0	35.14	3.3060	0.0184	0.2500	0.2684
+2×10	260.0	40.50	1.0499	0.0058	0.5000	0.5058
+3×10	270.0	45.95	0.3305	0.0018	0.7500	0.7518
+4×10	280.0	51.35	0.0924	0.0005	1.0000	1.0005
+5×10	290.0	56.76	0.0222	0.0001	1.2500	1.2501
+6×10	300.0	62.16	0.0039	0.0000	1.5000	1.5000
+7×10	310.0	67.57	0.0005	0.0000	1.7500	1.7500

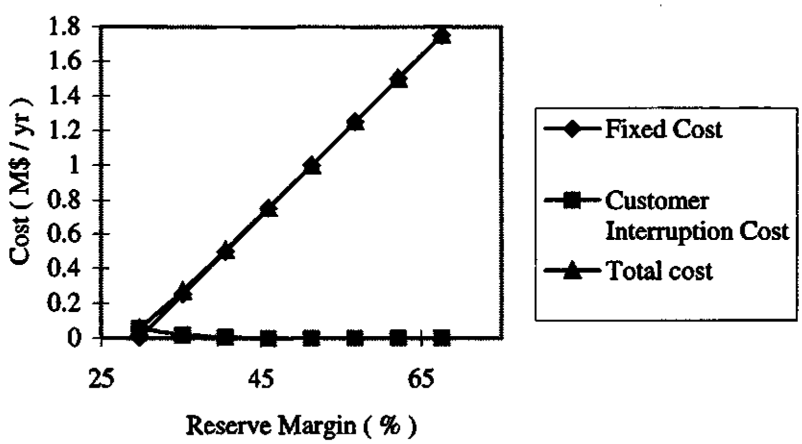


Figure 2.11 Case 3: Change in fixed, customer, and total costs with reserve margin (Fixed costs halved) for the RBTS

Case 4 — Peak Load Increased To 195 MW

Table 2.10 and Figure 2.12 show the variation in costs when the peak load in Case 1 is increased to 195 MW. The EENS increases considerably, but the increase is not sufficient to drive an injection of capacity. The original system therefore provides the optimum reserve but the reserve margin in this case is now 23.08 %.

Table 2.10 Case 4 analysis for the RBTS

Situation	Total capacity (MW)	Reserve margin (%)	EENS (MWh/yr)	ECOST (M$/yr)	Fixed cost (M$/yr)	Total cost (M$/yr)
original	240.0	23.08	24.7170	0.1377	0.0000	0.1377
+1×10	250.0	28.21	8.5625	0.0479	0.5000	0.5479
+2×10	260.0	33.33	2.6846	0.0150	1.0000	1.0150
+3×10	270.0	38.46	0.7773	0.0043	1.5000	1.5043
+4×10	280.0	43.59	0.1990	0.0011	2.0000	2.0011
+5×10	290.0	48.72	0.0398	0.0002	2.5000	2.5002
+6×10	300.0	53.85	0.0052	0.0000	3.0000	3.0000
+7×10	310.0	58.97	0.0003	0.0000	3.5000	3.5000

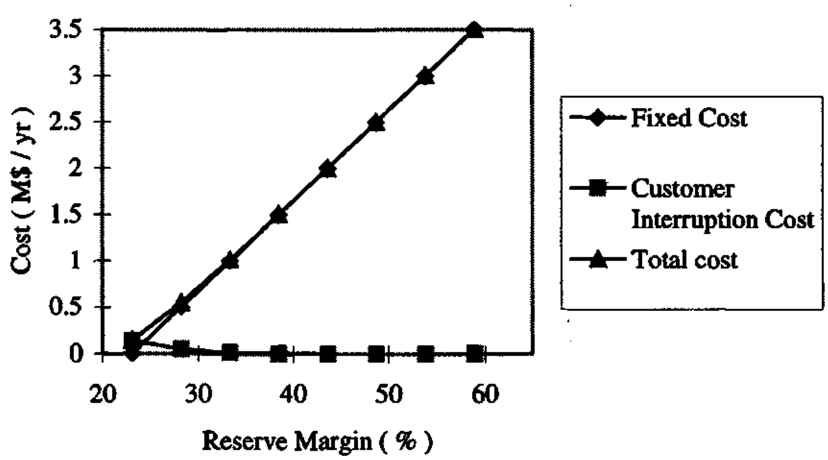


Figure 2.12 Case 4: Change in fixed, customer, and total costs with reserve margin (Peak load = 195 MW) for the RBTS

2.5.2 Application in the RTS

Case 1 — Basic System Analysis

Table 2.11 shows the EENS and ECOST for the RTS with the subsequent addition of 7-50 MW units. The results given in Table 2.11 are shown graphically in Figure 2.13, where it can be seen that the customer costs decrease rapidly as additional capacity is added to the system, and the fixed costs increase. The original system reserve margin of 19.47 % is the least cost value using an IEAR of 5.27 $/kW.

Table 2.11 Case 1 analysis for the RTS

Situation	Total capacity (MW)	Reserve margin (%)	EENS (MWh/yr)	ECOST (M$/yr)	Fixed cost (M$/yr)	Total cost (M$/yr)
original	3405.0	19.47	1179.845	6.2176	0.0000	6.2176
+1×50	3455.0	21.23	783.7927	4.1226	2.5000	6.6226
+2×50	3505.0	22.98	513.6724	2.6929	5.0000	7.6929
+3×50	3555.0	24.74	331.6794	1.7355	7.5000	9.2355
+4×50	3605.0	26.49	211.1410	1.1063	10.0000	11.1063
+5×50	3655.0	28.25	132.2290	0.6929	12.5000	13.1929
+6×50	3705.0	30.00	81.0882	0.4230	15.0000	15.4230
+7×50	3755.0	31.75	48.9647	0.2551	17.5000	17.7551

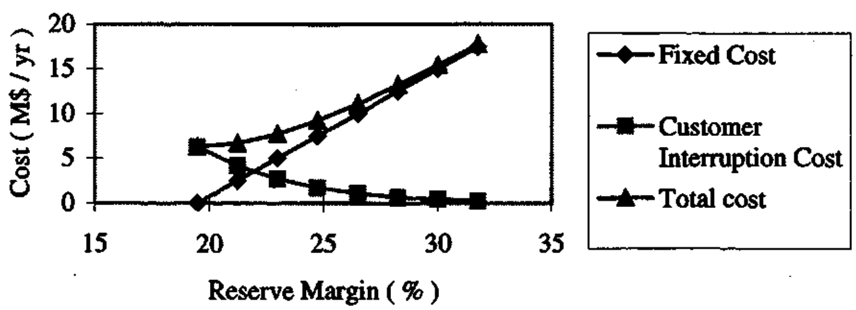


Figure 2.13 Case 1: Change in fixed, customer, and total costs with reserve margin (Base case) for the RTS

Case 2 — IEAR Increased By a Factor of 2

In this case, the IEAR is increased from the original value of 5.27 \$/kW to a value of 10.54 \$/kW. Table 2.12 and Figure 2.14 show the variation in costs with additional capacity for this case. The increase in the IEAR creates a sufficiently large increase in the ECOST that additional capacity is required in the form of 2-50 MW units. The optimum reserve margin is now 22.98 %.

Table 2.12 Case 2 analysis for the RTS

Situation	Total capacity (MW)	Reserve margin (%)	EENS (MWh/yr)	ECOST (M\$/yr)	Fixed cost (M\$/yr)	Total cost (M\$/yr)
original	3405.0	19.47	1179.845	12.4356	0.0000	12.4356
+1×50	3455.0	21.23	783.7927	8.2461	2.5000	10.7461
+2×50	3505.0	22.98	513.6724	5.4141	5.0000	10.4141
+3×50	3555.0	24.74	331.6794	3.4959	7.5000	10.9959
+4×50	3605.0	26.49	211.1410	2.2254	10.0000	12.2254
+5×50	3655.0	28.25	132.2290	1.3937	12.5000	13.8937
+6×50	3705.0	30.00	81.0882	0.8547	15.0000	15.8547
+7×50	3755.0	31.75	48.9647	0.5161	17.5000	18.0161

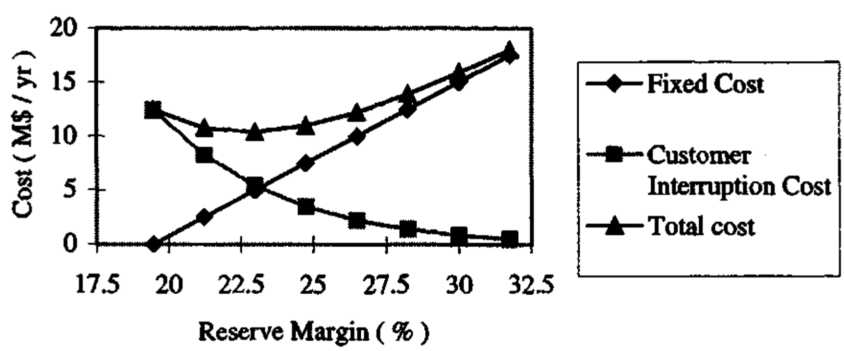


Figure 2.14 Case 2: Change in fixed, customer, and total costs with reserve margin (IEAR doubled) for the RTS

Case 3 — Additional Unit Costs Decreased By a Factor of 2

Table 2.13 and Figure 2.15 show the variation in costs when the additional unit fixed cost is halved. In this case, additional capacity can be justified to reduce the total system cost and 2-50 MW units are added. The optimum reserve margin is 22.98 %.

Table 2.13 Case 3 analysis for the RTS

Situation	Total capacity (MW)	Reserve margin (%)	EENS (MWh/yr)	ECOST (M$/yr)	Fixed cost (M$/yr)	Total cost (M$/yr)
original	3405.0	19.47	1179.845	6.2178	0.0000	6.2178
+1×50	3455.0	21.23	783.7927	4.1306	1.2500	5.3806
+2×50	3505.0	22.98	513.6724	2.7071	2.5000	5.2071
+3×50	3555.0	24.74	331.6794	1.7480	3.7500	5.4980
+4×50	3605.0	26.49	211.1410	1.1127	5.0000	6.1127
+5×50	3655.0	28.25	132.2290	0.6968	6.2500	6.9468

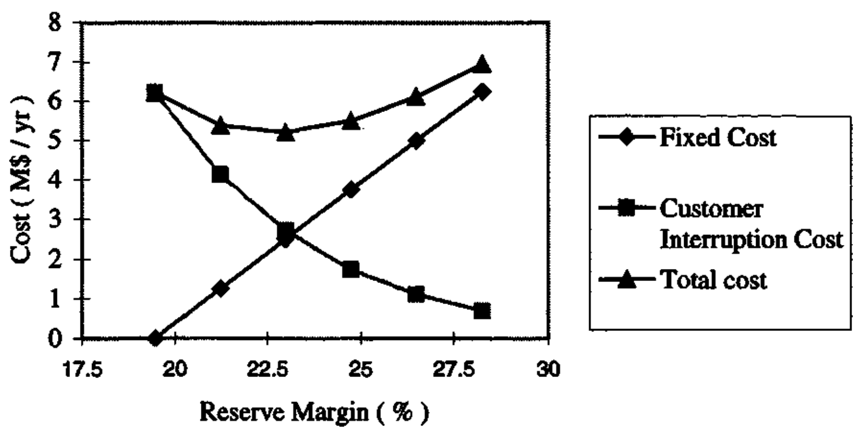


Figure 2.15 Case 3: Change in fixed, customer, and total costs with reserve margin (Fixed costs halved) for the RTS

Case 4 — Peak Load Increased To 2900 MW

Table 2.14 and Figure 2.16 show the variation in costs when the peak load in Case 1 is increased to 2900 MW. One additional 50 MW unit is added in this case and the optimum reserve margin is 19.14 %.

Table 2.14 Case 4 analysis for the RTS

Situation	Total capacity (MW)	Reserve margin (%)	EENS (MWh/yr)	ECOST (M$/yr)	Fixed cost (M$/yr)	Total cost (M$/yr)
original	3405.0	17.41	1672.397	8.8135	0.0000	8.8135
+1×50	3455.0	19.14	1128.886	5.9492	2.5000	8.4492
+2×50	3505.0	20.86	750.0605	3.9528	5.0000	8.9528
+3×50	3555.0	22.59	491.6468	2.5910	7.5000	10.0910
+4×50	3605.0	24.31	318.0396	1.6761	10.0000	11.6761
+5×50	3655.0	26.03	202.3619	1.0664	12.5000	13.5664
+6×50	3705.0	27.76	126.6055	0.6672	15.0000	15.6672
+7×50	3755.0	29.48	77.7034	0.4095	17.5000	17.9095

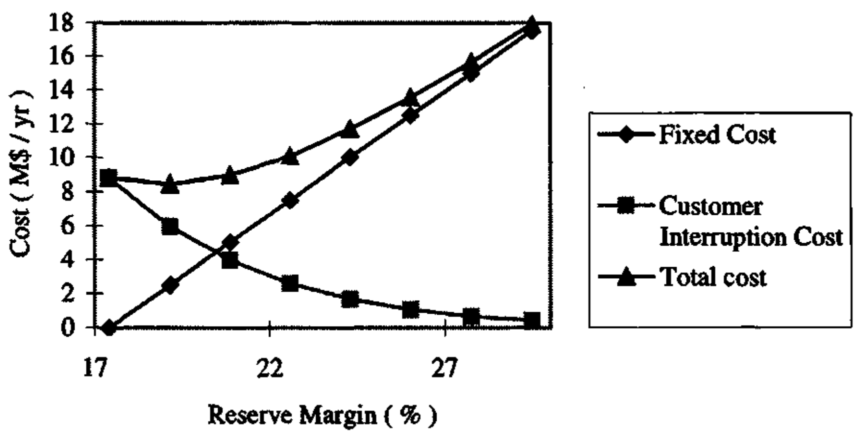


Figure 2. 16 Case 4: Change in fixed, customer, and total costs with reserve margin (Peak load = 2900 MW) for the RTS

2.6 Summary

This chapter describes the utilization of a frequency and duration (F&D) technique and an composite customer damage function to evaluate the IEAR at HLI. The chapter also presents several IEAR sensitivity studies at HLI. The studies show that the calculated IEAR is not very sensitive to variations in the generation data and is very dependent on the composite customer damage function for the service area.

The studies show that when the peak load is varied from 165 MW to 205 MW in the RBTS and from 2650 MW to 3050 MW in the RTS, the IEAR varies from 5.1946 \$/kWh to 5.5657 \$/kWh and from 5.2478 \$/kWh to 5.3036 \$/kWh respectively. When the unit failure and repair rates are varied from 0.5 to 4.0 times those of base case for both test systems, with the generating forced outage rate unchanged, the IEAR varies from 4.8986 \$/kWh to 5.8096 \$/kWh for the RBTS and from 4.9451 \$/kWh to 5.6267 \$/kWh for the RTS. The unit forced outage rates were also varied from 0.25 to 1.5 times those of the base case for the two systems. In these cases, the IEAR varied from 5.4597 \$/kWh to 5.9292 \$/kWh and from 5.1409 \$/kWh to 5.5883 \$/kWh respectively. The IEAR also varied from 5.5084 \$/kWh to 5.5813 \$/kWh for the RBTS and from 5.2607 \$/kWh to 5.3117 \$/kWh for the RTS using a series of different load curves.

A relatively stable IEAR greatly simplifies the reliability cost / worth process at HLI as it is a basic factor in system optimization. The HLI reliability cost / worth process is illustrated in this chapter by application to the RBTS and the RTS. It is shown in Section 2.5, that both the RBTS and the RTS can be considered to have optimal reserve margins in the base case analysis. The two systems respond quite differently in regard to optimum reserve requirements, however, when some of the basic parameters are changed. This is illustrated by the studies presented in this chapter.

