RELIABILITY ASSESSMENT OF NON-UTILITY GENERATION AND DEMAND-SIDE MANAGEMENT IN COMPOSITE POWER SYSTEMS

A Thesis

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Dedicated to my Beloved Daughter and Wife
Mavis Adzanu & Vivian Adzanu (Safo)

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ABSTRACT

The last two decades have brought about significant changes in the resource planning environment of electric power utilities throughout the world. The conventional generation technologies that have been the backbone of every electric utility, i.e., coal, hydro, nuclear, oil and natural gas, are being re-examined to address environmental concerns and resource utilization. The research described in this thesis focuses on the adequacy and economic assessment of non-utility generation (NUG) and demand-side management (DSM) initiatives within a typical power system. The main objective was to examine and extend the ability of the contingency enumeration approach to evaluate the economic reliability benefits of incorporating NUG and DSM options separately or jointly in composite system adequacy assessment. Two test systems were employed in the evaluations. The studies undertaken in this thesis demonstrate the need for accurate load model representations which clearly reflect the mix of customer sectors at each bus. Chronological hourly load curves were developed for each load bus in the test systems recognizing the individual load profiles of the customers. The adequacy and economic implications of demand-side management initiatives in the test systems were examined at each load point in the composite generation and transmission configuration. This thesis illustrates the development of techniques by which system planners and operators can incorporate reliability cost/worth assessment in power system applications. Focus is placed in the thesis on the utilization of reliability cost/worth concepts in integrated resource planning in the form of NUG additions and DSM initiatives. Methods for the joint implementation of NUG and DSM options in a composite power system are presented and examples from the studies conducted are used to illustrate the procedures. Studies are presented which illustrate the impacts of NUG additions and DSM initiatives on the test system planning reserve margins (PRM) and on the total societal cost of electrical energy. The total evaluated cost incorporates the explicit cost to customers associated with failures but does not include the cost associated with DSM program implementation. The results of the studies conducted show that NUG facilities and DSM programs can have considerable reliability and economic impacts on electric power systems.

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LIST OF ABBREVIATIONS

AC	Alternating Current
APM	Application of Probability Methods
Benelux	Belgium-Netherlands-Luxemborg
BPECI	Bulk Power Energy Curtailment Index
BPII	Bulk Power Interruption Index
BPSACI	Bulk Power Supply Average (MW) Curtailment Index
CCDF	Composite Customer damage Function
CDF	Customer Damage Function
CEA	Canadian Electricity Association
COMREL	COMposite system RELiability evaluation
CPU	Central Processing Unit
DC	Direct Current
DSM	Demand Side Management
EC	Energy Conservation
ECOST	Expected customer outage COST
EENS	Expected Energy Not Supplied (in MWh per year)
EES	Expected Energy Supplied
ENEL	Ente Nazionale Per L'Energia Elettrica, Italy
ENLC	Expected Number of Load Curtailment
EPRI	Electric Power Research Institute
EUE	Expected Unsupplied or Unserved Energy
ELC	Expected Load Curtailed (in MW)
EPS	Economic Principle of Substitution
F&D	Frequency and Duration
FERC	Federal Energy Regulatory Commission
FOR	Forced Outage Rate
GNP	Gross National Product
GW	Giga-Watt
HL	Hierarchical Level

HLI	Hierarchical Level I
HLII	Hierarchical Level II
HLIII	Hierarchical Level III
Hr.	Hour
IC	Investment Costs
IEEE	Institute of Electrical and Electronics Engineers
IEEE-RTS	IEEE-Reliability Test System
IEAR	Interrupted Energy Assessment Rate
IPP	Independent Power Producer
IRP	Integrated Resource Planning
K$	Kilo-Dollars
KV	Kilo-Voltage
KW	Kilo-Watt
KWh	Kilo-Watt-hour
LDC	Load Duration Curve
LF	Load Factor
LM	Load Modification or Load Management or Load Model
LM1	Load Model 1
LOLE	Loss of Load Expectation
LOEE	Loss of Energy Expectation
LS	Load Shifting
MBPECI	Modified Bulk Power Energy Curtailment Index
MW	Mega-Watt
MWh	Mega-Watt-hour
NERC	North American Electric Reliability Council
NSERC	Natural Science and Engineering Research Council
NUG	Non Utility Generation or Non-Utility Generator
NY	New York
Occ./yr.	Occurrences per year
PC	Production Costs or Peak Clipping
PLC	Probability of Load Curtailed
PRM	Planning Reserve Margin
PROCOSE	PRObabilistic COmposite System Evaluation
P.U.	Per Unit
PURPA	Public Utility Regulatory Policy Act
RBTS	Roy Billinton Test System

SCDF	Sector Customer Damage Function
SI	Severity Index (in System Minutes)
SIC	Standard Industrial Classification
SLG	Strategic Load Growth
UK	United Kingdom
US	United States
VBTRA	Value-Based Transmission Resource Analysis
VF	Valley Filling
WTA	Willingness to Accept
WTP	Willingness to Pay
Yr.	Year

1. INTRODUCTION

1.1. Introduction

Modern electric power systems are perhaps the most complex large-scale technical undertakings developed by humankind [1-5]. The study of electric power systems is concerned with the generation, transmission, distribution and utilization of electric power [3, 5]. The first of these, the generation of electric power, involves the conversion of energy from a non-electrical form (such as thermal, hydraulic, nuclear, wind or solar energy) to electric energy. This form of energy has given considerable impetus to the development of the many modern societies in the world today. Electricity has become a dominant factor in daily life, an essential input to industrial production and a major form of energy. Dependence on electricity has also increased with increased utilization. Such increasing dependence and growing affluence brings an awareness of the need for a high reliability of electric service and the inconveniences and losses to the consumers incurred by interruptions in power supply. The usage of electrical energy in any modern society is, therefore, closely associated with or related to the quality of life. The effectiveness of energy utilization is considerably influenced by the availability of electrical energy and has an impact on the cost of goods and services. A modern power system serves one function only and that is to supply customers, both large and small, with electrical energy as economically as possible and with an acceptable degree of reliability environmental impact and quality [2, 3]. Quality refers to the requirement that the power system frequency and voltage remain within prescribed limits. A basic requisite of a modern power system is the ability to satisfy the constantly changing system load requirement at all times. It is impossible to guarantee this ability, and any attempt to do so is impractical and uneconomical. Modern society, because of its pattern of social and working habits, has come to expect that the supply should be continuously available on demand [3]. This is not physically possible due to random system failures which are generally beyond the control of power system engineers, although the probability of customers being disconnected can be reduced by increased investment during either the planning phase, operating phase or both [3]. It is evident therefore that the economic and reliability constraints can conflict, and this can lead to difficult managerial decisions in the planning, design and operating phases. In most power systems, it becomes the responsibility of the system planning engineer to analytically determine the cost associated with a particular level of reliability and to provide management with quantitative assistance in making the final decision. Power system engineers have always attempted to respond to society's expectations and to achieve the highest possible reliability at an affordable cost. A high level of customer reliability can only be attained by incorporating reliability considerations in all aspects of power system planning, design and operation.

1.2. Power System Reliability Concepts

The first well known book on general reliability by Bazovsky [6], appeared in 1961. In the years since, many other books have been published. The first book on power system reliability was written by Billinton [7] and published in

1970. Reliability is an old concept and a new discipline [5]. Things and people have long been called or referred to as being reliable if they lived up to certain expectations, and unreliable otherwise. A reliable person would never (or hardly ever) fail to deliver what he/she has promised; a reliable watch would keep the correct time day after day. This approach to judging reliability is related to the performance of some function or duty. The reliability of a device is considered to be high if it repeatedly performed its function with success and low if it is tended to fail in repeated trials [1, 5]. Past experience helps to form advance estimates as to the degree of trust that one can place on success, or the extent that one should fear failure. Such a vague notion of reliability is of little use in technical applications. Before the concept of reliability can be transplanted into engineering applications, therefore, it must be converted into one or several measurable quantities by suitable definitions. The classical definition which was first employed to do this is as follows: Reliability is the probability of a device or system performing its function adequately, for the period of time intended, under the operating conditions intended or encountered [1-3, 5, 7]. It can also be defined as the overall ability of a system to perform its intended function [1-3].

In the above definition, reliability is defined using the mathematical concept of probability. This is a fundamental association. The above definition also follows the original, non-technical concept as reference is made to the performance of a function and to the successful completion of this performance (it must be carried out adequately for the period of time intended). The "degree of trust" placed in success on the basis of past experience is quantified as the probability of success. The probability of failure can be considered as a measure of unreliability. The "expected performance" can be very different in different applications. The definition of reliability implies a particular kind of performance, where a device is successful if it has not failed during its intended time of service. The possibility of repairs after failures and of continued service after repairs is not considered. An important class of devices and systems involves repair which returns the device or system to service. It is clear that the reliability of such a device needs to be expressed by a measure (or measures) different from the one defined above. An appropriate index in such cases is the availability, which is defined as follows: The availability of a repairable device is the proportion of time, in the long run, that it is in, or ready for, service. Note again the close connection with the "performance of duty". The availability, too, is a probabilistic measure and is equal to the probability of the device not being in the failed condition at some randomly chosen moment in the distant future.

The ability of an electric power system to provide an adequate supply of electrical energy is usually designated by the general term reliability. The concept of power system reliability, however, is extremely broad and covers all aspects of the ability of the electric power network or system to satisfy the consumer requirements [3, 4, 8, 9]. Because of the wide ranging implications of the term reliability, it is necessary to subdivide it into more specific segments. A simple but reasonable subdivision of the concern designated as system reliability is shown in Figure 1.1. This represents the two basic aspects of a power system namely system adequacy and system security [2, 3, 10-12]. These two terms or subdivisions of system reliability can be described as follows.

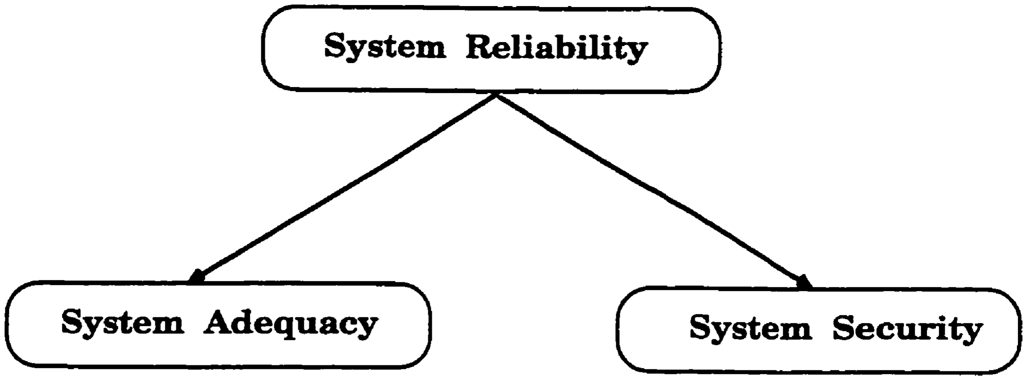

Figure 1.1: Subdivision of system reliability.

1.2.1. Adequacy and Security

Adequacy and security are major concerns for power system planners and operators. System adequacy relates to the existence of sufficient facilities within the system to satisfy the consumer load demand. These include the necessary facilities to generate sufficient electrical energy and the associated transmission and distribution required to transport the energy to the actual customer load points. Adequacy is therefore concerned with static conditions which do not include system disturbances.

System security, on the other hand, relates to the ability of the system to respond to disturbances or perturbations arising within that system. These include the conditions associated with both local and widespread disturbances and the loss of major generation and transmission facilities. It is clear that adequacy assessment and security analysis deal with quite different reliability issues and involve different assessment techniques. It is also important to realize that most of the probabilistic techniques presently available for power system reliability evaluation are in the domain of system adequacy assessment. The evaluation of Loss of Load Expectation (LOLE) and Loss of Energy Expectation (LOEE) or Expected Energy Not Supplied

(EENS) or Expected Unserved Energy (EUE) indices reside in the area of adequacy assessment [13-15]. The quantification of spinning or operating capacity requirements falls in the domain of security assessment. The research work reported in this thesis is restricted to adequacy evaluation of electric power systems.

1.2.2. Functional Zones and Hierarchical Levels

The basic techniques for system reliability assessment can be categorized in terms of their application to segments of a complete power system. These segments are shown in Figure 1.2 and are defined as the functional zones of generation, transmission and distribution. This division is the most appropriate as most utilities are either divided into these zones for purposes of organization, planning, operation, and/or analysis or are solely responsible for one of these functions. Adequacy studies can be, and are, conducted individually in these three functional zones. The above mentioned functional zones can be combined to give the hierarchical levels (HL), which are also depicted in Figure 1.2, for the purpose of conducting system reliability assessment [2]. Reliability analysis at the different hierarchical levels and functional zones has experienced continuous development and application since the 1930s. The developmental stages have been documented in the several bibliographies [7, 16-19] published in the IEEE Transactions which contain numerous historical and technical papers on system reliability evaluation of power systems. Adequacy assessment techniques can also be grouped under these hierarchical levels. Hierarchical level I (HLI) is concerned only with the generation facilities. Reliability analysis at HLI, therefore, provides a quantitative evaluation of the ability of the generating system to satisfy the total system load or demand. Adequacy assessment of the composite or bulk generation and transmission facilities is designated as a hierarchical level II (HLII) study. Reliability evaluation of the entire system is described as hierarchical level III (HLIII) assessment. HLIII adequacy analysis therefore involves the consideration of all the three functional zones so as to evaluate customer load point adequacies [9]. The reliability indices calculated at each hierarchical level are physically different. System reliability is usually predicted using one or more indices which quantify expected system reliability performance and implemented using criteria based on acceptable values of these indices. This research work, is concerned with power system adequacy assessment at HLII.

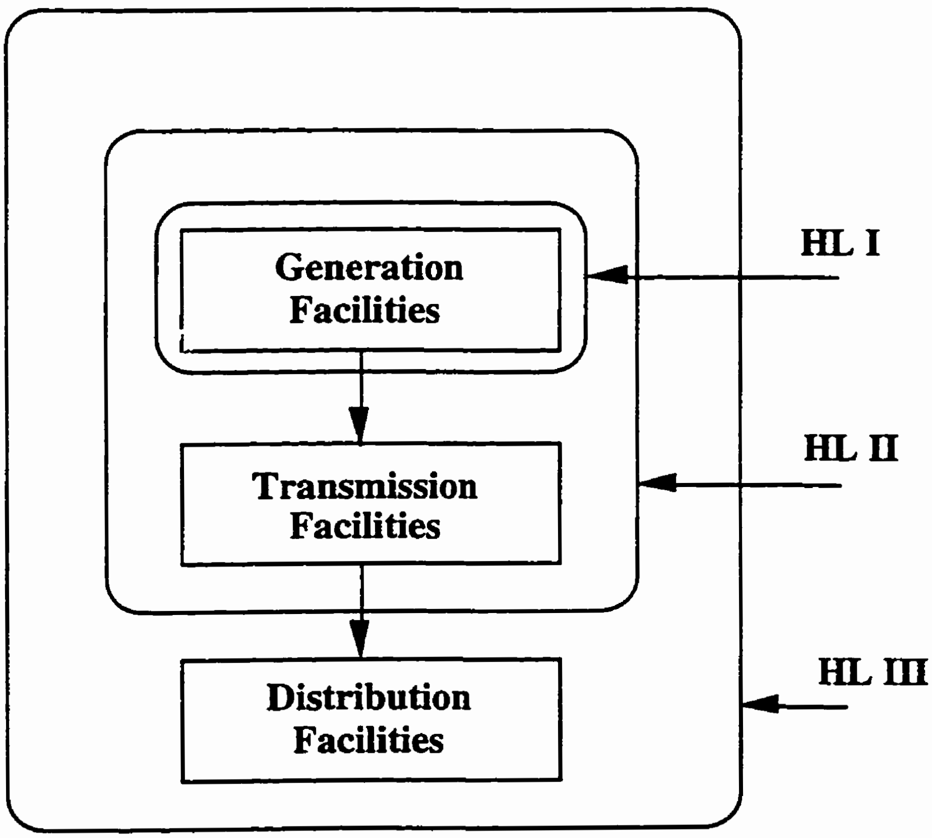

Figure 1.2: Hierarchical levels for reliability analysis.

1.3. Concepts of Composite System Analysis

The economic, social and political climate in which the electric power industry now operates has changed considerably during the last few decades. It is now widely recognized that statistical assessment of past performance is an important aspect in the planning and operation of power systems. The quantitative assessment of each of the functional zones of an electric power system is widely conducted using existing techniques. Application of these techniques in the planning of generation systems and distribution networks is fairly well advanced and is widely used. The development of a suitable transmission network to convey the energy to the major load points is an important part of the planning process and is termed as composite or bulk power system expansion planning. The application of quantitative reliability assessment techniques to bulk power systems (composite generation and transmission systems) is in its infancy and relatively little use is made of these techniques in practical decision-making. The need, however, is widely recognized and interest is expanding rapidly although deterministic criteria are still the norm [3].

Adequacy assessment at HLII includes the generating facilities covered in HLI together with the ability to move the generated energy through the bulk transmission system. This type of analysis is usually known as composite system adequacy evaluation. The word composite [3] stems from the fact that both generation and transmission facilities are involved in the assessment. There is a wide range of load-point and overall system reliability indices [3, 14] that can be calculated. The Probability of Failure, Frequency of Failure, Expected Load Curtailed (ELC) and Expected Energy not Supplied (EENS) [3] are some examples of load-point indices. These indices are calculated for each major load point in the system. They are very useful in system design for comparing alternative system configurations and modifications. They can also serve as input values in the adequacy assessment of distribution systems supplied from these bulk supply points. Examples of system indices are the Bulk Power Interruption Index (BPII) and Bulk Power Energy Curtailment Index (BPECI) or Severity Index (SI) [3]. System indices are indicators of the overall adequacy of the composite system to meet the total system load and energy requirements and are therefore quite useful for the system planner and manager. The load point indices monitor the effect on individual busbars and provide input values to the next hierarchical level. It is important to appreciate that the two sets of indices do not replace each other, but are complementary. This is because neither of the two sets of indices can individually provide the entire reliability picture of a power system. Although these indices add realism by including bulk transmission, they are still adequacy indicators. They do not include the system dynamics or the ability of the system to respond to transient disturbances, because they simply measure the ability of the system to adequately meet its requirements in a specified set of probabilistic states.

The procedures used for adequacy assessment at HLII can be broadly classified into the following two general areas:

- Contingency Enumeration (or Analytical) methods; and
- Monte Carlo simulation techniques.

Analytical techniques represent the system by a mathematical model and evaluate the reliability indices from this model using mathematical solutions. Monte Carlo simulation methods, however, estimate the reliability indices by simulating the actual process and random behaviour of the system. This approach therefore treats the problem as a series of experiments. There are merits and demerits in both methods. Generally Monte Carlo simulation requires a large amount of computing time compared to analytical methods. However, it can include any system effect or system process which may have to be approximated in an analytical approach.

1.4. Power System Planning

Power system planning can be divided into two distinct different areas dealing with static and operating capacity requirements [3]. The static capacity area relates to the long-term evaluation of the overall system requirements. It normally has a time span of ten (10) to thirty (30) years. Predictions beyond a thirty-year time span are usually meaningless and some argue that this time frame is too ambitious. The time horizon length is a management decision; however, the lead time requirements for implementing system expansion plans should be considered or recognized. This area of power system reliability assessment is the oldest and most extensively studied. As a result, considerable efforts have been devoted to the area of static capacity assessment [7, 12-18]. Operating reserve margin analysis, on the other hand, relates to the short-term evaluation of the actual capacity required to meet a given load level or demand [3]. System operation planning normally has a time horizon of up to one year. There are relatively fewer papers dealing with operating reserve problems or assessment [20-24] compared with those on static capacity assessment [7, 12-18]. The main reason is that very few electric power utilities utilize probabilistic techniques in short term assessment and prefer to use long established deterministic techniques and criteria. This is likely to change with time, although not necessarily in the very near future. This research project is restricted to the area of static capacity assessment.

One of the most basic elements in power system planning is the determination of how much generation capacity is required to give a reasonable assurance of satisfying the load requirements. The concern in this case is to determine whether there is sufficient capacity in the system to generate the required energy to meet the system load. A second but equally important element in the planning process is the development of a suitable transmission network to convey the energy generated to the customer load points [3, 7]. The transmission network can be divided into the general areas of bulk transmission and distribution facilities. The distinction between these two areas cannot be made strictly on a voltage basis but must include the function of the facility within the system [15, 16, 25]. Bulk transmission facilities must be carefully matched with the generation to permit energy movement from these sources to the points at which the distribution or sub-transmission facilities can provide a direct and often radial path to the customer.

Historically, operating reserves have been determined using deterministic techniques and the most frequently used method is to retain a reserve equal to the largest unit in the system [3]. Deterministic methods cannot account for the probabilistic or stochastic nature of system behaviour, of customer load demands or of component failures. Probabilistic techniques, however, can provide a comprehensive and realistic evaluation of the risk by incorporating the stochastic nature of system components. The need for probabilistic evaluation of system behaviour has been recognized since the 1930's [3], and it may be questioned why such methods have not been widely used in the past. The main reasons were lack of data, limitations of computational resources, lack of realistic reliability techniques, aversion to the use of probabilistic techniques and a misunderstanding of the significance and meaning of probabilistic criteria and risk indices. None of these reasons are valid today. Consequently, there is no need to artificially constrain the inherent probabilistic or stochastic nature of a power system into a deterministic one. However, most Canadian utilities still use deterministic techniques to assess their operating capacity. Probabilistic approaches generally base the design and operating constraints on the criterion that the risk of certain events must not exceed preselected limits. Many utilities still prefer to use a deterministic technique due to the difficulty in interpreting a numerical risk index and the lack of sufficient information provided by a single index [26]. There is considerable utility interest in including deterministic considerations in the evaluation of probabilistic indices [27]. Reference 13 clearly shows that virtually all Canadian electric power utilities utilize probabilistic techniques in the evaluation of generating capacity adequacy. The criteria and methodologies used are quite varied and provide a useful indication of the range of available techniques.

1.5. Scope and Objectives of the Thesis

The work described in this thesis is primarily concerned with composite generation and transmission system (or HLII) adequacy evaluation. These assessments involve the total problem of evaluating the adequacy of the generation and transmission facilities to supply the required electrical energy to the major system load points. The need to possess the ability to quantitatively assess the adequacy of a composite system is, however, now widely recognized and interest is expanding. Recent advancements in the establishment of comprehensive utility data bases and the enhancement of computing facilities are gradually removing the barriers which artificially constrain the probabilistic nature of power systems into a deterministic framework. These advances have resulted in the sequential development of a number of digital computer programs [28-36] based on probabilistic principles for composite system adequacy analysis.

The tasks involved in power system planning are becoming increasingly complex as a result of the rising costs of conventional electrical energy supplies coupled with the uncertain global economic and political conditions and the increasing environmental concerns facing power utilities. System planners are therefore faced with limited choices and numerous supply constraints leading to a trend in which previously unconventional energy resources are beginning to play a significant role in the planning process as potentially viable supply options. In recent years, a significant component of the overall electrical energy requirements of many utilities has been provided by independent power production facilities in the form of non-utility generation (NUG). These supply options are becoming increasingly important in least cost energy planning. It is therefore important that computational tools be developed which are efficient and sufficiently flexible to incorporate these new technologies in the analyses.

The basic objectives of this research project were to examine selected supply and demand side alternatives to meet the power system requirements at HLII. The following three distinct areas have been studied:

- Assessment of additional generation with particular emphasis on NUG additions,
- Investigation of load management strategies and
- Combined supply and demand side options.

Given the uncertainty of future demand, utilities and governments are looking at alternatives, and more flexible options for meeting the forecast load growth instead of constructing more traditional base load generating units. Some utilities have chosen to depend heavily on purchased power from other utilities and non-utility generators. Others are rehabilitating older units or installing combustion turbine peaking units. A wide range of alternatives available to utility management today are summarized in [37-39].

The Federal Energy Regulatory Commission (FERC) [40, 41] in the United States (U.S.) has shown a willingness to encourage further non-utility generation in the form of independent power producers (IPP) and cogenerators. Canada, on the other hand, does not have a national policy with regard to the development of non-utility generators. The federal and some provincial governments have indicated their interest in, and support for, non-utility generation development. The 1989 North American Electric Reliability Council (NERC) forecast [37] includes the addition of 93,600 MW of new capacity for the U.S. between 1989 and 1998 of which 38 percent is under construction. It is predicted, in the United States, that reforms will eventually be made to increase the amount of non-utility generation. At present, 20 percent of new generation will be developed by NUG. This is, however, predicted to increase steadily over the next 10 years and could reach 50 percent [42].

Practical expansion planning is an extremely difficult and complex design problem. The task can usually be divided into the two distinct aspects of generation expansion planning and transmission expansion planning. The studies were conducted in this research to examine the adequacy and economic implications of adding additional generating capacity (from conventional and non-conventional sources) at individual load buses in a typical electric power system. One of the main thrusts of this research work involved an examination of adding generating units from non-utility sources (e.g. NUG). Non-utility generation (NUG) includes all forms of generation sources, such as solar, wind, etc. and cogenerators. These sources of generation can become attractive alternatives to utility owned hydro, fossil and nuclear plants. Many utilities, therefore, strongly feel that these utility sources of energy can ease the critical future problem of fuel cost and availability. Some papers have been published in the area of integration of non-conventional electricity generators in the planning process [43-50] and the operation process [51-56] of a power utility. Most of the existing literature on independent power production [57-62] has, in the past, been focused on the economic effects of this form of power production on the utility, or on the customer, or on the ownership regarding the operation of the installations. There are very few publications which consider the reliability and economic impacts of NUG and cogenerating facilities on utility systems. The integration of independent power production (IPP) facilities can have significant effects on both load point adequacy and overall power system adequacy. This research project focuses on the reliability and economic implications of injecting additional generation from conventional NUG at individual load buses (i.e. HLII analysis).

Load management, which is the second main thrust of this research project, entered the scene in the 1960s and 1970s. The early activities were in Europe and New Zealand and then later in the United States [68, 73, 74]. A number of papers have been published in the area of utility load or demand-side management (DSM) [63-81]. Today, load management is a subject of active interest throughout the electric utility industry, in regulatory circles, and in the public at large. Load management ideally influences consumer demand in order to optimize joint supply-demand operation, efficiency and cost [82]. It has existed in many forms since the early days of electricity. The oldest form prescribes a maximum electricity flow, above which supplies are automatically cut off. Load management is important for the 1990s because, with modern techniques, it is cheaper to control certain demands than to build more generation, transmission and distribution facilities. In order for utilities to have a successful DSM or load management program, they must have specific goals in regard to the modified shape of the system load curve. Once these goals are in place, the utility can promote DSM activities to change the pattern of electricity consumption. It is important to realize that load management should, in the long-run, be beneficial to both a utility and its customers. The utility expects that load management programs will lead to their existing generating facilities being utilized more efficiently, i.e., using low cost base load generation. In doing so, it should be possible for the utility to reduce the electricity rates charged to customers [83]. In addition, load management strategies could result in a smaller electrical energy or load growth rate which should reduce or defer the need to add expensive additional generating units.

Load management is normally considered at HLI, in terms of its effect on the overall system generating requirements and the overall system risk. Load management in this research work has been considered to occur at individual load buses within the system and the effects of load management are therefore considered at HLII. The research then extends the concepts of HLII load management by considering the combined effects of dispersed generation in the form of NUG and dispersed load management at the individual load points in the system.

1.6 Outline of the Thesis

This thesis has been organized into seven chapters. A general description of an analytical technique and a computer program currently utilized for composite generation and transmission system adequacy assessment is presented in Chapter 2. The program which was developed at the University of Saskatchewan [35, 84-87], is designated as COMREL (COMposite system RELiability evaluation). The analysis procedure is outlined in Chapter 2 showing the various steps and how the different indices are computed and accumulated. The advantages and limitations of this analytical method are also stated. This chapter also contains a brief description of the two test systems which have been used to numerically illustrate the various concepts developed in this thesis. The test systems are a small educational configuration designated as the Roy Billinton Test System (RBTS) [88, 89] and the IEEE Reliability Test System (IEEE-RTS) [90]. Chapter 2 also presents a series of system studies which illustrates the composite system reliability impacts associated with NUG options in the RBTS. The effects on both load point and overall system adequacy are discussed.

Customer cost functions can be used in conjunction with the predicted frequency, duration and magnitude of interruptions to estimate the financial losses associated with electric power supply failures. The concepts involved in the utilization of basic cost of interruption data to create individual load point composite customer damage functions are described in Chapter 3. The concepts involved in combining the customer damage function and the EENS or LOEE index to develop an interrupted energy assessment rate (IEAR) at HLII are also illustrated in this chapter. System studies are presented in Chapter 3 to show the variation in the cost of customer interruptions associated with non-utility generation options. These costs, (i.e., the costs to customers due to power interruptions), when combined with the utility costs are used to determine, an optimum planning reserve margin for the two test systems.

The literature shows studies [91, 92] using the IEEE-RTS hourly load model in which it is assumed that the overall system load shape is applicable to each system load bus. Individual bus loads, at any hour are assumed to be proportional to the ratio of peak load at that bus to the peak load of the entire system. This procedure is not absolutely correct as individual buses follow different load curves depending on the mix of customers at that bus. There is therefore a need for a more accurate representation of the individual bus loads. This phenomenon is illustrated, and the procedures used to create hourly loads for all the load buses are presented in Chapter 4. System adequacy studies to illustrate the effect of using these time varying or dependent loads for the RBTS are also presented in this chapter.

The basic concepts and tenets governing demand-side management are discussed and presented in Chapter 5. A methodology to quantify the impacts or effects of DSM programs on the different customer sector load models is also described in this chapter. The methodology has been applied to selected customer types to generate some new time dependent load models that reflect possible load shape modifications due to DSM programs. Illustrative examples using the RBTS are depicted in this chapter. System studies using the RBTS are presented in Chapter 5 which illustrate the impacts of DSM on composite generation and transmission system adequacy using the contingency enumeration technique. Reliability worth assessment plays a significant role in electric power system planning and operation. Chapter 5 also illustrates a method developed to assess the effects on the system costs of interruptions due to a range of DSM programs applied to the individual bus load models in the RBTS. Studies have been conducted to analyze the impact of structured changes in the time dependent load curves.

The reliability cost/reliability worth approach to assessing an optimal level of customer service is based on evaluating the capital, operating and customer interruption costs associated with different system configurations. Recent emphasis on energy costs, in conservation of resources and impacts of government and environmental groups have resulted in the need for more adequate justification of new system facilities. Chapter 6 presents an approach for analyzing or evaluating the reliability and economic impacts of combinations of supply facilities (i.e., additional generation in the form of NUG) and demand-side initiatives (i.e., in the form of DSM options) in a composite power system with time varying loads. Studies, involving the utilization of reliability and economic techniques to justify both supply and demand options, are presented and discussed in this chapter.

Chapter 7 summarizes the research work described in this thesis and presents the conclusions.

2. ADEQUACY EVALUATION IN COMPOSITE GENERATION AND TRANSMISSION SYSTEMS INVOLVING NON-UTILITY GENERATIONS

2.1. Introduction

Electric power utilities in most industrial nations have either delayed or put a temporary hold on building large conventional base-load generating units due to environmental concerns, decreased demand growth, the possible depletion of conventional energy sources and the increasing costs of construction [93-96]. Utilities are looking at more flexible options for meeting some of their forecasted load growth, other than the construction of conventional base load units. Unstated but implicit in the utilities' decision to avoid new conventional base-load units is the presence of desirable alternatives that were either not present or less attractive when prior decisions on capacity expansion were made. The wide range of alternatives available to management today [97, 98] are shown in Figure 2.1. Some utilities are rehabilitating older units, while others have chosen to depend upon non-utility generation (NUG) in order to satisfy a portion of the customer demand.

The increasing economic costs, the intense global awareness of environmental and future energy shortage problems have created considerable attention in the development of non-conventional energy sources

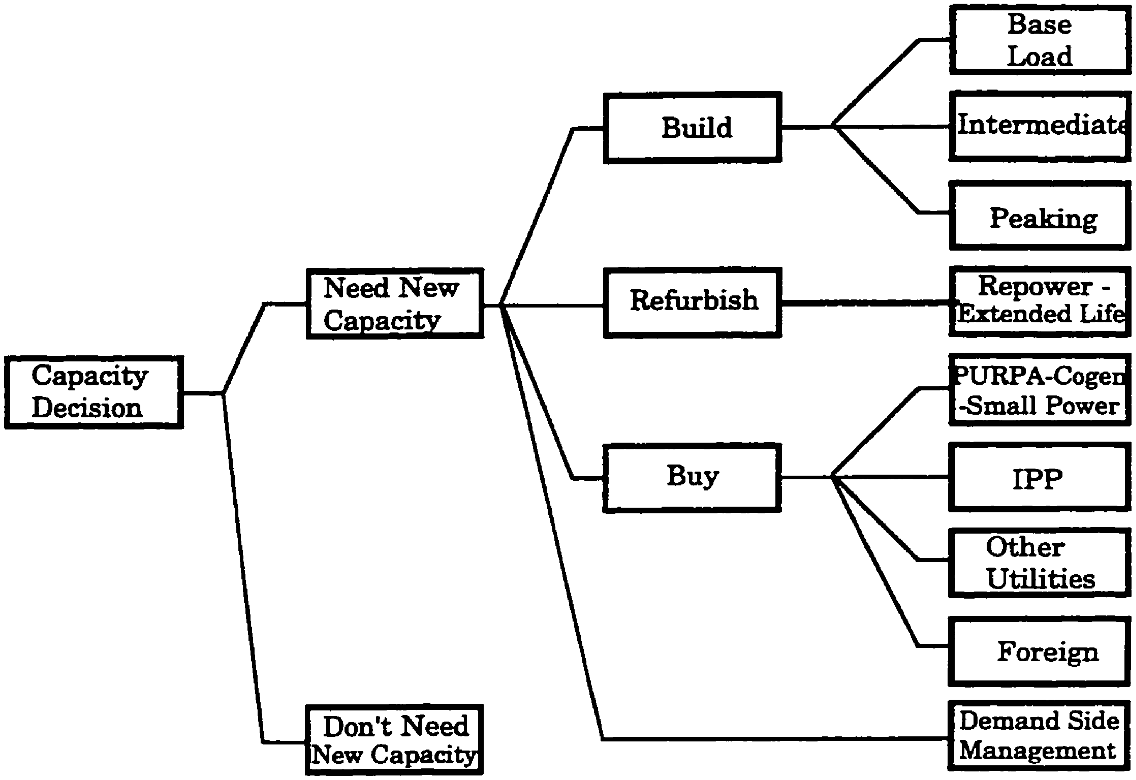

Figure 2.1: Capacity decision tree

and the adoption of energy conservation and efficient energy utilization measures. A significant portion of both present and future power plant investments will be made by non-utility generation (NUG) and cogeneration industries. Non-utility generation is an important bulk electric supply-option which is available to utilities when creating least cost energy plans. The task of evaluating the merits and demerits of such options is becoming an important function in power utility system planning. NUG is defined as those generating facilities owned and operated by electricity producers other than the main power utility. This may include relatively small private municipal utilities in addition to other independent power producers. Independent Power Production (IPP) comprises both non-utility generation and cogeneration facilities. Cogeneration is normally associated with an industry in which a significant requirement for electrical energy is linked with a large demand for process heat, normally in the form of steam. The introduction of IPP facilities provides opportunities to utilize renewable energy sources and assures the orderly, economic and efficient utilization of natural energy resources. Most of the publications on independent power production [57-62] are concentrated on the economic effects of this form of power production on the utility, on the customer, or on the ownership regarding the operation of the installation. There are very few publications which considered the reliability impacts of NUG and cogenerating facilities on utility systems [99-101]. The reliability impacts of IPP facilities can have a significant impact on the overall power system adequacy.

Bulk power system adequacy evaluation is primarily concerned with the total problem of assessing the ability of the generation and transmission facilities to supply acceptable electrical energy at the major system load buses. Two basic approaches have been applied in the development of the computing tools [28-36] used to evaluate composite system adequacy. These are contingency enumeration (analytical) and Monte Carlo simulation. A computer program, COMREL, based on the analytical technique and developed at the University of Saskatchewan by the Power System Research Group was used in the studies reported in this chapter. The primary objective in a composite system analysis is to evaluate adequacy indices for the total system and at every load bus or point in the system. A description of the COMREL program is given in the first part of this chapter.

The impact of this new power industry (NUG or IPP) is steadily growing. Electric power utilities should, therefore, prepare themselves for this growth by developing the ability to assess the impacts of NUG on their composite systems [99, 100]. The reliability impacts of independent power production can be quite significant on both load point and overall power system adequacy. Some studies have been conducted at the University of Saskatchewan [102], where the impact of NUG on load buses and the overall system was examined. This chapter extends this work by investigating the impact of single-bus NUG of different capacities on the composite system adequacy of the RBTS [99-101]. The general effects of NUG on the composite adequacy EENS index of the RBTS at individual load points and on the overall system adequacy are considered in this chapter.

2.2. COMposite System RELiability (COMREL) Program

The development of the digital computer program used to perform the composite system adequacy studies reported in this thesis was initiated at the University of Saskatchewan by Billinton in the 1960's. Extensive work was done in this area in subsequent years by Billinton and Bhavaraju, Billinton and Medicherla [85], Billinton and Kumar [86, 87] and Billinton and Khan [103] and has resulted in a refined digital software package designated as COMREL, which stands for COMposite system RELiability evaluation. This program is now one of the available innovative tools for composite system adequacy evaluation.

The COMREL program is based on the analytical concepts of reliability assessment and makes use of the contingency enumeration technique for the evaluation of composite systems. The program handles independent outages as well as common mode events and station-originated outages when required. Only independent outages are considered in the studies reported in this thesis. The program is equipped with three network solution techniques (i.e., a transportation model, a DC load flow algorithm and an AC load flow algorithm [104]) for analyzing system contingencies. These techniques are discussed in more detail later in this chapter. Any one of the solution techniques can be selected to analyze the system performance depending on the prescribed set of system failure criteria. The basic structure of the contingency enumeration algorithm used in the COMREL program is illustrated in the flow-chart shown in Figure 2.2. Additional features of the COMREL program are discussed in the following sub-sections.

In the contingency enumeration approach shown in Figure 2.2, a contingency is selected and examined in order to find out whether it causes any immediate system problem such as a circuit overload or bus voltage out of limits. If it does not, a new contingency is selected and tested. The occurrence of a system problem may by itself be considered as a failure. In some situations, however, it is possible to adjust generation to overcome overloads and change transformer taps to return voltages within the acceptable range. A system failure is therefore recorded when the remedial actions, short of curtailing customer loads, are insufficient to eliminate the system problems. The severity of such system problems are analyzed by evaluating the quantity and location of load curtailment necessary to remove the problem.

2.3. System Failure Criteria

Quantitative adequacy evaluation in a composite system is based on a prescribed set of criteria by which the system must be determined as being in either a success or failed state. A bulk power system is generally considered to be in the failed state if the service at the load buses is interrupted or if its level of quality becomes unacceptable. If any of the events listed below occur,

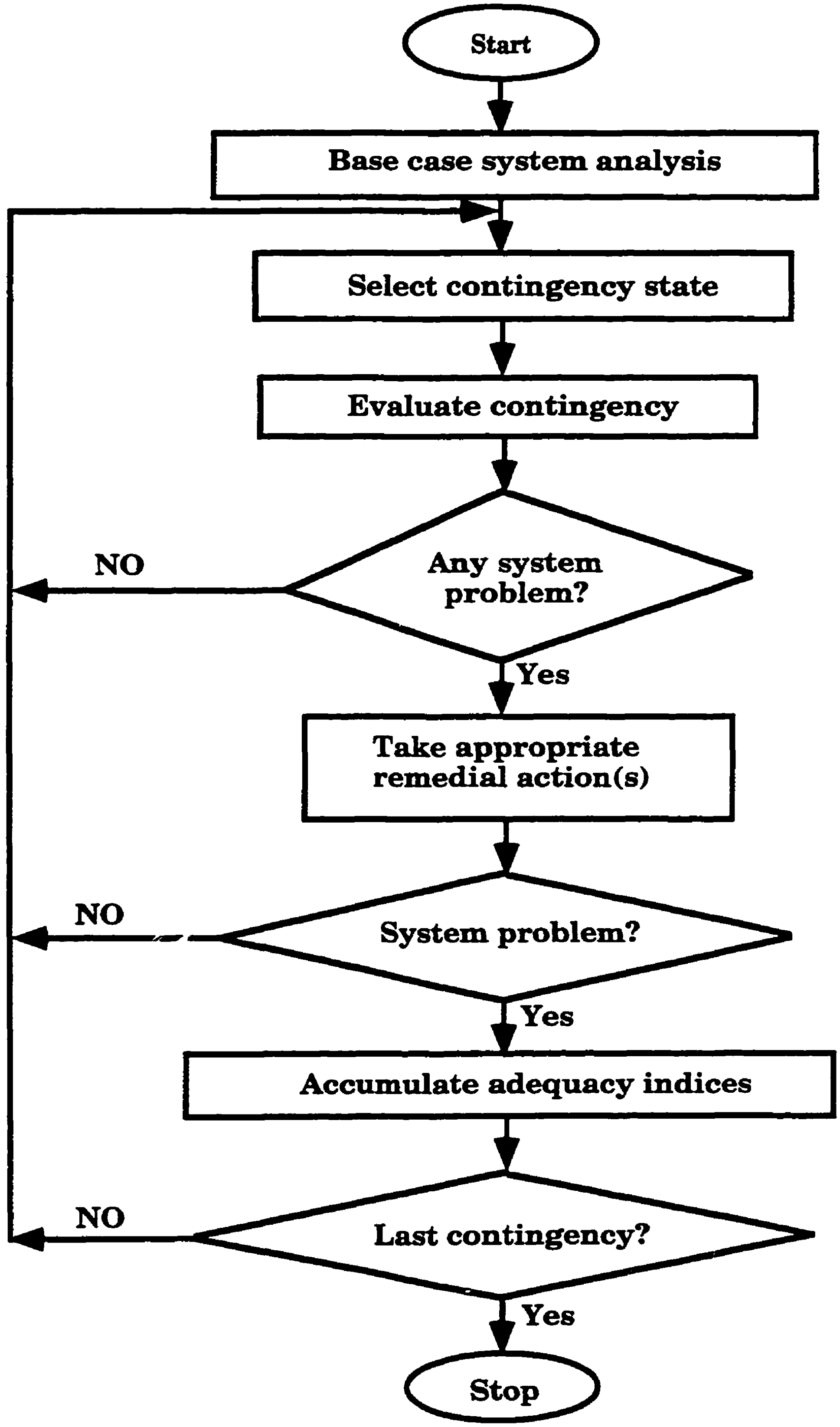

Figure 2.2: Flowchart for the COMREL program.

the composite system is considered to be in a failed state. These events are as follows:

- Lack of sufficient generation in the system to meet load demands;
- Interruption of continuity of power supply to a load point;
- Overload of transmission facilities (e.g., lines and transformers);
- Violation of bus voltage tolerances;
- Generating unit MVAr limit violations; and
- Ill-conditioned network situations.

It is important to note that if any of these conditions occur, it does not necessarily mean a collapse of the entire power system. This could, however, be recorded as a failure event. While it is possible for an overload condition to develop into a cascading sequence of events and finally lead to the collapse of the system, it is more likely that this would be prevented by taking appropriate corrective measures. The system failure criteria are therefore the set of undesirable events which form the basis for calculating load point and system adequacy indices.

2.4. Network Analysis

The adequacy analysis of a bulk power system generally involves the solution of the network configuration under selected outage conditions. Since the analysis normally involves many repetitive calculations for the various system contingency states to be tested, the efficiency and speed of the evaluation process depends considerably on the load flow algorithm used in the network analysis. Depending on the prescribed set of failure criteria, which in turn depends on the intent behind the studies, various solution techniques can be used; each producing a unique set of results. The three network solution techniques implemented in COMREL are listed below and described in the following sub-sections:

- Network Flow Method (or the transportation model),
- Direct Current (DC) Load Flow Method, and
- Alternating Current (AC) Load Flow Method.

2.4.1. Network Flow Method (Transportation Model)

The linear network flow or the transportation network model is the simplest solution technique. The basic concern in this case is continuity of power supply from the generation stations to the major load centres so as to satisfy the consumer load demands. The failure constraints addressed in the linear network flow model include limited availability of power at the generating stations to satisfy the system load requirements and the continuity of power flow to the major load centres. In the transportation model, capacity levels are assigned to every system component together with a probability corresponding to each capacity level. The network is solved by using Kirchhoff's First Law and maximal flow or minimal cut concepts [105]. This ensures that the lines flows do not exceed the prescribed capacities. This method produces approximate reliability indices which may be acceptable in some system applications.

2.4.2. Direct Current (DC) Load Flow Method

The DC load flow method, like the network flow method or the transportation model, does not provide any estimate of the bus voltages and the reactive power limits of the generating units. An approximate linear load flow technique such as DC load flow can be used to enhance the computation speed in composite power system adequacy assessment. In addition to recognizing generation unavailability and the lack of supply continuity as system constraints, the DC load flow solution technique also provides information regarding line overload conditions and permits this information to become system failure criteria when estimating the adequacy indices.

2.4.3. Alternating Current (AC) Load Flow Method

AC load flow methods are required when continuity of power supply and the quality of power supply (i.e. acceptable bus voltage levels and generating units MVAr limits) are important concerns in the adequacy assessment of a composite system. Conventional load flow techniques such as the Gauss-Siedel, Newton-Raphson and more accurate second order load flow methods are rarely used for adequacy studies due to their computing time and storage requirements. Several approximate versions of these algorithms, which are faster and require less storage have been developed and are more frequently used to produce results with an acceptable degree of accuracy. The fast decoupled AC load flow method is a good compromise between AC and DC load flow techniques with reference to storage requirements and speed of the solution. The computer program utilized to perform the adequacy evaluations of composite systems in this thesis, uses the fast decoupled load flow solution technique [85, 87]. The AC load flow method is capable of recognizing all the system failure criteria listed in Section 2.3. and can be used to produce reliability indices that reflect the impact of the operating characteristics of the electric power system.

The selection of an appropriate network solution technique is of prime importance and is basically an engineering decision. The selected technique, however, should be capable of satisfying the rationale behind the studies from a management, planning and design point of view.

2.5. Features of the COMREL Program

2.5.1. Contingency Selection and Evaluation

The large number of system contingency states that must be evaluated is a major handicap in the state enumeration approach. In order to handle these problems, the COMREL program has been equipped with the following features; most of which seek to truncate the state space and reduce the computational requirements.

2.5.1.1. Predetermined Contingency Level

This feature truncates the state space by selecting and specifying the order of overlapping outages to be considered. The COMREL program can consider simultaneous independent outages of generating units up to the (4th) level, of transmission facilities up to the (3rd) level and up to the (3rd) level for generating units and transmission facilities combined. The user is offered the flexibility of specifying, as input data, the appropriate levels within this range. It is therefore possible and convenient to study the incremental effect on system adequacy of higher order overlapping outages in order to determine the optimum cut-off point for a particular system.

2.5.1.2. Ranking

A contingency ranking facility was incorporated in one of the recent updates [103] of the COMREL program in order to enhance the truncation process by considering only those contingencies which have a sizeable impact on the system.

2.5.1.3. Frequency Cut-Off

To further enhance the computation speed, the program employs a frequency cut-off criterion which automatically neglects those contingencies with a frequency of occurrence less than a pre-specified value [106].

2.5.1.4. Sorting Facility

The sorting facility is a computation speed enhancement feature that neglects unnecessary repetitive assessments of identical outage events. Reliability indices are calculated using the sorting facility based on the result of system analysis for only one of the identical contingency states. The total number of identical contingencies is multiplied by the indices obtained using the first calculation in order to determine the contribution of the other identical contingencies. In this way, repetition of load flow analysis for contingency states that would ultimately produce identical effects is avoided. This approach results in significant saving in computing time. One assumption in this analysis is that, identical generating units are considered to be units with the same capacity rating, failure and repair rates and are located at the same generating bus or station.

2.5.2. Remedial Actions in the COMREL Program

It is important to determine whether it is possible to eliminate a system problem by employing a remedial action (corrective measure). The COMREL program is equipped with the following broad range of corrective actions based on the system failure criteria:

- Generation rescheduling in the case of capacity deficiency in the system: applicable in all the three network solution techniques;
- Handling of bus isolation and system splitting problems arising from transmission line(s) and transformer(s) outages: applicable to the three network solution techniques;
- Line overload alleviation: applicable to DC and AC load flow techniques;
- Correction of generation unit MVAr limit violation: applicable only in the AC load flow solution techniques;
- Correction of a bus voltage problem and the solution of ill-conditioned network situations: applicable in only the AC load flow solution technique; and
- Load curtailment in the event of an unavoidable system problem: applicable in all the three network solution methods.

The selection of a corrective measure depends on the situation that causes an outage in the system. If a generating unit outage at a generation bus results in a capacity shortfall at that bus, then the generation at other generation buses with reserve capacity is increased proportionally to make up for the deficiency. On the other hand, if the system remains deficient even after applying all the available reserve, load is curtailed at the relevant buses as dictated by the load curtailment philosophy.

2.5.2.1. Implementation of Load Curtailment Actions

A deterministic load curtailment policy is used in the COMREL program. The load at each system load bus is classified into two distinct groups:

- Firm load; and
- Curtailable load.

The proportion of the curtailable load at each bus is pre-specified as a percentage of the total bus load. This information is provided as input data. A system problem, such as a deficiency in system generation capacity, must be alleviated by load curtailment action. When a system problem occurs, curtailable load is interrupted first followed by the interruption of firm load, if necessary. The flexibility of either confining the load curtailment to the vicinity of the actual outage or distributing it over a wider area is implemented by defining three load curtailment passes, one of which must be selected by the analyst to indicate the preferred choice of confinement. The passes define sequential levels, each spreading the required curtailment over a wider area. This feature considerably enhances the flexibility of the COMREL program making it adaptable for use in a wide range of power system operating studies.

2.6. Composite System Adequacy Indices

In the probabilistic approach to reliability assessment, appropriate indices are defined in order to evaluate the reliability performance of the system in question. The basic indices produced by the COMREL program can be divided into two categories. The first category is a set of load point (or bus) indices and the second, a set of overall system indices. The load point indices are calculated for the major load points in the system and are necessary to identify the weak point in the system and very useful in helping to establish optimum response to system design changes for comparing alternate system configurations and modifications. They can also serve as input indices in the adequacy evaluation of distribution systems supplied from these bulk supply points.

The system indices are indicators of the overall adequacy of the composite system to meet the total system load demand and energy requirements and are quite useful for both the system planner and the utility management. It is important to understand that the two sets of indices do not replace each other, but are complementary. Both sets of indices are required in a complete assessment of power system reliability; i.e., these indices complement rather than substitute for each other. The severity of an outage event depends on the components under outage, their relative importance and their location in the network. An outage event may affect only a small area (bus) of the system or a large area (several buses). It is important to identify the areas of the system which have poor reliability and/or, are prone to disturbances. Such information cannot be obtained from the system indices, but is readily available from the individual load point values. A comprehensive list of HLII adequacy indices is provided in [3, 14, 85, 86, 107, 108] and some of the indices utilized in this thesis are described in this section.

2.6.1. Load Point Indices

There are three fundamental parameters in the evaluation of load point adequacy. These are the frequency, duration and severity associated with failure events. The probabilities can be derived by multiplying the frequency and duration values. Computationally, however, it is often easier to compute the event probabilities and frequencies and use them to derive the durations. Additional indices such as the expected load or energy curtailed can be created from these generic values [3, 14].

$$\text{Probability of failure} = \sum_j P_j P_{kj}, \tag{2.1}$$

$$\text{Frequency of failure} = \sum_j F_j P_{kj}, \tag{2.2}$$

where : j is an outage condition in the network,

P_j is the state probability of the outage event j,

F_j is the frequency of occurrence of the outage event j,

P_{kj} is the probability of load at bus k exceeding the maximum load that can be supplied at that bus during the outage event j.

$$\text{Expected number of load curtailments} = \sum_{j \in x,y} F_j \tag{2.3}$$

$$\text{Expected load curtailed} = \sum_{j \in x,y} L_{kj} F_j \quad \text{(MW)} \tag{2.4}$$

Expected energy not supplied $= \sum_{j \in x,y} L_{kj} D_{kj} F_j$ (MWh)

$$= \sum_{j \in x,y} 8760\ L_{kj} P_j \ \text{(MWhr)} \qquad (2.5)$$

Expected duration of load curtailment $= \sum_{j \in x,y} D_{kj} F_j$ (Hours)

$$= \sum_{j \in x,y} 8760 P_j \ \text{(hr)} \qquad (2.6)$$

where:

$j \in x$ includes all contingencies resulting in load curtailment at bus k,
$j \in y$ includes all contingencies which result in an isolation of bus k,
L_{kj} is the load curtailment at bus k to alleviate line overloads arising due to outage event j, or load not supplied at an isolated bus k due to the outage event j,
D_{kj} is the duration in hours of the load curtailment arising due to the outage event j, or the duration in hours of the load curtailment at an isolated bus k due to the outage event j.

2.6.2. Overall System Indices

The individual load point indices can be aggregated to yield a wide range of system indices. In addition to overall generation adequacy, system indices also recognize the need to transport the generated energy through the transmission network to consumer load points. Some of the basic system value indices are as follows:

Bulk Power Supply Average MW Curtailment Index (BPSACI)

$$= \frac{\sum_k \sum_{j \in x,y} L_{kj} F_j}{\sum_k \sum_{j \in x,y} F_j} \ \text{(MW/disturbance).} \qquad (2.7)$$

Bulk Power Interruption Index (BPII)

$$= \frac{\sum_{k} \sum_{j \in x,y} L_{kj} F_j}{L_S} \text{ (MW/MW-yr.).} \tag{2.8}$$

Bulk Power Energy Curtailment Index (BPECI)

$$= \frac{\sum_{k} \sum_{j \in x,y} 60 L_{kj} D_{kj} F_j}{L_S} \text{ (System Minutes),} \tag{2.9}$$

where L_S is the total system load and the index BPECI is also called Severity Index (SI).

Modified Bulk Power Energy Curtailment Index (MBPECI)

$$= \frac{\sum_{k} \sum_{j \in x,y} L_{kj} D_{kj} F_j}{8760 L_S}. \tag{2.10}$$

It can be appreciated that while the bus indices can sometimes be related to perceivable physical phenomena, the overall system (global) indices are generally more difficult to interpret as they are an aggregation of the individual bus values. It should also be appreciated that although the HLII indices add realism to the analysis by including bulk transmission, they still are adequacy indicators and do not include the ability of the system to respond to transient disturbances.

2.6.3. Annualized and Annual Indices

The indices calculated for a single fixed load level, which is normally the yearly peak, are designated as annualized indices. In a practical system, however, the load varies throughout the year according to the time-of-day, the day and the season. In a typical state enumeration assessment approach, the effect of variable load can be accounted for by creating a multi-step load model in which loads are aggregated into levels and their probability of occurrence determined from the chronological data of the load duration curve. Annualized indices are then computed for each load level and weighted by the corresponding load level probability of occurrence. The weighted values are summed to produce a more representative set of indices designated as annual indices. Annualized indices calculated at the system peak load level are, usually, much higher than the annual indices.

The annual indices presented in this thesis were calculated using the multi-step load aggregation method. The accuracy of the annual indices obtained in this way depends on the number of load steps assumed. In a particular case, the appropriate number of load steps depends upon the sensitivity of the composite system indices to load variations, but is also limited by computational constraints.

2.7. The Roy Billinton Test System

The Roy Billinton Test System designated as the RBTS [88, 89] is an educational test system developed by the Reliability Section of the Power Systems Research Group at the University of Saskatchewan [88, 89]. The single line diagram of the 6-bus RBTS is shown in Figure 2.3. The system has 2 generator (PV) buses, 4 load (PQ) buses, 9 transmission lines and 11 generating units. The minimum and maximum capacity ratings of the generating units are 5 MW and 40 MW respectively. The total installed generating capacity of the RBTS is 240 MW with a system peak load of 185 MW. This test system has a single transmission voltage level of 230 KV and the voltage limits for the system buses are assumed to be between 1.05 p.u. and 0.97 p.u. inclusive.

The portion of the system load, which is not located directly at either of the two generating stations, is approximately 89%. About 46% of 185 MW (system load) is located at a single bus (i.e. Bus 3). This necessitates a relatively large movement of bulk power from the two generating stations. The power transfer distances range from 75 kilometres to over 200 kilometres. The bus data, line data and generator data for this test system are given in Appendix A.

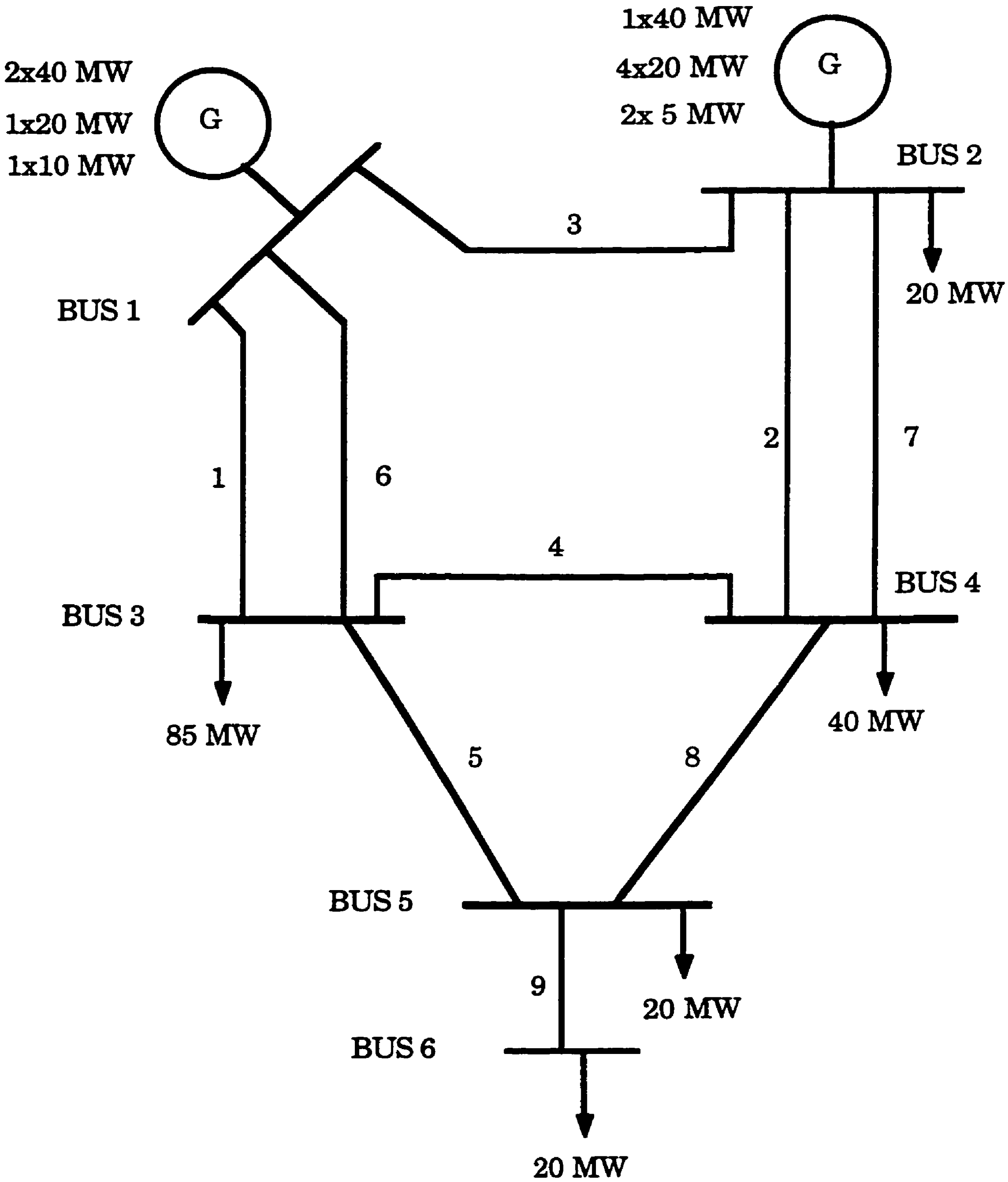

Figure 2.3: Single line diagram of the Roy Billinton Test System.

2.8. The IEEE Reliability Test System

The IEEE-Reliability Test System designated as the IEEE-RTS [90] was published in 1979 by the IEEE Subcommittee (or Task Force) on the Application of Probability Methods (APM) and has the structure of a relatively large practical power system. The IEEE-RTS provides a consistent and acceptable set of data that can be used in both generation and composite system adequacy assessment.

The single line diagram of the 24-bus IEEE-RTS is shown in Figure 2.4. This test system has 10 generator (PV) buses, 10 load (PQ) buses, 33 transmission lines, 5 transformers and 32 generating units. The total installed generating capacity of this system is 3405 MW and the annual system peak load is 2850 MW. The minimum and maximum rating of the generating units are 12 MW and 400 MW respectively. There are two transmission voltage levels i.e. 230 KV in the north region and 138 KV in the south region in the IEEE-RTS. The minimum and maximum voltage limits for the system buses are assumed to be 0.95 p.u. and 1.05 p.u. respectively. Approximately 80% of the installed generating capacity and 53% of the system load are located in the north region with the remainder located in the south region. The south region is therefore generation deficient. The bus data, line data and generation data for the IEEE-RTS are presented in Appendix B.

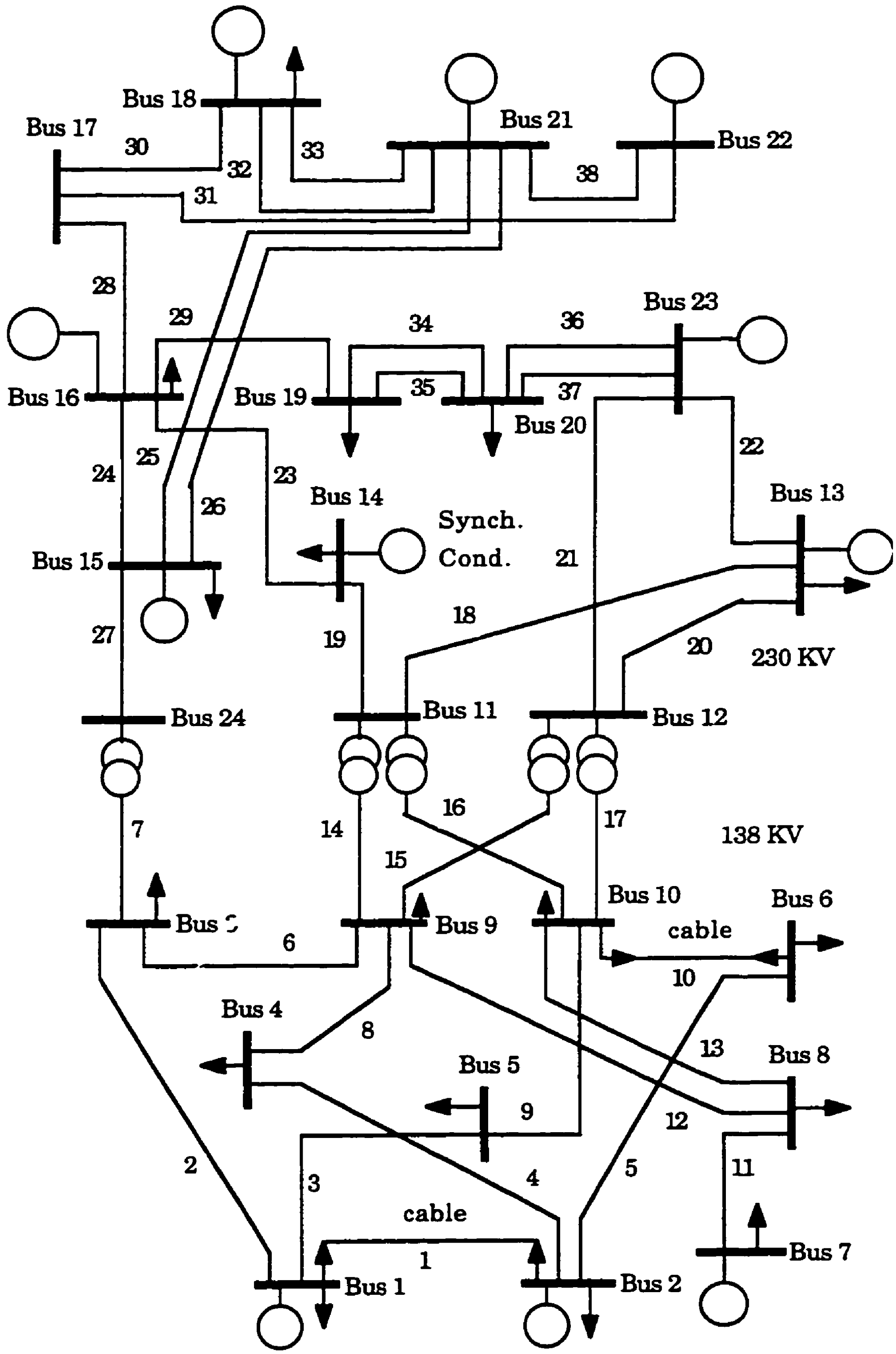

Figure 2.4: Single line diagram of the IEEE-Reliability Test System.

2.9. Load Model

The RBTS has a suggested annual peak load of 185 MW. The data on the weekly, daily and hourly loads for a one year period (8736 hours) are the same as those developed for the IEEE-Reliability Test System (RTS) [90]. A load duration curve can be obtained by arranging the 8736 hourly peak load data in descending order. The load model used, for the RBTS, originated from a set of 100 data points that best represent this hourly peak load variation curve. The load data are expressed in p.u. with the annual peak load as the base. Figure 2.5 shows the load duration curve obtained using these data points. The actual data points are provided in Appendix C.

