Reliability Cost/Worth Considerations in Distribution System Evaluation

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Peng Wang

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Reliability Cost/Worth Considerations in Distribution System Evaluation

Reliability cost/worth assessment plays an important role in power system planning, operation and expansion as it provides an opportunity to incorporate customer concerns in the analysis. This research work focuses on distribution system reliability cost/worth evaluation. The main objectives are:

- the development of analytical and time sequential simulation techniques to evaluate reliability cost/worth indices,
- the utilization of these techniques in optimal planning and operation decisions,
- an examination of the effect on reliability worth prediction of time varying load and cost models, and the dispersed nature of cost data, and
- the consideration of wind generation as an alternative supply in a radial distribution system.

An analytical technique designated as the reliability network equivalent approach has been developed to improve the computing efficiency of the conventional failure model and effect analysis method for distribution system reliability evaluation. A time sequential simulation approach is also developed and used to evaluate basic distribution system reliability indices and their distributions. A generalized analytical technique and a time sequential simulation technique in which the time varying nature of the load and cost models are incorporated in the analysis have been developed and used to evaluate reliability cost/worth indices. These indices are utilized in an optimization process to determine the optimal number of switches and locations in a distribution system. A bisection search technique is used to simplify the optimization procedure.

This thesis also recognizes the impact of different load and cost models and the dispersed nature of cost data on the distribution system reliability indices. The time varying load and cost models for seven different customers have been developed and illustrated. The effect of the time varying load and cost models on reliability worth is illustrated by application to several test distribution systems. The effect on the reliability worth indices of the dispersed nature of the cost data is also considered in the simulation technique.

Economic and environment concerns have created an increased interest in the use of wind as an alternative energy source. The impact on the reliability performance of a distribution system of using wind generation as an alternative supply is investigated. The effect of different wind sites and wind turbine generator parameters on system reliability is examined.

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ABSTRACT

Reliability cost/worth assessment plays an important role in power system planning, operation and expansion as it provides an opportunity to incorporate customer concerns in the analysis. This thesis focuses on the reliability cost/worth analysis of radial distribution systems. Distribution system reliability indices can be evaluated using analytical methods or by Monte Carlo simulation. The sequential simulation technique makes it possible to incorporate the time varying and random nature of load and cost models in the reliability evaluation. This simulation technique can also provide a wide range of indices and their probability distributions.

This research work focuses on distribution system reliability cost/worth evaluation. The main objectives are:

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HLI	Hierarchical Level I
HLII	Hierarchical Level II
HLIII	Hierarchical Level III
CDF	Customer damage function
CCDF	Composite customer damage function
SAIFI	System average interruption frequency index
SAIDI	System average interruption duration index
CAIDI	Customer average interruption duration index
ASAI	Average service availability index
ASUI	Average service unavailability index
ENS	Energy not supplied index
AENS	Average energy not supplies index
FMEA	Failure mode and effect analysis
RBTS	Roy Billinton Test System
TTF	The time to failure
FT	Failure time
TTR	The time to repair
SIC	Standard Industrial Classification
EENS	Expected energy not supplied
ECOST	Expected interruption cost
IEAR	Interrupted energy assessment rate
SCDF	Sector customer damage function
Govt.	Government
Inst.	Institution
TVC	Time varying cost
AIC	Average interruption cost

TVLM	**Time varying load model**
ALM	**Average load model**
AAM	**Average or aggregate model**
PDM	**Probability distribution model**
RWNR	**The reliability worth of network reinforcement**
RWFA	**The reliability worth of the lateral fuse addition**
RWSA	**The reliability worth of the disconnect switch addition**
RWAA	**The reliability worth of the alternative supply addition**
WTG	**Wing turbine generator**
CG	**Conventional generator**
NID	**Normally Independent Distributed**
MLC	**Maximum load capacity**
MWC	**Minimum wind generation capacity**
WGEB	**Wing generation energy benefit**
CBEB	**Conventional energy benefit**
WGCB	**Wind generation cost benefit**
CGCB	**Convention generation cost benefit**
ENCG	**Equivalent number of conventional generator units**
ECGC	**Equivalent conventional generator capacity**

1. Introduction

1.1. Basic Power System Planning Problems

The basic function of an electric power system is to supply customers with electricity. Modern society demands that electrical energy should be as economical as possible with a reasonable degree of continuity and quality. To build an absolutely reliable power system is neither practically realizable nor economically justifiable. The continuity of energy supply can be increased by improved system structure, increased investment during either the planning phase, operating phase or both. Over-investment can lead to excessive operating costs, which must be reflected in the tariff structure. Consequently, the economic constraint will be violated although the probability of the system being inadequate may become very small. On the other hand, under-investment leads to the opposite situation. It is evident therefore that the reliability and economic constraints can compete, and this can lead to difficult managerial decisions at both the planning and operating phases [1].

A power system can usually be divided into the subsystems of generation, transmission, and distribution facilities according to their functions. In a vertically integrated power system, one company often owns all the subsystems. In this case, a power system planner can relatively easily access most of the required information and decide when and where to perform generation expansion, line and station enforcement to meet future load growth and satisfy the corresponding reliability requirements. The balance between reliability and economic constraints is usually judged by the system planner according to past experience. Customer concerns are seldom considered because customers normally have little or no choice in regard to their electricity purchases.

Deregulation and privatization are new forces in modern electric power systems. In a deregulated or unbundled power system, generation, transmission and distribution facilities can belong to quite different owners. A customer potentially has a wide range of choice regarding power suppliers based on the price and corresponding reliability. Availability or unavailability of generation depends not only on variations in power demand but also on the competition between different generation owners. This new situation makes it difficult to assess system reliability and for a particular company planner to determine what is the best offer and reliability that will satisfy different customers. It is also difficult for customers to select the best company from the different power suppliers in order to receive the best price and reliability. The factors which generation utilities must consider in order to make consistent planning, operating and investment decisions are: load demand and variability, load growth, customer reliability expectations, customer price demands, the price that other generators offer, available transmission and the associated tariffs. A distribution utility and its customers will also require information in order to select the best generation utility. In this case, factors such as power supplier reliability, bid prices, transmission system reliability, distribution system reliability, and the reliability balance between the various subsystems will be involved.

Power system privatization and deregulation have put electric power utilities into a competitive market. This situation makes it more difficult for the system planners who work in the various companies to balance the reliability and the economic constraints. System planners have to make planning, operation and expansion decisions based not only on past experience and utility concerns but also on customer considerations regarding reliability cost/worth.

Power system planners have tried for many years to resolve the dilemma between the reliability and economic constraints. A wide range of techniques has been developed. These techniques can be divided into the two categories of deterministic and probabilistic approaches. Deterministic techniques often determine generation and network capacities based on the expected maximum demand plus a specified percentage of the expected maximum demand. The weakness of deterministic techniques is that they do not and cannot consider the stochastic nature of system behavior and of customer demands. Probabilistic approaches determine the generation and network redundancy based on element failure and repair rates and the time varying load being served. The procedures described in this thesis are probabilistic in nature.

1.2. Power System Reliability and Related Concepts

Power system reliability evaluation can be used to provide a measure of the overall ability of a power system to perform its intended function. The concept of reliability can be subdivided into the two main aspects of system adequacy and system security [2].

System security relates to the ability of the system to respond to disturbance arising within the system. System adequacy relates to the existence of sufficient facilities within the system to satisfy the customer demands within the system operating constraints. This includes the facilities necessary to generate sufficient energy and the associated transmission and distribution facilities to transport the energy to the actual customer load points.

The three subsystems of generation, transmission and distribution can be designated as power system functional zones. Reliability evaluation can be conducted in each of these functional zones or in the combinations that gives the hierarchical levels [3] shown in Fig. 1.1.

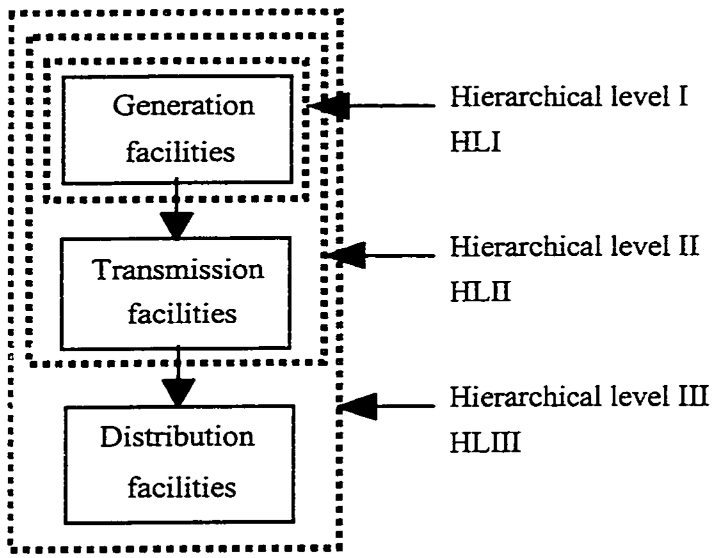

Fig. 1.1 Hierarchical levels

Reliability assessment at hierarchical level I (HLI) is concerned only with the generation facilities. In an HLI study, the total system generation is examined to determine its adequacy to meet the total system load requirement considering random failures, and corrective and protective maintenance of the generating units. The transmission and distribution system and the ability to move the generated energy to the consumer load points are not included in this analysis. This activity is usually termed as "generating capacity reliability evaluation".

Hierarchical Level II (HLII) assessment includes both generation and transmission facilities. HLII studies can be used to assess the adequacy of a system including the impact of various reinforcement alternatives at both the generation and transmission levels on bulk load point and overall system indices. Adequacy analysis at this level is usually termed as "composite system or bulk transmission system evaluation".

Hierarchical Level III evaluation (HLIII) includes all three functional zones and starts at the generating points and terminates at the individual load points in the distribution systems. A practical power system is very complex and therefore it is very difficult to evaluate the entire power system as a single entity using a completely realistic and exhaustive technique. HLIII studies are, therefore, not usually done directly. The analysis is usually performed only in the distribution functional zone and the HLII load point indices are used as input values to the zone.

Distribution system reliability evaluation can be used to obtain quantitative adequacy indices at the actual customer load points. These indices reflect the topology of the network, the components used, the operating philosophy and other particular functions.

Customer interruptions caused by generation and transmission system failures are normally only about 20 percent of the total load point interruptions. The remaining 80 percent of customer interruptions occur within distribution systems [4]. Power system reliability assessment without considering distribution systems therefore recognizes only a small part of the total outage costs. This research work is focussed on the distribution functional zone.

1.3. Reliability Cost/Worth Concepts

Adequacy studies at the three hierarchical levels without consideration of the economics are only part of an overall appraisal. In order to make a consistent appraisal of economics and reliability, albeit only the adequacy, it is necessary to combine the reliability criteria with certain cost considerations. Reliability cost/worth assessment provides the opportunity to incorporate cost analysis and quantitative reliability assessment into a common structured framework. Reliability cost refers to the investment needed to achieve a certain level of adequacy. Reliability worth is the benefit derived by the utility, consumer and society because of higher reliability due to more investment in system.

The reliability cost/worth concept can be illustrated using Fig. 1. 2. The figure shows that the system cost will generally increase with higher investment cost in equipment and facilities which provide higher reliability. On the other hand, the customer interruption costs due to higher reliability will decrease. The total cost to society is the sum of these two costs. There is a minimum point in the resulting total cost curve which indicates the optimal target level of reliability. Reliability worth/cost analysis is performed to find this optimal point.

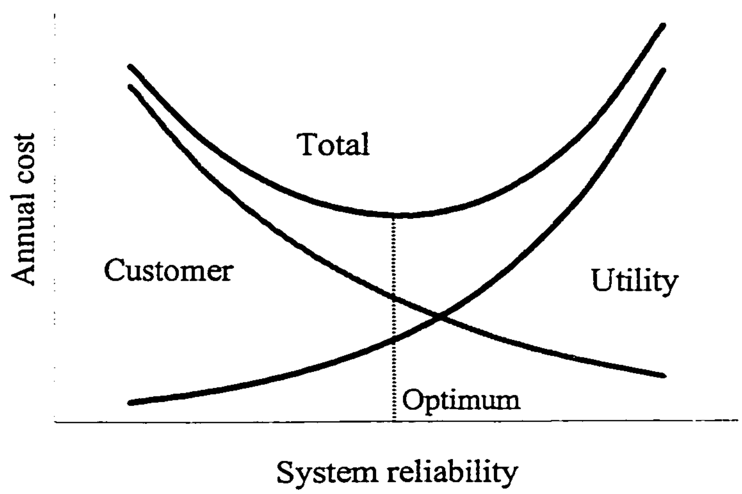

Fig. 1. 2 Costs as a function of system reliability

It is difficult to directly measure reliability worth. An indirect measurement of reliability worth can be obtained by evaluating the costs associated with customer service interruptions. There have been many studies concerning interruption and outage costs [5-10]. A series of surveys on the impacts of interruptions to different customer types have been carried out by Ontario Hydro and by the University of Saskatchewan. Large users, small industrial, agricultural, commercial, residential, institutional, and office customers have been surveyed for the losses incurred due to various interruption durations. The surveys show that interruption cost at an individual customer load point is dependent on the type of customer, the load curtailed, the duration of interruption and the time of interruption. The interruption costs corresponding to different durations for a given customer are represented by a customer damage function (CDF) [11-13] that shows the variation of interruption cost with outage duration.

Reliability cost/worth assessment can be carried out in the three hierarchical levels [14-17]. In HLI studies, the generation investment and operating costs for different generation capacities, the corresponding reliability levels and system interruption costs are evaluated and compared. The optimal reliability level which corresponds to the minimum total cost is determined. The optimal generation expansion plan can be determined based on maintaining the optimal reliability level. HLII studies examine not only the reliability cost/worth of different generation expansion plans but also the reliability cost/worth of different transmission line reinforcements. In HLI and HLII studies, the load is a mixture of different customer types and therefore composite customer damage functions (CCDF) which estimate the costs associated with power supply interruptions as a function of the interruption duration for the customer mix in the particular service area or total system are utilized.

Distribution system reliability cost/worth assessment can be used to study the reliability worth of different distribution reinforcements. These include the selection of the optimal distribution configuration, the optimal number of switches and their locations. Assessment of reliability cost/worth in distribution facilities has a very direct association with the actual customers served by these facilities [18]. The following factors are important in the analysis.

1). The predicted load point indices in a distribution system directly relate to actual user experience. The prediction of failure frequency and duration physically describe the interruptions that will be seen by a customer at a given load point.

2). User types are not as aggregated at distribution load points as those at composite system load points or as in the entire power system. The makeup of the customers interrupted during a distribution failure is therefore well defined. Realistic estimates of the actual load and customer types are therefore feasible for each load point.

3). User specific data can be readily applied and CCDF are not generally required. Global data is often unsuitable because of great variations in customer mix from load point to load point.

4). Interruption costs for individual important and sensitive users can be estimated and therefore local system or individual user facility improvements can be examined.

It is important to realize that, while power system reliability assessment has become a well established practice over the last few decades, power system reliability cost/worth assessment is still relatively immature especially for distribution systems. This research work concentrates on reliability cost/worth analysis of distribution systems.

1.4. Reliability Evaluation Techniques

Power system engineers and planners have always been conscious of the need for better reliability assessment procedures. The techniques first used in practical application were deterministic in nature and some of these are still in use today. Although deterministic techniques were developed in order to combat and reduce the effects of random failures on a system, these techniques did not and cannot account for the probabilistic or stochastic nature of system behavior, of customer demands and of component failures.

Probabilistic techniques that consider the stochastic nature of system behavior have been recognized since at least the 1930's [1]. They were not widely used in the past due to the lack of data, computer resources and realistic reliability techniques. With the development of computer techniques and the establishment of electric utility reliability data banks, probabilistic techniques have been widely developed and used in most utilities in many areas such as design, planning and maintenance [19-23].

The probabilistic techniques used in power system reliability evaluation can be divided into the two categories of analytical methods and stochastic simulation approaches.

The analytical and simulation approaches used in HLI are well developed and have been applied extensively in system planning and operation in North America. Considerable effort has also been expended during the last two decades on developing techniques and criteria for composite and transmission system assessment. The theories and techniques used to evaluate basic reliability indices of distribution systems are highly developed. The techniques used in distribution system reliability cost/worth analysis are not well developed. The practical application to distribution system planning is also not extensive.

Prior to the establishment of the hierarchical level approach, distribution system reliability evaluations were generally done together with those of transmission systems. The techniques developed initially for transmission and distribution system evaluation are, therefore, still used and are being extended in reliability assessment of distribution systems.

Quantitative assessment techniques in distribution system reliability evaluation can be said to have been initiated in 1964 with the presentation of two papers [24,25]. Reference 24 introduced the concept of failure bunching in parallel facilities due to storm-associated failures, together with some basic techniques which have been proved to be useful in many areas of application. A major contribution was the introduction of procedures for calculating failure frequency (approximated as failure rate) and average outage duration in addition to the probability of failure. These indices provide a practical basis for transmission, distribution, and customer reliability evaluation. Since these initial developments, many papers have been published which have considerably enhanced the basic techniques and which permit very realistic and detailed modeling of distribution and transmission system networks.

The application of Markov processes to transmission system evaluation was illustrated in [26], which considered the effect of storm-associated failures on simple parallel configurations. References 27 and 28 presented a consistent set of equations for series/parallel system reduction including adverse weather and permanent, temporary maintenance and overload outage modes. Reference 28 also illustrated the concept of utilizing minimal cuts in complex configurations. The incorporation of switching action in the evaluation of transmission circuits including protective elements was introduced in [29]. These ideas were formalized in [30], which presented a basic three-state model incorporating the switching after fault concept. This is the basic framework utilized in [31], which presented a procedure for evaluating substation and switching station reliability. Reference 31 also introduced the concept of active and passive faults in systems containing protective elements.

The probability distributions associated with the system and load point indices used in distribution system reliability evaluation are considered in [32] and a set of equations for calculating the probability distribution of the reliability indices is given using a direct analytical method. The application of Monte Carlo simulation to a small radial distribution system is described in [33]. Complex radial distribution system reliability evaluation using both analytical and time sequential simulation techniques are described in [34,35].

An analytical technique using the contingency numeration approach is presented and used to evaluate customer interruption cost indices of a simple radial distribution system in

Reference 36. A general analytical method and a time sequential simulation technique used to assess the reliability cost indices of a complex radial distribution systems are introduced in [37]. References 19-23 contain many publications which contribute to the development of techniques for reliability assessment of distribution systems. These techniques form the basis for distribution system reliability evaluation. The research work described in this thesis focuses on improvement of the existing techniques and the development of new techniques for reliability evaluation of distribution systems.

1.5. Research Objectives

The objectives of the research work described in this thesis are presented in the following sections, which introduce the basic concepts of the area under investigation. These areas include the utilization of analytical and Monte Carlo simulation methods, time varying load and cost models, the dispersed nature of the cost model and the utilization of wind energy as an alternative energy source in a dispersed distribution system.

Monte Carlo Simulation Techniques

As noted earlier, reliability cost/worth assessment can be carried out using both analytical and simulation techniques.

Analytical techniques represent the system by mathematical models and evaluate the reliability indices from these models using direct mathematical solutions. The mathematical models can be very complicated and difficult to solve in a large and complex system. Approximations have to be made to find solutions. The analytical methods are highly developed and can provided average values of the reliability indices, which are important for conventional power system adequacy evaluation. The mean values, however, do not provide system engineers with any information on the variability of the reliability indices about their means.

Simulation techniques estimate the reliability indices by directly simulating the actual process and the random behavior of the system and its components. They can be used to simulate a distribution system and all component characteristics can be recognized. These techniques can sometime be valuable in breaking down a complicated system into subsystems, each of which may then be modeled and analyzed separately [38-41].

Simulation techniques can provide both average values of the reliability indices and their probability distributions. Probability distributions give a pictorial representation of the way the parameter varies, including important information on significant events, which, although they occur very infrequently, can have very serious system effects. These effects, which can easily occur in real systems, may be lost if only average values are available. Probability distributions of the reliability indices are also important in reliability cost and reliability worth analysis for industrial customers with critical processes or commercial customers with nonlinear customer damage functions.

Simulation techniques can be classified into the two categories of nonsequential (state sampling) and sequential approaches (state duration sampling).

In the basic state sampling techniques, it is assumed that each element has failure and success states, and that component states are independent events. The behavior of each element is sampled by a uniform distribution between [0, 1]. A system state depends on the combination of all element states [42, 43]. The advantages of this approach are:

- The basic reliability data requirements are relatively low. Only component-state probabilities are required.

- The simulation procedure is very simple, as only uniformly distributed random numbers are generated.

A major disadvantage of this technique is that it cannot be used by itself to calculate frequency and duration related indices.

An approach which provides a solution to this problem is the state transition sampling technique [42, 44]. This technique focuses on state transition of the whole system instead of using a component state transition process. The technique can be used to calculate the exact frequency index, but requires that the component state durations be exponentially distributed, which is not always true.

The sequential method simulates component and system behavior in chronological time. System and component states in a given hour are dependent on the behavior in the previous hour. In this approach, chronological component state transition processes for all components are first sampled using random number generators and the probability distributions of the failure and repair processes. The chronological system state transition process is then created by combination of the chronological component state transition processes [45, 46]. The sequential technique can be used to simulate any state duration distribution and to calculate the actual frequency index and the probability distribution of the reliability indices. Compared to the state sampling approach, it requires more computing time and storage.

Two objectives of the research work described in this thesis were to develop both analytical and time sequential simulation techniques to evaluate reliability cost/worth of distribution systems and to apply these techniques to optimal distribution system planning.

Time Varying Load and Cost Models

Average and step average loads are usually used as the load models in the analytical and simulation techniques applied to distribution system reliability evaluation. An average load model is an approximate representation of the actual load profile. In a practical system, the load profile for a given customer varies with the time of the day, the day of the week and the week of the year. Using a residential customer as an example, the load levels between 7 p.m. and 12 p.m. are very different from those between 3 a.m. and 5 a.m. Power system engineers have recognized the time varying nature of the load profile for a long time. Reference 47 illustrates a 24 hour load profile for residential customers. References 48 and 49 utilize time varying load models in composite power system reliability evaluation. This phenomenon has not been extensively investigated at the distribution level.

The cost models (CDF) used in most studies are also average or aggregate models. Average models do not recognize the time varying nature of interruption costs. In a practical system, the customer interruption cost for a given load level and outage duration vary with the time of occurrence. For example, the interruption cost for a commercial customer is larger when a failure occurs at a peak shopping hour than when an interruption occurs at a relatively light shopping hour. References 50-52 indicate that there is considerable variation in interruption costs with time of interruption occurrence for some customers and there is relatively little variation for others. Reference 50 provides quantitative measures of variation in the worst case interruption cost as a function of the time of the day, the day of the week and the month of the year. Time varying cost models for different customers have not been investigated in power system reliability evaluation.

The research work described in this thesis examines the effect of time varying load and cost models on the reliability cost/worth indices of distribution systems.

Dispersed Nature of the Cost Model

The average cost model provides a measure of the central tendency of the customer interruption data. The average value, however, does not provide any indication of the spread in the survey data. Using commercial customers as example, some customers say that a one minute failure duration at a fixed time will cause some cost and others indicate no cost. The results obtained using average cost model do not reflect the dispersed nature of the actual interruption costs. Interruption cost analysis [53,54] shows that the monetary values exhibit a very large deviation and in some cases, the standard deviation is more than four times the mean. The effect of the dispersed nature of the customer interruption cost data on the reliability cost indices of generation and composite systems are illustrated in References 55, 56.

The research work described in this thesis examines the effect of the dispersed nature of customer interruption costs on distribution system reliability cost indices.

Wind Generation as an Alternate Supply in a Distribution System

Reliability evaluation of distribution systems show that alternative supplies play a very important role in enhancing the system reliability. Conventional alternative supplies from different points in the system are sometimes expensive and not always available, especially in remote rural areas. Increasing distribution system reliability within economic constraints is one of main concerns of this research. Wind, solar, battery and small hydro are attractive options as alternatives to replace more conventional facilities. These power supplies can be distributed in the lateral sections and main feeders of a distribution network.

The utilization of wind energy for electric power generation is considered to be an attractive generation alternative, due to increased interest in sources of energy that are cheap, renewable and environmentally-friendly. Wind energy is highly variable, site-specific, terrain-specific and has instantaneous, minute-by-minute, hourly, diurnal and seasonal variations. The power output of a wind conversion system depends on the wind velocity. The reliability of generation and transmission systems with wind generation is illustrated in [57-60]. Relatively little work has been done from a reliability point of view to evaluate the viability of wind energy as an alternative energy supply.

One objective of the proposed research work was to investigate the possibility of using wind generation as an alternative supply to the conventional supply in a distribution system, based on system reliability cost/worth. It was expected that the procedures developed would be capable of adaptation to other energy sources and form the basis of future work.

1.6. Outline of the Thesis

As described earlier, this research work concentrates on distribution system reliability evaluation considering reliability cost/worth using both analytical and time sequential simulation techniques. The techniques can be used by system planners to make utility planning and operating decisions and by customers to make purchase decisions in an bundled or unbundled utility regime based on reliability cost/worth. The thesis consists of the following parts:

Reliability evaluation techniques are basic requirements in power system planning and operation. The analytical and time sequential Monte Carlo simulation approaches are the basic methodologies used in distribution system reliability evaluation. A reliability network equivalent approach for basic reliability analysis is illustrated in Chapter 2 which can be used to replace the failure mode and effect analysis technique [1] in order to reduce the computer time. A time sequential simulation technique to assess basic reliability indices and their probability distributions is also illustrated. A practical distribution system is analyzed and the basic reliability indices and their distributions are presented.

Chapter 3 introduces the concept of distribution system reliability cost/worth. Basic system and load point reliability cost/worth indices are introduced. A generalized analytical technique used to evaluate the reliability cost/worth of distribution systems is illustrated. The time sequential simulation technique introduced in Chapter 2 is extended to evaluate reliability cost/worth indices. The effects of different switch, fuse, and alternative supply models on the distribution system reliability cost indices are discussed. The results obtained from the analytical method are compared with those obtained from the time sequential simulation approach.

The reliability cost/worth techniques and concepts described in Chapter 3 can be used in distribution system planning, operation and expansion. Chapter 4 applies the analytical reliability cost/worth evaluation technique to solve the optimal switch selection problem. This chapter formulates the problem of optimal switching device replacement based on reliability cost/worth. Enumeration combined with a direct search technique to find the optimal number of switches and their locations is utilized. A bisection technique incorporated with enumeration to simplify the optimization procedure is also introduced. The techniques are used to select the optimal number of switches and their locations in a practical distribution system.

The concepts of time varying load and cost models are introduced in Chapter 5. The time varying load and cost models for different types of customers are illustrated. The time sequential simulation technique utilizing the developed models is illustrated. The effect of time varying load and cost models on reliability cost/worth indices is illustrated by analyzing a practical distribution system.

The dispersed nature of cost data is discussed in Chapter 6. The probability distribution models for residential and industrial customers are introduced. The effect of the dispersed nature of the cost models on the reliability indices is also presented. The results obtained using the average cost model are compared with those obtained using the probability distribution cost model.

Chapter 7 investigates the possibility of using wind generation as an alternative supply in distribution systems. Wind generation models for different wind sites are presented and a time sequential simulation technique considering wind generation units is illustrated. The energy and cost benefit indices associated with using wind generation as an alternative supply are defined in terms of an equivalent conventional generation unit. The effects of wind generation model parameters and wind sites on the cost/worth indices are discussed

Chapter 8 presents the summary and conclusions.

2. Basic Distribution System Reliability Evaluation Using Analytical and Time Sequential Simulation Techniques

2.1. Introduction

The basic techniques used in power system reliability evaluation can be divided into the two basic categories of analytical and simulation methods. The analytical techniques are highly developed and have been used in practical applications for many years. Analytical techniques represent the system by mathematical models and evaluate the reliability indices from these models using mathematical solutions. The exact mathematical equations can become quite complicated and approximations may be required when the system is complicated. A range of approximate techniques therefore has been developed to simplify the required calculations. Analytical techniques are generally used to evaluate the mean or expected values of the load point and system reliability indices. The mean values are extremely useful and are the primary indices of system adequacy in distribution system reliability evaluation. The mean values have been used for many years to assist power system planners to make planning and operation decisions. A mean value, however, does not provide any information on the variability of the reliability index. The probability distributions of the index, however, provide both a pictorial representation of the way the parameter varies and important information on significant outcomes, which, although they occur very infrequently, can have very serious system effects. These effects, which can easily occur in real life, may be neglected if only average values are available. Probability distributions of the relevant reliability indices can be important for industrial customers with critical processes or commercial customers with nonlinear cost functions [1].

An analytical technique to evaluate the probability distributions associated with distribution system reliability indices is described in [32]. This technique can be used to evaluate approximate probability distributions. The technique, however, has the following limitations:

(1) The number of element failures in a year is assumed to follow a Poisson distribution.
(2) The repair and switching times of an element are considered be very small compared to the total operating time.
(3) The probability distribution can be approximated utilizing the mean and the second, third and fourth central moments only if it is unimodal in nature. This is sometimes not valid when the different element parameters are widely spread.
(4) The technique may be difficult to apply when the distribution system configuration is large or complex.

These limitations restrain the practical application of this analytical technique and the results obtained may have large errors.

Time sequential simulation techniques can be used to estimate the reliability indices by directly simulating the actual process and the random behavior of the system and its components. These techniques can be used to simulate any system and component characteristics that can be recognized. The sequential method simulates component and system behavior in chronological time and the system and component states in a given hour are dependent on the behavior in the previous hour. Time sequential simulation techniques can be used to evaluate both the mean values of the reliability indices and their probability distributions without excessive complications due to the probability distributions of the element parameters and the network configuration complexity. Simulation can be used to provide useful information on both the mean and the distribution of an index and in general to provide information that would not otherwise be possible to obtain analytically. The disadvantage of the simulation technique is that the solution time can be extensive.

Basic distribution system reliability indices are introduced first in this chapter. A new analytical technique called the reliability network equivalent approach [106] is then developed and illustrated to simplify the evaluation procedure. This chapter also briefly illustrates a time sequential Monte Carlo simulation technique. The development of the algorithm for this technique in distribution system reliability evaluation is described. The developed digital computer programs based on these two techniques are then briefly introduced followed by application to the reliability assessment of a practical distribution system.

2.2. Basic Distribution System Reliability Indices

The basic function of a distribution system is to supply electrical energy from a substation to the individual customer load points. Service continuity is, therefore, an important criterion in a distribution system, Service continuity can be described by three basic load point indices and a series of system indices [1].

2.2.1. Basic Load Point Indices

The three basic load point reliability indices usually used are the average failure rate λ, the average outage time r and the average annual unavailability or average annual outage time U. It should be noted that these indices are not deterministic values but are expected values of an underlying probability distribution and hence are long-run average values.

2.2.2. Basic System Indices

The three primary load point indices are fundamentally important parameters. They can be aggregated to provide an appreciation of the system performance using a series of system indices. The additional indices that are most commonly used [1] are defined in the following sections.

Customer-Oriented Indices

(i) system average interruption frequency index, *SAIFI*

$$SAIFI = \frac{\text{total number of customer interruptions}}{\text{total number of customers served}} = \frac{\sum \lambda_i N_i}{\sum N_i} \tag{2.1}$$

where λ_i is the failure rate and N_i is the number of customers at load points i.

(ii) system average interruption duration index, *SAIDI*

$$SAIDI = \frac{\text{sum of customer interruption durations}}{\text{total number of customers}} = \frac{\sum U_i N_i}{\sum N_i} \tag{2.2}$$

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

(iii) customer average interruption duration index, *CAIDI*

$$CAIDI = \frac{\text{sum of customer interrruption durations}}{\text{total number of customer interruptions}} = \frac{\sum U_i N_i}{\sum N_i \lambda_i} \tag{2.3}$$

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

(iv) Average service availability (unavailability) index *ASAI (ASUI)*

$$ASAI = \frac{\text{customer hours of available service}}{\text{customer hours demanded}} = \frac{\sum N_i \times 8760 - \sum N_i U_i}{\sum N_i \times 8760} \tag{2.4}$$

$$ASUI = 1\text{-}ASAI \tag{2.5}$$

where λ_i is the failure rate, U_i is the annual outage time, N_i is the number of customers at load point i and 8760 is the number of hours in a calendar year.

Load- and Energy-Oriented Indices

(i) Energy not supplied index, *ENS*

$$ENS = \text{ total energy not supplied by the system} = \sum L_{a(i)} U_i \quad (2.6)$$

where $L_{a(i)}$ is the average load connected to load point i.

(ii) Average energy not supplied index, *AENS*

$$AENS = \frac{\text{total energy not supplied}}{\text{total number of customers served}} = \frac{\sum L_{a(i)} U_i}{\sum N_i} \quad (2.7)$$

where $L_{a(i)}$ is the average load connected to load point i

The customer and load oriented indices described above are very useful for assessing the sensitivity analysis in predictive reliability assessment. They are also extensively used, however, as a means of assessing the past performance of a system [1].

2.3. Analytical Reliability Network Equivalent Technique

The analytical techniques required for distribution system reliability evaluation are highly developed. Many of the published concepts and techniques are presented and summarized in [41]. Conventional techniques for distribution system reliability evaluation are generally based on failure mode and effect analysis (FMEA) [1, 41, 61]. This is an inductive approach that systematically details, on a component-by-component basis, all possible failure modes and identifies their resulting effects on the system. Possible failure events or malfunctions of each component in the distribution system are identified and analyzed to determine the effect on surrounding load points. A final list of failure events is formed to evaluate the basic load point indices. The FMEA technique has been used to evaluate a wide range of radial distribution systems. In systems with complicated configurations and a wide variety of components and element operating modes, the list of basic failure events can become quite lengthy and can include thousands of basic failure events. This requires considerable analysis when the FMEA technique is used. It is therefore difficult to directly use FMEA to evaluate a complex radial distribution system. A reliability network equivalent approach is introduced in this section to simplify the analytical process. The main principle in this approach is that an equivalent element can be used to replace a portion of the distribution network and therefore decompose a large distribution system into a series of simpler distribution systems. This is a novel approach to distribution system evaluation which provides a repetitive and sequential process to evaluate the individual load point reliability indices.

2.3.1. Definition of a General Feeder

Fig. 2.1 shows a simple radial distribution system consisting of transformers, transmission lines, breakers, fuses and disconnect switches. The disconnect switches and transmission lines such as s1 and l2 are designated as a main section. The main sections deliver energy to the different power supply points. An individual load point is normally connected to a power supply point through a transformer, fuse and lateral transmission line. A combination such as f1, t2 and l5 is called a lateral section. The lateral transmission line may be on either the high or low voltage side of the transformer.

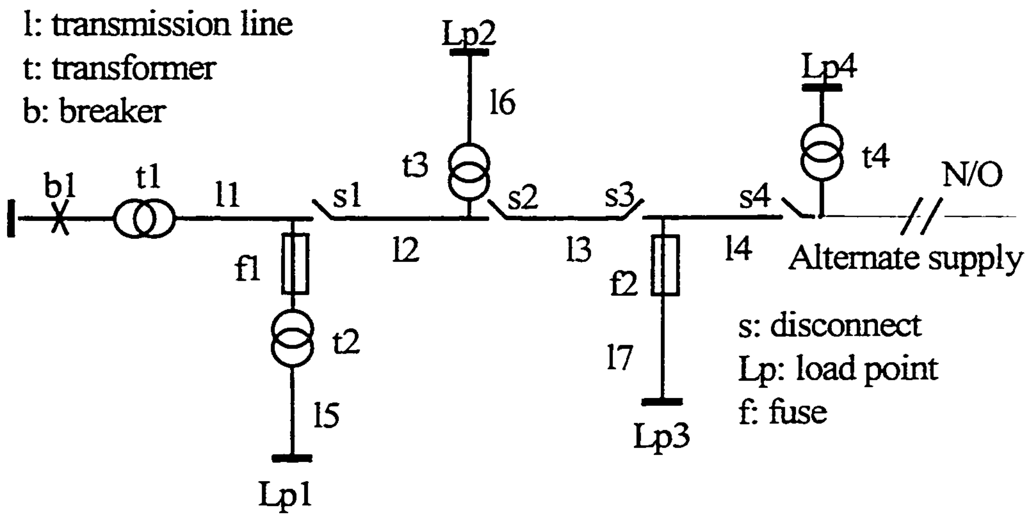

Fig. 2.1 A simple distribution system

A simple distribution system is usually represented by a general feeder which consists of n main sections, n lateral sections and a series component as shown in Fig. 2.2 In this feeder, Si, Li, Mi and Lpi represent series component i, lateral section i, main section i and load point i respectively. Li could be a transmission line , a line with a fuse or a line with a fuse and a transformer. Mi can be a line, a line with one disconnect switch or a line with disconnect switches on both ends.

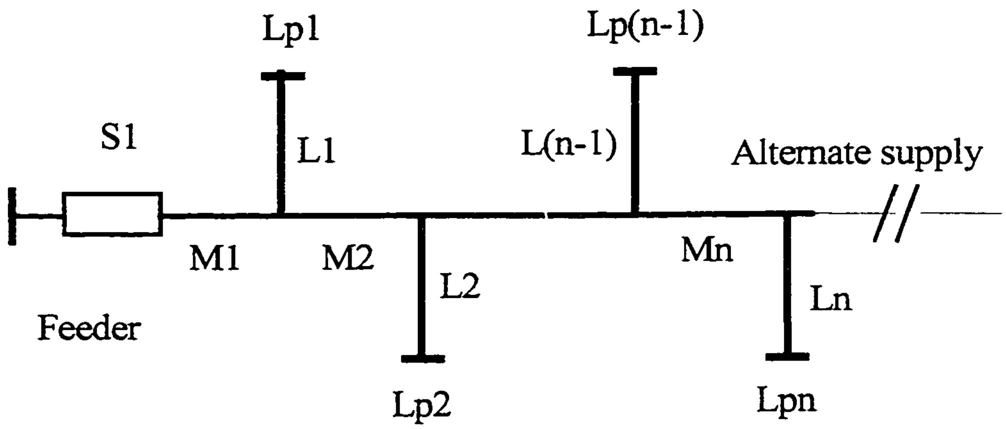

Fig. 2.2 General feeder

2.3.2. Basic Formulas for a General Feeder

Based on the element data ($\lambda_i, \lambda_k, \lambda_s, r_i, r_k, r_s, p_k$) and the configuration of the general feeder, a set of general formulas for calculating the three basic load point indices of load point failure rate λ_j, average outage duration r_j and average annual outage time U_j for load point j of a general feeder is as follows:

$$\lambda_j = \lambda_{sj} + \sum_{i=1}^{n} \lambda_{ij} + \sum_{k=1}^{n} p_{kj} \lambda_{kj} \tag{2.8}$$

$$U_j = \lambda_{sj} r_{sj} + \sum_{i=1}^{n} \lambda_{ij} r_{ij} + \sum_{k=1}^{n} p_{kj} \lambda_{kj} r_{kj} \tag{2.9}$$

$$r_j = \frac{U_j}{\lambda_j} \tag{2.10}$$

where p_{kj} is the control parameter of lateral section k that depends on the fuse operating model. It can be 1 or 0 corresponding to no fuse or a 100% reliable fuse respectively and a value between 0 and 1 for a fuse which has a probability of unsuccessful operation of p_{kj}. The parameters λ_{ij}, λ_{kj} and λ_{sj} are the failure rates of the main section i, lateral section k and series element s respectively and r_{ij}, r_{kj} and r_{sj} are the outage durations (switching time or repair time) for the three elements respectively.

The r_{ij}, r_{kj} and r_{sj} data have different values for different load points when different alternate supply operating modes are used and disconnect switches are installed in different locations on the feeder. This is illustrated in the following three cases.

Case 1: no alternate supply

In this case, r_s is the repair time of the series element s and r_i is the switching time for those load points that can be isolated by disconnection from the failure main section i or the repair time for those load points that cannot be isolated from a failure of the main section i. In this case, r_k is the switching time for those load points that can be isolated by disconnection from a failure on a lateral section k or the repair time for those load points that cannot be isolated from a failure on a lateral section k.

Case 2: 100% reliable alternate supply

In this case, r_i and r_k take the same values as in Case 1. The parameter r_s is the switching time for those load points that are isolated from the failure of a series element by disconnection or the repair time for those load points not isolated from the failure of a series element s.

Case 3: alternate supply with p_a availability

In this case, r_i is the repair time (r_1) for those load points not isolated by disconnection from the failure of main section i, the switching time (r_2) for those load points supplied by the main supply and isolated from the failure of the main section i or $r_2\ p_a + (1- p_a)\, r_1$ for those load points supplied by an alternate supply and isolated from the failure of the main section i. The parameter r_k is the repair time r_1 for those load points not isolated by disconnection from the failure of lateral section k, the switching time r_2 for those load points supplied by the main supply and isolated from the failure of lateral section k or r_2 p_a + $(1- p_a)\, r_1$ for those load points supplied by an alternate supply and isolated from the failure of a lateral section k. r_s is the same as in Case 2.

2.3.3. Network Reliability Equivalent

A practical distribution system is usually a relatively complex configuration that consists of a main feeder and subfeeders as shown in Fig. 2. 3 .

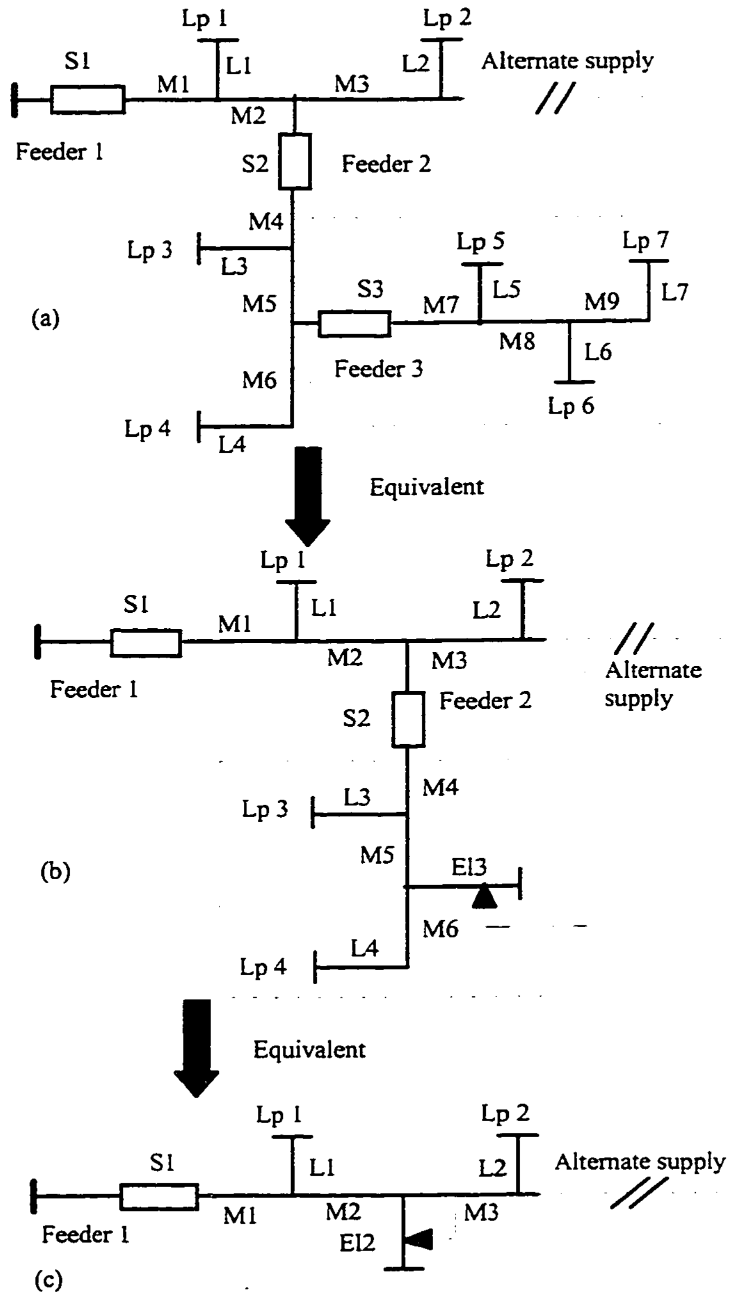

Fig. 2. 3 Reliability network equivalent

The main feeder is connected to a bus station. A subfeeder is a feeder connected such as Feeder 2 and Feeder 3 in Fig. 2. 3 . The three basic equations presented earlier cannot be used directly to evaluate the reliability indices of this system. The reliability network equivalent approach, however, provides a practical technique to solve this problem. The basic concepts in this approach can be illustrated using the distribution system shown in

Fig. 2. 3 The original configuration is given in Fig. 2. 3 (a) and successive equivalents are shown in Fig. 2. 3 (b) and (c). The procedure involves the development of equivalent lateral sections and associated series sections.

