26

# POWER SYSTEM RELIABILITY ANALYSIS APPLICATION GUIDE

## CIGRE WG 03 of SC 38 (Power system analysis and techniques) - 1987

Edited by :
Lesley KELLEY - REGNIER

Conférence Internationale des Grands Réseaux Électriques à Haute Tension
International Conference on Large High Voltage Electric Systems

# POWER SYSTEM RELIABILITY ANALYSIS

Prepared by
Working Group 38-03

Edited by
LESLEY KELLEY-RÉGNIER

Presented at the request of
Chairman of Study Committee 38
RALPH S. GENS
and
Chairman of Working Group 38-03
DONALD T. McGILLIS

## PREFACE

This document is intended as an application guide to power system reliability analysis. It presents an overview of system reliability concepts and an outline of the methodologies whereby these concepts are applied.

In accordance with the mandate of CIGRE Study Committee 38, the guide concerns the application of analytical methods to power system reliability evaluation based on pragmatic concepts and principles. Its purpose is to cover reliability aspects in the fields of power generation and transmission from the system point of view.

The document starts from a number of basic concepts to define a set of reliability-related objectives and discusses various reliability criteria to be used to fulfil those objectives. The reliability indices corresponding to these criteria are defined and the methodologies of calculating such indices for composite-system reliability evaluation and prediction are reviewed.

The models used in these methodologies are based on a number of parameters that characterize the performance of generation and transmission equipment. To estimate the values of these parameters, it is necessary to collect performance data on the system components. Two entire chapters are consequently devoted to the collection and processing of such data: one for generation equipment, the other for transmission equipment. The consideration of multiple-outage events leads to a discussion of dependency concepts with particular emphasis on weather modeling, to which a special appendix is dedicated. An appendix on substation modeling is provided for evaluating the impact of different substation schemes on transmission system reliability.

A consistent effort has been made to unify the terms and definitions used in this rapidly evolving field. The terminology currently employed for power system reliability analysis is given in Appendix III.

No guide of this nature can claim to impart all the skills necessary to carry out detailed reliability studies apart from providing basic orientation in this complex area. For a more thorough understanding of the mathematics, models and methods involved, readers are referred to the relevant literature, starting with the references given in each chapter and expanding upon this information with the books listed in Appendix IV. This application guide lays the groundwork for a wider use of the tools and techniques of reliability analysis in the planning, design and operation of power systems and, as such, should prove useful to all system engineers engaged in power system reliability assessment.

# TABLE OF CONTENTS

# CHAPTER 1

# CONCEPTS, PRINCIPLES, OBJECTIVES AND CRITERIA

## TASK FORCE

D. Thorne (Chairman)
J. Endrenyi
J. Kariger
D. McGillis
J. Mastrocola
J. Prince
R. Ringlee
W. Wellssow

Contributing members

P. Baxter
P. Manning

## 1.1 INTRODUCTION

The function of electrical utilities is to produce, transmit and distribute electrical energy safely, at reasonable cost and with a degree of technical quality (adequate voltage and frequency) and service continuity generally acceptable to the majority of customers. These conditions are related and are all components of service reliability. The main focus of this application guide is the continuity aspect of service reliability and, more specifically, the ways it can be measured, analysed and predicted at the bulk power system level.

The definition of reliability-related objectives and the consequent application of criteria to achieve them is essential to the planning, design and operation of reliable electric power generation and transmission systems.

Modern society places a high priority on service reliability and on fast restoration following loss of service. As a result, the availability of service provided by electrical utilities is generally high. For many years, utilities have achieved an average service availability of 0.9996 to 0.9998, the former corresponding to 3.5 hours of interruption expected per customer per year, the latter to 1.75 hours. Similar levels of availability are attained in other developed areas.

These high reliability levels used to be achieved by planning and operating practices based on intuition, experience and judgement but the increase in system size and complexity in the last 20 years or so has forced utility engineers to replace their empirical methods by more formal approaches. These include the categorization of concepts and indices, the analysis of failures, the establishment of criteria and the application of analytical methods.

## 1.2 FAILURE CLASSIFICATION

Many types of power supply system failure are possible. At least three categories should be identified, namely:

- deficiencies in the technical quality
- emergencies in the supply system
- failure of the power system.

Technical-quality deficiencies include unacceptable frequency and service voltage excursions, excessive harmonics and unbalance in polyphase power supplies. Such events may also originate within the customer's own system. Customer processes or equipment (printing processes and paper production, for example) may be susceptible to voltage excursions, which can result in process upsets and, consequently, poor-quality products or production interruption. The customer's equipment may also be vulnerable to abnormal voltage, harmonics, or unbalanced conditions.

Power system emergencies arise when demand exceeds supply capability, as in the case of widespread shortfall of resources, generation or transmission capability limitations. System responses to emergencies include appeals for voluntary load reduction, curtailment of interruptible loads, reduction of service voltage to customers or load management control. Load shedding and isolation of areas from interconnected systems (controlled separation) are accepted in major emergencies.

Power system interruptions result in sudden and controlled loss of service. The extent can vary from a few customers to a widespread area affecting millions of customers. Interruptions caused by disruptions and failure in the bulk power system differ in nature, extent, frequency and effect from those originating in distribution systems. While most events resulting in service interruption arise in the distribution system, the number of customers involved in each case is usually small, ranging from a few to several hundred. Disturbances arising in the bulk power system, on the other hand, are fewer but can affect large numbers of customers and have widespread social and economic impacts [1-4]. Public and political reaction is strongly influenced by their severity, the consequential damages and the facilities affected.

Typically, widespread interruptions result from a combination of causes, including the following:

- heavily stressed system
- critical facilities on maintenance
- high hazard conditions causing multiple failures
- protection system failure
- operator error.

The public has shown tolerance to localized outages in the distribution system, if the interval between them is reasonably long and service restoration proceeds within a few hours. On the other hand, reaction to widespread interruptions has been strong, particularly when the source of disturbance cannot be readily identified with severe natural causes such as hurricanes, thunderstorms, tornadoes or ice storms. Legal actions have even resulted from prolonged interruptions of service. Nonetheless, the public has responded to appeals for voluntary curtailment in emergencies and accepted emergency load-relief measures to protect the power system, provided service restoration is prompt.

## 1.3 RELIABILITY CONCEPTS

The main goals in the planning and operating philosophy for bulk power systems have been to provide adequate reserves to minimize the risk of power supply emergencies and to provide a system strength that will withstand specific classes of disturbances. In this document, and in power system analysis in general, reliability is used as an umbrella term describing an ability measured by a set of suitable quantitative indices (numerical variables). In other applications, such as space technology and electronics, "reliability" is itself given a quantitative definition and is one of the indices employed. Since the latter (narrower but more concrete) definition is not used in power system studies, there should be no confusion.

> **Reliability:** a general concept encompassing all the measures of the ability to deliver electricity to all points of utilization within acceptable standards and in the amount desired.

Bulk power system reliability can be described by two basic and functional attributes - **adequacy** and **security.**

> **Adequacy:** ability to supply the aggregate electric power and energy requirements of the customers within component ratings and voltage limits, taking account of planned and unplanned outages of system components.

> **Security:** ability to withstand specified sudden disturbances such as electric short circuits or unanticipated losses of system components together with operating constraints.

Adequacy is also referred to as static reliability and security as dynamic reliability (see section 2.1).

Another aspect of security is system **integrity,** which is the ability to maintain interconnected operations. Integrity relates to the preservation of interconnected system operation, or the avoidance of uncontrolled separation, in the presence of specified severe disturbances.

Service interruption may result from failure and outage of lines and equipment. The existence of various hazards makes failures and interruptions inevitable; theoretically, infinite investments would be needed to eliminate them completely. The value of any marginal investment made to obtain a given reduction in interruptions may be related to the benefit resulting from having fewer interruptions.

Utilities and their customers must strive for a balance of economy and reliability. The occurrence of system outages must therefore be accepted and the reliability criteria respond, in fact, to the level of acceptability.

## 1.4 RELIABILITY PRINCIPLES

### 1.4.1 System Planning

Planning covers three aspects:

- the forecasting of future demand (power and/or energy) taking into account uncertainties due to the economic situation or to weather events

- the establishment of technical and economic data relative to the devices to be installed: outages (forced and planned) and the cost of generating units and transmission components (lines, cables, transformers), fuel prices, uncertainties of hydroelectric resources, construction times, safety and operating regulations and their effect on costs

- the development of appropriate models and the search for the most economical solution through the evaluation of alternatives the latter includes the selection of devices to be installed at the appropriate time and in the required size and location to supply the forecast demand at lowest cost. The search is subject to a number of constraints:

- those related to the service expected by the customer such as power cuts limited in duration and frequency, voltage and frequency held within acceptable limits, etc.
- geographic and demographic constraints due to the nature of the territory to be served (load density level, necessity of transmitting power over long distances, isolated or highly meshed character of the system, etc.)
- environmental constraints limiting the level of various impacts (chemical effluents or waste heat, considerations of visual or audible effects, electric and magnetic field strengths), and constraints arising from public opposition to the construction of new power stations or lines
    - economic and political constraints: limitation of available capital, desire to reduce national dependence on particular fuels, uncertainty about costs and availability of various fuels, etc.

These constraints vary according to region and country but those related to service are common to all generation and transmission systems and are directly linked to reliability criteria. In a strict sense, the constraints noted do not fall within the terms of reference of this document and will be examined here only to the extent that they interact with the reliability criteria. They should be taken into account in the search for an economic optimum but, since they are not always well defined, they are sometimes impossible to model in precise mathematical terms.

### 1.4.2 System Design

A design philosophy has evolved for the bulk power system which assures that, in addition to being safe for customers and operating personnel, the system will have the capability and flexibility to minimize violations of adequacy, security and integrity during foreseeable contingencies. Allowance must be made for maintenance of system components as a part of the preconditions for the assessment of reasonably foreseeable contingencies. Consideration must be given to the power transfer requirements imposed upon the bulk power system by power flows arising from the normal economical dispatch of generation. Contingency conditions must reflect line configuration (double-circuit construction, common right-of-way), contamination considerations, and extreme weather (hazards of high winds, ice and snow loading) and flooding.

The system should be designed to minimize the risks of propagation of adverse effects of major disturbances that violate the design criteria. The objective sought is that the system be sufficiently protected and operated with sufficient reserve to confine the extent of disturbances, to avoid propagation of interruption beyond the portion affected, and to protect generation, substation equipment and lines from damage and personnel from injury.

The means for system reconfiguration and restoration of operation should be sufficient to permit rapid recovery from interruption. Communications, control and switching centres should be provided with emergency on-site auxiliary power capability to permit independent monitoring and operating capabilities for rapid reconfiguration and re-energization.

### 1.4.3 System Operations

Reliability of the bulk power system concerns the operator as much as the planner [2]. However, since the decision time frame is different for each, the reliability methods to be applied and the difficulties involved are also different. Operators make short-term risk assessments while planners are concerned with long-term predictions. In addition, operators ideally should obtain results fast enough for operating decisions based on them to be made with minimum delay.

Generally speaking, the purpose of operating-reliability assessments is to provide assistance in setting and carrying out various operating policies. Typical are the provisions of adequate spinning reserves, the allocation of preventive maintenance or the timing of sales to, and purchases from, interconnected utilities. These activities must be carried out so that operating risks are acceptable, economy and security are balanced, and the effects of component failures are minimized as well as the probability of catastrophic failures (system collapse). Since frequent reevaluations are required, an ideal program would produce them on-line.

The use of operational reliability methods depends on the time frame to which they are applied. Time frames are the various periods in the future for which assessments are made. While there is no general agreement on their classification, they may be categorized as follows:

. Time Frame A: from the present to a few hours or days hence

. Time Frame B: up to one year hence

. Time Frame C: up to the end of the operating time horizon (2 to 4 years).

In each of these categories, there are typical studies that may require reliability assessments.

Time Frame A

Economical utilization of available generating capacity

Provision of adequate spinning reserve to keep the risk of system failure below a predetermined level

Assessment of the amount of power that can be sold or needs to be purchased

Choice of corrective actions in contingencies

Time Frame B

Economical utilization of available generating capacity

Unavailability of hydroelectric energy

Impact of the uncertainty in forecast hydroelectric energy

Economic operating schedule

Scheduling of energy sales and purchases

Assessment of transmission transfer capabilities

Assessment of requests for deviations from schedules

Component maintenance and overhaul scheduling

Time Frame C

Economical utilization of available generating capacity

Mothballing and restoring of units

Fuel contracts

Long-term sales and purchases

It can be observed that the entries in Time Frame A serve mainly to help operators decide what action to take, while those in B concern operating policies. In the practice of some utilities in Europe (e.g. ENEL), evaluations in Time Frame C are carried out annually, to ensure constant risk over the years.

The development of indices and criteria to fit the above applications and of methods to compute these indices is fairly recent and by no means complete. To make full use of these approaches is still a task of the future.

## 1.5 RELIABILITY OBJECTIVES

Using the principles just presented, utilities should have the following objectives when planning, designing and operating a bulk power system:

- To preserve system adequacy, i.e. to supply the aggregate electric power and energy requirements with acceptable technical quality and service continuity.
- To preserve system security in such a way that recovery from more probable contingencies can be achieved without load curtailment or interruption and avoiding excessive stress on the system and its components.
- To preserve system integrity, such that more severe, less probable contingencies, including sequences of contingencies, will not result in uncontrolled separation of major portions of the system.
- To limit the extent of failure and minimize the risk of widespread shutdown.
- To promote rapid restoration following shutdown.

## 1.6 RELIABILITY CRITERIA

Reliability criteria can be viewed as conditions that should be satisfied by the generation and transmission system in order to achieve the required reliability. They fall into two categories: index or variable and attribute or performance test criteria. The former are numerical parameters which provide target levels of reliability or, more usually, upper bounds on unreliability, i.e. expected energy not supplied or expected frequency of failure. The use of such criteria forms the basis of probabilistic reliability assessments. Performance-based criteria take the form of sets of conditions, such as generation or transmission incidents, that the system must be capable of withstanding. The definition of incident includes the predisturbance as well as the disturbance itself and forms the basis of deterministic contingency evaluation.

Chapter 2 illustrates the division of the general reliability problem into the categories of adequacy and security and provides detailed descriptions of the indices utilized in both domains.

There are many techniques in use at the present time to assess the reliability of an existing or proposed bulk power system. Chapter 3 presents a summary of the methodologies, which can be generally categorized as being either deterministic or probabilistic in nature, and illustrates the computational techniques available for quantified reliability assessment.

In using reliability criteria, the planner's task consists in determining, within the bounds of these criteria, the bulk power system for which the overall costs are minimum. This can be thought of as a search for a constrained optimum system in which the overall cost is the economic function and the reliability criteria are the constraints.

## RELIABILITY CONCEPTS AND PRINCIPLES

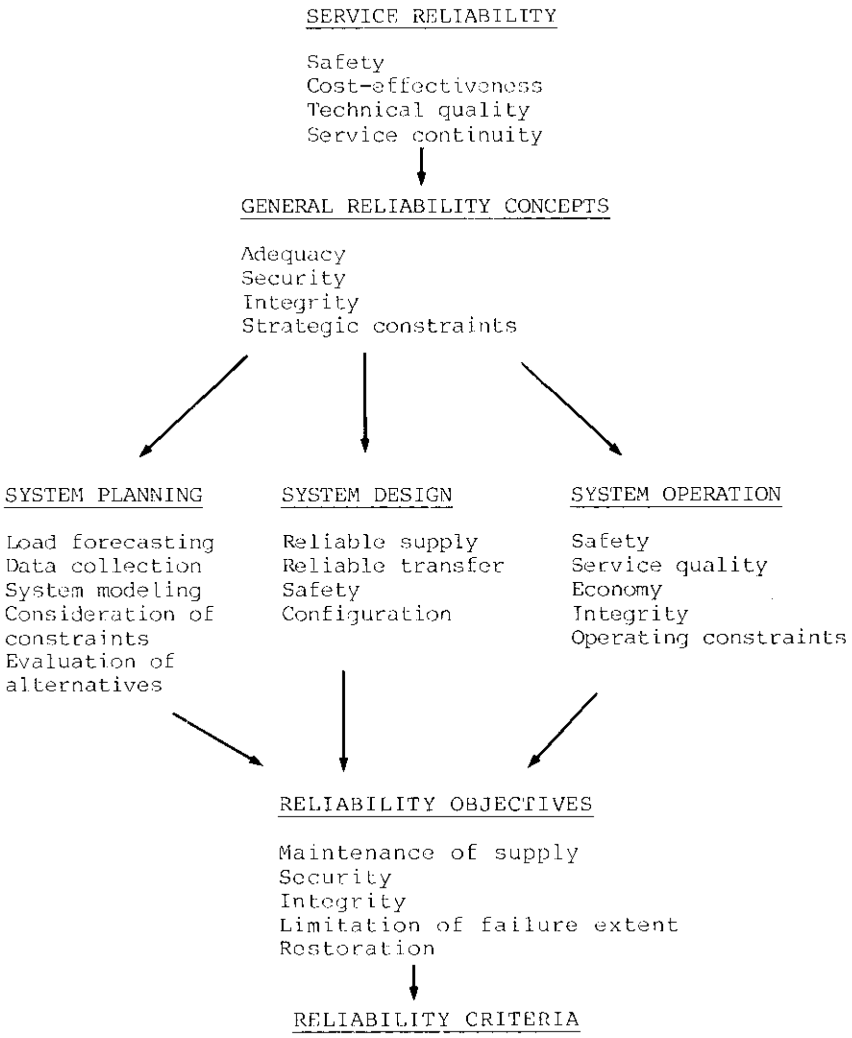


Figure 1.1 - Schematic representation of the progression of ideas in reliability criteria formulation

The progression of ideas in the formulation of reliability criteria is schematized in Fig. 1.1.

## 1.7 PERFORMANCE TESTING AND RELIABILITY PREDICTION

Most transmission and bulk power system reliability assessments employ performance tests which involve the application of specified disturbances, simulation of system response, and evaluation of system recovery capability. System conditions at the onset of the disturbance are included as part of the disturbance.

To limit the number of tests to be performed, a few cases representative of larger classes of disturbances are selected to serve as "umbrella performance tests". Experience and judgement play a significant role in the selection, since this affects the resultant system strength, reliability performance, capital requirements and operating costs.

### 1.7.1 System Failure Criteria

Acceptable response is determined by using suitable performance criteria: loadings within specified limits, bus voltages and changes within specified limits, and preservation of system frequency and integrity.

These limits are not necessarily thresholds of system failure or of loss of service quality but they reflect margins in the system withstand capability for the classes of disturbances represented by the umbrella tests.

Deterministic performance tests, or the choice of probabilistic reliability indices, are based on system failure criteria. The reliability criteria discussed earlier are then used in the assessment of test results or index values obtained for a given system.

### 1.7.2 Failure Assessment

Theoretically, all possible modes and levels of disturbances should be included in the assessment of risk and severity of failure for reliability predictions. Performance testing starts from the presumed healthy system and simulates the system response and recovery for prescribed contingencies. In contrast, index-based system reliability predictions require the ability to track system response into the failure states to establish the outcome and the degree or severity of failure for the significant contingencies. Risks and modes of errors in operation must also be modelled together with faults and malfunctions of protection relaying and control systems. In both cases, success is measured by acceptable response and recovery.

Note that correct evaluation of system response to performance tests requires the same level of modelling and computing accuracy as index-based failure evaluation.

Strictly speaking, failures should be measured in terms of losses of electrical service, interruptions and/or loss of service quality. From a practical standpoint, however, for planning and operation evaluations, they may be measured by the occurrence of such conditions as:

- loadings beyond limits
- frequency excursions beyond limits
- voltage excursions beyond limits
- real-power deficiencies
- reactive-power or voltage-support deficiencies
- separation
- instability
- cascading risks
- voltage collapse

These are descriptions rather than actual measures of failure because they are indications of conditions leading to failure.

## 1.8 UNCERTAINTY IN RELIABILITY EVALUATIONS

Uncertainties in power system reliability predictions may arise at any stage of a reliability investigation. Inaccuracies or even errors may occur at each step shown in Fig. 1.2 for a typical investigation [5].

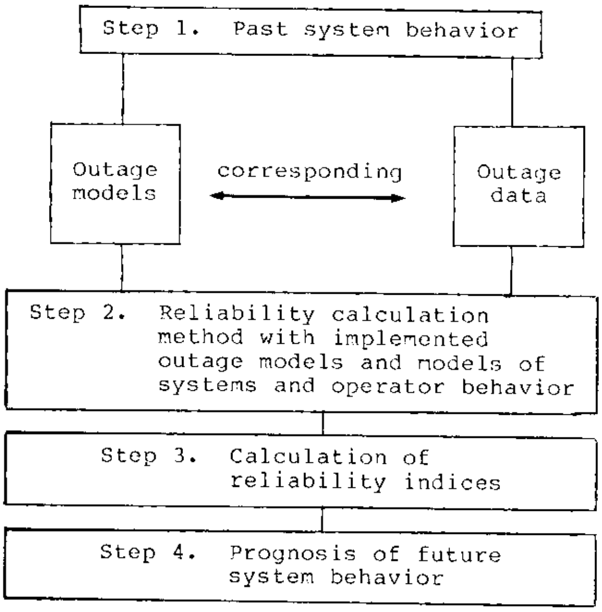


Figure 1.2 - Schematic overview of reliability investigation

Step 1

Observation of past system behavior in order to obtain outage models and corresponding component outage data. Uncertainties occur here due to:

- limited number of observed outages (sampling inadequacy)
- insufficiency of outage reports, which means that not all the desired information is obtained.

Step 2

Creation of a reliability calculation method and its implementation in a computer program. Many simplifications are necessary owing to limited computational power or because some effects involving plant and system operator actions, especially operator errors, are not easily modeled:

- impossibility of considering all possible outage events by creating outage models
- load-flow calculation, often done by an approximation method
- modeling of remedial actions, such as switching, busbar coupling or generation dispatching, often oversimplified
- modeling of load-shedding policies, very difficult but with significant impact on reliability indices.

Step 3

Calculation of reliability indices using a program.

- Inaccuracies may occur here as a result of limitation of the contingency selection, if analytical methods are used.

- Uncertainty may result from the small number of simulated time intervals, if simulation methods are used.

Step 4

Predicting the future system behavior or comparing planning variants for a given time period using reliability criteria. Deviation of loads from forecast and the stochastic nature of system failure events, combined with the fact that failure occurrence is infrequent for the highly reliable systems under study, contribute to uncertainty in predictions of future system behavior.

Quantitative evaluation of most of these errors is difficult, especially if modeling simplifications are involved.

Planning engineers should be aware that, because of the inherent uncertainties, reliability indices have a probability distribution with a considerable deviation. Account should therefore be taken of variances of the calculated indices when using reliability criteria to make planning decisions. These variances can be calculated. Full information on predicted system behavior is contained within the probability distributions of the indices. Ideally, reliability criteria should be based on these distributions but in practice the planner must settle for less, making use of the expected values of the indices.

The uncertainty in predicting system behavior depends on the reliability index. The uncertainty is especially high for the predicted interrupted-energy index, which means that evaluations of interrupted-energy costs based on this index are also forced to deal with significant uncertainty.

REFERENCES

[1] U.S. Government, "The National Electric Reliability Study," Technical Study Reports, DOE E/P - 005, April 1981.

[2] IEEE Task Force on Bulk Power System Reliability, Application of Probability Methods Subcommittee, "Bulk Power System Reliability Concepts and Applications," IEEE PES Winter Power Meeting, Paper No.87 WM 051-6, February 1987, to be published in IEEE Trans. on PS.

[3] North American Electric Reliability Council, Reliability Concepts in Bulk Power Electric Systems, Princeton, NJ, February 1985.

[4] CIGRE WG 37-01, "Comparison of the Reliability Criteria Used in the Various Countries," Paper No.84/07/103 (E), July 1984.

[5] H.J. Koglin, E. Roos and W.H. Wellssow, "Application of Reliability Calculation Methods to Planning of High Voltage Distribution Networks," 3rd International Conference on Reliability of Power Supply Systems, IEE Conference Publication No. 225, London 1983.

# CHAPTER 2

# RELIABILITY INDICES

## TASK FORCE

L. Salvaderi (Chairman)
R. Billinton
J. Endrenyi
A. Harpur
J. Prince
R. Ringlee
W. Wellssow
W. Winter

Contributing member

W. Thomson

## 2.1 INTRODUCTION

The concept of power system reliability is extremely broad, covering all aspects of the system's ability to satisfy customer requirements. It is therefore necessary to recognize this scope and to use it for general rather than specific indications of the overall ability of the system to perform its function. A much more precise classification is needed to obtain risk indices that express the various aspects of system reliability quantitatively. Risk indices refer to situations in which the system may be unable to guarantee the performance of its functions because of the forced outage of some components or, even if this occurs rarely, because the load has taken on values other than those expected. The simple but reasonable classification presented below reflects the two basic aspects of a power system: adequacy and security [1,2].

The risk indices quickest to obtain, and therefore most often used, are those deriving from a comparison in probabilistic terms at given instants between the load (demand) and the capability of the system in steady-state conditions. Such system capability is often referred to as **adequacy,** whence corresponding **adequacy indices** are derived. Since these indices do not consider transient phenomena[1] that occur in an electrical system from the moment a forced outage takes place until a new steady situation is reached, they are qualified as **static.**

The most common adequacy indices can be further classified into monoparametric and biparametric [2].

As their name implies, monoparametric risk indices use a single parameter. For their evaluation, it suffices to define the behavior of any system component simply by the long-term probability of outage, without specifying the related duration or frequency characteristics. These indices provide a measure of the average system behavior during the period under investigation, without stating whether the risk situation corresponds to a single long event or a number of short events.

Biparametric risk indices are expressed by two parameters, usually the annual expected value of the quantity representing the system deficiency (duration or amount) and the related annual frequency, or the expected value of a single deficiency and its frequency. Obviously, assuming the same unit of time (e.g. one year) the product of frequency and the expected value (duration or amount) of a single occurrence gives the corresponding total expected value in the unit of time (e.g. annual value). In order to evaluate these indices, the behavior of the various components from the point of view of their unavailability must be defined not only by the value of the average forced-outage rate (or outage probability) but also by the related average frequency (or duration).

Obviously, transient phenomena can make the disconnected load even greater than the difference between availability and demand in the new steady system state. The system's ability to overcome transient phenomena is often referred to as **security,** whence corresponding **security** or **dynamic indices** are derived.

It should be borne in mind that adequacy indices take account of faults of relatively long duration, since these require repair and therefore constitute what is commonly defined as permanent faults. For determination purposes, however, they do not cover transient faults lasting from fractions of a

---

[1] Such transient phenomena include both the electromechanical swinging of the machines and system frequency variations.

second up to a few minutes, which are caused for example by temporary breakdown of the air insulation of overhead lines. In order to include these faults, a further class of **dynamic** indices is needed. These indices are calculated in the same way as adequacy indices, by comparing availability and demand during the short temporary-outage interval of the component concerned. In radially operated systems, there may also be interruptions in supply, with the result that loads must be disconnected until supply is restored by other means. These interruptions are not covered by adequacy indices which, strictly speaking, only consider interruptions due to insufficient availability of installed components. Temporary indices may also include interruptions whose duration, even fairly long in some cases, can theoretically be obtained by means of suitable automatic devices.

It is important to realize that most probabilistic techniques available for power system reliability evaluation are used in the domain of adequacy assessment, although some work has been done on subsets of the security problem, such as quantifying spinning- or operating-capacity requirements and transient-stability evaluation.

## 2.2 GENERATING SYSTEM ADEQUACY INDICES

### 2.2.1 Monoparametric Risk Indices [2]

#### 2.2.1.1 Probability of not meeting the annual peak load

In this case, reliability is judged on the basis simply of the system's probability of being able, or not, to supply the maximum annual peak load. The risk index is evaluated by comparing the probabilistic distribution of the maximum annual load with that of the system capacity available on the day the peak occurs.

The index is obtained by considering the risk as the combined probability of two independent events A and B:

$$P(A,B) = P(A) \cdot P(B)$$

where A is the existence of a given stress
B is the existence of a strength less than the stress

Let $p_L(L)$ be the probability density function for the annual peak load (stress), defined between an upper extreme $L_{max}$ and a lower extreme $L_{min}$, and $P_A(L)$, the probability that the available capacity (strength) is lower than L.[1]

With reference to Fig. 2.1, the probability of not meeting a peak load between L and L + dL is

$$p_L(L)\ dL \cdot P_A(L) = r(L)dL$$

and, for the whole range of probable peak loads, the risk R is

where r(L) is the density function of the risk index under consideration.

$$R = \int_{L_{min}}^{L_{max}} r(L)dL = \int_{L_{min}}^{L_{max}} p_L(L).P_A(L)dL$$

$$R = \int_{L_{min}}^{L_{max}} p_L(L). \int_0^L p_A(C)dC.dL \quad \text{p.u.}$$

The case represented in Fig. 2.1 corresponds to a possible real system having an average peak load of 51.6 GW, normally distributed with $\sigma = 7\%$. The total installed generating capacity, $C_G$ = 65.1 GW, consists of various groups of nuclear, thermal and gas turbine units all having forced-outage rates of usual values. The cumulative probability function of the available capacity being lower than L is obtained from the corresponding probability density function which, in turn, is a combination of the various binomial probability density distributions of each group of generating units. This risk index, which has been adopted by CEGB,[2] is used in a system where all the generating units are thermal, with no limitation as regards the energy (fuel) at its disposal.

Obviously, judgment based exclusively on this index can suffice only if the index has acquired a degree of confidence, which presupposes a stable relationship between the peak value and the value for the rest of the year. This index was originally used to evaluate the reliability of generating systems and is therefore generally applied to busbar systems.

---

[1] If $p_A(C)$ is the related probability density function,

$$P_A(L) = \int_0^L p_A(C)\ dC$$

[2] The Central Electricity Generating Board (CEGB) standard, which emerged as a pragmatic choice during the period 1954-1958, defined a disconnection risk (after first obtaining a reduction in demand through operation at reduced voltage and frequency) of 3%, when some customers' loads would have to be disconnected for the 30-min duration of the annual peak demand; this remains unchanged. In 1971 the standard was extended to include a statement of the corresponding full demand risk of 23%, when there would be insufficient generation available to meet demand in full at the half-hour of annual peak demand, and load reduction up to a maximum of 7.5% by operation at reduced voltage and frequency would be necessary.

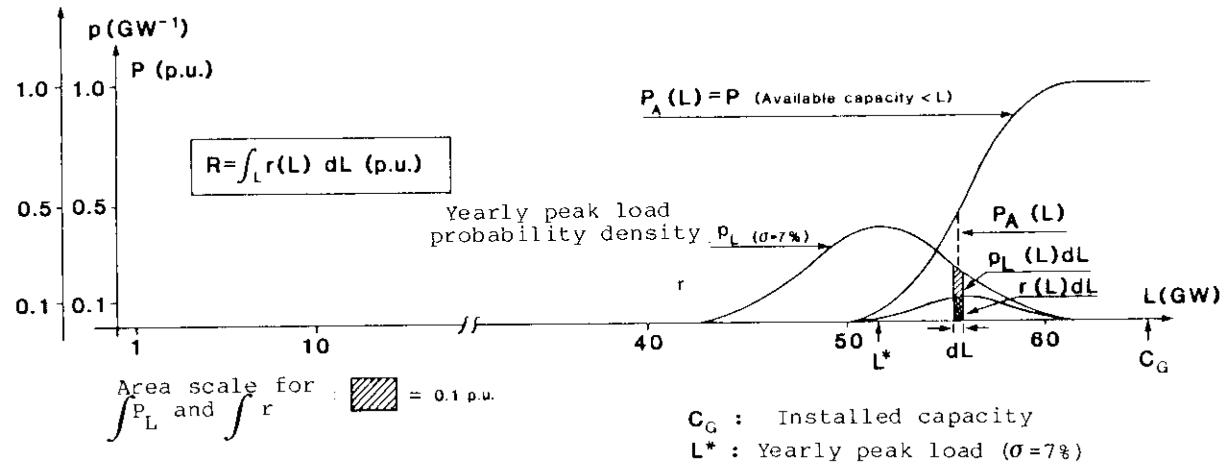


Figure 2.1 - Probability of not meeting the annual peak load, R

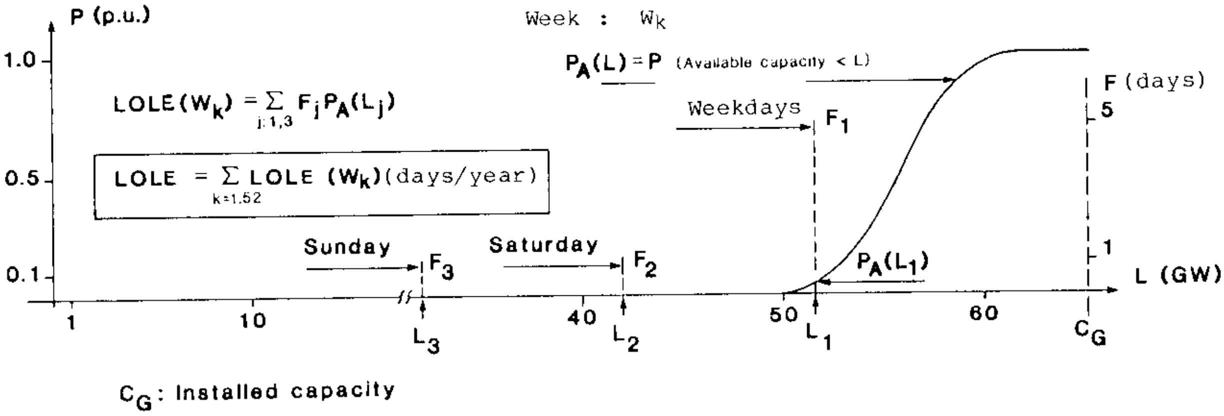


Figure 2.2 - Risk due to lack of installed capacity, or loss of load expectation (LOLE or LOLP)

### 2.2.1.2 Risk due to shortfall capacity

The loss-of-load expectation (LOLE), also commonly referred to as the or loss-of-load probability (LOLP), is defined as the expected number of days in the year when the daily peak load $L_j$ exceeds the available capacity. It is obtained by adding the probabilities $R_j$ (as calculated in 2.2.1.1) for every day in the year when the available capacity is unable to meet the daily peak:

$$\text{LOLE} = \sum_{1}^{365} R_j \ \text{(days/yr)}$$

The probability function $P_A(C)$ of the available capacity being lower than C depends on the number of generating units available for service and is stationary for an interval in which the units on planned maintenance do not change (normally one week).

In order to reduce the volume of calculations for the load, it is possible to assume the approximation that each daily peak load is known deterministically (only one value per day). Naturally, there is no obligation to use this approximation and the related probability density function can be adopted instead. A further approximation is to assume the same value of $L_j$ for a group of days in a given week, ascribing to it a frequency $F_j$ (days/week). With these approximations, the probability of not meeting the daily peak load is $P_A(L_j)$ and for the week is $w_k$,

$$\text{LOLE}\ (w_k) = \sum_j F_j\ P_A(L_j) \qquad \text{(days/wk)}$$

In Fig. 2.2, $F_j$ is 5 for weekdays, 1 for Saturday and Sunday. This figure shows how, in practice, only weekdays contribute to LOLE ($w_k$), so that unplanned maintenance of further units can be envisaged at weekends.

The yearly LOLE is easily obtained by repeating the same computations for each week of the year and summating the results:

$$\text{LOLE} = \sum_{k=1}^{52} \text{LOLE}\ (w_k) \qquad \text{(days/yr)}$$

It should pointed out that $R(y) = \frac{1}{365}$ LOLE is the probability of failure occurring at daily peaks during the year.

LOLE is the index most commonly used for planning purely thermal generating systems. Its values show a wide spread: in Europe, for instance, it varies roughly between 5 and 0.2 days/year, whereas the USA, Canada and Australia report values of 0.1 to 0.2 days/year. The differences among systems are due, in part, to calculation differences.

LOLE is much more significant than the previous index because it takes account of situations that occur throughout the year, albeit only those that correspond to daily peaks. In this case, too, the index considers only the occurrence of the event's "inadequacy to meet maximum load value", without evaluating the extent of the corresponding insufficiency. A shortfall of 1 kW for example, is judged in the same light as one of hundreds of megawatts. Furthermore, neither the frequency nor the duration of the load loss is indicated.

### 2.2.1.3 Risk due to lack of stored energy

When the generating system is mixed hydro-thermal, a possible cause of inadequacy to meet demand is lack of stored energy in the reservoirs. This can be quantized with a risk index similar to LOLE but it is more complex to calculate. In fact in the hypothesis of examining the system behavior on a weekly basis, the possibility of satisfying the load depends on five random variables:

C = available thermal and hydro capacity (MW). Probability densities: $p_t$ (C) and $p_h$ (C) ($\text{MW}^{-1}$)

L = load during the week (MW). Probability density: $p_L$ (L) ($\text{MW}^{-1}$)

$E_{LH}$ = load energy to be supplied weekly by the hydro plant (MWh). Probability density: $p_{LH}$ ($E_{LH}$) ($\text{MWh}^{-1}$)

$W_v$ = volumes stored in the reservoirs at the beginning of each week ($m^3$). Probability density: $p_v$ ($W_v$) ($(m^3)^{-1}$)

$W_i$ = weekly inflows to the reservoirs ($m^3$). Probability density: $p_{in}(W_i)$ ($(m^3)^{-1}$)

Direct analytical calculation of an index similar to LOLE is possible in the case that a) the system behavior can be considered on a weekly basis, b) the hydro subsystem is modeled with only one large (at least monthly) equivalent reservoir and c) the hydro plants are used for peaking purposes [3]. In other cases, when various hydro and pumped-storage plants are present, more detailed and complex simulation programs are suggested to estimate the indices related to the lack of stored energy [5,6].

Assuming two subsystems, one thermal, the other hydro, modeled with just one large seasonal reservoir, and assuming further that the hydro energy can be requested only after all thermal plant has been utilized ("defence of water" policy), an $\text{LOLE}_E$ index can be obtained for an entire year as the sum of all the weekly values of $\text{LOLE}_E(w_k)$ of not being able to meet the weekday peak load owing to lack of water in the reservoir. In other words, $\text{LOLE}_E(w_k)$ can be defined as the weekly probability that the energy available in the reservoirs during the week, which represents the sum of the volume stored at the beginning of the week plus the inflow during that week, is less than the energy required by the hydro plant during the same week.

The index can be calculated as follows (see Fig. 2.3). For a fixed week $w_k$, the weekly load duration curve $p_L(L)$ and the probability density of the available thermal capacity $p_t(C)$ (account having been taken for the thermal units on planned maintenance) can be used to obtain the probability density of the energy required by the hydro plants $p_{LH}(E_{LH})$ in that week (lower part of the figure).