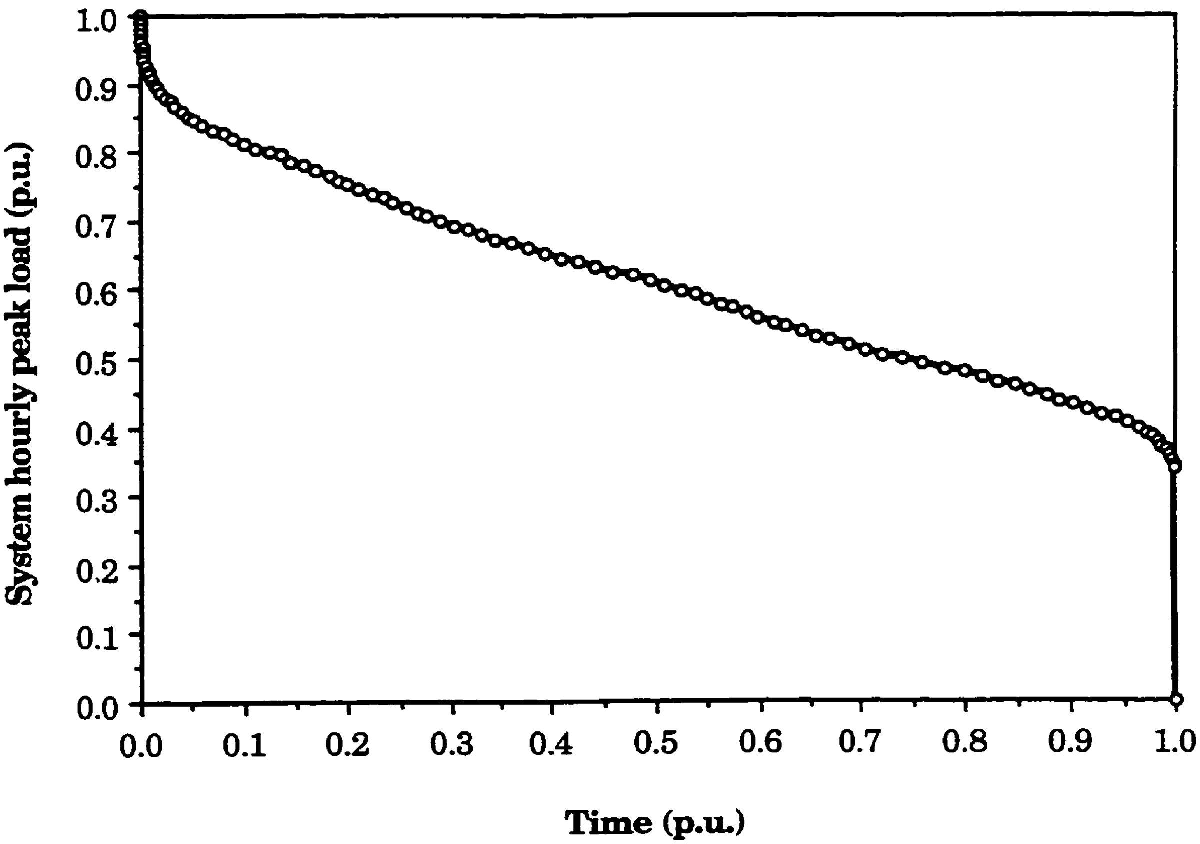

Figure 2.5: 100-point load duration curve.

The load duration curve can be represented by multiple discrete load levels which approximate the load model. A discrete load model was utilized in this research work to obtain annual indices which reflect the variation in system load over a one year period. A 7-step approximation of the load duration curve used in the RBTS base case studies is shown in Table 2.1. The load step size is 5%. The probability and duration in hours of occurrence corresponding to each load level over a period of one year are also shown in Table 2.1.

Table 2.1: 7-Step load model - (5% step size).

Step	Load (p.u.)	Load (MW) RBTS	Duration (hrs/year)	Probability
1	1.00	185.00	19.20	0.00219780
2	0.95	175.75	95.80	0.01096612
3	0.90	166.50	313.80	0.03592033
4	0.85	157.25	656.20	0.075114[illegible]7
5	0.80	148.00	727.70	0.08329[illegible]99
6	0.75	138.75	717.30	0.08210852
7	0.70	129.50	6206.00	0.71039377
Total			8736.00	1.00000000

Precision and Accuracy Considerations:

The probability values in Table 2.1 are shown with a high degree of precision. A similar degree of precision is shown for other calculated values throughout this thesis in order to facilitate comparison and sensitivity analysis. This does not imply a similar degree of accuracy due to residual uncertainty in the initial input parameters. The accuracy of a given calculated value cannot be associated with one half of the last digit in the value.

The number of steps considered appropriate for the aggregated approximation of the load model depends upon the sensitivity of the composite system indices to load variation [109]. The use of a large number of steps results in excessive computing time. Reducing the number of steps can lead to a significant reduction in computing time but can also result in an unacceptable degree of accuracy especially if the adequacy indices are very sensitive to load variation. An alternate 4-step approximation of the load model is shown in Table 2.2, with a step size of 10%.

Table 2.2: 4-Step load model - (10% step size).

Step	Load (p.u.)	Load (MW) RBTS	Duration (hrs/year)	Probability
1	1.00	185.00	115.00	0.01316392
2	0.90	166.50	970.00	0.11103480
3	0.80	148.00	1445.00	0.16540751
4	0.70	129.50	6206.00	0.71039377
Total			8736.00	1.00000000

2.10. Evaluation of the Base Case Results

2.10.1. Results for the RBTS

The reliability indices calculated for the original RBTS configuration are designated as the base case results. These values serve as a datum for comparing the effects of the modifications to the RBTS. This is illustrated later in this chapter. The COMREL program was used to compute both the load point and the overall system indices. The indices described earlier in this chapter are considered in this analysis. All the studies undertaken were conducted on the VAX-730 mainframe computer system using the COMREL program. The following options in the COMREL program were used for this analysis and for the rest of the work reported in this thesis.

(a) Contingency Selection:- In the COMREL program, independent overlapping outages up to the fourth level for generating units and up to the third level for transmission lines and/or transformers are considered. In the case of combined generator and line outages, situations involving up to two generating units and one line and one generating unit and two lines are considered.

(b) Network Analysis and Failure Criteria:- The solution technique, employed for the network analysis in the COMREL program, was the DC Load Flow method. Bus failure under an outage condition is defined as the inability of the system to meet the load requirements at that particular bus. This condition can be caused by outage combinations leading to line overloads, bus isolation or generation deficiencies.

(c) Remedial Actions:- Swing bus overload conditions are alleviated by curtailing load at various load buses in the COMREL program. Generation rescheduling and/or load curtailment are used to alleviate line or transformer overload conditions, if necessary, at the appropriate buses.

(d) Load Curtailment:- The curtailable load at each system load, in the COMREL program, was assumed to be 20% of the total load at the bus. In this analysis, the load curtailment pass was specified to be level one. This confines the load curtailment to load points immediately adjacent to the immediate location of the system problem.

Table 2.3 shows the base case load point indices produced by the COMREL program for the RBTS using the 4-step and 7-step load model approximations respectively. The corresponding system indices are shown in Table 2.4. Bus 5 is the most adequate load point in the RBTS. Bus 6 is the least adequate, which is obvious from the RBTS single line diagram shown in Figure 2.3. Bus 6 is located at a considerable distance from the two

Table 2.3: Annual load point indices for the base RBTS utilizing a 4-step or 7-step (10 or 5 percent step sizes) load model.

Bus Number	PLC	ENLC (Occ/yr)	ELC (MW/yr)	EENS (MWh/yr)
2	0.00030 (0.00028)	0.14489 (0.13381)	0.26860 (0.15430)	4.85430 (2.59930)
3	0.00047 (0.00044)	0.27518 (0.25704)	4.47520 (3.59420)	47.88740 (31.61310)
4	0.00031 (0.00028)	0.15197 (0.13928)	0.64270 (0.37280)	10.74120 (5.80550)
5	0.00001 (0.00001)	0.02021 (0.01884)	0.12640 (0.12010)	0.59640 (0.58270)
6	0.00114 (0.00114)	1.12872 (1.12865)	16.75370 (16.56320)	148.12020 (146.46530)

NB: Results obtained using 7-step load model are in parenthesis.

Table 2.4: System annual indices for the base RBTS using a single-step and a 4-step or 7-step (10 or 5 percent step sizes) load model respectively.

System Indices	System Annual Indices (4-Step)	System Annual Indices (7-Step)
ELC (MW/yr)	22.26641	20.80470
EENS (MWh/yr)	212.19951	187.06621
BPII (MW/MW-yr)	0.15841	0.15135
SI (System Minutes)	88.58437	80.61581

generating stations in the RBTS and is connected to the rest of the system by a single radial link. This bus, therefore, suffers complete isolation, and consequently load curtailment, whenever this radial connection is on outage.

When load curtailment pass one is specified, buses in the problem area are those directly connected to the immediate location of the system problem.

Under these conditions, Buses 5 and 6 are generally not affected by generating unit outages because they are outside the defined problem area. Based on this assumption, Bus 5 is rarely found to be in difficulty. In the COMREL program, loads are classified as being either firm or curtailable at the various system load buses. Load curtailment can therefore only be affected in a maximum of two steps which can lead to a situation of excessive load cuts beyond the limits considered adequate to alleviate a problem.

Comparing the results for the two load models, it can be seen from Tables 2.3 and 2.4 that the inadequacy indices computed for the individual load points and the overall system respectively using the 4-step load model are slightly higher than those obtained with the 7-step load model. This result is expected, as the effects of higher load levels generally last for shorter durations in the 7-step load model, which is a better reflection of the actual situation. It is, however, important to note that the calculations utilizing the 7-step load model require more computing (CPU) time than for the 4-step load model. The improvements achieved in the results may or may not be considered significant enough to merit the associated incremental computation costs. A decision regarding this, must be made by the analyst for the specific conditions and system under study.

2.10.2. Results for the IEEE-RTS

The indices produced by the COMREL program for the IEEE-RTS are shown in Tables 2.5 through 2.7 for both the 4-step load model and the 7-step load model. Tables 2.5 and 2.6 show the load point indices for the IEEE-RTS using the 4-step load model and the 7-step load model, respectively. Table 2.7 shows the overall system indices obtained using both load models.

Table 2.5: Annual load point indices for the base IEEE-RTS utilizing a 4-step (10 percent step size) load model.

Bus Number	PLC	ENLC (Occ/yr)	ELC (MW/yr)	EENS (MWh/yr)
1	0.00071	0.49186	3.99400	49.62640
2	0.00133	0.91395	7.43730	92.40630
3	0.00072	0.49599	8.04210	101.08930
4	0.00071	0.49352	3.75570	47.14930
5	0.00071	0.49352	3.17060	39.77610
6	0.00072	0.49481	6.94990	87.04490
7	0.00055	0.38128	4.38890	55.29320
8	0.00056	0.38520	8.00340	101.42410
9	0.00006	0.03992	0.63280	7.83010
10	0.00006	0.04017	0.69620	8.65560
13	0.00146	0.96364	34.44110	462.90610
14	0.00027	0.19954	4.35170	51.69920
15	0.00229	1.43846	59.71150	833.97[illegible]0
16	0.00081	0.60095	10.07550	98.25220
18	0.00296	1.87049	95.34120	1377.91770
19	0.00035	0.28247	9.05180	84.15250
20	0.00[illegible]61	1.05369	24.57410	341.47120

Buses 9 and 10 which are located at the mid-portion of the system where bulk power exchanges between the north and south regions of the IEEE-RTS occur are the most adequate buses in the IEEE-RTS. Bus 18 has the lowest adequacy. Most of this inadequacy is due to several swing bus overload conditions that arise as a result of many outage combinations involving the generating unit connected at Bus 18 and other relatively large generators in the system.

Table 2.6: Annual load point indices for the base IEEE-RTS utilizing a 7-step (5 percent step size) load model.

Bus Number	PLC	ENLC (Occ/yr)	ELC (MW/yr)	EENS (MWh/yr)
1	0.00033	0.22895	1.81470	23.08820
2	0.00063	0.43355	3.38460	43.07200
3	0.00033	0.23010	3.48910	44.59810
4	0.00033	0.22979	1.64790	20.97860
5	0.00033	0.22969	1.38130	17.58250
6	0.00033	0.23043	3.06820	38.85700
7	0.00026	0.18165	2.01640	25.60120
8	0.00026	0.18334	3.59490	45.95810
9	0.00002	0.01143	0.23140	2.73840
10	0.00002	0.01148	0.24930	3.00000
13	0.00085	0.55966	17.24340	229.76400
14	0.00015	0.11045	2.11140	24.36490
15	0.00129	0.80740	30.99020	441.156[illegible]0
16	0.00044	0.35014	7.17220	62.29970
18	0.00161	1.01277	47.95180	694.41620
19	0.00020	0.18178	6.83500	55.90160
20	0.00[illegible]92	0.59152	12.68030	177.85810

Table 2.7: System annual indices for the base IEEE-RTS using a 4-step (10 percent step size) and 7-step (5 percent step size) load model respectively.

System Indices	System Annual Indices (4-Step)	System Annual Indices (7-Step)
ELC (MW/yr)	284.6183	145.8622
EENS (MWh/yr)	3840.6707	1951.2350
BPII (MW/MW-yr)	0.1072	0.0570
SI (System Minutes)	86.2470	45.2370

The results obtained for the IEEE-RTS, using the 7-step load model, show a considerable (more than 50%) reduction in inadequacy both at the individual load points and for the overall system compared to the results obtained with the 4-step load model. This observation illustrates the high sensitivity of the composite system indices of the IEEE-RTS to the load duration curve, as reported in [109]. This increase in accuracy is obtained at a considerable increase in computation cost. The gain in accuracy of the annual indices as a result of using the 7-step load model is sufficiently large to warrant the attendant increase in computation cost.

2.11. Contribution of Electrical Energy from Non-Utility Generation

The legal and regulatory changes in some countries, the recent success of competitive procurement as a means of acquiring NUG, and the response of the NUG developers to competitive procurement solicitations has made NUG growth in the 1990s inevitable. In the United States, federal laws and regulations under the PURPA [110] clearly established the existence of qualifying facilities (QFs) [110], and the Federal Energy Regulatory Commission (FERC) [110] has shown a willingness to encourage further NUG in the form of IPPs and cogenerators. The 1989 North American Electric Reliability Council (NERC) forecast included the addition of 93,600 MW of new capacity for the U.S.A. between 1989 and 1998 [93].

In Italy, the total NUG production (26.6 TWh gross) in 1991 was about 9.6 percent of the country's total production [111]. Two laws on institutional aspects and on energy savings of January 1991 removed many of the shackles to independent producers giving additional administrative and financial incentives. The NUG production can be sold to ENEL or to any company. A rapid increase in IPP proposals has been observed. Approximately 9000 MW of new capacity has been proposed [111]. Forecast sales by NUG included in the ENEL plan are in the range of 3000-4500 MW of capacity with a projected supply of 18-27 TWh.

Use of cogeneration systems in Japan, is expected to expand from now on as their role and effectiveness is becoming well recognized. According to a recent study, potential demand of cogeneration systems in the commercial field, in 1990, was about 4.2 GW and is expected to be 5.2 GW by 2000 [111]. In Denmark, the independent generating capacity totaled 503 MW, or 5.5 percent of the installed capacity in the public generating system in 1992 [111]. The major portion of NUG comes from wind energy. According to a report published by Frost and Sullivan's London office [111], there is a potential market for 40,000 MW of cogeneration in Europe. In West Germany, the installed capacity of cogeneration was 14,000 MW in 198?. An additional 3000 MW of new cogeneration capacity was anticipated by 1993. In Scandinavia, about 2000 MW of new cogeneration was expected to be installed. With the additional capacity, the Scandinavian countries was to have a total cogeneration capacity of 13,000 MW. New cogeneration capacity of 2300 MW was added in the three Benelux countries. By the end of 1993, the total installed capacity of the Benelux countries was approximately 5300 MW. In the Mediterranean areas, Iberia and Greece were to add 840 MW of new cogeneration capacity by the end of 1993. With the privatization of the Central Electricity Generating Board in the UK, it was anticipated that by the end of 1993, an additional 2100 MW of new cogeneration capacity was to be added. This was to increase the area's cogeneration capacity by 53%. About 500 MW and 200 MW of new cogeneration capacities was to be added in France and Austria respectively. They also have the potential for developing additional hydropower in the Alps.

Canada does not have a national policy with regard to the development of NUG, nor is there any comprehensive legislation similar to PURPA in the United States. The federal and some provincial governments, however, have indicated their interest in, and support for, NUG development. It is predicted that regulations will eventually be created to increase the amount of electrical energy from NUG [112].

2.12. System Studies Involving Non-Utility Generation

Independent power production (IPP) in the form of non-utility generation (NUG) and cogeneration facilities is considered to be an important component in meeting future electrical energy requirements. The IPP facilities are usually small private electric power business operations which often use natural resources such as small hydro, wood waste, natural gas, the wind and other forms of renewable energy resources for the production of electrical energy. The NUG can, therefore, be modelled as small capacity components with relatively low forced outage rate (FOR) values compared to their conventional generating unit counterparts. In regard to cogeneration facilities, it is important to recognize that the production of by-product electric power is essentially a secondary industrial operation. The capacity components of cogeneration facilities are therefore determined by the available industrial process steam supply, and this usually depends on the level of production, which is generally variable. It is, therefore, operationally more economical to install multiple small capacity cogenerating units which can be run in stages as sufficient steam becomes available. This is better than having a single large unit installation that can only be operational when industrial output is at its maximum level.

The original design of the RBTS was modified to include independent power generation facilities at single locations in order to examine their impact on HLII adequacy indices. NUG can be inserted at almost any location in a utility system [99, 100]. Their basic function is to supply relatively small amounts of electrical energy to the system and under normal conditions, tend to reduce system operating costs by reducing system transmission losses. Because of their locations within the system, NUG can also be used to serve system loads which cannot be supplied because of transmission capacity limitations, load point isolation or other related split network situations resulting from system outage conditions. NUG are usually located at or close to system load points, apart from a few instances, such as those involving small hydro sources which are site specific. For the purposes of this study, NUG were considered to be introduced at the system load points. The following modifications were made to the basic RBTS:

(1) When a "pure" load bus of the RBTS is selected to serve as a NUG point, its definition is changed from a PQ-bus to a PV-bus. Therefore all of its relevant parameters such as the bus voltage and the scheduled generation are modified to conform with those of the other system PV-buses.

(2) The scheduled real power generation associated with a non-utility generator is assumed to be fixed and equal to the value of the rated capacity of the unit whenever the unit is available.

The procedure and assumptions utilized in running the COMREL program for the NUG studies are the same as those used to obtain the base case results for the RBTS. The studies described in this chapter include the injection of 2-MW and 5-MW NUG units (with assumed values of FOR = 2%) at different single-bus locations in the RBTS. The RBTS Buses 1 through 6 are used in this analysis.

2.13. Discussion of the RBTS Results

The impact of different capacity NUG facilities on load point and overall system adequacy of the RBTS are discussed in this section. The impacts on the expected energy not supplied (EENS) index at the various load points and the overall system of the hypothetical test system is considered. These injections produce different impacts on the load point and the overall power system EENS. The EENS results obtained using COMREL are presented. The result shown is an annual index which reflects the variations in load level over a year period. The 4-step (10 percent load step) load model was used for the analysis involving the RBTS.

2.13.1. Load Point Indices

The load point variations in the expected energy not supplied (EENS) or expected unserved energy (EUE) when identical 2-MW capacity NUG facilities are incrementally introduced at Buses 1, 2, 3, 4, 5 and 6 of the RBTS are presented in Tables 2.8 through 2.13. Similar results, obtained when 5-MW capacity NUG are introduced at different locations using the same load buses of the basic RBTS, are provided in Tables 2.14 to 2.19.

The results presented in Tables 2.8 through 2.19 show a general tendency towards reduction in the EENS for most load points, when NUG are introduced at the different buses of the RBTS. The addition of a highly available NUG will, to some extent, alleviate the severity or intensity of an outage problem affecting a particular load point. Results presented in Tables 2.8 to 2.19 show reductions in the expected energy not supplied at most load points in the early stages of unit additions. However, unless the unit additions are enough to entirely eliminate all the problems associated with the particular outage event, that event will still count as a problem contingency and has to be considered when evaluating the EENS for the load point. It can be observed from Tables 2.8 through 2.13 when compared with Tables 2.14 to 2.19 that the expected unserved energy at most of the individual load buses are lower, when five identical 2-MW capacity NUG facilities are injected at different buses of the RBTS, than when two identical 5-MW capacity NUG units are added to the same buses. Similar results were obtained for (10 * 2-MW) and (4 * 5-MW) capacity NUG additions.

The largest reduction in the expected energy not supplied occurs at Bus 6 when NUG are added at that location. The EENS at Bus 6 is generally unaffected by unit additions, except when the NUG facilities are introduced at Bus 6. This is the most unreliable load point in the RBTS because of the frequent isolation problems it experiences due to Line 9. The introduction of extra generation facilities anywhere beyond the radial connection does not significantly reduce the expected energy not supplied at Bus 6, because the isolation problems are not generally addressed by such actions. When NUG are injected at Bus 6, generation from these units is used locally to provide energy supply and therefore produces significant reductions in the expected unserved energy at this load point.

Table 2.8: The load point expected energy not supplied with the incremental addition of identical 2-MW capacity NUG to Bus 1 of the basic RBTS.

Addition of NUG	EENS At Bus 2 MWh/yr	EENS At Bus 3 MWh/yr	EENS At Bus 4 MWh/yr	EENS At Bus 5 MWh/yr	EENS At Bus 6 MWh/yr
RBTS+(0*2MW)	4.8543	47.8874	10.7412	0.6246	148.1483
RBTS+(1*2MW)	4.1622	42.6202	9.1458	0.6046	148.0880
RBTS+(2*2MW)	3.4808	37.6072	7.6021	0.5857	148.0178
RBTS+(3*2MW)	2.7771	32.6664	6.0821	0.5688	147.9374
RBTS+(4*2MW)	2.0688	27.7378	4.5750	0.5524	147.8463
RBTS+(5*2MW)	1.3918	22.8326	3.1503	0.5369	147.7440
RBTS+(6*2MW)	1.1005	19.4914	2.5065	0.5239	147.6305
RBTS+(7*2MW)	0.9561	18.1521	2.1724	0.5169	147.5056
RBTS+(8*2MW)	0.8419	17.2557	1.9061	0.5124	147.3685
RBTS+(9*2MW)	0.7376	16.4365	1.6631	0.5082	147.2188
RBTS+(10*2MW)	0.6363	15.6345	1.4296	0.5040	147.0562

Table 2.9: The load point expected energy not supplied with the incremental addition of identical 2-MW capacity NUG to Bus 2 of the basic RBTS.

Addition of NUG	EENS At Bus 2 MWh/yr	EENS At Bus 3 MWh/yr	EENS At Bus 4 MWh/yr	EENS At Bus 5 MWh/yr	EENS At Bus 6 MWh/yr
RBTS+(0*2MW)	4.8543	47.8874	10.7412	0.6246	148.1483
RBTS+(1*2MW)	4.2274	43.3062	9.2980	0.6730	148.0880
RBTS+(2*2MW)	3.5981	39.0077	7.8761	0.7085	148.0180
RBTS+(3*2MW)	2.9374	34.8777	6.4509	0.7291	147.9376
RBTS+(4*2MW)	2.2600	30.7056	5.0163	0.7382	147.8466
RBTS+(5*2MW)	1.5974	26.6821	3.6280	0.7461	147.7443
RBTS+(6*2MW)	1.2278	23.8151	2.8363	0.7642	147.6307
RBTS+(7*2MW)	1.0445	22.8914	2.4296	0.7740	147.5057
RBTS+(8*2MW)	0.9165	22.4909	2.3223	0.7826	147.3685
RBTS+(9*2MW)	0.8121	22.0401	2.4211	0.7930	147.2189
RBTS+(10*2MW)	0.7127	21.5540	2.5493	0.8044	147.0563

Table 2.10: The load point expected energy not supplied with the incremental addition of identical 2-MW capacity NUG to Bus 3 of the basic RBTS.

Addition of NUG	EENS At Bus 2 MWh/yr	EENS At Bus 3 MWh/yr	EENS At Bus 4 MWh/yr	EENS At Bus 5 MWh/yr	EENS At Bus 6 MWh/yr
RBTS+(0*2MW)	4.8543	47.8874	10.7412	0.6246	148.1483
RBTS+(1*2MW)	4.2946	44.9719	9.5659	0.7485	148.0884
RBTS+(2*2MW)	3.5842	39.9873	8.0324	0.8255	148.0178
RBTS+(3*2MW)	2.8588	34.9404	6.4992	0.8644	147.9372
RBTS+(4*2MW)	2.1283	29.8816	4.9401	0.8653	147.8461
RBTS+(5*2MW)	1.4285	24.7737	3.4548	0.8299	147.7437
RBTS+(6*2MW)	1.1002	20.9902	2.6976	0.7635	147.6302
RBTS+(7*2MW)	0.9451	19.2504	2.2734	0.7090	147.5053
RBTS+(8*2MW)	0.8276	18.2395	1.9800	0.6932	147.3681
RBTS+(9*2MW)	0.7203	17.3734	1.7269	0.6844	147.2184
RBTS+(10*2MW)	0.6166	16.5381	1.4804	0.6716	147.0558

Table 2.11: The load point expected energy not supplied with the incremental addition of identical 2-MW capacity NUG to Bus 4 of the basic RBTS.

Addition of NUG	EENS At Bus 2 MWh/yr	EENS At Bus 3 MWh/yr	EENS At Bus 4 MWh/yr	EENS At Bus 5 MWh/yr	EENS At Bus 6 MWh/yr
RBTS+(0*2MW)	4.8543	47.8874	10.7412	0.6246	148.1483
RBTS+(1*2MW)	4.3715	44.1593	9.9964	0.7822	148.0881
RBTS+(2*2MW)	3.6617	38.7555	8.3267	0.8514	148.0179
RBTS+(3*2MW)	2.9388	33.7714	6.8247	0.8845	147.9374
RBTS+(4*2MW)	2.2071	28.7727	5.2885	0.8831	147.8462
RBTS+(5*2MW)	1.4986	23.8633	3.7604	0.8481	147.7438
RBTS+(6*2MW)	1.1242	20.2942	2.8569	0.7838	147.6303
RBTS+(7*2MW)	0.9588	18.7489	2.3909	0.7324	147.5053
RBTS+(8*2MW)	0.8394	17.8872	2.0968	0.7140	147.3683
RBTS+(9*2MW)	0.7317	17.1704	1.8170	0.7051	147.2190
RBTS+(10*2MW)	0.6282	16.4803	1.5786	0.6937	147.0567

Table 2.12: The load point expected energy not supplied with the incremental addition of identical 2-MW capacity NUG to Bus 5 of the basic RBTS.

Addition of NUG	EENS At Bus 2 MWh/yr	EENS At Bus 3 MWh/yr	EENS At Bus 4 MWh/yr	EENS At Bus 5 MWh/yr	EENS At Bus 6 MWh/yr
RBTS+(0*2MW)	4.8543	47.8874	10.7412	0.6246	148.1483
RBTS+(1*2MW)	4.5654	46.2939	10.3701	0.9859	148.2097
RBTS+(2*2MW)	3.8370	40.6915	8.5638	1.0496	148.2193
RBTS+(3*2MW)	3.1136	35.3100	6.9911	1.0745	148.1828
RBTS+(4*2MW)	2.3736	30.1417	5.4234	1.0734	148.1014
RBTS+(5*2MW)	1.6418	25.0232	3.8504	1.0409	147.9740
RBTS+(6*2MW)	1.1639	20.7453	2.7910	0.9760	147.8014
RBTS+(7*2MW)	0.9772	18.6040	2.3053	0.9145	147.6107
RBTS+(8*2MW)	0.8531	17.5359	1.9763	0.8603	147.4395
RBTS+(9*2MW)	0.7432	16.6677	1.7150	0.8015	147.2734
RBTS+(10*2MW)	0.6387	15.8293	1.4693	0.7783	147.0928

Table 2.13: The load point expected energy not supplied with the incremental addition of identical 2-MW capacity NUG to Bus 6 of the basic RBTS

Addition of NUG	EENS At Bus 2 MWh/yr	EENS At Bus 3 MWh/yr	EENS At Bus 4 MWh/yr	EENS At Bus 5 MWh/yr	EENS At Bus 6 MWh/yr
RBTS+(0*2MW)	4.8543	47.8874	10.7412	0.6246	148.1483
RBTS+(1*2MW)	4.2857	43.5114	9.6291	0.7411	128.6957
RBTS+(2*2MW)	3.5659	38.0044	7.7716	0.8071	109.2136
RBTS+(3*2MW)	2.8288	32.6731	6.1633	0.8327	89.7049
RBTS+(4*2MW)	2.0867	27.4743	4.5545	0.8166	70.1803
RBTS+(5*2MW)	1.3839	22.3979	3.0705	0.7642	50.5791
RBTS+(6*2MW)	1.0840	18.9888	2.4049	0.6814	30.9834
RBTS+(7*2MW)	0.9340	17.5889	2.0558	0.6181	11.4364
RBTS+(8*2MW)	0.8171	16.6290	1.7814	0.5941	3.9912
RBTS+(9*2MW)	0.7087	15.7627	1.5310	0.5731	0.9360
RBTS+(10*2MW)	0.6008	14.9235	1.2854	0.5437	0.2728

Table 2.14: The load point expected energy not supplied with the incremental addition of identical 5-MW capacity NUG to Bus 1 of the basic RBTS.

Addition of NUG	EENS At Bus 2 MWh/yr	EENS At Bus 3 MWh/yr	EENS At Bus 4 MWh/yr	EENS At Bus 5 MWh/yr	EENS At Bus 6 MWh/yr
RBTS+(0*5MW)	4.8543	47.8874	10.7412	0.6246	148.1483
RBTS+(1*5MW)	3.1434	35.2321	6.8737	0.5816	148.0858
RBTS+(2*5MW)	1.4066	23.0375	3.1928	0.5443	148.0134
RBTS+(3*5MW)	0.9217	18.1186	2.0958	0.5248	147.9334
RBTS+(4*5MW)	0.6543	16.0327	1.4769	0.5186	147.8435

Table 2.15: The load point expected energy not supplied with the incremental addition of identical 5-MW capacity NUG to Bus 2 of the basic RBTS.

Addition of NUG	EENS At Bus 2 MWh/yr	EENS At Bus 3 MWh/yr	EENS At Bus 4 MWh/yr	EENS At Bus 5 MWh/yr	EENS At Bus 6 MWh/yr
RBTS+(0*5MW)	4.8543	47.8874	10.7412	0.6246	148.1483
RBTS+(1*5MW)	3.2393	37.1800	7.1114	0.7296	148.0859
RBTS+(2*5MW)	1.5731	27.0419	3.5943	0.7566	148.0138
RBTS+(3*5MW)	0.9968	23.3635	2.3610	0.7953	147.9335
RBTS+(4*5MW)	0.7103	22.2248	2.5805	0.8324	147.8436

Table 2.16: The load point expected energy not supplied with the incremental addition of identical 5-MW capacity NUG to Bus 3 of the basic RBTS.

Addition of NUG	EENS At Bus 2 MWh/yr	EENS At Bus 3 MWh/yr	EENS At Bus 4 MWh/yr	EENS At Bus 5 MWh/yr	EENS At Bus 6 MWh/yr
RBTS+(0*5MW)	4.8543	47.8874	10.7412	0.6246	148.1483
RBTS+(1*5MW)	3.2463	37.1705	7.2225	0.7296	148.0856
RBTS+(2*5MW)	1.4507	24.6664	3.4233	0.7317	148.0131
RBTS+(3*5MW)	0.9161	19.0116	2.1828	0.6590	147.9331
RBTS+(4*5MW)	0.6396	16.7348	1.4937	0.6196	147.8430

Table 2.17: The load point expected energy not supplied with the incremental addition of identical 5-MW capacity NUG to Bus 4 of the basic RBTS.

Addition of NUG	EENS At Bus 2 MWh/yr	EENS At Bus 3 MWh/yr	EENS At Bus 4 MWh/yr	EENS At Bus 5 MWh/yr	EENS At Bus 6 MWh/yr
RBTS+(0*5MW)	4.8543	47.8874	10.7412	0.6246	148.1483
RBTS+(1*5MW)	3.3260	36.5619	7.6154	0.7598	148.0858
RBTS+(2*5MW)	1.5213	24.2256	3.6179	0.7557	148.0133
RBTS+(3*5MW)	0.9318	18.7956	2.2139	0.6844	147.9331
RBTS+(4*5MW)	0.6517	16.9843	1.5234	0.6459	147.8440

Table 2.18: The load point expected energy not supplied with the incremental addition of identical 5-MW capacity NUG to Bus 5 of the basic RBTS.

Addition of NUG	EENS At Bus 2 MWh/yr	EENS At Bus 3 MWh/yr	EENS At Bus 4 MWh/yr	EENS At Bus 5 MWh/yr	EENS At Bus 6 MWh/yr
RBTS+(0*5MW)	4.8543	47.8874	10.7412	0.6246	148.1483
RBTS+(1*5MW)	3.5091	38.3089	7.9677	0.9418	148.1906
RBTS+(2*5MW)	1.6723	25.3990	3.8273	0.9182	148.1294
RBTS+(3*5MW)	0.9569	18.6097	2.2171	0.8309	147.9747
RBTS+(4*5MW)	0.5676	16.3280	1.4957	0.7373	147.8137

Table 2.19: The load point expected energy not supplied with the incremental addition of identical 5-MW capacity NUG to Bus 1 of the basic RBTS.

Addition of NUG	EENS At Bus 2 MWh/yr	EENS At Bus 3 MWh/yr	EENS At Bus 4 MWh/yr	EENS At Bus 5 MWh/yr	EENS At Bus 6 MWh/yr
RBTS+(0*5MW)	4.8543	47.8874	10.7412	0.6246	148.1483
RBTS+(1*5MW)	3.2198	35.5932	7.2299	0.7007	99.3887
RBTS+(2*5MW)	1.4067	22.6898	3.1323	0.6685	50.5759
RBTS+(3*5MW)	0.9028	17.5327	1.9870	0.5599	8.3329
RBTS+(4*5MW)	0.6253	15.3665	1.3447	0.4904	0.6442

2.13.2. System Indices

The results presented in Tables 2.20 and 2.21 show the overall system expected energy not supplied, obtained by summing all the corresponding individual load point EENS, when 2-MW and 5-MW capacity NUG facilities are respectively introduced at single locations involving Buses 1 through 6 of the basic RBTS.

Gradual improvements in the overall system EENS occur as the number of NUG introduced at a particular location increases. The rate of improvement, however, varies depending on the different capacity sizes of unit additions and locations. The corresponding overall system EENS also settles at different levels for the same total number of NUG added to the test system. It is important to appreciate that composite power system inadequacy, in addition to direct generation deficiencies and bus isolation due to transmission failures, is also related to the composite problem of generation and transmission outages. As already noted in the case of the RBTS, the weak transmission link to Bus 6 minimizes the benefits to Bus 6 of the additional NUG generation introduced at Buses 1 to 5. Bus 6 is the major source of inadequacy in the basic RBTS. It can be observed from Tables 2.20 and 2.21 that the expected system unserved energy is lower when five identical 2-MW capacity NUG facilities are injected at different buses of the RBTS, than when two identical 5-MW capacity NUG are added to the same buses of the RBTS.

The principal benefits of NUG additions at the various system locations is to alleviate generating capacity deficiencies which constitute a relatively insignificant portion of the overall system expected energy not supplied. Buses 3, 4 and 6 are the major contributors to the expected overall system

Table 2.20: The overall system expected energy not supplied (EENS) with the incremental addition of identical 2-MW capacity NUG at each individual bus of the basic RBTS.

Addition of NUG	EENS Bus 1 MWh/yr	EENS Bus 2 MWh/yr	EENS Bus 3 MWh/yr	EENS Bus 4 MWh/yr	EENS Bus 5 MWh/yr	EENS Bus 6 MWh/yr
RB+(0*2MW)	212.2559	212.2559	212.2559	212.2559	212.2559	212.2559
RB+(1*2MW)	204.6207	205.5927	207.6693	207.3975	210.4251	186.8629
RB+(2*2MW)	197.2937	199.2083	200.4472	199.6131	202.3613	159.3626
RB+(3*2MW)	190.0318	192.9323	193.1000	192.3567	194.6719	132.2028
RB+(4*2MW)	182.7803	186.5667	185.6614	184.9977	187.1134	105.1124
RB+(5*2MW)	175.6557	180.3978	178.2307	177.7142	179.5303	78.1955
RB+(6*2MW)	171.2528	176.2740	173.1816	172.6896	173.4778	54.1426
RB+(7*2MW)	169.3030	174.6451	170.6831	170.3362	170.4117	32.6332
RB+(8*2MW)	167.8845	173.8809	169.1085	168.9056	168.6650	23.8129
RB+(9*2MW)	166.5640	173.2851	167.7234	167.6432	167.2006	19.[illegible]15
RB+(10*2MW)	165.2607	172.6767	166.3625	166.4375	165.8085	17.6261

Table 2.21: The overall system expected energy not supplied (EENS) with the incremental addition of identical 5-MW capacity NUG at each individual bus of the basic RBTS.

Addition of NUG	EENS Bus 1 MWh/yr	EENS Bus 2 MWh/yr	EENS Bus 3 MWh/yr	EENS Bus 4 MWh/yr	EENS Bus 5 MWh/yr	EENS Bus 6 MWh/yr
RB+(0*5MW)	212.2559	212.2559	212.2559	212.2559	212.2559	212.2559
RB+(1*5MW)	193.9162	196.3462	196.4544	196.3487	198.9181	146.1324
RB+(2*5MW)	176.1946	180.9797	178.2853	178.1338	179.9461	78.4732
RB+(3*5MW)	169.5945	175.4500	170.7026	170.5588	170.5894	29.3153
RB+(4*5MW)	166.5260	174.1916	167.3307	167.6493	167.0424	18.4711

EENS in all the studies. The location of the NUG facilities is therefore an important factor in this assessment. Introduction of 2-MW and 5-MW capacity NUG facilities at Bus 6, however, produce significant drops in the overall system expected unserved or unsupplied energy as the NUG can now directly supply the load point both during normal system operation and when the load point is isolated from the conventional generation sources. Depending on the relative locations of the NUG additions, the extra generation facilities can lead to a reduction, an increase or virtually no change in the load point and overall system EENS or EUE. The system transmission topology is an important factor in this regard and therefore each system should be analyzed with care prior to making any general observations. Similar studies were conducted using the IEEE-RTS and the results support the general comments noted above. The IEEE-RTS is utilized extensively in studies described later in this thesis.

2.14. Summary

A detailed description of the COMREL program is described in this chapter. The COMREL program is used as a computational tool in the quantitative analysis of composite system adequacy. Two reliability test systems, the RBTS and the IEEE-RTS, utilized for composite adequacy analysis in the research work presented in this thesis are also described in this chapter. The base case load point and overall system indices were computed for the RBTS and the IEEE-RTS using the COMREL program. The base case values serve as the datum for comparing the results of the subsequent studies described in this chapter, involving modified forms of the RBTS. The two sets of results obtained using the 4-step and 7-step load models show the RBTS to be relatively insensitive to the load duration curve.

Further studies on the modified RBTS were conducted using only the 4-step load model.

This chapter also presents a series of composite system adequacy studies involving different capacity NUG sizes on the RBTS. The results show that the introduction of different NUG capacity streams at various single locations can have quite different impacts on both load point adequacy and the overall system adequacy. It can also be seen that different NUG size additions at the single locations produce quite distinct adequacy levels. Decisions regarding which particular NUG injection stream should be implemented will involve detailed economic analysis in addition to recognizing the different reliability implications and benefits.

The studies presented in this chapter examine the impacts of different non-utility generation capacity sizes on the individual load points and overall system adequacy of a small electric power system. These studies consider the impact of NUG sizes on EENS or EUE. The investigations show that NUG can serve as suitable alternatives to conventional power system reinforcement in the form of utility generation facilities [99-101]. Independent power production, therefore, offers an excellent energy supply option, as opposed to generating capacity expansion utilizing conventional sources, for meeting future system energy requirements. The results show that the introduction of non-utility generation at different single locations in a utility system has different impacts on both the expected load point and overall power system unserved energy depending upon the existing composite generation and transmission configuration of the utility system. The overall benefits in the expected energy not supplied therefore vary with the different NUG sizes and the locations where they are injected in the electric power system [99-101].

3. COST/BENEFIT ASSESSMENT IN A COMPOSITE GENERATION AND TRANSMISSION SYSTEM INVOLVING NON-UTILITY GENERATION

3.1 Introduction

Due to increases in the cost of energy and decreases in the rate of growth of electricity demand, utilities and governments are looking beyond the conventional sources of electrical energy to identify alternative flexible sources to meet the forecast load growth. Energy is a basic and necessary ingredient of economic development in the modern world. A major aspect in the justification of new facilities and the determination of acceptable planning or operating reliability levels is the assessment of reliability cost and reliability worth. Electric power utilities are also facing increasing uncertainties regarding the economic, political, societal, environmental constraints under which they operate and plan their systems. This has therefore led to increasing requirements for extensive justification of new facilities and increased emphasis on the optimization of system costs and reliability.

The impact of the new power industry, NUG or IPP, is steadily growing. Electric power utilities should, therefore, prepare themselves for this growth by developing the ability to assess the impacts of NUG on their composite systems. The reliability impacts of independent power production can be quite significant on both individual load point and overall power system adequacy [3, 14]. Adequacy analyses at hierarchical level I (HLI) [3, 14] can be utilized to assess the impact of NUG facilities on the overall capability of the generating system to meet the total system load requirement. These analyses, however, do not recognize the relative locations of the generation facilities within the system. As illustrated in Chapter 2, injection of electrical energy due to NUG development can occur at locations in the system which would not normally be considered as conventional sites for generation development. These effects were examined in terms of NUG impacts on calculated adequacy indices at load point and system levels. The impact of NUG facilities on both load point and overall system adequacy indices is also illustrated in [99, 100, 113, 114]. In the absence of specified adequacy targets at both the load point and system levels, it may be difficult to appreciate the benefit associated with a NUG injection at a specified point in the system. The concepts illustrated in [99, 100, 113, 114] are extended in this chapter by examining the potential benefits using a reliability cost and reliability worth technique [115-118]. The research described in this chapter examines the impacts of non-utility generation on composite generation and transmission customer interruption costs and the determination of the overall total system cost. The RBTS [88, 89] and the IEEE-RTS [90] shown in Figures 2.3 and 2.4 are used in these analyses. This chapter illustrates how the impacts of small capacity NUG streams at different locations in an electric power utility system can result in different total system costs and optimum planning reserve margins in composite generation and transmission systems.

3.2. Concepts of the Cost/Benefit Approach

There is a growing interest in power system planning for overall economic and reliability assessment using analysis which recognizes the system costs and the customer interruption costs. From an economic theory perspective, the selection of an optimum adequacy level should recognize the cost of providing extra reliability and the benefits accruing to society of having additional reliability. This procedure is designated as the cost/benefit approach [119] and is utilized by electric power utilities to determine target adequacy levels by balancing the reliability cost and the reliability worth. In order to make a consistent appraisal of economics and reliability, it is essential to compare the reliability cost (the investment cost required to achieve a certain level of reliability) with reliability worth (the benefit derived by the power utility, consumer and society). Optimum reliability is attained when the marginal worth of an extra increment of reliability to the consumer is equal to the marginal cost spent by the supply industry in achieving it [120]. The basic concept of reliability cost and reliability worth evaluation is shown in Figure 3.1. These curves show that the utility or system cost will generally increase as consumers are provided with higher reliability. On the other hand, the consumer costs associated with supply interruptions decrease as the reliability increases.

The sum of the two curves, i.e. the consumer and the utility costs, is the total societal cost. This curve displays a minimum value which indicates an optimum or target level of reliability R_{opt}. The value of R_{opt} depends not only on the generating system and the load data or model but also on the customer interruption costs. In contrast, the traditional approach pre-selects a level of reliability, R, and the utility system planner is then faced with the task of identifying the design which meets this reliability level at the lowest capital and operating costs. The selection of *R* is usually based on past experience and does not explicitly recognize customer factors in the evaluation process.

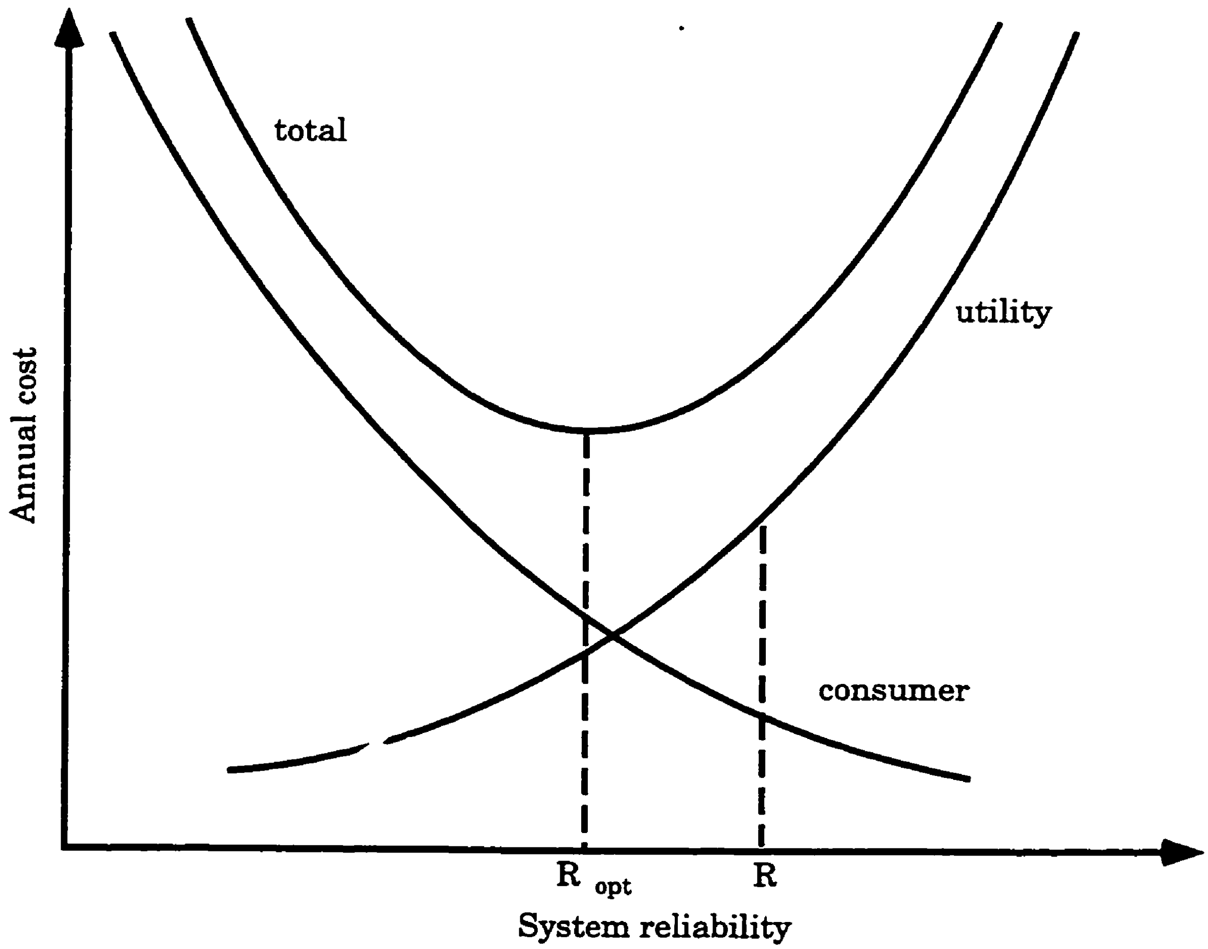

Figure 3.1: Optimum reliability level determined by balancing system costs and consumer interruption costs.

3.3. Cost of Interruption Assessment

The worth or value of electrical service reliability is not particularly easy to define and is more difficult to evaluate. From a customer viewpoint, the issue of service reliability is, for many customers, simply a question of whether the supply is available or not. Other customers may have quality requirements more stringent than the normal utility-allowed voltage or frequency variations and momentary interruptions, which might be considered as a state of "partial availability". Basically, customers have come to expect electrical energy supply to be continuously available on demand. While most customers would accept that this is not realizable in practice since equipment failures will occur, nevertheless the expectation remains, and to many it is considered almost a right. This is due, in part, to the high levels of reliability enjoyed in most service areas, and it has been exacerbated by escalating rate increases during the last three decades. These factors, along with the inherent characteristics of electrical supply systems such as their monopolistic nature and typical large size, result in a major impediment to the determination of reliability worth. Customers have little or no choice in terms of rates versus quality, nor do they have experience or background to choose if they were given that option. Unable to assess reliability worth directly, many researchers have turned their attention to evaluating the impacts or losses resulting from electrical supply interruptions, that is, the societal cost of unreliability.

A variety of methods has been utilized to evaluate customer impacts due to interruptions [121, 122]. These methods can be grouped, based on the methodological approach used, into three broad categories, namely: various indirect analytical evaluations, case studies of blackouts, and customer surveys. While a single approach has not been universally adopted, utilities appear to favour customer surveys as the means to determine specific information for their particular purposes.

A necessary preliminary step in the determination of interruption costs is an understanding of the nature and variety of customer impacts resulting from electric service interruptions. Impacts may be classified as direct or indirect, economic or otherwise (social), and short-term or long-term. Direct impacts are those resulting directly from cessation of power supply [123]. Indirect effects are secondary consequences of power failures, and can be both long term and short term. Hence, direct economic impacts include lost production, idle but paid-for resources (raw materials, labour, capital), restart costs for continuous processes plants, spoilage of raw materials or food, equipment damage, direct costs associated with human health and safety, and utility costs associated with the interruption. Direct social impacts include inconvenience due to lack of transportation, loss of leisure time, uncomfortable building temperatures, and personal injury or fear of crime. Indirect losses usually arise as spin-off consequences and it may be difficult to categorize them as social or economic. Examples of such costs are civil disobedience and looting during an extended blackout, or failure of an industrial safety device in an industrial plant necessitating neighbouring residential evacuation or damage law-suits brought against the power utility company for losses due to the power outage. The final distinction between short-term and long-term impacts relates to the immediacy of the consequence [123]. Specifically, long-term impacts are often identified as adaptive responses or mitigation undertaken to reduce or avoid future outage costs. Installation of protective switch gear, voltage regulation equipment, and non-utility generation and cogeneration or standby supplies would be included in this category, as would the relocation of an industrial plant to an area of higher electric service reliability.

There are many variables which influence interruption costs, and they can be broadly classified as customer or interruption related. The more important variables which have been found to affect the costs include:

- Type of customer;
- Duration of the interruption;
- Frequency of the interruption;
- Time of occurrence of the interruption;
- Advance notice for the interruption;
- Severity of the interruption; and
- Availability of the alternative supply.

Most of the above mentioned variables are self-explanatory. Perhaps the only exception is the severity of an interruption, which is the extent of the service disruption, e.g., a complete blackout, or voluntary partial load curtailment in response to the utility's public appeal. The first two variables, the type of customer and the duration of an interruption are usually considered as primary variables in assessing or evaluating interruption costs.

Interruption Cost Methodologies: - It is a difficult task to quantify the cost associated with a power outage. Economic consequences of power cessation are often straightforward, with some exceptions such as injuries or loss of life. On the other hand, social effects and indirect effects are typically quite difficult to quantify in monetary terms. Depending on the approach, the latter effects are often neglected. A review of the literature [121, 122] reveals that the cost impacts of power interruptions can be assessed using a variety of techniques. These include analytical methods, case studies of actual blackouts, and customer surveys.

Analytical Techniques: - There exist a large number of methods which can be classified as analytical. Analytical approaches generally assess the interruption costs from a purely theoretical economic viewpoint. Many of these techniques attempt to be market-based, while others utilize readily available secondary data such as global economic indices to measure the cost of interruption. An example of the analytical method is a technique which attempts to estimate the cost of interruption based on the ratio of the Gross National Product (GNP) and the consumption of electrical energy in the economy of the nation as a whole or in a given sector of the economy [124]. The main merit or advantage of the analytical methods is the relative simple nature of the evaluation. The inability to provide assessment other than for only large geo-political regions, and being very rough estimates, the utilization of analytical approaches is limited. These techniques do not, in general, reflect the actual needs of consumers.

Case Studies of Actual Blackouts: - The case studies method attempts to estimate the losses caused by an actual power interruption. Both direct costs as well as indirect consequences are addressed. The study of the 1977 New York (NY) blackout [125], for example, considered a wide range of societal and organizational impacts along with the direct and indirect consequences of the event. A very important finding of this particular study was that the total indirect costs ($300 million) can significantly exceed the total direct costs ($60 million). The outcomes also suggest that a widespread blackout has typically more serious consequences than one caused by local power failures. Valuable information can be obtained from case studies of actual blackouts. Unfortunately, the information is restricted to the specifics of the individual interruption and its location. The cost associated with that specific interruption can not be generalized to other locations or regions and other interruption characteristics.

Customer Surveys: - The findings from both the analytical techniques and the case studies have indicated that, for cost of interruption assessments to be realistic, they should obtain information that is customer specific or related. Customer specific costs are the losses that the customer experiences due to the unavailability of the functions, products and activities that are dependent upon electricity. The customer survey approach is, therefore, based on the assumption that the customer is in the best position to estimate the losses resulting from a power interruption. Moreover, the survey questions can be framed in a number of ways depending upon the type of customers, the resources available and the utility's needs.

Customer survey techniques can be grouped into three main categories namely, contingent valuation techniques, direct costing techniques, and indirect costing techniques [126]. Most of the customer surveys incorporate combinations of all three methods. The choice is largely dependent upon the customer types that are being surveyed.

Contingent valuation methods are based on two basic concepts of electricity use. The first concept is that customers consume electricity in a pre-determined pattern which has characteristics based on time of the day, day of the week, and season of the year. The pattern evolved so as to provide the greatest benefit to the consumer. An electric power outage interrupts this pattern of usage and either eliminates, diminishes or postpones the activity that is dependent on electricity. The second concept is that some uses of electricity are worth more to the consumer than others. The difference between the amount paid for the electricity and its worth to the consumer is lost when the supply is interrupted. The value or worth of electricity can therefore be quantified either by the customer's willingness to pay (WTP) to avoid interruption and have the benefit or by the customer's willingness to accept (WTA) compensation for having had an interruption and deprived of the benefit of electricity uses [123]. Theoretically speaking, these two concepts should yield the same results, but typically they do not. This is probably due to a strategic bias of the customer arising from a concern against the electricity rates, or it may simply be the reflection of the difference between the "bid" and the "asked for" price. These costs, however, can be considered as the two extreme values of reliability worth for the type of customers surveyed. The approach, which is based upon the fundamental principles of electricity use, is suitable for any type of customer. The limitation of this method is that, the costs evaluated may be extreme in comparison to other techniques.

Direct costing methods ask customers to identify the impacts or effects of a particular outage scenario and then evaluate the monetary losses of those impacts [123]. Customers may be guided to evaluate the monetary losses by suggesting possible impacts such as the loss of production or sales, raw material spoilage, paid staff unable to work, etc. This approach is particularly suitable for customers where the losses are economic in nature, such as in the industrial and commercial sectors.

Indirect costing methods are based on the economic principle of substitution (EPS), in which the evaluation of a replacement product or service is used as a measure of the worth of the original product or service [123]. This technique is particularly useful when social effects or other less tangible consequences are expected to comprise a significant portion of the overall interruption costs, such as in the residential sector. One form of this approach is to offer respondents or customers a series of preparatory actions to choose from in the event of recurring interruptions. The preparatory actions range from doing nothing to installing back-up supply capable of handling the entire load. These actions provide a means for assessing the financial or monetary burden which the customers are willing to bear so as to alleviate the consequences of electric power outages. The value of choice(s) that the customer makes represents the value or worth of electric power supply.

There is no doubt that customer surveys are expensive and a time consuming way of collecting cost of interruption data, but they are often preferred over the other techniques. The survey approach can easily include the effect of other variables or parameters such as timing, duration, frequency of interruptions, requires minimum assumptions and can be tailored to suit an electric power utility's needs.

Mail surveys have been utilized to obtain estimates of the customer losses associated with service interruptions [121, 127]. The cost of interruption data used in this thesis were collected by means of mail surveys conducted by the power systems reliability research group at the University of Saskatchewan. The University of Saskatchewan has conducted several systematic customer surveys. The first series was done in 1980-85 on behalf of the Canadian Electrical Association (CEA) [127-130], and the second in 1990-92, sponsored by the Natural Sciences and Engineering Research Council (NSERC) together with seven participating Canadian electric power utilities [126, 131].

3.4. Customer Damage Function

Surveys are normally undertaken for each user group, e.g., residential, commercial, industrial and can provide reasonably definitive results. This approach involves two main variables of which one is the type of customer. Seven sectors have been identified based on the Standard Industrial Classification (SIC) scheme from Statistics Canada. The seven sectors are shown in Figure 3.2 and Table 3.1. These data have been utilized in the RBTS studies described in this thesis.

The second important interruption related variable, apart from the type of customer, is the duration of power interruption. By combining this with the type of customer, a function that relates the cost of interruption to the duration of interruption for each customer group can be obtained. This consolidation of costs is known as a customer damage function (CDF) The data compiled from the surveys have been used to formulate sector customer damage functions (SCDF), which depict the sector interruption cost as a function of the interruption duration. Conceptually, the composite customer damage function (CCDF) for a particular bus represents the total costs for all customers at that bus as a function of the interruption duration. The customer load composition has to be known in order to proportionally weight the SCDF. The final cost for a given interruption depends on the load curtailed and on the duration of the interruption. The following section illustrates the procedure developed to transform the basic CDF data into useable parameters for reliability worth evaluation.

Table 3.1: Sector interruption cost estimates [88, 89] expressed as cost per KW of annual peak demand ($/KW).

	INTERRUPTION DURATION				
User Sector	**1 Minute**	**20 Minutes**	**1 Hour**	**4 Hours**	**8 Hours**
Large Users	1.005	1.508	2.225	3.968	8.240
Industrial	1.625	3.868	9.085	25.163	55.808
Commercial	0.381	2.969	8.552	31.317	83.008
Agricultural	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

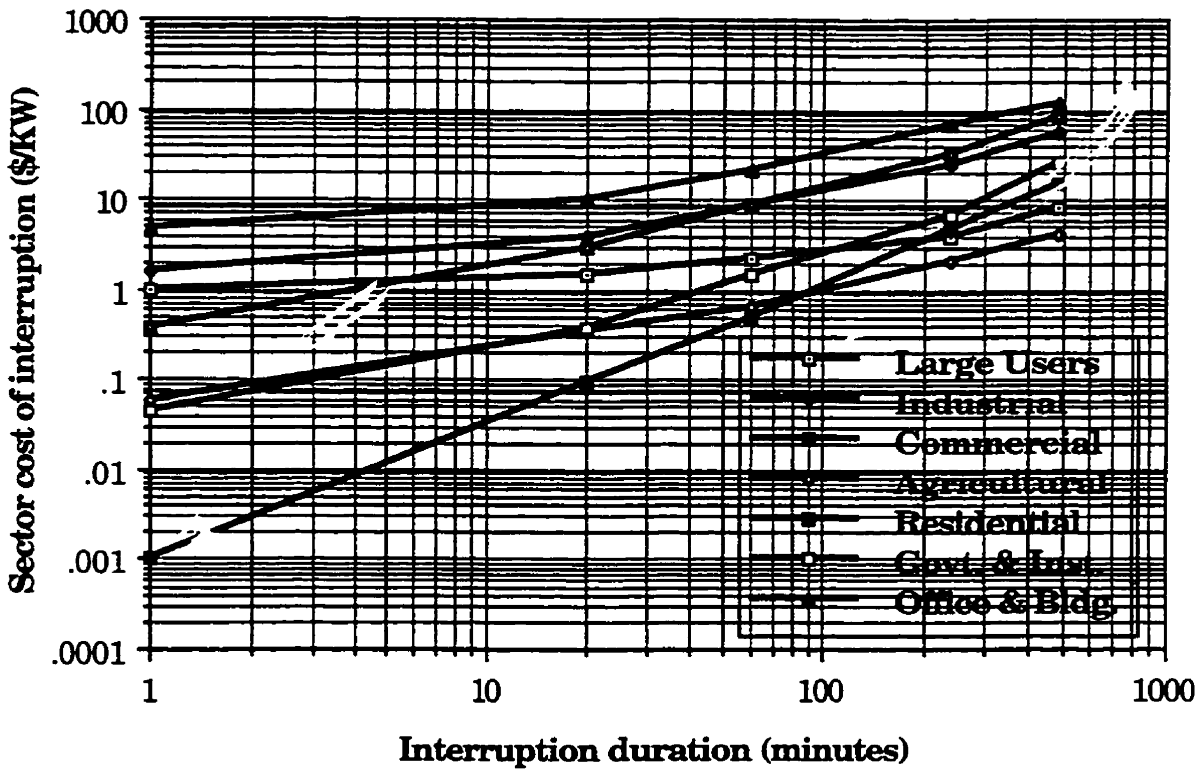

Figure 3.2: Sector customer interruption costs.

3.5. Generation of a Composite Customer Damage Function at each Load Bus

Conceptually, the composite customer damage function (CCDF) for a particular service area represents the total customer costs for that service area as a function of the interruption duration. The customer load composition for that area has to be known in order to proportionally weight the sector CDFs. The annual energy consumption distribution is usually used as the weighting factor though it has been argued that weighting by the annual peak demand is more appropriate for shorter durations (e.g. durations below 1 hour) since shorter duration interruptions result in a power shortage rather than in an energy shortage. The assumed load composition for the service area of the RBTS in terms of the annual peak demand and energy is given in Table 3.1.

One of the most basic requirements for evaluating the IEAR at HLII are the CCDF at each load bus of the system. These functions can be calculated using the different customer sectors at each load bus in the system. The sector allocations should meet the two requirements expressed in Equations (3.1) and (3.2). Other basic relationships are given by Equations (3.3) - (3.6)

$$\sum_{\text{all sectors}} (\text{Sector peak at Bus k}) = \text{Peak load at Bus k.} \tag{3.1}$$

$$\sum_{\text{all buses}} (\text{Sector peak at Bus k}) = \text{Sector peak of the system.} \tag{3.2}$$

$$\text{Sector peak distr. at Bus k} = \frac{\text{Sector allocation at Bus k}}{\text{Peak load at Bus k}} * 100. \tag{3.3}$$

$$\text{Sector L.F.} = \frac{\text{Sector energy distribution (\%)}}{\text{Sector peak distribution (\%)}} * \text{System L.F.} \tag{3.4}$$

$$\text{Sector average load at Bus k} = (\text{Sector L.F.}) * (\text{Sector peak at Bus k}). \quad (3.5)$$

$$\text{Sector energy distr. at Bus k} = \frac{\text{Av. load of sector at Bus k}}{\text{Av. load at Bus k}} * 100. \quad (3.6)$$

3.5.1. Application to the RBTS

The sector load allocations in the RBTS are shown in Table 3.2. It can be seen from this table that there are some residential and commercial sector customers at every load bus in the RBTS. For example, Bus 2 has industrial, commercial, residential and government and institutional users allotted to it.

Table 3.2: Sector allocation at each load bus of the RBTS.

PEAK LOAD ALLOCATION (MW)						
User Sector	**Bus 2**	**Bus 3**	**Bus 4**	**Bus 5**	**Bus 6**	**System**
Large Users	0.00	55.50	0.00	0.00	0.00	55.50
Industrial	3.50	3.05	16.30	0.00	3.05	25.90
Commercial	3.70	4.70	4.70	3.70	1.70	18.50
Agricultural	0.00	0.00	0.00	0.00	7.40	7.40
Residential	7.25	19.90	19.00	8.90	7.85	62.90
Govt. & Inst.	5.55	0.00	0.00	5.55	0.00	11.10
Office & Bldg.	0.00	1.85	0.00	1.85	0.00	3.70
Total	20.00	85.00	40.00	20.00	20.00	185.00

The CCDF at each load bus will be different due to the sector allocations and therefore the corresponding IEAR values will also be different, as shown later in this chapter. The annual peak load and energy consumption distributions are required, in addition to the allocation at the system load buses, in order to calculate the CCDF at the individual load buses. The annual peak load distribution of a given sector at Bus k can be calculated using Equation (3.3). This distribution is given for every load bus in the RBTS and for the whole system as shown in Table 3.3.

Table 3.3: Sector peak load distribution at each load bus of the RBTS.

SECTOR PEAK LOAD DISTRIBUTIONS (%)						
User Sector	**Bus 2**	**Bus 3**	**Bus 4**	**Bus 5**	**Bus 6**	**System**
Large Users	0.00	65.29	0.00	0.00	0.00	30.00
Industrial	17.50	3.59	40.75	0.00	15.25	14.00
Commercial	18.50	5.53	11.75	18.50	8.50	10.00
Agricultural	0.00	0.00	0.00	0.00	37.00	4.00
Residential	36.25	23.41	47.50	44.50	39.25	34.00
Govt. & Inst.	27.75	0.00	0.00	27.75	0.00	6.00
Office & Bldg.	0.00	2.18	0.00	9.25	0.00	2.00
Total	100.00	100.00	100.00	100.00	100.00	100.00

There are many ways of allocating the energy consumption of each user sector to the individual buses. One of the easiest ways consists of using the same sector load factor (L.F.) for each load bus in the system. This method ensures that the energy consumption of each sector is consistent at HLI and HLII. In an actual power system, it is expected that the load factor of a given sector will not vary greatly from one bus to another due to the aggregate effect of the various SIC groups within the sector. The load factor of a given sector can be evaluated from the system load factor, the sector energy distribution and sector peak load distribution as expressed by Equation (3.4). The load factor of a given system depends on the load model used. The RBTS [88, 89] has the same load model as the IEEE-RTS [90] which has an approximate load factor of 61.40%. This value can be used together with the sector peak and energy distributions given in Table 3.4 to calculate the load factor of each sector using Equation (3.4). The results from these calculations are given in Table 3.4. The sector load factors shown in Table 3.4 can be used together with the sector peak load allocations in Table 3.2 to calculate the average sector load at each bus using Equation (3.5). The average loads of each sector at every load bus in the RBTS and for the whole system are given in Table 3.5.

