ELECTRIC SERVICE RELIABILITY COST/WORTH ASSESSMENT IN A DEVELOPING COUNTRY

A Thesis Submitted to the College of

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By

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SUMMARY OF DISSERTATION

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of the requirements for the

DEGREE OF DOCTOR OF PHILOSOPHY

by

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Fall 1998

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ELECTRIC SERVICE RELIABILITY COST/WORTH ASSESSMENT IN A DEVELOPING COUNTRY

Considerable work has been done in developed countries to optimize the reliability of electric power systems on the basis of reliability cost versus reliability worth. This has yet to be considered in most developing countries, where development plans are still based on traditional deterministic measures. The difficulty with these criteria is that they cannot be used to evaluate the economic impacts of changing reliability levels on the utility and the customers, and therefore cannot lead to an optimum expansion plan for the system. The critical issue today faced by most developing countries is that the demand for electric power is high and growth in supply is constrained by technical, environmental, and most importantly by financial impediments. Many power projects are being canceled or postponed due to a lack of resources. The investment burden associated with the electric power sector has already led some developing countries into serious debt problems. This thesis focuses on power sector issues facing by developing countries and illustrates how a basic reliability cost/worth approach can be used in a developing country to determine appropriate planning criteria and justify future power projects by application to the Nepal Integrated Electric Power System (NPS).

A reliability cost/worth based system evaluation framework is proposed in this thesis. Customer surveys conducted throughout Nepal using in-person interviews with approximately 2000 sample customers are presented. The survey results indicate that the interruption cost is dependent on both customer and interruption characteristics, and it varies from one location or region to another. Assessments at both the generation and composite system levels have been performed using the customer cost data and the developed NPS reliability database. The results clearly indicate the implications of service reliability to the electricity consumers of Nepal, and show that the reliability cost/worth evaluation is both possible and practical in a developing country. The average customer interruption costs of Rs 35/kWh at Hierarchical Level I and Rs 26/kWh at Hierarchical Level II evaluated in this research work led to an optimum reserve margin of 7.5%, which is considerably lower than the traditional reserve margin

of 15% used in the NPS. A similar conclusion may result in other developing countries facing difficulties in power system expansion planning using the traditional approach. A new framework for system planning is therefore recommended for developing countries which would permit an objective review of the traditional system planning approach, and the evaluation of future power projects using a new approach based on fundamental principles of power system reliability and economics.

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ABSTRACT

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A reliability cost/worth based system evaluation framework is proposed in this thesis. Customer surveys conducted throughout Nepal using in-person interviews with approximately 2000 sample customers are presented. The survey results indicate that the interruption cost is dependent on both customer and interruption characteristics, and it varies from one location or region to another. Assessments at both the generation and composite system levels have been performed using the customer cost data and the developed NPS reliability database. The results clearly indicate the implications of

service reliability to the electricity consumers of Nepal, and show that the reliability cost/worth evaluation is both possible and practical in a developing country. The average customer interruption costs of Rs 35/kWh at Hierarchical Level I and Rs 26/kWh at Hierarchical Level II evaluated in this research work lead to an optimum reserve margin of 7.5%, which is considerably lower than the traditional reserve margin of 15% used in the NPS. A similar conclusion may result in other developing countries facing difficulties in power system expansion planning using the traditional approach. A new framework for system planning is therefore recommended for developing countries which would permit an objective review of the traditional system planning approach, and the evaluation of future power projects using a new approach based on fundamental principles of power system reliability and economics.

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Dedicated to My Parents

Shree Prem Lal Pandey and Shreemati Shanta Devi Pandey

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LIST OF ABBREVIATIONS

AC	Alternating Current
ADF	Average Demand Factor
AED	Average and Excess Demand
B	Succeptance
BPECI	Bulk Power Energy Curtailment Index
BPII	Bulk Power Interruption Index
CCDF	Composite Customer Damage Function
CEA	Canadian Electricity Association
CIDA	Canadian International Development Agency
COMREL	COMposite RELiability Evaluation Program
COPT	Capacity Outage Probability Table
CP	Coincident Peak
CRM	Capacity Reserve Margin
DC	Direct Current
DPLVC	Daily Peak Load Variation Curve
ECOST	Expected Cost
EDF	Excess Demand Factor
EES	Expected Energy Supplied
EENS	Expected Energy Not Supplied
ELC	Expected Load Curtailed
EUE	Expected Unserved or Unsupplied Energy
F&D	Frequency and Duration
FOR	Forced Outage Rate
HL	Hierarchical Level
IEAR	Interrupted Energy Assessment Rate
IEEE	Institute of Electrical and Electronics Engineers
km	Kilometer
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt hour
LDC	Load Duration Curve
LOEE	Loss of Energy Expectation
LOLE	Loss of Load Expectation
MRs	Million Rupees
MTTF	Mean Time To Failure
MTTR	Mean Time To Repair
MVA	Megavolt ampere
MVAr	Megavolt ampere reactive

MW	Megawatt
MWh	Megawatt hour
NCP	Non-Coincident Peak
NEA	Nepal Electricity Authority
NPS	Nepal Integrated Electric Power System
P	Active Power
P_G	Scheduled Real Power Generation
PONM	Probability of Negative Margin
PQ Bus	Load Bus
p.u.	Per Unit
PV Bus	Voltage Bus
Q	Reactive Power
$Q_{max.}$	Maximum Limit of Reactive Power Generation
$Q_{min.}$	Minimum Limit of Reactive Power Generation
R	Resistance
RTS	Reliability Test System
Rs	Nepalese Rupees
SCDF	Sector Customer Damage Function
SI	Severity Index
SIC	Standard Industrial Classification
SM	System Minute
UPM	Units Per Million
V_o	Nominal Bus Voltage
$V_{max.}$	Maximum Limit of Bus Voltage
$V_{min.}$	Minimum Limit of Bus Voltage
WTA	Willingness to Accept
WTP	Willingness to Pay
X	Reactance

1. INTRODUCTION

1.1. Power Sector Status in Developing Countries

Electric power is an important element in any modern economy. The availability of reliable power supply at reasonable cost is important for economic growth and development of a country. Electric power utilities throughout the world therefore strive to meet customer demands with a high quality, economic and reliable power supply.

Reliability of electric power supply is virtually taken for granted in most developed countries. This is not the case in developing countries. where resources are scarce and many basic development projects compete for the available funds. The critical issue faced by most developing countries today is that the demand for electric power is high and growth in supply is constrained by technical, environmental, and most importantly by financial impediments. Many power projects are canceled or postponed due to a lack of resources. The investment burden associated with the electric power sector has already lead some developing countries into serious debt problems.

Reference 1 notes, citing a World Bank report, that the electric power generation expansion in the past two decades in most of the developing countries was at an annual average rate of more than 7%, whereas average GDP growth was only 3%. The average power sector investments in most developing countries accounted for more than 20% of total public capital expenditures. Some developing countries expended over 30% of their annual development budget on this sector.

In spite of large investments in the electric power sectors of developing countries, considerable deficiencies in sector performance have been observed in the past. On an average, the operating ratio (i.e. operating cost as a fraction of revenue) for over 300 projects in developing countries reviewed by the World Bank increased from 0.58 in 1965 to 0.84 in 1985 [1]. In addition to the operating ratio, other financial performance indicators such as rate of return on assets, self financing ratio, etc., progressively declined over time. These adverse trends still exist in many developing countries throughout the world.

The issue is not that power development should be considered to have decreased importance, or that this capital intensive sector will not continue to merit significant resources in the future, but rather that it has to be scrutinized more carefully and greater justification is required. The developments over the past few years have indicated the need to improve efficiency in the production and use of electricity, and to achieve an optimum balance between customer demands and the required investment.

1.2. Power Sector Status in Nepal

Nepal is a small developing country located in South Asia. It borders with China in the north and India in the south, east and west (see location map Figure A.1). Some of the pertinent salient features of the country are shown in Table 1.1 [2, 3]. More than 80% of the population depends on agriculture and lives in the rural areas of the country. Industries and businesses are mostly located in major cities and towns. Tourist industries are the main sources for international currency income in the country. Hydro power is the main resource for electricity generation. Major development projects are financed by international development agencies such as the World Bank.

Some observations can be made on the Nepal Power System (NPS) performance over the past few years [3]. The operating ratio increased from 0.66 in 1987 to 0.97 in 1994. The total long-term loans from various international development agencies has increased from US $ 65 million in 1987 to over 300 million in 1994. In addition, financial indicators such as the rate of return on assets, self financing ratio, etc., have declined over the years.

Table 1.1. Pertinent Salient Features of Nepal [2, 3]

Description	Base Year 1995
Area	50,000 sq. km.
Population	20 million
Economy	Agriculture Based
Per Capita Income	US $ 200
Per Capita Electricity Consumption	100 kWh
Electricity Demand	244 MW
Population Growth	3 %
GDP Growth	6 %
Electricity Demand Growth	10 %
Number of Customers	460,000
Average Customer Consumption	1700 kWh
Average Price of Electricity	US $ 0.08/kWh
System Network Loss	25 %

The NPS has made significant growth in terms of electrical energy generation and consumers served. The average energy growth rate is approximately 10% per year

and the average growth in number of consumers served is 12% per annum. The peak demand has increased from 126 MW in 1987 to 244 MW in 1995, an average annual increase of approximately 10%. The growth in demand required large investment and high rates of expansion, which has given the NPS a tremendous economic burden.

Investments in the past have been predominantly weighted towards generation with a consequent under-funding in the transmission and distribution systems. In a developing country such as Nepal, the drive to electrify large geographical areas with a limited budget often diverts the funds required to reinforce existing important networks. As a result, the transmission system, or more precisely several large portions of the network have a radial structure, which results in a high level of transmission losses in the overall system. High loss levels increase supply costs and therefore financial burdens. They are also indicative of a poor quality of service as substandard networks are also responsible for voltage fluctuations and power outages. The total system network loss recorded in 1995 was 25% in the NPS [3].

The increasing operating ratio indicates that the revenues have not kept up with the operating costs. One way of increasing the revenue is to increase the service tariffs, which is a difficult proposition as there have been severe customer objections in the past to increasing the price of electricity. Unless there is substantial improvement in the reliability and the quality of electric supply, it will be extremely difficult for the NPS to persuade customers to pay higher tariffs.

Many utilities in developing countries are facing similar difficulties in their power system planning and operation as those observed by the NPS. Many new power projects are being canceled or postponed due to a lack of resources, environmental problems or other societal concerns. A more rational and consistent evaluation approach

is therefore required to justify future power projects in developing countries. One approach to overcome these difficulties is to explore and implement effective system planning criteria based on fundamental principles of power system reliability and economics.

1.3. Basic Power System Reliability Concepts

The mission-oriented definition of the term reliability is "the probability of a device or system performing its purpose adequately for the period of time intended under the operating conditions encountered" [4]. Reliability as applied to power systems is a measure of the ability of the system to meet the load demand by providing an adequate supply of electrical energy. The concept of power system reliability, however, is extremely broad and covers all aspects of the ability of the system to satisfy the consumer requirements. Figure 1.1 shows the subdivision of power system reliability which represents the two basic aspects of a power system: system adequacy and system security [5].

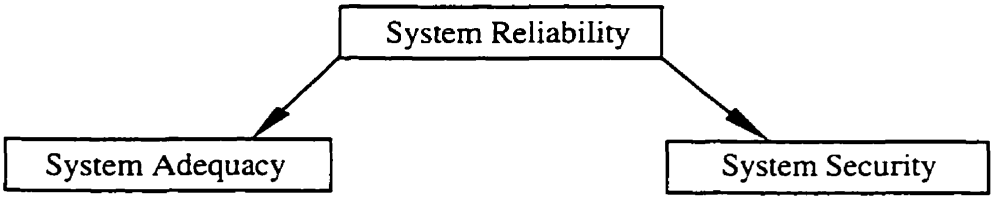

Figure 1.1. Subdivision of System Reliability

Adequacy relates to the existence of sufficient facilities within the system to satisfy the consumer load demand. These include the facilities necessary to generate sufficient energy and the associated transmission and distribution facilities required to

transport the energy to the actual consumer load points. Adequacy is therefore associated with static conditions which do not include system disturbances. Security, on the other hand, relates to the ability of the system to respond to disturbances arising within the system. Security is therefore associated with the response of the system to whatever perturbations it is subjected to. These include the conditions associated with both local and widespread disturbances and the loss of major generation and transmission facilities.

It is important to note that most of the probabilistic techniques available for reliability evaluation are in the domain of adequacy assessment [6-11]. Some work has been done on the security problem, such as quantifying spinning or operating capacity requirements and transient stability assessment. Many probabilistic techniques are now used in practice [12-16], which are based on the fact that power systems behave stochastically and all input and output states and event parameters are probabilistic variables.

1.3.1. Reliability Evaluation at Hierarchical Levels (HL)

A power system as a whole is a vast and complex entity. For the purposes of organization, planning, and operation, it can be divided into the three functional zones of generation, transmission and distribution, as shown in Figure 1.2. This division is appropriate as many utilities are either divided into these functional zones or are solely responsible for one of these functions.

The methods for reliability evaluation can be categorized in terms of their application to the functional zones. Reliability studies can be conducted individually in each of the three functional zones. The zones can be combined to form hierarchical

levels [5] as shown in Figure 1.3. Reliability evaluation can be performed at each hierarchical level.

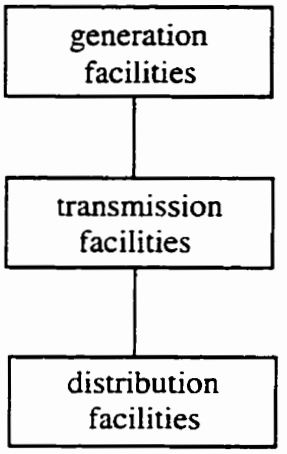

Figure 1.2. Basic Functional Zones of a Power System

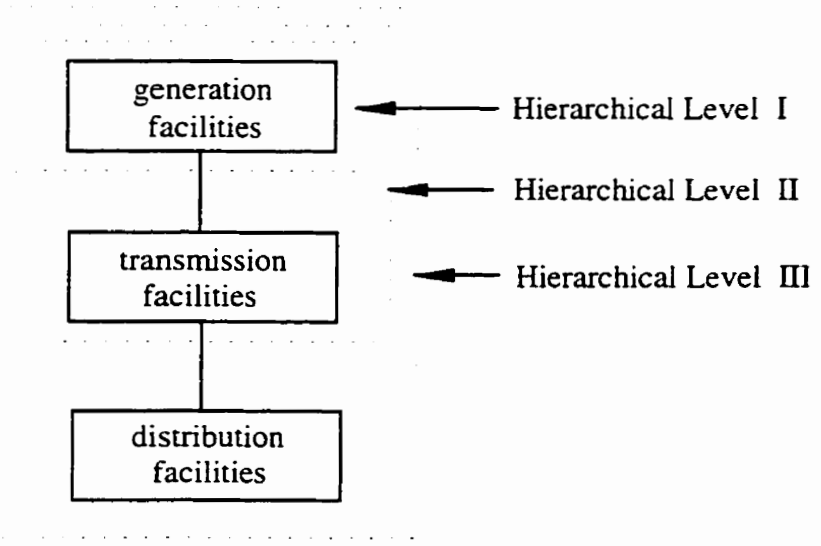

Figure 1.3. Hierarchical Levels in Reliability Studies

Reliability evaluation at Hierarchical Level I (HL I) is concerned only with the generation facilities. Hierarchical Level II (HL II) includes both generation and

transmission facilities and Hierarchical Level III (HL III) includes the entire power system in an attempt to assess the adequacy at consumer load points. The research work reported in this thesis deals with adequacy assessment at HL I and HL II.

HL I Evaluation

HL I evaluation is concerned with assessing the ability of the generation facilities to satisfy the total system load. This is usually termed as 'generating capacity reliability evaluation'. The reliability of the transmission system and its ability to deliver electricity to the consumer load points is not considered at this level. The basic system model used in HL I studies is shown in Figure 1.4 [17].

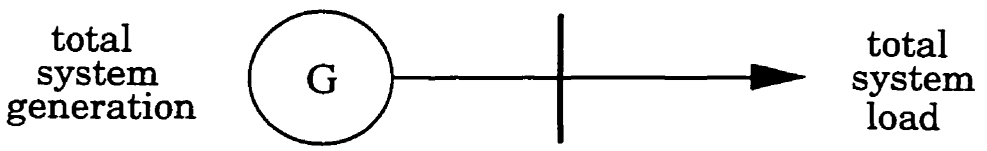

Figure 1.4. Basic Model for HL I Studies

The main concern in HL I evaluation is to estimate the generating capacity required to satisfy the total system load demand and to have sufficient capacity to perform corrective and preventive generating unit maintenance. The traditional methods used in HL I reliability evaluation are deterministic in nature. These methods do not consider the system composition or the system load characteristics, and do not reflect the probabilistic nature of system behavior and of component failures. These methods have now been largely replaced by probabilistic methods [12] which take into consideration the actual factors that influence the reliability of the system.

Basic probabilistic criteria widely used by utilities in HL I studies are the Loss of Load Expectation (LOLE), the Loss of Energy Expectation (LOEE) also called the Expected Unserved Energy (EUE), and the Frequency and Duration (F&D) of the occurrence of an insufficient capacity condition. These indices are generally evaluated using direct analytical techniques although Monte Carlo simulation is sometimes used [5]. Table 1.2 shows a summary of the criteria and indices used by Canadian utilities in HL I studies for planning purposes [12].

Table 1.2. Generating Adequacy Criteria Used by Canadian Utilities for Planning Purposes [12]

System	Type of Criterion	Index
British Columbia Hydro and Power Authority	LOLE	1 day/10 years
Alberta Interconnected System	LOLE	0.2 days/year
Saskatchewan Power Corporation	EUE	200 Units Per Million (UPM)
Manitoba Hydro	LOLE	0.003 days/year (with interconnections) 0.1 days/year (without interconnections)
Ontario Hydro	EUE	25 System Minutes (SM)
Hydro Quebec	LOLE	2.4 hours/year
New Brunswick Electric Power Commission	CRM[a]	Largest unit or 20% of the system peak(whichever is larger)
Nova Scotia Power Corporation	LOLE[b]	0.1 days/year (under review)
Newfoundland and Labrador Hydro	LOLE	0.2 days/year

Notes
LOLE - Loss of load expectation
EUE - Expected unserved energy
CRM - Capacity reserve margin
a - With supplementary checks for LOLE
b - With supplementary checks for CRM

HL II Evaluation

In Hierarchical Level II (HL II) evaluation, the simple generation-load model shown in Figure 1.4 is extended to include bulk transmission[17]. Reliability evaluation at this level (HL II) is termed as 'composite system' or 'bulk power system' evaluation. An example of a small composite generation and transmission system is shown in Figure 1.5.

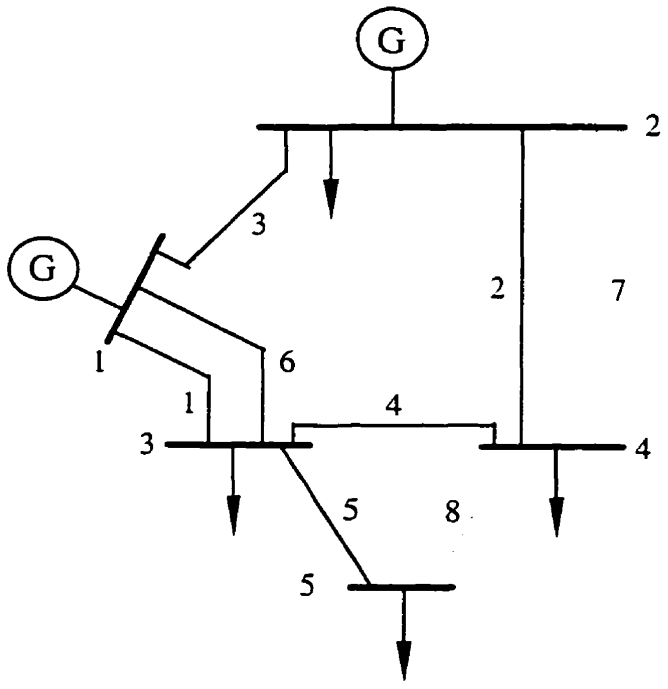

Figure 1.5. A Model of Composite System for HL II Studies

HL II studies can be used to assess the adequacy of an existing system and the impact of various reinforcements at both the generation and transmission levels. In the case of the system shown in Figure 1.5, studies may be required to evaluate the effects of such additions as lines 7 and 8. These effects can be assessed by using two sets of indices: individual load point indices and overall system indices. The load point indices

show the effect on individual load buses whereas the system indices give an assessment of the overall system.

There is a wide range of load-point and system indices that can be calculated in HL II studies. The Probability of Failure, Frequency of Failure, Expected Load Curtailed (ELC) and Expected Energy Not Supplied (EENS) are some examples of load-point indices. These indices are calculated for the major load points in the system. They are very useful in system design for the evaluation of alternative system configurations. They can also serve as input values in the adequacy assessment of distribution systems supplied from these bulk supply points. System indices give an assessment of overall system adequacy and are very useful in monitoring its performance for comparison with other systems. Some examples of system indices are Bulk Power Interruption Index (BPII), Bulk Power Energy Curtailment Index (BPECI), System Minutes (SM), Units Per Million (UPM), etc.. These indices are described in more detail later in this thesis.

Although the indices evaluated in HL II studies add realism by including bulk transmission, they are still adequacy indicators and are expected values. They are highly dependent on the modeling assumptions used in the computer simulation. Adequacy assessment at HL II is a complex problem requiring substantial system data and information. Considerable work has been done in this area in developed countries. There are still many power utilities and related organizations doing interesting and innovative work in this area. Many computer programs have been developed [18] to evaluate composite system adequacy. Some of the better known programs are shown in Table 1.3.

The first six programs listed in Table 1.3 are based on contingency enumeration techniques (analytical methods) which involve the selection and evaluation of

contingencies to determine specified system failure conditions and adequacy indices. The program SICRET is based on Monte Carlo simulation, and MECORE utilizes a combination of both analytical and simulation techniques in its approach to composite system evaluation.

Table 1.3. Digital Computer Programs for Composite System Reliability Evaluation

Program	Organization
COMREL	University of Saskatchewan, Canada
GATOR	Florida Power Corporation, USA
PROCOSE	Ontario Hydro, Canada
RELACS	Manchester Institute of Science and Technology, UK
SYREL	Electric Power Research Institute (EPRI), USA
TPLAN	Power Technologies Inc., USA
SICRET	Ente Nazionale per l'Energia Elettrica (ENEL), Italy
MECORE	University of Saskatchewan, Canada

HL III Evaluation

Hierarchical Level III (HL III) studies include all the three functional zones of a power system in an attempt to assess the consumer load point adequacy. The overall problem of HL III evaluation can become enormous and very complex in most practical systems. For this reason, evaluation is usually performed only in the distribution functional zone. Load point indices obtained from HL II studies are sometimes used as input values to the evaluation. The objective of an HL III study is to obtain suitable adequacy indices at the actual customer load points. The primary indices at this level are the expected frequency of failure, the average duration of failure, and the annual

unavailability of the load points. Additional indices, such as the expected load disconnected or the energy not supplied at customer load points, can also be calculated. The conventional analytical methods for evaluating these indices utilize techniques such as the minimal-cut-set method or failure modes analysis in conjunction with sets of analytical equations which can account for all realistic failure and restoration processes[17].

1.3.2. Reliability Cost/Worth Studies

System reliability studies are only part of the overall assessment process. The economics of alternative schemes play a major role in the decision making process associated with planning, design and operation of an electric supply system. The two aspects, reliability and economics, can be consistently appraised by comparing reliability cost (the investment cost required to achieve a certain level of reliability) with reliability worth (the benefits derived by society with the improved reliability). This type of economic appraisal is a fundamental and important area of engineering application, and it is possible to perform this evaluation at each of the three hierarchical levels [5]. The basic concepts associated with the reliability cost/worth approach to system evaluation are illustrated in Figure 1.6.

Figure 1.6 shows that utility costs, which include capital investment, operating and maintenance costs, increase as the reliability level increases. On the other hand, the socio-economic losses in the form of customer costs decrease as the reliability increases. The total societal cost is the sum of the utility and customer costs. This total cost exhibits a minimum, at what might be considered as an optimum level of reliability. The alternative which results in the minimum total cost can be considered as the plan that will produce an optimum reliability level for the system.

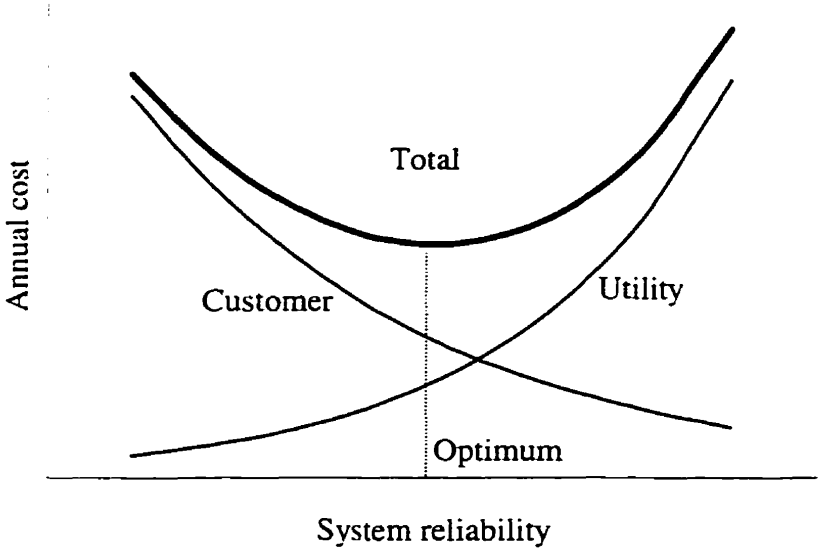

Figure 1.6. Utility, Consumer and Total Costs as a Function of System Reliability

Although, the basic concept of reliability cost/worth studies is relatively easy to understand, a number of difficulties arise in its assessment, particularly the worth part. The assessment of worth or benefit of power system reliability to its customers is normally done by estimating the costs to customers due to power supply interruptions. This is a complex and subjective task generally performed using customer survey techniques. Extensive studies regarding outage costs have been done [19,20] at the University of Saskatchewan. The two comprehensive references cited contain the bulk of the early contributions in the area of power system reliability worth assessment. The area is still the subject of significant study [21,11], and reliability cost/worth evaluation has become an important tool in power system planning in developed countries.

The reliability cost/worth approach to system evaluation can be used to provide valuable information to an electric power utility in two major ways. It can be used to

quantify the fundamental electric utility requirement of what is a reasonable level of reliability. It can also be used in a more direct and perhaps practical fashion to provide input to a wide range of utility decision making processes. This research work deals with developing reliability cost/worth based planning criteria and methodologies that can be used by utility planners in developing countries to evaluate future power projects.

The developed reliability cost/worth based system evaluation framework used throughout this research work is shown in Figure 1.7.

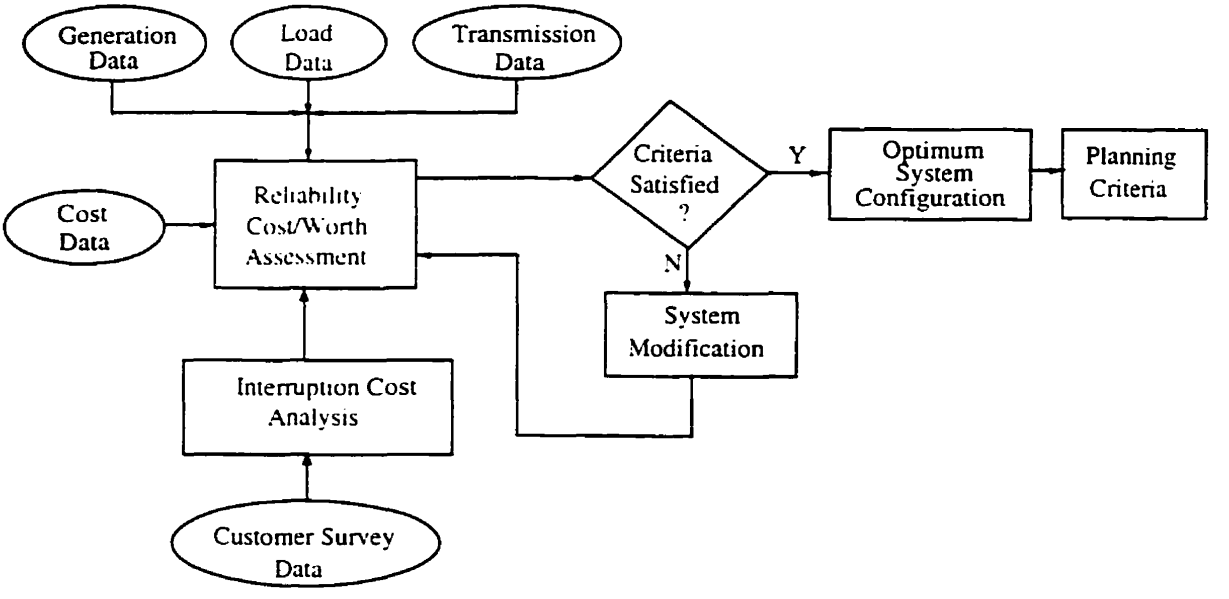

Figure 1.7. A Reliability Cost/Worth Based System Evaluation Framework

Reliability cost/worth adequacy evaluation studies at HL I and HL II require generation data, load data, transmission data, cost data and interruption cost data. The interruption cost data are usually obtained from customer surveys. Distribution system data are required, if studies at HL III are conducted. These input data requirements are shown in Figure 1.7.

Reliability cost/worth assessment is performed using the required input data. The basic approach is to select an expansion scheme having the minimum overall cost. If the design criteria are not satisfied, the expansion scheme is modified and assessed again. This procedure is repeated until the adequacy criteria are satisfied. The newly developed system configuration which produces the optimum reliability level is then used in future development of the power system. The corresponding set of indices obtained in the evaluation can be used as planning criteria for evaluation of future power projects. The overriding objective is to ensure that the system expansion is implemented only when the resulting costs equal the benefit that can be accrued by society due to its implementation.

1.4. Objective of the Research

Considerable work has been done in developed countries to optimize reliability levels on the basis of reliability cost versus reliability worth [11, 22]. This has yet to be considered in developing countries, where development plans are still based on traditional deterministic measures such as the largest single contingency or a fixed percentage reserve margin. The difficulty with these criteria is that they cannot be used to evaluate the economic impacts of changing reliability levels on the utility and the customers, and therefore cannot lead to the optimum expansion plan for the system. The reliability cost/worth approach to system evaluation provides an opportunity for developing countries to formulate suitable planning criteria for their power systems and to economically justify future power projects.

Reliability criteria used in developing countries are usually extrapolated from similar criteria adopted by more developed countries. This is usually done in the absence of basic system and component data and with little recognition of the explicit

worth associated with the reliability of electric power supply. The approach taken in this research considers the Nepal Integrated Electric Power System (NPS) as a typical power system in a developing country and examines the fundamental problems associated with using a reliability cost/worth technique to develop suitable planning criteria and methodologies. The research considers the basic system and component data required to formulate the analysis and by using the NPS as a surrogate system, those data that would likely be available for a power system in a developing country. The research considered the likely available data, the data that could be realistically estimated from external sources and those data which are specific to the system under study and which are absolutely necessary to conduct the analysis. The last data requirement involved an extensive analysis of customer interruption costs in the NPS in order to create a relevant and explicit reliability worth database. The survey approach used extends the existing techniques [20, 23] by application to electric power consumers in a developing country.

The principal contribution of this research is the recognition of the overall problems associated with determining power system reliability criteria and methodologies for a developing country and the creation of a practical framework to incorporate explicit recognition of reliability worth in the criteria and methodologies. As noted above, the developed concepts are illustrated by application to the NPS. The overall approach, however, can be used with relevant modification by utility planners in similar developing countries to formulate reliability criteria and methodologies in order to justify future power projects.

1.5. Research Stages

The research work described in this thesis was conducted in the following four stages.

1. Customer survey and data investigation;

2. Reliability cost/worth studies at HL I using the developed database and customer survey findings;
3. Reliability cost/worth studies at HL II using the developed database and customer survey findings; and
4. Reliability cost/worth based tariff design. The research stages are briefly described below.

1.5.1 Customer Survey and Data Investigation

Most of the customer surveys conducted in the past were in developed countries, such as Sweden, Finland, France, UK, USA and Canada [19, 20]. The Power System Research Group at the University of Saskatchewan has done extensive surveys in Canada since 1980 [23]. One of the main objectives of this research work was to extend the evaluation technique to a developing country and to examine the problems associated with incorporating the approach in such a system.

The research work commenced with a literature search in the area of reliability worth studies. Bibliographies [19, 20] written by the Power System Research Group were prime source of information for this activity. This overview provided valuable background information and a foundation for the study. Survey questionnaires were developed based on earlier work done by the Power System Research Group with modifications to suit the prevailing situation in a developing country. Customer surveys were conducted throughout Nepal using in-person interviews with approximately 2000 sample customers from the residential, commercial and industrial sectors.

One of the main difficulties in applying probabilistic methods in system evaluation is that these methods require extensive data. The increased popularity of

stochastic methods in system reliability evaluation in developed countries has created a demand for the collection of outage data and other relevant information. Many utilities in developed countries have established and implemented suitable outage data collection schemes [11]. In Canada, the Canadian Electricity Association (CEA) coordinates this activity through the Equipment Reliability Information System (ERIS) [24, 25]. These data are generally not available for power systems in developing countries. One of the tasks at this research stage was to investigate and to develop the required database for the NPS. The developed database for the NPS is presented and discussed in Chapter 2.

1.5.2. HL I Evaluation

The application of probabilistic techniques to generating capacity or HL I evaluation has become a routine activity for many utilities in developed countries. This is not the case in developing countries where plans are still based on deterministic measures such as the single largest contingency or a fixed percent reserve margin. The difficulty with these criteria is that they are somewhat arbitrary and depend entirely on the past. They cannot be used to determine the optimum expansion plan for the future. The reliability cost/worth evaluation approach provides an opportunity for developing countries to plan their future power requirements objectively.

Reliability cost/worth studies were conducted using the customer survey findings and the NPS database developed during visits to the Nepal Electricity Authority(NEA). An overall cost value associated with unsupplied energy designated as the Interrupted Energy Assessment Rate (IEAR) was established for the NPS at HL I. This index was used to determine the optimum system configurations for the planning period 1995 - 1999. Planning criteria were then developed from the evaluation process. Sensitivity studies were performed to investigate the impacts of important factors such

as peak loads, generating unit forced outage rates and system configurations. Comparisons of the costs of the proposed expansion using the reliability cost/worth approach and the traditional deterministic method plan proposed by the NEA were made to appreciate the differences.

1.5.3. HL II Evaluation

The most fundamental quantitative evaluation process in power system planning is the assessment of the adequacy of system generating capacity to meet the increasing load demands. This is the subject matter of HL I studies. A second, but equally important assessment process involves HL II studies, which consider both generation and transmission facilities in the evaluation. Studies at HL II clearly recognize the dispersed nature of system generation and load and are important in the development of an understanding of the impacts of generation and line additions at various locations in the system. Reliability cost/worth studies at HL II were performed by application to the NPS. The IEAR at HL II were established using the customer survey and the developed database. Suitable criteria were developed for the major load centers as well as for the overall system. Some sensitivity tests were performed and comparisons of the system costs for the proposed expansion using the reliability cost/worth approach and the traditional deterministic method plan proposed by the NEA were made to appreciate the implications.

1.5.4. Reliability Cost/Worth Based Tariff Design

It is generally true that the system cost behavior is dependent on the methods used in system planning and operation. The planning criteria drive the system development which further drives the system cost. It is therefore consistent that the cost

allocation method should follow the concepts used in the planning process. A reliability cost/worth based cost of service allocation framework was developed and allocation cost studies were conducted at this research stage.

The detailed class load data required in the analysis were developed using realistic assumptions and some available class data from the customer surveys. A probabilistic method proposed in [26] was used to calculate the cost allocation factors. These allocation factors, in conjunction with the system costs driven by the reliability cost/worth based planning criteria, can be used as basic input to the tariff design process. The overall proposition here is that the future power requirements and the resulting system costs in developing countries can be effectively planned and allocated using the reliability cost/worth analysis framework.

1.6. Scope of the Thesis

The research work presented in this thesis is primarily concerned with the application of the reliability cost/worth approach to system adequacy evaluation at HL I and HL II in a developing country. Reliability is generally taken for granted in developed countries. This is not the case in developing countries where many basic development projects compete for scarce resources. Many electric power projects are canceled or postponed due to a lack of resources, environmental problems and other societal concerns. The reliability cost/worth evaluation method can provide a rational and consistent approach to justify future power projects in developing countries.

This thesis focuses on power sector issues faced by developing countries where resources are scarce and developments in other basic sectors such as education, health and agriculture are at a subsistence level. There are many developing countries in Asia

and Africa that are facing this kind of situation. This thesis illustrates how the basic reliability cost/worth approach can be used in the system planning process and in the justification of future power projects by application to the NPS. The NPS can be considered as a representative model of electric power utilities in those developing countries which can be categorized as having scarce resources and a subsistence level of infrastructure development. The power system planning approach developed in this thesis can be used to address the basic resource planning and rate issues in these developing countries.

1.7. Thesis Outline

This thesis is structured into seven chapters. Chapter 1 introduces the research area and presents the objectives and scope of the research work described in this thesis.

Chapter 2 describes the various data requirements for reliability studies. The reliability data investigation conducted in Nepal is described in this chapter. A methodology adopted to derive the unavailable data required for the reliability studies is also explained. The assembled NPS database obtained through the investigation in Nepal is presented in this chapter.

The customer survey conducted in this research work is described in Chapter 3. An overview of the interruption cost methodologies is presented and the surveys conducted in the three basic residential, commercial and industrial customer sectors are described in this chapter. The survey findings and results are also discussed.

The basic concepts and techniques applied to reliability cost/worth studies at HL I are presented in Chapter 4. The IEAR determination using the basic analytical

technique is described and the impacts of different parameters on the IEAR are discussed. The optimum reserve margin determination using the IEAR is described and the impacts of various factors on the optimum reserve margin are presented. The expansion plan studies are presented and some planning criteria at HL I are suggested.

Chapter 5 presents the basic concepts and techniques applied to reliability cost/worth assessment at HL II. The IEAR determination for the individual buses as well as for the overall system is described. The effects of various parameters on the IEAR are discussed. The optimum overall expansion determination using the calculated IEAR is described and some planning criteria at HL II are suggested.

A reliability cost/worth analysis based tariff design process is presented in Chapter 6. An overview of the existing service cost allocation methodologies is presented and a reliability cost/worth based basic framework developed for the cost of service allocation process is briefly described in this chapter. The preparation of the required class load database and calculation procedures for allocation factors are also described. The results are discussed and the impacts of various parameters on the calculated indices are presented.

Chapter 7 presents a summary and the conclusions of this research work.

2. RELIABILITY DATA

2.1. Introduction

An electric power system is a large and complex entity consisting of generation, transmission and distribution facilities. The system evaluation therefore requires a large amount of data. One of the main reasons frequently cited for not using probabilistic methods in power system evaluation is the lack of data. The increasing popularity of applying probabilistic techniques in system reliability evaluation has created considerable demand for the collection of outage data and other relevant information. Substantial work has been done in developed countries to establish and implement suitable data collection schemes. Most utilities in developed countries now have reasonably adequate reliability data banks [11, 24, 25]. This is not the case in developing countries where quantitative reliability assessment techniques are virtually new and therefore most data required for their application are not readily available. This situation requires research to investigate the reliability data requirements and to examine the problems associated with the required data in a developing power system such as the NPS.

One of the main objectives of this research work was to investigate the availability of the required data in the NPS and to develop a methodology to derive unavailable data using a practical approach. The investigation was done during the NEA visits while conducting customer surveys in Nepal.

This chapter describes the various data requirements for quantitative reliability assessments at HL I and HL II. The available data for the NPS collected during the

customer survey work in Nepal are presented in this chapter. The required data, which are not available, were derived and are presented in this chapter. Some data utilized in previous NPS studies [27, 28, 29] are also presented to illustrate the data requirements. The NPS database presented in this chapter has been used in the system studies described later in this thesis.

2.2. Data Requirements for Reliability Studies

The various data requirements for adequacy studies at HL I and HL II involve the generation and transmission facilities and load information. Investment, operating and customer interruption cost data are also required for reliability cost/worth studies. The customer interruption cost data are described and presented in Chapter 3. Data related to distribution facilities are required if studies at HL III are to be conducted.

2.2.1. Generation Data

The basic generation data include rated capacity, failure rate and average repair time for each generating unit in the system. The generating unit rated capacities are standard deterministic data and therefore readily available. The stochastic data such as the unit failure rates and average repair times are obtained from unit past performance history. These parameters depend on unit sizes, types and designs. These data are usually realized from comprehensive forced outage data collection procedures and generally may not be available at the present time in developing countries.

2.2.2. Composite Generation and Transmission Data

The composite or bulk power system (i.e. HL II) contains both generating equipment and the necessary transmission facilities required to transport the generated

energy to the bulk or major system load points. The evaluation of such a system is a complex problem [30]. The data required to analyze the problem can be divided into the two basic segments of deterministic data and stochastic data.

Deterministic data are required at both the system level and at the actual component level. The component data include known parameters such as line impedances and susceptances, current carrying capacities, generating unit parameters and other similar factors normally utilized in conventional load flow studies. This is not normally difficult to obtain as these data are used in a wide range of studies. The system data, however, are more difficult to appreciate and to include, as they should take into account the response of the system under different outage conditions. An example of this might be that if one of the lines between buses 1 and 3 of system shown in Figure 1.5 in Chapter 1 suffered an outage, the loading on the remaining line may be such that the line is removed from service, or it carries the overload, or some remedial system action is taken in order to maintain the overall system integrity. This form of system data is important in a composite system reliability study. The modeling used in the evaluation process should follow the actual system response or the results will not be appropriate. This is an important aspect of the data requirement problem for HL II studies.

Stochastic data are the values associated with parameters which are random in nature. Typical parameters are failure rates and repair durations. These parameters can again be divided into the two segments of component and system requirements. The component requirements pertain to the failure and repair parameters of the individual elements within the system. These data are generally not difficult to appreciate and to include in system evaluation. It is, however, difficult to realize and to include system events which involve two or more components. This type of data is system specific and

usually included as a second and third level of data input in an overall composite system reliability analysis. System data includes relevant multiple failures resulting from common transmission line configurations or station originated effects.

The stochastic data requirements for composite system reliability evaluation therefore include both individual component parameters as well as higher levels of data which involve more than one component and are system specific. This form of input can be designated as system data requirements. These data again are obtained from comprehensive data collecting schemes and therefore may not be normally available for power systems in developing countries.

2.2.3. Load Data

The load models normally used in power system reliability evaluation depict the variation of system load at different times within a period. The basic period normally considered in system planning is a year. The annual load forecast in the planning process is usually based on past experience. The forecast load data are therefore stochastic parameters which are used in a range of planning studies.

The most readily available load model is that proposed in the IEEE Reliability Test System (RTS) [31]. This reliability test system was published in 1979 by the IEEE Subcommittee on the Application of Probability Methods (APM) to provide a consistent and generally acceptable set of data that can be used in generating capacity and composite system reliability evaluations. The test system provides a basis for the comparison of results obtained using different evaluation techniques. It also provides important information in regard to relevant data requirements for reliability studies. The system has been used extensively since it was proposed in 1979, in a wide range of

reliability studies conducted by power utilities, consultants and universities in developed countries [22]. Although the actual data given for the IEEE-RTS may not be relevant to the power system in a developing country, the concepts, modeling and data requirement aspects described in the test system are, however, fundamental to any system reliability evaluation.

Quantitative reliability studies require extensive load data. The system load modeling approach proposed in the IEEE-RTS can be used to generate appropriate load data for power system reliability studies in developing countries. In the test system, the load data are expressed sequentially, for example, weekly peak loads are expressed in percent of the annual peak load, daily peak loads in percent of the weekly peak loads, and hourly peak loads in percent of the daily peak loads. It is possible to obtain all the daily and hourly load data required from a single specific annual forecast peak load. Load data collected for the NPS were used to structure a load model based on the approach presented in the IEEE-RTS.

2.2.4. Cost Data

Reliability cost/worth studies require system cost data and interruption cost data in addition to the various reliability data described above. The interruption cost data obtained from the customer surveys conducted in Nepal are presented in Chapter 3. The system cost data requirements are as follows.

The basic system cost data include the capital and operating costs associated with each generation and transmission facility in the system. The capital cost is the total cost to install a facility. The operating cost is the annual expenditure incurred in operating a facility. The operating cost is further divided into fixed and variable costs.

The fixed costs include the annual charges which continue as long as capital is tied up in the enterprise. These charges comprise interest, depreciation, rent, taxes, insurance and any other expenditure that is based upon the magnitude of the capital investment. The variable costs include payment for materials, supplies, power, fuel costs, water rental charges, etc., and are associated with energy production.

2.3. The NPS Database

The investigation of the required reliability data described above was done in Canada. Bibliographies [6-10] and reports [24, 25] provided by the Canadian Electricity Association (CEA) were the prime resources used in this research work. During this research stage, appropriate data collection forms were developed to use in the data investigation subsequently conducted in Nepal. The developed data collection forms are presented in Appendix D.

The initial work in Nepal began with visits to the NEA headquarters in the capital city of Kathmandu. The objective was to familiarize the NEA with the research objectives and to gain support for the research work from the key personnel in the utility.

It was found that the NEA had begun to consider probabilistic criteria as a planning parameter in system evaluation [32]. The NEA has also started to collect some data to develop equipment forced outage rates. The Power System Research Group of the University of Saskatchewan conducted a short course on power system reliability through the Canadian International Development Agency (CIDA) funded program in Nepal. Representatives from universities, power industries and utilities including the NEA participated in the program. Some activities at the NEA regarding the initiation of

incorporating reliability criteria and the associated data collection can perhaps be attributed to the work of the University of Saskatchewan in Nepal.

Most data required for reliability studies are still not readily available in the NPS. The deterministic data available were assembled from various reports and information provided by the NEA. The required probabilistic data were derived using the available data and some realistic assumptions. A methodology adopted to derive the unavailable data required for the reliability studies is described below. The assembled NPS database obtained through the investigation in Nepal is presented to clearly illustrate the data requirements.

The single line diagram of the 46-bus NPS network existing in 1995 is shown in Figure 2.1. The system has 11 generator (PV) buses, 33 load (PQ) buses and 2 tie buses. There are 30 generating units having capacities ranging from 2.5 MW to 30 MW in the system with a total installed generating system capacity of 274 MW. The 46 bus locations are connected by 44 transmission lines and 21 transformers. The transmission lines are at two voltage levels of 132 kV and 66 kV. There are two 132/66 kV tie stations in the system. The system peak load was expected to be 237.17 MW in 1995 [2]. Table 2.1 lists the names and types of the system buses and the designated numbers by which they are referred to in this thesis.

The map of Nepal showing the power development network is given in Appendix A. The drive to electrify large geographical areas in the shortest possible time so as to provide at least some measure of electrification to as large a proportion of the population as possible is an important policy concern in a developing country like Nepal. The pressure to provide additional investment to electrifying some areas of the country often diverts funds needed to provide alternative infeed paths to existing

important load centers or reinforcing existing important interconnections. Hence the transmission system, or more precisely several large portions of the network, has the radial structure shown in Figure 2.1.

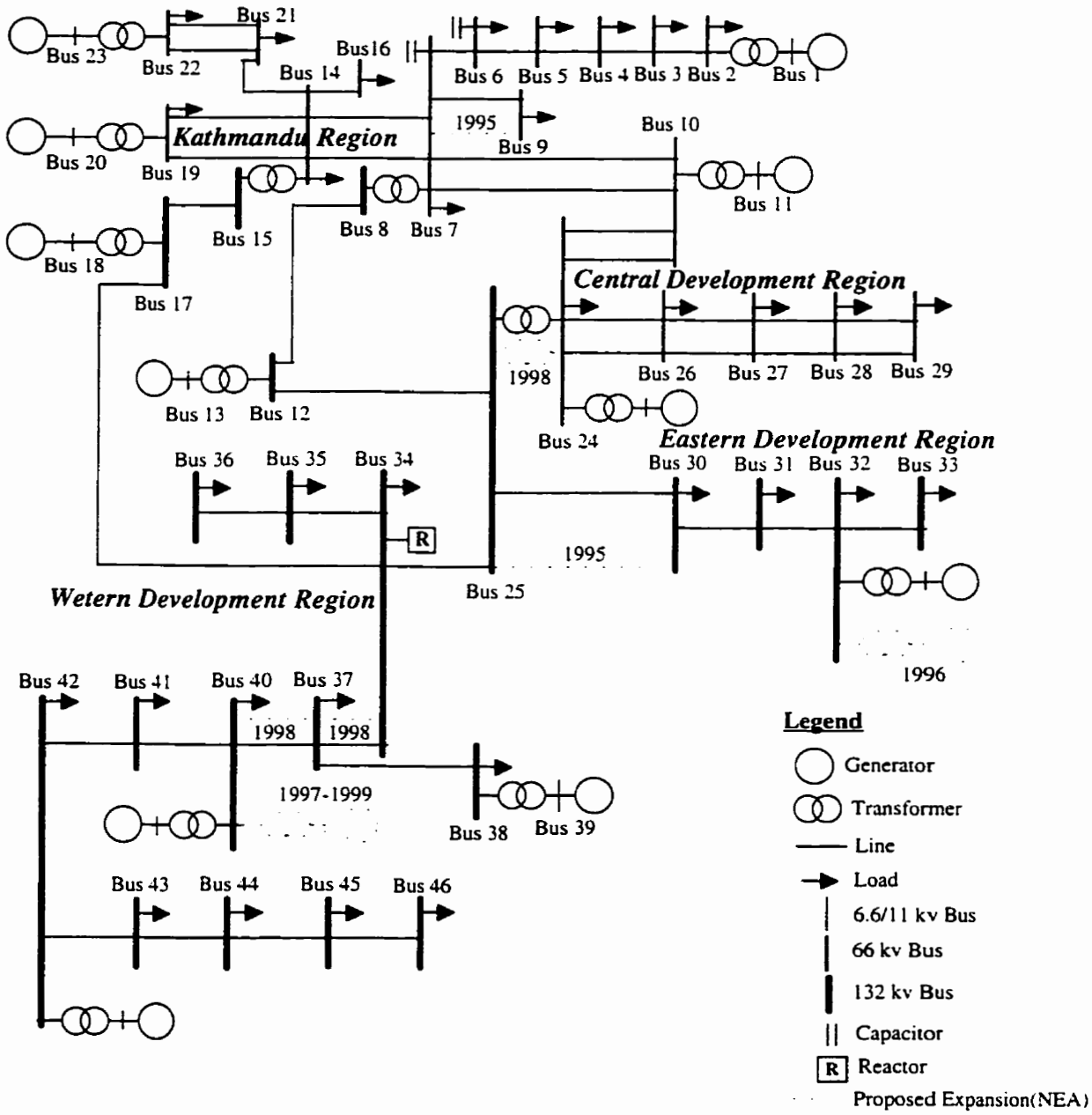

Figure 2.1. Single Line Diagram of the NPS

Table 2.1. Description of Existing Buses in the NPS

Bus Name	Bus No.	Load (p.u.) P	Load (p.u.) Q	P_G (p.u.)	Q_{max} (p.u.)	Q_{min} (p.u.)	V_o (p.u.)	V_{max} (p.u.)	V_{min} (p.u.)
Sunkosi	1	0.0000	0.0000	0.10	+ 0.06	- 0.06	1.02	1.05	0.95
Sunkosi	2	0.0228	0.0109	0.00	0.00	0.00	1.02	1.05	0.95
Banepa	3	0.0482	0.0231	0.00	0.00	0.00	1.00	1.05	0.95
Bhaktapur	4	0.0828	0.0397	0.00	0.00	0.00	1.00	1.05	0.95
Baneswar	5	0.1656	0.0794	0.00	0.00	0.00	1.00	1.05	0.95
Patan	6	0.1031	0.0494	0.00	+ 0.10	0.00	1.00	1.05	0.95
Siuchatar	7	0.0899	0.0431	0.00	+ 0.10	0.00	1.00	1.05	0.95
Siuchatar	8	0.0000	0.0000	0.00	0.00	0.00	1.00	1.05	0.95
Teku	9	0.1946	0.0934	0.00	0.00	0.00	1.00	1.05	0.95
Kulekhani I	10	0.0000	0.0000	0.00	0.00	0.00	1.02	1.05	0.95
Kulekhani I	11	0.0000	0.0000	0.60	+ 0.36	- 0.36	1.02	1.05	0.95
Kulekhani II	12	0.0000	0.0000	0.00	0.00	0.00	1.02	1.05	0.95
Kulekhani II	13	0.0000	0.0000	0.32	+ 0.19	- 0.19	1.02	1.05	0.95
Balaju	14	0.1138	0.0546	0.00	0.00	0.00	1.00	1.05	0.95
Balaju	15	0.0000	0.0000	0.00	0.00	0.00	1.00	1.05	0.95
Lainchaur	16	0.1921	0.0922	0.00	0.00	0.00	1.00	1.05	0.95
Marsyangdi	17	0.0000	0.0000	0.00	0.00	0.00	1.02	1.05	0.95
Marsyangdi	18	0.0000	0.0000	0.69	+ 0.40	- 0.40	1.02	1.05	0.95
Trisuli	19	0.0106	0.0051	0.00	0.00	0.00	1.02	1.05	0.95
Trisuli	20	0.0000	0.0000	0.21	+ 0.12	- 0.12	1.02	1.05	0.95
Chabel	21	0.1037	0.0497	0.00	0.00	0.00	1.00	1.05	0.95
Devighat	22	0.0160	0.0076	0.00	0.00	0.00	1.02	1.05	0.95
Devighat	23	0.0000	0.0000	0.14	+ 0.08	- 0.08	1.02	1.05	0.95
Hetaunda	24	0.1073	0.0515	0.10	+ 0.06	-0.06	1.02	1.05	0.95
Hetaunda	25	0.0000	0.0000	0.00	0.00	0.00	1.02	1.05	0.95
Amlekhgunj	26	0.0049	0.0023	0.00	0.00	0.00	1.00	1.05	0.95
Simra	27	0.0155	0.0074	0.00	0.00	0.00	1.00	1.05	0.95
Parwanipur	28	0.0736	0.0353	0.00	0.00	0.00	1.00	1.05	0.95
Birgunj	29	0.1011	0.0485	0.00	0.00	0.00	1.00	1.05	0.95
Dhalkebar	30	0.0665	0.0319	0.00	0.00	0.00	1.00	1.05	0.95
Lahan	31	0.1269	0.0609	0.00	0.00	0.00	1.00	1.05	0.95
Duhubi	32	0.2405	0.1154	0.26	+ 0.13	- 0.13	1.02	1.05	0.95
Anarmani	33	0.0471	0.0226	0.00	0.00	0.00	1.00	1.05	0.95
Bharatpur	34	0.0667	0.0320	0.00	0.00	- 0.10	1.00	1.05	0.95
Damauli	35	0.0196	0.0094	0.00	0.00	0.00	1.00	1.05	0.95
Pokhara	36	0.0936	0.0450	0.00	0.00	0.00	1.00	1.05	0.95
Bardhghat	37	0.0114	0.0054	0.00	0.00	0.00	1.00	1.05	0.95
Gandak	38	0.0065	0.0031	0.00	0.00	0.00	1.02	1.05	0.95
Gandak	39	0.0000	0.0000	0.15	+0.07	- 0.07	1.02	1.05	0.95
Butwal	40	0.1276	0.0612	0.05	+ 0.02	- 0.02	1.02	1.05	0.95
Shivpur	41	0.0090	0.0043	0.00	0.00	0.00	1.00	1.05	0.95
Lamahi	42	0.0068	0.0032	0.12	+ 0.06	- 0.06	1.02	1.05	0.95
Kohalpur	43	0.0634	0.0304	0.00	0.00	0.00	1.00	1.05	0.95
Chisapani	44	0.0031	0.0015	0.00	0.00	0.00	1.00	1.05	0.95
Ataria	45	0.0245	0.0117	0.00	0.00	0.00	1.00	1.05	0.95
Mahennagar	46	0.0128	0.0061	0.00	0.00	0.00	1.00	1.05	0.95

Deterministic data pertinent to individual generating units existing in the system are available and were obtained from Reference 2. The required stochastic data are not available at the present time. The required data were derived using the information given in Reference 24 and the actual unit characteristics obtained from the NEA. The basic process used was as follows.

Reference 24 lists average outage data in terms of generating unit type, maximum continuous rating (MCR), years of service and operating factor. For example, the Forced Outage Rates (FOR) for a 30 MW hydro unit with 20 years in service and an operating factor of 90%, [units connected at Kulekhani I power station (bus 11)], are 4.51%, 3.81% and 1.11% respectively. The average of these values is 3.1%, and therefore 3% was selected as the FOR for the unit and designated as the 'Normal' rate in Table 2.2. Other data were similarly derived. If the unit is out of the range given in Reference 24, then its value was extrapolated from the data already derived. The generating unit ratings and reliability data derived for the system are shown in Table 2.2.

Table 2.2. Generating Unit Reliability Data (Normal), 1995 Configuration

Unit Size MW	Number of Units	Type of Units	Forced Outage Rate(3)	MTTF(1) hrs.	MTTR(2) hrs.
2.50	4	Diesel	0.035	1251	45
3.00	7	Hydro	0.010	4380	45
3.35	3	Hydro	0.010	4380	45
4.70	3	Hydro	0.015	3504	55
5.00	4	Hydro	0.015	3504	55
12.00	1	Hydro	0.020	2920	60
16.00	2	Hydro	0.020	2920	60
23.00	3	Hydro	0.025	2502	65
26.00	1	Multifuel	0.050	1095	60
30.00	2	Hydro	0.030	2190	70

(1) MTTF = Mean Time To Failure
(2) MTTR = Mean Time To Repair
(3) Forced Outage Rate(FOR) = $\frac{MTTR}{MTTF + MTTR}$

The parameters needed in frequency and duration calculations, i.e. MTTF and MTTR were derived in addition to the FOR. Scheduled maintenance data are not available at the present time. Table 2.2 gives data on full outages only. Generating units can also experience partial outages, both forced and scheduled. Partial outage data are also not available. Scheduled maintenance and partial outages, however, can have significant effects on generation reliability [17]. These data therefore should be collected and incorporated in future studies.

The stochastic parameters shown in Table 2.2 were derived from comprehensive outage data provided by Canadian utilities. Arguably, they may not be valid for power systems in developing countries. These parameters can, however, be considered as 'Normal" or standard values. It is possible that the system component outage rates for developing countries may be higher than the 'Normal' values derived. A set of increased values designated as 'Extreme' were constructed for the NPS as shown in Table 2.3.

Table 2.3. Generating Unit Reliability Data (Extreme), 1995 configuration

Unit Size MW	Number of Units	Type of Units	Forced Outage Rate	MTTF hrs.	MTTR hrs.
2.50	4	Diesel	0.14	614	100
3.00	7	Hydro	0.04	2400	100
3.35	3	Hydro	0.04	2400	100
4.70	3	Hydro	0.06	1990	120
5.00	4	Hydro	0.06	1990	120
12.00	1	Hydro	0.08	1725	150
16.00	2	Hydro	0.08	1725	150
23.00	3	Hydro	0.10	1530	170
26.00	1	Multifuel	0.15	963	170
30.00	2	Hydro	0.10	1800	200

The 'Extreme' forced outage rate values were taken to be four times the corresponding normal values with a maximum limitation of 10% for hydro units and 15% for thermal units. The MTTF and MTTR values were scaled accordingly.

The NEA has recorded some component outage data over the past two years. These data were processed to derive the generating unit reliability data shown in Table 2.4.

Table 2.4. Generating Unit Reliability Data Derived from the Available Outage Data Collected by the NEA

Unit size MW	No of Units	Unit Type	Forced Outage Rate	MTTF Hours	MTTR Hours
2.50	4	Diesel	0.064	1460	100
3.00	7	Hydro	0.033	2920	100
3.35	3	Hydro	0.022	4380	100
4.70	3	Hydro	0.014	8760	120
5.00	4	Hydro	0.027	4380	120
12.00	1	Hydro	0.014	8760	120
16.00	2	Hydro	0.017	8760	150
23.00	3	Hydro	0.037	4380	170
26.00	1	Multifuel	0.093	1460	150
30.00	2	Hydro	0.022	8760	200

It can be seen from Table 2.4 that the actual unit FOR estimated from the collected data are lower than the designated 'extreme' values. With a few exceptions, the actual FOR were found to be higher than the derived 'normal' values. The data obtained from the NEA, however, contain considerable uncertainty as they are based on the specific units in question and collected for only a relatively short period of time. The

designated "normal" and "extreme" FOR values estimated for the NPS generating units were therefore used in the research work described in this thesis.

The generation mix in the existing system in 1995 obtained from Reference [2] is shown in Table 2.5.

Table 2.5. Generation Mix in the System

Generation	Installed Capacity (MW)	% of Total Installed
Hydro	238	87
Thermal	36	13
Total	274	100

The deterministic data pertinent to individual components within the system, such as line impedances and susceptances, current carrying capacities, generating unit parameters etc., were obtained from Reference 2. The required system data are not readily available at the present time. The stochastic data at both the system level and the component level are also not available. The data for lines and transformers were derived using the practical data given in Reference 25 and the actual transmission component characteristics obtained from the NEA. The basic approach used was as follows.

Reference 25 provides transmission line outage data under the classification of voltage level and the type of supporting structure. For example, for lines within voltage levels of 110 - 149 kV on self supporting steel tower structures, the number of sustained outages due to various causes is 878 for 60,234 Kilometer Years, which gives an average failure/year/kilometer of 0.014576. The value assumed for a 132 kV line in the

NPS is 0.015. Other data were similarly derived from the reference. The outage data so derived are again considered as 'Normal' or standard values for the NPS.

The detailed bus data used for studies at HL II for the NPS 1995 configuration are given in Appendix B. Bus load data at the time of system peak is shown in per unit. No data on load uncertainty or load diversity between buses are available. For times other than the annual system peak, the bus loads were assumed to have the same proportional relationship to the system load as at the peak conditions. The annual load duration curve was approximated in the form of a multi-step discrete load model in the bulk power system evaluation.

A 90% lagging load power factor was considered in order to derive the load MVAr requirements. This corresponds to an MVAr requirement of approximately 48 % of the MW load at each bus. The 90 % power factor is assumed to apply at all load levels. A nominal voltage of 1.0 p.u. is considered at all buses except for generating buses, in which case the value considered is 1.02 p.u. Voltage limits of ±5 % of the nominal voltage is considered at all the buses. These information were obtained from the NEA.

The locations and ratings of the generating units are shown in Table 2.6. It can be seen that 11 of the 46 buses are generating stations. Table 2.7 gives data on generating unit MVAr capability for use in load flow solutions.

The system has voltage corrective devices at buses 6, 7 and 34. Table 2.8 gives the MVAr capability of these devices.

Table 2.6. Generating Unit Locations

Bus	Unit 1 MW	Unit 2 MW	Unit 3 MW	Unit 4 MW	Unit 5 MW	Unit 6 MW	Unit 7 MW
1	3.35	3.35	3.35				
11	30.0	30.0					
13	16.0	16.0					
18	23.0	23.0	23.0				
20	3.00	3.00	3.00	3.00	3.00	3.00	3.00
23	4.70	4.70	4.70				
24	2.50	2.50	2.50	2.50			
32	26.0						
39	5.00	5.00	5.00				
40	5.00						
42	12.0						

Table 2.7. Generating Unit MVAr Capability Data

Unit Size (MW)	MVAr Capability	
	Minimum	Maximum
2.50	- 1.5	+ 1.5
3.00	- 1.7	+ 1.7
3.35	- 2.0	+ 2.0
4.70	- 2.7	+ 2.7
5.00	- 2.3	+ 2.3
12.0	- 6.0	+ 6.0
16.0	- 9.5	+ 9.5
23.0	- 13.4	+ 13.4
30.0	- 18.0	+ 18.0

Table 2.8. Voltage Correction Device Data

Device	Bus	MVAr Capability
Capacitor	6	10
Capacitor	7	10
Reactor	34	10

Transmission line lengths and the derived sustained forced outage data are given in Table 2.9. Sustained outages are those which require component repair in order to restore the component to service and therefore both outage rate and outage duration are given. Transient outages include both automatic and manual reclosing and are not considered in the studies described in this thesis.

Table 2.9. Transmission Facility and Outage Data

Line No	From Bus	To Bus	Facility or Length (km)	Outage Rate failure/yr	Outage Duration Hours
1	1	2	Transformer	0.020	768
2	1	2	Transformer	0.020	768
3	2	3	28	0.560	10
4	3	4	12	0.240	10
5	4	5	15	0.300	10
6	5	6	2.8	0.056	10
7	6	7	4.0	0.080	10
8	7	8	Transformer	0.020	768
9	7	9	3.0	0.060	10
10	7	10	29	0.058	10
11	7	10	29	0.058	10
12	8	12	34	0.510	15
13	10	11	Transformer	0.020	768
14	10	11	Transformer	0.020	768
15	10	24	16	0.320	10
16	10	24	16	0.320	10
17	12	13	Transformer	0.020	768
18	12	25	8	0.120	15
19	14	7	7	0.140	10
20	14	7	7	0.140	10
21	14	15	Transformer	0.020	768
22	14	16	2.33	0.046	10
23	14	19	29	0.580	10
24	14	19	29	0.580	10
25	14	21	15	0.300	10
26	15	17	84	1.260	15

Table 2.9. (Contd.)