Chapter 3

IEAR SENSITIVITY ANALYSIS AT HLII

3.1 Introduction

The objectives of the research described in this chapter were to evaluate the IEAR and to conduct sensitivity analysis at HLII. As in Chapter 2, the basic objective of the IEAR sensitivity study was to determine its response to the basic system parameters. As illustrated in the sensitivity study conducted at HLI, a relatively constant IEAR will greatly simplify the reliability worth assessment process in composite generation and transmission system expansion planning. The following factors were considered as basic system parameters in the IEAR sensitivity analysis at HLII:

1. Generating unit FOR.
2. Generating unit capacity additions.
3. Transmission line unavailability.
4. Transmission line capacities.
5. Different load models.
6. Different IEAR calculation processes.
7. Different CCDF calculation processes.

This chapter also illustrates the application of a single IEAR in reliability worth assessment to quantify the optimal reserve at HLII for the RBTS.

It is relatively simple to extend the concept of quantitative reliability evaluation at HLI to HLI reliability worth assessment. In contrast, quantitative reliability assessment techniques at HLII are much more complicated. The various techniques and programs describing HLII reliability evaluation are available in a wide range of published material. Reference 1 describes in detail the basic procedures for composite generation and transmission system evaluation using the contingency enumeration approach. Reliability worth calculations at HLII were conducted in this research by extending this technique. The digital computer program COMREL was modified to incorporate the customer costs associated with each load loss event. The new program was designated as COMRELW.

Hierarchical level II (HLII) includes both generation and transmission facilities. Reliability evaluation at HLII is therefore used to assess the adequacy of the generation and power transmission systems in regard to providing a suitable supply at each load bus. In the basic contingency enumeration approach, all component outages up to a specified level are considered in the analysis. Section 3.3 provides a brief discussion of the basic process.

In the research, a fast decoupled load flow solution technique for contingency evaluation [39] was used in the reliability worth evaluation. Corrective actions such as generating rescheduling, load curtailment, voltage adjusting, reactive power adjusting, line overload alleviation and etc., were utilized to alleviate different system problems. Reference 39 provides considerable detail on the utilization of the fast decoupled method in the adequacy assessment of composite power systems.

3.2 Cost Model

A single composite customer damage function is used in HLI worth assessment. In the case of HLII evaluation, a composite customer damage function for each bus in the system is used to evaluate the reliability worth indices. Table 3.1 gives the sector energy distribution at each load bus of the RBTS. The user sector costs given in Table

2.1 were weighted using the data given in Table 3.1 to generate the individual load bus CCDF shown in Table 3.2. These CCDF are then used to calculate the individual load bus IEAR.

Table 3.1 Sector energy distribution at each load bus of the RBTS

User	Sector energy distribution (%)					
sector	Bus 2	Bus 3	Bus 4	Bus 5	Bus 6	System
Large users		66.91				31.0
Small users	24.02	4.83	50.65		23.72	19.0
Comm.	16.84	4.94	9.69	18.12	8.77	9.0
Farm					26.50	2.5
Residential	33.42	21.17	39.66	44.14	41.01	31.0
Govt. & Inst.	25.72			27.68		5.5
Office & Bldg.		2.16		10.06		2.0
Total	100.0	100.0	100.0	100.0	100.0	100.0

Table 3.2 CCDF for each bus of the RBTS

System	Interruption duration				
Bus	1 min.	20 min.	1 h	4 h	8 h
Bus 2	0.367	1.362	4.167	14.646	39.322
Bus 3	0.840	10524	2.906	7.941	18.198
Bus 4	0.707	1.969	5.621	17.727	42.530
Bus 5	0.525	1.607	4.295	16.585	41.163
Bus 6	0.303	1.006	3.274	11.276	28.041

3.3 Basic Evaluation Methods

It is not practical to consider all outage contingencies in HLII adequacy assessment due to computer time and memory constraints. This is particularly true in large power system studies. The following component outages have been incorporated in the contingency enumeration approach utilized in this work.

1. Generator outages:

All outages involving four or less than four generating units.

2. Transmission line outages:

   All outages involving three or less than three transmission lines.

3. Combined generator and transmission line outages:

   All outages involving up to two generating units, one transmission line and one generating unit and two transmission lines.

The load model for each bus is a straight line at a constant peak load value for the assigned period. The calculated reliability indices are therefore designated as annualized values. The impact of each contingency on the individual load points in the system are evaluated by calculating the frequency, duration, and magnitude of load loss at each load point.

The procedure used to calculate the expected customer interruption cost at each bus is similar to that used in Chapter 2 for HLI analysis [1], and is given by:

$$EENS_k = \sum_{j=1}^{NC} L_{kj} f_j d_j, \qquad (\text{kWh/yr}) \qquad (3.1)$$

$$ECOST_k = \sum_{j=1}^{NC} L_{kj} f_j C_j(d_j), \qquad (\text{\$/yr}) \qquad (3.2)$$

$$IEAR_k = \frac{\sum_{j=1}^{NC} L_{kj} f_j C_j(d_j)}{\sum_{j=1}^{NC} m_j f_j d_j}, \qquad (\text{\$/kWh}) \qquad (3.3)$$

$$\text{Aggregate system } IEAR = \sum_{k=1}^{NB} q_k \times IEAR_k, \qquad (\text{\$/kWh}) \qquad (3.4)$$

where:

L_{kj} = margin state in kW of load loss event j at bus k

f_j = frequency in occ./year of load loss event j at bus k

d_j = duration in hours of load loss event j at bus k,

q_k = fraction of the system load utilized by the customers at bus k,

$C_f(d_j)$ = the interruption cost in \$/kW for a duration d_j in hours of a load loss event j,

NC = the total number of load loss events at bus k,

NB = the total number of load buses in the system.

3.4 Application to the Test Systems

3.4.1 Impact of Unit Forced Outage Rates (FOR)

There are two relatively simple ways to change the FOR of each unit, one is to change the failure rate (λ) of a unit while its repair rate remains unchanged, the other is to change the repair rate (μ) while the failure rate remains unchanged. Table 3.3 shows the change in aggregate IEAR with unit FOR using both ways. The data in Table 3.3 is shown graphically in Figure 3.1. The IEAR values show relatively little change with variation in the unit FOR.

Table 3.3 Change in the aggregate system IEAR with unit FOR

Forced Outage Rate	IEAR (\$/kWh)	
% Basic FOR	λ Unchanged	μ Unchanged
85	4.2629	4.4129
90	4.3048	4.4092
95	4.3562	4.4051
100	4.4008	4.4008
105	4.4431	4.3962
110	4.4844	4.3914
115	4.5232	4.3865

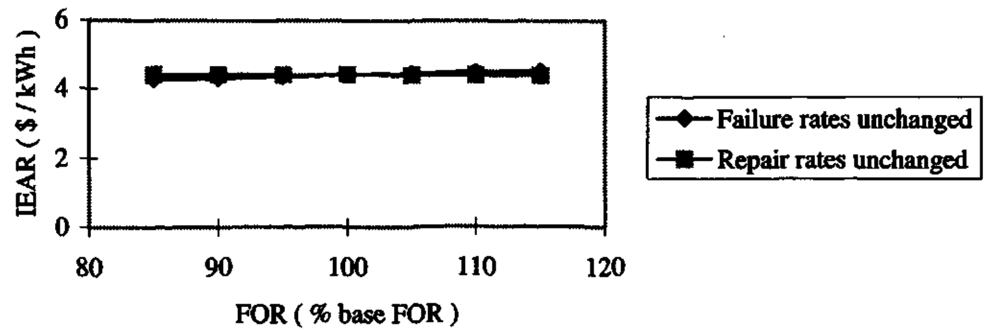


Figure 3.1 Change in the aggregate system IEAR with unit FOR

3.4.2 Impact of Unit Capacity

Figure 3.2 shows the change in the aggregate IEAR with reserve margin. The numerical IEAR values are shown in Appendix D. Additional capacity can be added at any bus in the composite system. In order to examine the effect of the location of capacity injection, a series of 10 MW units were added at bus 1 and bus 6 respectively. The IEAR of the system decreases rapidly when 7-10 MW turbine units were added sequentially to the system at bus 1. When the units were added sequentially to the system at bus 6, it can be observed that the estimated IEAR does not change significantly with variation in system generation capacity. It is therefore important to recognize the location of new capacity injections.

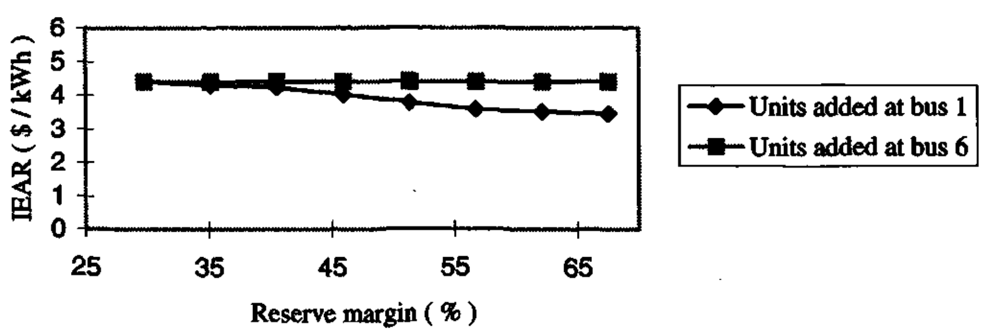


Figure 3.2 Change in the aggregate system IEAR with reserve margin

3.4.3 Impact of Transmission Line Unavailability

The transmission line unavailability was varied using the process described in Section 3.4.1 for the generating unit FOR. The variation in the aggregate system IEAR with the transmission line unavailability is shown in Figure 3.3. There is almost no change in the IEAR with the variation in the transmission line unavailability.

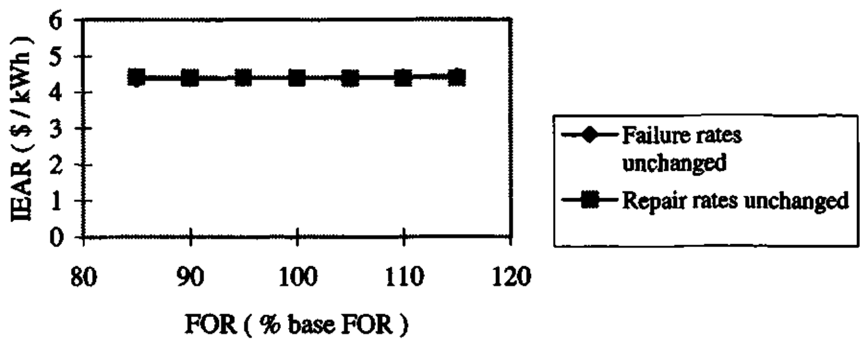


Figure 3.3 Change in the aggregate system IEAR with transmission line unavailability

3.4.4 Impact of Transmission Line Capacity

Figure 3.4 shows the change in the system aggregate IEAR when the capacity of

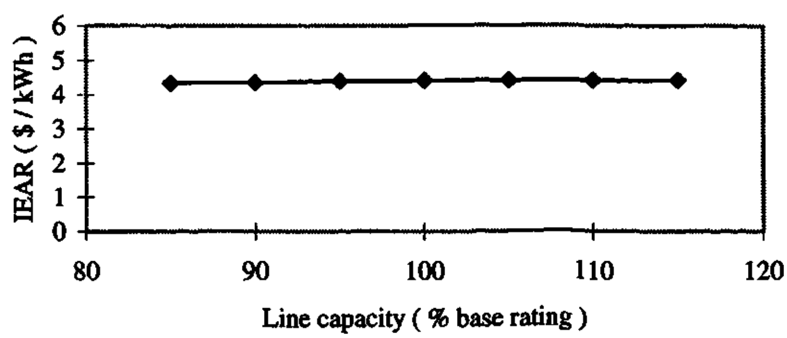


Figure 3.4 Change in the system aggregate system IEAR with the transmission line capacity

each transmission line is changed from 85 % to 115 % of its basic rating. The results show that little change occurs in the IEAR with variation in transmission line capacity.

3.4.5 Impact of Considering a Variable Load Model

Table 3.4 shows a four step annual load model. Figure 3.5 shows the change in the system aggregate IEAR with the annual peak load using the four step load model. There is relatively little change in the IEAR with the annual peak load using the four step load model.

Table 3.4 Four step load model

Step	Peak load (p. u.)	Peak load (MW)	Probability
1	1.0	185.0	0.01316392
2	0.9	166.5	0.11103480
3	0.8	148.0	0.16540751
4	0.7	129.5	0.71039377
Total			1.00000000

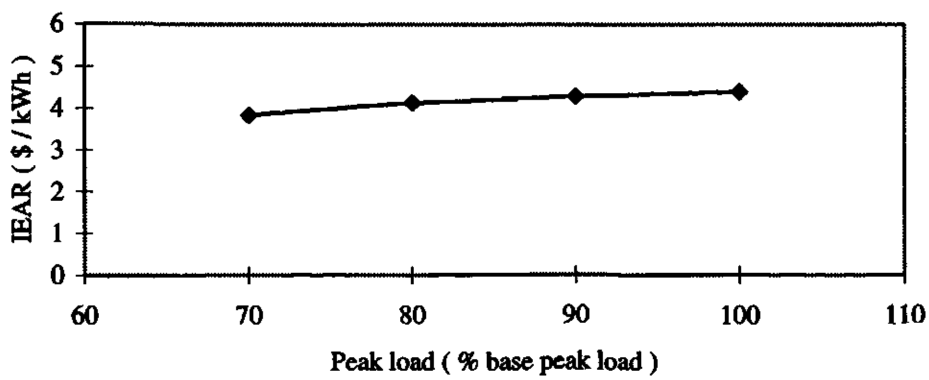


Figure 3.5 Change in the system aggregate IEAR with annual peak load using a four step load model

3.4.6 Impact of Different IEAR Calculation Processes

There are two basic ways to calculate the system aggregate IEAR as a function of the annual peak load using a discrete step load model These two ways are as follows:

Assuming that:

L_i = Load level of each step (MW),

q_i = Probability that the load is at L_i,

$ECOST_i$ = Aggregate system ECOST at L_i,

$IEAR_i$ = Aggregate system IEAR at L_i,

$EENS_i$ = Aggregate system EENS at L_i,

N = Number of steps in the load model.

<u>Method 1:</u>

$$\mathrm{ECOST} = \sum_{i=1}^{N} q_i \times ECOST_i \,,$$

$$\mathrm{EENS} = \sum_{i=1}^{N} q_i \times EENS_i \,,$$

$$\mathrm{IEAR} = \mathrm{ECOST} / \mathrm{EENS}.$$

<u>Method 2:</u>

$$\mathrm{IEAR} = \sum_{i=1}^{4} q_i \times IEAR_i \,.$$

Table 3.5 shows the change in the system aggregate EENS, ECOST and IEAR as a function of the annual peak load for the four step load model. Table 3.6 shows the change in the system aggregate IEAR due to the calculation process. It can be observed that Method 2 produces higher IEAR values. Method 1 provides a more representative IEAR value and is considered to be a better approach.

