University of Alberta

Analysis on Adverse-Weather-Related Power Transmission Line Outages

by

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A thesis submitted to the Faculty of Graduate Studies and Research in partial fulfillment of the requirements for the degree of Master of Science

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Dedication

This thesis is dedicated to my parents and my wife Rosalie.

Abstract

The performance of industrial and commercial power systems and the processes they control can be significantly affected by frequent forced outages of utility transmission equipment due to adverse weather. The objective of this thesis was to reveal the unique failure patterns and characteristics of adverse weather-related transmission line outages in the Province of Alberta. Lightning, wind and precipitation (ice, wet snow, frost) were the three regional adverse weather effects under investigation. Statistical analyses and Monte Carlo simulation were applied to the study of incorporating weather effects in reliability evaluation of transmission system. The major results and contributions of this thesis research are: (1) the underlying statistical distributions of the duration of adverse weather-related outages are skewed, (2) transmission line outage frequency is strongly associated with the elevated levels of adverse weather activities, and (3) an applicable Monte Carlo simulation model has been developed to incorporate weather effects in reliability evaluation of Alberta transmission system.

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Chapter 1

Introduction

1.1. Background

Power System transmission networks are exposed to a great variety of weather conditions. The failure rate of transmission lines increases very significantly during adverse weather periods, such as gales, ice storms, lightning, conductor icing, etc. The ice storm disaster sweeping through Québec and U.S. in January 1998 reminded us how adverse weather conditions can cause major and widespread catastrophic disruptions of electric supply.

The economic impact of these outages is not restricted to loss of revenue by the utility or loss of energy utilization by their customers, but includes indirect costs imposed on society and environment due to the outage. The ice storm disaster forced Hydro-Québec to invest about $525 million in 1998 to restore its transmission and distribution systems back to an operational state. The Québec government will pay Hydro-Québec $235 million, that is, the equivalent net value of the installations affected by the natural disaster. The Québec government will also reimburse the approximately $200 million in expenses that Hydro-Québec incurred for emergency measures. For its part, Hydro-Québec has announced a series of projects aimed at strengthening its transmission system. Four new high-voltage lines, totaling 265 kilometers in length, as well as a new interconnection with Ontario, will be completed between now and 2000. The cost of this work is estimated at about $815 million. Nearly half this investment was forecast in the utility's 1998-2002 strategic plan.

In today's deregulated power industry, the energy sources to supply a given geographical load can originate anywhere in North America, because today's utilities are purchasing economical energy from various geographical energy sources (e.g., out of province and out of country), and transporting the energy over various transmission line networks to load centers. New legislation throughout the world is presently focusing on the reliability of transmission lines during adverse weather conditions. The basic objective of transmission system adequacy assessment is to evaluate the ability of a transmission system to transfer energy reliably between sources of generation and distribution load points. Any single or multiple transmission line outage can significantly alter the transmission system operating configuration such that continuity between energy delivery sources to system load points is interrupted. One of the primary causes of major transmission line outages is adverse weather condition, particularly lightning, wind and icing. These weather events are dependent upon the geographical location of the transmission line.

Previous research has been conducted on the outage data collected by the Canadian Electricity Association's Equipment Reliability Information System Statistics on the forced outage performance characteristics of transmission equipment for Canadian utilities for the period 1988--1992 [1].

In 1975 the Canadian Electricity Association (CEA) adopted a proposal to create a facility for centralized collection, processing and reporting of reliability and outage statistics for electrical generation, transmission and distribution equipment. To coordinate the development of this equipment reliability information system, the CEA created a consultative committee on outage statistics. In 1978, the transmission stage of the information system was implemented when Canadian utilities began supplying data on transmission equipment in accordance with the instruction manual for reporting component forced outages of transmission equipment [4].

Historical transmission reliability data from the Canadian Electricity Association [2] provides the database to summarize the performance of various transmission line configurations under adverse weather conditions [1]. The reliability evaluation methodologies can be found in the IEEE Std. 493-1997 (IEEE Gold Book) [5].

1.1.1. Basics of Power Transmission Forced Outages

A forced outage can be described as an outage that results from emergency conditions directly associated with faulty components, requiring that they be taken out of service immediately, either automatically or as soon as switching operations can be performed, or an outage caused by improper operation of equipment or human error. To understand the performance of transmission lines from different perspectives, it is necessary to define the data base structure of transmission line performance data. The structure for the CEA transmission equipment forced outage data base is shown in figure 1-1 [1].

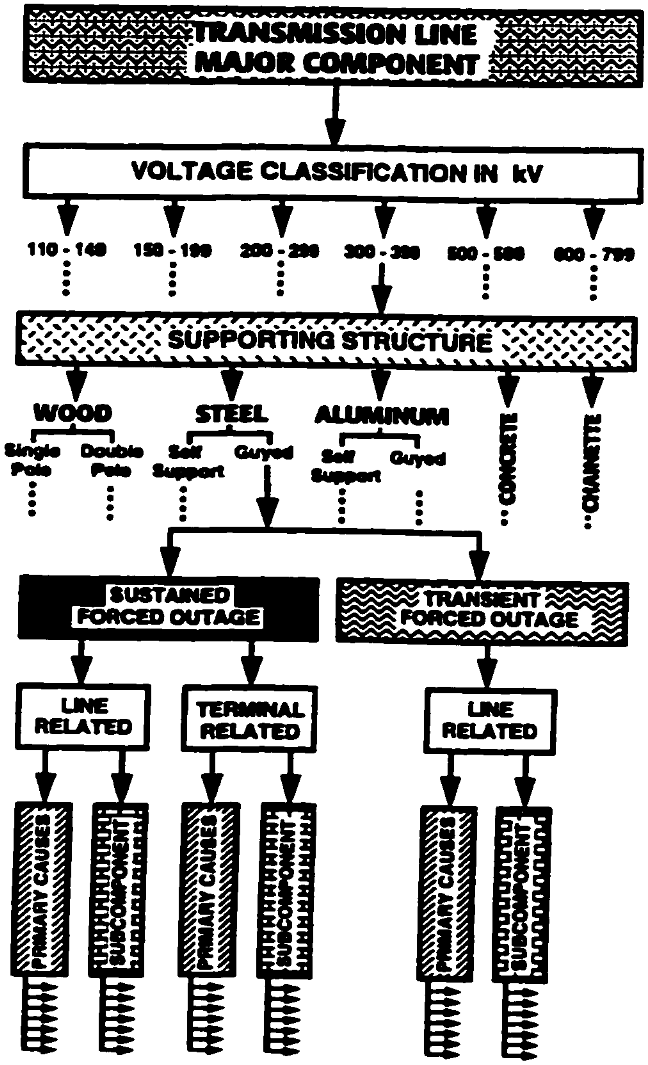

Figure 1-1 Canadian Electricity Association transmission line database structure

The major classifications of transmission lines are according to their operating voltage level and their supporting structures. The forced outage data can be categorized as "sustained" and "transient" forced outages. A "sustained" forced outage refers to a transmission line related forced outage, the duration of which is <u>one</u> minute or more. It does, therefore, not include automatic reclosing events [4]. A "transient" forced outage refers to a transmission line forced outage, the duration of which is less than one minute [4].

The sustained forced outages are further divided into "line-related" and "terminal- related" forced outages while transient forced outages are usually only defined in terms of "line-related" forced outages. The "line-related" and "terminal-related" forced outages are further subdivided into primary causes and sub component categories.

1.1.2. CEA Summary for Weather-Related Outages

The identified primary causes of transmission line forced outages are defective component, adverse weather, adverse environment, system condition, human element, foreign interference, and unknown.

Adverse weather designates weather conditions which cause an abnormally high rate of forced outages for exposed components while such conditions persist. Adverse weather conditions can be defined for a particular system by selecting the proper values and combinations of conditions reported by the weather bureau: thunderstorms, wind velocities, precipitation, temperature, etc. A major storm disaster event designates weather conditions which exceed design limits of the transmission lines and which satisfy all of the following (e.g., the Québec ice storm disaster) criteria:

- more than a specified percentage of customers out of service,
- service restoration longer than a specified time, or
- extensive mechanical damage to the transmission system.

The identification of the primary power transmission line forced-outage causes due to adverse weather can be summarized as follows: lightning, freezing rain, snow, high wind, high ambient temperature, low ambient temperature, freezing fog or frost, tornadoes, etc. [3].

According to the Canadian Electricity Association's equipment reliability information system statistics on the forced outage performance characteristics of transmission equipment for Canadian utilities for the period 1988-1992 [1], the general summarized adverse weather effects for different kinds of power line outages are shown in the following three figures: Figures 1-2, 1-3, 1-4 (classified as to different voltage levels).

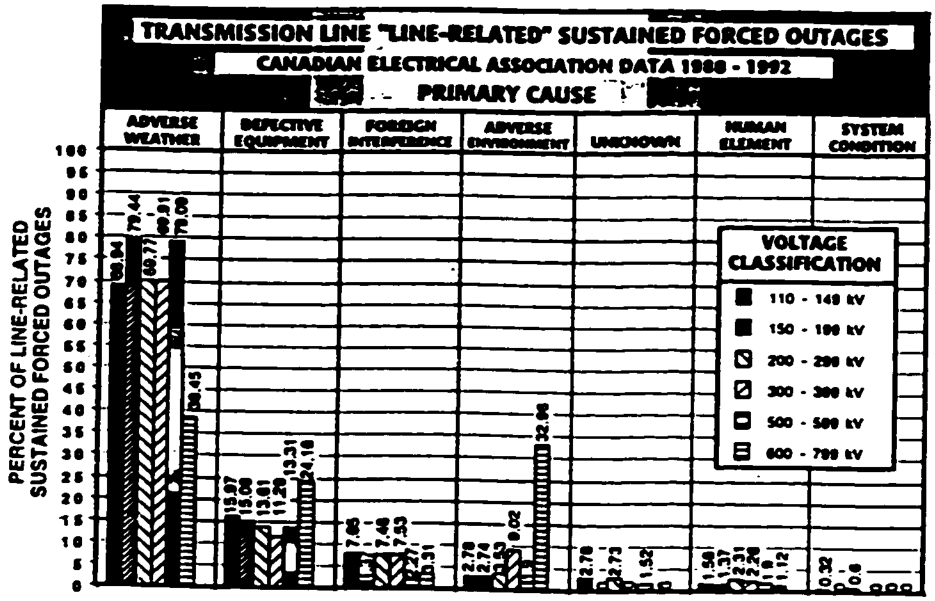

Figure 1-2 Percent of transmission line "line-related" sustained forced outages stratified by primary cause and voltage class

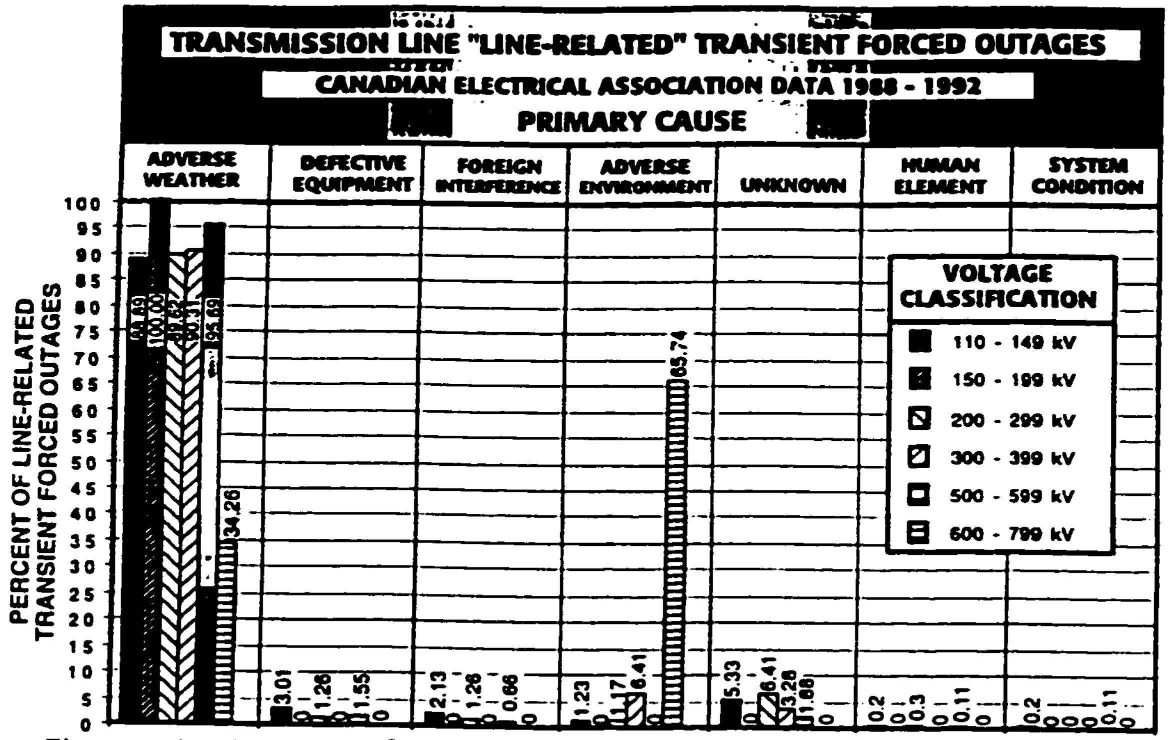

Figure 1-3 Percent of transmission line "line-related" transient forced outages stratified by primary cause and voltage class

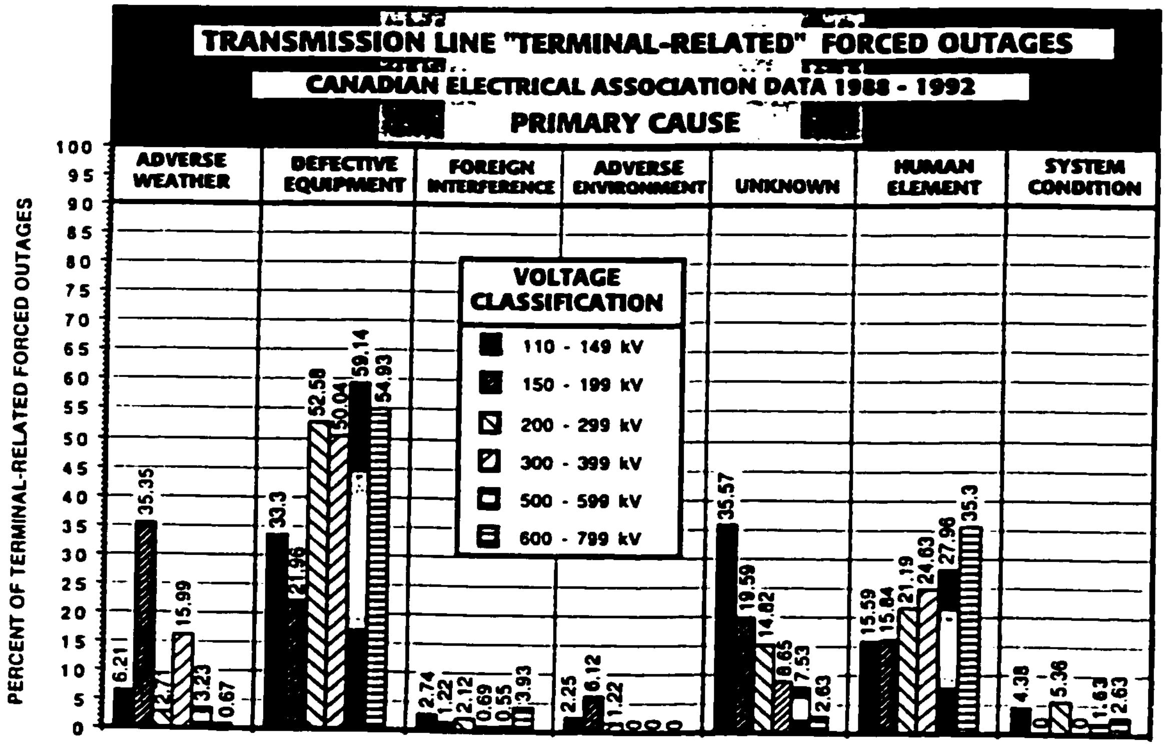

Figure 1-4 Percent of transmission line "terminal-related" sustained forced outages stratified by primary causes and voltage class

For all voltage classes of transmission lines, adverse weather accounts for approximately 70% of "sustained line-related" forced outages with the exception of the 600-799kV voltage classes (38.45%, figure 1-2). The major primary cause of "transient" forced outages is also the adverse weather which accounts for approximately 90% of all "transient" forced outages for all voltage classes except the 600-799kV class where adverse weather is the dominant cause (figure 1-3). The statistical patterns of primary causes of "transient line-related" forced outages and "sustained line-related" forced outages are similar. However, for "sustained terminal-related" forced outages, the statistical pattern of primary causes is significantly different from the "sustained line-related" and "transient" forced outages; in which case, defective equipment is the dominant cause for all voltage classes (figure 1-4) [1].

Chapter 3 will reveal that adverse weather conditions seriously affect Alberta transmission line reliability. The Alberta transmission line failure statistics stratified by adverse weather-related primary cause (lightning, wind and precipitation) and voltage level (72kV, 144kV, 240kV) will be shown.

1.2. Probabilistic Analysis of Power System

Monte Carlo simulation was used to analyze the reliability performance of the Alberta transmission network. Power system behavior is stochastic in nature, and therefore it is logical to consider that the assessment of such systems should be based on techniques that respond to this behavior (i.e., probabilistic techniques). This has been acknowledged since the 1930s, and lots of publications have dealt with the development of models, techniques, and applications on reliability assessment of power systems [8-12]. It remains a fact, however, that most of the present planning, design, and operational criteria are based on deterministic methods. These have been used by utilities for decades, and it is argued that they have served the industry extremely well in the past. The application of probabilistic approaches has been increasing due to their flexibility in analyzing complex power systems.

The main reasons for using deterministic methods in the past were lack of data, limitation of computational resources, lack of realistic reliability techniques, aversion to the use of probabilistic techniques, and a misunderstanding of the significance and meaning of probabilistic criteria and risk indices. These reasons are no longer valid today since most utilities now have applicable system data and new reliability evaluation techniques. With today's knowledge base, there is no need to deliberately constrain the inherent probabilistic or stochastic nature of a power system within the deterministic domain.

1.3. Research Objectives and Outline of the Thesis

1.3.1. Objectives

The objective of this thesis is to reveal the unique failure patterns and characteristics of adverse weather-related transmission line outage in the Province of Alberta.

Various adverse weather contributors to power transmission line forced-outages have been identified as the primary causes of different sorts of transmission line outages [3]. In order to determine what extent these weather contributors will affect the power system transmission reliability, a correlation analysis was conducted to reveal statistical relationships between adverse weather activities and Alberta transmission line outage frequency. Various techniques have been developed to accommodate the modeling of weather events in transmission system reliability evaluation during the last several decades [27-30]. In this thesis, an applicable Monte Carlo simulation model has been developed to incorporate weather effects in transmission system reliability evaluation.

The methodology and simulation results presented in this thesis can be used by electric utilities to make decisions as to the necessity of considering the adverse weather factors in power transmission system design, protection, and operation.

1.3.2. Outline of Thesis

Chapter 2 presents the basic concepts of power system reliability evaluation. The primary concept to be used in this thesis is the Monte Carlo simulation method.

Chapter 3 describes the procedures for data processing, including both the power line outage statistics and the adverse weather statistics. The concepts and interpretations of the data collected for power system reliability analysis are addressed. Correlation analysis results between adverse weather and Alberta transmission line outage are summarized.

Chapter 4 presents the general framework for Monte Carlo simulation evaluation and its application in weather-related transmission outage reliability analysis. An illustrative Monte Carlo simulation case study of evaluating basic reliability indices (frequency and duration of customer load point interruptions caused by adverse weather) on a portion of the Alberta Grid is presented to demonstrate the simulation procedure and the use of outage statistics in simulation.

Chapter 5 summarizes the major conclusions from this research.

Chapter 2

Basic Concepts of Power System Reliability Evaluation

2.1. Concepts of Adequacy and Security

Whenever a discussion of power system reliability occurs, it inevitably involves a consideration of system states and whether they are adequate, secure, and can be described as an alert, emergency, or some other designated status [6]. This is particularly the case for transmission systems. It is, therefore, useful to discuss the significance and meaning of such states.

Security [7] relates to the ability of a utility system to respond to disturbances arising within the system. These include the conditions causing local and widespread effects, and the loss of major generation and transmission facilities.

The concept of adequacy, on the other hand, is generally considered to be the existence of sufficient facilities within the system to satisfy the consumer demand [7]. These facilities include those necessary to generate sufficient energy and the associated transmission and distribution networks required to transport the energy to the actual consumer load points. Adequacy is therefore considered to be associated with static conditions which do not include system disturbances.

The implication of this division is that the two aspects are different in both concept and evaluation. In reality, the division is not intended to indicate that there are two distinct processes involved in power system reliability, but is intended to ensure that reliability can be calculated in a simply structured and logical fashion.

From a pragmatic point of view, adequacy, as defined, is far easier to calculate and provides valuable input to the decision-making process. Considerable work has been done in this regard [8-12]. It is surely an exciting area for further development and research for the problem of "security".

It is evident from the above definition that adequacy is used to describe a system state in which the actual entry to and departure from that state is ignored; thus, it is defined as a steady state condition. A system state can be analyzed and deemed adequate if all system requirements including the load, voltages, VAR requirements, etc., are all fully satisfied. A system state is deemed inadequate if any of the power system constraints are violated. An additional consideration that may sometimes be included is that an otherwise adequate state is deemed to be adequate, if and only if, on departure, it leads to another adequate state; it is deemed inadequate if it leads to a state which itself is inadequate in the sense that a network violation occurs. This consideration creates a buffer zone between the fully adequate states and the other obviously inadequate states. Such a buffer zone is better known as an alert state, the adequate states outside of the buffer zone as normal states, and inadequate states as emergency states.

The concept of adequacy considers a state in complete isolation, and neglects the actual entry and departure transitions as causes of problems. In reality, these transitions, particularly entry ones, are fundamental in determining whether a state can be static or whether the state is simply transitory and very temporary. This leads automatically to the consideration of security, and consequently, it is evident that security and adequacy are interdependent and part of the same problem; the division is one of convenience.