Line No	From Bus	To Bus	Facility or Length (km)	Outage Rate failure/yr	Outage Duration Hours
27	17	18	Transformer	0.020	768
28	17	18	Transformer	0.020	768
29	17	18	Transformer	0.020	768
30	17	34	25	0.375	15
31	19	20	Transformer	0.020	768
32	19	20	Transformer	0.020	768
33	21	22	33	0.660	10
34	21	22	33	0.660	10
35	22	23	Transformer	0.020	768
36	22	23	Transformer	0.020	769
37	22	23	Transformer	0.020	768
38	24	25	Transformer	0.020	768
39	24	25	Transformer	0.020	768
40	24	26	16	0.320	10
41	24	26	16	0.320	10
42	25	34	70	1.050	15
43	25	30	137	2.055	15
44	26	27	10	0.200	10
45	26	27	10	0.200	10
46	27	28	9	0.180	10
47	27	28	9	0.180	10
48	28	29	9	0.180	10
49	28	29	9	0.180	10
50	30	31	66	0.990	15
51	31	32	80	1.200	15
52	32	33	76	1.140	15
53	34	35	35	0.525	15
54	34	37	70	1.050	15
55	35	36	50	0.750	15
56	37	38	14	0.210	15
57	37	40	43	0.645	15
58	38	39	Transformer	0.020	768
59	38	39	Transformer	0.020	768
60	40	41	61	0.915	15
61	41	42	51	0.765	15
62	42	43	96	1.440	15
63	43	44	80	1.200	15
64	44	45	73	1.095	15
65	45	46	37	0.555	15

Impedance and rating data for lines and transformers obtained from Reference [2] are given in Appendix B. The "B" value in the impedance data is the total amount, not the value in one leg of the equivalent circuit. Only normal ratings are considered. Short term and long term ratings are not available at the present time. The normal rating is the daily peak loading capability of a circuit with due allowance for load cycles. The long term rating is the capability of a circuit to handle a 24 hour load cycle following a contingency, and the short term rating is the loading capability of a circuit following one or more system contingencies allowing for 15 minutes to provide corrective action [31].

There are several existing lines in the system which are on a common tower structure. Table 2.10 shows the line pairs and their lengths which share the common structure. In addition to the exposure to outages shown in Table 2.9, these circuits are exposed to common mode failures. Data on this type of failure are not available for the NPS. The common mode outage rates were considered as 10% of the independent outage rates and the repair times were based on available practical data. The derived data are given in Table 2.10. These values were considered to be the standard transmission parameters for the NPS.

The complete bus data, generator data and line data for 1995 NPS configuration required for composite system reliability evaluation are given in Appendix B. The data are sufficient to conduct a DC load flow evaluation for the system. The data are not complete, however, for an AC load flow as additional data on voltage regulation and transformer tap information are required.

Table 2.10. Common Mode Failure Data

Double Circuit No.	Line No.	From Bus	To Bus	Common Length (KM)	Outage Rate failures/yr	Repair Time (hr)
1	10	7	10	29	0.058	20
	11					
2	15	10	24	16	0.032	20
	16					
3	19	14	7	7	0.014	20
	20					
4	23	14	19	29	0.058	20
	24					
5	33	21	22	33	0.066	20
	34					
6	40	24	26	16	0.032	20
	41					
7	44	26	27	10	0.020	20
	45					
8	46	27	28	9	0.018	20
	47					
9	48	28	29	9	0.018	20
	49					

As noted, the load modeling approach provided with the IEEE-RTS can prove to be useful in generating the required load data for reliability studies in developing countries. A load model for the NPS was developed using actual annual system load

data in a similar manner to that proposed in the IEEE-RTS. The data on weekly peak loads in percent of the annual peak starting with the month of January are given in Table 2.11. The annual peak occurs in week 2 (January, during the winter season) and the lowest load occurs in week 27(July, during the summer season, Monsoon period)

Table 2.11. Weekly Peak Load in Percent of Annual Peak

Week	Peak Load (%)	Week	Peak Load (%)
1	97.5	27	64.8
2	100.0	28	71.7
3	99.5	29	79.4
4	96.8	30	77.9
5	96.6	31	78.3
6	99.2	32	80.9
7	96.2	33	75.7
8	78.3	34	80.4
9	77.4	35	82.9
10	77.2	36	90.6
11	85.5	37	89.4
12	84.1	38	85.6
13	85.1	39	87.5
14	77.2	40	77.9
15	85.4	41	90.2
16	75.9	42	89.4
17	70.1	43	89.1
18	72.8	44	90.8
19	70.8	45	93.6
20	70.5	46	94.2
21	73.8	47	95.9
22	68.7	48	92.5
23	75.6	49	95.3
24	69.3	50	95.6
25	66.3	51	96.3
26	70.4	52	94.7

The pattern of daily peaks in terms of weekly peaks was also derived from the actual daily peak load records of the system. Table 2.12 gives the derived data, which shows a daily peak load cycle in percent of the weekly peak. The same weekly peak load cycle is assumed to apply for all weeks of the year. The data in Tables 2.11 and 2.12, together with the annual peak load defines a daily peak load model of 52 x7 = 364 days, with Sunday as the first day of the year.

The actual hourly load variation data for three typical days: winter day, summer day and festival day were used in the model. Accordingly, the 52 weeks in a year can be grouped into three seasons: winter weeks (1-8 & 44-52), summer weeks (9-34) and festival weeks (35-43). Table 2.13 gives the hourly load data derived for the three seasons.

The data given in Tables 2.11, 2.12 and 2.13, and the annual peak load can be combined to create an hourly load model of 364 x 24 = 8736 hours. The load models obtained using the basic data listed in Tables 2.11, 2.12 and 2.13 provide a practical representation of the Nepal load profile which can be used in a wide range of reliability studies.

Table 2.12. Daily Peak in Percent of Weekly Peak

Day	Peak Load (%)
Sunday	95
Monday	98
Tuesday	98
Wednesday	100
Thursday	97
Friday	95
Saturday	92

Table 2.13. Hourly Load in Percent of Daily Peak

Hour	Winter Weeks (1-8 & 44-52)	Summer Weeks (9-34)	Festival Weeks (35-43)
12-1 a.m.	48	53	51
1-2	44	42	43
2-3	44	42	44
3-4	45	45	45
4-5	47	48	54
5-6	60	59	64
6-7	78	70	64
7-8	86	75	61
8-9	86	75	55
9-10	79	62	55
10-11	70	51	50
11-12 noon	60	51	42
12-1 p.m.	54	49	41
1-2	52	50	41
2-3	57	50	42
3-4	57	55	49
4-5	66	59	56
5-6	95	64	100
6-7	100	98	100
7-8	100	100	90
8-9	93	100	90
9-10	85	94	80
10-11	67	74	67
11-12 midnight	53	59	65

The generating unit priority loading order and operating cost data for the NPS obtained from the NEA are shown in Table 2.14. The cost data are given in the

Nepalese Rupees (Rs). These data are readily available as they are used in a range of system studies.

Table 2.14. Generating Unit Priority Loading Order and Operating Cost Data for the NPS

Priority Order	Unit ID	Rated Capacity (MW)	Fixed Cost (Rs/kW/year)	Variable Cost (Rs/MWh)	Bus	Location
1	1	3.00	285.00	170.00	20	Trisuli
2	2	3.00	285.00	170.00	20	Trisuli
3	3	3.00	285.00	170.00	20	Trisuli
4	4	3.00	285.00	170.00	20	Trisuli
5	5	3.00	285.00	170.00	20	Trisuli
6	6	3.00	285.00	170.00	20	Trisuli
7	7	3.00	285.00	170.00	20	Trisuli
8	8	3.35	400.00	180.00	1	Sunkoshi
9	9	3.35	400.00	180.00	1	Sunkoshi
10	10	3.35	400.00	180.00	1	Sunkoshi
11	11	4.70	567.00	190.00	23	Devighat
12	12	4.70	567.00	190.00	23	Devighat
13	13	4.70	567.00	190.00	23	Devighat
14	14	12.00	156.00	200.00	42	Jhimruk
15	15	30.00	100.00	210.00	11	Kulekhani I
16	16	30.00	100.00	210.00	11	Kulekhani I
17	17	16.00	156.00	200.00	13	Kulekhani II
18	18	16.00	156.00	200.00	13	Kulekhani II
19	19	23.00	87.00	250.00	18	Marsyangdi
20	20	23.00	87.00	250.00	18	Marsyangdi
21	21	23.00	87.00	250.00	18	Marsyangdi
22	22	5.00	267.00	320.00	39	Gandak
23	23	5.00	267.00	320.00	39	Gandak
24	24	5.00	267.00	320.00	39	Gandak
25	25	5.00	267.00	320.00	40	Andhikhola
26	26	26.00	115.00	2470.00	32	Duhabi
27	27	2.50	343.00	2500.00	24	Hetaunda
28	28	2.50	343.00	2500.00	24	Hetaunda
29	29	2.50	343.00	2500.00	24	Hetaunda
30	30	2.50	343.00	2500.00	24	Hetaunda

Table 2.15. Additional Generating Unit Cost Data

Rated Capacity (MW)	Type	FOR		MTTF (hr)		MTTR (hr)		Capital Cost (Rs/kW/yr)	Operating Cost	
		N	E	N	E	N	E		Fixed (Rs/kW/yr)	Variable (Rs/MWh)
26.0	Multifuel	0.050	0.15	1095	963	60	170	692.00	115.00	2470.00
2.5	Diesel	0.035	0.14	1251	614	45	100	800.00	343.00	2500.00

Note: N = 'normal'
E = 'extreme'

The transmission cost data were obtained from Reference 33. The basic transmission cost data used in the studies described later in this thesis are shown in Table 2.16. The costs are total costs inclusive of components, accessories and ancillary materials required for complete transmission facility installation.

Table 2.16. Basic Transmission Cost Data [33]

Description	Voltage	Type	Per	Cost (x 1000 US $)
Overhead Lines:	132 kV	Double Circuit	km	160.0
	132 kV	Single Circuit	km	100.0
	66 kV	Double Circuit	km	120.0
	66 kV	Single Circuit	km	80.0
Transformers:	66/11 kV	10 MVA	No.	150.0
	66/11 kV	20 MVA	No.	250.0
	66/11 kV	30 MVA	No.	300.0
	132/11 kV	20 MVA	No.	300.0
	132/11 kV	40 MVA	No.	400.0
	132/66 kV	20 MVA	No.	500.0
	132/66 kV	45 MVA	No.	800.0

US $ 1 = Rs 56 (1996)

2.4. Summary

This chapter describes the various aspects of data requirements in reliability evaluation. Two types of data designated as 'Deterministic' and 'Stochastic' data are required in reliability studies. Each type of data is required at both the system level and at the actual component level.

Data requirements for HL I evaluation are minimal compared to those required for HL II studies, as HL I involves only generating unit data. The evaluation of a composite system including both generation and bulk transmission is a complex problem and the data required to analyze this problem is therefore substantial. Comprehensive data at both the system level and component level are required for detailed studies at HL II.

Component level data are not normally difficult to determine as these data are used in a wide range of studies. The system data, however, are difficult to appreciate and to include in the studies. They tend to be system specific and therefore not quite as susceptible to data pooling as independent component outage data.

This chapter describes the available NPS database for reliability studies. Deterministic data at the component level are available at the present time. Stochastic data at the component level are not available for the NPS and therefore practical data were derived using information reported by Canadian utilities and actual NPS component characteristic considerations. These data were designated as 'Normal' or 'Standard' values in the system studies. Increased forced outage rates designated as 'Extreme' were also considered to conduct impact studies. At the present time, both deterministic and stochastic data at the system level are not available for the NPS.

The load modeling approach described in Reference 31 was used to derive load data for the NPS. The data obtained is based on the actual load characteristic records of the system and can be used for a wide range of reliability evaluation studies at HL I and HL II.

The cost data and some reliability data collected during the investigation in Nepal are presented in this chapter. The generating equipment forced outage rates derived from the collected data were generally lower than the designated 'extreme' values and higher than the 'normal' values. These data, however, were not considered in the studies due to inconsistencies and uncertainties in the data. The customer interruption cost data required in reliability cost/worth studies, are presented in Chapter 3.

This chapter delineates a wide range of data required for reliability studies at HL I and HL II. The investigation of the available reliability data in the NPS reveals that most data, specifically stochastic data, are not available at this time. The deterministic data, which are available, were difficult to assemble due to a lack of an appropriate data storage and retrieval system. The required data for the NPS, which are not available at the present time, were derived using comprehensive and practical outage data provided by Canadian utilities and the actual NPS component characteristics. A significant contribution of this research is an enhanced awareness of the data problems that may be encountered by system planners initiating reliability studies in developing countries. The developed NPS database and the practical approach adopted to derive the required unavailable data provides an important illustrative example for developing countries when conducting quantitative power system reliability assessments.

3. CUSTOMER SURVEY

3.1. Introduction

This chapter presents the results of a customer survey conducted in the service areas supplied by the Nepal Integrated Electric Power System (NPS). The survey conducted is an important part of the research work described in this thesis.

Most of the customer surveys conducted in the past were in developed countries, such as Sweden, Finland, France, UK, USA and Canada [22]. The Power System Research Group of the University of Saskatchewan has conducted extensive surveys in Canada since 1980 [23]. One of the main objectives of this research work was to extend the evaluation technique to a developing country and to examine the problems associated with incorporating the approach in such a system.

The research work is an investigation of direct, short term impacts and associated costs of electric interruptions in service areas supplied by a developing power system. No attempt was made to investigate the costs arising from indirect or long term impacts. The type of interruptions studied were limited to frequencies and durations typical of developing countries, i.e., frequent interruptions with short durations. The evaluation of short term and direct impacts provide valuable cost data for utility planning purposes since these are the events most customers experience due to power outages.

The major objective of the overall research work was to identify and delineate the characteristics, variables and criteria associated with the worth of electric service reliability and to develop reliability cost/worth methodologies that can be used by utilities in developing countries for power system planning and operation.

Prior to describing the survey in detail, the basic concepts of reliability worth assessment are introduced. An overview of the interruption cost methodologies is then presented. The survey methodology adopted in this research work is described and the survey results obtained for the residential, commercial and industrial customer sectors are presented and discussed.

3.2. Reliability Worth Assessment

Reliability cost/worth analysis involves an assessment of the costs of providing reliable service and a separate quantification of the worth of having that service. The objective of a reliability worth study is to estimate or assign a value to the worth of electric power service to the consuming public. This value can then be used in the cost/benefit analysis of an electric power system for planning purposes. This economic analysis is fundamental to establishing a balance between expenditures required to obtain a certain level of reliability and the worth of having that level.

The methodologies employed to assess the reliability of an electric power system and the associated costs of achieving that level of reliability are well established and are used by many utilities throughout the world in power system planning and operation [22]. The methodologies available to assess the worth to the consumer of a certain level of power system reliability, however, are still developing. Reliability worth assessment has become a matter of significant study in recent years [11, 21].

Direct assessment of power system reliability worth is a difficult task. Earlier work in this area indicates that the worth of reliability in monetary terms cannot be obtained directly. The cost associated with unreliability of the supply system, however, can be estimated and considered as an indirect indicator of the reliability worth.

A common approach used in quantifying reliability worth of an electric system is to estimate the customer costs or monetary losses resulting from power supply interruptions. It is therefore essential to have some understanding of the ways that an interruption affects the customer. Interruption effects can be broadly classified as direct and indirect effects [34]. Direct effects are those arising directly from the electrical interruption and relate to such impacts as lost production, spoiled food or raw materials, paid staff unable to work, lost personal leisure time, injury or loss of life. Indirect effects are related to impacts arising from response to the interruption, such as crimes during blackouts (short term effect) or businesses moving to areas with higher reliability (long term effect).

Impact evaluation requires identification and quantification in monetary terms. Many direct impacts are relatively easy to identify and assign a monetary value, while others, such as fear of crime, injury or loss of life, are easy to identify but difficult to quantify. Still others are less tangible and difficult to predict and evaluate, such as the loss of companies from an area due to unreliable power supply, or loss of customer faith earned by a utility. It is important to note that the interruption cost estimates are not considered equal to reliability worth, but are a very useful and practical surrogate.

The consequences of an interruption are highly dependent on the characteristics of the interruption as well as that of the customer concerned. Interruption characteristics

include frequency, duration, time of occurrence, advance warning, and the extent of the interruption. Customer characteristics include the type of customer, size of operation, demand and energy requirements, and advance preparation for the outage. Additional factors such as the outside temperature or the occurrence of the interruption during special events also affect the impact. The level of reliability the users have experienced in the past and expect in the future may have a significant effect on the interruption costs [34].

3.3. Interruption Cost Methodologies

Obtaining customer interruption costs is a complex and often subjective task. A review of the literature [11, 19, 20] reveals that the impacts of interruptions can be evaluated using a variety of approaches. These methods can be grouped into three basic categories: analytical methods, case studies of actual blackouts, and customer surveys.

3.3.1. Analytical Methods

There is a large number of methods which can be classified as analytical. Analytical methods generally evaluate the interruption costs from a theoretical economic viewpoint. Many of the methods attempt to be market-based, while others utilize readily available secondary data, such as global economic indices. An example of this approach is a method which attempts to estimate the interruption cost based on the ratio of the Gross National Product (GNP) and the consumption of electrical energy from the viewpoint of the nation as a whole [35]. The main advantage of these methods is the relative simplicity of the assessment. The inability to provide assessments other than for only large geopolitical regions limits the use of most analytical methods. In general, these approaches do not reflect the actual consumers needs.

3.3.2. Case Studies of Actual Blackouts

The case study approach attempts to estimate losses caused by an actual power interruption. Both direct costs as well as indirect consequences can be addressed. For example, the study of the 1977 New York blackout [36] considered a wide range of societal and organizational impacts along with the direct and indirect consequences of the events. A very important finding of this particular study was that the indirect costs (3.45 $/kWh) can significantly exceed the direct costs (0.66 $/kWh). The results also suggest that a widespread blackout has more serious consequences than local power outages. Valuable information can be obtained from case studies of actual blackouts. Unfortunately, this information is restricted to the specifics of the individual interruption event and its location. The costs associated with specific interruptions cannot be generalized to other locations and other interruption characteristics.

3.3.3. Customer Surveys

The results from both the analytical methods and the case studies indicate that for interruption cost assessments to be realistic, they should obtain information that is customer specific. 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 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 locations, the resources available and the utility's needs.

Customer survey methods can be grouped into the three categories of contingent valuation methods, direct costing methods, and indirect costing methods [23]. Most customer surveys incorporate a combination of all three approaches. The choice is largely dependent upon the type of customer being surveyed.

Contingent Valuation Methods

Contingent valuation methods are based on two basic concepts of electricity use. The first concept is that customers consume electricity in a predetermined 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 by either the customer's willingness to pay (WTP) to avoid an interruption and have the benefit or by the customer's willingness to accept (WTA) compensation for having an interruption and deprived of the benefit of electricity uses.

Theoretically, the WTP and WTA methods should yield the same cost value, but typically they do not. This is probably due to customer bias regarding electricity rates, or it may simply be a reflection of the difference between the "bid" and "asked for" price. These costs, however, can be considered as two bounds on reliability worth for a given type of customer surveyed. This approach, being based upon the fundamental principal of electricity use, is suitable for any type of customer. The limitation is the costs evaluated may be comparatively very rough compared to other costing methods.

Direct Costing Methods

Direct costing methods ask the customer to identify impacts of a particular outage scenario and then to evaluate the monetary losses of those impacts. Customers are guided to evaluate the monetary losses by suggesting possible impacts such as 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 of an economic nature, such as in commercial and industrial sectors.

Indirect Costing Methods

Indirect costing methods are based on the economic principle of substitution (EPS), in which the value of a replacement product or service is used as a measure of the worth of the product or service that was replaced. This approach is particularly useful when social impacts or other less tangible consequences are expected to comprise a significant portion of the overall interruption effects, such as in the residential sector. One form of this approach is to offer customers a choice from a series of preparatory actions that they might take in the event of recurring interruptions. The actions may range from doing nothing to installing a back-up supply capable of handling the entire load. The value of the preparatory actions provides a means to evaluate the financial burden that the customer would be willing to bear to alleviate the consequences of outages. The value of the choice(s) that the customer makes represents the value or worth of electric supply.

In this research work, both the contingent valuation method and the indirect costing method were used for residential customers and the direct costing method was used for commercial and industrial sectors.

3.4. Survey Methodology

The investigation was conducted using the following three main stages:

1. Background Information and Preparation;
2. Conducting the Surveys in Nepal; and
3. Data Analysis.

3.4.1. Background Information and Preparation

The investigation began with an extensive literature search in the area of customer surveys. Substantial time was spent in collecting and reviewing dominant literature in the study area. Bibliographies [19, 20] written by the Power System Research Group were prime sources of information for this activity. This overview provided valuable background information and a foundation for the study to follow.

Initial work began with the development of survey questionnaires for the following five main categories of electric consumers in developing countries:

1. Residential Consumers;
2. Commercial Trades and Services;
3. Industrial Companies;
4. Agriculture Farms; and
5. Government Institutions and other Organizations.

Specific questionnaires and approaches used by others were thoroughly investigated. The questionnaire contents and formats developed by the Power System Research Group [23] were considered to be the most suitable and were used as the basis for the survey. Modifications were incorporated to suit the prevailing situations in a developing country. Further modifications to be incorporated in the questionnaires were anticipated after the pre-test survey in Nepal.

All sector questionnaires begin with questions related to the respondents' experience with electrical service. This is important as it establishes the context for the remaining questions. As respondents begin to consider how many interruptions they have experienced, they also begin to consider what happens during an interruption.

The next set of questions then asks about the specific effects of an interruption. Respondents are asked to rate the negative effects of an interruption using a list of activities or equipment that are electricity dependent. These questions move the respondent from general thoughts about interruptions to the more specific effects of an interruption.

After the negative effects of an interruption are identified and considered, respondents are asked to rate these effects in terms of different interruption scenarios, such as outage frequency, duration, time of the day, day of the week, and season of the year. This is a shift from the evaluation of user characteristics to an evaluation of interruption characteristics.

The last section of the questionnaire contains the cost questions. This is the most important section of the questionnaire and seeks to obtain information about the monetary values associated with the effects of the interruption on the respondent.

The following service areas were considered for conducting surveys. This was based on considering the major development regions of the country, and the load centers identified in a previous investigation [27] as being critical for reliability improvement.

- Areas in Kathmandu Region (capital city of the country): Baneswar, Patan, Siuchatar, Teku, Balaju, Lainchaur and Chabel; Load buses 5, 6, 7, 9, 14, 16 and 21 respectively (see Figure 2.1).
- Western Development Region: Butwal and Bhairahawa; Load bus 40.
- Central Development Region: Hetaunda, Simra, Parwanipur, Birgunj and Bharatpur; Load buses 24, 27, 28, 29 and 34 respectively.
- Eastern Development Region: Lahan, Biratnagar and Anarmani; Load buses 31, 32 and 33 respectively.

An initial contact with the Nepal Electricity Authority (NEA) was made by correspondence in order to familiarize the utility with the objectives of the research and to gain support for the survey at a later stage. The NEA showed interest and agreed to provide information and data required in the research work.

3.4.2. Conducting the Surveys in Nepal

Customer surveys can be conducted by mail, telephone or using in-person interviews. The activity in Nepal began by investigating the possibilities of using these techniques and selecting the most viable approach. Researchers who had conducted

similar surveys in other areas such as health, education etc., were contacted to have an input. It was found that most surveys conducted in Nepal used in-person interviews. Mail surveys were not considered viable because of the unavailability of a bulk postage paid mail system in Nepal, and extremely poor response rates experienced by other research organizations. Customer surveys by telephone are not feasible because of the detailed customer information requirements, and the lack of awareness of the concept and practice in the country. It was therefore decided to conduct surveys using in-person interviews.

The NEA offices at Kathmandu were visited during this phase of the research work. The purpose was to explain the objectives of the research and to gain support from the key personnel within the utility. These initial visits also served to finalize the proposed service areas and to provide input on the sample sizes for each of the service areas.

After the decision was made to use in-person interviews, a survey team was established by hiring experienced surveyors and substantial time was spent in orientation and training. The questionnaires developed earlier in Canada were discussed, revised and translated into the local language. The team conducted a pre-test survey of 200 sample customers in Kathmandu. The samples comprised 100 residential, 75 commercial and 25 industrial customers. This pre-test survey served as a means to review and subsequently finalize the survey procedures and questionnaire format and content for the detailed survey subsequently conducted throughout the country.

An area sector sample size was selected for the detailed survey based on information obtained from the NEA regarding the population of each customer sector in the proposed service areas, and the pre-testing survey results indicating the number of a

particular sector customers that could be interviewed in a day. Table 3.1 lists the resulting survey sample sizes by area and sector.

A detailed customer survey was first conducted in the designated service areas in Kathmandu followed by surveys in other parts of the country with the objective of obtaining the target samples in the residential, commercial and industrial sectors. A typical feature of these sectors in a developing country such as Nepal is that residential and commercial customers are usually found together but spread throughout an area, whereas most industries are located in specifically designated areas called industrial districts. The survey team was therefore divided into two groups. One group was assigned to conduct surveys on both residential and commercial sectors, whereas the other group was devoted to the industrial sector.

Table 3.1. Planned Area Sector Sample Sizes

Service Area	Bus No	Residential	Commercial	Industrial
Baneswar	5	100	75	-
Patan	6	100	100	50
Siuchatar	7	25	100	-
Teku	9	150	100	-
Balaju	14	75	25	50
Lainchaur	16	50	25	-
Chabel	21	75	75	-
Total Kathmandu		575	500	100
Hetaunda	24	100	25	25
Parwanipur	28	-	-	25
Birgunj	29	100	50	25
Biratnagar/Duhabi	32	100	50	25
Anarmani/Bhadrapur	33	25	25	25
Bharatpur	34	100	50	25
Butwal/Bhairawa	40	200	100	50
Total Nepal		**1200**	**800**	**300**

After completing the pre-testing and the detailed survey in Kathmandu, the team conducted the surveys in other parts of the country. Due to a lack of time and funding, the customer survey in Simra, Lahan, and Anarmani could not be conducted. The usable responses obtained from the interviews were 944, 709 and 236 for the residential, commercial and industrial sectors respectively.

The number of customers interviewed was limited due to a lack of time and funding. The service areas investigated, however, are considerable in terms of the network load representation and country-wide coverage. The areas represent more than 60% of the system peak load, and more than 50% of the population of the country resides in these areas. It is therefore assumed that the results are fairly representative of the sectors throughout the country. Details of the results are discussed later in the sections dedicated to each of these sectors.

3.4.3. Data Analysis

The final stage of the research work involved data compilation, analysis, and interpretation of the results. Compilation and analysis of the data was performed using a Microsoft Access relational data base management program. The survey results for the residential, commercial and industrial sectors are presented in the following sections.

3.5. Residential Customer Survey

3.5.1. Preface

The effects of power failures on residential customers tend to be of intangible nature, such as inconvenience, discomfort, etc., which are difficult to quantify in

monetary terms. A similar study in Canada [37] indicated that interruption costs in this sector cannot be obtained by a direct costing approach. Contingent valuation and indirect costing methods were therefore used to evaluate the outage costs in this sector.

It was important to survey in the residential sector because more than 90% of electricity customers in Nepal belong to this sector [3]. In-person interviews were conducted by random selection of the customers to ensure that the views represent the general perception of the customers belonging to this sector.

3.5.2. Survey Results

This section presents the results obtained from the residential customer survey. The questionnaire and additional results are included in Appendix C.

Most of the results obtained from the survey are presented in a concise and general qualitative way. Quantitative cost estimates derived from the cost questions are presented in more detail. All values quoted are from the combined customer responses except as otherwise indicated. Results for each question are reported in the same order as they appear in the questionnaire. Not all respondents answered all questions and as a result, the number of responses vary from one question to another.

Opinions Regarding Electric Service and Interruptions

Customers were asked to give their opinions regarding the quality of service provided by the NEA, the price of electricity compared to other commodities, and the number of power failures at their home. More than 85% of respondents consider the quality of service to be "poor" or "fair" and the price of electricity to be "high" or "moderate".

Regarding the number of power failures, 52% of respondents indicated it to be "high" or "moderate", 10% as "very high" and 38% as "low" or "very low".

Opinions Regarding Power Interruptions

Customers were asked to estimate the number of power failures at their house in the last two months. The mean value of the number of power interruptions in two months for the NPS was found to be 35.69 or approximately 4 times per week. It is, however, interesting to note that, of these 35.69 outages, 6.97 or approximately 20% of the failures were considered to be disruptive, and 1.69 or approximately 5% of the failures lasted 4 hours or more. It was found that some areas in the NPS have a much higher number of failures than others. Most service areas in the country (Buses 29-40) have an extremely high frequency of failure compared to those in the capital city of Kathmandu (Buses 5-21). This is a typical power system scenario in a developing country.

Electricity Demand and Consumption Information

Customers were asked to estimate their electricity demand and average monthly consumption. This information is normally obtained from the utility in developed countries. However, due to difficulties in locating and obtaining records from the NEA system, it was sought from the customers assuming that they would be in a better position to provide their individual records. The possibility was confirmed during the pre-test survey. A similar approach was used to obtain consumption information in other customer sector surveys. The average household maximum demand for the residential customers was found to be 3.4 kW and the average annual consumption 2056 kWh.

Interruption Undesirability as a Function of Household Activities

Respondents were asked to rate the undesirable effects of a power interruption on several typical household activities that are dependent on electricity. Loss of lighting was rated as being the most undesirable effect. This was followed closely by fear of crime, and leisure equipment not usable. Of less importance are motor-pumps not usable, kitchen appliances not usable, and fans, heaters not usable. The least rated undesirable effects are fear of accidents in the home, loss of use of a computer, and washing and cleaning appliances not usable.

Variation of Undesirability with Interruption Characteristics

Respondents were asked to rate the undesirability of various interruption scenarios for their household. By varying only one parameter within each set of scenarios, a relative indication of the undesirability was obtained as a function of that parameter. This question encourages the respondents to consider a range of interruption scenarios prior to answering the interruption cost questions.

Residential respondents indicated that there are significant variations in undesirability when interruption characteristics such as frequency, duration, and time of occurrence are considered. Results show that the interruptions during festival seasons are the most undesirable, followed by those in the summer and winter seasons.

It was found that the rated undesirability increases substantially as the frequency of interruption increases. Respondents were equally divided on monthly failures. A large majority of respondents considered weekly failures as undesirable. Daily failure is considered to be extremely undesirable to most of the respondents.

The results indicated that longer duration failures have greater undesirable consequences than shorter ones. Most respondents considered a 4 hour failure as extremely undesirable. The majority of respondents stated that a 1 hour failure is undesirable, whereas an interruption of 20 minutes duration is tolerable. Respondents also indicated that failures after 5 pm are considered to have worse consequences than those before 5 pm, and failures on Saturdays or other holidays have greater undesirability than on weekdays.

Cost Estimates from a Preparatory Action Approach

Customers were asked to choose from a series of preparatory actions that they might take to alleviate the consequences of recurring outages. The following six possible preparatory actions and their associated hourly costs in Nepalese Rupees (Rs) were provided to help respondents estimate their valuation:

Make no preparation;

Burn a candle at Rs 2.00 per hour;

Use a lantern at Rs 5.00 per hour;

Use a kerosene stove or equivalent at Rs 10.00 per hour;

Rent a portable electric generator at Rs 50.00 per hour; or

Rent a large electric generator at Rs 200.00 per hour.

These preparatory actions were considered to be reasonable actions that a respondent might take to alleviate the effects of an outage to his or her household activities. The costs associated with the preparatory actions were the estimated costs in Nepal at the time of the survey (March, 1996). These costs were used to estimate the

cost that respondents were willing to undertake to reduce or eliminate the adverse effects of the stated interruptions.

It was found that customers tended to choose costlier choices as the interruption frequency or duration increases. It was also found that extreme actions such as "make no preparation" or "rent a generator" are not the choices for most residential customers for any interruption. Table 3.2 presents the interruption costs estimated using the preparatory action approach. The Rs/interruption listing presents the simple average or mean value for all users whose costs were determined. The other listings are the aggregated average costs normalized by annual energy consumption (not by the unserved energy during interruptions) in Rs/MWh and peak demand in Rs/kW.

The aggregated average approach was used to off-set the impact of the relatively few large or small customers, or the relatively few respondents who report very large or very small costs. The demand normalized costs in Rs/kW were calculated using consumption normalized costs in Rs/kWh and the sector load factor information obtained from the NEA. The number of respondents used to obtain the cost estimates is shown in parenthesis.

Table 3.2. Residential Interruption Cost Estimate from the Preparatory Action Approach

Interruption Characteristic	Mean Value Rs/Interruption	Consumption Normalized Rs/MWh	Demand Normalized Rs/kW
20 minutes	1.79 [916]	0.87 [916]	1.52 [916]
1 hour	9.45 [907]	4.59 [907]	8.05 [907]
4 hours	48.87 [892]	24.02 [892]	42.08 [892]
8 hours	99.83 [886]	49.33 [886]	86.43 [886]
24 hours	358.37 [884]	177.03 [884]	310.16 [884]
48 hours	772.45 [885]	380.06 [885]	665.87 [885]

Note: Cdn $ 1 = Rs 40 (1996)
Figures in paranthesis indicate number of respondents

Customer Willingness to Reduce Consumption

Respondents were asked to indicate their willingness and ability to reduce consumption if requested to do so. This response can be used in system planning to estimate possible curtailable load. Prior to asking the question, customers were told that there is a limit to the amount of electricity that the power company can produce (due to the capacity of its equipment), and that the customer requirements at any instant must not be allowed to exceed this limit. The question begins by suggesting a scenario in which the total requirement of all the customers was nearing the maximum limit of the power company. Two options are possible: all users reduce consumption for 2 to 4 hours, or some users will experience a temporary outage.

It was found that approximately half of the population was not willing to reduce the consumption. The other half was divided over a reduction range from less than 5% to more than 20%. It can be estimated from the response that 10-15% can be considered as the maximum curtailable load in the NPS.

Cost Estimates from the Willingness-to-Pay (WTP) Questions

Respondents were asked to suppose that failures occur without warning any time during the daytime or evening, and that during a typical power failure another independently supplied source of electricity is immediately available for the respondent's use. They were then asked how much they would be willing to pay for each half hour of electricity use. It was found that a large majority of the respondents either do not want to pay or are willing to pay a maximum of Rs 2.00 for one half hour of electricity use.

Prior to asking the other willingness-to-pay question, respondents were asked to estimate an average monthly cost of electricity for their household. This serves two purposes. It reminds respondents of the cost of electricity, and it establishes a base value for the cost estimates from willingness-to-pay and willingness-to-accept questions. The average monthly electricity cost for residential customers lies in the range of Rs 300-500. The base value for the analysis was considered to be Rs 400.00.

Another WTP question was asked in which the respondents were directed to suppose that the existing electric system has become subject to more frequent power failures and that an alternative system has become available which would provide an assured electric power supply without any failures. They were then asked to indicate the maximum additional cost that they would be willing to pay each month to avoid power failures of increasing frequency by choosing the assured system. It was found that the majority of respondents were unwilling to pay additional costs for the assured system. Table 3.3 presents the interruption cost estimates obtained from the WTP questions.

Table 3.3. Interruption Cost Estimates from the WTP Questions

Interruption Characteristic	Mean Value Rs/Interruption	Consumption Normalized Rs/MWh	Demand Normalized Rs/kW
4 hour monthly	15.04 [944]	7.07 [929]	12.40 [929]
4 hour weekly	20.47 [944]	9.74 [929]	17.07 [929]
4 hour daily	33.42 [944]	15.84 [929]	27.75 [929]
30 minutes	2.30 [944]	1.16 [929]	1.95 [929]

Cost Estimates from the Willingness-to-Accept (WTA) Questions

A similar approach to that of willingness to pay for an increase in reliability is that of willingness to accept a decrease in reliability in exchange for a decrease in rates. The WTA question begins with asking respondents to suppose that they were offered the option of a cut in rates along with an increase in the number of failures. Respondents were then asked to indicate the minimum percentage decrease in rates that would satisfy them to accept an increased number of failures. It was found that almost 50% of respondents wanted a 50% or more decrease in rates to accept a four hour weekly failure and 80% of the respondents wanted a 50% or more decrease in rates to accept a four hour daily failure. This clearly indicates customer attitudes towards electricity rates and associated reliability levels. Table 3.4 presents the interruption costs obtained from the WTA questions.

Table 3.4. Interruption Cost Estimates from the WTA Questions

Interruption Characteristic	Mean Value Rs/Interruption	Consumption Normalized Rs/MWh	Demand Normalized Rs/kW
4 hour weekly	117.61 [944]	57.25 [929]	101.77 [929]
4 hour daily	166.78 [944]	81.33 [929]	142.50 [929]

3.5.3. Discussion of the Interruption Cost Results

The interruption cost estimates obtained from each approach measure different aspects of reliability worth and are not strictly comparable. Each estimate relates to different attitudes, perceptions and needs of the respondent.

In both the WTP and WTA approaches, the customer is asked to make monetary choices related to various reliability options. These decisions are based on their own needs and conditions. These methods therefore provide valuable upper and lower bound data on possible reliability levels and allow consideration of changes in reliability, both in terms of improvements and reductions.

Theoretically, costs based on WTP and WTA should be the same. Actual customer valuations however revealed that the WTP values are significantly lower than the WTA values. Consumers normally do not have a choice of supplier, and therefore their responses may be governed largely by their concern for potential rate changes. They may also think that the utility should supply a reliable power supply regardless of rates or other factors. When the above cautions are taken into account, valuations based on WTP and WTA are valuable measures and can be considered as outside bounds for cost of outage assessments.

Table 3.5 shows the outage costs obtained from the three costing methodologies. It is clear, as expected, that the WTP cost is the lowest and the WTA cost is the highest. WTP and WTA costs establish a range of costs within which the preparatory action cost lies.

Table 3.5. Outage Costs for a Four Hour Daily Failure

Methodology	Rs/Interruption	Rs/MWh	Rs/kW
Willingness-to-pay	33.42	15.84	27.75
Preparatory action	48.87	24.02	42.08
Willingness-to-accept	166.78	81.33	142.50

As shown in Table 3.5, the results from each of the three approaches are obviously not interchangeable. As previously stated, each approach measures different aspects of reliability worth. Therefore caution should be exercised in applying the costs for planning purposes. WTP and WTA costs can be used as data for reliability levels in planning new systems in new areas, or as a range for an existing system. Preparatory action costs, which are based on existing practices and costs, can be used in evaluating existing systems.

However, one point was very clear from the results shown in Tables 3.2, 3.3 and 3.4. The residential customer survey approach using indirect costing techniques such as preparatory action, WTP and WTA are quite effective in a developing country such as Nepal (more than 75% of the planned sample customers responded to the cost questions).

3.5.4. Variation in Interruption Cost Estimates with Electricity Bill

The interruption cost estimates were analyzed with variations in respondents monthly electricity bills. Figure 3.1 shows the correlation between the interruption cost and the monthly electricity cost reported by the customers. It can be clearly seen from Figure 3.1 that the value customers place on electricity is directly related to their electricity bill or use.

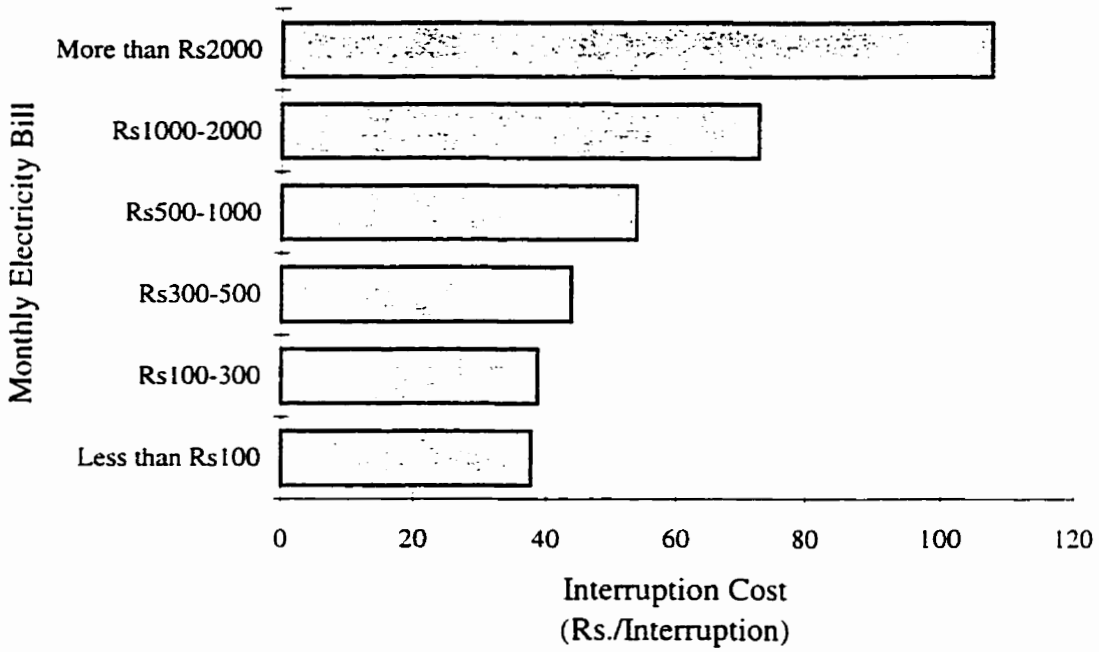

Figure 3.1. Variation in Interruption Cost with Electricity Bill

3.5.5. Variation in Interruption Cost Estimates with Service Areas and Associated Service Reliability

The study investigated the variation in interruption cost estimates among different service areas and regions. It also investigated whether there exists a relationship between the level of service reliability that users experience and the value they place on that reliability. Figure 3.2 shows the results of this study. The service areas are ordered, left to right from the highest reliability level to the lowest.

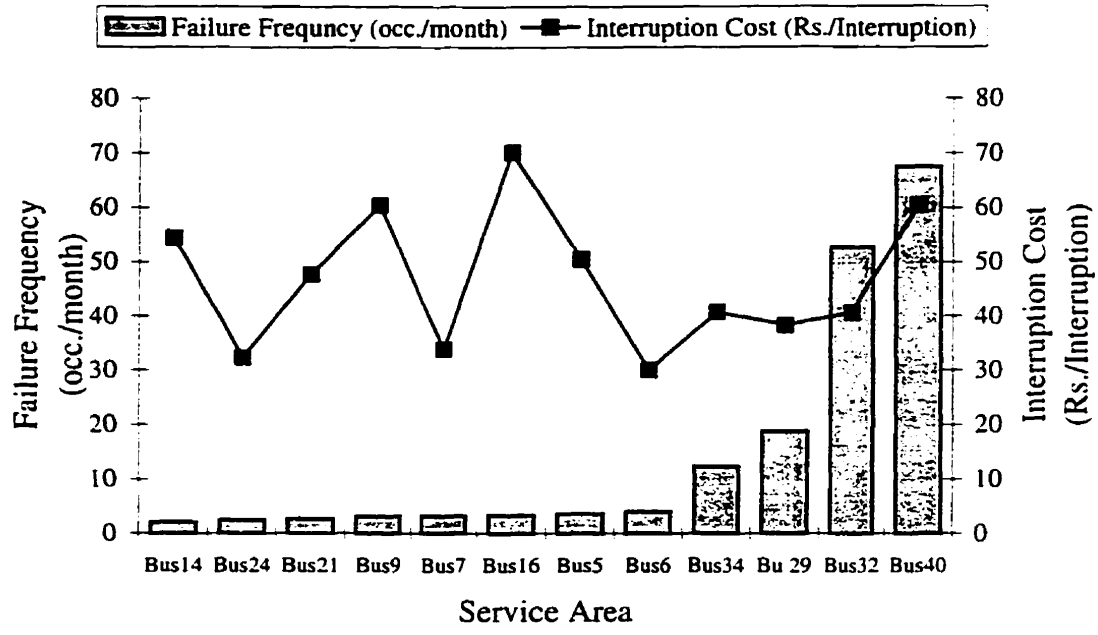

Figure 3.2. Variation in Interruption Cost with Service Area and Associated Reliability

It can be seen from Figure 3.2 that there is considerable variation in interruption cost estimates as well as reliability levels between service areas. The cost varies from Rs.30/interruption in service areas supplied by Bus 6 to Rs.70/interruption in those supplied by Bus 16. The failure frequency varies from 2 occ./month in service areas supplied by Bus 14 to 68 occ./month in those supplied by Bus 40. The perceived reliability levels in most service areas in the country (Buses 29-40) are extremely low compared to those in the capital city of Kathmandu (Buses 5-21). Figure 3.2 also shows that there is no definitive relationship between interruption cost and service reliability.

3.6. Commercial Customer Survey

3.6.1. Preface

This section presents the results of the survey conducted in the commercial sector. The effects and costs from power interruptions to commercial customers are

distinctly different from those in the residential sector. Interruptions to commercial customers tend to be related to the inability to conduct retail sales, which involve monetary transactions. The determination of interruption costs in the commercial sector is more direct than in the residential sector and therefore a direct costing method was used to estimate the costs.

It is important to survey the commercial sector as retail stores, trades and services are rapidly growing in Nepal. At present, this consumer sector accounts for more than 20% of the energy sales in the country, and is growing fast [3].

3.6.2. Survey Results

This section presents the results obtained from the commercial customer survey. The questionnaire and additional results are included in Appendix C.

Most of the results obtained from the survey are presented in a concise and general qualitative way. Quantitative cost estimates derived from the cost questions are presented in more detail. All values quoted are from the combined customer responses except as otherwise indicated.

Survey Response

The respondents were provided with a list of standard company descriptions and asked to select one that best described their company. This question was used to form a basis for grouping the customers into standard categories. Standard industrial classification (SIC) descriptions and numbers used by Statistics Canada [38] were

utilized in grouping the customers. Table 3.6 provides a list of usable responses by SIC category. This information is presented to illustrate the extent and limitation of the survey, as well as to indicate the composition of the customers surveyed in the investigation.

Table 3.6. Usable Commercial Survey Response by SIC Category

Two Digit SIC No.	Description	Number of Respondents	Percentage of Respondents
60	Food, Beverage & Drug	142	22
61	Shoe, Apparel & Fabric	91	14
62	Household Furnishings	33	5
63	Automotive	35	6
64	General Merchandising	15	2
65	Other Retail	153	24
91	Accommodations	26	4
92	Food & Beverage Service	43	7
96	Amusement & Recreation	23	4
97	Personal Services	14	2
99	Other Services	65	10
	TOTAL	**640**	**100**

Interruption Cost Estimates

Interruption costs in the commercial sector were estimated using a direct cost assessment work-sheet. Customers were asked to estimate the costs to their company for interruptions of various durations. A list of possible effects was suggested, and respondents were directed on what to include in the estimates. Most respondents had difficulty in estimating costs for various possible effects suggested in the cost question. This problem was identified during the pre-testing of the questionnaire. Most of the

respondents, however, indicated that the suggestion of possible effects helped them to understand and estimate the total costs of interruption, which they suggested can be attributable to all the effects combined. Consequently, only the total cost for all effects were obtained in the cost evaluation. In addition, not all respondents provided information for each of the durations asked.

Table 3.7 presents interruption cost estimates in Nepalese Rupees (Rs) associated with various interruption durations. The Rs/interruption listing presents the simple average or mean value for all users whose costs were determined. The other listings are the aggregated average costs normalized by annual energy consumption in Rs/MWh and peak demand in Rs/kW. The aggregated average approach was used to off-set the impact of the relatively few large or small customers, or the relatively few respondents who report very large or very small costs. The demand normalized costs were calculated using consumption normalized costs in Rs/kWh and the sector load factor information obtained from the NEA. The number in the brackets indicates the number of respondents that provided the cost information for that particular duration and used to calculate the cost. It can be clearly seen from the results shown in Table 3.7 that most responses were obtained for 24 hours or 1 day interruption duration followed by 8 hours and 4 hours.

Table 3.7. Average Interruption Costs Reported by the Commercial Customers

Interruption Duration	Mean Value Rs/Interruption	Consumption Normalized Rs/MWh	Demand Normalized Rs/kW
1 minute	267 [15]	10.90 [15]	38.19 [15]
20 minutes	478 [11]	37.20 [11]	130.35 [11]
1 hour	509[109]	80.30[109]	281.37[109]
2 hours	810 [74]	192.90 [74]	675.92 [74]
4 hours	1228[170]	316.30[170]	1108.31[170]
8 hours	2173[225]	447.70[225]	1568.74[225]
24 hours	2703[439]	579.80[439]	2031.62[439]

Variation in Interruption Cost with Respondent Category

The cost estimates shown in Table 3.7 are for all the respondents combined. Analysis was performed to determine how this cost varies with the respondent category. Figure 3.3 shows the interruption costs for a 24 hour interruption for various customer categories. It can be seen that considerable variation exists in the cost estimates for respondents in different categories. In addition to the variation of cost with respondent category, it was also found that the cost estimates vary greatly from respondent to respondent within each category.

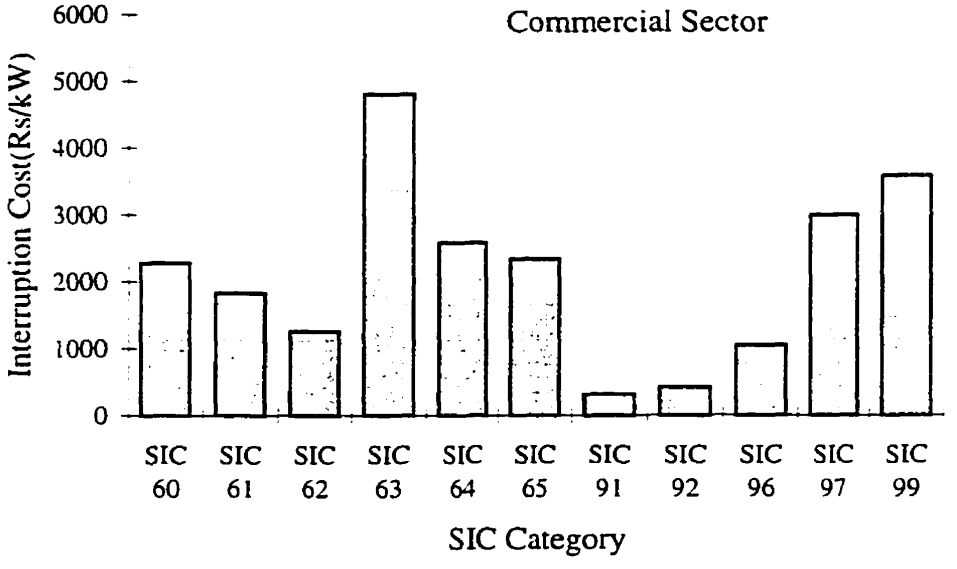

Figure 3.3. Variation in Commercial Interruption Cost with Respondent Category

Interruption Cost Variation with Service Area

The study also investigated the interruption cost variations between service areas and regions. As shown in Figure 3.4, considerable variations in the commercial

customer cost estimates were found for the various service areas and regions of the country.

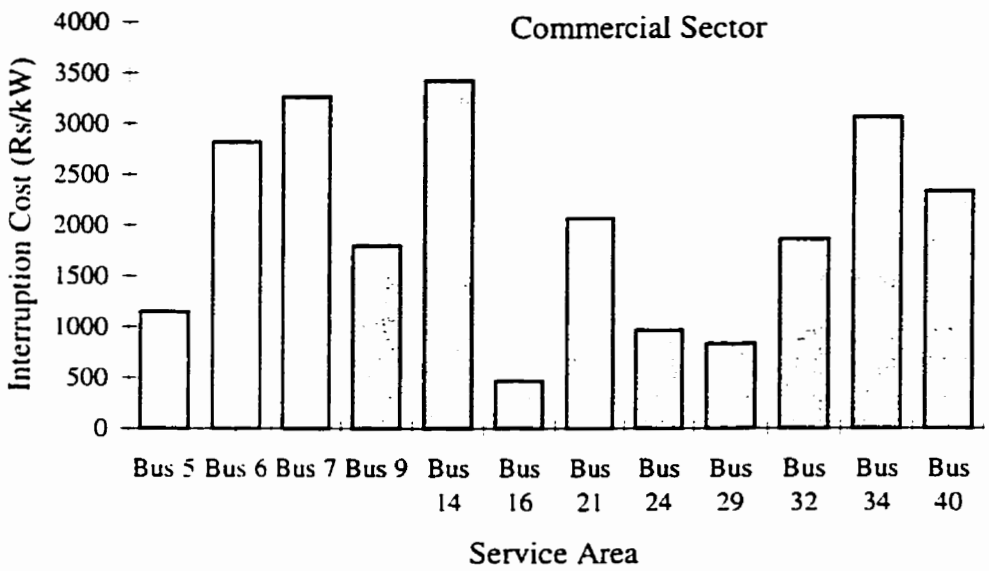

Figure 3.4. Commercial Cost Variation with Service areas

Variation in Interruption Cost with the Time of Year, Week and Day

The interruption cost estimates provided by commercial respondents in Table 3.7 are for the worst time(i.e. worst month of the year, worst day of the week, and worst time of the day) for a power failure to occur in their companies. In order to determine the variation of this cost with time of year, week and day, respondents were asked to estimate approximate percentage differences from the worst cost figures. The monthly, weekly and daily cost variation were determined for the commercial sector. A summary of the results are presented in Table 3.8. The detailed information is given in Appendix C.

Table 3.8. Variation in Interruption Cost with Time of Year, Week and Day

Cost Variation	Commercial Sector
Most Costly Time of Year	April/May (Summer Season)
Least Costly Time of Year	July - September (Monsoon period)
Most Costly Day of Week	All weekdays (Sunday - Friday)
Least Costly Day of Week	Saturday(Weekend)
Most Costly Time of Day	5 pm - 9 pm
Least Costly Time of Day	Midnight - 6 am

Ability to Reduce Interruption Costs

Questions were asked to obtain information from the customers on their company's ability to reduce interruption costs under two scenarios: if advanced warning of an interruption is provided, and if expected interruption duration information is provided at the start of the interruption. The results are given in Table 3.9.

Table 3.9. Interruption Cost Reduction Ability of the Commercial Sector

A. Given Advance Warning:	
% of respondents that could reduce the interruption cost	33
Maximum % cost reduction (for 1 - 2 days advance warning)	50
B. Duration Information:	
% of respondents that could reduce the interruption cost	5

Variation In Interruption Costs with User Characteristics

In order to investigate the variation in interruption cost by user characteristics and to obtain an indication of the representatives in the sample, several questions were asked concerning company characteristics. Some average values are presented in Table 3.10. The number in brackets indicates the number of respondents in the analysis. It was found that considerable variation in values exists between respondents.

Table 3.10. Characteristics of Respondents

Description	Average Value
No. of full time employees	7.6 [675]
No. of part time employees	3.1 [113]
Annual Energy Consumption (kWh)	5472 [694]
Peak Demand (kW)	5 [695]

The data were analyzed to investigate the variation in interruption cost with user characteristics. It was generally found that the average Rs/Interruption cost increases as the energy consumption, demand and number of employees increases. The results, however, did not indicate a significant relationship between the normalized Rs/MWh and Rs/kW costs and the user characteristics. No significant relationship between the cost estimates and the respondent estimates of service reliability could be observed.

Importance of Electrical Equipment

Commercial customers were provided with a list of equipment and services that are dependent on electricity and asked to rate the importance to their company. The most important electrical equipment for commercial customers are indoor lights,

followed by outdoor lights, and fan and heaters (comfort). This reveals that the main concern of commercial customers are related to maintaining sales. A less importance rating of equipment such as computers, electric cash registers, telecommunications etc., indicates that most of the businesses are yet to be influenced by high technology in a developing country such as Nepal.

Power Quality Requirements

Questions were asked to obtain information on company power quality requirements. Respondents were asked whether their company has equipment that are particularly sensitive to frequency and voltage deviations from the nominal values. The results are reported in Table 3.11.

Table 3.11 Power Quality Requirements of the Commercial Customers

% of respondents that have frequency sensitive equipment	10
% of respondents that have voltage sensitive equipment	45

Interruption Hazards

Respondents were asked whether interruptions result in possible hazard to their customers or staff and what is the shortest warning time their company would require to reduce the safety hazard. More than 90% of the respondents indicated that a power outage would not result in any health or safety hazard to their staff or to the public. Of those who indicated otherwise, the majority chose a minimum advance warning time of 20 minutes to reduce the risk.

Emergency Electrical Supply Equipment

Respondents were asked to indicate what type of standby electrical supply equipment their company had and the purpose of the standby equipment. The results are presented in Table 3.12. Regarding the standby purpose, most respondents indicated that the backup facilities are mostly for maintaining business. Only 10% of the respondents indicated that the purpose was to minimize hazard to the staff or public.

Table 3.12 Emergency Electrical Supply Equipment

Type of Standby Equipment	Respondents (%)
No emergency supply system	69
Battery system	7
Engine generator	24

Estimates of Service Reliability

In order to determine the service reliability status, customers were asked to estimate the number of times that their company experienced a supply interruption in the past two months and to indicate those that lasted for 4 hours or more. Considerable variation in failure frequency was found, from an average of once a week in most service areas in the Kathmandu region to twice a day in other parts of the country. Approximately 3% of the supply interruptions reported had a duration of 4 hours or more.

3.7. Industrial Customer Survey

3.7.1. Preface

This section deals with the results of the survey conducted in the industrial sector. Interruptions to industrial customers tend to be related to the inability to manufacture products and therefore involves direct monetary costs similar to those for commercial customers. A similar survey [39] conducted in Canada reported that the customer survey yields reasonably consistent results using direct cost assessment work-sheet questions for both commercial and industrial customers. A similar survey approach was used in both the commercial and industrial sectors. Some of the descriptions in this section therefore appear to duplicate the discussion presented earlier for the commercial survey. The duplication is intentional in order that each sector survey can be dealt with independently.

It was important to conduct a survey of industrial customers as this consumer sector accounts for more than 39% of the energy sales in the country and is developing quickly [3]. The industrial survey was conducted concurrently with the other two surveys described earlier. The surveyors used in this sector were more specialized because of the complexity involved in this sector. In-person interviews were conducted by random selection of the customers, as in other sectors. Mostly small scale industries were considered in the survey. These are normally the majority of industries in developing countries like Nepal.

3.7.2. Survey Results

This section presents the results obtained from the industrial customer survey. The questionnaire and additional results are included in Appendix C. Quantitative cost estimates derived from the cost questions are presented in detail. Results from opinion

type questions are presented in a concise qualitative form. All values quoted are from the combined customer responses except as otherwise indicated.

Survey Response

Customers in the industrial survey were provided with a list of standard industrial company descriptions and asked to select one that best described their operations. The SIC descriptions and numbers used by Statistics Canada [38] were utilized in grouping the industrial customers. Table 3.13 provides a list of usable responses by SIC category. This information is presented to illustrate the extent and limitations of the survey and to indicate the composition of the customers surveyed in this investigation.

Table 3.13. Usable Industrial Survey Response by SIC Category

Two Digit SIC No	Description	Number of Respondents	Percentage of Respondents
04	Logging /Wood Industries	5	2.17
06	Mining	-	-
07	Petroleum/Natural Gas/Fuel	1	0.43
08	Quarry/Sand/Cement/Brick	11	4.78
10	Food Industries	59	25.65
11	Beverage Industries	7	3.04
15	Rubber Products	3	1.30
16	Plastic Products	14	6.08
17	Leather Products	5	2.17
19	Textile Products	13	5.65
26	Furniture	10	4.35
27	Paper Products	2	0.86
28	Printing & Publishing	10	4.35
29	Primary Metal Industries	11	4.78
30	Fabricated Metal	36	15.65
31	Machinery	4	1.74
32	Transportation	1	0.43
33	Electrical Products	4	1.74
35	Non-Metal Minerals	-	-
37	Chemical Products	-	-
39	Other Manufacturing	39	14.78
	TOTAL	**235**	**100**

Interruption Cost Estimates

Interruption costs in the industrial sector were estimated using a direct cost assessment work-sheet. Customers were asked to estimate the costs to their company for interruptions of various durations. A list of possible effects was suggested, and respondents were directed on what to include in the estimates. It was also found in the industrial survey that most respondents had difficulty in providing cost information for all the suggested effects and durations. No one provided interruption cost information for a 2 second duration. Some respondents provided information for only one duration. Some only gave a cost to one effect and duration. Others provided only selected portions. In order that the results have some statistical meaning, only the "Total" cost for each duration were considered in the analysis. This aspect represents one of the difficulties in using a direct costing approach in a developing country such as Nepal where impact assessment record keeping in industries is inadequate.

Table 3.14 presents interruption cost estimates in Nepalese Rupees (Rs) associated with various interruption durations. The Rs/interruption listing presents the simple average or mean value for all users whose costs were determined. The other listings are the aggregated average costs normalized by annual energy consumption in Rs/MWh and peak demand in Rs/kW. The aggregated average approach is used to off-set the impact of small numbers of large or small customers, or a small number of respondents who report large or small costs. The demand normalized costs were calculated using consumption normalized costs in Rs/kWh and the sector load factor information obtained from the NEA. The number in the brackets indicates the number of respondents that provided the cost information for that particular duration and used to calculate the cost. It can be clearly seen from the cost results shown in Table 3.14 that the largest number of respondents provided cost information for 24 hour or 1 day interruption duration.

Table 3.14. Average Interruption Costs Reported by the Industrial Customers

Interruption Duration	Mean Value Rs/Interruption	Consumption Normalized Rs/MWh	Demand Normalized Rs/kW
1 minute	1854 [24]	1.31 [22]	5.16 [22]
20 minutes	3733 [27]	2.87 [24]	11.31 [24]
1 hour	11011 [57]	5.20 [53]	20.50 [53]
2 hours	14795 [50]	7.17 [46]	28.26 [46]
4 hours	20361 [54]	18.38 [49]	72.45 [49]
8 hours	29960 [70]	36.88 [64]	145.38 [64]
24 hours	47974[203]	135.03[197]	532.31[197]

Variation in Interruption Cost with Respondent Category

The cost estimates shown in Table 3.14 are for all the industrial customers combined. Analysis was performed to determine how this cost varies with the respondent category. Figure 3.5 shows the interruption costs for a 24 hour interruption for various industrial categories. It can be seen that considerable variation exists in the cost estimates for respondents in different categories. In addition to the variation of cost with respondent category, it was also found that the cost estimates vary greatly from respondent to respondent within each category.

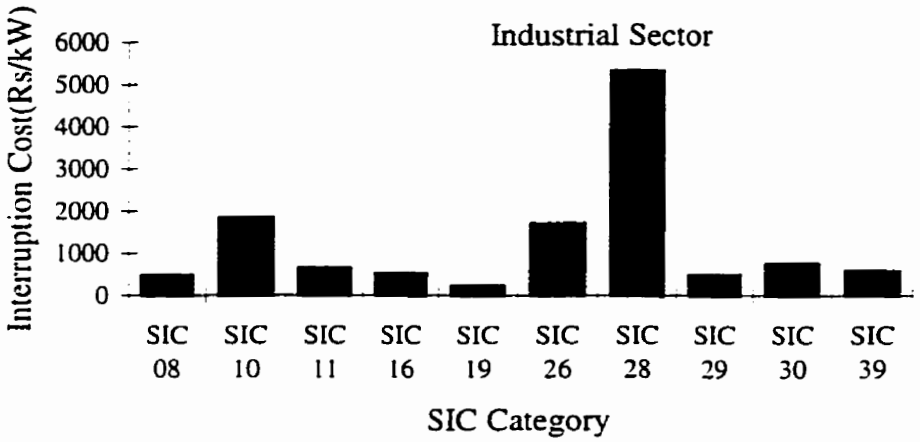

Figure 3.5. Variation in Industrial Interruption Cost with Respondent Category

Interruption Cost Variation with Service Areas

The study also investigated the interruption cost variations between service areas and by regions. As shown in Figure 3.6, industrial customer cost estimates were found to be more or less the same throughout the country except for those industries in the Kathmandu region (Buses 6 and 14). This is due to the fact that most industries in a developing country such as Nepal are of small scale and therefore the costs incurred due to power interruptions are more or less uniform throughout the country.

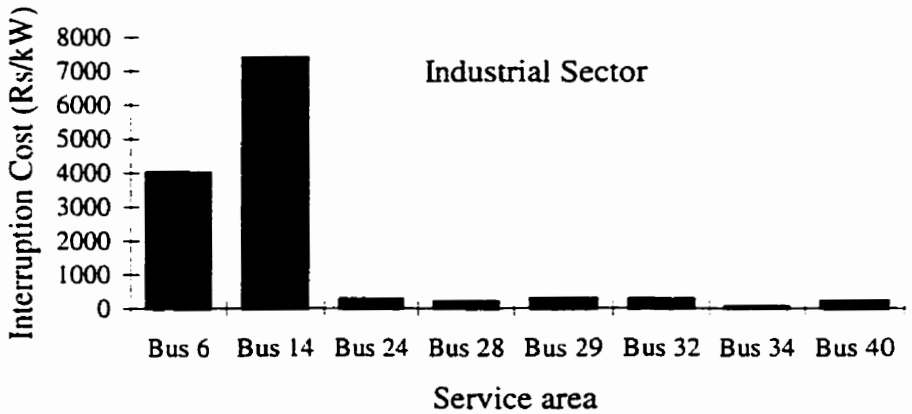

Figure 3.6. Industrial Customer Cost Variation with Service areas

Variation in Interruption Cost with the Time of Year, Week and Day

The industrial interruption cost estimates provided in Table 3.13 are for the worst time(i.e. worst month of the year, worst day of the week, and worst time of the day) for a power failure to occur in their companies. In order to determine the variation of this cost with time of year, week and day, respondents were asked to estimate approximate percentage differences from the worst cost figures. The monthly, weekly and daily cost variation were determined for the industrial sector. A summary of the results are presented in Table 3.15. The detailed information is given in Appendix C.

Table 3.15. Variation in Interruption Cost with Time of Year, Week and Day

Cost Variation	Industrial Sector
Most Costly Time of Year	April/May (Summer Season)
Least Costly Time of Year	July - September (Monsoon period)
Most Costly Day of Week	All weekdays (Sunday - Friday)
Least Costly Day of Week	Saturday (Weekend)
Most Costly Time of Day	9 am - Noon & 1 pm - 5 pm
Least Costly Time of Day	Midnight - 6 am

Ability to Reduce Interruption Costs

Questions were asked to obtain information from the customers on their company's ability to reduce interruption costs under two scenarios: if an advanced warning of an interruption is provided, and if expected interruption duration information is provided at the start of the interruption. The results are given in Table 3.16.

Table 3.16. Interruption Cost Reduction Ability in the Industrial Sector

A. Given Advance Warning:	
% of respondents that could reduce the interruption cost	38
Maximum % cost reduction (for 1 - 2 days advance warning)	40
B. Duration Information:	
% of respondents that could reduce the interruption cost	23
Maximum % cost reduction (for an expected 24 hour interruption)	20

Variation In Interruption Costs with User Characteristics

In order to investigate the variation in interruption cost by user characteristics and to obtain an indication of the representatives in the sample, several questions were asked concerning company characteristics. Some average values are presented in Table 3.17. The number in brackets indicates the number of respondents in the analysis. It was found that considerable variation in values exists between respondents.

