

CERTIFICATE

This is to certify that the thesis entitled **Some Aspects of Generation Expansion Planning** which is being submitted by **Md. Abul Kalam Azad** in the fulfilment of the requirements for the award of the degree of Doctor of Philosophy to the Indian Institute of Technology, Kharagpur (India) is a record of bonafide work carried out by him under my guidance and supervision. In my opinion, the thesis has fulfilled the requirements according to the regulations of this institute and has reached the standard necessary for submission. The results embodied in this thesis have not been submitted to any other University or Institute for the award of any degree or diploma. This is, further, to certify that he worked as a full time sponsored candidate to prepare the thesis at this Institute on deputation from Bangladesh Institute of Technology, Khulna (Bangladesh) under the Government of India scholarship scheme (1992-93).

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PAPERS BASED ON THE WORK PRESENTED IN THE THESIS

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Abstract

The primary objective of generation expansion planning is to meet the electrical energy needs of the customers as economically as possible with an acceptable degree of safety, reliability, and quality. Power system planning involves studies to determine the resources required to meet the growth in demand at the lowest possible cost considering environmental and financial constraints. A power utility should meet the demand under a wide range of normal, abnormal, and emergency conditions including the reasonable foreseeable failures and maintenance outages of facilities. This requires some generation system capacity reserve in excess of forecasted demand. The uncertainty associated with future demand projections could make the system facilities inadequate, or excessive and uneconomical, both cases being unacceptable. Purchasing cheaper power from other utility through interconnection is another alternative which improves system reliability.

In this thesis, some studies have been made on generation expansion planning taking into account the above important criteria. The thesis contains a brief research background, motivation and objective to the modelling and analysis of some important requirements of generation expansion planning. The proposed techniques are implemented to an existing electric utility for generation expansion.

The key to all generation expansion planning is a good forecast of load that reflects current and future trends, tempered with good judgment. This is quite important for financial success. Undoubtedly, the most obvious deficiency in any expansion plan is and eventually is seen to be, the accuracy of the demand forecasts.

Four modules of Artificial Neural Network have been studied in detail, to forecast peak load of two distribution substations. It is observed from the sensitivity

analysis that all modules are not valid for all systems. In other words, for a specific system only a particular module is suitable for load forecasting. It is also found that the predicted results of minimum mean absolute error (MAE) is dependent on learning rate and learning momentum. Using the findings of the sensitivity analysis, various modules of ANN are studied and the most suitable module found is used to forecast yearly peak load of an existing electric utility for fifteen years choosing an appropriate module for the system.

Reliability criterion, the next aspect, is primarily used to determine the required system generating capacity reserve, to operate the system under equipment failures, equipment maintenance, and load variations. Probabilistic methods are used to evaluate reliability of generation expansion plans using stochastic representation of the generating unit failure-repair process, load variability and emergency help from interconnections.

A modified FFT method has been proposed to evaluate the loss of load probability (LOLP) of a power generating system consisting of different types and sizes of unit. This approach uses hourly loads, or any suitable time interval for system demand, for a given period. Out of several properties of FFT scheme, some properties have been used for the reduction of computational complexity. The accuracy of the method has been illustrated using an example. This modified FFT algorithm is applied to IEEE Reliability Test System (IEEE-RTS). The modified approach improves the efficiency in comparison to the conventional FFT method.

Further, another new approach has also been developed to evaluate the LOLP of a power generating system. This approach uses joint probability density function (PDF) concepts to convolve the unit outages and loads of the system. The reduction of computational effort for identical generating units is obtained using the binomial distribution. The method has been illustrated through an example and is applied to IEEE-RTS. This method is found efficient and easy to use as compared to other existing methods. In addition, the proposed approach can simulate multistate representations of generating units at less computational efforts.

Exploiting these advantages of the proposed approach, generation expansion planning of an existing utility has been made based on levelized LOLP for projected future demand.

In generation expansion planning, interconnected system may play an important role on system reliability. Reliability evaluation methodology of interconnected systems is different from that of a single area system. If the available capacity in one geographical region can be transmitted to other regions whenever it is needed without tie line restrictions then and only then, this system may be treated as a single area. Though it is possible to evaluate interconnected systems as a single system with some approximation, but, it is not in practice due to many obvious reasons.

The improved modified FFT scheme, developed for single area, has been extended to evaluate LOLP of two area interconnected power systems. A stochastic procedure for interconnected systems is presented using improved two dimensional FFT IMSL subroutine of Cyber 180/840A mainframe. This method can simulate multi-state generating units without affecting the computational complexity, whereas the computational complexity of other existing methods increases with the increase of number of outage states of generating units.

The joint PDF approach, developed for single area, has also been applied to evaluate LOLP of two area interconnected power system consisting of different types and sizes of generating units considering independent as well as correlated system demands. The Probability Density Function (PDF) of equivalent load is obtained by convolving the PDF of generating unit outages with the PDF of system demands using the proposed approach. The LOLP values of each system are obtained from the PDF of equivalent load. The accuracy of the proposed method has been illustrated using a simple example. The results obtained for IEEE-RTS are compared with existing methods.

In addition, the above approach is also implemented to an existing utility for which expansion planning studies were carried out. The system under study is considered to be interconnected with a hypothetical system. The benefits desired due to interconnection are evaluated and the impact of interconnection on expansion planning is studied.

An efficient approach has been developed to evaluate the expected energy generation, expected unserved energy, production costs (in the thesis production cost is used for fuel cost) and loss of load probability of a power generating system. The

expected energy generation of a given generating unit is obtained by evaluating the difference of unserved energy before and after the commitment of the unit. The method can evaluate expected energy generation and production costs of identical generating units at a time. This is not restricted to load duration curves and unit outage density function of any shapes, or size of the systems with a large number of generation units. Multiple generating units with same outage behavior can be committed with system demand efficiently.

The new developed approach has been extended to evaluate the expected energy generation, expected unserved energy and production costs for two area interconnected power generating system. An example and IEEE-RTS have been used for illustration.

Further, the proposed method has been used to evaluate expected energy generation, unserved energy and production cost of the generation expansion plan developed for existing utility under study. Based on the detailed study, addition of generating units for the existing utility has been recommended for the period under consideration.

Reliability index is derived from the estimates of availabilities of generating units, forecasted loads and unit incremental costs. Uncertainty which results in an unacceptable estimates of system reliability is implicit in the estimates of availability of units and forecasted loads. The uncertainty in the availability of generating units is due to the variation of failure data for different reporting sources and fluctuation in environmental conditions. Fuzzy set theory provides *optimistic* and *pessimistic* values of the derived quantities, corresponding to the assumptions of the highest and lowest *possibilities* of concerned events. In many cases, these bounds provide excellent guidelines to the generation expansion planners.

A model has been developed for fuzzy reliability to quantify the effect of uncertainty associated with unit capacity, FORs and the forecast loads on the LOLP of a power generating system. The model has been explained with the help of a simple generation system. Studies are also conducted on the IEEE-RTS to demonstrate effect of uncertainty on system parameters. Effects on the system reliability index due to variation in the amount of uncertainty of the parameters is studied. This proposed model has also been applied to a practical system to predict fuzzy LOLP.

Chapter 1

INTRODUCTION

1.1 Introduction

Generation system planning has become considerably more complex now a days because of uncertainties in load growth, fuel prices, and cost recovery under regulation. The criteria and constraints which are important in generation system planning are load forecasting, reliability, economies, financial ability, environmental standards, and societal impacts. Some of the criteria conflict with others, requiring some trade-off in making planning decisions. To plan a generation system considering these criteria, detailed analytical studies which typically "simulate" the operation of the system under the projected future conditions are required. The choice of robust plan comes out from the comparison of the attributes such as reliability level and price of electricity estimated from these studies for different plans [47, 68, 71, 76, 89, 99, 100, 101].

Generation system planning has progressed from being a mainly heuristic procedure based on experience supported by computer analyses of increasing complexity, to the present stage where synthesizing techniques are being used. At the same time, as greater understanding needs to be gained about such techniques, further power system developments are likely to be influenced to a much greater degree by overall energy system constraints [47, 49, 50, 51].

The primary objective of generation system planning is to meet the electrical

energy needs of the customers as economically as possible with an acceptable degree of safety, reliability, and quality [99]. Generation system planning involves studies to determine the resources required to meet the growth in demand at the lowest possible cost considering environmental and financial constraints.

The utility system should meet the customer's demand under a wide range of normal, abnormal, and emergency conditions including reasonable foreseeable failures and maintenance outages of facilities. This requires some generation system capacity reserve in excess of forecast demand and some redundancy in transmission and distribution systems. The uncertainty associated with future demand projections could make the system facilities inadequate or excessive and uneconomical, both cases being unacceptable. The uncertainties associated with capital costs and fuel prices could make a sound economic decision, a poor decision after the facility is built because of several years of time lag between the decision and completion of projects.

Uncertainties in demand, fuel prices, and capital costs have always existed to some degree. However, additional uncertainties are making power system planning considerably more complex [206]. The Public Utility Regulatory Policies Act (PURPA 1978, USA) created incentives to non-utilities to produce power as co-generation or small power producer, and utilities have an obligation to purchase this power whether they need it or not. Conservation and load management (Demand side management) are considered as significant options by utilities to reduce growth in customer demand and to defer new generation requirements. Purchasing cheaper power from other utilities is another alternative which has impact on system reliability through interconnection. Many utilities are using integrated resource planning methods to evaluate the potential resources and uncertainties and determine the best mix of resources.

The important planning criteria and constraints in power system planning are:

1. Load forecasting - a close tracking of loads is the basic requirement of a generation system planning.
2. Reliability - was critical around the 1970s and is again a concern in the 1990s.
3. Economics and electricity prices became critical in 1980s.

4. Financial constraints are critical now because of various uncertainties and risks.
5. Environmental - concerns started in the 1970s and continues to be important.

Environmental Constraints - include stack emission (SO_2, NO_x), solid wastes, and thermal discharges from power plants. Acid rain is a major concern today requiring complex solutions that are acceptable to all. The constraint in the case of transmission line additions is typically public opposition based on perceived hazards or aesthetic value. An important uncertainty in planning is the future changes in various regulations.

6. Societal impacts and value of electricity are being addressed now.

Societal Considerations - include the effect of utility plans on local economy and jobs. They might also include reduction in the usage of premium fuel for energy.

Criteria and constraints such as load growth, reliability, economic, financial, and environmental factors can be quantified. However, societal effects are evaluated qualitatively. Some of these criteria conflict, thereby making the planning decisions more complex. For example, meeting higher reliability levels may be constrained by financial limitations to build new facilities. Achieving lower environmental impacts will likely increase the cost of electricity to the customers (economic factor) due to the need to use low sulfur fuels or clean up equipment. A trade-off is often required between conflicting objectives and constraints to make the best decisions.

To plan a generation system expansion considering the criteria as discussed above, detailed analytical studies are to be performed which typically simulate the operation of the projected system that includes future resource additions to meet the forecasted customer demand for electricity. These simulations provide various attributes (forecasted load, reliability, price of electricity, financial performance, etc.) associated with alternate system plans. The most desirable plans are selected based on a balance among these attributes. Arriving at these plans may require iterations with management and regulators.



Generation Expansion Planning

Generation expansion planning begins with the estimates of system demands [206, 208]. After identifying the need for generating capacity additions, the planner develops a number of feasible expansion alternatives on the basis of load growth, construction time, availability of sites and availability of fuel.

Given these alternative plans, it is a common practice to evaluate each plan on the basis of reliability to ensure that the adopted plan satisfies desired reliability level [206]. Plans which do not meet the reliability criteria are eliminated or appropriately modified. The plans which satisfy the required reliability criteria are evaluated on the basis of economics. For each potential plan, financial and environmental impacts are analyzed. Finally, the alternative plans are compared in order to identify the most suitable one.

The first and primary step of generation expansion planning is the prediction of future load properly. For any robust planning, the estimation of both demand and energy is very important and crucial. The effective prediction of these two quantities have different significance. Demand forecast is used to determine the capacity of generation, transmission, and distribution system additions, and energy forecasts determine the type of facilities required [206]. For example, if a demand forecast stated that 100 MW of capacity was needed and a corresponding annual energy forecast stated the need for only 200 GWh, in all probability a peaking generating unit would be installed, instead of base-load unit; the difference in cost between these two is often substantial. Load forecasts are also used to establish procurement policies for construction capital, where, for sound operation, a balance must be maintained in the use of debt and equal capital. Further, energy forecasts are needed to determine future fuel requirements. In summary, a good forecast reflecting current and future trends, tempered with good judgment, is the key to all planning, needed to financial success.

With the increase in demand of electrical energy all over the world, reliability and economy of power supply have drawn the attention of power system engineers [206]. For on-line control of integrated system, a close tracking of the system loads by the generation system is a basic requirement. This must be accomplished over a

broad spectrum of time-intervals in order to ensure the economy of operations.

Undoubtedly, the most obvious deficiency in any expansion plan is and eventually is seen to be, the accuracy of the long term demand forecasts. Previous experiences indicate that the load growth rate may be considered of approximately 7% p.a. The discrepancies between predictions and reality are embarrassing, which is equivalent to predicting a possible planning error in any system.

From the present statistical information, it is found that at present 42% of the total demand of electrical energy comes from the domestic sector. It is evident that demand is reaching saturation, which, when coupled with an unchanged population level, implies little or no growth in electricity demand. Other subsector demands have followed similar patterns but with saturation levels fluctuating with economic activity levels.

The accuracy of a forecast is crucial to any electric utility, since it dictates the timing and characteristics of major system additions. A forecast that is too low can easily result in loss of revenue from sales to neighbouring utilities or even in load curtailment. On the other hand, forecasts that are too high can result in severe financial problems due to excessive investment in an electric plant that is not fully utilized or, equivalently, is operated at low capacity factors.

The evaluation of reliability is one of the important aspects of generation expansion planning. Reliability criteria are primarily used to determine the required system generating capacity reserve needed to be able to operate the system under equipment failures, equipment maintenance, and load variations. The criteria are based on many years of experience with the system and judgment as to the adequacy of performance and future standards. Power system reliability is maintained very high because, the system outages are sudden and uncontrolled, and they affect a large number of customers simultaneously.

Probabilistic methods are widely used for generation system planning by considering generating unit failure and repair process, load variability due to weather and forecast uncertainty, and emergency help from interconnections.

The methodology to evaluate the reliability of interconnected systems is different from that of a single area system. If the available capacity in a geographical region can be transmitted whenever it is needed without tie line restrictions then

this region may be treated as a single area [16].

Although it is possible to evaluate interconnected systems as a single systems with some approximation, however, it is not in practice due to following reasons [202]:

1. A utility is primarily interested in the benefits that its own system can earn from interconnections.
2. The tie lines forming interconnections are usually limited in capacity and, in addition, are subjected to failures.
3. The load characteristics in the various interconnected networks may be different and, in addition, these load patterns may be independent of each other.
4. It may be necessary to determine the transactions (import/export) between the systems.

Electric power grid interconnections have been well established in Europe and North America for over seventy years. Power grid interconnections have many technical and economical advantages for all the participating power utilities. They include;

- a. The pooling of power system reserve generating capacities;
- b. Emergency assistance to day-to-day power system operations;
- c. Economy interchange of energy to exploit time dependent diversities in the peak demands of the individual power network;
- d. Economy of scale in the earlier installation of bigger and more efficient generating units;
- e. Exploitation of major renewable but non transferable energy sources like hydro-electric power, and
- f. Exploitation of major fossil-fuel energy resources like coal and natural gas without incurring huge capital outlay in fuel transportation infrastructure.

The Economic Criterion - commonly used in utilities is *minimum revenue requirement*. Carrying charges (depreciation, return of investment, taxes) on capital cost facilities, fuel costs, and operating & maintenance costs constitute next revenue requirement [100]. Net present value of revenue requirements of different system expansion plans is evaluated to identify plans with lowest revenue requirement. Year to year change in revenue requirements is also very important since a large increase could represent a *rate shock* to customers. In addition to revenue requirement, cost of electricity to rate payers is also used as an economic attribute in comparing plans. This is a better indicator when energy sales are different in the plans studied. Therefore, the production cost evaluation of any system is a very important aspect. The fuel cost is the only variable cost component of the production cost. That is why, the fuel cost evaluation of any system in this thesis has been treated as the production cost.

A plan that requires lowest revenue requirement may not be the best considering other constraints or it may not be feasible due to financial constraints. Typically, the external financing required and internal funds generated are used to indicate the ability of a utility to finance a plan.

In this age of growing uncertainty, electric utilities are anxious to explore new choices of units for their future. Perceiving the great risks associated with power plant construction and industrial by pass, they are reviewing their traditional role as suppliers of electricity. Many have disposition themselves as marketers of energy services and are forging closer relationships with their customers to help them control electricity costs and shape electricity demand patterns in mutually beneficial ways. The electric customer has thus emerged as a central figure in contemporary utility thinking, gaining a new generation that goes beyond being a source of revenue [101].

A great deal of uncertainty in future demand, fuel prices, construction costs, availability and cost of power from other utilities and independent power producers, and the regulatory environment is leading electric utilities toward their resources planning. This framework offers utility management many alternatives for improving customer satisfaction and maintaining good customer relations in the increasingly competitive area of electric supply, besides improving the utility's financial health. Decision analysis can provide a sound basis for selecting alternatives in an environ-

ment of uncertainty. However the integrated planning procedures require continuous monitoring to assure that desired load changes. This is achieved by maintaining the system reliability.

1.2 Historical Background

Load forecasting is a very important tool in operation and planning studies in modern power systems. In the last few decades various classes of models for load forecasting have been proposed [143]-[155, 157]-[201]. The methods vary from simple regression and extrapolation to very complex and computation intensive, such as fading memory Kalman filter [143]-[155, 157, 158, 159, 160, 161, 168, 169, 170, 171, 183, 185, 188, 190, 192, 195, 197]. Almost all the conventional load forecasting models fall in to the class of time series or regression approaches, which have the possibility of numerical instability and improper modelling of the stochastic nature of the loads. In recent years, knowledge based systems and ANN based algorithms have also been proposed for load forecasting in power system [162, 163, 169, 178, 189].

Various methods available in the literature can be classified into two categories. In one category, the methods rely solely on past data and model the load pattern as a time series. The second category methods give emphasis to weather variables (temperature, humidity, light intensity etc.) and find functional relationship between these variables and the load demand. The use of weather dependent model is difficult because local metrological data may not be reliable and in many cases may not be available.

Most of the methods available in the literature have been proposed for short term load forecasting. There has been hardly any work for medium and long term load forecasting of an utility. But the long term load forecasting plays the most important role in case of generation expansion planning. Other way, it can be noted that the overall performance of generation expansion planning depends on the long range demand prediction of any system appropriately.

At present, application of Artificial Neural Network (ANN) has got a popularity in load forecasting. Almost all the research papers available in the literature using ANN address short term load forecasting using multilayered feed forward neural

network (MLFFNN) architecture with back-propagation (BP) learning algorithm [172, 173, 176, 177, 180, 181, 182, 184, 186, 187, 191, 193, 194, 201]. The popularity of MLFF architecture with BP learning algorithm is mainly due to its simple learning algorithm and its good generalization properties.

Probabilistic methods are used extensively at present for evaluating reliability and production costs of power generating systems. The historical development of these method is extremely interesting. Interest in the application of capacity requirements became evident in 1933. The first large group of papers was published in 1947. The papers, by Calabrese [1], Lyman [2] Seelye [3], Lane and Watchorn [4] proposed some of the basic concepts upon which some of the methods presently in use are based. In 1948, the first AIEE, subcommittee on the application of probability methods was organized. The subcommittee submitted several reports containing comprehensive definitions of the equipment outage classifications in 1949 [5], 1954 [6], and 1957 [7].

In 1947, few papers proposed the methods which, with some modifications are now generally known as the 'Loss of Load Approach' described in detail in a 1960 AIEE committee report [8]. The effect of interconnections and the determination and allocation of capacity benefits resulting from interconnections were discussed by Watchorn [9] and Calabrese [10] in 1950 and 1953 respectively. Until 1954 most probability studies had been done either by hand or by using conventional desk calculators. The benefits associated with digital computers were noted by Watchorn [11] in 1954 and illustrated in 1955 by Kirchmayer and his associates [12] in the evaluation of unit additions in system expansion studies. The reserve capacity requirement in expansion planning was introduced by Halperin and Adlar [13]. In 1960 Brown, Dean and Caprez [14] published the results of a statistical study of five years of data on 387 hydro-electric generating units. Shortly after this in 1961, the AIEE subcommittee produced a manual [15] outlining reporting procedures and methods of analyzing forced outage data using digital equipment.

Cook et al.[16] proposed in their paper the basic method for evaluating LOLP of two interconnected systems. Garver [17] has reported the load carrying capability concept of a new generating unit. However, the initial approach to the calculation of outage frequency and duration indices in generating capacity reliability evaluation

was modified by the introduction of recursive approach. The technique is described in detail in series of three publications [20, 21, 22]. The improvement of these methods have been depicted in [25, 26, 27, 34, 62, 63, 79, 80, 84, 95, 111, 118, 119, 121]. A few research works are also available for the evaluation of reliability and production costs in [94, 108, 110, 112, 113, 114, 115, 117].

The most important development in the evaluation of production costs and LOLP by probabilistic simulation was suggested by Beleriaux [18] and Booth [28]. Rau and Schenk [41] introduced fast Fourier transform (FFT) to evaluate capacity outage probabilities. This scheme has been used by researchers Mohan et al. [82] and Lakshmi et al. [126].

In 1980, Stremel and Rau [38], Rau, Toy and Schenk [42] and Stremel et al. [43] proposed a computationally fast method, which approximates the discrete distribution of load (equivalent load) through Gram-Charlier series expansion as a continuous function. They have also presented the sensitivity studies in [44, 45, 60, 73, 74, 81, 87]. Rau et al. [48, 103], Misra et al. [53] proposed the utilization of the bivariate Gram-Charlier expansion to evaluate the LOLPs of two interconnected systems [19]. The improvement of this approach for interconnected system have been introduced in [57, 58, 59, 61, 70, 78, 9, 109, 123, 124]. Researchers have made comparative studies of different methods in [54, 66, 125].

Schenk et al. [65] proposed the segmentation method for the evaluation of expected energy generation and LOLP of single area system. The segmentation method has been extended in [67, 72, 75, 77, 83, 106, 107] to incorporate the reliability evaluation and production costs of two interconnected systems.

Researchers have done some work on uncertainty analysis in loss of load probability (LOLP) evaluation. They have treated the uncertain nature of forecasted load and generator FOR (forced outage rate) in LOLP evaluation using mean and variance of probabilistic methods. The first publication in this regard appeared in 1975 [127]. Additional research works are available in successive research publications [36, 98, 128, 130]-[138, 140]. Basically, these methods are developed on the basis of probabilistic approach. The probabilistic methods are unable to solve the optimistic and pessimistic LOLPs simultaneously considering uncertain or imprecise system parameters. These methods have constraints to provide information on the

variation and the distribution of LOLP. Increasing importance of use of fuzzy set theory in modern power system has been reported in [142].

1.3 Aim of the Present Work

Generally, the generation system planning is complex in nature and has been the subject of intense research in the recent past. The number of papers published during the past decades is itself an indication of the importance of this problem.

The present thesis provides a detailed study of some aspects of generation expansion planning like load forecasting, reliability evaluation, production costing and uncertainty analysis. The generation expansion planning is also an iterative process, hence the computational time of each iteration is an important aspect. In the past, many attempts have been made in different directions of expansion planning, however research is still needed to exploit the further developments and improvements through artificial neural network, probabilistic method and fuzzy set theory.

The thesis is divided into seven chapters. The first chapter is introductory which contains a brief research background, motivation and objectives of the present work.

In chapter 2 Back-Propagation algorithm of multi-layered feed forward neural network (MLFFNN) is applied to carry out sensitivity analysis of load prediction using ANN. For simplicity, four modules of Artificial Neural Network have been studied for sensitivity analysis using various value of learning rate and learning momentum to forecast medium and long range demand. The modules of ANN structure are trained by the same input/output patterns. The one month ahead load of IIT substation & TATA Carnac substation, Bombay and one year load of a practical utility have been predicted. The accuracy of the predicted load is checked for twelve months in case of substations and five years for the utility system.

It is also found, from the sensitivity analysis, that all modules are not valid for all systems. For a specific system only a particular module is suitable for load forecasting. Further, it is observed that module-IV is suitable for IIT substation. While the module-III is suitable for TATA Carnac substation. It is also found that the predicted results, MAE may not be minimum at the convergence of least iteration, but the minimum MAE also depends on the learning rate and momentum.

The forecasted results are compared with actual loads and it is found that the forecasted results are in close agreement with the actual in spite of inaccuracies in records. In most of the cases, it is found that the mean absolute average error (MAE) is close to 2.5%. The above concept is used to forecast yearly peak load of an electric utility for fifteen years after choosing the appropriate module for the system.

First portion of chapter 3 proposes a modification of existing FFT method [82] to evaluate the loss of load probability (LOLP) of a power generating system consisting of different types and sizes of unit. This approach uses hourly loads, or any suitable time interval for system demand, for a given period. Out of several properties of FFT scheme, some properties have been used for the reduction of computational complexity. The accuracy of the method has been illustrated using an example. This modified FFT algorithm is applied to IEEE Reliability Test System (IEEE-RTS) [40]. The modification of this method improves the efficiency in comparison to the conventional FFT method.

Second part of chapter 3 describes a new approach to evaluate the LOLP of a power generating system. This approach uses joint probability density function (PDF) concepts to convolve the unit outages and loads of the system. Reduction of computational effort for identical generating units is obtained using the binomial distribution. The method has been illustrated through an example and is applied to IEEE-RTS to verify the accuracy of the method. This method is found efficient and easy to apply as compared to other existing methods. In addition, the proposed approach can simulate multistate representations of generating units.

Exploiting these advantages of the proposed approaches, generation expansion planning of an existing utility has been made on the basis of evaluated LOLP for projected future demand forecasted in chapter 2.

The first part of chapter 4 presents the application of improved FFT scheme proposed in chapter 3, to evaluate LOLP of two interconnected power systems. A stochastic procedure for interconnected systems is presented using improved two dimensional FFT IMSL subroutine of Cyber 180/840A mainframe. This method can simulate multi-state generating units without affecting the computational complexity, whereas the computational complexity of other existing methods linearly

increases with the increase in the outage states of generating units. The proposed method is applied to IEEE-RTS interconnected to a hypothetical system [67] and the results obtained are compared.

Second part of chapter 4 presents the application of new approach, developed in the second part of chapter 3, to evaluate LOLP of two area interconnected power system consisting of different types and sizes of generating units considering independent as well as correlated system demands. The Probability Density Function (PDF) of equivalent load is obtained by convolving the PDF of generating unit outages with the PDF of system demands using proposed approach. LOLP values of each system are obtained from the equivalent load PDF. Accuracy of the proposed method has been illustrated through a simple example. The results obtained for IEEE-RTS are compared with existing method [67].

In addition, the above approach is also implemented to an existing utility system for which expansion planning studies were carried out in chapter 3. The system under study is considered to be interconnected with a hypothetical system. The benefits of interconnection of the existing generation system have also been studied in this chapter.

The first portion of chapter 5 presents an efficient approach to evaluate the expected energy generation (EG), expected unserved energy (USE), expected production costs (PC) and LOLP of a power generating system. Expected energy generation of a given generating unit is obtained from the difference of unserved energy before and after the commitment of the unit with equivalent demand. The method can evaluate EG and PC of identical generating units at a time. Further, the proposed method is not restricted to load duration curves and unit outage density function of any shapes, or size. Multiple generating units with same outage behavior are committed with system demand efficiently in the proposed method.

Next portion of chapter 5 presents an extension of the new approach described above to evaluate the expected energy generation, expected unserved energy and production costs of two area interconnected power generating system. An example has been used to illustrate the method and its applicability is verified through its application to IEEE-RTS.

Further, the proposed method has been used to evaluate EG, USE and PC of

the generation expansion plan developed in chapter 3 for existing utility under study. Based on the detailed study, addition of generating units for the existing utility has been recommended for the period under consideration.

In chapter 6, a model has been developed for fuzzy reliability to quantify the effect of uncertainty associated with unit capacity, FORs and the forecast loads on the LOLP of a power generating system. The model has been explained with the help of a simple generation system. Studies are also conducted on the IEEE-RTS to demonstrate effect of uncertainty on system parameters. Effects on the system reliability index due to variation in the amount of uncertainty of the parameters is studied. This proposed model has also been applied to a practical system to predict fuzzy LOLP.

In chapter 7, the important conclusions of all the contributions of the present work embodied in the thesis has been summarized and the area for further investigations in future have also been suggested. This will enable the generation expansion planning analyst to make judicious decisions for various items in the expansion flow diagram under consideration. In addition, each chapter is concluded by summarizing the advantages of the proposed method(s), presented in that chapter.

In short, the sensitivity analysis of load forecasting using ANN may help the planner to choose the proper useful module for any system of load forecasting. The simple and efficient new approaches presented in the thesis provide exact solution of reliability and production costing in generation expansion planning. For final selection of any plan in generation expansion planning, a new approach to uncertainty analysis using fuzzy set theory may help the planner through the realistic output.

It is hoped that with the detailed analysis presented in the thesis for the problems of evaluating different parameters in generation expansion planning under specified conditions along with the introduction of new ideas described herein, will help to pave the way for making the generation expansion planning more reliable and economic, and the task of planner to evaluate some quantities in planning will be easier and less cumbersome than before.

Chapter 2

ARTIFICIAL NEURAL NETWORKS BASED LOAD FORECASTING



2.1 Introduction

Electric energy is a superior form of energy for all types of consumer needs. Its demand is growing rapidly and the main aim of electric utilities is to ensure the reliability of power supply to their consumers. The electric load growth apparently affects the planning of generation in power utility. In summary, a good forecast reflecting current and future trends, tempered with good judgment, is the key to all planning, needed to financial success [206].

Generation expansion planning starts with a forecast of anticipated future load requirements. Estimates of both demand and energy requirement are crucial to effective system planning. Demand forecasts are used to determine the capacity of generation, transmission, and distribution system additions, and energy forecasts determine the type of facilities required. For example, if a demand forecast stated that 100 MW of capacity was needed and a corresponding annual energy forecast stated the need for only 200 GWh, in all probability a peaking generating unit would be installed, instead of base-load unit; the difference in cost between these two is

often substantial. Load forecasts are also used to establish procurement policies for construction capital, where, for sound operation, a balance must be maintained in the use of debt and equal capital. Further, energy forecasts are needed to determine future fuel requirements and if necessary when fuel prices soar, rate relief to maintain an adequate rate of return.

The accuracy of a forecast is crucial to any electric utility, since it dictates the timing and characteristics of major system additions. A forecast that is too low can easily result in lowest revenue from sales to neighbouring utilities or even in load curtailment. On the other hand, forecasts that are too high can result in severe financial problems due to excessive investment in an electric plant that is not fully utilized or, equivalently, is operated at low capacity factors (C.F.). Capacity factor is defined as the ratio of average energy supplied to maximum energy capability. Unfortunately, an accurate forecast depends on the judgment of the forecaster, and it is impossible to rely strictly on analytical procedures to obtain an accurate forecast. Good judgment can not be emphasized enough in forecasting future requirements. An accurate load forecast procedure can provide effective and accurate information to support generation expansion planning.

Each and every utility is having various type of bulk consumers of different demand capacity. Tariff of each consumer varies with their maximum demand requirement and energy consumption. For this reason, each bulk consumer tries to accurately predict maximum demand for cost minimization. Therefore long term forecasting is required by the bulk consumers and, each and every bulk power consumer is trying to find methods for accurate load forecasting. On the other hand, long term peak load forecasting method is also very important in generation expansion planning of any utility.

2.2 Existing Methods

In the last few decades, several techniques for deriving load forecasting model have been proposed [157, 166]. The most commonly used techniques include regression techniques [145, 146, 149, 153, 155, 164, 168, 188, 192], time series approaches [143, 158, 159, 160, 161, 163, 171, 185, 197, 204], expert system based methods [162,

165, 169, 179, 196, 198, 199, 201], and artificial neural network (ANN) algorithms [172, 176, 177, 180, 181, 182, 184, 186, 187, 191, 193, 194]. In time series, approach load pattern is treated as time series signal with known periodicities. The techniques used for analysis of time series signal includes Kalman filtering, Box-Jenkins criteria, ARMA models and spectra expansion techniques etc.

In regression approach, functional elements are assumed and finally the coefficients for linear combinations are found. The functional relationships as found in regression approaches are either linear or piece wise linear. Hence it is not possible to get accurate forecast using these techniques.

Recent research in the area of ANN has opened new vistas for such applications like non-linear smoothing and interpolations ability to learn complex non-linear mappings and fitting themselves to different statistical distributions. The ANN can learn from past experience, generalize from previous examples to new ones, abstracts essential characteristics from input containing irrelevant data, modify their behaviour in response to their environments. The user needs to select proper attributes for training pattern which affect the output pattern. Then the ANN, at the time of training, automatically develops the relationship between input and output pattern.

In recent years, most of the researches using Artificial Neural Networks (ANN) have been restricted to estimate the short term load forecasting. However, the long term load forecast of a power system is the basic need for generation expansion planning. In this chapter, long term load forecasting method using ANN is presented and analyzed.

The concept of long term load forecasting using ANN has been employed from the previous research works on short term load forecasting [172, 176, 177, 180, 181, 182, 184, 186, 187, 191, 193, 194]. Park et al. [173], Lee et al.[174] have demonstrated the efficacy and elegance of the neural network to short term load forecasting solution. Ho et al. [181] proposed a learning algorithm of ANN to predict short term load forecasting of an utility. Pang et al.[182] have used minimum distance measurement to estimate the networks weights. Papalexopoulos et al.[193] have given a comparison between regression based model and ANN based model to estimate demand for energy management system. A hybrid model for short term load prediction using ANN has been proposed by Kim et al.[199] and further development

has been done by Srinivasan et al.[200].

However, all the ANN models are alternative classical and adaptive forecasting models [182]. Though, these models do not rely on human experience but attempt to make a link between sets of input data and observed outputs. The link is nothing but a training of neural network to determine connection weights between neurons. Therefore, connection weights of trained networks varies from the selection of input pattern and learning rate & learning momentum and predicted results thereby. For this, an attempt has been taken to study sensitivity of different modules of ANN structures on various systems.

A multilayered feedforward (MLFF) neural network with back propagation (BP) algorithm has been used for predicting load of a large educational institution like Indian Institution of Technology (IIT), Kharagpur. This is done to carry out sensitivity studies of forecasted loads using ANN. The input to the neural network is past load data. For simplicity, four modules of MLFF neural network have been used for two practical systems to compare the results obtained for the sensitivity analysis of load forecasts. These two practical systems are of bus level i.e. substation based; one is large educational institute's substation and other is large commercial establishment's substation. These modules are further used to predict the yearly peak demand of a practical existing electric utility.

The load forecasting problem is a generalization problem, in the sense that the neural network is expected to correctly predict the outputs for the inputs which are distinct from the input-output sets it has learned through training. Therefore, a network gets trained using all the training examples. Before going to the main work in this chapter, however, a brief background of artificial neural network (ANN), analogous to the human brain, is presented in what follows to help the reader to follow the proposed idea of this chapter.

2.3 Overview of Neural Networks

Artificial neural networks(ANN) are biologically inspired i.e., they are composed of elements that perform in a manner that is analogous to the most elementary functions of the biological neuron. These elements are then organized in a way that

may (or may not) be related to the anatomy of the brain. Despite this superficial resemblance, artificial neural networks exhibit a surprising number of the brain characteristics. For example, they learn from experience, generalize from previous examples to new ones, and abstract essential characteristics from inputs containing irrelevant data.

2.3.1 The Biological Prototype

The brain is a large scale system connecting many neural cells called neurons. It is estimated that a human being has around 10^{10} brain cells or neurons [215]. The neuron has unique capabilities to receive, process and transmit electrochemical signals over the neural pathways. The neuron consists of three main sections; the cell body, the dendrites and the axon, each with separate but complementary functions. Functionally, the dendrites receive the signals from the other cells at connection points called synapse. From there, the signals are passed onto the cell body where they are essentially summed, some inputs tending to excite the cell, others tending to inhibit its firing. When the cumulative excitation in the cell body exceeds a threshold, the cell fires, sending a signal down the axon to the other neurons. This basic functional outline has many complexities and exceptions, nevertheless. The most artificial neural networks models are only these simple characteristics.

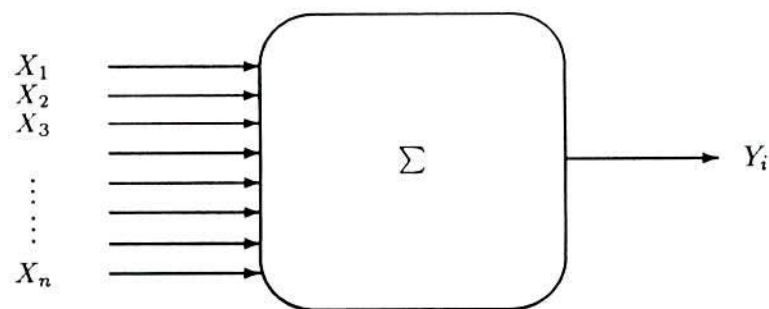


Figure 2.1: Artificial Neuron

2.3.2 The Artificial Neuron

In artificial neural networks, the fundamental employed unit is a simple mathematical model of biological neuron. This mimics only the first order characteristics of a biological neuron. The artificial neuron has a set of input, each representing the output of another neuron. Each input is multiplied by a corresponding weight, analogous to a synaptic strength, and all of the weighted inputs are then summed to determine the activation level of the neuron. Figure 2.1 shows a model that implements the above idea.

Neuron in ANN can be viewed as simple processing elements (PE). A commonly used representation of neuron as a PE is shown in Figure 2.2. PEs can be interconnected in various network topologies and can be programmed (trained). ANNs can be trained for various purpose such as - pattern recognition, to solve combinational optimization problems, estimation of sampled function whose form is not known, etc. Depending on the various network topologies, activation function and learning strategies a large number of ANN architectures are developed – Multilayered Feed Forward Network (MLFFN), Kohonen Network (KN) etc.

Since ANNs store pattern information with distributed encoding, this endows ANNs with fault tolerance and graceful degradation in case of loss of some information or faults in some processing elements of the ANN. Although, ANNs are of comparatively recent origin a very large amount of literature, which is growing at a very rapid pace, is already available in books and journals [156, 172, 176, 177, 180, 181, 182, 184, 186, 187, 191, 193, 194, 209, 210]. Following section briefly discusses the basics required for the work presented in this thesis.

2.3.3 Processing Elements (PE) in ANN

As shown in Figure 2.2, each PE performs two functions:

1. sum the weighted input signal to the PE, and
2. produce an output that is function of the weighted sum.

Thus the PEs possess the following two important quantities:

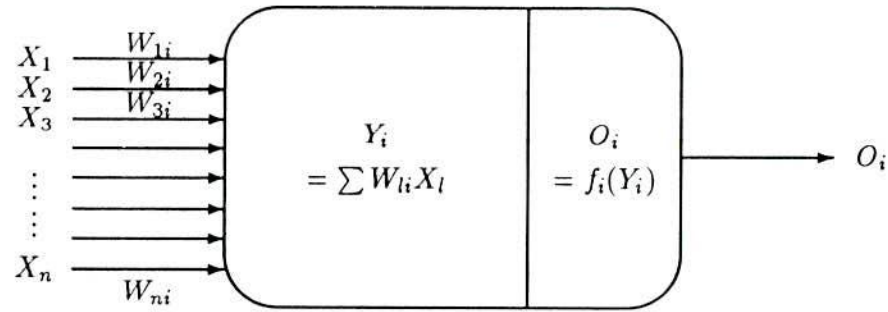


Figure 2.2: Commonly used processing elements in ANN

1. PEs require only local information. All the information necessary for the PE to produce an output is available at its inputs and resides within the PE. Information about other values in the network is not required.
2. PEs produce only one output value which is transmitted through interconnection links to other receiving PEs or as output of the network.

These two quantities allow PEs of the ANN to operate in parallel.

2.3.4 PE Functions

The processing elements produce output that is a function of sum of the weighted inputs. The functions, also called activation functions or squashing functions map the unbounded activation (sum of weighted inputs) into a bounded output signal. Among the infinite number of possible PE functions, generally sigmoidal or hyperbolic tangent functions are preferred. Linear functions are not preferred because linear function do not suppress noise. Non-linearity increases computational richness and facilitates noise suppression but, however, introduces computational intractability. Monotonic continuous nonlinear function appear to be the nature's compromise most biological neurons have sigmoidal signal characteristics [215].

The logistic signal function

$$f(x) = \frac{1}{1 + e^{-cx}} \quad (2.1)$$

is a sigmoid and strictly increasing (monotonic) for positive scaling constant $c > 0$ as shown in Figure 2.3(a). Strict monotonicity implies that its derivative

$$f' = \frac{df}{dx} = cf(1-f) \quad (2.2)$$

is positive as shown in Figure 2.3(b).

Logistic signal function is also a minimum entropy signal function, which, along with its computational simplicity, may account for its popularity in ANN models [156]. The other popular activation functions used are:

1. The hyperbolic tangent function

$$f(x) = \tanh(cx) = \frac{e^{cx} - e^{-cx}}{e^{cx} + e^{-cx}} \quad (2.3)$$

2. The radial basis function

$$f_i(x) = e^{-\frac{1}{2\sigma_i^2} \sum_{j=1}^n (x_j - \mu_j^i)^2} \quad (2.4)$$

Where $X = (x_1, x_2, \dots, x_n) \in \mathbb{R}^n$, activation vector with variance σ_i^2 and mean vector $\mu_i = (\mu_1^i, \mu_2^i, \dots, \mu_n^i)$.

3. The threshold linear

$$f_i(x) = \begin{cases} 1 & \text{if } cx \geq 1 \\ 0 & \text{if } cs < 0 \\ cs & \text{otherwise} \end{cases} \quad (2.5)$$

Between the upper and lower bounds, the threshold linear function is monotonic increasing as $f_i = c > 0$.

In the work presented in this thesis, only sigmoidal activation function is used.

2.4 Multi-Layered Feed Forward Neural Networks

The Artificial Neurons are organized in such a way that may be related to the anatomy of brain to make an ANN. Various types of ANNs such as BP, ART,

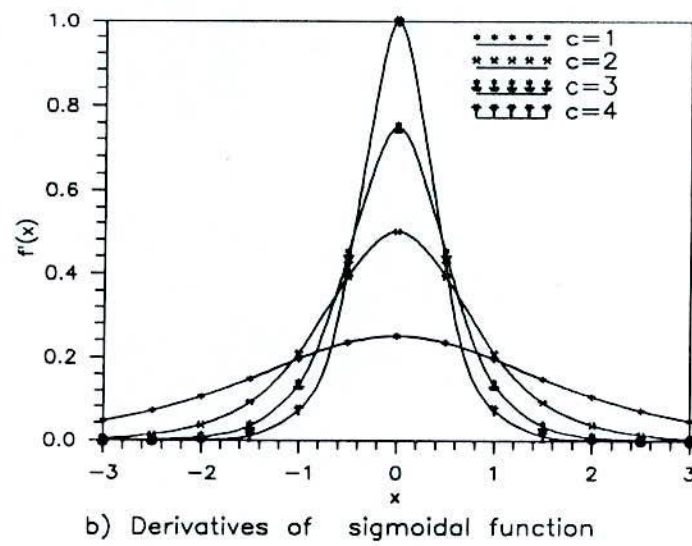
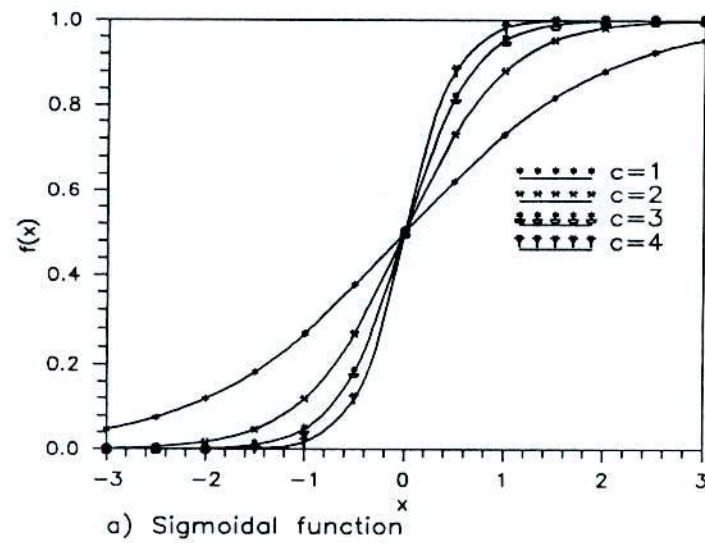


Figure 2.3: Characteristics of sigmoidal function

BAM, Hopfield, Kohonen etc.[156] are available. The most popular ANN used for load forecasting is back propagation (BP) multilayered feed forward neural network (MLFFNN). The network, as shown in Figure 2.4, consists of neurons connected by links and the neurons (Nodes) are divided into layers, the input layer, the output layer and the hidden layers in between. The nodes in the output layer provide the desired output signal. The signals are allowed to propagate from input layer to the hidden layer and from hidden layer to the output layer. Signals propagation between nodes with the same layer or from the input layer to output layer directly has not been entertained.

For each neuron in the input layer, the neuron output is the same as the neuron input. For each neuron of the next j th layer, the network input Y_j is given by

$$Y_j = \theta_i + \sum_i W_{ij} O_i \quad (2.6)$$

where,

i denotes the neuron in the preceding layer i th.

O_i is the output of the neuron in the preceding layer i th

W_{ij} is the connection weight from neuron of i th layer to neuron of j th layer.

θ_i is the threshold or bias value for j th layer = 1.0

The neuron output is given by

$$O_j = \frac{1}{1 + e^{-Y_j}} = f(Y_j) \quad (2.7)$$

and

$$f'(Y_j) = O_j(1 - O_j) \quad (2.8)$$

where f is the activation function

and Y_j is the input signal to the neuron of j th layer.

A number of pairs of input pattern $X_p[X_1, X_2, \dots, X_n]$ and target pattern $T_p[t_1, t_2, \dots, t_m]$ are presented to the ANN shown in Figure 2.2 and then ANN is asked to adjust weights in all connecting links such that the desired output patterns T_p are produced at the output nodes.

In general, the network output $O_p[O_1, O_2, \dots, O_m]$ will not be the same as the target or desired output patterns T_p . For each pattern the square of the error is defined as

$$E_p = \frac{1}{2} \sum_{j=1}^m (t_{pj} - O_{pj})^2 \quad (2.9)$$

where

m is the number of output neuron

$p[1, ns]$ is the p th pattern

ns = total number of training samples (patterns).

Therefore, the average system error would be represented by

$$E = \frac{1}{2ns} \sum_{p=1}^{ns} E_p \quad (2.10)$$

This error is minimized to a specified value by adjusting the connection weights between layers. A common approach for adjusting the connection weights of the back propagation feed forward neural network is the Generalized Delta Rule (GDR). This generalized delta rule is given in the Appendix-A.

The steps for back propagation learning algorithm of a three layer feed forward neural network shown in Figure 2.4 are presented below. The notations used for weights in algorithm may be referred to Figure 2.4.

Step 1: Initialize all weights $V_{ij}(i[1, n]; j[1, r])$ and $W_{jl}(j[1, r]; l[1, q])$ to small random values $[-0.5, +0.5]$. Set iteration number $k = 1$; Set training sample (pattern) number $p = 1$.

Step 2: Present the next input vectors $I_p = (I_{p1}, I_{p2}, \dots, I_{pn})$ to the input neurons $X_p(X_1, X_2, \dots, X_n)$ from the training set samples $(I_1, I_2, \dots, I_{ns})$; ns = number of input-output samples in the training set; $p[1, ns]$.

Step 3: Calculate the outputs H_{pj} for the hidden layer neurons $Y_p(Y_1, Y_2, \dots, Y_r)$; where

$$H_{pj} = f_j(Y_{pj}) \quad (2.11)$$

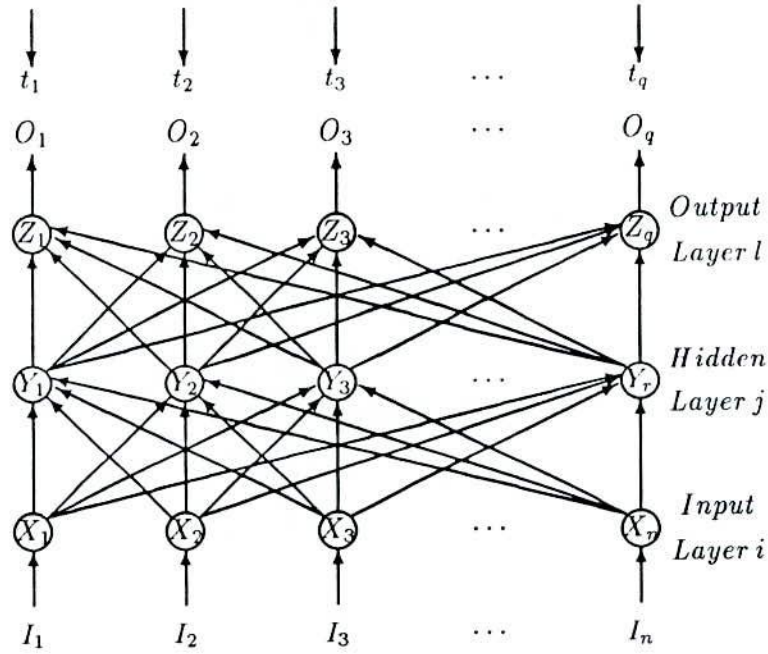


Figure 2.4: Three Layered Feed Forward Neural Network

and,

$$Y_{pj} = \theta_j + \sum_{i=1}^n V_{ij} X_{pi} \quad (2.12)$$

f_j = activation function of neuron in hidden layer j .

n is the number of neurons in the input layer.