Assuming the week as the unit of time, the load duration curve gives the probability that the load is equal to or higher than L:

$$\overline{P}_L(L) = \int_L^{L_{max}} p_L(L)dL$$

If the thermal subsystem has an available capacity L, the energy to be supplied by the hydro subsystem is

$$E_{LH}(L) = \int_L^{L_{max}} \overline{P}_L(L)dL$$

and therefore

$$dE_{LH}(L) = -\ \overline{P}(L)dL \qquad (2.1)$$

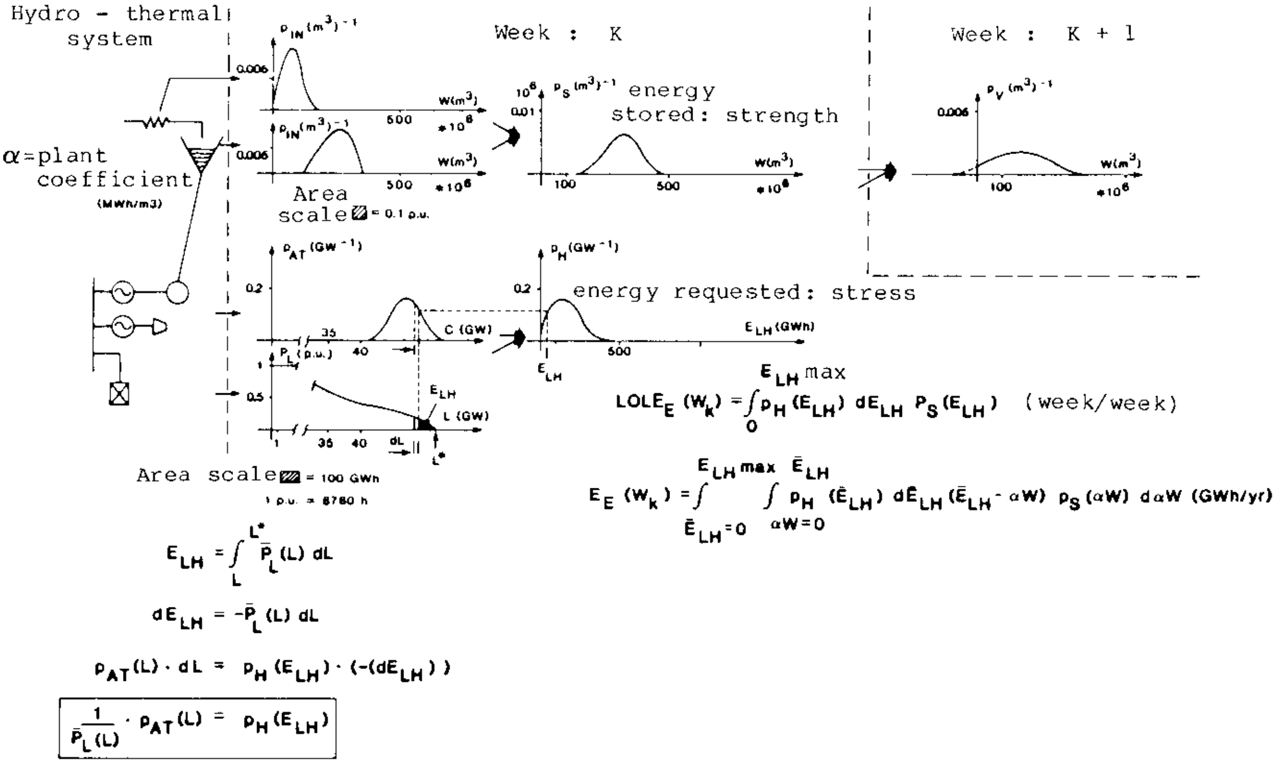


Figure 2.3 - Random variables to be taken into account when computing the risk due to lack of stored energy

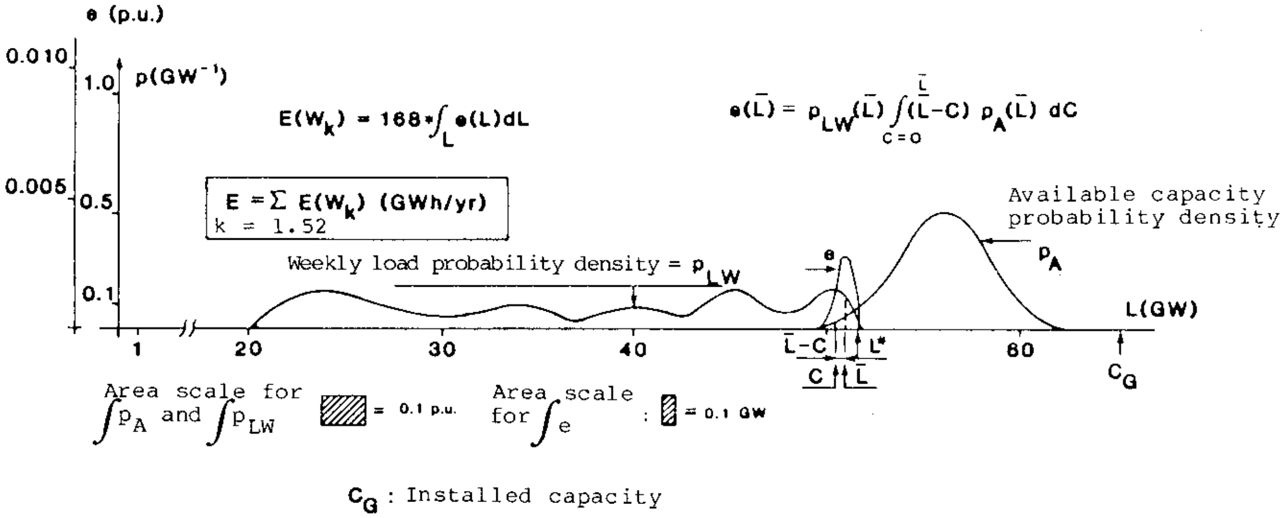


Figure 2.4 - Expected energy not supplied due to shortfall of installed capacity

2

The probability of having a request for hydro energy between $E_{LH}(L)$ and $E_{LH}(L) + dE_{LH}$ is:

$$p_{LH}(E_{LH})\, dE_{LH} = pt(L)(-dL) \qquad (2.2)$$

Substituting eq. (2.1) into expression (2.2) yields the probability density function of a demand for $E_{LH}$ as follows:

$$p_{LH}(E_{LH})\,(-\overline{P}(L)dL) = Pt(L)\,(-dL)$$

$$p_{LH}(E_{LH}) = pt(L)/\overline{P}_L\,(L) \qquad (MWh^{-1})$$

Furthermore, from the probability density of the water stored at the beginning of the week $p_v(Wv)$ and that of the inflow during that week $p_i(W_i)$, it is possible to evaluate the probability density of the water available from the reservoir in the same week $p_s(W_s)$ (upper part of Fig. 2.3).

$P_s(W_s)$, the probability that the water volume available during the week will be equal to or lower than $W_s$ when the water volume stored at the beginning of the week is between $W_v$ and $W_v + dW_v$, is the product of the related probability $p_v(W_v)dW_v$ and the probability $P_{in}(W_s-W_v)$. For the range of $W_v$ between 0 and $W_s$:

$$P_s(W_s) = \int_{W_v=0}^{W_s} P_{in}\,(W_s-W_v).p_v(W_v)dW_v$$

By analogy, considering the probabilities $P_v(W_s-W_i)$ and $p_{in}(W_i)dW_i$,

$$P_s\,(W_s) = \int_{W_i=0}^{W_s} P_v(Ws-W_i).p_i(W_i)dW_i$$

Therefore, the density function $p_s$ equals $dP_s(W_s)/dW_s$

$$p_s(W_s) = \int_{W_v=0}^{W_s} p_{in}\,(W_s-W_v).p_v(W_v)dW_v$$

$$= \int_{W_i=0}^{W_s} p_v(W_s-W_i).p_i(W_i)dW_i$$

If the energy obtainable from the reservoir is proportional to the water volume stored, through a plant coefficient

$$E_{SH} = W_s \cdot \alpha$$

the related probability density function is

$$p_{SH}(E_{SH}) = \frac{1}{\alpha}\, p_s \cdot W_s = \frac{1}{\alpha}\, p_s(\frac{E_{SH}}{\alpha})$$

and $P_{SH}(E_{SH})$ is the probability that the energy obtainable from the reservoir is equal to or lower than $E_{SH}$.

When $p_{LH}(E_{LH})$ and $P_{SH}(E_{SH})$ are known, it is possible to calculate

$$R_E(w_k) = \int_0^{E_{LHmax}} p_{LH}(E_{LH})\; d\, E_{LH} \cdot P_{SH}(E_{LH}) \qquad \text{(dimensionless)}$$

where $E_{LHmax}$ is the value at which $p_H(E_{LH})$ practically vanishes.

Summing the $R_E(w_k)$ for the 52 weeks of the year[1] yields

$$LOLE_E = \sum_{k=1}^{52} R_E(w_k) \qquad (wk/yr)$$

It should be mentioned that the function $p_v(W_v)$ of each week depends on the probabilistic history of the system during the previous weeks.

#### 2.2.1.4 Expected capacity shortfall

For events in which load exceeds capacity, the expected value (long-term average) of the capacity shortfall $C_x$ provides a measure of the extent of such shortfall.

For this purpose, let $p_A(C)$ be the probability density function of the capacity, valid for a time period with a given group of generating units. The group excludes units on planned outage. Let $p_L(L)$ be the probability density function of the load for a time interval within the period in which $p_A(C)$ is defined (depending on the application, p(L) can refer to the annual peak load, the daily peak load, daily peak loads in a week, hourly loads in a day or a week, daily loads, weekly loads, etc.). Various indices $C_x$ can therefore be considered. Let us start with the simplest case, related to the annual peak load (see Fig. 2.4).

---

[1] It is sometimes necessary to combine the index LOLE (days/year), related to the lack of capacity at the peak, with the index $LOLE_E$ (weeks/year) related to the weekly lack of stored energy. For this, the rough approximation can be assumed that all five weekdays should be affected at the peak by the weekly deficit; according to this assumption, $R_E(w_k)$ is the probability of having five days with an energy shortfall and $LOLE_E$ multiplied by five is the expected number of days per year when the energy shortfall occurs.

$C_x(w_k)$ gives the average expected capacity shortfall for all hours of the week. Assuming the duration of each capacity shortfall will not be less than one hour, the expected energy curtailment that week can be obtained as the product of $C_x(w_k)$ and the number of hours in the week (8760/52 = 168):

$$E(w_k) = 168\ C_x(w_k)$$

$$= 168 \cdot \int_{L_{min}}^{L_{max}} p_{LW}(L) \int_{0}^{L} (L - C)p_{AW}(C)dC\ dL$$

The annual value E (or EENS) is the sum of the 52 weekly values:

$$E = \sum_{k=1}^{52} E(w_k) = EENS$$

It is easy to check that, if $C_x(y)$ is the yearly index corresponding to the weekly values, $C_x(w_k)$, then E is equal to 8760 $C_x(y)$.

The index is normally expressed both in absolute values, i.e. in megawatthours/year, and in per-unit values of the total energy required by the load. The per-unit values are in the range of $10^{-4}$ to $10^{-5}$, depending on the size of the generating system and the adequacy target pursued by planners.

When the generation system is not purely thermal but includes hydro and/or storage plants (pumped storage, battery systems, etc.), the other component of the possible deficiencies, namely the energy curtailment due to lack of stored energy, must be evaluated. To distinguish between these two components, the indices quoted above are usually referred to as the "risk of power" in the case of capacity shortfall and the "risk of energy" in the case of primary-energy deficiencies.

Under conditions such as those assumed in section 2.2.1.3, the expected value of the weekly curtailed energy due to lack of stored energy $E(w_k)$ is the weighted average of the random-variable deficit of stored energy. E is defined as follows:

$$E = E_{LH} - E_{SH} \quad \text{if} \quad E_{LH} > E_{SH}$$

$$E = 0 \quad \text{if} \quad E_{LH} \leq E_{SH}$$

where $E_{LH}$, the energy required from the hydro plant by the load, can vary between 0 and $E_{LHmax}$ while $E_{SH}$, the energy available in the reservoir, can vary between 0 and $E_{SHmax}$ according to the total volume of the reservoir.

The relevant probability densities $p_{LH}(E_{LH})$ and $p_{SH}(E_{SH})$ were illustrated in section 2.2.1.3. The problem is analogous to that of evaluating $C_x$ (see section 2.2.1.4).

Therefore,

$$E_E(w_k) = \int_0^{E_{LH\ max}} p_{LH}(E_{LH})dE_{LH} \cdot \int_0^{E_{LH}} (E_{LH}-E_{SH})p_{SH}(E_{SH})dE_{SH}$$

and, for the whole year,

$$E_E = \sum_{k=1}^{52} E_E(w_k)$$

When the hydro systems are complex and/or the phenomena studied require a sampling of yearly system behavior covering less than one week, the proposed index cannot be evaluated without resorting to special programs based on the Monte Carlo method, which simulates the system behavior on an hourly basis [4,5].

The resulting expected yearly energy curtailment will be:

$$E_{TOT} = E + E_E \text{ (MWh/yr)}$$

or $$EENS_{TOT} = EENS + EENS_E \text{ (MWh/yr)}$$

The EENS index has found widespread use for power system planning in Europe, particularly in France (EDF) and Italy (ENEL).

### 2.2.1.6 Utilization of monoparametric risk indices

All the above-mentioned monoparametric indices are used in generating system planning (busbar model). Table 2.3 provides an idea of those most often adopted by electrical utilities in various countries. Naturally, the indices shown are often complemented by others that take local conditions into account.

It should be emphasized that direct comparison of numerical figures not only is difficult but could be misleading, since different computational methods may have been used, resulting in different interpretations. Furthermore, allowance must be made for load variations due to weather effects and errors in growth forecasts, for assistance from interconnections with other utilities, for remedial or emergency actions and for multi-state modeling of generating-unit availability. Finally, for utilities expressing the index as a probability (e.g. 0.02), direct comparison is further hampered by the difficulty of defining the population to which this refers.

It should be recalled that the expected value is the weighted average of all the values of a random variable, the weights being the related probabilities. The random variable in the present case is the capacity shortfall, defined as follows:

$$\begin{array}{lll} \Delta = L - C & \text{if} & L > C \\ \Delta = 0 & \text{if} & L \leq C \end{array}$$

where L varies between $L_{min}$ and $L_{max}$ with a probability density $p_L(L)$ and C between 0 and $C_{max}$ with a probability density $p_A(C)$.

When the load has only a fixed value L, the expected value of $C_x$ is

$$C_x(L) = \frac{\int_0^L (L-C)p_A(C)dC + 0 \cdot \int_L^{C_{max}} p_A(C)dC}{\int_0^{C_{max}} p_A(C)dC} \qquad (MW)$$

But the integral $\int_0^{C_{max}} p_A(C)dC$ extended over the entire range of C, which is the total weight of the probabilities considered, is equal to one and the zero values can be deleted so that the following relation can be written:

$$C_x(L) = \int_0^L (L - C)p_A(C)dC \qquad (MW)$$

In the second member of the expression, only shortfalls different from zero appear but the weighted average also takes account of zero shortfalls.

By analogy, when the load is a random variable, for the whole range of probable loads

$$C_x = \frac{\int_{L_{min}}^{L_{max}} p_L(L)dL \cdot \left[\int_0^L (L-C)p_A(C)dC + 0 \cdot \int_L^{C_{max}} p_A(C)dC\right]}{\int_{L_{min}}^{L_{max}} p_L(L)dL \cdot \int_0^{C_{max}} p_A(C)dC} \quad (MW)$$

Any possible deficiency, including zero deficits, is weighted with the related probability $[p_L(L)dL \cdot p_A(C)dC]$ and the total weight appearing in the denominator is equal to one. We can therefore write

$$C_x = \int_{L_{min}}^{L_{max}} p_L(L)dL \cdot \int_0^L (L-C)p_A(C)dC = \int_{L_{min}}^{L_{max}} -C_x(L)dL \quad (MW)$$

where

$$-C_x(L)dL = \left[ p_L(L) \cdot \int_0^L (L-C)p_A(C)dC \right] dL$$

As before, only shortfalls different from zero appear in the second member of this expression but in the weighted average zero shortfalls are also taken into account.

Likewise, it is possible to use the related probability density functions of L and C to calculate the expected capacity shortfalls $C_{xp}(d_j)$ at the daily peak load for an entire year and to obtain an annual index $C_{xp}(y)$

$$C_{xp}(y) = \frac{1}{365} \sum_{j=1}^{365} C_{xp}(d_j) \qquad (MW)$$

This index has been proposed as a companion to LOLE and, like the latter, is used for systems where there is no limitation on the primary energy (fuel) supply to the generating units.

If the related probability density functions of L and C are used to calculate $C_x(s_j)$ for N time intervals $s_j$ covering a whole year, an annual index $C_x(\bar{y})$ can be obtained as the weighted average of the $C_x(s_j)$ values, the weights being the ratios $_j$, which represent the duration of each interval expressed in fractions of a year.

$$\left(\sum_{j=1}^{N} \alpha_j = 1\right)$$

$$C_x(y) = \frac{\sum_{j=1}^{N} \alpha_j C_x(s_j)}{\sum_{j=1}^{N} \alpha_j} = \sum_{j=1}^{N} \alpha_j \cdot C_x(s_j) \, (MW)$$

For instance, if the week is chosen as the time interval, the following equation is obtained:

$$C_x(y) = \frac{1}{52} \cdot \sum_{k=1}^{52} C_x(w_k) \qquad (MW)$$

#### 2.2.1.5 Expected energy not supplied

This index, $E_{TOT}$ ($EENS_{TOT}$), is defined as the long-term average of the energy curtailed because of system deficiencies. For generating systems having units with unlimited primary energy at their disposal (thermal systems), this index can be obtained from the appropriate expected capacity shortfall index $C_x$.

Considering a one-week time interval (see Fig. 2.4) and the probability density function of hourly loads $p_{LW}(L)$, and assuming that the probability density function of the available capacity $p_{AW}(C)$ does not vary during the interval, the corresponding index

## Table 2.3

### Example of monoparametric static risk criteria used by various electrical utilities for generating systems

Source: CIGRE SC-37 - Oslo Meeting 1983
Udpated: Electra No. 110, January 1987

| | Reserve (%) | LOLE (days/yr) | E and $E_{TOT}$ (MWh/yr) (p.u.) |
|---|---|---|---|
| **Europe** | | | |
| Belgium | | x (16 h/yr) | |
| Finland | (17) | | |
| France (EDF) | | x (5) | x |
| Ireland (ESB) | | x (0.2) | |
| Italy (ENEL) | | x (0.2) | x ($10^{-5}$) |
| Spain | | x (0.1) | |
| Sweden (SSPB) | | x (0.4) | x |
| United Kingdom (CEGB) | (28) | x (1.8) | |
| Hungary | | x (50 h/yr) | |
| **North America** | | | |
| Canada (Ontario Hydro) | | x (0.1) | |
| USA (most utilities | | x (0.1) | |
| **Others** | | | |
| Australia (Victoria) | (25-35) | x (0.5) | |
| Brazil | x | x (2.5) | |
| Japan | see note | x (0.3) | |
| South Africa (ESCOM) | (28) | x (6) | |

x = Index in use
( ) = Target values

Note: In the case of Japan, the reserve values of 8-10% usually indicated do not take planned maintenance into account and are therefore not comparable with other reserve values.

### 2.2.2 Biparametric Indices

#### 2.2.2.1 Frequency and duration of capacity shortfalls

The indices based on frequency and duration, F&D, represent an extension of the LOLE (or LOLP) index in that they provide more information: they identify the average rate at which a capacity shortfall occurs as well as its average duration. The frequency of occurrence typically refers to events per year and the duration is generally expressed in days or hours [6-8].

Two-state (peak and off-peak), multi-state and continuous daily load models have been used in computing this index.

Both the LOLP (LOLE) and the EENS indices utilize the steady-state unavailability U and availability A parameters. In addition, F&D techniques utilize the transition rate parameters (failure rate = $\lambda$ and repair rate = $\mu$).

In order to determine this particular index, the following variables must be evaluated:

- Margin: difference between available capacity and load
- Cumulative margin, M, a state containing all states with a margin less than or equal to that specified
- Probability of that cumulative margin state, $P_M$, obtained as $P_M = P(X) \cdot P_{load}(C^*-X-M)$ where:

P(X) = probability of a capacity outage of magnitude X

C* = installed capacity of the system less any scheduled outage (assumed constant throughout each week)

$P_{load}(C^*-X-M)$ = probability that the load is less than or equal to $(C^*-X-M)$.

Note that when M is zero, $P_M$ is the LOLP in the traditional sense.

- Frequency of state M, $f_M$, whose expression can be found in [7] and [8].

The following general expression exists between the above variables:

$$D_M = P_M/f_M$$

where $D_M$ = average duration of M

$P_M/f_M$ = probability of residing in state M divided by the frequency of encountering it

The frequency of encountering a load loss and the latter's average duration are determined simply on the basis of the cumulative margin being equal to zero (M = 0).

The F&D technique that produced this index originated in the USA [6-8]. In reality, the index is not widely employed in generating system analysis although it has found extensive use in transmission studies, as will be seen later.

### 2.2.2.2 Mean amount and duration of energy curtailment

This index is based on two parameters: the mean amount of an energy curtailment $e_c$, which is given in megawatthours per curtailment, and its mean duration $r_c$, given in hours. It is used by ENEL in Italy in conjunction with the monoparametric index EENS (see Fig. 2.5) for quantitative reliability assessment of generating systems. The following relationship can be employed to obtain the frequency of curtailment $f_c$:

$$EENS = f_c \cdot e_c \quad (MWh/yr)$$

It was pointed out earlier that particular difficulties arise in risk index evaluation when the generating system includes hydroelectric plants and when the time intervals to be considered during the year are short and therefore numerous. The latter situation is peculiar to systems that comprise pumped-storage plants with a night-day cycle, especially when the reservoir storage capacity limits the generation mode at full capacity to a range of 4 - 14 h.

In such situations, sequential Monte Carlo samples[1] of relevant variables are performed at hourly intervals chronologically throughout the year. In the hourly situation defined by the samples [4,5,15], the appropriate operating policies (dispatching, drawdown from reservoirs, etc.) are implemented and possible capacity shortfalls and primary-energy (water) deficits are recorded.

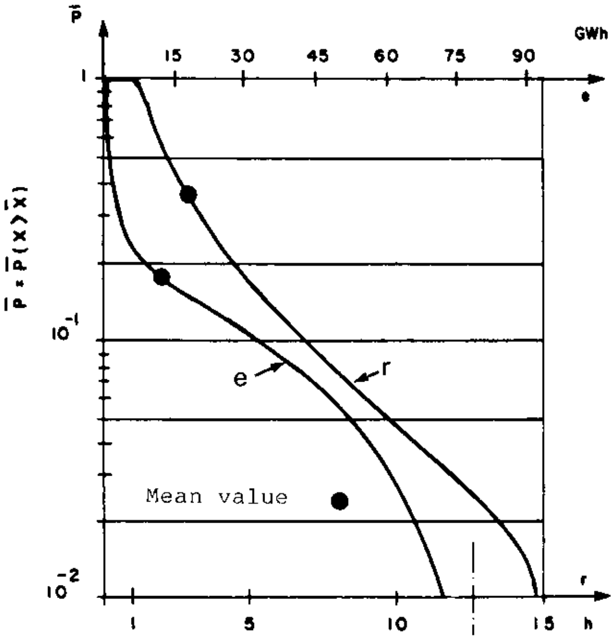


Figure 2.5 - Probability distributions of durations (r) and amount (e) of curtailment for the definition of biparametric indices

The relevant statistics give both the average values of $f_c$, $e_c$ and $r_c$ and their probability distributions. The yearly scan is repeated a suitable number of times to obtain averages of the various indices that provide a good estimate of the expected values.

Obviously, detailed simulation like this is also used to evaluate the expected values of other system performance indices of interest in planning assessment: the load factors of each generating unit's primary-energy consumption and related running costs.

## 2.3 TRANSMISSION SYSTEM ADEQUACY INDICES

If the evaluation of the adequacy risk indices includes the transmission system, it is usually termed "composite-system" or "bulk transmission system" adequacy evaluation.

When considering the influence of the transmission system on the overall system reliability, it should be recalled that the system's capability to transfer the output from the generating units to the load supply points depends not only on the pos-

---

[1] As far as the availability of generating units is concerned, the distributions of availability-state or outage-state durations of the form $P\{t \leq T\} = 1 - e^{-\alpha t}$ are used, $\alpha$ being the relevant transition rate from the state considered ($\lambda, \mu$). Naturally, with Monte Carlo simulation, any arbitrary distribution for service and repair states may be incorporated.

sible outages of components but also on the load flows determined by Kirchhoff's laws for different generation and transmission states, loads and dispatch situations. The availability of reactive sources and their flows should be considered as well.

The power flows resulting from the different system states can give rise to currents in the network components and/or voltages at the network nodes that are outside permissible limits: to ensure return to within these limits, appropriate operating (redispatching) policies are applied in reality, and must be simulated when computing adequacy indices. Should such policies be unsuccessful, the load supply may be curtailed; these curtailments constitute measures for the adequacy risk indices.

When the transmission system is included, adequacy is usually assessed by considering two sets of indices: individual bus ("where") indices and overall system indices. These are naturally complementary, not alternatives: the bus or load-point ("where") indices monitor the effect on individual buses and can be used to provide input for adequacy evaluation at the secondary-transmission level, whereas system indices give an assessment of overall adequacy.

Two main evaluation methods are used, contingency enumeration and Monte Carlo simulation.

### 2.3.1 Contingency Enumeration Method

The contingency enumeration method is an extension of the approach quoted in connection with generating systems [8]. The basic parameters are the probability and frequency of failure at individual load points but additional indices can be created from these generic values.

It is important to appreciate that if these indices are calculated for a single load level and expressed on the basis of one year they should be designated as "annualized" values. Annualized indices calculated at the system peak load level are usually much higher than the actual annual indices and can therefore be used only for comparing different alternatives of system structure, not for system optimization.

#### 2.3.1.1 Load-point indices

The annualized load-point indices for each bus of the system are given below.

Basic Values

- Probability of failure[1] : $Q_k = P_j\ P_{kj}$ (dimensionless)

- Frequency of failure[1] : $F_k = F_j\ P_{kj}$ (occ/yr)

  where $j$ is a network outage condition

  $P_j$ is the probability of existence of $j$

  $F_j$ is the frequency of occurrence of $j$

  $P_{kj}$ is the probability of the load at bus k exceeding the maximum load that can be supplied at the bus during $j$

- Expected number of voltage violations:

  $$\sum_{j\epsilon V} F_j (\text{occ/yr})$$

  where $j$ $V$ includes all contingencies causing a voltage violation at bus k

- Expected number of load curtailments:

  $$\sum_{j\epsilon x,y} F_j (\text{occ/yr})$$

  where $j\epsilon x$ includes all contingencies resulting in line overloads alleviated by the load curtailment at bus k

  $j\epsilon y$ includes all contingencies resulting in isolation of bus k

- Expected load curtailed:

  $$\sum_{j\epsilon\ x,y} L_{kj} F_j = \text{ELC}(\text{MW/yr})$$

  where $L_{kj}$ is the load curtailment at bus k to alleviate line overloads arising due to the contingency j or the load not being supplied at an isolated bus k due to j.

- Expected energy curtailed:

  $$\sum_{j\,\epsilon\,x,y} L_{kj} D_{kj} F_j\ (\text{MWh/yr}) = \sum L_{kj} P_j$$

  $$\times\ 8760\ (\text{MWh/yr}) = \text{EENS}\ (\text{MWh/yr})$$

  where $D_{kj}$ is the duration in hours of the load curtailment either arising as a result of the outage j or occurring at an isolated bus k due to outage $j = D_j \times P_{kj}$

- Expected duration of load curtailment:

  $$\sum D_{kj} F_j = \sum D_j P_{kj} F_j =$$

  $$\sum P_j P_{kj}\ 8760 = 8760\ Q_k = F_k\ D_k\ (\text{h/yr})$$

---

[1] In the case of a two-state component outage model.

Maximum Values

- Maximum load curtailed:

$$\max\ (L_{k1}',\ L_{k2},\dots,L_{kj}) \quad \text{(MW)}$$

- Maximum energy curtailed:

$$\max\ (L_{k1}\ D_{K1}',\ L_{K2}D_{K2},\dots L_{kj}D_{kj}) \quad \text{(MWh)}$$

- Maximum duration of load curtailment:

$$\max\ (D_{k1},\ D_{k2},\dots,D_{kj},\dots) \quad \text{(h)}$$

Additional information on the contingencies that cause these maxima is desirable in order to appreciate their severity.

Average Values

- Average load curtailed:

$$\frac{\sum\limits_j L_{kj}F_j}{\sum\limits_j F_j} \quad \text{(MW/curtailment)}$$

- Average energy not supplied : $\dfrac{\text{EENS}}{\sum\limits_j F_j}$ (MW/curtailment)

- Average duration of curtailment: $\dfrac{D_{kj}F_j}{\sum\limits_j F_j}$ (h/curtailment)

The individual load-point indices can be aggregated for all k buses to produce a set of system indices which can provide an overall assessment of the system adequacy.

### 2.3.1.2 System indices

A set of indices for the overall system is given below [1].

Bulk Power Interruption Index

The BPII is defined as the average number of megawatts of system or area load interrupted per megawatt of system or area load served, which is the ratio of total load interrupted to annual peak load ($L_{max}$). Its calculation calls for the study of sufficient load levels to be able to adequately define the system reliability.

$$\text{BPII} = \frac{\sum\limits_k \sum\limits_j L_{kj}F_j}{L_{max}} \quad \frac{\text{(MW)}}{(\text{MW}_p)} \ /\text{yr}$$

Bulk Power Energy Curtailment Index

The BPECI, an extension of the BPII, relates the annual energy not supplied to the peak load, which can be calculated using EENS:

$$\text{BPEC} = \text{EENS}/L_{max}$$

$$\text{BPECI} = \frac{\sum\limits_k \sum\limits_j L_{kj}D_{kj}F_j}{L_{max}} \quad \frac{\text{(MWh)}}{(\text{MW}_p)} \ /\text{yr}$$

Severity Index

The BPECI is also known as the severity index. The total unsupplied energy expressed in megawatts per minute is divided by the peak system load in megawatts. The severity is therefore expressed in system-minutes, one system-minute being equivalent to an interruption of the total system load for one minute at peak load. It does not represent a real system outage time because the interruption need not be concurrent with the peak.

It is useful to remember that this severity index has made it far easier to compare operating events and system behavior from year to year. A recent survey on bulk electricity system disturbances, initiated in 1983 on behalf of CIGRE SC 39, WG 05, grouped disturbances according to four degrees of severity, depending on the impact on customers (less than 1 (disturbance acceptable), 1 to 9, 10 to 99 and 100 to 999), and obtained statistics on all degrees of severity. More details on this subject are given in section 7.

Bulk Power Supply Average MW Curtailment/ Disturbance

$$\frac{\sum\limits_k \sum\limits_j L_{kj}F_j}{\sum_j F_j} \quad \text{(MW/disturbance)}$$

Other annualized system indices, similar to those for load points, can be obtained as indicated below.

Average Values Per Load Point

- Number of curtailments $= \sum\limits_k \sum\limits_j F_j/L_p$
- Load curtailed $= \sum\limits_k \sum\limits_j L_{kj}F_j/L_p$
- Energy curtailed $= \sum\limits_k \sum\limits_j L_{kj}D_{kj}F_j/L_p$

- Duration of load curtailed =

$$\sum_{k} \sum_{j} F_j D_{kj}/L_p$$

- Number of voltage violations =

$$\sum_{k} \sum_{j \in V} F_j/L_p$$

### Maximum Values Under Any Contingency

- System load curtailed =

$$\left\{ \max \sum_{k} L_{k1}, \ldots\ldots, \sum_{k} L_{kj} \ldots \right\}$$

- System energy not supplied =

$$\left\{ \max \quad \sum_{k} L_{k1}\ D_{k1}, \ldots\ldots \sum_{k} L_{kj}\ D_{kj}, \ldots \right\}$$

### 2.3.2 Monte Carlo Simulation Method

The Monte Carlo simulation method evaluates indices similar to the ones described earlier.

It commonly utilizes the EENS risk index, in MWh/year.

This index is usually obtained according to various options: "why", "where" and "when", as explained below.

#### "Why" Option

The EENS is subdivided according the cause of the curtailment:

- static deficiency of installed generation (this figure corresponds to EENS in the busbar system, assuming no primary-energy constraints, as found in purely thermal systems)
- static deficiency of transmission and/or transformation capacity
- network islanding.

European systems are very meshed, with the result that thermal problems usually arise before voltage problems. For adequacy evaluation, satisfactory network solutions are usually obtained with a DC load flow based on active power.[1] The Monte Carlo approach also permits assessment of risk due to lack of reactive capacity; in such cases, another linearized load flow model for reactive power is adopted to solve the network.[2]

#### "Where" Option

The EENS is subdivided with respect to the buses where the deficiency occurs. The deficiency at each bus can be subdivided according to the "how" option.

#### "When" Option

The EENS may be also subdivided with respect to the weather conditions (normal, adverse) under which a deficiency occurs.

It is worthwhile mentioning that at ENEL this index is converted into monetary terms by adopting a suitable unit cost: the corresponding "risk cost" is used in the system optimization along with the capital cost of the plants and the fuel cost of the system.

## 2.4 SECURITY INDICES

Adequacy indices obviously do not provide complete information on the reliability of an electric power system. In particular, they totally ignore transient faults which, when eliminated, would theoretically allow the system to operate correctly but could, in practice, cause significant load disconnections as a result of stability problems or protection malfunctions. More generally, static indices may be said to understate the

---

[1] $|P| = |Y| \cdot |\theta|$

where $|P|$ = column matrix of active power injected in network nodes, known

$|Y|$ = square matrix of network admittances, known

$|\theta|$ = column matrix of voltage angles, to be determined under the assumptions:

i) voltage constant in each bus = rated voltage = 1 p.u.

ii) no active losses

iii) differences $\Delta\theta$ of bus angles are small, such that $\sin \Delta\theta \approx 1$, $\cos \Delta\theta \approx 1$.

[2] $|Q^*| = |Y| \cdot |\theta|$

where $|Q^*|$ = column matrix of reactive injections plus reactive losses in each bus, known

$|\alpha|$ = column matrix of percentage voltage variation with respect to rated value ($V = V_n(1 + \alpha)$) under assumptions ii) and iii) in note 1.

way load reductions can occur due to faults and outages.

It is well known that load reductions due to unavailability can either be implemented by a dispatcher, according to a prevention program based on short- or long-term forecasts, or happen suddenly, at the moment a change in availability occurs. Such events may be the consequence of automatic-device action (underfrequency), separation from generation or instability. In these cases, the disconnected load may be considerably greater than the load corresponding to the shortfall of static capacity of the system (Fig. 2.6a) and could even affect the entire system load, resulting in a general blackout (see Fig. 2.6b). It may happen, therefore, that two systems characterized by the same adequacy index could have very different reliability, for two main reasons:

- different policy followed by the dispatcher in programming load reduction at critical moments
- different system behavior during the dynamic phase.

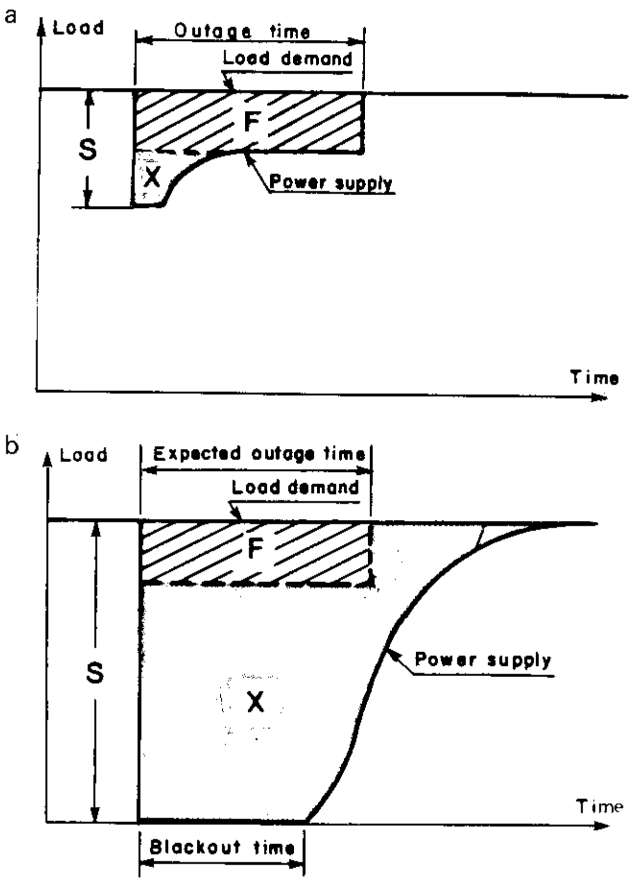


Figure 2.6 - Power supply trend during system outages:
S = suddenly disconnected power
F = curtailed energy, disregarding transients
F+X = total curtailed energy

Consider, for example, two systems whose production is the same in every respect except in their amount of capacity reserve; e.g. system 2 has a 5% greater reserve margin than system 1. Suppose that during critical periods system 1 is operated using all the generating power available, i.e. without keeping any spinning reserve, while system 2 is operated using only 95% of the available generating power, keeping the remaining 5% as spinning reserve. Obviously, the adequacy index will be the same but, just as obviously, system 2 is more reliable because, if a generator has a forced outage during a critical period, the dynamic consequences for system 1 may be far more serious.

Now consider two other systems, both operated according to the same criterion but consisting of units very different in size, although with an installed reserve sufficiently similar to have the same static risk index. It might therefore be said that the systems have the same adequacy, yet the first, characterized by larger units, is not as secure as the other, in practice, and the dynamic consequences of forced outage of the generators are far more serious in fact.

Such considerations are also of fundamental importance in the case of long point-to-point transmission systems where reinforcements may often be required just for preventing stability problems, while the static risk is negligible. Even in these cases, however, the usual procedure for selecting a priori the same "credible faults" for which stability must be maintained can lead to unnecessary investments. It seems far preferable to evaluate the consequences of the different types of fault in terms of the estimated amount and duration of load disconnection, for instance, and to weigh these consequences with the probability of occurrence of such faults.

In this way, it is possible to arrive at security indices that permit a quantitative comparison of the expansion alternatives. A number of such indices are described below.

### 2.4.1 Probability of Lower-than-Critical System Frequency During a Transient

Since the system cannot operate below a certain frequency value (critical level), in particular because thermoelectric stations cannot operate under such conditions, the corresponding probability approximates the probability of total breakdown, or blackout. This index considers only the more serious or rarer consequences of the breakdown of system components and therefore does not give sufficient information for a fairly secure system, where less serious but more probable occurrences may be of greater interest.

### 2.4.2 Average Value of Suddenly Disconnected Load

This index takes account of inconveniences, apart from total breakdown, caused by a fault in a system component. For example, a suddenly disconnected load (indicated by S in Fig. 2.6) consists of:

- load that becomes isolated from generation
- load disconnected by underfrequency relays
- power required by the whole system (or by the parts that remain separated) when the frequency drops below the critical value.

Alternatively, it would have been possible to consider the energy (X in Fig. 2.6) not supplied following a transient and exceeding that already evaluated in the static index dealt with in section 2.1.6 (F in Fig. 2.6). Quantitative evaluation of this energy is even more difficult than evaluation of the disconnected power, however, since it calls for estimation of the time and modalities of service restoration following total or partial system breakdown.

### 2.4.3 Response Risk - Long-Term Average Value of Undelivered Energy During an Operating-Reserve Intervention

Evaluation of this type of index is considered here in the more general framework of evaluating the operating-reserve duty, which consists in rapidly supplying the power required for maintaining or restoring the frequency to its normal value in the event of sudden variations in generation (outages).

Two components in the operating reserve can be distinguished:

- spinning reserve, to immediately face the sudden outage of a generating unit and quickly restore the frequency to prevent a drop to inadmissible values;
- ready standby reserve, to restore the spinning reserve at such times and minimize the possibility that the outage of a second unit, finding the system without sufficient spinning reserve, result in a frequency collapse.

Naturally, the use of different plants for the operating reserve not only affects the system running cost but also has a determining influence on its dynamic behavior. In fact, taking such factors as start-up time, loading rate, etc. into account, it is clear that the various means provided to make use of the standby reserve actually offer duties of different quality, which should also be quantified in the comparison. In fact, the quicker the reserve action, the lower the risk that further capacity shortfalls will find the system without sufficient spinning reserve and possibly bring about a frequency collapse.

The need to assess this risk of not covering outages that occur within the time needed to start up a replacement unit has long been recognized and various schemes based on direct analytical approaches have been devised. In the past, due to the system structure (especially in the United States) being based on almost entirely conventional thermal units with very few gas turbine, hydroelectric and pumped-storage plants, the theory assumed that every loss of spinning reserve was compensated after a time T = 3-4 h, which corresponded to the start-up time of a thermal unit.

The increasing use of gas turbines in generating systems and the foreseen large utilization of conventional storage means have changed this situation as well as the concept of response risk.

Nowadays in the United States, 5-min and 1-min response risks are computed by direct analytical methods using time-dependent probabilities to obtain a system response table of the generation used. The computations are similar to those performed to determine the (LOLE) LOLP risk in the static reliability evaluation [8,20].

ENEL, in the more general framework of evaluation of the dynamic duties of storage plants, has opted rather for simulation of the system operation, examining in detail the hourly intervals where forced outages take place and simulating, within the hour, the intervention of the various means allocated to the operating reserve [13,14]. The modeling procedure is as follows. Outages are assumed to happen at the beginning of the hour. The spinning reserve available at the end of the previous hour instantaneously intervenes and makes up for all (or part) of the outage. Then, when dispatched, the standby reserve intervenes:

- firstly, if necessary, it contributes to the amount of forced outage, adding its capacity to the spinning capacity already utilized;
- secondly, it restores the spinning reserve by replacing it, as far as possible.

