NTNU
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Reliability Assessment of Distribution Systems

-Including a case study on Wangdue Distribution System in Bhutan

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Master of Science in Electric Power Engineering
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Supervisor: Kjell Sand, ELKRAFT

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Problem Description

In distribution system planning, reliability aspects are an important part of the decision base. Hence, to be able to assess and simulate reliability is needed in the planning process. In reliability planning, several issues are addressed:

- Fault statistics
- Outage consequence assessment
- Simulation tools and methods

The objective of the master thesis work is to develop and evaluate a framework for reliability analysis of distribution systems in Bhutan. The following issues should be included:

- Literature survey to report state of the art within reliability analysis
- Evaluate available fault statistic information for distribution systems in Bhutan
- Describe outage consequences for different sectors and how outage cost estimates can be obtained
- Case studies on distribution system in Bhutan using available reliability tools

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NORWEGIAN UNIVERSITY OF SCIENCE AND TECHNOLOGY

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Department of Electric Power Engineering

MASTER THESIS

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Abstract

A stable and reliable electric power supply system is an inevitable pre-requisite for the technological and economic growth of any nation. Due to this, utilities must strive and ensure that the customer's reliability requirements are met and the regulators requirements satisfied at the lowest possible cost. It is known fact around the world that 90% of the of the customer service interruptions are caused due to failure in distribution system. Therefore, it is worth considering reliability worth assessments as it provides an opportunity to incorporate the cost or losses incurred by the utilities customer as a result of power failure and this must be considered in planning and operating practices.

The system modeling and simulation study is carried out on one of the district's distribution system which consists of 33kV and 11kV network in Bhutan. The reliability assessment is done on both 11 and 33kV system to assess the performance of the present system and also predictive reliability analysis for the future system considering load growth and system expansion. The alternative which gives low SAIDI, SAIFI and minimum breakeven costs are being assessed and considered. The reliability of 33kV system could be further improved by installation of load break switch, auto recloser and connecting with line coming from other district (reserve) at reasonable break even cost. The decision base could be further improved by having Bhutan's context interruption cost. However, the questionnaire's which may be used in Bhutan to acquire interruption costs from the customers are being proposed.

The utility should have their own reliability improvement strategy depending upon their needs and requirements of the regulators. Although there is no magic bullet in managing power quality issues, utilities can maximize network performance and better serve customers by diligently addressing trouble prone areas. In order to achieve this objective, a computer program NetBas/Lesvik is used to run load flow and reliability analysis, thus selecting the alternatives either based on reliability indices or on cost benefit ratio.

1.0 Introduction

1.1 Overview

The basic function of the power system is to provide an adequate electrical supply to its customers as economically as possible with reasonable level of reliability. With growing demand and increasing dependence on electricity supplies, the necessity to achieve an acceptable level of reliability, quality and safety at an economic price, the utility have to evolve and improve the systems continuously depending upon the requirement of the customers.

Over the past, distribution systems have received considerably less attention devoted to reliability modeling and evaluation than the generating and the transmission systems [1]. The reasons for this are that the generating stations and the transmission systems are capital intensive and the generation and the transmission inadequacy can have widespread catastrophic consequences for both society and the environment. A distribution system, however, is relatively cheap as compared to the other two as its effects are localized. Therefore, less effort has been devoted to quantitative assessment of the adequacy of various alternatives and reinforcements. On the other hand, analysis of the customer failure statistics of most utilities shows that the distribution system makes the greatest individual contribution to the unavailability of supply to a customer [1]. The distribution systems account for upto 90% of all customer reliability problems, improving distribution reliability is the key to improving customer reliability [2]. Since the primary purpose of the system is to satisfy customer requirements and the proper functioning and longevity of the system are essential requisites for continued satisfaction, it is necessary that both demand and supply considerations are appropriately viewed and included in the systems. Therefore, the distribution reliability is one of the most important in the electric power industry due to its high impact on the cost of electricity and its high correlation with customer satisfaction.

The average interruption duration that a customer can experience is minimal, as low as 2,40 hours/customer per year in Norway[32], where average interruption in Bhutan is 20-30hrs/customer per year. The difference of indices between two countries shows that the reliability in Bhutan is comparatively poor and needs immediate attention. With the mission of electricity to all by 2017 in Bhutan, the distribution system is expanding rapidly with in very short duration, this may lead to haphazard distribution system and the system may not be as reliable as expected.

The power system basically consists of generation, transmission and distribution, regulated either by a single entity or by the number of entities. Hence, the responsibility of maintaining reliability at different levels falls with different entities and should be the common goals of the custodians of the various system at different levels. Also Regulators require most of investor owned utilities to report their reliability indices and the regulator trend is moving towards performance based rates where performance is rewarded and penalized based as quantified by regulator indices.

Reliability Improvement Strategy has to be developed for each utilities depending upon their requirements. Also with strategies, Outage mitigation technique in distribution system is to be used and this can be classified in two categories namely; Electric and Non-electric. Electric mitigation techniques have a direct impact on the distribution system and affect the distribution system analysis and these techniques includes addition of protective devices (reclosers and fuses) and switching devices (manual and automated switches), system reconfiguration, feeder re-conductoring and integration of distributed generation. On the other hand, non electric mitigation techniques do not have any impact on other engineering analysis tools and can be evaluated solely with reliability studies and these techniques includes vegetation management, installation of lightning arresters and animal guards. The impact and the efficiency of the mitigation techniques could be assessed through quantitative reliability evaluation of the distribution system such as; measuring of the past performance and predicting the future performance. The level of reliability is closely related to its cost function; achieving good level of reliability necessitates huge financial investment on system reinforcement and poor reliability entails more downtime cost to customer. Hence, the concept of value-based reliability(socio economic) planning may be used in Bhutan, which is illustrated in figure: 1-1. This approach generally aims at maximizing the social welfare by minimizing the total societal cost that includes utility cost of reliability and customer cost due to poor reliability.

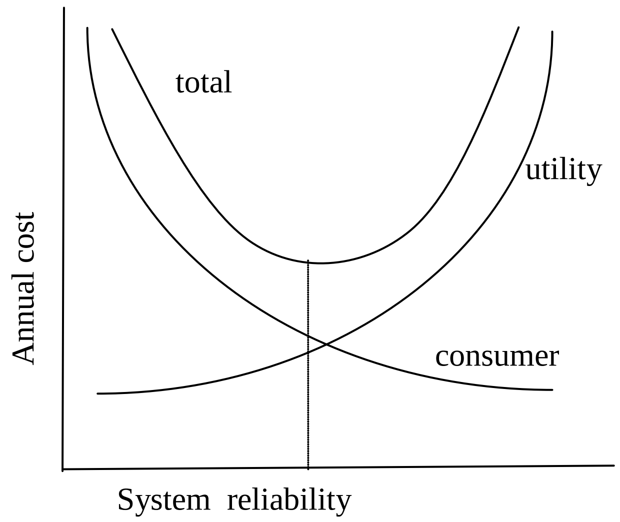


Fig.1-1: Total reliability cost

Therefore in this thesis, approaches such as; electric and non electric mitigation techniques shall be evaluated to find the means to improve reliability of distribution system and is being considered.

1.2 Problem Formulation

Electricity networks are, and will continue to be a critical part of our energy infrastructure, and we have the responsibility to ensure that they are developed consistently and in a manner that meets future demands of society and customers. The process of network development should be directed towards a long term vision aligned with the expectations of the present and future customers. After corporatization and forming as utility company, BPCL`s mission is to transmit, distribute and supply adequate electricity in a safe, reliable and efficient manner and this has to be accomplished.

The main problem facing by electric power utilities in developing countries today is that the power demand is increasingly rapidly where supply growth is constrained by scarce resources, environmental problems and other societal concerns. This has resulted in a need for more extensive justifications of the new system facilities, and improvements in production and use of electricity. System planning and operation based on reliability cost/worth evaluation approach provides an opportunity to justify one of the scrutinized and vulnerable economic sectors in Bhutan. It is with this objective to conduct customer surveys to find out the outage cost of interruptions**.**

The analysis of the customer failure statistics reveal that the distribution system makes highest individual contribution to the unavailability of supply to the customer. With the existing system, the customer interruptions in Bhutan is as high as 20-30hours per year. With the vision of electricity to all within 2017, the interruptions per customer may further deteriorate due to rapid expansion of the distribution systems. As of now, no sufficient technical research have been carried out in the distribution network, it may be due to lack of technical expertise in the Utility. And most of the interruption has been caused due to the failure in the distribution systems in Bhutan. Comparing with other utilities around the world, reliability standards are very low in distribution system of Bhutan. Hence it is felt necessary to improve the reliability of the system in order to improve the utility’s performance and to keep our valued customers satisfied. The reliability improvement should be based most probably upon the consideration of reliability worth and to find the reliability worth, a questionnaire to find the cost of interruption which is suitable to Bhutanese context is being be formulated.

Intelligent placement of protection devices, sectionalizers and switches in the distribution feeders has significant impact in reliability improvement and this will be further assessed along with the outage mitigation techniques for the distribution system in Bhutan. Therefore, in this thesis, the distribution system of Bhutan has been considered, particularly focusing on Wangdue district’s distribution system.

1.3 Objectives

The main objective of this thesis is to evaluate and develop a framework for reliability analysis of distribution system in Bhutan. Its main aim is to determine system reliability and customer satisfaction. The following issues shall be discussed;

- Assess, Evaluate and Compute reliability indices of the existing system of Wangdue area using available reliability tools and suggest further improvements if necessary.
- Predictive reliability analysis shall be carried out and compute its indices by using present fault rates and durations of outages in 33kV network since this network will have major expansion for rural electrification works. The same predictive analysis shall be carried out for 11kV system fed from Lobesa substation since a substantial load growth is expected. Analyze the major causes of outage in the existing system and the various Outage Mitigation Techniques shall be evaluated and find cost effective techniques.
- Describe outage consequences and prepare questionnaires for the outage evaluation cost to find the outage cost for different sectors, which could used in Bhutanese system in future for assessing the reliability worth from customers perspectives.

The above analysis shall be carried out in order to accomplish the Bhutan Power Corporation’s mission to supply reliable and quality power to the customers at a reasonable price.

2.0 Literature review

2.1 Overview on Reliability

Electric power is a vital element in any modern economy. The availability of a reliable power supply at a reasonable cost is crucial for the economic growth and development of a country. Electric power utilities throughout the world therefore endeavor to meet customer demands as economically as possible at a reasonable service of reliability. To meet customer demands, the power utility has to evolve and the distribution system have to be upgraded, operated and maintained accordingly. An analysis throughout the world shows that around 90% of all customer reliability problems are due to the problem in distribution system, hence, improving distribution reliability is the key to improving customer reliability [2].

Increasingly, the utilities are being squeezed between the conflicting demands of customer who require higher quality of (and more costly) service and those demand lower rates. To compete effectively given this situation it is important for utilities to establish a balance between the cost of improving service reliability and quality, and the economic benefits that these improvements bring to customers and this approach is generally know as Value Base Reliability Planning (VBRP). The Value Based Reliability Planning directly takes account of the value of reliability and power quality to customers in assessing the cost effective of the proposed investment alternatives [4]. In general, VBRP follows the process as shown in the figure 2-1. The probability of consumers being disconnected for any reasons can be reduced by increased investment during planning phase, operating phase or both and is vice versa. It is evident therefore that the economic and reliability constraints can be competitive, and this can lead to difficult managerial decisions at both planning and operating phase [1].

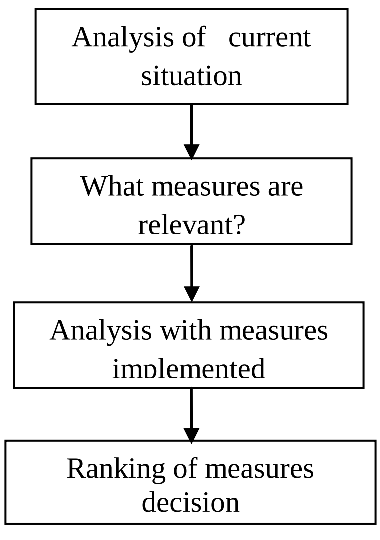


Fig. 2-1: Identification of problems and analysis of measures

Due to its localized effect and minimal cost on the outages while comparing with the generation and transmission system, less effort have been devoted to distribution system in quantitative assessment of the adequacy of the various alternative designs and reinforcements in Bhutan's system. However, analysis of the customer failure statistics reveals that the distribution system makes the greatest individual contribution to the unavailability of supply to a customer. Statistics such as these reinforce the need to be concerned with the reliability evaluation of distribution system, to evaluate quantitatively the merits of various reinforcement schemes available to the planner and to ensure that the limited capital resources are used to achieve the greatest possible incremental reliability and improvement in the system. Therefore, it is necessary to ensure a reasonable balance in the reliability of the various constituent parts of a power system, i.e generation, transmission and distribution [1]. Once the distribution systems are planned, designed and built, they must be continually monitored, adjusted, expanded and repaired. This distribution operation plays an important role in distribution reliability.

The Mitigation Techniques like electric or non electric methods could be used to improve the reliability in the system. Modern automation technologies can reduce contingency margins, improve utilization and economy of operation and even provide improved scheduling and effectiveness of maintenance and service [5]. However, they must be applied well, with the technologies selected to be compatible with systems need and targeted effectively. On the other hand, non-electric method such as vegetation management, system improvements, crew placement and management, maintenance practices plays an important role in improving reliability in the system.

Recent significant increase in energy costs, concern with conservation of resources, and impacts of government and environmental groups have resulted in a need for more adequate justification of new system facilities and operating reliability levels. A major aspect of this justification is the assessment of worth or benefit of power system reliability to its customers or conversely, the cost of losses which result from system unreliability [6].

2.2 Reliability Evaluation

The ultimate goal of reliability analysis is to help answer questions like "is the system reliable enough?" "which scheme will fail less?" and "where can the next dollar be best spent to improve the system?"[11]. Reliability in power system can be divided in two basic aspects; System adequacy and System security. Adequacy relates to the capacity of the system in relation to energy demand and security relates to the dynamic response of the system to disturbances (such as faults). Since distribution systems are seldom loaded near their limits, system adequacy is of relatively small concern and reliability emphasis in on system security.

The two main approaches applied to reliability evaluation of distribution systems are [10] ;

- Simulation methods based on drawings from statistical distributions (Monte Carlo).
- Analytical methods based on solution of mathematical models

The Monte Carlo techniques are normally very “time” consuming due to large number of drawings necessary in order to obtain accurate results. The fault contribution from each component is given by a statistical distribution of failure rates and outage times.

The analytical approach is based on assumptions concerning the statistical distributions of failure rate and repair times. The most common evaluation techniques using a set of approximate equations are failure mode analysis or minimum cut set analysis. This method is less time consuming than the simulation methods, but suffers from problems of representing repair times adequately. The analytical approach to reliability evaluation of radial distribution system shall be used. The approach is called RELRAD (Reliability in Radial systems) and is complimentary to the minimum cut set approach.

2.2.1 Reliability Indices

Quantitative reliability evaluation of a distribution system can be divided into two basic segments; measuring of the past performance and predicting the future performance [12]. Some of the basic indices that have been used to assess the past performance are;

- System Average Interruption Frequency Index (SAIFI)
- System Average Interruption Duration Index (SAIDI)
- Customer Average Interruption Duration Index (CAIDI)
- The Average Service Availability Index {Unavailability} (ASAI){ASUI}
- Energy not supplied(ENS)

Past performance statistics provide valuable reliability profile of the existing system. However, distribution planning involves the analysis of future systems and evaluation of system reliability when there are changes in; configuration, operation conditions or in protection schemes. This estimates the future performance of the system based on system topology and failure data of the components. Due to stochastic nature of failure occurrence and outage duration, it is generally based on probabilistic models. The basic indices associated with system load points are ; failure rate, average outage duration and annual unavailability.

SAIFI indicates how often an average customer is subjected to sustained interruption over a predefine time interval where as SAIDI indicates the total duration of interruption an average customer is subjected for a predefined time interval. CAIDI indicates the average time required to restore the service. ASAI specifies the fraction of time that a customer has received the power during the predefine interval of time and is vice versa for ASUI. ENS specifies the average energy the customer has not received in the predefined time.

2.2.2 Reliability Cost and Worth

As a concept, reliability is an inherent characteristics and a specific measure that describes the ability of any system to perform its intended function. The primary technical function of a power system is to supply electrical energy to its end customers. This has always been an important system issue and power system personnel have always strive to ensure that customers receive adequate and secure supplies within reasonable economic constraints [7]. The system adequacy basically means the availability of enough generation, transmission and distribution capacities to meet the customer demand. While on the other hand security is considered to relate to the ability of the system to respond to disturbances arising within the system. Therefore, adequacy assessment represents the static conditions, where as security assessment pertains to the dynamic conditions of the power system [1].

Utilities, in a venture to supply power at an economic price with an adequate level of reliability, often faces challenges to balance the high level of reliability at relatively low cost, since these two aspects counters each other. Direct evaluation of reliability worth is a difficult task, therefore, a practical alternative, which is being widely used is to evaluate the impacts and monetary losses incurred by customers due to power failures. When an interruption is experienced by a customer, there is an amount of money that the customer is willing to pay to evade the interruption and this amount is referred to as the ‘customer cost of reliability’. These costs include both tangible and intangible cost and also the opportunity cost. As such, to maximize the reliability, utility should balance their reinforcement cost for reliability improvement and the customer cost for poor reliability. Therefore, the optimal level of reliability is said to be achieved when the sum of utility cost and the customer cost is at minimum.

2.3 Impacts of Mitigation techniques and Protection System on Reliability

A properly co-ordinated protection system is vital to ensure that an electricity distribution network can operate within preset requirements for safety for individual items of equipment, staff and public, and the network overall. Suitable and reliable equipment should be installed on all circuits and electrical equipment and to do this, protective relays are used to initiate the isolation of faulted sections of a network in order to maintain supplies elsewhere on the system. This then leads to an improved electricity service with better continuity and quality of supply. This can reduce the permanent outages and its durations. Nowadays, with the increase of sensitive load with the end users, to improve the power quality and to mitigate the momentary interruptions is also equally important. The first step is to find out the root cause of the problem and apply mitigation solutions to a circuit that affects the largest number of customers.

A better over-current protection scheme can reduce number of customers affected by temporary and permanent faults. The reliability of the system depends on the mitigation techniques being used by the utility namely, electric and non electric mitigation techniques.. So, historical data can be used to quantify improvements and predict the best locations for sectionalizing devices for reliability improvements. Adding numbers of recloser at optimal locations can reduce SAIFI, SAIDI but it should be economically viable. The location and installation of number of Auto-recloser, Switches, Load Break Swtiches and Sectionalizers either manual or automated helps to reduce fault rate, repair time and sectioning time which directly reduces the impacts on the system when fault occurs. The Mitigation Techniques applied shall depend on the need of utility whether it wants to reduce fault rate, repair time or both or outage duration.

3.0 Methodology

3.1 Overview

The foremost aim of this study is to see how reliability could be improved in the distribution system by incorporating reliability analysis in the systematic planning approach so that "Optimum Reliability" is achieved, meaning that the Utility cost is equal to the customer cost. The reliability indices of the present system shall be evaluated, assessed and compared with the international standards and see how risk of failure could be mitigated. The fault rates and reliability indices for the year 2008, is being considered as base year for the case study. The general process flow chart is being developed based upon the systematic planning approach of distribution network design as shown in the figure 3-1. It consists of nine modules. However, in this master project, it will be only concentrated on the reliability analysis of the case study area (i.e Wangdue Dzongkhag) and the choice of alternatives shall be based on cost benefit.

The analysis shall be carried out by using software tool "Netbas/Levsik" which is available with NTNU for simulation. Levsik calculates reliability indices like SAIFI, SAIDI, CAIDI and ASAI. It also calculates the number of interruptions per year, interruption duration, Non Delivered Energy, Interrupted Power and the Power Outage cost(cost of energy not supplied)t based upon input data in the existing network. This helps us to analyze how various measures affect the results. However, in this project, the actual value of outage cost in the Bhutanese context could not be obtained since the value of interruption cost is not available. So, the questionnaire's for finding the outage cost which could be used in Bhutan in near future is being developed based upon my experience in the field and also after going through the methodologies developed by other utilities around the world.

This software helps us to find the best location of line equipments like, reclosers, switches either automated or manual, based on long term approach rather than short term approaches. The computer generated reliability improvement solutions are not a substitute for good human engineering. They are to be used along with the system analysis results, as a starting point for manually generated reliability improvement recommendations. The results of the computer generated solution depend on the quality of input data or the data available with the user. Therefore, it is very important for the utilities to maintain and update the data recording systems for future use. This would enhance to improve the system studies in future and overall reliability in the system could be improved and the need of the regulators and customers are met.

The failure in the system cannot be prevented, however, the impacts of the failure could be reduced with proper analysis and planning.

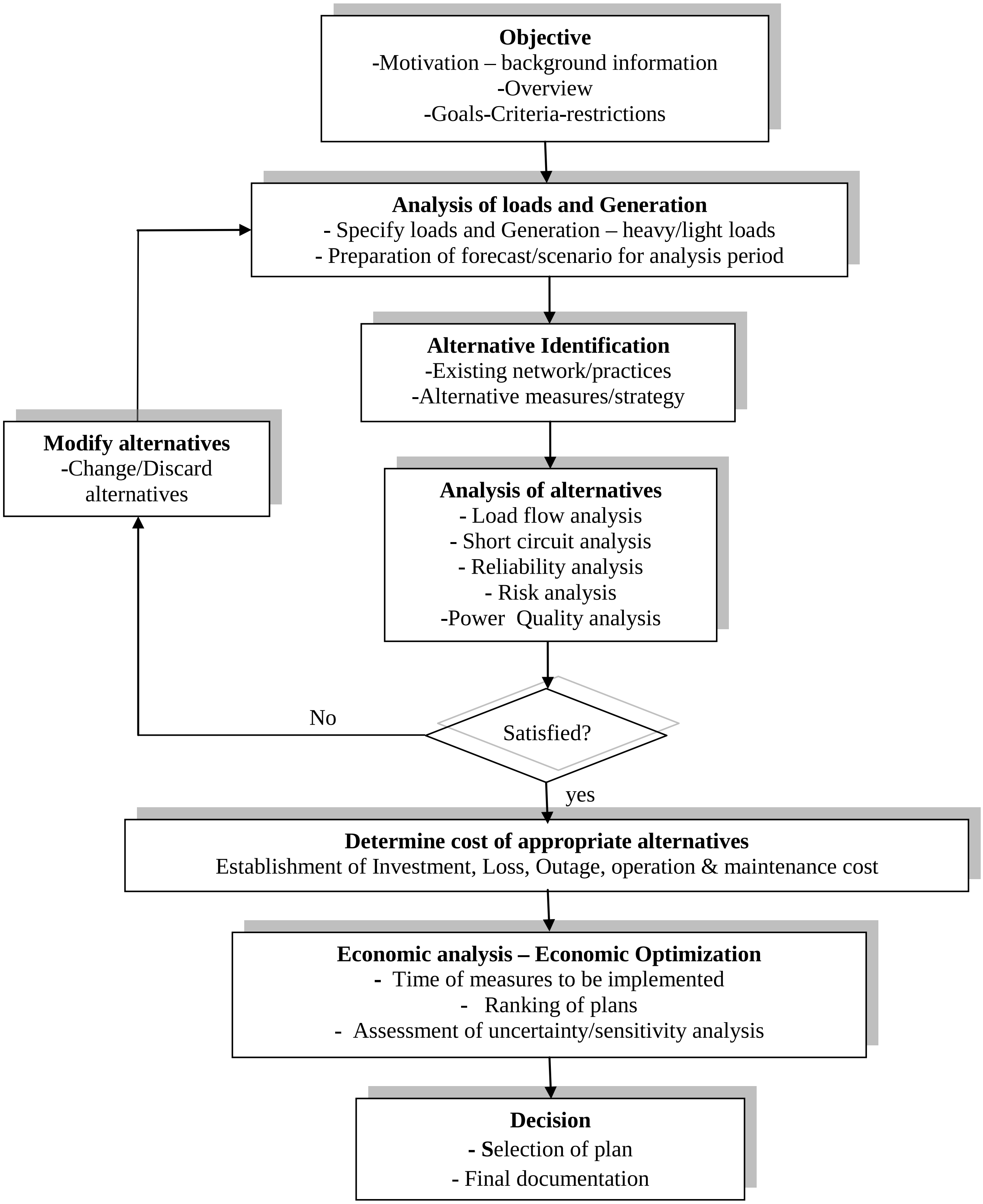


Fig. 3-1: System planning approach of distribution network

3.2 Objectives

The main objective is to plan a electric power system which can deliver adequate electric supply to its customer as economically as possible while satisfying all the technical restrictions, and with a reasonable level of reliability. It is also to see how reliability analysis/evaluation could be incorporated in the systematic planning approach and to see its effect on the plan, with inclusion of the outage/interruptions costs. The objective function of the project is to minimize the sum of Investment cost and the outage cost.

In any plan, it is important to set goals, criteria and restrictions which have to be satisfied by the solutions to be considered for implementation. Data collection and documentation is equally important for the study area so that one can have overview of the existing systems and the area.

In this master project, the following studies shall be carried out as summarized below:

- The use of reliability analysis within the framework of distribution system planning.
- Assessment of the reliability indices of the existing network of Wangdue dzongkhag, analyse major cause of interruptions and to find out the improvement techniques with use of reliability tool NetBas/Levsik and recommend alternatives which could improve the reliability in the system.
- Describe outage consequences and prepare questionnaires for the outage cost evaluation, which could be incorporated in our system in near future.

3.3 Analysis of Load and Generation

The determination of the required amount of system generating capacity to ensure an adequate supply is an important aspect of power system planning and operation. Conceptually, it can be divided into static and operating capacity requirements. The static capacity area relates to long term evaluation of this overall system requirement, while, the operating capacity area relates to the short term evaluation of the actual capacity required to meet a given load level. Both these areas must be examined at a planning level in evaluating alternative facilities, however, once the decision is made, the short term requirement becomes operating problem.

The static requirement can be considered as the installed capacity that must be planned and constructed in advance of the system requirements. The static reserve must be sufficient to provide for the overhaul of the generating equipments, outages that are not planned or scheduled and load growth requirements in excess of the estimates. Load estimate is one of the most vital requirements either in network design or for the expansion studies. The load growth of the specific area will basically influence the reinforcement or expansion of the system. However, the degree of redundancy has had to commensurate with the requirement that the supply should be as economic as possible. Design, planning, and operating criteria and techniques have been developed in an attempt to resolve and satisfy the dilemma between the economic and reliability constraints. The criteria and techniques first used in practical applications, however, were deterministically based and the typical criteria are [1] :

(a) Planning Generating Capacity – installed capacity equals the expected maximum demand plus a fixed percentage of the expected maximum demand.

(b) Operating capacity – spinning capacity equals expected load demand plus a reserve equal to one or more large Units.

(c) Planning network capacity – Construct a minimum number of circuits to a load group (generally known as (n-1) or (n-2) criterion depending on the amount of redundancy), the minimum number being dependent on the maximum demand of the group.

Their essential weakness is that they do not and cannot account for the probabilistic or stochastic nature of system behavior, of customer demands or of component failures. Typical probabilistic aspects are:

(a) Forced outage rates of generating units are known to be a function of unit size and type and therefore a fixed percentage of reserves cannot ensure a consistent risk.

(b) The failure rate of an over head line is a function of length, design, location and environment and therefore a consistent risk of supply interruption cannot be ensured by constructing a minimum number of circuits.

(c) All planning and operating decisions are based on load forecasting techniques. This technique cannot predict loads precisely and uncertainties exists in the forecast.

3.4 Identification of alternatives

Actually, we can have number of possibilities/alternatives in any plan. Based upon experience and knowhow, the alternatives which are technically feasible and economically viable shall be considered. The existing networks solution will be taken as reference solution. As seen from the flow chart, the alternative which does not meet the objective or criteria shall be discarded. Today’s practices of the utility should be reviewed if performance is found to be below the standards. Here we will also look at the future performance of the distribution system reliability when there are changes in the configuration, operation conditions or in protection schemes, and expansions in the network. In this project, the Predictive Reliability Analysis shall be carried out in 33kV and 11kV feeder fed from Lobesa substation and number of alternatives shall be evaluated. The 33kV system interconnecting with Trongsa line after 2017 shall be assessed (treating Trongsa line as reserve).

An alternative to maximize reliability is to use Predictive Reliability Assessment(PRA) for expansion planning. The main advantage of PRA is its ability to forecast the reliability impacts of the system expansion and to quantify the impact of reliability improvement projects. Typical improvement options that PRA can address [12] includes : Load transfers between feeders, new substations and substation expansions, new feeder tie points, feeder automation, replacement of aging equipments and optimal location of dispatch centres. Therefore, in this master project, the following alternatives which may improve reliability in the system shall be considered as mentioned below:

1. Assessment of the existing system
2. Change in network configuration
    - Interconnection of 11kV network feeders fed from Lobesa Substation
    - Interconnection of 33kV network fed from Trongsa and Wangdue at Chazam
3. Use of additional sectionalizing switches
4. System Automation (Auto Reclosing devices)
5. Placement of Distributed Generation
6. Evaluation by applying Mitigation Techniques.

The reliability in the system could be drastically improved by use of remote monitoring and controlling, however, this may not be economically viable in case study area since the load on the system is not high. Most of the customers are rural based which is away from the infeed substation. Still reliability could be improved by placing auto-reclosers. The Placement of distribution generators could play a vitol role in improvement of the reliability in the system (adding reserve).

3.5 Analysis of the alternative systems

The Network planning is often performed starting with today's network as reference [16]. The following analysis shall be carried out on the alternatives chosen with the help of computer program NetBas/Levsik which is developed by Powel Company.

NetBas is one of the basic products in Powel Utility Management - a global software solution that addresses all distribution and transmission requirements including asset management, GIS, analysis, planning, design and construction, maintenance, traditional engineering and real-time operations analysis [17]. Powel NetBas holds all your data in a data model specifically designed and optimized for distribution and transmission issues. Documenting the power grid is the basis of Powel NetBas. GIS analyses, as well information handling functions such as searching, grouping and statistic are also available.