Power system engineers tend to relate security to the dynamic process that occurs when the system transits between one state and other states. Both of these states may themselves be acceptable if viewed only from adequacy; i.e., they are both able to satisfy all system demands and all system constraints. However, this ignores the dynamic and transient behavior of the system; it may not be possible for the system to reside in one of these states in a steady state condition. If this is the case, then a subsequent transition takes the system from one of the so-called adequate states to another state, which itself may be adequate or inadequate. In the latter case, the state from which the transition occurred could be deemed adequate but insecure. Further complications can arise because the state from which the above transition can occur may be inadequate but secure in the sense that the system is in steady state, i.e., there is no transient or dynamic transition from the state. Finally, the state may be inadequate and insecure.

If a state is inadequate, it implies that one or more system constraints, either in the network or the system demand, are not being satisfied. Emergency actions are therefore required, such as those actions taken by load dispatchers, load shedding, or various alternative ways of controlling system operations. All of these remedial actions require time to accomplish. If the dynamic process of the power system causes departure from this state before the remedial action can be accomplished, then the system state is clearly not only inadequate but also insecure. If, on the other hand, the remedial action can be accomplished in a shorter time than that taken by the dynamic process, the state is secure though inadequate. This leads to the conclusion that the time to perform a remedial action is a fundamental parameter in determining whether a state is adequate and secure, adequate and insecure, inadequate and secure, or inadequate and insecure. Any state which can be defined as either inadequate or insecure is clearly a system failure state and contributes to system unreliability.

The existing reliability evaluation techniques generally relate to the assessment of adequacy. This is not of great significance in the case of generation systems or of transmission systems; however, it can be important when considering combined generation and transmission systems. The ability to assess security is so far very limited. Probabilistic transient stability evaluation lies in this domain together with techniques for quantifying unit commitment and response risk [7]. Indices, which are obtained by assessing past system performance, encompass the effect of all system faults and failures irrespective of cause and, therefore, include the effect of insecurity as well as those due to inadequacy. The techniques used in this thesis are only concerned with using the basic adequacy indices to evaluate weather-related transmission line outages.

2.2. System Hierarchical Levels and Functional Zones

The basic techniques for adequacy assessment can be categorized in terms of their application to segments of a complete power system. These segments are shown in figure 2-1 and can be defined as the functional zones of generation, transmission and distribution [13]. This classification is an appropriate one as most utilities are divided into these zones for the purposes of organization, planning, operation, and analysis. Adequacy studies can be, and are, conducted in each of these three functional zones.

Figure 2-1 Basic functional zones

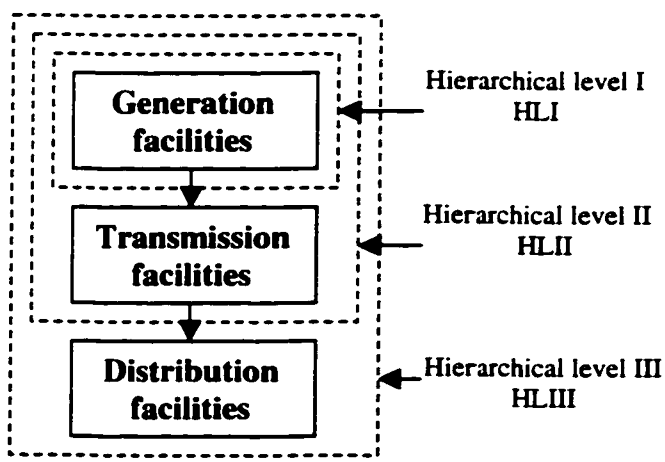

Figure 2-2 Hierarchical levels

The functional zones shown in figure 2-1 can be combined to give the hierarchical levels shown in figure 2-2. These levels are used in adequacy assessment. Hierarchical Level 1 (HL1) is concerned with only the generation facilities. Hierarchical Level 2 (HL2) includes both generation and transmission facilities while HL3 includes all three functional zones in an assessment of consumer load point adequacy. HL3 studies are not usually conducted directly, due to the complexity of the problem in an actual power system.

Functional zone studies often do not include the hierarchical levels above them. These studies are usually conducted on a subset of a system in order to examine a particular configuration or topological change. These analyses are frequently undertaken in the sub transmission and distribution system functional zones, as these areas are less affected by the actual location of the generating facilities.

In composite system (HL2), adequacy studies of relatively large-scale transmission systems, it is reasonable to limit a study area and, in doing so, provide more realistic results than by evaluating the whole system. This is due to the fact that the addition of a transmission facility may considerably affect a local area but have little impact on other parts of the system. The contribution to overall reliability of a large system due to a local transmission line addition may be so small that it is masked by computational errors, and consequently cannot reflect the reliability change of the whole system. This contribution, however, can be a relatively large proportion of the reliability change in the local area. When the planning task is to investigate reinforcement alternatives of the subsystem represented by a local area, evaluating the whole system's reliability may lead to erroneous conclusions. In this case, it is desirable to limit the size of the examined system and utilize system equivalent techniques.

Particular studies of a practical power system for evaluating special factors (e.g., adverse weather, defective equipment, system conditions, etc.) should be included in the model. The objective of this thesis is to detect and model the relationships between adverse weather and Alberta transmission line outages.

2.3. Statistical and Probabilistic Measures

It is important to realize what can be done regarding reliability assessment and why it is necessary. Failures of components, plant, and systems occur randomly, and are caused by various reasons, e.g., adverse weather. The frequency, duration and impact of failures vary from one year to the next. Usually all utilities record details of the events as they occur and produce a set of performance measures. These can be limited or extensive in number and concept and include such items as:

- System availability,
- Estimated unsupplied energy,
- Number of incidents,
- Number of hours of interruption,
- Categorized reasons for the interruption,
- Excursions beyond set voltage limits, and
- Excursions beyond frequency limits.

These performance measures are valuable because they:

- Identify weak areas needing reinforcement or modifications,
- Identify the primary causes for the interruptions,
- Establish chronological trends in reliability performance,
- Establish existing indices which serve as a guide for acceptable values in future reliability assessments,
- Enable previous predictions to be compared with actual operating experience, and
- Monitor the response to system design changes.

The important point to note is that these measures are statistical indices. They are not deterministic values, but at best are average or expected values of a probability distribution.

The same basic principles apply if future behavior of the system is being assessed. The assumption can be made that failures, which have occurred randomly in the past, will also occur randomly in the future; therefore, the system behaves probabilistically, or more precisely, stochastically. Predicted measures that can be compared with past performance measures or indices can also be extremely beneficial in comparing the past history with the predicted future. These measures can only be predicted using probabilistic techniques, and attempts to do so using deterministic approaches are misleading.

2.4. Reliability Evaluation Techniques

Power system reliability evaluation has been extensively developed utilizing probabilistic methods, and a wide range of appropriate indices have been developed. A single all-purpose equation or technique does not exist. The approach used and the resulting reliability equations depend on the system configuration and the assumptions used. Many assumptions must be made in all practical applications of probability and statistical theory. The validity of the analysis is directly related to the validity of the models used to represent the system. Actual failure distributions seldom fit the analytical descriptions used in statistical analysis, and care must be taken to ensure that significant errors are not introduced through oversimplification. On the other hand, a potential user of reliability evaluation techniques should clearly keep in mind the objective behind the evaluation process. In generation system capacity assessment, a reference adequacy level can often be obtained in terms of historical experience of an individual utility. This generally requires a model as accurate as possible so that the resulting indices can be compared with the given target level. However, in evaluating composite generation and transmission systems, distribution systems, and substation configurations, it is generally necessary to assess the relative benefits between the various alternatives available, including the option of not doing any reinforcement at all. The level of analysis need not be any more complex than that which enables the relative merits to be assessed. The apparent ability to include a high degree of precision in the calculations should never override the inherent uncertainties in the forecast data, including load, failure rates, restoration times, etc. Absolute reliability, although an ideal objective, is almost impossible to evaluate. This does not weaken the necessity to objectively assess the relative merits of alternate schemes.

The most important point to note is that it is absolutely necessary to have a complete understanding of the system. No amount of probability theory can outweigh this important engineering function. Probability theory is simply a tool that enables the analyst to transform knowledge of the system into a prediction of its likely future behavior. Only after this understanding has been achieved, can a model be derived and an appropriate evaluation technique chosen. Both of these must reflect and respond to the way a system operates and fails. The basic steps involved are to:

- Understand the way in which the components and system operate,
- Identify the way in which they can fail,
- Deduce the consequences of the failures,
- Derive models to represent these characteristics, and
- Finally select the evaluation technique.

The two main approaches are analytical calculations and numerical simulation. The vast majority of techniques have been analytically based, and simulation techniques have taken a minor role in specialized applications. The main reason for this is because simulation generally requires large amounts of computing time, and analytical models and techniques have been sufficient to provide planners and designers with the results needed to make objective decisions. This is now changing, and increasing interest is being shown in modeling the system behavior more comprehensively, and in evaluating a more informative set of system reliability indices. This implies the need to consider Monte Carlo simulation.

Analytical techniques represent a system by a mathematical model, e.g., the Markov state model, and evaluate the reliability indices from this model using direct numerical solutions. They generally provide expectation indices in a relatively short computing time. Unfortunately, assumptions are frequently required in order to simplify the problem to produce a practical analytical model of the system. This is particularly the case when complex systems and complex operating procedures have to be modeled. The analysis in this case can be extremely cumbersome. The resulting analysis can, therefore, lose some or much of its significance. The use of a simulation technique is very important in the reliability evaluation of such situations.

Simulation methods estimate the reliability indices by simulating the actual process and random behavior of the system. The method therefore treats the problem as a series of real experiments. The techniques can theoretically take into account virtually all aspects and contingencies inherent in the planning, designing, and operation of a power system. These include random events, such as outages and repairs of elements represented by general probability distributions, dependent events and component behavior, e.g., transmission lines under adverse weather conditions, queuing of failed components, maintenance outages, load variations, variation of energy input such as that occurring in hydro generation, as well as all different types of operating policies.

If the operating life of the system is simulated over a long period of time, it is possible to study the behavior of the system and obtain a clear picture of the type of deficiencies that the system may suffer. This recorded information permits the expected values of reliability indices together with their frequency distributions to be evaluated. This comprehensive information gives a very detailed description, and, hence, understanding of the system reliability.

The simulation process can follow one of two approaches:

- Random -- this examines basic intervals of time in the simulated period after choosing these intervals in a random manner, or
- Sequential -- this examines each basic interval of time of the simulated period in chronological order.

The basic interval of time is selected according to the type of system under study, as well as the length of the period to be simulated in order to ensure a certain level of confidence in the estimated indices.

The choice of a particular simulation approach depends on whether the history of the system plays a role in its behavior. The random approach can be used if the history has no effect, but the sequential approach is required if the past history affects the present conditions (i.e., an inherent weakness of Markov modeling techniques).

Merits and demerits exist in both analytical and simulation methods. In general, if complex operating conditions are not considered and the failure probabilities of components are quite small, the analytical techniques are more efficient. Otherwise, Monte Carlo simulation methods are often preferable. The main advantages of Monte Carlo methods are as follows:

- In theory, they can include system effects or system processes which may have to be approximated in analytical methods.
- Non-electrical system factors, such as weather effects, reservoir operating conditions, etc. can also be simulated.
- The required number of samples for a given accuracy level is independent of the size of the system and, therefore, it is suitable for evaluation of large-scale system.
- They can simulate probability distributions associated with component failure and restoration activities. This generally cannot be performed using analytical methods.
- They can calculate not only reliability indices in the form of expected values of random variables, but also the distributions of these indices, which analytical techniques generally cannot.

It should be noted that irrespective of which approach is used, the predicted indices are only as good as the model derived for the system, the appropriateness of the technique, and the quality of the data used in the models and techniques.

Chapter 3

Data Collection, Processing and Analysis

This chapter describes the applications of weather and failure statistics used to analyze the raw transmission outage data, the weather exposure data, and present relevant summary data necessary for the applications of those reliability methodologies used to analyze adverse weather-related transmission line outages in the next chapter, the Monte Carlo simulation. Correlation studies were conducted to reveal the underlying statistical relationships between adverse weather conditions and transmission line outages.

3.1. Concepts of Data

The quantitative reliability evaluation invariably leads to a discussion of the data available and the data required to support such studies. Valid and useful data are expensive to collect, but it should be mentioned that in the long run it will be even more expensive not to collect them. (deregulated utilities are legislated to collect reliability performance data.)

Meaningful reliability evaluation requires reasonable and acceptable data. The data are not always easy to obtain (e.g., adverse weather and transmission line outage data). Although an unlimited amount of data can be collected, it is inefficient to collect, analyze and store more data than necessary for the purpose of evaluating power system reliability. It is, therefore, essential to identify how and for what purposes the data will be used. In deciding which data is needed, a utility must make its own decisions since no rigid rules are defined. Each utility is unique. The factors that must be identified are those that have an impact on a utility's own planning, design, and asset management policies.

The processing of the data acquisition includes two distinct stages. Field data are first obtained by documenting the details of failures and duration of the outage associated with utility component failures. These field data are then analyzed to create statistical indices. These indices are updated annually for utilities. The quality of data and, thus, the confidence that can be placed in it, are clearly dependent on the accuracy and completeness of the acquired information. The quality of the statistical indices is also dependent on how the data is processed, on how much pooling is done, and on the age of the data currently stored. These factors affect the results of both simulation and analytical studies.

A wide range of data can be collected and most utilities collect some, but not usually all, of these data in one form or another. There are many different data collection schemes around the world. It should be recognized that, although considerable similarities exist between different schemes, particularly in terms of concepts, considerable differences also exist, particularly in the details of the individual schemes. It was also concluded that no one scheme could be said to be the "right" scheme, just that they are different.

There are two main methods for collecting system data: the component approach and the unit approach. The unit approach is considered useful for assessing the chronological changes in reliability of existing systems, but it is less useful for the prediction assessment of future system performance, the effect of various alternative reinforcement schemes, and the reliability characteristics of individual pieces of equipment. The component approach is preferable in these cases and, therefore, data collected using this method is more convenient for such applications.

Other types of data, such as weather data, are collected specifically for the need of reliability analyses. The weather data can be collected according to the different geographical regions chronologically. The basic daily, monthly, and annual data series for each type of weather condition can then be constructed, along with the designated criteria for the adverse weather conditions. Adverse weather information can be extracted from the raw meteorological data, and the common statistics like frequency and duration probabilities of weather states can be calculated subsequently.

The transmission line outage database of ATCO Electric Limited covers the entire area of the Province of Alberta and defines the primary causes of transmission line outages, e.g., adverse weather, defective equipment, foreign interference, adverse environment, human element, systems conditions, and unknown. The Alberta provincial weather database of Atmospheric Environment Service, Environment Canada contains some of the following parameters: daily extreme temperature, daily highest wind speed, monthly lightning records, monthly precipitation records, etc. The monthly extreme weather statistics includes "Extreme Daily Snowfall(cm)", "Days with Precipitation greater than 10.0 mm", "Days with Freezing Rain/Drizzle", "Days with Thunderstorms", "Days with at Least 1 Hourly Wind Speed greater than 30 km/h", etc.

3.2. Transmission Line Outage Data from ATCO Electric Limited

The raw transmission outage data reported by ATCO Electric Limited for performing the failure statistics in the Alberta region is mainly for the voltage levels from 72kV to 240kV. The raw transmission outage database has the transmission failure records for three voltage levels (72kV, 144kV, 240kV) from January, 1977 to December, 1996. To obtain a clear scenario about the structure of the recorded utility outage, the format of the raw transmission failure record is illustrated in table 3-1.

The transmission outages are recorded chronologically according to different transmission components (e.g., Line, Circuit Breaker, Transformer or DC Station, etc.). The outage duration, affected line number, terminals at the end of the line, the voltage level (72kV, 144kV, 240kV), primary outage cause, and fault detail are specified. These raw outage records have to be categorized and statistically processed to get the summary needed for the later reliability evaluation methodologies.

An outage record database (Microsoft Access) has been constructed in order to perform the outage categorization and failure statistics. According to the Canadian Electricity Association transmission line database structure specification described in chapter 1 [1], the raw transmission line outage records are categorized. (See figure 3-1.)

	ALL TRANSMISSION COMPONENT OUTAGES - January, 1977 - December, 1996									
	OUTAGE			COMPONENT IDENTIFICATION					PRIMARY CAUSE	
Occurrence		Duration		Transmission Line			Component			
date	time	hours	min	Line #	from	to	type	kV	CEA primary cause	API description
770727	16:03	0	5	1	9	17	LINE	240	Adverse weather	lightning
810222	12:33	0	50	2	10	18	LINE	72	Adverse weather	wind
810406	02:45	8	15	3	11	19	LINE	144	Adverse weather	ice, wet snow, frost
810805	13:56	0	30	4	12	20	LINE	240	System condition	over voltage
810909	20:10	0	25	5	13	21	LINE	72	Human element	protection coor.
810910	03:00	4	45	6	14	22	LINE	72	Foreign interference	third party
810914	16:54	0	20	8	16	24	LINE	72	Defective equipment	equipment failure

Table 3-1 ATCO Electric Limited power transmission component outage data (from 1977-1996)

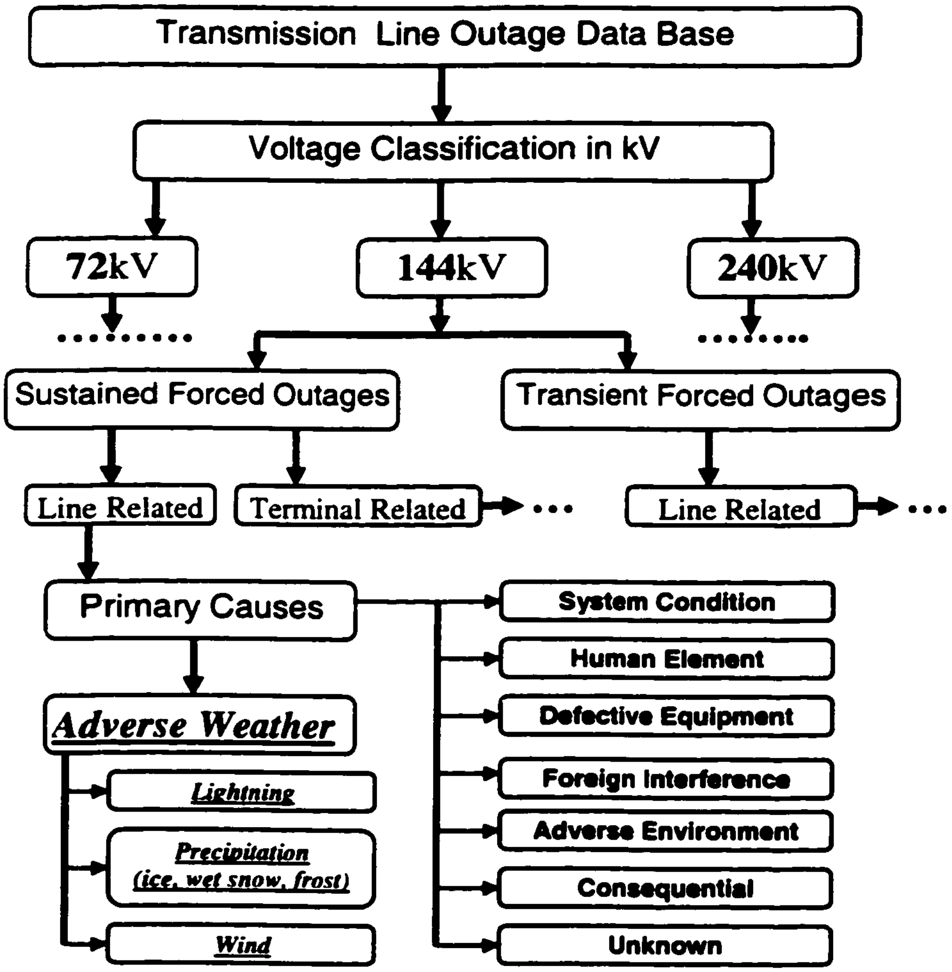

Figure 3-1 Alberta transmission line outage database structure

3.3. Outage Statistics for "Line-Related" Outages

3.3.1. Outage Statistics for Sustained "Line-Related" Outages

Outage types are categorized as transient or sustained, "line-related" or "terminal-related". In this thesis, the sustained "line-related" forced outages are considered to be the most serious type of outage. The percentage of transmission line "line-related" sustained forced outages classified according to the primary cause of forced outages and voltage class is shown in figure 3-2. The summary of transmission line failure statistics for "line-related" sustained forced outages is shown in table 3-2. Significant differences in statistics exist among the voltage classes.