Step 4: Calculate the O_{pl} for the output layer neurons $Z_p(Z_1, Z_2, \dots, Z_q)$;

where,

$$O_{pl} = f_l(Z_{pl}) \quad (2.13)$$

and

$$Z_{pl} = \theta_l + \sum_{j=1}^r W_{jl} Y_{pj} \quad (2.14)$$

f_l = activation function of neuron in output layer l .

Step 5: Adjust the weights W_{jl} for the interconnections between Y_p (hidden) and Z_p (output) layer using

$$W_{jl}(k+1) = W_{jl}(k) + \eta \Delta_{jl} + \alpha \Delta W_{jl}(k) \quad (2.15)$$

where η is the non-negative constant called learning rate,
and α is an acceleration to the learning rate called learning momentum.
and,

$$\Delta_{jl} = (t_{pl} - O_{pl})f(Z_{pl})H_{pj} \quad (2.16)$$

$T_p \triangleq (t_{p1}, t_{p2}, \dots, t_{pq})$; is the desired output (target) vector for the input vector I_p .

Step 6: Adjust the weights V_{ij} for the interconnections between X_p (input) and Y_p (hidden) layer using

$$V_{ij}(k+1) = V_{ij}(k) + \eta \Delta_{ij} + \alpha \Delta V_{ij}(k) \quad (2.17)$$

where

$$\Delta_{ij} = f(Y_{pj}) \sum_{l=1}^q [(t_{pl} - O_{pl})f(Z_{pl})W_{jl}] \quad (2.18)$$

Step 7: Calculate the output errors across all the output neurons, using

$$E_p = \frac{1}{2} \sum_{l=1}^q (t_{pl} - O_{pl})^2 \quad (2.19)$$

Step 8: Update error

$$E = E + E_p \quad (2.20)$$

if $p < ns$; set $p = p + 1$, goto step 2

if $p = ns$, compute the mean square error (MSE)

$$MSE = \frac{E}{ns} \quad (2.21)$$

Step 9: Check for convergence to maximum tolerance label ϵ

The algorithm continue for all set of samples until,

if $MSE \leq \epsilon$ (a specified tolerance) stop;

otherwise; set iteration count $k = k + 1$

goto step 2 .

2.5 ANN Based Load Forecasting

In this chapter, sensitivity analyses of ANN modules are carried out to predict future yearly peak demand of an electric utility. The most important work in developing an ANN based load forecasting model is the selection of input variables. There is no general rule that can be followed for this purpose. It largely depends on engineering judgment and experience.

For the purpose of one month ahead load forecasts the influence of weather variables are implicitly taken into account in the previous load and therefore, it is not necessary to include the weather variables (temperature, visibility, wind speed, etc.) explicitly in the input to the ANN. Thus the input to the ANN consists past load data only.

2.5.1 Characteristics of the load data

In order to reflect the load behaviour in the input information, the historical monthly load for a few years of a number of bulk customers are analyzed. It was observed that the load data exhibits a monthly and yearly periodicity. It was also observed that the monthly load pattern from January to December showed marked similarity with the previous years load pattern. Similarly, the historical yearly peak load of an existing power utility is studied. It is found that the load data exhibits a five years periodicity. This is due to the five years plan of each utility. Therefore, the yearly peak load data for five years of any utility system may be treated as analogous of the monthly peak load data for one year of any bulk consumer.

2.5.2 Normalization of the Input and Output Data

The input and output variables for the neural network will have different ranges if the actual load data is directly used. This may cause convergence problem during the learning process. To avoid this, the input and output load data were normalized such that they were within the range $[0., 1.0]$. For this purpose the actual loads were scaled using the relationship,

$$L_n = (0.8) \frac{L - L_t}{L_p - L_t} \quad (2.22)$$

where, L = actual load

L_p = the maximum load (2 to 5 time of peak load)

L_t = the minimum load (0.1 to 0.3 time of base load)

L_n = Normalized load which is used as input to the network

Note: Choice of L_p and L_t is such that in no case L_n will be greater than 1 or less than 0. It also ensures that majority of the L_n will have values near 0.5 where the slope of the activation is highest.

2.6 ANN Architecture Modules

This section presents the architectural details of the ANN models used in this chapter. Four modules of ANN architecture, as shown in Figure 2.5, are studied. The input and output neurons data for training is given below.

1. Module-I

Input	$y(i-1, j)$ $j=1$ to 12
Output	$\hat{y}(i, j)$ $j=1$ to 12

where i denote year of prediction and j denote month of prediction

2 Module-II

Input	$y(i-1, j-k)$ $k = 1, 0, -1$
	$y(i, j-k)$ $k = 1, 2, 3$
Output	$\hat{y}(i, j)$

3 Module-III

Input	$y(i-2, j-k)$	$k = 1, 0, -1$
	$y(i-1, j-k)$	$k = 1, 0, -1$
	$y(i, j-k)$	$k = 1, 2, 3$
Output	$\hat{y}(i, j)$	

4 Module-IV

Input	$y(i-k, j)$	$k = 1, 2, 3$
Output	$\hat{y}(i, j)$	

In multilayered feed forward neural network, one of the most important configuration issue is to select an optimal number of hidden layers. It has been shown by researchers [156, 209, 172, 173] that with homogeneous sigmoidal output functions in MLFFNN one hidden layer is sufficient to compute arbitrary decision boundaries for the outputs and that two hidden layers are sufficient to compute an arbitrary output function of the outputs. A number of empirical test were conducted by researchers [174, 175] to suggest that for simple applications there is no significant advantage in using two or more hidden layers over single hidden layer and for most purposes MLFFNN with one hidden layer is sufficient.

Choosing optimal number of hidden layer nodes is perhaps the most interesting and challenging aspects in designing the MLFFNN configuration. One approach to this problem is to start from a theoretical upper bound for the number of hidden layer neurons and to keep reducing this number till the performance starts degrading. For single hidden layer MLFFNN uses ANN interpretation of Kolmogorov's theorem to arrive at the upper bound on number of hidden layer neurons as $2 \times (n + 1)$, where n is the number of input layer neurons. While, Lipmann [156] predicts this upper bound to be equal to $q \times (n + 1)$, where q is the number of output layer neurons. Whereas, some other researchers [163, 164] using empirical tests suggests this upper bound to be $q \times 3$ and for two hidden layers they suggest a ratio 3 : 1 between the number of first and second hidden layers neurons.

It has been established that with few neurons the networks is unable to create complex decision boundaries and therefore, it will create difficulties in convergence

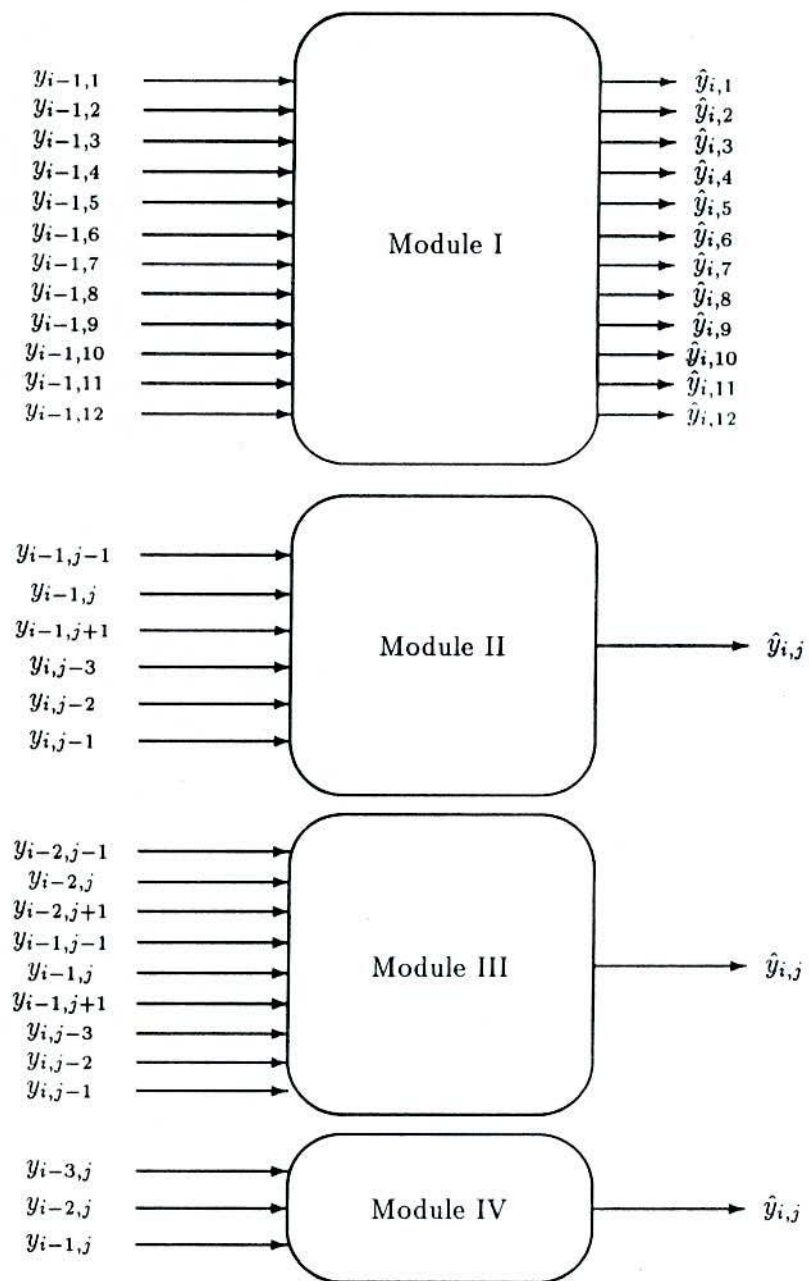


Figure 2.5: ANN Structure Modules

during training. Whereas, too many neurons will create decision boundaries which may perfectly encapsulate the training points. Thus, ANN will lose its generalization capabilities. Taking these points in consideration, it is suggested that a good starting point for obtaining the optimum number of neurons in single hidden layer MLFFNN is the number of input layer neurons plus one i.e. $(n + 1)$ [156].

The MLFFNN used in this chapter is a three layered feed forward architecture with one input layer, one output layer and one hidden layer of neurons. Each neuron of input layer receives the input data from each sample consisting of few variables. The neuron(s) of output layer provide(s) the prescribed load forecast. The number of hidden layer neurons equals to number of input neurons plus one.

A number of training samples or patterns have been used for training the networks to predict loads. For this the load data of six years (72 months) of IIT substation and eleven years (132 months) of Carnac substation have been used for training patterns for the respective system. The ANN is then trained upto desired accuracy (system error tolerance is taken as 0.00008 for IIT system and 0.00012 for Carnac system) using training patterns. In case of existing utility, the yearly peak load for six plan years (30 years) has been used for training patterns. ANN architecture modules are trained upto the system accuracy of 0.00012.

2.7 Results and Discussions

Performance analysis of the four modules of MLFFNN is carried out for following two load centres using monthly load data and one utility system using yearly peak demand.

- a. Indian Institution of Technology, Kharagpur; Monthly load data of IIT campus 33 kV substation from January 1990 to December 1995.
- b. TATA electric supply co., Bombay; Monthly load data of Carnac 33kV substation from January 1974 to December 1985.
- c. Orissa State Electricity Board (OSEB), India; Yearly peak demand of OSEB from 1961 to 1995.

Table 2.1: Numerical configuration of four modules, Module-I to IV

ANN Structure	No.of input samples			No.of Pred. sample		No.of hidden neurons	
	IIT	TATA	OSEB	IIT/TATA	OSEB	IIT/TATA	OSEB
Module-I	4	9	4	1	1	13	6
Module-II	47	107	24	12	5	7	7
Module-III	35	95	19	12	5	10	10
Module-IV	24	84	15	12	5	4	4

The two substation level systems are of different load patterns. One is commercial and other is the largest advanced engineering institute campus of Indian subcontinent. On the other hand, the third one is a utility system, which is having abundant quantity of coal and hydro-energy resources. The accuracy of the load forecasted, in this chapter, is defined by mean absolute error (MAE) as

$$MAE = \frac{1}{N} \sum_{i=1}^N \frac{|\hat{Y}_i - Y_i|}{Y_i} \quad (2.23)$$

where,

N = number of predicted sample

$\hat{Y}_i$ = forecasted value

Y_i = actual value

The studies regarding the following points are carried out;

- η and α at minimum MAE
- η and α at least convergence of iteration count
- suitable module selection for the systems.

The numerical configurations of four modules for training and prediction are given in Table 2.1.

One month to one year ahead forecasted results for two substation level systems are given in Table 2.2. Table 2.3 also shows the highlights of results of these two

Table 2.2: Comparison of results for Module-I to IV at minimum MAE

ANN Structure	IIT substation				TATA Carnac substation			
	η	α	MAE	Iteration	η	α	MAE	Iteration
Module-I	—	—	—	—	—	—	—	—
Module-II	0.08	0.99	3.62	238	0.20	0.76	4.50	2948
Module-III	3.05	0.74	2.96	320	0.88	0.82	3.82	547
Module-IV	1.85	0.90	2.57	2783	—	—	—	—

— means no convergence.

systems obtained from different modules at the convergence of least iteration. From these it is also found that the minimum MAE is not occurring at minimum iteration counts.

Figure 2.6 and 2.7 represent the forecasted results of IIT substation and TATA Carnac substation for different modules with actual loads. The predicted point to point errors for different modules of both the systems are also shown in these figures. Mean absolute error of different modules are evaluated from the point to point errors depicted in Figure 2.6. These are 3.62%, 2.96% and 2.57% for the modules II, III & IV, respectively.

However, no system converges at the time of training with module-I and TATA Carnac substation also does not converge using module-IV within 3000 iteration

Table 2.3: Comparison of results for Module-I to IV at minimum Iteration

ANN Structure	IIT Substation				TATA Carnac Substation			
	η	α	MAE	Iteration	η	α	MAE	Iteration
Module-I	—	—	—	—	—	—	—	—
Module-II	0.09	0.99	3.64	229	1.60	0.12	4.96	1322
Module-III	1.95	0.98	11.64	183	3.00	0.54	4.57	81
Module-IV	2.05	0.90	5.16	7	—	—	—	—

— means no convergence.



counts. Mean absolute errors of TATA Carnac system are also evaluated from the point to point errors of different modules presented in Figure 2.7. These are found to be 4.5% and 3.82% for module II & III, respectively. From the above analysis of different ANN modules, it is clear that all the modules are not valid for every system.

Above important points are exploited after rigorous studies of four ANN modules. Detailed studies are given in Appendix-A.2 in terms of figures. Highlighted Figures 2.8-2.16 to be analyzed are extracted from the elaborated figures in Appendix-A.2. These figures are the characteristic curves of two systems for different modules, drawn for MAE or iterations counts versus α or η . These characteristic curves show the effects of MAE or Iteration counts on wide range of α or η .

The extracted characteristic curves are analyzed in what follows.

- a. Figure 2.8 shows that minimum MAE of module II for IIT substation is occurring at $\eta = 0.08$ and $\alpha = 0.99$, when the number of iteration for convergence is 238. Whereas, the same Figure shows that the least number of iteration for convergence of that module is 229, which occurs at $\eta = 0.09$ and $\alpha = 0.99$. However, the MAE of the module for the same system is 3.64% at this condition, which is higher than that of previous condition.
- b. Figure 2.9 shows that the MAE of the module III for IIT substation is decreasing as η is increasing. This nature is valid upto $\eta = 3.05$ at $\alpha = 0.74$. But, after $\eta = 3.05$ the MAE is increasing, though the number of iteration for convergence is still reducing. At the point of minimum value of MAE, the iteration count is 320 and MAE is 2.96%.

On the other hand, Figure 2.10 shows the characteristic curves of least iteration count of 183. This value is found for $\eta = 1.95$ and $\alpha = 0.98$. At this point, the MAE of the system for module III is 11.46%.

- c. The characteristic curves shown in Figure 2.11 represents the curves for minimum MAE of IIT substation for the module IV. This figure depicts that the number of iteration count for convergence increases with the increase of η . Whereas, the MAE of the system decreases with the increment of η . The

curves of MAE changes its nature after the value of $\eta = 1.85$ at $\alpha = 0.9$. At this point, the minimum MAE is 2.57% and the iteration count for convergence is 2783. Note that the system does not converge for the value of $\eta = 2.3$ at $\alpha = 0.9$ for the module IV of IIT system.

However, Figure 2.12 shows the characteristic curves of least number of iteration count. This figure depicts that the system converges at only 07 iteration count with the learning rate $\eta = 2.05$ and learning momentum $\alpha = 0.9$. But, the MAE at this condition is 5.16%. Which is very high than that at the condition of $\eta = 1.85$ and $\alpha = 0.9$.

- d. The characteristic curves shown in Figure 2.13 show the curves for minimum MAE of module II for the TATA Carnac substation. Minimum MAE is found for $\eta = 0.20$ at $\alpha = 0.76$. At this point, the number of iteration for convergence is 2948 and MAE=4.50%. The characteristic curve for iteration count also represents that the system does not converge beyond the value of $\eta = 0.15 \rightarrow 0.22$.

Figure 2.14 represents the characteristic curves of the same system of least iteration count for the convergence. Minimum number of iteration count for convergence is found at $\eta = 1.60$ and $\alpha = 0.12$. From this curve, it is distinct that the number of iteration count for convergence is increasing with the increase of α at $\eta = 1.6$. It is also found that the MAE is decreasing with the increase of α upto a certain value. That is, the curve has formed a trough, which indicates the minimum MAE=4.75%. But, this value is higher than that of module II found at $\eta = 0.20$ & $\alpha = 0.76$.

- e. Figure 2.15 shows the characteristic curve of TATA Carnac substation using module III drawn for minimum MAE of the system. The characteristic curve for iteration shows that the iteration count is increasing nature with the value of η at $\alpha = 0.82$. Whereas, MAE is of decreasing nature upto the value of $\eta = 0.88$. After this, the value of MAE has changed its nature. But, this nature is uniform till $\eta = 0.96$. The value of MAE at $\eta = 0.97$ increased abruptly. Again, the value of MAE is uniform after $\eta = 0.98$ of ramp nature

with η . Minimum MAE=3.82% is found at the trough point of MAE curve at 547 numbers of iteration count.

Similar to the other modules, Figure 2.16 represents the characteristic curve of least iteration count for convergence of module III. The curve for iteration count gives the minimum iteration count of 81 for $\eta = 3.0$ and $\alpha = 0.54$. At this condition, the MAE is 4.57%. However, the minimum MAE=4.35% is found from this graph at $\alpha = 0.6$ and $\eta = 3.0$. At this point, the number of iteration count for convergence is 100. But, minimum MAE found from this characteristic curve is higher than that of Figure 2.15.

Following points may be noted from the above discussion.

1. Module IV provides the minimum MAE of IIT substation in comparison to other modules. It is obtained at $\eta = 1.85$ and $\alpha = 0.9$.

Whereas, Module III presents the minimum MAE of TATA Carnac substation. It is also obtained at $\eta = 0.88$ and $\alpha = 0.82$.

Therefore, same module may not be suitable for all systems.

2. The nature of different figures show that the minimum MAE of any module for any systems is completely dependent on η and α , and not on the least number of iteration of convergence.

For this reason, the values of η and α for any module and any system is to be chosen appropriately after rigorous study.

Once the η and α are chosen for any system for suitable module, the minimum MAE may remain nearer to the actual values minimizing the prediction error.

2.8 Numerical Evaluation

This section uses the findings of the preceding sections for long term load prediction of an existing electric utility - Orissa State Electricity Board (OSEB). Yearly peak demands of OSEB from 1961 to 1995 have been used for the yearly peak demand prediction from 1996 to 2010. Each five years (belonging to a five year plan) yearly

Table 2.4: ANN based Yearly Peak Load of OSEB (1996-2010)

Year	Predicted+3%	Year	Predicted+3%	Year	Predicted+3%
1996	1590	2001	2380	2006	2980
1997	1750	2002	2530	2007	3225
1998	1900	2003	2660	2008	3460
1999	2050	2004	2750	2009	3650
2000	2220	2005	2825	2010	3840

peak load is considered as one sequence of data. That is equivalent to twelve months of a year in the original modelling concept. The configuration for this system to train the ANN with different modules is given in Table 2.1.

Figure 2.17 represents the forecasted results of OSEB for the module II and III with actual yearly peak loads of the years 1991 to 1995. The predicted yearly errors of both the modules are also shown in the figure. Note that the MAE of the system using module II is minimum with respect to module III. Therefore, module II is suitable to predict future yearly peak demand of the utility. The system does not converge using other modules. Further, It may be observed in Figure 2.18 that minimum MAE = 3.05% of the system OSEB does not occur at the least iteration count of convergence. It may also be noted that the minimum MAE occurs at $\eta = 0.97$ and $\alpha = 0.94$, where the convergence does not occur at minimum number of iteration. Therefore, this figure shows that the MAE is not minimum at the convergence of least iteration.

Figure 2.19 shows the characteristic curves of the system using module III. This also provides that the minimum MAE is not occurring at the convergence of least iteration count. From the overall performance analysis of all the modules, it is found that the module II is suitable to predict future demand of the system OSEB. The predicted yearly peak demand for the period 1996 to 2010 using module II is given in the Table 2.4. In this table, 3% error as the minimum MAE of the selected module, is added with the predicted yearly peak demand. These projected loads will be used for generation expansion planning of OSEB in the remaining chapters to follow.

Table 2.5: Comparison of Yearly Peak Load of OSEB (1991-1995)

Year	Actual load	ANN based		CEA based	
		Load	Error	Load	Error
1991	1062	1058	0.0037665	1306	0.229755
1992	1217	1138	0.064915	1451	0.192776
1993	1210	1275	0.05371	1721	0.422314
1994	1300	1340	0.029233	1821	0.400769
1995	1441	1440	0.000695	2068	0.435114
		MAE=0.0305		MAE=0.3361	

Table 2.5 shows the comparison of forecasted load predicted by proposed ANN module and Central Electricity Authority (CEA), India in the first phase of planning of OSEB. It is found that the MAE of CEA prediction is 33.61% whereas MAE using ANN module II is only 3.05%. Therefore, the prediction using ANN module is far better than that of CEA results.

On the other hand, Table 2.6 shows the load of OSEB forecasted by CEA in the second phase of planning (1996-2010). The results depicted in this table can also be compared with the results presented in Table 2.4 obtained through ANN prediction. It may be noted that the load predicted by CEA has always been overestimated. The overestimates of CEA loads are mainly due to consideration of load growth rate. In this case, previous and restricted loads influences are neglected. Whereas, previous load with restriction has directly influenced the forecasted load in ANN modules. It is also well known that the properly estimated load is very economical in expansion planning of any utility system. Therefore, the nearest estimated load is always accepted and it is well done by ANN. Note that the ANN base forecasted load is nearest to the actual value of load as shown in Table 2.5.

Table 2.6: CEA based Yearly Peak Load of OSEB (1996-2010)

Year	Predicted load	Year	Predicted load	Year	Predicted load
1996	1692	2001	2631	2006	3519
1997	1771	2002	2781	2007	3720
1998	1952	2003	2940	2008	3935
1999	2268	2004	3127	2009	4164
2000	2450	2005	3331	2010	4409

2.9 Conclusions

Artificial Neural Networks have been applied to forecast the one month ahead load of Indian Institute of Technology substation at Kharagpur and TATA Carnac substation at Bombay. This study is carried out for the sensitivity analysis of different modules of ANN. It has been found that accuracy of results forecasted by a particular ANN module is system dependent. Therefore, one has to find out an ANN module configuration which suits to a particular system.

ANN approach can make fairly accurate short term and long term forecasting of loads. However, for a system initially, before adopting a module sensitivity studies are to be made. This will be only one time effort and then the module so studied can be used to predict system loads.

This concepts is used to predict the future yearly peak load of Orissa State Electricity Board (OSEB) for the period 1996 to 2010. The error evaluated from predicted load for the period 1991-1995 of the system was found to be 3%.

2.10 Figures

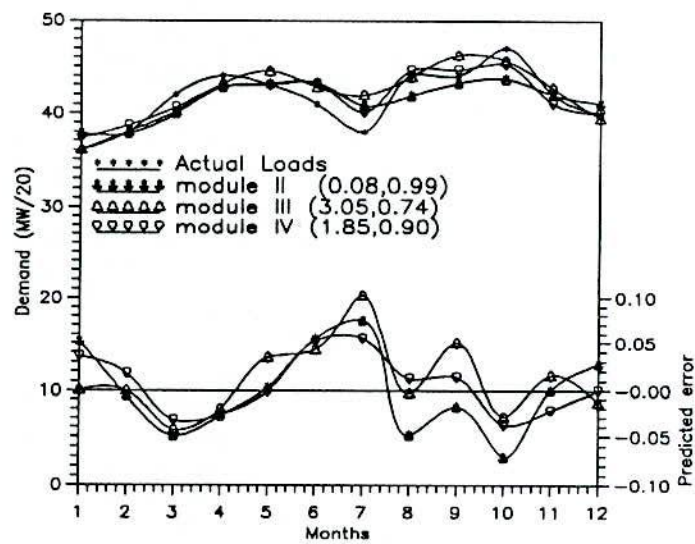


Figure 2.6: Variation of Actual load, Predicted loads and Predicted error with Months at minimum MAE of IIT s/s, Kharagpur

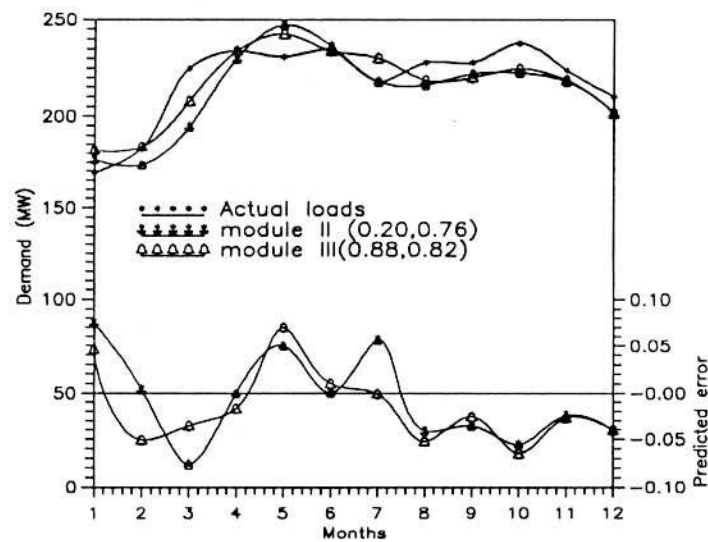


Figure 2.7: Variation of Actual load, Predicted loads and Predicted error with Months at minimum MAE of Carnac s/s, Bombay

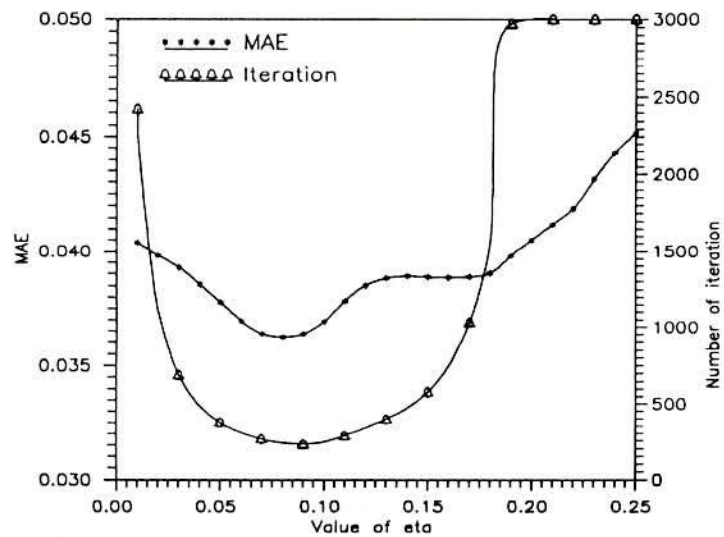


Figure 2.8: Variation of MAE and Iteration count with η for IIT s/s, Kharagpur (at $\alpha = 0.99$ in the Module II)

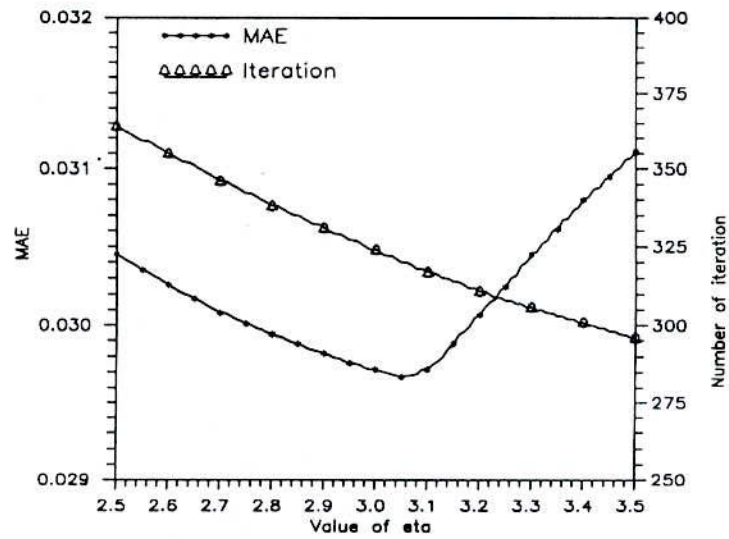


Figure 2.9: Variation of MAE and Iteration count with η for IIT s/s, Kharagpur (at $\alpha = 0.74$ in the Module III)

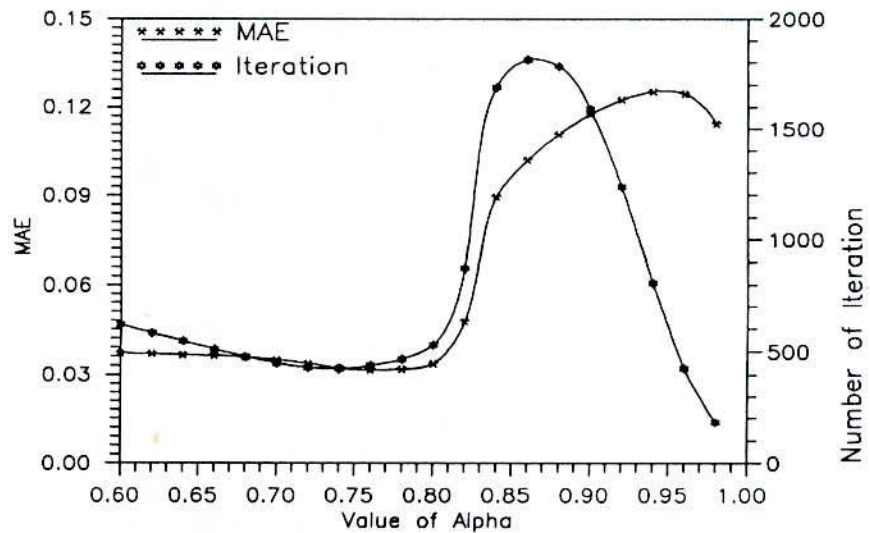


Figure 2.10: Variation of MAE and Iteration count with α for IIT s/s, Kharagpur (at $\eta = 3.5$ in the Module III)

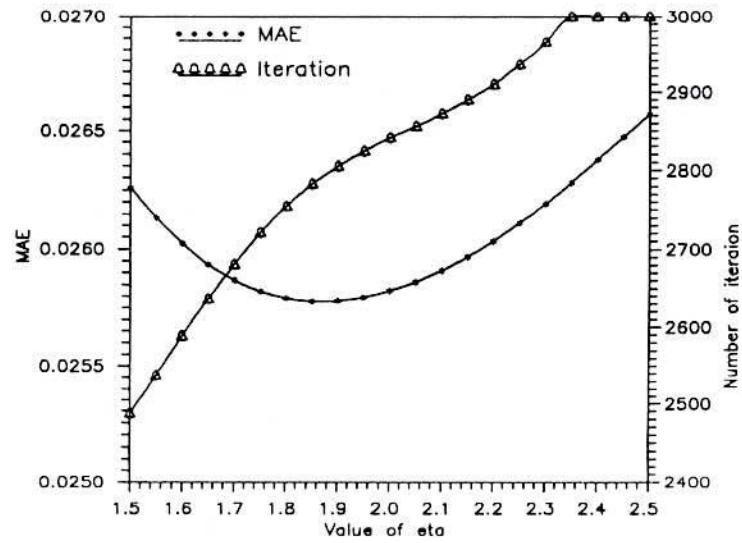


Figure 2.11: Variation of MAE and Iteration count with η for IIT s/s, Kharagpur (at $\alpha = 0.9$ in the Module IV)

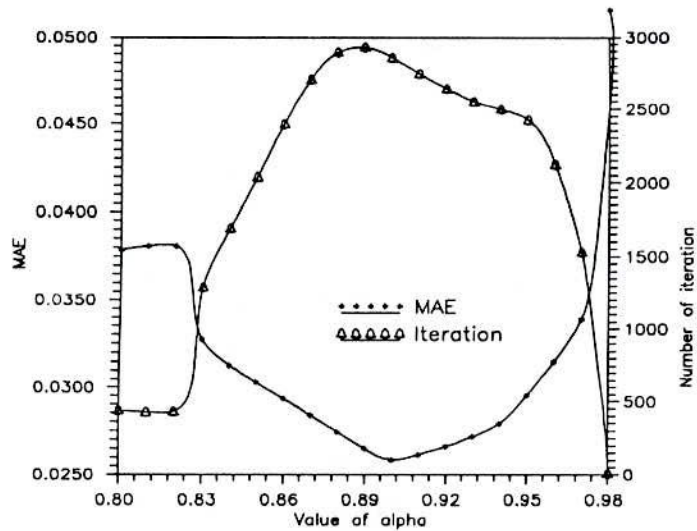


Figure 2.12: Variation MAE and Iteration count with α for IIT s/s, Kharagpur (at $\eta = 2.05$ in the Module IV)

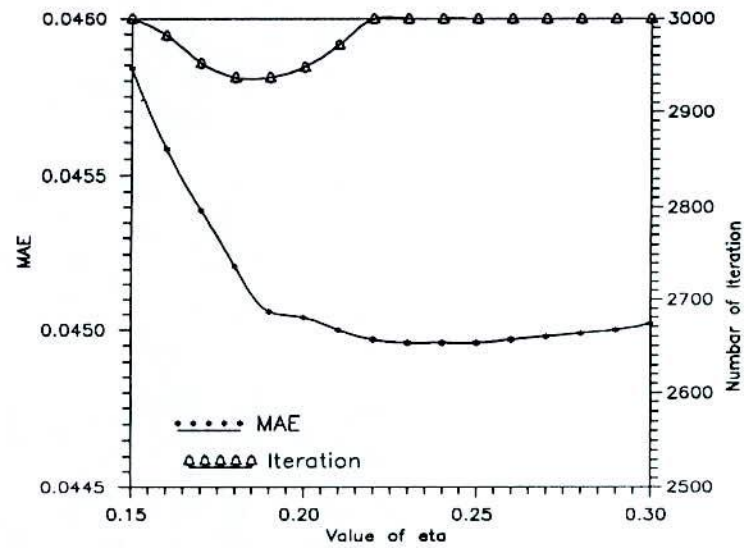


Figure 2.13: Variation of MAE and Iteration count with η for Carnac s/s, Bombay (at $\alpha = 0.76$ in the Module II)

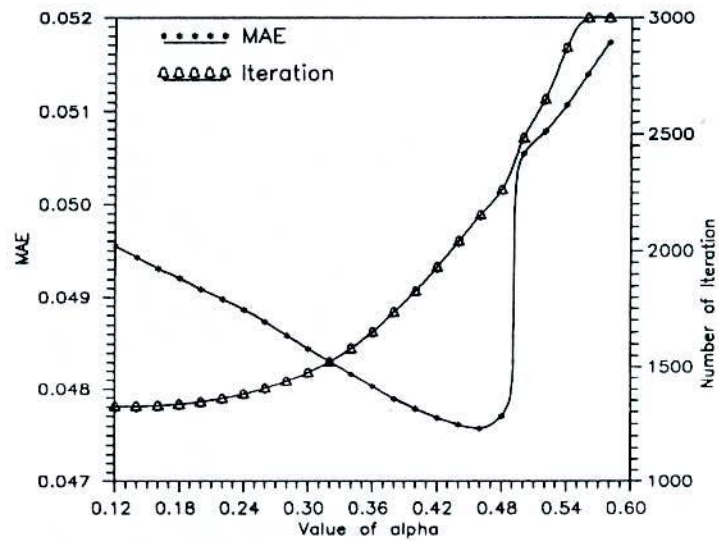


Figure 2.14: Variation of MAE and Iteration count with α for Carnac s/s, Bombay (at $\eta = 1.6$ in the Module II)

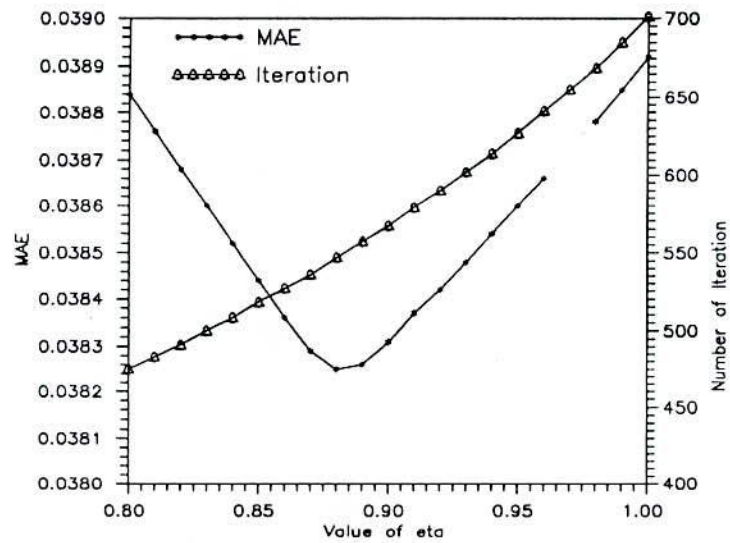


Figure 2.15: Variation of MAE and Iteration count with η for Carnac s/s, Bombay (at $\alpha = 0.82$ in the Module III)

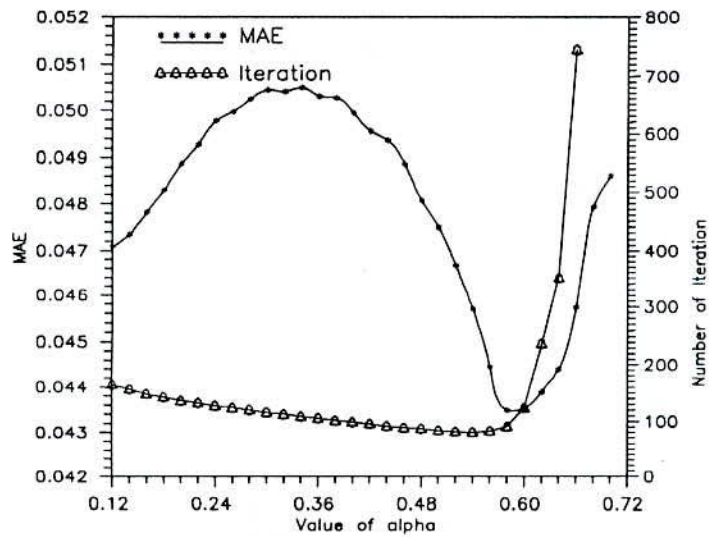


Figure 2.16: Variation of MAE and Iteration count with α for Carnac s/s, Bombay (at $\eta = 3.0$ in the Module III)

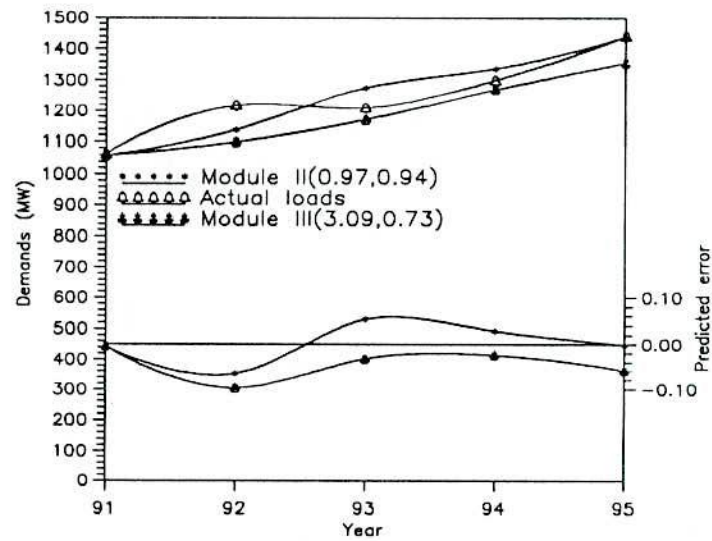


Figure 2.17: Variation of Actual load, Predicted loads and Predicted error with Years at minimum MAE of OSEB, Orissa

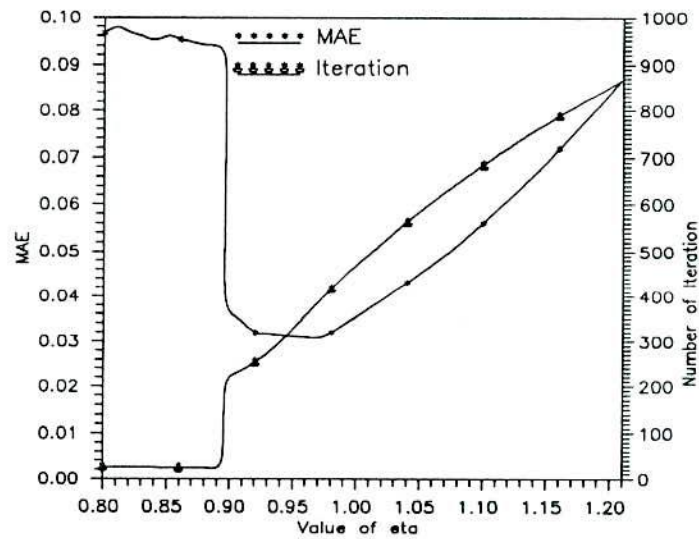


Figure 2.18: Variation of MAE and Iteration count with η for OSEB, Orissa (at $\alpha = 0.94$ in the Module II)



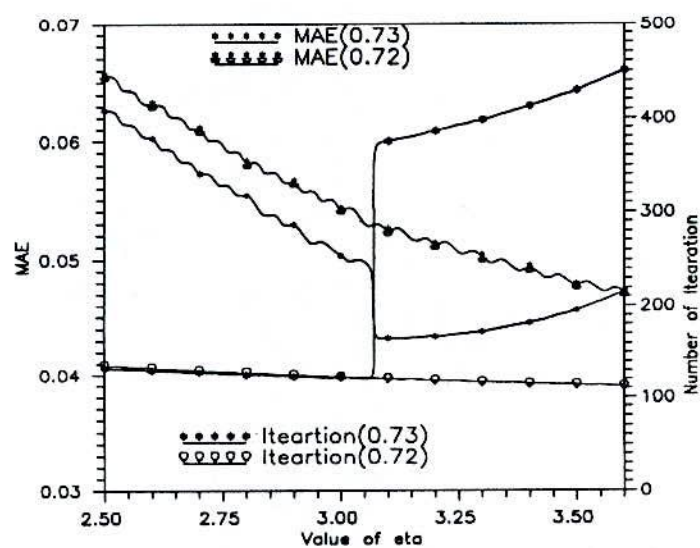


Figure 2.19: Variation of MAE and Iteration count with η for OSEB, Orissa (at $\alpha = 0.72$ & 0.73 in the Module III)

Chapter 3

RELIABILITY EVALUATION OF A POWER GENERATING SYSTEM

3.1 Introduction

The main objective of an utility (power company) is to supply customers with reliable electrical energy at minimum price. The economic and reliability constraints are the major factors which influence the decisions regarding generation expansion planning. In generation expansion planning process, reliability of each potential expansion plan is evaluated. The plans which do not comply with the desired reliability level are either modified or discarded. The plans satisfying the reliability constraints are further evaluated on the basis of economics in order to identify the one that impacts on the utility in the most favourable way. Therefore, reliability index evaluation is the first important aspect of generation expansion planning.

Classical definition of reliability is the probability of a device or system performing its functions adequately, for the period of time intended, under the operating conditions encountered [202].

Reliability is thus defined through the mathematical concept of probability. The time span for a power system is divided into two phases: the planning phase and

operating phase. Accordingly, it is customary to divide reliability assessment into two categories: static reliability assessment and spinning reliability assessment [88].

For the assessment of reliability, probability distribution of forecasted load and scheduled generation is required, especially for the assessment of static reliability. For the operation of a power system what is mainly required is the ability to operate the system as economically as possible with adequate operating reserve. In the reliability assessment, it may be necessary to include one or more of the following factors:

- a. rapid start units such as gas turbines and hydro-plant,
- b. interruptible loads,
- c. assistance from interconnected systems,
- d. voltage and/or frequency reduction.

However, the major factors influencing reserve capacity and, therefore generating system reliability are:

1. Unit size
2. Number of units
3. System load factor
4. Delayed capacity additions
5. Scheduled and forced outages
6. Interconnections with other systems
7. Uncertain total energy and peak demand.

Till 1930, the methods applied in evaluating the power system reliability were all based on deterministic approach. The weakness of this approach is that this does not take into consideration of probabilistic or stochastic nature of system behaviour, customer demands or component failures. The need for probabilistic evaluation of

system has been recognized since 1930s. The main reason for not considering such stochastic nature of system in the past is the limitation of computational resources. Now, the computing facilities are greatly enhanced and many probabilistic evaluation techniques have been developed [211]. In order to quantify the reliability of power system a number of reliability indices have been devised. Some of the commonly used indices are described below.

Frequency and Duration (FAD)

This performance index gives the average number of times and the average length of time during which available generation is inadequate to supply the load. This requires the consideration of daily load cycle and data on the frequency and duration of unit outage. One problem with the FAD technique is that it requires more detailed data than it is usually available [203]. In addition to failure rates of various components, repair times must also be available.

Monte Carlo Simulation (MCS)

In MCS, actual realization of the life process of a component or a system is simulated on the computer and, after having observed the simulated process for some time, estimates are made of the desired reliability indices [91, 92, 93, 105, 116, 120, 122]. Thus, the simulation is treated as series of real experiments. During its course, events are made to occur at times determined by random processes obeying predetermined probability distributions. The method is computationally expensive. However, it may produce a solution in cases where more traditional analytical techniques fail [108].

Loss of Load probability (LOLP)

The most effective and popular reliability index for generating systems is LOLP. The basic technique for LOLP evaluation is known as recursive method [208]. In order to incorporate the contribution to system LOLP by all values of loads for any period under consideration, Booth [28] introduced the concept of equivalent load. Essentially, equivalent load is defined as the sum of load and the amount of capacity

on forced outage considering the generating unit to be fully available. The LOLP is obtained as probability that the equivalent load equals or exceeds the installed capacity in the system. A number of papers [25, 26, 27, 28, 34, 62, 63, 79, 80, 95, 111, 118, 119, 121] have contributed to the advancement and improvement of probabilistic techniques in the area of reliability evaluation of power systems.

Two different sets of generation reliability indices are used by the electric utility industry; one in the context of long-range planning and the other for short-term operational planning, namely Loss of Load Probability (LOLP) and Capacity Factor (CF) respectively. The former provides inputs to decisions in generation expansion planning and the scheduling of new unit additions. The latter index is of use to the operating engineer in the daily operation of a power system. The loss of load probability (LOLP) index is used in the long-range planning context, and it measures the probability that a given system's available capacity will be insufficient to meet the system peak load. It estimates the fraction of time the utility system will have a generation deficit, with no consideration given to the magnitude of the deficit. If AC and L are the available capacity and the demand respectively. Then,

$$LOLP = Pr\{AC < L\}$$

In the evaluation of *LOLP*, forced and scheduled outages of generating units as well as load forecast uncertainty and assistance due to interconnections is to be taken into account.