- **Load Flow Analysis**

It is performed to determine the steady state operation of an electric power system. A load flow calculates the voltage drop on each feeder, the voltage at each bus, and the power flow in all branch and feeder circuits. At a given load situation, usually peak load, electrical quantities are evaluated, such as voltage, thermal loading, active and reactive losses. Active losses make the most important contribution to the operating cost. Voltage drop and thermal loading indicate if the system solutions satisfy the given limitations. Losses in each branch and total power losses are also calculated.

Load flow studies determine if system voltages remain within the specified limits under various contingency conditions, and whether equipment such as transformers and conductors are overloaded. It is also used to identify the need of additional generation, capacitive, or inductive VAR support, or the placements of capacitors/or reactors to maintain system voltages within the specified limits.

At a given load situation, usually peak load, electrical quantities are evaluated, such as voltage, thermal loading, active and reactive losses. Active losses make the most important contribution to the operating cost. Voltage drop and thermal loading indicate if the system solutions satisfy the given limitations.

- **Short Circuit Analysis**

The optimal design of switch gear and network protection requires knowledge of short circuit currents and levels, In case of restricted short circuit levels, this type of analysis may have an impact when selecting system solutions.

- **Reliability**

Frequency and duration of outages are relevant measures for reliability in electricity supply systems. If reliability is regarded as a technical restriction, adequate outage indices have to be evaluated. If outages are associated with costs, reliability shall be included within operating costs. The estimation of outage cost mostly used around is the customer survey approach. When comparing among alternatives of approximately equal total costs, the outage indices will be helpful in selection of the best solution.

- **Risk Analysis**

Is to find the probability that an unwanted event may occur and to weigh the consequences of this unwanted event and these risk can be categorized as:

  - Economic risk
  - Quality
  - Personal safety
  - Environment
  - Reputation

It helps us to set the management priorities, such as which of several alternatives/activities should be considered for the future plan. A detailed overview of the risk in this context will be important to give decision makers a most complete picture of the all risk factors that are relevant. In network planning context, we have to weigh the probability of failures of the system(outage/interruption) and the consequences of the failure (cost of energy not supplied) in the system. This help us to make the best choice among the alternatives which satisfies all the criteria set.

- **Power Quality Analysis**

Power Quality is thus a measure for the ability of the system to let customer use their electrical equipment. Any peculiarity or fault in the power system that (might) prevent the use of electrical devices or might interrupt their operations a means of power quality. The ability of the system to let customers use their equipment is determined by the extent to which the voltage and/of the current of the customers power supply are ideal. It is basically to identify the source of disturbance inorder to determine the required corrective action.

It includes an evaluation of the impact of the voltage sags and interruptions on end user equipment. The analysis on the following topic is being carried out.

- voltage
- current
- frequency
- power factor
- harmonics

After completing the technical analysis, the alternatives which satisfies all the technical criteria and condition set shall be chosen and the economic analysis should be carried out. The alternatives which does not satisfy the criteria or conditions set are either discarded or changed and reevaluated. The final decision will be based on the result of economic and technical analysis.

3.6 Economic Analysis

After identifying the alternatives which are technically feasible, it is important to evaluate the cost of all the alternatives chosen including Investment cost, Cost of losses in the system, Outage cost (CENS), Operation and Maintenance cost throughout the period of analysis. After the evaluation of the cost, it is important to devise a plan of development (i.e size, type and time of investments), minimizing the total costs and maximizing social benefits.

The above analysis helps us to make the decision to choose the solution among the number of alternatives and to recommend for the future system to be implemented.

4.0 Reliability Assessment, Metrics and Indices

Distribution reliability is the ability of the distribution system to perform its function under stated conditions for a stated period of time without failure[3]. Distribution reliability is becoming significantly important in the current competitive climate because the distribution system feeds the customer directly. The distribution system is the face of the utility to the customer. Its assessment is to determine the system reliability and customer satisfaction.

Rigorous analytical treatment of distribution reliability requires well defined units of measurement, referred to as metrics. Many utilities across the world today use reliability indices to track the performance of the utility or a region or a circuit. Regulators require most investor owned utilities to report their reliability indices. The regulatory trend is moving to performance based rates where performance is penalized or rewarded based as quantified by reliability indices. Most of the utilities also pay bonuses to managers or others based in part on reliability achievements. Even some of the commercial and industrial customer ask utilities for their reliability indices when planning to find a location for their establishments.

4.1 Power Quality, Reliability and Availability

Power quality is an ambiguous term that means many things to many people. From a consumer perspective, a power quality problem might be defined as any electric supply condition that causes appliances to malfunction or prevents their use. From a utility perspective, a power quality problem might be viewed as non compliance with various standards such as RMS voltage or harmonics. Perfect power quality is a perfect sinusoid with constant frequency and amplitude. The power Quality is affected when a voltage waveform is distorted by transients or harmonics, changes its amplitudes or deviates in frequency[3].

Customer interruptions are power quality concern since it reduces voltage to zero. Reliability is primarily concerned with customer interruptions and is therefore a subset of power quality.

Availability is defined as the percentage of time a voltage source is uninterrupted. The hierarchy of power quality, reliability and availability is shown in figure 4-1. The figure 4-1) indicates availability is a subset of reliability and reliability is a subset of power quality. Power quality deals with any deviation from a perfect sinusoidal voltage source. Reliability deals with interruptions. Availability deals with the probability of being in a interrupted state.

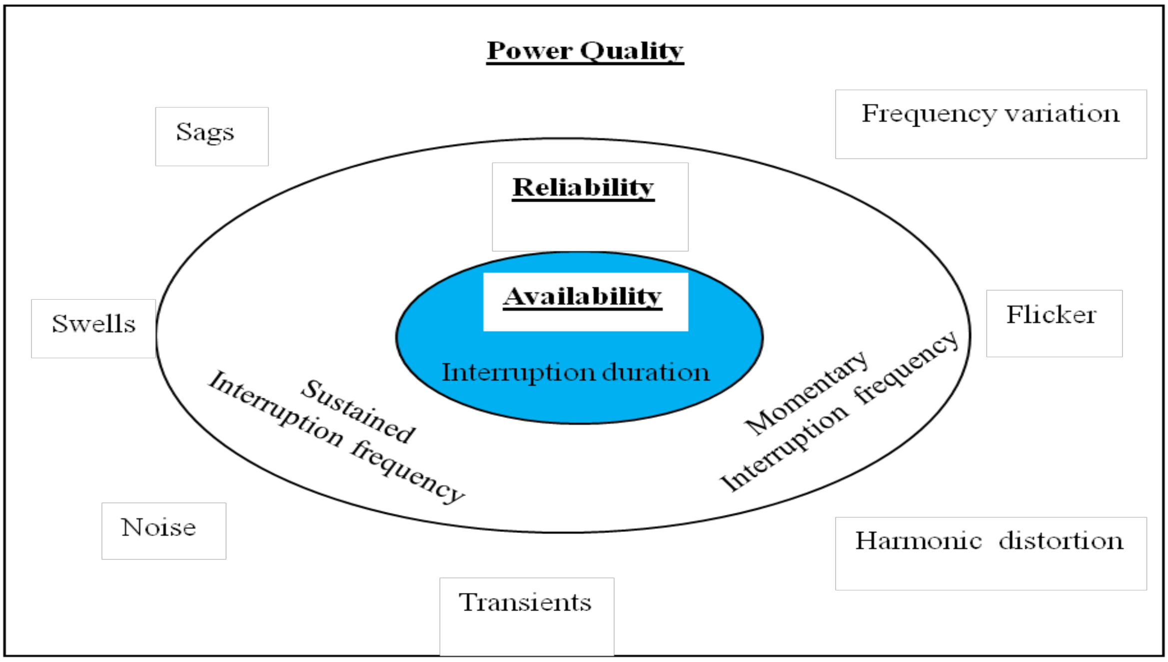


Fig. 4-1: Heirarchy of power quality, reliability and availability

4.1.1 Power Quality

Perfect power quality is characterized by a perfect sinusoidal voltage source without waveform distortion, variation in amplitude or variation in frequency. To attain near perfect quality, a utility could spend vast amounts of money and accommodate equipment with higher power quality needs. On the other hand a utility could spend little and require customer s to compensate for the resulting power quality problems. Neither of extreme is desirable, utilities must find a balance between cost and power quality provided to the customer. Power quality concerns are becoming more frequent with the proliferation of sensitive electronic equipment and automated process. Power quality problems are basically divided into many categories such as interruptions, sags, swells, transients, noise, flicker, harmonic distortion and frequency variations.

4.1.2 Reliability

Distribution reliability primarily relates to equipment outages and customer interruptions. In normal operating conditions, all equipment (except stand by) is energized and all customers are energized. Schedule and unscheduled events disrupt normal operating conditions and can lead to outages and interruptions. The unscheduled events are caused either due to human error or due to equipment failures. The schedule events are meant for periodic maintenance of the equipment and shall be notified in advance to the customers. Several indicators are used to evaluate reliability in the transmission and distribution system. The Regulation can aim to compensate customers for very long interruptions, keep restoration times under control and create incentives to reduce the total number and duration of interruptions (disincentives to increase them).

4.1.3 Availability

Availability is the probability of something being energized and Unavailability is the probability of not being energized. It is most basic aspect of reliability and is typically measure in percent or per unit. Unavailability can be computed directly from interruption duration information. If a customer experiences 9 hours of interrupted power in a year, unavailability is equal to 9÷8760 = 0.10% (8760 hours in a year). Then availability is equal to 100% - 0.1% = 99.90%.

With the growth of ultrasensitive loads, it has become common to describe high levels of reliability. Internet data centers may demand reliability as high as nine nines for their servers- less than two cycles of interrupted power per year.

4.2 Reliability Analysis

Reliability analysis of electrical distribution system is considered as a tool for the planning engineer to ensure a reasonable quality of service and to choose between different system expansion plans that cost wise were comparable considering system investment and cost of losses [10].

There are two main approaches applied for reliability evaluation of distribution system, namely Simulation method based on drawings from statistical distributions (Monte Carlo) and Analytical methods based on solutions of mathematical models. The Monte Carlo techniques are normally time consuming due to large number of drawings necessary inorder to obtain accurate results. The analytical approach is based on assumptions concerning based on statistical distributions of failure rates and repair times. The usual method of evaluating the reliability indexes is an analytical approach based on failure modes assessment and the use of equations for series and parallel networks. The common indices used for evaluation: the expected failure rate (λ), the average outage time(r), and the expected annual outage time(U) which are adequate to the simple radial system. In distribution system whether the networks are radial or meshed, they are operated radially mostly, is simple to assess. The process is more complex for parallel or meshed networks.

The basic theory for reliability analysis is discussed below.

4.2.1 Markov Chain Model

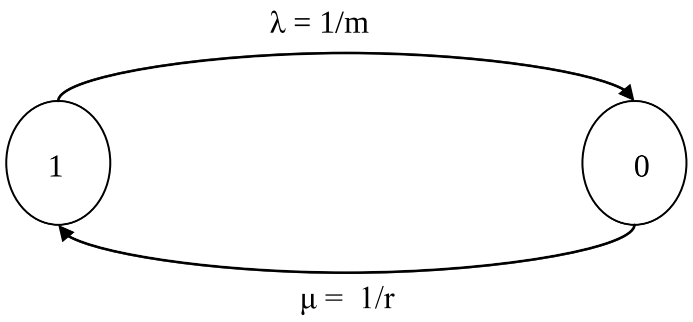
The two main approaches used are analytical and simulation. The vast majority of techniques have been analytically based and simulation techniques have taken minor role in specialized applications [1]. The main reason for this is because simulation generally requires large amount of computing time, and analytical models and techniques have been sufficient to provide planners and designers with results needed to make objective decisions. Analytical techniques represent the system by a mathematical model and evaluate the reliability indices from this model using direct numerical solutions. They generally provide expectations indices in a relatively short computing time.

A Markov model is quite popular in the quantitative reliability analysis, and that is suitable to give fair idea about reliability analysis principle. On the basis of Markov models, a simple formula can be developed that can be used to calculate the reliability of the radial distribution network [33]. The method is called like duration-frequency technique, and the starting point is the failure of the individual component. In a so-called stationary Markov process, it basically operates with two central concepts

- Failure frequency (λ)
- Repair time (r)

It is assumed for example that a component-wise reliability can only be in one of the following conditions; Condition 1: Component is in the function (in); Condition 2: Component is in repair (out).

This is illustrated in two state model diagram in figure 4-2 represented by 0(component in failed state) and 1(component is in a normal state) .



λ	fault frequency
m	mean time to failure
μ	repair frequency
r	mean time to repair

Fig.4-2 : Transition diagram of component states where, $\lambda = \frac{\text{Number of outages on component in a given period}}{\text{Total time component is in operation}}$

The figure 4-3 illustrates expected functional and outage time for a component (so called state cycle).The system can be represented by Markov process and equations developed for the probabilities of residing in each state in terms of state transition rates are as follows[33];

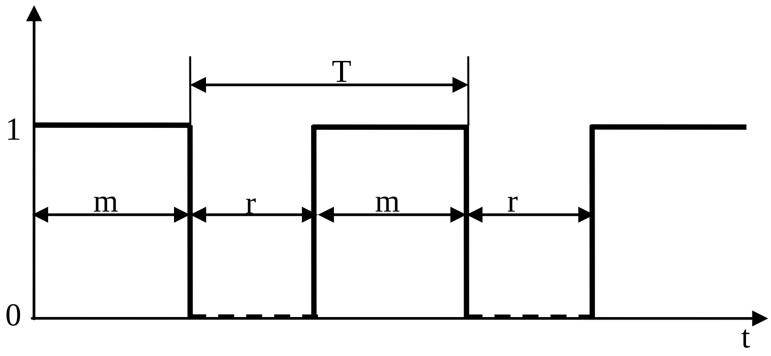


Fig.4-3 : Average state cycle

The average function time, m, is given by ; m = 1/ λ

Where, m = MTTF, mean time to failure = 1/ λ

r = MTTR, mean time to repair = 1/ μ

m+r = MTBR, mean time between failures = T = 1/f

f = cycle frequency = 1/T

T = cycle time = 1/f

The probability of component to be in either one of the two states are as shown in the figure;

$$P_0 = \frac{r}{m+r} = \frac{\lambda}{\lambda+\mu} = \frac{r}{T} = \frac{f}{\mu} = \frac{\Sigma(\text{down time})}{\Sigma(\text{down time})+\Sigma(\text{up time})}$$ where $f = \mu \, . \, P_0$

$$P_0 = \frac{m}{m+r} = \frac{\mu}{\lambda+\mu} = \frac{m}{T} = \frac{f}{\lambda} = \frac{\Sigma(\text{up time})}{\Sigma(\text{down time})+\Sigma(\text{up time})}$$ where $f = \lambda \, . \, P_1$

$f = P_0 \, . \, \lambda = P_1 \, . \, \mu$

where, P_0 = probability for a component to be in state 0 (down)

P_1 = probability of a component to be in state 1 (up)

f = cycle frequency (frequency to be in or out)

4.2.2 Series System

The distribution systems in Bhutan are basically designed, constructed and operated in radial system. A radial system basically consists of set of series components like; breakers, lines, switches, transformers and at the end a "Customers". In the series structure both components must be intact for the system to function, "a chain is no stronger than its part" while in the parallel structure both must fail for the system to stop functioning. In this case, all the components are connected in series as shown in figure 4-4 and the equations needed to evaluate the basic indices are as follows;

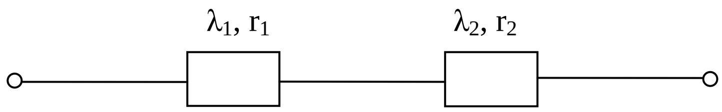


Fig.4-4 : Series structure

- Average failure rate of the system;

$$\lambda_s = \lambda_1 + \lambda_2 = \sum_{i=1}^{2} \lambda_i$$

- Average Outage time of the system;

$$r_s = \frac{\lambda_1 r_1 + \lambda_2 r_2 + \lambda_1 \lambda_2 r_1 r_2}{\lambda_1 + \lambda_2} = \frac{\sum \lambda_i r_i}{\sum \lambda_i} = \frac{U_s}{\lambda_s}$$

If $\lambda_1 \lambda_2 r_1 r_2 << \lambda_1 r_1$ or $\lambda_2 r_1 r_2$

- Average Annual Outage time

$U_s = f_s . r_s = \lambda_s . r_s$

Where λ_i is the failure rate at node i, r_i is the outage time at node i.

4.2.3 Parallel System

In this case the failure modes of the load point involve overlapping outages, i.e two or more components must be on outage at the same time in order to interrupt a load point as shown in figure 4-5. It is assumed that the failures are independent and that restoration involves repair or replacement, the equations used to evaluate the indices of the overlapping outage are as shown below.

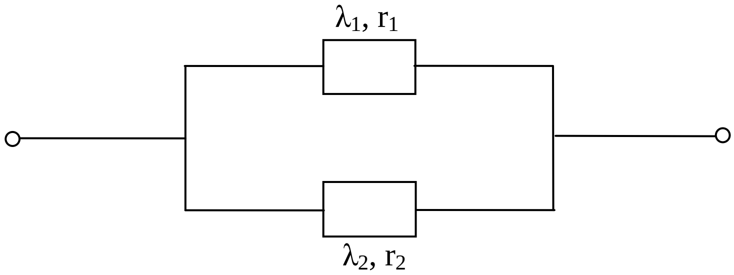


Fig.4-5 : Parallel structure

- Average Failure rate of the system;

$$\lambda_p = \frac{\lambda_1 \lambda_2 (r_1 + r_2)}{1 + \lambda_1 r_1 + \lambda_2 r_2} = \lambda_2 \lambda_1 \lambda_2 (r_1 + r_2)$$

where, $\lambda_1 r_1$ and $\lambda_2 r_2$ usually << 1

- Average Outage time of the system;

$$r_p = \frac{r_1 r_2}{r_1 + r_2}$$

- Average Annual Outage time of the system;

$$U_p = \lambda_p r_p$$

These are adequate for simple radial systems and more extended indices are have to be used for general distribution systems (mixed radial and meshed systems).

4.2.4 The RELRAD Model

To evaluate cost benefit of reinforcements and measure to improve reliability, two additional indices are being used; the expected annual non-delivered power and energy (NDP and NDE) [10]. The most common evaluation techniques, using a set of approximate equations, are failure mode analysis or minimum cut set analysis. The methods applied are less time consuming than simulation methods, but suffers from problem of representing repair time adequately. To deal with the general distribution system, the Norwegian Electric Power Research Institute (EFI), Trondheim, Norway has developed a model called Reliability evaluation of Radial distribution network (RELRAD) [10]. This approach is complimentary to minimum cut set approach.

RELRAD is an analytical approach, based on the fault contribution from all network components and their consequences to the load point outages. This differs from failure mode or minimum cut set analysis which assesses the individual load points reliability directly by the minimum cut set. In short the minimum cut set analysis the individual load points, while the analytical simulation approach analysis the individual network components as shown. The figure 4-6 shows which component give outage at the load point L_1 and the figure 4-7 shows a RELRAD approach which load points will have outage caused by the component.

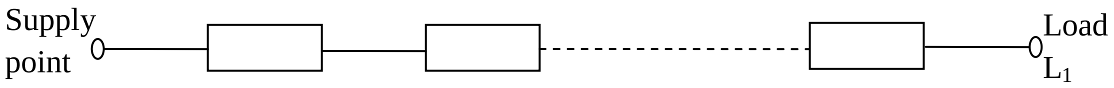


Fig. 4-6: Minimum cut set for load point L_1

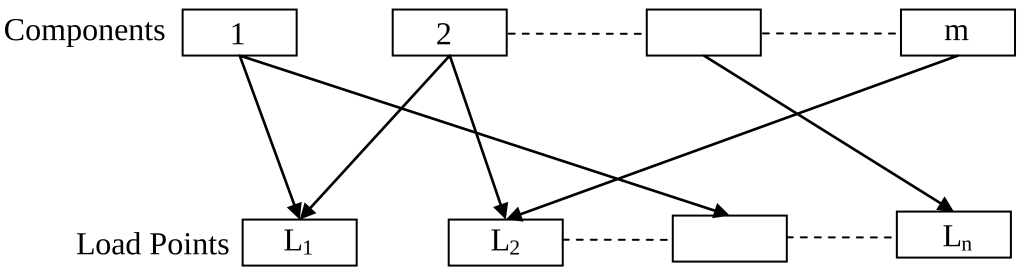


Fig. 4-7: Analytical techniques (RELRAD approach)

The full network topology is reduced to reliability section (figure 4-8), defined by the location of breaker equipment. The depth of system load points outages are determined by the circuit breakers locations. Some disconnected loads will have the supply restored after a short sectioning time while others will be connected after the repair of the faulty component.

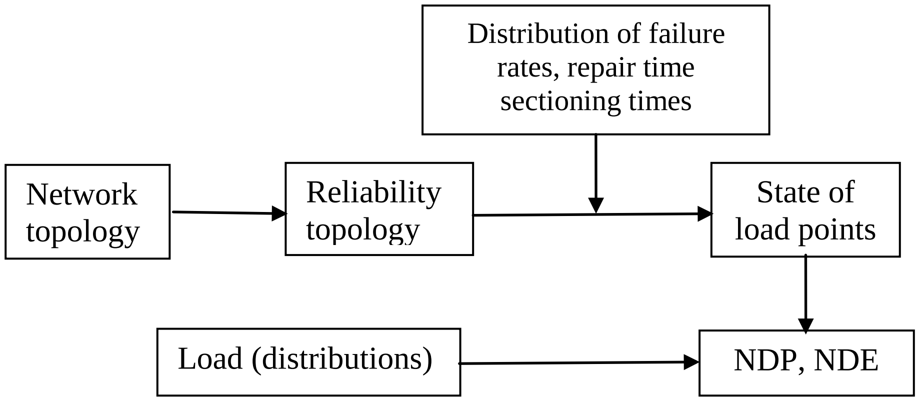


Fig. 4-8: Model for reliability analysis

The logic describing the relation between the components and their fault contribution to different load points-the reliability topology is generated before starting the reliability calculations.

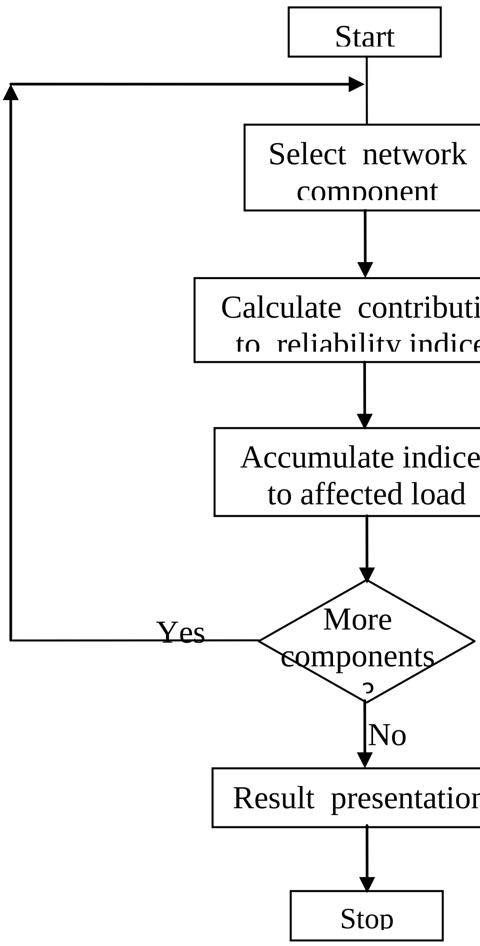


Fig. 4-9: Flow chart for calculation of reliability indices

The next step is to generate expected values from the statistical distribution of failure rates, repair times and sectioning times for all components in the system. The algorithm then accumulates reliability indices for each load point from each component giving outages to the load point. Finally, when all the fault contribution is found, the total accumulated indices are available. The figure 4-9 shows a flow chart of the algorithm.

- Main Assumptions

The topology description is based on the following assumptions :

- ✓ Radial operation of the network.
- ✓ No transfer restrictions on reserve connections.
- ✓ All faults are isolated by the upstream circuit breakers, by the first or the second depending on the probability of malfunction of the circuit breaker.
- ✓ When the fault is located, the upstream dis-connector will be opened and the circuit breaker closed.

- Main statistical assumption

- ✓ All failures are statistically independent
- ✓ Multiple faults are not represented except for circuit breaker malfunctions
- ✓ All failures are repaired before next fault occurs.

- Other features of the model

The main interest in reliability analysis has been to consider forced outages leading to repair due to use of NDE as a measure of customers inconvenience of outages. In addition to permanent faults, temporary and voltage dips are very important to certain consumers giving significant cost of NDP. Scheduled outages will also lead to relatively large inconvenience cost compared to forced outages. The RELRAD model can handle all three types of outages by using specific failure statistics for forced outages, temporary faults and scheduled outages.

Beside components, it also takes into account of different reserve possibilities, e.g. normally open ring connection within the network, mobile reserve cables, mobile generating units, other external reserve supply. Automatic sectioning devices or remote control on certain dis-connectors may be specified by reduced sectioning times for these dis-connectors or circuit breakers.

Though above indices are fundamentally important, it doesn't give us the clear picture of the system behavior and its performance and also significance of the system outage and its duration. It also doesn't reflect the number of customer affected due to outage. So, the indices which are commonly used around the world is described in the next section.

4.3 Reliability Indices

Reliability indices are statistical aggregations of reliability data for a well defined set of loads, components or customers. Most reliability indices are average values of a particular reliability characteristic for an entire system, operating region, substation service territory, or feeder. Comprehensive treatment is not practicable, but the following sections discuss the most important reliability indices used around the world. The utility indices have traditionally only included long duration interruption (usually defined as interruptions longer than 5 minutes). A common way of defining reliability is in terms of customer and load based indices.

4.3.1 Customer Based Indices

The Utilities commonly use the following two reliability indices for frequency and duration to quantify the performance of their systems[3].

(i) System Average Interruption Frequency Index (SAIFI) is designed to give information about the average frequency of sustained interruptions per customer over a predefined area.

$$\text{SAIFI} = \frac{\text{Total number of cutsomer interruptions}}{\text{Total number of customer served}} = \frac{\sum \lambda_{i\ N_i}}{\sum N_i} \quad (/\text{yr})$$

Where λ_i is the failure rate and N_i is the number of customers of load point i.

(ii) System Average Interruption Duration Index, (SAIDI) is commonly referred to as customer minutes of interruption or customer hours, and is designed to provide information about the average time that the customers are interrupted:

$$\text{SAIDI} = \frac{\text{Sum of customer interruption durations}}{\text{Total number of customer served}} = \frac{\sum U_{i\ N_i}}{\sum N_i} \quad \text{hr/yr)}$$

Where U_i is the annual outage time and N_i is the number of customers of load point i.

(iii) Customer Average Interruption Duration Index (CAIDI) is the average time needed to restore service to the average customer per sustained interruption:

$$\text{CAIDI} = \frac{\text{Sum of customer interruption durations}}{\text{Total number of customer interruptions}} = \frac{\sum U_{i\ N_i}}{\sum \lambda_{i\ N_i}} = \frac{\text{SAIDI}}{\text{SAIFI}} \quad \text{(hr)}$$

Where λ_i is the failure rate, U_i is the annual outage time and N_i is the number of customers of load point i.

(iv) Customer Average Interruption Frequency Index (CAIFI) is designed to show trends in customers interrupted and helps to show the number of customers affected out of whole customer base.

$$\text{CAIFI} = \frac{\text{Total number of customer interrupted}}{\text{Number of customer affected}} = \frac{\sum U_{\ N_i}}{N}$$

(v) Average Service Availability Index (ASAI)

$$\text{ASAI} = \frac{\text{Customer hours of available service}}{\text{Customer hours demanded}} = \frac{\sum N_i\ X\ 8760 - \sum \text{U}_{i\ N_i}}{\sum N_i\ X\ 8760}$$

Where 8760 is the number of hours in a calendar year.

4.3.2 Load and energy Based Indices

Two of the oldest distribution reliability indices weight customer based on connected kVA instead of weighing each customer equally. From a utility perspective, ASIFI and ASIDI represents better measure of reliability than SAIFI and SAIDI. Larger kVA corresponds to higher revenue and should be considered when making investment decisions.

(i) Average System Interruption Frequency Index (ASIFI):

$$\text{ASIFI} = \frac{\text{Connected kVA interrupted}}{\text{Total connected kVA served}} \quad \text{(/year)}$$

(ii) Average System Interruption Duration Index (ASIDI):

$$\text{ASIDI} = \frac{\text{Connected kVA hours interrupted}}{\text{Total connected kVA served}}$$

However, one of the important parameters required in the evaluation of load and energy oriented indices is the average load at each load point busbar [1]. The average load L_a is given by;

(a) $L_a = L_p f$

Where L_p = peak load demand

f = load factor

$$L_a = \frac{\text{total energy demanded in period of interest}}{\text{period of interest}} = \frac{E_d}{t}$$

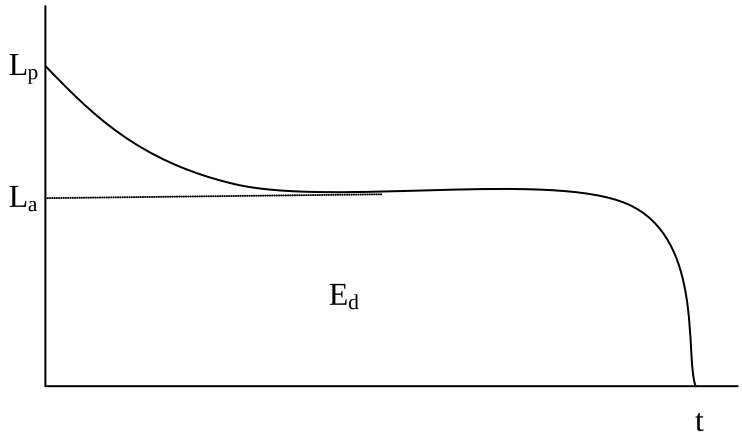


Fig. 4-10: Illustration of L_a, L_p, E_d and t

(i) Energy not supplied index, ENS

ENS = total energy not supplied by the system = $\sum L_{a(i)} U_i$

Where $L_{a(i)}$ is the average load connected to load point I, U_i is the average outage time.

