Generating System Reliability Optimization

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Department of Electrical Engineering
University of Saskatchewan
Saskatoon, Saskatchewan

by

Hua Chen

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0-612-63854-5

Permission to Use

Head of the Department of Electrical Engineering
University of Saskatchewan
57 Campus Drive
Saskatoon, Saskatchewan
Canada, S7N 5A9

Abstract

Reliability optimization can be applied in both conventional and non-conventional generating system planning. This thesis is concerned with generation adequacy optimization, with emphases on applications to wind energy penetration planning and interruptible load utilization. New models, indices and techniques for generation adequacy optimization including wind turbines and interruptible load utilization have been developed in this research work.

A sequential Monte Carlo simulation technique for wind power modeling and reliability assessment of a generating system was developed in the research associated with optimum wind energy penetration planning. An auto-regressive and moving average (ARMA) time series model is used to simulate the hourly wind speeds. Two new risk-based capacity benefit indicators designated as the Load Carrying Capability Benefit Ratio (LCCBR) and the Equivalent Capacity Ratio (ECR) are introduced. These two indices are used to indicate capacity benefit and credit associated with a wind energy conversion system. A bisection technique to assess them was further developed. The problem of determining the optimum site-matching windturbine parameters was studied with the LCCBR and ECR as the optimization objective functions. Sensitivity studies were conducted to show the effect of wind energy penetration level on generation capacity benefit. A procedure for optimum penetration planning was formed, which extends the methods developed for conventional generation adequacy optimization.

A basic framework and techniques to conduct interruptible load analysis using sequential Monte Carlo simulation were created in the research associated with interruptible load utilization. A new index designated as the Avoidable Additional Generating Capacity (AAGC) is introduced. Bisection search techniques were developed to effectively determine the Incremental Load Carrying Capability (ILCC) and AAGC. Case studies on suitable contractual options for interruptible load customers under given conditions are also presented in this thesis. The results show that selecting a suitable set of interruptible load contractual conditions, in which various risk conditions are well matched, will achieve enhanced interruptible load carrying capability or capacity benefits.

The series of case studies described in this thesis indicate that the proposed concepts, framework, models and quantitative techniques can be applied in practical engineering situations to provide a scientific basis for generating system planning.

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List of Symbols and Abbreviations

λ_{ai}	active failure rate of component i
λ_{pi}	passive failure rate of component i
λ_i''	scheduled maintenance outage rate of component i
$\lambda_{Ea}(F_m)$	equivalent active failure rate associated with failure event F_m
$\lambda_{Ep}(F_m)$	equivalent passive failure rate associated with failure event F_m
μ	the mean wind speed of all the observed data
μ_t	the mean observed wind speed at hour t
$\mu_E(F_m)$	equivalent repair rate associated with failure event F_m
$\{\alpha_t\}$	normal white noise process
$\sigma(X)$	the standard deviation of reliability index X
σ_t	the standard deviation of the observed wind speed at hour t
σ_a^2	variance of a normal white noise process
ϕ_i	auto-regressive parameters.
θ_j	moving average parameters.
$AP_k^{(s)}$	the available power output in sub-network s at state k
AP_k	the total available power in state k
C_i	the load curtailment of load loss event i in MW
$C(i)$	capacity of component I
D_i	the duration of load loss event i in hours
E_i	the energy not supplied of interruption i in MWh
$E(X)$	the mean value of reliability index X
$EDNG(F_m)$	Expected Demand Not Generated when failure event F_m occurs
$EENG(F_m)$	Expected Energy Not Generated when failure event F_m occurs
F	the set of failure events

F_i	the frequency of load loss event i in occ./year
F_m	a failure event
$F(t)$	cumulative probability distribution function
$Freq(F_m)$	frequency of failure event F_m
$Freq\_IS(m)$	frequency of m units being isolated
$Freq\_LG(m)$	frequency of losing m lines which link the generation source
$FLOG(F_m)$	frequency of Loss of Generation when failure event F_m occurs
G_i	Green function
GC_{new}	the total system installed capacity that is required to maintain the system risk at the same level of R_c
GC_{old}	the original system installed capacity, at which the system risk is maintained at the level of R_c.
$IPLCC_C$	the incremental load carrying capability benefit from conventional generation additions
$IPLCC_W$	the incremental load carrying capability benefit from WECS additions
LOG_k	demanded power not generated in the state k of the generalized model shown in Figure 3.1.
$LOGP(F_m)$	Loss of Generation Probability when failure event F_m occurs
N	the number of simulated years
NPO	the power output of the generating station in the normal operating state
OW_t	observed wind speed at hour t
$PLCC_{new}$	the peak load that the expanded generating system can carry
$PLCC_{orig}$	the peak load that the original generating system can carry at risk level R_c
P_k	probability of state k
P_r	the rated power of a WTG unit or a WECS
P_{si}	probability of a stuck breaker i
PL	system peak load
$Prob(F_m)$	probability of failure event F_m

Prob_IS(m)	probability of *m* units being isolated
Prob_LG(m)	probability of losing *m* lines which link the generating source
r_i	repair time of component *i*
r_i''	scheduled maintenance time of component *i*
R_c	the criterion reliability
R_i	the reliability criterion selected for the additional interruptible load.
RSS(n,n-1)	the Residual Sum of Squares of model ARMA(n,n-1)
SW_t	the simulated wind speed at hour t.
V_{ci}	the cut-in speed of a WTG unit
V_{co}	the cut-out speed of a WTG unit
V_r	the rated speed of a WTG unit
$W(D_i)$	customer damage function in $/kW
X_k	switching rate of the *k th* switching action

AAGC	Avoidable Additional Generating Capacity
AR	Auto-Regressive
ARMA	Auto-Regressive and Moving Average
BEPCI	Bulk Power/Energy Curtailment Index
BPII	Bulk Power Interruption Index
BPACI	Bulk Power Supply Average MW Curtailment Index
CCDF	Composite Customer Damage Function
CDF	Customer Damage Function
CEA	the Canadian Electricity Association
CF	Capacity Factor
D	Duration per interruption
DFS	Depth First Searching
DLOG	Duration of Loss of Generation
DLOIL	Duration of a Loss of Interruptible Load
DLOL	Duration of Loss of Load

DSM	Demand Side Management
ECR	Equivalent Capacity Ratio
EDNG	Expected Demand Not Generated
EDNS	Expected Demand Not Supplied
EENG	Expected Energy Not Generated
EENS	Expected Energy Not Supplied
EIC	Expected Interruption Cost
ENS	Energy Not Supplied
ENSI	Energy Not Supplied per Interruption
FLCC	Firm Load Carrying Capability
FLOG	Frequency of Loss of Generation
FLOIL	Frequency of Loss-of-Interruptible-Load
FLOL	Frequency of Loss of Load
FOR	Forced Outage Rate
GRASS	a computer program for Generation Reliability Assessment using Sequential Simulation
GSRAP	a computer program for Generating Station Reliability Assessment
HL I	Hierarchical Level I
HL II	Hierarchical Level II
HL III	Hierarchical Level III
HVDC	High Voltage Direct Current
IEAR	Interrupted Energy Assessment Rate
ILCC	Interruptible Load Carrying Capability
ILPASS	a computer program for Interruptible Load Probabilistic Analysis using Sequential Simulation
IPLCC	Incremental Peak Load Carrying Capability
LCCBR	Load Carrying Capability Benefit Ratio
LNSI	Load Not Supplied per Interruption
LOEE	Loss of Energy Expectation
LOGE	Loss of Generation Expectation
LOGP	Loss of Generation Probability

LOIEE	Loss of Interruptible Energy Expectation
LOILE	Loss-of-Interruptible-Load Expectation
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
MTTF	Mean Time-To-Failure
MTTR	Mean Time-To-Repair
NID	Normally Independently Distributed
NSERC	the Natural Science and Engineering Research Council
PLCC	Peak Load Carrying Capability
RBTS	The Roy Billinton Test System
SCDF	Sector Customer Damage Functions
SI	Severity Index
SWIND	a computer program to simulate the wind speed
TTF	Time-To-Failure
TTR	Time-To-Repair
WECS	Wind Energy Conversion System
WGRASS	a computer program for generation reliability assessment including WECS using sequential simulation
WSERIES	a computer program used to establish the time series model of wind speed.
WTG	Wind Turbine Generator

Chapter 1
Introduction

1.1 Power System Reliability Evaluation

Electricity began to penetrate into daily life with the introduction of public power supply in the early 20th century. Today, electricity dominates almost every aspect of life in industrialized countries. As deregulation of electric power utilities escalates, the importance of high quality electrical supply will constantly grow as consumers increase their expectations [1]. Failure in any part of a power system can cause poor quality of power supply, load curtailment or interruptions, which range from inconvenience to small numbers of local residents, to widespread catastrophic disruptions of supply. Almost every country has suffered serious power interruptions in the past several decades. The social and economic losses due to these outages can be substantial. The cost in the case of the 1977 New York blackout was estimated to be as high as $350 million [2]. Catastrophic events such as this indicate the importance and necessity of developing realistic power system reliability evaluation and optimization techniques. With these quantitative techniques, utilities can determine a reasonable balance between reliability and economics for a particular project justification, locate weak links in a power system, determine improvement measures and conduct optimum expansion and operational planning within their socioeconomic constraints.

The reliability associated with a power system, in a general sense, is a measure of the overall ability of the system to generate and supply electrical energy. Power system reliability can be further divided into the two distinct categories of system adequacy and system security [2, 3, 4, 5, 6, 7], as shown in Figure 1.1.

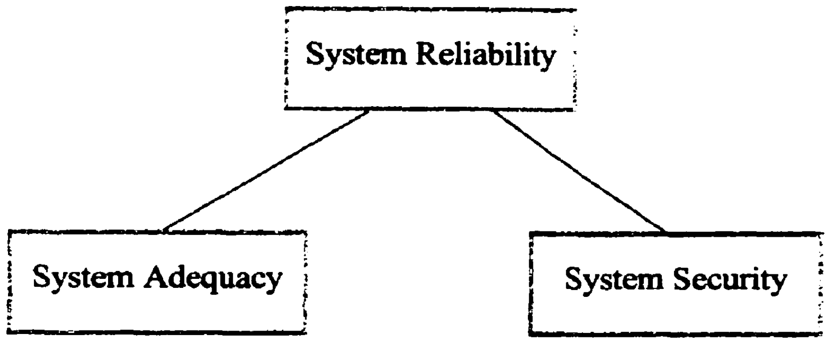

Figure 1.1 Subdivision of system reliability

Adequacy is an indicator of the existence of sufficient facilities within the system to satisfy future consumer load demand or system operational constraints. It relates to the facilities necessary to generate sufficient energy, and the associated facilities required to transmit and distribute the energy to the actual consumer load points. Steady state system conditions are usually considered in adequacy evaluation. These assessments are mainly used in power system planning.

Security is a measure of the ability of the system to respond to dynamic and transient disturbances arising within the system. It relates to the response of the system to whatever perturbation it is subjected to. Contingency events such as the abrupt loss of major generation and transmission facilities, which can lead to dynamic, transient or voltage instability of the system, are considered in security evaluation. Security assessment is used in both power system planning and operation.

Most probabilistic techniques available at the present time for power system reliability evaluation are in the domain of adequacy assessment. The ability to assess security is very limited [3, 8]. The reason for this limitation is due to the complexity associated with modeling the dynamic and transient characteristics of a system. The main indices presently utilized in power utilities are adequacy indices rather than overall reliability indices, which include both adequacy and security connotations. The indices obtained by assessing past system performance, however, include the effect of all the system faults and failures irrespective of cause, and therefore encompass insecurity as well as inadequacy.

A complete power system can be categorized into the three segments, or functional zones, of generation, transmission and distribution. This division is an appropriate one as most utilities are either divided into these zones for the purpose of organization, planning, operation and analysis or are solely responsible for one of these functions. As shown in Figure 1.2, the three functional zones can be combined to create three hierarchical levels, which provide a basic framework for power system adequacy evaluation [6, 7].

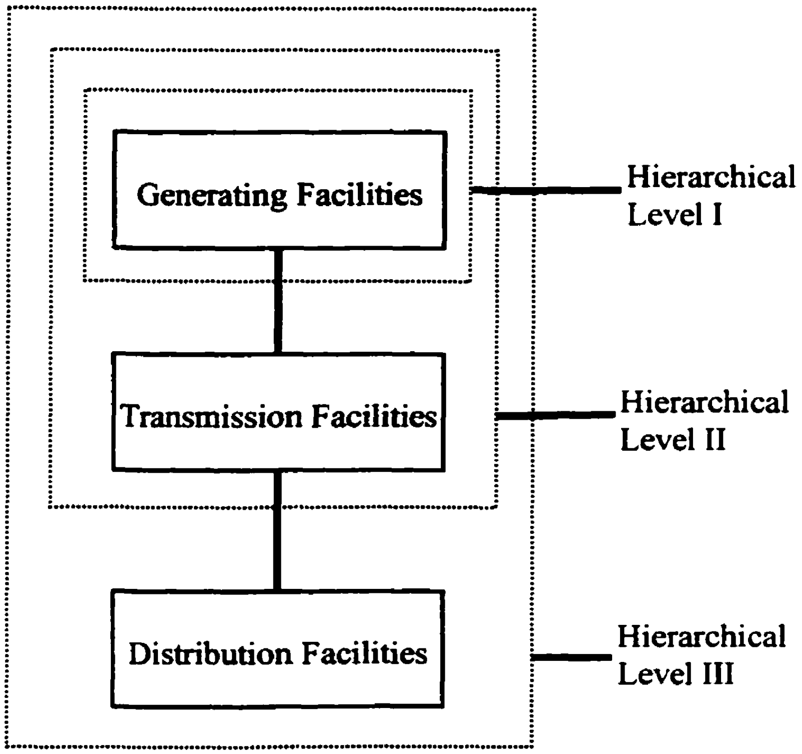

Figure 1.2 Hierarchical level structure

Hierarchical Level I (HL I) assessment, usually termed as "generating capacity reliability evaluation", is mainly concerned with assessing the amount of generating capacity that must be installed in order to satisfy the perceived system load and to perform necessary corrective or preventive maintenance with an acceptable level of risk. The effects of both the transmission network and the distribution facilities are neglected.

Conceptually, a capacity model and a load model are created and then convolved to obtain probabilistic risk indices.

Hierarchical Level II (HL II) analysis, which is usually termed as "composite system reliability evaluation" or "bulk power system reliability evaluation", considers both generation and transmission systems. The techniques for HL II adequacy evaluation are concerned with the composite problem of assessing the generation and transmission facilities in regard to their ability to supply adequate, dependable and suitable electrical energy at the bulk power load points. The inclusion of the transmission network usually results in a sharp increase in computational effort and analysis complexity.

Hierarchical Level III (HL III) analysis, which can be termed as "complete power system reliability evaluation", includes all three functional zones, starting with the generation and terminating at the individual consumer load points. The objective of an HL III study is to obtain suitable adequacy indices at actual consumer load points. HL III reliability assessment is not usually conducted in a practical system due to the computational complexity involved in this assessment. This analysis is therefore normally performed only in the distribution functional zone, in which the effects of HL II can be incorporated as input to the distribution system.

In addition to the basic three hierarchical levels of reliability evaluation, the assessment can be also performed separately on any system subset such as generating stations, switching stations and substations, in order to examine the effect of a particular topological change within the subset, or to create an equivalent component for reliability evaluation in HL I, HL II or HL III [3,7].

1.2. Basic Framework for Power System Reliability Optimization

1.2.1 Concept of Reliability Optimization

Reliability studies of a power system are only part of the required overall assessment. The economics of alternative facilities, together with the technical aspects, play a major role in the decision-making process. The simplest approach that can be used to relate economics with reliability is to consider the investment cost only. In this approach, the increase in reliability due to the various alternatives is evaluated together with the investment cost associated with each scheme. Dividing this cost by the increase in reliability gives the incremental cost of reliability, i.e., how much it will cost for a per-unit increase in reliability. This approach is useful when comparing alternatives given that the reliability of the facilities under consideration of the power system is inadequate. In this case, the lowest incremental cost of reliability is the most cost effective. This is a significant step forward from simply comparing alternatives and making major capital investment decisions using deterministic techniques.

The weakness of this approach is that it is not related to either the likely return on investment or the real benefit accruing to the consumer, utility, and society. In order to make a consistent appraisal of economics and reliability, it is necessary to compare the reliability cost with the reliability worth and search for an optimum balance between the cost and the worth.

The basic concept in power system reliability optimization is relatively simple and can be illustrated using the cost/reliability curves of Figure 1.3 [2, 3]. Figure 1.3 shows that utility costs will generally increase as consumers are provided with higher reliability. On the other hand, consumer costs associated with supply interruption will decrease as the reliability increases. The total costs to society are the sum of these two individual costs. This total cost exhibits a minimum point at which an "optimum" or target level of reliability is achieved.

The system cost and reliability level are mapped one to one in Figure 1.3. This is not true in a practical situation. A given investment can be put into any part of a power system. In addition, there are many available alternatives and each alternative will affect system reliability in its own way. Consequently, different reliability levels can be achieved for the same system cost. Figure 1.4 has a more comprehensive form than Figure 1.3. In Figure 1.4, a zone rather than a curve express the cost-reliability relationship. Three cost zones are given, that is, "Utility Cost Zone", "Consumer Outage Cost Zone" and "Total Cost Zone".

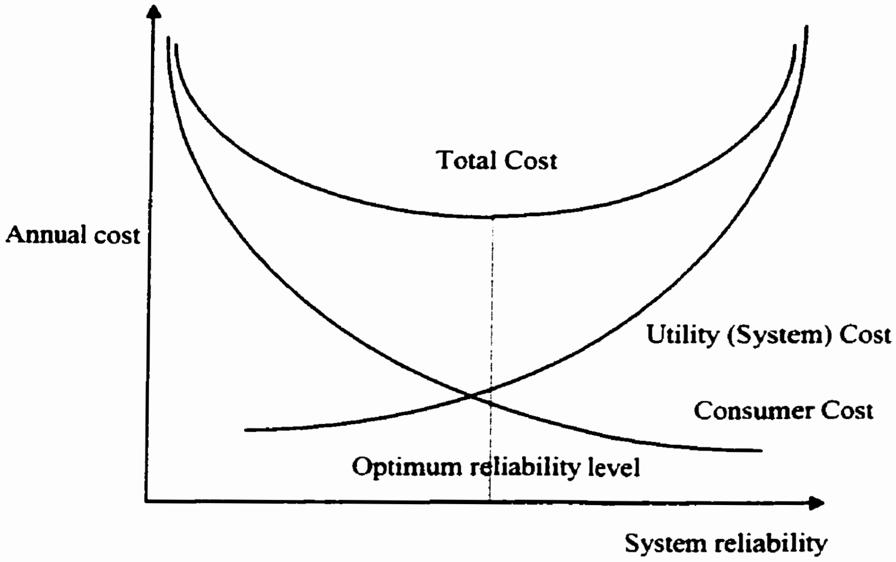

Figure 1.3 Consumer, utility and total cost as a function of system reliability

Figure 1.3 can be considered as a special form of Figure 1.4 if the curves in Figure 1.3 indicate the relationship of the cost with the corresponding maximum reliability achieved for the given cost, or the relationship of the given reliability with the minimum costs.

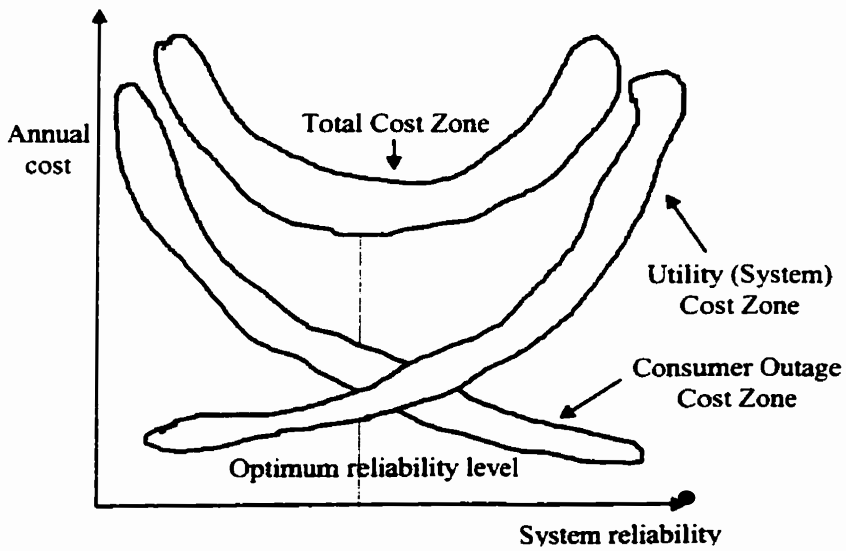

Figure 1.4 Extended concept of power system reliability optimization

Conventionally, only one optimum level of reliability is associated with a reliability optimization problem. In the open power market, different reliability levels rather than one single level may be assigned to different sets of consumers in order to achieve the maximum total benefits. For example, firm load and interruptible load should be given different treatment. Consequently, a set of optimum reliability levels are sought in a new form of power system reliability optimization.

1.2.2 Basic Types of Reliability Optimization Problems

Generally, any power system optimization problem that considers reliability as a variable, an objective function or part of the objective function, can be regarded as a reliability optimization problem. Reliability indices or reliability worth indicators can be either incorporated as part of an objective function or be associated with one of the possible constraints. Basically, there are three types of reliability optimization problems.

Type 1 involves the determination of the most suitable reliability level that minimizes the total costs or maximizes the utility and social benefits subject to various constraints. The utility costs and the customer outage costs are incorporated in the objective function.

Type 2 involves a search for the highest reliability or the maximum incremental reliability for the given investment. Reliability is the only item in the objective function. Various reliability indices, or the customer damage cost that is implicitly related to a reliability index, can be selected as the objective function.

Type 3 involves a search for the minimum investment implemented for the given reliability level. Reliability is considered as a constraint in this case.

Type 1 is more complex than Types 2 and 3. Types 2 and 3 can be considered as subsets of Type 1. The optimized results associated with Types 2 and 3, however, can give different physical meanings and thus provide different inputs to the decision process.

The approaches utilized in power system reliability optimization can be divided into two categories. The first one can be designated as the "absolute optimization technique". The basic approach is to first create a mathematical model and then obtain the optimum solution using a classic linear or nonlinear optimization approach. This type of technique has not been widely used in power utilities as it is difficult to incorporate human factors such as environmental effects, or political philosophies into the decision model. The second type is designated as the "alternative optimization technique". The basic procedure in this technique is to first roughly determine a number of alternatives. Economic and technical analyses are then conducted for each alternative. The alternative with the minimum cost and a reasonable technical quality can then be selected as the final plan. This technique is widely used by power utilities in both developing and developed countries. A relative optimization rather than an absolute optimization can be achieved using this type of technique.

1.2.3 Adequacy Optimization and Security Optimization

Power system reliability optimization can be conceptually divided into two distinct categories of "Adequacy Optimization" and "Security Optimization", as shown in Figure 1.5.

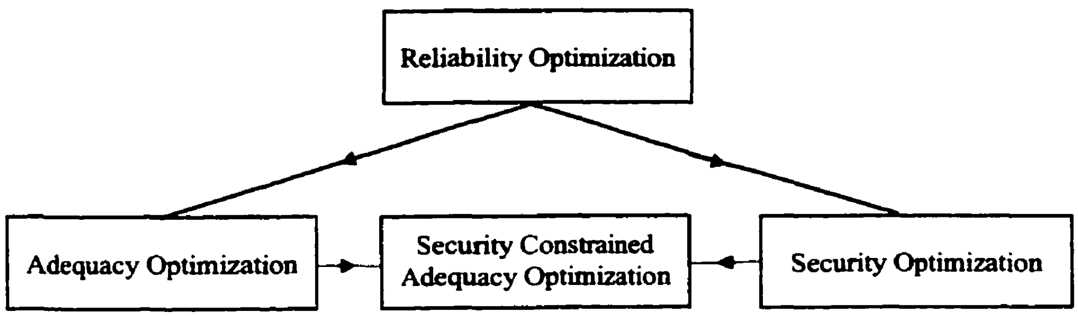

Figure 1.5 Division of power system reliability optimization

Adequacy optimization is mainly used in power system development planning to determine the most suitable adequacy levels or structures that give the minimum total cost or maximum utility and social benefits. It relates to the optimum expansion, allocation and penetration of new facilities or energy sources. The objective function in adequacy optimization is usually the summation of the system investment, operating costs and consumer damage costs.

Security optimization is mainly used in power system operational planning to determine the most suitable operating risk that gives the maximum operating benefit. It relates to different operating policies. The normal operating cost, the costs of insecurity to consumers, the costs associated with uneconomic unit commitment and dispatch, and the incremental transmission losses caused by remedial actions taken to preserve system security, can be partially or completely incorporated into the objective function. Power system security evaluation techniques are still immature due to the complexity associated with modeling the dynamic and transient characteristics of a system. Security optimization, based on the related evaluation techniques, therefore has not received very much attention in overall power system reliability optimization, although optimization applications do exist in certain specific operating and maintenance areas.

Ideally, both adequacy optimization and security optimization should be incorporated and integrated to form reliability optimization. This is neither realistic nor necessary. "Security Constrained Adequacy Optimization" as shown in Figure 1.5, however, can be considered as a realistic approximation.

1.2.4 Adequacy Optimization Hierarchical Structure

Adequacy optimization is a special application of adequacy evaluation techniques to power system development planning. Power system adequacy evaluation can be divided into three hierarchical levels and therefore power system adequacy optimization can also be categorized into three hierarchical levels, as shown in Figure 1.6.

Hierarchical Level I (HL I) optimization is mainly concerned with generating facilities. The objective of HL I optimization is to determine the optimum generation capacity reserve and capacity structure. The optimization form or objective function varies from one application to another. If renewable energy development is the major consideration, the corresponding optimization problem could be to determine the optimum penetration level of renewable energy into the conventional generation system. This thesis is focussed on HL I adequacy optimization.

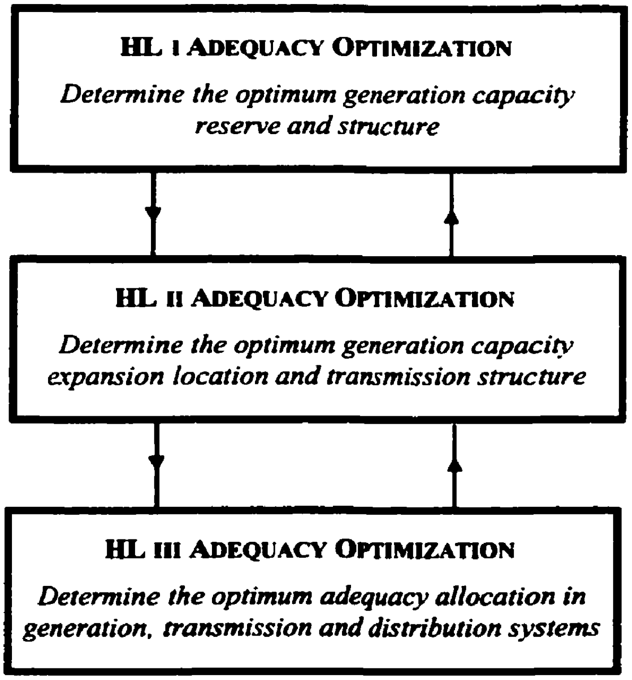

Figure 1.6 Hierarchical structure for adequacy optimization

Hierarchical Level II (HL II) optimization considers both generation and the associated transmission system. The objective of HL II optimization is to determine the optimum location of the required generation and the corresponding transmission structure.

Hierarchical Level III (HL III) optimization is concerned with the overall assessment of the three functional zones. It can be used to determine the optimum adequacy balance between the generation, transmission and distribution systems or to locate the adequacy bottlenecks. As shown in Figure 1.7, HL III adequacy optimization can be decomposed into two sub-problems, i.e., HL II adequacy optimization and distribution adequacy optimization. Principally, HL III adequacy optimization can be achieved by iterating these two sub-problems and coordinating the adequacies of the HL II and the distribution zone at each iteration.

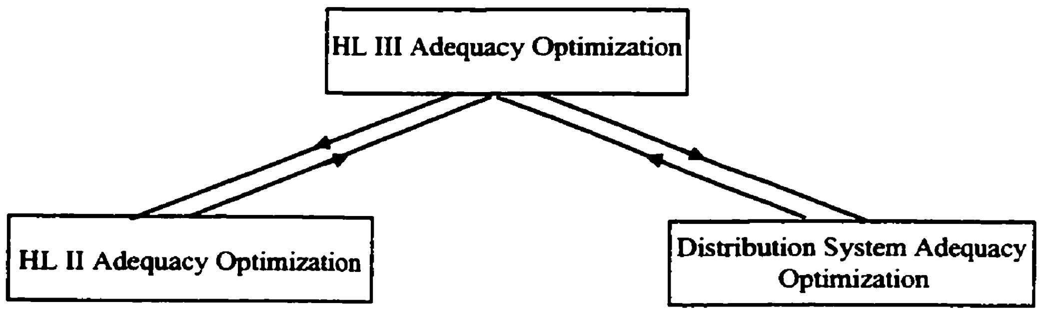

Figure 1.7 Division of power system reliability optimization.

In addition to the basic three reliability optimization hierarchical levels, optimization can be also performed separately on any system subset such as generating stations, switching stations and substations, in order to determine a local optimal topological structure or alternative.

1.3 Objective and Scope of the Thesis

Power utilities have historically been primarily concerned with providing their customers with a safe, reliable and affordable supply of electrical energy. The basic problem of conventional power system expansion planning is therefore to determine the most economical and reliable expansion alternatives that will accommodate the generation and the expected load growth over the planning period. This is particularly true in the developing countries, where in many cases, the demand for electrical energy is greater than the ability to add additional capacity. Deregulation in the power industry and power utilities legislation in the developed countries, however, have challenged the widely accepted concepts and the related risk assessment techniques in conventional power system planning. Social, economic, technical and regulatory forces are having a significant impact on the conventional philosophy of power system assessment and planning. New concepts are being created to incorporate factors such as open power markets and dynamic pricing [8-10], interruptible load considerations [11-16], power wheeling strategies [17], co-generation policies as well as renewable energy developments.

An important question in power system development assessment is "what is an appropriate level of reliability?" or "what is the most reasonable reliability level?" [9]. Usually, a specified level of reliability, adequacy or security, is employed as a constraint in power system planning. The selection of actual reliability criteria has been largely based on past experience and judgment, and it has been suggested that these criteria can lead to unduly expensive systems with unnecessarily low probabilities of failure to meet the load [18]. Optimization techniques can be utilized to determine a reasonable set of reliability levels. Reliability optimization can be applied in systems containing conventional power sources [18-41] such as hydro, fossil, nuclear and gas turbine facilities, and also in systems containing non-conventional sources such as photo-voltaic and wind generating facilities.

The objective of the research described in this thesis was to develop models and techniques for generation adequacy optimization in both conventional and non-conventional power systems, with emphasis on applications to optimum wind energy penetration planning and interruptible load utilization. The basic problem in optimum HLI planning is to determine a reasonable generation capacity or supply side structure. Wind energy is being considered as a major supply side option. The successful operation of many wind farms throughout the world has illustrated that wind energy can be an encouraging and promising energy option [42-62]. At the present time, many utilities are prepared to give an energy credit to a wind facility but are reluctant to assign it a capacity credit. The actual benefits cannot be assigned in the absence of a comprehensive reliability modeling technique for Wind Energy Conversion System (WECS) analysis. It is therefore both necessary and important to develop reliability evaluation and optimization techniques that include WECS. The research described in this thesis focuses on the development of techniques, by which utilities can assess the effect of a WECS on the system reliability, estimate the generation capacity benefit & credit, determine the optimum site-matching wind turbine, and choose the most suitable wind power penetration level to augment the conventional energy conversion systems.

The basic problem in optimum interruptible load utilization is to search for suitable demand side load compositions and strategies. On the load or demand side, cost-effective opportunities to utilize demand side management initiatives, such as interruptible contracts, can be used to better utilize low cost base load generation capacity and to reduce the need for addition capacity [10-19]. Different reliability levels rather than one single level can be assigned to different sets of consumers in order to achieve maximum total benefits in the open power market. Analytic techniques have been developed to conduct interruptible load analysis [13, 14]. An inherent weakness in an analytical approach is the difficulty of incorporating chronological load characteristics in this analysis. More comprehensive techniques are required to be developed for power utilities to assess the risk conditions inherent in an interruptible-load-contract, and to achieve the optimum interruptible load utilization. A basic objective of the research described in this thesis was to integrate comprehensive interruptible load considerations into the general framework of HLI optimization.

This thesis establishes a framework for power system reliability optimization in which new models, indices, techniques for generation adequacy optimization with WTCS development and interruptible load utilization are proposed. A number of case studies are presented to illustrate the possible application of the proposed techniques in practical system development planning.

Chapter 2 focuses on a general procedure for determining the most suitable generation capacity expansion plans or strategies using reliability analysis techniques for a given conventional generation system in order to meet forecast loads. Capacity expansion analyses using both fixed reliability criterion and reliability optimization techniques are examined. The Roy Billinton Test System (RBTS) [63] is used in the case studies to show that capital cost can be saved by using the optimum reliability techniques based on reliability cost-worth evaluation.

Chapter 3 presents a systematic technique for large individual generating station reliability assessment and optimization. Factors such as active failures, passive failures, stuck breaker conditions, scheduled maintenance, normally open components are incorporated in the algorithms. Two sets of indices are presented in order to recognize the different intent underlying an individual generating station assessment. These indices complement each other, and provide valuable information for engineering assessment and decision making in selecting the optimum station configuration. The case study shows that the technique and the resulting indices can be applied in practical engineering situations to provide a scientific basis for optimum planning and design of a generation station.

Chapter 4 presents a sequential Monte Carlo simulation technique for wind power modeling and reliability assessment of a generating system. The method is based on an hourly random simulation to mimic the operation of a generating system, taking into account the auto-correlation and fluctuating characteristics of wind speeds, the random failure of generating units, and other recognized dependencies. An auto-regressive and moving average (ARMA) time series model is used to simulate the hourly wind speeds and thus the available wind power considering chronological characteristics. The model is established based on the F-criterion [48]. The RBTS containing a WECS with wind data obtained from Environment Canada is utilized in this chapter to illustrate the proposed method. A number of sensitivity analyses are also presented to illustrate possible applications of the proposed method.