The energy consumption distribution of each sector and each bus of the RBTS can be evaluated from the data in Table 3.5 using Equation (3.6). The results are given in Table 3.6. The CCDF for each load bus of the RBTS are evaluated by weighting the user sector costs given in Table 3.1 for each interruption duration. The sector peak load distribution given in Table 3.3 is used for weighting the sector user costs for short durations. The sector energy distributions shown in Table 3.6 were used to weight the sector user costs for interruption durations longer than one half hour. The results are given in Table 3.7.

In order to illustrate the weighting procedure, two sample calculations for Buses 2 and 6 at interruption durations of 1 minute and 8 hours respectively are presented below.

$$\text{Interruption Cost at Bus 2 (1 Minute)} = (1.625)(0.1750) + (0.381)(0.1850) + (0.001)(0.3625) + (0.044)(0.2725) = 0.367\ \$/\text{kW}.$$

$$\text{Interruption Cost at Bus 6 (8 Hours)} = (55.808)(0.2372) + (83.008)(0.0877) + (4.120)(0.2650) + (15.690)(0.4101) = 28.041\ \$/\text{kW}.$$

Table 3.4: Load factors of each user sector in the RBTS.

User Sector	Sector Peak (%)	Sector Energy (%)	Sector L.F. (%)
Large Users	30.00	31.00	63.45
Industrial	14.00	19.00	83.88
Commercial	10.00	9.00	55.26
Agricultural	4.00	2.50	38.38
Residential	34.00	31.00	55.98
Govt. & Inst.	6.00	5.50	56.28
Office & Bldg.	2.00	2.00	61.40
Total	100.00	100.00	

Table 3.5: Sector average load at each load bus of the RBTS.

AVERAGE LOADS (MW)						
User Sector	**Bus 2**	**Bus 3**	**Bus 4**	**Bus 5**	**Bus 6**	**System**
Large Users	0.00	35.21	0.00	0.00	0.00	35.21
Industrial	2.92	2.52	13.58	0.00	2.54	21.58
Commercial	2.04	2.60	2.60	2.04	0.94	10.22
Agricultural	0.00	0.00	0.00	0.00	2.84	2.84
Residential	4.06	11.14	10.64	4.98	4.39	35.21
Govt. & Inst.	3.12	0.00	0.00	3.12	0.00	6.25
Office & Bldg.	0.00	1.14	0.00	1.14	0.00	2.27
Total	12.14	52.63	26.82	11.29	10.72	113.59

Table 3.6: Sector energy distribution at each load bus of the RBTS.

SECTOR ENERGY DISTRIBUTIONS (%)						
User Sector	**Bus 2**	**Bus 3**	**Bus 4**	**Bus 5**	**Bus 6**	**System**
Large Users	0.00	66.91	0.00	0.00	0.00	31.00
Industrial	24.02	4.83	50.65	0.00	23.72	19.00
Commercial	16.84	4.94	9.69	18.12	8.77	9.00
Agricultural	0.00	0.00	0.00	0.00	26.50	2.50
Residential	33.42	21.17	39.66	44.14	41.01	31.00
Govt. & Inst.	25.72	0.00	0.00	27.68	0.00	5.50
Office & Bldg.	0.00	2.16	0.00	10.06	0.00	2.00
Total	100.00	100.00	100.00	100.00	100.00	100.00

Table 3.7: CCDF for each load bus of the RBTS ($/KW).

System Bus	INTERRUPTION DURATION				
	1 Minute	20 Minutes	1 Hour	4 Hours	8 Hours
Bus 2	0.367	1.362	4.167	14.646	39.322
Bus 3	0.840	1.524	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

The CCDF for each load bus is illustrated in Figure 3.3.

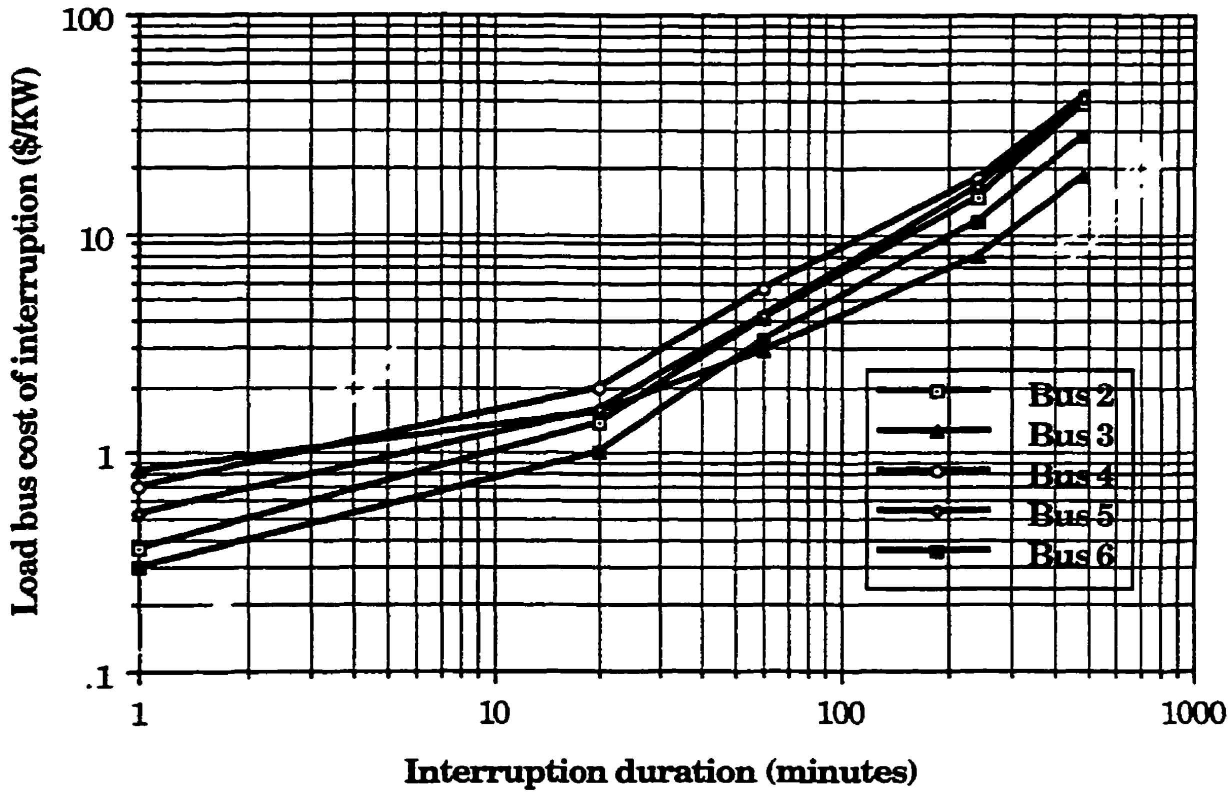

Figure 3.3: Composite customer damage function at each load bus in the RBTS.

3.5.2. Application to the IEEE Reliability Test System

This section briefly discusses the evaluation of the individual load bus and the aggregated system IEAR values for the IEEE-RTS. The composite customer damage function (CCDF) at each load bus of the IEEE-RTS can be calculated using the concepts given in Section 3.5 and Sub-section 3.5.1 of this chapter. The sector peak load allocation at each bus of the IEEE-RTS is given in Table 3.8.

where,

LU	represents the Large Users sector;
I	represents the Industrial sector;
C	represents the Commercial sector;
A	represents the Agricultural sector;
R	represents the Residential sector;
G&I	represents the Government and Institutions sector; and
O&B	represents the Offices and Buildings sector.

Equation (3.3) was used to calculate the annual peak load distribution for every load bus in the IEEE-RTS and the results are given in Table 3.9. The average loads of each sector at every load bus and the overall system are shown in Table 3.10. These values were evaluated using the sector load factors given in Table 3.4. The distribution of the energy consumption of each load bus in each sector of the IEEE-RTS was evaluated using Equation (3.6) and the results are shown in Table 3.11. The CCDF for each load bus in the IEEE-RTS was evaluated by weighting the user sector costs given in Table 3.1 for each interruption duration. The sector peak load given in Table 3.9 and the sector energy distribution supplied in Table 3.11 respectively were used to weight the sector costs for short durations and interruption durations longer than one half hour. The results are shown in Table 3.12.

Table 3.8: Sector allocation at each load bus of the IEEE-RTS.

System Bus	PEAK LOAD ALLOCATION (MW)							
	LU	I	C	A	R	G & I	O & B	System
Bus 1	0.00	39.90	14.25	0.00	36.85	17.00	0.00	108.00
Bus 2	0.00	0.00	14.25	0.00	48.45	34.30	0.00	97.00
Bus 3	0.00	58.80	14.25	11.45	94.50	0.00	0.00	180.00
Bus 4	0.00	0.00	14.25	0.00	25.55	34.20	0.00	74.00
Bus 5	0.00	19.90	14.25	0.00	36.85	0.00	0.00	71.00
Bus 6	0.00	39.95	14.25	11.45	67.50	0.00	2.85	136.00
Bus 7	0.00	39.95	14.25	22.70	48.10	0.00	0.00	125.00
Bus 8	0.00	19.90	28.55	0.00	94.05	25.65	2.85	171.00
Bus 9	85.50	0.00	8.50	33.80	41.50	0.00	5.70	175.00
Bus 10	42.75	39.95	14.25	17.90	80.15	0.00	0.00	195.00
Bus 13	42.75	59.80	28.55	16.70	80.15	25.65	11.40	265.00
Bus 14	85.47	39.95	5.60	0.00	62.98	0.00	0.00	194.00
Bus 15	213.75	0.00	34.50	0.00	54.50	0.00	14.25	317.00
Bus 16	42.75	0.00	14.25	0.00	25.90	17.10	0.00	100.00
Bus 18	188.20	39.90	22.55	0.00	62.40	0.00	19.95	333.00
Bus 19	110.97	0.00	14.25	0.00	55.78	0.00	0.00	181.00
Bus 20	42.86	0.00	14.25	0.00	53.79	17.10	0.00	128.00
Total	855.00	399.00	285.00	114.00	969.00	171.00	57.00	2850.00

Table 3.9: Sector peak load distribution at each load bus of the IEEE-RTS.

System Bus	SECTOR PEAK LOAD DISTRIBUTIONS (%)							
	LU	I	C	A	R	G & I	O & B	System
Bus 1	0.00	36.94	13.19	0.00	34.12	15.74	0.00	100.00
Bus 2	0.00	0.00	14.69	0.00	49.95	35.36	0.00	100.00
Bus 3	0.00	33.22	7.92	6.36	52.50	0.00	0.00	100.00
Bus 4	0.00	0.00	19.26	0.00	34.53	46.22	0.00	100.00
Bus 5	0.00	28.03	20.07	0.00	51.90	0.00	0.00	100.00
Bus 6	0.00	29.38	10.48	8.42	49.63	0.00	2.10	100.00
Bus 7	0.00	31.96	11.40	18.16	38.48	0.00	0.00	100.00
Bus 8	0.00	11.64	16.70	0.00	55.00	15.00	1.67	100.00
Bus 9	48.86	0.00	4.86	19.31	23.71	0.00	3.26	100.00
Bus 10	21.92	20.49	7.31	9.18	41.10	0.00	0.00	100.00
Bus 13	16.13	22.57	10.77	6.30	30.25	9.68	4.30	100.00
Bus 14	44.06	20.59	2.89	0.00	32.46	0.00	0.00	100.00
Bus 15	67.43	0.00	10.88	0.00	17.19	0.00	4.50	100.00
Bus 16	42.75	0.00	14.25	0.00	25.90	17.10	0.00	100.00
Bus 18	56.52	11.98	6.77	0.00	18.74	0.00	5.99	100.00
Bus 19	61.31	0.00	7.87	0.00	30.82	0.00	0.00	100.00
Bus 20	33.48	0.00	11.13	0.00	42.02	13.36	0.00	100.00

Table 3.10: Sector average load at each load bus of the IEEE-RTS.

System Bus	AVERAGE LOADS (MW)							
	LU	I	C	A	R	G & I	O & B	System
Bus 1	0.00	33.25	7.87	0.00	20.43	9.57	0.00	71.32
Bus 2	0.00	0.00	7.87	0.00	27.12	19.31	0.00	54.30
Bus 3	0.00	49.83	7.87	4.39	52.90	0.00	0.00	115.00
Bus 4	0.00	0.00	7.87	0.00	14.30	19.25	0.00	41.43
Bus 5	0.00	16.58	7.87	0.00	20.63	0.00	0.00	45.09
Bus 6	0.00	33.29	7.87	4.39	37.79	0.00	1.75	85.10
Bus 7	0.00	33.29	7.87	8.71	26.93	0.00	0.00	76.80
Bus 8	0.00	16.58	15.78	0.00	52.65	14.44	1.75	101.20
Bus 9	54.25	0.00	4.70	12.97	23.23	0.00	3.50	98.65
Bus 10	27.12	33.29	7.87	6.87	44.87	0.00	0.00	120.03
Bus 13	27.12	49.83	15.78	6.41	44.87	14.44	7.00	165.45
Bus 14	54.23	33.29	3.09	0.00	35.26	0.00	0.00	125.87
Bus 15	135.62	0.00	19.06	0.00	30.51	0.00	8.75	193.94
Bus 16	27.12	0.00	7.87	0.00	14.50	9.62	0.00	59.12
Bus 18	119.41	33.29	12.46	0.00	34.93	0.00	12.25	212.30
Bus 19	70.41	0.00	7.87	0.00	31.23	0.00	0.00	109.51
Bus 20	27.19	0.00	7.87	0.00	30.11	9.62	0.00	74.81
Total	542.47	332.48	157.49	43.75	542.47	96.24	35.00	1749.90

Table 3.11: Sector energy distribution at each load bus of the IEEE-RTS.

System Bus	SECTOR ENERGY DISTRIBUTIONS (%)							
	LU	I	C	A	R	G & I	O & B	System
Bus 1	0.00	46.62	11.04	0.00	28.93	13.42	0.00	100.00
Bus 2	0.00	0.00	14.50	0.00	49.95	35.55	0.00	100.00
Bus 3	0.00	43.33	6.85	3.82	46.00	0.00	0.00	100.00
Bus 4	0.00	0.00	19.01	0.00	34.53	46.46	0.00	100.00
Bus 5	0.00	36.78	17.47	0.00	45.76	0.00	0.00	100.00
Bus 6	0.00	39.12	9.25	5.16	44.41	0.00	2.06	100.00
Bus 7	0.00	43.34	10.25	11.34	35.06	0.00	0.00	100.00
Bus 8	0.00	16.39	15.59	0.00	52.03	14.27	1.73	100.00
Bus 9	54.99	0.00	4.76	13.15	23.55	0.00	3.55	100.00
Bus 10	22.60	27.74	6.56	5.72	37.38	0.00	0.00	100.00
Bus 13	16.39	30.12	9.54	3.87	27.12	8.73	4.23	100.00
Bus 14	43.08	26.45	2.46	0.00	28.01	0.00	0.00	100.00
Bus 15	69.93	0.00	9.83	0.00	15.73	0.00	4.51	100.00
Bus 16	45.88	0.00	13.32	0.00	24.52	16.28	0.00	100.00
Bus 18	56.24	15.66	5.87	0.00	16.45	0.00	5.77	100.00
Bus 19	64.29	0.00	7.19	0.00	28.52	0.00	0.00	100.00
Bus 20	36.35	0.00	10.53	0.00	40.26	12.87	0.00	100.00

Table 3.12: CCDF for each load bus of the IEEE-RTS ($/KW).

System Bus	INTERRUPTION DURATION				
	1 Minute	20 Minutes	1 Hour	4 Hours	8 Hours
Bus 1	0.658	1.911	5.519	17.489	43.213
Bus 2	0.072	0.613	2.011	9.327	29.131
Bus 3	0.574	1.591	4.769	15.387	37.241
Bus 4	0.094	0.774	2.485	10.697	33.295
Bus 5	0.532	1.728	5.056	16.973	42.202
Bus 6	0.623	1.729	5.026	16.446	39.144
Bus 7	0.574	1.673	5.057	16.075	38.669
Bus 8	0.340	1.217	3.650	13.688	36.024
Bus 9	0.677	1.291	2.577	7.544	16.948
Bus 10	0.587	1.410	3.801	11.885	28.888
Bus 13	0.784	1.946	5.094	16.113	37.804
Bus 14	0.789	1.577	3.707	10.511	24.746
Bus 15	0.934	1.800	3.423	9.731	21.766
Bus 16	0.492	1.155	2.521	8.264	22.923
Bus 18	1.075	2.126	4.471	12.791	27.704
Bus 19	0.646	1.187	2.183	6.204	15.741
Bus 20	0.385	0.924	2.095	7.561	21.400

3.6. Evaluation of the Interrupted Energy Assessment Rate

Interruption duration, frequency, and load curtailed are three fundamental quantities in power system reliability evaluation. Reliability worth analysis provides a value-based assessment which reflects the integrated effects of these three quantities. Different models have been used to assess the outage or damage costs to the system at both the generation level [132] and composite generation and transmission level [133-135]. Both the frequency and duration approach [133, 134] and a Monte Carlo sequential method [135, 136] have been used to assess the damage cost at Hierarchical Levels I and II.

The interrupted energy assessment rate (IEAR) is a factor [137] which aggregates the total dollars lost by utility customers for each unit of unsupplied energy due to electric power interruptions. Reliability worth can be evaluated in terms of expected customer interruption costs (ECOST) or IEAR. The loss of load expectation (LOLE) index cannot be directly related to customer interruption costs due to the fact that it does not measure the severity of system deficiencies. The loss of energy expectation (LOEE) or the expected energy not supplied (EENS) index, on the other hand, provides a measure of the severity of system deficiencies and can therefore be related to the customer cost of interruptions. This index has been used in conjunction with the interruption cost functions to obtain IEAR at HLI and HLII.

The frequency and duration (F&D) approach used in an analytical technique evaluates the probability, frequency and duration of each load loss event. These values are the expected or average performance indices. Reference [133] utilizes a basic frequency and duration approach and a sequential Monte Carlo simulation method to estimate the IEAR at Hierarchical Level I (HLI).

Three input models are required to evaluate the customer load point or the global system IEAR. These are the composite generation and transmission system model, the load model and the cost model. Under the composite system model, the generating units are represented by their capacities in MW, failure rates in occurrence per year and the repair times in hours. The transmission lines and transformers are represented by their starting and end buses, impedances (p.u.), susceptances (p.u.), current rating (p.u.), failure rates (occ./yr.) and repair times (hours). The bus data includes the active and reactive load (p.u.), power generated (p.u.), maximum and minimum reactive vars. permitted (p.u.), initial estimated voltages and the minimum and maximum voltages at the various buses.

The COMREL program has the capability of using either a single-step or a multi-step load model. The analysis of the system performance using a single step peak load model may be highly pessimistic since, the peak load does not remain constant throughout the year. Such indices are referred to as annualized indices. Modelling the system load as a multi-step model gives more accurate results at the expense of higher computation time. The indices from a multi-step load model are designated as annual indices. The results presented in this chapter utilize both single-step and multi-step load models.

The sector customer damage functions provide the primary data for the cost model. These are then aggregated at each bus as illustrated earlier in this chapter to create CCDF at each load point [137, 138].

The detailed formulation of IEAR at HLII is presented in [137, 138]. A brief review is therefore presented in this section. For each contingency j leading to load curtailment at Bus i, the unsupplied energy $EENS_i$ is evaluated using Equation (3.7).

$$EENSi = \sum_{j=1}^{N} Lij\ fj\ dj \qquad (MWh/yr) \tag{3.7}$$

where:

Lij = Load curtailed (MW) at Bus i due to contingency j,

f_j = Frequency (occ./yr) of contingency j,

d_j = Duration (hr) of contingency j and

N = Number of load curtailment contingencies for Bus i.

The expected cost, $ECOST_i$ of an electric power interruption at Bus i, for all the contingencies that lead to load curtailment can be obtained using Equation (3.8).

$$ECOST_i = \sum_{j=1}^{N} cj(dj)\ fj\ Lij \qquad (MW.\$/ KW.yr) \tag{3.8}$$

where $c_j(d_j)$ is the cost in \$/kW corresponding to duration d_j using the composite customer damage function (CCDF) at Bus i.

The bus $IEAR_i$ is then evaluated as,

$$IEAR_i = \frac{ECOSTi}{EENSi} \qquad (\$/KWh). \tag{3.9}$$

The System IEAR is given by Equation (3.10);

$$\text{System IEAR} = \frac{\text{System ECOST}}{\text{System EENS}}. \tag{3.10}$$

where:

$$\text{System ECOST} = \sum_{i=1}^{\text{all buses}} \text{ECOSTi}, \tag{3.11}$$

$$\text{System EENS} = \sum_{i=1}^{\text{all buses}} \text{EENSi}. \tag{3.12}$$

It is also possible to create an aggregate IEAR from the individual bus values using the fraction of total system load at each bus.

$$\text{Aggregate IEAR} = \sum_{i=1}^{NB} \text{IEAR}_i * q_i \quad (\$ / \text{KWh}), \tag{3.13}$$

where:

NB is total number of customer load buses in the system, and

q_i is fraction of the system load utilized by the customers at Bus i.

3.6.1. Application to the RBTS

This sub-section contains the evaluation of the IEAR at each load bus and the aggregate system IEAR using the functions and the basic reliability data of the RBTS. The detailed generation, transmission and load data for the RBTS are given in [88, 89].

The cost model given in Table 3.7 was used together with the basic RBTS data in COMREL to calculate the IEAR at each load bus and the aggregate system IEAR. The results are summarized in Tables 3.13 and 3.14. The following options in the COMREL program were used in the analysis:

- The peak load of the RBTS was fixed at 185 MW;

- A single-step and a multi-step load models are used in the analysis. The effect of a multi-step load model was included in order to produce more representative annual IEAR values at the expense of additional computational time;

- All load buses are assumed to have 20% curtailable load;

- Load curtailment philosophy of PASS 1 was used; and

- The DC load flow technique was used.

- Contingency enumeration of up to the following contingency levels was used:

  (i) Four or less generating units were examined,

  (ii) Three or less transmission lines were examined, and

  (iii) Up to two generating units and one line and one generating unit and two lines were considered.

The load in an actual system does not stay at its peak throughout the period of study. An evaluation of a system performance based on a single peak load step model gives highly pessimistic indices. A 4-step load model was used to examine the impact of multi-step load models. For each load step, the modified COMREL program was utilized to evaluate the expected energy not supplied (EENS) and the associated cost of unserved energy (ECOST) at each load bus and overall system. The sum of the costs of unsupplied energy for all the load buses of the test system is the system cost of unserved energy for this load step. The expected system cost of unserved energy is obtained by weighting the system cost of unsupplied energy by the probability of having this load step. This same procedure was repeated for the remaining load steps and the sum of the corresponding system costs of unserved energy gives the annual system cost.

The individual load point and overall system ECOST and IEAR using single-step and 4-step load models for the RBTS are presented in this sub-section. Tables 3.13 and 3.14 show the load point and system EENS, ECOST and IEAR produced by the modified COMREL program for the RBTS using a single fixed system peak of 185 MW and a 4-step (10 percent step size) load model approximations respectively. The cost of unserved energy (ECOST) for the load buses and the total system presented in Tables 3.13 and 3.14 are depicted graphically in Figure 3.4.

Table 3.13: Annualized load point and system reliability worth indices of the base RBTS (single-step load model).

Load Bus	**ECOST (K$/yr)**	**EENS (MWh/yr)**	**IEAR ($/KWh)**	**Fraction of System Load**	**Weighted IEAR ($/KWh)**
Bus 2	923.9686	124.6556	7.4122	0.1081	0.8013
Bus 3	2283.0550	849.4794	2.6876	0.4595	1.2348
Bus 4	1845.0820	272.2408	6.7774	0.2162	1.4654
Bus 5	14.1259	2.9497	4.7889	0.1081	0.5177
Bus 6	724.8362	199.7129	3.6294	0.1081	0.3924
System	5791.0677	1449.0384	3.9965	1.0000	3.9965
AGGREGATE IEAR					**4.4116**

Table 3.14: Annual load point and system reliability worth indices of the base RBTS (4-step load model).

Load Bus	ECOST (K$/yr)	EENS (MWh/yr)	IEAR ($/KWh)	Fraction of System Load	Weighted IEAR ($/KWh)
Bus 2	34.3859	4.8543	7.0836	0.1081	0.7658
Bus 3	121.0984	47.8874	2.5288	0.4595	1.1619
Bus 4	70.6667	10.7412	6.5790	0.2162	1.4225
Bus 5	2.6571	0.5964	4.4552	0.1081	0.4816
Bus 6	537.6467	148.1202	3.6298	0.1081	0.3924
System	766.4548	212.1995	3.6120	1.0000	3.6120
AGGREGATE IEAR					**4.2242**

Tables 3.13 and 3.14 also show the aggregate system IEAR obtained from the individual bus values using Equation (3.13). The aggregate system IEAR of 4.4116 $/kWh (annualized) and 4.2242 $/kWh (annual) at HLII are greater than the 3.6000 $/kWh calculated at HLI. This difference is attributed to the contribution of the transmission system and the differences in concepts and input models utilized in HLI and HLII assessment studies. The individual bus and system IEAR values given in Tables 3.13 and 3.14 are basic values which can be used to link interruption costs and quantitative reliability assessment studies in reliability worth evaluation at HLII. Sensitivity of the IEAR to various modelling assumptions is reported in references [137] and [139]. It was found that the IEAR is largely insensitive to most modelling assumptions.

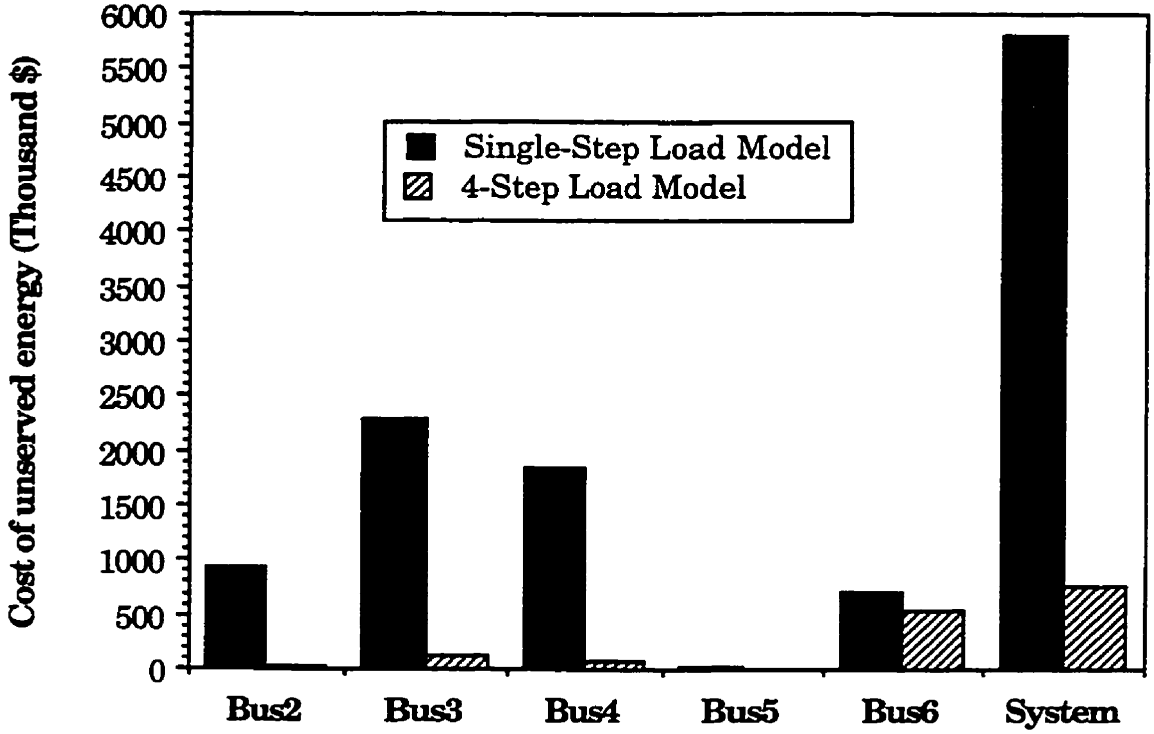

Figure 3.4: Annualized and annual load point and overall system ECOST for the base RBTS using single-step and 4-step load models respectively.

The results shown in Table 3.13 indicate that Buses 3, 4, 2, and 6 are the major contributors to the overall system cost of expected energy not supplied. Meanwhile, Buses 6, 3, and 4 are the major contributors to the total system cost of expected unserved energy as shown in Table 3.14. The system costs of unsupplied energy utilizing a single step and a 4-step load models are \$5,791,068 and \$766,455 from Tables 3.13 and 3.14 respectively when the peak load is 185 MW for the RBTS. The large difference between these two values suggests that, annual cost values rather than the annualized cost values, should be used in composite generation and transmission facilities reinforcement evaluations or assessments.

3.6.2. Application to the IEEE-RTS

The generation, transmission and load data given in Appendix B and the methodology outlined for the RBTS in Section 3.6 and Sub-section 3.6.1 were also used to evaluate the individual load bus IEAR for the IEEE-RTS. The assumptions used in the COMREL program are the same as those used in the RBTS study given in Sub-section 3.6.1. The system peak load in this case is 2850 MW. The IEAR values for each load bus of the IEEE-RTS are shown in Table 3.15. This table also shows the aggregate system IEAR is obtained from the individual load bus values [137, 139]. These IEAR values are used later in this chapter, to evaluate the customer costs of unserved energy when additional generation from non-utility generation facilities are introduced at selected load buses of the IEEE-RTS.

Table 3.15: IEAR values for each load bus in the IEEE-RTS.

System Bus	ECOST (K$/yr)	LOEE (MWh/yr)	IEAR ($/KWh)	Fraction of System Load	Weighted IEAR ($/KWh)
Bus 1	12387.6816	1998.2441	6.1993	0.0379	0.2350
Bus 2	17930.6289	3670.0325	4.8857	0.0340	0.1661
Bus 3	24062.8809	4543.2339	5.2964	0.0632	0.3347
Bus 4	11718.9941	2086.6218	5.6163	0.0260	0.1460
Bus 5	10638.8984	1741.7764	6.1081	0.0249	0.1521
Bus 6	21250.6133	3863.0203	5.5010	0.0477	0.2624
Bus 7	9843.5723	1818.3523	5.4135	0.0439	0.2377
Bus 8	20802.7793	3855.5020	5.3956	0.0600	0.3237
Bus 9	1425.8457	619.8625	2.3003	0.0614	0.1412
Bus 10	2644.1968	639.0935	4.1374	0.0684	0.2830
Bus 13	125268.9219	23258.3652	5.3860	0.0930	0.5009
Bus 14	6292.6504	1843.3873	3.4136	0.0681	0.2325
Bus 15	84045.2422	27895.0078	3.0129	0.1112	0.3350
Bus 16	8675.5459	2452.2488	3.5378	0.0351	0.1242
Bus 18	190810.6094	50921.0938	3.7472	0.1168	0.4377
Bus 19	4751.9922	2077.2766	2.2876	0.0635	0.1453
Bus 20	42503.0273	11681.1514	3.6386	0.0449	0.1634
AGGREGATE OR SYSTEM IEAR					**4.2208**

3.7. Evaluation of System Cost for the RBTS and the IEEE-RTS

The costs associated with constructing a generating system for a specified level of reliability can be evaluated relatively easily. In general, the total system cost is comprised of all the various costs incurred by an electric power utility in supplying customers with electrical energy at a specified service reliability and does not include the cost of unserved energy. The total system cost has two subsets:

- Variable costs; and
- Fixed costs.

The variable costs are the operating costs and the fuel costs. The fuel costs are the costs directly linked with energy production and form the bulk of the variable costs. The operating costs include maintenance costs and payment for materials, supplies, etc. The fixed costs are made up of the annual charges associated with equipment regardless of whether or not it is operating. The annual charges are independent of the degree of usage and consist primarily of interest, depreciation, rent, taxes, insurance and any other capital investments [88, 89]. The variable operating cost data, fixed cost data and the priority loading order of the RBTS and the IEEE- RTS are presented in Tables 3.16 and 3.17 respectively.

Table 3.16: Priority loading order and generating unit cost data for the RBTS.

Priority Loading Order	Rated Capacity (MW)	Fixed Costs ($)	Variable Costs ($/MWh)
1	40.00 (Hydro)	100000.00	0.50
2	20.00 (Hydro)	50000.00	0.50
3	20.00 (Hydro)	50000.00	0.50
4	5.00 (Hydro)	12500.00	0.50
5	5.00 (Hydro)	12500.00	0.50
6	40.00 (Thermal)	790000.00	12.00
7	40.00 (Thermal)	790000.00	12.00
8	20.00 (Thermal)	680000.00	12.25
9	10.00 (Thermal)	600000.00	12.50
10	20.00 (Hydro)	50000.00	0.50
11	20.00 (Hydro)	50000.00	0.50
TOTAL	----	3185000.00	----

Table 3.17: Priority loading order and generating unit cost data for the IEEE-RTS.

Priority Loading Order	Rated Capacity (MW)	Fixed Costs ($)	Variable Costs ($/MWh)
1	50.00	125000.00	0.50
2	50.00	125000.00	0.50
3	50.00	125000.00	0.50
4	50.00	125000.00	0.50
5	50.00	125000.00	0.50
6	50.00	125000.00	0.50
7	400.00	2000000.00	6.30
8	400.00	2000000.00	6.30
9	350.00	1575000.00	12.10
10	197.00	985000.00	50.62
11	197.00	985000.00	50.62
12	197.00	985000.00	50.62
13	155.00	1085000.00	12.44
14	155.00	1085000.00	12.44
15	155.00	1085000.00	12.44
16	155.00	1085000.00	12.44
17	100.00	850000.00	52.80
18	100.00	850000.00	52.80
19	100.00	850000.00	52.80
20	76.00	760000.00	15.30
21	76.00	760000.00	15.30
22	76.00	760000.00	15.30
23	76.00	760000.00	15.30
24	12.00	120000.00	63.30
25	12.00	120000.00	63.30
26	12.00	120000.00	63.30
27	12.00	120000.00	63.30
28	12.00	120000.00	63.30
29	20.00	60000.00	103.60
30	20.00	60000.00	103.60
31	20.00	60000.00	103.60
32	20.00	60000.00	103.60
TOTAL	-----	20050000.00	-----

3.7.1. System Fixed Cost

The sum of all costs associated with the system generation gives the total fixed cost of the entire system. The basic RBTS and IEEE-RTS have annual system fixed costs of $3,185,000 and $20,050,000 as shown in Tables 3.16 and 3.17 respectively. This value is independent of the loading order and the reliability data of the units.

3.7.2. System Production Cost

The production cost of a system, is the sum of the expected energy supplied (EES) by each generating unit times the variable cost for each unit. The system energy production cost is the sum of the individual production costs of all the committed units. The load modification (LM) method [140-143], was used to evaluate the EES by each generating unit and the LOEE or EENS of the overall system.

3.7.3. Load Modification Method

The load modification method, is a unified probabilistic technique which can be used to evaluate the generating capacity adequacy and the energy production costs in an electric power system. The method can be regarded as a sequential process of modifying a system load duration curve (LDC) with the capacity distribution of all committed generating units to give an equivalent load model [142]. The concept underlying this technique is the determination of the appearance of the system load to the remainder of the system capacity when a given generating unit is committed to supply energy to the system. A pre-requisite for the load modification method is a knowledge of the priority loading order of the generating units.

The area under the original unaltered load duration curve is the expected total energy requirements of the system. The area under any capacity-modified LDC gives the expected energy not supplied (EENS) by the system composed of all the generating units which contributed to the modification process. The difference in the area before and after a unit is added, is the expected energy output of the unit. Repeated application of this approach for each generating unit in the system, results in a final unsupplied load model from which various adequacy indices can be evaluated. The basic indices generated by this method are loss of load expectation (LOLE), loss of energy expectation (LOEE) or expected energy not supplied (EENS) and the expected energy supplied (EES) by each generating unit within the system.

The results obtained for the RBTS using the load modification method are presented in Table 3.18. The expected energy supplied by each unit with reference to its position on the given priority loading order, is in column 3 of Table 3.18. The product of an EES value and the corresponding variable cost gives the individual unit energy production cost. The sum of all the individual costs produces a total production cost of $3,220,745.85 for the RBTS.

The sum of the system fixed cost ($3,185,000.00) and production cost ($3,220,745.85), gives a total system cost of $6,405,745.85 for the RBTS. The basic RBTS, therefore, has a system cost of $6,405,746 to satisfy the load demand of 185 MW using the loading order listed in Table 3.16. The total energy demand of the RBTS is 992,955.90 MWh per year. The total energy supplied by the RBTS taking into consideration the listed loading order is 992,946.13 MWh per year. The system LOEE or EENS, which is the difference between the total energy demand (992,955.90 MWh per year) and the total energy supplied (992,946.13 MWh per year), is 9.77 MWh per year.

Table 3.19 shows the results using the load modification approach for the base IEEE-RTS. The total annual expected energy required is approximately 15,297,444 MWh and the EENS is 1176 MWh. The summation of the fixed costs ($20,050,000) and the production costs ($234,836,275) gives a total system cost of $254,886,275 for the IEEE-RTS. The basic IEEE-RTS, therefore, has a total system cost of $254,886,275 to satisfy the load demand of 2850 MW using the load order provided in Table 3.19

Table 3.18: Unit expected energy output and energy production for the RBTS.

Rated Capacity (MW)	Variable Energy Cost ($/MWh)	Expected Energy Output (MWh)	Expected Energy Cost ($)
40.00 (Hydro)	0.50	340603.56	170301.78
20.00 (Hydro)	0.50	173783.09	86891.55
20.00 (Hydro)	0.50	167695.56	83847.78
5.00 (Hydro)	0.50	38080.31	19080.16
5.00 (Hydro)	0.50	35593.50	17796.75
40.00 (Thermal)	12.00	183622.88	2203474.56
40.00 (Thermal)	12.00	49271.56	591258.72
20.00 (Thermal)	12.25	3298.72	40409.32
10.00 (Thermal)	12.50	602.23	7527.88
20.00 (Hydro)	0.50	335.27	167.64
20.00 (Hydro)	0.50	59.45	29.73
TOTAL	-----	992946.13	3220745.85

Table 3.19: Unit expected energy output and energy production for the IEEE-RTS.

Rated Capacity (MW)	Variable Energy Cost ($/MWh)	Expected Energy Output (MWh)	Expected Energy Cost ($)
50.00	0.50	432442.99	216221.50
50.00	0.50	432433.99	216217.00
50.00	0.50	432419.01	216209.50
50.00	0.50	432440.00	216220.00
50.00	0.50	432441.99	216221.00
50.00	0.50	432436.00	216218.00
400.00	6.30	3075029.05	19372684.00
400.00	6.30	3067735.11	19326732.00
350.00	12.10	2521790.04	30513660.00
197.00	50.62	1189214.97	60198064.00
197.00	50.62	973198.97	49263332.00
197.00	50.62	725398.50	36719672.00
155.00	12.44	430385.50	5353995.50
155.00	12.44	303027.50	3769662.00
155.00	12.44	190415.25	2368765.75
155.00	12.44	112653.50	1401409.50
100.00	52.80	44360.63	2342241.00
100.00	52.80	28473.00	1503374.38
100.00	52.80	17612.53	929941.63
76.00	15.30	8693.25	133006.73
76.00	15.30	5717.73	87481.34
76.00	15.30	3639.16	55679.09
76.00	15.30	2274.70	34802.96
12.00	63.30	268.12	16971.82
12.00	63.30	247.73	15681.09
12.00	63.30	228.64	14472.95
12.00	63.30	210.42	13319.46
12.00	63.30	194.06	12283.91
20.00	103.60	265.28	27482.73
20.00	103.60	233.43	24182.91
20.00	103.60	205.49	21288.99
20.00	103.60	181.28	18780.13
TOTAL		15296268.55	234836274.87

3.8. Assessment of Hierarchical Level II Interruption Costs Involving Non-Utility Generation

The load point and system benefit of adding a NUG at a specific location cannot be easily appreciated. It is possible, however, to determine the reliability worth at each load point and for the overall system due to NUG additions at specific locations [115-118]. The NUG can be inserted at many locations in the system and their basic function is to supply electrical energy to the overall system. Under normal conditions, the NUG tends to reduce system operating cost by reducing system transmission losses. They can also be used to provide energy to system loads which cannot be supplied due to conventional generating capacity deficiencies. The NUG, because of their locations within the system, can also be used to serve system loads which can not be supplied because of transmission capacity limitations, load point isolation or other related split network situations arising from system outage conditions. Apart from a few instances, such as those involving small hydro sources which are site specific in nature, non-utility generation is usually located close to system load points. For the purposes of this study, NUG are considered to be located at the system load points.

In the non-utility generation injection studies, an increasing number of 2-MW and 5-MW capacity NUG facilities with 2 percent forced outage rates was introduced at different single bus locations in the RBTS. As illustrated in Chapter 2, these injections produce different impacts on the load point and the overall power system expected customer cost of unserved energy. The customer unserved energy costs are directly proportional to the expected energy not supplied. The EENS results from HLII adequacy studies using COMREL were combined with the IEAR values given in Table 3.14 for the

RBTS. All the results shown are annual indices which reflect the variations in load level over a year. A 4-step (10 percent load step) load model was used for the RBTS analysis .

3.8.1. Discussion of the RBTS Results

The analyses conducted on the impact of NUG on the composite system customer costs of unserved energy in the RBTS are illustrated in this section [115, 116]. The results show similar trends in several respects to those obtained in Chapter 2 for studies involving the impact of NUG on composite system adequacy indices. Similar trends occur because the energy method for estimating consumer costs assumes that the cost of unsupplied energy increases in direct proportion to the expected energy not supplied, as expressed by Equation (3.14). The customer cost of unserved energy is an integral component in explicit cost evaluation of system reliability worth.

$$ECOST = IEAR * EENS. \qquad (3.14)$$

3.8.1.1. Load Point Indices

The load point variations in the customer costs of unserved energy when identical 2-MW capacity NUG facilities are incrementally introduced at Buses 1 to 6 of the RBTS are presented in Tables 3.20 through 3.25. Similar results, obtained when 5-MW capacity NUG are introduced at different locations using the same load buses of the basic RBTS, are provided in Tables 3.26 through 3.31.

The results presented in Tables 3.20 through 3.31 show a general tendency towards reduction in the customer cost of unsupplied or unserved energy for most load points, when NUG are introduced at the different buses of the RBTS. The addition of a highly available NUG will, to some extent, alleviate the severity or intensity of an outage affecting a particular load point. Results presented in Tables 3.20 to 3.31 show reductions in the expected customer cost of unsupplied energy at most load points in the early stages of unit additions. However, unless the unit additions are enough to entirely eliminate all the problems associated with the particular outage event, that event will still count as a problem contingency and has to be considered when evaluating the expected customer cost of unserved energy for the load point. It can be observed from Tables 3.20 through 3.25 that the expected customer monetary losses at most of the individual load buses or points as a result of energy not supplied are less, when five identical 2-MW capacity NUG facilities are injected at different buses of the RBTS, than when two identical 5-MW capacity NUG units are added to the same buses of the RBTS. Similar results were obtained for the case when (10 * 2-MW) and (4 * 5-MW) capacity NUG additions as can be seen from Tables 3.20 to 3.31.

Significant reductions in the customer cost of unserved energy at most load points is observed as different capacity sizes of NUG streams are injected in single locations at Buses 1 to 6. The largest reduction in the customer cost of unserved energy occurs at Bus 6 when NUG are added to Bus 6. The customer costs of unserved energy at Bus 6 are generally unaffected by the unit additions, except when the NUG are introduced at Bus 6. This is the most unreliable load point in the RBTS because of the frequent isolation problems it experiences due to Line 9. The introduction of extra generation facilities anywhere beyond the radial connection does not significantly reduce the cost of energy not supplied at Bus 6, because the isolation problems are not generally addressed by such actions. When the

NUG are injected at Bus 6, generation from these units can be used locally to provide energy supply to the load point and therefore produces significant reductions in the cost of unserved energy at this load point.

Table 3.20: Load point expected cost of unserved energy (ECOST) with the incremental addition of identical 2-MW capacity NUG to Bus 1 of the basic RBTS.

Addition of NUG	ECOST At Bus 2 (K$/yr.)	ECOST At Bus 3 (K$/yr.)	ECOST At Bus 4 (K$/yr.)	ECOST At Bus 5 (K$/yr.)	ECOST At Bus 6 (K$/yr.)
RBTS+(0*2MW)	35.97	128.82	72.83	3.01	537.78
RBTS+(1*2MW)	30.84	114.65	62.01	2.91	537.56
RBTS+(2*2MW)	25.79	101.16	51.54	2.82	537.30
RBTS+(3*2MW)	20.58	87.87	41.24	2.74	537.01
RBTS+(4*2MW)	15.33	74.61	31.02	2.66	536.68
RBTS+(5*2MW)	10.31	61.42	21.36	2.59	536.31
RBTS+(6*2MW)	8.15	52.43	16.99	2.53	535.90
RBTS+(7*2MW)	7.08	48.83	14.73	2.49	535.45
RBTS+(8*2MW)	6.24	46.42	12.92	2.47	534.95
RBTS+(9*2MW)	5.47	44.21	11.28	2.45	534.40
RBTS+(10*2MW)	4.71	42.06	9.69	2.43	533.81

Table 3.21: Load point expected cost of unserved energy (ECOST) with the incremental addition of identical 2-MW capacity NUG to Bus 2 of the basic RBTS.

Addition of NUG	ECOST At Bus 2 (K$/yr.)	ECOST At Bus 3 (K$/yr.)	ECOST At Bus 4 (K$/yr.)	ECOST At Bus 5 (K$/yr.)	ECOST At Bus 6 (K$/yr.)
RBTS+(0*2MW)	35.97	128.82	72.83	3.01	537.78
RBTS+(1*2MW)	31.33	116.49	63.04	3.24	537.56
RBTS+(2*2MW)	26.66	104.93	53.40	3.41	537.31
RBTS+(3*2MW)	21.77	93.82	43.74	3.51	537.01
RBTS+(4*2MW)	16.75	82.60	34.01	3.56	536.68
RBTS+(5*2MW)	11.84	71.77	24.60	3.60	536.31
RBTS+(6*2MW)	9.10	64.06	19.23	3.68	535.90
RBTS+(7*2MW)	7.74	61.58	16.47	3.73	535.45
RBTS+(8*2MW)	6.79	60.50	15.75	3.77	534.95
RBTS+(9*2MW)	6.02	59.29	16.42	3.82	534.40
RBTS+(10*2MW)	5.28	57.98	17.28	3.88	533.81

Table 3.22: Load point expected cost of unserved energy (ECOST) with the incremental addition of identical 2-MW capacity NUG to Bus 3 of the basic RBTS.

Addition of NUG	ECOST At Bus 2 (K$/yr.)	ECOST At Bus 3 (K$/yr.)	ECOST At Bus 4 (K$/yr.)	ECOST At Bus 5 (K$/yr.)	ECOST At Bus 6 (K$/yr.)
RBTS+(0*2MW)	35.97	128.82	72.83	3.01	537.78
RBTS+(1*2MW)	31.82	120.97	64.86	3.61	537.56
RBTS+(2*2MW)	26.56	107.57	54.46	3.98	537.30
RBTS+(3*2MW)	21.18	93.99	44.06	4.17	537.01
RBTS+(4*2MW)	15.77	80.38	33.49	4.17	536.68
RBTS+(5*2MW)	10.59	66.64	23.42	4.00	536.31
RBTS+(6*2MW)	8.15	56.46	18.29	3.68	535.90
RBTS+(7*2MW)	7.00	51.78	15.41	3.42	535.44
RBTS+(8*2MW)	6.13	49.06	13.42	3.34	534.95
RBTS+(9*2MW)	5.34	46.73	11.71	3.30	534.40
RBTS+(10*2MW)	4.57	44.49	10.04	3.24	533.81

Table 3.23: Load point expected cost of unserved energy (ECOST) with the incremental addition of identical 2-MW capacity NUG to Bus 4 of the basic RBTS.

Addition of NUG	ECOST At Bus 2 (K$/yr.)	ECOST At Bus 3 (K$/yr.)	ECOST At Bus 4 (K$/yr.)	ECOST At Bus 5 (K$/yr.)	ECOST At Bus 6 (K$/yr.)
RBTS+(0*2MW)	35.97	128.82	72.83	3.01	537.78
RBTS+(1*2MW)	32.39	118.79	67.78	3.77	537.56
RBTS+(2*2MW)	27.13	104.25	56.46	4.10	537.30
RBTS+(3*2MW)	21.78	90.85	46.27	4.26	537.01
RBTS+(4*2MW)	16.35	77.40	35.86	4.26	536.68
RBTS+(5*2MW)	11.10	64.19	25.50	4.09	536.31
RBTS+(6*2MW)	8.33	54.59	19.37	3.78	535.90
RBTS+(7*2MW)	7.10	50.43	16.21	3.53	535.44
RBTS+(8*2MW)	6.22	48.12	14.22	3.44	534.95
RBTS+(9*2MW)	5.42	46.19	12.32	3.40	534.40
RBTS+(10*2MW)	4.65	44.33	10.70	3.34	533.[illegible]2

Table 3.24: Load point expected cost of unserved energy (ECOST) with the incremental addition of identical 2-MW capacity NUG to Bus 5 of the basic RBTS.

Addition of NUG	ECOST At Bus 2 (K$/yr.)	ECOST At Bus 3 (K$/yr.)	ECOST At Bus 4 (K$/yr.)	ECOST At Bus 5 (K$/yr.)	ECOST At Bus 6 (K$/yr.)
RBTS+(0*2MW)	35.97	128.82	72.83	3.01	537.78
RBTS+(1*2MW)	33.83	124.53	70.31	4.75	538.00
RBTS+(2*2MW)	28.43	109.46	58.06	5.06	538.04
RBTS+(3*2MW)	23.07	94.98	47.40	5.18	537.90
RBTS+(4*2MW)	17.59	81.08	36.77	5.17	537.61
RBTS+(5*2MW)	12.17	67.31	26.11	5.02	537.15
RBTS+(6*2MW)	8.62	55.80	18.92	4.70	536.52
RBTS+(7*2MW)	7.24	50.04	15.63	4.41	535.83
RBTS+(8*2MW)	6.32	47.17	13.40	4.15	535.21
RBTS+(9*2MW)	5.51	44.84	11.63	3.86	534.60
RBTS+(10*2MW)	4.73	42.58	9.96	3.75	533.95

Table 3.25: Load point expected cost of unserved energy (ECOST) with the incremental addition of identical 2-MW capacity NUG to Bus 6 of the basic RBTS.

Addition of NUG	ECOST At Bus 2 (K$/yr.)	ECOST At Bus 3 (K$/yr.)	ECOST At Bus 4 (K$/yr.)	ECOST At Bus 5 (K$/yr.)	ECOST At Bus 6 (K$/yr.)
RBTS+(0*2MW)	35.97	128.82	72.83	3.01	537.78
RBTS+(1*2MW)	31.76	117.05	65.29	3.57	467.17
RBTS+(2*2MW)	26.42	102.23	52.69	3.89	396.45
RBTS+(3*2MW)	20.96	87.89	41.79	4.01	325.63
RBTS+(4*2MW)	15.46	73.91	30.88	3.94	254.75
RBTS+(5*2MW)	10.25	60.25	20.82	3.68	183.60
RBTS+(6*2MW)	8.03	51.08	16.31	3.28	112.47
RBTS+(7*2MW)	6.92	47.31	13.94	2.98	41.51
RBTS+(8*2MW)	6.05	44.73	12.08	2.86	14.49
RBTS+(9*2MW)	5.25	42.40	10.38	2.76	3.40
RBTS+(10*2MW)	4.45	40.14	8.72	2.62	0.99

Table 3.26: Load point expected cost of unserved energy (ECOST) with the incremental addition of identical 5-MW capacity NUG to Bus 1 of the basic RBTS.

Addition of NUG	ECOST At Bus 2 (K$/yr.)	ECOST At Bus 3 (K$/yr.)	ECOST At Bus 4 (K$/yr.)	ECOST At Bus 5 (K$/yr.)	ECOST At Bus 6 (K$/yr.)
RBTS+(0*5MW)	35.97	128.82	72.83	3.01	537.78
RBTS+(1*5MW)	23.29	94.77	46.60	2.80	537.55
RBTS+(2*5MW)	10.42	61.97	21.65	2.62	537.29
RBTS+(3*5MW)	6.83	48.74	14.21	2.53	537.00
RBTS+(4*5MW)	4.85	43.13	10.01	2.50	536.67

Table 3.27: Load point expected cost of unserved energy (ECOST) with the incremental addition of identical 5-MW capacity NUG to Bus 2 of the basic RBTS.

Addition of NUG	ECOST At Bus 2 (K$/yr.)	ECOST At Bus 3 (K$/yr.)	ECOST At Bus 4 (K$/yr.)	ECOST At Bus 5 (K$/yr.)	ECOST At Bus 6 (K$/yr.)
RBTS+(0*5MW)	35.97	128.82	72.83	3.01	537.78
RBTS+(1*5MW)	24.00	100.01	48.22	3.52	537.55
RBTS+(2*5MW)	11.66	72.74	24.37	3.65	537.29
RBTS+(3*5MW)	7.39	62.85	16.01	3.83	537.00
RBTS+(4*5MW)	5.26	59.78	17.50	4.01	536.67

Table 3.28: Load point expected cost of unserved energy (ECOST) with the incremental addition of identical 5-MW capacity NUG to Bus 3 of the basic RBTS.

Addition of NUG	ECOST At Bus 2 (K$/yr.)	ECOST At Bus 3 (K$/yr.)	ECOST At Bus 4 (K$/yr.)	ECOST At Bus 5 (K$/yr.)	ECOST At Bus 6 (K$/yr.)
RBTS+(0*5MW)	35.97	128.82	72.83	3.01	537.78
RBTS+(1*5MW)	24.06	99.99	48.97	3.52	537.55
RBTS+(2*5MW)	10.75	66.35	23.21	3.53	537.29
RBTS+(3*5MW)	6.79	51.14	14.80	3.18	537.00
RBTS+(4*5MW)	4.74	45.02	10.13	2.99	536.67

Table 3.29: Load point expected cost of unserved energy (ECOST) with the incremental addition of identical 5-MW capacity NUG to Bus 4 of the basic RBTS.

Addition of NUG	ECOST At Bus 2 (K$/yr.)	ECOST At Bus 3 (K$/yr.)	ECOST At Bus 4 (K$/yr.)	ECOST At Bus 5 (K$/yr.)	ECOST At Bus 6 (K$/yr.)
RBTS+(0*5MW)	35.97	128.82	72.83	3.01	537.78
RBTS+(1*5MW)	24.65	98.35	51.63	3.66	537.55
RBTS+(2*5MW)	11.27	65.17	24.53	3.64	537.29
RBTS+(3*5MW)	6.90	50.56	15.01	3.30	537.00
RBTS+(4*5MW)	4.83	45.69	10.33	3.11	536.67

Table 3.30: Load point expected cost of unserved energy (ECOST) with the incremental addition of identical 5-MW capacity NUG to Bus 5 of the basic RBTS.

Addition of NUG	ECOST At Bus 2 (K$/yr.)	ECOST At Bus 3 (K$/yr.)	ECOST At Bus 4 (K$/yr.)	ECOST At Bus 5 (K$/yr.)	ECOST At Bus 6 (K$/yr.)
RBTS+(0*5MW)	35.97	128.82	72.83	3.01	537.78
RBTS+(1*5MW)	26.00	103.05	54.02	4.54	537.93
RBTS+(2*5MW)	12.39	68.32	25.95	4.43	537.71
RBTS+(3*5MW)	7.09	50.06	15.03	4.00	537.15
RBTS+(4*5MW)	4.95	43.92	10.14	3.55	536.56

Table 3.31: Load point expected cost of unserved energy (ECOST) with the incremental addition of identical 5-MW capacity NUG to Bus 6 of the basic RBTS.

Addition of NUG	ECOST At Bus 2 (K$/yr.)	ECOST At Bus 3 (K$/yr.)	ECOST At Bus 4 (K$/yr.)	ECOST At Bus 5 (K$/yr.)	ECOST At Bus 6 (K$/yr.)
RBTS+(0*5MW)	35.97	128.82	72.83	3.01	537.78
RBTS+(1*5MW)	23.86	95.75	49.02	3.38	360.78
RBTS+(2*5MW)	10.42	61.04	21.24	3.22	183.59
RBTS+(3*5MW)	6.69	47.16	13.47	2.70	30.25
RBTS+(4*5MW)	4.63	41.34	9.12	2.36	2.34

3.8.1.2. System Indices

The results presented in Tables 3.32 and 3.33 show the overall system customer cost of unserved energy, obtained by summing all the corresponding individual load point customer interruption costs, when 2-MW and 5-MW capacity NUG facilities are respectively introduced at single locations in the basic RBTS. Similarly, overall system customer interruption costs using the aggregate system IEAR of $4.2242 per KWh reported in Table 3.14 are

Table 3.32: The overall system expected cost of unserved energy (ECOST) with the incremental addition of identical 2-MW capacity NUG at each individual bus of the basic RBTS.

Addition of NUG	ECOST Bus 1 (K$/yr.)	ECOST Bus 2 (K$/yr.)	ECOST Bus 3 (K$/yr.)	ECOST Bus 4 (K$/yr.)	ECOST Bus 5 (K$/yr.)	ECOST Bus 6 (K$/yr.)
RB+(0*2MW)	778.41 (938.17)	778.41 (938.17)	778.41 (938.17)	778.41 (938.17)	778.41 (938.17)	778.41 (938.17)
RB+(1*2MW)	747.97 (904.42)	751.66 (908.72)	758.82 (917.90)	760.29 (916.70)	761.42 (930.08)	684.84 (825.93)
RB+(2*2MW)	718.61 (872.04)	725.71 (880.50)	729.87 (885.98)	729.24 (882.29)	739.05 (894.44)	581.68 (704.38)
RB+(3*2MW)	689.44 (839.94)	699.85 (852.76)	700.41 (853.50)	700.17 (850.22)	708.53 (860.45)	480.28 (584.34)
RB+(4*2MW)	660.30 (807.89)	673.60 (824.62)	670.49 (820.62)	670.55 (817.69)	678.22 (827.04)	378.94 (464.60)
RB+(5*2MW)	631.99 (776.40)	648.12 (797.36)	640.96 (787.78)	641.19 (785.50)	647.76 (793.52)	278.60 (345.62)
RB+(6*2MW)	616.00 (756.94)	631.97 (779.13)	622.48 (765.46)	621.97 (763.29)	624.56 (766.77)	191.17 (239.31)
RB+(7*2MW)	608.58 (748.32	624.97 (771.93)	613.05 (754.42)	612.71 (752.89)	613.15 (753.22)	112.66 (144.24)
RB+(8*2MW)	603.00 (742.05)	621.76 (768.55)	606.90 (747.46)	606.95 (746.56)	606.25 (745.50)	80.21 (105.25)
RB+(9*2MW)	597.81 (736.21)	619.95 (765.92)	601.48 (741.34)	601.73 (740.98)	600.44 739.03)	64.19 (86.24)
RB+(10*2MW)	592.70 (730.45)	618.23 (763.23)	596.15 (735.32)	596.84 (735.65)	(594.97 (732.87)	56.92 (77.91)

NB: Results obtained using an aggregate system IEAR of $4.2242 per kWh are presented in parenthesis

Table 3.33: The overall system expected cost of unserved energy (ECOST) with the incremental addition of identical 5-MW capacity NUG at each individual bus of the basic RBTS.

Addition of NUG	ECOST Bus 1 (K$/yr.)	ECOST Bus 2 (K$/yr.)	ECOST Bus 3 (K$/yr.)	ECOST Bus 4 (K$/yr.)	ECOST Bus 5 (K$/yr.)	ECOST Bus 6 (K$/yr.)
RB+(0*5MW)	778.41 (938.17)	778.41 (938.17)	778.41 (938.17)	778.41 (938.17)	778.41 (938.17)	778.41 (938.17)
RB+(1*5MW)	705.01 (857.11)	713.30 (867.85)	714.09 (868.33)	715.84 (867..86)	725.54 (879.22)	532.79 (645.91)
RB+(2*5MW)	633.95 (778.78)	649.71 (799.93)	641.13 (788.02)	641.90 (787.35)	648.80 (795.36)	279.51 (346.85)
RB+(3*5MW)	609.31 (749.61)	627.08 (775.49)	612.91 (754.51)	612.77 (753.87)	613.33 (754.01)	100.27 (129.57)
RB+(4*5MW)	597.16 (736.04)	623.22 (769.93)	599.55 (739.60)	600.63 (741.01)	599.12 (738.33)	59.79 (81.64)

NB: Results obtained using an aggregate system IEAR of $4.2242 per kWh are presented in parenthesis

presented in parenthesis in Tables 3.32 and 3.33.

Gradual improvements in the overall system customer cost of unsupplied energy occurs as the number of NUG introduced at a particular location increases. The rate of improvement, however, varies depending on the different capacity sizes of the unit additions and the locations. The corresponding costs also settle at different levels for the same total number of NUG added to the system. It is important to appreciate that composite power system inadequacy, in addition to direct generation deficiencies and bus isolation due to transmission failures, is also related to the composite problem of generation and transmission outages. As already noted in the case of the RBTS, the weak transmission link to Bus 6 minimizes the benefits to Bus 6 of the additional NUG generation introduced at Buses 1 through 5.

Bus 6 is the major source of inadequacy in the basic RBTS. It can be observed from both Tables 3.32 and 3.33 that the expected customer monetary losses at all the individual load buses as a result of energy not supplied are lower, when five identical 2-MW capacity NUG facilities are injected at different buses of the RBTS, than when two identical 5-MW capacity NUG units are added to the same buses. Similar results were also obtained for the (10 * 2-MW) and (4 * 5-MW) capacity NUG additions as can be seen from Tables 3.32 and 3.33. The expected overall system customer interruption costs are lower, using the summation of all the corresponding expected individual load point customer costs, than when the aggregated IEAR of $4.2242 per KWh is used. This can clearly be seen from Tables 3.32 and 3.33. The use of a single aggregate IEAR, while relatively easy to apply, severely over-estimates the overall cost of unserved energy and does not properly reflect the diversity of customer locations throughout the system.

The principal benefits of NUG additions at the various locations is to alleviate generating capacity deficiencies which constitute a relatively insignificant portion of the overall system customer cost of unserved energy. Buses 3, 4 and 6 are the major contributors to the expected overall system energy interruption costs in all the studies. The location of the NUG facilities is therefore an important factor in this assessment. Introduction of 2-MW and 5-MW capacity NUG facilities at Bus 6 produces significant drops in the overall system customer cost of unsupplied energy as the NUG can now directly supply the load point both during normal system operation and when the load point is isolated from the conventional generation sources. Depending on the relative locations of the NUG additions, the extra generation facilities can lead to a reduction, an increase or virtually no change in the load point and overall system customer monetary losses. The system transmission topology is an important factor in this regard and therefore each system should be analyzed with care prior to making any general observations.

3.8.2. Discussion of IEEE-RTS Results

In the non-utility generation injection studies, an increasing number of 10-MW capacity NUG with 2 percent forced outage rates was introduced at different single-bus locations in the IEEE-RTS. These injections produce different impacts on the load point and the overall power system expected customer cost of unserved energy. The customer cost of unserved energy is directly proportional to the expected energy not supplied. The EENS results from HLII adequacy studies using COMREL were combined with the IEAR values given in Table 3.15. All the results shown are annual indices which reflect the variations in load level over a year. A 7-step (5 percent load step) load model was used in the analysis of the IEEE-RTS.

3.8.2.1. Load Point Indices

The major load point variations in the customer costs of unserved energy when identical 10-MW capacity NUG are incrementally introduced at load Buses 1, 8, 13 and 18 of the IEEE-RTS are shown in Figures 3.5 through 3.8. The figures show a general decreasing trend in the customer cost of unserved energy for most load points, when additional NUG are introduced at selected single locations. The customer cost of interruption at load Bus 19 increases in all cases except when all of the 10 MW NUG are introduced at Bus 13 as shown in Figure 3.7. A similar situation is encountered by customers connected to Buses 16 and 19 when all of the assumed NUG capacity is injected at Bus 18, as indicated in Figure 3.8. The results show a general decrease in the cost of unserved energy for most load points as non-utility generators are introduced at single buses. This indicates that generation deficiency is a major cause of inadequacy at the load points in the IEEE-RTS. The general strength of the IEEE-RTS transmission network increases the effective penetration of the generation from the NUG such that some of the generation outage contingencies which originally made a meaningful contribution to load point inadequacy are virtually eliminated. The provision of the extra generation from NUG alleviates a significant portion of the generation deficiency problems.

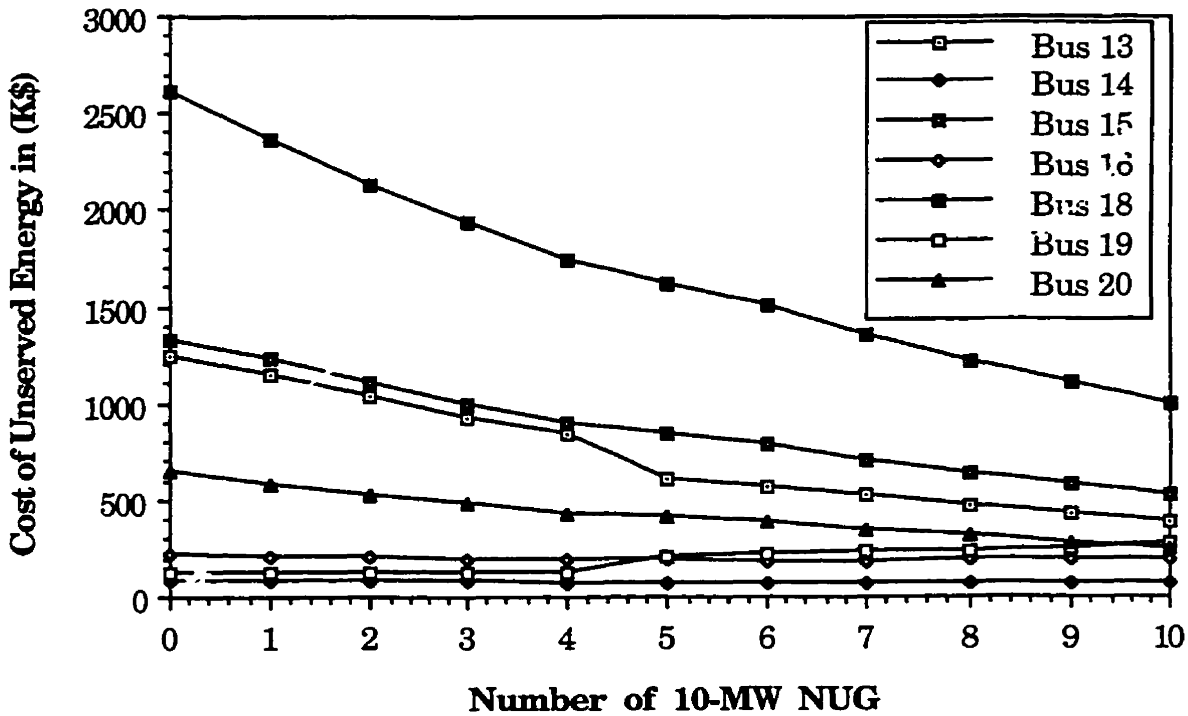

Figure 3.5: Variation in load point customer cost of unsupplied energy as identical 10-MW capacity NUG are sequentially added at Bus 1 of the IEEE-RTS.