Whenever the available spinning reserve cannot match the amount of forced outages, the integral over time of the share of the load not covered by the operating reserve during its interventions is computed. This energy can be assumed as an indication, albeit simplified, of the load shedding needed to prevent the frequency from dropping to dangerously low values. The expected value of the yearly energy shortfall could be assumed as being the dynamic risk of the system.

To complete the illustration, Fig. 2.7 shows the rarest situation that could arise, namely two forced outages in one hour and a third at the beginning of the following hour. This dynamic risk is naturally expressed in megawatthours not supplied, i.e. the same units used for the indices assumed to evaluate the static reliability of the system. The problem of its conversion into monetary terms arises of course. This index is still under examination by ENEL and is mentioned here simply to complete the present review in order to give an idea of the planning problems in which it can be utilized.

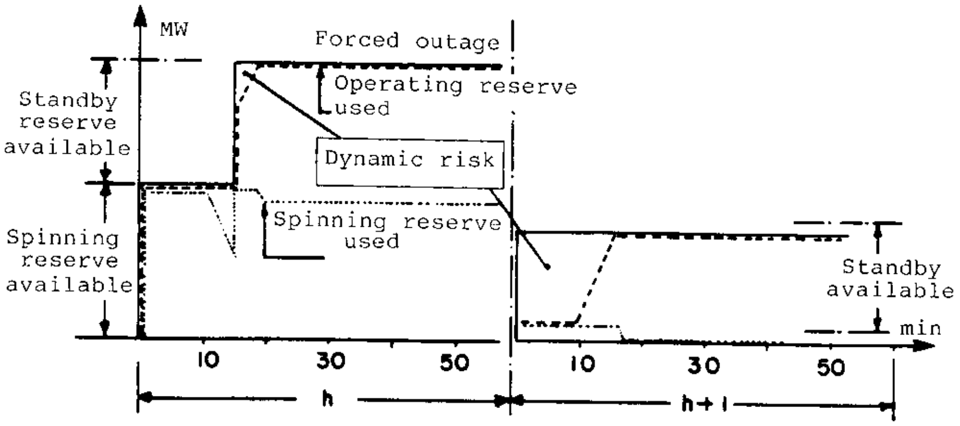


Figure 2.7 - Simulation of the intervention of spinning reserve and ready standby reserve for definition of the proposed dynamic risk of the system

## 2.5 TEMPORARY-INTERRUPTION RISK INDICES

These indices belong to a category that considers system reliability in terms of unavailabilities involving temporary interruption of a supply for intervals of time ranging between fractions of a second and many minutes. Examples include interruptions following a successful opening and reclosing or a switching operation.

In general, temporary interruptions can be classified according to their duration:

- up to one second
- a few minutes (corresponding to slow reclosing or slow automatic switching)
- dozens of minutes (corresponding to manual operations for eliminating the faulty component and possibly restoring supply by other means).

The gravity of a temporary interruption depends on the class of the duration and on the type of load curtailed. In fact, there are some load types for which a temporary interruption, even one lasting a few seconds, may involve a pause in productive activity for a number of minutes. A typical diagram showing the consumption trend after a very short temporary interruption of the supply (three-phase opening and reclosing) is given in Fig. 2.8.

With regard to different load behavior with different classes of interruption duration, separate risk indices are generally required. Those specified below can be considered as valid for the various classes. They are generally applied to systems with several supply points, and the local index values can be combined into an overall index.

- Annual expected value of the temporarily interrupted load for a given class

  This index, within the framework of the respective duration classes, does not take into account the actual duration of the interruption.

- Annual expected value of the temporarily interrupted energy for a given duration class

  This index is obtained by multiplying the interrupted load by the corresponding interruption duration. It does not take into account the energy curtailed while the load is being

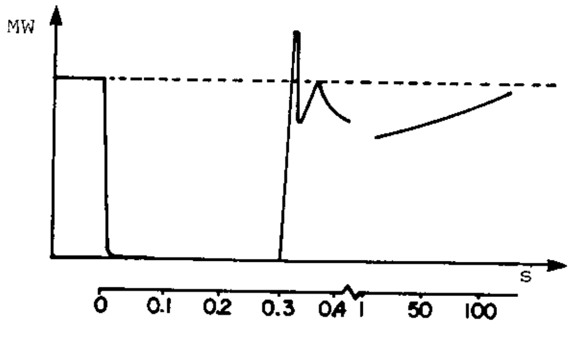


Figure 2.8 - An example of the active power consumption trend following a very short temporary interruption (0.3 s) of supply (three-phase opening and reclosing)

picked up following restoration of the supply (which depends on the characteristics of the load, not on those of the system).

## 2.6 INDICES FOR MEASURING ACTUAL COMPOSITE-SYSTEM RELIABILITY

A variety of indices exist for studying different aspects of composite-system reliability. Since they mainly concern planning problems, these indices are calculated by system planners.

Recent years have also seen an effort to measure the composite-system reliability actually incurred. Thus each utility can compare the actual reliability of its power system at different times, compare it with the performances recorded by other utilities and assess it in terms of a suitable industry average. These measurements also allow the identification of various factors that can account for differences in performance. In other words, composite-system reliability is assessed by making inferences based on actual data. The collection of performance data allows feedback information to be used to validate the design of the composite system as well as the reliability model that served in its evaluation.

A performance reporting system has been proposed [9] for measuring composite-system reliability. This system acknowledges that collecting and analysing unreliability data can be time-consuming and expensive, while some quantities may be difficult to obtain and analyse. Simplicity of measurement is therefore the main aim of this reporting system, which is also designed in terms of providing adequate coverage of the various possible impacts of unreliability events on customers.

### 2.6.1 Elements of the Performance Reporting System

For the purpose of the performance reporting system, the composite system is referred to as the bulk electricity system (BES). The BES supplies electricity to distribution networks through various low-voltage buses, which are considered as load points but referred to as delivery points to indicate that they are points where the BES delivers electricity to the distribution networks. The latter, in turn, supply electricity to various customer systems.

The recommended performance reporting system comprises three specific systems covering:

- BES delivery point interruptions
- BES effects on distribution networks and customers
- BES disturbances.

Delivery point interruptions comprise two types: momentary and sustained. In the case of the former, lasting less than 1 min, service is restored by automatic reclosure schemes and the impact is mainly on industrial and commercial customers with little effect on residential and rural customers. Sustained interruptions are those lasting 1 min or more.

BES unreliability can affect distribution and customer systems in other ways, without the low-voltage buses or delivery points being interrupted. The following actions can take place:

- opening of circuit breakers on distribution system feeders, for rotational load cuts, by underfrequency and undervoltage system protection or by automatic system load rejection
- cuts implemented on customer systems, such as reduction of interruptible load, voluntary load reduction in response to public appeals, regulatory curtailments...
- cuts occurring on customer systems, such as response to a lowering of BES supply voltage, or initiation of customers' protective devices caused by abnormal BES voltage or a frequency excursion.

The third type of unreliability event of importance, BES disturbances, is defined as widespread load loss characterized by one or more of the following phenomena:

- loss of system stability
- cascading outages of transmission circuits
- abnormal ranges of frequency and/or voltage.

A BES disturbance is characterized by many delivery point interruptions, while in addition there may be the tripping of distribution system feeders for rotational load cuts, or load shaken off due to frequency or voltage excursions, etc. BES disturbances therefore include both delivery point interruption and effects on distribution and customer systems. The reporting of these additional aspects of BES unreliability must however be segregated, on the basis that the coincidental loss of supply to a large number of customers should be examined separately.

### 2.6.2 Indices for the Performance Reporting System

Indices have been arrived at for the first two reporting systems described above, namely, BES delivery point interruptions and BES disturbances. Performance data for the latter have been collected in a survey conducted by CIGRE WG 39.05 among 168 utilities, totalling 1369 utility years of experience. The data have been analysed and the observations and conclusions reported [10].

### 2.6.2.1 Indices for delivery point interruptions

The indices for delivery point interruptions are:

- the frequency of interruption, for momentary interruptions
- the frequency of interruption and the annual duration of interruption (i.e. sum of interruption durations/year), for sustained interruptions,

These three indices are calculated every year for all BES delivery points. Obviously, each year some points will experience unusually good or unusually poor performances and a satisfactory performance at one point will not compensate for a poor performance at another. Portrayal of average results alone would mask poor performances, so that a cumulative frequency portrayal should also be employed.

### 2.6.2.2 Indices for BES disturbances

These are based on the severity index discussed in section 2.4.1. The number and severity of BES disturbances give a measure of a) the effectiveness of the design and operating criteria established to provide security against such events arising due to contingencies having a reasonable probability of occurrence, b) the controls provided for both normal and emergency states, and c) the selection and training of operating personnel.

For ease of presentation and assessment, individual unreliability events such as BES disturbances are classified according to the following definitions:

| | |
|---|---|
| Degree 0 | - unreliability condition normally considered acceptable |
| Degree 1 (Significant) | - unreliability condition with possibly significant impact on customers but not considered serious, typically less than a factor of 10 above that considered acceptable |
| Degree 2 (Serious) | - unreliability condition with a serious impact on customers, typically 10 to 100 times above that normally considered acceptable |
| Degree 3 (Very serious) | - unreliability condition with a very serious impact on customers, i.e. 100 to 1000 times above that normally considered acceptable. |

Thus, each BES disturbance is measured in terms of the severity index and classified according to its degree of severity:

Degree 0 - incident with a severity index of less than 1 system-minute

Degree 1 - incident with a severity index from 1 to 9 system-minutes

Degree 2 - incident with a severity index from 10 to 99 system-minutes

Degree 3 - incident with a severity index from 100 to 999 system-minutes

Based on the foregoing, the indices recommended for reporting BES disturbance performances are:

- frequency of degree 0 disturbance
- frequency of degree 1 disturbance
- frequency of degree 2 disturbance
- frequency of degree 3 disturbance.

## 2.7 SUGGESTED USES OF RISK INDICES IN SYSTEM PLANNING

The possibility of evaluating reliability in quantitative terms is of primary importance in the planning of electric power systems. Indeed, such a task generally requires an economic comparison of various alternatives designed to be equally able to meet the load but this can only be done if the alternatives have the same value with respect to the pre-established risk index.

It is often assumed that alternative systems have identical reliability when the risk index adopted does not exceed the permissible limit. The economic comparison is then made by taking into account only the usual cost components, capital costs and running costs. For a deeper analysis, however, it may be argued that this assumption has some fundamental limitations, as seen below.

An electric power system consists of a finite number of components whose nominal rating is chosen in discrete steps. The reliability of the system can therefore be increased or decreased by finite quantities which, according to the limit value of the index, may present different margins. These should be taken into consideration in the comparison, allowing some compensation proportional to the reliability margin, for example. This compensation may be interpreted as an economic evaluation, albeit conventional, of the greater reliability of the system. Thus, a third economic component appears in the comparison of planning alternatives: reliability compensation. Actually, in conformity with the other economic components, it is more convenient to take a risk cost as third component by ascribing a monetary value to each unit of the risk index.

An even more serious criticism of the methods of comparison on the basis of so-called equal reliability is that the risk limit (or reliability level) is chosen a priori, without considering the advisability of a given choice. Indeed, no account is taken of the fact that an increase in reliability might be advisable if this results in only a slight increase in cost, while in other cases a slight reduction in reliability might be acceptable if it promises significant savings.

A reasonable basis for comparing planning alternatives would therefore appear to be one that does not involve any fixed reliability level but rather makes economic comparisons among alternatives, each being optimized by minimizing its overall cost made up of capital costs, operating costs and risk costs. The level of reliability of each alternative is thus its optimal level and the comparison can be based on the minimum overall cost of each alternative.

Assignment of a risk cost proportional to the value of the risk index means that the unit value of that cost (e.g. for LOLE, the $/day on which the peak is not met, or for EENS the $/MWh not supplied) must be predetermined. This is termed the failure cost. Theoretically, failure cost corresponds to the change in socioeconomic costs corresponding to a change of one unit in the reliability index.

Two classical approaches exist for relating the socioeconomic costs to the risk index: the implicit cost and the explicit cost.

With respect to the implicit cost, it may be argued that the values of reliability indices developed over time in response to public needs as shaped by economic and regulatory forces tend to reflect the optimum trade-off between the cost of achieving the value and the benefit derived by society. From the Kuhn-Tucker theory of mathematical programming, a strict relationship exists at the optimum between an active system constraint (which may represent either a physical or a performance limit) and the shadow price for a unit change in the constraint. Assuming the reliability index to be an active constraint for a given system plan, the shadow price is the implicit value of the failure cost. For example, suppose that the addition of a peaking unit is necessary for a plan to satisfy a system reliability index, EENS. At optimum, the variation in capital and operating costs associated with the addition of the peaking unit corresponds to the decrease in the cost of the curtailed energy. A unit cost for curtailed energy can therefore be determined. Although it may appear that the a **priori** choice of reliability level is more robust than the a **priori** choice of failure cost, it is important to stress the dual relationship implied between reliability level and reliability cost. If one were to examine a number of typical systems, it would be possible to develop median and range statistics and to fix the order of magnitude of failure costs for various risk indices.

The explicit-cost approach uses subjective and objective measures of customer losses arising from interruption or curtailment of service. The unit cost of losses due to curtailed energy, kWh, is normally a composite formed from the losses of various classes of customer affected by the interruption. Some organizations employ expressions representing increasing cost of losses as a function of the severity of curtailment. EDF, for example, uses quadratic functions to express the cost of losses as a function of the severity of curtailment.

Investigations of the customer perception of the cost of losses of service have shown that the figures vary widely from one customer type to another [15-17] but also depend on considerations that are purely subjective [18]. Costs of losses due to interruptions are not readily deduced from the direct economic consequences of interruptions and curtailments of service. There are also indirect effects, which are more difficult to observe and to predict. Moreover, account must be taken of social quality factors, which cannot be directly evaluated in direct economic terms. Finally, many practical risk indices used for planning and design are not absolute measures of system reliability but relative, and consequently very schematic versions of reality.

When studying systems with several supply points, it should also be borne in mind that the consequences of curtailments on various loads may differ. This can be taken into account by assigning different failure costs to the local risk indices, according to the nature of the respective loads. This is equivalent to using a single risk reference cost and correcting the local indices with a coefficient of importance. In such cases the overall risk index is obtained not from a simple summation of the local indices but from a weighted sum of these indices.

The reliability concept should always be interpreted in a more general frame, taking into account the various historical, social, siting and financial constraints faced by the utilities. After the last oil crisis, for instance, the main problem was not the reliability level in the traditional sense - that is the correct assessment of installed capacity - but energy substitution (for instance, energy obtained with oil-fired units to be replaced by base-duty energy obtained with coal-fired and/or nuclear units). This may have led utilities to accept even an overdesigning of base-duty units and, therefore, oversizing of the overall generating system in the transient phase from the old to the future optimized structure. This could have created systems that were safer than usual, so that the concept of reliability really has to be interpreted in the context of the case.

The recent decrease in oil prices and the worldwide nuclear debate have recently added new uncertainties to the planning optimization problem and, therefore, to reliability assessment.

Utilities are increasingly facing the dilemma of trading off their customers' interest in reliability for the owner's interest in ensuring adequate return on investments. Reliability is conceived more and more as a commodity that can be differentiated, priced and marketed.

It is worthwhile emphasizing here that EPRI has sponsored many research projects [19] to determine how reliability can best be evaluated and how customers perceive its importance compared with other attributes of electricity. Other questions cover the new approaches needed to introduce rates based on reliability, the ability of new technologies to distinguish between specific end-use applications for rating or curtailment purposes and the way reliability considerations affect both demand-side and supply-side planning. The results of such research will certainly help utilities to better evaluate, maintain and improve system reliability under the constraints imposed by the present-day environment.

REFERENCES

[1] M.B. Guertin, P.F. Albrecht, M.P. Bhavaraju, R. Billinton, G.E. Jorgensen, A.N. Karas, W.D. Masters, A.D. Patton, N.D. Repen and R.P. Spence, "Reliability Indices for Use in Bulk Power Supply Adequacy Evaluation," IEEE Trans. PAS-97, No. 4, July-August 1978.

[2] G. Manzoni, L. Paris, L. Salvaderi and M. Valtorta, "Risk Indices for Reliability Assessment in Electrical Power System Planning," Position Paper for CIGRE W.G. 38.03 Montreux Meeting, 1983.

[3] G. Manzoni, P.L. Noferi and M. Valtorta, "Planning Thermal and Hydraulic Power System Relevant Parameters and their Relative Influence," CIGRE Report No. 32-16, 1972.

[4] P.L. Noferi, L. Paris and L. Salvaderi, "Monte Carlo Methods for Power System Reliability Evaluations in Transmission and Generating Planning," Proceedings of Annual Reliability and Maintainability Symposium, IEEE 75 CHO 918-3 RQC, p. 449, Washington, January 1975.

[5] L. Paris, L. Salvaderi and M. Valtorta, "Energy Storage Peak Load Plants in Future Energy Production Systems," CIGRE Session Paper 31.10, Paris, 1976.

[6] R. Billinton, R.J. Ringlee and A. Wood, Power System Reliability Calculation, MIT Press, 1972.

[7] J.D. Hall, R.J. Ringlee and A.J. Wood, "Frequency and Duration Methods for Power System Reliability Calculations - Part I - Generation System Model," IEEE Trans. PAS-87, September 1968.

[8] R. Billinton and R. Allan, Reliability Evaluation of Power Systems, Longmans (London, England)/Plenum Publishing (New York), 1984.

[9] W. Winter, "Measuring and Reporting Overall Reliability of Bulk Electricity Systems," CIGRE, Paper No. 32.15, Paris, 1980.

[10] W. Winter and B. Le Reverend, "Disturbance Performance of Bulk Electricity Systems," CIGRE, Paper No. 38/30/39, Paris, 1986.

[11] P.L. Noferi and L. Paris, "Quantitative Evaluation of Power System Reliability in Planning Studies," IEEE Trans. PAS-91, No. 2, April/March 1972.

[12] P.L. Noferi and L. Paris, "Effects of Voltage and Reactive Power Constraints on Power System Reliability," IEEE PES Summer Meeting, Paper T74428-9, Anaheim, July 1974.

[13] S. Panichelli, L. Salvaderi and M. Valtorta, "Quantitative Evaluation in System Planning of Dynamic Duties for Load-Curve Following," CIGRE Paper No. 31-14, Paris, 1980.

[14] S. Panichelli and L. Salvaderi, "Dynamic Benefits of Pumped Storage Plants: Why and How," DOE-EPRI International Symposium and Workshop on Dynamic Benefits of Energy Storage Plant Operation, Boston, May 7-14, 1984.

[15] L. Paris and L. Salvaderi, "Optimization of the Basis Characteristics of Pumped - Storage Plants," IEEE PES Winter Power Meeting, C74-152/2, New York, 1974.

[16] E.M. Mackay and L.H. Berk, "Cost of Power Interruptions to Industry - Survey Results," CIGRE Paper No. 32.07, Paris 1987.

[17] M. Munasinghe, "A New Approach to Power System Planning," IEEE Trans. PAS-99, No. 3, May-June 1980.

[18] "Value of Service Reliability to Consumers," Seminar Proceedings prepared by Criteria Inc., EPRI EA 4494, March 1986.

[19] "The Value of Reliability," EPRI Journal, March 1986.

[20] L.G. Leffler, R.J. Chambliss, G.A. Cucchi, N.D. Repen and R.J. Ringlee, "Operating Reserve and Generation Risk Analysis for the PJM Interconnection," IEEE Trans. PAS-94, pp. 396-407, March-April 1975.

# CHAPTER 3

# METHODOLOGIES

## TASK FORCE

L. Salvadori (Chairman)
R. Billinton
J. Endrenyi
J. Prince
R. Ringlee

## 3.1 INTRODUCTION

The reliability of an electrical power system refers to the system's ability to perform its function of supplying load, when and where it is requested, at the appropriate voltage and frequency levels. The term "ability" is chosen intentionally to indicate the combination of hazards with respect both to the load (economic and climatic) and to the generation/transmission system (random availability of hydro energy, outages of units and network components). The effects of these combined hazards must be adequately countered by the structure that the planner gives to the system. Whether for planning or operating the power system, evaluation of its reliability level therefore is indispensable.

To produce a system free of failure would demand theoretically infinite investments. In practice, therefore, the planner must find the best compromise between economy and reliability: he is obliged to accept system failures, provided that the resulting drawbacks for the customers remain at a level which the latter will accept. This level of acceptability is defined quantitatively by reliability criteria which, historically, can be classified in two main categories: deterministic and probabilistic. Deterministic criteria are based on an examination of a number of constraining situations chosen according to the planner's and the operator's experience, taking into consideration the uncertainty of loads and the availability of system components. Probabilistic criteria recognize the random nature of probabilistic loads and outages of generation/transmission equipment. In a way, reliability evaluations constitute generalizations of the deterministic criteria, since (at least in principle) all possible constraining situations are examined and, from their results, risk indices are obtained which have an expected meaning in a probabilistic sense.

Deterministic criteria were the first to be adopted and are still in widespread use in many countries, especially for transmission system reliability evaluation. However, as new methodological approaches and computing facilities become available, probabilistic criteria are now gaining ground. They are already used by many utilities for generation system reliability evaluation, although still in the development phase for composite systems.

The intent of this chapter is to present the state of the art of power system reliability evaluation. It refers frequently to papers and books published in the last 15 years which provide more detailed information for those interested.

Although risk indices are considered here mainly from the planner's standpoint, it should be stressed that the utility's planning techniques call for feedback from the operations side. This is also true for reliability evaluation.

It is anticipated that a comprehensive unreliability measurement system will be more widely applied in the operation of bulk electricity systems. Measurement of the performance of such systems and their subsystems is desirable to evaluate trends and to compare the performance of different systems. Monitoring and recording data for each unreliability event provide a number of risk indices which form a numerical base for establishing methods for analysing the operational performance of present and future systems. These concepts could be integrated into design criteria at the planning stage.

## 3.2 DETERMINISTIC CRITERIA

Deterministic criteria are derived by examining a number of constraining situations (load and outage conditions) to check the soundness of the generating and/or transmission system. These situations are based on cases considered **a priori** to be difficult for the system (annual peak load with loss of the largest generating unit, for example). The underlying hypothesis is that if the system functions can be assured for such cases, the same will be true in all other, more favorable, cases.

The advantages of deterministic criteria, in addition to their conceptual clarity, are first the limited number of cases to be examined and, second, the fact that the tools available for this task, e.g. AC load flows, provide detailed and precise descriptions of system performance. Furthermore, such criteria often correspond to an extension to the planning stage of the techniques already used in system operation.

With regard to drawbacks, even ignoring the failure of these criteria to take into account the probability of occurrence of the case considered and, therefore, the weight of its effect, selection of the list of constraining cases depends inevitably on the planner's experience. Hence there is always a risk of omitting some cases, a risk that is ever-increasing because the nature of difficult cases can change with time in subtle ways sometimes barely perceptible. Difficulties may also arise from the sheer number of operators, whose contribution is essential in order to identify the maximum number of constraining cases based on their experience and knowledge of the existing system.

### 3.2.1 Criteria for Generating Systems

The most frequently used index is the reserve margin, which is equal to the ratio of the installed capacity to the maximum annual load, minus one. The required value is determined taking into consideration the size of the system, the size of the largest generating unit or the number of units on maintenance, among other factors. As the generating system is assumed to be on a single bus, this problem is relatively easy to solve by state enumeration methods.

The index based on the percentage reserve has gradually been replaced by other indices based on probabilistic calculations. For example, some countries indicate the range of reserve margins to which the use of probabilistic criteria lead.

Another type of criteria has been adopted for systems where hydro generation constitutes a considerable share of the total installed capacity. In this case, an energy criterion is used with respect to the portion of total demand to be served by the energy generated by hydro units.

Table 3.1 summarizes the results of an August 1984 review by CIGRE WG 37.01 of criteria used at the present time by electrical utilities throughout the world [1].

### 3.2.2 Criteria for Transmission Systems

The previous section mentioned the historical trend away from deterministic towards probabilistic indices for generating systems. Once the concept that random phenomena could be handled in a probabilistic way had been accepted, the computation algorithms were relatively easy to implement. With a transmission system, on the other hand, the calculation is much more complicated. Firstly, the problem has a spatial dimension, since the system extends over an entire territory. Secondly, the fundamental laws of electric circuits (Kirchhoff's laws) must be satisfied.

Power flows and voltages obviously depend on the component availability and other aspects of system reliability. Various simplifications can be adopted: use of linear DC load flows instead of complete nonlinear AC load flows, for instance, or limitation of the number of overlapping contingencies to be examined. Despite this effort, recourse to probabilistic indices for the reliability evaluation of large transmission systems still calls for the implementation of sophisticated models, powerful computer programs and the associated hardware. It is therefore easy to understand why most countries continue to use deterministic criteria to evaluate transmission system reliability.

The general procedure for application of deterministic criteria may be described as follows:

- Select one or several base cases to test the system capability. These should correspond to operating situations considered difficult **a priori** and preferably result from a combination of planners' and operators' experience. The base cases may differ in load conditions, in generation dispatch (corresponding to different maintenance and forced-outage conditions, with available units brought on-line according to an order of priority usually based on operating costs) and in network configuration (corresponding to various (maintenance and) forced-outage conditions, with the available components usually being all in service).

- Subject each base case to a series of generation and/or transmission incidents and examine how the system withstands them from various points of view:
  - Flows through system components kept within permissible limits: usually their maximum permissible values under steady-state conditions (generally, the thermal limit, sometimes combined with the stability limit). Some countries permit higher temporary flows for transformers for incidents involving the loss of two components or for a limited duration and sometimes use different maximum values, according to the time of year.
  - Voltage changes at network nodes kept within permissible limits: according to data obtained from surveys, these limits, which vary according to the nominal voltage, range from 85 to 110% approximately.

## Table 3.1

## Criteria for generating systems used by different utilities

| | AUSTRALIA (*) | BRAZIL | FINLAND | JAPAN | NETHERLANDS | ROUMANIA | SOUTH AFRICA | UNITED KINGDOM |
|---|---|---|---|---|---|---|---|---|
| Criteria | | | | | | | | |
| * Power (reserve ratio) | 25 to 35% | X | 17% | 8 to 10% | 30% | 9 to 14% | 28% | 23% |
| * Energy | | | | | | | | |
| Calculation period | Year | Year | | Average of three monthly peaks (Dec. - Aug.) | Year | Year (monthly peak) | All working days throughout the year | Winter peak |
| Loads | | | | | | | | |
| Uncertainty taken into account | | | | | X | | | |
| * Economic situation | X | | | X | X | | | -9.0% |
| * Climatic consideration | X | | | X | X | | | -3.8% |
| Interruptible loads taken into account | Yes | | | | | | | |

* Orders of magnitude resulting from another criterion.

Some countries use different procedures and criteria depending on the area or function of the section of transmission system under consideration (generation injection, load supply, interconnection). In fact, uniform practices do not exist but the most widespread deterministic criteria can nevertheless be ideally grouped in two classes, known as N-1 and N-2, according to the number of network components involved in the loss.

The N-1 criterion, the most widely used in practice, consists of the simulated loss of one network component (line, cable, transformer, sometimes even a reactive-power compensation component) or a generator. While all countries that have adopted this criterion consider the loss of a component, few take into account generation outages.

The N-2 criterion consists of the simulated loss of two system components, either two network components or one network and one generation component. Its use is not as widespread as N-1 because simultaneous failures are generally considered unlikely: the underlying idea is that two items would have to trip in the same region during a difficult operating situation, such as the peak load period (which lasts only a short time), for the double failure to have serious consequences. The probability of such an incident is to be judged to be very slight, however.

Some countries simulate N-2 incidents by building on the base cases examined according to the N-1 criterion. Others examine special cases of double incidents that would be most serious for their systems: for example, the loss of two principal lines in cascade, from the point of system collapse and with recourse to load shedding and other operations, or the loss of both lines of a double circuit linking a nuclear power station to the system.

Criteria based on other incidents

Some countries consider even more serious cases than those examined above. For instance:

- loss of a set of busbars (and corresponding lines)
- multiple incidents or cascade tripping, which are usually not considered by the reliability criteria and may cause major disturbances.

As these multiple incidents are most unlikely, they are assumed to occur outside peak periods and no attempt is made to invest in network components that could withstand such cases. Instead, the utility relies on operating manoeuvres to avoid system collapse as a result of cascade tripping: introduction of reactive reserves, operation of remote-control devices to shed customer loads, controlled system splitting, use of generation limiters, changes to the generation scheme and network switching. Table 3.2 summarizes the results of a recent review of this question by CIGRE WG 37.01 [1].

## 3.3 PROBABILISTIC CRITERIA AND METHODS

It was mentioned earlier that the random nature of the phenomena affecting the quantitative evaluation of power system reliability called for a shift from deterministic to probabilistic reliability indices and criteria.[1] In fact, probabilistic methods are now in almost general use in generating system planning and are increasingly being applied to composite planning.

The main reasons such methods were not widely used in the past are shortage of data, limitation of computational resources, lack of realistic reliability techniques, aversion to the use of probabilistic techniques and misunderstanding of the significance of probabilistic criteria and risk indices [2]. Today, many utilities have reliability data bases, computing facilities are greatly enhanced and most engineers have a working understanding of probabilistic techniques. However, even though reliability evaluation techniques have become highly developed, there is nevertheless a general dearth of programs for applying these techniques to large systems. Those available fall into two categories: state enumeration (analytical) and Monte Carlo simulation. These techniques are detailed in section 5 but a brief description is presented here for practical purposes and to identify the major differences between the two.

Analytical techniques represent the system by simplified mathematical models and evaluate the reliability indices from these models using mathematical solutions. In reality, when the network is taken into account, the modeling of system laws and operating policies is indispensable, even with analytical techniques. Monte Carlo simulation methods, however, estimate the reliability indices by simulating the actual process and random behavior of the overall system as well as its components and can therefore be defined as experimental mathematics.

Each approach has its merits and demerits. Generally, Monte Carlo simulation requires a large amount of computing time and is not used extensively if alternative analytical methods are available. In theory, however, it can include any system effect or process, which in analytical methods may have to be approximated, and can supply indices close to those used in actual practice by system operators and customers.

Naturally, the two approaches can evaluate the same risk indices. Comparison of the numerical values obtained offers a better understanding of their limits. With analytical tools, the system structure and components must be greatly simplified while with the Monte Carlo approach the volume of experiments and, therefore, the computing time, must be reduced. Comparison is in fact essential for system planners to become more familiar with these methods and, on the basis of their own experience and good sense, to judge which tool is appropriate for the task involved.

## 3.4 COMPUTATIONAL METHODS FOR PROBABILISTIC ASSESSMENT OF COMPOSITE-SYSTEM ADEQUACY

The evaluation of reliability indices for composite systems calls for answers to three equally essential questions: how to intro-

---

[1] The subject of risk indices is developed in Chapter 2; an outline of the basic concept is presented here to complete the reasoning. The two basic aspects of the power system reliability evaluation are its adequacy and security [3,4]. The adequacy is the power system's ability to meet the demand under steady-state conditions with full component availability and the indices derived are static because they do not take transients into consideration. Security describes the system's ability to withstand transient phenomena, which can result in the disconnected load being greater than the difference between capability and demand in the new system state; the security indices are consequently dynamic. (A third category of indices, known as temporary indices, is used to cover short-duration faults caused, for example, by temporary breakdown of the air insulation on overhead power lines, or interruptions and on radially operated systems). It should be borne in mind that most of the probabilistic techniques available for power system reliability evaluation are in the domain of adequacy assessment.

Table 3.2

Reliability criteria for the planning of the transmission and interconnection networks

Source: CIGRE SC. 37 - Oslo Meeting

| | AUSTRALIA | BELGIUM | BRAZIL | CZECHOSLOVAKIA | FED. REP. OF GERMANY |
|---|---|---|---|---|---|
| Case examined and remarks | The criterion depends on the role on played by the component | Maximum load and reduced load (85% of max.) at 300 kV | Maximum load and off-peak load<br>No switching (load shedding, generation, network) | Division of network into subsystems examined at different load levels and in different basic conditions | All possible and and realistic basic conditions<br>Special cases: long-duration maintenance and faults |
| N-1 criterion | 1 N, under the following conditions:<br>- injection lines:<br>coal units: max. gen.<br>hydroelectric: ave. gen.<br>- loads supplied: normal loads | 1 N or 1 G | 1 N | 1 N (including 1 C) or 1 G<br>Note: Power cut during repair can be accepted | 1 N or 1 G |
| N-2 criterion | 1 N + 1 $N^m$, under the following conditions:<br>- injection lines: ave. gen.<br>- interconnection: all loads<br>- loads supplied: normal loads | (1 N or 1 G) + 1 $N^m$ | | 2 (N, C or G)<br>Note: Power cut during repair cannot be accepted | No |
| Loss of busbars | | at 380 kV | | In local studies | X |
| Multiple incidents | No (because rare and reduced loads; resolved by remote control and reactive reserves) | | | | |
| Examination: | | | | | |
| - of transit flows: all countries | X | X | X | X | X |
| - of voltage limits | | X | X | X | |
| - of network splitting and collapse | | | | | X |

Captions: The loss of components is indicated by n E: n = number of components lost: 1 or 2

E = type of component: G = generator, N = network (L or T), L = (line or cable), T = transformer, C = reactive compensation

The index "m" denotes a component on scheduled outage (maintenance or repair).

Table 3.2 (cont'd)

Reliability criteria for the planning of the transmission and interconnection networks

Source: Cigre SC. 37 - Oslo Meeting

| | FINLAND | HUNGARY | IRELAND | JAPAN | NETHERLANDS |
|---|---|---|---|---|---|
| Case examined and remarks | Several load and network configuration conditions | Maximum of peak loads | Winter peak and autumn peak (with unit maintenance) | | - Max. and 90% load<br>- Criterion according to function:<br>a) service continuity<br>b) economic dispatching<br>c) use of reserve (must be possible, since whole network in service) |
| N-1 criterion | 1 N or 1 G | 1 N or 1 G | 1 N or 1 G | 1 N or 1 G | 1 N or 1 G, under the following conditions:<br>max. loads:<br>a) 1 (N or G)$^m$<br>b) no maintenance<br>90% loads:<br>a) 2 (N or G)$^m$<br>b) 1 N$^m$ |
| N-2 criterion | | 2 N at nuclear plant | | 2 L (for the main interconnection lines) | Combined with (N-1) criterion |
| Loss of busbars | X | | | | |
| Multiple incidents | | NO | | | |
| Examination: | | | | | |
| - of transit flows: all countries | X | X | X | X | X |
| - of voltage limits | X | X | X | | X |
| - of network splitting and collapse | | | | X | |

Captions: The loss of components is indicated by n E: n = number of components lost: 1 or 2

E = type of component: G = generator, N = network (L or T), L = (line or cable), T = transformer, C = reactive compensation

The index "m" denotes a component on scheduled outage (maintenance or repair).

Table 3.2 (cont'd)

Reliability criteria for the planning of the transmission and interconnection networks

Source: Cigre SC. 37 - Oslo Meeting

| | NORWAY | ROMANIA | SOUTH AFRICA | SWEDEN | UNITED KINGDOM | UNITED STATES |
|---|---|---|---|---|---|---|
| Case examined and remarks | - Various generation and load situations<br>- Criterion according to role in network (transmission, reliability, reduction of losses)<br>- Local criteria can be less strict | - Division of network into subsystems | - Several hypotheses on loads, generation and hydrology<br>- Special criteria for lines linking power stations to the network | No load shedding | Examination of the network by zones according to load level | |
| N-1 criterion | I N or 1 G | I N | 1 N | 1 N or 1 G | For area with load 60 MW:<br>1 N<br>(fault or maint.) | 1 G or 1 N<br>(typical) |
| N-2 criterion | | Loss of two circuits of a nuclear power plant | 1 L + (1 L or 1 T) | | For area with load 60 MW:<br>1 N + 1 $N^m$ | |
| Loss of busbars | X | X | | X | | |
| Multiple incidents | | | | NO (because unlikely: plan the measures to be taken | | |
| Examination:<br>- of transit flows: all countries | X | X | X | X | X | X |
| - of voltage limits | X | | X | X | | |
| - of network splitting and collapse | X | | | | | |

Captions: The loss of components is indicated by n E: n = number of components lost: 1 or 2
E = type of component: G = generation, N = network (L or T), L = (line or cable), T = transformer, C = reactive compensation

The index "m" denotes a component on scheduled outage (maintenance or repair).

duce proper recognition of dependent outages of transmission units, how to handle the large number of possible states, and how to incorporate operating strategies for relieving stress on the transmission system.

With respect to dependency, it should be noted that important outage modes, including common-mode outages involving multiple units or multiple outages due to station-originated events, ought to be included in the list of contingencies. The risks associated with these dependent causes of multiple-unit outages frequently outweigh the risks of independent overlapping outages. One chapter of this book and two appendices are devoted to the modeling of dependencies because of the significant, frequently dominating effects of dependent causes on composite-system unreliability. Chapter 6 provides an overview of the issues to be considered, including common-mode and weather-exposure effects. Attention should be paid to the risks of common loss of lines supported on the same structure or lines in close proximity on the same right-of-way. Consideration should also be given to the increase in the risk of overlapping outages of overhead lines during periods of adverse weather. A discussion of the data collection requirements for identification of common-mode events is offered in Chapter 4. Appendix 1, Weather Modeling, provides extended discussion of weather-exposure models and approaches for estimating the modeling parameters.

Prediction of the risks of substation-originated multiple-unit outages is discussed in Chapter 6 and detailed modeling and procedures for substation reliability analyses are presented in Appendix II. It is often desirable to perform substation reliability analyses in conjunction with static and dynamic system studies to determine specific ways in which component faults and maloperation of protective relaying and circuit breakers can lead to system failure.

The second question, how to deal with the large number of possible contingency states, concerns the criteria for computations. Theoretically, evaluation of composite-system adequacy would involve analysing all possible system contingency states, or at least a sufficient number of them to estimate indices with required accuracy. This could be a formidable task. Consider the IEEE reliability test system, RTS, illustrated in Fig. 3.1, which is a small representation of a composite system containing only 32 generating units and 38 lines and transformers. Allowing each line and generator two states, the number of composite-system states would be $2^{70}$. Obviously an exhaustive analysis of all these states would be impossible for the IEEE RTS, so the number considered must be limited, according to their contribution to the risk index, for instance. This might be done by means of threshold values to select states based upon their probability of occurrence: a state would be considered only if the probability of occurrence were greater than the threshold value. But setting threshold values depends on the risk of failure and the relative size of the system.

An alternative approach is to limit the number of contingency states to be investigated to those most likely to represent failures.[1] One of the characteristics of bulk power systems is the relatively low ratio of transmission lines and transformers to buses: for the IEEE RTS system, it is 38/24 or 1.58. Setting aside radial-generation buses, the IEEE RTS has an N-1 contingency capability. Loss of load requires the removal of two or more lines or transformers. Outages must be close together in order to cause an interruption or network overload or voltage problems. In other words, of the (38x37)/2 possible second contingencies, only a few combinations will be found to result in failure. To exploit this property of bulk power systems, methods are being developed to rank contingencies on the basis of their predicted impact on system overloads and voltage violations [17].

Another issue to consider is the system size to be used to represent the bulk power system for reliability predictions. Two aspects are involved: the size of the model for properly representing the flows in the network under contingency conditions and the span of the network within which contingencies should be considered. The computing effort to solve power flow problems tends to vary linearly with network size (number of buses). The number of contingencies to be investigated tends to be proportional to (N)!/(N-K)!K!, where N is the number of elements (lines and generators) subject to outage and K the number of contingencies to be investigated. If the system under observation is sufficiently large, it is quite likely that in most cases the existence of more than one line out will not represent a condition of stress in that system. Multiple outages generally represent a problem when they are geographically close, not when they are far apart.

As far as modeling the system response to contingency states is concerned, the power flows and voltages in the system and the generator loading must be determined for each state to be analysed. It may also be required to develop models of operating policies to represent remedial actions and resource allocations. Each contingency state must be checked for violation of the specified service quality criteria, which for adequacy assessments will be defined in terms of static loadings and voltages as well as events involving separation of loads from sources. These assessments must be performed with AC load flows or, if failure to meet the voltage criteria and reactive flows can be neglected, with DC load flows.