Chapter 5 introduces two new risk-based capacity benefit indicators designated as the WECS Load Carrying Capability Benefit Ratio (LCCBR) and the Equivalent Capacity Ratio (ECR). These two indices can be used to indicate the capacity benefit and credit associated with a WECS, and thus provide valuable information for energy policy makers in decision problems involving the selection and classification of wind sites. A midpoint-sectionalized technique is presented to calculate the Incremental Peak Load Carrying Capability (*IPLCC*) and to assess the *LCCBR* and *ECR*.

Chapter 6 investigates the effects of different windturbine design parameters on basic adequacy indices and risk-based capacity benefit factors. A procedure and a case study for determining the optimum site-matching windturbine generator are presented. The risk based indices *LCCBR* and *ECR* are utilized as an objective function to determine the optimum site-matching windturbine for a potential wind site. Significant capacity benefit can be obtained by selecting appropriate site-matching windtubine parameters.

Chapter 7 investigates the effects of penetration levels on generation capacity adequacy and benefit. The incremental load carrying capability due to the utilization of wind energy increases exponentially as the corresponding wind penetration level increases. A procedure to determine the optimum penetration level is introduced in this chapter and extends the method developed for conventional generation adequacy optimization. Case studies for optimum penetration planning are presented for different wind site and cost parameters.

Chapter 8 presents a basic framework and technique to conduct interruptible load analysis using sequential Monte Carlo simulation. A new index designated as the Avoidable Additional Generating Capacity (AAGC) is introduced. Bisection search techniques were developed to effectively determine the Interruptible Load Carrying Capability (ILCC) and the AAGC. These two factors can be utilized in generating capacity assessment and interruptible load contract analysis to achieve maximum utilization of both supply and demand resources. Case studies to determine the most suitable contractual options for interruptible load customers under given conditions are also presented in this chapter.

Chapter 9 concludes the thesis by presenting a comprehensive summary and some general conclusions on generating system reliability optimization.

Chapter 2
Conventional Generating Capacity Adequacy Optimization

2.1 Introduction

The time periods required to design, construct and commission a generating station can be quite extensive depending on the environmental and regulatory requirements. It therefore becomes necessary to determine the system requirements considerably in advance of the actual unit in-service date. The general planning problem in a generation system consists traditionally of a comparison between various alternatives for generation capacity development made on the basis of system cost. There are two fundamental approaches to evaluate the system cost [32].

The first approach is one that has been used for many years and it can be argued to have resulted in the high level of reliability enjoyed by electrical energy consumers in developed countries. In this approach, system investment is driven by deterministic criteria or by fixed quantitative reliability indices that are selected on the basis of experience and judgement. The capital cost of the proposed facilities plus the cost of operating and maintaining them are compared under the assumption that each alternative provides the same reliability based on whatever deterministic or probabilistic techniques are used. This approach implies that an implicit socio-economic cost is closely associated with the selection of the reliability criterion. The deterministic or probabilistic criteria adopted by power utilities are therefore presumed to be based on a perception of public need and shaped by economic and/or regulatory forces to implicitly include recognition of the socio-economic costs. Utilization of such criteria should therefore reflect the optimum trade-offs between the cost of achieving the required reliability and the benefits derived by society.

The second approach, known as the explicit cost technique, incorporates reliability or risk in the costing process by comparing the overall cost including the societal costs of unreliability, or customer damage cost. The explicit cost approach uses subjective and objective measures of customer damage losses arising from electrical energy supply curtailments. The LOEE (Loss-Of Energy Expectation), sometime known as the EENS (Expected Energy Not Supplied), is usually used as the index to link reliability worth with system unreliability. Considerable work has been done on developing procedures for assessing customer damage costs due to power supply failures [7, 33-37]. The explicit cost approach to reliability worth assessment incorporating the capital costs, operating and maintenance costs, as well as customer damages costs into the optimization, can be used to quantify the fundamental electric utility requirement of what is a reasonable level of service reliability.

Reliability evaluation can be used in generation capacity expansion planning to determine the optimum capacity reserve and the timing of new units to be committed. This chapter focuses on a general procedure for determining the most suitable generation expansion plans or strategies for a given system in order to meet forecast loads. Capacity expansion analyses using fixed reliability criteria, i.e. the implicit method, as well as capacity expansion analysis using reliability optimization techniques, i.e. the explicit method, are illustrated. The RBTS (Roy Billinton Test System) [63] is utilized in the case studies to show the principles and applications.

2.2 Adequacy Evaluation

The basic approach to evaluate the adequacy of an electrical power generating system consists of three parts as shown in Figure 2.1.

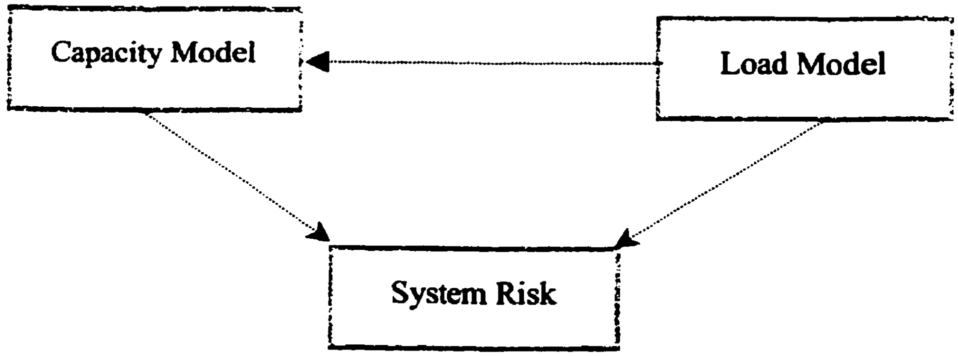

Figure 2.1 Conceptual tasks in generating capacity reliability evaluation

The generation and load models shown in Figure 2.1 are convolved to form an appropriate risk model. Adequacy evaluation, therefore, consists of the following three general steps:

1. Build a capacity model based on the operating characteristics of the generating units.
2. Construct an appropriate load model.
3. Obtain a risk model by combining the capacity model with the load model.

The calculated indices do not normally include transmission constraints or transmission reliability. The indices simply indicate the ability of the generating facilities to meet the system load requirement.

At the present time, the most popular indices used in generating capacity evaluation are the Loss of Load Expectation (LOLE) and the Loss of Energy Expectation (LOEE). The LOLE indicates the expected time for which the available generation will be insufficient to meet the demand. The LOEE specifies the expected energy that will not be supplied by the generation system due to those occasions when the load demanded exceeds the available generating capacity.

The methods used to calculate the reliability indices can be classified as being either analytical or simulation or a combination of both approaches. Analytical techniques represent the system by analytical models and evaluate the indices from these models using mathematical solutions. Monte Carlo simulations, however, estimate the indices by simulating the actual process and random behavior of the system. The method therefore treats the problem as a series of experiments. Both techniques have advantages and disadvantages, and can be very powerful with proper application. The main advantage of the analytical approach lies in its relative compactness, which can be enhanced by making suitable approximations. Monte Carlo simulation, on the other hand, may be preferable if:

1. Non-exponential time distributions have to be modeled;
2. The basic characteristics of peaking units have to be considered;
3. The distributions of some of the output indices are required; and
4. Time dependent or chronological issues have to be considered.

In the direct analytical method for generation capacity adequacy assessment, the basic capacity model is a generating capacity outage probability table [3] which can be created by techniques such as the recursive approach, or as an approximation using the normal distribution or the Gram Charlier Expansion [3]. The load model is usually either a daily peak load model or an hourly load duration model [3].

In the Monte Carlo method, the capacity model is fundamentally different from that used in an analytical study. The capacity model is the generating capacity available at points in time established chronologically or independently by random sampling. The generation model is then superimposed on the load model to form the risk model. State sampling, state transition sampling or sequential simulation methods can be used. The sequential Monte Carlo simulation method is the most comprehensive technique for generation capacity adequacy assessment. The basic simulation procedure can be briefly described as follows:

1. Generate operating histories for each generating unit by drawing sampling values of TTF (Time-To-Failure) and TTR (Time-To-Repair) of the unit. The operating history of each unit is then in the form of chronological up-down-up operating cycles. The

system available capacity is then obtained by combining the operating cycles of all units.

2. Superimpose the system available capacity curve on the chronological system hourly load curve to obtain the system available margin model. If the available capacity is less than the load at time t, simulate the commitment of peaking units and update the system capacity model. A positive margin denotes that the system generation is sufficient to meet the system load, while a negative margin implies that the system load has to be curtailed. This superposition is indicated in Figure 2.2.

3. Form the required reliability indices by observing the system capacity reserve model over a long time period.

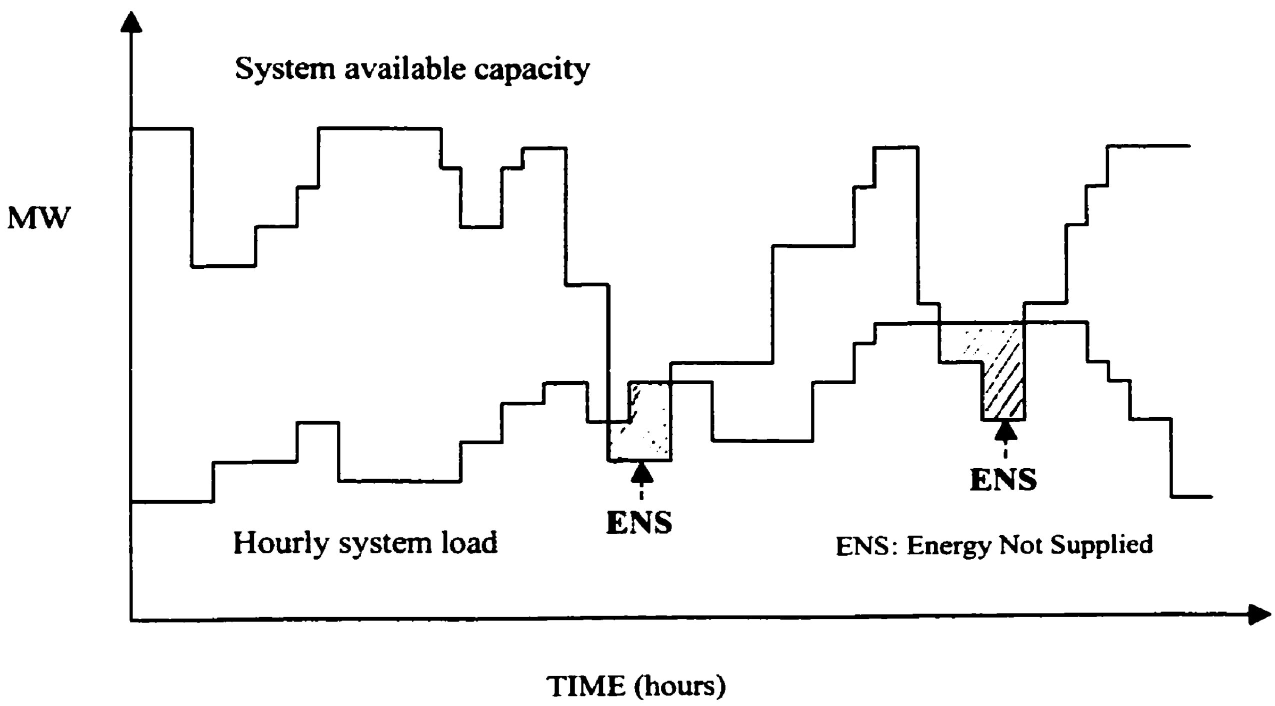

Figure 2.2 Superimposition of the system available capacity model on the load model

In the process of generating operating history, the initial state of each generator is first specified. Generally, it is assumed that all components are initially in the success or up state. The duration of each generator residing in its present state is sampled from its probability distribution. For example, an exponentially distributed random variable has the following probability density function [2],

$$f_T(t) = \lambda\ e^{-\lambda t} \qquad (2.1)$$

where λ is the mean value of the distribution. The cumulative probability distribution function is

$$F(t) = 1 - e^{-\lambda t} \qquad (2.2)$$

Using the inverse transform method, the random variable T is given by:

$$T = -\frac{1}{\lambda}\ \ln(1 - U) \qquad (2.3)$$

where U is a uniformly distributed random number obtained from a suitable random number generator. Since $1-U$ is distributed uniformly in the same way as U in the interval [0,1],

$$T = -\frac{1}{\lambda}\ \ln(U) \qquad (2.4)$$

If the present state is the up state, λ is the failure rate of the generator. If the current state is the down state, λ is the repair rate of the generator.

The reference period in this simulation process is one year. Each year is further divided into a number of hours and therefore the minimum time unit in the simulation is an hour. The sampling of the operating history is, consequently, hourly.

The mean value $E(X)$ and standard deviation $\sigma(X)$ for any reliability index X after N sampling years can be obtained using (2.5) and (2.6):

$$E(X) = \frac{1}{N} \sum_{k=1}^{N} X_k \qquad (2.5)$$

$$\sigma(X) = \sqrt{\frac{1}{N-1}\left[\sum_{k=1}^{N} X_k^2 - N \times E^2(X)\right]} \qquad (2.6)$$

in which X_k is the observed value of the index X in sampling year k. The indices are as follows:

1. Loss of Load Expectation (LOLE), hours/year
2. Loss of Energy Expectation (LOEE), MWh/year
3. Frequency of Loss of Load (FLOL), occurrences/year
4. Duration per interruption (D), hours/occurrence
5. Load Not Supplied per Interruption (LNSI), MW/occurrence
6. Energy Not Supplied per Interruption (ENSI), MWh/occurrence.

The stopping criterion used in the simulation is the ratio of the standard deviation of the sample mean of a reliability index of interest over the sample mean of the index. Mathematically, the simulation is stopped when

$$\frac{\sigma[E(X)]}{E(X)} \leq \varepsilon_X \tag{2.7}$$

where, X is a selected reliability index, ε_X is the maximum allowable error and $\sigma[E(X)]$ can be expressed:

$$\sigma[E(X)] = \sigma(X) / \sqrt{N} \tag{2.8}$$

Compared to analytical methods or the basic state sampling approach, the sequential Monte Carlo Simulation technique requires more computation time and storage since it is necessary to generate a random variable following a given distribution for each generator as well as store information on the chronological state transition processes of all generators in a long time period. In addition, the approach requires parameters associated with all generator state duration distributions. In some cases, especially for a multi-state generator representation, it may be difficult to provide all the transition rates between the states of each generator. However, with the sequential approach, any state duration distribution can be considered and the actual frequencies and statistical probability distributions of the various reliability indices can be calculated in addition to the expected values. This method is particularly useful when renewable energy such as wind power is incorporated in the generation system.

2.3 Customer Interruption Cost Evaluation

There is increasing interest in economic optimization approaches for power system planning and expansion. Evaluation of the cost associated with different system configuration/operating practices and the corresponding reliability worth at the customer end is generally termed as reliability cost/benefit or reliability-worth assessment. Reliability-worth assessment is an important aspect of power system planning and operating. One approach utilized to assess reliability worth is to relate it to the cost or losses incurred by utility customers as a result of power failures.

The most obvious approach to evaluate interruption costs is a direct solicitation of the customer's interruption costs for given outage conditions. Guidance can be offered as to what should and should not be included in the cost estimate so that the meaning of the results is not ambiguous. This approach provides reasonable and consistent results in those situations where most losses tend to be tangible, directly identifiable and quantifiable. Another approach is to ask respondents what they would be willing to pay to avoid having interruptions, or conversely what amount they would be willing to accept for having to experience an outage. The basis of this approach is that incremental willingness to pay (willing to accept) constitutes a valuation of corresponding marginal increments (decrements) in reliability. The third approach is that of indirect worth evaluation. If direct valuation is not possible, customer-selected alternatives or responses to indirect method questions may be used to derive a value. The customer survey method has been effectively used to assess customer costs associated with service interruptions [36, 37]. In this method, customers are asked to estimate their costs or losses due to supply outages of varying duration and frequency, and at different times of the day and year. The strength of this method lies in the fact that the customer is probably in the best position to assess the losses. Direct costs are relatively easy to determine for some customer categories (e.g., industrial), but users' opinions are particularly important in assessing less tangible losses, such as inconvenience, for other categories.

The University of Saskatchewan has conducted several systematic customer surveys. The first series was done in 1980-1985 on behalf of the Canadian Electrical Association (CEA), and the second 1990-1992, sponsored by the Natural Sciences and Engineering Research Council (NSERC) together with seven participating Canadian electric power utilities. The corresponding data for such survey studies can be used to generate a customer damage function for a given area. Conceptually, the creation of a composite customer damage function for a special area is an attempt to define the total customer costs for that area as a function of interruption duration. The customer mix for the area must be known so that the costs for the various customer groups can be proportionally weighted by the respective energy or demand consumption within the area. Weighting by the annual peak demand is usually used for short duration interruptions and weighting by the energy consumption for interruptions longer than half an hour [38]. These weighted costs are summed for each interruption duration to yield the total cost for the area for that duration. The variation of the total cost with interruption duration is referred to as the composite customer damage functions for the service area.

Table 2.1 presents a sampling list of Sector Customer Damage Functions (SCDF) in $/kW of annual peak demand. These data are from studies conducted by the Power Systems Research Group at the University of Saskatchewan [63] and Ontario Hydro [41]. The SCDF can be determined for a given customer type and aggregated to produce sector customer damage functions for the various classes of customers in the system.

Table 2.1 Sector customer damage function in S/kW of annual peak demand

	Duration				
User Sector	1 min	20 mins	1 hour	4 hours	8 hours
Larger Users	1.005	1.508	2.225	3.968	8.240
Industrial	1.625	3.868	9.085	25.163	55.808
Commercial	0.381	2.969	8.552	31.317	83.008
Agriculture	0.060	0.343	0.649	2.064	4.120
Residential	0.001	0.093	0.487	4.914	15.690
Government	0.044	0.369	1.492	6.558	26.040
Office Space	4.778	9.878	21.065	68.830	119.160

The load composition for the RBTS in terms of the annual peak demand and energy consumption is shown in Table 2.2. The user sector costs in Table 2.1 were weighted in accordance with the load composition. The Composite Customer Damage Function (CCDF) is shown in Table 2.3.

Table 2. 2 Load composition

User Sector	*Sector Peak %*	*Sector Energy %*
Large users	31.0	30.0
Industrial	19.0	14.0
Commercial	9.0	10.0
Agriculture	2.5	4.0
Residential	31.0	34.0
Government	5.5	6.0
Office space	2.0	2.0
	100.0	100.0

Table 2.3 System CCDF

	Duration				
	1 min	*20 mins*	*1 hour*	*4 hours*	*8 hours*
Interruption cost (\$/kW)	0.67	1.56	3.85	12.14	29.41

The data shown in Table 2.3 can also be expressed by Equation (2.9) to illustrate the basic form of a composite customer damage function.

$$Interruption\ Cost = \begin{cases} 0.670000 \bullet t^{0.282122} & 1 \le t \le 20 \\ 0.132828 \bullet t^{0.822298} & 20 \le t \le 60 \\ 0.129540 \bullet t^{0.828419} & 60 \le t \le 240 \\ 0.011109 \bullet t^{1.276587} & 240 \le t \end{cases} \tag{2.9}$$

where t is the interruption duration in minutes.

The composite customer damage function for a system can be utilized to obtain a single cost factor in \$/kWh known as the interrupted energy assessment rate (IEAR), which can then be applied to the expected energy not supplied to produce a cost associated with generating capacity inadequacy. The energy method of assessing the customer interruption costs assumes that the interruption cost C increases in direct proportion to the system expected energy not supplied [39].

$$C = [IEAR]\ [LOEE] \tag{2.10}$$

Two techniques have been utilized to produce an IEAR using the system CCDF. The first is an analytical approach based on the classical frequency and duration techniques [3]. The second approach uses sequential Monte Carlo simulation to calculate the unserved energy cost [40].

Equations (2.11), (2.12) and (2.13) are the basic equations used in the analytical application of this concept. Given that it is possible to calculate the frequency and duration associated with a load loss event, the LOEE in MWh/yr is given by equation (2.11):

$$LOEE = \sum_{i=1}^{M} C_i F_i D_i \tag{2.11}$$

where C_i is the load curtailment of load loss event i in MW, F_i is the frequency of load loss event i in occ./yr, D_i is the duration of load loss event i in hours, and M is the total number of load loss events.

The total Expected Interruption Cost in k$/yr. is given by

$$EIC = \sum_{i=1}^{M} C_i F_i W(D_i) \tag{2.12}$$

where $W(D_i)$ is the customer damage function in $/kW, i.e., the unit interruption cost of the duration D_i of load loss event i.

The Interrupted Energy Assessment Rate in $/kWh is defined as

$$IEAR = \frac{\sum_{i=1}^{M} C_i F_i W(D_i)}{\sum_{i=1}^{M} C_i F_i D_i} \tag{2.13}$$

In a sequential Monte Carlo simulation, individual load loss events are encountered sequentially and therefore not only the specific random system states but also the transition process between system states can be simulated. In other words, the effects of the load loss event duration and frequency distribution can be considered in the simulation. The total Expected Interruption Cost in k$/yr. is given by [2, 40]:

$$EIC = \frac{\sum_{i=1}^{M} W(D_i) E_i / D_i}{N} \tag{2.14}$$

where $W(D_i)$ is the customer damage function in $/kW, D_i is the duration of interruption i in hours, E_i is the energy not supplied of interruption i in MWh, M is the total number of interruptions experienced in the simulated years, and N is the number of simulated years.

The IEAR can be calculated using

$$IEAR = \frac{\sum_{i=1}^{M} W(D_i)E_i / D_i}{\sum_{i=1}^{M} E_i} \tag{2.15}$$

The detailed description of the procedure to obtain an IEAR using Sequential Monte Carlo Simulation procedure is contained in [3]. The estimated results for the RBTS system using the computer program GRASS (Generation Reliability Assessment using Sequential Simulation) developed at the University of Saskatchewan are presented in Table 2.4. This table shows the convergence of the IEAR and EIC with increase in simulated years. The results are for the base case of the RBTS with a peak load of 185 MW. The basic details of the RBTS are given in the Appendix.

Table 2.4 The IEAR and IEC of the RBTS versus the number of simulated years

Sampling Years	30000	40000	50000	60000	70000	80000
IEAR ($/kW)	3.9021	3.9003	3.8974	3.8925	3.8977	3.8947
EIC (k$/yr.)	39.3830	38.4971	38.3789	37.7393	37.8331	37.8450

Reference 40 states that the IEAR is reasonably stable and does not vary significantly with peak load or other operating conditions. The combination of a basic LOEE index and the IEAR as shown in Equation (2.10) provides a basic and primary tool for assessing adequacy worth in generation capacity adequacy studies.

2.4 Capacity Expansion Analyses with Fixed Reliability Criteria

2.4.1 Basic Principle

In this approach, the system investment is driven by deterministic criteria or by fixed quantitative reliability indices that are selected on the basis of experience and judgement. The objective of this approach is to search for the optimum expansion plan with minimum expansion cost for each year under the limitation that the risk criterion cannot be violated. This is basically a Type III optimization problem categorized in Section 1.1.2. It involves a search for the minimum investment implemented for the given reliability criterion. The risk level is considered as a constraint in this case. This is the basic approach that has been used by electric power utilities for some time.

The heuristic procedure to conduct generation capacity expansion analyses using a fixed reliability criterion can be described as follows:

For year *i*, conduct reliability assessment using the techniques illustrated in Section 2.2.

1. If the fixed reliability criterion is satisfied, no additional generating units will be required for the particular planning year. The analysis then moves into the next planning year *i+1*.

2. If the assumed reliability criterion cannot be satisfied, additional generating units are required for year *i*. In order to determine the minimum investment implemented for the specific year, the available units are ranked in cost (investment), from least to largest. The unit with least cost will be taken into the system first until the fixed reliability criterion is satisfied. If the reliability criterion cannot be satisfied with the addition of any single unit, various additional combinations of available units are tested and the plan with minimum cost then obtained for that particular year.

2.4.2 Case Study

The RBTS system is utilized to illustrate the analysis procedure. The peak load in Year 0 (current year) in the RBTS is 185 MW, and it has been assumed that the installed capacity of 240 MW is adequate for this condition. The initial risk index of LOLE = 1.1282 hours /year can therefore be considered as the system criterion and used to schedule capacity additions. It has been assumed that any new units to be added are 5 MW gas turbine units with FOR (Forced Outage Rate) of 0.12. The MTTF (Mean Time-To-Failure) is assumed to be 550 hours and the MTTR (Mean Time-To-Repair) 75 hours. A 5-year risk analysis was conducted using the procedure described in Section 2.4.1.

The risk levels due to the forecast growth in load and the sequential addition of units are shown in Table 2.5 for a 5 year period.

Table 2.5 LOLE (hours/year) in generation expansion

		Capacity Expansion Cases								
Year	***Peak Load (MW)***	***11 units***	***12 units***	***13 units***	***14 units***	***15 units***	***16 units***	***17 units***	***18 units***	***19 units***
0	185.0	**1.1282**	-	-	-	-	-	-	-	-
1	192.4	2.0689	1.3236	**0.8705**	-	-	-	-	-	-
2	200.1	-		1.7143	**1.1190**	-	-	-	-	-
3	208.1	-	-		2.1511	1.4165	**0.9247**	-	-	-
4	216.4	-	-	-	-		1.8816	1.2430	**0.8144**	
5	225.1	-	-	-	-	-	-	-	1.6989	**1.1260**

The results shown in Table 2.5 are illustrated as follows:

1. In the 1st year, if no additional unit is added to the original system (11-unit system), the system risk level will be 2.0689 hours/year. This violates the system risk criterion of 1.1282 hours/year. If one 5 MW unit is added to the 11-unit system, the risk criterion will still be violated. Consequently, two 5 MW units are added and a 13-unit system is formed for this year. The system risk level for the 13-unit system is ***0.8705 hours/year***, which is within the risk criterion.

2. In the 2nd year, if no additional units are added, the system risk level will be 1.7143 hours/year. This violates the system risk criterion. Consequently, one 5 MW unit is added and a 14-unit system is formed for this year. The system risk level for the 14-unit system is ***1.1190 hours/year***, which is within the risk criterion.

3. In the 3rd year, if no additional units are added, the system risk level will be 2.1511 hours/year. This violates the system risk criterion. If one 5 MW unit is added to the 14-unit system, the risk criterion will still be violated. Consequently, two 5 MW units are added and a 16-unit system formed for this year. The system risk level for this 16-unit system will be ***0.9247 hours/year***, which is within the risk criterion.

4. In the 4th year, if one 5 MW unit is added to the 16-unit system, the system risk level will be 1.2430 hours/year, which violates the system risk criterion. Consequently, two 5 MW units are added and a 18-unit system formed for this year. The system risk level for this 18-unit system will be ***0.8144 hours/year***, which is within the risk criterion.

5. In the 5th year, if no additional units are added, the system risk level will be 1.6989 hours/year, which violates the system risk criterion. Consequently, one 5 MW unit is added and a 19-unit system formed for this year. The system risk level will be ***1.1260 hours/year***, which is within the risk criterion.

The timing of unit additions is obtained using the above analysis. The complete expansion schedule is given in Table 2.6.

Table 2.6 Generation expansion results

Year	*Unit added (MW)*	*System Capacity (MW)*	*Peak load (MW)*	*LOLE (hours/year)*
0	-	240	185.0	1.1282
1	-	240	192.4	2.0689
	5+5	250		0.8705
2	-	250	200.1	1.7143
	5	255		1.1190
3	-	255	208.1	2.1511
	5+5	265		0.9247
4	-	265	216.4	1.8816
	5+5	275		0.8144
5	-	275	225.1	1.6989
	5	280		1.1260

2.5 Capacity Expansion Analysis Using Reliability Optimization Techniques

2.5.1. Basic Principle

The technique discussed in Section 2.4 uses a fixed reliability level as the criterion to determine the generation capacity expansion. It does not incorporate reliability cost and worth, and may not be adequate for modern power systems that are facing increasing uncertainty regarding the economic, political, societal and environmental constraints.

An important question in power system planning is "what is an appropriate level of reliability?" or "what is the most reasonable reliability level?" Usually, a specified level of reliability is employed as a constraint in power system planning, as shown in the studies described in Section 2.4. The selection of actual reliability criteria have been largely based on past experience and judgment and it has been suggested that these criteria can lead to unduly expensive systems with unnecessarily low probabilities of failure to meet the load. Optimization techniques can be utilized to determine a reasonable set of reliability levels.

This section uses a reliability optimization technique to determine the optimum generation capacity plan and the corresponding optimum reliability levels. In this approach, the total societal cost is minimized. The total societal costs include the capital cost, the operating and maintenance cost and the customer outage costs. This is basically a Type I optimization problem categorized in Section 1.1.2.

The costs associated with constructing a generating system for any specified level of reliability can be evaluated relatively easily. In general, the total system cost is made up of all the cost incurred by the utility in providing the customer with power at a specific service reliability and does not include the cost of unserved energy. Examples of such costs are fixed costs associated with system, variable operating costs, maintenance costs, cost of new investments, environmental charges and the cost of any emergency actions taken to alleviate the total interruption of power supply to customers. The production cost of a system can be estimated as the sum of the expected energy supplied (EES) by each unit times the variable operating charge rate for each unit. Table 2.7 present the basic capital and operating costs used for the studies described in this chapter.

Table 2.7 Capital and operating cost

Generating Units	*Investment (Installed)*	*Operating & Maintenance Cost*
Gas Turbine	\$ 700/kW	\$0.050/kWh

The bank rate is assumed to be constant at 7%. The equipment life is assumed to be 20 years. The annual capital costs are calculated using the following formula:

$$(Annual\ Cost) = \frac{I(1+I)^K}{(1+I)^K - 1} \bullet (Total\ Capital\ Cost) \qquad (2.16)$$

where I is the annual interest rate and K is the unit life in years.

Table 2.8 shows the annual capital cost for additional units based on a 20 year life and a 7% interest rate.

Table 2.8 Unit capital cost

Capacity (MW)	*Fixed cost ($/yr.)*
5.0	330,400

The production cost can be obtained using Monte Carlo simulation. The customer outage cost can be obtained using the IEAR calculated in the Section 2.3. The number of sampling years for each calculation was 50000. The optimum reserve margin for each year in the next five years can be estimated from the expansion studies including reliability worth and cost. The results are presented sequentially as follows:

2.5.2 Year 1 (Peak Load = 192.4 MW)

Table 2.9 shows the capital cost, production and maintenance cost, Loss-of-Energy Expectation, the consumer outage cost and the total annual societal cost for the original system and subsequent additions of 5 MW units. The production cost was estimated assuming for simplicity that all the units in the system are gas turbines. A practical production cost simulation may include many system specific factors.

Table 2.9. Determination of an optimum plan (Year 1)

			Production (Operation)		*Outage*		
Number of units added	*Total Capacity (MW)*	*Capital Cost (M$/yr.)*	*Energy (MWh/yr.)*	*Cost (M$/yr.)*	*LOEE (MWh/yr.)*	*Cost (M$/yr.)*	*Total Cost*
0	240	0.0000	1,032,665	51.6333	19.6185	0.0763	***51.7096***
1	245	0.3304	1,032,673	51.6337	12.4526	0.0484	52.0125
2	250	0.6608	1,032,677	52.6339	7.8183	0.0302	52.3249

It can be seen from Table 2.9 that the customer interruption cost decreases rapidly as additional capacity is added to the system while the capital cost increases. The production cost is basically the same. The least cost reserve margin occurs with no additional units and is 24.74%.

2.5.3 Year 2 (Peak Load = 200.1 MW)

Table 2.10 shows the capital cost, production and maintenance cost, LOEE, the consumer outage cost and the total annual societal cost for the original system and for subsequent additional of 5 MW units. It can be seen that the least cost reserve margin occurs with no additional units and is 19.9 %. The corresponding total annual cost is 53.8487 M$/year.

Table 2.10. Determination of an optimum plan (Year 2)

			Production (Operation)		*Outage*		
Number of units added	*Total Capacity (MW)*	*Capital Cost (M$/yr.)*	*Energy (MWh/yr.)*	*Cost (M$/yr.)*	*LOEE (MWh/yr.)*	*Cost (M$/yr.)*	*Total Cost*
0	240	0.0000	1,073,976	53.6988	38.0048	0.1499	***53.8487***
1	245	0.3304	1,073,989	53.6995	25.0086	0.0975	54.1274
2	250	0.6608	1,073,998	53.6999	16.1041	0.0625	54.4232

2.5.4 Year 3 (Peak Load = 208.1 MW)

Table 2.11 shows the capital cost, production and maintenance cost, the consumer outage cost and the total annual societal cost for the original system and for subsequent addition of 5 MW units. The lowest annual cost is 56.1308 M$/year. The optimum reserve margin is 15.32% with no additional units added in this particular year.

Table 2.11. Determination of an optimum plan (Year 3)

			Production (Operation)		*Outage*		
Number of units added	*Total Capacity (MW)*	*Capital Cost (M$/yr.)*	*Energy (MWh/yr.)*	*Cost (M$/yr.)*	*LOEE (MWh/yr.)*	*Cost (M$/yr.)*	*Total Cost*
0	240	0.0000	1,116,880	55.8440	72.5692	0.2868	***56.1308***
1	245	0.3304	1,116,904	55.8452	48.7842	0.1919	56.3675
2	250	0.6608	1,116,921	55.8461	32.4144	0.1266	56.6335

2.5.5 Year 4 (Peak Load = 216.4 MW)

Table 2.12 shows the capital cost, production and maintenance cost, the consumer outage cost and the total annual societal cost for the original system and for subsequent unit additions. The lowest annual cost is 58.6229 M$/year. The optimum reserve margin is 10.9 % with no additional units in this particular year.