Consider a power system consisting of n generating units such that the installed capacity of i th generating unit is c_i and its *equivalent* forced outage rate or unavailability is p_i , where $i = 1, 2, \dots, n$. Let X_i be an independent discrete random variable (RV) representing unavailable capacity or the outage capacity of unit i with a distribution of

$$X_i = \begin{cases} c_i & \text{with probability} = p_i, \\ 0 & \text{with probability} = 1 - p_i \end{cases}$$

Let L denote the system peak load. Then the loss of load probability (LOLP) is measured by

$$LOLP = Pr\{(X_1 + X_2 + \dots + X_n) > (c_1 + c_2 + \dots + c_n - L)\} \quad (3.1)$$

In case of a random load L , which has m values, $L_1, L_2, L_3, \dots, L_m$ with probabilities $p_1, p_2, p_3, \dots, p_m$ respectively, the loss of load probability for the load value of L_i , $LOLP_i$ is given as,

$$LOLP_i = Pr\{(X_1 + X_2 + \dots + X_n) > (c_1 + c_2 + \dots, c_n - L_i)\} \quad (3.2)$$

Hence, the system $LOLP$ considering all occurrences of load equal likely is,

$$LOLP = \frac{1}{m}(LOLP_1 + LOLP_2 + \dots + LOLP_n) \quad (3.3)$$

In general,

$$LOLP = \int_{IC}^{IC+P_l} f(X) dX = \sum Pr(X > IC) \quad (3.4)$$

where, $f(X)$ is the equivalent load PDF

$IC = c_1 + c_2 + \dots + c_n$ = Installed capacity

P_l = Peak load of the system

The LOLP does not give an indication of the magnitude or duration of the generation deficiency. This reliability index only provides the probability of occurrence of the loss of load [24, 29, 32, 69, 104]. The LOLP for a system is realistic indication than the reliability figure for an individual machine operating in the system or even of a section of the entire generation system. Since LOLP is the simplest and most commonly used reliability index [16, 31]. For this, it has been used for planning and analysis of any system in this thesis.

In order to evaluate any one of these reliability indices, following steps are to be followed and mathematical background is given in Appendix B.

- a. Development of generation model
- b. Development of a load model

- c. Combination of these two models to define the appropriate index.

In this chapter, two methods have been proposed to evaluate the Loss of Load Probability of a power generating system. These approaches need less number of multiplications and additions in the convolution of a group of identical generating units. Using the proposed approaches, generation expansion planning of an utility system has also been carried out for a projected future load.

3.2 Proposed FFT Approach

This section describes the fast Fourier transform (FFT) scheme to evaluate the LOLP of a generation system. FFT scheme is used to convolve the loads and the generating unit outages. The resultant distribution obtained through the convolution is known as the *equivalent load distribution* of the system. The LOLP of a system is evaluated by integrating the *equivalent load distribution* over the appropriate limits.

Following sections describe basic FFT procedure and improvements incorporated in FFT approach to calculate LOLP of a generation system.

3.2.1 FFT Convolution Procedure

Let a function Z be expressed as:

$$Z(X) = \sum_{i=1}^m X_i \quad (3.5)$$

where X_i is i th random variable and Z is the resultant random variable.

The characteristic function of a discrete Random variable X_i is

$$H_{X_i}(k) = \sum_{l=0}^{n-1} f_{X_i}(l) e^{\frac{-2\pi i l k}{n}} \quad (3.6)$$

which is the discrete Fourier transform (DFT) of the probability density function $f_{X_i}(l)$. The characteristic function of sum of m independent random variables equals the product of the characteristic function of each independent RV point by point. i.e.,

$$H_z(k) = \prod_{i=1}^m H_{X_i}(k) \quad (3.7)$$

Equation (3.7) is very useful, because it does not involve multiple (nested) integrations, and therefore, is particularly convenient for large value of m . The probability density function (PDF) of random variable Z may be found by inverse DFT as:

$$f_z(l) = \frac{1}{n} \sum_{k=0}^{n-1} H_X(k) e^{\frac{-2\pi i l k}{n}} \quad (3.8)$$

Above three equations represent the computational steps of convolving m RVs using conventional fast Fourier transform technique [214]. Computational effort associated with the solution of equations (3.6)-(3.8) can be reduced by employing discrete fast Fourier transform scheme. However, it requires the discretization of random variables which may introduce some error in the final result. The number theoretic FFT is an algorithm for rapidly evaluating the discrete Fourier series (DFS). The concepts behind the algorithm have been discussed at length in [82]. To implement this FFT scheme, the range and the number of points are to be carefully considered.

3.2.2 FFT Range

In applying a FFT technique, each PDF is considered as a time varying *signal*. Because in FFT scheme each signal is treated as periodic, the range (signal length) must be wide enough to avoid the *wrap-around phenomena* [39]. Consider function $Z = X_1 + X_2$. In Figure 3.1, the two PDF's have ranges $R_1 = B$ and $R_2 = D$. If the FFT range, R_0 is less than $R_1 + R_2$, the resulting PDF for Z would be incorrect because of the periodic assumption in FFT scheme. This means that the minimum range is

$$R_0 = \sum_{i=1}^m R_i \quad (3.9)$$

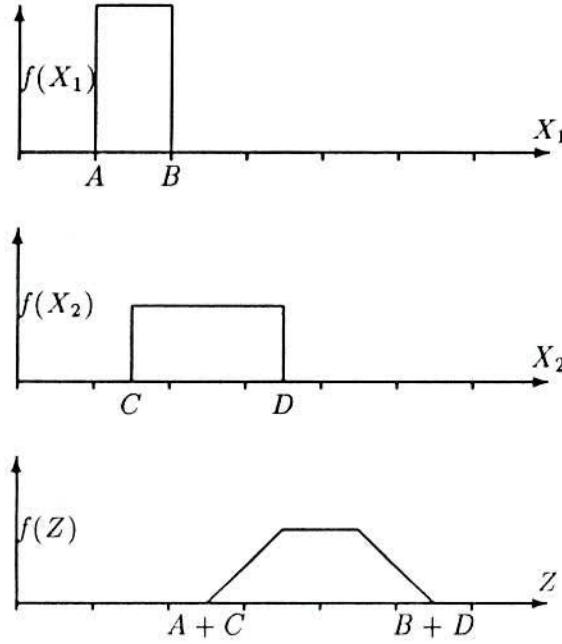


Figure 3.1: Selection of range for FFT

where each R_i is a range that *sufficiently* defines the PDF shape of i th RV. Because a large R_0 means that more points are required to model the PDF shape, R_i should be chosen as small as possible to maximize the computational efficiency.

Referring to Figure 3.1, the range may be reduced if the two signals are shifted such that $A = 0$ and $C = 0$. This implies that the bounds must be defined first. One way of defining bounds is to truncate the distribution using a probability tolerance, ε_i . For each random variable X_i , the lower bound (x_{iL}) is defined as

$$f_{x_i}(x_{iL}) \leq \varepsilon \text{ (left tail) at } X < x_{iL}$$

Because there is no *signal* before x_{iL} , the following transformation can be performed to allow each signal to start at *time zero*.

$$Y_i = X_i - x_{iL} \quad (3.10)$$

The new PDF of each RV is truncated and ranges from 0 to $(R_i - x_{iL})$. Define a new performance function Z' as:

$$Z' = \sum_{i=1}^m Y_i = \sum_{i=1}^m X_i - \sum x_{iL} = Z - \sum_{i=1}^m x_{iL} \quad (3.11)$$

Using the Z' coordinate, the FFT range becomes:

$$R_0 = \sum_{i=1}^m (R_i - x_{iL}) \quad (3.12)$$

In defining the bounds, the tolerances ε_i should be selected such that the resulting error due to truncation is sufficiently small.

FFT points

The number of points n , should be large enough to describe the PDF's shape correctly. In general, the number of points used for any random variable X_i should be within the range n satisfying the following two relations.

$$n = 2^b \quad (3.13)$$

$$\text{and, } n \geq R_0 \quad (3.14)$$

where b is any real positive integer to satisfy equation (3.14).

If any one of the random variables violate the above requirement, the result may be affected by wrap-around phenomena [39]. However, the minimum number of points is related to the shape of the PDF and the machine accuracy and can not be generalized.

3.2.3 Proposed Modification of Conventional FFT

There are several properties of FFT algorithm, which play important roles in computational complexity [214]. In this case, the following properties of FFT algorithm have been analyzed and applied for the reduction of computational complexity.

1. The sequences are purely real;
2. Arithmetic sum of the PDFs of independent RVs are unity. i.e., $\sum p_i = 1.0$

3. Transforms of generating units outage PDFs fulfil following properties.

$$\begin{aligned}
 a) \quad & H_{x_i}(k) = 1.0 & \text{for } k = 0 \\
 b) \quad & H_{x_i}(k) = \text{real}; & \text{for } k = n/2 \\
 c) \quad & \Re[H_{x_i}(k)] = \Re[H_{x_i}(n-k)] & \text{for } k \neq 0 \text{ or } \frac{n}{2} \\
 d) \quad & \Im[H_{x_i}(k)] = -\Im[H_{x_i}(n-k)] & \text{for } k \neq 0 \text{ or } \frac{n}{2} \\
 e) \quad & |H_{x_i}(k)| = |H_{x_i}(n-k)| & \text{for } k \neq 0 \text{ or } \frac{n}{2}
 \end{aligned} \tag{3.15}$$

From equations (3.15c) and (3.15d), it may be concluded that the most of the transformed values are complex conjugates, i.e.,

$$H_{x_i}(k) = \text{Conj}[H_{x_i}(n-k)] \quad \text{for } k \neq 0 \quad \text{or} \quad \frac{n}{2} \tag{3.16}$$

Equation (3.15) is modified using the relations given in equation (3.16) to reduce the computational complexity in what follows.

$$\begin{aligned}
 a) \quad & H_z(k) = 1.0 & \text{for } k = 0 \\
 b) \quad & H_z(k) = \prod_{i=1}^m \Re[H_{x_i}(k)] & \text{for } k = \frac{n}{2} \\
 c) \quad & H_z(k) = \prod_{i=1}^m H_{x_i}(k) & \text{for } k = 1, \dots, \frac{n}{2} - 1 \\
 d) \quad & H_z(k) = \text{Conj}[H_z(n-k)] & \text{for } k = \frac{n}{2} + 1, \dots, n-1
 \end{aligned} \tag{3.17}$$

The point (a) needs no multiplication. Points (c) and (d) reduce multiplication by $m * (n-1)/2$ due to equation (3.16). Therefore, total reduction of multiplication is equal to $m * (n-1)/2 + m$.

3.2.4 Convolution of Identical Units

Computational complexity should be reduced as much as possible to improve the efficiency of the method. Computational complexity of the proposed procedure is further reduced by using a modified procedure for convolution of identical generating units as explained in following paragraphs.

Let the i th group of identical units have n_i generating units each of capacity c_i MW. Let p_i be the outage probability, then the convolved distribution will

have nonzero probabilities for MW values $0, c_i, 2c_i, \dots, (n_i - 1)c_i$ and $n_i c_i$. The corresponding probabilities are given by

$$Pr(X = k \cdot c_i MW) = \binom{n_i}{k} (p_i)^k (1 - p_i)^{n_i - k} \quad (3.18)$$

$$\text{where} \quad \binom{n_i}{k} = \frac{n_i!}{k!(n_i - k)!}$$

$$\text{and} \quad k = 0, 1, 2, \dots, n_i$$

The number of multiplication for powering (conventional) method is $2 * n^{n_i}$, whereas number of multiplication would be only $(n_i + 1) * n$ using equation (3.18). Where n is the FFT range of the system. This approach obviously reduces the need of multiplication in the transformed domain than the powering of number of identical generating units.

3.2.5 Computational Steps

The computational steps to evaluate the LOLP of a generating system using the modified FFT scheme are summarized in what follows.

- Step 1: Read the PDF of capacity outages of all type of generating units.
- Step 2: Evaluate the step size of the generation system from the *largest common factor* (LCF) of all the units.
- Step 3: Determine total number of points of FFT scheme for generating units by $\frac{\sum c_i}{LCF}$ satisfying equation (3.13).
- Step 4: Evaluate the equivalent outage PDF of identical generating units using equation (3.18).
- Step 5: Take transform of the outage PDFs of each type of generating units using proposed FFT scheme.
- Step 6: Multiply the transformed outage PDFs of all type of units point by point using equation (3.17).

Step 7: Take the inverse FFT of the product and extract the real part of the inverse FFT for the PDF of the generating unit outage of the system.

Step 8: Read the chronological hourly load of the system.

Step 9: Determine the sampling size of load C_s and consider C_s as basic step size of the system (for both load and generation).

Step 10: Determine the total number of points of FFT scheme for both load and generating units using equation (3.12) satisfying equation (3.13).

Step 11: Take transform of the sampled load using proposed FFT scheme with the step size C_s .

Step 12: Rearrange the PDFs of unit outages of the system found in step 7 with the step size C_s .

Step 13: Take transform of unit outages in step 12 using FFT scheme.

Step 14: Multiply the transformed output of step 11 and step 13 point by point using equation (3.17).

Step 15: Take the inverse transform of the product in step 14.

Step 16: Extract the real part of the complex output function from step 15 and store the PDF values of capacity greater than the installed capacity (IC) at $IC + C_s$ MW for the system LOLP.

3.2.6 Example

The computational steps of the proposed approach are described with the help of an example of a power system in what follows.

Consider hourly loads of a small power system as shown in Table 3.1 and the generating units data given in Table 3.2. PDFs of all generating unit outages of the system are to be convolved with load PDFs of the system to obtain the PDF of equivalent load.

Table 3.1: Hourly load data

Hours	Load
1	15
2	20
3	30
4	25

Table 3.2: Generation data

System Gen. Data		
No.of Units	Cap (MW)	FOR
2	10	0.2
1	30	0.1

Convolution of generating units:

As discussed in the previous section, the capacity outage size of generating units is determined by $n = 2^3$ which satisfies $n > \frac{IC}{LCF} = 50/10 = 5$, where $IC = 50$ MW installed capacity and $b = 3$ is any positive integer number and $LCF = 10$ MW is the largest common factor of generating unit's capacities.

Capacity of first generator is 10MW, forced outage rate is 0.2 and number of unit is two. That is, $c_1 = 10$ MW, $n_1 = 2$ and $FOR = 0.2$. Using equation (3.18) for the identical generator group, the generator outage PDF of first generator group is evaluated as shown in Figure 3.2. With a largest common factor of 10MW as a step in horizontal-axis, the generator outage PDF of Figure 3.2 is represented by Figure 3.3. Similarly Figure 3.4 and 3.5 show the PDF of second generator.

The discrete RV X of Figure 3.3 and discrete RV Y of Figure 3.5 are convolved using proposed approach to develop a combined outage PDF of all generating units as shown in Figure 3.6. The combined outage PDF of all generating units shown in

X	0	10	20
p	0.64	0.32	0.04

Figure 3.2: Outage PDF of First Generator Group

X	0	1	2
p	0.64	0.32	0.04

Figure 3.3: Outage PDF of First Generator Group (10 MW step)

X	0	10	20	30
p	0.9	0.0	0.0	0.1

Figure 3.4: Outage PDF of Second Gen. Group

X	0	1	2	3
p	0.9	0.0	0.0	0.1

Figure 3.5: Outage PDF of Second Generator (10 MW step)

Z	0	10	20	30	40	50
p	0.576	0.288	0.036	0.064	0.032	0.004

Figure 3.6: PDF of generating unit outages of the System

Z	0	5	10	15	20	25	30	35	40	45	50
p	0.576	0	0.288	0	0.036	0	0.064	0	0.032	0	0.004

Figure 3.7: PDF of generating unit outages of the System

Figure 3.6 is represented by Figure 3.7. The system demand is sampled by $C_s = 5$ MW sampling size to reduce the sampling error.

Sampling of load in Table 3.2 is shown in Figure 3.9. With a base load of 15 MW and 5 MW step, the load PDF of Figure 3.9 is also represented by Figure 3.10.

Figure 3.7 is rearranged as new values of PDF sequence with combined (load and generation system) step $\min(10, 5) = 5$ MW as shown in Figure 3.8 to take the transform.

PDF shown in Figure 3.8 is again convolved with Figure 3.10 to obtain the PDF of equivalent load of the system. LOLP value is found by simple integration of this equivalent load above the installation capacity (IC) using equation (3.4). This value is stored in $(IC + C_s) = 55$ MW at the block $(IC - \text{Base load})/C_s + 2 = 9$ as shown in Figure 3.11. Since, there is no pulse of capacity outage value of less than base load 15 MW.

$$LOLP = Pr(L_e > IC) = 0.272/4 = 0.0680$$

Z	0	1	2	3	4	5	6	7	8	9	10
p	0.576	0	0.288	0	0.036	0	0.064	0	0.032	0	0.004

Figure 3.8: PDF of generating unit outages of the System (5 MW step)

Y	15	20	25	30
q	$\frac{1}{4}$	$\frac{1}{4}$	$\frac{1}{4}$	$\frac{1}{4}$

Figure 3.9: PDF of sampled load

Y	1	2	3	4
q	1	1	1	1

Figure 3.10: PDF of sampled load (PDF to be divided by 4)



3.2.7 Numerical Evaluation

This section applies the proposed approach discussed in the preceding sections to a prototype generating system provided by the Reliability Test System Task Force of the IEEE Power Engineering Application of Probabilistic Methods Subcommittee [40]. This system is slightly modified with an installed capacity of 3400 MW [65]. Table C.1 of Appendix C gives the generation mix of the 32 units of the system, their installed capacities and FORs. For the system X, the thirteen winter weeks (48-52 & 1-8 Weeks) hourly loads data of IEEE-RTS [40] is used as a load model of 2850 MW peak load. Generation data of system Y is given in Table C.2 of Appendix C. Thirteen summer weeks (18-30 weeks) hourly loads data of peak load 2565 MW of IEEE-RTS is used for system Y.

In the application of the conventional FFT algorithm, a 5 MW step increment is utilized. In order to evaluate the LOLP of the system using conventional FFT

L_e	15	20	25	30	35	40	45	50	55
p	0.576	0.576	0.864	0.864	0.324	0.324	0.1	0.1	0.272

Figure 3.11: Equivalent Load PDFs (PDF to be divided by 4)

Table 3.3: LOLP for 5 MW Step

Hourly Loads	LOLP	
	SYSTEM X	SYSTEM Y
Winter Weeks	0.00274014	0.0708647
Summer Weeks	0.00094363	0.06543189

Table 3.4: Comparison of CPU time at different step size

Step Size (MW)	LOLP	CPU Time (Seconds)	
		Conventional FFT Scheme	Proposed Scheme
1	0.00279227	21.457519	5.507537
5	0.00274014	5.299622	2.181416
10	0.00266794	2.794558	1.701654

technique, the procedure as described in Mohan et al. [82] is utilized. In order to avoid the enormous number capacity margin states to be considered, the hourly loads as given in IEEE-RTS are slightly modified. The modification consists in rounding off the loads to the nearest value which is devisable by sampling size of load. LOLPs evaluated for 5 MW step size using the proposed method are shown in Table 3.3 for winter and summer weeks. It is found that the differences of LOLP in system X is more as compared to that of system Y. This is due to the differences of install capacities and peak load of system X and Y.

Same values of LOLP as shown in the Table 3.3 are obtained using existing methods [65, 82]. The CPU time comparison with conventional FFT algorithm [82] with different step size obtained using mainframe CYBER 180/840A is presented in Table 3.4.

Though the evaluated results from both the methods are similar, but the CPU time requirement is different as shown in Table 3.4, which proves the computational efficiency of the proposed method with respect to the conventional FFT method

[82].

The time requirement of the proposed method reduces further, if more machines of a particular type are included in the system. In addition, when multistate generating units are considered, the computational time requirement of proposed modified method is less as compared to conventional FFT method.

3.3 Proposed Joint PDF Approach for LOLP Evaluation

This section proposes another new approach using joint probability density function (PDF) concept, to evaluate the LOLP of power systems. The loads and the generating unit outages are convolved using joint PDF concept to obtain the resultant distribution of *equivalent load* PDF. The LOLP of the system is evaluated by integrating the equivalent load distribution over the appropriate limits.

3.3.1 Convolution Procedure

Let X is a discrete random variable (RV) which represents n values in ascending sequence ($X_1, X_2, \dots, X_n$) at equal interval with the corresponding probability values of $p(X_1), p(X_2), p(X_3), \dots, p(X_n)$ and Y represents another discrete RV having m values in ascending sequence ($Y_1, Y_2, Y_3, \dots, Y_m$) at the same interval with the corresponding probability values of $q(Y_1), q(Y_2), q(Y_3), \dots, q(Y_m)$ respectively. The convolution of these two discrete RVs can be performed as shown in Figure 3.12.

In Figure 3.12, each Box of venn diagram contains the elements of the RV, Z (lower left side $X + Y$) and its corresponding probability values (upper right side $p \cdot q$). The resultant PDF values, r are equal to the product of corresponding PDFs of X and Y , and the PDF at Z_i is equal to the sum of all PDFs for all $X_j + Y_k = Z_i$. The maximum length of the resultant RV, Z will be $X_n + Y_m$. The elements of resultant random variable Z and its corresponding PDFs are given in Table 3.5. In a similar way, any number of random variables can be convolved.

The mathematical representations of above convolution of two random variables X and Y using joint probability density function (PDF) may be explained in what

		X_1	X_2	X_3	...	X_n
		p_1	p_2	p_3	...	p_n
Y_1	q_1	$X_1 + Y_1$ $p_1 q_1$	$X_2 + Y_1$ $p_2 q_1$	$X_3 + Y_1$ $p_3 q_1$	...	$X_n + Y_1$ $p_n q_1$
Y_2	q_2	$X_1 + Y_2$ $p_1 q_2$	$X_2 + Y_2$ $p_2 q_2$	$X_3 + Y_2$ $p_3 q_2$	...	$X_n + Y_2$ $p_n q_2$
Y_3	q_3	$X_1 + Y_3$ $p_1 q_3$	$X_2 + Y_3$ $p_2 q_3$	$X_3 + Y_3$ $p_3 q_3$	...	$X_n + Y_3$ $p_n q_3$
$\vdots$	$\vdots$	$\vdots$	$\vdots$	$\vdots$	$\vdots$	$\vdots$
Y_m	q_m	$X_1 + Y_m$ $p_1 q_m$	$X_2 + Y_m$ $p_2 q_m$	$X_3 + Y_m$ $p_3 q_m$	...	$X_n + Y_m$ $p_n q_m$

Figure 3.12: Equivalent PDF Generating Venn Diagram

follows.

The sequence of random variable (RV) X of n discrete samples can be represented by

$$X = [X_1, X_2, X_3, \dots, X_n]$$

and its corresponded probabilities

$$P = [p(X_1), p(X_2), p(X_3), \dots, p(X_n)]$$

$$\text{or, } X = \sum_{i=1}^n X_i \delta(N-i) \quad \text{and} \quad P = \sum_{i=1}^n p(X_i) \delta(N-i)$$

$$\text{but, } \sum_{i=1}^n p(X_i) = 1.$$

Table 3.5: Resultant RV, Z and its corresponding probabilities

Z	r
$Z_1 = X_1 + Y_1$	$r_1 = p_1 q_1$
$Z_2 = X_1 + Y_2 = X_2 + Y_1$	$r_2 = p_1 q_2 + p_2 q_1$
$Z_3 = X_1 + Y_3 = X_2 + Y_2 = X_3 + Y_1$	$r_3 = q_1 q_3 + p_2 q_2 + p_3 q_1$
$\vdots$	$\vdots$
$Z_{n+m-1} = X_n + Y_m$	$r_{n+m-1} = p_n q_m$

where $\delta(\bullet)$ is dirac delta function and N is a random number of range $[1, n]$. The representation of the above RV X represents that there are n discrete values. This type of RVs are used frequently in this thesis. For simplicity, the RV X is represented without dirac delta function as:

$$\begin{aligned}
 X &= \bigvee_{i=1}^n X_i & \text{and} & & P &= \bigvee_{i=1}^n p(X_i) \\
 \text{Similarly, } Y &= \bigvee_{j=1}^m Y_j & \text{and} & & Q &= \bigvee_{j=1}^m q(Y_j) \\
 \text{Then, } Z &= \bigvee_{k=1}^{m+n-1} Z_k & \text{and} & & R &= \bigvee_{k=1}^{m+n-1} r(Z_k) \\
 \text{where, } Z_k &= X_i + Y_j & \text{and} & & r(Z_k) &= \sum_{\forall Z_k = X_i + Y_j} p(X_i)q(Y_j)
 \end{aligned}$$

3.3.2 Computational Steps

- Step 1: Read the PDF of capacity outages of all type of generating units $f_{g_i}(L)$.
- Step 2: Read the chronological hourly load of the system $f_l(L)$.
- Step 3: Determine largest common factor C_s from the system load and the generating unit capacity.
- Step 4: Determine the number of blocks required to solve the system by $(\sum C_i - \text{Base load})/C_s + 2$, where C_i is the capacity of i th unit.
- Step 5: Sample the load in step 2 by C_s and stored in the capacity values at which the loads occur.
- Step 6: If there are n_i identical units in any type of generating unit. Evaluate the equivalent outage PDF of identical generating units using equation (3.18).
- Step 7: Convolve the PDF of capacity outage with the load PDF using venn diagram shown in Figure 3.12.
- Step 8: Continue the commitment of generating units till all the units convolved.
- Step 9: Evaluate LOLP of the system from the last block (i.e. block immediately after the installed capacity) of the capacity values.

X		0	10	20
q		0.64	0.32	0.04
Y	p			
15	1	0.64	0.32	0.04
		15	25	35
20	1	0.64	0.32	0.04
		20	30	40
25	1	0.64	0.32	0.04
		25	35	45
30	1	0.64	0.32	0.04
		30	40	50

Figure 3.13: Equivalent Loads boxes (PDF to be divided by 4)

3.3.3 Example

The computational steps of the proposed approach are explained with the help of an example of a power system in what follows.

Consider hourly loads of a small power system as shown in Table 3.1 and the generating units data given in Table 3.2. Let the step size of demand and generating unit capacities be 5 MW. PDFs of all generating unit outages of the system are convolved with load PDFs of the system to obtain the PDF of equivalent load. The capacity outages size in the evaluation of the equivalent load, as discussed in previous section, is $50 + 5 = 55$ MW or at the block $(50 - 15)/5 + 2 = 9$.

The sampling of load is shown in Figure 3.9. With a base load of 15 MW and 5 MW step, the load PDFs of Figure 3.9 can also be represented by Figure 3.10.

Convolution of first generator group

Capacity of first generator is 10 MW, forced outage rate is 0.2 and number of unit is two. That is, $c_1 = 10$ MW, $n_1 = 2$ and $FOR = 0.2$. Now using equation (3.18)

Z	15	20	25	30	35	40	45	50
r	0.64	0.64	0.96	0.96	0.36	0.36	0.04	0.04

Figure 3.14: Equivalent Loads array (PDF to be divided by 4)

for identical generator group, the generator outages PDFs of first generator group is evaluated as shown in Figure 3.2. With a largest common factor of 10 MW as a step in x-axis, the generator outage PDFs of Figure 3.2 can be represented by Figure 3.3.

Now the discrete RV X of Figure 3.3 and discrete RV Y of Figure 3.10 are convolved using the proposed approach to develop an equivalent load PDFs as shown in Figure 3.13. The equivalent load PDFs of Figure 3.13 is represented as single valued PDF using Table 3.5 at 5 MW step size as shown in Figure 3.14.

Convolution of Second generator

The second generator of capacity $c_2 = 30$ MW and $FOR = 0.1$ is a single unit, therefore the generator outage PDF of second generator is having only two values i.e. $p(X = 0 \text{ MW}) = 0.9$ and $p(X = 30 \text{ MW}) = 0.1$. The PDF of second generator in Figure 3.5 is convolved with equivalent load PDFs of Figure 3.14 as shown in Figure 3.15. The equivalent load PDF of Figure 3.15 is represented as shown in Figure 3.16 at 5 MW step size. LOLP is evaluated using equation (3.4) from the PDF of equivalent load as,

$$\begin{aligned}
 LOLP &= Pr(L_e > IC) \\
 &= 0.272/4 = 0.0680
 \end{aligned}$$

3.3.4 Numerical Evaluation

This section applies the proposed approach discussed in the preceding section to the same prototype generating system described in the section 3.2.7.

In the application of the recursive algorithm a 5 MW step increment is utilized and capacity margin states with cumulative probabilities less than 10^{-10} are

Z		15	20	25	30	35	40	45	50
r		0.64	0.64	0.96	0.96	0.36	0.36	0.04	0.04
X	p								
0	0.9	0.576	0.576	0.864	0.864	0.324	0.324	0.036	0.036
		15	20	25	30	35	40	45	50
30	0.1	0.064	0.064	0.096	0.096	0.036	0.036	0.004	0.004
		45	50	55	60	65	70	75	80

Figure 3.15: Equivalent Load Boxes after convolving system load with all generator (PDF to be divided by 4)

Z	15	20	25	30	35	40	45	50	55
r	0.576	0.576	0.864	0.864	0.324	0.324	0.1	0.1	0.272

Figure 3.16: Equivalent Load PDFs (PDF to be divided by 4)

neglected. In order to evaluate the LOLP of the system using recursive technique, the procedure as described in Endrenyi [202] is utilized. In order to avoid the enormous number capacity margin states to be considered, the hourly loads as given in IEEE-RTS are slightly modified. The modification consists in rounding off the loads to the nearest value which is devisable by sampling size of demand. Same modified loads are used in the segmentation method [65] and the proposed approach. The results obtained are same as given in Table 3.3.

The method was also tested for various sampling sizes for the generation system given in Table C.1. The computational time requirement of this method is less as compared to existing methods and as the step size is decreased the proposed method becomes more computationally efficient. Further, it is still better for the systems having a large number of identical units. This method would be useful to evaluate exact value of LOLP of any system efficiently for short-range scheduling as well as for long-term system planning.

3.4 Generation Expansion Planning

The proposed methods are used to carry out expansion planning studies of an electric utility - OSEB. The expansion plan is developed for fifteen years (1996 to 2010) to maintain the levelized risk value of the year 1990. A minimum five years time gap has been considered for the commissioning of new generation, as few years time gap is required to construct planned new generator(s). The hourly load of the year 1990 has been used to consider the hourly load pattern of the utility. These hourly loads have been projected to the planned years (1996-2010) in proportion to the respective yearly peak demand, forecasted in chapter 2. The available generation of the utility in 1995 is given in Table C.3 of Appendix C. Note that the system is having many energy limited hydro-electric generating units. This type of units are committed with the system demand using the concept discussed in [65]. A plan shown in Table 3.6 is developed for a desired level LOLP of 0.004. The effect of LOLP on addition and without addition of generating unit(s) in the previous year of the planned year is shown in Figure 3.17. Figure 3.18 shows the reserve requirements to maintain the desired level of reliability of the system.

3.5 Conclusions

In this chapter, two new methods are presented to evaluate the Loss of Load Probability of a power generating system. There is no explicit approximation apart from that arising from the discretization of continuous function which is necessary for any digital computer application. Both the proposed approaches can simulate multistate representations of generating units. These approaches reduce the number of multiplications and additions in the convolution of a group of identical generating units. This further reduces thousands of load impulses to a few discrete values making the convolution process numerically simpler and faster. Multiple generating units with same outage behavior are committed with system demand efficiently in the proposed methods. These methods are simple in comparison to the existing methods. The accuracy of these methods have been illustrated.

The modified FFT algorithm was applied to IEEE-RTS system and another

Table 3.6: Expansion plan for LOLP=0.004

Year	Peak load (MW)	Total Cap. (MW)	LOLP	Addition of units
1995	1480	2175	0.0041593	exist
1996	1590	2175	0.00859072	—
1996	1590	2385	0.002509	1x210
1997	1750	2385	0.0071334	—
1997	1750	2595	0.00214477	1x210
1998	1900	2595	0.00573169	—
1999	2050	2595	0.01386510	—
1999	2050	3005	0.00138813	1x300
2000	2220	2895	0.00755985	—
2000	2220	3195	0.00374085	1x300
2001	2380	3195	0.00820212	—
2001	2380	3405	0.00315606	1x210
2002	2530	3405	0.00660385	—
2002	2530	3645	0.0020563	2x120
2003	2660	3645	0.00398136	—
2004	2750	3645	0.00611295	—
2004	2750	3895	0.00205271	1x250
2005	2825	3895	0.00299155	—
2006	2980	3895	0.00620482	—
2006	2980	4095	0.00243876	2x100
2007	3225	4095	0.00757708	—
2007	3225	4295	0.00366876	2x100
2008	3460	4295	0.0094186	—
2008	3460	4545	0.00384004	1x250
2009	3650	4545	0.00849565	—
2009	3650	4945	0.00182116	4x100
2010	3940	4945	0.00413658	—
2010	3040	5195	0.00157901	1x250

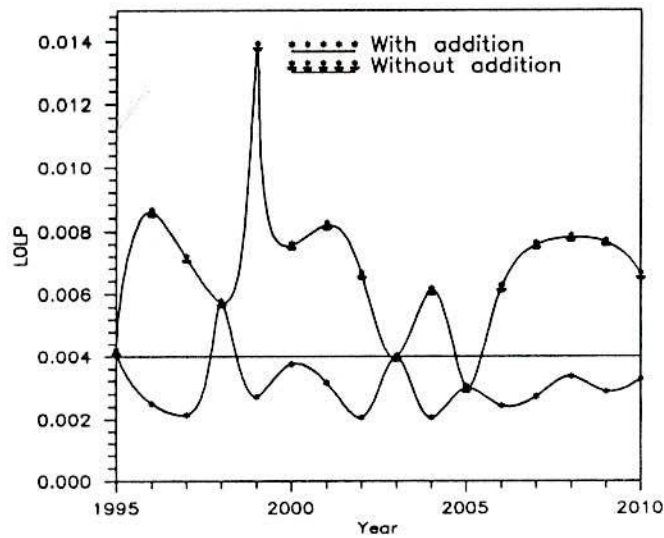


Figure 3.17: Comparison of LOLP with Year (before and after addition of unit(s) in the previous year)

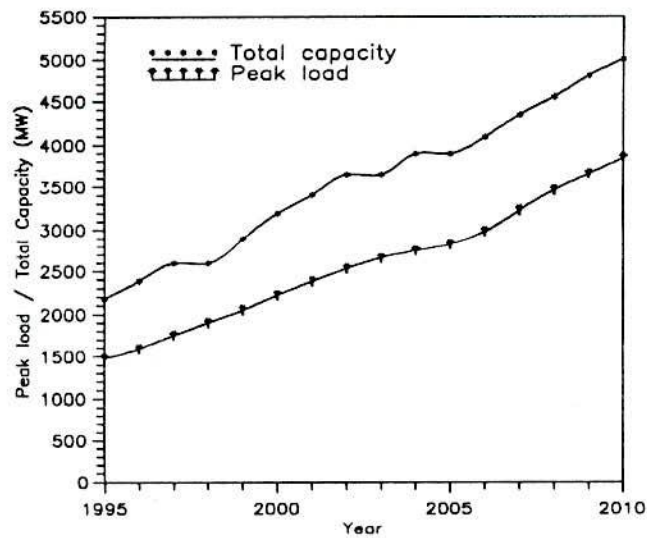


Figure 3.18: Peak load and Total capacity vs Year at desired level of LOLP of OSEB

system to evaluate the LOLP and it is observed that it is an efficient algorithm as compared with the conventional FFT algorithm [82]. On the other hand, the new approach, presented in the second part, is found to be more efficient in comparison to other existing methods with the similar data. These methods are as computationally efficient as the cumulant method, based on the Gram-Charlier expansion (GCE) but without the inherent inaccuracies of GCE.

Exploiting the advantages of the proposed approach, generation expansion planning of an utility system is performed for the projected future load forecasted in chapter 2.

Chapter 4

RELIABILITY EVALUATION OF INTERCONNECTED SYSTEM

4.1 Introduction

Electric power companies are looking for ways and means to overcome the problem caused by rapid increase of construction cost of a new power plant. Some of the utilities are solving this problem of huge investment in constructing a new power plant by sharing the plant between the two or more utilities [23, 30, 33].

Interconnections between systems (power companies/utilities) is an effective means of improving the system availability [37, 46, 55, 56, 85, 86, 90, 97]. The simplest way to evaluate reliability indices of interconnected system would be to consider it as a single system where the number of generating units is the sum of the units in the constituent systems, and the load on this system is the total load of interconnected systems. There are reasons, however, for keeping the identities of the constituent systems separate and evaluating their reliabilities individually.

The methodology to evaluate the reliability of interconnected systems is, however, different from that of a single area system. If the available capacity in geographical region can be transmitted whenever it is needed without tie line restrictions then

this region may be treated as a single area [16]. Although it is possible to evaluate interconnected systems as a single system with some approximations, but it is not in practice for the following reasons [202]:

1. A utility is primarily interested in the benefits that its own system can earn from interconnections.
2. The tie lines forming interconnections are usually limited in capacity.
3. The load characteristics in the various interconnected networks may be different and, in addition, these load patterns may be independent of each other.
4. It may be necessary to determine the transactions (import/export) between the systems.

Probabilistic techniques for reliability evaluation of interconnected systems are the most advanced and popular methods at present. In these techniques, LOLP of a system interconnected with other systems is the probability that the available generation of the system and the possible capacity assistance from the interconnected utilities will be insufficient to meet its own demand.

Researchers have contributed to the advancement and improvement of probabilistic techniques used for reliability evaluation of interconnected systems. Cook et al.[16] proposed a basic method for evaluating LOLP of two interconnected systems. Rau et al.[48] proposed an approximate method utilizing the Bivariate Gram Charlier Expansion (BGCE) to evaluate the LOLPs of two interconnected systems by approximating the discrete distribution of equivalent load by a bivariate continuous distribution. The bivariate distribution allows for the consideration of load correlation between the two systems. Schenk et al.[67] proposed the segmentation method for evaluating LOLP of interconnected power systems.

In this chapter, two effective approaches proposed in chapter 3 for reliability evaluation for single area system have been extended to calculate the reliability of interconnected systems. The fast Fourier transform is capable to convolve random variables effectively in case of power system reliability evaluation. Further, it can convolve multi-state generating units and the convolution of this type of units does not affect the computational complexity.

The first part of this chapter proposes an accurate technique to calculate the LOLP of interconnected systems with independent as well as correlated loads. This method is based on the convolution of PDF of generating units and loads (peak or hourly) using multi-dimensional FFT, which is an extension of the improved FFT algorithm developed in chapter 3. The proposed method has been applied for LOLP evaluation of two interconnected systems considering independent and correlated system loads. The results obtained are compared in terms of accuracy to those obtained from segmentation and recursive methods. Further, there is no conceptual difficulty in extending it to three or more areas by using multi-dimensional FFT.

The approach developed in the latter part of chapter 3 is extended in the second part of this chapter. The proposed approach is new, but faster than commonly used methods to evaluate the reliability of two area interconnected power systems. This can, further, simulate multi-megawatt generating units having multi-state representation more efficiently. The proposed method has also been applied to evaluate LOLPs of two interconnected systems considering independent and correlated system loads. The results obtained are compared in terms of accuracy and efficiency with those obtained from segmentation and recursive methods.

4.2 LOLP Evaluation of Interconnected Systems Using FFT

The modified fast Fourier transform (FFT) algorithm developed in chapter 3 is extended in the following sections to evaluate Loss of Load Probability (LOLP) of two interconnected power systems considering independent as well as correlated system demands. The Probability Density Function (PDF) of equivalent load of interconnected system is obtained by convolving the PDF of generating unit outages with the PDF of system demands. The generated two dimensional PDF of equivalent load is integrated over the appropriate range to obtain the LOLP values of each and global system.

4.2.1 Mathematical Modelling

The equivalent load concept [30] based on the convolution of PDF of generating unit outages and that of system demand using the modified FFT algorithm developed in chapter 3 is used for LOLP calculation. Following paragraphs describe the steps for reliability evaluation of interconnected power generating systems.

The PDF of generating unit outage of a system, $f_g(X)$ is obtained by convolving all the individual unit outage density functions, and it consists of a train of impulses from the origin upto the value of system installed capacity on the x-axis.

1. In case of independent load, unit outage density function, $f_g(X)$ is further convolved with the load PDF $f_l(X)$ of that system to obtain the equivalent load PDF $f_{le}(X)$. The value of capacity outage limit to be considered in the evaluation of the equivalent load must equal or exceed the sum of the installed capacity (IC) and LC (peak load-base load) of that system. The load and system outage density function must also be considered over the capacity range IC+LC satisfying equation (3.13). Similarly, the equivalent load PDF $f_{le}(Y)$ of other system is obtained. The joint equivalent load PDF $f_{le}(X, Y)$ is obtained by multiplying the equivalent load PDF of each system, i.e. $f_{le}(X, Y) = f_{le}(X) \cdot f_{le}(Y)$ giving a two-dimensional array of probability. The LOLPs are obtained through the integration of joint equivalent load PDF over appropriate range considering the tie line assistance.
2. In case of correlated load, joint PDF of generating unit outage $f_g(X, Y)$ is obtained through the multiplication of generating unit outage PDF of each system, i.e., $f_g(X, Y) = f_g(X) \cdot f_g(Y)$. This two-dimensional probability $f_g(X, Y)$ is again convolved with joint load PDF $f_l(X, Y)$ of two systems to obtain the joint equivalent load PDF $f_{le}(X, Y)$ of two systems using two-dimensional FFT. System LOLPs are calculated in a way similar to the independent load case.

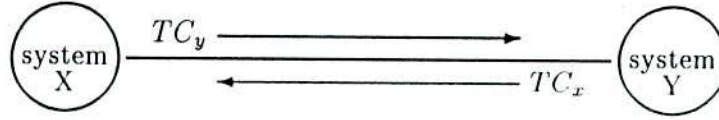


Figure 4.1: Two Area Interconnected System

LOLP Evaluation

Consider a two area interconnected system shown in Figure. 4.1.

TC_x = transfer capacity from system Y to X

TC_y = transfer capacity from system X to Y

It is known that interconnected systems are said to be isolated, when there is no assistance between system X and system Y. Then, loss of load will occur when the equivalent load exceeds the installed capacity in either system. The LOLP of system X without assistance is evaluated by,

$$LOLP_1 = \int_{IC_1}^{IC_1+Pl_1} \int_0^{IC_2+Pl_2} f_{le}(X,Y) dX dY \quad (4.1)$$

where, IC_1 & IC_2 represent installed capacity of system X and Y, respectively, and Pl_1 & Pl_2 represent the peak load in system X and Y, respectively, and $f_{le}(X,Y)$ is the joint equivalent load PDF of interconnected system as expressed above.

Similarly, the LOLP of system Y without assistance is given by

$$LOLP_2 = \int_{IC_2}^{IC_2+Pl_2} \int_0^{IC_1+Pl_1} f_{le}(X,Y) dX dY \quad (4.2)$$

Considering the tie-line capacity $TC = TC_x = TC_y$ and PA_2 represents the probability of assistance from system Y to system X due to the assistance of capacity A_{yx} , the LOLP of system X being assisted by Y (upto the limit of its own reserves) is given by

$$LOLP_{12} = LOLP_1 - PA_2 \quad (4.3)$$

Similarly, PA_1 represents the probability of assistance from system X to system Y for A_{xy} . Then the LOLP of system Y being assisted by X (upto the limit of its own region) is given by

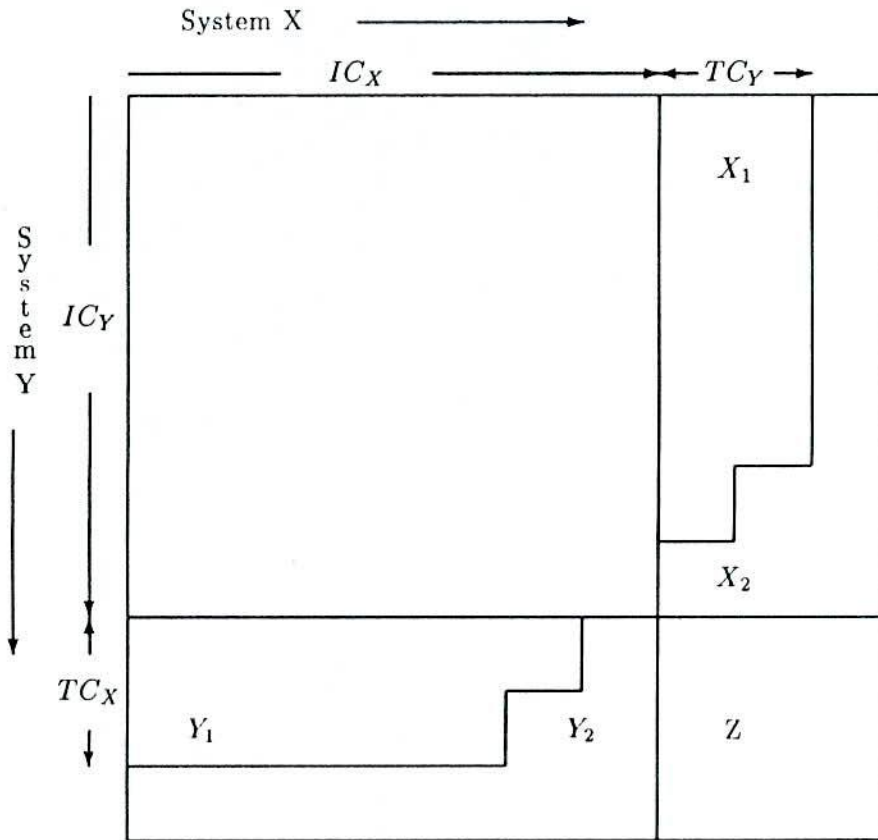


Figure 4.2: Venn diagram of two interconnected system

$$LOLP_{21} = LOLP_2 - PA_1 \quad (4.4)$$

Figure 4.2 represents the Venn diagram of the joint probability density function $f_{lc}(X, Y)$, which can be generated for independent and correlated loads of interconnected system. The probabilities for the capacity value of either system greater than the installed capacity of that system is LOLP of that system. Therefore, equations (4.1) and (4.2) can be written with reference to the Venn diagram in Figure 4.2 in what follows.

$$\begin{aligned}
 LOLP_1 &= \int_{IC_1}^{IC_1+Pl_1} \int_0^{IC_2+Pl_2} f_{le}(X, Y) dX dY \\
 &= X_1 + X_2 + Z
 \end{aligned} \tag{4.5}$$

$$\begin{aligned}
 LOLP_2 &= \int_{IC_2}^{IC_2+Pl_2} \int_0^{IC_1+Pl_1} f_{le}(X, Y) dX dY \\
 &= Y_1 + Y_2 + Z
 \end{aligned} \tag{4.6}$$

The assistance PA_2 and PA_1 in equations (4.3) and (4.4) can be determined by X_1 and Y_1 , respectively, from Figure 4.2. Hence, equations (4.3) and (4.4) can be replaced with reference to Figure 4.2 by;

$$\begin{aligned}
 LOLP_{12} &= LOLP_1 - PA_2 \\
 &= X_1 + X_2 + Z - X_1 \\
 &= X_2 + Z
 \end{aligned} \tag{4.7}$$

$$\begin{aligned}
 LOLP_{21} &= LOLP_2 - PA_1 \\
 &= Y_1 + Y_2 + Z - Y_1 \\
 &= Y_2 + Z
 \end{aligned} \tag{4.8}$$

4.2.2 Computational Algorithm

The computational steps to evaluate the LOLP of a generating system using the modified FFT scheme are summarized in what follows.

- Step 1: Read the PDF of capacity outages of all type of generating units of two systems.
- Step 2: Convolve all the generating units' outage PDF to produce PDF of generating unit outage of system X using modified FFT method developed in chapter 3.
- Step 3: Convolve all the generating units' outage PDF to produce PDF of generating unit outage of system Y using modified FFT method.
- Step 4: Read the chronological hourly load of both the systems.

- Step 5: In case of independent load, sample the loads of system X and Y separately. Otherwise goto step 8.
- Step 6: Convolve the sampled loads with the PDFs of generating unit outages found in step 3 of respective systems using modified FFT method separately to produce PDFs of equivalent load of each systems.
- Step 7: Multiply PDFs of both the systems to produce joint PDF of equivalent load of two system. Goto step 11.
- Step 8: In case of correlated load, sample the loads of system X and Y jointly .
- Step 9: Multiply PDFs of generating unit outage of both the systems found in step 2 and 3 to produce joint PDF of generating unit outages of two systems.
- Step 10: Convolve the joint PDFs found in step 8 and 9 to produce joint PDF of equivalent load of both systems using two-dimensional FFT.
- Step 11: Integrate the joint PDFs of equivalent loads found in step 7 for independent loads and in step 10 for correlated loads using equations (4.5)-(4.8).

4.2.3 Example

The computational steps for independent and correlated loads described in the previous section, are explained below with an example of two area interconnected power systems.

Consider the hourly loads of two interconnected systems as shown in Table 4.1 and the generating units data given in Table 4.2. These two systems are interconnected by a $TC = 10$ MW tie-line capacity. The sampling size of load is chosen 5 MW. The largest common factor of generating unit capacities of system X, tie line capacity and sampling size of load is $C_s = 5$ MW. The PDF of first generating unit group of system X is given in Figure 4.3 using equation (3.18). The PDF of second generating unit is shown in Figure 4.4. Figure 4.5 shows the outage PDF of all generating units of system X after convolving Figure 4.3 and 4.4 using modified FFT described in chapter 3. Similarly, the outages PDF of all generating units of system Y is obtained as shown in Figure 4.6.