Table 3.17. Characteristics of Industrial Respondents

Description	Average Value
No. of full time employees	57.5 [230]
No. of part time employees	94.3 [13]
Annual Energy Consumption (kWh)	404884 [225]
Peak Demand (kW)	578 [200]

The data were analyzed to investigate the variation in interruption cost with user characteristics. It was generally found that the average Rs/Interruption cost increases as the energy consumption, demand and number of employees increases. The results, however, did not indicate a significant relationship between the normalized Rs/MWh and Rs/kW costs and the user characteristics. No definitive relationship between the cost estimates and the respondent estimates of service reliability could be observed.

Importance of Industrial Uses of Electricity

Industrial customers were provided with a list of usual industrial applications of electricity and asked to rate the importance of these various uses from their company's perspective. It was found that the most important electricity use functions are related to maintaining the production process followed by building services.

Power Quality Requirements

Questions were asked to obtain information on company power quality requirements. Respondents were asked whether their companies have equipment that are particularly sensitive to frequency and voltage deviations from the nominal values. The results are reported in Table 3.18.

Table 3.18. Power Quality Requirements of Industrial Customers

% of respondents that have frequency sensitive equipment	37
% of respondents that have voltage sensitive equipment	69

Interruption Hazards

Respondents were asked whether interruptions result in possible hazard to their customers or staff and what is the shortest warning time their company would require to reduce the safety hazard. More than 90% of the respondents indicated that a power outage would not result in any health or safety hazard to their staff or to the public. Of those who indicated otherwise, the majority chose a minimum advance warning time of 1 hour to reduce the risk.

Ability to Make-Up Lost Production

Industrial respondents were asked whether lost production can be made up once power is restored or on days following the interruption without overtime or additional staff. For interruption durations of 1 hour or more, most respondents indicated that lost production could not be made up without overtime or additional staff.

Emergency Electrical Supply Equipment

Industrial customers were asked to indicate the standby electrical supply equipment their company had and the purpose of the standby equipment. The results are presented in Table 3.19. Regarding the standby purpose, most respondents indicated that the backup uses are mostly for maintaining production and to prevent damage to finished products. Only 10% of the respondents indicated that the purpose was to minimize hazard to the staff or public.

Table 3.19. Emergency Electrical Supply Equipment

Type of Standby Equipment	Respondents (%)
No emergency supply system	73
Battery system	1
Engine generator	25
Turbine	1

Estimates of Service Reliability

In order to determine the service reliability status, customers were asked to estimate the number of times that their company experienced a supply interruption in the past two months and to indicate those that lasted for 4 hours or more. Considerable variation in failure frequency was found, from an average of once a week in most service areas in the Kathmandu region to twice a day in other parts of the country. Approximately 3% of the supply interruptions reported had a duration of 4 hours or more.

3.8. Sector Customer Damage Functions (SCDF)

The cost results determined were used to create sector customer damage functions (SCDF). Table 3.20 and Figure 3.7 show the sector customer damage functions for the residential, commercial and industrial sectors of Nepal. The costs are aggregated average, unweighted, country-wide interruption costs in 1996 Nepalese rupees (Rs), normalized according to annual peak demand and presented as a function of outage duration. They are unweighted because no specific service area or customer

classification is considered. All costs for all service areas and all customers in a particular sector have been combined.

Sector customer damage functions can be weighted in proportion to their energy utilization within a particular service area to create a composite customer damage function (CCDF) for the service area of interest [40]. The composite customer damage function is then used in reliability cost/worth evaluation to determine the optimum reliability level for the service area. These basic quantitative reliability assessment concepts are described in detail in Chapters 4 and 5.

Table 3.20. Sector Customer Damage Functions(SCDF) for the NPS in Rs/kW

Interruption Duration	Residential	Commercial	Industrial
1 minute	--	38.19	5.16
20 minutes	1.52	130.35	11.31
1 hour	8.05	281.37	20.50
2 hours	--	675.92	28.26
4 hours	42.08	1108.31	72.45
8 hours	86.43	1568.74	145.38
24 hours	310.16	2031.82	532.31
48 hours	665.87	--	--

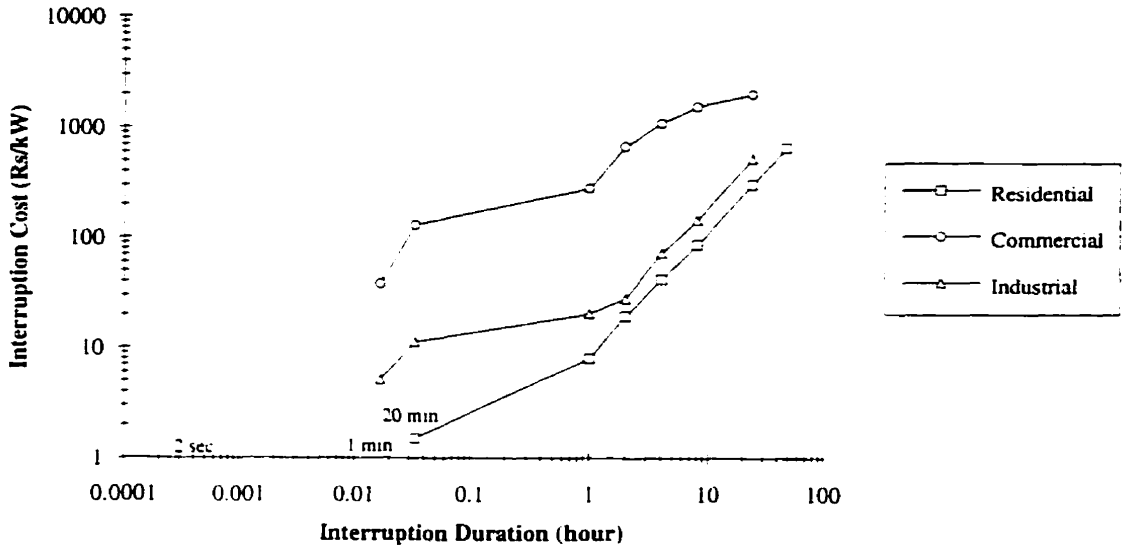

Figure 3.7. Sector Customer Damage Functions

3.9. Summary

This chapter presents an investigation of the customer interruption costs in selected service areas of the NPS. The final cost estimates are given in Table 3.20. These cost estimates were used in the planning studies described later in this thesis.

A review of the various interruption cost methodologies is presented. The various approaches used in customer surveys are described. The particular customer survey methodology adopted to conduct the survey in Nepal is described. The survey results obtained in the residential, commercial and industrial sectors are presented in detail. Most of the results obtained from the survey are presented in a concise and general qualitative way. Quantitative cost estimates derived from the cost questions for each of the customer sectors are presented in more detail.

It was noted that a customer survey approach by mail or telephone, which is frequently used in developed countries, is not viable in a developing country such as Nepal due to a lack of awareness of the concept and practice in the country. It was found that an in-person interview customer survey approach yields reasonable results in a developing country.

The customer survey approach to obtaining interruption cost estimates requires electricity consumption information for each customer sample considered in the survey. This information is normally obtained from the utility in a developed country [23]. This is not the case in a developing electric power system such as the NPS. The individual customer consumption information is not readily available in the NPS due to an inadequate record system. These data were derived from information provided by the customers through their electricity bills.

It was noted that the indirect costing approaches, such as preparatory action, willingness-to-pay and willingness-to-accept methods, used for the residential customers are quite effective in a developing country such as Nepal. The direct costing approach, which was used for commercial and industrial sectors, had some difficulties in application due to the detailed cost information requirements. In a developing country such as Nepal, impact assessment records are not kept adequately in businesses and industries, and respondents have difficulty in providing the detailed cost information requested in this survey. Most respondents could not provide cost information for each of the power interruption effects asked in the survey. Not many respondents provided data for all the durations considered in the investigation. Most cost information were obtained for 24 hour or 1 day interruption duration followed by 8 hours and 4 hours.

Impact assessment studies are conducted and discussed in this chapter. It was found that the interruption cost is dependent on customer characteristics as well as interruption characteristics. It also varies from one location or region to another. However, no definitive relationship between interruption cost and service reliability was found.

The major contribution of this research work is in obtaining the power interruption costs for customers in a developing country, and in advancing the customer surveying concept for power system reliability worth evaluation to a developing world environment. The results indicate the implications of service reliability to the customers of Nepal, and show that reliability worth evaluation is both possible and practical in a developing country. The approach is illustrated by application to the NPS. The concepts, however, can be used by utility planners in similar developing countries to evaluate reliability worth.

4. RELIABILITY COST/WORTH STUDIES AT HL I

4.1. Introduction

The application of reliability concepts in power system planning has become a routine activity for many electric power utilities in developed countries. Considerable work has been done in developed countries to optimize reliability levels on the basis of reliability cost versus reliability worth [22]. This has yet to be considered in developing countries where new facilities are still routinely planned using traditional deterministic measures which are somewhat arbitrary and based on judgment and experience. The reliability cost/worth approach to system evaluation provides an opportunity for developing countries to formulate suitable system planning criteria and to objectively justify new facility requirements. This chapter describes how the reliability cost/worth approach to system evaluation can be used to develop appropriate generating capacity planning criteria by application to the Nepal Integrated Electric Power System (NPS).

The most popular indices used in generating capacity adequacy evaluation or HL I study are the Loss of Load Expectation (LOLE) and the Loss of Energy Expectation (LOEE). The LOLE index measures the expected time during which the generation available will be insufficient to meet the load demand within the study period considered in the evaluation. The LOEE, on the other hand, specifies the expected energy that will not be supplied by the generation system within the study period [17]. The LOEE index can be used in conjunction with the customer cost function to obtain a factor designated as the Interrupted Energy Assessment Rate (IEAR), which relates the customer energy losses to the cost of electric power failures [41].

An analytical method based on the Frequency and Duration (F&D) approach to system evaluation [17] was used in the IEAR determination. The basic concepts involved in calculating the IEAR using the F&D technique is described. The optimum reserve margin determination using the IEAR is illustrated by application to the NPS. Both the base case analysis and expansion plan studies are described. Sensitivity studies performed to understand the impacts of important system parameters such as the peak load and the generating unit forced outage rates are presented and finally, some planning criteria for the NPS are suggested.

4.2. Basic Framework for HL I Studies

A suggested reliability cost/worth based system evaluation framework for HL I studies is shown in Figure 4.1. Power transmission facilities are not considered at this study level.

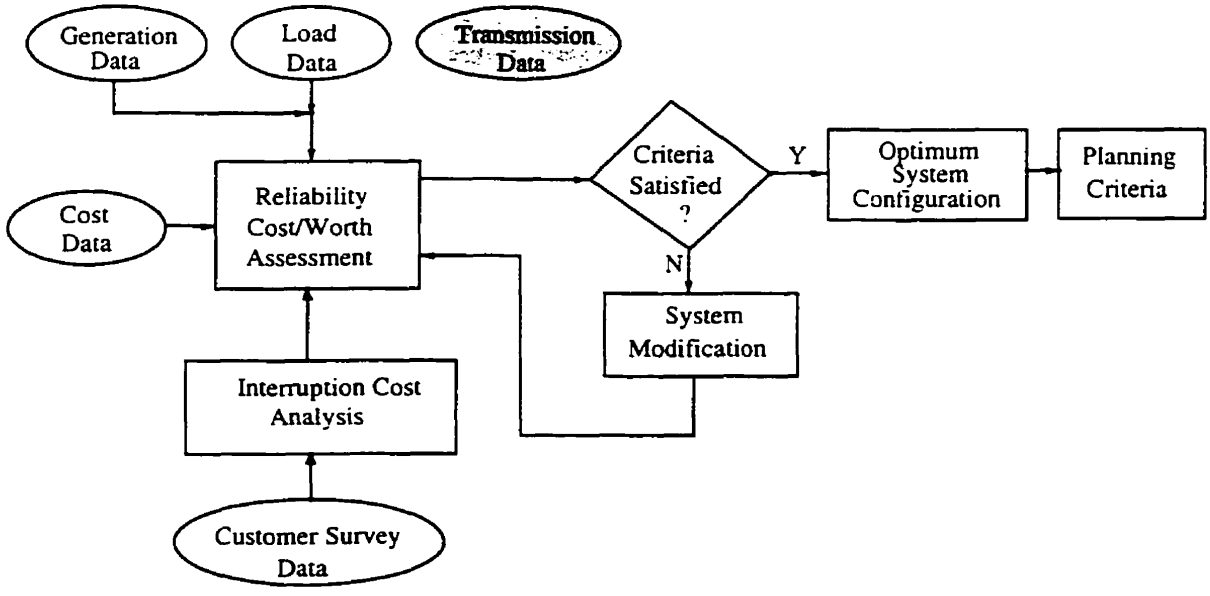

Figure 4.1. Reliability Cost/Worth Evaluation Framework for HI I Studies

Reliability cost/worth based adequacy evaluation at HL I requires generation data, load data, cost data and interruption cost data. The interruption cost data are usually obtained from customer surveys as described in Chapter 3. These input data requirements are shown in Figure 4.1.

Reliability cost/worth assessment is performed using the required input data. An expansion scheme having the minimum overall cost is selected. If the minimum overall cost criterion is not satisfied, the expansion scheme is modified and assessed again. This procedure is repeated until the adequacy criteria is satisfied. The newly developed system configuration which produces the optimum reliability level is then utilized for the future power system development. The set of indices produced in the evaluation process can be selected as planning criteria for future power project evaluation. The basic objective is to ensure that the system expansion is implemented on the basis of overall societal benefit.

4.3. Interrupted Energy Assessment Rate (IEAR) Evaluation

4.3.1. Basic Concepts

Actual or perceived interruption costs obtained through customer surveys conducted in a service area can be used to create a composite customer damage function (CCDF) [40]. The generation of a CCDF for a service area defines the total customer costs for that area as a function of the interruption duration. The procedure involved in developing a CCDF for a service area using the survey data is as follows.

As described in Chapter 3, the customer interruption costs are dependent on a wide range of factors related to customer and interruption characteristics. The

investigation reveals that electricity consumers are able to relate their interruption costs most realistically in terms of interruption durations. Chapter 3 shows that the normalized interruption costs (expressed in Rs./kW) for a particular customer category or sector (i.e. residential, commercial or industrial) can be obtained as a function of interruption duration using the survey data. These are designated as sector customer damage functions (SCDF) as shown in Table 3.19 and Figure 3.12.

For each interruption duration shown in Table 3.19, the sector interruption costs are weighted in proportion to their respective energy demand within the service area. The sector energy demand for the NPS is shown in Table 4.1. The "Other" category includes mostly government, institutions and office buildings, whose interruption cost data are not available at the present time. Reference 42 reports that this customer sector can be considered to have similar interruption cost characteristics as that of the industrial sector. The 'Other' category was therefore combined with the industrial sector in developing the system CCDF.

Table 4.1. System Energy Demand for the NPS [3]

User Sector	Sector Energy (%)
Residential	37.29
Commercial	7.17
Industrial	39.56
Other	15.98
Total	100.00

The weighted costs, as described above, are summed to evaluate the total interruption cost for the area at each specified duration. The variation of this total cost

with duration is designated as the composite customer damage function for the service area. The developed CCDF for the NPS is shown in Table 4.2 and displaced graphically in Figure 4.2. It can be clearly seen from Figure 4.2 how the overall customer interruption cost varies with the interruption duration in the service area supplied by the NPS. The overall customer cost is given in 1996 Nepalese Rupees(Rs) per kW of annual peak demand in the service area.

Table 4.2. Composite Customer Damage Function (CCDF) for the NPS

Interruption Duration	Interruption Cost (1996 Rs/kW)
1 minute	5.63
20 minutes	16.19
1 hour	34.56
2 hours	71.38
4 hours	135.39
8 hours	225.45
24 hours	556.98
48 hours	1061.78

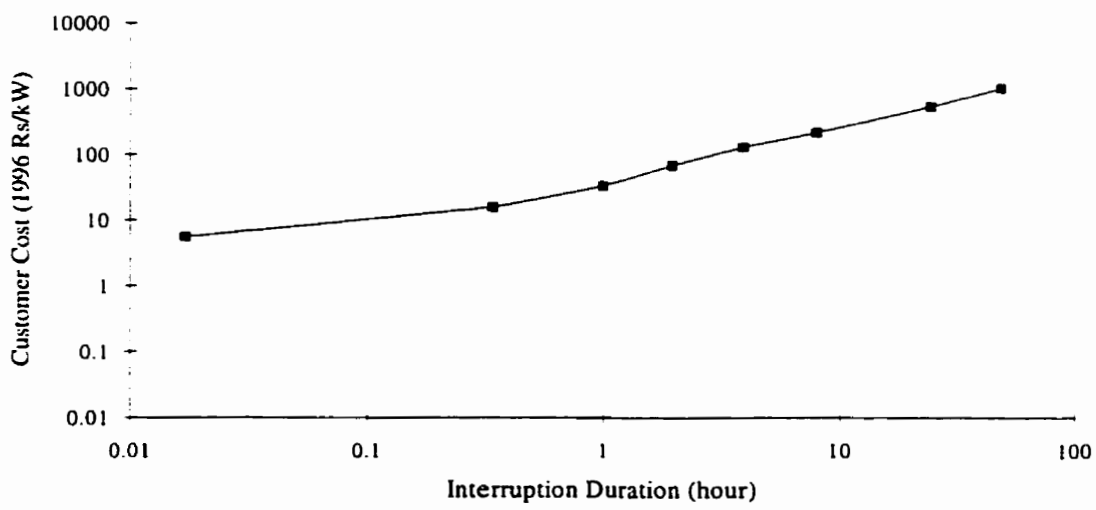

Figure 4.2. The Developed CCDF for the NPS

Chapter 3 notes that the interruption costs for each requested duration could not be obtained for all customer sectors. The cost data for durations other than those obtained in the customer surveys were derived by linear interpolation of the available duration cost data to cover all expected interruption durations.

Despite the uncertainties affecting the development of a CCDF, it should be noted that this is the most practical tool available at the present time for determining monetary estimates of reliability worth in an electric power system. The CCDF can be tailored to reflect the individual nature of the service area supplied by the system as a whole, the region within the area, and any particular customer sector.

The developed CCDF can be used in conjunction with the F&D technique to evaluate the interrupted energy assessment rate (IEAR). The basic concepts of the evaluation technique are as follows.

Estimation of the IEAR using the F&D approach involves the development of a capacity margin model which indicates the severity, frequency and duration of the expected negative margin states [17]. The generation model is developed from the capacities, forced outage rates, failure rates and repair rates of the generating units. The generating unit reliability data shown in Table 2.2 were used in the analysis. The load model used is an exact-state load model which represents the actual daily system load cycle by a sequence of discrete load levels. The exact state load model for the NPS is shown in Table 4.3.

Table 4.3. The Exact-State Load Model for the NPS

Load Level (p.u.)	Number of Occurrences (Days)
0.97	24
0.93	64
0.88	60
0.83	45
0.77	54
0.73	57
0.68	46
0.63	14
0.60*	364

* Daily Low load Level

The load model shown in Table 4.3 was derived from the daily peak load model described in Chapter 2. The daily peak loads were arranged in descending order and then grouped in class intervals. The mean of each class is considered as the discrete load level and the class frequency as the number of occurrences of that load level. The study period is one year which consists of 364 days in the load model used. The daily peak loads were assumed to exist for 12 hours giving an exposure factor of 0.5 [17].

The total EENS for the estimated loss of load events within the period of study is given by

$$\text{Total EENS} = \sum_{i=1}^{N} m_i f_i d_i \quad \text{(kWh/year)} \tag{4.1}$$

where, m_i (kW) is the margin state capacity for load loss event i;

f_i (occ/year) is the frequency of load loss event i;

d_i (hr) is the duration of load loss event i; and

N is the total number of load loss events.

The total expected cost for all the load loss events is given by

$$\text{Total Cost} = \sum_{i=1}^{N} m_i f_i c_i \quad \text{(Rs/year)} \tag{4.2}$$

where, c_i (Rs/kW) is the cost associated with the duration d_i (hr) for the load loss event i, and is obtained using the developed CCDF shown in Table 4.2. The IEAR is then calculated as the ratio of the total cost and the total EENS as shown in Equation (4.3).

$$\text{Estimated IEAR} = \frac{\sum_{i=1}^{N} m_i f_i c_i}{\sum_{i=1}^{N} m_i f_i d_i} \quad \text{(Rs/kWh).} \tag{4.3}$$

4.3.2. The IEAR for the NPS

The IEAR calculated for the NPS using the above procedure is Rs 35/kWh. The CCDF shown in Table 4.2 was used as the cost model. The generation data used are given in Table 2.2 and the load model used is shown in Table 4.3.

The above procedure can also be used to calculate individual sector IEAR within the service area. For example, if the service area is considered to be made up of only the residential sector, then the residential cost data given in Table 3.19 becomes the CCDF for the service area. The resulting IEAR is simply the residential sector IEAR. The other

sector IEAR can be similarly evaluated. The calculated sector IEAR for the residential, commercial and industrial customer sectors in the NPS are shown in Table 4.4.

Table 4.4. Sector IEAR Estimates for the NPS

User Sector	IEAR (Rs/kWh)
Residential	10.00
Industrial	16.00
Commercial	310.00

It can be seen from Table 4.4 that considerable variation in interruption costs exists between the customer sectors. The commercial sector has the highest cost of Rs 310/kWh and the residential has the lowest cost with Rs 10/kWh. The specific IEAR for other user sectors such as agriculture, government, institutions and office buildings, etc., can be determined when the interruption cost data for those sectors become available. This is a subject for future research.

The IEAR for each sector is weighted by its percentage of energy consumption to provide a contribution to the system expected IEAR. The sum of the weighted IEAR of all the customer sectors gives the system IEAR for the service area. In the development of the system CCDF for the NPS, it was assumed that the sector designated as "Other" in Table 4.1 has the same interruption cost characteristics as that of the industrial sector and was subsequently combined to obtain the system CCDF. An analysis was performed to calculate the system IEAR considering "Other" as being

associated with different sectors and weighted accordingly. The calculated system IEAR from this study is shown in Table 4.5.

Table 4.5. System IEAR Considering "Other" as Different Sectors

Consideration	System IEAR (Rs/kWh)
Weighted as per load composition and considering "Other" as Residential Sector	34.00
Weighted as per load composition and considering "Other" as Industrial Sector	35.00
Weighted as per load composition and considering "Other" as Commercial Sector	83.00

Table 4.5 shows that the IEAR value increases substantially to Rs 83.00/kWh, if the "Other" sector is considered to have interruption cost characteristics similar to those of the commercial sector. As mentioned earlier, the "Other" sector consists mostly of government, institutions and office buildings. Reference 42 indicates that this sector can be considered to have similar interruption cost characteristics to that of the industrial sector. The standard system IEAR for the NPS was therefore taken to be Rs 35.00/kWh. This rate was used in the remaining analyses described in this chapter.

4.3.3. Sensitivity Studies

Sensitivity analysis conducted in Reference 41 shows that the IEAR is quite robust and does not vary significantly with variations in system conditions. Sensitivity studies conducted on the NPS also indicated that the IEAR value is quite stable and can

be considered as a constant factor in a wide range of system studies. Some of the sensitivity studies conducted in this area are briefly described as follows.

Variation in the IEAR with Peak Load and Unit FOR

The peak load and generating unit forced outage rate (FOR) are important parameters in HL I evaluation. Studies were conducted to evaluate the impacts of these variables on the calculated IEAR. In the first study, the 'normal' FOR shown in Table 2.2 were utilized and the peak load was varied. Secondly, the increased FOR designated as 'extreme' shown in Table 2.3 were then utilized and the peak load was again varied. The results of the studies are shown in Figure 4.3 where it can be seen that, in both cases, a 30 % change in peak load produces only about a 1% change in the IEAR. It can also be seen from Figure 4.3 that only about a 2% change in the IEAR resulted when the unit FOR values were changed from the 'normal' to the 'extreme' case.

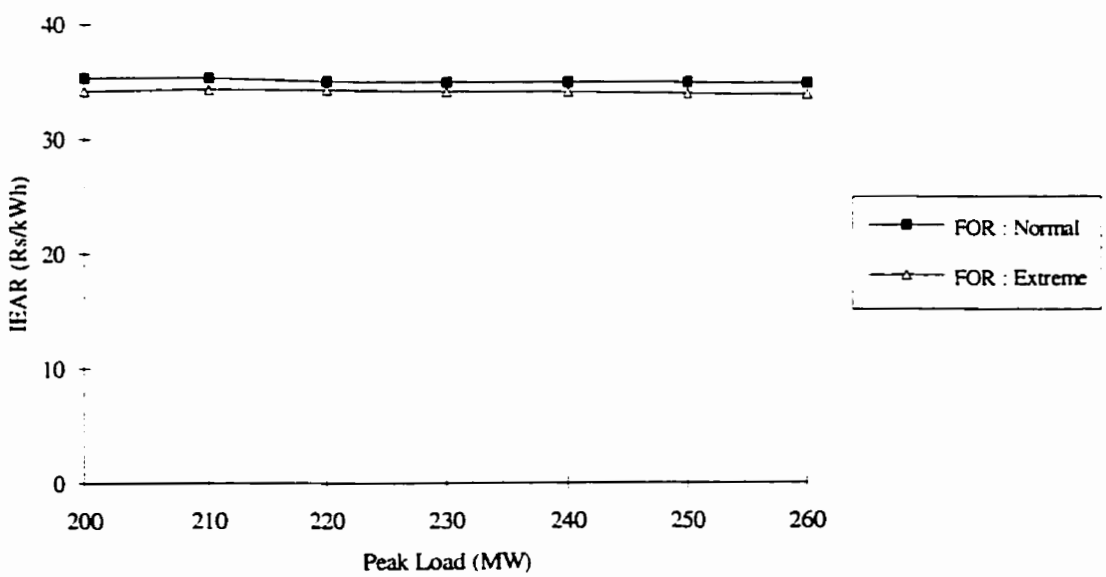

Figure 4.3. Variation in the IEAR with Peak Load and FOR

Variation in the IEAR with System Modifications

An electric power system is a dynamic entity. Its operating condition changes over time due to modifications in system configuration or changes in load demand or both. An investigation was conducted to evaluate how the calculated system IEAR varies with system modifications. The five year generation expansion plan proposed by the NEA [2] was considered for this analysis. The expansion plan is shown in Table 4.6.

Table 4.6. Expansion Plan Proposed by the NEA for the Period 1995-1999

Year	Peak Load (MW)	Unit Addition			Installed Capacity (MW)	Reserve (% of Peak Load)
		Capacity (MW)	Type	To Bus		
1995	237.17	-	-	-	274.15	15.59
1996	254.98	26	Multifuel	32	300.15	17.71
1997	279.53	26	Multifuel	40	326.15	16.68
1998	307.00	26	Multifuel	40	352.15	14.71
1999	347.29	26	Multifuel	40	378.15	8.89

The system configuration and the peak load for each year 1995-1999 shown in Table 4.6 were considered and the system IEAR calculated. The results are shown in Figure 4.4. The change in the IEAR is within 1% when the system conditions change in each of the five years as shown in Table 4.6.

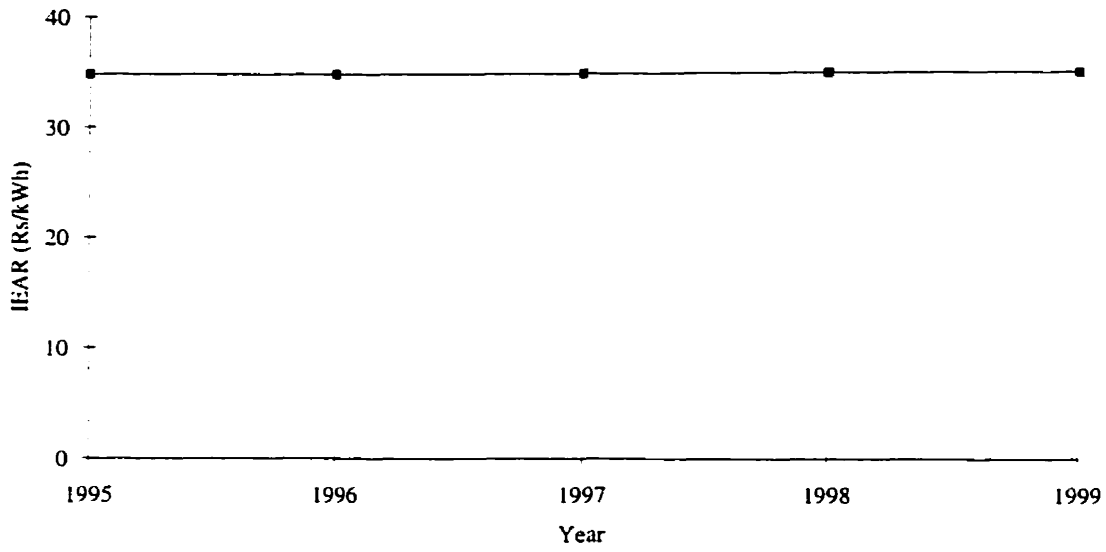

Figure 4.4. Variation in the IEAR with System Configuration as Planned by the NEA

4.4. Optimum Reserve Margin Determination Using the IEAR

The calculated system IEAR can be used in conjunction with the system energy index EENS to estimate the customer interruption cost as shown in Equation (4.4).

$$\text{Interruption Cost} = [\text{IEAR}] \times [\text{EENS}]. \tag{4.4}$$

Since the system IEAR is considered to be a constant factor, the assumption is that the interruption cost increases in direct proportion to the expected energy not supplied by the system. The customer interruption cost is considered to represent the system reliability worth.

The system reliability cost is made up of all the costs incurred by the utility in providing the customer with electric energy at a specific level of reliability. This cost basically consists of capital and operating costs. The capital cost relates to the investment required for new facilities. The operating cost consists of the fixed costs and the variable costs. The fixed costs include the annual charges, which continue as long as

capital is tied up in the enterprise and whether or not the equipment is operating. These charges comprise interest, depreciation, rent, taxes, insurance and any other expenditure that is based upon the magnitude of the capital investment. The variable costs include payment for materials, supplies, power, fuel costs, water rental charges, etc., and is associated with energy production. The variable cost is also referred to as the production cost in this research work.

The reliability cost/worth approach to system evaluation considers the capital, operating and customer interruption costs as the total system cost and attempts to optimize this total cost by evaluating the available expansion plan alternatives. This total is the actual societal cost that customers will see for the supply of electricity. The reliability cost/worth approach to system evaluation provides an opportunity for power system planners to minimize this total societal cost rather than only those costs incurred by the utility.

The above concepts have been applied to the NPS in order to estimate the optimum reserve margin. An analysis was performed for the base case, which is the 1995 system configuration. Sensitivity studies were performed to evaluate the impacts of various factors, such as different proposed expansions, generating unit FOR and the IEAR, on the reserve margin estimate. An expansion plan based on the reliability cost/worth approach was derived and compared with the NEA plan for the 1995-1999 period. Suitable planning criteria for the NPS were then determined. These studies are briefly described as follows.

4.4.1. The Base Case Analysis

The 1995 system configuration (see Table 2.14) is considered as the base case in the analysis. The expected peak load for the system is 237.17 MW [2]. The generating

unit reliability data used are given in Tables 2.2 and 2.3. The hourly load model used in the evaluation was derived from the load models shown in Tables 2.11, 2.12 and 2.13. The operating cost data and the priority loading order of the units are given in Table 2.14. The data for additional units used in the analyses are shown in Table 2.15.

The LOEE method [17] was used to calculate the expected energy supplied [EES] by each unit and the overall EENS for the system. The production cost was evaluated using the EES and the unit variable costs. The annual fixed cost was evaluated using the unit fixed costs and the ratings. The required annual capital cost was added to the fixed cost for any new unit addition in the system. The customer interruption cost was evaluated using Equation (4.1) and an IEAR of Rs 35/kWh.

In order to illustrate the determination of an optimum reserve margin using the reliability cost/worth approach, the 26 MW multifuel unit was removed from the existing system (Table 2.14, 1995 system) and then considered as an available additional generating unit in the proposed expansion. The results obtained with the sequential addition of 26 MW units are shown in Table 4.7 and presented graphically in Figure 4.5.

Table 4.7. Total Cost in Million Rupees(MRs) with Sequential Capacity Additions

System Configuration	Reserve Margin (%)	Fixed Cost (MRs.)	Production Cost (MRs.)	Interruption Cost (MRs.)	Total Cost (MRs.)
Existing - 1x26 MW	4.63	45.636	206.636	5.882	258.154
Existing	15.59*	48.627	207.004	0.563	256.194
Existing + 1x26 MW	26.55	69.617	207.039	0.048	276.704
Existing + 2x26 MW	37.52	90.607	207.042	0.004	297.653
Existing + 3x26 MW	48.48	111.596	207.043	0.000	318.639

* Optimum Reserve Margin

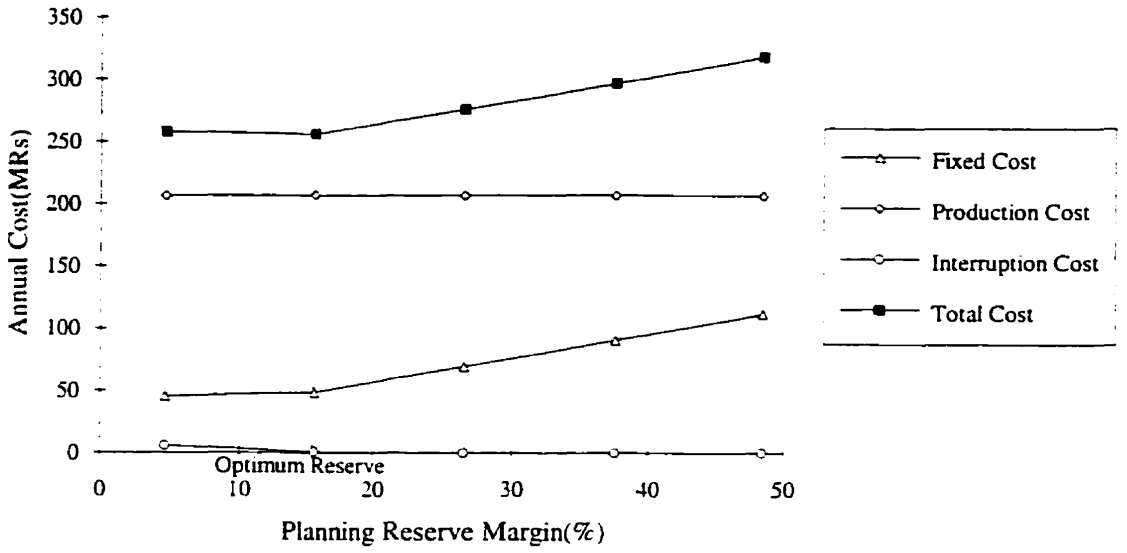

Figure 4.5. Variation in Fixed, Production, Interruption and Total Costs with Planning Reserve Margin

It can be seen from Table 4.7 that the existing system has the lowest total cost and therefore is the optimum configuration for 1995. The associated reserve is 15.59% which becomes the optimum reserve margin.

From the results shown in Table 4.7 and Figure 4.5, it can be seen that the interruption cost decreases rapidly as the reserve margin increases and approaches the optimum reserve. The fixed cost and the production cost increase as the reserve margin is increased. The total societal cost varies with the reserve margin. The total cost is minimum for a reserve of 15.59% which is therefore the optimum reserve margin for 1995. It is, however, important to note that this conclusion is based on the assumption that the proposed sequential addition of 26 MW multifuel units having FOR of 5% is appropriate for the NPS at the present time [2]. The optimum percent reserve margin will be different when different unit addition sequences are used. The basic concept, however, is that the alternative having the minimum total societal cost is selected.

4.4.2. Sensitivity Studies

Sensitivity studies were performed to evaluate the impacts of various factors, such as different proposed expansions, generating unit FOR and the IEAR, on the reserve margin. The results are discussed below.

Variation in the Optimum Reserve Margin for Selected Expansion Plans

In order to evaluate the impact of different expansion sequences on the optimum reserve margin, three hypothetical plans: Plan A, Plan B and Plan C were considered.

Plan A: This is the plan considered in the base case analysis in which the 26 MW multifuel unit was removed from the base case system and then considered as an available additional generating unit.

Plan B: In this plan, the 26 MW multifuel unit and the 2.5 MW diesel units are removed from the base case system and then considered as available generating units in the proposed expansion. The 26 MW unit was added first, then the 2.5 MW diesel units were added sequentially.

Plan C: In this scenario, the 26 MW multifuel unit and the 2.5 MW diesel units are removed from the base case system, and then only 2.5 MW diesel units were considered as available generating units in the proposed expansion and added sequentially.

The results obtained using the three plans are summarized in Table 4.8 and presented graphically in Figure 4.6.

Table 4.8. Variation in the Optimum Reserve Margin with Selected Expansion Plans

Expansion Plan Alternative	Optimum Reserve Margin (% of Peak Load)	Total Annual Cost (MRs)
A	15.59	256.194
B	11.38	253.732
C	4.63	258.154

It can be seen from Table 4.8 and Figure 4.6 that each expansion plan produces a unique optimum reserve margin and total societal cost. The optimum reserve margins obtained using expansion plans A, B and C are 15.59%, 11.38% and 4.63% respectively for the base case i.e. the 1995 system. The annual total costs for these reserve margins are 256.194, 253.732 and 258.154 million rupees respectively. If these alternatives are available, then expansion plan B, which yields the lowest total cost of 253.732 million rupees, should be selected for 1995. It is interesting to note that although expansion plan C produces the lowest optimum reserve margin (4.63%), it results in the highest annual charge of 258.154 million rupees.

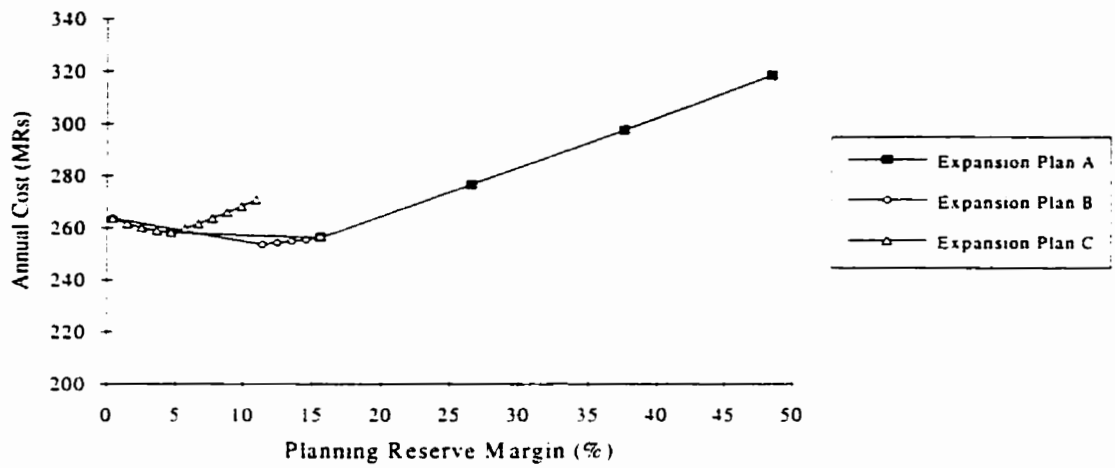

Figure 4.6. Variation in the Optimum Reserve Margin with Selected Expansion Plans

Variation in the Optimum Reserve Margin with Unit FOR

In order to understand the impact of generating unit FOR on the optimum reserve margin, expansion plan C was evaluated using the increased unit FOR designated as 'extreme' (see Table 2.3). The results are shown in Figure 4.7.

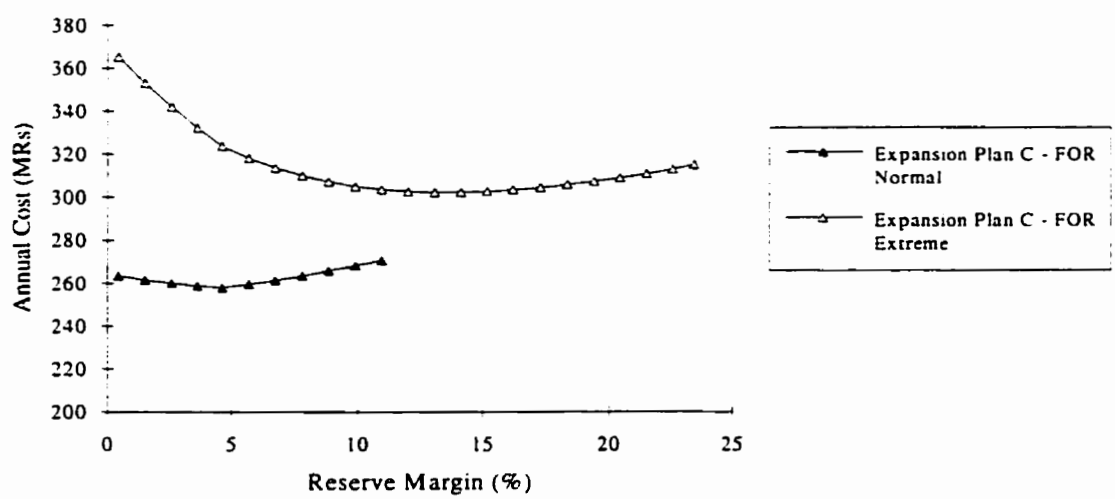

Figure 4.7. Variation in the Optimum Reserve Margin with Unit FOR

The results presented in Figure 4.7 show that the optimum reserve margin increases when the generating unit FOR increase. It can be seen that the total cost curve shifts towards the right and upwards when the FOR used are the 'extreme' values. This results in higher reserve margins and costs. The optimum reserve margin increases from about 5% to 13%, when the FOR is increased from 'normal' to 'extreme'. The increased unit FOR increase the system risk (EENS), which allows the reserve margin to increase to balance the cost. The increased reserve also drives the utility cost higher. The total societal cost therefore increases from about 260 million to 300 million rupees when the FOR are increased from 'normal' to 'extreme'.

Variation in the Optimum Reserve Margin with the IEAR

The total societal cost is critically dependent on the cost assigned to the unserved energy, i.e., the IEAR. In order to recognize the impact of the IEAR on the optimum reserve margin and the total societal cost, the IEAR value was varied and the optimum reserve margin and the resulting total cost evaluated. The results are shown in Table 4.9 and presented graphically in Figure 4.8.

Table 4.9. Variations in the Optimum Reserve and the System Cost with the IEAR

IEAR (Rs/kWh)	Multiples of Base IEAR	Optimum Reserve (% of Peak Load)	Annual System Cost (MRs)
35.00*	1.00	4.63	258.154
40.00	1.14	5.68	258.465
50.00	1.43	6.74	258.729
60.00	1.71	7.79	259.285
70.00	2.00	8.85	259.780
80.00	2.28	9.90	260.195
90.00	2.57	10.95	260.598

* Base IEAR for the NPS

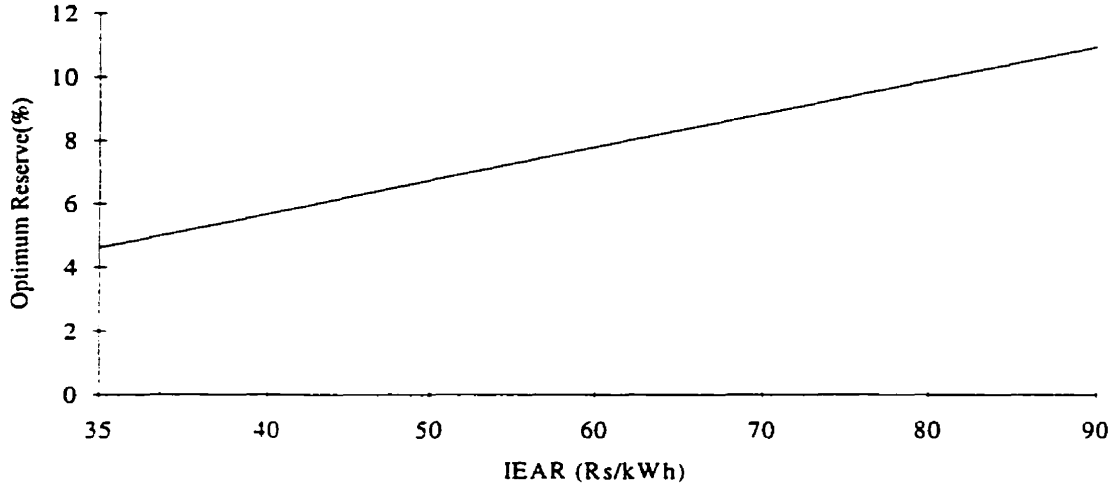

Figure 4.8. Variation in the Optimum Reserve Margin with the IEAR

The base case IEAR for the NPS is Rs 35/kWh. It can be seen from Table 4.9 and Figure 4.8 that the optimum reserve margin increases in proportion to the IEAR. The optimum reserve margin increased from about 5% to 11% (more than 2 times), when the IEAR was increased from Rs 35/kWh to Rs 90/kWh. The total cost, however, increases from 258.154 to 260.598 million rupees, an increase of approximately 1%, when the IEAR value was increased by 157%. The increased IEAR value allows a higher reserve margin to be utilized in the system by offsetting the utility cost due to the increased margin with a lower customer interruption cost. Figure 4.8 provides a quantitative relationship for the fact that a higher system IEAR will allow the system to have more reserve and therefore a higher reliability level.

4.4.3. Expansion Plan Studies

The expansion plan proposed by the NEA for the period 1995-1999 is shown in Table 4.6 [2]. The expected peak load for 1995 is 237.17 MW and the installed capacity is 274.15 MW giving a reserve margin of about 15%. The system configuration for this

year is shown in Table 2.14. This is the base case system configuration and is designated as the 'existing' system throughout the studies described in this chapter. The system peak loads for other years are shown in Table 4.6. A 26 MW multifuel generating unit is proposed for addition in each year of 1996-1999, maintaining a reserve of about 15% on average except for 1999 in which the reserve is about 9%.

An expansion plan based on the reliability cost/worth approach was derived and compared with the NEA plan to evaluate the implications. The sequential addition of 26 MW multifuel generating units proposed by the NEA was used in the evaluation assuming that the proposed sequence is appropriate for the NPS at the present time [2].

The evaluation procedure and the results for 1995 are described in Section 4.4.1. as the base case analysis. Similar analyses were done to determine the optimum configuration for each of the other four years in the planning period, i.e. 1996-1999. A summary of the results is shown in Table 4.10.

Table 4.10. Optimum Configuration Determination for the 1995-1999 Planning Period

Year	Peak Load (MW)	System Configuration	Annual Cost (MRs.)	Reserve (%)
1995	237.17	Existing - 1x26 MW	258.154	4.63
		Existing*	256.194	15.59*
		Existing + 1x26 MW	276.704	26.55
1996	254.98	Existing*	279.497	7.52*
		Existing + 1x26 MW	297.709	17.72
1997	279.53	Existing	342.741	-1.92
		Existing + 1x26 MW*	340.314	7.38*
		Existing + 2x26 MW	358.188	16.68
1998	307.00	Existing + 1x26 MW	431.708	-2.23
		Existing + 2x26 MW*	424.464	6.24*
		Existing + 3x26 MW	441.137	14.71
1999	347.29	Existing + 2x26 MW	631.282	-6.09
		Existing + 3x26 MW	582.618	1.40
		Existing + 4x26 MW*	581.980	8.89*
		Existing + 5x26 MW	607.586	16.37

*Optimum Configuration and Corresponding Reserve Margin

The configuration marked by an asterisk(*) in Table 4.10 is the optimum configuration and the corresponding reserve is the optimum reserve margin for the year shown. The derived expansion plan for the NPS for the planning period 1995-1999 is shown in Table 4.11.

Table 4.11. Proposed Expansion Plan for the NPS for the 1995-1999 Period using the Reliability Cost/Worth Approach

Year	Peak Load (MW)	Unit Addition			Installed Capacity (MW)	Reserve (% of Peak Load)
		Capacity (MW)	Type	To Bus		
1995	237.17	-	-	-	274.15	15.59
1996	254.98	-	-	-	274.15	7.52
1997	279.53	1 x 26	Multifuel	32	300.15	7.38
1998	307.00	1 x 26	Multifuel	40	326.15	6.24
1999	347.29	2 x 26	Multifuel	40	378.15	8.89

It can be seen from Table 4.11 that the existing 1995 system configuration is adequate for years 1995 and 1996. One additional 26 MW unit is required in each of the years 1997 and 1998 and thereafter two 26 MW units in 1999. It can be seen from Table 4.11 that the proposed plan limits the reserve margin to an average value of about 7.5%.

The proposed expansion plan derived using the reliability cost/worth approach and shown in Table 4.11 was compared with the NEA plan given in Table 4.6 to evaluate the differences. The results are summarized in Table 4.12.

It can be seen from Table 4.12 that in the proposed plan, one 26 MW multifuel unit is added in each year of 1997 and 1998 and two units are added in 1999, whereas in the NEA plan, one 26 MW unit is added in each year from 1996-1999. In effect, the new proposed plan allows a postponement of the 26 MW multifuel generating addition from year 1996 to 1999. This yielded a saving of about 18 million rupees i.e. more than 5% in the total societal cost in each of the years 1996-1998, with a total saving of more than 15% in the costs over the five year planning period. This can be clearly seen from Figure 4.9.

Table 4.12. Comparison of the Proposed Expansion with the NEA Plan

Year	Peak Load (MW)	Unit Addition (MW)		Total Annual Cost (MRs)		Reserve Margin (% of Peak Load)	
		Proposed	NEA Plan	Proposed	NEA Plan	Proposed	NEA Plan
1995	237.17	-	-	256.194	256.194	15.59	15.59
1996	254.98	-	1 x 26	279.497	297.709	7.52	17.72
1997	279.53	1 x 26	1 x 26	340.314	358.188	7.38	16.68
1998	307.00	1 x 26	1 x 26	424.464	441.137	6.24	14.71
1999	347.29	2 x 26	1 x 26	581.980	581.980	8.89	8.89

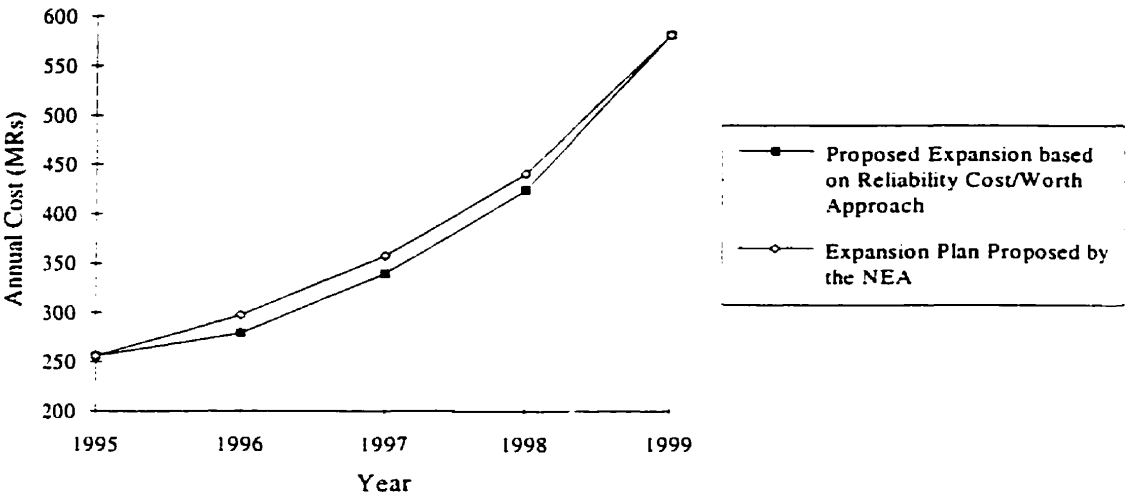

Figure 4.9. Total Costs Faced by the NPS Consumers due to the Proposed Plan and the NEA Plan for the 1995-1999 Period

It can be seen from the results shown in Table 4.11 that the proposed plan limits the system reserve margin to an average of about 7.5%, whereas the NEA plan proposes to maintain an average 15% reserve margin, except for 1999 which is approximately 9%. The lower average reserve margin of 7.5% resulting from the reliability cost/worth studies is due to the low system IEAR, i.e. Rs 35/kWh for the NPS. This research work clearly indicates that NPS should not consider a higher reserve margin until there is a substantial increase in the system IEAR.

4.4.4. Planning Criteria

The optimum expansion plan proposed for the 1995-1999 period was further analyzed to evaluate corresponding risk indices. The evaluation was performed as shown in Table 4.10 and the corresponding risk indices were calculated using the basic recursive technique [17]. The results are shown in Table 4.13 and displayed graphically in Figure 4.10. These results were used to develop appropriate criteria for the following long range planning discussion.

Table 4.13. Optimum Expansion Plan and Corresponding Risk Indices

Year	Peak Load (MW)	Optimum Configuration	Optimum Reserve (%)	Annual Cost (MRs)	Risk Index			
					LOLE day/yr	LOLE hr/yr	UPM	SM
1995	237.17	Existing System (See Table 2.14)	15.59	256.194	0.85	1.92	15.53	4.07
1996	254.98	Existing System	7.52	279.497	4.32	9.85	85.12	22.3
1997	279.53	Existing System + 1 - 26 MW Unit	7.38	340.314	4.47	10.18	88.14	23.1
1998	307.00	Existing System + 2 - 26 MW Units	6.24	424.464	5.93	13.4	112.9	29.6
1999	347.29	Existing System + 4 - 26 MW Units	8.89	516.980	3.29	7.33	55.77	14.6

It can be seen from Table 4.13 and Figure 4.10 that the risk index corresponding to the optimum configuration varies in each year of the planning period. The maximum risk index of 112.96 UPM occurs in 1998 as shown in Table 4.13. It is normal in system reliability evaluation to attempt to maintain the system at a lower risk than the maximum permissible level (see Figure 4.10). The maximum permissible risk level obtained in the NPS expansion plan evaluation was 112.9 UPM as shown in Table 4.13. It can be suggested that the standard risk for the NPS should be lower than this value. It was therefore decided to use a standard risk level of 100 UPM, which corresponds to an optimum reserve margin of about 7.5% (see Figure 4.10). The standard risk criterion of 100 UPM corresponds approximately to a risk index of 25 SM and a LOLE of 5 days /yr or 10 hrs/yr. These probabilistic criteria can be considered as standard risk indices in the long range planning process for the NPS.

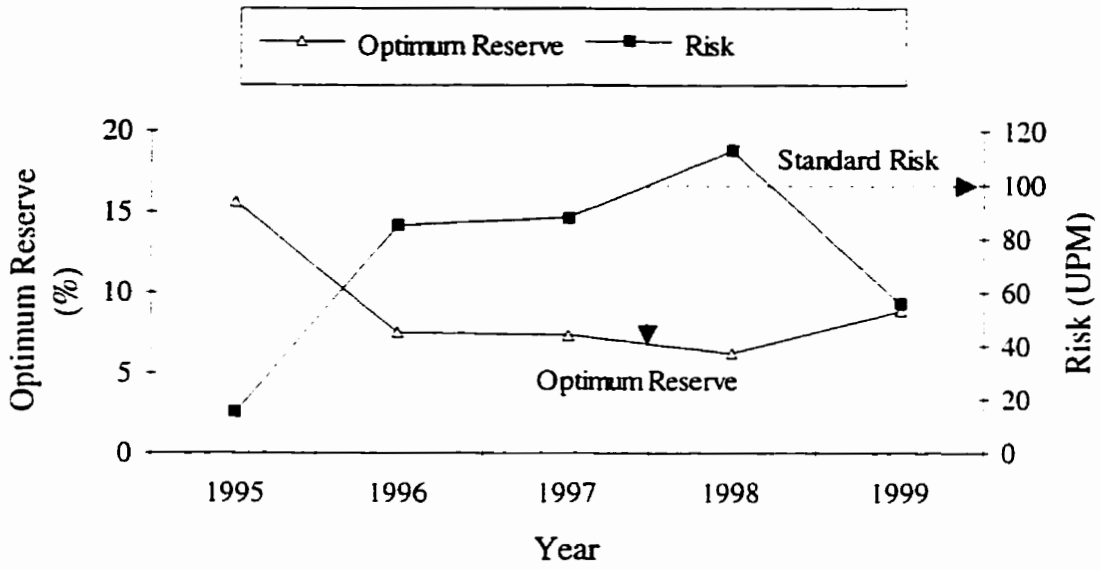

Figure 4.10. Optimum Reserve Margin and Corresponding Risk Profile for the NPS

The optimum reserve margin and corresponding risk profile for the NPS within the planning period is shown in Figure 4.10. The derived probabilistic planning criteria for the NPS obtained from the analysis are listed in Table 4.14. These criteria can be used to assess future power projects in Nepal, and in other long range NPS planning processes.

Table 4.14. Generating Capacity Planning Criterion Options for the NPS

Criterion	Index
LOLE	5 days/yr
LOLE	10 hrs/yr
EUE	25 SM
EUE	100 UPM

Note: EUE - Expected Unserved Energy

4.5. Summary

This chapter presents a reliability cost/worth approach to system evaluation at HL I. A reliability cost/worth based framework for HL I studies is described. An analytical method for interrupted energy assessment rate (IEAR) determination using the frequency and duration technique is described. The IEAR for the service area supplied by the NPS was evaluated using the interruption cost data obtained from the customer surveys described in Chapter 3.

The customer survey results described in Chapter 3 indicate that the customer interruption cost estimates are dependent upon various customer and interruption related characteristics and variables. This chapter illustrates how these interruption cost information data can be used to develop an overall interruption cost function designated as the composite customer damage function(CCDF). The developed CCDF is then used to evaluate the IEAR for the service area. The results show that the IEAR value for the NPS is highly dependent on the interruption cost characteristics of the customer sectors considered in the evaluation.

Some sensitivity studies are presented to recognize the impacts on the calculated IEAR of important system parameters such as the peak load, generating unit forced outage rates and system modifications. The results show that variations in these factors do not significantly affect the IEAR value and therefore it can be considered as a constant factor in a wide range of studies.

A methodology for determining the optimum reserve margin or system reliability level is presented. It shows how the calculated IEAR can be used to select the optimum system configuration from the available expansion plan alternatives.

Sensitivity studies are presented to show the impacts on the estimated optimum reserve margin of factors such as different expansion schemes, generating unit forced outage rates and the IEAR. The results show that different unit addition schemes yield differing optimum system reserve margins. The results also indicate that increased unit forced outage rates require higher reserve margins to optimize the cost. It is also shown that the optimum reserve margin increases in proportion to the system IEAR.

A five year expansion plan based on the reliability cost/worth approach is derived and compared with the plan proposed by the NEA for the 1995-1999 planning period. A different unit addition sequence to that proposed by the NEA was obtained using the reliability cost/worth approach. The results indicate a saving of more than 15% in total costs within the planning period when the proposed expansion is used. The results also reveal that the optimum reserve margin for the NPS at the present time is about 7.5% whereas the NEA plan has an average reserve margin of about 15%. The evaluation results indicate that a higher reserve margin or reliability level for the NPS is not justified until the system IEAR increases substantially higher than the Rs 35/kWh calculated in this research work.

The optimum system configuration for the planning period 1995-1999 were further analyzed and the additional risk indices are determined. These risk indices are introduced as possible planning criteria for use in the NPS long range system planning.

This chapter illustrates a reliability cost/worth approach to generating capacity planning in the Nepal Integrated Electric Power System. It shows that an optimum system configuration that maximizes the net social benefits can be determined for the power system in a developing country. It also shows that a short term expansion plan can be developed based on the least societal cost approach. The optimum plan can then

be utilized to develop suitable probabilistic criteria which can be used in long range system planning. The primary contribution of the research work described in this chapter is the formulation of an overall approach to determine appropriate generating capacity planning criteria, which despite the inherent system uncertainties, can be used effectively in a developing country.

5. RELIABILITY COST/WORTH STUDIES AT HL II

5.1. Introduction

The most fundamental quantitative evaluation process in power system planning is the assessment of system generating capacity adequacy to meet the increasing load demands. This is the subject matter of HL I studies. A second but equally important assessment process is the system studies required at HL II, which consider both generation and transmission facilities in the evaluation. This assessment process is also known as "composite system" or "bulk power system" evaluation.

The transmission facilities represent a significant portion of the overall power system cost. In addition, a failure in the transmission network may cause wide-spread customer outages, which may incur considerable costs to the consumers. It is therefore important that the transmission network be included in a reliability cost/worth approach to system evaluation.

The evaluation studies at HL II incorporate the dispersed nature of system generation and load points, and are important in an understanding of the impacts of generation and line additions at various locations in the system. This chapter illustrates how the basic reliability cost/worth concepts applied in the HL I studies described in Chapter 4 can be extended to include the system transmission facilities in an overall bulk power system evaluation.

In this chapter, a basic reliability cost/worth based analysis framework for HL II studies is presented. The fundamental concepts underlying the IEAR evaluation at HL II are described. Some sensitivity studies performed to evaluate the impacts on the calculated IEAR of important system parameters such as the peak load, component outage rates and system modifications are presented. The application of IEAR in determining the optimum overall expansion plan is then illustrated. Some planning criteria developed in the studies are suggested and finally, the chapter concludes with a summary. The assembled NPS reliability data obtained through the data investigation described in Chapter 2 and the interruption cost data obtained from the customer survey described in Chapter 3, have been used in this research work.

5.2. The Basic Framework for HL II Studies

A suggested methodology for reliability cost/worth studies at HL II is shown in Figure 5.1 in the form of a block diagram.

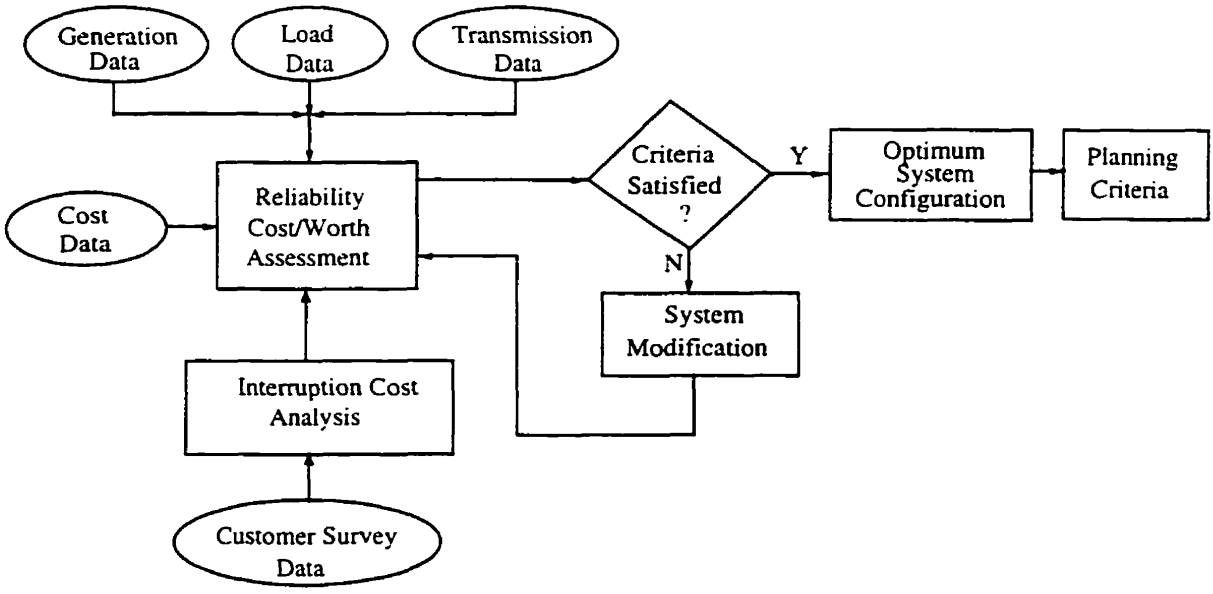

Figure 5.1. Reliability Cost/Worth Analysis Framework for HI II Studies

Reliability cost/worth studies at HL II require generation data, load data, transmission data, cost data and interruption cost data. The interruption cost data are normally obtained from customer surveys. These input data requirements are shown in Figure 5.1.

Reliability cost/worth assessment can be performed for any given system condition using the required input data shown in Figure 5.1. An overall expansion scheme that will incur the lowest cost to the customers is selected. This is the basic criterion used in this system evaluation approach. If the criterion is not satisfied, the expansion scheme in consideration is modified and assessed again. The modification in this case may be addition of a generation or transmission facility or both, or even an entirely new expansion scheme. This procedure is repeated until the adequacy criterion is satisfied. The newly developed overall system configuration which produces the optimum reliability level is then utilized in the future power system development. The set of indices produced in the evaluation process can be selected as planning criteria for future long range power project evaluation. The basic objective is to ensure that the system expansion is implemented on the basis of overall societal benefit.

5.3. IEAR Evaluation at HL II

5.3.1. Basic Concepts

The fundamental concept underlying an HL II evaluation, as an extension to HL I evaluation which incorporates the transmission facility, is to evaluate the impacts on each individual load point due to modification(s) in the system and to aggregate the individual bus impacts to evaluate the overall system condition. In other words, all the

studies conducted on the system basis at HL I are performed on an individual load-bus basis at HL II. The individual load-bus results are then processed to obtain the overall system indices to compare the alternatives. Composite system evaluation therefore requires the system network topology details as well as individual load center and overall system information.

The actual or perceived cost of interruptions obtained through the customer surveys described in Chapter 3 are now used to develop customer damage functions (CCDF) for each individual bus using the sector energy demand composition in the service area supplied by that bus. The individual bus CCDF are then used in conjunction with the expected energy not supplied (EENS) in a bus to calculate the individual bus IEAR. This requires an HL II evaluation program that can generate for each individual bus, the variables such as the magnitude '*m*', frequency '*f*', and the duration '*d*' of load curtailment due to the various possible system outage contingencies. The composite system evaluation program used in this research work is the COMREL software [43] developed at the University of Saskatchewan. A brief description of the program is presented in the next section.

5.3.2. Brief Description of the HL II Evaluation Program COMREL

The composite system reliability evaluation program (COMREL) is an outcome of substantial research work done in the area by the Power System Research Group in the Electrical Engineering Department at the University of Saskatchewan.

The COMREL program is based on the analytical method of bulk power system reliability evaluation [17]. It uses a contingency enumeration technique which considers all outages up to a prescribed level. For each outage contingency, the system state is

scrutinized and if necessary, appropriate corrective actions are taken [44]. A system failure is recorded when corrective actions, short of curtailing customer loads, are unable to eliminate the system problem. The severity of a failure is evaluated by calculating the magnitude, frequency, duration and location of load curtailment.

The individual bus and the system IEAR can be calculated using the COMREL program. The evaluation procedure is explained in the next section.