(ii) Average energy not supplied, AENS or Average system curtailment index, ASCI,

$$AENS = \frac{\text{total energy not supplied}}{\text{total number of customers served}} = \frac{\sum L_{a(i)}\ U_i}{\sum N_i}$$

(iii) Average Customer curtailment index, ACCI

$$ACCI = \frac{\text{total energy not supplied}}{\text{total number of customers affected}}$$

4.3.3 System Performance

The customer and load based indices described in section 4.3.1 and 4.3.2 are useful for assessing the severity of system failures in future reliability prediction analysis. They can be used, however, as a means of assessing the past performance of a system. The assessment of system performance is a valuable procedure for three important reasons [1] ;

- It establishes the chronological changes in system performance and therefore helps to identify weak areas and the need for the reinforcement.
- It establishes existing indices which serves as a guide for acceptable values in future reliability assessments.
- It enables previous predictions to be compared with actual operating experience.

4.4 Potential problems with standard indices

Although the most commonly used indices do a reasonable job in tracking the reliability performance of utilities, they have the potential of allocating spending decisions that are not closely aligned with customer interests. This is true for utilities that are mature in their reliability improvement process. Once first round of investment is made, traditional reliability measure may present complications [2]. The following describes the potential problem with the standard indices.

SAIDI and SAIFI – When making reliability investments, reductions in SAIDI and SAIFI are proportional to the number of affected customers. This means projects that affect many customers are preferred to those that affect few customers. However, feeders with many customers typically have better than average reliability, and feeders with few customers have worse than average reliability. Therefore, reliability investment based on SAIFI and SAIDI can drive investments towards densely populated areas where reliability is already satisfactory.

CAIDI – Although popular with many utilities and regulators, CAIDI is problematic as measure of reliability. This is because, many view CAIDI as a measure of operation efficiency; when utility responds more quickly after a fault, CAIDI will go down. In fact, CAIDI is mathematically equal to SAIDI divided by SAIFI. That is reliability could be improving in both frequency and duration, but CAIDI could be increasing. Because of the above problem, the use of CAIDI is decreasing in today’s world.

4.5 Factors affecting reliability performance

Reliability performance varies dramatically from one system to another and this is not necessarily an indication that one system has poor performance. Many factors influence the expected reliability at a particular location or for an entire system.

Reliability indices that reflect reliability performance differ with data definitions and data classifications. Most Utilities define separate indices for planned and unplanned events[3]. The interruption caused due to major event like storm, forest fire or a forced majeure may or may not be considered in reliability performance. Transmission and Distribution events are considered separately for reliability performance evaluation due to data classess or nature of events.

The service territory of the utility determines the nature of the events that could be expected which effect reliability performance. Geography of the service territory such as thick forest, mountainous terrain, etc are likely to cause reliability issues. Weather is an important factor that can seriously affect reliability levels. The effects of vegetation such as tree falls, branch intrusion and animal activity from birds, squirrels and pests casuing ground faults affect reliability levels. Maintenance practices such as tree trimming programs and installation of animal guards could help achieve higher levels of reliability. Hence, it is obvious to expect a different reliability levels at various locations.

5.0 Customer Cost of Electric Service Interruptions

5.1 Overview

The basic function of modern electric power system is to provide an adequate electrical supply to its customers as economically as possible at a reasonable level of reliability. The determination of what is reasonable level of reliability has been based on past experience and judgments, albeit somewhat arbitrarily.

The main problem facing by utilities in developing countries today is that the power demand is increasingly rapidly where supply growth is constrained by scarce resources, environmental problems and other societal concerns. This has resulted in need for more extensive justifications of new system facilities, and improvements in production and use of electricity. System planning and operation based on reliability cost/worth evaluation approach will provide an opportunity to justify one of the most scrutinized and vulnerable economic sectors. Conceptually, performing a reliability cost/worth analysis requires the assessment of cost of providing reliable service and quantification of the worth of having it. A critical requirement of using interruption costs in utility planning is accurate measurement of the economic losses that customers experience as a result of outages and power quality problems [14]. The ability to assess the level of reliability within the system and the cost associated are well established [13] and comparatively, the ability to assess the worth of reliability is an immature technique. As it is unable to assess the worth directly, it is found worth to evaluate the impacts or losses resulting from electrical interruptions, that is, the societal cost of unreliability. Hence, the cost of providing reliable service and the losses arising from unreliability are being assessed at different locations in the system [15].

Interruption or outage costs can be broadly classified into direct and indirect costs. Direct costs are those arising directly from the electrical interruption and relate to such impacts such as lost industrial production, spoiled food or raw materials, personnel leisure time, injury or loss of life. Indirect costs are related to impacts arising from response to the interruption, such as crime during blackouts (short term) and business relocation (long term). Impacts require identification and quantification in momentary terms. Many direct impacts are relatively easy to identify and quantify, while such as injury and loss of life are easily identified but difficult to quantify.

A various methods that have been used to evaluate interruption impacts on electrical customers can be conveniently grouped into three broad categories, namely; indirect analytical evaluations, case studies of actual black outs, and customer surveys [13]. Till date, no single approach has been universally adopted, however, customer survey approach appears to be the method of choice widely used among the utilities around the world.

5.2 Reliability Cost and Worth

As a concept, reliability is an inherent characteristics and a specific measure that describes the ability of any system to perform its intended function. In the case of a power system, the primary technical function is to supply electrical energy to its end customers. This has always been an important system issue and power system personnel have always strive to ensure that customers receive adequate and secure supplies within reasonable economic constraints [7]. If failure/outages occurs in any part of the system, the economic impact of this outage is not necessarily restricted to loss of revenue by utility or loss of energy utilization by the customer but, in-order to estimate true costs, it should also include indirect cost imposed on customer, society, and the environment due to outage [1, 9].

An important aspect is that reliability levels are interdependent with economics since increased investment is necessary to achieve increased reliability or even to maintain its current and acceptable levels [8]. This concept as illustrated in figure 5-1 which shows the change in incremental cost of reliability ΔR with investment cost ΔC needed to achieve it or alternatively a given increase in investment produces a decreasing increment in reliability as the reliability is increased. It is one way of deciding whether an investment in the system is worth. In either case a high reliability is expensive to achieve. It is therefore, important to recognize that reliability and economics must be treated together in-order to perform objective cost benefit studies.

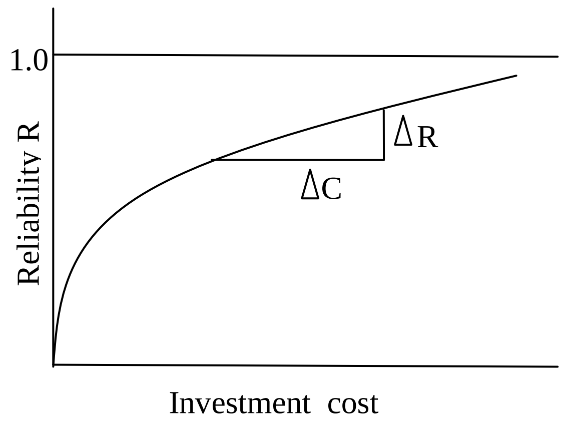


Fig. 5-1: Incremental cost of reliability

The basic concept of reliability cost/reliability worth evaluation is presented in the figure 5-2. The figure shows that the investment cost generally increases with higher reliability. On the other hand, the customer costs associated with failures decreases as reliability increases. The total costs therefore are the sum of these two individual cost. So, if the aggregate total of all customer interruption costs is assumed to be measure of worth or benefit of service reliability to society, then an optimal target reliability level is one in which the marginal cost of incremental improvements in service reliability would result in equal marginal reductions in societal interruption cost.

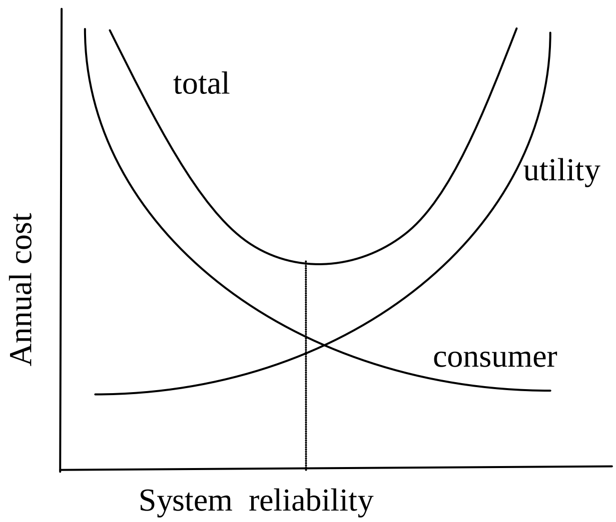


Fig. 5-2: Total reliability cost

This total cost exhibits a minimum, and so an “Optimum” or target level of reliability is said to be deduced. Although the concept of optimum reliability may be worthy an ultimate goal, it can only be achieved best in slow steps. Firstly it requires an assumption that the measure, reliability and economics can be obtained in absolute terms where as in reality all the measures are relative. Secondly most of the customers assessment of outage costs are perceptions of worth than absolute outage costs. However, two difficulties arises in its assessments, firstly the calculated indices are usually derived only from approximate models and secondly, there are significant problems in assessing customer perceptions of system failure cost.

5.3 Outage Cost Evaluation

A variety of methods has been utilized to evaluate customer impacts due to interruption. These methods can be grouped, based on methodological approach used, into three broad categories, namely; various analytical evaluations, case studies of black outs, and customer surveys [13,15]. While a single approach has not been universally adopted, utilities appear to favor customer surveys as the means to determine specific information for their particular purposes.

The determination of interruption cost is to understand the nature and variety of customer impacts resulting from electric service interruptions. Impacts may be classified as direct or indirect, economic or otherwise (social), and short term or long term. Direct impacts are those resulting from cessation of supply while indirect impacts results from a response to an interruption. Hence direct economic impacts include lost production, idle but paid for resources (raw materials, labour, capital), process restart cost, spoilage of raw materials or food, equipment damage, direct cost associated with human health and safety, and utility cost associated with interruption. Direct social impacts include inconvenience due to lack of transportation, loss of leisure time, uncomfortable building temperatures, and personnel injury or fear. Indirect losses usually arise as spin-off consequences and it may be difficult to categorize them as social or economic. Examples of such costs are civil disobedience and looting during an extended black out, or failure of an industrial safety device in an industrial plant necessitating neighboring residential evacuation. The distinction between short term and long term impacts relates to the immediacy of the consequence. Long term impacts are often identified as adaptive responses or mitigation undertaken to reduce or avoid future outage costs. Installation of protective switch gear, voltage regulation equipment, cogeneration or standby supplies would be included in this category, as would the relocation of an industrial plan to an area of higher service reliability.

Broadly speaking, the cost of interruption from the customer's perspective is related to the nature of and degree to which the activities interrupted are dependent on electrical supply. In turn, this dependency is a function of both customer and interruption characteristics. Customer characteristics include type of customer, nature of customers activities, size of operation and other demographic data, demand and energy requirements, energy dependence as function of time of day, etc. Interruption characteristics include duration, frequency, and time of occurrence of interruptions; whether an interruption is complete or partial, if advance warning or duration information is supplied by the utility; and whether the area affected by outage is localized or widespread. Finally, the impact of an outage is partially dependent on the attitude and preparedness of customers, which in turn is related to the existing reliability levels.

5.3.1 Basic Evaluation Approaches

As states above, the three main methodologies used to evaluate the interruption cost are explained below;

- Analytical methods

This method infer interruption costs from a broad perspective and associated global indices and variables. It analyze the interruption cost generally from primarily a theoretical economic perspective. For example, one method quantified reliability worth by relating the use of electricity to the Gross National Product (GNP). The disadvantage of this approach is that it is based on severely limiting assumptions that are often invalid and it does not capture many direct costs and virtually all indirect costs [13, 15].

One of the most difficult areas to quantify interruption cost is in the residential sector since it involves household activities and leisure time. Some cost assessments used customers wage rates as value basis for residential interruptions. Some make simplifying assumptions and base their results on lost leisure time. This approach is based on the notion that the marginal values of leisure and labor are equal, since consumers can and do make certain labour/leisure time tradeoffs. It likely yields overestimates of the outage cost, since equating the value of leisure time with working wages may be difficult to justify. Another approach use the hourly depreciation rates of all electrical appliances in the households that become unavailable because of an outage. A major limitation of these approaches is that the do not reflect the users actual needs.

- Case Studies of Blackouts

The second category of methodologies is to conduct after-the-fact case studies of particular outages. This approach is limited to major, large scale black outs such as 1977 New York black out [13]. This particular study attempted to assess both direct and indirect short term costs. Direct costs included food spoilage, wage loss, loss of sales, loss of taxes and similar items. Indirect costs included the emergency costs, losses due to civil disorder (looting, rioting and arson), and losses to government and insurance companies. It was observed that many of losses were difficult to give monetary value. The results indicated that indirect cost were much higher than the direct costs. But this information may be only relevant to the particular incident and the costs cannot be generalized.

- Customer Surveys

Following from both analytical and case study approaches, it is clear that costs assessments should attempt to be more customer specific. That is, the need to understand the losses experienced by the consumers due to unavailability of the functions, products and activities that are dependent on electricity. To fully understand this dependency, it is necessary to obtain certain level of information from the customer themselves. The main intent is to obtain better information for system planners use in optimizing system reliability.

This method can be further sub-divided into three divisions; Contingent valuation, direct costing and indirect costing methods. It is possible and desirable to include more than one method of interruption cost valuation when conducting a customer survey and the choices depends on the resource available and the customer that is being surveyed.

✓ Contingent Valuation Methods

It is essentially an economic approach, where this approach is to ask the respondents what they would be willing to pay to avoid having the interruption, or conversely what amount they would be willing to accept for having to experience the outage. Theory suggest that, incremental “willingness to pay” amounts should be nearly equal to “willingness to accept” valuations. However, actual valuations consistently yield willingness to pay values significantly less than willingness to accept values and this result does not perform like normal markets. Nevertheless, valuations based on willingness to pay and accept are worthwhile measures, possibly as outside bounds if the limitations are recognized.

- ✓ Direct Costing Methods

This may be the most obvious approach for determining the customers interruption costs for given outage conditions. The respondent is given a "worksheet" and asked to identify the impacts and evaluate the cost associated with particular outage scenarios. Guidance should be given as to what and what not to be included in the cost estimate so that the results are not ambiguous. This approach is more suitable in those situations where most losses tends to be tangible, directly identifiable and quantifiable. Thus it is most applicable for industrial sectors and it can also be effective in commercial/retail markets but must be used with care. Its major weakness lies in those areas where the impacts rends to be less tangible and the monetary loss is not directly identifiable such as residential sector.

- ✓ Indirect Costing Methods

This method is based on substitution in which the evaluation of a replacement good is used as a measure of worth of the original good, It is extremely useful when social considerations or effects are (have been found) to comprise significant part of the over all interruption costs, such as in residential sector. This approach attempts to provide a means to lessen the problems associated with rate related antagonism and the customers lack of experience in rating the worth of reliability. These could include such approaches as; the cost of hypothetical insurance policies to compensate for possible interruption effects, preparatory actions the respondent might take in the event of recurring interruptions or ranking a set of reliability rate alternatives. These methods yield evaluations of the financial burden that the customer would be willing to bear to alleviate the effects of interruption. These derived expenditures can be considered to be the respondents perception of the value of avoiding the interruption consequences. The limitation of this method is the possibility that the derived value is not an estimate of worth but is instead related to some other aspect or entity associated with the indirect approach. However, it is the customers perception that places value or worth (at least to the individual) upon a particular commodity. The customers behavior will be determined by his perceptions of value.

The "customer survey approach" has the distinct advantage in that the customer is in the best position to assess the costs associated with his condition and experience. Since it is the customer who makes decisions regarding energy consumption, this ultimately becomes important to the electric utility planners. Although this method is beset with all problem of questionnaire surveys, and the cost and effort of conducting surveys, is significantly higher than the others, nevertheless, it is the method favoured by utilities who require cost outage data for planning purpose [13].

5.3.2 Questionnaire Content and Survey Procedures

It is possible and perhaps desirable to include more than one method of interruption cost valuation in survey, in addition, it should seek interruption cost variation characteristics to the extent possible and consistent with particular objectives of the study. Other information such as customer demographics, principal use of electric supply, availability and nature of standby, and the possibility of creating uncomfortable situations due to interruption must be included. The customer pool must be broken down in appropriate customer categories or sectors, such as residential (domestic), commercial, industrial, agricultural, etc., so that category specific survey instruments can be used. The survey instrument can be developed for each of the customer sectors (categorized by the utilities). The customer energy and demand information must be secured from utility, and the actual interruption statistics are required if cost estimates based on unserved energy are sought. While it would be desirable to investigate all possible factors which might affect the cost of interruptions, the length of a questionnaire will be limited by the degree of effort which respondents are willing to engage in. This limitation is particularly relevant to the residential sector where significant of the cost is related to less tangible impacts.

The objective of sample size and sample selection decision is to secure representative and statistically meaningful response in all standard industrial classification (SIC) categories and geographical or regional divisions to the extent possible.

The **residential** questionnaire is prepared by using attitudinal, power rationing preference, electric heat dependence, and experience with past interruption questions to set the stage[15]. These were followed by two sets of questions which request qualitative assessments using a relative scale of undesirability to describe the severity of interruption impact. One set of questions addresses a range of residential household activities and end uses. The other posed hypothetical interruption scenarios, varying one interruption characteristic at a time, variations with duration, frequency, and time of occurrence (day, week, season) is requested. Quantitative (monetary) evaluations were obtained by means of an indirect worth assessment and two rate change questions. The indirect worth approach requested respondents to predict the preparatory actions they would take in the event. Two rate change questions (one willingness to pay and one willingness to accept) sought respondents opinions concerning electrical rate adjustment appropriate for particular changes in reliability. One question suggest what customer is willing to pay for alternative assured supply if one is available and the other asked respondents to indicate minimum reduction in rates for them to choose a specific reduced reliability. Demographic information and the number and age of household members, type of households, and the total income of the households are solicited.

The **commercial and industrial** questionnaires are prepared by attempting to qualitatively assess user dependence on electrical supply according to end use. Power rationing preference is also included. Quantitative assessment is achieved by using direct worth evaluation approach. Respondents shall be requested to estimate the cost of their company for various interruptions scenarios. The commercial is requested to include lost business or sales, wages paid to staff who are unable to work, equipment or goods damaged, etc., but not to include sales or business that could be made after the interruption is ceased. The industries shall be requested to include plant and equipment damaged, raw material and finished product spoilage or damage, and the cost of special procedures to restart production (e.g., extra clean up, maintenance, check ups etc.). Production lost during the failure and failure time is to be evaluated as the estimated revenue (sale price) of product not made less the expenses saved in labor materials, utilities, etc. If production could be made during slack time or overtime, that portion is not to be included. Other costs such as the cost of operating standby equipment or of special procedures to prevent damage could be listed as well. Availability, size, and purpose of standby were to be identified. The method to obtain cost estimate variations with time of day, day of the week, and month of the year is being developed. The users shall be asked to indicate the possibility and cost saving that could be effected if advance warning or interruption duration was provided. Demographic information on the nature and size of company's operation is requested.

After going thought number of papers presented by the different utilities and experts, the questionnaires which may be used in the Bhutanese context for residential and industries are prepared based upon my experience in the field and it is attached in the appendix A. However, the commercial will be almost same as industries except its sizes and losses.

6.0 Overview on Case study Area

6.1 Overview on Bhutan

Bhutan is landlocked mountainous country located in the eastern Himalayas with an area of 38394sq.km and is bordered by China in the north and India in the South as shown in the figure 6-1. Its altitude varies from 100 meter above sea level in the south to 7500m in the northern mountain peaks. This high rise mountains form the watershed to the river systems in Bhutan. Around 72.50% of the area is still covered by the forest. The country has a population of 634982 as per the census carried out in May 2005.

Fig. 6-1: Geographical map of Bhutan

Hydropower is presently the major driver of Bhutan's economic growth. It not only caters to domestic energy needs but also helps generate revenues by way of export of electricity to India.

In addition to benefitting the people, hydropower has other tangible benefits in terms of enhanced forest growth and reduction in destructive floods. This, in turn, leads to ecological benefits with forest acting as a carbon sinks and also offsetting local industrial pollution. Some of the key socio economic indicators are shown in table 6-1.

Table 6-1: Socio-economic indicators

Sl	Particulars	Values
1	Population	646851.00
2	Population density (person per square kilometer	16
3	GDP per capita (USD)	1334.00
4	Adult Literacy	54.30%
5	Health coverage	90%
6	Life expectancy (year)	65.20
7	Forest cover	72.50%

Source : [18]

6.2 Background on Bhutan Power Corporation

The erstwhile Department of Power under the Ministry of Trade and Industry was bifurcated into three separate entities namely Bhutan Power Corporation – a public utility, Department of Energy – A government department responsible for policy, planning and coordination activities for the energy sector and Bhutan Electricity Authority – Regulatory body under the Department of Energy. The reason why BPC was corporatized is many but the basic premise was to remove conflict of interest and reconcile commercial, social and policy objectives, and also to accept worldwide trend of restructuring that was happening in the power sector and accept the best practices. Running of electric utility is a business activity and by corporatization, BPC has been able to bring this focus into its operations. Corporatization also gives the public a clearer idea of the cost of supply and subsidy, it is in line with future plans for privatization and leaves the government free to concentrate on policy and proper planning for the Energy sector.

For economic growth to take place sufficient supply of electricity is an important prerequisite and our mandate provides a direct link to achieving the national goal of Gross National Happiness. Beside the above organizations a office namely Druk Green Power Corporation(DGPC) has been formed with effect from 1st January 2008, a major reason for forming is to amalgamate the existing plants for better sharing of scarce resources. Apart from this, DGPC will be responsible to manage renewal energy projects, particularly hydro power, in an efficient and sustainable manner and maximize wealth and revenues for the nation.

Bhutan Power Corporation was launched as a public utility on the 1st of July 2002 with the mandate of distributing electricity throughout the Country and also providing transmission access for generating stations for domestic supply as well as export. BPC started with 1193 employees with 967 employees joining from DoP and 226 employees from Chukha Hydro Power Corporation. BPC is the largest corporation in the Kingdom of Bhutan with a human resource size equal to almost 9% of the total Civil Services strength. It is the sole provider of electricity in the Kingdom with operations spread in 20 Dzongkhags. One of BPC's basic mandate was to not only ensure that electricity is available to all our citizens but to also make sure that it is reliable, adequate and above all within the means of all consumers.

The power transmission and distribution network is owned and operated by Bhutan Power Corporation Ltd (BPCL). Electricity is distributed at 66kV for high voltage customers and 33kV, 11kV and 6.6kV for industries, commercial institutions and bulk consumers. The power is exported to India from Tala Hydro project via 400kV, and from Chukha via 220kV and from Kurichu is via 132kV line. The BPCL also owns and maintains some of the small/mini/micro hydro plants. All the rural electrification works are also planned and is executed by BPCL and BPCL has the mandate to reach electricity to all by 2020 throughout the country. However, with coming of the new government, the Bhutan Power Corporation has been asked to accelerate the RE-programmes and to complete the RE-works through out the country with in 2017.

6.3 Introduction of the case study area

Wangdue Phodrang Dzongkhag is located in the western part of Bhutan and it consists of fifteen gewogs with 3264 households and a population of 31135 as shown in the figure 6-2. The dzongkhag has an area of about 4038 sq. km with an elevation ranging from 800 to 5800meters above sea level. The summers are moderate hot with cool winters. The dzongkhag has a forest cover of about 65 percent consisting of both broadleaf and conifer tree-species. The Phobji Gewog in the dzongkhag is famous as the winter nesting place of the black-necked-cranes. The dzongkhag has a total of 18 schools ranging from community to high schools providing education to about 6107 students. Health services are provided by an Army Hospital and 10 Basic Health Units(BHUs) and 23 Out Reach Clinics (ORCs). Over 60% of the rural households have access to electricity and the Government has initiated to electrify all the rural households by 2017.

Wangdue received its first electricity in 1969 from Hesothangka Power house (400kVA) under Wangdue dzongkhag which was constructed under the Government of India funding and also the expertise from India. Wangdue has huge potential of hydropower development since the two major river is flowing through namely, Punatshangchu and Basochu.

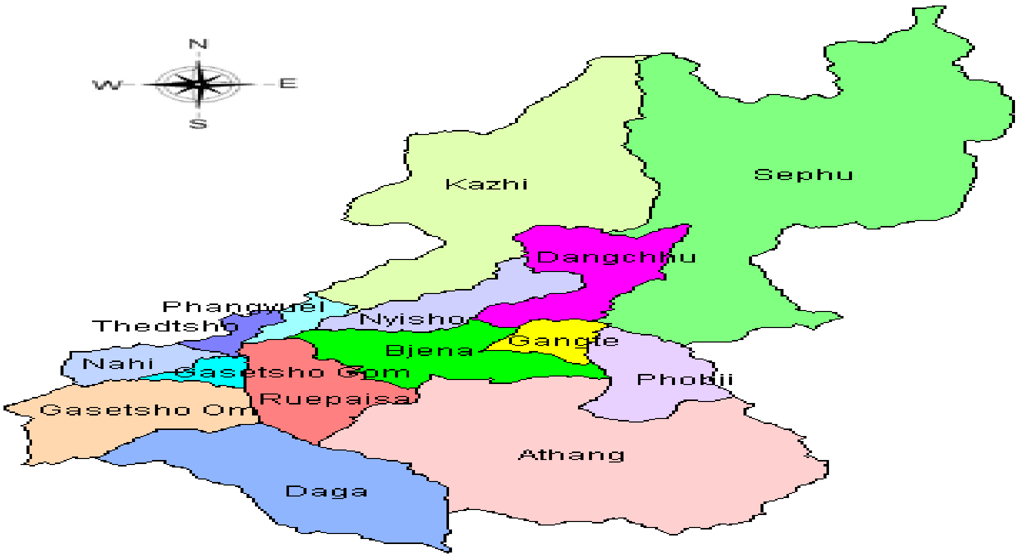


Fig. 6-2: Administrative map of Wangduephodrang

Basochu Hydro Power Plant, Capacity of 64MW, which was constructed in two phases has been completed in 2005 under Austrian funding. Also, Punatshangchu I, 1200MW has been just begun under GOI funding and the detail study for Punatshangchu II, 1000MW is almost completed and the construction will follow shortly. Because of the above reasons, the dzongkhag has huge potential for future development which demands electricity with quality.

All those activities will bring socio economic development which demands more power. As of now, Wangdue dzongkhag does not have proper town. Though the town area is black topped and developed a few years back, the land has been allocated just months back to the individuals and they have been asked to go ahead with the construction. This will drastically increase the overall electricity requirement. The governments ambitious vision to reach electricity to all by 2017 will further aggravate the load growth since almost 40% of the rural households are to be electrified.

6.3.1 Power Supply Source

The basic distribution network model as seen from the source at Lobesa and Rurichu substation are as shown in the figure 6-3 and 6-4. Wangdue dzongkhag is fed from two sources ie Lobesa and Rurichu Substation (Basochu Power House). The source of electricity for Punakha and Wangduephodrang dzongkhag is from 66/33/11kV substation located at Lobesa and some of the area under Wangdue is fed from 66/11kV substation located at Rurichu. The two substations are inter connected via 66kV line and the Rurichu is also connected with Semtokha substation via 220kV which is the main source to Lobesa substation before Basochu Power house was constructed and the other 220kV feeder is connected to Tsirang Dzongkhag which will be ultimately connected to other southern dzongkhag and then to the Indian Grid.

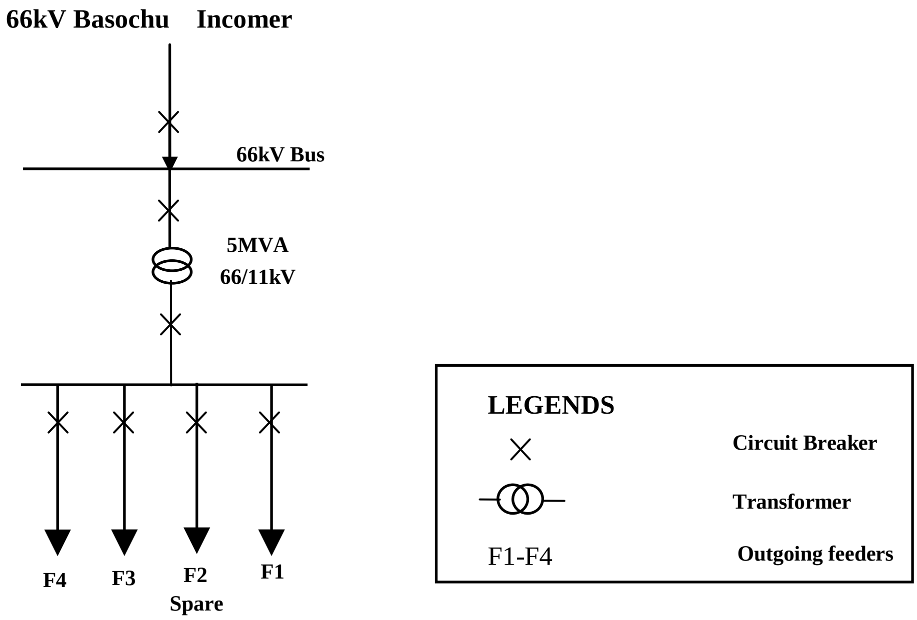


Fig. 6-3: Distribution schematic from Rurichu substation

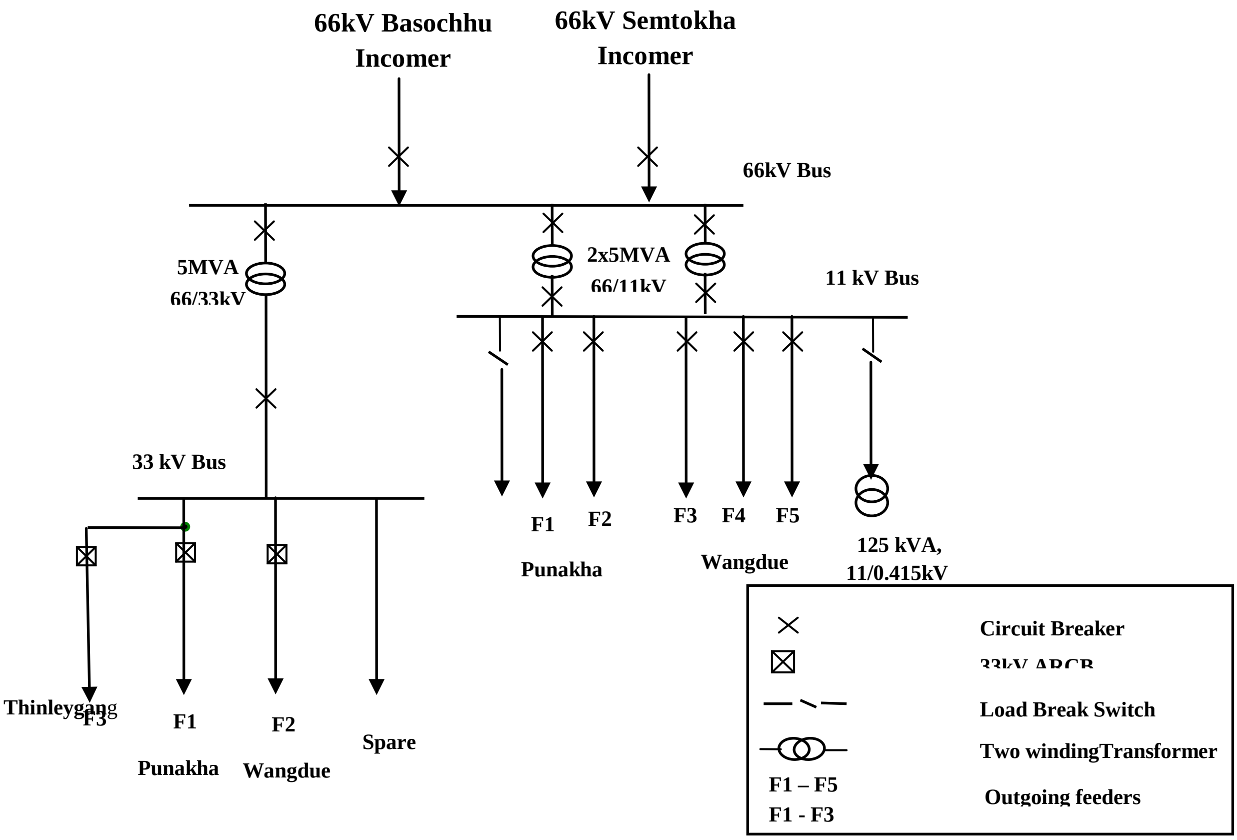


Fig. 6-4: Distribution schematic from Lobesa Substation.