---

[1] Confining it up to the second level for the transmission system and up to the fourth level for generating units, the total number of outage combinations would be 30 755 158, which is still very large.

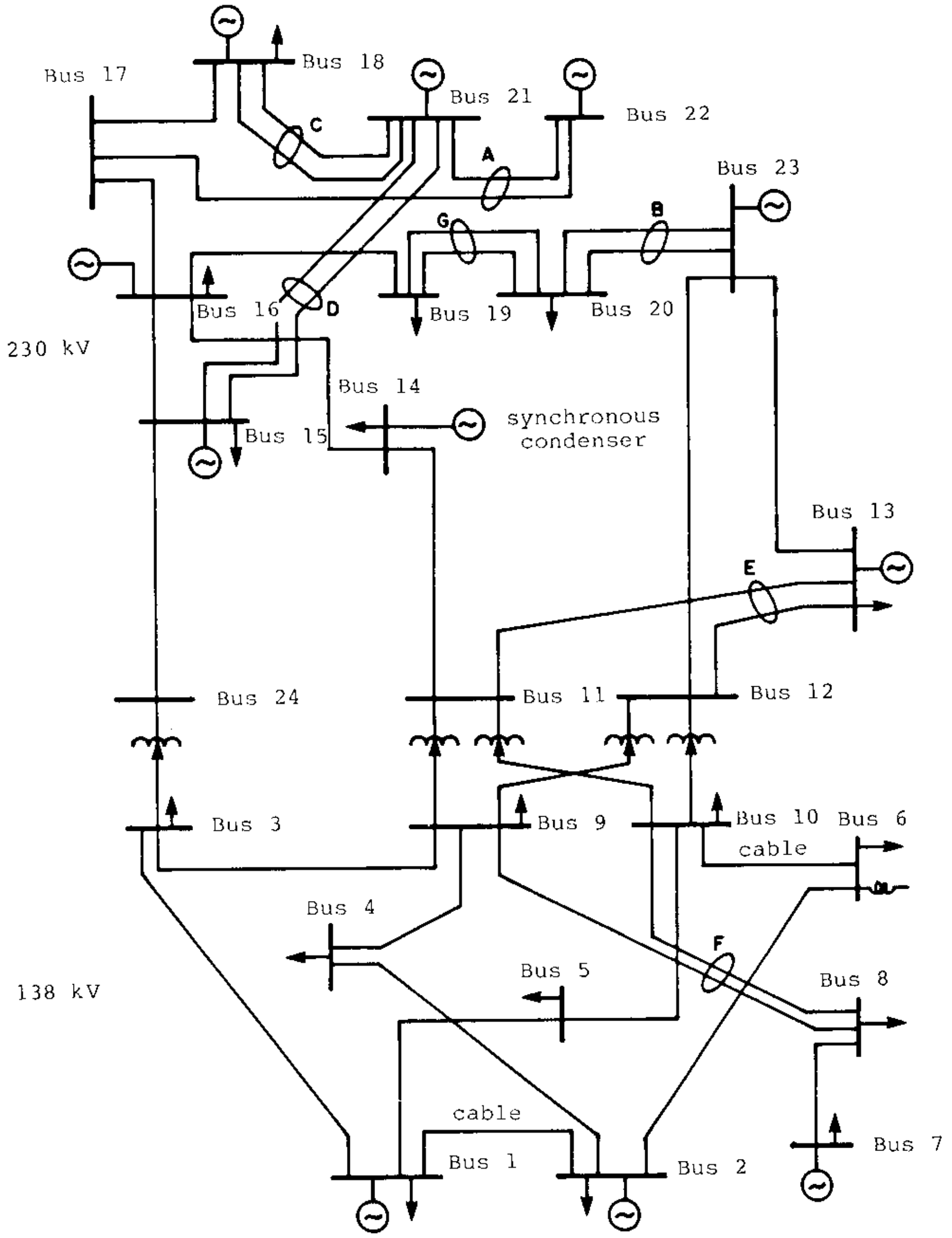


Figure 3.1 - IEEE 24-bus reliability test system, RTS

Most of the computing time is spent on load flow analysis and on the determination of remedial steps to correct the violation of service quality criteria.

For each generating-unit contingency, the dispatch schedule must be modified to compensate for the loss of generation, whereas for each transmission contingency checks must be made of the network topology. For either type, if transmission line or transformer loadings are excessive or if bus voltages become unacceptable, the approaches used to relieve the violation of criteria comprise phase shifting, changing transformer ratios, generation rescheduling and selective load curtailment.

Composite-system reliability evaluation thus involves models and strategies for systems of large dimension. It is therefore vital to keep the number of states under investigation no larger than the results warrant. For example, it may be unnecessary to model a system spanning an entire continent in order to study the reinforcement in a given region. Similarly, the number of lines and transformers to be subjected to outages can be limited to those that will have significant impact on the region under investigation. Network equivalents are employed to retain the overall effects of large systems without involving individual elements in the solution. A careful choice of equivalents can similarly be used to merge the generating-capacity reserves in distant areas without being encumbered by detailed representation of individual generators.

### 3.4.1 Simulation and State Enumeration

Two broad approaches have evolved for the computation of composite-system reliability: enumeration and simulation. These are not strictly exclusive and hybrid versions have been used in attempts to combine the efficiency of each. Both approaches have strengths and weaknesses. For example, enumeration is very effective for determining generation capacity and capacity margin states, whereas simulation is generally better for treating complex or involved models for operating, remedial and resource-allocation strategies.

It should be emphasized that when load curtailment is required, the resulting values for the bus indices are strongly affected by the curtailment policy used and this should be taken into account when selecting operating policies for use in adequacy assessments. The requirement for calculating bus indices also affects the choice of algorithm. The calculation methods should be selected with a view to the end results and bearing in mind that more than one method may be needed for composite-system reliability evaluation.

#### 3.4.1.1 Monte Carlo simulation

The advantages of adopting Monte Carlo simulation methods for the reliability assessment of busbar generating systems, including peak storage plants, were identified earlier. The Monte Carlo approach is even more suitable for index evaluation when the influence of the transmission system is taken into account. It is a technique that can be defined, in fact, as experimental mathematics and its suitability increases as the simulation problem becomes more complex and more difficult to handle by direct analytical methods. Its main advantages are the feasibility it offers of theoretically accounting for any random variable and any contingency and the possibility of adopting operating policies similar to real ones. Monte Carlo also allows useful dialogue between a utility's planning and operation departments, since the factors/indices used are nearly the same. The only disadvantage, if it can be termed thus, could be the computing time, which may or may not be a critical factor, depending on the computing capacity available and its cost. The main features of these methods are detailed below.[1]

Approach : Simulation of system steady state on an hourly basis, each group of 8760 simulated hours constituting a yearly sample

Purpose : Evaluation of reliabilily and system running cost

Risk Index : Reliability is just one component of system cost optimization, which at ENEL and EDF is done by adding:

- plant installation cost
- system running cost
- reliability cost

subject to a number of constraints:

- type of energy
- siting
- licensing
- financial.

Reliability must be expressed by a risk index that is easy to use in the two stages of system life, planning and operation, which should be mutually interactive. The risk index adopted by ENEL and EDF in their planning practice is the Expected Energy Not Supplied (EENS), expressed in megawatthours per year.

At ENEL, this index is given by the computing program subdivided according to:

- causes (lack of generation, lack of transmission and/or transformer capacity): "why" option;
- buses where the curtailment occurs: "where" option;
- weather when the curtailment occurs: "when" option;

EENS is expressed in monetary terms for optimizing the sum of the costs of installation, operation and system adequacy.

---

[1] Many of these features were obtained from the description of ENEL's SICRET computing program [5-7] but most are found also in the Monte Carlo approach adopted by EDF for the MEXICO and ANASEC models [31-33] and by CEPEL in the CONFTRA model [34].

Input data : For each network component:

- electrical and topological characteristics
- planned and forced outage data:
  - forced-outage probability (%)
  - planned maintenance duration (wk/yr)
  - rate of repair (occ/yr)
  - rate of failure (occ/yr)

Load and its composition in each bus. Weather conditions alternating over the year.

For the system:

- operating policies to be simulated for:
  - generation dispatching
  - overload relief
  - load shedding

Program steps : In each sampled hour the program:

- randomly simulates:
  - component availability
  - load at each bus
- carries out generation dispatching and makes a first comparison of generation vs. load. If necessary, load curtailments are made; this gives a first risk component, "lack of generation capacity".

When a balance between generation and load is obtained:

- fast DC load flow gives the power flows;
- overload relief is performed, if necessary;
- if overload relief is impossible, other curtailments are made, representing a second risk component, "lack of transmission and/or transformer capacity";
- the system running cost is evaluated together with the yearly utilization cost of each generating unit.

Hourly cost and curtailments are accumulated, giving, on a yearly basis:

- system running cost
- system reliability (adequacy)

Operating policies : Two policies are possible, according to the planning goal, namely safety alone or safety and economy.

i) Safety

- Aim : to minimize computing time and maximize overload relief
- Application: system reliability and running-cost evaluation for system and component optimization at final planning stage.

ii) Safety and Economy

- Aim : to minimize system running cost and maximize overload relief
- Dispatching: according to careful increase in generator running cost
- Overload relief : capacity shifting between the two nodes presenting the lowest function: cost of shifting + cost of residual overload
- Application: system reliability and running-cost evaluation for system and component optimization at final planning stage.

By way of illustration, it might be useful to know that for the last ten years ENEL has been using the SICRET program for planning large meshed systems of roughly the dimensions given in the table on the next page.

| | 1985 | 1995(?) |
|---|---|---|
| Generation (GW) | 41 | 57.5 |
| Transmission system (km) | | |
| 380 kV | 7 000 | 10 000 |
| 220 kV* | 12 000 | 12 000 |
| Transformer capacity(MVA) | | |
| 380 kV | 39 000 | 48 000 |
| 220 kV* | 32 000 | 32 000 |
| Peak load (GW) | 31 | 41.6-45.3 |
| Energy demand (TWh) | 170 | 225-245 |

* The 220-kV level to be discontinued.

### 3.4.1.2 State enumeration techniques [8,17]

The fundamental procedure comprises three general steps:

- systematic selection and evaluation of contingencies
- contingency classification according to predetermined failure criteria
- compilation of appropriate predetermined reliability indices.

The total number of contingencies selected in the first step can be reduced by ranking them according to specified criteria, using either predetermined contingency levels or a probability or frequency cut-off criterion. Classification may involve a transportation model for the system or use DC or AC load flow representations. Use of one model rather than another depends on the system configuration and on the need felt to recognize certain system conditions and factors in the analysis. Full system representation involving AC load flow analysis as opposed to a linearized flow or transportation model produces more accurate answers, albeit at the expense of computer time. The basic structure of the enumeration approach is schematized in Fig. 3.2.

### 3.4.1.3 Simulation versus enumeration

The enumeration and Monte Carlo simulation approaches are not mutually exclusive and an attempt should always be made to use the advantages while avoiding the drawbacks of each. In practice, the choice depends on the individual planner's background and working experience. The main features of the two approaches are compared in schematic form in Figure 3.3.

### 3.4.2 Case Studies

Two sample cases will now be presented to illustrate the possibilities of each approach [13]. The first, based on a Monte Carlo method, is used by ENEL in its planning practice while the second, based on a contingency evaluation, was developed by the University of Saskatchewan. They are both representative of other evaluation methods found in Europe and North America.

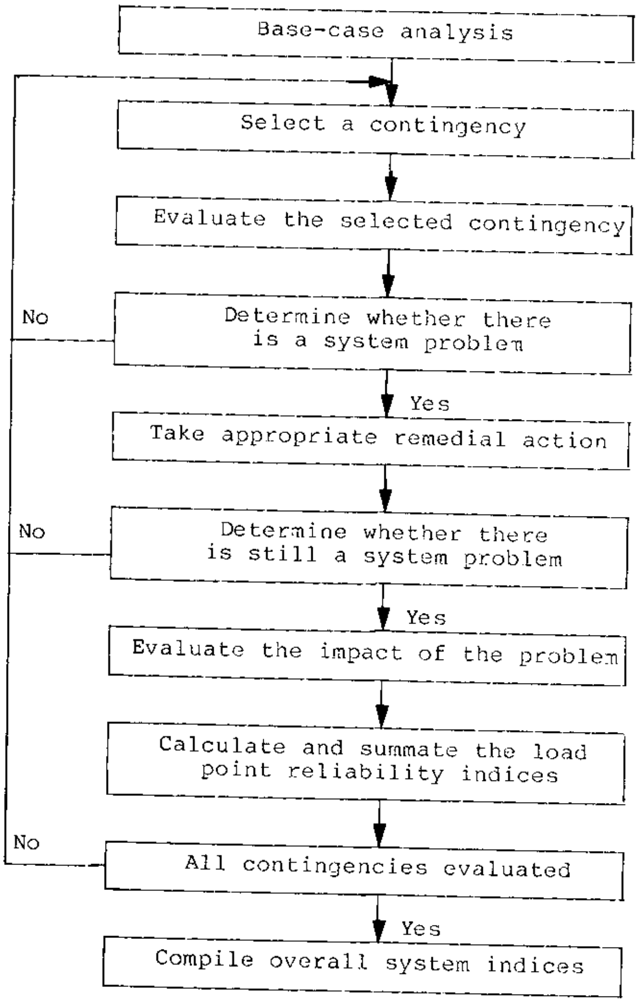


Figure 3.2 - Basic structure of enumeration approach

Both techniques were applied to the IEEE RTS, although it must be emphasized that, despite this common background, unless both methods use exactly the same system and load models and remedial actions, the results must be handled with caution. Notwithstanding, they should allow deeper insight into each approach.

The RTS has only two voltage levels and is divided geographically into two regions: the upper region at 230 kV, the lower region at 138 kV. The complete data for the RTS is given in [11] but certain salient features are summarized here. The main characteristics are given in Table 3.1 while Table 3.2 recalls the RTS generation mix.

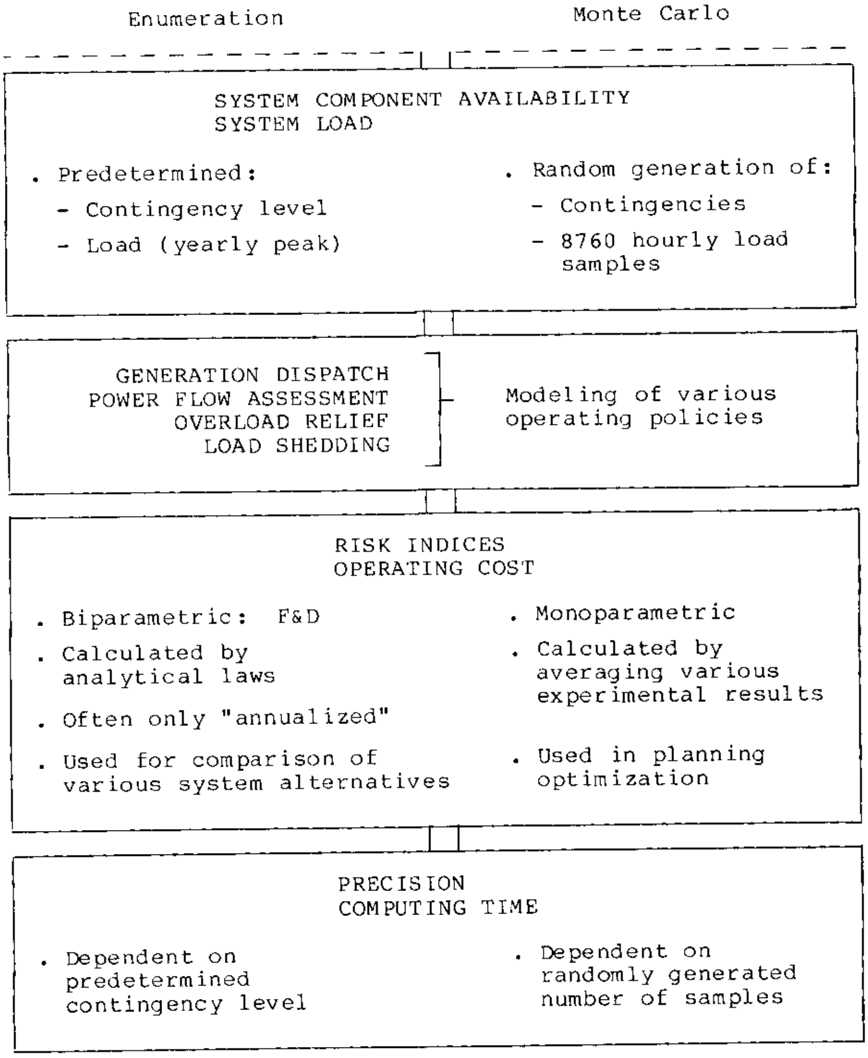


Figure 3.3 - Schematic comparison of Monte Carlo and enumeration methods

Table 3.1

Main characteristics of IEEE reliability test system

| | |
|---|---|
| Generators | 32 |
| Lines + transformers | 38 |
| Loads | 16 |
| Buses | 24 |
| Installed capacity | $P_G$ = 3405 MW |
| Yearly peak | $P_L$ = 2850 MW |
| Installed reserve | r = 19.5% |
| Energy demand | $E_L$ = 15 300 GWh/yr |

Table 3.2

RTS generation mix

| TYPE | CAPACITY | PERCENTAGE |
|---|---|---|
| Nuclear | 800 MW | 24% |
| Coal | 1274 MW | 37% |
| Oil | 951 MW | 28% |
| Hydroelectric | 300 MW | 9% |
| Gas turbine | 80 MW | 2% |
| | 3405 MW | 100% |

Just to give an idea, the following outage parameters are assumed:

- Generating units: forced-outage probability: 2% (12-MW size) to 12% (400-MW size)
- Overhead lines:
  - 138 kV: forced-outage rate = 0.52 L + 0.22 (occ/yr)
  - 230 kV: forced-outage rate = 0.34 L + 0.29 (occ/yr)

  where L = length in 160 km

### 3.4.2.1 Case study 1: Monte Carlo simulation

ENEL's SICRET program, based on Monte Carlo simulation, was applied to the RTS to compute its adequacy and show how it is used in the ENEL approach to system optimization. Some of the results presented at the 1983 EPRI Workshop on Transmission System Reliability Methods in Washington [12] will be recalled as well as some of those listed in Ref. 13.

Table 3.3 and Fig. 3.4 show the results of simulation of the yearly system behavior. These results are the average of five yearly samples of the same chronological year. The CPU time on IBM 3032 for one year (8760 h) was 2 h 18 min.

The Expected Energy Not Supplied (EENS) index is subdivided according to cause (lack of generation, component overload, etc.) and location (buses) of the curtailments.

The IEEE RTS input data did not take into consideration the effect of weather conditions on overhead-line forced-outage rates. The results therefore do not incorporate the effect of overlapping outages on the network adequacy, which could be higher if the increased outage probability under adverse weather conditions had been accounted for [5,6].

From such results, bearing in mind that the network solution has been obtained by DC load flows, it can be argued that the power system is quite safe as far as transmission is concerned and that the major contributions to its inadequacy come from the generating system. This consideration can be helpful for further steps.

Thanks to its flexibility in supplying risk indices in terms of the number of megawatt-hours curtailed in each bus per year according to the cause, SICRET can be effectively used in composite-system optimization by comparing the variations in risk cost fol-

Table 3.3

Expected energy not supplied (MWh/yr) according to cause and location

| NODES | GENERATION SHORTFALL | OVERLOAD | TOTAL |
|---|---|---|---|
| 18 | 2597 | | 2597 = 63.3% |
| 16 | 491 | | 491 = 12.0% |
| 13 | 215 | | 215 = 5.2% |
| 5 | - | 232 | 232 = 5.6% |
| 7 | 213 | | 213 = 5.2% |
| 15 | 190 | | 190 = 4.6% |
| 2 | 64 | | 64 = 1.6% |
| 1 | 56 | | 56 = 1.4% |
| 4 | - | 36 | 36 = 0.9% |
| 20 | 8 | | 8 = 0.2% |
| 8 | 1 | | 1 = |
| | 3835 +<br>(93.55) | 268<br>(6.5%) | 4103 = 100%<br>= (100%) |

$$\frac{\text{EENS}}{\text{energy demand}} = 3 \times 10^{-4}$$

energy demand: 15.3 TWh

Table 3.4

Effect of modifications on system adequacy (EENS) (in MWh/yr)

| NODES | REFERENCE SYSTEM | MINUS ONE LINE BETWEEN 17-18 | PLUS ONE GAS TURBINE AT BUS 18 AFTER LINE REMOVAL |
|---|---|---|---|
| 18 | 2597 | 2597 | 2434 |
| 16 | 491 | 491 | 491 |
| 13 | 215 | 215 | 215 |
| 5 | $\boxed{232}$ | $\boxed{232}$ | $\boxed{179}$ |
| 7 | 213 | 213 | 213 |
| 15 | 190 | 190 | - |
| 2 | 64 | 64 | 64 |
| 1 | 56 | 56 | - |
| 4 | $\boxed{36}$ | $\boxed{36}$ | $\boxed{16}$ |
| 20 | 8 | 8 | - |
| 8 | 1 | 1 | - |
| Total :<br>of which overload | 4103<br>$\boxed{268}$ | 4103<br>$\boxed{268}$ | 3612<br>$\boxed{195}$ |
| Total decrease: EC | | - | 491 |

lowing modifications to the system composition with the related investment cost.

Table 3.4 shows the effects of two possible modifications. The first is the removal of one line between buses 17-18: no variation in EENS was found. The second is the addition of a gas turbine unit at bus 18: this results in a lower EENS on some buses both for lack of generation and for lack of transmission capacity. Values in boxes reflect the influence of overload.

Table 3.5 and Fig. 3.5 represent the other results supplied by the computer program, the yearly utilization of each generating unit, from which the yearly running cost of the system can be obtained.

Table 3.6, finally, shows how all these results (capital, running, and risk costs) serve for system optimization. Such a table can therefore be considered the ultimate target of the system planner: its values - all monetary - can be easily transmitted to and understood by the utility's management for final decision-making.

Table 3.6 shows not only the way to utilize the results but also the importance of a correct running-cost evaluation. In fact the two solutions appear to be equivalent when the running cost is considered.

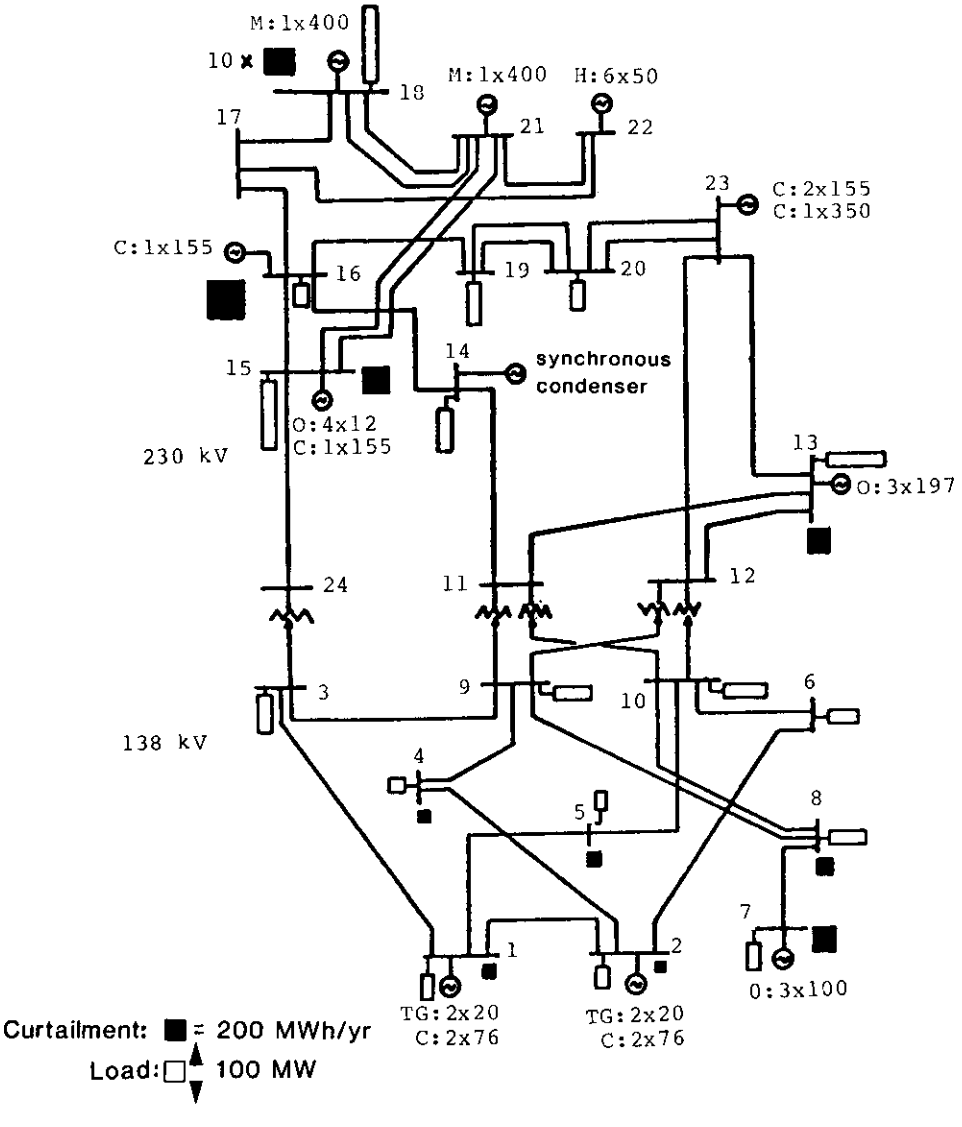


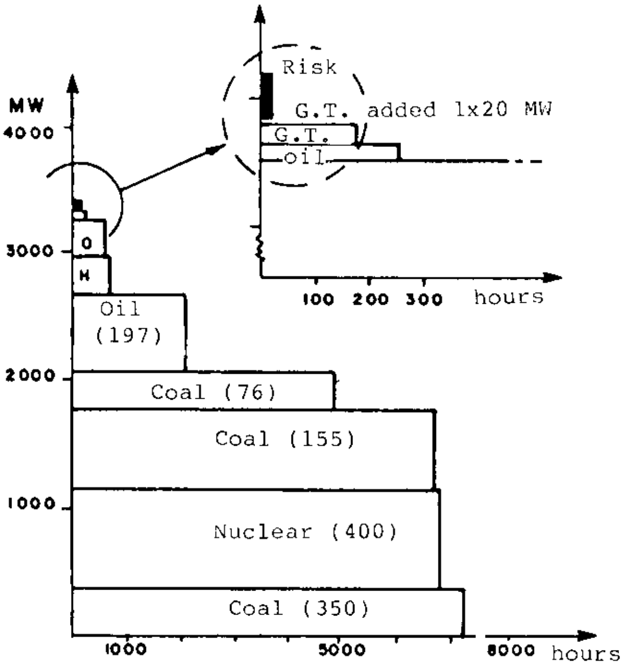
Figure 3.4 - IEEE RTS curtailments in network buses

## Table 3.5

## IEEE test system: generation duration curve

| TYPE | SIZE (MW x No.) | CAPACITY (MW) | DURATION (h) |
|---|---|---|---|
| Coal | 350 x 1 | 350 | 7265 |
| Nuclear | 400 x 2 | 800 | 6784 |
| Coal | 155 x 4 | 620 | 6763 |
| Coal | 76 x 4 | 304 | 5000 |
| Oil | 197 x 3 | 591 | 2157 |
| Oil | 100 x 3 | 300 | 666 |
| Hydro | 50 x 6 | 300 | 666 |
| Oil | 12 x 5 | 60 | 262 |
| Gas turbine | 20 x 4 | 80 | 181 |
| (Additional gas turbine) | 20 x 1 | 20 | 24 |
| Total installed: | | 3405 + 20 | |
| Yearly running cost (in Italian fuel prices[1]) = $284.6 X $10^6$/yr | | | |

[1] At the time of writing (Jan. 1, 1982), one US dollar was worth 1450 liras.



| | |
|---|---|
| Nuclear | 8.0 mills/kWh |
| Coal | 23.0 mills/kWh |
| Oil | 34.8 mills/kWh |
| Gas turbine | 79.6 mills/kWh |

Figure 3.5 - Generation duration curve

## Table 3.6

## IEEE RTS optimization: quantitative comparison of various solutions[1] ($$10^6$/yr)

| VARIABLE | MINUS ONE LINE | PLUS ONE GAS TURBINE |
|---|---|---|
| . Capital cost | - 0.22 | - 0.22<br>+ 0.46 |
| . Running cost | - | + 0.04 |
| . Reliability cost | - | - 0.49 |
| | - 0.22 | - 0.21 |

[1] Constant money: All figures refer to Jan. 1, 1982 when one US dollar was worth 1450 liras.

220-kV line : $7586/km.yr

Gas turbine : $23.1/kW.yr

Life : 25 years

Interest rate : 7%/yr (inflation removed)

## Table 3.7

## Effect of operating policies on generating unit utilization and on yearly running cost

| TYPE | CAPACITY (MW) | OPERATING POLICIES | |
|---|---|---|---|
| | | PURE SAFETY (h/yr) | MIXED (h/yr) |
| Nuclear | 800 | 6785 | 6785 |
| Coal | 1274 | 5127 | 6451 |
| Oil | 951 | 3171 | 1543 |
| Hydro | 300 | 666 | 666 |
| Gas turbine | 100 | 1535 | 150 |
| Yearly running cost ($$10^6$/yr) | | 310.9 | 284.64<br>-9% |

The previous considerations stress yet again the importance of disposing of a tool that can simulate realistic operating policies and therefore supply correct results for system optimization. This is why ENEL's, SICRET program is used with the two dispatching policies (mentioned in 3.4.1) regarding the planning stage (early planning or operational planning) to be faced.

Table 3.7 provides an example of the difference in annual hours' utilization of various generating units and of running costs evaluated in terms of a simplified pure safety policy and in terms of a mixed (economy+safety) policy. Naturally, only the latter result can be used in optimization work.

### 3.4.2.2 Case study 2: contingency evaluation method

The main characteristics of the University of Saskatchewan's COMREL program, based on a contingency evaluation method, are detailed in section 3.4.1.2 and [13] together with an explanation of the need to limit the number of contingencies considered. When this method was applied to the RTS, independent overlapping outages up to the fourth level for generating units and up to the second level for transmission elements were taken into account. The effects of higher-order generating-unit failures were incorporated by using a cumulative probability and frequency for the highest-level contingency considered. Common-mode or common-cause outages were not included.

The indices were evaluated with the aid of a single-step load model. One of the assumptions underlying this model is that the load remains constant throughout the period of study: in the example, the yearly peak load value (2850 MW) was assumed. In order to calculate the annualized indices, the period of study is taken as one year. No account was taken of planned maintenance of the generating units.

The system adequacy indices obtained using this approach are given in two forms: individual bus indices (Table 3.8) and overall system indices (Table 3.9). Actually, the full range of indices given in [10] can also be obtained.

Adequacy indices are very sensitive to the load level. The severity index, for example, drops to 71.1 system-minutes when the load level decreases to 2400 MW from 2850 MW.

A bus failure under any outage condition is defined as including violations of the acceptable voltage limits at that bus and/or failure to meet the load requirements at that bus, violations of generator reactive-power limits, nonconvergent situations, etc. Swing-bus overloads, if any, are alleviated by curtailing the load at various

Table 3.8

Annualized bus indices for the IEEE RTS
System load = 2850 MW

| BUS No. | FAILURE PROBABILITY | FAILURE FREQUENCY (occ/yr) | LOAD CURTAILED (MW) | ENERGY CURTAILED (MWh) |
|---|---|---|---|---|
| 1 | .022446 | 16.59 | 171.5 | 2 086 |
| 2 | .040999 | 30.01 | 314.6 | 3 827 |
| 3 | .022640 | 16.73 | 369.2 | 4 560 |
| 4 | .022394 | 16.54 | 172.4 | 2 133 |
| 5 | .022446 | 16.54 | 145.2 | 1 794 |
| 6 | .022395 | 16.54 | 317.0 | 3 920 |
| 7 | .015922 | 11.98 | 160.4 | 1 905 |
| 8 | .015950 | 12.01 | 326.3 | 3 972 |
| 9 | .003171 | 1.98 | 32.4 | 425 |
| 10 | .003171 | 1.98 | 36.6 | 474 |
| 13 | .071273 | 45.83 | 1769.2 | 23 662 |
| 14 | .009556 | 6.70 | 150.4 | 1 793 |
| 15 | .056509 | 35.38 | 1961.7 | 28 069 |
| 16 | .026011 | 18.35 | 204.9 | 2 478 |
| 18 | .083433 | 51.51 | 3377.9 | 50 912 |
| 19 | .011667 | 8.05 | 166.4 | 2 017 |
| 20 | .046213 | 29.97 | 853.4 | 11 792 |
|  |  |  |  | 145 819 |

Table 3.9

IEEE RTS: annualized system indices

| SYSTEM INDICES | VALUE |
|---|---|
| Bulk power interruption index (MW/MW.yr) | 3.69 |
| Bulk power energy curtailment index (MWh/MW.yr) | 51.16 |
| Bulk power supply average power curtailment index (MW/disturbance) | 167.00 |
| Energy unreliability index | 0.005841 |
| Severity index (system-minutes) | 3070.00 |

buses. In these studies, the curtailable load at each bus is assumed to be 20% of the total bus load and the number of load curtailment steps is specified as 1. Line or transmission overload conditions are alleviated by generation rescheduling and/or load curtailment at the busses. Bus 6 experiences load curtailment because of the overloading of the connection between buses 6 and 10 when the line between buses 6 and 2 is out.

A 400-MW generator outage at bus 18 results in unsatisfactory system performance because of generator reactive-power limits. Line (except line 5) outages on bus indices have a negligible to moderate effect. Buses 6, 13, 15, 18 and 20 have higher inadequacy indices than the others. Buses 3 and 6 also experience voltage violations. The maximum and minimum bus voltage limits were assumed to be 1.05 and 0.85 respectively.

Outage of the largest generating unit (400-MW) alone does not cause load curtailment but that of one 400-MW generator at either bus 18 or bus 21 together with other relatively large generating units results in load curtailment at the buses. Bus 18 has the lowest adequacy value because of many combinations of the outages of the connected generator with those of any other relatively large generator in the system. Meanwhile buses 13 and 20 have low adequacy values as a result of the outage of a generator at bus 23 and that of another larger generator elsewhere in the system.

Summarizing the results, it can be said that, firstly, line overload is not a major problem, except for the outage of a few lines, in which case the connection between bus 6 and bus 10 is overloaded. Secondly, the contribution of line outages to reliability indices is negligible. And thirdly, the major contribution to bus indices is generation shortfall during the outage of large generating units.

### 3.4.2.3 Comparison of the two approaches

The two techniques described above represent valid ways to evaluate composite or bulk system adequacy; they also reveal conceptual differences in modeling and problem perception. Some of the major differences are given in Table 3.10 together with the risk indices obtained, the contingencies examined and the load-alleviation techniques employed.

The tabulated results (Tables 3.4, 3.5 and 3.8, 3.9) cannot be compared directly, mainly because different load models were used in the two studies. Several specific cases examined in [13] pinpoint other differences and facilitate direct comparison.

Case 1

The load was held constant at 2850 MW for the entire year and no planned maintenance was considered. The following results were obtained:

- simulation : EENS = 125.215 MWh
- analytical : EENS = 145.819 MWh

The higher EENS yielded by the University of Saskatchewan calculations is due to the different load curtailment policies used (but also perhaps to line overload alleviation arising from AC load flow representation).

Case 2

The load was again held constant at 2850 MW for the entire year. All system components were in service but one 400-MW unit at bus 18 and one 197-MW unit at bus 13 were on forced outage. The results were as follows:

- simulation : overall available capacity lower than the load to be supplied; load shedding necessary owing to lack of generating capacity; no line overloads.
- analytical : load curtailed due to inadequate generating capacity in accordance with the prespecified policy; no line overloads.

Case 3

The load was held constant at 2850 MW for the entire year while one 400-MW unit at bus 18 and one 197-MW unit at bus 13 were on forced outage. The line between buses 2 and 6 was removed from service. The results were as follows:

- simulation : no overload conditions determined by the DC load flow as in case 2
- analytical : in addition to load shedding due to generation sufficiency, load curtailed at bus 6 due to line overloading between buses 6 and 10.

These three cases illustrate some of the fundamental differences between the two methods. In Case 1, the EENS is basically the same for both methods and is attributable largely to generation deficiencies. It should be appreciated that the load bus components of the curtailed energy will be very dependent on the load-curtailment philosophy. The additional component in the University of Saskatchewan results in Cases 2 and 3 is due to load alleviation to remove difficulties perceived by the AC load flow.

Table 3.10

Comparison of simulation and analytical approaches

| METHOD | SIMULATION | ANALYTICAL |
|---|---|---|
| Risk index | EENS according to cause and location | Range of load points and system indices |
| Situation examined | For a fixed year, 8760 hourly samples resulting from the random combination of available system components and load levels | Predetermined contingency level: up to four generating units and two transmission lines, at a specified load level |
| Load model | Any load level for the year considered (8760 in all) | Specified load level (e.g. yearly peak load) |
| Generation analysis | Planned maintenance of all units for the year considered | Not included |
| Risk due to generation shortfall | Evaluated by curtailing load according to priority list | Curtailment by a firm/curtailable load policy and regional bounds |
| Initial dispatch | Priority list based on running costs | Prespecified |
| Network analysis load flow | DC load flow, not including voltage limits | AC load flow, including reactive-power limits |
| Overload relief policy and risk due to lack of transmitting capacity | DC load flow, overloads relieved using a "coefficient of influence" policy | Alleviation at close-proximity points |

As already mentioned, the results calculated by these two methods cannot be compared directly but differences can be traced. The load models employed account for the major difference but the solution techniques, system representation and load curtailment policies all introduce further attributable discrepancies in the calculated indices.

### 3.4.3 Extended Applications Using Contingency Enumeration Methods

A number of digital computer programs for evaluating composite-system adequacy using contingency enumeration are described in the literature. The SYREL program, developed under an EPRI contract, is detailed in [17] while the University of Saskatchewan's COMREL program is described in [13]. The application of these programs to the IEEE-RTS, as reported in several publications, illustrates some of the significant elements in contingency enumeration methods [20,30].

The effect of station-originated outages in composite-system adequacy evaluation is clearly indicated in [27]. This study extends the IEEE-RTS scheme shown in Fig. 3.1 by adding practical substations and switching stations at each bus. Tables 3.11 and 3.12 illustrate the effects of incorporating station considerations on annualized load point and system indices; the peak load considered was 2400 MW.

The adequacy indices were also calculated for a system load of 2850 MW, the same value assumed in the two examples in sections 3.4.1.1 and 3.4.1.2. The effect of station-originated outages here is overshadowed by the contribution from independent outage contingencies, as seen in Table 3.12, which gives various system indices for this load level. These indices are dominated by the outage of generating units. At 2850 MW, the outage of one large generating unit (300 MW or 400 MW) and one medium-size generating unit results in a capacity shortfall, since the system static reserve at this load level is only 555 MW. Tables 3.11 and 3.12 show that by increasing the yearly peak load from 2400 MW to 2850 MW the severity index due to independent outage events increases from 71 to 3070 system-minutes, whereas with station-originated outages it increases from 123 to 309 system-minutes.

Table 3.11

Annualized system indices for the RTS
System load = 2400 MW

| | WITHOUT STATIONS | WITH STATIONS | % IN-CREASE |
|---|---|---|---|
| Bulk power interruption index (MW/MW-yr) | 0.08579 | 0.13666 | 59.29 |
| Bulk power supply average load curtailment index (MW/disturbance) | 92.81903 | 104.54426 | 12.63 |
| Bulk power energy curtailment index (MWh/MW) | 1.18503 | 2.05153 | 73.12 |
| Modified bulk power energy curtailment index (MWh/MW) | 0.000135 | 0.000234 | 73.33 |
| Severity index (system-minutes) | 71.102 | 123.092 | 73.12 |

This nonuniform increase in the system indices illustrates the great sensitivity of the effects of independent and station-originated outage events to the system load at which the indices are calculated. Definite conclusions about these effects cannot be drawn for any particular system at specific load levels without conducting a detailed analysis, however. In addition to load and generation reserves, several other factors such as system topology, component reliability and the components involved in the contingency also play an important role in the contribution of station-originated outages in composite-system reliability evaluation.