5.3.3. The COMREL Program and the IEAR Evaluation

For each contingency j that leads to load curtailment at a load bus k, the following variables are generated by COMREL:

- the magnitude m_{kj} of load curtailment in MW;
- the frequency f_j of the contingency j in occ/year; and
- the duration d_j of the contingency j in hours.

The total expected energy not supplied (EENS) at bus k due to all contingencies that lead to load curtailment is calculated using Equation (5.1).

$$\text{Total EENS} = \sum_{j=1}^{NC} m_{kj} f_j d_j \quad \text{(MWh/year).} \tag{5.1}$$

The total expected cost (ECOST) of power interruptions to customers at bus k is calculated using Equation (5.2).

$$\text{Total ECOST} = \sum_{j=1}^{NC} m_{kj} f_j c_j \quad \text{(MW Rs/kW year)} \tag{5.2}$$

where, NC is the total number of outages that lead to power interruption at bus k, and c_j is the cost in Rs/kW for an outage of duration d_j, which is obtained from the developed CCDF for bus k.

The IEAR at bus k is then evaluated by the ratio shown in Equation (5.3) and the aggregate system IEAR is calculated using Equation (5.4).

$$\text{IEAR}_k = \frac{\sum_{j=1}^{NC} m_{kj} f_j c_j}{\sum_{j=1}^{NC} m_{kj} f_j d_j} \quad \text{(Rs/kWh).} \tag{5.3}$$

$$\text{System IEAR} = \sum_{k=1}^{NB} IEAR_k \times q_k \,, \tag{5.4}$$

where, NB is the total number of load buses in the system and q_k is the fraction of the system load utilized by the customers at bus k.

5.3.4. Individual Bus IEAR for Major NPS Load Buses

The COMREL program was modified to incorporate individual load bus CCDF and to evaluate the IEAR using the basic concepts described in Section 5.3.3. The modified program was then used to evaluate the IEAR for the NPS load buses.

The individual load bus CCDF was developed using the sector customer damage functions (SCDF) shown in Table 3.9 and the sector load demand composition at the bus. The sector load demand composition data for all the NPS load buses were not

readily available due to a lack of adequate record keeping system in the NEA. However, data for some major system load buses were available. The sector load composition data collected in Nepal for some of the major NPS load buses are given in Table 5.1. These load buses carry more than 55% of the system load.

The sector load composition data shown in Table 5.1 and the SCDF given in Table 3.9 obtained through the customer surveys conducted in Nepal were used to develop CCDF for the major NPS load buses. The results are shown in Table 5.2.

Table 5.1. Sector Load Composition for the Major NPS Load Buses

Bus	1995 Load (MW)	Weight (%)	Sector Load Composition (%)			
			Residential	Commercial	Industrial	Other
5	16.56	7.0	77.20	9.20	10.50	3.10
7	8.99	3.8	69.73	12.39	15.85	2.03
9	19.46	8.2	81.00	10.00	3.00	6.00
14	11.38	4.8	76.90	4.20	14.10	4.80
16	19.21	8.1	39.97	37.85	1.20	20.98
24	10.73	4.5	10.10	0.82	86.65	2.43
29	10.11	4.2	16.79	1.15	76.13	5.93
32	24.05	10.1	14.49	1.80	80.93	2.78
40	12.76	5.4	27.58	3.10	56.76	12.56

Table 5.2. Developed CCDF in Rs/kW for the Major NPS Load Buses

Load Bus	Interruption Duration							
	1 min	20 min	1 hr	2 hr	4 hr	8 hr	24 hr	48 hr
5	4.28	14.51	34.89	80.99	147.63	230.82	498.76	916.21
7	5.71	19.23	44.14	102.32	179.61	280.53	563.19	1001.06
9	4.35	15.28	36.50	85.84	151.43	239.96	502.32	912.14
14	2.64	8.78	21.88	48.64	92.60	159.83	424.45	836.86
16	15.63	52.45	114.26	269.85	452.38	660.56	1011.08	1544.90
24	4.92	11.29	21.38	32.67	77.87	151.09	522.17	1080.80
29	4.68	11.03	21.41	34.22	79.26	151.85	512.25	1056.23
32	5.02	12.03	23.39	38.63	86.69	162.46	527.11	1077.00
40	4.78	12.30	25.15	45.89	96.18	173.24	517.52	1039.49

The developed CCDF shown in Table 5.2 and the assembled NPS generation and transmission data presented in Chapter 2 were used to evaluate the individual bus IEAR for the major NPS load buses. The results for the base case, i.e. the 1995 system configuration, are presented in Table 5.3. Buses 5, 7, 9, 14 and 16 serve the important load centers in the Kathmandu region (see Figure 2.1). Bus 24 serves the major industrial town of Hetaunda, whereas Bus 29 serves the major city of Birgunj, both in the central development region of the country. Bus 32 serves the major city of Biratnagar in the eastern development region, and Bus 40 serves the major load center in the western region of the country. These buses carry more than 55% of the system load.

Table 5.3. Individual Load Bus IEAR in Rs/kWh for the Major NPS Buses (Base Case: 1995 Configuration)

Load Bus	ECOST (kRs/year)	EENS (MWh/year)	IEAR (Rs/kWh)
5	444.784	16.113	27.60
7	14454.160	612.641	23.59
9	1518.417	64.942	23.38
14	6417.615	359.305	17.86
16	674.481	9.841	68.54
24	11407.180	522.830	21.82
29	27.285	1.285	21.23
32	16518.710	774.451	21.33
40	874.030	64.826	13.48

It can be seen from Table 5.3 that the individual bus IEAR differs from bus to bus. Bus 16 of the Kathmandu region has the highest IEAR value of Rs 68.54/kWh whereas Bus 40 of the western development region has the lowest value of Rs 13.48/kWh.

5.3.5. Sensitivity Studies

Sensitivity studies were conducted in order to appreciate how the calculated individual bus IEAR varies with variation in system parameters such as the peak load, line and generating unit outage rates, and variation in system operating conditions.

The generating unit outage data used for 'normal' and 'extreme' cases are given in Tables 2.2 and 2.3 respectively. The outage data considered for transmission facilities are shown in Table 5.4. The 'extreme' data were derived from the outage information provided by the NEA. The 'normal' data shown are given in Chapter 2. All the other generation and transmission data used in the load flow studies are given in Chapter 2 and detailed in Appendix B. The results are discussed below.

Table 5.4. Outage Data for Transmission Facilities

Line	Failure Rate (failure/yr/km)		Repair Time (hr)	
	Normal	Extreme	Normal	Extreme
132 kV	0.015	0.030	15	48
66 kV	0.020	0.060	10	16
Equipment	Failure Rate (failure/yr)		Repair Time (hr)	
	Normal	Extreme	Normal	Extreme
Transformer	0.020	0.040	768	768

Variation in the Individual Bus IEAR with the Peak Load and the Component Outage Rates

The peak load and component outage rates are important parameters utilized in an adequacy evaluation. Studies were conducted to evaluate the impacts of these variables on the calculated individual bus IEAR. The 'normal' outage rates were first considered following which the peak load was varied. The increased rates designated as 'extreme' were then considered and the peak load again varied. The results for some selected buses are shown in Figure 5.2. It can be seen from Figure 5.2 that the individual bus IEAR does not change significantly with the variations in the peak load or component outage rates.

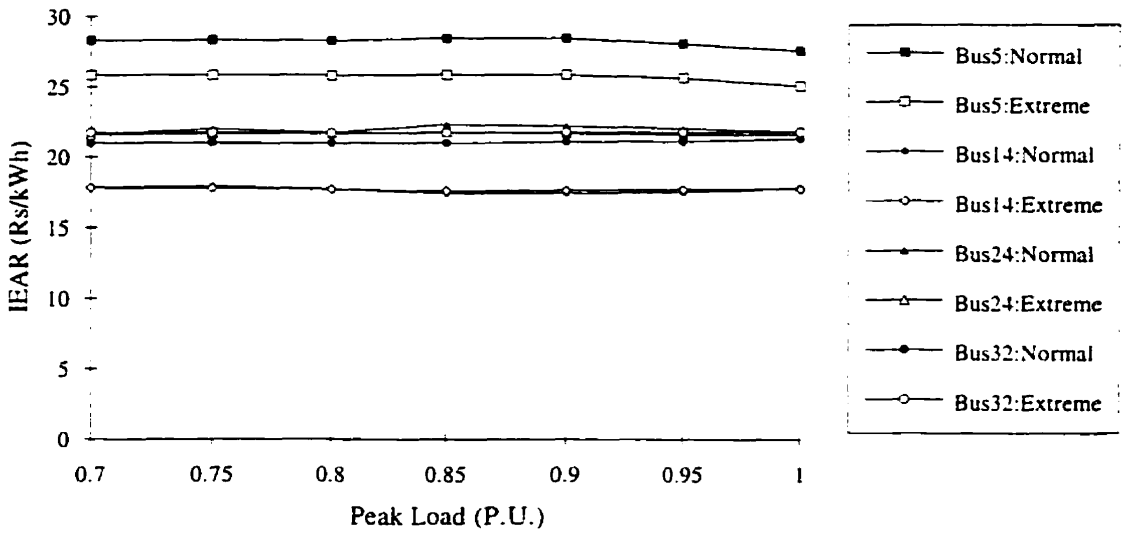

Figure 5.2. Variation in the Individual Bus IEAR with Peak Load and Component Outage Rates

Variation in the Individual Bus IEAR with System modifications

System operating conditions change over time due to modifications in system configuration or changes in load demand or both. An investigation was conducted to evaluate how the calculated individual bus IEAR varies with system modifications. A five year composite system expansion plan proposed by the NEA [2] was utilized for this analysis. The proposed expansion plan considering both generation and transmission systems is presented in Table 5.5. The impact results for some selected major NPS buses are shown in Figure 5.3.

It can be seen from Figure 5.3 that the individual bus IEAR values remain relatively constant even though the system operating conditions change considerably.

Table 5.5. Composite Generation and Transmission Expansion Plan Proposed by the NEA for the Period 1995-1999

Year	Peak Load (MW)	Generation (MW)	Addition of Generation			Addition of Line		
			Capacity (MW)	Type	Bus	kV	km	Bus-Bus
1995	237.17	274	-	-	-	132	137	25-30
						66	3	7-9
1996	254.98	300	26	Multifuel	32	-	-	-
1997	279.53	326	26	Multifuel	40	-	-	-
1998	307.00	352	26	Multifuel	40	132	70	34-37
						132	43	37-40
1999	347.29	378	26	Multifuel	40	-	-	-

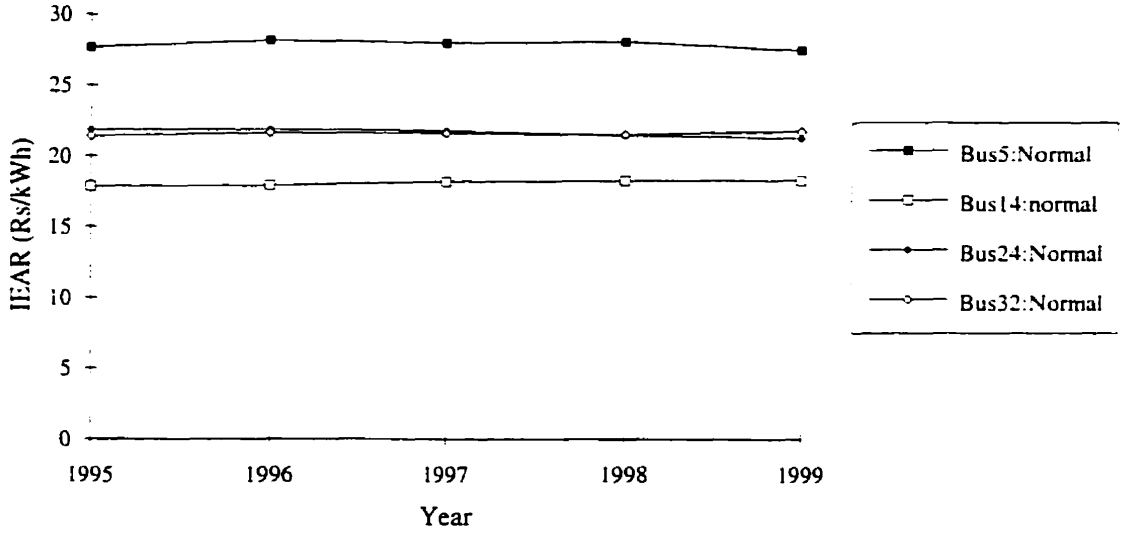

Figure 5.3. Variation in the Individual Bus IEAR with System Configuration Planned by the NEA for the Period 1995-1999

The sensitivity analyses conducted in this research clearly indicate that the individual bus IEAR are quite robust and do not vary significantly with variations in operating conditions. They can therefore be considered as a constant factor in a wide range of system studies. For each major bus, an average of all the IEAR values from the sensitivity analyses was calculated and then rounded to a two digit Rs value. These values were then considered as the standard IEAR for the service area supplied by that bus. The results are shown in Table 5.6. The standard values for the major NPS buses analyzed in the sensitivity studies were used in the further studies described later in this chapter.

Table 5.6. Individual Bus IEAR Considered for the Major NPS Load Buses

	Individual Bus IEAR (1996 Rs/kWh)								
	5	7	9	14	16	24	29	32	40
Average Value	27.23	23.94	23.23	17.83	69.83	21.78	20.29	21.48	14.60
Standard value	27.00	24.00	23.00	18.00	70.00	22.00	20.00	21.00	15.00

5.3.6. IEAR Estimates for Other Load Buses and the System IEAR

The sector load demand data for all the load buses in the NPS were not available due to an inadequate data recording system in the NEA. The data available for the major buses were used to estimate the IEAR shown in Table 5.6. Overall system evaluation at HL II involves the determination of the system IEAR which is based upon the individual load point IEAR for all buses in the system (i.e. Equation 5.4). System reliability cost/worth studies cannot be performed at HL II in the absence of individual bus sector demand data without making some necessary assumptions. These kind of difficulties will be encountered by system planners attempting to initiate reliability cost/worth

studies in most developing countries. A practical approach was adopted to solve this problem. The methodology utilized is as follows.

It is generally understood that the IEAR in a particular service area depends on the way electricity is used, or in other words, the socio-economic status of that area. The link between energy consumption and socio-economic development is well established [1]. Based on this concept, it is reasonable to assign a known service area IEAR to other areas in its vicinity, or if required to a region represented by that particular service area.

Nepal has been divided into five distinct regions for development purposes. These are the central, eastern, western, mid-western and far-western development regions (see Figure A.2, The NPS Development Plan). This kind of socio-economic division is normally found in developing countries. The development settings can be utilized to implement the IEAR extension approach noted earlier.

In order to apply the IEAR extension approach, the NPS service area was divided into four distinct regions. These are the Kathmandu, central, eastern and western regions (see Figure 2.1). From an electricity availability point of view, the central development region was divided into the Kathmandu and the central regions, and the western, mid-western and far-western development regions were combined and designated as the western region. All the buses that supply service areas within a particular region belong to that region. The evaluated IEAR of the major buses in a particular region, whose sector composition data were available, were averaged and rounded to a two digit Rs value. The standardized regional IEAR was then assigned on a regional basis to the buses whose IEAR could not be directly evaluated due to the lack of data. The estimated major load bus IEAR were therefore extended to other load buses in the system on this regional based approach. The results are presented in Table 5.7.

Table 5.7. Extension of Major Load Bus IEAR to Other Load Buses on a Regional Basis

Bus	Region	Representative Bus	Average Regional IEAR (Rs/kWh)	Standardized IEAR (Rs/kWh)
2	Kathmandu	5, 7, 9, 14, 16	32.40	32.00
3	Kathmandu	5, 7, 9, 14, 16	32.40	32.00
4	Kathmandu	5, 7, 9, 14, 16	32.40	32.00
6	Kathmandu	5, 7, 9, 14, 16	32.40	32.00
19	Kathmandu	5, 7, 9, 14, 16	32.40	32.00
21	Kathmandu	5, 7, 9, 14, 16	32.40	32.00
22	Kathmandu	5, 7, 9, 14, 16	32.40	32.00
26	Central	24, 29	21.00	21.00
27	Central	24, 29	21.00	21.00
28	Central	24, 29	21.00	21.00
30	Eastern	32	21.00	21.00
31	Eastern	32	21.00	21.00
33	Eastern	32	21.00	21.00
34	Western	40	15.00	15.00
35	Western	40	14.60	15.00
36	Western	40	15.00	15.00
37	Western	40	15.00	15.00
38	Western	40	15.00	15.00
41	Western	40	15.00	15.00
42	Western	40	15.00	15.00
43	Western	40	15.00	15.00
44	Western	40	15.00	15.00
45	Western	40	15.00	15.00
46	Western	40	15.00	15.00

Table 5.8 presents the individual bus IEAR for all the load buses in the NPS and the aggregate system IEAR. The system IEAR is obtained by summing the weighted individual bus IEAR, where the weight used is the load at a particular bus as a fraction of the system load. The aggregate system IEAR was used in a wide range of system studies as described later in this chapter. The system IEAR calculated for the NPS is 25.93 or approximately Rs 26.00/kWh at HL II. The system IEAR evaluated at HL I is Rs 35/kWh. The difference in the rates is due to the differences in modeling approaches

used at the two levels of evaluation and in the relative contributions to outage cost and unserved energy from the two functional zones.

Table 5.8. Individual Load Bus IEAR and Aggregate IEAR

Load Point	IEAR (Rs/kWh)	Weight (% of Peak Load)	Weighted IEAR (Rs/kWh)
2	32.00	0.96	0.31
3	32.00	2.03	0.65
4	32.00	3.49	1.12
5	27.00	7.00	1.89
6	32.00	4.35	1.40
7	24.00	3.80	0.91
9	23.00	8.20	1.89
14	18.00	4.80	0.86
16	70.00	8.10	5.67
19	32.00	0.45	0.15
21	32.00	4.38	1.40
22	32.00	0.68	0.21
24	22.00	4.50	0.99
26	21.00	0.22	0.05
27	21.00	0.65	0.14
28	21.00	3.10	0.65
29	20.00	4.20	0.84
30	21.00	2.80	0.57
31	21.00	5.35	1.12
32	21.00	10.15	2.13
33	21.00	1.99	0.42
34	15.00	2.81	0.42
35	15.00	0.83	0.13
36	15.00	3.95	0.59
37	15.00	0.48	0.07
38	15.00	0.27	0.04
40	15.00	5.40	0.81
41	15.00	0.38	0.06
42	15.00	0.29	0.04
43	15.00	2.68	0.40
44	15.00	0.14	0.02
45	15.00	1.03	0.16
46	15.00	0.54	0.08
System IEAR			25.93

5.4. Optimum Overall Expansion Determination Using the IEAR

The individual bus IEAR and the system IEAR can be used in conjunction with the EENS at each load point and the overall system to predict load point and system interruption costs for the existing system and for changed conditions due to load growth and/or system modifications. The predicted interruption costs are then used to determine optimum overall expansion in the form of additional generation and transmission facilities. These evaluation concepts were applied to the NPS. The results are described below.

The investigation commenced by analyzing the base case, which is the 1995 NPS configuration without any addition of generators and lines. An impact study was conducted to appreciate the effects on the major load points and the overall system of generation injections at different locations in the system. An expansion plan based on the reliability cost/worth approach was derived and compared with the plan proposed by the NEA for the 1995-1999 period. Suitable planning criteria for the NPS were then formulated. These studies are briefly described in the following.

5.4.1. Base Case Analysis

The 1995 NPS configuration without the addition of generators and lines is considered as the base case. The NPS data used in the analysis are given in Chapter 2. The additional generating units and lines shown in Table 5.5 for the system expansion proposed by the NEA were considered in the analysis. A seven-step load model [27] was used to represent the annual load in the NPS. Table 5.9 shows the annual EENS and the customer outage costs at each load bus and for the NPS using the IEAR values given in Table 5.8.

Table 5.9. Annual EENS and Customer Outage Costs at each Load Bus and for the System (Base Case: 1995 Configuration)

Load Point	EENS (MWh)	IEAR (Rs/kWh)	Customer Cost (Rs x 10^3)
2	4.92	32.00	157.44
3	8.46	32.00	270.72
4	5.90	32.00	188.80
5	8.98	27.00	242.46
6	20.90	32.00	668.80
7	189.74	24.00	4553.76
9	11.34	23.00	260.82
14	42.72	18.00	768.96
16	6.49	70.00	454.30
19	3.02	32.00	96.64
21	1.01	32.00	32.32
22	6.25	32.00	200.00
24	32.87	22.00	723.14
26	0.29	21.00	6.09
27	0.35	21.00	7.35
28	0.05	21.00	1.05
29	0.02	20.00	0.40
30	69.08	21.00	1450.68
31	129.55	21.00	2720.55
32	179.19	21.00	3762.99
33	84.44	21.00	1773.24
34	120.75	15.00	1811.25
35	9.48	15.00	142.20
36	110.78	15.00	1661.70
37	20.53	15.00	307.95
38	13.01	15.00	195.15
40	5.15	15.00	77.25
41	0.51	15.00	7.65
42	0.44	15.00	6.60
43	87.20	15.00	1308.00
44	7.05	15.00	105.75
45	85.08	15.00	1276.20
46	51.45	15.00	771.75
System	1317.00		26011.96

It can be seen from Table 5.9 that Bus 7 in the Kathmandu region contributes the most to the system cost of unsupplied energy. Buses 31, 32 and 33 are load points in the

eastern region that have substantial customer interruption costs. Similarly, Buses 34, 36, 43 and 45 are the load points in the western region that have major interruption costs. The base case analysis therefore identifies the most immediate problems in the system. The information can be considered as input to the system design.

5.4.2. Impact of Generation Additions at Different System Locations

The future generation facility additions to the NPS were identified as being in the eastern and western regions of the country [32]. An investigation was therefore conducted to evaluate the effects of generation additions at the major buses in these regions. It was assumed that 26 MW generating units having forced outage rates of 5% are appropriate as the additional units for NPS generating capacity expansion [2]. An impact study of the addition of these units at the eastern region Bus 32, the western region Bus 40, and alternately at Bus 32 and Bus 40, was conducted. The impacts on both the selected major NPS load buses and the overall system were investigated. The results are shown in Figures 5.4, 5.5 and 5.6 respectively.

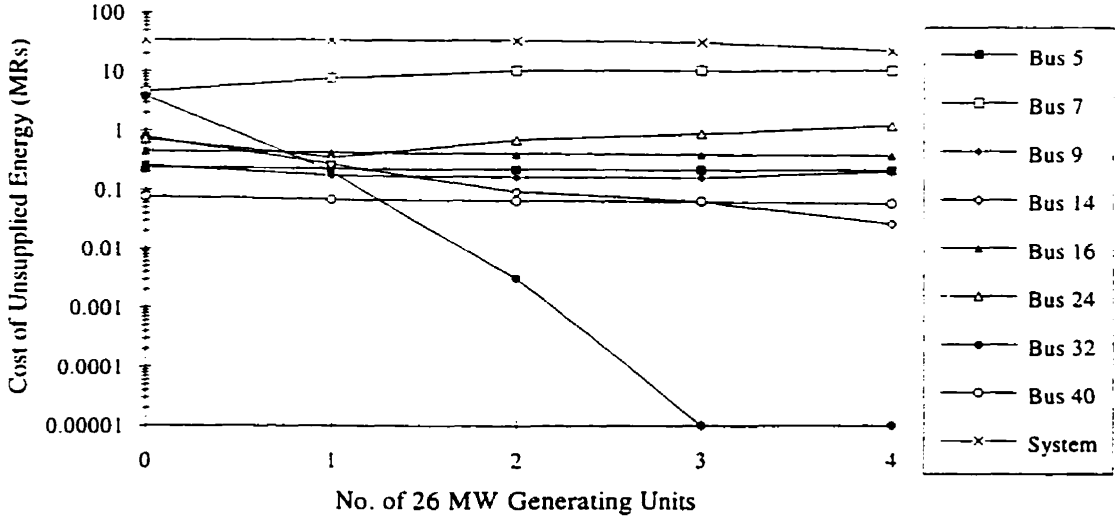

Figure 5.4. Variation in the Annual Cost of Unsupplied Energy at Major NPS Load Buses and the System as 26 MW Generating Units with FOR of 5% are Sequentially Added at the Eastern Region Bus 32

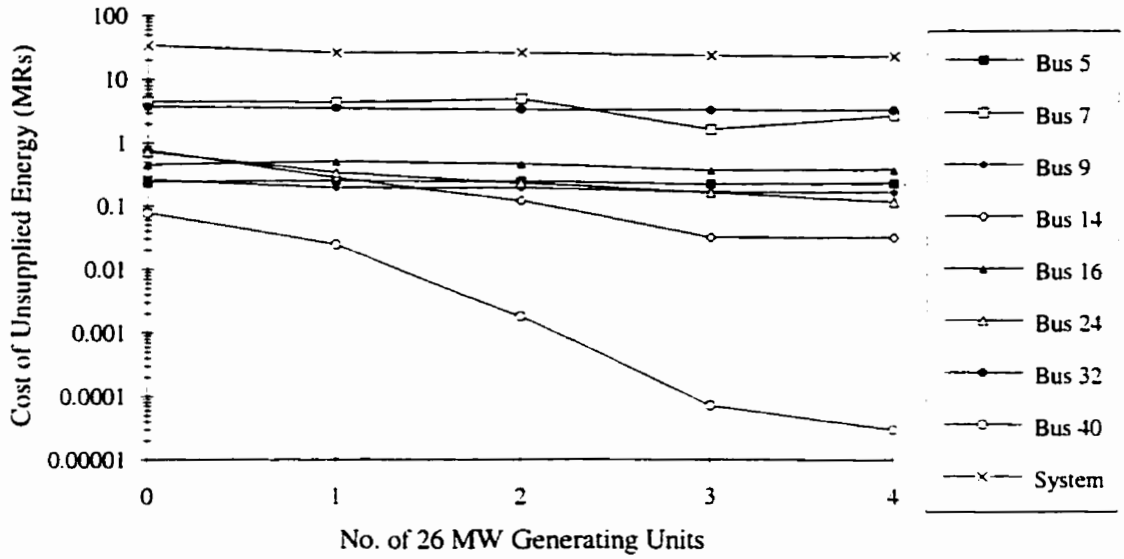

Figure 5.5. Variation in the Annual Cost of Unsupplied Energy at Major NPS Load Buses and the System as 26 MW Generating Units with FOR of 5% are Sequentially Added at the Western Region Bus 40

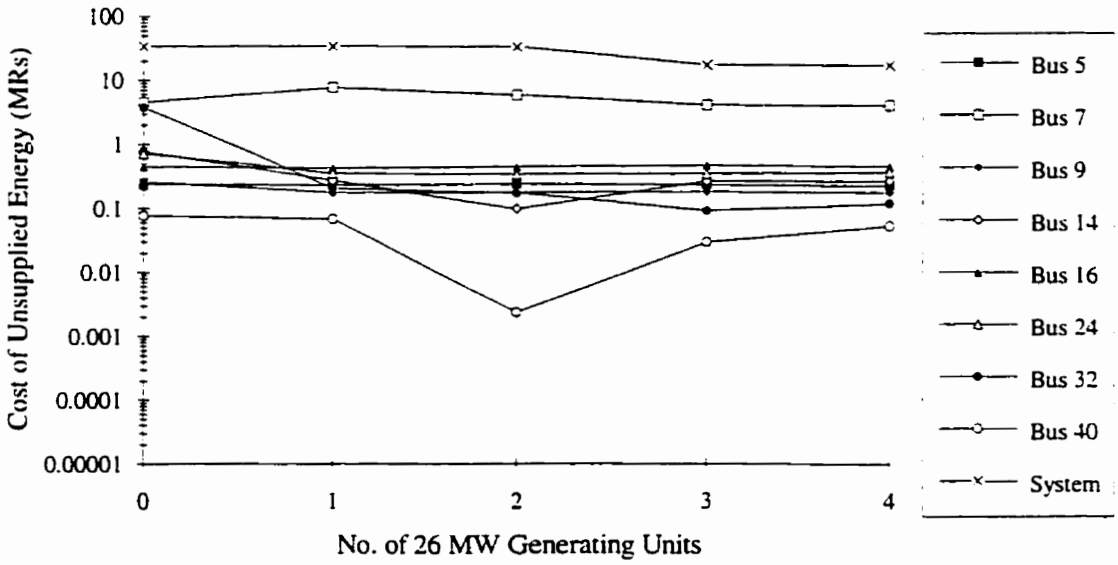

Figure 5.6. Variation in the Annual Cost of Unsupplied Energy at Major NPS Load Buses and the System as 26 MW Generating Units with FOR of 5% are Sequentially Added Alternately at Eastern Region Bus 32 and Western Region Bus 40

It can be seen from Figure 5.4 that the injection of generating units at Bus 32 has adverse impacts on buses 7 and 24 as the customer costs at these buses increase with the additions. The interruption cost at Bus 32 is considerably reduced, as expected, and the cost at Bus 14 is also progressively reduced as the number of added units increases. The costs at buses 5, 9, 16 and 40 decrease, but not significantly. The overall reduction in the system interruption cost is not significant unless 4 or more units are added.

The impact of unit additions at western region Bus 40 shown in Figure 5.5 is different. The figure shows a general decreasing trend in customer cost of unserved energy for most load points and the overall system, when additional generating units are sequentially introduced at Bus 40. The system cost of unsupplied energy reduces considerably when the first unit is added. This indicates a requirement for generation addition in the western sector rather than the eastern part of the NPS network.

The effect due to the addition of generating units alternately at Bus 32 and Bus 40 shown in Figure 5.6 is similar to that of addition at Bus 32 except that the adverse impacts on buses 7 and 24 are basically eliminated. The customer cost reduction in the overall system is not significant unless 3 or more generating units are added.

The impact studies described above clearly indicate that generation additions in the western part of the country will yield more benefits to NPS customers.

5.4.3. Optimum Reserve Margin Determination at HL II

A similar study to that conducted at HL I and described in Chapter 4 was done to determine the optimum reserve margin at HL II. The generation, transmission and cost data given in Chapter 2 and the IEAR shown in Table 5.8 were used in the analysis. In

order to illustrate the evaluation process, the 26 MW multifuel unit was removed from the base case and considered as an additional unit in the proposed expansion. The results obtained by sequentially adding 26 MW units at Bus 40 are shown in Table 5.10 and presented graphically in Figure 5.7.

It can be seen from Table 5.10 that the base case system has the lowest total societal cost and therefore is an optimum configuration for 1995 system conditions. The associated reserve is 15.59%, which is the optimum reserve margin for the 1995 system conditions. The optimum HL I reserve margin for the base case is also 15.59%. The associated total societal costs, however, increase from 26.194 million rupees at HL I to 374.421 million rupees at HL II. This is due to incorporating the transmission system in the evaluation.

Table 5.10. Variation in Utility, Customer and Total Costs with Reserve Margin

System Configuration	Reserve Margin (%)	Utility Cost (MRs)	Annual EENS (GWh)	Customer Cost (MRs)	Total Cost (MRs)
Base Case - 1x26 MW	4.63	336.821	3.078	80.028	416.849
Base Case	15.59*	340.079	1.317	34.242	374.421
Base Case + 1x26 MW	26.55	361.205	1.002	26.052	387.257
Base Case + 2x26 MW	37.52	382.198	1.001	26.026	408.224
Base Case + 3x26 MW	48.48	403.188	0.902	23.452	426.640
Base Case + 4x26 MW	59.44	424.179	0.862	22.412	446.591

* Optimum Reserve Margin

order to illustrate the evaluation process, the 26 MW multifuel unit was removed from the base case and considered as an additional unit in the proposed expansion. The results obtained by sequentially adding 26 MW units at Bus 40 are shown in Table 5.10 and presented graphically in Figure 5.7.

It can be seen from Table 5.10 that the base case system has the lowest total societal cost and therefore is an optimum configuration for 1995 system conditions. The associated reserve is 15.59%, which is the optimum reserve margin for the 1995 system conditions. The optimum HL I reserve margin for the base case is also 15.59%. The associated total societal costs, however, increase from 26.194 million rupees at HL I to 374.421 million rupees at HL II. This is due to incorporating the transmission system in the evaluation.

Table 5.10. Variation in Utility, Customer and Total Costs with Reserve Margin

System Configuration	Reserve Margin (%)	Utility Cost (MRs)	Annual EENS (GWh)	Customer Cost (MRs)	Total Cost (MRs)
Base Case - 1x26 MW	4.63	336.821	3.078	80.028	416.849
Base Case	15.59*	340.079	1.317	34.242	374.421
Base Case + 1x26 MW	26.55	361.205	1.002	26.052	387.257
Base Case + 2x26 MW	37.52	382.198	1.001	26.026	408.224
Base Case + 3x26 MW	48.48	403.188	0.902	23.452	426.640
Base Case + 4x26 MW	59.44	424.179	0.862	22.412	446.591

* Optimum Reserve Margin

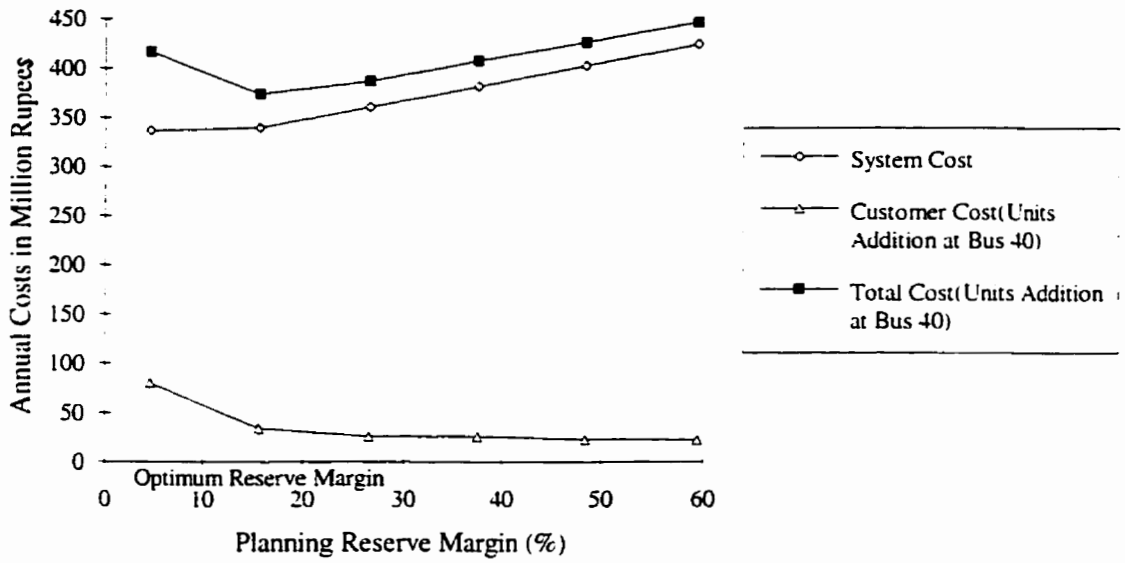

Figure 5.7. Variation in the Utility, Customer and Total Costs at HL II with the Panning Reserve Margin

The optimum reserve margin obtained at HL II is shown in Figure 5.7. It can be seen from Figure 5.7 that the interruption cost decreases rapidly as the reserve is increased to the optimum level. The utility cost, which consists of investment and operating costs, increases as the reserve margin is increased. The total societal cost for the supply of electricity varies with variation in the planning reserve margin. The total societal cost shows a minimum at the reserve margin of 15.59% which is therefore the optimum value for the base case.

5.4.4. Expansion Plan Studies

The expansion plan and reinforcement schemes proposed by the NEA at HL II for the period 1995-1999 is shown in Table 5.5. This expansion scheme was considered in the analysis. An expansion plan based on the reliability cost/worth approach was

derived and compared with the NEA plan. Suitable planning criteria at HL II were developed from the evaluation. The results and the findings are as follows.

The 26 MW multifuel generating units and the transmission lines proposed by the NEA shown in Table 5.5 were considered as available generating units and lines in the analysis. The transmission lines proposed for addition in 1995 and 1998 are referred to as L1, L2, L3 and L4 respectively in this evaluation. For each year in the planning period 1995-1999, these available generating units and lines were sequentially added, and the total annual cost for each addition calculated. The total cost considered is the sum of the investment cost, operating cost and the customer cost of interruption. Each addition sequence was considered as an expansion alternative, and the alternative having the least annual societal cost was selected. The results are shown in Table 5.11.

It can be seen from Table 5.11 that the base case configuration is adequate for both 1995 and 1996. One 26 MW multifuel unit is required in 1997 and 1998, and two 26 MW units are required in 1999. The proposed NEA expansion is also shown in Table 5.11. It was found that the additional transmission lines proposed by the NEA for the 1995-1999 period are not justified on the basis of the reliability cost/worth analysis.

The proposed expansion plan derived using the reliability cost/worth approach is shown in Table 5.12. The proposed plan was compared with the NEA plan to evaluate the differences. The results are presented graphically in Figure 5.8.

Table 5.11. Optimum Configuration Determination for the NPS for 1995-1999

Year	Peak Load (MW)	System Configuration	Annual Cost (MRs.)	Reserve (%)
1995	237.17	Base Case - 1x26 MW	416.849	4.63
		Base Case*	374.421	15.59*
		Base Case + L1 +L2**	383.734	15.59
		Base Case + 1x26 MW	387.257	26.55
1996	254.98	Base Case*	396.462	7.52*
		Base Case + L1 +L2	412.763	7.52
		Base Case + 1x26 MW	418.017	17.72
		Base Case + 1x26 MW + L1 + L2**	444.799	17.72
1997	279.53	Base Case + 1x26 MW*	467.056	7.38*
		Base Case + 1x26 MW + L1 + L2	489.617	7.38
		Base Case + 2x26 MW + L1 + L2**	497.327	16.68
		Base Case + 2x26 MW	474.975	16.68
1998	307.00	Base Case + 2x26 MW*	563.698	6.24*
		Base Case + 2x26 MW + L1 + L2	584.035	6.24
		Base Case + 3x26 MW + L1 + L2	587.300	14.71
		Base Case + 3x26 MW + L1 + L2 + L3 + L4**	606.445	14.71
		Base Case + 3x26 MW	565.443	14.71
1999	347.29	Base Case + 4x26 MW*	740.895	8.89*
		Base Case + 4x26 MW + L1 + L2	756.227	8.89
		Base Case + 4x26 MW + L1 + L2 + L3 + L4**	775.446	8.89

* Optimum Configuration and Corresponding Reserve Margin
** Proposed NEA Plan

It can be seen from Figure 5.8 that the utility cost incurred in the NEA plan is higher whereas the customer interruption cost is generally lower than the plan developed using the reliability cost/worth approach. The overall total societal cost for the supply of electricity is, however, lower for the developed plan than the NEA plan throughout the planning period 1995-1999.

Table 5.12. Proposed Overall Expansion Plan for the NPS for the Period 1995-1999 using the Reliability Cost/Worth Approach

Year	Peak Load (MW)	Installed Capacity (MW)	Unit Addition			Line Addition			
			Capacity (MW)	Type	To Bus	Volt (kV)	Length (km)	From Bus	To Bus
1995	237.17	274.15	-	-	-	-	-	-	-
1996	254.98	274.15	-	-	-	-	-	-	-
1997	279.53	300.15	1x26	Multifuel	32	-	-	-	-
1998	307.00	326.15	1x26	Multifuel	40	-	-	-	-
1999	347.29	378.15	2x26	Multifuel	40	-	-	-	-

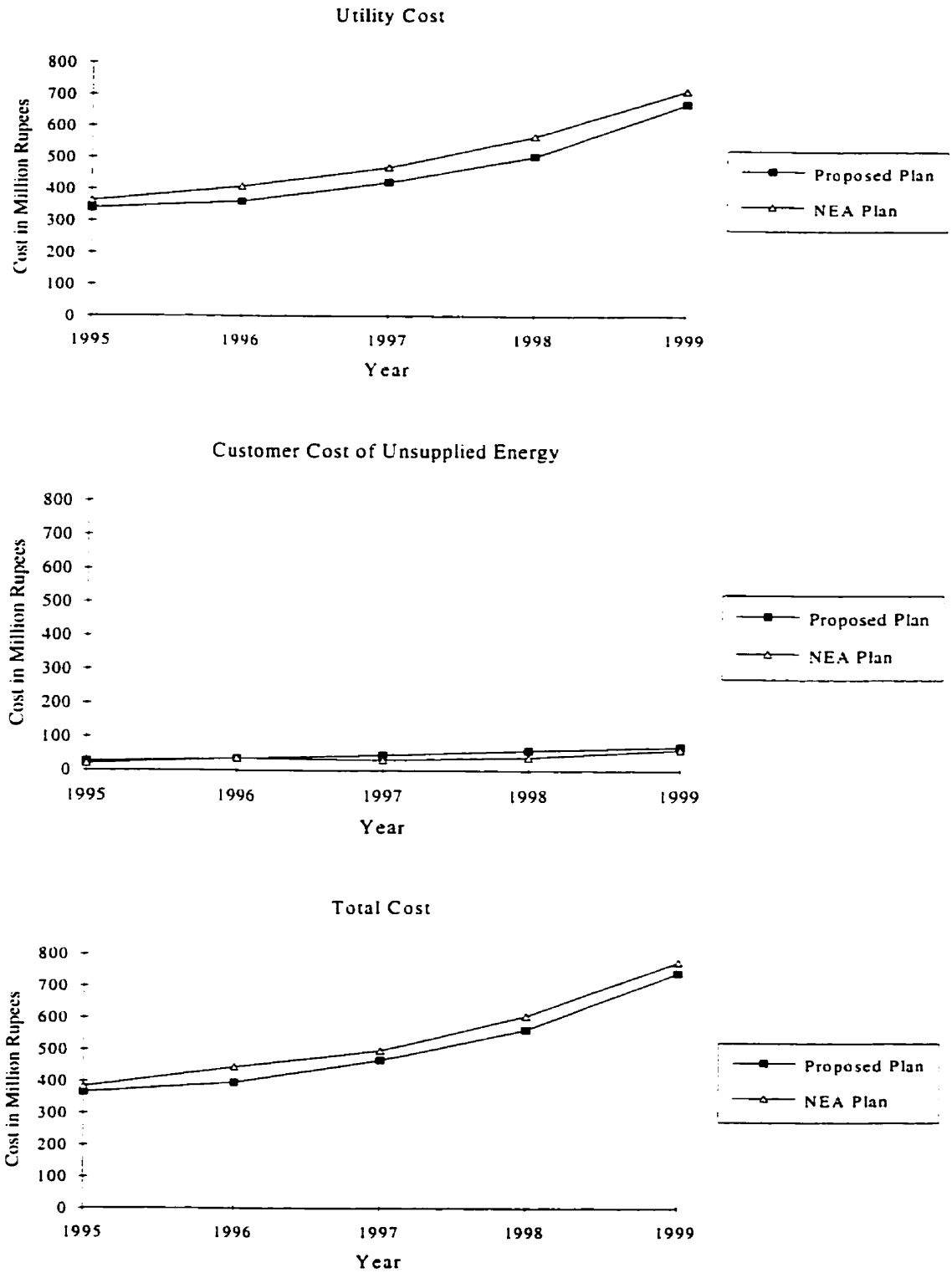

Figure 5.8. Comparison of the Developed Plan with the NEA Plan for the Planning Period 1995-1999

5.4.5. Overall Planning Criteria

The optimum expansion plan proposed for the 1995-1999 period shown in Table 5.12 was further analyzed to evaluate the corresponding risk indices. The evaluation was performed and the risk indices of some selected major load points and the overall system were calculated using the COMREL program. The results are shown in Table 5.13. These results were used to develop appropriate HL II criteria which can be used for possible NPS long range planning.

Table 5.13. Optimum Overall Configuration and Corresponding Reliability Criteria for the NPS Considering Economic Aspects of Reliability

Year	Optimum Configuration	Risk Index								
		Major Load Points Failure Frequency (occ/yr)								System EUE (UPM)
		5	7	9	14	16	24	32	40	
1995	Base case	0.15	1.71	0.10	0.27	0.07	0.21	3.69	0.75	982
1996	Base case	0.17	2.52	0.26	0.59	0.15	0.68	4.17	0.80	1234
1997	Base case +1x26 MW	0.16	3.39	0.23	0.63	0.09	1.40	1.14	0.82	1455
1998	Base case +2x26 MW	0.17	5.53	0.26	0.81	0.31	1.41	1.92	0.70	1720
1999	Base case +4x26 MW	0.21	6.18	0.15	0.41	0.21	0.78	3.27	0.87	1783

It can be seen from Table 5.13 that the risk index corresponding to optimum configuration varies in each year in the planning period 1995-1999. The maximum system risk index of 1783 UPM occurs in 1999 and for the load points the maximum risk indices indicated by failure frequencies occur in different years for different load

buses as shown in Table 5.13. It is normal practice in power system planning to maintain the risk at or below a maximum permissible level when evaluating the various possible expansion alternatives. The maximum optimum risk indices obtained in this evaluation can therefore be considered as the permissible risk limits for the selected load points and the overall system and used as standard probabilistic criteria in NPS long range planning. The derived probabilistic planning criteria for selected major NPS load buses and the overall system are listed in Table 5.14. These criteria can be used to assess future power projects in Nepal, and in other long range planning processes for the NPS at HL II.

Table 5.14. Suggested Probabilistic Criteria at HL II for the NPS

Load Point	Criterion	Index
Bus 5	Failure Frequency	0.21 occ./yr
Bus 7	Failure Frequency	6.18 occ./yr
Bus 9	Failure Frequency	0.26 occ./yr
Bus 14	Failure Frequency	0.81 occ./yr
Bus 16	Failure Frequency	0.31 occ./yr
Bus 24	Failure Frequency	1.41 occ./yr
Bus 32	Failure Frequency	4.17 occ./yr
Bus 40	Failure Frequency	0.87 occ./yr
System	EUE	1783 UPM

5.5. Summary

This chapter presents a reliability cost/worth approach to bulk power system evaluation. A suggested reliability cost/worth based framework for system studies at HL

II is described. An analytical method using the contingency enumeration approach has been used in this research work. A procedure for IEAR determination using an HL II evaluation program such as COMREL is described.

The IEAR for major NPS load buses were evaluated using the interruption cost data obtained from the customer surveys described in Chapter 3. Some sensitivity studies are presented to appreciate the impacts on the calculated IEAR of important system parameters such as the peak load, component outage rates and system modifications. The results show that the variation in these factors do not significantly affect the IEAR and therefore it can be considered as a constant factor in a wide range of studies.

It is noted that system IEAR evaluation at HL II requires IEAR determination at all the load buses in the system. This may not be possible in a developing power system such as the NPS due to a lack of detailed individual load bus information. A methodology for system IEAR determination using limited system individual load bus information is illustrated. The approach was used to estimate the IEAR for all the buses and the system IEAR at HL II for the NPS.

An impact study was conducted to understand how the injection of generation at different locations in the system affect the customer costs of unsupplied energy at individual load centers and for the overall system. The results reveal that the customer costs at individual load centers and the system will be different when the same generation addition sequence is implemented at different location points in the system. In the case of Nepal, it was found that maximum customer benefit can be achieved by the injection of generation in the western development region rather than the eastern development region of the country.

A five year expansion plan based on the reliability cost/worth approach was derived and compared with the composite system plan proposed by the NEA for the 1995-1999 planning period. A different addition sequence than that proposed by the NEA resulted when the reliability cost/worth approach was used. The results indicate a saving in total societal costs throughout the planning period with the proposed expansion. The results also reveal that the transmission line additions proposed by the NEA cannot be justified based on the system IEAR calculated in this research work.

This chapter illustrates how the reliability cost/worth approach to generating capacity evaluation described in Chapter 4 can be extended to include transmission facilities in a composite generation and transmission system study by application to the Nepal Integrated Electric Power System. It shows that an overall optimum system configuration that maximizes the net social benefits can be determined for the power system in a developing country. It also shows that a short term expansion scheme can be developed based on the least societal cost approach. The optimum expansion plan can then be utilized to develop suitable probabilistic criteria which can be used in a long range system planning process. The main contribution of the research work described in this chapter is the development of an overall approach to determine appropriate composite generation and transmission system planning criteria. Despite the inherent system uncertainties, the approach can be used effectively in a developing country to evaluate electric power projects.

6. RELIABILITY COST/WORTH BASED TARIFF DESIGN

6.1. Introduction

Electric service tariff design is a complex task. The rate setting process assigns the responsibility for providing a utility's revenue requirement among the various classes of customer served by the utility. The revenue requirement of a utility is the operating expenses plus the cost of capital related to the investment in the property, plant and equipment which are used in the provision of utility service. This cost must be allocated to the customer classes in a reasonable and justifiable manner.

A variety of considerations, such as historic rate structures, customer demands, load characteristics, location in the utility's system, ability to pay, subsidization, value of service, etc., influence the utility rate structure profile. In addition, social and political factors may influence the rates. This research deals with a utilization related cost of service allocation to the various classes of customers based on their load characteristics.

The approach described in this research work is based on the assumption that system cost behavior is generally dependent on the methods used in the system planning and operation, and the cost allocation method should therefore follow the concepts used in the planning process [26]. Quantitative evaluation based on the reliability cost/worth approach was used in developing planning criteria throughout this research work. A reliability cost/worth analysis based cost of service allocation framework was therefore developed and utilized in the cost allocation process described in this chapter. Prior to describing the cost allocation studies conducted in this research work, it is appropriate

to appreciate the various cost allocation methods that are used in practice. An overview of these methods is presented in the next section.

6.2. An Overview of Cost of Service Allocation Methods

Many methods have been proposed in the past and utilized by utilities for demand related cost allocation among the different customer classes [45, 46]. A brief description of popularly used methods is presented here to illustrate the underlying concepts.

The methods used for cost of service allocation process can be grouped into two categories:

1. Deterministic Methods; and
2. Probabilistic Methods.

The deterministic methods do not consider the stochastic nature of component failures, of customer demands, or of system behavior as a whole, whereas the probabilistic methods consider these inherent characteristics as well as pertinent factors on which the reliability of an electric power system depends.

6.2.1. Deterministic Methods

Some of the popularly used deterministic methods are:

1. Coincident peak(CP) method;
2. Non-coincident peak(NCP) method; and

3. Average and excess demand(AED) method. These methods are briefly described below.

Coincident Peak (CP) Method

This method allocates the system capacity cost to each class according to contribution of that class to the system demand at the time of the system peak. The allocation factor for each class is the ratio of the class load at the system peak to the system peak load, i.e.

$$\text{Allocation Factor for a Class} = \frac{\text{Class Load at System Peak}}{\text{System Peak Load}}. \tag{6.1}$$

This method assumes that the class peaks coincide with each other and the system, i.e. the class loads at the system peak are the class peaks to be considered for cost allocation. This is generally not true because each load class has its own unique usage pattern and is normally non-coincident with the other classes or the system. A further difficulty with this method is that it penalizes excessively the class which has a high contribution at system peak, although the class may have a very low demand during off-peak periods. On the other hand, a class having high load consumption during the off-peak periods and a very low demand at system peak will not be adequately penalized for its high load consumption during the off-peak periods.

The main advantages of this method are its simplicity and the requirement of very little class load information. The method requires only the class load information at the time of system peak.

Non-Coincident Peak (NCP) Method

This method allocates the system capacity costs to various load classes based on their peak loads, whenever they occur within the study period. The allocation factor for a class is the ratio of the class peak load to the sum of all class peak loads.

$$\text{Allocation Factor for a Class} = \frac{\text{Class Peak Load}}{\text{Sum of All Class Peak Loads}}. \tag{6.2}$$

This method recognizes the non-coincidence of class peaks and is therefore more realistic than the coincident peak method. The method, however, as with the coincident peak method, does not recognize the class load characteristics. It penalizes classes with high peaks regardless of when and for how long they occur. For example, a class such as a seasonal load, which may have a peak in the summer for a few months then no demand during the other period including during the system winter peak, will be required to pay a share based on the ratio of its peak load to the system peak load despite the fact that it does not contribute any demand during the system peak as well as most of the other periods.

Average and Excess Demand (AED) Method

This is also called the Consumption and Demand method. This method allocates the cost using the average and excess demands of each class and the system. The excess demand is the difference between the peak demand and the average demand. The allocation factor calculation procedure is as follows.

$$\text{Average Demand Factor(ADF) for a Class} = \frac{\text{Average Demand of the Class}}{\text{Average Demand of the System}}. \tag{6.3}$$

$$\text{Excess Demand Factor(EDF) for a Class} = \frac{\text{Excess Demand of the Class}}{\text{Excess Demand of the System}}. \quad (6.4)$$

$$\text{Allocation Factor} = \text{ADF x System Load Factor} + \text{EDF x (1 - System Load Factor)}. \quad (6.5)$$

This method recognizes the system load factor but still does not recognize the individual class load factors properly. It has the same drawback as the non-coincident peak method due to the fact that it charges off-peak customers in the same manner as on-peak customers.

6.2.2. Probabilistic Methods

The methods described above are all deterministically based. They do not recognize the stochastic nature of electric power systems nor do they respond to the factors which actually affect the system cost behavior. Some of the existing probabilistic methods are:

1. Probability of Negative Margin (PONM) Method; and
2. Loss of Energy Expectation (LOEE) Method.

The LOEE method which was used in this research work is described later in the chapter. The PONM method is briefly described here.

Probability of Negative Margin (PONM) Method

This method uses a probability technique to calculate the allocation factors for each class. The evaluation procedure is as follows. The probability of negative margin (PONM) i.e. the probability of loss of load for each load period considered is calculated first. The PONM for each period is then normalized by the total system PONM to form the weighting factor for the period. The weighting factor is then used to calculate the allocation factor for each class for the period. The allocation factor for the class is then the sum of all the period allocation factors. The procedural equations used in the evaluation are given below.

$$\text{Weighting Factor for a period, } W_k = \frac{PONM_k}{PONM}. \tag{6.6}$$

$$\text{Allocation Factor for a class in a period} = W_k \times \frac{\text{Class Load in the period}}{\text{System Load in the period}}. \tag{6.7}$$

$$\text{Allocation Factor for a class} = \text{Sum of Allocation Factors for all the periods.} \tag{6.8}$$

This method is responsive to system parameters and load characteristics. It allocates the capacity cost to each class on a time-differentiated basis, i.e. both seasonal and diurnal. The major drawback of this method is that it requires detailed class load data i.e. load data of each class for each period considered in the analysis.

As noted earlier, quantitative evaluation based on the reliability cost/worth approach is used in developing planning criteria throughout this research work. A reliability cost/worth analysis based basic cost of service allocation framework was

therefore developed and utilized in the cost allocation process. This is described in the next section.

6.3. Basic Cost of Service Allocation Framework

A suggested general block diagram for the cost of service allocation process is shown in Figure 6.1.

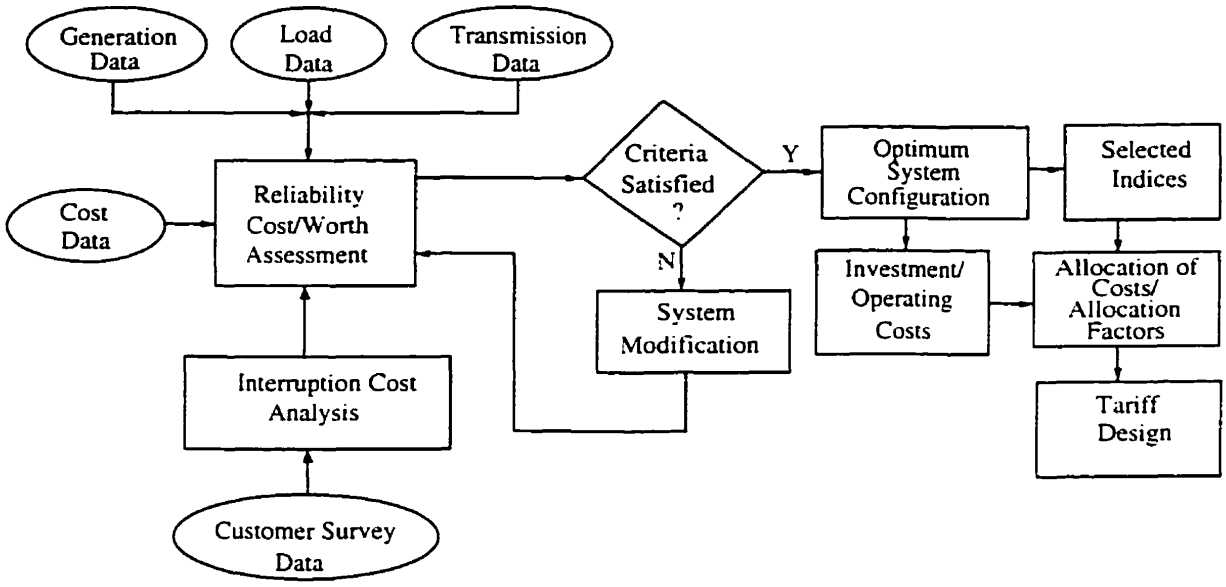

Figure 6.1. Reliability Cost/Worth Analysis Based Tariff Design Framework

Power system expansion must be planned well ahead to meet the increased future load demand due to regulatory time delays and the required construction time. All utilities use selected planning techniques and criteria to develop their expansion plans. These techniques can be either deterministic or probabilistic. Depending on the nature of these techniques, the input data requirements differ from one method to another. Reliability cost/worth based adequacy evaluation studies require generation data, load

data, transmission data, cost data, and interruption cost data usually obtained from customer surveys. These input data requirements are shown in Figure 6.1. These inputs, however, may not all be necessary in a given adequacy evaluation method, for example, deterministic techniques require only information on the system load whereas many probabilistic techniques do not require interruption cost information.

Reliability cost/worth assessment is performed using the required input data. An expansion scheme having the minimum overall cost is selected, which is the criterion used in this evaluation approach. If the criterion is not satisfied, the expansion scheme is modified and evaluated again. This procedure is repeated until the adequacy criterion is satisfied. The newly developed optimum system configuration is then utilized in future development of the power system, which will require new investment and operating costs. An index selected from the set of indices obtained in the system adequacy evaluation is used in calculating cost allocation factors for the various customer classes. These factors in association with the new investment and operating costs can be used as basic inputs to the tariff design process.

It can be observed from the above procedure that the criterion and planning technique used in the system adequacy assessment, which also includes the different variables considered in the method, drives the development of the system which further drives the cost of the future investment in the system. It is therefore consistent that similar criteria and methods are used in the cost allocation process including, the variables considered in the system adequacy evaluation. The system planning technique used throughout this research work is the reliability cost/worth based probabilistic method which uses the loss of energy expectation (LOEE) as the basic criterion. The LOEE based cost of service allocation method was therefore used in this research work. The method is briefly described below.

6.4. Loss of Energy Expectation (LOEE) Method

This is a probabilistic method for cost of service allocation factor evaluation. The method is based on the LOEE method of system reliability evaluation. The basic evaluation concept of this method is based on the following HL I formulation [17]:

The LOEE for a capacity outage O_k in the system is given by:

$$LOEE = \sum_{k=1}^{n} E_k p_k \tag{6.9}$$

where, E_k = energy curtailed due to the capacity outage O_k in the period k ;

p_k = individual probability of a capacity outage O_k ; and

n = number of periods.

The cost of service allocation procedure uses this concept in calculating the allocation factor for a class as explained below.

The loss of energy is first calculated for each possible capacity outage in the system for each load period of the year, which is usually one hour. The calculated energy not served due to each possible outage is weighted by the probability of occurrence of the outage which causes this loss of energy. The sum of the weighted energy losses is the loss of energy expectation for the period. The LOEE for each period is then normalized by the total LOEE for the system to form the weighting factor for the period. The weighting factor is then used to calculate the allocation factor for a class in a period. The annual allocation factor for a class is then the sum of all period allocation factors. The following procedural equations are used in the evaluation.

$$\text{Weighting Factor for a period, } W_k = \frac{LOEE_k}{LOEE}. \tag{6.10}$$

$$\text{Allocation Factor for a class in a period} = W_k \times \frac{\text{Class Load in the period}}{\text{System Load in the period}}. \tag{6.11}$$

$$\text{Allocation Factor for a class} = \text{Sum of Allocation Factors for all the periods.} \tag{6.12}$$

This method can be used to allocate cost to each rate class on a time-differentiated basis, i.e. both seasonal and diurnal. The weighting factor in each period for each class is determined using the LOEE, i.e. only those periods in which there is a probability of being unable to meet the energy demand are given weight in determining the allocation factors.

The method is obviously responsive to the generating unit sizes, forced outage rates, and load characteristics, which are the actual factors on which the reliability of a power system depends. These are also the important factors in the cost behavior of a system, which are not considered in conventional deterministic methods. This method therefore corresponds more to the system cost behavior than the deterministic methods and is therefore more economically efficient. The major drawback of this method is that it requires detailed load information of each class for each period considered in the analysis, which may be very difficult to realize. The next section addresses this difficulty and describes how the required load data were developed for this research work.

6.5. Preparation of Class Load Database

One of the difficulties in applying probabilistic methods in the area of cost of service allocation is that these methods require extensive load information for each class considered in the analysis. These data are usually not available. In the absence of these data, it was therefore necessary to create a database using some available data and realistic assumptions.

As described in Chapter 2, a load model for the NPS was developed using actual annual system load data in a similar manner to that proposed in the IEEE-RTS. The load model gives hourly loads for one year on a per unit basis. The model is expressed in a chronological fashion so that daily, weekly and seasonal load patterns can be modeled once the annual system peak load is known. The load data are sufficient for most system reliability studies described in this thesis. The information, however, is not adequate for a cost of service allocation study, which requires load information for each customer class in addition to total system demand for each period considered in the analysis. It is therefore necessary to allocate the total system load for each period to the different customer classes.

The system load allocation can be achieved using some available class data to create the class loads and adjusting them so that the sum of these class loads match the total system load. Realistic assumptions and compromises were made in estimating the load patterns as explained in the following sub-sections.

6.5.1. Estimating the Monthly Class Load Pattern

The monthly system peak load pattern was obtained from the available weekly system peak load pattern. The system peak load composition in terms of customer classes was obtained during the customer survey and data collection in Nepal. The system peak load composition is shown in Table 6.1. The 'Other' class is basically government institutions and other public and private organizations, whose load characteristics are considered to be similar to the industrial class and therefore combined with the industrial class in the cost allocation studies.

Table 6.1. Allocation of the Peak Load Among the Customer Classes

Load Class	Peak Load (p.u.)
Residential	0.37
Commercial	0.07
Industrial	0.40
Other	0.16
System	1.00

During the customer surveys, the commercial and industrial customers were asked related questions to find out the worst month for an interruption to occur and the monthly variation of the interruption costs. These data were processed to obtain the monthly variation pattern of the interruption costs in the percentage form. This information was used to obtain the monthly demand variation pattern for the commercial and industrial classes assuming that the monthly class load demand pattern follows its interruption cost variation pattern. Using this assumption and the load

composition data of Table 6.1, the total commercial and industrial class load for each month was calculated. This was then compared with the total system load and adjusted to calculate the residential class contribution for the period. The results are shown in Table 6.2.

It can be seen from Table 6.2 that, even after adjusting for the residential class load, there exists a difference between the system load and the calculated system load for the months of November, December, January and February. This was considered as a seasonal load which occurs only during the winter months. This seasonal load may be due to water pumping for irrigation purposes during the winter harvest season in Nepal. The developed monthly load patterns for different classes are shown in Figure 6.2.

Table 6.2. Monthly Load Pattern for the Customer Classes

Class	Month											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Res	1.000	1.000	0.687	0.605	0.345	0.537	0.710	0.730	0.901	0.864	1.000	1.000
Com	0.880	0.900	0.900	1.000	0.960	0.920	0.870	0.820	0.900	0.880	0.860	0.840
Ind	0.960	0.970	0.960	1.000	0.970	0.880	0.840	0.860	0.910	0.930	0.940	0.950
Sys	1.000	0.992	0.855	0.854	0.738	0.756	0.794	0.809	0.906	0.902	0.959	0.963
Calc	0.969	0.976	0.855	0.854	0.738	0.756	0.794	0.809	0.906	0.902	0.957	0.961
Diff	0.031	0.016	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002	0.002
Diff(p.u.)	1.000	0.516	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.064	0.064
Seas	1.000	0.516	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.064	0.064

It can be seen from Figure 6.2 that each class has a unique load demand characteristic. For example, the residential class has peaks during the winter season and the load fluctuates from 1.00 p.u. during the winter down to 0.34 p.u. during the summer. Industrial and commercial loads are relatively constant throughout the year and have their peaks during the summer season. Their minimum load demand is 0.84 p.u. The seasonal load occurs only during the winter season and has a peak during the month of January, reduces to half in February and the load does not exist until the months of November and December when it has a load of 0.064 p.u.

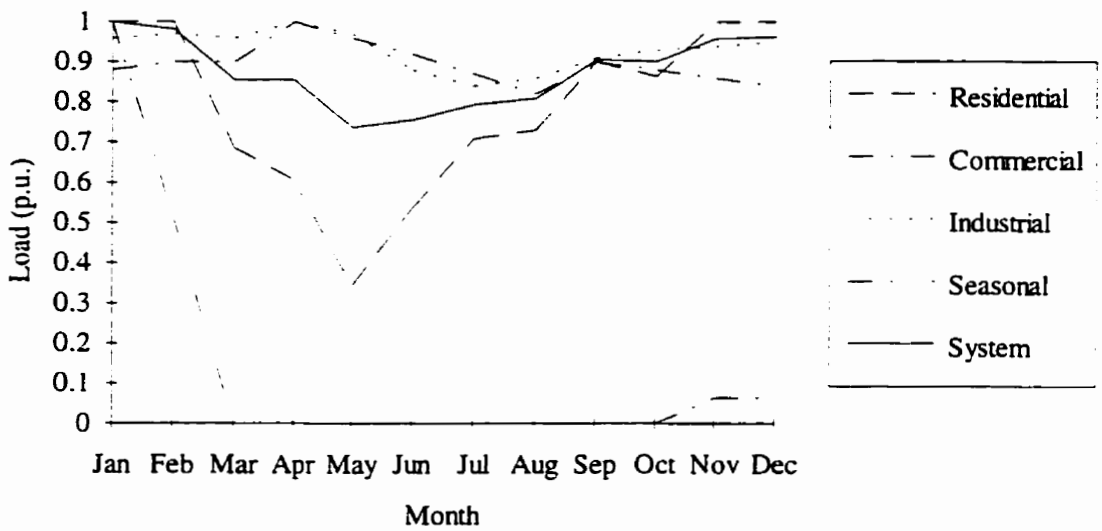

Figure 6.2. Monthly Load Curves for the Different Classes and the System

6.5.2. Estimating the Weekly Class Load Pattern

The weekly load patterns for each class were estimated based on the monthly peak curves established as shown in Table 6.2. The weekly peak loads were reconstructed for each class so that when added will create the known system weekly

peak load pattern. This was accomplished by assuming that each class load within the month varies in the same way as the system load.