At present Lobesa Substation has three 33kV outgoing feeders with a provision to add a fourth feeder. The 33kV system has one VCB(Vaccum Circuit Breaker) for the incomer and the outgoing individual feeders are controlled through ARCB`s(Auto Reclosing Circuit breaker). Though the 33kV feeder has low power losses on lines as compared to 11kV feeders, the 33kV supply is limited by having only one 5MVA, 66/33kV transformer capacity. Even if the line interconnections permit in near future, the capacity limitation of the 66/33kV transformer will not permit us to transfer the load from the 11kV to 33kV system especially during the total shutdown of 11kV system. Any maintenance on this single transformer needs complete shutdown of the 33kV system. Around 80% of the case study area is presently fed from Lobesa substation.

With in the vicinity of Rurichu substation, a mega hydro project of 1200MW has just begun which will need lots of power once the project is under full swing. The expansion of 11kV line will be mainly limited for the project and the rural households within that area. Table 6-2 shows the detail of number of transformers and outgoing feeders available with each station.

Table 6-2: Overview of the station system

Station	**Volatge level (kV)**	**Number & Transformer rating(MVA)**	**No. of outgoing feeders**	**Remarks**
Lobesa Substation	66/33	1x5	4	1-Punakha, 1-Thinleygang, 1-spare, 1-Wangdue
	66/11	2x5	7	2-Punakha, 2-spare, 2-Wangdue, 1-station transf.
Rurichu Substation	11/220	2x30	2	1-Semtokha, 1-Tsirang
	220/66	1x30	1	1-Lobesa
	66/11	1x5	4	3-Wangdi, 1-spare

6.3.2 Existing distribution line and Transformers

The low voltage and MV networks are usually operated radially and thus each network has only one in-feed points. The medium system voltage provides a convenient voltage for connecting substantial loads or the larger blocks or the office buildings. So, the requirements of medium voltage systems are as close as possible to each individual load points. In existing system, 33kV line is used mainly for far flung rural areas which has to be extended further in order to cover all the rural electrification activities and 11kV lines are usually used for nearby rural areas and mainly for town areas.

The various size of distribution transformers are used. The transformers from 16kVA-250kVA are usually pole mounted for both urban and rural areas. They are mounted either on a single pole or a double pole. Beyond 250kVA transformer, the transformers are mounted on the ground and is provided with 10m x10 m GI chain link fencing. Almost all the transformers are equipped with individual fuse and dis-connector on MV side. In some of the case, one three phase dis-connector covers a group of pole mounted transformers connected to the section of a line. Lightning arrester is provided for individual transformers for protection from lightning. On the low voltage side the feeder is protected either with fuse or miniature circuit breaker and some of the substation with both the protective equipments. For distribution transformers, GI pipe is used as earthing materials. Three numbers of earthing set which is meshed in the ground is provided for every transformer. The neutral and the body of the transformer is solidly grounded and one earthing is meant for lightning arrester.

The number of distribution lines and Transformers operated and maintained by ESD, BPCL, Wangdue is as shown in the table 6-3.

Table 6-3: Details of MV, LV and distribution transformers

Distribution lines				**Distribution Transformers**						**Consu-mers (No)**
				33 kV		**11kV**		**6,6kV**		
33kV (km)	11kV (km)	6.6kV (km)	0.415kV (km)	33/0.4 kV (No)	kVA connec-ted	11/0,4 kV (No)	kVA connec-ted	6,6/0,4 kV (No)	kVA connec-ted	
88,80	90,93	1,16	301,579	74	4345	63	10870	2	50	3624
180,89			**301,579**	139 numbers in total			15265 kVA in total			3624

Source: [20]

6.3.3 Chronological requirement of electricity

The historical energy requirement trend is presented in table 4.1. The total energy required has been worked out from the available energy sale figures for the different consumer categories on which the energy losses has been added in proportion to the respective category energy sale figures.

Table 6-4: Electricity requirement trends

Customer Category	2000-2001	2001-2002	2002-2003	2003-2004	2004-2005	2005-2006	2006-2007	2007-2008
	Energy sales (MU)							
Domestic	1,076	1,541	1,819	2,468	2,993	3,132	3,667	4,100
Commercial	1,396	0,861	1,747	1,166	1,318	1,220	1,317	1,303
Govt. sector	0,860	1,326	1,539	2,252	1,827	1.334	1,326	2,007
Industrial	0,136	0,378	0,215	0,064	0,064	0,061	0,060	0,069
Public lighting	0.002	0,002	0,075	0,010	0,011	0,041	0,043	0,041
Total	**3,470**	**4,108**	**5,395**	**5,960**	**6,213**	**5,788**	**6,413**	**7,520**
Energy loss(MU)	2,088	3,521	1,860	1,842	1,586	1,696	0,870	0,584
Energy loss%	37,60	46,20	25,60	23,60	20,30	22,67	11,95	7,21
Total energy requirement(MU)	**5,558**	**7,629**	**7,255**	**7,802**	**7,799**	**7,484**	**7,283**	**8,104**
Growth over previous year(%)	5,80	37,26	-4,90	7,50	0,00	-4,04	-2,69	11,27
Customer category								
Domestic	1,724	2,862	2,446	3,231	3,757	4,050	4,165	4,419
Commercial	2,236	1,599	2,349	1,526	1,654	1,577	1,496	1,404
Govt. sector	1,377	2,463	2,070	2,948	2,293	1,724	1,506	2,163
Industrial	0,218	0,702	0,289	0,084	0,080	0,079	0,068	0.075
Public lighting	0,003	0,004	0,101	0,013	0,014	0,053	0,049	0,044
Total	**5,558**	**7,63**	**7,255**	**7,802**	**7,799**	**7,484**	**7,283**	**8,104**
No. of customers				2156	2296	2794	3424	3624
Average requirement annually (kWH)				3619	3397	2679	2127	2236

Source: [20,21]

The energy requirement trend for Wangdue is as shown in the figure 6-5. As observed from the figure 6-5, the energy requirement in year 2005 and year 2006 is decreasing, this may be due to the completion of the 64MW construction project at Basochu and the requirement increases in the year 2007. There is decrease in the consumption by Govt. category and one can observe increase in the domestic consumption.

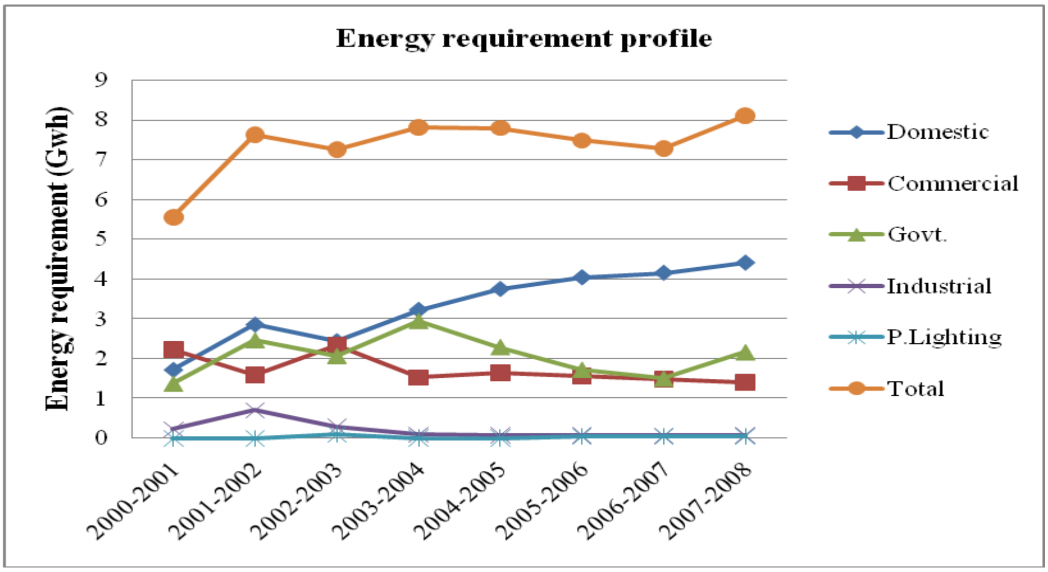


Fig. 6-5: Electricity requirement trend

The sector wise energy consumption for the year 2007-08 is shown in figure 6-6. The consumption by the domestic consumer is the highest where as the consumption by the industry and public lighting is the lowest.

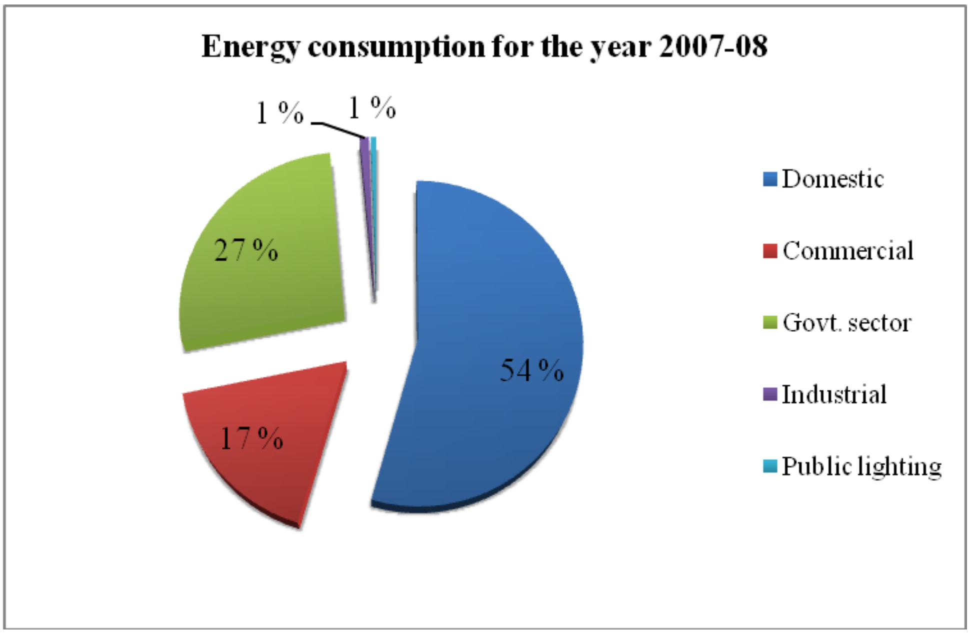


Fig. 6-6: Energy consumption for year 2007-08.

6.3.4 Estimated Power demand by 2020

The Royal Government has a vision to reach electricity to all by year 2020 and this program has been further accelerated and around 2038 numbers of rural households will be connected by grid extension. The grid extension power demand has been estimated assuming an average peak demand of 1,30kW, 1,36kW, 1.43kW and 1,47kW per households for the year 2007, 2012, 2017 and 2020 respectively (source: RE-Master Plan).

The existing Wangdue town serves as the administrative centre and the growth of township is accelerated by the population growth of the civil servants, military establishments, the east west highway and the highway to Tsirang, Dagana and Sarpang dzongkhags, thus provides township with good growth potential. The other factor that would contribute to the growth of Wangdue town would be due to the mega projects like Punatsangchu I and II, which is coming up shortly and those likely to come in future. The relocation of existing town and the local area plan have been finalized and has a provision of 138 plots which is already connected black topped roads and other utility services. Each plot will accommodate a three storey building with five dwelling units and two shops on an average. Also, there are several settlements in the vicinity of the planned town area where new building construction activities are already coming up. In addition, the military training centre is taking several building constructions and is also likely construct more in future. The demand forecast made by the Druk-Care consultancy is presented in table 6-5 and is illustrated in figure: 6-7.

Table 6-5: Power demand forecast upto year 2020

Five Year Plans	**2007**	**2012**	**2017**	**2020**
Project demand of RE(MW)	1,00	2,40	3,30	3,40
Projected demand of UE(MW)	2,50	3,50	4,00	4,50
Total projected demand(MW)	**3,50**	**5,90**	**7,30**	**7,90**

Source: [21]

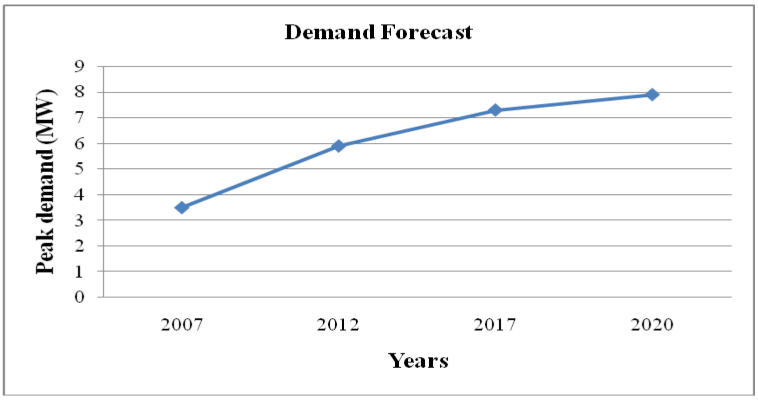


Fig. 6-7: Power demand forecast

6.4 Reliability Aspects

The reliability standards for electricity supply is determined on past engineering principles and is practiced as of now in Bhutan. The statistical data for reliability aspects are not readily available and the available data are not rationalized since the reliability aspect was not given of its due importance. After formation of BPC in 2002, the reliability considerations has picked up some importance and even bench marking of the reliability indices have stated. However, the bench marking of the distribution reliability indices is challenging due to the geographical locations, data gathering practices, index definitions and inclusion/exclusion of notified/non notified interruptions and of major events.

As of now, BPC has included only SAIFI and SAIDI as its reliability indices and these indices are not able to justify the reliability worth, how much the customers value for the electricity supply. The present reliability value of the indices used in the study area (ESD, Wangdue) is presented in table 6-8.

Table 6-8: Reliability indices of case study area

Reliability indices	Unit	Calculated value for 2008	Norwegian values
SAIFI	Interruption/Cust. /yr	12,150	1,70
SAIDI	Hrs/Cust./yr	17,744	2,40

The average service availability index(ASAI) of the system is 0.997995 in the year 2008 for case study area. This just gives the overall picture of the whole system in the area and not the localized problem (feeder wise). The indices helps us to establishes the chronological changes in the system performance and therefore help us to identify the weak areas and the need of reinforcement. This data will also help us to make predictive analysis for the future system.

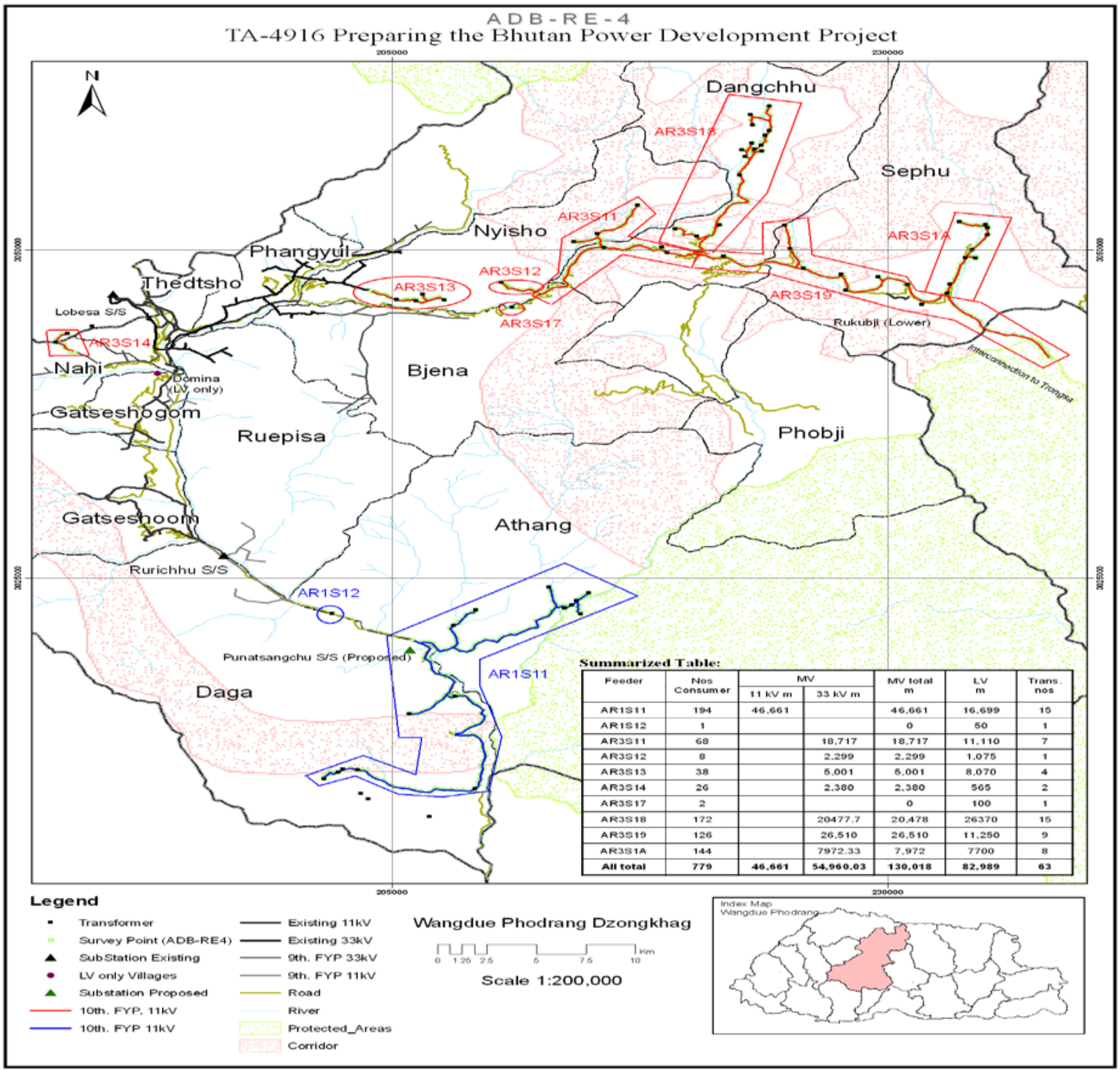
7.0 Reliability Assessment

The reliability assessment is carried out for the existing system and predictive reliability analysis for the future system with the help of NetBas/Levsik. A number of alternatives such as placement of Load Break Switch, Auto reclosers has been simulated along with the mitigation techniques such as vegetation management and overvoltage protection have been evaluated and considered since it is found to be economically viable. The alternatives such as automation were not considered since the energy consumption of the feeder is not able to justify the investments which have to be made. For reliability analysis of the existing system, the reliability indices are both calculated and simulated. For predictive reliability analysis of the future system, the reliability indices are simulated. Reference values are the results obtained from simulation of the existing system in case of reliability assessment, where reference values are the simulated values of the best alternative of the previous year incase of predictive analysis. Calculated values are obtained based upon the historical data of failures and the number of customers connected and affected by the outage. The detail calculation for the calculated value is attached in appendix B-9, where as historical fault and consumer data is incorporated in appendix B-1 to B8.

Section 7.1 deals with the reliability assessment of the existing systems where section 7.3 deals with the predictive reliability analysis of the future system. The predictive analysis is carried out on 33kV and 11kV systems which are fed from Lobesa substation since major expansion and load growth is expected on theses feeders. Section 7.2 deals with the sources of faults causing outages in the system. The possible mitigation technique to help in reducing the fault caused by the sources as described in section 7.2 are discussed in detail in chapter 8. Some of the mitigation techniques have been evaluated along with the alternatives in the analysis and assessments. The alternative which gives minimum reliability indices and minimum non delivered energy based on cost benefit ratio shall be considered.

7.1 Reliability Assessment of the existing System

The ESD, Wangdue is fed from two sources as described in chapter 6, sub section 6.3.1. There is one 33kV and two 11kV feeders feeding Wangdue Dzongkhag from Lobesa substation and three 11kV feeders from Basochu Substation. In existing system, 33kV line is used mainly for far flung rural areas and again, this 33kV line be further expanded for the upcoming rural electrification works. One 11kV line is mainly used for Wangdue town area and the other 11kV line is used for nearby rural areas. However, there is a possibility of transferring load between these two 11kV feeders. The map showing the expansion of 33kV and 11kV network in the case study are is as shown in figure 7-1.



Feeder	Nos Consumer	MV		MV total m	LV m	Trans. nos
		11 kV m	33 kV m			
AR1S11	194	46,661		46,661	16,699	15
AR1S12	1			0	50	1
AR3S11	68		18,717	18,717	11,110	7
AR3S12	8		2,299	2,299	1,075	1
AR3S13	38		5,001	5,001	8,070	4
AR3S14	26		2,380	2,380	565	2
AR3S17	2			0	100	1
AR3S18	172		20477.7	20,478	26370	15
AR3S19	126		26,510	26,510	11,250	9
AR3S1A	144		7972.33	7,972	7700	8
All total	**779**	**46,661**	**54,960.03**	**130,018**	**82,989**	**63**

Fig. 7-1: Geographical map of Wangdue dzongkhag showing future network expansions

The three 11kV feeders from Basochu substation feeds most probably the village within its vicinity of the project area and the project. The expansion of 11kV line will be mainly limited for the upcoming Punatshangchu project and the rural households within the vicinity of the project area.

Reliability data of the past year (2008) has been collected through email from ESD, Wangdue and the same will be computed for the reliability indices and the energy not supplied during interruption. Past performance statistics provide a valuable reliability profile of the existing system. However, distribution planning involves the analysis of the future systems and the evaluation of the system reliability when there are changes in the; configuration, operation conditions, or in protection schemes. Hence, it is important to have Predictive Reliability Analysis(PRA) for the future system. With the help of this data, the predictive analysis shall be carried out on 33kV system since major expansion for rural electrification works shall be carried out on the system. As major load growth is expected on the 11kV system fed from Lobesa substation, the PRA shall be carried out to see how the future reliability could be improved in the system. As for the 11kV feeders fed from Basochu substation, the PRA is not carried out since the load growth on this feeder is not known (load growth on adhoc) since a power mega project is coming within its vicinity. The PRA will give the fair idea of the reliability that would be expected for the whole system after expansion and the reliability improvement techniques may be evaluated depending upon the utilities objective and strategies.

7.1.1 33kV Feeder

The 33kV feeder provides electricity to most of far flung rural areas and it passes through a very thick forest. This feeder caters load to 1606 number of customers and mainly to the rural areas. There will be a significant load growth on the feeder for the next 12 years since majority of the rural areas will be connected to this feeder. At present the feeders connected load is 4345kVA with 74 numbers of substations. The trunk line is constructed mainly with ACSR conductor, Wolf (150sqmm) and the spur lines are constructed either with Dog (95sqmm) and Rabbit(50sqmm) depending upon the future expansion of the network. It is assumed that the RE-works will be completed by 2017 and the load growth from thereon will be minimal as all the rural households by then would have been covered.

The 33kV net work has radial configuration and this feeder shall be further expanded to meet the rural requirement as shown in the figure 7-2. Though this feeder is radial system, it could be connected to the other feeder at Chazam which is coming from the other dzongkhag in near future (latest by 2017). This will serve as back up source for 33kV network for both Dzongkhags. With connection of back up to each other, reliability could be improved in 33kV system of both dzongkhags. Most of the consumers connected to this feeder are rural domestic, schools, BHU's and other government extension offices**.**

The location of circuit breaker (auto recloser) and the Load break switch in the existing system are as shown in figure 7-2 which plays vitol role in restoration of system back to normal after interruption and for maintenance, thus providing the opportunity to make an step restoration which reduces SAIDI of the system though it may not help in SAIFI. It also helps to reduce Non Delivered Energy to the customer and the total cost of customer interruption is therefore reduced.

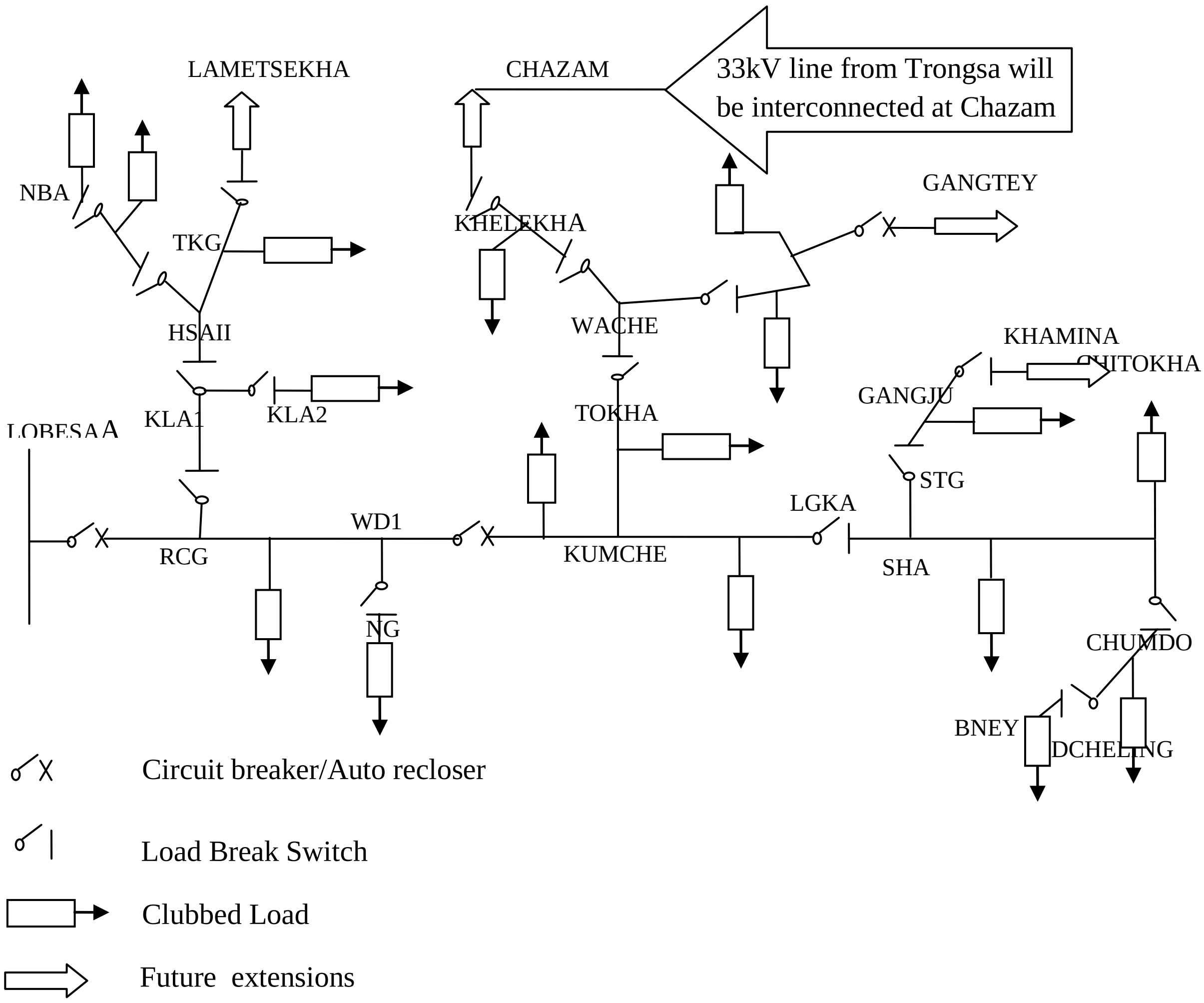


Fig.7-2: Stylized single line diagram of 33kV network

A summarized reliability data (2008) for the feeder collected from the ESD, Wangdue is presented below, which will be used for further analysis. The detailed single diagram showing all the extensions and the detail interruption data are presented in the appendix C-1 and B-1 respectively.

Table 7-1: Summarized reliability data

Outage frequency (No./yr)	**Outage duration (hrs/yr)**		**∑ Customers affected (No.)**	**∑ Customer hours curtailed (cust. hours)**	**Customer served (No.)**	**Feeder length (km)**
	Perm.	**Temp.**				
20	32,43	0	30031	48388,45	1606	100,92

Using above data, reliability indices were both calculated and simulated with the help of NetBas/Levsik. The interrupted energy for the interruption duration is also shown which will help us to calculate the reliability worth after finding out the cost of interruption from the customer perspectives.