Table 3.5 Change in the system aggregate EENS, ECOST and IEAR as a function of the annual peak load for the four step load model

Peak load L_i (% Base case)	q_i	$EENS_i$ (MWh/yr)	$ECOST_i$ (k$/yr)	$IEAR_i$ ($/kWh)
100	0.01316392	1444.8520	5753.7220	4.4008
90	0.11103480	457.7325	1680.2950	4.2945
80	0.16540751	192.1155	693.5350	4.1299
70	0.71039377	151.2206	537.3989	3.8560

Table 3.6 Change in the system aggregate IEAR due to the calculation process

Load model	IEAR ($/kWh)	
	Method 1	Method 2
Four step load model	3.6693	3.9572

3.4.7 Impact of Different CCDF Representations

The surveys to determine sector interruption costs did not obtain data for outages of long duration and in general limited the questions to specific outage durations with a maximum of 8 hours. It is therefore necessary to interpolate for outage durations less than 8 hours and extrapolate for outage durations larger than 8 hours. Table 3.7 shows the change in the IEAR for different extrapolation processes for durations greater than 8 hours. The conventional interpolation process for duration less than 8 hours is to use a linear relationship on the logarithmic scale [31]. This process was used for all interpolation calculations in this thesis. The following describes the three extrapolation processes examined in this section.

Assuming that:

$C(d_8)$ = The interruption cost in $/kW for a duration of 8 hours,

$C(d_4)$ = The interruption cost in $/kW for a duration of 4 hours,

$C(d)$ = the interruption cost in $/kW for a duration of d hours which is larger than 8 hours.

Method 1: Linear extrapolation on a logarithmic scale

$$\log(\, C(d \times 60)\,) =$$

$$\log(\, C(d_8 \times 60)\,) + \frac{\log(C(d_8 \times 60)) - \log(C(d_4 \times 60))}{\log(d_8 \times 60) - \log(d_4 \times 60)} \times (\log(d \times 60) - \log(d_8 \times 60))$$

Method 2: Linear extrapolation

$$C(d \times 60) = C(d_8 \times 60) + \frac{C(d_8 \times 60) - C(d_4 \times 60)}{d_8 - d_4} \times (d - d_8)$$

Method 3: Limited value

$$C(d) = C(d_8)$$

Table 3.7 Change in the system aggregate IEAR with the different calculation processes

Calculation method	IEAR (\$/kWh)
Linear extrapolation on the log scale	4.6117
Linear extrapolation	3.8844
Limited value	1.9917

It can be seen from Table 3.7 that limiting the interruption costs for long durations to the 8 hour value considerably reduces the aggregate IEAR. This may be somewhat optimistic. The linear extrapolation on the logarithmic scale may be somewhat severe but may also serve to recognize some of the indirect effects of interruptions which are not captured in the conventional survey process. Based on the variation shown in Table 3.7, there is very clearly a need for surveys in the area of long duration interruptions.

3.5 Application of the System Aggregate IEAR in Cost / Worth Evaluation

In the studies described in this section, the EENS is calculated for the composite generation and transmission system and used in conjunction with the system aggregate IEAR to determine the ECOST. The optimum reserve capacity margin can now be determined using the process described in Chapter 2. In this approach, the physical location of each generating unit within the transmission system is included in the evaluation. The following four cases illustrates the variation in the optimum reserve with changes in selected factors. The system aggregate IEAR was assumed to be constant at 3.6693 \$/kWh, as shown in Table 3.6, for the first three cases and modified to 3.7933 \$/kWh, for the fourth case, as discussed in the relevant section.

It is assumed that the additional capacity is in the form of 10 MW gas turbine units. The annual fixed cost of these units is 50 \$/kW. The annual fixed costs associated with the original system are not included in the analysis.

Case 1 — Basic System Analysis

Table 3.8 shows the EENS and ECOST for the RBTS with the sequential addition of 7-10 MW units at bus 1. The results given in Table 3.8 are shown graphically in Figure 3.6, where it can be seen that the customer costs decrease rapidly as additional capacity is added to the system and the fixed costs increase. The least cost reserve margin occurs with the addition of 1-10 MW unit at bus 1. This provides a system reserve margin of 35.14 %.

Table 3.8 Case 1 analysis for the RBTS

Situation	Reserve Margin (%)	EENS (MWh/yr)	ECOST (M$/yr)	Fixed Cost (M$/yr)	Total Cost (M$/yr)
Original	29.73	1444.8520	5.7537	0.0	5.7537
+1×10 MW	35.14	483.6602	1.7747	0.5	2.2747
+2×10 MW	40.54	397.9102	1.4601	1.0	2.4601
+3×10 MW	45.95	262.3812	0.9628	1.5	2.4628
+4×10 MW	51.35	237.3242	0.8708	2.0	2.8708
+5×10 MW	56.76	226.7997	0.8322	2.5	3.3322
+6×10 MW	62.16	222.1231	0.8150	3.0	3.8150
+7×10 MW	67.57	218.2799	0.8009	4.5	4.3009

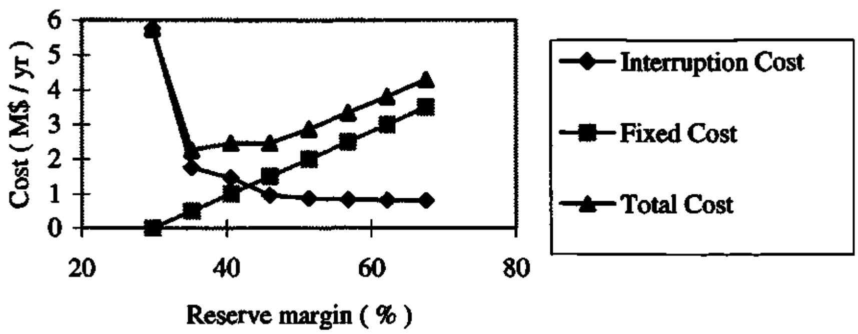


Figure 3.6 Change in interruption, fixed and total costs with reserve margin — RBTS

Case 2 — IEAR Increased By a Factor of 2

Figure 3.7 shows the variations in costs when the IEAR used in Case 1 is doubled. The numerical cost values are shown in Appendix D. The customer costs increase in this case and the system reserve margin of 45.95 % is the least cost value. In this case, 3-10 MW units are added at bus 1.

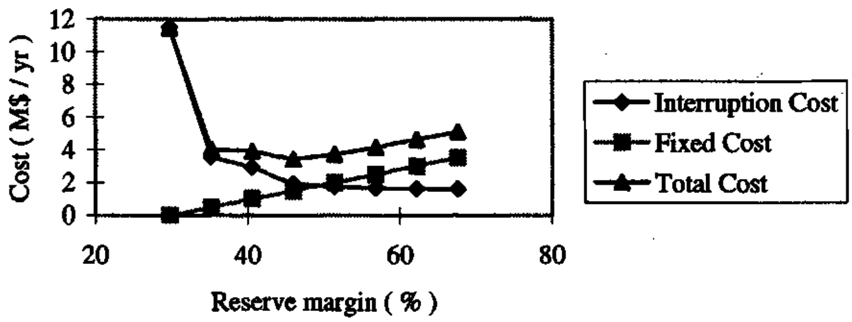


Figure 3.7 Change in Interruption, fixed and total costs with reserve margin (IEAR doubled) — RBTS

Case 3 — Additional Unit Costs Decreased By a Factor of 2

Figure 3.8 shows the variations in interruption, fixed and total costs with reserve margin when the additional unit fixed costs are decreased by a factor of 2. The optimum reserve margin increases from the base case value of 35.14% to 45.95 %.

The effect on the optimum reserve margin of decreasing the additional unit costs by a factor of 2 (Case 3) is the same as increasing the IEAR by a factor of 2 (Case 2) in this case. This is not a general conclusion and the relationship will be system specific.

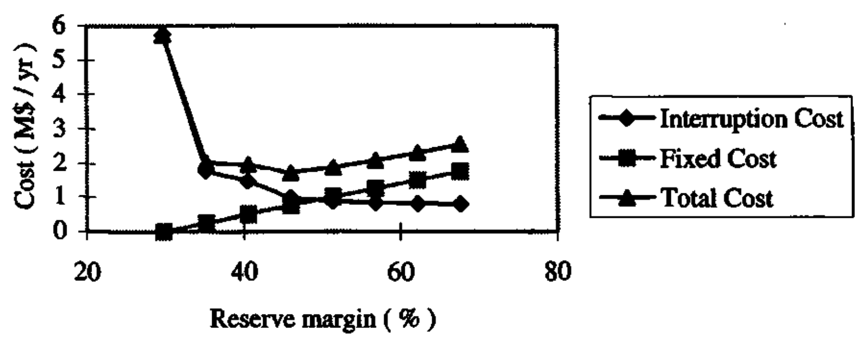


Figure 3.8 Change in interruption, fixed and total costs with reserve margin (Fixed cost doubled) — RBTS

Case 4 — Peak Load Increased To 200 MW

Figure 3.9 shows the variations in interruption, fixed and total costs with reserve margin when the system peak load increases to 200 MW. The IEAR in this case is 3.7933 \$/kWh and was obtained using Method 1 described in Section 3.4.6. The optimum reserve margin is 35.0 % with the addition of 3-10 MW units. This can be compared with the basic system analysis in Case 1 in which the optimum reserve is 35.14 % with the addition of 1-10 MW unit.

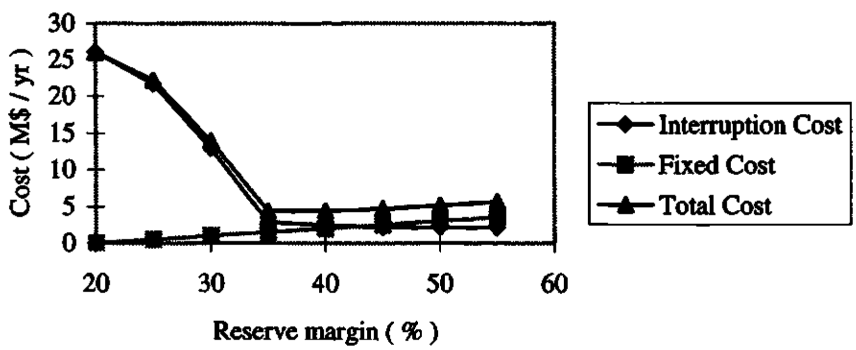


Figure 3.9 Change in interruption, fixed and total costs with reserve margin (Peak load = 200 MW) — RBTS

3.4 Summary

This chapter describes the utilization of a contingency enumeration approach and the individual load bus composite customer damage functions to evaluate the system aggregate IEAR at HLII. The chapter also presents several IEAR sensitivity studies at HLII.

The research shows that the calculated system aggregate IEAR is not very sensitive to variations in the system facility data in most cases and is very dependent on the composite customer damage functions for the service area. The studies show that when the unit forced outage rates were varied from 0.25 to 1.15 times those of the system base case, the system aggregate IEAR varied from 4.2629 \$/kWh to 4.5232 \$/kWh with the unit failure rates unchanged, and from 4.4129 \$/kWh to 4.3865 \$/kWh with the unit repair rates unchanged. The location of a new capacity injection is an important factor in the system aggregate IEAR evaluation. The IEAR decreases rapidly with new capacity injections at Bus 1 but shows almost no change when the new units are added at Bus 6. When the transmission line unavailability is varied from 0.85 to 1.15 times those of the system base case, the system aggregate IEAR varied from 4.3703 \$/kWh to 4.4276 \$/kWh with the transmission line failure rates unchanged, and from 4.4173 \$/kWh to 4.3841 \$/kWh with the transmission line repair rates unchanged. The transmission line capacities were also varied from 0.85 to 1.15 times those of the system base case. In these cases, the IEAR varied from 4.3322 \$/kWh to 4.4195 \$/kWh. In the case of the peak load varying from 185 MW to 129.5 MW, the system aggregate IEAR varies from 4.4008 \$/kWh to 3.856 \$/kWh. The system aggregate IEAR decreases rapidly when the peak load drops below 80 % of the base value due to the high reserve margin. The system aggregate IEAR are 3.6693 \$/kWh and 3.9572 \$/kWh for the two different calculation processes described in Section 3.4.6. Method 1 as described in Section 3.4.6 which resulted in the 3.6693 \$/kWh is considered to be a more representative process. Section 3.4.7 clearly shows the effect on the system aggregate IEAR values of different CCDF representations when the interruption duration is more than 8 hours. The IEAR is 4.6117 \$/kWh using linear extrapolation on a logarithmic scale, 3.8844 \$/kWh using linear extrapolation and 1.9917 kWh using a limiting value. This is clearly an area where further survey work and research is needed.

A relatively stable IEAR greatly simplifies the reliability cost / worth process at HLII as it is a basic factor in system optimization planning. The HLII reliability cost / worth process is illustrated in this chapter by application to the RBTS.

CHAPTER 4

IEAR Sensitivity Studies in the Distribution Functional Zone

4.1 Introduction

The objective of the research described in this chapter was to conduct IEAR evaluation in the distribution functional zone and examine its sensitivity to major system parameters. The distribution circuits used in these studies are those developed for the RBTS [40]. These circuits are shown in Appendix C. The following system factors were considered in the IEAR sensitivity study:

1. Transmission line repair times.
2. Station bus repair times.
3. Transformer replacement times.
4. Breaker active failure rates.
5. Fuse failure probability.
6. Restrictions in load transfer capacity.
7. Different IEAR calculation processes.

A distribution system can be defined as these facilities which link the bulk system to the customer facilities. It normally consists of subtransmission circuits, distribution substations, primary and secondary feeders, distribution transformers and customer connections, etc. Main feeders and lateral branches are normally used in a traditional radial distribution circuit. Originating at the distribution substation, the main feeders connect the individual customer loads through lateral branches. In order to improve the system reliability, most practical distribution systems have open points in the meshed configuration and are operated as radial systems. In the case of a failure, the open points can be moved and the disconnected load can then be transferred to another part of the system. The distribution segments of the RBTS are a good example of such a system.

Quantitative adequacy indices at each load point can be obtained using the basic analytical procedures described in [1]. The contingency enumeration approach [1] is used in this chapter as the basic technique for obtaining the customer load point unsupplied energy (EENS). This index is utilized together with the appropriate sector customer cost functions to determine the IEAR in the distribution functional zone.

All the customer load points associated with a given load center or service area should be considered in the determination of the distribution system IEAR. Each contingency that results in customer load curtailment can be quantified by the rate of occurrence (λ), the average outage duration (γ), and the contribution to the average annual outage time (U). The summation of the contingency values gives the actual customer load point adequacy indices.

Three basic models are required in the estimation of customer IEAR. The three models are the cost model, the load model and the system model and are introduced in detail in the next section. Continuity of supply is assumed to be the sole criterion in this analysis and therefore partial load curtailment due to equipment overload is not considered. A single aggregate IEAR value for each load bus can be obtained by summing the weighted individual IEAR in proportion to the fraction of bus load.

4.2 Basic Evaluation Methods

In distribution system analysis, the relevant cost models are the sector customer damage function (SCDF) for the customer types connected to the system. The demand at each load point is assumed to be constant throughout the period. The system model includes the relevant reliability parameters of all components such as the main feeders, lateral branches from which the individual customers are supplied, and associated components. The failure rate, average outage time, average annual outage time, the load curtailed and the customer interruption cost at each load point are evaluated for each considered contingency.

The following failure events were included in the detailed contingency enumeration analysis conducted in this research.

1. All first order permanent outages.
2. All second order overlapping permanent outages.
3. All first order active failure events.

The studies performed include failures on the incoming 33 kV supply circuits, the 33/11 kV substation together with the outgoing 11 kV feeder breakers, 11 kV main feeders, lateral branches and transformers in the circuits shown in Appendix C.