The monthly peak is assumed to occur in the week within the month having the highest demand as given by the system weekly peak load information. For example, the second week in January has the highest demand which is 1.0 p.u. of the system peak, therefore the monthly peaks of all the classes established in Table 6.2 are assumed to fall on the second week of this month. This way the positions of the monthly class peaks were established within the weekly load frame. The weekly class load within the month, other than the week when the monthly peak occurs, was calculated using the following formula:

$$\text{Weekly Class Peak} = \text{Class Monthly Peak} \times \frac{\text{System Weekly Peak}}{\text{System Monthly Peak}}. \qquad (6.5)$$

The results are shown in Table 6.3. The asterisk (*) beside the week number denotes where the peak in the month occurs.

Table 6.3. Weekly Load Patterns for Customer Classes and the System

Month Weight:	Week	System 1.000	Res. 0.370	Com. 0.070	Ind. 0.560	Seas. 0.031
Jan	1	0.975	0.975	0.858	0.936	0.968
	2*	1.000	1.000	0.880	0.960	1.000
	3	0.995	0.995	0.876	0.955	1.000
	4	0.968	0.968	0.852	0.929	0.968
Feb	5	0.966	0.974	0.876	0.945	0.484
	6*	0.992	1.000	0.900	0.970	0.516
	7	0.962	0.970	0.873	0.941	0.484
	8	0.783	0.789	0.710	0.766	0.387
Mar	9	0.774	0.622	0.815	0.869	0.000
	10	0.772	0.620	0.813	0.867	0.000
	11*	0.855	0.687	0.900	0.960	0.000
	12	0.841	0.676	0.885	0.944	0.000
	13	0.851	0.684	0.896	0.956	0.000

Table 6.3. (Contd.)

Month	Week	System	Res.	Com.	Ind.	Seas.
Weight:		1.000	0.370	0.070	0.560	0.031
Apr	14	0.772	0.547	0.904	0.904	0.000
	15*	0.854	0.605	1.000	1.000	0.000
	16	0.759	0.538	0.889	0.889	0.000
	17	0.701	0.497	0.821	0.821	0.000
May	18	0.728	0.340	0.947	0.957	0.000
	19	0.708	0.331	0.921	0.931	0.000
	20	0.705	0.330	0.917	0.927	0.000
	21*	0.738	0.345	0.960	0.970	0.000
Jun	22	0.687	0.488	0.836	0.800	0.000
	23*	0.756	0.537	0.920	0.880	0.000
	24	0.693	0.492	0.843	0.807	0.000
	25	0.663	0.471	0.807	0.772	0.000
	26	0.704	0.500	0.857	0.819	0.000
Jul	27	0.648	0.579	0.710	0.686	0.000
	28	0.717	0.641	0.786	0.759	0.000
	29*	0.794	0.710	0.870	0.840	0.000
	30	0.779	0.697	0.854	0.824	0.000
Aug	31	0.783	0.707	0.794	0.832	0.000
	32*	0.809	0.730	0.820	0.860	0.000
	33	0.757	0.683	0.767	0.805	0.000
	34	0.804	0.725	0.815	0.855	0.000
Sep	35	0.829	0.824	0.824	0.833	0.000
	36*	0.906	0.901	0.900	0.910	0.000
	37	0.894	0.889	0.888	0.898	0.000
	38	0.856	0.851	0.850	0.860	0.000
	39	0.875	0.870	0.869	0.879	0.000
Oct	40	0.779	0.746	0.760	0.803	0.000
	41*	0.902	0.864	0.880	0.930	0.000
	42	0.894	0.856	0.872	0.922	0.000
	43	0.891	0.853	0.869	0.919	0.000
Nov	44	0.908	0.947	0.814	0.890	0.065
	45	0.936	0.976	0.839	0.917	0.097
	46	0.942	0.982	0.845	0.923	0.097
	47*	0.959	1.000	0.860	0.940	0.065
Dec	48	0.925	0.961	0.807	0.913	0.065
	49	0.953	0.990	0.831	0.940	0.065
	50	0.956	0.993	0.834	0.943	0.065
	51	0.963	1.000	0.840	0.950	0.065
	52	0.947	0.983	0.826	0.934	0.065

* Week at which the monthly peak occurs

6.5.3. Estimating the Daily and Hourly Class Load Patterns

The technique discussed in the previous sub-section to derive the weekly loads from the monthly loads can also be used to create the daily loads from the weekly loads and the hourly loads from the daily loads for each class. This becomes more and more difficult as the number of points increases from 52 (number of weeks in a year) to 364 (number of days in a year) for deriving daily load patterns, and to 8736 (number of hours in a year) for hourly load patterns.

The class load modeling would not be a difficult procedure if the development of the models followed what could be considered as the normal procedure, i.e. defining first the load shape of each class and then adding them to form the system load. This was, however, not possible in this case as the total system load had already been defined. The total system load had to be divided into different class loads while maintaining a unique characteristic for each load class.

A compromise was made to resolve this difficulty. It was assumed that the daily peak variation as a percent of weekly peak and the hourly peak variation as a percent of daily peak for the class will follow the same pattern as those for the system peak load. The uniqueness of class load characteristics was maintained in deriving the weekly load for each class. Although, this uniqueness will be somewhat disturbed by this assumption, there will be still consistency in the class load characteristics.

The system load daily peak variation as a percent of weekly peak and the hourly peak variation as a percent of daily peak, which were also used to derive the daily and hourly class loads, are presented in Tables 2.12 and 2.13 respectively in Chapter 2. The

load models for the different classes and the system are now completely defined for the NPS. The hourly load models so derived were used to evaluate the cost of service allocation factors by the LOEE method as explained in Section 6.3. The results are described in the next section.

6.6. Cost of Service Allocation

The cost of service allocation was performed using the basic framework proposed in Section 6.2 and the LOEE method described in Section 6.3. The NPS configuration, and the class load models created in Section 6.5, were used in the evaluation. The results are discussed below.

6.6.1. Load Characteristics

The load characteristics for the class load models derived are shown in Table 6.4. The system load factor was calculated as 0.52, which is close to the present NPS value of 0.50 [32]. As expected, the industrial class has the highest load factor (0.55) followed by the commercial (0.53) and the residential (0.47). The newly created seasonal class has the lowest value of 0.24.

It can be seen from Table 6.4 that the residential and seasonal classes contribute their maximum demand during the system peak whereas the commercial and industrial classes contribute lower than their peaks at this time.

Table 6.4. Load Characteristics of the Component Classes and the System

Class Name	Peak Demand (p.u.)	System Peak Contribution (p.u.)	Average Demand (p.u.)	Load Factor
System	1.000	1.000	0.5264	0.5264
Residential	0.370	0.370	0.1745	0.4717
Commercial	0.070	0.062	0.0374	0.5341
Industrial	0.560	0.538	0.3120	0.5571
Seasonal	0.031	0.031	0.0077	0.2481

6.6.2. Base Case Analysis

The cost allocation study commenced with the base case analysis. The base case is the 1995 optimum system configuration considering the generating unit 'normal' FOR. The results are shown in Table 6.5. Although it is difficult to indicate any concluding remarks regarding calculated indices because of the complexity of the class load models, some observations can still be made from the results in association with the load characteristics shown in Table 6.4.

It can be seen from Table 6.5 that the allocation factor for the residential class is 0.38, which is higher than its peak demand of 0.37. This is due to the fact that its contribution to the system peak load is quite high (37% of the system peak). Even a lower load factor of 0.47 could not offset the increased allocation factor.

Table 6.5. Base Case Allocation Indices (1995 Optimum Configuration, FOR: Normal)

Peak Load	Allocation Factors			
(MW)	Residential	Commercial	Industrial	Seasonal
237.17	0.3845	0.0643	0.5617	0.0180

The allocation factor for the commercial class is 0.06 which is less than its peak demand of 0.07. This is due to the fact that its contribution during the system peak is lower (0.062) than its peak demand. The higher load factor of 0.53 does not create an increase in its allocation index.

The allocation factor for the industrial class is even with its peak demand which is 0.56. Although its contribution to the system peak is less (0.53) than its peak demand, this is offset by its high load factor, which is 0.55. The allocation factor for the seasonal load is 0.018 which is much lower than its peak load contribution of 0.031. This is due to its low load factor, which is 0.24.

It can be seen from the base case analysis that the LOEE method used in the cost of service allocation process is quite responsive to a variety of factors associated with the load characteristics and yields reasonable allocation factors to the different classes. In order to appreciate its response to system parameters such as the peak load, load forecast uncertainty and generating unit forced outage rates, sensitivity studies were performed and are discussed below.

6.6.3. Sensitivity Studies

The system peak load was varied from 85% to 115% in 5% steps and the allocation factors were evaluated. The results are shown in Table 6.6. It can be seen from the results that the allocation factors do not change significantly with the peak load. This was expected because the variation in the peak load does not change the load characteristics and therefore the class contribution in each period considered will vary

in proportion to the system peak without significantly changing the weighting and the allocation factors.

Table 6.6. Variation in the Allocation Factors with the Peak Load

Peak Load (p.u.)	Allocation Factors (p.u.)			
	Residential	Commercial	Industrial	Seasonal
0.85	0.3851	0.0644	0.5625	0.0184
0.90	0.3849	0.0643	0.5618	0.0180
0.95	0.3833	0.0641	0.5599	0.0178
1.00*	0.3845	0.0643	0.5617	0.0180
1.05	0.3815	0.0638	0.5572	0.0171
1.10	0.3814	0.0639	0.5578	0.0175
1.15	0.3789	0.0635	0.5542	0.0165

* Base Case

Power system planning and operation are done based on load forecasts, which are uncertain. Studies were performed to understand the impact of load forecast uncertainty on the calculated allocation factors. The results are shown in Table 6.7. It can be seen from the results that the allocation factors do not change significantly with load forecast uncertainty. For a 15% uncertainty in the load forecast (i.e. a standard deviation of 15%), the variation in the allocation indices from the base value (0% uncertainty) are 0.57%, 0.47%, and 0.53% respectively for the residential, commercial and industrial loads. The reason for this insignificant variation is due to the fact that the allocation factors did not change significantly with the peak load as explained earlier.

Table 6.7. Variation in the Allocation Factors with the Load Forecast Uncertainty

Uncertainty (%)	Allocation Factors (p.u.)			
	Residential	Commercial	Industrial	Seasonal
0*	0.3845	0.0643	0.5617	0.0180
5	0.3833	0.0641	0.5599	0.0177
10	0.3832	0.0641	0.5599	0.0177
15	0.3823	0.0640	0.5587	0.0175

* Base Case

Sensitivity studies were also performed to examine the impact of generating unit forced outage rates on the allocation indices. The generating unit FOR were increased to the 'extreme' values and the allocation factors evaluated. The results of both the base case ('normal' FOR) and the generators having increased FOR ('extreme'), and their percentage differences are shown in Table 6.8.

Table 6.8. Impact of Generating Unit FOR on the Allocation Factors

Class	Allocation Factors (p.u.)		Difference
	FOR: Normal	FOR: Extreme	(%)
Residential	0.3845	0.3575	-7.0
Commercial	0.0643	0.0609	-5.3
Industrial	0.5617	0.5295	-5.7
Seasonal	0.0180	0.0133	-26.1

The interaction of the system load and the system capacity outage probability table have considerable effect on the allocation factors. These effects can be explained

by examining the class contributions at different load levels and the distribution of the outage probabilities.

It is generally understood that when the generating unit FOR are increased, the system is more likely to have higher capacity outages and therefore the outage probability distribution moves downward towards the higher outage levels. It can be seen by examining the class contributions to the system load that all classes have lower load level contributions in the middle (summer season) than that at both ends (winter season). Therefore, the allocation indices for all classes decrease as the forced outage rates are increased from the 'normal' to the 'extreme' values. The degree of decrement in the contribution is, however, quite unique for each load class, which results in unique differences in the allocation indices shown in Table 6.8. For example, the seasonal class contribution in the summer is nil and therefore it has a maximum difference of 26%. The residential class contribution in the summer decreases more than those of the industrial and commercial classes. The impact of FOR change on the residential class is therefore more (7%) than that of the industrial (5.7%) and the commercial (5.3%).

Expansion plan studies were conducted for the NPS over the five year period 1995 - 1999. An optimum generating capacity expansion plan was proposed for the period using the reliability cost/worth approach. The proposed optimum system configuration was examined to understand how the cost of service allocation indices vary with the variation in the system configuration over the planning period. The results are shown in Table 6.9.

It can be seen from the results shown in Table 6.9 that the allocation indices do not change significantly with the system modifications provided that the load characteristics and the system parameters such as the unit FOR remain the same. It

should, however, be noted that although the allocation factor for each class remains the same, the allocated cost for each class will increase because the system cost increases due to the addition of new facilities.

Table 6.9. Variation in the Allocation Indices with the New System Configuration Planned for the Period 1995-1999

Year	Peak Load (MW)	Optimum Configuration	Allocation Factors			
			Res.	Com.	Ind.	Seas.
1995	237.17	Base Case	0.3845	0.0643	0.5617	0.0180
1996	254.98	Base Case	0.3813	0.0638	0.5573	0.0173
1997	279.53	+1-26 MW	0.3827	0.0640	0.5589	0.0174
1998	307.00	+1-26 MW	0.3842	0.0642	0.5608	0.0177
1999	347.29	+2-26 MW	0.3888	0.0649	0.5669	0.0188

The cost allocation studies conducted and described in this chapter are at HL I. The LOEE method used in this research work can be extended to studies at HL II. This, however, will require additional detailed class load data for each load bus in the system. In the absence of the detailed class load data for each bus, further load data must be created and considerable assumptions have to be made in the studies, which may not be appropriate. Cost allocation studies at HL II were therefore not conducted in this research work.

6.7. Tariff Design

As noted earlier, tariff design is a complex task. There are many factors involved in determining actual electricity service rates including socio-economic or

political considerations. The rate setting process differs from one utility to another depending upon the unique situation that each utility has. The allocation methodology described in this chapter, however, can provide basic input to the tariff design process for any utility.

The service cost allocation factors for the various classes were evaluated based on their burden to the system, which is the basic principle of the cost allocation process. In addition, the allocation factors were evaluated based on a method that follows the cost behavior of the system. These factors are therefore used to calculate the allocated cost for each customer class by multiplying the total utility cost with their respective allocation factors. Other social and political considerations can then be incorporated as warranted by the unique utility situation to adjust the allocated costs and arrive at the final service rates for the different classes.

6.8. Summary

This chapter describes a probabilistic capacity cost of service allocation methodology that can be used by developing countries in tariff design. A basic cost of service allocation framework incorporating the reliability cost/worth approach to system planning is suggested. The basic concept of this formulation is that the system adequacy assessment technique used in system planning should also be used in the cost allocation process to ensure that the cost allocations follow the system cost behavior.

It was noted that the probabilistic method requires extensive customer class load information, which is usually not available. It was therefore necessary to create load models for each customer class considered in the analysis, i.e. residential, commercial and industrial. Complete load modelswere created for each class using some available

class data and realistic assumptions. The class load characteristics obtained using the created load data were found to be consistent.

Cost of service allocation factors were evaluated for the base case which is the 1995 system configuration. The calculated class indices were discussed in conjunction with their load characteristics. The cost allocation factors were found to be reasonable and consistent. Some sensitivity studies were performed to examine the impact of system parameters such as the peak load, load forecast uncertainty, forced outage rate, system modifications etc., on the calculated indices. The probabilistic method (LOEE) used responds to these important system parameters, on which the reliability of an electric power system depends.

Electric tariff rate determination is an important integral part of the utility planning process. The purpose of this research work was to extend the reliability cost/worth technique to incorporate service cost allocation in the planning process. This chapter has illustrated how the extension can be done by an application to the Nepal Integrated Electric Power System. The developed approach can be used effectively by system planners to address electric service rate issues in developing countries.

7. SUMMARY AND CONCLUSIONS

Electric power is an important element in any modern economy. The availability of reliable power supply at reasonable cost is important for economic growth and development of a country. Electric power utilities throughout the world therefore strive to meet customer demands with a high quality, economic and reliable power supply.

Considerable work has been done in developed countries to optimize the reliability of electric power systems on the basis of reliability cost versus reliability worth. This has yet to be considered in most developing countries, where development plans are still based on traditional deterministic measures such as the single largest contingency or a fixed percentage reserve margin. The difficulty with these criteria is that they cannot be used to evaluate the economic impacts of changes in reliability levels on the utility and the customers, and therefore cannot be used to determine an optimum system expansion plan. The reliability cost/worth approach to system evaluation provides a framework upon which developing countries can formulate suitable planning criteria and economically justify future power projects.

The main objective of the research described in this thesis was to examine the problems associated with incorporating the reliability cost/worth approach to system evaluation in a developing country and to develop methodologies that can be used by utility planners in developing countries to initiate reliability cost/worth studies. This chapter presents a summary and the conclusions of this research work.

Chapter 1 presents a brief review of the power sector status in developing countries and the sector issues and difficulties faced by a developing power system such as the Nepal Integrated Electric Power System. A hierarchical approach to quantitative reliability evaluation of electric power systems is described in this chapter. A developed framework for basic reliability cost/worth studies is also presented and described. Chapter 1 illustrates that there is a wide range of studies that can be conducted using quantitative reliability assessment. Many probabilistic techniques exist and are now used in practice in developed countries. The studies in the developed countries indicate that the complexity of the studies and the data and information requirements are high if a complete range of possible studies are considered. A practical approach for developing countries is to focus on a limited range of studies that readily provide useful input to utility decision making process.

It is important to appreciate the data requirements for reliability studies. Chapter 2 describes the various data requirements for HL I and HL II adequacy evaluations. Two types of data, designated as 'deterministic' and 'stochastic', are recognized as being necessary for these studies. Each type of data is required at both the system level and at the component level for detailed studies. System cost data are also required for reliability cost/worth studies. Most data required for basic quantitative reliability assessment are not readily available in the NPS. A practical procedure was therefore developed to create a basic system database required for the evaluations described in this thesis. The developed methodology and the resulting system database provides a useful reference for system planners in developing countries when initiating reliability studies. It should, however, be noted that the application of the reliability cost/worth technique to system evaluation require a commitment to the collection and compilation of appropriate reliability data. It is therefore strongly recommended that developing countries establish and implement suitable data collection schemes.

Chapter 3 presents an overview of the methods used in power system reliability worth evaluation. It describes the survey techniques used in reliability worth assessment and explains how they were applied to estimate the customer outage costs in the service areas supplied by the NPS. The results reveal that the interruption cost depends on customer and interruption characteristics and varies from one location or region to another within a service area. The results clearly indicate that it is possible to develop reasonably good customer outage cost estimates using survey methods in a developing country.

The basic concepts and techniques used in generating capacity evaluation are presented in Chapter 4. It shows how the interruption cost data obtained from the customer surveys can be used to evaluate a relatively constant factor designated as the IEAR which is used to link customer outage cost with power system reliability. It then shows by an application to the NPS how an optimum system configuration that maximizes the net societal benefits can be determined for the power system in a developing country. It further shows that a short term expansion plan can be developed based on the least societal cost approach. The optimum plan can then be utilized to develop suitable probabilistic criteria that can be used in long range planning. The primary contribution of the research work described in this chapter is the development of a methodology that can be effectively used in a developing country to derive appropriate generating capacity planning criteria from an overall societal cost perspective.

Chapter 5 presents an extension of the reliability cost/worth assessment techniques used in generating capacity evaluation to include transmission facilities in a composite generation and transmission system evaluation. A methodology for system

IEAR determination using limited individual load bus information is presented in this chapter. The approach was used to estimate all the individual load bus IEAR and the system IEAR for the NPS. Chapter 5 then presents a wide range of planning studies conducted at HL II using the estimated IEAR. A methodology to develop planning criteria for long range system planning at HL II is also presented and some suitable criteria for the NPS are suggested. The major contribution of the research work described in this chapter is the development of an approach to derive suitable planning criteria from an overall societal cost perspective. The approach can be effectively used by system planners in developing countries to evaluate a bulk power system.

A basic probabilistic cost of service allocation process incorporating the reliability cost/worth approach to system evaluation is presented in Chapter 6. A conceptual utility service cost allocation framework incorporating the reliability cost/worth approach to system planning is proposed in this chapter. The electric service tariff determination is an important integral part of the utility planning process. Chapter 6 illustrates how the reliability cost/worth technique can be extended to incorporate service cost allocation in the planning process by an application to the NPS. The developed approach can be effectively used by system planners in developing countries to address electric service rate issues.

This thesis presents the methodologies, assumptions and results of research conducted on application of the reliability cost/worth technique to determine appropriate planning criteria for developing countries. The criteria and methodologies were developed using the Nepal Integrated Electric Power System as a surrogate power system. The Nepal studies provided the means for the examination and development of an overall framework, which can be used by utility planners in similar developing countries to determine reliability criteria for their power systems. The developed framework was used to formulate criteria at both HL I and HL II for the NPS. It is, however, important to note the limitations of this research work. Many reliability data

required for the analysis are not available in the NPS and were therefore created using practical assumptions and data pooling from external resources. The interruption cost estimates were obtained using a limited customer sample size of approximately 2000 out of a total of more than 400,000 electricity consumers in Nepal. Many service areas, specifically rural parts of the country, could not be surveyed due to lack of time and funds. In addition, the 'Other' customer sectors such as agriculture, government, institutions and office buildings could not be surveyed and their interruption cost characteristics were incorporated in the analysis using practical assumptions.

Based on the limited data and system information and the approximate techniques developed in the analysis, the average customer outage costs at HL I and HL II were evaluated and found to be Rs 35.00 and Rs 26.00 respectively. These outage costs led to an optimum reserve margin of 7.5% for the NPS in the study period considered in the evaluation. The optimum reserve margin determined is considerably lower than the traditional reserve margin of 15% used in the NPS. This clearly indicates that there is a need for a developing country such as Nepal to consider new criteria in power system planning. The selection of more economically justified criteria may permit scarce resources to be diverted to other important sectors such as education, health or agriculture rather than investing in new power system facilities that are not justifiable.

A similar conclusion may result in other developing countries which are facing difficulties in power system expansion planning using the traditional deterministic approach. It is therefore strongly recommended that developing countries objectively review the traditional approach to system planning and evaluate future power projects with a new approach based on fundamental principles of power system reliability and economics.

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A. THE LOCATION MAP AND NPS DEVELOPMENT PLAN

The location map of Nepal is shown in Figure A.1. Nepal is a small developing country located in South Asia. It borders with China in the north and India in the south, east and west. More than 80% of the population depend on agriculture and live in the rural areas of the country. Industries and businesses are mostly located in major cities and towns. Tourist industries are the main sources for international currency income in the country. Hydro power is the main resource for electricity generation. Major development projects are financed by international development agency such as the World Bank.

Figure A.2 shows the existing power network as of 1993, and the long term power development plan for the NPS. Figure A.2 also shows the power transactions with neighboring country India at different locations.

The details of existing power plants and the transmission lines including sub-stations are given in Figure A.3. Figure A.3 also shows the capacities of potential hydro power plants which are identified as economically feasible, and are listed under long-term power development plan for the country.

The plants listed under Small Hydro Project in Figure A.3 are not considered in the assessment due to their low capacities and perhaps negligible impacts on the studies. Similarly, only the major diesel power station at Hetauda shown in Figure A.3 has been considered in the evaluation.

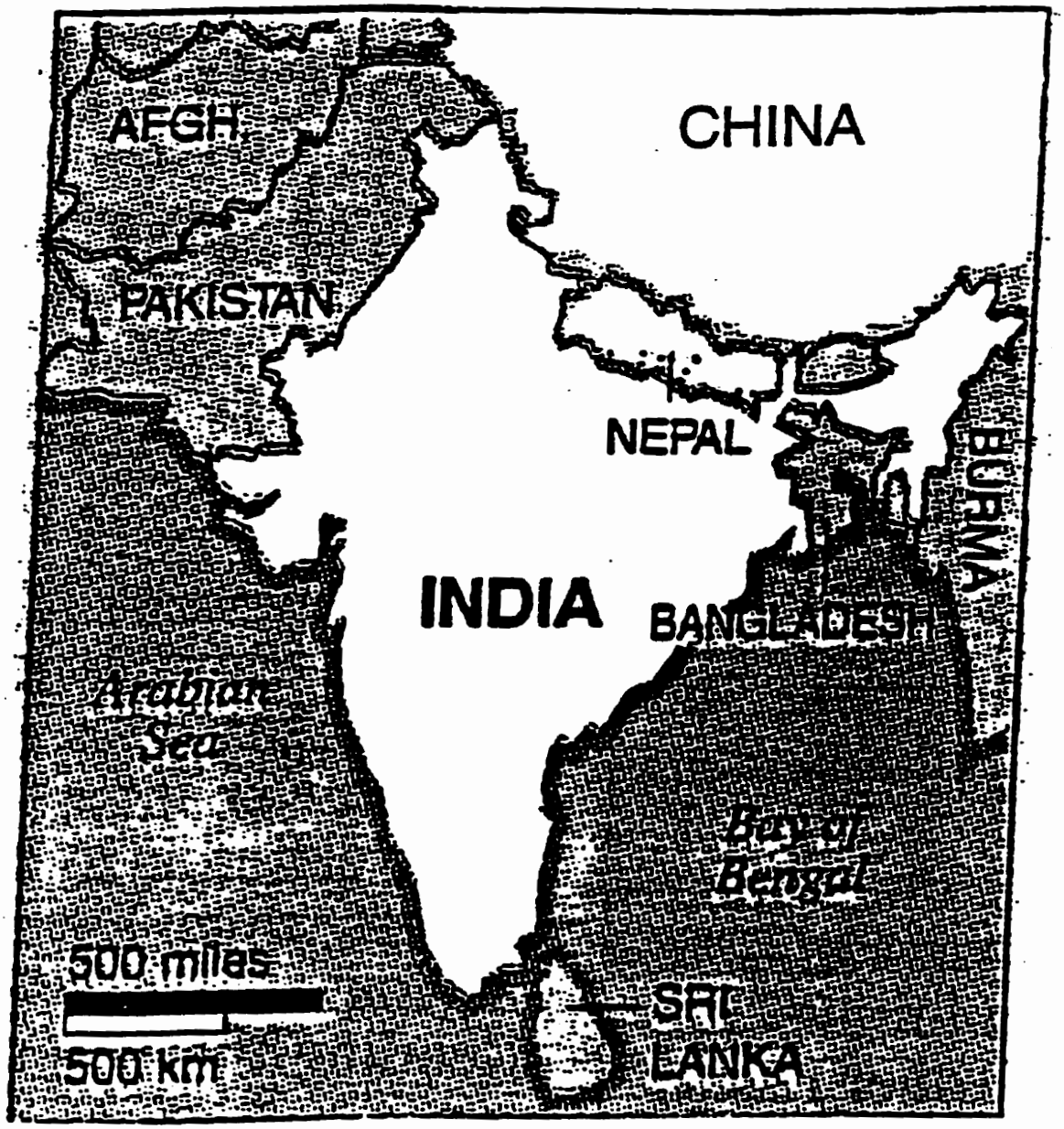

Figure A.1. Location Map of Nepal

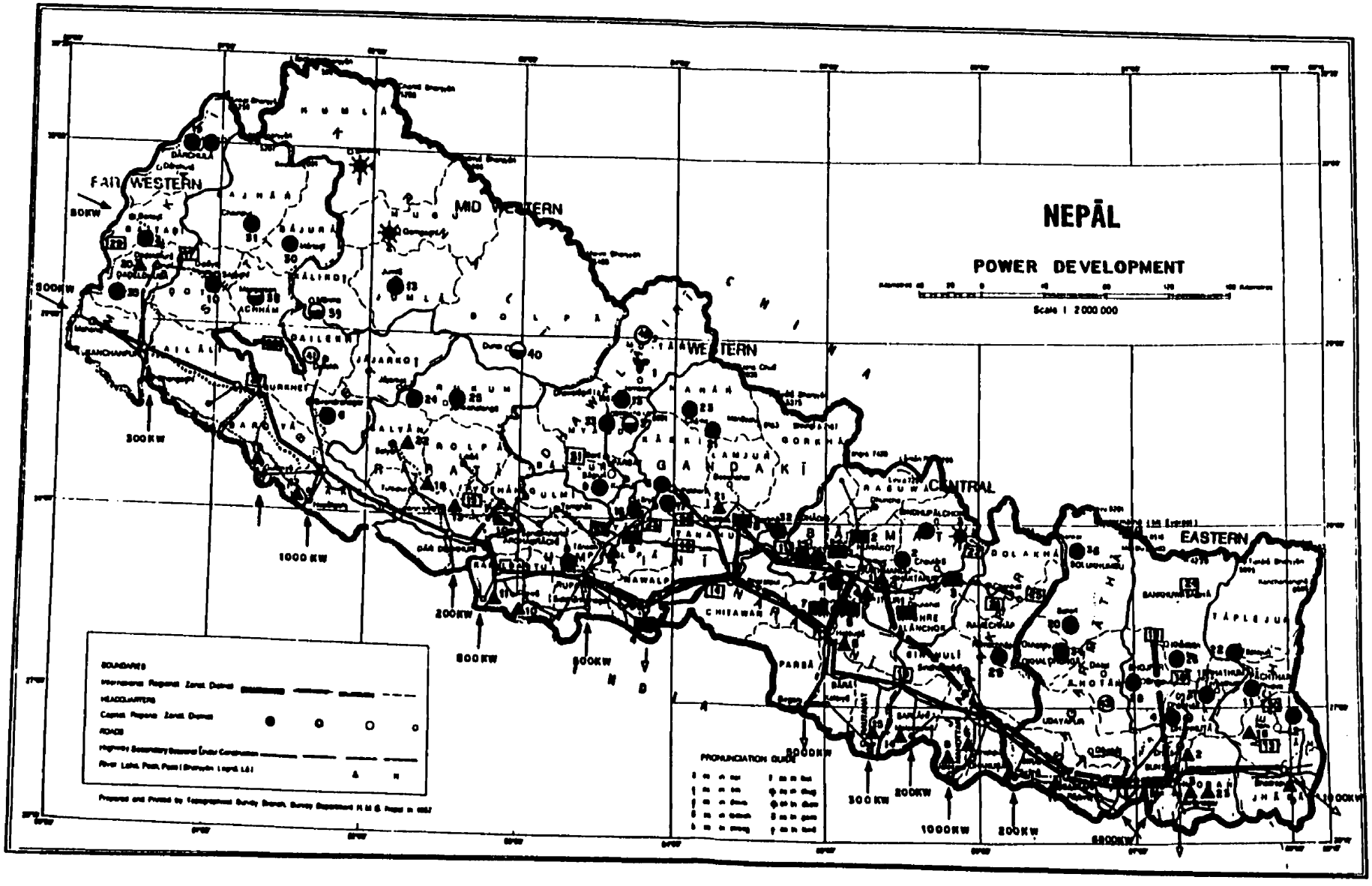

Figure A.2. The NPS Development Plan

MAJOR HYDRO PROJECT

EXISTING

1. PANAUTI	2,400	KW
2. TRISULI	21,000	"
3. SUNKOSI	10,050	"
4. GANDAK	15,000	"
5. KULEKHANI NO. 1	60,000	"
6. DEVIGHAT	14,100	"
7. KULEKHANI NO. 2	32,000	"
8. MARSYANGDI	69,000	"
9. ANDHI KHOLA (BPC)	5,100	"
TOTAL	228,650	KW

UNDER CONSTRUCTION

10. JHIMRUK PIUTHAN	12,500	KW

PLANNED & PROPOSED

11. BUDHI GANDAKI	6,00,000	KW
12. KALI GANDAKI NO. 2	6,60,000	"
13. KANKAI (MULTIPURPOSE)	60,000	"
14. SAPTA GANDAKI	2,25000	"
15. NAUMURI	2,00,000	"
16. LOWER ARUN	3,00,000	"
17. SETI (WEST)	2,85,000	"
18. ARUN 3	4,00,000	"
19. BAGMATI	1,40-2,10,000	"
20. KALI GANDAKI A	1,40,000	"
21. TAMA KOSHI NO. 2	1,23,000	"
22. UPPER BHOTE KOSHI	36,000	"
23. ANDHI KHOLA NO. 1 (RESERVOIR)	1,80,000	"
24. UPPER ARUN	3,80,000	"
25. KHIMTI KHOLA	60,000	"
26. SETI GANDAKI	3,20,000	"
27. KARNALI I (CHISAPANI)	1,06,00,000	"
28. UPPER KARNALI	2,40,000	"
29. PANCHESHWAR (MAHAKALI)	10,00,000	"
30. PUWA KHOLA	5,000	"
31. MODI KHOLA	14,000	"

SMALL HYDRO PROJECT

EXISTING

1. SURNAYAGAD (BAITADI)	200	KW
2. SUDARIJAL	640	"
3. POKHARA	1,088	"
4. DHANKUTA	240	"
5. TINAU (BUTWAL)	1,024	"
6. SURKHET (JHUPRA)	345	"
7. GAJURI	25	"
8. THANSING	20	"
9. BAGLUNG	175	"
10. DOTI	200	"
11. PHIDIM	240	"
12. GORKHE	64	"
13. JOMSOM	240	"
14. JUMLA	200	"
15. DHADING	32	"
16. SYANGJA	80	"
17. SETI (POKHARA)	1,500	"
18. HELAMVU	50	"
19. DARCHULA (I) & (II)	300	"
20. SALLERI (SCECO)	200	"
21. CHAME	45	"
22. TAPLE JUNG	125	"
23. MANANG	80	"
24. CHAURJHARI	150	"
25. SYARPUDAHA	200	"
26. KHANDBARI	250	"
27. TERHA THUM	100	"
28. BHOJPUR	250	"
29. RAMECHHAP	75	"
30. BAJURA	200	"
31. BAJHANG	200	"
32. ARUGHAT GORKHA	150	"
33. TATOPANI I MYAGDI	1,000	"
34. OKHALDHUNGA	125	"
35. RUPAL GAD DADELDHURA	100	"
36. NAMCHE	600	"
TOTAL	10,513	KW

UNDER CONSTRUCTION

37. TATOPANI II MYAGDI	1,000	"
38. ACHHAM	400	"
39. KALIKOT	500	"
40. DOLPA	160	"

PLANNED & PROPOSED

41. DAILEKH	300	KW
42. LAMANGTHAN (MUSTANG)	65	"
43. KHOTANG	2,300	"

DIESEL POWER STATIONS

EXISTING

1. MAHENDRA, KATHMANDU	1,728	KW
2. BIRATNAGAR	1,028	"
3. PATAN (LALITPUR)	1,490	"
4. HETAUDA	14,470	"
5. ILAM	200	"
6. DADELDHURA	112	"
7. ANBUKHAIRENI	2250	"
8. SALYAN	100	"
9. MULTI-FUEL (MORANG)	26,000	"
TOTAL	47,378	KW

N.B. Obsolete diesel plants with total installed capacity of 7305 KW are excluded.

SOLAR POWER STATIONS

EXISTING

1. SIMIKOT	50	KW
2. GAMGADHI	50	"
3. KODARI TATOPANI	30	"
TOTAL	130	KW

TRANSMISSION LINE LENGTH

EXISTING

132 K. V.	1,191 KM	SINGLE CIRCUIT
66 K. V.	158 KM	DOUBLE CIRCUIT
66 K. V.	64 KM	SIGLE CIRCUIT
33 K. V.	1,196 KM	SINGLE AND DOUBLE CIRCUIT

SUB-STATION CAPACITY

EXISTING

132/11 KVA	-	28.5 MVA
132/33 KVA	-	145.0 MVA
132/66 KVA	-	102.8 MVA
66/11 KVA	-	193.3 MVA
66/33 KVA	-	12.5 MVA
132/33/11 KVA	-	10.0 MVA
TOTAL		492.1 MVA

ELECTRICITY

IMPORT →

EXPORT ←

TRANSMISSION LINE

PARTICULAR	EXISTING	UNDERCONSTRUCTION	PLANNED PROPOSED
33 KV LINE			
66 KV LINE			
132 KV LINE			
220 KV LINE			

Installed capacity in Nepal: 288076 KW (excludes Andhi Khola, Salleri and Kaghani)

Figure A.3. Legends for Figure A.2

B. ADDITIONAL NPS RELIABILITY DATA

The basic component level data used in the quantitative reliability assessment at HL II are given in this Appendix. The data are for 1995 system configuration without considering the proposed generation and transmission line reinforcement plans. Table B.1 shows the bus data used in the load flow analysis. The name and the corresponding bus number referred to in this thesis are also given in the table.

The basic generator reliability data are shown in Table B.2. The unit failure rate and repair time derived in Chapter 2 and designated as 'Normal' values are listed in the table.

The impedance and rating data for transmission lines and transformers existing in the NPS are shown in Table B.3. The line and transformer data required for HL II evaluation are given in Table B.4. The component failure rate and repair time derived in Chapter 2 and designated as 'Normal' values are also listed in the table. The presented database is sufficient for dc load flow studies.

Table B.1. Bus Data (1995 Configuration), Base MVA = 100

Bus Name	Bus No.	Load (p.u.) P	Load (p.u.) Q	P_G (p.u.)	Q_{max} (p.u.)	Q_{min} (p.u.)	V_o (p.u.)	V_{max} (p.u.)	V_{min} (p.u.)
Sunkosi	1	0.0000	0.0000	0.10	+ 0.06	- 0.06	1.02	1.05	0.95
Sunkosi	2	0.0228	0.0109	0.00	0.00	0.00	1.02	1.05	0.95
Banepa	3	0.0482	0.0231	0.00	0.00	0.00	1.00	1.05	0.95
Bhaktapur	4	0.0828	0.0397	0.00	0.00	0.00	1.00	1.05	0.95
Baneswar	5	0.1656	0.0794	0.00	0.00	0.00	1.00	1.05	0.95
Patan	6	0.1031	0.0494	0.00	+ 0.10	0.00	1.00	1.05	0.95
Siuchatar	7	0.0899	0.0431	0.00	+ 0.10	0.00	1.00	1.05	0.95
Siuchatar	8	0.0000	0.0000	0.00	0.00	0.00	1.00	1.05	0.95
Teku	9	0.1946	0.0934	0.00	0.00	0.00	1.00	1.05	0.95
Kulekhani I	10	0.0000	0.0000	0.00	0.00	0.00	1.02	1.05	0.95
Kulekhani I	11	0.0000	0.0000	0.60	+ 0.36	- 0.36	1.02	1.05	0.95
Kulekhani II	12	0.0000	0.0000	0.00	0.00	0.00	1.02	1.05	0.95
Kulekhani II	13	0.0000	0.0000	0.32	+ 0.19	- 0.19	1.02	1.05	0.95
Balaju	14	0.1138	0.0546	0.00	0.00	0.00	1.00	1.05	0.95
Balaju	15	0.0000	0.0000	0.00	0.00	0.00	1.00	1.05	0.95
Lainchaur	16	0.1921	0.0922	0.00	0.00	0.00	1.00	1.05	0.95
Marsyangdi	17	0.0000	0.0000	0.00	0.00	0.00	1.02	1.05	0.95
Marsyangdi	18	0.0000	0.0000	0.69	+ 0.40	- 0.40	1.02	1.05	0.95
Trisuli	19	0.0106	0.0051	0.00	0.00	0.00	1.02	1.05	0.95
Trisuli	20	0.0000	0.0000	0.21	+ 0.12	- 0.12	1.02	1.05	0.95
Chabel	21	0.1037	0.0497	0.00	0.00	0.00	1.00	1.05	0.95
Devighat	22	0.0160	0.0076	0.00	0.00	0.00	1.02	1.05	0.95
Devighat	23	0.0000	0.0000	0.14	+ 0.08	- 0.08	1.02	1.05	0.95
Hetaunda	24	0.1073	0.0515	0.10	+ 0.06	-0.06	1.02	1.05	0.95
Hetaunda	25	0.0000	0.0000	0.00	0.00	0.00	1.02	1.05	0.95
Amlekhgunj	26	0.0049	0.0023	0.00	0.00	0.00	1.00	1.05	0.95
Simra	27	0.0155	0.0074	0.00	0.00	0.00	1.00	1.05	0.95
Parwanipur	28	0.0736	0.0353	0.00	0.00	0.00	1.00	1.05	0.95
Birgunj	29	0.1011	0.0485	0.00	0.00	0.00	1.00	1.05	0.95
Dhalkebar	30	0.0665	0.0319	0.00	0.00	0.00	1.00	1.05	0.95
Lahan	31	0.1269	0.0609	0.00	0.00	0.00	1.00	1.05	0.95
Duhubi	32	0.2405	0.1154	0.26	+ 0.13	- 0.13	1.02	1.05	0.95
Anarmani	33	0.0471	0.0226	0.00	0.00	0.00	1.00	1.05	0.95
Bharatpur	34	0.0667	0.0320	0.00	0.00	- 0.10	1.00	1.05	0.95
Damauli	35	0.0196	0.0094	0.00	0.00	0.00	1.00	1.05	0.95
Pokhara	36	0.0936	0.0450	0.00	0.00	0.00	1.00	1.05	0.95
Bardhghat	37	0.0114	0.0054	0.00	0.00	0.00	1.00	1.05	0.95
Gandak	38	0.0065	0.0031	0.00	0.00	0.00	1.02	1.05	0.95
Gandak	39	0.0000	0.0000	0.15	+0.07	- 0.07	1.02	1.05	0.95
Butwal	40	0.1276	0.0612	0.05	+ 0.02	- 0.02	1.02	1.05	0.95
Shivpur	41	0.0090	0.0043	0.00	0.00	0.00	1.00	1.05	0.95
Lamahi	42	0.0068	0.0032	0.12	+ 0.06	- 0.06	1.02	1.05	0.95
Kohalpur	43	0.0634	0.0304	0.00	0.00	0.00	1.00	1.05	0.95
Chisapani	44	0.0031	0.0015	0.00	0.00	0.00	1.00	1.05	0.95
Ataria	45	0.0245	0.0117	0.00	0.00	0.00	1.00	1.05	0.95
Mahennagar	46	0.0128	0.0061	0.00	0.00	0.00	1.00	1.05	0.95

Table B.2. Generator Data (1995 Configuration)

Plant	Unit	Bus	Rating (MW)	Failures Per Year	Repair Time (hour)
Trisuli	1	20	3.0	2.0	45
Trisuli	2	20	3.0	2.0	45
Trisuli	3	20	3.0	2.0	45
Trisuli	4	20	3.0	2.0	45
Trisuli	5	20	3.0	2.0	45
Trisuli	6	20	3.0	2.0	45
Trisuli	7	20	3.0	2.0	45
Devighat	8	23	4.7	2.5	55
Devighat	9	23	4.7	2.5	55
Devighat	10	23	4.7	2.5	55
Sunkosi	11	1	3.35	2.0	45
Sunkosi	12	1	3.35	2.0	45
Sunkosi	13	1	3.35	2.0	45
Gandak	14	39	5.0	2.5	55
Gandak	15	39	5.0	2.5	55
Gandak	16	39	5.0	2.5	55
Andhikhola	17	40	5.0	2.5	55
Jhimruk	18	42	12.0	3.0	60
Marsyangdi	19	18	23.0	3.5	65
Marsyangdi	20	18	23.0	3.5	65
Marsyangdi	21	18	23.0	3.5	65
Kulekhani I	22	11	30.0	4.0	70
Kulekhani I	23	11	30.0	4.0	70
Kulekhani I	24	13	16.0	3.0	60
Kulekhani I	25	13	16.0	3.0	60
Hetaunda	26	24	2.5	7.0	45
Hetaunda	27	24	2.5	7.0	45
Hetaunda	28	24	2.5	7.0	45
Hetaunda	29	24	2.5	7.0	45
Duhubi	30	32	26.0	8.0	60

Table B.3. Impedance and Rating Data

Line No	From Bus	To Bus	Impedance (p.u.) / 100 MVA Base			Rating MVA	Equipment
			R	X	B		
1	1	2	0.0023	0.0797	0.0000	5.6	Transformer
2	1	2	0.0023	0.0797	0.0000	5.6	Transformer
3	2	3	0.1767	0.2321	0.0037	44	66 KV Line
4	3	4	0.0757	0.0995	0.0016	44	66 KV Line
5	4	5	0.0946	0.1244	0.0019	44	66 KV Line
6	5	6	0.0177	0.0232	0.0004	44	66 KV Line
7	6	7	0.0196	0.0350	0.0005	51	66 KV Line
8	7	8	0.0023	0.1200	0.0000	37.8	Transformer
9	7	9	0.0147	0.0265	0.0004	51	66 KV Line
10	7	10	0.1424	0.2538	0.0038	51	66 KV Line
11	7	10	0.1424	0.2538	0.0038	51	66 KV Line
12	8	12	0.0249	0.0766	0.0171	142	132 KV line
13	10	11	0.0023	0.0725	0.0000	35	Transformer
14	10	11	0.0023	0.0725	0.0000	35	Transformer
15	10	24	0.0786	0.1401	0.0021	51	66 KV line
16	10	24	0.0786	0.1401	0.0021	51	66 KV line
17	12	13	0.0023	0.1200	0.0000	37.8	Transformer
18	12	25	0.0058	0.0181	0.0040	142	132 KV Line
19	14	7	0.0344	0.0613	0.0009	51	66 KV line
20	14	7	0.0344	0.0613	0.0009	51	66 KV line
21	14	15	0.0023	0.1200	0.0000	45	Transformer
22	14	16	0.0085	0.0204	0.0003	62	66 KV line
23	14	19	0.2120	0.2538	0.0038	40	66 KV line
24	14	19	0.2120	0.2538	0.0038	40	66 KV line
25	14	21	0.0196	0.1313	0.0019	40	66 KV line

Table B.3. (Contd.)

Line No	From Bus	To Bus	Impedance (p.u.) / 100 MVA Base R	X	B	Rating MVA	Equipment
26	15	17	0.0617	0.1910	0.0419	142	132 KV Line
27	17	18	0.0023	0.1200	0.0000	30	Transformer
28	17	18	0.0023	0.1200	0.0000	30	Transformer
29	17	18	0.0023	0.1200	0.0000	30	Transformer
30	17	34	0.0184	0.0569	0.0125	142	132 KV Line
31	19	20	0.0023	0.0840	0.0000	11.25	Transformer
32	19	20	0.0023	0.0840	0.0000	11.25	Transformer
33	21	22	0.1620	0.2889	0.0043	51	66 KV line
34	21	22	0.1620	0.2889	0.0043	51	66 KV line
35	22	23	0.0023	0.0697	0.0000	6.3	Transformer
36	22	23	0.0023	0.0697	0.0000	6.3	Transformer
37	22	23	0.0023	0.0697	0.0000	6.3	Transformer
38	24	25	0.0023	0.0780	0.0000	20	Transformer
39	24	25	0.0023	0.0735	0.0000	10	Transformer
40	24	26	0.0785	0.1401	0.0021	51	66 KV line
41	24	26	0.0785	0.1401	0.0021	51	66 KV line
42	25	34	0.0641	0.1614	0.0343	123	132 KV Line
43	25	30	0.1005	0.3088	0.0690	142	132 KV Line
44	26	27	0.0491	0.0875	0.0013	51	66 KV line
45	26	27	0.0491	0.0875	0.0013	51	66 KV line
46	27	28	0.0442	0.0788	0.0012	51	66 KV line
47	27	28	0.0442	0.0788	0.0012	51	66 KV line
48	28	29	0.0442	0.0788	0.0012	51	66 KV line
49	28	29	0.0442	0.0788	0.0012	51	66 KV line
50	30	31	0.0484	0.1488	0.0332	142	132 KV Line
51	31	32	0.0587	0.1803	0.0403	142	132 KV Line
52	32	33	0.0558	0.1729	0.0378	142	132 KV Line
53	34	35	0.0429	0.0828	0.0167	103	132 KV Line
54	34	37	0.0641	0.1614	0.0343	123	132 KV Line
55	35	36	0.0613	0.1183	0.0239	103	132 KV Line
56	37	38	0.0128	0.0323	0.0069	123	132 KV Line
57	37	40	0.0315	0.0969	0.0217	142	132 KV Line
58	38	39	0.0023	0.0840	0.0000	10	Transformer
59	38	39	0.0023	0.0840	0.0000	10	Transformer
60	40	41	0.0448	0.1375	0.0307	142	132 KV Line
61	41	42	0.0374	0.1149	0.0257	142	132 KV Line
62	42	43	0.0704	0.2164	0.0484	142	132 KV Line
63	43	44	0.0587	0.1819	0.0398	142	132 KV Line
64	44	45	0.0536	0.1660	0.0364	142	132 KV Line
65	45	46	0.0271	0.0841	0.0184	142	132 KV Line

Table B.4. Line Data for NPS (1995 Configuration)

Line No	From Bus	To Bus	Impedance (p.u) R	X	B/2	Tap	Current Rating(p.u.)	Failures Per Year	Repair Time(hr)
1	1	2	0.0023	0.0797	0.0000	1.0	0.056	0.020	768
2	1	2	0.0023	0.0797	0.0000	1.0	0.056	0.020	768
3	2	3	0.1767	0.2321	0.0018	1.0	0.440	0.560	10
4	3	4	0.0757	0.0995	0.0008	1.0	0.440	0.240	10
5	4	5	0.0946	0.1244	0.0009	1.0	0.440	0.300	10
6	5	6	0.0177	0.0232	0.0002	1.0	0.440	0.056	10
7	6	7	0.0196	0.0350	0.0002	1.0	0.510	0.080	10
8	7	8	0.0023	0.1200	0.0000	1.0	0.378	0.020	768
9	7	9	0.0147	0.0262	0.0002	1.0	0.510	0.060	10
10	7	10	0.1424	0.2538	0.0019	1.0	0.510	0.580	10
11	7	10	0.1424	0.2538	0.0019	1.0	0.510	0.580	10
12	8	12	0.0249	0.0766	0.0085	1.0	1.420	0.510	15
13	10	11	0.0023	0.0725	0.0000	1.0	0.350	0.020	768
14	10	11	0.0023	0.0725	0.0000	1.0	0.350	0.020	768
15	10	24	0.0786	0.1401	0.0010	1.0	0.510	0.320	10
16	10	24	0.0786	0.1401	0.0010	1.0	0.510	0.320	10
17	12	13	0.0023	0.1200	0.0000	1.0	0.378	0.020	768
18	12	25	0.0058	0.0181	0.0020	1.0	1.420	0.120	15
19	14	7	0.0344	0.0613	0.0004	1.0	0.510	0.140	10
20	14	7	0.0344	0.0613	0.0004	1.0	0.510	0.140	10
21	14	15	0.0023	0.1200	0.0000	1.0	0.450	0.020	768
22	14	16	0.0085	0.0204	0.0001	1.0	0.620	0.047	10
23	14	19	0.2120	0.2538	0.0019	1.0	0.400	0.580	10
24	14	19	0.2120	0.2538	0.0019	1.0	0.400	0.580	10
25	14	21	0.1096	0.1313	0.0009	1.0	0.400	0.300	10

Table B.4. (Contd.)

Line No	From Bus	To Bus	Impedance (p.u) R	X	B/2	Tap	Current Rating(p.u.)	Failures Per Year	Repair Time(hr)
26	15	17	0.0617	0.1910	0.0209	1.0	1.420	1.260	15
27	17	18	0.0023	0.1200	0.0000	1.0	0.300	0.020	768
28	17	18	0.0023	0.1200	0.0000	1.0	0.300	0.020	768
29	17	18	0.0023	0.1200	0.0000	1.0	0.300	0.020	768
30	17	34	0.0184	0.0569	0.0062	1.0	1.420	0.375	15
31	19	20	0.0023	0.0840	0.0000	1.0	0.1125	0.020	768
32	19	20	0.0023	0.0840	0.0000	1.0	0.1125	0.020	768
33	21	22	0.1620	0.2889	0.0021	1.0	0.510	0.660	10
34	21	22	0.1620	0.2889	0.0021	1.0	0.510	0.660	10
35	22	23	0.0023	0.0697	0.0000	1.0	0.063	0.020	768
36	22	23	0.0023	0.0697	0.0000	1.0	0.063	0.020	768
37	22	23	0.0023	0.0697	0.0000	1.0	0.063	0.020	768
38	24	25	0.0023	0.0780	0.0000	1.0	0.200	0.020	768
39	24	25	0.0023	0.0735	0.0000	1.0	0.100	0.020	768
40	24	26	0.0785	0.1401	0.0011	1.0	0.510	0.320	10
41	24	26	0.0785	0.1401	0.0011	1.0	0.510	0.320	10
42	25	34	0.0641	0.1614	0.0171	1.0	1.230	1.050	15
43	25	30	0.1005	0.3088	0.0345	1.0	1.420	2.055	15
44	26	27	0.0491	0.0875	0.0007	1.0	0.510	0.200	10
45	26	27	0.0491	0.0875	0.0007	1.0	0.510	0.200	10
46	27	28	0.0442	0.0788	0.0006	1.0	0.510	0.180	10
47	27	28	0.0442	0.0788	0.0006	1.0	0.510	0.180	10
48	28	29	0.0442	0.0788	0.0006	1.0	0.510	0.180	10
49	28	29	0.0442	0.0788	0.0006	1.0	0.510	0.180	10
50	30	31	0.0484	0.1488	0.0166	1.0	1.420	0.990	15
51	31	32	0.0587	0.1803	0.0201	1.0	1.420	1.200	15
52	32	33	0.0558	0.1729	0.0189	1.0	1.420	1.140	15
53	34	35	0.0429	0.0828	0.0084	1.0	1.030	0.525	15
54	34	37	0.0641	0.1614	0.0171	1.0	1.230	1.050	15
55	35	36	0.0613	0.1183	0.0119	1.0	1.030	0.750	15
56	37	38	0.0128	0.0323	0.0034	1.0	1.230	0.210	15
57	37	40	0.0315	0.0969	0.0108	1.0	1.420	0.645	15
58	38	39	0.0023	0.0840	0.0000	1.0	0.100	0.020	768
59	38	39	0.0023	0.0840	0.0000	1.0	0.100	0.020	768
60	40	41	0.0448	0.1375	0.0153	1.0	1.420	0.915	15
61	41	42	0.0374	0.1149	0.0128	1.0	1.420	0.765	15
62	42	43	0.0704	0.2164	0.0242	1.0	1.420	1.440	15
63	43	44	0.0587	0.1819	0.0199	1.0	1.420	1.200	15
64	44	45	0.0536	0.1660	0.0182	1.0	1.420	1.095	15
65	45	46	0.0271	0.0841	0.0092	1.0	1.420	0.555	15

C. SURVEY QUESTIONNAIRES AND ADDITIONAL RESULTS

C. 1. Questionnaires Developed in Canada

The customer survey questionnaires were developed in Canada prior to conducting survey in Nepal. Customer survey questionnaires developed by others were thoroughly investigated. The questionnaires developed by the Power System Research Group of the University of Saskatchewan found to be the most suitable and were used in the survey. Modifications were incorporated to suit the prevailing situations in a developing country. Further modifications to be incorporated in the questionnaires were anticipated after the pre-test survey in Nepal. The developed questionnaires are presented in this appendix.

C. 2. Questionnaires Developed in Nepal

The survey questionnaires developed in Canada were used in the pre-test survey conducted in Nepal. The questionnaires were modified to address the difficulties encountered in the pre-test survey. The questionnaires developed in Canada were discussed, revised and translated into the local language. The finalized questionnaires used in the detailed survey conducted throughout the country are also presented in this appendix.

C. 3. Additional Survey Results

The additional survey results obtained in the research work are presented in this appendix. Most results presented are obtained from opinion type questions incorporated in the questionnaires and are shown in the form of a bar chart.

C. 1. Questionnaires Developed in Canada

CUSTOMER SURVEY
NEPAL ELECTRIC POWER SYSTEM

WHAT IS THE EFFECT OF ELECTRIC POWER INTERRUPTIONS ON RESIDENTIAL CUSTOMERS IN NEPAL?

This Survey is being conducted to understand the impact of electric power interruptions on residential users. The objective is to assess the service reliability worth in the Nepal Electric Power System. Please answer carefully. Your contribution in this study will help ensure an economic and reliable power supply in Nepal.

This research is funded by the Canadian International Development Agency (CIDA) and the Institute of Engineering (IOE), Nepal.
The study is being conducted by:

THE POWER SYSTEMS RESEARCH GROUP
DEPARTMENT OF ELECTRICAL ENGINEERING
UNIVERSITY OF SASKATCHEWAN
SASKATOON, CANADA, S7N 0W0

When the term POWER FAILURE is used in this survey booklet, it means a complete interruption of electricity for a period lasting a few seconds, minutes, hours, or even days. In your answers, please consider the needs of all members of your household.

Q.1 What is your opinion on the following matters? (Check the answer which best describes your opinion for each of the following.)

1. In general, the service provided by my electric power company is...

   ☐ very good ☐ good ☐ fair ☐ poor ☐ very poor

2. Compared with other public services and commodities, the price of electricity is..

   ☐ very low ☐ low ☐ moderate ☐ high ☐ very high

3. The number of electrical power failures to my home is...

   ☐ very low ☐ low ☐ moderate ☐ high ☐ very high

Q.2

1. As well as you can remember, how many times has your household experienced a power failure in the last two months? _____
2. How many of these failures caused a problem or were disruptive? _____
3. How many of these failures lasted for four hours or more? _____

The following information concerns your usage of electricity.

Q.3 What is the maximum demand of electricity of your home?

_____Amperes _____KW

Q.4 What is the average electrical energy consumption per month of your home?

_____KWh

Q.5(a) This question asks you to rate the undesirable effects of a power failure, in general. Suppose a power failure lasting 1 to 4 hours occurred. How undesirable would this be for you and your household?

> A scale of 1 to 6 is used to indicate various degrees of undesirability from 1 meaning "NO UNDESIRABLE EFFECT" to 6 being "EXTREMELY UNDESIRABLE". For example, if you felt there was a *low to moderate* undesirable effect, you would circle "2 or 3"; or if you felt there was a *moderate to high* undesirable effect, you would circle "4 or 5". If a specific item in the left hand column does not apply to your home please circle "NA".

Circle the number which indicates your rating

How much would your household be affected by the following?	NO UNDESIRABLE EFFECT				EXTREMELY UNDESIRABLE EFFECT		NOT APPLICABLE
1. Loss of lighting	1	2	3	4	5	6	NA
2. Kitchen appliances not usable	1	2	3	4	5	6	NA
3. Washing or cleaning appliances not usable	1	2	3	4	5	6	NA
4. Discomfort due to heating or ventilating equipment not usable (e.g. heaters, fans etc.)	1	2	3	4	5	6	NA
5. Leisure equipment not usable (e.g. TV, VCR, stereo, etc.)	1	2	3	4	5	6	NA
6. Loss of use, or damage to equipment that is particularly sensitive to power failures (e.g. computers, digital clocks)	1	2	3	4	5	6	NA
7. Water supply system not working	1	2	3	4	5	6	NA
8. Fear of accidents in home (e.g. due to inadequate lighting)	1	2	3	4	5	6	NA
9. Fear of crime (e.g. due to street or outdoor lightings not working)	1	2	3	4	5	6	NA

(b) Are there any other effects which would be especially undesirable for you or your household?

☐ Yes ☐ No

If "Yes" please explain: _____

Q.6 The undesirable effects of power failures may depend on the duration of the failure and the time of day and season when the failure occurs. This question asks you to rate how undesirable each of the following situations would be for your household. For each question, assume that you did not know prior to the failure when it would occur or how long it would last. A four hour, weekly failure after 5 pm on winter weekdays is considered as a reference case to assist you in comparing the effects in other cases, and is repeated in each part below.

Circle the number which indicates your rating

(a)	How undesirable would you rate a four hour failure after 5:00 pm on weekdays in winter if such a failure occurred	NO UNDESIRABLE EFFECT					EXTREMELY UNDESIRABLE EFFECT
	1. once a month	1	2	3	4	5	6
	2. once a week (reference case)	1	2	3	4	5	6
	3. twice a week	1	2	3	4	5	6
	4. daily	1	2	3	4	5	6
(b)	How undesirable would you rate a four hour weekly failure after 5:00 pm on weekdays...	NO UNDESIRABLE EFFECT					EXTREMELY UNDESIRABLE EFFECT
	1. in winter (reference case)	1	2	3	4	5	6
	2. in summer	1	2	3	4	5	6
	3. in monsoon	1	2	3	4	5	6
	4. in festival season	1	2	3	4	5	6
(c)	How undesirable would you rate a four hour weekly failure in winter, if such a failure occurred...	NO UNDESIRABLE EFFECT					EXTREMELY UNDESIRABLE EFFECT
	1. on weekdays after 5:00 pm(reference case)	1	2	3	4	5	6
	2. on Saturday after 5:00 pm	1	2	3	4	5	6
	3. on Saturday before 5:00 pm	1	2	3	4	5	6
(d)	How undesirable would you rate a weekly failure on weekdays in winter, if such a failure occurred *after 5:00 pm and lasted...*	N O UNDESIRABLE EFFECT					EXTREMELY UNDESIRABLE EFFECT
	1. four hours (reference case)	1	2	3	4	5	6
	2. one hour	1	2	3	4	5	6
	3. 20 minutes	1	2	3	4	5	6
	before 5:00 pm and lasted...						
	1. four hours	1	2	3	4	5	6
	2. one hour	1	2	3	4	5	6
	3. 20 minutes	1	2	3	4	5	6

The following value related questions are the most important questions in the survey.

Q.7 Suppose you have been told by your power company that more frequent power failures can be expected, but the exact days or times are not known. Possible actions which your household might take to lessen the effects of the failures are listed in the box below.
Assume that your household does not already have any of the emergency equipment listed in the box. Also assume that the equipment is readily available for rent or purchase and that connecting it or using it is not a problem.

LIST OF POSSIBLE ACTIONS

1. Make no preparations and put up with the failures.
2. Use candles which costs Rs.2 per hour and provides minimal lighting.
3. Use lanterns which costs Rs.5 per hour to rent and operate, and provides better lighting.
4. Use kerosene stoves or equivalent which costs Rs.10 per hour to rent and operate, to provide some heating and cooking.
5. Use a portable electric generator which costs Rs.50 per hour to rent and operate. It can handle light loads such as lighting, small appliances, some cooking, TV, etc.
6. Use an emergency electric generator which can handle the full house load and costs Rs.200 per hour to rent and operate.

Use one or more of the action choices from the box above to answer each part of the following. Circle the numbers corresponding to your choices.

(a) Which actions would you take if failures occur daily, on winter weekdays after 5:00 pm and last...

20 minutes [Circle one or more].....	1	2	3	4	5	6
1 hour [Circle one or more].....	1	2	3	4	5	6
4 hours [Circle one or more].....	1	2	3	4	5	6

(b) Which actions would you take if failures occur once a week, on winter weekdays after 5:00 pm and last...

20 minutes [Circle one or more].....	1	2	3	4	5	6
1 hour [Circle one or more].....	1	2	3	4	5	6
4 hours [Circle one or more].....	1	2	3	4	5	6

(c) Which actions would you take if failures occur once a month on winter weekdays and last...

8 hours [Circle one or more].....	1	2	3	4	5	6
24 hours [Circle one or more].....	1	2	3	4	5	6
48 hours [Circle one or more].....	1	2	3	4	5	6

(d) Changing now to summer failures on weekdays, which actions would you take if...

4 hour failures after 5:00 pm occur **daily**	1	2	3	4	5	6
4 hour failures after 5:00 pm occur **once a week**	1	2	3	4	5	6
8 hour failures occur **once a month**	1	2	3	4	5	6
24 hour failures occur **once a month**.....	1	2	3	4	5	6

A note of explanation is important for the following question. There is a limit to the amount of electricity that your power company can produce, due to the limitations of its equipment. The total amount of electricity that all the customers require at any instant must never be allowed to exceed this limit.

Q.8 Suppose that the total requirement of electricity of all customers was nearing the power company's maximum capacity. In order to ensure that the customers requirement does not rise above the company's maximum capacity, two options are possible. One is that all electricity users are asked to reduce the amount of electricity they are using for a period of time. The other is that some of the users will experience a temporary outage. If, at 5 pm (late afternoon) on a winter weekday, the utility asked its customers to reduce their electrical consumption for a period of 2 to 4 hours:

(a) Would your household be willing to reduce its electrical consumption?

- ☐ Yes
- ☐ No

(b) Regardless of your answer to part (a) above, would your household be able to reduce its consumption by the following amounts...

	YES	NO	
less than 5% reduction	☐	☐	**PLEASE ANSWER**
5% - 10% reduction	☐	☐	**EACH LINE OF**
10% - 15% reduction	☐	☐	**THE QUESTION**
15% - 20% reduction	☐	☐	**EITHER**
more than 20% reduction	☐	☐	**YES OR NO**

The next four questions concern your opinion about the tradeoff between the cost of electricity and power failures. Suppose that failures occur without warning **any time during the daytime or evening**.

Q.9 Suppose that during a typical power failure, another independently supplied source of electricity was immediately available for your use. To access this source, all you had to do was to deposit money in a conveniently located meter that had been previously installed in your residence at no cost to you. How much would you be willing to pay for each 30 minutes of electricity?

Would you be willing to pay....	YES	NO	
Rs.2 for each half hour	☐	☐	**PLEASE ANSWER**
Rs.5 for each half hour	☐	☐	**EACH LINE OF**
Rs.10 for each half hour	☐	☐	**THE QUESTION**
Rs.15 for each half hour	☐	☐	**EITHER**
Rs.25 or more for each half hour	☐	☐	**YES OR NO**

Q.10 To establish a baseline, what is the approximate average monthly cost of electricity for your household?

☐ Rs.100 or less ☐ Rs.100-300 ☐ Rs.300-500 ☐ Rs.500-1000

☐ Rs.1000-2000 ☐ more than Rs.2000.

Q.11 Suppose that the existing electric system has become subject to more frequent power failures. Also suppose that an alternative system has become available which would provide an assured electric power supply without any failures. You are able to choose between the two systems.

(a) If a **four** hour failure occurred **monthly** on the existing system, would you choose the assured system if it cost....

	YES	NO	
Rs.25 a month higher than the existing system	☐	☐	**PLEASE ANSWER**
Rs.50 a month higher than the existing system	☐	☐	**EACH LINE OF**
Rs.100 a month higher than the existing system	☐	☐	**THE QUESTION**
Rs.200 a month higher than the existing system	☐	☐	**EITHER**
Rs.500 a month higher than the existing system	☐	☐	**YES OR NO**

(b) If a **four** hour failure occurred **weekly** on the existing system, would you choose the assured system if it cost.....