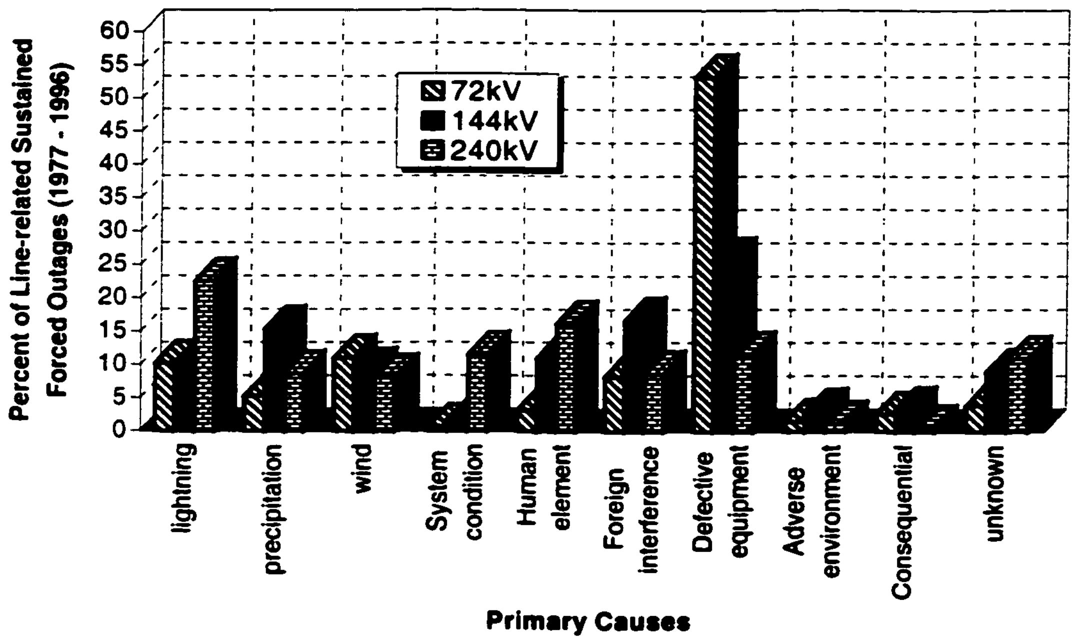

Figure 3-2 Percent of "line-related" sustained forced outages stratified by voltage level and primary cause (ATCO Electric Limited's transmission outage data 1977-1996)

Statistics	72kV	144kV	240kV
Kilometer Years (km.a)	39823.9	36018.3	19594.3
Number of Outages from 77-96	606	299	173
Total Duration Time for all Outages (h)	3048.9	1839.0	1799.4
Frequency per 100km.a	1.521699	0.830133	0.882908
Mean Duration (h)	5.03	6.15	10.40
Median Duration (h)	2.35	1.93	2.36

Table 3-2 Summary of "line-related" transmission line sustained forced outage statistics

The failure statistics focused on the frequency and duration analysis stratified by adverse weather-related primary cause and voltage class. The frequency of transmission line outages is the number of outages divided by kilometer years, and then divided by 100. The frequency analysis is stratified by the outage type and the voltage class. To conform to the CEA outage format, the underlying cumulative distribution functions of the duration of transmission line outage for the various causes and voltage levels were modeled as discrete distribution functions (shown in figures 3-3 to 3-14) based on 20 years (1977-1996) of field data. It is important to note that the duration of outages for the various primary causes associated with adverse weather varied significantly with the operating voltage level of the transmission line, emphasizing the need to categorize transmission lines by voltage levels instead of grouping them into a single category. The mean and median duration of transmission line sustained forced outages are summarized in tables 3-2 to 3-6. The outage duration analyses are classified by outage type, voltage class and primary cause.

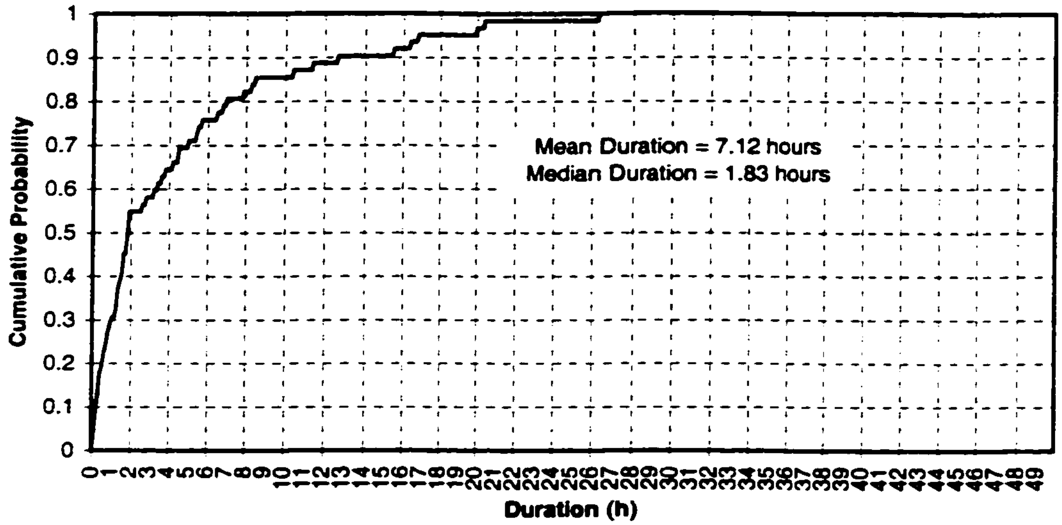

Figure 3-3 Cumulative probability of transmission line "line-related" sustained forced outage duration [72kV primary cause: Lightning]

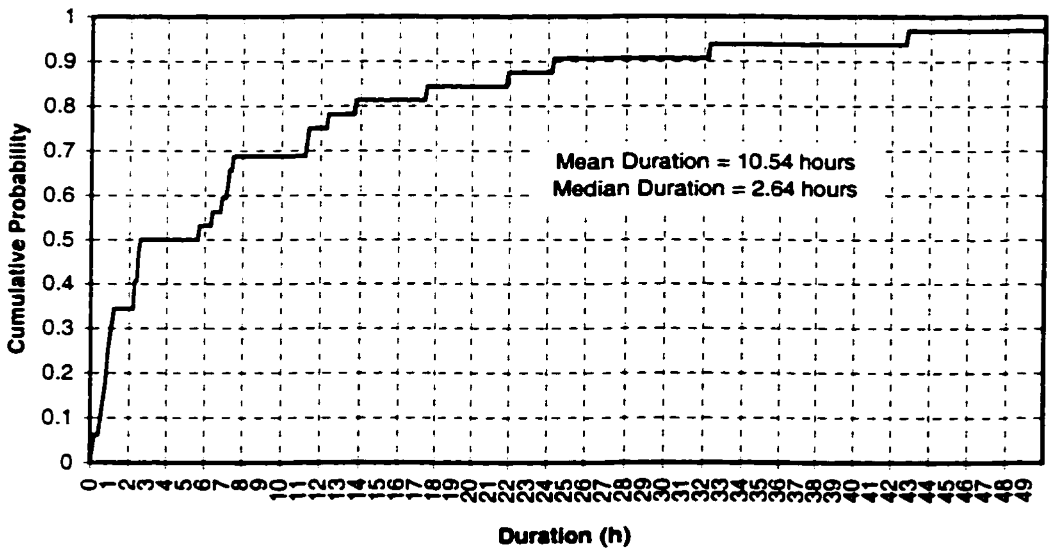

Figure 3-4 Cumulative probability of transmission line "line-related" sustained forced outage duration [72kV primary cause: Precipitation]

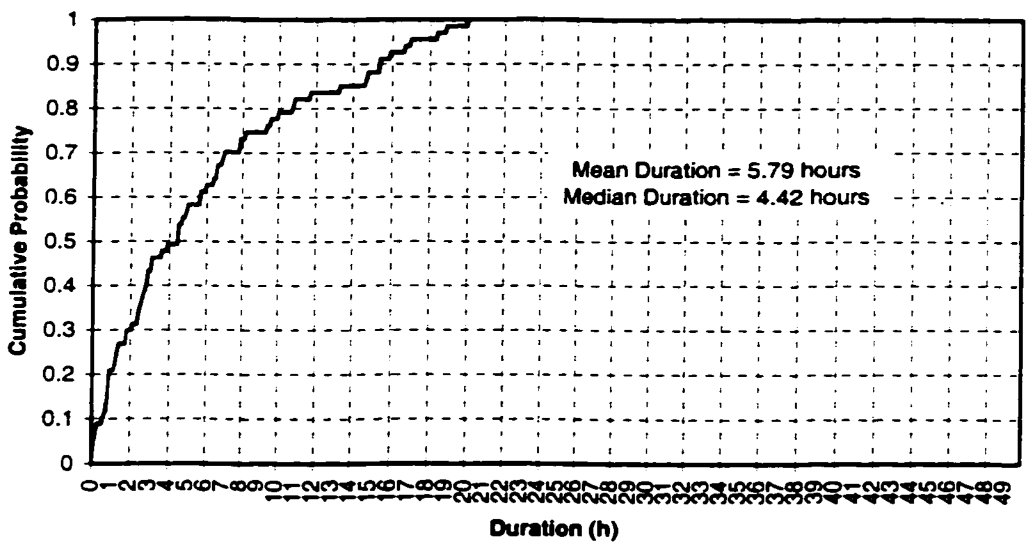

Figure 3-5 Cumulative probability of transmission line "line-related" sustained forced outage duration [72kV primary cause: Wind]

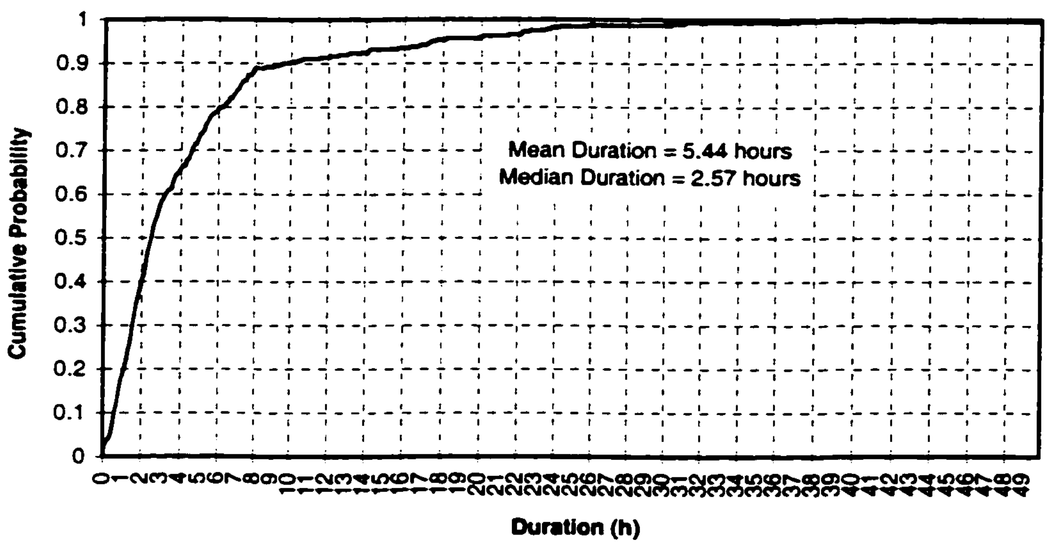

Figure 3-6 Cumulative probability of transmission line "line-related" sustained forced outage duration [72kV primary cause: Defective Equipment]

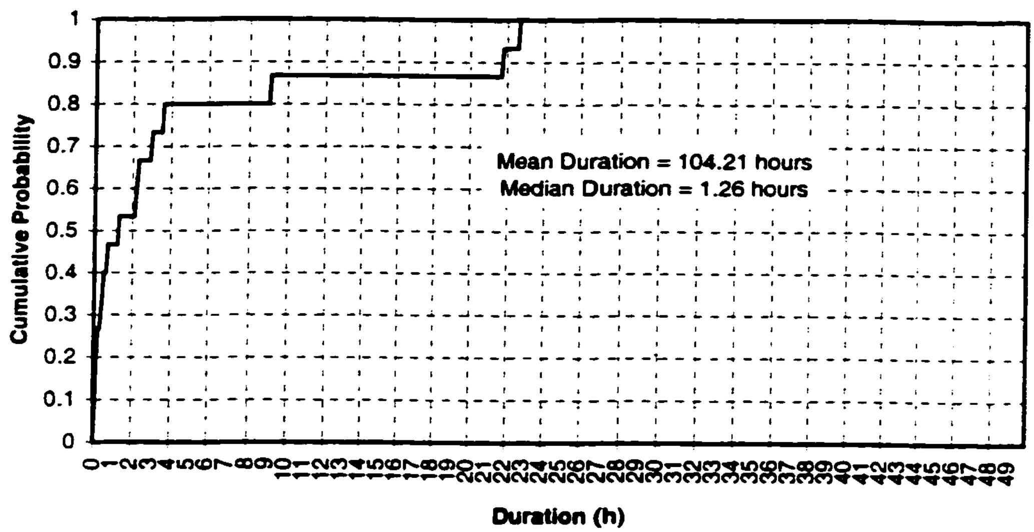

Figure 3-7 Cumulative probability of transmission line "line-related" sustained forced outage duration [144kV primary cause: Lightning]

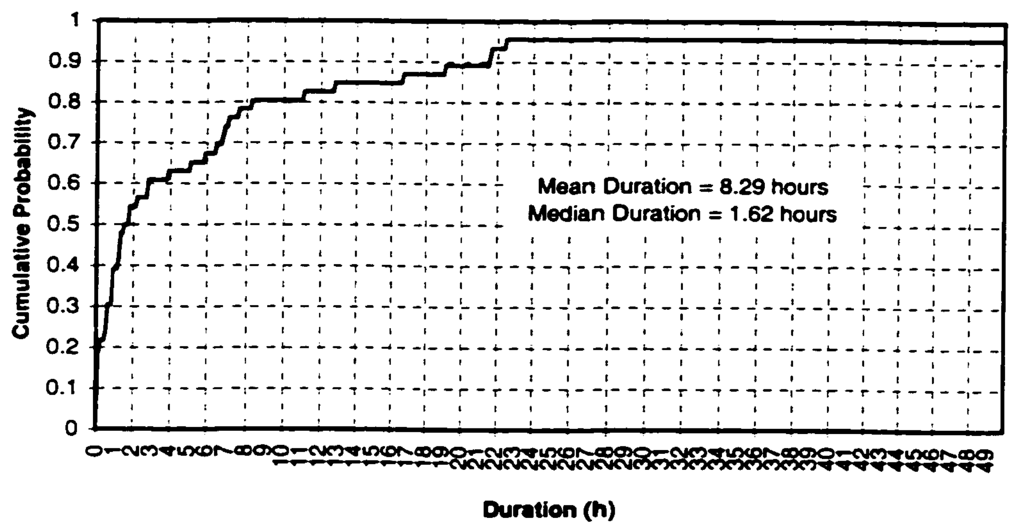

Figure 3-8 Cumulative probability of transmission line "line-related" sustained forced outage duration [144kV primary cause: Precipitation]

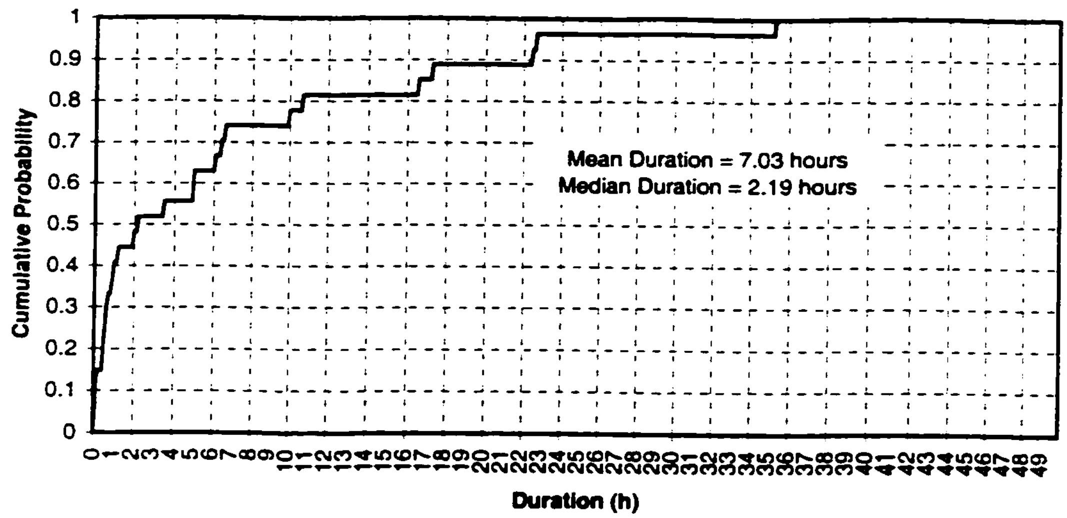

Figure 3-9 Cumulative probability of transmission line "line-related" sustained forced outage duration [144kV primary cause: Wind]

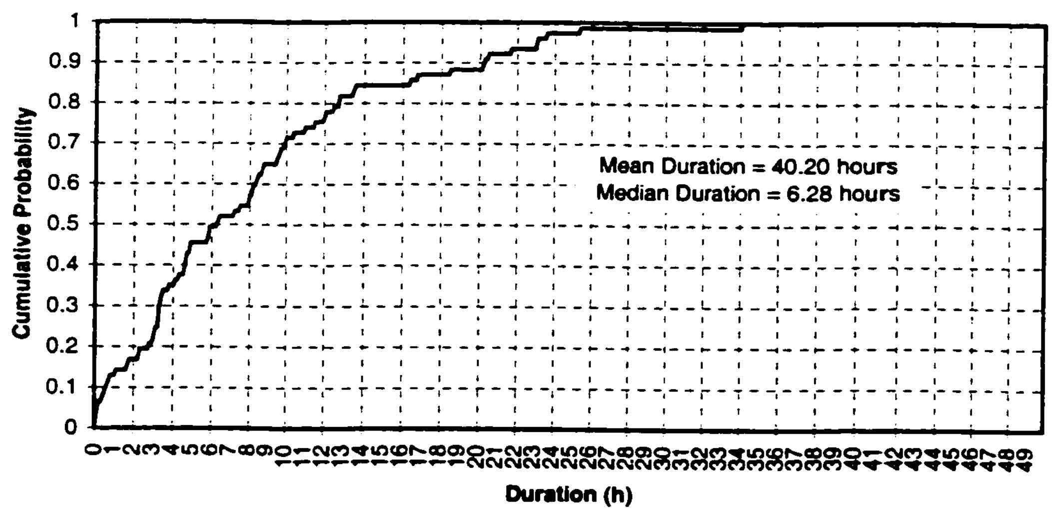

Figure 3-10 Cumulative probability of transmission line "line-related" sustained forced outage duration [144kV primary cause: Defective Equipment]

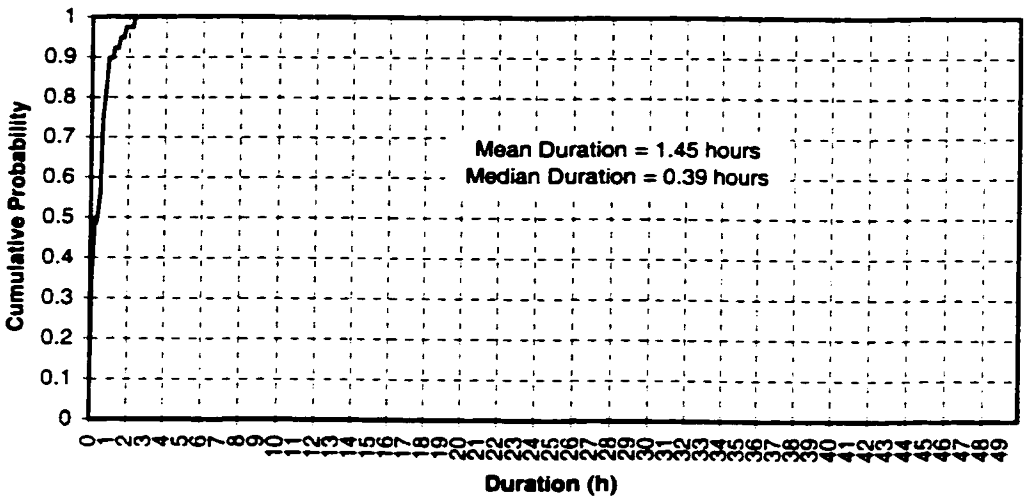

Figure 3-11 Cumulative probability of transmission line "line-related" sustained forced outage duration [240kV primary cause: Lightning]

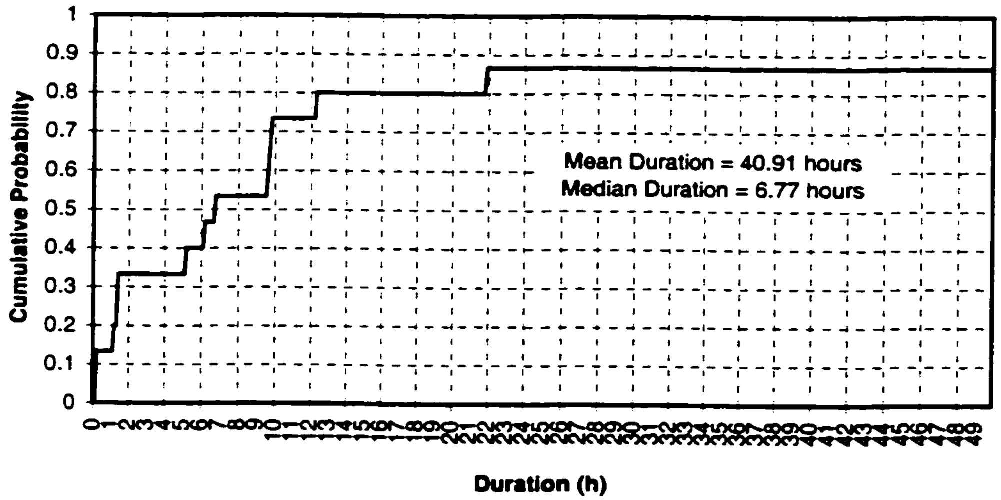

Figure 3-12 Cumulative probability of transmission line "line-related" sustained forced outage duration [240kV primary cause: Precipitation]

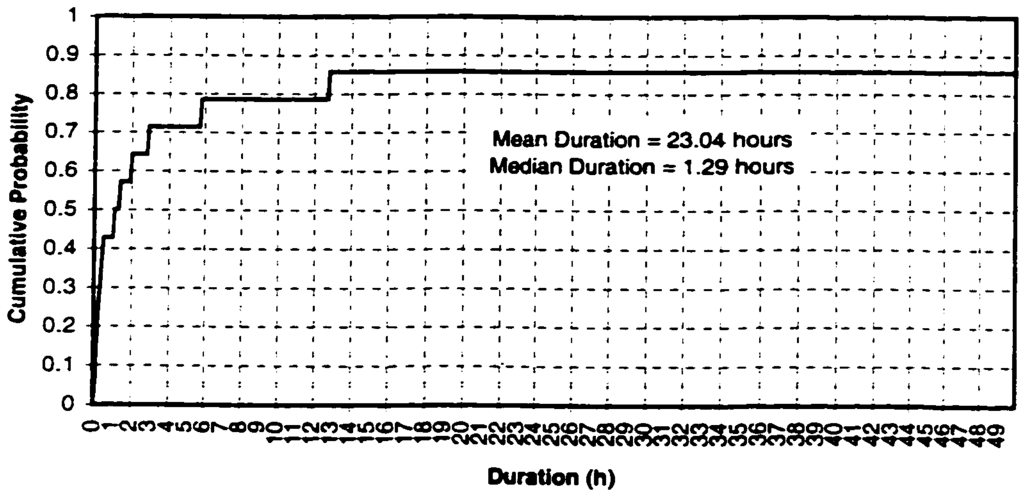

Figure 3-13 Cumulative probability of transmission line "line-related" sustained forced outage duration [240kV primary cause: Wind]

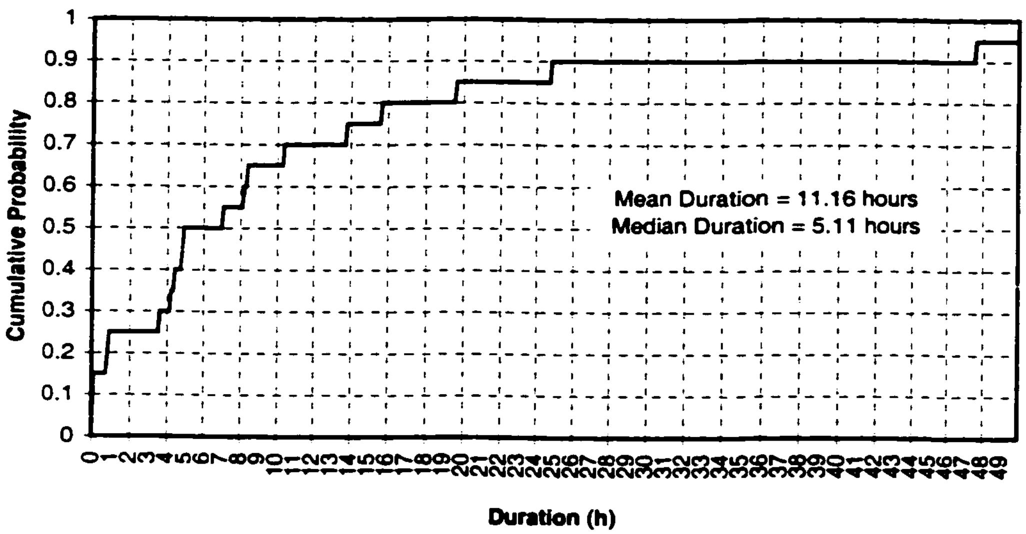

Figure 3-14 Cumulative probability of transmission line "line-related" sustained forced outage duration [240kV primary cause: Defective Equipment]

A transmission line outage summary based on 48 transmission lines from Alberta transmission system, sorted by the outage occurrences is shown in figure 3-15. The seasonal and monthly outage occurrence time series (for different adverse weather associated primary causes, figures 3-16 to 3-21) were constructed and used for correlation analysis between adverse weather variables and adverse weather-related transmission line outage occurrences.