Table 2.12. Determination of an optimum plan (Year 4)

			Production (Operation)		*Outage*		
Number of units added	*Total Capacity (MW)*	*Capital Cost (M$/yr.)*	*Energy (MWh/yr.)*	*Cost (M$/yr.)*	*LOEE (MWh/yr.)*	*Cost (M$/yr.)*	*Total Cost*
0	240	0.0000	1,161,361	58.0681	140.7486	0.5548	***58.6229***
1	245	0.3304	1,161,407	58.0704	94.9224	0.3735	58.7743
2	250	0.6608	1,161,438	58.0719	63.9279	0.2509	58.9836

2.5.6 Year 5 (Peak Load = 225.1 MW)

Table 2.13 shows the capital cost, production and maintenance cost, the consumer outage cost and the total annual societal cost for the sequential addition of 5 MW units. It can be seen that the least cost reserve margin occurs with 1 additional unit and is 8.8 %. The corresponding annual total cost is 61.4781 M$/year.

Table 2.13. Determination of an optimum plan (Year 5)

			Production (Operation)		*Outage*		
Number of units added	*Total Capacity (MW)*	*Capital Cost (M$/yr.)*	*Energy (MWh/yr.)*	*Cost (M$/yr.)*	*LOEE (MWh/yr.)*	*Cost (M$/yr.)*	*Total Cost*
0	240	0.0000	1,207,920	60.3960	278.4304	1.0991	61.4951
1	245	0.3304	1,208,009	60.4005	189.9205	0.7472	***61.4781***
2	250	0.6608	1,208,070	60.4035	128.5093	0.5025	61.5668
3	255	0.9912	1,208,112	60.4056	86.6893	0.3386	61.7354
4	260	1.3216	1,208,140	60.4070	58.2316	0.2272	61.9558

2.5.7 Optimum Expansion Schedule

The optimum generation capacity expansion schedule, which minimizes the annual total societal cost is presented in Table 2.14.

Table 2.14 Generation expansion results (with optimum adequacy level)

Year	*Unit added (MW)*	*System Capacity (MW)*	*Peak load (MW)*	*Capacity Reserve (%)*	*COST (M$/yr.)*
0	-	240	185.0	29.72	-
1	-	240	192.4	24.74	***51.7096***
2	-	240	200.1	19.94	***53.8487***
3	-	240	208.1	15.33	***56.1308***
4	-	240	216.4	10.91	***58.6229***
5	+ 5	245	225.1	8.84	***61.4781***

It can be seen by comparing Tables 2.6 and 2.14 that the capital costs in the next five years obtained using the optimum reliability technique are much lower than those obtained using the fixed criterion techniques. In this case, the fixed criterion leads to an unduly expensive system. It should be appreciated that the results and the conclusion obtained in this case are very dependent on the data used in the analysis. This is illustrated in the following analysis.

2.7.8 Sensitivity Analysis

The customer damage function can have considerable effect on the optimum reliability results. In order to investigate this, the data in Table 2.3 has been multiplied by 1.5. The new CCDF is presented in Table 2.15.

Table 2.15 Modified system CCDF

	Duration				
	1 min	*20 mins*	*1 hour*	*4 hours*	*8 hours*
Interruption cost ($/kW)	0.938	2.184	5.390	16.996	41.174

The data shown in Table 2.15 is described by Equation (2.17) :

$$Interruption\ Cost = \begin{cases} 0.938000 \bullet t^{0.282122} & 1 \le t \le 20 \\ 0.185959 \bullet t^{0.822299} & 20 \le t \le 60 \\ 0.181357 \bullet t^{0.828419} & 60 \le t \le 240 \\ 0.015557 \bullet t^{1.276538} & 240 \le t \end{cases} \tag{2.17}$$

Tables 2.16~20 show the capital, production , consumer outage and total annual societal cost for sequential 5 MW units additions. The optimum generation capacity expansion schedule, which minimizes the total annual societal cost is presented in Table 2.21. It can be seen that the least cost reserve margin in the 5th year includes 2 additional units and the optimum margin is 11.06%. The corresponding annual total cost is 61.7678 M$/year. It has been shown from the sequential unit addition analysis, that the annual customer outage costs are enhanced using the increased CDF. The increase is still not enough to drive the addition of units in Years 1-4 but the change results in the need to add two units in Year 5. Further increase in the CDF would result in earlier unit additions. A similar situation would occur if the RBTS generating unit forced outage rates are increased.

Table 2.16. Determination of an optimum plan (Year 1)

Number of units added	Total Capacity (MW)	Capital Cost (M$/yr.)	Production (Operation) Energy (MWh/yr.)	Production (Operation) Cost (M$/yr.)	Outage LOEE (MWh/yr.)	Outage Cost (M$/yr.)	Total Cost
0	240	0.0000	1,032,665	51.6333	19.6185	0.1068	***51.7401***
1	245	0.3304	1,032,673	51.6337	12.4526	0.0677	52.0318
2	250	0.6608	1,032,677	52.6339	7.8183	0.0423	53.3370

Table 2.17. Determination of an optimum plan (Year 2)

Number of units added	Total Capacity (MW)	Capital Cost (M$/yr.)	Production (Operation) Energy (MWh/yr.)	Production (Operation) Cost (M$/yr.)	Outage LOEE (MWh/yr.)	Outage Cost (M$/yr.)	Total Cost
0	240	0.0000	1,073,976	53.6988	38.0048	0.2099	***53.9087***
1	245	0.3304	1,073,989	53.6995	25.0086	0.1365	54.1664
2	250	0.6608	1,073,998	53.6999	16.1041	0.0874	54.4481

Table 2.18. Determination of an optimum plan (Year 3)

Number of units added	Total Capacity (MW)	Capital Cost (M$/yr.)	Production (Operation) Energy (MWh/yr.)	Production (Operation) Cost (M$/yr.)	Outage LOEE (MWh/yr.)	Outage Cost (M$/yr.)	Total Cost
0	240	0.0000	1,116,880	55.8440	72.5692	0.4015	***56.2455***
1	245	0.3304	1,116,904	55.8452	48.7842	0.2687	56.4443
2	250	0.6608	1,116,921	55.8461	32.4144	0.1772	56.6841

Table 2.19. Determination of an optimum plan (Year 4)

Number of units added	Total Capacity (MW)	Capital Cost (M$/yr.)	Production (Operation) Energy (MWh/yr.)	Production (Operation) Cost (M$/yr.)	Outage LOEE (MWh/yr.)	Outage Cost (M$/yr.)	Total Cost
0	240	0.0000	1,161,361	58.0681	140.7486	0.7766	***58.8447***
1	245	0.3304	1,161,407	58.0704	94.9224	0.5229	58.9234
2	250	0.6608	1,161,438	58.0719	63.9279	0.3513	59.0840

Table 2.20. Determination of an optimum plan (Year 5)

Number of units added	Total Capacity (MW)	Capital Cost (M$/yr.)	Production (Operation)		Outage		Total Cost
			Energy (MWh/yr.)	Cost (M$/yr.)	LOEE (MWh/yr.)	Cost (M$/yr.)	
0	240	0.0000	1,207,920	60.3960	278.4304	1.5381	61.9341
1	245	0.3304	1,208,009	60.4005	189.9205	1.0462	61.7771
2	250	0.6608	1,208,070	60.4035	128.5093	0.7035	***61.7678***
3	255	0.9912	1,208,112	60.4056	86.6893	0.4741	61.8709
4	260	1.3216	1,208,140	60.4070	58.2316	0.3181	62.0467

Table 2.21 Generation expansion results (with optimum adequacy level)

Year	*Unit added (MW)*	*System Capacity (MW)*	*Peak load (MW)*	*Capacity Reserve (%)*	*COST (M$/yr.)*
0	-	240	185.0	29.72	-
1	-	240	192.4	24.74	***51.7096***
2	-	240	200.1	19.94	***53.8487***
3	-	240	208.1	15.33	***56.1308***
4	-	240	216.4	10.91	***58.6229***
5	+ 5 + 5	250	225.1	11.06	***61.7678***

2.6 Summary

This chapter illustrates a procedure for determining the most suitable generation capacity expansion plan using reliability analysis techniques. Capacity expansion analyses using the implicit method, i.e. a fixed reliability criterion, as well as capacity expansion analyses using the explicit method, i.e., reliability optimization techniques, are illustrated. The RBTS is used in the case studies to show the principles and procedure. The result shows that capital costs may be reduced using optimum reliability techniques based on reliability cost-worth evaluation. The procedure briefly described in this chapter and illustrated using the basic RBTS is utilized later in this thesis to incorporate the effects of non-conventional operating facilities in the form of WECS.

Chapter 3
Generating Station Reliability Assessment

3.1. Introduction

A basic element in power system expansion planning is the determination of how much generation capacity is required to give a reasonable assurance of satisfying future load requirements. Load growth can be satisfied by a wide range of options such as purchases from associated interconnected systems or by non-utility generation and co-generation facilities. It has, however, traditionally been accomplished by constructing new generating stations. This is particularly true in developing countries where in many cases; the demand for electrical energy is greater than the ability to add additional capacity.

The conventional approach to generating capacity evaluation is to develop a model for all the capacity in the system and then convolve this with a suitable load model to obtain a set of system risk indices [3, 6]. In this model, the individual identities of each generating unit and station are lost in the overall capacity model. The objective of the research described in this chapter was to develop a reliability evaluation and optimization technique for individual generating station configuration planning in order to select an appropriate overall design for the individual station. This technique is particularly suited to reliability evaluation and design of large generating stations that have a substantial impact on the overall system reliability. Relatively few studies have been conducted on individual generating station reliability as attention has been mainly focused on overall HL I assessment [7]. In addition, the need for individual generating station assessment has not been fully recognized. The analysis of station evaluation is usually limited to creating an equivalent component for more extensive system assessments associated with that station [64-78]. Adequacy and security assessments of an individual generating station, however, can highlight the effect of different alternative station configurations and thus provide detailed and comparative information for decision making in selecting the optimum station configuration when planning that station.

This chapter presents the index structure, the model and algorithm developed for generation station reliability assessment and optimization.

3.2. Index Structure

There are many indices which can be used to measure the reliability of a power system at a given hierarchical level and different utilities adopt different indices. The main indices in HL I reliability assessment are *LOLP* (Loss of Load Probability), *LOLE* (Loss of Load Expectation), *LOEE* (Loss of Energy Expectation), *FLOL* (Frequency of Loss of Load) and *DLOL* (Duration of Loss of Load) [2, 3]. Additional indices are required in HL II studies in order to reflect the operating features of composite generation and transmission systems. These include *EDNS* (Expected Demand Not Supplied), *BPII* (Bulk Power Interruption Index), *BEPCI* (Bulk Power/Energy Curtailment Index), *BPACI* (Bulk Power Supply Average MW Curtailment Index) and *SI* (Severity Index) [3].

The system indices at HL I or HL II shown above cannot be directly applied to individual generation station reliability evaluation due to the different intent underlying individual generation station assessment. Two sets of indices, i.e., adequacy indices and indices that indicate operating security are therefore proposed in this chapter. They are presented sequentially as follows.

A. Adequacy indices

This set of indices includes:

- Loss of Generation Probability *LOGP*,

- Loss of Generation Expectation *LOGE*,
- Frequency of Loss of Generation *FLOG*,
- Average Duration of Loss of Generation *DLOG*,
- Expected Demand Not Generated *EDNG*,
- Expected Energy Not Generated *EENG*.

The concept of Loss of Generation is somewhat different from the widely used concept of Loss of Load. When a failure event occurs and some generators and (or) transmission lines are isolated, the generating station cannot generate or dispatch the demanded or assigned power output. Such phenomenon can be designated as Loss of Generation. A Loss of Generation may or may not result in a system Loss of Load depending on the overall conditions in the system. Loss of Load is determined by many factors such as the overall system configuration and load, not just by a single generating station. The concept of Loss of Generation is more meaningful than that of Loss of Load when the generation capability of a generating station is evaluated separately.

If the assigned power output of a generating station is equal to the total installed capacity of that station, the adequacy indices shown above can be used to express the maximum possible generation capability of a station (without considering energy limitations). Valuable information, which can be used in planning a generating station, such as expected maximum energy production and expected maximum power output, can thus be obtained from these indices.

B. Indices indicating operating security

This set of indices includes:

- Probability of *m* units being isolated *Prob_IS(m)*,
- Frequency of *m* units being isolated *Freq_IS(m)*,
- Probability of losing *m* lines which link the generating source *Prob_LG(m)*,

- Frequency of *losing m* lines which link the generation source *Freq_LG(m)*.

This set of indices implicitly relate to system operating security, as the isolation of generation and / or transmission facilities in a station may lead to dynamic, transient or voltage instability of the power network to which the station is connected. For simplicity, the indices indicating operating security can be designated as "*m*-security indices" or more simply "security indices".

In addition to the two sets of indices, the conventional indices associated with bulk power system Loss of Load can be used to express the effect of station originated outages on the related power network [4, 5, 6, 7]. The three sets of indices indicate the reliability of a generating station, in different ways. They complement each other and provide comprehensive information for engineering assessment and decision making in generating station planning and design.

3.3. Generalized n+2 State System Model

The component-based three-state representation is considered as a basic model in station related reliability evaluation [3, 64, 65]. The existing dependencies and required restorative actions, however, cannot be completely represented using this model. The error due to using the three-state model may be significant for some system states or particular applications [87, 88]. In addition, practical factors such as stuck breaker conditions and normally open components cannot be modeled directly using the three state model. An extended model was therefore developed to overcome the weaknesses and limitations of the conventional three-state model [89]. This model is designated as the "generalized n+2 state system model" and is shown in Figure 3.1.

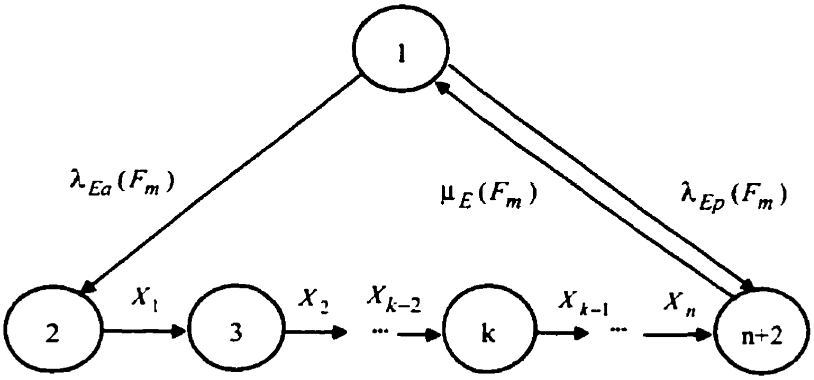

Figure 3.1 Generalized n+2 state system model

In Figure 3.1, state *1* is the system up state and state *2* is the system state immediately following the failure event F_m. Switching actions are initiated in this state and states $3 \sim n+2$ are the system states associated with the switching procedures. State *3* is the system state in which only the first switching action has been performed. State *k* represents the state in which *k-2* switching actions have occurred and *n* represents the total number of required actions.

X_k is the switching rate of the *k th* switching action, i.e., the transition rate from state $k+1$ to $k+2$. The transition rates $\lambda_{Ea}(F_m)$, $\lambda_{Ep}(F_m)$, $\mu_E(F_m)$ are the equivalent active failure rate, passive failure rate and repair rate associated with a failure event (or the sub-event) F_m respectively [89].

3.4. Algorithms

The general concepts and detailed techniques for individual generating station reliability assessment are formed and presented in this section, based on the proposed series of indices and the generalized n+2 state system model. Factors such as active failures, passive failures, stuck breaker conditions and normally open components are incorporated in the algorithms.

3.4.1. General Algorithm

The contingency enumeration approach can be used in the reliability evaluation of an individual generating station. The main procedures are as follows:

1. Read the data defining the generating station topology and the reliability parameters of each component in the station, i.e., active and passive failure rates, repair time, switching time and, for breakers, stuck breaker probability.
2. Generate a station contingency event.
3. For each generated contingency event, conduct an analysis on the station operating behavior. Calculate the three basic components of probability, frequency, the demanded power not generated in each state due to the failure event using the generalized n+2 state model.
4. Accumulate the reliability indices for each contingency event and form the final adequacy and security indices.
5. Output the associated indices.

The main steps shown above are illustrated in detail in the following sections.

3.4.2. Generation of Contingency Events

Contingency event levels are usually considered up to the second order in station-related reliability evaluation [3, 76, 77, 78]. There are two different types of first-order failure events and six different types of second-order failure events. Designate the two components in a second-order failure event as i and j. The possible types to be generated are:

- First-order active failure events,
- First-order passive failure events,
- Component i active failure and component j stuck condition,
- Component i active failure + component j active failure,

- Component i active failure + component j passive failure,
- Component i active failure during the period of component j on scheduled maintenance,
- Component i passive failure during the period of component j on scheduled maintenance,
- Component i passive failure + component j passive failure.

An active failure not only leads directly to switching state S, but also leads indirectly to repair state R [3]. Therefore, (component i active failure + component j active failure) not only means that component i in the S state overlaps component j in the S state, but can also cause other forms of overlapping. This type of failure event can be approximately divided into three sub-events. The first one is that both components are in the S state, and is designated as "component i active failure completely overlapping component j active failure". The second one is that component i active failure during the period of component j in the R state, and is designated as "conditional active failure of component i on j". The third one is that component j active failure during the period of component i in the R state, and is designated as "conditional active failure of component j on i".

From a computation point of view, the six second-order failure event types can be combined and simply classified into three types in order to decrease the computation complexity (if switching action is required when passive failure of component i or j occurs, the six second-order failure event types can be further classified into five types). Events in each type basically have the same effect on the operational behavior of a generating station (including the same switching procedure). The three types are as follows.

Type 1. Active + Active.

This includes:

- Component i active failure completely overlapping component j active failure (and vice versa),
- Component i active failure and component j stuck condition (if possible),
- Component j active failure and component i stuck condition (if possible).

Type 2. Passive + Active

This includes:

- Component j active failure + component i passive failure,
- Conditional active failure of component j on i,
- Component j active failure during the period of component i on scheduled maintenance.

The three events shown above, however, are respectively different from events (component i active failure + component j passive failure), (conditional active failure of component i on component j) and (component i active failure during the period of component j on scheduled maintenance). They have different effects on the operational behavior and therefore should be considered separately.

Type 3. Passive + Passive

- Component i passive failure + component j passive failure,
- Component j passive failure during the period of component i on scheduled maintenance,
- Component i passive failure during the period of component j on scheduled maintenance.

The generated sequences for the possible second-order failure events will affect the computation complexity of the reliability assessment. A good sequence will decrease the computation complexity and vice versa. If the analysis in Type 1 for components i and j proves that there is no system trouble, that is, no demanded power is not generated, it is not necessary to go through Types 2 and 3 for components i and j, as Type 1 is the most serious station operation situation of all the possible combinations of components i and j. If the analysis in Type 2 for components i and j indicates that there is no system trouble, it is not necessary to go through Type 3 to enumerate other combinations of component i and j. The optimum sequence is therefore shown in Figure 3.2.

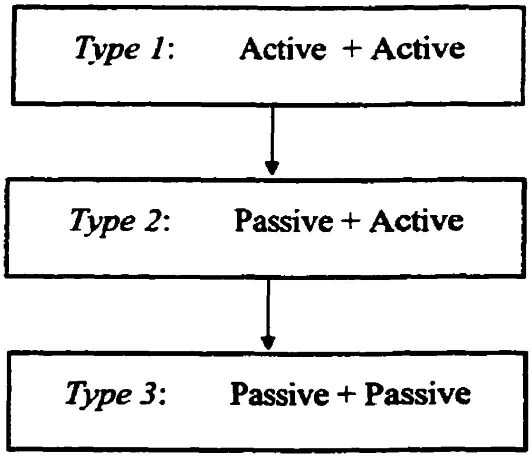

Figure 3.2 Optimum calculation sequence for general 2nd-order failure events

3.4.3. Calculation of the Demanded Power Not Generated

A generating station is basically a network and therefore methods of network (flow) analysis can be used to calculate the demanded power not generated. The station is, however, a particular network, and therefore specific techniques can be developed in order to decrease the computation complexity of the algorithm. The capacity of a breaker is normally designed to be large enough to serve its function. The effect of breaker capacity on the adequacy and security of a power station can therefore be considered to be negligible. The effect of the capacities of transformers can also be considered to be negligible for the same reason. Based on this, only the capacities of generators, transmission lines are considered in the computation of the demanded power not generated.

When a failure state occurs, some generators or transmission lines are isolated, and the whole power station is divided into several parts. The number of independent connected sub-networks in a failure state k is assumed to be N_{IS}. In each independent connected sub-network s, the generators are $G_{s1}, G_{s2}, \ldots, G_{sg}$ and the transmission lines are $L_{s1}, L_{s2}, \ldots, L_{sl}$. The capacity of component i is designated as $C(i)$.

The available power output in sub-network s at state k is:

$$AP_k^{(s)} = \min\left(\sum_{j=1}^{g} C(G_{sj}), \sum_{j=1}^{l} C(L_{sj}) \right) \tag{3.1}$$

Consequently, the total available power in state k is:

$$AP_k = \sum_{s=1}^{N_{IS}} AP_k^{(s)} \tag{3.2}$$

The demanded power not generated in state k can therefore be calculated as:

$$LOG_k = NPO - AP_k \tag{3.3}$$

where NPO is the power output of the generating station in the normal operating state.

If $LOG_k \leq 0$, then all demanded power is generated. Designate LOG_k as 0 in this case.

In the generalized n+2 state system model, the demanded power not generated at each state after a failure event occurs, requires calculating. This can be done using (3.1)~(3.3). The *DFS* (Depth First Searching) algorithm and linking data structure [83] are used to judge and form the independent connected sub-networks. A more effective approach has been developed to calculate the demanded power not generated in each state using the relationships between the adjacent states.

3.4.4. Calculation of Reliability Indices

The Loss of Generation Probability, Frequency of the Loss of Generation and Expected Energy Not Generated when failure event F_m occurs are designated as $LOGP(F_m)$, $FLOG(F_m)$ and $EENG(F_m)$, respectively. They can be calculated as:

$$LOGP(F_m) = \left(\sum_{k=2}^{n+2} P_k \times h_k \right) \times B \tag{3.4}$$

$$FLOG(F_m) = P_1 \times (\lambda_{Ea}(F_m) + h_{n+2} \times \lambda_{Ep}(F_m)) \times B \tag{3.5}$$

$$EENG(F_m) = 8760 \times \left(\sum_{k=2}^{n+2} P_k \times LOG_k \right) \times B \tag{3.6}$$

in which

P_k is the probability of state k, and

$$B = Prob\{all\ \ components\ \ except\ F_m\ \ work\} \tag{3.7}$$

$$h_k = \begin{cases} 1 & LOG_k \succ 0 \\ 0 & LOG_k = 0 \end{cases} \tag{3.8}$$

The adequacy indices of a generating station can be calculated as follows, assuming that the set of failure events that cause the power station Loss of Generation is F:

$$LOGP = \sum_{F_m \in F} LOGP(F_m) \tag{3.9}$$

$$FLOG = \sum_{F_m \in F} FLOG(F_m) \tag{3.10}$$

$$EENG = \sum_{F_m \in F} EENG(F_m) \tag{3.11}$$

Other indices can be calculated in a similar way.

3.5. Case Study

3.5.1. Schemes, Data and Assumptions

Assume that a new hydro station with 10 generating units and 5 transmission lines, is to be constructed. The capacity of each unit is 200 MW, and that of each transmission line is 500 MW. There are two alternatives to be considered.

Alternative 1. This is shown in Figure 3.3. Three lines and/or generator connections are made using four circuit breakers on a bus leg between two main buses. This configuration is usually referred to as *a breaker and one third system*.

Alternative 2. This is shown in Figure 3.4. Line connections are made using two circuit breakers. Two generator connections are made using three circuit breakers. The overall configuration can be referred to as a combination of *double breaker, and breaker and one half connections*. Because of the large number of legs, the two main buses require bus sectionalizing circuit breakers.

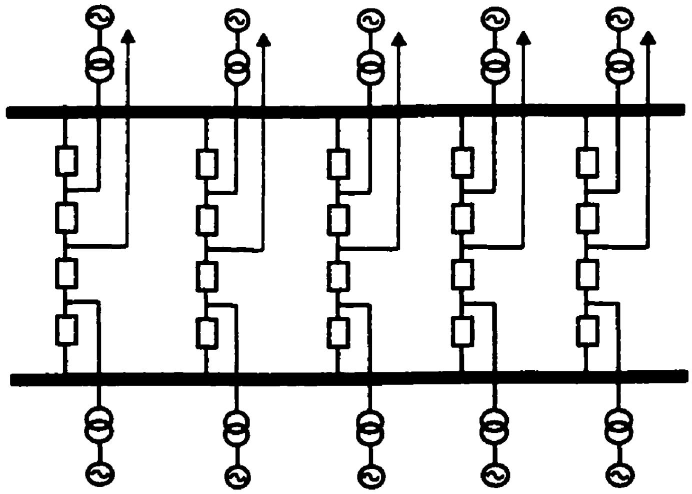

Figure 3.3 Alternative 1

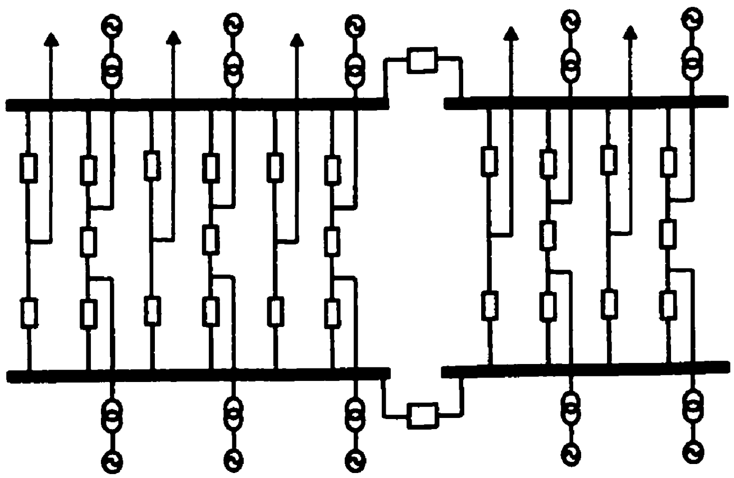

Figure 3.4 Alternative 2

The expected or demanded power outputs of the station are divided into 4 levels as shown in Table 3.1.

Table 3.1. Demand power outputs (MW)

Level	*2000*	*1800*	*1600*	*1400*
Probability	0.15	0.35	0.35	0.15

Table 3.2 shows the reliability data. In this table, λ_{ai}, λ_{pi}, r_i, λ_i'', r_i'' are the active failure rate, passive failure rate, repair time, scheduled maintenance rate and scheduled maintenance time of component *i* respectively, P_{si} is the probability of a stuck breaker *i*, and *l* is the length of a transmission line in 100 km.

Table 3.2. Basic reliability data

Component	λ_{ai} *(f/yr.)*	λ_{pi} *(f/yr.)*	P_{si} *(%)*	r_i *(hour)*	λ_i'' *(f/yr.)*	r_i'' *(hours)*
unit	3.5000	-	-	73	1/5	2190
line	0.933•*l*	-	-	16	0.5	24
transformer	0.0205	-	-	300	1	160
bus	0.0150	-	-	20	1	12
breaker	0.0600	0.02	0.5	160	1	120

Failure events were considered up to the second order except for generating units, where up to 4th order contingencies were considered. For simplicity, each transmission line was assumed to be 100 km. The scheduled maintenance of generating units, transformers and transmission lines was not considered in the assessment.

3.5.2. Adequacy Assessment

The adequacy indices of the two alternatives at the maximum operating mode and the whole year were calculated.

The maximum operating mode denotes the situation in which all the generators and transmission lines are committed for operation. In this mode, the assigned power output is assumed to be the installed capacity. The adequacy indices in the maximum operating mode can be used to judge the adequacy under maximum demand conditions for each different station configuration. The maximum operating mode indices were evaluated on the basis of one month. The main adequacy indices for the two alternatives are listed in Table 3.3. The adequacy indices for the whole year are shown in Table 3.4

Table 3.3. Adequacy indices at the maximum operating mode

Scheme	*LOGE (hours/month)*	*FLOG (f/month)*	*EDNG (MW/month)*	*EENG (MWh/month)*
1	188.837	3.077	766.91	42890
2	188.881	3.086	775.61	42904

Table 3.4. Adequacy indices in the whole year

Scheme	*LOGE (hours/yr.)*	FLOG *(f/yr.)*	*EDNG (MW/yr.)*	*EENG (MWh/yr.)*
1	496.485	9.825	2314.60	110210
2	496.655	9.936	2350.10	110265

It can be seen from Tables 3.3 and 3.4 that Alternative 1 has better adequacy than Alternative 2. While there are differences, the results shown in Tables 3.3 and 3.4 for the two alternatives are very similar as generating unit and transmission line failures provide the major contribution to the total loss of generation.

3.5.3. Security Assessment

In a security assessment using the set of indices introduced in Section 3.2, the probability or frequency associated with the isolation of a single unit (line) is obviously not the major concern as the *N-1* state (*N* is the number of system elements) does not usually result in stability problems. The main concern is the probability and frequency of more than one unit (line) being isolated at the same time or within a short time. Disturbances of *N-2*, *N-3*, ..., *N-m* can cause large changes in the system dynamic characteristics and therefore loss of stability could occur.

Tables 3.5 and 3.6 present the security indices for the two alternatives when up to 2nd order events are considered. In Tables 3.5 and 3.6, *NGIS* and *NLIS* respectively denotes the number of generating units and transmission lines being isolated.

Table 3.5. Security indices of Alternative 1

NGIS	*Prob.*	*Freq.* *(f/yr.)*	NLIS	*Prob.*	*Freq.* *(f/yr.)*
1	1.07×10^{-4}	1.18091	1	4.54×10^{-4}	0.59619
2	1.22×10^{-6}	0.01600	2	1.43×10^{-9}	0.00002
3	1.43×10^{-9}	0.00002	> 2	-	-
> 3	-	-	-	-	-

Table 3.6. Security indices of Alternative 2

NGIS	*Prob.*	*Freq.* *(f/yr.)*	NLIS	*Prob.*	*Freq.* *(f/yr.)*
1	6.24×10^{-5}	0.60330	1	2.09×10^{-5}	0.31121
2	3.16×10^{-5}	0.30441	2	4.77×10^{-7}	0.00630
3	2.78×10^{-8}	0.00037	3	1.37×10^{-7}	0.00179
4	1.38×10^{-7}	0.00181	> 3	-	-
5	-	-	-	-	-
6	1.37×10^{-7}	0.00179	-	-	-
> 6	-	-	-	-	-

It can be seen from Table 3.5 that Alternative 1 has good security. The maximum number of generators isolated in Alternative 1 is 3 and that of lines isolated that curtail generation is only 2. The associated magnitudes are relatively small. The frequency of two units being isolated is 0.016 times per year, i.e., once per 63 years. That of three units being isolated is 0.00002 times per year, i.e., once per 50,000 years. For Alternative 2, serious security problems can occur when one breaker in the double-breaker system has an active failure and the other breaker in the same leg is in a stuck condition. Up to four or six generators, and two or three transmission lines will be isolated due to this event. The probability and frequency of this event occurring are usually much higher than those associated with the overlap of two active breaker failures. As shown in Table 3.6, the frequency of four or more units being isolated due to a single event is 0.0036 times per year, i.e., once in 277 years. The loss of four or more units due to a single event will cause significant system disturbance and the stability of the related power network could be affected. In addition, the frequency of two units being isolated for Alternative 2 is 0.30441 times per year, that is once in 3 years, which is much great than that for Alternative 1. Consequently, Alternative 1 has much better operating security than Alternative 2.

In summary, Alternative 1 has higher adequacy and better security than Alternative 2 does. In addition, it utilizes a reasonable number of circuit breakers for the number of generators and lines involved. The main disadvantages of Alternative 1 are the relatively high number of switchgear operations required and that the protective relaying could be quite complicated. Alternative 2 has good adequacy, but poor security. In addition, a much larger number of circuit breakers are required compared to Alternative 1.

Many factors such as investment, service security and adequacy, operating flexibility and simplicity, protective relaying etc., should be considered when selecting a specific station configuration. Both quantitative and qualitative considerations can be combined to assess these factors. Not all of these practical factors are considered in the case study shown in this section. The case study, however, presents a numerical example to indicate how the proposed indices and techniques can be utilized to provide a scientific basis for planning and design decisions in large generating stations. Chapter 2 illustrates the determination of the need for additional operating capacity using implicit and explicit reliability cost/worth optimization. This chapter illustrates a technique that can be used for second level optimization of the individual station deemed to be required to meet the increasing system load demands.

3.6. Summary

Adequacy and security assessments of an individual generating station can highlight the effect of different alternative station configurations and thus provide detailed and comparative information for decision making in selecting the optimum station configuration when planning that station. Two sets of indices have been developed to recognize the different intent underlying an individual generating station assessment. They complement each other and can provide valuable information for engineering assessment and decision making in generating station design. A systematic technique for large individual generating station reliability assessment is presented. Factors such as active failures, passive failures, stuck breaker conditions, scheduled maintenance, normally open components are incorporated in the algorithms. The case study presented shows that the suggested indices and technique can be applied in practical engineering situations to provide a scientific basis for optimum planning and design of a generating station.

Chapter 4

Adequacy Evaluation of Generating Systems Including Wind Energy

4.1 Introduction

Generating facilities include conventional units, such as fossil fuel, hydro or nuclear units, and may include interconnected benefits from neighboring systems. Renewable energy sources such as wind turbine generators and photovoltaic cells can also be included in the potential list of options available to the system planner. Considerable attention has been given in recent years to these unconventional energy resources due to concerns with dwindling fossil fuel reserves and the potential impact of conventional energy systems on the environment. Wind is a non-depletable and environmentally sound source of energy. Approximately 2000 MW of installed generating capacity is being driven by wind energy worldwide and the available energy in the winds over the earth's surface amounts to many trillions of kilowatt-hours. A major problem and therefore a major obstacle to the effective use of wind as a power source is the fact that it is both intermittent and diffuse. The successful operation of many wind farms throughout the world, however, has proved that the wind energy can be an encouraging and a promising energy option.

In order to determine the potential benefits associated with wind as a possible energy option, assess the effect of Wind Energy Conversion Systems (WECS) on system reliability, and select a suitable wind power penetration level into a conventional energy conversion system, it is both necessary and important to develop a generation capacity adequacy evaluation technique which realistically includes WECS. At the present time, many utilities are prepared to give an energy credit to a wind facility but are reluctant to assign it a capacity credit. The actual benefits cannot be assigned in the absence of a comprehensive WECS reliability modeling technique.