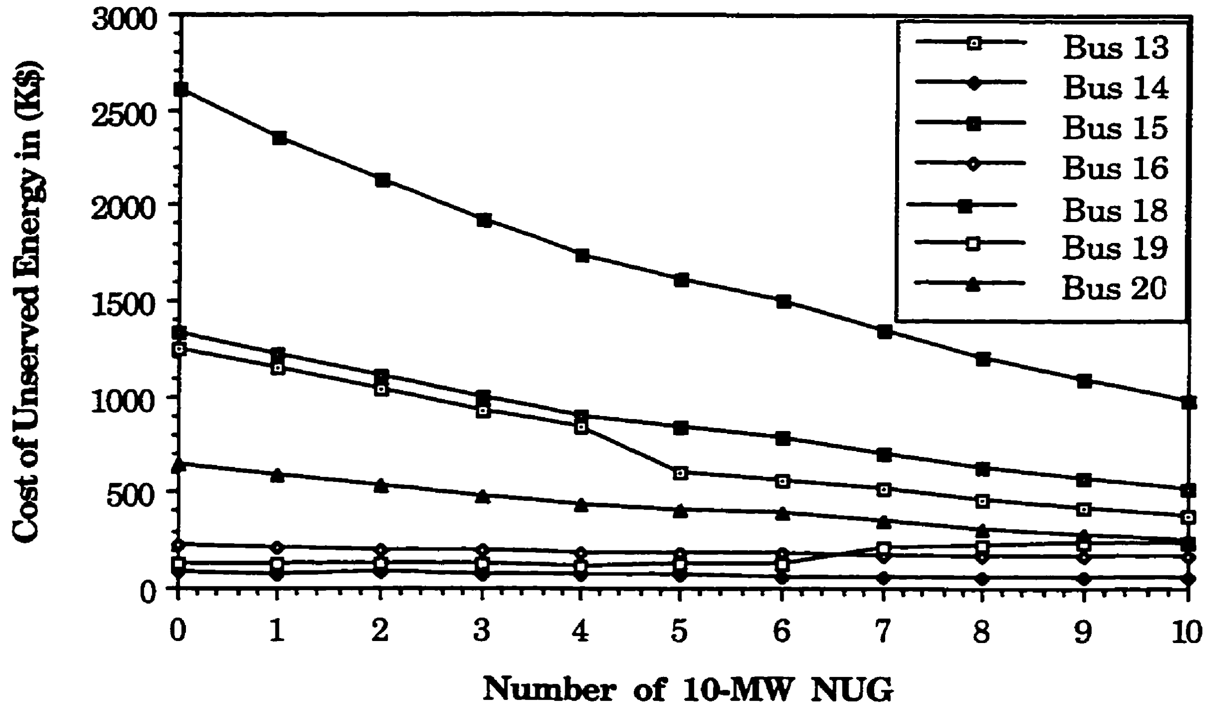

Figure 3.6: Variation in load point customer cost of unsupplied energy as identical 10-MW capacity NUG are sequentially added at Bus 8 of the IEEE-RTS.

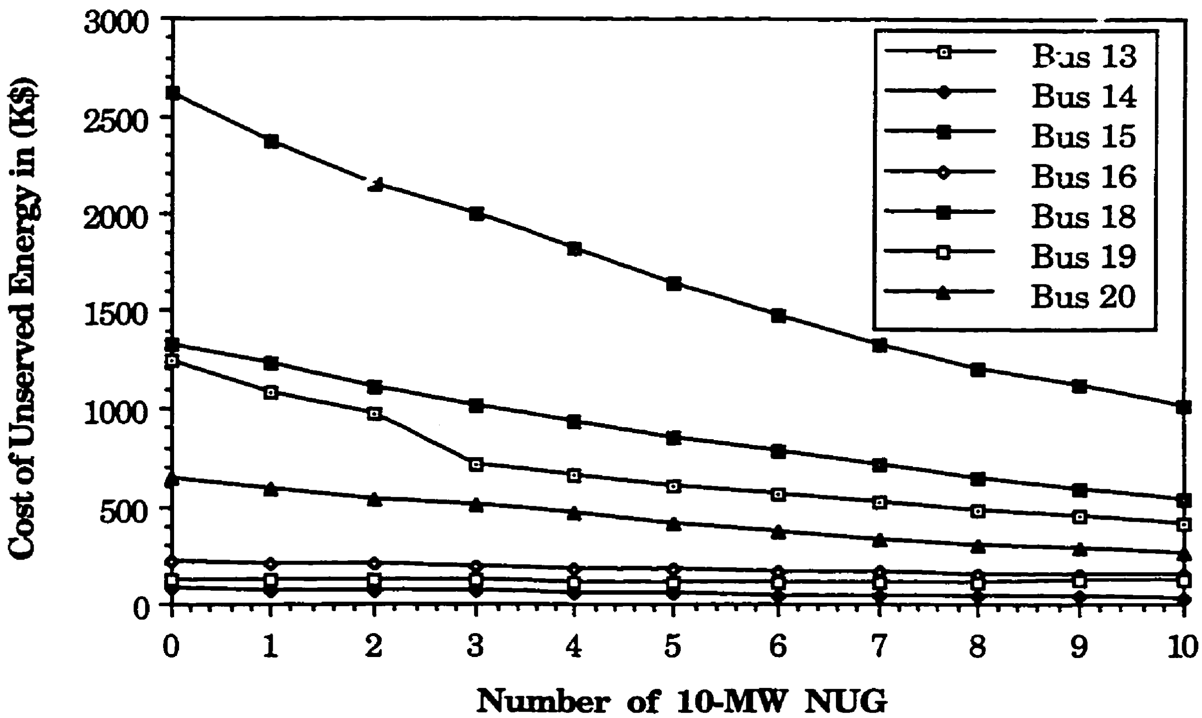

Figure 3.7: Variation in load point customer cost of unsupplied energy as identical 10-MW capacity NUG are sequentially added at Bus 13 of the IEEE-RTS.

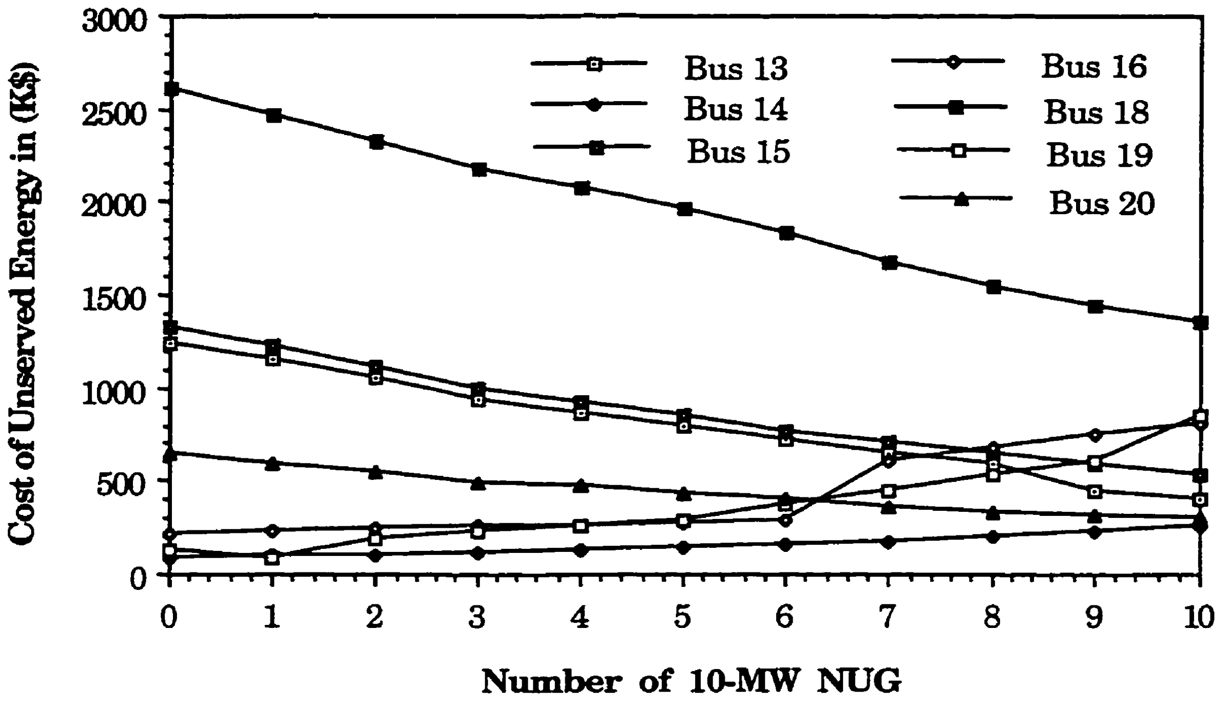

Figure 3.8: Variation in load point customer cost of unsupplied energy as identical 10-MW capacity NUG are sequentially added at Bus 18 of the IEEE-RTS.

3.8.2.2. System Indices

Figure 3.9 shows the overall system customer cost of unserved energy when 10-MW NUG are introduced at Buses 1, 8, 13 and 18 of the IEEE-RTS. The results in Figure 3.9 show a decreasing trend in the system customer costs of unserved energy in all single-bus injection cases except when NUG are introduced at Bus 18. The extra NUG generation at Bus 13 reinforces the supply from the east region therefore reducing the frequency of overload conditions experienced by the swing bus. The addition of NUG at either Buses 1 or 8 in the south region also reduces that region's dependence on supply from the north thus releasing considerable generation for use in preventing the occurrence of swing bus overloads. This accounts for the considerable improvement recorded when the NUG were added to Buses 1 and 8 in the south region of the IEEE-RTS. The additional supply made available when NUG are injected at Bus 18 are used up locally to reduce the curtailment effects caused by the swing bus overload conditions to a minimum instead of attempting to prevent the occurrence of such conditions. In the end, since other buses are also adversely affected by these system conditions, the adverse effects of the swing bus overload conditions at the buses located nearby exceed the gains made at Bus 18 and therefore reverse the initial trend of improvement in overall system cost of unserved energy. A significant improvement in overall composite system adequacy occurs when non-utility generators are added to a large power system such as the IEEE-RTS. Effective penetration of the extra generation from the NUG occurs at most of the single-bus injection points investigated, because of the strong transmission network. Further improvements in the overall system customer cost of unserved energy could be achieved if additional units are added to Buses 1, 8 and 13, in the single-bus additions. References [116, 117] and [115, 118] describe extensions on these analyses where NUG are added at more than one bus in the RBTS and IEEE-RTS respectively. Similar conclusions to those obtained using single NUG streams were obtained. Depending on the relative locations of the NUG additions, the extra generation facilities can lead to a reduction, an increase or virtually no change in the load point and overall system customer monetary losses. As noted earlier, the system transmission topology is an important factor in this regard and therefore each system should be analyzed with care prior to making any general observations.

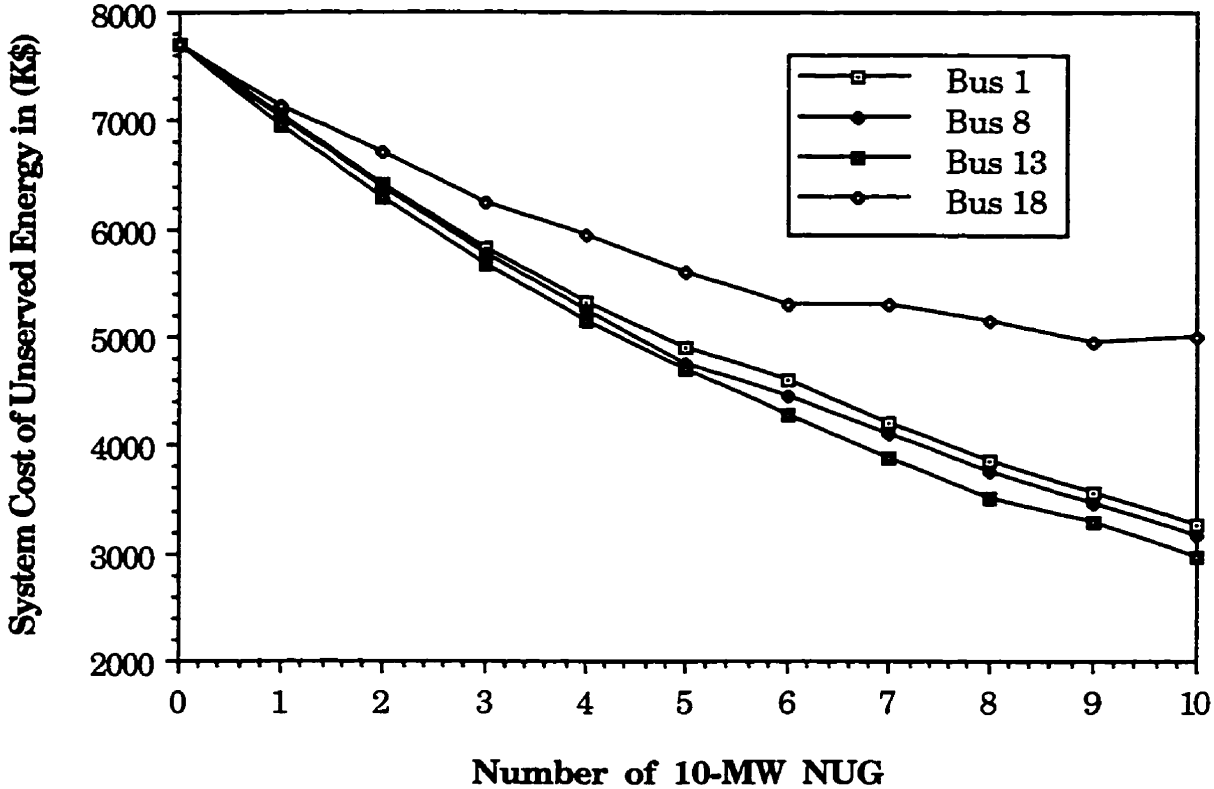

Figure 3.9: Variation in system customer cost of unsupplied energy as identical 10-MW capacity NUG are sequentially added at Buses 1, 8, 13 and 18 of the IEEE-RTS.

3.9. Total System Cost Assessment as a Result of Non-Utility Generation Injections at Individual Load Buses

The first part of this section examines the assessment of the total system costs at hierarchical level I (HLI). Reliability worth considerations can be incorporated in HLI evaluations using either an implicit or an explicit cost approach. The implicit approach is by far the most common. In this case, the selection of the criterion, either deterministic or probabilistic, is considered to implicitly include the recognition of reliability worth. The probabilistic criterion most often used in this approach is the loss of load expectation (LOLE). In the explicit approach, the worth of reliability is incorporated using customer interruption costs and the total system costs are assessed to determine an optimum level of reliability. The probabilistic adequacy index used in this approach is the loss of energy expectation (LOEE) [3, 14]. In the explicit cost approach, the selection of an optimum adequacy level incorporates the cost of providing reliability and the benefits accruing to society of having that reliability. This approach is often simply designated as the reliability cost/benefit approach [119] and used to determine target adequacy levels. Reference [133] illustrates the development of an HLI interrupted energy assessment rate (IEAR) using a frequency and duration technique and a Monte Carlo approach. The IEAR of the RBTS using the F & D method is 3.60 ($/KWh). Sensitivity analysis conducted in [133] shows that the IEAR is quite stable and does not vary significantly with the peak load and other relevant system operating considerations. The combination of the loss of energy expectation (LOEE) index and the IEAR as shown in Equation (3.14) provides a basic and primary tool for assessing adequacy worth in an HLI study.

Customer interruption costs decrease as additional capacity is added to the system. The explicit cost approach can be used to determine the reliability worth associated with these additions and also to evaluate the optimum planning reserve margin. This approach has been applied to the RBTS using 2 MW NUG additions. The generation data and the load model for the RBTS are presented in [88]. The load modification technique [140-143] was used to evaluate the expected energy supplied (EES) by each unit and also the expected energy not supplied (EENS) of the entire system. Figure 3.10 shows the reduction in customer interruption costs as 2 MW NUG with annual fixed costs of $4.00/KW are successively added to the base RBTS. The NUG were assumed to have the same energy production or

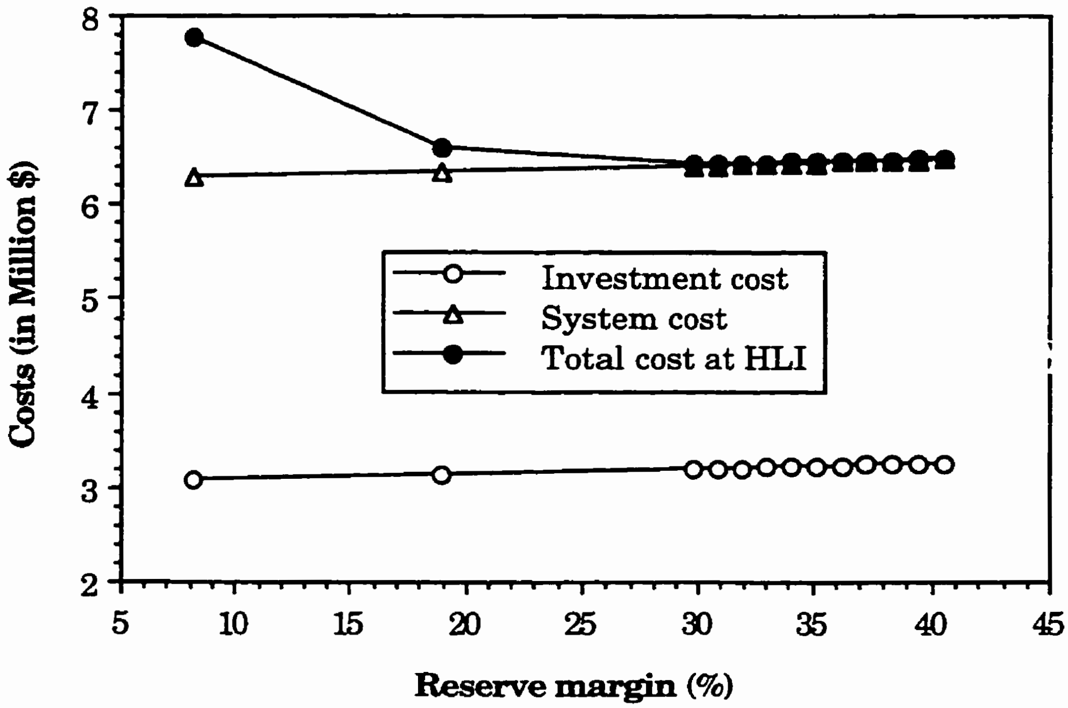

Figure 3.10: Variation of costs with planning reserve margin when 2-MW capacity NUG are added to the RBTS (fixed cost of $4/KW)

variable costs as the 25 MW gas turbine units proposed for the original RBTS [88, 89]. The 2 MW NUG have forced outage rates of 2%.

In order to illustrate the determination of an optimum reserve margin, two 20 MW hydro units were removed and considered as the first units in the proposed study. The nine unit modified RBTS has a total installed capacity of 200 MW. The associated reserve margin is 8.11 percent for a system peak load of 185 MW. Customer interruption costs decrease as additional capacity is added to the system. The explicit cost technique can be used to determine the reliability worth associated with additional capacity and also to evaluate the optimum planning reserve margin (PRM). This approach has been applied to the basic RBTS using 2-MW NUG additions. Figure 3.10 shows a reduction in customer interruption costs as two 20 MW hydro units and 2-

MW capacity NUG are sequentially added to the nine unit modified RBTS. In Figure 3.10, both the production and the investment costs increase slowly as additional generation from the NUG facilities are added to the base RBTS.

The fixed and production costs are $3,185,000 and $3,220,746 respectively. The corresponding customer interruption cost is $35,168 at an IEAR of 3.60 $/KWh. The index most commonly used to measure system adequacy is the planning reserve margin (PRM). A reserve margin can be defined as the additional generating capacity above the peak load. The least cost reserve margin occurs with the addition of the two 20 MW hydro-units and is 29.73 percent. The total system cost at this reserve margin is $6,440,914 per annum. The EENS or LOEE at this point is 9.77 MWh. The optimum reserve margin shown in Figure 3.10 is obviously dependent on the data used in the system evaluation, including the perceived customer interruption cost. The optimum reserve margin is also dependent on the size and type of units used in the proposed expansion and will vary somewhat with different proposed configurations. It is not, however, a fixed pre-determined value which can be used under all conditions and expansion scenarios. In the explicit cost technique, the reserve margin is an outcome of the analysis, not a fixed criterion used to drive the unit addition process.

The second part of this section extends the previously described HLI total system cost assessment to hierarchical level II (HLII). The least cost determination process is summarized in Equation (3.15). The objective is to obtain the optimum overall system cost associated with the injection of NUG facilities at different locations in a composite generation and transmission system by minimizing the investment costs, the operating costs and the unserved energy costs;

$$\text{Min Cost} = [IC + PC + \sum_{k=1}^{nl} \sum_{j=1}^{nc} \sum_{i=1}^{nb} ((EENSi, j, k) \times IEAR)] \quad (3.15)$$

subject to the following constraints:

$$\sum_{i=1}^{ng} PGi + \sum_{j=1}^{nb} PLCi = \sum_{i=1}^{nb} PLi;$$

$$PGimin \leq PGi \leq PGimax;$$

$$P_{ij}min \leq P_{ij} \leq P_{ij}max.$$

where IC and PC denote the investment costs and production costs respectively. The remaining variables and constraints in Equation (3.15) are as follows:

- nl: number of load steps;
- nc: number of contingencies;
- nb: number of load buses or points in the entire system;
- ng: number of generators;
- P_{Gi}: generation at Bus i;
- P_{LCi}: load curtailment at Bus i;
- P_{Li}: load at Bus i;
- P_{ij}: active power in the line connecting Buses i and j;
- EENS: the expected energy not supplied calculated by the composite reliability model in KWh; and
- IEAR: the interrupted energy assessment rate representing an average of the costs per KWh of unsupplied energy.

3.9.1. Discussion of the RBTS Results

The total system costs were evaluated for the scenarios described earlier in which an increasing number of 2-MW and 5-MW capacity NUG with forced outage rates of 2 percent and fixed costs of $4.00/KW were introduced at different single-bus locations within the RBTS [116, 117].

The variation in the total system cost as a function of the PRM when the NUG streams are introduced at selected load buses of the RBTS are shown in Figures 3.11 through 3.14. An investment cost of \$4.00/KW was considered for the 2-MW and 5-MW capacity NUG located at Buses 1 to 6 in determining the minimum total societal costs at HLII shown in Figures 3.11 and 3.12 respectively. An investment cost of \$40.00/KW was utilized in the studies shown in Figures 3.13 and 3.14 respectively. The \$4.00/KW and \$40.00/KW values were used to represent situations in which the added capacity was provided by IPP and by the utility itself respectively. Figures 3.11 through 3.14 show the variation in total costs as the reserve margin increases due to the injection of the NUG streams at all buses of the RBTS. In order to illustrate the effect of the different NUG streams, the process was initiated by removing one 20-MW hydro-unit from Bus 2 of the basic RBTS. Under these conditions, the PRM is 18.92 percent. One 20-MW unit was then added to the available capacity at Bus 2 followed by one of the NUG at Buses 1 to 6 of the RBTS.

As the percent reserve margin increases, the expected unserved energy costs decrease gradually when NUG streams are introduced at Buses 1 through 5 but decrease rapidly when the NUG streams were located at Bus 6, as can be seen from Figures 3.11 to 3.14. The detailed results are shown in Appendix E. It can be seen from the tables provided in Appendix E that, both the investment and production costs increase slowly as additional generation from the NUG facilities with an investment cost of \$4.00 per KW are introduced at all the single-bus locations within the RBTS. There is a sharp increase in these costs when different capacity NUG with a fixed cost of

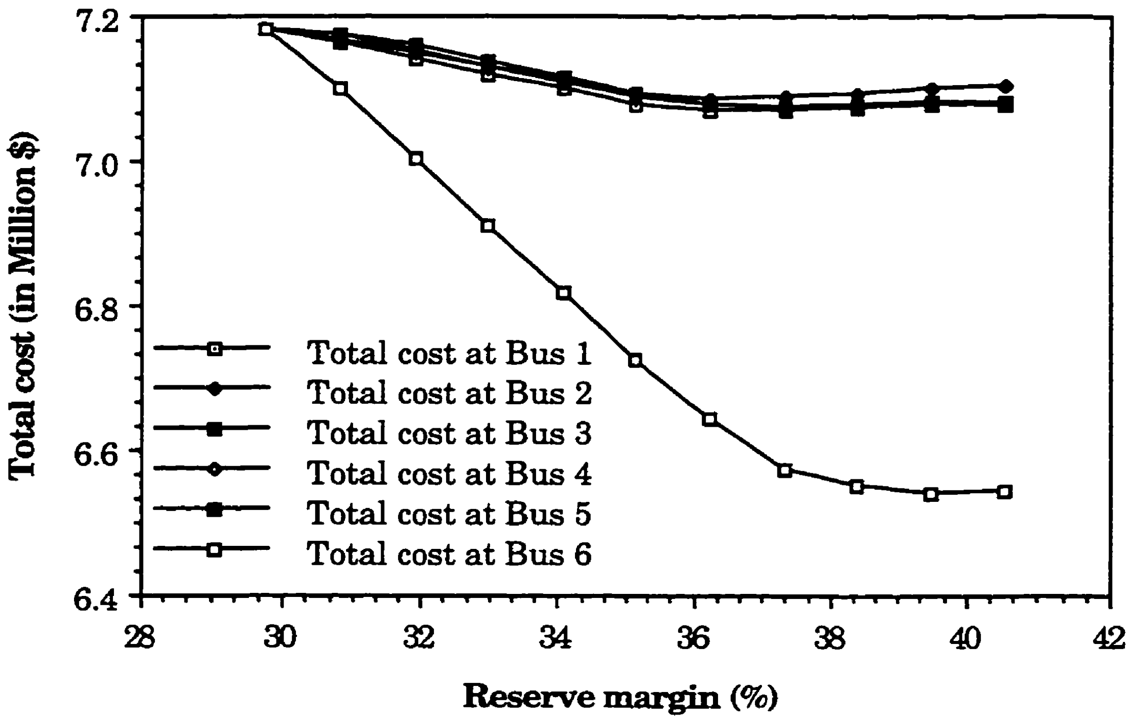

Figure 3.11: Variation of costs with planning reserve margin when 2-MW capacity NUG are injected at Buses 1 to 6 of the RBTS (fixed cost of $4/KW).

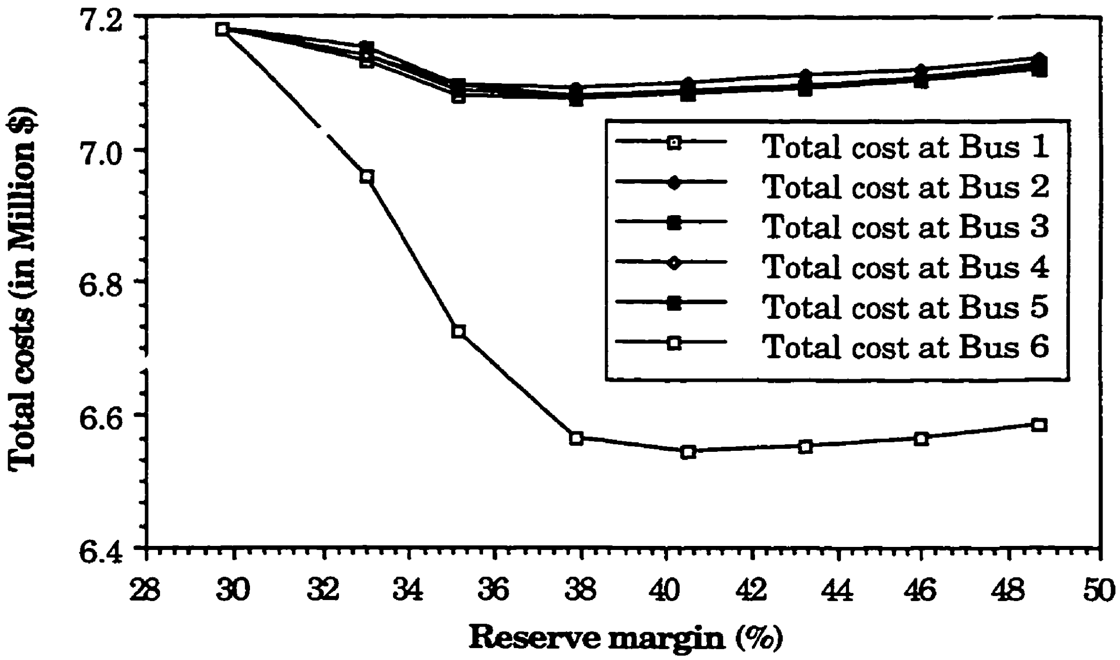

Figure 3.12: Variation of costs with planning reserve margin when 5-MW capacity NUG are injected at Buses 1 to 6 of the RBTS (fixed cost of $4/KW).

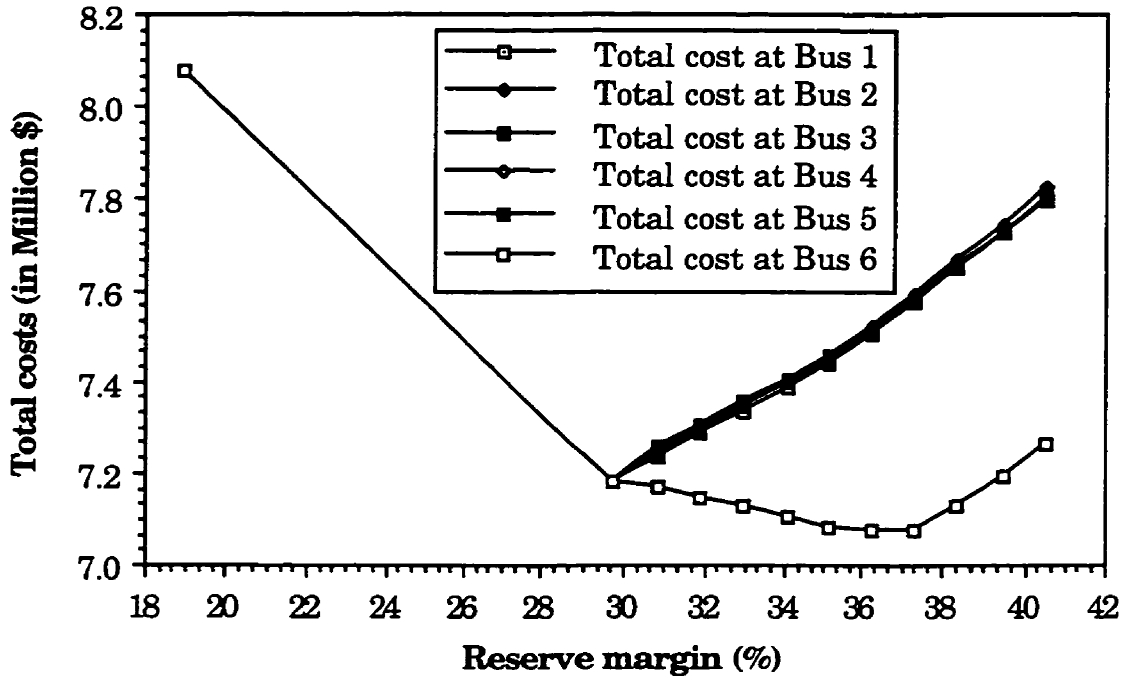

Figure 3.13: Variation of costs with planning reserve margin when 2-MW capacity NUG are injected at Buses 1 to 6 of the RBTS (fixed cost of $40/KW).

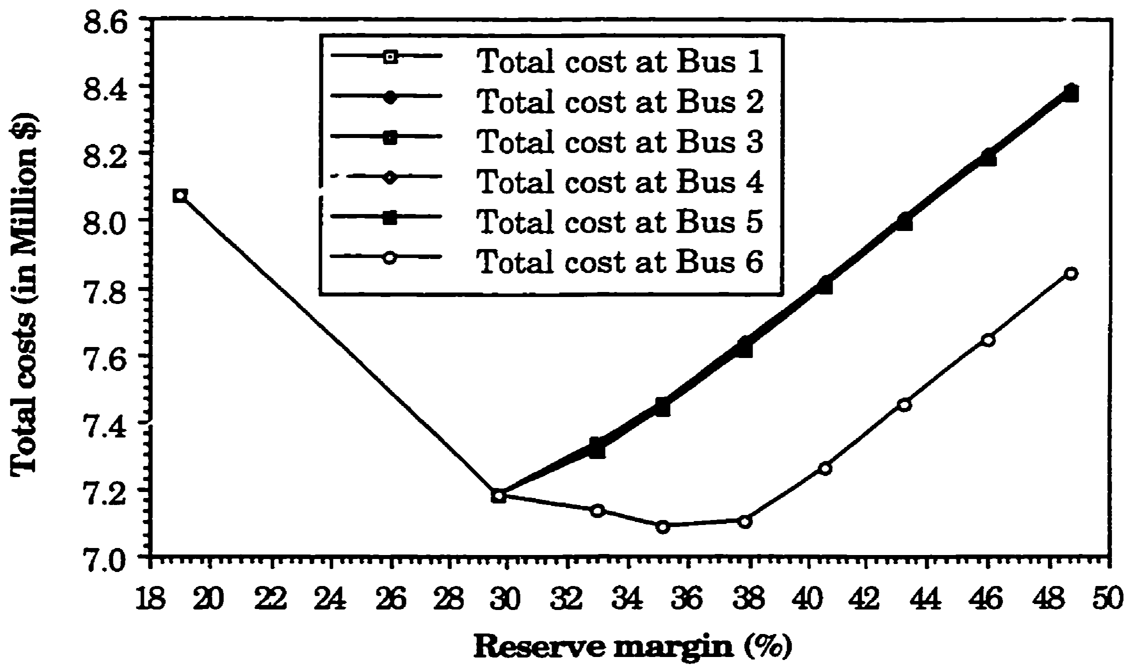

Figure 3.14: Variation of costs with planning reserve margin when 5-MW capacity NUG are injected at Buses 1 to 6 of the RBTS (fixed cost of $40/KW).

$40.00 per KW was used. The total system costs obtained at HLII when the same or different capacity NUG stream(s) are injected at the single-bus locations of the RBTS settle at different end-points as can be observed from Figures 3.11 through 3.14.

The ten-unit modified RBTS has a total installed capacity of 220 MW. The associated PRM is 18.92 percent for a system peak load of 185 MW. Under these conditions, the expected unserved energy cost is $1.7198 million at HLII. The capital investment and energy production costs are $3.1350 million and $3.2207 million respectively, for a total societal cost of $8.0755 million. Tables E.1 to E.8 present these costs for the 220 MW base case and with the addition of one 20 MW hydro-unit at Bus 2 and an increasing number of 2-MW and 5-MW capacity NUG located at Buses 1 through 6 of the RBTS.

The results provided in the last three columns of Tables E.1 and E.8 were used in preparing Figures 3.11 to 3.14. It can be seen from Figures 3.11 and 3.12 that the total system costs decrease up to the minimum point and then begin to increase when 2-MW and 5-MW capacity NUG facilities with a fixed cost of $4.00 per KW are located at Buses 1- 6 of the RBTS. The minimum total costs in this case, as can be seen from Tables E.1 - E.4, are $7.0702 M, $7.0862 M, $7.0753 M, $7.0749 M, $7.0754 M and $6.5424 M (for the 2-MW NUG streams) and $7.0755 M, $7.0933 M, $7.0791 M, $7.0790 M, $7.0795 M and $6.5460 M (for the 5-MW NUG streams). The corresponding planning reserve margins (PRM) are 36.22%, 36.22%, 37.30%, 37.30%, 37.30% and 39.46% (for the 2-MW NUG streams) and 37.84%, 37.84%, 37.84%, 37.84%, 37.84% and 40.54% (for the 5-MW NUG streams). Similar results for the total societal costs when a fixed cost of $40.00 per KW for the 2-MW and 5-MW NUG are provided in Tables E.5 to E.8. The results presented in Tables

E.5 - E.8 show minimum-cost planning reserve margins of 29.73%, 29.73%, 29.73%, 29.73%, 29.73% and 36.22% for the 2-MW NUG streams introduced at Buses 1 - 6 and 29.73%, 29.73%, 29.73%, 29.73%, 29.73% and 35.14% for the 5-MW NUG streams introduce at Buses 1 - 6. The corresponding total societal costs are as follows: \$7.1814 M, \$7.1814 M, \$7.1814 M, \$7.1814 M, \$7.1814 M and \$7.0774 M (for the 2-MW NUG streams) and \$7.1814 M, \$7.1814 M, \$7.1814 M, \$7.1814 M, \$7.1814 M and \$7.0856 M (for the 5-MW NUG streams). The results obtained for the total societal costs and their corresponding planning reserve margins vary depending on the different capacity sizes of unit additions and locations. The total cost and its corresponding PRM also settle at different levels for the same total number of NUG added to the test system, as can be seen from Tables E.1 to E.8 and Figures 3.11 through 3.14.

The different NUG streams injected at all of the single-bus locations within the RBTS have a significant effect on the least total societal or system costs and the optimum planning reserve margin as can be seen from Tables E.1 through E.8. The total costs and the optimum reserve margins shown in Tables E.1 - E.8 and Figures 3.11 to 3.14 are obviously dependent on the data used in the system evaluation. The total system cost decreases as the 20 MW unit and subsequent NUGs are added. Both the total minimum cost and the optimum reserve margin are different for each case. The addition of NUGs at Bus 6 leads to a lower total cost and at the same time permits the system to hold a higher reserve margin. The optimum reserve margin and the total societal costs at HLII are also dependent on the size and the exact locations of the NUG facilities used in the expansion and will vary with different proposed configurations. The explicit cost approach however, provides the opportunity to examine the total societal costs and the optimum reserve margin associated with small capacity NUG additions in a composite system. The studies performed using the RBTS are illustrated in this section of the thesis. The results of the studies conducted show that the addition of NUG facilities can have considerable cost-benefits impacts in existing conventional utility systems. The injection of small capacity NUG streams at different locations in a composite generation and transmission systems, will result in different total societal costs and optimum planning reserve margins.

3.9.2. Discussion of the IEEE-RTS Results

The RBTS analyses illustrated earlier clearly show that the incorporation of NUG into a composite generation and transmission system can have considerably influence on the determination of an optimal PRM. These concepts were applied to the IEEE-RTS in order to determine the impact of NUGs on a more complex and real life power system [118]. In order to evaluate the total system costs, an increasing number of 10-MW capacity NUG with assumed forced outage rates of 2 percent and investment or fixed costs of $4.00 per KW and $40.00 per KW were introduced at different single-bus locations within the IEEE-RTS [118]. Selected IEEE-RTS load buses were used in this analysis. The variation in the total system costs as a function of the PRM when the NUG facilities or streams are introduced at these load buses are shown in Figures 3.15 and 3.16. An investment cost of $4.00 per KW was used for the 10-MW capacity NUG facilities in Figure 3.15. An investment cost of $40.00 per KW was utilized in Figure 3.16.

As the percent reserve margin increases, the total societal costs initially decrease when NUG facilities are introduced at Buses 1, 8, 13 and 18, as can be seen from Tables E.9 to E.12 and Figures 3.15 and 3.16. Tables E.9 and E.10, show that both the investment and system costs increase slowly as the additional generation from the NUG facilities with a fixed cost of $4.00 per KW are introduced at the selected locations within the IEEE-RTS. There is a sharp increase in these costs when 10-MW capacity NUG facilities with an investment cost of $40.00 per KW is used as seen in Tables E.11 and E.12. The total system costs obtained at HLII when the 10-MW capacity NUG are injected at the selected load buses settle at different end-points as can observed from Tables E.9 to E.12 and Figures 3.15 and 3.16.

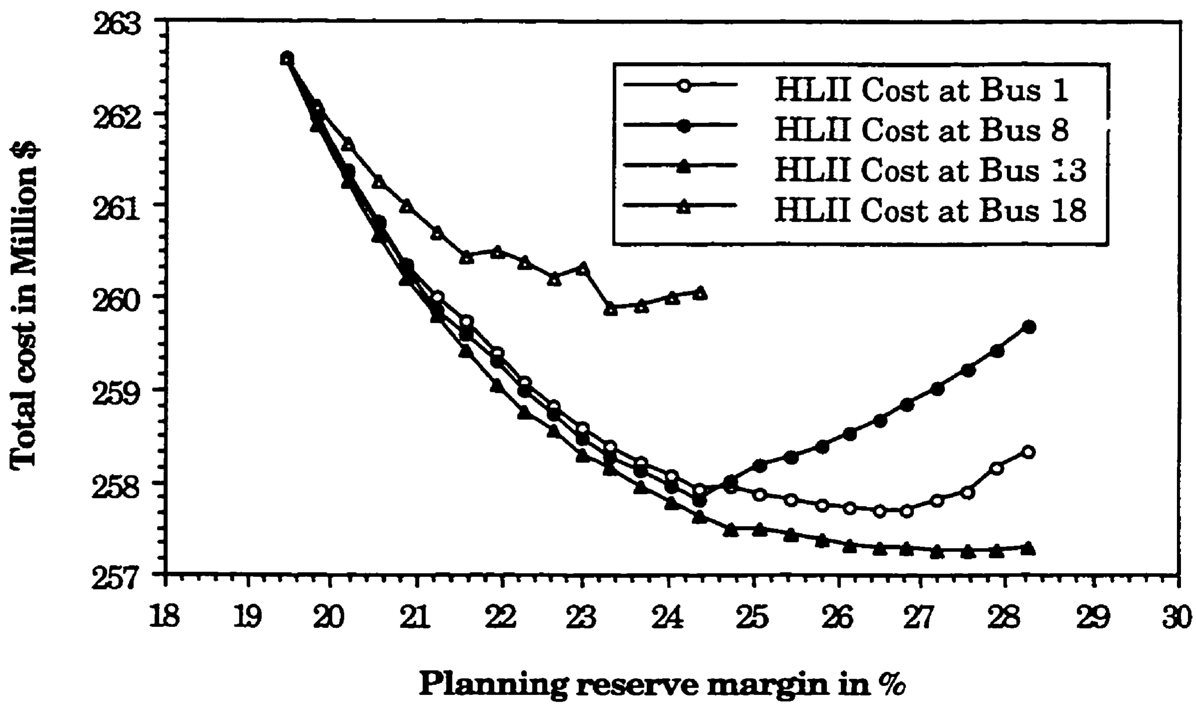

Figure 3.15: Variation of costs with planning reserve margin when 10-MW capacity NUG are injected at Buses 1, 8, 13 and 18 of the IEEE-RTS (fixed cost of $4 per KW).

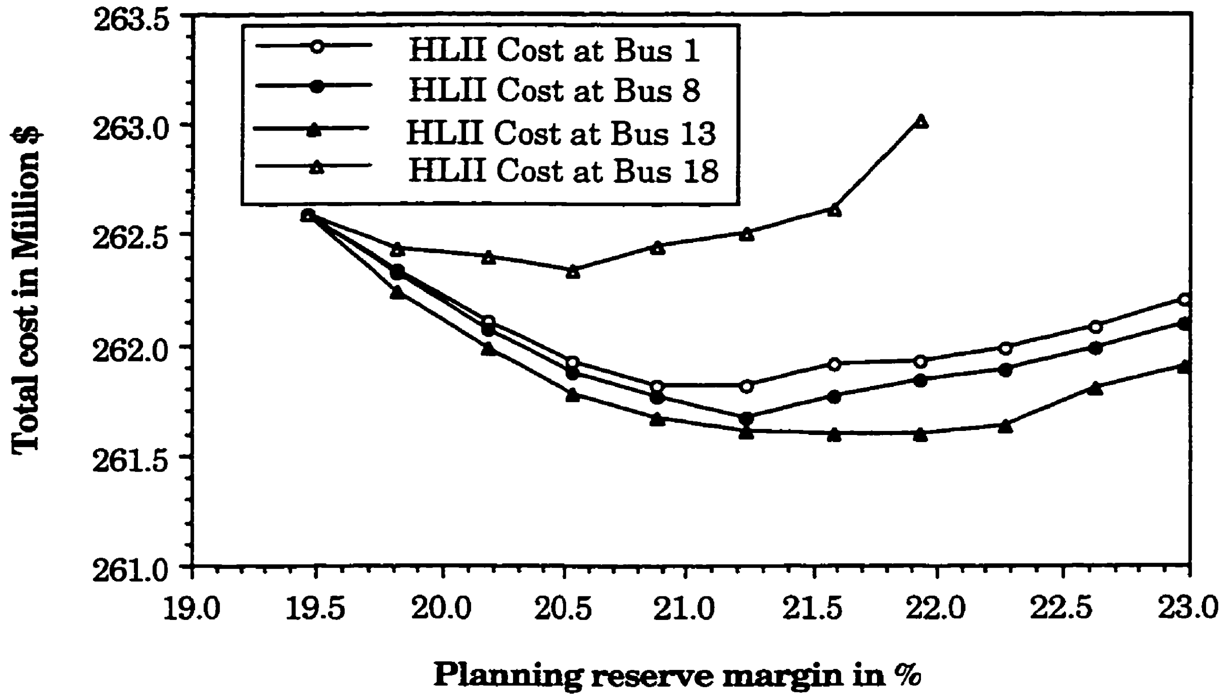

Figure 3.16: Variation of costs with planning reserve margin when 10-MW capacity NUG are injected at Buses 1, 8, 13 and 18 of the IEEE-RTS (fixed cost of $40 per KW).

The results provided in the last columns of Tables E.9 & E.10 and Tables E.11 & E.12 were used in preparing Figures 3.15 and 3.16 respectively. The minimum total costs in this case, as can be seen from Tables E.9 - E.10, are $257.7015 million, $257.8216 million, $257.2676 million and $259.8963 million with corresponding PRM of 26.49%, 24.39%, 27.54% and 23.33%. Similar results obtained for the total societal costs when an investment cost of $40.00 per KW for the 10-MW capacity NUG facilities are provided in Tables E.11 and E.12. Tables E.11 and E.12 show minimum-cost planning reserve margins of 21.23%, 21.23%, 21.58% and 20.53% due to the NUG facilities with corresponding total societal costs of $261.8090 million, $261.6707 million, $261.5886 and $262.3390 million respectively.

The NUG facilities injected at the selected load buses within the IEEE-RTS have a significant effect on the least total societal costs and the optimum planning reserve margin as can be seen from Tables E.9 to E.12. The total costs and the optimum reserve margins shown in Tables E.9 through E.12 and Figures 3.15 and 3.16 are obviously dependent on the data used in the system evaluation. The optimum reserve margin and the total societal costs at HLII, for the IEEE-RTS, are also dependent on the size and the exact locations of the NUG facilities used in the proposed expansion. The results from the IEEE-RTS analyses support the conclusions drawn for the RBTS.

3.10. Summary

This chapter focuses on the economic evaluation of the reliability worth associated with non-utility generation additions in both the RBTS and the IEEE-RTS. The ability to conduct such an evaluation is an important consideration in modern electric power utility planning and system design. The chapter illustrates the utilization of reliability worth concepts involving non-utility generation in composite generation and transmission systems. The determination of reliability worth is a direct extension of quantitative reliability assessment and provides the opportunity to incorporate customer considerations in the planning and design of an electric power system. The initial part of this chapter presents a brief outline of the basic concepts employed in utilizing customer cost of interruption data to evaluate interrupted energy assessment rates (IEAR) at HLII. The IEAR values can be used to link customer monetary losses to electric service reliability at each load point in a composite generation and transmission system.

The studies described in this chapter illustrate that non-utility generation can serve as alternatives to conventional power system reinforcement in the form of utility generation and transmission facilities. The results show that the introduction of non-utility generation at different locations in a utility system have different impacts on both load point and overall power system customer costs of unserved energy depending upon the existing composite generation and transmission configuration of the utility system. The studies presented clearly illustrate that quantitative reliability assessment can be performed in systems containing NUG and that these assessments can be extended to include reliability worth evaluation. Depending on the relative locations for the NUG additions, the extra generation facilities can lead to a reduction, an increase or virtually no change in the load point and overall system customer monetary losses. The system transmission topology is an important factor in this regard and therefore each system should be analyzed with care prior to making any general observations.

Most utilities use an implicit cost technique to incorporate reliability worth in their planning and decision making processes. The explicit cost technique in which investment costs, operating costs and expected customer outage costs are incorporated in the evaluation and in the selection of an optimum reliability target is illustrated by application to the RBTS and the IEEE-RTS. The implicit cost technique cannot be extended to NUG assessment at HLII, because very few, if any, electric power utilities have specified quantitative reliability indices for each load point in their composite generation and transmission system. The explicit cost approach however provides the opportunity to examine the total societal costs and the optimum reserve margin associated with small capacity NUG additions in a composite system. The studies performed using a hypothetical test system (i.e., RBTS) and a fairly complex power system (IEEE-RTS) are illustrated in this chapter. The results of the studies conducted show that the addition of NUG facilities can have considerable cost-benefit impacts in existing conventional utility systems. The introduction of small capacity NUG streams at different single-bus locations in an electric power utility system resulted in different total system and optimum generation planning reserve margins at HLII.

4. COMPOSITE GENERATION AND TRANSMISSION SYSTEM ADEQUACY ASSESSMENT WITH TIME VARYING LOADS

4.1 Introduction

Composite generation and transmission system adequacy evaluation is concerned with the total problem of assessing the ability of the generation and transmission system to supply adequate electrical energy to the major system load points [3, 14, 144]. The word composite [3, 14] stems from the fact that both generation and transmission facilities are involved in the assessment. Composite system adequacy assessment is still in its infancy and there is relatively little published material available on practical applications. While there is no consensus on techniques, criteria or indices, there are many electric power utilities and related organizations doing interesting and innovative work in this area.

Two basic approaches or techniques have been applied in the development of tools used to evaluate composite system adequacy. These are Contingency Enumeration (analytical) and Monte Carlo simulation techniques. Irrespective of the approach, the general outline of the evaluation procedure is the same in both cases, although implementation methodologies differ in certain respects. The ultimate objective of any evaluation technique is to quantify supply adequacy both at the individual load buses and for the overall system using appropriate indices. A wide range of indices can be produced and these are generally classified as either load point indices or system indices. There is no consensus in the electric power industry regarding which particular set of indices is the best. In the analytical approach to composite system adequacy evaluation [35], mathematical models are used to represent the system and its operating policies. The models are based on specific assumptions which, at times, are limited in the degree of sophistication that can be accommodated in modeling the complex characteristics of practical power systems.

The IEEE-Reliability Test System (IEEE-RTS) [90] has been used extensively to develop and illustrate composite system evaluation. The load model information provided, can be used to calculate total system hourly loads for one complete year on a per unit basis, expressed in a chronological fashion so that daily, weekly and seasonal patterns can be developed. This procedure is not entirely accurate because individual buses follow different load curves depending on the mix of customers at that bus. The above noted load model is sufficient for generating capacity reliability studies such as loss of load expectation (LOLE) and loss of energy expectation (LOEE) assessment [3, 144]. The published information, however, is not as comprehensive as might be desired for composite system studies since the IEEE-RTS load data is specified as total system demand and does not indicate how individual bus loads vary during the period concerned. A more comprehensive load model would recognize that individual load buses have different load curves which depend on the mix of customer classes at that load bus [145]. Different hourly load curves at each bus can be developed but collecting this data is difficult and the data is, therefore not generally available. Creation of suitable data necessitated the development of a load model using a bottom-up approach starting from the customer sectors present at each bus [146, 147]. This thesis illustrates composite system adequacy assessment using an analytical technique and hourly load curves developed for each load bus. The Roy Billinton Test System (RBTS) shown in Figure 2.4, which is a small hypothetical test system, is used in the studies described in this chapter.

4.2. Representation of the Load Model at each Load Bus

The IEEE - Reliability Test System (IEEE-RTS) [90] was published in 1979 by the IEEE Subcommittee on the Application of Probability Methods (APM). The creation of the IEEE-RTS also provided impetus to collecting relevant data required in reliability studies. The IEEE-RTS has been used extensively, since it was proposed, in various reliability studies conducted by reliability engineers in electric power industries and institutions (e.g., universities). The report [90] by the IEEE Reliability Test System Task Force describes a load model, generation system and transmission network. The system load is described by specifying the weekly peak loads in percent of the annual peak load, the daily peak load in percent of the weekly peak load and the hourly peak load in percent of the daily peak load.

This load model is sufficient for doing system reliability studies at HLI. The published information, however, is not adequate for estimating costs of interruption which require additional information for each customer class. The IEEE-RTS load data is specified as total system demand and does not indicate how individual customer class loads vary during the period concerned.

All the earlier studies [91, 92] have used the IEEE-RTS hourly load model for the system as a whole. Individual bus loads, at any hour were assumed to be proportional to the ratio of peak load at that bus to the peak load of the system. This procedure is not absolutely correct as individual buses follow different load curves depending on the mix of customers at that bus. As a result, different hourly load curves at each load bus of the RBTS have been developed so that they can be used in adequacy and economic (e.g., cost of interruption) studies involving demand-side management (DSM) options.

4.3. Development of a Chronological Load Model at each Load Bus

One of the difficulties in applying probability methods in the area of cost of interruption studies is that these methods require extensive load information for each customer sector [148]. These data are not usually available. The increased popularity of applying stochastic methods in system reliability evaluation has created a demand for the collection of outage data and other relevant information. Detailed load consumption and demand information is, however, still not readily available. In the absence of this information, it was therefore necessary to create a database which contains relevant information about each customer sector load. This was accomplished using some available data and a series of realistic assumptions.

The Standard Industrial Classification (SIC) has been used to identify seven types of customer sectors [139]. These sectors are as follows:

- Large users,
- Industrial,
- Commercial,

- Agricultural,
- Residential,
- Government & Institutions,
- Office & Buildings.

The load at each bus has been allocated to these different sectors [139] for the test system used in this work. The general load shapes of these sectors are quite unique. Their characteristics are described in the next sub-section.

4.3.1. Customer Characteristics

Industrial loads are considered to be base loads that contain little weather dependent variation [149]. However, depending on the type of industry, these loads may have unique characteristics because of shift operations, etc. The electricity use characteristics of large users and industrial customers are similar. Large industrial customers normally have a relatively large demand for electric power that remains quite stable from day to day or season to season. In general, larger industrial customers, with more continuous production activities, have the most uniform demand for electrical energy. Smaller industrial customers who may run only two shifts per day with minimal or no weekend production have lower demands during evenings and weekends. However, these smaller industrial customers exhibit a fairly constant demand during production hours.

Commercial and government & institutional demand curves are relatively high but constant during the daylight hours of the normal business day and fall off during the night.

In the case of commercial establishments, evening demand may fall off gradually due to the accommodation of evening shopping hours in many retail outlets. This class of customers also shows seasonal variations as a result of air conditioning and seasonal differences in lighting, which constitute their major energy requirements.

Residential [150, 151] and agricultural customers show greater temporal variability in their demand for electrical power than do commercial and industrial customers. Demand, particularly by residential customers, is very strongly dependent upon seasonal weather variations and also exhibits very pronounced daily peak demands during the early morning and early evening. Daily load variation in the residential sector is primarily as a result of domestic uses of cooking equipment, hot water and lighting.

Residential loads have the most seasonal fluctuations. The seasonal variations of the residential components in many cases are responsible for the seasonal variations in system peak, the extent of the residential influence depending on the percentage of the total system load that is residential [151]. This characteristic is due to the widespread use of weather sensitive devices such as space heaters and air conditioners. Other high-energy devices used by residential customers are water heaters, refrigerators and dryers. Refrigeration loads tend to have constant characteristics compared to the cyclical load characteristics of dryers and water heaters.

The assumed load profiles of these seven customer sectors for a typical day are shown in Figures 4.1 through 4.3.

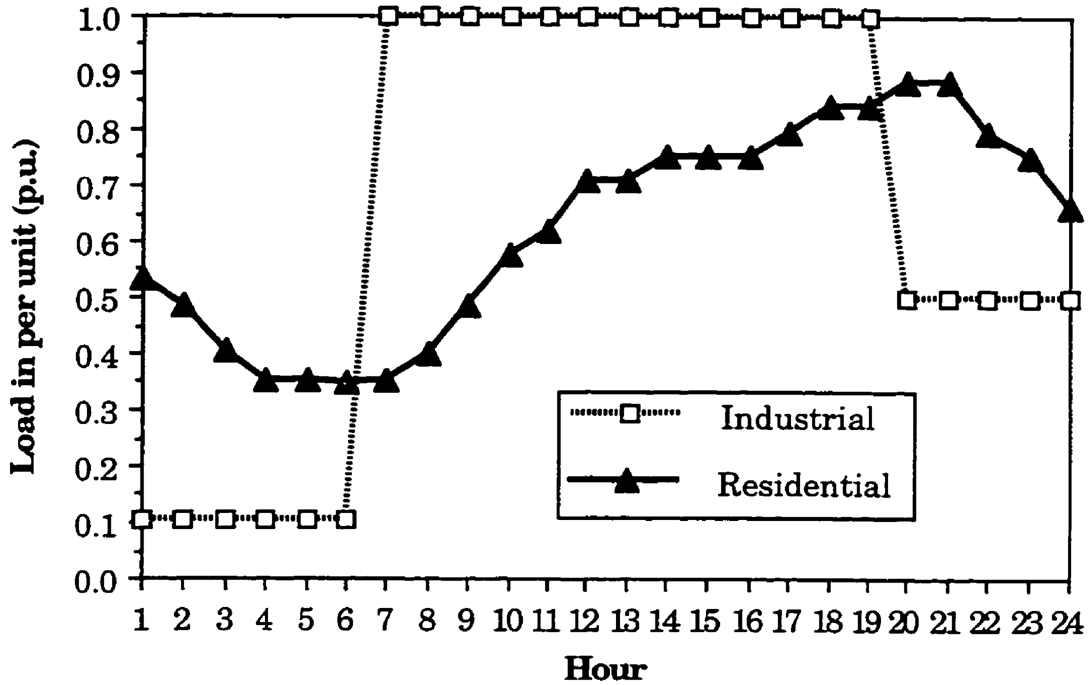

Figure 4.1: Load profile for the Residential and Industrial Sectors.

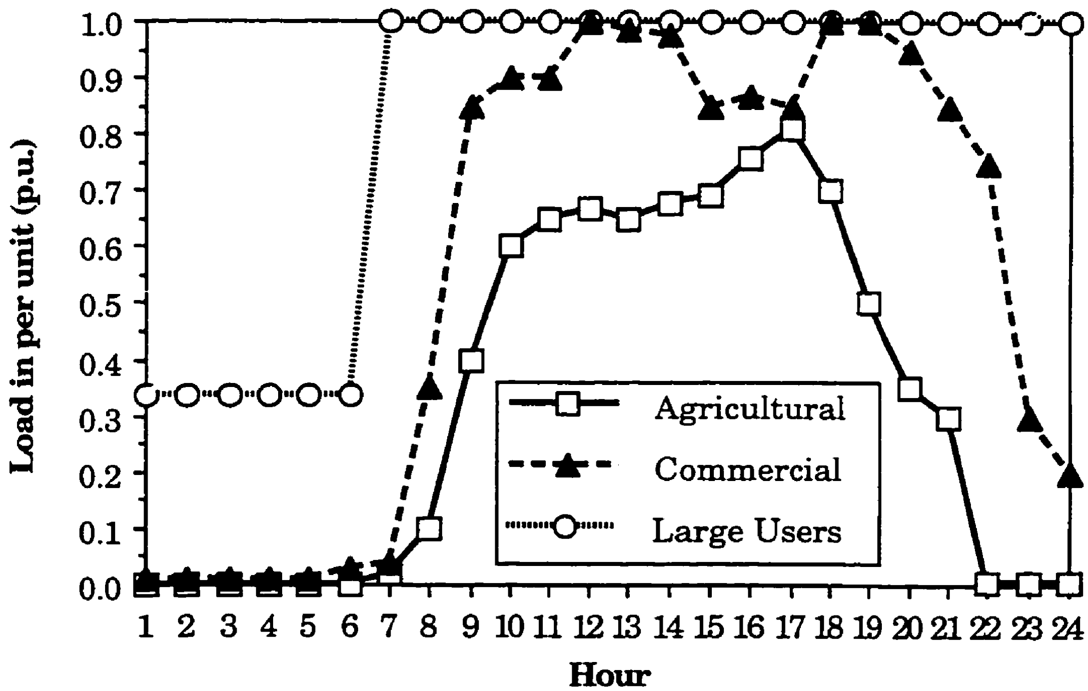

Figure 4.2: Load profile for the Commercial, Large Users and Agricultural Sectors.

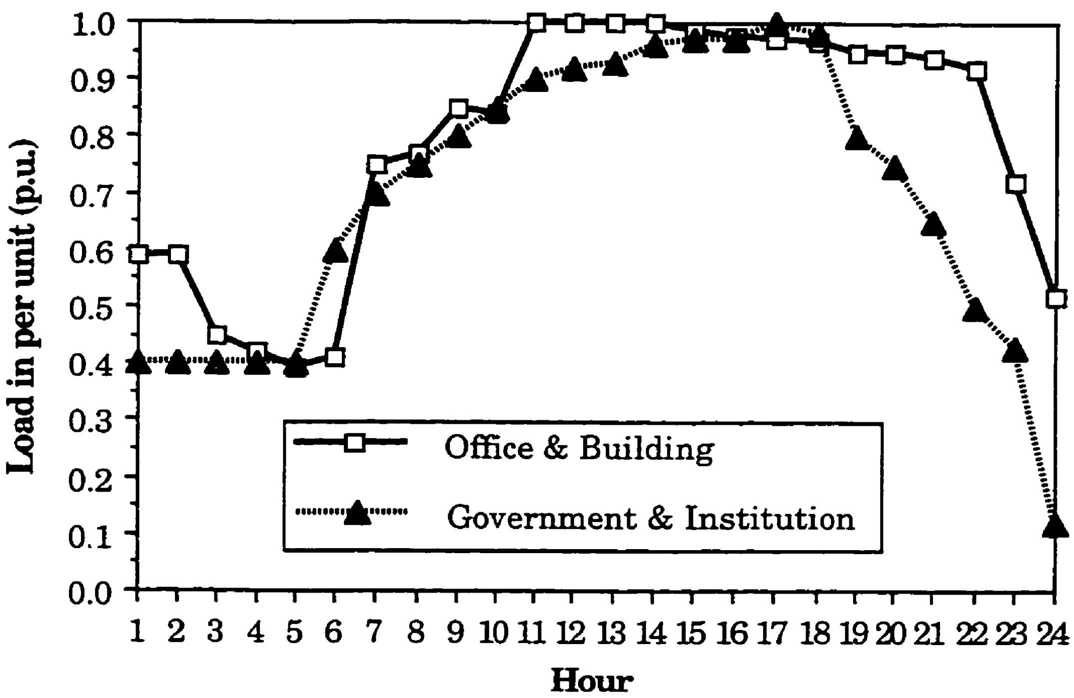

Figure 4.3: Load profile for the Government & Institution and Office & Building Sectors.

4.4. Development of Load Curves for each Load Bus

The load curves for the customer sectors were developed taking into account daily, weekly and seasonal patterns. Seasonal influences have also been considered in the load model. The yearly or annual load model in this analysis has been divided into three seasons namely: winter, spring/fall and summer. The 52 weeks or 8736 hours are therefore distributed into the three seasons as follows:

- Winter weeks: = (1 - 8) and (44 -52);
- Spring/Fall weeks: = (9 - 17) and (31 - 43); and
- Summer weeks: = (18 - 30).

OR

- Winter hours: = (1 - 1344) and (7225 - 8736);
- Spring/Fall hours: = (1345 - 2856) and (5041 - 7224); and
- Summer hours : = (2857 - 5040).

The weekly, daily and hourly percent of the sector peak load attributed to the various sectors is given in Appendix D. These hourly load curves were developed for the RBTS [88, 89].

4.4.1. Application to the RBTS

The test system used in these studies is the 6-bus RBTS [88, 89]. This system is sufficiently small to permit the conduct of a large number of reliability studies with reasonable solution time but sufficiently detailed to reflect the actual complexities involved in a practical test system.

Seven customer sectors are considered and a detailed description of this test system is given in Reference [88, 89]. A single line diagram of the test system which shows the assigned load bus customer compositions is shown in Figure 4.4. It can be seen from this figure that there are some residential and commercial sector customers at every load bus. As an example, Bus 2 has industrial, commercial, residential, and government and institutional users allotted to it. The bus data and generator data of this system are given in Appendix B. The transmission network shown in Figure 4.4 has been drawn to give a more geographic representation.