Table 3.12

Annualized system indices for the RTS
System load = 2850 MW

| | WITHOUT STATIONS | WITH STATIONS | % IN-CREASE |
|---|---|---|---|
| Bulk power interruption index (MW/MW.yr) | 3.69510 | 3.71753 | 0.607 |
| Bulk power supply average load curtailment index (MW/disturbance) | 167.6755 | 168.41957 | 4.443 |
| Bulk power energy curtailment index (MWh/MW) | 51.16847 | 51.57207 | 0.788 |
| Modified bulk power energy curtailment index (MWh/MW) | 0.0058411 | 0.00058872 | 0.789 |
| Severity index (system-minutes) | 3070.108 | 3094.324 | 0.788 |

The inclusion of station-originated outage events significantly increases the load point and system adequacy indices, particularly at lower load levels, and must therefore be examined. Line outages merit special attention. The total computation time is not much longer when station-originated outages are added but can be when higher-level independent outages are included. The load at each bus and, hence, the system load do not remain at a constant value throughout the year. In practice, the system load spends only a short time at its peak value on the whole. At lower load levels, the effect of station-originated outage events on the system adequacy may be compared to that of independent outage events.

The results of incorporating weather effects in a composite-system adequacy evaluation are reported in [30]. Several models are described in Chapter 6 and Appendix II of this guide together with their influence on the load point and system adequacy indices for the IEEE-RTS. Recognition of the fluctuating environment produces different impacts on the indices at different load points: for example, the probability of transmission line failures overlapping would be far stronger, whereas the probability of all lines being in service would decrease slightly. The indices calculated at buses whose inadequacy is due mainly to overlapping line failures would be very sensitive to weather effects. This inadequacy increases markedly when weather effects are incorporated, yet the latter have almost no influence on the inadequacy indices at buses whose main contribution comes from first-order line outages.

The number of contingencies evaluated can be limited by means of a ranking procedure, which automatically selects those to be studied. This procedure is used in the SYREL program [17].

### 3.4.3.1 Effect of number of contingency levels

Figure 3.6 shows the overload probability as a function of the contingency level for the 25-bus system. The upper and lower bounds of the probability indices are presented for one, two and three levels of independent and dependent outages [17,18]. It may be concluded that, in this particular case, two contingency levels suffice for computing the transmission reliability indices for the 25-bus system. In view of the uncertainties in the input outage statistics, the difference between the upper and lower bounds at two levels is negligible, even when independent outages alone are considered.

### 3.4.3.2 Effect of probability cutoff

The number of contingencies evaluated could possibly be further reduced by excluding all those below a certain cutoff probability. Figure 3.7 [17,18] shows the upper and lower bounds on the overload probability for the 25-bus system as a function of the probability cutoff criterion. Both independent and dependent multiple outages are considered. It appears that a probability cutoff as low as $10^{-7}$ could be used for this system without a major impact on the reliability indices. This would mean testing 200 contingencies as compared to 469 at $10^{-10}$ and 740 at $10^{-12}$. Use of an appropriate probability cutoff criterion could thus result in a significant reduction in computer time without significant loss of accuracy.

### 3.4.3.3 Capability approach - system load curtailment indices

Probability indices for the 25-bus system as a function of the load curtailed (MW) are shown in Fig. 3.8. The gap between the upper and lower reliability bounds widens as the curtailment increases, which is only to be expected since the number of primary- and secondary-level contingencies causes more moderate load curtailments, down to about 200 MW, owing to the dominance of several severe dependent multiple-outage events.

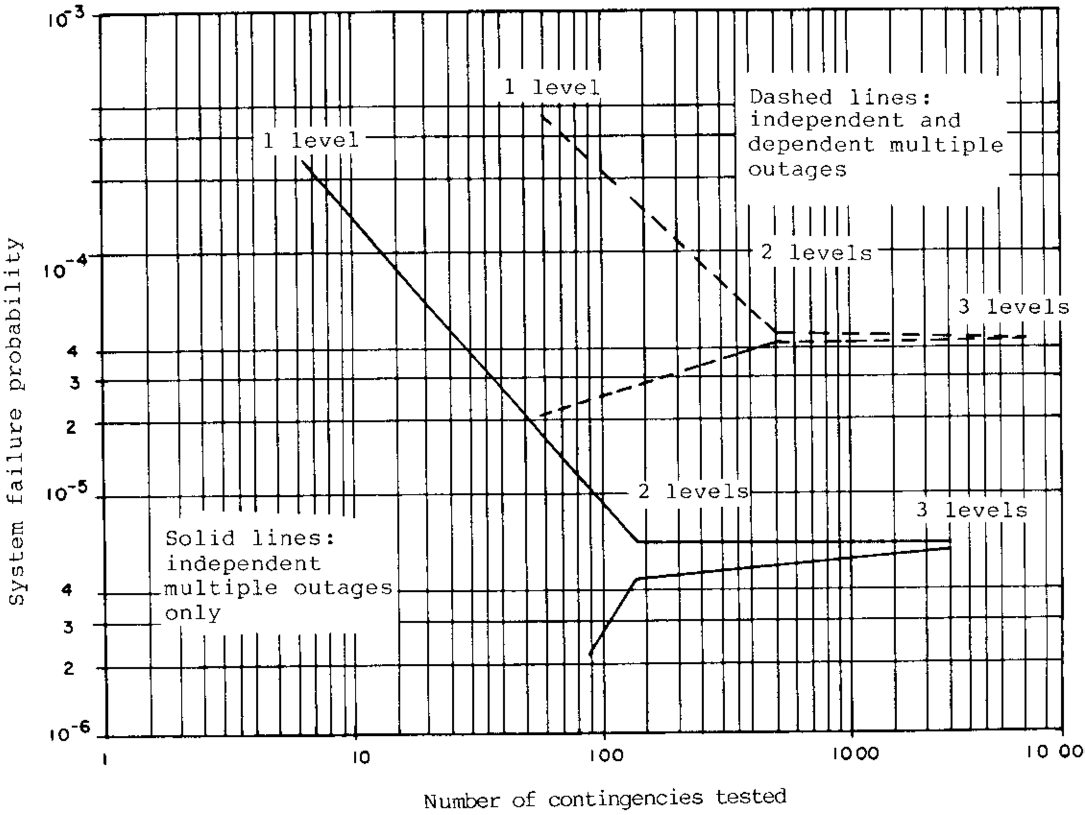


Figure 3.6 - Effect of number of contingencies tested and contingency level

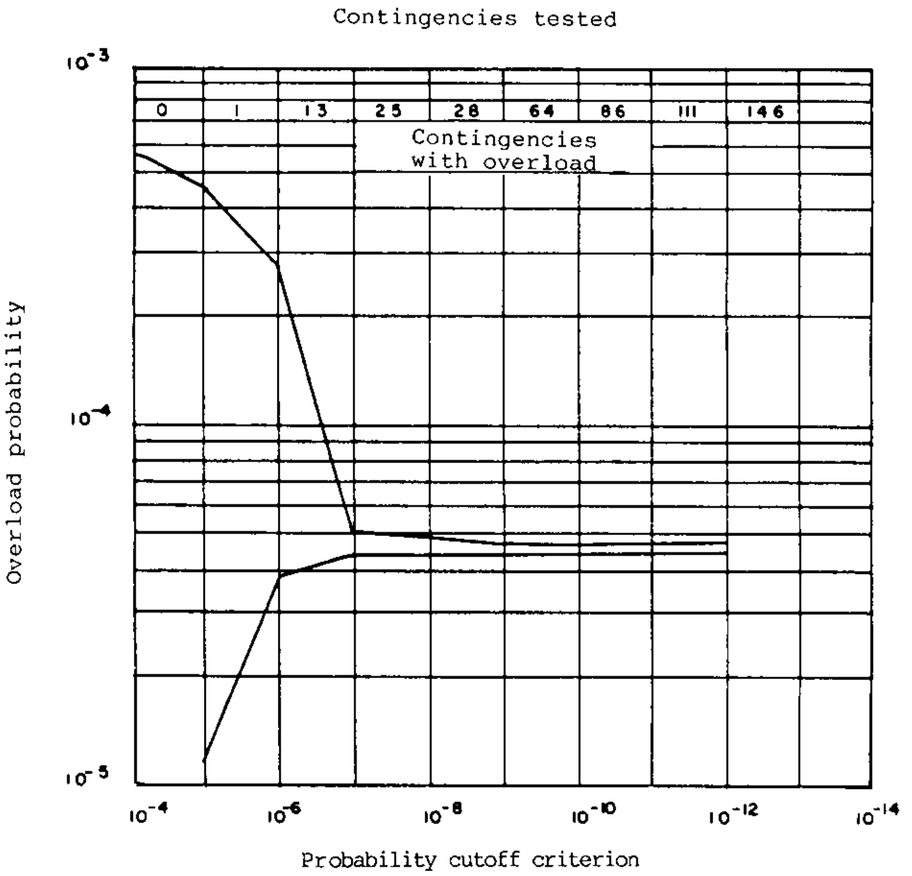


Figure 3.7 - Effect of probability cutoff criterion

## 3.5 USE OF PROBABILISTIC RISK INDICES IN SYSTEM PLANNING

As explained in greater detail in Chapter 2, the possibility of evaluating reliability in quantitative terms is of primary importance in power system planning. A reasonable basis for comparing planning alternatives would appear to be one that does not involve any fixed reliability level but makes economic comparisons among the alternatives involved. Each alternative is optimized by minimizing its overall cost, which comprises three components: capital expenditure, running cost and risk cost. The reliability level of each alternative is thus its optimal level, and the alternatives can be compared on the basis of their respective minimum overall cost.

When the failure cost is to be used in planning a given system, however, both the explicit cost (expressing the economic prejudice to the customers) and the implicit cost (related to a physical system constraint) must be used with caution. In particular, attempts to deduce the economic consequences of a curtailment [14-16] have shown that the cost assigned to it by different customers not only varies greatly from one customer to another but also depends on considerations that are extremely subjective. Moreover, account must be taken of the fact that the consequences of the failure include many that cannot be evaluated in economic terms, while the risk indices themselves often represent highly schematic versions of the reliability. It must be remembered that the reliability concept should always be seen in a more general frame, taking into account the various historical, social, siting and financial constraints facing utilities.

Utilities, at least privately owned ones, are increasingly facing the dilemma of trading off their customers' demand for reliability with their own interest in an adequate return on investments. Reliability is seen more and more as a commodity that can be differentiated, priced and marketed.

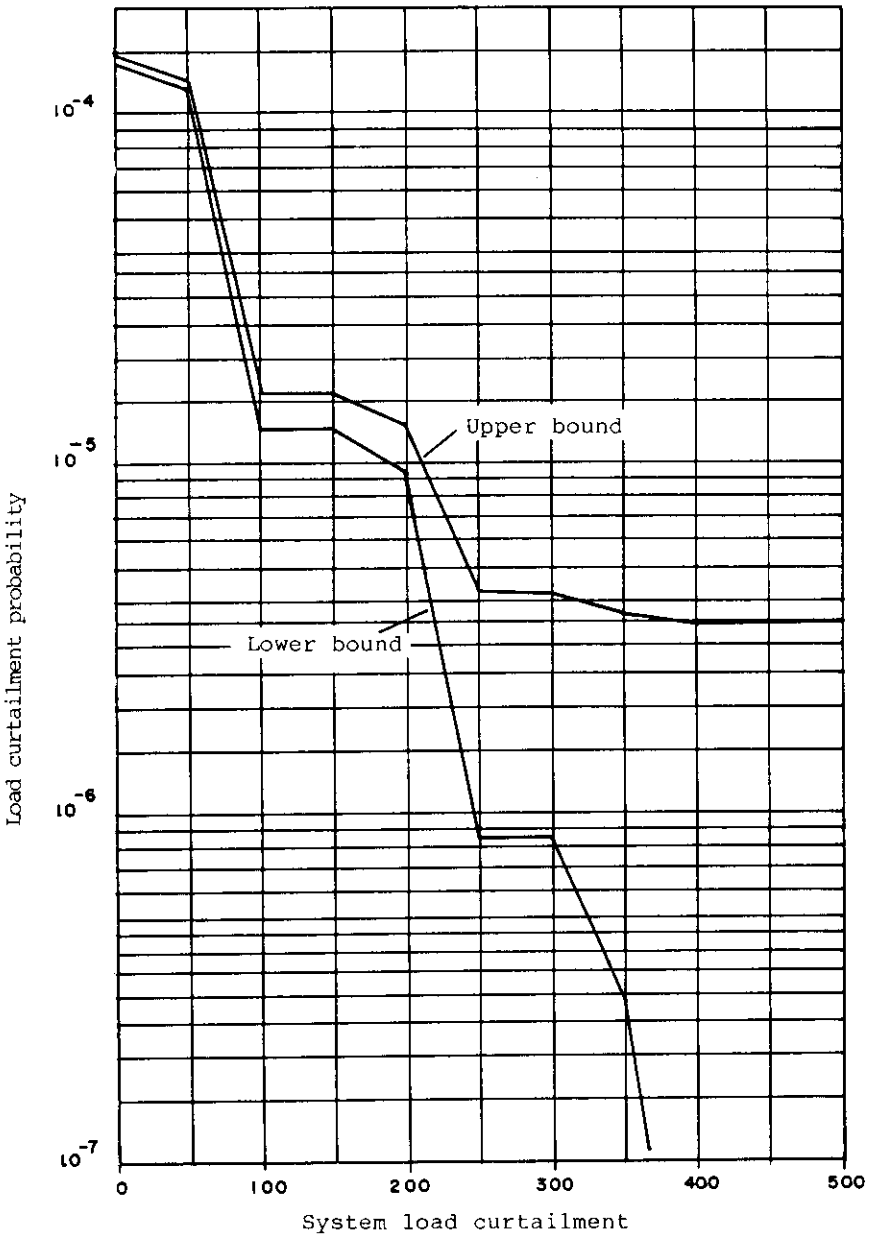


Figure 3.8 - Cumulative probability distribution of load curtailment for 25-bus system

REFERENCES

[1] R. Jusseret, "Comparison of the Reliability Criteria used in Various Countries - Synthesis," CIGRE WG 37.01, Internal Document 84/07/103 (E), August 1984.

[2] R. Billinton and R.N. Allan, "Power System Reliability in Perspective," IEE Electronics and Power, Vol. 30, pp. 231-236, March 1984.

[3] M.B. Guertin, P.F. Albrecht, M.P. Bhavaraju, R. Billinton, G.E. Jorgensen, A.N. Karas, W.D. Masters, A.D. Patton, N.D. Repen and R.P. Spence, "Reliability Indices for Use in Bulk Power Supply Adequacy Evaluation," IEEE Trans. PAS-97, No. 4, p. 1097, July-August 1978.

[4] G. Manzoni, L. Paris, L. Salvaderi and M. Valtorta, "Risk Indices for Reliability Assessment in Electrical Power System Planning," Position Paper for CIGRE WG 38.03 Montreux Meeting, September 1983.

[5] P.L. Noferi and L. Paris, "Quantitative Evaluation of Power System Reliability in Planning Studies," IEEE Trans. PAS-91, No. 2, March/April, 1972.

[6] P.L. Noferi, L. Paris and L. Salvaderi, "Monte Carlo Methods for Power System Reliability Evaluation in Transmission and Generation Planning," Proceedings of Annual Reliability and Maintainability Symposium, IEEE 75 CHO 918-3RQC, p. 449, Washington, January 1975.

[7] L. Salvaderi, I. Facchinei, E. Giampiere and S. Scalcino, "Network Reliability Evaluation: Peculiar Problems to be Faced when Planning Bulk Meshed Transmission Systems," Proceedings of the VII PSCC Conference, Lausanne, published by Westbury House, p. 97, 1981.

[8] R. Billinton, R. Ringlee and A. Wood, Power System Reliability Calculation, MIT Press, 1972.

[9] J.D. Hall, R. J. Ringlee and A. Wood, "Frequency and Duration Methods for Power Reliability Calculations. Part I: Generation System Model," IEEE Trans. PAS-87, No. 9, September 1968.

[10] R. Billinton and R. Allan, Reliability Evaluation of Power Systems, Longmans (London/England)/Plenum Publishing (New York), 1984.

[11] Task Force of the IEEE Application of Probability Methods Subcommittee, "IEEE Reliability Test System," IEEE Trans. PAS-I, 96-6, Nov./Oct. 1979.

[12] L. Salvaderi, "ENEL Method for Reliability Evaluation," EPRI Workshop on Transmission System Reliability Methods, Washington, Oct. 28-29, 1982, Proceedings, EL 3306, RP 1530.1, Paper 9, December 1983.

[13] R. Billinton and L. Salvaderi, "A Comparison Between Two Fundamentally Different Approaches to Composite System Reliability Evaluation," IEEE Trans. PAS-104, No. 12, December 1985, pp. 3486-3492.

[14] L. Paris and M. Valtorta, "Economic Aspects of Planning Large Generating Units in Interconnected Systems," World Power Conference, Report No. 101, Moscow, 1968.

[15] E.M. Mackay and L. H. Berk, "Cost of Power Interruptions to Industry: Survey Results," CIGRE Paper 32.07, Paris, 1978.

[16] M. Munasinghe, "A New Approach to Power Planning," IEEE Trans. PAS-99, No. 3, May/June 1980.

[17] EPRI EL 2526 Vol. 1 "Transmission System Reliability Methods," Project 1530-1.

[18] K.A. Clements et al., "Computation of Upper and Lower Bounds on Reliability Indices for Bulk Power Systems," IEEE Trans. PAS-103, No. 8, pp. 2318, August 1984.

[19] "The Value of Reliability," EPRI Journal, March 1986.

[20] R. Billinton, "Composite System Reliability Evaluation," IEEE Trans. PAS-88, No. 4, pp. 276-281, April 1969.

[21] R. Billinton and M.P. Bhavaraju, "Transmission Planning Using a Reliability Criterion. Part I, Reliability Criterion," IEEE Trans. PAS-89, pp. 28-34, 1970.

[22] R. Billinton, T.K.P. Medicherla and M.S. Sachdev, "Adequacy Indices for Composite Generation and Transmission System Reliability Evaluation," IEEE PES Winter Power Meeting, Paper No. A 79 024-1, February 1979.

[23] R. Billinton, T.K.P. Medicherla and M.S. Sachdev, "Application of Common-Cause Outage Models in Composite System Reliability Evaluation," IEEE Trans. PAS-100, No. 7, pp. 3648-3659, July 1981.

[24] R. Billinton and T.K.P. Medicherla, "Station-Originated Multiple Outages in the Reliability Analysis of a Composite Generation and Transmission System," IEEE Trans. PAS-100, No. 8, pp. 3869-3878, August 1981.

[25] R. Billinton and J. Tatla, "Composite Generation and Transmission System Adequacy Evaluation Including Protection System Failure Modes," IEEE Trans. PAS-102, No. 6, pp. 1823-1831, June 1983.

[26] R. Billinton and S. Kumar, "Adequacy Evaluation of a Composite Power System - A Comparative Study of Existing Computer Programs," CEA Transactions, Vol. 24, 1985.

[27] R. Billinton, P.K. Vohra and S. Kumar, "Effect of Station-Originated Outages in a Composite System Adequacy Evaluation of the IEEE Reliability Test System," IEEE Trans. PAS-104, No. 10, pp. 2649-2656, October 1985.

[28] R. Billinton and S. Kumar, "A Comparative Study of System Versus Load Point Indices for Bulk Power Systems," IEEE PES Winter Power Meeting, January 1986.

[29] R. Billinton and S. Kumar, "Pertinent Factors in the Adequacy Assessment of a Composite Generation and Transmission System," CEA Transactions, Vol. 25, 1986.

[30] R. Billinton and L. Cheng, "Incorporation of Weather Effects in Transmission System Models for Composite System Adequacy Evaluation," IEE Proceedings, Vol. 133, Pt.C, No. 6, pp.319-327, September 1986.

[31] J.C. Dodu, "A Probabilistic Model for Overall Study of Power Transmission Network Supply," Power System Computation Conference, Grenoble, France 1972.

[32] J.C. Dodu and A. Merlin, "Recent Improvements of the MEXICO Model for Probabilistic Studies", Int. J. Electric Power and Energy Systems, 1, pp. 46-56, 1979.

[33] J. Batut, J.C. Dodu and A. Merlin, "Taking into Account Service Quality and Operation Security in Planning Studies for EHV Systems: the MEXICO and ANASEC Models," IFAC Proceedings, Budapest, July 1984.

[34] S.H.F. Cunha et al., "Composite Generation and Transmission Reliability Evaluation in Large Hydroelectric Systems," IEEE Trans. PAS-104, No. 10, pp. 2657-2663, 1985.

# CHAPTER 4

# GENERATION EQUIPMENT OUTAGE DATA COLLECTION AND PROCESSING

## TASK FORCE

M. Bhavaraju (Chairman)
R. Billinton
M. Brown
J. Kariger
R. Ringlee

## 4.1 INTRODUCTION

This chapter describes the generation equipment data to be collected and the form it should take so that the relevant statistics can be calculated and interpreted. The data collection and statistics (performance indices) discussed are at the generating-unit level, since the primary application considered is the bulk power system reliability assessment. Another important application of equipment performance data is availability engineering, where the performance of major components of a generating unit such as a boiler, turbine, generator or condenser is analysed to evaluate availability improvements either at the design stage or in the actual operation of the unit. The important aspects of equipment performance data collection are definition of the various types of outage and proper interpretation of these definitions by data collectors. There are obviously similarities among the terms and schemes used but differences do and always will exist. Data collection schemes are based on long-standing practices within each country, which are unlikely to change.

This chapter also describes the generating-unit performance indices in use or proposed for system planning applications. The important aspect in predicting unit performance for system planning studies is careful analysis of the historical performance data, taking account of data sparsity (need for data pooling), abnormal events which may not recur, changes in configuration, and operating and maintenance practices (e.g. overtime, spares policy).

Inadequacies in the definitions of terms and the data analysis methods are identified. For example, special definitions and analysis methods may be needed in the case of peaking units, complex configurations such as coal gasification combined cycle units, storage devices and renewable technologies (solar, wind, etc.)

The terms related to generating-unit outages fall into five groups: outage states, capacity levels, time designations, energy quantities and performance indices.

The concepts involved in these five areas are described below using terms in common use in North America. Where European practice differs, this is discussed. The intention here is to generally describe the state of the art rather than give definitions employed in specific data collection systems used in different countries.

## 4.2 UNIT STATES

The status of a generating unit can be completely described by a set of mutually exclusive states. An important grouping of unit states is used to indicate operational readiness: the unit is either available or unavailable. When the unit is available, it can be either in service, electrically connected to the system, or on reserve shutdown, available but not in service. For instance, generating units in peaking service are characterized by significant fractions of time in the reserve shutdown state: they are placed in reserve shutdown whenever it is not economical to operate them.

The unavailable state may be further classified into planned or unplanned outage states. Planned outages are scheduled well in advance for inspection, testing, nuclear refuelling or overhaul and can typically last two to eight weeks, depending on the size, fuel and condition of the unit. Several states may be used to classify unplanned outages in terms of the postponability of the outage.

Two classifications in common use in North America are forced outages and maintenance outages. The former include starting failures as well as failures during the in-service state that cannot be postponed too long. For example, the North American Electric Reliability Council's Generation Availability Data System (NERC GADS) definition of forced outage includes all events that require the unit to be removed from the in-service state before the end of the next weekend. Unplanned outages that can be postponed beyond the next weekend but require a unit to be removed from the available state before the next planned outage are called maintenance outages[1] [1]. The hierarchy of these unit states is illustrated in Fig. 4.1.

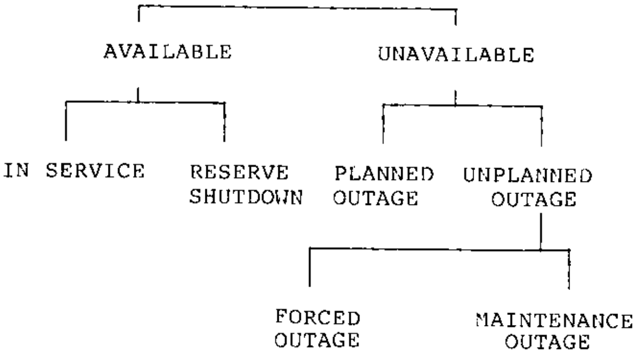


Figure 4.1 - Generating-unit states

Different classifications can be used to describe unit states. For example, UNIPEDE defines as forced all outages that are not part of the annual maintenance plan and records two outage states: planned outages and forced outages.

## 4.3 CAPACITY LEVELS

It should be noted that the states described in the previous section do not refer to the unit capability but simply indicate whether or not the unit is available to serve load. When the unit is available, it may or may not be able to supply the rated maximum output. The terms used to define capacity levels and capacity deratings are given below.

Two methods of defining, reporting and analysing capacity levels are used widely in the industry: gross and net. In general, utilities interested in plant design and efficiency seem to prefer data collection on a gross basis whereas those interested in system planning and concerned with the unit output available to serve system load prefer the net basis. Whichever the preference, it is important to use all quantities consistently on the same basis.

The following terms are in general use:

- The maximum capacity of a unit is established by formal demonstration under specified ambient weather conditions.
- The dependable capacity is the maximum capacity modified for ambient limitations for a specified period of time, such as a month or a season (this seasonal effect is not recognized in Europe).
- The seasonal derating, which is the difference between maximum and dependable capacity.
- The available capacity is the dependable capacity, modified for equipment limitation at any time.
- The unit derating (also known as partial outage or restriction) is the difference between dependable and available capacity and, similar to outage states, can be planned or unplanned. The latter category can be further classified into forced and maintenance derating, depending on postponability. These unit capacity levels are shown in Fig. 4.2.

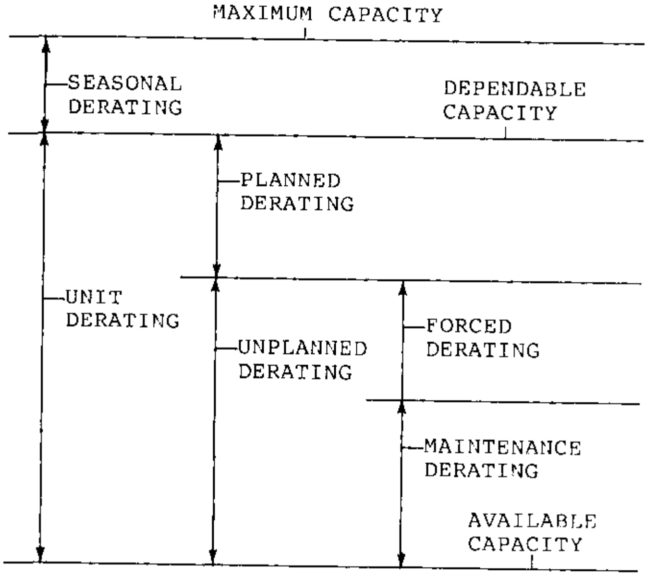


Figure 4.2 - Unit capacity levels

## 4.4 TIME DESIGNATIONS

For convenience of data analysis, the time spent in various outage states and at various capacity levels is described by the following specific terms: available, unavailable, in service, on reserve shutdown, on planned outage, on unplanned outage, on forced outage and on maintenance outage.

The unit states with which these times are associated can be seen in Fig. 4.1. Period time refers to the entire duration of a data-reporting period.

---

[1] Definitions of outage states must address events resulting in unanticipated extensions of the duration as well as postponability of the time the outage starts. For example, if maintenance or planned outages exceed the estimated duration as a result of a wrong estimate, these extensions are usually taken into account in the data collection effort but the outages are not reclassified. However, an extension due to a component failure or a condition discovered during the outage that forced the extension is reclassified as a forced outage.

Similarly, the times describing capacity levels are seasonal derated, unit derated, planned derated, unplanned derated, forced derated and maintenance derated times.

The unit capacity levels with which these times are associated are shown in Fig. 4.2. A common practice here is to calculate the "equivalent full" time of a unit derating, i.e. the time a unit spends at a derating level multiplied by the percentage derating. For example, if a unit with a 200-MW maximum capacity is derated by 50 MW (25%) for 20 h, then the equivalent time is 20 h x 25%, or 5 h. Equivalent time is accumulated for different derating levels to obtain the total equivalent seasonal derated time, equivalent unit derated time, and other derated categories.

Since time is typically measured in hours, these various times are referred to as available hours, unavailable hours, etc. in North American data collection systems. The subsequent examples will therefore be expressed in terms of "hours" rather than "time".

## 4.5 ENERGY QUANTITIES

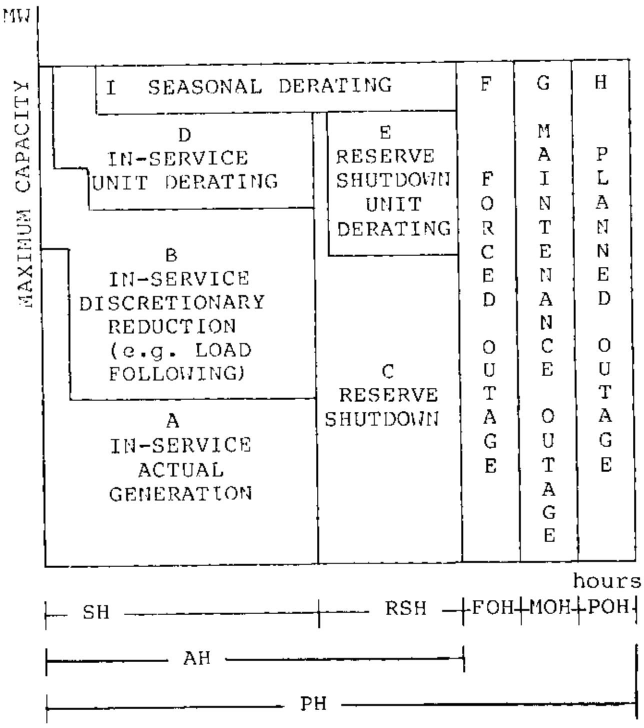
Energy quantities are also expressed as gross or net. The two most important are the measurable energy generated by a unit in a given period, i.e. actual generation, and the maximum generation, which is the energy that could be produced by a unit in a given period of time if operated continuously at maximum capacity.

## 4.6 PERFORMANCE INDICES

From the time designations of various unit states, capacity levels and energy quantities, it is possible to calculate the important unit performance indices. These can be classified into reliability, availability and productivity indices, reliability being the index of the ability of a generating unit to perform its intended function. The mean service time to forced outage can be used to calculate the probability of a unit not failing in a specified period as a reliability index.

Availability indices are concerned with the fraction of time a unit is capable of providing service; they consider both mean time to outage and mean outage duration. Availability indices include the forced outage, maintenance outage, unplanned and planned outage, unavailability and availability factors as well as the forced-outage rate. Productivity indices are concerned with the total power output of a unit with respect to its potential production and therefore consider the outage magnitude in addition to the mean time to outage and mean outage duration. Productivity indices include the unit-derating, equivalent availability, equivalent unavailability, seasonal derating and capacity factors.

Some of these performance indices are based on period hours and can be described using Fig. 4.3, which shows capacity versus time (all capacity values should be either gross or net). The total height of the diagram is maximum capacity (MC), and the total width is period hours (PH). Thus, the total area Y is MC x PH, which is the total energy that could have been generated during the period if the system is operating continuously at maximum capacity.



SH = service hours
RSH = reserve-shutdown hours
FOH = forced-outage hours
MOH = maintenance-outage hours
POH = planned-outage hours
AH = available hours
PH = period hours
MC = maximum capacity

Figure 4.3 - Relationship between time and energy terms

The area Y is divided into several vertical segments by the various time designations. The vertical segments involving available hours are further divided into sections to show the energy associated with seasonal derating, unit derating, discretionary reduction and actual generation. All performance indices, which are based on period hours, can be expressed as percentages of the total area in Fig. 4.3.

Availability indices (time-based availability in Europe):

Forced-outage factor $= \frac{F}{Y} \times 100$

Maintenance-outage factor $= \frac{G}{Y} \times 100$

Unplanned-outage factor $= \frac{F + G}{Y} \times 100$

Planned-outage factor $= \frac{H}{Y} \times 100$

Unavailability factor $= \frac{F + G + H}{Y} \times 100$

Availability factor $= \frac{A+B+C+D+E+I}{Y} \times 100$

Productivity indices (energy-based availability in Europe):

Unit derating factor $= \frac{D + E}{Y} \times 100$

Equivalent availability factor $= \frac{A + B + C}{Y} \times 100$

Equivalent unavailability factor $= \frac{D+E+F+G+H}{Y} \times 100$

Seasonal derating factor $= \frac{I}{Y} \times 100$

Capacity factor $= \frac{A}{Y} \times 100$

Indices not based on the total period hours include:

Mean service time to forced outage

$$= \frac{\text{service hours}}{\text{number of forced outages (excluding starting failures)}}$$

Mean forced-outage duration

$$= \frac{\text{forced-outage hours}}{\text{number of forced outages (excluding starting failures)}}$$

Forced-outage probability[1]

$$= \frac{\text{forced outage hours}}{\text{forced-outage hours} + \text{service hours}}$$

Equivalent forced-outage probability[1]

$$= \frac{\text{forced-outage hours} + \text{equivalent forced derated hours}}{\text{forced-outage hours} + \text{equiv. forced derated hours during reserve shutdown} + \text{service hours}}$$

(The definition of equivalent forced-outage rate has variations in the industry. That used here is taken from ANSI/IEEE Standard 762 as an illustration).

Starting-failure probability

$$= \frac{\text{No. of starting failures}}{\text{No. of starting successes} + \text{No. of starting failures}}$$

The basic performance indices used in system planning are the forced-outage, equivalent forced-outage and starting-failure probabilities and the planned-outage and maintenance-outage factors. The forced-outage probability provides an estimate of the probability of a unit being on forced outage when not on planned or maintenance outage and is the basic statistic used in the loss-of-load probability method. Both the mean time to forced outage and mean forced-outage duration are required for the frequency and duration method or the Monte Carlo simulation for evaluating bulk power system reliability. The other performance indices discussed are useful for assessing the individual generating unit's productivity for studying methods of improving it.

A state transition matrix is used to perform a systematic analysis of the outage data and define the performance indices. Figure 4.4 is a general state transition matrix showing the unit states described earlier in this chapter. These unit states are mutually exclusive and exhaustive. The left side of the matrix shows the possible unit states before a transmission event while the top row shows the same possible unit states after a transition event. Clear definitions and interpretations of transition events are important in the collection of generating-unit outage data because the actual reporting includes the dates and times of the transition events from which the state duration times and performance indices are calculated.

---

[1] These indices are dimensionless and provide estimates of the probability of forced outage. The terms "forced-outage rate" and "equivalent forced-outage rate" (rather than probability) have been in use in North America for many years.

| STATE BEFORE TRANSITION | STATE AFTER TRANSITION | | | | |
|---|---|---|---|---|---|
| | IN SERVICE | RESERVE SHUTDOWN | PLANNED OUTAGE | FORCED OUTAGE | MAINTENANCE OUTAGE |
| IN SERVICE | | SHUT DOWN FOR ECONOMY | SHUT DOWN FOR PLANNED OUTAGE | SHUT DOWN FOR FORCED OUTAGE | SHUT DOWN FOR MAINTENANCE OUTAGE |
| RESERVE SHUTDOWN | STARTING SUCCESS | | BEGIN PLANNED OUTAGE | Y | BEGIN MAINTENANCE OUTAGE |
| PLANNED OUTAGE | STARTING SUCCESS | END PLANNED OUTAGE | | Y | X |
| FORCED OUTAGE | STARTING SUCCESS | END FORCED OUTAGE | EXTEND FOR PLANNED WORK | | X |
| MAINTENANCE OUTAGE | STARTING SUCCESS | END MAINTENANCE OUTAGE | EXTEND FOR PLANNED WORK | STARTING FAILURE | |

X - Transfer not possible

Y - Starting failure or component failure found during shutdown

Figure 4.4 - State transition matrix

## 4.7 DATA COLLECTION SYSTEMS FOR GENERATING-UNIT OUTAGES

The major data collection schemes have been developed by CEA in Canada, NERC in the United States, EDF in France, CEGB in the United Kingdom, VDEW in West Germany and the International Union of Producers and Distributors of Electricity. Information on NERC's GADS system and CEA's ERIS is summarized in Annex 4A, while Annex 4B provides a description of the data collection systems used in Europe.

## 4.8 OUTAGE DATA ANALYSIS AND PERFORMANCE PREDICTION

The analysis methods currently used for generator outage data are relatively simple. Generating units are disaggregated by type, size, design, vintage and fuel used, and the performance indices for a specified period are calculated. The indices are provided for each unit as well as for a group of similar units as a group average. There are usually sufficient performance data to calculate the indices with reasonable confidence. Some analysts use statistical tools (e.g. regression analysis) to assess the performance of units by type, size, design, vintage, fuel used and any other significant factors.

System planning requires the prediction of generating-unit performance for long-range bulk power system reliability studies. In a number of systems, the prediction is based on historical performance indices, with certain adjustments to account for new components, changes in repair policies or in operating conditions and factors such as age, all of which can be studied using regression analysis. Unless suitable data analysis tools are used, however, it is not straightforward to make these adjustments and many utilities use simply the historical performance indices.

The tools mentioned above are those that can analyse historical data to develop outage statistics for the components of a unit and synthesize the component performance indices to determine the unit performance. Such tools can account for the effects of changes in the component performance (e.g. due to age) or configuration (e.g. additional pulverizer) on the unit performance. They can also be used to predict the performance of future units by means of a synthesis of the planned components and their configuration. This is the approach referred to earlier as availability engineering.

## 4.9 FUTURE NEEDS OF GENERATING-UNIT OUTAGE DATA

In view of new generation technologies, it is important to recognize the inadequacies in existing data collection systems, definitions of terms and analysis methods. Future work by the industry will resolve these issues and provide the required tools.

In the case of data collection systems, further emphasis should be given to component performance. As most data collection systems today are unit-oriented, component performance data is extracted from the cause codes for unit failures. However, the failure and repair processes of major components should be identified independently of unit states for developing the appropriate data for availability engineering.

The second area, definitions, should cover outages for unconventional technologies. For example, when an energy-storage device is discharged or is charging, it is not available to supply power. Similarly, solar and aerogenerator devices cannot supply power when there is no resource (sun or wind). Theoretically, such cases should be considered as outages when evaluating the economics of these devices, although this may introduce misleading indices in the evaluation of component configuration and design. In these cases, outages due to equipment failures would have to be defined separately from those due to resource failures [4] and appropriate performance indices developed. Another example is generating units with peaking duty, which have low service hours. The conventional forced-outage rate index used for base-load units could be misleading here and several methods have been proposed to calculate a special performance index for this case.

The third area in need of further work is data analysis to predict component and unit performances. This aspect is now being addressed by the industry, as indicated by current availability engineering activities [5, 6]. Complex configurations such as coal gasification combined cycle (CGCC) units (comprising a coal gasifier, a steam unit and a combustion turbine) are being planned for the future. The performance indices of the different components will have to be combined to calculate a composite index for the CGCC unit [7].

# ANNEX 4A

## NORTH AMERICAN DATA SYSTEMS

### 4A.1 NERC GADS (USA)

The North American Electric Reliability Council (NERC) maintains the Generating Availability Data System (GADS) on behalf of all US utilities and participating Canadian NERC members. Participation in NERC GADS is voluntary. As of 1985, program participants represented nearly 90% of the installed capacity in North America and more utilities were in the process of entering the program.

Three types of data are used in GADS: unit pedigree, in which major systems and components are identified; unit event, an event being recorded each time a unit experiences a change in operating status or capability, permitting the reconstruction of the unit's operational history; and unit performance, recording the unit's actual performance data for a given period. This data permits the analysis of performance trends for specific units and for various categories of units and their major systems and components.

NERC reporting instructions provide an outline of the procedures and format for submitting information to the GADS program. These are directed to enable consistent reporting of the unit design information, outage and derating descriptions, and selected overall unit performance information. All reporting requirements and definitions are based on ANSI/IEEE Standard 762 "Definitions for Reporting Electrical Generating Unit Reliability, Availability and Productivity" [1]. The GADS definitions are compatible with but not identical to the definitions used by UNIPEDE and the World Energy Conference.

Data submissions using the present GADS reporting format began in 1982, replacing procedures used since the early 1960s. The GADS recording format provides means for describing the type and cause of outage and derating events on both the total unit and the component(s) that failed. This may be further amplified by a written description of the type and mode of failure, cause of immediate failure and any contributing factors and corrective actions taken. Performance reporting includes information on unit ratings, energy generated, unit loading characteristics and a description of fuels consumed.