A wind energy conversion system poses some special difficulties in the analysis of generating system capacity adequacy. The wind energy is intermittent and nondispatchable as wind velocity is highly variable and site-specific. Each wind turbine generator (WTG) in a wind farm will not have an independent capacity distribution because of the dependence of the individual WTG output on the same primary energy source -- the wind. The nonlinear relationship between WTG power output and wind velocity leads to further complications in constructing a reliability capacity model of a WECS.

Most of the reported work done on modeling wind power generation and on the use of such models for generating system adequacy evaluation is in the analytical domain [51-54]. Analytical methods usually proceed by creating separate generation models for the conventional unit and unconventional unit group. A WTG unit is usually considered to be either a multi-state unit [51, 52, 54] or an energy-limit unit [53]. The most obvious deficiency of analytical methods is that the chronological characteristics of the wind velocity and its effects on wind power output cannot be considered. A sequential Monte Carlo approach, on the other hand, is capable of incorporating such considerations in an adequacy assessment of a generating system containing WECS.

This chapter presents a sequential Monte Carlo simulation technique for wind power modeling and reliability assessment of a generating system. The method is based on an hourly random simulation to mimic the operation of a generating system, taking into account the auto-correlation and fluctuating characteristics of wind speeds, the random failure of generating units, and other recognized dependencies. An auto-regressive and moving average (ARMA) time series model is used to simulate the hourly wind speeds and thus the available wind power considering chronological characteristics. The model is established based on the F-criterion. The RBTS [63] containing a WECS with wind data obtained from Environment Canada is utilized in this chapter to illustrate the proposed method. A number of sensitivity analyses are also presented to illustrate possible applications of the proposed method.

4.2 Wind Speed Modelling Methodology

Energy from the wind is a form of solar energy. Winds are turbulent masses of air resulting from evening out the differences in atmospheric pressure created by the sun. Wind is, therefore, highly variable, site-specific and also terrain specific. It has instantaneous, minute-by-minute, hourly, diurnal and seasonal variations. Wind force varies with the square of wind speed whereas the power in the wind varies with the cube of the wind speed. As an example, if the power (P) in the wind is known at a wind speed of 10 miles per hour (mph), and the wind speed increases to 11 mph, the power in the wind is as follows:

$$P \times \left(\frac{11}{10} \right)^3 = P \times 1.331 \qquad (4.1)$$

The example shows that an increase in wind speed from 10 to 11 mph, just one mph, or 10 percent, causes a 33 percent increase in the power in the wind. A small increase in wind speed produces a large increase in power.

In addition to the variability, wind has a highly diffuse characteristic and is not a concentrated source of energy. In order to generate a significant amount of power, a windmill must harvest a large cross-sectional area of wind. The wind at any point in time may be insufficient to operate a wind system, as wind power is depend upon climatic and weather conditions. Wind energy therefore is a non-dispatchable or intermittent resource.

One of the crucial steps in reliability evaluation of a power system containing WECS using sequential Monte Carlo simulation is to simulate the hourly wind speed and this has been the subject of several publications [42-45]. In 1981, a method using the Weibull distribution function and a lag-one Auto-Regressive (AR) model which uses 24 previously estimated diurnal cycle factors per month was developed [42]. In this approach, the relatively high order auto-correlation was significantly underestimated. A simplified AR(24) model was subsequently established to mimic both the hourly wind speed and direction [43, 44]. There are many assumptions in this model, one of which is that "the hourly wind speed must be normally distributed". In References 45 and 47, a series of AR(2) models are presented for simulating the main statistical characteristics of wind speed. There are no indications in these references on whether the proposed models can preserve the diurnal distribution and some of these models do not pass the Chi-square distribution test.

This section presents the methodology [90] that is used in this research work to model wind speed. In order to check the adequacy of the models, the F-criterion and Q-test were utilized, and the statistical properties of the simulated wind velocity are compared with those obtained from the actual wind velocity

4.2.1. General Expressions for Wind Speed Models

Let

OW_t be the observed wind speed at hour t,

μ_t be the mean observed wind speed at hour t,

σ_t be the standard deviation of observed wind speed at hour t,

μ be the mean wind speed of all the observed data,

σ be the standard deviation of wind speed obtained from all the observed data and

SW_t be the simulated wind speed at hour t.

Different time series models can be established using different combinations of the above data. Generally, let

$$y_t = f(OW_t, \mu_t, \sigma_t, \mu, \sigma) \tag{4.2}$$

The data series set y_t can be used to build the following Auto-Regressive and Moving Average ARMA(n,m) time series model:

$$y_t = \phi_1 y_{t-1} + \phi_2 y_{t-2} + \cdots \phi_n y_{t-n} + \alpha_t - \theta_1 \alpha_{t-1} - \theta_2 \alpha_{t-2} - \cdots - \theta_m \alpha_{t-m} \tag{4.3}$$

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

A pure AR(n) model can be treated as a special form of Auto-Regressive and Moving Average Model ARMA(n,m) by setting $m = 0$.

Once the time series model of the wind speed is established, the simulated wind speed can be calculated as follows:

$$SW_t = f^{-1}(y_t, \mu_t, \sigma_t, \mu, \sigma) \tag{4.4}$$

where $f^{-1}(\cdot)$ is the inverse function of $f(\cdot)$.

4.2.2 Estimation of Parameters

The linear least squares approach can be used to estimate the parameters ϕ_i and σ_a^2 when $m = 0$; whereas the non-linear least squares approach should be adopted to estimate the values of ϕ_i, θ_j and σ_a^2 when $m \neq 0$. The basic steps used in the least squares approach include estimating the initial values and searching for the optimal values based on the initial guesses.

The qualities of the starting values play a very important role in the convergence of the iterations. A systematic method for estimating the initial values was developed in this research work [90]. Three different approaches were used to guess the starting values. The set of guess values that results in the smallest residual sum of squares is chosen as the best set of initial values.

The Gauss-Newton method with the halving mechanism, which is a strategic modification of the classic Gauss-Newton method, is used to minimize the sum of squares. Since this method encounters difficulties in some instances, the Marquart procedure [49] is also used to improve the convergence.

4.2.3. Determination of the Order (n,m)

The question of what are the values of n and m before fitting a model is very difficult. Box and Jenkins provided some empirical guidelines for the determination of n and m when one of them is zero [50]. It has also been shown that any stationary stochastic system can be approximated as closely as required by an ARMA model of order $(n,n-1)$ [48]. Consequently, the question of determining (n,m) becomes that of determining n. The basic procedure in [48], which is based on the F-criterion or F-test, was adopted to determine the value of n which provides the best fit of the wind speed time series model given by (4.3). The main steps of this procedure are:

Step 1 Let $n=2$; fit the ARMA$(n,n-1)$ model using the approach outlined in Section 4.2.2, calculate the residual sum of squares of the model and designate it as RSS$(n,n-1)$.

Step 2 Fit the ARMA$(n+1,n)$ model and calculate the residual sum of square RSS$(n+1,n)$ using the same approach as above.

Step 3 Let $F=\dfrac{RSS(n,n-1)-RSS(n+1,n)}{2}\div\dfrac{RSS(n+1,n)}{N-r}$, in which N is the total number of observations and $r = 2n+2$. Perform the following comparisons using the value of F:

1. If $F > F_p(2, N-r)$, where $F_p(2, N-r)$ denotes the F-distribution with 2 and $N-r$ degrees of freedom at probability level p, then the improvement in the residual sum of squares in going from ARMA(n,n-1) to ARMA(n+1,n) is significant at the $(1-p)\times 100$ % significance level and therefore there is evidence that the ARMA(n,n-1) model is inadequate; go to Step 4.
2. IF $F < F_p(2, N-r)$, then the ARMA(n,n-1) model is adequate at the level of significance, go to Step 5.

Step 4 Set $n+1 \longrightarrow n$, go to Step 2.

Step 5 Fit a pure AR(n) model and use the F-criterion to check the adequacy of the model AR(n). If it is adequate, AR(n) can be used as a possible substitute model for ARMA(n,n-1); If it is not adequate, fit the desired forms of models AR(n') where $n' > n$ until an insignificant F value is reached. The last AR(n') model can be used as a possible substitute for ARMA(n,n-1).

4.2.4. Diagnostic Checking

The procedure for calculating the order (n,m) as given in Section 4.2.3 determines the adequacy of the fitted model from a mathematical point of view. However, as a precautionary measure, additional diagnostic checking is needed.

If a fitted ARMA(n,m) model is adequate, $\{\alpha_t\}$ should be uncorrelated and normally distributed. There are different approaches to check the independence of $\{\alpha_t\}$. One approach can roughly check the independence of $\{\alpha_t\}$ by ensuring that its auto-correlations are small, say within the permissible band $\left(\pm 2/\sqrt{N}\right)$ or the more precise Bartlett band. Another alternative involves using the "portmanteau" test or "statistic Q" suggested by Box and Jenkins [50]. If Q is less than $\chi^2(K-n-m)$ at an appropriate probability level, the $\{\alpha_i\}$ of the ARMA(n,m) can be considered as independent. K should be large enough so that the Green function G_i [48] is particularly zero for $j \geq K$.

Diagnostic checking from a mathematical point of view is necessary but not sufficient to determine whether a wind speed model is feasible or not. A simulation procedure is further needed to check whether a wind speed model can retain the main characteristics of wind speed or not. In order to do so, the statistical properties of the simulated wind speed should be compared with those obtained from the actual wind speed. The main statistical properties to be compared are the auto-correlation function, the mean and standard deviation of wind speed, the seasonal property, the diurnal distribution and so on.

4.2.5. Programs

Two computer programs designated as WSERIES and SWIND have been developed at the University of Saskatchewan based on the principles outlined in Sections 4.2.1-4.2.5. The first program WSERIES is used to establish the time series model of wind speed and check the feasibility of the model from the mathematical point of view. The second program SWIND is used to simulate the wind speed according to the established model, thus providing the statistical properties of the simulated wind speed in order to compare them with those obtained from the actual wind speed when determining the feasibility of the fitted model.

Using the methodology described above, two different time-series models generated using different available wind data are presented in the following sections.

4.3. Wind Speed Models: Type One

The actual hourly wind speed for 3 years (from 1 January 1991 to 31 December 1993) and the hourly mean and standard deviation of wind speeds from a 37-year database (from 1 January 1953 to 31 December 1989) for a site near North Battleford, Saskatchewan were obtained from Environment Canada and used to illustrate this type of wind speed model.

Let

$$y_t = (OW_t - \mu_t)/\sigma_t \tag{4.5}$$

Then y_t can be used to establish the wind speed model (4.3) and the simulated wind speed SW_t can be calculated as:

$$SW_t = \mu_t + \sigma_t \cdot y_t \tag{4.6}$$

Figure 4.1 presents the auto-correlation functions of wind speed in years 1991 and 1993. It can be seen from this figure that the auto-correlation functions of different years are different, thus the time series models based on one year of actual hourly data may cause somewhat approximate results. The complete three-year record of hourly actual wind speed was therefore adopted in subsequent studies.

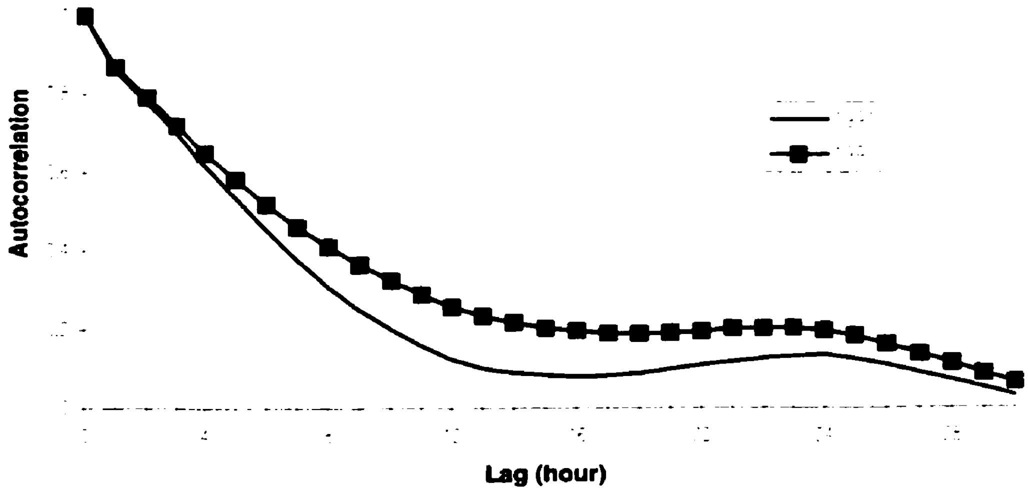

Figure 4.1 Comparison of the auto-correlation functions of wind speed for 1991 and 1993 (site: North Battleford)

4.3.1 ARMA(3,2) Model

The program WSERIES was used to establish several models. The first model generated was an ARMA(2,1) model:

$$y_t = 0.9204\,y_{t-1} - 0.0081\,y_{t-2} + \alpha_t - 0.2227\,\alpha_{t-1}$$
$$RSS(2,1) = 5927.595 \tag{4.7}$$

The second model created was an ARMA(3,2) model, which can be written as:

$$y_t = 1.7901y_{t-1} - 0.9087y_{t-2} + 0.0948y_{t-3} + \alpha_t - 1.0929\alpha_{t-1} + 0.2892\alpha_{t-2}$$
$$\alpha_t \in NID\left(0, 0.474762^2\right) \; and \; RSS(3,2) = 5922.804 \tag{4.8}$$

The residual sum of the squares of the ARMA(3,2) model is smaller than that of the ARMA(2,1) model. The F-criterion shows that:

$$F = \frac{5927.595 - 5922.804}{2} \div \frac{5922.804}{8760 \times 3 - 6} = 10.63 > F_{0.95}(2, \infty) = 3.00$$

Since the F-test shows significance, the ARMA(2,1) model is not considered to be an adequate model for the given wind speed data. An ARMA(4,3) model was further generated as:

$$\begin{aligned} y_t &= 1.0143y_{t-1} + 0.4848y_{t-2} - 0.6180y_{t-3} + 0.0768y_{t-4} \\ &\quad + \alpha_t - 0.3172\alpha_{t-1} - 0.5629\alpha_{t-2} + 0.2280\alpha_{t-3} \\ RSS(4,3) &= 5922.727 \end{aligned} \tag{4.9}$$

The residual sum of the squares of the ARMA(4,3) model is almost the same as that of the ARMA(3,2) model. The F-criterion shows that:

$$F = \frac{5927.804 - 5922.727}{2} \div \frac{5922.727}{8760 \times 3 - 8} = 0.17 > F_{0.95}(2,\infty) = 3.00$$

As the computed F-value is less than the F-distribution value at a 5% level of significance, the ARMA (3,2) model as expressed by (4.8) can be considered adequate for the given wind speed data.

The ARMA(3,2) model was obtained by minimizing the sum of the squares of the difference between the actual wind speed and those given by the model. The distribution of these residuals is given in Figure. 4.2 which shows how well the residuals satisfy the characteristics of the normal distribution. Fig.4.3 presents the first 50 auto-correlations for the residuals. It can be seen from this figure that about 96% of the auto-correlations are in the permissible band ± 0.012337, thus $\{\alpha_t\}$ can be roughly taken as independent. An additional test was conducted using the Q-statistic and the results are given in Table 4.1.

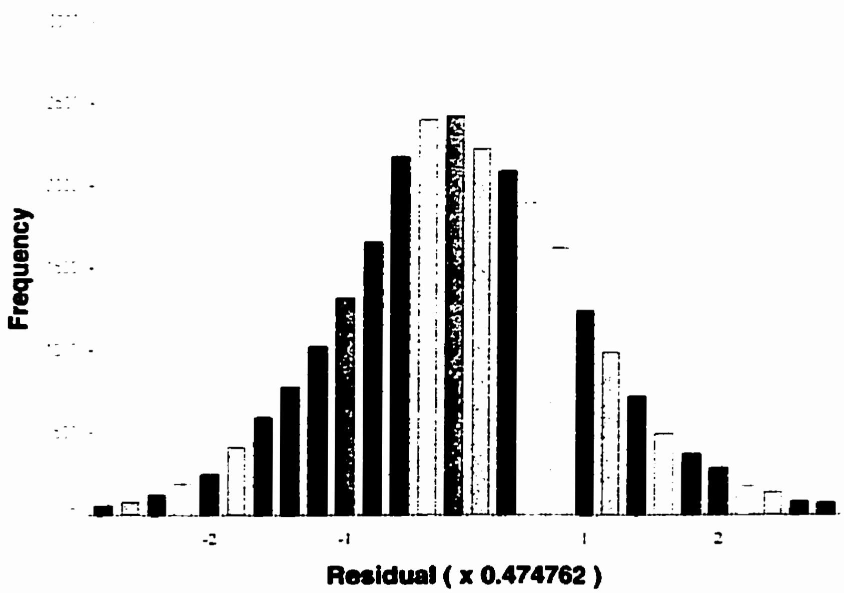

Figure 4.2 Distribution of residuals.

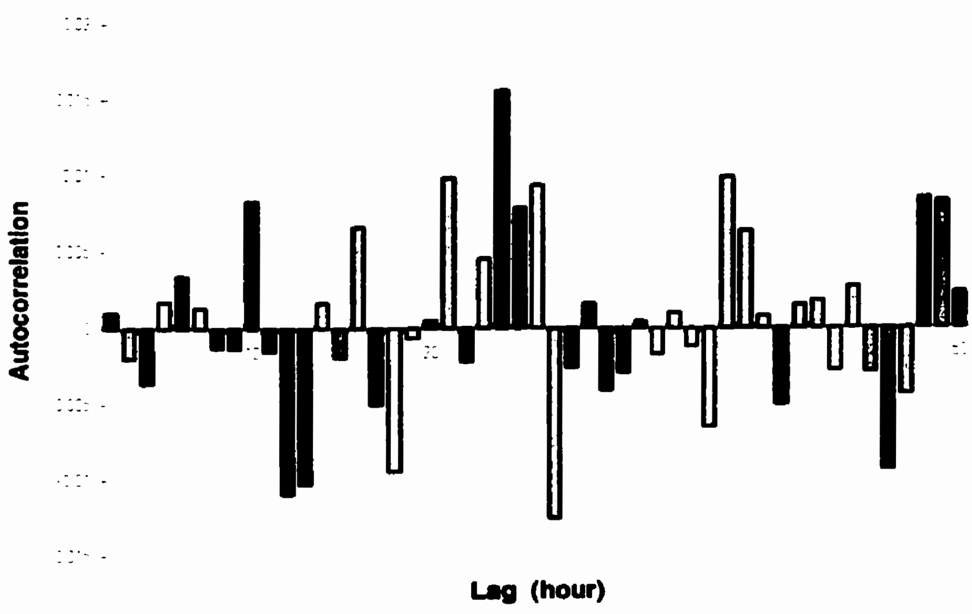

Figure 4.3 Auto-correlation function of residuals

Table 4.1 Statistic Q for ARMA(3,2) model

K	15	35	55	75	95
Q	8.97	32.01	46.88	63.54	75.48
$\chi^2(K-n-m)$	18.31	43.77	67.50	90.53	113.10

It is clear from Table 4.1 that the Q values are always smaller than the critical values at the 95% probability level for different K. Therefore $\{\alpha_t\}$ can be considered an independent stochastic variable. The analyses of the normal distribution and independence of $\{\alpha_t\}$ give the supplementary mathematical support for the suitability of the ARMA(3,2) model.

In addition to the mathematical checking procedure described above, a complete validation of the ARMA(3,2) model should include an analysis of the wind speed generated by the model. The program SWIND was used to generate 38 years of wind data. Several characteristics of the simulated wind speed are compared with those of the observed wind speed as follows:

1. The observed average wind speed is *14.62 km/hr*, and the simulated value is *14.84 km/hr*.
2. Figure 4.4 presents a comparison of the auto-correlations of the actual wind speed with those of the simulated wind speed. It can be seen from this figure that the forms of the observed and simulated auto-correlation functions are almost the same including the superimposed sinusoidal damping which reflects the diurnal cycle.
3. Figure 4.5 shows the observed and simulated seasonal distributions of wind speed. A comparison of these distributions indicates generally good agreement.

4. The observed and simulated diurnal distributions of wind speed in August were randomly selected and are listed in Figure 4.6 which shows a relatively close consistency.

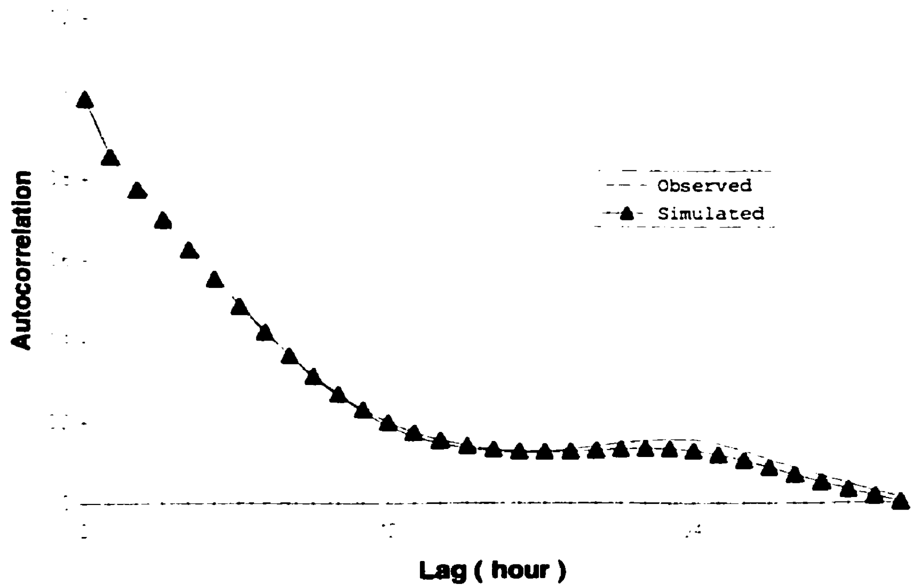

Figure 4.4 Observed and simulated auto-correlation functions of wind speed at North Battelford.

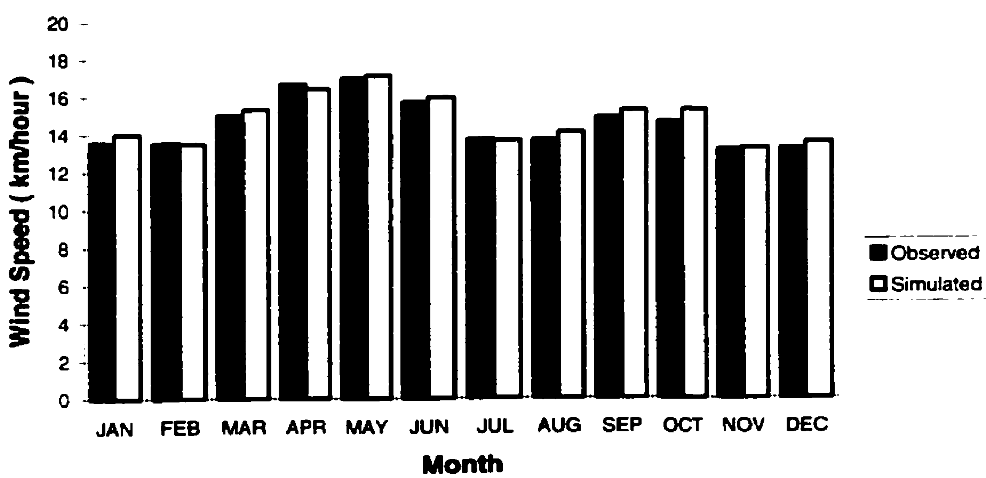

Figure 4.5 Observed and simulated seasonal distributions of wind speed at North Battleford.

Other properties were also compared and the results did not show any significant difference. It can be concluded from these comparisons that the ARMA(3,2) model proposed in this chapter can quite closely reproduce the auto-correlation of hourly wind speed, the seasonal characteristics and the diurnal distribution of wind speed, and therefore can be used as a feasible site specific time series model for reliability evaluation of power systems including WECS.

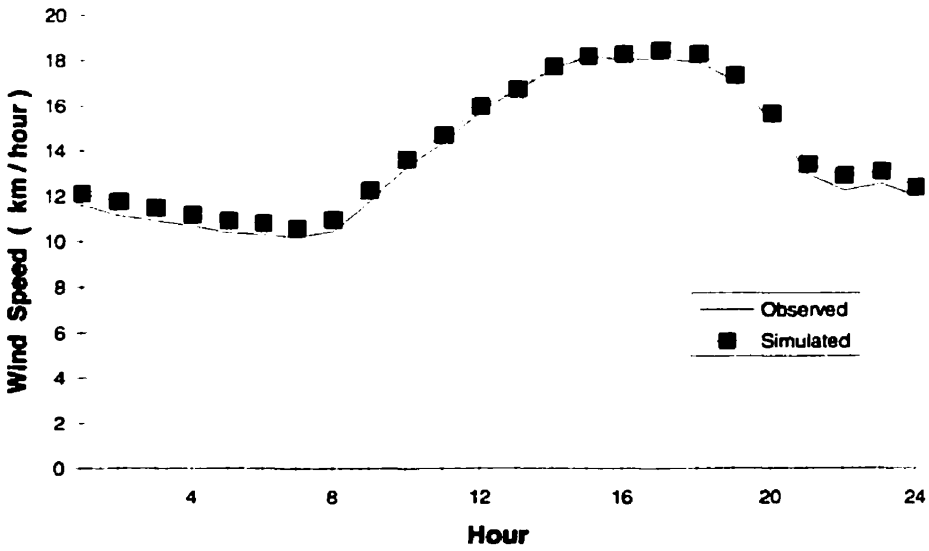

Figure 4.6 Observed and simulated diurnal distributions of wind speed in August at North Battleford

4.3.2. Substitute Models for ARMA(3,2)

As stated in Section 4.2, some pure AR models can be established as possible replacements for the fitted ARMA model. Generally, AR models, because of their simplicity and ease of interpretation, are often used in practical applications.

The first possible substitute model for ARMA(3,2) is AR(3). The residual sum of the squares of the AR(3) model is 5926.74. The F-value resulting from substituting ARMA(3,2) with AR(3) is 8.73, which is much greater than $F_{0.95}(2,\infty)$. This means that the reduction in the residual sum of the squares from AR(3) to ARMA(3,2) is substantial at this significance level. The AR(3) model was therefore rejected and is not an acceptable substitute for the ARMA(3,2) model.

By increasing the order of AR(n), AR(4) ~ AR(8) can also be formed. The established AR(8) model has almost the same residual sum of the squares as the ARMA(3,2) model. A similar checking procedure was used for the AR(8) model and the results show that it is feasible and can be considered as a reasonable substitute model for ARMA(3,2). The fitted AR(8) is as follows:

$$\begin{aligned} y_t = {} & 0.6971y_{t-1} + 0.1441y_{t-2} + 0.0464y_{t-3} + 0.01y_{t-4} + \\ & 0.0038y_{t-5} - 0.0194y_{t-6} - 0.0068y_{t-7} - 0.0117y_{t-8} + \alpha_t \end{aligned}$$

$$\alpha_t \in NID\left(0, 0.474801^2\right) \tag{4.10}$$

In order to investigate whether there is a much better time series model than AR(3,2) or AR(8), a complete AR(24) (not the simplified form as presented in [43,44]) was developed. The results show that the improvement created by the AR(24) model is very slight. The main improvement is in the auto-correlation function of wind speed. The AR(24) model reproduces damping more closely than the AR(3,2) does. As shown in Figure 4.4, the AR(3,2) model has almost the same damping as that of the actual wind speed, therefore the more detailed AR(24) model is not necessary unless more precise simulation procedures are required in some specific applications.

4.3.3 Comparison of the Models for Different Sites

The wind data for a site near Regina, Saskatchewan which has relatively high wind speed, were also obtained from Environment Canada. A series of wind speed models were established by WSERIES. The ARMA(2,1), ARMA(3,2) were rejected based on the F-criterion. The most acceptable model for the Regina site is ARMA(4,3) and can be written as:

$$y_t = 0.9336y_{t-1} + 0.4506y_{t-2} - 0.5545y_{t-3} + 0.111y_{t-4}$$
$$+\alpha_t - 0.2033\alpha_{t-1} - 0.4684\alpha_{t-2} + 0.2301\alpha_{t-3}$$

$$\alpha_t \in NID\left(0, 0.409442^2\right) \tag{4.11}$$

The AR(8) model developed as the substitute model for ARMA(4,3) is as follows:

$$y_t = 0.7306y_{t-1} + 0.1294y_{t-2} + 0.0475y_{t-3} + 0.0105y_{t-4} -$$
$$0.0103y_{t-5} + 0.0047y_{t-6} - 0.0114y_{t-7} - 0.0072y_{t-8} + \alpha_t$$

$$\alpha_t \in NID\left(0, 0.409432^2\right) \tag{4.12}$$

The above wind speed models for the site near Regina are different from those at the North Battleford - not only in the coefficients, but also in the orders of the models. New time series models should be established using the same procedure for any given location.

4.4. Wind Speed Models: Type Two

The hourly mean and standard deviation of the wind speed are needed to establish the previously described models. For some sites, however, such records are unavailable or inadequate and therefore a different type of model is required.

Data were provided by SaskPower for a site near Billimun [57]. Only one year of hourly actual wind speed data (from 1 August, 1993 to 31 July 1994) was available.

Let:

$$y_t = OW_t - \mu \tag{4.13}$$

Then y_t can be used to establish a wind speed model (4.3), and the simulated wind speed SW_t, can be calculated as:

$$SW_t = \mu + y_t. \tag{4.14}$$

The finally fitted wind speed model for Billimun is ARMA(3,2) as follow:

$$y_t = 1.4541y_{t-1} - 0.3756y_{t-2} - 0.1116y_{t-3} + \alpha_t - 0.3806\alpha_{t-1} - 0.1988\alpha_{t-2}$$
$$\alpha_t \in NID\left(0,1.301342^2\right) \tag{4.15}$$

The substitute model is AR(4):

$$y_t = 1.0738y_{t-1} - 0.1688y_{t-2} + 0.041y_{t-3} + 0.0221y_{t-4} + \alpha_t$$
$$\alpha_t \in NID\left(0,1.301547^2\right). \tag{4.16}$$

As shown in Figure 4.7, underestimation of the auto-correlation function occurs only when the lag is greater than 20 and the fitted ARMA(3,2) model (4.15) can basically preserve the auto-correlation of the actual wind at Billimun. It should be noted that there is no superimposed sinusoid damping in the auto-correlation function of wind speed at Billimun.

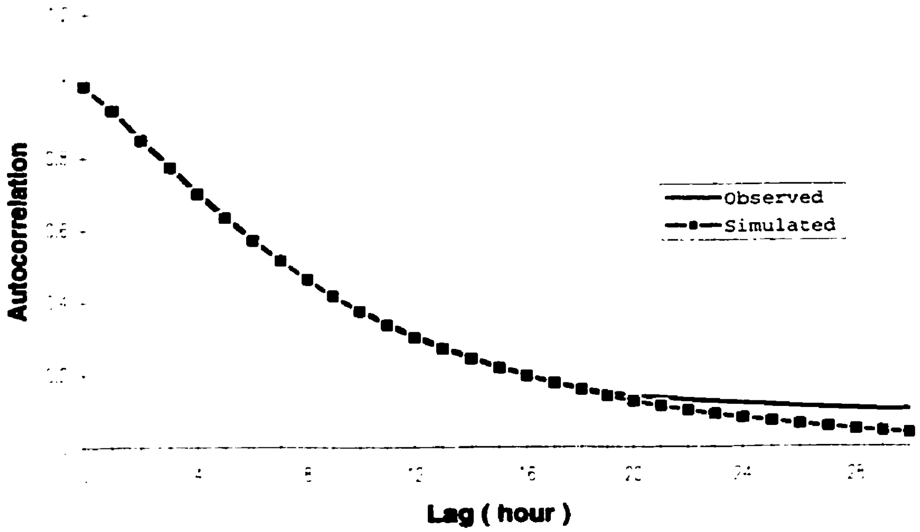

Figure. 4.7 Observed and simulated auto-correlation functions of wind speed at Billimun

Although the time series model given by (4.15) passes the statistical tests and fundamentally reproduces the auto-correlation of the actual wind speed, it unfortunately cannot retain the seasonal and diurnal distribution of the actual wind speed as shown in

Figures 4.8 and 4.9 respectively. It can be clearly seen from these figures that the simulated results are significantly different from the observed ones.

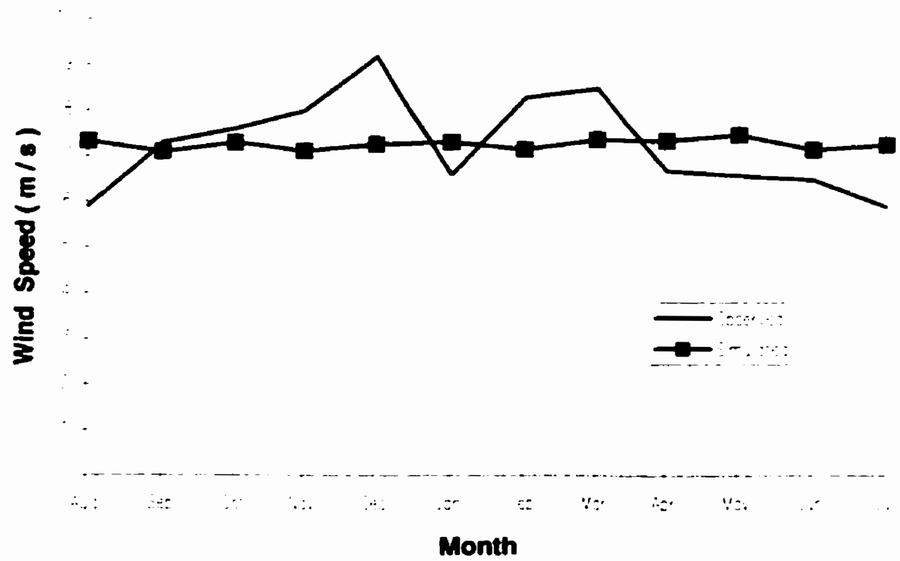

Figure 4.8 Observed and simulated seasonal distributions of wind speed at Billimun.