Table 4.1: Hourly load data

Hour	System X	System Y
1	15	25
2	20	40
3	30	30
4	25	20

Table 4.2: Generation data

SYSTEM X			SYSTEM Y		
Number of Units	Capacity (MW)	FOR	Number of Units	Capacity (MW)	FOR
2	10	0.2	2	15	0.1
1	30	0.1	1	25	0.3

X	0	10	20
p	0.64	0.32	0.04

Figure 4.3: Outage PDF of First Generator Group

X	0	10	20	30
p	0.9	0.0	0.0	0.1

Figure 4.4: Outage PDF of Second Generator

0	5	10	15	20	25	30	35	40	45	50
0.576	0	0.288	0	0.036	0	0.064	0	0.032	0	0.004

Figure 4.5: PDF of generating unit outages of System X

0	5	10	15	20	25	30	35	40	45	50	55
0.567	0	0	0.126	0	0.243	0.007	0	0.054	0	0	0.003

Figure 4.6: PDF of generating unit outages of System Y

Y	15	20	25	30
q	1	1	1	1

Figure 4.7: PDF of sampled load of system X (PDF to be divided by 4)

Independent Loads

In case of independent load, demands of each system are convolved with respective generating unit outage PDF separately. Figure 4.7 and 4.8 represent the sampled loads of system X and system Y, respectively. Figure 4.7 is convolved with Figure 4.5 to develop equivalent load PDF of system X shown in Figure 4.9. Where, the probabilities for the capacity outage value greater than $IC + TC$ are summed up and stored in the capacity value of $IC + TC + C_s = 65$ MW at the block $(IC + TC - Base\ load)/C_s + 2 = 11$. Similarly, the equivalent load of system Y shown in Figure 4.10 is developed from the convolution of Figure 4.4 and 4.6.

The joint PDF of equivalent load is obtained by multiplying the equivalent load of system X and system Y as shown in Figure 4.11. The LOLPs are obtained by integrating the joint PDF of equivalent load over the appropriate limits using equations (4.5)-(4.8).

Y	20	25	30	35	40
q	1	1	1		1

Figure 4.8: PDF of sampled load of system Y (PDF to be divided by 4)

15	20	25	30	35	40	45	50	55	60	65
0.576	0.576	0.864	0.864	0.324	0.324	0.1	0.1	0.096	0.096	0.08

Figure 4.9: Equivalent load of System X (PDF to be divided by 4)

20	25	30	35	40	45	50	55	60	65	70
0.567	0.567	0.567	0.126	0.693	0.360	0.25	0.376	0.061	0.297	0.127

Figure 4.10: Equivalent load of System Y (PDF to be divided by 4)

	INSTALLED CAPACITY								TC		
	15	20	25	30	35	40	45	50	55	60	65
X											
Y											
20									0.05443	0.05443	0.04536
25									0.05443	0.05443	0.04536
30									0.05443	0.05443	0.04536
35									0.01209	0.01209	0.01008
40									0.06653	0.06653	0.05544
45									0.03542	0.03424	0.02952
50									0.02400	0.02400	0.02000
55									0.03609	0.03609	0.03008
60	0.03514	0.03514	0.05270	0.05270	0.01976	0.019764	0.00610	0.00610	0.13192		
65	0.17107	0.17107	0.25661	0.25661	0.09623	0.09623	0.02970	0.02970			
60	0.07315	0.07315	0.10973	0.10973	0.04115	0.04115	0.01270	0.01270			

Figure 4.11: Joint PDF of equivalent loads of two systems (Independent loads)(values to be divided by 4x4)

$LOLP_s$ without assistance through tie line

$$\begin{aligned} LOLP_1 &= (X_1 + X_2 + Z)/(4 \times 4) \\ &= (0.57868 + 0.377392 + 0.12192)/(4 \times 4) \\ &= 0.068 \end{aligned}$$

$$\begin{aligned} LOLP_2 &= (Y_1 + Y_2 + Z)/(4 \times 4) \\ &= (1.26912 + 0.538956 + 0.13192)/(4 \times 4) \\ &= 0.12125 \end{aligned}$$

Hence, $LOLP_s$ with assistance of $TC = 10$ MW tie line capacity,

$$\begin{aligned} LOLP_{12} &= (X_2 + Z)/(4 \times 4) \\ &= (0.377392 + 0.12192)/(4 \times 4) \\ &= 0.031832 \\ LOLP_{21} &= (Y_2 + Z)/(4 \times 4) \\ &= 0.04192975 \end{aligned}$$



Correlated Loads

It is more realistic to consider the loads in the neighbouring utilities as correlated. Assign equal probability ($1/4$ in this case) to each sampled hourly load of the joint PDF of load shown in Figure 4.12.

In case of correlated load, Figure 4.5 and 4.6 represent the two set PDFs of generating unit outages of each system. The joint PDF of generating unit outages shown in Figure 4.13 is obtained by multiplying the PDF of generating unit outages of system X and system Y.

Now, the joint PDF of loads in Figure 4.12 and that of generating unit outages in Figure 4.13 are convolved using two-dimensional FFT of CYBER 180/360A IMSL SUBROUTINE as shown in Figure 4.14. LOLPs are calculated from Figure 4.14 in a way similar to that of independent load using equations (4.5)-(4.8).

$X \rightarrow$	15	20	25	30
$Y \downarrow$				
20			1	
25	1			
30				1
35				
40		1		

Figure 4.12: Joint PDF of correlated load (PDF to be divided by 4)

X		0	5	10	15	20	25	30	35	40	45	50
p		.576	0	.288	0	.036	0	.064	0	.032	0	.004
Y	p	Y ↓ X →										
0	0.567	0.32659	0	0.1633	0	0.02041	0	0.036288	0	0.018144	0	0.002268
5	0											
10	0											
15	0.126	0.07258	0	0.03628	0	0.00454	0	0.008064	0	0.004032	0	0.000504
20	0											
25	0.243	0.139968	0	0.069984	0	0.000875	0	0.015551	0	0.007776	0	0.000972
30	0.007	0.004032	0	0.002016	0	0.000252	0	0.000448	0	0.000224	0	0.000028
35	0											
40	0.054	0.031104	0	0.015552	0	0.001944	0	0.003456	0	0.001728	0	0.000216
45	0											
50	0											
55	0.003	0.001728	0	0.000864	0	0.000108	0	0.000192	0	0.000096	0	0.000012

Figure 4.13: Joint PDF of generating unit outages

X	15	20	25	30	35	40	45	50	55	60	65
Y	$Y \downarrow \quad X \rightarrow$										
20									0.03629		0.02041
25									0.01814		0.00227
30										0.03629	0.02041
35									0.00806		0.00454
40									0.00403	0.01814	0.00277
45									0.01555	0.00806	0.01328
50									0.00822		0.00122
55									0.00022	0.01958	0.00928
60			0.03110	0.00403	0.01555	0.00202	0.00194	0.00025	0.025204		
65	0.03110	0.13997	.015552	7.06998	0.00194	0.00875	0.00346	0.015552			
70	0.00173	0.03686	0.00259	0.05126	0.00097	0.01872	0.00030	0.00615			

Figure 4.14: Joint PDF of equivalent loads of two systems (Correlated loads)(values to be divided by 4)

$$\begin{aligned}
& LOLP_s \quad \text{without assistance of tie line} \\
& LOLP_1 = (X_1 + X_2 + Z)/4 \\
& \quad = (0.152798 + 0.093996 + 0.025204)/4 \\
& \quad = 0.068 \\
& LOLP_2 = (Y_1 + Y_2 + Z)/4 \\
& \quad = (0.32220 + 0.137848 + 0.025204)/4 \\
& \quad = 0.12125
\end{aligned}$$

Therefore, *LOLPs* with assistance of 10 MW tie line capacity,

$$\begin{aligned}
& LOLP_{12} = (X_2 + Z)/4 \\
& \quad = (0.093996 + 0.025204)/4 \\
& \quad = 0.0298 \\
& LOLP_{21} = (Y_2 + Z)/4 \\
& \quad = (0.137848 + 0.025204)/4 \\
& \quad = 0.040763
\end{aligned}$$

4.2.4 Numerical Evaluation

The application of the proposed method is demonstrated through two interconnected systems of practical size. The first system is a slightly modified IEEE-RTS [40] with an installed capacity of 3400 MW. The second system is a hypothetical system with installed capacity of 2950 MW [67]. Generation data for both the systems is given in Table C.4 of Appendix C.

For the load model, the IEEE Reliability Test System IEEE-RTS hourly load data is used. For system X thirteen winter weeks and for system Y thirteen summer weeks data is considered for both independent and correlated load. In the application of the recursive algorithm, 5 MW step increment is considered. Further, capacity margin states with cumulative probabilities less than 10^{-10} are neglected.

Table 4.3: LOLPs for independent and correlated load

Tie Line Capacity (MW)	Independent load		Correlated load	
	$LOLP_{12}$	$LOLP_{21}$	$LOLP_{12}$	$LOLP_{21}$
0.0	0.00280	0.06610	0.00280	0.06610
100	0.00147	0.04578	0.00156	0.04583
200	0.00082	0.03060	0.00097	0.03076
300	0.00052	0.01968	0.00072	0.02000
400	0.00039	0.01237	0.00062	0.01283
500	0.00034	0.00786	0.00058	0.00850
600	0.00032	0.00513	0.00057	0.00594
700	0.00031	0.00344	0.00057	0.00441

In order to evaluate the LOLPs for the independent load case using the recursive technique, the procedure as described in Endrenyi [202] is followed. In this procedure, a joint probability matrix is constructed from the capacity margin table of each system. In order to avoid the enormous number of capacity margin states to be considered, the hourly loads as given in IEEE-RTS are sampled on 5 MW step. The calculations are performed on hourly load basis.

Table 4.3 shows the results obtained in case of independent as well as correlated loads using proposed approach for various values of tie line capacity. The LOLPs evaluated by other existing methods give exactly the same results with similar set of data.

4.3 New Approach for LOLP Evaluation of Interconnected System

This section proposes a new method for LOLP evaluation of interconnected systems. The proposed method is an extension of the joint PDF approach developed in chapter 3 to evaluate Loss of Load Probability (LOLP) of single area power generating systems. The proposed method can consider independent as well as correlated sys-

tem demands. This approach uses hourly loads, or any suitable time interval for system demand, for a given period. The Probability Density Function (PDF) of equivalent load is obtained by convolving the PDF of generating unit outages with the PDF of system demands using the new approach. LOLP values for each system are obtained from the PDF of equivalent load.

4.3.1 Proposed Method

The outage density functions of individual generating units are based on historical data, and contain information on their complete and partial outage rates. The outage density function of a unit is represented by the probabilities of its being in two or more capacity outage states, and consists of one impulse at the origin, and one or more impulses at different values of capacity on the x-axis. The load PDF consists of impulses at different load points on the x-axis. Therefore,

- a. In case of independent load, the loads of both the systems are sampled separately. The probability of each sampled load is known as PDF of system load. The unit outage density function of each system e.g. $f_g(X)$ is convolved with the corresponding load PDF e.g. $f_l(X)$ to obtain the equivalent load PDF of that system i.e. $f_{le}(X)$. The capacity outage value of either system in the evaluation of the PDFs of equivalent load, is to be considered greater than the sum of the installed capacity (IC) and tie line capacity (TC) of that system. The computational complexity can be further reduced by reducing the capacity outage values of equivalent load corresponding to base load, since there are no probability values in the equivalent load below the base load. The capacity outage value of equivalent load of either system is determined using the range reduction procedure discussed in chapter 3 and is given by;

$$IC + \text{Tie Cap.} + C_s \text{ MW at step } (IC + \text{Tie Cap.} - \text{Base load}) / C_s + 2.$$

Similarly, the equivalent load PDF $f_{le}(Y)$ of other system is obtained. The joint equivalent load PDF $f_{le}(X, Y)$ is obtained by multiplying the equivalent load PDF of each system, i.e. $f_{le}(X, Y) = f_{le}(X) \cdot f_{le}(Y)$ giving a two-dimensional array of probability. LOLPs are obtained through the integration

of joint equivalent load PDF over appropriate range, considering the tie line assistance using equations (4.5)-(4.8).

- b. In case of correlated load, the joint PDF of load $f_l(X, Y)$ is developed by sampling the demand of both the system. The unit outage density function of system X, $f_g(X)$ and of system Y, $f_g(Y)$ are convolved one by one with joint load PDF $f_l(X, Y)$ to obtain the joint equivalent load PDF $f_{le}(X, Y)$ of two systems using new approach, which is discussed in the following paragraphs. The determination of capacity outage limit of both system are discussed in case of independent loads. System LOLPs are calculated in a way similar to the independent load case.

Convolution technique for correlated loads

The joint PDF of equivalent load $f_{le}(X, Y)$ for correlated load is to be developed to determine the LOLPs for two area interconnected power systems. Therefore, the solution procedure of equation (4.9) is essential before integration, which is explained below.

Joint equivalent load PDF $f_{le}(X, Y)$ of two systems is obtained by

$$f_{le}(X, Y) = f_l(X, Y) * f_g(X) * f_g(Y) \quad (4.9)$$

where, * denotes the convolution sign.

The equivalent load of single area system and its solution technique has been discussed previously in chapter 3. However, this can be extended for two area interconnected system by transferring two dimensional joint PDF of equivalent load into the single dimension. The transformation process of two dimensional joint PDF of equivalent load into one dimension and thereby the process of two dimensional convolution is explained in what follows.

Equation (4.9) interprets that the unit outage density function of any generating unit of either systems $f_g(\bullet)$ may be convolved with joint load PDF of two systems $f_l(X, Y)$, one after another to obtain the joint equivalent load PDF $f_{le}(X, Y)$ of two systems. Therefore, equation (4.9) of equivalent load PDF of two systems for correlated load $f_{le}(X, Y)$ can be represented as

$$f_{l_e}(X, Y) = f_l(X, Y) * f_g(\bullet) \quad (4.10)$$

where, $f_g(\bullet)$ is the PDF of a generating unit of any system X or Y.

Consider total $(k - 1)$ generators from both the systems have been committed. Now the k th generating unit of any system is to be committed and is coming from system X. Equation (4.10) can now be represented as

$$f_k(X, Y) = f_{k-1}(X, Y) * f_{gk}(X) \quad (4.11)$$

In equation (4.11), the joint PDF of equivalent load $f_{k-1}(X, Y)$ is a two dimensional PDF, whereas $f_{gk}(X)$ is a single dimensional PDF. Therefore, equation (4.11) can be solved as a sequence of single dimensional convolution for a specific capacity outage value of system Y. For simplicity, equation (4.11) can be rewritten as,

$$f_k(X, Y_i) = f_{k-1}(X, Y_i) * f_{gk}(X) \quad (4.12)$$

where, the PDF $f_{k-1}(X, Y_i)$ represents any one impulse of probability in the i th row of two dimensional Venn diagram for the specific capacity outage element Y_i . Equation (4.12) can be solved row wise by the process described in chapter 3.

If k th generator comes from system Y, the above equation (4.12) would be written as;

$$f_k(X_j, Y) = f_{k-1}(X_j, Y) * f_{gk}(Y) \quad (4.13)$$

where, the PDF $f_{k-1}(X_j, Y)$ represents any one impulse of probability in the j th column of two dimensional Venn diagram for the specific capacity outage element X_j .

The solution process of equation (4.13) is similar to that of equation (4.12). In this way, the PDF of all generators' capacity outage are convolved with the joint load PDF to produce joint equivalent load PDFs. These LOLPs of both the systems are evaluated by integrating equation (4.9) over the appropriate limits using equation (4.1)-(4.4).

Computational Steps

- Step 1: Read the PDF of capacity outages of all type of generating units of two systems.
- Step 2: Read the chronological hourly load of the two systems.
- Step 3: In case of independent loads, sample the chronological loads of both system separately. Otherwise goto step 6.
- Step 4: Convolve all the generating outage PDFs of each system separately using the joint PDF approach developed in chapter 3 to produce equivalent load PDF of each system.
- Step 5: Multiply equivalent load PDF of each system to produce joint equivalent load PDF of two systems. Goto step 7.
- Step 6: In case of correlated loads, sample the chronological loads of both system jointly.
- Step 7: Convolve all the generating outage PDFs of each system with the joint PDF of system load found in step 6 using the procedure developed in section 4.3.1 to produce joint equivalent load PDF of two systems.
- Step 8: Integrate joint PDFs of equivalent loads found in step 5 for independent loads and in step 7 for correlated loads using equations (4.5)-(4.8) to evaluate LOLPs.

4.3.2 Example

The computational steps for independent and correlated loads described in the previous section are clarified with the help of a simple example of two area interconnected power system.

Consider the hourly loads of two interconnected systems as shown in Table 4.1 and the generating units data given in Table 4.2. These two systems are interconnected by a 10 MW tie line capacity. The sampling size of load is chosen to be 5 MW. The outage PDFs of all generating units of system X and Y are shown in Figures 4.15, 4.16, 4.17 and 4.18.

C_{gx_1}	0	10	20
p_g	0.64	0.32	0.04

Figure 4.15: Outage PDFs of First Generator Group of X

C_{gx_2}	0	30
p_g	0.9	0.1

Figure 4.16: Outage PDFs of Second Generator of X

C_{gy_1}	0	15	30
p_g	0.81	0.18	0.01

Figure 4.17: Outage PDFs of First Generator Group of Y

C_{gy_2}	0	25
p_g	0.7	0.3

Figure 4.18: Outage PDFs of Second Generator of Y

15	20	25	30	35	40	45	50	55	60	65
0.576	0.576	0.864	0.864	0.324	0.324	0.1	0.1	0.096	0.096	0.08

Figure 4.19: Equivalent load of System X (PDF to be divided by 4)

20	25	30	35	40	45	50	55	60	65	70
0.567	0.567	0.567	0.126	0.693	0.360	0.25	0.376	0.061	0.297	0.127

Figure 4.20: Equivalent load of System Y (PDF to be divided by 4)

Independent Loads

In case of independent load, the chronological loads of system X and system Y are sampled as shown in Figures 4.7 and 4.8. Figure 4.7 is convolved with Figures 4.15 and 4.16 one by one, using joint PDF approach developed in chapter 3. Which produce the equivalent load PDF of system X as shown in Figure 4.19. Convolution of Figures 4.17 and 4.18 with the Figure 4.8 provides the equivalent load of system Y as shown in Figure 4.20.

The joint PDF of equivalent load is obtained by multiplying the equivalent load of system X shown in Figure 4.19 and that of system Y shown in Figure 4.20 and it is shown in Figure 4.21. The LOLPs are obtained by integrating the joint PDF of equivalent load over the appropriate range using equations (4.5)-(4.8). The LOLPs for independent load are;

LOLPs without assistance through tie line

$$\begin{aligned}
 LOLP_1 &= (X_1 + X_2 + Z)/(4 \times 4) \\
 &= (0.57868 + 0.377392 + 0.12192)/(4 \times 4) \\
 &= 0.068 \\
 LOLP_2 &= (Y_1 + Y_2 + Z)/(4 \times 4) \\
 &= (1.26912 + 0.538956 + 0.13192)/(4 \times 4) \\
 &= 0.12125
 \end{aligned}$$

X	INSTALLED CAPACITY								TC		
	15	20	25	30	35	40	45	50	55	60	65
Y	Y ↓ X →										
20									0.05443	0.05443	0.04536
25									0.05443	0.05443	0.04536
30									0.05443	0.05443	0.04536
35									0.01209	0.01209	0.01008
40									0.06653	0.06653	0.05544
45									0.03542	0.03424	0.02952
50									0.02400	0.02400	0.02000
55									0.03609	0.03609	0.03008
60	0.03514	0.03514	0.05270	0.05270	0.01976	0.019764	0.00610	0.00610	0.13192		
65	0.17107	0.17107	0.25661	0.25661	0.09623	0.09623	0.02970	0.02970			
60	0.07315	0.07315	0.10973	0.10973	0.04115	0.04115	0.01270	0.01270			

Figure 4.21: Joint PDF of equivalent loads of two systems (Independent loads)(values to be divided by 4×4)

Hence, *LOLPs* with assistance of $TC = 10$ MW tie line capacity,

$$\begin{aligned}
 LOLP_{12} &= (X_2 + Z)/(4 \times 4) \\
 &= (0.377392 + 0.12192)/(4 \times 4) \\
 &= 0.031832 \\
 LOLP_{21} &= (Y_2 + Z)/(4 \times 4) \\
 &= 0.04192975
 \end{aligned}$$

Correlated Loads

Assign equal probability ($1/4$ in this case) to each sampled hourly load of the joint PDF of load shown in Figure 4.12. The joint PDF of loads in Figure 4.12 is transferred into single dimension, row wise as shown in Figure 4.22. The outage PDF of first generator group of system X shown in Figure 4.15 is convolved with each row of Figure 4.22 separately using equation (4.12). Figure 4.23 shows the resultant PDFs after convolving the PDFs of Figure 4.22 and Figure 4.15. The outage PDF of second generator of system X is shown in Figure 4.16. In a similar way, the convolution of the PDFs of Figure 4.23 and Figure 4.16 is performed and it is shown in Figure 4.24.

$X \rightarrow$	15	20	25	30
$Y \downarrow$				
20			1	
25	1			
30				1
35				
40		1		

Figure 4.22: Transferred joint PDF of correlated load of Figure 4.12 into one dimension (PDF to be divided by 4)

$X \rightarrow$	15	20	25	30	35	40	45	50	55
$Y \downarrow$									
20			0.64		0.32		0.04		
25	0.64		0.32		0.04				
30				0.64		0.32		0.04	
35									
40		0.64		0.32		0.04			

Figure 4.23: Joint equivalent load PDFs after convolving First Generator group of system X with load (PDF to be divided by 4)

X	15	20	25	30	35	40	45	50	55	60	65
Y											
20			0.576		0.288		0.036		0.064		0.036
25	0.576		0.288		0.036		0.064		0.032		0.004
30				0.576		0.288		0.036	0.064		0.036
35											
40		0.576		0.288		0.036		0.064		0.032	0.004

Figure 4.24: Joint equivalent load PDFs after convolving 2nd generator of X in Figure 4.16 with equivalent load in Figure 4.23(PDF to be divided by 4)

X	15	20	25	30	35	40	45	50	55	60	65
Y	Y ↓ X →										
20			0.46656		0.23328		0.02916		0.05184		0.02916
25	0.46656		0.23328		0.02916		0.05184		0.02592		0.00324
30				0.46656		0.23328		0.02916		0.05184	0.02916
35			0.10368		0.05184		0.00648		0.01152		0.00648
40	0.10368	0.46656	0.05184	0.23328	0.00648	0.02916	0.01152	0.05184	0.00576	0.02592	0.00396
45				0.10368		0.05184		0.00648		0.01152	0.00648
50			0.00576		0.00288		0.00036		0.00064		0.00036
55	0.00576	0.10368	0.00288	0.05184	0.00036	0.00648	0.00064	0.01152	0.00032	0.00576	0.00076
60				0.00576		0.00288		0.00036	0.00000	0.00064	0.00036
65											
70		0.00576		0.00288		0.00036		0.00064		0.00032	0.00004

Figure 4.25: Joint equivalent load PDFs after convolving first generator group of Y in Figure 4.17 with equivalent load in Figure 4.24(PDF to be divided by 4)

After committing the generating units of system X, the generating unit outage PDF of system Y is to be committed with Figure 4.24. The outage PDF of first generator group of system Y shown in Figure 4.17 is convolved with each column of Figure 4.24 separately using equation (4.13). Similarly, the resultant PDF shown in Figure 4.25 is again convolved with the PDF of second generator in Figure 4.18. The resultant PDF of the systems obtained represents the joint PDF of equivalent load of interconnected power system as shown in Figure 4.26. LOLPs are calculated from Figure 4.26 in a way similar to that of independent load. The LOLPs for correlated loads are;

$LOLP_s$ without assistance of tie line

$$\begin{aligned}
 LOLP_1 &= (X_1 + X_2 + Z)/4 \\
 &= (0.152798 + 0.093996 + 0.025204)/4 \\
 &= 0.068
 \end{aligned}$$

$$\begin{aligned}
 LOLP_2 &= (Y_1 + Y_2 + Z)/4 \\
 &= (0.32220 + 0.137848 + 0.025204)/4 \\
 &= 0.12125
 \end{aligned}$$

X	15	20	25	30	35	40	45	50	55	60	65
Y	Y ↓ X →										
20									0.03629		0.02041
25									0.01814		0.00227
30										0.03629	0.02041
35									0.00806		0.00454
40									0.00403	0.01814	0.00277
45									0.01555	0.00806	0.01328
50									0.00822		0.00122
55									0.00022	0.01958	0.00928
60			0.03110	0.00403	0.01555	0.00202	0.00194	0.00025	0.025204		
65	0.03110	0.13997	0.015552	0.00403	0.00194	0.00875	0.00346	0.015552			
70	0.00173	0.03686	0.00259	0.05126	0.00097	0.01872	0.00030	0.00615			

Figure 4.26: Joint PDF of equivalent loads of two systems (Correlated loads)(values to be divided by 4)

Therefore, LOLPs with assistance of 10 MW tie line capacity,

$$\begin{aligned}
 LOLP_{12} &= (X_2 + Z)/4 \\
 &= (0.093996 + 0.025204)/4 \\
 &= 0.0298 \\
 LOLP_{21} &= (Y_2 + Z)/4 \\
 &= (0.137848 + 0.025204)/4 \\
 &= 0.040763
 \end{aligned}$$

4.3.3 Numerical Evaluation

This section implements the proposed approach to a interconnected generating system described in the previous section 4.2.4.

The procedure as described in Endrenyi [202] is utilized to evaluate the LOLPs for the independent load case using the recursive technique. In this procedure a joint probability matrix is constructed from the capacity margin table of each system. In order to avoid the enormous number of capacity margin states to be considered, the hourly loads as given in IEEE-RTS are sampled on 5 MW step. Figure 4.27 shows the variation of LOLPs with tie line capacity for both systems considering independent loads. Figure 4.28 shows the variation of LOLPs with tie line capacity for both systems in case of correlated loads. The results obtained in both cases of

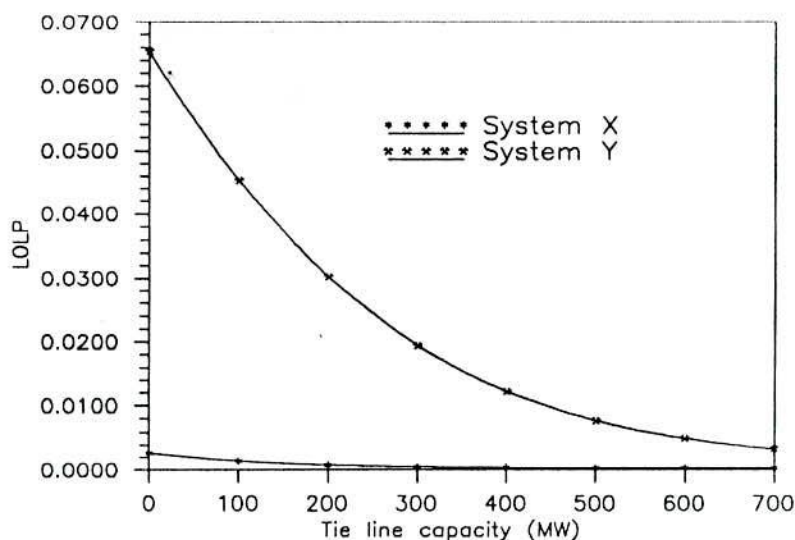


Figure 4.27: LOLPs vs Tie line capacity (Independent loads)

loads (independent and correlated) using proposed method are same as tabulated in Table 4.3. The CPU time comparison on CYBER 180/840A is also shown in Table 4.4.

Applicability of the proposed method is also demonstrated for an interconnected system of practical size considering multistate generating units. Generation data of both the systems with multistate nature are given in Table C.6 and C.7 of Appendix C. Load models for both the systems are considered from IEEE-RTS [41] as used

Table 4.4: Comparison of CPU Time (in Sec.)

Hourly Loads	Recursive Method	Segmentation Method	Proposed Approach
Correlated	2757.842082	261.452912	177.625892
Independent	8.035402	6.01777	5.884093

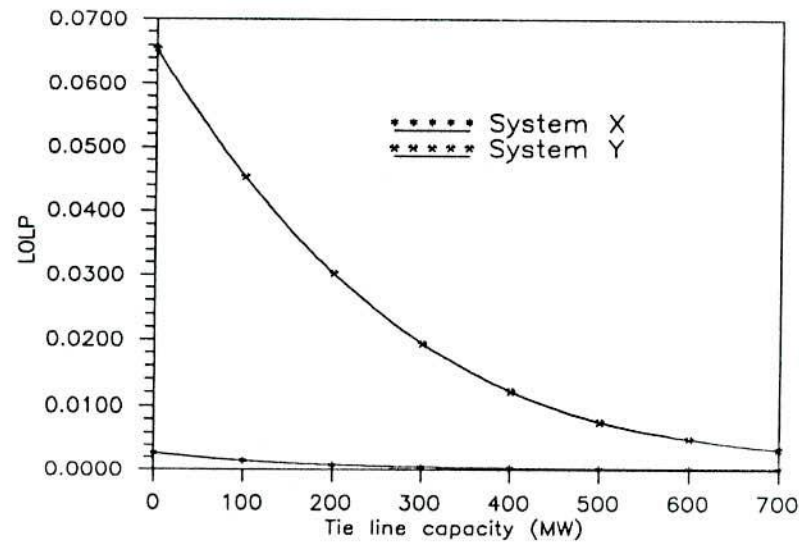


Figure 4.28: LOLPs vs Tie line capacity (Correlated loads)

in the two state case. Table 4.5 shows the results obtained in case of independent loads using proposed approach for various values of tie line capacity for multistate generating units. Table 4.3 and 4.5 show that the LOLPs evaluated for two state generating unit are higher than the LOLPs for multistate generating units. Therefore, multistate generating units ensure higher reliability with respect to two state generating units with equivalent FORs. Calculations are performed on an hourly basis for 2184 hours under consideration.

4.4 Application

The proposed approaches of this chapter are used for the LOLP evaluation of an existing utility (OSEB) considered to be interconnected with a hypothetical generating system. The studies are made to observe impact of interconnection on the system reserve requirement. Following assumptions are made for the hypothetical system.

Table 4.5: LOLPs with Multistate Generating units

Tie Line Capacity (MW)	Independent load		
	$LOLP_{12}$	$LOLP_{21}$	Overall LOLP
0	0.00087139	0.03946611	
100	0.00038419	0.02478626	0.02513605
200	0.00018005	0.01492005	0.01506572
300	0.00010087	0.00858054	0.00864702
400	0.00007320	0.00480778	0.00484660
500	0.00006361	0.00268603	0.00271525
600	0.00006081	0.00151808	0.00154450
700	0.00006005	0.00089549	0.00092115

1. A hypothetical generation system shown in Table C.5.
2. Hourly loads are taken from OSEB (March 1990 to August 1990)
3. The hypothetical system is assumed to have constant generation and load throughout the planning period. It may be considered equivalent to the firm capacity available or it may represent the purchase agreement.

The existing utility is connected with the hypothetical system by tie line of capacity 400 MW. The reliability of the interconnected system is evaluated for the following four years - 1996, 2000, 2004 and 2005. Figure 4.29 shows the variation of LOLPs with tie line capacity for both the systems for the year 1996. Here the generation of OSEB for year 1995 is used, but the load for 1996 is used. It is found from Figure 4.29 that LOLP of OSEB can be as per desired level without adding any generating unit in the year 1996. This can be done only by interconnecting the OSEB system with the hypothetical system through a tie line capacity of 100 MW.

Similarly Figure 4.30, Figure 4.31 and Figure 4.32 are obtained for the year 2000, 2004 and 2005. From these figures, it is found that both the systems are benefited. To maintain a desired LOLP, the requirements of tie line capacity of interconnected system varies from system to system and from year to year. Minimum capacity of tie

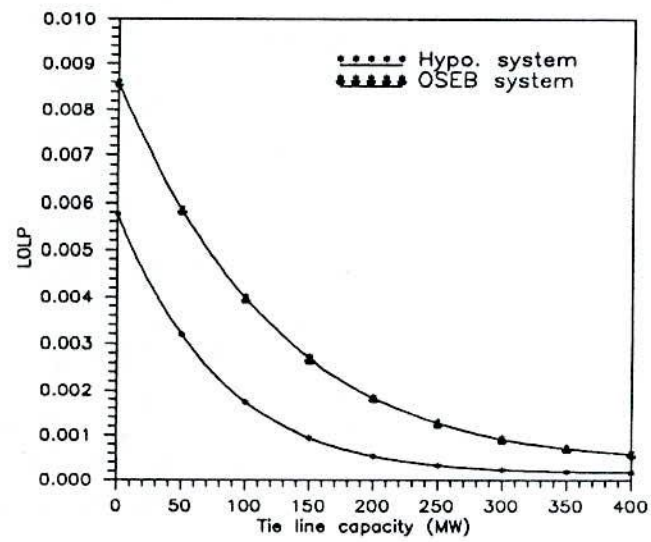


Figure 4.29: LOLPs vs Tie line capacity of OSEB (year 1996 with generation of 1995)

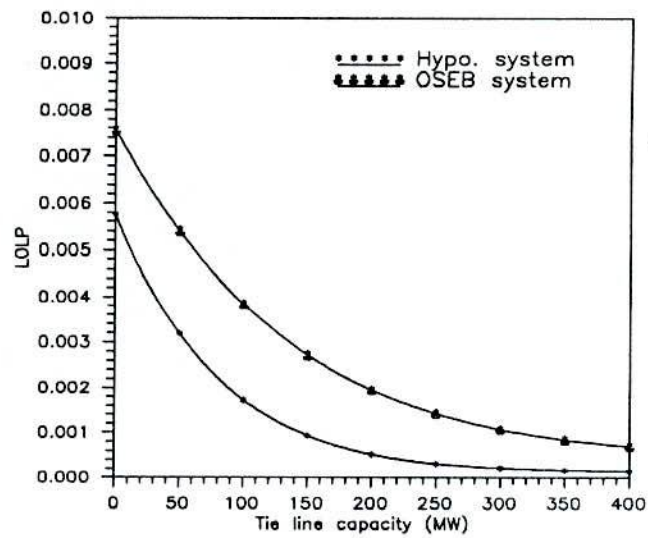


Figure 4.30: LOLPs vs Tie line capacity of OSEB (year 2000 with generation of 1999)

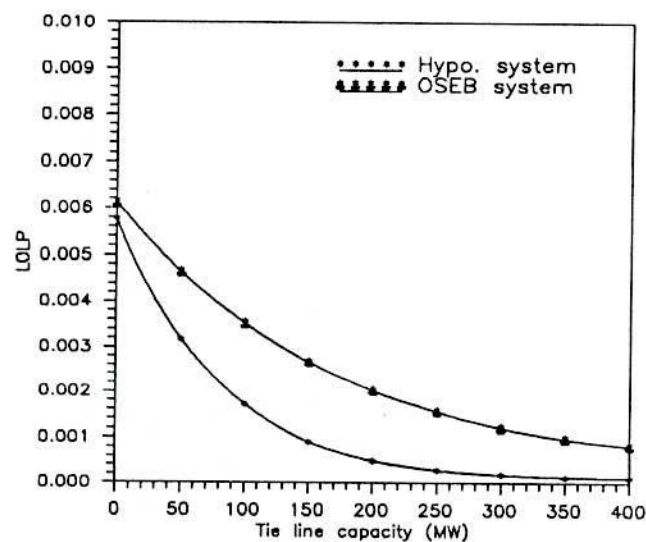


Figure 4.31: LOLPs vs Tie line capacity of OSEB (year 2004 with generation of 2002)

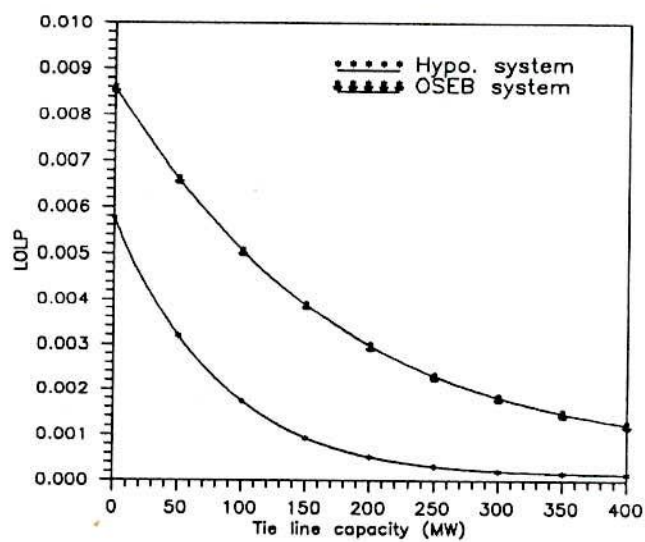


Figure 4.32: LOLPs vs Tie line capacity of OSEB (year 2005 with generation of 2002)

line of interconnected system provides the value of tie line capacity, at which both the systems are remaining within their desired level of reliability. Figure 4.30 shows that 100 MW tie line capacity is sufficient to maintain the reliability of either system for the year 2000 with the generation of the year 1999. Figure 4.31 shows that 100 MW tie line capacity is more than sufficient for the year 2004 to maintain the desired reliability of either system with the generation of the year 2002. Thus, either of the systems shows better performance in 2002 at 100 MW tie line capacity. On the other hand, Figure 4.32 predicts that 150 MW tie line capacity is required to maintain the desired level of reliability for the year 2005 with the generation of the year 2002. It is also shown that higher tie line capacity improves the system reliability more. However, the rate of improvement of reliability decreases with increase of tie line capacity.

4.5 Conclusion

Two exact methods to evaluate the LOLP of two area interconnected systems with independent and correlated system demands are proposed. The results obtained using proposed methods are compared with other existing methods. Proposed methods can also convolve multistate generating units. It is found that LOLP evaluated considering multistate generating units is less than that obtained using equivalent two state generating units model. Therefore, multistate generating unit model provides better measure of reliability index.

The results using BGCE are approximate and not close to the actual value [48]. But, the results for large as well as small interconnected systems obtained by proposed methods are always similar to the actual values. Proposed methods are as computationally efficient as the cumulant method, based on the BGCE but without the inherent inaccuracies.

These methods reduce the number of multiplications and additions in the convolution of a group of identical generating units by reducing thousands of load impulses to a few discrete values, making the convolution process numerically simpler. These methods are more efficient and easier to apply as compared to other existing methods with the similar data. The accuracy of the method has been illustrated using

an example.

In addition, these methods have been implemented to an existing utility, for which expansion plan was carried out in chapter 3. A few aspects of interconnection of the electric utility with a hypothetical system have been studied.

Chapter 5

PRODUCTION COST EVALUATION

5.1 Introduction

Evaluation of production cost and system reliability are important aspects of generation system planning. For the economic operation of a power system, the usually accepted dispatch strategy for minimum cost is one that commits units in order of increasing average marginal or incremental costs. The final ranking of units is called the merit order of loading. In probabilistic simulation, the units are committed in their merit order to meet the demand economically. Fuel cost of any generating system is the only variable part of production cost and depends on the consumption of energy. Usually, for expansion planning, the variable part of the production cost i.e fuel cost is considered to compare various alternative plans. Therefore, in this thesis, production cost indicates the fuel cost of generation systems.

A number of papers [28, 31, 42, 43, 54, 64, 65] have contributed to the advancement and improvement of probabilistic techniques in production cost evaluation of power generating systems. The most important development for the evaluation of production costing was suggested by Booth [28] using probabilistic simulation. This method evaluates the expected energy generation of each unit. The method takes into consideration of random failures of generating units, in terms of the Forced Out-

age Rate (FOR). The fuel costs are evaluated from the knowledge of the expected energy generation of all units.

Rau et al. [42] proposed the method of cumulant using the Gram-Charlier expansion to calculate the expected energy generated by each unit in a system. Stremel [45] as well as Levy et al. [52] have concluded that the accuracy of the method decreases for smaller systems with different unit capacities. It was also observed that even the inclusion of more terms in the expansion may not help to increase the accuracy of the methods.

Stremel et al. [43] agree, in the discussion of their paper by Manhire [43], that the approximation of the load curve by cumulant method may be limited to load shapes which are approximately Gaussian and thus might be unable to represent accurately.

Present day, multi-megawatt generating units are represented by multistate generating units. The computational effort of existing techniques [28, 64, 65] increases linearly with the increase of number of outage states of generating units. Though, existing cumulant methods [42, 43, 45] provide solution for this problem but however, the approximate results obtained and non-uniformity in the convergence of these methods poses problems. Thereby, necessity of developing an efficient method which can reduce the computational complexity of convolution process is realised.

In this chapter, a new accurate and efficient method has been developed to evaluate unserved energy, expected energy served and production cost of power generating systems. The method can operate multistate generating units efficiently. The proposed method has also been applied to an electric system for its future generation expansion plan. Finally, the proposed approach has been extended to interconnected system to evaluate the production costs and its economic benefits.

5.2 A New Approach to Evaluate Production Cost

The probability density function (PDF) of hourly system demands is considered in this approach. Before committing any generating unit outages, the zeroth and first moment of demand are evaluated from the hourly loads of the system. The

sum of the first moments is the expected demand of the system. The expected unserved energy of various types of generating units is evaluated from the equivalent load moments after committing all the generating units. The generating units are committed with loads in the merit order of loading for economic operation. The mathematical relationship to evaluate expected unserved energy, expected served energy, production costing and the mathematical model of proposed convolution process are described in the following subsections.

Expected Energy Generation

The evaluation of unserved energy is essential to evaluate the expected energy generation of a particular generating unit. The expected energy generation by a given generating unit is obtained by evaluating the difference of unserved energies before and after the commitment of that generating unit. Initially the system demand is sampled in terms of zeroth and first moment. The procedure of evaluating the expected unserved energy, expected energy generation and production cost follows:

Consider that $(k - 1)$ generating units have been committed with the system demand. At this stage, the expected unserved energy (USE) of the system before committing k th generating unit is given by,

$$USE_{k-} = T \sum_{i=l}^N [m_{1i}(X) - C_g m_{0i}(X)] \quad (5.1)$$

$$l = \frac{C_g}{C_s}, \quad N = \sum_{k=1}^n \frac{C_k}{C_s} + 1$$

$$\text{and} \quad C_g = \sum_{k=1}^{n_g} C_k \quad (5.2)$$

where,

$m_{0i}(X), m_{1i}(X)$ = Zeroth & first moment of i th element of RV X (equivalent load)

C_k = Capacity of k th generating unit.

C_g = Total capacity of committed generating unit.

n = Total number of generating units

n_g = Total number of committed generating units.

N = Total number of discrete blocks or steps

C_s = Step size of discretization.

T = Time period under consideration.

After the commitment of the k th generating unit, the unserved energy USE_k , may be evaluated using equation (5.1) including the parameters of the k th generating unit. The expected energy generation (EG) by the k th generating unit is then given by

$$EG_k = USE_{k-} - USE_k \quad (5.3)$$

The total expected energy generation (TEG) is given by

$$TEG = \sum_{k=1}^n EG_k \quad (5.4)$$

The production cost (PC) of the k th generating unit is given by

$$PC_k = \lambda_k \times EG_k \quad (5.5)$$

where, λ_k = incremental cost of k th unit

The total production cost (TPC) is,

$$TPC = \sum_{k=1}^n \lambda_k \times EG_k \quad (5.6)$$

The expected unserved energy (USE) and energy balance (EB) and LOLP after committing all the generating units of the system are given by

$$USE_n = m_{1N}(X) - IC \times m_{0N}(X) \quad (5.7)$$

$$EB = USE_{1-} - (TEG + USE_n) \quad (5.8)$$

$$LOLP = m_{0N}(X) \quad (5.9)$$

where, Installed capacity (IC) of the generating system;

$$IC = \sum_{k=1}^n C_k \quad (5.10)$$

Convolution Procedure

Consider, $f_g(l)$ and $f_l(l)$ represent the PDF of generating unit outage and that of system demand respectively. The PDF of equivalent load, $f_{le}(L_e)$ is obtained by convolving the PDF of each generating unit outage and that of system demand, i.e.

$$f_{le}(L_e) = f_g(l) * f_l(l) \quad (5.11)$$

where, $*$ denotes the convolution

Equation (5.11) is known as equivalent load PDF. Each element of the random variable have one zeroth moment (or probability pulse) and one first moment. Commitment of zeroth and first moment of two random variables is performed simultaneously in what follows;

Let X is a discrete random variable (RV) of system load which represents n values in ascending sequence $(X_1, X_2, X_3, \dots, X_n)$ at equal interval with the corresponding zeroth moments represented by $m_{01}(X_1), m_{02}(X_2), m_{03}(X_3), \dots, m_{0n}(X_n)$ and the first moments represented by $m_{11}(X_1), m_{12}(X_2), m_{13}(X_3), \dots, m_{1n}(X_n)$ respectively. Consider another discrete RV Y represents unit outage having m values in ascending sequence $(Y_1, Y_2, Y_3, \dots, Y_m)$ at equal interval with the corresponding zeroth moments represented by $m_{01}(Y_1), m_{02}(Y_2), m_{03}(Y_3), \dots, m_{0m}(Y_m)$ and the first moments represented by $m_{11}(Y_1), m_{12}(Y_2), m_{13}(Y_3), \dots, m_{1m}(Y_m)$. The convolution of these two discrete RVs $Z = X + Y$ can be performed as follows:

$$X = \bigvee_{i=1}^n X_i \quad \text{and} \quad m_{0X} = \bigvee_{i=1}^n m_{0i}(X_i) \quad m_{1X} = \bigvee_{i=1}^n m_{1i}(X_i) \quad (5.12)$$

$$Y = \bigvee_{j=1}^m Y_j \quad \text{and} \quad m_{0Y} = \bigvee_{j=1}^m m_{0j}(Y_j) \quad m_{1Y} = \bigvee_{j=1}^m m_{1j}(Y_j) \quad (5.13)$$

Then,

$$Z = \bigvee_{k=1}^{n+m} Z_k \quad \text{and} \quad m_{0Z} = \bigvee_{k=1}^{n+m} m_{0k}(Z_k) \quad m_{1Z} = \bigvee_{k=1}^{n+m} m_{1k}(Z_k) \quad (5.14)$$

where,

$$\begin{aligned} Z_k &= X_i + Y_j \quad \text{and} \quad m_{0k}(Z_k) = \sum_{\forall(Z_k=X_i+Y_j)} [m_{0i}(X_i).m_{0j}(Y_j)] \\ m_{1k}(Z_k) &= \sum_{\forall(Z_k=X_i+Y_j)} \{m_{0j}(Y_j)[m_{1i}(X_i) + m_{0i}(X_i).m_{1j}(Y_j)]\} \end{aligned} \quad (5.15)$$

5.2.1 Computational Steps

- Step 1: Read the zeroth and first moments of all type of generating units $f_{gi}(L)$. Store the units in the merit order of loading for economic benefits.
- Step 2: Read the chronological hourly load of the system $f_l(L)$.
- Step 3: Determine the largest common factor (C_s) from the system load and generating units' capacity.
- Step 4: Determine the number of blocks length required to solve the system by $(IC - \text{Base load})/C_s + 2$, where IC is the installed capacity of the system.
- Step 5: Sample the system load in step 2 by C_s MW. Store the zeroth and first moments of sampled load in the capacity values at which the loads occur.
- Step 6: Evaluate the unserved energy of the system from the first moments using equation (5.1) before committing first generating unit,.
- Step 7: If there are n_i identical units in first economic type of generating unit, evaluate the equivalent zeroth and first moments of identical generating units using equation (3.18).
- Step 8: Convolve the moments in step 7 with the moments of load in step 5 using equations (5.12)-(5.15).

Table 5.1: Hourly load data

Hours	Load
1	15
2	20
3	30
4	25

- Step 9: After committing first generating unit, recalculate the unserved energy of the system from the first moments using equation (5.1).
- Step 10: Evaluate the energy served by the unit from the difference of unserved energy obtained in step 6 and step 9 using equation (5.3). Evaluate production cost using equation (5.5).
- Step 11: Repeat step 7 to 10 to evaluate energy served and production costs of remaining generating units, till all the units committed.

5.2.2 Example

The computational steps of the proposed approach are described with the help of an example of a power system in what follows.

Consider hourly loads of a small power system as shown in Table 5.1 and the generating units data given in Table 5.2. Let the step size of demand (also called sampling size) and generating unit capacities are 5 MW and 10 MW respectively. The largest common factor of step size of load and generating units is $C_s = \min(5, 10) = 5$ MW. The capacity outages size of the equivalent load, as discussed in previous section, is $50 + 5 = 55$ MW or $\text{blocks} = (IC - \text{baseload}/C_s + 2) = (50 - 15/5 + 2) = 9$.