Equivalent Lateral Sections

The failure of an element in Feeder 3 will affect load points not only in Feeder 3 but also in Feeder 1 and Feeder 2. The effect of Feeder 3 on Feeder 1 and Feeder 2 is similar to the effect of a lateral section on Feeder 2. Feeder 3 can be replaced using the equivalent lateral section (El 3) shown in Fig. 2. 3 (b). The equivalent must include the effect of the failures of all elements in Feeder 3. The equivalent lateral section (El 2) of Feeder 2 can then be developed as shown in Fig. 2. 3 (c). The contributions of the failures of different elements to parameters of an equivalent lateral section will depend on the location of the disconnect switches. The reliability parameters of an equivalent lateral section can be divided into two groups and obtained using the following equations:

$$\lambda_{e1} = \sum_{i=1}^{m} \lambda_i \tag{2.11}$$

$$U_{e1} = \sum_{i=1}^{m} \lambda_i r_i \tag{2.12}$$

$$r_{e1} = \frac{U_{e1}}{\lambda_{e1}} \tag{2.13}$$

$$\lambda_{e2} = \sum_{i=1}^{n} \lambda_i \tag{2.14}$$

$$U_{e2} = \sum_{i=1}^{n} \lambda_i r_i \tag{2.15}$$

$$r_{e2} = \frac{U_{e2}}{\lambda_{e2}} \tag{2.16}$$

where λ_{e1} and r_{e1} are the total failure rate and restoration time of the failed components that are not isolated by disconnects in the subfeeder and m is the total number of these elements. The effect of this equivalent lateral section on the load points in the prior supply feeder (designated as upfeeder) depends on the configuration and operating mode of the upfeeder elements. The parameters λ_{e2} and r_{e2} are the total equivalent failure rate and the switching time of those failed elements that can be isolated by disconnects in the branch and n is the total number of these elements. They do not depend on the configuration and operating modes of the upfeeders. The equivalent parameters do not depend on alternate supplies in the subfeeders.

Equivalent Series Component

Using successive network equivalents, the system is reduced to a general distribution system in the form shown in Fig. 2. 3 (c). Only Feeder 1 remains in the system. The basic formulas can now be used to evaluate the load point indices of Feeder 1. On the other hand, the failure of elements in Feeder 1 also affect the load points in Feeder 2 and Feeder 3. These effects are equivalent to those of a series element S2 in Feeder 2. The parameters of the equivalent series component S2 are obtained as the load point indices of Feeder 1 are calculated. Feeder 2 becomes a general distribution system after the equivalent series element is calculated. The load point indices of Feeder 2 and the parameters of the equivalent series element S3 are then calculated in the same way as with Feeder 1. Finally, the load point indices of Feeder 3 are evaluated. The reliability parameters of a equivalent series component can be calculated using the same method used for the load point indices. The only difference is that the equivalent parameters should be divided into two groups. The effect of one group on the load points of a subfeeder is independent of the alternate supplies in subfeeders, the effect of the other group depends on the alternate supplies in the subfeeders.

The simplification in computation provided by the proposed method can be illustrated using Fig. 2. 3 (a). In this distribution system, there are 7 load points and 19 elements.

Using the standard FMEA approach, 19×7 =133 calculations are required as all load points are checked for each element failure. Using the reliability network equivalent approach, however, 7+7+7 =21 calculations are required to find the equivalent lateral sections and 7×3+ 7×3+ 7×3 =63 calculations to find the load point indices for a total of 84. This is 37% of the required FMEA calculation. This is a simple network. If there are more elements in each subfeeder, the savings can be quite substantial. In addition, all the network must be searched for each element failure to find the affected load points in a standard FMEA. The search procedure for the affected load points outside a feeder for element failures in the feeder is the same. This search procedure requires considerable computer time. Using the reliability network equivalent, no repeat searches are required, with an attendant saving in computer time.

2.3.4. Procedure for Calculating Reliability Indices

The procedure described in the previous section for calculating the reliability indices in a complex distribution system using the reliability network equivalent approach can be summarized by two protocols.

A bottom-up process is used to search all the subfeeders and to determine the corresponding equivalent lateral sections. As shown in Fig. 2. 3 , the equivalent lateral section El 3 is first found, followed by El 2. The system then is reduced to a general distribution system.

Following the bottom-up process, a top-down procedure is then used to evaluate the load point indices of each feeder and equivalent series components for the corresponding subfeeders until all the load point indices of feeders and subfeeders are evaluated. The load point indices and the equivalent parameters of the series components are calculated using Equations (1)-(3). Referring to Fig. 2. 3 , the load point indices in Feeder 1 and the equivalent series element S2 for Feeder 2 are first calculated, followed by the load point indices in Feeder 2 and S3. The load point indices in Feeder 3 are finally calculated. After all the individual load point indices are calculated, the final step is to obtain the feeder and system indices. The example presented in Fig. 2. 3 (a) considers a single alternate supply. The procedure can be extended, however, to consider more than one supply to a general feeder.

2.3.5. Program and System Analysis

A general program for calculating the load point and system reliability indices of a complex radial distribution system has been developed using the network reliability equivalent technique. The program can be used to calculate the indices for different main section configurations containing no disconnects, one disconnect or two disconnects on the main sections and different fuse operating models on the lateral sections. The following illustrates an application to a small but practical test system known as the RBTS [62, 63] developed at the University of Saskatchewan. This system has been used extensively in recent years for development work in reliability evaluation of generation, transmission, station and distribution systems. It provides a consistent set of data which enables a wide range of techniques and application to be analyzed and compared. The RBTS has proved to be a useful and consistent reference source for comparing alternative techniques and computer programs. There are five local distribution systems in the RBTS. The single line diagram of the RBTS is shown in Appendix A.

Fig. 2.4 shows the distribution system connected to bus 6. The distribution system contains 4 feeders, 3 subfeeders, 42 main sections, 42 lateral sections and 40 load points. Each system segments consists of a mixture of components. The disconnect switches, fuses and alternate supplies can operate in the different modes described earlier. The data used in these studies is given in [62, 63]. The existing disconnect switches are shown in Fig. 2.4 , but additional switches can be added at any location. System analysis has been carried out for three different operating conditions. The detailed procedure followed in the reliability network equivalent approach is illustrated in Case 1.

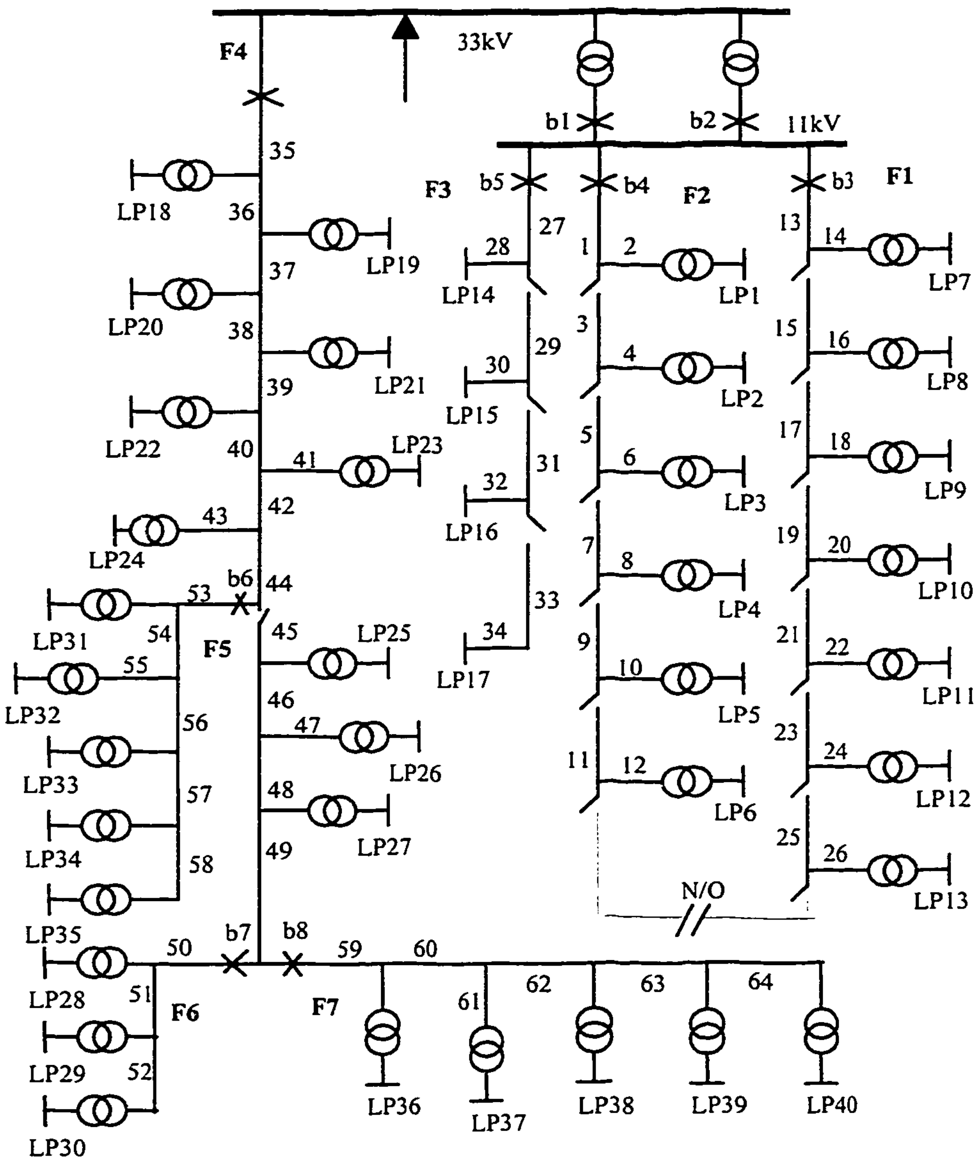

Fig. 2.4 Distribution system of RBTS

Case 1: In order to illustrate the reliability network equivalent approach in a general sense, breakers b6, b7 and b8 are assumed to be 80% reliable with no alternate supply to main Feeder 4. The detailed analysis is as follows:

There are three subfeeders in main Feeder 4. The first step is to find the equivalent lateral sections of subfeeders F5, F6 and F7. The equivalent lateral section parameters for the three subfeeders are as follows:

For subfeeder F5,

$$\lambda_{e51} = 0.8645(occ / yr)$$
$$U_{e51} = 4.3225(hr / yr)$$
$$r_{e51} = 5.0(hr)$$
$$\lambda_{e52} = 0(occ / yr)$$
$$U_{e52} = 0(hr / yr)$$
$$r_{e52} = 0(hr)$$

For subfeeder F6,

$$\lambda_{e61} = 0.5525(occ / yr)$$
$$U_{e61} = 2.7625(hr / yr)$$
$$r_{e61} = 5.0(hr)$$

$$\lambda_{e62} = 0(occ / yr)$$
$$U_{e62} = 0(hr / yr)$$
$$r_{e62} = 0(hr)$$

For subfeeder F7,

$$\lambda_{e71} = 0.8385(occ / yr)$$
$$U_{e71} = 4.1925(hr / yr)$$
$$r_{e71} = 5.0(hr)$$
$$\lambda_{e72} = 0(occ / yr)$$
$$U_{e72} = 0(hr / yr)$$
$$r_{e72} = 0(hr)$$

After finding the equivalent lateral sections of subfeeders F5, F6 and F7, Feeder 4 becomes a general feeder. The next step is to calculate the load point indices in Feeder 4. The parameters of the equivalent series components for subfeeder F5, F6 and F7 are as follows:

For subfeeder F5,

$$\lambda_{es5} = 2.7703(occ/yr)$$
$$U_{es5} = 10.9566(hr/yr)$$
$$r_{es5} = 3.95824(hr)$$

For subfeeder F6,

$$\lambda_{es6} = 2.7911(occ/yr)$$
$$U_{es6} = 13.9555(hr/yr)$$
$$r_{es6} = 5.0(hr)$$

For subfeeder F7,

$$\lambda_{es7} = 3.0199(occ/yr)$$
$$U_{es7} = 15.0995(hr/yr)$$
$$r_{es7} = 5.0(hr)$$

After determining the parameters of the three equivalent series elements, the indices of load points connected to the three subfeeders can be calculated. Table 2.1 shows the representative load point reliability indices for Feeder 4.

Table 2.1 Load point indices, Case 1

Load point	Failure rate (occ/yr)	Outage Duration (hrs)	Unavailability (hrs/yr)
1	.3303	2.4716	.8163
10	.3595	2.2434	.8065
20	3.4769	4.1915	14.5735
25	3.4769	5.0216	17.4595
30	3.3586	5.0223	16.8680
35	3.6498	4.2298	15.4380
40	3.8734	5.0194	19.4420

The system indices for Feeder 4 can be evaluated using the load point indices and are shown in Table 2.2 .

Table 2.2 System indices, Case 1

SAIFI (interruptions/customer yr)	1.6365
SAIDI (hours/customer yr)	6.9695
CAIDI (hours/customer interruption)	4.2588
ASAI	0.9992
ASUI	0.0008
ENS (MWh/yr)	83.9738
AENS (kWh/customer yr)	0.02858

Case 2: In this case, breakers 6, 7 and 8 are assumed to be 100% reliable and no alternative supply is available to Feeder 4. The system indices are shown in Table 2.3 .

Table 2.3 System indices, Case 2

SAIFI (interruptions/customer yr)	1.0065
SAIDI (hours/customer yr)	3.8197
CAIDI (hours/customer interruption)	3.7949
ASAI	.999956
ASUI	.00044
ENS (MWh/yr)	48.3691
AENS (kWh/customer yr)	.01646

Case 3: Breakers 6, 7 and 8 are assumed to be 80% reliable and alternative supply is available to Feeder 4 at the point between the two breakers in F6 and F7. The system indices are shown in Table 2.4 .

Table 2.4 System indices, Case 3

SAIFI (interruptions/customer yr)	1.6365
SAIDI (hours/customer yr)	4.8478
CAIDI (hours/customer interruption)	2.9623
ASAI	0.99945
ASUI	0.00055
ENS (MWh/yr)	57.8922
AENS (kWh/customer yr)	0.0197

It can be seen by comparing the results of Case 2 with those of Case 1 that the probability of successful operation of breakers 6, 7 and 8 is important for the reliability of the whole distribution system. Comparing the results of Case 1 and Case 3, it can be seen that the reliability of the overall system is greatly increased by providing the alternate supply in Feeder 4.

These conclusions can obviously be determined by other techniques such as the standard FMEA approach. The reliability network equivalent method is a novel approach to this problem which uses a repetitive and sequential process to evaluate the individual load point and subsequently the overall system indices.

2.4. Time Sequential Simulation Technique

A number of papers have been published [3] on the application of Monte Carlo simulation in reliability evaluation of generating systems, transmission systems, substations and switching stations. Relatively little work has been done to evaluate the reliability of distribution systems using simulation techniques. A time sequential simulation program for distribution system reliability evaluation is described in [33]. This program has been used to study the random behavior of simple distribution systems. This technique, however, cannot be applied to a complex distribution system with complicated component operating models. The results obtained using this approach are also approximate as overlapping time is ignored in the simulation procedure. A time sequential simulation technique to evaluate the reliability of a complex distribution system is developed in [35].

The behavior pattern of n identical systems in real time will all be different in varying degrees, including the number of failures, times to failure, restoration times, etc. This is due to the random nature of the processes involved. The behavior of a particular system, could therefore follow any of these behavior patterns. The time sequential simulation process can be used to examine and predict behavior patterns in simulated time, to obtain the probability distributions of the various reliability parameters and to estimate the expected or average value of these parameters.

In a time sequential simulation, an artificial history that shows the up and down times of the system elements is generated in chronological order using random number generators and the probability distributions of the element failure and restoration parameters. A sequence of operating-repair cycles of the system is obtained from the generated component histories using the relationships between the element states and system states. The system reliability indices and their probability distributions can be obtained from the artificial history of the system.

2.4.1. Element Models and Parameters

The essential requirement in time sequential simulation is to generate realistic artificial operating/restoration histories of the relevant elements. These artificial histories depend on the system operating/restoration modes and the reliability parameters of the elements. Distribution system elements include basic transmission equipment such as transmission lines and transformers, and protection elements such as disconnect switches, fuses, breakers and alternate supplies.

Transmission equipment can generally be represented by the two-state model shown in Fig. 2.5 where the up state indicates that the element is in the operating state and the down state implies that the element is inoperable due to failure.

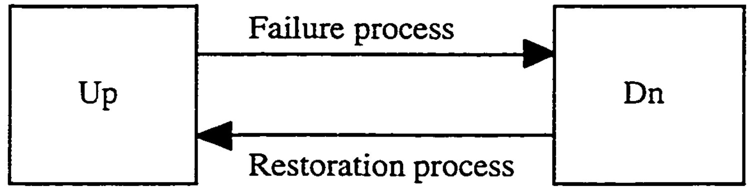

Fig. 2.5 State space diagram of element

The time during which the element remains in the up state is called the time to failure (TTF) or failure time (FT). The time during which the element is in the down state is called the restoration time that can be either the time to repair (TTR) or the time to replace (TTR). The process of transiting from the up state to the down state is the failure process. Transition from an up state to a down state can be caused by the failure of an element or by the removal of elements for maintenance. Fig. 2.6 shows the simulated element operating/restoration history of an element.

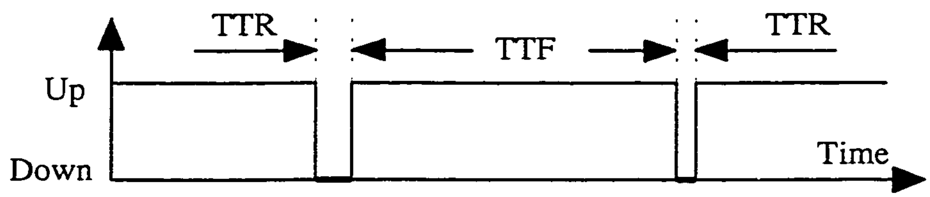

Fig. 2.6 Element operating/repair history

The parameters TTF, TTR are random variables and may have different probability distributions. The probability distributions used to simulate these times are Exponential, Gamma, Normal, Lognormal and Poisson distributions .

Protection elements are used to automatically isolate failed elements or failed areas from healthy areas when one or more failures occur in system. They can exist in either functioning or failed states which can be described in terms of their probabilities. Alternative supply situations can be described by probabilities that alternative supplies are available. A uniform distribution is used to simulate these probabilities.

2.4.2. Probability Distributions of the Element Parameters

The parameters that describe the operating/restoration sequences of the elements such as TTF, TTR, repair time (RT) and switching time (ST) are random variables, and may have different probability distributions. The most useful probability distributions in distribution system reliability evaluation are:

(1) Uniform Distribution

The probability density function (p.d.f.) of a uniform distribution is

$$f_U(u) = \begin{cases} 1 & 0 \le u \le 1 \\ 0 & \text{otherwise} \end{cases} \tag{2.17}$$

The availability of an alternate supply and the probability that a fuse or breaker operates successfully can be obtained directly from this distribution.

(2) Exponential Distribution

The p.d.f. of an exponential distribution is

$$f_T(t) = \begin{cases} \lambda e^{-\lambda t} & 0 < t < \infty \\ 0 & \text{otherwise} \end{cases} \tag{2.18}$$

Many studies indicate that time to failure is reasonably described by an exponential distribution.

(3) Gamma Distribution

A random variable T has a Gamma distribution if its p.d.f. is defined as

$$f_T(t) = \begin{cases} \dfrac{t^{\alpha-1} e^{-t/\beta}}{\beta^{\alpha}\Gamma(\alpha)} & 0 \le t \le \infty \\ 0 & \text{otherwise} \end{cases} \tag{2.19}$$

(4) Normal Distribution

A random variable T has a normal distribution if its p.d.f. is

$$f_T(t) = \frac{1}{\sigma\sqrt{2\pi}} \exp[-\frac{(t-\mu)^2}{2\sigma^2}] \tag{2.20}$$

and is denoted $N(\mu, \sigma^2)$, here μ is the mean and σ^2 is the variance.

(5) Lognormal Distribution

Let T be from $N(\mu, \sigma^2)$, then $Y = e^T$ has the lognormal distribution with p.d.f.

$$f_T(t) = \begin{cases} \frac{1}{\sqrt{2\pi}\sigma t} \exp[-\frac{(\ln t - \mu)^2}{2\sigma^2} & 0 \le t \le \infty \\ 0 & \text{otherwise} \end{cases} \tag{2.21}$$

(6) Poisson Distribution

A random variable x has a Poisson distribution if the p.m.f. is

$$p_x = \frac{\lambda^x e^{-\lambda}}{x!} \qquad x = 0, 1, \cdots, \lambda > 0 \tag{2.22}$$

Studies show that the number of element failures in a year is Poisson distributed.

The TTR, TTF, RT and ST in the operating/restoration history of the elements and load point can be described by any one of these distributions.

2.4.3. Generation of Random Numbers

As described earlier, the uniform distribution can be generated directly by a uniform random number generator. The random variables from other distributions are converted from the generated uniform number. The three basic methods are the inverse transform, composition and acceptance-rejection techniques. These methods are discussed in detail in [39, 41]. The following example shows how to convert the uniform distribution into an exponential distribution using the inverse transform method.

The cumulative probability distribution function for the exponential distribution (2.18) is

$$U = F_T(t) = 1 - e^{-\lambda t} \tag{2.23}$$

where U is a uniformly distributed random variable over the interval [0,1].

Solving for T:

$$T = -\frac{1}{\lambda}\ln(1-U) \tag{2.24}$$

Since (1-U) is distributed in the same way as U, then:

$$T = -\frac{1}{\lambda}\ln U \tag{2.25}$$

U is uniformly distributed and T is exponentially distributed.

2.4.4. Determination of the Failed Load Point

The function of a distribution system is to supply electric power to individual customers. Element failures may affect one or more load points. The most difficult problem in the simulation is to find the load points affected by the failure of an element and to determine their failure duration, which are dependent on the network configuration, the system protection and the maintenance philosophy. In order to create a structured approach, the distribution system can be broken down into general segments. A complex radial distribution system can be divided into the combination of a main feeder (a feeder is connected to a switch station) and subfeeders (a subfeeder is a branch connected to a main feeder or to other subfeeders [34]. The direct search procedure for determining the failed load points and their operating-restoration histories is as follows:

(1) Determine the type (main section, lateral section or series element). If the failed element is a lateral section, go to step 2. If the failed element is a main section or a series element, go to step 3.

(2) Determine the state of the corresponding lateral fuse If the failed element is a lateral section line. If the lateral fuse is in a functioning state, the load point connected to this

lateral section is the only failed load point and the search procedure is stopped. If the lateral fuse is in a malfunction state, go to the next step.

(3) Determine the location of the failed element, that is the failed element number and the feeder that the failed element is connected to. If the failed feeder is the main feeder, all the load points connected to this main feeder are the failed load points and the search procedure is stopped. If the failed feeder is a subfeeder, go to step 4.

(4) Determine the subfeeders which are the down stream feeders connected to the failed subfeeder and all the load points connected to these subfeeders are the failed load points.

(5) Determine the breaker state of the failed subfeeder. If the breaker is in a functioning state, the search procedure is stopped. If not, go to step 6.

(6) Determine the upfeeder which is the up stream feeder to which the failed subfeeder is connected. All the load points in the upfeeder are the failed load points. The upfeeder becomes the new failed subfeeder.

(7) Repeat (5) to (6) until the main feeder is reached and all the failed load points are found.

Some failed load points can be restored to service by switching action. The failure durations therefore is the switching time that is the time to isolate the failed element from the system. Others can only be restored by repairing the failed elements. In this case, the failure duration is the repair time of the failed element. The failure durations of the load points, are determined based on the system configuration and operating scheme for the disconnect switches in the system.

The operating/restoration history of a load point is shown in Fig. 2.7 and is conceptually similar to that of a component as shown in Fig. 2.6 . In this case, however, it is based on the operating/restoration histories of the pertinent elements, the system configuration and protection scheme. The TTR is the time to restoration, which can be the repair time or the switching time.

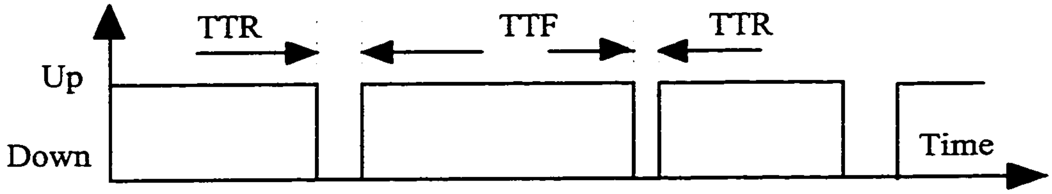

Fig. 2.7 Load point operating/restoration history

2.4.5. Consideration of Overlapping Times

The failure of one element can overlap that of another element. The duration of this event is called overlapping time and can occur with more than one element. Overlapping time can affect a load point failure duration as illustrated in Fig. 2.8 . The artificial histories of the elements j, k and the load point i are shown in Fig. 2.8 where the failures of both elements j and k affect load point i. It is usually assumed in radial distribution system reliability evaluation, that the restoration time is very short compared with the operating time which means that the probability of two elements or more elements being failed at the same time is very small. This is not true if all the elements have similar failure rates and the deviations in TTF are large. The effects of overlapping times on the load point indices are considered in the simulation program.

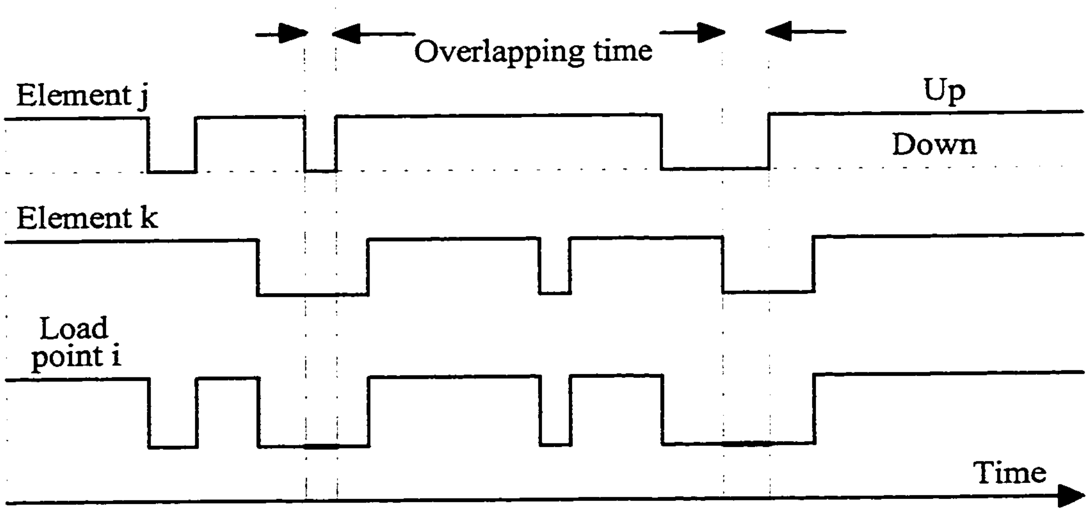

Fig. 2.8 Overlapping time of element failures

2.4.6. Determination of the Reliability Indices and Their Distributions

Distribution system reliability can be expressed in terms of load point and system indices. Both the average values and the probability distributions of these indices can be calculated from the load point operating/restoration histories.

The average values of the three basic load point indices for load point j can be calculated from the load point up-down operating history using the following formulae:

$$\lambda_j = \frac{N_j}{\sum T_{uj}} \tag{2.26}$$

$$r_j = \frac{\sum T_{dj}}{N_j} \tag{2.27}$$

$$U_j = \frac{\sum T_{dj}}{\sum T_{uj} + \sum T_{dj}} \tag{2.28}$$

Where $\sum T_{uj}$ and $\sum T_{dj}$ are the respective summations of all the up times T_u and all the down times T_d and N_j is the number of failures during the total sampled years.

In order to determine the probability distributions of the load point failure frequency, the period values k of this index are calculated for each sample year. The number of years m(k) in which the load point outage frequency equals k is counted. The probability distribution $p(k)$ of the load point failure frequency can be calculated using

$$p(k) = \frac{m(k)}{M} \qquad k = 0, 1, 2 \cdots, \tag{2.29}$$

where M is the total sample years. The probability distribution of the load point unavailability can be calculated in a similar manner. To calculate the probability distribution of outage duration, the failure number $n(i)$ with outage duration between i-1 and i is counted. The probability distribution $p(i)$ is

$$p(i) = \frac{n(i)}{N} \qquad i = 1, 2, 3 \cdots, \tag{2.30}$$

where N is the total failures in the sampled years.

The system indices can be calculated from the basic load point indices as system indices are basically weighted averages of the individual load point values. Distributions of the system indices therefore can also be obtained from the period load point indices.

2.4.7. Simulation Procedure

The process used to evaluate the distribution system reliability indices using time sequential simulation consists of the following steps:

Step 1: Generate a random number for each element in the system.

Step 2: Convert these random numbers into times to failures (TTF) corresponding to the probability distribution of the element parameters.

Step 3: Generate a random number and convert this number into the repair time (RT) of the element with minimum TTF according to the probability distribution of the repair time.

Step 4: Generate another random number and convert this number into a switching time (ST) according to the probability distribution of the switching time if this action is possible.

Step 5: Utilize the procedure described earlier under Determination of Load Point Failures and record the outage duration for each failed load point.

Step 6: Generate a new random number for the failed element and convert it into new TTF, and return to Step 3 if the simulation time is less than one year. If the simulation time is greater than one year, go to Step 9.

Step 7: Calculate the number and duration of failures for each load point for each year.

Step 8: Calculate the average value of the load point failure rate and failure duration for the sample years.

Step 9: Calculate the system indices of SAIFI, SAIDI, CAIDI, ASAI, ASUI, ENS and AENS and record these indices for each year.

Step 10: Calculate the average values of these system indices.

Step 11: Return to Step 3 if the simulation time is less than the specified total simulation years, otherwise output the results.

2.4.8. Simulation Program

A program has been developed to simulate the performance of a complex radial distribution system using the time sequential technique. Exponential, Normal, Lognormal and Gamma distributions can be used to model the element probability distributions associated with failure, repair and switching times. The program can simulate main sections and lateral sections which have different structures. The program can also simulate different operating models for fuses, breakers and alternative supplies. Overlapping time is also considered in the program. The following load point indices and their probability distributions can be calculated:

(1) Average load point failure frequency (failures/year).

(2) Average load point failure duration (hours/year).

(3) The probability distribution of failure durations.

(4) The probability distribution of the annual failure rate.

(5) The probability distribution of the annual failure duration.

The system indices are as follows:

(1) Average value of SAIFI, SAIDI, CAIDI, ASAI, ASUI, ENS and AENS.

(2) The probability distributions of the system indices

Additional information in the form of the variation in the annual failure rate and failure duration as a function of the number of samples is also developed. This is also available for the system indices and shows the convergence of the simulation process.

2.4.9. Application to a Distribution System

The developed program has been used to evaluate a range of distribution systems. The following illustrates an application to the system shown in Fig.2.4. The failure rate of each element is assumed to be constant. The repair and switching times are assumed to be lognormally distributed. It is assumed that the standard deviations of the transmission line repair time, transformer replace time and switching time of all elements are one hour, 10 hours and 0.4 hours respectively. The simulation was performed for a period of 15000 years. The following shows the simulation results.

Average Value of the Load Point and System Indices

The average values of the load point and system indices can be calculated using both the analytical and simulation techniques. Table 2.5 shows representative results of the load point indices obtained using the analytical (A) and simulation (S) techniques. The average values of system indices are shown in Table 2.6 for two approaches.

Table 2.5 Comparison of the load point indices

Load	Failure rate (occ/yr)			Unavailability (hrs/yr)		
Point (i)	(A)	(S)	difference %	(A)	(S)	difference %
1	0.3303	0.3340	-1.11	0.8163	0.8310	-1.77
5	0.3400	0.3460	-1.73	0.8260	0.8520	-3.05
10	0.3595	0.3570	0.07	0.8065	0.8170	-1.29
15	0.2373	0.2390	-0.07	0.8353	0.8330	0.03
20	1.6274	1.7680	-7.95	5.5515	5.5919	-0.07
25	1.6725	1.7681	-5.41	8.4375	8.8573	-4.73
30	2.2250	2.2919	-2.91	11.2000	11.4572	-2.24
35	2.5370	2.6008	-2.45	9.8740	9.7233	1.55
40	2.5110	2.5593	-1.88	12.6300	12.7872	-1.23

Table 2.6 Comparison of the system indices

Indices	(S)	(A)	difference %
SAIFI(interruption/customer yr)	1.03872	1.00655	3.18
SAIDI(hrs/customer yr)	3.86350	3.81970	1.15
CAIDI(hrs/customer interruption)	3.71951	3.79485	-1.98
ASAI	0.99956	0.99956	0
ASUI	0.00044	0.00044	0
ENS(MWh/yr)	48.85556	48.36910	1.00
AENS(kWh/customer yr)	0.01663	0.01646	1.03

The results in Table 2.5 and Table 2.6 from both simulation and analytical approaches are very close. The maximum difference in the load point indices is 7.95 percent at load point 20. The maximum error in the system indices is 3.18 percent for SAIFI. The analytical approach provides a direct and practical technique for radial distribution system evaluation and is quite adequate if only the average values of the load point and system indices are required.

Probability Distributions of the Load Point Indices

The probability distributions of the annual failure frequency and failure duration for each load point in the distribution system have been evaluated. Fig. 2.9 and Fig. 2.10 present the histograms of the failure frequency for load point 1 and load point 30.

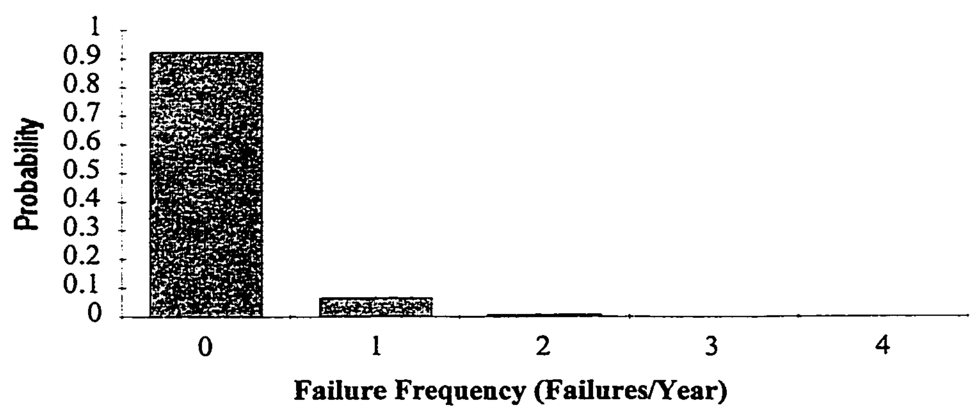

Fig. 2.9 Failure frequency histogram, Load point 1

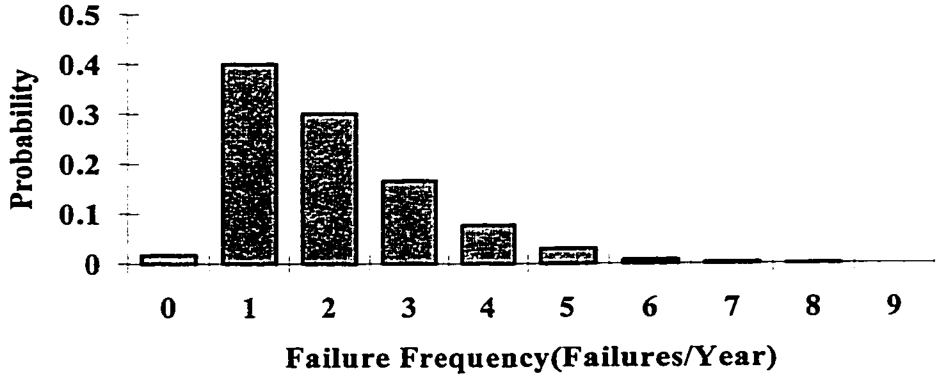

Fig. 2.10 Failure frequency histogram, Load point 30

The probability distribution of the failure frequency clearly shows the probability of having a different number of load point failures in each year for each load point. It can be seen in Fig. 2.9 that the probability of having zero failures per year at load point 1 is more than 0.9. The probability of having one failure per year is less than 0.1 and the probability of two failures per year is less than 0.01. It can be seen from Fig. 2.10 that the probability of zero failures per year is about 0.02 at load point 30 and the probability of having 6 or more outages per year is very small. The additional information provided by the probability distributions can be very important for those customers which have special reliability requirements.

The probability distributions of failure durations for load point 1 and 30 are shown in Fig. 2.11 and Fig. 2.12 . A class interval width of one hour has been used in this example. It can be seen from Fig. 2.11 that failure durations between 0 and 1 hour at load point 1 have the largest probability. The durations between 1 and 2 hours has the second largest probability and the duration with the third largest probability is between 4 and 5 hours. Durations in excess of 12 hours have a very small possibility. For load point 30, outage durations between 4 and 5 hours have the largest probability 0.38. The durations are mainly distributed between 0 and 12 hours. The longest duration is about 12 hours. The information provided by these probability distributions are very useful for reliability worth/cost analysis for customers with nonlinear customer damage functions. The 2.488

hour average failure duration from the analytical technique does not provide any distribution information. A one hour class interval is used in Fig. 2.11 and Fig. 2.12 Any class interval, however, can be used in the simulation.

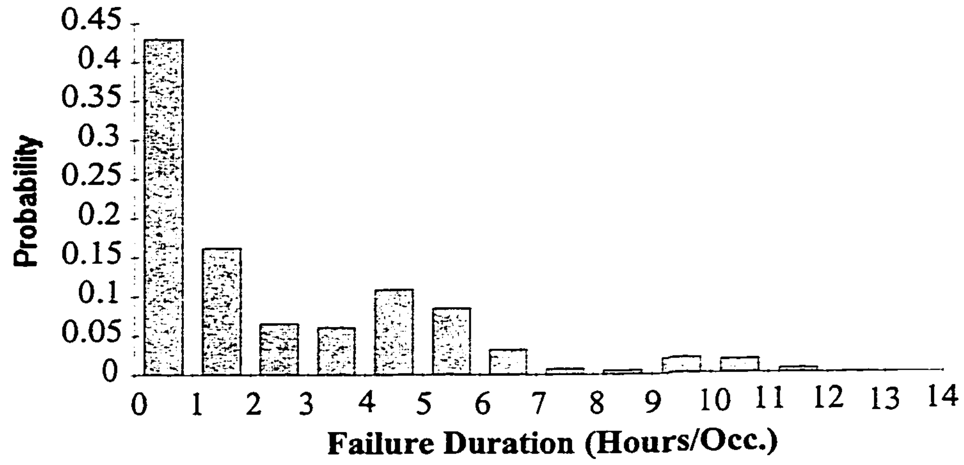

Fig. 2.11 Failure duration histogram, Load point 1

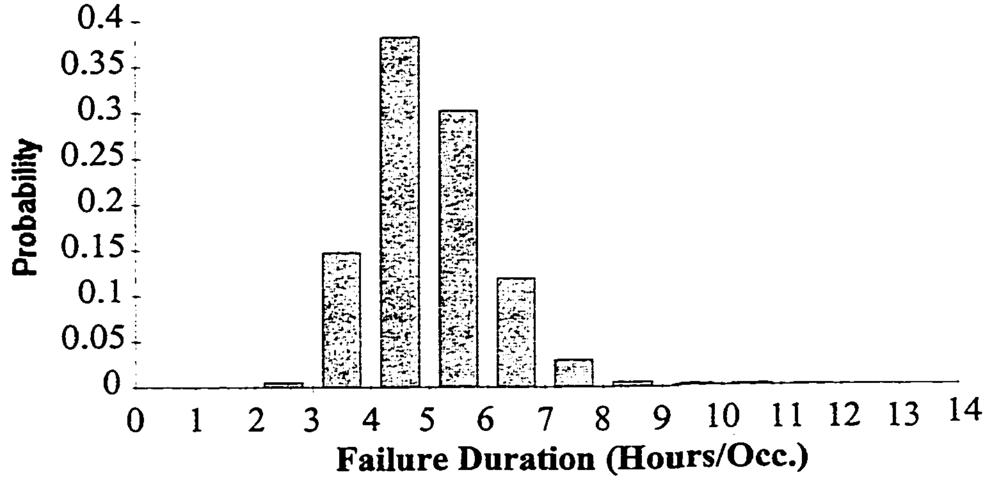

Fig. 2.12 Failure duration histogram, Load point 30

Probability Distributions of System Indices

The probability distributions of all seven system indices for each feeder were also evaluated. Fig. 2.13 -Fig. 2.19 show the probability distributions of SAIFI, SAIDI, CAIDI, ASAI, ASUI, ENS and AENS for Feeder 4.