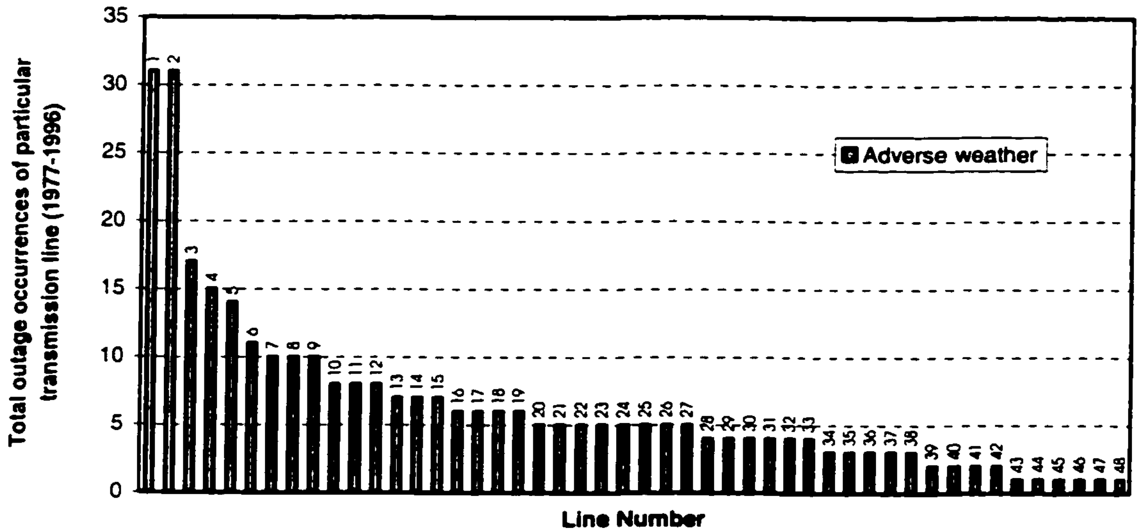

Figure 3-15 Summary of transmission lines affected by adverse weather-related outages

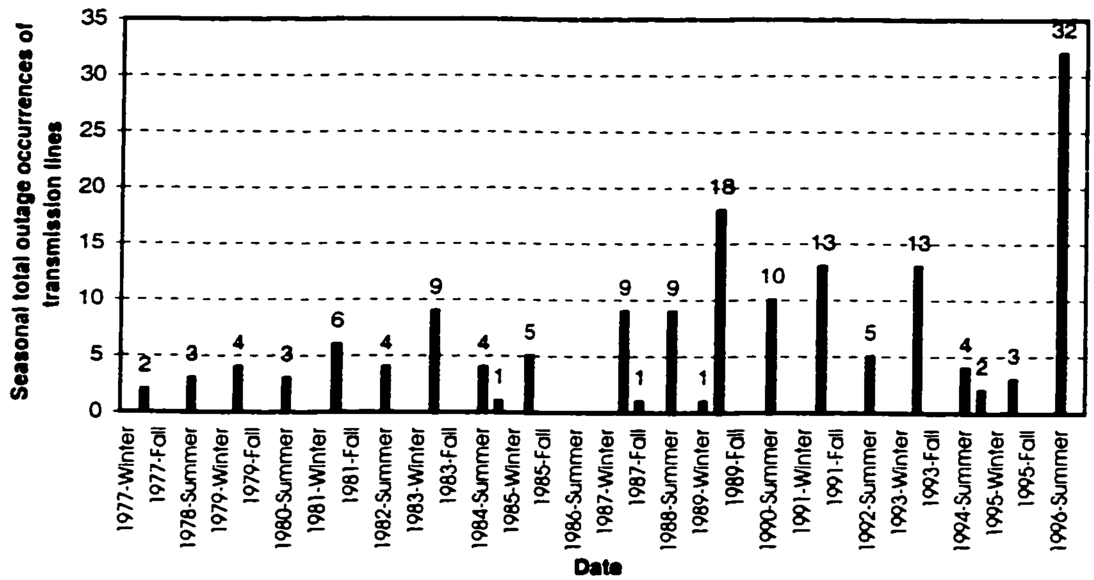

Figure 3-16 Seasonal total outage occurrences of transmission lines due to lightning (Seasonal time series 1977-1996)

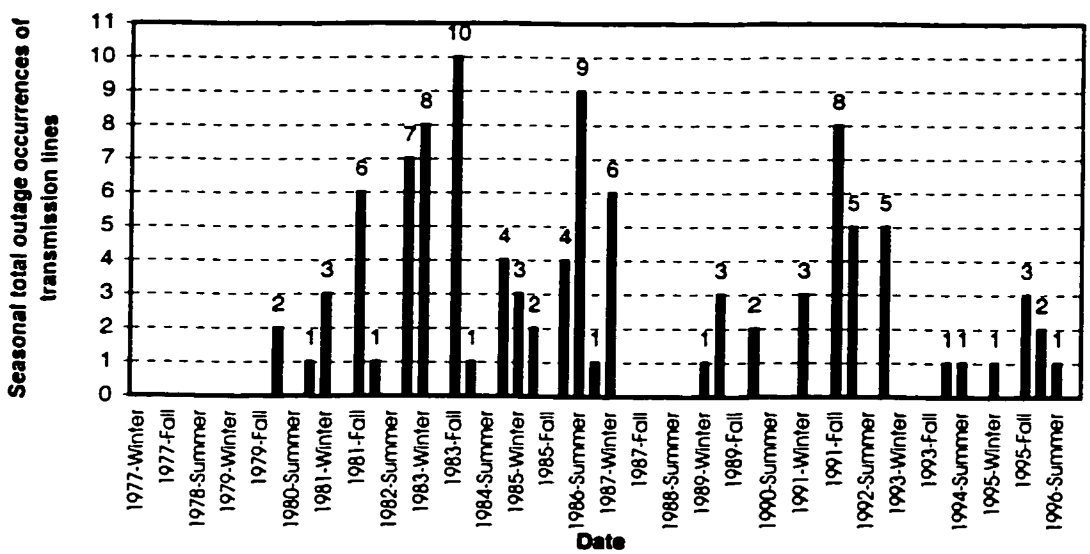

Figure 3-17 Seasonal total outage occurrences of transmission lines due to precipitation (ice, wet snow, frost, seasonal time series 1977-1996)

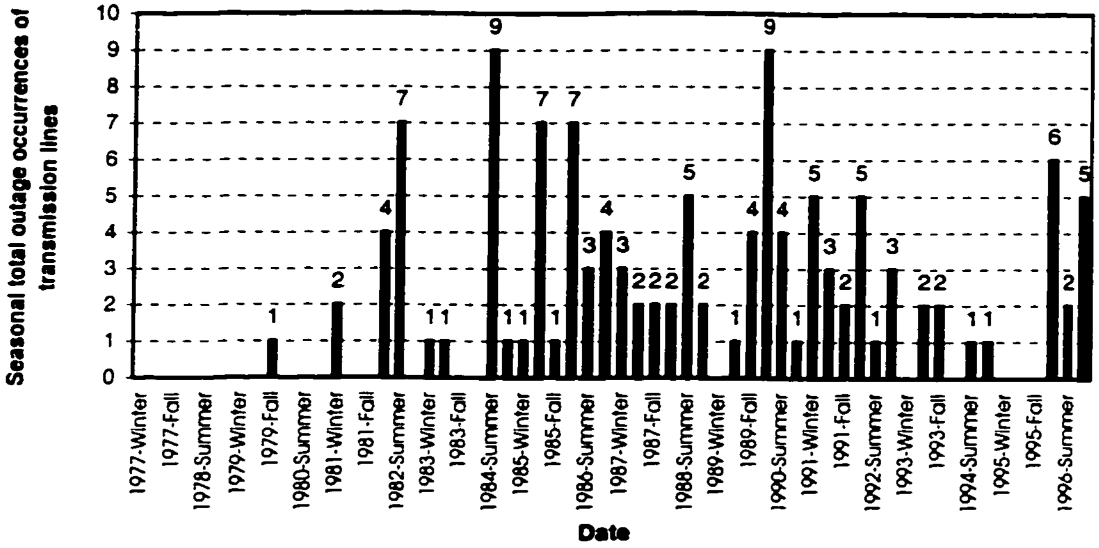

Figure 3-18 Seasonal total outage occurrences of transmission lines due to wind (Seasonal time series 1977-1996)

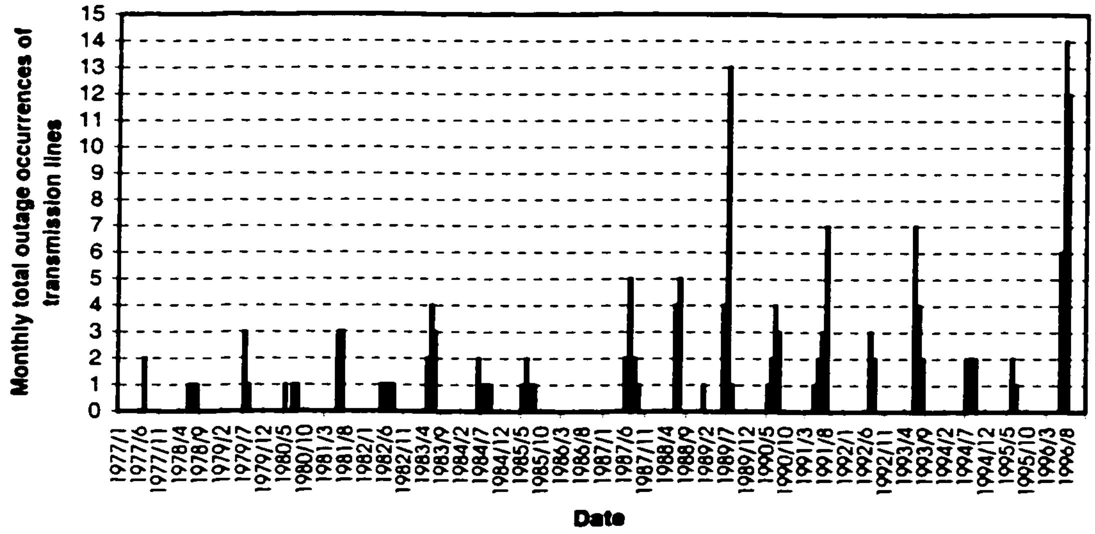

Figure 3-19 Monthly total outage occurrences of transmission lines due to lightning (Monthly time series 1977-1996)

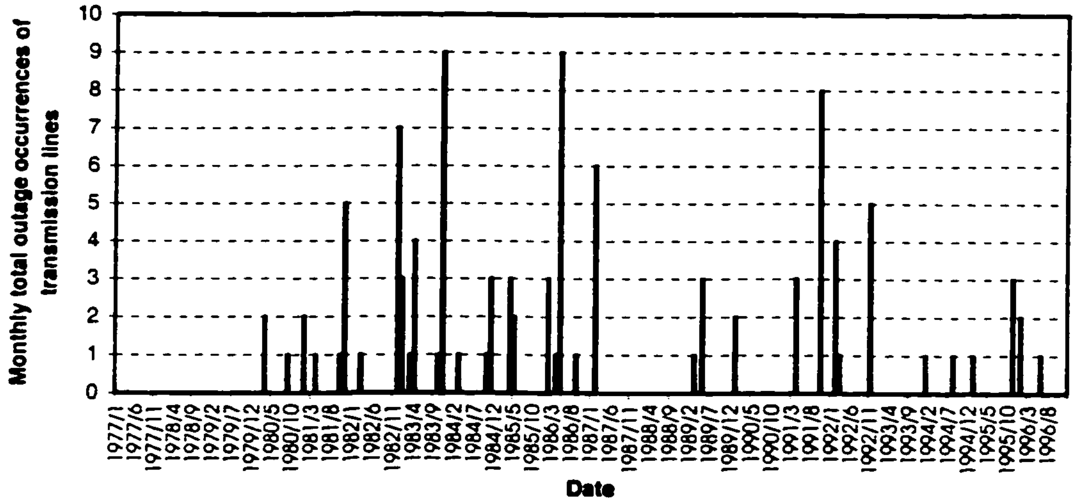

Figure 3-20 Monthly total outage occurrences of transmission lines due to precipitation (ice, wet snow, frost, Monthly time series 1977-1996)

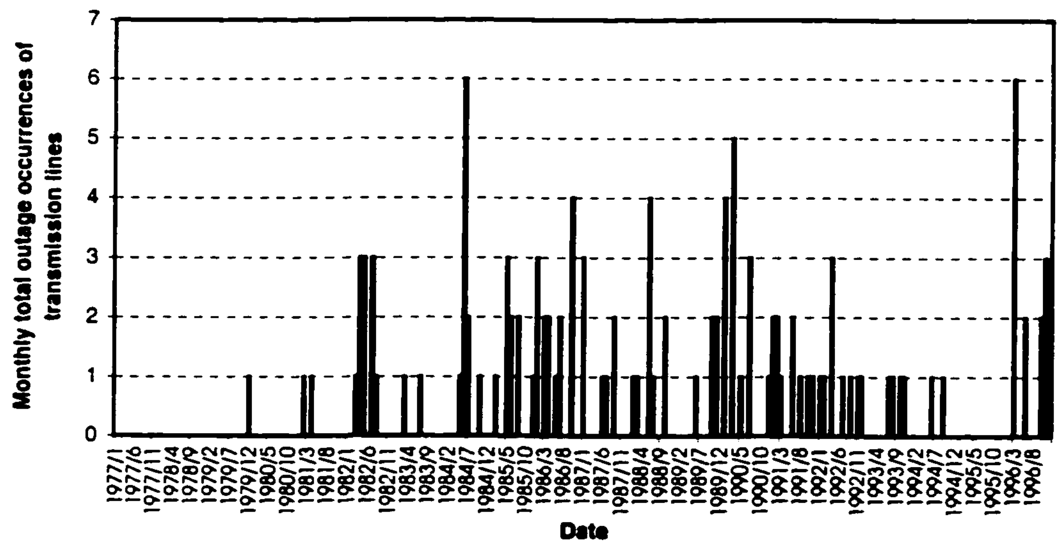

Figure 3-21 Monthly total outage occurrences of transmission lines due to wind (Monthly time series 1977-1996)

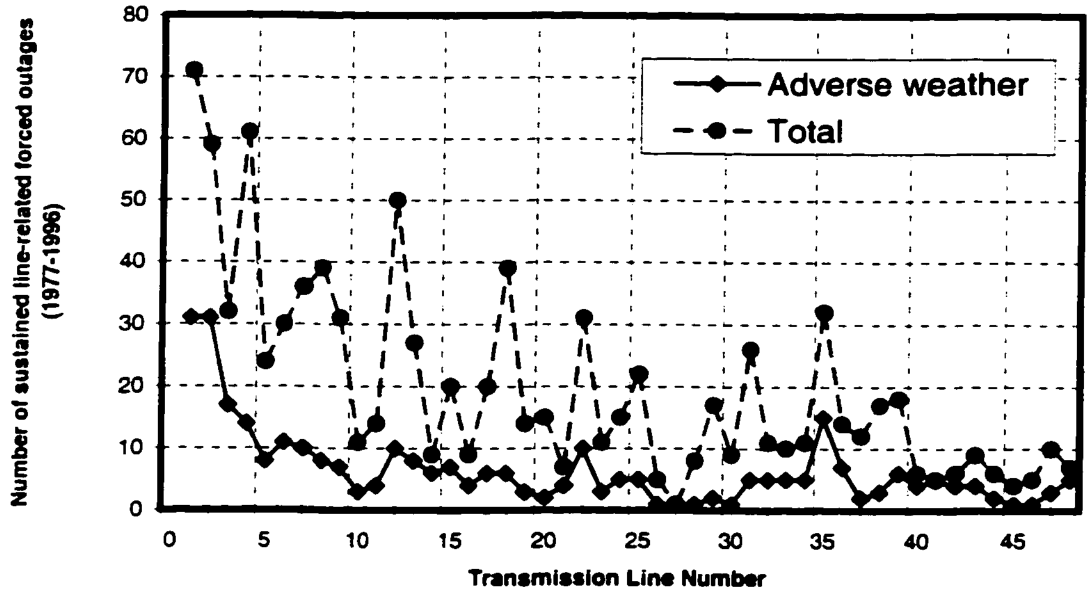

Figure 3-22 Frequency of adverse weather outages vs. total number of outages

Adverse weather conditions are mainly related to lightning, wind and precipitation. A major concern for utilities is the answer to the question: "Are adverse weather conditions a significant cause of transmission line outages in my electric delivery system?" The answer to this question is clearly shown in figures 3-2, and 3-22 where the frequency of sustained line-related outages is shown for all the ATCO Electric Limited transmission lines. When comparing the primary causes of outages, adverse weather outages are significant and account for approximately 33% of all outages as shown in figure 3-22.

The basic framework for a Monte Carlo simulation model of a transmission line network configuration is to have the probability density functions of the frequency and duration of individual transmission lines for various weather-related primary causes. In order to illustrate the significant differences among transmission line outage statistical patterns, the probability density functions of the failure rate of transmission line outages are expressed as relative frequency histograms and are shown in figures 3-23, 3-24 and 3-25:

1. Figure 3-23 – The primary cause is precipitation,
2. Figure 3-24 – The primary cause is wind, and
3. Figure 3-25 – The primary cause lightning.

For outage duration statistics, refer to the outage duration cumulative distributions stratified by voltage level and adverse weather-related primary cause summarized in the previous section.

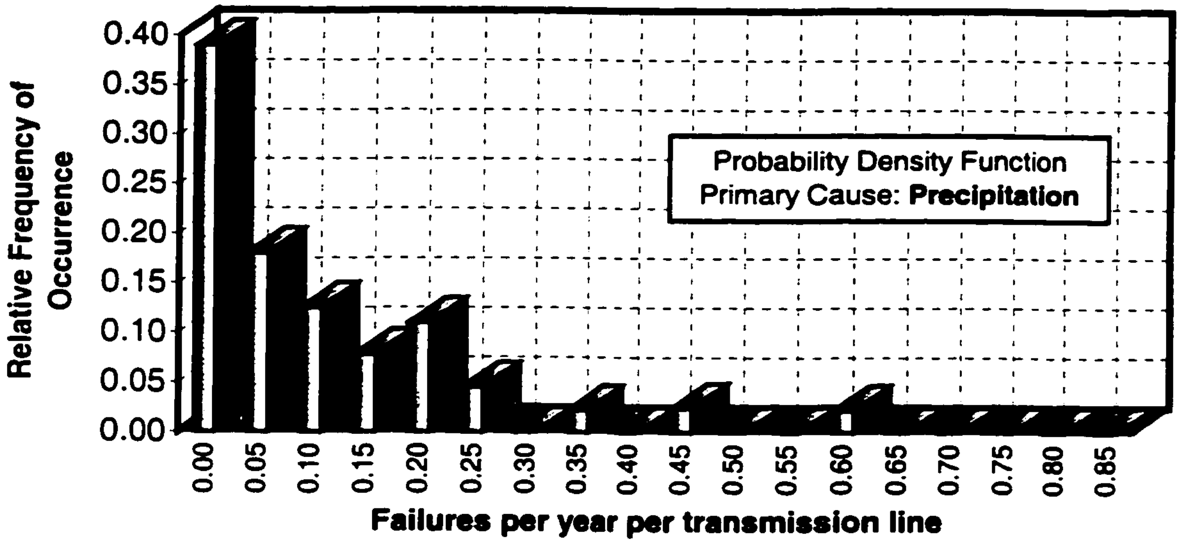

Figure 3-23 Relative frequency of outages when the primary cause is precipitation

The impact of lightning, wind and precipitation varies from one transmission line to another. A correlation analysis of the transmission line outage data revealed that the wind and precipitation related outages were not proportional to the physical length of the transmission line, however, lightning related outages were strongly correlated with the physical length of the transmission line.