The sampling of load in terms of zeroth and first moment is shown in Figure 5.1. With a base load of 15 MW and 5 MW step, the load moments of Figure 5.1 can also be represented by Figure 5.2. The unserved energy before committing any generating unit is evaluated using equation (5.1) as

Table 5.2: Generation data

Generation Data of Small System			
No.of Units	Cap (MW)	FOR	Inc. Cost λ , \$/MWh
2	10	0.2	5.0
1	30	0.1	7.0

X	15	20	25	30
m_{0X}	$\frac{1}{4}$	$\frac{1}{4}$	$\frac{1}{4}$	$\frac{1}{4}$
m_{1X}	$\frac{15}{4}$	$\frac{20}{4}$	$\frac{25}{4}$	$\frac{30}{4}$

Figure 5.1: Moments of sampled load

$$USE_{1-} = 4.(15 + 20 + 25 + 30)/4 = 90 MWh \quad (5.16)$$

Convolution of first generator group

Capacity of first generator is 10 MW, forced outage rate is 0.2 and number of unit is two. That is, $c_1 = 10MW$, $n_1 = 2$ and $FOR = 0.2$. Using equation (3.18) for identical generator group, the zeroth and first moments of first generator group are evaluated as shown in Figure 5.3.

The sampled load in Figure 5.2 and outage PDF of first generating group in

X	15	20	25	30
m_{0X}	1	1	1	1
m_{1X}	15	20	25	30

Figure 5.2: Moments of sampled load (values to be divided by 4)

Y	0	10	20
m_{0Y}	0.64	0.32	0.04
m_{1Y}	0	10	20

Figure 5.3: Outage moments of first Generator Group

X			15	20	25	30
m_{0X}			1	1	1	1
m_{1X}			15	20	25	30
Y	m_{0Y}	m_{1Y}				
0	0.64	0	15 0.64 9.6	20 0.64 12.8	25 0.64 16	30 0.64 19.2
10	0.32	10	25 0.32 8.	30 0.32 9.6	35 0.32 11.2	40 0.32 12.8
20	0.04	20	35 0.04 1.4	40 0.04 1.6	45 0.04 1.8	50 0.04 2.0

Figure 5.4: Equivalent Load Boxes after convolving system load with first unit group (values to be divided by 4)

Figure 5.3 are convolved using the equations (5.12)-(5.15) to generate the moments of an equivalent load as shown in Figure 5.4. The equivalent load moments of Figure 5.4 can be represented as shown in Figure 5.5.

The unserved energy after committing the first generator group is evaluated using equation (5.1) from the equivalent load boxes shown in Figure 5.5. That is,

$$\begin{aligned}
 USE_1 &= 4 \times [(24 + 28.8 + 12.6 + 14.4 + 1.8 + 2.0) \\
 &\quad - 20 \times (0.96 + 0.96 + 0.36 + 0.36 + 0.04 + 0.04)]/4 \\
 &= 29.2 \text{ MWh}
 \end{aligned} \tag{5.17}$$

Z	15	20	25	30	35	40	45	50
m_{0Z}	0.64	0.64	0.96	0.96	0.36	0.36	0.04	0.04
m_{1Z}	9.6	12.8	24	28.8	12.6	14.4	1.8	2.0

Figure 5.5: Equivalent Load moments (values to be divided by 4)

Y	0	30
m_{0Y}	0.9	0.1
m_{1Y}	0	30

Figure 5.6: Outage moments of second Generator Group

The expected energy generation and production cost of the first generator group evaluated using equations (5.3) and (5.5) are given by

$$EG_1 = 90 - 29.2 = 60.8 \text{ MWh}$$

$$PC_1 = 60.8 \times 5.0 = 304.0 \text{ US\$}$$

Convolution of Second generator

The second generator of capacity $c_2 = 30 \text{ MW}$ and $FOR = 0.1$ is a single unit. Therefore, the moments of second generator are having only two set of values. These are $m_{01} = 0.9$, $m_{02} = 0.1$, $m_{11} = 0 \text{ MW}$ and $m_{12} = 30 \text{ MW}$. The moments of second generator shown in Figure 5.6 are again convolved with equivalent load of Figure 5.5. The moments beyond the installed capacity are accumulated in the last block i.e. 55 MW at the step $(50 - 15)/5 + 2 = 9$ of Figure 5.7, which shows the the equivalent load moments after convolving all generating units.

Z	15	20	25	30	35	40	45	50	55
m_{0Z}	0.576	0.576	0.864	0.864	0.324	0.324	0.1	0.1	0.272
m_{1Z}	8.64	11.52	21.60	25.92	11.34	12.96	4.5	5.0	16.52

Figure 5.7: Equivalent Load moments after convolving all units (PDF to be divided by 4)

The unserved energy after committing all the generating units is evaluated using equation (5.1) from the equivalent load shown in Figure 5.7.

$$USE_2 = 4. \times [16.32 - 50. \times 0.272]/4 = 2.92 MWh \quad (5.18)$$

The expected energy generation and production cost of last generating unit evaluated using equations (5.3)-(5.5) are

$$EG_2 = 29.20 - 2.92 = 26.28 MWh$$

$$PC_2 = 26.28 \times 7.0 = 183.96 US\$$$

The total expected energy generation, production cost, unserved energy, energy balance and LOLP of the system are evaluated using equations (5.3)-(5.10) as,

$$TEG = 60.8 + 26.28 = 87.08 MWh$$

$$TPC = 304.0 + 183.96 = 487.96 US\$$$

$$USE = 2.92 MWh$$

$$EB = 90. - (87.08 + 2.92) = 0.0 MWh$$

$$LOLP = Pr(L_e > IC) = 0.272/4 = 0.0680$$

5.2.3 Numerical Evaluation

This section applies the proposed approach explained in the preceding sections to a prototype generating system provided by the Reliability Test System Task Force of the IEEE Power Engineering Application of Probabilistic Methods Subcommittee

Table 5.3: Expected Energy Generation and Production Costs

Unit Type	Unit Cap(MW)	No.of Unit	Expected Energy Generation (GWh)	Production Cost (M\$)
Hydro	50	6	648.64800000	0.0000000
Nuclear	400	2	1537.53600000	8.59790131
Coal	150	4	1124.78503632	12.55260101
Coal	350	1	417.25453335	4.75670168
Coal	80	4	270.15967681	4.02051631
Oil	200	3	153.20737545	3.04423055
Oil	100	3	9.96805652	0.20015858
Oil	10	5	0.56621445	0.01616995
Oil	20	4	0.56096771	0.02103629

[40]. This system is slightly modified with an installed capacity of 3400 MW. Table C.8 of Appendix C gives the generation mix of the 32 units comprising the system, their installed capacities and FORs. For this system, thirteen winter weeks (48- 52 & 1-8 Weeks) hourly loads data of IEEE-RTS [40] is used as a load model of 2850 MW peak load, 1102 MW base load and 2184 hours time duration.

The evaluated expected energy generation and production cost of each type of generating unit using new method with a step size of 5 MW are given in Table 5.3. The loading order of the generating are as specified in this table which is obtained from the average incremental cost (λ) of each type of generating unit.

The same values of expected energy generation and production costs shown in the Table 5.3 are also observed from the existing accepted segmentation method [65] with the similar type of generation data and step size. In the proposed method, the process of load sampling with a lower value of step size avoids the sampling error. The capacity of the generating unit is considered as a step size of that type of unit at the time of committing with demands. Finally the step size of load sampling is considered as the basic step size of the proposed approach.

The global expected energy generations, production costs, unserved energies

Table 5.4: Results at different step size

Step Size (MW)	LOLP (%)	Unserved Energy (GWh)	Expected Energy (GWh)	Production Costs (M\$)
1	0.280078	0.794966	4162.68534	33.20924
5	0.280078	0.794449	4162.68586	33.20931
10	0.280078	0.792987	4162.68772	33.20879

Table 5.5: Comparison of CPU time at different step size

Step Size (MW)	CPU Time (Seconds)	
	Segmentation Method	Proposed Approach
1	2.101877	1.68620
5	0.821253	0.71886
10	0.664936	0.60974

and LOLPs with different step size of the system are given in Table 5.4. CPU time for different methods with different step size obtained using CYBER mainframe 180/840A is presented in Table 5.5.

Though, the evaluated results from both the methods are similar, but the CPU time requirement is different as shown in Table 5.5. Table 5.4 and Table 5.5 prove the computational efficiency and accuracy of the proposed method. This approach may again be considered exact because of its zero energy balance. Note that the expected energy demand for this system is 4163.48031 GWh.

Table 5.6 shows the CPU time comparison of different methods for 170 units of capacity 20 MW at FOR = 0.1 and Table 5.7 shows the same for 68 units of capacity 50 MW at FOR = 0.1. This approach, therefore, specially handles the identical generating unit efficiently. The time required for committing these type of generating units requires further less time if more machines of similar type are

Table 5.6: Comparison of CPU time with 170x20 MW (0.1)

Step Size (MW)	CPU Time (Seconds)	
	Segmentation Method	Proposed Approach
1	9.014677	5.23184
5	2.154783	1.43653
10	1.303276	0.96186

Table 5.7: Comparison of CPU time with 68x50 MW (0.1)

Step Size (MW)	CPU Time (Seconds)	
	Segmentation Method	Proposed Approach
1	3.908846	2.408357
5	1.336773	0.860731
10	0.817378	0.663561

included in the system. Similarly when multistate generating units are considered, the computational time requirement of proposed method is much less as compared to existing methods.

5.3 Application to an Existing System

Production cost and unserved energy of an existing utility (OSEB) are evaluated using the proposed method. The OSEB system is discussed in chapter 3 in detail, and a sample plan of OSEB has also been developed based on risk levelisation criterion.

In this section, the developed plan is again levelised on the basis of unserved energy and production cost considering acceptable level of unserved energy of 3.0 GWh. The hydro units available in system are energy limited. The concept of

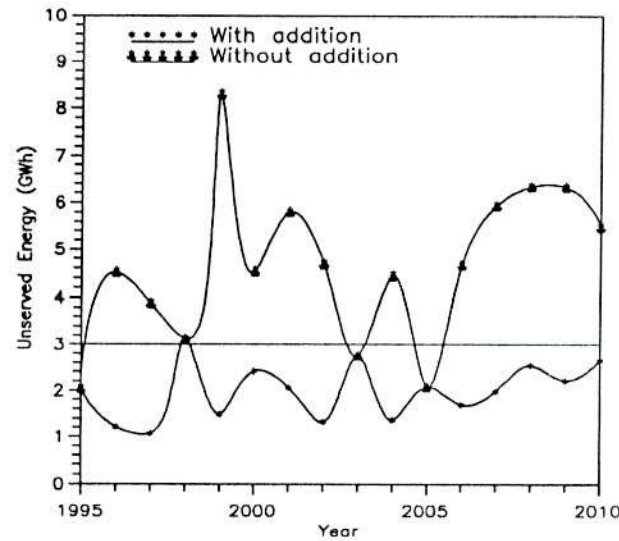


Figure 5.8: Unserved energy vs Year (before and after addition of unit(s) in the previous year)

committing energy limited hydro units in reference [65] is used here. This type of units can be used only as mid-range or peaking units. Forty to fifty percent variation of base load of the system is considered for the planning period. The generation mix ratio of thermal and energy limited hydro-electric units are considered as 40%–50% : 60%–50%.

Above generation mix has been used to evaluate the production cost of the plan maintaining the desired level of reliability and unserved energy, which is given in Table 5.8. Figure 5.8 shows the variation of unserved energy, with and without addition of units in the planned year. Figure 5.8 also shows that no additional generating unit is required in the year 1998, 2003 and 2005. In these years, unserved energy and reliability are remaining within the prescribed level with no additional units.

Variation of yearly peak load and production cost with year is depicted in Figure 5.9. Note that the expected energy generation is increasing as the peak load of each

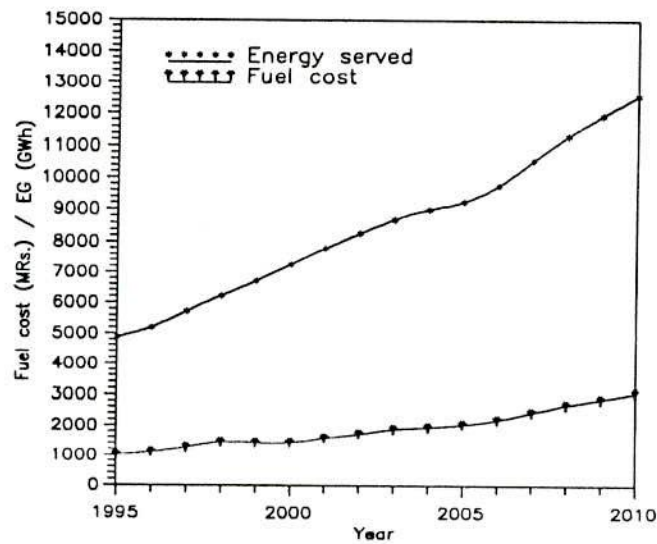


Figure 5.9: Fuel cost and Expected energy served vs Year

year increased. The production cost or fuel cost curve is not following the nature of expected energy, due to plenty of hydro electric generating units.

Table 5.8 shows that the thermal unit of 210 MW capacity is added in the year 1996 to levelize the reliability and unserved energy. The incremental cost of the unit 210 MW is $\lambda = 320$ Rs/MWh. It is found that the production cost with addition of the unit is less than that of without addition of unit in the same year. This effect happens, when the unit of higher incremental cost contributes towards the base load in load duration curve. The newly added unit to the system in 1996 has started contributing to the base load due to its merit order of loading and due to this reduction in system production cost is obtained. From the results compared for the years 1999 and 2000, it is found that variation in production cost is very small with respect to change of the expected energy generation or peak load.

Table 5.8: LOLP, Production Cost and Unserved Energy for the generation expansion plan

Year	Load (MW)	IC (MW)	LOLP	USE (GWh)	ES (GWh)	Fuel cost (M.Rs)	Addition (MW)
1995	1480	2175	0.0041593	2.03793	4883.667	1011.0153	exist
1996	1590	2175	0.00859072	4.5135	5201.34223	1142.6603	—
1996	1590	2385	0.002509	1.22197325	5204.6362	1105.8838	T1x210
1997	1750	2385	0.0071334	3.883102	5725.8315	1297.683	—
1997	1750	2595	0.00214477	1.0756855	5728.6387	1262.5702	T1x210
1998	1900	2595	0.00573169	3.12683606	6217.7080	1440.7322	—
1999	2050	2595	0.0138651	8.29679680	6703.6545	1619.556	—
1999	2050	3005	0.00138813	0.712637892	6711.2246	1419.9419	H1x300
2000	2220	2895	0.00755985	4.53085947	7264.022	1623.3679	—
2000	2220	3195	0.00374085	2.4146564	7266.1377	1421.7467	H1x300
2001	2380	3195	0.00820212	5.8074689	7786.605	1613.2782	—
2001	2380	3405	0.00315606	2.06123447	7790.3516	1576.6987	T1x210
2002	2530	3405	0.00660385	4.6866885	8298.8467	1756.4597	—
2002	2530	3645	0.0020563	1.32888675	8282.2061	1720.8984	H2x120
2003	2660	3645	0.00398136	2.75563693	8706.4141	1877.0011	—
2004	2750	3645	0.00611295	4.43533611	8999.4033	1984.8202	—
2004	2750	3895	0.00205271	1.3765782	9002.4619	1940.772	T1x250
2005	2825	3895	0.00299155	2.0823042	9247.3164	2030.8728	—
2006	2980	3895	0.00620482	4.66428947	9752.2246	2216.67	—
2006	2980	4095	0.00243876	1.69513679	9755.1934	2180.9624	H2x100
2007	3225	4095	0.00757708	5.94331264	10553.1035	2474.5850	—
2007	3225	4295	0.00366876	2.806633	10556.2393	2442.6191	H2x100
2008	3460	4295	0.0094186	8.4428444	11320.0254	2723.687	—
2008	3460	4545	0.00384004	3.029672	11325.4395	2680.5017	T1x250
2009	3650	4545	0.00849565	7.275063	11943.2695	2907.853	—
2009	3650	4945	0.00182116	1.42284382	11949.123	2830.8867	H4x100
2010	3940	4945	0.00413658	3.4769454	12529.1582	3059.053	—
2010	3040	5195	0.00157901	1.24607038	12571.3887	3014.708	T1x250

T2x210 represents two thermal units of capacity 210 MW $\lambda = 320 \text{ Rs/MWh}$

T1x250 represents one thermal unit of capacity 250 MW $\lambda = 320 \text{ Rs/MWh}$

H1x300 represents two hydro units of capacity 150 MW, Total energy generation=550 GWh

H2x120 represents two hydro units of capacity 120 MW, Total energy generation=100 GWh

H2x100 represents two hydro units of capacity 100 MW, Total energy generation=100 GWh

5.4 Production Cost Evaluation of Two Area Interconnected Systems

Electric utilities are increasingly facing great financial pressures to construct new unit(s). For this, they are very much concerned about the returns from their investment. Utilities are placing increasing emphasis on the economics of their generation system. Interconnection of electric utilities is one way in which economic benefits are achieved. Such benefits include lower production costs as well as deferral of plant construction due to reduced reserve capacity requirements.

The basic method to evaluate the production cost and reliability has been described in [202]. A number of papers [42, 65] have contributed to the improvement of the probabilistic techniques and extended their methods to evaluate the production costs of two interconnected systems [57, 61, 75, 106]. However, the economic benefits estimates from production cost is another factor altogether. Khan and Lee [45] proposed a methodology for estimating the benefits of power pooling. This procedure obtains the production costs for each system in isolation as well as for all interconnected operation. Rau et al.[57] have described a method based on the representation of the incremental costs as affected by plant outages. This methodology utilizes the BGCE [57] to evaluate economic benefits of two interconnected systems. The BGCE has also been utilized by Noyes [58] and Ahsan et al. [61] in the evaluation of production costs of two interconnected systems. The notion of residual demand is used in [58]. Import and export are evaluated by dividing the residual demand plane into zones. The concept of residual tie line capacity is introduced in [61, 75, 106]. Import and export are also evaluated by modifying the joint distribution of load appropriately [61].

This section proposes an extension of the approach proposed in previous section to evaluate the production cost of two area interconnected systems. The proposed approach avoids inherent errors presented by suggested numerical convolution formula of series expansion [57, 58, 61]. The IEEE-RTS [40] as well as a hypothetical system [75] are used in the analysis.

5.4.1 Proposed Method to Evaluate Production Cost of Interconnected System

The loads of the two interconnected systems are assumed correlated. The random failure of each generating unit is assumed independent of other as well as independent of load. The random failures of the respective generating units are taken into account through the well known *equivalent load approach*.

The proposed approach is based on the zeroth and first moment of hourly system loads, and the first moment of tie line capacity. The zeroth and first moment of system demands are evaluated from the hourly loads of both the systems before committing any generating unit. The zeroth moment is the representation of joint PDF of interconnected system demand. Initially, the first moment of residual tie line capacity for each system is set equal to the product of the corresponding tie line capacity and the joint PDF. The sum of the first moments of load is the expected demand of the system. The expected unserved energy is evaluated from the equivalent load moments after committing all the generating units in the merit order of loading for economic operation. Following paragraphs describe the methodology to evaluate the unserved energy, expected energy generation and production cost of interconnected systems using,

1. The merit order of loading of generating units.
2. The mathematical relations to evaluate expected unserved energy, expected served energy and production cost.
3. The mathematical model of proposed convolution process.

5.4.2 Merit Order of Loading

The basic idea in the loading order procedure is to commit generating units in the ascending order of their average incremental costs. The generating unit of lowest average incremental cost is the most economic unit. The procedure to be followed in case of two interconnected systems is to select the generating unit, from among the set of generating units in both systems, with the lowest average incremental cost,

to be loaded first. This is followed by the next most efficient generating unit among this set and so on.

5.4.3 Expected Export or Import

The basic strategy in evaluation of export is that each system must keep its own interest paramount. That is, a utility will only export power to another as long as it has excess capacity of generation after having met its own demand. An electric utility with loss of load will therefore not undertake export of capacity [106].

The principal factors which affect the energy transactions between the two interconnected systems are:

1. The unserved demand of the exporting system
2. The unserved demand of the importing system
3. The capacity of the generating unit to be committed, and
4. The residual tie line capacity of the exporting system.

In what follows, the system in which a generating unit is being committed is referred to as the exporting system and the other system will be referred to as the importing system. The residual tie line capacity for a system is the capacity of the tie line that remains at any stage of the loading process after having been utilized by the previously committed generating unit(s) from the system.

The value of possible export e_{ij} may be evaluated by,

$$\begin{aligned} e_{ij} &= \min(Z_1, Z_2, Z_3) \\ \text{but } e_{ij} &\geq 0. \end{aligned} \tag{5.19}$$

where i and j denote the row and column of the joint equivalent load.

The values Z_1 , Z_2 and Z_3 represent excess generation of the exporting system, residual tie line capacity of the exporting system, and unserved demand of the importing system respectively and are evaluated from the following relations:

$$Z_1 = \sum_{k=1}^{S^E+1} C_k^E m_{0ij}(EL) - m_{1ij}^E(EL) \quad (5.20)$$

$$Z_2 = mt_{ij}^E(EL) \quad (5.21)$$

$$Z_3 = m_{1ij}^I(EL) - \sum_{k=1}^{S^I} C_k^I m_{0ij}(EL) \quad (5.22)$$

where, the superscripts E and I refer to the exporting and importing systems respectively. EL refers to as the random variable (RV) of joint equivalent load. $m_{0ij}(EL)$ and $m_{1ij}(EL)$ represent zeroth and first moments of joint equivalent load (EL) at $(i, j)th$ position respectively.

In equation (5.21), $mt_{ij}^E(EL)$ is the first moment of residual tie line capacity and initially it is obtained by the product of the zeroth moment and the tie line capacity; i.e., $mt_{ij}^E(EL) = TC \times m_{0ij}(EL)$

5.4.4 Expected Energy Generation

The expected energy generation by a given generating unit is obtained by evaluating the difference of unserved energies before and after the commitment of that generating unit with joint equivalent load. The evaluated energy generation clearly must include the energy required to meet its own as well as export demand. To accomplish this the first moment of loads must be properly modified before the evaluation of unserved energy for the export demand. The procedure of evaluating the expected unserved energy, energy generation is as follows:

Consider that $(k - 1)$ generating units have been committed (from either system). At this stage, the modified first moments of load in the joint equivalent load for the exporting and importing system, $\hat{m}_{1ij}^E(EL)$ and $\hat{m}_{1ij}^I(EL)$ respectively are given by

$$\hat{m}_{1ij}^E(EL) = m_{1ij}^E(EL) + e_{ij} \quad (5.23)$$

$$\hat{m}_{1ij}^I(EL) = m_{1ij}^I(EL) - e_{ij} \quad (5.24)$$

The first moments of residual tie line capacity must also be modified in those blocks where transactions take place. The modification of the first moment of residual tie line capacity is necessary to carry out the information to the corresponding blocks of equivalent load.

The modified first moments of residual tie line capacity are

$$\hat{m}t_{ij}^E(EL) = mt_{ij}^E(EL) - e_{ij} \quad (5.25)$$

$$\hat{m}t_{ij}^I(EL) = mt_{ij}^I(EL) + e_{ij} \quad (5.26)$$

It is assumed that simultaneous transactions in both directions can not occur. The expected unserved energy of the exporting system before committing the k th generating unit is given by,

$$USE_{k-} = T \sum_{i,j=1}^{i=t_y, j=y_x} [\hat{m}t_{ij}^E(EL) - C_t^E \times m_{0ij}(EL)] \quad (5.27)$$

where T = the time period under consideration.

C_t^E = the total capacity of already committed generating units of the exporting system is evaluated by

$$C_t^E = \sum_{k=1}^{S^E} C_k^E \quad (5.28)$$

The limits t_x and t_y in equation (5.27) are given by

$$t_x = \frac{1}{C_s} \left[\sum_{k=1}^{n_x} C_k^x + TC \right] + 1 \quad (5.29)$$

$$t_y = \frac{1}{C_s} \left[\sum_{k=1}^{n_y} C_k^y + TC \right] + 1 \quad (5.30)$$

where C_s is the sampling size,

n_x is the total number of generating units in system X

n_y is the total number of generating units in system Y

TC is the tie line capacity

C^x and C^y are generating units in system X and Y respectively. Note that the unserved demand at any (i, j) block of equation (5.27) must be positive. That is,

$$(\hat{m}_{1ij}^E(EL) - C_t^E \times m_{0ij}(EL)) > 0 \quad (5.31)$$

After the commitment of the k th generating unit, the unserved energy USE_k may be evaluated using equation (5.27), where the parameter of the k th generating unit must be included. The expected energy generation by the k th generating unit is given by

$$EG_k = USE_{k-} - USE_k \quad (5.32)$$

The total expected energy generation, therefore, is given by

$$TEG = \sum_{k=1}^{n_x+n_y} EG_k \quad (5.33)$$

The production cost of the k th generating unit is given by

$$PC_k = \lambda_k \times EG_k \quad (5.34)$$

where, λ_k = incremental cost of the k th unit
and the total production cost is

$$TPC = \sum_{k=1}^{n_x+n_y} \lambda_k \times EG_k \quad (5.35)$$

The expected unserved energy of the system after committing all the generating units of both the systems is given by

$$USE = T \times \text{Expected Demand} - \text{Expected Energy Generation} \quad (5.36)$$

where, T is the time period under consideration and the Expected Demand of the global system before committing any unit is given by

$$\text{Expected Demand} = \sum_X m_{1ij}(l) + \sum_Y m_{1ij}(l) \quad (5.37)$$

5.4.5 Convolution Procedure

Convolution of generating units with system demands is responsible for the maximum part of the computational burden in the probabilistic production costing. For this reason the major effort of any modelling depends on reducing computation of convolution of generating unit outage with the random loads.

The PDF of equivalent load is obtained by convolution of PDF of generating unit outages with that of system demand. Equation (5.11) shows the convolution concept for one dimension and its solution procedure is given in equations (5.12)-(5.15).

However, this procedure can be extended to a two area interconnected system. This is done by transferring the two dimensional joint PDF of equivalent load into single dimension. The transformation process of two dimensional joint PDF of equivalent load as well as the process of two dimensional convolution are explained below.

From the concept of merit order of loading, the unit outage density function of most economic generator of both the systems $f_g(\bullet)$ is to be convolved first with joint load PDF $f_l(EL)$ of two systems. Successively the remaining generating units are committed to obtain the joint equivalent load PDF $f_{le}(EL)$ of two systems. The equivalent load PDF $f_{le}(EL)$ of two systems is obtained as

$$\begin{aligned} f_{le}(EL) &= f_l(EL) * f_g(\bullet) \\ \text{or,} \\ f_{le}(X, Y) &= f_l(X, Y) * f_g(\bullet) \end{aligned} \quad (5.38)$$

where, $f_g(\bullet)$ is the PDF of a generating unit of any system X or Y.

Let $f_{k-1}(X, Y)$ is the equivalent load PDFs after convolving $(k-1)$ generating units. Consider the k th generating unit is to be committed and is coming from system X. Equation (5.38) can be represented as

$$f_k(X, Y) = f_{k-1}(X, Y) * f_{gk}(X) \quad (5.39)$$

Equation (5.39) shows the joint PDF of equivalent load. Each element of joint random variable (joint equivalent load) have five values: one zeroth moment (joint probability pulse) represented by $m_{0ij}(EL)$ and four first moment pulses. These are,

1. two first moments of load, one for system X and other for system Y
2. two first moments of residual tie line, one for each system

Before committing the k th generating unit, these four first moments are represented by,

- a. $m_{1ij(k-1)}^E(EL)$ = first moment of equivalent loads for exporting system,
- b. $m_{1ij(k-1)}^I(EL)$ = first moment of equivalent loads for importing system,
- c. $mt_{ij(k-1)}^E(EL)$ = first moment of RTC for exporting system,
- d. $mt_{ij(k-1)}^I(EL)$ = first moment of RTC for importing system.

Equation (5.39) also shows that $f_{gk}(X)$ is one dimensional function and $f_{k-1}(X, Y)$ is a two dimensional function. Solution technique of equation (5.39) is discussed for probability impulse in chapter 4. The zeroth moment of this equation is transferred from two dimensional form into one dimensional form along with all first moments. The transferred form is solved by the procedure similar to equation (5.11). Therefore, equations (5.12)-(5.15) are used to provide the zeroth moment of the system and the first moment of the exporting system, $m_{1ij(k-1)}^E(EL)$ of joint equivalent load (EL). The remaining first moments $m_{1ij(k-1)}^I(EL)$, $mt_{ij(k-1)}^E(EL)$ and $mt_{ij(k-1)}^I(EL)$ mentioned above are also evaluated using equations (5.12)-(5.15) eliminating $m_{1j}(Y_j)$ part of equation (5.15). However, before committing any generating unit from any system, these four first moments (a-b-c-d) are to be modified using equation (5.19).

5.4.6 Computational Steps

Computational steps of the proposed approach to evaluate the production cost, expected energy generation and expected unserved energy of two area interconnected system are,

- Step 1: Read the zeroth and first moments of all type of generating units of both systems. Store the units in the merit order of loading for economic benefits.
- Step 2: Read the chronological hourly load of both the system.
- Step 3: Sample the system load jointly in step 2 by C_s MW. Store the zeroth and first moments of sampled load in the capacity values at which the loads occur. Store the first moment of tie line capacity for both the system in each block.
- Step 4: Refer the system of most economic generator of step 1 as exporting system.
- Step 5: Modify the first moments of load and tie line capacity of step 3 using equations (5.23)-(5.26).
- Step 6: Evaluate the unserved energy of the exporting system from the first moments of that system's load using equation (5.27) before committing the assigned generating unit.
- Step 7: If there are n_i identical units in the most economic generating unit, evaluate the equivalent zeroth and first moments of identical generating units using equation (3.18).
- Step 8: Convolve the assigned generating unit with the moments of step 5 using the procedure in section 5.4.5.
- Step 9: Recalculate the unserved energy of the exporting system from the first moments of that system's load using equation (5.27) after committing assigned generating unit.
- Step 10: Evaluate the energy served by the assigned unit from the difference of unserved energy obtained in step 6 and step 9 using equation (5.3).
- Step 11: Repeat step 4 to 10 to evaluate the energy served of remaining generating units, till all the units convolved.

Table 5.9: Hourly load data

Hourly loads	System X (MW)	System Y (MW)
1	15	25
2	20	40
3	30	30
4	25	20

Table 5.10: Generation data

SYSTEM X				SYSTEM Y			
No.of Units	Cap (MW)	FOR	Inc. Cost $\lambda, \$/\text{MWh}$	No.of Units	Cap (MW)	FOR	Inc. Cost $\lambda, \$/\text{MWh}$
2	10	0.2	5.0	2	15	0.1	6.0
1	30	0.1	7.0	1	25	0.3	9.0

5.4.7 Example

Consider the hourly loads of two interconnected systems as shown in Table 5.9 and the generating units data given in Table 5.10. These two systems are interconnected by a 10 MW tie-line. The sampling size is chosen to be $C_s = 5$ MW. Following expected demands are evaluated from the first moment of individual systems.

Expected Demand of System X = 90 MWh

Expected Demand of System Y = 115 MWh

Expected System Demand = 205 MWh

The loading order of any generating unit is determined by looking up Table 5.10 with respect to the incremental cost. Thus the 2x10 MW generating unit of system X is to be loaded first. This would be followed by the 2x15 MW generating unit of system Y. Then the 30 MW generating unit of system X and finally the 25 MW generating unit of system Y.



	15	20	25	30
20			1 25 20 10 10	
25	1 15 25 10 10			
30				1 30 30 10 10
35				
40		1 20 40 10 10		

Figure 5.10: Joint PDF of interconnected systems and their first moments of loads and tie line capacity (values to be divided by 4)

The sampling of load in terms of zeroth and first order moments and first order moments of residual tie line capacity of interconnected systems is shown in Figure 5.10. The first, second and third rows of each block shown in Figure 5.10, depict the following:

1. first row is the probability or zeroth moments at $(i, j)th$ position
2. second row is the first moments of load of both systems (system X shown first)
3. third row is the first moments of residual tie line of both systems (system X shown first)

	15	20	25	30
20			1 25 20 10 10	
25	1 20 20 5 15			
30				1 30 30 10 10
35				
40		1 20 40 10 10		

Figure 5.11: Joint PDF of interconnected systems and their first moments of loads and tie line capacity after applying equation (5.19) in Figure 5.10 (values to be divided by 4)

Before the commitment of first generating unit group of system X, the possible export is evaluated using equation (5.19). Only in the (2, 1)*th* block of Figure 5.10, export is possible and that corresponds to the 15 MW of load in system X and 25 MW of load in system Y. At (2, 1)*th* block, 5 MW generation of system X can be exported to system Y. Therefore, using equations (5.23)-(5.24) the modified first moment of load of system X is $(15 + 5)/4 = 20/4$ and that of system Y is $(25 - 5)/4 = 20/4$. Since the system X is exporting and system Y is importing, using equations (5.25)-(5.26) the modified first moment of residual tie line capacity of system X would be $(10 - 5)/4 = 5/4$ and that of system Y would be $(10 + 5)/4 = 15/4$. Figure 5.11 shows the modified moments before convolving the committed generating unit.

The unserved energy before committing any generating unit is evaluated using equation (5.27) considering modified first moments of load, as

$$USE_{1-} = 4 \times (25 + 20 + 30 + 20)/4 = 95 \text{ MWh.}$$

The modified moments in Figure 5.11 has been transferred into one dimension

		1	
		25 20	
		10 10	
1			
20 20			
5 15			
			1
			30 30
			10 10
	1		
	20 40		
	10 10		

Figure 5.12: Transferred one dimensional (row wise) form of modified moments of Figure 5.11 (values to be divided by 4)

i.e. row wise as shown in Figure 5.12. Outage moments of first generating unit group $2 \times 10(0.2)$ MW to be committed are shown in Figure 5.3. Therefore, Figure 5.12 is committed row wise with the generator outage moments in Figure 5.3 using equations (5.12)-(5.15). Figure 5.13 shows the equivalent load and moments after commitment of the generating unit 2×10 MW.

The unserved energy is recalculated from Figure 5.13 using equation (5.27) satisfying the condition in equation (5.31) and is given by

$$\begin{aligned}
 USE_1 &= 4 \times [(16 + 4.8 + 1.8 + 9.6 + 1.6 + 19.2 + 12.8 + 2.0 + 9.6 + 1.6) \\
 &\quad - 20 \times (0.64 + 0.32 + 0.04 + 0.32 + 0.04 + 0.64 + 0.32 + 0.04 \\
 &\quad + 0.32 + 0.04)]/4 \\
 &= 31 \text{ MWh}
 \end{aligned} \tag{5.40}$$

The (2, 1)*th* and (5, 2)*th* blocks of Figure 5.13 do not satisfy the condition given in equation (5.31). For this, they are excluded from equation (5.40). The expected

	15	20	25	30	35	40	45	50
20			0.64 6 12.8 6.4 6.4		0.32 11.2 6.4 3.2 3.2		0.04 1.8 0.8 0.4 0.4	
25	0.64 12.8 12.8 3.2 9.6		0.32 9.6 6.4 1.6 4.8		0.04 1.6 0.8 0.2 0.6			
30				0.64 19.2 19.2 6.4 6.4		0.32 12.8 9.6 3.2 3.2		0.04 2.0 1.2 0.4 0.4
35								
40		0.64 12.8 25.6 6.4 6.4		0.32 9.6 12.8 3.2 3.2		0.04 1.6 1.6 0.4 0.4		

Figure 5.13: Resultant moments after committing 2x10 MW unit with Figure 5.12(values to be divided by 4)

energy generation of first generating unit group of system X using equation (5.32) is,

$$EG_1 = 95 - 31 = 64.0 \text{ MWh.}$$

According to the merit order of loading, now the first generating unit group of system Y is to be committed with the Figure 5.13. Before commitment of these units, possible export from system Y to system X is determined using equations (5.20)-(5.22). It is found that power export is possible in (1,3)th, (1,5)th, (1,7)th, (2,3)th and (2,5)th blocks of Figure 5.13. For this, the moments of Figure 5.13 are modified before committing the generating units using equations (5.23)-(5.26) as shown in Figure 5.14.

	15	20	25	30	35	40	45	50
20			0.64 12.8 16 9.6 3.2		0.32 8 9.6 6.4 0		0.04 1.4 1.2 0.8 0	
25	0.64 12.8 12.8 3.2 9.6		0.32 6.4 9.6 4.8 1.6		0.04 1.2 1.2 0.6 0.2			
30				0.64 19.2 19.2 6.4 6.4		0.32 12.8 9.6 3.2 3.2		0.04 2.0 1.2 0.4 0.4
35								
40		0.64 12.8 25.6 6.4 6.4		0.32 9.6 12.8 3.2 3.2		0.04 1.6 1.6 0.4 0.4		

Figure 5.14: Resultant moments before committing 2x15 MW units of system Y after modification of Figure 5.13 (values to be divided by 4)

The unserved energy before committing generating units 2x15 MW of system Y is evaluated using equation (5.27) considering modified first moments of load given in Figure 5.14 as,

$$\begin{aligned}
 USE_{2-} &= 4 \times (16 + 9.6 + 1.2 + 12.8 + 9.6 + 1.2 \\
 &\quad + 19.2 + 9.6 + 1.2 + 25.6 + 12.8 + 1.6)/4 \\
 &= 120.40 \text{ MWh.}
 \end{aligned}$$

Outage moments of first generating unit group of system Y $2 \times 15(0.2)$ MW to be committed with Figure 5.14 is shown in Figure 5.15. Each row of Figure 5.14 is committed with the generator outage moments in Figure 5.15 using equations (5.12)-(5.15).

The distribution of zeroth moments (equivalent load) and the corresponding first moments after committing 2x15 MW generating unit of system Y is shown in Figure 5.16. The unserved energy is recalculated from Figure 5.16 using equation (5.27) utilizing the condition in equation (5.31) and is given by

Y	0	15	30
m_{0Y}	0.81	0.18	0.01
m_{1Y}	0	15	30

Figure 5.15: Outage moments of first Generator Group of system Y

		0.5184 10.368 12.96 7.776 2.592		0.2592 6.48 12.96 5.184 0.		0.0324 1.134 0.972 0.648 0.	
0.5184 10.368 10.368 2.592 0.0		0.2592 5.184 7.776 3.888 0.		0.0324 0.972 0.972 0.48600 0.			
			0.5184 15.552 15.552 5.184 5.184		0.2592 10.368 7.776 2.592 2.592		0.0324 1.62 .972 0.324 0.324
		0.1152 2.304 4.608 1.728 0.576		0.0576 1.44 2.592 1.152 0		0.0072 0.252 0.324 0.144 0.	
0.1152 2.304 4.032 0.576 5.18	0.5184 10.368 20.736 5.184 5.184	0.0576 1.152 2.592 0.864 0.288	0.2592 7.776 10.368 2.592 2.592	0.0072 0.216 0.324 0.108 0.036	0.0324 1.296 1.296 0.324 0.324		
			0.1152 3.456 5.184 1.152 1.152		0.0576 2.304 2.592 0.576 0.576		0.0072 0.36 0.324 0.072 0.072
		0.0064 0.128 0.352 0.096 0.032		0.0032 0.08 0.192 0.064 0.		0.0004 0.014 0.024 0.008 0.	
0.0064 0.128 0.32 0.032 0.096	0.1152 2.304 6.336 1.152 1.152	0.0032 0.064 0.192 0.048 0.016	0.0576 1.728 3.168 0.576 0.576	0.0004 0.012 0.024 0.006 0.002	0.0072 0.288 0.396 0.072 0.072		
			0.0064 0.194 0.384 0.064 0.064		0.0032 0.128 0.192 0.032 0.032		0.0004 0.02 0.024 0.004 0.004
	0.0064 0.128 0.448 0.064 0.064		0.0032 0.096 0.224 0.032 0.032		0.0004 0.016 0.028 0.004 0.004		

Figure 5.16: Resultant moments after committing 2x15 MW units of system Y with Figure 5.14 (values to be divided by 4)

Table 5.11: Expected Energy Generation and Production Cost vs Tie line Capacity

Tie Cap (MW)	System X			System Y			Gross Results		
	Unit Cap(MW)	Energy Gen. (MWh)	Prod.Cost (US\$)	Unit Cap(MW)	Energy Gen. (MWh)	Prod.Cost (US\$)	EEG (MWh)	EPC (US\$)	USE (MWh)
0	2x10	60.08	304.00	2x15	95.85	575.01	196.19	1182.44	8.81
	30	26.28	183.96	25	13.26	119.38			
10	20	64.00	320.00	30	100.22	601.34	202.00	1195.91	3.00
	30	32.70	229.00	25	5.06	45.57			
20	20	64.00	320.00	30	100.22	601.34	203.11	1201.16	1.89
	30	35.09	245.63	25	3.79	34.18			

$$\begin{aligned}
 USE_2 &= 4 \times [(4.61 + 2.59 + 0.324 + 4.03 + 20.74 + 2.59 + 10.37 + 0.324 + 1.30 \\
 &\quad + 5.184 + 2.59 + 0.324 + 0.35 + 0.19 + 0.025 + 0.324 + 6.34 + 0.19 \\
 &\quad + 3.17 + 0.025 + 0.40 + 0.38 + 0.19 + 0.025 + 0.45 + 0.22 + 0.03) \\
 &\quad - 30 \times (0.1152 + 0.0576 + 0.0072 + 0.1152 + 0.5184 + 0.0576 + 0.2592 \\
 &\quad + 0.0072 + 0.0324 + 0.1152 + 0.0576 + 0.0072 + 0.0064 + 0.0032 \\
 &\quad + 0.0004 + 0.0064 + 0.1152 + 0.0032 + 0.0576 + 0.0004 + 0.0072 \\
 &\quad + 2 \times (0.0064 + 0.0032 + 0.0004)]/4 \\
 &= 66.276 - 30 \times 1.57 = 20.176 \text{ MWh}
 \end{aligned} \tag{5.41}$$

The blocks of first three rows in Figure 5.16 do not satisfy equation (5.31). For this, these blocks are excluded from equation (5.41). The expected energy generation of first generating unit group of system Y using equation (5.32) is,

$$EG_2 = 120.40 - 20.176 = 100.224 \text{ MWh.}$$

In a similar way, the remaining generating units (next 30 MW of system X and lastly 25 MW unit of system Y) are committed and the expected energy generation, production costs of them are evaluated as shown in Table 5.11.

5.4.8 Numerical Evaluation

This section applies the proposed approach to a prototype generating systems provided by the Reliability Test System Task Force of the IEEE Power Engineering Ap-

plication of Probabilistic Methods Subcommittee [40]. The first system is a slightly modified IEEE-RTS [40] with an installed capacity of 3400 MW as given in Table C.8 of Appendix C. The second system is a hypothetical system with installed capacity of 3150 MW [75] as given in Table C.9 of Appendix C.

For the load model, the IEEE Reliability Test System IEEE-RTS hourly load data is used. For system X thirteen winter weeks (48-52 & 1-8 weeks) with a peak load of 2850 MW and for system Y thirteen summer weeks (18-30 weeks) with a peak load of 2565 MW are considered. Calculations are performed on an hourly basis and added over the 2184 hours under consideration. Note that the expected energy demand for the system X and Y are 4163.48031 and 3964.14302 GWh respectively. The total expected energy demand of both systems is 8127.623 GWh. In the proposed method, the process of load sampling with a lower value of step size avoids the sampling error.

Evaluated expected energy generation and production cost of each type of generating unit based on a numerical integration with a step of 5 MW is given in Table 5.12 for 300 MW tie line capacity. The loading order as specified in this table is obtained from the average incremental cost (λ) of each type of generating unit. Total expected energy and production costs of each system for different tie line capacity are given in Table 5.13. Figure 5.17 shows that expected energy generation of system X increases with the increase in tie line capacity whereas expected energy generation of system Y decreases. Rate of change of expected energy generation with tie line capacity in system X is more than the reduction rate of that of system Y. However, overall energy generation of interconnected system increases with tie line capacity. The increased energy generation contributes to decrease the unserved energy of both systems. The unserved energy and excess energy generation of the global system for various tie line capacity is shown in Figure 5.18.

The expected energy generation and production cost evaluated using different methods are compared and given in Table 5.14. Figure 5.19 shows the production cost of individual and global system. It may be noted from Figure 5.19 that the rate of change of expected production cost of system X with tie line capacity is less than reduction rate of that of system Y. A saving in global production cost is also shown in Figure 5.19. Figure 5.20 shows this effect clearly and also shows the cause

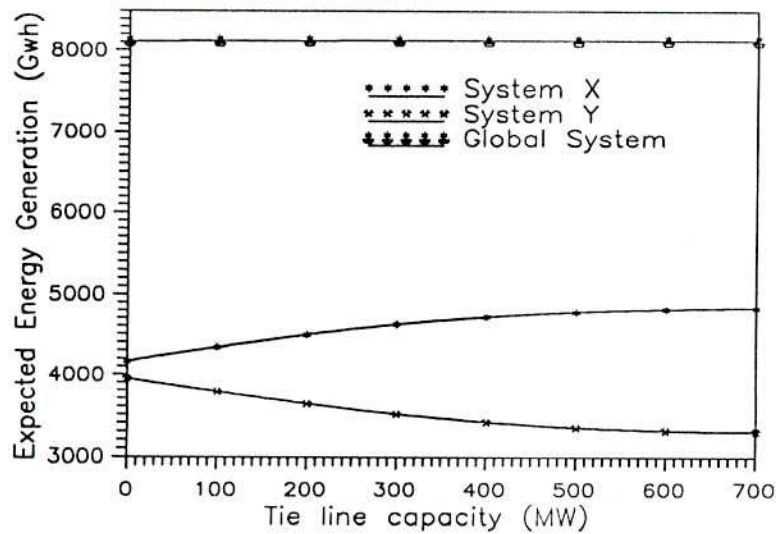


Figure 5.17: Expected energy generation vs Tie line capacity

of reduction of production cost of global system. However, savings rate decreases with the increase in tie line capacity of interconnected system. Table 5.15 shows the results tested by proposed method at different step size. This approach may be considered exact because of its zero energy balance.

The proposed algorithm is implemented on the ALPHA DEC AXP-3000 MODEL-400 in FORTRAN 77. Comparison of computational requirement is presented in Table 5.16 for step size of 5x5 and 10x10 MW. Figures 5.21 and 5.22 show the comparison of computational time using proposed approach at different step size. It is noted that the proposed approach is very fast.