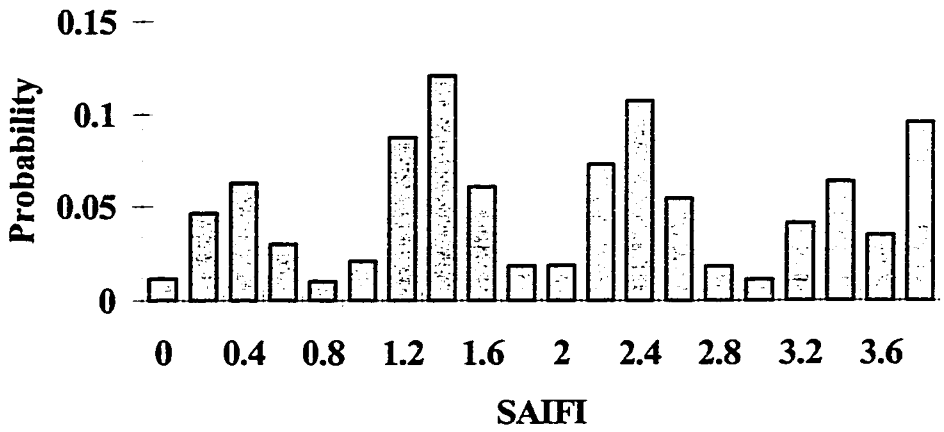

Fig. 2.13 Histogram of *SAIFI*, Feeder 4

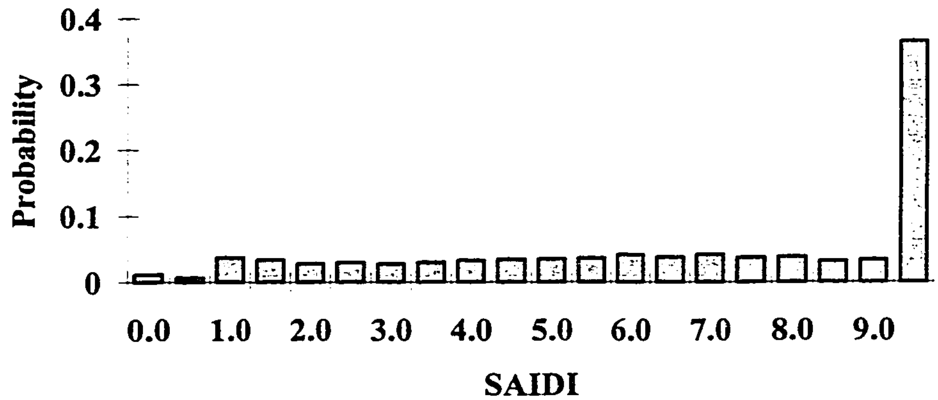

Fig. 2.14 Histogram of *SAIDI*, Feeder 4

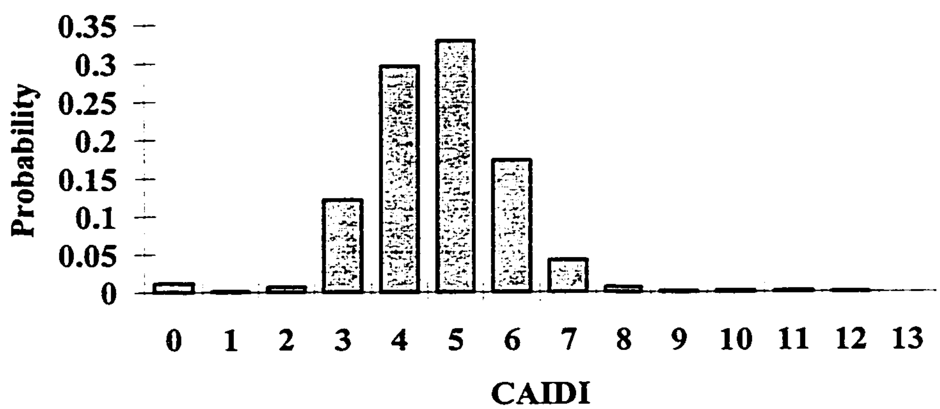

Fig. 2.15 Histogram of *CAIDI*, Feeder 4

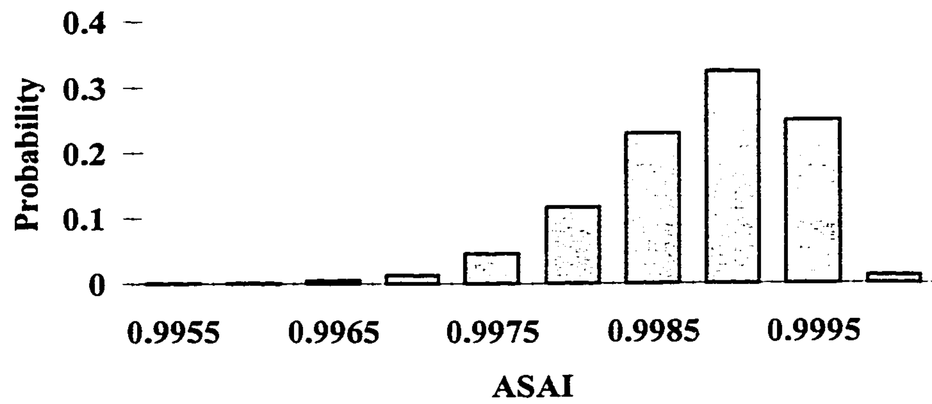

Fig. 2.16 Histogram of *ASAI*, Feeder 4

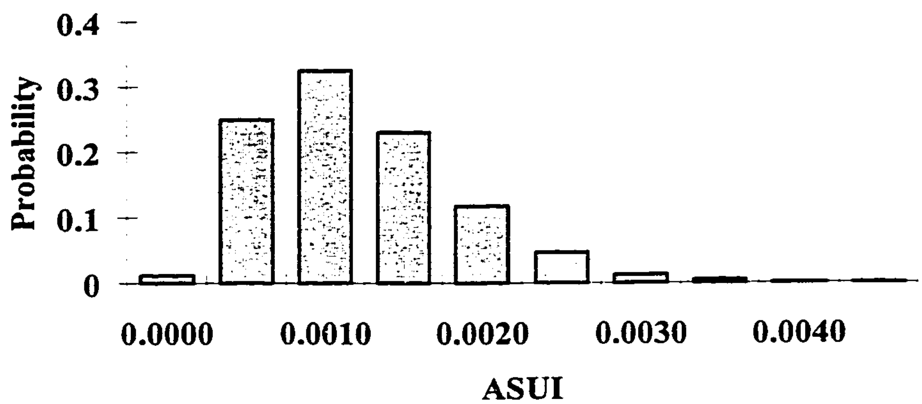

Fig. 2.17 Histogram of *ASUI*, Feeder 4

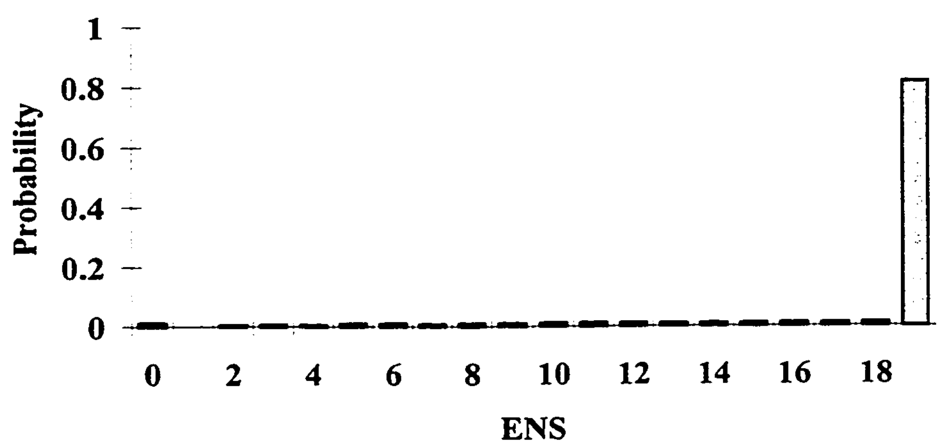

Fig. 2.18 Histogram of *ENS*, Feeder 4

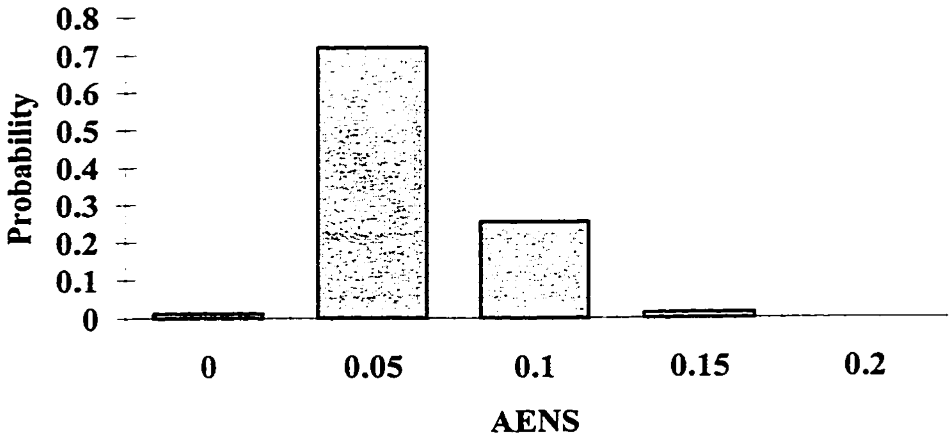

Fig. 2.19 Histogram of *AENS*, Feeder 4

The probability distribution of SAIFI is a combination of the failure frequency distribution weighted by the percentage of customers connected to the corresponding load points. The distribution shows the variability in the average annual customer interruption frequency. The distribution of SAIDI is the summation of the unavailability distribution weighted by the percentage of customers connected to corresponding load points. The distribution shows the probabilities of different average annual customer failure durations. The CAIDI distribution shows the probability of different failure durations for each customer interruption in each year. The probability distribution of ASUI mainly depends on the distribution of SAIDI and provides the probability of different percentages of unavailable customer hours in each simulation year. The distribution of ENS is a summation of the load point unavailability distributions weighted by the corresponding load level and shows the probability of different total energies not supplied in each year. The distribution of AENS is the distribution of ENS per customer. These indices provide a complete picture based on the number of customers, the energy level, duration hours and the number of interruptions.

2.5. Conclusion

This chapter illustrates a reliability network equivalent technique for complex radial distribution system reliability evaluation. A general feeder is defined and a set of basic equations is developed based on a general feeder concept. A complex radial distribution system is reduced to a series of general feeders using reliability network equivalents. Basic equations are used to calculate the individual load point indices. The reliability network equivalent method provides a simplified approach to the reliability evaluation of complex distribution systems. Reliability evaluations for several practical test distribution systems have shown this technique to be superior to the conventional FMEA approach. This method avoids the required procedure of finding the failure modes and their effect on the individual load points and results in a significant reduction in computer solution time.

A time sequential simulation technique is also introduced in this chapter. A time sequential simulation procedure is presented and a computer program has been developed using the simulation approach. In the simulation technique, the direct search technique is used and overlapping time is considered. A practical test distribution system was evaluated using this technique. In comparing the analytical technique with the time sequential technique, the analytical approach evaluates the reliability indices by a set of mathematical equations and therefore the analysis procedure is simple and requires a relatively small amount of computer time. The simulation technique evaluates the reliability indices by a series of trials and therefore the procedure is more complicated and requires a longer computer time. The simulation approach can provide information on the load point and system indices that the analytical techniques can not provide. It may be practical therefore to use the analytical technique for basic system evaluation and to use the simulation technique when additional information is required.

3. Distribution System Reliability Cost/Worth Analysis Using Analytical and Sequential Simulation Techniques

3.1. Introduction

The basic function of a modern electric power system is to provide electric power to its customers at the lowest possible cost and with an acceptable level of reliability. The two aspects of economics and reliability often conflict and present power system managers, planners and operators with a wide range of challenging problems. The price that a customer is willing to pay for higher reliability is directly related to the interruption costs created by power failures. If the price that a customer pays for increased reliability is less than the decrease in interruption costs, the customer could be expected to react favorable to the increased charge. Some customers therefore may be willing to pay more to receive higher reliability and others may be willing to pay less for lower reliability. Utilities may be willing to provide higher reliability of power supply at no increase in customer cost because of competition. Decision-making depends on many aspects such as social, economic, environmental and government considerations etc. and is a difficult task. System reliability cost/worth analysis provides the opportunity to incorporate cost analysis and quantitative reliability assessment into a common structured framework, which can assist the decision making process.

Considerable research has been done on reliability cost/worth assessment of generation and transmission systems. Both analytical and Monte Carlo simulation methods are used in these areas [6,15,16,64-66]. Relatively little work has been done in the area of distribution systems. An analytical technique using the contingency enumeration approach is presented and used to evaluate customer interruption cost indices of a radial distribution system in Reference [36]. An approximate simulation technique is also used in [36] to evaluate a small distribution system.

The technique [36] used to evaluate customer interruption costs requires considerable analysis when it is applied to a complex distribution system (a distribution system with branches). The simulation technique used in [36] was applied to a small system, which includes simple switch, fuse and alternate supply models and simple configurations.

A major objective of this research work was to develop both analytical and time sequential simulation techniques for distribution system reliability cost/worth analysis. A generalized analytical technique and a time sequential Monte Carlo simulation technique to evaluate the reliability cost/worth indices of a complex distribution system are illustrated in this chapter. Two distribution systems in the RBTS [62,63] have been evaluated using the developed techniques. Different switch, fuse, breaker, alternate supply models are included in the analysis. The results obtained using the analytical technique are compared with those obtained using the Monte Carlo simulation approach.

3.2. Measurement of Reliability Worth

The price customers are willing to pay for the benefit they associate with any product or service is referred to as its perceived value [67]. The concept of perceived value has been used in many competitive industries with regard to the development of product features, pricing, packaging and promotion strategies. This perceived value concept originally had little place in electric power utility planning. The main reason behind this is that the electric power industry had total market dominance at that time and did not find itself in competition similar to that faced by most other service industries. In recent years, privatization and deregulation of electric power industries have gradually placed power utilities in a competitive market. This new trend of power industry reform has begun to force utilities to utilize the perceived value concept in their planning, designing, operation and expansion decision makings. The perceived value of service is usually referred to in the electric power industry as the benefit accruing or cost decrease to customers by receiving a given level of service reliability and is simply termed as the reliability worth.

Under this new situation of power system deregulation and open markets, power system planners must ask the question "Is it worth it?" before making any reinforcement and expansion decisions. Direct measurement of reliability worth due to system reinforcement is difficult. One surrogate way to measure the reliability worth is to evaluate the annual investment and maintenance cost for system reinforcement and the annual customer interruption costs caused by power failures before and after the reinforcement. In conventional supply-side planning, the reliability worth of system reinforcement is mainly decided based on the experience and judgement of the system planner. Relatively little weight is placed on the concerns of customers. Supply-side planning can result in higher reliability and over investment which exceeds the customer demands or lower reliability and under investment which may not meet customer requirements. The premise that the customer is in the best position to assess his/her monetary losses associated with a power failure places increased emphasis on customer perspectives. This has resulted in supply/demand-side system planning in which the reliability worth of the reinforcement is judged from both utility and customer concerns.

3.3. Customer Interruption Cost Evaluation

In order to measure reliability worth of system reinforcement, it is necessary to first evaluate the investment and maintenance costs and secondly, the customer interruption costs. It is relatively easy to evaluate the investment and maintenance costs. It is, however, difficult to evaluate the customer interruption costs. Customer interruption costs can be divided into direct costs resulting directly from cessation of supply and indirect costs resulting from a response to an interruption. Direct costs include such impacts as lost production, idle but paid for resources (raw materials, labor and capital), process restart costs, spoilage raw materials and equipment damage, direct costs associated with human health and safety, and utility costs associated with the interruption. Examples of indirect costs are civil disobedience and looting during an extended blackout, or failure of an industrial safety device in an industrial plant, necessitating neighboring residential evacuation [1,68].

There are various approaches which can be used to evaluate interruption costs [69,70]. These approaches can be grouped into three broad categories: various indirect analytical evaluations, case studies of blackouts, and customer surveys [1]. While a single approach has not been universally adopted, utilities appear to favor customer surveys as the means to determine specific information for their purposes [71].

Indirect analytical methods infer interruption costs from associated indices. Two simple examples of these approaches are described in [69,72]. The value of lost production is determined by taking the ratio of the annual gross national product to the total electrical consumption and ascribing to it the value of service reliability in $/kWh [69]. A similar value-added approach has been used to evolve an analytical model which, with appropriate adjustments, is applicable to different customer categories [72]. The disadvantages of indirect analytical approaches are that most, though very simple and easy to use, are based on numerous and severely limiting assumptions. Most generate global rather than specific results and consequently do not reveal variations in cost with specific parameters, as required by the utilities.

Case study methods can be used to evaluate the losses of a particular outage. This approach has been limited to major, large-scale power interruptions such as the 1967 New

York blackout [73]. The study evaluated a wide range of direct and indirect economic and social impacts. The results indicate that the indirect costs were much higher than the direct costs.

The customer survey methods [9,10,70,74-76] are developed based on the assumption that the customer is in the best position to evaluate the losses due to the unavailability of electricity. These approaches are considered to be the most practical method of obtaining outage cost information. In this method, customers are asked to estimate their costs or losses due to supply outages of varying durations and frequency at different times of the day and year. These methods can readily be tailored to seek particular information related to the specific needs of the utility. The customers can be easily divided into different categories, such as residential, industrial, commercial, agricultural, etc., so that category-specific survey instruments can be used. This appears to be the method favored by most utility planners.

A Standard Industrial Classification (SIC) can be used to divide customers into large user, industrial, commercial, agriculture, residential, government&institutions and office categories. Postal surveys have been conducted by the University of Saskatchewan to estimate the customer interruption losses for seven different customer sectors [5,51]. The surveys show that the cost of an interruption depends on the type of customer interrupted, and the magnitude and the duration of the interruption. The interruption data obtained provide efficient data for reliability cost/worth analysis of distribution systems.

3.4. Distribution System Reliability Cost/Worth Indices

Compared with generation and transmission systems, most distribution systems are single input or double input and multiple output (load points) systems. Two groups of load point and system indices are usually used to describe the adequacy of the system [1].

Load point reliability cost/worth indices include:

Load point Expected Energy Not Supplied (EENS) (MWh/yr),

Load point Expected Interruption Cost (ECOST) (k$/yr),

Load point Interrupted Energy Assessment Rate (IEAR) ($/kWh)

System and feeder reliability cost/worth indices indlude:

System or feeder Expected Energy Not Supplied (EENS) (MWh/yr),

System or feeder Expected Interruption Cost (ECOST) (k$/yr),

System or feeder Interrupted Energy Assessment Rate (IEAR) ($/kWh)

The equations used to calculate these indices are given in the following sections.

3.5. Models Used in the Analysis

A number of different models are required in order to evaluate customer interruption cost indices. These include the equipment operating models for lines, breakers, fuses, disconnect switches and alternate supplies, the load models and the customer sector interruption cost models.

3.5.1. Element Operating Models and the Load Model

The models used for the transmission and protection elements are the models described in Section 2.4.1. The average load at each load point is used as the load model in this chapter. Time varying load models are illustrated in the following chapters.

3.5.2. Customer Interruption Cost Models

Customer interruption costs can be easily represented by customer damage functions (CDF). The CDF for a specific customer sector is called a sector customer damage function (SCDF). The survey data have been analyzed to give the SCDF for each of the seven customer sectors used in this chapter. The data for different customer sectors and different failure durations are shown in Table 3.1

Table 3.1 Sector Interruption Cost ($/kW)

User Sector	Interruption Duration (Min.) & Cost ($/kW)				
	1 min.	20 min.	60 min.	240 min.	480 min.
Larger user	1.005	1.508	2.225	3.968	8.240
Industrial	1.625	3.868	9.085	25.16	55.81
Commercial	0.381	2.969	8.552	31.32	83.01
Agricultural	0.060	0.343	0.649	2.064	4.120
Residential	0.001	0.093	0.482	4.914	15.69
Govt.&Inst.	0.044	0.369	1.492	6.558	26.04
Office	4.778	9.878	21.06	68.83	119.2

Table 3.1 gives the interruption costs for five discrete outage durations. A log-log interpretation of the cost data is used where the interruption duration lies between two separate times. In the case of durations greater than 8 hours, a linear extrapolation with the same slope as that between 4 and 8 hour values was used to calculate the interruption cost.

3.6. A Generalized Analytical Approach

The basic procedure used in the generalized analytical method to evaluate the customer interruption cost indices can be summarized in the following steps:

Step 1: Find the average failure rate λ_j, the average repair time r_j and the average switching time s_j for a failed element j.

Step 2: Find the affected load points caused by the failed element j using a direct search technique according to the network configuration and protection scheme. The failure rate λ_{ij} and the failure duration r_{ij} for an affected load point i can be calculated using Equations (3.1) and (3.2).

$$\lambda_{ij} = \lambda_j \prod_{k=1}^{Npr}(1-p_k) \tag{3.1}$$

where p_k is the probability that fuse (or breaker) k operates successfully. N_{pr} is the total number of breakers and fuses between the load point i and the failed element j.

$$r_{ij} = p_a s_j + (1-p_a)r_j \tag{3.2}$$

where p_a is the probability of being able to restore supply using switching action for the load point that is affected by the failed element j. p_a is zero for load points that cannot be isolated by disconnect switches from the failed element j.

Step 3: Determine the per unit (kW) interruption cost c_{ij} using the corresponding sector customer damage function (SCDF) according to the outage time r_{ij} and the customer type at load point i,.

$$c_{ij} = f(r_{ij}) \tag{3.3}$$

where $f(r_{ij})$ is the SCDF.

Step 4: Evaluate the expected energy not supplied $EENS_{ij}$ and expected interruption cost $ECOST_{ij}$ of the load point i caused by failure of element j.

$$EENS_{ij} = L_i r_{ij} \lambda_{ij} \tag{3.4}$$

$$ECOST_{ij} = c_{ij} L_i \lambda_{ij} \tag{3.5}$$

where L_i is the average load of load point i.

Step 5: Repeat 1-4 for all elements in order to calculate the total load point $EENS_i$, $ECOST_i$ and $IEAR_i$ for load point i using the following equations:

$$EENS_i = \sum_{j=1}^{N_e} L_i r_{ij} \lambda_{ij} = L_i \sum_{j=1}^{N_e} r_{ij} \lambda_{ij} \tag{3.6}$$

$$ECOST_i = \sum_{j=1}^{N_e} c_{ij} L_i \lambda_{ij} = L_i \sum_{j=1}^{N_e} c_{ij} \lambda_{ij} \tag{3.7}$$

$$IEAR_i = \frac{ECOST_i}{EENS_i} = \frac{\sum_{j=1}^{N_e} c_{ij}\lambda_{ij}}{\sum_{j=1}^{N_e} r_{ij}\lambda_{ij}} \tag{3.8}$$

where N_e the is total number of elements in the distribution system.

Step 6: Repeat 5 until the $EENS_i$, $ECOST_i$ and $IEAR_i$ of all the load points are evaluated.

Step 7: Evaluate the total system $EENS, ECOST$ and $IEAR$ using the following equations:

$$EENS = \sum_{i=1}^{N_p} EENS_i = \sum_{i=1}^{N_p} L_i \sum_{j=1}^{N_e} r_{ij}\lambda_{ij} \tag{3.9}$$

$$ECOST = \sum_{i=1}^{N_p} ECOST_i = \sum_{i=1}^{N_p} L_i \sum_{j=1}^{N_e} c_{ij}\lambda_{ij} \tag{3.10}$$

$$IEAR = \frac{ECOST}{EENS} \tag{3.11}$$

where N_p is the total number of load points in the system.

It can be seen from Equation 3.8 that the interrupted energy assessment rate of a load point is independent of the average load.

3.7. Time Sequential Simulation Approach

The process used to assess the customer interruption cost of a distribution system using the time sequential simulation technique consists of the following steps. This process also recognizes the overlap that can occur in the different equipment failure/repair cycles.

Step 1: Generate a random number for each element in the system and convert these random numbers into time to failure (TTF) values using the appropriate element failure probability distributions.

Step 2: Comparing the TTF of all elements, find the failure event j that has the minimum TTF and location of the element that caused the event j.

Step 3: Generate two random numbers for the element with minimum TTF and convert them into times to repair (TTR) and times to switch (TTS) using the appropriate probability distributions for the element repair and switching times.

Step 4: Find the load points that are affected by failed event j

Step 5: Determine the failure duration r_{ij} for the load point i in the system configuration.

$$r_{ij} = ks_j + (1-k)r_j \tag{3.12}$$

where k is a control constant depending on the probability p_a of load being transferred to an alternate supply. A random number is generated and is converted into a uniformly distributed random value. If the random value is less than p_a, $k=0$, otherwise, $k=1$.

Step 6: If the restoration time caused by the new failure event is overlapped by the old restoration time caused by the old failure event, the overlapping time is deducted from the new restoration time.

Step 7: Evaluate the per unit interruption cost c_{ij} of load point i using r_{ij} and the load point customer damage function $f(r_{ij})$.

$$c_{ij} = f(r_{ij}) \tag{3.13}$$

Step 8: Evaluate the energy not supplied ENS_{ij} and the interruption cost $COST_{ij}$ of the load point i due to the failure event j.

$$ENS_{ij} = L_i r_{ij} \tag{3.14}$$

$$COST_{ij} = c_{ij} L_i \tag{3.15}$$

Step 9: Add the ENS_{ij} and $COST_{ij}$ to their total values respectively.

Step 10: Repeat Step 5-9 for all load points.

Step 11: If the total simulation time is less than the specified simulation time, go to Step 12, otherwise, go to Step 13.

Step 12: Generate a new random number for the repaired element and convert it into the new TTF and go to Step 2.

Step 13: The total energy not supplied ENS_i and the interruption cost $COST_i$ of the load point i for the total simulation years are:

$$ENS_i = \sum_{j=1}^{N_s} L_i r_{ij} = L_i \sum_{j=1}^{N_s} r_{ij} \qquad (3.16)$$

$$COST_i = \sum_{j=1}^{N_s} c_{ij} L_i = L_i \sum_{j=1}^{N_s} c_{ij} \qquad (3.17)$$

where N_s is the total number of failure events in the specified simulation period. The expected energy not supplied $EENS_i$, the expected interruption cost $ECOST_i$ and $IEAR_i$ can be calculated using the following equations:

$$EENS_i = \frac{ENS_i}{TST}, \qquad (3.18)$$

$$ECOST_i = \frac{COST_i}{TST}, \qquad (3.19)$$

$$IEAR_i = \frac{ECOST_i}{EENS_i} = \frac{COST_i}{ENS_i} = \frac{\sum_{j=1}^{N_s} c_{ij}}{\sum_{j=1}^{N_s} r_{ij}}, \qquad (3.20)$$

where TST is the total specified simulation period in years.

The system $EENS$, $ECOST$ and $IEAR$ can be calculated using equations similar to Equations (3.9), (3.10) and (3.11).

3.8. System Analysis

Two computer programs designated as DISRE1 and DISRE2 which use the generalized analytical technique and the time sequential simulation approach respectively have been developed. These programs can be used to assess a range of distribution systems. The set of reliability indices provided by the two programs include:

the three basic load point indices,

the probability distributions of the three basic load point indices,

the load point cost/worth indices (EENS, ECOST, IEAR),

the probability distributions of the cost/worth indices,

the basic system indices (SAIFI, SAIDI,...),

the probability distributions of the basic system indices,

the system cost/worth indices,

and the probability distributions of the system cost/worth indices.

These indices can be used to evaluate the reliability of an existing distribution system and to provide useful planning information regarding improvement to existing systems and the design of new distribution systems. This chapter is focused on the development and utilization of the cost/worth indices for individual load points and for the system. The following illustrates applications to two distribution systems shown in Fig. 3.1 and Fig. 2.5. The restoration time of the element is assumed to be lognormally distributed with a standard deviation of half the average value.

3.8.1. Application to a Typical Urban Distribution System

The system in Fig. 3.1 is a typical urban distribution system connected to Bus 2 of the RBTS [62,63]. The distribution system contains 4 feeders, 14 main sections, 22 lateral sections and 22 load points. There are four types of customers: residential, commercial, small industrial and government/institutional. The data used in these studies is given in [62,63]. Transformer repair times are used in the evaluation. The techniques described earlier were used to evaluate the reliability of this system.

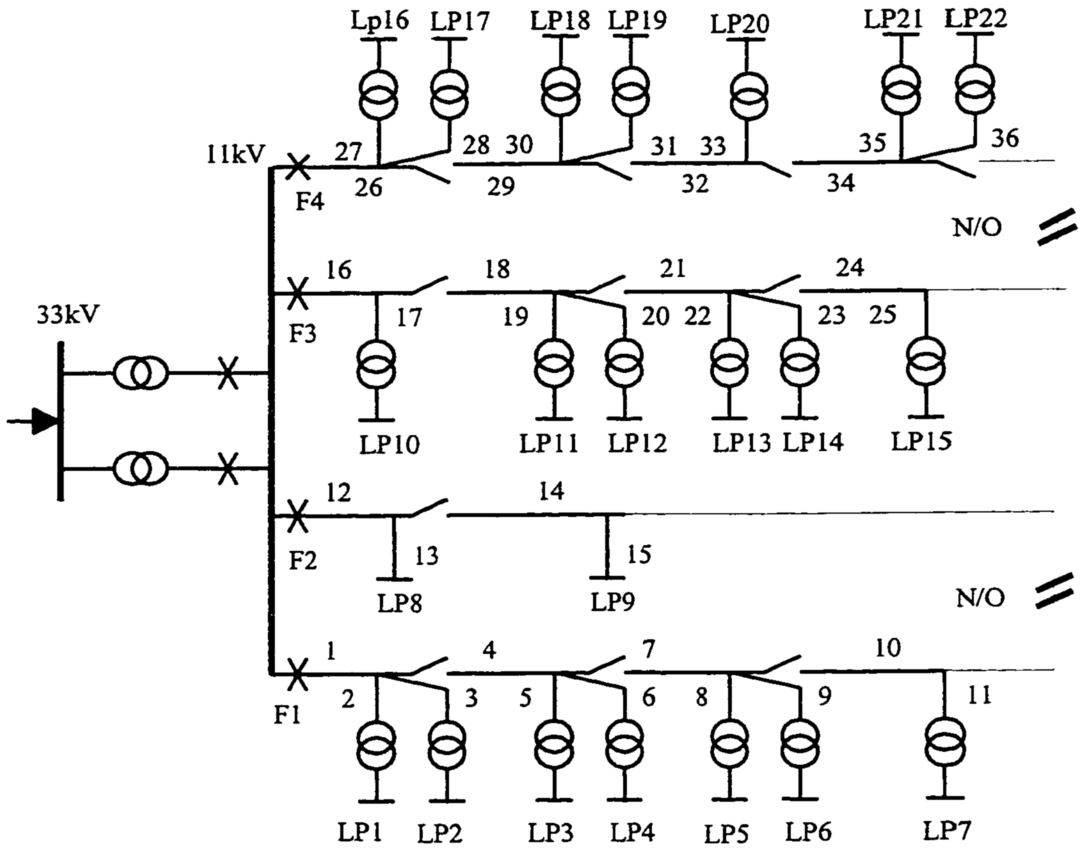

Fig. 3.1 A typical urban distribution system

The Convergence of the Simulation Algorithm

The convergence of the simulation algorithm can be illustrated by the convergence curves of the indices. Fig. 3.2 and Fig. 3.3 show the convergence of the load point and feeder indices. The analytical (A) and simulation (S) results are shown in these figures.

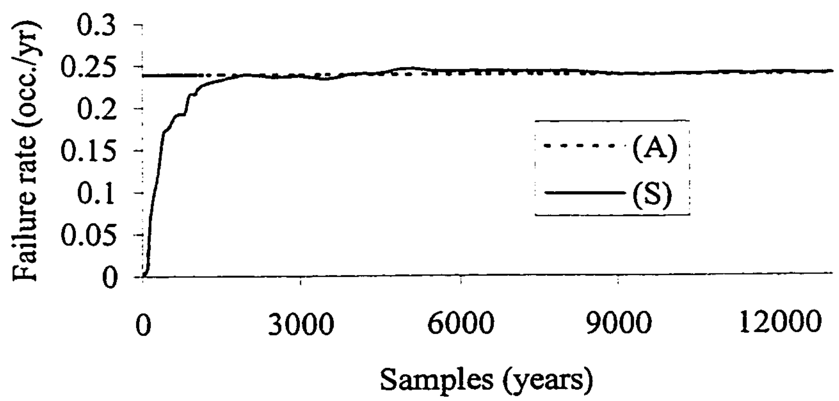

Fig. 3.2 Convergence of the load point 1 failure rate

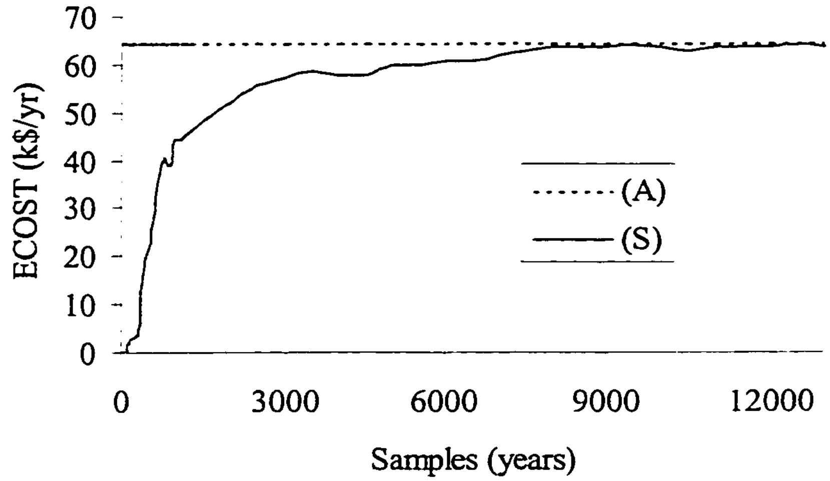

Fig. 3.3 Convergence of ECOST for Feeder 1

It can be seen from these figures that both indices convergence reasonable quickly.

Cost Indices Using the Three Different Approaches

The EENS, ECOST and IEAR indices for all the load points, the feeders and the system using the generalized analytical method and the time sequential simulation technique with and without considering overlapping time have been evaluated. The load point ECOST obtained using the three different approaches are shown in Table 3.2. In Table 3.2, (A), (SO) and (SN) represent the analytical method and the simulation approach with and without considering overlapping time respectively. It can be seen from Table 3.2 that the results obtained using the three different technique are very close and that overlapping time has little effect on the cost indices for this system. The simulation was performed for a period of 13000 years.

Table 3.2 Interruption costs of load points

Load (i)	ECOST (k$/yr) (A)	ECOST(k$/yr) (SO)	ECOST (k$/yr) (SN)
1	4.209	4.198	4.198
2	4.254	4.157	4.157
3	4.254	4.301	4.301
4	7.999	8.560	8.560
5	8.057	8.731	8.732
6	17.917	16.182	16.258
7	17.837	17.689	17.689
8	4.926	4.818	4.818
9	5.309	5.404	5.404
10	4.210	4.546	4.546
11	4.254	4.071	4.072
12	3.588	3.674	3.674
13	8.009	8.570	8.570
14	8.024	7.481	7.481
15	17.757	16.971	16.972
16	17.974	18.949	18.949
17	3.551	3.798	3.810
18	3.54180	3.249	3.250
19	3.579	3.466	3.467
20	8.059	8.687	8.688
21	8.009	8.014	8.014
22	17.848	17.234	17.235

Table 3.3 and Table 3.4 show the system cost/worth indices obtained using the analytical and simulation techniques respectively. The difference in the ECOST between the analytical value and the simulation value is 0.2% based on the analytical result. The relative difference in EENS and IEAR is 0.4% and 0.6% respectively. This clearly indicates that the analytical technique can provide accurate average load point and system indices.

Table 3.3 System cost indices using the analytical approach

FEEDER	EENS(MWh/yr)	ECOST(k$/yr)	IEAR($/kWh)
1	11.978	64.525	5.387
2	1.522	10.235	6.724
3	10.203	45.841	4.493
4	11.141	62.561	5.615
Total	34.844	183.163	5.257

Table 3.4 System cost indices using the simulation method

FEEDER	EENS	ECOST	IEAR
1	12.049	63.890	5.302
2	1.513	10.222	6.756
3	10.216	45.309	4.435
4	11.227	63.407	5.648
Total	35.005	182.828	5.223

The Probability Distribution of the Indices

The probability distributions of the load point, feeder and system indices can be obtained using the time sequential simulation technique. Fig. 3.4 shows the probability distributions of the interruption cost and the energy not supplied for Feeder 1. It can be seen from the figure that the energy not supplied is between 2 and 3 kWh for over 30 percent of the failures and interruption costs are larger than $9,000 for over 60 percent of the failures.

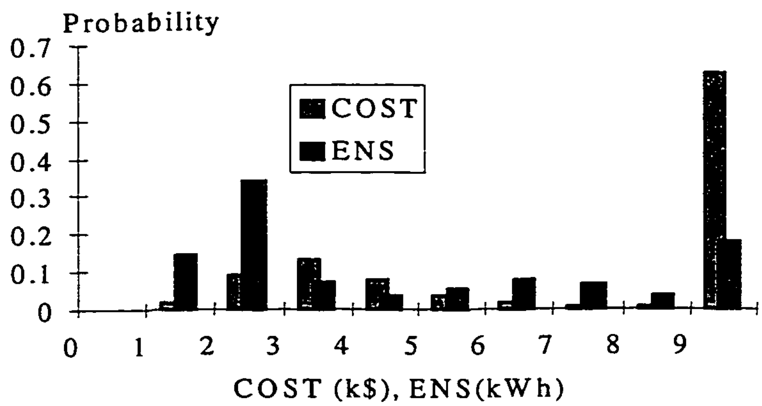

Fig. 3.4 Probability distributions of COST and ENS for Feeder 1

Fig. 3.5 shows the probability distributions for load point failure duration, interruption cost and energy not supplied for load point 1. The failure durations peak between 0 and 1 hour.

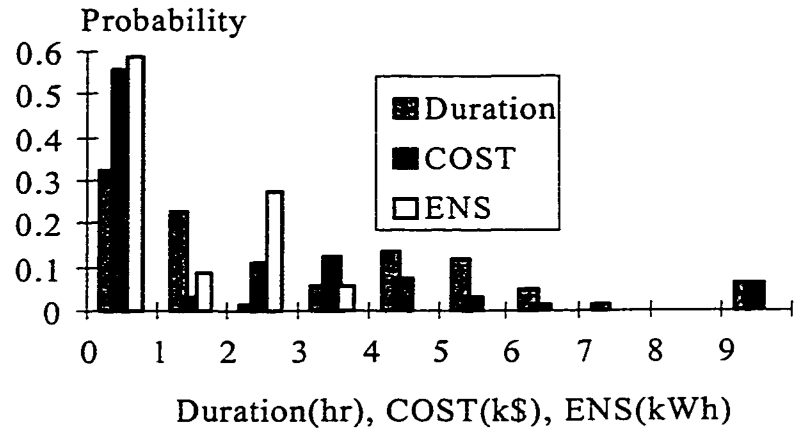

Fig. 3.5 Probability distributions of COST and ENS for load point 1

3.8.2. Application to the Bus 6 Distribution System

Reliability cost/worth indices obtained using either of the two described techniques can assist a system planner to modify and improve an existing system. The time sequential simulation technique is used in the following application to illustrate the effect on the system interruption cost of different elements and parameters and provide input to the decision making process. Fig. 2.5 is a mixed urban/rural distribution system with residential, commercial small industrial and farm customers. Transformer replacement is used in this analysis rather than transformer repair used in the previous system. The four different cases investigated are as follows. Case 1 is the base case in which all breakers are assumed to be 100% reliable. The probabilities of the breakers in the three branches of Feeder 4 operating successfully are assumed to be 0.8 in Case 2. Based on Case 1, alternate supplies are installed in Feeders 3 and 4 in Case 3. Based on Case 3, one additional switch is installed in line section 40 in Case 4.

Load Point and System Cost Indices for the Basic System

The basic structure of the Bus 6 distribution system is shown in Fig.2.5. The system was evaluated using the analytical and simulation techniques. Fig. 3.6 shows the load point EENS indices using the two techniques respectively. Fig. 3.7 shows the load point ECOST indices. The load point IEAR is shown in Fig. 3.8 . The cost indices for some load points using the simulation technique are little bigger than those obtained using the analytical approach. The opposite conclusion is reached for other load points. It can be seen from the figures that the differences in the load point EENS, ECOST and IEAR using the two methods are very small.

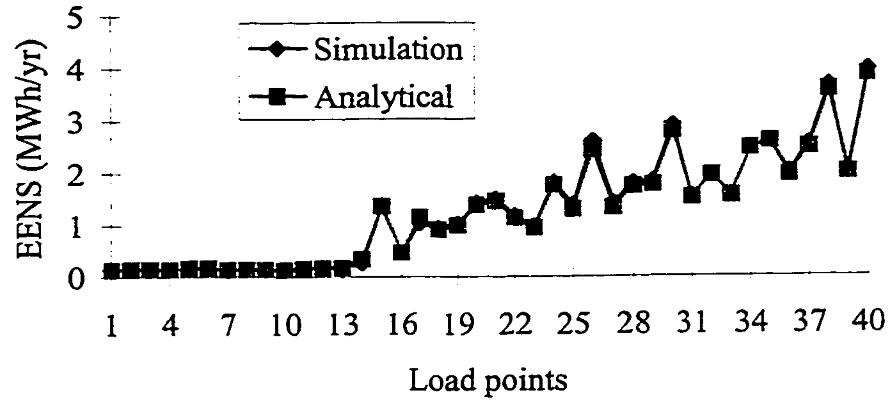

Fig. 3.6 Load point EENS using the two techniques

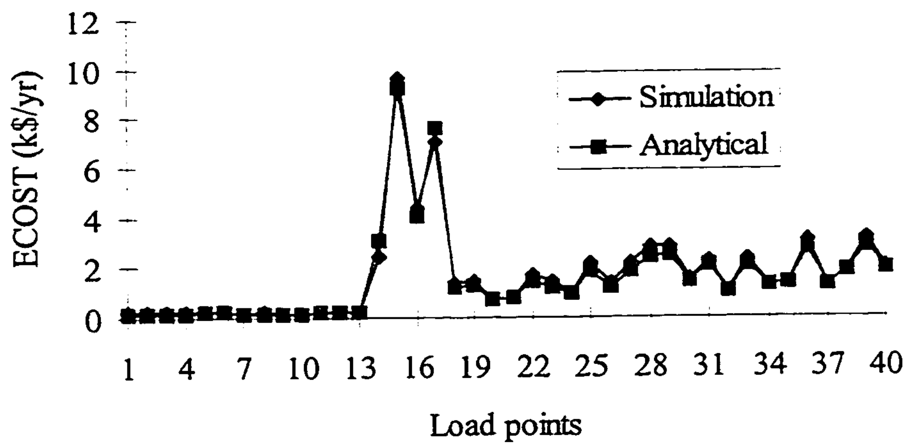

Fig. 3.7 Load point COST using the two techniques

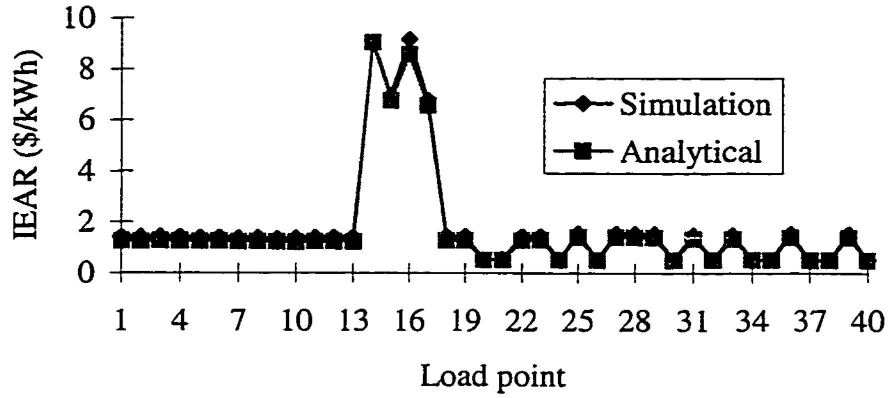

Fig. 3.8 Load point IEAR using the two techniques

The system indices are shown in Fig. 3.9 and Fig. 3.10 . It can be seen from the two figures that the results using the two techniques show very little difference.

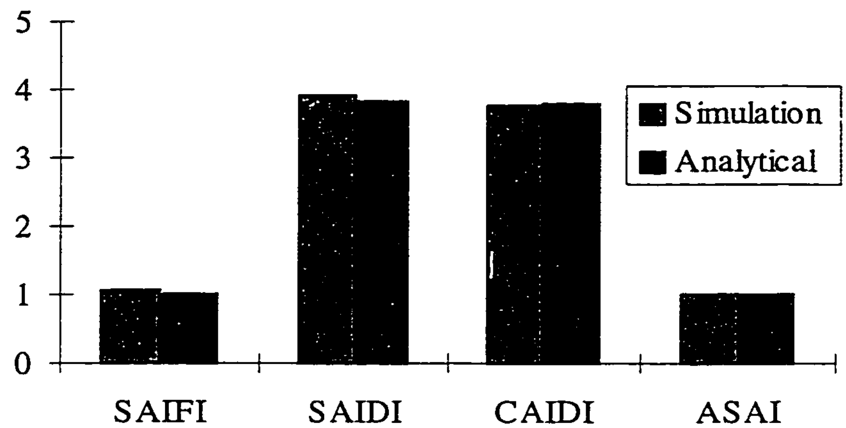

Fig. 3.9 System indices using the two techniques

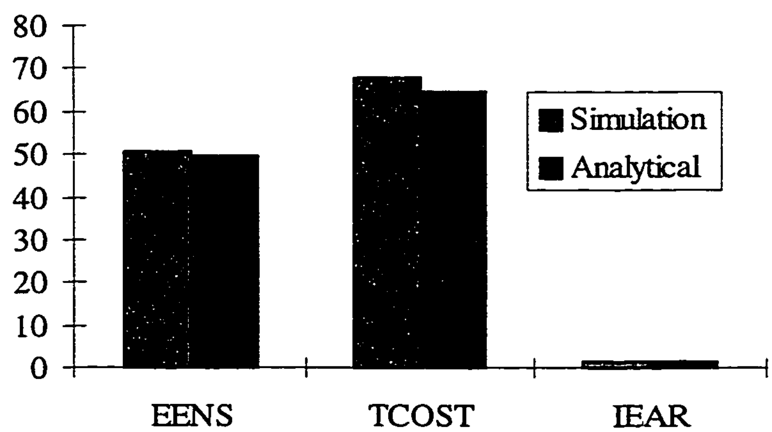

Fig. 3.10 System indices using the two techniques

Effect of Overlapping Time

The cost indices using the simulation technique with and without considering overlapping time were evaluated. Fig. 3.11 -Fig. 3.13 show the results.

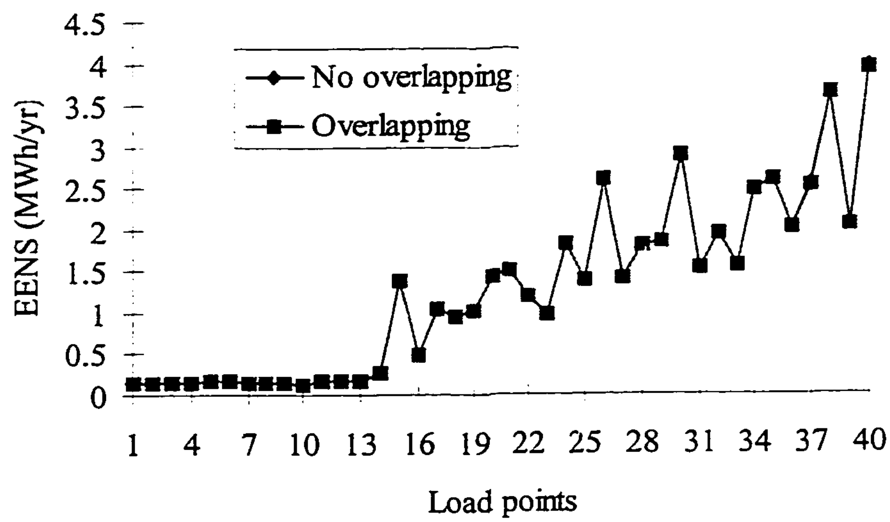

Fig. 3.11 EENS with and without considering overlapping time

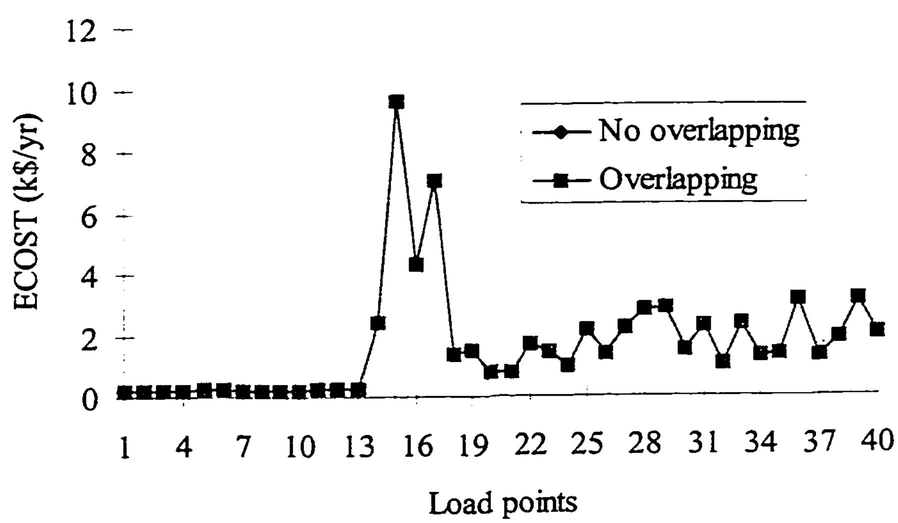

Fig. 3.12 EENS with and without considering overlapping time

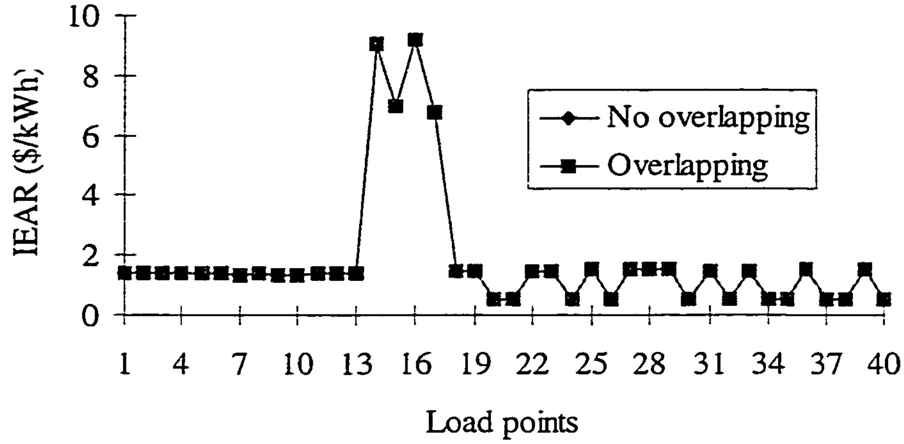

Fig. 3.13 EENS with and without considering overlapping time

It can be seen from the figures that overlapping time does not affect the cost indices in this particular distribution system.