There are number of ways to improve reliability, however, it is not economically viable to consider all the possibilities due to dispersed customer locations, low energy consumption and too less number of customers connected to the feeder. In this case study area, auto reclosers and load break switch were proposed. It is placed at a location which gives minimum SAIDI and minimum energy interrupted. The alternatives were placement of the Load break switch at different locations and the alternative which gives lowest SAIDI, SAIFI and minimum interrupted energy shall be considered. The detail, showing the reliability simulation of various alternatives is incorporated in the appendix D-1.

The alternatives chosen for the case study is placement and number of Load break switch at different locations are listed below and the present system is treated as reference case;

1. Present system as reference system (simulation values)
2. Alt.1 - Installation of LBS at nodes KUMCHE-CGP, DKHA-LKHA, LKA-LUKA
3. Alt.2 - Installation of LBS at node KUMCHE-CGP, DKHA-LKHA
4. Alt.3 - Installation of LBS at KUMCHE-CGP, DKHA-LKHA, shift LBS from LKGA-SHA to SHA- RKH

Table 7-2: Reliability results with the existing system for year 2009

Indices	**Unit**	**Calculated value**	**Reference Value**	**Alt. 1**	**Alt. 2**	**Alt. 3**
SAIFI	Inter./yr	18,699	15,264	15,264	15,264	15,264
SAIDI	h/inter.	30,130	26,100	25,310	25,405	25,211
CAIDI	h/yr	1,611	1,709	1,658	1,664	1,651
ASAI	%	99,66	99,702	99,711	99,710	99,712
Energy interrupted	kWh/yr		13300,90	12843.70	12892.20	12795.30
Peak Power	MW		1,035			
Heaviest loaded line	%		4,28			
Max. Volt. drop	%		0,44			

From table 7-2, it is being observed that alternative 3 gives the better results in terms of improvement of SAIDI, which inturn gives the minimum interrupted energy. Also, it is found that the more number of sectionalizing switches does not give the better results. It is very important to place the sectionalizing switches at strategic locations however, it may not be practically true since the location of such switches should be near the motorable roads and the availability of other communication facilities. If it is located at such points, it will facilitate to sectionalize the faulty sections faster and to make the supply available to the unfaulty ones.

The reliability indices like SAIFI and SAIDI with different alternative is illustrated in the figure 7-3. It is found that an Alt. 3 gives the minimum SAIDI where SAIFI is found to be same with all the alternatives.

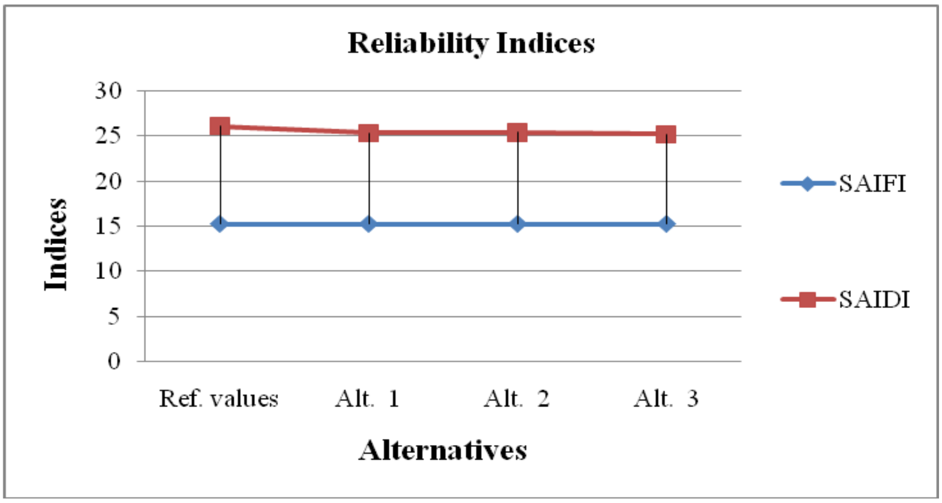


Fig. 7-3: Reliability indices

The energy interrupted due to interruption is illustrated in the figure 7-4 and it is found that an Alt. 3 gives less energy interrupted.

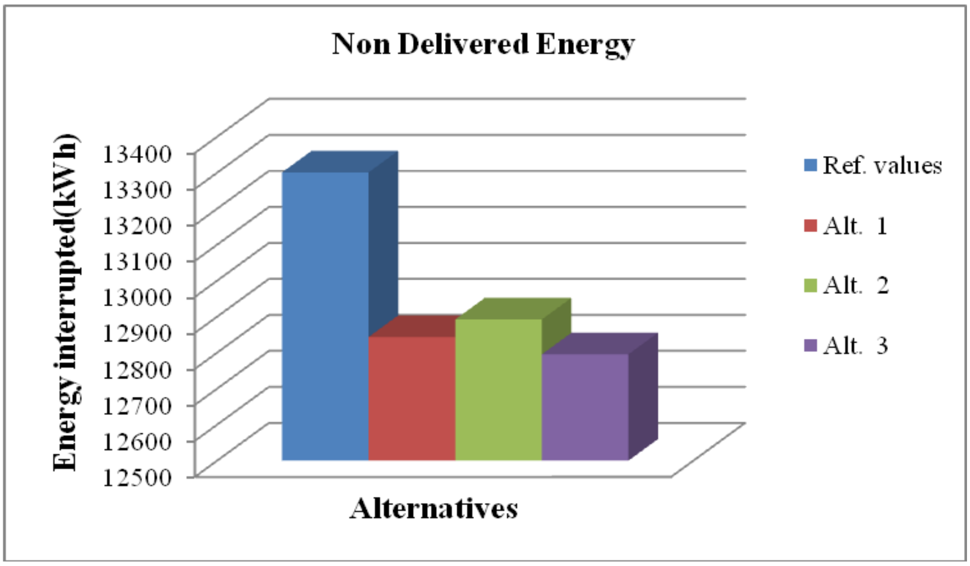


Fig. 7-4: Annual energy interrupted due to interruptions

To improve reliability further, we have to look at non electric mitigation technique which is discussed in chapter 8. The difference observed between calculated and simulated values may be due to the difference in data. The calculated value considers only the data obtained for the past one year where as simulation represents long run average values and the outage of the supply grid is also considered. The other reason may be due to difference in actual time in operation of the switches and the sectionalizing time used for simulations.

7.1.2 11kV feeder IV&V

The feeder IV usually feeds a mixture of consumers both rural and urban. Urban consumer includes; commercial, Government offices, small Industries, Training institute and residential/domestic customers while the rural consumers are mostly domestic category while feeder V feeds Wangdue town and the main Administrative centre. Urban consumer includes all Government offices, Hospital, RBA training centre, commercial and urban domestic.

The growth of township is accelerated by the population growth of the civil servants, military establishments, the east west highway and the highway to Tsirang, Dagana and Sarpang dzongkhags, thus provides township with good growth potential. The other factor that would contribute to the growth of Wangdue town would be due to the mega projects like Punatsangchu I and II, where the construction of the I is undergoing and II will be coming up shortly. The relocation of existing town and the local area plan have been finalized and has a provision of 138 plots which is already connected with black topped roads and other utility services. Each plot will accommodate a three storey building with five dwelling units and two shops on an average. Also, there are several settlements in the vicinity of the planned town area where new building construction activities are already visible. In addition, the military training centre is taking several building constructions and is also likely construct more in future. So there will be substantial load growth on both the feeders though there may not be major extensions. The stylized single line diagram of the feeder is presented in figure 7-5 and detail single line diagram is presented in appendix C-2.

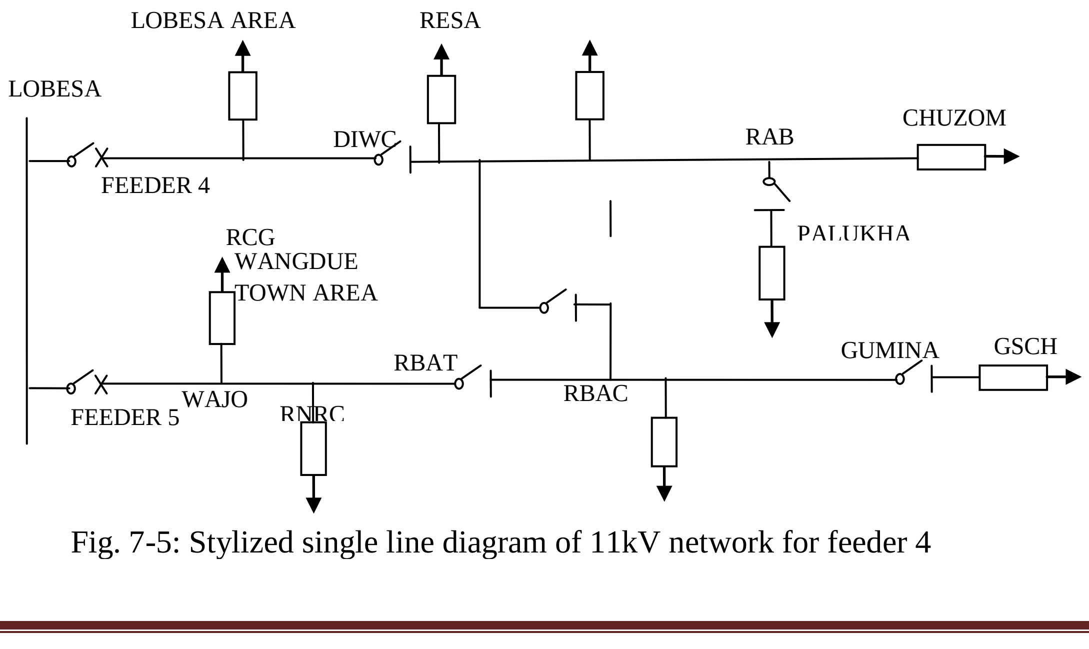


Fig. 7-5: Stylized single line diagram of 11kV network for feeder 4

A summarized reliability data (2008) is presented in table 7-3 and detail interruption data is enclosed in appendix B-2, B-3 and simulation results in appendix D-2.

Table 7-3: Summarized reliability data.

Feeder	**Outage frequency (No./yr)**		**Outage duration (hrs/yr)**		**∑ Customers affected (No.)**	**∑Customer hours Curtailed**	**Customer served (No.)**	**Feeder length (km)**
	Perm.	**Temp.**	**Perm.**	**Temp.**				
F4	13	1	14,24	0,15	10217	10906,63	951	35,261
F5	2	0	2,09	0	1560	1622,10	841	12,953
Total	**15**	**1**	**16,48**	**0,15**	**11,777**	**12528,73**	**1792**	**48,214**

With the use of above data, the reliability indices shall be both calculated and simulated for the year 2009. As seen from the single line diagram, these two feeders acts as a reserve to each other when there is fault/interruption on either side of the feeder. So the placement and location of Load Break switch for reconfiguration during interruption will play a important role in reducing the SAIDI and the energy interrupted. In this feeder, an alternatives considered is placement of LBS/sectionalizer which are manually operated and reduction of faults due to trimming of trees in time, are listed below;

1. Present system as reference system (Ref. value)
2. Alt.1 – Assumed that fault rate could be reduced (from 31.14-27)
3. Alt.2 - Installation of LBS at node WAJOK-BHS, WAJOK-TGU, HPH-PASO.
4. Alt.3 –Combination of 2 & 3.

Table 7-4: Reliability results with the existing system for year 2009

Indices	**Unit**	**Cal. value**	**Ref. Value**	**Alt. 1**	**Alt. 2**	**Alt. 3**
SAIFI	Inter./yr	6,57	7,703	6,924	7,706	6,927
SAIDI	h/inter.	6,99	10,117	9,155	9,836	8,956
CAIDI	h/yr	1,064	1,313	1,322	1,276	1,2929
ASAI	%	99,92	99,885	99,895	99,888	99,898
Energy interrupted	kWh/yr		10924,50	9920,50	10079,50	9240,40
Peak Power	MW		2,501			
Heaviest loaded line	%		24,14			
Max. Volt. drop	%		3,75			

The difference between the calculated and simulation result is mainly due to the sectionalizing time. In simulation, the outage of supply grid (fault rate of 1 with duration of 2 hours) is being considered where as in calculated value, it is not. From the table, it is observed that the location of the LBS has so much of impact on reduction of SAIDI where SAIFI remains almost constant which is illustrated in the figure 7-6.

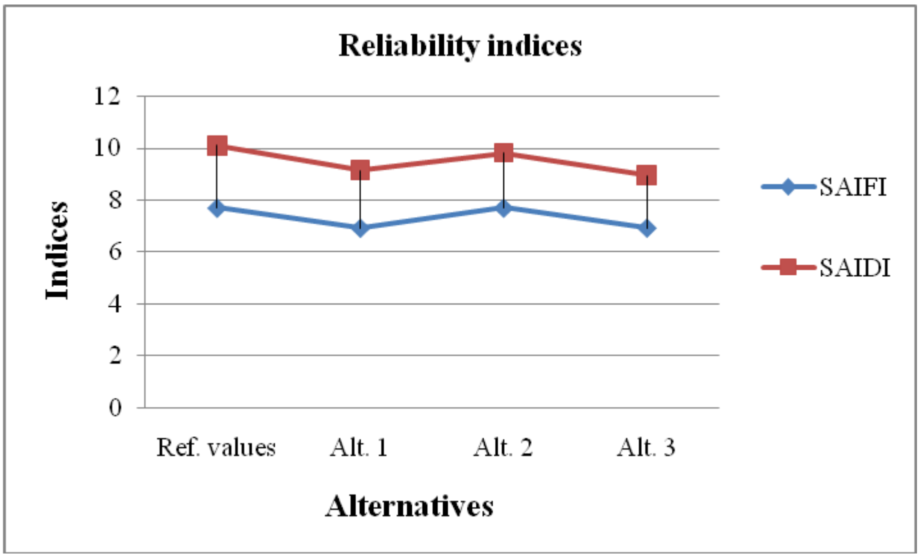


Fig. 7-6: Reliability Indices

The energy interrupted with different alternatives are illustrated in figure 7-7 and it is found that the location and number of LBS installed plays a major role in the annual quantity of energy interrupted(Non Delivered Energy). It can be seen from the figure that Alt. 2, mitigation techniques like vegetation management gives good result in reducing the fault frequency, outage time and the interrupted energy (Non-delivered energy).

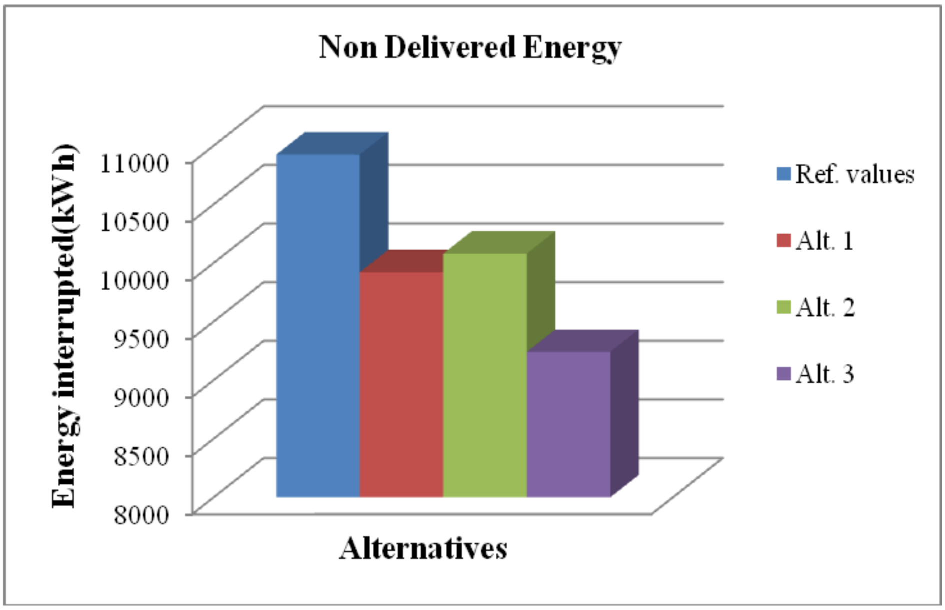


Fig. 7-7: Annual energy interrupted due to interruptions

7.1.3 11kV feeders fed from Rurichu substation

These feeders are lightly loaded as of now since these feeders feeds only the Basochu Power house and the few villages near by the area. The customer connected to these feeders are mixture of residential/domestic, commercial and government offices. The said area is located near the ongoing mega hydro project, where consumption on this feeder will grow on adhoc basis where load forecasting may not be easy. So it is simulated with the present system and no alternatives were tried since load growth on this feeder could not be known.

The stylized single diagram is presented in figure 7-8 and the detailed single line diagram is incorporated in appendix C-3.

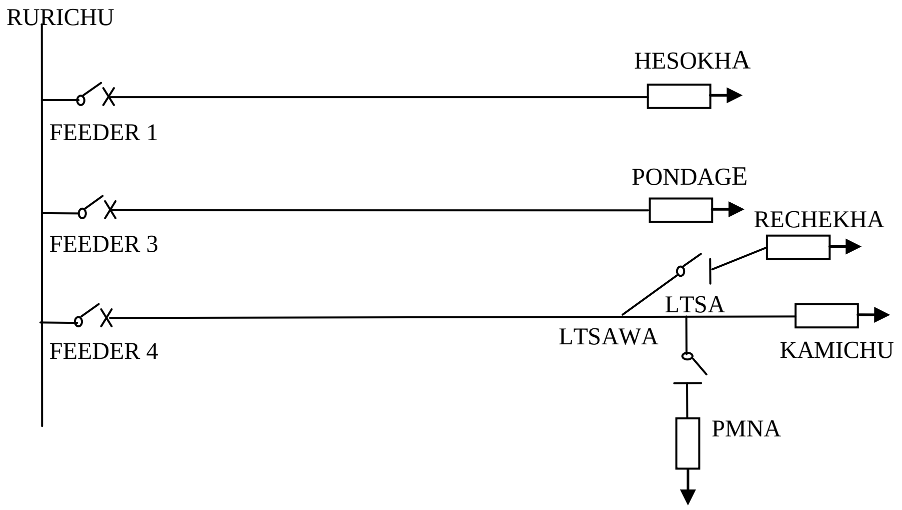


Fig. 7-8: Stylized Single line diagram of 11kV network for feeder fed from

A summarized reliability data (2008) is presented in table 7-5 and detail interruption data are presented in appendix B-4, B-5, B-6 respectively.

Table 7-5: Summarized reliability data

Feeder	Outage frequency (No./yr)		Outage duration (hrs/yr)		∑ Customers affected (No.)	∑ Customer hours curtailed	Customer served (No.)	Feeder length (km)
	Perm.	**Temp.**	**Perm.**	**Temp.**				
F1	6	5	23,90	0,36	351	853,33	37	7,33
F3	5	12	26,69	1,06	2779	4679,88	225	16,41
F4	1	6	0,22	0,47	602	59,50	88	17,32
Tot.	**12**	**23**	**50,81**	**1,89**	**3732**	**5592,71**	**350**	**41,06**

With the use of above data, the reliability indices were calculated and simulated and is presented in table 7-6.

Table 7-6: Reliability results with the existing system for year 2009

Indices	Unit	Calculated values	Simulation values
SAIFI	Inter./yr	10,6629	10,057
SAIDI	h/inter.	15,979	25,671
CAIDI	h/yr	1,5042	2,5526
ASAI	%	99,82	99,707
Energy interrupted	kWh/yr		3187,10
Peak Power	MW		0,348
Heaviest loaded line	%		3,40
Max. Volt. drop	%		0,27

The calculated values is based on performance of the past one year where simulated values considers for the long average value. However, the difference between the two value is contributed by the actual repair time and the sectionalizing time since the statistic used for the simulation is based on the value of the time taken for one year.

7.2 Major Causes of Interruption

Faults are not evenly distributed along lines. Not all faults are inevitable "acts of nature." Most of them are from specific deficiencies at specific structures. On overhead circuits, most faults result from inadequate clearances, inadequate insulation, old equipment, or from trees or branches falling onto a line[28]. A first step in eliminating faults is to identify what is causing them. Keeping in mind that most faults result from specific structural deficiencies, field identification of fault sources is a key part of construction-improvement programs. Field personnel can be trained to spot pole structures where faults have occurred or might likely occur. Common structural deficiencies include poor jumper clearances; old equipment (such as expulsion arresters); bushings or other equipment unprotected against animals, ground leads or grounded guys near phase conductors; poor clearances with polymer arresters; damaged insulators; damaged covered wire; and dangerous trees or branches present.

When attempting to improve reliability, it is important to know the greatest contributing factors to these indices. However, predictive root cause analysis is different than historical root cause analysis which typically identifies the physical cause of faults [25] where predictive root cause analysis computes each components contribution to reliability indices. The cause of outage depends on geographical locations of the area. From historical data of the past years, major cause of outages in the system is being evaluated and is shown in table 7-7 and is illustrated in figure 7-9.

Table 7-7: Sources of cause of outages

Causes	**Trees**	**Birds**	**Component failure**	**Wind**	**Lightning**	**Forced outages**	**Temporary**
Numbers	16	9	9	3	7	7	20

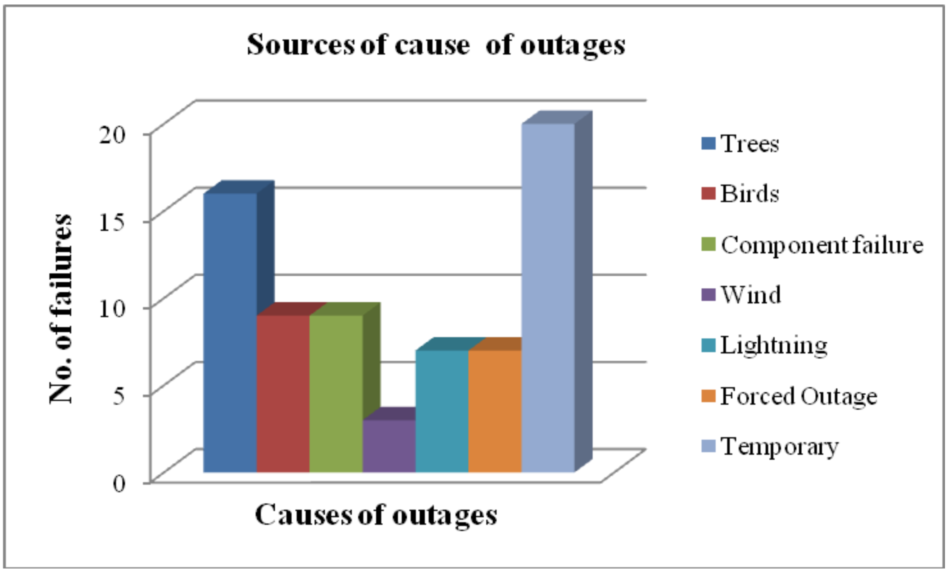


Fig. 7-9: Sources of causes of outages

The statistic should be built over long run averages and this may not give us right direction to be considered for mitigation techniques. From the figure above it is understood that the maximum number of faults are caused mainly due to vegetations and trees which needs to be mitigated to improve the reliability in the system. The reliability improvement technique is explained in chapter 8. We can see from the figure that there are number of outages which could have been easily mitigated by creating awareness (since most of the people in area is receiving electricity for the first time) among the public regarding safety precautions and the importance of electricity to various consumers, so they could take preventive measure to avoid damage to electric lines and equipments, thus avoiding interruptions.

The temporary faults were mainly caused on Rurichu feeders meaning that the vegetation along the right of ways(ROW) have to be cleared and maintained as per the required standards. Temporary faults are faults which are self clearing or self reclosing or can be recharged within 10 minutes or less without any maintenance or repair. Forced outages are one caused by human errors either by the staffs or by general public working within the vicinity of the power system and enforcing interruption.

7.3 Predictive Reliability Analysis

Due to increase in sensitive loads in all the customer sectors (Residential, Commercial and Industrial) such as the influx of digital computers , power electronic devices, microprocessor based control and the Industries mostly depending on automated equipment to achieve maximum productivity. So the interruption causes severe impact to the customers as well to the utility than before. Therefore, utilities must maximize reliability to ensure that customer reliability requirements are met at the lowest possible cost.

The predictive reliability analysis(PRA) estimates the future performance of the distribution system [23] based on system topology and failure data of the components. Its assessment provides a basis to select the best options from several competing projects. Due to stochastic nature of failure occurrences and outage duration, PRA is generally based on probabilistic models as described in RELRAD model in section 4.2.3, where this model is used to estimate the performance in customer load points. The basic indices associated with load points are; failure rate, average outage duration and annual unavailability. Furthermore, theses models can predict statistical indices such as SAIFI, SAIDI, CAIDI, ASAI, and ENS.

The main advantage of the PRA is its ability to forecast the reliability impacts of the system expansion and to quantify the impact of the reliability improvement projects. The improvement options it address include; load transfers between feeders, new substations and its expansions, new feeder tie points, feeder automation, replacement of aging equipment and optimal location of dispatch centers. The reliability indices computed by a predictive tool may not give the system performance in an absolute manner [25]; however it does provide information in order to compare various alternatives;

- ✓ What reliability improvements can be expected by implementing the proposed changes?
- ✓ Which initiative gives an optimal benefit to cost ratio?
- ✓ Or what changes should be made to a distribution system to attain the set targets? For example, if a utility wants to reduce SAIDI by x percent, then what facilities should be planned to meet target.

7.3.1 Predictive Reliability Analysis on 33kV network

The predictive reliability analysis is carried out with the same fault rate as of today and the results are summarized below for the year 2012 and 2017. By 2017, the 33kV line from Trongsa shall be connected to 33kV line of Wangdue and will act as reserve to each other. For every year, a number of alternatives are considered and the one which gives best result in term of reliability and minimum energy interrupted shall be chosen for the future system. The 33kV line will be passing through thick forest and the fault due to vegetation could be reduced through vegetation management. For 2012, Gangtey area is connected and the following alternatives are considered;

1. Case 1: Alt. 3 of 2009 with connection of Gangtey shall be taken as reference
2. Case 2: Assumed that the fault rate is reduced due to timely trimming of trees(fault reduce from 20 to 14)
3. Case 3: Installation of ARCB at node WACHE
4. Case 4: Installation of ARCB and tree trimming (reduce fault from 20-14)

Table 7-8: Predictive Reliability results for year 2012 (connecting Gantey)

Indices	**Unit**	**Case 1**	**Case 2**	**Case 3**	**Case 4**
SAIFI	Inter./yr	17,587	12,802	13,565	9,799
SAIDI	h/inter.	28,00	20,276	23,734	17,300
CAIDI	h/yr	1,568	1,583	1,749	1,765
ASAI	%	99,68	99,769	99,729	99,803
Energy interrupted	kWh/year	41973,99	30212,43	39337,57	28396,39
Annual invest.* cost	Nu.[1)]/year		24000,00	113268.60	137268,60
Break even cost	Nu./kWh		2,04	42,96	10,10

* Assume economic life time is 20 years and interest rate of 7%. [1)] (1$ = Nu.48) {Nu. = Ngultrum (Bhutanese currency)}

The detail nodes are shown in the single line diagram attached in the appendix C-1. Table 7-8, shows the expected values and the annual cost of investments for different alternatives. For case 2, the expected number of outages per year is reduced from 17,587 to 12,802, while the annul outage time is reduced by 7.724 hours by applying outage mitigation techniques (trimming of trees in time) thus reducing fault rates. The break-even cost in table 7-8 is the specific cost of energy interrupted (Non Delivered Energy, NDE) that makes the investment cost effective. Case 2 has the lowest break even cost and represents relatively small investment giving reductions in both number of outages and outage durations. The non delivered energy for different case is illustrated in figure 7-10.

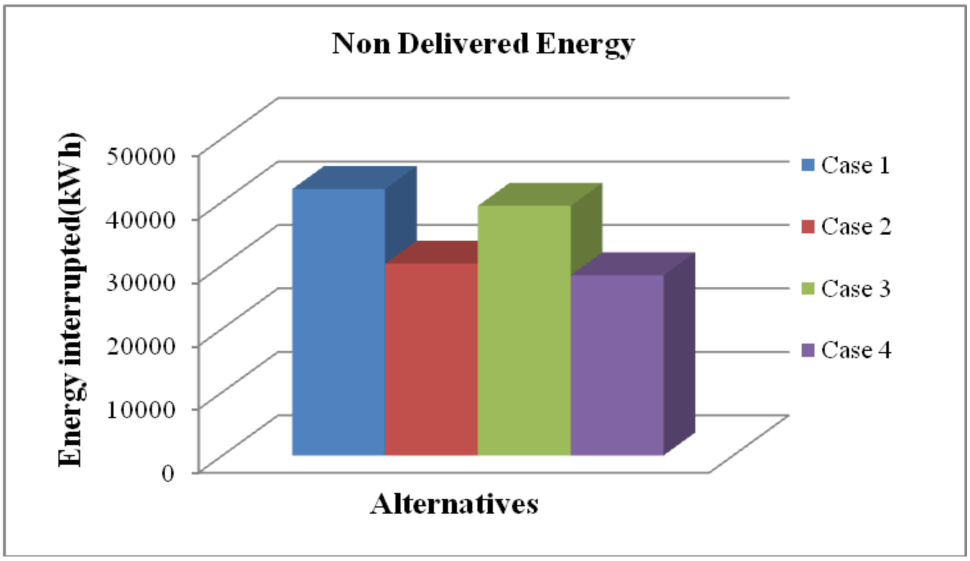


Fig. 7-10: Annual energy interrupted due to interruptions

However, the utility could further improve reliability by combining case 2 and case 3 thus reducing the expected number of outages from 17,587 to 9,799 and annual outage time by 10.70 hours. Case 4 will be cost effective for any cost of NDE higher than 10.10Nu./kWh. It shall be further be further investigated since expansion and load growth is expected till 2017 on this feeder.