5.5 Conclusions

This chapter presents two new approaches to evaluate the expected energy generation, expected unserved energy, and production cost for single area and interconnected power generating system. These are not restricted to load duration curves

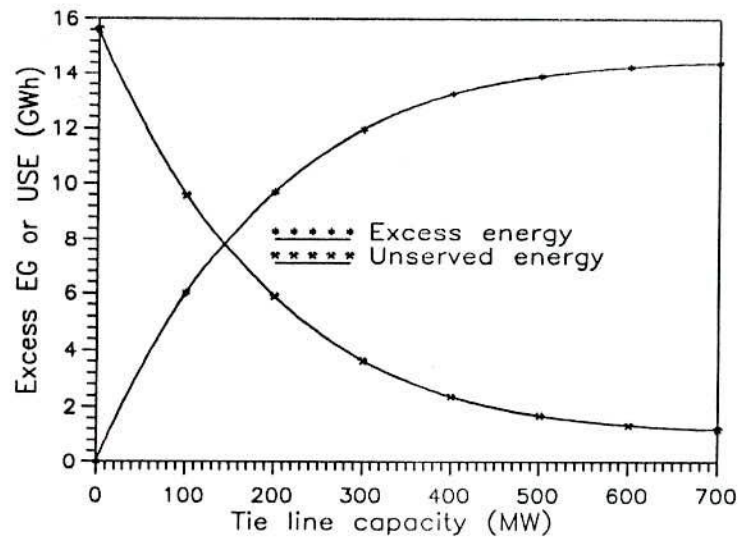


Figure 5.18: Variation of Excess energy generation and Unserved energy with Tie line capacity

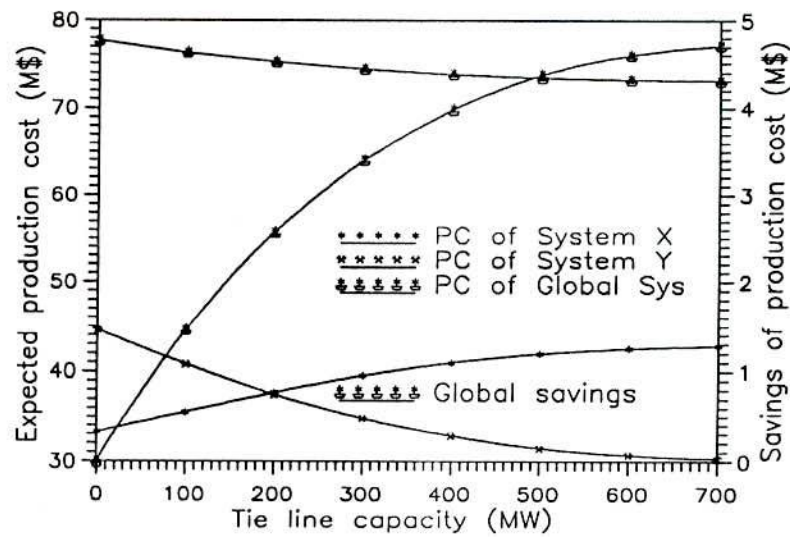


Figure 5.19: Variation of Expected production cost with Tie line capacity

Table 5.12: Expected energy generation and production cost of each type of unit for tie line capacity = 300 MW

System X				
Unit Type	Unit Cap(MW)	No.of Unit	Expected Energy Generation (GWh)	Production Cost (M\$)
Hydro	50	6	648.69250	0.00000
Nuclear	400	2	1537.43481	8.59733
Coal	150	4	1241.10119	13.85068
Coal	350	1	564.69244	6.43749
Coal	80	4	358.42401	5.33406
Oil	200	3	239.57627	4.76038
Oil	100	3	25.19046	0.50582
Oil	10	5	1.78617	0.05100
Oil	20	4	0.32071	0.01202
System Y				
Hydro	100	2	648.69152	0.00000
Nuclear	500	1	950.07452	4.27533
Coal	400	2	1234.53320	17.65382
Coal	350	1	347.05343	5.24050
Coal	250	1	208.74003	3.88256
Oil	350	1	79.66856	2.42192
Oil	200	2	33.02587	1.15590
Oil	50	4	4.98061	0.21516

Table 5.13: Expected energy generation and production cost of individual and interconnected system

Tie Cap (MW)	EEG (GWh)			USE (GWh)	EPC(M\$)		
	System X	System Y	Global		System X	System Y	Total
0	4162.57	3949.44	8112.00	15.62	33.21	44.58	77.79
100	4333.13	3784.90	8118.04	9.59	35.5	40.80	76.33
200	4488.29	3633.43	8121.72	5.91	37.71	37.51	75.21
300	4617.27	3506.77	8123.99	3.64	39.55	34.85	74.39
400	4715.86	3409.38	8125.24	2.38	40.98	32.83	73.81
500	4780.78	3345.14	8125.92	1.71	41.96	31.46	73.42
600	4815.29	3310.97	8126.27	1.36	42.51	30.69	73.19
700	4829.94	3296.49	8126.42	1.20	42.77	30.31	73.08

Table 5.14: Comparison of Expected Energy Generation and Production Costs

Tie Cap (MW)	Expected Energy Generation (GWh)		Expected Production Cost (M\$)	
	Segmentation Method	Proposed Method	Segmentation Method	Proposed Method
00	8112.00390	8112.00439	77.79244	77.79246
100	8118.03710	8118.03759	76.33306	76.33306
200	8121.71337	8121.71533	75.21439	75.21439
300	8124.02197	8123.98583	74.39455	74.39405
400	8125.28613	8125.23876	73.80741	73.80667
500	8125.97998	8125.91748	73.41879	73.41774
600	8126.33300	8126.26806	73.19331	73.19224
700	8126.48925	8126.42285	73.07747	73.07634

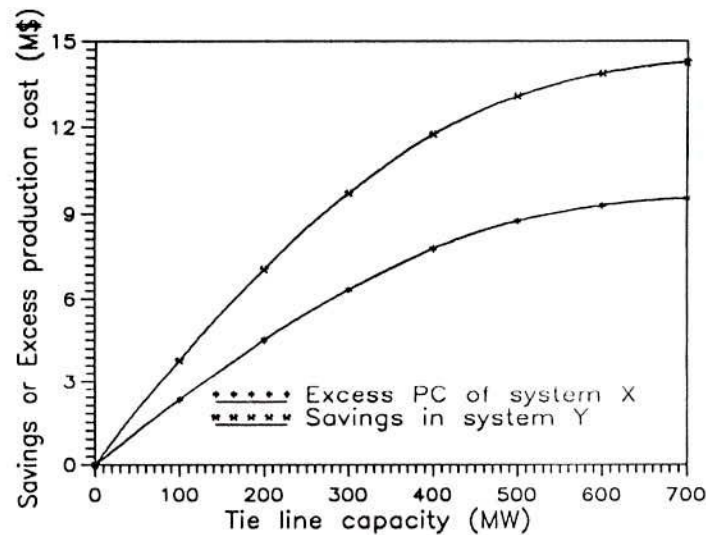


Figure 5.20: Savings and Excess production cost vs Tie line capacity

Table 5.15: Over all results at different step size

Tie Cap (MW)	Exp. Energy Generation (GWh)		Exp. Production cost (M\$)	
	Step Size	Step Size	Step Size	Step Size
	5x5	10x10	5x5	10x10
0	8112.00439	8112.25537	77.79246	77.79672
100	8118.03759	8118.29541	76.33306	76.33744
200	8121.71533	8122.00976	75.21439	75.21934
300	8123.98583	8124.24316	74.39405	74.39849
400	8125.23876	8125.52880	73.80667	73.81175
500	8125.91748	8126.24169	73.41774	73.42339
600	8126.26806	8126.61230	73.19224	73.19823
700	8126.42285	8126.79003	73.07634	73.08273

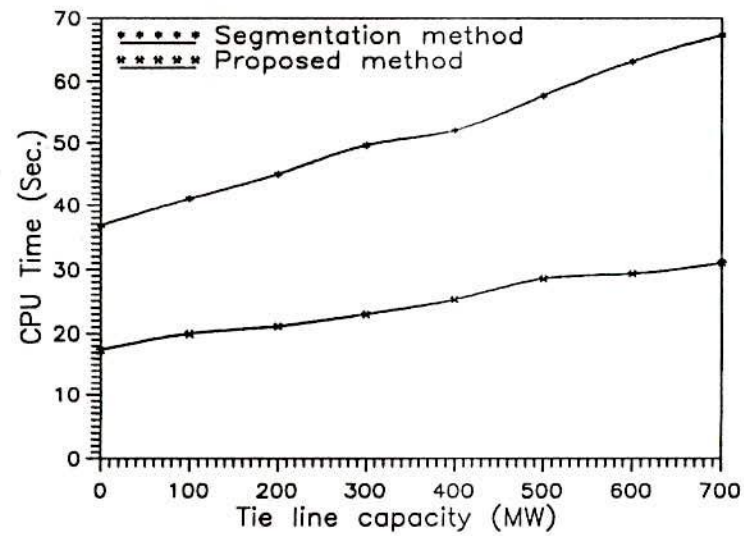


Figure 5.21: Comparison of CPU time with Tie line capacity at 5×5 step size

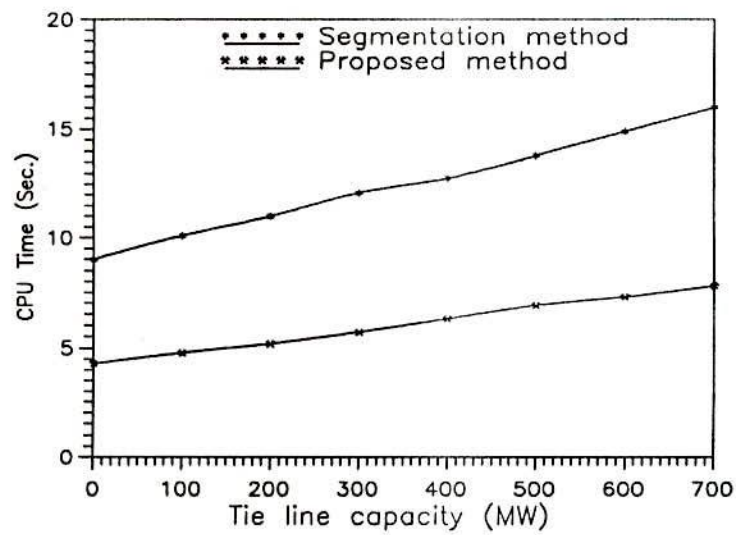


Figure 5.22: Comparison of CPU time with Tie line capacity at 10×10 step size

Table 5.16: Comparison of CPU time (Sec.)

Tie Cap (MW)	5x5 step size		10x10 step size	
	Segmentation method	Proposed method	Segmentation method	Proposed method
0	36.8	17.4	9.0	4.3
100	41.1	20.0	10.1	4.8
200	45.2	21.1	11.0	5.2
300	49.7	23.0	12.1	5.7
400	52.1	25.3	12.8	6.3
500	57.8	28.6	13.8	6.9
600	63.2	29.4	14.9	7.3
700	67.3	31.1	16.0	7.8

and unit outage density function of any shapes, or size of the systems and are efficiently applicable to systems having a large number of generation units. Multiple generating units with same outage behavior are efficiently committed with system demand. The accuracy of the method has been illustrated using an example and IEEE-RTS. Application of the proposed approach to a practical system for its future expansion plan is also given. In both approaches, no explicit approximation has been made, apart from that arising from the discretization of continuous function which is necessary for any digital computer application. These methods are found efficient and easy to apply in comparison to the existing methods.

Chapter 6

UNCERTAINTY ANALYSIS

So far as the laws of mathematics refer to reality, they are not certain.

And so far as they are certain, they do not refer to reality.

—Albert Einstein

6.1 Introduction

The Power system parameters used for generation system reliability evaluation play an important role in the determination of the adequacy of power supply. Most of these parameters are subjected to uncertainty, because, these are calculated from field data which is usually collected over a certain period of time. If such a period is short, the values assigned to these parameters may differ considerably from the true but unknown values. The limited amount of data therefore constitutes the basic source of uncertainty associated with these parameters. Variations in the values of these parameters may also be caused by the environment in which the component operates.

An additional source of uncertainty is the change of parameter with age and lack of statistics regarding additions of new components. The difference in operating policy of a system may also have some influence on the values of its parameters. In addition, a further major source of uncertainty is the prediction of future performance or events. Uncertainty in load forecasting, for example, is due to the

complex nature of the interaction between future physical, economic and sociological demands.

A power system is normally designed so that the intended goals and objectives can be attained in the most economic manner with an acceptable level of reliability. The determination of an acceptable level of reliability is a difficult problem. In principle, the quality of service could be determined using standards that contain measures of reliability. In practice, however, such standards are difficult to establish. Considerations involved would range from customer's satisfaction to extra cost or profits attributable to the alternative arrangement; often these factors can not be evaluated satisfactorily. In the majority of cases, it is essential to rely on history and experience to establish acceptable levels of reliability.

It should be noted that an acceptable level of reliability can be achieved through a sequence of considerations such as reliable components and adequate design and operation. Each of these considerations contributes to the system performance when the system is put into operation. System performance is normally characterized by a set of indices which can be expressed in terms of the basic system parameters involved. These indices of reliability provide a criterion by which different alternatives can be compared and allow for the consideration of uncertainty in the planning process. System performance indices based on single value (crisp value) best-estimates of the parameters involved, are not sufficient when making decisions under uncertain conditions. Fuzzy performance indices, on the other hand, reflect the generic uncertainty in system parameters and can be used more adequately in those situations where judgments are made under uncertainty.

In case of power generation systems, reliability is evaluated from the availabilities of generating units, forecasted loads and unit incremental costs. A large amount of uncertainty is implicit in the availability of units and forecasted loads. It is often very difficult to evaluate the probability of many failures since they have never occurred before, in which case classical statistics does not help very much [205]. The uncertainty in the availability of generating units is caused by the influence of failure data, variation due to different reporting sources, variation in application and fluctuation in environmental conditions, etc., if they are not due to erroneous modelling. Uncertainty in load forecasting is due to the stochastic nature of consumers,

variations in weather forecasting, and fluctuations in environmental conditions, etc.

Considerable work has been done on treating the uncertain nature of forecasted load and generator FOR (forced outage rate) in LOLP evaluation using probabilistic methods [62, 127, 128, 132, 133, 134, 137, 140]. In 1975, Patton and Stasinou [127] recognized the uncertain nature of generating units' forced outage rates in LOLP evaluation. They treated FORs as random variables with specified mean and variance. Wang [128] presented an analysis of variation of system LOLP due to uncertainties in the estimated forced outage rates of generating units and the forecasted peak loads. Patton [36], in 1978, gave a sensitivity analysis for the treatment of generator parameter uncertainty in the calculation and use of system reliability indices. Fourier transform techniques have been utilized in probabilistic modelling by Hamoud and Billinton [132] for evaluating the significance of uncertainty associated with system parameters on the LOLP. Further, the frequency and duration approach was used by the authors [133, 134] to study the effect of parameters' uncertainty on system reliability. Anders [62] in 1983, also proposed a similar type of method.

Further, Mazumdar and Yin found in their paper that the utility decisions based on the mean value only might mislead in expansion planning [135]. The method developed by Mazumdar and Yin has been extended by Feng et al. [137] utilizing load duration curve and equivalent unit concepts. Hoffer and Dorfner [138] also have modelled the uncertainty effects of peak loads forecast on reliability and production cost through probabilistic approach. These methods are unable to solve *optimistic and pessimistic* LOLPs simultaneously using uncertain or imprecise system parameters. The imprecisions of system parameters can be best modelled using fuzzy set theory.

In most cases, the analyst who knows very much about system functions and its failure characteristics is not familiar with mathematical statistics and can express the knowledge only in a colloquial language. It is now well known that conventional reliability analysis using probability concepts alone is not adequate to treat such imprecise system performance data. Thus, it has become necessary to develop a new kind of formulation to capture the subjectivity and imprecision of failure data for use in reliability analysis. Fuzzy set theory provides a powerful approach for this

kind of problems.

Fuzzy set theory is another research area which is receiving increased attention lately. The pioneering work of Zadeh [129] in fuzzy set theory has inspired works in many research areas with excellent results. Fuzzy systems have been successfully applied in process control, system identification and pattern recognition [198]. In power systems, fuzzy set theory have also been applied in many diverse areas like transient stability evaluation, optimal power flow and dynamic dispatch [136, 141]. However, application of fuzzy set theory for the evaluation of uncertainty in the generation expansion planning is still relatively new and not much have been published in this area.

In this chapter, a new model is developed to evaluate the impact of uncertain system parameters on the reliability index using fuzzy set techniques. The proposed approach is demonstrated through a prototype large generation system of practical size. A major importance of this approach is that it provides *optimistic* as well as *pessimistic* values of the derived quantities, corresponding to the assumptions of the highest and lowest *possibilities* of concerned events. In many cases, these bounds provide excellent guidelines to generation expansion planners. In addition, an attempt is made to see to what extent some of the results found in chapters 3 are affected using new technique. For this, the results obtained are defuzzified to compare with the results obtained using probabilistic models. The model developed in this chapter, has also been implemented on an electric utility to study the effect of uncertainty of system parameters on system reliability.

6.2 Mathematical Modelling

A linguistic declaration such as *peak value will surely not occur below 19 or above 26 MW and the optimistic estimate is say between 20 and 25 MW* is the representation of uncertain forecasted system demand. The uncertain load is represented by a fuzzy number (FN) which is in fact a membership function over the real set. Fuzzy numbers may have variety of shapes (trapezoidal, triangular). But, the linguistic declared uncertain load can only be represented by trapezoidal shape membership function properly as per the declaration rather triangular function. Therefore, the

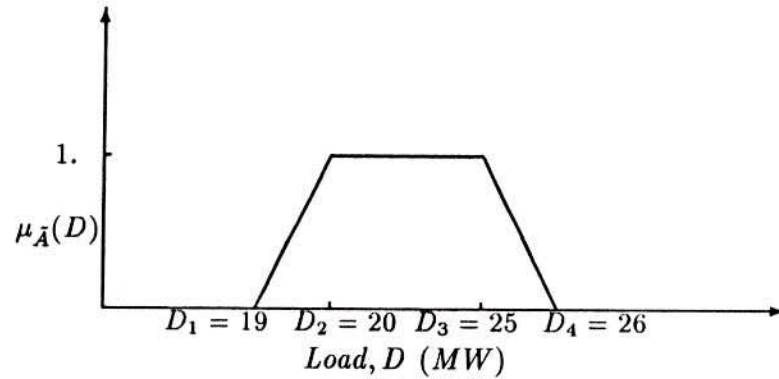


Figure 6.1: Trapezoidal shape Fuzzy number representing a qualitative linguistic load

uncertain load is translated into a trapezoidal shape fuzzy membership function as shown in Figure 6.1 [136, 139]. Similarly, the fuzzy numbers of generation outage can also be represented by a trapezoidal shape membership function. The possibility distribution of any uncertain quantity can easily be expressed by fuzzy number and these set of data can also be operated by extended fuzzy arithmetics. The method has the unique advantages of simplicity for ascertaining the uncertainties in the final results.

Therefore, the system demands, forced outage rates (FORs) and unit capacities are considered trapezoidal shape fuzzy membership function for uncertainty analysis. The concept of fuzzy algebra used in the modelling is briefly discussed in Appendix D.

6.2.1 Fuzzy Loads, Capacity and FOR

The trapezoidal shape fuzzy number representation of forecasted load parameter is shown in Figure 6.1. This fuzzy number of load $\tilde{D}$ is usually represented by breaking points:

$$\tilde{D} = (D_1, D_2, D_3, D_4) \quad (6.1)$$

Similarly, the elementary fuzzy data of the other parameters like forced outage

rate (FOR) and unit capacity are represented by

$$\begin{aligned}\tilde{F} &= (F_1, F_2, F_3, F_4) \\ \tilde{C} &= (C_1, C_2, C_3, C_4)\end{aligned}$$

The breaking points of trapezoidal fuzzy number of load in equation (6.1) can be transferred into $L - R$ representation of fuzzy numbers such as [207],

$$D_{LR} = (D_2, D_3, d_2, d_3)_{LR} \quad (6.2)$$

where d_2 and d_3 are the spreads of D_2 and D_3

and they are evaluated by $d_2 = (D_2 - D_1)$ and $d_3 = (D_4 - D_3)$.

Similarly the $L - R$ representations of other parameters will be

$$\begin{aligned}\tilde{F}_{LR} &= (F_2, F_3, f_2, f_3)_{LR} \\ \tilde{C}_{LR} &= (C_2, C_3, c_2, c_3)_{LR}\end{aligned}$$

6.2.2 Fuzzy Capacity Outage Table

The fuzzy capacity outage table is developed to produce the reliability indices from the combination of fuzzy unit outages C_{LR} and F_{LR} using the following $L - R$ type fuzzy addition, subtraction and multiplication relations in the recursive process [203].

$$\begin{aligned}(A, B, a, b) \oplus (C, D, c, d) &= (A + C, B + D, a + c, b + d) \\ (A, B, a, b) \ominus (C, D, c, d) &= (A - D, B - C, a + d, b + c) \\ (A, B, a, b) \odot (C, D, c, d) &= (A.C, B.D, A.c + C.a, B.d + D.b)\end{aligned} \quad (6.3)$$

Consider two fuzzy random variables $\tilde{Y}$ and

$$\begin{aligned} \tilde{Y}[\tilde{Y}_1, \tilde{Y}_2] & \quad \tilde{P}_Y[\tilde{P}_{Y_1}, \tilde{P}_{Y_2}] \\ \tilde{Z}[\tilde{Z}_1, \tilde{Z}_2] & \quad \tilde{P}_Z[\tilde{P}_{Z_1}, \tilde{P}_{Z_2}]. \end{aligned}$$

In which,

$$\begin{aligned} \tilde{Y}_1 &= (Y_{12}, Y_{13}, y_{12}, y_{13})_{LR} & \tilde{P}_{Y_1} &= (P_{Y_{12}}, P_{Y_{13}}, p_{y_{12}}, p_{y_{13}})_{LR} \\ \tilde{Y}_2 &= (Y_{22}, Y_{23}, y_{22}, y_{23})_{LR} & \tilde{P}_{Y_2} &= (P_{Y_{22}}, P_{Y_{23}}, p_{y_{22}}, p_{y_{23}})_{LR} \\ \tilde{Z}_1 &= (Z_{12}, Z_{13}, z_{12}, z_{13})_{LR} & \tilde{P}_{Z_1} &= (P_{Z_{12}}, P_{Z_{13}}, p_{z_{12}}, p_{z_{13}})_{LR} \\ \tilde{Z}_2 &= (Z_{22}, Z_{23}, z_{22}, z_{23})_{LR} & \tilde{P}_{Z_2} &= (P_{Z_{22}}, P_{Z_{23}}, p_{z_{22}}, p_{z_{23}})_{LR}. \end{aligned}$$

Other parameters may also be defined similar to above four terms. The fuzzy capacity outage table would be developed in what follows.

Fuzzy capacity outage	Fuzzy outage probabilities
$\tilde{Y}_1 \oplus \tilde{Z}_1$	$\tilde{P}_{Y_1} \odot \tilde{P}_{Z_1}$
$\tilde{Y}_1 \oplus \tilde{Z}_2$	$\tilde{P}_{Y_1} \odot \tilde{P}_{Z_2}$
$\tilde{Y}_2 \oplus \tilde{Z}_1$	$\tilde{P}_{Y_2} \odot \tilde{P}_{Z_1}$
$\tilde{Y}_2 \oplus \tilde{Z}_2$	$\tilde{P}_{Y_2} \odot \tilde{P}_{Z_2}$

Consider two independent fuzzy random variables $\tilde{Y}$ and $\tilde{Z}$ represent two generating units. $\tilde{P}_Y$ and $\tilde{P}_Z$ are their corresponding fuzzy probabilities. Using equation (6.3) and substituting the values of each elements, a fuzzy capacity outage table is developed. The developed capacity outage table is the resultant fuzzy random variable $\tilde{X}_{LR}$ of two generating units as follows;

Fuzzy capacity outage random variable, $\tilde{X}_{LR}$	Fuzzy outage probabilities $\tilde{P}_{LR}$
$(X_{12}, X_{13}, x_{12}, x_{13})_{LR}$	$(P_{12}, P_{13}, p_{12}, p_{13})_{LR}$
$(X_{22}, X_{23}, x_{22}, x_{23})_{LR}$	$(P_{22}, P_{23}, p_{22}, p_{23})_{LR}$
$(X_{32}, X_{33}, x_{32}, x_{33})_{LR}$	$(P_{32}, P_{33}, p_{32}, p_{33})_{LR}$
$\vdots$	$\vdots$

The i th element of fuzzy random variable $\tilde{X}_{LR}$ and its corresponding fuzzy probabilities is represented as,

$$\begin{aligned} \tilde{X}_{iLR} &= (X_{i2}, X_{i3}, x_{i2}, x_{i3})_{LR}, \\ \tilde{P}_{iLR} &= (P_{i2}, P_{i3}, p_{i2}, p_{i3})_{LR} \end{aligned} \quad (6.4)$$

where, $\tilde{X}_{iLR}$ is an element of fuzzy random variable $\tilde{X}_{LR}$ and $\tilde{P}_{iLR}$ is fuzzy probability corresponding the element.

6.2.3 Fuzzy $\tilde{LOLP}$ Evaluation

The fuzzy loss of load probability $\tilde{LOLP}$, is evaluated from the fuzzy inequality relation for any fuzzy load, for the insufficient reserve capacity from fuzzy capacity outage random variable,

$$\begin{aligned} \tilde{LOLP}_{LR} &= Pr(\tilde{X}_{LR} \tilde{>} R\tilde{C}_{LR}) \\ &= \sum \mu_i P_i(\tilde{X}_{LR} \tilde{>} R\tilde{C}_{LR}) \end{aligned} \quad (6.5)$$

where,

$R\tilde{C}_{LR}$ = fuzzy reserve capacity

and $\tilde{X}_{LR}$ = fuzzy capacity outage random variable

The fuzzy reserve capacity $R\tilde{C}_{LR}$ of equation (6.5) is evaluated using the fuzzy subtraction of fuzzy installed capacity $I\tilde{C}_{LR}$ and fuzzy system load $D\tilde{L}_{LR}$ by

$$R\tilde{C}_{LR} = I\tilde{C}_{LR} \ominus D\tilde{L}_{LR} \quad (6.6)$$

$$= (IC_2, IC_3, ic_2, ic_3)_{LR} \ominus (D_2, D_3, d_2, d_3)_{LR}$$

$$R\tilde{C}_{LR} = (RC_2, RC_3, rc_2, rc_3) \quad (6.7)$$

The membership values μ_i in equation (6.5) are evaluated by comparing $R\tilde{C}_{LR}$ with fuzzy random variable $\tilde{X}_{LR}$ using fuzzy event inequality relation given in equation (6.8).

$$\mu_i = \begin{cases} 1 & \text{if } X_{i3} + x_{i3} \geq RC_3 + rc_3 \\ \frac{(X_{i2} - x_{i2} - RC_2 + rc_2)}{(X_{i2} - x_{i2} - RC_2 + rc_2) + (RC_3 + rc_3 - X_{i3} - x_{i3})} & \text{if } X_{i3} + x_{i3} < RC_3 + rc_3 \\ & \text{and } X_{i2} - x_{i2} > RC_2 - rc_2 \\ 0 & \text{if } X_{i2} - x_{i2} \leq RC_2 - rc_2 \end{cases} \quad (6.8)$$

Hence, the fuzzy $LO\tilde{L}P_{LR}$ of equation (6.5) can be rewritten utilizing the above relationships.

$$LO\tilde{L}P_{LR} = \sum \mu_i \cdot \tilde{P}_{iLR} \quad (6.9)$$

or,

$$\begin{aligned} LO\tilde{L}P_{LR} &= (\sum \mu_i \cdot P_{i2}, \sum \mu_i \cdot P_{i3}, \sum \mu_i \cdot p_{i2}, \sum \mu_i \cdot p_{i3}) \\ &= (m, n, \alpha, \beta) \end{aligned}$$

where, $m = \sum \mu_i \cdot P_{i2}$, $n = \sum \mu_i \cdot P_{i3}$, $\alpha = \sum \mu_i \cdot p_{i2}$ and $\beta = \sum \mu_i \cdot p_{i3}$.

Comparison of fuzzy reserve capacity and fuzzy capacity outage random variables provide fuzzy $LO\tilde{L}P$. The evaluated LOLP will be a possibility distribution function. In this possibility distribution, m & n are known as left and right mean values and α & β are their spreads. That is,

$$LO\tilde{L}P_{LR} = (LOLP_L, LOLP_R, spread_L, spread_R)_{LR} \quad (6.10)$$

Intermediate $LO\tilde{L}P_{LR}$

From these $L-R$ type fuzzy $LO\tilde{L}P_{LR}$ values, the intermediate credibility of $LO\tilde{L}P$, may be evaluated. For any credibility level $0 < \omega < 1$,

$$\begin{aligned} LO\tilde{L}P_L &= L(\omega) \\ &= \max\{0, m - |(1 - \omega)\alpha|\} \end{aligned} \quad (6.11)$$

$$\begin{aligned} \text{and, } LO\tilde{L}P_R &= R(\omega) \\ &= \max\{0, n + |(1 - \omega)\beta|\} \end{aligned} \quad (6.12)$$

Defuzzification of $LO\tilde{L}P_{LR}$

In principle, the system can use the entire trapezoidal shape fuzzy distribution as the output. But, the single valued scalar results are necessary to compare the outputs. Therefore, the trapezoidal shape fuzzy results have to be converted into a single scalar output values. The conversion process of fuzzy results into single valued scalar results is known as *defuzzification*.

The output fuzzy number is usually defuzzified to generate an exact numerical output. The more popular defuzzification technique in the trapezoidal shape fuzzy distribution is the centroid or center of mass of trapezoid. The centroid of trapezoidal distribution is computed in what follows.

$$LOLP = \frac{m+n}{2} + \frac{\beta-\alpha}{4} \quad (6.13)$$

6.2.4 Computational Steps

- Step 1: Read the PDF of capacity outages of all type of generating units.
- Step 2: Develop capacity outage table using the procedure discussed in section 6.2.2.
- Step 3: Read peak loads of the system.
- Step 4: Evaluate reserve capacity of the system using equation (6.7).
- Step 5: Evaluate the membership values correspondent to each element of capacity outage using equation (6.8).
- Step 6: Calculate $LO\tilde{L}P$ for each peak load of the system using equation (6.9).
- Step 7: Repeat step 3 to step 6 till $LO\tilde{L}Ps$ for all the peak loads computed.
- Step 8: Evaluate the system $LO\tilde{L}P$ from the average of all $LO\tilde{L}P$ found from each peak load.
- Step 9: Compute $LO\tilde{L}Ps$ at different credible level using equations (6.11)-(6.12).
- Step 10: Defuzzify fuzzy $LO\tilde{L}Ps$ found in step 8 using equation (6.13).

Table 6.1: Hourly fuzzy Load data of small system

Hour	(Fuzzy Load data) _{LR}
1	(18., 22. , 1., 1.)
2	(22.5, 27.5 , 1. , 1.)
3	(27. , 33. , 1. , 1.)
4	(13.5, 16.5, 1. , 1.)

Table 6.2: Fuzzy generation data of small system

No. of Units	Fuzzy FORs (L-R type)	Fuzzy Capacity (MW) (L-R type)
2	(0.18, 0.22, 0.02, 0.03)	(10., 15., 1., 1.)
1	(0.08, 0.10, 0.03, 0.05)	(25., 30., 1., 1.)
3	Total capacity = (45., 60., 3., 3.)	

6.2.5 Example

The computational steps of the proposed approach are described with the help of an example of a generating system in what follows.

Consider $L - R$ representation of fuzzy data of hourly system demands and generating units as shown in Table 6.1 and Table 6.2 respectively.

The fuzzy capacity outage table shown in Table 6.3 of the generation system is developed using extended fuzzy arithmetic model described in section 6.2.2.

Using equation (6.3) and (6.6), the fuzzy reserve capacity,

$$RC_{LR} = IC_{LR} \ominus D_{LR}$$

The fuzzy reserve capacity of first hour load is,

$$\begin{aligned}
 RC_{1LR} &= (45., 60., 3., 3.) \ominus (18., 22., 1., 1.) \\
 &= (23., 42., 4., 4.)
 \end{aligned} \tag{6.14}$$

Table 6.3: Fuzzy capacity outage table with their probabilities.

Fuzzy Cap. Outage (L-R type)	Fuzzy Outage Probabilities (L-R type)
(0., 0., 0., 0.)	(0.5475599, 0.618608, 0.072540, 0.050348)
(10., 15., 1., 1.)	(0.2527200, 0.331936, 0.051840, 0.064184)
(20., 30., 2., 2.)	(0.0291600, 0.044528, 0.008100, 0.013596)
(25., 30., 1., 1.)	(0.0486720, 0.067240, 0.021996, 0.036900)
(35., 45., 2., 2.)	(0.0224640, 0.036080, 0.011784, 0.023840)
(45., 60., 3., 3.)	(0.0025920, 0.004840, 0.001548, 0.003740)

This reserve capacity is compared with the fuzzy capacity outage table using the fuzzy inequality relations given in equation (6.8) to evaluate the membership values to be used in equation (6.9). From equation (6.14),

$$RC_3 + rc_3 = 42 + 4 = 46 \text{ MW and } RC_2 - rc_2 = 23 - 4 = 19 \text{ MW.}$$

First element of fuzzy capacity outage random variable,

$$X_1 = (0., 0., 0., 0.)_{LR}.$$

That is $X_{13} + x_{13} = 0. + 0. = 0. \text{ MW}$ and $X_{12} - x_{12} = 0. - 0. = 0. \text{ MW}$.

Therefore, $X_{12} - x_{12} < RC_2 - rc_2 = 23 - 4 = 19$.

and, $\mu_1 = 0$. from equation (6.8).

Similarly, the evaluated membership values for second and third elements are $\mu_2 = 0.$, $\mu_3 = 0$.

The fourth element of fuzzy capacity outage random variable,

$$X_4 = (25., 30., 1., 1.)_{LR}.$$

That is $X_{43} + x_{43} = 30. + 1. = 31. \text{ MW}$ and $X_{42} - x_{42} = 25. - 1. = 24. \text{ MW}$.

Therefore, $X_{12} - x_{12} > RC_2 - rc_2 = 23 - 4 = 19$

and $X_{13} + x_{13} < RC_3 + rc_3 = 42 + 4 = 46$.

Then, from equation (6.8)

$$\mu_4 = \frac{(X_{42} - x_{42} - RC_2 + rc_2)}{(X_{42} - x_{42} - RC_2 + rc_2) + (RC_3 + rc_3 - X_{43} - x_{43})}$$

$$\begin{aligned}
&= \frac{24 - 19}{(24 - 19) + (46 - 31)} \\
&= 0.25
\end{aligned}$$

In case of fifth and sixth elements of fuzzy capacity random variable,

$$X_{53} + x_{53} > RC_3 + rc_3 = 46 \text{ and } X_{63} + x_{63} > RC_3 + rc_3 = 46.$$

Hence, $\mu_5 = 1.$ and $\mu_6 = 1.$ from equation (6.8).

Therefore, the fuzzy $LOLP$ for the load of first hour is evaluated using equation (6.9).

$$\begin{aligned}
LOLP_{1LR} &= 0.25(0.048672, 0.06724, 0.021996, 0.0369)_{LR} \\
&\oplus 1.(0.022464, 0.03608, 0.011784, 0.02384)_{LR} \\
&\oplus 1.(0.002592, 0.00484, 0.001548, 0.00374)_{LR} \\
&= (0.03724, 0.0773, 0.018831, 0.036805)_{LR}
\end{aligned}$$

Similarly, the evaluated membership values and fuzzy $LOLP$ of remaining hourly loads are;

Hour	μ_1	μ_2	μ_3	μ_4	μ_5	μ_6
2	0.	0.	0.3214286	0.5	1.	1.
3	0.	0.04455	0.66667	0.727273	1.	1.
4	0.	0.	0.	0.	0.7083333	1.

$$\begin{aligned}
LOLP_{2LR} &= (0.058765, 0.088853, 0.026934, 0.0504)_{LR} \\
LOLP_{3LR} &= (0.091381, 0.134595, 0.037085, 0.066398)_{LR} \\
LOLP_{4LR} &= (0.018504, 0.030397, 0.009895, 0.020627)_{LR}
\end{aligned}$$

The overall fuzzy $LOLPs$ is given by,

$$LOLP_{LR} = \frac{1}{NH} \sum_i LOLP_{iLR}$$

where NH = Number of hours and $i[1, NH]$

Therefore,

$$LOLP_{LR} = (0.051468, 0.077894, 0.023186, 0.043557)_{LR}$$

The first and second values of fuzzy $LO\tilde{L}P$ s represent the left and right mean of $LO\tilde{L}P$ and, third and forth values are their spreads. The limit of $LO\tilde{L}P$ for $\mu(LO\tilde{L}P_{LR}) = 1$ represents the optimistic LOLP and the same for $\mu(LO\tilde{L}P_{LR}) = 0$ is pessimistic. The confidence level depends on the planning engineer known as credibility level ω . Therefore, the desired credibility level is necessary to determine for decision making planner. The $LO\tilde{L}P_{LR}$ for the intermediate credibility level $\omega = 0.5$, are evaluated using equations (6.11) and (6.12).

$$\begin{aligned}
 LO\tilde{L}P_L &= L(0.5) \\
 &= \max\{0, 0.051468 - (1 - 0.5)0.023186\} \\
 &= \max(0, 0.039875) \\
 \text{or, } LO\tilde{L}P_L &= 0.039875 \\
 \text{and, } LO\tilde{L}P_R &= R(0.5) \\
 &= \max\{0, 0.077894 + (1 - 0.5)0.043557\} \\
 LO\tilde{L}P_R &= 0.0996725
 \end{aligned}$$

The defuzzified LOLP is evaluated using equation (6.13).

$$\begin{aligned}
 \text{Defuzzified value} &= (0.051468 + 0.77894)/2 + (0.043557 - 0.023186)/4 \\
 &= 0.0697737
 \end{aligned}$$

6.2.6 Numerical Evaluation

This section applies the proposed approach to a prototype generation system provided by the Reliability Test System Task Force of the IEEE Power Engineering Application of probabilistic Methods Subcommittee [40] considering fuzzy data. Table 6.4 shows the fuzzy data for the generation mix of the 32 units comprising the system, their installed capacities and FORs. For this system, the thirteen winter weeks (48-52 weeks and 1-8 weeks) hourly loads of IEEE-RTS [40] are considered for analysis. The percentage variation of demand in each hour is determined using equation (6.15), which provides the L-R representation of fuzzy load. In equation (6.15), v_i

Table 6.4: Fuzzy Generation Data for a prototype system [40]

No.of unit	FORs (single valued)	Fuzzy Capacity (MW) (L-R type)
6	0.01	(50., 55., 5., 5.)
5	0.02	(10., 15., 5., 5.)
4	0.12	(20., 25., 5., 5.)
4	0.02	(80., 85., 5., 5.)
4	0.04	(150., 155., 5., 5.)
3	0.04	(100., 105., 5., 5.)
3	0.05	(200., 205., 5., 5.)
2	0.12	(400., 405., 5., 5.)
1	0.08	(350., 355., 5., 5.)
Total fuzzy capacity = (3400., 3560., 160., 160.)		

represents the percentage variation of crisp predicted load and varied $1\% \rightarrow 10\%$. To analyze the effect of FORs uncertainty on LOLPs, the single valued FORs of the system given in Table 6.4 are also varied from $1\% \leq v_f \leq 10\%$ using equation (6.16).

Fuzzy hourly loads of i th hour is,

$$D_{iLR}^{\sim} = \{D_i(1 - v_l/200.), D_i(1 + v_l/200.), 5., 5.\}_{LR} \quad (6.15)$$

where, $i = 1$ to NH , NH = Number of hours

Fuzzy FOR of i th generating unit is represented by,

$$\tilde{F}_{iLR} = \{F_i(1 - v_f/200.), D_i(1 + v_f/200.), 0.005, 0.005\}_{LR} \quad (6.16)$$

The $LO\tilde{L}P_{LR}$ are evaluated for each percentage variation (v_l) of loads for a particular fuzzy FORs and these are shown in Table 6.5 at $v_f = 5\%$. Similarly, the $LO\tilde{L}P_{LR}$ of percentage variation of FORs v_f at constant fuzzy hourly loads are also calculated and these are shown in Table 6.6 at $v_l = 5\%$. The membership functions of fuzzy $LO\tilde{L}P$ with the variation of hourly loads at $v_f = 7\%$ are given in Figure 6.2.

Table 6.5: Variation of $LOLP$ s with hourly loads for IEEE-RTS at $v_f = 5\%$

$v_l(\%)$	$LOLP_L$	$LOLP_R$	$spread_L$	$spread_R$
1	0.002169	0.002779	0.000650	0.000649
2	0.002247	0.002876	0.000671	0.000670
3	0.002331	0.002980	0.000692	0.000691
4	0.002421	0.003092	0.000715	0.000715
5	0.002517	0.003210	0.000739	0.000739
6	0.002619	0.003336	0.000765	0.000766
7	0.002727	0.003470	0.000793	0.000793
8	0.002843	0.003613	0.000822	0.000823
9	0.002968	0.003766	0.000853	0.000854
10	0.003100	0.003929	0.000886	0.000888

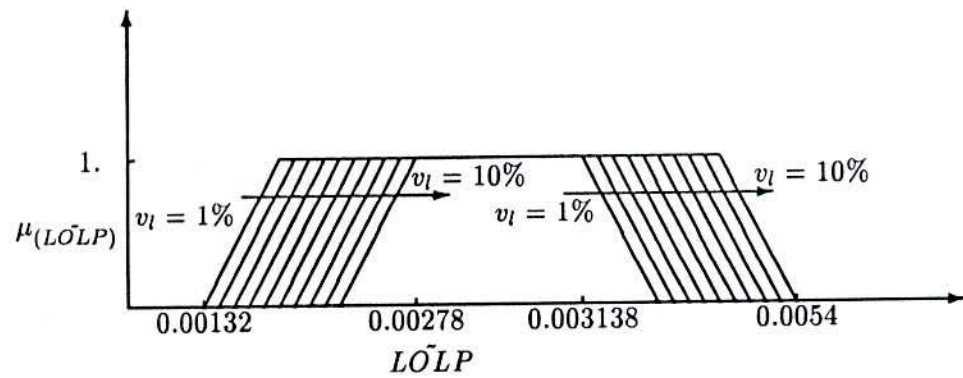
The membership functions of fuzzy $LOLP$ with the variation of FOR s at $v_l = 7\%$ are shown in Figure 6.3. The results shown in Figure 6.2 and Figure 6.3 provide the fuzzy $LOLP$ values of credible level from zero to one. The intermediate credible level $LOLP$ can also be determined using equations (6.11)-(6.12).

Figure 6.2 shows that the evaluated $LOLP_{LR}$ are moving (trapezoidal shape) away from the origin with the increment of load uncertainty at constant FOR s. Figure 6.3 shows that the fuzzy $LOLP$ s at constant hourly loads are affected in a way of increasing the trapezoidal shape with the increase of fuzzy FOR s. Comparison of Figure 6.2 and Figure 6.3 dictates that the effect of fuzzy FOR is less than the effect of fuzzy hourly loads.

Though, the fuzzy $LOLP$ can not be compared with the crisp results due to its input and output nature. But, defuzzified results may provide approximate single valued $LOLP$. For this, the previously obtained fuzzy $LOLP$ are defuzzified using equation (6.13). Figure 6.4 shows the defuzzified results for constant FOR . Figure 6.5 shows the defuzzified results for constant load. From these two figures, it is shown that the rate of change of $LOLP$ in Figure 6.4 are more than that of Figure 6.5. Therefore, the variation of load affects this system reliability more than the

Table 6.6: Variation of $LO\tilde{L}P$ s with FORs for IEEE-RTS at $v_l = 5\%$

$v_f(\%)$	$LOLP_L$	$LOLP_R$	$spread_L$	$spread_R$
1	0.002776	0.002915	0.000806	0.000677
2	0.002709	0.002986	0.000789	0.000692
3	0.002644	0.003059	0.000772	0.000708
4	0.002580	0.003133	0.000756	0.000723
5	0.002517	0.003210	0.000739	0.000739
6	0.002455	0.003288	0.000724	0.000756
7	0.002396	0.003367	0.000708	0.000772
8	0.002337	0.003448	0.000693	0.000789
9	0.002279	0.003532	0.000677	0.000807
10	0.002223	0.003617	0.000663	0.000824

Figure 6.2: Membership functions of $LO\tilde{L}P$ for various hourly load variation at $v_f = 5\%$

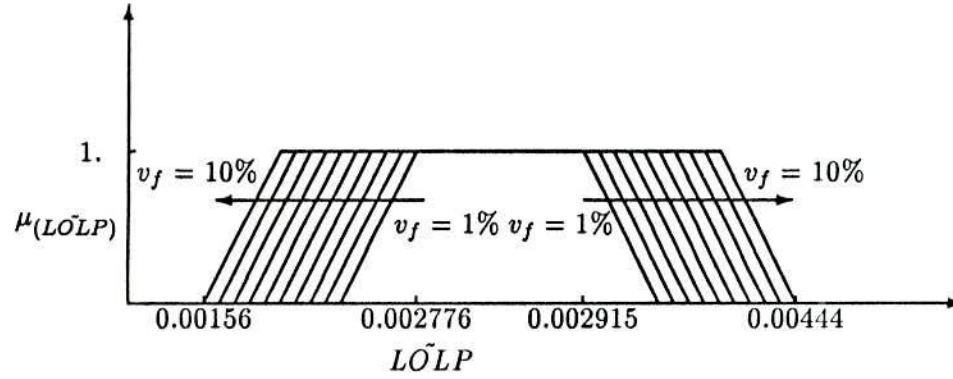


Figure 6.3: Membership functions of $LOLP$ for different FORs variation at $v_l = 5\%$

variation of FOR. As a result, the uncertain load should be as minimum as possible in this case, which can be properly performed using a suitable load prediction method.

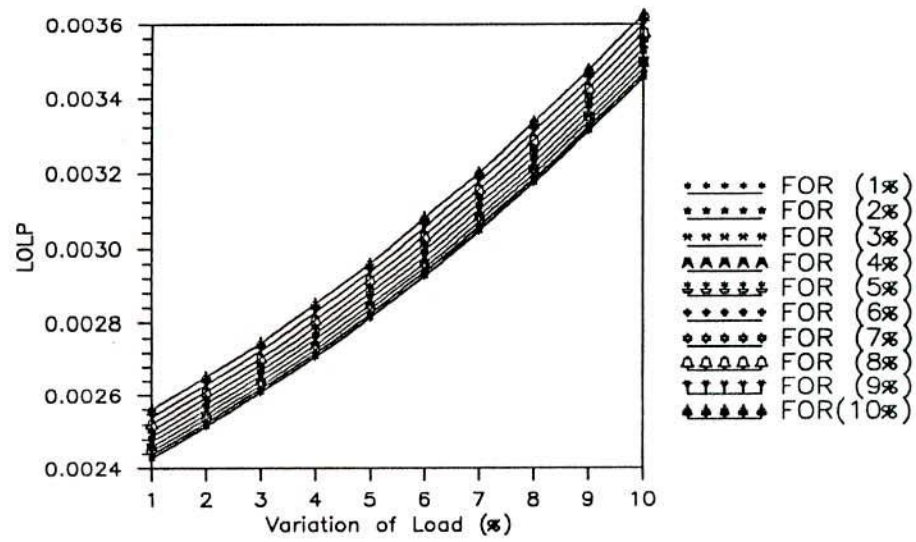
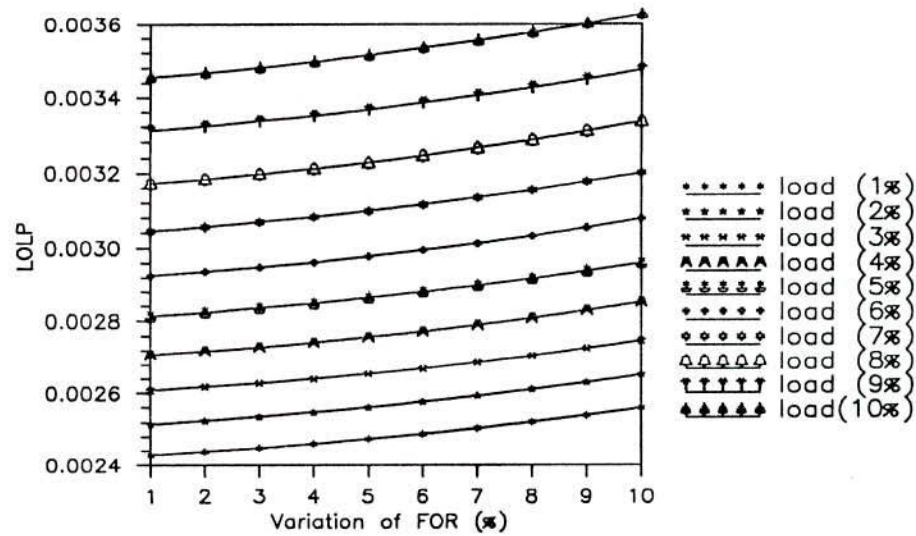
6.3 Application to a Practical System

This section presents the effect of parameter uncertainty on the LOLP of an electric utility for which generation expansion plan has been developed using proposed approaches in chapter 3. Only one year planning data of generation and load is considered for study. The data for the year 2000 is considered for uncertainty analysis.

Fuzzy generation data of OSEB considered for the year 2000 is shown in Table 6.7. Six months hourly load data of that year (september to February) is used to study the system. Equations (6.15) and (6.16) are used for calculating hourly loads and FORs under uncertain conditions. Table 6.8 shows the variation of fuzzy LOLP with hourly loads at specified FORs of $v_f = 7\%$. Fuzzy LOLP variation with FORs at particular hourly loads of $v_l = 7\%$ are tabulated in Table 6.9. Note that the variation of load influences the fuzzy LOLP and the LOLP changes in increasing direction, whereas variation of FOR increases the spread of the trapezoidal shape possibility distribution.

Figure 6.6 and 6.7 show that the variation of LOLP (obtained through defuzzification using equation (6.13)) with load and FOR respectively. Note that the rate of change of LOLP in Figure 6.6 is not different as compared to that of Figure 6.7.

From these figures, it may be concluded that both the parameters - load and

Figure 6.4: $\tilde{LOLP}$ vs v_l of IEEE-RTS at different FORsFigure 6.5: $\tilde{LOLP}$ vs v_f of IEEE-RTS at different loads

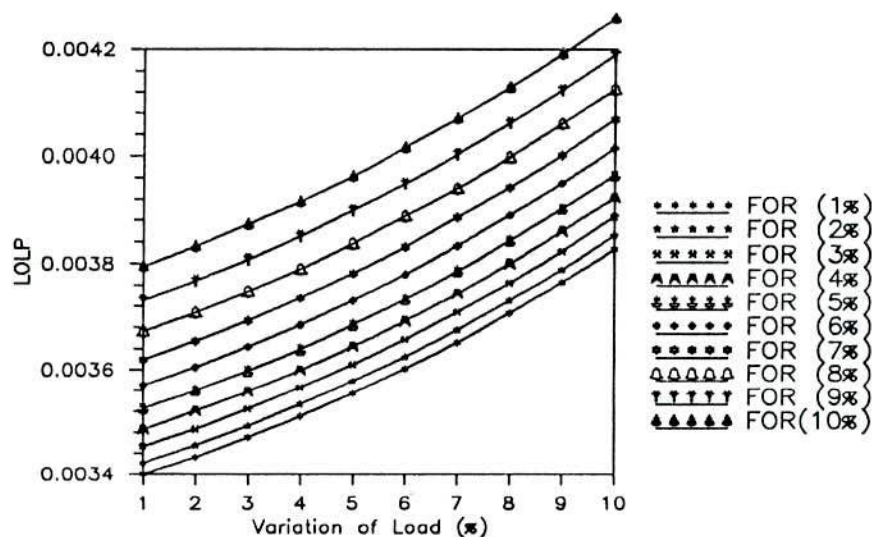


Figure 6.6: $LOLP$ vs v_l of OSEB at different FORs

FOR are, more or less, equally responsible for the variation of system LOLP. Whereas, in case of IEEE-RTS system, effects of FOR on system LOLP was less than load. This phenomenon happened due to the lower initial FOR consideration. It may be noted from the generation system data of both the systems that the initial values of FOR in Table 6.3 are less than that of Table 6.7. Therefore, it may be concluded that the effect of uncertainty, associated with FORs of generating units having higher values of FOR, is more on the system LOLP.