All participants receive annual GADS publications [2] and reporting instructions. The annual publications are available to non-NERC utilities and others on a cost-based fee.

A copy of one summary page from the "Equipment Availability Report - 1985" is offered in Fig. 4A.1 to illustrate the form of summary statistics provided by NERC GADS.

### 4A.2 CEA ERIS (CANADA)

The Equipment Reliability Information System, ERIS, of the Canadian Electrical Association, CEA, has been developed to satisfy the need of Canadian utilities for a uniform method of recording the performance of generation and transmission equipment and for the centralized processing of such data. The generation equipment reporting system was inaugurated in 1977 and annual reports have been issued since then using software written for that purpose [3]. The data base contains information on pumped-storage and hydaulic turbine units of maximum continuous ratings (MCR) of 24 MW or larger, fossil steam units with an MCR of 60 MW or larger, combustion turbine units and internal combustion units with an MCR of 1 MW or greater, and nuclear units with an MCR of 200 MW or larger. As of 1982, the data base contains operating experience on 702 units including 483 hydraulic, 94 fossil, 76 combustion turbine, 39 internal combustion and eight nuclear units.

The generation equipment reporting system is based on that developed by the Edison Electric Institute. Several additional characteristics have been introduced which significantly enhance the value of the data without placing an unreasonable burden on those responsible for acquiring and reporting it. Four distinctive characteristics define this system:

- recording of the state of a unit over the entire reporting period
- recording of deratings of a unit, including concurrent deratings
- recording of the causes of each change of state of a unit using a five-digit outage code
- recording of the outages of certain selected components even when these do not cause a change of state of the unit.

The CEA ERIS generation data system uses an eleven-state model consisting of six available states:

- O - operating
- O(FD) - operating under a forced derating
- O(SD) - operating under a scheduled derating
- ABNO - available but not operating
- ABNO(FD) - ABNO under forced derating
- ABNO(SD) - ABNO under scheduled derating

five unavailable states:

- FO - forced outage
- FEMO - forced extension of a maintenance outage

## Fossil Units—All Fuel Types

All Size Ranges 1985

**NERC GADS**

Annual Summary Report

| | |
|---|---|
| NUMBER OF SYSTEMS - - | 148 |
| NUMBER OF UNITS - - - | 1438 |
| NUMBER OF UNIT-YEARS - | 1438 |

UNIT-YEAR AVERAGES

| | |
|---|---|
| PERIOD HOURS | 8690 |
| SERVICE HOURS | 5120 |
| RESERVE HOURS * | 2114 |
| AVAILABLE HOURS | 7233 |
| AVG UNIT CAPACITY-MW | 272 |
| G CAPACITY FACTOR-% | 49.66 |
| OUTPUT FACTOR-% | 73.00 |
| SERVICE FACTOR-% | 58.92 |
| AVAILABILITY FACTOR-% | 83.24 |
| SCH OUT FACTOR-% | 11.93 |
| FORCED OUT FACTOR-% | 4.82 |
| FORCED OUT RATIO-% | 28.80 |
| F O INCIDENT RATE-% | 69.21 |
| ATTEMPTED STARTS ** | 28.32 |
| SUCCESSFUL STARTS ** | 27.82 |

NOTES

* SOME CLASSES OF UNITS ARE NOT REQUIRED TO REPORT RESERVE HOURS. RESERVE HOURS ARE COMPUTED FROM PERIOD HOURS, SERVICE HOURS AND UNIT OUTAGES.

** BASED ON THOSE UNITS REPORTING STARTS.

| PLANT EQUIPMENT GROUPINGS | FORCED OUTAGE RATE | EQUIV FORCED OUTAGE RATE | AVAIL FACTOR | EQUIV AVAIL FACTOR | SCHED OUTAGE FACTOR | -- DERATED HOURS -- EQUIV UNPLANNED (FORCED) | EQUIV SCHED |
|---|---|---|---|---|---|---|---|
| BOILER | 4.21 | 5.69 | 89.65 | 88.58 | 7.76 | 78.72 | 13.80 |
| SCRUBBER | 0.08 | 0.68 | 95.95 | 95.54 | 4.00 | 30.44 | 5.19 |
| TURBINE | 1.22 | 1.47 | 93.43 | 93.25 | 5.84 | 13.42 | 2.34 |
| GENERATOR (ELEC) | 0.87 | 0.90 | 97.20 | 97.18 | 2.28 | 1.45 | 0.08 |
| TURBINE-GEN SET | 2.07 | 2.35 | 92.44 | 92.24 | 6.31 | 14.87 | 2.41 |
| CONDENSER | 0.16 | 0.45 | 97.99 | 97.76 | 1.91 | 14.88 | 5.11 |
| BALANCE OF PLANT | 0.94 | 1.81 | 96.95 | 96.37 | 2.49 | 45.28 | 4.86 |
| REGULATORY | 0.00 | 0.00 | 99.98 | 99.98 | 0.02 | 0.04 | 0.02 |
| TOTAL UNIT | 7.57 | 10.38 | 83.24 | 81.14 | 11.93 | 155.63 | 26.51 |

PROBABILITY STATES

| PERCENTAGE AVAILABLE CATEGORIES | UNPLANNED (FORCED) DERATINGS NUMBER OF OCC | DERATING HOURS | % OF PERIOD | SCHEDULED DERATINGS NUMBER OF OCC | DERATING HOURS | % OF PERIOD |
|---|---|---|---|---|---|---|
| 00.1 - 19.9 | 1.1 | 3.0 | 0.0 | 0.2 | 1.2 | 0.0 |
| 20.0 - 29.9 | 0.7 | 5.4 | 0.1 | 0.2 | 0.8 | 0.0 |
| 30.0 - 39.9 | 1.4 | 9.3 | 0.1 | 0.6 | 4.4 | 0.1 |
| 40.0 - 49.9 | 2.6 | 34.2 | 0.4 | 0.9 | 6.1 | 0.1 |
| 50.0 - 59.9 | 3.9 | 63.3 | 0.7 | 1.2 | 12.3 | 0.1 |
| 60.0 - 69.9 | 4.0 | 60.9 | 0.7 | 0.7 | 6.9 | 0.1 |
| 70.0 - 79.9 | 6.3 | 102.9 | 1.2 | 0.9 | 13.7 | 0.2 |
| 80.0 - 89.9 | 10.6 | 203.2 | 2.3 | 1.4 | 36.5 | 0.4 |
| 90.0 - 99.9 | 12.8 | 362.6 | 4.2 | 0.9 | 35.4 | 0.4 |

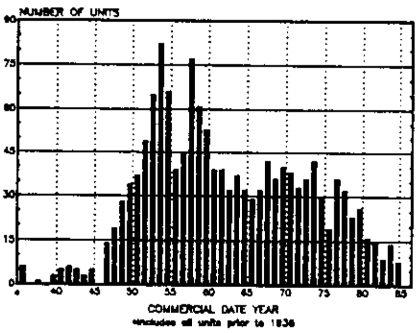
| PLANT EQUIPMENT GROUPINGS | UNPLANNED (FORCED) OUTAGES | | | PLANNED OUTAGES | | | MAINTENANCE OUTAGES | | | NONCURTAILING EVENTS | | | CAUSE CODE SERIES |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | NUMBER OF OCC | OUTAGE HOURS | MAN HOURS | NUMBER OF OCC | OUTAGE HOURS | MAN HOURS | NUMBER OF OCC | OUTAGE HOURS | MAN HOURS | NUMBER OF OCC | OUTAGE HOURS | MAN HOURS | |
| BOILER | 5.00 | 225.6 | 630 | 0.85 | 557.8 | 5483 | 1.64 | 116.4 | 708 | 7.49 | 362.1 | 1541 | 100-199 |
| SCRUBBER | 0.28 | 4.5 | 54 | 0.37 | 279.7 | 4195 | 0.53 | 68.1 | 2069 | 15.45 | 591.7 | 3758 | 400-450 |
| TURBINE | 1.35 | 63.2 | 390 | 0.66 | 436.2 | 2969 | 0.64 | 71.7 | 224 | 0.23 | 15.1 | 35 | 600-699 |
| GENERATOR (ELEC) | 0.55 | 45.0 | 176 | 0.24 | 176.5 | 1107 | 0.25 | 21.7 | 107 | 0.13 | 10.0 | 41 | 700-799 |
| TURBINE-GEN SET | 1.90 | 108.3 | 363 | 0.75 | 468.0 | 3396 | 0.84 | 80.4 | 235 | 0.00 | 0.0 | 0 | 600-799 |
| CONDENSER | 0.38 | 8.4 | 109 | 0.19 | 142.8 | 909 | 0.28 | 23.1 | 149 | 1.20 | 130.7 | 273 | 800-899 |
| BALANCE OF PLANT | 1.52 | 48.6 | 127 | 0.24 | 175.9 | 1616 | 0.57 | 40.5 | 256 | 4.27 | 366.5 | 587 | 900-999 |
| REGULATORY | 0.00 | 0.0 | 0 | 0.00 | 1.5 | 240 | 0.00 | 0.3 | 64 | 0.00 | 0.3 | 0 | 500-545 |
| TOTAL UNIT | 8.88 | 419.6 | 760 | 1.43 | 851.3 | 8487 | 2.52 | 185.9 | 924 | 0.00 | 0.0 | 0 | 100-999 |

TOP 15 UNPLANNED (FORCED) AND SCHEDULED COMPONENT OUTAGES AND DERATINGS RANKED BY AVERAGE MWH PER UNIT-YEAR
NUMBER OF SYSTEMS - 148 NUMBER OF UNITS - 1,438 NUMBER OF UNIT-YEARS - 1,438

| CAUSE CODE | AVG NO. OCC PER UNIT-YR | AVERAGE MWH PER UNIT-YR | AVERAGE MWH PER OUTAGE | CAUSE CODE DESCRIPTION |
|---|---|---|---|---|
| 101 | 1.08 | 22725 | 21042 | WATER WALLS |
| 103 | 0.73 | 12175 | 16786 | SUPERHEATER |
| 104 | 0.34 | 6956 | 20753 | REHEATER - FIRST |
| 712 | 0.15 | 6678 | 44662 | EXCITER |
| 106 | 0.46 | 5884 | 12780 | ECONOMIZER |
| 631 | 0.15 | 4174 | 27280 | LUBE OIL SYSTEM & BEARINGS (EXCEPT BEARING VIBRATION) |
| 629 | 0.02 | 4133 | 185718 | BUCKETS AND BLADES |
| 900 | 0.46 | 3774 | 8224 | OTHER, GENERAL CODE; SEE CODES 500-545 FOR ADDITIONAL CLASSIFICATIONS |
| 799 | 0.10 | 3489 | 36360 | MISCELLANEOUS; SEE CODES 500-545 FOR ADDITIONAL CLASSIFICATIONS |
| 199 | 0.23 | 3242 | 13877 | MISCELLANEOUS; SEE CODES 500-545 FOR ADDITIONAL CLASSIFICATIONS |
| 903 | 0.07 | 3119 | 47211 | MAIN TRANSFORMER |
| 915 | 0.18 | 2414 | 13722 | OPERATING ERROR |
| 630 | 0.22 | 2185 | 9790 | VIBRATION OF TURBINE GENERATOR UNIT |
| 699 | 0.18 | 2149 | 11886 | MISCELLANEOUS; SEE CODES 500-545 FOR ADDITIONAL CLASSIFICATIONS |
| 622 | 0.17 | 2145 | 12290 | CONTROL, TURBINE AND REHEAT STOP VALVES |

AGE DISTRIBUTION (COMMERCIAL DATE)

NUMBER OF UNITS: 1438 YEARS: 1936–1985



SIZE DISTRIBUTION (NAMEPLATE)

NUMBER OF UNITS: 1438 SIZE RANGE: 8–1300 MW

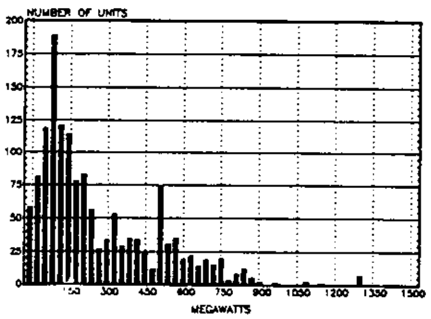


Figure 4A.1 - Copied from "Equipment Availability Report - 1985," North American Reliability Council.

- FEPO - forced extension of a planned outage
- MO - maintenance outage
- PO - planned outage

and four substates for classes of forced outages:

- sudden forced outage
- immediately deferrable forced outage
- deferrable forced outage
- starting failure.

The first three available states refer to the level of capability when the unit is operating and the latter three to the capability level when not operating. For each of these available states, the capability of the unit is recorded.

The outage states are listed in descending order with respect to the urgency of the action required.

Summary data derived from CEA ERIS hydraulic, fossil and nuclear statistics for the interval 1980-84 for base-load operation is offered in Table 4A.1 and summary statistics for gas turbines in Table 4A.2.

Table 4A.1

CEA base-load generation data 1980-84

Hydraulic units

| MCR class (MW) | FOR[1] (%) | DAFOR[2] (%) | Failure rate (occ /yr) |
|---|---|---|---|
| 24 - 99 | 2.88 | 3.08 | 2.91 |
| 100 - 199 | 2.41 | 2.51 | 4.66 |
| 200 - 299 | 6.58 | 6.95 | 10.47 |
| 300 - 399 | 12.09 | 12.32 | 13.96 |
| 400 - 499 | 3.36 | 3.40 | 3.83 |
| All units | 3.15 | 3.33 | 3.74 |

Fossil units

| MCR class (MW) | FOR (%) | DAFOR (%) | Failure rate (occ /yr) |
|---|---|---|---|
| 60 - 99 | 17.15 | 23.56 | 13.09 |
| 100 - 199 | 8.83 | 12.97 | 14.68 |
| 200 - 299 | 12.85 | 17.32 | 40.71 |
| 300 - 399 | 5.77 | 10.84 | 16.27 |
| 400 - 499 | 9.81 | 10.43 | 6.47 |
| All units | 9.51 | 13.53 | 14.69 |

Nuclear units

| MCR class (MW) | FOR (%) | DAFOR (%) | Failure rate (occ /yr) |
|---|---|---|---|
| 400 - 599 | 16.29 | 17.02 | 3.62 |
| 600 - 799 | 5.47 | 7.47 | 7.17 |
| 800 & over | 0.07 | 0.24 | 3.35 |
| All units | 10.64 | 12.02 | 5.54 |

Table 4A.2

CEA gas turbine data 1980-84

| MCR class (MW) | FOR[1] (%) | DAFOR[2] (%) | Failure rate (occ /yr) |
|---|---|---|---|
| 1 - 9 | 63.26 | 10.80 | 196.57 |
| 10 - 24 | 27.18 | 11.18 | 28.47 |
| 25 - 49 | 38.95 | 15.34 | 16.22 |
| 50 & over | 69.34 | 34.51 | 22.15 |
| All units | 48.77 | 15.88 | 27.62 |

---

[1] FOR : forced-outage rate

[2] DAFOR: derated adjusted forced-outage rate

# ANNEX 4B

## EUROPEAN DATA BANKS

### 4B.1 INTRODUCTION

The purpose of this annex is to identify and briefly describe the major data banks presently in operation in Europe which contain information useful for analysing the performance and availability of generating plants.

Table 4B.1 summarizes currently known systems in operation in Europe. Owing mainly to their safety implications but also to their use for reliability evaluation, data bases designed for nuclear power plants are more numerous than those for conventional thermal plants. The table also indicates data systems containing only nuclear plant operating data.

International organizations that have set up useful data systems for nuclear plants are IAEA, UNIPEDE and EEC. UNIPEDE also has a system, perhaps the oldest of all such systems, for thermal plants.

An international effort is now under way to standardize data collection and reporting and a master questionnaire on common operating experience has recently been developed by the International Atomic Energy Agency (IAEA), the European Economic Community (EEC), UNIPEDE and World Energy Conference.

### 4B.2 EUROPEAN DATA SYSTEMS

#### 4B.2.1 IAEA Power Reactor Information System (PRIS)

PRIS basically provides information on nuclear plant availability and, to some extent, on key economic parameters for nuclear power plants. Since 1973, it also contains information on the main causes of plant unavailability. While PRIS is not primarily designed for availability and performance analysis, it could be used in the future for improving performance by learning from significant common causes of outages.

Its main limitations are the small number of classifications or unit subsystems and major components to which an unavailability cause can be assigned, its non-inclusion of events leading to outages of less than 10 full power-hours, and its exclusive use of load factor. Load factor is not a sufficient description for plants that depart from base load operation.

#### 4B.2.2 UNIPEDE Thermal Plant Data Bank

Since 1968, UCPTE (Union for the Coordination of the Production and Transmission of Energy) and UNIPEDE have been collecting monthly information about the performance of thermal plants installed in their member countries. The data supplied includes all unavailabilities and a list of 19 main causes. The items of equipment that fail due to these causes number 84, grouped according to the major systems of the plant: boiler, turbine, generator, feedwater and electrical.

The cause codes and reporting criteria have undergone several changes during the existence of this data bank until it reached its present status.

Normal yearly reports are produced after statistical processing. The performance indicators used are the load and the energy availability factor.

#### 4B.2.3 UNIPEDE Significant Events Reporting System (USERS)

On June 6, 1982 the Steering Committee of UNIPEDE approved a project to design and operate a system of exchanging and processing information related to nuclear plant operation, based on an existing system, INPO-NSAC, for American plants.

The main specifications were:

- The system must allow for information exchange among users.
- All significant events involving not only safety but also plant availability must be collected.
- Computer processing, because of the large number of events to be handled.
- Very fast reporting and use.
- Easy coordination with other international data systems.

The system architecture comprises a central data bank, the terminals, the data transmission network and the electronic mail network.

Events are reported if they meet one of three criteria:

- The event has great safety significance.
- The event produces an unavailability exceeding or equal to 3 full-power days.

Table 4B.1

Data banks containing European generating-plant performance statistics

| Organization responsible | Name of data bank | Operational in year | Plants covered | Subsystems within data bank | Level of information |
|---|---|---|---|---|---|
| IAEA | Power Reactor Information System (PRIS) | 1971 | Nuclear | | - Plant performance with major systems (15)<br>- Load factor used as the performance index<br>- Only significant outages reported (duration exceeding 10 full-power hours) |
| IAEA | Incident Reporting System (IRS) | 1980 | Nuclear | | - Abnormal occurrences related to safety:<br>. Releases, exposure<br>. Degradation of safety systems<br>. Generic design or operating problems |
| UNIPEDE | Thermal Plant Statistics | 1968 | Thermal | | - Plant performance<br>- 19 main causes for 84 major units of equipment<br>- Monthly information |
| UNIPEDE | UNIPEDE Significant Events Reporting System (USERS) | 1985 | Nuclear | | - Events, with causes and plant effects. Events must neet one of three criteria:<br>. Very significant from safety standpoint<br>. Plant unavailability equal to or exceeding 3 full-power days<br>. Decision of the reporter |
| EEC | European Reliability Data System (ERDS) | 1985 | Nuclear | Component Event Data Bank (CEDB)<br>Abnormal Occurrences Reporting System (AORS)<br>Operating Units Status Report (OUSR)<br>Reliability Parameter Data Bank (RPDB) | - Failure of components (light-water reactors)<br>- Abnormal events<br>- Plant performance<br>- Reliability of similar components |

Table 4B.1 (cont'd)

| Organization responsible | Name of data bank | Operational in year | Plants covered | Subsystems within data bank | Level of information |
|---|---|---|---|---|---|
| EDF (France) | | 1960 | Thermal (plus graphite gas reactors) | | - Plant performance level (similar to UNIPEDE's system) |
| | Système de Recueil de Données de Fiabilité (SRDF) | 1978 | Nuclear | | - Reliability of components (up to 1000 items) |
| | Système de Recueil de Données d'Exploitation des centrales nucléaires (RDE) | 1978 | Nuclear | | - Plant performance level |
| | Fichier d'événements concernant les centrales nucléaires françaises | 1981 | Nuclear | | - More complete information about significant events |
| UKAEA (UK) | System Reliability Services Data Bank (SRS) | 1970 | All industry | Event data store | - Component performance |
| | | | | Reliability data store | - Reliability data calculated from the component performance information |
| VATTENFALL (Sweden) | | 1978 | Nuclear | | - Reliability |
| VDEW (West Germany) | Thermal Plant Statistics | 1970 | Nuclear<br>Thermal | | - Plant performance level |
| CEGB (England and Wales) | PR/A | 1977 | Nuclear )<br>Thermal )<br>Gas turbine) | | - Plant performance level<br>- Reliability of components causing loss of output<br>- Reliability of duplicated components (special data collection) |

- The reporter considers that even if the incident does not fall into the two categories above, it must be shared with other users.

The system contains the following information:

- Unit identification
- Type and nominal power of the reactor
- Nature of the event
- Plant status before the event
- Assigned function of the failed component
- Causes and circumstances of the event
- Impact on the plant
- Impact on other components
- Impact on personnel and the environment
- Unavailable power and duration
- Impact on safety
- Event code
- Event summary
- References

### 4B.2.4 EEC European Reliability Data System (ERDS)

The Joint Research Centre of the European Communities (Ispra, Italy) started work on developing the design of a centralized system to collect and process European nuclear plant operating data in 1977. ERDS contains four main subsystems according to the type and level of information collected:

- Component Event Data Bank (CEDB), to collect component failure data from national information systems

- Abnormal Occurrences Reporting System (AORS), for collecting data from national systems about events to be used in safety analysis

- Operating Unit Status Report (OURS), to obtain, process and make available performance data

- Reliability Parameter Data Bank (RPDB), to collect and process reliability parameters for similar components.

The CEDB stores information about failures, repairs, maintenance and other activities related to the main components of the European light-water reactors. The major files are:

- Component data: identification by type, manufacturer, design, test and maintenance, operating characteristics, operating data. Family classification of components allowing up to 20 characteristics, to be specified for accurate identification.

- Failure data: indication of causes, effects, corrective actions, etc.

- Operating data: operating hours, demands, etc.

Such information, together with a powerful data base management system (ADABAS), allows a statistics reporting system from the terminals.

## REFERENCES

[1] Institute of Electrical and Electronics Engineers, IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability and Productivity, ANSI/IEEE Std. 762, 1987.

[2] North American Electric Reliability Council, Generator Availability Data System, Annual Reports.

[3] Canadian Electrical Association, Equipment Reliability Information System: Generation Equipment Status, Annual Reports.

[4] L.D. Jaffe, "Availability of Solar and Wind Generating Units," IEEE Joint Power Generation Conference, Paper No. 84JPGC810-8, September 1984.

[5] Electrical Power Research Institute, User's Guide for the UNIRAM Availability Assessment Methodology, AP-3956 CCM, April 1985.

[6] Electrical Power Research Institute, GO Methodology, NP-3123-CCM, June 1983.

[7] Electrical Power Research Institute, Guide for the Assessment of the Availability of Gasification-Combined Cycle Power Plants, AP-2202, January 1982.

# CHAPTER 5

# TRANSMISSION EQUIPMENT OUTAGE DATA COLLECTION AND PROCESSING

## TASK FORCE

R.N. Allan (Chairman)
S.J. Argent
R. Billinton
J. Endrenyi
A. Inesi
A.W. Schneider
F. Talandier
P.O. Wright

## 5.1 INTRODUCTION

### 5.1.1 Objective

The power transmission system is monitored continuously, with the result that many system parameters such as the configuration, open and closed status of breakers, power injections, power flows and busbar voltages are known as a function of real time. All these parameters constitute data that is essential for efficient, economic and secure operation of the system. The more important elements of this real-time data, augmented by information derived post-event, are crucial to well-structured planning and design.

In this chapter, the subject of collecting and analysing data is treated within the framework of the objective to create an application guide on the methodologies associated with predicting the reliability of the composite (generation/transmission) system. The text that follows is therefore not intended to be an exhaustive discourse on the topic; instead, it considers data only in terms of the above comments.

### 5.1.2 Purpose of Data

Unlimited amounts of data can be collected but it is both inefficient and undesirable to collect, analyse and store more than required for the intended purpose. Before deciding what data to collect, it is therefore essential to positively identify its purpose.

In conceptual terms, data can be collected for assessing past system performance and/or predicting future performance.

For assessment of the past performance of components, plant and systems, data is valuable for the following reasons:

- It identifies chronological changes in performance and therefore helps determine weak areas needing reinforcement or plant modifications.
- It establishes existing indices, which serve as a guide for determining acceptable values in future system reliability assessment.
- It enables previous predictions to be compared with actual operating experience.

In order to look at future system behavior, past experience must be transformed into the required predictions. Collection of data is therefore invaluable, since this forms the input to relevant reliability models, techniques and equations that estimate:

- the future system performance
- the benefits of alternative system designs, reinforcements and expansion plans
- the effects of alternative operational and maintenance policies
- the related reliability cost, benefit and worth of these alternatives.

At the present time, data is more widely used for assessing past system performance than for predicting future performance. Several plant-oriented CIGRE study committees have been active in this field for many years and are still involved with collecting, analysing and comparing plant data. The objective of this application guide is not to duplicate that activity but merely to outline the collection, processing and transformation of data relevant to the modeling and analysis of the reliability of the overall power system.

It follows that data requirements reflect and respond to the needs of the predictive methodology. This means that the data must be sufficiently comprehensive to ensure the methods can be applied but restrictive enough to ensure that unnecessary data is not collected and avoid irrelevant statistics being evaluated. Consequently, the discussion here is limited to the data required for the models and techniques associated with system reliability prediction and cost/benefit analyses.

### 5.1.3 Processing of Data

Data processing comprises two activities:

- collection of field data by operations and maintenance (O & M) personnel documenting the details of failures as they occur, together with the associated outage durations
- analysis of this data to create statistical indices, which will be subsequently updated by the entry of new data.

The field data and/or the statistical data may be stored in a data bank for later use. However, the quality of the stored data depends on two important factors: confidence and relevance. The quality of the data and, hence, the confidence that can be placed in it, are clearly dependent on the accuracy and completeness of the information compiled by O & M personnel. The latter should therefore be made fully aware of the future use to which the data will be put and the importance it will have in later system developments. They must also have direct access to the data for their work.

The quality of the statistical indices also depends on how the data is processed, how much pooling is done and the age of the data currently stored, since these factors affect the relevance of the indices for their intended use.

The objective of the following overview of the two main data processing activities is to determine which elements of transmission equipment performance should be collected and in what format, so that the relevant statistics can be calculated and interpreted. This objective has three distinct features:

- data to be collected, including equipment classification
- data collection schemes
- statistical indices

These features are discussed individually in the following section.

## 5.2 Data to be Collected

### 5.2.1 Equipment Classification

The failure and restoration processes depend on the type of component considered. There are several reasons for this, including the different functions the components perform in the transmission system and the exposure parameters to which they are subjected. The items of equipment for which data is to be collected should therefore be divided into classes, each class being determined by operational functions and/or exposure conditions. The number of classes is a function of the perceived requirement and/or application of the data collected but a minimum of three should be respected:

CLASS A - Components of varying length, i.e. transmission lines and cables. These form a class of their own because their failure rate is a function of their length. If terminal effects are neglected, then for most practical purposes the failure rate can be assumed proportional to the length and can be quoted in failures per unit length per year. Care must be exercised in extrapolating such a value for excessively long or very short lines. In practice, certain terminal effects are included which, since their contribution is constant, add a constant value to the proportional rate mentioned above. These terminal effects can dominate for short lines.

CLASS B - Static components, i.e. all other components except switchgear. This class therefore includes transformers, reactors, etc. The failure rate of these components can be quoted per item per year and is therefore conceptually different from that of Class A.

CLASS C - Switching components, e.g. circuit breakers, disconnecting switches and their associated protection and control systems, which differ from the previous class because of their function within the network, i.e. they are expected to open and/or close on command. In some situations, for example if the protection system is being studied actively in its own right, it may be desirable to subdivide this class, separating the breaker (or switch) from the actual protection or control system. However, it is not essential for the methodology associated with predicting future system behavior, where the breaker and its associated protection system are generally treated as one entity (as explained in Chapter 3).

The data to be collected for each component will depend on the class to which it belongs. Each component should therefore be specified by an appropriate class, which may be in accordance with those defined above or with similar classes defined by a utility according to its own requirements. It is also very useful in practice to divide each class into a number of subclasses (e.g. type, manufacturer, voltage, function, thermal rating, fault rating, geographical location) as appropriate for greater precision in defining causes and effects of the failure/restoration processes. An appropriate set of such subclasses relating to and reflecting the requirements of individual utilities can be created.

### 5.2.2 Concepts of Data

The data collected must be sufficiently detailed to allow the factors that affect system reliability to be modeled and analysed. It should therefore reflect the two main processes involved in component behavior, namely the failure process and the restoration process. The following discussion identifies the various factors concerned. It cannot be stressed too strongly that a utility must make its own decision on the data to be collected since no universal rigid rules can be predefined. The factors identified must be those that have an impact on the utility's own planning and design considerations.

### 5.2.3 Failure Process

#### 5.2.3.1 Concepts of failure

It is important to recognize that for failure data to be used for predicting future system behavior it must be divided into categories according to the impact of the different failure modes.

Two of the most obvious and easily identifiable failure modes are open circuits and short circuits. The latter will always cause appropriate breakers to trip via primary or secondary protection schemes, thus possibly causing the outage of other branches and circuits. Open circuits, on the contrary, will not generally affect other circuits. This clearly indicates that failure modes have different system impacts and therefore should be identified separately. Open circuits can be further classified as open-phase faults, which although rare are likely to evolve into short circuits, and inadvertent switching, which is less likely to have the same outcome. Additionally, components are sometimes removed from service following detection of an incipient failure, e.g. detection of gas, hot spots or partial discharges. These can be defined as precautionary actions to prevent serious damage occurring to components. Generally, all failures associated with Class A and B components can be attributed to one of the above failure events. However, further subdivision can be made according to other attributes of the process. Class C components require additional failure modes, as discussed in more detail below.

#### 5.2.3.2 Short-circuit failures

Short-circuit failures are the most common power system faults and cause the majority of the outages. All three classes of components can suffer such failures. Short circuits will cause the operation of relevant circuit breakers and the immediate impact is the same, irrespective of the subsequent duration. This type of event has been defined in some literature as an "active failure" [1,2]. Since all short circuits have the same impact from a failure viewpoint, it may seem that they can be pooled and the underlying causes or attributes ignored but this would be too simplistic because, among other things, it does not permit the effect of different restoration processes to be considered.

For this reason, short circuits are generally divided into three subcategories:

a) Permanent. This generally includes all failures that require repair or replacement, i.e. the component causing the outage is damaged. This mode therefore also includes components removed for repair or replacement due to the detection of incipient faults such as the operation of gas detection (Buchholtz) alarms. Some utilities define this mode for outages exceeding a certain duration.

b) Temporary. This generally includes all outages in which the component causing the outage is not physically damaged but the restoration process is manual, perhaps after close physical inspection. A typical situation is a trip following a lightning flashover in a system not having automatic reclosure. Some utilities define this mode for outages having minimum and maximum durations.

c) Transient. This is similar to the temporary mode and the two are sometimes grouped together as so-called "undamaged" faults. When used as a separate subcategory, it is generally associated with restoration due to auto-reclosure or durations less than a certain value.

It should be noted that not all utilities use these three subcategories, while some use different terms to define them (see section 5.3). The method used to classify failures differs from one utility to another; it may be based on the physical nature of the process or on the outage duration.

#### 5.2.3.3 Open-circuit failures

Open circuits are usually rare events, particularly for Classes A and B. Although it is physically possible for a conductor to break, causing an open circuit, in many cases a short circuit follows when the conductor end comes into contact with the ground.

Another important open circuit is the inadvertent opening of a breaker (also known as a false opening or mal-trip), which includes manual operating errors. Only Class C components exhibit this type of open-circuit failure.

The open-circuit failure mode includes any condition, other than a fault, which causes the protection system to operate. This type of event has been defined in some literature as a "passive failure" [1,2].

### 5.2.3.4 Switching failures

Class C components can suffer short circuits and open circuits in the same way as Classes A and B components but also, owing to their switching functions, failure events. These include:

- Failure to open. This failure mode relates to normally closed breakers and their associated relaying system. When a system fault occurs, the primary protection scheme is intended to operate. Occasionally, however, owing to faults within the protection system or the breaker itself, one or more of the breakers controlling the zone fails to trip. This means that a back-up or secondary protection must operate, which is likely to result in the outage of a greater section of the system, with a more significant impact on its operation. This failure mode, generally known [2] as a "stuck breaker", is therefore very important and should be recognized as such. A detailed knowledge of relay behavior and failure modes is essential to the protection engineer but from the point of view of the overall power system the protection and the breaker can be treated as a single component.

- Failure to close. A complementary event exists for normally open breakers and their associated control, or for breakers that have tripped following system failure and are being reclosed. The principles and related needs are similar in concept to those involved in the mode described above.

### 5.2.3.5 Multiple failures

In practice, it is sometimes found that a particular event has caused the outage of more than one component. If the events leading to this so-called multiple outage are not related, then each event in the multiple outage can be recorded separately and treated as an independent failure.

This has been the practice in the past but it is now acknowledged that multiple failures can result from common line configurations leading to common-mode (or common-cause) outages [2-6, 15], from station-induced effects [2,7] and from cascade failures [16]/secondary outages [9]. These events should be recognized and treated accordingly.

### 5.2.3.6 Environmental effects

Power system networks are exposed to varying environments due to different weather conditions. Adverse weather such as lightning, gales, snow and ice can greatly enhance the failure rate of transmission circuits and, therefore, the likelihood of a multiple (overlapping) outage known [2, 3] as "failure bunching". Its effect should be taken into account but unfortunately, although most utilities identify the weather conditions when outages occur, the data collected is sometimes insufficient to establish detailed weather-related failure rates and relevant statistics. This aspect is covered in greater depth in Chapter 6 and Appendix I.

### 5.2.3.7 Planned outages

Outages can also be planned (scheduled) in order to carry out preventive maintenance, construction or refurbishment so as to keep the system in a condition consistent with the required level of performance, efficiency and reliability. Although such outages can have a significant impact on system reliability, the action is scheduled in advance of the relevant outage. It is thus a routine action not directly related to the stochastic behavior of the system and has therefore been ignored in the detailed discussion of data here. It must be remembered, however, that planned outages weaken a system, with the consequence that forced outages causing customer interruptions are more likely to occur. It may be beneficial therefore to record all planned outages and relate these, if possible, to any subsequent forced outages. For similar reasons, it is important to include the effect of planned outages in predictive reliability evaluation (see Chapter 3).

### 5.2.3.8 Stochastic data

The data associated with the failure processes discussed above can be defined as stochastic because it relates to the random nature of the process. Within each failure mode category, the failure events are measured by counting the number of relevant events that occur in a defined period of time, or the number of failures to operate following a given number of commands. The former applies to failures of all continuously operated components or inadvertent operation of Class C components whereas the latter applies only to failures to open or close of Class C components.

#### 5.2.3.9 Population and exposure data

In order to evaluate relevant statistical indices (see section 5.4) from stochastic data, it is essential to know certain exposure parameters, namely:

- number of operating components of each designated type, in order to pool relevant and related data and know the number of components exposed to failure. This applies to all classes.
- length of lines and cables, including lengths of double circuits and lines on common rights-of-way. This applies to Class A only.
- exposure time, which is the continuous elapsed time during which an event can take place. It may be the up-time if failure is being considered, the down-time if repair is being considered, etc. This applies to all classes.
- discrete exposure, which represents the number of times a failure can occur. It is relevant only to those components which receive commands to operate and therefore applies to Class C only.

All these exposure parameters relate to the denominator of the equations from which statistical indices are evaluated.

### 5.2.4 Restoration Process

#### 5.2.4.1 Types of restoration

Restoration can be perceived as being of two types: restoring supply to the consumers and restoring a failed component to its working state, which are not necessarily the same. For example:

- A component is repaired in situ and service is restored upon completion of the repair process. In this case, the restoration times are the same.
- A short-circuit failure of a component trips breakers, which may cause healthy components to be disconnected. The failed component is isolated and the breakers reclosed. This could lead to all or some of the load points being restored to service. Consequently, the restoration time of the load points is different from that of the component, which itself must be repaired or replaced.
- A component is replaced by a spare. The time to restore supply is therefore different from that of repairing the component, which may itself be retired.

Care is therefore required in appropriately recording restoration times. In order to compile component data, the restoration times associated with the component are required. Service restoration times are also important, since these measure the quality of service to customers. It is therefore pertinent to record both sets of restoration times as well as the failure events resolved by repair and those necessitating replacement. This aspect can be important in subsequent planning decisions relating to spares, optimum provision thereof and their impact on quality of service.

It is clear that restoration can be categorized by a number of subevents such as repair, replacement, reclosure or switching. In most cases, a particular restoration process is coupled with a specific type of failure event. For example:

- Repair or replacement usually follows a permanent failure. In practice, the system may be restored by repairing and reusing the failed component or by replacing it. In the latter case, the failed component may be retired or repaired, following which it may itself be used as a spare or reinstated in the system to replace a component used as a temporary restoration measure. Care is required to correctly identify each of these actions.
- Manual switching usually follows a temporary failure. It can also be used to reinstate supply from alternative sources while the failed component is being repaired or replaced.
- Automatic reclosure usually follows a transient failure.

The elapsed time before circuit restoration is not always a good guide to the process involved because non-urgent manual restoration can take longer than urgent repairs.

#### 5.2.4.2 Stochastic data for restoration processes

The data associated with the restoration processes can also be defined as stochastic because it relates to the random nature of the restoration procedure. The process is measured by the time that elapses between the occurrence of the failure event and the completion of the restoration process. More than one such elapsed time may thus be recorded for each failure event if the different sets of restoration times discussed above are being determined.

Individual outage times can be accumulated for each failure category identified by the utility. Population or exposure data is not required in these cases since the only additional information needed to evaluate relevant statistical indices (see section 5.4) is the number of events leading to each of these failure categories; this is the data being collected for the failure process (see section 5.2.3.8).

## 5.3 Review of Some Data Collection Schemes

### 5.3.1 Purpose

It is evident from the discussion in section 5.2 that there is a wide range of collectable data. This does not mean that all data should be recorded nor that every possible mode and attribute of the failure and restoration processes should be identified. It simply means that the data actively collected should be sufficient to identify the likelihood of the failure and the duration of the restoration process.

Most utilities collect data in one form or another. A review of the various schemes shows that, despite great similarities, particularly in terms of concepts, considerable differences also exist, especially in the details. No one scheme can be said to be right or better, just different. It is therefore inappropriate to judge individual merits or make recommendations for a particular data base and, therefore, for a particular format for collecting data. Instead, the purpose of this review is to identify such similarities and differences in order to highlight:

- the need for particular data
- the need to subdivide the data into relevant classes and subclasses
- the important aspects and factors to be considered.

Providing a framework within which individual utilities can organize their own data base can benefit the utility by:

- ensuring a consistent set of data that can be transformed into an intelligible set of statistical parameters
- ensuring that the collected data conforms conceptually with international understanding and agreement
- allowing inter-utility comparisons of transmission system performance
- allowing wide and consistent application of common reliability models.

### 5.3.2 Scope

It should be recognized that there are probably nearly as many data collection schemes and formats as there are utilities in the world and that no single internationally accepted data base system exists, although several studies have been made. For this reason, it was considered more desirable to review schemes in present use. In view of the impossibility to identify and review all that exist, an arbitrary selection was essential. Those chosen are:

- Canadian Electrical Association's Equipment Reliability Information System (ERIS)
- Central Electricity Generating Board's Transmission Fault Reporting Scheme (OR9A)
- Commonwealth Edison's Fault Reporting Scheme (FRS).

Although this choice is arbitrary, it is believed that the comparisons are adequate for the following reasons:

- They highlight the aspects and features likely to be found in most data collection schemes.
- Sufficient differences exist to illustrate that there is no one single internationally recognized scheme and that most are individually created to suit and satisfy local requirements.
- The schemes chosen represent three distinct situations:
  - The CEA system is a pooled data system of many individual utilities within a single nation.
  - The CEGB scheme is for a single major utility encompassing the majority of a nation and no pooling is involved.
  - The CE scheme is for a single utility representing a small part of a large nation and no pooling is involved.

It is evident, therefore, that these three schemes, although not necessarily representative in themselves, are indicative of the range, type and scope of data collection schemes organized by different types of utility.