The approach used to calculate the expected customer interruption cost at each load point is similar to that used in Chapter 3 for HLII analysis. For each outage event j contributing to the isolation of load point p connected to the system, the worth indices can be calculated using the following equations.

$$ECOST_j = C_j(\gamma_j)\, L\, \lambda_j, \qquad (\$/yr) \qquad (4.1)$$

$$EENS_j = L\, U_j\,, \qquad (kWh/yr) \qquad (4.2)$$

where:

λ_j = failure rate in occ./year of load loss event j,

γ_j = duration in hours of load loss event j,

U_j = unavailability in hour/year of load loss event j,

$C_j(\gamma_j)$ = the interruption cost in \$/kW for a duration γ_j in hours of a load loss event j,

L = margin state in kW of load loss event j at load point p,

$$ECOST_p = \sum_{j=1}^{NP} ECOST_{jp}, \qquad (\$/yr) \qquad (4.3)$$

$$EENS_p = \sum_{i=1}^{NP} EENS_{jp}, \qquad (kWh/yr) \qquad (4.4)$$

$$IEAR_p = \frac{\sum_{j=1}^{NP} ECOST_{jp}}{\sum_{j=1}^{NP} EENS_{jp}}, \qquad (\$/kWh) \qquad (4.5)$$

where:

$ECOST_{jp}$ = the interruption cost at load point p due to outage event j,

$EENS_{jp}$ = the $EENS$ at load point p due to outage event j,

$ECOST_{jp}$ and $EENS_{jp}$ can be obtained using Equations 4.1 and 4.2.

$$ECOST_k = \sum_{p=1}^{NK} ECOST_p, \qquad (\$/yr) \qquad (4.6)$$

$$EENS_k = \sum_{p=1}^{NK} EENS_p, \qquad (kWh/yr) \qquad (4.7)$$

$$IEAR_k = \frac{\sum_{p=1}^{NK} ECOST_p}{\sum_{p=1}^{NK} EENS_p}, \qquad (\$/kWh) \qquad (4.8)$$

$$\text{Aggregate system } IEAR = \sum_{k=1}^{NB} q_k \times IEAR_k \text{ ,} \quad (\text{\$/kWh}) \qquad (4.9)$$

where:

q_k = fraction of the system load utilized by the customers at bus k,

NP = the total number of load loss events at load point p,

NK = the total number of load points at bus k,

NB = the total number of load buses in the system.

4.3 Application to the RBTS Distribution Systems

As previously noted, the distribution circuits for the RBTS are shown in Appendix C. The base system results were obtained by assuming that there are disconnects on the main feeders, the fuses in the lateral branches are 100 % reliable, the alternate back feeders have no restrictions on load transfer and failed low voltage transformers are replaced with a spare instead of being repaired. Sets of IEAR values can be obtained for every load point in the system. These values can be aggregated to produce a single IEAR representing the distribution customers connected to the major load bus. Table 4.1 shows the basic reliability indices (λ, U), the expected interruption cost, the expected unserved energy and the IEAR for every customer load point connected to Bus 2. Similar indices for Buses 3, 4, 5 and 6 are shown in Appendix D. The overall values for each major load point are shown in Table 4.2.

Table 4.1 Load point reliability and cost indices (Bus 2) for the RBTS

Load Point	λ (1/yr)	U (hr/yr)	Cost (\$/yr)	EENS (kWh/yr)	IEAR (\$/kWh)
1	0.2993	0.6312	3719.05	2747.44	1.3536
2	0.3123	0.6962	4163.44	3062.82	1.3593
3	0.3123	0.6962	4163.44	3062.82	1.3593
4	0.2993	0.6312	6518.07	2947.9	2.2111
5	0.3123	0.6962	7091.44	3286.29	2.1579
6	0.3090	0.6800	25060.59	2514.74	9.9655
To be continued					

Table 4.1 continued					
7	0.3123	0.6962	25631.14	2581.18	9.9300
8	0.1998	0.4487	43432.99	5205.57	8.3436
9	0.1998	0.4487	49948.74	5986.50	8.3436
10	0.3025	0.6345	3726.31	2763.21	1.3485
11	0.3123	0.6832	4059.61	2999.75	1.3533
12	0.3155	0.6995	3508.82	2590.03	1.3547
13	0.3123	0.6832	6973.42	3218.61	2.1666
14	0.3155	0.6995	7116.76	3303.21	2.1545
15	0.3025	0.6345	23462.62	2328.69	10.0755
16	0.3123	0.6832	25174.28	2528.02	9.9581
17	0.3025	0.6345	3134.96	2324.70	1.3485
18	0.3025	0.6345	3134.96	2324.70	1.3485
19	0.3155	0.6995	3508.82	2590.03	1.3547
20	0.3155	0.6995	7116.76	3303.21	2.1545
21	0.3123	0.6832	6973.42	3218.61	2.1666
22	0.3155	0.6995	25744.83	2594.47	9.9230
TOTAL:	6.5925	14.3932	293364.50	67482.49	4.3473

Table 4.2 Aggregate IEAR values for each major load point

IEAR ($/kWh)					
Bus 2	Bus 3	Bus 4	Bus 5	Bus 6	Aggregate
4.3473	2.9013	5.4214	4.7151	1.3736	3.6335

4.3.1 Impact of Transmission Line Repair Times

The repair times of all the 11 kV transmission lines were varied from 0.85 to 1.15 times the basic line values. Table 4.3 shows the changes in the major bus IEAR and in the aggregate system value with the 11 kV transmission line repair time. The data in Table 4.3 are shown graphically in Figure 4.1.

It can be seen that changing the 11 kV transmission repair times has relatively little effect on the major bus IEAR.

Table 4.3 Change in the IEAR with the transmission line repair time

Repair time (% Base repair time)	IEAR ($/kWh)					
	Bus 2	Bus 3	Bus 4	Bus 5	Bus 6	Aggregate
85	4.2754	2.9312	5.4011	4.6844	1.3241	3.6263
90	4.2975	2.9201	5.4062	4.6927	1.3404	3.6274
95	4.3215	2.9101	5.4130	4.7030	1.3570	3.6298
100	4.3473	2.9013	5.4214	4.7151	1.3736	3.6335
105	4.3745	2.8935	5.4312	4.7288	1.3904	3.6382
110	4.4032	2.8867	5.4423	4.7442	1.4072	3.6441
115	4.4331	2.8807	5.4545	4.7611	1.4239	3.6508

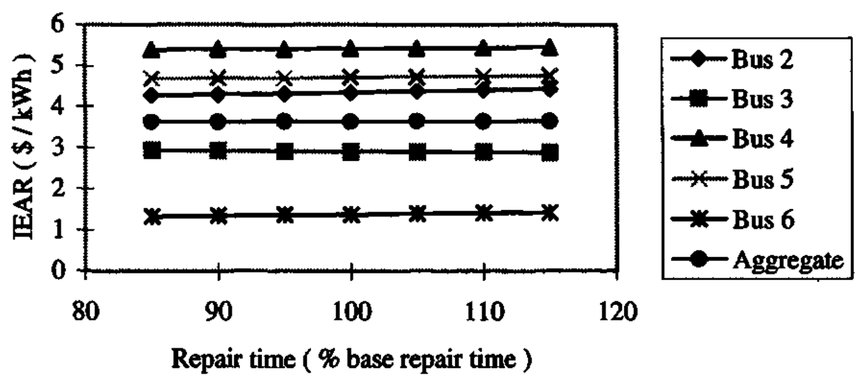


Figure 4.1 Change in the IEAR with transmission line repair time

It can be seen that Bus 4 has the highest IEAR and Bus 6 has the lowest. This is due to the fact that Bus 4 has a significant amount of commercial and office building load while Bus 6 is largely residential and farm customers.

4.3.2 Impact of Station Bus Repair Times

Figure 4.2 shows the change in the IEAR with repair time of the 11 kV station bus. The numerical data for Figure 4.2 are given in Appendix D. It can be seen from Figure 4.2 that the IEAR do not vary significantly due to the change in the station bus repair times.

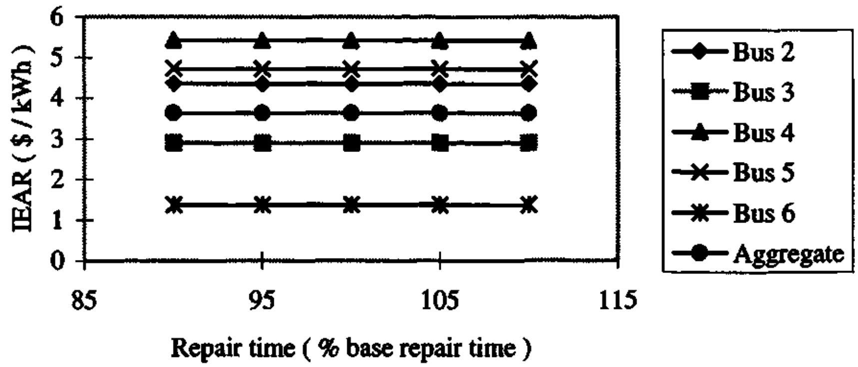


Figure 4.2 Change in the IEAR with station bus repair times

4.3.3 Impact of Transformer Replacement Times

As previously noted, a failed transformer is replaced by a spare rather than being repaired, Figure 4.3 shows the variation in IEAR with the replacement time of the 11/0.415 kV transformers. As in the previous cases, the IEAR do not vary significantly when the replacement time of the 11/0.415 kV transformers vary.

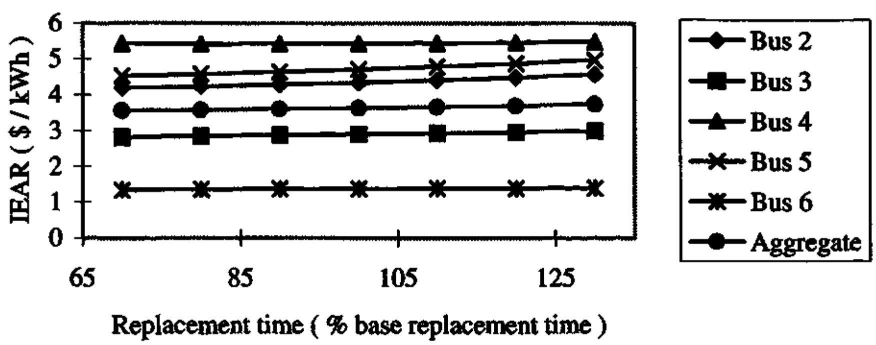


Figure 4.3 Change in the IEAR with the transformer replacement times

4.3.4 Impact of Breaker Active Failure Rate

Figure 4.4 shows the variation in the IEAR due to changes in the active failure rate of the 11 kV breakers. The IEAR indices again change very little from those of the base case.

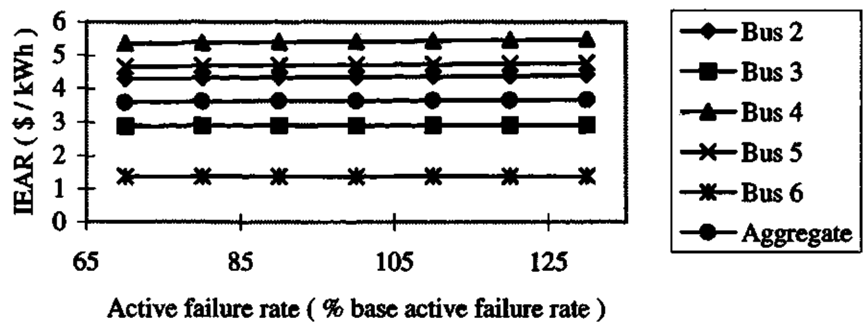


Figure 4.4 Change in the IEAR with breaker active failure rate

4.3.5 Impact of Fuse Failure

The previous analyses assume that the fuses on each lateral branch are 100 % reliable; that is, whenever a failure occurs on the lateral branch, the fuse will operate perfectly without leading to the isolation of any other lateral branches. This is not always the case in a practical distribution system. Fuses fail to operate occasionally and the back - up protection , which is the circuit breaker on the main feeder in the RBTS is called upon to operate. All the load points served by the circuit breaker will be affected under this condition. The contribution to the failure rate of the load points (*p*) tapped from the same feeder other than the one (*j*) connected to the failed lateral branch can be evaluated using the following equation:

$$\lambda_p = \lambda_j \times (1 - P_j), \qquad (p \neq j)$$

where:

λ_p = failure rate at load point p resulting from unsuccessful fuse operating at load point j on the same feeder,

λ_j = sum of failure rates of all the components after the fuse on the lateral through which load point j are connected to the system,

P_j = successful fuse operating probability on the lateral through which load point j is connected to the system.

Figure 4.5 shows the variation in the IEAR with changes in the successful operating probability of the 11 kV fuses. It can be seen that the IEAR index at each bus increase significantly when the successful fuse operating probability changes from 1.0 to 0.99. This is due to the fact that when fuse failures are considered, the increase in ECOST due to the short load interruption times (average 1 hour) is much greater than the corresponding increase in EENS.

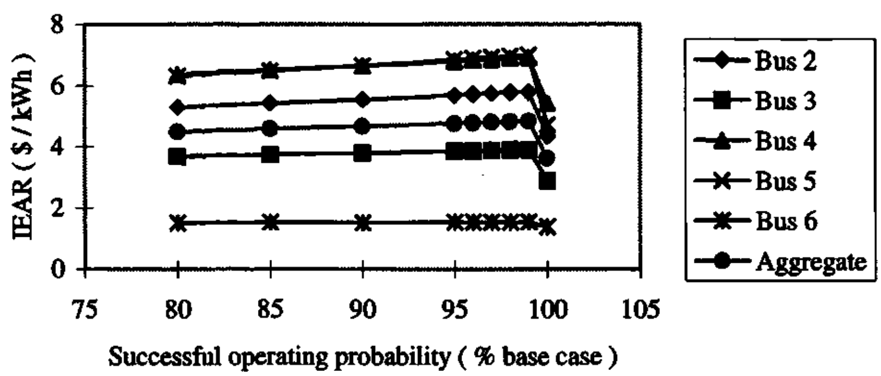


Figure 4.5 Change in the IEAR with successful fuse operating probability

4.3.6 Impact of Restricted Load Transfer

It was assumed in the base case study that there are no restrictions in transferring an isolated load to another feeder of the distribution system through a normally open point. This is not always feasible in a practical system as both the feeder to which the load is being transferred and the supply point feeding the feeder may have capacity limitations. In these cases, the outage time of the isolated load point p should be modified as follows:

$$\gamma_p = \gamma_{js} \times P_p + \gamma_{jr} \times (1 - P_p),$$

where:

γ_p = outage time of isolated load point p for failure event j,

γ_{js} = isolated time for failure event j,

γ_{jr} = repaired time for failure event j,

P_p = probability of being able to transfer load.

Figure 4.6 shows the variation in the IEAR with changes in the load transfer probability. These variations result in relatively little change in the IEAR.

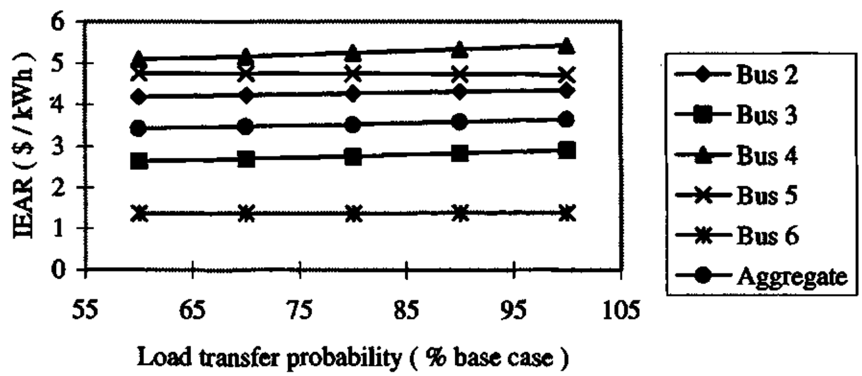


Figure 4.6 Change in the IEAR with the load transfer probability

4.3.7 Impact of Different CCDF Representations

Subsection 3.4.7 illustrated three extrapolation processes for estimating the CCDF for durations exceeding 8 hours. These three processes have been used to examine the system aggregate IEAR value for the distribution functional zone. Table 4.4

shows the IEAR for the three different processes. As expected, Method 1 results in the highest IEAR.