However, it may be recommended from Figures 6.6 and 6.7 that fuzzy LOLP of OSEB for the year 2000 might remain within the desired reliability level for an uncertainty level of 6% in hourly system demands and FORs.

6.4 Conclusions

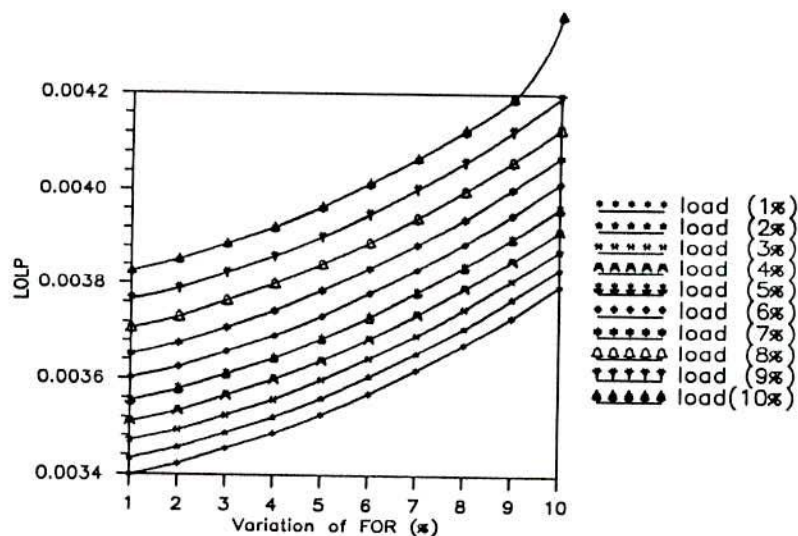
This chapter has presented a fuzzy set approach for modelling the effect of uncertainty associated with unit capacity, FORs and the forecast loads on the LOLP of

Table 6.7: Fuzzy Generation Data of the system OSEB

No.of unit	FORs (single valued)	Fuzzy Capacity (MW) (L-R type)
4	0.14	(60., 65., 5., 5.)
3	0.14	(210., 215., 5., 5.)
2	0.14	(110., 115., 5., 5.)
1	0.14	(135., 140., 5., 5.)
2	0.18	(40., 45., 5., 5.)
1	0.10	(600., 605., 5., 5.)
1	0.10	(305., 310., 5., 5.)
1	0.10	(360., 365., 5., 5.)
1	0.10	(250., 255., 5., 5.)
1	0.10	(320., 325., 5., 5.)
1	0.10	(55., 60., 5., 5.)
Total fuzzy capacity = (3195, 3285, 90, 90)		

Table 6.8: Variation of $LOLPs$ with hourly loads for OSEB at $v_f = 7\%$

$v_l(\%)$	$LOLP_L$	$LOLP_R$	$spread_L$	$spread_R$
1	0.002570	0.004407	0.000824	0.001347
2	0.002597	0.004450	0.000831	0.001358
3	0.002625	0.004496	0.000839	0.001370
4	0.002657	0.004547	0.000848	0.001384
5	0.002691	0.004602	0.000858	0.001398
6	0.002728	0.004661	0.000868	0.001414
7	0.002768	0.004725	0.000879	0.001431
8	0.002811	0.004794	0.000891	0.001449
9	0.002856	0.004866	0.000904	0.001468
10	0.002905	0.004944	0.000917	0.001489

Figure 6.7: $LOLP$ vs v_f of OSEB at different loadsTable 6.9: Variation of $LOLP$ s with FORs for OSEB at $v_l = 7\%$

$v_f(\%)$	$LOLP_L$	$LOLP_R$	$spread_L$	$spread_R$
1	0.003494	0.003771	0.001085	0.001164
2	0.003360	0.003914	0.001048	0.001205
3	0.003233	0.004067	0.001012	0.001248
4	0.003110	0.004221	0.000977	0.001292
5	0.002992	0.004383	0.000943	0.001337
6	0.002878	0.004551	0.000911	0.001383
7	0.002768	0.004725	0.000879	0.001431
8	0.002663	0.004902	0.000849	0.001480
9	0.002561	0.005088	0.000819	0.001532
10	0.002461	0.005281	0.000790	0.001584

a power generating system. Utilization of extended fuzzy arithmetic is capable to deal with all fuzzy parameters in any power system simultaneously to produce the fuzzy output. LOLP values at any credible level can also be found from the results obtained using fuzzy approach.

Effect on the reliability index produced by uncertainty in system parameters is studied. Numerical example presented illustrates that the reliability index is usually affected by uncertainties on various system parameters. Studies are also conducted on the IEEE-RTS to demonstrate effect of uncertainty on system parameters.

The proposed approach has also been applied to a practical system. Reliability indices are evaluated for a specific planned year. It is found from the results that the system is capable to operate within the desired system reliability limit upto 6% uncertainty in generating units' FORs and system demand.

Chapter 7

CONCLUSIONS

Generation expansion planning has become considerably more complex now a days because of uncertainties in load growth, fuel prices, and cost recovery under regulation. The important criteria and constraints in generation expansion planning are load forecasting, reliability, economies, financial ability, environmental standards, and societal impacts. To plan a generation system considering these criteria, detailed analytical studies which typically simulate the operation of the system under the projected future conditions are required.

The primary objective of generation expansion planning is to meet the electrical energy needs of the customers as economically as possible with an acceptable degree of safety, reliability, and quality.

A power utility should meet the demand under a wide range of normal, abnormal, and emergency conditions including the reasonable foreseeable failures and maintenance outages of facilities. This requires some generation system capacity reserve in excess of forecasted demand. The uncertainty associated with future demand projections could make the system facilities inadequate, or excessive and uneconomical, both cases being unacceptable. Purchasing cheaper power from other utility through interconnection is another alternative which improves system reliability. Though it is possible to evaluate interconnected systems as a single system with some approximation, but, it is not in practice due to many obvious reasons.

The investigations accumulated in the thesis deal with the modelling and anal-

ysis of some important requirements of generation expansion planning and implementation of the proposed developments to existing electric utility system. Each chapter contains detailed literature review, discussions and conclusions for the work presented therein. Following paragraphs present only the significant features of the effort mounted in the thesis. Some suggestions for further study are also included at the end.

In chapter 2, four modules of Artificial Neural Network have been studied to carry out sensitivity analysis of applicability of various ANN configurations for load forecasting. It is observed, from the sensitivity analysis, that all modules (four modules studied) are not valid for all systems. In other words, for a specific system only a particular module is suitable for load forecasting. It is also found that the predicted results of MAE (mean absolute error) may not be minimum at the convergence of lowest iteration number and the minimum MAE depends on the learning rate and learning momentum.

Based upon the conclusions of sensitivity analysis, a module was selected to forecast the peak loads of an existing electric utility for fifteen years period to carry out generation expansion planning.

The first portion of chapter 3 proposes a modification of existing FFT method to evaluate the loss of load probability (LOLP) of a power generating system consisting of different types and sizes of unit. Some properties of FFT scheme have been used for the reduction of computational complexity. The accuracy of the method has been illustrated using an example. This modified FFT algorithm is applied to IEEE Reliability Test System (IEEE-RTS). Further, the multi-megawatt generating units can be efficiently handled by the proposed method.

The second part of chapter 3 describes a new approach to evaluate the LOLP of a power generating system. This approach uses joint probability density function (PDF) concepts to convolve the unit outages and loads of the system. The reduction of computational effort for identical generating units is obtained using the properties of binomial distribution. The accuracy and applicability of the method has been illustrated through a simple example. Further, the proposed approach has been implemented on IEEE-RTS. This method is found efficient and possesses simplified procedure as compared to existing methods. In addition, the proposed approach



can simulate multistate representations of generating units.

Exploiting these advantages of the proposed approaches, generation expansion planning of an electric utility has been made on the basis of risk levelization criterion using projected future demand forecasted in chapter 2.

The first part of chapter 4 presents the application of improved FFT scheme proposed in chapter 3 to evaluate LOLP of two interconnected power systems. A stochastic procedure for interconnected systems is presented using improved two dimensional FFT IMSL subroutine of Cyber 180/840A mainframe. The proposed method is applied to IEEE-RTS interconnected to a hypothetical system and the results obtained are compared.

The second part of chapter 4 proposes extension of the application of new approach developed in the second part of chapter 3 for LOLP evaluation of two area interconnected power systems consisting of different types and sizes of generating units considering independent as well as correlated system demands. The Probability Density Function (PDF) of equivalent load is obtained by convolving the PDF of generating unit outages with the PDF of system demands using proposed new approach. The LOLP values of each system are obtained from the PDF of equivalent load. The accuracy of the proposed method has been illustrated using a simple example and IEEE-RTS.

In addition, the above approach is also implemented to an electric utility system for which expansion planning studies were carried out in chapter 3. The system under study is considered to be interconnected with a hypothetical system. The benefits of interconnection, on the expansion planning, of the existing generation system have been studied at the end of this chapter.

The first portion of chapter 5 presents an efficient approach to evaluate the expected energy generation (EEG), expected unserved energy (USE), expected production costs (EPC) and LOLP of a power generating system. The method can evaluate EEG, EPC of identical generating units at a time. The proposed method is not restricted to any shapes, or size of LDC and unit outage density function and applicable to systems having large number of generation units. Multiple generating units with same outage behavior are committed with system demand efficiently. A simple example is used to clarify the procedure. The accuracy and computational

efficiency of the proposed method are additional benefits.

Further, the proposed method is used to evaluate EEG, USE and EPC of the generation expansion plan developed in chapter 3 for an electric utility under study. Based on the risk levelization, unserved energy and production cost, addition of generating units for the electric utility has been recommended for the period under consideration.

The last part of chapter 5 presents another new approach to evaluate the expected energy generation, expected unserved energy and production costs for two area interconnected power generating system. An small system has been used to describe the applicability of the proposed method. For numerical evaluation, IEEE-RTS have been used to verify its applicability.

In chapter 6, a model has been developed for fuzzy reliability to quantify the effect of uncertainty associated with unit capacity, FORs and the forecast loads on the LOLP of a power generating system. The model has been explained with the help of a simple generation system. Studies are also conducted on the IEEE-RTS to demonstrate effect of uncertainty on system parameters. Effects on the system reliability index due to variation in the amount of uncertainty of the parameters is studied. This proposed model has also been applied to a practical system to predict fuzzy LOLP.

Suggestions for Further Work

After having summarized the contributions of the present study, following areas for further investigations in future are being suggested:

1. Investigation may be made to see impacts of jointly owned unit.
2. The hydro unit may be considered as multi-state unit, so that the impact of derated hydro unit on system reliability and production cost may be studied.
3. The maintenance scheduling may be investigated using the developed methods.
4. The methods proposed in this thesis may be extended for more than two interconnected systems.
5. Fuzzy set theory applications may be made for generation expansion planning studies.

The references which has been used to carry out the work presented in this thesis, by no means cover the entire literature that is available on the topic of the thesis. Care has been taken to include all possible representative references which reflect the philosophy of generation expansion planning and are easily accessible in the form of published work. A reader is also recommended to look for the cross references in the reference list provided. The listing has been done in chronological order of year with the subjects reliability & production costing, uncertainty analysis and load forecasting respectively.

Appendix A

A.1 Generalized Delta Rule

The common approach for adjusting the connection weights of the back propagation feed forward neural network is the Generalized Delta Rule (GDR). Let, the network input to the next k th layer Y_k is given by

$$Y_k = \theta_j + \sum_j W_{jk} O_j \quad (\text{A.1})$$

where, j denotes the neuron in the preceding layer j th.

O_j is the output of the neuron in the preceding layer j th

W_{jk} is the connection weight from neuron of j th layer to neuron of k th layer.

θ_j is the threshold or bias value for k th layer = 1.0

The neuron output in the k th layer is given by

$$O_k = \frac{1}{1 + e^{-Y_k}} = f(Y_k) \quad (\text{A.2})$$

and

$$f'(Y_k) = O_k(1 - O_k) \quad (\text{A.3})$$

where, activation function, $f(Y_k) = \frac{1}{1 + e^{-Y_k}}$

and Y_k is the input signal to the neuron of k th layer.

Let, the square of the error for each pattern is defined as

$$E = \frac{1}{2} \sum_{k=1}^m (t_k - O_k)^2 \quad (\text{A.4})$$

where, t_k and O_k are the target and calculated output in the output layer k respectively.

Let j is the previous layer of the output layer k . In generalized delta rule, the weights are adopted according to the gradient error i.e.,

$$\begin{aligned}\Delta W_{jk} &\propto -\frac{\partial E}{\partial W_{jk}} \\ \Delta W_{jk} &= -\eta \frac{\partial E}{\partial W_{jk}}\end{aligned}\tag{A.5}$$

$$\frac{\partial E}{\partial W_{jk}} = \frac{\partial E}{\partial Y_k} \frac{\partial Y_k}{\partial W_{jk}}\tag{A.6}$$

Now, differentiating equation (A.1), it is obtained,

$$\begin{aligned}\frac{\partial Y_k}{\partial W_{jk}} &= \frac{\partial}{\partial W_{jk}}(\theta_k + \sum_j W_{jk} O_j) \\ &= O_j\end{aligned}\tag{A.7}$$

Therefore, equation (A.5) becomes

$$\begin{aligned}\Delta W_{jk} &= -\eta \frac{\partial E}{\partial Y_k} O_j \\ &= \eta \delta_k O_j\end{aligned}\tag{A.8}$$

where, $\delta_k = -\frac{\partial E}{\partial Y_k}$.

Now, it is required to solve,

$$\begin{aligned}\delta_k &= -\frac{\partial E}{\partial Y_k} \\ &= -\frac{\partial E}{\partial O_k} \frac{\partial O_k}{\partial Y_k}\end{aligned}\tag{A.9}$$

Now, differentiating equation (A.4), it is obtained,

$$\frac{\partial E}{\partial O_k} = \frac{1}{2} \frac{\partial}{\partial O_k} \sum_{k=1}^m (t_k - O_k)^2$$

$$= -(t_k - O_k) \quad (\text{A.10})$$

$$\text{and} \quad \frac{\partial O_k}{\partial Y_k} = f'(Y_k) \quad (\text{A.11})$$

Therefore, equation (A.9) and (A.8) become

$$\delta_k = (t_k - O_k)f'(Y_k) \quad (\text{A.12})$$

and

$$\begin{aligned} \Delta W_{jk} &= \eta \delta_k O_j \\ &= \eta (t_k - O_k) f'(Y_k) O_j \end{aligned} \quad (\text{A.13})$$

Circumstances are different, if the weights do not affect output nodes directly. Then,

$$\begin{aligned} \Delta W_{jk} &= -\eta \frac{\partial E}{\partial W_{ij}} \\ &= -\eta \frac{\partial E}{\partial Y_j} \frac{\partial Y_j}{\partial W_{ij}} \\ &= -\eta \frac{\partial E}{\partial Y_j} O_i \\ &= -\eta \frac{\partial E}{\partial O_j} \frac{\partial O_j}{\partial Y_j} O_i \\ &= \eta \left(-\frac{\partial E}{\partial O_j} \right) f'(Y_j) O_i \\ &= \eta \delta_j O_i \end{aligned}$$

where, i and j are intermediate layers and $\delta_j = \left(-\frac{\partial E}{\partial O_j} \right) f'(Y_j)$

However, the factor $\frac{\partial E}{\partial O_j}$ can not be evaluated directly for intermediate layers. Instead, it is written in terms of quantities that are known and other quantities that can be evaluated. Specifically, it is written as,

$$-\frac{\partial E}{\partial O_j} = -\sum_k \frac{\partial E}{\partial Y_k} \frac{\partial Y_k}{\partial O_j}$$

$$\begin{aligned}
&= \left(-\sum_k \frac{\partial E}{\partial Y_k}\right) \frac{\partial Y_k}{\partial O_j} \\
&= \sum_k \left(-\frac{\partial E}{\partial Y_k}\right) \left(\frac{\partial}{\partial O_j} \sum_j W_{jk} O_j\right) \\
&= \sum_k \left(-\frac{\partial E}{\partial Y_k}\right) W_{jk} \\
&= \sum_k \delta_k W_{jk} \tag{A.14}
\end{aligned}$$

$$\text{In this case, } \delta_j = f'(Y_j) \sum_k \delta_k W_{jk} \tag{A.15}$$

where k is the next higher layer.

Therefore, if the j nodes are output layer nodes, then using equation (A.2) in equation (A.12),

$$\delta_j = (t_j - O_j) O_j (1 - O_j) \tag{A.16}$$

However, if the j nodes are internal nodes, it is required to evaluate δ_j in terms of δ s at a higher layer; that is,

$$\delta_j = O_j (1 - O_j) \sum_{k=1} \delta_k W_{jk} \tag{A.17}$$

For p th pattern (samples) the above equations are represented respectively as,

$$\delta_{pk} = (t_{pk} - O_{pk}) O_{pk} (1 - O_{pk}) \tag{A.18}$$

and for other layers nodes

$$\delta_{pj} = O_{pj} (1 - O_{pj}) \sum_{k=1} \delta_{pk} W_{jk} \tag{A.19}$$

Finally, weights are adjusted by taking an additional proportional constant α . That is,

$$\Delta W_{ij}(n+1) = \eta O_i \delta_j + \alpha \Delta W_{ij}(n) \tag{A.20}$$

$$\Delta W_{ij}(n+1) = \eta \Delta_{ij} + \alpha \Delta W_{ij}(n) \tag{A.21}$$

where, n indicates the n th iteration, $\Delta_{ij} = O_i \delta_j$, η is learning rate and α is learning momentum.

A.2 Detail Study of ANN Modules

Regorious studies of four ANN modules are carried out and given in terms of figures. These figures are the characteristic curves of two systems for different modules, drawn for the variation of MAE or iterations counts with α or η . These characteristic curves show the effects of MAE or Iteration counts on wide range of α or η . However, the highlighted Figures 2.8-2.16 of chapter 2 are extracted from these elaborated Figures A.1 to A.5.

- a. The characteristic curves shown in Figures A.1(a-g) are drawn for IIT substation using module II under wide range of $\eta[0 - 0.8]$ and $\alpha[0.40 - 0.99]$. From these figures, it is observed that minimum value of MAE and least number of iteration counts are available at $\alpha = 0.99$. Two characteristic curves from Figures A.1c and A.1d at $\alpha = 0.99$ and $\eta[0 - 0.25]$ are extracted and put in Figure 2.8.
- b. Figures A.2(a-l) represent the characteristic curves for IIT substation using module III for the wide range of $\eta[1.8-3.5]$ and $\alpha[0.6-0.99]$. It is observed from these figures that minimum value of MAE is occurring at $\eta = 3.05$ and $\alpha = 0.74$. The characteristic curves for MAE and Iteration counts are extracted from Figures A.2i and A.2j respectively. These two characteristic curves are kept in Figure 2.9. In a similar way, minimum number of iteration count for convergence is available in Figure A.2d. Therefore, characteristic curves for MAE and Iteration counts shown in Figure 2.10 are extracted from Figures A.2c and A.2d at $\eta = 1.85$ & $\alpha = 0.98$.
- c. The characteristic curves for the wide range of $\eta[1.6 - 2.75]$ and $\alpha[0.8 - 0.99]$ of module IV for IIT substation are depicted if Figures A.3(a-h). The value of $\eta = 1.85$ and $\alpha = 0.9$ in these figures provide minimum MAE and found from Figure A.3a. Characteristic curve at $\alpha = 0.9$ of Figure A.3a and A.3b

are extracted for MAE and Iteration count respectively. Figure 2.11 presents the extracted characteristic curves from these two figures.

On the other hand, Figure 2.12 represents the characteristic curves extracted from Figures A.3e and A.3f for the least iteration count of convergence. These were found for $\eta = 2.05$ and $\alpha = 0.9$. At this condition, Iteration count=7 and MAE=5.16%.

- d. Similar to IIT substation, characteristic curves for the Carnac substation are drawn using module II and III under wide range of η and α . Figures A.4(a-f) and A.5(a-j) are drawn using module II and module III respectively. Typical range of η and α of both the modules are considered. Here, wide range of $\eta[0.15-0.90]$ & $\alpha[0.12-0.84]$ are considered for module II, and $\eta[0.3-1.05, 2.3-3.0]$ & $\alpha[0.12-0.96]$ are considered for module III.

- (i) Characteristic curves of module II shown in Figures A.4a and A.4b belong minimum MAE at $\eta = 0.20$ and $\alpha = 0.76$. Note that, these curves are extracted from figures 2.24c and 2.24d, which is drawn for wide range of η and α . Figure 2.13 is also extracted from Figures A.4a and A.4b. Least number of iteration to converge, is found from Figure 2.24f at $\eta = 1.6$ and $\alpha = 0.12$. Therefore, Figure 2.14 is extracted from Figures A.4e and A.4f for module II at $\eta = 1.6$.

- (ii) It is shown from figures of module III that minimum MAE occurs at $\eta = 0.88$ & $\alpha = 0.82$ and found from Figures A.5a & A.5b. These figures are extracted from Figures A.5e and A.5f respectively for the range of $\eta[0.8-1]$ & $\alpha[0.81-0.84]$. Again, these Figures A.5a & A.5b are used to provide Figure 2.15 at $\alpha = 0.82$ for more simplicity.

Similarly, least number of iteration count for TATA Carnac substation of module III occurs at $\eta = 3.0$ and $\alpha = 0.54$. With reference to this point, Figure 2.16 is extracted from Figures A.5i and A.5j.

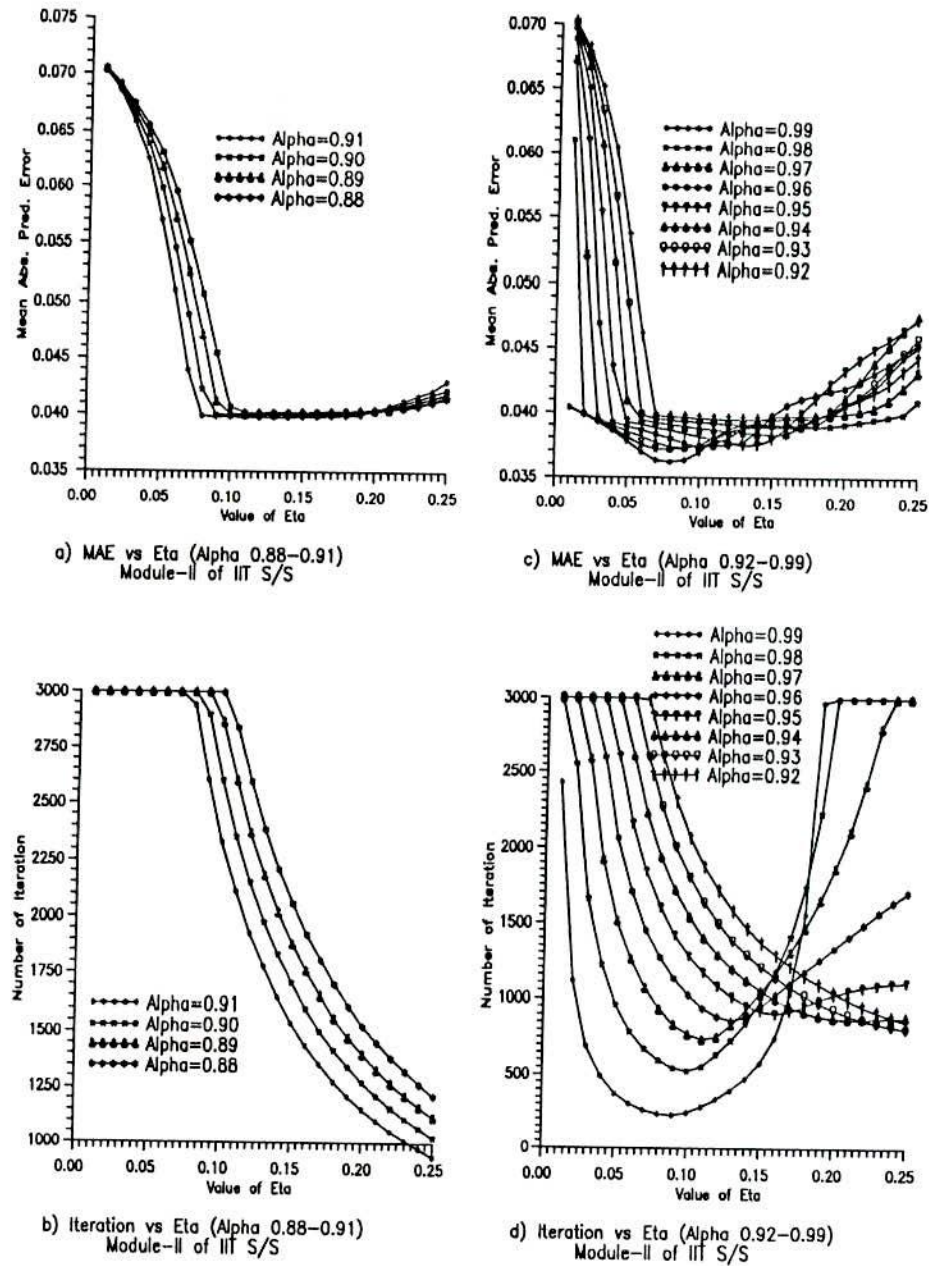
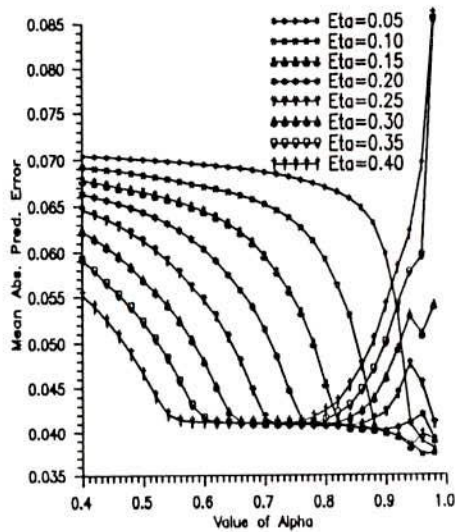
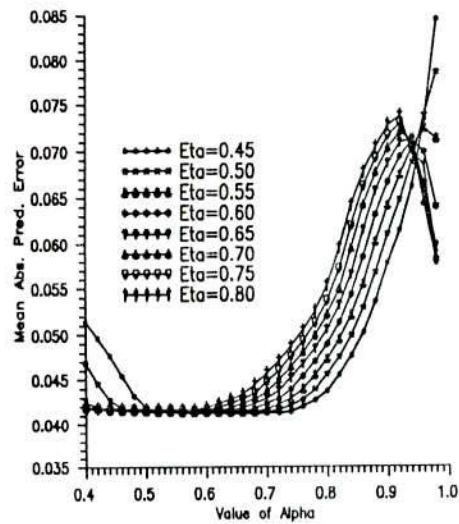


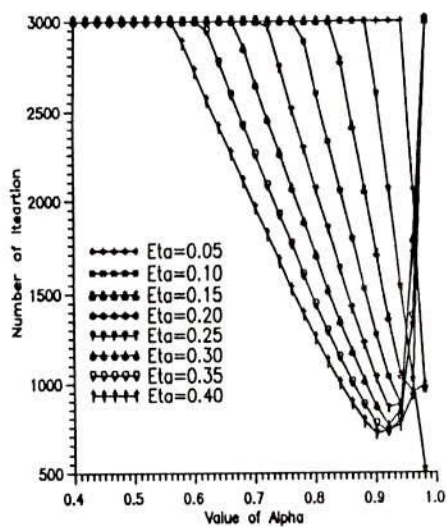
Figure A.1: Characteristic curves for different values of α and η for IIT system using Module II



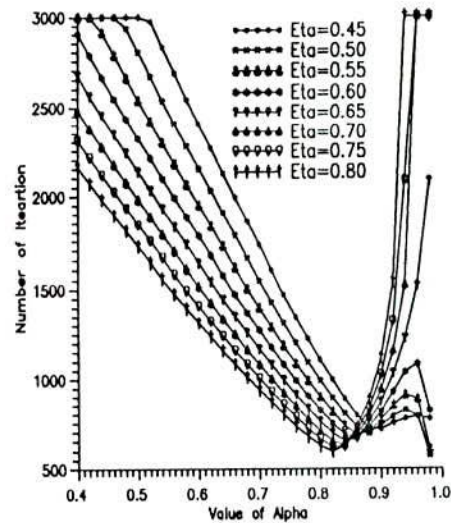
e) MAE vs Alpha (Eta 0.05-0.40)
Module-II of IIT S/S



g) MAE vs Alpha (Eta 0.45-0.80)
Module-II of IIT S/S



f) Iteration vs Alpha (Eta 0.05-0.40)
Module-II of IIT S/S



h) Iteration vs Alpha (Eta 0.45-0.80)
Module-II of IIT S/S

Continuation of Figure A.1

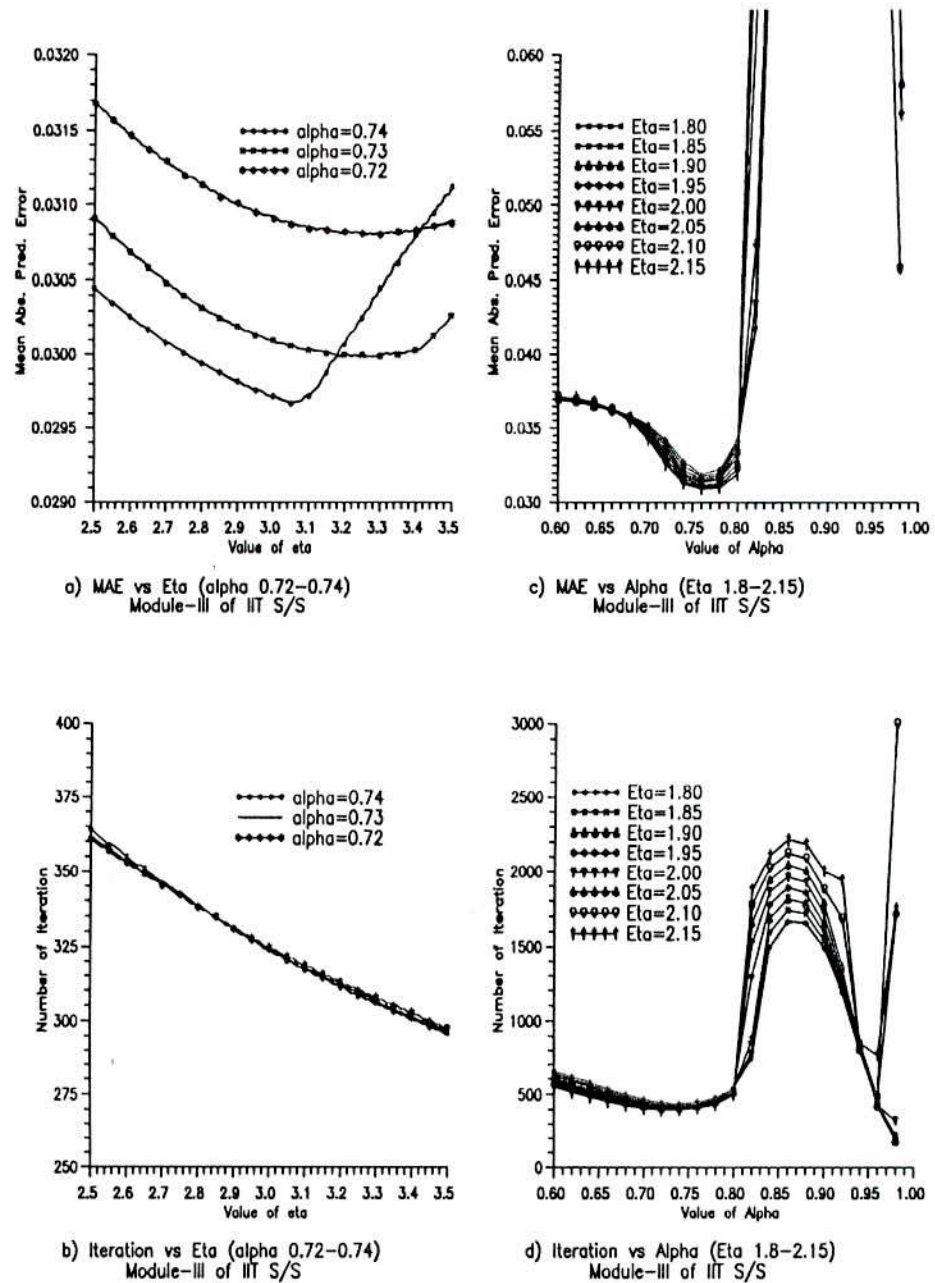
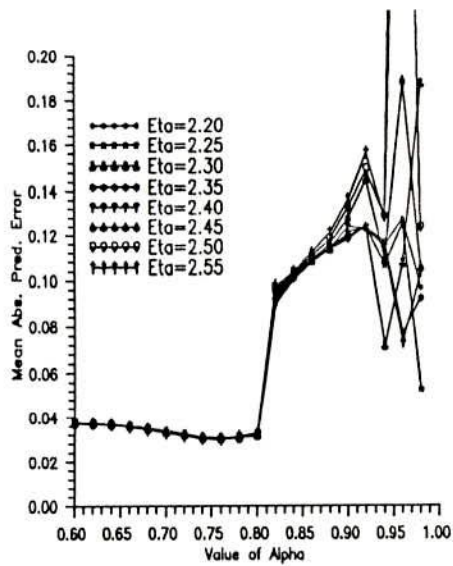
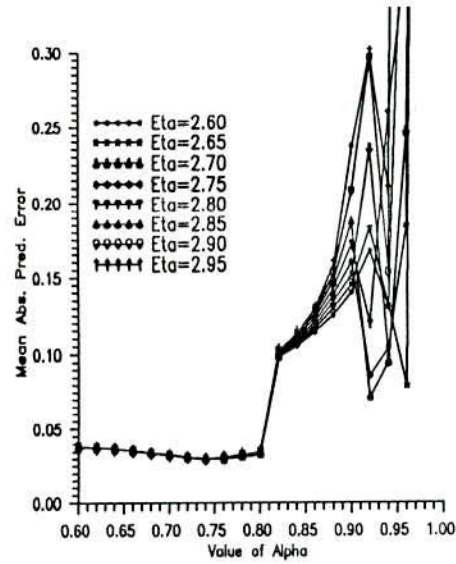


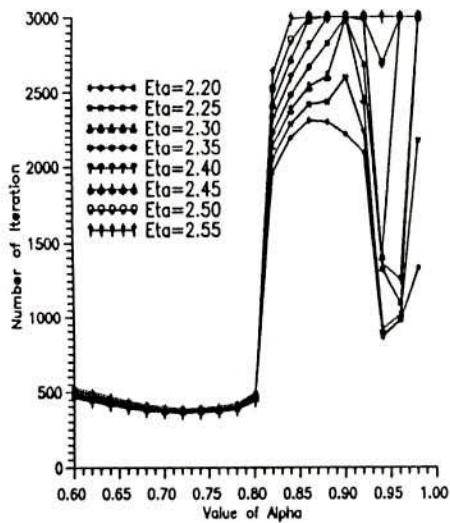
Figure A.2: Characteristic curves for different values of α and η for IIT system using Module III



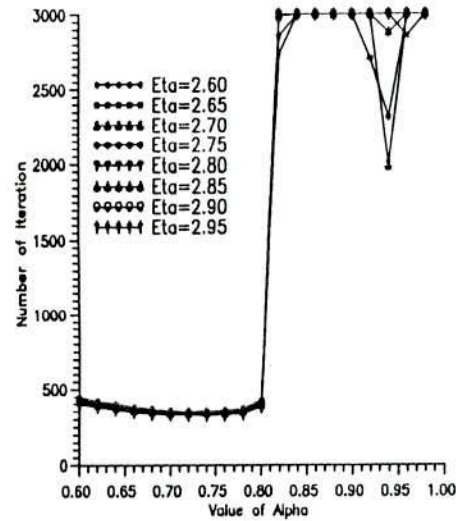
e) MAE vs Alpha (Eta 2.20-2.55)
Module-III of IIT S/S



g) MAE vs Alpha (Eta 2.60-2.95)
Module-III of IIT S/S

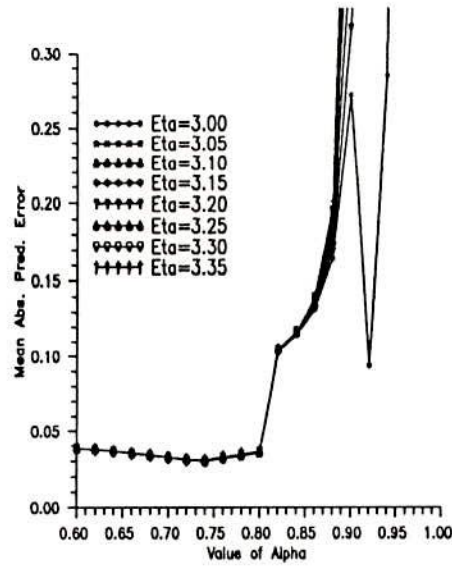


f) Iteration vs Alpha (Eta 2.20-2.55)
Module-III of IIT S/S

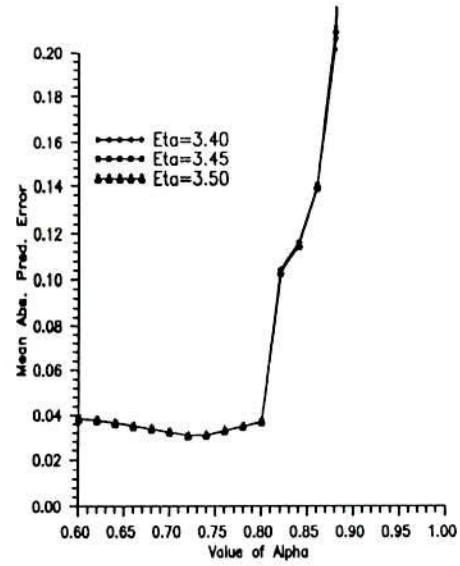


h) Iteration vs Alpha (Eta 2.60-2.95)
Module-III of IIT S/S

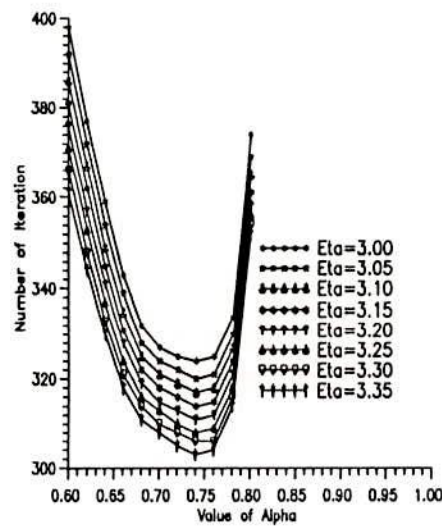
Continuation of Figure A.2



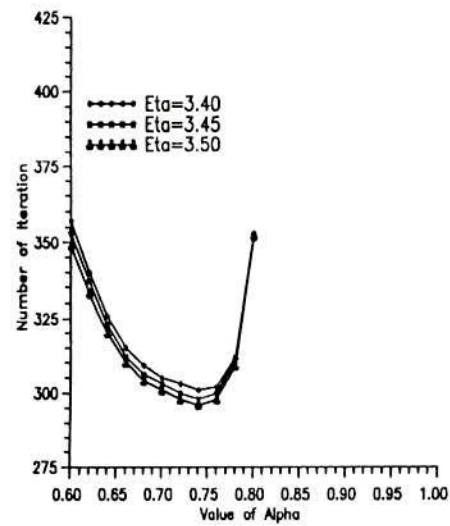
i) MAE vs Alpha (Eta 3.00-3.35)
Module-III of IIT S/S



k) MAE vs Alpha (Eta 3.40-3.50)
Module-III of IIT S/S



j) Iteration vs Alpha (Eta 3.00-3.35)
Module-III of IIT S/S



l) Iteration vs Alpha (Eta 3.40-3.50)
Module-III of IIT S/S

Continuation of Figure A.2

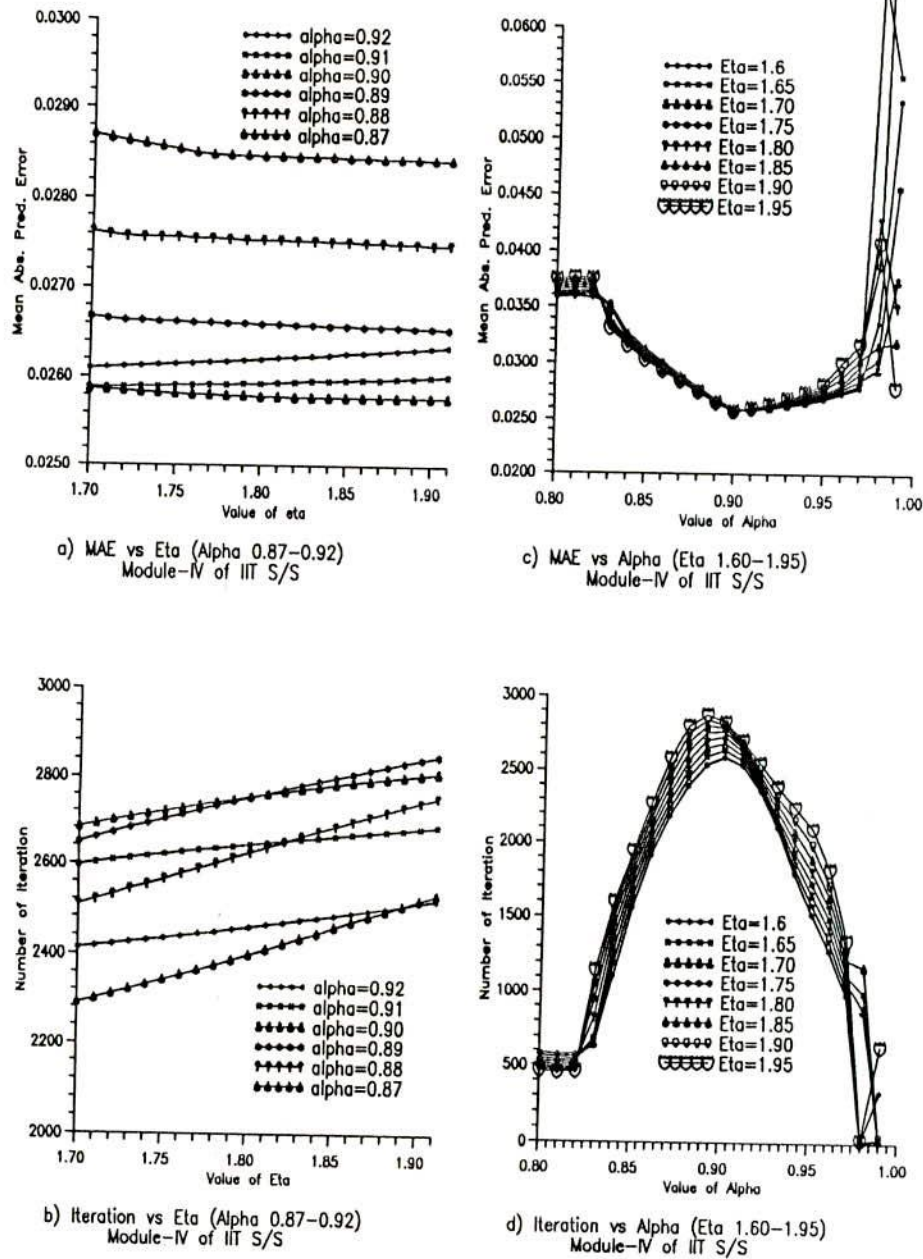
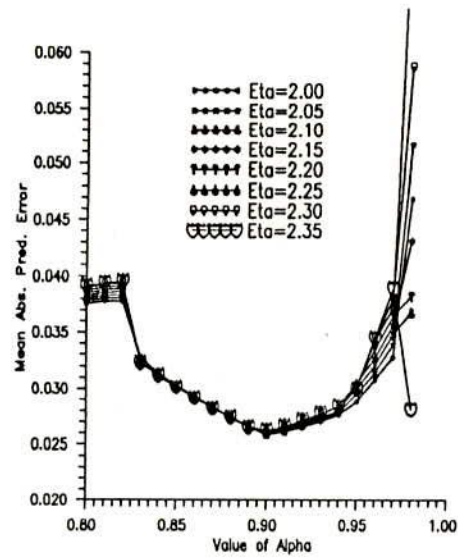
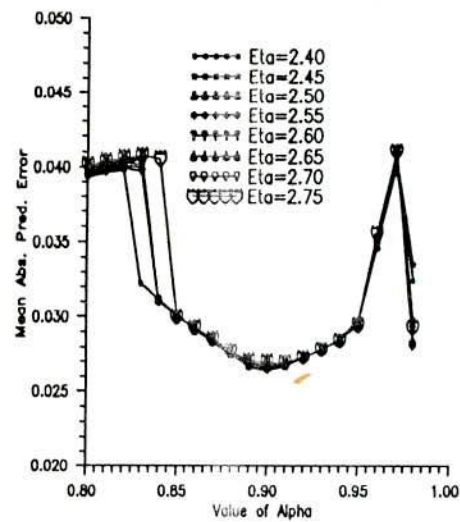


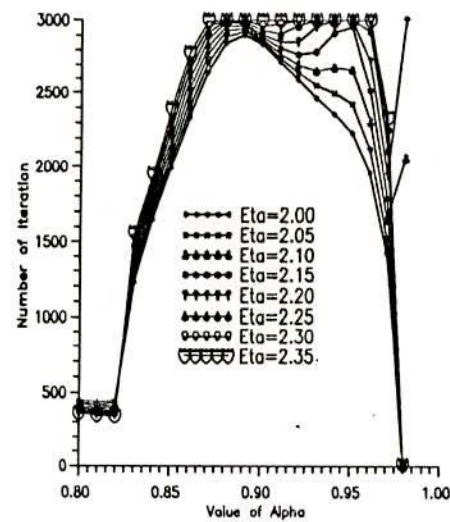
Figure A.3: Characteristic curves for different values of α and η for IIT system using Module IV



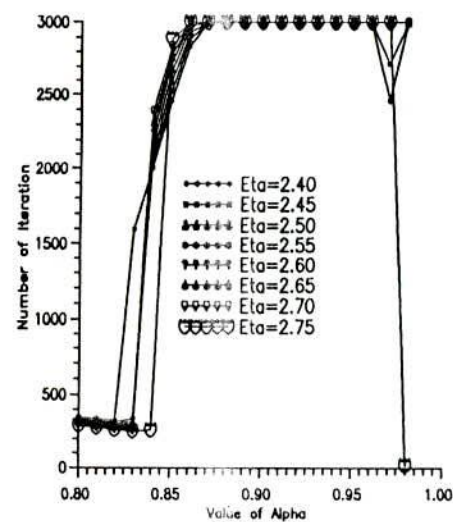
e) MAE vs Alpha (Eta 2.0-2.35)
Module-IV of IIT S/S



g) MAE vs Alpha (Eta 2.40-2.75)
Module-IV of IIT S/S



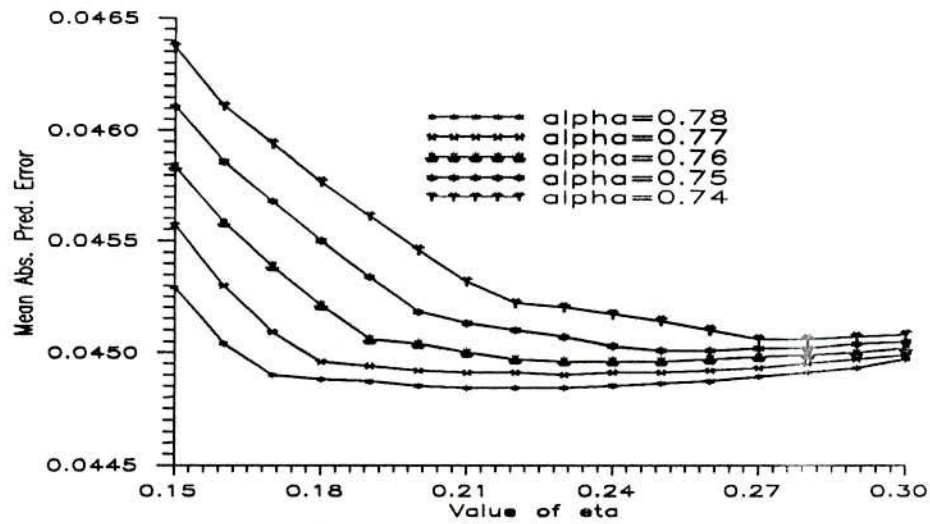
f) Iteration vs Alpha (Eta 2.0-2.35)
Module-IV of IIT S/S