1. Case 1: Case 1 of 2012 is being taken as reference
2. Case 2: With ARCB at WACHE and LBS at DPSA-RIDA, DDSA-GAN and ZAM-DLO
3. Case 3: Case 2 + assume reduce fault rate (20-16)
4. Case 4: Case 3 + connection of reserve (Trongsa line will be connected)

Table 7-9: Predictive Reliability results for year 2017 (connecting Trongsa)

Indices	Unit	Case 1	Case 2	Case 3	Case 4
SAIFI	Inter./yr	29,250	21,992	17,796	17,796
SAIDI	h/inter.	43,147	35,944	29,114	23,861
CAIDI	h/yr	1,475	1,634	1,641	1,347
ASAI	%	99,507	99,590	99,666	99,726
Energy interrupted	kWh/year	86898,83	79698,44	64610,28	53235,36
Annual invest.* cost	Nu[1)]./year		113268,60	149268,60	152100,30
Break even cost	Nu./kWh		15,73	6,697	4,518

* Assume economic life time is 20 years and interest rate of 7%. [1] (1$ = Nu.48)

From table 7-9, it is being observed that the addition of reserve from Trongsa helps to reduce the interrupted energy from 64610.28 to 53235.36kWh/year and SAIDI is reduced from 28,114 to 23,861hours/year and ultimately break even cost is reduced from 6,697 to 4,518 Nu./kWh since Trongsa line is assumed to be within the vicinity of the Wangdue line and it needs only addition of one LBS. The interconnection of 33kV line between Trongsa and Wangdue should be made available since it can act as reserve to each other during interruption and the reliability of the system could be improved. With increase in energy consumption, non delivered energy also increases. The breakeven cost for installation of ARCB is Nu.15,73/kWh where as in year 2012, the breakeven cost for the choice of installation of ARCB was Nu.42,96/kWh.

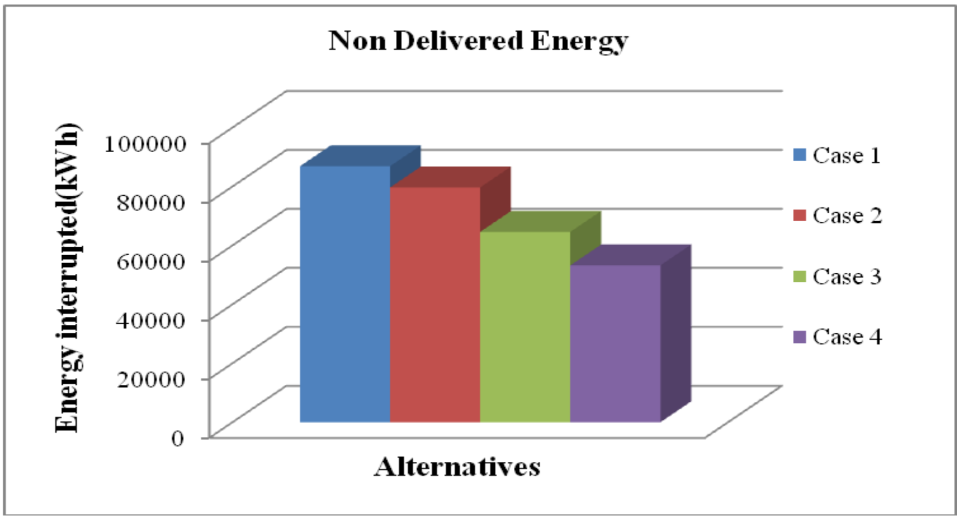


Fig. 7-11: Annual energy interrupted due to interruptions

In this regard, break even cost helps us to make a choice among the alternatives which gives the best cost benefit for the investment planned. So, Case 4 as proposed should be considered from 2017.

7.3.2 Predictive Reliability Analysis on 11kV network

The analysis is carried out the with the fault rate as described in table 7-3, which shall be further assessed with number of alternatives and find which is more effective based upon its cost effectiveness and outage frequencies and its consequences. The following cases has been considered and Alt. 3 of 2009, which gave the minimum SAIFI, SAIDI and the Non Delivered Energy is being considered as reference.

1. Case 1: Alt. 3 of 2009 is considered as reference
2. Case 2: Fault rate further reduced to 24 (Vegetation management and over voltage protection)
3. Case 3: Installation of ARCB at node RBAC-DZONG
4. Case 4: Case 3 + Case 2

Table 7-10 shows the expected values and annualized cost of investments for various alternatives chosen. The break-even cost is the specific cost of energy interrupted (Non Delivered Energy, NDE) which shows the cost effectiveness of the investment made on the alternatives. Smaller break even cost indicates relatively small investment which gives the maximum benefit on cost benefit ratio.

Table 7-10: Predictive Reliability results for year 2012

Indices	Unit	Case 1	Case 2	Case 3	Case 4
SAIFI	Inter./yr	6,927	6,358	5,738	5,313
SAIDI	h/inter.	8,956	8,314	7,759	7,229
CAIDI	h/yr	1,2929	1,307	1,352	1,360
ASAI	%	99,898	99,905	99,911	99,918
Energy interrupted	kWh/year	14647,93	13677,10	12362,81	11567,99
Annual invest.* cost	Nu.[1)]/year		26166,00	113268,60	139434,60
Break even cost	Nu./kWh		26,96	49,57	44,27

* Assume economic life time is 20 years and interest rate of 7%. [1] (1$ = Nu.48)

However, the choice of the alternatives does not depend only on the break even cost, also it depends on the wants of the customer and also the needs of the regulator. The non delivered energy for different case is illustrated in figure 7-12.

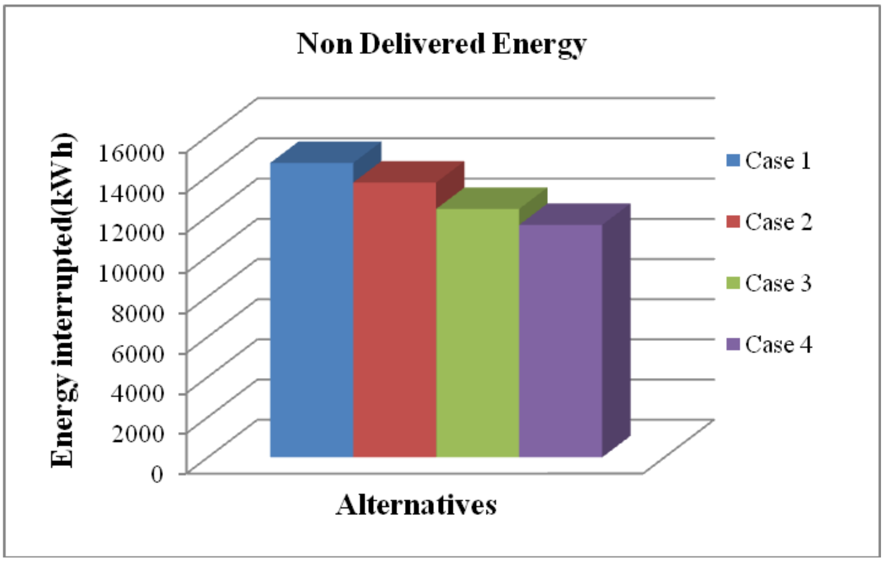


Fig. 7-12: Annual energy interrupted due to interruptions

The investigation is further carried out with the load growth of 2017 and the following alternative is being proposed;

1. Alt. 3 of 2009 is considered as reference
2. Fault rate reduced to 24 from 27 on lines
3. Installation of ARCB at node RBAC and fault reduced to 24 on lines
4. Installation of ARCB at node RBAC and fault rate of 27 on lines

Table 7-11: Predictive Reliability results for year 2017

Indices	Unit	Case 1	Case 2	Case 3	Case 4
SAIFI	Inter./yr	6,927	6,358	5,284	5,738
SAIDI	h/inter.	8,956	8,314	7,603	8,156
CAIDI	h/yr	1,2929	1,3076	1,4389	1,4214
ASAI	%	99,898	99,905	99,913	99,907
Energy interrupted	kWh/year	17804,40	16624,43	14944.64	15920,37
Annual invest.* cost	Nu.[1)]/year		26166,00	139434,60	125268,60
Break even cost	Nu./kWh		22,17	48,75	66,48

* Assume economic life time is 20 years and interest rate of 7%. [1] (1$ = Nu.48)

The Non Delivered Energy for different alternatives are illustrated in figure 7-13. Case 3 gives the minimum interrupted energy, minimum SAIFI and SAIDI at break even cost of Nu.48,75/kWh where as Case 2 gives least break even cost among all alternatives.

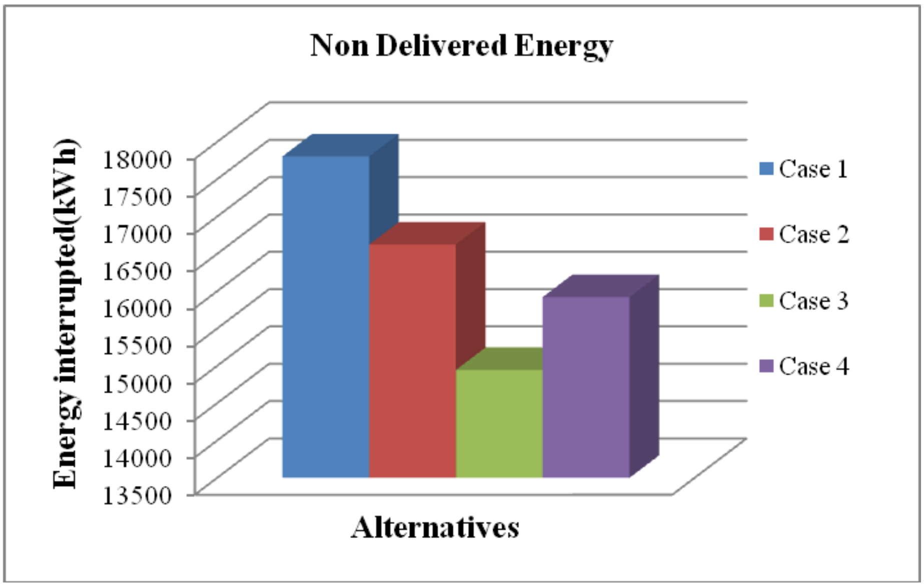


Fig. 7-13: Annual energy interrupted due to interruptions

8.0 Reliability Improvement Strategy

8.1 Overview

Due to increase in dependence on electricity and the growth of sensitive loads in all customer sectors(residential, commercial and industrial), the utilities must strive to maximize reliability to ensure that customer requirements are satisfied while incurring the lowest possible cost. Although there is no magic in managing power quality issues, utilities can maximize network performance and better serve customers by diligently addressing trouble prone areas. The first step in maximizing reliability is identifying the root cause of the outages. The main strategy to improve reliability and power quality to customers are to eliminate faults and then to minimize the effect of faults on customers even if it occurs.

At present, utilities are receiving pressure from three stake holders to develop and reevaluate their strategies for providing adequate reliability at suitable cost levels [27]. **First**, most customers expect a level of reliability which is either the same as, or better than, the reliability which they have given in the past. **Second**, as part of deregulation, industry regulators are increasingly considering performance based regulation mechanisms, or variations thereof, which can explicitly express reliability targets for companies. These targets are accompanied by financial bonuses or penalties, which directly impact the distribution company's bottom line. **Third**, Shareholders or company owners, expecting suitable rates of return, demand that all capital expenditures and O&M expenditures be selected in order to maximize results. . These demands force utilities to have a sound strategy for balancing expenditures with appropriate level of reliability. However, it may be difficult for BPCL to develop a comprehensive strategy specifically due to the following obstacles in the system and must be addressed.

- ✓ Reliability targets

  Since predictive reliability indices are not available, it will be unsure as to which indices will be used for the future reliability targets and what value of those target is to be used. The other problem would be due to uncertainty in future regulatory rules.

- ✓ Data Availability

  As of now, data collections mechanism are not in place to provide the raw operating and economic data for evaluation of reliability improvement alternatives.

- ✓ Skills

The skilled required for development of a sound strategy is lacking at the moment and this may have to be developed in development of different methods for improving reliability and quantifying estimate the projected impacts on system performance.

- ✓ Reliability Analysis Software

The necessary software/analytical tools, such as predictive reliability analysis, are not available with the ESD's and this may have to be available to all ESD's.

8.1.1 Overview of procedure

The pragmatic procedure for a utility to develop a reliability improvement strategy applied around the world is reproduced in figure 8-1, a three step procedure for developing a reliability improvement which could be applied on the distribution systems in any utilities[27].

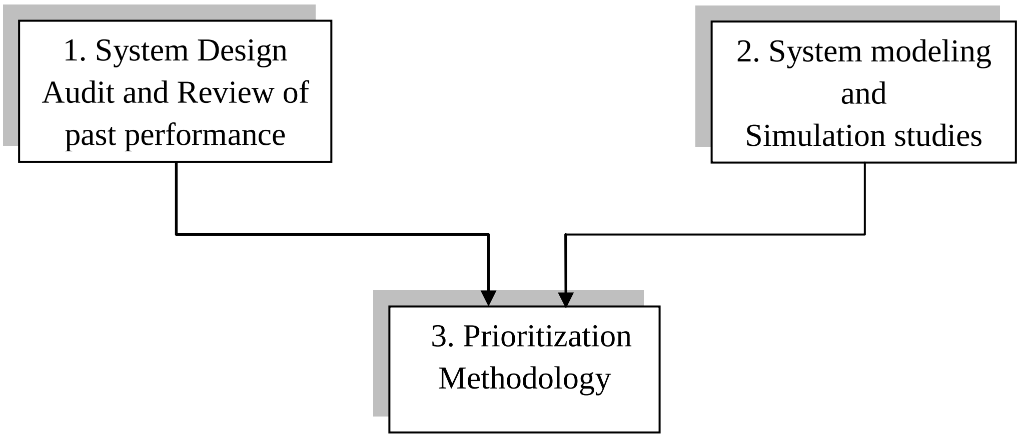


Fig 8-1: Three step procedure for development of a Reliability Improvement strategy

In the first step, a system design audit, review of historic performance data, and the application of good distribution engineering principles are performed to estimate the reliability impact of reliability improvement alternatives. A large part of this work is performed in the field, involves inspections and discussions with operating personnel.

In the second step, system modeling and simulation studies are performed to evaluate the reliability impact of characteristics such as system configuration, layout, and protection. This step involves the use of predictive reliability analysis software on distribution circuits in particular areas of the system.

In the third step, a prioritization of reliability improvement strategies is conducted based upon the cost-effectiveness of the various reliability improvement programs. This step uses the findings of the first two steps, extrapolated to the rest of the system, in order to arrive at the most cost-effective reliability improvement alternatives.

8.1.2 System Design Audit and Review of past performance

The first step in the procedure is the system design audit and review of past performance. It generates insight into the underlying causes of poor reliability. This is a necessary first step in being able to gauge how reliability-improvement funds can be spent most effectively. The system design audit involves a physical inspection of representative areas of the distribution system. During the audit, it is also important for the auditor to have discussions with area engineers and operating personnel to gain their perspective on the root causes of reliability problems. It is recommended that the following areas be audited:

- ✓ Planning guidelines

  What are the typical equipment capacities which are used, and what are the loading guidelines? What is the distribution system voltage level, which often influences length (exposure) of circuits, and number of customers per circuit? How are contingencies planned for?

- ✓ System design

  What percentage of the system is radial, loop, or network? What percentage of the distribution system is underground vs. overhead? What type of grounding is typically used for distribution circuits?

- ✓ Construction practices

  What are the typical conductor spacings and configurations? What types of structures, insulators, conductors, and other equipment is used? Where are shield wires used? Where are lightning arresters applied?

- ✓ Overcurrent protection practices

  Does the system have coordination problems? What are the guidelines for applying reclosers? Is automatic sectionalizing used? What is the policy for fusing of laterals? Is feeder selective relaying, or “fuse-saving” by blocking the instantaneous trip function, used and in what situations?

- ✓ Environmental data

  What are the isokeraunic levels in different parts of the system? What are the characteristics of trees which are present in the service territory? What types of wildlife problems exist? What are the typical (and nontypical) values of soil resistivity in the service territory? How common is ice, snow, or high wind in the service territory?

- ✓ Restoration practices

What is the typical length of time it takes for a crew to arrive at the outage location and to restore service? Is SCADA used to determine when outages have occurred? What types of fault location procedures are in place? Is auto-restoration in use? Do operators use remote controlled switching to restore service?

- ✓ Tree-trimming practices

How long is the typical tree trimming cycle for backbone feeders? For laterals?

- ✓ Inspection practices

Are formal inspection practices in place for distribution circuits? What is the interval? What equipment is inspected?

A review of past system performance is also valuable to perform. Where are the most troublesome spots on the system, and conversely, where is the reliability the best and why? What are the causes of outages, by percentage, on the system? What are the typical line failure rates and equipment failure rates?

An audit of a distribution system may be performed as part of the three-step reliability improvement procedure. These includes verifying the, Overall Condition, Lightining protection, Tie capacity, Sectionalizing, Crew locations etc.

Observations such as these are valuable in evaluating different reliability improvement alternatives, in that they provide insight into the underlying causes of poor reliability. They also provide insight during the system modeling and simulation studies since they are reflective of the system's real operating problems. The results of the audit and the review of past performance take on an additional dimension of value if one is able to gain insights from how other companies compare – either through a direct comparison with another company, or through personnel who are familiar with other systems. Such a comparison permits an increased understanding as to the effectiveness of possible reliability improvement alternatives.

8.1.3 System Modeling and Simulation studies

The second step in developing the reliability improvement strategy is the modeling of the distribution system using predictive reliability analysis software. Predictive reliability analysis software models the distribution circuit topology, probability and impact of outages, protective equipment response, post-fault switching, and time to restore service. The advantages of creating a system model and performing simulations are;

- weak spots and critical areas can be identified in a systematic manner.
- The largest contributors to poor reliability can be systematically identified,
- Alternative solutions, such as configuration changes, equipment additions or upgrades, improved protection and switching, etc, can be evaluated and compared in terms of their ability to cost-effectively improve system reliability.

Predictive reliability analysis software can be thought of as a “load flow program for system reliability.” That is, instead of simulating the electrical conditions of the system, the software simulates the expected reliability performance of the system. The model included system topology, line segment lengths, switching device locations and main feeder capacity limitations.

After creation of the models in the software, the models were calibrated so that the calculated reliability was reasonably close to historic reliability levels This is done by adjusting component reliability parameters (failure rates and mean time to restore). The actual performance of the systems with the calculated performance after the calibration was performed and compared. An exact calibration is not necessary, since the objective in developing the model is to evaluate the relative impact of different improvement alternatives. However, if the main aim is to get an idea of the reliability in the future system, then the model should almost represent the true system.

8.1.4 Prioritization Methodology

The third step of the procedure is the prioritization of the various reliability improvement alternatives. The selection of the index, or indices, which is used in the prioritization should be based upon the utilities own metrics for reliability performance. These can be internal measurements, or those established and negotiated with the regulator. The metric should consider both the benefits and the costs of the reliability improvement alternatives. Some indices frequently used to measure the benefit of reliability improvement alternatives are:

- Avoided customer-minutes of outage. This is directly related to SAIDI, and considers both the number of customers affected and the duration of interruptions.

- Avoided customer interruptions. This directly related to SAIFI, and considers both the number of customer affected and the number of interruptions.

- Avoided kWh of outage. This considers the kW demand of customers, and the duration of the interruption, but not necessarily the number of customers.

- CENS-Cost of energy not supplied. This considers the cost of energy not supplied, however the cost of interruption have to be obtained.

The projected benefits of alternatives can be determined in one of two ways. The first way is through system modeling and predictive reliability assessment. This method is good for examining the benefits of system configuration changes, addition of protective devices or sectionalizing devices, automated switching, and other system design changes. The second way is through experience with monitored programs of reliability improvement alternatives on the system. Very often it is this second alternative which must be used to determine the project impact of lightning arrester application, or changes in tree-trimming policies. Data collected from one's own system is best, since one knows how the data was collected, and it is reflective of one's own system. For this reason, utilities should make the efforts to set up appropriate monitoring programs of various reliability improvements on their system.

8.2 Outage Mitigation Techniques

After developing the reliability improvement strategy, it is important to apply the interruption mitigation techniques inorder to obtain a better results. Hence it is important to analyze the root cause and apply mitigation techniques. The mitigation techniques can be basically classified into two categories [12]: electric and non electric. Electric mitigation techniques have a direct impact on the distribution system and affect the distribution system analysis while non electric mitigation techniques do not have any impact on other engineering analysis tools and can be evaluated solely with reliability studies. It is therefore necessary to apply both the techniques inorder to gain better improvement in reliability of the system which is detailed below.

When evaluating structures and possible fault causes, the distinction is to be made between the cause of the fault and the deficiency in the structure. The cause of the fault may have been squirrel, but the underlying source of the problem may have been a poor electrical clearances (unprotected bushings, tight spacings and so forth). Although the squirrels cannot be eliminated, structure can be made more resistant to squirrel.

With change of construction design in 33kV networks, the hotline maintenance must be initiated especially changing of fuse on MV side since one LBS controls number of distribution substations and some substation are constructed on trunk line which needs shutting down of whole line downstream.

8.2.1 Electric Mitigation Techniques

These techniques has direct impact on the distribution system and affect the distribution system analysis. These technique includes: addition of protective devices (reclosers and fuses) and switching devices (manual and automated switches), system reconfiguration and feeder re-conductoring.

Distribution automation may be the way forward to improve system performance and reliability, reduce cost in long run and improve overall customer services but the revenue earned from the ESD may not be large enough to justify the investment required for automation of the distribution systems in the case study area. Therefore, it is important to look at the equipments which are cost beneficial to the system.

8.2.1.1 Reclosing devices , Sectionalizers and Switches

At present, we have auto reclosers used for 33kV networks and Circuit breakers for the11kV systems. Reclosers have two basic functions on the system, reliability and over current protection and they are mainly used for reliability reasons, mainly due to three main benefits; Reclosing, single phase reclosing and automated loop capabilities. Reclosing was normal for virtually all utilities since most lines were overhead and most temporary faults could be cleared by the recloser before the fuse operated (feeder selective relaying). Modern reclosers have open times as low as 100 milliseconds, allowing consumer power quality devices such as microwaves and clocks to not be affected by momentaries. Most of the over head faults are generally temporary in nature, any feeders with primarily over head exposure should be protected by a reclosing relay on its main circuit breaker. Placing a line recloser on a feeder will improve the reliability of all the upstream customers by protecting them from downstream faults. However, the placement of the recloser should be such that a maximum benefit is obtained in improving reliability.

However, it would be justified to install remote controlled sectionalizers on the distribution feeders which would provide significant benefits both during normal operation and emergencies. The function of a sectionaliser is not to interrupt a faulted line but count the fault occurrences on the line and upon a predefined number of counts, and open up when the line is de-energized. This can be installed either an upstream recloser or circuit breaker in the substation. Under normal operation, these switches can be operated to reconfigure the system based on load and desired reliability levels. It will be beneficial while isolating the fault sections and restoring power to un fault sections through alternate routes. Prompt operation of these sectionalizers reduces restoration time and significantly and thus improves system reliability. A remote controlled sectionalizers provide more efficient and reliable operation, and also facilitates higher utilization of assets.

The installation of additional Load Break switch at strategic locations (considering the line sections, load, motorable roads and other communication facilities) would be more beneficial for making step restoration of the system at the time of fault. The installation of sectionalizers/load break switch have the potential to improve reliability by allowing faults to be isolated and the customer service to be restored before the fault is repaired. Generally more manual normally closed and normally open switches will result in reduced duration oriented indices like SAIDI and will not impact frequency oriented indices like SAIFI. Since each switch has a probability of failure, placing more and more switches on a feeder will eventually result in degradation of the system reliability.

8.2.1.2 System Configuration

A distribution system can be reconfigured by changing the location of the normally open switches, effectively changing the allocation of the customers and the flow of power for the effected feeders. It not only improves reliability, it also minimizes the losses and the operation costs. The basic strategy is to transfer customers presently receiving poor reliability to a nearby feeders with better reliability and the effectiveness of this technique primarily depends upon number of tie switches on the system.

Sometimes the best way to improve reliability of heavily loaded or heavily exposed systems is to construct new feeders but have to be cost effective in any way.

8.2.2 Non Electric Mitigation Techniques

Non electric mitigation techniques do not have any impact on other engineering analysis tools and can be evaluated solely with reliability studies. Types of non electric mitigation technique include: Vegetation management and installation of lightning arresters, animal protection guards, placement of crews and human factors.

8.2.2.1 Vegetation Management

As observed from the causes of interruption of the system in the study area, vegetation causes around 31.37% of interruptions in the system. Major factors impacting reliability would depend on tree density, species, line clearance, pruning practices and weather. The right of way(ROW) maintained by BPC at present is reproduced in table 8-1.

Table 8-1: Right of way requirements

Sl. No#	Structures	Easement Required*
1	400kV lines	35 meters
2	220kV lines	35 m
3	132kV lines	27 m
4	66kV lines	18 m
5	33kV lines	12 m
6	11kV lines	12 m
7	LV lines	7 m

*In specific locations this corridor might vary depending on the gradient of the slope along which the line runs.

Therefore, tree trimming, periodically pruning vegetation adjacent to power line is necessary to ensure safe and reliable clearance. It is required to maintain safe and reliable distribution systems. Tree trimming should be done in such a way that its re-growth is away from the conductor location. The frequency of tree trimming/pruning cycles depends on the practical aspects like re-growth rate, bush fire risk, climate and the cost involved.

As most of the distribution lines in Bhutan passes through a dense forest, steep terrain, so there is also a risk of bush fires which may damage the utility’s equipment and line cables. When exposed to mild fires, over head lines cannot effectively dissipate heat and must be de-rated. When exposed to severe fires, overhead lines may start to anneal and loose mechanical strength. In the worst case, lines become too weak to support themselves and break.

The present ROW standards maintained by BPC along the distribution lines especially (for the line passing horizontal towards the steep terrain) is not sufficient to avoid fall of trees and its branches on the line which inturn interrupts the supply to the customer. This has to be reworked and discussed with the concern agencies and get approval for broader clearance especially in steep terrains. Therefore, it is very important to maintain the standard right of way or even more where it is felt necessary to avoid damages to the equipments and the interruptions to the customer.

For new expansion, it is very important to choose a line route which has minimal impact on the vegetation if the difference in the length of the line is not much. This would decrease the cost in operation and maintenance of the system in long run and will be more reliable than the line passing through the dense forest. The new route chosen should be as close to the motorable road if possible since restoration of the system is comparatively faster and the step restoration could be done easily in a shorter time, thus improving SAIDI drastically

8.2.2.2 Animal Guards

Animals are one of the largest causes of customer interruptions for every electric utility around the world. In the study area, interruptions caused by animals is around 12,68% . These type of faults and mitigation techniques will mostly depends on the system configuration, behavior and type of animals involved. Majority of the animals involved for the cause of interruption in the study area are birds and domestic animals. Different type of bird and animals causes different types of problems, so different mitigation technique is required.

For such faults, detail post fault investigation should be done inorder to find out the type of animals that causes faults on the distribution system and record maintained. This will help the utilities to plan and develop mitigation techniques so that same fault is avoided in future. The overhead bare conductor should be provided with insulating sleeves at the joints over the pole and wherever it is not possible, appropriate animal guards may be provided at the said location. Another possibility is to provide covered conductor as jumpers so that short circuiting by an animals is avoided.

All distribution substations should be fenced to avoid animals to have contact with live wires. The distribution transformers bushings and jumpers should be retrofitted with appropriate insulation to prevent fault caused by animal contacts such as birds, squirrels etc. The birds nest must be removed on regular intervals on distribution installations.

8.2.2.3 Overvoltage protection

It is necessary to ensure that excessive voltage do not cause damage to equipment or lead to unnecessary outages. The optimum methods of protection against over voltages, and how widely such protection should be applied, depend on system operation practice and local weather conditions, e.g. Lightning strikes.

Overvoltage protection can be basically achieved in two ways: - reducing the amplitude and rate of occurrence of lightning overvoltages at the point of origin (e.g. through shielding the line conductors or improving the footing resistance of towers); - limiting the overvoltage at the equipment location (e.g. through surge arresters). In high voltage networks, both methods of protection are common. In MV networks shielding the conductors is generally not very effective. Due to the small clearance between the earth wire and the conductors, a direct lightning stroke will usually hit the conductors as well. In addition, induced overvoltages can be reduced only to a low extent by shield wires. For these reasons, the most effective protection against overvoltages in such networks is the use of surge arresters or spark gaps in the vicinity of the equipment, no more than 10m away from the equipment under protection [9].

Though lightning strikes cannot be eliminated but its effects could be minimized thorugh intelligent use of lightning protective equipments.

8.3 Maintenance Strategy

With increasing pressures from three stakeholders as described in section 8.1, and to remain competitive, it is critical to prioritize maintenance task so that best possible reliability is achieved with increasingly constrained budgets. The main aim of maintenance is to extend equipment lifetime and or/reduce the probability of failure. Maintenance may be divided into two strategies namely; Preventive and Corrective maintenance. Corrective maintenance replaces or repairs failed components, while preventive maintenance is a proactive approach to improve the condition of an unfailed component that may be deteriorated to some degree.

Traditional preventive maintenance policies include time based maintenance(TBM) and condition based maintenance(CBM). TBM is performed at regular and scheduled intervals, loosely based on service history of a component or the experience of service personnel. This maintenance policy can be expensive and may not minimize the annualized cost of equipment. CBM periodically determines the state of equipment deterioration, and maintains equipments when the condition fails below thresholds. CBM is generally an improvement over TBM, but is still suboptimal since it does not explicitly consider the probability of failure and the consequences of its failure; e.g two identical circuit breakers with same condition may receive same level of maintenance , even though one serves customer without alternate supply while other serves load which is transferrable should an interruption occur. Therefore, Reliability Centered maintenance(RCM) is an improvement over TBM and CBM, and considers both the probability of equipment failure and the system impact should a failure occurs. So it is important for utilities to apply RCM policies based on marginal benefit to cost analysis. The following proposals are being made that could be followed in future in BPC;

- ✓ The awareness campaign is to be held for the customers before being connected to the supply since this could reduce the fault which is being caused by this customers unawareness (faults have been caused due to negligence on the customer part by felling of trees on line and hoisting flags near the line as observed from the fault report).
- ✓ Maintaining inventories, record keeping/data base of all the equipments are pre requisite for the successful operation and maintenance of the systems and it should be constantly updated. A computer aided recording shall be systematic and faster and reporting to the higher authority shall be easier.
- ✓ The maintenance crew should be well trained and informed on the need of maintenance and it procedures so that they appreciate the system and the instructions are strictly followed (e.g safety precautions before the work is executed).