Table 4.4 Change in the bus and system aggregate IEAR with the different calculation processes

Method	IEAR ($/kWh)					
	Bus 2	Bus 3	Bus 4	Bus 5	Bus 6	Aggregate
Method 1	4.3473	2.9013	5.4214	4.7151	1.3736	3.6335
Method 2	4.2826	2.8863	5.3893	4.6500	1.3695	3.6052
Method 3	4.0610	2.8058	5.2589	4.3431	1.3521	3.4809

where:

Method 1: Linear extrapolation on a logarithmic scale.

Method 2: Linear extrapolation.

Method 3: Limited value.

In this case, the bulk of the load point interruption are of relatively short duration and therefore the extrapolation process for outage durations larger than 8 hours has little effect.

4.4 Summary

This chapter illustrates the utilization of a contingency enumeration technique and appropriate sector customer damage functions to evaluate the IEAR at individual customer load points, at each bus and for the overall distribution system.

The studies show that the calculated system aggregate IEAR is not very sensitive to variations in the system facility data in most cases and is very dependent on the sector customer damage functions for the service area. The studies show that when the transmission line repair time was varied from 0.85 to 1.15 times those in the system base case, the system IEAR varied from 3.6263 $/kWh to 3.6508 $/kWh. When the station bus repair time was varied from 0.90 to 1.10 times those of the base case, the system IEAR varied from 3.6336 \$/kWh to 3.6333 \$/kWh. The transformer replacement time was also varied from 0.70 to 1.30 times those of base case. In these cases, the IEAR varied from 3.5578 \$/kWh to 3.7389 \$/kWh. When the breaker active failure rates were varied from 0.7 to 1.3 times those of the base case, the system aggregate IEAR varies from 3.6023 \$/kWh to 3.6646 \$/kWh. The system IEAR decreases significantly when the fuse successful operating probability goes from 0.99 to 1.0. This is because when the fuse is 100 % reliable, the decrease in the interruption cost is much more than the decrease in the expected energy not supplied. The system IEAR varies from 3.4304 \$/kWh to 3.6335 \$/kWh when the load transfer probability varies from 0.6 to 1.0 times those of the base case. The different CCDF representations for interruption durations more than 8 hours produced slightly different system IEAR values. The IEAR are 3.6335 \$/kWh using linear extrapolation on a logarithmic scale, 3.6025 \$/kWh using linear extrapolation and 3.4809 \$/kWh using a limiting value.

A relatively stable IEAR greatly simplifies the reliability cost / worth process in the distribution functional zone as it is a basic factor in system optimization planning.

CHAPTER 5

SUMMARY AND CONCLUSIONS

5.1 Summary

This thesis presents an evaluation of a series of IEAR and describes associated sensitivity studies conducted at HLI, HLII and in the distribution functional zone. The extension of quantitative reliability evaluation to reliability worth assessment at the two hierarchical levels and the distribution functional zone is illustrated in this thesis. Two test systems were used to illustrate the various analyses. The RBTS is a relatively small educational development system and the IEEE - RTS is a large practical system.

The increasing interest in economic optimization in power system planning and expansion dictates the need for practical tools for adequacy worth evaluation. Assessing the customer interruption costs due to supply failure is considered to be a practical alternative to establishing the worth of service reliability. The Interrupted Energy Assessment Rate (IEAR) is an important parameter in reliability cost / worth evaluation and can be used in a wide range of practical system studies [25, 26, 32, 33, 38].

Chapter 2 of this thesis is focused on the evaluation of the IEAR and describes a range of sensitivity studies conducted at HLI. The assessment of an IEAR at HLI involves the utilization of the F&D technique in association with a composite customer damage function. Selected major factors such as the system peak load, the unit failure rates and repair rates for fixed unit forced outage rates, the unit FOR and the shape of the load model were considered in the IEAR sensitivity studies. Chapter 2 shows that the

IEAR for the RBT and the IEEE - RTS do not depend significantly on the above factors. The utilization of economic theory concepts to estimate the optimum planning reserve margin at HLI is also illustrated in this chapter.

The sensitivity studies described in Chapter 2 show that when the peak load is varied from 165 MW to 205 MW in the RBTS and from 2650 MW to 3050 MW in the RTS, the IEAR varies from 5.1946 \$/kWh to 5.5657 \$/kWh and from 5.2478 \$/kWh to 5.3036 \$/kWh respectively. When the unit failure and repair rates are varied from 0.5 to 4.0 times those of base case for both test systems, with the generating forced outage rate unchanged, the IEAR varies from 4.8986 \$/kWh to 5.8096 \$/kWh for the RBTS and from 4.9451 \$/kWh to 5.6267 \$/kWh for the RTS. The unit forced outage rates were also varied from 0.25 to 1.5 times those of the base case for the two systems. In these cases, the IEAR varied from 5.4597 \$/kWh to 5.9292 \$/kWh and from 5.1409 \$/kWh to 5.5883 \$/kWh respectively. The IEAR also varied from 5.5084 \$/kWh to 5.5813 \$/kWh for the RBTS and from 5.2607 \$/kWh to 5.3117 \$/kWh for the RTS using a series of different load curves.

A relatively stable IEAR greatly simplifies the reliability cost / worth process at HLI, as it is a basic factor in system optimization. The HLI reliability cost / worth process is illustrated in this chapter by application to the RBTS and the RTS. It is shown in Section 2.5, that both the RBTS and the RTS can be considered to have optimal reserve margins in the base case analysis. The two systems respond quite differently in regard to optimum reserve requirements, however, when some of the basic parameters are changed. This is illustrated by the studies presented in Chapter 2.

Chapter 3 presents the evaluation of an IEAR and conducts a range of sensitivity studies at HLII. The basic assessment of reliability worth at HLII involves the utilization of a contingency enumeration technique in association with appropriate composite system customer damage functions. The sensitivity studies described in Chapter 3 focus on examining the variation in the system aggregate IEAR as a function of the generating unit forced outage rates, the installed generating unit capacity, transmission line unavailabilities, transmission line capacities, different load models, different IEAR calculation processes and different CCDF representations. Estimation of the optimum reserve margin at HLII is also illustrated in the chapter.

The studies show that the calculated system aggregate IEAR for the RBTS is not very sensitive to variations in the system facility data in most cases and is very dependent on the composite customer damage functions for the service area. The studies show that when the unit forced outage rates were varied from 0.25 to 1.15 times those of the system base case, the system aggregate IEAR varied from 4.2629 $/kWh to 4.5232 $/kWh with the unit failure rates unchanged, and from 4.4129 $/kWh to 4.3865 $/kWh with the unit repair rates unchanged. The location in the RBTS of new capacity injection is an important factor in the system aggregate IEAR evaluation. The IEAR decreases rapidly with new capacity injections at Bus 1 but has almost no change when the new units are added at Bus 6. When the transmission line unavailability is varied from 0.85 to 1.15 times those of the system base case, the system aggregate IEAR varied from 4.3703 $/kWh to 4.4276 $/kWh with the transmission line failure rates unchanged, and from 4.4173 $/kWh to 4.3841 $/kWh with the transmission line repair rates unchanged. The transmission line capacities were also varied from 0.85 to 1.15 times those of system base case. Under these conditions, the IEAR varied from 4.3322 $/kWh to 4.4195 $/kWh. The system aggregate IEAR varies from 4.4008 $/kWh to 3.856 $/kWh when the peak load varies from 185 MW to 129.5 MW. The system aggregate IEAR decreases rapidly when the peak load drops below 80 % of the base value due to the high reserve margin. The system aggregate IEAR are 3.6693 $/kWh and 3.9572 $/kWh for the two different calculation processes described in Section 3.4.6. Method 1 which results in the 3.6693 $/kWh is considered to be a more representative process. Section 3.4.7 clearly shows the effect on the system aggregate IEAR of different CCDF representations when the interruption duration is more than 8 hours. The IEAR is 4.6117 $/kWh using linear extrapolation on a logarithmic scale, 3.8844 $/kWh using linear extrapolation and

1.9917 kWh using a limiting value. This is clearly an area where further survey work and research is needed.

Chapter 4 presents the evaluation of aggregate IEAR and a range of associated sensitivity studies in the distribution functional zone. The impact of factors such as transmission line repair times, station bus repair times, transformer replacement times, breaker active failure rates, fuse operating probabilities, load transfer restrictions and different IEAR calculation processes were considered. Decisions on preferred load curtailment strategies can be based on the individual customer load point IEAR and the aggregate customer IEAR at each bulk system load bus. The determination of IEAR in the distribution functional zone utilizes a contingency enumeration technique in association with appropriate sector customer damage functions. The approach incorporates the effects on each customer load point of outages of substation components, subtransmission and distribution elements.

The studies described in Chapter 4 show that the calculated system aggregate IEAR is not very sensitive to variations in the system facility data in most cases and is very dependent on the sector customer damage functions for the service area. The studies show that when the transmission line repair time was varied from 0.85 to 1.15 times those in the system base case, the system IEAR varied from 3.6263 $/kWh to 3.6508 $/kWh. When the station bus repair time was varied from 0.90 to 1.10 times those of the base case, the system IEAR varied from 3.6336 $/kWh to 3.6333 $/kWh. The transformer replacement time was also varied from 0.70 to 1.30 times those of the base case. Under these conditions, the IEAR varied from 3.5578 $/kWh to 3.7389 $/kWh. When the breaker active failure rates were varied from 0.7 to 1.3 times those of the base case, the system aggregate IEAR varied from 3.6023 $/kWh to 3.6646 $/kWh. The system IEAR decreases significantly when the fuse operating probability is varied from 0.99 to 1.0. This is because when the fuse is 100 % reliable, the decrease in the interruption cost is much more than the decrease in the expected energy not supplied. The system IEAR varies from 3.4304 $/kWh to 3.6335 $/kWh when the load transfer probability varies from 0.6 to 1.0 times those of the base case. The different CCDF representations for interruption durations more than 8 hours produced slightly different system IEAR values. The IEAR are 3.6335 $/kWh using linear extrapolation on a logarithmic scale, 3.6025 $/kWh using linear extrapolation and 3.4809 $/kWh using a limiting value.

5.2 Conclusion

The studies described in this thesis show that the various IEAR remain relatively unchanged and generally do not vary significantly with various operating conditions as long as the system topology, and customer damage functions remain unchanged. The studies show that the IEAR can be assumed to be relatively constant for a given system and used in a wide range of reliability cost / worth studies. The expected customer interruption costs or reliability worth can be assumed to increase in direct proportion to the system unsupplied energy EENS. This considerably simplifies the evaluation of reliability cost / worth in studies of system growth and expansion.

As noted in this thesis, the relevant customer damage functions play an important role in the determination of appropriate IEAR. The customer damage functions are usually determined from surveys conducted in the system under study. These surveys should be conducted on a regular basis in order to provide relevant and up to date information on customer interruption costs.

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APPENDIX A

ROY BILLINTON TEST SYSTEM (RBTS)

The RBTS is an educational test system developed by the Power System Research Group at the University of Saskatchewan. The generating system is made up of 11 units with a total installed capacity of 240 MW. This generation model is shown in Table A.1. The transmission network consists of 6 buses and 9 transmission lines. The transmission voltage level is 230 kV. The locations of the generating units are shown in Table A.2. Bus load data at the time of system peak in MW and in percentage of the total system load are shown in Table A.3. Table A.4 shows the basic transmission line reliability data. The single line diagram of the test system is shown in Figure A.1.

The load model is assumed to be the same as that of the IEEE - RTS given in Table B.2, B.3 and B.4. The suggested peak load is 185 MW and the period of study is 8736 hours.

Table A.1 RBTS Generation Data

Unit size (MW)	Type	No. of unit	Forced outage rate	MTTF (hrs)	Failure rate per year	MTTR (hrs)	Repair rate per year	Scheduled maintenance (wks/yr)
5	hydro	2	0.010	4380	2.0	45	198.0	2
10	thermal	1	0.020	2190	4.0	45	196.0	2
20	hydro	4	0.015	3650	2.4	55	157.6	2
20	thermal	1	0.025	1752	5.0	45	195.0	2
40	hydro	1	0.020	2920	3.0	60	147.0	2
40	thermal	2	0.030	1460	6.0	45	194.0	2

Table A.2 Generating unit locations

Unit No.	Bus	Rating	Type
1	1	40	thermal
2	1	40	thermal
3	1	10	thermal
4	1	20	thermal
5	2	5	hydro
6	2	5	hydro
7	2	40	hydro
8	2	20	hydro
9	2	20	hydro
10	2	20	hydro
11	2	20	hydro

Table A.3 Bus load data

Bus	Load (MW)	Bus load in % system load
2	20.0	10.81
3	85.0	45.95
4	40.0	21.62
5	20.0	45.95
6	20.0	10.81
Total	185.0	100.00

Table A.4 Transmission line length and outage data

Line	From Bus	To Bus	Length (km)	Permanent outage rate per year	Outage duration (hours)	Transient outage rate per year
1	1	3	75	1.5	10.0	3.75
2	2	4	250	5.0	10.0	12.50
3	1	2	200	4.0	10.0	10.00
4	3	4	50	1.0	10.0	2.50
5	3	5	50	1.0	10.0	2.50
6	1	3	75	1.5	10.0	3.75
7	2	4	250	5.0	10.0	12.50
8	4	5	50	1.0	10.0	2.50
9	5	6	50	1.0	10.0	2.50

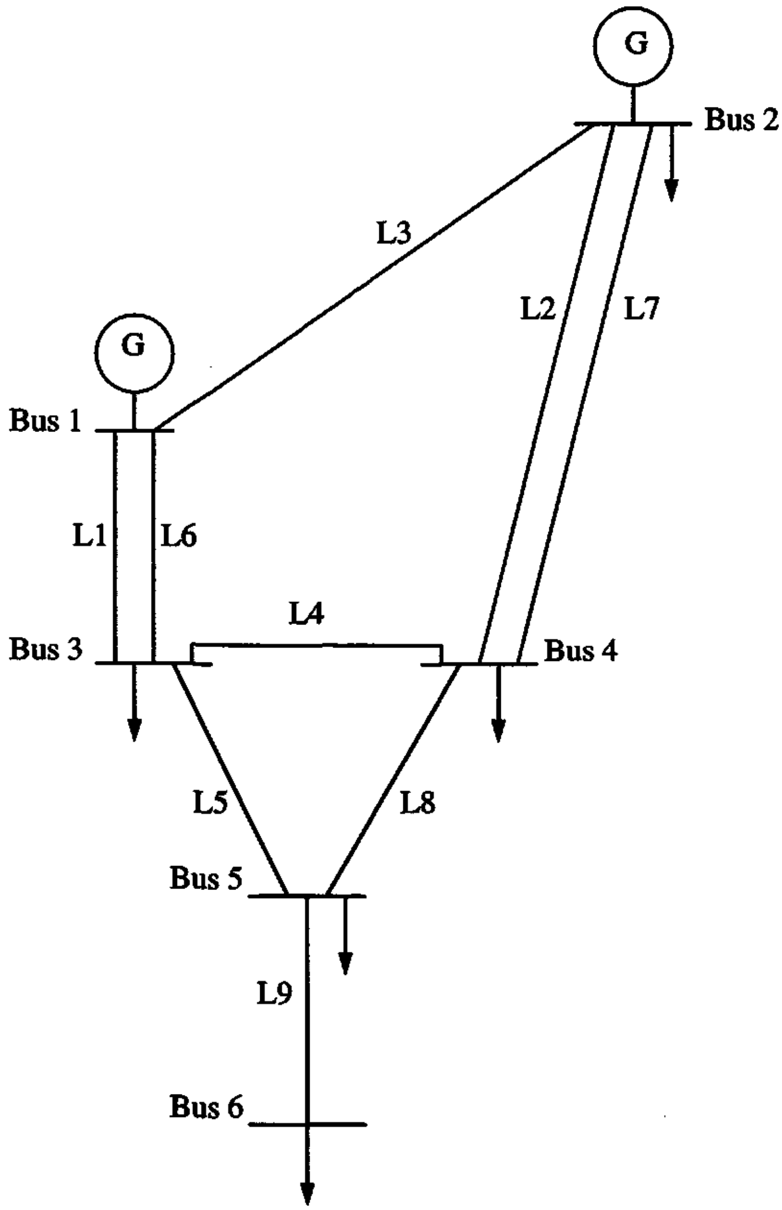

Figure A.1 Single line diagram of the RBTS

APPENDIX B

IEEE RELIABILITY TEST SYSTEM (IEEE - RTS)

Generation System: The IEEE - RTS consists of 32 generating units of various types and sizes. The total installed capacity is 3405 MW. The system capacity composition is given in Table B.1.