Breaker Reliability Effects

The reliability of the breakers installed in a distribution system affects the load point interruption costs. Fig. 3.14 shows the load point interruption costs for Cases 1 and 2. It can be seen from Fig. 3.14 that breaker reliability has a large effect on the load point interruption costs. When the breaker reliability decreases from 1 to 0.8, the interruption cost of Feeder 4 increases by 13.2% from 40,686$ to 46,065 $/yr and the total system cost increases by 8% from 66,968 $/yr to 72,347 $/yr.

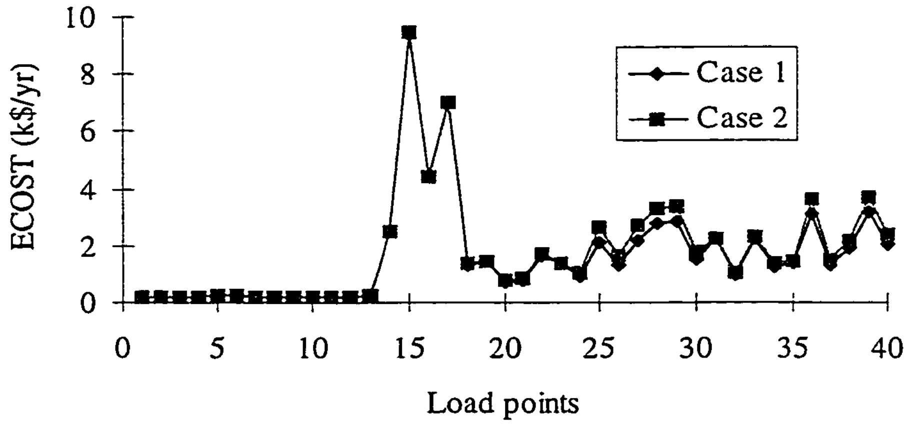

Fig. 3.14 Load point ECOST values for Case 1 and Case 2

Alternate Supply Effects

There is no alternate supply to Feeders 3 and 4 in the basic structure shown in Fig. 2.5. In order to investigate the effect of alternate supply on the customer interruption costs, two alternate supplies were installed in these two feeders. Fig. 3.15 shows the variations in load point interruption costs compared to the base case. It can be seen that alternate supply has a significant effect on the customer interruption costs. The customer interruption costs of Feeders 3 and 4 decrease by 8,314 \$/yr and 7,212 \$/yr respectively. The total system customer interruption costs decrease by 15,526 \$/yr (23.2%) from 66,968 \$/yr to 51,442 \$/yr. These data can be compared with the investment cost of constructing two alternate supplies and used in the decision making process.

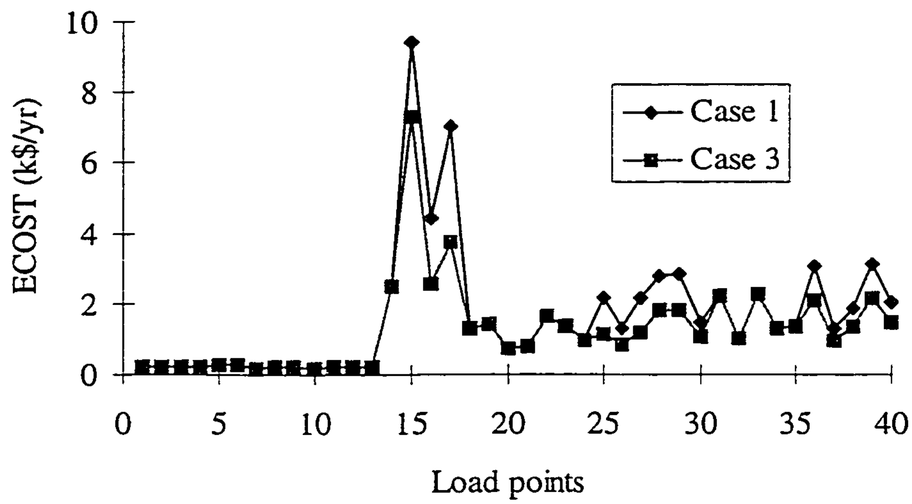

Fig. 3.15 Load point ECOST values for Case 1 and Case 3

Effect of Disconnecting Switches

Switching devices affect the customer interruption durations and therefore affect the customer interruption costs. Fig. 3.16 shows the effect on the load point customer interruption costs of the additional switch in Feeder 4. The customer interruption costs of Feeder 4 decrease by 4,697 \$/yr from 32,372 \$/yr to 27,676 \$/yr. This value is larger than the general annual investment cost of a switching device and therefore the additional switch is justified.

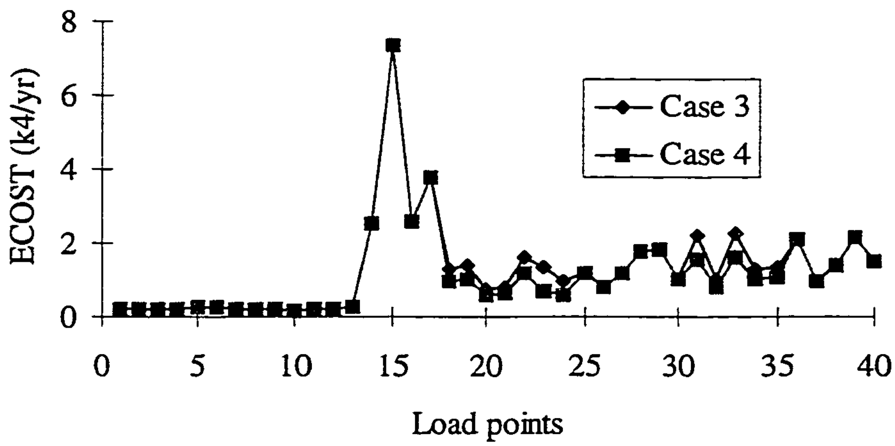

Fig. 3.16 Load point ECOST values for Case 3 and Case 4

The studies conducted show that reliability cost/worth techniques can be useful and efficient tools in distribution system planning and design.

The studies conducted on the system shown in Fig. 2.5 used the time sequential approach. It should be appreciated that similar values could have been obtained using the analytical technique. If specific event parameters and the distributions associated with these parameters are required then the time sequential approach must be used.

3.9. Conclusion

This chapter presents a generalized analytical technique and a time sequential simulation approach to evaluate load point and system customer interruption cost indices of complex radial distribution systems. The two techniques have been used to evaluate the load point and system EENS, ECOST and IEAR of two RBTS distribution systems. Overlapping time was considered in the simulation technique, and the results with and without considering overlapping time are compared. The results show that overlapping time has little influence on the results when the system is small and the element restoration times are short and therefore can be ignored. When the distribution system includes many elements and the element repair times are relatively long, the effect of overlapping time should be considered. This situation does not usually occur in practical application. This chapter also compares the results obtained by the simulation technique with those obtained using the analytical approach. The results show that the two techniques give comparable load point and system average cost estimates. The simulation technique can be used, however, to obtain both the average values of the interruption indices and their distributions. The chapter also briefly illustrates how the two techniques and the cost data can be used in system planning and operation. The studies conducted show that the reliability cost/worth technique can be a useful and efficient tool in distribution system planning and design. It can also be concluded from the analyses conducted that the distributions of element restoration times have an effect on the cost indices, but these effects can generally be ignored when only average cost indices are required.

4. Demand Side Optimal Selection of Switching Devices in Radial Distribution System Planning

4.1. Introduction

The reliability cost/worth analysis techniques described in the previous chapters can be used in optimal system planning and expansion. One of the applications in power system planning is to identify those devices and structures that can be used to create systems which meet customer demands for reliable low cost power and also have reasonable low investment costs [77]. The number and location of sectionalizing switches is an important consideration in distribution system planning and design [78]. The function of disconnect switches is to isolate the faulted parts from the healthy parts in a system, to improve system reliability and to reconfigure the distribution network. The addition of more disconnect switches permits the system to be easily segmented under fault conditions by reducing the area affected by the fault. Additional switches, however, result in higher investment costs which can be quite significant. It is therefore important to select the optimal number of switches and to install them in suitable system locations, which make the system investment and customer interruption costs minimum.

Utility planning methodologies have historically evolved to minimize the investment costs required to meet a specified load at a given level of reliability. The justification is traditionally based on past experience and judgement. This approach can be designated as supply-side planning. Supply-side planning emphasizes the financial viewpoint of the utility company [77, 79]. Considerable research using this approach has been done over the past decade and a variety of techniques have been developed [78, 80-86]. Supply side problems can be summarized by the following equation, with certain voltage, current and capacity constraints:

$$\text{Minimize}\, Cost = \sum_{i=1}^{M} SCost_i + \sum_{i=1}^{M} LCost_i \tag{4.1}$$

where M is the total number of elements in system, $SCost_i$ and $LCost_i$ represent the investment cost (including maintenance and operation cost) and the cost of transmission loss for element i respectively.

Conventional techniques do not normally consider the planning problem from a societal point of view which includes both the utility investment cost and the customer interruption costs caused by power outages. Planning which includes customer interruption cost considerations can be designated as supply/demand-side planning. The concept of investigating the demand side effects relating to the economic worth of reliability has received relatively little attention, mainly because of the difficulties associated with measuring the benefits of improved service. The customer damage functions described in Chapter 3 provide a valuable opportunity to integrate customer costs into distribution system planning. Some research work which considers reliability cost in the distribution system domain are presented in [6,36,87-89]. In the specific area of switching device placement, Reference 87 includes the investment, maintenance and outage costs in the selection of reclosers. A general combinatorial optimization procedure known as simulated annealing is used to optimize switching device placement in radial distribution systems in [88]. The simulated annealing technique has been applied to many difficult combinatorial optimization problems. The simulated annealing technique cannot guarantee to find the global optimal number of switches and locations in general switch selection problems.

This chapter formulates the problem of optimal switching device replacement from the societal cost/benefit point of view and presents two techniques involving direct enumeration and a mixed enumeration/bisection search to solve the problem. The bisection search is incorporated with enumeration to simplify the optimization procedure. The two techniques are illustrated and compared using a sample distribution system. The optimum number of switches and their locations in a practical distribution system are selected in order to minimize the total system cost, using the two techniques.

4.2. Formulation of the Problem

Consider a distribution system with N possible locations where disconnect switches can be installed. The number of switches that can be installed in the system may be 1 or 2, ..., or N. Given a fixed number of switches, there are also many possible location sets. Using 3 switches as an example, the switches can be installed in location (1, 2, 3), (1, 3, 4), (1, 4, 5), ..., (N-2, N-1, N). Let the switch/location set L_k^l represent the kth location set for l switches, and corresponding system reliability and the total customer interruption cost be R_k^l and $ICOST_k^l$ respectively. The total annual system interruption cost can be represented as a function of the set L_k^l:

$$ICOST_k^l = ICOST_k^l(R_k^l(L_k^l)) \qquad (4.2)$$

For l switches, the number of location sets NS_N^l is:

$$NS_N^l = \frac{N!}{l!(N-l)!} \qquad (l=0,1,2,...,N) \qquad (4.3)$$

The total number of switch/location sets NT is:

$$NT = \sum_{l=0}^{N} NS_N^l = 2^N + 1 \qquad (4.4)$$

The total customer interruption cost $ICOST_k^l$ for the set L_k^l can be calculated using the technique for reliability cost/worth analysis described in Chapter 2.

$$ICOST_k^l = (\sum_{i=1}^{N_p} L_i \sum_{j=1}^{N_e} c_{ij} \lambda_{ij})_k^l \qquad (4.5)$$

where L_i is the average load at load point i, λ_{ij} and c_{ij} are respectively the failure rate and the per unit (kW) interruption cost at load point i caused by the failure of element j, N_p is the total number of load points in the system, N_e is the total number of elements in the distribution system. c_{ij} is the nonlinear function of interruption duration r_{ij}.

$$c_{ij} = c_{ij}(r_{ij}) \qquad (4.6)$$

Let $SCOST_k^l$ represent the sum of the investment cost and the cost of element transmission losses for the set L_k^l. The optimum selection problem of the number and location of switches is to minimize the total cost of investment, maintenance, element transmission loss and interruption $TCOST_k^l$ which can be expressed mathematically as:

$$\text{Minimize } TCOST_k^l = SCOST_k^l + ICOST_k^l = SCOST_k^l + (\sum_{i=1}^{N_p} L_i \sum_{j=1}^{N_e} c_{ij}(r_{ij}) \lambda_{ij})_k^l \qquad (4.7)$$

Subject to the following constraints:

$$V_s^{\min} \le V_s \le V_s^{\max}$$

$$I_q^{\min} \le I_q \le I_q^{\max}$$

where V_s is the voltage of the node s, and I_q is the current of section line q.

The total number of switch/location sets is finite when the number of switch locations is fixed, and therefore the optimization problem has finite solutions.

4.3. Development of the Solution Algorithm

The optimization problem described above is a non-linear and non-differential problem with a finite number of solutions. It can be seen from the analysis that the total system cost depends on both the number of switches and their location. In order to solve this problem, the relationship between the total customer interruption cost and the number of switches and their locations is analyzed and corresponding techniques are used to find the optimal switch location set and the optimum number of switches. The techniques developed to solve the problem are illustrated in the following section.

If there is maximum of N possible switch locations where switches can be installed in the system, the number of switches to be installed can be any number between 0 and N. There are many different location sets for a fixed number of switches l $(0<l<N)$. The total customer interruption cost for each location set is different. The analysis shows that the total system cost is a function of the location sets with several local minimum values. Finding the optimum location set with minimum total system cost among the all the location sets is a multiminima optimization problem which is usually very complicated to solve. No single universal algorithm is suitable for solving different multiminima optimization problems. The simulated annealing technique was used in References [88] to solve the switch selection problem. This technique, however, cannot guarantee finding the global optimal location. In order to find the location set with the minimum total system cost from all the location sets, the enumeration technique suggested in [89] for a finite number of feasible solutions has been used. All the possible switch sets are calculated and compared in this technique to avoid using a local optimal location as the global optimal location.

Enumeration Technique

The enumeration technique is used to determine the optimal location set from all the location sets for a given number of switches. In order to apply the enumeration technique to this problem, the switch in location i is represented by a switch variable S_i. S_i=1 if there is a switch at location i and S_i=0 if there is no switch at location i. The switch/location sets can be determined using the states of the switch variables in all the switch locations. Each switch/location set is represented by a binary number which can in turn be represented by the corresponding decimal number. A particular switch/location set, therefore, corresponds to a decimal number. Using a system with 5 switch locations as example, the switch/location set (01010) means that there are two switches at location 2 and 4. The corresponding decimal number is 10. The enumeration procedure for determining the optimal location of fixed number of switches utilizes the following steps:

Step 1: Determine the number of the switch/location sets NS_N^l for the fixed number of switches l.

Step 2: Select a location set according to the order of the decimal number and convert the decimal number into the corresponding binary number which determines the switch state in each switch location.

Step 3: Do a reliability cost/worth analysis and evaluate the total interruption cost $ICOST_k^l$ for the location set L_k^l and compare $ICOST_k^l$ with the current minimum cost $MICOST$.

Step 4: Replace the $MICOST$ with the $ICOST_k^l$ if the $ICOST_k^l$ is less than the $MICOST$.

Step 5: Repeat Steps 2 to 4 until all the location sets are evaluated and compared, and the location set with the minimum total cost is obtained.

Direct and Bisection Search Techniques

For a given number of switches, the optimal switch location set can be determined using the enumeration technique. For a system with N possible switch locations, the number of switches can be anywhere between 0 and N. There is a corresponding optimum location set for each fixed number of switches. A direct search incorporating the enumeration technique (designated as the direct search technique) and a bisection search combined with the enumeration technique (designated as the bisection search approach) were developed to determine the number of switches between 0 and N and their installation locations.

Direct Search Technique

In order to find the global optimal number and the switch locations using the direct search technique, the search procedure starts with one switch. The corresponding optimal location set is then determined using the enumeration technique. Two switches are then selected and the corresponding optimum switch location set is found using the same technique. The total system costs for one switch and two switches are compared. The procedure continues for 3 switches, 4 switches, ... until the optimum number of switches and the corresponding location set are found. The direct search technique requires considerable calculation as the search progresses sequentially from zero switches to the optimum number of switches.

Bisection Search Technique

In order to simplify the search procedure and reduce the calculation time, the relationship between the total system cost corresponding to the optimum location set and the number of switches has been analyzed. Cost variation with the number of switches is shown in Fig. 4.1

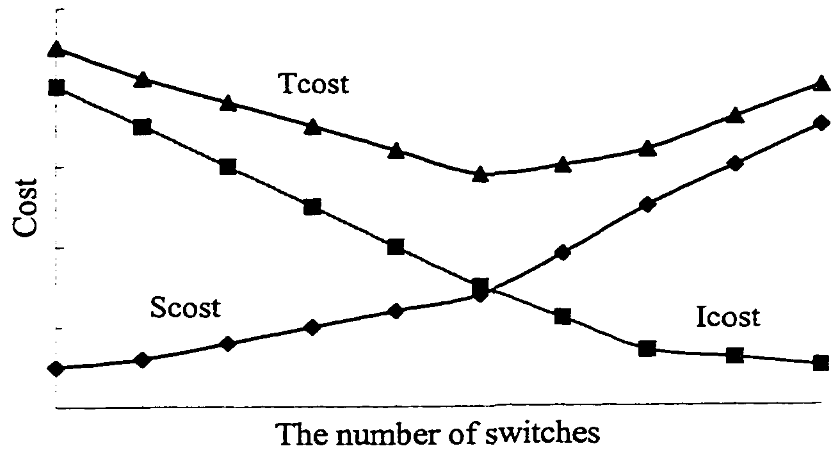

Fig. 4.1 System cost as function of the number of switches

It can be seen from Fig. 4.1 that the minimum customer interruption cost (Icost) corresponding to the optimal switch location decreases nonlinearly and the investment and maintenance cost (Scost) increase when the number of switches increases. The total minimum system cost (Tcost) corresponding to the optimal location set is either a concave or monotonic function of the number of switches. This means that there exists only one global optimal number of switches and a corresponding location set with minimum total system cost.

The bisection search technique is an efficient tool for solving discrete variable optimization problems with a single minimum. Fig. 4.2 shows the bisection algorithm used to find the global optimum number of switches and the corresponding location set. Assume that there is a maximum of M possible switch locations in a system. The selection range of the number of switches [K_{min}, K_{max}] is defined where the low limit K_{min} is the minimum number of switches and the high limit K_{max} is the maximum number of switches.

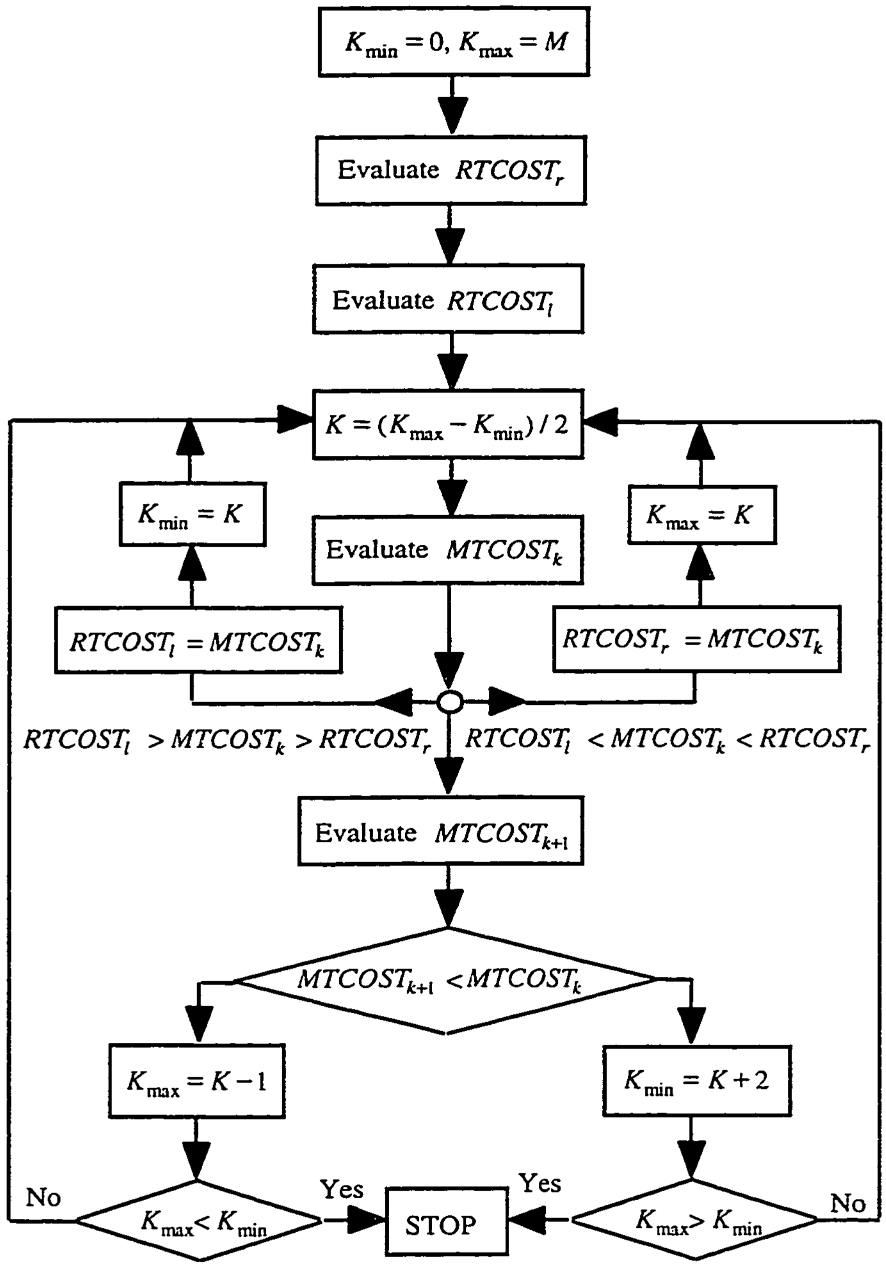

Fig. 4.2 Bisection algorithm

Step 1: The evaluation starts at the point [$K_{min} = 0$, $K_{max} = M$]. The total cost $RTCOST_l$ for $K_{min} = 0$ and the total cost $RTCOST_r$ for $K_{max} = M$ are first calculated using the enumeration technique.

Step 2: $K = (K_{max} - K_{min})/2$ switches are selected and the enumeration technique is used to find the optimal location set with the minimum total cost $MTCOST_k$.

Step 3: If $MTCOST_k$ is larger than $RTCOST_l$ and smaller than $RTCOST_r$, let $K_{\max} = K$ and go to Step 2. If not, go to next step.

Step 4: If $MTCOST_k$ is smaller than $RTCOST_l$ and larger than $RTCOST_r$, let $K_{\min} = K$ and go to Step 2. If not, go to the next step.

Step 5: If $MTCOST_k$ is smaller than both $RTCOST_l$ and $RTCOST_r$ $K+1$ switches is selected and a similar analysis is done to find $MTCOST_{k+1}$. The low limit is replaced by $K_{\min} = K+2$ if the $MTCOST_{k+1}$ is less than the $MTCOST_k$, the high limit is replaced by $K_{\max} = K-1$ if not, then go to Step 2. The procedure is not stopped until the optimal number of switches and the corresponding location set are found.

It can be seen that the partial number of switches and the corresponding location sets (not all of them) are evaluated and compared to find the global optimal switch/location set. This technique will result in a considerable saving in calculation time when the optimum number of switches is large.

An important requirement in Equation 4.7 is to evaluate the customer interruption costs for the different switch configurations. A generalized analytical technique developed in previous chapters is used in this section to evaluate the system interruption cost.

4.4. System Studies

In order to illustrate and compare the two techniques, the optimum number of switches and the location set for the simple radial distribution system shown in Fig. 4.3 and the Bus 6 distribution system shown in Fig. 2.5 were analyzed.

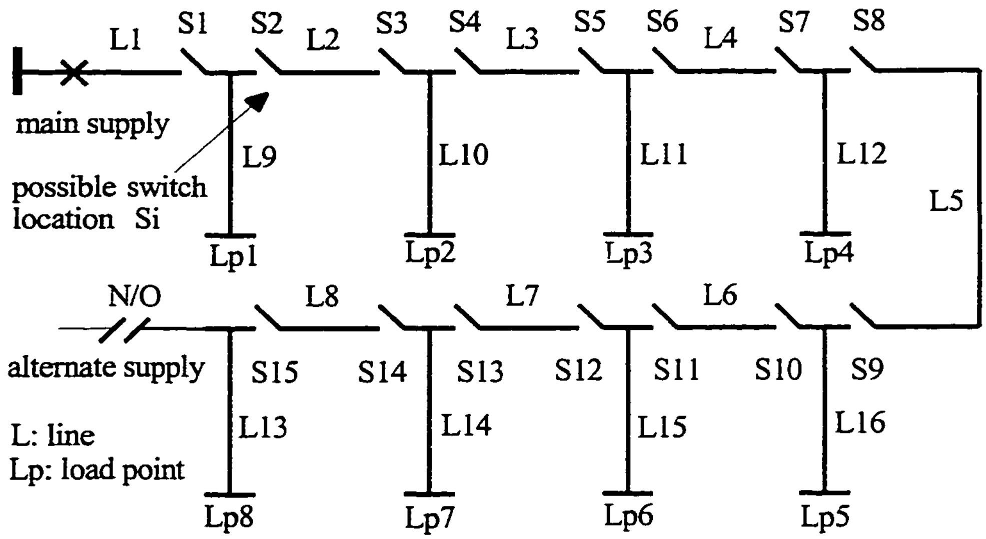

Fig. 4.3 A radial distribution system

The switches used in the simple system are all pad mounted sectionalizing switches, at an assumed cost of \$20,337/switch. The switches used in the complex distribution system are all pole top gang operated, at a cost of \$4,700/switch. The switch cost includes the installation cost. The annual maintenance cost was assumed to be 2% of the annual investment cost and the interest rate 8%. The life of the switch was assumed to be twenty years.

Application to a Simple System

There are 16 transmission line sections, 8 load points and 15 possible switch locations (S1-S15) in the system shown in Fig. 4.3 . The failure rate λ (occ./yr) and repair time r (hours) of the line sections used in the calculation are given in Table 4.1 . The load capacities (MW) are shown in Table 4.2 . The switching time required to isolated a failure is assumed to be 30 minutes.

Table 4.1 Parameters of line sections

Lines	Failure rate	Repair time
1	0.2	4
2	0.1	4
3	0.3	4
4	0.2	4
5	0.2	4
6	0.1	4
7	0.3	4
8	0.2	4
9	0.2	2
10	0.6	2
11	0.4	2
12	0.2	2
13	0.2	2
14	0.6	2
15	0.4	2
16	0.2	2

Table 4.2 Load point parameters

Load points	1	2	3	4	5	6	7	8
Capacity(MW)	0.5	0.4	0.3	0.2	0.5	0.4	0.3	0.2

A 40% commercial and 60% residential customer mix was assumed for each load point. The composite customer damage function (CCDF) for the customer mix at each load point is shown in Fig. 4.4 . Two cases with different failure rates for the primary line sections are presented. The total annual switch investment cost (*Tcost*) for a switch can be calculated using the following equation:

$$T\cos t = \frac{SC}{ty}(1+ir)^{ty}(1+mc)\,, \qquad (4.8)$$

where SC is the total investment cost which includes the switch installation cost, ty is the life of the switch, ir represents the interest rate and mc is the percentage of annual switch cost for switch maintenance.

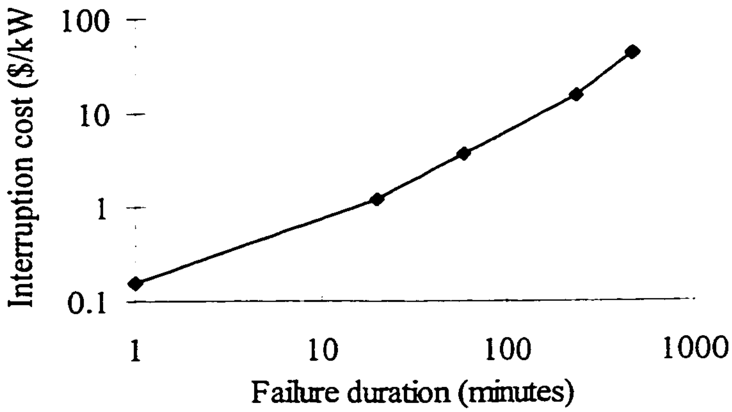

Fig. 4.4 Composite customer damage function

Case 1: The optimum cost curves obtained using the bisection algorithm and the direct search are shown in Fig. 4.5 and Fig. 4.6 respectively. It can be seen from these figures that the total system cost corresponding to the optimum location set decreases monotonically with the number of switches. The optimum number of switches in this case is 15 which means that switches should be installed in all the possible switch locations. It can also be seen from Fig. 4.5 that the optimization procedure using the bisection search technique starts with 8 switches followed by 12 and 14, and ends with 15 switches. 5 iterations are required to find the optimum number of switches and the corresponding location set.

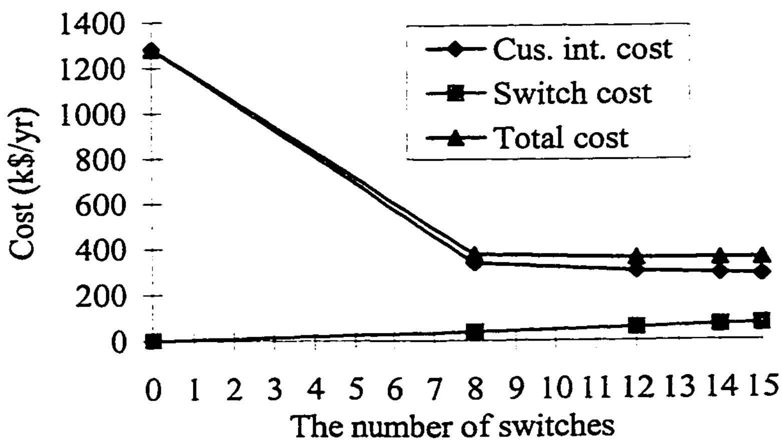

Fig. 4.5 System cost for Case 1 using the bisection algorithm

The switch investment cost, the customer interruption cost and the total system cost for the different number of switches using the bisection search are shown in Table **4.3** . The table also shows the optimum switch locations for each different number of switches.

Table 4.3 System cost and switch location for Case 1

Switches	Cus. int. cost k$	Switch cost k$	Total cost k$	Switch locations
0	1281.485	0	1281.485	no switch
8	337.7324	38.67427	376.4067	S1 S2 S4 S6 S9 S10 S12 S14
12	302.6499	58.01141	360.6613	S1-S3 S4-S7 S9 S10 S12-S14
14	291.8553	67.67998	359.5353	S1-S14
15	**286.458**	**72.51427**	**358.9723**	**S1-S15**

In the direct search, the procedure starts with zero switches and continues one by one ending with 15 switches. In this case, 16 iterations are required to do the same analysis. Fig. 4.6 shows the cost components in this case.

Table 4.4 shows the optimum switch locations and the costs for each different number of switches.

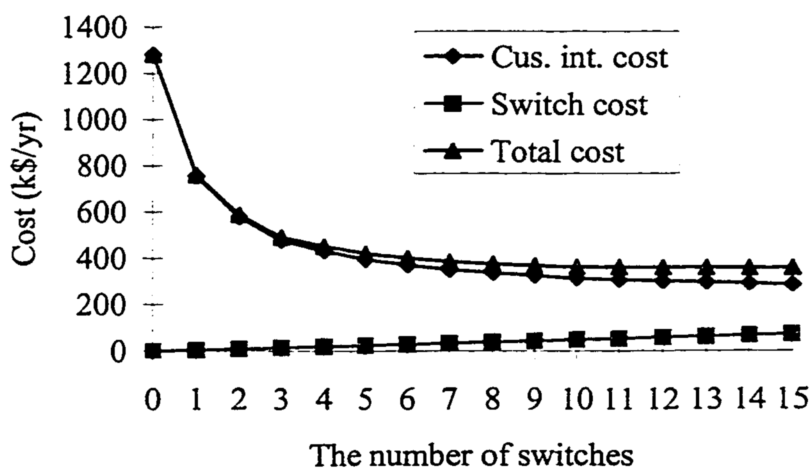

Fig. 4.6 System cost for Case 1 using the direct search method

Table 4.4 System cost and switch location for Case 1

Switches	Cus. int. cost k$	Switch cost k$	Total cost k$	Switch locations
0	1281.485	0	1281.485	No switches
1	755.4241	4.83428	760.2584	S8
2	577.5101	9.66857	587.1786	S5 S10
3	475.372	14.50285	489.8749	S4 S9 S12
4	432.0868	19.33714	451.4239	S2 S5 S9 S12
5	395.5481	24.17142	419.7195	S2 S4 S7 S10 S13
6	371.3629	29.00571	400.3686	S2 S4 S6 S9 S10 S13
7	351.2257	33.83999	385.0657	S2 S4 S6 S9 S10 S12 S14
8	337.7324	38.67427	376.4067	S1 S2 S4 S6 S9 S10 S12 S14
9	325.5884	43.50856	369.097	S1 S2 S4 S6 S9 S10 S12-S14
10	313.4445	48.34284	361.7874	S1 S2 S4-S6 S9 S10 S12-S14
11	308.0472	53.17713	361.2243	S1 S2 S4-S6 S9 S10 S12-S15
12	302.6499	58.01141	360.6613	S1-S3 S4-S7 S9 S10 S12-S14
13	297.2526	62.8457	360.0983	S1-S9 S10 S12-S14
14	291.8553	67.67998	359.5353	S1-S14
15	**286.458**	**72.51427**	**358.9723**	**S1-S15**

Case 2: The failure rates of line sections L1-L8 are reduced to 10% of the values used in Case 1. The total cost curve obtained using the direct search method becomes concave as shown in Fig. 4.7. The optimum number of switches is 7. A total of 10 iterations were required to find the optimum number and location of switches. Table 4.5 shows the optimum switch locations and the costs for each different number of switches.

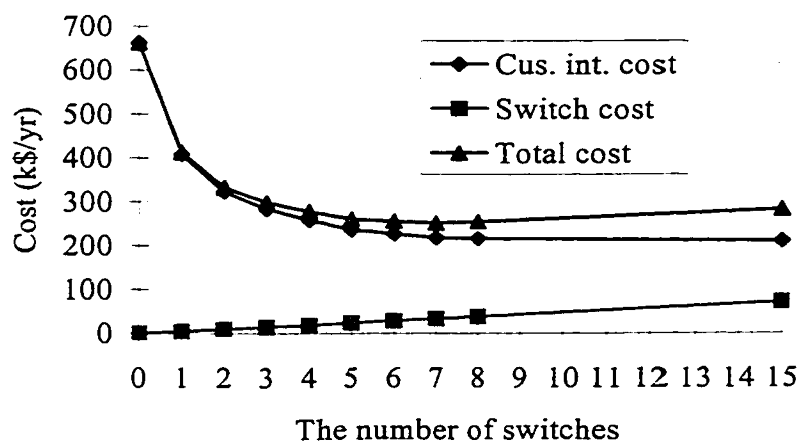

Fig. 4.7 System cost for Case 2 using the direct search method

Table 4.5 System cost and switch location for Case 1

Switches	Cus. int. cost k$	Switch cost k$	Total cost k$	Switch locations
0	662.373	0	662.373	No Switches
1	408.3359	4.83428	413.1702	S9
2	322.7157	9.66857	332.3843	S5 S10
3	283.726	14.50285	298.2289	S4 S9 S12
4	258.9365	19.33714	278.2737	S3 S7 S10 S13
5	236.6907	24.17142	260.8621	S2 S4 S7 S10 S13
6	227.0782	29.00571	256.0839	S2 S4 S6 S9 S10 S13
***7**	**217.8705**	**33.83999**	**251.7105**	**S2 S4 S6 S9 S10 S12 S14**
8	216.5212	38.67427	255.1954	S1 S2 S4 S6 S9 S10 S12 S14
15	211.3938	72.51427	283.908	S1-S15

The total cost curve obtained using the bisection search approach is shown in Fig. 4.8 . The optimum number of switches is 7. In this case, 7 iterations were required to find the optimum number and location of switches.

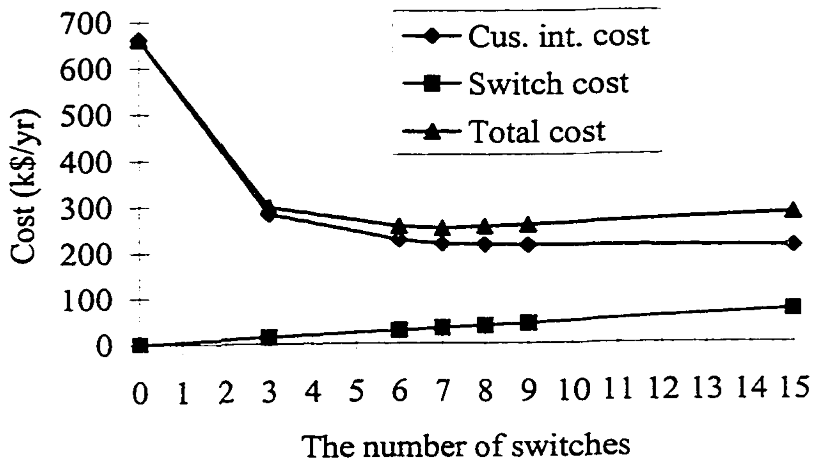

Fig. 4.8 System cost for Case 2 using the bisection algorithm

The optimum location sets are shown in Table 4.6 where it can be seen that the total system cost for the optimum switch set (7 switches) is 251,711$/yr. The total system costs for 6 and 8 switches and corresponding location sets are 256,084 $/yr and 255,195$/yr respectively, which are more than the total cost for the optimum switch set.

Table 4.6 System cost and switch location for Case 2

Switches	Cus. int. cost k$	Switch cost k$	Total cost k$	Switch locations
0	662.373	0	662.373	No Switches
1	408.336	4.834	413.170	S9
3	283.726	14.503	298.229	S4 S9 S12
6	227.078	29.006	256.084	S2 S4 S6 S9 S10 S13
***7**	**217.871**	**33.840**	**251.711**	**S2 S4 S6 S9 S10 S12 S14**
8	216.521	38.674	255.195	S1 S2 S4 S6 S9 S10 S12 S14
9	215.307	43.509	258.815	S1 S2 S4-S6 S9 S10 S12 S14
15	211.394	72.514	283.908	S1-S15

Case 1 and Case 2 show that the bisection technique is very efficient. This does not mean that the direct search technique is without value. The studies conducted in this research show that the direct search technique works very well in situations when the global optimum number of switches is small and the search starts from zero or when the global optimal number of switches is close to the maximum number of switches and the search start from the maximum number. If the optimal number of switches is between 1-6, the direct search method is both efficient and practical.

Application to a Practical System

The techniques were applied to select the number of switches and the corresponding locations in the Bus 6 distribution system shown in Fig. 2.5. This system is a rural/urban type configuration. The different costs for the feeders and the system are shown in Table 4.7 based on the original number of switches and corresponding locations. The total system cost is 81,157 $/yr, the customer interruption cost is 64,398 $/yr and the switch investment and maintenance costs are 16,758 $/yr.

Table 4.7 System cost for the original system

Feeder	Number of switches	Cus. int. cost k$	Switch cost k$	Total cost k$
1	5	1.217	5.586	6.803
2	6	1.364	6.703	8.068
3	3	24.080	3.352	27.432
4	1	37.737	1.117	38.854
total	15	64.398	16.758	81.157

The Bus 6 distribution system was originally designed to test techniques for evaluating the reliability indices of distribution systems. The number of switches and their locations were not optimized. The number of switches and the locations were determined using the optimization techniques. The different feeder and system costs are shown in Table 4.8 . Compared with the original switch set, the total customer interruption cost increases by 3.845% from 64,398 $/yr to 66,874 $/yr. The switch investment cost decreases by 73.33% from 16,758 $/yr to 4,469 $/yr. The total system cost decreases by 12.1% from 81,157 $/yr to 71,343 $/yr. More switches are required in Feeder 4 than in the original design and fewer switches are required in Feeder 1, 2 and 3 than in the original design.

Table 4.8 System cost after optimization

Feeder	Number of switches	Cus. int. cost k$	Switch cost k$	Total cost k$
1	0	2.959	0	2.959
2	1	2.258	1.117	3.375
3	1	23.978	1.117	25.095
4	2	37.680	2.234	39.914
total	4	66.874	4.469	71.343

The optimal number of switches and the corresponding locations are shown in Fig. 4.9 after the optimization.

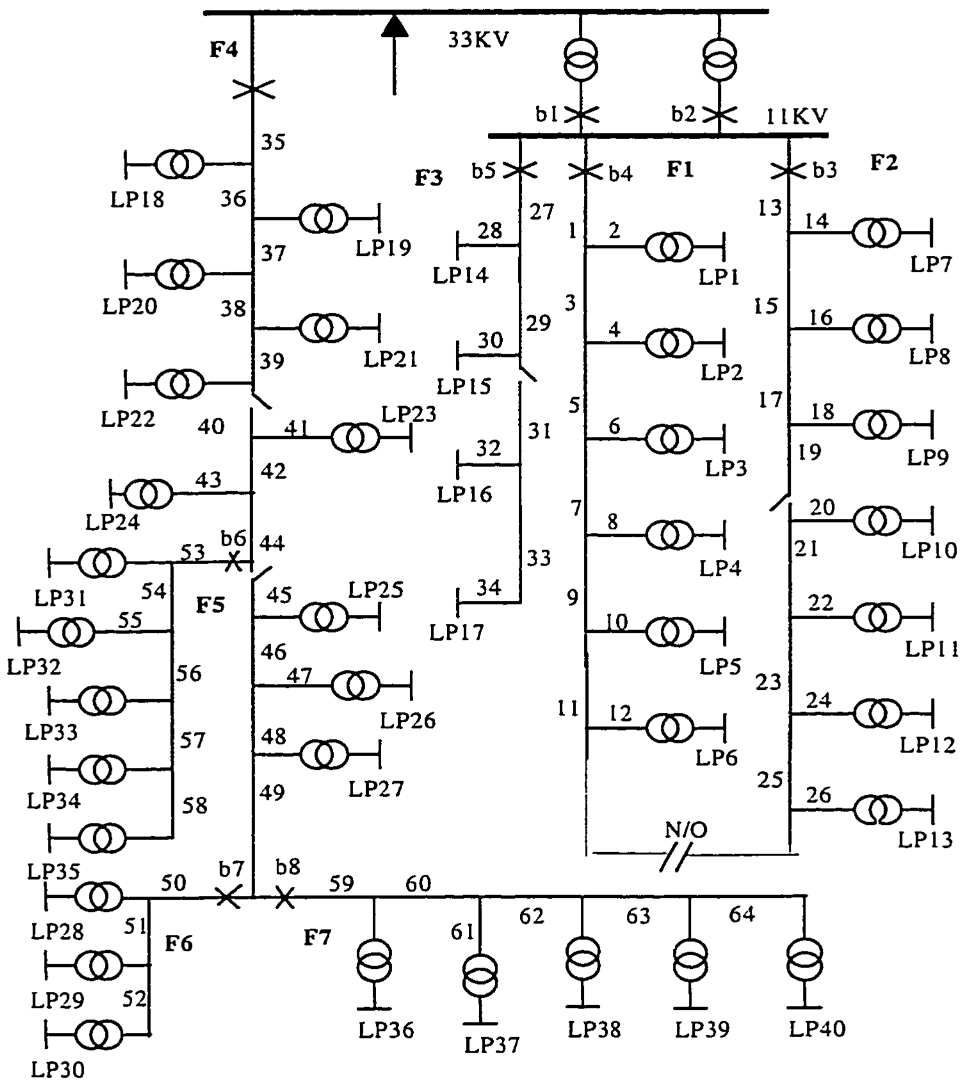

Fig. 4.9 The distribution system after optimization

It can be seen from the analysis that the number of switches and their locations can be determined from a societal point of view when customer interruption costs are included in the optimization strategy. The optimization techniques include load point reliability in the switch selection problem. Customer interruption costs are nonlinear functions of failure durations, and provide an important new dimension in the switching optimization process as they provide the opportunity to incorporate actual customer considerations in the analysis.