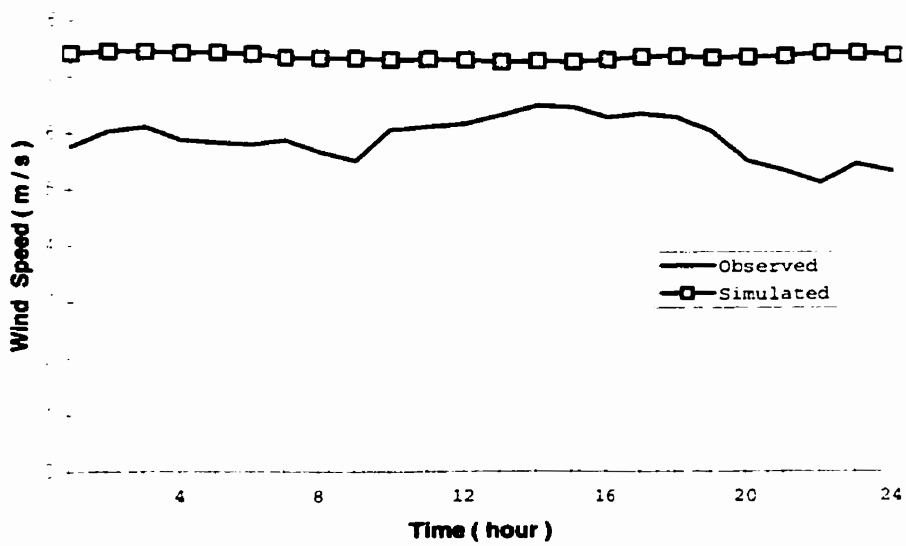

Figure 4.9 Observed and simulated diurnal distributions of wind speed at site Billimun.

Some improvement can be achieved by dividing the wind data into 12 months and establishing 12 time series models. In this way, the seasonal distribution of wind speed can be retained, but the diurnal distribution cannot be preserved. It can be therefore concluded that the second type of model is not adequate as the wind data used to establish the model are not sufficient. Generally, the more wind data utilized in developing the model, the more accurate the model is.

4.5 Reliability Simulation Procedure

4.5.1 General Simulation Procedure

Generating capacity adequacy assessment involves the creation of a capacity model and the convolution of this model with a suitable load model. In an analytical method, the capacity model is normally referred to as a capacity outage probability table, which provides the probability of existence of each possible outage capacity level. In a chronological Monte Carlo simulation approach, the capacity model is the system available capacity at points in time established sequentially, taking into account unit random failures. The load model is a chronological hourly load profile. The available system reserve at a point in time is the difference between available capacity and the load. A negative margin denotes a load loss situation. The system reliability indices can be formed by observing the available system reserve profile over a sufficiently long time period.

The simulation procedure for generating capacity adequacy assessment including WECS is basically similar to the procedure described in Chapter 2. There are, however, some significant differences and therefore the procedure is described in the following:

1. Create a capacity model for the conventional base load generating facilities using chronological simulation techniques;

2. Construct a capacity model for the wind turbine generating units using the time series models and the corresponding simulation techniques;

3. Obtain a combined system capacity model. If the available capacity is less than the load at time t, simulate the commitment of peaking units and update the system capacity model;

4. Form the required reliability indices by observing the system capacity reserve model over a long time period.

As noted in the above procedure, a WTG unit is considered to be a base load unit in that energy is supplied whenever the wind is sufficient.

The reference period in this simulation process is one year. Each year is further divided into a number of hours and therefore the minimum time unit in the simulation is an hour. The sampling of the operating history is, consequently, hourly.

The mean value $E(X)$ and standard deviation $\sigma(X)$ for any reliability index X after N sampling years can be obtained using (4.17) and (4.18):

$$E(X) = \frac{1}{N}\sum_{k=1}^{N} X_k \tag{4.17}$$

$$\sigma(X) = \sqrt{\frac{1}{N-1}\left[\sum_{k=1}^{N} X_k^2 - N \times E^2(X)\right]} \tag{4.18}$$

in which X_k is the observed value of the index X in sampling year k. X can be one of the following indices:

1. Loss of Load Expectation (LOLE), hour/year
2. Loss of Energy Expectation (LOEE), MWh/year
3. Frequency of Loss of Load (FLOL), occurrence/year
4. Duration per interruption (D), hours/occurrence
5. Load Not Supplied per Interruption (LNSI), MW/occurrence
6. Energy Not Supplied per Interruption (ENSI), MWh/occurrence.

The stopping criterion used in the simulation is the ratio of the standard deviation of the sample mean of a reliability index of the interest over the sample mean of the index. Mathematically, the simulation is stopped when

$$\frac{\sigma[E(X)]}{E(X)} \leq \varepsilon_X \tag{4.19}$$

where, X is a selected reliability index, ε_X is the maximum error allowed and $\sigma[E(X)]$ can be expressed as:

$$\sigma[E(X)] = \sigma(X)/\sqrt{N} \tag{4.20}$$

A computer program designated as WGRASS based on the general simulation procedure presented above has been developed at the University of Saskatchewan.

The simulation procedures for both conventional units and WTG units are presented in detail in the following sections.

4.5.2. Modeling Conventional Units

Conventional generating units can be classified as two basic unit types: base load unit or peaking units. A base load unit is simulated using a two state or multistate model depending on whether unit deratings are taken into account. The up-down-up or up-derate-down-up cycle of a base load unit can be generated using a random sampling technique from the corresponding state residence time distributions. The residence time distribution of a unit at a state can be any one of the following forms: exponential; Rayleigh; Weibull; normal; long-normal and uniform. Generally, if F(t) is the cumulative probability density function of a unit residence time t, which is a random variable, a residence time T corresponding to a uniformly distributed random number U $(0 \leq U \leq 1)$ can be calculated as follows:

$$T = F^{-1}(U) \tag{4.21}$$

A peak load unit is modeled by the conventional four-state representation proposed by an IEEE Task Force [2]. The four states in this model are: (1) in service; (2) reserve shutdown; (3) forced out when needed; (4) forced out but not needed. The operation of a peak load unit is dependent on the updated available capacity and the load. Whenever a peak load unit is needed, a uniformly distributed random number U is drawn and compared with the unit starting failure probability to determine if the unit starts. If the unit starts, a random time to failure is sampled using Equation (2.4). If the unit fails to start, a random repair time is drawn from the Time-To-Repair distribution using the same equation. The unit's next state is determined by comparing the reserve shutdown time and the operating time or repair duration.

4.5.3. Modeling WECS

<u>*Simulation of Wind Power*</u>

In each sampling year, the hourly wind speeds are simulated in order to obtain the hourly available output of the WECS. The time series model described by Equation (4.3), and Equation (4.4) are used to do this. The main steps can be expressed as:

1. The white noise α_t is first simulated;

2. y_t *is* subsequently generated using time series model (4.3);

3. the simulated wind speed SW_t at time point t is then obtained using (4.4).

For $t \leq 0$, y_t and α_t are assumed to 0.

The tabulating technique of normal distribution sampling [85] is used to generate the white noise. The method is more computationally efficient than the direct inverse function transformation method.

After the hourly wind speed SW_t is generated, the available power output of a WTG at any time point t can be calculated using the nonlinear relationship between wind power output and the wind velocity, as shown in (4.22).

$$P_t = \begin{cases} 0 & 0 \leq SW_t \leq V_{ci} \\ (A + B \times SW_t + C \times SW_t^2)P_r & V_{ci} \leq SW_t \leq V_r \\ P_r & V_r \leq SW_t \leq V_{co} \\ 0 & SW_t \geq V_{co} \end{cases} \tag{4.22}$$

where V_{ci}, V_r, V_{co} and P_r are the cut-in speed, the rated speed, the cut-out speed and the rated power of a WTG unit respectively. The constants A, B and C are presented in [51]:

Simulation of WTG Forced Outages

In addition to the output variations with wind speed, a WTG unit can also suffer a forced outage. In order to recognize this, the operating cycle of a WTG is simulated in the same way as that of a conventional base load generating unit. The sequential up-down-up cycles of a WTG are combined with the hourly available wind power derived from (4.22) to obtain the final hourly available power output. The available power of a WECS at a given hour is the sum of the available power outputs of all the wind turbine generators.

4.6. Case Studies

Case studies have been conducted using the RBTS. The system configuration and basic data are given in Appendix [63]. The RBTS has 11 conventional generating units, ranging in size from 5 MW to 40 MW, with a total installed capacity of 240 MW. The chronological load profile consists of 8736 load points and the annual peak load is 185 MW. A WECS containing 100 WTG units was incorporated in the RBTS. Each unit has a rated power output of P_r =225 kW and a Forced Outage Rate (FOR) of 0.04. The cut-in, rated and cut-out speeds are 12, 38 and 80 km/h respectively.

The WECS is assumed to be located in a site near North Battleford, Saskatchewan. It has been seen in Section 4.3 that the model (4.8) and the corresponding wind speed simulator can quite closely reproduce the auto-correlation of hourly wind speed, the seasonal characteristics and the diurnal distribution of wind speed, and therefore can be used in these case studies as a feasible time series model for reliability evaluation of generating systems including WECS.

4.6.1. The Basic Simulation Results for RBTS Including WECS

The program WGRASS was used to simulate the generation / load characteristics of the RBTS including WECS. The residence time distributions of all units were assumed to be exponential and a stopping criterion of $\varepsilon_{LOLE} = 0.05$ was used to control the simulation length. Figure 4.10 shows the estimated LOLE index in hour/year versus the number of sampled years for the RBTS including WECS. It can be seen from Figure 4.10 that at the early stages of simulation, there can be considerable difference in the estimated results. This is because the sample space is so small that an estimate with a high confidence cannot be achieved. As the simulation continues, the estimated indices get closer to each other. The location at which the estimated LOLE begin to stabilize is about 6000 years. The means and standard deviations of the reliability indices after 7319 sample years are given in Table 4.2.

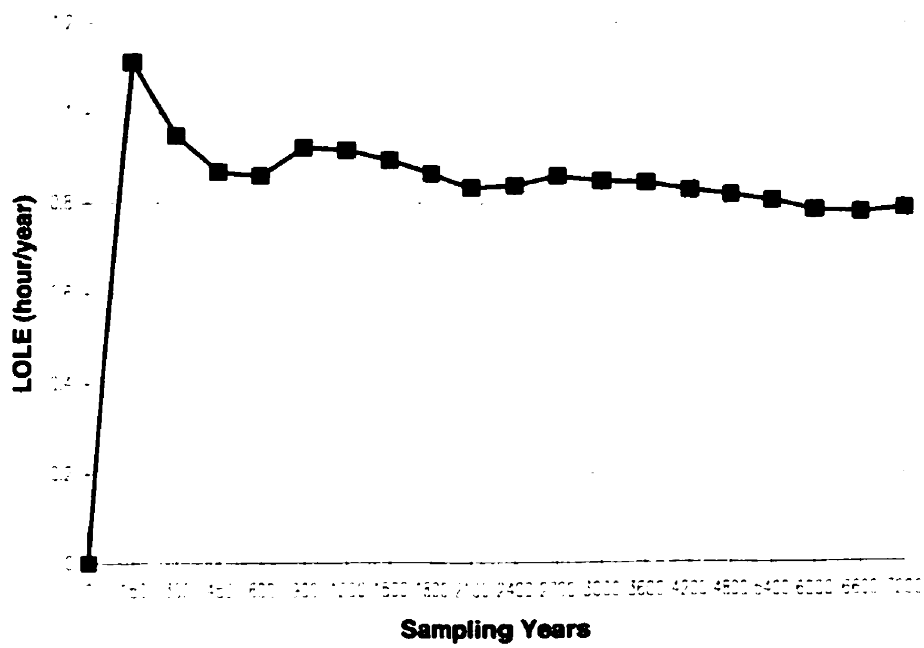

Figure 4.10 LOLE versus sampling years for the RBTS including WECS.

Table 4.2. Reliability indices of the RBTS containing 100 WTG units

Reliability indices	*Mean*	*Standard deviation*
LOLE (hours/yr.)	0.7895	3.3769
LOEE (MWh/yr.)	7.3572	49.8830
FLOL (occ./yr.)	0.1910	0.6696
D (hours/occ.)	4.1330	3.6535
LNSI (MW/occ.)	6.0371	6.0605
ENSI (MWh/occ.)	38.5174	73.3655

4.6.2. Benefit Assessment of the WECS

Table 4.3 presents the reliability indices before and after the 100 WTG units are added to the RBTS. It can be seen from this table that the adequacy of the RBTS improves with the addition of 22.5 MW in the form of 100 WTG units.

Table 4.3 Effects of adding 100 WTG's on the reliability indices of the RBTS

Reliability indices	*Before adding WECS*	*After adding WECS*
LOLE (hours/yr.)	1.1282	0.7895
LOEE (MWh/yr.)	10.3109	7.3572

Table 4.4 compares the reliability indices after adding 100 WTG's with those obtained when the additional wind capacity is replaced by conventional units with the same capacity of 22.5 MW. In this case, 3×5 MW + 1×7.5 MW units were added, each with a FOR of 0.04. It can be seen from this table that the wind energy conversion system does not provide the same degree of adequacy as do the conventional unit additions.

Table 4.4 Comparison of the reliability indices of the RBTS after adding 22.5 MW in WTG's or conventional units

Reliability indices	100 WTG's	Conventional units
LOLE (hours/yr.)	0.7895	0.0990
LOEE (MWh/yr.)	7.3572	0.8251

In order to quantitatively assess the benefits of a WECS, the LOLE indices of the RBTS before and after adding 100 WTG units are plotted as functions of the annual peak load in Figure 4.11.

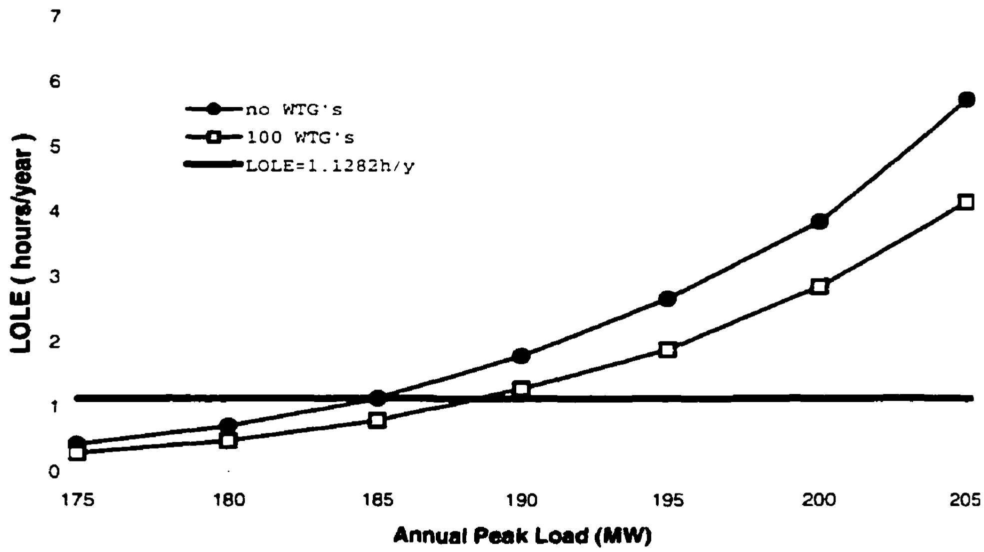

Figure 4.11 Variation of the LOLE with the annual peak load of RBTS.

It can be clearly seen from this figure that there is a load carrying capability benefit from the WECS addition. The incremental annual peak load carrying capability (IPLCC) at an LOLE of 1.1282 hours/year (which is the LOLE obtained for the basic RBTS) is approximately 4.2 MW after 100 WTG units are added to the system. This can be compared with an IPLCC of 24.5 MW when 100 WTG units are replaced by 22.5 MW of conventional base load units. It can be seen from Figure 4.11 that the differences between the values of IPLCC at different risk levels are relatively small, which means that the load carrying capability benefits are relatively independent of the selected risk level.

The IPLCC as a percentage of the added generating capacity is designated as the Load Capacity Benefit Ratio (LCBR). The LCBR is 18.67% (4.2/22.5) in the case of the WTG additions and 108.9% in the case of the conventional unit additions. These values are obviously functions of the system and equipment parameters used in the analysis.

4.6.3. Effect of Wind Speed

The output of a WECS is extremely site specific and therefore the power and energy output of a WECS will increase if the wind facility is located at a point in the system that experiences higher wind velocities. This, in turn, will have a positive impact on the performance of the system. In order to illustrate this phenomenon, the hourly mean wind speeds have been modified by a simple multiplication factor and used to calculate the reliability indices for the RBTS containing WECS. The LOLE values for the 100 WTG unit's case are shown in Figure 4.12. It can be observed from this figure that, in the case of the RBTS, the LOLE decreases as the wind speed multiplication factor increases.

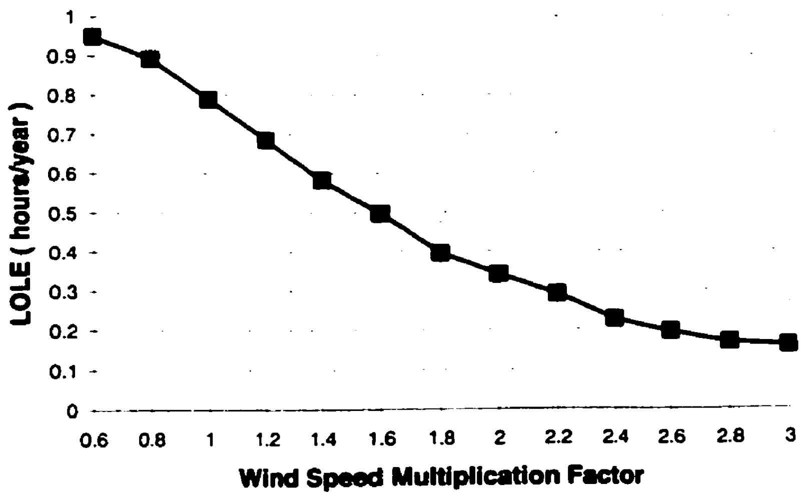

Figure 4.12 LOLE versus, wind speed multiplication factor.

Figure 4.13 shows the IPLCC at a LOLE of 1.1282 hours/year, as a function of the wind speed multiplication factor. It can be seen that the load carrying capability benefits of the WECS increase relatively linearly as wind speeds rise but tend to saturate when wind speeds continue to increase. This is due to the unique non-linear characteristics of a WTG. A wind machine is not operational when the wind speed is below the cut-in speed and is shut down for safety reasons if the wind velocity is too high. In both cases, the power output is zero. The power output of a WTG unit increases with the wind speed between the cut-in speed and rated speed after which the power output remains constant. The IPLCC (LCBR) curve can be useful in determining optimal equipment parameters, such as V_{ci}, V_r, V_{co} and P_r for a specific wind site. This is discussed further in Chapter 6.

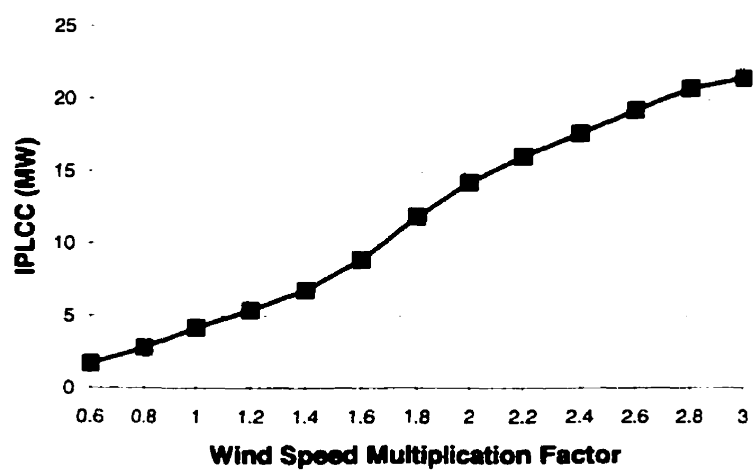

Figure 4.13 IPLCC versus wind speed multiplication factor.

4.7. Summary

This chapter presents a Monte Carlo simulation procedure for reliability evaluation of generating system containing WECS. The model uses a sequential Monte Carlo sampling technique to generate artificial operating histories of the generating units. An ARMA time series analysis method is used to simulate the wind speed and the chronological correlation of wind speeds is considered.

A procedure for fitting ARMA wind speed models is presented in this chapter. Two different time series models are established using different available wind speed data. No assumptions or previously estimated factors are introduced in the models. This approach ensures that there is no inherent distortion in the resulting model. The F-criterion, statistical tests based on the chi-square distribution, and a simulation procedure are used to check the feasibility of the model. The first series of models presented in this chapter can pass the statistical tests and reproduce the high-order auto-correlation, the seasonal and diurnal distribution of the actual wind speed and therefore can be used in power system reliability studies including WECS. The second series of models cannot maintain the statistical seasonal characteristics or diurnal distribution as the wind data used to establish them are not sufficient. Availability of actual wind data in sufficient detail is an essential requirement for developing feasible wind speed models. The studies in this chapter also show that the sampling auto-correlation functions of different years at the same site may be significantly different , thus a wind speed model based on only one year of actual wind data should be used with caution.

The contribution of a WECS to the reliability performance of a generating system depends upon many factors including the wind penetration level and wind conditions. The case studies in this chapter show that the adequacy improvement and therefore the load carrying contribution of a WECS can be quantitatively evaluated. It is believed that the technique proposed in this chapter can assist the system planner and utility manger to quantitatively assess the system worth of WECS and provide useful input to the managerial decision process.

Chapter 5
Risk-Based Capacity Benefit Assessment Associated with WECS

5.1. Introduction

A WECS has a different impact on the load carrying capability of a generating system than does a conventional energy conversion system. This is due to the variation in wind speeds, the dependencies associated with the power output of each Wind Turbine Generator (WTG) in a wind farm, and the nonlinear relationship between WTG power output and wind velocity. Two risk-based capacity factors designated as the Load Carrying Capacity Benefit Ratio (*LCCBR*) and the Equivalent Capacity Ratio (*ECR*) are introduced in this chapter. These two indices indicate the capacity benefit and credit of a WECS, and thus provide valuable information for energy policy makers in decision problems involving the selection and classification of wind sites. A midpoint sectionalized technique has been developed to calculate the Incremental Peak Load Carrying Capability (*IPLCC*) and to assess the *LCCBR* and *ECR*. The technique is effective and usually takes a few iterations to obtain the *LCCBR*. The sequential Monte Carlo simulation described in Chapter 4 is utilized in each iteration to assess the risk of generating systems including WECS. The RBTS containing a WECS with wind data obtained from Environment Canada is utilized to illustrate the basic simulation approach and the proposed technique to assess the load carrying benefit ratio of a WECS.

5.2. Concept of Risk-Based Capacity Benefit Factors

Wind energy is intermittent and nondispatchable as wind velocity is highly variable and site-specific. The WTG in a particular wind farm cannot be considered to be independent because of the dependence on the same primary energy source -- the wind. The relationship between WTG power output and wind velocity is also nonlinear. Consequently, a 1 MW WTG cannot usually carry the same amount of load as a 1 MW conventional generating unit. The following questions arise when considering wind energy as a potential power option:

1. How much incremental peak load can a per unit injection of WECS capacity carry while maintaining the original risk criterion?

2. What is the equivalence between conventional generation capacity and a per unit injection of WTG capacity?

The answers to these questions provide considerable information on the possible capacity credit that can be assigned to a WECS. The Capacity Factor (*CF*) shown in (5.1) can be used [61] to provide an equivalent capacity measure.

$$CF = {}^{P_e}\!/_{P_r} \tag{5.1}$$

where P_e is the expected power output of a WECS, P_r is the total rated power output. This factor indicates the potential wind energy production capability at a wind site. It is, however, not related to the system capacity composition, the chronological load and wind profiles, and the accepted system risk level. Risk based capacity benefit indices are required which recognize these factors in the assessment of the potential capacity benefit or credit of a WECS.

5.2.1 Load-Carrying Capacity Benefit Ratio (LCCBR)

Figure 5.1 illustrates the relationship between a risk index and the annual peak load before and after adding WTG units. In Figure 5.1, R_c is the criterion reliability, $PLCC_{orig}$ is the peak load that the original generating system can carry at risk level R_c, $PLCC_{new}$ is the peak load that the expanded generating system (with the addition of WTG' s) can carry at the same risk level.

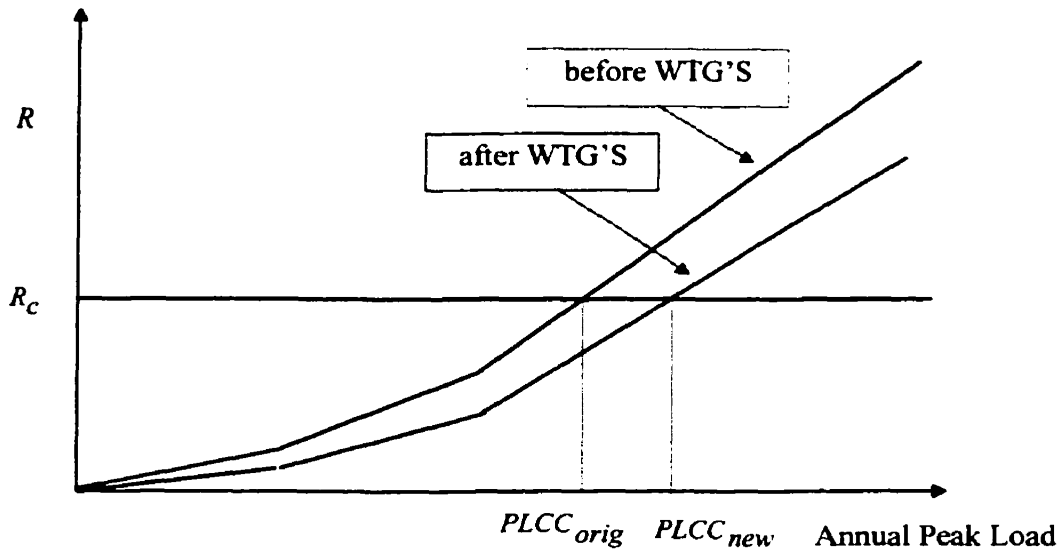

Figure 5.1 Variation of reliability indices with annual peak load.

The incremental load carrying capability benefit [3] from the WECS addition is

$$IPLCC_W = PLCC_{new} - PLCC_{orig} \tag{5.2}$$

The $IPLCC_W$ as a percentage of the added WTG generating capacity is defined as the WECS Load Carrying Capacity Benefit Ratio and is given by

$$LCCBR = \frac{IPLCC_W}{P_r} = \frac{PLCC_{new} - PLCC_{orig}}{P_r}. \tag{5.3}$$

The $LCCBR$ indicates the per unit incremental peak load that the system can carry due to the WECS addition while maintaining the criterion reliability. This index is a function of the system and the equipment parameters used in the analysis.

5.2.2 Equivalent Capacity Ratio (ECR)

If the additional wind capacity is replaced by conventional units with the same capacity P_r MW, the corresponding incremental peak load carrying capability can be designated as $IPLCC_C$. The Equivalent Capacity Ratio (ECR) is defined as the ratio of the incremental peak load carrying capability of a WECS addition and the incremental peak load carrying capability of a conventional generation addition.

$$ECR = \frac{IPLCC_W}{IPLCC_C} \tag{5.4}$$

The *ECR* provides a risk-based equivalence between conventional generating unit power and the WTG power. If the assessed *ECR* is 0.2, then 1 unit of WTG is equivalent to 0.2 units of conventional capacity, or 1 unit of conventional capacity is equivalent to 5 units of WTG, in that they provide the same incremental peak load carrying capability.

The risk-based indices *LCCBR* and *ECR* give a more direct and physical indication of the benefits of WECS additions compared to the classic reliability indices of LOLE, FLOL and LOEE [3]. They provide valuable information for energy policy makers when selecting and classifying wind sites.

5.3 Bisection Technique

It can be seen from definitions (5.3) and (5.4) that a crucial step in assessing capacity factors *LCCBR* and *ECR* is to calculate the incremental peak load carrying capability, or peak load carrying capability (*PLCC*) after the system capacity is increased. The procedure to calculate *PLCC* at a given reliability level is more complicated than that required to calculate a reliability index at a given load profile.

A reliability index can be expressed mathematically as a function of the system peak load *PL*:

$$R = f(PL) \tag{5.5}$$

Similarly, *PLCC* is a function of the reliability level:

$$PLCC = f^{-1}(R) \tag{5.6}$$

where $f^{-1}(*)$ is the inverse function of $f(*)$.

There is no explicit expression for the function $f(PL)$, nor for $f^{-1}(R)$. The concept illustrated in Figure 5.1 can, however, be used to obtain *PLCC*. The relationship between the system peak load and the risk level for the expanded system with the WTG addition can be established using incremental sensitivity analysis. In this approach, the initial *PLCC* is assumed to be the peak load carrying capability for the original system ($PLCC_{orig}$). The peak load is then increased by specified increments and the risk index is evaluated until the calculated risk index is approximately equal to the criterion risk level. The peak load corresponding to the last iteration is the *PLCC* for the expanded system. This approach can involve considerable computational effort when the sequential Monte Carlo simulation method shown in Chapter 4 is utilized in each step to estimate the reliability indices.

The risk increases with increase in the peak load, and therefore $f(PL)$ is a monotonic increasing function. The midpoint sectionalizing or bisectionalizing technique can be effectively utilized to calculate the *PLCC*. The initial boundary values for *PLCC* are first established. The lower boundary can be set at the $PLCC_{orig}$, as the expanded system has at least the same load carrying capability as the original system. The upper boundary is set as the sum of the $PLCC_{orig}$ and the total rated WTG capacity addition, recognizing that 1 MW of WTG does not usually provide 1 MW of *IPLCC*. It is possible, however, that 1 MW of incremental conventional unit capacity can provide more than 1 MW of *IPLCC*. The upper boundary is therefore set as the sum of the $PLCC_{orig}$ and twice the rated capacity of the conventional unit addition. Generally, the risk level of the expanded system at the upper *PLCC* boundary exceeds the criterion reliability. If this is not true, the initial upper boundary must be adjusted until the condition is satisfied. After the initial values are determined, the midpoint of the initial boundary is calculated, and the risk index at the midpoint is assessed using the related techniques. This risk index is further utilized to judge whether the actual *PLCC* is in the zone between the lower bound and the midpoint or that between the midpoint and the upper limit. If the risk index is greater than the given risk level, the expanded system cannot carry a peak load greater than the value at the midpoint without violating the criterion risk. The actual *PLCC* is then in the first zone. The midpoint becomes the new upper boundary for this case. If the calculated risk is less than the criterion risk, the expanded system can at least carry the peak load at the midpoint. The actual *PLCC* is then in the second zone and the midpoint becomes the new lower boundary for this case. The peak load carrying capability of the expanded system can be obtained by repeating the above procedure until the difference between the upper and low bounds, or the difference between the risk index at the midpoint and the given risk level, is within a tolerance error.

The midpoint algorithm to determine the *PLCC* of a generating system can be further described as follows:

Step 1. Set the initial boundary values $PLCC^{(low)}$ and $PLCC^{(upper)}$. Usually, $PLCC^{(low)} = PLCC_{orig}$,

$PLCC^{(upper)} = PLCC_{orig} + P_r$ for the WTG addition,

$PLCC^{(upper)} = PLCC_{orig} + 2P_r$ for conventional capacity addition.

Step 2. Adjust the initial value of $PLCC^{(upper)}$ in order that the corresponding risk level is greater than the given reliability level.

Step 3. Let $PLCC^{(mid)} = \dfrac{PLCC^{(upper)} + PLCC^{(low)}}{2}$.

If $\left|PLCC^{(upper)} - PLCC^{(low)}\right| \le \varepsilon_{PLCC}$ (ε_{PLCC} is the related maximum error allowed), go to Step 6.

Step 4. Calculate the reliability index $R^{(mid)}$ corresponding to the system peak load $PLCC^{(mid)}$ using the sequential Monte Carlo simulation procedure shown in Chapter 4, if a WECS is considered. Either Monte Carlo simulation or analytical approaches can be utilized if only conventional units are considered.

Step 5. Form the new boundary:

If $R^{(mid)} > R^{(org)}$, then $PLCC^{(mid)} \rightarrow PLCC^{(upper)}$;

If $R^{(mid)} < R^{(org)}$, then $PLCC^{(mid)} \rightarrow PLCC^{(low)}$;

If $R^{(mid)} = R^{(org)}$, go to Step 6.

Step 6. $PLCC^{(mid)}$ is the *PLCC* for the expanded system.

The boundary length in each iteration is decreased to half of the last length, and therefore the convergence is fast. The initial length is P_r for WTG additions. Designating the number of iterations as n, the relationship among n, P_r and ε_{PLCC} can be expressed as follows.

$$\frac{P_r}{2^n} \leq \varepsilon \tag{5.7}$$

Consequently, the (minimum) number of iterations, by which the accuracy can be reached, is

$$n = 1.4427 \ln\left(\frac{P_r}{\varepsilon}\right) \tag{5.8}$$

If ε is taken as 1 MW, the number of iterations is 4 for P_r=10 MW, 7 for P_r=100 MW and 10 for P_r=1000 MW. The number of iterations is not sensitive to the initial bounds or the size of the expanded WTG' s. If ε is taken as 0.1 MW, the number of iterations is 7 for P_r=10 MW, 10 for P_r=100 MW and 14 for P_r=1000 MW. This further states that the number of iterations is also not sensitive to the maximum allowed error. Similar formulae and conclusions can be deduced for conventional unit expansion. The midpoint sectionalized algorithm proves to be very effective when estimating *PLCC*, *IPLCC*, *LCCBR* and *ECR*.

5.4. Case Studies

Numerical studies have been conducted using the RBTS [63]. The RBTS has 11 conventional generating units, ranging in size from 5 MW to 40 MW, with a total installed capacity of 240 MW. The chronological load profile consists of 8736 load points and the annual peak load is 185 MW [63]. A WECS containing 100 WTG units is incorporated in the RBTS. Each unit has a rated power output of 225 *kW* and a Forced Outage Rate (FOR) of 0.04. The cut-in, rated and cut-out speeds are 12, 38 and 80 km/hour respectively.