The mean and median duration of transmission line "line-related" sustained forced outages caused by precipitation are shown in table 3-3.

Statistics	72kV	144kV	240kV
Mean Duration (hours)	10.54	8.29	40.91
Median Duration (hours)	2.64	1.62	6.77

Table 3-3 Duration of transmission line "line-related" sustained forced outage statistics where the primary cause is precipitation

The mean and median duration of transmission line outages caused by wind are shown in table 3-4. It is important to note that the median and mean duration of outages are significantly different, revealing that the underlying distribution of the duration of transmission lines is skewed and not symmetrical.

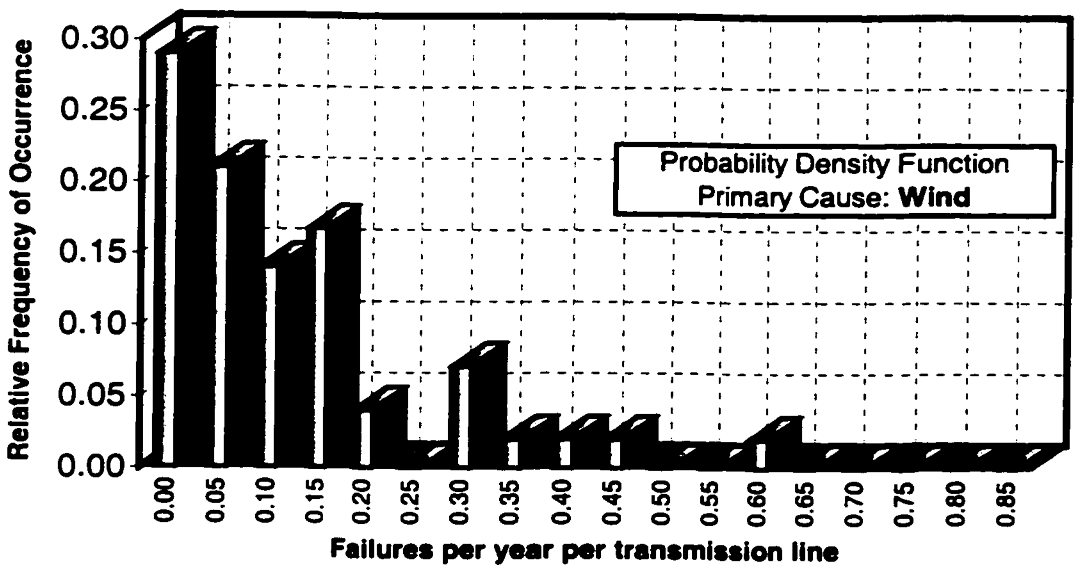

Figure 3-24 Relative frequency of outages when the primary cause is wind

Statistics	72kV	144kV	240kV
Mean Duration (hours)	5.79	7.03	23.04
Median Duration (hours)	4.42	2.19	1.29

Table 3-4 Duration of transmission line "line-related" sustained forced outage statistics where the primary cause is wind

The mean and median duration of transmission line "line-related" sustained forced outages caused by lightning are shown in table 3-5 and for defective equipment in table 3-6.

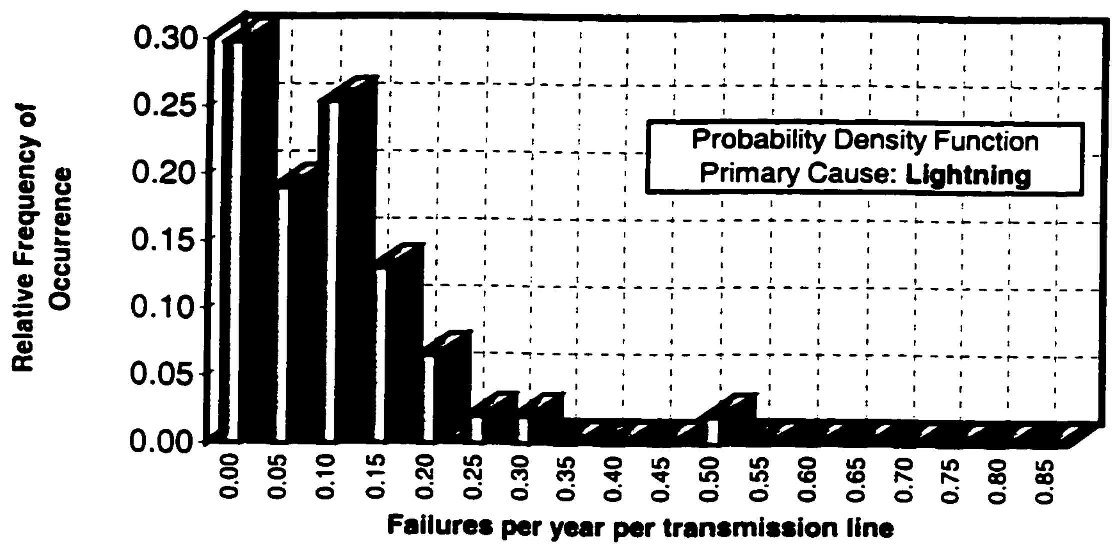

Figure 3-25 Relative frequency of outages when the primary cause is lightning

Statistics	72kV	144kV	240kV
Mean Duration (hours)	7.12	104.21	1.45
Median Duration (hours)	1.83	1.26	0.39

Table 3-5 Duration of transmission line "line-related" sustained forced outage statistics where the primary cause is lightning

Statistics	72kV	144kV	240kV
Mean Duration (hours)	5.42	40.20	11.16
Median Duration (hours)	2.57	6.28	5.11

Table 3-6 Duration of transmission line "line-related" sustained forced outage statistics where the primary cause is defective equipment

It is important to note that for all the primary causes of adverse weather, the duration of transmission line outage statistics varied significantly. The mean value and the median value were significantly different. This implies the underlying statistical distributions for the duration of outages are not symmetric and are skewed toward right. This skewness significantly impacts the mean value which is often used in reliability modeling of transmission lines.

The Province of Alberta was divided into four distinctive geographical regions. The percentage of transmission line outages by geographical region is shown in figure 3-26.

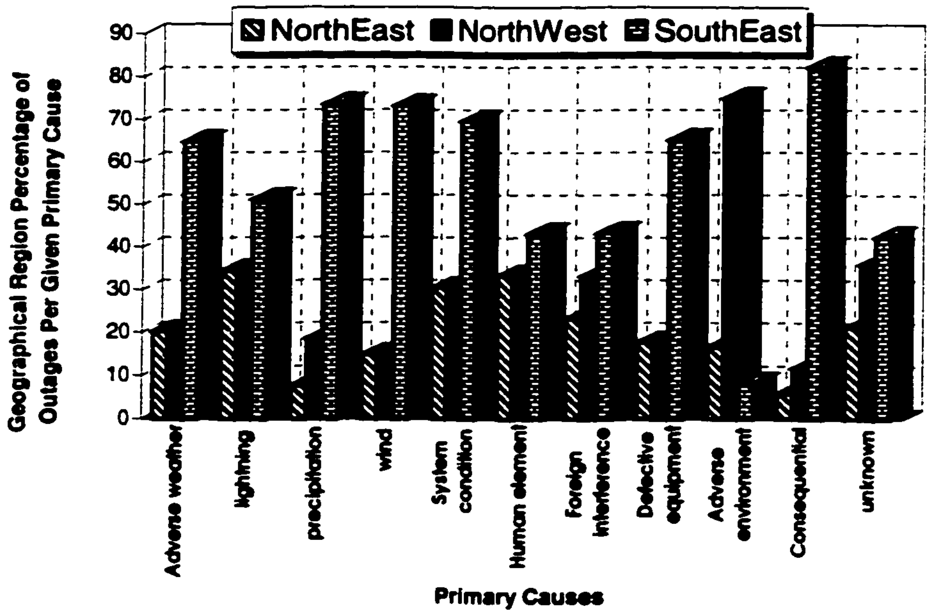

Figure 3-26 Percent of transmission line outages by geographical region for a given primary cause

It is clear from figure 3-26 that most of the transmission line outages occurred in the Southeast region of the Province (i.e., 56.2%), while the Northwest region accounted for 36.9% of the transmission line outages and the Northeast region only 6.9%. The Southwest region of the Province has very few major transmission lines and was not considered in this study.

3.3.2. Outage Statistics for Transient "Line-Related" Outages

The frequency analysis results (stratified by transmission line voltage level) of transmission line transient "line-related" forced outages caused by adverse weather is shown in table 3-7. The major primary cause of transient "line-related" forced outages is lightning for all voltage levels (i.e., 72kV, 144kV, 240kV) as shown in figure 3-27.

Statistics	72kV	144kV	240kV
Kilometer Years(km.a)	39823.9	36018.3	19594.3
Number of Outages from 77-96	18	26	13
Frequency per 100km.a	0.045199	0.072186	0.066346

Table 3-7 Summary of "line-related" transmission line transient forced outage statistics

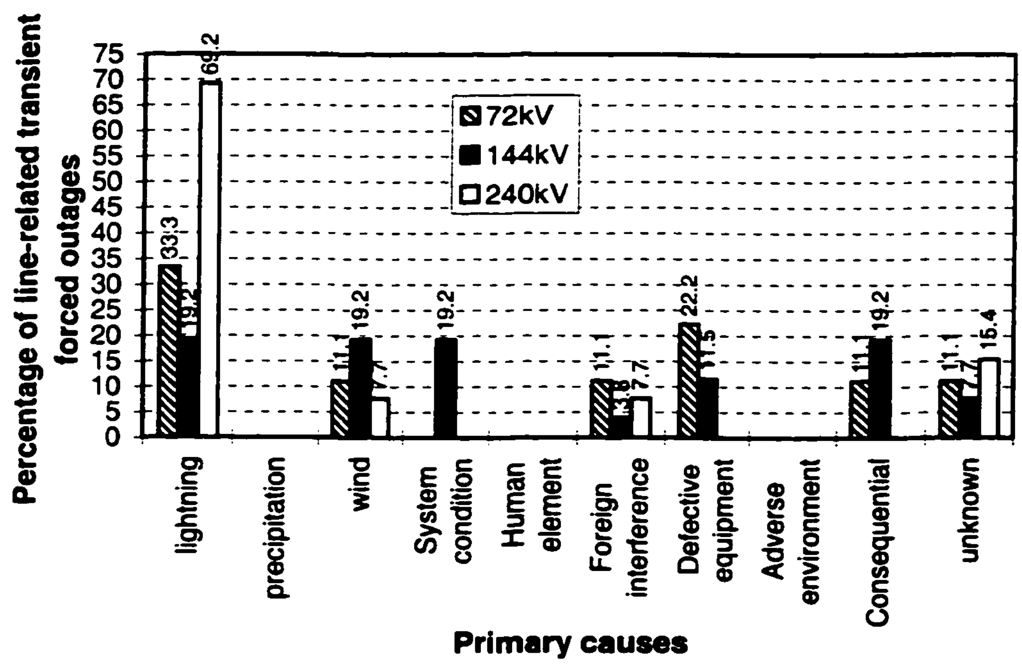

Figure 3-27 Percent of "line-related" transient forced outages stratified by voltage level and primary cause (Alberta transmission outage data 1977-1996)

3.4. Outage Statistics for Sustained "Terminal-Related" Outages

The mean and median duration of transmission line "terminal-related" sustained forced outages caused by adverse weather is shown in table 3-8. Human element and defective equipment account for approximately 70% of "terminal-related sustained" forced outages for 72kV and 240kV voltage levels and approximately 60% for 144kV voltage level (figure 3-28). It is noted that few "terminal-related" outages were caused by adverse weather.

Statistics	72kV	144kV	240kV
Number of Outages from 77-96	180	440	229
Total Duration Time for all Outages (h)	2096.8	5306.4	1493.1
Frequency of Outages (outages per year)	9.0	22.0	11.45
Median Duration (h)	5.22	1.56	3.51
Mean Duration (h)	11.64	12.06	6.52

Table 3-8 Summary of transmission line for "terminal-related" sustained forced outage statistics

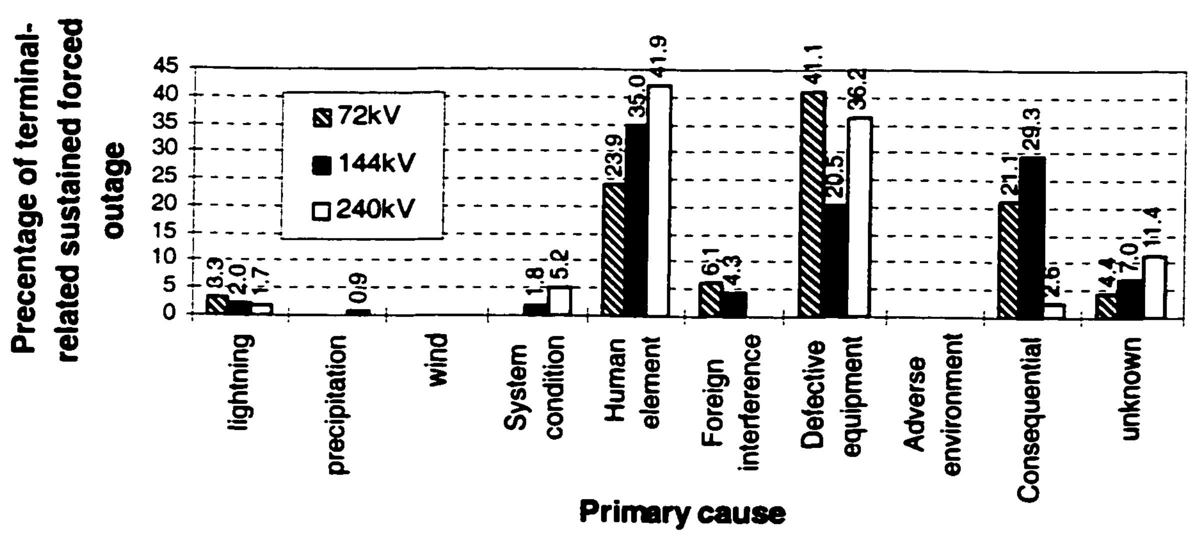

Figure 3-28 Percent of "terminal-related" sustained forced outages stratified by voltage level and primary cause (Alberta transmission outage data 1977-1996)

3.5. Adverse Weather Statistics

An adverse weather statistical analysis was conducted in order to identify Alberta geographical climate patterns and the seasonal sensitivities of adverse weather variables. The analytical results were utilized in correlation analysis between adverse weather variables and transmission line outage data. In this section, regional statistical summaries of adverse weather variables are presented as monthly uniform averages (arithmetic means of the reference period 1961-1990) over the available climate stations in three distinctive geographical areas of the Province of Alberta: Northeast, Northwest, and Southeast regions. The Southwest region of the Province has very few major transmission lines and was not considered in this study.

A Microsoft Access database was constructed to store and process Alberta weather data. All the weather data were collected from the Atmospheric Environment Service, Environment Canada over the time period 1961 to 1993. An example of the monthly weather data format is shown in table 3-9. Data from 183 climate stations in Alberta were selected for adverse weather data analysis. The selection of climate stations represents a reasonable cross-section of the climate stations over the Province of Alberta.

Seven monthly adverse (or extreme) weather variables were selected for analyzing adverse weather patterns:

1) Extreme Daily Snowfall (cm),
2) Extreme Daily Precipitation (mm),
3) Days with Snowfall greater than 10.0 cm,

4) Days with Precipitation greater than 10.0 mm,

5) Days with Freezing Rain/Drizzle,

6) Days with Thunderstorms, and

7) Days with at Least 1 Hourly Wind Speed greater than 30 km/h.

The geographical adverse weather patterns (shown in figures 3-29 to 3-35) can be compared with the geographical statistical patterns of outage presented in the previous section (figure 3-26) in order to detect the geographical dependencies on adverse weather related outages. The seasonal sensitivities of adverse weather variables can be used to determine what time series of adverse weather variables should be used for correlation studies between the adverse weather variables and adverse weather-related transmission line outage.

EDMONTON INT'L A		3012205					
January – December		1990					
	Mean Max Temp (øC)	Mean Min Temp (øC)	Mean Temp (øC)	Total Rainfall (mm)	Total Snowfall (cm)	Total Pcpn (mm)	Median SOG (cm)
Jan-90	-3.4	-13	-8.2	Trace	16.4	13.6	3
Feb-90	-4.6	-17.3	-11	0	15.7	15.7	11
Mar-90	5.1	-6	-0.5	2.2	16.4	18.3	3
Apr-90	9.6	-1.4	4.1	49.2	11.4	61	0
May-90	17.4	3.7	10.6	48.9	4.8	53.7	0
Jun-90	20.7	8.6	14.7	63.8	0	63.8	0
Jul-90	22.3	10.5	16.4	149.3	0	149.3	0
Aug-90	22.7	9.6	16.2	64.2	0	64.2	0
Sep-90	20.7	5.3	13	4.2	0	4.2	0
Oct-90	8.7	-3.4	2.7	1.6	21.8	21.3	0
Nov-90	-2.1	-13.1	-7.6	Trace	27.6	26.8	7
Dec-90	-8.3	-20.4	-14.4	Trace	27.2	22.4	14

Table 3-9 The format of the monthly summary in the AES daily data CD

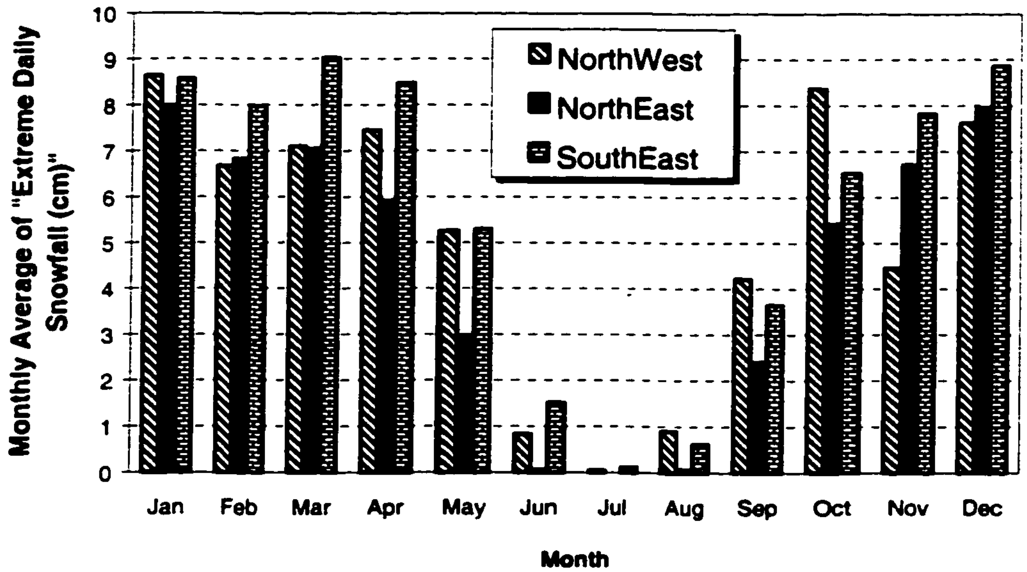

Figure 3-29 Monthly average of "Extreme Daily Snowfall (cm)" stratified by geographical region (Average reference period 1961-1990)

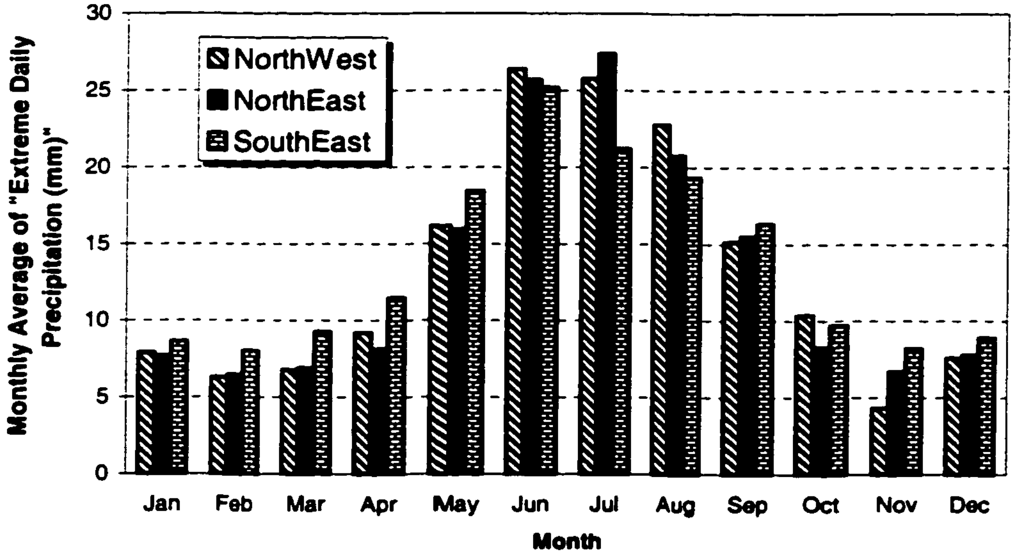

Figure 3-30 Monthly average of "Extreme Daily Precipitation (mm)" stratified by geographical region (Average reference period 1961-1990)