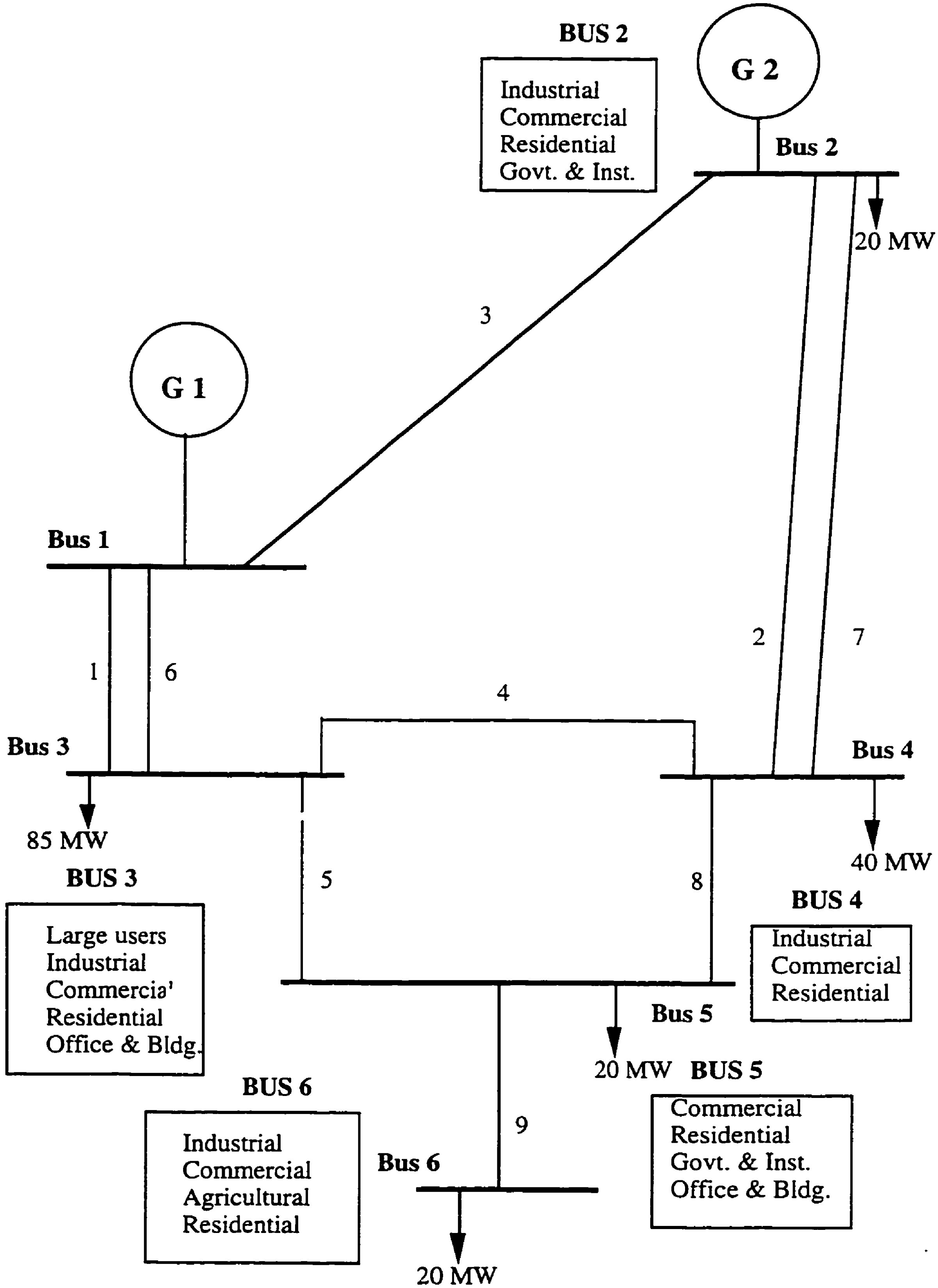

Figure 4.4: Single line diagram of the RBTS with customer compositions.

4.4.1.1. Evaluation of Hourly Load at each Load Bus

The load curves for the customer sectors were developed taking into account daily, weekly and seasonal patterns. Let Lji be the proportion of the sector peak load contributed by sector i during hour j, to the load at bus k. Lji is also referred to as the allocation factor. The load at bus k, for hour j is given by Equation (4.1).

Load at Bus k for hour j =

$$\sum_{i=1}^{\text{all sectors in Bus k}} (\text{Lji} \times \text{sector j's peak load at Bus k}) \qquad (4.1)$$

This load model can be used with other test systems such as the IEEE-RTS, provided that the sector peak load allocation is known at each bus. Table 4.1 indicates the sector peak load allocation for the RBTS.

Table 4.1: Sector peak load allocation in MW at each load bus of the base RBTS.

User Sector	Bus 2	Bus 3	Bus 4	Bus 5	Bus 6
Large Users	----	55.50	----	----	----
Industrial	3.50	3.05	16.30	----	3.05
Commercial	3.75	4.70	4.70	3.70	1.70
Agricultural	----	----	----	----	7.40
Residential	7.25	19.90	19.00	8.90	7.85
Govt. & Inst.	5.55	----	----	5.55	----
Office & Bldg.	----	1.85	----	1.85	----

In order to illustrate the procedure, a sample calculation for determining the bus loads for a specific hour in a year is described.

Depending upon the season, day of week and time of day, the allocation factor in per unit for the various sectors is obtained. Table 4.2 describes the allocation factor for the seven customer sectors during the hour.

Table 4.2: Allocation factors in per unit for a specific hour.

User Sector	Allocation factor
Large users	0.337000
Industrial	0.103700
Commercial	0.010000
Agricultural	0.001000
Residential	0.531072
Government. & Institution	0.400000
Office & Building.	0.590000

Weighting these allocation factors by the respective bus sector peak load results in the sector hourly load at a bus. The bus loads are then calculated as the summation of these sector hourly loads at the bus using Equation (4.1). Equations (4.2) to (4.6) present a sample calculation for determining the bus and sector loads at the specific hour of the year.

$$\begin{aligned}\text{Bus 2} &= (0.531072\times 7.25)+(0.1037\times 3.50)+(0.01\times 3.75)+(0.4\times 5.55)\\ &= 6.46\text{ MW}\end{aligned} \tag{4.2}$$

$$\begin{aligned}\text{Bus 3} = {} & (0.337\times 55.50)+(0.1037\times 3.05)+(0.01\times 4.70)+(0.531072\times 19.90)\\ & +(0.59\times 1.85) = 30.727\text{ MW}\end{aligned} \tag{4.3}$$

$$\text{Bus 4} = (0.531072\times 19)+(0.1037\times 16.30)+(0.01\times 4.70) = 11.828\text{ MW} \tag{4.4}$$

$$\begin{aligned}\text{Bus 5} &= (0.01\times 3.70)+(0.531072\times 8.90)+(0.4\times 5.55)+(0.59\times 1.85)\\ &= 8.075\text{ MW}\end{aligned} \tag{4.5}$$

$$\text{Bus 6} = (0.1037\times 3.05)+(0.01\times 1.70)+(0.001\times 7.40)+(0.531072\times 7.85)$$
$$= 4.509\ \text{MW} \tag{4.6}$$

Figures 4.5 to 4.7 show the load profiles on a per unit basis for a given week for the residential, industrial, commercial, large users, agricultural, government & institution and office and building sectors in the winter season. These load profiles vary depending upon the season. It can be seen from Figure 4.5 that the load curve for Bus 3 has a relatively flat segment during the day, since the major contribution to the load at this bus is from the large user sector. Annual chronological load curves have been developed for all the load buses of the RBTS, considering the different mix of customer sectors at each bus. Figure 4.7 combines the data from Figures 4.5 and 4.6 and shows the total system load.

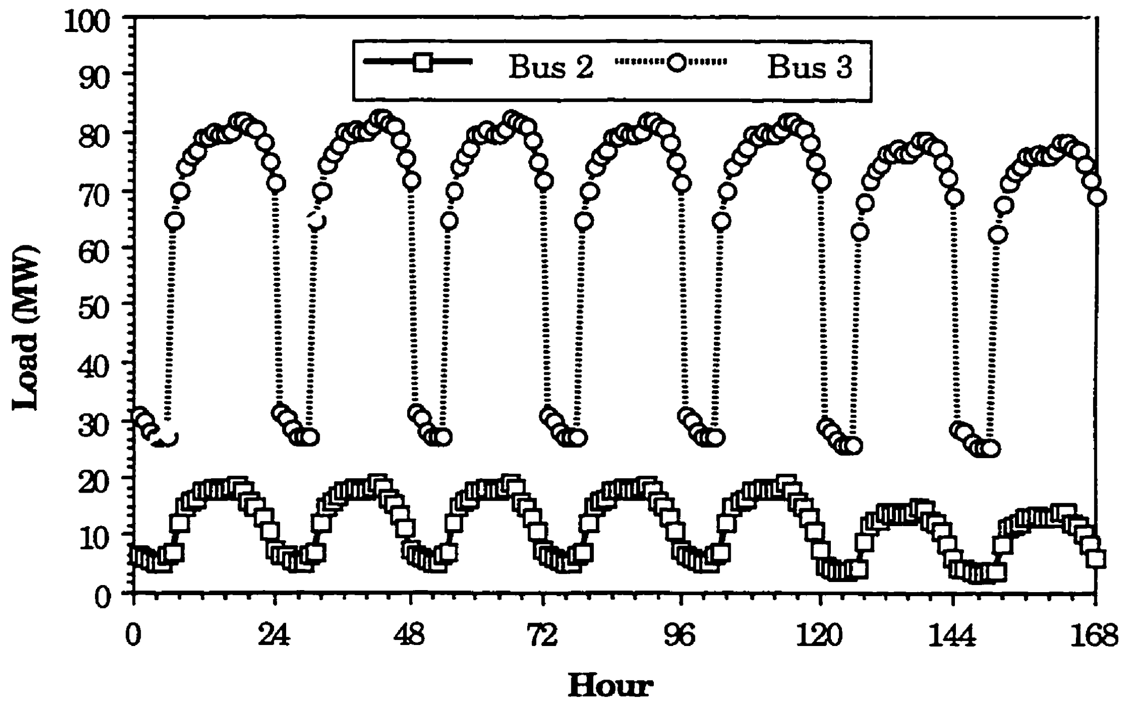

Figure 4.5: Load curves for Buses 2 and 3 of the RBTS.

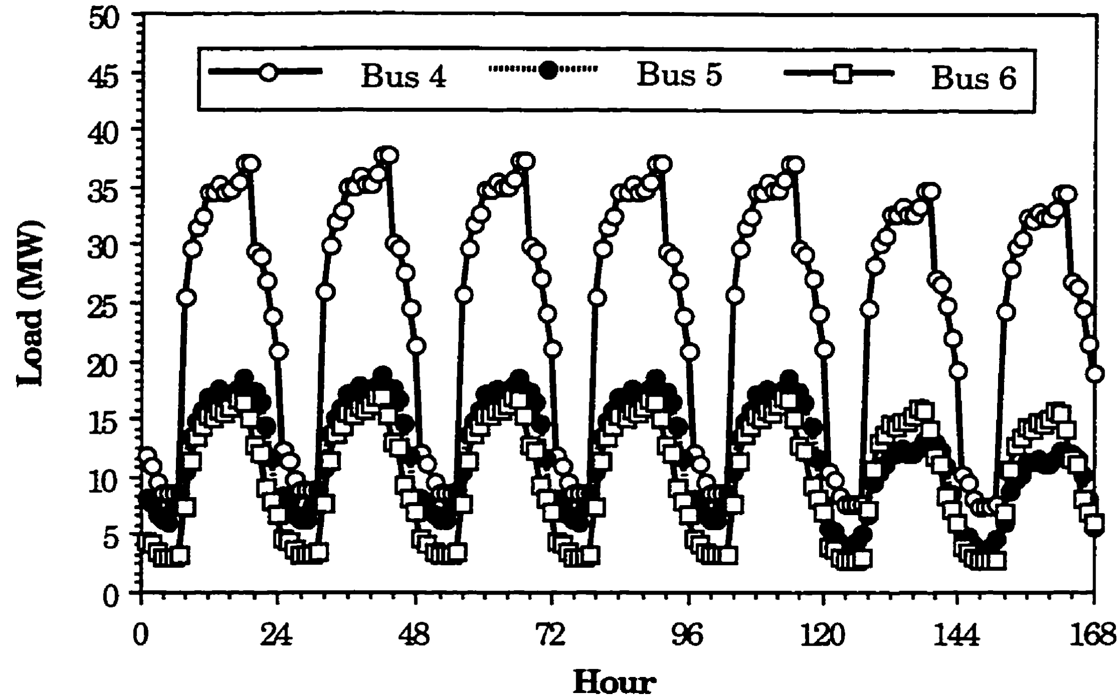

Figure 4.6: Load curves for Buses 4, 5 and 6 of the RBTS.

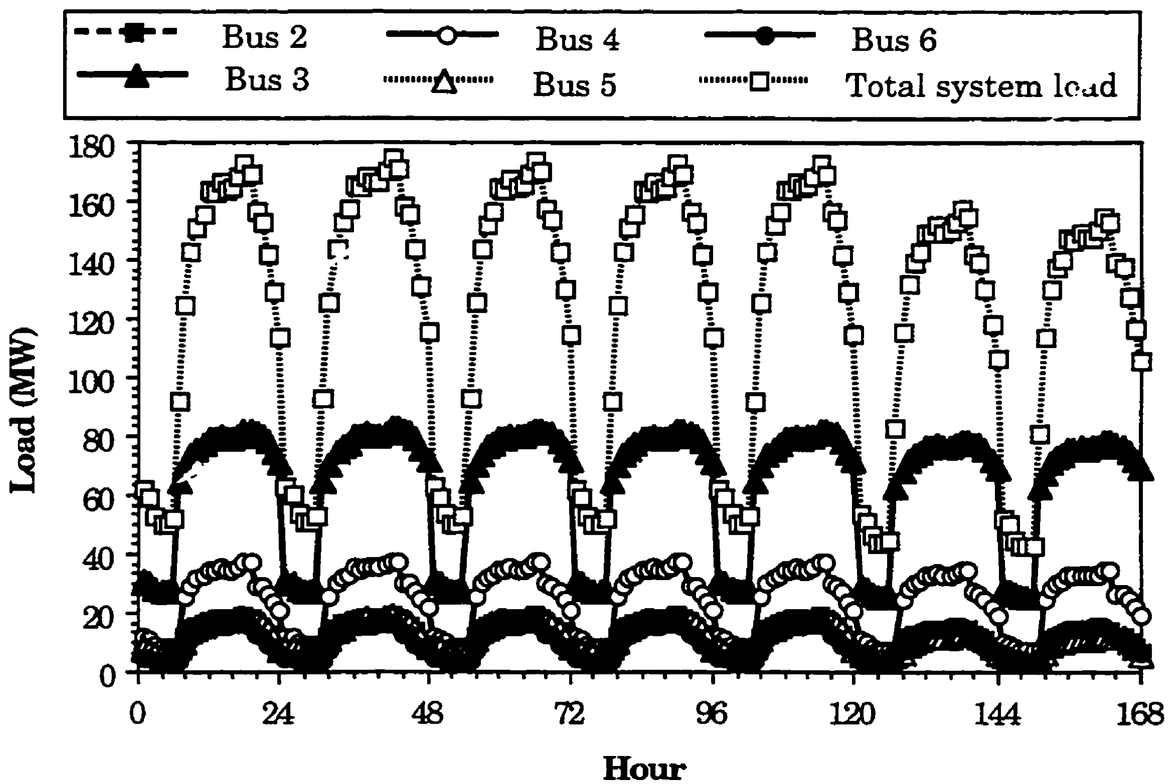

Figure 4.7: Load curves for all the load buses and the total system load of the RBTS.

4.5. Adequacy Studies using Time Dependent Loads

4.5.1. Application to the RBTS

The annual chronological load model consisting of the 8736 (i.e., 24 x 364) hourly loads of the RBTS have been used in the studies presented in this section. Only the first 168 hourly loads for the first week of the year are shown in Figures 4.5 through 4.7. The study-year is represented in this load model by three seasons namely winter, spring/fall and summer. As a result, the reliability evaluation was performed for each of the above mentioned season-segments and summed to obtain the total reliability or adequacy indices at each load bus and the overall system. This section discusses the effect of assessing the system by dividing the hourly chronological load curves for each load bus into the same finite number of steps or time intervals. In the first case, the individual load bus curve is divided into 5 non-uniform intervals [i.e., 1-6, 7-8, 9-12, 13-18 and 19-24, hours]. The mean of all the loads in any particular time interval is used to represent the load for this time interval in all the analyses reported in this section. The same time interval is used for all load buses in order to establish correlation between the bus loads, which is lacking when a load duration curve is used. The contingency enumeration approach has been applied to this load model and the individual load point indices are presented in Table 4.3.

Equation (4.7) was used to obtain the indices for the load buses and the overall system indices of the RBTS. The data shown in Figure 4.8 were used in Equation (4.7).

Table 4.3: Annual load point indices for the base RBTS using a 5-step daily load model.

Bus Number	PLC	ENLC (Occ./yr.)	ELC (MW/yr.)	EENS (MWh/yr.)
2	0.00029298	0.14547625	0.1857	3.0784
3	0.00046850	0.29349244	4.3612	39.6322
4	0.00031173	0.17882662	0.6763	8.0742
5	0.00002788	0.04840783	0.2604	1.2519
6	0.00114665	1.14250124	11.4334	100.9220

$$Rtotal = Rwinter^{(a+e)} + Rspring/fall^{(b+d)} + Rsummer^{(c)} \quad (4.7)$$

where,

Rtotal is the expected total annual reliability index for the three seasons;

Rwinter is the reliability index obtained for the winter season expressed on an annual basis;

Rspring/fall is the reliability index obtained for the combined spring and fall seasons expressed on an annual basis;

Rsummer is the reliability index obtained for the summer season expressed on an annual basis;

a and e are the expected winter durations in per unit on an annual basis;

b and d are the expected spring and fall durations in per unit on an annual basis; and

c is the expected summer duration in per unit on an annual basis.

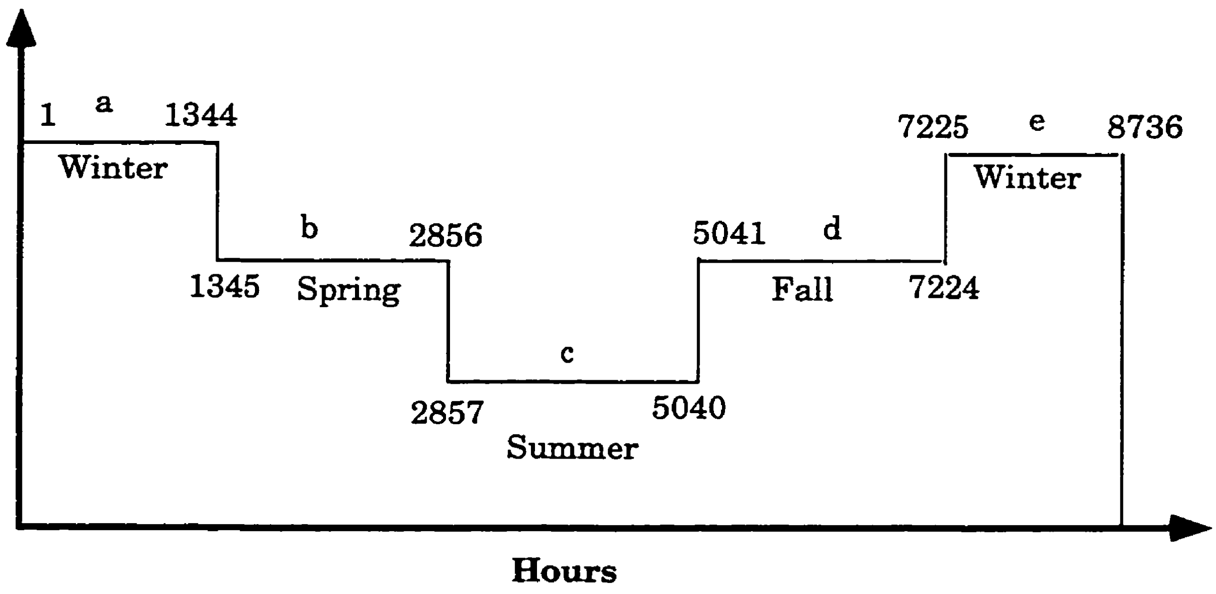

Figure 4.8: The annual representation of the three main seasons

The chronological load model for each load bus was then divided into 10 non-uniform time intervals [i.e., 1-2, 3-6, 7, 8, 9-11, 12-19, 20-21, 22, 23, and 24, hours]. Table 4.4 shows the individual load point indices obtained using this model.

Table 4.4: Annual load point indices for the base RBTS using a 10-step daily load model.

Bus Number	PLC	ENLC (Occ./yr.)	ELC (MW/yr.)	EENS (MWh/yr.)
2	0.00035290	0.17178230	0.2224	3.7369
3	0.00057019	0.34364637	4.8589	46.6469
4	0.00037527	0.21125127	0.8052	9.7590
5	0.00003189	0.05472623	0.2800	1.3498
6	0.00114945	1.14749383	11.4401	100.9263

The chronological load curves for each load bus shown in Figures 4.5 to 4.7 were then divided into 24 uniform time intervals with a time increment of one hour. The individual load point indices utilizing this load model are provided in Table 4.5. Table 4.6 shows the overall system indices for each of the three load models.

The set of load point indices for the RBTS shown in Table 4.5 are the most accurate as the loads are modelled in one hour steps. The results obtained for the 10 non-uniform time interval model are relatively close to the results obtained for the 24 uniform step model. The first case (i.e., using 5 non-uniform load model steps) results in lower unreliability indices due to the lower degree of correlation between the individual load bus values. The system indices given in Table 4.6 show that the results for the 10 step model are very close to those obtained for the 24 step model and that the reduced model could possibly be used in this case. This conclusion is system specific and should be examined in detail before being extended to different systems and load models.

Table 4.5: Annual load point indices for the base RBTS using a 24-step daily load model.

Bus Number	PLC	ENLC (Occ./yr.)	ELC (MW/yr.)	EENS (MWh/yr.)
2	0.00037172	0.17953151	0.2234	3.7521
3	0.00061842	0.36579738	4.9020	47.2138
4	0.00039399	0.21888778	0.8116	9.8594
5	0.00003202	0.05484222	0.2786	1.3232
6	0.00114972	1.14791636	11.4403	100.9132

Table 4.6: Annual system indices for the base RBTS using 3 different daily load models.

System Indices	5-Step Daily Load Model	10-Step Daily Load Model	24-Step Daily Load Model
ELC (MW/yr)	16.91692	17.60639	17.65594
EENS (MWh/yr)	152.95856	162.41879	163.10171
BPII (MW/MW-yr)	0.09433	0.09818	0.09845
SI (System Minutes)	51.17568	54.34081	54.56930

4.6. Summary

This chapter describes the development of new load models for the various load buses in a composite generation and transmission system. Earlier composite system assessments and the studies described in Chapters 2 and 3 of this thesis used the same single load model or load duration curve for each load point obtained from the overall load data of the IEEE-RTS. This assumption is not completely accurate since diverse load variations exist as a result of the different customer mix or composition at each bus.

The need for developing time varying load curves at load buses is discussed in this chapter. Seven types of customer sectors namely, agricultural, industrial, commercial, large users, residential, government and institutions, and office and buildings have been identified and the load characteristics of these customer sectors are presented. The procedure used for developing the hourly load curves with reference to the hypothetical test system is illustrated. The chronological hourly load curves developed for the RBTS are used as the load models for the adequacy and economic studies performed in Chapters 4 through 6 of this thesis.

The reliability of composite systems with time varying loads at each bus can be effectively assessed using the contingency enumeration technique. The approach used in this analysis considered three seasons. This could be extended to more seasons over the year. This will depend on the system under consideration. More periods might require a reduced daily step model. The effect of using the chronological load models and multi-step or time interval load models for an period of one year or 8736 hours are presented with reference to the RBTS. The study conducted shows that in this case only 10 steps are required to accurately model a given day. The 24 step model was, however, used in subsequent studies in this thesis. The complete range of load point and system indices described in Chapter 2 can be obtained using a representative set of daily models at each load point created by summing the individual customer sector contributions. Any variation in customer sector patterns created by load management incentives are therefore reflected in the individual bus load profiles and in the calculated reliability indices.

5. IMPACTS OF DEMAND-SIDE MANAGEMENT ON COMPOSITE GENERATION AND TRANSMISSION SYSTEM ADEQUACY AND RELIABILITY WORTH EVALUATION WITH TIME VARYING LOADS

5.1 Introduction

Demand-side management (DSM) or load management (LM) in general, refers to any activity adopted by a utility that ultimately changes the utility's total system load curve. In other words, DSM can be defined as the planning and implementation by a power utility of those activities designed to influence customer use of electricity in ways that will promote desired changes in the load shape of the electric power utility [152]. The goal of DSM is to make changes in the pattern and the magnitude of the load seen by the utility. Power utilities view DSM activities as a way of making their power system operations more efficient and cost-beneficial. For utilities to have a successful DSM program, they must have specific goals in terms of how they wish to modify the shape of the system load curve.

Traditionally, electric utilities have been primarily interested in supply-side initiatives in their power system planning, and demand-side options such as DSM initiatives were not extensively considered. This situation is no longer the case as both supply-side and demand-side options are integral elements in system planning and operation [153, 154]. The function of an electric power system is to satisfy the system load requirement at the lowest possible cost and with an acceptable degree of continuity and quality. Inherent in the above statement is the fact that the system load must be satisfied but not altered. Historically, the customer side of the meter has not been a major concern for power utilities. Greater emphasis, in recent years, on altering the load through DSM has led power utilities to think about the customer side of the meter. This concern has gained in importance because power utilities are faced with higher energy costs, environmental issues and the need to conserve natural resources. Canadian power companies have only recently tried to integrate DSM in their planning activities [152].

It has been a common experience for power utilities to see the demand for electricity increase due to industrial load growth and an increase in population. In order to meet the increase in demand, power utilities must decide whether to install new generating capacity, purchase power from a neighbouring utility or implement a DSM program. A significant number of utilities are opting for DSM as a practical solution. There has been significant research in the last few years on the study of DSM. The majority of this research deals with the design, implementation and marketing of DSM programs and with the end-use technologies that form an integral part of DSM programs. Many DSM publications deal with the pre-evaluation process of DSM programs and the pros and cons of government involvement in DSM. More research is required, however, in the area of post-evaluation of DSM programs [155].

5.2 Basic Concepts of Demand-Side Management

One of the basic tenets underlying the development and regulation of the electric power industry has been the notion that a power system will supply its customers with whatever amount of power they wish to purchase at whatever time they desire. In exercising their preferences, customers have evolved electric power use patterns which display considerable variability with time of day, day of week, and season of the year. Prior to the 1970s, utility planners thought of the demand for electric energy as an uncontrollable quantity. Their job, as they saw it, was to predict demand and then plan the power supply to meet it. However, in the 1970s and 1980s, accurate demand predictions became harder and harder to achieve [156]. In the 1960s and early 1970s, demand was growing at a rate of more than 7 percent per year in the United States. However, in the 1980s the rate declined to 3 percent [157]. Utility planners had not anticipated this decrease. Many plants designed in the 1960s were not needed by the time they were ready for operation. The utilities had to recover the capital invested in them and accordingly raised the rates charged to customers.

The loads seen by utilities are composites of a large number of customers, each using electricity for a variety of purposes: heating, cooling, lighting, and industrial machine drives. The loads vary by day, month, and season. They are also functions of the time of day, the price of electricity, the weather, economic conditions, and the utilization choices of the customers. Some utilities have their yearly peaks in winter and others in summer. Weather-sensitive loads (air conditioning and space heating) can contribute significantly to the highest demand peaks seen by utilities and thereby degrade their annual load factors. Weather-sensitive loads are therefore good candidates for management strategies aimed at improving load factors.

As previously noted, demand-side management (DSM), in general, refers to any activity adopted by a utility that ultimately changes the utility's total system load curve. The term DSM encompasses the entire range of activities that influence the pattern and magnitude of a utility's load [82]. This includes load management, strategic conservation, increased market share, and other behind-the-meter actions. Technically, load management is a subset of DSM, encompassing only the actions initiated by the utility or its customers [82]. However, in common usage, DSM is often thought of as having a horizon extending over decades, while load management is thought of as having a shorter horizon. Load management actions are taken to control load growth, alter the load shape of the load curve or increase the supply through non-utility or non-traditional sources. The actions may be initiated to reduce capital expenditure, improve capacity limitations, provide for economic dispatch, reduce the cost of service, improve load factors. improve system efficiency, or improve system reliability.

In order for utilities to have a successful DSM or load management program, they must have specific goals in terms of the shape of the system load curve. Once these goals are in place, the utility can promote DSM activities to change the pattern of electricity consumption. It is important to realize that load management will in the long-run be beneficial to both utilities and customers. The utility hopes that load management programs will lead to their existing generating facilities being utilized more efficiently, i.e., using low cost base load generation. In doing so, it is possible for the utility to reduce the electricity rates charged to customers

[83, 153, 154]. In addition, power utilities are of the opinion that load management strategies will result in a smaller electrical energy or load growth rate which will reduce or defer the need to add expensive additional generating units.

The addition of extra generating capacity is not the only means which can be employed to meet the reserve requirements and satisfy the specified reliability constraints. It may be advantageous to improve the existing units by load management in order to modify the load factor of the system. The objective of the research work described in this chapter was to develop and use different kinds of load shapes at individual load buses to evaluate the adequacy or reliability implications of these effects on the load points and the overall system indices.

5.3 Demand-Side Management Methodology

There are many classified [158] DSM programs available for use by the electric power utilities. In this study, it was decided not to investigate any one particular DSM program as there are many intangibles involved such as customer behaviour, market penetration, and economic conditions. The approach taken was to investigate the impacts on the load point and system adequacy and the interruption costs of changing the individual customer sector load profiles at specific locations in the system. The purpose of DMS programs is to alter the shape of the load curve by either increasing, decreasing, or shifting load. The time pattern and magnitude of the system load curve changes with the implementation of DSM programs.

The main load shape modification goals of DSM programs are peak clipping (this is intended to reduce electricity demand (KW) at certain critical times, typically when the utility experiences system peaks}, load shifting {this is intended to move electricity consumption from one time to another, usually from the on-peak to off-peak periods during a single day}, valley filling {attempts to increase off-peak electricity consumption (without necessarily reducing on-peak demands)}, energy conservation {aims at reducing the energy used by specific end use devices and systems without degrading the services provided, thereby reducing overall electricity consumption, often without regard for the timing of program-induced savings. Such savings are generally achieved by substituting technically more advanced equipment to produce the same level of end-use services with less electricity} and additional energy sales {also known as strategic load growth-this is a general increase in sales over and those which may arise from valley filling} [155, 159].

After the expected impacts of DSM are estimated, it is important to quantify these impacts on the chronological hourly load curve at each load bus. A model is proposed in this chapter to quantify the effects of DSM on the respective individual load buses. This model can be used to represent the basic load-shaping goals of DSM programs [160, 161]. The model consists of Equations (5.1) and (5.4) [160, 161]. Since most utilities use one hour as the smallest resolution for their system or individual bus load data, the daily load curve consists of 24 load data points. The load curves at each load bus therefore can be described by $L(t)$, where t represents time and has integer values in the range $1 \leq t \leq 24$. The function $L(t)$ can be used to describe the load in megawatt or in per unit values. $\hat{L}(t)$ is the modified load curve at each load bus which results from implementing DSM activities.

Equation (5.1) is used to simulate peak clipping and load shifting activities. P is the pre-specified peak demand of the customer sector that results from the implementation of DSM initiatives. Any customer load above the pre-specified peak demand is reduced and/or shifted to off-peak hours. The amount of energy shifted to off-peak hours depends on the value of a in Equation (5.1). The first time during the day when the original load is greater than the pre-specified peak demand ($L(t) > P$) is represented by the variable p. The last time during the day when the original load is greater than the pre-specified peak demand ($L(t) > P$) is represented by the variable q. t_1 is the starting time for the off-peak recovery of energy and t_2 is the ending time for the off-peak recovery energy. The difference between t_1 and t_2 , denoted as h, is the amount of time during which energy will be recovered. The range for a is $0 \leq a \leq 1$ and depends on the amount of recovered energy required during off-peak hours. If a has a value of J.85, then 85% of the energy reduced during the on-peak hours is rccovered during off-peak hours.

$$\hat{L}(t) = L(t) - \{(L(t) - P)\Omega(L(t))\} + a\left\{\frac{\sum_{T=p}^{q}\{(L(T) - P)\Omega(L(T))\}}{h}\right\}\lambda_{(t_1,t_2)}(t) \quad (5.1)$$

where

$$\begin{aligned} &\Omega(L(t)) = 1 \quad \text{for } L(t) \triangleright P \\ &\Omega(L(t)) = 0 \quad \text{for } L(t) \leq P \end{aligned} \quad (5.2)$$

$$\begin{aligned} &\lambda_{(t_1,t_2)}(t) = 1 \quad \text{for } t_1 \leq t \leq t_2 \\ &\lambda_{(t_1,t_2)}(t) = 0 \quad \text{for other values of } t \end{aligned} \quad (5.3)$$

Equation (5.4) is used to simulate energy conservation, additional energy sales or valley filling when applied during off-peak times. A is any load, either additive or subtractive, that can result from DSM initiatives. b is a parameter that indicates whether A is additive load or subtractive load. If $b = 1$, Equation (5.4) simulates additional energy sales and A is referred to as additional load. If $b = (-1)$, Equation (5.4) simulates energy conservation and A is referred to as reduced load. The parameter t_3 represents the starting time during which load (A) is added or subtracted and t_4 represents the end time after which load is neither added nor subtracted.

$$\hat{L}(t) = L(t) + bA\sigma_{(t_3,t_4)}(t) \tag{5.4}$$

where

$$\begin{aligned} &\sigma_{(t_3,t_4)}(t) = 1 \ \text{ for } \ t_3 \le t \le t_4 \\ &\sigma_{(t_3,t_4)}(t) = 1 \ \text{ for other values of } \ t \end{aligned} \tag{5.5}$$

The variables t_1, t_2, t_3, and t_4, are times during a 24 hour day. Equations (5.1) and (5.4) are used for a 24 hour interval of time. They can be used to simulate load shaping activities on a yearly, seasonal, monthly, weekly or daily basis. For example, Equation (5.1) can be applied to each day of the winter, spring/fall and summer seasons to simulate the use of load shifting programs during the entire year.

The implementation of DSM programs will result in the creation of new load shapes. Equations (5.1) and (5.4) were applied to the base case load model to generate new load models. In this study, the base case load models were the load models developed for all the individual load buses in the RBTS which consists of 8736 (i.e., 24×364) load data points. The application of Equations (5.1) and (5.4) to the base case load models resulted in modifications by either decreasing, shifting, or increasing loads. Some new load models were created that represent possible effects of implementing demand-side management or load management end-use technologies. Equations (5.1) and (5.4) can be used to develop a wide variety of load shapes, however, the load models developed provide a good overview of the most common load-shape modification objectives that are being implemented by electric utilities.

The new load models developed to represent possible impacts of DSM activities can be further classified into groups that categorize the load models on the basis of the load shape changes that occurred in developing the new load models. This classification is shown in Table 5.1. Tables 5.2 and 5.3 indicate the value of the parameters used to generate the new load shapes used in the studies represented in this chapter. Time values are specified in the 24 hour format.

Table 5.1: Classification of load models into groups

Group	Load Shaping Goal	Load Models
One (I)	Load Shifting	LM1, LM2, LM5-LM7
Two (II)	Peak Clipping	LM3, LM4, LM8-LM10
Three (III)	Valley Filling	LM11
Four (IV)	Energy Conservation	LM12
Five (V)	Strategic Load Growth	LM13

Table 5.2: Parameter values for load models LM1-LM10

Load	Parameter Values					
Model	P	t_1	t_2	h	a	Equation Applied
LM1	0.95	0	6	6	1.0	5.1 to Large User Load (All Days)
LM2	0.85	0	6	6	1.0	5.1 to Large User Load (All Days)
LM3	0.95	--	--	--	0.0	5.1 to Large User Load (All Days)
LM4	0.85	--	--	--	0.0	5.1 to Large User Load (All Days)
LM5	0.95	0	7	7	1.0	5.1 to Industrial Load (All Days)
LM6	0.85	0	7	7	1.0	5.1 to Industrial Load (All Days)
LM7	0.70	0	7	7	1.0	5.1 to Industrial Load (All Days)
LM8	0.95	--	--	--	0.0	5.1 to Industrial Load (All Days)
LM9	0.85	--	--	--	0.0	5.1 to Industrial Load (All Days)
LM10	0.70	--	--	--	0.0	5.1 to Industrial Load (All Days)

Table 5.3: Parameter values for load models LM11-LM13

Load	Parameter Values				
Model	A	b	t_3	t_4	Equation Applied
LM11	0.40	1.0	0	7	5.4 to Industrial Load (All Days)
LM12	0.15	-1.0	8	23	5.4 to Commercial Load (All Days)
LM13	0.10	1.0	0	24	5.4 to Industrial Load (All Days)

5.4 Illustrative Examples using the RBTS

A computer program was developed in the FORTRAN language to implement the load shaping methodology. The base case load models used were the seven customer sector load models developed for use in composite system analysis. In these studies, the winter season occurs from week 1 - 8 or (hour 1 - 1344) and week 44 - 52 or (hour 7225 - 8736). The summer season occurs from week 18 - 30 or (hour 2857 - 5040). The spring season occurs from week 9 - 17 or (hour 1345 - 2856) and the fall season occurs from week 31 - 43 or (hour 5041 - 7224). The use of Equations (5.1) and (5.4) in changing the basic load shape are illustrated in the following subsections.

5.4.1 Load Model 1 (LM1) and Load Model 6 (LM6)

In LM1 and LM6, any large user load or industrial load above (0.95 p.u.) or (0.85 p.u.) respectively throughout the entire year was reduced and shifted to off-peak hours. In the LM1 example, all of the energy is recovered during the hours of mid-night and 6 am. In the LM6 example, all of the energy is recovered during the hours of mid-night to 7 am. Figures 5.1 and 5.2 show the impact of load shifting on the base case load models for large user load and industrial load respectively for a typical day in the winter season.

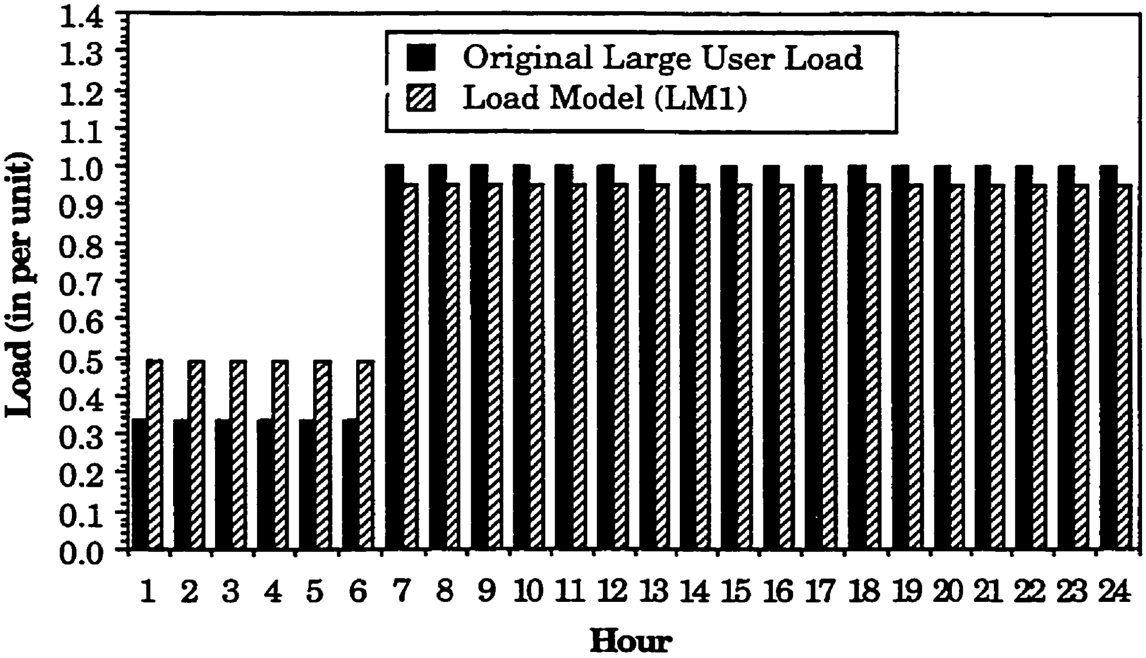

Figure 5.1: Application of load shifting (LM1) to the base case large user customer sector load model in a typical day for the winter season.

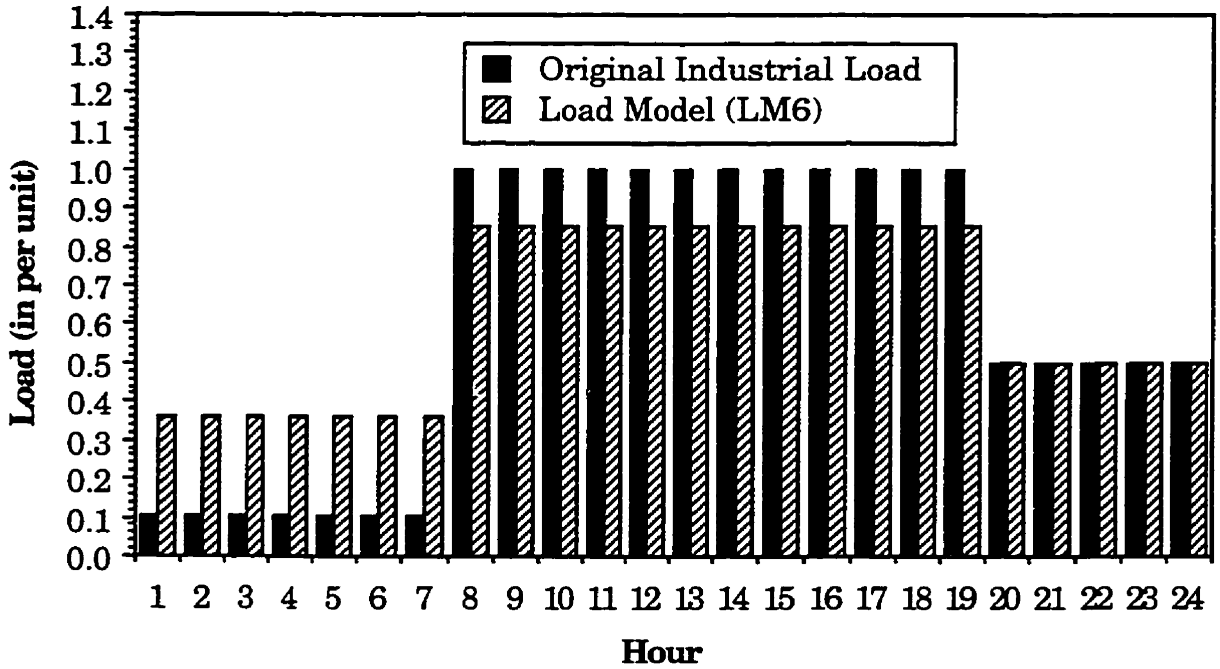

Figure 5.2: Application of load shifting (LM6) to the base case industrial customer sector load model in a typical day for the winter season.

5.4.2 Load Model 11 (LM11)

Load model 11 is representative of the load modification objective of valley filling. Off-peak industrial production is one method of achieving valley filling by replacing alternate energy sources with electricity. LM11 was created by increasing the load during the hours of midnight to 7 am during the days of all the three distinct seasons. Figure 5.3 shows the impact of valley filling on the base case load model for the industrial load for a typical winter day.

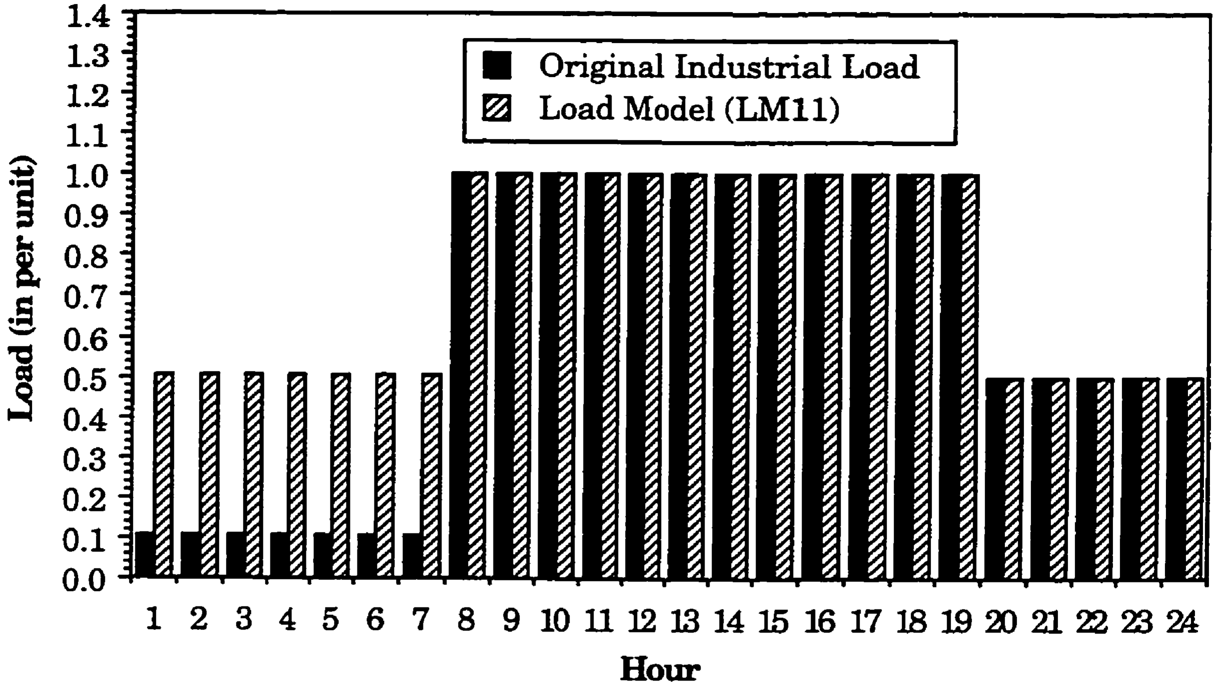

Figure 5.3: Application of valley filling (LM11) to the base case industrial customer sector load model in a typical day for the winter season.

5.4.3 Load Model 12 (LM12)

There is a wide range of energy conservation initiatives undertaken by power utilities to achieve their demand-side management goals. These initiatives include installing energy efficient lighting in office and commercial buildings which will result in reduced load. Load model 12 (LM12) was generated by reducing the base case commercial load by 0.15 p.u. from 8 a.m. to 11 p.m. for all days during the year. Figure 5.4 illustrates the possible effects of this energy conservation measure on the base case commercial load model for a typical winter day.

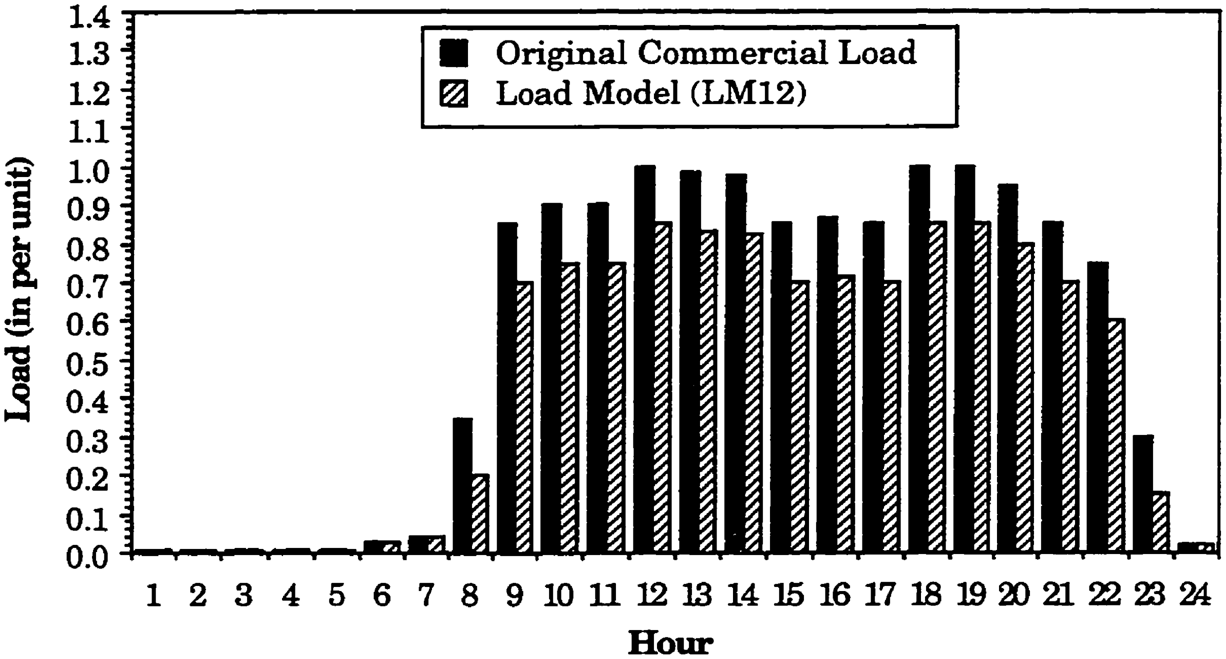

Figure 5.4: Application of energy conservation (LM12) to the base case commercial customer sector load model in a typical day fc. the winter season.

5.5 Effects of Demand-Side Management on Adequacy Indices using the Chronological Load Curves for each Load Bus

The annual chronological load model consisting of 8736 (i.e., 24 x 364) hourly loads of the entire year for the RBTS have been used in the studies presented in this section. Only the first 168 hourly loads for the first week of the year are shown in Figures 4.5 through 4.7 of the previous chapter. As described in Chapter 4, the study-year is represented in this load model by three seasons namely winter, spring/fall and summer. The reliability evaluation was performed for each season-segment and summed up to obtain the total reliability or adequacy indices at each load bus and the overall system. In the studies described in this section, the chronological load curves for each load bus have been divided into 24 uniform time intervals with a time increment of one hour. The mean of all the loads in any particular time interval was used to represent the load for the said time interval in all the analyzes reported in this section. The same time interval is used for all load buses in order to establish correlation between the bus loads, which is lacking when a load duration curve is used. The contingency enumeration approach has been applied to all the load models.

The impacts or effects of DSM, utilizing customer sector load curves, on the load point and overall system adequacy are presented in this section. The impacts are considered in terms of the Failure Probability, the Failure Frequency, the Expected Load Curtailed (ELC) and the Expected Energy Not Supplied (EENS) indices at the various load points. The effects on the system Expected Load Curtailed, the Expected Energy Not Supplied, the Bulk Power Interruption index (BPII), and the Severity Index (SI) are presented to illustrate the impacts on the overall power system adequacy.

Tables 5.4 to 5.6 show the results obtained for the five load points and the overall system level in the RBTS when a portion of the large user customer sector load at Bus 3, is reduced throughout the year and 100% of the energy was recovered during the off-peak hours (i.e., using load shifting load shape changes (load models LM1 and LM2)). Specific details on the load shape modifications are given in Appendix F. The variations in the EENS index at each load point and for the system are shown in Figure 5.5.

Similarly, Tables 5.7 through 5.9 show the load point and system indices when the large user customer sector load curve at Bus 3, is reduced during the year and zero percent of the energy was recovered during off-peak hours (i.e. using peak clipping load shape changes (load models LM3 and LM4)).

The variation in the EENS index of the individual load points and the system are shown in Figure 5.6.

The variations in the load point and system indices, when industrial load at any bus of the RBTS, is reduced and hundred percent of the energy was recovered during off-peak hours (i.e., using load shifting load shape changes (load models LM5 - LM7)), are presented in Tables 5.10 to 5.13. The corresponding variation in the EENS index at each load bus and the overall system are shown in Figure 5.7. The results obtained for the load points and system levels when all the industrial loads at any bus is reduced and no energy was recovered during off-peak hours (i.e., using peak clipping load shape changes (LM8 - LM10)), are provided in Tables 5.14 through 5.17. The variation in the EENS index at Buses 2 to 6 and the overall system are shown in Figure 5.8.

Tables 5.18 and 5.19 show some of the adequacy indices at each of the five load points and overall system when all industrial loads at any bus of the RBTS during the off-peak hours was increased by 0.40 per unit for all days during the year (i.e., using valley filling load shape changes (LM11)). Figure 5.9 depicts the corresponding variations in the individual load bus EENS and system EENS.

The individual load point and system results obtained when all commercial customer sector loads at any bus in the RBTS during the hours of 8 a.m. to 11 p.m. was decreased by 0.15 per unit for all days during the year (i.e., by using energy conservation load shape changes (LM12)), are presented in Tables 5.20 and 5.21. The variations in the EENS index at each load point and total system are illustrated in Figure 5.10.

Tables 5.22 and 5.23 show the adequacy indices at each of the five load points and overall system when all industrial loads at any bus was increased by 0.10 per unit for all days during the year (i.e., by using strategic load growth load shape changes (LM13)). Figure 5.11 depicts the corresponding variations in the individual load bus EENS and system EENS index.

A wide range of impacts on the load point and the overall system adequacy indices result from the various customer sector load shape changes as a result of the demand-side management strategies considered. The impacts of DSM can lead to a reduction, an increase or virtually no change in the load point and overall system adequacy indices as shown in Tables 5.4 through 5.23 and Figures 5.5 to 5.11.

Table 5.4: Annual load point indices of the RBTS using a 24-step daily load model from (LM1).

Bus Number	PLC	ENLC (Occ./yr.)	ELC (MW/yr.)	EENS (MWh/yr.)
2	0.00031617	0.15429228	0.1697	2.7614
3	0.00053186	0.32328283	4.3269	37.1266
4	0.00033713	0.19171542	0.6769	7.5906
5	0.00003050	0.05276977	0.2747	1.2986
6	0.00114955	1.14770150	11.4400	100.9109

Table 5.5: Annual load point indices of the RBTS using a 24-step daily load model from (LM2).

Bus Number	PLC	ENLC (Occ./yr.)	ELC (MW/yr.)	EENS (MWh/yr.)
2	0.00015121	0.07980921	0.0963	1.4552
3	0.00028026	0.20823278	3.5662	23.8086
4	0.00017019	0.11422765	0.4927	4.5948
5	0.00002644	0.04731982	0.2687	1.2619
6	0.00114916	1.14724129	11.4399	100.9100

Table 5.6: Annual overall system indices of the RBTS using a 24-step daily load model from (LM1 or LM2).

Case	ELC (MW/yr.)	EENS (MWh/yr.)	BPII (MW/MW-yr)	SI (Sys. Mins.)
LM1	16.8881	149.6881	0.0942	50.0949
LM2	15.8636	132.0305	0.0885	44.1871

Table 5.7: Annual load point indices of the RBTS using a 24-step daily load model from (LM3).

Bus Number	PLC	ENLC (Occ./yr.)	ELC (MW/yr.)	EENS (MWh/yr.)
2	0.00031617	0.15429228	0.1697	2.7614
3	0.00052391	0.30871861	4.0896	35.9901
4	0.00032910	0.17698596	0.5576	7.0215
5	0.00002090	0.03516615	0.1631	0.7645
6	0.00114112	1.13228333	11.3933	100.6879

Table 5.8: Annual load point indices of the RBTS using a 24-step daily load model from (LM4).

Bus Number	PLC	ENLC (Occ./yr.)	ELC (MW/yr.)	EENS (MWh/yr.)
2	0.00015121	0.07980921	0.0963	1.4552
3	0.00027070	0.19060355	3.5386	23.6918
4	0.00015882	0.09325772	0.2587	3.4797
5	0.00000905	0.01544350	0.0869	0.3924
6	0.00113958	1.12967178	11.3874	100.6587

Table 5.9: Annual overall system indices of the RBTS using a 24-step daily load model from (LM3 or LM4).

Case	ELC (MW/yr.)	EENS (MWh/yr.)	BPII (MW/MW-yr)	SI (Sys. Mins.)
LM3	16.3733	147.2254	0.0913	49.2700
LM4	15.3677	129.6778	0.0857	43.3997

Table 5.10: Annual load point indices of the RBTS using a 24-step daily load model from (LM5).

Bus Number	PLC	ENLC (Occ./yr.)	ELC (MW/yr.)	EENS (MWh/yr.)
2	0.00034863	0.16919193	0.1966	3.2618
3	0.00057782	0.34354883	4.5746	42.3428
4	0.00036885	0.20503314	0.7495	8.6878
5	0.00002925	0.05015810	0.2573	1.2174
6	0.00114775	1.14435169	11.4294	100.8452

Table 5.11: Annual load point indices of the RBTS using a 24-step daily load model from (LM6).

Bus Number	PLC	ENLC (Occ./yr.)	ELC (MW/yr.)	EENS (MWh/yr.)
2	0.00027452	0.13655117	0.1495	2.3899
3	0.00048591	0.29665321	3.9585	33.4563
4	0.00029041	0.16462174	0.6099	6.5118
5	0.00002443	0.04179791	0.2076	0.9783
6	0.00114342	1.13652167	11.4100	100.7678

Table 5.12: Annual load point indices of the RBTS using a 24-step daily load model from (LM7).

Bus Number	PLC	ENLC (Occ./yr.)	ELC (MW/yr.)	EENS (MWh/yr.)
2	0.00017012	0.08911712	0.1016	1.5453
3	0.00029434	0.20651217	3.3719	24.5145
4	0.00018202	0.11032662	0.4768	4.4927
5	0.00001756	0.03061706	0.1618	0.7421
6	0.00113965	1.12980019	11.3900	100.6636

Table 5.13: Annual overall system indices of the RBTS using a 24-step daily load model from (LM5 or LM6 or LM7).

Case	ELC (MW/yr.)	EENS (MWh/yr.)	BPII (MW/MW-yr)	SI (Sys. Mins.)
LM5	17.2075	156.3550	0.0960	52.3133
LM6	16.3355	144.1041	0.0911	48.2259
LM7	15.5021	131.9582	0.0864	44.1676

Table 5.14: Annual load point indices of the RBTS using a 24-step daily load model from (LM8).

Bus Number	PLC	ENLC (Occ./yr.)	ELC (MW/yr.)	EENS (MWh/yr.)
2	0.00034863	0.16919193	0.1966	3.2618
3	0.00057975	0.34709397	4.6571	42.7369
4	0.00037032	0.20771847	0.7390	8.6380
5	0.00003138	0.05405755	0.2803	1.3281
6	0.00114963	1.14780379	11.3516	100.1298

Table 5.15: Annual load point indices of the RBTS using a 24-step daily load model from (LM9).

Bus Number	PLC	ENLC (Occ./yr.)	ELC (MW/yr.)	EENS (MWh/yr.)
2	0.00027451	0.13654070	0.1495	2.3899
3	0.00049196	0.30775655	4.2354	34.7819
4	0.00029555	0.17406218	0.6129	6.5268
5	0.00003096	0.05375450	0.2859	1.3498
6	0.00114952	1.14765606	11.1822	98.6321

Table 5.16: Annual load point indices of the RBTS using a 24-step daily load model from (LM10).

Bus Number	PLC	ENLC (Occ./yr.)	ELC (MW/yr.)	EENS (MWh/yr.)
2	0.00017006	0.08907267	0.1016	1.5451
3	0.00030305	0.22260162	3.7980	26.5566
4	0.00018984	0.12473514	0.4879	4.5280
5	0.00002846	0.05060033	0.2929	1.3782
6	0.00114912	1.14714802	10.9265	96.3618

Table 5.17: Annual overall system indices of the RBTS using a 24-step daily load model from (LM8 or LM9 or LM10).

Case	ELC (MW/yr.)	EENS (MWh/yr.)	BPII (MW/MW-yr)	SI (Sys. Mins.)
LM8	17.2248	156.0947	0.0961	52.2262
LM9	16.4658	143.6805	0.0918	48.0841
LM10	15.6068	130.3697	0.0870	43.6350

Table 5.18: Annual load point indices of the RBTS using a 24-step daily load model from (LM11).

Bus Number	PLC	ENLC (Occ./yr.)	ELC (MW/yr.)	EENS (MWh/yr.)
2	0.00037176	0.17955568	0.2234	3.7522
3	0.00060976	0.34988597	4.4900	45.2478
4	0.00038624	0.20463379	0.7863	9.7380
5	0.00002212	0.03670449	0.1606	0.7580
6	0.00114059	1.13122806	11.7908	104.1902

Table 5.19: Annual overall system indices of the RBTS using a 24-step daily load model from (LM11).

Case	ELC (MW/yr.)	EENS (MWh/yr.)	BPII (MW/MW-yr)	SI (Sys. Mins.)
LM11	17.4513	163.6862	0.0973	54.7845

Table 5.20: Annual load point indices of the RBTS using a 24-step daily load model from (LM12).

Bus Number	PLC	ENLC (Occ./yr.)	ELC (MW/yr.)	EENS (MWh/yr.)
2	0.00031686	0.15475159	0.1632	2.6551
3	0.00053362	0.32570277	4.3935	36.4074
4	0.00033788	0.19230317	0.6680	7.3673
5	0.00003075	0.05321326	0.2773	0.9360
6	0.00114958	1.14773235	11.2507	101.4589

Table 5.21: Annual overall system indices of the base RBTS using a 24-step daily load model from (LM12).

Case	ELC (MW/yr.)	EENS (MWh/yr.)	BPII (MW/MW-yr)	SI (Sys. Mins.)
LM12	16.7530	148.8247	0.0934	49.6358

Table 5.22: Annual load point indices of the RBTS using a 24-step daily load model from (LM13).

Bus Number	PLC	ENLC (Occ./yr.)	ELC (MW/yr.)	EENS (MWh/yr.)
2	0.00037666	0.18261452	0.2265	3.7822
3	0.00063180	0.36903110	4.7978	46.8778
4	0.00039700	0.21830495	0.8215	9.9466
5	0.00002966	0.05024736	0.2450	1.1576
6	0.00114706	1.14303038	11.6031	102.4010

Table 5.23: Annual overall system indices of the RBTS using a 24-step daily load model from (LM13).

Case	ELC (MW/yr.)	EENS (MWh/yr.)	BPII (MW/MW-yr)	SI (Sys. Mins.)
LM13	17.6940	164.1652	0.0987	55.0170

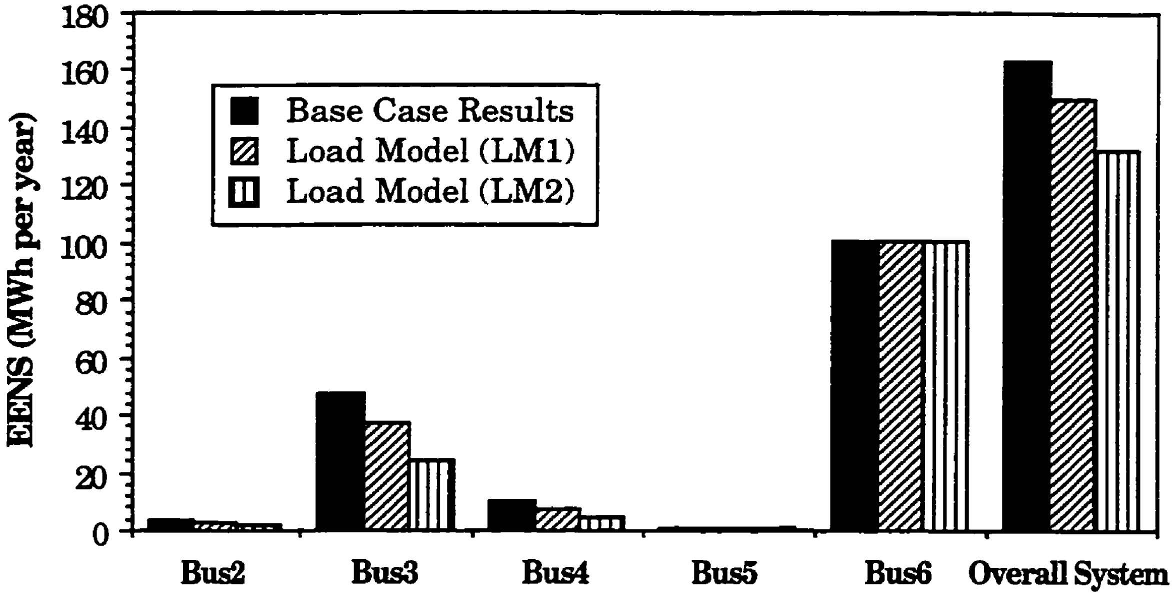

Figure 5.5: Annual load point and overall system EENS for the RBTS using the base case load model, LM1 and LM2.

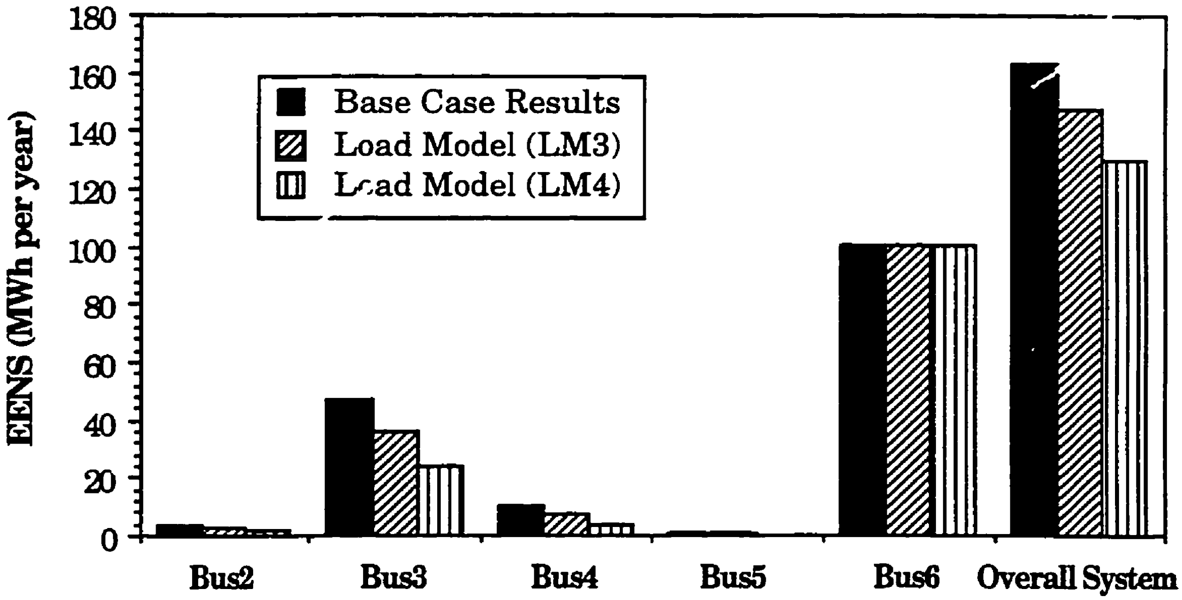

Figure 5.6: Annual load point and overall system EENS for the RBTS using the base case load model, LM3 and LM4.