Four wind sites near Prince Albert, North Battleford, Saskatoon and Regina, which are in the Province of Saskatchewan, Canada, were selected for study. The actual hourly wind speed for 3 years and the hourly mean and standard deviation of wind speeds from a 37-year database for each site were obtained from Environment Canada and used to establish the wind speed model. The mean and standard deviation of the site wind speeds are shown in Table 5.1.

Table 5.1 Basic wind speed data (km/hour)

Sites	Prince Albert	North Battleford	Saskatoon	Regina
μ	13.29	14.63	16.78	19.52
σ	9.25	9.75	9.23	10.99

The fitted wind speed model for the Prince Albert site is:

$$\begin{aligned} &y_t = 1.0136\,y_{t-1} - 0.0836\,y_{t-2} + a_t - 0.3666\,a_{t-1} \\ &a_t \in NID(0, 0.459048^2) \end{aligned} \tag{5.9}$$

For the North Battleford site [90],

$$\begin{aligned} &y_t = 1.7901 y_{t-1} - 0.9087 y_{t-2} + 0.0948 y_{t-3} + \\ &\quad a_t - 1.0929 a_{t-1} + 0.2892 a_{t-2} \\ &a_t \in NID(0, 0.474762^2) \end{aligned} \tag{5.10}$$

For the Saskatoon site,

$$
\begin{aligned}
y_t &= 1.5047\, y_{t-1} - 0.6635\, y_{t-2} + 0.115\, y_{t-3} + \\
&\quad a_t - 0.8263\, a_{t-1} + 0.2250\, a_{t-2} \\
a_t &\in NID(0, 0.447423^2)
\end{aligned}
\tag{5.11}
$$

For the Regina site [90],

$$
\begin{aligned}
y_t &= 0.9336\, y_{t-1} + 0.4506\, y_{t-2} - 0.5545\, y_{t-3} + 0.111\, y_{t-4} \\
&\quad a_t - 0.2033\, a_{t-1} - 0.4684\, a_{t-2} + 0.2301\, a_{t-3} \\
a_t &\in NID(0, 0.409432^2)
\end{aligned}
\tag{5.12}
$$

The program WGRASS was used to simulate the generation / load characteristics of the RBTS including WECS. The residence time distributions of all units were assumed to be exponential and a stopping criterion of $\varepsilon_{LOLE} = 0.05$ was used to control the simulation length. Table 5.2 presents the reliability indices before and after the 100 WTG units are added to the RBTS. It can be seen from this table that the adequacy of the RBTS improves with the addition of 22.5 MW in the form of 100 WTG units. The maximum improvement occurs at the site near Regina, which is in the southern part of Saskatchewan province, while the minimum occurs at the site near Prince Albert, which is located in northern part of the province.

Table 5.2 RBTS reliability indices with and without the 100 WTG units

Case	LOLE (hours/yr.)	LOEE (MWh/yr.)	FLOL (occ./yr.)	D (hours/occ.)
original system	1.1282	10.3109	0.2194	5.1414
Prince Albert	0.8421	7.8272	0.1985	4.2423
North Battleford	0.7895	7.3572	0.1910	4.1330
Saskatoon	0.7369	6.5770	0.1863	3.9554
Regina	0.5884	5.3221	0.1525	3.8584

The iterative procedure to calculate the *PLCC* of the RBTS including a WECS at Regina is illustrated in Figure 5.2. The maximum error ε_{PLCC} is set as 0.1 MW and the number of iterations is 8. Figure 5.2 further indicates the rapid convergence of the midpoint sectionalizing technique introduced in Section 5.3.

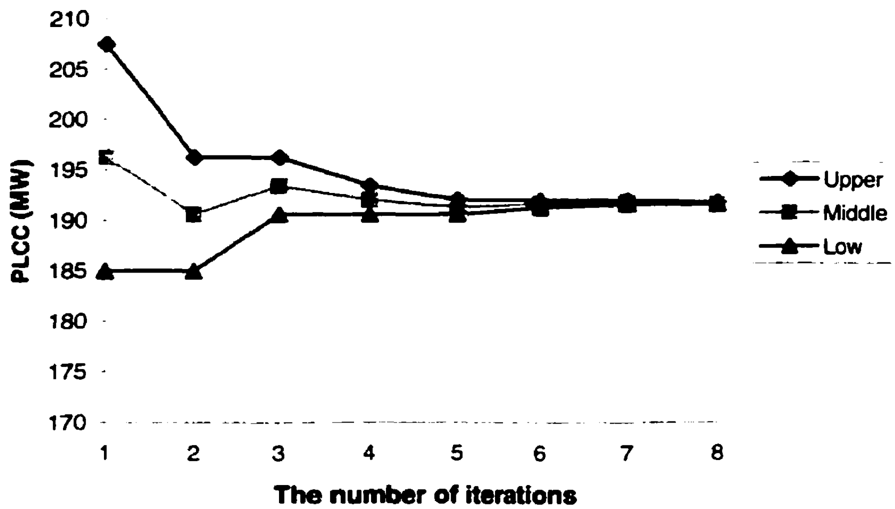

Figure 5.2 Iteration procedure for the site near Regina

In order to calculate the $IPLCC_C$ and therefore the *ECR*, the additional wind capacity is assumed to be replaced by conventional units with the same total capacity of 22.5 MW. The 22.5 MW of conventional generation capacity can consist of different units with various sizes and parameters. Table 5.3 presents five compositions and the corresponding incremental peak load carrying capability at an LOLE of 1.1282 h/year. For simplicity and comparison, the FOR of each additional conventional unit is the same as that of the WTG units. It can be seen from Table 5.3 that there is little difference in the $IPLCC_C$ for the different compositions. The $IPLCC_C$ for a 3×7.5 MW conventional generating composition was used to calculate the *ECB*.

Table 5.3 Effect on the $IPLCC_C$ of different conventional unit compositions

The number of units	Composition (MW)	$IPLCC_C$ (MW)
5	$4\times5+1\times2.5$	24.8
4	$3\times5+1\times7.5$	24.8
3	3×7.5	24.7
2	$1\times10+1\times12.5$	24.4
1	1×22.5	23.5

Tables 5.4 and 5.5 give the $IPLCC_W$, $LCCBR$ and ECB at an LOLE of 1.1282 hours/year and an LOEE of 10.3109 MWh/year respectively. These are the reliability indices obtained for the original RBTS and are assumed to be the system criterion reliability. It can be seen from Tables 5.4 and 5.5 that the differences between the two sets of factors are relatively small and can be neglected. The factors $LCCBR$ and ECR are therefore relatively independent of the risk index selected and are mainly determined by the system, the equipment parameters and the wind conditions. The results in Tables 5.4 and 5.5 also show that the $LCCBR$ and ECR increase as the average wind speed increases. The relationship between the risk-base capacity factors and the average wind speed, however, is not linear. The wind site near Regina, where the average wind speed is highest, has twice the load carrying capability and capacity credit than that near Prince Albert, where the average wind speed is lowest. The difference in the average wind speeds at these two sites is, however, not that large.

Table 5.4 Capacity Benefit Factors at an LOLE of 1.1282 hours/year

Sites	$IPLCC_C$ (MW)	$LCCBR$ (%)	ECR
Prince Albert	3.3	14.67	0.1336
North Battleford	4.2	18.67	0.1700
Saskatoon	4.7	20.89	0.1903
Regina	6.8	30.22	0.2753

Table 5.5 Capacity Benefit Factors at an LOEE of 10.3109 MWh/year

Sites	$IPLCC_C$ (MW)	*LCCBR (%)*	*ECR*
Prince Albert	3.1	13.78	0.1275
North Battlefore	4.1	18.22	0.1687
Saskatoon	4.5	20.00	0.1852
Regina	6.6	29.33	0.2716

Practical engineering assessment usually deals with many aspects such as investment feasibility, economic benefit, environmental effects and operating constraints. The relatively simple case studies in this chapter show that the developed indices *LCCBR* and *ECR* provide a good indication of the potential capacity benefits, are easily evaluated, and can provide practical input to the managerial decision process associated with the development of WECS.

5.5 Summary

Two risk-based capacity benefit factors, which can be used in WECS assessment, are introduced in this chapter. The *LCCBR* indicates the incremental peak load carrying capability in per unit of the incremental WTG capacity at the criterion reliability level. The *ECR* provides a risk-based equivalence between the proposed WECS and conventional generating capacity. Both factors provide a more direct and physical indication of the capacity benefits and possible credits of a WECS than do the classic reliability indices. The developed midpoint sectionalizing approach has a fast convergence and usually takes only a few iterations to obtain the risk-based capacity factors. The case studies in this chapter show that both the load carrying contribution and capacity credit of a WECS can be quantitatively evaluated. It is believed that the indices and technique presented in this chapter can assist system planners and utility managers to assess the capacity worth of WECS and provide useful input to the managerial decision process.

Chapter 6
Optimum Site-Matching Windturbine

6.1. Introduction

Windmills have existed since earliest antiquity in Apersia, in Iraq, in Egypt and in China. In the seventeenth century B.C., it is said that Hammurabi, king of Babylonia, conceived a plan to irrigate the rich plain of Mesopotamia with the aid of wind energy. It was only during the Middle Ages that windmills appeared in Italy, France, Spain, and Portugal and later in Great Britain, Holland, and Germany. The first modern fast wind turbine driving an electrical generator, appeared in France at the dawn of the 20th century and subsequently spread all over the world. This invention was attributed to the French Academician Darrieus.

With the invention of the steam engine, the internal combustion engine, and the development of electricity, emphasis on wind power development declined and could be said to have been virtually abandoned. Due to concerns regarding decreases in the world stock of hydrocarbons and the fear of expanding pollution, wind energy has, however, again become important.

Although wind energy has been exploited for thousands of year by windmills and sailors and the principles of wind-generated electricity are well known, the actual developments of grid-connected, efficient and reliable wind turbines has proved to be a major challenge. Many technological developments have occurred over the late twenty years and a range of commercial wind turbines is now available from about 30 manufacturers worldwide. The most dramatic rise in wind energy application occurred in the U.S.A. during the 1980s, when favorable tax credits and energy rates for independent power producers resulted in 1500 MW of installed capacity. About 500 MW of wind turbines were operational in Europe in 1991.

The electricity production by a wind turbine at a specific site depends on many factors. These factors include the wind speed conditions at the site, and most importantly, the characteristics of the wind turbine generator (WTG) itself, particularly the cut-in, rated and cut-out wind speed parameters. As shown in Figure 6.1, The power output of a WTG does not vary linearly with the wind speed. A wind machine is not operational when the wind speed is below the cut-in speed V_{ci} and will be shut down for safety reasons if the wind velocity is higher than the cut-out speed V_{co}. In both cases, the power output is zero. The power output of a WTG unit increases with the wind speed between the cut-in speed and the rated wind speed V_r after that the power output remains constant at the rated power P_r [51].

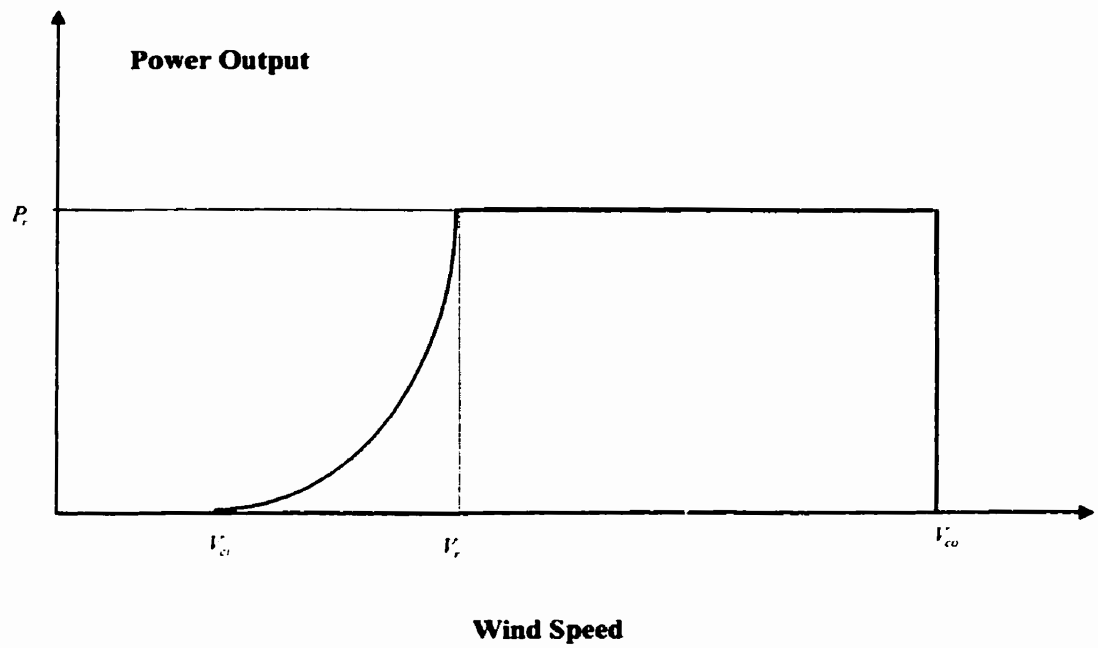

Figure 6.1. Typical WTG output as a function of wind speed

Different types of windturbines are commercially available on the market. Wind turbines range from less than 1 kW to as large as 3 MW or more [61]. It is therefore desirable to select a wind turbine which is best suited for a particular site in order to obtain the maximum generation capacity benefit at the given criterion reliability level. In order to achieve this, the effect on generating capacity adequacy of different windturbine parameters should first be investigated.

6.2. Effect of Windturbine Parameters on Adequacy

The reliability test system RBTS [63] is utilized to illustrate the effect of windturbine design parameters on generation capacity adequacy. A WECS with a total capacity of 22.5 MW is incorporated in the RBTS. The WECS is assumed to be located at a site with a wind profile the same as that at North Battleford, Saskatchewan, Canada.

The wind speed mean and standard deviation at this site are 14.63 and 9.75 km/hour respectively. The actual hourly wind speed for 3 years (from 1 January 1991 to 31 December 1993) and the hourly mean and standard deviation of wind speeds from a 37-year database (from 1 January 1953 to 31 December 1989) for the site were obtained from Environment Canada and used to establish the wind speed model. The fitted model is an ARMA(3,2) model [90]:

$$
\begin{aligned}
y_t &= 1.7901 y_{t-1} - 0.9087 y_{t-2} + 0.0948 y_{t-3} + \\
&\quad a_t - 1.0929 a_{t-1} + 0.2892 a_{t-2} \\
a_t &\in NID(0, 0.474762^2)
\end{aligned}
\tag{6.1}
$$

6.2.1. Base Case

The WECS is assumed to have 100 WTG units. Each unit has a rated power output of P_r =225 kW and a forced outage rate (FOR) of 0.04. The cut-in, rated and cut-out speeds are 12, 38 and 80 km/h respectively. The curve shown between the cut-in speed and rated speed in Figure 6.1 is represented by a straight line in the following analyses.

The program WGRASS was used to simulate the generation / load characteristics of the RBTS including WECS. The residence time distributions of all units were assumed to be exponential and a stopping criterion of ε_{LOLE} =0.05 [8] was used to control the simulation length. The means of the reliability indices with and without the WECS for the base case are given in Table 6.1.

Table 6.1. RBTS reliability indices with and without 100 WTG units

Case	LOLE (hours/yr.)	LOEE (MWh/yr.)	FLOL (occ./yr.)	D (hours/occ.)
Original system	1.1282	10.3109	0.2194	5.1414
with 100 WTG	0.7895	7.3572	0.1910	4.1330

6.2.2. *Effect of Cut-in Wind Speed*

The cut-in wind speed is assumed to range from 8 to 18 km/hour while other parameters remain the same as those in the base case. Table 6.2 and 6.3 respectively present the effects of different cut-in wind speeds on the basic reliability indices and the Load Carrying Capacity Benefit Ratio of the RBTS. The relationship between cut-in wind speeds and *LCCBR* is illustrated graphically in Figure 6.2.

Table 6.2 Effect of cut-in wind speed on the basic indices

Cut-in speed (km/hour)	LOLE (hours/yr.)	LOEE (MWh/yr.)	FLOL (occ./yr.)	D (hours/occ.)
8	0.6921	6.3993	0.1728	4.0041
10	0.7459	7.0044	0.1837	4.0601
12	0.7895	7.3572	0.1910	4.1330
14	0.8383	7.8505	0.2010	4.1712
16	0.8911	8.3312	0.2070	4.3049
18	0.9209	8.3522	0.2131	4.3205

Table 6.3 Effect of cut-in wind speed on the *LCCBR* and *ECR*

Cut-in speed (km/hour)	$IPLCC_W$ (MW)	*LCCBR (%)*	*ECR*
8	5.2	23.11	0.2105
10	4.6	20.44	0.1862
12	4.2	18.67	0.1700
14	3.3	14.67	0.1336
16	2.7	12.00	0.1093
18	2.2	9.78	0.0891

It can be seen from Table 6.3 and Figure 6.2 that the cut-in wind speed has a significant effect on the capacity adequacy and thus on the load carrying capacity benefit. The Incremental Peak Load Carrying Capability and the Load Carrying Capacity Benefit Ratio decrease approximately linearly as the cut-in wind speed increases. The *LCCBR* at the cut-in speed of 8 km/hour is 2.36 times as much as that at the cut-in speed of 18 km/hour.

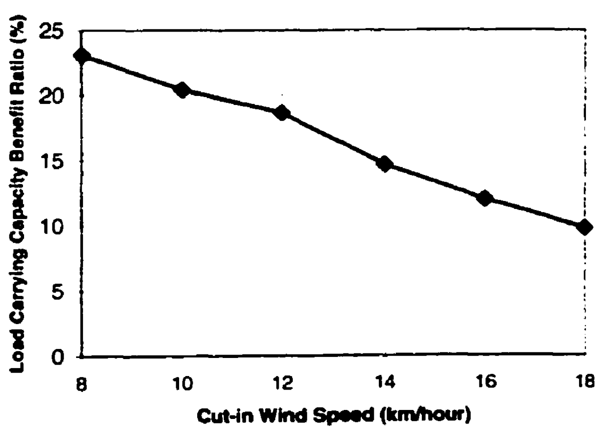

Figure 6.2 *LCCBR* versus cut-in wind speed

6.2.3. Effect of Rated Wind Speed

Six different rated wind speeds ranging from 32 to 42 km/hour were utilized to investigate the effect of rated wind speed on the adequacy and load carrying capacity benefit. The results are presented in Tables 6.4 and 6.5 and Figure 6.3.

Table 6.4 Effect of rated wind speed on the basic indices

Rated speed (km/hour)	LOLE (hours/yr.)	LOEE (MWh/yr.)	FLOL (occ./yr.)	D (hours/occ.)
32	0.7466	6.9406	0.1900	3.9304
34	0.7635	7.1250	0.1907	4.0028
36	0.7797	7.2492	0.1923	4.0555
38	0.7895	7.3572	0.1910	4.1330
40	0.8089	7.5578	0.1936	4.1772
42	0.8197	7.7092	0.1941	4.2221

Table 6.5 Effect of rated wind speed on the *LCCBR* and *ECR*

Rated speed (km/hour)	$IPLCC_W$ (MW)	*LCCBR (%)*	*ECR*
32	4.6	20.44	0.1862
34	4.4	19.56	0.1781
36	4.3	19.11	0.1741
38	4.2	18.67	0.1700
40	4.1	18.22	0.1660
42	4.0	17.78	0.1619

It can be seen from Tables 6.4 and 6.5 and Figure 6.3 that the rated wind speed has a relatively small effect on the capacity adequacy and load carrying capability. This effect is less significant than that of the cut-in wind speed at the North Battleford site. The

Load Carrying Capacity Benefit Ratio decreases from 20.44% to 17.78 % as the design rated speed increases from 32 km/hour to 42 km/hour. This is mainly because the average wind speed at this site is near the cut-in wind speed but is far from the rated wind speed.

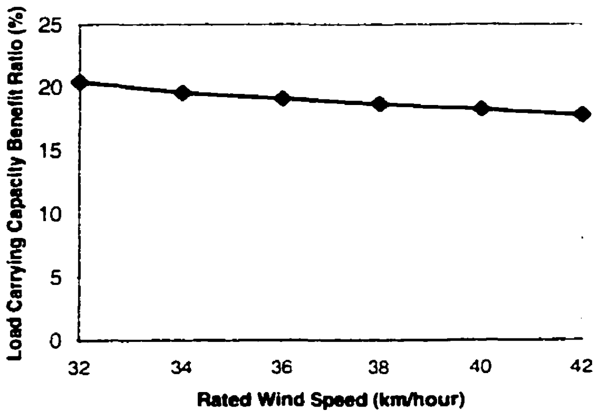

Figure 6.3 *LCCBR* versus rated wind speed

6.2.4. Effect of Cut-out Wind Speed

Tables 6.6 and 6.7 present the relationship between the cut-out wind speeds, the basic reliability indices and the Load Carrying Capacity Benefit Ratio. It can be seen that the cut-out wind speed has virtually no effect on the capacity adequacy and *LCCBR*. The cut-out wind speed is a safety parameter and is usually quite large. Only for relatively few time periods will the actual wind speed at a particular wind site be larger than the cut-out speed. The selection of the cut-out speed parameter is therefore less important than that of the cut-in and the rated wind speed parameters.

Table 6.6 Effect of cut-out wind speed on the basic indices

Cut-out speed (km/hour)	LOLE (hours/yr.)	LOEE (MWh/yr.)	FLOL (occ./yr.)	D (hours/occ.)
40	0.7932	7.4150	0.1941	4.0860
50	0.7903	7.3589	0.1916	4.1237
60 ~ 90	0.7895	7.3572	0.1910	4.1330

Table 6.7 Effect of cut-out wind speed on the *LCCBR* and *ECR*

Cut-out speed (km/hour)	$IPLCC_{II'}$ (MW)	*LCCBR (%)*	*ECR*
40	4.1	18.22	0.1660
50	4.1	18.22	0.1660
60~90	4.2	18.67	0.1700

6.2.5. Effect of Hub Height

Wind speed increases with hub height. The effect of projected height on the generation adequacy and capacity benefit is presented in Tables 6.8, 6.9. The reference height is assumed to be 10 m and the power -law exponent is taken as 1/7 [61] in the calculation. It can be seen from the two tables that the hub height has a relatively small effect on the generation capacity adequacy and the incremental capacity benefit. This effect is less significant than that of the cut-in wind speed at the North Battleford site. The Load Carrying Capacity Benefit Ratio increases approximately from 18% to 20% as the hub height increases from 10 m to 30 m. These values are based on the approximate formula relating wind velocity to hub-height. Actual data, if available, should be used which recognize the terrain and local conditions.

Table 6.8 Effect of hub height on the Basic Indices

Hub height (m)	LOLE (hours/yr.)	LOEE (MWh/yr.)	FLOL (occ./yr.)	D (hours/occ.)
10	0.7895	7.3572	0.1910	4.1330
14	0.7894	7.3009	0.1892	4.1724
18	0.7600	7.1737	0.1864	4.0781
22	0.7407	7.0893	0.1797	4.1219
26	0.7154	6.5707	0.1776	4.0280
30	0.7095	6.4356	0.1783	3.9786

Table 6.9. Effect of rated wind speed on the *LCCBR* and *ECR*

Hub height (m)	$IPLCC_{W}$ (MW)	*LCCBR (%)*	*ECR*
10	4.2	18.67	0.1700
14	4.3	19.11	0.1741
18	4.4	19.56	0.1781
22	4.6	20.44	0.1862
26	4.7	20.89	0.1903
30	4.7	20.89	0.1903

6.3. Determination of an Optimum Site-matching Windturbine

6.3.1. Windturbine Types

As shown in the analyses in Section 6.2, the windturbine design parameters, particularly cut-in speeds, affect generation capacity adequacy and the load carrying benefit. Selecting a suitable site-matching windturbine is therefore important in order to achieve the maximum capacity and energy benefit from a WECS.

Table 6.10 presents the seven windturbine types assumed and utilized for the case study. Each unit has a forced outage rate of 0.04 irrespective of the size. The wind turbines range from less than 200 kW to as large as 900 kW, the cut-in wind speed parameters from 10 km/hour to 18 km/hour and the rated speeds from 22.0 km/hour to 46.8 km/hour. The projected hub height is assumed to be the same as the reference height for simplicity.

Table 6.10 Wind turbine characteristics

Type	Rated Power (kW)	Cut-in Speed (km/h)	Rated Speed (km/h)	Cut-out Speed (km/h)
A	225.00	12.0	38.0	80.0
B	112.50	14.1	36.1	97.2
C	112.50	10.0	40.0	64.1
D	450.00	15.0	25.2	50.4
E	900.00	18.0	46.8	72.0
F	900.00	13.0	28.0	60.0
G	450.00	15.5	22.0	60.0

6.3.2. Optimum Windturbine for the North Battleford Site Data

Tables 6.11 and 6.12 respectively present the basic adequacy indices and the risk based capacity factors for the different alternatives. It can be seen from these tables that,

1. The differences in the basic adequacy indices for any two alternatives are relatively small while the differences in the risk-based capacity benefit factors are quite large. This means that the developed risk-based capacity benefit factors, compared to the classic reliability indices, are more sensitive to alternatives, and therefore more suitable for alternative comparisons.

2. Types C and D have different reliability while they have the same load carrying capability. Type F has higher Loss of Load Expectation than Type G, while Type G has higher Loss of Load Frequency than Type F. These conflicts make it difficult to select the optimum windturbine and may result in an incorrect decision if the classic reliability indices are used to determine the best site-matching windturbine.

3. Type F gives the maximum load carrying capacity benefit ratio and the maximum equivalent capacity rate, and can be considered as the most suitable windturbine for the particular site. The *ECR* for Type F is 0.1946, which is 3 times larger than that

for Type E. Significant generation capacity benefits can therefore be achieved by selecting the best site-matching windturbine parameters.

Table 6.11. Basic adequacy indices for different alternatives (North Battleford site)

Type	LOLE (hours/yr.)	LOEE (MWh/yr.)	FLOL (occ./yr.)	D (hours/occ.)
A	0.7895	7.3572	0.1910	4.1330
B	0.8324	7.8251	0.2023	4.1151
C	0.7555	7.0775	0.1824	4.1410
D	0.7708	7.1002	0.2035	3.7880
E	0.9623	8.7511	0.2155	4.4645
F	0.7465	7.0040	0.1901	3.9275
G	0.7369	7.2304	0.1993	3.6979

Table 6.12. Risk based capacity benefit factors for different alternatives (North Battleford site)

Type	$IPLCC_W$ (MW)	*LCCBR (%)*	*ECR*
A	4.2	18.22	0.1700
B	3.3	14.67	0.1336
C	4.4	19.56	0.1781
D	4.4	19.56	0.1781
E	1.6	7.11	0.0648
F	4.8	21.33	0.1943
G	4.6	20.44	0.1862

6.3.3 Optimum Windturbine for the Regina Site Data

A similar study was conducted using wind data from a site near Regina in order to examine the possible differences in the optimum windturbines for different sites. Regina is in the southern part of Saskatchewan while North Battleford is in the north. The average wind speed for the site near Regina is 19.52 km/hour [4], which is 5 km higher per hour than that in the North Battleford. The fitted wind speed time series model for the site is an ARMA(4,3) model [90]:

The basic adequacy indices and the risk-based capacity factors for the different alternatives are presented in Tables 6.13 and 6.14 respectively. It can be seen from these tables that the load carrying capability benefit ratios and the equivalent capacity factors at this site increase greatly compared to those for the North Batttleford site. Type G rather than Type F is the most suitable windturbine using the Regina data since it has the maximum capacity factors. These results clearly illustrate that the optimum site matching windturbine could differ from site to site, and depends on the wind speed conditions and the available windturbines.

Table 6.13. Basic adequacy indices for different alternatives (Regina site data)

Type	LOLE (hours/yr.)	LOEE (MWh/yr.)	FLOL (occ./yr.)	D (hours/occ.)
A	0.5884	5.3220	0.1525	3.8574
B	0.6175	5.7030	0.1672	3.6939
C	0.5427	5.0068	0.1405	3.8621
D	0.5029	4.6061	0.1550	3.2434
E	0.8143	7.5691	0.1945	4.1871
F	0.4922	4.4682	0.1437	3.4251
G	0.4862	4.5101	0.1549	3.1426

Table 6.14. Risk based capacity benefit factors for different alternatives (Regina site)

Type	$IPLCC_{W}$ (MW)	*LCCBR (%)*	*ECR*
A	6.8	30.22	0.2753
B	6.4	28.44	0.2591
C	7.5	33.33	0.3036
D	8.3	36.89	0.3360
E	3.9	17.33	0.1579
F	9.2	40.88	0.3725
G	9.3	41.33	0.3765

Practical engineering assessment involves many different aspects. The relatively simple case study presented in this chapter illustrates that the proposed indices and techniques can provide practical input to the managerial decision process associated with the selection of windturbine parameters.

6.4. Summary

The effects of different windturbine design parameters on the basic adequacy indices and the risk-based capacity benefit factors are illustrated in this chapter. The case studies show that turbine cut-in wind speed has a significant effect on the capacity adequacy of a generating system while the cut-out wind speed has almost no effect. The risk based indices *LCCBR* and *ECR* provide a more direct and physical indication of the capacity benefits of a WECS than do the basic reliability indices, and can be utilized as an objective function to determine the optimum site-matching windturbine for a potential wind site. Significant capacity benefits can be obtained by selecting appropriate site-matching windturbine parameters.

Chapter 7

Optimum WECS Penetration Level Assessment

7.1 Introduction

Wind, as an environmentally sound source of energy, is becoming increasingly economically competitive with conventional sources. In Denmark, the installed cost of wind farms has dropped from $2400/kW in 1985 to about $800-$1200/kW in 1994, and the cost of wind energy has gone from 14c/kwh to 5c/kwh from 1982 to 1992. Projections on energy sources in the year 2000 estimated that 5-10% of the total US energy needs could come from wind power [51]. This has not come about due to a wide variety of reasons. In some systems, the penetration of wind-driven generation already exceeds 1%. In Northern California, the electric energy supplied by wind sources exceeds 1000 GWh [52].

The integration of wind power in a conventional generating system results in fuel or gas savings for power utilities. It may also allow future capital expenditure on conventional plants to be reduced or deferred. The integration is, however, not without problems mostly due to the unpredictable nature of the wind. The daily and seasonal patterns in the wind speed distribution and the distance of the resource from the customer load center also creates problems. Other important factors that affect the integration of wind turbines include the extent of dispersion, the weather, the array interference, as well as the level of penetration.

A major question arising in the development of wind energy is, what is a suitable penetration level of wind energy conversion systems into a conventional generating system. The penetration level is the percentage of wind capacity in the total combined conventional and unconventional system capacity and has a significant effect on generation adequacy. Searching for the optimum penetration level is therefore an important reliability optimization problem. There are economic penetration limits as well as reliability penetration limits associated with wind power. As shown in Chapter 5, a 1 MW WTG cannot usually carry the same amount of load as a 1 MW conventional generating unit, and therefore a high penetration level greatly affects the operating security and flexibility. The optimum penetration level should be determined by balancing the investment, operating and outage costs as well as operating security.

This chapter investigates the effect of WECS penetration on generation capacity benefit. A procedure to determine the optimum wind penetration level is introduced, which extends the method developed for conventional generation adequacy optimization described in Chapter 2.

7.2 Effect of WECS Penetration on Generation Capacity Benefit

The RBTS reliability test system [63] is utilized to illustrate the effect of wind penetration on generation capacity benefit. A WECS containing 100 WTG units is incorporated in the RBTS. Each unit has a rated power output of P_r =225 kW and a Forced Outage Rate of 0.04. The cut-in, rated and cut-out speeds are 12, 38 and 80 km/h respectively. The WECS is assumed to be located at a site which has the same wind profile as North Battleford, Saskatchewan.

The adequacy indices of the RBTS were calculated as a function of the number of WTG units added and the results are presented in Table 7.1 and correspondingly in Figure 7.1. It can be seen from Figure 7.1 that the LOLE of the RBTS decreases somewhat exponentially with the number of WTG units added to the system, and that increasing the wind penetration level by adding WTG at the same location will not substantially reduce the system LOLE. A similar comment can be made with respect to the relationship between LOEE, FLOL and the wind energy penetration level.

Table 7.1 The effect of wind penetration levels on generation capacity adequacy

Number of WTG	Penetration Level	LOLE (hours/yr.)	LOEE (MWh/yr.)	FLOL (occ./yr.)	D (hours/occ.)
0	0	1.1282	10.3109	0.2194	5.1414
25	2.29 %	1.0025	9.0764	0.2083	4.8120
50	4.48 %	0.9126	8.5167	0.2004	4.5531
75	6.57 %	0.8470	7.8951	0.1963	4.3145
100	8.57 %	0.7860	7.3722	0.1908	4.1193
125	10.49 %	0.7542	7.0541	0.1912	3.9443
150	12.33 %	0.7180	6.7379	0.1873	3.8336
175	14.09 %	0.6915	6.4877	0.1852	3.7345

Table 7.2 shows the effect of wind penetration levels on the generation capacity benefit factors IPLCC, LCCBR and ECR. It can be seen from Table 7.2 that the load carrying capability benefit ratio and the equivalent capacity rate decrease significantly as the wind penetration level in the RBTS increases. A 1 MW injection of WTG is equal to a 0.1993 MW of conventional generation capacity when the penetration level is 2.29%, while a 1MW injection of WTG is just equal to a 0.1258 MW of conventional generation capacity when the penetration level becomes 14.09%. This indicates that as the wind power penetration level increases, the incremental generation capacity benefit decreases.