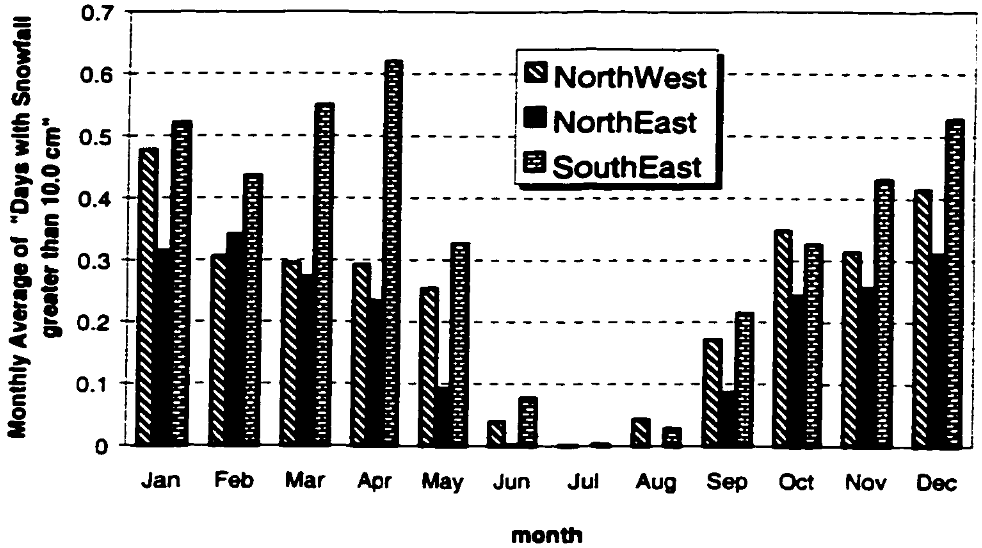

Figure 3-31 Monthly average of "Days with Snowfall greater than 10.0 cm" stratified by geographical region (Average reference period 1961-1990)

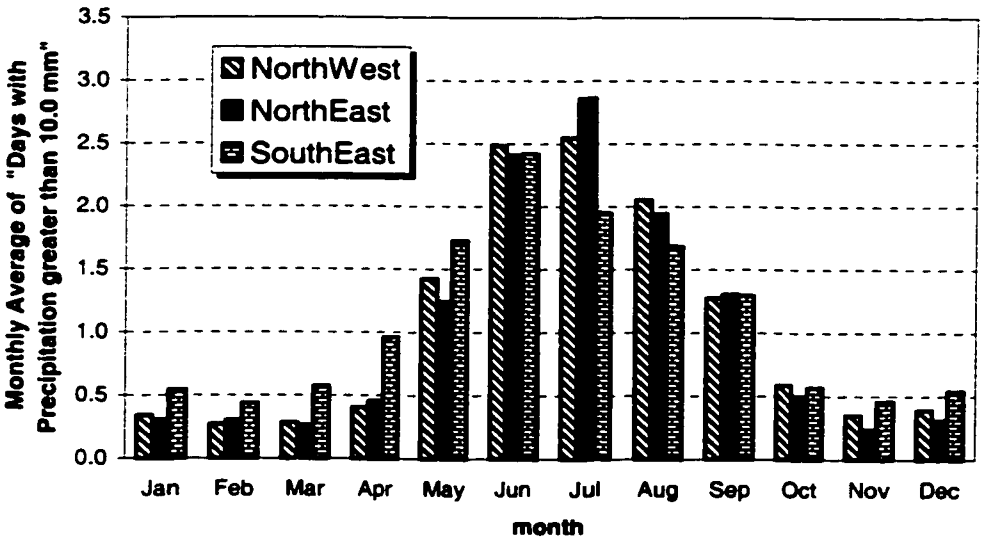

Figure 3-32 Monthly average of "Days with Precipitation greater than 10.0 mm" stratified by geographical region (Average reference period 1961-1990)

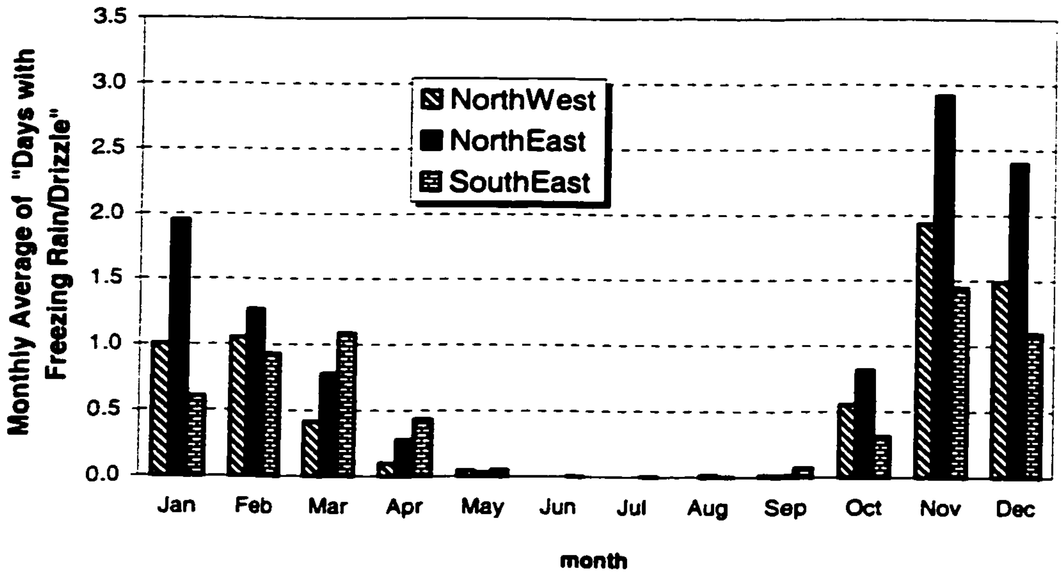

Figure 3-33 Monthly average of "Days with Freezing Rain/Drizzle" stratified by geographical region (Average reference period 1961-1990)

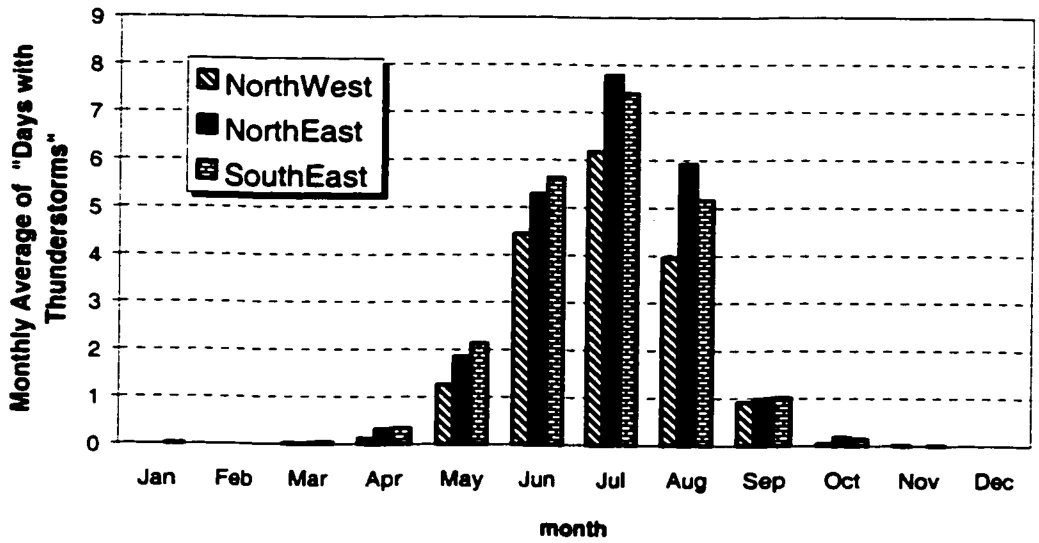

Figure 3-34 Monthly average of "Days with Thunderstorms" stratified by geographical region (Average reference period 1961-1990)

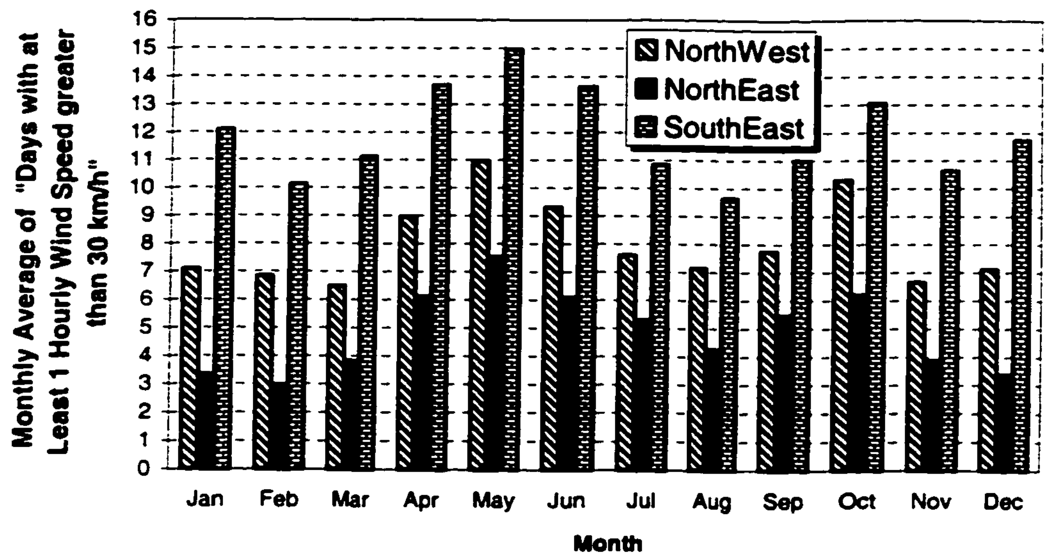

Figure 3-35 Monthly average of "Days with at Least 1 Hourly Wind Speed greater than 30 km/h" stratified by geographical region (Average reference period 1961-1990)

It is noted that averages of adverse weather variables "Extreme Daily Snowfall (cm)", "Days with Snowfall greater than 10.0cm", and "Days with at Least 1 Hourly Wind Speed greater than 30 km/h" are the highest in the Southeast geographical area of Alberta where adverse weather conditions cause much more transmission line outages than in the other geographical areas.

3.6. Adverse Weather vs. Transmission Line Outage Correlation Analysis

Various correlation studies were conducted to find the statistical correlation between adverse weather variables and transmission line outage data. The annual time series of adverse weather variables and transmission line outage data (stratified by primary cause and voltage level) were constructed for correlation analysis over the period 1977 to 1992, where both weather and outage data were available.

Due to the strong seasonal dependence of thunderstorm and snowfall adverse weather variables (shown in figures 3-29 to 3-35), the annual value of those adverse weather variables in time series was obtained by using the monthly average of the variable over the seasonal period (e.g., Summer: May-August, Winter: September-April). See figures 3-36 to 3-37 for thunderstorm and snowfall adverse weather variable time series. The annual value of the wind adverse weather variable time series was obtained by using the variable monthly average over January to December. (See figure 3-38.)

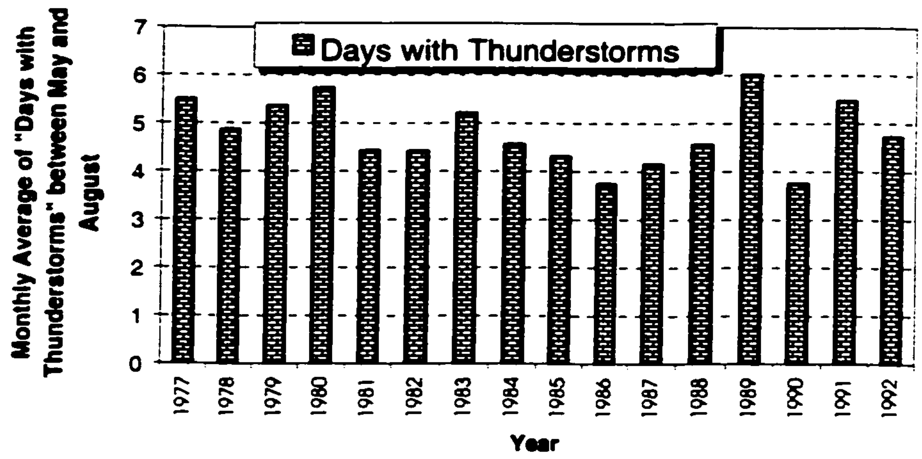

Figure 3-36 Annually based time series of "Days with Thunderstorms" with annual value obtained by using the monthly average value between May and August

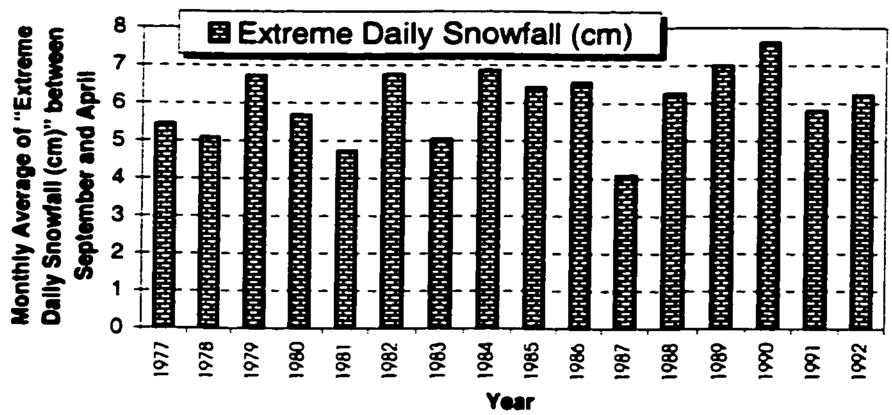

Figure 3-37 Annually based time series of "Extreme Daily Snowfall (cm)" with annual value obtained by using the monthly average value between September and April

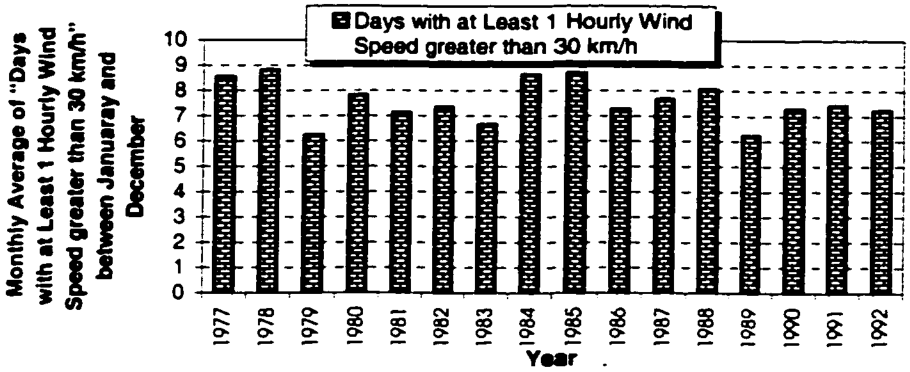

Figure 3-38 Annually based time series of "Days with at Least 1 Hourly Wind Speed greater than 30 km/h" with annual value obtained by using the monthly average value between January and December

The correlation analysis results were summarized in tables 3-10, 3-11 and figure 3-39. A strong correlation exists between summer (May-August) monthly average "Days with Thunderstorms" and overall lightning-related transmission line outage frequency. Elevated levels of the 144kV transmission line outage frequency were most strongly associated with the summer (May-August) thunderstorm adverse weather activities as shown in table 3-10.

Correlation Coefficient	Annual frequency of total Lightning related outages	Annual frequency of Lightning related outages (72kV lines)	Annual frequency of Lightning related outages (144kV lines)	Annual frequency of Lightning related outages (240kV lines)
Annual monthly average of "Days with Thunderstorms" between May-August	0.31	0.16	0.45	0.11

Table 3-10 Statistical correlation between annual summer monthly average of "Days with Thunderstorms" adverse weather variable and lightning-related transmission line outage frequency stratified by voltage level (summer period: May-August in 1977-1992)

Precipitation-related outage frequency of 240kV transmission lines is strongly correlated with winter (September-April) monthly averages of four precipitation adverse weather variables: "Extreme Daily Snowfall (cm)", "Extreme Daily Precipitation (mm)", "Days with Snowfall greater than 10.0 cm", and "Days with Precipitation greater than 10.0 mm". The adverse snowfall weather condition indicated by the winter (September-April) monthly average of "Days with Snowfall greater than 10.0 cm" has a significant impact on the precipitation-related outage frequency of 72kV transmission lines (figure 3-39).

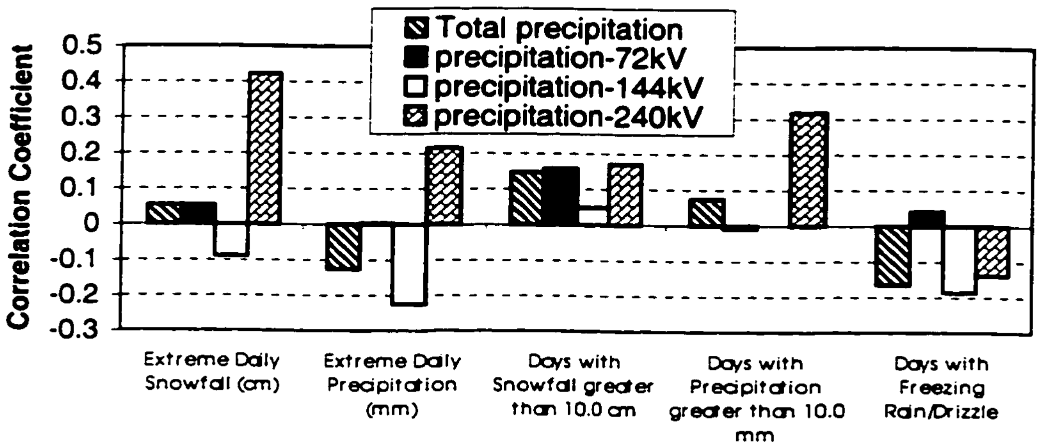

Figure 3-39 Statistical correlation between annual winter monthly average of precipitation adverse weather variables and precipitation-related transmission line outage frequency stratified by voltage level (winter period: September-April in 1977-1992)

The correlation analysis also revealed that the monthly average (January-December) of "Days with at Least 1 Hourly Wind Speed greater than 30 km/h" adverse weather variable was a little proportional to the wind-related 144kV transmission line outage frequency as shown in table 3-11.

Correlation Coefficient	Annual frequency of total Wind related outages	Annual frequency of Wind related outages (72kV lines)	Annual frequency of Wind related outages (144kV lines)	Annual frequency of Wind related outages (240kV lines)
Annual monthly average of "Days with at Least 1 Hourly Wind Speed greater than 30 km/h" between January –December	0.02	-0.02	0.16	-0.03

Table 3-11 Statistical correlation between annual monthly average of "Days with at Least 1 Hourly Wind Speed greater than 30 km/h" adverse weather variable and wind-related transmission line outage frequency by voltage level (1977-1992)

Chapter 4

Monte Carlo Simulation

4.1. Introduction

The Monte Carlo method is the general designation for stochastic simulation using random numbers. Monte Carlo is the name of the suburb in Monaco made famous by its gambling casino. The name was also used as the secret code for atomic bomb work performed during World War II involving random simulation of the neutron diffusion process. Monte Carlo methods have been used in many areas since that time.

The basic concept of the Monte Carlo method dates back to the 18^{th} century when the French scientist Buffon presented the famous needle throw test method to calculate π in 1777. The method is as follows. A needle of length d is thrown randomly onto a plane on which some parallel lines with equal width a have been drawn, where $d<a$. It can be shown that the probability of the needle hitting the line is $P = 2d/\pi a$. Since the probability can be estimated as the ratio of the number of throws hitting a line to the total number of throws, the value of π can be obtained by $\pi = 2d/Pa$. This is the earliest and most interesting example of using the Monte Carlo method.

The example indicates that the Monte Carlo method can be used to solve not only stochastic but also deterministic problems. Applications of Monte Carlo techniques can be found in many fields, such as complex mathematical calculations, stochastic process simulation like power transmission system state transition and weather state transition, medical statistics, engineering system analysis, and reliability evaluation.

In this chapter, the basic concepts of the Monte Carlo method are presented and discussed from the reliability evaluation point of view. Adverse weather-related power transmission line reliability evaluation using Monte Carlo simulation will be illustrated, and the results of a simulation case study on a local Alberta transmission network will be presented.

4.2. Monte Carlo : General Concepts

4.2.1. Two Simple Examples

Two simple examples are presented to illustrate the basic concepts of the Monte Carlo method.

Example 1: A fair die is thrown. What is the probability of an "one" occurring on the upper face? Obviously, this probability is ***1/6*** as each of the six faces has equal probabilities of happening. This probability can be estimated by sampling simulation. Throw the die N times, and record the times of an "one" occurring. Let this be f times. The estimation of the probability is f/N. As N increases sufficiently, f/N approaches ***1/6***.

Example 2: Calculate the following integral by sampling simulation:

$$I = \int_0^1 g(x)dx$$

It is well known that the integral equals the area under curve $y = g(x)$ as shown in figure 4-1. A point is thrown randomly N times and the number of points hitting the shaded area ($0 \leq x \leq 1,\ 0 \leq y \leq 1$) is M. The integral is therefore equal to the probability of the point hitting the shaded area, i.e.,

$$I = p \approx M/N$$

The sampling simulation can be performed on a computer. Two uniformly distributed random numbers x_i and y_i between $[0, 1]$ can be generated and checked to see if the inequality $y_i \leq g(x_i)$ is satisfied or not to obtain M . The most basic aspect of Monte Carlo simulation is the generation of random numbers.

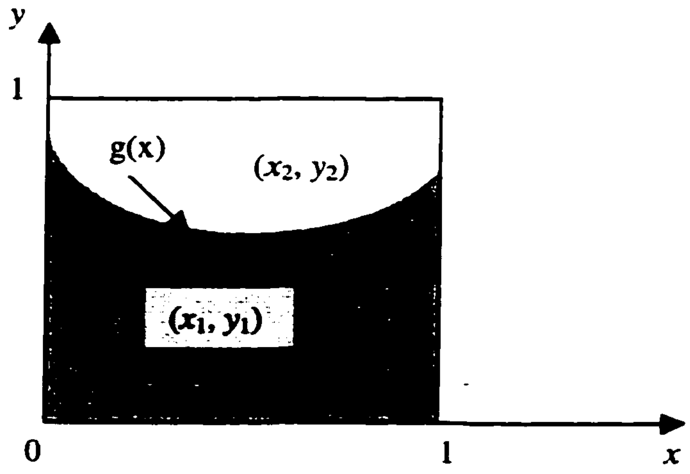

Figure 4-1 One-dimension integral by Monte Carlo simulation

4.2.2. Features of Monte Carlo Methods in Reliability Evaluation

A fundamental parameter in reliability evaluation is the mathematical expectation of a given reliability index. Salient features of the Monte Carlo method for reliability evaluation, therefore, can be discussed from an expectation point of view.