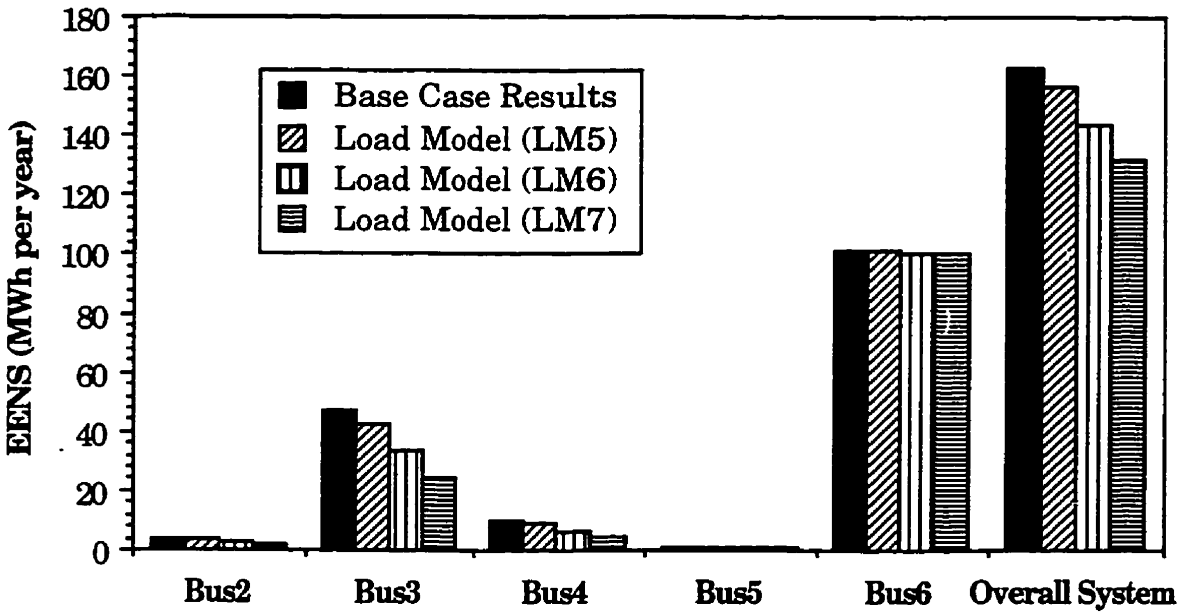

Figure 5.7: Annual load point and overall system EENS for the RBTS using the base case load model, LM5, LM6 and LM7.

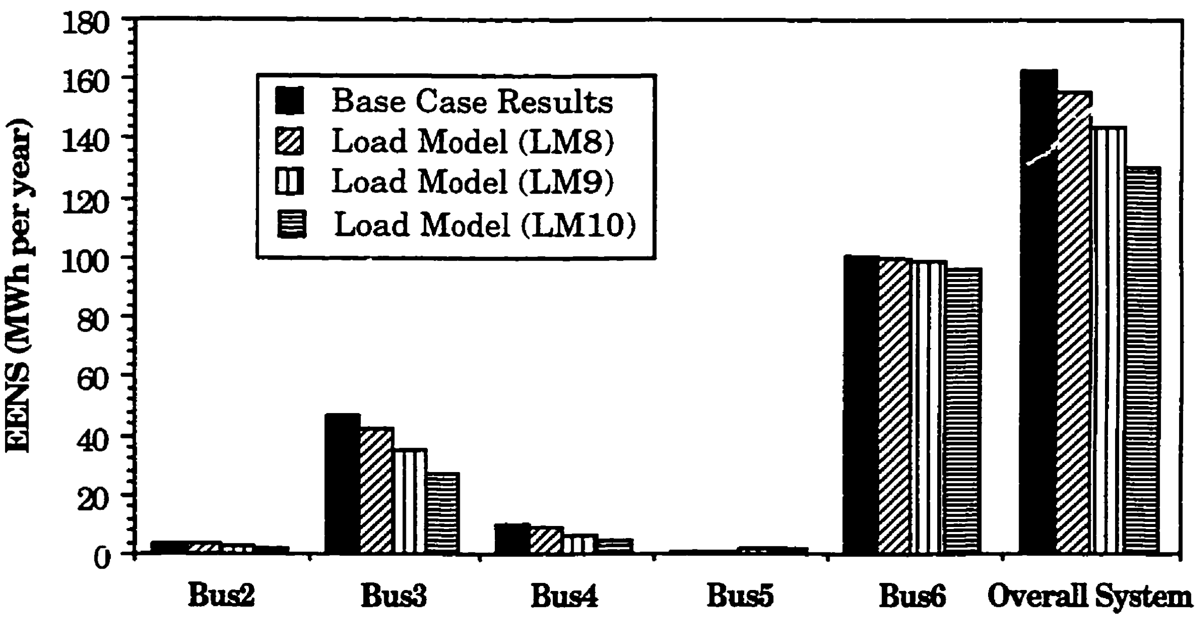

Figure 5.8: Annual load point and overall system EENS for the RBTS using the base case load model, LM8, LM9 and LM10.

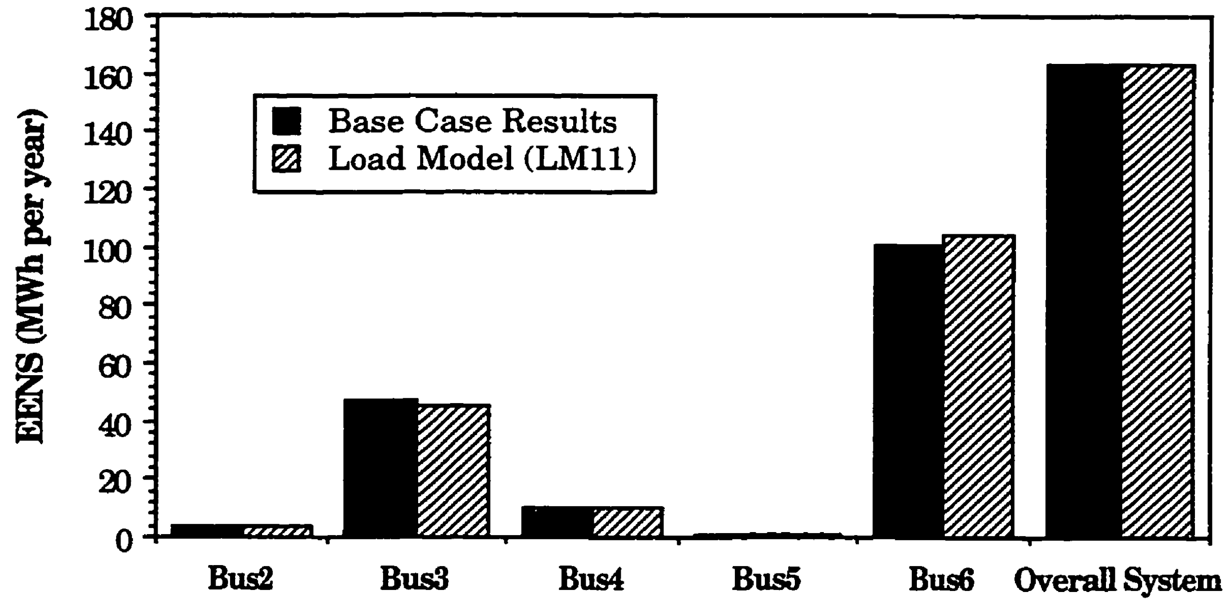

Figure 5.9: Annual load point and overall system EENS for the RBTS using the base case load model and LM11.

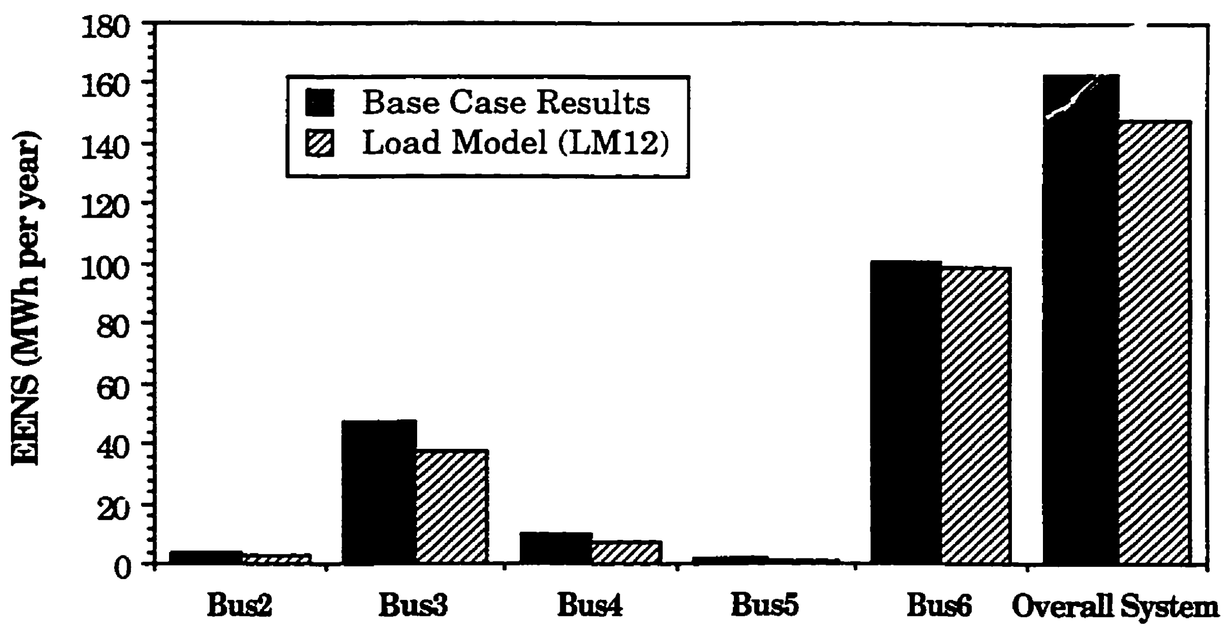

Figure 5.10: Annual load point and overall system EENS for the RBTS using the base case load model and LM12.

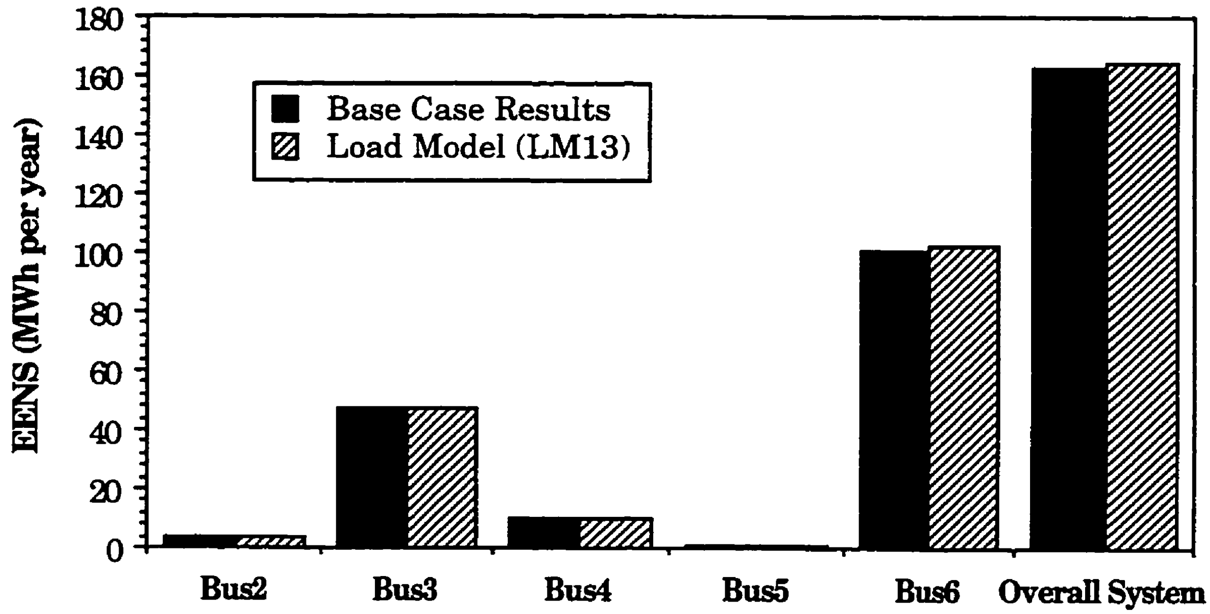

Figure 5.11: Annual load point and overall system EENS for the RBTS using the base case load model and LM13.

The conclusions drawn from the studies performed in this chapter can be applied only to the RBTS. It can be seen from Figures 5.5 and 5.6 that load point EENS at Bus 3 decreases significantly when DSM initiatives (such as load shifting (LS) and peak clipping (PC) options respectively) are applied to the large user customer sector connected to that bus. Meanwhile, there is little reduction in the EENS at Buses 2 and 4 and no noticeable change in the EENS at Bus 6, which is the major contributor to the total system EENS. This reduction in the EENS at Bus 3 is the major contributor to the significant decrease in the overall system EENS as shown in Figures 5.5 and 5.6.

Similar results are obtained when DSM programs are applied to all industrial customer sectors at each load bus as shown in Figures 5.7 and 5.8. Slight changes in the EENS at Bus 6 can be observed when the peak clipping DSM option was applied to all industrial customer sector load at each bus. This is because Bus 6 also has some industrial load connected to it which has been shaved by using the peak clipping DSM program.

The EENS presented in Figures 5.9 through 5.11 for the valley filling (VF), energy conservation (EC) and strategic load growth (SLG) DSM initiatives are quite different from the results obtained by using load shifting (shown in Figures 5.5 and 5.7) and peak clipping (shown in Figures 5.6 and 5.8). The reason being that, the various customer sector load shape changes resulting from the DSM alternatives produced different or varying effects on the individual load points and overall system adequacy. These conclusions are system specific and should be investigated fully before being extended to other systems and load models.

5.6. Expected Outage Cost Assessment Utilizing Time Dependent Load Models

There has been substantial progress in recent years to incorporate the customer's view-point in power system planning. The worth of electric service reliability can be quantified and incorporated in the planning function. The term reliability worth refers to the benefit derived by the users receiving electrical energy and can be related to the costs associated with the loss of electric power supply.

Methods generally used to assess the reliability worth [133-136] do not explicitly consider the time varying aspect of the loads at the various buses. Some reliability worth analysis utilizing time dependent loads at each bus using the Monte Carlo simulation method has been conducted [147]. The analytical technique presented in this thesis for assessing the impacts of demand-side management programs on the damage or outage cost

(ECOST) and IEAR at HLII is a new approach to this area. The research work described in this section is believed to be the first application of an analytical technique to assess reliability worth with time varying loads at each bus. Reference [161] examined the reliability worth assessment with DSM initiatives at HLI. The research work described in this thesis extends the HLI concepts reported in [161] by evaluating the costs of unserved energy and the interrupted energy assessment rates at each load bus and for the overall system using time varying loads at each bus.

5.6.1. Application to the RBTS

Sub-section 3.6.1 of this thesis shows the expected outage costs (i.e., ECOST) and the IEAR for single-step and 4-step basic RBTS load models. Tables 5.1 to 5.3 show the developed time varying base case load model and the modified load models generated using DSM initiatives for the RBTS. The effects of these DSM programs on the load point and system reliability worth have been examined. These impacts were considered in terms of the ECOST and IEAR at all the load buses and for the total system. These results are shown in Tables 5.24 to 5.37 and Figures 5.12 to 5.16. These results are annual indices using a 24-step daily load model. Tables 5.24 to 5.37 show the EENS, ECOST and IEAR values while Figures 5.12 to 5.16 provide a pictorial representation of the variation in the ECOST. There is a wide range of impacts on the load point and the system ECOST from the various customer sector load shape changes due to the demand-side management strategies. The DSM options can lead to a general decrease or reduction, an increase or no significant change in the load point and overall system ECOST.

Table 5.24: Annual load point and system reliability worth indices of the RBTS using a 24-step daily basic load model.

LOAD BUS	EENS (MWh/yr.)	ECOST (K$/yr.)	IEAR ($/KWh)
2	3.7521	25.6958	6.8484
3	47.2138	117.0009	2.4781
4	9.8594	61.3661	6.2241
5	1.3232	5.8310	4.4067
6	100.9132	366.1196	3.6281
SYSTEM	163.1017	576.1068	3.5322

The results in Table 5.24 can be compared with those shown in Table 3.14. The results in Table 3.14 were obtained using the same 4-step system load duration curve at each bus in the composite system. The results in Table 5.24 were obtained using a 24-step daily load model at each bus created from the actual customer composition at that bus. The year was divided into three seasons. The results in Table 3.14 and Table 5.24 would change somewhat if more than 4 steps and 3 seasons respectively were used in the analysis. The results in these two tables can, however, be compared on the basis of the fundamental differences in the two modelling techniques. The 24-step load model representation described in this thesis does not assume that each bus has the same load factor and that there is perfect correlation between all the bus load variations. This can particularly be seen by considering the ECOST for Bus 6 in Tables 3.14 and 5.24. Bus 6 has a lower load factor than has the overall system. Due to the system topology, Bus 6 also has the highest individual bus ECOST. The use of specific customer load profiles to create a bus load profile provide a more accurate load point representation at this bus and more accurate

Table 5.25: Annual load point and system reliability worth indices of the RBTS using a 24-step daily load model from (LM1).

LOAD BUS	EENS (MWh/yr.)	ECOST (K$/yr.)	IEAR ($/KWh)
2	2.7614	18.6273	6.7456
3	37.1266	89.9370	2.4224
4	7.5906	46.3922	6.1118
5	1.2986	5.7134	4.3997
6	100.9109	366.1120	3.6281
SYSTEM	149.6881	526.7819	3.5192

Table 5.26: Annual load point and system reliability worth indices of the RBTS using a 24-step daily load model from (LM2).

LOAD BUS	EENS (MWh/yr.)	ECOST (K$/yr.)	IEAR ($/KWh)
2	1.4552	9.4529	6.4959
3	23.8086	54.2986	2.2806
4	4.5948	26.8068	5.8342
5	1.2619	5.5389	4.3893
6	100.9100	366.1082	3.6281
SYSTEM	132.0305	462.2054	3.5007

Table 5.27: Annual load point and system reliability worth indices of the RBTS using a 24-step daily load model from (LM3).

LOAD BUS	EENS (MWh/yr.)	ECOST (K$/yr.)	IEAR ($/KWh)
2	2.7614	18.6273	6.7456
3	35.9901	87.5986	2.4340
4	7.0215	43.7489	6.2307
5	0.7645	3.3699	4.4080
6	100.6879	365.4462	3.6295
SYSTEM	147.2254	518.7909	3.5238

Table 5.28: Annual load point and system reliability worth indices of the RBTS using a 24-step daily load model from (LM4).

LOAD BUS	EENS (MWh/yr.)	ECOST (K$/yr.)	IEAR ($/KWh)
2	1.4552	9.4529	6.4959
3	23.6918	54.0629	2.2819
4	3.4797	21.6293	6.2159
5	0.3924	1.7238	4.3930
6	100.6587	365.3582	3.6297
SYSTEM	129.6778	452.2271	3.4873

Table 5.29: Annual load point and system reliability worth indices of the RBTS using a 24-step daily load model from (LM5).

LOAD BUS	EENS (MWh/yr.)	ECOST (K$/yr.)	IEAR ($/KWh)
2	3.2618	22.1940	6.8042
3	42.3428	104.1133	2.4588
4	8.6878	53.5415	6.1628
5	1.2174	5.3617	4.4042
6	100.8452	365.8942	3.6283
SYSTEM	156.3550	551.1047	3.5247

Table 5.30: Annual load point and system reliability worth indices of the RBTS using a 24-step daily load model from (LM6).

LOAD BUS	EENS (MWh/yr.)	ECOST (K$/yr.)	IEAR ($/KWh)
2	2.3899	15.9807	6.6868
3	33.4563	80.7025	2.4122
4	6.5118	39.3466	6.0424
5	0.9783	4.3044	4.3999
6	100.7678	365.6842	3.6290
SYSTEM	144.1041	506.0184	3.5115

Table 5.31: Annual load point and system reliability worth indices of the RBTS using a 24-step daily load model from (LM7).

LOAD BUS	EENS (MWh/yr.)	ECOST (K$/yr.)	IEAR ($/KWh)
2	1.5453	10.0719	6.5178
3	24.5145	59.0659	2.4094
4	4.4927	28.2510	6.2882
5	0.7421	3.2585	4.3909
6	100.6636	365.3702	3.6296
SYSTEM	131.9582	466.0175	3.5316

Table 5.32: Annual load point and system reliability worth indices of the RBTS using a 24-step daily load model from (LM8).

LOAD BUS	EENS (MWh/yr.)	ECOST (K$/yr.)	IEAR ($/KWh)
2	3.2618	22.1940	6.8042
3	42.7369	104.9239	2.4551
4	8.6380	53.3110	6.1717
5	1.3282	5.8482	4.4031
6	100.1298	363.2765	3.6281
SYSTEM	156.0947	549.5536	3.5206

Table 5.33: Annual load point and system reliability worth indices of the RBTS using a 24-step daily load model from (LM9).

LOAD BUS	EENS (MWh/yr.)	ECOST (K$/yr.)	IEAR ($/KWh)
2	2.3899	15.9805	6.6867
3	34.7819	83.4289	2.3986
4	6.5268	39.4171	6.0393
5	1.3498	5.9347	4.3967
6	98.6321	357.8406	3.6280
SYSTEM	143.6805	502.6018	3.4981

Table 5.34: Annual load point and system reliability worth indices of the RBTS using a 24-step daily load model from (LM10).

LOAD BUS	EENS (MWh/yr.)	ECOST (K$/yr.)	IEAR ($/KWh)
2	1.5451	10.0706	6.5178
3	26.5566	63.2640	2.3822
4	4.5280	28.4131	62750
5	1.3782	6.0495	4.3894
6	96.3618	351.6004	3.6488
SYSTEM	130.3697	459.3976	3.5238

Table 5.35: Annual load point and system reliability worth indices of the RBTS using a 24-step daily load model from (LM11).

LOAD BUS	EENS (MWh/yr.)	ECOST (K$/yr.)	IEAR ($/KWh)
2	3.7522	25.6966	6.8484
3	45.2478	112.9581	2.4964
4	9.7380	60.8021	6.2438
5	0.7580	3.3512	4.4211
6	104.1902	378.1631	3.6295
SYSTEM	163.6862	580.9711	3.5493

Table 5.36: Annual load point and system reliability worth indices of the RBTS using a 24-step daily load model from (LM12).

LOAD BUS	EENS (MWh/yr.)	ECOST (K$/yr.)	IEAR ($/KWh)
2	2.6551	17.9084	6.7449
3	36.4074	88.6496	2.4349
4	7.3673	45.0584	6.1160
5	0.9360	4.1214	4.4032
6	101.4589	368.1954	3.6290
SYSTEM	148.8247	523.9332	3.5205

Table 5.37: Annual load point and system reliability worth indices of the RBTS using a 24-step daily load model from (LM13).

LOAD BUS	EENS (MWh/yr.)	ECOST (K$/yr.)	IEAR ($/KWh)
2	3.7822	25.8879	6.8447
3	46.8778	116.4807	2.4848
4	9.9466	61.8989	6.2231
5	1.1576	5.1048	4.4098
6	102.4010	371.5565	3.6284
SYSTEM	164.1652	580.9288	3.5387

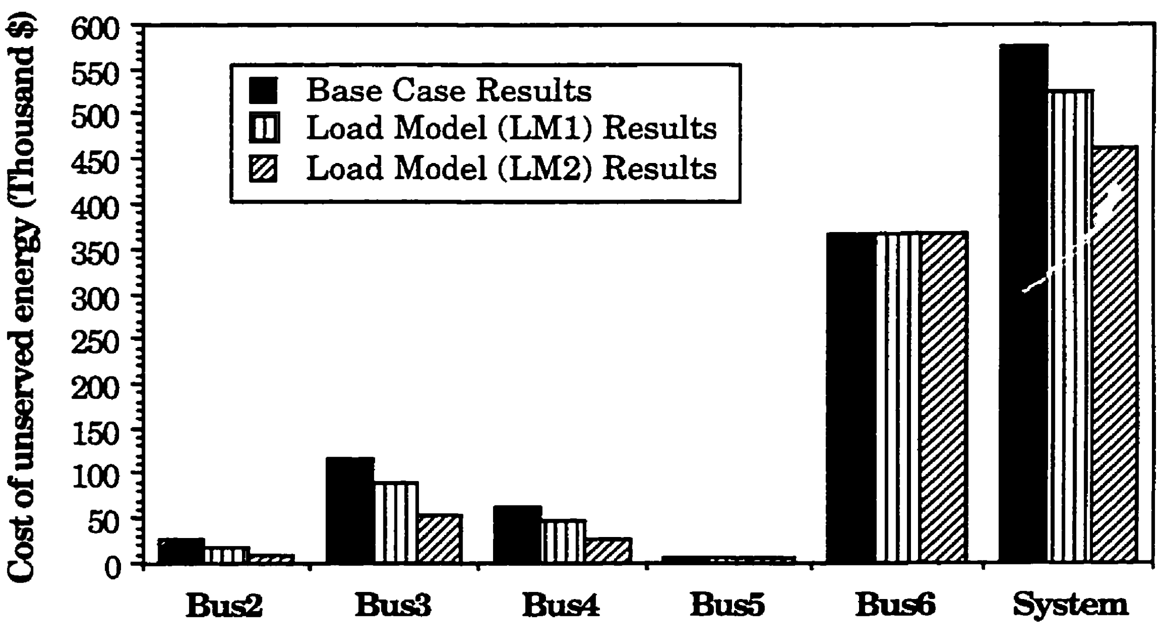

Figure 5.12: Annual load point and overall system ECOST for the RBTS using the base case load model, LM1 and LM2.

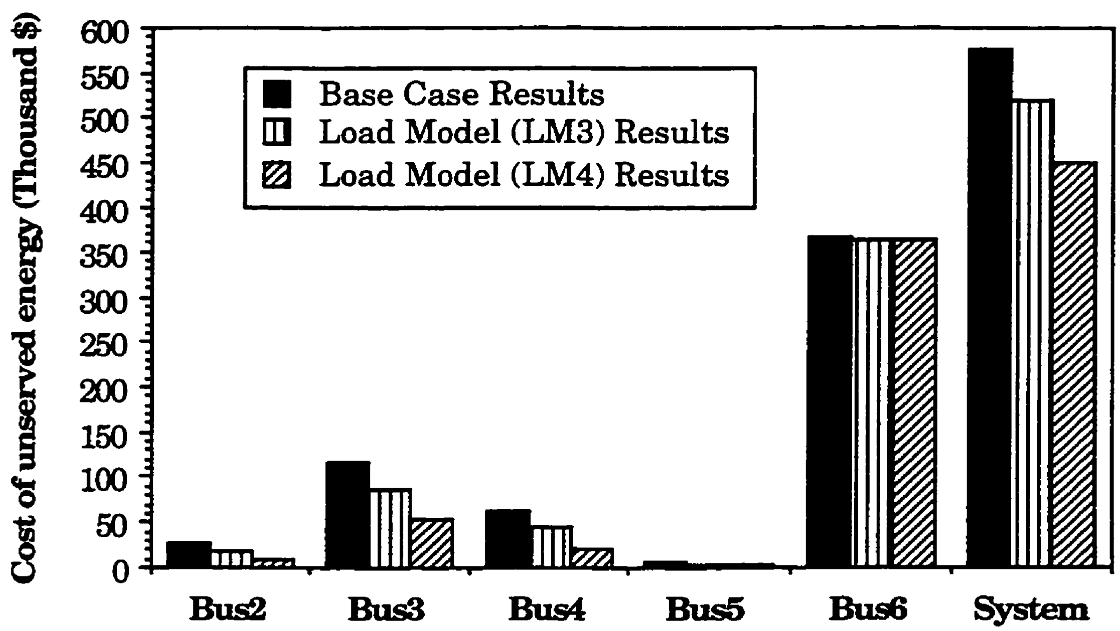

Figure 5.13: Annual load point and overall system ECOST for the RBTS using the base case load model, LM3 and LM4.

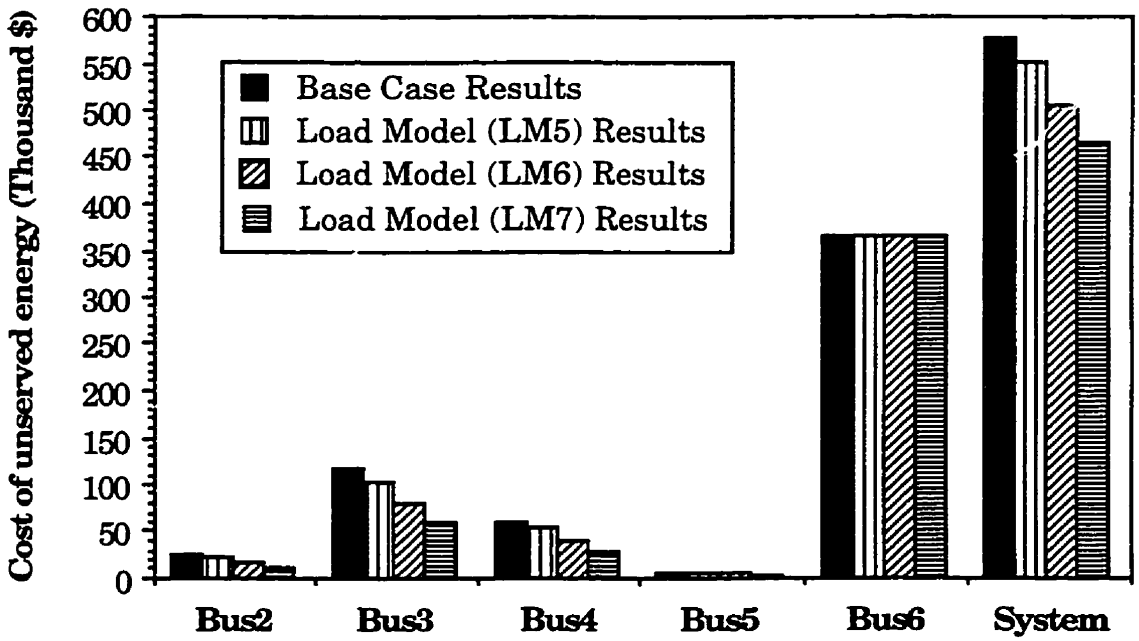

Figure 5.14: Annual load point and overall system ECOST for the RBTS using the base case load model, LM5, LM6 and LM7.

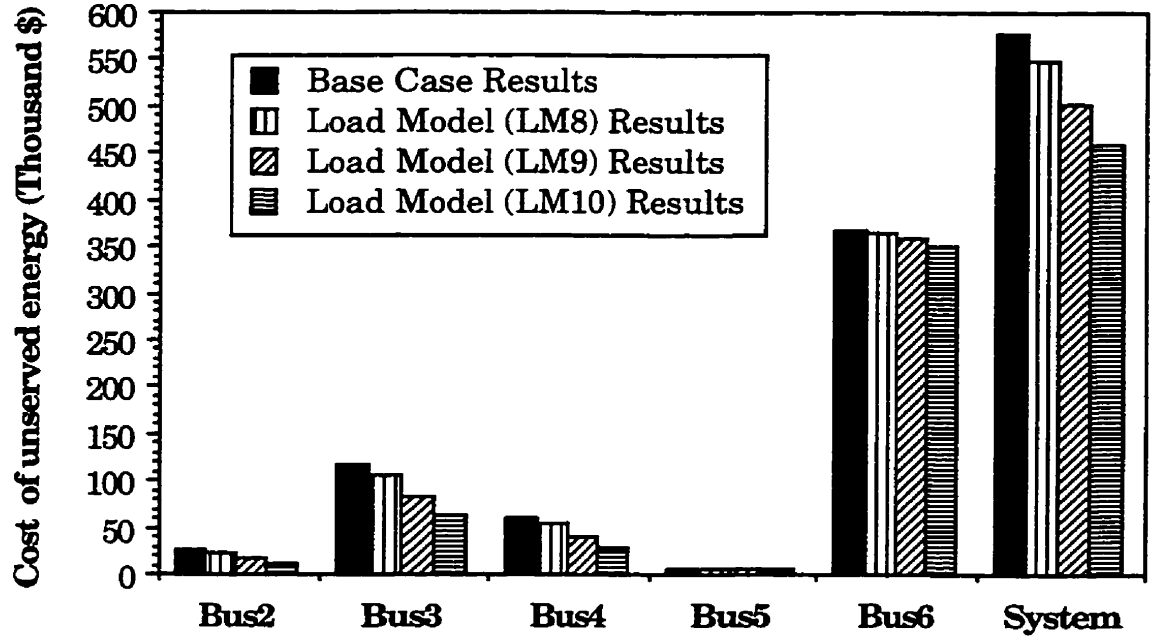

Figure 5.15: Annual load point and overall system ECOST for the RBTS using the base case load model, LM8, LM9 and LM10.

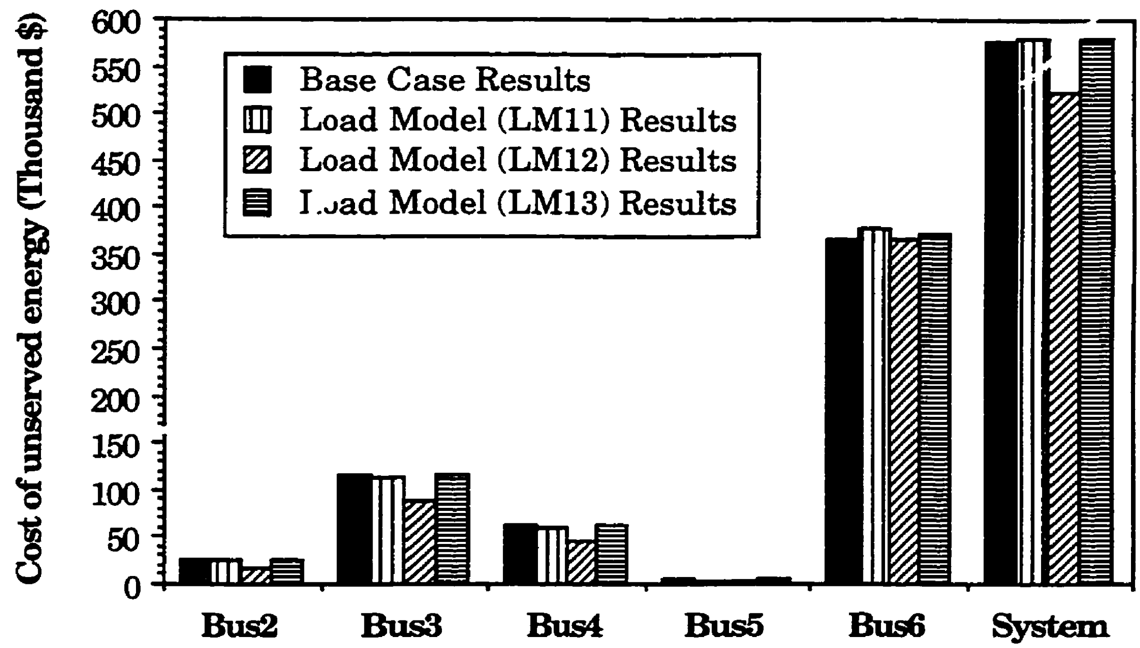

Figure 5.16: Annual load point and overall system ECOST for the RBTS using the base case load model, LM11, LM12 and LM13.

assessment of the actual ECOST. The actual numerical values are obviously system specific. The general conclusions, however, apply to any system and have not been examined in the available published literature.

As expected, there are significant reductions in the load bus and system expected outage costs as more sector peak loads are shifted or clipped using the DSM initiatives as can be seen from Tables 5.25 & 5.26 (and Figure 5.12) and Tables 5.29 through 5.31 (and Figure 5.14) or Tables 5.27 & 5.28 (and Figure 5.13) and Tables 5.32 through 5.34 (and Figure 5.15).

The IEAR evaluated at each load bus and for the entire system are presented in the fourth column of Tables 5.24 through 5.37. It can be seen from Tables 5.24 to 5.37 that there is no significant changes in the load point and total system IEAR for the different DSM options implemented. This is an important point. It has been shown in Reference [133] that the IEAR value at HLI is a relatively stable index which does not change considerably with variations in system peak load, modelling assumptions and operating policies of the system. This important conclusion is extended significantly by the analysis described in this thesis which considers IEAR assessment values for individual load points and for the overall system using time varying bus loads and demand-side management initiatives.

5.7. Summary

This chapter presents a methodology to model the effects of DSM initiatives on individual customer sector load curves. The methodology is represented by two equations which are discrete functions of time. Equation (5.1) is used to simulate load shifting and peak clipping. Equation (5.4) is used to simulate valley filling, energy conservation and additional energy sales or strategic load growth. The selected parameters in the equations determine the load shape changes that result. Thirteen modified load curves were developed using these equations. The base case load shapes are the customer sector load models which combine to create the individual bus load models of the RBTS. It was noted that any customer sector load model could be used given that the model consists of 8736 data points representing the individual bus load curve for a 364-day year. The approach presented is completely general and can be applied to any system. It provides the opportunity for a utility to investigate a particular DSM strategy by modifying the appropriate customer load profile, creating a new bus load profile and then examining the effect in the overall system. The results of the research work presented in this chapter describe a process to integrate the effects or impacts of demand-side management on adequacy assessment at HLII.

The chapter also contains studies which were performed to ascertain the impacts of demand-side management programs using time dependent load models at all load buses on the expected outage cost and interrupted energy assessment rate values for the individual load points and the entire system. These studies show that DSM initiatives can produce a wide range of changes in the load bus and total system expected outage cost. These changes are a complex function of the DSM initiatives, the customer load bus compositions, the topology and the operating practices of the system. There is, however, very little change in the IEAR values for the load points and for the system with the considered DSM initiatives. This is considered to be an important point and extends the concept of using a basic set of IEAR values in a wide range of initial or exploratory series of studies.

6. EFFECTS OF GENERATION SUPPLY AND LOAD DEMAND OPTIONS ON COMPOSITE SYSTEM ADEQUACY AND COST/BENEFIT EVALUATION WITH TIME DEPENDENT LOADS

6.1. Introduction

In the last few years, profound changes have occurred in the electricity industry in general and in its planning environment in particular. Planners engaged in designing composite generation and transmission systems are usually faced with the difficult task of comparing different alternatives. As noted earlier, utilities have been primarily interested in supply-side alternatives, and demand-side considerations such as DSM initiatives were not extensively considered. This situation is no longer the case as both supply-side and demand-side options are now being actively considered [153, 154]. Chapter 3 clearly illustrates that divergent issues can be incorporated into a single solution using a reliability cost and reliability worth philosophy in the analysis. The reliability cost and reliability worth technique is based on computing the costs corresponding to different solutions and then calculating the reliability worth to the customer. The integration of demand-side and supply-side planning in the reliability cost and reliability worth approach has been referred to as integrated resource planning (IRP). This approach considers both demand and supply options as resources which can be used to provide energy service at the lowest possible cost [153].

Power utilities attempt to use IRP to minimize the total costs their customers have to pay. Some of these costs cannot be easily quantified and expressed in monetary terms. The IRP process includes the selection, out of a large number of options, of a combination of demand-side and supply-side projects that are likely to provide the best results under future uncertain conditions. The selected combination of projects has to be able to fully comply with a predefined set of constraints. This is obviously a departure from the traditional planning process that aimed at finding solutions which offered a reasonable level of reliability combined with the lowest possible cost. The new planning process aims at achieving maximum societal value. In the traditional supply-side only planning process, the demand forecast remained unchanged by the selection of the supply options. In the new integrated resource planning process, the demand forecast changes in accordance with the selected options whenever these options include DSM. Using the explicit cost approach, the change in the demand forecast may create changes in the optimal value of the system reliability criterion. Integrated resource planning is not an easy task at the bulk power system level as very few utilities have the capability to conduct HLII adequacy assessment. Considerable work has been done in this area by Ontario Hydro. PROCOSE (Probabilistic Composite System Evaluation) is a program developed by Ontario Hydro to facilitate HLII evaluation in planning studies [162]. This program has been used successfully in major planning studies of the Ontario Hydro system [163], in planning studies of power systems in Asia and the Middle East, and in an Electric Power Research Institute (EPRI) sponsored project on Value-Based Transmission Resource Analysis (VBTRA).

The studies described in the earlier chapters were done using either supply-side options or demand-side management but do not include joint considerations. In this chapter, the possible combined effects on a composite system of NUG and DSM initiatives are assessed. This is a new area of research which is made possible by extending the explicit reliability worth concept to the evaluation of the multiple options covered in an integrated resource planning scenario.

6.2. System Modelling Considerations for the Generation Supply and Load Demand

This chapter discusses the adequacy and economic impacts of supply-side (i.e., NUG) and demand-side (i.e., DSM) initiatives on the composite generation and transmission model of the RBTS. The effects on the individual load point and overall system reliability of the test system are examined. The analyses were conducted utilizing the contingency enumeration technique, the modelling considerations in Chapter 2 for non-utility generators, and the new load model representations described in Chapters 4 & 5 for the DSM initiatives.

6.2.1. Capacity Size of Non-Utility Generation

As discussed in Section 2.12, the non-utility generation facilities used in these studies, were modelled as small capacity components with relatively low forced outage rates. The base RBTS was modified to include independent power generation facilities at single locations in order to examine their impact on HLII adequacy indices. The NUG were injected at specified locations in the test system. The studies described in this chapter include the injection of 2-MW capacity NUG (with assumed FOR of 2%) at different single-bus locations in the RBTS. Buses 3 and 6 were utilized in these analyses.

6.2.2. Load Model Using Demand-Side Management

The following three different load models were used in the analyses described in this chapter.

(1). The 24-step daily basic load model developed in Chapter 4;

(2). The 24-step daily load model from LM10 [i.e., All industrial load at any bus during the year that exceeded (0.70 p.u.) was reduced to this value and no energy was recovered during the off-peak hours. (i.e., Equation (5.1) was applied to all loads; where: P=0.70, a=0.0)]; and

(3). The 24-step daily load model from LM11 [i.e., All industrial load at any bus during the off-peak hours of 1 a.m. to 7 a.m. was increased by 0.40 p.u. for all days during the year (i.e. Equation (5.4) was applied to all loads; where: A=0.40, t1=0, t2=7, h=7, and b=1.0)].

The 24-step daily load models from LM10 and LM11 were developed using the DSM initiative concepts described in Chapter 5.

6.3. Impacts of Generation Supply and Load Demand Options on Adequacy Indices

6.3.1. RBTS Adequacy Analysis

This section of the thesis illustrates the adequacy implications associated with the joint use of supply-side and demand-side initiatives in the RBTS. These concepts are extended to include reliability worth implications later in this chapter. The extension to reliability worth evaluation provides the opportunity to utilize the explicit cost approach in decision making. Many utilities, however, are not prepared to advance this far due to perceived difficulties and uncertainties in customer perceptions of outage cost. Integrated resource planning adequacy evaluation, which provides quantitative indices at the load points and at the system level can also be used in conjunction with the more conventional implicit cost approaches. The analysis in this chapter is, therefore, first focussed on adequacy assessment and then extended to reliability worth evaluation. All the results shown are annual indices which reflect the variations in the load level over a one year period. The 24-step daily load models noted from Chapter 5 were used for the analyses.

6.3.1.1. Load Point Indices

Figures 6.1 and 6.2 show the EENS results obtained for the five load points of the RBTS when identical 2-MW capacity NUG are sequentially introduced at Buses 3 and 6 using the 24-step daily basic load model developed in Chapter

4. The results presented in Tables 6.1 and 6.2 are shown pictorially in Figures 6.1 and 6.2. These results are not the same as those shown in Tables 2.10 and 2.13 due to different load models. These values are referred to as the base case results in the analyses described in this section. Figures 6.3 and 6.4 show the variations in the EENS index as the number of NUG injected at Buses 3 and 6 increase using a 24-step daily load model from LM10 (which shaves some of the industrial customer sector peak loads). The EENS results for this case are presented in Tables G.1 and G.2. Similar variations in the EENS at the individual load points are shown in Figures 6.5 and 6.6 using a 24-step daily load model from LM11. The results presented for these cases are given in Tables G.3 and G.4.

The results in Figures 6.1 to 6.6 show a general tendency towards reduction in the EENS at most of the load points for the different 24-step daily load models as NUG are injected into the system. The addition of NUG facilities and the implementation of DSM initiatives alleviate to some extent, the severity or intensity of an outage problem affecting a particular load point. This can be seen from Figures 6.1 to 6.6 and Tables 6.1, 6.2 and G.1 to G.4 which show the reductions in the expected energy curtailed at the load points from the early unit addition stages. The EENS at Bus 6 is not affected by the combined implementation of capacity or NUG additions and DSM initiatives except when the NUG are introduced at that bus. As noted in Chapter 2, Bus 6 is the most unreliable load point in the RBTS because of the frequent isolation problems it experiences whenever its single-line radial connection with the rest of the system is on outage.

Table 6.1: Annual load point expected energy not supplied (EENS) with the incremental addition of identical 2-MW capacity NUG to Bus 3 of the RBTS using the basic load model.

Addition of NUG	EENS At Bus 2 MWh/yr	EENS At Bus 3 MWh/yr	EENS At Bus 4 MWh/yr	EENS At Bus 5 MWh/yr	EENS At Bus 6 MWh/yr
RBTS+(0*2MW)	3.7521	47.2138	9.8594	1.3232	100.9132
RBTS+(1*2MW)	3.1736	43.3353	8.9353	1.6484	101.0347
RBTS+(2*2MW)	2.4669	36.8491	7.4086	1.7243	101.0023
RBTS+(3*2MW)	1.9240	31.3796	6.2185	1.7648	100.9650
RBTS+(4*2MW)	1.5157	27.3992	5.2534	1.7554	100.9012
RBTS+(5*2MW)	1.1991	24.3085	4.4858	1.7290	100.8291
RBTS+(6*2MW)	0.9549	21.9667	3.8882	1.6994	100.7492
RBTS+(7*2MW)	0.7725	20.3158	3.4297	1.6709	100.6707
RBTS+(8*2MW)	0.6326	19.1352	3.0851	1.6447	100.5856
RBTS+(9*2MW)	0.5216	18.2642	2.8064	1.6218	100.4893
RBTS+(10*2MW)	0.4265	17.5534	2.5737	1.6092	100.3825
RBTS+(11*2MW)	0.3413	16.9241	2.3652	1.5875	100.2593
RBTS+(12*2MW)	0.2652	16.3675	2.1827	1.5736	100.1275

Table 6.2: Annual load point expected energy not supplied (EENS) with the incremental addition of identical 2-MW capacity NUG to Bus 6 of the RBTS using the basic load model.

Addition of NUG	EENS At Bus 2 MWh/yr	EENS At Bus 3 MWh/yr	EENS At Bus 4 MWh/yr	EENS At Bus 5 MWh/yr	EENS At Bus 6 MWh/yr
RBTS+(0*2MW)	3.7521	47.2138	9.8594	1.3232	100.9132
RBTS+(1*2MW)	3.1526	41.5387	8.6152	1.4201	81.4523
RBTS+(2*2MW)	2.4405	34.9925	6.9305	1.5556	63.4668
RBTS+(3*2MW)	1.9011	29.7856	5.7834	1.6148	49.2322
RBTS+(4*2MW)	1.4937	25.9747	4.8962	1.6240	36.4375
RBTS+(5*2MW)	1.1790	23.1786	4.2094	1.5984	25.4716
RBTS+(6*2MW)	0.9413	21.1927	3.6988	1.5369	15.1437
RBTS+(7*2MW)	0.7619	19.7550	3.2889	1.3957	7.0273
RBTS+(8*2MW)	0.6179	18.6868	2.9469	1.2873	1.3692
RBTS+(9*2MW)	0.5063	17.9249	2.6784	1.1722	0.2200
RBTS+(10*2MW)	0.4127	17.3188	2.4570	1.0933	0.0868
RBTS+(11*2MW)	0.3274	16.7983	2.2055	1.0630	0.0672
RBTS+(12*2MW)	0.2533	16.3637	1.9977	1.0428	0.0532

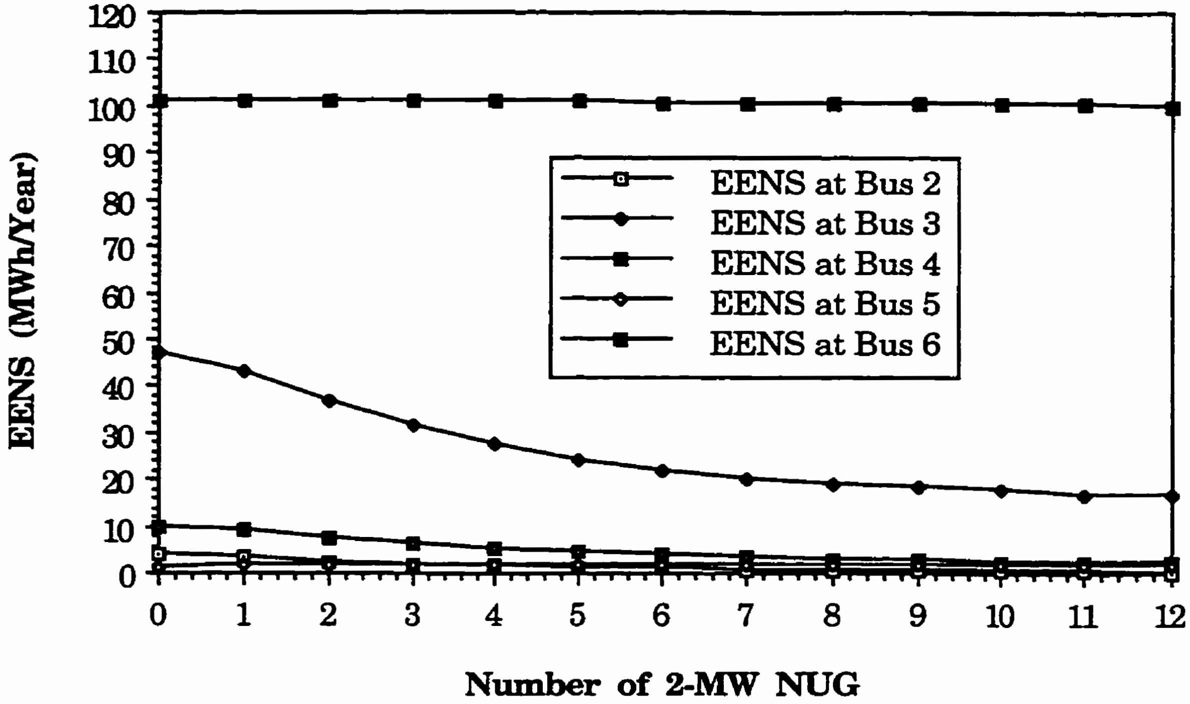

Figure 6.1: Annual load point EENS with incremental addition of identical 2-MW capacity NUG to Bus 3 of the RBTS using the basic load model.

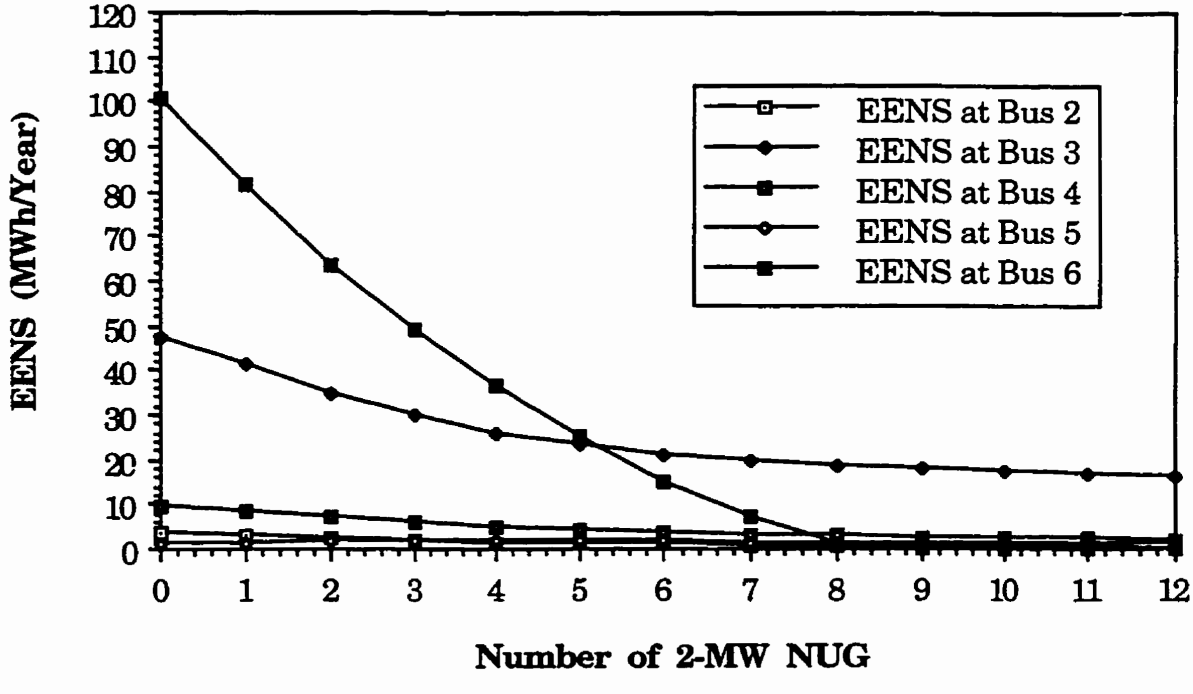

Figure 6.2: Annual load point EENS with incremental addition of identical 2-MW capacity NUG to Bus 6 of the RBTS using the basic load model.

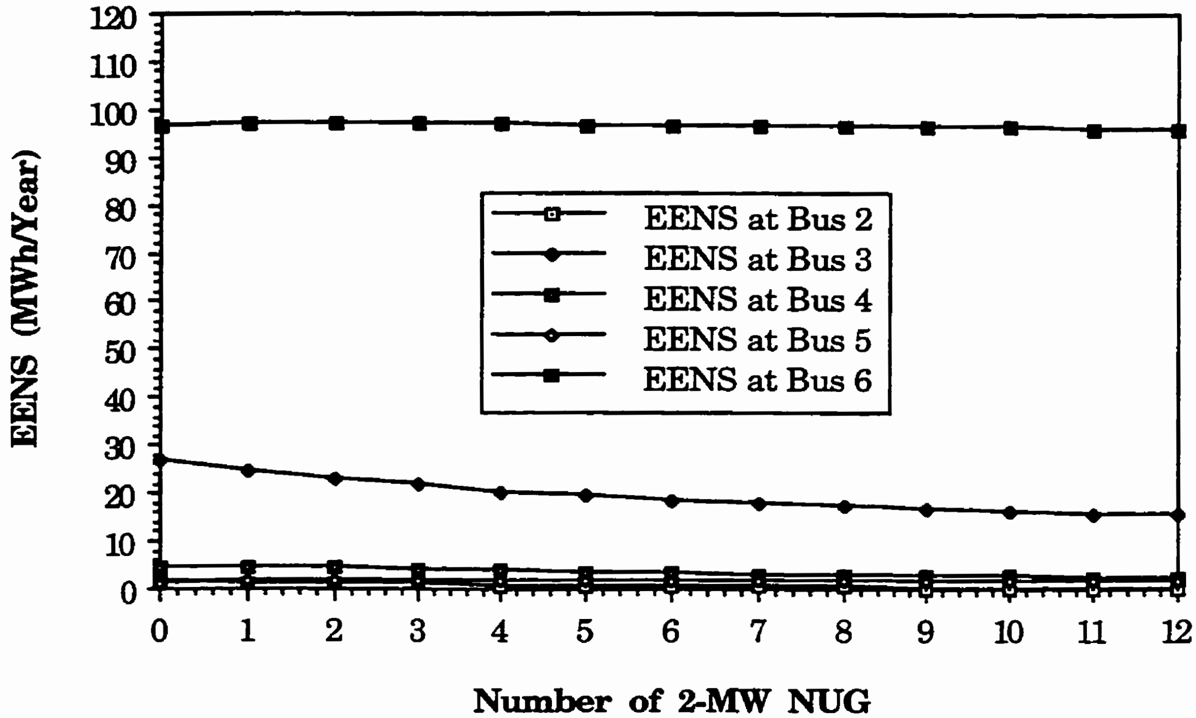

Figure 6.3: Annual load point EENS with incremental addition of identical 2-MW capacity NUG to Bus 3 of the RBTS using LM10.

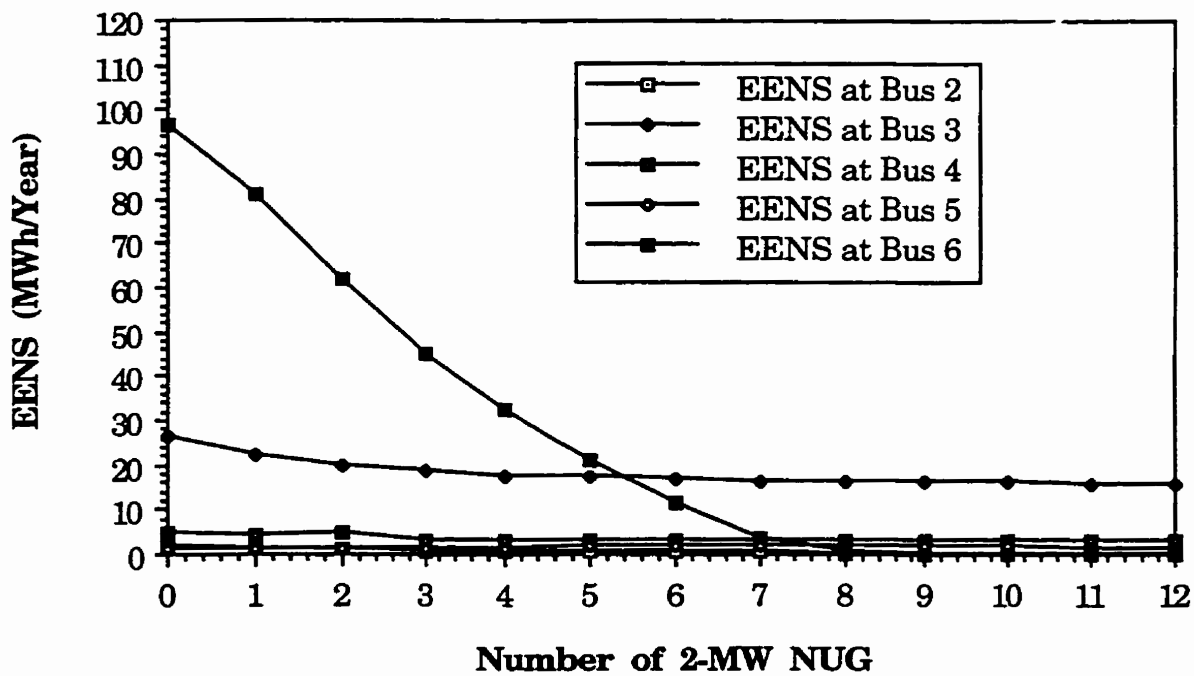

Figure 6.4: Annual load point EENS with incremental addition of identical 2-MW capacity NUG to Bus 6 of the RBTS using LM10.

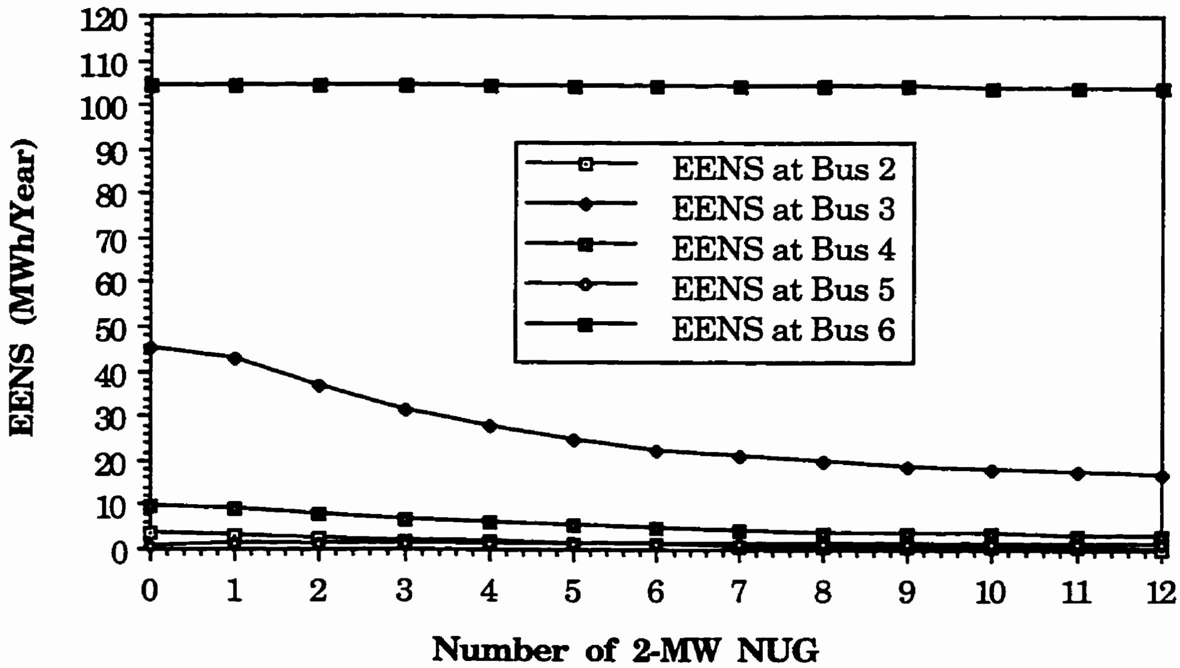

Figure 6.5: Annual load point EENS with incremental addition of identical 2-MW capacity NUG to Bus 3 of the RBTS using LM11.

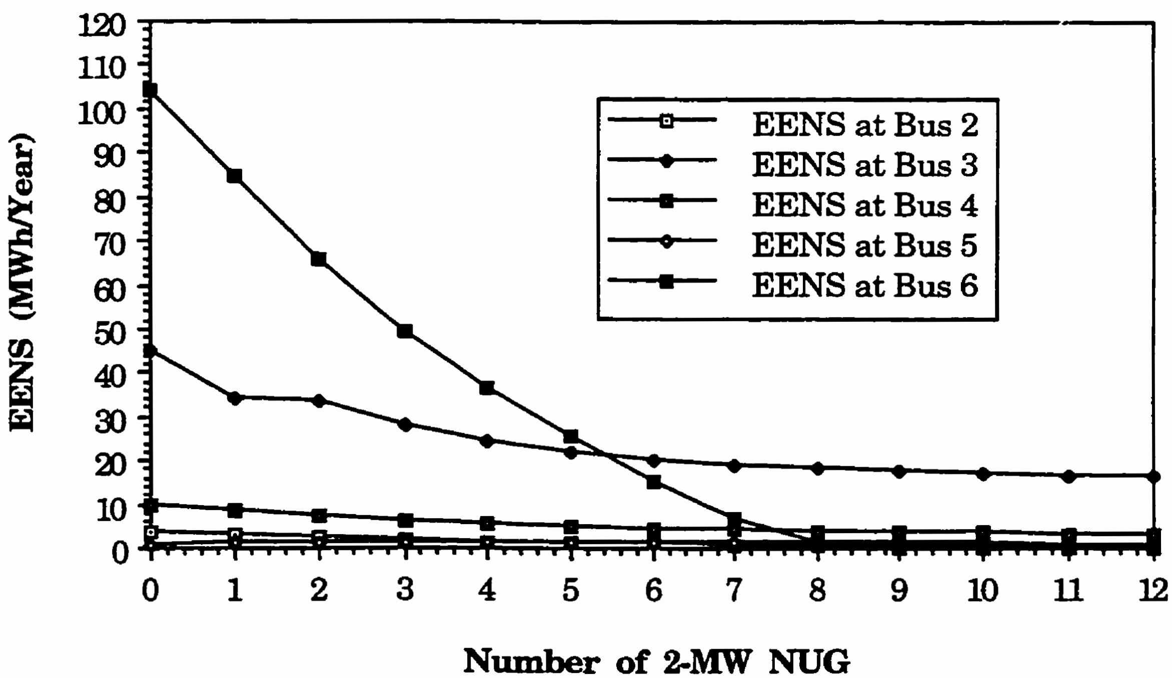

Figure 6.6: Annual load point EENS with incremental addition of identical 2-MW capacity NUG to Bus 6 of the RBTS using LM11.

The benefits of injecting NUG into the system and the implementation of DSM initiatives are considered separately in earlier analyses described in Chapters 2 to 5. The base case results presented in Tables 6.1 and 6.2 and Figures 6.1 and 6.2 respectively were obtained by examining the impacts of non-utility generation on the RBTS. In these analyses, the new responsive load models were utilized. The benefits obtained, when supply-side options and DSM alternatives are jointly implemented, is not as great as the sum of the benefits derived from examining the effects of supply-side and demand-side options separately. It is important to understand that the two separate sets of benefits obtained when examining the impacts of NUG additions and DSM initiatives are not mutually exclusive but are highly interrelated. An appreciation of this interaction is required in a complete assessment of the reliability and economic impacts of joint NUG injection at different locations and the application of DSM initiatives to the customer sectors at each bus load in an electric power system. The specific conclusions drawn are highly dependent on the system under analysis and should be examined in detail in each application.