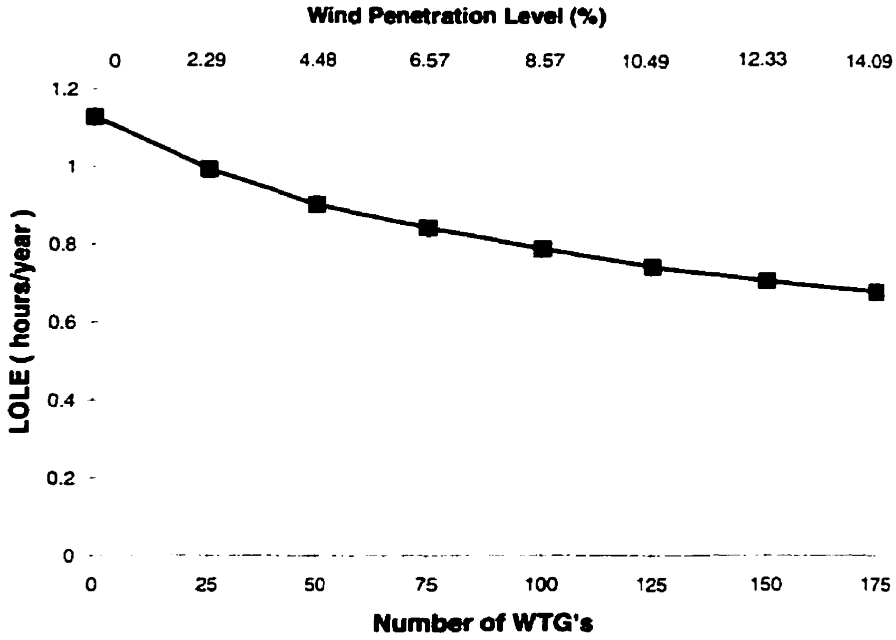

Figure. 7.1 LOLE versus the number of WTG units added to the RBTS

Table 7.2 The effect of wind penetration levels on generation capacity benefit

Number of WTG	Penetration Level	$IPLCC_W$ (MW)	LCCBR (%)	ECR
0	0.00 %	-	-	-
25	2.29 %	1.2	21.33	0.1993
50	4.48 %	2.3	20.44	0.1910
75	6.57 %	3.2	18.96	0.1772
100	8.57%	4.2	18.22	0.1700
125	10.49 %	4.5	16.00	0.1495
150	12.33 %	4.9	14.52	0.1357
175	14.09 %	5.3	13.46	0.1258

The IPLCC presented in Table 7.2 is also shown graphically in Figure 7.2. As shown in Figure 7.2, the incremental load carrying capability due to utilization of wind energy increases steadily when the penetration level is less than 10%. This increase, however, tends to decline when the penetration level exceeds 10%, which indicates that reduced capacity benefits will be obtained by adding more WTG into the wind farm.

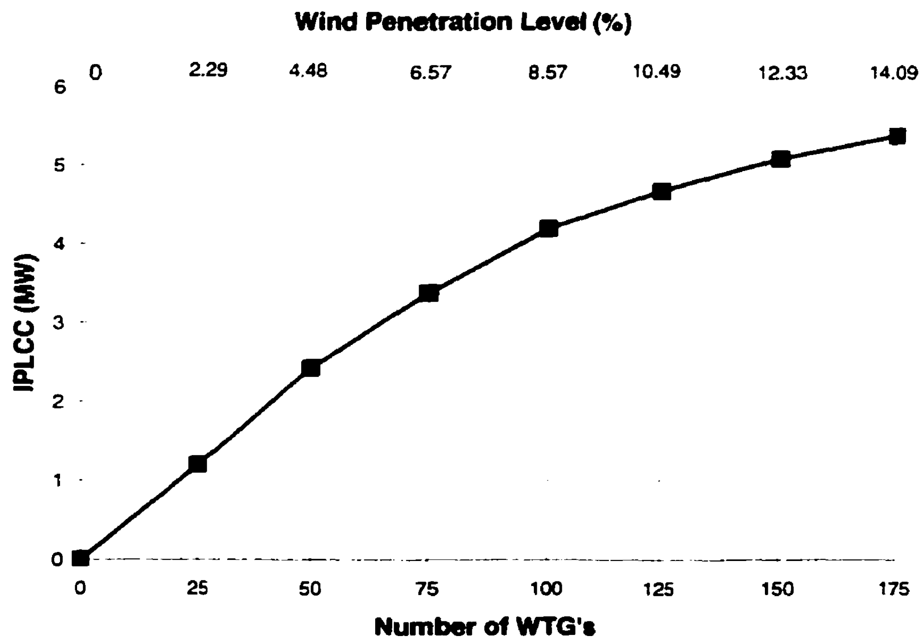

Figure 7.2 IPLCC versus the number of WTG units added to the RBTS

7.3. Customer Interruption Cost Assessment Associated with WECS

Evaluation of the cost associated with different system configurations or planning practices and the corresponding reliability worth at the customer end is generally termed as reliability worth assessment. Reliability worth assessment is an important aspect of power system planning and operating. The key step in reliability worth assessment is to estimate customer interruption cost. Many studies have been conducted on the evaluation of customer outage cost in conventional generation systems. Relatively few studies, however, have been conducted on outage cost assessment in systems containing WECS.

The sequential Monte Carlo Simulation method for adequacy assessment of a generating system including WECS presented in Chapter 4, can be extended to assess customer outage cost associated with a WECS related system. The basic procedure to calculate the outage cost can be briefly described as follows:

1. Create a generation capacity model for the conventional base load generating units using chronological simulation techniques;
2. Construct a capacity model for the wind turbine generators using the time series models;
3. Form a combined system capacity model;
4. Obtain the customer interruption cost by observing the system capacity reserve model over a long time period.

This is the same basic procedure utilized in the conventional generating capacity studies described in Chapter 2. Equations 2.14 and 2.15 are repeated below to illustrate the procedure.

In the simulation process, individual load loss events are encountered sequentially. The duration of each individual loss of load event can be combined with the customer damage function to determine the outage cost for this particular event. The total Expected Interruption Cost in k\$/year is therefore expressed as:

$$EIC = \frac{\sum_{i=1}^{M} W(D_i)E_i / D_i}{N} \tag{7.1}$$

where $W(D_i)$ is the customer damage function in \$/kW, E_i is the energy not supplied due to interruption i in MWh, D_i is the duration of interruption i in hours, M the total number of interruptions experienced in the simulated years, and N is the number of simulated years.

The IEAR can be calculated by

$$IEAR = \frac{\sum_{i=1}^{M} W(D_i)E_i / D_i}{\sum_{i=1}^{M} E_i} \tag{7.2}$$

Index CPI (Cost Per Interruption) can be obtained from dividing EIC by FLOL.

Table 7.3 lists the EIC, IEAR and CPI of the RBTS during the simulation process when 100 wind turbine generators are added to the test system. The simulated results become relatively stable after the number of sampling years reaches 7000.

Table 7.3 EIC, IEAR, CPI of RBTS with 100 WTG's

Number of Sampling Years	EIC (k\$/yr.)	IEAR (\$/kWh)	CPI (\$/int.)
1000	44.215	5.319	198.27
2000	38.983	5.356	186.52
3000	39.959	5.302	196.20
4000	40.910	5.208	203.03
5000	39.533	5.226	199.06
6000	37.737	5.290	194.69
7000	38.977	5.245	203.91
8000	39.201	5.272	205.64
9000	38.077	5.272	204.47
10000	37.056	5.285	201.94

The relationships between EIC, IEAR, CPI and the wind penetration levels are presented in Table 7.4. It can be seen that the IEAR decreases slightly as the wind capacity penetration level increases. It is usually assumed that the IEAR is stable and does not vary significantly with peak load or other operating conditions. The combination of a basic LOEE index and the IEAR as shown in Equation (2.10) provides a basic and primary tool for assessing adequacy worth in generation capacity adequacy studies. This assumption is generally well founded. It, however, may cause error in the reliability worth assessment (optimization) associated with WECS when the difference between alternatives is much smaller, since the IEAR does vary as the penetration level changes. The EIC can be calculated directly using the sequential Monte Carlo Simulation approach instead of using Equation (2.10). This does not increase the computational burden compared to utilizing Equation (2.10) since both methods simulate the operating and failure process, which involves most of the computational effort.

Table 7.4 EIC, IEAR, CPI versus the number of WTGs added

Number of WTG	Penetration Level	EIC (k$/yr.)	IEAR ($/kWh)	CPI ($/int.)
0	0	40.420	3.920	184.19
25	2.29 %	35.280	3.887	169.34
50	4.48 %	33.012	3.876	164.70
75	6.57 %	30.569	3.872	155.71
100	8.57 %	28.278	3.836	148.19
125	10.49 %	26.950	3.820	140.94
150	12.33 %	25.673	3.810	137.06
175	14.09 %	24.576	3.788	132.73

7.4 Determination of the Optimum WECS Penetration Level

As stated in Section 7.2, the WECS penetration level has a significant effect on generation capacity adequacy and the capacity benefit. Selecting a suitable WECS penetration level is therefore important in order to achieve the maximum capacity or energy benefit, and to obtain the minimum societal cost.

The RBTS is further utilized to illustrate the determination of the optimum WECS penetration level. The basic data are the same as those shown in Chapter 2. The fixed and operating costs associated with WTG are shown in Table 7.5. The costs for a gas turbine generator are also shown for comparison.

Table 7.5 WTG Capital and Operating Cost

Generating Units	Investment (Installed)	Operating & Maintenance Cost
WTG	$ 1200/kW	$0.0065/kWh
Gas Turbine	$ 700/kW	$0.0500/kWh

Wind power penetration analyses using a fixed reliability criterion and with the reliability optimization technique were conducted. A one year scenario with an annual peak load of 192.4 MW was considered. Wind data from two locations near Regina and North Battleford were utilized in order to examine the possible differences in the optimum penetration level for different wind sites. Regina is in the southern part of Saskatchewan while North Battleford is in the north. The average wind speed for Regina is 19.52 km/hour, which is approximately 5 km higher per hour than that at North Battleford.

7.4.1 Regina Wind Data Analysis

Fixed reliability criterion

The objective of the methodology is to search for the most suitable wind power penetration plan with minimum investment under the limitation that the risk criterion is not violated. The peak load in the original system is 185 MW. It was assumed that the installed capacity of 240 MW is acceptable and therefore the previous risk index of LOLE = 1.1282 hour/year can be considered as the system reliability criterion.

Table 7.6 presents the reliability indices with the wind power capacity additions. The minimum step is assumed to be 10 WTG. The reliability criterion cannot be satisfied until 110 wind turbines are added to the system. The minimum investment to supply the incremental load at the risk criterion of LOLE = 1.1282 hour/year is therefore 110 WTG for the wind firm near Regina, and the corresponding penetration level is 9.35%.

Table 7.7 shows the reliability variation with the addition of gas turbines rather than wind turbines. Each gas turbine generator has a capacity of 5 MW. If one gas turbine generator is added to the system, the LOLE is 1.3236 hours/year, which violates the system risk criterion. With two additional gas turbine generators, the LOLE becomes 0.8765 hours/year and the risk is acceptable. The minimum investment is, therefore, two gas turbine units with a total additional capacity of 10MW. The result may be different if other gas turbine generator sizes are available for selection.

Table 7.6 Determination of WTG penetration using a fixed risk criterion (Regina Site)

Number of WTG	Penetration Level	LOLE (hours/yr.)	LOEE (MWh/yr.)	FLOL (occ./yr.)	D (hours/occ.)
0	0.00%	2.2348	21.2769	0.4351	5.1361
10	0.93%	2.0427	19.4308	0.4084	5.0016
20	1.84%	1.8762	17.8696	0.3790	4.9503
30	2.74%	1.7602	17.0893	0.3640	4.8364
40	3.60%	1.6385	15.9413	0.3512	4.6652
50	4.48%	1.5343	14.7987	0.3402	4.5102
60	5.33%	1.4342	13.8076	0.3286	4.3643
70	6.16%	1.3662	13.0881	0.3204	4.2638
80	6.98%	1.2968	12.2731	0.3100	4.1831
90	7.78%	1.2348	11.5884	0.3062	4.0328
100	8.57%	1.1782	11.1572	0.2985	3.9466
110	***9.35%***	***1.1281***	10.5820	0.2942	3.8346
120	10.22%	1.0790	10.1037	0.2933	3.6793

Table 7.7 Gas turbine generator additions

Number of Gas Turbine	Total Capacity (MW)	LOLE (hours/yr.)	LOEE (MWh/yr.)	FLOL (occ./yr.)	D (hours/occ.)
0	240	2.2348	21.2769	0.4351	5.1361
1	245	1.3236	13.6681	0.2873	4.9060
2	***250***	***0.8705***	8.1330	0.1895	4.7888

It is interesting to compare the difference between the WTG and gas turbine additions. As shown in Table 7.8, the total monetary investment associated with WTG implementation is approximately 4 times that associated with gas turbines. Selecting gas turbines for generation capacity expansion is therefore much better than selecting WTG from a capital cost point of view. The operating costs of WTG, however, are generally much lower than those of gas turbines. If the objective is to search for the minimum societal cost that includes fixed, operating and outage costs, the utilization of wind power at some particular locations could be a better alternative for capacity expansion than gas turbines.

Table 7.8 Investment comparison with WTG and gas turbines (Regina site)

Alternative	Additional Capacity	Investment
110 WTG	24.75 MW	29.7 million
2 Gas Turbines	10 MW	7 million

Reliability optimization

The fixed reliability criterion method may lead to unduly expansive WECS penetration with unnecessarily low probabilities of failure to meet the load. Reliability optimization techniques can be utilized to determine the most suitable wind power penetration level that minimizes the total societal cost.

Table 7.9 shows the capital, production and maintenance costs, LOEE, the consumer outage cost and the total annual societal cost for the original system and the subsequent addition of 10 wind turbine generators. The production cost was estimated assuming that all the wind turbine generators are base load units, and whenever there is wind power output it will be utilized by the system.

It can be seen from Table 7.9 that the system capital cost increases linearly, while the operating and outage costs decrease, as the penetration level increases. The total societal cost decreases with the WTG additions as shown in Table 7.9. Addition of

WTG generally decreases the higher operating cost generation requirement, creating the operating cost savings. If the wind conditions at a particular site are good and the WTG parameters are reasonably selected to match the wind conditions, the wind power obtained at that site can significantly decrease the operating cost, and therefore compensate for the additional capital investment. In such cases, the total societal costs will decrease until the penetration level is too high to be acceptable from an operating security point of view.

Table 7.9. Determination of optimum penetration (Regina site)

			Production (Operation)			*Outage*		
Number of WTG	*Penetration Level*	*Capital Cost (M$/yr.)*	*Wind Energy (MWh/yr.)*	*Gas Energy (MWh/yr.)*	*Cost (M$/yr.)*	*LOEE (MWh/yr.)*	*Cost (M$/yr.)*	*Total Cost (M$/yr.)*
0	0.00%	0.0000	-	1,032,664	51.6332	21.2769	0.0832	51.7164
10	0.93%	0.2549	6,211	1,026,454	51.3631	19.4308	0.0759	51.6939
20	1.84%	0.5098	12,430	1,020,237	51.0926	17.8696	0.0698	51.6722
30	2.74%	0.7647	18,654	1,014,013	50.8219	17.0893	0.0670	51.6536
40	3.60%	1.0196	24,872	1,007,796	50.5515	15.9413	0.0624	51.6335
50	4.48%	1.2745	31,091	1,001,579	50.2810	14.7987	0.0577	51.6132
60	5.33%	1.5294	37,304	995,368	50.0109	13.8076	0.0536	51.5939
70	6.16%	1.7843	43,527	989,145	49.7402	13.0881	0.0507	51.5752
80	6.98%	2.0392	49,741	982,931	49.4699	12.2731	0.0473	51.5564
90	7.78%	2.2941	55,956	976,717	49.1996	11.5884	0.0444	51.5381
100	8.57%	2.5490	62,172	970,502	48.9292	11.1572	0.0426	51.5208
110	9.35%	2.8039	68,383	964,291	48.6591	10.5820	0.0403	51.5033
120	10.22%	3.0588	74,598	958,076	48.3887	10.1037	0.0382	***51.4857***

Both economic and security limits must be applied to wind power penetration. The capability of a power system to accept all the wind energy generated is limited because of operating constraints such as the minimum loading levels of thermal generating units, the need for sufficient capacity on line to meet the load plus the spinning reserve, and management of hydro energy to avoid water spillage [3]. Lower wind energy penetration generally creates fewer problems than high penetration. If the installed WTG capacity is small relative to the total demand, wind fluctuations are simply lost in the general fluctuations in electricity demand. If the installed wind capacity is large, having the turbines spread out over a number of wind sites will smooth the overall output. In practical WECS penetration planning, it is reasonable to assume that the penetration level is limited. A penetration limitation of 11% was utilized in the studies described in this thesis. With this limitation, the optimum penetration level in this case is 10.22% and the minimum total societal cost is 51.4847 M$/year assuming that the WECS has the Regina data characteristics.

The results in Table 7.9 can be compared with those in Table 2.9 where gas turbine generators are considered as expansion alternatives. It is obvious from the comparison that WTG implementation is better than gas turbine additions for this case study.

Sensitivity Analysis

The investment and operating cost parameters associated with WTG can have great effect on the optimization results. Two cases are presented in order to illustrate this effect:

Case I: The WTG capital investment is changed from $1200/kW to $1300/kW with the other parameters the same as in the original case.

Case II: The WTG operating cost is changed from $0.0065/kWh to $0.01/kWh with the other parameters the same as in the original case.

Tables 7.10 and 7.11 show the capital, production and maintenance, consumer outage and total annual societal costs for the original system and subsequent additions of 10 wind turbine generators for Cases I and II respectively.

It can be seen from Table 7.10 that the minimum societal cost for Case I occurs when 20 wind turbine generators are inserted into the RBTS. The corresponding optimum penetration level is 1.84 %. In Case II, the minimum societal cost occurs when only 10 wind turbine generators are added to the system and the corresponding penetration level is 0.93%. These results are significantly different from those presented in Table 7.9. It can be concluded that the optimum penetration plan is highly dependend on the capital and operating parameters of the WTG generators.

Table 7.10. Determination optimum penetration (Case I)

			Production (Operation)			*Outage*		
Number of WTG	*Penetration Level*	*Capital Cost (M\$/yr.)*	*Wind Energy (MWh/yr.)*	*Gas Energy (MWh/yr.)*	*Cost* (M\$/yr.)	*LOEE (MWh/yr.)*	*Cost (M\$/yr)*	*Total Cost (M\$/yr.)*
0	0.00%	0.0000	-	1,032,664	51.6332	21.2769	0.0832	51.7164
10	0.93%	0.2761	6,211	1,026,454	51.3631	19.4308	0.0759	51.7161
20	1.84%	0.5523	12,430	1,020,237	51.0926	17.8696	0.0698	***51.7147***
30	2.74%	0.8284	18,654	1,014,013	50.8219	17.0893	0.0670	51.7173
40	3.60%	1.1046	24,872	1,007,796	50.5515	15.9413	0.0624	51.7185
50	4.48%	1.3807	31,091	1,001,579	50.2810	14.7987	0.0577	51.7194
60	5.33%	1.6569	37,304	995,368	50.0109	13.8076	0.0536	51.7214
70	6.16%	1.9330	43,527	989,145	49.7402	13.0881	0.0507	51.7239
80	6.98%	2.2091	49,741	982,931	49.4699	12.2731	0.0473	51.7263
90	7.78%	2.4853	55,956	976,717	49.1996	11.5884	0.0444	51.7293
100	8.57%	2.7614	62,172	970,502	48.9292	11.1572	0.0426	51.7332
110	9.35%	3.0376	68,383	964,291	48.6591	10.5820	0.0403	51.7370
120	10.22%	3.3137	74,598	958,076	48.3887	10.1037	0.0382	51.7406

Table 7.11. Determination of optimum penetration (Case II)

Number of WTG	Penetration Level	Capital Cost (M$/yr.)	Production (Operation) Wind Energy (MWh/yr.)	Production (Operation) Gas Energy (MWh/yr.)	Production (Operation) Cost (M$/yr.)	Outage LOEE (MWh/yr.)	Outage Cost (M$/yr)	Total Cost (M$/yr.)
0	0.00%	0.0000	-	1,032,664	51.6332	21.2769	0.0832	51.7164
10	0.93%	0.2549	6,211	1,026,454	51.3848	19.4308	0.0759	***51.7156***
20	1.84%	0.5098	12,430	1,020,237	51.1362	17.8696	0.0698	51.7158
30	2.74%	0.7647	18,654	1,014,013	50.8872	17.0893	0.0670	51.7189
40	3.60%	1.0196	24,872	1,007,796	50.6385	15.9413	0.0624	51.7205
50	4.48%	1.2745	31,091	1,001,579	50.3899	14.7987	0.0577	51.7221
60	5.33%	1.5294	37,304	995,368	50.1414	13.8076	0.0536	51.7244
70	6.16%	1.7843	43,527	989,145	49.8925	13.0881	0.0507	51.7275
80	6.98%	2.0392	49,741	982,931	49.6440	12.2731	0.0473	51.7305
90	7.78%	2.2941	55,956	976,717	49.3954	11.5884	0.0444	51.7339
100	8.57%	2.5490	62,172	970,502	49.1468	11.1572	0.0426	51.7384
110	9.35%	2.8039	68,383	964,291	48.8984	10.5820	0.0403	51.7426
120	10.22%	3.0588	74,598	958,076	48.6498	10.1037	0.0382	51.7468

7.4.2 North Battleford Wind Data Analyses

The wind regime at North Battleford was also selected in order to examine the effect of wind conditions on the optimum wind penetration plan. The average wind speed at North Battleford is relatively low, while that at Regina is relatively high. The same methods shown in Section 7.4.1 were utilized.

Fixed reliability criterion

Table 7.12 presents the risk indices with the WTG additions. The reliability criterion cannot be satisfied until 310 wind turbine generators are added. The minimum addition to supply the increase load at a risk criterion of LOLE = 1.1282 hour/year is 310 WTG, and the corresponding penetration level is 22.52%. This penetration level violates the maximum limitation assumed earlier and could cause severe operating security problems.

An investment comparison between WTG and gas turbine implementation is presented in Table 7.13. The cost for the WTG additions in this case is approximately 12 times more than that for the gas turbine additions. The cost for WTG implementation using the Regina wind data regime, as shown in Table 7.8, is just 4 times more than that for gas turbine additions. The WTG investment in the North Battleford case is 3 times more than that in the Regina case in order to achieve a similar risk level. Selecting a suitable wind site with good wind conditions is obviously extremely important in planning wind power penetration.

Table 7.12 Determination of WTG penetration using fixed a risk criterion (North Battleford Site)

Number of WTG	Penetration Level	LOLE (hours/yr.)	LOEE (MWh/yr.)	FLOL (occ./yr.)	D (hours/occ.)
0	0.00%	2.2348	21.2769	0.4351	5.1361
10	0.93%	2.1333	20.2823	0.4265	5.0016
20	1.84%	2.0213	19.2732	0.4074	4.9613
...					
...					
110	9.35%	1.5099	14.7689	0.3677	4.1065
120	10.22%	1.4706	14.4770	0.3640	4.0399
...					
...					
310	22.52%	***1.1249***	10.9551	0.3304	3.4044
320	23.08%	1.1165	10.8690	0.3306	3.3766

Table 7.13 Investment comparison with WTG and gas turbines (North Battleford site)

Alternative	Additional Capacity	Investment
310 WTG	69.75 MW	83.7 million
2 Gas Turbines	10 MW	7 million

Reliability optimization

Table 7.14 presents the capital, production and maintenance, consumer outage and total annual societal costs for the original system and subsequent additions of 10 wind turbine generators using the North Battleford data.

Table 7.14. Determination of penetration (site:Battleford)

			Production (Operation)			*Outage*		
Number of WTG	*Penetration Level*	*Capital Cost (M\$/yr.)*	*Wind Energy (MWh/yr.)*	*Gas Energy (MWh/yr.)*	*Cost* (M\$/yr.)	*LOEE (MWh/yr.)*	*Cost (M\$/yr)*	*Total Cost (M\$/yr.)*
0	0.00%	0.0000	-	1,032,664	51.6332	21.2769	0.0832	***51.7164***
10	0.93%	0.2549	3,782	1,028,882	51.4687	51.4687	0.0793	51.8029
20	1.84%	0.5098	7,564	1,025,101	51.3042	19.2732	0.0753	51.8893
...								
110	9.35%	2.8039	41,642	991,027	49.8221	14.7689	0.0574	52.6834
120	10.22%	3.0588	45,430	987,240	49.6573	14.4770	0.0561	52.7722

It can be seen from Table 7.14 that the system capital cost increases, while the operating cost and outage cost decrease as the penetration level increases. The total societal cost increases with the addition of wind turbine generators. This situation is the reverse of that for a site having the Regina wind regime. The wind power from the site with North Battleford data can decrease the operating cost. It, however, cannot compensate for the additional capital investment since the wind condition at such a site is inadequate and wind power production is therefore relatively low. The optimum wind penetration level is 0% in this case. Wind sites and the related wind speed conditions have a significant effect on the optimum wind power penetration level.

7.5 Summary

The sensitivity studies presented in this chapter show that the WECS penetration level can significantly affect the generation adequacy and capacity benefits. The incremental load carrying capability due to the utilization of wind energy increases exponentially as the corresponding wind penetration level increases. The incremental benefit saturates as the wind power penetration level increases. The procedure introduced in this chapter to determine the optimum penetration level extends the method developed for conventional generation adequacy optimization. The case studies conducted show that the optimum penetration plan is not only highly related to the investment and operating parameters of the WTG generators, but is also highly dependent on wind speed conditions at the actual site. Selecting a suitable WECS penetration level and a good wind energy site is, therefore extremely important in order to achieve maximum capacity or energy benefits, and minimum societal costs.

Chapter 8

Optimum Interruptible Load Utilization

8.1 Introduction

Generating capacity adequacy is mainly dictated by the installed capacity and the system load profile. Generating system adequacy can be therefore categorized into two basic aspects: supply side formulation and demand side management (DSM). On the supply side, electric utilities continually search for suitable incremental energy options and optimum supply structures. On the load side, cost-effective opportunities are being found to use DSM initiatives, such as interruptible contracts, in order to better utilize low cost generation capacity and to reduce the need for additional capacity [15, 62].

The installed generation capacity in a power system should exceed the annual peak demand by an acceptable margin in order to maintain a reasonable level of power supply reliability and permit scheduled maintenance of the generating units. The excess capacity is generally not required under normal operating conditions. This temporarily unused capacity could be utilized to serve a limited amount of interruptible load. In this way, incremental load could be served without acquiring additional generating resources and the supply reliability for the firm load can be maintained. Interruptible load customers are asked to accept a pre-determined number of hours of interruption or a lower overall reliability level at times of system stress during which these loads are curtailed prior to shedding firm load. Interruptible contracts provide benefits to both utilities and interruptible load customers. Utilities enjoy operating flexibility and additional revenues from serving interruptible customers, without committing corresponding investment in generating capacity. Interruptible load customers, on the other hand, receive rate discounts conditional on accepting a lower reliability of power supply.

Analytic techniques have been developed to conduct interruptible load analysis [13, 14]. An inherent weakness of an analytical approach is that practical operating characteristics cannot be easily incorporated. Monte Carlo simulation techniques, on the other hand, can incorporate these characteristics easily and comprehensively. A further benefit associated with using simulation techniques is that the index distributions can be obtained and therefore additional detailed information can be provided on the risk conditions inherent in an interruptible-load-contract.

This chapter presents a sequential Monte Carlo simulation approach for interruptible load analysis and planning. A bisection search technique is utilized to effectively determine the system Interruptible Load Carrying Capability (ILCC). A new index designated as the Avoidable Additional Generating Capacity (AAGC) and a procedure to calculate it are presented. Numerical studies were performed to illustrate the possible applications of the proposed techniques in optimum interruptible load utilization.

8.2 Interruptible Load Carrying Capability

A generating system should have sufficient capacity to serve a target firm load at a pre-specified or criterion level of reliability. In the deregulated environment, the generating system includes all the generating facilities contained within the system. The target capability at the reliability criterion is referred to as the Firm Load Carrying Capability (FLCC) of the system.

Figure 8.1 illustrates the relationship between the risk and the annual peak load. In Figure 8.1, R_c is the firm load risk criterion, $PLCC_{old}$ is the peak load that the generating system can carry at risk level R_c, which is the Firm Load Carrying Capability. $PLCC_{new}$ is the peak load that the system can carry at a new reliability criterion R_i selected for the additional interruptible load.

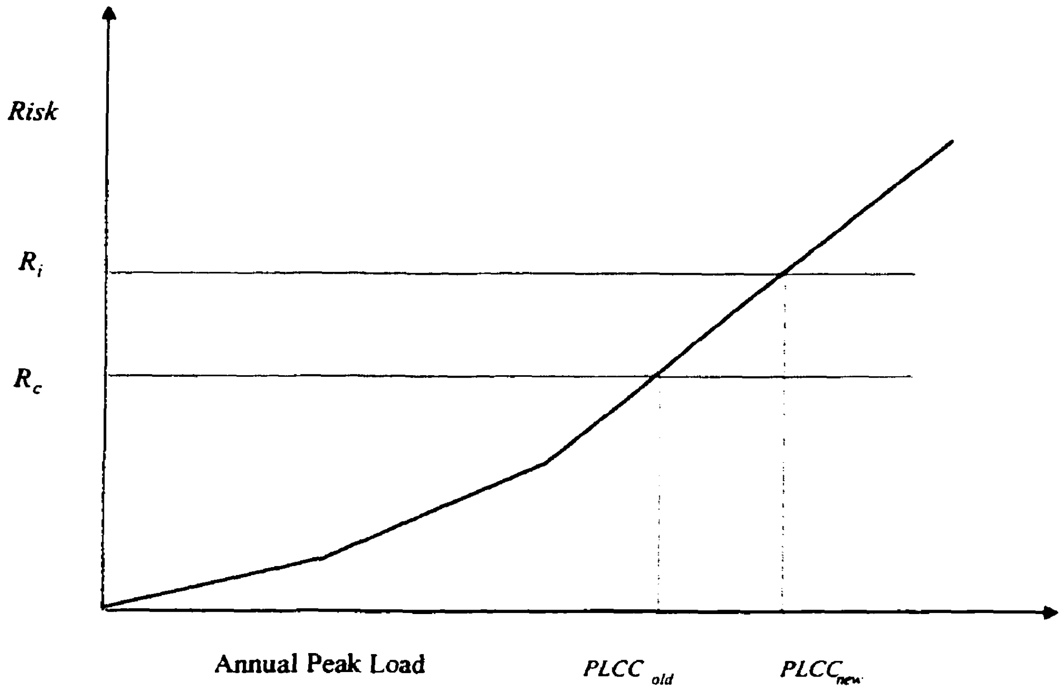

Figure. 8.1 Variation of reliability indices with annual peak load.

The incremental load carrying capability benefit [3] due to the utilization of interruptible load is

$$IPLCC = PLCC_{new} - PLCC_{old}. \tag{8.1}$$

This incremental capability, that is, the capability of the existing system to serve the additional interruptible load can also be designated as the Interruptible Load Carrying Capability (ILCC) of the system. The ILCC is made possible because of the interruptible nature of the additional load. Interruptible load, outside the additional interruptible hours, can be considered simply as load, with a risk similar to that of regular firm load. The interruption of service to the additional load ensures the integrity of the firm load when the capacity deficiencies occur.

The ILCC of a system is dependent on many factors. These include the generation adequacy level, the (firm) reliability criterion, the emergency operating practices, and most importantly, the interruptible load contract conditions or the selected risk criterion for interruptible load.

A more reliable system requires larger reserve capacity, which in turn means more underused capacity at times and can therefore support a higher ILCC. The annual duration of allowable interruption has a direct impact on the ILCC. An increased allowable interruption duration provides greater flexibility without adversely affecting the firm load.

8.3. Avoidable Additional Generation Capacity

Interruptible load contracts can reduce the need for additional capacity. The incremental generating capacity that can be delayed or avoided due to utilization of interruptible load contracts, while the original risk criterion for firm load is maintained, is defined as the AAGC (Avoidable Additional Generation Capacity).

Figure 8.2 illustrates the relationship between a risk index and the installed generating capacity. In Figure 8.2, GC_{old} is the original system installed capacity, at which the system risk is maintained at the level of R_c. GC_{new} is the total system installed capacity that is required to maintain the system risk at the same level of R_c given that the additional load is firm load.

The Avoidable Additional Generating Capacity (AAGC) can be expressed as:

$$AAGC = GC_{new} - GC_{old}. \tag{8.2}$$

The ILCC defined in Section 8.2 indicates the generation capacity benefit due to utilization of interruptible load from a demand-side point of view, while AAGC defined here indicates the benefit from a supply-side point of view. These two indices are, therefore, highly related. Some planners may use ILCC as the indicator of capacity benefit, while others use AAGC. Both indices can be utilized in long range generating capacity assessment to provide quantitative decision information.

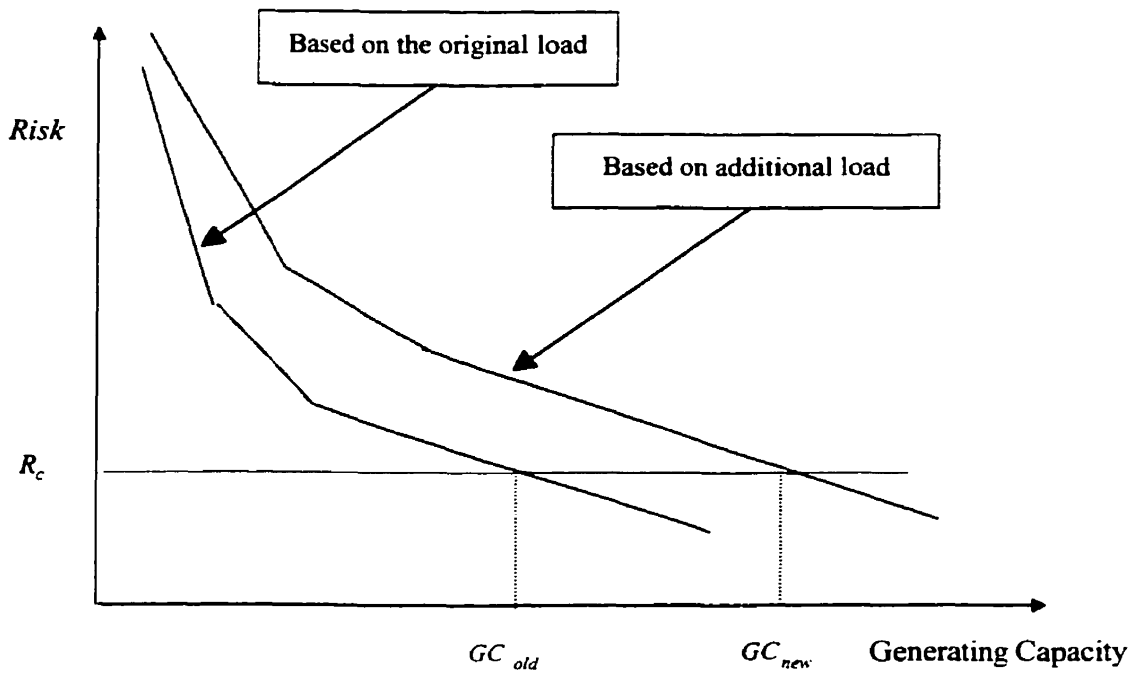

Figure. 8. 2 Variation of reliability indices with generating capacity.