	YES	NO	
Rs.25 a month higher than the existing system	☐	☐	**PLEASE ANSWER**
Rs.50 a month higher than the existing system	☐	☐	**EACH LINE OF**
Rs.100 a month higher than the existing system	☐	☐	**THE QUESTION**
Rs.200 a month higher than the existing system	☐	☐	**EITHER**
Rs.500 a month higher than the existing system	☐	☐	**YES OR NO**

(c) If a **four** hour failure occurred **daily** on the existing system, would you choose the assured system if it cost.....

	YES	NO	
Rs.25 a month higher than the existing system	☐	☐	**PLEASE ANSWER**
Rs.50 a month higher than the existing system	☐	☐	**EACH LINE OF**
Rs.100 a month higher than the existing system	☐	☐	**THE QUESTION**
Rs.200 a month higher than the existing system	☐	☐	**EITHER**
Rs.500 a month higher than the existing system	☐	☐	**YES OR NO**

Q.12 Suppose you were offered the option of a cut in rates along with an increase in the number of failures. Suppose that your present supply situation is four hour failure occurring once a month.
(a) If a four hour failure occurred **once a week**, would you be satisfied with....

	YES	NO	
2% decrease in rates	☐	☐	**PLEASE ANSWER**
5% decrease in rates	☐	☐	**EACH LINE OF**
10% decrease in rates	☐	☐	**THE QUESTION**
20% decrease in rates	☐	☐	**EITHER**
50% decrease in rates	☐	☐	**YES OR NO**

(b) If a four hour failure occurred **daily**, would you be satisfied with....

	YES	NO	
2% decrease in rates	☐	☐	**PLEASE ANSWER**
5% decrease in rates	☐	☐	**EACH LINE OF**
10% decrease in rates	☐	☐	**THE QUESTION**
20% decrease in rates	☐	☐	**EITHER**
50% decrease in rates	☐	☐	**YES OR NO**

Q.13 Are there any other comments you would like to make about the effects of electric power failures, or the course of action your power company should follow regarding reliability of electric service in Nepal? If so, please use this space for that purpose.

Thank you for taking time
to complete this survey

Your Name and Address:

A note about confidentiality. No one but the researchers will ever see this booklet. Your answers to the questions will not be released to your power company or to any one else. Only summary and average results will be published.

CUSTOMER SURVEY
NEPAL ELECTRIC POWER SYSTEM

WHAT IS THE EFFECT OF ELECTRIC POWER INTERRUPTIONS ON THE COMMERCIAL TRADES AND SERVICES IN NEPAL?

This Survey is being conducted to understand the impact of electric power interruptions on business community. The objective is to assess the service reliability worth in the Nepal Electric Power System. Please answer carefully. Your contribution in this study will help ensure an economic and reliable power supply in Nepal.

This research is funded by the Canadian International Development Agency (CIDA) and the Institute of Engineering (IOE), Nepal.
The study is being conducted by:

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DEPARTMENT OF ELECTRICAL ENGINEERING
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SASKATOON, CANADA, S7N 0W0

Q.1(a) How many times has your operation experienced an interruption in your electrical supply in the last two months? (Do not include those caused by your company's equipment). _____

(b) How many of these interruptions lasted for 4 hours or more? _____

Q.2 Below are listed various types of electrical equipment that are usually used by business companies, or organizations. For each type listed, please check the box that best describes how important it is to your company.

TYPES OF ELECTRICAL EQUIPMENT	Do Not Have in Company	Not at All Important	Not Very Important	Quite Important	Very Important
Air Conditioning	☐	☐	☐	☐	☐
Electric Space Heating	☐	☐	☐	☐	☐
Electric Hot Water Heating	☐	☐	☐	☐	☐
Ventilation Equipment	☐	☐	☐	☐	☐
Office Equipment (typewriters, calculators, photocopiers, etc.)	☐	☐	☐	☐	☐
Electric Cash Registers	☐	☐	☐	☐	☐
Computers	☐	☐	☐	☐	☐
Telecommunications Equipment	☐	☐	☐	☐	☐
Electric Cooking Equipment	☐	☐	☐	☐	☐
Motors other than Pumps	☐	☐	☐	☐	☐
Pumps	☐	☐	☐	☐	☐
Refrigeration and Freezing	☐	☐	☐	☐	☐
Elevators	☐	☐	☐	☐	☐
Indoor Lighting	☐	☐	☐	☐	☐
Outdoor Lighting	☐	☐	☐	☐	☐
Other Equipment used in your business (please specify)					
_____	☐	☐	☐	☐	☐

Q.3 What emergency standby electrical supply equipment does your company have? What type(s) of electrical equipment does each emergency source serve?

Type of Back-up	Identify Types of Electrical Equipment That Back-up Source Serves	How long will it carry its intended load
☐ Battery System		hours
☐ Engine Generator		hours
☐ Turbine		hours
☐ Other (please specify) _____		hours
☐ None (if "None" please go to Q.4)		

Q.4 (a) Could an electrical interruption result in any health or safety hazard to your staff or the public?

☐ Greatly ☐ Moderately ☐ Slightly ☐ Not at all (if "Not at all" go to Q.5)

(b) What is the shortest warning time, before an electrical interruption, that your company needs to reduce the risk of harm to customers or staff?

☐ 20 minutes	☐ 8 hours	☐ Other _____
☐ 1 hour	☐ 1 day (24 hours)	(please specify the shortest warning time)
☐ 4 hours	☐ More than one day	

This section is the most important part of the questionnaire.
It asks for information about the losses resulting from power interruptions during the worst possible time for your company.

Q.5 This question establishes your company's worst possible time for an interruption to occur.

WORST MONTH:

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Check one or more months:	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐

or ☐ All months the same

WORST DAY OF THE WEEK:

	Sun	Mon	Tue	Wed	Thu	Fri	Sat
Check one or more days:	☐	☐	☐	☐	☐	☐	☐

or ☐ All seven days of the week the same

or ☐ All weekdays the same (excluding Sat)

or ☐ Worst day is irregular (indefinite or non-seven-day cycle)

WORST TIME OF THE DAY:

	early morning 6 - 9 am	fore-noon 9 -12 am	noon hour 12 -1 pm	after-noon 1 - 5 pm	evening 5 - 9 pm	late evening 9 - 12 pm	overnight 12 - 6 am
Check one or more times:	☐	☐	☐	☐	☐	☐	☐

or ☐ All times of the day and night the same

or ☐ All working hours the same [Working hours are from _____

or ☐ Worst time of day is irregular (indefinite or non-24-hour cycle)

You have now established the WORST TIME for an interruption to occur to your company. This will be used as a reference (basis for comparison) in questions Q.6 & Q.7.

Q.6 Suppose that a power interruption occurred, without warning, at the WORST TIME (worst time of day, worst day of week and worst month) you have just identified in Q.5. What costs or losses attributable to the power interruption would occur in your company or business, if the interruption lasts for each of the durations mentioned in the table below?

In the cost estimate please include wages paid to staff unable to work, loss of sales, start-up costs, spoilage of food, and damage to equipment or supplies. If sales are made up later , do not include that portion of loss in the lost sales category. Any overtime cost for clean-up, repair or recovery should be estimated separately. Other costs such as operating back-up equipment and cost of special procedures required to limit damages should be included as well.

If you own a back-up power supply and if this supply is normally in operation during an interruption, then please estimate the interruption losses with the assumption that your back-up supply is utilized to the fullest extent possible during the interruption.

In the table below, please estimate the interruption costs (in Rs.) for a power interruption taking place during the WORST TIME and for each of the interruption durations mentioned. Estimate the general situation that would develop at your place of business over the time span of each interruption. Then, estimate costs occurring for each "possible effect" mentioned in the table below for each interruption duration.

NOTE: The table is provided for your convenience. Should you have difficulty in classifying the losses for your particular situation, you may fill in only the "**TOTAL OF ALL ABOVE**" boxes in the bottom row.

		Duration of Electrical Interruption							
	Possible Effect on Your business	2 seconds	1 minute	20 minutes	1 hour	2 hours	4 hours	8 hours	1 day
	Wages paid to idle workers								
	Loss of sales								
R	Overtime costs								
U	Damage to equipment or supplies								
P	Start-up costs								
E	Spoilage of perishable materials								
	Back-up supply and other special procedures costs to limit damages								
E	Other costs (identify) _____								
S	**TOTAL OF ALL ABOVE**								

Q.7 The purpose of this question is to determine the monthly, weekly and daily variations of the cost of an interruption as compared to the WORST TIME you specified in Q.5. If you think the categories are not adequate, please use the column marked "Other estimate."

(a) If a one hour power interruption occurs during a month other than your worst month, what would be your estimate of the cost for each month as compared to the cost in the worst month you have identified in Q.5? [If you had selected "All months the same" in Q.5 then go to Q.7 (b).]

MONTHLY VARIATION OF INTERRUPTION COST

	Cost Compared to Worst Month							
Month	**Same as worst month**	**10% Less**	**25% Less**	**50% Less**	**75% Less**	**Negligible**	**Other Estimate**	
January	☐	☐	☐	☐	☐	☐	__% Less	
February	☐	☐	☐	☐	☐	☐	__% Less	
March	☐	☐	☐	☐	☐	☐	__% Less	**Check**
April	☐	☐	☐	☐	☐	☐	__% Less	**one**
May	☐	☐	☐	☐	☐	☐	__% Less	**box**
June	☐	☐	☐	☐	☐	☐	__% Less	**for**
July	☐	☐	☐	☐	☐	☐	__% Less	**each**
August	☐	☐	☐	☐	☐	☐	__% Less	**calendar**
September	☐	☐	☐	☐	☐	☐	__% Less	**month**
October	☐	☐	☐	☐	☐	☐	__% Less	
November	☐	☐	☐	☐	☐	☐	__% Less	
December	☐	☐	☐	☐	☐	☐	__% Less	

(b) If a one hour power interruption occurs during a typical week but on a different day than was chosen as your worst day, what would be your estimate of the cost compared to the cost of the worst day that you identified in Q.5? [If you had selected "worst day is irregular" in Q.5 then use Friday as your worst day for this question. If you had selected "All seven days of the week the same" then go to Q.7 (c).]

WEEKLY VARIATION OF INTERRUPTION COST

	Cost Compared to Worst Day of Week							
DAY OF WEEK	**Same as worst day**	**10% Less**	**25% Less**	**50% Less**	**75% Less**	**Negligible**	**Other Estimate**	
Sunday	☐	☐	☐	☐	☐	☐	__% Less	
Monday	☐	☐	☐	☐	☐	☐	__% Less	**Check**
Tuesday	☐	☐	☐	☐	☐	☐	__% Less	**one**
Wednesday	☐	☐	☐	☐	☐	☐	__% Less	**box**
Thursday	☐	☐	☐	☐	☐	☐	__% Less	**for**
Friday	☐	☐	☐	☐	☐	☐	__% Less	**each**
Saturday	☐	☐	☐	☐	☐	☐	__% Less	**day**

(c) If a one hour power interruption occurs during a typical day but at a different time than your worst time of day, what would be your estimate of the cost compared to the cost of the worst time of day you identified in Q.5? [If you had selected "worst time of day is irregular" then use "1 - 5 pm" as your worst time of day for this question. If you had selected "All working hours the same" in Q.5 then go to Q.8.]

DAILY VARIATION OF INTERRUPTION COST

	Cost Compared to Worst Time of Day							
TIME OF DAY	**Same as worst time**	**10% Less**	**25% Less**	**50% Less**	**75% Less**	**Negligible**	**Other Estimate**	
Early Morning (6 - 9 am)	☐	☐	☐	☐	☐	☐	__% Less	**Check**
Forenoon (9 - 12 am)	☐	☐	☐	☐	☐	☐	__% Less	**one**
Noon Hour (12 - 1 pm)	☐	☐	☐	☐	☐	☐	__% Less	**box**
Afternoon (1 - 5 pm)	☐	☐	☐	☐	☐	☐	__% Less	**for**
Evening (5 - 9 pm)	☐	☐	☐	☐	☐	☐	__% Less	**each**
Late Evening (9 - 12 pm)	☐	☐	☐	☐	☐	☐	__% Less	**time**
Overnight (12 - 6 am)	☐	☐	☐	☐	☐	☐	__% Less	**period**

The following question asks about possible ways of reducing interruption costs. Do not consider it a reduction in interruption costs if you are transferring the cost to either employees or customers. (e.g. reducing the paid hours to employees if the employees will not be given an opportunity to make up the time.)

Q.8 Is it possible for your company to make arrangements to reduce the cost associated with interruptions in the following situations?

(a) Would an advance warning about a short-term interruption reduce your interruption costs?

☐ Yes ☐ No [if "No please go to Q.9]

Compared with the worst-case one hour NO WARNING scenario that you have identified in Q.6, estimate by what percentage you would be able to reduce the interruption costs for different amounts of advanced warning time received prior to interruption?

	Advanced Warning Time					
	Less than 1 hour	1 to 4 hours	5 to 16 hours	17 to 24 hours	1 day to 2 days	3 days or longer
Reduction of cost from the NO WARNING total cost you calculated in Q.6	%	%	%	%	%	%
	Indicate cost reductions for each warning time					

(b) If information about the expected duration of a short-term interruption was provided just after the interruption has started, would you be able to reduce your interruption costs?

☐ Yes ☐ No [if "No please go to Q.9]

Compared with the worst-case NO WARNING scenario that you have identified in Q.6, If you were informed at the start of an interruption as to how long the interruption would last, by what percentage would you be able to reduce interruption costs?

	Interruption Duration					
	1 minute	20 minutes	1 hour	4 hours	8 hours	1 day
Reduction of cost from the NO WARNING total cost you calculated in Q.6	%	%	%	%	%	%
	Indicate cost reductions for each interruption duration					

Q.9 Does your company have equipment which is particularly sensitive to frequency and voltage deviations from the nominal values?

Sensitivity to:	Yes	No	Unsure	Identify Sensitive Equipment
Frequency Deviations	☐	☐	☐	_____
Voltage Deviations	☐	☐	☐	_____

Please check one per line

This section of the questionnaire asks a few questions concerning your company in order that the results can be categorized by company characteristics.

Q.10 Approximately how much commercial space does your company occupy at this location?

☐ Less than 70 square meters (750 square feet)
☐ 70 - 185 square meters (750 - 2000 square feet)
☐ More than 185 square meters (2000 square feet)

Q.11 Approximately, what is your maximum demand of electricity?
_____KW _____KVA

Q.12 What is your average electrical energy consumption per month?
_____KWh

Q.13 What is your approximate average number of full time and part time employees during the last twelve months? (including managers and working owners)

Full time _____ Part time _____

Q.14 Is your outlet located in an enclosed shopping mall?
☐ Yes ☐ No

Q.15 (a) Please check the box which <u>best</u> describes your business:

☐ Food Stores
☐ Liquor, Wine & Beer Stores
☐ Prescription Drug Stores
☐ Shoe Stores
☐ Clothing Stores
☐ Furniture Stores
☐ Television & Stereo Stores
☐ Furnishing Stores
☐ Automobile Dealers
☐ Gasoline Service Stations
☐ Automotive Parts & Accessories
☐ Motor Vehicle Repair Shops
☐ General Merchandise Stores
☐ Book and Stationary Stores
☐ Hardware Stores
☐ Jewelry Stores
☐ Electrical and Electronic Stores
☐ Other Retail Stores_____
☐ Camera and Photographic Services
☐ Hotels, Motels & Tourist Centers
☐ Recreation & Vacation Centers
☐ Restaurants
☐ Bars and Night Clubs
☐ Barber and Beauty Shops
☐ Laundries and Cleaners
☐ Film, Audio & Video Production
☐ Sports & Health Clubs
☐ Other Commercial Trades & Services

_____
(Please specify)

(b) What are the main products that your business sells or services?

_____

Q.16 Are there any other comments you would like to make about the effects of electric power failures, or the course of action your power company should follow regarding reliability of electric service in Nepal? If so, please use this space for that purpose.

Thank you for taking time
to complete this survey

Name and Address of Your Business:

A note about confidentiality. No one but the researchers will ever see this booklet. Your answers to the questions will not be released to your power company or to any one else. Only summary and average results will be published.

CUSTOMER SURVEY
NEPAL ELECTRIC POWER SYSTEM

WHAT IS THE EFFECT OF ELECTRIC POWER INTERRUPTIONS ON INDUSTRIAL COMPANIES IN NEPAL?

This Survey is being conducted to understand the impact of electric power interruptions on industrial community. The objective is to assess the service reliability worth in the Nepal Electric Power System. Please answer carefully. Your contribution in this study will help ensure an economic and reliable power supply in Nepal.

This research is funded by the Canadian International Development Agency (CIDA) and the Institute of Engineering (IOE), Nepal.
The study is being conducted by:

THE POWER SYSTEMS RESEARCH GROUP
DEPARTMENT OF ELECTRICAL ENGINEERING
UNIVERSITY OF SASKATCHEWAN
SASKATOON, CANADA, S7N 0W0

Q.1 (a) How many times has your operation experienced an interruption in electrical supply in the last two months? (Do not include those caused by your company's equipment). _____

(b) How many of these interruptions lasted for 4 hours or more? _____

Q.2 Various uses of electricity are listed below. For each use listed, please check the box that best describes how important it is to your company.

USES OF ELECTRICITY	Not Applicable	Not at all important	Not very important	Important	Very Important
Building Services (e.g. lighting, space heating, air conditioning, ventilation...)	☐	☐	☐	☐	☐
Production Process	☐	☐	☐	☐	☐
Refrigeration and Freezing	☐	☐	☐	☐	☐
Electronic Systems (e.g.computer, communication and control systems)	☐	☐	☐	☐	☐
Misc. Auxiliary Systems	☐	☐	☐	☐	☐
Other Use (please specify) _____	☐	☐	☐	☐	☐

Q.3 (a) What emergency standby electrical supply equipment does your company have?

TYPE OF BACK-UP	Size	Units	How long will it carry its intended load	Time required to bring it on-line	Equipment the back-up serves
☐ Battery System		☐ kWh ☐ hp	hours	minutes	
☐ Engine Generator		☐ kWh ☐ hp	hours	minutes	
☐ Turbine		☐ kWh ☐ hp	hours	minutes	
☐ Other (please specify) _____		☐ kWh ☐ hp	hours	minutes	

☐ None (please go to Q.4)

(b) During a power interruption, does your back-up system acts to:

	Not at all	Partly	Mostly	Not needed
Minimize possible hazard tostaff or the public	☐	☐	☐	☐
Prevent damage to equipment, materials or finished product	☐	☐	☐	☐
Maintain production	☐	☐	☐	☐
Other (please specify) _____	☐	☐	☐	☐

Note: "Not at all" means that your back-up does not provide for this need. "Not needed" means that you do not have back-up for this .

Please check one box per line

Q.4 (a) Could an electrical interruption result in any health or safety hazard to your staff or the public?

☐ Greatly ☐ Moderately ☐ Slightly ☐ Not at all (if "Not at all" go to Q.5)

(b) What is the shortest warning time, before an electrical interruption, that your company needs to reduce the risk of harm to customers or staff?

☐ 20 minutes ☐ 8 hours ☐ Other _____
☐ 1 hour ☐ 1 day (24 hours) (please estimate the shortest warning time required)
☐ 4 hours ☐ More than one day

Q.5 Is the nature of your operation such that lost production can be made up once power is restored (or on days following the interruption) without overtime or extra staff? To what extent can you make up lost production that has resulted from interruptions having the following durations: (check box)

The extent to which lost production can be made up:

	Not at All	Partly	Mostly	Make up Not Needed
1 minute	☐	☐	☐	☐
20 minutes	☐	☐	☐	☐
1 hour	☐	☐	☐	☐
4 hours	☐	☐	☐	☐
8 hours	☐	☐	☐	☐

Please check one box per line

This section is the most important part of the questionnaire.It asks for information about the losses resulting from power interruptions during the worst possible time for your company.

Q.6 This question establishes your company's worst possible time for a power interruption to occur.

WORST MONTH:

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Check one or more months:	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐

or ☐ All months the same

WORST DAY OF THE WEEK:

	Sun	Mon	Tue	Wed	Thu	Fri	Sat
Check one or more days:	☐	☐	☐	☐	☐	☐	☐

or ☐ All seven days of the week the same
or ☐ All weekdays the same (excluding Sat)
or ☐ Worst day is irregular (indefinite or non-seven-day cycle)

WORST TIME OF THE DAY:

	early morning 6 - 9 am	fore-noon 9 - 12 am	noon hour 12 - 1 pm	after-noon 1 - 5 pm	early evening 5 - 9 pm	late evening 9 - 12 pm	overnight 12 - 6 am
Check one or more times:	☐	☐	☐	☐	☐	☐	☐

or ☐ All times of the day and night the same

or ☐ All working hours the same [Working hours are from_____]

or ☐ Worst time of day is irregular (indefinite or non-24-hour manufacturing cycle)

You have now established your company's WORST TIME for a power interruption to occur. This will be used as a basis for comparison in questions Q.7 & Q.8.

Q.7 Suppose that a power interruption occurred, without warning, at the WORST TIME (worst time of day,worst day of week and worst month) you have just identified. What is the loss to your company and how long does it take to restart production for each interruption duration?

In the cost estimate please include plant equipment damage, raw material and finished product spoilage or damage and the cost of special procedures to restart production (i.e. extra clean-up, maintenance check-ups, etc.). Production loss during the interruption and re-start time should be calculated as the estimated foregone profit: selling price of product not made less expenses saved in labor, materials, utilities, etc. If production is made up later during a slow period or overtime, do not include that portion of loss in the lost production category. Such overtime cost should be estimated separately. Other costs such as operating back-up equipment and cost of special procedures required to limit damages should be included as well.

If you own a back-up power supply and if this supply is normally in operation during an interruption, then please estimate the interruption losses with the assumption that your back-up supply is utilized to the fullest extent possible during the interruption.

If your company not a manufacturer, "Production loss" should be redefined to "Value of service lost" or some similar measure related to the function of the operation of your organization.

In the table below, please estimate re-start times (in hours) and interruption costs (in Rs.) for a power interruption taking place during the WORST TIME you identified in Q.6 and for each of the interruption durations mentioned. Estimate the general situation that would develop in your place of work over the time span of each interruption duration. Then, estimate the cost occurring for each "possible effect"mentioned in the table below.

NOTE: The table is provided mainly for your convenience. Should you have difficulty classifying the losses for your particular situation, you may fill in only the "**TOTAL OF ALL ABOVE**" boxes in the bottom row.

		DURATION OF ELECTRICAL INTERRUPTION							
	POSSIBLE EFFECT ON YOUR OPERATION	2 seconds	1 minute	20 minutes	1 hour	2 hours	4 hours	8 hours	1 day
	Time to restart production once power is restored (in hours)								
	Production loss (during interruption and restart time)								
R	Overtime cost to make-up lost production								
U	Damage to raw material or finished product								
P	Damage to plant equipment (include freeze-up)								
E	Start-up cost (extra clean up or maintenance)								
E	Back-up supply and other special procedures cost to limit damages								
S	Other costs (identify) _____								
	TOTAL OF ALL ABOVE								

Q.8 The purpose of this question is to determine the monthly, weekly and daily variations of the cost of an interruption as compared to the WORST TIME you specified in Q.6. If you think the categories are not adequate, please use the column marked "Other estimate."

(a) If a one hour power interruption occurs during a month other than your worst month, what would be your estimate of the cost for each month as compared to the cost in the worst month you identified in Q.6? [If you had selected "All months the same" in Q.6 then go to Q.8 (b).]

MONTHLY VARIATION OF INTERRUPTION COST

	Cost Compared to Worst Month							
Month	**Same as worst month**	**10% Less**	**25% Less**	**50% Less**	**75% Less**	**Negligible**	**Other Estimate**	
January	☐	☐	☐	☐	☐	☐	__ % Less	
February	☐	☐	☐	☐	☐	☐	__ % Less	**Check**
March	☐	☐	☐	☐	☐	☐	__ % Less	
April	☐	☐	☐	☐	☐	☐	__ % Less	**one**
May	☐	☐	☐	☐	☐	☐	__ % Less	
June	☐	☐	☐	☐	☐	☐	__ % Less	**box**
July	☐	☐	☐	☐	☐	☐	__ % Less	
August	☐	☐	☐	☐	☐	☐	__ % Less	**for**
September	☐	☐	☐	☐	☐	☐	__ % Less	
October	☐	☐	☐	☐	☐	☐	__ % Less	**each**
November	☐	☐	☐	☐	☐	☐	__ % Less	
December	☐	☐	☐	☐	☐	☐	__ % Less	**month**

(b) If a one hour power interruption occurs during a typical week but on a different day than was chosen as your worst day, what would be your estimate of the cost compared to the cost of the worst day that you identified in Q.6? [If you had selected "worst day is irregular" in Q.6 then use Friday as your worst day for this question. If you had selected "All seven days of the week the same" then go to Q.8 (c).]

WEEKLY VARIATION OF INTERRUPTION COST

	Cost Compared to Worst Day of Week							
DAY OF WEEK	**Same as worst day**	**10% Less**	**25% Less**	**50% Less**	**75% Less**	**Negligible**	**Other Estimate**	
Sunday	☐	☐	☐	☐	☐	☐	__ % Less	
Monday	☐	☐	☐	☐	☐	☐	__ % Less	**Check**
Tuesday	☐	☐	☐	☐	☐	☐	__ % Less	**one**
Wednesday	☐	☐	☐	☐	☐	☐	__ % Less	**box**
Thursday	☐	☐	☐	☐	☐	☐	__ % Less	**for**
Friday	☐	☐	☐	☐	☐	☐	__ % Less	**each**
Saturday	☐	☐	☐	☐	☐	☐	__ % Less	**day**

(c) If a one hour power interruption occurs during a typical day but at a different time than your worst time of day, what would be your estimate of the cost compared to the cost of the worst time of day identified in Q.6? [If you had selected "worst time of day is irregular" then use "1 - 5 pm" as your worst time of day for this question. If you had selected "All working hours the same" in Q.6 then go to Q.9.]

DAILY VARIATION OF INTERRUPTION COST

TIME OF DAY	Cost Compared to Worst Time of Day: Same as worst time	10% Less	25% Less	50% Less	75% Less	Negligible	Other Estimate	
Early Morning (6 - 9 am)	☐	☐	☐	☐	☐	☐	_ % Less	Check one box for each daily time period
Forenoon (9 - 12 am)	☐	☐	☐	☐	☐	☐	_ % Less	
Noon Hour (12 - 1 pm)	☐	☐	☐	☐	☐	☐	_ % Less	
Afternoon (1 - 5 pm)	☐	☐	☐	☐	☐	☐	_% Less	
Early Evening (5 - 9 pm)	☐	☐	☐	☐	☐	☐	_ % Less	
Late Evening (9 - 12 pm)	☐	☐	☐	☐	☐	☐	_ % Less	
Overnight (12 - 6 am)	☐	☐	☐	☐	☐	☐	_ % Less	

The following question asks about possible ways of reducing interruption costs. Do not consider it a reduction in interruption costs if you are transferring the cost to either employees or customers, (e.g. reducing the paid hours to employees if the employees will not be given an opportunity to make up the time.)

Q.9 Is it possible for your company to make arrangements to reduce the cost associated with interruptions in the following situations?

(a) Would an advance warning about a short-term interruption reduce your interruption costs?

☐ Yes ☐ No [if "No", please go to Q.10]

Compared with the one hour NO WARNING cost that you identified in question Q.7, by what percentage will you be able to reduce that cost for different amounts of advanced warning time prior to the interruption?

	Advanced Warning Time					
	Less than 1 hour	1 to 4 hours	5 to 16 hours	17 to 24 hours	1 to 2 days	3 days or longer
Reduction of cost from the NO WARNING total cost you calculated in Q.7	%	%	%	%	%	%
	Indicate percentage cost reduction for each warning time					

(b) If information about the expected duration of a short-term interruption was provided just after the interruption has started, would you be able to reduce your interruption costs?

☐ Yes ☐ No [if "No please go to Q.10]

If your company was informed at the start of an interruption as to how long the interruption would last, by what percentage could your company reduce its costs?

	Interruption Duration					
	1 minute	20 minutes	1 hour	4 hours	8 hours	1 day
Reduction of cost from the NO WARNING total cost you calculated in Q.7	%	%	%	%	%	%
	Indicate percentage cost reduction for each interruption duration					

Q.10 Does your company have equipment which is particularly sensitive to frequency and voltage deviations from the nominal values?

Sensitivity to:	Yes	No	Unsure	Identify Sensitive Equipment
Frequency Deviations	☐	☐	☐	_____
Voltage Deviations	☐	☐	☐	_____

Please check one per line

This section of the survey form asks a few questions concerning your company in order that the results can be categorized by company characteristics

Q.11 (a) Please check the box which best describes your company.

- ☐ Logging/Forestry Services
- ☐ Dairy Industries
- ☐ Mining Industries
- ☐ Petroleum and Gas
- ☐ Quarry and Sand Pit
- ☐ Cement Factories
- ☐ Sugar Factories
- ☐ Food Industries
- ☐ Beverage Industries
- ☐ Tobacco Products
- ☐ Rubber Products
- ☐ Plastic Products
- ☐ Leather & Allied Products
- ☐ Primary Textile Products
- ☐ Textile Industries
- ☐ Wood/Coal Industries
- ☐ Furniture and Fixtures
- ☐ Paper & Allied Products
- ☐ Printing, & Allied Products
- ☐ Primary Metal Industries
- ☐ Fabricated Metal Products
- ☐ Machinery Industries
- ☐ Transportation Equipment
- ☐ Electrical and Electronics
- ☐ Non-metal Mineral Products
- ☐ Brick Factories
- ☐ Drugs & Herbal Products
- ☐ Other Manufacturing Industries

_____

_____

(please specify)

(b) What are the main products that your company produces?

_____

Q.12 What is the approximate average number of full time and part time people employed at your plant during the last twelve months?

Full time _____ Part time _____

Q.13 How many daily shifts does your plant normally operate?

☐ one ☐ two ☐ three ☐ other _____

Q.14 What is your company's maximum demand of electricity?

_____KW _____KVA

Q.15 What is the monthly average electrical consumption of your company?

_____KWh

Q.16 Are there any other comments you would like to make about the effects of electric power failures, or the course of action your power company should follow regarding reliability of electric service in Nepal? If so, please use this space for that purpose.

Thank you for taking time
to complete this survey

Name and Address of Your Company :

A note about confidentiality. No one but the researchers will ever see this booklet. Your answers to the questions will not be released to your power company or to any one else. Only summary and average results will be published.

C. 2. Questionnaires Developed in Nepal

ग्राहक सर्वेक्षण
नेपाल विद्युत प्रणाली
(विद्युत आपूर्तिमा ह्रास हुनाले घर परिवारमा पर्न जाने असर)

सर्वेक्षक .....
ठाउँ .....
सि.नं. .....

प्र.नं.१ तल दिईएका कुराहरुमा तपाईको विचार कस्तो छ, कृपया बताउनुहोस् ।

(क) विद्युत प्राधिकरणबाट गरिएको सेवा तपाईलाई कस्तो लाग्छ ?

☐ अति उत्तम ☐ उत्तम ☐ ठिकै छ ☐ खराब छ ☐ अति खराब छ

(ख) अरु सार्वजनिक सेवा र सार्वजनिक उपभोग्य वस्तुहरुको दाँजोमा विद्युत सेवाको मूल्य यहाँलाई कस्तो लाग्छ ?

☐ धेरै कम ☐ कम ☐ ठिकै ☐ धेरै ☐ ज्यादै धेरै

(ग) तपाईको घरमा कतिको बत्ति निभ्छ ?

☐ धेरै कम ☐ कम ☐ ठिकै ☐ धेरै ☐ अत्तिनै

प्र.नं.२ (क) जहाँसम्म तपाई सम्झनुहुन्छ गएको दुई महिनामा तपाईको घरमा कतिपटक बत्ति निभ्यो ?

.....

(ख) ति मध्ये कतिपटकले धेरै समस्या वा बाधा पुगायो ? .....

(ग) ति मध्ये चार घण्टा वा त्यो भन्दा बढी समयसम्म जाने गरी कति पटक बत्ति गयो ? .....

प्र.नं.३ तपाईको घरमा जडान गरिएको मिटरको एम्पीयर कति छ होला ।

.....

प्र.नं.४ तपाईको घरमा साधारणतया एक महिनामा कति बिजुली खपत हुन्छ ?

खपत युनिट _____

प्र.नं.५ (क) साधारणतया एक देखि चार घण्टासम्म विद्युत जानाले तपाईलाई के-कस्तो मर्का वा बाधा पुग्न जान्छ ?

सि.नं.	निम्न कुराहरुले तपाईलाई कतिको मर्का पर्छ ?	कुनै मर्का पर्दैन	खास मर्का पर्दैन	ठिकै मर्का पर्दछ	मर्का पर्दछ	धेरै नै मर्का पर्दछ	अतिनै मर्का पर्दछ	उपलब्ध छैन
१.	बत्ति नआउनाले	☐	☐	☐	☐	☐	☐	☐
२.	भान्छा कोठामा सामान प्रयोग गर्न नपाउनाले	☐	☐	☐	☐	☐	☐	☐
३.	लुगा धुने, सफा गर्ने उपकरणहरु चलाउन नपाउनाले	☐	☐	☐	☐	☐	☐	☐
४.	हिटर, पंखा आदि चलाउन नपाउनाले	☐	☐	☐	☐	☐	☐	☐
५.	रेडियो, टि.भी., डेक आदि उपयोग गर्न नपाउनाले	☐	☐	☐	☐	☐	☐	☐
६.	कम्प्यूटर आदि उपयोग गर्न नपाउनाले	☐	☐	☐	☐	☐	☐	☐
७.	पानी पम्प चलाउन नपाउनाले	☐	☐	☐	☐	☐	☐	☐
८.	घरमा बत्ति नहुनाले दुर्घटना हुने संभावनावाट	☐	☐	☐	☐	☐	☐	
९.	वाटोमा बत्ति नहुनाले अपराधको घटना हुने संभावनावाट	☐	☐	☐	☐	☐	☐	

(ख) तपाईको घरमा विद्युत आपूर्ति रोकिनाले अरु खास असर के पर्दछ ?

(१) ☐ छ ☐ छैन

(२) यदि छ भने के के छन् ?

.....

प्र.नं.६ विद्युत जानाले असर पर्ने कुरा विद्युत जाने समय, याम तथा गएको संख्या र अवधीमा भर पर्दछ । निम्न अनुसारले बत्ति जाँदा तपाईलाई कत्तिको मर्का पर्दछ, कृपया भन्नुहोस्:-

(क) निम यामहरुमा साँझ ५ बजेपछि हप्तामा एक पटक चार घण्टासम्म बत्ति जाँदा तपाईलाई कस्तो मर्का पर्दछ ?

	कुनै मर्का पर्दैन	खास मर्का पर्दैन	ठिकै मर्का पर्दछ	मर्का पर्दछ	धेरै नै मर्का पर्दछ	अतिनै मर्का पर्दछ
(अ) जाडो याममा	—	—	—	—	—	—
(आ) गर्मीको याममा	—	—	—	—	—	—
(इ) चाडपर्वको याममा	—	—	—	—	—	—

(ख) जाडोयाममा साँझ ५ बजेपछि चारघण्टासम्म निम्न अनुसारले बत्ति जाँदा तपाईलाई कस्तो असर पर्दछ ?

	कुनै मर्का पर्दैन	खास मर्का पर्दैन	ठिकै मर्का पर्दछ	मर्का पर्दछ	धेरै नै मर्का पर्दछ	अतिनै मर्का पर्दछ
(अ) महिनामा एक पटक	—	—	—	—	—	—
(आ) हप्तामा एक पटक	—	—	—	—	—	—
(इ) हप्तामा दुई पटक	—	—	—	—	—	—
(ई) दिन दिनै	—	—	—	—	—	—

(ग)(१) जाडोयाममा हप्तामा एक पटक साँझ ५ बजेपछि निम्न अवधी अनुसारले बत्ति जानाले तपाईलाई कत्तिको मर्का पर्दछ ?

	कुनै मर्का पर्दैन	खास मर्का पर्दैन	ठिकै मर्का पर्दछ	मर्का पर्दछ	धेरै नै मर्का पर्दछ	अतिनै मर्का पर्दछ
(अ) चार घण्टासम्म	—	—	—	—	—	
(आ) एक घण्टासम्म	—	—	—	—	—	
(इ) २० मिनेट सम्म	—	—	—	—	—	

(२) साँझ ५ बजे अगाडी तर सोही अनुसारले हप्तामा एक पटक:-

	कुनै मर्का पर्दैन	खास मर्का पर्दैन	ठिकै मर्का पर्दछ	मर्का पर्दछ	धेरै नै मर्का पर्दछ	अतिनै मर्का पर्दछ
(अ) चार घण्टासम्म	—	—	—	—	—	
(आ) एक घण्टासम्म	—	—	—	—	—	
(इ) २० मिनेट सम्म	—	—	—	—	—	

(घ) जाडोयाममा हप्तामा एक पटक चार घण्टासम्म निम्न दिन तथा समयमा बत्ति जानाले तपाईलाई कत्तिको मर्का पर्दछ ।

	कुनै मर्का पर्दैन	खास मर्का पर्दैन	ठिकै मर्का पर्दछ	मर्का पर्दछ	धेरै नै मर्का पर्दछ	अतिनै मर्का पर्दछ
(अ) साँझ ५ वजे पछि अफिस जाने दिनहरुमा	☐	☐	☐	☐	☐	☐
(आ) साँझ ५ वजे पछि शनिवार वा अन्य विदाको दिन	☐	☐	☐	☐	☐	☐
(इ) साँझ ५ वजे अगाडी शनिवार वा अन्य विदाको दिनमा	☐	☐	☐	☐	☐	☐

प्र.नं.७ यदि विद्युत प्राधिकरणवाट वरावर विद्युत जानसक्ने सूचना गरिएको छ तर समय अवधी र दिन तोकिएको छैन भने तपाईले विद्युत आपूर्तिको लागि निम्न व्यवस्था मध्ये कुन-कुन गर्नुहुन्छ ?

(सम्झनुस कि तल दिईएको साधनहरु मध्ये तपाईको घरमा कुनै पनि छैनन् र यी साधनहरु तपाईले सजिलैसँग भाडामा वा किन्न सक्नु हुन्छ)

संभाव्य व्यवस्थाहरु:

(१) तयारी गर्नु हुन्न र यतिकै वस्नु हुन्छ,

(२) मैनबत्ति प्रयोग गर्नु हुन्छ जसको खर्च घण्टामा रु. २/- पर्दछ,

(३) पेट्रोमेक्स प्रयोग गर्नु हुन्छ जस्को खर्च घण्टामा रु. ५/- पर्दछ

(४) खाना पकाउन र कोठा तताउन मट्टितेलले चल्ने उपकरणहरु प्रयोग गर्नुहुन्छ, जस्को खर्च घण्टामा रु. १०/- पर्दछ,

(५) सानो जेनेरेटर प्रयोग गर्नु हुन्छ जस्ले तपाईलाई बत्ति बाल्न, टि.भी.हेर्न र सानोतिनो सामान चलाउन पुग्छ तर यसको खर्च घण्टामा रु. ५०/- पर्दछ,

(६) ठूलो जेनेरेटर चलाउनु हुन्छ, जस्ले तपाईको घरको पूरा विद्युत आपुर्ती गर्दछ, तर यसको खर्च घण्टामा रु. २००/- पर्दछ ।

(क) जाडोयाममा दिनदिनै साँझ ५ वजेपछि निम्न अनुसार बत्ति गएमा तपाई के गर्नु हुन्छ ?

	केही नगर्ने	मैनबत्ति बाल्ने	पेट्रोमेक्स बाल्ने	स्टोभ बाल्ने	सानो जेनेरेटर प्रयोग गर्ने	ठूलो जेनेरेटर प्रयोग गर्ने
२० मिनेट गएमा	१	२	३	४	५	६
एक घण्टासम्म गएमा	१	२	३	४	५	६
चार घण्टा गएमा	१	२	३	४	५	६

(ख) जाडोयाममा हप्ताको एक पटक साँझ ५ वजेपछि निम्न अनुसार बत्ति गएमा के गर्नुहुन्छ ?

२० मिनेट गएमा	१	२	३	४	५	६
एक घण्टासम्म गएमा	१	२	३	४	५	६
चार घण्टा गएमा	१	२	३	४	५	६

(ग) जाडोयाममा महिनाको एक पटक निम्न अनुसार बत्ति गएमा के गर्नुहुन्छ ?

८ घण्टा गएमा	१	२	३	४	५	६
२४ घण्टा गएमा	१	२	३	४	५	६
४८ घण्टा गएमा	१	२	३	४	५	६

(घ) अब गर्मीयाममा निम्न अनुसार बत्ति गएमा तपाई के गर्नुहुन्छ ?

साँझ ५ बजेपछि दिनदिनै चार घण्टा गएमा	१	२	३	४	५	६
साँझ ५ बजेपछि हप्तामा एक पटक चार घण्टा गएमा	१	२	३	४	५	६
महिनामा १ पटक आठ घण्टासम्म गएमा	१	२	३	४	५	६
महिनामा १ पटक २४ घण्टासम्म गएमा	१	२	३	४	५	६

प्र.नं.८ यदि विद्युत प्राधिकरणले विविध कारणवश तपाईलाई पर्याप्त विद्युत आपूर्ति गर्न सकेन भने तपाई न्यम अवस्थामा विजुली खपत घटाएर कसरी सहयोग गर्न सक्नुहुन्छ ?

(क) के तपाई आफ्नो घरमा कम विजुलीको प्रयोग गरेर विद्युत आपूर्ति घटाउन सक्नु हुन्छ ?

☐ सक्नुहुन्छ ☐ सक्नु हुन्न

(ख) यदि सक्नुहुन्छ भने अन्दाजी कति प्रतिशत विजुलीको खपत कम गर्न सक्नुहुन्छ ?

	सकिन्छ	सकिदैन
५ प्रतिशत	—	—
५ देखि १० प्रतिशत	—	—
१० देखि १५ प्रतिशत	—	—
१५ देखि २० प्रतिशत	—	—
२० प्रतिशत भन्दा बढी	—	—

प्र.नं.९ यदि समय समयमा बत्ति गइरहन्छ र तपाईलाई अरु कुनै साधन वा श्रोतवाट विजुली उपलब्ध गराईन्छ भने तपाई हरेक ३० मिनेटकोलागि कति तिर्न तयार हुनुहुन्छ ?

	हुन्छ	हुदैंन
रु. २ हरेक आधा घण्टाकोलागि	—	—
रु. ५ हरेक आधा घण्टाकोलागि	—	—
रु. १० हरेक आधा घण्टाकोलागि	—	—
रु. १५ हरेक आधा घण्टाकोलागि	—	—
रु. २५ वा सो भन्दा बढी आधा घण्टाकोलागि	—	—

प्र.नं.१० तपाईको घरको विजुलीको खर्च महिनामा औसत कति सम्म हुन्छ ?

— रु. १०० भन्दा कम
— रु. १०० - ३००
— रु. ३०० - ५००
— रु. ५०० - १०००
— रु. १००० - २०००
— रु. २००० भन्दा बढी

प्र.नं.११ मानौं हाल तपाईलाई विद्युत उपलब्ध गराइएको अवस्था, महिनामा एक पटक चार घण्टासम्म बत्ति जाने गर्दछ । बत्ति बढी जाने अनुपातमा बत्तिको दर रेट घटाउन तपाईलाई सोधिएमा निम्न अवस्थामा कति सम्म घटाईदिएमा तपाई मान्नु हुन्छ ?

(क) अब हरेक हप्तामा एक पटक चारघण्टा सम्म बत्ति जाने गरेमा, कतिसम्म दररेट घटाईदिएमा तपाई मान्नुहुन्छ ?

	हुन्छ	हुदैंन
२ प्रतिशत घटाईदिएमा	—	—
५ प्रतिशत घटाईदिएमा	—	—

१० प्रतिशत घटाईदिएमा	—	—
२० प्रतिशत घटाईदिएमा	—	—
५० प्रतिशत घटाईदिएमा	—	—

(ख) अब हरेक दिन एक पटक चारघण्टा सम्म बत्ति जाने गरेमा कतिसम्म दररेट घटाईदिएमा तपाइं मान्नुहुन्छ ?

	हुन्छ	हुदैंन
२ प्रतिशत घटाईदिएमा	—	—
५ प्रतिशत घटाईदिएमा	—	—
१० प्रतिशत घटाईदिएमा	—	—
२० प्रतिशत घटाईदिएमा	—	—
५० प्रतिशत घटाईदिएमा	—	—

प्र.नं.१२ मानौ नेपाल विद्युत प्राधिकरणले उपलब्ध गराइआएको विद्युत सेवामा धेरै पटक बत्ति जान थाल्यो र अर्को विद्युत सेवा जसले अटुट रुपमा विद्युत उपलब्ध गराउन सक्छ भने, सो नयाँ प्रणालीलाई कतिसम्म वढी तिरी रोज्न सक्नुहुन्छ ?

(क) यदि हाल उपलब्ध गराईएको विद्युत सेवामा हरेक महिनामा एक पटक चार घण्टा सम्म विजुली जान्छ भने .....

	हुन्छ	हुदैंन
हालको महिनाको खर्चमा रु. २५ बढी तिरी उक्त नयाँ सेवा रोज्न चाहनुहुन्छ ?	—	—
हालको महिनाको खर्चमा रु. ५० बढी तिरी उक्त नयाँ सेवा रोज्न चाहनुहुन्छ ?	—	—
हालको महिनाको खर्चमा रु. १०० बढी तिरी उक्त नयाँ सेवा रोज्न चाहनुहुन्छ ?	—	—
हालको महिनाको खर्चमा रु. २०० बढी तिरी उक्त नयाँ सेवा रोज्न चाहनुहुन्छ ?	—	—
हालको महिनाको खर्चमा रु. ५०० बढी तिरी उक्त नयाँ सेवा रोज्न चाहनुहुन्छ ?	—	—

(ख) यदि हाल उपलब्ध गराईएको विद्युत सेवामा हरेक हप्तामा एक पटक चार घण्टा सम्म बत्ति जान्छ भने .....

	हुन्छ	हुँदैन
हालको महिनाको खर्चमा रु. २५ बढी तिरी उक्त नयाँ सेवा रोज्न चाहनुहुन्छ ?	—	—
हालको महिनाको खर्चमा रु. ५० बढी तिरी उक्त नयाँ सेवा रोज्न चाहनुहुन्छ ?	—	—
हालको महिनाको खर्चमा रु. ९००बढी तिरी उक्त नयाँ सेवा रोज्न चाहनुहुन्छ ?	—	—
हालको महिनाको खर्चमा रु. २०० बढी तिरी उक्त नयाँ सेवा रोज्न चाहनुहुन्छ ?	—	—
हालको महिनाको खर्चमा रु. ५०० बढी तिरी उक्त नयाँ सेवा रोज्न चाहनुहुन्छ ?	—	—

(ग) यदि हाल उपलब्ध गराईएको विद्युत सेवामा दिनहुँ एक पटक चार घण्टा सम्म बत्ति जान्छ भने .....

	हुन्छ	हुँदैन
हालको महिनाको खर्चमा रु. २५ बढी तिरी उक्त नयाँ सेवा रोज्न चाहनुहुन्छ ?	—	—
हालको महिनाको खर्चमा रु. ५० बढी तिरी उक्त नयाँ सेवा रोज्न चाहनुहुन्छ ?	—	—
हालको महिनाको खर्चमा रु. ९०० बढी तिरी उक्त नयाँ सेवा रोज्न चाहनुहुन्छ ?	—	—
हालको महिनाको खर्चमा रु. २०० बढी तिरी उक्त नयाँ सेवा रोज्न चाहनुहुन्छ ?	—	—
हालको महिनाको खर्चमा रु. ५०० बढी तिरी उक्त नयाँ सेवा रोज्न चाहनुहुन्छ ?	—	—

प्र.नं.१३ यदि तपाईको विचारमा विद्युत आपूर्तिको कमी वा रोकावटवाट हुने असर अथवा विद्युत प्राधिकरणले गर्नुपर्ने कार्य बारे सल्लाह वा सुझाव केही छ भने कृपया बताईदिनु हुन्छ की ?

धन्यवाद !

यहाँको नाम तथा ठेगाना

.....

.....

इन्जिनियरिङ्ग अध्ययन संस्थान नेपाल

क्यानेडियन अन्तर्राष्ट्रिय विकास एजेन्सी

ग्राहक सर्वेक्षण **सर्वेक्षक** .....

नेपाल विद्युत प्रणाली **ठाउँ** .....

(विद्युत आपूर्तिमा ऱ्हास हुनाले ब्यापार क्षेत्रमा पर्न जाने असर) **सि.नं.** .....

प्र.नं. १. (क) जहाँसम्म तपाई सम्झनु हुन्छ, तपाईको कम्पनीमा गएको दुई महिनामा कति पटक बिजुली गएको थियो ? (आफ्नो संस्थाको कारणले बाहेक) _____

(ख) त्यसमध्ये कति पटक चार घण्टा वा सो भन्दा लामो समयसम्म भएको थियो ? _____

प्र.नं. २. विभिन्न ब्यापारीक कम्पनीहरू अथवा सस्थाहरूमा बढी विद्युतवाट चल्ने विभिन्न प्रकारका उपकरणहरूको तल तालिका तयार पारिएको छ । प्रत्येक उपकरण तपाईको कम्पनीका लागि कति महत्वपूर्ण छ कृपा गरी भन्नु होला ।

विद्युतवाट चल्ने उपहरणहरू	कम्पनीमा छैन	महत्वपूर्ण छैन	धेरै महत्वपूर्ण छैन	महत्वपूर्ण छ	धेरै महत्वपूर्ण छ
एयर कण्डीसनिङ	—	—	—	—	
हिटर आदि	—	—	—	—	
विद्युतवाट पानी तताउने	—	—	—	—	
भेन्टीलेशनको साधन	—	—	—	—	
अफिसमा प्रयोग हुने उपकरणहरू (टाईप राइटर, क्यालकुलेटर, फोटोकपियर मेशिन आदि	—	—	—	—	
इलेक्ट्रिक क्यास रेजिस्टर	—	—	—	—	
कम्प्यूटर	—	—	—	—	
दूरसञ्चारका विद्युतिय सामानहरू	—	—	—	—	
विद्युतिय पकाउने भांडा	—	—	—	—	
विद्युतिय मोटरहरू (पम्प वाहेक)	—	—	—	—	

विद्युतीय पम्पहरू	☐	☐	☐	☐	☐
रेफ्रीजरेटर र फ्रिजर्स	☐	☐	☐	☐	☐
लिफ्ट	☐	☐	☐	☐	☐
बत्तिहरू	☐	☐	☐	☐	☐
घर वाहिरी बत्तिहरू	☐	☐	☐	☐	☐

अन्य उपकरणहरू भए
सो को नाम_____

प्र.न. ३. काम गर्दा गर्दै विद्युत आपूर्ति बन्द हुन गएमा इमर्जेन्सीको लागि कुनै विद्युत उत्पादन गर्न उपकरण छ कि ?

इमर्जेन्सी उपकरणहरू:	कस्तो प्रकारको उपकरणको लागि प्रयोग गनुहुन्छ	कति समयसम्म यो चलाउन सकिने छ
☐ व्याट्री प्रणाली		घण्टा
☐ इन्जिन जेनेरेटर		घण्टा
☐ टरवाइन		घण्टा
☐ अन्य खुलाउनुहोस्		घण्टा
☐ कुनै पनि छैन (छैन भने प्र.नं. मा जानुहोस्)		

प्र.न. ४. (क) विद्युत आपूर्ति बन्द हुंदा तपाईको कम्पनीका कामदार तथा सर्वसाधारण जनताको स्वास्थ्यमा वा ज्यानको कुनै खतरा पुग्ने गरेको छ ?

☐ असाध्यै ☐ केहि मात्रामा ☐ नगन्यरूपमा ☐ छैन

(ख) तपाईको कम्पनीका कामदार तथा ग्राहकहरूलाई खतरा नहोस् भन्नाका लागि विद्युत आपूर्ति बन्द हुनुभन्दा कम्तीमा कतिवेर अगाडि तपाईलाई सूचना दिनु पर्दछ ?

☐ २० मिनेट ☐ आठ घण्टा ☐ अन्य
☐ एक घण्टा ☐ एक दिन (२४ घण्टा)
☐ चार घण्टा ☐ १ दिनभन्दा वढी

प्र.नं. ५. विद्युत आपूर्ति बन्द हुंदा कुन समयमा यसले सबैभन्दा वढी हानी तपाईको कम्पनीलाई पुऱ्याउछ भन्ने कुरा तल उल्लेखित प्रश्नहरूले प्रष्ट पार्ने छन् ।

(क) कुन महिनामा विद्युत आपूर्ति वन्द भएमा तपाईको कम्पनीलाई वढी नोक्सान हुन्छ ?

वैशाख	जेष्ठ	आषाढ	श्रावण	भाद्र	आश्विन
—	—	—	—	—	—
कार्तिक	मार्ग	पौष	माघ	फाल्गुण	चैत्र
—	—	—	—	—	—

अथवा

— सवै महिनाहरूमा एकै नासले हुन्छ ।

(ख) कुन दिनमा विद्युत आपूर्ति वन्द भएमा तपाईको कम्पनीलाई वढी नोक्सान हुन्छ ?

आइतवार	सोमवार	मङ्गलवार	वुधवार	शुक्रवार	शनिवार
—	—	—	—	—	—

अथवा — सवै सात दिन एकै नास हुन् ।

अथवा — शनिवार वाहेक अन्य सवै दिनमा एकैनास हुन् ।

अथवा — खराव दिन नियमित छैन ।

(ग) कुन समयमा विद्युत आपूर्ति वन्द भएमा तपाईको कम्पनीलाई वढी नोक्सान हुन्छ ?

विहान		दिउँसो	
६-९ वजेसम्म	—	१२-१ वजेसम्म	—
९-१२ वजेसम्म	—	१-५ वजेसम्म	—
साँझ		**राती**	
५-९ वजेसम्म	—	९-१२ वजेसम्म	—
		१२-६ वजेसम्म	—

अथवा — विहान, दिउँसो सवै समयमा एकैनास ।

अथवा — काम हुने समयमा (काम हुने समय _____ देखि _____ सम्म)

अथवा — निश्चित समय छैन ।

प्र.न. ६. मानौ यदि विना सूचना तपाईको कम्पनीलाई वढी नोक्सान पुग्ने समयमा (जुन तपाई प्रश्न न. ५ वाट पत्ता लगाउनु भएको छ) विद्युत आपूर्ति वन्द भयो भने तपाईको व्यापारमा कति नोक्सान हुन सक्छ ? नोक्सान र खर्चको मूल्याङ्कन निम्न अनुसार गर्नु होला । जस्तै: काम नहुँदा कामदार वा स्टाफलाई दिनुपर्ने खर्च, विक्री गर्न नपाउँदा हुन जाने नोक्सानी खानेकुराहरू विग्रिएर भएको नोक्सानी र छपाईको साधनमा क्षति पुगेर भएको खर्च आदि । क्षति कम होस् भनेर अरू स्रोत संचालन गर्दा भएको खर्च र मेशिनरी सामानको वचावटका लागि प्रयोग भएका अन्य खर्च पनि हिसाव गर्नुहोला । कुनै ओभर टाइम काम, मरसफाई, मर्मत सम्हार जस्ता काममा भएको खर्चहरूको अनुमान छुट्टै गर्नुहोला ।

यदि तपाईले, विद्युत आपूर्ति नभएमा पनि काम चलाउने कुनै विद्युत उत्पादन गर्ने उपकरण उपकरण विद्युत आपूर्ति रोकिंदा चलाउने गर्नुहुन्छ भने सो चलाउन लागेको खर्च यसमा हिसाब गर्नुहोस् ।

तलको तालिकामा दिइएको अनुसार तपाईको सबभन्दा बढी "नोक्सान हुने समय" मा विद्युत आपूर्ति बन्द हुँदा हुने खर्चहरू रूपैयाँमा लेख्नुहोस् ।

नोटः- तपाईको सुविधाको लागि तलको तालिका तयार पारिएको हो । यदि तपाईलाई तालिका अनुसार छुट्टयाएर लेख्न गाह्रो भए, अन्तिममा भएको "माथिको जम्मा जोड्दा" लेखिएको हरफ अगाडिको वाकसमा मात्र लेखे पनि हुन्छ ।

	विद्युत आपूर्ति बन्द हुँदा तपाईको व्यावसायमा हुनसक्ने सम्भावित असरहरू	विद्युत आपूर्ति बन्द हुने समय अवधि							
		२ सेकेण्ड	१ मिनेट	२० मिनेट	१ घण्टा	२ घण्टा	४ घण्टा	८ घण्टा	२४ घण्टा वा १ दिन
रुपैयामा लेख्नुहोला	काम रोकिंदा कामदारलाई दिएको खर्च								
	बिक्रिमा घाटा								
	ओभर टाइम काम हुदाको खर्च								
	सामानहरू क्षति भएको खर्च								
	पुनः सचालन गर्नुपर्दा भएको खर्च								
	नोक्सान हुनसक्ने वस्तुहरू बिग्रिएकोमा खर्च								
	विद्युत आपूर्तिका लागि प्रयोग भएको प्रणालीहरू र क्षति हुनबाट बचाउन प्रयोग गरेका उपायहरूको खर्च								
	अन्य खर्च भए (कृपया उल्लेख गर्नुहोस्) _____								
	माथिको सबै जम्मा जोड्दा								

प्र.न. ७ यो प्रश्नावलीद्वारा प्रश्न न. ५ मा निर्णय गरिएको सबभन्दा खराब समय बाहेक अन्य समयमा, दिनमा वा महिनामा विद्युत आपूर्ति बन्द हुँदा नोक्सानीमा फरकपर्न जाने कुरा पत्ता लगाउने प्रयास गरिएको छ । यहाँ तालिकामा छुट्टयाइएका शीर्षकहरू तपाईको लागि पर्याप्त नभएमा "अन्य अनुमानित खर्च" मा उल्लेख गर्नुहोला ।

(क) तपाईको सबभन्दा खराब महिना बाहेक अन्य कुनै महिनामा एक घण्टा विद्युत आपूर्ति रोकिएमा प्र.नं. ५ अनुसारको खराब समयमा विद्युत रोकिदाभन्दा कति खर्च फरक पर्न सक्छ ? (प्रश्न न. ५ को सबै महिना बराबर भन्ने चिन्ह लगाउनु भएको भए प्रश्न नं. ७ "ख" मा जानुहोला ।)

महिना	खराब महिना जस्तै	१०% कम	२५% कम	५०% कम	७५% कम	अन्य गन्य	अन्य अनुमानित
वैशाख	—	—	—	—	—	—	_____% कम
जेष्ठ	—	—	—	—	—	—	_____% कम
आषाढ	—	—	—	—	—	—	_____% कम
श्रावण	—	—	—	—	—	—	_____% कम
भाद्र	—	—	—	—	—	—	_____% कम
आश्विन	—	—	—	—	—	—	_____% कम
कार्तिक	—	—	—	—	—	—	_____% कम
मार्ग	—	—	—	—	—	—	_____% कम
पौष	—	—	—	—	—	—	_____% कम
माघ	—	—	—	—	—	—	_____% कम
फाल्गुण	—	—	—	—	—	—	_____% कम
चैत्र	—	—	—	—	—	—	_____% कम

(ख) कुनै हप्तामा खराब दिन बाहेक अन्य कुनै दिनमा एक घण्टा विद्युत आपूर्ति रोकिदा प्र.न. ५ अनुसारको खराब दिनभन्दा खर्चमा कति फरक पर्न सक्छ ? (प्रश्न न. ५ मा नियमित नभएको भन्ने चिन्ह लगाउनु भएको भए शुक्रवारलाई तपाईको खराब दिन मानेर यस प्रश्नमा चिन्ह लगाउनु होस् । यदि तपाईले सबै वार बराबर भन्ने चिन्ह लगाउनु भएको भए (ग) मा जानुहोस् ।)

विद्युत रोकिंदा हुने खर्चको फरक (हप्तामा)

हप्ताका वार	खराब दिन जस्तै	१०% कम	२५% कम	५०% कम	७५% कम	नगण्य	अन्य अनुमानित
	—	—	—	—	—	—	_____% कम
सोमवार	—	—	—	—	—	—	_____% कम
मङ्गलवार	—	—	—	—	—	—	_____% कम
बुधवार	—	—	—	—	—	—	_____% कम
बिहीवार	—	—	—	—	—	—	_____% कम
शुक्रवार	—	—	—	—	—	—	_____% कम
शनिवार	—	—	—	—	—	—	_____% कम

(ग) कुनै दिनमा तपाईको सबभन्दा खराब समय बाहेक अन्य समयमा एक घण्टा विद्युत आपूर्ति रोकिदा सबभन्दा खराब समयभन्दा खर्चमा कती फरक पर्नसक्छ ? (सबभन्दा खराब समय निश्चित गर्न सकिन्न भन्ने भाग्मा दिनको "१-५" बजेसम्मको समयलाई सबैभन्दा खराब समय मान्नु होला । यदि प्रश्न न. ५ मा सबै काम हुने घण्टा बराबर भन्ने चिन्ह लगाउनु भएको छ भने प्रश्न न. ८ मा जानुहोस् ।)

सबभन्दा खराब समयसंग तुलना गर्दा

दिनका समय	खराब समय	१०% कम	२५% कम	५०% कम	७५% कम	नगण्य	अन्य अनुमानित
विहान (६-९ बजे)	— —	— —	— —	— —	— —	— —	_____% कम
मध्यान्ह अगाडी (९-१२)	— —	— —	— —	— —	— —	— —	_____% कम
मध्यान्ह (१२-१ बजे)	— —	— —	— —	— —	— —	— —	_____% कम
अपरान्ह (१-५ बजे)	— —	— —	— —	— —	— —	— —	_____% कम
सूर्यास्त (५-९ बजे)	— —	— —	— —	— —	— —	— —	_____% कम
रात्रि (९-१२ बजे)	— —	— —	— —	— —	— —	— —	_____% कम
मध्यरातपछि (१२-६ बजे)	— —	— —	— —	— —	— —	— —	_____% कम

प्र.न.८. तल दिइएका अवस्थामा विद्युत आपूर्ति बन्द हुंदा तपाईको कम्पनीमा हुने नोक्सानीलाई कम गर्न सकिन्छ ?

(क) छोटो समयका लागि विद्युत बन्द हुने कुरा अग्रिम सूचना गरिदिएमा विद्युत रोकिदा नोक्सान हुने खर्चमा कम हुन्छ ?

— हुन्छ — हुदैन (यदि हुदैन भने प्रश्न न. ९ मा जानुहोस् ।)

प्र.न. ६. अनुमानित गरिएको कुनै सूचना नगरी एक घण्टा विद्युत रोकिदा हुनसक्ने नोक्सानीका तुलनामा पूर्व सूचना गरिदिंदा तपाईको नोक्सानीमा के कति कम हुनसक्छ ?

	पूर्व सूचना दिने समयावधि					
	१ घण्टाभन्दा कम	१ देखि ४ घण्टासम्म	५-१५ घण्टा	१७-२४ घण्टा	१-२ दिन	३ वा सोभन्दा बढी समय
प्रश्न न. ६ मा निकालिएको पूर्व सूचना नदिंदा जम्मा खर्चवाट घट्ने खर्च	%	%	%	%	%	%
हरेक पूर्व सूचना समयका लागि % मा खर्च कटौती देखाउनुहोस् ।						

(ख) विद्युत आपूर्ति रोकिएको समयमा कति समयसम्म विद्युत रोकिन सक्छ भन्ने जानकारी तपाईको कम्पनीलेपाउँदा नोक्सानीलाई घटाउन सम्भव छ ?

☐ छ ☐ छैन (छैन भने प्रश्न ९ मा जानुहोस् ।)

विद्युत रोकिने शुरूको अवस्थामा नै तपाईलाई कति समयका लागि विद्युत रोकिन सक्छ भन्ने जानकारी दिइयो भने तपाईको व्यापारमा हुने नोक्सानी कति प्रतिशतले कम हुनसक्छ ?

	विद्युत रोकिने समयावधि					
	१ मिनेट	२० मिनेट	१ घण्टा	४ घण्टा	८ घण्टा	१ दिन
प्र.नं. ६ मा निकालिएको पूर्व सूचना नदिंदा हुने जम्मा खर्चबाट घट्ने खर्च	%	%	%	%	%	%
हरेक विद्युत रोकिने समयावधिमा कति प्रतिशत कम खर्च हुनसक्छ लेख्नुहोस् ।						

प्र.नं. ९. विद्युत भोल्टेज र फ्रिकोएन्सीमा फरक पर्नाले असर पर्ने उपकरण तपाईको कम्पनीमा छन् कि ?

प्रभावित हुने अवस्था:	छ	छैन	थाहा छैन	छ भने असर पर्ने उपकरणहरूको नाम लेख्नुहोस्
फ्रिकोएन्सीमा अन्तर हुँदा	☐	☐	☐	_____
भोल्टेज अन्तर हुँदा	☐	☐	☐	_____

प्रत्येक हरफमा एउटा कोठामा मात्र चिन्ह लगाउनुहोस् ।

प्र.नं. १०. तपाईको कम्पनीले अन्दाजी कति क्षेत्रफल ओगटेको छ ?

☐ ७० वर्ग मि. भन्दा कम (७५० वर्ग फिटभन्दा कम)

☐ ७०-१८५ वर्ग मि. (७५०-२००० वर्ग फिट)

☐ १८५ वर्ग मि. भन्दा बढी (२००० वर्ग फिटभन्दा धेरै)

प्र.नं. ११. तपाईको कम्पनीको लागि जडान गरिएको मिटरको एम्पीयर कति छ होला ?

_____ एम्पीयर

प्र.नं. १२. महिनाको औसत कति विद्युत तपाईको कम्पनीले खपत गर्ने गरेको छ ?

_____ खपत युनिट

प्र.नं. १३. गएको १२ महिनामा तपाईको व्यापारमा पूरै समय अथवा केहि समय काम गर्ने कति जना थिए ?

पूरा समय _____ केहि समय _____

प्र.नं. १४. के तपाईको पसल कुनै सुपर मार्केटभित्र पर्दछ ?