6.3.1.2. System Indices

Figure 6.7 and Table G.5 show the variation in the system EENS when NUG are incrementally introduced at Buses 3 and 6 using the three different load models. Gradual improvements in the overall system adequacy (i.e., EENS) can be observed for all combinations of NUG addition at a particular location and the implementation of different load models using DSM programs. The rate of improvement, however, varies depending on the different combinations of NUG additions at the specified locations and the

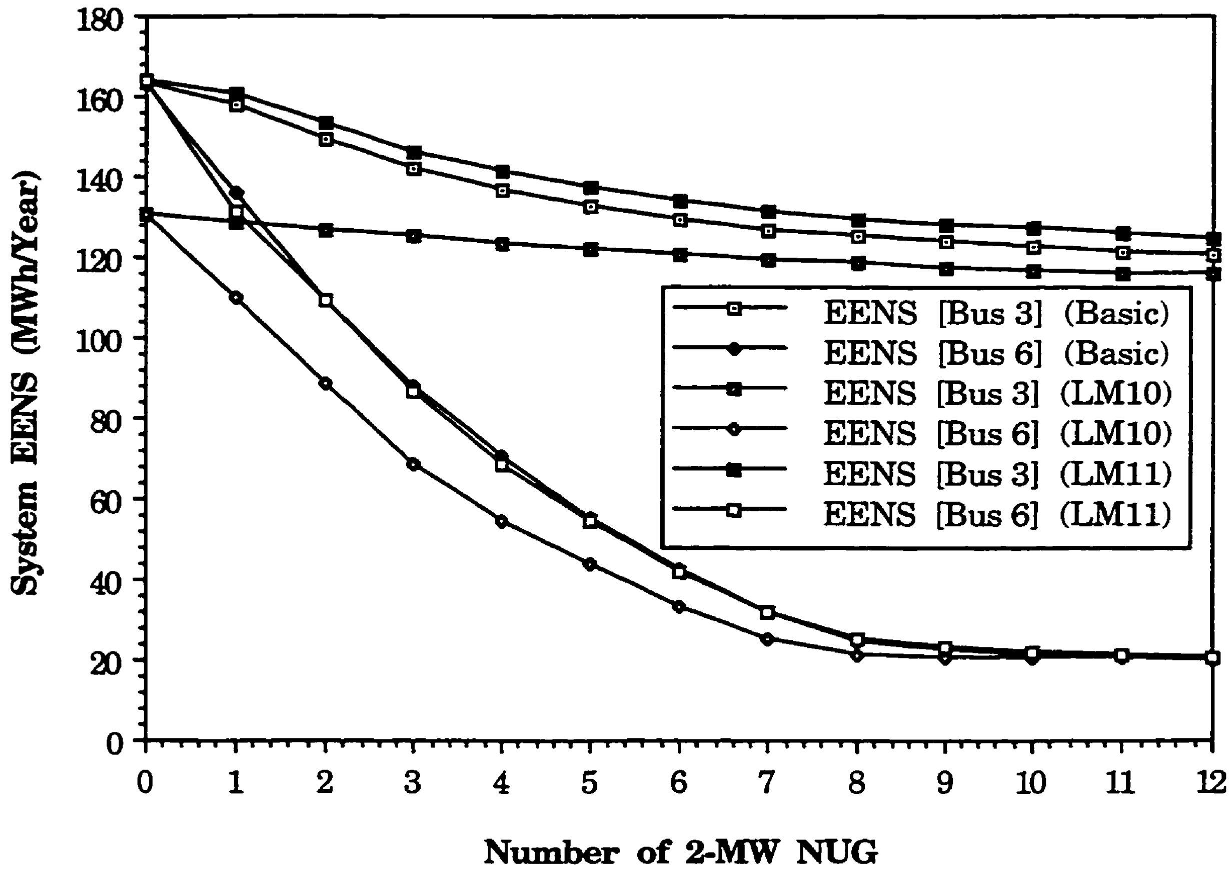

Figure 6.7: Annual system EENS with incremental addition of identical 2-MW capacity NUG to Buses 3 and 6 of the RBTS using the base case load model, LM10 and LM11.

load models. The corresponding system EENS for each combination of supply-side and demand-side options also settle at different levels of adequacy for the same total number of NUG added to the system. The best combination of NUG additions and DSM initiatives, as can be seen from the family of curves shown in Figure 6.7, is when all the twelve identical NUG are sequentially introduced at Bus 6 in conjunction with the utilization of load model 10 (LM10). There is a significant drop in the system EENS as a result of implementing LM10 without the introduction of additional NUG units. As already noted, the weak transmission link to Bus 6 minimizes the benefits to Bus 6 of the additional NUG introduced at Bus 3 and the application of the three load models. Bus 6, therefore, is a major source of inadequacy in the RBTS.

It can be seen from Figure 6.7 and Table G.5 that, there is virtually no significant benefit in applying DSM initiatives after the addition of the ninth 2-MW capacity NUG. An improvement in Bus 6 EENS occurs as soon as NUG are introduced at Bus 6 regardless of the type of load model used. This clearly indicates that supply-side deficiency is the major cause of inadequacy at Bus 6. The introduction of additional generating facilities in the form of NUG beyond the radial connection does not improve the situation at Bus 6, because the isolation problems are not addressed by such actions. As noted earlier, the injection of NUG at Bus 6 produces significant drops in the overall system EENS as the NUG can now directly supply the load point during normal system operation and when the load point is isolated from the conventional generating sources. Supply or demand-side initiatives considered individually or in combination, in this case, offer a technically feasible alternative to transmission system reinforcement as a measure for improving overall system adequacy.

6.4. Expected Outage Cost Evaluation Utilizing Combined Supply and Demand Options

This study extends the composite system analysis described earlier in this chapter by evaluating the annual expected customer costs of unserved energy at each load point and the overall system. The EENS values illustrated earlier in the chapter are used in conjunction with the appropriate load point

IEAR to determine the expected consequences of the load point failure. This extension permits the determination of the economic benefits associated with introducing additional generation from NUG facilities at selected locations and utilizing the DSM initiatives described by the three load models.

6.4.1. RBTS Reliability Worth Analysis

The annual customer costs of unserved energy evaluated at each load bus and the overall system are illustrated and presented in this subsection. The trends in the results are similar to those presented for the load point and overall system EENS in Subsection 6.3. The ECOST results also include the actual customer composition at the various load points through the respective IEAR values.

6.4.1.1. Load Point Indices

The variation in the annual expected customer costs of unserved energy (ECOST) at the load points when NUG are incrementally introduced at load Buses 3 and 6 with the selected load models are shown in Figures 6.8 to 6.13. The base case results are presented in Tables 6.3 and 6.4 and illustrated graphically in Figures 6.8 and 6.9. The remaining results in table form for NUG additions using LM10 and LM11 are presented in Appendix G.

Figures 6.10 and 6.11 show the variations in the bus ECOST when the NUG injected at Buses 3 and 6 incrementally increase using LM10. Similar ECOST results are shown in Figures 6.12 and 6.13 for LM11.

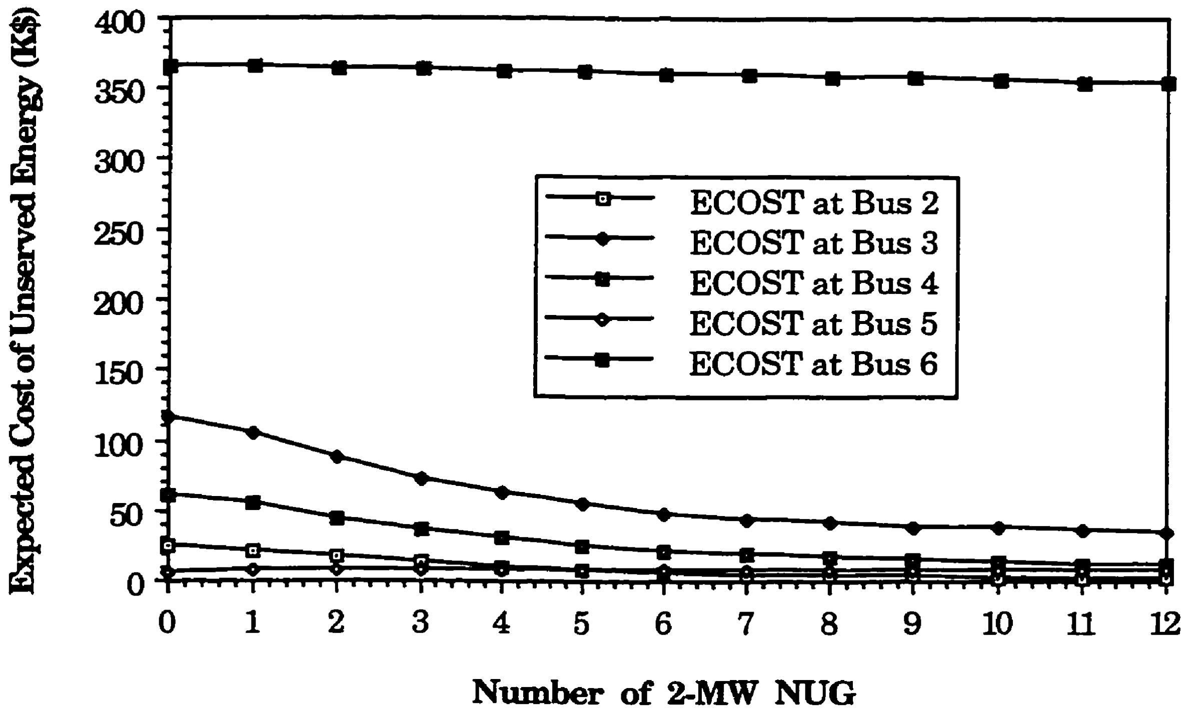

Figure 6.8: Annual expected customer cost of unserved energy with incremental addition of identical 2-MW capacity NUG to Pus 3 of the RBTS using the basic load model.

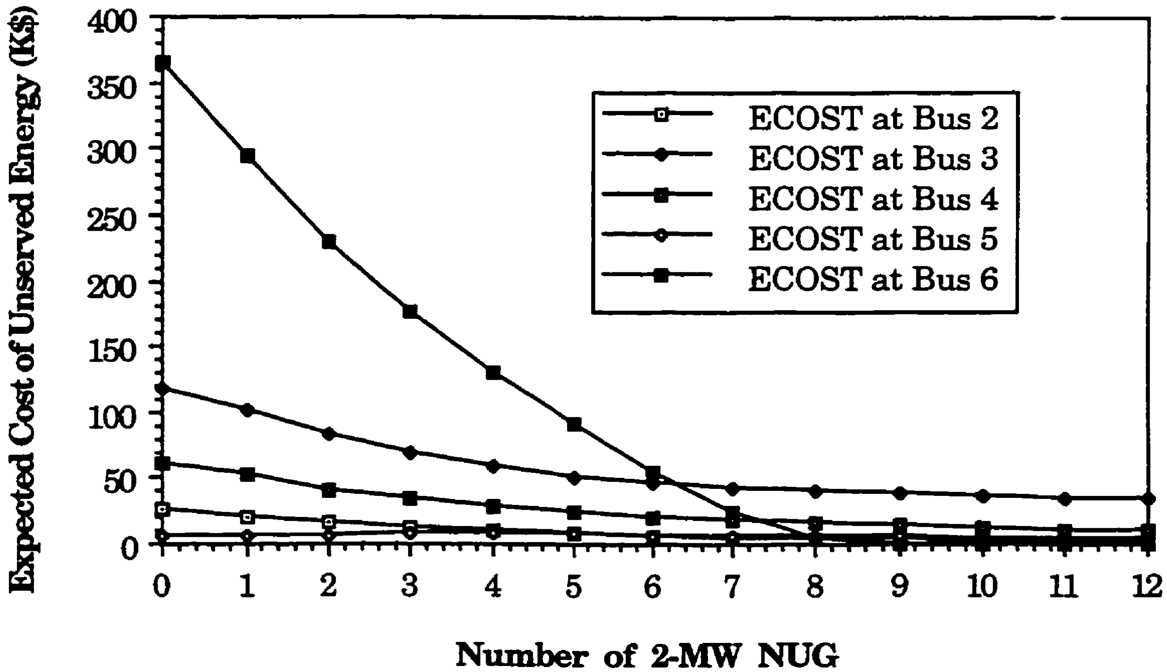

Figure 6.9: Annual expected customer cost of unserved energy with incremental addition of identical 2-MW capacity NUG to Bus 6 of the RBTS using the basic load model.

Table 6.3: Annual load point expected cost of unserved energy (ECOST) with the incremental addition of identical 2-MW capacity NUG to Bus 3 of the RBTS using the basic load model.

Addition of NUG	ECOST At Bus 2 (K$/yr.)	ECOST At Bus 3 (K$/yr.)	ECOST At Bus 4 (K$/yr.)	ECOST At Bus 5 (K$/yr.)	ECOST At Bus 6 (K$/yr.)
RBTS+(0*2MW)	25.6958	117.0009	61.3661	5.8310	366.1196
RBTS+(1*2MW)	21.4507	105.5526	54.4368	7.4197	365.6038
RBTS+(2*2MW)	16.3669	88.0014	44.1871	7.8291	364.6362
RBTS+(3*2MW)	12.5309	73.2994	36.2676	8.0147	363.6615
RBTS+(4*2MW)	9.7032	62.6230	30.0033	7.9392	362.6151
RBTS+(5*2MW)	7.5546	54.4828	25.0888	7.7776	361.5507
RBTS+(6*2MW)	5.9395	48.4622	21.3148	7.5990	360.4701
RBTS+(7*2MW)	4.7527	44.1442	18.4564	7.4301	359.4003
RBTS+(8*2MW)	3.8759	41.1478	16.3369	7.2794	358.3177
RBTS+(9*2MW)	3.1804	38.9614	14.6313	7.1539	357.2084
RBTS+(10*2MW)	2.5865	37.1823	13.2123	7.0784	356.0836
RBTS+(11*2MW)	2.0541	35.6118	11.9463	6.9627	354.8975
RBTS+(12*2MW)	1.5851	34.2278	10.8443	6.8809	353.7018

Table 6.4: Annual load point expected cost of unserved energy (ECOST) with the incremental addition of identical 2-MW capacity NUG to Bus 6 of the RBTS using the basic load model.

Addition of NUG	ECOST At Bus 2 (K$/yr.)	ECOST At Bus 3 (K$/yr.)	ECOST At Bus 4 (K$/yr.)	ECOST At Bus 5 (K$/yr.)	ECOST At Bus 6 (K$/yr.)
RBTS+(0*2MW)	25.6958	117.0009	61.3661	5.8310	366.1196
RBTS+(1*2MW)	21.3011	101.4889	52.6792	6.4215	294.7614
RBTS+(2*2MW)	16.1806	83.6727	41.6101	7.0944	229.1942
RBTS+(3*2MW)	12.3730	69.4926	33.8942	7.3606	177.3860
RBTS+(4*2MW)	9.5530	59.2229	28.0312	7.3663	130.9334
RBTS+(5*2MW)	7.4218	51.7488	23.5504	7.2079	91.2679
RBTS+(6*2MW)	5.8453	46.4746	20.2456	6.8898	54.0517
RBTS+(7*2MW)	4.6946	42.7437	17.6888	6.2284	24.9416
RBTS+(8*2MW)	3.7887	40.0073	15.5895	5.7174	4.7540
RBTS+(9*2MW)	3.0897	38.0755	13.9503	5.1883	0.7647
RBTS+(10*2MW)	2.5045	36.5311	12.5997	4.8275	0.3150
RBTS+(11*2MW)	1.9749	35.2039	11.1475	4.6792	0.2462
RBTS+(12*2MW)	1.5183	34.0937	9.9444	4.5742	0.1958

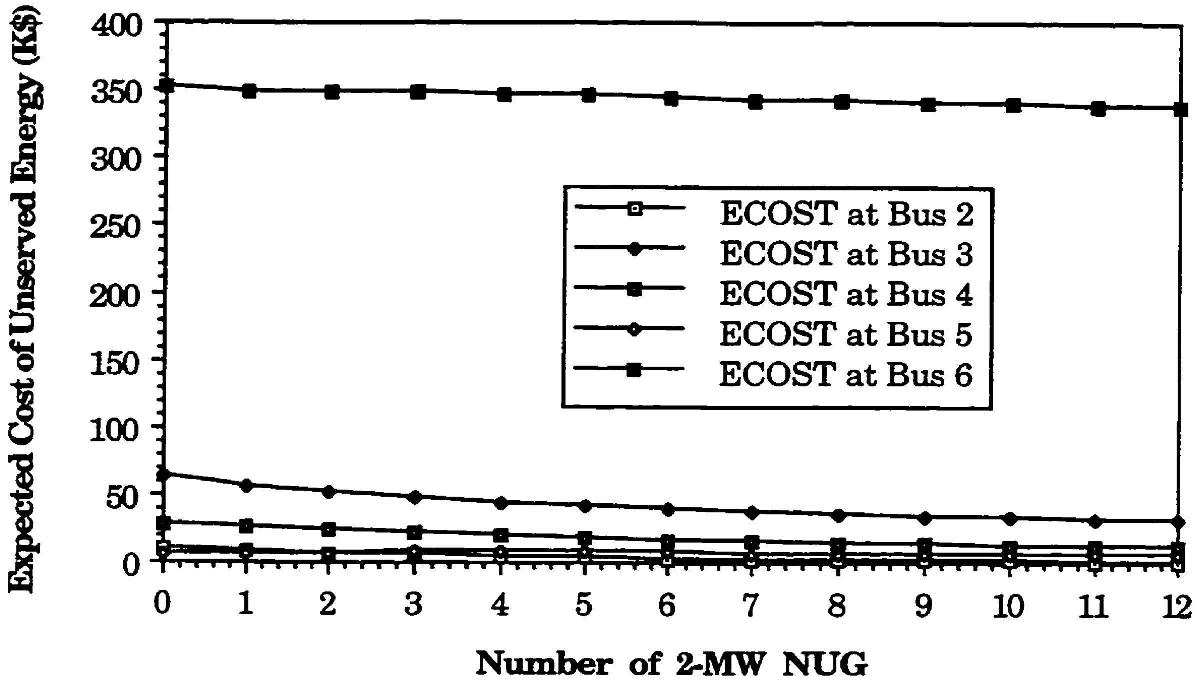

Figure 6.10: Annual expected customer cost of unserved energy with incremental addition of identical 2-MW capacity NUG to Bus 3 of the RBTS using LM10.

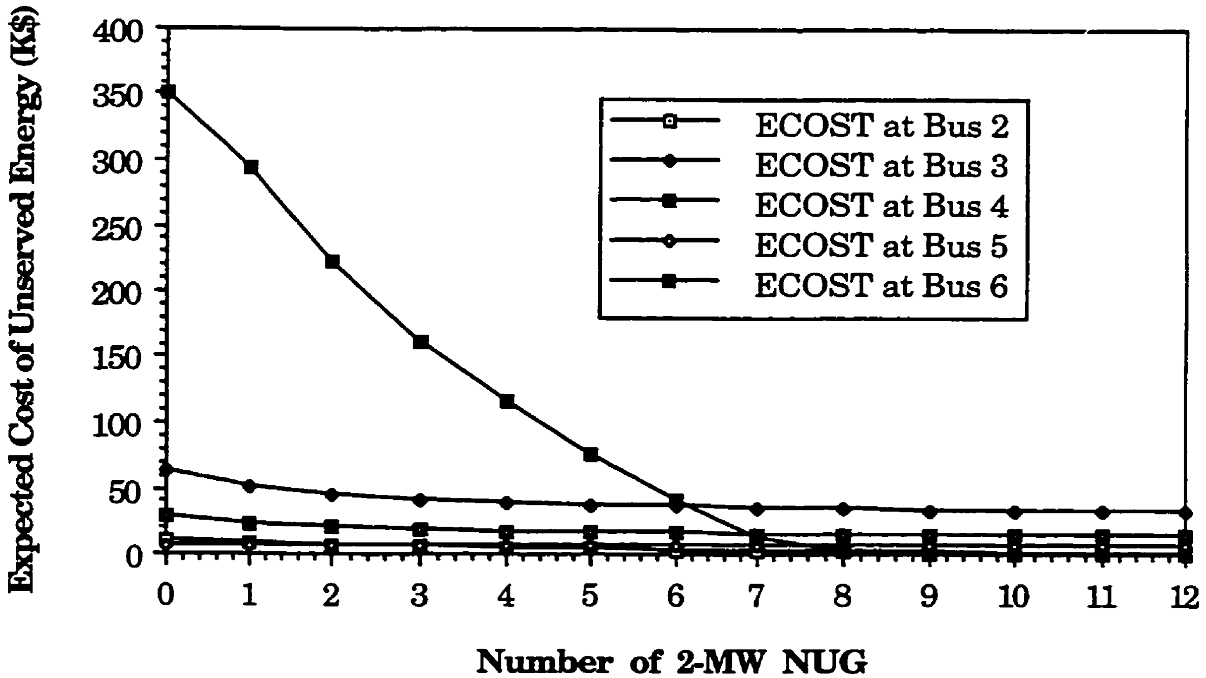

Figure 6.11: Annual expected customer cost of unserved energy with incremental addition of identical 2-MW capacity NUG to Bus 6 of the RBTS using LM10.

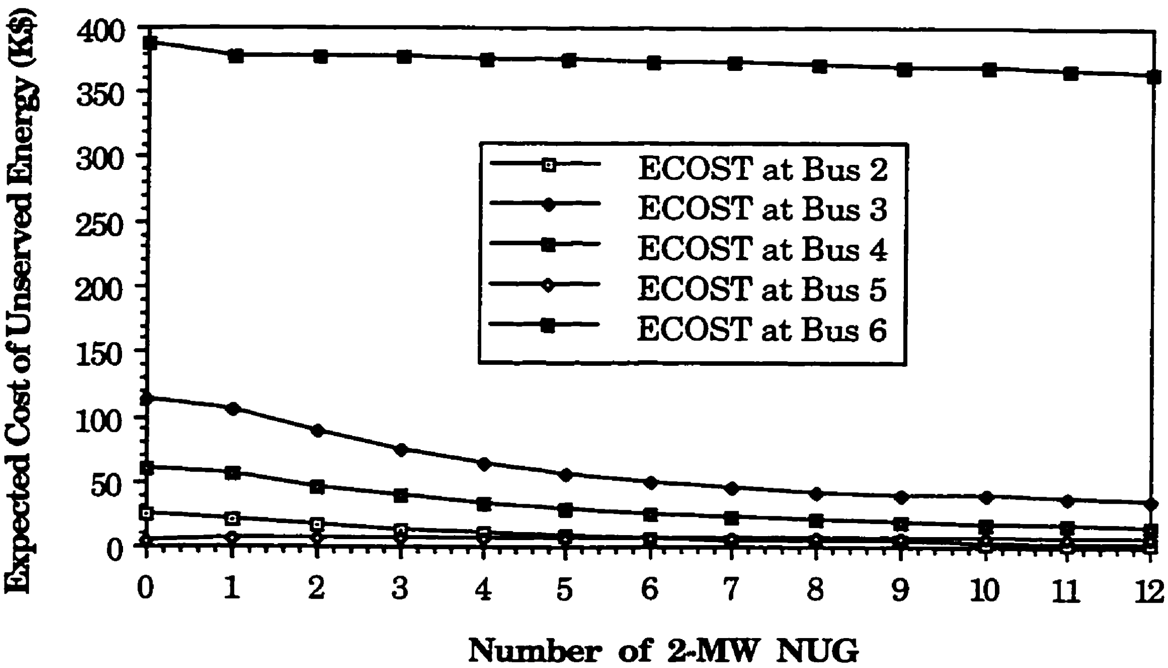

Figure 6.12: Annual expected customer cost of unserved energy with incremental addition of identical 2-MW capacity NUG to Bus 3 of the RBTS using LM11.

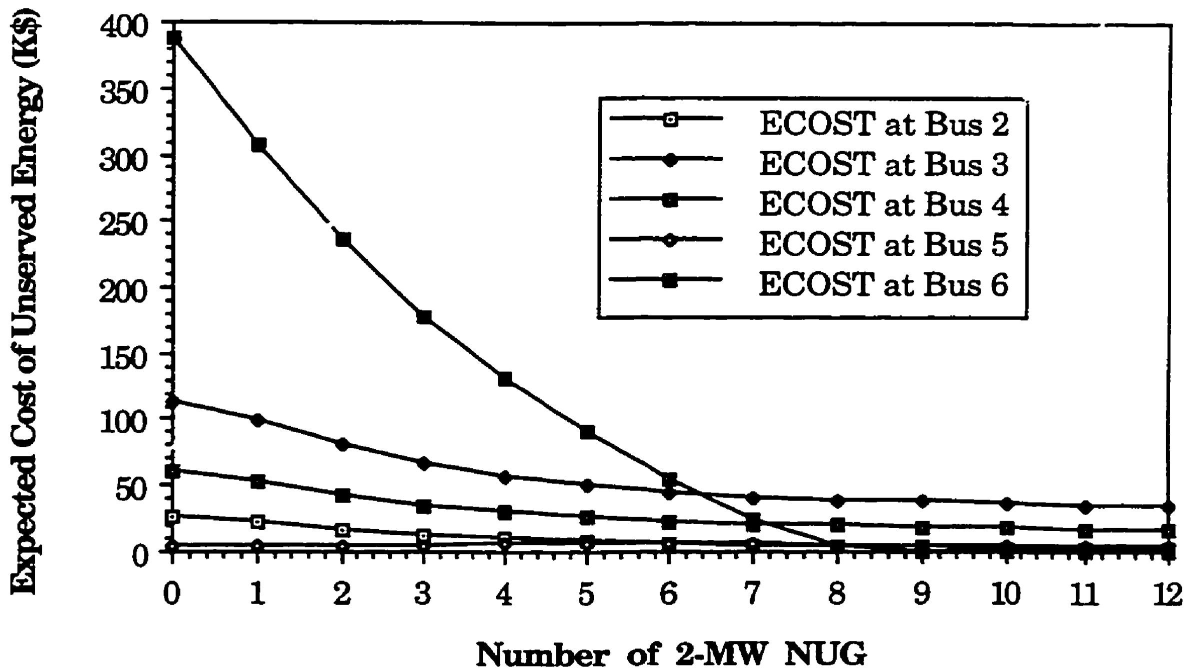

Figure 6.13: Annual expected customer cost of unserved energy with incremental addition of identical 2-MW capacity NUG to Bus 6 of the RBTS using LM11.

A general decreasing trend in the ECOST for most of the load points can be seen in Figures 6.8 to 6.13 as the number of NUG added to the system increase. The implementation of both NUG additions and DSM initiatives helped in some cases to reduce the expected customer monetary losses or ECOST at the individual load points. In all the cases considered, the load point ECOST at Bus 6 remained virtually unaffected throughout the entire analyses involving the combinations of supply-side options and demand-side management initiative scenarios except when the NUG are injected at that bus. As noted earlier, the addition of NUG and the implementation of DSM initiatives beyond the radial link do not address the isolation problems basically responsible for inadequacy at Bus 6.

The conclusions drawn from the studies described in Section 6.3 can be extended to the analyses performed in this section because there is a direct link between the expected energy not supplied and the expected customer monetary losses (ECOST) due to power interruptions. Not all load points have the same IEAR and therefore improvement in reducing the EENS at any given bus may not translate in comparable reduction in ECOST. As noted from the earlier studies, the actual numerical conclusions are system specific and cannot be generally applied to other systems and particularly to systems with considerably different topology.

6.4.1.2. System Indices

The overall system customer costs of unserved energy obtained for the NUG addition stream using the three load models are shown in Figure 6.14. The system ECOST family of curves illustrated in Figure 6.14 are similar to the corresponding system expected energy not supplied diagram shown in Figure

6.7. The overall system expected energy not supplied values shown in Subsection 6.3.1.2 were transformed into customer monetary losses utilizing Equations (3.11) to (3.13). Buses 6, 3 and 4 are the major contributors to the total system costs of expected unsupplied energy in all the studies. The location of the NUG in addition to the load model types used are important factors in these analyses.

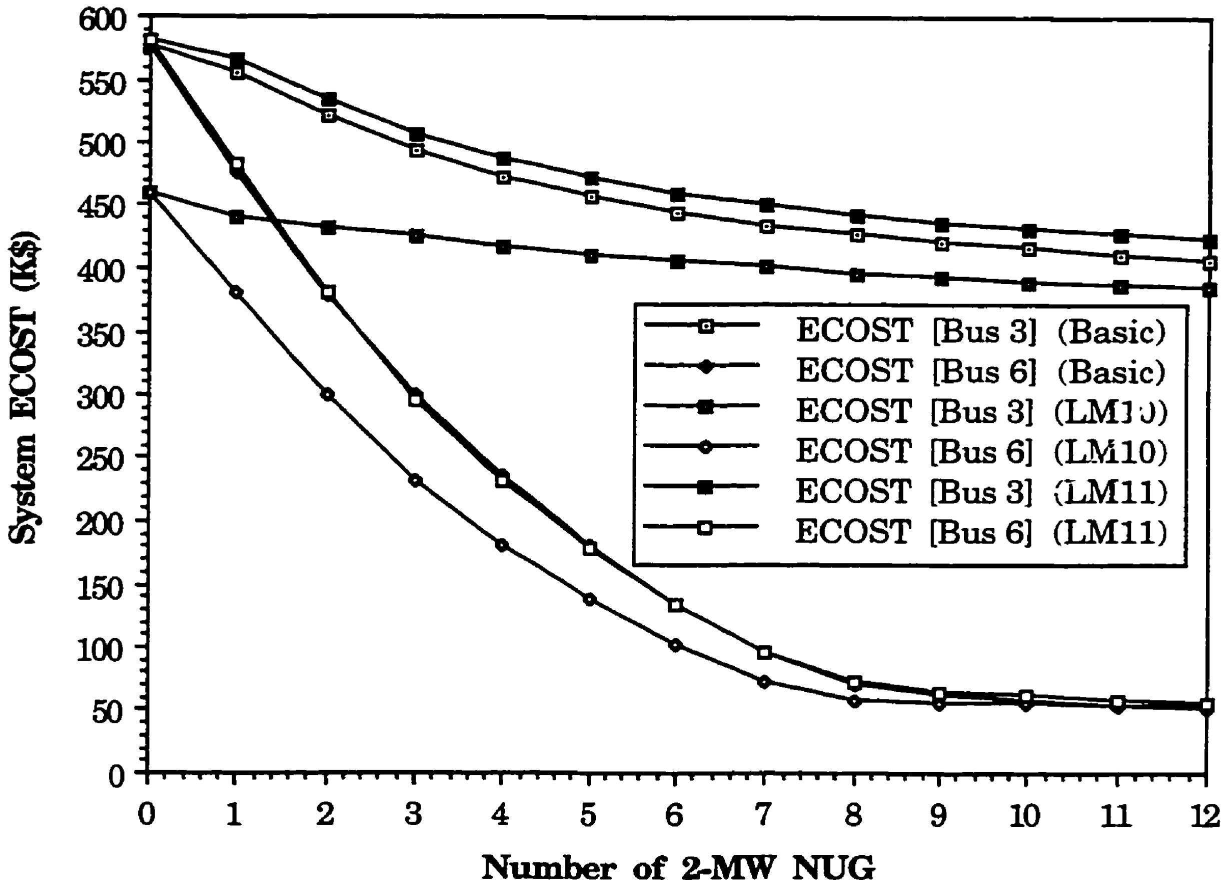

Figure 6.14: Annual system ECOST with incremental addition of identical 2-MW capacity NUG to Buses 3 and 6 of the RBTS using the base case load model, LM10 and LM11.

6.5. Determination of the Optimum Reserve Margin Utilizing the Combined Effects of Supply and Demand Options

The economic impacts of supply-side options on the planning reserve margin of the RBTS was examined in Chapter 3. In these studies, the addition of extra generating capacity in the form of NUG were considered to be the only means available to meet the reserve requirements and satisfy the specified reliability constraints. Chapters 4 and 5 illustrate that DSM initiatives can also be used as an alternative strategy. DSM alternatives can alleviate the reliability problem by changing the load shape and the load factor.

As noted earlier, the total societal cost, which is the sum of the system fixed costs, the system production costs and the customer interruption costs, is dependent upon the given generation configuration, priority loading order and the system load curve at HLI. The unit operating costs and the overall system production costs are dependent on the expected energy output of each unit in the system. The introduction of DSM to change the customer sector load curves affects the overall system EENS and consequently changes the expected energy output of each generating unit in the system. This in turn, leads to different system production costs and customer interruption costs. The impact of both supply-side options and DSM initiatives on the total societal costs and the RBTS PRM of electric power are illustrated in this section.

6.5.1. RBTS Optimal Reserve Margin Analysis

The total societal costs for the scenarios described in Chapter 3 were assessed for an increasing number of identical 2-MW capacity NUG with forced outage rates of 2% and the DSM initiatives from the three different load models listed in Subsection 6.2.2. Fixed costs of \$4/KW and \$40/KW were utilized for the NUG in these analyses.

The variation in the total societal cost as a function of the PRM, when a NUG stream is injected at Buses 3 and 6 using the three separate load models are illustrated in Figures 6.15 through 6.20 and presented in Tables G.11 to G.16. An investment cost of \$4/KW was used for the added NUG to evaluate the optimum total societal costs at HLII shown in Figures 6.15 to 6.17. Similarly, a fixed cost of \$40/KW was utilized in the analyses illustrated in Figures 6.18 to 6.20. The process was initiated by removing one 20-MW hydro-unit from Bus 2 of the basic RBTS. Under these conditions, the PRM is 18.92 percent. The 20-MW unit was then added to the available capacity at Bus 2 followed by the 2-MW capacity NUG streams at Buses 3 and 6 of the RBTS. The effects of varying the target generation reserve on the expected consumers costs are shown in Figures 6.15 to 6.20. The detailed results are also presented in Appendix G (i.e., Tables G.11 to G.16). The results illustrated in Figures 6.15 and 6.18 are the base case data for Buses 3 and 6 when \$4/KW and \$40/KW are considered for the NUG facilities. Supply-side and DSM options were considered concurrently in the results shown in Figures 6.16 & 6.17 and Figures 6.19 & 6.20.

It can be seen from Figures 6.15 to 6.17 that, as the PRM increases, the total societal costs decrease gradually up to the minimum point and then begin to increase when NUG facilities with an investment cost of \$4/KW are

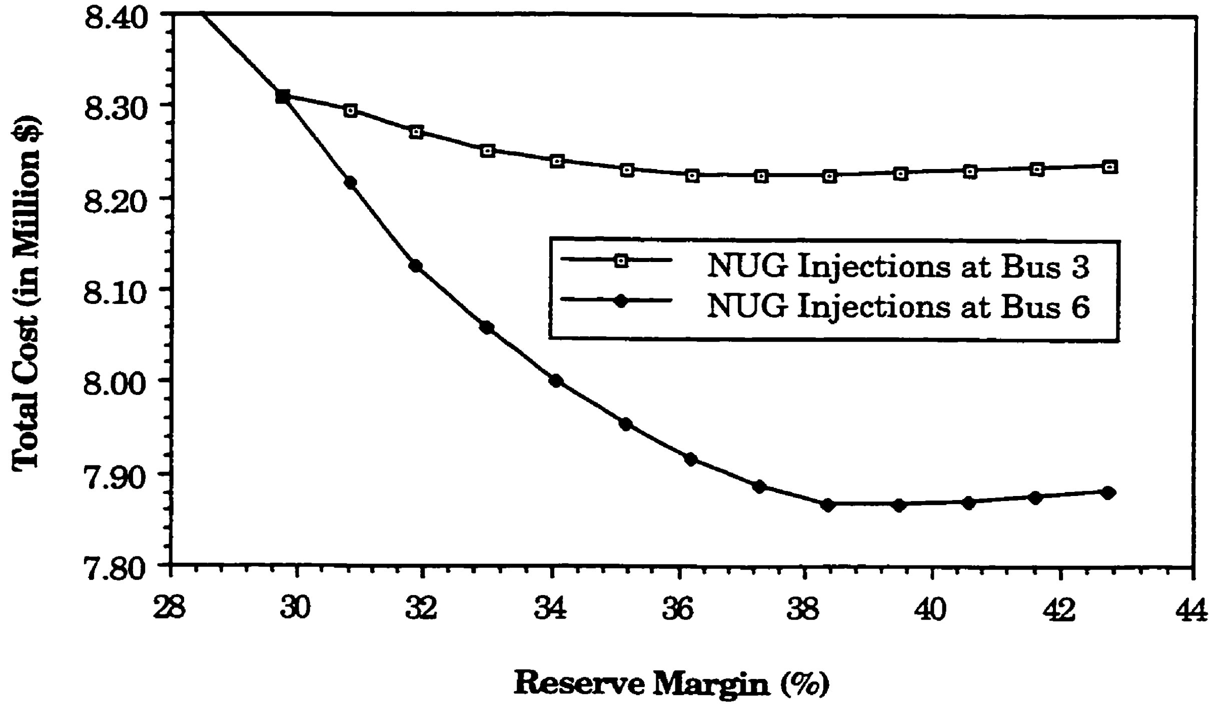

Figure 6.15: Variation of costs with planning reserve margin when 2-MW capacity NUG are injected at Buses 3 and 6 of the RBTS using the basic load model (fixed cost of $4/KW).

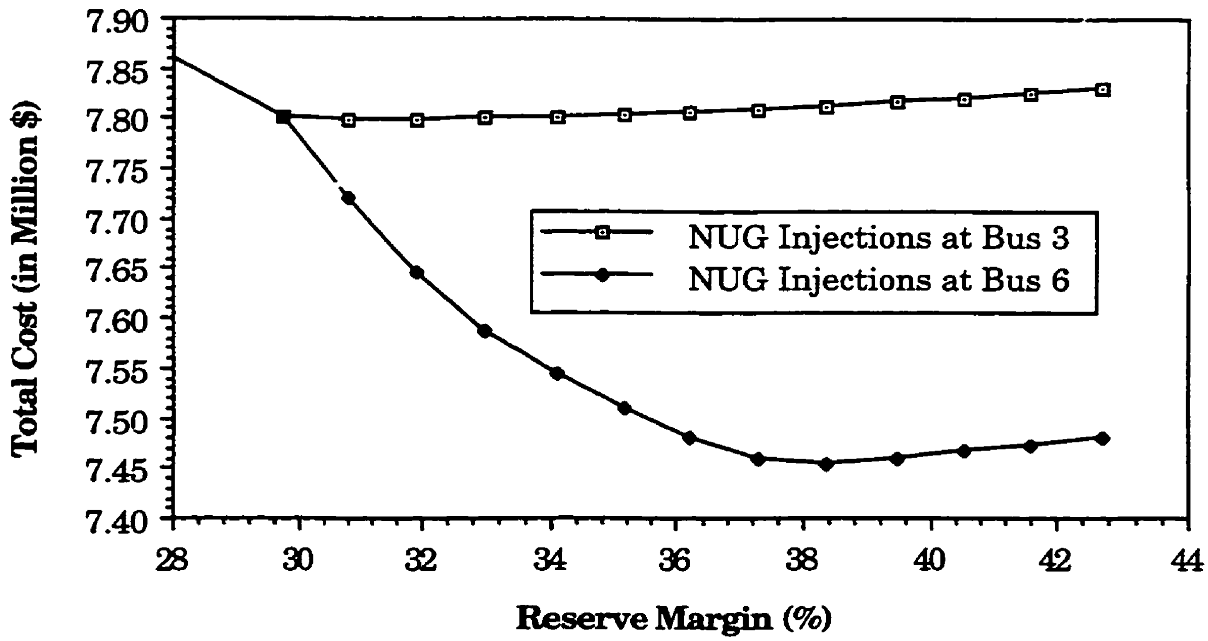

Figure 6.16: Variation of costs with planning reserve margin when 2-MW capacity NUG are injected at Buses 3 and 6 of the RBTS using LM10 (fixed cost of $4/KW).

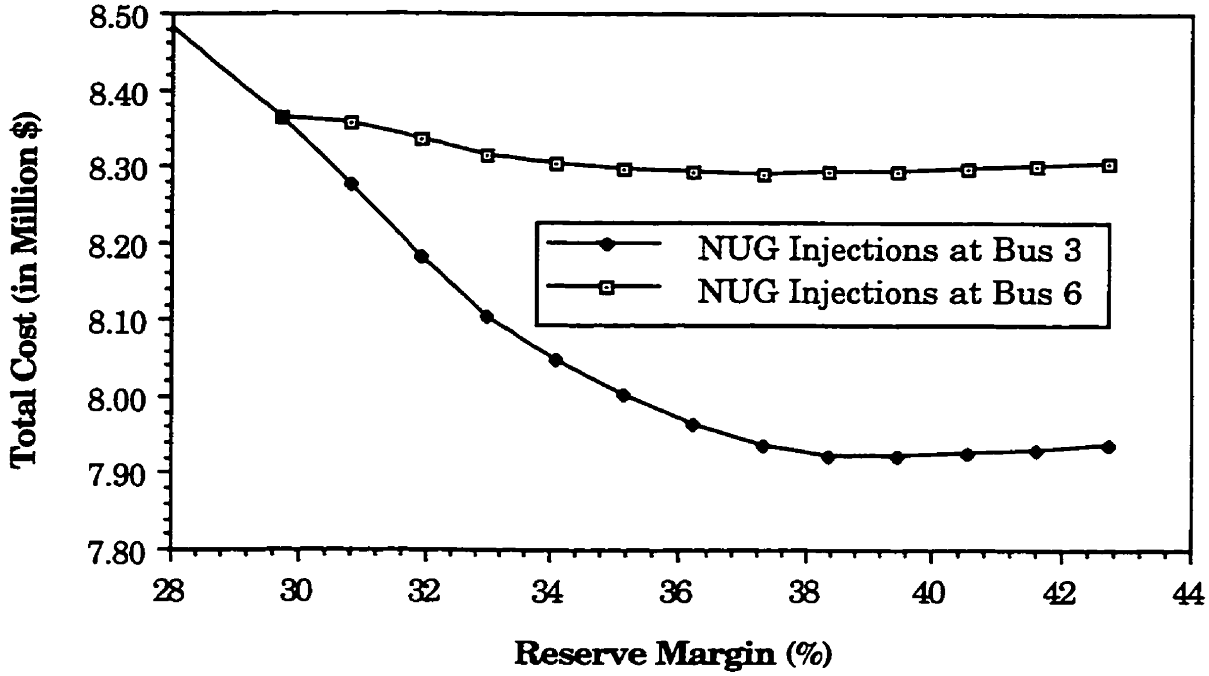

Figure 6.17: Variation of costs with planning reserve margin when 2-MW capacity NUG are injected at Buses 3 and 6 of the RBTS using LM11 (fixed cost of $4/KW).

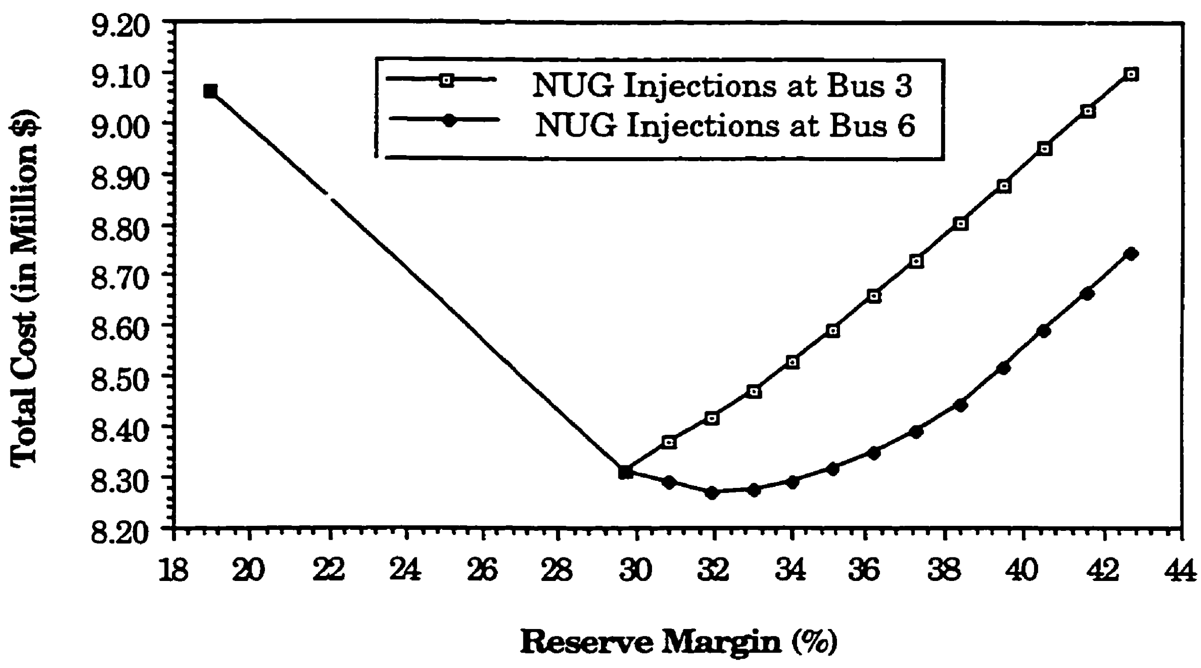

Figure 6.18: Variation of costs with planning reserve margin when 2-MW capacity NUG are injected at Buses 3 and 6 of the RBTS using the basic load model (fixed cost of $40/KW).

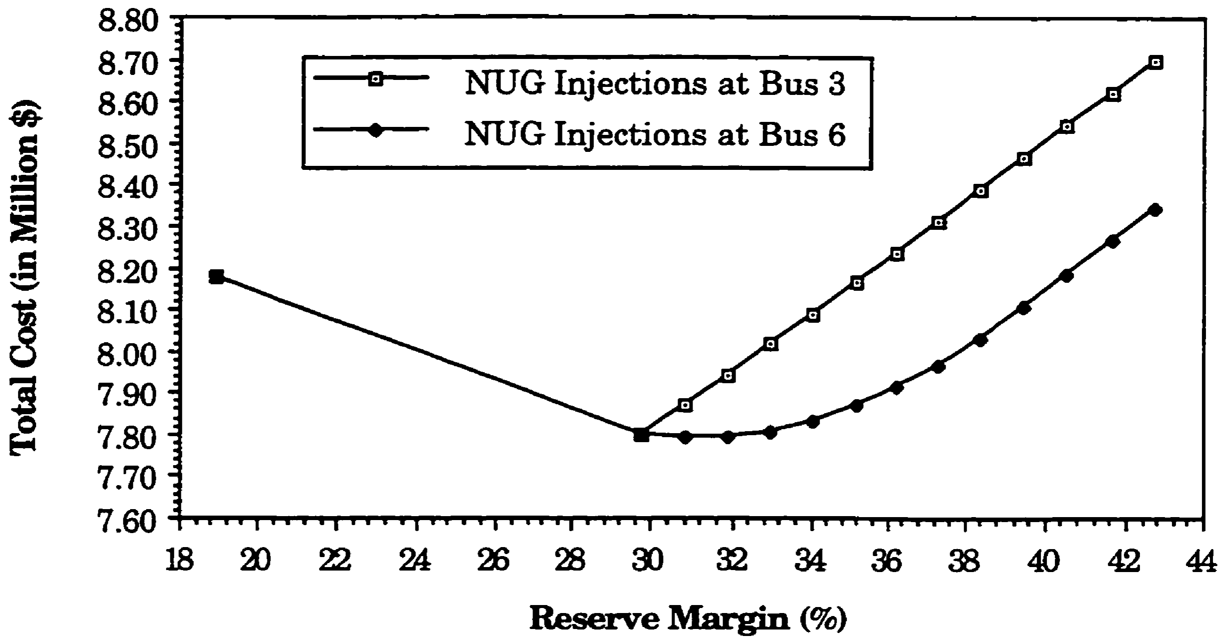

Figure 6.19: Variation of costs with planning reserve margin when 2-MW capacity NUG are injected at Buses 3 and 6 of the RBTS using LM10 (fixed cost of $40/KW).

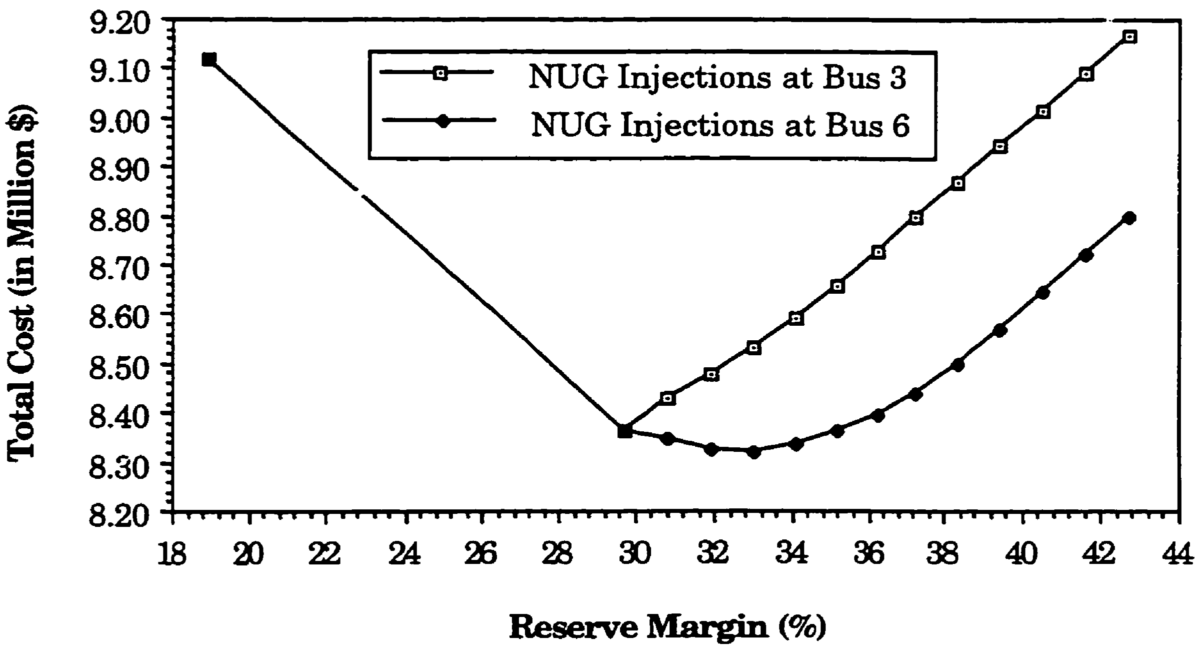

Figure 6.20: Variation of costs with planning reserve margin when 2-MW capacity NUG are injected at Buses 3 and 6 of the RBTS using LM11 (fixed cost of $40/KW).

located at Buses 3 and 6. The minimum total costs in this case, as can be seen from Tables G.11 to G.13 for the three load models, , are $8.2245 million and $7.8675 million (for the basic load model), $7.7992 million and $7.4540 million (for LM10), and $8.2913 million and $7.9216 million (for LM11) respectively. The corresponding PRMs are, 37.30% and 39.46% (for the basic load model), 31.89% and 38.38% (for LM10), and 37.30% and 38.38% (for LM11). Similarly, as the PRM increases, the total system costs decrease initially up to the minimum point and then increase rapidly using an investment cost of $40/KW for the NUG. The results presented in Tables G.14 - G.16 show total societal costs of $8.3087 million and $8.2712 million (for the basic load model), $7.8018 million and $7.7908 million (for LM10), and $8.3644 million and $8.3210 million (LM11) for Buses 3 and 6 respectively. The corresponding minimum-cost planning reserve margins are, 29.73% and 31.89% (for the basic load model), 29.73% and 31.89% (for LM10), and 29.73% and 32.97% (for LM11).

The results obtained for the total societal costs and the corresponding PRM vary widely depending on the different combinations of supply-side options and demand-side management initiatives. It can be observed from Figures 6.15 to 6.20 and Tables G.11 to G.16 that, the total system cost and its corresponding PRM also settle at different levels for the same total number of NUG injected into the system. In Figure 6.16 and Table G.12, the combined effect of NUG additions with a fixed cost of $4/KW and DSM initiatives from LM10 (i.e., peak shaving or clipping of all industrial loads) results in the reduction of both the total societal costs and the optimal PRM compared to the base case. At the same time, the total system costs from Table G.15 and Figure 6.19 are lower and the PRM values are the same as in the base case, when a fixed cost of $40/KW for the NUG is considered. It would, therefore, be beneficial to concurrently add extra units and also implement DSM options associated with LM10.

Figures 6.17 and 6.20 and Tables G.13 and G.16, show that LM11 and the introduction of NUG at Buses 3 and 6, creates an increase in the minimum total societal cost compared to that for the base case . This is expected as this load model deals with valley filling. The optimal PRM is the same for the base case and LM11 load models and NUG injections at Bus 3. The optimal PRM decreases for Bus 6 when a fixed cost of $4/KW for the NUG is considered, but increases when a fixed cost of $40/KW is used. The different NUG injections at Buses 3 & 6 and the DSM initiatives have a significant effect on the least total societal costs and the optimum planning reserve margin as can be seen from Tables G.11 through G.16. Both the addition of NUG at Bus 6 and the implementation of DSM lead to a lower total cost and at the same time permits the system to hold a higher planning reserve margin. The optimum reserve margin and the total societal costs at HLII are also dependent on the exact locations of the NUG facilities and the DSM initiatives used in the expansion and will vary with different proposed configurations.

The perceived power system planning problem is concerned with creating appropriate expansion plans that indicate what new generation in the form of non-utility generators or independent power producers are required and what demand-side programs should be implemented. This includes when and where to locate the additional capacity, and which customer types should be targeted for DSM program implementation. The purpose for the planning activity should be to select the most economical and reliable expansion plans to meet future power demands at minimum cost and maximum reliability over a period of time. The plans are subject to a multitude of technical, economic, environmental and political constraints. The electric power industry is capital intensive in nature, and therefore, it is important to have flexible decision strategies for adding the additional generation and the implementing of the DSM initiatives. The plans must be sufficiently flexible to recognize the uncertainties associated with capital investment by NUG and future load growth and customer reaction to DSM initiatives..

6.6. Summary

This chapter illustrates an approach to integrate both supply-side with demand-side considerations in adequacy assessment at HLII. The chapter also extends composite system analysis by illustrating how an optimum planning reserve margin, which maximizes the net societal benefits, may be determined for a composite generation and transmission system. One basic observation from these studies is that it is possible to consider the long range implementation of supply-side options and demand-side initiatives in an integrated resource plan. In the approach, the system is driven by the least cost economic criterion which is the sum of both system costs and customer interruption costs, rather than by a fixed reliability criterion.

The studies show that the implementation of supply-side facilities and demand-side initiatives can have considerable impact on the optimal planning reserve margin and also on the total societal costs of electricity. The cost of demand-side management has not been included in the total societal cost of electricity in the studies described in this chapter. This can only be assessed if specific DSM programs are utilized. It should be appreciated that, even if specific DSM programs are selected, the cost associated with these programs is quite uncertain. Demand-side management costs are determined from the DSM participation rates, the equipment costs, the marketing costs and the administration costs associated with implementing the program.

The analysis of the results presented in this thesis justifies the following preliminary conclusions namely,

(1) The selection of the "best" value for a given reliability criterion in integrated resource planning can be done using methods basically similar to those used for supply-side planning.

(2) It is unlikely that the specific numerical reliability criteria previously used for supply-side planning can be economically justified when integrated resource planning is conducted. Utilities may have to revise and adopt new reliability criteria for integrated resource planning.

(3) More complex reliability criteria , such as energy related indices, which permit consideration of the explicit worth of reliability are better adapted to the increased complexity of integrated resource planning than simple capacity-based reliability criteria such as loss of load expectation.

This thesis clearly illustrates how the energy based indices can be extended to include monetary considerations. This permits explicit consideration of the customer costs and an integral approach to the evaluation of both supply and demand side factors. These conclusions were reached following a wide range of system studies, some of which are presented in this thesis. These conclusions should be tested in the future under a much wider range of diverse conditions and also with different system configurations.

7. SUMMARY AND CONCLUSIONS

The research work described in this thesis is concerned with composite generation and transmission system adequacy and economic assessment. These analyses involve the evaluation of the adequacy of the combined generation and transmission facilities in regard to their ability to supply the required electrical energy to the major load points within a typical power system. Considerable attention is now being focused on incorporating the wide variety of conventional and non-conventional energy sources normally considered to be outside the domain of electric power utilities for needed additional generating capacity. Independent power producers (IPP) or non-utility generation (NUG) have become increasingly important due to environmental concerns, possible depletion of fuel supplies and government regulation. Addition of generating capacity is not the only means which can be employed to balance the supply and demand of electrical energy. It may be advantageous to better utilize the existing units by managing the load using demand-side management (DSM) initiatives. The goal of DSM is to make changes in the time pattern and the magnitude of the load seen by the utility. In order for a power utility to have a successful DSM program, it must have specific goals in terms of how it wants to modify the shape of the targeted customer sector load curves. Once these goals are in place, the utility can promote DSM initiatives to change the pattern of electricity consumption. The research work described in this thesis focuses on the adequacy and economic assessment of the impacts of NUG and DSM initiatives at the individual load buses within a typical power system. The main objective was to examine the ability of contingency enumeration techniques to incorporate the required factors in the analysis and to extend the general concepts associated with contingency enumeration to create methods which can be utilized to evaluate the benefits of incorporating NUG and DSM options separately or jointly in composite system adequacy assessment.

Chapter 1 provides a brief introduction to the overall area of power system reliability evaluation and some background information about non-utility generation and load or demand-side management.

A general description of an analytical technique and a computer program currently utilized for composite generation and transmission system adequacy assessment is presented in Chapter 2. The program which was developed at the University of Saskatchewan [35, 84-87], is designated as COMREL (COMposite system RELiability evaluation). The COMREL program is used as a computational tool in the quantitative analysis of composite system adequacy. The analysis procedure is outlined in Chapter 2 showing the various steps and how the different indices are computed and accumulated. The advantages and limitations of this analytical method are also stated. It is important to appreciate the theoretical aspects of the analytical approach utilized in COMREL. The program was subsequently modified as the research work progressed to incorporate the various new factors examined in the analyses. Two reliability test systems, the Roy Billinton Test System (RBTS) and the IEEE-Reliability Test System (IEEE-RTS), utilized for composite adequacy analysis in the research work presented in this thesis are also described in this chapter. The base case load point and overall system indices were computed for the RBTS and the IEEE-RTS using the COMREL program. The base case values serve as the datum for comparing the results of the subsequent studies described in this chapter, involving modified forms of the RBTS. The two sets of results obtained using the 4-step and 7-step load models show the RBTS to be relatively insensitive to the load duration curve. Further studies on the modified RBTS were conducted using only the 4-step load model. This chapter also presents a series of composite system adequacy studies on the RBTS involving different capacity NUG. The results show that the introduction of different NUG capacity streams at various single locations can have quite different impacts on both load point and overall system adequacy. These impacts are highly dependent on the topology of the composite generation and transmission system. Decisions regarding which particular NUG injection stream should be implemented will involve detailed economic analysis in addition to recognizing the different reliability implications and benefits. The studies presented in this chapter examine the impacts of different non-utility generation capacity sizes on individual load points and overall system adequacy. The inadequacy of an electric power system can be expressed by a wide range of indices. The basic index used in the analyses described in Chapter 2 is the expected energy not supplied (EENS). This index was selected as it provides the ability to extend the evaluation to include monetary considerations. This is covered in Chapter 3. The investigations show that NUG can serve as suitable alternatives to conventional power system reinforcement in the form of conventional utility generation [99-101]. Independent power production offers an excellent energy supply option, which can augment utility generating capacity expansion utilizing conventional sources, for meeting future system energy requirements. The overall reliability benefits vary with the different NUG considered and the locations at which this energy is injected into the electric power system [99-101].

Chapter 3 focuses on the economic evaluation of the reliability worth associated with non-utility generation additions in both the RBTS and the IEEE-RTS. The ability to conduct such an evaluation is an important consideration in modern electric power utility planning and system design. The chapter illustrates the utilization of reliability worth concepts in composite generation and transmission systems. The determination of reliability worth is a direct extension of quantitative reliability assessment and provides the opportunity to incorporate customer considerations in the planning and design of an electric power system. The initial part of this chapter presents a brief outline of the basic concepts employed in utilizing customer cost of interruption data to create interrupted energy assessment rates (IEAR) at HLII. The IEAR values can be used to link customer monetary losses to electric service reliability at each load point in a composite generation and transmission system. The studies described in this chapter illustrate that non-utility generation can serve as alternatives to conventional power system reinforcement in the form of utility generation and transmission facilities. The studies presented clearly illustrate that quantitative reliability assessment can be performed in systems containing NUG and that these assessments can be extended to include reliability worth evaluation. Depending on the relative locations for the NUG additions, the extra generation facilities can lead to a reduction, an increase or virtually no change in the load point and overall system customer monetary losses. The system transmission topology is an important factor in this regard and therefore each system should be analyzed prior to making any general observations. Most utilities use an implicit cost technique to incorporate reliability worth in their planning and decision making processes. The explicit cost technique in which investment costs, operating costs and expected customer outage costs are incorporated in the evaluation and in the selection of an optimum reliability target is illustrated by application to the RBTS and the IEEE-RTS. The implicit cost technique cannot be extended to NUG assessment at HLII, because very few, if any, electric power utilities have specified quantitative reliability indices for each load point in their composite generation and transmission system. The explicit cost approach, however, provides the opportunity to examine the total societal costs and the optimum reserve margin associated with small capacity NUG additions to a composite system. The results of the studies conducted using the RBTS and IEEE-RTS show that the addition of NUG facilities can have considerable cost-benefit impacts. The introduction of small capacity NUG streams at different single-bus locations resulted in different total system and optimum generation planning reserve margins at HLII.

Virtually all the published studies on composite system reliability evaluation assume that the overall system load shape is applicable to each system load bus. Individual bus loads, at any hour are normally assumed to be proportional to the ratio of the peak load at that bus to the peak load of the entire system. This is not correct as individual buses follow different load curves depending on the mix of customers at that bus. There is, therefore, a need for a more accurate representation and utilization of the individual bus loads. Chapter 4 describes the development of new load models for the various load buses in a composite generation and transmission system. Earlier composite system assessments and the studies described in Chapters

2 and 3 of this thesis used the same single load model or load duration curve for each load point obtained from the overall load data of the IEEE-RTS. This assumption does not recognize the diversity of bus load variations due to the different customer compositions at each bus. The need for developing time varying load curves at each load bus is discussed in this chapter. Seven customer sectors namely, agricultural, industrial, commercial, large users, residential, government and institutions, and office and buildings have been identified and the load characteristics of these customer sectors are presented. The procedure used to develop the hourly load curves with reference to the hypothetical test system is illustrated. The chronological hourly load curves developed for the RBTS were subsequently used in the adequacy and economic studies described in Chapters 4 through 6 of this thesis. The research work described in Chapter 4 shows that the reliability of composite systems with time varying loads at each bus can be effectively assessed using the contingency enumeration technique. The approach used in this analysis considered three seasons. This could be extended to more seasons over the year and will depend on the system under consideration. Increase in the number of seasons will create an increase in the required computation time and might require a reduction in the daily step model. The effects of representing chronological load models by multi-step load models for an period of one year are presented with reference to the RBTS. The study conducted shows that in this case only 10 steps were required to accurately model a given day. The 24 step model was, however, used in subsequent studies in this thesis. This is a possible area of future research. The complete range of load point and system indices described in Chapter 2 can be obtained using a representative set of daily models at each load point created by summing the individual customer sector contributions. The

objective of the research work described in Chapter 4 was to develop an approach by which variations in customer sector patterns created by load management incentives could be reflected in the individual bus load profiles and in the calculated reliability indices.

The basic concepts and tenets governing demand-side management are discussed and presented in Chapter 5. A methodology to quantify the impacts or effects of DSM programs on the different customer sector load models is also described in this chapter. The methodology was applied to selected customer types to generate some new time dependent load models that reflect possible load shape modifications due to DSM programs. This chapter presents a methodology to model the effects of DSM initiatives on individual customer sector load curves. The methodology is represented by two equations which are discrete functions of time. Equation (5.1) is used to simulate load shifting and peak clipping. Equation (5.4) is used to simulate valley filling, energy conservation and additional energy sales or strategic load growth. The selected parameters in the equations determine the load shape changes that result. Thirteen modified load curves were developed using these equations. The base case load shapes are the customer sector load models which combine to create the individual bus load models of the RBTS. It was noted that any customer sector load model could be used given that the model consists of 8736 data points representing the individual bus load curve for a 364-day year. The approach presented is completely general and can be applied to any system. It provides the opportunity for a utility to investigate a particular DSM strategy by modifying the appropriate customer load profile, creating a new bus load profile and then examining the effect in the overall system. The research work presented in this chapter illustrates a process to integrate the effects of demand-side management on adequacy assessment at HLII. The chapter also contains studies which were performed to ascertain the impacts of demand-side management programs on the expected outage costs and interrupted energy assessment rates for the individual load points and the entire system. These studies show that DSM initiatives can produce a wide range of changes in the load bus and total system expected outage costs. These changes are a complex function of the DSM initiatives, the customer load bus compositions, the topology and the operating practices of the system. There is, however, very little change in the IEAR values for the load points and for the system with the considered DSM initiatives. The IEAR are primarily a function of the actual customers located at specific load points within the system. This is considered to be an important point and extends the concept of using a basic set of IEAR values in a wide range of initial or exploratory studies.

The reliability cost/reliability worth approach to assessing an optimal level of customer service is based on evaluating the capital, operating and customer interruption costs associated with different system configurations. Recent emphasis on energy costs, in conservation of resources and impacts of government and environmental groups have resulted in the need for more adequate justification of new system facilities. Chapter 6 illustrates an approach to integrate both supply-side with demand-side considerations in adequacy assessment at HLII. The chapter also extends composite system analysis by illustrating how an optimum planning reserve margin, which maximizes the net societal benefits, may be determined for composite generation and transmission system. One basic observation from these studies is that, it is possible to consider the long range implementation of supply-side options and demand-side initiatives in an integrated resource plan. In the approach, the system is driven by the least cost economic criterion which is the sum of both system costs and customer interruption costs, rather than by a fixed reliability criterion. The studies show that, the implementation of supply-side facilities and demand-side initiatives can have considerable impact on the optimal planning reserve margin and also on the total societal costs of electricity. The cost of demand-side management has not been included in the total societal cost of electricity in the studies described in this chapter. This can only be assessed if specific DSM programs are utilized. It should be appreciated that, even if specific DSM programs are selected, the cost associated with these programs is quite uncertain. Demand-side management costs are determined from the DSM participation rates, the equipment costs, the marketing costs and the administration costs associated with implementing the program.