4.5. Long Term Planning

The selection of the optimal number of switches and the optimal locations discussed in the previous section is based on the concept that the system load is assumed to be constant. This kind of planning problem is usually called short term planning. In a practical distribution system, the system load increases with time. The number of switches and the locations selected based on the load of the first year may not be optimized in the following years. The load growth should therefore be considered in the optimization procedure. Instead of making the decision based on a short period in the future, the optimization can be done each year for a long period of time such as 20 years. This is designated as long term planning. The long term optimal switch selection problem can be represented by the following equation:

$$Minimize(\sum_{y=1}^{P} TCOST_k^l) = Minimize(\sum_{y=1}^{P}(SCOST_k^l + ICOST_k^l))$$

$$= Minimize(\sum_{y=1}^{P}(SCOST_k^l + (\sum_{i=1}^{N_p} L_i \sum_{j=1}^{N_c} c_{ij}(r_{ij})\lambda_{ij})_k^l)) \qquad (4.9)$$

where y and P represent the year and the total planned years respectively.

The procedure used to select the optimal number of switches and the locations for a long term is to repeat the short term optimization procedure for many years considering the load growth. After determining the optimal number of switches and the locations for each year, a schedule of installing additional switches and a corresponding location table are obtained. Based on the schedule and location table, the different options in the tables are then compared to give the optimal number of switches and the corresponding location set for a long planning period. Using the system shown in Fig. 4.3 as example, the optimal number of switches and the total minimum system cost (k$) are shown in Table 4.9 . The optimal switch locations for 7, 8 and 10 switches are shown in Table 4.10 .

Table 4.9 Switch expansion planning table

Years	7 switches	8 switches	9 switches	10 switches	11 switches
1	**251.711**	255.195	258.815	262.435	266.730
2	**273.498**	276.848	280.346	283.845	288.085
3	**297.463**	300.665	304.030	307.395	311.576
4	**323.826**	326.864	330.082	333.300	337.416
5	**352.824**	355.683	358.739	361.796	365.840
6	**384.723**	387.384	390.262	393.141	397.106
7	**419.811**	422.255	424.938	427.621	431.499
8	**458.408**	460.613	463.081	465.548	469.331
9	**500.865**	502.807	505.038	507.269	510.946
10	**547.567**	549.220	551.191	553.162	556.723
11	**598.940**	600.275	601.959	603.643	607.078
12	**655.450**	656.435	657.804	659.174	662.468
13	**717.611**	718.211	719.234	720.257	723.397
14	**785.988**	786.164	786.806	787.448	790.419
15	861.203	**860.913**	861.136	861.359	864.143
16	943.939	943.137	942.899	**942.660**	945.240
17	1034.949	1033.583	1032.838	**1032.092**	1034.446
18	1135.060	1133.074	1131.771	**1130.467**	1132.573
19	1245.182	1242.514	1240.597	**1238.679**	1240.513
20	1366.317	1362.898	1360.306	**1357.713**	1359.246

Table 4.10 The optimal locations for different switches

The optimal number of switches	The optimal switch locations
7	S2,S4,S6,S7,S10,S12,S14
8	**S1**,S2, S4,S6,S7,S10,S12,S14
10	S1,S2, S4, **S5**,S6,S7,S10, **S11**,S12,S14

It can be seen from Table 4.9 and Table 4.10 that the number of switches does not change for the first 14 years. One switch has to be installed at the beginning of the 15th year, and two more switches have to be added at the beginning of the16th year.

This is a very simple example. For a complex distribution system, not only the optimum number of switches changes with years but also the optimal switch locations. In this case, switch movement should be considered. Different options must be compared to determine the optimal number of switches and the corresponding locations.

4.6. Conclusion

The optimum selection of the number and locations of switches is an important aspect of distribution system planning, design and operation. Different numbers of switches and their locations can have quite significant effects on system reliability and on the total system cost. This chapter formulates the switch selection problem from the customer and utility point of view. It is based on evaluating and comparing the reliability cost (the investment and maintenance cost of adding the switches) with the reliability worth (the decrease in customer interruption costs because of the addition of the switches) for different switch connections.

An enumeration technique is used to find the optimal local location set for a given switch. A direct search technique is applied to determine the global optimal location set and the corresponding number of switches. A bisection search approach was developed to improve and simplify the search procedure and to save computing time.

The results from a study of a test system are used to illustrate the optimization procedure. The effect of element reliability parameters on the optimal results is discussed. The number of switches and the locations for a urban/rural distribution system are optimized. The results are compared with the original switch locations. It can be concluded that the switch mix will be very different if demand side concerns are considered in the evaluation. The techniques presented provide efficient tools, which can be used by distribution system planners, to find the optimum number of switches and their locations from a societal point of view.

5. Distribution System Reliability Cost/Worth Analysis Considering Time Varying Load and Cost Models

5.1. Introduction

As described in Chapter 3, a basic task in reliability cost/worth analysis is to evaluate the customer interruption costs. The analysis shows that the magnitude of the customer interruption cost has a direct effect on power system operating and planning decisions. The customer interruption cost depends on the customer type, the interruption duration, and load interrupted. The load model used in the previous chapters is the average customer load. The average load model (ALM) is an approximate representation of the actual load profile. Average or aggregate cost models are also used in the previous chapters. In the average cost model, the interruption cost for a given duration for a selected customer type is a constant value. In a practical power system, the load level for a given customer varies with time of the day, the day of the week and the week of the year. This representation can be designated as a time varying load model (TVLM). The customer interruption cost for a given customer also changes with the time of failure occurrence.

The time varying nature of power system load has been recognized for a long time by power system engineers. The load model information provided in the IEEE Reliability Test System (IEEE-RTS) [92] can be used to calculate system hourly loads for a year on a per unit basis, expressed in a chronological fashion so that daily, weekly and seasonal patterns can be developed. This load model is sufficient for generating capacity reliability studies. References 90 and 91 have used the IEEE-RTS hourly load model for the system as a whole. References 48 and 49 utilize time varying customer load models at each bus in a composite generation and transmission system analysis. This is a quite comprehensive load model for the mix of customer classes. References [50-52] indicate that there is considerable variation in customer interruption costs with time of interruption occurrence for some customers and there is relatively little variation for others.

In order to give a more realistic representation of the load and cost profiles, time varying load and cost models are introduced and used in distribution system reliability cost/worth analysis in this chapter. How the time varying load and cost affect the customer interruption cost is illustrated. A time varying cost weight factor is defined in this chapter in order to consider the time varying nature of the cost model. The customer damage function is combined with the time varying cost factors to create a time varying cost model for an individual customer.

5.2. Development of the Time Varying Load Model

The time varying load model represents the load using an hourly load level for each hour. The detailed customer load profile varies with the type of customer, the location and time of the day, the day of the week and the week of the year. The load shape also changes randomly for similar customers connected at the same location at any given time. These factors make it very difficult to develop a universal load model that is suitable to all customers.

Fortunately the general load shapes for customers which belong to the same sector are quite similar. A detailed load model for a specific customer in a specific system can be developed based on a general load profile combined with the available data and some realistic assumptions. General load shapes for different customers are discussed in the following section.

5.2.1. General Customer Load Characteristics

The load level for some system loads is relatively constant over some time intervals. The load level for others may vary from hour to hour, minute to minute and second to second during day. It is not realistic in practice to represent the load second by second. The load profile used in practice is the hourly load. The load profiles can be divided into periodic constant load and variable load.

Periodic Constant Load

The energy consumption of a periodic constant load is relatively constant during a period of hours with very little weather dependent variation [49]. The demand for electrical energy is quite stable from day to day and season to season. The load level changes one, two or three times over 24 hours depending on different shift operation and production. For example, the load profile for these customers for a typical day with three shifts may look like the one shown in Fig. 5. 1. Large users and many industrial customers belong to the periodic constant load class.

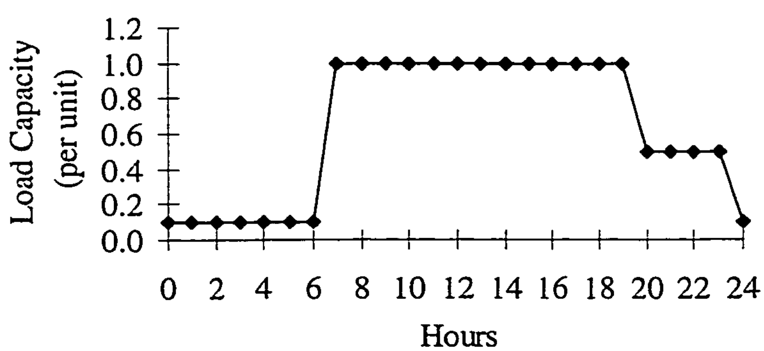

Fig. 5. 1 Load Profile for a Periodic Constant Load

Variable Load

The characteristics of a variable load are that the load level varies from hour to hour, from minute to minute and from second to second. An hourly load model is usually used in practice. The load may also change from week to week during a year. These loads are usually called seasonal loads. A possible load profile over 24 hours for a variable load for a specific season may looks like the one shown in Fig. 5. 2 Most residential, agricultural, commercial, office and government & institution customers belong to the variable load class.

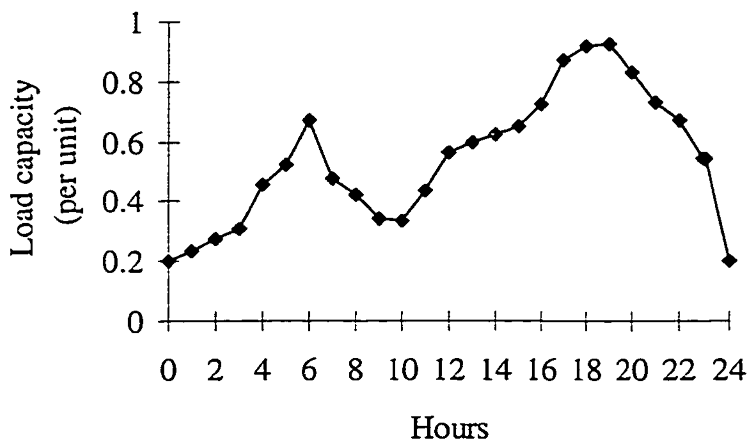

Fig. 5. 2 Load Profile for a Variable Load

5.2.2. Time Varying Load Model

Detailed chronological customer load consumption data are generally not available in most utilities. An alternate way to develop time varying customer load models is to analyze the individual customer load characteristics and combine them with the annual peak load to generate annual models. The development of an hourly time varying load model consists of the following steps:

(a): develop a 24 hour daily load curve as a percentage of the daily peak load,

(b): develop a 7 day weekly load curve as a percentage of the weekly peak load, (c): develop a 52 week yearly load curve as a percentage of the yearly peak load,

(d): determine the load $L(t)$ for hour t using the following equation:

$$L(t) = L_y \times P_w \times P_d \times P_h(t), \tag{5.1}$$

where L_y is the annual peak load, P_w is the percentage of weekly load in terms of the annual peak, P_d is the percentage of daily load in terms of the weekly peak and $P_h(t)$ is the percentage of hourly load in terms of daily peak.

5.2.3. Load Forecast Uncertainty

The actual load is random in nature and it is very unlikely that the forecast load will be the same as the actual load. Load forecast uncertainty can be described by a probability distribution whose parameters can be determined from past experience and possible subjective evaluation. It is very difficult to obtain sufficient historical data to determine the detailed distribution associated with load forecast uncertainty. Published data, however, suggests that load uncertainty can be reasonably described by a normal distribution. The distribution mean is the forecast load and the deviation can be obtained from previous forecasts.

The load uncertainty can be combined with the hourly time varying load model to develop a practical load model as shown in the following equation.

$$L_r(t) = L(t) + STD * Z \tag{5.2}$$

Where $L_r(t)$ is the load for hour t considering load uncertainty, $L(t)$ is the load level obtained using Equation 5.1, STD is the standard deviation of $L(t)$, and Z is the standard normal variable denoted by N(0,1) generated by a random number generator using the following formula:

$$Z = \sum_{l=1}^{12} U_l - 6.0 \tag{5.3}$$

$U_1, \ldots, U_{12}$ are uniformly distributed random variates from a uniform random number generator $U(0,1)$.

5.3. Load Models for the RBTS Customers

There are seven customer types in the RBTS distribution systems. The number of customers, peak load and average load are given in [62, 63]. The load models for the seven customer sectors are developed in this section. In order to represent the seasonal variations in the load model, a year is divided into the three seasons of summer (weeks 18-20), fall/spring (weeks 9-17 & 31-43) and winter (weeks 1-8 & 44-52). The characteristics for each customer type was analyzed and the 24 hour load curves for different seasons, weekly percentages for 52 weeks and daily percentages for 7 days were determined.

As discussed in the previous section, the residential loads have the most daily, hourly and seasonal load variation. The fluctuation is caused by random domestic uses of cooking equipment, entertainment facilities, refrigerators, air conditioners and lighting. The 24 hour load profile varies seasonally. The 24 hour load profiles showing the hourly load variation for the three seasons are shown in Fig. 5.3 .

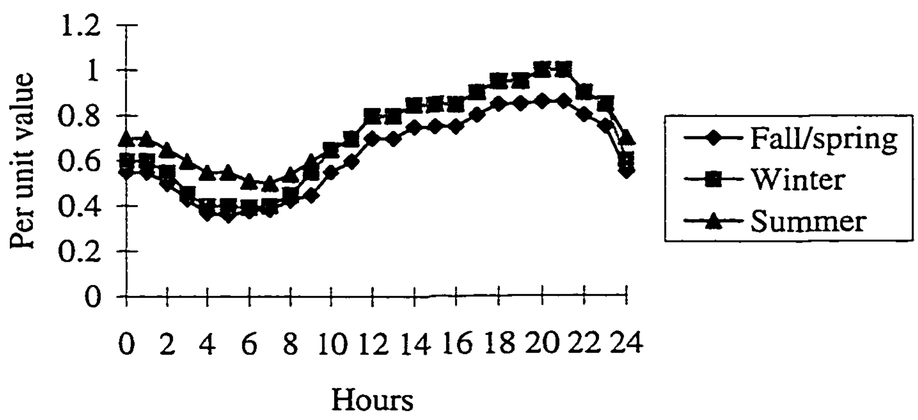

Fig. 5.3 Load profiles for the residential sector

Agricultural and commercial demands are relatively high during daylight hours and fall off during the night. The load profile also varies with the season. The 24 hour load profiles for these customer sectors the fall/spring and summer/winter are shown in Fig. 5.4 and Fig. 5.5 .

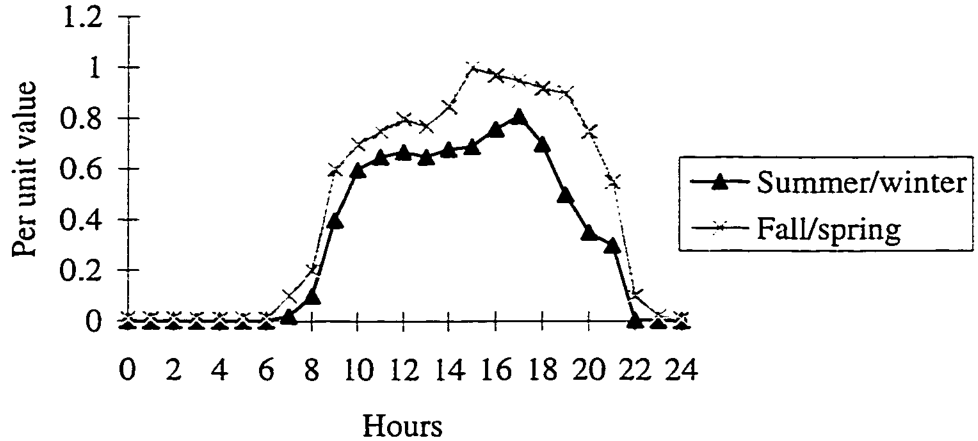

Fig. 5.4 Load profiles for the agricultural sector

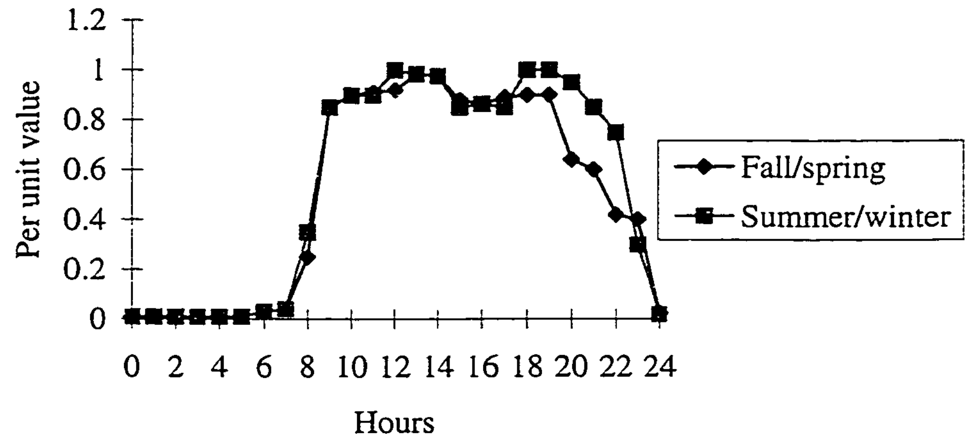

Fig. 5.5 Load profiles for the commercial sectors

Power consumption equipment in the office & building sector are office facilities, space air conditioners and lighting. The power demand is high during work hours and also changes with the weather. The 24 hour load profiles for the fall/spring and summer/winter seasons are shown in Fig. 5.6 .

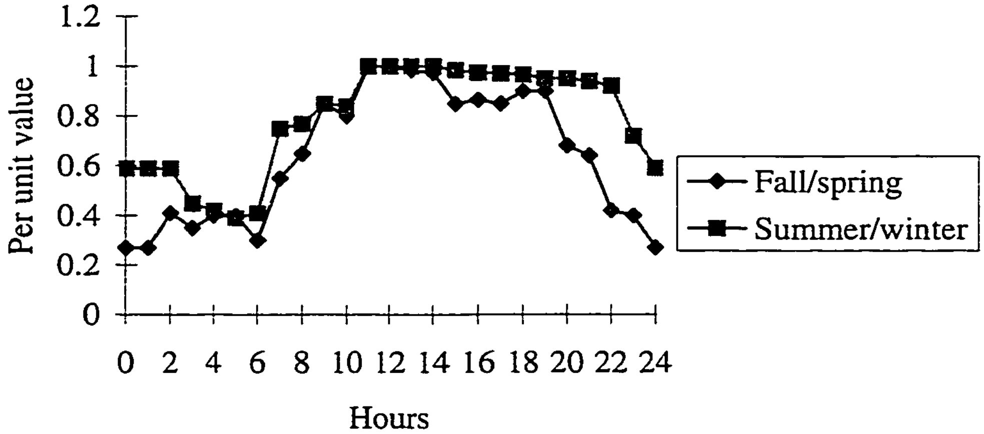

Fig. 5.6 Load profiles for the office & building sector

Industrial, large user and government & institutional customer sectors have less seasonal fluctuations. The government & institutional load has hourly variations. The industrial and large user sectors show a relatively constant demand during specified periods of time. The 24 hour load profiles of the three sectors are shown in Fig. 5.7 .

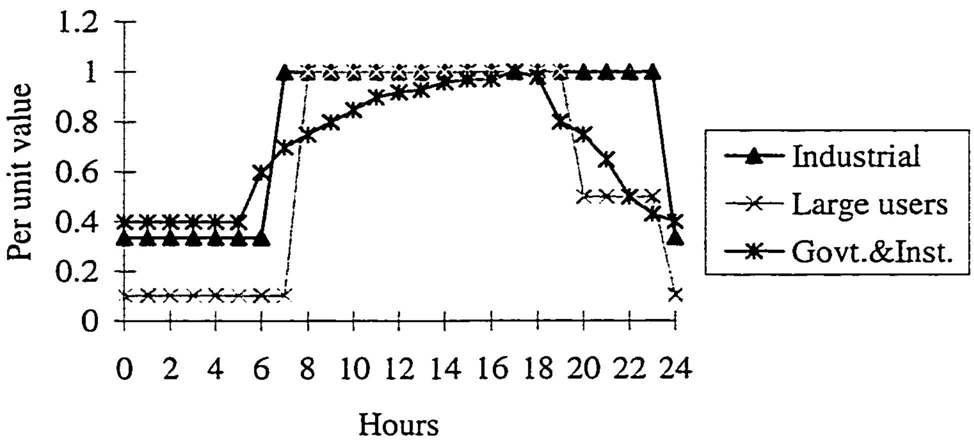

Fig. 5.7 Load profiles

for the industrial, large user and government &institution sectors

The per unit values over 24 hours for the seven customer sectors are shown in Appendix A. Seasonal variations can also be represented by different weekly percentages and different daily percentages. The weekly percentages for the residential sector also are shown in Appendix A. The load profiles of other customer sectors show no weekly variation. The load profiles are also different for different days during a week. The daily load fluctuation is represented by different daily percentages. The daily percentages for the residential, government & institutional and office & building sectors are shown in Appendix A.

After the annual peak load, weekly percentage, daily percentage and 24 hour load profile are determined, the annual hourly load curve can be developed using Equation 5.1. Using the residential load as a example, the hourly load curve of a residential customer with a 0.8668 MW annual peak load is shown in Fig. 5.8 for 350 hours.

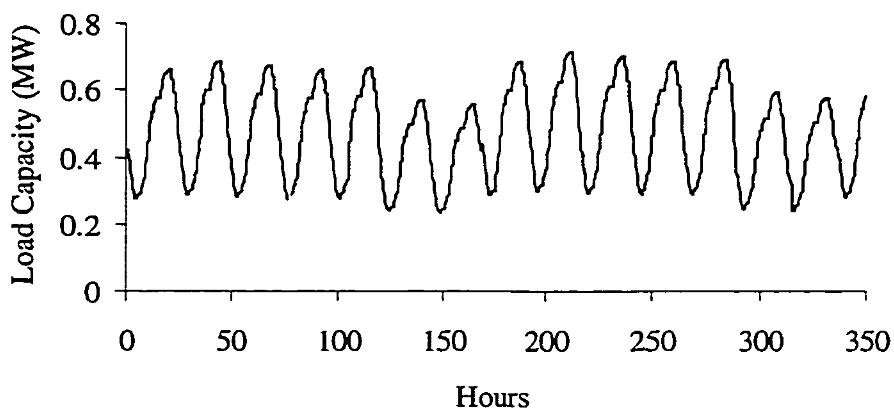

Fig. 5.8 Time varying load model

5.4. Time Varying Cost Model

5.4.1. Cost Weight Factors

As described in the previous section, the CIC for a specified customer sector depends on the load interrupted and the interruption duration. The time varying attributes of customer interruption costs are not portrayed in the SCDF shown in Table 3.1. In a practical system, the CIC for a given load level and outage duration also changes with the time of occurrence. For example, the interruption cost for a commercial customer is larger when a failure occurs at a peak shopping hour than when an interruption occurs at a relatively light shopping hour.

Most cost studies provide little or no time varying data. References [50-52] indicate that there is considerable variation in interruption costs with time of interruption occurrence for some customers and there is relatively little variation for others. Reference 16 provides quantitative measures of variation in the worst interruption cost as a function of the time of the day, the day of the week and the month of the year. In order to easily incorporate the time varying nature in distribution system reliability analysis, a time varying cost weight factor (W(t)) at hour *t* is defined using the following formula:

$$W(t) = \frac{\text{Actual interruption cost at hour } t}{\text{Average interruption cost}} \qquad (5.4)$$

5.4.2. The Cost Weight Factor Profiles for the RBTS Customers

The cost weight factor profiles are different for each customer sector. Time varying weight factors for the seven customer sectors in the RBTS over 24 hours were developed based on the survey information.

For a residential customer, the cost profile for weekdays is different from weekends because of the different schedules. During weekdays, the cost weight factor has three levels corresponding to the sleeping hours, working hours (not at home) and cooking/relaxing hours (at home). During weekends, there are two levels. The interruption costs for agricultural customers show relatively little daily and hourly change. The weight factors are divided into the two time intervals. The large user sector usually shows a very small daily and hourly change. The weight factors are assumed to be constant during a day. The time varying cost weight factors for these three customer sectors are shown in Fig. 5.9

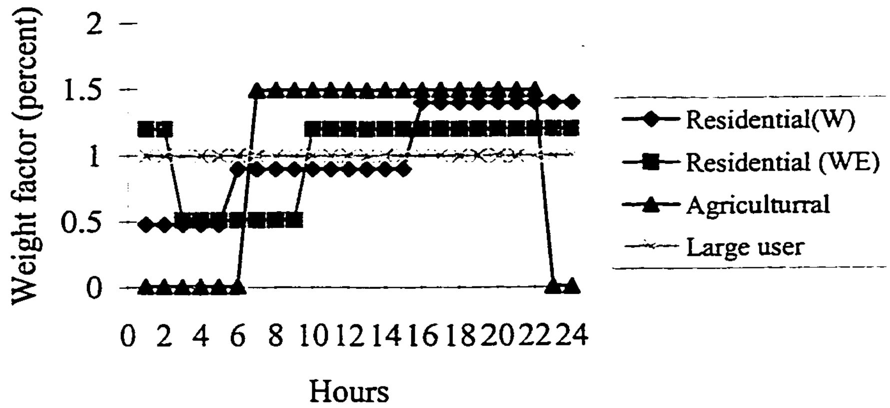

Fig. 5.9 The hourly time varying cost weight factors for three customer classes

Small industries may run two or three shifts per day depending on their characteristics. The cost weight factors are divided into three time intervals with different weight factors. For commercial customers, there is little cost change with month and day, and the cost is higher from 9 am to 5 p.m. than for other hours of a day. For an industrial customer, the cost for each month is almost constant and weekdays have higher costs than weekends, and the interruption costs over 24 hours are generally constant. The seasonal costs for agricultural customers depend on the location and customer type. The time varying cost weight factors for these two customer sectors are shown in Fig. 5.10

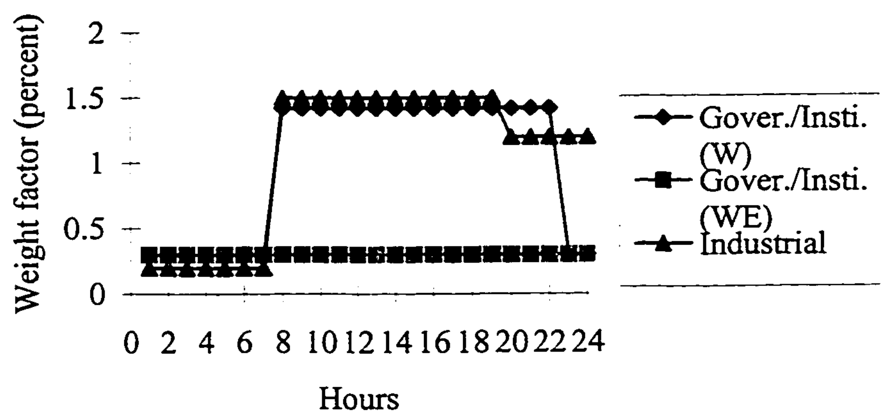

Fig. 5.10 The hourly time varying cost weight factors for two customer classes

For an office customer, the interruption costs for weekdays and weekends are considerably different. The weight factors at the weekend are assumed to be small and constant over 24 hours. The weight factors on weekdays are larger than those at the weekend during office hours. The profile of the cost weight factors for a commercial customer depends on the shopping hours. The interruption cost during rush shopping hours is considerable larger. The time varying cost weight factors for these two customer sectors are shown in Fig. 5.11

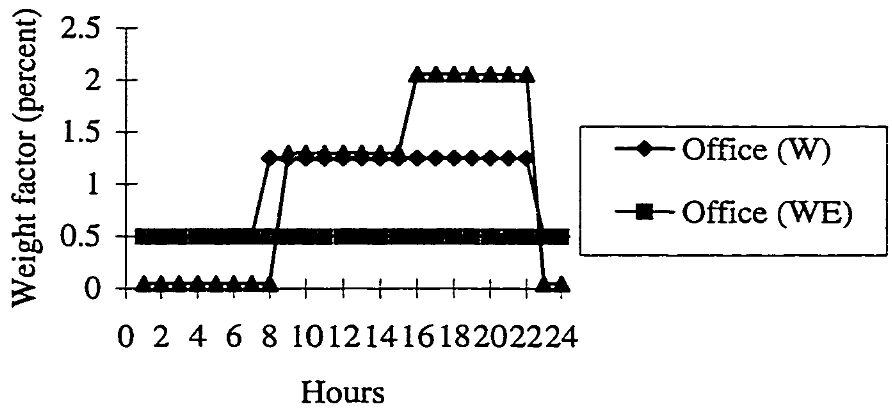

Fig. 5.11 The hourly time varying cost weight factors for two customer classes

The detailed time varying cost weight factors over 24 hours for the seven customer sectors are shown in Appendix A.

It should be noted that the time varying cost models may change with customer geographic location. It is not realistic to attempt to create a universal time varying cost profile that is suitable for all customers within a particular sector. Time varying cost models, therefore, should be developed for different systems. A realistic time varying cost model should be obtained using a relatively large sample survey for the specified customer sector in the system under study. This chapter presents a general methodology for considering time varying aspects in the cost analysis and illustrates how this affects the predicted customer interruption costs.

The time varying cost at hour t (*TVC(t)*) is obtained using the appropriate weighting factor (*W(t)*) and the average interruption cost (*AIC*) provided by the SCDF using the following formula:

$$TVC(t) = W(t) * AIC \qquad (5.5).$$

5.5. Time Sequential Technique with Developed Models

The time sequential simulation technique provides a practical and relatively straight forward approach to evaluate distribution system reliability cost/worth considering time varying load and cost models. The procedure used consists of the following steps:

1: Generate a random number for each element in the system and convert these random numbers into time to failure (*TTF*) values using the appropriate element failure probability distributions.

2: Comparing the *TTF* of all elements, find the failure event *j* that has the minimum *TTF* and the location of the element that caused the event *j*.

3: Generate two random numbers for the element with minimum *TTF* and convert them into times to repair (TTR_j) and times to switch (TTS_j) using the appropriate probability distributions for the element repair and switching times.

4: Find the load points that are affected by the failed event *j*.

5: Determine the failure duration r_{ij} for the load point *i* according to the network configuration, fuse, switch and alternated supply operating models.

$$r_{ij} = k * TTS_j + (1-k) * TTR_j \qquad (5.6)$$

where *k* is a control constant; *k=1* for the load points whose service can be restored by switching action, *k=0* for other load points.

6: Determine the possible load profile for load point i during the failure period based on the time varying load model and load probability distribution, and calculate the average load L_{aij} during this period using the following equation:

$$L_{aij} = \frac{\sum_{t=ts}^{te} L_{ri}(t)}{te - ts + 1} \qquad (5.7)$$

where ts and te are failure start and end hour respectively, and t represents hour t.

7: Determine the per unit interruption cost pc_{ij} for load point i using the r_{ij}, the load point customer damage function $f(r_{ij})$ and the probability distribution of costs.

$$pc_{ij} = f(r_{ij}) \qquad (5.8)$$

8: Determine the adjusted per unit interruption cost c_{ij} according to the time varying weight factor using the following equation if the time varying cost model is used. Otherwise, let $c_{ij} = pc_{ij}$ and go to step 9.

$$c_{ij} = \frac{\sum_{t=ts}^{te} W_i(t)}{te - ts + 1} * pc_{ij} \qquad (5.9)$$

where $W_i(t)$ is the cost weight factor for hour t.

9: Evaluate the energy not supplied ENS_{ij} and the interruption cost $COST_{ij}$ of the load point i due to the failure event j.

$$ENS_{ij} = L_{aij} r_{ij} \qquad (5.10)$$

$$COST_{ij} = c_{ij} L_{aij} \qquad (5.11)$$

10: Add the ENS_{ij} and the $COST_{ij}$ to the corresponding total values respectively.

11: Repeat Step 5-10 for all load points.

12: If the coefficient of variation of the chosen index is greater than the tolerance level, go to Step 13. If convergence is achieved, go to Step 14. The coefficient of variation β is calculated as:

$$\beta = \frac{\sqrt{V(I)/NS}}{E(I)} \tag{5.12}$$

where V(I) is the variance of the test index, E(I) is the expected value of the test index and NS is the number of samples.

13: Generate a new random number for the repaired element and convert it into the new TTF and go to Step 2.

14: The total energy not supplied ENS_i and the interruption cost $COST_i$ of the load point i for the total simulation years are:

$$ENS_i = \sum_{j=1}^{N_s} L_{aij} r_{ij} \tag{5.13}$$

$$COST_i = \sum_{j=1}^{N_s} c_{ij} L_{aij} \tag{5.14}$$

where N_s is the total number of failure events in the specified simulation period. The expected energy not supplied $EENS_i$, the expected interruption cost $ECOST_i$ and interrupted energy assessment rate $IEAR_i$ can be calculated using the following equations:

$$EENS_i = \frac{ENS_i}{TST} \tag{5.15}$$

$$ECOST_i = \frac{COST_i}{TST} \tag{5.16}$$

$$IEAR_i = \frac{ECOST_i}{EENS_i} = \frac{COST_i}{ENS_i} = \frac{\sum_{j=1}^{N_s} c_{ij}}{\sum_{j=1}^{N_s} r_{ij}} \tag{5.17}$$

where TST is the total specified simulation period in years.

15: Calculate the system $EENS, ECOST$ and $IEAR$.

5.6. System Analysis

A computer program using the time sequential simulation technique considering the time varying nature of the load and cost models has been developed. The following examples illustrate the effect of time varying load and cost models on customer interruption costs using the representative distribution systems shown in Fig. 3.1 and Fig. 2.5. The basic reliability parameters for this system are presented in [62]. The restoration times of the elements were assumed to be lognormally distributed with standard deviations of half their average values.

5.6.1. Considering the Time Varying Load Model

The effect of the time varying load model on the cost indices is first considered. The time varying loads for the different load types are used in the evaluation.

Application to the Bus 2 Distribution System

The simulation program was used to evaluate the Bus 2 distribution system. The convergence of the program is discussed first. The load point and system cost indices and the probability distribution of the indices are then illustrated.

Convergence of Indices

The convergence characteristics of the load point and system indices are important parameters in a simulation program. Fig. 5.12 and Fig. 5.13 show the ECOST of Feeder 1 versus simulation years for the average and time varying load models respectively. It can be seen that the ECOST of the feeder converges at virtually the same speed for both models.

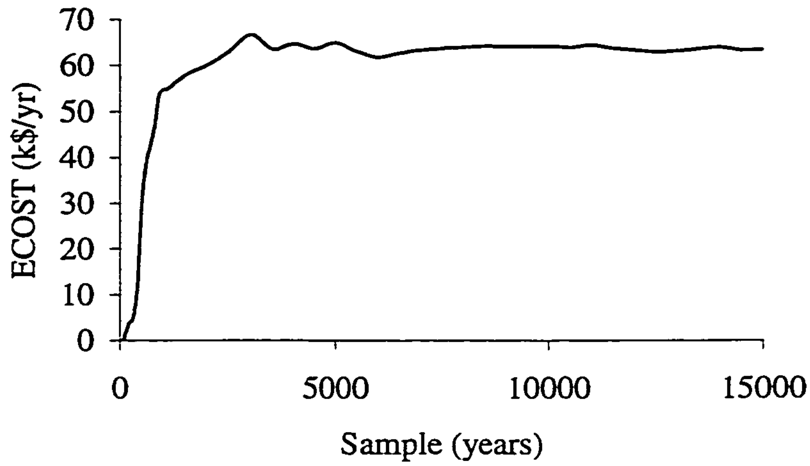

Fig. 5.12 Convergence of ECOST for Feeder 1 (Average load)

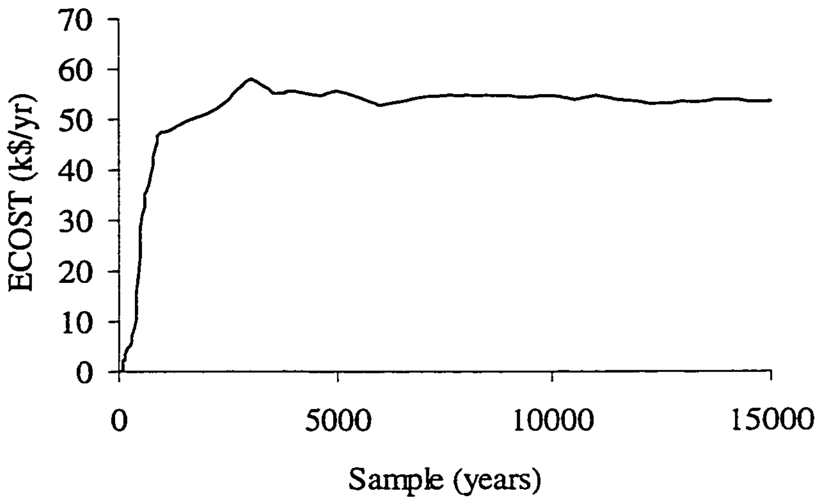

Fig. 5.13 Convergence of ECOST for Feeder 1 (Time varying load)

Load Point Indices

The EENS, ECOST and IEAR indices for all the load points for both time varying and average load models are shown in Fig. 5.14 - Fig. 5.16 .

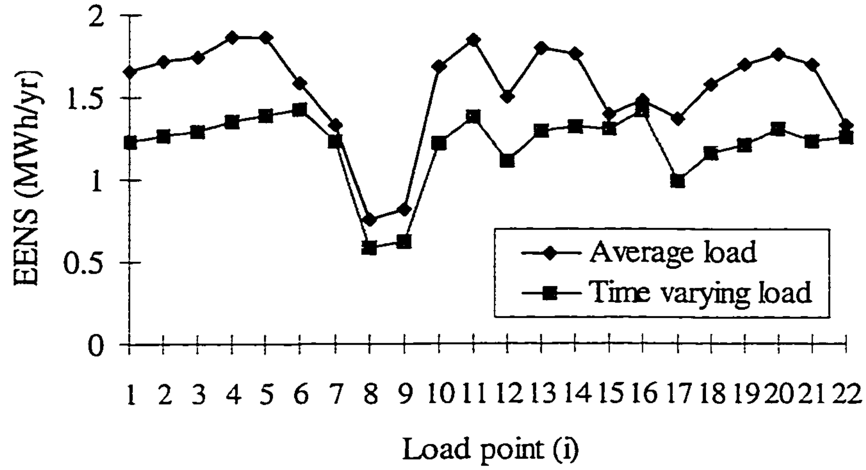

Fig. 5.14 Load point EENS for the two load models

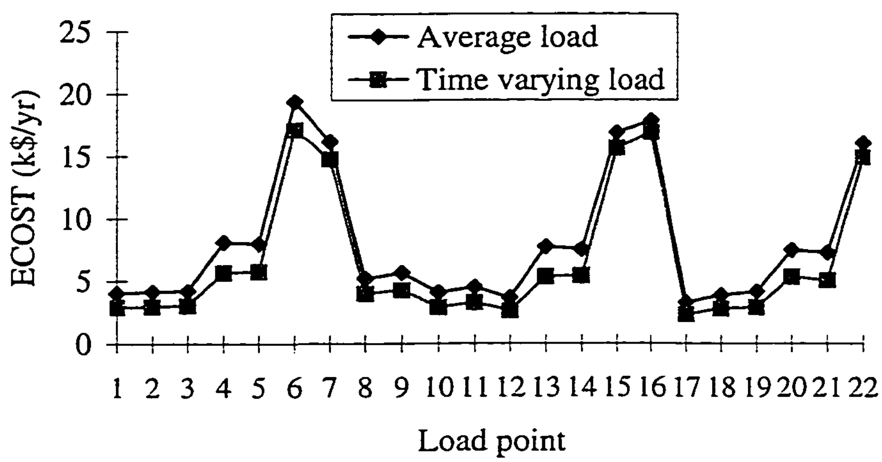

Fig. 5.15 Load point ECOST for the two load models

It can be seen from Fig. 5.14 and Fig. 5.15 that the load point EENS and ECOST calculated using the time varying load model are smaller than those obtained using average loads.

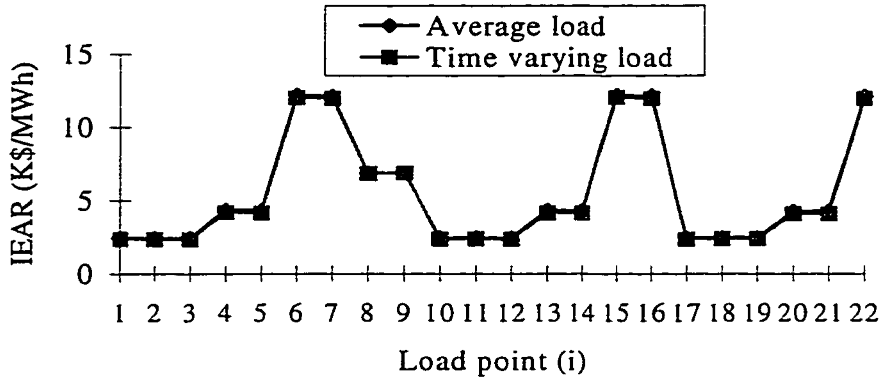

Fig. 5.16 Load point IEAR for the two load models

Fig. 5.16 shows that the IEAR of the load point is basically the same for the two models. The time varying load model has only very small effect on the load point IEAR as the IEAR is mainly determined by the inherent system reliability and the customer composition at that load point.

Probability Distributions of the Indices

The probability distribution of an index provides important information which complements the average values. Fig. 5.17 and Fig. 5.18 show the probability distributions of the load point failure duration (hr/failure), ENS (MWh/failure) and COST (k$/failure) for load points 1 and 8 respectively.

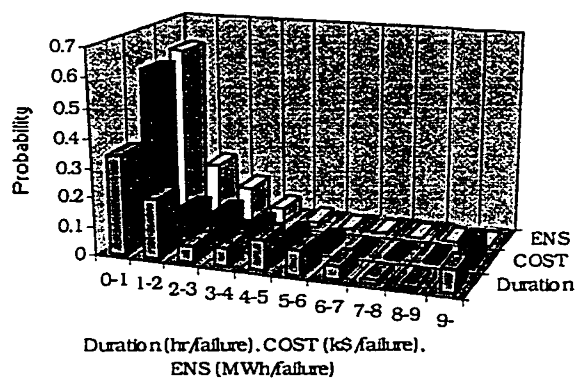

Fig. 5.17 Distributions of the indices for load point 1 (time varying load)

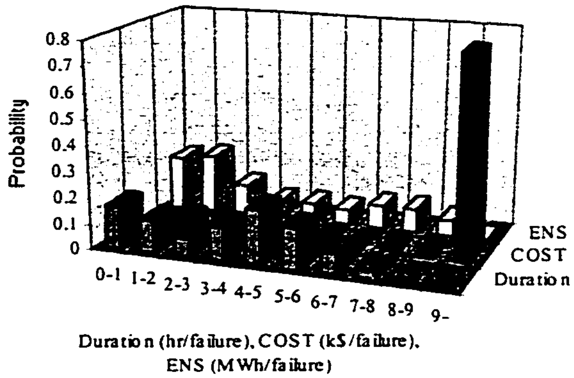

Fig. 5.18 Distributions of the indices for load point 8 (time varying load)

It can be seen from Fig. 5.17 that for a large portion of the failures at load point 1, the duration is between 0 and 1 hour, the ENS is between 1 Wh and 1 MWh and the COST is between $1 and $1000. Fig. 5.18 shows that for load point 8, the duration between 4 and 5 hours has the highest probability, that failures with the ENS between 1 and 3 MWh occur more frequently, while the customer damages resulting from most failures are over $9000. The probability distributions of the load point and feeder indices provide a revealing picture of load point and system behavior.

Fig. 5.19 shows the probability distributions of the feeder ENS and COST.