Table B.1 IEEE - RTS Generation System Data

Unit size (MW)	No. of Units	Forced Outage Rate	MTTF (hrs)	MTTR (hrs)	Scheduled Maintenance (wks/yr)
12	5	0.02	2940	60	2
20	4	0.10	450	50	2
50	6	0.01	1980	20	2
76	4	0.02	1960	40	3
100	3	0.04	1200	50	3
155	4	0.04	960	40	4
197	3	0.05	950	50	4
350	1	0.08	1150	100	5
400	2	0.12	1100	150	6

The load model is given in Tables B.2, B.3 and B.4. The suggested peak load is 2850 MW and the period of study is 8736 hours.

Table B.2 shows data on weekly peak loads in percent of the annual peak load. The annual peak occurs in week 51.

Table B.2 IEEE - RTS Load Data --- weekly peak load in percent of the annual peak load

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

Table B.3 gives a daily peak loads, in percent of the weekly peak. The weekly peak occurs on Tuesday.

Table B.3 IEEE - RTS Load Data --- Daily peak load
in percent of the weekly peak load

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

Table B.4 gives the weekday and weekend hourly load models for each of the three seasons. A suggested interval in weeks is given for each season. Combination of Table B.2, Table B.3 and Table B.4 with the annual peak load defines the hourly model of 8736 hours.

Table B.4 IEEE - RTS Load Data --- Hourly peak load
in percent of the daily peak load

	Winter Weeks 1 - 8 & 44 - 52		Summer Weeks 18 - 30		Spring / Fall Weeks 9 - 17 & 31 - 43	
Hour	Wkdy	Wknd	Wkdy	Wknd	Wkdy	Wknd
0 - 1	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 - 12	95	91	100	93	99	94
To be continued						

Table B.4 continued						
12 - 13	95	90	99	93	93	91
13 - 14	95	88	100	92	92	90
14 - 15	93	87	100	91	90	90
15 - 16	94	87	97	91	88	86
16 - 17	99	91	96	92	90	85
17 - 18	100	100	96	94	92	88
18 - 19	100	99	93	95	96	92
19 - 20	96	97	92	95	98	100
20 - 21	91	94	92	100	96	97
21 - 22	83	92	93	93	90	95
22 - 23	73	87	87	88	80	90
23 - 24	63	81	72	80	70	85

APPENDIX C

DISTRIBUTION NETWORKS OF THE RBTS

The RBTS is a 6 bus test system with five load buses (bus 2 - bus 6) which has four voltage levels, 230 kV, 138 kV, 33 kV and 11 kV. Bus 2 has generation associated with it and the others (bus 3 - bus 6) do not. Table C.1 shows the customer and loading data of the networks.

Table C.1 Customer and loading data of the networks

No. of load points	Load points	Customer type	Peak load level per load point, Mw
Bus 2			
5	1 - 3, 10, 11	residential	0.8668
4	12, 17 - 19	residential	0.7291
1	8	small user	1.6279
1	9	small user	1.8721
6	4, 5, 13, 14, 20, 21	govt. & inst.	0.9167
5	6, 7, 15, 16, 22	comm.	0.7500
Total			20.00
Bus 3			
15	1, 4 - 7, 20, 24, 32, 36	residential	0.8367
5	11, 12, 13, 18, 25	residential	0.8500
4	2, 15, 26, 30	residential	0.7750
3	39, 40, 44	large users	6.9167
3	41 - 43	large users	11.5833
3	8, 9, 10	small users	1.0167
9	3, 16, 17, 19, 28, 29, 31, 37, 38	comm.	0.5222
To be continued			

Table C.1 Continued			
2	14, 27	office & bldg.	0.9250
Total			85.00
<u>Bus 4</u>			
15	1 - 4, 11 - 13, 18 - 21, 32 - 35	residential	0.8869
7	5, 14, 15, 22, 23, 36, 37	residential	0.8137
7	8, 10, 26 - 30	small user	1.6300
2	9, 31	small user	2.4450
7	6, 7, 16, 17, 24, 25, 38	comm.	0.6714
Total			40.00
<u>Bus 5</u>			
4	1, 2, 20, 21	residential	0.7625
4	4, 6, 15, 25	residential	0.7450
5	26, 9 - 11, 13	residential	0.5740
5	3, 5, 8, 17, 23	govt. & inst.	1.1100
5	7, 14, 18, 22, 24	comm.	0.7400
3	12, 16, 19	office & bldg.	0.6167
Total			20.00
<u>Bus 6</u>			
3	1, 3, 9	residential	0.3171
4	2, 4, 11, 19	residential	0.3229
2	5, 6	residential	0.3864
5	7, 8, 10, 18, 23	residential	0.2964
3	12, 13, 22	residential	0.3698
4	25, 28, 31, 36	residential	0.2776
4	27, 29, 33, 39	residential	0.2831
2	14, 17	comm.	0.8500
1	15	small	1.9670
1	16	small	1.0830
2	32, 37	farm	0.5025
3	20, 30, 34	farm	0.6517
2	21, 35	farm	0.6860
2	24, 40	farm	0.7965
2	26, 38	farm	0.7375
Total			20.00

The lengths of the main feeder sections and the lateral branch sections are presented in Table C.2.

Table C.2 Feeder types and lengths

Feeder type	Length km	Feeder section numbers
Bus 2		
1	0.60	2 6 10 14 17 21 25 28 30 34
2	0.75	1 4 7 9 12 16 19 22 24 27 29 32 35
3	0.80	3 5 8 11 13 15 18 20 23 26 31 33 36
Bus 3		
1	0.60	1 2 3 7 11 12 15 21 22 29 30 31 36 40 42 43 48 49 50 56 58 61 64 67 70 72 76
2	0.80	4 8 9 13 16 19 20 25 26 32 35 37 41 46 47 51 53 57 60 62 65 68 71 75 77
3	0.90	5 6 10 14 17 18 23 24 27 28 33 34 38 39 44 45 52 54 55 59 63 66 69 73 74
Bus 4		
1	0.60	2 6 10 14 17 21 25 28 30 34 38 41 43 46 49 51 55 58 61 64 67
2	0.75	1 4 7 9 12 16 19 22 24 27 29 32 35 37 40 42 45 48 50 53 56 60 63 65
3	0.80	3 5 8 11 13 15 18 20 23 26 31 33 36 39 44 47 52 54 57 59 62 66
Bus 5		
1	0.50	1 6 9 13 14 18 21 25 27 31 35 36 39 42
2	0.65	4 7 8 12 15 16 19 22 26 28 30 33 37 40
3	0.80	2 3 5 10 11 17 20 23 24 29 32 34 38 41 43
Bus 6		
1	0.60	2 3 8 9 12 13 17 19 20 24 25 28 31 34 41 47
2	0.75	1 5 6 7 10 14 15 22 23 26 27 30 33 43 61
3	0.80	4 11 16 18 21 29 32 35 55
4	0.90	38 44
5	1.60	37 39 42 49 54 62
6	2.50	36 40 52 57 60
7	2.80	35 46 50 56 59 64
8	3.20	45 51 53 58 63
9	3.50	48

Table C.3 shows the reliability data for the 33 kV and 11 kV system components. This includes sufficient data to perform the basic analyses included in this thesis. The disconnects are assumed to be 100 % reliable.

Table C.3 Reliability data for the 33 kV and 11 kV systems

Component	λ_P	λ_A	γ	γ_P	γ_C	s
transformers						
138/33	0.0100	0.0100		15	0.083	1.0
33/11	0.0150	0.0150		15	0.083	1.0
11/0.415	0.0150	0.0150	200	10		1.0
breakers						
138	0.0058	0.0035	8		0.083	1.0
33	0.0020	0.0015	4		0.083	1.0
11	0.0060	0.0040	4		0.083	1.0
busbars						
33	0.0010	0.0010	2		0.083	1.0
11	0.0010	0.0010	2		0.083	1.0
* lines						
33	0.0460	0.046	8		0.083	2.0
11	0.0650	0.065	5			1.0

* Single weather state

where:

λ_P = permanent (total) failure rate (f/yr) [for lines (f/yr.km)],

λ_A = active failure rate (f/yr) [for lines (f/yr.km)],

γ = repair time (hr),

γ_P = replacement time by a spare (hr),

γ_C = reclosure time (hr),

s = switching time (hr),

The single line diagrams are shown in Figure C.1 to Figure C.5 for bus 2 to bus 6 respectively.