The analyses described in Chapter 6 resulted in the realization that the selection of the "best" value for a given reliability criterion in integrated resource planning can be done using methods basically similar to those used for supply-side planning. It was found that it is unlikely that the specific numerical reliability criteria previously used for supply-side planning can be economically justified when integrated resource planning is conducted. Utilities may have to revise and adopt new reliability criteria for integrated resource planning. More complex reliability criteria , such as energy related indices, which permit consideration of the explicit worth of reliability are better adapted to the increased complexity of integrated resource planning than simple capacity-based reliability criteria such as loss of load expectation. This thesis clearly illustrates how energy based indices can be extended to include monetary considerations. This extension permits explicit consideration of the customer costs and an integrated approach to the evaluation of both supply and demand side factors. These conclusions were reached following a wide range of system studies, some of which are presented in this thesis. These conclusions should be tested in the future under a much wider range of diverse conditions and also with different system configurations.

Reliability cost and reliability worth considerations are playing an ever increasing role in power system planning and operation. The theoretical composite system evaluation techniques developed in this research work have been applied to the determination of the total societal costs associated NUG and DSM options in a composite generation and transmission system. The results of the studies conducted show that NUG facilities and DSM programs can have considerable reliability and economic impacts on utility systems. The energy related indices such as the expected energy not supplied index is the most responsive index for measuring these impacts. This index was used as a basis in evaluating the reliability costs and worth associated with NUG and DSM alternatives. This thesis examines the effects of NUG and DSM or IRP options on power system adequacy and costs and shows that these resources have considerable potential in the difficult problem of meeting future electrical energy demand at an acceptable level of reliability.

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A. DATA OF THE ROY BILLINTON TEST SYSTEM

Table A.1: Generator Data

Unit Number	Bus Number	Rating (MW)	Failure Rate per year	Repair Time (Hrs)
1	1	40.0	6.00	45.0
2	1	40.0	6.00	45.0
3	1	10.0	4.00	45.0
4	1	20.0	5.00	45.0
5	2	5.0	2.00	45.0
6	2	5.0	2.00	45.0
7	2	40.0	3.00	60.0
8	2	20.0	2.40	55.0
9	2	20.0	2.40	55.0
10	2	20.0	2.40	55.0
11	2	20.0	2.40	55.0

Table A.2: Bus Data

Bus No.	Active Load (p.u.)	Reactive Load (p.u.)	P_g (p.u.)	Q_{max} (p.u.)	Q_{min} (p.u.)	V_0 (p.u.)	V_{max} (p.u.)	V_{min} (p.u.)
1	0.00	0.00	1.00	0.50	-0.40	1.05	1.05	0.97
2	0.20	0.00	1.20	0.75	-0.40	1.05	1.05	0.97
3	0.85	0.00	0.00	0.00	0.00	1.00	1.05	0.97
4	0.40	0.00	0.00	0.00	0.00	1.00	1.05	0.97
5	0.20	0.00	0.00	0.00	0.00	1.00	1.05	0.97
6	0.20	0.00	0.00	0.00	0.00	1.00	1.05	0.97

Table A.3: Line Data

Line No.	Bus No. (From)	Bus No. (To)	R	X	Current Rating (p.u)	Failures per year	Repair Time (Hrs)
1	1	3	0.0342	0.18	0.85	1.50	10.00
2	2	4	0.1140	0.60	0.71	5.00	10.00
3	1	2	0.0912	0.48	0.71	4.00	10.00
4	3	4	0.0228	0.12	0.71	1.00	10.00
5	3	5	0.0228	0.12	0.71	1.00	10.00
6	1	3	0.0342	0.18	0.85	1.50	10.00
7	2	4	0.1140	0.60	0.71	5.00	10.00
8	4	5	0.0228	0.12	0.71	1.00	10.00
9	5	6	0.0228	0.12	0.71	1.00	10.00

B. DATA OF THE IEEE - RELIABILITY TEST SYSTEM

Table B.1: Generator Data

Unit Number	Bus Number	Rating (MW)	Failures per year	Repair time (Hrs)
1	22	50.00	4.42	20.00
2	22	50.00	4.42	20.00
3	22	50.00	4.42	20.00
4	22	50.00	4.42	20.00
5	22	50.00	4.42	20.00
6	22	50.00	4.42	20.00
7	15	12.00	2.98	60.00
8	15	12.00	2.98	60.00
9	15	12.00	2.98	60.00
10	15	12.00	2.98	60.00
11	15	12.00	2.98	60.00
12	15	155.00	9.13	40.00
13	7	100.00	7.30	50.00
14	7	100.00	7.30	50.00
15	7	100.00	7.30	50.00
16	13	197.00	9.22	50.00
17	13	197.00	9.22	50.00
18	13	197.00	9.22	50.00
19	1	20.00	19.47	50.00
20	1	20.00	19.47	50.00
21	1	76.00	4.47	40.00
22	1	76.00	4.47	40.00
23	2	20.00	19.47	50.00
24	2	20.00	19.47	50.00
25	2	76.00	4.47	40.00
26	2	76.00	4.47	40.00
27	23	155.00	9.13	40.00
28	23	155.00	9.13	40.00
29	23	350.00	7.62	100.00
30	18	400.00	7.96	150.00
31	21	400.00	7.96	150.00
32	16	155.00	9.13	40.00

Table B.2: Bus Data

Bus No.	Active Load (p.u)	Reactive Load (p.u)	P_g (p.u.)	Q_{max} (p.u.)	Q_{min} (p.u.)	V_0 (p.u.)	V_{max} (p.u.)	V_{min} (p.u.)
1	1.080	0.220	1.720	1.20	-0.75	1.00	1.05	0.95
2	0.970	0.200	1.720	1.20	-0.75	1.00	1.05	0.95
3	1.800	0.370	0.000	0.00	0.00	1.00	1.05	0.95
4	0.740	0.150	0.000	0.00	0.00	1.00	1.05	0.95
5	0.710	0.140	0.000	0.00	0.00	1.00	1.05	0.95
6	1.360	0.280	0.000	0.00	0.00	1.00	1.05	0.95
7	1.250	0.250	3.000	2.70	0.00	1.00	1.05	0.95
8	1.710	0.350	0.000	0.00	0.00	1.00	1.05	0.95
9	1.750	0.360	0.000	0.00	0.00	1.00	1.05	0.95
10	1.950	0.400	0.000	0.00	0.00	1.00	1.05	0.95
11	0.000	0.000	0.000	0.00	0.00	1.00	1.05	0.95
12	0.000	0.000	0.000	0.00	0.00	1.00	1.05	0.95
13	2.650	0.540	5.500	3.60	0.00	1.00	1.05	0.95
14	1.940	0.390	0.000	3.00	-0.75	1.00	1.05	0.95
15	3.170	0.640	2.100	1.65	-0.75	1.00	1.05	0.95
16	1.000	0.200	1.450	1.20	-0.75	1.00	1.05	0.95
17	0.000	0.000	0.000	0.00	0.00	1.00	1.05	0.95
18	3.330	0.680	4.000	3.00	-0.75	1.00	1.05	0.95
19	1.810	0.370	0.000	0.00	0.00	1.00	1.05	0.95
20	1.280	0.260	0.000	0.00	0.00	1.00	1.05	0.95
21	0.000	0.000	3.500	3.00	-0.75	1.00	1.05	0.95
22	0.000	0.000	2.500	1.45	-0.90	1.00	1.05	0.95
23	0.000	0.000	6.600	4.50	-1.75	1.00	1.05	0.95
24	0.000	0.000	0.000	0.00	0.00	1.00	1.05	0.95

Table B.3: Line Data

Line No.	Bus No. (From)	Bus No. (To)	R	X	Current Rating (p.u)	Failures per year	Repair Time (Hrs)
1	1	2	0.0260	0.0139	1.93	0.240	16.0
2	1	3	0.0546	0.2112	2.08	0.510	10.0
3	1	5	0.0218	0.0845	2.08	0.330	10.0
4	2	4	0.0328	0.1267	2.08	0.390	10.0
5	2	6	0.0497	0.1920	2.08	0.390	10.0
6	3	9	0.0308	0.1190	2.08	0.480	10.0
7	3	24	0.0023	0.0839	5.10	0.020	768.0
8	4	9	0.0268	0.1037	2.08	0.360	10.0
9	5	10	0.0228	0.0883	2.08	0.340	10.0
10	6	10	0.0139	0.0605	1.93	0.330	35.0
11	7	8	0.0159	0.0614	2.08	0.300	10.0
12	8	9	0.0427	0.1651	2.08	0.440	10.0
13	8	10	0.0427	0.1651	2.08	0.440	10.0
14	9	11	0.0023	0.0839	6.00	0.020	768.0
15	9	12	0.0023	0.0839	6.00	0.020	768.0
16	10	11	0.0023	0.0839	6.00	0.020	768.0
17	10	12	0.0023	0.0839	6.00	0.020	768.0
18	11	13	0.0061	0.0476	6.00	0.020	768.0
19	11	14	0.0054	0.0418	6.00	0.390	11.0
20	12	13	0.0061	0.0476	6.00	0.400	11.0
21	12	23	0.0124	0.0966	6.00	0.520	11.0
22	13	23	0.0111	0.0865	6.00	0.490	11.0
23	14	16	0.0050	0.0389	6.00	0.380	11.0
24	15	16	0.0022	0.0173	6.00	0.330	11.0
25	15	21	0.0063	0.0490	6.00	0.410	11.0
26	15	21	0.0063	0.0490	6.00	0.410	11.0
27	15	24	0.0067	0.0519	6.00	0.410	11.0
28	16	17	0.0033	0.0259	6.00	0.350	11.0
29	16	19	0.0030	0.0231	6.00	0.340	11.0
30	17	18	0.0018	0.0144	6.00	0.320	11.0
31	17	22	0.0135	0.1053	6.00	0.540	11.0
32	18	21	0.0033	0.0259	6.00	0.350	11.0
33	18	21	0.0033	0.0259	6.00	0.350	11.0
34	19	20	0.0051	0.0396	6.00	0.380	11.0
35	19	20	0.0051	0.0396	6.00	0.380	11.0
36	20	23	0.0028	0.0216	6.00	0.340	11.0
37	20	23	0.0028	0.0216	6.00	0.340	11.0
38	21	22	0.0087	0.0678	6.00	0.450	11.0

C: LOAD DATA

Table C.1: 100 points load data

study period [p.u.]	peak load [p.u.]	study period [p.u.]	peak load [p.u.]	study period [p.u.]	peak load [p.u.]	study period [p.u.]	peak load [p.u.]
0	1	0.0002	0.9933	0.0003	0.9866	0.0004	0.98
0.0006	0.9733	0.0008	0.9666	0.001	0.9599	0.0015	0.9532
0.0024	0.9466	0.0034	0.9399	0.004	0.9332	0.0058	0.9265
0.0076	0.9199	0.0081	0.9132	0.01	0.9065	0.0137	0.8998
0.016	0.8931	0.0189	0.8865	0.0239	0.8798	0.029	0.8731
0.0333	0.8664	0.0401	0.8597	0.0464	0.8531	0.0517	0.8464
0.0614	0.8397	0.0718	0.833	0.0823	0.8264	0.0906	0.8197
0.1004	0.813	0.1122	0.8063	0.1254	0.7996	0.1353	0.796
0.1452	0.7863	0.1574	0.7796	0.1704	0.7729	0.1823	0.7662
0.1918	0.7596	0.2005	0.7529	0.2114	0.7462	0.2232	0.7395
0.2339	0.7329	0.2436	0.7262	0.2561	0.7195	0.267	0.7128
0.2773	0.7061	0.2909	0.6995	0.303	0.6928	0.3163	0.6861
0.33	0.6794	0.3448	0.6727	0.3616	0.6661	0.3769	0.6594
0.3934	0.6527	0.4094	0.646	0.426	0.6394	0.442	0.6327
0.4591	0.626	0.4771	0.6193	0.4932	0.6126	0.5089	0.606
0.5242	0.5993	0.539	0.5926	0.5501	0.5859	0.5625	0.5792
0.5742	0.5726	0.5869	0.5659	0.5992	0.5592	0.6134	0.5525
0.6265	0.5459	0.6415	0.5392	0.6544	0.5325	0.6706	0.5259
0.6881	0.5191	0.7043	0.5125	0.7218	0.5058	0.741	0.4991
0.7603	0.4924	0.781	0.4857	0.7992	0.4791	0.8158	0.4724
0.8302	0.4657	0.8473	0.459	0.8599	0.4523	0.8758	0.4457
0.888	0.439	0.9029	0.4323	0.9159	0.4256	0.9293	0.419
0.942	0.4123	0.9549	0.4056	0.9647	0.3989	0.9721	0.3922
0.9783	0.3856	0.9827	0.3789	0.9867	0.3722	0.9905	0.3655
0.9949	0.3588	0.9977	0.3522	0.9991	0.3455	1	0.3388

D. TIME VARYING LOAD MODEL DATA

Table D.1 gives the percentage allocation of the sector peak for all the 52 weeks (1 - 52) in the residential sector.

Table D.1: Weekly residential sector allocation

Week Number	Percentage Allocation	Week Number	Percentage Allocation
1	0.922	27	0.815
2	0.960	28	0.876
3	0.938	29	0.861
4	0.894	30	0.940
5	0.940	31	0.782
6	0.901	32	0.836
7	0.892	33	0.860
8	0.866	34	0.789
9	0.800	35	0.786
10	0.797	36	0.765
11	0.775	37	0.840
12	0.787	38	0.755
13	0.764	39	0.784
14	0.810	40	0.784
15	0.781	41	0.803
16	0.860	42	0.804
17	0.814	43	0.860
18	0.897	44	0.941
19	0.930	45	0.945
20	0.940	46	0.969
21	0.916	47	1.000
22	0.871	48	0.950
23	0.960	49	0.975
24	0.947	50	0.970
25	0.956	51	0.980
26	0.921	52	0.990

Table D.2: Hourly percentage of the sector peak load for all sectors

Hour #	Res. Avg. Day	Res. Peak Winter	Res. Peak Summer	Avg. Com.	Peak Com.	Industrial
1	0.5500	0.6000	0.7000	0.0100	0.0100	0.1037
2	0.5000	0.5500	0.6500	0.0100	0.0100	0.1037
3	0.4300	0.4550	0.6000	0.0100	0.0100	0.1037
4	0.3700	0.4000	0.5500	0.0100	0.0100	0.1037
5	0.3600	0.4000	0.5500	0.0100	0.0100	0.1037
6	0.3800	0.3950	0.5100	0.0300	0.0300	0.1037
7	0.3850	0.4000	0.5000	0.0400	0.0400	0.1037
8	0.4250	0.4500	0.5400	0.2500	0.3500	1.0000
9	0.4500	0.5500	0.6000	0.8500	0.8500	1.0000
10	0.5500	0.6500	0.6500	0.9000	0.9000	1.0000
11	0.6000	0.7000	0.7000	0.9100	0.9000	1.0000
12	0.7000	0.8000	0.8000	0.9200	1.0000	1.0000
13	0.7000	0.8000	0.8000	0.9850	0.9850	1.0000
14	0.7500	0.8500	0.8500	0.9750	0.9750	1.0000
15	0.7500	0.8500	0.8500	0.8800	0.8500	1.0000
16	0.7500	0.8500	0.8500	0.8650	0.8650	1.0000
17	0.8000	0.9000	0.9000	0.8900	0.8500	1.0000
18	0.8500	0.9500	0.9500	0.9000	1.0000	1.0000
19	0.8500	0.9500	0.9500	0.9000	1.0000	1.0000
20	0.8600	1.0000	1.0000	0.6400	0.9500	0.5000
21	0.8600	1.0000	1.0000	0.6000	0.8500	0.5000
22	0.8000	0.9000	0.9000	0.4200	0.7500	0.5000
23	0.7500	0.8500	0.8500	0.4000	0.3000	0.5000
24	0.650	0.7500	0.7500	0.0250	0.0200	0.5000

Legend:

Res. Avg. Day = *Average (fall / spring season) day for residential sector*

Res. Peak Summer = *Peak Summer day for residential sector*

Res. Peak Winter = *Peak Winter day for residential sector*

Avg. Com. = *Average (fall / spring) day for commercial sector*

Peak Com. = *Peak (summer & winter) day for commercial sector*

Table D.3: Hourly percentage of the sector peak load for all sectors

Hour #	Large Users	Govt. & Inst.	Peak Office & Bldg.	Avg. Office & Bldg.	Avg. Agri.	Peak Agri.
1	0.337	0.400	0.590	0.270	0.001	0.010
2	0.337	0.400	0.590	0.410	0.001	0.010
3	0.337	0.400	0.450	0.350	0.001	0.010
4	0.337	0.400	0.420	0.400	0.001	0.010
5	0.337	0.400	0.390	0.400	0.001	0.010
6	0.337	0.600	0.410	0.300	0.001	0.010
7	1.000	0.700	0.750	0.550	0.020	0.100
8	1.000	0.750	0.770	0.650	0.100	0.200
9	1.000	0.800	0.850	0.850	0.400	0.600
10	1.000	0.850	0.840	0.800	0.600	0.700
11	1.000	0.900	1.000	1.000	0.650	0.750
12	1.000	0.920	1.000	1.000	0.670	0.800
13	1.000	0.930	1.000	0.985	0.650	0.770
14	1.000	0.960	1.000	0.975	0.680	0.850
15	1.000	0.970	0.985	0.850	0.690	1.000
16	1.000	0.970	0.975	0.865	0.760	0.970
17	1.000	1.000	0.970	0.850	0.810	0.950
18	1.000	0.980	0.965	0.900	0.700	0.920
19	1.000	0.800	0.950	0.900	0.500	0.900
20	1.000	0.750	0.950	0.680	0.350	0.750
21	1.000	0.650	0.940	0.640	0.300	0.550
22	1.000	0.500	0.920	0.420	0.005	0.100
23	1.000	0.430	0.720	0.400	0.004	0.020
24	1.000	0.120	0.520	0.025	0.003	0.010

Legend:

Govt. & Inst. = *Government & Institutions for all seasons*

Peak Office & Bldg. = *Peak (summer & winter) day for Office & Buildings sector*

Avg. Office & Bldg. = *Average (fall / spring) day for Office & Buildings sector*

Avg. Agri. = *Average (summer & winter) day for Agricultural sector*

Peak Agri. = *Peak (fall / spring) day for Agricultural sector*

Table D.4: Daily percentage of the sector peak load

Day	Residential	Government & Inst.	Office & Bldg.
Monday	0.96	1.00	1.00
Tuesday	1.00	1.00	1.00
Wednesday	0.98	1.00	1.00
Thursday	0.96	1.00	1.00
Friday	0.97	1.00	1.00
Saturday	0.83	0.40	0.50
Sunday	0.81	0.30	0.40

Table D.5: Daily percentage of the sector peak load

Day	Industrial	Large User	Agricultural	Commercial
Monday	1.00	1.00	1.00	1.00
Tuesday	1.00	1.00	1.00	1.00
Wednesday	1.00	1.00	1.00	1.00
Thursday	1.00	1.00	1.00	1.00
Friday	1.00	1.00	1.00	1.00
Saturday	1.00	1.00	1.00	1.00
Sunday	1.00	1.00	1.00	1.00

D.1. Calculation of Sector Load Factors

$$\text{Sector load factor} = \frac{\sum_{k=1}^{3}\left((\sum_{i=1}^{24} x_i)\times(\sum_{i=1}^{\text{no. of weeks in k}} w_i)\times(\sum_{i=1}^{7} d_i)\right)}{364\times 24}$$

where:
k = season type (k=1 refers to fall/spring, k=2 refers to winter and k=3 refers to summer),
$\sum_{i=1}^{24} x_i$ = summation of hourly per unit values from Tables D.2 and D.3,

w_i = weekly allocation (Table D.1 for residential sector),
d_i = daily allocation from Tables D.4 and D.5.

1. Residential sector load factor =
$$\frac{((15.07\times 17.636\times 6.51)+(17\times 16.033\times 6.51)+(18\times 11.83\times 6.51))}{364\times 24} = 0.5598$$

2. Commercial sector load factor =
$$\frac{((12.43\times 22\times 7)+(13.515\times 17\times 7)+(13.515\times 13\times 7))}{364\times 24} = 0.5440$$

3. Industrial sector load factor =
$$\frac{((15.2259\times 22\times 7)+(15.2259\times 17\times 7)+(15.2259\times 13\times 7))}{364\times 24} = 0.6344$$

4. Government & Institutions sector load factor =
$$\frac{((16.58\times 22\times 5.7)+(16.58\times 17\times 5.7)+(16.58\times 13\times 5.7))}{364\times 24} = 0.5625$$

5. Office & Buildings sector load factor =
$$\frac{((15.47\times 22\times 5.9)+(18.955\times 17\times 5.9)+(18.955\times 13\times 5.9))}{364\times 24} = 0.6139$$

6. Agricultural sector load factor =
$$\frac{((11\times 22\times 7)+(7.898\times 17\times 7)+(7.898\times 13\times 7))}{364\times 24} = 0.3838$$

7. Large Users sector load factor =
$$\frac{((20.022\times 22\times 7)+(20.022\times 17\times 7)+(20.022\times 13\times 7))}{364\times 24} = 0.8343$$

Table D.6 describes the sector average loads for the RBTS obtained using the above sector load factors and the sector peak loads.

Table D.6: Sector average load value in MW at each load bus of the RBTS

User Sector	Bus 2	Bus 3	Bus 4	Bus 5	Bus 6	System
Large users		46.30				46.30
Industrial	2.22	1.93	10.34		1.93	16.42
Commercial	2.04	2.56	2.56	2.01	0.92	10.09
Agricultural					2.84	2.84
Residential	4.06	11.14	10.64	4.98	4.39	35.21
Govt. & Inst.	3.09			3.12		6.21
Office & Bldg.		1.14		1.14		2.28
TOTAL	11.41	63.07	23.54	11.25	10.08	119.35

E. ADDITIONAL RESULTS FROM CHAPTER THREE

Table E.1: Variation of costs with planning reserve margin when 2-MW capacity NUG, using an investment cost of $4.00/KW, are injected at Buses 1, 2 and 3 of the basic RBTS.

Resrve Margin (%)	Investment Cost (Million $)	System Cost (Million $)	Total Cost (Million $)		
			Bus 1	Bus 2	Bus 3
18.92	3.1350	6.3557	8.0755	8.0755	8.0755
29.73	3.1850	6.4057	7.1814	7.1814	7.1814
30.81	3.1930	6.4139	7.1619	7.1656	7.1727
31.89	3.2010	6.4219	7.1405	7.1476	7.1518
32.97	3.2090	6.4300	7.1194	7.1299	7.1304
34.05	3.2170	6.4381	7.0984	7.1117	7.1086
35.14	3.2250	6.4461	7.0781	7.0942	7.0871
36.22	3.2330	6.4542	7.0702	7.0862	7.0767
37.30	3.2410	6.4622	7.0708	7.0872	7.0753
38.38	3.2490	6.4702	7.0732	7.0920	7.0771
39.46	3.2570	6.4782	7.0760	7.0982	7.0797
40.54	3.2650	6.4862	7.0789	7.1044	7.0824

Table E.2: Variation of costs with planning reserve margin when 2-MW capacity NUG, using an investment cost of $4.00/KW, are injected at Buses 4, 5 and 6 of the basic RBTS.

Resrve Margin (%)	Investment Cost (Million $)	System Cost (Million $)	Total Cost (Million $)		
			Bus 4	Bus 5	Bus 6
18.92	3.1350	6.3557	8.0755	8.0755	8.0755
29.73	3.1850	6.4057	7.1814	7.1814	7.1814
30.81	3.1930	6.4139	7.1742	7.1753	7.0987
31.89	3.2010	6.4219	7.1511	7.1610	7.0036
32.97	3.2090	6.4300	7.1302	7.1385	6.9103
34.05	3.2170	6.4381	7.1087	7.1163	6.8170
35.14	3.2250	6.4461	7.0873	7.0939	6.7247
36.22	3.2330	6.4542	7.0762	7.0788	6.6454
37.30	3.2410	6.4622	7.0749	7.0754	6.5749
38.38	3.2490	6.4702	7.0772	7.0765	6.5504
39.46	3.2570	6.4782	7.0799	7.0786	6.5424
40.54	3.2650	6.4862	7.0830	7.0812	6.5431

Table E.3: Variation of costs with planning reserve margin when 5-MW capacity NUG, using an investment cost of $4.00/KW, are injected at Buses 1, 2 and 3 of the basic RBTS.

Resrve Margin (%)	Investment Cost (Million $)	System Cost (Million $)	Total Cost (Million $)		
			Bus 1	Bus 2	Bus 3
18.92	3.1350	6.3557	8.0755	8.0755	8.0755
29.73	3.1850	6.4057	7.1814	7.1814	7.1814
32.97	3.2050	6.4259	7.1309	7.1392	7.1400
35.14	3.2250	6.4461	7.0801	7.0958	7.0872
37.84	3.2450	6.4662	7.0755	7.0933	7.0791
40.54	3.2650	6.4862	7.0834	7.0994	7.0858
43.24	3.2850	6.5063	7.0930	7.1107	7.0949
45.95	3.3050	6.5263	7.1031	7.1200	7.1047
48.65	3.3250	6.5463	7.1195	7.1361	7.1208

Table E.4: Variation of costs with planning reserve margin when 5-MW capacity NUG, using an investment cost of $4.00/KW, are injected at Buses 4, 5 and 6 of the basic RBTS.

Resrve Margin (%)	Investment Cost (Million $)	System Cost (Million $)	Total Cost (Million $)		
			Bus 4	Bus 5	Bus 6
18.92	3.1350	6.3557	8.0755	8.0755	8.0755
29.73	3.1850	6.4057	7.1814	7.1814	7.1814
32.97	3.2050	6.4259	7.1417	7.1514	6.9587
35.14	3.2250	6.4461	7.0880	7.0949	6.7256
37.84	3.2450	6.4662	7.0790	7.0795	6.5665
40.54	3.2650	6.4862	7.0868	7.0853	6.5460
43.24	3.2850	6.5063	7.0973	7.0952	6.5544
45.95	3.3050	6.5263	7.1095	7.1055	6.5658
48.65	3.3250	6.5463	7.1284	7.1223	6.5840

Table E.5: Variation of costs with planning reserve margin when 2-MW capacity NUG, using an investment cost of $40.00/KW, are injected at Buses 1, 2 and 3 of the basic RBTS.

Resrve Margin (%)	Investment Cost (Million $)	System Cost (Million $)	Total Cost (Million $)		
			Bus 1	Bus 2	Bus 3
18.92	3.1350	6.3557	8.0755	8.0755	8.0755
29.73	3.1850	6.4057	7.1814	7.1814	7.1814
30.81	3.2650	6.4859	7.2339	7.2376	7.2447
31.89	3.3450	6.5659	7.2845	7.2916	7.2958
32.97	3.4250	6.6460	7.3354	7.3459	7.3464
34.05	3.5050	6.7261	7.3864	7.3997	7.3966
35.14	3.5850	6.8061	7.4381	7.4542	7.4471
36.22	3.6650	6.8862	7.5022	7.5182	7.5087
37.30	3.7450	6.9662	7.5748	7.5912	7.5793
38.38	3.8250	7.0462	7.6492	7.6680	7.6531
39.46	3.9050	7.1262	7.7240	7.7462	7.7277
40.54	3.9850	7.2062	7.7989	7.8244	7.8024

Table E.6: Variation of costs with planning reserve margin when 2-MW capacity NUG, using an investment cost of $40.00/KW, are injected at Buses 4, 5 and 6 of the basic RBTS.

Resrve Margin (%)	Investment Cost (Million $)	System Cost (Million $)	Total Cost (Million $)		
			Bus 4	Bus 5	Bus 6
18.92	3.1350	6.3557	8.0755	8.0755	8.0755
29.73	3.1850	6.4057	7.1814	7.1814	7.1814
30.81	3.2650	6.4859	7.2462	7.2573	7.1707
31.89	3.3450	6.5659	7.2951	7.3050	7.1476
32.97	3.4250	6.6460	7.3462	7.3545	7.1263
34.05	3.5050	6.7261	7.3967	7.4043	7.1050
35.14	3.5850	6.8061	7.4473	7.4539	7.0847
36.22	3.6650	6.8862	7.5082	7.5108	7.0774
37.30	3.7450	6.9662	7.5789	7.5794	7.0789
38.38	3.8250	7.0462	7.6532	7.6525	7.1264
39.46	3.9050	7.1262	7.7279	7.7266	7.1904
40.54	3.9850	7.2062	7.8030	7.8012	7.2631

Table E.7: Variation of costs with planning reserve margin when 5-MW capacity NUG, using an investment cost of $40.00/KW, are injected at Buses 1, 2 and 3 of the basic RBTS.

Resrve Margin (%)	Investment Cost (Million $)	System Cost (Million $)	Total Cost (Million $)		
			Bus 1	Bus 2	Bus 3
18.92	3.1350	6.3557	8.0755	8.0755	8.0755
29.73	3.1850	6.4057	7.1814	7.1814	7.1814
32.97	3.3850	6.6060	7.3110	7.3193	7.3201
35.14	3.5850	6.8061	7.4401	7.4558	7.4472
37.84	3.7850	7.0062	7.6155	7.6333	7.6191
40.54	3.9850	7.2062	7.8034	7.8194	7.8058
43.24	4.1850	7.4063	7.9930	8.0107	7.9949
45.95	4.3850	7.6063	8.1831	8.2000	8.1847
48.65	4.5850	7.8063	8.3795	8.3961	8.3808

Table E.8: Variation of costs with planning reserve margin when 5-MW capacity NUG, using an investment cost of $40.00/KW, are injected at Buses 4, 5 and 6 of the basic RBTS.

Resrve Margin (%)	Investment Cost (Million $)	System Cost (Million $)	Total Cost (Million $)		
			Bus 4	Bus 5	Bus 6
18.92	3.1350	6.3557	8.0755	8.0755	8.0755
29.73	3.1850	6.4057	7.1814	7.1814	7.1814
32.97	3.3850	6.6060	7.3218	7.3315	7.1388
35.14	3.5850	6.8061	7.4480	7.4549	7.0856
37.84	3.7850	7.0062	7.6190	7.6195	7.1065
40.54	3.9850	7.2062	7.8068	7.8053	7.2660
43.24	4.1850	7.4063	7.9973	7.9952	7.4544
45.95	4.3850	7.6063	8.1895	8.1855	7.6458
48.65	4.5850	7.8063	8.3884	8.3823	7.8440

Table E.9: Variation of costs with planning reserve margin when 10-MW capacity NUG with forced outage rate of 2%, using an investment cost of $4.00/KW, are injected at Buses 1 and 8 of the basic IEEE-RTS.

Resrve Margin (%)	Investment Cost (Million $)	System Cost (Million $)	Total Cost (Million $)	
			Bus 1	Bus 8
19.47	20.0500	254.8863	262.5844	262.5844
19.82	20.0900	254.9314	261.9780	261.9584
20.18	20.1300	254.9762	261.3793	261.3537
20.53	20.1700	255.0206	260.8390	260.7958
20.88	20.2100	255.0646	260.3760	260.3224
21.23	20.2500	255.1084	260.0090	259.8707
21.58	20.2900	255.1518	259.7540	259.5992
21.93	20.3300	255.1951	259.4047	259.3132
22.28	20.3700	255.2381	259.1008	259.0011
22.63	20.4100	255.2809	258.8352	258.7395
22.98	20.4500	255.3235	258.5969	258.4909
23.33	20.4900	255.3659	258.3950	258.2846
23.68	20.5300	255.4081	258.2233	258.1173
24.04	20.5700	255.4503	258.0606	257.9479
24.39	20.6100	255.4921	257.9411	257.8216
24.74	20.6500	255.5338	257.9490	258.0134
25.09	20.6900	255.5754	257.8724	258.1856
25.44	20.7300	255.6169	257.8034	258.2855
25.79	20.7700	255.6582	257.7540	258.4028
26.14	20.8100	255.6994	257.7232	258.5448
26.49	20.8500	255.7405	257.7015	258.6922
26.84	20.8900	255.7817	257.7042	258.8575
27.19	20.9300	255.8227	257.7995	259.0241
27.54	20.9700	255.8634	257.9066	259.2222
27.89	21.0100	255.9043	258.1586	259.4335
28.25	21.0500	255.9451	258.3394	259.7022

Table E.10: Variation of costs with planning reserve margin when 10-MW capacity NUG with forced outage rate of 2%, using an investment cost of $4.00/KW, are injected at Buses 13 and 18 of the basic IEEE-RTS.

Resrve Margin (%)	Investment Cost (Million $)	System Cost (Million $)	Total Cost (Million $)	
			Bus 13	Bus 18
19.47	20.0500	254.8863	262.5844	262.5844
19.82	20.0900	254.9314	261.8826	262.0738
20.18	20.1300	254.9762	261.2677	261.6772
20.53	20.1700	255.0206	260.6910	261.2590
20.88	20.2100	255.0646	260.2252	261.0046
21.23	20.2500	255.1084	259.8056	260.6993
21.58	20.2900	255.1518	259.4286	260.4517
21.93	20.3300	255.1951	259.0718	260.4944
22.28	20.3700	255.2381	258.7546	260.3788
22.63	20.4100	255.2809	258.5591	260.2252
22.98	20.4500	255.3235	258.3003	260.3297
23.33	20.4900	255.3659	258.1519	259.8963
23.68	20.5300	255.4081	257.9570	259.9370
24.04	20.5700	255.4503	257.7906	260.0243
24.39	20.6100	255.4921	257.6253	260.0851
24.74	20.6500	255.5338	257.4852	274.7141
25.09	20.6900	255.5754	257.4849	**
25.44	20.7300	255.6169	257.4306	**
25.79	20.7700	255.6582	257.3724	**
26.14	20.8100	255.6994	257.3255	**
26.49	20.8500	255.7405	257.2897	**
26.84	20.8900	255.7817	257.2766	**
27.19	20.9300	255.8227	257.2689	**
27.54	20.9700	255.8634	257.2676	**
27.89	21.0100	255.9043	257.2734	**
28.25	21.0500	255.9451	257.2824	**

Table E.11: Variation of costs with planning reserve margin when 10-MW capacity NUG with forced outage rate of 2%, using an investment cost of $40.00/KW, are injected at Buses 1 and 8 of the basic IEEE-RTS.

Resrve Margin (%)	Investment Cost (Million $)	System Cost (Million $)	Total Cost (Million $)	
			Bus 1	Bus 8
19.47	20.05	254.8863	262.5844	262.5844
19.82	20.45	255.2914	262.3380	262.3184
20.18	20.85	255.6962	262.0993	262.0737
20.53	21.25	256.1006	261.9190	261.8759
20.88	21.65	256.5046	261.8160	261.7624
21.23	22.05	256.9084	261.8090	261.6707
21.58	22.45	257.3118	261.9140	261.7592
21.93	22.85	257.7151	261.9247	261.8332
22.28	23.25	258.1181	261.9808	261.8811
22.63	23.65	258.5209	262.0752	261.9795
22.98	24.05	258.9235	262.1969	262.0909

Table E.12: Variation of costs with planning reserve margin when 10-MW capacity NUG with forced outage rate of 2%, using an investment cost of $40.00/KW, are injected at Buses 13 and 18 of the basic IEEE-RTS.

Resrve Margin (%)	Investment Cost (Million $)	System Cost (Million $)	Total Cost (Million $)	
			Bus 13	Bus 18
19.47	20.05	254.8863	262.5844	262.5844
19.82	20.45	255.2914	262.2426	262.4338
20.18	20.85	255.6962	261.9877	262.3972
20.53	21.25	256.1006	261.7710	262.3390
20.88	21.65	256.5046	261.6652	262.4460
21.23	22.05	256.9084	261.6056	262.4993
21.58	22.45	257.3118	261.5886	262.6117
21.93	22.85	257.7151	261.5918	263.0144
22.28	23.25	258.1181	261.6346	263.2588
22.63	23.65	258.5209	261.7991	263.4659
22.98	24.05	258.9235	261.9003	263.9297

F. LOAD MODIFICATION DATA

F.1. The load modification used in the studies described by Tables 5.4 to 5.6 and Figure 5.5 are as follows:

All large user load at bus 3 during the year that exceeded (0.95 p.u. or 0.85 p.u.) was reduced to this value and 100% of the energy was recovered during off-peak hours. (i.e., Equation (5.1) was applied to all loads; where: P=0.95 or 0.85 t1=0, t2=6, h=6, and a=1.0).

F.2. The load modification used in the studies described by Tables 5.7 to 5.9 and Figure 5.6 are as follows:

All large user load at bus 3 during the year that exceeded (0.95 p.u. or 0.85 p.u.) was reduced to this value and no or 0% of the energy was recovered during off-peak hours. (i.e. Equation (5.1) was applied to all loads; where: P=0.95 or 0.85, and a=0.0).

F.3. The load modification used in the studies described by Tables 5.10 to 5.13 and Figure 5.7 are as follows:

All industrial load at any bus during the year that exceeded (0.95 p.u. or 0.85 p.u. or 0.70 p.u.) Was reduced to this value and 100% of the energy was recovered during off-peak hours. (i.e. Equation (5.1) was applied to all loads; where: P=0.95 or 0.85 or 0.70, t1=0, t2=7, h=7, and a=1.0).

F.4. The load modification used in the studies described by Tables 5.14 to 5.17 and Figure 5.8 are as follows:

All industrial load at any bus during the year that exceeded (0.95 p.u. or 0.85 p.u. Or 0.70 p.u.) was reduced to this value and no or 0% of the energy was recovered during off-peak hours. (i.e., Equation (5.1) was applied to all loads; where: P=0.95 or 0.85 or 0.70, a=0.0).

F.5. The load modification used in the studies described by Tables 5.18 and 5.19 and Figure 5.9 are as follows:

All industrial load at any bus during the off-peak hours of 1 a.m. to 7 a.m. was increased by 0.40 p.u. for all days during the year (i.e. Equation (5.4) was applied to all loads; where: A=0.40, t1=0, t2=7, h=7, and b=1.0).

F.6. The load modification used in the studies described by Tables 5.20 and 5.21 and Figure 5.10 are as follows:

All commercial load at any bus during the hours of 8 a.m. to 11 p.m. was decreased by 0.15 p.u. for all days during the year (i.e, Equation (5.4) was applied to all loads; where: A=0.15, t1=8, t2=23, and b= -1.0).

F.7. The load modification used in the studies described by Tables 5.22 and 5.23 and Figure 5.11 are as follows:

All industrial load at any bus was increased by 0.10 p.u. for all days during the year and any new load that exceeded 1.0 p.u. peak load was reduced to this value (i.e. Equation (5.1) was applied to all loads; where: P=1.0, t1=0, t2=24, h=24, and a=1.0) and (i.e, Equation (5.4) was applied to all loads; where: A=0.10, t1=0, t2=24, h=24, and b=1.0).

G. ADDITIONAL RESULTS FROM CHAPTER SIX

Table G.1: Annual load point expected energy not supplied (EENS) with the incremental addition of identical 2-MW capacity NUG to Bus 3 of the RBTS using LM10.

Addition of NUG	EENS At Bus 2 MWh/yr	EENS At Bus 3 MWh/yr	EENS At Bus 4 MWh/yr	EENS At Bus 5 MWh/yr	EENS At Bus 6 MWh/yr
RBTS+(0*2MW)	1.5451	26.5566	4.5280	1.3782	96.3618
RBTS+(1*2MW)	1.2936	24.6509	4.4403	1.5764	96.8612
RBTS+(2*2MW)	1.0399	22.8935	4.2602	1.7138	96.9167
RBTS+(3*2MW)	0.8472	21.4885	4.0591	1.7874	96.9199
RBTS+(4*2MW)	0.7029	20.2466	3.7439	1.7841	96.8593
RBTS+(5*2MW)	0.5810	19.2934	3.4650	1.7788	96.7878
RBTS+(6*2MW)	0.4735	18.4722	3.2216	1.7734	96.7086
RBTS+(7*2MW)	0.3754	17.7318	3.0037	1.7646	96.6211
RBTS+(8*2MW)	0.2899	17.0731	2.8141	1.7546	96.5252
RBTS+(9*2MW)	0.2248	16.5260	2.6671	1.7437	96.4207
RBTS+(10*2MW)	0.1755	16.0972	2.5522	1.7332	96.3074
RBTS+(11*2MW)	0.1375	15.7655	2.4611	1.7234	96.1951
RBTS+(12*2MW)	0.1078	15.4877	2.3877	1.7120	96.0537

Table G.2: Annual load point expected energy not supplied (EENS) with the incremental addition of identical 2-MW capacity NUG to Bus 6 of the RBTS using LM10.

Addition of NUG	EENS At Bus 2 MWh/yr	EENS At Bus 3 MWh/yr	EENS At Bus 4 MWh/yr	EENS At Bus 5 MWh/yr	EENS At Bus 6 MWh/yr
RBTS+(0*2MW)	1.5451	26.5566	4.5280	1.3782	96.3618
RBTS+(1*2MW)	1.2844	22.1773	4.1039	1.3656	81.1299
RBTS+(2*2MW)	1.0312	20.0399	4.5921	1.4243	61.6387
RBTS+(3*2MW)	0.8393	18.5565	3.2903	1.4527	44.7971
RBTS+(4*2MW)	0.6952	17.5574	3.0900	1.4713	32.1245
RBTS+(5*2MW)	0.5737	17.2971	3.1911	1.5769	21.1876
RBTS+(6*2MW)	0.4663	16.9456	3.1852	1.6322	11.2067
RBTS+(7*2MW)	0.3678	16.4674	3.0636	1.6368	3.6646
RBTS+(8*2MW)	0.2809	16.1542	3.0178	1.6464	0.4921
RBTS+(9*2MW)	0.2174	16.0306	3.0532	1.6168	0.0741
RBTS+(10*2MW)	0.1698	16.0438	3.1295	1.5138	0.0380
RBTS+(11*2MW)	0.1330	15.8936	3.0691	1.4523	0.0292
RBTS+(12*2MW)	0.1042	15.8502	3.0655	1.4308	0.0219

Table G.3: Annual load point expected energy not supplied (EENS) with the incremental addition of identical 2-MW capacity NUG to Bus 3 of the RBTS using LM11.

Addition of NUG	EENS At Bus 2 MWh/yr	EENS At Bus 3 MWh/yr	EENS At Bus 4 MWh/yr	EENS At Bus 5 MWh/yr	EENS At Bus 6 MWh/yr
RBTS+(0*2MW)	3.7522	45.2478	9.7380	0.7580	104.1902
RBTS+(1*2MW)	3.1618	42.6966	9.2437	1.1832	104.5380
RBTS+(2*2MW)	2.4658	36.9554	7.8720	1.2911	104.5419
RBTS+(3*2MW)	1.9160	31.5596	6.6839	1.3246	104.5009
RBTS+(4*2MW)	1.5080	27.8298	5.9395	1.3841	104.4900
RBTS+(5*2MW)	1.1912	24.8873	5.2541	1.3835	104.4299
RBTS+(6*2MW)	0.9481	22.5886	4.6627	1.3563	104.3481
RBTS+(7*2MW)	0.7640	20.9035	4.2044	1.3324	104.2571
RBTS+(8*2MW)	0.6284	19.6973	3.8598	1.3074	104.1573
RBTS+(9*2MW)	0.5195	18.8327	3.5811	1.2901	104.0488
RBTS+(10*2MW)	0.4249	18.0938	3.3459	1.2756	103.9312
RBTS+(11*2MW)	0.3431	17.4614	3.1458	1.2574	103.7373
RBTS+(12*2MW)	0.2626	16.8483	2.9488	1.2497	103.5983

Table G.4: Annual load point expected energy not supplied (EENS) with the incremental addition of identical 2-MW capacity NUG to Bus 6 of the RBTS using LM11.

Addition of NUG	EENS At Bus 2 MWh/yr	EENS At Bus 3 MWh/yr	EENS At Bus 4 MWh/yr	EENS At Bus 5 MWh/yr	EENS At Bus 6 MWh/yr
RBTS+(0*2MW)	3.7522	45.2478	9.7380	0.7580	104.1902
RBTS+(1*2MW)	3.1409	33.9220	8.6804	0.9149	84.8508
RBTS+(2*2MW)	2.4316	33.4661	7.0619	1.0136	65.5035
RBTS+(3*2MW)	1.8930	28.2874	5.9770	1.0646	49.4367
RBTS+(4*2MW)	1.4859	24.6514	5.2190	1.1057	36.5135
RBTS+(5*2MW)	1.1712	22.0936	4.6809	1.1427	25.5418
RBTS+(6*2MW)	0.9318	20.3624	4.3249	1.1638	15.1508
RBTS+(7*2MW)	0.7510	19.0775	4.0031	1.1607	6.7617
RBTS+(8*2MW)	0.6144	18.3156	3.8340	1.1329	1.3684
RBTS+(9*2MW)	0.5044	17.7075	3.6527	1.0443	0.2194
RBTS+(10*2MW)	0.4111	17.2290	3.5038	0.9424	0.0866
RBTS+(11*2MW)	0.3260	16.7244	3.3115	0.8843	0.0669
RBTS+(12*2MW)	0.2525	16.2692	3.1350	0.8605	0.0530

Table G.5: Annual system EENS with incremental addition of identical 2-MW capacity NUG to Buses 3 and 6 of the RBTS using the base case load model, LM10 and from LM11.

	BASE LOAD		LOAD MODEL 10		LOAD MODEL 11	
Addition of NUG	EENS Bus 3 (MWh/yr)	EENS Bus 6 (MWh/yr)	EENS Bus 3 (MWh/yr)	EENS Bus 6 (MWh/yr)	EENS Bus 3 (MWh/yr)	EENS Bus 6 (MWh/yr)
RB+(0*2MW)	163.1017	163.1017	130.3697	130.3697	163.6862	163.6862
RB+(1*2MW)	158.1273	136.1789	128.8224	110.0611	160.8233	131.5090
RB+(2*2MW)	149.4512	109.3859	126.8241	87.7262	153.1262	109.4767
RB+(3*2MW)	142.2519	88.3171	125.1021	68.3359	145.9850	86.6587
RB+(4*2MW)	136.8249	70.4261	123.3368	54.9384	141.1514	68.9755
RB+(5*2MW)	132.5515	55.6370	121.9060	43.8264	137.1460	54.6302
RB+(6*2MW)	129.2584	42.5134	120.6493	33.4360	133.9038	41.9337
RB+(7*2MW)	126.8596	32.2288	119.4966	25.2002	131.4614	31.7540
RB+(8*2MW)	125.0832	24.9081	118.4569	21.5914	129.6502	25.2653
RB+(9*2MW)	123.7033	22.5018	117.5823	20.9921	128.2722	23.1283
RB+(10*2MW)	122.5453	21.3686	116.8655	20.8949	127.0714	22.1729
RB+(11*2MW)	121.4774	20.4614	116.2726	20.5772	125.9450	21.3131
RB+(12*2MW)	120.5165	19.7107	115.7489	20.4726	124.9077	20.5702

Table G.6: Annual load point expected cost of unserved energy (ECOST) with the incremental addition of identical 2-MW capacity NUG to Bus 3 of the RBTS using LM10.

Addition of NUG	ECOST At Bus 2 (K$/yr.)	ECOST At Bus 3 (K$/yr.)	ECOST At Bus 4 (K$/yr.)	ECOST At Bus 5 (K$/yr.)	ECOST At Bus 6 (K$/yr.)
RBTS+(0*2MW)	10.0706	63.2640	28.4131	6.0495	351.6004
RBTS+(1*2MW)	8.3174	55.8918	25.0185	6.1359	349.0827
RBTS+(2*2MW)	6.5919	50.8916	23.2115	6.7557	348.3784
RBTS+(3*2MW)	5.3137	47.0320	21.5553	7.0760	347.5248
RBTS+(4*2MW)	4.3832	43.8231	19.5666	7.0525	346.4879
RBTS+(5*2MW)	3.6024	41.3945	17.8330	7.0202	345.4263
RBTS+(6*2MW)	2.9180	39.3106	16.3271	6.9859	344.3477
RBTS+(7*2MW)	2.2976	37.4414	14.9872	6.9355	343.2516
RBTS+(8*2MW)	1.7612	35.7898	13.8285	6.8768	342.1370
RBTS+(9*2MW)	1.3572	34.4351	12.9384	6.8129	341.0034
RBTS+(10*2MW)	1.0536	33.3813	12.2484	6.7533	339.8501
RBTS+(11*2MW)	0.8205	32.5678	11.7060	6.6989	338.6767
RBTS+(12*2MW)	0.6399	31.8935	11.2723	6.6387	337.4826

Table G.7: Annual load point expected cost of unserved energy (ECOST) with the incremental addition of identical 2-MW capacity NUG to Bus 6 of the RBTS using LM10.

Addition of NUG	ECOST At Bus 2 (K$/yr.)	ECOST At Bus 3 (K$/yr.)	ECOST At Bus 4 (K$/yr.)	ECOST At Bus 5 (K$/yr.)	ECOST At Bus 6 (K$/yr.)
RBTS+(0*2MW)	10.0706	63.2640	28.4131	6.0495	351.6004
RBTS+(1*2MW)	8.2566	50.6806	23.3657	5.2133	293.7121
RBTS+(2*2MW)	6.5355	44.8870	20.0279	5.4894	222.5073
RBTS+(3*2MW)	5.2638	40.8774	17.9141	5.6135	161.3024
RBTS+(4*2MW)	4.3350	38.1827	16.4713	5.6875	115.3648
RBTS+(5*2MW)	3.5562	37.1862	16.5101	6.1410	75.8454
RBTS+(6*2MW)	2.8724	36.0737	16.1089	6.3722	39.9219
RBTS+(7*2MW)	2.2505	34.7517	15.2161	6.3781	12.9143
RBTS+(8*2MW)	1.7072	33.8197	14.7260	6.4009	1.6717
RBTS+(9*2MW)	1.3138	33.3514	14.6866	6.2565	0.2523
RBTS+(10*2MW)	1.0195	33.2185	14.8850	5.7953	0.1322
RBTS+(11*2MW)	0.7943	32.7867	14.4850	5.5189	0.1019
RBTS+(12*2MW)	0.6192	32.6012	14.3763	5.4179	0.0768

Table G.8: Annual load point expected cost of unserved energy (ECOST) with the incremental addition of identical 2-MW capacity NUG to Bus 3 of the RBTS using LM11.

Addition of NUG	ECOST At Bus 2 (K$/yr.)	ECOST At Bus 3 (K$/yr.)	ECOST At Bus 4 (K$/yr.)	ECOST At Bus 5 (K$/yr.)	ECOST At Bus 6 (K$/yr.)
RBTS+(0*2MW)	25.6966	112.9581	60.8021	3.3512	387.1631
RBTS+(1*2MW)	21.3755	104.1856	55.8256	5.3803	378.3373
RBTS+(2*2MW)	16.3617	88.1988	46.3359	5.9315	377.4722
RBTS+(3*2MW)	12.4804	73.6159	38.3964	6.0890	376.4312
RBTS+(4*2MW)	9.6543	63.4500	33.1559	6.3171	375.5117
RBTS+(5*2MW)	7.5059	55.6068	28.6186	6.2691	374.4525
RBTS+(6*2MW)	5.8970	49.6083	24.8744	6.1029	373.3366
RBTS+(7*2MW)	4.7071	45.2787	22.0194	5.9547	372.1999
RBTS+(8*2MW)	3.8511	42.2275	19.9014	5.8125	371.0443
RBTS+(9*2MW)	3.1681	40.0519	18.1983	5.7122	369.8691
RBTS+(10*2MW)	2.5770	38.2101	16.7656	5.6298	368.6738
RBTS+(11*2MW)	2.0693	36.6428	15.5540	5.5324	367.2369
RBTS+(12*2MW)	1.5724	35.1210	14.3654	5.4784	365.9738

Table G.9: Annual load point expected cost of unserved energy (ECOST) with the incremental addition of identical 2-MW capacity NUG to Bus 6 of the RBTS using LM11.

Addition of NUG	ECOST At Bus 2 (K$/yr.)	ECOST At Bus 3 (K$/yr.)	ECOST At Bus 4 (K$/yr.)	ECOST At Bus 5 (K$/yr.)	ECOST At Bus 6 (K$/yr.)
RBTS+(0*2MW)	25.6966	112.9581	60.8021	3.3512	387.1631
RBTS+(1*2MW)	21.2268	98.1219	52.9371	4.2071	307.1823
RBTS+(2*2MW)	16.1239	80.5030	42.1871	4.7210	236.4896
RBTS+(3*2MW)	12.3224	66.3877	34.7613	4.9539	178.0974
RBTS+(4*2MW)	9.5040	56.4804	29.4984	5.1019	131.2045
RBTS+(5*2MW)	7.3729	49.4959	25.7050	5.2187	91.5190
RBTS+(6*2MW)	5.7926	44.7434	23.1183	5.2635	54.0756
RBTS+(7*2MW)	4.6271	41.3047	20.9497	5.2058	23.9880
RBTS+(8*2MW)	3.7673	39.2087	19.6730	5.0465	4.7512
RBTS+(9*2MW)	3.0783	37.5812	18.4363	4.6326	0.7628
RBTS+(10*2MW)	2.4953	36.2947	17.4169	4.1720	0.3138
RBTS+(11*2MW)	1.9669	34.9933	16.2341	3.9040	0.2452
RBTS+(12*2MW)	1.5130	33.8348	15.1712	3.7840	0.1949

Table G.10: Annual system expected cost of unserved energy (ECOST) with incremental addition of identical 2-MW capacity NUG to Buses 3 and 6 of the RBTS using the base case load model, LM10 and from LM11.

	BASE LOAD		LOAD MODEL 10		LOAD MODEL 11	
Addition of NUG	ECOST Bus 3 (K$/yr.)	ECOST Bus 6 (K$/yr.)	ECOST Bus 3 (K$/yr.)	ECOST Bus 6 (K$/yr.)	ECOST Bus 3 (K$/yr.)	ECOST Bus 6 (K$/yr.)
RB+(0*2MW)	576.1068	576.1068	459.3976	459.3976	580.9711	580.9711
RB+(1*2MW)	554.4636	476.6521	440.8463	381.2283	565.1043	483.6752
RB+(2*2MW)	521.0207	377.7520	432.2291	299.4471	534.3001	380.0246
RB+(3*2MW)	493.7741	300.5064	424.9018	230.9712	507.0129	296.5227
RB+(4*2MW)	472.8838	235.1068	417.7133	180.0413	488.0890	231.7892
RB+(5*2MW)	456.4545	181.1968	411.6764	139.2389	472.4529	179.3115
RB+(6*2MW)	443.7856	133.5070	406.2893	101.3491	459.8192	132.9934
RB+(7*2MW)	434.1837	96.2971	401.3133	71.5107	450.1598	96.0753
RB+(8*2MW)	426.9577	69.5869	396.7933	58.3255	442.8368	72.4467
RB+(9*2MW)	421.1354	61.0685	392.9470	55.8606	436.9996	64.4912
RB+(10*2MW)	416.1431	56.7778	389.6867	55.0505	431.8563	60.6927
RB+(11*2MW)	411.4724	53.2517	386.8699	53.6868	427.0354	57.3435
RB+(12*2MW)	407.2399	50.3264	384.3270	53.0914	422.5110	54.4979

Table G.11: Variation of costs with planning reserve margin when 2-MW capacity NUG, using an investment cost of $4/KW, are injected at Buses 3 and 6 of the RBTS utilizing the base case load model.

Resrve Margin (%)	Investment Cost (Million $)	System Cost (Million $)	Total Cost (Million $)	
			Bus 3	Bus 6
18.92	3.1350	7.6826	9.0612	9.0612
29.73	3.1850	7.7326	8.3087	8.3087
30.81	3.1930	7.7410	8.2955	8.2177
31.89	3.2010	7.7494	8.2704	8.1272
32.97	3.2090	7.7577	8.2515	8.0582
34.05	3.2170	7.7659	8.2388	8.0010
35.14	3.2250	7.7741	8.2306	7.9553
36.22	3.2330	7.7822	8.2260	7.9157
37.30	3.2410	7.7903	8.2245	7.8866
38.38	3.2490	7.7984	8.2254	7.8680
39.46	3.2570	7.8064	8.2275	7.8675
40.54	3.2650	7.8144	8.2305	7.8712
41.62	3.2730	7.8225	8.2340	7.8758
42.70	3.2810	7.8305	8.2377	7.8808

Table G.12: Variation of costs with planning reserve margin when 2-MW capacity NUG, using an investment cost of $4/KW, are injected at Buses 3 and 6 of the RBTS utilizing LM10.

Resrve Margin (%)	Investment Cost (Million $)	System Cost (Million $)	Total Cost (Million $)	
			Bus 3	Bus 6
18.92	3.1350	7.2828	8.1766	8.1766
29.73	3.1850	7.3328	7.8018	7.8018
30.81	3.1930	7.3410	7.7996	7.7204
31.89	3.2010	7.3492	7.7992	7.6468
32.97	3.2090	7.3573	7.8000	7.5865
34.05	3.2170	7.3653	7.8008	7.5435
35.14	3.2250	7.3734	7.8029	7.5108
36.22	3.2330	7.3814	7.8055	7.4809
37.30	3.2410	7.3895	7.8086	7.4592
38.38	3.2490	7.3975	7.8121	7.4540
39.46	3.2570	7.4055	7.8162	7.4596
40.54	3.2650	7.4136	7.8211	7.4669
41.62	3.2730	7.4216	7.8263	7.4735
42.70	3.2810	7.4296	7.8317	7.4809

Table G.13: Variation of costs with planning reserve margin when 2-MW capacity NUG, using an investment cost of $4/KW, are injected at Buses 3 and 6 of the RBTS utilizing LM11.

Resrve Margin (%)	Investment Cost (Million $)	System Cost (Million $)	Total Cost (Million $)	
			Bus 3	Bus 6
18.92	3.1350	7.7334	9.1164	9.1164
29.73	3.1850	7.7835	8.3644	8.3644
30.81	3.1930	7.7918	8.3569	8.2755
31.89	3.2010	7.8002	8.3345	8.1802
32.97	3.2090	7.8085	8.3155	8.1050
34.05	3.2170	7.8167	8.3048	8.0485
35.14	3.2250	7.8249	8.2974	8.0042
36.22	3.2330	7.8330	8.2928	7.9660
37.30	3.2410	7.8411	8.2913	7.9372
38.38	3.2490	7.8492	8.2920	7.9216
39.46	3.2570	7.8572	8.2942	7.9217
40.54	3.2650	7.8653	8.2972	7.9260
41.62	3.2730	7.8733	8.3003	7.9306
42.70	3.2810	7.8813	8.3038	7.9358

Table G.14: Variation of costs with planning reserve margin when 2-MW capacity NUG, using an investment cost of $40/KW, are injected at Buses 3 and 6 of the RBTS utilizing the base case load model.

Resrve Margin (%)	Investment Cost (Million $)	System Cost (Million $)	Total Cost (Million $)	
			Bus 3	Bus 6
18.92	3.1350	7.6826	9.0612	9.0612
29.73	3.1850	7.7326	8.3087	8.3087
30.81	3.2650	7.8130	8.3675	8.2897
31.89	3.3450	7.8934	8.4144	8.2712
32.97	3.4250	7.9737	8.4675	8.2742
34.05	3.5050	8.0539	8.5268	8.2890
35.14	3.5850	8.1341	8.5906	8.3153
36.22	3.6650	8.2142	8.6580	8.3477
37.30	3.7450	8.2943	8.7285	8.3906
38.38	3.8250	8.3744	8.8014	8.4440
39.46	3.9050	8.4544	8.8755	8.5155
40.54	3.9850	8.5344	8.9505	8.5912
41.62	4.0650	8.6145	9.0260	8.6678
42.70	4.1450	8.6945	9.1017	8.7448

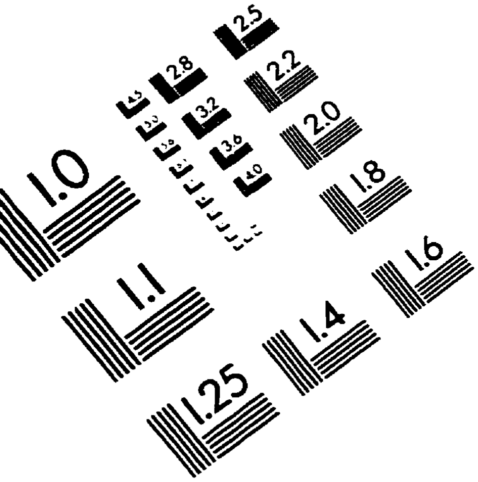
Table G.15: Variation of costs with planning reserve margin when 2-MW capacity NUG, using an investment cost of $40/KW, are injected at Buses 3 and 6 of the RBTS utilizing LM10.

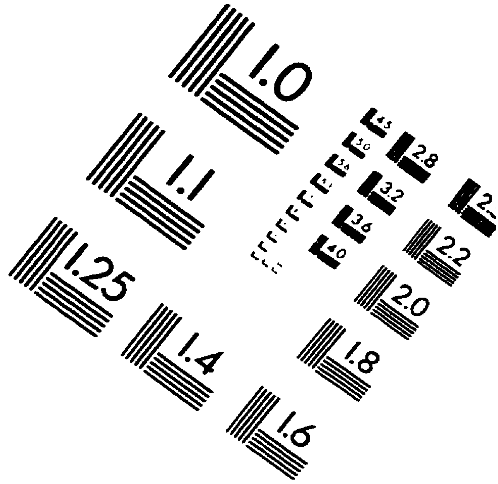
Resrve Margin (%)	Investment Cost (Million $)	System Cost (Million $)	Total Cost (Million $)	
			Bus 3	Bus 6
18.92	3.1350	7.2828	8.1766	8.1766
29.73	3.1850	7.3328	7.8018	7.8018
30.81	3.2650	7.4130	7.8716	7.7924
31.89	3.3450	7.4932	7.9432	7.7908
32.97	3.4250	7.5733	8.0160	7.8025
34.05	3.5050	7.6533	8.0888	7.8315
35.14	3.5850	7.7334	8.1629	7.8708
36.22	3.6650	7.8134	8.2375	7.9129
37.30	3.7450	7.8935	8.3126	7.9632
38.38	3.8250	7.9735	8.3881	8.0300
39.46	3.9050	8.0535	8.4642	8.1076
40.54	3.9850	8.1336	8.5411	8.1869
41.62	4.0650	8.2136	8.6183	8.2655
42.70	4.1450	8.2936	8.6957	8.3449

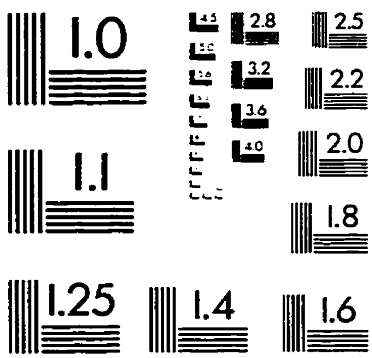
Table G.16: Variation of costs with planning reserve margin when 2-MW capacity NUG, using an investment cost of $40/KW, are injected at Buses 3 and 6 of the RBTS utilizing LM11.

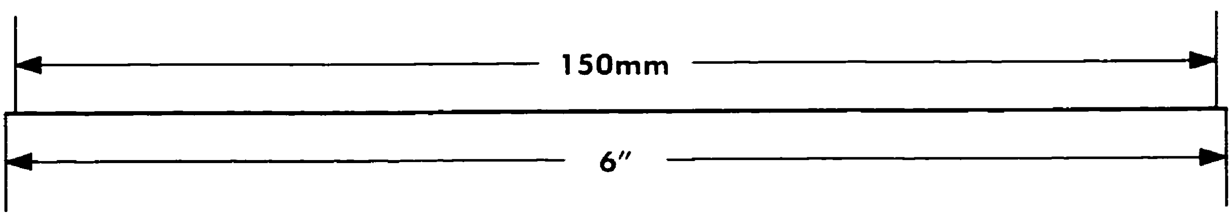
Resrve Margin (%)	Investment Cost (Million $)	System Cost (Million $)	Total Cost (Million $)	
			Bus 3	Bus 6
18.92	3.1350	7.7334	9.1164	9.1164
29.73	3.1850	7.7835	8.3644	8.3644
30.81	3.2650	7.8638	8.4289	8.3475
31.89	3.3450	7.9442	8.4785	8.3242
32.97	3.4250	8.0245	8.5315	8.3210
34.05	3.5050	8.1047	8.5928	8.3365
35.14	3.5850	8.1849	8.6574	8.3642
36.22	3.6650	8.2650	8.7248	8.3980
37.30	3.7450	8.3451	8.7953	8.4412
38.38	3.8250	8.4252	8.8680	8.4976
39.46	3.9050	8.5052	8.9422	8.5697
40.54	3.9850	8.5853	9.0172	8.6460
41.62	4.0650	8.6653	9.0923	8.7226
42.70	4.1450	8.7453	9.1678	8.7998

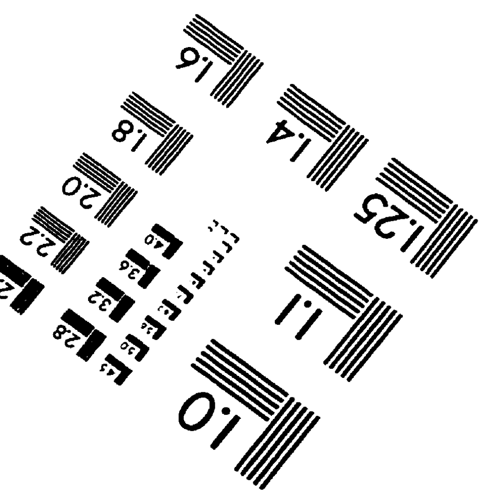
IMAGE EVALUATION TEST TARGET (QA-3)

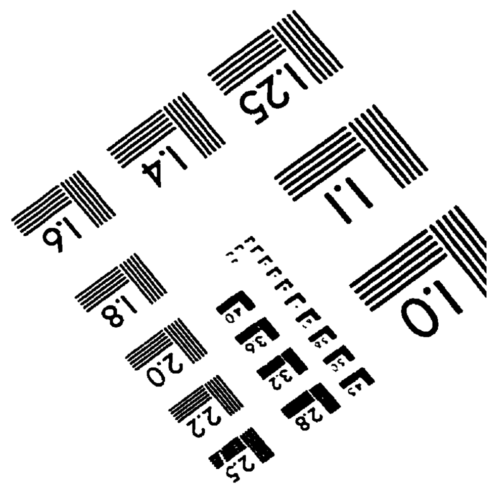












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