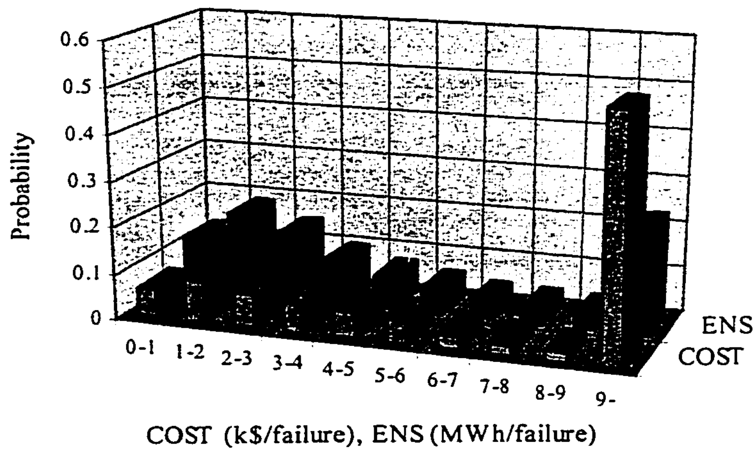

Fig. 5.19 Distributions of the indices for Feeder 1 (time varying load)

It can be seen from this figure that the total interruption cost for Feeder 1 is more than \$9000 per failure for almost 50 percent of the failures, and the total energy not supplied is more than 9 MWh/failure for over 20 percent of the failures.

Effect of the TVLM on the Probability Distribution of Index

Fig. 5.20 and Fig. 5.21 show the effect of the TVLM on the probability distributions of the load point costs. It can be concluded that the effect is negligible for some load points, such as load point 1, while the effect on others such as load point 8 is relative large.

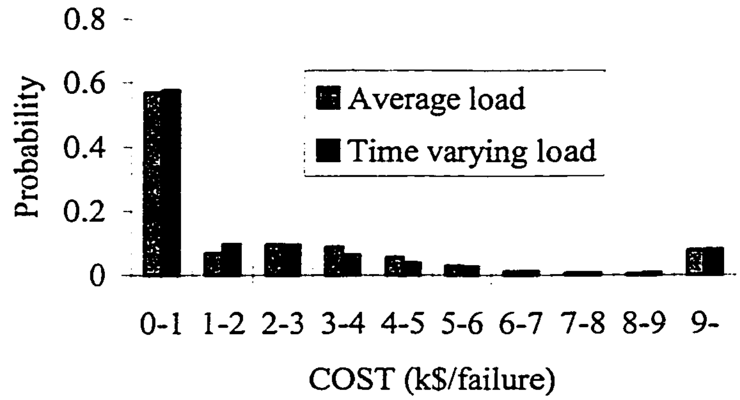

Fig. 5.20 Distributions of the COST for load point 1 using the two load models

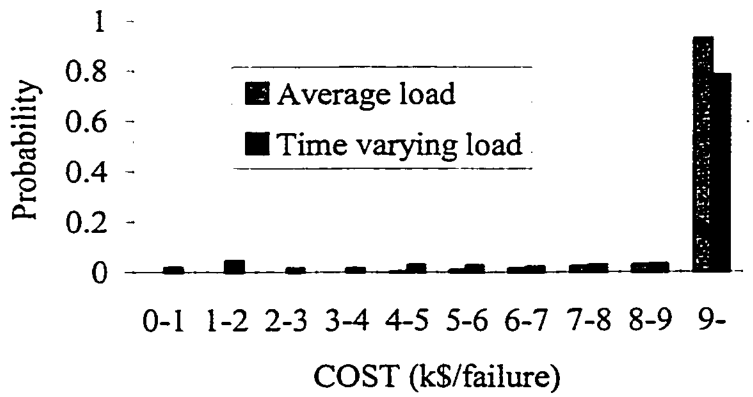

Fig. 5.21 Distributions of the COST for load point 8 using the two load models

Consideration of Load Uncertainty

A time varying load model incorporating load uncertainty was also included in the analysis. Table 5.3 shows the system EENS, ECOST and IEAR for three cases using average load (AL), time varying load (TL) and time varying load with load uncertainty (TLU). The difference in the ECOST between using AL and TL is 18.5% based on the average load. The relative difference in the EENS and IEAR is 22.3% and 5% respectively. It can also be seen from the table that load uncertainty has little effect on the system EENS, ECOST and IEAR.

Table 5.3 System EENS, ECOST and IEAR

Cases	EENS	ECOST	IEAR
AL	34.19875	179.104	5.23715
TL	26.57912	146.0245	5.49395
TLU	26.74698	146.8955	5.49204

Application to Bus 6 Distribution System

The program has also been used to evaluate the Bus 6 distribution system. The load point and system cost indices were calculated and load uncertainty has been considered.

The Load Point Cost Indices

The load point EENS, ECOST and IEAR obtained using the two load models are shown in Fig. 5.22 -Fig. 5.24 respectively. It can be seen from these figures that the load point EENS and ECOST for some load points using the time varying load have almost no change, the cost indices for some load points change little compared those using the average load. The load point cost indices for some load points using TVLM are bigger than those using ALM, and some are smaller than those using ALM. The IEAR of the load points shows almost no change.

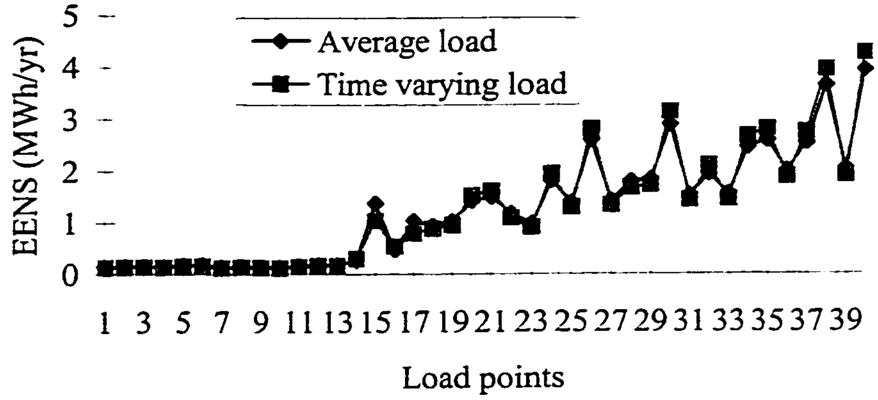

Fig. 5.22 EENS for Cases 1 and 3

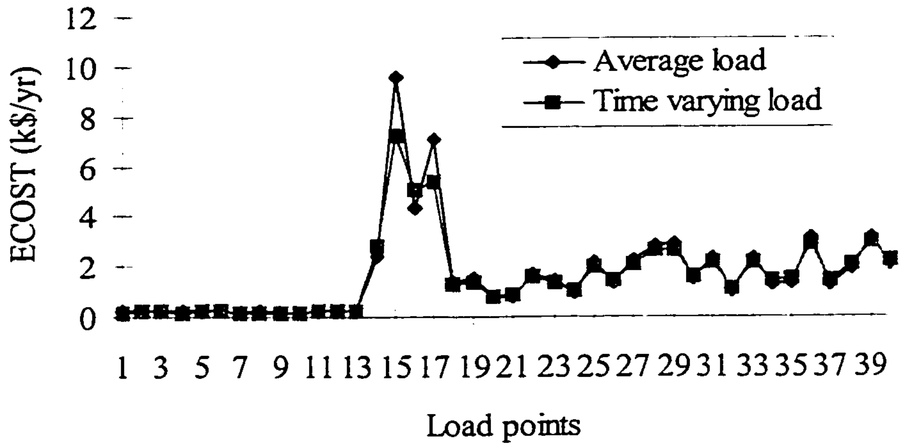

Fig. 5.23 ECOST for Cases 1 and 3

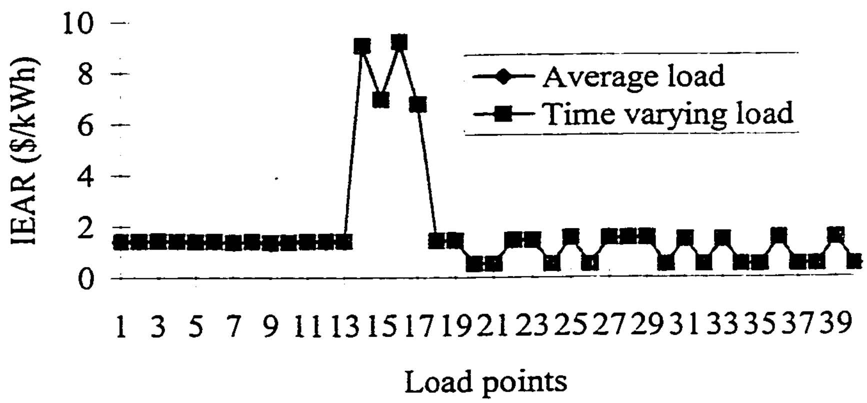

Fig. 5.24 IEAR for Cases 1 and 3

The System Cost Indices

The system cost indices obtained using the two load models are shown in Fig. 5.25 . It can be seen from the figure that the EENS obtained using the two models shows almost no difference. The ECOST shows relatively little difference and the IEAR is virtually the same.

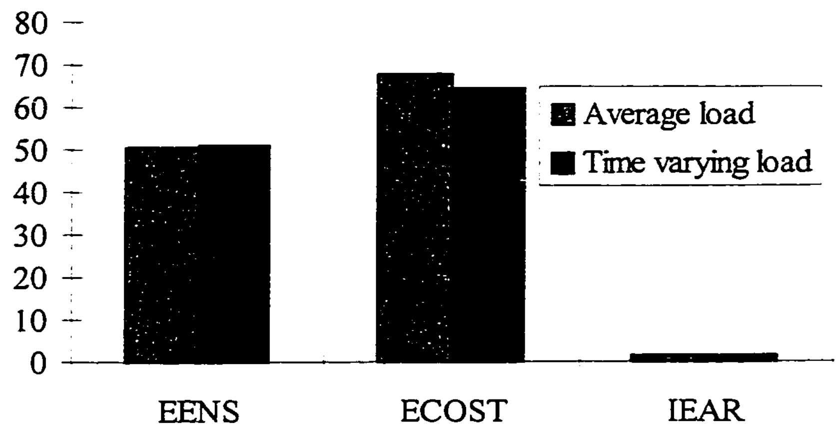

Fig. 5.25 System indices for Cases 1 and 3

Effect of Load Uncertainty

The effect of load uncertainty on the cost indices are shown in Fig. 5.26 -Fig. 5.28 . It can be seen from these figures that load uncertainty has very little effect on the indices.

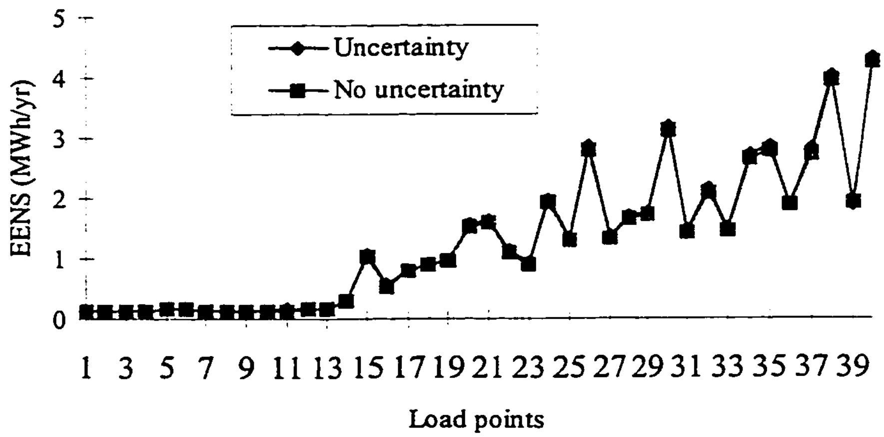

Fig. 5.26 EENS for Cases 3 and 4

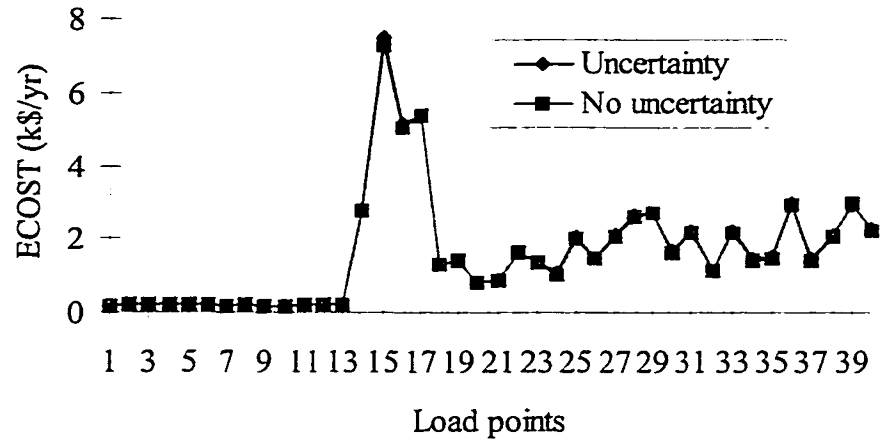

Fig. 5.27 ECOST for Cases 3 and 4

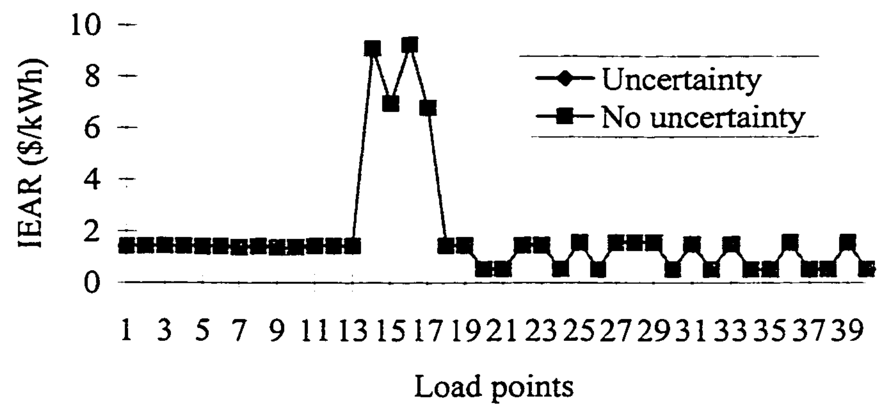

Fig. 5.28 IEAR for Cases 3 and 4

It can be concluded from the analysis that using a time varying load model has varying effects on the cost indices. The effect depends on system configuration and the reliability parameters of the system elements. Load uncertainty has relatively little effect on the cost indices of distribution systems.

5.6.2. Considering the Time Varying Cost Model

The time varying cost models developed in the previous section were used to examine the reliability cost/worth of the Bus 2 distribution system.

Load Point Indices

The ECOST values for all load points are shown in Fig. 5.29. The ECOST values obtained using the two models are almost the same for the residential customers (load points 1-3, 10-12 and 17-19). Load points 8 and 9 are industrial customers. The ECOST values calculated for these customers using the time varying cost model are larger than those obtained using the average load model. The ECOST values of government & institution customers (load points 4-5, 13-14, 20-21) decreases when the time varying model is used as these customer interruption costs are low on the weekend. The ECOST values for the time varying cost model for commercial customers such as load points 6-7, 15-16 and 22 are larger than those for the average model. It can be concluded that the difference in the ECOST is largely dependent on the customer type. The ECOST value for a customer can increase or decrease depending on the shape of the cost model profile. Fig. 5.30 shows the IEAR for all the load points in the system. It can be seen that the cost model has observable impact on the IEAR for some customers.

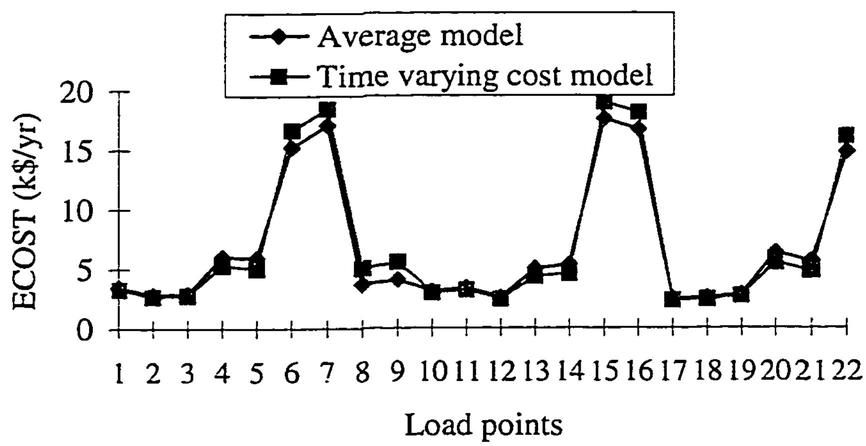

Fig. 5.29 Load point ECOST for two cost models

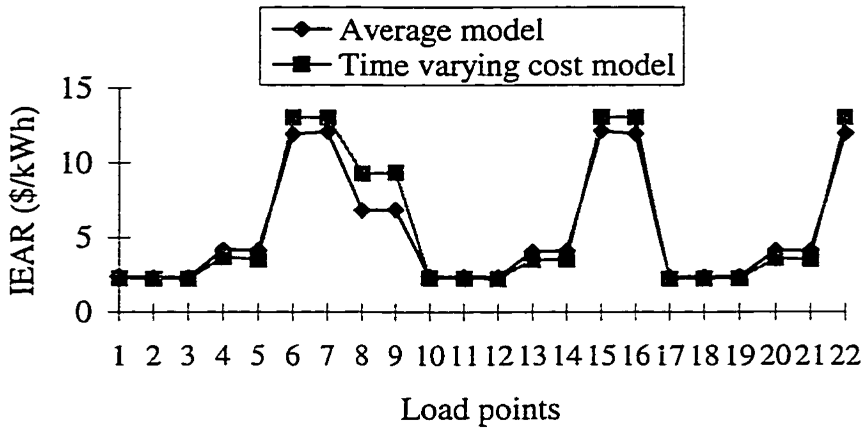

Fig. 5.30 Load point IEAR for two cost models

Feeder and System Indices

Fig. 5.31 shows the feeder and system ECOST values obtained using the two models. It can be seen that the ECOST increases for both the feeders and the system using the time varying cost model. Fig. 5.32 shows the feeder and system IEAR for the two models. It can be seen that while there is a relatively large difference in the IEAR of Feeder 2 there are only relatively small differences for other feeders and for the system.

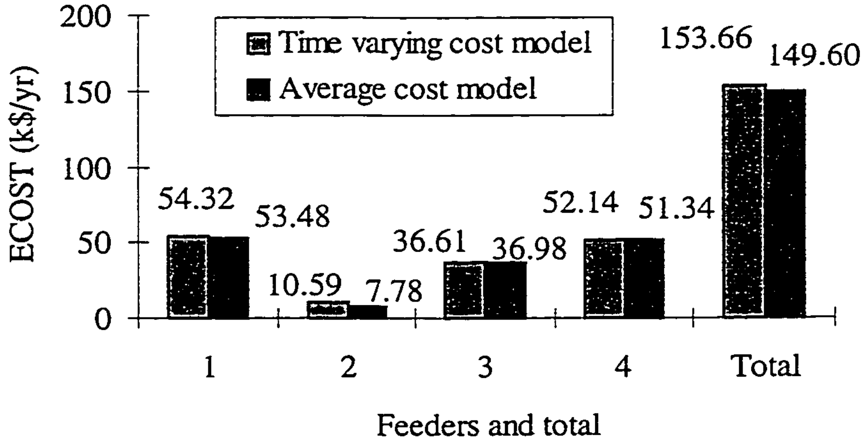

Fig. 5.31 Feeder and system ECOST for the two models

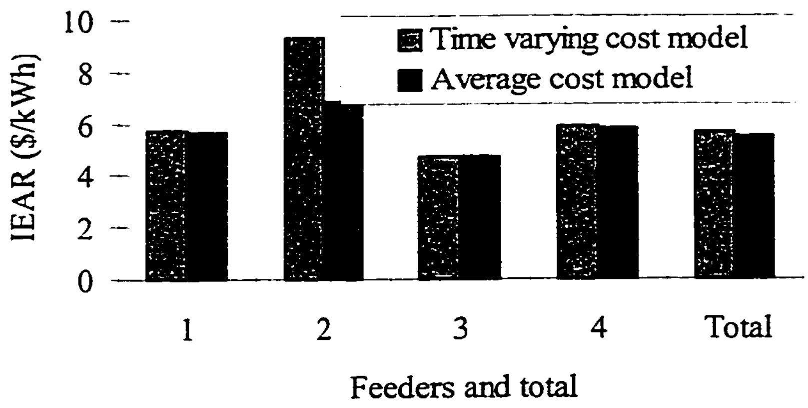

Fig. 5.32 Feeder and system IEAR for the two models

5.7. Conclusion

The time varying nature of the load and cost models for the seven customer sectors is examined in this chapter. A time sequential simulation approach was used in conjunction with the developed models to evaluate the load point and system customer interruption costs of a practical radial distribution system. The effect of the time varying load and cost models on the reliability cost/worth indices of different customer sectors is illustrated by application to the test distribution system. The technique presented can be used to provide a complete set of load point and system indices. These indices and their probability distributions provide the system planner with a clear picture of the system reliability profile. The results presented illustrate that in general, the use of an average load model provides a slightly inflated estimate of the system unreliability and that a time varying load model can be used to give a more accurate estimate. The results also show that the system interruption cost can increase or decrease using a time varying load model depending on the customer type and the shape of the cost model.

6. Reliability Worth of Distribution System Network Reinforcement Considering Dispersed Customer Cost Data

6.1. Introduction

As described in the previous chapters, reliability cost/worth analysis plays an important role in distribution system planning and operation. The interruption cost model used in the analysis directly affect the predicted reliability worth used to make reinforcement decisions The basic cost models used for reliability cost/worth analysis are the sector customer damage functions which are usually average or aggregate models (AAM). The major disadvantage of the SCDF is that the function considers only the average or aggregate monetary losses for selected interruption scenarios. The average or aggregate model provides a measure of the central tendency of the customer interruption data. The customer interruption cost data for a specified customer and a given duration, however, shows a very large variation [75, 93, 94]. In some cases, the standard deviation is more than four times the mean. References 53, 54 and 55 illustrate the dispersed nature of customer interruption costs at the specified failure durations and show that this can have a significant effect on the predicted expected customer interruption cost. The dispersed nature of the cost data has been considered in the reliability cost/worth analysis of generation and transmission systems [55,56]. The analysis shows that the dispersed nature of the cost data can have considerable effect on the reliability cost indices at HLI and HLII.

Considerable work has been done on reliability cost/worth evaluation of distribution systems using average or aggregate cost models. The dispersed nature of cost data, however, has not been considered in reliability cost/worth analysis of distribution systems. This chapter illustrates the use of a new cost model in distribution system reliability cost/worth evaluation. This new cost model is called the probability distribution cost model (PDM) which includes the effect of the dispersed nature of the cost data. The average or aggregate cost models and the probability distribution models for the residential and industrial customers from the 1991 Canadian survey data are introduced. A time sequential simulation technique for distribution system reliability cost/worth assessment considering the dispersed nature of the cost models and incorporating time varying loads is illustrated. The technique is used to evaluate the reliability worth of installing lateral fuses, disconnect switches and alternate supplies in a test distribution system.

6.2. 1991 Average and Aggregate Cost Model

A Canadian customer postal survey was conducted by the Power System Research Group at the University of Saskatchewan to obtain customer interruption data in 1991 [52]. The survey covered the residential, commercial, small industrial and agricultural sectors. A general overview of the survey methodology used is given in [52]. The detailed descriptions of the survey rationale, questionnaire development and content are introduced in [10,71]. More complete details and results are presented in the final project report [50]. The 1991 survey data have been analyzed in reference [55] to give the SCDF for residential and industrial customers. The resultant SCDF is tabulated in Table 6.1 and displayed in Fig. 6.1

Table 6.1 Sector interruption cost (1991 $/kW)

User Sector	Interruption Duration (Min.) & Cost ($/kW)				
	1min.	20 min	60 min.	240 min.	480 min.
Industrial	3.1663	4.3217	6.5508	16.2679	30.3254
Residential	0.0002	0.0278	0.1626	1.8126	4.0006

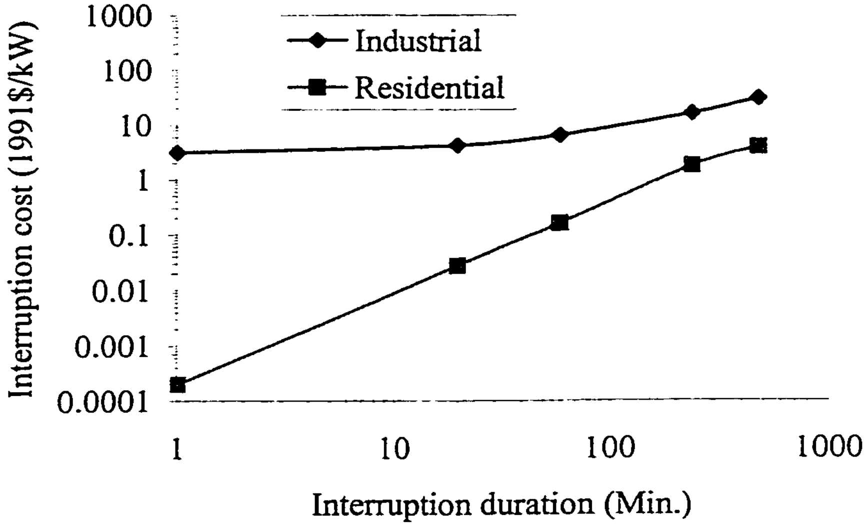

Fig. 6.1 SCDFs generated form 1991 $/kW cost data

In reality, the duration of a power failure is not limited to those durations noted in the survey and the failure duration can be any possible value. Unfortunately, a survey questionnaire can only include a very limited number of interruption scenarios. The problem is how to infer intermediate costs from those of the known durations. A log-log linear interpolation of the cost data is used where the interruption duration lies between two separate times. In the case of a duration greater than 8 hours, a linear extrapolation with the same slope as that between the 4 and 8 hour values was used to calculate the interruption cost.

6.3. Dispersion Nature of Cost Data

As described earlier, the AAM provides a measure of the central tendency of the customer interruption data. The approach used to evaluate the reliability cost using the AAM is called the customer damage function method (CDFM). The average value does not provide any indication of the spread in the survey data. The results obtained using this approach therefore do not reflect the dispersed nature of the actual interruption costs. The dispersion nature at a specified duration time can be represented by basic statistics such as the range, variance and standard deviation. Table 6.2 shows the interruption cost data for commercial customer from the 1991 customer survey [55].

Table 6.2 Basic Statistics of Cost Data for the 1991 Commercial Sector ($/interruption)

Interruption duration	Mean	Standard deviation	Minimum	Maximum	Skewness
1 minute	170.9	810.6	0.0	7500.0	7.03
20 minutes	400.5	1187.0	0.0	9158.0	5.06
1 hour	1182.6	4798.5	0.0	61375.0	10.17
2 hours	2087.5	6499.8	0.0	62250.0	6.94
4 hours	4352.9	15000.0	0.0	158908.0	7.52
8 hours	7806.7	23385.8	0.0	220600.0	6.65
1 day	17138.7	116875.8	0.0	1685000.0	13.71

It can be seen from the table that the interruption cost values display a very large variation. Using a one day duration as an example, although the average cost is $17,138 per interruption, some users have significantly larger losses ($1,685,000/interruption) and some users indicate that they have negligible losses. It is evident therefore that the conventional SCDF does not provide complete information on the cost profile.

6.4. Probability Distribution Cost Model

The variability of a set of widely scattered data can be described by a probability distribution [95]. There are many different types of probability distributions available to describe a continuous random variable. The most common one in use is the normal distribution. Fig. 6.2 shows the possible dispersed nature of the cost data based on the assumption of a nonnal distribution. The cost model that represents the cost data using a probability distribution is called a probability distribution model (PDM) [55].

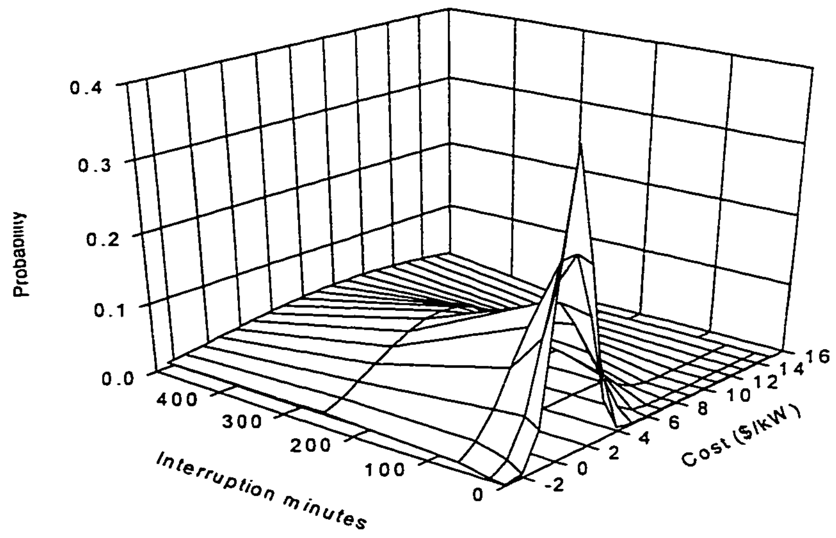

Fig. 6.2 Dispersion nature of cost data

6.4.1. Normality Transformation of True Cost Data

Unless a detailed examination is conducted, it is difficult to identify the probability distribution model which best fits a given set of data. Conceptually, actual cost data can follow any possible probability distribution. Rather than arbitrary selecting a probability distribution and examining its appropriateness to describe the data, a more systematic procedure designated as Normality Transformation was used to conduct the analysis [55]. In this approach, the set of cost data for a specified duration are transformed into a normal distribution using the Normality Transformation proposed by Box and Cox [96]. The transformation equations used are:

$$y=\begin{cases}\dfrac{x^{\lambda}-1}{\lambda}, & \text{if } \lambda \neq 0, \\ \log(x), & \text{if } \lambda = 0, \end{cases} \qquad (6.1)$$

where x refers to the original data, λ is the power exponent and y is the transformed value. There are two limitations to this family of equations. It applies only to continuous variables and it does not apply to zero-valued data. In order to satisfy these constraints, zero value customer outage cost observations were extracted from the duration specific data and treated separately. The remaining data were analyzed for normality using an iterative process designed to determine the value of λ which best transforms a set of cost data into a normal distribution. The detailed procedure to determine λ is presented in Reference [55].

6.4.2. Parameters of Normally Distributed Data

When the normality transformation approach is utilized to deal with a group of cost data, the results can be described by a set of parameters. The distributed nature of the interruption cost data for a particular customer sector and a specific outage duration is defined by four parameters. The mean of the normal transformed distribution μ is used to determine the central location of the cost data. The variance of the normal transformed distribution σ^2 describes its dispersion. The parameter P_z represents the proportion of zero-valued data. The normality power transformation factor λ is used to convert the original data such that the transformed distribution satisfies the goodness-of-fit test of normality.

Tables 6.3 and 6.4 show these parameters for the residential and industrial customer sectors from the 1991 survey data. The detailed procedure to determine the four parameters from the survey data is illustrated in [55].

Table 6.3 The parameters for a residential customer

Duration	λ	μ	σ^2	P_z (%)
20 min	-0.2207	-5.6618	4.8689	0.3295
1 hr	-0.1828	-2.7329	2.8790	0.0973
4 hr	-0.0105	0.2886	1.6551	0.0265
8 hr	-0.0160	1.1345	1.5725	0.0426

Table 6.4 The parameters for a industrial customer

Duration	λ	μ	σ^2	P_z (%)
1 min	-0.0488	0.3352	3.8770	0.3488
20 min	-0.6605	1.0487	2.7866	0.1513
1 hr	-0.0707	1.6327	2.3443	0.0613
4 hr	-0.0387	2.8272	2.3620	0.0047
8 hr	-0.0020	3.6939	2.9880	0.0047

6.4.3. Parameter Determination for Intermediate Durations

It is more difficult to determine intermediate duration costs when the PDM is used. The interpolation method utilized in the AAM cannot be used as there is no single parameter at each particular studied duration. Regression analysis was used to predict the distribution patterns for the intermediate durations based on the known parameter values. The least square method [97] was used to obtain the equations describing the relationship between the studied duration values and each of the four parameters. The procedure defines the best fitting curve as that which minimizes the sum of the squared vertical distances from the observed points to the curve. The detailed procedure to determine the best fitting curves of the four parameters is discussed in [55]. The equations for the four parameters from the 1991 survey data are presented in the following:

The equations for a residential customer are:

$$\lambda = -0.6690 + 0.1456\log(d), \tag{6.2}$$

$$\mu = -19.23 + 4.5563\log(d), \tag{6.3}$$

$$\sigma^2 = 34.989 - 14.88\log(d) + 1.6512[\log(d)]^2, \tag{6.4}$$

$$P_z = 284.7[\log(d)]^{-6.1758}. \tag{6.5}$$

The equations for an industrial customer are:

$$\lambda = 0{,}0175 - 0.0515\log(d) + 0.0053[\log(d)]^2 + 0.001[\log(d)]^3, \tag{6.6}$$

$$\mu = 0.148*10^{0.2955\log(d)}, \tag{6.7}$$

$$\sigma^2 = 4.2983 + 0.6234\log(d) - 0.6779[\log(d)]^2 + 0.1007[\log(d)]^3, \tag{6.8}$$

$$P_z = \begin{cases} 0.5409 - 0.1297\log(d), & d < 4 hours, \\ 0.0047, & d \geq 4 hours. \end{cases} \tag{6.9}$$

Equations (6.5) and (6.9) are used to determine the portion of zero-valued costs. Equations (6.2-6.4) and (6.6-6.8) can be used to generate normally distributed random numbers which can be used to determine the transformed customer interruption costs for both the specified and intermediate durations based on Equations (6.1).

6.4.4. Conversion to True Cost Values

Previous studies [55] deal with the conversion of actual cost data to the transformed normally distributed forms. Transformed data can be easily generated by a random number generator based on the mathematical models. It is important to realize that the transformed values are not actual values. Before the interruption cost indices are calculated, the transformed data must be converted back to actual values. The conversion equation which is simply an inverse function of Equation (6.1) is shown in the following equation.

$$x = \begin{cases} (1+\lambda \cdot y)^{1/\lambda} & \text{if } \lambda \neq 1, \\ \log^{-1}(y) & \text{if } \lambda = 0, \end{cases} \qquad (6.10)$$

where x and y relate to the customer outage cost and transformed cost respectively.

6.5. Simulation Procedure

The procedure used to simulate customer interruption costs using a PDM is more complex than that required using the CDFM. Most of the steps in the PDM procedure are the same as the steps described in Chapter 4, except for those steps used to evaluate the interruption cost for a simulated interruption duration. The PDM procedure for a failure event i which occurs with d_i duration consists of the following steps:

1). P_z is calculated from the d_i using equations (6.2)-(6.5) or (6.6)-(6.9) depending on the specified customer.

2). A uniform distributed U(0,1) random number X_1 for a customer is generated and compared with P_z to determine whether or not a zero interruption cost should be assigned to the outage.

3). If X_1 is less than, or equal to P_z, the customer is assigned a zero outage cost.

4). If X_1 is larger than P_z, the parameters (λ, μ and σ) are determined from the corresponding failure duration d_i and another normally distributed random number X_2 is generated to sample a transformed cost y from the parameters.

5). The y value is converted to its actual or true $/kW cost x using Equation (11) and is used to calculate the cost indices.

6.6. System Studies

The two approaches of average or aggregate modeling and probability distribution modeling were used to evaluate the load point interruption cost of the distribution system shown in Fig. 3.1. The time varying load models used in the previous chapter are used as the load models. The reliability parameters of the transmission lines and transformers and the average loads are given in [62, 53]. The only difference is that there are two types of customer in this system. Load points (1-7, 10-19) consist of residential customers and load points (8-9 and 20-22) are industrial customers. The AAM and PDM obtained from the 1991 survey data were used for the residential and industrial customers.

6.6.1. Load Point Cost Indices

The load point and system reliability cost/worth indices were calculated using the simulation technique with the two cost models. The annual expected load point interruption costs (ECOST) and load point interrupted energy assessment rate (IEAR) for all the load points are shown in Fig. 6.3 and Fig. 6.4 respectively.

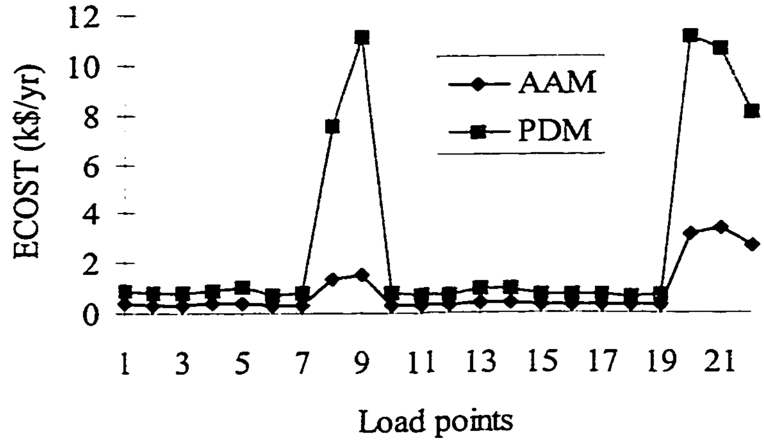

Fig. 6.3 Load point ECOST for the two cost models

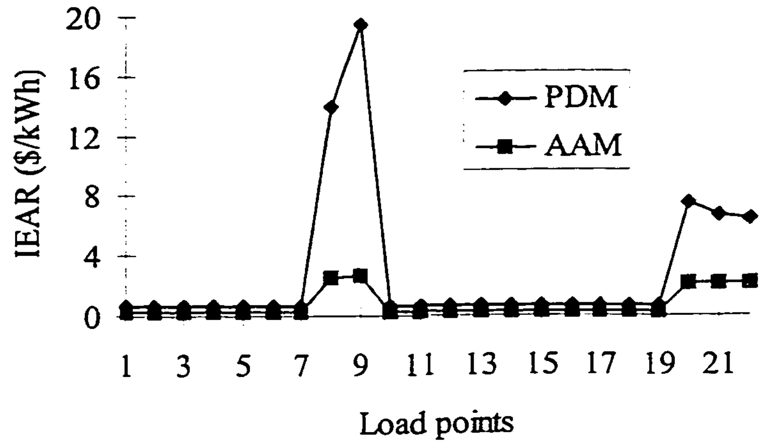

Fig. 6.4 Load point IEAR for the two cost models

Table 6.5 presents the detailed load point ECOST (k$/yr) and IEAR ($/kWh). The ECOST of Load point 1 increases by 133% from $369 to $859 per year. The ECOST of load point 9 increases by 644% from $1,498 to $11,141. The IEAR of load point 1 increases from 0.284 $/kWh to 0.660 $/kWh and the IEAR of load point 8 increases from 2.624 $/kWh to 19.517 $/kWh. It can be seen from the figures and tables that the ECOST and IEAR values obtained using the two approaches are considerably different.

Table 6.5 Load point ECOST and IEAR using the two models

Load	ECOST		IEAR	
(i)	AAM	PDM	PDM	AAM
1	0.3695	0.8593	0.6604	0.2839
2	0.3576	0.7796	0.6134	0.2814
3	0.3480	0.7790	0.6263	0.2798
4	0.3796	0.9141	0.6826	0.2835
5	0.4007	1.0428	0.7359	0.2827
6	0.3097	0.6952	0.6343	0.2825
7	0.3493	0.7963	0.6530	0.2865
8	1.3690	7.5376	13.9480	2.5332
9	1.4976	11.1410	19.5173	2.6236
10	0.3433	0.8078	0.6623	0.2814
11	0.3273	0.7580	0.6452	0.2786
12	0.3201	0.7512	0.6633	0.2826
13	0.4206	0.9838	0.6670	0.2852
14	0.3990	0.9515	0.6758	0.2834
15	0.3142	0.7398	0.6689	0.2841
16	0.3012	0.7286	0.6787	0.2806
17	0.2976	0.7316	0.6979	0.2839
18	0.2980	0.6791	0.6469	0.2839
19	0.2873	0.6910	0.6773	0.2816
20	3.1498	11.1006	7.5126	2.1317
21	3.3466	10.6507	6.7043	2.1066
22	2.6431	8.0876	6.5080	2.1269

Table 6.6 shows the cost indices of the feeders and the system. The ECOST of the system increases by 248 percent from \$62,184 using the PDM, to \$17,826 using the AAM.

Table 6.6 System ECOST and IEAR using the two models

Feeder	ECOST		IEAR	
(i)	PDM	AAM	PDM	AAM
1	5.8664	2.5144	0.6600	0.2829
2	18.6562	2.8632	16.8089	2.5797
3	4.9919	2.1243	0.6642	0.2827
4	32.6692	10.3238	3.8431	1.2145
Total	62.1837	17.8256	2.3904	0.6852

It can be concluded that the dispersed nature of the cost model has a significant impact on the ECOST and IEAR of a load point and the system. The AAM tends to severely underestimate the interruption cost at a load point.

6.6.2. The Probability Distribution of the Cost Indices

As described earlier, probability distributions of the load point and system indices provide important information about the system and load point reliability. Fig. 6.5 and Fig. 6.6 show the probability distributions of the failure duration (hr/failure), COST (k$/failure) and ENS (MWh/failure) for load point 1 using the PDM. The variates are grouped into discrete class intervals for clarity. It can be seen from Fig. 6.5 that the first peak in failure duration is between 0-1 hours with 0.37 probability and the second peak occurs at 4-5 hours with 0.13 probability. The interruption costs are between 0 and $1000 for approximately 85 percent of the failures. The energy not supplied for 65 percent of the failures is between 0-1 MWh. Fig. 6.6 shows that the most probable interruption costs are in the $9000 or more category for load point 8. The duration of 20 percent of the failures lasts 4-5 hours. The first peak for the energy not supplied occurs at 1-2 hours.

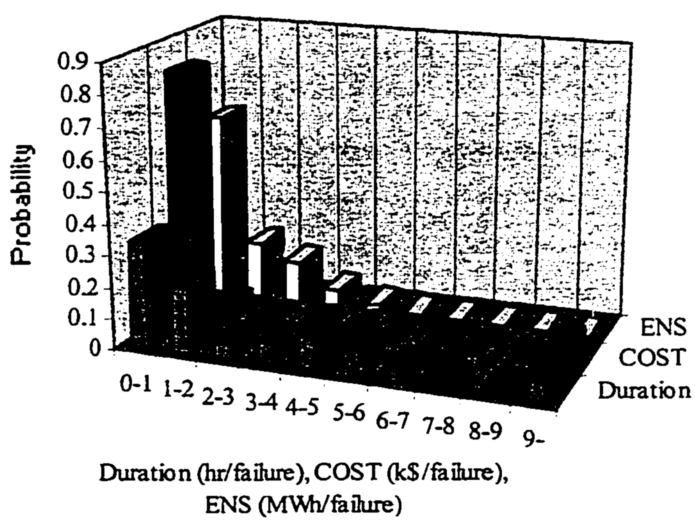

Fig. 6.5 Probability distribution of Duration, COST and ENS for load point 1

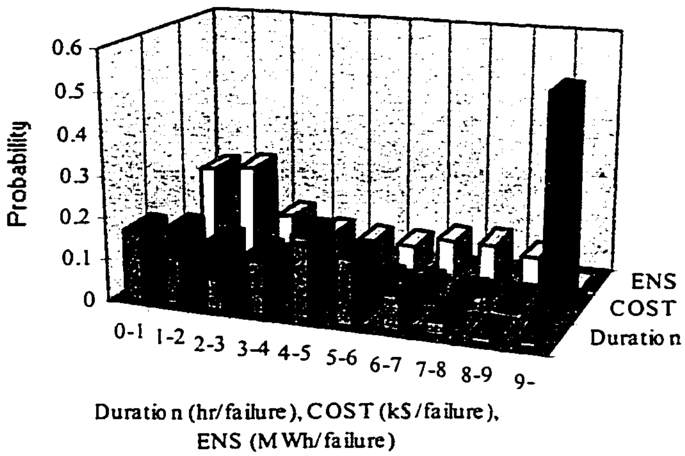

Fig. 6.6 Probability distribution of Duration, COST and ENS for load point 8

Fig. 6.7 shows the COST and ENS probability distributions for Feeder 1. The index probability distribution provides a clear picture of the performance of the load points and the system.