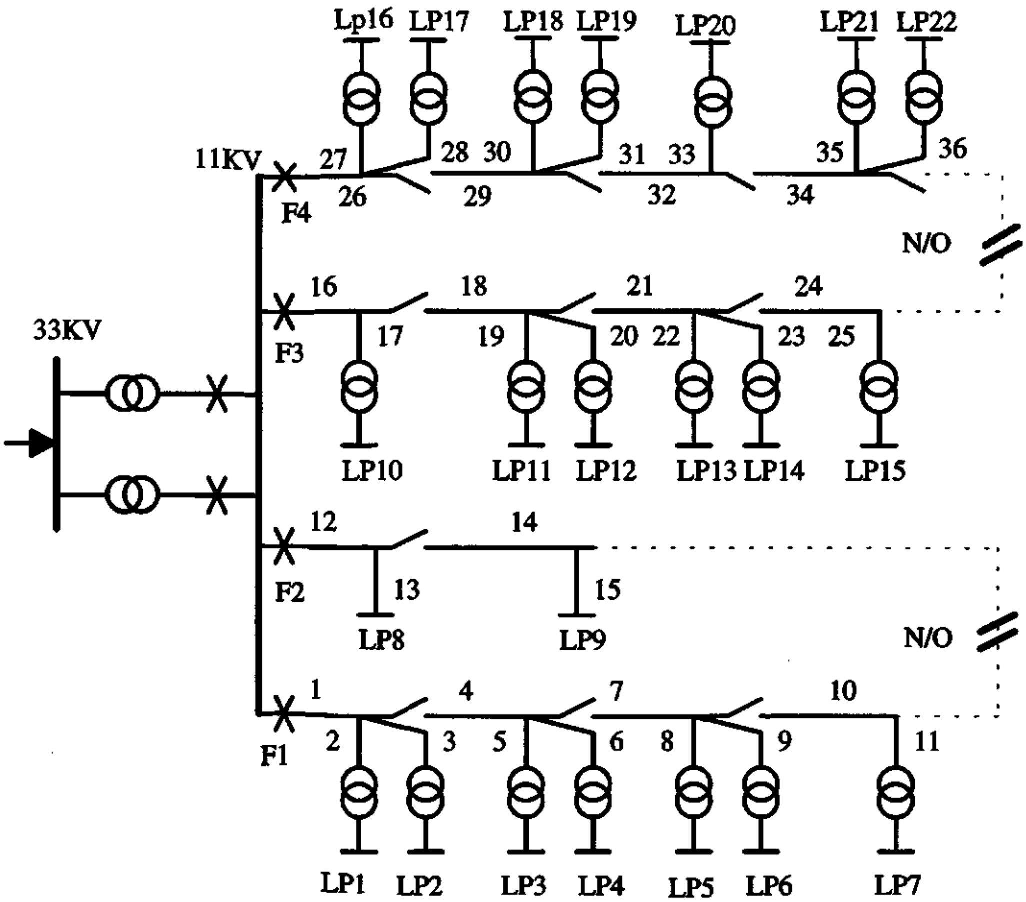

Figure C.1 Distribution network at Bus 2

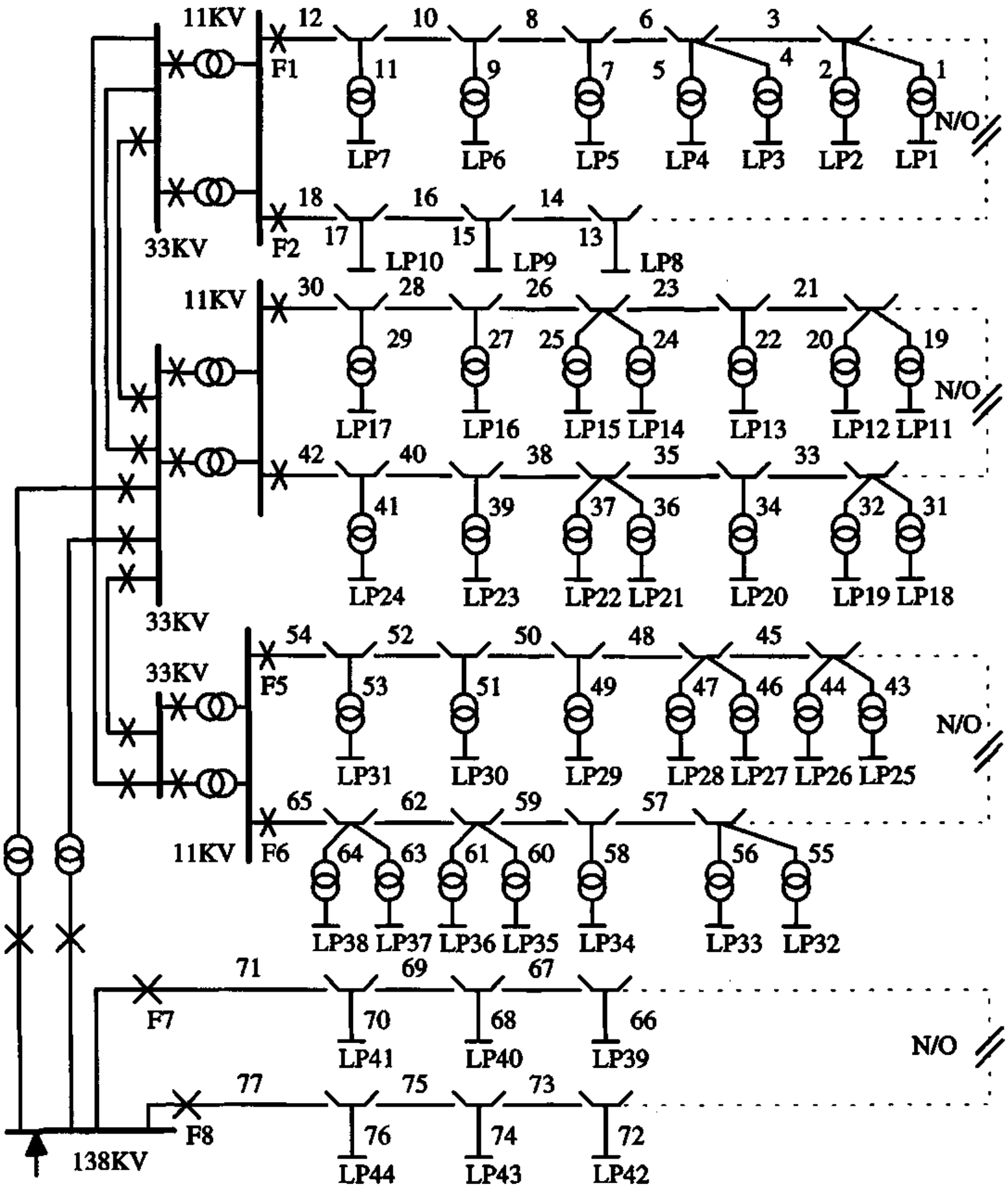

Figure C.2 Distribution network at Bus 3

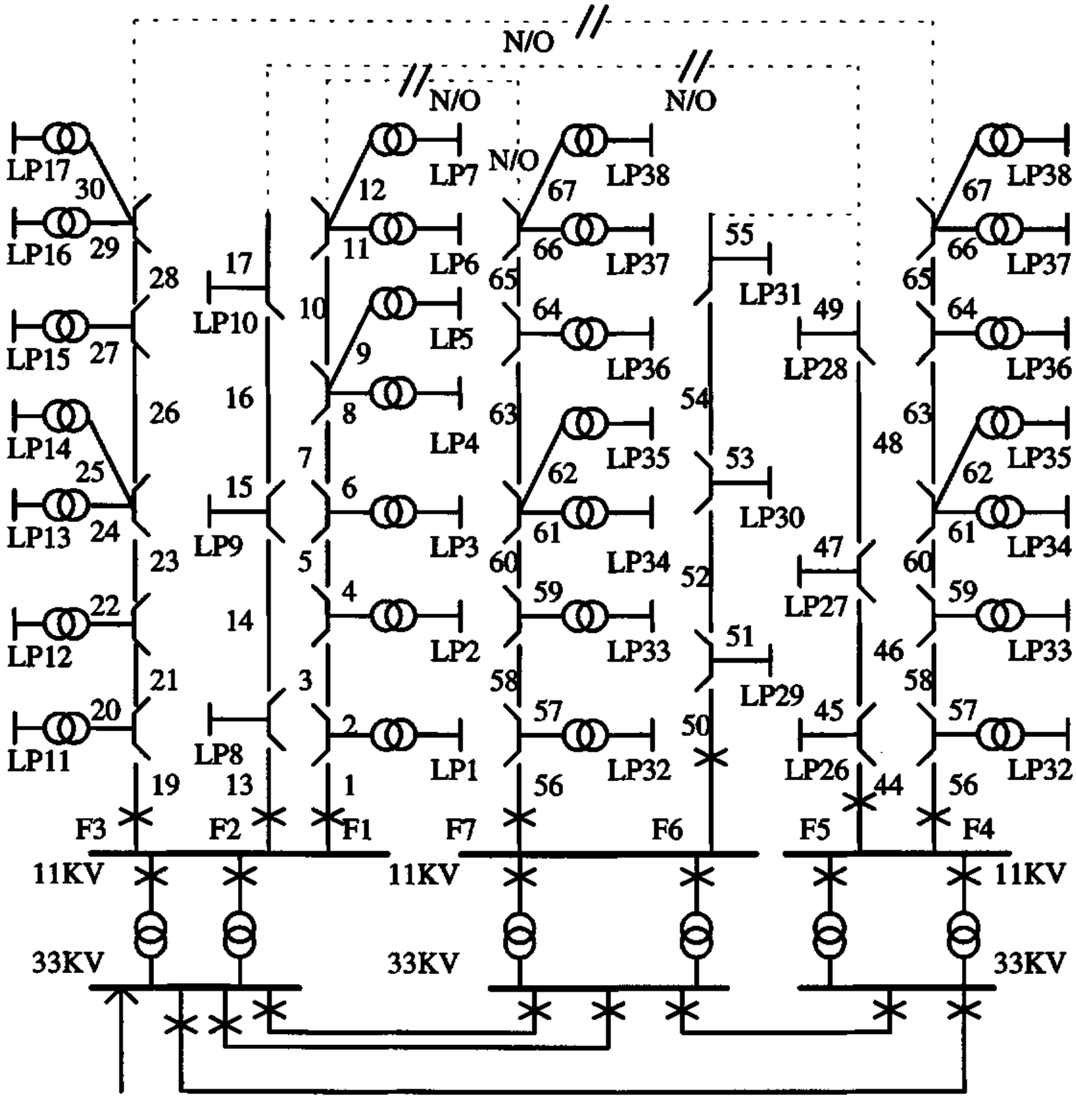

Figure C.3 Distribution network at Bus 4

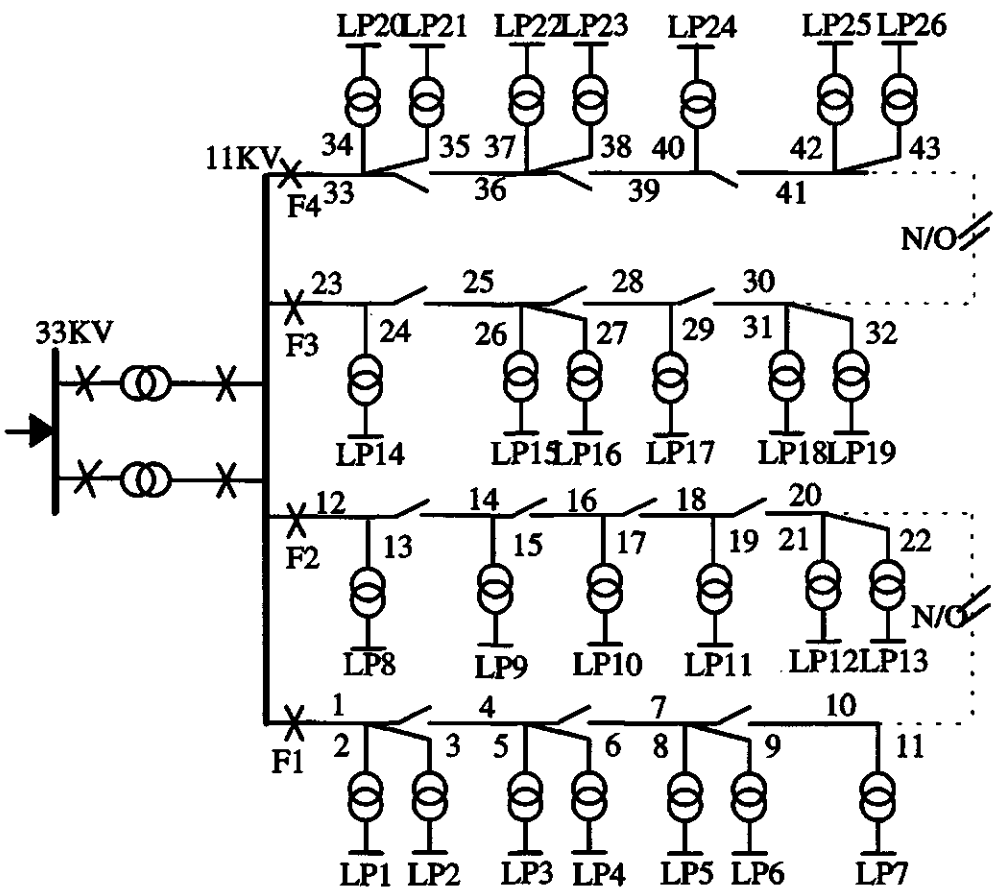

Figure C.4 Distribution network at Bus 5

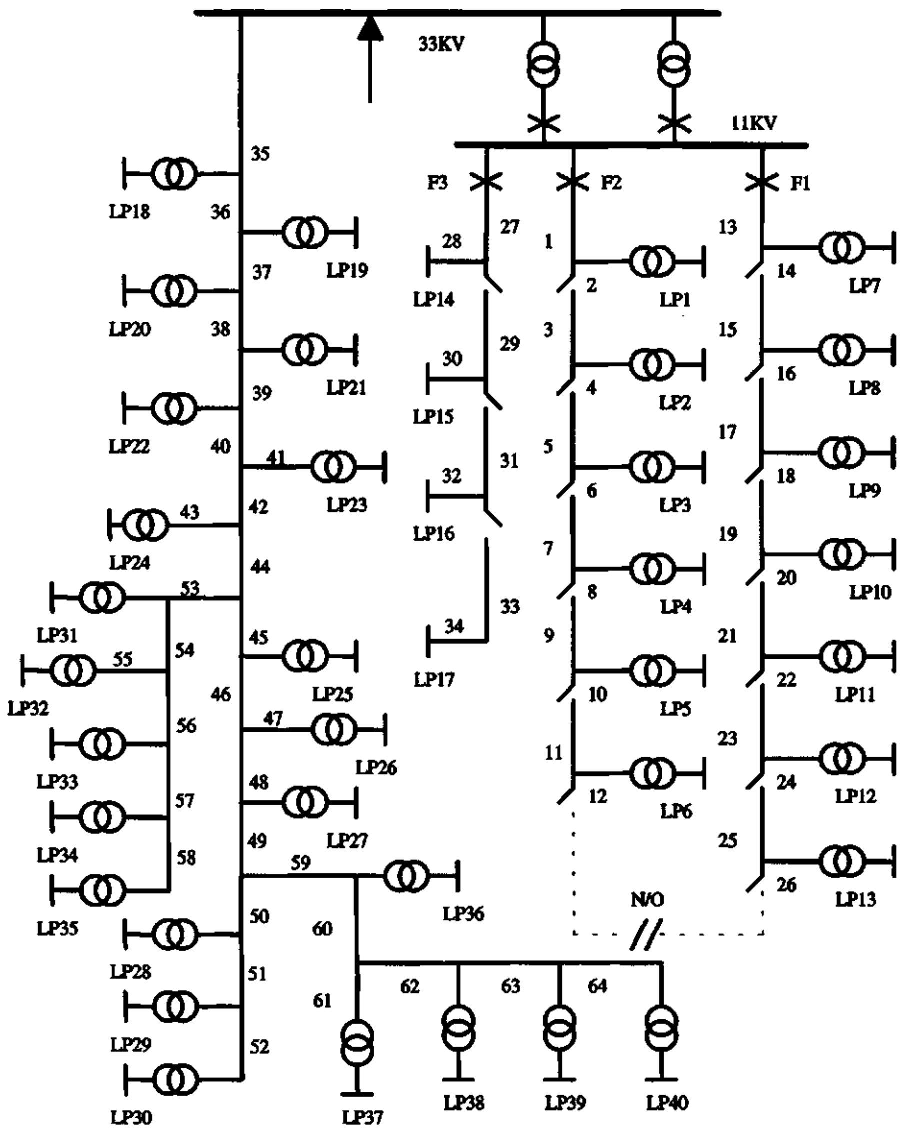

Figure C.5 Distribution network at Bus 6

APPENDIX D

RESULTS IN TABULAR FORM

Tables D.1 to D.4 show the variations in the IEAR with changes in system parameters at HLI. The data in these tables are shown pictorially in Figures 2.4 to 2.7 respectively.

Table D.1 Variation in the IEAR with changes in the unit failure and repair rates(fixed FOR) for the RBTS

Factor	IEAR ($/kWh)
0.5	5.8096
1.0	5.5657
1.5	5.3004
2.0	5.0932
2.5	4.9416
3.0	4.8986
3.5	4.9130
4.0	4.9764

Table D.2 Variation in the IEAR with changes in the unit failure and repair rates (fixed FOR) for the RTS

Factor	IEAR ($/kWh)
0.5	5.6267
1.0	5.2680
1.5	5.0225
2.0	4.9451
2.5	4.9803
To be continued	

Table D.2 continued	
3.0	5.0628
3.5	5.1481
4.0	5.2372

Table D.3 Variation in the IEAR with unit FOR for the RBTS

Factor	IEAR ($/kWh)
0.25	5.9292
0.50	5.7362
0.75	5.6552
1.00	5.5657
1.25	5.5081
1.50	5.4597

Table D.4 Variation in IEAR with unit FOR for the RTS

Peak Load (MW)	IEAR ($/kWh)
0.25	5.5883
0.50	5.5246
0.75	5.3968
1.00	5.2680
1.25	5.1409
1.50	5.2858

Tables D.5 to D.11 show the variations in the IEAR with changes in system parameters at HLII. The data in these tables are shown pictorially in Figures 3.2 to 3.5 and 3.7 to 3.9 respectively.

Table D.5 Change in the aggregate system IEAR with reserve margin

Situation	Reserve margin (%)	IEAR ($/kWh) Unit added at bus 1	IEAR ($/kWh) Unit added at bus 6
Original	29.73	4.4008	4.4008
$+1 \times 10$ MW	35.14	4.2922	4.4014
$+2 \times 10$ MW	40.54	4.2253	4.4022
To be continued			

Table D.5 continued			
$+3 \times 10$ MW	45.95	4.0153	4.4029
$+4 \times 10$ MW	51.35	3.7811	4.4036
$+5 \times 10$ MW	56.76	3.5817	4.4036
$+6 \times 10$ MW	62.16	3.5145	4.4036
$+7 \times 10$ MW	67.57	3.4473	4.4036

Table D.6 Change in the aggregate system IEAR with the transmission line unavailability

Forced Outage Rate (% base FOR)	IEAR ($/kWh)	
	λ Unchanged	μ Unchanged
85	4.3703	4.4173
90	4.3812	4.4118
95	4.3904	4.4063
100	4.4008	4.4008
105	4.4107	4.3952
110	4.4201	4.3897
115	4.4276	4.3841

Table D.7 Change in the system aggregate IEAR with transmission line capacity

Transmission line capacity (% base ratings)	IEAR ($/kWh)
85	4.3322
90	4.3512
95	4.3916
100	4.4008
105	4.4110
110	4.4168
115	4.4195

Table D.8 Change in the system aggregate IEAR with annual peak load using a the four step load model

Peak load (100 % base peak load)	IEAR ($/kWh)
100	4.4008
90	4.2945
80	4.1299
70	3.8560

Table D.9 Case 2 analysis for the RBTS

Situation	Reserve Margin (%)	EENS (MWh/yr)	ECOST (M$)	Fixed Cost (M$)	Total Cost (M$)
Original	29.73	1444.8520	11.5074	0.0000	11.5074
+1×10 MW	35.14	483.6602	3.5494	0.5000	4.0494
+2×10 MW	40.54	397.9102	2.9201	1.0000	3.9201
+3×10 MW	45.95	262.3812	1.9255	1.5000	3.4255
+4×10 MW	51.35	237.3242	1.7416	2.0000	3.7416
+5×10 MW	56.76	226.7997	1.6644	2.5000	4.1644
+6×10 MW	62.16	222.1231	1.6301	3.0000	4.6301
+7×10 MW	67.57	218.2799	1.6019	3.5000	5.1019

Table D.10 Case 3 analysis for the RBTS

Situation	Reserve Margin (%)	EENS (MWh/yr)	ECOST (M$)	Fixed Cost (M$)	Total Cost (M$)
Original	29.73	1444.8520	5.7537	0.0000	5.7537
+1×10 MW	35.14	483.6602	1.7747	0.2500	2.0247
+2×10 MW	40.54	397.9102	1.4601	0.5000	1.9601
+3×10 MW	45.95	262.3812	0.9628	0.7500	1.7128
+4×10 MW	51.35	237.3242	0.8708	1.0000	1.8708
+5×10 MW	56.76	226.7997	0.8322	1.2500	2.0822
+6×10 MW	62.16	222.1231	0.8050	1.5000	2.305
+7×10 MW	67.57	218.2799	0.8009	1.7500	2.5509

Table D.11 Case 4 analysis for the RBTS

Situation	Reserve Margin (%)	EENS (MWh/yr)	ECOST (M$)	Fixed Cost (M$)	Total Cost (M$)
Original	20.00	6851.8980	25.9913	0.0000	25.9913
+1×10 MW	25.00	5704.3550	21.6383	0.5000	22.1383
+2×10 MW	30.00	3406.3330	12.9212	1.0000	13.9212
+3×10 MW	35.00	754.5881	2.8624	1.5000	4.3624
+4×10 MW	40.00	635.7738	2.4117	2.0000	4.4117
+5×10 MW	45.00	570.5936	2.1644	2.5000	4.6644
+6×10 MW	50.00	556.5776	2.1113	3.0000	5.1113
+7×10 MW	55.00	551.0325	2.0902	3.5000	5.5902

Tables D.12 to D.15 shows the load point reliability and cost indices at Bus 3 to Bus 6 respectively. Tables D.16 to D.20 show the variations in the IEAR with changes in the system parameters at HLII. The data in these tables are shown pictorially in Figures 4.2 to 4.6 respectively.