☐ पर्दछ ☐ पर्दैन

प्र.नं. १५. (क) तपाईको व्यापार निम्न मध्ये कुन चाहिं हो ?

- ☐ खाद्य सामाग्रीको पसल
- ☐ तरल पदार्थ रक्सी र बियरको पसल
- ☐ औषधिको पसल
- ☐ जुत्ताको पसल
- ☐ लुगा (कपडा) पसल
- ☐ फर्निचर पसल
- ☐ टि.भि. तथा स्टेरियो पसल
- ☐ फर्निसिङ्ग पसल
- ☐ अटोमोवाइल पसल
- ☐ पेट्रोलपम्प/सर्भिस स्टेशन
- ☐ अटोमोटिभ पार्ट तथा एक्सेसेरीज
- ☐ मोटर तथा मोटरसाइकल मर्मत केन्द्र
- ☐ जेनेरल मर्चेनडाइज स्टोर
- ☐ किताव तथा पत्रपत्रिका पसल
- ☐ हार्डवेयर स्टोर
- ☐ गरगहना पसल
- ☐ विद्युतिय सरसमान पसल
- ☐ अन्य खुद्रा पसल
- ☐ क्यामरा तथा फोटोग्राफीक सर्भिस
- ☐ होटल, मोटेल तथा टुरिष्ट सेन्टर
- ☐ रेष्टुरेन्ट
- ☐ वार र नाइट क्लव
- ☐ हजाम र व्यूटीपार्लर
- ☐ लुगा धुने पसल
- ☐ फिल्म, अडियो र भिडियो पसल
- ☐ खेलकूद तथा स्वास्थ्य सेवाको क्लव
- ☐ अन्य वाणिज्य व्यापार तथा सेवा

_____

(कृपया प्रष्ट पार्नुहोस् ।)

(ख) तपाईले व्यापार गर्ने मुख्य सरसामानहरू के के हुन् ?

_____

प्र.न. १६. यदि तपाईको विचारमा विद्युत आपूर्तिको कमी वा रोकावटवाट हुने असर अथवा विद्युत प्राधिकरणले गर्नुपर्ने कार्य वारे सल्लाह वा सुझाव छन् भने कृपया वताई दिनुहुन्छ कि ?

धन्यवाद ।

इन्स्टीच्यूट अफ इन्जिनियरिङ्ग
त्रिभुवन विश्वविद्यालय, काठमाडौं
क्यानेडियन अन्तर्राष्ट्रिय विकास एजेन्सी

यहांको नाम तथा ठेगाना

.....

.....

ग्राहक सर्वेक्षण **सर्वेक्षक.....**

नेपाल विद्युत प्रणाली **ठाउँ.....**

(विद्युत आपूर्तिमा ऱ्हास हुनाले औद्योगिक क्षेत्रमा पर्नजाने असर) **सि.नं.....**

प्र.नं. १. (क) तपाईको काममा गएको दुई महिना भित्रमा कति पटक विद्युत आपूर्ति रोकिएको अनुभव गर्नु भएको छ ? (तपाईको संस्था भित्रकै कारणले बन्द भएको अवस्थालाई छाडेर) _____

(ख) ति मध्ये चार घण्टा वा बढीका लागि कति पटक भए ? _____

प्र.नं. २. तपाईको कम्पनिको लागि निम्न विद्युतको उपयोगिताहरु कत्तिको महत्वपूर्ण छ उपयुक्त कोठामा चिन्ह लगाउनु होला ?

विद्युतको उपयोगिता	कम्पनीमा छैन	महत्वपूर्ण छैन	खास महत्वपूर्ण छैन	महत्वपूर्ण छ	धेरै नै महत्वपूर्ण छ
भवनका लागि सेवा (बत्ति, हिटर, एयरकन्डिसन, भेन्टिलेसन आदि)	—	—	—	—	
उत्पादन प्रणाली	—	—	—	—	
रेफ्रीजरेशन तथा फ्रिजर	—	—	—	—	
इलेक्ट्रोनिक साधनहरु (कम्प्यूटर, टि.भि., टेलिफोन आदि)	—	—	—	—	
अन्य उपयोगिता _____	—	—	—	—	

प्र.नं.३. (क) तपाईको कम्पनीमा अपर्झट विद्युत आपूर्ति बन्द हुंदा विद्युत उपलव्ध गराउने के उपकरणहरु छन् ?

आपूर्ति प्रणाली	परिमाण	युनिट	कति लामो समयसम्म भार लिन सक्छ	तयार हुन लाग्ने समय	सेवा गर्ने उपकरणहरु
☐ व्याट्री		☐ किलो वाट ☐ हर्स पावर	घण्टा	मिनेट	
☐ इन्जिन जनेरेटर		☐ किलो वाट ☐ हर्स पावर	घण्टा	मिनेट	
☐ टरवाइन		☐ किलो वाट ☐ हर्स पावर	घण्टा	मिनेट	
☐ अन्य (भएमा)		☐ किलो वाट ☐ हर्स पावर	घण्टा	मिनेट	

☐ छैन (छैन भने प्र.नं. ४ मा जानुहोस ।)

(ख) विद्युत आपूर्ति नभएको समयमा तपाईसंग भएको आपूर्ति प्रणालीले .....

	खास गर्दैन	केही अंशमा	धेरैजसो	यसकोलागि उपलव्ध गराइएको छैन
कर्मचारी वा सर्वसाधारणलाई पर्ने खतरा कम गर्छ ?	☐	☐	☐	☐
मेशिनरी वा तयारी सामानको नोक्सानी हुनबाट बचाउँछ ?	☐	☐	☐	☐
उत्पादन कार्य कायम नै गर्दछ ?	☐	☐	☐	☐
अन्य भएमा खुलाउनुहोस् _____	☐	☐	☐	☐

प्र.नं.४. (क) विद्युत आपूर्ति बन्द हुनाले तपाईका कामदार वा सर्वसाधारण जनताको सुरक्षामा खतरा उत्पन्न हुने गर्छ कि ?

☐ धेरै नै ☐ साधारणतया ☐ केही मात्रामा ☐ गर्दैन (गर्दैन भने प्र.न ५ मा जानुस्)

(ख) तपाईका कामदार वा ग्राहकलाई पर्न जाने खतरालाई कम गर्न न्यूनतम कति समय अगावै तपाईको कम्पनीलाई विजुली बन्द हुने जानकारी दिनु पर्छ होला ?

☐ २० मिनेट ☐ ८ घण्टा ☐ अन्य _____
☐ १ घण्टा ☐ १ दिन (२४ घण्टा)
☐ ४ घण्टा ☐ १ दिन भन्दा बढी

प्र.नं.५. के तपाईको कामको प्रकार यस्तो किसिमको छ जुन विद्युत आपूर्ति नभएर कम भएको उत्पादन, फेरि विद्युत आपूर्ति हुंदा ओभर टाईम वा अन्य कामदार नलगाई पूरा गर्न सकिन्छ ?

निम्न समय सम्म विद्युत आपूर्ति बन्द हुंदा तपाईले आफ्नो उत्पादनलाई कति सम्म पूरा गर्न सक्नु हुन्छ :

	पटक्कै गर्न सकिन्न	आंशिक मात्रामा	धेरैजसो	पूरा गर्न आवश्यक छैन
१ मिनेट जाँदा	☐	☐	☐	☐
२० मिनेट जाँदा	☐	☐	☐	☐
१ घण्टा जाँदा	☐	☐	☐	☐
४ घण्टा जाँदा	☐	☐	☐	☐
८ घण्टा जाँदा	☐	☐	☐	☐

कृपया प्रत्येक हरपमा एउटा कोठामा मात्र चिन्ह लगाउनु होला ।

प्र.नं.६. यो प्रश्नले तपाईको कारखानामा विद्युत आपूर्ति बन्द हुँदा सबभन्दा बढी नोक्सान हुने समयको जानकारी गर्न प्रयास गर्ने छ ।

	वैशाख	जेठ	असार	श्रावण	भदौ	असोज	कार्तिक	मंसिर	पौष	माघ	फागुन	चैत्र
वर्षमा बढी नोक्सान हुने महिना:	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	

अथवा ☐ सबै महिना बराबर

	आइत	सोम	मंगल	बुध	बिहि	शुक्र	शनी
हप्तामा बढी नोक्सान हुने दिन:	☐	☐	☐	☐	☐	☐	

अथवा ☐ सबै दिन बराबर
अथवा ☐ शनिवार बाहेक हप्ताको सबै दिन बराबर
अथवा ☐ भन्न नसकिने (कुनै दिन तोक्न नसकिने)

दिनमा बढीनोक्सान हुने समय:	बिहान सवेरै ६-९ बजे	मध्यान्न अघि ९-१२ बजे	मध्यान्न १२-१ बजे	अपरान्ह १-५ बजे
	☐	☐	☐	☐
	सूर्यास्त ५-९ बजे	रात्री ९-१२ बजे	मध्यरात्री पछि १२-६ बजे	
	☐	☐	☐	

अथवा ☐ दिन वा रात सबै समय बराबर

अथवा ☐ काम गर्ने सबै घण्टाहरु बराबर (काम गर्ने समय _____ बजे देखि _____बजे सम्म)

अथवा ☐ समय निश्चित छैन (समय तोक्न नसकिने)

तपाईले आफ्नो कम्पनीको लागि विद्युत आपूर्ति बन्द हुंदा सबभन्दा बढी नोक्सान हुने समय निश्चित गर्नु भएको छ । यही समयलाई आधार मानेर प्रश्न नं.७ र ८ मा तुलनात्मक अध्ययन गरिने छ ।

प्र.नं.७. मानौं, तपाईको सबभन्दा बढि नोक्सान हुने समय (दिनको सबभन्दा बढी नोक्सान हुने समय, हप्ताको सबै भन्दा बढी नोक्सान हुने दिन र वर्षको सबभन्दा बढि नोक्सान हुने महिना) जुन भखरै गरिएको प्रश्नावलीमा निर्णय गरिएको थियो, त्यस्तो बेलामा कुनै चेतावनी बिना विद्युत आपूर्ति बन्द भै दिंदा आफ्नो कारखानामा के कति नोक्सान हुन्छ र पुन: कार्य सञ्चालन हुन कति समय लाग्दछ तल दिइएको तालिका अनुसार अनुमान लगाउनु होला ।

क्षतिको अनुमान गर्दा मेशिनरी ल्पान्टमा हुनसक्ने खरावी, कच्चा पदार्थ र तयारी मालमा हुने नोक्सानी तथा विशेष प्रकृया गरेर पुन: संचालन गर्नु पर्दा (जस्तै पुन: सफा गर्नु पर्ने, जांच, मर्मत आदि) लाग्ने रकमहरु समावेश गर्नु होस् । विद्युत आपूर्ति रोकिएर भएको नोक्सानीलाई लिन नसकेको मुनाफाको रुपमा हिसाव गर्नुहोला अर्थात उत्पादन हुन सक्ने मालको बिक्री मूल्यबाट उत्पादन रोकिएकोमा खर्च नभएका उत्पादन खर्चहरु जस्तै मजदुरी, कच्चा पदार्थ अथवा अन्य यस्तै खर्चहरुको रकम घटाएर राख्नुहोस् । यदि यसरी क्षति भएको उत्पादनलाई पछि ओभर टाइमद्वारा पुरा गर्न सकिन्छ भने त्यसलाई नोक्सान भएको हिसाव नगरिदिनुहोला । यस्तो ओभरटाइम खर्चलाई भिन्दै अनुमान गर्नुपर्ने छ । क्षति कम गर्नकोलागि अरु श्रोतबाट विद्युत आपूर्ति गर्नुहुन्छ भने सो संचालनमा लाग्ने खर्च तथा विद्युत आपूर्तिमा गडवडी भइ दिंदा मेशिनरी सामानमा सुरक्षा गर्न प्रयोग गरिएको उपकरणहरुको संचालनमा पर्ने मूल्य हिसाव गर्नु होला ।

नोक्सानीको अनुमान लगाउँदा यदि तपाईको उद्योगमा विद्युत आपूर्ति नभएमा पनि काम चलाउने कुनै व्यवस्था मिलाउनु भएको छ भने र त्यस्तो उपकरण विद्युत आपूर्ति रोकिंदा चलाउने गर्नु हुन्छ भने सो पूरा मात्रामा चलाएको हिसाव गर्नु होला ।

यदि तपाईको कम्पनीले उत्पादन गर्दैन भने तपाईले गुमाउनु भएको सेवाको मूल्यका रुपमा नोक्सानीलाई गणना गर्नु होला । अथवा तपाईको कम्पनीको अन्य कार्य भएमा यस्तै किसिमले नोक्सानीलाई हिसाव गर्नु होस् ।

तालिकामा दिइएको प्रत्येक विद्युत वन्द हुने समयावधीमा तपाईको कम्पनीको काम गर्ने ठाउंमा हुन सक्ने संभावित अवस्थाको मूल्यांकन गर्नु होला । त्यस पछि तालिकामा उल्लेखित संभावित असर पर्नाले नोक्सान हुने मूल्यको अनुमान गर्नुहोस् ।

पुनश्च: तपाईको सुविधाको लागि यो तालिका उपलव्ध गराएको हो । तपाईको विशेष परिस्थितिमा तालिका अनुसार लेख्न मिल्दैन भने "माथि सबै जोड्दा" लेखिएको हरपको कोठाहरुमा जम्मा खर्च मात्र अनुमान गरी भनिदिनु भए हुन्छ ।

		विद्युत आपूर्ति बन्द हुने समयावधी							
	कम्पनीको कार्यमा हुनसक्ने असरहरु:	२ सेकेन्ड	१ मिनेट	२० मिनेट	१ घण्टा	२ घण्टा	४ घण्टा	८ घण्टा	१ दिन
	विद्युत पुन: प्राप्त भएपछि कार्य संचालनहुन लाग्ने समय (घण्टामा)								
रु पैया मा हिसाब गर्नु होला	उत्पादनमा ह्रास (विद्युत बन्द भएको र पुन संचालन गर्न लाग्ने समयावधी भित्र) आउनाले नोक्सानीको रकम								
	रोकिएको उत्पादन पूरा गर्न लाग्ने ओभर टाईम खर्च								
	कच्चा पदार्थ वा तयारी सामानमा हुने नोक्सानीको खर्च								
	उपकरणहरुमा हुन सक्ने नोक्सानीको मूल्य								
	पुन: संचालन गर्दा आवश्यक पर्ने खर्च (सरसफाई, मर्मत आदि)								
	आकस्मिक समयकोलागि विद्युत उपलव्ध गराउने उपकरणहरु संचालन गर्दा लाग्ने खर्च								
	अन्य खर्च (खुलाउनुहोस्)								
	माथिका सबै जोड्दा								

प्र.नं.८. यो प्रश्नावलीद्वारा प्रश्न नं.६ मा निर्णय गरिएको सबभन्दा बढी नोक्सान हुने समय भन्दा अरु समय वा दिन वा महिनामा विद्युत आपूर्ति बन्द हुंदा नोक्सानीमा कति फरक पर्न जानेछ भन्ने कुरा पत्तालगाउने प्रयास गरिएको छ । यहाँ तालिकामा छुट्याएका शिर्षकहरु तपाईकोलागि पर्याप्त नभएमा "अन्य अनुमानित खर्च" मा उल्लेख गर्नु होला ।

(क) तपाईको सबैभन्दा नोक्सानी हुने महिना भन्दा अन्य कुनै महिनामा एक घण्टा विद्युत आपूर्ति रोकिन गएमा कति कम नोक्सानी हुन्छ ?

(प्रश्न नं.६ को उत्तरमा सबै महिना बराबर भन्ने चिन्ह लगाउनु भएको भए (ख) मा जानुहोस्

विद्युत रोकिदा हुने खर्चको फरक (महिना अनुसार)

सबभन्दा बढि नोक्सान हुने महिनाको खर्चसंग तुलनात्मक खर्च

महिना	बढी नोक्सानी हुने महिना बराबर	१०% कम	२५% कम	५०% कम	७५% कम	नगण्य	अन्य अनुमानित खर्च
वैशाख	☐	☐	☐	☐	☐	☐	_____% कम
जेष्ठ	☐	☐	☐	☐	☐	☐	_____% कम
असार	☐	☐	☐	☐	☐	☐	_____% कम
श्रावण	☐	☐	☐	☐	☐	☐	_____% कम
भाद्र	☐	☐	☐	☐	☐	☐	_____% कम
असोज	☐	☐	☐	☐	☐	☐	_____% कम
कार्तिक	☐	☐	☐	☐	☐	☐	_____% कम
मंसीर	☐	☐	☐	☐	☐	☐	_____% कम
पौष	☐	☐	☐	☐	☐	☐	_____% कम
माघ	☐	☐	☐	☐	☐	☐	_____% कम
फाल्गुन	☐	☐	☐	☐	☐	☐	_____% कम
चैत्र	☐	☐	☐	☐	☐	☐	_____% कम

प्रत्येक महिनामा एउटा कोठामा मात्र चिन्ह लगाउनु होला ।

(ख) कुनै हप्तामा तपाईको सबभन्दा बढि नोक्सान हुने दिन बाहेक अरु कुनै दिनमा एक घण्टा विद्युत आपूर्ति रोकिन गयो भने तपाईको सबभन्दा बढी नोक्सान हुने दिनको तुलनामा कति कम नोक्सानी हुन्छ ? (सबभन्दा बढी नोक्सान हुने दिन भन्न सकिदैन भने उत्तर प्रश्न नं.६ मा गर्नु भएको भए शुक्रबारको दिनलाई सबभन्दा बढी नोक्सानी हुने दिन मान्नु होस । यदि तपाईले सबै दिन बराबर भन्ने चिन्ह लगाउनु भएको छ भने (ग) मा जानुहोस) ।

विद्युत रोकिदा हुने खर्चको फरक (हप्तामा)

हप्ताको सबभन्दा बढी नोक्सानी हुने दिनको खर्चसंग तुलनात्मक खर्च

हप्ताका बार	सब भन्दा नोक्सान हुने दिन बराबर	१०% कम	२५% कम	५०% कम	७५% कम	नगण्य	अन्य अनुमानित खर्च	
आईत	☐	☐	☐	☐	☐	☐	_____% कम	प्रत्येक
सोम	☐	☐	☐	☐	☐	☐	_____% कम	दिनमा
मंगल	☐	☐	☐	☐	☐	☐	_____% कम	एउटा
बुध	☐	☐	☐	☐	☐	☐	_____% कम	कोठामा
बिही	☐	☐	☐	☐	☐	☐	_____% कम	मात्र चिन्ह
शुक्र	☐	☐	☐	☐	☐	☐	_____% कम	लगाइदिनु
शनी	☐	☐	☐	☐	☐	☐	_____% कम	होस् ।

(ग) कुनै दिनमा तपाईको सबभन्दा बढी नोक्सान हुने समय बाहेक अन्य समयमा एक घण्टा विद्युत आपूर्ति रोकिन गयो भने सबभन्दा बढी नोक्सान हुने समयको तुलनामा खर्चमा कति कम हुन्छ ? (सबभन्दा बढी नोक्सान हुने समय निश्चित गर्न सकिन्न भन्ने प्रश्न नं.६ मा उत्तर दिनु भए यो प्रश्नका लागि १-५ बजे अपरान्हको समयलाई सबभन्दा बढी नोक्सानी हुने समय मान्नु होला । यदि प्रश्न नं.६ मा सबै काम हुने घण्टा बराबर भन्ने चिन्ह लगाउनु भएको छ भने प्र.नं.९ मा जानु होस् ।)

विद्युत रोकिंदा हुने खर्चमा फरक (घण्टामा):-

दिनका समय	बढी नोक्सान हुने समय सरह	१०% कम	२५% कम	५०% कम	७५% कम	नगण्य	अन्य अनुमानित
विहान (६-९ बजे)	☐	☐	☐	☐	☐	☐	_____% कम
मध्यान्ह अगाडी (९-१२ बजे)	☐	☐	☐	☐	☐	☐	_____% कम
मध्यान्ह (१२-१ बजे)	☐	☐	☐	☐	☐	☐	_____% कम
अपरान्ह	☐	☐	☐	☐	☐	☐	_____% कम
(१-५ बजे)	☐	☐	☐	☐	☐	☐	_____% कम
सूर्यास्त (५-९ बजे)	☐	☐	☐	☐	☐	☐	_____% कम
रात्रि (९-१२ बजे)	☐	☐	☐	☐	☐	☐	_____% कम
मध्यरातपछि (१२-६ बजे)	☐	☐	☐	☐	☐	☐	_____% कम

प्र.नं.९ तल दिइएका अवस्थामा विद्युत आपूर्ति वन्द हुँदा तपाईको कम्पनिमा हुने नोक्सानीलाई कम गर्न सकिन्छ ?

(क) छोटो समयका लागि विद्युत बन्द हुने कुरा अग्रिम सूचना गरिदिएमा विद्युत रोकिदा नोक्सान हुने खर्चमा कम हुन सक्छ ?

☐ हुन्छ ? ☐ हुदैन (यदि हुदैन भने प्र.नं.१० मा जानुहोस्)

प्र.नं. ७ मा अनुमान गरिएको पूर्व सूचना नगरि एक घण्टा विद्युत रोकिंदा हुन सक्ने नोक्सानीका तुलनामा निम्न उल्लेखित भिन्न भिन्न समय अगाडि पूर्व सूचना गरिदिंदा तपाईको नोक्सानीमा के कति कमी आउन सक्छ । अनुमान गर्नु होला ।

	पूर्व सूचना गर्ने समयावधी					
	एक घण्टा भन्दा कम	१ देखि ४ घण्टा	५ देखि १६ घण्टा	१७ देखि २४ घण्टा	१ देखि २ दिन	३ दिन भन्दा बढी
प्र.नं.७ मा निकालिएको पूर्व सूचना विहिन जम्मा खर्चबाट घट्ने खर्च	%	%	%	%	%	%
	हरेक पूर्व सूचना समयका लागि प्रतिशतमा खर्च कटौती देखाउनुहोस्					

(ख) विद्युत आपूर्ति रोकिएको समयमा कति समय सम्म विद्युत रोकिन सक्छ भन्ने जानकारी तपाईको कम्पनी दिएको खण्डमा नोक्सानीलाइ घटाउन संभव छ ?

☐ छ ? ☐ छैन (छैन भने प्र.नं. १० मा जानुहोस)

विद्युत रोकिने शुरुको अवस्थामा नै तपाईलाई कति समयका लागि विद्युत रोकिन सक्छ भन्ने जानकारी दिइयो भने तपाईको उत्पादनमा हुने नोक्सानी कति प्रतिशतले कम हुन्छ ?

	विद्युत रोकिने समय अवधी					
	१ मिनेट	२० मिनेट	१ घण्टा	४ घण्टा	८ घण्टा	१ दिन
प्र.नं.७ मा निकालिएको पूर्व सूचना नदिंदा हुने जम्मा खर्चबाट घट्ने खर्च	%	%	%	%	%	%
	हरेक विद्युत रोकिने समयावधीकोलागि कति % कम खर्च हुनसक्छ अनुमान गर्नुहोस् ।					

प्र.नं.१० भोल्टेज तथा फ्रिक्वेन्सी घटबढ भएको अवस्थामा असर पर्ने उपकरणहरु कारखानामा छन् कि ?

प्रभावित हुने अवस्था:	छ	छैन	थाहा छैन	छ भने असरपर्ने उपकरणहरुको नाम लेख्नुहोस्
फ्रिक्वेन्सीमा घटबढ	___	___	___	_____
भोल्टेजमा घटबढ	___	___	___	_____

प्रत्येक हरपमा एउटा कोठामा मात्र चिन्ह लगाउनुहोस

प्र.नं.११ (क) तपाईको कम्पनी निम्न सूची अनुसार कुन चाँहि संग मिल्न आउँछ उपयुक्त कोठामा चिन्ह लगाउनु होस् ।

___ काठको गोदाम ।
___ दुग्ध उत्पादन ।
___ खानी संबन्धी ।
___ पेट्रोलियम तथा ग्याँस ।
___ क्वोरी तथा स्यान्ड पिट ।
___ सिमेन्ट उद्योग ।
___ चिनी मिल ।
___ खाद्य उद्योग ।
___ पेय पदार्थ उद्योग ।
___ सुर्ति उद्योग ।
___ रवर उत्पादन ।
___ प्लास्टिक उद्योग ।
___ छाला वा छालाजन्य उद्योग ।
___ कपडा उद्योग ।
___ इन्धन वा कोइला उद्योग ।
___ फर्निचर संवन्धी ।
___ कागज संबन्धीत उद्योग ।
___ छपाई उद्योग ।
___ प्राथमिक धातु उद्योग ।
___ धातुका सामान बनाउने उद्योग ।
___ मेशिन कारखाना ।
___ सवारी उपकरण ।
___ विद्युतीय वा इलेक्ट्रोनिक उद्योग ।
___ खनिज पदार्थ उत्पादन ।
___ ईटा कारखाना ।
___ औषधि वा जडीवुटी सम्बन्धी उद्योग ।
___ अन्य उत्पादनमूलक उद्योग ।

_____
(कृपया खुलाउनुहोस्)

(ख) तपाईको उद्योगले उत्पादन गर्ने मुख्य सामानहरु के के हुन् ?

_____

_____

प्र.नं.१२. गएको १२ महिनामा तपाईको उद्योगमा पूरै समय वा आंशिक समय कार्य गर्ने अन्दाजी कति जना कामदार (स्टाफ) थिए ?

पूरा समय _____ आंशिक समय _____

प्र.नं.१३. दिनमा कति सिफ्ट तपाईको कम्पनीमा कार्य हुने गर्दछ ?

☐ एक ☐ दुई ☐ तीन ☐ अन्य _____

प्र.नं.१४. तपाईको कम्पनीको विद्युत माग कति छ ?

_____ (किलो वाटमा) _____ (के.भिए.मा) _____ (मिटर एम्पीयर)

प्र.नं.१५. सालाखाला महिनाको कति विद्युत युनिट तपाईको कम्पनीले खपत गर्ने गरेको छ ?

_____ खपत युनिट

प्र.नं.१६. विद्युत आपूर्ति रोकिनाले हुन सक्ने असरहरु तथा नोक्सानी बारे वा नेपालमा विद्युत सेवालाई सुचारुरुपले चलाउन प्राधिकरणले अपनाउनु पर्ने उपायहरु बारे केही सुझाव दिन चाहनु हुन्छ भने कृपा गरी भन्नु होला ।

धन्यवाद
इन्जीनियरिङ्ग अध्ययन संस्थान, नेपाल
क्यानेडियन अन्तराष्ट्रिय विकास एजेन्सी

तपाईको नाम तथा ठेगाना

_____

_____

C. 3. Additional Survey Results

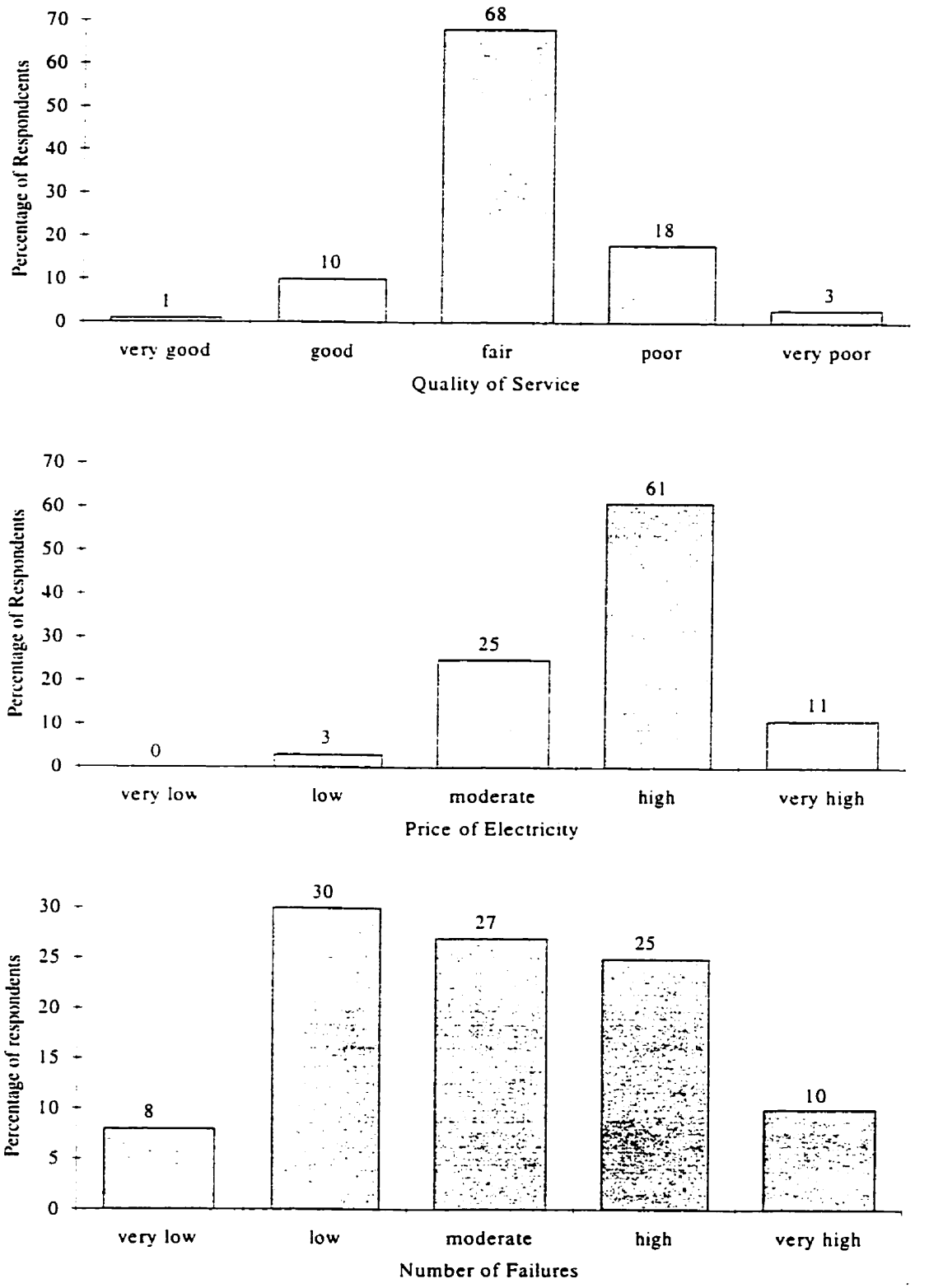


Figure C.1. Respondents' Opinions Regarding Service, Price and Number of Failures

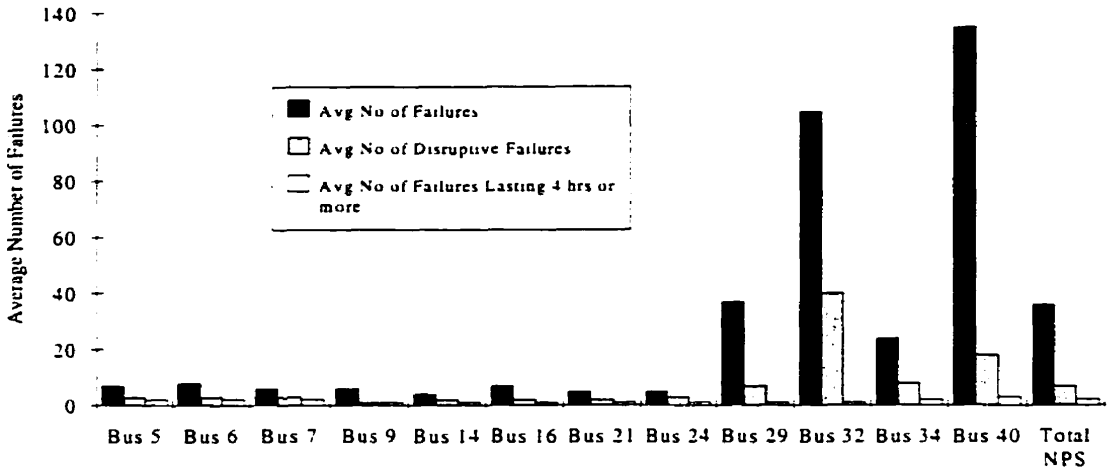


Figure C.2. Average Number of Failures in Two Months Reported by Residential Customers

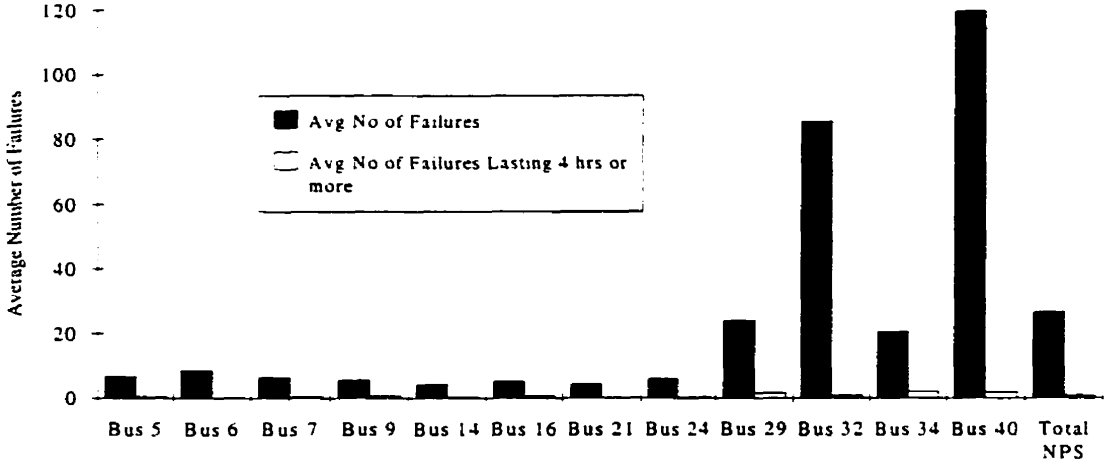


Figure C.3. Average Number of Failures in Two Months Reported By Commercial Customers

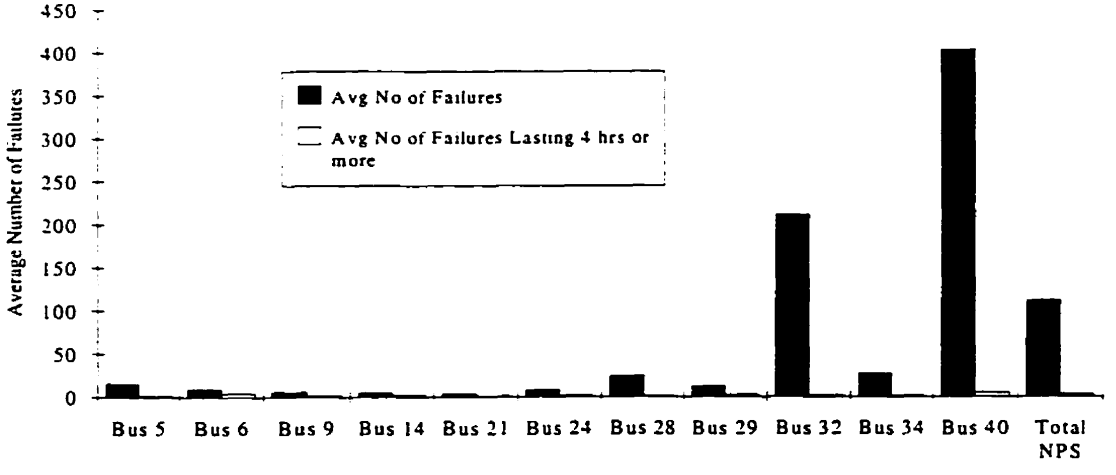


Figure C.4. Average Number of Failures in Two Months Reported By Industrial Customers

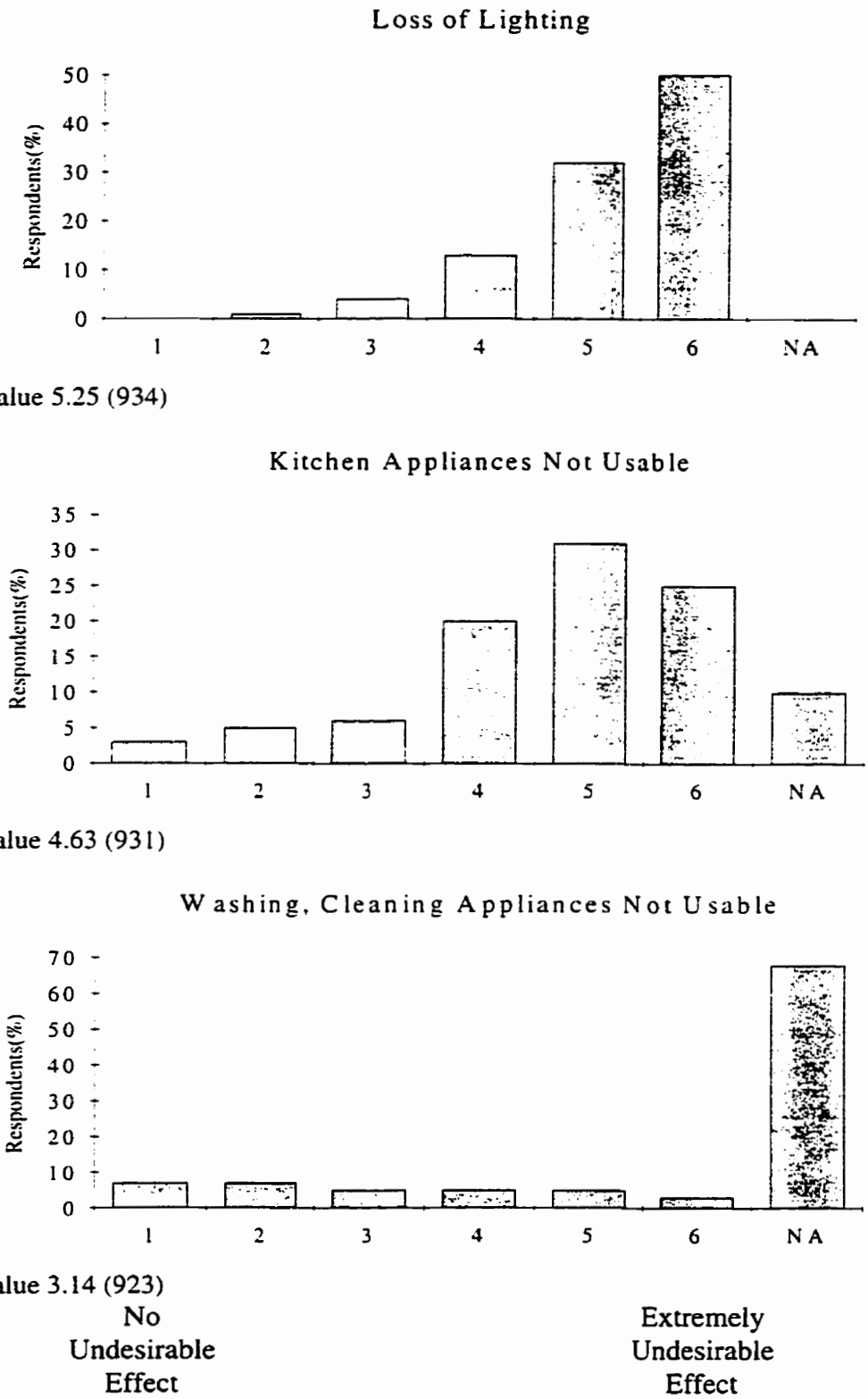
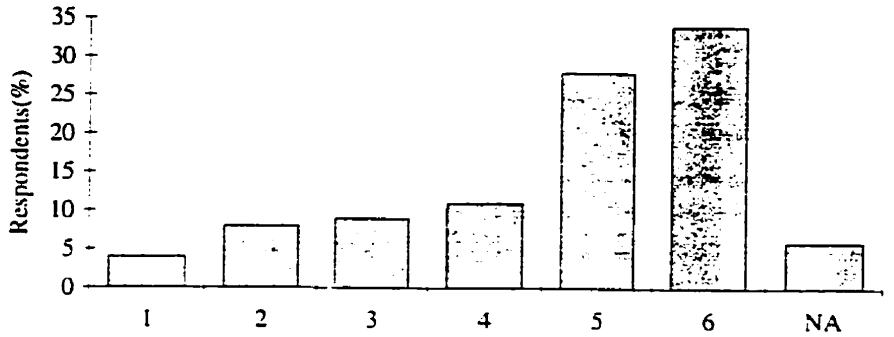


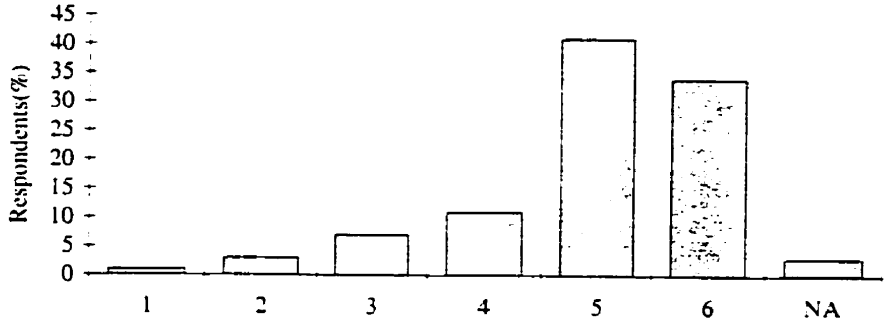
Figure C.5. Interruption Effects on Household Activities

Electric Fans, Heaters Not Usable



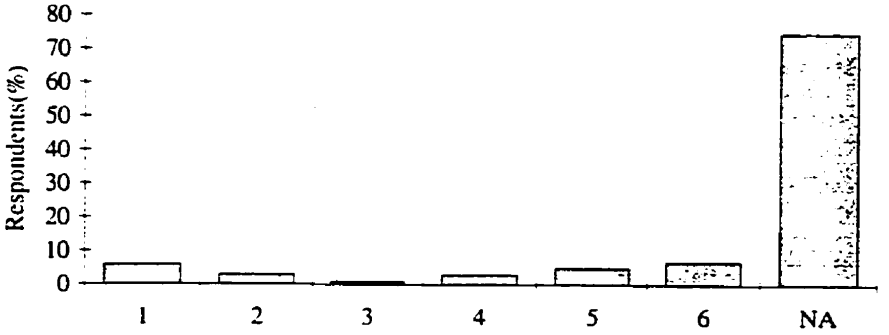
Mean Value 4.63 (932)

TV, VCR, Radio Not Usable



Mean Value 4.92 (927)

Loss of Use of Computer



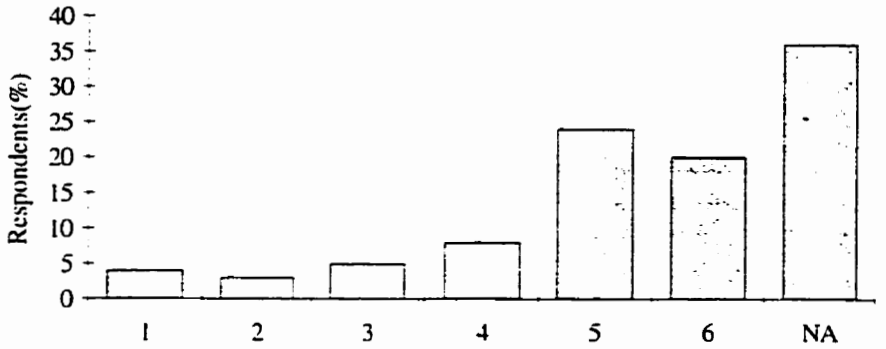
Mean Value 3.66 (921)

No Undesirable Effect

Extremely Undesirable Effect

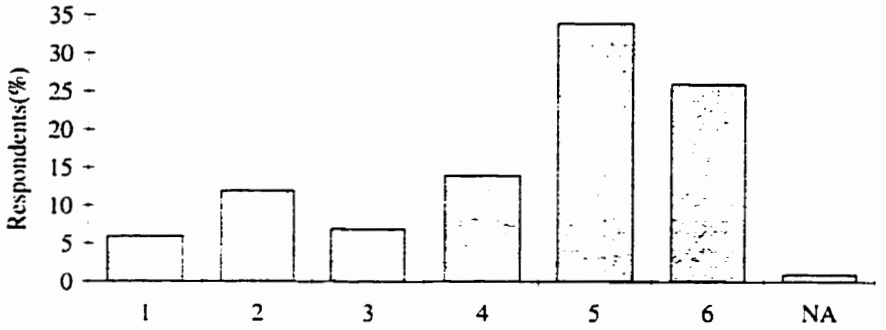
Figure C.5.(contd.) Interruption Effects on Household Activities

Motor-Pump Not Usable



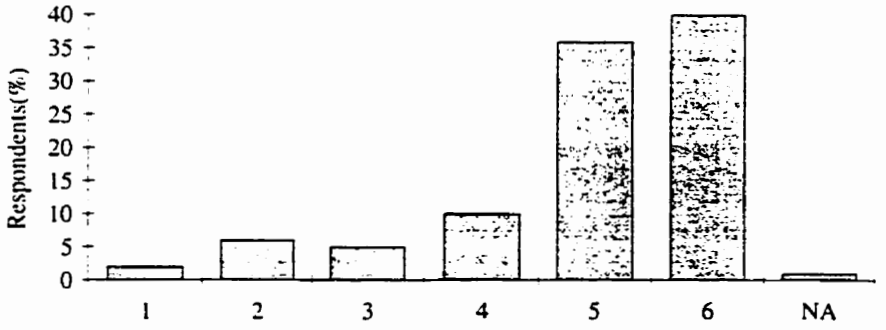
Mean Value 4.64 (926)

Fear of Accidents in the Home



Mean Value 4.38 (924)

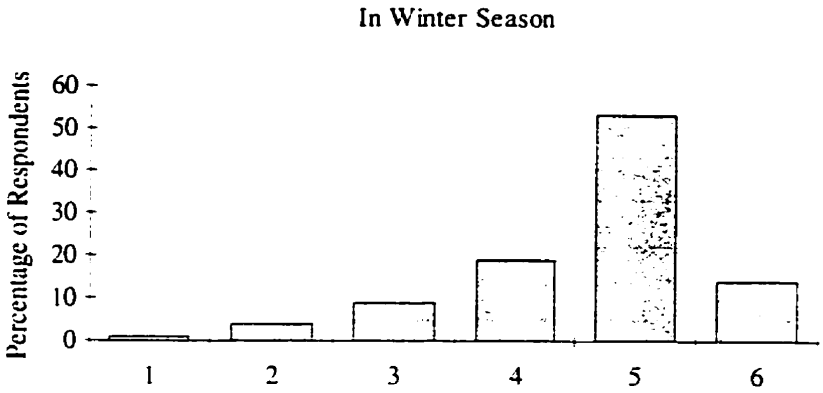
Fear of Crime



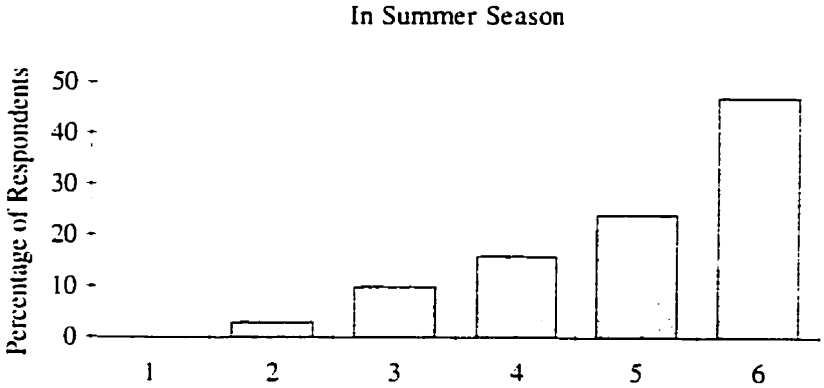
Mean Value 4.95 (930)

No Undesirable Effect — Extremely Undesirable Effect

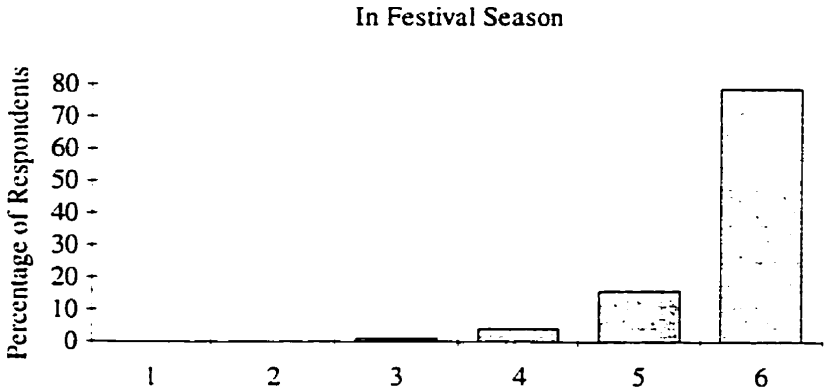
Figure C.5.(contd.) Interruption Effects on Household Activities



Mean Value 4.63 (937)



Mean Value 5.01 (932)

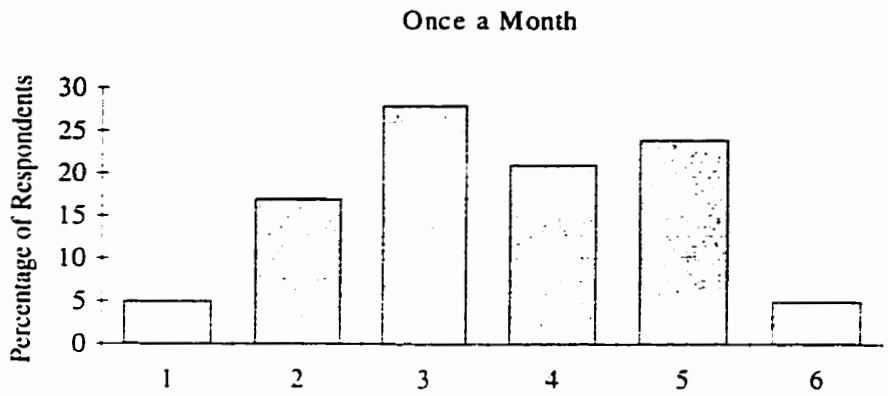


Mean Value 5.70 (934)

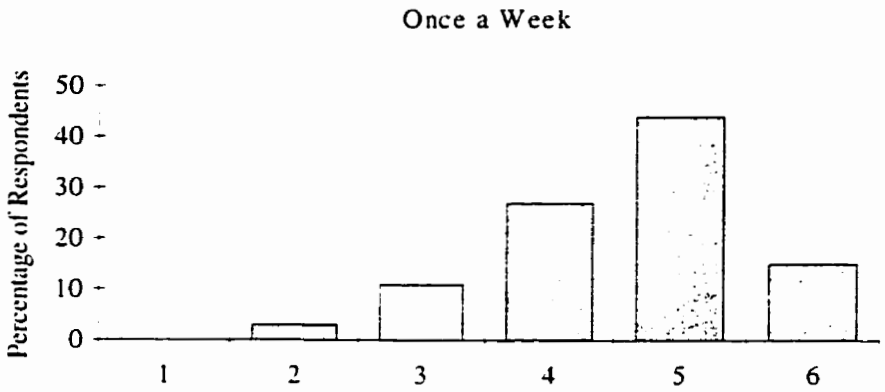
No Undesirable Effect

Extremely Undesirable Effect

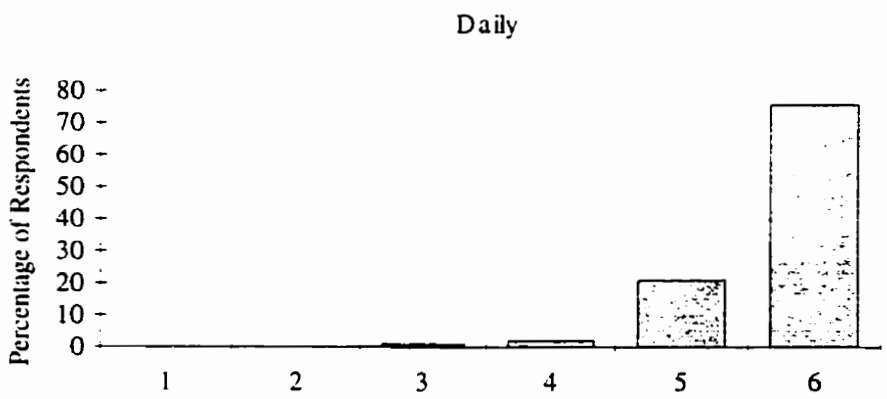
Figure C.6. Undesirability of Interruption Effects as a Function of Season



Mean Value 3.63 (935)



Mean Value 4.55 (930)



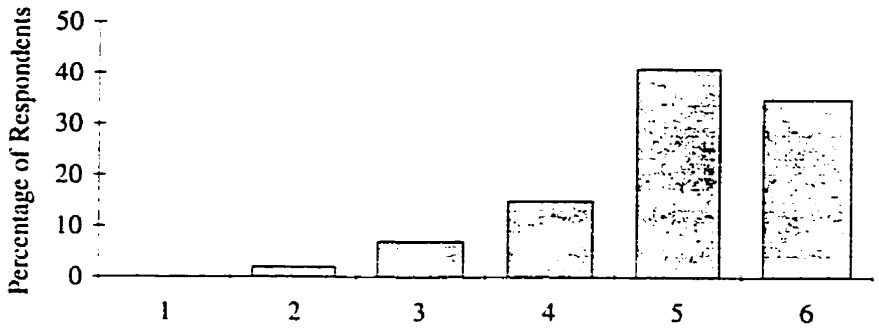
Mean Value 5.72 (928)

No Undesirable Effect

Extremely Undesirable Effect

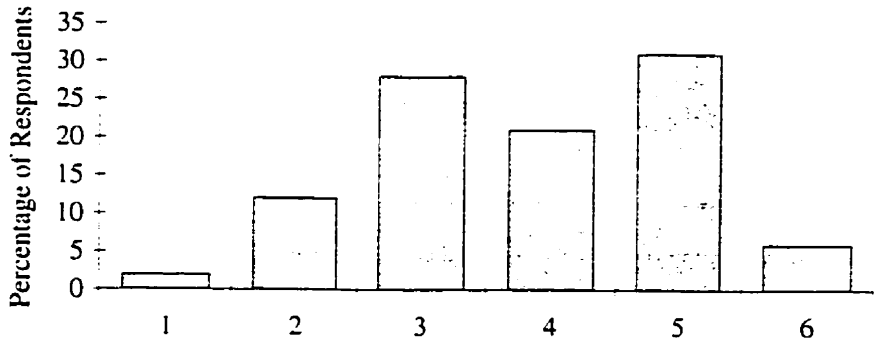
Figure C.7. Undesirability of Interruption Effects as a Function of Frequency

After 5 pm and lasted 4 hours



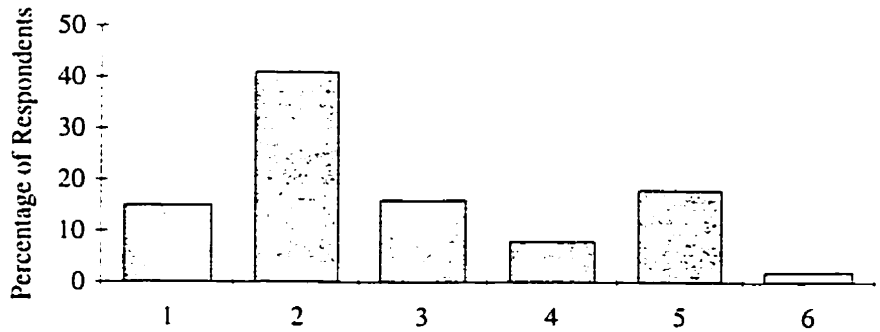
Mean Value 5.00 (934)

After 5 pm and lasted 1 hour



Mean Value 3.84 (930)

After 5 pm and lasted 20 minutes



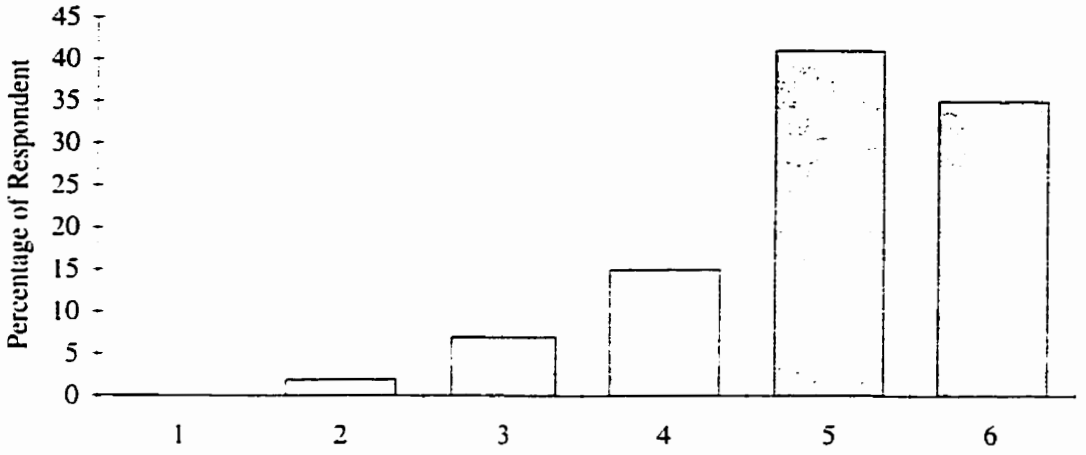
Mean Value 2.79 (931)

No Undesirable Effect

Extremely Undesirable Effect

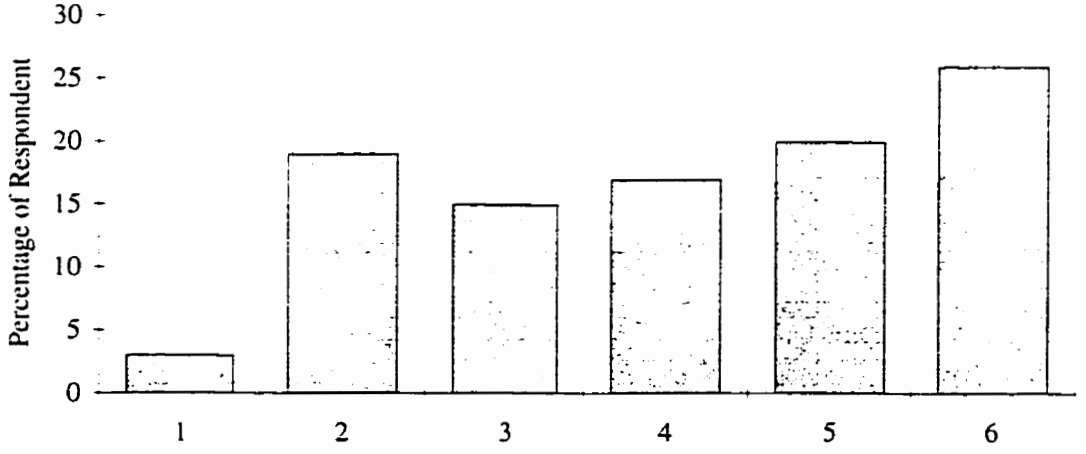
Figure C.8. Undesirability of Interruption Effects as a Function of Duration

After 5 PM and Lasted 4 Hours



Mean Value 5.00 (934)

Before 5 PM and Lasted 4 Hours

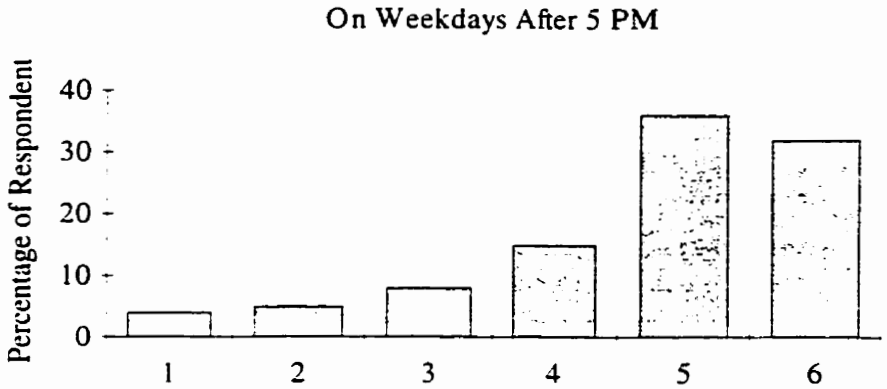


Mean Value 4.09 (935)

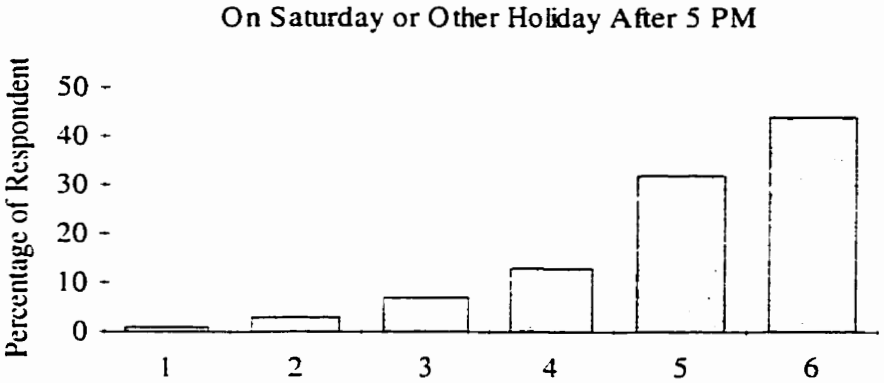
No Undesirable Effect

Extremely Undesirable Effect

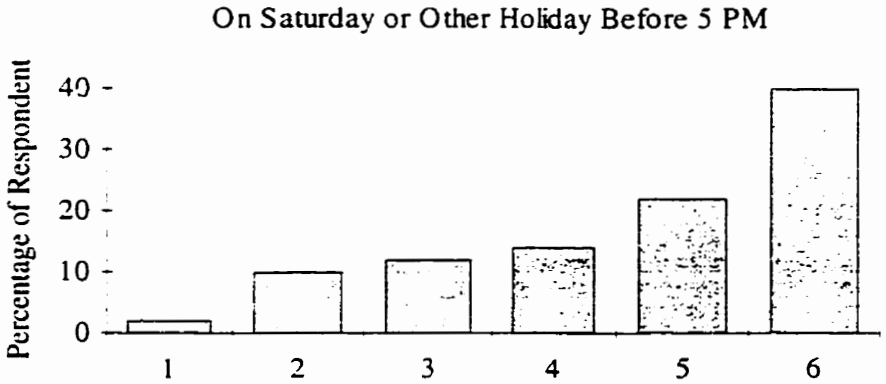
Figure C.9. Undesirability of Interruption Effects as a Function of the Time of a Day



Mean Value 4.69 (932)



Mean Value 5.04 (931)



Mean Value 4.64 (931)

No Undesirable Effect

Extremely Undesirable Effect

Figure C.10. Undesirability of Interruption Effects as a Function of the Day of a Week

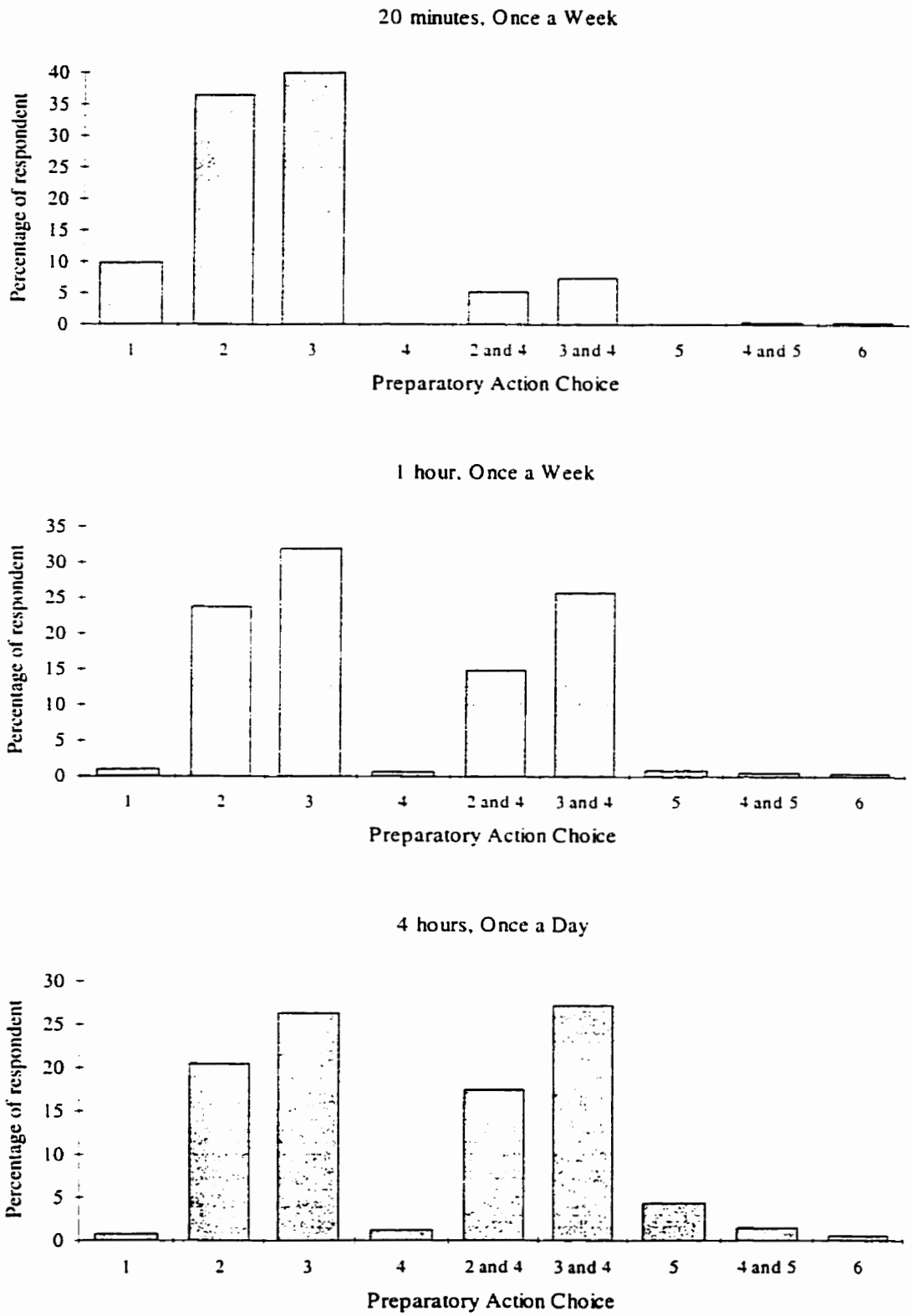


Figure C.11. Variation of Preparatory Action Choices with Interruption Characteristics