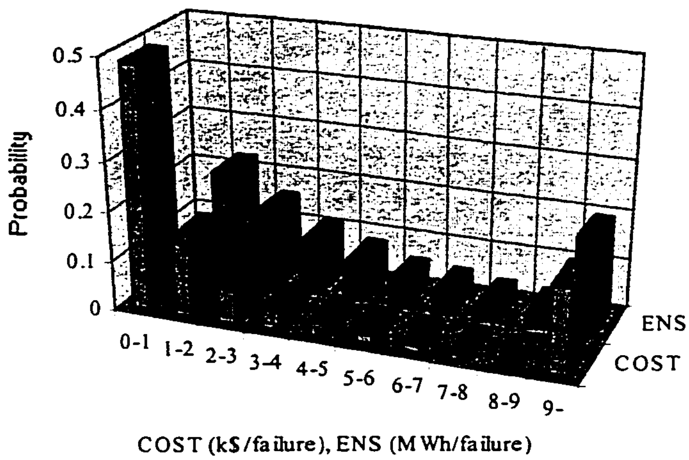

Fig. 6.7 Probability distribution of COST and ENS for Feeder 1

6.6.3. Effect of the Two Cost Models on the Probability Distributions

The probability distributions of the load point and system indices obtained using the two cost models may be different. Fig. 6.8 and Fig. 6.9 show the effect of the different cost models on the probability distributions of the cost indices. It can be seen from Fig. 6.8 that the probabilities of large interruption costs using the PDM increase compared with those obtained using the AAM. The probabilities of small interruption costs decrease using the PDM compared with those obtained using the AAM. For load point 8, the probabilities of costs over $9000 are virtually the same for both models. The probabilities associated with other cost levels can increase or decrease depending on the load types.

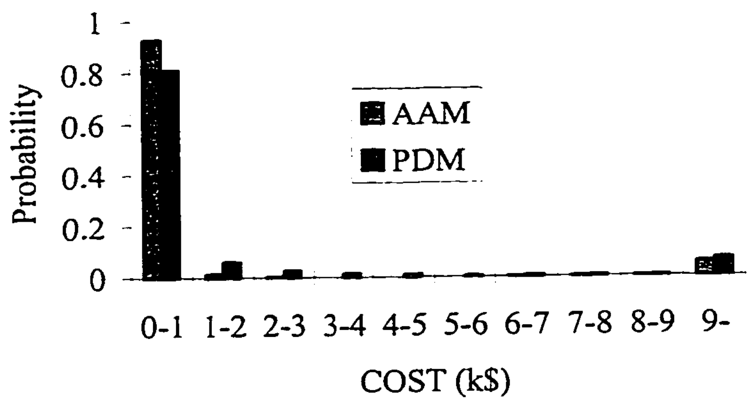

Fig. 6.8 Probability distribution of COST for Load point 1 using the two cost models

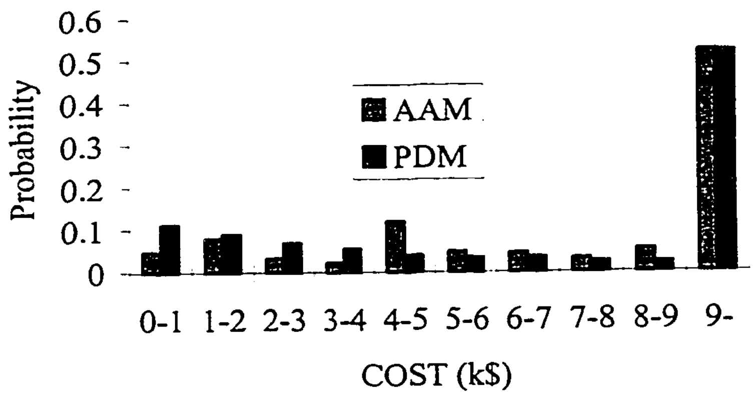

Fig. 6.9 Probability distribution of COST for Load point 8 using the two cost models

6.7. Reliability Worth of Network Reinforcement Using the Two Models

The reliability worth of network reinforcement (RWNR) plays an important role in power system planning, design and expansion. If the RWNR is large or equals the investment in the reinforcement, both utilities and customers will benefit. The RWNR can be calculated using the following equation:

$$RWNR = COST_B - COST_A, \qquad (6.12)$$

where $COST_B$ and $COST_A$ are the system or load point interruption costs before and after reinforcement respectively.

The reliability worth of three different network reinforcements for the distribution system in Fig. 3.1 is illustrated in this section. The distribution system is first modified into a basic structure (Case 1) in which there are no fuses in the lateral sections, no disconnect switches in the main sections and no alternate feeder supplies. The fuses are then added to all lateral sections (Case 2). After that disconnect switches are installed in selected locations in the main sections (Case 3). Alternate supplies are then added to all feeders (Case 4). The four cases were evaluated and compared to determine the corresponding reliability worth of the stated reinforcements.

6.7.1. Reliability Worth of Lateral Fuses

Fuses are usually installed in the lateral sections of a distribution system. In this case, 22 lateral fuses are installed in the system. The ECOST of the system and the load points with and without the lateral fuses were evaluated using the two cost models. The reliability worth of the lateral fuse additions (RWFA k$/yr) is calculated. The results for Case 1 and Case 2 are shown in Table 6.7 -Table 6.10

Table 6.7 Load point RWFA using the AAM

Load (i)	ECOST (Case 1)	ECOST (Case 2)	RWFA
1	2.4736	0.4149	2.0587
2	2.4734	0.4035	2.0699
3	2.4734	0.3942	2.0792
4	2.6394	0.4285	2.2109
5	2.6394	0.4503	2.1891
6	2.1115	0.3493	1.7622
7	2.1115	0.3914	1.7201
8	2.1335	1.5444	0.5891
9	2.456	1.7818	0.6742
10	2.1072	0.3907	1.7165
11	2.1069	0.375	1.7319
12	1.7722	0.3599	1.4123
13	2.2484	0.4751	1.7733
14	2.2484	0.4534	1.795
15	1.7987	0.3555	1.4432
16	2.0856	0.3395	1.7461
17	2.0546	0.3358	1.7188
18	2.0546	0.3379	1.7167
19	2.0546	0.327	1.7276
20	17.4875	3.5384	13.9491
21	17.4875	3.752	13.7355
22	13.99	2.9622	11.0278

Table 6.8 System RWFA using the AAM

Feeder	ECOST (Case 1)	ECOST (Case 2)	RWFA
1	16.922	2.832	14.090
2	4.584	3.322	1.262
3	12.281	2.409	9.87184
4	57.214	11.593	45.622
Total	91.002	20.156	70.845

Table 6.9 Load point RWFA using the PDM

Load (i)	ECOST (Case 1)	ECOST (Case 2)	RWFA
1	5.741	1.0563	4.6847
2	5.8404	0.9774	4.863
3	5.5322	1.0157	4.5165
4	6.1981	1.1275	5.0706
5	6.5181	1.2593	5.2588
6	5.0769	0.9215	4.1554
7	4.8653	0.9729	3.8924
8	15.2955	9.8406	5.4549
9	16.165	12.4356	3.7294
10	4.8852	1.0021	3.8831
11	5.0021	0.9237	4.0784
12	4.3064	0.8449	3.4615
13	5.3454	1.2509	4.0945
14	5.2562	1.1899	4.0663
15	4.3114	0.8347	3.4767
16	4.7262	0.9352	3.791
17	4.8302	0.8517	3.9785
18	4.9047	0.8663	4.0384
19	5.0322	0.8594	4.1728
20	44.8396	14.3572	30.4824
21	49.2017	14.9917	34.21
22	37.9661	10.4444	27.5217

Table 6.10 System RWFA using the PDM

Feeder	ECOST	ECOST	RWFA
	(Case 1)	(Case 2)	
1	39.772	7.331	32.441
2	31.423	22.249	9.173
3	29.105	6.046	23.059
4	151.50	43.306	108.194
Total	251.80	78.932	172.869

It can be seen from Table 6.7 that the ECOST of Load point 1 decreases from \$2,474 to \$ 415 with a \$2,059 RWFA using the AAM. Table 6.8 shows that the ECOST of Load point 1 decreases from \$5,741 to \$1,056 with a \$4,685 RWFA using the PDM. The variation in the system ECOST obtained using the two models can be seen from Table 6.9

and Table 6.10 The RWFA of adding the lateral fuses in each lateral section is $70,845 per year using the AAM and $172,869 using the PDM.

Fig. 6.10 compares the load point RWFA using the two models. The RWFA values obtained using the PDM are larger than those obtained using the AAM. Fig. 6.11 shows the RWFA of the feeders and the system. The RWFA obtained using the PDM for Feeders 1, 3, 4 and the total system are clearly higher than those for the AAM.

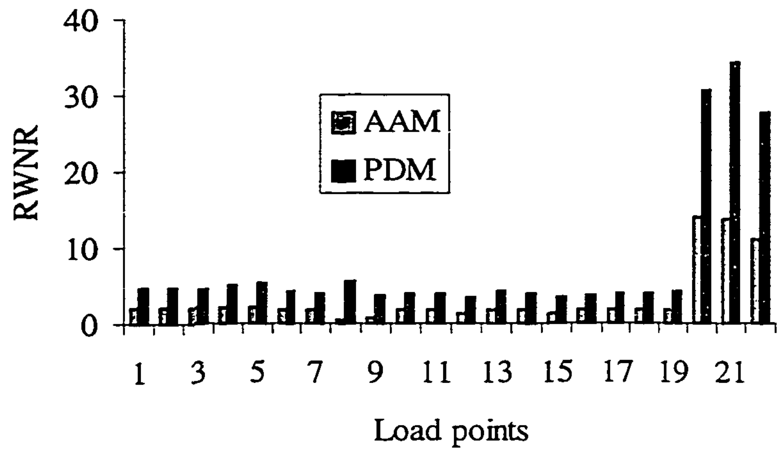

Fig. 6.10 Load point RWFA using two models

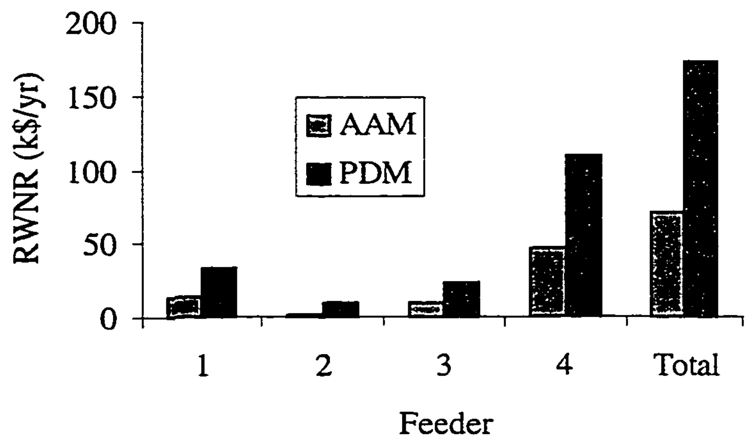

Fig. 6.11 System RWFA using two models

It can be concluded that using the AAM clearly underestimates the reliability worth of adding lateral fuses.

6.7.2. Reliability Worth of Disconnect Switches

The function of disconnect switches in the main feeder is to isolate failed elements and affected load points and to restore other loads to service if a failure occurs in the main section. In this example, ten disconnect switches were installed in the system used in Case 2. The reliability worth of the disconnect switch additions (RWSA) obtained using the two models is shown in Fig. 6.12 and Fig. 6.13 It can be seen that the RWSA of the load points and the system using the two cost models exhibit large differences. The RWSA for some load points is zero as disconnect switches have no effect on the reliability at these load points. The results show that some load points benefit considerably from the installation of disconnect switches and some do not.

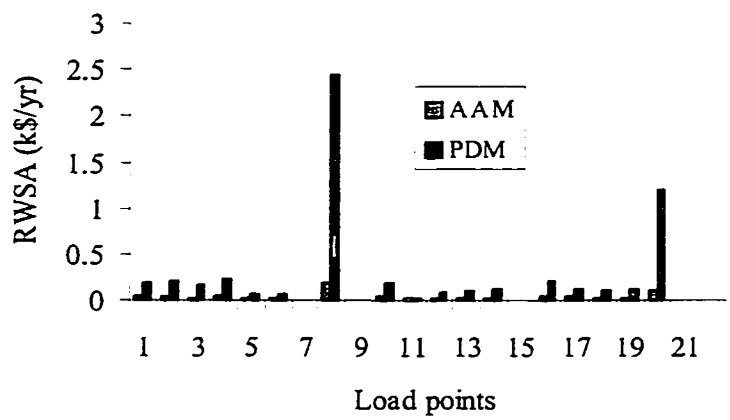

Fig. 6.12 Load point RWSA using the two models

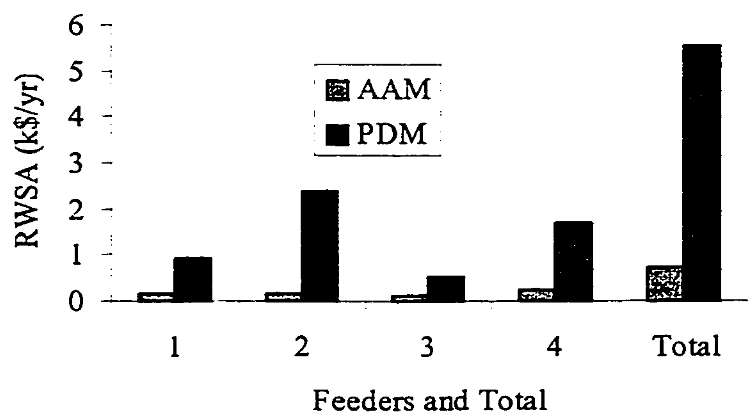

Fig. 6.13 System RWSA using the two models

6.7.3. Reliability Worth of Alternate Supplies

After the failed elements are isolated from the system, service to some load points is restored through the main supply and service to other load points is restored by an alternate supply. Alternate supplies were provided on each feeder in the system for Case 3. The reliability worth of the alternate supply additions (RWAA) is shown in Fig. 6.14 and Fig. 6.15 The RWAA at some load points are zero as the alternate supplies have no effect on these loads, and therefore not all load points benefit from this reinforcement.

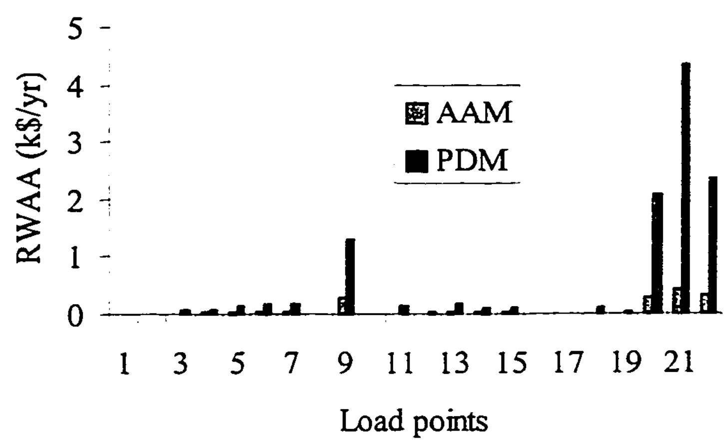

Fig. 6.14 Load point RWAA using the two models

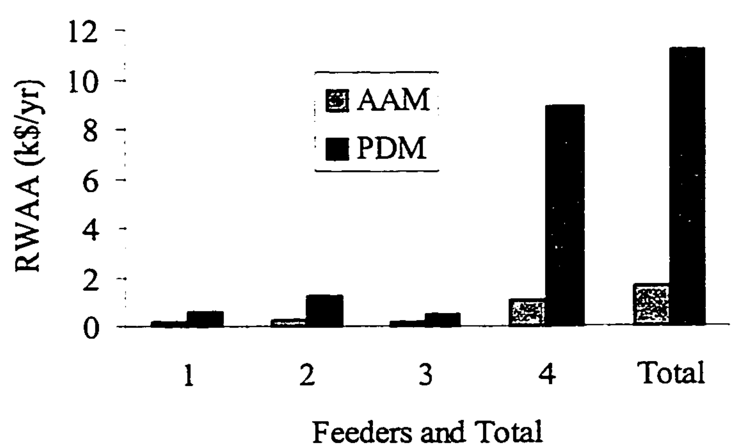

Fig. 6.15 System RWAA using the two models

It can be seen from the analyses that lateral fuses, disconnect switches and alternate supplies have different impacts on the reliability of the load points and the system. In this distribution system, the installation of lateral fuses has higher reliability worth than the addition of disconnect switches and alternate supplies. Some load points benefit from the installation of disconnect switches and alternate supplies and others do not. In each case, however, the monetary value of the reliability worth associated with the reinforcement is higher using the PDM than that obtained using the AAM. The PDM provides a better estimate and therefore the AAM can be considered to underestimate the reliability worth of installing protective devices.

6.8. Summary and Conclusion

The dispersed nature of the interruption cost data is discussed in this chapter. Two cost models designated as the average or aggregate model which does not consider the dispersed nature and the probability distribution model which does consider the dispersed nature are presented. The AAM and PDM for the residential and industrial customers based on 1991 survey data are illustrated. A time sequential simulation technique using the two developed models has been developed. The technique has been used to evaluate individual load point and system interruption costs and the probability distributions of the cost indices in a representative distribution system. The reliability worth of installing lateral fuses, disconnect switches and alternate supplies in a distribution system were also investigated using the two cost models. The reliability worth can be compared with the investment in the reinforcement to assist system planners in making economic planning and operating decisions. It can be concluded from the cost/worth analysis that using an average or aggregate model can result in underestimating of the reliability worth of network reinforcements and that the probability distribution model provides a more realistic approach.

7. Reliability Evaluation of a Rural Distribution System Considering Wind Generation as An Alternative Supply

7.1. Introduction

Economic and environment concerns with electrical energy derived from fossil and nuclear fuels as well as dwindling fossil resources have caused an increased interest in the development and use of alternative sources, such as wind, wave, geothermal and solar energy. The wind is potentially a huge energy source. The World Meteorological Organization has estimated that a little less than 1 percent of the wind energy (that is, 0.6 quads or 10^{18} Btu or 175×10^{12}kWh) is available at selected sites throughout the world [98]. The capture of a significant amount of energy from the wind as a fuel-saving option has being considered by many utilities throughout the world.

The integration of large numbers of wind turbines can have considerable impact on the reliability performance of an aggregate system. It is therefore necessary to develop reliability evaluation techniques which can be used by utilities to assess the effects of wind turbine generators (WTG) on system adequacy and to make relatively optimal planning and operating decisions.

Both analytical and simulation techniques have been used to evaluate the reliability of an electric power system containing WTG. [58,99-104]. Analytical techniques are very useful and efficient for evaluating the basic reliability indices. The weaknesses of the analytical techniques are that the chronological characteristic of wind velocity cannot be considered and the probability distributions of the indices are difficult to evaluate. The basic time varying nature of wind velocity can be included using sequential simulation techniques.

Simulation techniques considering WTG have been utilized to evaluate generation system reliability. Relatively little research work has been done using simulation techniques in rural distribution system reliability evaluation including WTG as an alternative supply.

In urban distribution systems, distribution feeders are usually connected to an alternative supply by a normally open switch in order to improve the reliability of each individual load point. The alternative supply and the main supply are connected to the same bulk system but at different locations. For example, a feeder on one street can be the alternative supply for the feeder on other parallel street. This type of structure improves the load point reliability without large increases in investment. In a remote rural distribution system, this configuration cannot be utilized because of economical reasons. An interesting question therefore is, can WTG be used to increase the reliability of a rural distribution system and how efficient are WTG compared to conventional generators (CG)?

Wind and WTG models are introduced in this chapter. The possible utilization of wind turbine generation as an alternative supply is investigated from both energy and capacity points of view. The focus is on the reliability implications rather than on installation and operating economics. The time sequential simulation technique is used to evaluate the reliability indices including WTG. The effects on the reliability benefits of WTG parameters and wind site location were investigated and are discussed in this chapter. A small rural test distribution system is utilized to illustrate the technique.

7.2. Wind Energy Models

The wind energy is regarded as a very promising renewable and environmentally friendly energy source and has been used as a source of power for many centuries. It was used first to drive windmills for water pumping and corn grinding and is now used to drive electric turbine generators. Widespread interest has been taken in the potential of the wind as a source of energy in recent years for the following reasons [98,104]:

(1) rapidly increasing demand for electrical energy,

(2) limitations of potential hydro-electric resources,

(3) high and rising costs of generation at steam-driven stations and the corresponding transmission,

(4) realization that coal and oil resources are being used at an increasing high rate,

(5) public and government objections to the use of coal and fuel resources because of environmental concerns,

(6) development of better technology for wind turbine generation,

(7) perceived quantity of kilowatt-hours of wind energy available each year over the earth's surface.

Wind speed varies with time and space and at a specified hour is related to the wind speeds of previous hours. Many wind speed models have been developed and utilized [60, 100]. Wind speed can be represented using auto-regressive and moving average time series models [57,101].

Designate OW_t, μ_t, σ_t and SW_t as the observed wind speed, the mean of OW_t, the standard deviation of OW_t and simulated wind speed at hour t respectively. Let $y_t = (OW_t - \mu_t)/\sigma_t$. The auto-regressive and moving average (*ARMA*) time series model y_t is:

$$y_t = \phi_1 y_{t-1} + \phi_2 y_{t-2} + \ldots + \phi_n y_{t-n} + \alpha_t - \theta_1 \alpha_{t-1} - \theta_2 \alpha_{t-2} - \ldots - \theta_m \alpha_{t-m} \qquad (7.1)$$

where ϕ_i $(i = 1,2,...,n)$ and θ_j $(j = 1,2,...,m)$ are the auto-regressive and moving average parameters of the model respectively, $\{\alpha_t\}$ is a normal white noise process with zero mean and variance α_a^2, i.e., $\alpha_t \in NID(0,\sigma_a^2)$, where NID denotes Normally Independent Distributed.

The simulated wind speed can be calculated using the following equation:

$$SW_t = \mu_t + \sigma_t y_t \tag{7.2}$$

7.3. Wind Turbine Generator Model

A conventional generation unit is normally represented using two states. If the unit is in the up state it is capable of producing its rated capacity. If the unit is in the down state, the power output is zero. A wind turbine generation (WTG) unit can also be represented using up and down states. The main difference is that the WTG output in the up state varies with wind speed, which is a random variable which varies chronologically. The relationship between wind speed and power output is shown in Fig. 7.1

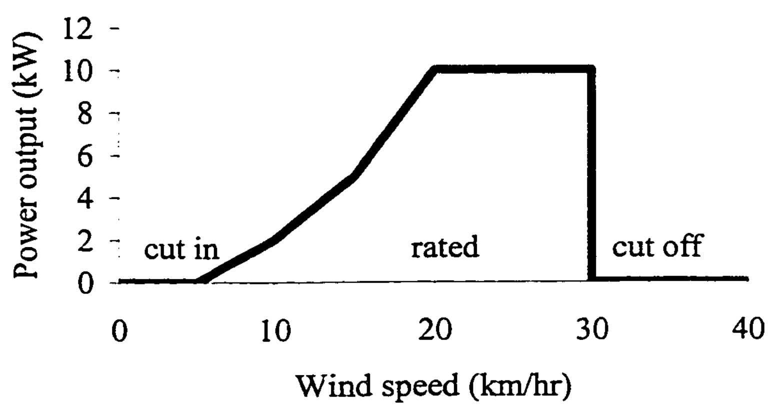

Fig. 7.1 Power output as a function of wind speed

The power output of a WTG is calculated using the following equation [58].

$$P_t = \begin{cases} 0 & 0 \le SW_t \le V_{ci} \\ (A + B \times SW_t + C \times SW_t^2) P_r & V_{ci} \le SW_t \le V_r \\ P_r & V_r \le SW_t \le V_{co} \\ 0 & SW_t \ge V_{co} \end{cases} \tag{7.3}$$

where V_{ci}, V_r, V_{co} and P_r are the cut-in speed, the rated speed, the cut-out speed and the rated power of a WTG unit respectively. The parameters A, B and C are presented in [58].

7.4. Wind Farm Model

A wind farm usually consists of many WTG units and therefore the specified wind velocity is assumed to the same for all WTG units in the farm. A WTG can also suffer a forced outage. In order to consider this effect, the sequential up-down-up cycle of a WTG is simulated based on the TTF and TTR of the WTG. The power output of a wind farm at hour *i* is the summation of the output of all the available WTG.

7.5. Simulation Procedure

The simulation procedure used to conduct reliability worth analysis using WTG as an alternative supply consists of the following steps:

Step1: Generate the time to failure (TTF) for each element in the system according to the probability distribution of TTF.

Step 2: Determine the element with minimum time to failure (MTTF).

Step 3: Generate the time to repair (TTR) and time to switch (TTS) for the element with MTTF according to the probability distribution of TTR and TTS respectively.

Step 4: Isolate the failed element using a series of switching actions.

Step 5: Determine the load points that can be supplied by the main supply and the load points that can be supplied by the WTG.

Step 6: Calculate the maximum load capacity (MLC) of load points that have to be supplied by the WTG.

Step 7: Generate the hourly time sequential wind speed for TTF+TTR hours and calculate the hourly wind output for each hour during the TTR.

Step 8: Calculate the minimum wind generation capacity (MWC) that can be supplied by the WTG during failure hours.

Step 9: Compare the MWC and MLC to determine the load points to be isolated using the load cut policy (discussed in a later section).

Step 10: Calculate the number of load point failures, durations, ENS and interruption cost.

Step 11: If the stopping criterion is satisfied, go to Step 13 otherwise go to Step12.

Step 12: Generate a new TTF for the failed element and go to Step 2.

Step 13: Calculate the load point and system reliability indices.

Load Curtailment Policy

When a fault occurs in a distribution system, a series of switching actions are required to isolate the failed elements from the distribution system. Many load points can often be restored to service through main and alternative supplies. The output capacity of a wind farm depends on the wind velocity and the number of available WTG and therefore the number of load points that can be restored to service due to the wind farm varies with the wind speed during the repair time. The load to be cut is therefore based on the available wind generation capacity at that time and the switching connections. The minimum available wind generation capacity (MWC) of a wind farm during the repair time and the maximum load capacity (MLC) to be supplied by the wind farm are calculated. If the MWC is larger than the MLC, no load is cut. If not, some load must be cut. The curtailment policy used in this research work for both WTG and CG as alternative supplies is to cut the loads connected to the subfeeders first and then the loads connected to the main feeder. Load points are isolated from the down stream feeders to the up stream feeders sequentially. Before a load cut, the switch connection is checked to see if this load can be isolated alone. If no switches exist to isolate this load point alone, the neighboring load point is considered and the switch connection is checked again. This procedure continues until the MLC exceeds or equals the MWC.

It should be appreciated that this is a somewhat idealized procedure and there are many practical problems associated with practical isolation of load points in a distribution system in order to match the connected load with the available WTG capacity. This approach also assumes that the WTG units are self commutating and do not require an external source of ac supply to operate [98]. The approach therefore gives an optimistic assessment of WTG contributions to distribution system reliability.

7.6. Cost/Worth-Based Indices

Energy and Cost/Worth Benefit

Using wind generation as an alternative supply can increase the reliability of a distribution system. The question is what are the benefits of adding wind generation from energy and reliability worth points of view.

The reliability worth of adding wind generation as an alternative supply can be represented by a factor designated as the wind generation energy benefit (WGEB), which can be calculated using the following equation:

$$WGEB = \frac{EENS\text{ (before adding new WTG)} - EENS\text{ (after adding new WTG)}}{\text{Incremental WTG capacity}} \quad (7.4)$$

The reliability worth of adding a conventional generation unit as an alternative supply can be represented by a factor designated as the conventional generation energy benefit (CGEB), which can be calculated using a similar formula to (7.4).

The reliability worth of adding wind generation as an alternative supply can be represented by a factor designated as the wind generation cost benefit (WGCB), which can be calculated using the following equation:

$$WGCB = \frac{ECOST\text{ (before adding new WTG)} - ECOST\text{ (after adding new WTG)}}{\text{Incremental WTG capacity}} \qquad (7.5)$$

The CGCB (conventional generation cost benefit) can also be calculated using a similar formula to (7.5).

The WGCB can be used by a system planner to evaluate possible WTG additions based on investment/kW per year.

Equivalent Unit

Because of the uncertain and time varying nature of wind speed, a 1MW WTG cannot provide the same capacity and energy as a conventional unit of the same size. One problem therefore is how many WTG units should be added to provide the same reliability as that provided by a conventional unit. An index was created to illustrate the number of WTG units required to replace a CG unit of the same size for a specified annual system interruption cost. The equivalent number of CG units (ENCG) of a WTG is defined as follows:

$$ENCG = \left.\frac{\text{The required number of CG}}{\text{The required number of WTG}}\right|_{\text{for a specified reliability cost}} \qquad (7.6)$$

A similar index in terms of equivalent CG capacity (ECGC) is defined using the following equation:

$$ECGC = \left.\frac{\text{The required capacity of CG}}{\text{The required capacity of WTG}}\right|_{\text{for a specified reliability cost}} \quad (7.7)$$

It should be noted that customer interruption cost varies nonlinearly with the number of units and the unit capacities. The ENCG (or ECGC) of WTG is a function of the number (or capacity) of CG.

The procedure used to determine the ENCG includes the following steps:

(1) evaluate the corresponding ECOST for different numbers of CG,

(2) draw the two curves that show the variation in ECOST with the number of CG units and the variation in ECOST with the number of WTG units respectively,

(3) determine the number of WTG for a specified ECOST based on the curves in (2),

(4) determine the number of CG for a specified ECOST based on the curves in (2),

(5) calculate the ENCG using Equation (8.6)

The ECGC can be determined in a similar manner.

7.7. System Analysis

The rural distribution system including WTG connected to Bus 6 of the RBTS distribution system was analyzed using the time sequential simulation technique. This distribution system is a typical rural distribution system with one main feeder (Feeder 4) and three subfeeders (Feeders 5, 6 and 7). Four different cases were considered and the WGEB, CGEB, WGCB and CGCB for the four cases were determined. A comparison is made after the results of the four studies are shown in Tables 7.1 to 7.8

Case 1 (Without an Alternative Supply)

In order to determine the benefit of using WTG as an alternative supply, the basic system was first analyzed to provide a base for comparison. The load point and system indices without an alternative supply are shown in Table 7.1 and Table 7.2. The units of the load point and system indices are the same as those used in the previous chapters. The average load on this feeder is 4.8155 MW and the peak load is 10.9284 MW. The reliability analysis was conducted using the average load at each customer load point.

Table 7.1 Load point indices without an alternative supply

Load (I)	Failure (Occ/Yr)	Unavail. (Hr/Yr)	EENS (MWh/yr)	ECOST (k$/yr)	IEAR ($/kWh)
1	1.766	2.635	0.437	0.473	1.082
2	1.767	3.295	0.596	0.725	1.218
3	1.767	3.694	0.924	0.523	0.566
4	1.768	3.961	1.043	0.585	0.561
5	1.766	4.351	0.901	1.212	1.346
6	1.807	5.208	0.864	1.217	1.409
7	1.814	5.638	1.724	0.932	0.541
8	1.767	6.492	1.009	1.496	1.482
9	1.806	7.433	2.104	1.110	0.528
10	1.765	8.113	1.286	1.975	1.536
11	2.291	9.725	1.511	2.291	1.516
12	2.294	10.538	1.670	2.562	1.534
13	2.291	11.156	2.790	1.455	0.521
14	2.602	7.319	1.137	1.587	1.395
15	2.650	7.954	1.534	0.832	0.542
16	2.600	8.386	1.329	1.913	1.440
17	2.602	9.020	2.256	1.207	0.535
18	2.600	9.795	2.579	1.370	0.531
19	2.583	10.093	1.568	2.347	1.496
20	2.628	10.938	2.110	1.112	0.527
21	2.582	11.109	3.145	1.654	0.526
22	2.582	11.899	1.886	2.893	1.534
23	2.583	12.605	3.853	2.009	0.521

Table 7.2 System indices without an alternative supply

SAIFI	2.061
SAIDI	6.636
CAIDI	3.221
ASAI	0.99924
AENS	0.032
EENS	38.257
ECOST	33.481
IEAR	0.875

Case 2 (One CG as the Alternative Supply)

In this case, one 11.25 MW CG with a forced outage rate of 0.04 is installed at the end of Feeder 4. It is assumed that the CG unit would trip off the line when a fault occurs on the distribution system. It is assumed that the average restoration time of the alternative supply is 0.5 hours. The load point indices and system are shown in Table 7.3 and Table 7.4 .

Table 7.3 Load point indices with one CG as the alternative supply

Load (I)	Failure (Occ/Yr)	Unavail. (Hr/Yr)	EENS (MWh/yr)	ECOST (k$/yr)	IEAR ($/kWh)
1	1.766	2.635	0.437	0.473	1.082
2	1.767	2.568	0.464	0.495	1.067
3	1.767	2.323	0.581	0.356	0.613
4	1.768	2.193	0.577	0.358	0.621
5	1.766	2.326	0.482	0.479	0.995
6	1.807	2.767	0.459	0.509	1.108
7	1.814	2.558	0.782	0.473	0.604
8	1.767	2.758	0.429	0.478	1.116
9	1.806	2.861	0.810	0.479	0.592
10	1.765	2.797	0.443	0.497	1.122
11	2.291	3.515	0.546	0.600	1.097
12	2.294	4.329	0.686	0.837	1.220
13	2.291	4.947	1.237	0.698	0.564
14	2.602	3.830	0.595	0.637	1.070
15	2.650	4.466	0.861	0.504	0.585
16	2.600	4.897	0.776	0.944	1.217
17	2.602	5.531	1.383	0.782	0.565
18	2.600	6.306	1.660	0.922	0.555
19	2.583	3.883	0.603	0.655	1.085
20	2.628	4.729	0.912	0.528	0.579
21	2.582	4.900	1.387	0.797	0.574
22	2.582	5.690	0.902	1.168	1.295
23	2.583	6.396	1.955	1.083	0.554

Table 7.4 System indices with one CG as the alternative supply

SAIFI	2.061
SAIDI	3.316
CAIDI	1.609
ASAI	0.99962
AENS	0.016
EENS	18.970
ECOST	14.753
IEAR	0.778

Case 3 (50 CG as the Alternative Supply)

In order to provide a basis for comparison between CG and WTG, it was assumed that it is possible to install similar size CG and WTG units. This is not practical at the present time but could occur with fuel cell or other unit developments in the future. The Case 2 parameters are more likely at the present time. In this case, 50 identical CG units are installed at the end of Feeder 4. The unit capacities are 0.225 MW with forced outage rates of 0.04. The total capacity is 11.25 MW. The system was evaluated using the developed technique. The load point indices for the system are shown in Table 7.5. The system indices are shown in Table 7.6

Table 7.5 Load point indices with 50 CG units as the alternative supply

Load (I)	Failure (Occ/Yr)	Unavail. (Hr/Yr)	EENS (MWh/yr)	ECOST (k$/yr)	IEAR (k$/mWh)
1	1.766	2.635	0.437	0.473	1.082
2	1.767	2.568	0.464	0.495	1.067
3	1.767	2.323	0.581	0.356	0.613
4	1.768	2.193	0.577	0.358	0.621
5	1.766	2.326	0.482	0.479	0.995
6	1.807	2.767	0.459	0.509	1.108
7	1.814	2.558	0.782	0.473	0.604
8	1.767	2.758	0.429	0.478	1.116
9	1.806	2.861	0.810	0.479	0.592
10	1.765	2.797	0.443	0.497	1.122
11	2.291	3.515	0.546	0.600	1.097
12	2.294	4.329	0.686	0.837	1.220
13	2.291	4.947	1.237	0.698	0.564
14	2.602	3.830	0.595	0.637	1.070
15	2.650	4.466	0.861	0.504	0.585
16	2.600	4.897	0.776	0.944	1.217
17	2.602	5.531	1.383	0.782	0.565
18	2.600	6.306	1.660	0.922	0.555
19	2.583	3.883	0.603	0.655	1.085
20	2.628	4.729	0.912	0.528	0.579
21	2.582	4.904	1.388	0.797	0.574
22	2.582	5.707	0.905	1.174	1.297
23	2.583	7.228	2.210	1.208	0.546

Table 7.6 System indices with 50CG units as the alternative supply

SAIFI	2.061
SAIDI	3.318
CAIDI	1.610
ASAI	0.99962
AENS	0.016
EENS	19.228
ECOST	14.883
IEAR	0.774

Case 4 (50 WTG as the Alternative Supply)

A wind farm is located at the end of Feeder 4 containing 50 WTG units. The rated output of each WTG unit is 0.225 MW. The unit forced outage rate is 0.04. The V_{ci}, V_r and V_{co} are 9, 38 and 80 km/hr respectively. The wind model data used in this study were based on actual data from North Battleford, Saskatchewan, Canada. The annual average wind speed is 14.63 km/hr and the standard deviation is 9.75. The ARMA(3,2) model shown in the following was used as the wind model.

$$y_t = 1.7901 y_{t-1} - 0.9087 y_{t-2} + 0.0948 y_{t-3} + \alpha_t - 1.0929\alpha_{t-1} + 0.2892\alpha_{t-2} \qquad (7.8)$$

where $\alpha_t \in NID(0, 0.474762^2)$.

The system indices are shown in Table 7.7. The load point indices are shown in Table 7.8.

Table 7.7 System indices

SAIFI	2.061
SAIDI	6.022
CAIDI	2.923
ASAI	0.99931
AENS	0.030
EENS	35.420
ECOST	30.503
IEAR	0.861

Table 7.8 Load point indices with WTG as the alternative supply

Load	Failure	Unavail.	EENS	ECOST	IEAR
1	1.766	2.635	0.437	0.473	1.082
2	1.767	3.235	0.585	0.708	1.211
3	1.767	3.563	0.891	0.507	0.569
4	1.768	3.733	0.983	0.556	0.566
5	1.766	3.994	0.827	1.094	1.323
6	1.807	4.699	0.780	1.080	1.386
7	1.814	4.906	1.500	0.823	0.549
8	1.767	5.337	0.829	1.198	1.445
9	1.806	5.861	1.659	0.894	0.539
10	1.765	5.795	0.919	1.357	1.477
11	2.291	8.532	1.326	1.984	1.496
12	2.294	9.466	1.500	2.282	1.521
13	2.291	10.334	2.584	1.355	0.524
14	2.602	6.810	1.058	1.459	1.379
15	2.650	7.551	1.457	0.795	0.545
16	2.600	8.039	1.274	1.827	1.434
17	2.602	8.773	2.194	1.177	0.536
18	2.600	9.624	2.534	1.348	0.532
19	2.583	9.364	1.455	2.161	1.485
20	2.628	10.345	1.996	1.057	0.530
21	2.582	10.687	3.025	1.596	0.527
22	2.582	11.532	1.828	2.799	1.531
23	2.583	12.361	3.779	1.973	0.522

The load point EENS and ECOST indices for the four cases are shown in Fig. 7.2 and Fig. 7.3 .

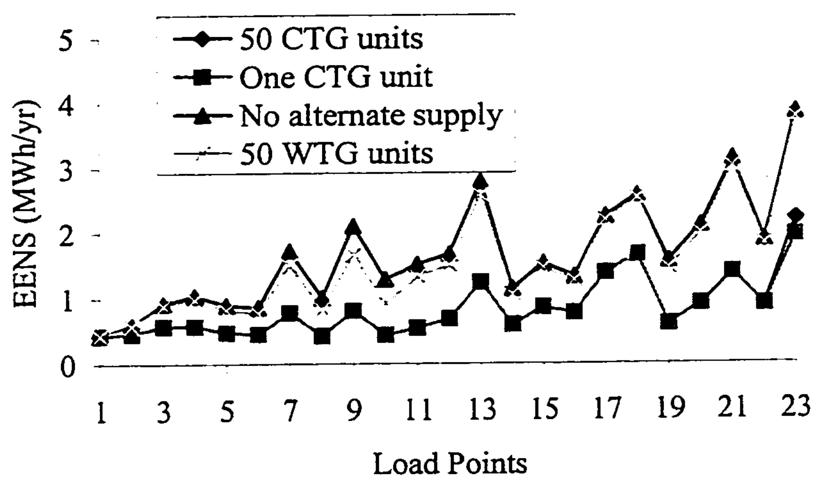

Fig. 7.2 EENS for the load points with different alternative supplies

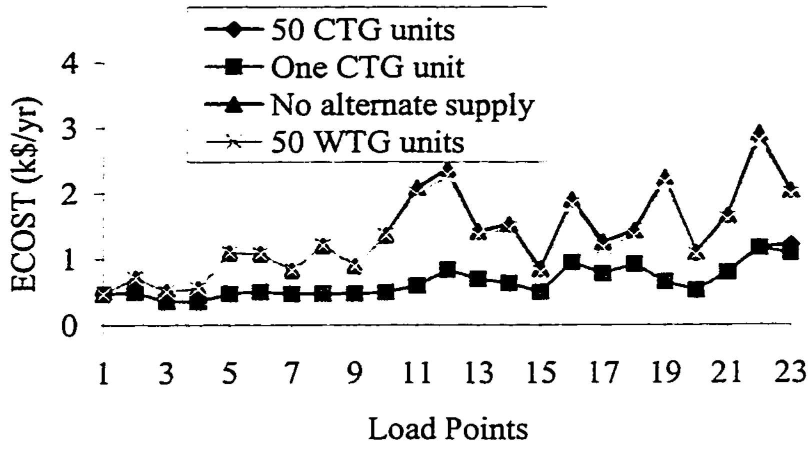

Fig. 7.3 ECOST for the load points with different alternative supplies

It can be seen from Fig. 7.2 and Fig. 7.3 that the individual load point EENS and ECOST have small decreases after the 50 WTG units are added to the system. The load point EENS and ECOST, however, are improved significantly when 50 CG are added to the system.

The system indices for the four different cases are shown in Fig. 7.4

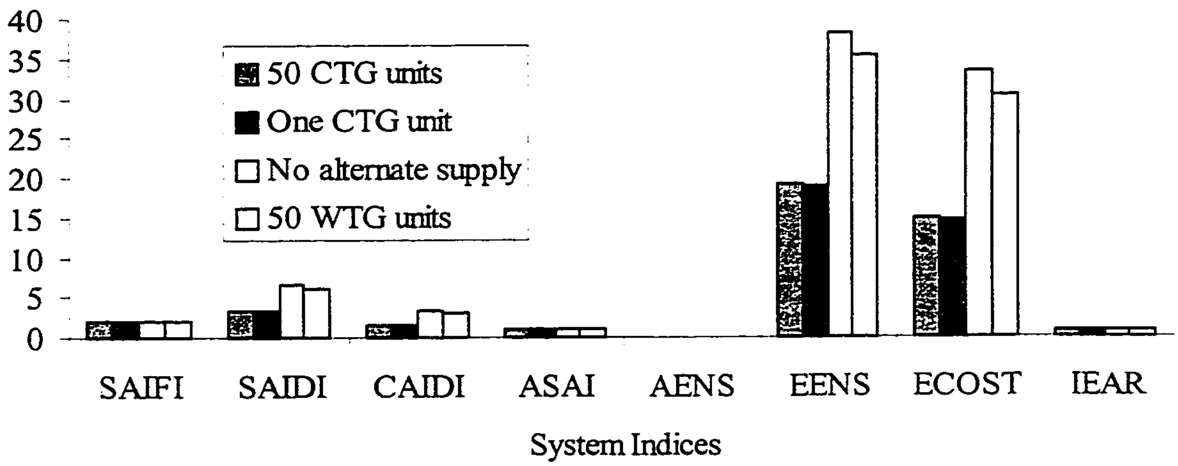

Fig. 7.4 The system indices for the different alternative supplies

It can be seen from Table 7.1 to 7.8 and Fig. 7.4 that the system EENS decreases by 52 percent from 38.257 to 19.228 MWh per year using CG. The system EENS decreases by about 7 percent from 38.257 to 35.42 MWh per year using the WTG. The system ECOST decreases by 56 percent using the CG and 9 percent using the WTG. It can therefore be concluded that a WTG cannot produce the same capacity and energy benefits as the same size CG.

7.8. System Benefit of Adding an Alternative Supply

The system benefits of adding WTG units as an alternative supply depend on the parameters of the wind site (i.e. average hourly wind speed, wind speed deviation etc) and the number of WTG. The system reliability indices when adding CG as an alternative supply are illustrated in this section. The indices when adding different numbers of WTG units are then assessed using three sets of wind site model data. The basic system configuration and parameters are the same as in Case 3 in Section 7.7.2.

7.8.1. System Benefit of Adding CG

A CG station is used as an alternative supply. The system reliability indices for different numbers of CG were obtained using the developed technique. Table 7.3 shows the EENS and ECOST variation with the number of CG. Table 7.9 gives the system indices for the different CG unit additions.