- ✓ Maintenance should be well planned and the affected customers be informed at least three days in advance before the shut is taken for maintenance.

- ✓ The conditions of the equipment should be physically inspected atleast twice a year and the status recorded for further action.

- ✓ Post fault analysis should be carried out for all the faults occurred to find out the root cause of failure and take remedial actions accordingly so that the same fault in future is avoided.

- ✓ Reliability Centered Maintenance approach should be given due considerations for replacement and major maintenance of the equipments in the system.

- ✓ The works should be prioritized based upon the need and the situation on the ground.

- ✓ Vegetation management should be carried out twice in a year and the ROW is to be maintained as per the standard of the BPC inorder to avoid faults and to minimize the effect of bush fires on lines and substations.

- ✓ Due to change in construction method and design, the crew members have to be trained in use of hotline stick to change blown off fuse. This have to be translated into reality since it affects number of upstream customers while changing fuse for low stream customers with the present method of changing fuse.

9.0 Observations, Results and Recommendations

9.1 Observations

The observation made from overall project is stated below;

- ✓ The primary purpose of the system is to satisfy customer requirements and since the proper functioning and longevity of the system are found to be essential requisites for continued satisfaction, hence it is necessary that both demand and supply side considerations are appropriately included in the planning and analysis.

- ✓ The conceptual objective of undertaking reliability cost benefit analysis makes it necessary to independently asses the cost of providing reliability and worth of having it. In order to render a rational means of decision making on the necessity of changing service continuity levels experienced by customers, utility cost and the cost incurred by customer associated with interruptions of service must be incorporated in planning and operating practices. Electric system planning based on reliability cost and worth assessment approach provides an opportunity to justify future system expansion project.

- ✓ A methodology widely utilized in quantifying the benefit of power delivery service reliability is to estimate the customer monetary loss associated with power supply interruptions by collecting data with customer surveys.

- ✓ The choice of alternatives should be based on "Value based planning" meaning that all projects are ranked inorder of cost effectiveness, projects and project combinations could be approved in the order of decreasing cost effectiveness until reliability targets are met and budget constraints become binding.

- ✓ The data recording have to be made systematic and rationalized meaning that all individual component failure data, localized fault data, have to be precisely recorded if future system analysis should represent true state of the system. As of now, the data have been recorded only when there is fault on the feeder and no further data is available. The switching and the sectionalizing time have to be maintained for different locations of switches. Data for non-notified and notified outages have to be maintained separately. The reasons for outage have to be detailed and precise. The present manual system of data recording should be revolutionized to computer aided system.

- ✓ Predictive reliability analysis helps to make the optimized location of dispatch centres, prioritization of vegetation management, the impact of aging infrastructures and the maintenance policy where as the assessment of the past performance indicates the strength and the weakness of the present system.

- ✓ Historical root cause analysis identifies physical cause of faults where predictive root cause analysis computes each component on the system.

- ✓ Tree trimming and pruning programs are vitol to distribution reliability and can have profound effect on the failure rate of over head lines. Another way to reduce number of vegetation related failure is to replace bare over head conductor with covered conductor. This will have significant effect both on SAIDI and SAIFI.
- ✓ The computer generated reliability improvement projects are not a substitute for good human engineering. They are to be used along with the system analysis results, as a starting point for manually generated reliability improvement recommendation.

- ✓ Due to change in construction method and design, the maintenance crew must be trained in use of hotline stick to change blown off fuse. This have to be translated into reality since it affects number of upstream customers while changing fuse for low stream customers.

- ✓ Maintaining fault resistance should be an ongoing process and the utilities must maintain consistency in it.

- ✓ The fault rate, sectionalizing time and the time to repair the fault plays a vitol role in the analysis of the system, so it is must to have the correct data to obtain the right results.

- ✓ The reliability improvement project should depend on the wants of Customers and the needs of Regulators.

9.2 Results

The result from the overall project is interpreted below;

- ✓ As observed from the past performance of 33kV system, the system could be further improved by installation of LBS at node at KUMCHE-CGP, DKHA-LKHA and shifting of LBS from LGKHA-SHA to SHA-RKH (Alt. 3) which gives minimum interrupted energy and the lowest SAIDI.

- ✓ For 11kV system fed from Wangdue, the performance of the present system could be enhanced and improved by installation of LBS at node WAJO-WAJOK, HPH-PASO and WAJO-BHS (Alt. 3) which gives minimum energy interrupted and low SAIDI.

- ✓ For 11kV system fed from Rurichu, most of the interruption has been caused due to temporary faults and this may be mainly due to low clearance maintained between lines and trees than the required standards.

- ✓ As per the predictive analysis made on 33kV system for year 2012, Case 2 (Assume the fault rate could be reduced due to timely trimming of trees) gives minimum break even cost of Nu. 2,04/kWh, while case 4(Installation of ARCB + Case 2) gives minimum SAIFI and SAIDI with break even cost of Nu10,10/kWh meaning that any cost of Non Delivered Energy higher than Nu.10,10/kWh will be cost effective. From 2017, Case 3(ARCB at WACHE and LBS at DPSA-RIDA, DDSA-GAN, ZAM-DLO and reduce fault rate from 20-16) gives a break even cost of Nu.6,697/kWh where as Case 4 (Case 3+ connection of Trongsa line as reserve) gives minimum SAIDI among alternatives and break even cost of Nu.4,518/kWh.

- ✓ For 11kV line fed from Lobesa, predictive analysis for year 2012, shows that Case 2 gives minimum break even cost of Nu.26,96/kWh where the rest of the case gives break even cost more than Nu.44,27/kWh. Case 4 gives less SAIFI and SAIDI than the rest of the case. In this context, Case 2 is preferred over case 3&4 due to large difference in break even cost and small difference in value of SAIFI & SAIDI. As for 2017, the minimum break even cost is Nu. 22,17/kWh in case 2, where maximum break even cost is Nu. 66,48/kWh in case of case 4. The high break even cost indicates that the system is already in optimized condition and need high investment to have further improvement. Therefore, customer interruption cost is required to assess reliability worth of having the reliability improvement project.

9.3 Recommendations

In order to achieve better results for predictive reliability analysis, to judge the present performance and to improve the reliability in the system the following recommendations are presented below.

- ✓ Due to change in construction and operation methods, use of hot line stick to change fuse should be practically practiced for the benefit of both customer and utility.

- ✓ The present data recording system should be revolutionized from manual to computer aided system. All the events should be specific and the step restorations made should be recorded accordingly so that true reliability indices are obtained. The failure of individual components in the system should be maintained so the probability of failure represents its true system. Its repair time and sectionalizing time should be separated since it has high affect on the reliability indices during predictive analysis.

- ✓ Reliability of 33kV system could be further improved by installing LBS at node at KUMCHE-CGP, DKHA-LKHA and shifting of LBS from LGKHA-SHA to SHA-RKH (Alt. 3) which gives minimum interrupted energy and the lowest SAIDI. For year 2012, Case 2 (Assume the fault rate could be reduced due to timely trimming of trees) which gives minimum break even cost of Nu. 2,04/kWh is considered while

Case 4 (Case 3 + connection of Trongsa line as reserve) for 2017, which gives minimum SAIDI among alternatives with break even cost of Nu.4,518/kWh is being recommended.

- ✓ For 11kV system fed from Lobesa substation, it should run with the alternative 3 of year 2009, since the break even cost for year 2012 and 2017 is quite high. Further analysis has to be carried out to find the reliability cost and worth from customer's perspective (interruption cost) and compare with the break even cost to find the worth of having reliability improvement projects.
- ✓ BPC should further explore on this studies to find out the reliability worth assessments based upon customer's perspective. The sample questionnaires developed could be further improved by doing detail study after visiting customer's premises and learning about their activities and use of electricity.

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Appendix-A : Questionnaire's for survey of power Outage Cost

A-1 : Questionnaires for survey of costs associated with electric power interruptions (Residential/Domestic Customers)

Part 1: Personnel and electricity consumption information	
Customer Category : Domestic/Residential	Customer No……………………………
1	Location : --
	Type of House (please tick) : ☐ Building ☐ Traditional house ☐ Bungalow ☐ Others
	Plinth area of your residence(sqm):…………………………………..
	Do you own or rent this residence? ☐ Yes ☐ No
	How many persons live in your household? (write number) ______________
	What is the households total income (in Nu.)?(please tick) ☐ Less than 100,000 ☐ Less than 250,000 ☐ Less than 500,000 ☐ 1000,000 and above
2	For what purpose you use electricity ☐ Lighting only ☐ Room Heating(room heaters) ☐ Air conditioner ☐ Water heating (water heater, geyser) ☐ Cooking ☐ Washing machine ☐ Others, specify………………………………………..
	Annual Energy consumption: kWh…………………………….. Yearly expenditure(Nu.)……………………..
3	**Residents experience with reliability of supply and satisfaction**
	Number of Interruptions you had last year (please tick)
	☐ None ☐ few(0-10) ☐ (more than 10)

Duration of interruptions:

☐ Less than 10min ☐ 2 hrs ☐ 4 hrs ☐ more than 4 hrs ☐ Don't know

Time of Interruption occurred in a day:

☐ 00.00-07.00 ☐ 07.00-20.00 ☐ 20.00-24.00 ☐ Don't know

Which time of the interruption of the day effects you most?

☐ 00.00-06.00 ☐ 06.00-21.00 ☐ 21.00-24.00 ☐ Don't know

Where any of these interruptions notified by the utility?

☐ Yes ☐ No ☐ Don't know

Are you satisfied with the notification practice of the utility ?

☐ Bad ☐ Saticfactory ☐ Good ☐ Very good

Are you satisfied with their response when you are subjected to interruption?

☐ Bad ☐ Saticfactory ☐ Good ☐ Very good

what is your opinion on number of interruptions you have expericienced in your area?

☐ Very low ☐ Low ☐ High ☐ Very high

How many hours of interruption you have experienced in the previous year?

☐ 0-5 hours ☐ 5-10hours ☐ 10-20hours ☐ 20 hours & more

Do you think that utilities overall service is improving comparing to the last year?

☐ Improved ☐ Remained same ☐ Worsening ☐ Don't know

In which season do you think that the interruption of electricity would effect you most ?

☐ Spring ☐ Summer ☐ Autumn ☐ Winter

Part 2: Consequences of power interruptions

4 Inconvenience caused due to power interruptions

Assume that power interruption occurs in your area without advance notice on week days, at 18.00 hrs in winter and it lasts for about 4 hours. How much inconvenience it would cause to your activities?

Please mark (X) — Degree of inconvenience

	Low	Medium	High
Unable to cook dinner	☐	☐	☐
Unable to use electric lighting	☐	☐	☐
Unable to use Radio/TV	☐	☐	☐

	Water source interruption	☐	☐	☐
	Unable to use PC/internet	☐	☐	☐
	Uneasiness due to change in temperature	☐	☐	☐
	Risk of accidents/exposed to criminal acts	☐	☐	☐
5	**Estimate Interruption Cost due to non-notified interruption in winter season**			
	When electricity is interrupted, some cost have to be borne (e.g. cost of spoiled food, inconvenience caused , etc….). Assume an interruption occurs on a week day at, 18.00 in winter and it last for 4 hours. How much cost the power interruption will cause you? Put x-mark on the scale (cost in Nu.):			
	Weekday at 18.00 hours in winter & last for 4 hours — scale: 0, 100, 200, 300, 400, 500 — More than 500 ☐			
6	**Estimate Interruption Cost due to non-notified interruption with another duration**			
	Would the cost be different if the interruption duration is different from above? If yes, how much?			

	Reduction			Same	Increase			
	75%	50%	25%	0%	25%	50%	75%	100%
Duration 1 hour	☐	☐	☐	☐	☐	☐	☐	☐
Duration 2 hours	☐	☐	☐	☐	☐	☐	☐	☐
Duration 8 hours	☐	☐	☐	☐	☐	☐	☐	☐
More than 8 hours	☐	☐	☐	☐	☐	☐	☐	☐

7	**Estimate Interruption Cost due to non-notified interruption in summer**
	Assume the cost that would have incurred if interruption occurs at different season and time instead of mentioned above. Imagine an interruption at 18.00Hrs in summer. What would be the cost?
	Weekday at 18.00 hours in winter & last for 4 hours — scale: 0, 100, 200, 300, 400, 500 — More than 500 ☐
	If interruption without advance warning occurs at .:…………., What would be your cost associated with interruption?
	Weekday at 00.00 hours in winter & last for 4 hours — scale: 0, 100, 200, 300, 400, 500 — More than 500 ☐
8	**Do you think that the interruption cost would be reduced if interruption was notified minimum of 1 day in advance?**

	If yes, how much the cost would have changed from the cost quoted in question 5(occuring on weekday, at 18.00Hrs in winter) Percent reduction in interruption cost — 0 20% 40% 60% 80% 100%
9	**How many days do you think it as appropriate duration for the notified interruption?**
	☐ Minimum oneday ☐ Minimum three days ☐ Minimum five days
10	**Valuation of reliability of supply**
	Suppose you are given a choice between rebate in your electricity bill or a standby supply, which one will you choose during interruption? ☐ rebate ☐ standby supply
	If the utilities make an availability of stand by supply to your house during interruptions, how much you will be willing to pay for a service each each time you use it? Weekday at 18.00 hours in winter & last for 4 hours — 0 100 200 300 400 500 — More than 500 ☐
	If the utilities provide you a rebate on your electiricty bill every time your residence is subjected to interruption, what would be the fair amount if you are given a choice? Weekday at 18.00 hours in winter & last — 0 100 200 300 400 500 — More than 500 ☐

Further Comments

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A-2: Sample questionnaires for Industrial Customers

Part 1: Business and electricity consumption information

Customer Category : Industries/commercial Customer No……………………………

1 Location : --

2 Type of business :……………………………………

3 Size of the business

Number of staff:……………………………….Yearly turn over:………………………..

4 Man power strength and working hours

Man power	Work hours From	Work hours To	Number of persons	weekdays	weekends
Office staff					
Workman without shift work					
Shift workers	Shift 1				
	Shift 2				

5 Last years total electricity consumption(purchased from utility only)

Usage:…………………………….(kWh) Expenditure:……………………(Nu.)

6 Do your business have access to other electricity source ?

If yes, what is the consumption from the source?

Usage:…………………(kWh) Expenditure:……………………(Nu.)

7 **Business experience with reliability of supply**

How may power interruptions have your business unit experienced in the last one year?

	Notified interruptions	Non-notified interruptions
Number of temporary interruptions(<10 min)	…………………..	…………………..
Number of interruptions between 10m to 1hour	…………………..	…………………..
Number of interruption for more than 1hour	…………………..	…………………..

Where any of the interruptions notified by the utility?

☐ Yes ☐ No ☐ Don't know

	Are you satisfied with the notification parctice of the utility ? ☐ Bad ☐ Saticfactory ☐ Good ☐ Very good
	At what time of the interruption effects your business most? ☐ 7.00 ☐ 13.00 ☐ 18.00
	what is your opinion on number of interruptions your business has experienced ? ☐ Very low ☐ Low ☐ High ☐ Very high
	Are you satisfied with their response when you are subjected to interruption? ☐ Bad ☐ Saticfactory ☐ Good ☐ Very good
Part 2 Cost associated with interruptions (complete loss of power to your business Unit)	
8	Estimate costs associated with interruptions
	Consider a power interruption occurs at 08.00 on a week day in winter. Estimates cost at different durations assuming that duration of interruption were not known when interruption occurred:

	Duration of Interruptions				
	10 minutes	1 hour	2 hours	4 hours	8 hours
Total costs (Nu.)					
If possible, estimate the following cost componens (Nu.)					
A. Damage to equipment and production (e.g destroyed raw material and finished products)					
B. Extra cost for restarting process to recover lost production. (extra labour, material costs, overtime, etc)					
C. Loss of profits from production that cannot be recovered(loss marginal contribution*)					
D. Other cost, specify					

* Lost marginal cost is lost sales minus cost of production lost due to interruption

9	**Estimate costs associated with non notified interruption if it occurred at another time?**
	Do you think the cost quoted in question 8 for 4 hour interruption would be different if interruptions occurred at different time(e.g time, day on weekend, season)? How much do you think it would vary?

	Reduction			Same	Increase			
	75%	50%	25%	0%	25%	50%	75%	100%
Weekend, 8.00 in summer	☐	☐	☐	☐	☐	☐	☐	☐

	Night time, 1.00
10a	Do you think that the interruption cost would be reduced if interruption was notified minimum of 1 day in advance?
	If yes, how much the cost would have changed from the cost quoted in question 8(occuring on weekday, at 8.00Hrs in winter) Percent reduction in interruption cost — 0, 20%, 40%, 60%, 80%, 100%
10b	Do you think that the interruption cost would be reduced if interruption was notified minimum of 7 days in advance?
	If yes, how much the cost would have changed from the cost quoted in question 8(occuring on weekday, at 8.00Hrs in winter) Percent reduction in interruption cost — 0, 20%, 40%, 60%, 80%, 100%
11	**Valuation of reliability of supply**
	Suppose you are given a choice between rebate in your electricity bill or a standby supply, which one will you choose during interruption? rebate standby supply
	If the utilities make an availability of stand by supply during interruptions, how much you will be willing to pay for a service each each time you use it? Weekday at 8.00 hours in winter & last for 4 hours Nu………………………….
	If the utilities provide you a rebate on your electiricty bill every time you are subjected to interruption, what would be the fair amount if you are given a choice? Weekday at 8.00 hours in winter & last for 4 hours Nu………………………….
12	**Do you have a back up power supply?**
	Yes No What is the purchase cost of your back up supply equipment? Nu…………………… What is the yearly expenditure to keep your equipment running? Nu. …………………

Further Comments

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Appendix- B: Detail Interruption report

B-1: 33 kV Feeder 2 (Sha-Nahi)

Sl#	Date	Time of outage			Time fault was cleared			Duration of outage		Total Outage		Affected Customers	Location of fault	Cause of the fault	Reason for the outage
		Hrs	Min	Sec	Hrs	Min	Sec	Hrs	Min	Sec	Hours				
1	23/1/08	19	15	0	20	55	0	1	0,67	0,00	1,67	1414	Rinchengang	Wind	Tripped on line fault.
2	23/1/08	18	20	0	18	48	0	0	0,47	0,00	0,47	1414	Rabuna	Wind	Tripped on line fault.
3	19/2/08	8	30	0	10	43	0	2	0,22	0,00	2,22	1413	Khujula	LBS insulator failure	Tripped due to line fault.
4	04/1/08	5	55	0	8	24	0	3	-0,52	0,00	2,48	1435	Rinchengang	Wind	Tripped on line fault
5	04/9/08	14	45	0	15	13	0	1	-0,53	0,00	0,47	1435	Jena	Bamboo	Tripped on line fault
6	05/7/08	14	2	0	16	45	0	2	0,72	0,00	2,72	1457	Khotokha	Trees felled by public	Tripped due fault at inst o/c & 86 relay
7	05/8/08	14	44	0	16	58	0	2	0,23	0,00	2,23	1457	Sha	Landslide	Tripped due fault at inst o/c & 86 relay
8	30/5/08	7	20	0	7	50	0	0	0,50	0,00	0,50	1457	Sha	Birds	Tripped due fault at inst o/c & 86 relay
9	30/5/08	8	30	0	9	30	0	1	0,00	0,00	1,00	1457	Lobeysa	Trees branch	Tripped due fault at inst o/c & 86 relay
11	30/6/08	23	40	0	24	0	0	1	-0,67	0,00	0,33	1467	Sha Ngawang	Trees felled by public	INST O/C, E/F & 86 RELAY
12	07/1/08	0	0	0	7	20	0	7	0,33	0,00	7,33	1467			INST O/C, E/F & 86 RELAY
13	07/6/08	14	15	0	15	0	0	1	-0,25	0,00	0,75	1503	Sha	Birds	INT O/C, E/F & 86 relay
14	07/6/08	16	30	0	17	47	0	1	0,28	0,00	1,28	1503	Jena/Tokha	Failure of LBS insulator	INT O/C, E/F & 86 relay

15	21/9/08	15	24	0	15	40	0	0	0,27	0,00	0,27	1590	Rabuna	Jumper out	INST E/F & 86 RELAY
16	26/9/08	7	48	0	9	20	0	2	-0,47	0,00	1,53	1590	Khelekha	Trees	INST E/F & 86 RELAY
17	29/9/08	15	20	0	17	30	0	2	0,17	0,00	2,17	1590	Khelekha	Trees	INST E/F & 86 RELAY
18	13/10/08	8	38	0	9	40	0	1	0,03	0,00	1,03	1592	Phangyul	Birds	INST E/F & 86 relay
19	19/10/08	14	12	0	15	35	0	1	0,38	0,00	1,38	1592	Sha Nawang	Trees	INST E/F & 86 relay
20	11/6/08	12	11	0	14	23	0	2	0,2	0	2,2	1599	Khotokha	Trees	INST E/F & 86 relay
21	25/11/08	11	57	0	12	20	0	1	-0,62	0	0,38	1599	Khotokha	Trees felled by public	INST E/F & 86 relay
											32,41				

B-2: 11 kV Feeder 4 from Lobesa substation (Gaselo & Chuzomsa)

1	29/1/08	14	50	0	15	14	0	1	-0,60	0,00	0,40	949	Gaselo area	Birds	Tripped on line fault
2	29/1/08	15	55	0	16	14	0	1	-0,68	0,00	0,32	949	Gaselo area	Birds	Tripped on line fault
3	29/1/08	18	22	0	18	31	0	0	0,15	0,00	0,15	949	Gaselo area	Birds	Tripped on line fault
4	30/1/08	11	8	0	11	20	0	0	0,20	0,00	0,20	949	Gaselo area	Birds	Tripped on line fault
5	29/3/08	15	29	0	16	3	0	1	-0,43	0,00	0,57	951	Hesothangkha	Step up transformer problem	Tripped on line fault.
6	27/4/08	18	59	0	19	30	0	1	-0,48	0,00	0,52	950	Lobeysa Substation	Step up transformer problem	Tripped on heavy line fault.
7	06.06.2008	22	21	0	24	0	0	2	-0,35	0,00	1,65	951	Chuzomsa	Bamboo	Inst O/C IDMT E/F & 86 RELAY.
8	06.07.2008	0	0	0	6	24	0	6	0,40	0,00	6,40	951	Lobeysa	Flag poles	Inst O/C IDMT E/F & 86 RELAY.
9	30/9/08	13	50	0	14	3	0	1	-0,78	0,00	0,22	868	Wangdue Bazaar	Jumper out	INST O/C ON R,Y &B PHASE & IDMT O/C ON b PHASE

10	11.05.2008	16	23	0	16	34	0	0	0,18	0	0,18	872	Gaselo	Birds
11	22/11/08	14	10	0	16	0	0	2	-0,17	0	1,83		Wangdue Bazaar	Jumper out
12	12.10.2008	12	25	0	13	23	0	1	-0,03	0	0,97	1606	Khepajichu	fuse blown
13	12.12.2008	15	16	0	16	15	0	1	-0,02	0	0,98		Jena	Trees
											14,38			

B-3: 11 kV Feeder 5 (Dorangtha-Omtekha)

1	17/4/08	7	5	0	8	12	0	1	0,12	0,00	1,12	726	Lobesa	Insulator broken by miscrents	Tripped on line fault
2	22/10/08	13	57	0	14	55	0	1	-0,03	0,00	0,97	834	Thangu	Jumper out	IDMT E/F
											2,08				

B-4: 11 kV Feeder 1 from Rurichu Subattaion(Hebesa-Pondage)

1	02.10.2008	16	52	0	16	58	0	0	0,10	0,00	0,10	35	220KV Substation	No fault	DT tripped due to Fdr.IV's fault.
2	02.10.2008	15	35		16	28	0	1	-0,12	0,00	0,88	35	Switch yard	Jumper out	Tripped due to E/F & O/C on R.phase.
3	20/3/08	16	24	0	16	28	0	0	0,07	0,00	0,07	35	220kv rurichu substation	No fault	Tripped due to earth fault
4	28/3/08	14	49	0	14	51	0	0	0,03	0,00	0,03	35	220kv rurichu substation	No fault	Tripped due to earth fualt.
5	05.11.2008	12	17	0	12	20	0	0	0,05	0,00	0.05	35	220kv rurichu substation,	No fault	Tripped due to Earth fault.
6	23/6/08	11	30	0	12	7	0	1	-0,38	0,00	0,62	35	Hebesa area	Trees	Tripped due to E/F & O/C on YB-phase
7	23/6/08	15	15	0	24	0	0	9	-0,25	0,00	8,75	35	Hebesa area	Trees	Tripped due to O/C on YB-phase
8	24/6/08	0	0	0	13	26	0	13	0,43	0,00	13,43	35	Hebesa area	Trees	Tripped due to O/C on YB-phase

9	09.01.2008	9	24	0	9	30	0	0	0,10	0,00	0,10	35	220kv substation, Basochu	No fault	Due to Fdr-IV(E/F.O/C on R,Y &B phase)
10	22/9/08	15	25	0	15	38	0	0	0,22	0,00	0,22	35	220kv substation, Basochu	Birds	Due to E/F on fdr-IV
11	10.03.2008	20	36	0	20	38	0	0	0,03	0,00	0.03	36	220kv substation, Basochu	No fault	Tripped due to O/C on B-phase
12	12.11.2008	9	47	0	9	49	0	0	0,03	0	0,03			No fault	
											24,23				

B-5: 11 kV Feeder 4 (Rurichu-Mephuna)

1	02.02.2008	13	49	0	13	53	0	0	0,07	0,00	0,07	84	220KV substation	No fault	Tripped due to earth fault.
2	02.10.2008	16	52	0	16	58	0	0	0,10	0,00	0,10	84	220KV substation	No fault	DT tripped due to Fdr.No.iV's fault.
3	15/6/08	7	45	0	7	51	0	0	0,10	0,00	0,10	85	22kv substation	No fault	Tripped due to the earth fault.
4	23/6/08	11	30	0	11	35	0	0	0,08	0,00	0,08	85	22kv substation	No fault	DT tripped due to fdr.no.1 fault.
5	09.01.2008	9	24	0	9	30	0	0	0,10	0,00	0,10	88	220kv substation, Basochu	No fault	Due to Fdr-IV(E/F.O/C on R,Y &B phase)
6	22/9/08	15	25	0	15	38	0	0	0,22	0,00	0,22	88	Hesokha/ Intake	Tree	Due to E/F on fdr-IV
7	16/10/08	22	5	0	22	6	0	0	0,02	0,00	0.02	88	220kv substation Rurichu	No fault	Tripped due to O/C on RY-phase
8	20/11/08	10	11	0	10	4	0	0	0,05	0	0,05			No fault	
											0,72				

B-6: 11 kV Feeder 3 (Jala-Ulla)

1	02.10.2008	16	52	0	16	58	0	0	0,10	0,00	0,10	153	220 KV Substation	No fault	DT tripped due to Fdr.no.IV's fault.
2	17/3/08	22	6	0	22	12	0	0	0,10	0,00	0,10	156	220kv substation	No fault	Tripped due to earth fualt.
3	17/3/08	22	12	0	42	55	0	20	0,72	0,00	20,72	156	Baychu	Trees	Tripped due to earth fault.
4	28/5/08	9	55	0	10	0	0	1	-0,92	0,00	0,08	159	220kv substation, rurichu	No fault	Tripped due to E/F & O/C on B=phase
5	14/6/08	9	50	0	9	53	0	0	0,05	0,00	0.05	160	220kv substation	No fault	Tripped due to E/F & O/C on B-phase.
6	15/6/08	8	17	0	8	20	0	0	0,05	0,00	0.05	160	220kv substation	No fault	Tripped due to E/F & O/C on B-phase.
7	07.06.2008	10	14	0	10	20	0	0	0,10	0,00	0,10	163	220kv substation	No fault	Tripped due to E/F & O/C on B-phase
8	31/7/08	18	25	0	18	34	0	0	0,15	0,00	0,15	163	220kv substation	No fault	Tripped due to E/F & O/C on BR-phase.
9	08.01.2008	16	23	0	18	56	0	2	0,55	0,00	2,55	212	Jalla zampa area	By PHPA works	Taken shut down for line fault petrolling at uma area.
10	08.03.2008	6	59	0	7	7	0	1	-0,87	0,00	0,13	212	220kv substation, Basochu	No fault	Tripped due to E/F & on RY-phase
11	09.01.2008	9	24	0	9	30	0	0	0,10	0,00	0,10	217	220kv substation, Basochu	No fault	Due to Fdr-IV(E/F.O/C on R,Y &B phase)
12	17/9/08	9	26	0	9	30	0	0	0,07	0,00	0.07	217	220kv substation, Basochu	No fault	Due to O/C on B-phase
13	22/9/08	15	25	0	15	38	0	0	0,22	0,00	0,22	217	Baychu	Trees	Due to E/F on fdr-IV
14	25/9/08	12	26	0	12	38	0	0	0,20	0,00	0,20	217	Jala Zam	By PHPA works	Due to E/F & O/C

15	27/10/08	10	3	0	13	3	0	3	0,00	0,00	3,00	217	Surge shaft	Trees	Tripped due to O/C on RYB phase
16	25/11/08	15	58	0	16	1	0	1	-0,95	0	0,05			No fault	
17	28/12/08	19	25	0	19	30	0	0	0,08	0	0,08			No fault	
											27,58				

B-7: Line length and customers connected

Sl	Name of feeder	Customer connected	Line length
1	33kV Feeder 2 (Sha-Nahi)	1606	100,92
2	11 kV feeder 4 (Gaselo & Chuzomsa)	951	35,261
3	11kV feeder 5(Dotangtha-Omtekha	841	12,953
4	11 kV feeder 1 (Hebesa-Pondage)	37	7,329
5	11 kVfeeder 4 (Rurichu-Mephuna)	88	17,316
6	11 kV feeder 3 (Jala-Ulla)	225	16,407
	Total	**3748**	**190,186**