8.4. Framework of Interruptible Load Analysis

The objective of interruptible load analysis is to provide input to managerial decisions regarding generating capacity requirements and interruptible load contracts. Power engineers face many problems and questions in the utilization of interruptible load. These problems can be categorized into four basic types:

1. Calculate the risk level for interruptible load customers for the given amount of interruptible load.
2. Determine the interruptible load carrying capability or avoidable additional generation capacity for the given risk level.
3. Determine the interruptible load contract conditions.
4. Determine the optimum interruptible load carrying capability.

The first type of question arises when the system operator wants to know the quantitative risk level for interruptible load customers if the amount of interruptible load is specified. Basic reliability evaluation techniques can be used to do this. The main reliability indices are LOILE (Loss-of-Interruptible-Load Expectation), LOIEE (Loss of Interruptible Energy Expectation), FLOIL (Frequency of Loss-of-Interruptible-Load), DLOIL (Average Duration of a Loss of Interruptible Load).

A second type of question is the inverse of the first one and is, what is the potential interruptible load carrying capability at a given reliability level? Given the potential interruptible load carrying capability, a system operator can determine the avoidable additional generation capacity. General reliability calculation techniques cannot be directly utilized to solve this problem and more effective techniques are required.

A third type of question is what are the most suitable interruptible load contract conditions that maximize the ILCC. A warning is issued by the operator prior to the interruption when an interruptible load is to be shed. The allowable duration of each interruption, the frequency of interruption and the annual cumulative interruption duration, are specified in the supply contract. The attractiveness of interruptible contracts to customer is increased when a number of optional provisions are offered. An interruptible customer could perhaps choose an annual cumulative interruption of 100, 200 or 400 hours, or an annual outage frequency of 20, 40 or 80. The duration of each interruption could be up to 4, 8 or 12 hours, based on the customer's requirements. The ILCC and AAGC will be different for each set of contractual options. It is therefore necessary to determine the most suitable set of conditions that maximize the ILCC and AAGC. The technique utilized to solve the second question noted above can be used to determine the most suitable interruptible load contract conditions.

A fourth type of question that is more comprehensive or complicated than previous questions is one associated with optimum interruptible load utilization. This question is what is the optimal interruptible load carrying capability, or the most suitable demand side load composition, which minimizes the total societal cost. The total societal cost includes the utility cost as well as the consumer outage costs. The reliability cost and worth evaluation techniques [3] developed for generation capacity planning can be used to estimate the outage cost for both the firm load customers and the interruptible load customers.

8.5 Sequential Monte Carlo Simulation

The interruptible load carrying capability of a system is highly related to the reliability criterion and the generation adequacy level. Generating capacity adequacy assessment normally involves the creation of a capacity model and the convolution of this model with a suitable load model. In a sequential Monte Carlo simulation approach, the capacity model is the system available capacity at points in time established sequentially, taking into account random unit failures. The load model is a chronological hourly load profile. The available system reserve at a point in time is the difference between the available capacity and the load. A negative margin denotes a load loss situation. The reliability indices for interruptible loads can be obtained by observing the available system reserve profile over a sufficiently long time period.

The basic sequential simulation procedure for probabilistic interruptible load assessment can be briefly described as follows:

1. A capacity model for the conventional base load generating facilities is created using chronological simulation techniques. A similar capacity model for the non-conventional generation facilities, such as wind turbine generating units, is constructed using time series models and the corresponding simulation techniques [6, 7]. A combined system capacity model is then formed.
2. If the available capacity is less than the load at time t, the commitment of available peaking units is simulated and the system capacity model is updated.
3. The required adequacy indices for interruptible load customers are calculated by observing the system capacity reserve model over a suitably long time period.

The main adequacy indices for probabilistic interruptible load assessment are:

1. Loss of Load Expectation (LOLE) or LOILE, hours/year,
2. Loss of Energy Expectation (LOEE) or LOIEE, MWh/year,

3. Frequency of Loss of Load (FLOL) or FLOIL, occurrences/year,
4. Duration per interruption (D) or DLOIL hours/occurrence.

A computer program designated as ILPASS (Interruptible Load Probabilistic Analysis using Sequential Simulation) based on the general simulation procedure presented above has been developed at the University of Saskatchewan

8.6. Bisection Technique to Determine ILCC

It can be seen from Equation (8.1) that a crucial step in determining the Interruptible Load Carrying Capability is to calculate the incremental peak load carrying capability associated with the two specified reliability criteria, i.e. the firm load reliability criterion and the interruptible load criterion. This problem is more complicated than calculating a reliability index at a given load level.

A risk index R can be expressed mathematically as a function of the system peak load or *PLCC*:

$$R = f(PLCC) \tag{8.3}$$

Similarly, *PLCC* is a function of the reliability level:

$$PLCC = f^{-1}(R) \tag{8.4}$$

where $f^{-1}(*)$ is the inverse function of $f(*)$.

There is no explicit expression for the function $f(PLCC)$, or for $f^{-1}(R)$. The concept illustrated in Figure 8.1 can, however, be used to obtain *PLCC*. The relationship between the system peak load and the risk level for the system with the interruptible load addition can be established using incremental sensitivity analysis. The interruptible load (and therefore the total system peak load) are increased by specified increments and the risk index evaluated until the calculated risk index (indices) is (are) approximately equal to the designated contract risk level for the interruptible load customers. This approach can involve considerable computational effort, particularly when the sequential Monte Carlo simulation method shown in Section 8.5 is utilized to estimate the reliability indices.

The risk increases with increase in the peak load, and therefore $f(PLCC)$ is a monotonic increasing function. The bisection technique can be effectively utilized to calculate the $PLCC$ and therefore the $ILCC$. Boundary values for the $ILCC$ are first established. The lower boundary can be set at zero. The upper boundary should be set such that the risk level exceeds the interruptible load reliability criterion. If this is not true, the initial upper boundary must be adjusted until the condition is satisfied. After the initial values are determined, the midpoint of the initial boundary is calculated, and the risk index at the midpoint is assessed using the related techniques. This risk index is used to judge whether the actual $ILCC$ is in the zone between the lower bound and the midpoint or between the midpoint and the upper limit. If the risk index is greater than the given interruptible load risk level, the generating system cannot carry an interruptible load greater than the value at the midpoint without violating the interruptible load criterion risk. The actual $ILCC$ is then in the first zone. The midpoint becomes the new upper boundary for this case. If the calculated risk is less than the criterion risk, the system can at least carry the interruptible load at the midpoint. The actual $ILCC$ is then in the second zone and the midpoint becomes the new lower boundary for this case. The $ILCC$ can be then obtained by repeating the above procedure until the difference between the upper and low bounds, or the difference between the risk index at the midpoint and the given risk level, is within a tolerance error.

The bisection algorithm to determine the $ILCC$ of a generating system can be further described as follows:

Step 1. Set the initial boundary values $ILCC^{(low)}$ and $ILCC^{(upper)}$. Usually, $ILCC^{(low)} = 0$

Step 2. Adjust the initial value of $ILCC^{(upper)}$ in order that the corresponding risk level is greater than the given risk criterion.

Step 3. Let $ILCC^{(mid)} = \dfrac{ILCC^{(upper)} + ILCC^{(low)}}{2}$.

If $\left|ILCC^{(upper)} - ILCC^{(low)}\right| \le \varepsilon_{PLCC}$ (ε_{PLCC} is the related maximum error allowed), go to Step 6.

Step 4. Calculate the risk index $R^{(mid)}$ corresponding to the (additional) interruptible load $ILCC^{(mid)}$ using the sequential Monte Carlo simulation procedure shown in Section 8.5.

Step 5. Form the new boundary:

If $R^{(mid)} > R^{(org)}$, then $ILCC^{(mid)} \to ILCC^{(upper)}$;

If $R^{(mid)} < R^{(org)}$, then $ILCC^{(mid)} \to ILCC^{(low)}$;

If $R^{(mid)} = R^{(org)}$, go to Step 6.

Step 6. $ILCC^{(mid)}$ is the Interruptible Load Carrying Capability for the system considered.

The boundary length in each iteration is decreased to half of the last length, and therefore the convergence is fast. The midpoint sectionalized algorithm proves to be very effective when estimating *ILCC*.

8.7 Assessment of the AAGC

As described in Section 8.3, the AAGC is defined as the amount of incremental generation capacity that could be delayed or avoided due to the utilization of interruptible load contracts, while the risk level for firm load is maintained. On the other hand, the AAGC can be considered as the incremental generating capacity required to supply the incremental load at the given risk criterion assuming that the additional load is firm load or the reliability criterion for interruptible load (R_i) is the same as that for firm load (R_c).

Mathematically,

$$R_c = f(GC_{old}, PLCC_{old}) \tag{8.5}$$

$$R_c = f(GC_{old} + AAGC, PLCC_{old} + ILCC) \tag{8.6}$$

Equation (8.6) must be solved in order to calculate the AAGC. This can be done using an enumeration method. The AAGC can be increased by specified increments and the system risk index with the total load of $(PLCC_{old} + ILCC)$ evaluated until the calculated risk index is approximately equal to the reliability criterion for firm load customers. This is, however, not an effective approach. The bisection technique shown in Section 8.6 can be further utilized to decrease the computational complexity. The algorithm to determine the AGGC of a generation system can be described as follows:

Step 1. Set the initial boundary values $AAGC^{(low)}$ and $AAGC^{(upper)}$. Usually, $AAGC^{(low)} = 0$ $AAGC^{(upper)} > ILCC$ and $AAGC^{(upper)}$ can be set as $2 * ILCC$.

Step 2. Adjust the initial value of $AAGC^{(upper)}$ in order that the corresponding risk level is less than the given risk criterion.

Step 3. Let $AAGC^{(mid)} = \dfrac{AAGC^{(upper)} + AAGC^{(low)}}{2}$.

If $\left|AAGC^{(upper)} - AAGC^{(low)}\right| \le \varepsilon_{PLCC}$ (ε_{PLCC} is the related maximum error allowed), go to Step 6.

Step 4. Calculate the risk index $R^{(mid)}$ corresponding to the additional generating capacity $AAGC^{(mid)}$.

Step 5. Form the new boundary:

If $R^{(mid)} > R_c$, then $AAGC^{(mid)} \rightarrow AACC^{(low)}$;

If $R^{(mid)} < R_c$, then $AAGC^{(mid)} \rightarrow AAGC^{(upper)}$;

If $R^{(mid)} = R_c$, go to Step 6.

Step 6. The current $AAGC^{(mid)}$ is the Avoidable Additional Generation Capability for the system considered.

8.8 Determination of Optimum Interruptible Load Contracts

The methodologies described above were applied to the RBTS [8]. The program ILPASS was used to simulate the generation / load characteristics of the RBTS including interruptible loads. The unit residence time distributions were assumed to be exponentially distributed and a stopping criterion of $\varepsilon_{LOLE}=0.01$ was used to control the simulation length.

8.8.1. Interruptible Load Customers Risk Level

A system operator may want to know the quantitative risk level for interruptible load customers. The developed program ILPASS can be directly utilized to do this. Table 8.1 presents the main risk indices for a range of interruptible loads. The calculated indices LOIEE and System Minutes are based on the interruptible load. It can be seen from Table 8.1 that the interruptible load risk increases considerably as the utilized interruptible load increases. The incremental index magnitudes are significantly different. If the interruptible load is increased from 5 MW to 30 MW, the LOILE for the RBTS increases by a factor of 7, the LOIEE by a factor of 20, the FLOIL by a factor of 5, while the System Minutes increase by a factor of 3. The utilization of different indices as risk criteria can influence the interruptible load analysis conclusion.

Table 8.1. Risk indices for interruptible load customers

Interruptible Load (MW)	LOILE (hours/yr.)	LOIEE (MWh/yr.)	FLOIL (f/yr.)	System Minutes
+0	1.0622	+0	0.2116	-
+5	1.6728	6.0382	0.3431	72.4584
+10	2.4619	14.8353	0.4779	89.0118
+15	3.5780	27.7332	0.6541	110.9328
+20	5.2980	47.1090	1.0554	141.3270
+25	7.4840	74.2223	1.4905	178.1335
+30	11.9082	115.8074	2.4225	231.6148

8.8.2. ILCC and AAGC Determination

The LOILE was used as the specified risk index to calculate the potential Interruptible Load Carrying Capability and the Avoidable Additional Generation Capacity benefit. The ILCC and AAGC of the RBTS at different reliability criteria are shown in Table 8.2.

Table 8.2. ILCC and AAGC (MW) of the RBTS

Interruptible Load Risk Criterion LOILE (hours/yr.)	ILCC	AAGC
2.0	7.0	6.0
4.0	16.2	14.0
6.0	21.4	18.0
8.0	25.4	22.0
10.0	27.8	24.0

The data in Table 8.2 are presented graphically in Figure 8.3 where it can be seen that the ability of the generating system to accommodate interruptible load is enhanced as the annual allowable interruption duration increases. The Interruptible Load Carrying Capability and Avoidable Additional Generation Capacity increase somewhat exponentially with increase in the annual allowable interruption duration. The ILCC tends to saturate quicker than the AAGC does as the predetermined risk increases.

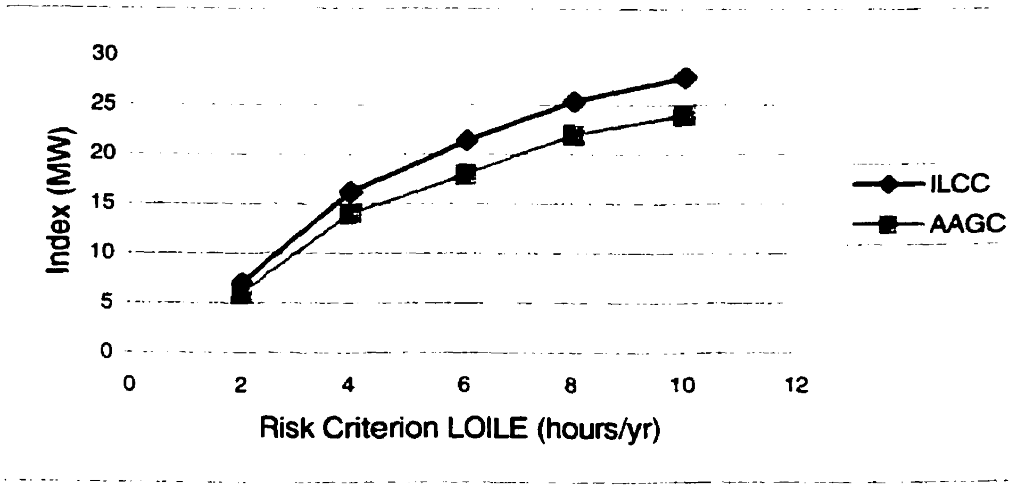

Figure 8.3. ILCC and AAGC versus the annual allowable interruption duration

The values presented in Table 8.3 were obtained assuming total flexibility in optimizing the resources and curtailing load, and therefore represent the potential ability to accommodate interruptible load and the potential generation capacity benefit within the given conditions. Interruptible loads are discrete in nature and are generally distributed over a large number of customers with varying load sizes and characteristics. The terms and conditions of interruptible load service may vary from customer to customer. Specific values of ILCC and AAGC will vary from one system to another depending on the nature of each individual system and the operating practices employed by each power utility. The values obtained using the technique shown in this paper can be employed in long-range interruptible load utilization planning to provide quantitative information for decision making.

8.8.3. Optimum Interruptible Load Contract Conditions

The annual cumulative interruption duration, the frequency of interruption and the average allowable duration of each interruption can be specified in an interruptible load supply contract. There are a number of contract options that could be offered to an interruptible load customer. The ILCC and AAGC could be different for each set of options. It is therefore meaningful to determine the most suitable set of conditions that maximize the ILCC or AAGC. Table 8.3 presents six options proposed for interruptible customers in the RBTS. One alternative could have high LOILE and low FLOIL limits, while others have low LOILE and high FLOIL limits. The DILOL limits were assumed to be constant for the different alternatives in this case study.

Table 8.3. Assumed interruptible load contract options

Option	Limting LOILE (hours/yr.)	Limiting FLOIL (f/yr.)	Limiting DILOL (hours/f)
1	9.0	0.5	6.0
2	8.0	1.0	6.0
3	7.0	2.0	6.0
4	6.0	3.0	6.0
5	5.0	4.0	6.0
6	4.0	5.0	6.0

The ILCC, AAGC and the basic reliability indices for the six alternatives are presented in Table 8.4.

Table 8.4. The ILCC, AAGC and the basic reliability indices for the six options

Option	ILCC (MW)	AAGC (MW)	LOILE (hours/yr.)	FLOIL (f/yr.)	DILOL (hours/f)
1	10.5	9.1	2.625	0.500	5.248
2	19.5	17.0	5.135	1.000	5.135
3	23.5	20.1	7.000	1.412	5.016
4	21.4	18.0	5.993	1.175	5.101
5	19.1	16.7	5.000	0.998	5.096
6	16.2	14.0	3.979	0.7963	4.997

It can be seen from this table, that Alternative 3, with the maximum ILCC capability as well as the maximum AAGC benefit, can be considered as the most suitable contractual option for the interruptible load customers in the RBTS under the given conditions. Significant variations occur in both the ILCC and the AAGC for the six alternatives. The ILCC varies from 10.5 MW to 23.5 MW, while the AAGC varies from 8.1 MW to 20.1 MW. This means that it is important to select a suitable set of interruptible load contractual conditions, in which the various risk conditions are well matched, and the best interruptible load carrying capability or capacity benefits are achieved. Practical engineering assessment usually deals with many aspects. The relatively simple case studies in this thesis show that the proposed techniques can provide practical input to the managerial decision process associated with interruptible load utilization.

8.9 Summary

The objective of interruptible load analysis is to provide decision and/or managerial information in generation capacity assessment and in the determination of interruptible load contracts with consumers. This chapter presents a basic framework and techniques to conduct interruptible load analysis using sequential Monte Carlo simulation. The bisection search techniques were developed to effectively determine the Interruptible Load Carrying Capability and the Avoidable Additional Generating Capacity indices. These factors can be utilized in generating capacity assessment and interruptible load contract analysis in order to obtain maximum utilization of both supply and demand side capabilities.

Chapter 9

Summary & Conclusions

An important question in power system development assessment is "what is an appropriate level of reliability?" or "what is the most reasonable reliability level?" A prespecified level of reliability, adequacy or security is usually employed as a constraint in power system planning. The selection of actual reliability criteria has been largely based on past experience and judgment, and it has been suggested that these criteria can lead to unduly expensive systems with unnecessarily low probabilities of failure to meet the load. Optimization techniques can be utilized to determine a reasonable reliability level. Reliability optimization applies to both conventional and non-conventional generation system planning. This is an area that has not been well developed in conventional generation system planning and should create considerable interest in non-conventional system application.

In conventional generation planning, adequacy evaluation is an important tool in determining the optimum capacity reserve and the timing of new units to be committed. Capacity expansion analyses using the reliability optimization technique have been conducted using a small reliability test system designated as RBTS in the research described in this thesis. The results were compared to those obtained using a fixed reliability criterion. The analyses show that significant capital cost can be saved using the reliability optimization techniques based on reliability cost-worth evaluation.

The decision to add generating capacity to an existing system to meet future load growth will be influenced by the selected reliability criteria or by the customer interruption costs due to generation system inadequacies. Once having decided on the required capacity, attention can be focussed on optimization in the basic design of the new generating station. Adequacy and security assessments of an individual generating station can highlight the effect of different alternative station configurations and thus provide detailed and comparative information for decision making in selecting the optimum station configuration when planning that station. Two sets of indices have been developed to recognize the different intent underlying an individual generating station assessment. They complement each other and can provide valuable information for engineering assessment and decision making in generating station design. A systematic technique for large individual generating station reliability assessment is presented. Factors such as active failures, passive failures, stuck breaker conditions, scheduled maintenance, normally open components are incorporated in the algorithms. The case study shows that the suggested indices and technique can be applied in practical engineering situations to provide a scientific basis for optimum planning and design of a generation station.

Considerable attention has been given in recent years to renewable energy resources due to concerns with dwindling fossil fuel resources and the potential impact of conventional energy systems on the environment. Wind energy is being considered as a major supply side option. At the present time, many utilities are prepared to give an energy credit to a wind facility but are reluctant to assign it a capacity credit. The actual benefits cannot be assigned in the absence of comprehensive reliability modeling and optimization techniques. One crucial step in the reliability evaluation and optimization of a power system containing WECS is to simulate the hourly wind speed. An ARMA time series analysis method incorporating the chronological correlation of wind speeds was therefore developed. The F-criterion, statistical tests based on the chi-square distribution, and a simulation procedure are used to check the feasibility of the model. Two different time series models were established using different available wind speed data. The first series of models established using wind date obtained from Environment Canada can pass the statistical tests and reproduce the high-order auto-correlation, the seasonal and diurnal distribution of the actual wind speed, and therefore can be used in reliability studies of power system containing WECS. The second series of models cannot reflect the statistical seasonal characteristics or diurnal distribution as the wind data used to establish them are not sufficient. Availability of actual wind data in sufficient detail is an essential requirement for developing feasible wind speed models. The studies described in this thesis also indicate that the sampling auto-correlation functions of different years at the same site may be significantly different, thus a wind speed model based on only one year of actual wind data should be used with caution. A sequential Monte Carlo simulation method for reliability evaluation of generating systems containing WECS was further developed based on the proposed ARMA wind simulation model. Most of the reported work done on modeling wind power generation and on the use of such models for generating system adequacy evaluation is in the analytical domain. The most obvious deficiency of the analytical methods is that the chronological characteristics of wind velocity and its effects on wind power output cannot be considered. The sequential Monte Carlo approach proposed, however, is capable of incorporating such considerations in an adequacy assessment of a generating system containing WECS.

A wind energy conversion system has a different impact on the load carrying capability of a generating system than does a conventional energy conversion system. This is due to the variation in wind speeds, the dependencies associated with the power output of each WTG in a wind farm, and the nonlinear relationship between WTG power output and wind velocity. Two risk-based capacity factors designated as the Load Carrying Capacity Benefit Ratio and the Equivalent Capacity Ratio are introduced in this thesis. The *LCCBR* indicates the incremental peak load carrying capability in per unit of the incremental WTG capacity at the criterion reliability level, while the *ECR* provides a risk-based equivalence between the proposed WECS and conventional generating capacity. Both factors provide a more direct and physical indication of the capacity benefits and possible credits of a WECS than do the classic reliability indices. A midpoint sectionalized technique has been developed to calculate the Incremental Peak Load Carrying Capability, and thus to assess the *LCCBR* and *ECR*. This method has a fast convergence and usually takes only a few iterations to obtain the risk-based capacity factors. The case studies conducted in this research show that both the load carrying contribution and capacity credit of a WECS can be quantitatively evaluated. The site using the Regina wind regime has twice the load carrying capability and capacity credit than the site using the Prince Albert data. The average wind at the Regina site is just 6 km /hr lower than at the Prince Albert location. Selecting suitable sites with good wind energy resources is extremely important in order to achieve maximum capacity or energy benefits and credits.

The electric energy output of a wind turbine at a specific site depends on many factors. These factors include the wind speed conditions at the site, and most importantly, the characteristics of the wind turbine generator (WTG) itself, particularly the cut-in, rated and cut-out wind speed parameters. Different types of windturbines are commercially available on the market. It is therefore desirable to select a wind turbine which is best suited for a particular site in order to obtain the maximum generation capacity benefit at the given criterion reliability. The effects of different windturbine design parameters on the basic adequacy indices and the risk-based capacity benefit factors were investigated. The case studies show that turbine cut-in wind speed has a significant effect on the capacity adequacy of a generating system while the cut-out wind speed has almost no effect. The proposed risk based indices *LCCBR* and *ECR* can be utilized as objective functions to determine the optimum site-matching windturbine for a potential wind site. Significant capacity benefits can be obtained by selecting appropriate site-matching windturbine parameters.

The integration of wind power in a conventional generating system results in fuel or gas savings for power utilities. It may also allow future capital expenditure on conventional plants to be reduced or deferred. The integration is, however, not without problems mostly due to the unpredictable nature of the wind. There are both economic penetration and reliability penetration limits associated with wind power. Sensitivity studies were conducted to investigate the effect of the WECS penetration level on the incremental load carrying contribution associated with additional wind power. The results show that the penetration level has significant effects on both adequacy and benefit. The incremental load carrying capability due to utilization of wind energy increases exponentially as the corresponding wind penetration level increases. The incremental benefit saturates as the wind penetration level increases. A procedure to determine the optimum penetration level was developed, and extends the method developed for conventional generation adequacy optimization. The related case studies conducted show that the optimum penetration plan is not only highly related to the investment and the operating parameters of WTG generators, but is also highly dependent on the wind speed condition at the actual site.

Generation capacity adequacy is mainly dictated by the installed capacity and the system load profile. Generating system adequacy can be therefore categorized into the two basic aspects of supply side formulation and demand side management. On the supply side, electric utilities continually search for suitable incremental energy options and optimum supply structures. On the load side, cost-effective opportunities exist to use interruptible contracts, in order to better utilize low cost generation capacity and to reduce the need for additional capacity. This research also focuses on interruptible load assessment and utilization. A basic framework and techniques to conduct interruptible load analysis using sequential Monte Carlo simulation was created. A new index designated as the Avoidable Additional Generating Capacity (AAGC) is introduced. Bisection search techniques were developed to effectively determine the ILCC and AAGC. Case studies conducted to determine the most suitable contractual option for interruptible load customers under given conditions are also presented in the thesis. The results show that selecting a suitable set of interruptible load contractual conditions, in which various risk conditions are well matched, will achieve maximum interruptible load carrying capability or capacity benefits.

Opportunities to apply optimization techniques exist in both supply side formulation and demand site management. The series of case studies illustrated in this thesis indicate that the proposed concepts, framework, models and quantitative techniques can be applied in practical engineering situations to provide a scientific basis for optimum generation planning.

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Appendix

RBTS - the Roy Billinton Test System

The RBTS has 11 conventional generating units, ranging in size from 5 MW to 40 MW, with a total installed capacity of 240 MW. The chronological load profile consists of 8736 load points and the annual peak load is 185 MW.

Figure A.1 presents the system diagram of the RBTS.

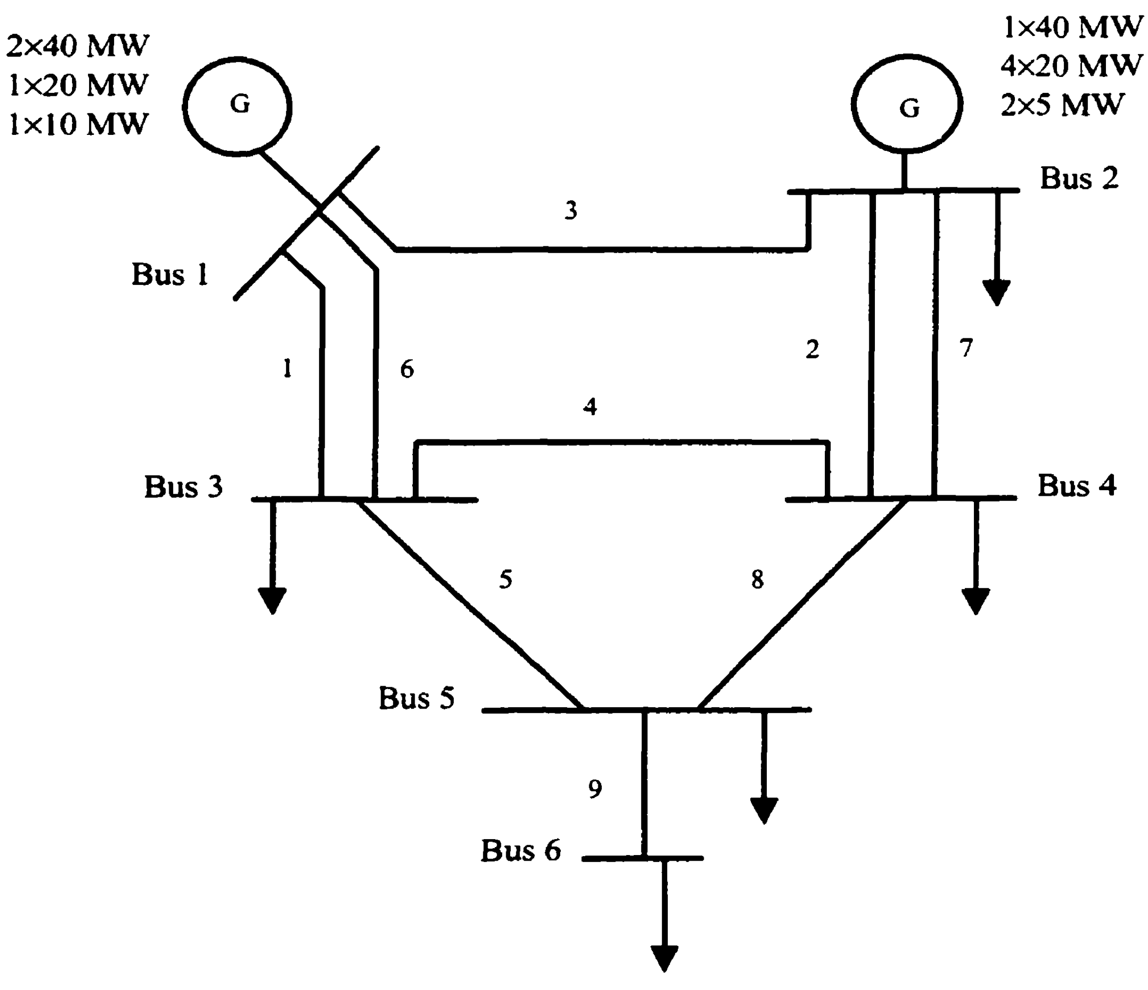

Figure A.1 Diagram of the RBTS

The system capacity composition is shown in Table A.1. Table A.2 presents the daily peak load cycle, as a percentage of the weekly peak. Table A.3 presents the daily peak load cycle, as a percentage of the weekly peak. The same weekly peak load cycle is assumed to apply for all times of the year. The data in Tables A.2 and A.3 defines a daily peak load model of 365 days with Monday as the first day of the year. Table A.4 gives weekend and weekend hourly load data for each of three seasons. Combining the data given in Tables A.2-4 defines an hourly load model of 8736 hours.

Table A.1 Generating unit data of the RBTS

Unit No.	Bus No.	Rating (MW)	Failure Rate (occ/year)	Repair Time (hours)
1	1	40.0	6.0	45.0
2	1	40.0	6.0	45.0
3	1	10.0	4.0	45.0
4	1	20.0	5.0	45.0
5	2	5.0	2.0	45.0
6	2	5.0	2.0	45.0
7	2	40.0	3.0	60.0
8	2	20.0	2.4	55.0
9	2	20.0	2.4	55.0
10	2	20.0	2.4	55.0
11	2	20.0	2.4	55.0

Table A.2 Weekly peak load as a percentage of annual peak

Week	*Peak Load (%)*	*Week*	*Peak Load (%)*
1	86.2	27	75.5
2	90.0	28	81.6
3	87.8	29	80.1
4	83.4	30	88.0
5	88.0	31	72.2
6	84.1	32	77.6
7	83.2	33	80.0
8	80.6	34	72.9
9	74.0	35	72.6
10	73.7	36	70.5
11	71.5	37	78.0
12	72.7	38	69.5
13	70.4	39	72.4
14	75.0	40	72.4
15	72.1	41	74.3
16	80.0	42	74.4
17	75.4	43	80.0
18	83.7	44	88.1
19	87.0	45	88.5
20	88.0	46	90.9
21	85.6	47	94.0
22	81.1	48	89.0
23	90.0	49	94.2
24	88.7	50	97.0
25	89.6	51	100.0
26	86.1	52	95.2

Table A.3 Daily peak load as a percentage of weekly peak

Day	*Peak load (%)*
Monday	93
Tuesday	100
Wednesday	98
Thursday	96
Friday	94
Saturday	77
Sunday	75

Table A.4 Hourly peak load as a percentage of daily peak

	Winter weeks 1-8 & 44-52		*Summer Weeks 18-30*		*Spring/Fall Weeks 9-17 & 31-43*	
Hour	*weekday*	*weekend*	*weekday*	*weekend*	*weekday*	*weekend*
12-1 am	67	78	64	74	63	75
1-2	63	72	60	70	62	73
2-3	60	68	58	66	60	69
3-4	59	66	56	65	58	66
4-5	59	64	56	64	59	65
5-6	60	65	58	62	65	65
6-7	74	66	64	62	72	68
7-8	86	70	76	66	85	74
8-9	95	80	87	81	95	83
9-10	96	88	95	86	99	89
10-11	96	90	99	91	100	92
11-Noon	95	91	100	93	99	94
Noon-1pm	95	90	99	93	93	91
1-2	95	88	100	92	92	90
2-3	93	87	100	91	90	90
3-4	94	87	97	91	88	86
4-5	99	91	96	92	90	85
5-6	100	100	96	94	92	88
6-7	100	99	93	95	96	92
7-8	96	97	92	95	98	100
8-9	91	94	92	100	96	97
9-10	83	92	93	93	90	95
10-11	73	87	87	88	80	90
11-12	63	81	72	80	70	85