Table 7.9 System indices for different numbers of CG units

Units	SAIFI	SAIDI	CAIDI	ASAI	AENS	EENS	ECOST	IEAR
0	2.061	6.637	3.220	0.99924	0.03234	38.257	33.481	0.875
5	2.061	6.084	2.952	0.99931	0.03089	36.551	30.950	0.847
10	2.061	5.559	2.697	0.99937	0.02853	33.755	28.043	0.831
15	2.061	4.839	2.349	0.99945	0.02584	30.566	24.895	0.814
20	2.061	4.536	2.201	0.99948	0.02359	27.913	22.700	0.813
25	2.061	4.169	2.022	0.99952	0.02161	25.569	20.536	0.803
30	2.061	3.926	1.906	0.99955	0.02031	24.027	19.052	0.793
35	2.061	3.690	1.790	0.99958	0.01899	22.473	17.600	0.783
40	2.061	3.467	1.682	0.99960	0.01769	20.925	16.167	0.773
45	2.061	3.399	1.650	0.99961	0.01688	19.974	15.505	0.776
50	2.061	3.318	1.610	0.99962	0.01625	19.228	14.883	0.774

It can be seen from Fig. 7.5 and Table 7.9 that the EENS decreases by 1.71 MWh/yr from 38.256 to 36.551 MWh/yr and the ECOST decreases by 2.531 k$/yr when the CG units increase from 0 to 5. The CGEB and CGCB at this point are 1.52 MWh/(yr-MW) and 2.25 k$/(yr-MW) respectively. When the CG units increase from 45 to 50, the CGEB and CGCB are 0.66 and 0.55 respectively. It can be concluded that the CGEB and CGCB are a function of the number of units. When the number of units reaches a particular value, the CGEB and CGCB of adding more CG units becomes very small. This information can help system planners to determine the number of units to be added based on reliability worth.

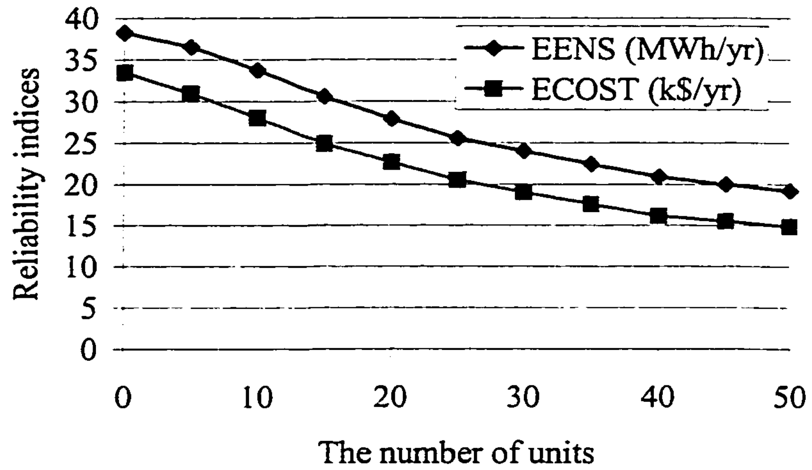

Fig. 7.5 EENS and ECOST as a function of the number of CG units

7.8.2. System Benefit for Adding WTG Units

A WTG farm was considered as the alternative supply to the distribution system. The effect on the system benefit of the wind site was examined using wind data from three locations in Saskatchewan. The three model sites are at North Battleford, Regina and Saskatoon. The WTG parameters used are those given in Section 7.7.3.

North Battleford Model

North Battleford is located north of Saskatoon. The wind model is that used in Section 7.7.3. The number of WTG units was varied from 45 to 400. The system indices are shown in Table 7.10 . Because the system SAIFI for each site is the same as that shown in the previous tables, the system SAIFI is not shown in the following tables.

Table 7.10 System indices for different number of WTG units (NB)

# of units	SAIDI	CAIDI	ASAI	AENS	EENS	ECOST	IEAR
0	6.637	3.220	0.99924	0.03234	38.257	33.481	0.875
5	6.567	3.186	0.99925	0.03219	38.085	33.205	0.872
45	6.074	2.946	0.99931	0.03019	35.716	30.786	0.862
50	6.020	2.920	0.99931	0.02994	35.420	30.503	0.861
55	5.979	2.902	0.99932	0.02974	35.180	30.285	0.861
60	5.936	2.880	0.99932	0.02954	34.941	30.062	0.860
65	5.898	2.861	0.99933	0.02934	34.712	29.855	0.860
70	5.862	2.844	0.99933	0.02916	34.493	29.657	0.860
75	5.830	2.828	0.99933	0.02898	34.288	29.471	0.860
80	5.800	2.814	0.99934	0.02882	34.093	29.297	0.859
85	5.771	2.799	0.99934	0.02866	33.905	29.127	0.859
90	5.744	2.787	0.99934	0.02851	33.733	28.974	0.859
95	5.719	2.774	0.99935	0.02838	33.570	28.828	0.859
100	5.694	2.762	0.99935	0.02825	33.416	28.687	0.858
150	5.522	2.679	0.99937	0.02727	32.266	27.662	0.857
200	5.427	2.633	0.99938	0.02672	31.609	27.081	0.857
300	5.321	2.581	0.99939	0.02611	30.886	26.436	0.856
400	5.265	2.554	0.99940	0.02578	30.498	26.093	0.856

The variations in the EENS and ECOST with the number of WTG are shown in Fig. 7.6 .

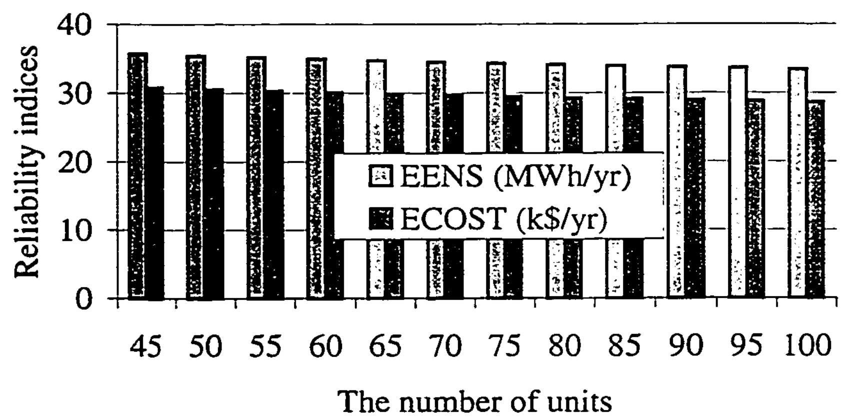

Fig. 7.6 EENS and TCOST variation for the North Battleford model

The system cost and energy benefits can be obtained from Table 7.10 and Fig. 7.6. The WGEB and WGCB are 0.153 MWh/(MW-yr) and 0.245 k$/(MW-yr) respectively when 5 WTG units are installed in the system. The WGEB and WGCB are 0.263 and 0.251 respectively when units increase from 45 to 50. The benefit of adding the first 5 WTG units is less than the benefit of adding 5 WTG units to a system with 45 units. The WGEB and WGCB are lower than the CGEB and CGCB.

Regina Model

Regina is located in the southern part of Saskatchewan. The wind speed model used is the ARMA (4,3) model [105] shown as follows:

$$\begin{aligned} y_t = &\, 0.9336 y_{t-1} + 0.4506 y_{t-2} - 0.5545 y_{t-3} + 0.111 y_{t-4} + \\ &\alpha_t - 0.2033\alpha_{t-1} - 0.4684\alpha_{t-2} + 0.2301 y_{t-3} \end{aligned} \qquad (7.9)$$

where $\alpha_t \in NID(0, 0.409432^2)$.

The annual average wind speed is 19.52 km/hr with a standard deviation of 10.99. The system reliability indices are shown in Table 7.11 . Fig. 7.7 shows the variation in the EENS and ECOST with the number of units.

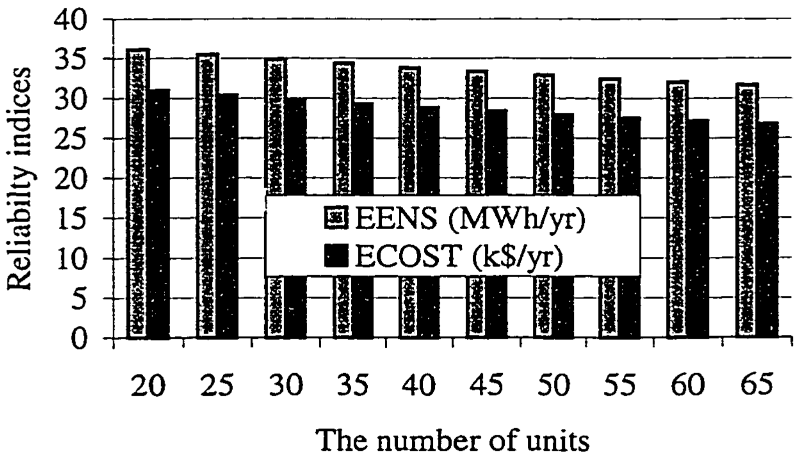

Fig. 7.7 EENS and ECOST variation with the number of WTG units for the Regina model

Table 7.11 System indices
for different numbers of WTG units (Regina model)

# of units	SAIDI	CAIDI	ASAI	AENS	EENS	ECOST	IEAR
20	6.108	2.963	0.99930	0.03054	36.133	30.986	0.858
25	5.989	2.905	0.99932	0.03003	35.529	30.396	0.856
30	5.882	2.853	0.99933	0.02954	34.949	29.841	0.854
35	5.780	2.804	0.99934	0.02907	34.387	29.312	0.852
40	5.688	2.760	0.99935	0.02862	33.858	28.820	0.851
45	5.603	2.718	0.99936	0.02820	33.365	28.357	0.850
50	5.525	2.680	0.99937	0.02781	32.900	27.928	0.849
55	5.453	2.645	0.99938	0.02743	32.453	27.519	0.848
60	5.388	2.614	0.99938	0.02709	32.046	27.148	0.847
65	5.330	2.585	0.99939	0.02677	31.673	26.810	0.846

The WBEG and WBCG can be obtained from Table 7.11. The WGEB is 0.413 and WGCB is 0.381 when the WTG units increase from 45 to 50. The benefit of adding WTG units with this wind data is larger than for the North Battleford data. The number of WTG units required with the Regina model for a specified reliability index is lower than the number of WTG units required with the North Battleford data.

Saskatoon Model

Saskatoon is located in the southern central part of Saskatchewan. The wind speed model used is the ARMA (3,2) model [105] shown as follows:

$$y_t = 1.5047 y_{t-1} - 0.6635 y_{t-2} + 0.115 y_{t-3} + \alpha_t - 0.8263\alpha_{t-1} + 0.225\alpha_{t-2} \quad (8.10)$$

where $\alpha_t \in NID(0, 0.447423^2)$.

The annual average wind speed is 16.78 km/hr with a standard deviation of 9.23. The system reliability indices are shown in Table 7.12 . Fig. 7.8 shows the variation in the EENS and ECOST with the number of units.

Table 7.12 System indices for different number of WTG units (Saskatoon model)

# of units	SAIDI	CAIDI	ASAI	AENS	EENS	ECOST	IEAR
45	5.871	2.848	0.99933	0.02942	34.803	29.778	0.856
50	5.808	2.818	0.99934	0.02911	34.440	29.443	0.855
55	5.750	2.789	0.99934	0.02882	34.092	29.124	0.854
60	5.694	2.762	0.99935	0.02854	33.761	28.820	0.854
65	5.640	2.736	0.99936	0.02827	33.446	28.525	0.853
70	5.592	2.713	0.99936	0.02802	33.151	28.255	0.852
75	5.547	2.691	0.99937	0.02778	32.865	27.996	0.852
80	5.504	2.670	0.99937	0.02755	32.597	27.752	0.851
85	5.464	2.651	0.99938	0.02734	32.344	27.520	0.851
90	5.428	2.633	0.99938	0.02714	32.111	27.309	0.850

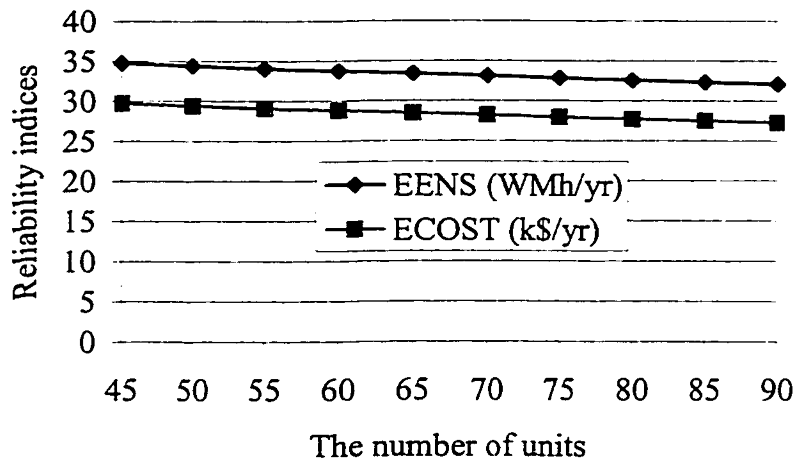

Fig. 7.8 EENS and ECOST variation with the number of WTG units for the Saskatoon site

It can be determined from Table 7.12 that the WGEB and WGCB are 0.323 and 0.298 respectively when the WTG units increase from 45 to 50. These values are lower than those for the Regina model and larger than those for the North Battleford model.

Comparison of the Results

Fig. 7.9 shows the variation in the EENS with the number of WTG units for the three wind models.

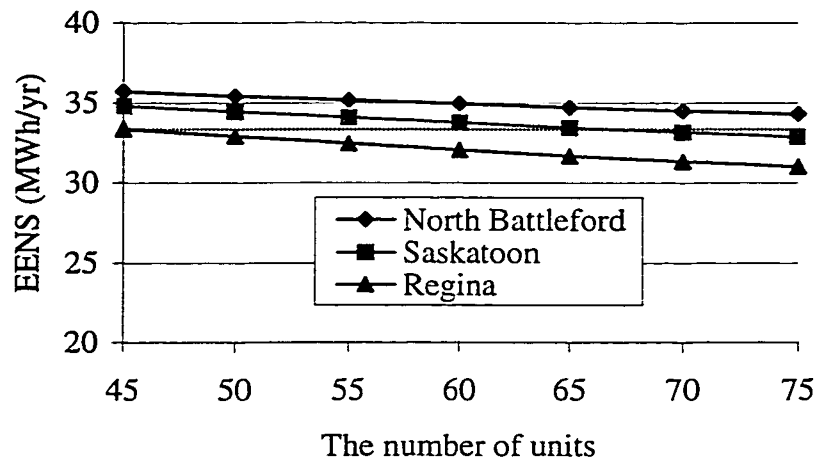

Fig. 7.9 EENS variation with the number of WTG units

Fig. 7.10 shows the variation in the ECOST variation with the number of WTG units for the three wind models. The Regina model provides the greatest benefit.

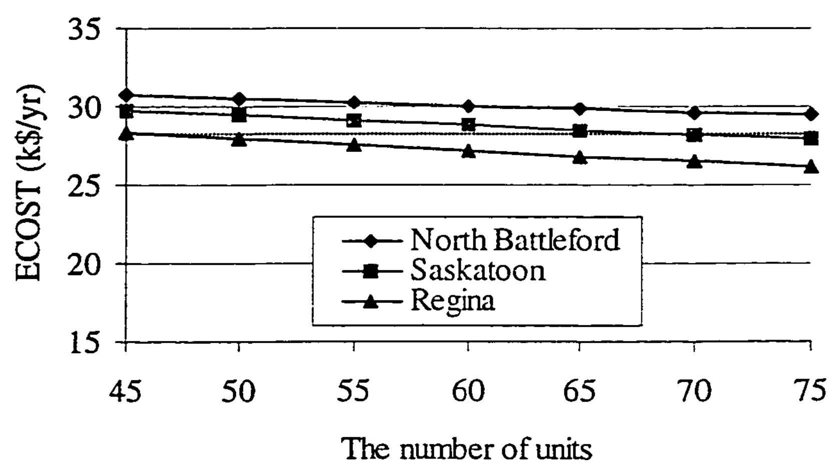

Fig. 7.10 ECOST variation with the number of WTG units

It can be seen from Fig. 7.9 that the EENS for the three models are different for a given number of WTG. The Regina model has the smallest EENS followed by the Saskatoon and the North Battleford data. It can also be seen from Fig. 7.9 that if the EENS is 33.365 MWh/yr, 45 units is required for the Regina model, over 65 units for the Saskatoon model and even more units for the North Battleford model. Similar conclusions regarding ECOST can be drawn from Fig.7.10.

7.8.3. Equivalent CG

It can also be seen from Tables 7.8 and Table 7.10 that the number of CG required for a given EENS or ECOST is considerably smaller than the required number of WTG. The equivalent CG of a WTG was calculated using the curves which show the variation of EENS with the number of CG and WTG units. Fig. 7.11 shows the variation in EENS with the number of units for both WTG and CG.

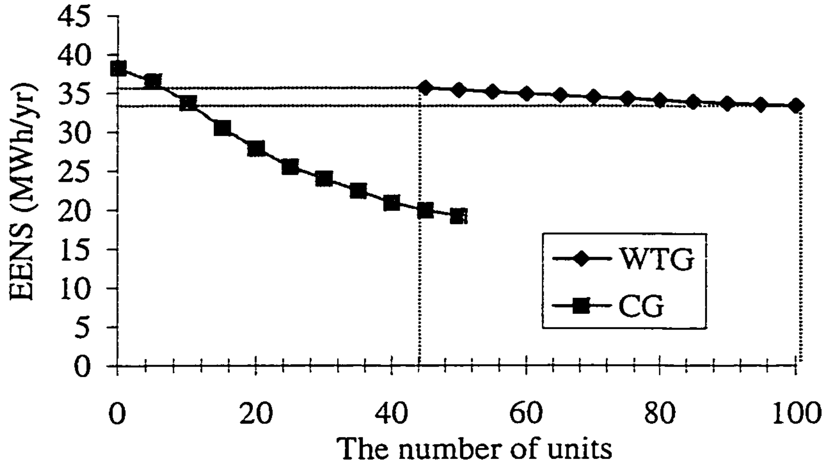

Fig. 7.11 Selection of the number of units based on EENS

If the EENS is limited to 35.716 MWh/yr, 45 WTG units are required to satisfy this reliability criterion. At most, 7 CG units need to be installed to satisfy the same requirement. The ENCG is 0.156 which means one 0.225 MW WTG equals 0.156 of the same size CG units or one 0.225 MW CG unit is equivalent to 6.43 same size WTG units. If the EENS is limited to 33.416 MWh/yr, 100 WTG units are required and about 10 CG have to be installed. The ENCG in this case is 0.1. The value is even smaller than the previous value which indicates that 10 WTG equals one CG. The ENCG can also be determined using Fig. 7.12 which shows the variation in ECOST with the number of units.

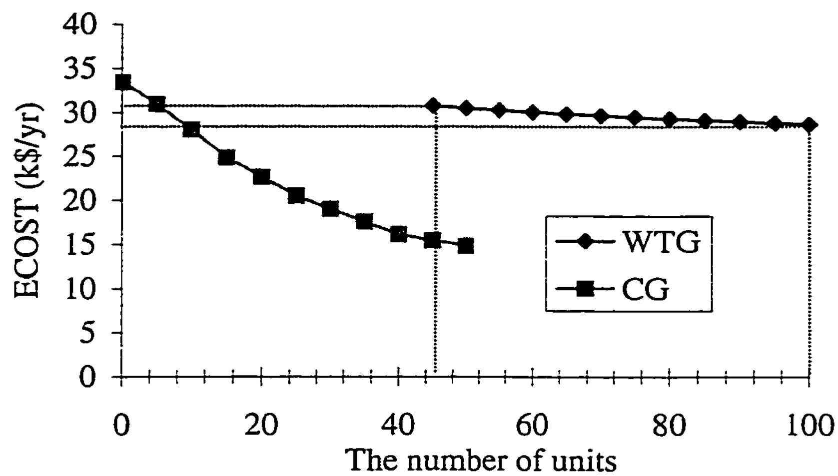

Fig. 7.12 Selection of the number of units based on ECOST

It can be seen from Fig. 7.12 that the number of units selected according to ECOST is a little lower than the number of units selected based on EENS. For ECOST = 30.786 k$/yr, 5 CG and 45 WTG units are required respectively. The ENCG is 0.111 which means that 9 WTG units are required to replace one CG unit.

It can be concluded from the previous analysis that the capacity and energy benefits from one wind generation unit does not equal the capacity and energy benefits from one same size conventional generation unit.

7.9. Effect of WTG Model Parameters

It can be seen from the previous analysis that the actual power output for a given WTG model depends on the site model data. The power output at a given wind site also varies with the WTG model. The effect of WTG model parameters is illustrated in this section using the Regina model. It was assumed that 50 wind generation units are installed in the wind farm.

7.9.1. Effect of Cut-in Wind Speed

Cut-in wind speed is an important parameter which represents the initial sensitivity of a WTG to wind velocity. A low cut-in wind speed would make the WTG suitable for more wind sites. Different cut-in wind speeds were analyzed assuming that the rated wind speed is 38km/hr and the cut-off wind speed is 80km/hr. The resulting system indices are shown in Table 7.13

Table 7.13 System indices for different cut-in wind speeds

Cut in speed	SAIDI	CAIDI	ASAI	AENS	EENS	ECOST	IEAR
5	5.189	2.517	0.99941	0.02638	31.207	26.170	0.839
7	5.353	2.597	0.99939	0.02709	32.050	27.038	0.844
9	5.525	2.680	0.99937	0.02781	32.900	27.928	0.849
11	5.691	2.761	0.99935	0.02849	33.704	28.776	0.854
13	5.847	2.837	0.99933	0.02914	34.470	29.579	0.858
15	5.994	2.908	0.99932	0.02973	35.176	30.324	0.862
17	6.123	2.971	0.99930	0.03026	35.794	30.973	0.865

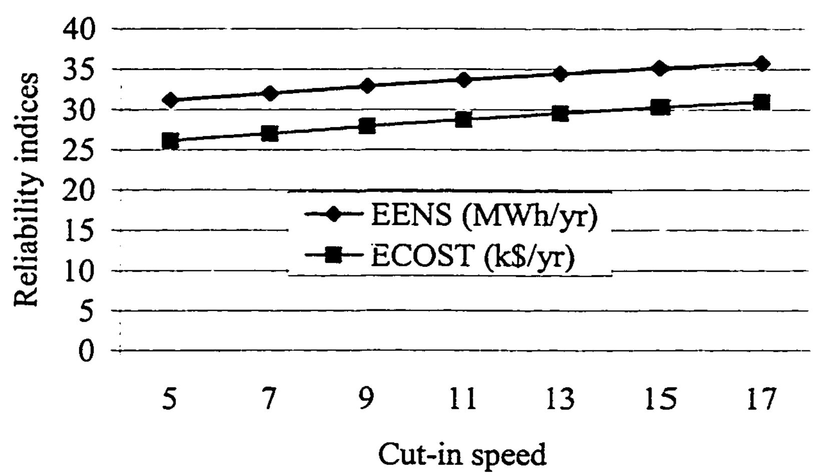

Fig. 7.13 EENS as a function of cut-in wind speed

It can be seen from Table 7.13 and Fig. 7.13 that the system EENS decreases from 35.794 to 31.207 (MWh/yr) and the system ECOST decreases from 30.973 to 26.170 (k$/yr) when the cut-in wind speed decreases from 17 to 5 (km/hr). The cut-in speed is an important parameter in relatively low wind velocity areas.

7.9.2. Effect of the Rated Wind Speed

The rated wind speed reflect the efficiency of a WTG to reach its rated output. If the rated wind speed of a WTG is close to the cut-in speed, the WTG will generate more output.

Assume that the cut-in wind speed is constant at 9 km/hr and the cut-off wind speed is 80km/hr. The system indices in this case are shown in Table 7.14 and Fig. 7.14

Table 7.14 The system indices for the different rated wind speed

Rated speed	SAIDI	CAIDI	ASAI	AENS	EENS	ECOST	IEAR
14	4.606	2.235	0.99947	0.02271	26.868	22.435	0.835
18	4.794	2.326	0.99945	0.02380	28.154	23.607	0.838
22	4.976	2.414	0.99943	0.02483	29.374	24.717	0.841
26	5.138	2.493	0.99941	0.02574	30.453	25.694	0.844
30	5.285	2.564	0.99940	0.02655	31.408	26.560	0.846
34	5.413	2.626	0.99938	0.02723	32.212	27.297	0.847
38	5.525	2.680	0.99937	0.02781	32.900	27.928	0.849
42	5.620	2.726	0.99936	0.02828	33.461	28.449	0.850

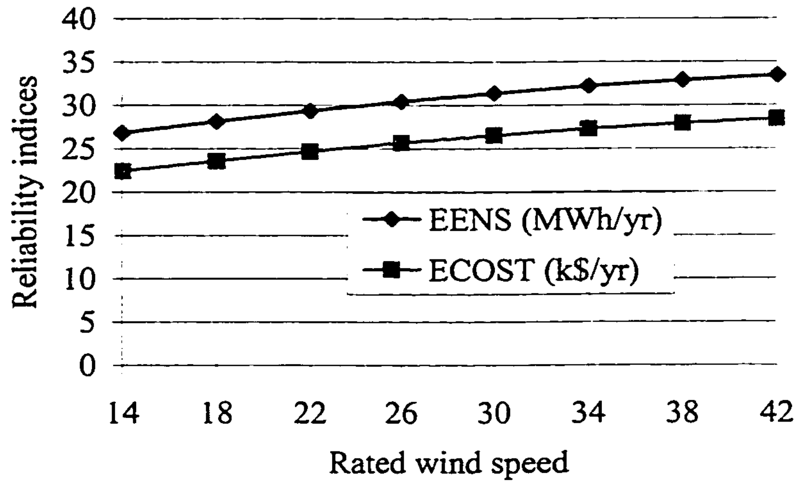

Fig. 7.14 EENS and ECOST as a function of rated wind speed

The system EENS increases from 26.868 to 33.461 MWh/yr and the system ECOST increases from 22.435 to 28.449 k$/yr when the rated wind speed increases from 14 to 42 (km/hr). It can be concluded that reducing the cut-in and the rated wind speeds will significantly increase the reliability benefits a given wind farm.

7.9.3. Effect of Cut-off Wind Speed

The cut-off wind speed represents the maximum wind speed at which a WTG can operate safely. Assume that the cut-in wind speed is constant at 9 km/hr and the rated wind speed is 38km/hr. The system indices for different cut-off wind speeds are shown in the Table 7.15 and Fig. 7.15

Table 7.15 The system indices for the different cut-off wind speed

Cut-off	SAIDI	CAIDI	ASAI	AENS	EENS	ECOST	IEAR
40	5.724	2.777	0.99935	0.02870	33.956	29.023	0.855
50	5.553	2.694	0.99937	0.02794	33.055	28.084	0.850
60	5.526	2.681	0.99937	0.02782	32.905	27.933	0.849
70	5.525	2.680	0.99937	0.02781	32.900	27.928	0.849
80	5.525	2.680	0.99937	0.02781	32.900	27.928	0.849

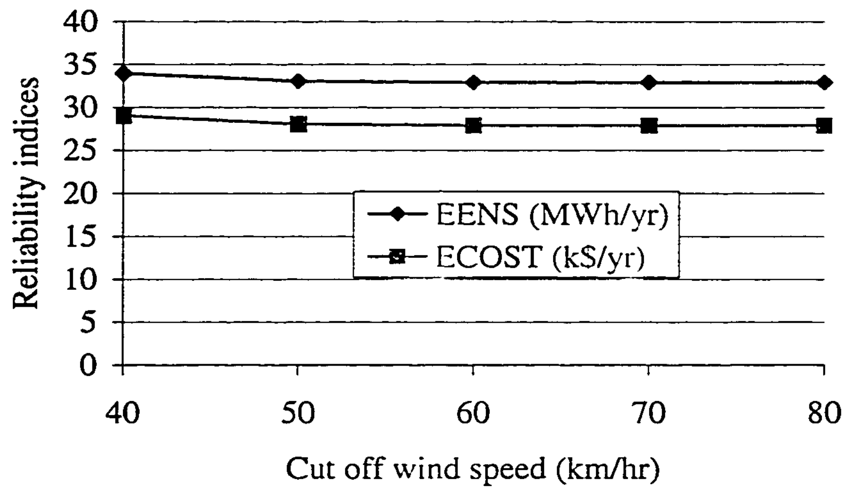

Fig. 7.15 EENS and ECOST as a function of cut-off wind speed

It can be seen that the EENS and ECOST decrease initially and then are relatively constant after 70 km/hr. The reason for this is that the annual hourly wind speed is 19.52 km/hr and standard deviation is 10.99. The probability of wind speeds is excess of 70 km/hr is very small for this model data. This information is important in system planning when selecting economical WTG because WTG with high cut-off wind speed may be expensive.

7.10. Optimum WTG Location

The location of the wind farm in a distribution system will affect the system reliability. The optimal location of the wind farm is investigated in this section assuming that wind speeds are the same at the different areas of a distribution system. The three different wind farm locations are Option 1: the wind farm is located at the end of the main feeder. Option 2: the wind farm is located at the end of subfeeder 2. Option 3: the wind farm is connected to the end of subfeeder 3. The wind data used is the North Battleford model. The cut-in wind speed is 9 (km/hr) and 50 WTG units are installed. The system reliability indices are shown in Table 7.16

Table 7.16 System reliability indices for the three location options

location	SAIDI	CAIDI	ASAI	AENS	EENS	ECOST	IEAR
1	6.020	2.920	0.99931	0.02994	35.420	30.503	0.861
2	6.452	2.564	0.99926	0.03155	37.328	31.775	0.851
3	6.866	2.492	0.99922	0.03202	37.882	32.670	0.862

It can be seen from Table 7.16 that Option 1 is the best location. The EENS and ECOST are lower that those for the other two options. Information of this type can be useful when selecting a location for a wind farm.

7.11. Conclusion

A time sequential simulation technique used to evaluate the reliability indices including WTG as an alternative supply is presented in this chapter. This technique has been used to evaluate the basic reliability indices and the reliability benefit indices. A WTG has a different impact on the reliability of a distribution system than does a conventional generator (CG) because of the random nature of wind speed, and the nonlinear relationship between WTG output and wind velocity. The equivalent CG of a WTG is introduced. The analysis shows that a number of WTG units may be required to replace a same size CG. The energy and reliability benefit indices of using WTG as an alternative supply are defined. The results show that the WGEB and WGCB vary with the selected wind model data and the reliability benefits per kW of WTG are relatively small. The effect on the EENS and ECOST of WTG cut-in, rated and cut-off speeds have been evaluated. The cut-in and rated wind speeds have more effect than does the cut-off speed. The effect on the reliability and benefit of the hourly average wind speed and the wind speed deviation at the wind site were also investigated. The location of a wind farm in a distribution system can have an impact on the reliability benefits and this approach can be used to assist in the selection of a suitable site. In general, it can be concluded that WTG are not an efficient way to improve the reliability of a rural distribution system.

8. Summary and Conclusion

It is neither practically realizable nor economically justifiable to attempt to create an absolutely reliable power system. The continuity of energy supply can be increased by improved system structure, increased investment during either the planning and construction phase, operating phase or both. Over-investment can lead to excessive operating costs, which must be reflected in the tariff structure. On the other hand, under-investment can result in an inadequate system. It is evident therefore that reliability and economic constraints can compete, and can lead to difficult managerial decisions at both the planning and operating phases [1].

Power system planners have struggled for many years to resolve the dilemma between the reliability and economic constraints. A wide range of techniques has been developed. These techniques can be divided into the two categories of deterministic and probabilistic approaches. Deterministic techniques often determine generation and network capacities based on the expected maximum demand plus a specified percentage of the expected maximum demand. The weakness of deterministic techniques is that they do not and cannot consider the stochastic nature of system behavior and of customer demands. Probabilistic approaches determine the generation and network redundancy based on element failure and repair rates and the time varying load being served. The techniques used in generation and transmission systems are well developed. Relatively little work has been done in the area of distribution system reliability evaluation.

Chapter 2 introduces the basic concepts of distribution system reliability evaluation and illustrates a network equivalent technique for complex radial distribution system evaluation. A general feeder is defined and a set of basic equations is developed based on the general feeder concept. In this approach, a complex radial distribution system is reduced to a series of general feeders using reliability network equivalents. Basic equations are used to calculate the individual load point indices. The reliability network equivalent method provides a simplified approach to the reliability evaluation of complex distribution systems. Reliability evaluations for several practical test distribution systems have shown this technique to be superior to the conventional FMEA approach. This method avoids the required procedure of finding the failure modes and their effect on the individual load points and results in a significant reduction in computer solution time.

A time sequential simulation procedure used to evaluate the basic load point and system indices and their probability distributions is presented in Chapter 2. A computer program has been developed using the simulation approach in which a direct search technique is used and overlapping time is considered. The analytical technique and the time sequential technique are compared using a practical test distribution system. The analytical approach evaluates the reliability indices by a set of mathematical equations and therefore the analysis procedure is simple and requires a relatively small amount of computer time. The simulation technique evaluates the reliability indices by a series of trials and therefore the procedure is more complicated and requires a longer computer time. The simulation approach can provide information on the load point and system indices that the analytical techniques can not provide. It may be practical therefore to use the analytical technique for basic system evaluation and to use the simulation technique when additional information is required.

In order to make a consistent appraisal of economics and reliability, it is necessary to combine the reliability criteria with certain cost considerations. Reliability cost/worth assessment provides the opportunity to incorporate cost analysis and quantitative reliability assessment into a common structured framework. Reliability cost refers to the investment needed to achieve a certain level of adequacy. Reliability worth is the benefit (reduction of customer interruption cost and utility damage) derived by the utility, consumer and society because of higher reliability. Considerable research has been done on reliability cost/worth assessment of generation and transmission systems and both analytical and Monte Carlo simulation methods are used in these areas. Reliability cost/worth analysis of distribution systems has not been extensively examined [19-23].

Chapter 3 presents a generalized analytical technique and a time sequential simulation approach to evaluate load point and system customer interruption cost indices of complex radial distribution systems. The two techniques have been used to evaluate the load point and system interruption cost indices and their distributions for two RBTS distribution configurations. Overlapping time was considered in the simulation technique, and the results with and without considering overlapping time are compared. The results show that overlapping time has little influence on the results when the system is small and the element restoration times are short and therefore can be ignored. When the distribution system includes many elements and the element repair times are relatively long, the effect of overlapping time should be considered. This chapter also compares the results obtained by the simulation technique with those obtained using the analytical approach. The results show that the two techniques give comparable load point and system average cost estimates. The simulation technique can be used, however, to obtain both the average values of the interruption indices and their distributions. Chapter 3 also briefly illustrates how the two techniques and the cost data can be used in system planning and operation. The studies conducted show that the reliability cost/worth technique can be a useful and efficient tool in distribution system planning and design. It can also be concluded from the analyses that the distributions of element restoration times have an effect on the cost indices, but these effects can generally be ignored when only average cost indices are required.

Conventional techniques do not normally consider the planning problem from a societal point of view, which includes both the utility investment cost and the customer interruption costs caused by power outages. The concept of investigating the demand side effects relating to the economic worth of reliability has received relatively little attention, mainly because of the difficulties associated with measuring the benefits of improved service. Reliability cost/worth analysis techniques provide an opportunity to incorporate customer concerns in optimal system planning, operation and expansion. One of the tasks in power system planning is to identify those devices and structures that can be used to create systems which meet customer demands for reliable low cost power and also have reasonably low investment costs [77]. The number and location of sectionalizing switches is an important consideration in distribution system planning and design [78]. The addition of more disconnect switches permits the system to be easily segmented following a fault and facilitates system restoration. Additional switches, however, result in a higher investment cost which can be quite significant. It is therefore important to select the optimal number of switches and to install them in suitable system locations, which make the total system cost (system investment and customer interruption costs) minimum.

Chapter 4 formulates the switch selection problem from the customer and utility point of view. It is based on evaluating and comparing the reliability cost (the investment and maintenance cost of adding the switches) with the reliability worth (the decrease in customer interruption costs because of the addition of the switches) for different switch connections.

An enumeration technique is used to find the optimal local location set for a given switch. A direct search technique is applied to determine the global optimal location set and the corresponding number of switches. A bisection search approach was developed to improve and simplify the search procedure and to save computing time.

The results from a study of an urban/rural test distribution system are used to illustrate the optimization procedure and the effect of element reliability parameters on the optimal results. The number of switches and the locations are optimized and results are compared with the original switch locations. It can be concluded that the switch mix will be very different if demand side concerns are considered in the evaluation. The techniques presented provide efficient tools, which can be used by distribution system planners, to find the optimum number of switches and their locations from a societal point of view.

The analysis shows that the magnitude of the customer interruption cost has a direct effect on power system operating and planning decisions. The customer interruption cost depends on the customer type, the interruption duration, and load interrupted. The average load model is an approximate representation of the actual load profile. In the average cost model, the interruption cost for a given duration for a selected customer type is a constant value. In a practical power system, the load level for a given customer varies with time of the day, the day of the week and the week of the year. This representation can be designated as a time varying load model. The customer interruption cost for a given customer also changes with the time of failure occurrence.

The time varying nature of the load and cost models for seven customer sectors is examined in Chapter 5. A time sequential simulation approach was used in conjunction with the developed models to evaluate the load point and system customer interruption costs in a practical radial distribution system. The effect of the time varying load and cost models on the reliability worth for different customer sectors is illustrated by application to the test distribution system. The technique presented can be used to provide a complete set of load point and system indices. These indices and their probability distributions provide a system planner with a clear picture of the system reliability. The results presented illustrate that in general, the use of an average load model provides a slightly inflated estimate of the system unreliability and that a time varying load model can be used to give a more accurate estimate. The results also show that the system interruption cost can increase or decrease using a time varying load model depending on the customer type and the shape of the cost model.

The interruption cost models used in the analysis directly affect the predicted reliability worth used to make reinforcement decisions. The basic cost models used for reliability cost/worth analysis are the sector customer damage functions, which are usually average or aggregate models (AAM). The major disadvantage of the SCDF is that the function considers only the average or aggregate monetary losses for selected interruption scenarios. The average or aggregate model provides a measure of the central tendency of the customer interruption data. The customer interruption cost data for a specified customer and a given duration, however, shows a very large variation. The dispersed nature of the cost data has been considered in the reliability cost/worth analysis of generation and transmission systems. The analysis shows that the dispersed nature of the cost data can have considerable effect on the reliability cost indices at HLI and HLII.

The dispersed nature of the interruption cost data is discussed in Chapter 6. Two cost models are presented. The first is designated as the average or aggregate model (AAM) and does not consider the dispersed nature of the cost data. The second is designated as the probability distribution model (PDM) and considers the dispersed nature. The AAM and PDM for the residential and industrial customers based on 1991 survey data are illustrated. A time sequential simulation technique using the two models has been developed. The technique has been used to evaluate individual load point and system interruption costs and the probability distributions of the cost indices in a representative distribution system. The reliability worth of installing lateral fuses, disconnect switches and alternative supplies in a distribution system were also investigated using the two cost models. The reliability worth can be compared with the reinforcement investment to assist in making economic planning and operating decisions. It can be concluded from the cost/worth analysis that using an average or aggregate model can result in underestimating the reliability worth of network reinforcements and that the probability distribution model provides a more realistic approach.

Economic and environment concerns with electrical energy derived from fossil and nuclear fuels as well as dwindling fossil resources have caused an increased interest in the development and use of alternative sources, such as wind, wave, geothermal and solar energy. The wind is potentially a huge energy source. The integration of large numbers of wind turbines can have considerable impact on the reliability performance of an aggregate system. It is therefore necessary to develop reliability evaluation techniques which can be used by utilities to assess the effects of wind turbine generators (WTG) on system adequacy and to make relatively optimal planning and operating decisions.

Wind and WTG models are introduced in Chapter 7. The possible utilization of wind turbine generation as an alternative supply is investigated from both energy and capacity points of view. A time sequential simulation technique used to evaluate the reliability indices including WTG as an alternative supply is presented. This technique has been used to evaluate the basic reliability indices and the reliability benefit indices. A WTG has a different impact on the reliability of a distribution system than does a conventional generator (CG) because of the random nature of wind speed, and the nonlinear relationship between WTG output and wind velocity. The equivalent CG of a WTG is introduced. The analysis shows that a number of WTG units may be required to replace a same size CG. Energy and reliability benefit indices of using WTG as an alternative supply are defined. The results show that the wind generation energy benefit and the wind generation cost benefit vary with the selected wind model data and the reliability benefits per kW of WTG are relatively small. The effect on the cost indices of WTG cut-in, rated and cut-off speeds have been evaluated. The cut-in and rated wind speeds have more effect than does the cut-off speed. The effect of the hourly average wind speed and the wind speed deviation at the wind site on the reliability and the benefits was also investigated. The location of a wind farm in a distribution system can have an impact on the reliability benefits and this approach can be used to assist in the selection of a suitable site. In general, it can be concluded that WTG are not an efficient way to improve the reliability of a rural distribution system.

It can be concluded from the analysis conducted in this research work and described in this thesis that:

- reliability cost/worth indices provide an opportunity to include customer concerns into system planning, operation and expansion,
- both analytical and simulation approaches can provide useful information to system planners regarding optimal decisions,
- the simulation technique can give relatively detailed results and provide information on the index distributions,
- the simulation technique also make it possible to consider time vary load and cost models in the evaluation,
- using reliability cost/worth indices in system optimal planning and reconfiguration analysis may result in different solutions compared with conventional approaches,
- time varying load and cost models provide more accurate estimates for both the load point and system indices than those obtained using average load and cost medels,
- consideration of the dispersed nature of the cost data in the evaluation can result in significant differences in the reliability cost/worth indices and should be recognized in the evaluation,
- wind generation as an alternative supply in a distribution network is useful as an energy source rather than as a means to improve the system reliability.

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Appendix A

Weekly percentage of the residential peak load

Week No.	Percentage	Week No.	Percentage
1	0.922	27	0.815
2	0.960	28	0.876
3	0.938	29	0.861
4	0.894	30	0.940
5	0.940	31	0.782
6	0.901	32	0.836
7	0.892	33	0.860
8	0.866	34	0.789
9	0.800	35	0.786
10	0.797	36	0.765
11	0.775	37	0.840
12	0.787	38	0.755
13	0.764	39	0.784
14	0.810	40	0.784
15	0.781	41	0.803
16	0.860	42	0.804
17	0.814	43	0.860
18	0.897	44	0.941
19	0.930	45	0.945
20	0.940	46	0.969
21	0.916	47	1.000
22	0.871	48	0.950
23	0.960	49	0.975
24	0.947	50	0.970
25	0.956	51	0.980
26	0.921	52	0.990

Daily percentage of the sector peak load

Day No.	Recidential	Govern.&Inst.	Office
1	0.96	1.00	1.00
2	1.00	1.00	1.00
3	0.98	1.00	1.00
4	0.96	1.00	1.00
5	0.97	1.00	1.00
6	0.83	0.40	0.50
7	0.81	0.30	0.40

Cost parameters for different customer sectors

Hours	Residential (week days)	Residential (week ends)	Agricultural	Large user	Industrial
1	0.48	1.2	0.01	1	0.2
2	0.48	1.2	0.01	1	0.2
3	0.48	0.514	0.01	1	0.2
4	0.48	0.514	0.01	1	0.2
5	0.48	0.514	0.01	1	0.2
6	0.9	0.514	0.01	1	0.2
7	0.9	0.514	1.495	1	0.2
8	0.9	0.514	1.495	1	1.5
9	0.9	0.514	1.495	1	1.5
10	0.9	1.2	1.495	1	1.5
11	0.9	1.2	1.495	1	1.5
12	0.9	1.2	1.495	1	1.5
13	0.9	1.2	1.495	1	1.5
14	0.9	1.2	1.495	1	1.5
15	0.9	1.2	1.495	1	1.5
16	1.4	1.2	1.495	1	1.5
17	1.4	1.2	1.495	1	1.5
18	1.4	1.2	1.495	1	1.5
19	1.4	1.2	1.495	1	1.5
20	1.4	1.2	1.495	1	1.2
21	1.4	1.2	1.495	1	1.2
22	1.4	1.2	1.495	1	1.2
23	1.4	1.2	0.01	1	1.2
24	1.4	1.2	0.01	1	1.2

Cost parameters for different customer sectors

Hours	Office (week days)	Office (week ends)	Commercial	Gover./Insti. (week days)	Gover./Insti. (week ends)
1	0.5	0.5	0.05	0.3	0.3
2	0.5	0.5	0.05	0.3	0.3
3	0.5	0.5	0.05	0.3	0.3
4	0.5	0.5	0.05	0.3	0.3
5	0.5	0.5	0.05	0.3	0.3
6	0.5	0.5	0.05	0.3	0.3
7	0.5	0.5	0.05	0.3	0.3
8	1.25	0.5	0.05	1.42	0.3
9	1.25	0.5	1.3	1.42	0.3
10	1.25	0.5	1.3	1.42	0.3
11	1.25	0.5	1.3	1.42	0.3
12	1.25	0.5	1.3	1.42	0.3
13	1.25	0.5	1.3	1.42	0.3
14	1.25	0.5	1.3	1.42	0.3
15	1.25	0.5	1.3	1.42	0.3
16	1.25	0.5	2.06	1.42	0.3
17	1.25	0.5	2.06	1.42	0.3
18	1.25	0.5	2.06	1.42	0.3
19	1.25	0.5	2.06	1.42	0.3
20	1.25	0.5	2.06	1.42	0.3
21	1.25	0.5	2.06	1.42	0.3
22	1.25	0.5	2.06	1.42	0.3
23	0.5	0.5	0.05	0.3	0.3
24	0.5	0.5	0.05	0.3	0.3

Single line diagram of the RBTS