Let Q denote the unavailability (failure probability) of a transmission line and x_i be a zero-one indicator variable which states that:

$x_i = 0$ if the transmission line is in the up or operational state, and

$x_i = 1$ if the transmission line is in the down or failed state.

The estimate of the transmission line unavailability is given by:

$$E(Q) = \overline{Q} = \frac{1}{N}\sum_{i=1}^{N} x_i \tag{4-1}$$

where N is the number of transmission line state samples.

The unbiased sample variance is:

$$V(x) = \frac{1}{N-1}\sum_{i=1}^{N}(x_i - \overline{Q})^2 \tag{4-2}$$

When the sample size is large, equation (4-2) can be approximated as:

$$V(x) = \frac{1}{N}\sum_{i=1}^{N}(x_i - \overline{Q})^2 \tag{4-3}$$

Because x_i is a zero-one variable, it follows that:

$$\sum_{i=1}^{N} x_i^2 = \sum_{i=1}^{N} x_i \tag{4-4}$$

Substituting equations (4-1) and (4-4) into equation (4-3) yields:

$$\begin{aligned} V(x) &= \frac{1}{N}\sum_{i=1}^{N} x_i^2 - \frac{1}{N}\sum_{i=1}^{N} 2x_i\overline{Q} + \frac{1}{N}\sum_{i=1}^{N}\overline{Q}^2 \\ &= \overline{Q} - 2\overline{Q}^2 + \overline{Q}^2 \\ &= \overline{Q} - \overline{Q}^2 \end{aligned} \tag{4-5}$$

It is important to note that equation (4-1) gives only an estimate of the transmission line unavailability. The uncertainty of the estimate can be measured by the variance of the expectation estimate:

$$\begin{aligned} V(\overline{Q}) &= \frac{1}{N}V(x) \\ &= \frac{1}{N}(\overline{Q} - \overline{Q}^2) \end{aligned} \tag{4-6}$$

The accuracy level of Monte Carlo simulation can be expressed by the coefficient of variation, which is defined as:

$$a = \frac{\sqrt{V(\overline{Q})}}{\overline{Q}} \tag{4-7}$$

Substitution of equation (4-6) into equation (4-7) gives:

$$a = \sqrt{\frac{1-\overline{Q}}{N\overline{Q}}} \quad (4\text{-}8)$$

which can be rewritten as:

$$N = \frac{1-\overline{Q}}{a^2\overline{Q}} \quad (4\text{-}9)$$

This equation indicates two important points:

1. For a required accuracy level a (defined in equation 4-7), the required number of samples N depends on the system unavailability but is independent of the size of the analyzed system. Therefore, Monte Carlo methods are applicable to both small and large-scaled system reliability evaluation. This is an important advantage of Monte Carlo methods compared to analytical enumeration techniques for reliability assessment.
2. The unavailability (failure probability) of a practical system is usually much smaller than 1.0. Therefore equation (4-9) can be approximated as:

$$N \approx \frac{1}{a^2\overline{Q}} \quad (4\text{-}10)$$

This equation means that the number of samples N is approximately inversely proportional to the unavailability of the system. In other words, in the case of a very reliable system, a large number of samples is required to satisfy the given accuracy level.

4.2.3. Efficiency of Monte Carlo Methods

Different Monte Carlo techniques can be used to solve the same problem. These include different random number generation methods, different sampling approaches, and different variance reduction techniques, etc. Therefore, it is sometimes necessary to compare the efficiency of different Monte Carlo methods.

Suppose two Monte Carlo methods are used to evaluate the same system and the expectation estimates of the reliability index obtained using these two methods are statistically the same. Let t_1 and t_2 denote computing times and σ_1^2 and σ_2^2 be the variances of the reliability index for the two methods, respectively. Let η be defined as follows:

$$\eta = \frac{t_1 \sigma_1^2}{t_2 \sigma_2^2} \tag{4-11}$$

If $\eta < 1$, then the first method can be considered to be more efficient than the second method; η is determined by the computing time multiplied by the variance of the estimate, but not simply by the number of required samples.

In conducting a reliability evaluation of power systems using Monte Carlo methods, the computing time and the variance are directly affected by the selected sampling techniques and system analysis requirements. Sampling techniques include random number (or variate) generation methods, variance reduction techniques, and different sampling approaches. The purpose of system analysis is to judge if a system state is good or bad. The system analysis requirements are different in generation, composite and distribution system reliability evaluations.

4.2.4. Convergence Characteristics of Monte Carlo Methods

(1) **Convergence Process.** Monte Carlo simulation creates a fluctuating convergence process as shown in figure 4-2, and there is no guarantee that a few more samples will definitely lead to a smaller error. It is true, however, that the error bound or the confidence range decreases as the number of samples increases.

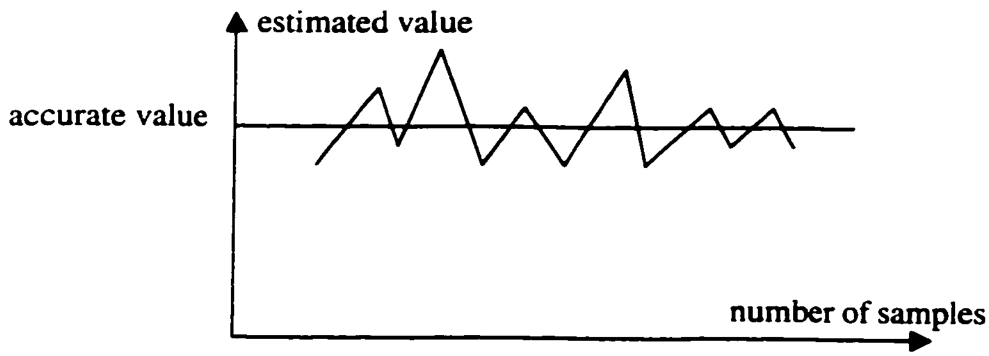

Figure 4-2 Convergence process in Monte Carlo simulation

(2) **Convergence Accuracy**. The variance of the expectation estimate is given by equation (4-6). The standard deviation of the estimate can be expressed as follows:

$$\sigma = \sqrt{V(\overline{Q})} = \frac{\sqrt{V(x)}}{\sqrt{N}} \tag{4-12}$$

This indicates that two measures can be utilized to reduce the standard deviation of the estimate in a Monte Carlo simulation: increasing the number of samples and decreasing the sample variance. Variance reduction techniques can be used to improve the effectiveness of Monte Carlo simulation. The variance cannot be reduced to zero and, therefore, it is always necessary to utilize a reasonable and sufficiently large number of samples.

(3) **Convergence Criteria**. The coefficient of variation shown in equation (4-7) is often used as the convergence criterion in Monte Carlo simulation. In power system reliability evaluation, different reliability indices have different convergence speeds. This coefficient of variation should be used as the convergence criterion in order to guarantee reasonable accuracy in a multi-index study.

4.3. Monte Carlo Simulation: Random Number Generation

A random number can be generated by either a physical or a mathematical method. The mathematical method is most common, as it can guarantee reproducibility and can be easily performed on a digital computer. A random number generated by a mathematical method is not really random and therefore is referred to a pseudorandom number. In principle, a pseudorandom number sequence should be tested statistically to assure its randomness.

The basic requirements for a random number generator are:

1. Uniformity -- The random numbers should be uniformly distributed between **[0, 1]**.
2. Independence -- There should be minimal correlation between random numbers.
3. Long Period -- The repeat period of a number should be sufficiently long.

There is a wide range of random number generation methods. Two commonly used are multiplicative [14] and mixed [15] congruential generators, refer to the references for the detailed algorithms.

4.4. Monte Carlo Simulation: Random Variate Generation

A random variate refers to a random variable following a given distribution. The random number generation methods mentioned in the previous section are essentially ones which generate a random variate following a uniform distribution between **[0, 1]**. Generators of random variates which follow other distributions are based on uniformly distributed random numbers between **[0, 1]**.

The three commonly used methods for generating nonuniformly distributed random variates are: (1) inverse transform method, (2) composition method, and (3) acceptance-rejection method. There are also particular methods for specific distributions [16]. This section emphasizes the inverse transform method, which is most frequently used. The exponential and normal distributions are the most important ones in power system reliability evaluation. The techniques for generating exponentially distributed random variates will be discussed in detail. Methods for other distributed random variates can be found in relevant references.

4.4.1. Random Variate Generation : Inverse Transform Method

The inverse transform method is based on the following proposition:

> *If a random variate U follows a uniform distribution in the interval between* **[0, 1]**, *the random variate $X = F^{-1}(U)$ has a continuous cumulative probability distribution function $F(x)$.*

This proposition can be generalized to the case of a discrete distribution and, in this case, the inverse function of $F(x)$ is defined as:

$$X = F^{-1}(U) = \min\{x : F(x) \geq U\} \qquad (0 \leq U \leq 1) \qquad \text{(4-13)}$$

See figure 4-3 to get the idea for this proposition.

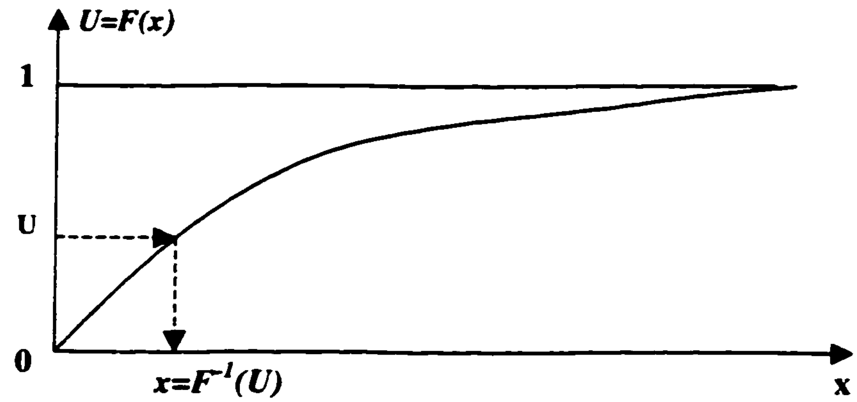

Figure 4-3 Explanation of the inverse transform method

The procedure for generating random variates using the inverse transform method can be summarized as follows:

1. Generate a uniformly distributed random number sequence U between [0, 1], and
2. Calculate the random variate which has the cumulative probability distribution function $F(x)$ by $X = F^{-1}(U)$.

4.4.2. Generating Exponentially Distributed Random Variates

The exponential probability distribution is most frequently used in power system reliability evaluation, e.g., in a two-state component representation. The component state durations including failure, repair, and switching activities are usually assumed to be exponentially distributed.

The inverse transform method is often used for generating the exponential random variates. The probability density function for the exponentially distributed variate is:

$$f(x) = \lambda e^{-\lambda x} \tag{4-14}$$

Its cumulative probability distribution function is:

$$F(x) = 1 - e^{-\lambda x} \tag{4-15}$$

The inverse transform:

$$U = F(x) = 1 - e^{-\lambda x} \tag{4-16}$$

leads to:

$$x = F^{-1}(U) = -\frac{1}{\lambda}\ln(1 - U) \tag{4-17}$$

Since *(1-U)* distributes uniformly in the same way as U in the interval **[0, 1]**, therefore:

$$x = -\frac{1}{\lambda}\ln U \tag{4-18}$$

where U is a uniformly distributed number sequence and x follows an exponential distribution.

4.5. Monte Carlo Simulation: Three Simulation Approaches

The basic principles for three Monte Carlo simulation approaches are discussed in detail in references [17-21].

4.5.1. State Sampling Approach

The system state depends on the combination of all component states and each component state can be determined by sampling the probability that the component appears in that state [22-23].

The behavior of each component can be described by a uniform distribution between **[0, 1]**. Assume that each component has two states of failure and success and that component failures are independent events. Let S_i denote the state of the ***ith*** component and PF_i denotes its failure probability. Draw a random number U_i distributed uniformly between **[0, 1]** for the *i*th component,

$$S_i = \begin{cases} 0 & \text{(operational state)} \quad \text{if } U_i \geq PF_i \\ 1 & \text{(failed state)} \quad \text{if } 0 \leq U_i \leq PF_i \end{cases} \tag{4-19}$$

The state of the system containing m components is expressed by the vector S,

$$S = (S_1, \ldots, S_i, \ldots, S_m) \tag{4-20}$$

Assuming that each system state has the probability $P(S)$ and the reliability index function $F(S)$, the mathematical expectation of the index function of all system states is given by:

$$E(F) = \sum_{S \in G} F(S)P(S) \tag{4-21}$$

where G is the set of system states.

Substituting the sampling frequency of the state S for its probability $P(S)$ gives:

$$E(F) = \sum_{S \in G} F(S) \frac{n(S)}{N} \tag{4-22}$$

where N is the number of samples, $n(S)$ is the number of occurrences of state S, and $F(S)$ can be obtained by appropriate system analysis.

The advantages of the state sampling approach are:

1. Sampling is relatively simple. It is only necessary to generate uniformly distributed random numbers between [0, 1]. It is not necessary to sample a distribution function.
2. Required basic reliability data are relatively few. Only the component-state (e.g., up and down states) probabilities are required.
3. The idea of state sampling applies to component failure events and can also be easily generalized to sample states of other parameters in power system reliability evaluation, such as weather states, load, and hydrological, etc.

The disadvantage of this approach is that it cannot be used by itself to calculate the actual frequency of outages.

4.5.2. State Duration Sampling Approach

The state duration sampling approach is based on sampling the probability distribution of the component state duration. In this approach, chronological component state transition processes for all components are first simulated by sampling. The chronological system state transition process is then created by combination of the chronological component state transition processes [24, 25].

This approach uses the component state duration distribution functions. In a two-state component representation, these are the operating and repair state duration distribution functions and are usually assumed to be exponential. Other distributions, however, can be easily used.

The state duration sampling approach can be summed up in the following steps:

1. Specify the initial state of each component. Generally, it is assumed that all components are initially in the operational or up state.
2. Sample the duration of each component residing in its present state. For example, given an exponential distribution, the sampling value of the state duration is $T_i = -\frac{1}{\lambda_i}\ln U_i$, where Ui is a uniformly distributed random number between **[0, 1]** corresponding to the ***ith*** component; if the present state is the up state, λ_i is the failure rate of the ***ith*** component; if the present state is the down state, λ_i is the repair rate of the ***ith*** component. The analytical exponential distribution may not be valid if the underlying statistics of the data invalidate the distribution assumption. In that case, the discrete cumulative distribution functions should be used to calculate the duration time in the simulation.
3. Repeat step 2 in the given time span (year) and record sampling values of each state duration for all components. Chronological component state transition processes in the given time span for each component can be obtained and have the forms shown in figure 4-4.
4. The chronological system state transition process can be obtained by combining the chronological component state transition

processes of all components. The chronological system state transition process for the two components is shown in figure 4-4.

5. Conduct system analysis for each different system state to obtain the reliability index ***F(S)***, and use the concept given in equation (4-21) to calculate ***E(F)***.

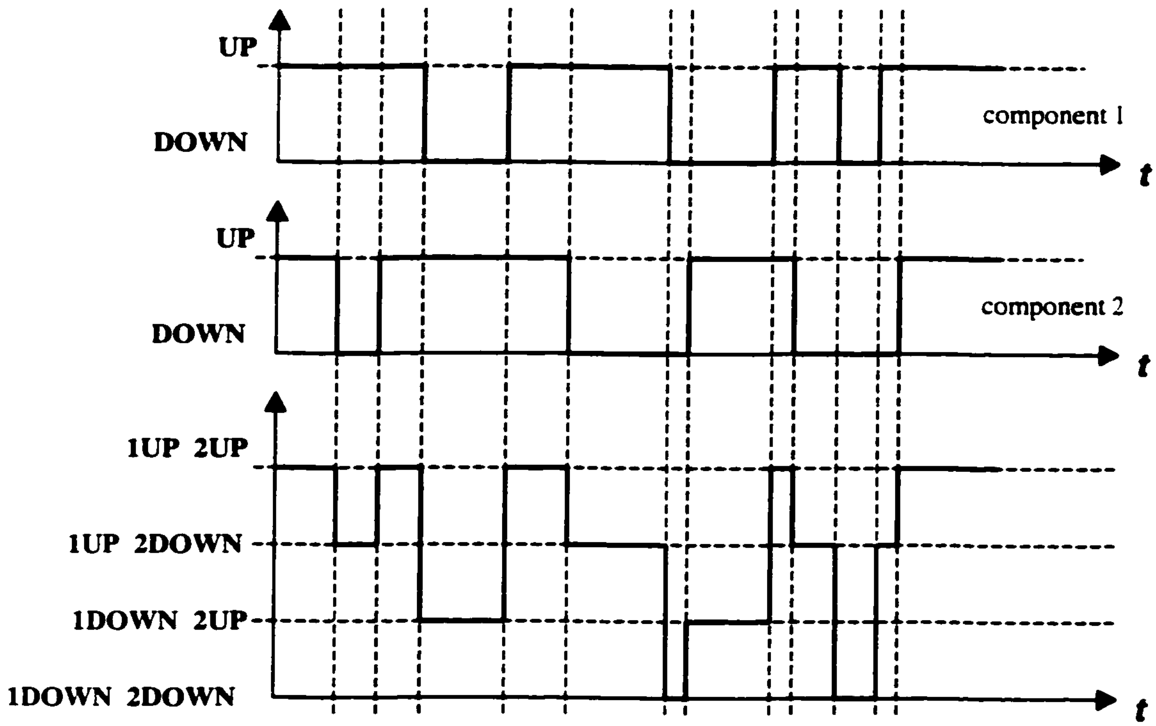

Figure 4-4 Chronological component and system state transition process

The advantages of the state duration sampling approach are:

1. It can be easily used to calculate the actual frequency index.
2. Any state duration distribution can be easily considered.
3. The statistical probability distributions of the reliability indices can be calculated in addition to their expected values.

The disadvantages of this approach are:

1. Compared to the state sampling approach, it requires more computing time and storage because it is necessary to generate a random variate following a given distribution for each component, and store information on chronological component state transition processes of all components in a long time span.
2. The approach requires parameters associated with all component state duration distributions. Even under a simple exponential assumption, these are all transition rates between states of each component. In some cases, especially for a multi-state component representation, it might be quite difficult to provide all these data in an actual system application.

4.5.3. System State Transition Sampling Approach

This approach focuses on state transition of the whole system instead of component states or component state transition processes [22, 26]. Assume that a system contains m components and that the state duration of each component follows an exponential distribution. The system can experience a system state transition sequence $\{S^{(1)}, \ldots, S^{(n)}\} = G$, where G is the system state space. Let us suppose that the present system state is $S^{(k)}$ and that the transition rate of each component relating to $S^{(k)}$ is λ_i ($i = 1, \ldots, m$). The state duration T_i of the ith component corresponding to system state $S^{(k)}$ has the probability density function: $f_i(t) = \lambda_i \exp(-\lambda_i t)$. Transition of the system state depends randomly on the state duration of the component which departs earliest from its present state, i.e., the duration T of the system state $S^{(k)}$ is a random variable which can be expressed by:

$$T = \min_i \{T_i\} \qquad (4\text{-}23)$$

It can be proved that since the state duration of each component T_i follows an exponential distribution with parameter λ_i, the random variable T also follows an exponential distribution with the parameter $\lambda = \sum_{i=1}^{m} \lambda_i$, i.e., T has the probability density function:

$$f(t) = \sum_{i=1}^{m} \lambda_i \exp(-\sum_{i=1}^{m} \lambda_i t)$$

Assume that system state $S^{(k)}$ starts at instant 0 and the transition of the system state from $S^{(k)}$ to $S^{(k+1)}$ takes place at instant t_0. The probability that this transition is caused by departure of the ***jth*** component from its present state is the following conditional probability: $P_j = P(T_j=t_0/T=t_0)$. According to the definition of conditional probability and equation (4.23), it follows that:

$$\begin{aligned} P_j &= P(T_j = t_0 / T = t_0) \\ &= P(T_j = t_0 \cap T = t_0) / P(T = t_0) \\ &= P[T_j = t_0 \cap (T_i \geq t_0, i = 1,\ldots,m)] / P(T = t_0) \qquad (4\text{-}24) \\ &= P(T_j = t_0) \prod_{i=1, i \neq j}^{m} P(T_i \geq t_0) / P(T = t_0) \end{aligned}$$

Since $Ti(i=1,\ldots,m)$ and T follow exponential distributions,

$$P(T_i \geq t_0) = \int_{t_0}^{\infty} \lambda_i e^{-\lambda_i t} dt = e^{-\lambda_i t_0} \qquad (4\text{-}25)$$

$$P(T_j = t_0) = \lim_{\Delta t \to 0} \lambda_j e^{-\lambda_j t} \Delta t \qquad (4\text{-}26)$$

$$P(T = t_0) = \lim_{\Delta t \to 0} (\sum_{i=1}^{m} \lambda_i e^{-\sum_{i=1}^{m} \lambda_i t_0}) \Delta t \qquad (4\text{-}27)$$

Substituting equations 4-25, 4-26, 4-27 into equation 4-24 yields:

$$P_j = P(T_j = t_0 / T = t_0) = \lambda_j / \sum_{i=1}^{m} \lambda_i \qquad (4\text{-}28)$$

State transition of any component in the system may lead to system state transition. Consequently, starting from state $S^{(k)}$, the system containing m components has m possible reached states. The probability that the system reaches one of these possible states is expressed by equation (4-28) and obviously:

$$\sum_{j=1}^{m} P_j = 1 \qquad (4\text{-}29)$$

Therefore, the next system state can be determined by simple sampling. The probabilities of m possible reached states are successively placed in the interval **[0, 1]** as shown in figure 4-5. Generate a uniformly distributed random number U between **[0, 1]**. If U falls into a segment corresponding to P_j, this means that transition of ***jth*** component leads to the next system states. A long system state transition sequence can be obtained by a number of samples and the reliability of each system state can be evaluated.