The following review makes it very clear that the three schemes chosen show some sharp distinctions. In particular, it is evident that utilities do not attempt to make an exhaustive record of all possible data. This is an essential point to be recognized by a utility thinking of setting up its own data collection scheme. It is important that the objectives of the data collection scheme be decided in advance and a scheme created that matches these objectives. The utility should recognize that collecting data for ill-defined purposes not only is undesirable but discourages accuracy and precision in the recording of events, times and other necessary attributes. Finally, it should be prepared to adapt and extend its scheme as and when desirable.

The review of the selected data collection schemes began by arbitrarily taking CEA's ERIS scheme as a basis for comparison. This was followed by comparisons of ERIS with OR9A and FRS. It is not the purpose of this guide to make a detailed review of these comparisons - which can only be done effectively by reading the annexes - but some specific observations are made below by highlighting certain features and aspects that came to the fore during the comparisons.

### 5.3.3 Basic Concept of Schemes

#### 5.3.3.1 Approaches used

The two main approaches to data collection are the component approach and the unit approach. These are quite distinct and not easily reconcilable. Both are identified in the annexes, CEA and CEGB using the former and CE the latter. There is a grey area in defining "component" and "unit", a point highlighted in Annex 5C and exemplified in Annex 5A, where a "major component" is defined as a "unit". This problem is being considered by an IEEE Committee [9] and both terms are defined in Appendix III.

#### 5.3.3.2 Scope and limitations of schemes

The comparisons included in the appendices to this chapter also identify another particular difference between data collection schemes. This relates to the scope and scale to which a given scheme is used. Some attempt to create a common data collection system spanning a number of utilities within a nation, e.g. the CEA system, others are tailored to meet the objectives of a single utility within an entire nation, e.g. the CEGB system, while a third group is associated with a single utility representing only a small section of a nation, e.g. the CE system.

None of these can be said to be the best, since they all have merits and demerits. The particular merits of the common scheme are that it allows easy comparison of the performance between neighboring utilities and potential pooling of relevant data. On the other hand, consensus between participating utilities is required. It is possible, therefore, that the final agreement reflects the "lowest common denominator" and is not as detailed, comprehensive or extensive as may be desired to meet the needs of individual utilities. This problem appears to be eliminated when the scheme devised relates directly to the particular requirements of a utility, e.g. the CEGB and CE schemes. In such cases, it may be possible to provide considerably more detail in specific areas. The disadvantage is that pooling of data and comparing performances between utilities may be handicapped.

The main advantage of pooling is that it enables the size of data samples to be increased. Although this can increase confidence in any calculated statistic, associated problems may arise. Such problems are outside the scope of this chapter but several studies have been made. For instance, the effects of pooling transmission outage data have been analysed [17,18] using a chisquared test statistic developed by Hoel [19], which demonstrated that there can be significant differences between seasons, utilities and terminal configurations. This has led some utilities, e.g. CEGB [20], to analyse subsets of their systems and even to adopt slightly different operating rules for these subsets.

It is evident, therefore, that care must be exercised when interpreting bulk transmission system performance indices. Misinterpretation can lead to erroneous conclusions regarding overall system performance. Techniques implemented to ascertain the system performance can often obscure important parameters which affect the indices [21]. Awareness of differences (i.e. seasons, terminal configurations, etc.) can be instrumental in understanding and using the calculated indices in system reliability evaluations.

### 5.3.4 Outage Classification

None of the schemes selected are comprehensive in their outage classification. Although all recognize independent forced outages and common-mode outages, only the CE system seems to identify dependent outages. Also, even if the weather conditions at the time of the outage are reported, the weather-related information is insufficient to accurately determine outage or failure rates in different environmental conditions (see Chapter 6 and Appendix I). Finally, although forced outages have been classified in several places as permanent, temporary and transient [2,8,9], CEA does not seem to distinguish between them, while CEGB distinguishes between transient and sustained (temporary plus permanent) on the basis of the restoration time only when preparing the statistical indices, and CE uses only two, namely momentary (transient and temporary) and lockout (permanent).

It is important that utilities developing their own data collection system acknowledge that existing schemes are not necessarily comprehensive. It is beneficial to set in motion a scheme that is not fully developed, to gain data and to allow the scheme to develop and expand as the need for a more comprehensive system becomes apparent.

### 5.3.5 Failure Modes

The number of failure modes differs considerably. CEA uses ten (eight specified in Annex 5A plus manual removal and unknown), CEGB uses six (although others are classed under primary causes rather than under failure mode) while CE uses only three. This point is also worth noting by utilities developing their own data bases. There is no universally acceptable conceptual set of failure modes but it is important for a utility to recognize all potential modes of failure, to decide which (if any) can be pooled, and to consider whether subgrouping or the specification of attributes is desirable. No benefit can be derived by an excessive number of groups, as this will lead to wrong classification by operations personnel, which may thus override all potential gains in the use of the data.

### 5.3.6 Outage Times

All schemes recognize the duration of outages but appear to allocate them differently. For instance, the CEA definition of repair time differs from that of the CEGB: the first relates to the repair of the component, the second to the time taken to restore the circuit to service. The CEGB system also records the component repair time.

Destroyed components are likewise treated differently: the CEA system quotes the time as "X" whereas the CEGB system records 999 days. Similarly, outage times of less than 1 min are specified as zero in the CEA system and as 1 min in the CEGB system.

### 5.3.7 Statistics

All schemes use the data to calculate statistics which, besides giving basic reliability indices, are used to provide performance indicators of the transmission system. The performance indices differ in several respects. A more detailed description of statistical indices is given in the next section.

## 5.4 Statistical Indices

### 5.4.1 General Concepts

As discussed previously, the statistics that need to be considered in this application guide are those to be used in the system prediction methodology discussed in Chapters 2 and 3. These statistics therefore form the interface between the collected data and the system reliability evaluation techniques.

A large number of statistics can be deduced but all can generally be classified in one of the following main conceptual sets of indices:

- rate and/or frequency of occurrence of an event
- average duration of a state
- probability of a command failure.

These are expanded and discussed in more detail below. It should be noted that the indices that follow are not deterministic values but the expected or mean values of a probability distribution, which itself may be unknown. In addition, it is sometimes desirable to evaluate the variance (or standard deviation) and possibly higher moments of this distribution from the raw data but these are not considered here.

### 5.4.2 Rate and Frequency of Occurrence

#### 5.4.2.1 Concept of indices

The concept of failure rate, $\lambda$, is given [2-4] by

$$\lambda = \frac{\text{number of events}}{\text{exposure time when event can occur}} = \frac{N}{E} \qquad (5.1)$$

and that of frequency, f, [2-4] by

$$f = \frac{\text{number of events}}{\text{period time}} = \frac{N}{T} \qquad (5.2)$$

Thus the denominator is the only difference between these two indices. Both this and the numerator of eqs. 5.1 and 5.2, the number of events, require short explanations.

#### 5.4.2.2 Number of events

The number of events, N, is essentially self-explanatory: it is the number of times a particular event occurs during the period of interest. This concept is true, whether it is failures, repairs, weather-state transitions or any other transitional occurrences that are being considered and therefore counted.

There is usually no conceptual problem when the events are being counted for a single, identifiable component but problems of interpretation can occur when data is being pooled. Consider the case of failures. In this case, N is the number of events (failures) observed for all the relevant component population divided by the total population, including components that did not fail at all during the particular reporting period. It is for this reason that an accurate inventory of the system is required. This is also one of the reasons why weather-state data is difficult to determine and why it is generally lacking. In this case, the number of occasions when adverse weather occurs must be counted, even if on those occasions it has no effect on system operation. Such data is difficult to determine and requires close cooperation between the utility and the local weather bureau.

The event being counted can be any event for which the utility wishes to record data, e.g. individual counts can be made for permanent failures, temporary failures, transient failures, permanent failures occurring in normal and adverse weather, etc. Similarly, the events being counted can be differentiated on the basis of causes of failure. The study period is the same for all individual counts.

### 5.4.2.3 Period time

The period time, T, is simply the period of interest used in section 5.4.2.2. It follows, therefore, that frequency represents the number of times an event of interest occurs during the total reporting period. This is conceptually very different from the rate of occurrence, as seen in the next section.

### 5.4.2.4 Exposure time

The exposure time, E, is the parameter that often causes most problems associated with the interpretation of eq. 5.1. It is the time during which the event of interest can occur. For example:

- If failure rates are being evaluated, the exposure time includes only the time during which the component is in the operating state. It does not include any repair time, maintenance time, etc. or any other state times during which the component is not exposed to failure. Even standby times would be excluded, although a standby failure rate could be determined using, as data, the number of failures whilst in the standby mode and the time spent in this state.
- If repair rates are being evaluated, the exposure time includes only that during which the component is undergoing repair.
- If weather transition rates are being evaluated, e.g. "normal-to-adverse weather transition rate", the exposure time is the time spent in the normal weather state. Similarly for adverse weather. This leads to problems resembling those discussed in section 5.4.2.2, since these durations are needed even on occasions when no operational problems are encountered.

It is evident from these examples that for a given number of events occurring in T, since the exposure time E decreases as a proportion of T, the rate of occurrence increases. It also follows that a relation exists [4] between rate and frequency, i.e.

$$f = \frac{E}{T} \cdot \lambda \qquad (5.3)$$

Also, eqs. 5.1 and 5.2 may be expanded to:

$$f = \frac{N/n}{T} \qquad (5.4)$$

$$\lambda = \frac{N/n}{T-\Sigma r/n} \qquad (5.5)$$

$$= \frac{N}{Tn-\Sigma r}$$

where N and T are as before, n is the number of components and $\Sigma r/n$ is the average time each component is not in the operating state during the period of study, i.e. $(T-\Sigma r/n)$ is the average exposure time of the relevant components.

It follows from the above discussion that the rate represents the number of times an event of interest actually occurs during the period of time it can occur.

### 5.4.2.5 Comparison between failure rate and frequency

Equation 3 indicates that the failure rate and frequency are numerically very different if $E \ll T$, i.e. the exposure time of an event is a small fraction of the period time. This applies to the repair process, for example. If E and T are approximately the same, then so are λ and f also. This applies, for example, to the failure process of a continuously operated component, since the time not spent in the operating state (T-E) is very short and often negligible. For this reason, failure rate and frequency are often numerically equivalent and the value of λ is sometimes evaluated using the simpler equation 5.2.

### 5.4.2.6 Numerical examples

In order to illustrate the evaluation of rate and frequency of occurrence, consider a system containing ten identical components. In a two-year calendar period, these components behaved as shown below:

| Component | No. of failures | Repair duration (h) |
|---|---|---|
| 1 | 3 | 18, 25, 93 |
| 2 | 3 | 56, 39, 107 |
| 3 | 2 | 22, 49 |
| 4 | 1 | 37 |
| 5 | 1 | 16 |
| 6 | 1 | 52 |
| 7-10 | 0 | -- |
| 10 | 11 | 514 |

Using the concept of eqs. 5.1 and 5.2,

$$\text{frequency of failure} = \frac{11/10}{2} = 0.550 \text{ occ /yr}$$

$$= \text{frequency of repair}$$

$$\text{failure rate} = \frac{11}{2\text{x}10-514/8760} = 0.552 \text{ occ /yr}$$

$$\text{repair rate} = \frac{11}{514/8760} = 187.5 \text{ rep/yr}$$

These values indicate that, although the failure rate and frequency of failure may be approximately the same numerically, the repair rate and frequency of repair are very different, owing to the small exposure time associated with repair.

### 5.4.3 Average Duration of a State

The concept of duration is given [4] by:

$$\frac{\text{total time spent in a particular state}}{\text{number of events leading to that state}} \qquad (5.6)$$

This is a much easier equation to interpret. All that is required is for the appropriate durations associated with each separately identifiable state to be accumulated. This gives the numerator. The denominator is the same as the number N discussed in 5.4.2.2.

In order to illustrate the application of eq. 5.6, the reader is referred back to the example used in 5.4.2.6 where

$$\text{average duration of repair} = \frac{\Sigma r}{N} \qquad (5.7)$$

$$= 514/11 = 46.73\ \text{h}$$

Similarly,

$$\text{average operating time (up-time)} \qquad (5.8)$$

$$= \frac{Tn - \Sigma r}{N}$$

$$= (2 \times 8760 \times 10 - 514)/11$$
$$= 15881\ \text{h}$$
$$= 1.81\ \text{yr}$$

It is seen that eqs. 5.7 and 5.8 are the reciprocals of the concept given by eq. 5.5. Consequently, the average duration and the occurrence rate are the reciprocal of each other. For this reason, it is more usual in practice to define the failure and restoration processes as follows:

- the failure process in terms of its failure rate. This is relatively easy to evaluate, particularly if the downtime is a very small fraction of the period time, as it is then ignored;
- the restoration process in terms of its average duration. This is usually easier to determine, interpret and understand than the concept of repair (or restoration) rate.

### 5.4.4 Command Failures

The probability of a command failure (i.e. probability of a component failing to respond to a command) is given [4,9] by

$$\frac{\text{number of failures to operate}}{\text{number of commands to operate}} \qquad (5.9)$$

In the case of opening commands, "operate" in eq. 5.9 is interpreted as "open" and, in the case of "closing" commands, as "close".

Equation 5.9 seems to be conceptually easy to interpret in that only the counting of events is needed. However, difficulties can and do arise in counting both the number of failures and the number of commands. For example, if a switch fails to close on the first command but closes after the second or subsequent attempt, is this counted as a failure or not? And is the number of commands one or the number of attempts? Also, the commands can be separated into fault-switching and load-switching commands. There is no simple, unique answer to these questions but they do indicate that care must be taken to construct a data-reporting scheme that gives the required information and to ensure that the data recorded responds to this information, e.g. multiple attempts are recorded as single or multiple events, as needed.

### 5.4.5 Illustration of Data and Statistics

Figures 5.1 and 5.2 illustrate the output of typical data collection schemes. The tables are reproduced from the CEA [11] and CEGB [12] schemes. The following observations can be made from these figures:

- Both schemes maintain an inventory of the system: Table 5.1 in Fig. 5.1 for the CEA scheme and Table 10 of Fig. 5.2 for the CEGB scheme.
- Both schemes divide components into subclasses on the basis of voltage, the CEA scheme using six levels, the CEGB scheme only two, these being the two main transmission voltages.
- Both record lines/cables in terms of length, as required for Class A components.
- The terminals in the CEA scheme and the substations in the CEGB scheme are essentially the same.
- The CEA scheme evaluates and quotes "frequency of events" whereas the CEGB scheme quotes "rate of events" but actually evaluates frequency, since it uses the simplified evaluation method.
- Both schemes evaluate the duration of the events.

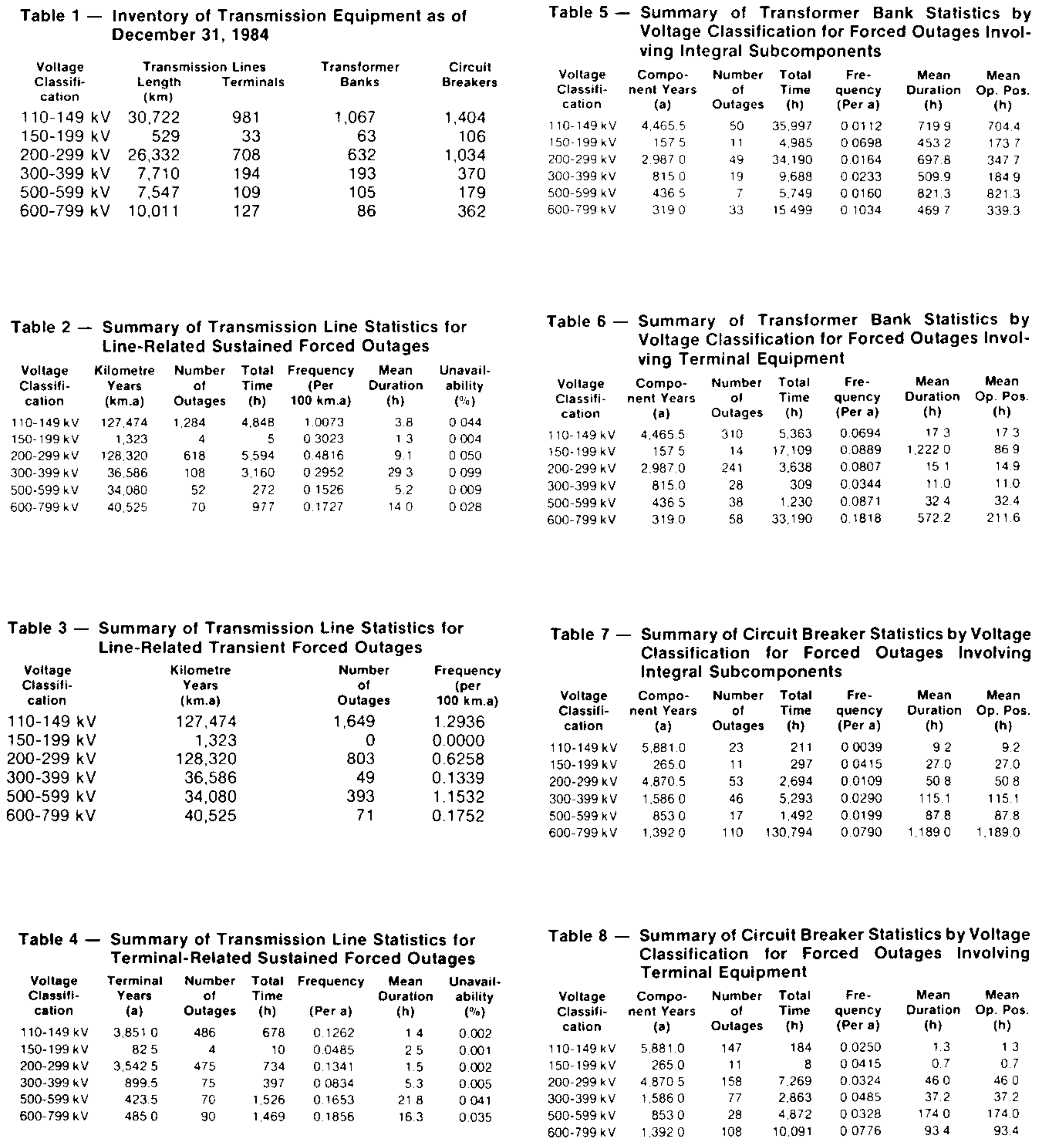


**Table 1 — Inventory of Transmission Equipment as of December 31, 1984**

| Voltage Classification | Transmission Lines Length (km) | Transmission Lines Terminals | Transformer Banks | Circuit Breakers |
|---|---|---|---|---|
| 110-149 kV | 30,722 | 981 | 1,067 | 1,404 |
| 150-199 kV | 529 | 33 | 63 | 106 |
| 200-299 kV | 26,332 | 708 | 632 | 1,034 |
| 300-399 kV | 7,710 | 194 | 193 | 370 |
| 500-599 kV | 7,547 | 109 | 105 | 179 |
| 600-799 kV | 10,011 | 127 | 86 | 362 |

**Table 2 — Summary of Transmission Line Statistics for Line-Related Sustained Forced Outages**

| Voltage Classification | Kilometre Years (km.a) | Number of Outages | Total Time (h) | Frequency (Per 100 km.a) | Mean Duration (h) | Unavailability (%) |
|---|---|---|---|---|---|---|
| 110-149 kV | 127,474 | 1,284 | 4,848 | 1.0073 | 3.8 | 0.044 |
| 150-199 kV | 1,323 | 4 | 5 | 0.3023 | 1.3 | 0.004 |
| 200-299 kV | 128,320 | 618 | 5,594 | 0.4816 | 9.1 | 0.050 |
| 300-399 kV | 36,586 | 108 | 3,160 | 0.2952 | 29.3 | 0.099 |
| 500-599 kV | 34,080 | 52 | 272 | 0.1526 | 5.2 | 0.009 |
| 600-799 kV | 40,525 | 70 | 977 | 0.1727 | 14.0 | 0.028 |

**Table 3 — Summary of Transmission Line Statistics for Line-Related Transient Forced Outages**

| Voltage Classification | Kilometre Years (km.a) | Number of Outages | Frequency (per 100 km.a) |
|---|---|---|---|
| 110-149 kV | 127,474 | 1,649 | 1.2936 |
| 150-199 kV | 1,323 | 0 | 0.0000 |
| 200-299 kV | 128,320 | 803 | 0.6258 |
| 300-399 kV | 36,586 | 49 | 0.1339 |
| 500-599 kV | 34,080 | 393 | 1.1532 |
| 600-799 kV | 40,525 | 71 | 0.1752 |

**Table 4 — Summary of Transmission Line Statistics for Terminal-Related Sustained Forced Outages**

| Voltage Classification | Terminal Years (a) | Number of Outages | Total Time (h) | Frequency (Per a) | Mean Duration (h) | Unavailability (%) |
|---|---|---|---|---|---|---|
| 110-149 kV | 3,851.0 | 486 | 678 | 0.1262 | 1.4 | 0.002 |
| 150-199 kV | 82.5 | 4 | 10 | 0.0485 | 2.5 | 0.001 |
| 200-299 kV | 3,542.5 | 475 | 734 | 0.1341 | 1.5 | 0.002 |
| 300-399 kV | 899.5 | 75 | 397 | 0.0834 | 5.3 | 0.005 |
| 500-599 kV | 423.5 | 70 | 1,526 | 0.1653 | 21.8 | 0.041 |
| 600-799 kV | 485.0 | 90 | 1,469 | 0.1856 | 16.3 | 0.035 |

**Table 5 — Summary of Transformer Bank Statistics by Voltage Classification for Forced Outages Involving Integral Subcomponents**

| Voltage Classification | Component Years (a) | Number of Outages | Total Time (h) | Frequency (Per a) | Mean Duration (h) | Mean Op. Pos. (h) |
|---|---|---|---|---|---|---|
| 110-149 kV | 4,465.5 | 50 | 35,997 | 0.0112 | 719.9 | 704.4 |
| 150-199 kV | 157.5 | 11 | 4,985 | 0.0698 | 453.2 | 173.7 |
| 200-299 kV | 2,987.0 | 49 | 34,190 | 0.0164 | 697.8 | 347.7 |
| 300-399 kV | 815.0 | 19 | 9,688 | 0.0233 | 509.9 | 184.9 |
| 500-599 kV | 436.5 | 7 | 5,749 | 0.0160 | 821.3 | 821.3 |
| 600-799 kV | 319.0 | 33 | 15,499 | 0.1034 | 469.7 | 339.3 |

**Table 6 — Summary of Transformer Bank Statistics by Voltage Classification for Forced Outages Involving Terminal Equipment**

| Voltage Classification | Component Years (a) | Number of Outages | Total Time (h) | Frequency (Per a) | Mean Duration (h) | Mean Op. Pos. (h) |
|---|---|---|---|---|---|---|
| 110-149 kV | 4,465.5 | 310 | 5,363 | 0.0694 | 17.3 | 17.3 |
| 150-199 kV | 157.5 | 14 | 17,109 | 0.0889 | 1,222.0 | 86.9 |
| 200-299 kV | 2,987.0 | 241 | 3,638 | 0.0807 | 15.1 | 14.9 |
| 300-399 kV | 815.0 | 28 | 309 | 0.0344 | 11.0 | 11.0 |
| 500-599 kV | 436.5 | 38 | 1,230 | 0.0871 | 32.4 | 32.4 |
| 600-799 kV | 319.0 | 58 | 33,190 | 0.1818 | 572.2 | 211.6 |

**Table 7 — Summary of Circuit Breaker Statistics by Voltage Classification for Forced Outages Involving Integral Subcomponents**

| Voltage Classification | Component Years (a) | Number of Outages | Total Time (h) | Frequency (Per a) | Mean Duration (h) | Mean Op. Pos. (h) |
|---|---|---|---|---|---|---|
| 110-149 kV | 5,881.0 | 23 | 211 | 0.0039 | 9.2 | 9.2 |
| 150-199 kV | 265.0 | 11 | 297 | 0.0415 | 27.0 | 27.0 |
| 200-299 kV | 4,870.5 | 53 | 2,694 | 0.0109 | 50.8 | 50.8 |
| 300-399 kV | 1,586.0 | 46 | 5,293 | 0.0290 | 115.1 | 115.1 |
| 500-599 kV | 853.0 | 17 | 1,492 | 0.0199 | 87.8 | 87.8 |
| 600-799 kV | 1,392.0 | 110 | 130,794 | 0.0790 | 1,189.0 | 1,189.0 |

**Table 8 — Summary of Circuit Breaker Statistics by Voltage Classification for Forced Outages Involving Terminal Equipment**

| Voltage Classification | Component Years (a) | Number of Outages | Total Time (h) | Frequency (Per a) | Mean Duration (h) | Mean Op. Pos. (h) |
|---|---|---|---|---|---|---|
| 110-149 kV | 5,881.0 | 147 | 184 | 0.0250 | 1.3 | 1.3 |
| 150-199 kV | 265.0 | 11 | 8 | 0.0415 | 0.7 | 0.7 |
| 200-299 kV | 4,870.5 | 158 | 7,269 | 0.0324 | 46.0 | 46.0 |
| 300-399 kV | 1,586.0 | 77 | 2,863 | 0.0485 | 37.2 | 37.2 |
| 500-599 kV | 853.0 | 28 | 4,872 | 0.0328 | 174.0 | 174.0 |
| 600-799 kV | 1,392.0 | 108 | 10,091 | 0.0776 | 93.4 | 93.4 |

Figure 5.1 - Extracts from CEA Statistics, 1986 [11]

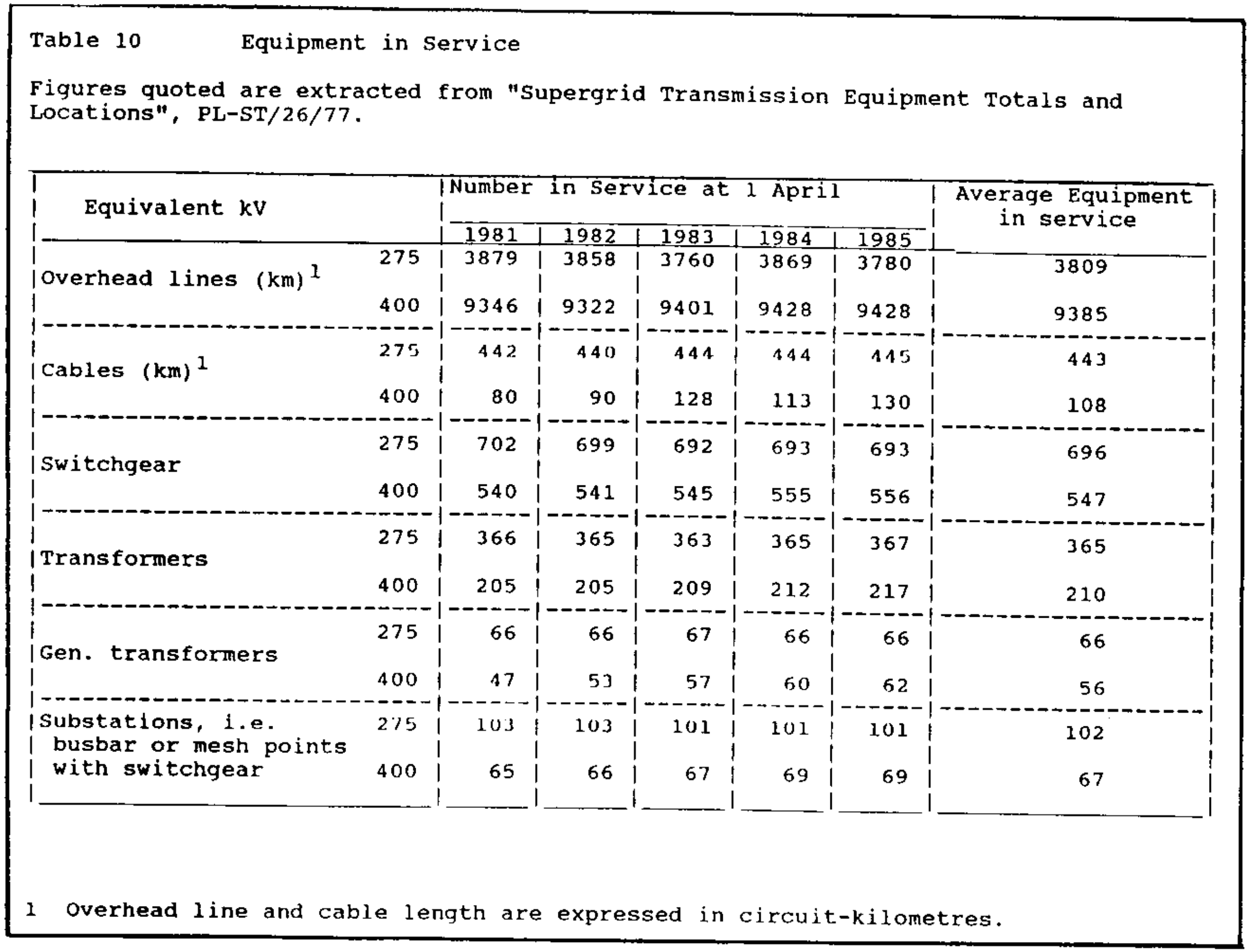


Table 10 Equipment in Service

Figures quoted are extracted from "Supergrid Transmission Equipment Totals and Locations", PL-ST/26/77.

| Equivalent kV | | Number in Service at 1 April | | | | | Average Equipment in service |
|---|---|---|---|---|---|---|---|
| | | 1981 | 1982 | 1983 | 1984 | 1985 | |
| Overhead lines (km)[1] | 275 | 3879 | 3858 | 3760 | 3869 | 3780 | 3809 |
| | 400 | 9346 | 9322 | 9401 | 9428 | 9428 | 9385 |
| Cables (km)[1] | 275 | 442 | 440 | 444 | 444 | 445 | 443 |
| | 400 | 80 | 90 | 128 | 113 | 130 | 108 |
| Switchgear | 275 | 702 | 699 | 692 | 693 | 693 | 696 |
| | 400 | 540 | 541 | 545 | 555 | 556 | 547 |
| Transformers | 275 | 366 | 365 | 363 | 365 | 367 | 365 |
| | 400 | 205 | 205 | 209 | 212 | 217 | 210 |
| Gen. transformers | 275 | 66 | 66 | 67 | 66 | 66 | 66 |
| | 400 | 47 | 53 | 57 | 60 | 62 | 56 |
| Substations, i.e. busbar or mesh points with switchgear | 275 | 103 | 103 | 101 | 101 | 101 | 102 |
| | 400 | 65 | 66 | 67 | 69 | 69 | 67 |

[1] Overhead line and cable length are expressed in circuit-kilometres.

Figure 5.2 - Extracts from CEGB Statistics, 1981-85 [12]

**Table 11** **Fault Rates and Repair Times**

**Year 1984/85**
**Five-year average**

| Main Equipment | Plant - Years of Operating Experience | Total No. of Faults Reported | Mean Annual Fault Rate | Average Outage Time Hours/Fault | Average Non-availability Due to Faults Hours/Annum |
|---|---|---|---|---|---|
| Overhead Lines | | | | | |
| 275 kV | 19,046 km year | 590 | 3.10 faults/100 km | 44.12 | 1.367 per km |
| 400 kV | 46,925 km year | 1199 | 2.56 faults/100 km | 10.86 | 0.277 per km |
| Underground Cables | | | | | |
| 275 kV | 2,215 km year | 68 | 3.07 faults/100 km | 1702.05 | 52.253 per km |
| 400 kV | 541 km year | 17 | 3.14 faults/100 km | 107.47 | 3.377 per km |
| Transformers | | | | | |
| 275 kV | 2,157 km year | 184 | 8.53 faults/100 transformers | 532.73 | 45.444 per transformer |
| 400 kV | 1.327 km year | 110 | 8.29 faults/100 transformers | 392.62 | 32.546 per transformer |
| Circuit Breakers | | | | | |
| 275 kV | 3,479 circuit breaker year | 279 | 8.02 faults/100 circuit breaker | 88.67 | 7.111 per circuit breaker |
| 400 kV | 2,737 circuit breaker year | 376 | 13.74 faults/100 circuit breaker | 117.04 | 16.079 per circuit breaker |
| Protection | | | | | |
| 275 kV | 3,479 circuit breaker year | 401 | 11.53 faults/100 circuit breaker | 52.19 | 6.016 per circuit breaker |
| 400 kV | 2,737 circuit breaker year | 253 | 9.24 faults/100 circuit breaker | 8.47 | 0.783 per circuit breaker |

Figure 5.2 (cont.)

# ANNEX 5A

# CANADIAN ELECTRICAL ASSOCIATION'S EQUIPMENT RELIABILITY INFORMATION SYSTEM

## 5A.1 SCOPE OF ERIS

The Canadian Electrical Association's Equipment Reliability Information System, ERIS, includes both generation and transmission system data. Developed by consensus between Canadian utilities, it provides a practical vehicle for the collection of equipment performance information and the derivation of relevant statistical parameters. The transmission reporting system is conceptually different from that developed for generating equipment and is confined to the recording of forced outages for selected major components only. The causes of forced outages are reported using a set of primary-cause codes and a classification of the subcomponents of the major components involved. The failure modes associated with a forced outage are also included. A minimal but basic inventory is established for each major component. A brief description of the salient features of this reporting system follows.

Transmission equipment is limited to all equipment with an operating voltage of 110 kV and above but includes associated elements such as synchronous and static compensators and, also, shunt reactors and capacitors on the tertiaries of transformers at 110 kV and above. ERIS divides transmission equipment into major components, each of which is considered a "unit" and includes all the associated auxiliaries that make it a functional entity within a power system. The reporting system covers component forced outages, their duration, the primary cause and the subcomponent involved, where applicable. These forced outages are limited to those of major components wherein the cause of the outage originated. Outages of a major component caused by the outage of another major component are not included.

## 5A.2 DEFINITIONS

The following basic definitions [10] are used in ERIS:

Transmission equipment: all equipment with an operating voltage of 110 kV and above, including those elements associated with transmission systems such as synchronous and static compensators and, also, shunt reactors and capacitors on the tertiaries of transformers of 110 kV and above.

Major component: a unit of transmission equipment, including all the associated auxiliaries that make it a functional entity within a power system.

Subcomponent: a constituent component of a major component, including the external elements associated with it.

Terminal: a transmission line end or cable end equipped with primary line protection. Stations which are tapped into the transmission line are not included in this definition.

Unit of transmission equipment: a three-phase installation made up of either one three-phase element or three single-phase elements.

Primary cause: the reason to which the outage or malfunction of a major component can be attributed.

Component forced outage: the unscheduled removal from service of a major component (or its inability to perform its specified function) due to defective equipment, adverse environment, system condition, human element, foreign interference or some unknown reason.

Common-mode outage: event where more than one component forced outage results from a single primary cause and where the outages are not consequences of each other.

Failure mode: the type of fault (or malfunction) that the system sustains as a result of a component forced outage.

Replacement time: elapsed time required to replace the major component from stock or from some other location in the network.

Repair time: elapsed time required to restore the major component to service or make it serviceable again.

## 5A.3 INVENTORY OF MAJOR COMPONENTS

Utilities are requested to send, once a year, a tabulation of the number of major components by classification. For transmission lines and cables, the listing is given in terms of the number of kilometres (of three-phase circuits) and terminals, whereas for the other major components the total number of units in each classification is required. This inventory forms the design data bank for the ERIS reporting system.

## 5A.4 CLASSIFICATION OF MAJOR COMPONENTS

### 5A.4.1 Concepts of Classification

It was not considered practical to compile a data bank on each major component since there are too many items to consider. Instead, a classification system has been established in which each major component is divided into classes according to certain distinguishing characteristics.

It is an alphanumeric system where each digit describes one of the chosen characteristics. The first digit identifies the major component, the second identifies the voltage class, and subsequent digits (or letters) are used to identify the other characteristics. Since the number of main categories of major components is limited to nine, there are likely to be external elements (such as disconnecting switches) which could be considered as belonging to more than one category. To avoid the necessity of having to choose where an external element belongs, the boundary of each major component must be defined.

### 5A.4.2 List of Major Components

The first digit identifies the major components of transmission equipment:

- Transmission line
- Cable
- Transformer bank
- Circuit breaker
- Synchronous compensator
- Static compensator
- Shunt reactor bank
- Shunt capacitor bank
- Series capacitor bank

### 5A.4.3 Classification by Voltage (Phase-to-Phase)

The voltage class of each major component is identified by the second digit:

- up to 109 kV (for static compensators, shunt reactors and capacitors)
- 110 - 150 kV
- 151 - 200 kV
- 201 - 300 kV
- 301 - 400 kV
- 401 - 500 kV
- 501 - 600 kV
- 601 - 800 kV
- above 800 kV

## 5A.5 OUTAGE DEFINITIONS

Unlike the generation equipment status reporting system, no attempt is made in this reporting system to describe all the various states in which a major component can reside. Either it is out due to a component forced outage or it is assumed to be in service.

It was decided that the recording of scheduled or maintenance outages for transmission equipment would be too laborious. In addition, it was believed that scheduled outages do not normally interfere with the continuity of supply so that statistics would not be of a value commensurate with the work involved in reporting such outages.

ERIS distinguishes between component forced outages and common-mode outages (see definitions in A.2). As far as the former are concerned, recording is not required for healthy major components removed from service as a result of cascading system events or as a result of the outage (or malfunction) of some other major component.

As for common-mode outages, ERIS records all of them but places a strong emphasis on those occurring on transmission lines. A special column has been provided on the reporting form for registering common-mode outages. For the special case of common-mode outages on transmission lines, another column has been provided to indicate whether the transmission lines involved are on the same tower.

## 5A.6 TIME DEFINITIONS

Two different times are identified in association with each component forced outage, the replacement time and the repair time (see definitions in A1.2).

The replacement time gives a measure of the practice of utilities in the allocation of spare units. If no spare is available, this time is not reported.

In the case of repair times, if the time is less than 1 min, a zero is indicated. The letter "X" is used to indicate that the major component has been destroyed beyond repair.

## 5A.7 PRIMARY-CAUSE CODE

A component forced outage is defined in terms of the possible causes, each of which is termed a primary cause. ERIS does not subdivide these primary causes.

The following primary causes have been assigned codes:

- Defective equipment
- Adverse weather
- Adverse environment
- System condition
- Human element
- Foreign interference
- Unknown

## 5A.8 FAILURE MODES

Failure modes describe either a type of fault or an equipment malfunction. Faults are described in terms of the type of fault which the system sustains as a result of the event. Malfunctions comprise those events where a major component or subcomponent does not perform as desired.

Codes have been assigned to the following failure modes involving major components:

- Phase-to-ground short circuit
- Phase-to-phase short circuit
- Phase-to-phase-to-ground short circuit
- Three-phase short circuit
- One or two open phases
- Refusal of a circuit breaker to open
- Refusal of a circuit breaker to close
- False operation of a circuit breaker

## 5A.9 STATISTICS

The outage data collected in ERIS is used to produce basic reliability indices. In addition, ERIS is expected to provide data from which the performance of transmission equipment in the following areas may be obtained:

- nature and frequency of common-mode outages with particular reference to transmission lines
- utility's policy with respect to the allocation of spares, as given by an analysis of the replacement time
- distribution of primary causes of component forced outages
- importance of certain subcomponents, such as control and protection equipment
- failure modes of equipment, especially active components such as circuit breakers
- performance of the same type of equipment from different suppliers.

The basic statistics which this reporting system produces and which form part of the annual report are:

- failure rate, $\lambda$
- repair rate, $\mu$
- forced-outage frequency, f.

These statistics are calculated using the following relations:

$$\mu = \frac{\text{No. of forced outages}}{\text{sum of forced-outage times}}$$

$$\lambda = \frac{\text{No. of forced outages}}{\text{total operating time}} =$$

$$= \frac{\text{No. of forced outages}}{\text{component years - sum of forced-outage times}}$$

$$f = \frac{\text{No. of forced outages}}{\text{total time}} =$$

$$= \frac{\text{No. of forced outages}}{\text{component years}}$$

Since the major components are subdivided into classes, it is possible to provide these statistics for each classification.

## 5A.10 CONCLUSION

This brief report has not attempted to duplicate the material contained in [10] and [11]. Its aim has been to provide an overview of the intent behind the transmission equipment component of ERIS and an indication of data that can and will be made available in the future.