Table D.12 Load point reliability and cost indices (Bus 3) for the RBTS

Load Point	λ	U	Cost	EENS	IEAR
	(1/yr)	(hr/yr)	($/yr)	(kWh/yr)	($/kWh)
1	0.4218	0.8083	4248.30	3130.79	1.3569
2	0.4218	0.8083	3935.39	2900.19	1.3569
3	0.4348	0.8733	22362.53	2116.59	10.5653
4	0.4413	0.9058	4891.80	3587.48	1.3636
5	0.4218	0.8083	4248.30	3130.79	1.3569
6	0.4348	0.8733	4677.30	3435.25	1.3616
7	0.4218	0.8083	4248.30	3130.79	1.3569
8	0.3418	0.6453	40393.68	4281.75	9.4339
9	0.3288	0.5803	36810.92	3731.07	9.8661
10	0.3483	0.6778	42185.06	4557.09	9.2570
11	0.3913	0.8194	4634.07	3480.00	1.3316
12	0.3913	0.8194	4634.07	3480.00	1.3316
13	0.3783	0.7544	4198.29	3170.73	1.3241
14	0.3978	0.8519	83794.37	4338.95	19.3121
To be continued					

Table D.12 continued					
15	0.3913	0.8194	4225.98	3173.54	1.3316
16	0.3978	0.8519	21990.47	2204.62	9.9747
17	0.3783	0.7544	19574.31	1923.23	10.1778
18	0.3783	0.7544	4198.29	3170.73	1.3241
19	0.3913	0.8194	21185.08	2110.82	10.0364
20	0.3978	0.8519	4776.50	3578.11	1.3349
21	0.3783	0.7544	4132.99	3121.42	1.3241
22	0.3913	0.8194	4562.00	3425.88	1.3316
23	0.3978	0.8519	4776.50	3578.11	1.3349
24	0.3913	0.8194	4562.00	3425.88	1.3316
25	0.4268	0.8127	4325.77	3211.17	1.3471
26	0.4463	0.9102	4540.94	3351.44	1.3549
27	0.4398	0.8777	87007.04	4202.63	20.7030
28	0.4398	0.8777	22483.12	2135.35	10.5290
29	0.4268	0.8127	20872.34	1947.76	10.7161
30	0.4398	0.8777	4342.24	3210.43	1.3525
31	0.4398	0.8777	22483.12	2135.35	10.529
32	0.4073	0.8712	4817.90	3435.25	1.4025
33	0.3878	0.7737	4174.39	2978.56	1.4015
34	0.3878	0.7737	4174.39	2978.56	1.4015
35	0.4008	0.8387	4603.40	3283.02	1.4022
36	0.3878	0.7737	4174.39	2978.56	1.4015
37	0.4073	0.8712	22325.63	2116.59	10.5479
38	0.3878	0.7737	19909.47	1835.21	10.8486
39	0.2301	0.5536	32765.70	23470.23	1.3961
40	0.2236	0.5211	31331.78	22043.94	1.4213
41	0.2106	0.4561	47668.63	32139.80	1.4832
42	0.2236	0.4691	49794.82	33095.25	1.5046
43	0.2431	0.5666	56999.00	40261.11	1.4157
44	0.2236	0.4691	29733.53	19761.87	1.5046
TOTAL:	16.6496	33.8880	837773.90	288755.80	2.9013

Table D.13 Load point reliability and cost indices (Bus 4) for the RBTS

Load Point	λ	U	Cost	EENS	IEAR
	(1/yr)	(hr/yr)	($/yr)	(kWh/yr)	($/kWh)
1	0.3550	0.6865	3933.31	3085.75	1.2747
To be continued					

Table D.13 continued					
2	0.3648	0.7352	4274.37	3327.79	1.2844
3	0.3550	0.6865	3933.31	3085.75	1.2747
4	0.3680	0.7515	4388.05	3408.47	1.2874
5	0.3648	0.7352	3921.40	3052.99	1.2844
6	0.3680	0.7515	25026.07	2546.91	9.8260
7	0.3648	0.7352	24508.40	2486.63	9.8561
8	0.2425	0.4390	44627.93	5080.04	8.7850
9	0.2523	0.4877	73402.29	8613.11	8.5222
10	0.2555	0.5040	50372.11	5962.94	8.4475
11	0.3583	0.7417	4365.76	3360.06	1.2993
12	0.3550	0.7255	4252.08	3279.38	1.2966
13	0.3550	0.7255	4252.08	3279.38	1.2966
14	0.3453	0.6767	3588.06	2786.52	1.2876
15	0.3550	0.7255	3900.95	3008.58	1.2966
16	0.3550	0.7255	24199.96	2450.45	9.8753
17	0.3453	0.6767	22646.95	2269.59	9.9780
18	0.4093	0.7871	4396.61	3369.99	1.3046
19	0.3995	0.7383	4055.55	3127.95	1.2966
20	0.4093	0.7871	4396.61	3369.99	1.3046
21	0.4093	0.7871	4396.61	3369.99	1.3046
22	0.3995	0.7383	3720.65	2869.65	1.2966
23	0.4093	0.7871	4033.54	3091.71	1.3046
24	0.4093	0.7871	26040.30	2518.16	10.3410
25	0.3995	0.7383	24487.29	2337.30	10.4767
26	0.2870	0.5298	53581.98	5725.23	9.3589
27	0.2903	0.5461	55018.02	5945.96	9.2530
28	0.2773	0.4811	49273.85	5063.06	9.7320
29	0.2918	0.4962	51073.90	5239.64	9.7476
30	0.3015	0.5450	55382.03	5901.81	9.3839
31	0.2918	0.4962	76608.97	7859.27	9.7476
32	0.4010	0.7925	4484.62	3386.13	1.3244
33	0.4010	0.7925	4484.62	3386.13	1.3244
34	0.3880	0.7275	4029.88	3063.40	1.3155
35	0.4010	0.7925	4484.62	3386.13	1.3244
36	0.3880	0.7275	3697.10	2810.43	1.3155
37	0.4010	0.7925	4114.29	3106.51	1.3244
38	0.3880	0.7275	24125.98	2289.07	10.5396
TOTAL:	13.5115	26.1064	771478.10	142301.90	5.4214

Table D.14 Load point reliability and cost indices (Bus 5) for the RBTS

Load Point	λ (1/yr)	U (hr/yr)	Cost ($/yr)	EENS (kWh/yr)	IEAR ($/kWh)
1	0.2690	0.6518	3568.60	2625.43	1.3592
2	0.2690	0.6518	3568.60	2625.43	1.3592
3	0.2690	0.6518	8083.86	3841.91	2.1041
4	0.2495	0.5543	2913.65	2158.49	1.3499
5	0.2593	0.6031	7567.85	3537.36	2.1394
6	0.2495	0.5543	2913.65	2158.49	1.3499
7	0.2690	0.6518	24045.40	2514.74	9.5618
8	0.2820	0.5868	7355.68	3435.85	2.1409
9	0.2918	0.6356	2512.44	1923.18	1.3064
10	0.3015	0.6843	2733.08	2079.77	1.3141
11	0.2918	0.6356	2512.44	1923.19	1.3064
12	0.2820	0.5868	38586.65	2082.30	18.5308
13	0.2918	0.6356	2512.44	1923.19	1.3064
14	0.2690	0.6518	24045.40	2514.73	9.5618
15	0.2593	0.6031	3200.16	2361.83	1.3550
16	0.2495	0.5543	35994.91	1959.25	18.3717
17	0.2690	0.6518	8083.86	3841.91	2.1041
18	0.2495	0.5543	20622.10	2116.06	9.7455
19	0.2690	0.6518	42058.52	2328.39	18.0633
20	0.2593	0.6421	3549.43	2583.81	1.3737
21	0.2398	0.5446	2962.94	2167.58	1.3669
22	0.2495	0.5933	21992.69	2275.53	9.6649
23	0.2593	0.6421	7992.71	3781.00	2.1139
24	0.2495	0.5933	21992.69	2275.53	9.6649
25	0.2398	0.5446	2894.92	2117.83	1.3669
26	0.2593	0.6421	2670.60	1944.06	1.3737
TOTAL:	6.8965	15.9531	306935.30	65096.84	4.7151

Table D.15 Load point reliability and cost indices (Bus 6) for the RBTS

Load Point	λ (1/yr)	U (hr/yr)	Cost ($/yr)	EENS (kWh/yr)	IEAR ($/kWh)
1	0.3878	0.7179	1432.49	1166.62	1.2279
2	0.4008	0.7829	1624.72	1305.83	1.2442
3	0.3975	0.7667	1554.42	1253.15	1.2404
4	0.3878	0.7179	1459.12	1188.31	1.2279
5	0.3975	0.7667	1894.20	1527.08	1.2404
6	0.3878	0.7179	1745.62	1421.63	1.2279
7	0.4268	0.7959	1475.18	1219.78	1.2094
8	0.4300	0.8122	1513.16	1246.74	1.2137
9	0.4300	0.8122	1618.96	1333.91	1.2137
10	0.4170	0.7472	1361.22	1138.90	1.1952
11	0.4268	0.7959	1607.67	1329.33	1.2094
12	0.4170	0.7472	1698.44	1421.05	1.1952
13	0.4268	0.7959	1840.63	1521.97	1.2094
14	0.3000	0.8252	34715.09	3590.86	9.6676
15	0.2948	0.9319	104074.10	14280.66	7.2878
16	0.2980	1.1042	66511.16	9417.59	7.0624
17	0.3000	1.3842	57281.40	6216.48	9.2144
18	2.2680	3.1506	4303.39	5149.54	0.8357
19	2.2680	3.8006	6624.54	6787.23	0.9760
20	2.2680	4.2166	6023.03	10429.17	0.5775
21	2.2680	4.4506	6636.53	11595.73	0.5723
22	2.2680	4.8666	11217.11	9977.40	1.1243
23	2.3070	5.7116	11220.99	9398.23	1.1939
24	2.3167	6.1763	10261.78	18738.64	0.5476
25	2.2680	6.9986	13875.13	10803.41	1.2843
26	2.3070	7.9216	11869.07	22294.13	0.5324
27	2.2680	8.6366	18425.9	13615.2	1.3533
28	2.2680	9.7806	20992.15	15126.64	1.3878
29	2.2680	10.6126	23581.83	16747.11	1.4081
30	2.2680	11.2626	14478.15	28051.21	0.5161
31	1.8585	6.5891	13582.14	10167.04	1.3359
32	1.9105	7.2651	7350.04	13924.49	0.5279
33	1.8585	7.7331	16838.09	12183.10	1.3821
34	1.8585	8.3831	10849.06	20849.59	0.5203
To be continued					

Table D.15 continued					
35	1.8585	9.2151	12472.74	24140.66	0.5167
36	2.5540	10.0666	21196.77	15571.08	1.3613
37	2.6028	10.9603	10996.67	21052.63	0.5223
38	2.5540	11.1326	16349.26	31384.46	0.5209
39	2.5540	11.9646	26572.01	18890.03	1.4067
40	2.5540	12.6926	19942.58	38658.82	0.5159
TOTAL:	58.3000	197.8087	599066.60	436115.40	1.3736

Table D.16 Change in the IEAR with station bus repair times

Repair time (% base repair time)	IEAR($/kWh)					
	Bus 2	Bus 3	Bus 4	Bus 5	Bus 6	Aggregate
90	4.3476	2.9012	5.4219	4.7153	1.3736	3.6336
95	4.3474	2.9013	5.4217	4.7152	1.3736	3.6335
100	4.3473	2.9013	5.4214	4.7151	1.3736	3.6335
105	4.3471	2.9014	5.4212	4.7149	1.3737	3.6334
110	4.3470	2.9014	5.4209	4.7148	1.3737	3.6333

Table D.17 Change in the IEAR with the transformer replacement times

Replacement time (% base replacement time)	IEAR($/kWh)					
	Bus 2	Bus 3	Bus 4	Bus 5	Bus 6	Aggregate
70	4.1912	2.8271	5.4116	4.5260	1.3538	3.5578
80	4.2347	2.8498	5.4098	4.5813	1.3598	3.5791
90	4.2870	2.8746	5.4132	4.6447	1.3664	3.6045
100	4.3473	2.9013	5.4214	4.7151	1.3736	3.6335
110	4.4148	2.9298	5.4340	4.7918	1.3814	3.6657
120	4.4889	2.9600	5.4505	4.8741	1.3897	3.7009
130	4.5690	2.9917	5.4707	4.9616	1.3985	3.7389

Table D.18 Change in the IEAR with the breaker active failure rate

Active failure rate (% base active failure rate)	IEAR($/kWh)					
	Bus 2	Bus 3	Bus 4	Bus 5	Bus 6	Aggregate
70	4.2991	2.8866	5.3590	4.6669	1.3697	3.6023
80	4.3151	2.8915	5.3798	4.6830	1.3710	3.6127
90	4.3312	2.8964	5.4006	4.6990	1.3723	3.6231
100	4.3473	2.9013	5.4214	4.7151	1.3736	3.6335
110	4.3633	2.9062	5.4422	4.7311	1.3750	3.6438
120	4.3794	2.9111	5.4631	4.7471	1.3763	3.6542
130	4.3955	2.9160	5.4839	4.7632	1.3776	3.6646

Table D.19 Change in the IEAR with successful fuse operating probability

Successful fuse operating probability (% base case)	IEAR($/kWh)					
	Bus 2	Bus 3	Bus 4	Bus 5	Bus 6	Aggregate
80	5.2921	3.6807	6.3726	6.3158	1.5018	4.4862
85	5.4169	3.7370	6.5048	6.4804	1.5086	4.5727
90	5.5477	3.7950	6.6427	6.6537	1.5154	4.6628
95	5.6850	3.8549	6.7866	6.8365	1.5223	4.7568
96	5.7133	3.8671	6.8161	6.8743	1.5237	4.7761
97	5.7419	3.8794	6.8459	6.9125	1.5251	4.7955
98	5.7707	3.8918	6.8759	6.9512	1.5265	4.8152
99	5.7999	3.9042	6.9062	6.9902	1.5279	4.8349
100	4.3473	2.9013	5.4214	4.7151	1.3736	3.6335

Table D.20 Change in the IEAR with the load transfer probability

Load transfer probability (% base case)	IEAR($/kWh)					
	Bus 2	Bus 3	Bus 4	Bus 5	Bus 6	Aggregate
60	4.1920	2.6377	5.0967	4.7644	1.3708	3.4304
70	4.2261	2.6932	5.1689	4.7562	1.3705	3.4743
80	4.2636	2.7559	5.2483	4.7465	1.3709	3.5233
90	4.3044	2.8259	5.3341	4.7339	1.3720	3.5771
100	4.3473	2.9013	5.4214	4.7151	1.3736	3.6335