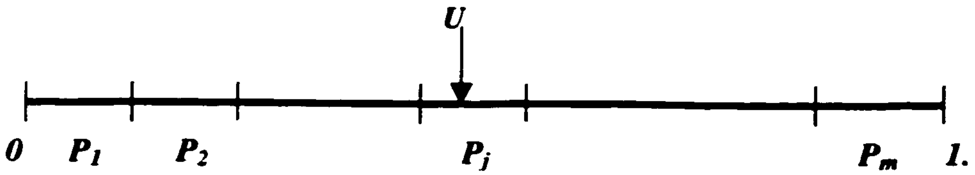

Figure 4-5 Explanation of the transition sampling of system state

The advantages of the system state transition sampling approach are:

1. It can be used to calculate the exact frequency index without the need to sample the distribution function and to store chronological information as in the state duration sampling approach.
2. In the state sampling approach, m random numbers are required to obtain a system state for an m-component system. This approach requires only a random number to produce a system state.

The disadvantage of this approach is that it applies only to exponentially distributed component state duration. It should be noted, however, that the exponential distribution is the most commonly used distribution in the reliability evaluation.

4.6. A State Duration Sampling Monte Carlo Simulation Model Used to Evaluate Transmission Line Reliability

The Monte Carlo simulation algorithm developed to evaluate the impact of adverse weather on transmission line reliability in the Province of Alberta was based on the state duration sampling approach. The frequency/duration of load point interruptions was examined to analyze the transmission line reliability. The Monte Carlo simulation model was applied to a portion of a transmission network configuration (shown in figure 4-6) in the Southeast region of Alberta where most adverse weather-related outages were recorded. The transmission line network shown is only a small portion of the total transmission system, and will be used to illustrate the application of the Monte Carlo simulation model. The cumulative up and down time distributions for the various adverse weather elements for transmission line#1 are illustrated in figures 4-8 and 4-9, respectively.

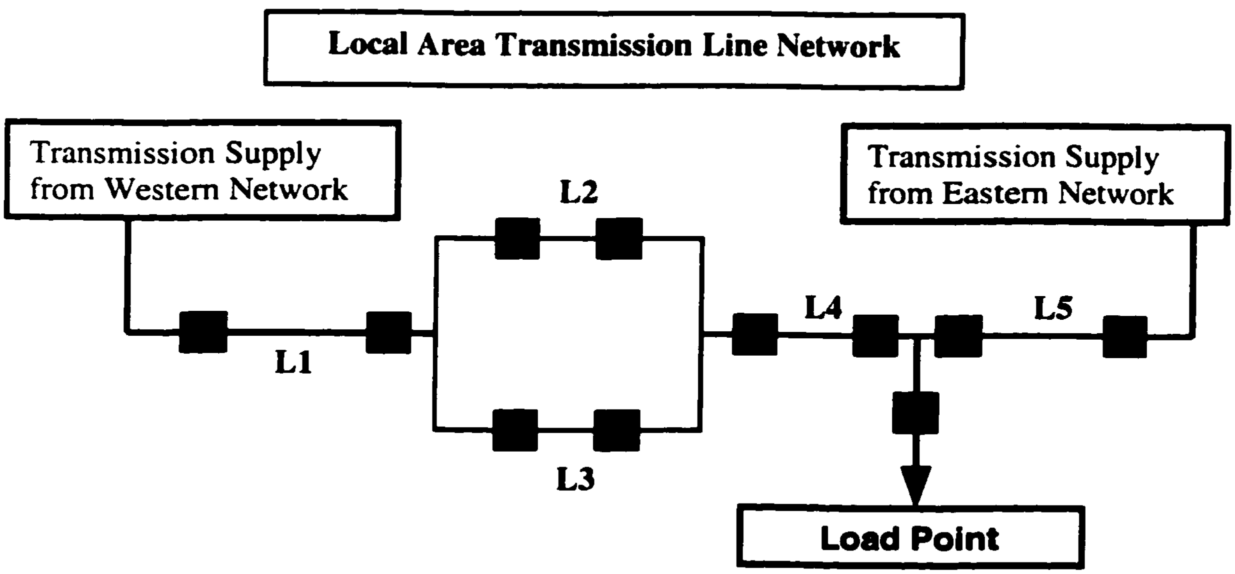

Figure 4-6 Partial transmission network serving a single load point

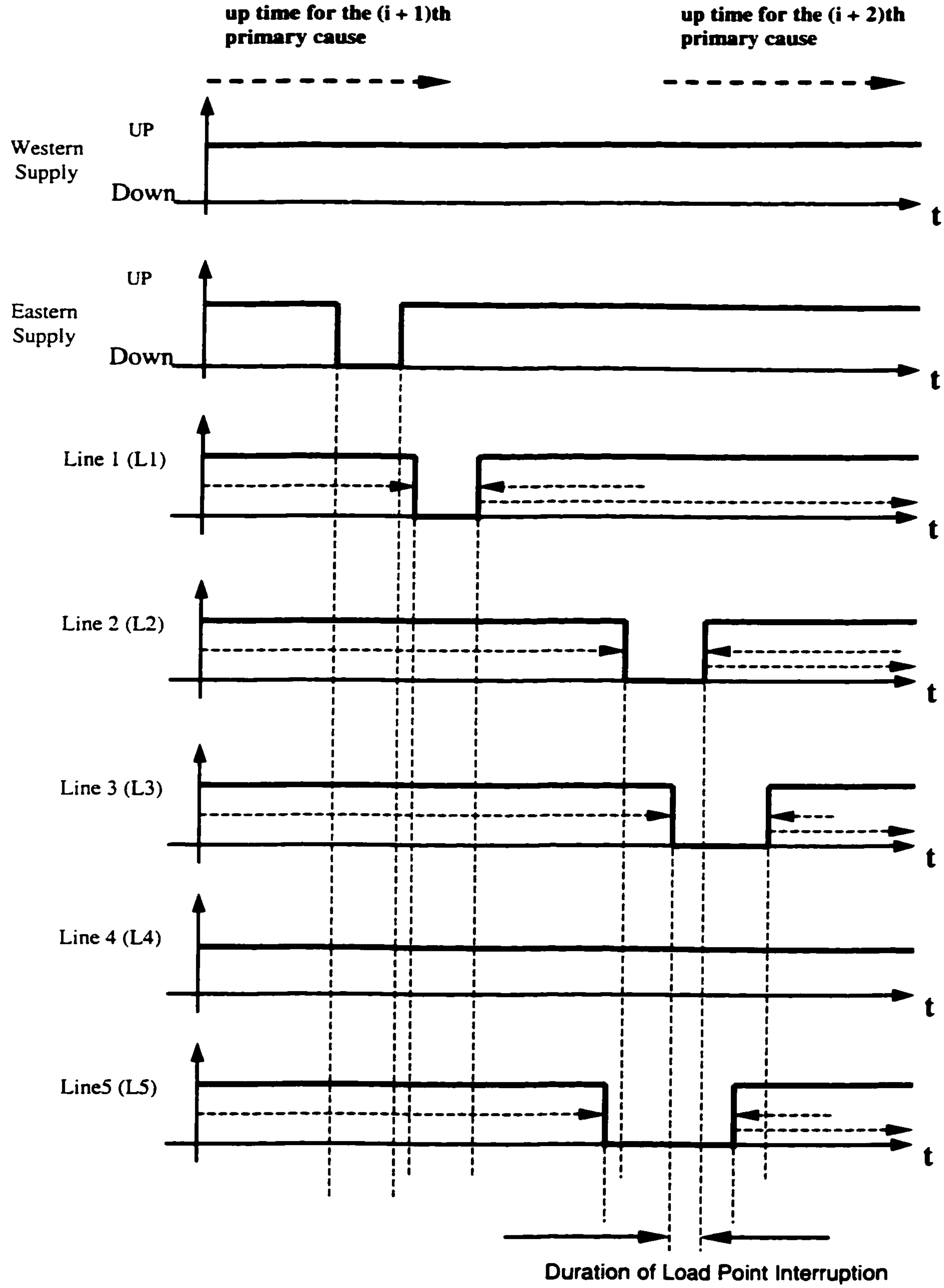

Figure 4-7 Illustration of simulation time lines for the system lines and interconnections

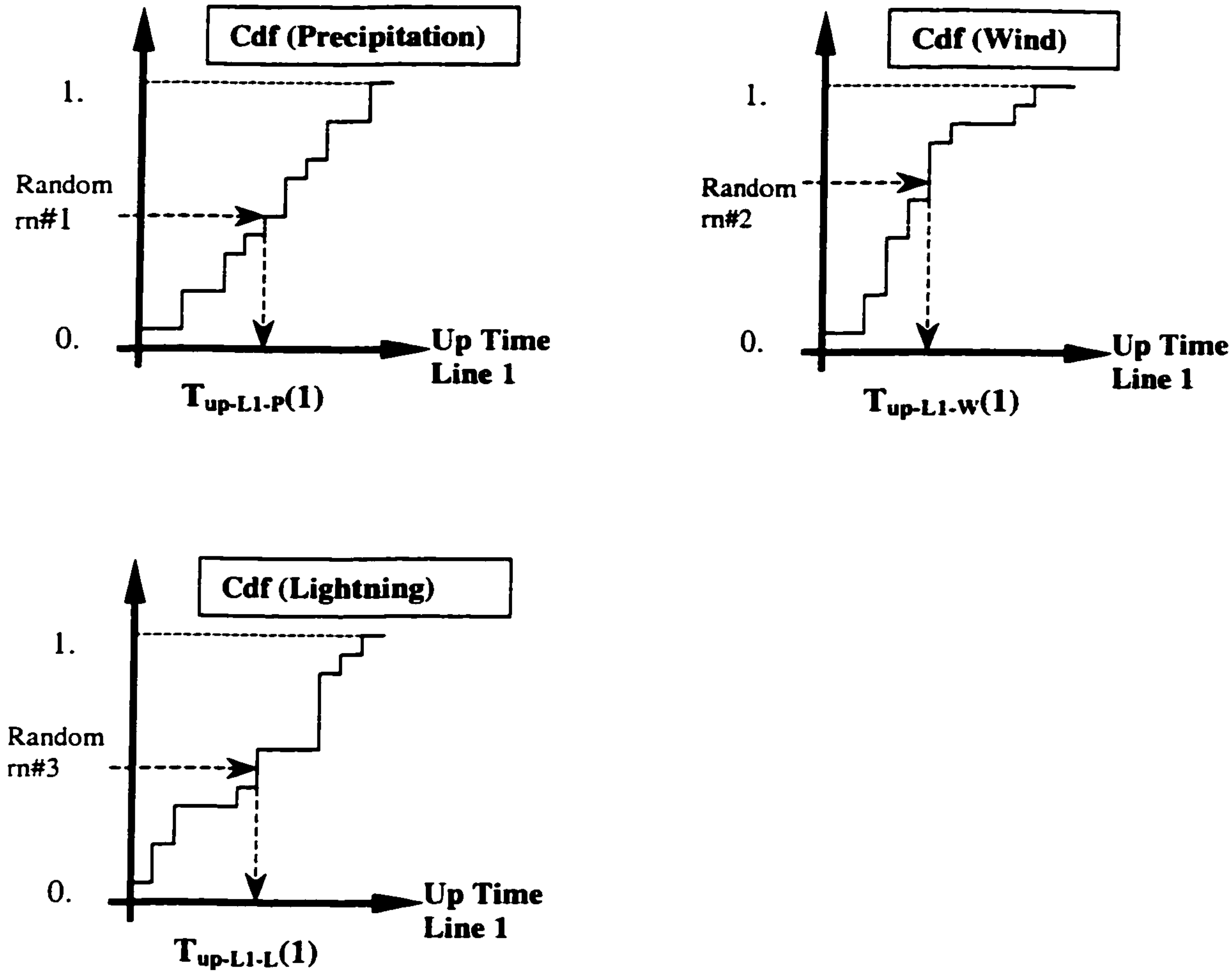

Figure 4-8 Cumulative distribution of up or operational time for transmission line L1

The cumulative distribution functions (cdf) for up and down time outage durations for each primary cause for the western and eastern transmission line supplies to the local transmission line area network are defined. In this case study only the adverse weather primary causes were considered. Random numbers (**rn#i**, ***ith*** random number) are continuously generated. Each pair of random numbers generates both an up and down time of a transmission line from its state cumulative distribution function for a particular primary cause. For example:

rn #1 -- generates a corresponding "up" time for transmission
line #1: $T_{up\text{-}L1\text{-}p}(1)$ for the primary cause precipitation, and

rn #2 -- generates a corresponding "down" time for transmission
line #1: $T_{down\text{-}L1\text{-}p}(1)$ for the primary cause precipitation.

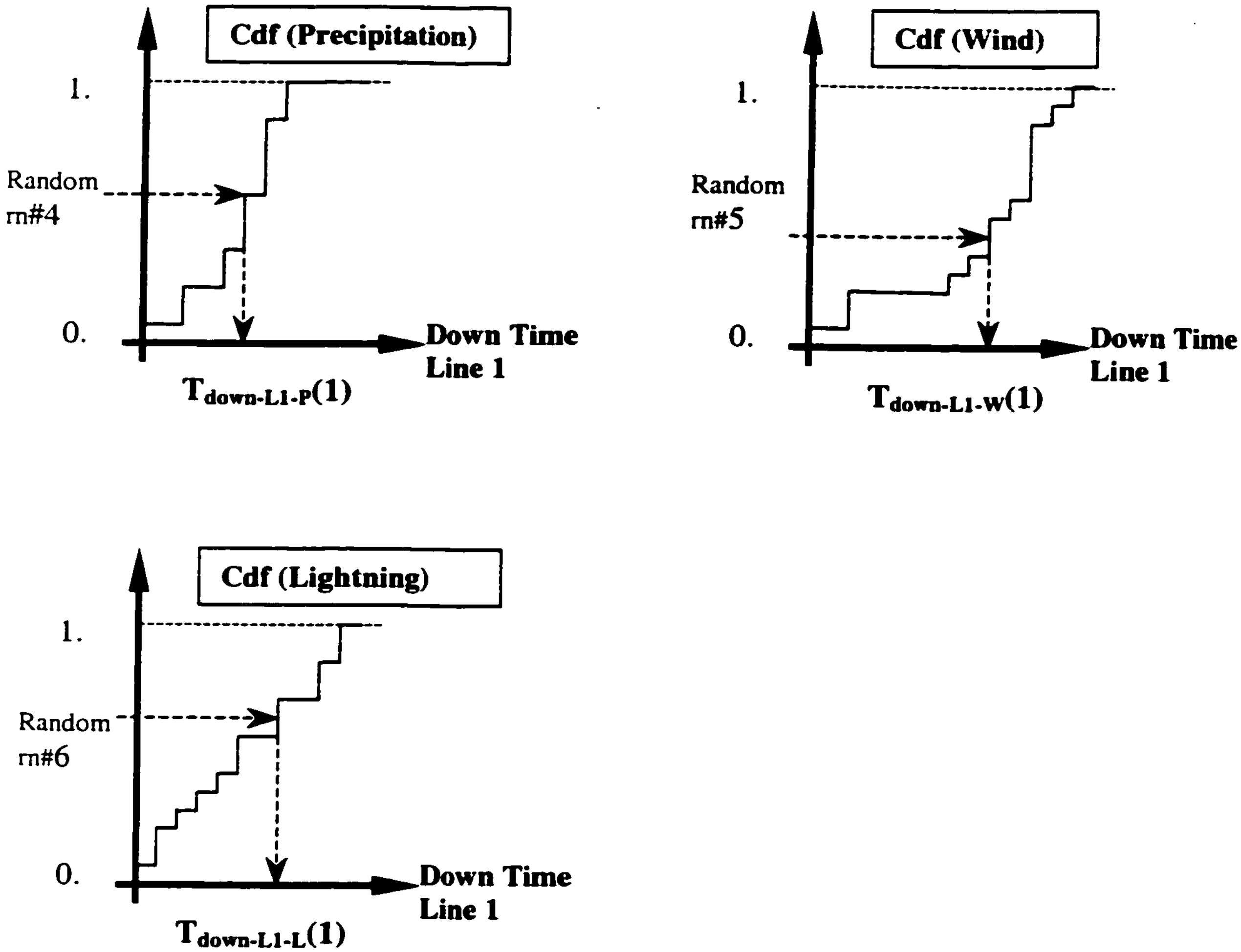

Figure 4-9 Cumulative distribution of down or failure time for transmission line L1

The corresponding "up" and "down" times for each primary cause are plotted on a time line as shown in figures 4-8, 4-9. For each down state or combination of down states, the local transmission line network is evaluated if a single or multiple transmission line outage causes an interruption to the load point. If the load is interrupted, then the appropriate duration of the load point interruption is determined and summed over the entire length of the simulation study. The frequency of occurrence of these down states is counted. At the end of the simulation study, the average frequency and duration of load point interruptions are determined. The time line is continued in the Monte Carlo study for a minimum of 10,000 years in order to obtain a stable estimate of the frequency and duration of load point interruptions. Depending upon the size of the local area transmission network, convergence constraints may limit the number of years; however, each network configuration is unique.

The following simulation results for the frequency and duration of load point interruptions considering only adverse weather were obtained:

1. λ (load point) = 2.7 interruptions per year - western network supply only;
   r (load point) = 2.225 hours per interruption - western network supply only,
2. λ (load point) = 3.55 interruptions per year - eastern network supply only;
   r (load point) = 1.45 hours per interruption - eastern network supply only, and
3. λ (load point) = 0.004 interruptions per year - both eastern and western supply;
   r (load point) = 0.878 hours per interruption - both eastern and western supply.

Note that when both the eastern and western supplies supply the load, the frequency and duration of load point interruptions is the lowest.

Chapter 5

Conclusion

This thesis has presented the adverse weather-related transmission line outage statistics for a 20 year (1977-1996) outage database of ATCO Electric Limited and a 33 year (1961-1993) climate database of the Atmospheric Environment Service, Environment Canada. The objective of this thesis was to reveal the unique failure patterns and characteristics of adverse weather-related transmission line outage in the Province of Alberta. These statistics and the patterns of failure provide the framework for a Monte Carlo simulation methodology to incorporate weather effects in transmission system reliability evaluation. An illustrative case study of a portion of the Alberta Grid was presented to reveal the simulation procedure and the use of outage statistics in the Monte Carlo simulation. Various correlation studies between adverse weather variables and transmission line outage frequency, stratified by voltage level and adverse weather-related primary cause, were conducted and the results were discussed.

There is often the belief that adverse weather-related transmission line outages are infrequently occurring events. This thesis has clearly shown that adverse weather transmission line outages account for approximately one third of all transmission line outages in the Province of Alberta over the time period of 1977-1996. Adverse weather conditions of precipitation, wind, and lightning were major causes of transmission line "line-related" sustained forced outages of three voltage levels (i.e., 72kV, 144kV, 240kV). Lightning was the dominant primary cause for transmission line "line-related" transient forced outages. Adverse weather accounts little for "terminal-related" sustained forced outages.

The impact of lightning, wind, and precipitation on transmission line reliability varies significantly among transmission lines. The correlation analysis between adverse weather variables and transmission line outage frequency is summarized as follows:

1. Strong correlation exists between the summer (May-August) monthly average "Days with Thunderstorms" and overall lightning-related transmission line outage frequency. Elevated levels of the 144kV transmission line outage frequency were most strongly associated with the summer (May-August) thunderstorm adverse weather activities.
2. Precipitation-related outage frequency of 240kV transmission lines was strongly correlated with winter (September-April) monthly averages of four precipitation adverse weather variables: "Extreme Daily Snowfall (cm)", "Extreme Daily Precipitation (mm)", "Days with Snowfall greater than 10.0 cm", and "Days with Precipitation greater than 10.0 mm". The adverse snowfall weather condition indicated by the winter (September-April) monthly average of "Days with Snowfall greater than 10.0 cm" has a significant impact on the precipitation-related outage frequency of 72kV transmission lines.
3. The monthly average (January-December) of "Days with at Least 1 Hourly Wind Speed greater than 30 km/h" adverse weather variable was not proportional to the wind-related 144kV transmission line outage frequency.

The correlation analysis of the transmission line outage data revealed that, wind related outage occurrences were not proportional to the physical length of the transmission line, however, lightning related outage occurrences were strongly correlated with the physical length of the transmission line and precipitation related outage occurrences were slightly proportional to the transmission line physical length.

The probability density functions of the failure rate of transmission line outages expressed as relative frequency histograms were shown to illustrate the significant differences between transmission line outage statistical patterns of different adverse weather primary causes (i.e., wind, precipitation, and lightning). This thesis also revealed that the underlying statistical distributions of the duration of adverse weather outages were skewed (i.e., the mean and median values of the outage duration of the various primary causes of adverse weather were significantly different). This conclusion limits the application of many existing reliability methodologies based on assumed statistical distributions (e.g., normal, exponential, etc.). Detailed outage duration cumulative distribution functions of all the primary adverse weather causes (i.e., precipitation, wind, and lightning) were presented in chapter 3.

The use of overall average transmission line failure rates in power system reliability planning can lead to incorrect results when applied to local transmission line networks. This thesis illustrated a Monte Carlo simulation methodology that was applied to a local area transmission network. The Monte Carlo simulation methodology presented in this thesis can be applied to any other utility transmission line system configuration to determine the frequency and duration of load point interruptions subject to adverse weather or any other combination of causes.

Monte Carlo methods can be applied to simulate any actual process and random behavior of a system. In this thesis, only the outage statistics was used in the Monte Carlo simulation for evaluating Alberta transmission system reliability. Studies of adverse weather patterns have shown that further research into modeling adverse weather conditions is advisable. If enough weather data (e.g., hourly weather data) are available, the simulation studies for evaluating a transmission system reliability can be extended to first simulate weather conditions around transmission lines, and then simulate the transmission system operation under different weather conditions to estimate the overall reliability indices of the transmission system. Markov state modeling studies for incorporating weather effects in reliability evaluation of Alberta transmission system need to be conducted. The reliability evaluation results from Markov state modeling studies and Marte Carlo simulation studies can be compared.

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