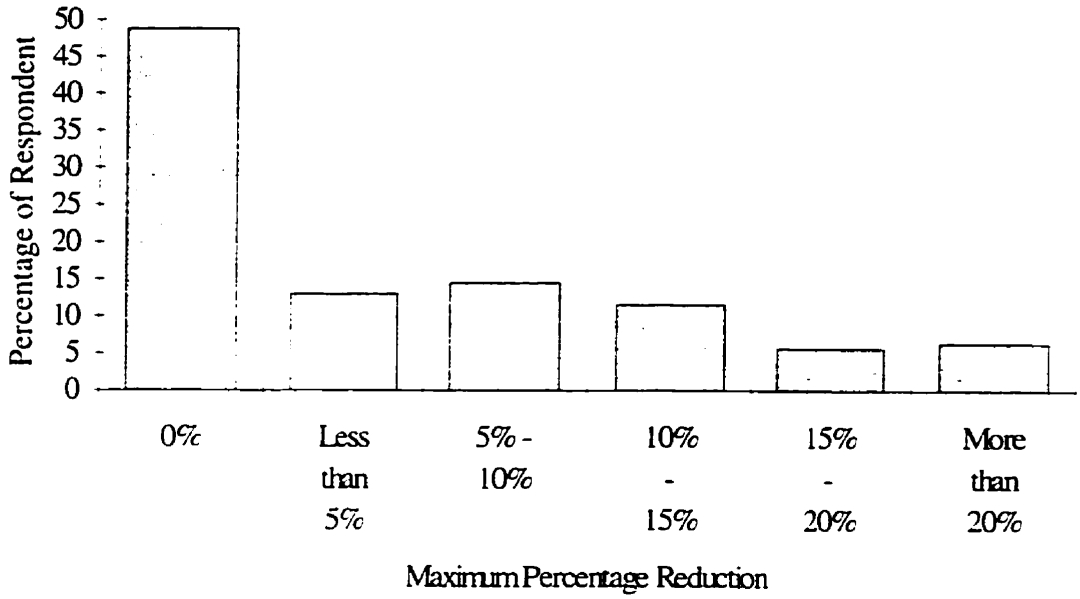


Figure C.12. Residential Respondents' Willingness to Reduce Consumption

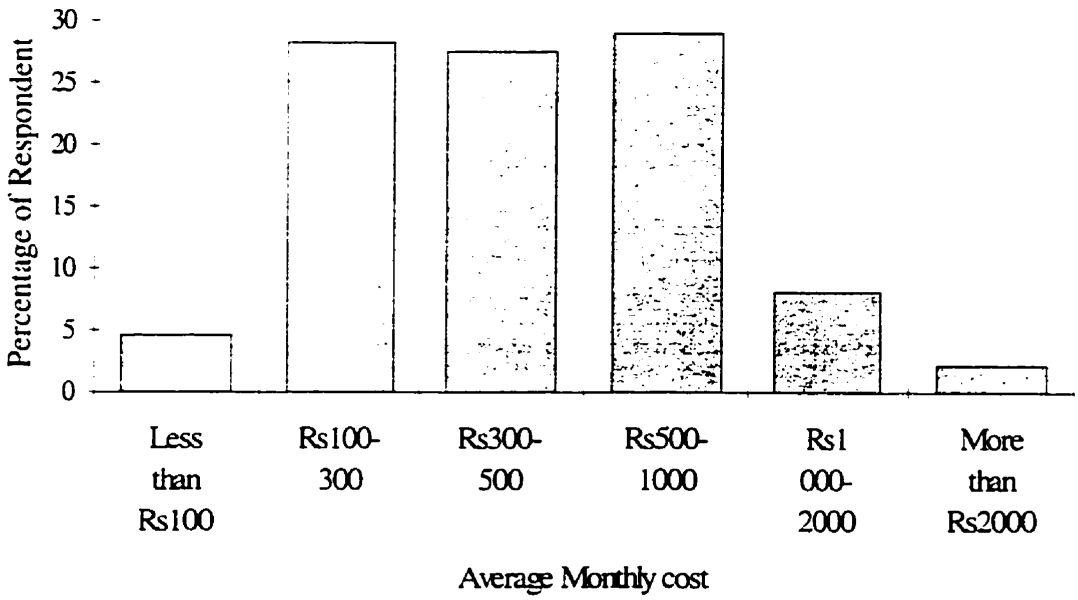


Figure C.13. Residential Estimate of Average Monthly Cost of Electricity

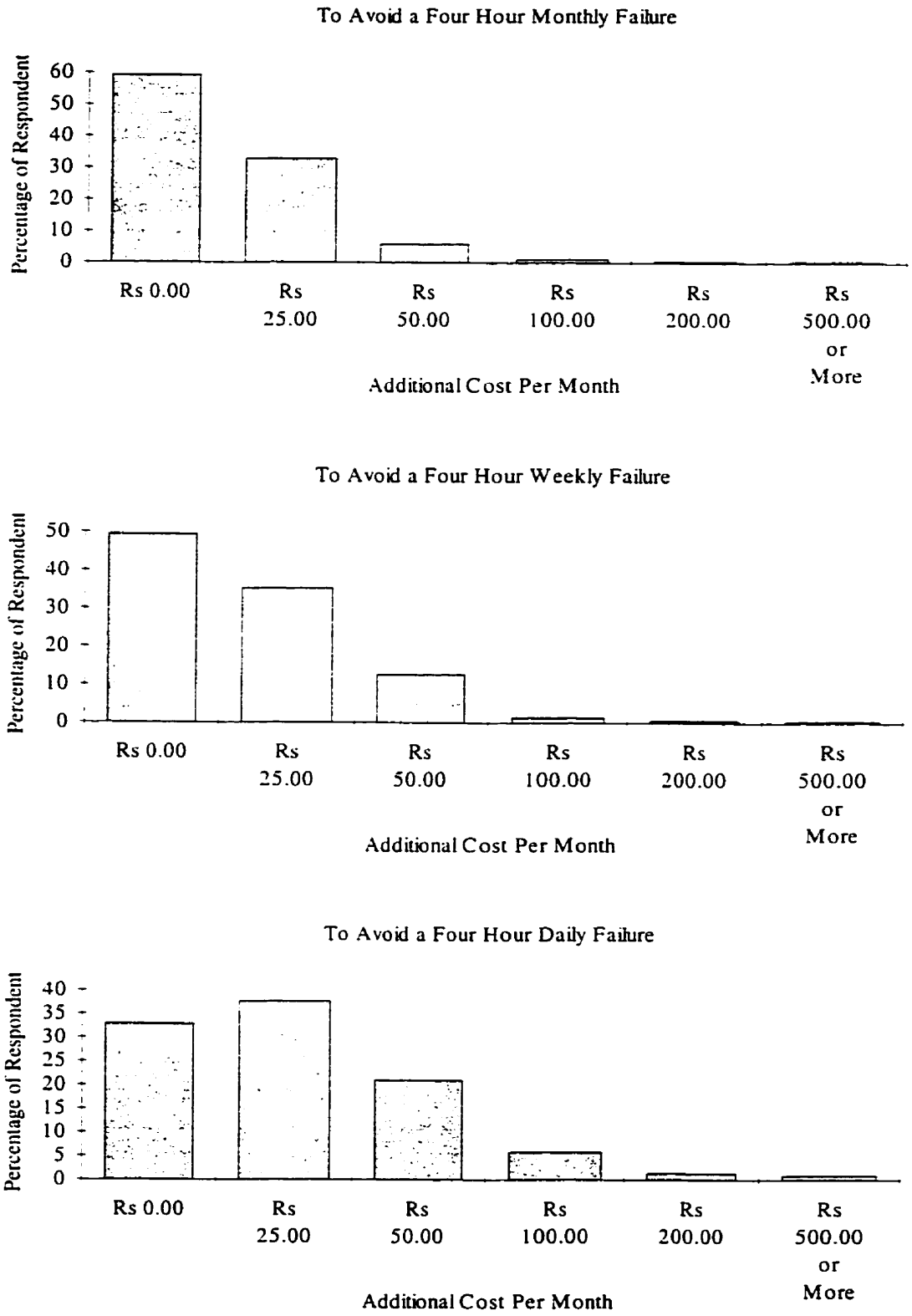


Figure C.14. Residential Respondents' Willingness-to-Pay for an Assured System

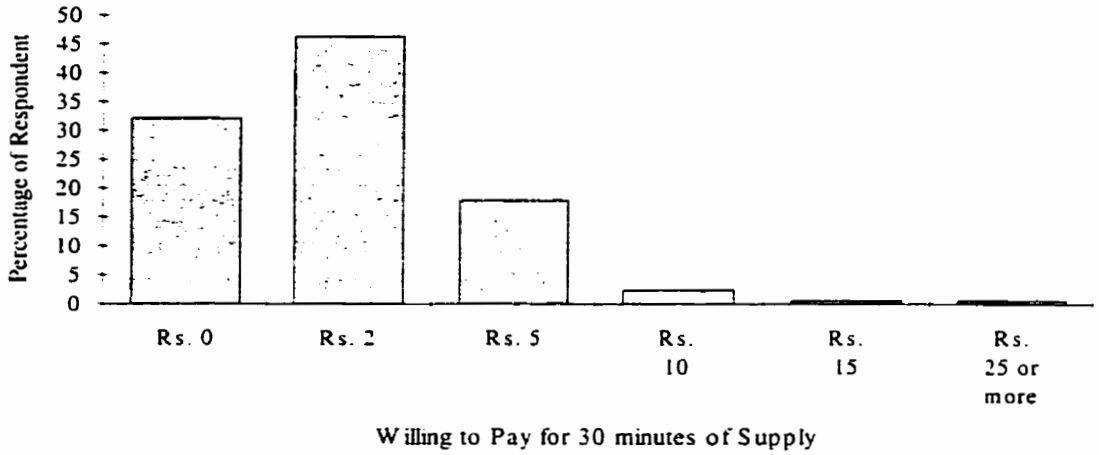


Figure C.15. Respondents' Willingness-to-Pay for an Independent Source of Electricity

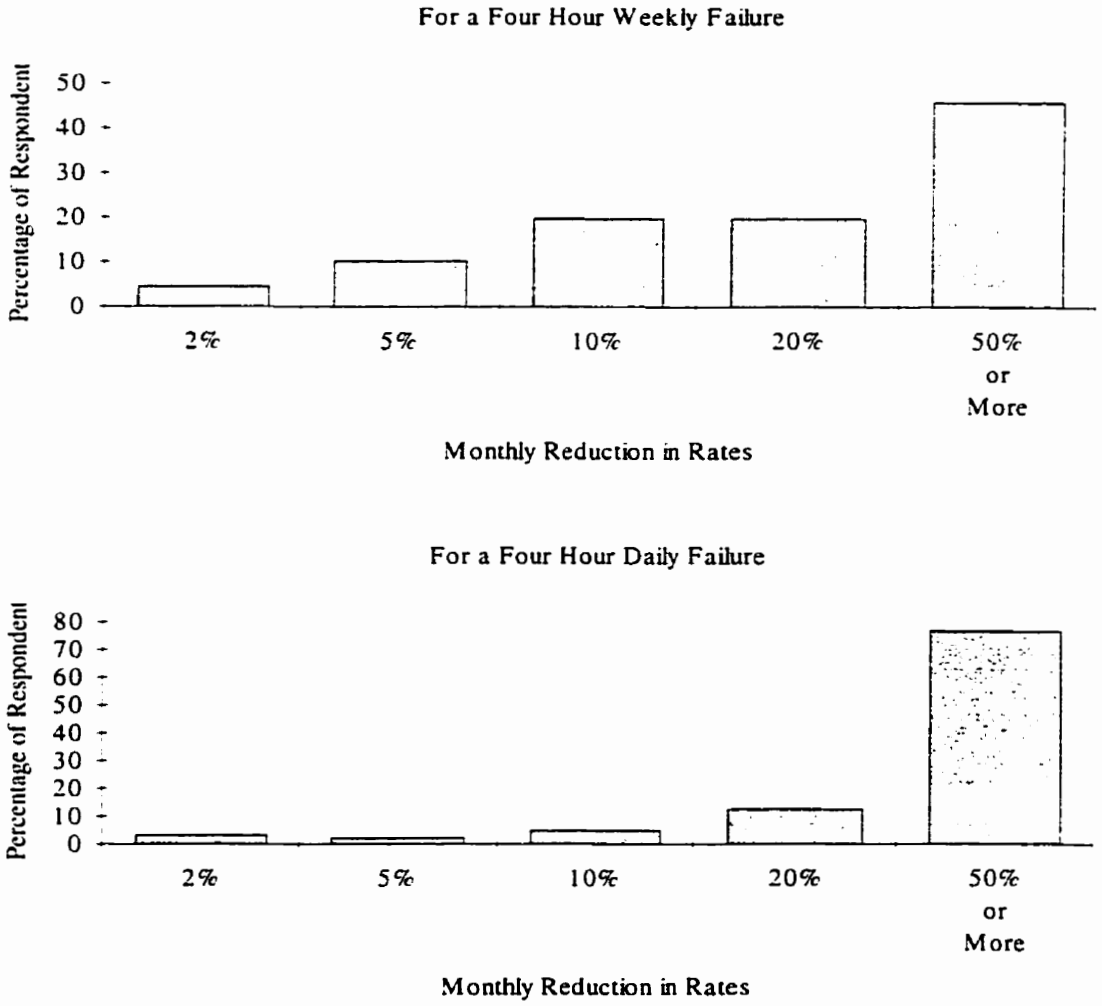
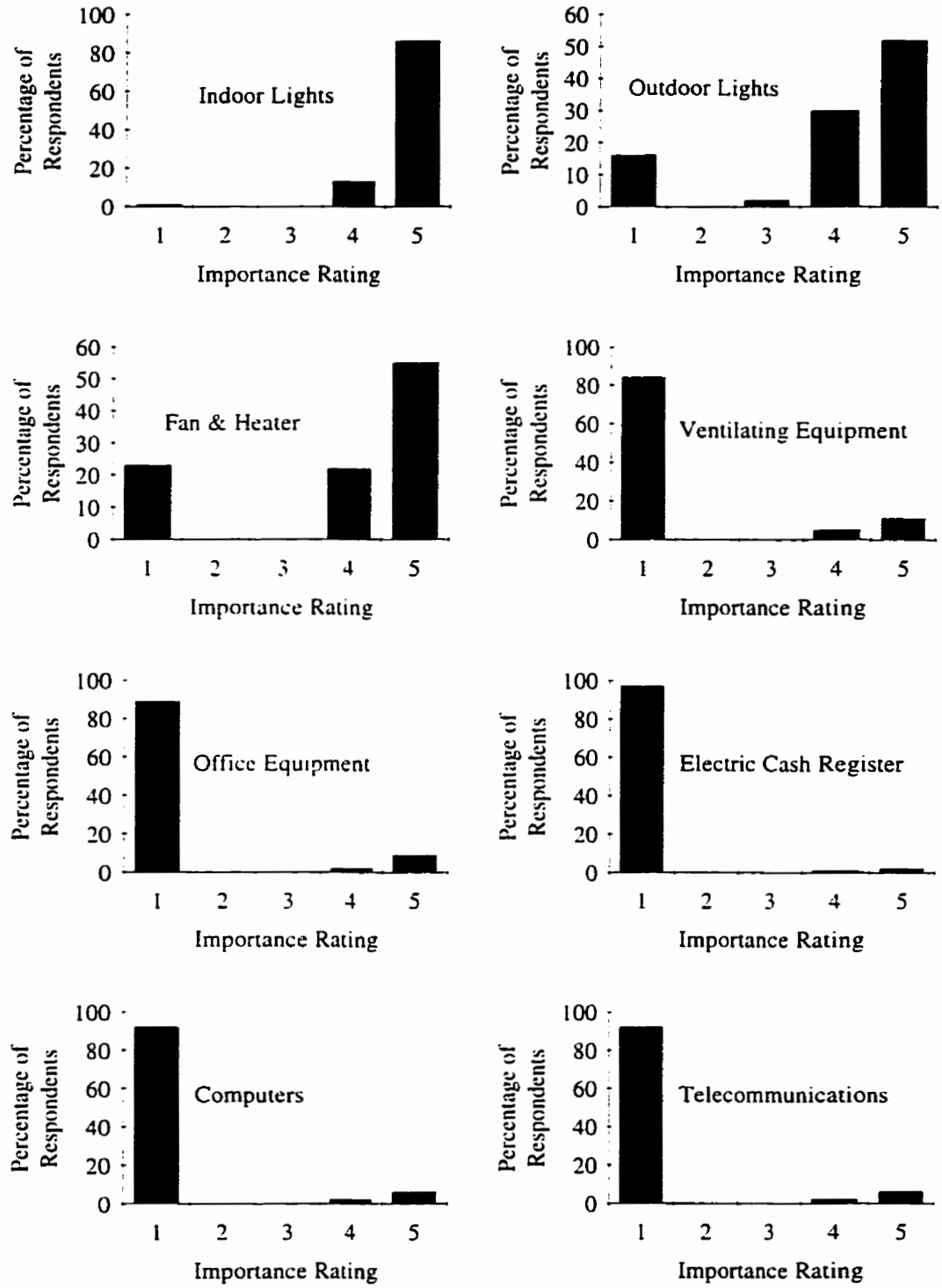
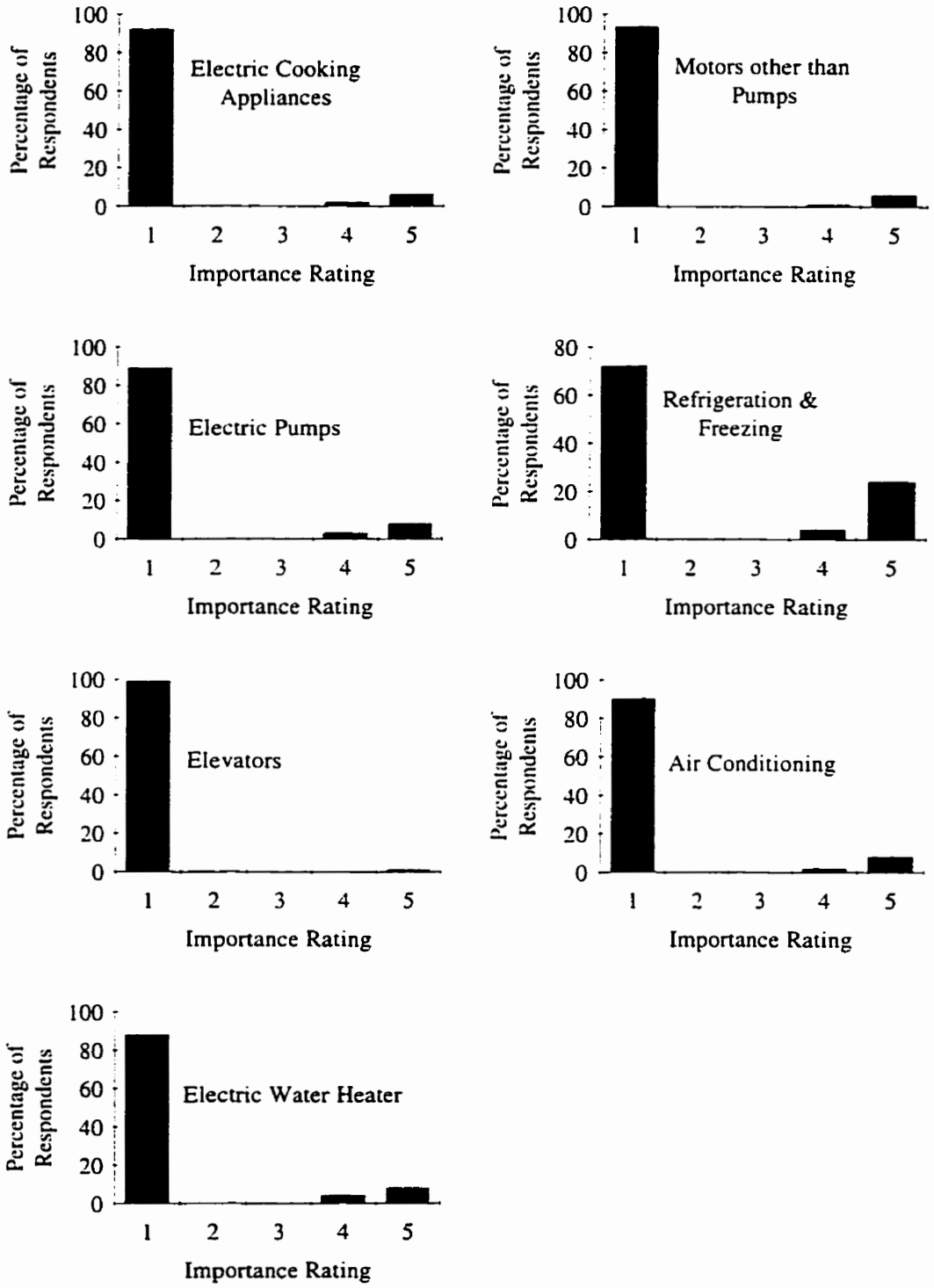


Figure C.16. Residential Respondents' Willingness-to-Accept a Reduction in Rates



KEY: 1 = Do not have in the Company, 2 = Not at all Important, 3 = Not very Important, 4 = Important, 5 = Very Important

Figure C.17. Importance Ratings given by the Commercial Customers for Electrical Equipment



KEY: 1 = Do not have in the Company, 2 = Not at all Important, 3 = Not very Important, 4 = Important, 5 = Very Important

Figure C.17.(contd.) Importance Ratings given by the Commercial Customers for Electrical Equipment

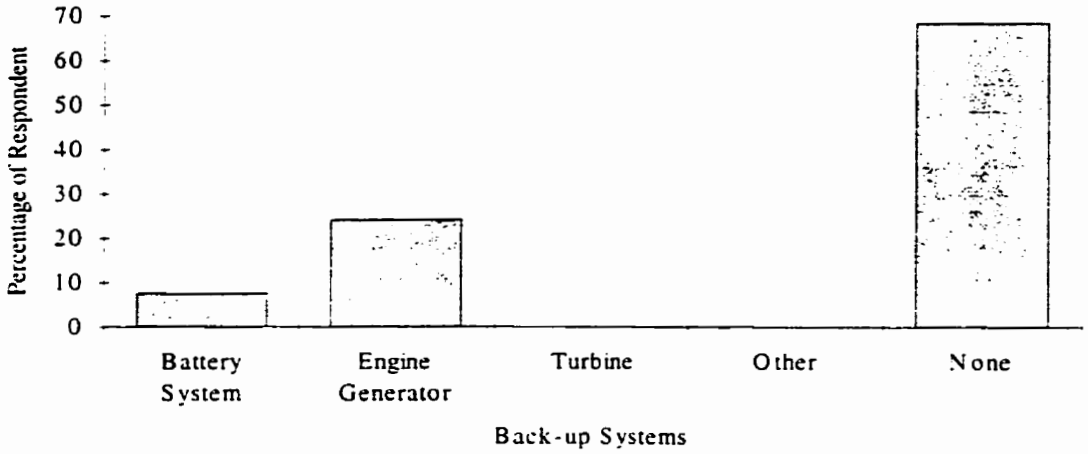


Figure C.18. Back-up Systems Reported by Commercial Customers

Figure C.19. Health and Safety Hazard due to Electric Interruptions Reported by Commercial Customers

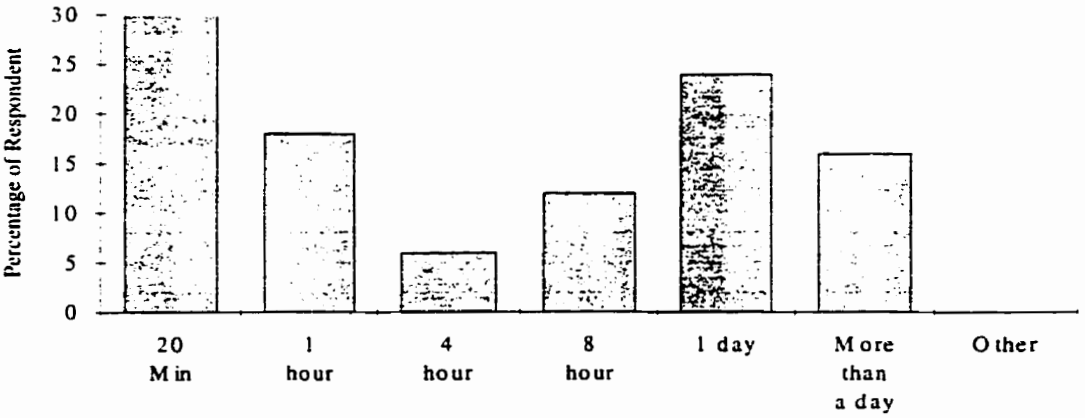


Figure C.20. Shortest Warning Time Necessary to Reduce Health and Safety Hazard Reported by Commercial Customers

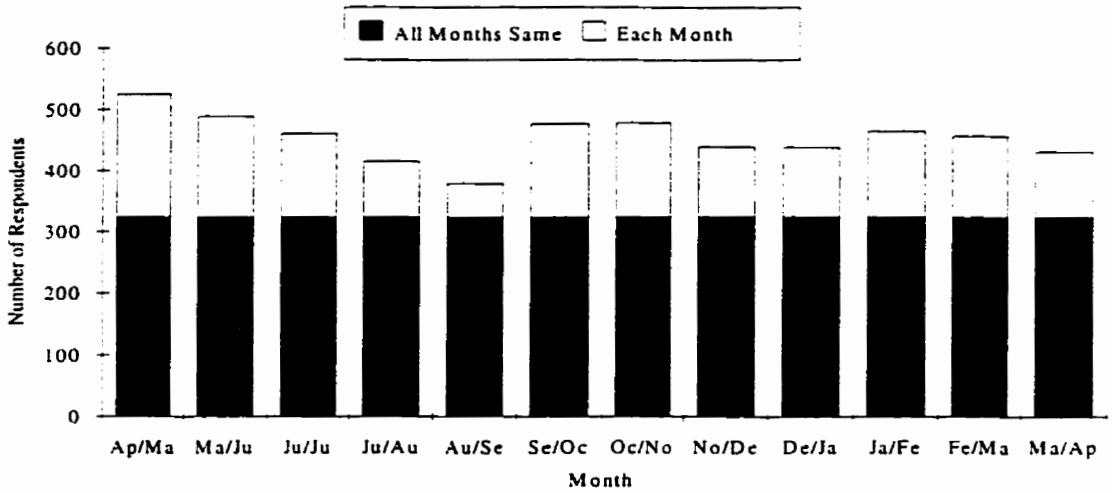


Figure C.21. Worst Month for an Interruption to occur Reported by Commercial Customers

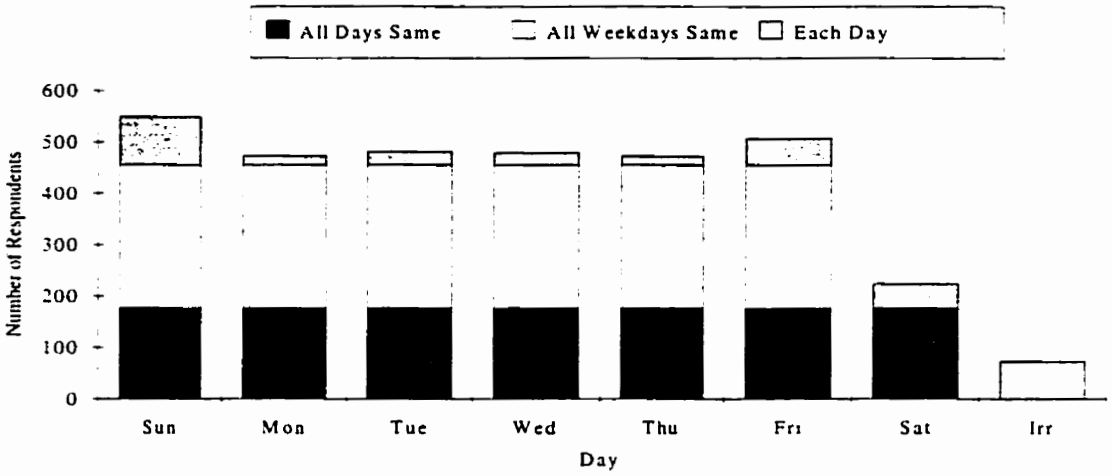


Figure C.22. Worst Day of the Week for an Interruption to Occur for Commercial Customers

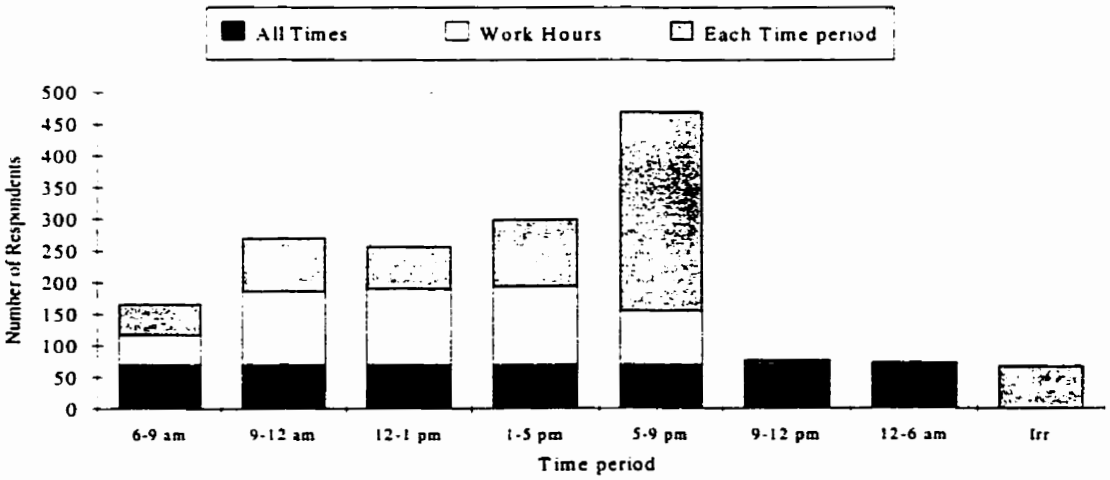


Figure C.23. Worst Time of the Day for an Interruption to Occur Reported by Commercial Customers

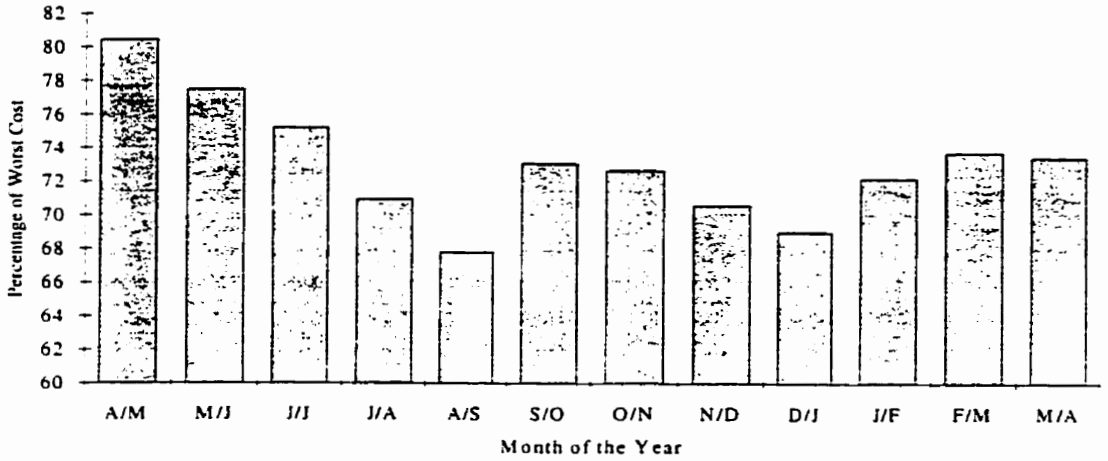


Figure C.24. Monthly Cost Variation as Reported by Commercial Customers

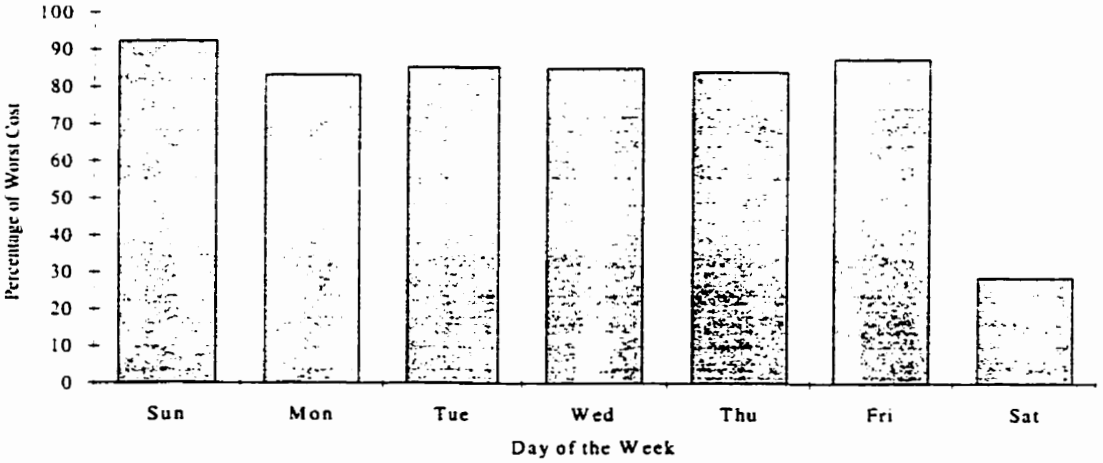


Figure C.25. Weekly Cost Variation Reported by Commercial Customers

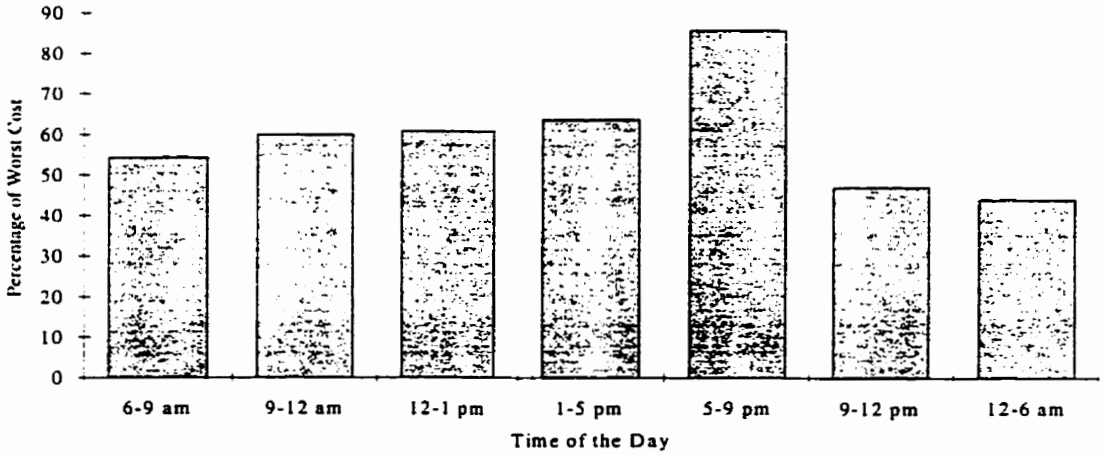
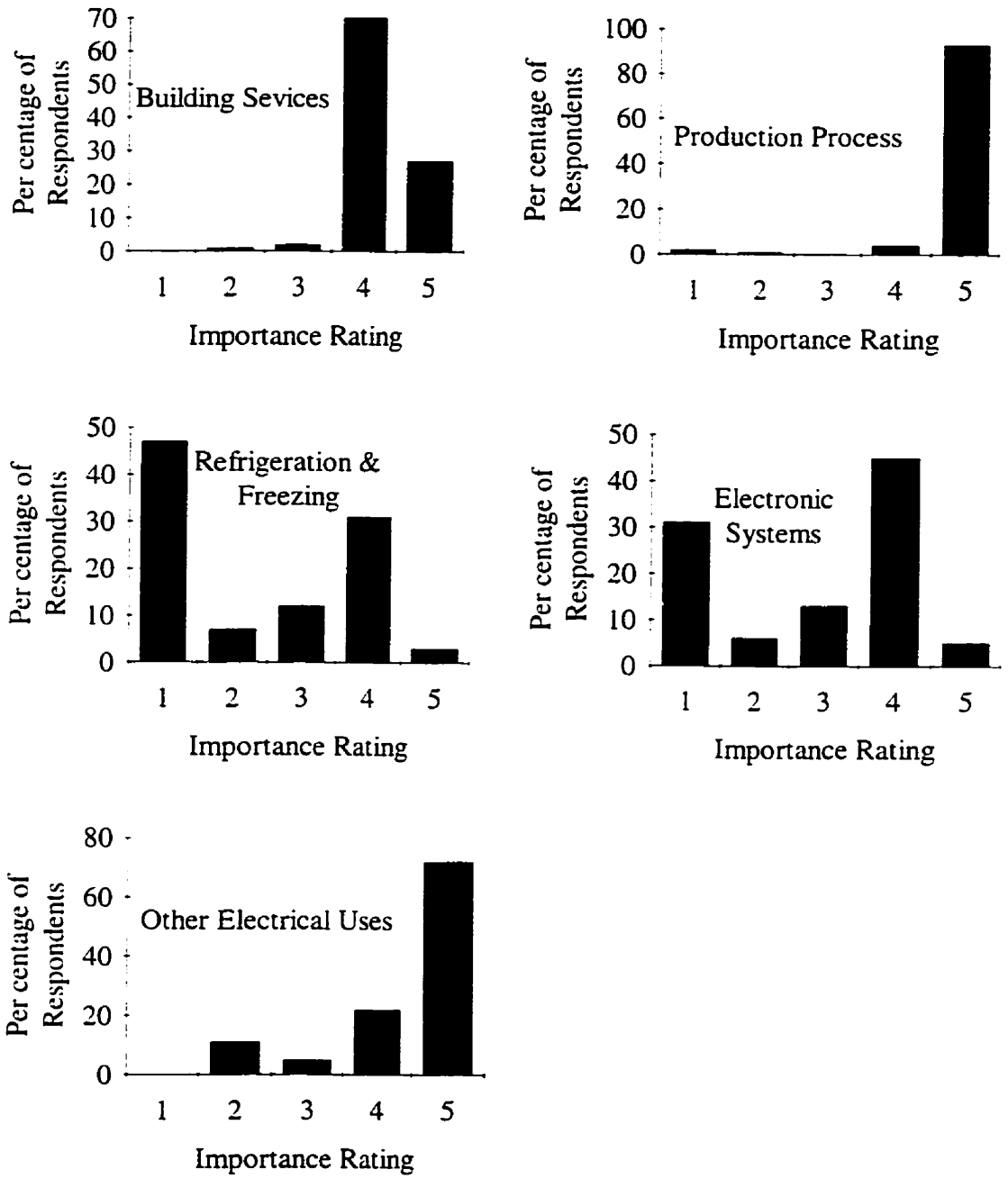


Figure C.26. Daily Cost Variation Reported by Commercial Customers



KEY : 1 = Do not have in the Company, 2 = Not at all Important, 3 = Not very Important, 4 = Important, 5 = Very Important

Figure C.27. Importance Ratings for Industrial Uses of Electricity

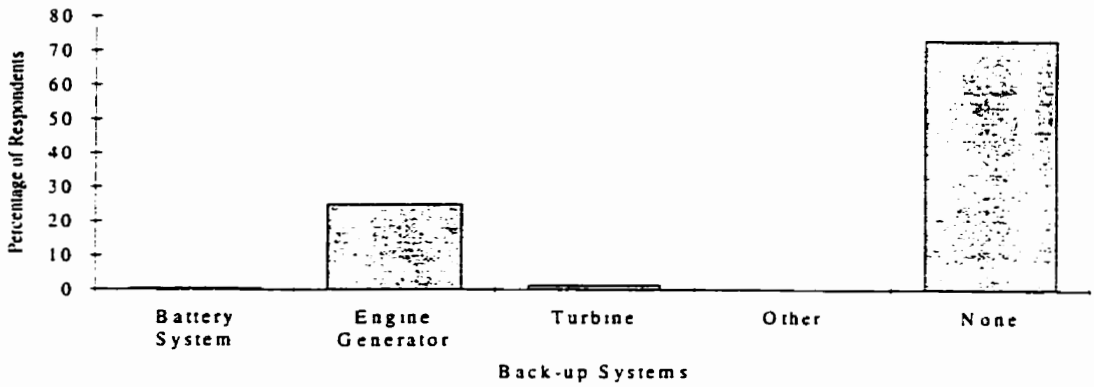


Figure C.28. Back-up Systems Reported by Industrial Customers

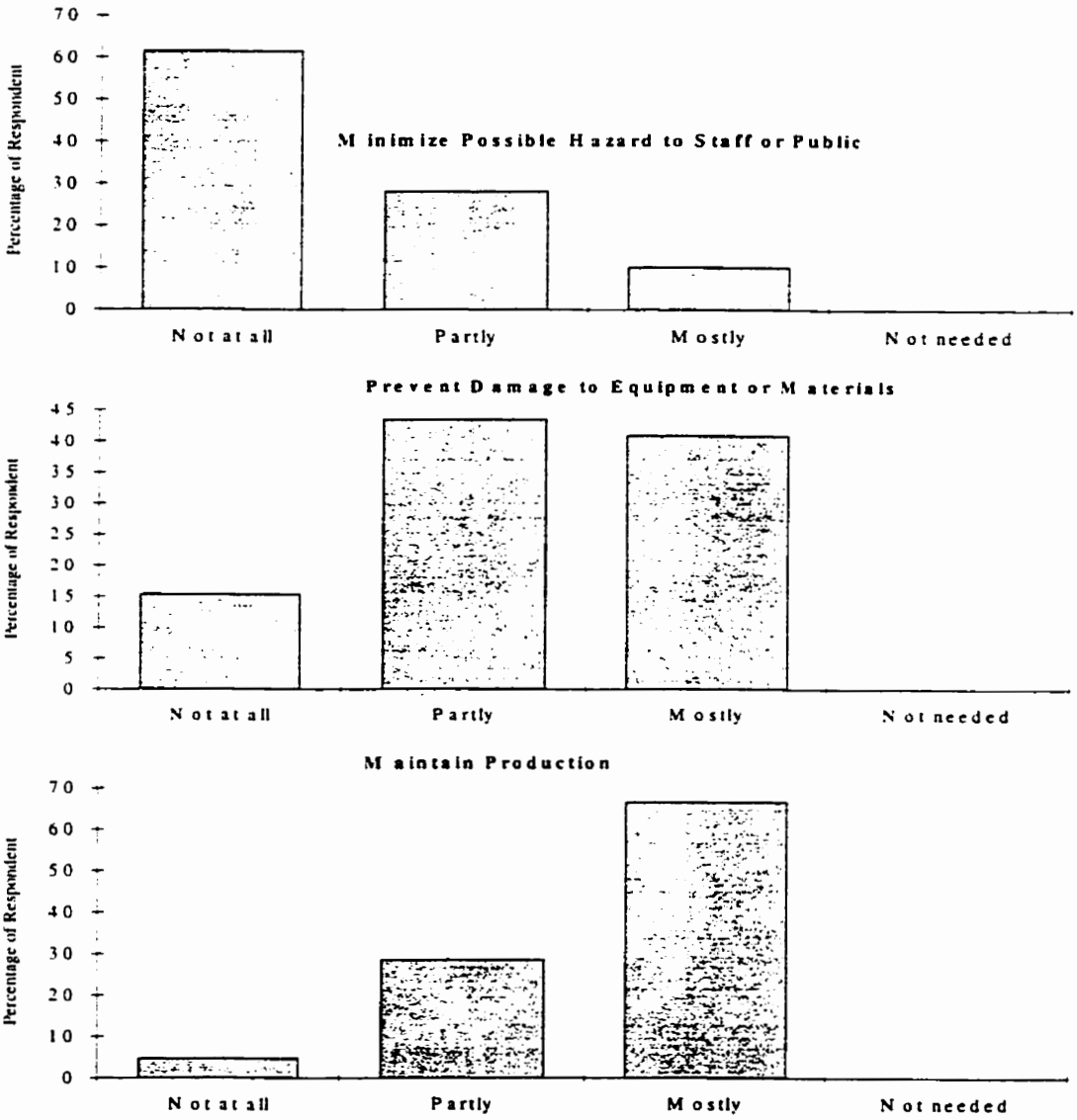


Figure C.29. Back-up Uses Reported by Industrial Customers

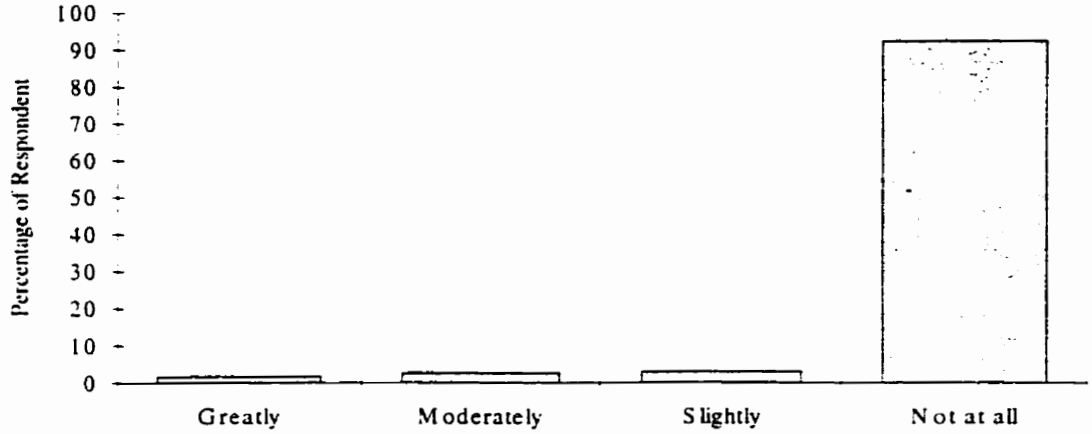


Figure C.30. Safety Hazards due to Electric Interruption Reported by Industrial Customers

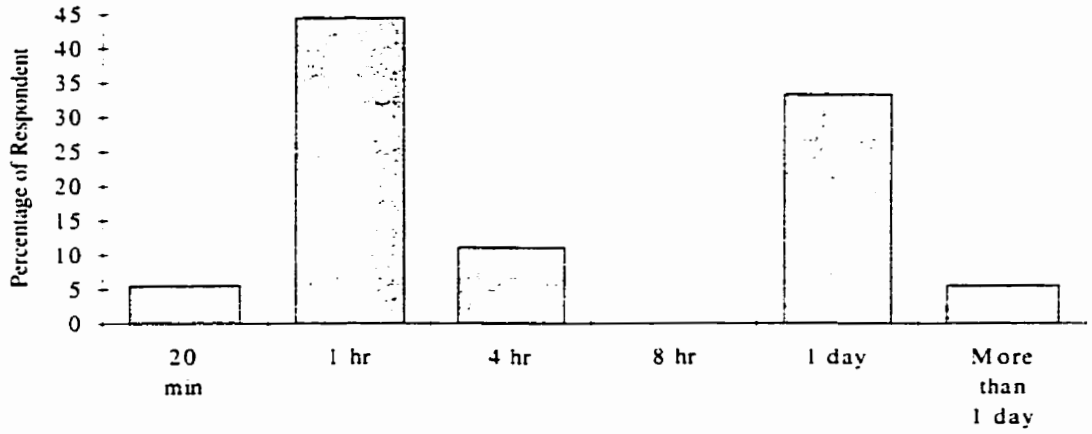


Figure C.31. Shortest Warning Time to Reduce interruption Hazards for Industrial Customers

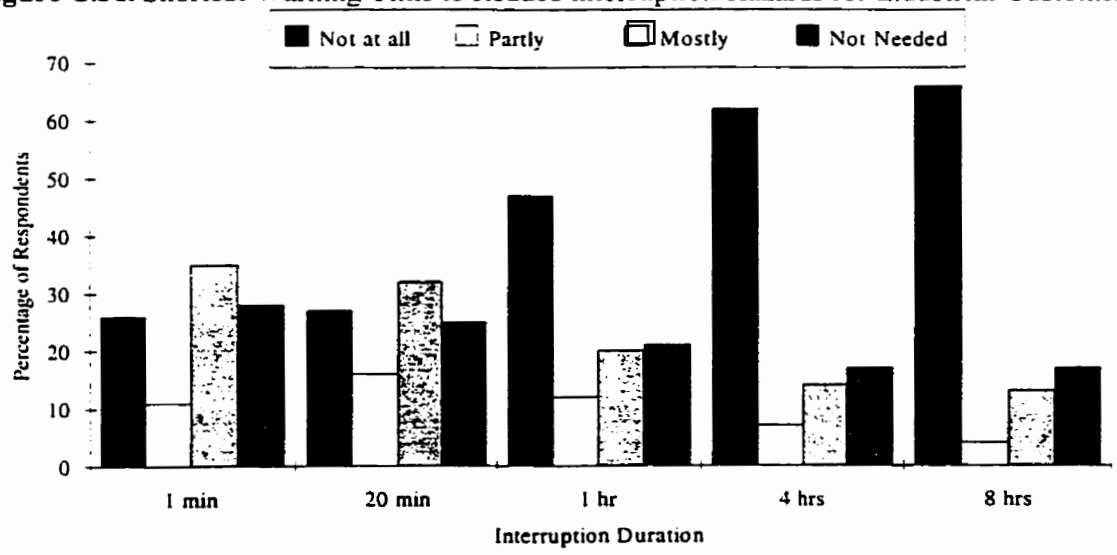


Figure C.32. Ability to Make Up Lost Production Without Overtime or Additional Staff

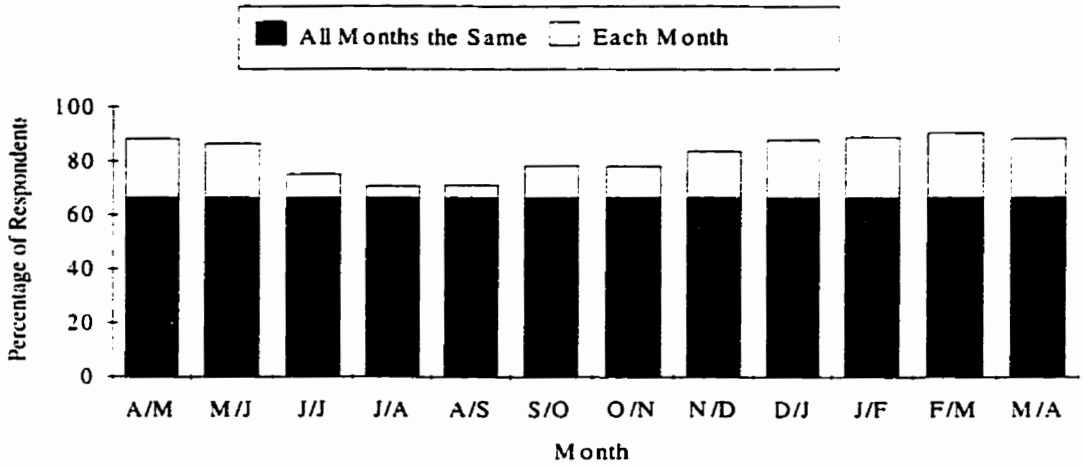


Figure C.33. Worst Month for an Interruption to Occur for Industrial Customers

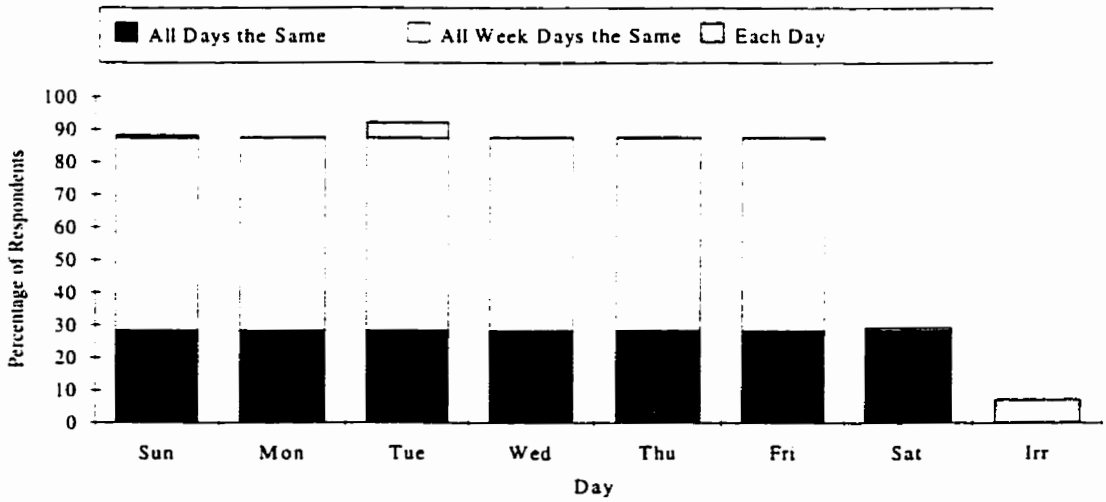


Figure C.34. Worst Day of the Week for an Interruption to Occur for Industrial Customers

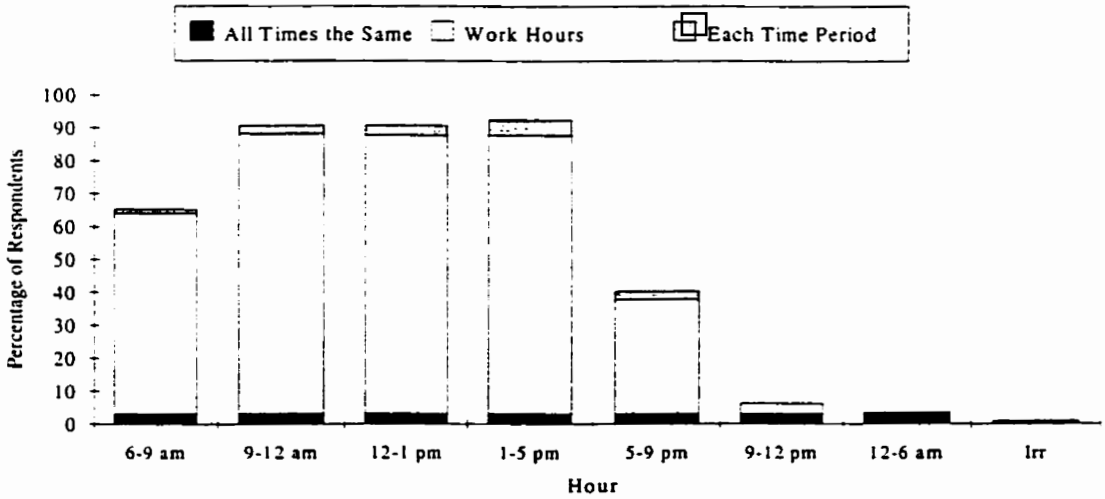


Figure C.35. Worst Time of the Day for an Interruption to Occur for Industrial Customers

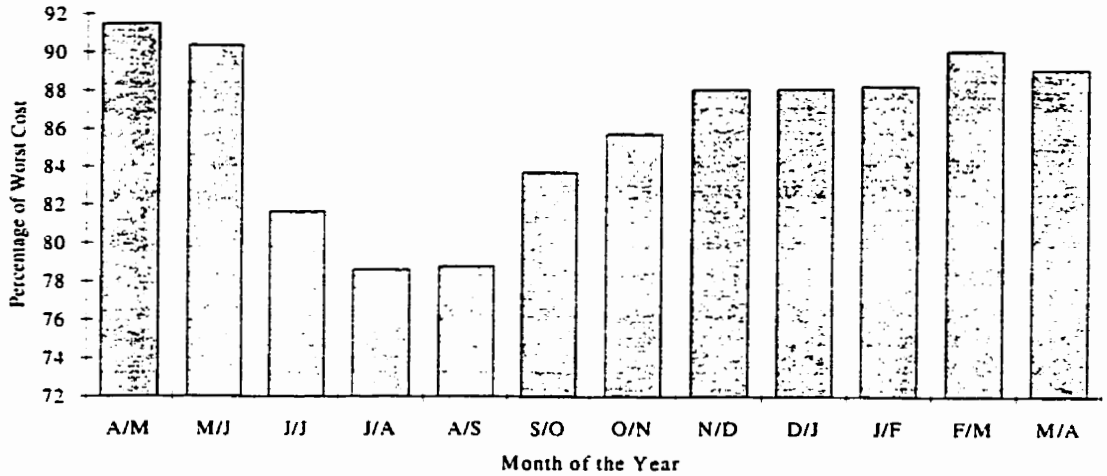


Figure C.36. Monthly Cost Variation as Reported by Industrial Customers

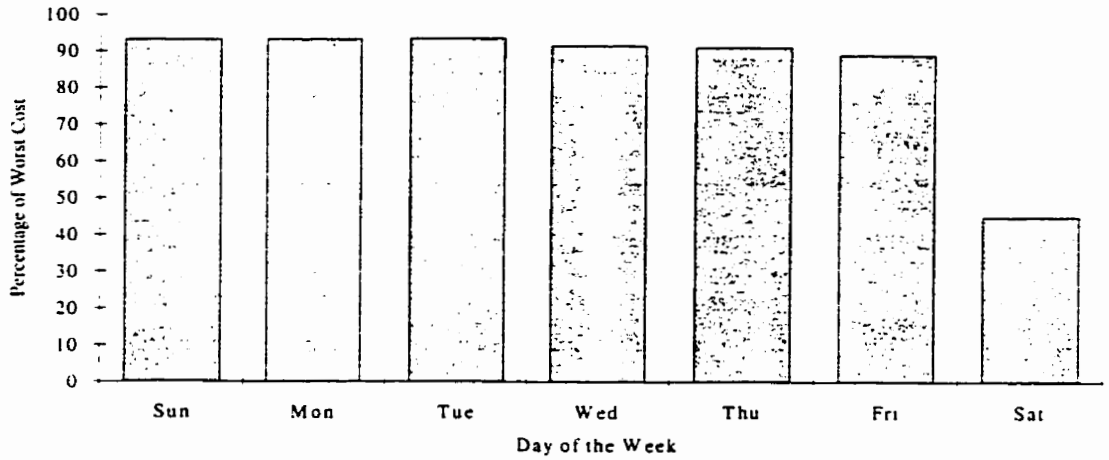


Figure C.37. Weekly Cost Variation Reported by Industrial Customers

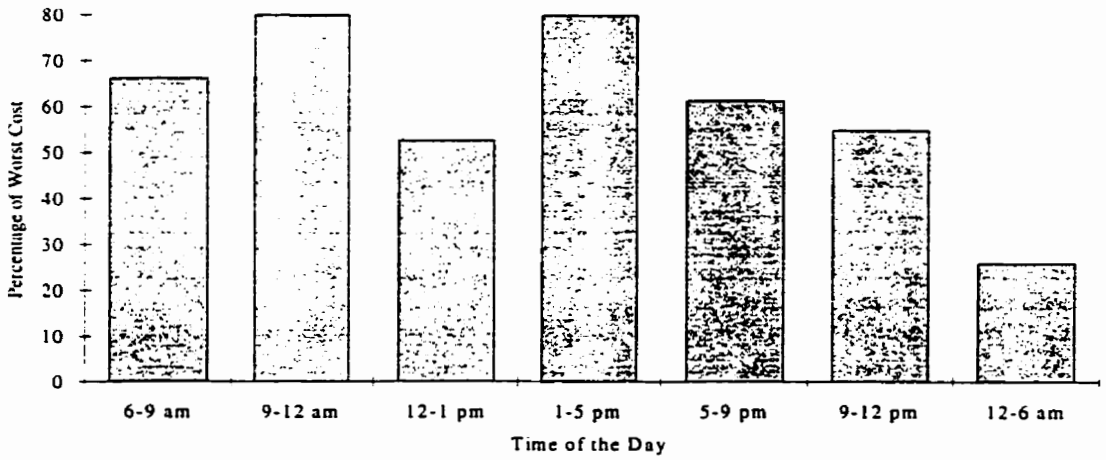


Figure C.38. Daily Cost Variation Reported by Industrial Customers

D. DEVELOPED RELIABILITY DATA COLLECTION FORMS

One of the main objectives of the research work was to investigate on the data requirements for reliability studies. This activity was done in Canada. Bibliographies [6-10] and the reports [24, 25] provided by the Canadian Electricity Association (CEA), were the prime resources used in this research work. During this research stage, appropriate data collection forms were developed to use in the data investigation subsequently conducted in Nepal. The developed data collection forms used are presented in this appendix. Tables D.1, D.2 and D.3 show the data collection forms used to gather information in regards to generator units, transformer units and transmission lines existing in the NPS. A form was developed to collect data on class load information of various NPS load buses. The form used is shown in Table D.4.

Table D.1. Data Collection Form Used for Generating Unit Information

Reliability Data (Generating Unit)

Rated Capacity : .....kW. Unit Type: .....

Output Rate(Thermal) : .....kW(Max.), ...kW(Min.).

Energy Limitations(Hydro) : .....MWh(Max.), ...MWh(Min.).

No. of Failures : .....in..... years. No. of Repairs : .....in..... years.

Average Repair Duration : .....hours(Max.), ...hours(Min.).

Forced Partial Outage : .....kW, Scheduled Partial Outage : .....kW.

Scheduled Maintenance : .....weeks/year. Unit Dispatch Order : .....

O & M Cost :
Fixed Cost : Rs. ...../year, Variable Cost : Rs. ...../MWh.
Total Cost : Rs. ...../year

Capital Cost : Rs. .....

Year Installed : ..... Name of the Plant : .....

No. of Similar Units in the Plant : .....

Any other Information/Comments :

Table D.2. Data Collection Form Used for Transformer Unit Information

Reliability Data (Transformer Unit)

Rated Capacity : .....MVA. Unit Type : .....

Voltage Ratio : ...../.....kV.

No. of Failures : .....in..... years. No. of Repairs : .....in..... years.

Average Repair Duration : .....hours(Max.), ...hours(Min.).

O & M Cost : Rs. ...../year.

Capital Cost : Rs. ..... Year Installed : .....

S/s Location : ..... No. of Similar Units in the S/S : .....

Any other Information/Comments :

Table D.3. Data Collection Form Used for Transmission Line Information

Reliability Data (Transmission Line)

Voltage Level : .....kV. Circuit Type : .....

Connecting Buses : From ..... To .....

Line Length : .....km.

No. of Failures : .....in..... years. No. of Repairs : .....in..... years.

Average Repair Duration : .....hours(Max.), ...hours(Min.).

O & M Cost : Rs. ...../year.

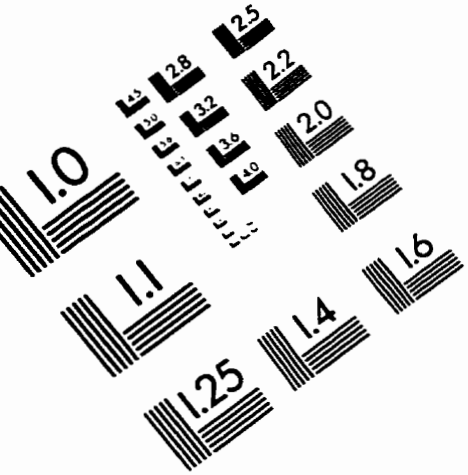
Capital Cost : Rs. ..... Year Installed : .....

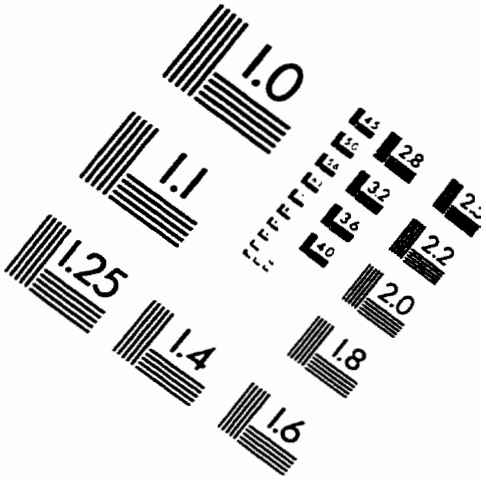
Any other Information/Comments :

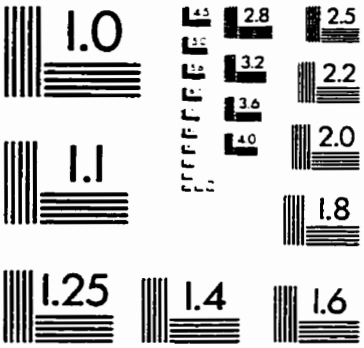
Table D.4. Data Collection Form Used for Class Load Information

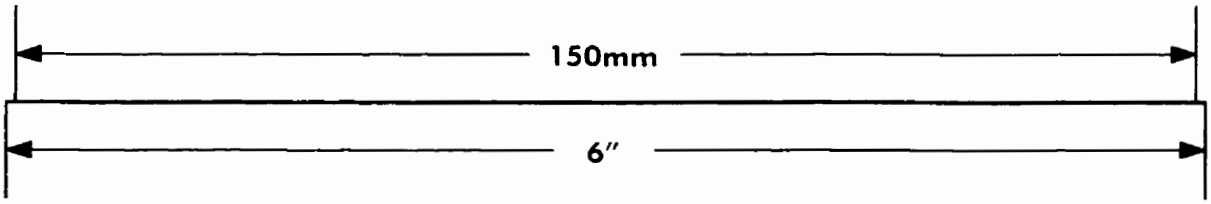
User Sector Load/Energy Composition for the Areas Supplied by Major NPS Load Buses			
Load Bus :			
User Sector	Sector Peak(MW)	Sector Peak(%)	Sector Energy(%)

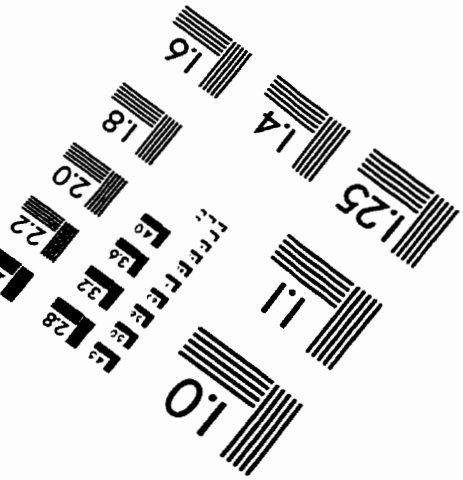
IMAGE EVALUATION TEST TARGET (QA-3)











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