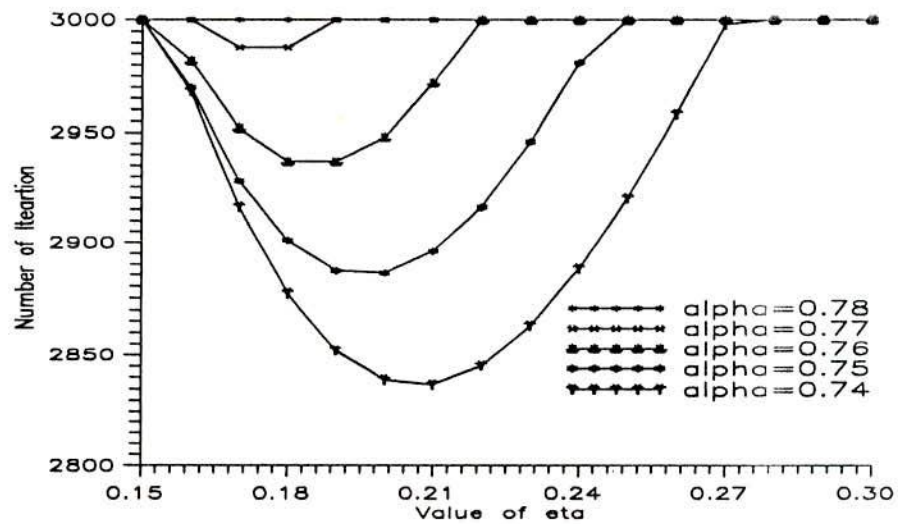
h) Iteration vs Alpha (Eta 2.40-2.75)
Module-IV of IIT S/S

Continuation of Figure A.3



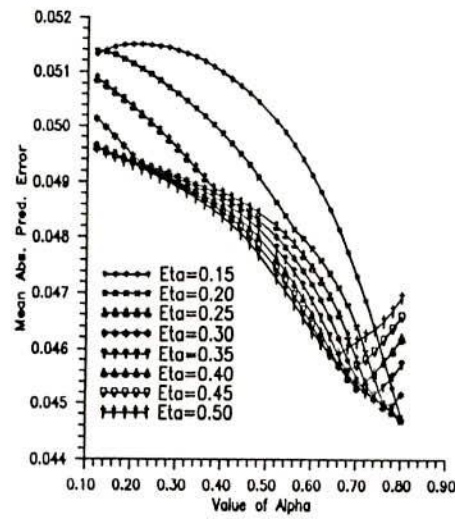


a) MAE vs Eta (Alpha 0.74–0.78)
Module-II of TATA S/S

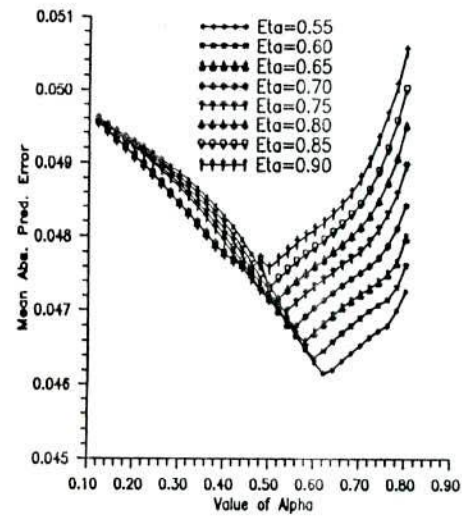


b) Iteration vs Eta (Alpha 0.74–0.78)
Module-II of TATA S/S

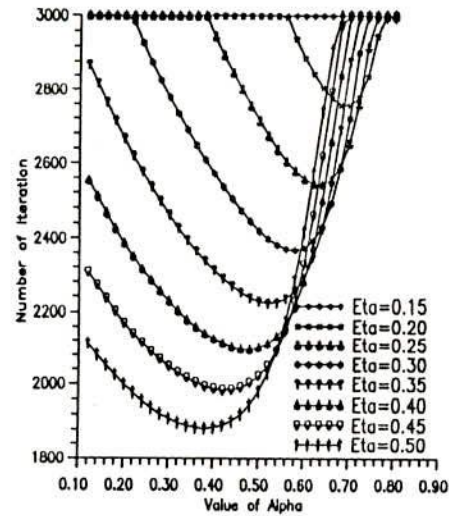
Figure A.4: Characteristic curves for different values of α and η for TATA Carnac system using Module II



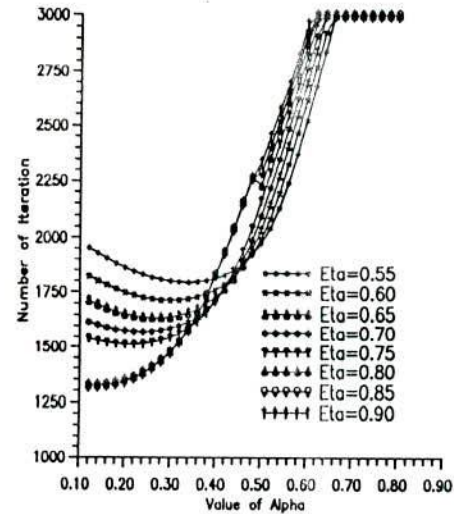
c) MAE vs Alpha (Eta 0.15-0.5)
Module-II of TATA S/S



e) MAE vs Alpha (Eta 0.55-0.9)
Module-II of TATA S/S

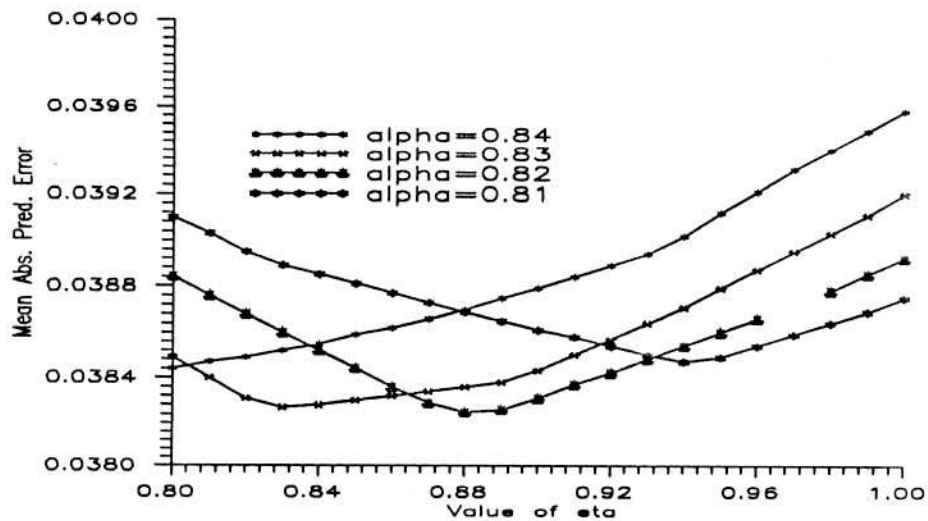


d) Iteration vs Alpha (Eta 0.15-0.5)
Module-II of TATA S/S

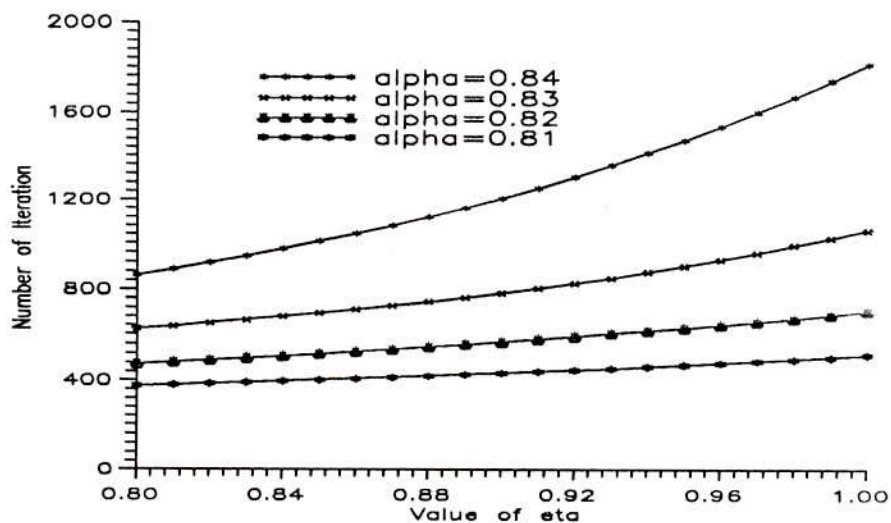


f) Iteration vs Alpha (Eta 0.55-0.9)
Module-II of TATA S/S

Continuation of Figure A.4

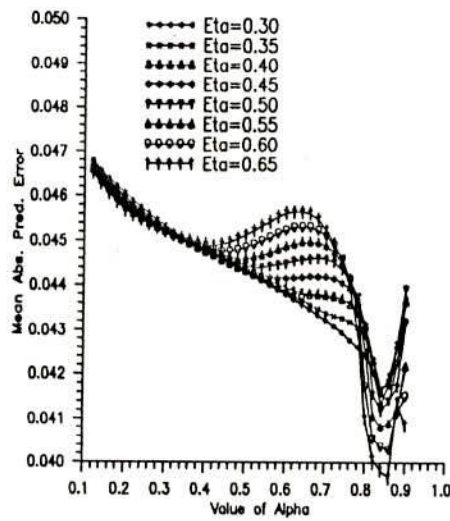


a) MAE vs Eta (Alpha 0.81-0.84)
Module-III of TATA S/S

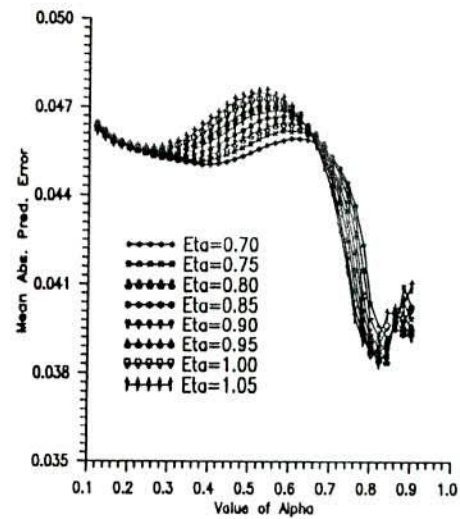


b) Iteration vs Eta (Alpha 0.81-0.84)
Module-III of TATA S/S

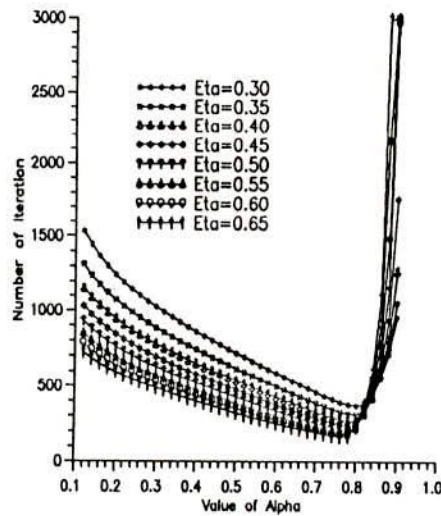
Figure A.5: Characteristic curves for different values of α and η for TATA Carnac system using Module III



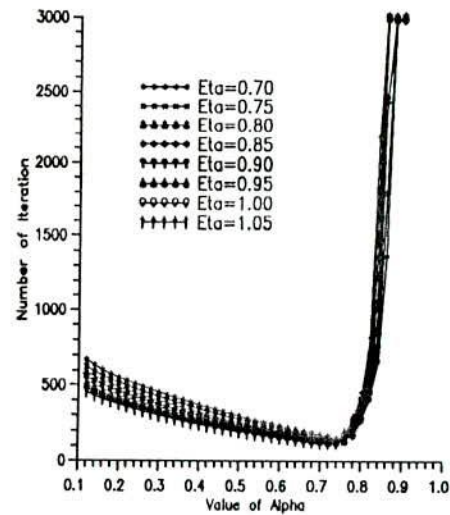
c) MAE vs Alpha (Eta 0.3-0.65)
Module-III of TATA S/S



e) MAE vs Alpha (Eta 0.70-1.05)
Module-III of TATA S/S

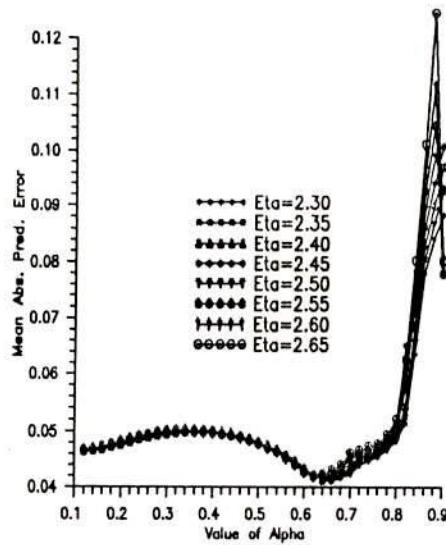


d) Iteration vs Alpha (Eta 0.3-0.65)
Module-III of TATA S/S

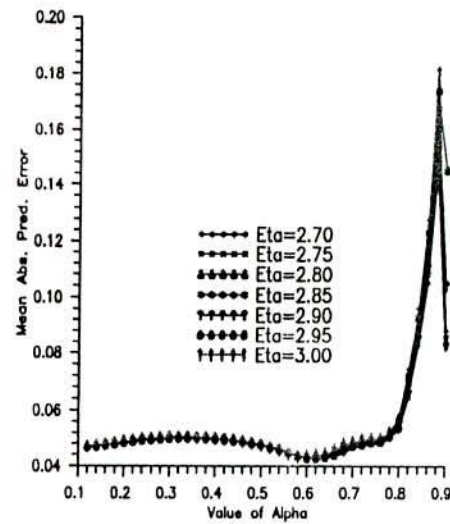


f) Iteration vs Alpha (Eta 0.70-1.05)
Module-III of TATA S/S

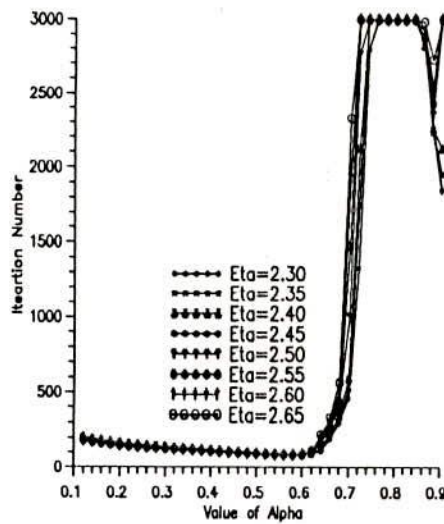
Continuation of Figure A.5



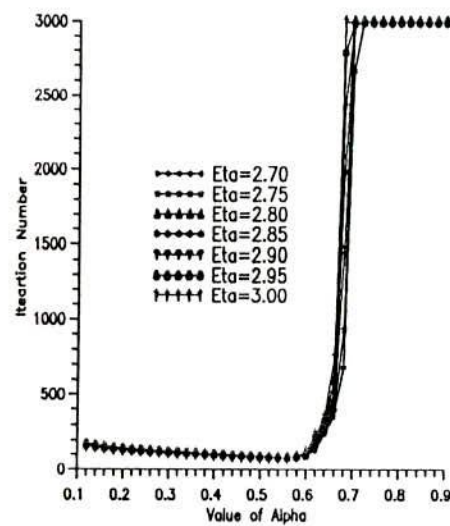
g) MAE vs Alpha (Eta 2.3-2.65)
Module-III of TATA S/S



i) MAE vs Alpha (Eta 2.7-3.0)
Module-III of TATA S/S



h) Iteration vs Alpha (Eta 2.30-2.65)
Module-III of TATA S/S



j) Iteration vs Alpha (Eta 2.7-3.0)
Module-III of TATA S/S

Continuation of Figure A.5

Appendix B

B.1 Generating unit and Load Models

The two basic models, the load and generation unit model, for different methods differ greatly in their degree of sophistication. The models suitable for the proposed methods used in this thesis are presented here.

B.1.1 Conventional Generating Unit Model

Different types of generating units are in use today and all types of units are randomly forced off-line because of technical problems during normal period of operation. To account for the random outage or availability of a unit, it is necessary to determine the probability density function (PDF) that describes the probability that a unit will be forced off-line or will be unavailable during its normal period of operation.

On the basis of historical data, the availability of the generating capacity of a given unit may be graphically represented as in Figure B.1. This figure conveys the idea that random failure and repair of a unit can be defined as two-state stochastic process. A stochastic process is defined as a process that develops in time in a manner controlled by probabilistic laws.

The system alternates between an operating state, or, up state, in which repair is effected. For i th cycle, let

m_i = up time

r_i = down time

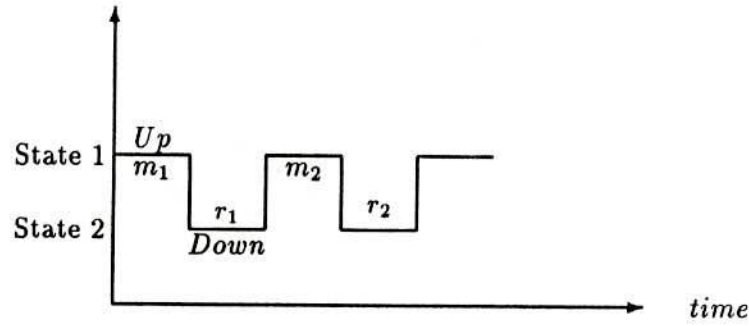


Figure B.1: Run-fail-repair-run cycle for a generating unit.

The generating unit may be represented in terms of an average (mean) up time and an average down time as follows:

$$m = \text{mean up time} = \frac{1}{N} \sum m_i$$

$$r = \text{mean down time} = \frac{1}{N} \sum r_i$$

where N is the total number of run-fail-repair-run cycles. Thus the system failure rate λ and the system repair rate μ may be expressed as

$$\lambda = \text{system failure rate} = \frac{1}{m} \quad (\text{B.1})$$

$$\mu = \text{system repair rate} = \frac{1}{r} \quad (\text{B.2})$$

With these two parameters the random failure and repair of a system can be defined by the state-space diagram (two-state) shown in Figure B.2.

Two important parameters can be obtained from this model [206]:

1. System availability - the long term probability that the system will be in the up state.

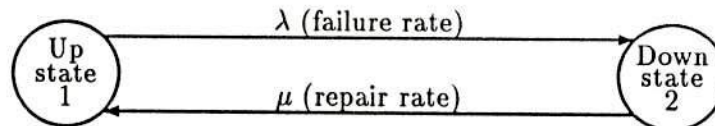


Figure B.2: System's State Space Diagram

2. System unavailability - the long term probability that the system will be in the down state.

To obtain the expressions for long term availability and unavailability of a system, it is necessary to recognize that the stochastic process, called a zero-order, discrete state, continuous transition Markov process [206]. Such a stochastic process has the following properties:

1. Mutually exclusive and discrete states, that is, the system can either be in the up or the down state, but not in both states simultaneously.
2. Collectively exhaustive states, that is, since it is assumed that only possible states for a system are the up and the down states, then these states define all the possible states.
3. Changes of states are possible at any time.
4. The probability of departure from a state depends only on the current state and is independent of time.
5. The probability of more than one change of state during a small time interval Δt is negligible.

Let,

$$P_1(t + \Delta t) = \begin{array}{l} \text{probability that the system will be in the up state} \\ \text{at time}(t + \Delta t) \end{array} \quad (\text{B.3})$$

Thus,

$$P_1(t + \Delta t) = \left[\begin{array}{l} \text{Probability of being} \\ \text{in state 1 at time } t \\ \text{and not leaving that} \\ \text{state during interval } \Delta t. \end{array} \right] + \left[\begin{array}{l} \text{Probability of being} \\ \text{in state 2 at time } t \\ \text{and moving to state 1} \\ \text{during interval } \Delta t. \end{array} \right] \quad (\text{B.4})$$

Considering the exponential distribution of a system failure.

$$\begin{aligned}
 P_1(t) &= e^{-\lambda t} \\
 &\triangleq \text{probability of system being available upto time } t
 \end{aligned}
 \tag{B.5}$$

Expanding the right hand side of equation (B.5) into infinite series and neglecting higher order terms, it is obtained as

$$\begin{aligned}
 P_1(t) &= 1 - \lambda \Delta t + \frac{\lambda^2 (\Delta t)^2}{2!} + \dots \\
 &\cong 1 - \lambda \Delta t \\
 &\triangleq \text{probability of system being available during time } \Delta t
 \end{aligned}
 \tag{B.6}$$

where,

$\lambda \Delta t \triangleq$ probability of transition from state 1 to state 2 in time Δt

Again,

$$\begin{aligned}
 P_2(t) &= e^{-\mu t} \\
 &\triangleq \text{probability of system being unavailable upto time } t
 \end{aligned}
 \tag{B.7}$$

Expanding into an infinite series and neglecting higher order terms, it is obtained as

$$\begin{aligned}
 P_2(t) &\cong 1 - \mu \Delta t \\
 &\triangleq \text{probability of system being unavailable during time } \Delta t
 \end{aligned}
 \tag{B.8}$$

where,

$\mu \Delta t \triangleq$ probability of transition from state 2 to state 1 in time Δt

Using the definitions of equations (B.5) to (B.8) equation (B.4) may be written as;

$$P_1(t + \Delta t) = P_1(t)(1 - \lambda \Delta t) + P_2(t)\mu \Delta t \tag{B.9}$$

similarly,

$$P_2(t + \Delta t) = P_2(t)(1 - \mu\Delta t) + P_1(t)\lambda\Delta t \quad (\text{B.10})$$

Rearranging these two equations, these become

$$\begin{aligned} \frac{P_1(t + \Delta t) - P_1(t)}{\Delta t} &= -\lambda P_1(t) + \mu P_2(t) \\ \frac{P_2(t + \Delta t) - P_2(t)}{\Delta t} &= \lambda P_1(t) - \mu P_2(t) \end{aligned}$$

Letting $\Delta t \rightarrow 0$, following differential equations are obtained:

$$\frac{dP_1}{dt} = -\lambda P_1 + \mu P_2 \quad (\text{B.11})$$

$$\frac{dP_2}{dt} = \lambda P_1 - \mu P_2 \quad (\text{B.12})$$

with,

$$P_1(t) + P_2(t) = 1$$

Equations (B.11) and (B.12) can be written in the matrix form as follows:

$$\begin{bmatrix} P_1(t) \\ P_2(t) \end{bmatrix} = \begin{bmatrix} P_1(t) & P_2(t) \end{bmatrix} \begin{bmatrix} -\lambda & \lambda \\ \mu & -\mu \end{bmatrix} \quad (\text{B.13})$$

Solving equation (B.13)

$$P_1(t) = \frac{\mu}{\lambda + \mu} [P_1(0) + P_2(0)] + \frac{e^{-(\lambda + \mu)t}}{\lambda + \mu} [\lambda P_1(0) - \mu P_2(0)] \quad (\text{B.14})$$

$$P_2(t) = \frac{\lambda}{\lambda + \mu} [P_1(0) + P_2(0)] + \frac{e^{-(\lambda + \mu)t}}{\lambda + \mu} [-\lambda P_1(0) + \mu P_2(0)] \quad (\text{B.15})$$

where $P_1(0)$ and $P_2(0)$ represents initial states (conditions) such that $P_1(0) + P_2(0) = 1$

Consider that at $t = 0$ the system is in the up state, i.e. state 1, then from equation (B.14) and (B.15) these are found,

$$P_1(0) = 1 \quad \text{and} \quad P_2(0) = 0$$

$$P_1(t) = \frac{\mu}{\lambda + \mu} + \frac{\lambda e^{-(\lambda + \mu)t}}{\lambda + \mu} \quad (\text{B.16})$$

$$P_2(t) = \frac{\lambda}{\lambda + \mu} + \frac{-\lambda e^{-(\lambda + \mu)t}}{\lambda + \mu} \quad (\text{B.17})$$

$$(\text{B.18})$$

In generation expansion planning long-term (steady-state) probabilities are required. Hence, letting $t \rightarrow \infty$ equations (B.16) and (B.17) become

$$P_1(\infty) = \frac{\mu}{\lambda + \mu}$$

$$P_2(\infty) = \frac{\lambda}{\lambda + \mu}$$

Thus, the long-term probabilities of system availability and unavailability are given by:

$$\text{pr(up state)} = p = \frac{\mu}{\lambda + \mu} = \frac{m}{m + r} \quad (\text{B.19})$$

$$\text{pr(down state)} = q = \frac{\lambda}{\lambda + \mu} = \frac{r}{m + r} \quad (\text{B.20})$$

so that,

$$p + q = 1 \quad (\text{B.21})$$

The traditional term for the unit unavailability is forced outage rate (FOR), a misnomer in fact, since the concept is not a rate. An estimate of this important parameter may be given by

$$FOR = \frac{\text{forced outage hours}}{\text{forced outage hours} + \text{service hours}}$$

or,

$$FOR = \frac{FOH}{FOH + SH} \quad (\text{B.22})$$

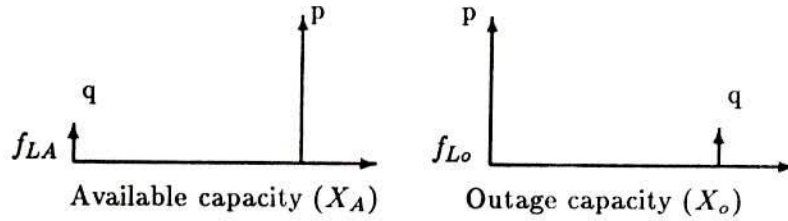


Figure B.3: PDFs of available and forced outage capacity.

For a conventional generating unit of capacity C MW, $FOR = q$ and availability p , the probability density function (PDF) of available and forced outage capacity are given in Figure B.3.

The PDF of forced outage capacity may be mathematically expressed as

$$f_{Lo}(X_o) = p\delta(X_o) + q\delta(X_o - C) \quad (\text{B.23})$$

where,

f_{Lo} = PDF of forced outage capacity

$\delta(\bullet)$ = Dirac-delta function

B.1.2 Probabilistic Load Model

Proper modelling of load is an important factor in the evaluation of LOLP. The probabilistic load model which is widely used, describes the probability that load will exceed a certain value. The data required to develop such a model are readily available, since continuous readings of system demand and energy are usually obtained on a routine basis by electric utilities. If the recordings of instantaneous demand were plotted for a particular period of time, a curve such as depicted in Figure B.4(a) might result. This is known as the *chronological load curve* (CLC). From this curve the so called *load duration curve* (LDC) in Figure B.4(b) is easily constructed. The load duration curve is created by determining what percentage of time demand exceeded a particular level.

B.1.2.1 Load Duration Curve

Load duration curve shown in Figure B.4(b) is plotted from *chronological load curve*. It is obtained from the knowledge of percentage of time the demand exceeded a

a) Instantaneous load curve b) Load duration curve

Figure B.4: Chronological load curve and load duration curve.

particular load level.

For generation system studies it is necessary to interchange the axis parameters in Figure B.4(b) and normalize time, producing *load probability distribution* shown in Figure B.5. This curve is also called *Inverted load duration curve*. This load distribution will be denoted by $F_k(L)$, where k indicates the time period for which the distribution is applicable.

B.1.2.2 Hourly Load

Another load model which is often used in various probabilistic methods for evaluating LOLP is hourly load. It is derived from the *chronological load curve* (CLC). Figure B.6 shows a CLC, the time axis being divided into a number of small intervals between times $t_0, t_1, t_2, \dots, t_{r-1}, t_r, \dots, t_{n-1}, t_n$.

In Figure B.6, the energy demand during the period between t_{r-1} and t_r is given by the area A_r under the CLC between t_{r-1} and t_r .

Figure B.5: Load probability distribution for week k.

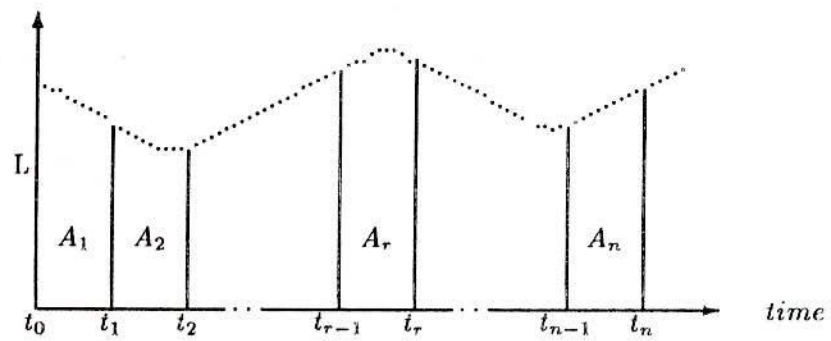


Figure B.6: CLC with time axis divided into n small interval

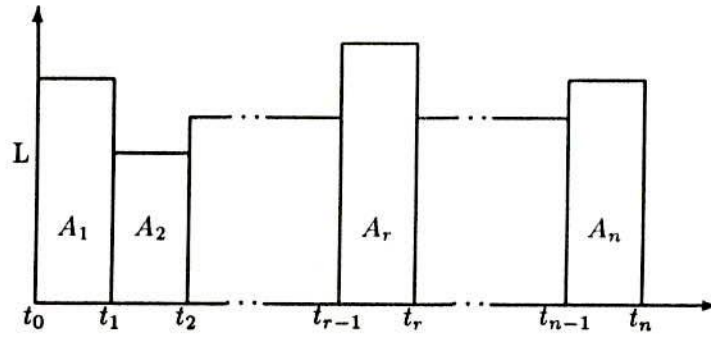


Figure B.7: Load distribution assuming constant load for each small interval

Hence,

$$A_r = \int_{t_{r-1}}^{t_r} L dt \quad (\text{B.24})$$

Dividing this area by the period of time ($t_{r-1} \rightarrow t_r$), the *average load* during that period is obtained. Thus,

$$L_{avg.} = \frac{A_r}{t_r - t_{r-1}} \quad (\text{B.25})$$

In this way, the average load for all other time intervals may be obtained. If the average load for such a time interval is assumed to remain constant for the corresponding interval, then a average load curve shown in Figure B.7 will result. It may be noted by such construction of load curve, the energy demand for each interval usually remains unchanged. If the time interval is one hour then the resulting curve is called *hourly load curve*.

B.1.3 Equivalent Load

The randomness in the availability of generation capacity is taken into consideration by defining a fictitious load, known as *equivalent load* (L_e) [28]. Figure B.8 depicts the relationship between the system load and generation units, where actual units have been replaced by fictitious perfectly reliable (100% reliable) units and fictitious random loads, whose probability density functions are the outage capacity density functions of the units.

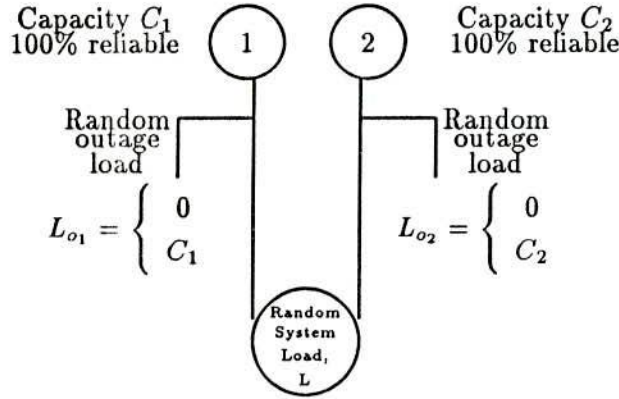


Figure B.8: Fictitious Generating Unit and System Load Model

If L_{oi} represent the random outage load corresponding to the i th unit, then the equivalent load (L_e) may be expressed as

$$L_e = L + \sum_{i=1}^n L_{oi} \quad (\text{B.26})$$

where n is the total number of generating units. When $L_{oi} = C_i$, the net demand injected to the system is zero for the i th unit, just as it would be if the actual unit of capacity C_i were forced off-line. Note that the installed capacity of the system is given by

$$IC = \sum_{i=1}^n C_i \quad (\text{B.27})$$

The outage of the generating units may be assumed independent of the system load. Then the distribution of the equivalent load will be the outcome of convolution of two distributions: f_{Lo} and f_L representing the PDFs of the outage capacity L_{oi} and the system load L , respectively. For the discrete case the PDFs, f_L and f_{Lo} may be written as;

$$f_L(L) = \sum_i p_{L_i} \delta(L - L_i) \quad (\text{B.28})$$

$$f_{L_o} = \sum_j p_{L_j} \delta(L - L_{o_j}) \quad (\text{B.29})$$

Then the PDF of equivalent load f_{L_e} may be written as

$$\begin{aligned} f_{L_e}(L_e) &= f_L(L) * f_{L_o}(L_o) \\ &= \sum_{ij} p_{L_i} p_{L_{o_j}} \delta[L_e - (L_i + L_{o_j})] \end{aligned} \quad (\text{B.30})$$

where $*$ indicates the convolution sign and p_L and p_{L_o} are the probabilities of load and outage of machine respectively. The letters L and L_o in equation (B.30) are the values of the corresponding random variables (RVs) and L_e is the resultant random variable. Now LOLP can also be expressed in terms of equivalent load (L_e) as

$$LOLP = Pr(L_e > IC) \quad (\text{B.31})$$

Appendix C

Generation Data

Table C.1: Generation Data of a Prototype System X from IEEE-RTS [40]

Type of Unit	Unit size (MW)	Number of Units	Forced Outage Rate (FOR)
Oil	10	5	0.02
Oil	20	4	0.10
Hydro	50	6	0.01
Coal	80	4	0.02
Oil	100	3	0.04
Coal	150	4	0.04
Oil	200	3	0.05
Coal	350	1	0.08
Nuclear	400	2	0.12
Total 3400 MW and 32 units			
Hourly Load	48-52 & 1-8 Weeks		
Peak Load	2850 MW		

Table C.2: Generation Data for other system Y [67].

Type of Unit	Number of Units	Unit size (MW)	Forced Outage Rate (FOR)
Nuclear	1	500	0.13
Coal	2	400	0.13
Coal	1	350	0.13
Coal	1	150	0.08
Oil	1	350	0.14
Oil	2	200	0.10
Oil	4	50	0.11
Hydel	2	100	0.01
Total 2950 MW and 14 units			
Hourly Load	18-30 Weeks		
Peak Load	2565MW		

Table C.3: Generation system of OSEB available at 1995

Station of Unit	Unit size (MW)	Number of Units	Forced Outage Rate (FOR)	Av. Inc. cost (Rs./MWh)
Thermal Generation:				
1. Talcher-I	60	4	0.14	368
2. Talcher-II	110	2	0.14	368
3. Ib thermal-I	210	1	0.14	320
Thermal Share				
a) Farakka	135	1	0.14	344
b) NALCO	40	1	0.18	368
c) ICCL	40	1	0.18	368

Station of Unit	Unit size (MW)	Forced Outage Rate (FOR)	Hydel Gen. (GWh)
Hydro Electric Generation (station-wise)			
1. Hirakund (Burla & Chiplima)	305	0.10	550
2. Balimela	360	0.10	550
3. Ringali	250	0.10	355
4. Upper Kulab	320	0.10	405
5. Muchkund	55	0.10	150

Table C.4: Two state Generation Data for two systems [67].

Type of Unit	SYSTEM X			SYSTEM Y		
	Number of Units	Capacity (MW)	FOR	Number of Units	Capacity (MW)	FOR
Nuclear	2	400	0.12	1	500	0.13
Coal	4	150	0.04	2	400	0.13
Coal	1	350	0.08	1	350	0.13
Coal	4	80	0.02	1	150	0.08
Oil	3	200	0.05	1	350	0.14
Oil	3	100	0.04	2	200	0.10
Oil	5	10	0.02	4	50	0.11
Oil	4	20	0.10			
Hydel	6	50	0.01	2	100	0.01
Total	32	3400		14	2950	
Load Hourly	48-52 & 1-8 Weeks			18-30 Weeks		
Peak Load	2850 MW			2565MW		

Table C.5: Generation data of the hypothetical systems Interconnected with OSEB by 400 MW tie line capacity

Number of Units	FOR	Capacity (MW)
4	0.14	150.
2	0.14	110.
2	0.14	210
4	0.18	50.

Table C.8: A prototype Generation System X [40]

Type of Unit	Unit size (MW)	Number of Units	Forced Outage Rate (FOR)	Inc. Cost λ ,\$/MWh
Oil	10	5	0.02	25.875
Oil	20	4	0.10	37.500
Oil	100	3	0.04	20.853
Coal	150	4	0.04	10.704
Oil	200	3	0.05	20.730
Coal	80	4	0.02	13.494
Coal	350	1	0.08	10.883
Nuclear	400	2	0.12	5.450
Hydro	50	6	0.01	0.00
Total 3400 MW and 32 units				
Hourly loads 48-52 and 1-8 IEEE winter weeks				
Peak load 2850 MW				

Table C.9: A hypothetical Generation System Y [75]

Type of Unit	Unit size (MW)	Number of Units	Forced Outage Rate (FOR)	Inc. Cost λ ,\$/MWh
Nuclear	500	1	0.13	4.5
Coal	400	2	0.13	14.3
Coal	350	1	0.13	15.1
Coal	250	1	0.08	18.6
Oil	350	1	0.14	30.4
Oil	200	2	0.10	35.0
Oil	50	4	0.11	43.2
Hydro	100	3	0.01	0.0
Total 3150 MW and 15 units				
Hourly loads 18-30 IEEE summer weeks				
Peak load 2565 MW				

Appendix D

CONCEPTS OF FUZZY SET THEORY

Some concepts of fuzzy set theory required in sequel are explained below in brief, following the references [136, 142, 207, 212, 213].

D.1 Fuzzy Set, Membership Function, Fuzzy Number

A fuzzy set $\tilde{A}$ of a variable $x \in X (\subset \mathbb{R})$ is characterized by an ordered set of pairs $\{x, \mu_{\tilde{A}}(x) | x \in X\}$, where $\mu_{\tilde{A}}(x)$ ($\mu_{\tilde{A}}(x) \in [0, 1]$) is a number representing the degree of compatibility or truth of x in $\tilde{A}$. The function $\mu_{\tilde{A}}(x)$, which is called a *membership function* thus maps X to a membership space S . The membership is usually called the possibility distribution of X . When $S = 0$ or 1 , $\tilde{A}$ is crisp (that is non-fuzzy); it is thus a generalization of the indicator function in a set. A fuzzy set $\tilde{A}$ is said to be convex if its membership function $\mu_{\tilde{A}}(x)$ is convex.

A fuzzy set $\tilde{A}$ is said to be a *fuzzy number*, if

1. $\tilde{A}$ is convex set.
2. $\mu_{\tilde{A}}(x_0)$ is piece wise continuous
3. there exists one real number $x_0 \in X$ such that $\mu_{\tilde{A}}(x_0) = 1$. where, x_0 is called the mean value of $\tilde{A}$.

if the last item is replaced by the statement:

3. there exists a flat top region for $\mu_{\tilde{A}}(x_0) = 1$ corresponding to $\mu_{\tilde{A}}(x_0) = 1$ then $\tilde{A}$ is said to be an *extended fuzzy number*.

D.2 Arithmetic Operations of Extended Fuzzy Numbers

Arithmetic operations (addition, subtraction, multiplication and division) on extended fuzzy numbers are defined and the operations are taken place in terms of membership functions [136, 142, 207, 212, 213]. These can be represented more completely by using the resolution identity, and their properties can be analyzed more conveniently through interval arithmetic and confidence intervals. Arithmetic operations on two extended fuzzy numbers M and N give the following expressions, which are similar to those defined in interval arithmetic.

D.3 Extended operations for L-R representation of fuzzy numbers

Computational efficiency is of particular importance when using fuzzy set theory to solve real problem, that is, problems of realistic size. It would, therefore, be considered in the following in detail the L-R representation of fuzzy sets, which increases computational efficiency without limiting the generality beyond acceptable limits.

Dubois and Prade [207] suggested a special type of representation for fuzzy numbers of the following type:

A function, usually denoted L or R , is a reference function of fuzzy numbers iff

1. $L(x) = L(-x)$;
2. $L(0) = 1$;
3. L is nonincreasing on $[0, +\infty]$.

In general,

$$L(x) = \max(0, 1 - |x|)$$

A fuzzy number M is said to be an L-R type fuzzy number iff

$$\begin{aligned}\mu_M(x) &= L\left(\frac{m-x}{\alpha}\right) \quad \text{for } x \leq m, \alpha > 0. \\ \mu_M(x) &= R\left(\frac{x-m}{\beta}\right) \quad \text{for } x \geq m, \beta > 0.\end{aligned}$$

where, L is for left and R is for right reference function, m is the mean value of M . α and β are called left and right spreads respectively.

When the spreads are zero, M is a non-fuzzy number by conventions. As the spreads increase, M becomes fuzzier and fuzzier. Symbolically it is written as,

$$M = (m, \alpha, \beta)_{LR} \text{ for a triangular shape fuzzy number.}$$

D.4 Flat fuzzy numbers

A flat fuzzy number shown in Figure D.1 is a trapezoidal fuzzy number M such that there exist $(m_1, m_2) \in \mathfrak{R}$, $m_1 < m_2$ and $\mu_M(x) = 1$ for all $x \in [m_1, m_2]$. The membership function of a flat fuzzy number M is defined as

$$\begin{aligned}\mu_M(x) &= L\left(\frac{m_1-x}{\alpha}\right) \quad \text{for } x \leq m_1, \quad \alpha > 0. \\ \mu_M(x) &= R\left(\frac{x-m_2}{\beta}\right) \quad \text{for } x \geq m_2, \quad \beta > 0. \\ \mu_M(x) &= 1. \quad \text{otherwise}\end{aligned}$$

More briefly, the fuzzy interval is then denoted by

$$M = (m_1, m_2, \alpha, \beta)_{LR}$$

This is very general and allows quantification of quite different types of information.

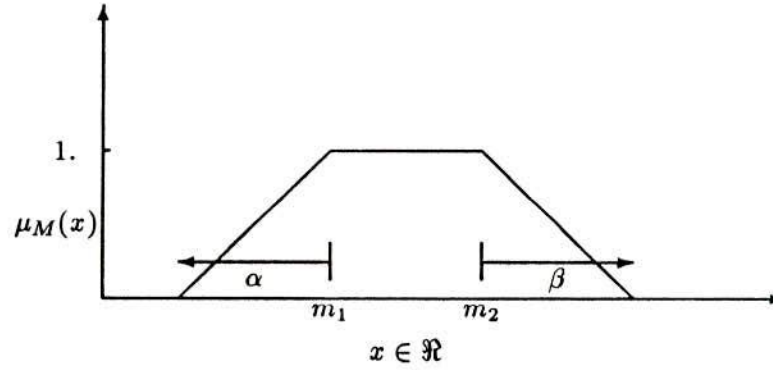


Figure D.1: Flat type or trapezoidal shape Fuzzy number M

- a. For instance, if M is supposed to be a real crisp number for $m \in \mathbb{R}$, $M = (m, m, 0, 0)_{LR}$ for all L are R.
- b. if M is a crisp interval, $M = (m_1, m_2, 0, 0)_{LR}$,
- c. and if M is a "trapezoidal fuzzy number" of equal spread, then $L(x) = R(x) = \max(0, 1 - |x|)$ is implied.

For L-R fuzzy numbers the computations necessary for the above mentioned operations are considerably simplified. Dubois et al.[207] showed the exact formulae can be given for addition $[\oplus]$ and subtraction $[\ominus]$. They also suggested approximate expressions for multiplication $[\odot]$ and division $[\oslash]$, which approximate is better when the spreads are smaller compared to the mean values. These are given below.

D.4.1 Addition

Let us consider the increasing parts of two fuzzy numbers $M = (m, \alpha, \beta)_{LR}$ and $N = (n, \gamma, \delta)_{LR}$. Let x and y be the unique real number such that

$$L\left(\frac{m-x}{\alpha}\right) = \omega = L\left(\frac{n-y}{\gamma}\right)$$

where ω is a fixed value in $[0, 1]$. This is equivalent to

$$x = m - \alpha L^{-1}(\omega)$$

and

$$y = n - \gamma L^{-1}(\omega),$$

which implies

$$\begin{aligned} z &= x + y = m + n - (\alpha + \gamma)L^{-1}(\omega) \text{ or,} \\ L\left(\frac{m + n - z}{\alpha + \gamma}\right) &= \omega \end{aligned}$$

The same reasoning holds on decreasing parts of M and N , which implies or,

$$R\left(\frac{z - [m + n]}{\beta + \delta}\right) = \omega$$

Hence, the addition $M \oplus N$ is found from

$$M \oplus N = (m, \alpha, \beta) \oplus (n, \gamma, \delta) = (m + n, \alpha + \gamma, \beta + \delta)_{LR}$$

The formula for the opposite fuzzy number is

$$-M = -(m, \alpha, \beta) = (-m, \beta, \alpha)$$

Note that the reference are exchanged. Therefore, the formula for subtraction,

$$M \ominus N = (m, \alpha, \beta)_{LR} \ominus (n, \gamma, \delta)_{LR} = (m - n, \alpha + \delta, \beta + \gamma)_{LR}$$

D.4.2 Multiplication

Using the same reasoning as above, for positive fuzzy numbers,

$$z = x.y = m.n - (m.\gamma + n.\alpha)L^{-1}(\omega) + \alpha.\gamma[L^{-1}(\omega)]^2$$

$\mu_{m \odot n}$ is explicitly deduced by neglecting the term $\alpha\gamma[L^{-1}(\omega)]^2$, provided α and γ are small compared with m and n . Then above equation becomes simpler. Therefore,

if $M > 0$ and $N > 0$ then,

$$M \odot N = (m, \alpha, \beta) \odot (n, \gamma, \delta) = (m.n, m\gamma + n\alpha, m\delta + n\beta)_{LR}$$

D.4.3 Scalar multiplication

For all $\lambda > 0$, $\lambda \in \mathfrak{R}$,

$$\lambda \odot m = \lambda \odot (m, \alpha, \beta) = (\lambda m, \lambda \alpha, \lambda \beta)$$

The addition, subtraction and multiplication of L-R type trapezoidal/flat fuzzy numbers are easily constructed in the similar way of the above procedures.

$$\begin{aligned} (m_1, m_2, \alpha, \beta)_{LR} \oplus (n_1, n_2, \gamma, \delta)_{LR} &= (m_1 + n_1, m_2 + n_2, \alpha + \gamma, \beta + \delta)_{LR} \\ (m_1, m_2, \alpha, \beta)_{LR} \ominus (n_1, n_2, \gamma, \delta)_{LR} &= (m_1 - n_2, m_2 - n_1, \alpha + \delta, \beta + \gamma)_{LR} \\ (m_1, m_2, \alpha, \beta)_{LR} \odot (n_1, n_2, \gamma, \delta)_{LR} &= (m_1.n_1, m_2.n_2, n_1\alpha + m_1\gamma, n_2\beta + m_2\delta)_{LR} \end{aligned}$$

D.4.4 Probability of Fuzzy Events

In a random process, let X be the space of elementary events or outcomes, B is the subsets of X and P is the probability measure on B , i.e., P is a function on B into $[0,1]$, such that

$$\begin{aligned} P_1 &: P(A) \geq 0, \quad \forall \quad A \in B \\ P_2 &: P(X) = 1 \\ P_3 &: \text{If } A_1, A_2, \dots, A_n \end{aligned}$$

is a countable disjoint sequence of sets in B (mutually exclusive), then

$$P\left(\bigcup_{i=1}^n A_i\right) = \sum_{i=1}^n P(A_i)$$

and the probability space may be defined by the triplet (X, B, P) .

It is assumed that $X \subseteq \mathfrak{R}$. For a particular nonfuzzy event A on X , the probability can be defined as

$$Pr(A) = \sum P(A_i) = \sum_{x \in A} P(x_i) = \sum_{x \in X} \mu_A(x_i) P(x_i)$$

where, $\mu_A(x)$ is characteristic function of A , i.e.,

$$\mu_A(x) = 0 \text{ or } 1$$

This concept has been extended to the event of fuzzy environment [129]. That is, if $\tilde{A}$ is a fuzzy event on X whose membership function $\mu_{\tilde{A}}(x)$ is measurable, then the probability of fuzzy events $\tilde{A}$ is defined by

$$Pr(\tilde{A}) = \sum_{x \in X} \mu_{\tilde{A}}(x_i) P(x_i)$$

Thus, the probability of $\tilde{A}$ is the expectation of its membership function. Fuzzy random variables are random variables whose values are not real (crisp), but fuzzy numbers.

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