B-8: Abstract of causes of faults

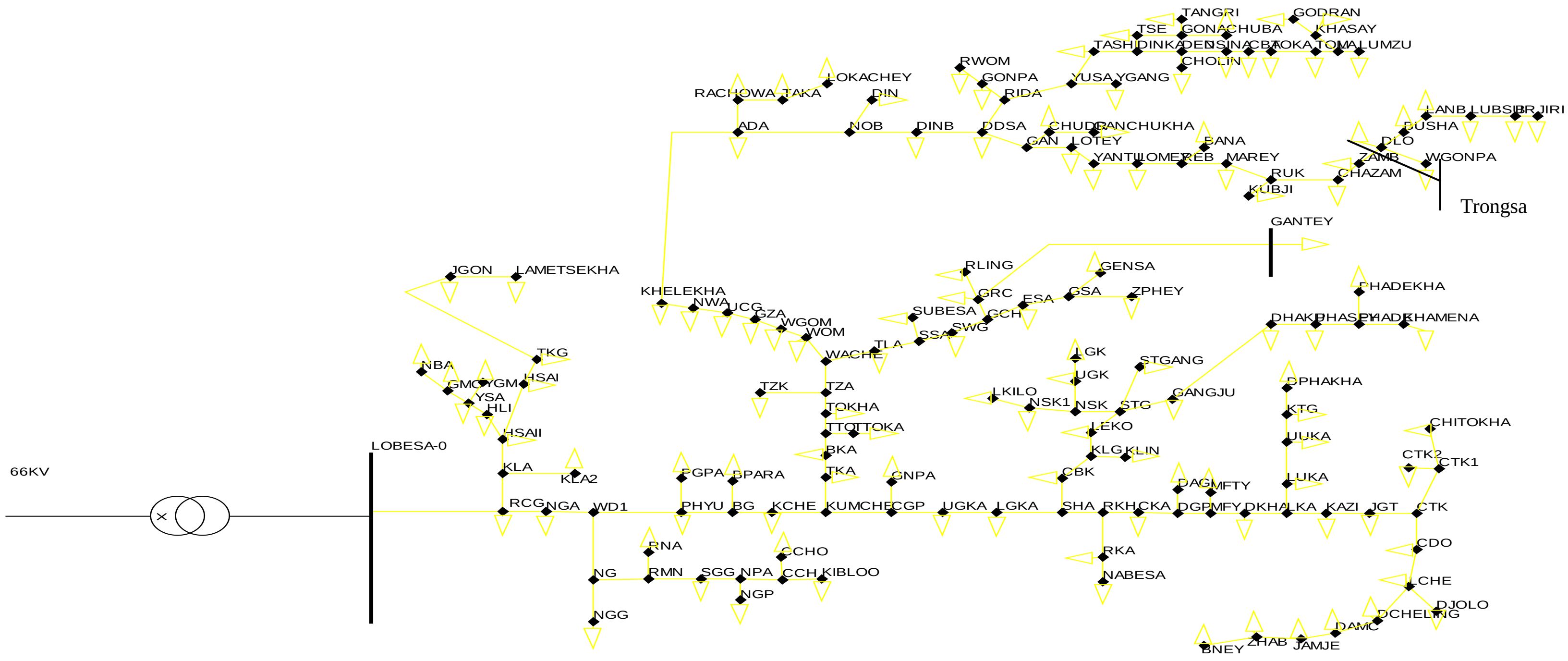
Sl	Causes of faults	Number
1	Trees	16
2	Birds	9
3	Component failure	9
4	Wind	3
5	Lightning	7
6	Forced Outage	7
7	Temporary	20
	Total	**71**

B-9 : Calculated reliability indices of the system

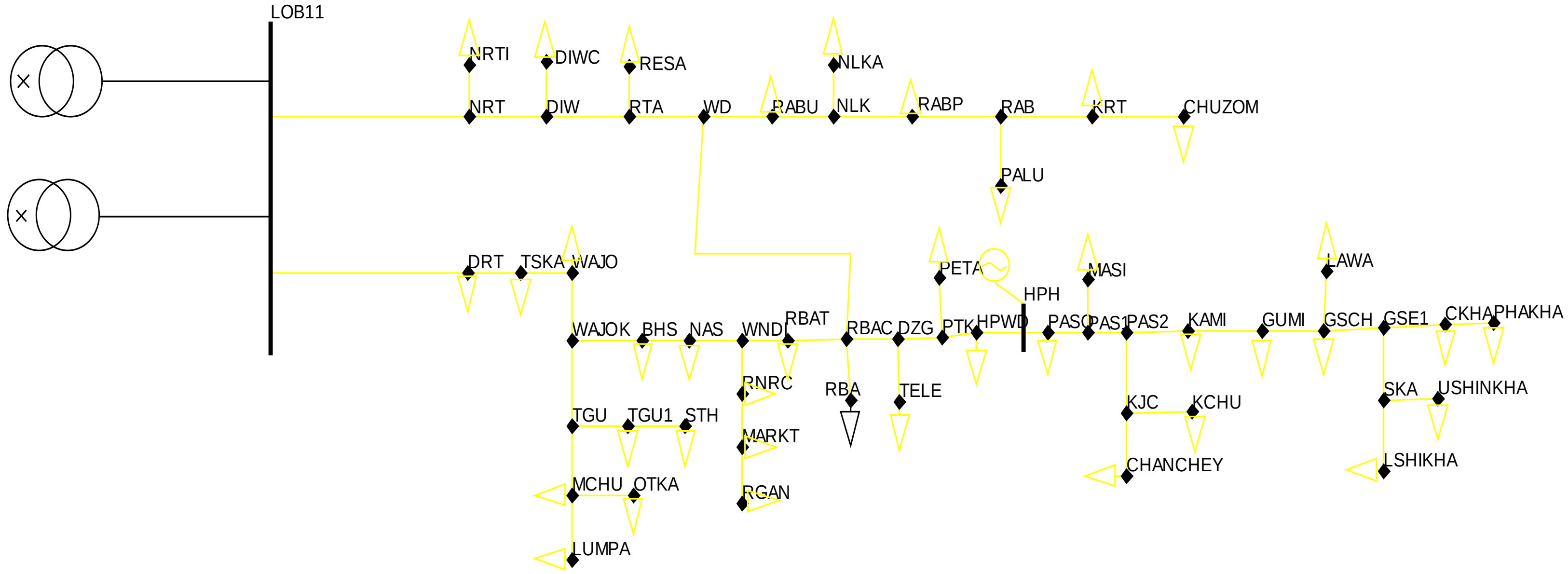
	Served from Lobesa Substation									Served from Basochu Substation								
	33kV feeder F2			**11kV feeder F4**			**11kV feeder F5**			**11kV feeder F1**			**11kV feeder F3**			**11kV feeder F4**		
Month	Fault duration(Hrs)	Affected customers (Nos)	Customer hours curtailed	Fault duration (Hrs)	Affected customers(Nos)	Customer hours curtailed	Fault duration (Hrs)	Affected customers(Nos)	Customer hours curtailed	Fault duration (Hrs)	Affected customers(Nos)	Customer hours curtailed	Fault duration (Hrs)	Affected customers(Nos)	Customer hours curtailed	Fault duration (Hrs)	Affected customers(Nos)	Customer hours curtailed
Jan	1,67	1414	2361,38	0,40	949	379,60	No fault			0,10	35	3,50	2,55	212	540,60	0,10	88	8,80
	0,47	1414	664,58	0,32	949	303,68							0,10	217	21,70			
	2,48	1435	3558,8	0,15	949	142,35												
	7,33	1467	10753,11	0,20	949	189,80												
Total	**11,95**	**5730**	**17337,87**	**1,07**	**3796**	**1015,43**			**0**	**0,10**	**35**	**3,50**	**2,65**	**429**	**562,30**	**0,10**	**88**	**8,80**
Feb	2,22	1413	3136,86	No fault			No fault			No fault			No fault			0,07	84	5,88
Total	**2,22**	**1413**	**3136,86**			**0**			**0**		**0**				**0**	**0,07**	**84**	**5,88**
March	No fault			0,57	951	542,07	No fault			0,03	35	1,05	0,10	156	15,60	No fault		
										0,03	36	1,08	20,72	156	3232,32			
										0,07	35	2,45	0,13	212	27,56			
Total				**0,57**	**951**	**542,07**				**0,13**	**106**	**4,58**	**20,95**	**524**	**3275,48**			
April	No fault			0,52	950	494,00	1,12	726	813,12	No fault			No fault			No fault		
Total				**0,52**	**950**	**494,00**	**1,12**	**726**	**813,12**									**0**
May	0,50	1457	728,50	0,18	872	156,96	No fault			No fault			0,08	159	12,72	No fault		
	1,00	1457	1457,00															
Total	**1,50**	**2914**	**2185,50**	**0,18**	**872**	**156,96**							**0,08**	**159**	**12,72**			
June	0,33	1467	484,11	1,65	951	1569,15	No fault			0,62	35	21,70	0,05	160	8	0,10	85	8,50
	0,75	1503	1127,25							8,75	35	306,25	0,05	160	8	0,08	85	6,80
	1,28	1503	1923,84							13,43	35	470,05	0,10	163	16,3			
	2,22	1599	3549,78															

Total	**4,58**	**6072**	**7084,98**	**1,65**	**951**	**1569,15**				**22,80**	**105**	**798,00**	**0,20**	**483**	**32,3**	**0,18**	**170**	**15,30**
July	2,72	1457	3963,04	6,40	951	6086,40	No fault			No fault			0,15	163	24,45	No fault		
Total	**2,72**	**1457**	**3963,04**	**6,40**	**951**	**6086,40**							**0,15**	**163**	**24,45**			
Aug	2,23	1457	3249,11	No fault			No fault			No fault			No fault			No fault		
Total	**2,23**	**1457**	**3249,11**															**0**
	0,47	1435	674,45															
Sept	0,27	1590	429,30										0,07	217	15,19			
	1,53	1590	2432,70	0,22	868	190,96	No fault			0,22	35	7,70	0,22	217	47,74	0,22	88	19,36
	2,17	1590	3450,30										0,20	217	43,4			
Total	**4,44**	**6205**	**6986,75**	**0,22**	**868**	**190,96**				**0,22**	**35**	**7,70**	**0,49**	**651**	**106,33**	**0,22**	**88**	**19,36**
Oct	1,03	1592	1639,76	0,97	878	851,66	0,97	834	808,98	0,10	35	3,50	0,10	153	15,30	0,10	84	8,40
	1,38	1592	2196,96							0,88	35	30,80	3,00	217	651,00	0,02	88	1,76
Total	**2,41**	**3184**	**3836,72**	**0,97**	**878**	**851,66**	**0,97**	**834**	**808,98**	**0,98**	**70**	**34,30**	**3,10**	**370**	**666,30**	**0,12**	**172**	**10,16**
Nov	0,38	1599	607,62	1,83			No fault			0,03			0,05					
Total	**0,38**	**1599**	**607,62**	**1,83**						**0,03**			**0,05**					
Dec	No fault			0,98			No fault						0,08					
Total	**0**	**0**	**0**	**0,98**									**0,08**					
	32,43	**30031**	**48388,45**	**14,39**	**10217**	**10906,63**	**2,09**	**1560**	**1622,10**	**24,26**	**351**	**848,08**	**27,75**	**2779**	**4679,88**	**0,69**	**602**	**59,50**
Customers served		1606		951			841			37			225			88		
SAIFI	18,699			10,743			1,855			9,486			12,351			6,841		
SAIDI	30,130			11,469			1,929			22,921			20,799			0,676		
ASAI	99,96			99,92						99,82								
Reliability indices of over all system																		
SAIFI	**12.150**																	
SAIDI	**17,744**																	

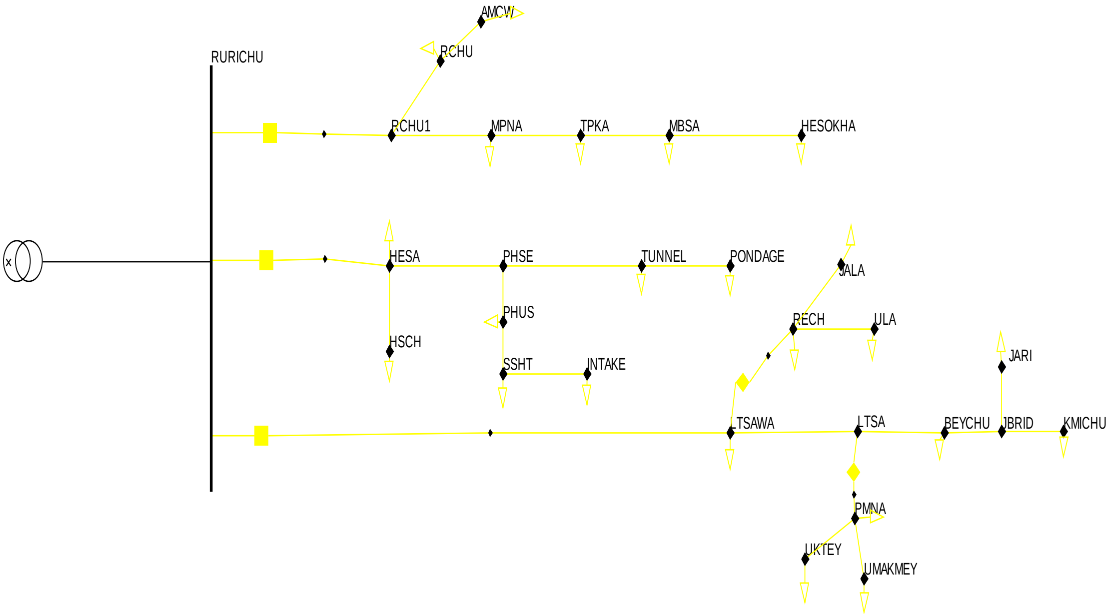
Appendix-C: Detail single line diagrams



C-1: Detail single line diagram of 33kV system showing future expansions



C-1: Detail single line diagram of 33kV system fed from Lobesa Substation



C-3: Detail single line diagram of 11kV system fed from Rurichu Substation

Appendix-D: Reliability Simulation results for 2009

D-1: Reliability simulation result of 33 kV system for 2009

Reference: Results with present system

Load flow

Data set : 66KV. Year of calculation 2009.

Summary :

		MW	Mvar	
Generation LOBESA-0	:	1.035	0.154	
Total generation	:	1.035	0.154	
Total voltage ind. load	:	1.032	0.496	
Total voltage dep. load	:	0.000	0.000	
Total losses in line sections	:	0.003	-0.343	
Total electrical losses	:	0.003	-0.343	0.000 (No-load losses)

Max. voltage drop : BNEY : 0.44 %
Heaviest loaded line : RCG - LOBESA-0 : 4.28 %

Reliability

Data set : 66KV. Year of calculation 2009.

*** SUMMARY, WHOLE GRID ***

Period of analysis : 1 years
With faults in supplying grid
Without sectionalize fuses
Without emergency generator
Fixed sectioning time

		Short inter.	Long inter.	Total
Average:				
No. of interruptions	:	0.000	15.264	15.264 (interr./year)
Interruption duration	:	0.000	1.768	1.768 (h/interr.)
Interruption time	:	0.000	26.100	26.100 (h/year)
Total:				
Interrupted power	:	0.0	7772.1	7772.1 (kW)
Interrupted Energy	:	0.0	13300.9	13300.9 (kWh)
Per thousand of total load	:			3.008
Total load	:			4421.7 (MWh)
Interruption costs	:	0.0	519.6	519.6 ($K)
Costs of repairs	:			0.0 ($K)
Loads with maximum values:				
Max. no. of outages	:	0.000	18.234	18.234 (outages/yr) at PHYU
Max. outage duration	:	0.000	2.254	2.254 (h/outage) at NBA
Max. outage time	:	0.000	33.323	33.323 (h/yr) at CDO
Max interrupted power	:	0.0	18.2	1032.2 (kW) for MFTY
Max Non-Delivered-Energy	:	0.0	18.2	1706.8 (kWh) for MFTY
Max costs of interruptions	:	0.0	18.2	66.7 ($K) for MFTY

Data set : 66KV. Year of calculation 2009.

*** SUMMARY, WHOLE GRID ***

Indices:

SAIFI	:	15.264
SAIDI	:	26.100
CAIDI	:	1.709
ASAI	:	99.702 %

Alt. 1: Installation of LBS at Kumche-CGP, DKHA-LKHA and LKHA-LUKA

Reliability

Data set : 66KV. Year of calculation 2009.

*** SUMMARY, WHOLE GRID ***

Period of analysis : 1 years
With faults in supplying grid
Without sectionalize fuses
Without emergency generator
Fixed sectioning time

		Short inter.	Long inter.	Total	
Average:					
No. of interruptions	:	0.000	15.264	15.264	(interr./year)
Interruption duration	:	0.000	1.725	1.725	(h/interr.)
Interruption time	:	0.000	25.310	25.310	(h/year)
Total:					
Interrupted power	:	0.0	7772.1	7772.1	(kW)
Interrupted Energy	:	0.0	12843.7	12843.7	(kWh)
Per thousand of total load	:			2.905	
Total load	:			4421.7	(MWh)
Interruption costs	:	0.0	501.9	501.9	($K)
Costs of repairs	:			0.0	($K)
Loads with maximum values:					
Max. no. of outages	:	0.000	18.234	18.234	(outages/yr) at PHYU
Max. outage duration	:	0.000	2.254	2.254	(h/outage) at NBA
Max. outage time	:	0.000	32.730	32.730	(h/yr) at CDO
Max interrupted power	:	0.0	18.2	1032.2	(kW) for MFTY
Max Non-Delivered-Energy	:	0.0	18.2	1601.8	(kWh) for MFTY
Max costs of interruptions	:	0.0	18.2	62.6	($K) for MFTY

Data set : 66KV. Year of calculation 2009.

*** SUMMARY, WHOLE GRID ***

Indices:

SAIFI	:	15.264
SAIDI	:	25.310
CAIDI	:	1.658
ASAI	:	99.711 %

Alt. 2: Installation of LBS at KUMCHE-CGP and DKH-LKHA

Reliability

Data set : 66KV. Year of calculation 2009.

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*** SUMMARY, WHOLE GRID ***

Period of analysis : 1 years
With faults in supplying grid
Without sectionalize fuses
Without emergency generator
Fixed sectioning time

		Short inter.	Long inter.	Total
Average:				
No. of interruptions	:	0.000	15.264	15.264 (interr./year)
Interruption duration	:	0.000	1.730	1.730 (h/interr.)
Interruption time	:	0.000	25.405	25.405 (h/year)
Total:				
Interrupted power	:	0.0	7772.1	7772.1 (kW)
Interrupted Energy	:	0.0	12892.2	12892.2 (kWh)
Per thousand of total load:			2.916	
Total load	:			4421.7 (MWh)
Interruption costs	:	0.0	503.8	503.8 ($K)
Costs of repairs	:			0.0 ($K)
Loads with maximum values:				
Max. no. of outages	:	0.000	18.234	18.234 (outages/yr) at PHYU
Max. outage duration	:	0.000	2.254	2.254 (h/outage) at NBA
Max. outage time	:	0.000	33.323	33.323 (h/yr) at CDO
Max interrupted power	:	0.0	18.2	1032.2 (kW) for MFTY
Max Non-Delivered-Energy	:	0.0	18.2	1601.8 (kWh) for MFTY
Max costs of interruptions	:	0.0	18.2	62.6 ($K) for MFTY

Data set : 66KV. Year of calculation 2009.

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*** SUMMARY, WHOLE GRID ***

Indices:		
SAIFI	:	15.264
SAIDI	:	25.405
CAIDI	:	1.664
ASAI	:	99.710 %

Alt.3: Installation of LBS at KUMCHE-CGP, LBS at DKH-LKHA, shift LBS from LGKA-SHA to SHA-RKH

Reliability

Data set : 66KV. Year of calculation 2009.

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*** SUMMARY, WHOLE GRID ***

Period of analysis : 1 years
With faults in supplying grid

Without sectionalize fuses
Without emergency generator
Fixed sectioning time

		Short inter.	Long inter.	Total
Average:				
No. of interruptions	:	0.000	15.264	15.264 (interr./year)
Interruption duration	:	0.000	1.719	1.719 (h/interr.)
Interruption time	:	0.000	25.211	25.211 (h/year)
Total:				
Interrupted power	:	0.0	7772.2	7772.2 (kW)
Interrupted Energy	:	0.0	12795.3	12795.3 (kWh)
Per thousand of total load	:			2.894
Total load	:			4421.7 (MWh)
Interruption costs	:	0.0	500.1	500.1 ($K)
Costs of repairs	:			0.0 ($K)
Loads with maximum values:				
Max. no. of outages	:	0.000	18.234	18.234 (outages/yr) at PHYU
Max. outage duration	:	0.000	2.254	2.254 (h/outage) at NBA
Max. outage time	:	0.000	33.323	33.323 (h/yr) at CDO
Max interrupted power	:	0.0	18.2	1032.2 (kW) for MFTY
Max Non-Delivered-Energy	:	0.0	18.2	1601.8 (kWh) for MFTY
Max costs of interruptions	:	0.0	18.2	62.6 ($K) for MFTY

Data set : 66KV. Year of calculation 2009.

*** SUMMARY, WHOLE GRID ***

Indices:

SAIFI	:	15.264
SAIDI	:	25.211
CAIDI	:	1.651
ASAI	:	99.712 %

D-2: Reliability simulation result of 11 kV System for 2009 fed from Lobesa Substation

Reference : Results with present system

<u>Load flow</u>

Data set : 66KV. Year of calculation 2009.

Summary :

		MW	Mvar	
Generation LOB11	:	2.501	1.172	
Total generation	:	2.501	1.172	
Total voltage ind. load	:	2.464	1.151	
Total voltage dep. load	:	0.000	0.000	
Total losses in line sections	:	0.036	0.021	
Total electrical losses	:	0.036	0.021	0.000 (No-load losses)

Max. voltage drop	: LAWA		:	3.75 %
Heaviest loaded line	: NRT	- LOB11	:	24.14 %

Reliability

Data set : 66KV. Year of calculation 2009.

*** SUMMARY, WHOLE GRID ***

Period of analysis : 1 years
With faults in supplying grid
Without sectionalize fuses
Fixed sectioning time

		Short inter.	Long inter.	Total
Average:				
No. of interruptions	:	0.000	7.703	7.703 (interr./year)
Interruption duration	:	0.000	1.450	1.450 (h/interr.)
Interruption time	:	0.000	10.117	10.117 (h/year)
Total:				
Interrupted power	:	0.0	8172.9	8172.9 (kW)
Interrupted Energy	:	0.0	10924.5	10924.5 (kWh)
Per thousand of total load	:			1.034
Total load	:			10562.0 (MWh)
Interruption costs	:	0.0	402.0	402.0 ($K)
Costs of repairs	:			0.0 ($K)
Loads with maximum values:				
Max. no. of outages	:	0.000	10.150	10.150 (outages/yr) at NRTI
Max. outage duration	:	0.000	2.214	2.214 (h/outage) at LOB11
Max. outage time	:	0.000	13.979	13.979 (h/yr) at GSCH
Max interrupted power	:	0.0	10.2	795.7 (kW) for HPWD
Max Non-Delivered-Energy	:	0.0	10.2	961.6 (kWh) for HPWD
Max costs of interruptions	:	0.0	10.2	34.7 ($K) for HPWD

Data set : 66KV. Year of calculation 2009.

Indices:

SAIFI	:	7.703
SAIDI	:	10.117
CAIDI	:	1.313
ASAI	:	99.885 %

Alt. 1: Assumed that fault rate could be reduced from 31.11-27

Reliability

Data set : 66KV. Year of calculation 2009.

*** SUMMARY, WHOLE GRID ***

Period of analysis : 1 years
With faults in supplying grid
Without sectionalize fuses
Fixed sectioning time

		Short inter.	Long inter.	Total
Average:				
No. of interruptions	:	0.000	6.924	6.924 (interr./year)
Interruption duration	:	0.000	1.455	1.455 (h/interr.)
Interruption time	:	0.000	9.155	9.155 (h/year)
Total:				
Interrupted power	:	0.0	7363.3	7363.3 (kW)
Interrupted Energy	:	0.0	9920.5	9920.5 (kWh)
Per thousand of total load	:			0.939
Total load	:			10562.0 (MWh)
Interruption costs	:	0.0	365.5	365.5 ($K)
Costs of repairs	:			0.0 ($K)
Loads with maximum values:				
Max. no. of outages	:	0.000	9.086	9.086 (outages/yr) at NRTI
Max. outage duration	:	0.000	2.214	2.214 (h/outage) at LOB11
Max. outage time	:	0.000	12.537	12.537 (h/yr) at GSCH
Max interrupted power	:	0.0	9.1	712.3 (kW) for HPWD
Max Non-Delivered-Energy	:	0.0	9.1	866.2 (kWh) for HPWD
Max costs of interruptions	:	0.0	9.1	31.3 ($K) for HPWD

Data set : 66KV. Year of calculation 2009.

Indices:

SAIFI	:	6.924
SAIDI	:	9.155
CAIDI	:	1.322
ASAI	:	99.895 %

Alt. 2: Installation of LBS at WAJOK-BHS, WAJOK-TGU and HPH-PASO

<u>Reliability</u>

Data set : 66KV. Year of calculation 2009.

Period of analysis : 1 years
With faults in supplying grid
Without sectionalize fuses
Fixed sectioning time

		Short inter.	Long inter.	Total
Average:				
No. of interruptions	:	0.000	7.706	7.706 (interr./year)
Interruption duration	:	0.000	1.357	1.357 (h/interr.)
Interruption time	:	0.000	9.836	9.836 (h/year)
Total:				
Interrupted power	:	0.0	8176.5	8176.5 (kW)
Interrupted Energy	:	0.0	10079.5	10079.5 (kWh)
Per thousand of total load:			0.954	

Total load	:			10562.0 (MWh)
Interruption costs	:	0.0	364.7	364.7 ($K)
Costs of repairs	:			0.0 ($K)

Loads with maximum values:

Max. no. of outages	:	0.000	10.152	10.152 (outages/yr) at NRTI
Max. outage duration	:	0.000	2.541	2.541 (h/outage) at LOB11
Max. outage time	:	0.000	14.317	14.317 (h/yr) at GSCH
Max interrupted power	:	0.0	10.2	795.8 (kW) for HPWD
Max Non-Delivered-Energy	:	0.0	10.2	826.6 (kWh) for HPWD
Max costs of interruptions	:	0.0	10.2	28.7 ($K) for HPWD

Data set : 66KV. Year of calculation 2009.

*** SUMMARY, WHOLE GRID ***

Indices:

SAIFI	:	7.706
SAIDI	:	9.836
CAIDI	:	1.276
ASAI	:	99.888 %

Alt. 3: Combination of Alt.2 & Alt.3

<u>Reliability</u>

Data set : 66KV. Year of calculation 2009.

*** SUMMARY, WHOLE GRID ***

Period of analysis : 1 years
With faults in supplying grid
Without sectionalize fuses
Fixed sectioning time

		Short inter.	Long inter.	Total
Average:				
No. of interruptions	:	0.000	6.927	6.927 (interr./year)
Interruption duration	:	0.000	1.377	1.377 (h/interr.)
Interruption time	:	0.000	8.956	8.956 (h/year)
Total:				
Interrupted power	:	0.0	7366.9	7366.9 (kW)
Interrupted Energy	:	0.0	9240.4	9240.4 (kWh)
Per thousand of total load	:			0.875
Total load	:			10562.0 (MWh)
Interruption costs	:	0.0	335.5	335.5 ($K)
Costs of repairs	:			0.0 ($K)

Loads with maximum values:

Max. no. of outages	:	0.000	9.088	9.088 (outages/yr) at NRTI
Max. outage duration	:	0.000	2.541	2.541 (h/outage) at LOB11
Max. outage time	:	0.000	12.875	12.875 (h/yr) at GSCH
Max interrupted power	:	0.0	9.1	712.4 (kW) for HPWD
Max Non-Delivered-Energy	:	0.0	9.1	752.5 (kWh) for HPWD
Max costs of interruptions	:	0.0	9.1	26.3 ($K) for HPWD

Data set : 66KV. Year of calculation 2009.

Indices:

SAIFI	:	6.927
SAIDI	:	8.956
CAIDI	:	1.292
ASAI	:	99.898 %

D-3: Reliability simulation result of 11 kV System for 2009 fed from Rurichu Substation

Results from the present system for 2009

Load flow

Data set : 66KV. Year of calculation 2009.

Summary :

		kW	kVAr		
Generation RURICHU	:	348.868	153.245		
Total generation	:	348.868	153.245		
Total voltage ind. load	:	348.499	168.786		
Total voltage dep. load	:	0.000	0.000		
Total losses in line sections	:	0.368	-15.541		
Total electrical losses	:	0.368	-15.541	0.000	(No-load losses)

Max. voltage drop : KMICHU : 0.27 %
Heaviest loaded line : HESA - RURICHU : 3.40 %

Reliability

Data set : 66KV. Year of calculation 2009.

*** SUMMARY, WHOLE GRID ***

Period of analysis : 1 years
With faults in supplying grid
Without sectionalize fuses
Fixed sectioning time

		Short inter.	Long inter.	Total	
Average:					
No. of interruptions	:	0.000	10.057	10.057	(interr./year)
Interruption duration	:	0.000	2.619	2.619	(h/interr.)
Interruption time	:	0.000	25.671	25.671	(h/year)
Total:					
Interrupted power	:	0.0	1240.2	1240.2	(kW)
Interrupted Energy	:	0.0	3187.1	3187.1	(kWh)
Per thousand of total load:			2.540		
Total load	:			1254.6	(MWh)

Interruption costs	:	0.0	128.4	128.4 ($K)
Costs of repairs	:			0.0 ($K)

Loads with maximum values:

Max. no. of outages	:	0.000	13.952	13.952 (outages/yr) at LTSAWA
Max. outage duration	:	0.000	2.811	2.811 (h/outage) at RURICHU
Max. outage time	:	0.000	35.782	35.782 (h/yr) at RECH
Max interrupted power	:	0.0	14.0	365.5 (kW) for BEYCHU
Max Non-Delivered-Energy	:	0.0	14.0	814.1 (kWh) for BEYCHU
Max costs of interruptions	:	0.0	14.0	32.7 ($K) for BEYCHU

Data set : 66KV. Year of calculation 2009.

*** SUMMARY, WHOLE GRID ***

Indices:

SAIFI	:	10.057
SAIDI	:	25.671
CAIDI	:	2.5526
ASAI	:	99.707 %