# ANNEX 5B

## COMPARISON OF ERIS WITH CEGB TRANSMISSION FAULT REPORTING SCHEME

## 5B.1 SCOPE

Broadly speaking, the CEGB fault reporting scheme collects the same transmission data as CEA's. Most definitions are practically equivalent, although the CEGB collection scheme provides considerably more detail in certain areas.

Whereas ERIS covers all equipment with operating voltages of 110 kV and above, CEGB-OR9A now only covers voltages of 200 kV and above. Transmission fault data on the 132-kV system was recently transferred to the distribution collection scheme NAFIRS (National Fault and Interruption Reporting Scheme), which covers the range from 6.6 to 132 kV.

The CEGB and CEA schemes appear identical in their treatment of associated equipment, e.g. tertiary-connected shunt reactors, and neither records planned outages.

## 5B.2 DEFINITIONS

Transmission equipment: similar definition as ERIS but for 200 kV and above.

Major component: OR9A is more detailed, as it records both the type of circuit and the main equipment item in the circuit that causes the outage. It also has the facility to record two (or more) items that contribute to one outage, e.g. a transient line fault plus a switchgear problem that delays circuit restoration.

Subcomponent: OR9A uses a series of component codes to identify the subcomponents of each main equipment item affected by the fault.

Terminal: this is one area where the two schemes differ. OR9A records the circuit outage and terminal equipment faults are recorded as the main equipment item, e.g. transformer or circuit breaker.

Unit: OR9A also treats three single-phase units as one three-phase unit.

Primary cause: OR9A is similar to ERIS but more detailed in that it has 57 primary-cause classifications. In addition, two further classifications are possible, secondary cause and contributory cause.

Component forced outage: broadly the same for both schemes but, for clarity, the full OR9A definition is given.

Reportable electrical faults include any abnormal event involving the tripping of a circuit breaker either automatically or manually, switchgear failure to open or close when required; any switchgear operation in error; any interruption of supply resulting from a reportable electrical fault; and any load reduction or disconnection caused by the incorrect operation of equipment.

Common-mode outage: a multiple outage is recorded under the one event number and there is also a code which indicates simultaneous faults on two circuits carried on the same set of towers.

Failure mode: OR9A has several codes which give details of the failure mode.

Replacement time: OR9A does not record this information.

Repair time: OR9A records the elapsed time to restore the circuit in addition to the repair times of the main equipment items.

## 5B.3 INVENTORY

The CEGB maintains a separate inventory for all transmission plant. This contains such information as type, ratings, manufacturer, etc. and is updated regularly.

Because the inventory is separate, combined use with the OR9A scheme is not easy. In practice, only basic population data is extracted; fault data summary tables, e.g. by manufacturer or transformer rating, can only be produced indirectly.

## 5B.4 CLASSIFICATION

### 5B.4.1 Concept of Classification

The CEGB scheme is primarily intended to provide data using a classification scheme similar to ERIS. However, it is possible to identify the particular major component, i.e. circuit name and number and equipment items; this facility is used extensively in ad hoc searches of the data base.

### 5B.4.2 List of Major Components

CEGB employs the following classifications:

| | |
|---|---|
| Circuit types | Overhead line<br>Cable<br>Transformer<br>Banked transformers<br>Transformer feeder<br>Transformers banked with line<br>Reactor<br>Bus coupler or bus section switch<br>Busbar<br>Synchronous compensator<br>Static compensator<br>Capacitor<br>Converter (DC - AC)<br>Generator |
| Item types | Overhead line<br>Cable<br>Transformer<br>Reactor<br>Booster<br>Generator<br>Generator-transformer<br>Switchgear (with number to indicate circuit breaker, disconnecting switch, etc.)<br>Protection<br>Busbar<br>Capacitor<br>Converter<br>Synchronous compensator<br>Static compensator<br>Voltage or current transformer<br>Induction motor |

### 5B.4.3 Voltage Classification

The nominal operating voltage is recorded and can be any 4-digit value. In practice, this provides two classifications, 275 and 400 kV, as these are the two operating voltages on the CEGB supergrid system. (Note that the 200-kV DC link is classified with 275-kV equipment). In addition, OR9A records the lower voltage level for transformer equipment/circuits.

### 5B.4.4 Subcomponent Codes

Like the CEA scheme, OR9A collects additional information on the subcomponents of the main equipment that are involved in the fault. Up to three component codes can be recorded for each equipment item and there are more than 100 codes to choose from. A complete list is shown in the Annual Report [12].

## 5B.5 OUTAGE DEFINITIONS

The comments above indicate that the definition of outage used in the two schemes is very similar. Although planned-outage data is not collected at present, CEGB is contemplating that possibility. The collection scheme would probably be separate from but compatible with OR9A.

## 5B.6 TIME DEFINITIONS

The repair time in this scheme is the time to restore the circuit to service. Repair times of less than 1 min (delayed autoreclose) are entered as 1 min (not 0 as in ERIS). Destroyed equipment is allocated a repair time of 999 days (compare "X" in ERIS).

OR9A also defines what it calls event time but ERIS makes no mention of this. Data on event times is required to ascertain that the assumption of random independent failures is valid or is of particular interest to demonstrate the bunching of faults during adverse weather.

## 5B.7 PRIMARY-CAUSE CODES

A full list of the primary and secondary/contributory cause codes is published in the Annual Report [12]. These codes cover all the aspects of the seven codes in ERIS and, also, precautionary action and switching surges.

## 5B.8 FAILURE MODES

The CEA and CEGB schemes record similar failure-mode data but this information is held in several places in OR9A. The main information field is "Nature of Fault", which includes ERIS codes 1 to 5 plus insulation failure. ERIS codes 6 to 8 are covered in the Cause Code section.

## 5B.9 STATISTICS

In addition to the derivation of basic reliability indices, the OR9A data base is used for purposes similar to ERIS items 1, 3, 4 and 5. As replacement time is not recorded, spares holding and allocation are not directly monitored. Note that in England and Wales, the time to replace a transformer say, can be estimated with reasonable accuracy and there is therefore no perceived need to collect replacement time data.

Other uses of the collected data include investigation of repair time distribution, identification of circuits experiencing a higher-than-average fault rate, identification of the effects of season, weather and location on equipment fault rates, and use of observed data to check the predicted performance of circuits/systems (model validation).

The CEGB scheme also calculates the basic statistics of $\lambda$, $\mu$ and f, although in practice the failure rate $\lambda$ and the forced-outage frequency f are effectively identical, since down-times are much shorter than up-times.

## 5B.10 CONCLUSIONS

Currently the data is collected manually and initially recorded on an input document prior to being entered into the computer data base.

An example of the various outputs from the OR9A reporting system is the annual report of supergrid fault statistics [12]. However, in the CEGB system the data extractions can be varied at will and tailored to specific needs as they arise. Outputs are therefore constrained only by the scope of the data recorded and as such can be considered quite separately from the raw-data collection.

## ANNEX 5C

## COMPARISON OF ERIS WITH COMMONWEALTH EDISON'S SCHEME

The major differences between ERIS and Commonwealth Edison's transmission outage data collection system for planning and operating purposes can be summarized as follows.

The most important difference is the level of entities on which data is collected. CEA compiles data for nine types of component and nine voltage classes. Up to four additional attributes for classification are reported but a count or total mileage (rather than a list) of entities within each subgroup is reported.

Commonwealth Edison compiles data for 345-kV units of four types: transmission line units (including tapped lines), transformer units, bus units and generating units.

Each entity is reported separately. In addition, data is compiled on sections and segments of lines as appropriate. Commonwealth Edison also identifies the component to which each outage was attributed, based on the more extensive list of components identified by EPRI RP-1283 [8] and an inventory compiled under RP-1468-2 [13].

Inconsistent application of the terms "component" and "unit" is causing confusion in this area. Commonwealth Edison considers a unit as the complete entity within the clearing zone of one or more protection systems, interfaced to other adjacent units by one or more circuit breakers, which are automatically tripped by that protection system in response to a fault on the unit.

CEA apparently considers a component as a functional entity including the protection system, which may interface other components directly rather than only through a circuit breaker. In fact, circuit breakers constitute another class of components. One member of CEA, Ontario Hydro, seemingly uses the same level of functional entities in reporting as CEA components but terms them units, so this utility has transformer units tapped to transmission line units.

EPRI RP-1283-1 [8] subdivides components more narrowly, in a manner corresponding closely to design considerations such as IEEE Standard 500 [14]. A transformer and its protection system are considered to be separate components.

Ten failure modes (including manual removal and unknown) are recognized by the CEA scheme whereas Commonwealth Edison reports three: fault, no fault and unknown, and distinguishes between momentary and lockout (permanent) outages.

CEA distinguishes common-mode but not dependent outages. Commonwealth Edison identifies dependent outages, distinguishing between those due to the network configuration and those due to a circuit breaker and/or protection equipment malfunction.

CEA does not consider transformers tapped into a line when enumerating terminals. Commonwealth Edison counts such tapped transformers if they are at a separate location where there is no 345-kV circuit breaker, although such application is infrequent.

CEA recognizes common-tower exposure as a special case of common-mode outage. Commonwealth Edison also recognizes common right-of-way and common terminal for line-related common-mode outages. Terminal-related common-mode outages are distinguished as related line or bus and miscellaneous. An "other proximity" category is provided.

CEA distinguishes outages attributed to terminal equipment from those attributable to the integral subcomponents (structure, conductors, bushings, etc.) of each component. "Unknown" is reported separately but analysed as if it were line-related. This facilitates normalizing by length or terminals, as required.

Commonwealth Edison identifies line, terminal and unknown, and also tapped transformers, as locations of trouble. The latter is not needed by CEA as tapped transformers are considered separate reporting entities. Commonwealth Edison uses regression models for prediction rather than average historical performance.

Commonwealth Edison is experimentally recording weather conditions at the time of the outage, based on weather records at Chicago's O'Hare International Airport.

CEA records circuit-breaker tripping operations that do not outage any unit because of redundant paths within the terminal (ring bus configuration). Commonwealth Edison does not record such operations but, on the other hand, reports as outaged, those units which were energized but open at one terminal.

## REFERENCES

[1] M.S. Grover and R. Billinton, "A Computerized Approach to Substation and Switching Station Reliability Evaluation," IEEE Trans. PAS-93, pp. 1488-1497, 1974.

[2] R. Billinton and R.N. Allan, Reliability Evaluation of Power Systems, Longmans (London, England)/Plenum Publishing (New York, USA), 1984.

[3] J. Endrenyi, Reliability Modelling in Electric Power Systems, J. Wiley (Chichester, England) 1978.

[4] R. Billinton and R.N. Allan, Reliability Evaluation of Engineering Systems: Concepts and Techniques, Longmans (London, England)/Plenum Publishing (New York, USA), 1983.

[5] R.N. Allan, E.N. Dialynas and I.R. Homer, "Modelling Common-Mode Failures in the Reliability Evaluation of Power System Networks," IEEE PES Winter Power Meeting, Paper A79 040-7, 1979.

[6] R. Billinton, T.K.P. Medicherla and M.S. Sachdev, "Common-Cause Outages in Multiple Circuit Transmission Lines," IEEE Trans. R-27, pp. 128-131, 1978.

[7] R. Billinton and T.K.P. Medicherla, "Station-Originated Multiple Outages in the Reliability Analysis of a Composite Generation and Transmission System," IEEE Trans. PAS-100, pp. 3869-3879, 1981.

[8] Electrical Power Research Institute, "Bulk Transmission System Component Outage Data Base," EPRI Report EL-1797 on Project RP-1283-1, April 1981.

[9] Institute of Electrical and Electronics Engineers, Committee Report, "Proposed Terms for Reporting and Analysing Outages of Electrical Transmission and Distribution Facilities," IEEE Trans. PAS-104, pp. 337-348, 1985.

[10] Canadian Electrical Association, Instruction Manual for Reporting Component Forced Outages of Transmission Equipment, Montreal, Canada, 1978.

[11] Canadian Electrical Association, Forced-Outage Performance of Transmission Equipment for the Period January 1, 1980 to December 31, 1984, Montreal, Canada, June 1986.

[12] Central Electricity Generating Board, CEGB Supergrid Fault Statistics - Annual Report for 1984/85, London, England, August 1986.

[13] Electrical Power Research Institute, "Predicting Transmission Outages for System Reliability Evaluations," EPRI Report EL-3880 on Project RP-1468-2, May 1985.

[14] Institute of Electrical and Electronics Engineers, Standard 500, IEEE Guide to the Collection and Presentation of Electrical, Electronic and Sensing Component Reliability Data for Nuclear-Power Generating Stations, 1977.

[15] Institute of Electrical and Electronics Engineers, Committee Report, "Common-Mode Forced Outages of Overhead Transmission Lines," IEEE Trans. PAS-95, pp. 859-863, 1976.

[16] R.N. Allan and R. Billinton, "Effect of Common Mode, Common Environment and Other Common Factors in the Reliability Evaluation of Repairable Systems," Proceedings 7th Advances in Reliability Technology Symposium, National Centre of Systems Reliability, Paper 4B/2, Culcheth, Warrington, UK, 1982.

[17] M.G. Lauby, J.H. Doudna, R.W. Polesky, P.J. Lehman and D.D. Klempel, "Effects of Pooling Weather-Associated MAPP Bulk Transmission Outage Data on Calculated Forced Outage Rates," IEEE Trans. PAS-103, pp. 2345-2351, 1984.

[18] M.G. Lauby, R.P. Ludorf, J.H. Doudna, D.D. Klempel, P.J. Lehman and C.G. Dahl, "Analysis of Pooling 345-kV Bulk Transmission Outage Data Between the Mid-Continent Area Power Pool and Northeast Utilities," IEEE Trans. PAS-104, pp. 2427-2434, 1985.

[19] P.G. Hoel, "Testing the Homogeneity of Poisson Frequencies," Annuals of Mathematical Statistics, pp. 362-368, 1945.

[20] S.J. Argent and S.G. Ryan, "An Analysis of Supergrid Transmission Fault Data in a Specific Area of England and Wales," Reliability Engineering, 12, pp. 205-216, 1985.

[21] A. Bendell and L.A. Walls, "Exploring Reliability Data," Quality and Reliability Engineering International, 1, pp. 37-52, 1985.

## CHAPTER 6

## DEPENDENCY CONCEPTS

### TASK FORCE

R. Billinton (Chairman)
R.N. Allan
O. Bertoldi
M.G. Lauby

### 6.1 INTRODUCTION

A basic requirement in all areas of power system reliability evaluation is the recognition and ability to assess the likelihood of multiple-outage events. These events can arise in a wide variety of ways and under a wide range of conditions. In some situations, the events may be completely independent of each other or there may be an association between them which has a major influence on the likelihood of the overlapping outage condition. Recognition of the stress level under which facilities are operating is a major factor in reliability evaluation. In the case of outdoor facilities such as transmission elements, the weather can have a dominating influence on the likelihood of failure. The fact that many elements can be simultaneously affected by a single storm creates a form of dependency which must be recognized and evaluated. This chapter considers the concept of dependency with particular emphasis on the weather modeling of transmission elements.

### 6.2 INDEPENDENT OUTAGES

Independent outages are by far the simplest multiple events to include in reliability assessment. These events involve two or more elements and are referred to as overlapping or simultaneous independent outages. The probability normally associated with a multiple event is the product of the failure probabilities for each of the elements. The basic component model used in these applications is usually the simple two-state representation in which the component is either up or down. In this model, the rate of departure from a component up-state to its down-state is designated as the failure rate $\lambda$. The restoration process from the down-state to the up-state is somewhat more complicated and is normally designated by the repair rate $\mu$. Restoration following a forced outage can take place in a number of markedly different ways which can result in quite different probabilities of finding the component in the down-state (usually designated as unavailability). Processes such as reclosure, which can be either manual or automatic, or repair involve quite different outage times and, therefore, quite different restoration rates. The state space diagram for a two-element configuration considering independent failures is shown in Fig. 6.1. A component may also be removed from service for a scheduled outage. The scheduled-outage rate, however, cannot be added directly to the failure rate as scheduled outages are not random events.

Most of the published techniques for generation and composite-system reliability evaluation assume that the outages constituting a contingency situation are independent.

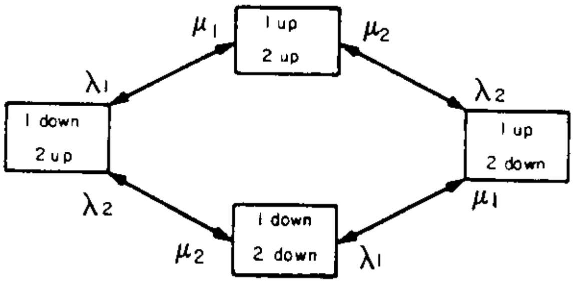


Figure 6.1 - Basic two-element independent failure model

### 6.3 DEPENDENT OUTAGES

These outages are dependent on the occurrence of one or more other outages, e.g. an independent outage of one line of a double circuit followed by the removal of the second line due to overload. Such outages are not normally included in the reliability evaluation of composite systems and require detailed appreciation of system data in addition to individual component data.

### 6.4 COMMON-MODE OUTAGE

As stated earlier, the probability of an event consisting of two or more simultaneous outages is the product of the individual outage probabilities. If these probabilities are low, the product can become extremely small. The probability of a common-mode outage resulting in a similar contingency event can however be many times larger. The effect of these outages on load point reliability indices can therefore be quite significant compared with the impact of second- and higher-order independent outages.

A common-mode or common-cause outage is an event having an external cause with multiple failure effects where the effects are not consequences of each other. The most obvious example is the failure of a transmission tower supporting two or more transmission circuits. This event can be contrasted with the outcome for a similar configuration in which the two circuits are on separate tower structures and physically separated by a large distance.

The Task Force on Common-Mode Outages of Bulk Power Supply Facilities in the IEEE Subcommittee on the Application of Probability Methods has suggested a common-mode outage model for two transmission lines on the same right-of-way or on the same transmission tower [9]. This model (Fig. 6.2) contains a direct transition rate $\lambda_c$ from state 1 to state 4 and assumes that the same repair process applies for all failures, including common-cause failures. Other common-cause outage models have been analysed and are described in detail in Ref. [1].

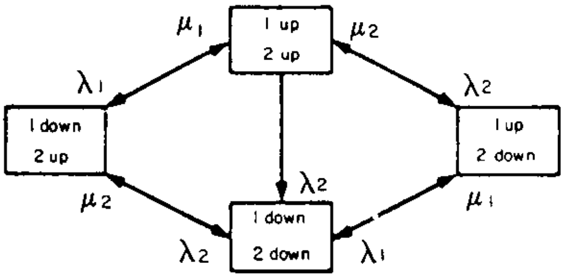


Figure 6.2 - A common-mode outage model (IEEE)

## 6.5 STATION-ORIGINATED OUTAGES

The outage of two or more transmission elements not necessarily on the same right-of-way and/or generating unit can arise from station-originated causes such as a ground fault on a breaker, a stuck breaker, a bus fault, etc., or a combination of these conditions. Such outages are sometimes accounted for in transmission line and/or generator outage rates by combining them with independent outages. However, this approach cannot recognize a situation in which more than one element of the system is simultaneously removed from service because of a single event in the terminal station. Such outages must be considered as separate events. The effect of station-originated outages in composite-system reliability has not been extensively analysed and can have an appreciable effect on load point reliability indices. The impact can be clearly seen in the station shown in Fig. 6.3, where a ground fault on breaker 901 will open breakers 902 and 907 and hence isolate four generating units from the system. This type of event is not normally included in either generating-capacity or composite-system reliability studies. The duration of the outage in this case, however, might be associated not with the repair of breaker 901 but simply with the switching action required to remove the breaker from the system and restore the four units to system service. It is therefore important to recognize that restoration in the case of terminal-station faults may not involve repair directly but may be by switching action and, consequently, a different model is required. Figure 6.4 shows one possible model which includes both common-mode and station-related events.

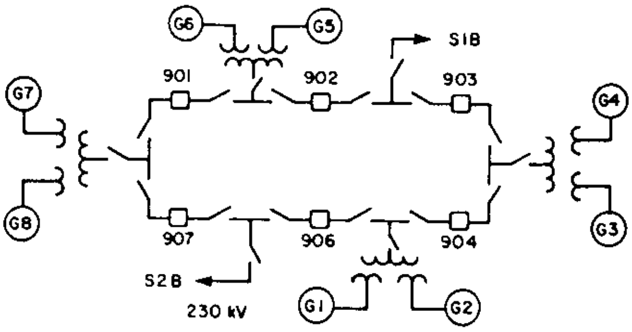


Figure 6.3 - Squaw Rapids Generating Station configuration in the Saskatchewan Power Corporation System

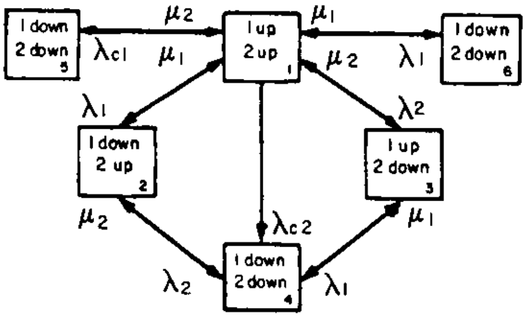


Figure 6.4 - General model for common-cause, independent and station-originated events

The state transition diagram above illustrates two possible common-mode failure events characterized by $\lambda_{c1}$ and $\lambda_{c2}$. These events are physically different: in one case, repair follows the same process as for the independent events, while in the other a common-mode repair process is used. Either one or both may exist in a particular situation.

It is important to appreciate the different impact that common-mode and station-originated events can have on the system transmission components. Figure 6.5 shows two double-line configurations. Lines 1 and 2 in Fig. 6.5(a) start at station A and terminate at two different stations B and C. The two lines may be removed from service by two overlapping independent failures or by a single element failure in station A. In Fig. 6.5(b) both lines terminate at station B. In this case, the two lines may also be removed from service by a common-mode failure if they are on a common tower structure or a common right-of-way. All these factors must be included for a comprehensive analysis of a composite system. The most suitable way is to consider them as separate levels of component and system data.

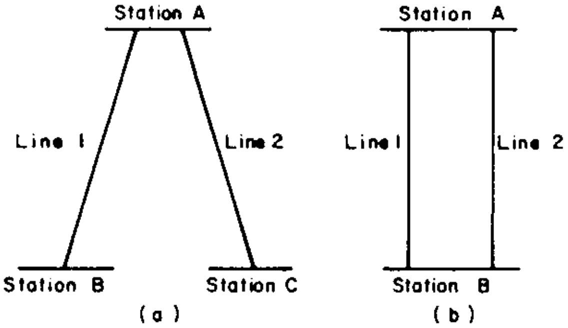


Figure 6.5 - Double-line configurations

The stochastic data requirements for composite-system reliability therefore include both individual component parameters and higher levels of data which involve more than one component and may be system-specific.

There is a relatively large amount of available data related to individual component outages. Many companies have or are in the process of establishing comprehensive outage data collection procedures, which should provide individual component outage data with an acceptable level of confidence. This is not the case with common-mode, dependent and station-originated failures, although increasing awareness of the necessity for such data should lead to better and more comprehensive collection procedures.

## 6.6 INCLUSION OF WEATHER EFFECTS

### 6.6.1 Concepts

All power system networks are exposed to varying weather conditions and it has been found from experience that the failure rate of many components is a function of the weather to which they are exposed. In some weather conditions, the failure rate of a component can be many times greater than that found in the most favorable weather condition. The impact of weather has been considered for a number of years and techniques have been developed that allow its effect to be included in basic reliability analysis.

Weather conditions that cause high component failure rates are generally infrequent and of short duration. During these periods, however, the failure rates can increase sharply and the probability of overlapping failures is much greater than in favorable weather. This creates what is known as the bunching effect, due to the fact that component failures are not randomly distributed throughout the year but far more likely to occur in certain constrained short periods within the year. If this fact is neglected, the reliability indices evaluated for a load point can be over-optimistic and consequently very misleading.

It should be noted that the techniques used to account for failure bunching do not imply dependence between component failures. Although the components may reside within a common environment which affects their failure rates, the actual failure process still assumes the component failures to be independent. There is no suggestion, therefore, that the process involves a common-mode or dependent failure, only that the independent failure rates are enhanced because of the common environment. There may also be enhanced common-mode failure rates existing during the adverse weather wherever such failures can occur. It should be noted that, although the following techniques are described in regard to failure processes in a common weather environment, they are equally applicable to other types of varying environment such as temperature or loading level. The key factor is that the environment is common to more than one element.

### 6.6.2 Weather State Modeling

The failure rate of a component is a continuous function of the weather, which suggests that it should be described by either a continuous function or a large set of discrete states. This proves impossible, in practice, owing to difficulties in system modeling, data collection and data validation, and the problem must therefore be restricted to a limited number of states. The number should be sufficient to represent failure bunching but small enough to make the problem tractable.

A set of approximate equations was presented in 1964 which incorporated the weather effects using two weather states designated as normal and stormy [3]. A more complete analysis, which introduced the utilization of Markov models to examine the effects of weather, was published in 1968 [4]. This paper illustrated the error existing in the approximate equations and presented a theoretically more rigorous approach to weather modeling [4,6].

The IEEE standard [5] subdivides the weather environment into the three classifications of normal, adverse and major storm disaster. Although techniques have been developed to evaluate the effect of these three weather states, the problems are still great and therefore only the first two (normal and adverse) are generally considered. The third state is usually reserved for consideration of major system disturbances.

A set of equations for accurately modeling the effects of weather using the two-state representation was published in 1975 [7,8]. The results using these equations were found to compare favorably with those obtained using the Markov modeling approach [4,6]. References [7] and [8] also provide a set of equations to incorporate the three weather states in the prediction of load point reliability indices. Owing to difficulties in the data collection of both failure and weather data, the problem is usually restricted to normal- and adverse-weather states.

The general range of weather conditions is therefore classified as either normal or adverse. This restriction frequently causes concern and is one reason why two-state weather modeling has seldom been used in the past. The criterion for deciding into which category each type of weather must be placed is dependent on its impact on the component failure rates. Weather conditions having little or no effect should be classified as normal and those having a large effect classified as adverse. Examples of adverse weather include lightning storms, gales, typhoons, snow and ice.

One important feature in the collection of weather duration data is that all periods of normal and adverse weather must be collated even if no failures occur during any given period. This point cannot be overstressed, since there is little use in allocating a particular failure event to normal weather or adverse weather after it has occurred if the starting and finishing times of the weather periods have not been ascertained. This aspect requires cooperation between the utility and the appropriate weather bureau. Failure to collect such statistics comprehensively will introduce significant errors, not only in the statistics themselves but also in subsequent reliability analyses.

The durations associated with each of the designated weather states can be shown in the form of a chronological profile as presented in Fig. 6.6. A similar profile can be created for the three weather categories (normal, adverse and major storm [5]) if it is decided to model extremely adverse weather.

The pattern of weather durations can be considered as a random process which can then be described by expected values, i.e. the expected durations of normal weather and adverse weather are given by N and S respectively. These expected values produce the average-weather profile shown in Fig. 6.7.

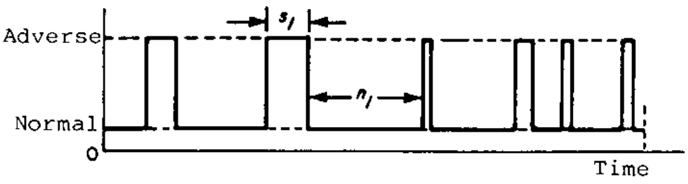


Figure 6.6 - Chronological variation of weather

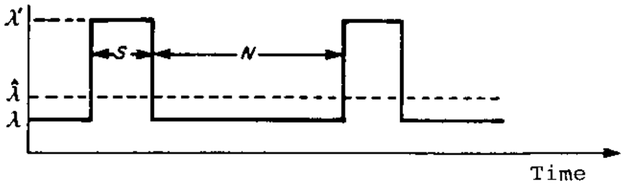


Figure 6.7 - Adverse-weather duration profile

### 6.6.3 Failure Rates in a Two-State Weather Model

After the decision has been made regarding which weather conditions contribute to the constrained two-state model, all subsequent failures should be allocated to one of these states depending on the prevailing weather at the time of a failure. This permits the failure rate in each of the weather states to be ascertained. These failure rates must be expressed as the number of failures per year of that particular weather condition and not as the number of failures in a calendar year. This requirement follows from the concepts and definition of a transition rate, as given in Section 9.2.1 of Ref. [2]. Because adverse weather is generally of short duration, many calendar years of operation may be necessary to achieve one year of adverse weather.

Define

$\lambda$ - component failure rate in normal weather, expressed in failure occurrences/year of normal weather

$\lambda'$ - component failure rate in adverse weather, expressed in failure occurrences/year of adverse weather.

An average value of failure rate $\hat{\lambda}$ expressed in failures per calendar year can be derived from $\lambda$, $\lambda'$, N and S using the concept of expectation,

i.e.

$$\hat{\lambda} = \frac{N}{N+S}\lambda + \frac{S}{N+S}\lambda'$$

Since generally $N \gg S$, the value of $\hat{\lambda}$ is approximately equal to $\lambda$. These values of $\lambda$, $\lambda'$ and $\hat{\lambda}$ are shown in Fig. 6.7.

At the present time, most data collection schemes do not recognize $\lambda$ and $\lambda'$ but are only responsive to $\hat{\lambda}$. This is slowly changing, however, as many utilities now acknowledge the need to identify such data. As this development continues, the quality of both fault-reporting schemes and the resulting reliability analysis will improve. The values of $\lambda$ and $\lambda'$ can, however, be evaluated from $\hat{\lambda}$ using the equation above if the values of N, S and the proportion of failures (F) occurring in adverse weather are known, since

$$\lambda = \hat{\lambda}\ \frac{N+S}{N}\ (1=F)$$

$$\lambda' = \hat{\lambda}\ \frac{N+S}{S}\ F$$

If the value of F is unknown, a complete sensitivity analysis can be made using $0 \leq F \leq 1$ to establish the effect of adverse failures on the behavior of the system.

The relative magnitude of $\lambda$ and $\lambda'$ can be illustrated by considering a realistic numerical example in which $\hat{\lambda}$ = 0.594 occ/yr, N = 200 h, S = 2 h. These values are shown in Table 6.1 for values of F = 0, 0.5 and 1.0, i.e. no failures, 50% of failures and all failures occur in adverse weather, respectively.

Table 6.1

Relative magnitude of $\lambda$ and $\lambda'$

| F | $\lambda$ (occ/yr of normal weather) | $\lambda'$ (occ/yr of adverse weather |
|---|---|---|
| 0 | 0.600 | 0.0 |
| 0.5 | 0.300 | 30.0 |
| 1.0 | 0.000 | 60.0 |

The results shown in Table 6.1 clearly indicate that the failure rate during short periods of adverse weather is much greater than the overall average value and will significantly increase the probability of overlapping failures during these periods.

It is worth noting the significance of $\lambda$, $\lambda'$ and $\hat{\lambda}$ at this point. Although a data collection scheme may identify and store $\hat{\lambda}$, this is not a physical parameter but only a statistical quantity that relates $\lambda$, $\lambda'$, N and S. It therefore does not truly represent the behavior of a component. The real physical parameters determining component failure are the values of $\lambda$ and $\lambda'$. Consequently the consistency of $\hat{\lambda}$ and confidence in the data will increase if $\lambda$ and $\lambda'$ are collected instead of $\hat{\lambda}$.

### 6.6.4 Analytical Approach

The first contribution to the evaluation of a two-state weather model proposed a set of approximate equations for use with a network reduction method. Although representing a major step forward, these equations contained certain weaknesses which were identified from a Markov analysis of the same problem. The Markov approach is shown in detail in Ref. [4]. Subsequently, a modified set of equations was proposed which now forms the basis of most evaluation methods and can be used as part of a network reduction process or, more fruitfully, in association with a failure-mode (minimal cut-set) analysis. These equations, together with a listing of the original references describing this work, are detailed in Refs. [1] and [4].

### 6.6.5 Numerical Example

The application of the equations developed to consider the effect of overlapping forced outages can be illustrated using the simple parallel network shown in Fig. 6.8.

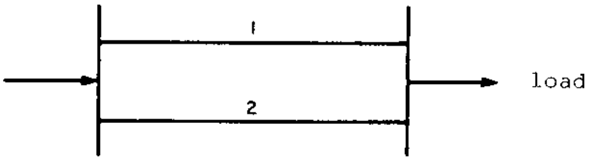


Figure 6.8 - Simple parallel transmission circuit

This system may represent either a real parallel circuit or a second-order failure event (minimal cut-set) of a more complicated network. The process of analysis is identical in both cases.

It is assumed that both elements are identical and that each has the following numerical data:

$\lambda$ = 0.20 occ/yr of normal weather
$\lambda'$ = 40.0 occ/yr of adverse weather
r = 10 h

In addition it is assumed that the weather states have the following average durations:

N = 200 h
S = 2 h

### 6.6.6 Neglecting Weather

The average failure rate $\hat{\lambda}$ corresponding to the normal and adverse data given above can be obtained using the following equation

$$\hat{\lambda} = \frac{200}{202} \times 0.20 + \frac{2}{202} \times 40 = 0.594 \text{ occ/yr}$$

This value of $\hat{\lambda}$ is the failure rate that would be identified by a data collection scheme if the weather state were not associated with each system failure. It is evident that the value of is much closer to the failure rate during normal weather because the value of N is much greater than that of S.

Using this value of $\hat{\lambda}$, the load point reliability indices can be evaluated as

$$\lambda_p = \lambda_1 \lambda_2 (r_1 + r_2)$$

$$\lambda_p = 0.594 \times 0.594 (10+10)/8760 = 8.06 \times 10^{-4} \text{ occ/yr}$$

$$r_p = \frac{r_1 x r_2}{r_1+r_2} = \frac{10x10}{10+10} = 5 \text{ h}$$

$$U_p = \lambda_{pp} r_{pp} = 4.03 \times 10^{-3} \text{ h/yr}$$

### 6.6.7 Two Weather States - Repair Possible in Adverse Weather

This contribution can be evaluated from the data given above using the following equations [1].

$$\lambda_p = \lambda_a + \lambda_b + \lambda_c + \lambda_d$$

$$\lambda_a = \frac{N}{N+S} [\lambda_1 \lambda_2 (r_1 + r_2)$$

$$\lambda_b = \frac{N}{N+S} \left[\lambda_1 (\frac{r_1}{N})(\frac{\lambda_2 Sr_1}{S + r_1}) + \lambda_2 (\frac{r_2}{N})(\frac{\lambda'_1 Sr_2}{S + r_2})\right]$$

$$\lambda_c = \frac{S}{N+S} \left[\lambda'_1 \lambda_2 r_1 + \lambda'_2 \lambda_1 r_2\right]$$

$$\lambda_d = \frac{S}{N+S} \left[\lambda'_1 (\frac{\lambda'_2 Sr_1}{S + r_1}) + \lambda'_2 (\frac{\lambda'_1 Sr_2}{S + r_2})\right]$$

$$\lambda_p = 6.45 \times 10^{-3} \text{ occ/yr}$$

$$r_p = \frac{r_1 r_2}{r_1+r_2} = \frac{10x10}{10+10} = 5 \text{ h}$$

$$U_p = \lambda_{pp} r_{pp} = 3.23 \times 10^{-2} \text{ h/yr}$$

A similar set of results would be obtained if repair was not possible in adverse weather [1].

### 6.6.8 Sensitivity Analyses

Comparison of the previous results for a single-state and a two-state weather model shows that the failure rate and annual outage time are much greater for the two-state weather model. The concept of sensitivity analysis is illustrated considering the system shown in Fig. 6.8 and assuming N = 200 h, S = 2 h, r = 10 h and $\hat{\lambda}$ = 0.594 occ/yr, i.e. as used in the example above. The values of $\lambda$ and $\lambda'$ can be evaluated for values of F between zero and unity and the system indices evaluated.

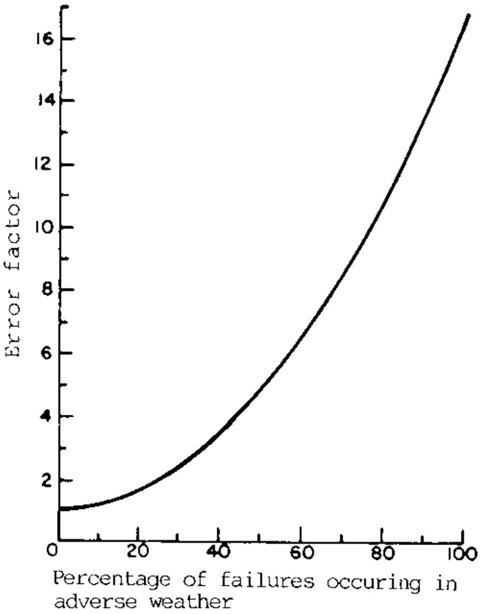


Figure 6.9 - Error factor in value of failure rate

These results are shown in Fig. 6.9, where it can be clearly seen that, as the number of failures occurring in adverse weather increases, the system failure rate also increases sharply. The ratio between the failure rate if all failures occur in adverse weather and that when all failures occur in normal weather is about 17 to 1. This ratio can be defined as an error factor, since it defines the error introduced in the evaluation of failure rate if the effect of weather is neglected. The variation in the value of this error factor is shown in Fig. 6.9 as a function of the percentage of failures that occur in adverse weather. It can be seen that the error increases rapidly as the percentage of adverse weather failures increases. A very optimistic evaluation would be obtained if the effects of weather were ignored.

## 6.7 DATA COLLECTION AND UTILIZATION

There are many difficulties associated with the determination of $\lambda$ and $\lambda'$, i.e. the failure rate in normal and adverse weather respectively. The recognition of adverse weather durations when failures do not occur is difficult if not impossible. Alternative approaches are sometimes used to recognize adverse weather and its effects. Periods of adverse weather are revealed by the bunching of overhead line faults that the adverse weather causes. Therefore, by analysing fault incidents recorded in a transmission fault database it is possible to identify fault bunching and, hence, estimate the number and average duration of adverse weather periods. Appendix I illustrates several approaches used by various utilities to obtain weather-related statistics. There is no unanimity regarding the most appropriate means to obtain these data and owing to differences in climate and system configuration, the approaches tend to become system-specific.

## REFERENCES

[1] R. Billinton and R.N. Allan, Reliability Evaluation of Power Systems, Longmans (London, England)/Plenum Press (New York, USA), 1984.

[2] R. Billinton and R.N. Allan, Reliability Evaluation of Engineering Systems: Concepts and Techniques, Longmans (London, England)/Plenum Press (New York, USA), 1983.

[3] D.P. Gaver, F.E. Montmeet and A.D. Patton, "Power System Reliability. II - Measures of Reliability and Methods of Calculation," IEEE Trans. PAS-83, pp. 727-37, 1964.

[4] R. Billinton and K.E. Bollinger, "Transmission Reliability Evaluation Using Markov Processes," IEEE Trans. PAS-87, pp. 538-547, 1968.

[5] IEEE Standard 346: Terms for Reporting and Analysing Outages of Electrical Transmission and Distribution Facilities and Interruptions to Customer Service, 1973.

[6] R. Billinton, Power System Reliability Evaluation, Gordon and Breach Science Publishers (New York), 1970.

[7] R. Billinton and M.S. Grover, "Quantitative Evaluation of Permanent Outages in Distributions System," IEEE Trans. PAS-94, pp. 733-741, 1975.

[8] R. Billinton and M.S. Grover, "Reliability Assessment of Transmission and Distribution Schemes," IEEE Trans. PAS-94, pp. 724-732, 1975.

[9] IEEE Task Force Report, "Common Mode Forced Outages of Overhead Transmission Lines", IEEE Trans. PAS-95, pp. 859-863, 1976.

# APPENDIX I

# WEATHER MODELING

## TASK FORCE

O. Bertoldi (Chairman)
R. Billinton
M.G. Lauby
S.J. Argent

## I.1 HOW TO MODEL WEATHER

Weather is a continuum in which phenomena such as wind, lightning, snow and so forth occur with an intensity ranging from zero upwards. No theory has yet been developed for combining meteorological parameters into an index, while doubts persist as to the possibility and usefulness of such an undertaking. Nevertheless, in terms of weather effects on overhead lines, a relationship could be conceived between the probability of line faults due to weather and some weather severity index, at least for a given standard line design and a given location [1-5].

Such a relationship may resemble the solid line in Fig. I.1: as the weather severity increases, so does the fault probability, up to the point where the weather becomes severe enough to make failure certain. For practical modeling purposes, the weather can be classified into discrete states, as illustrated by the dashed line in the same figure.

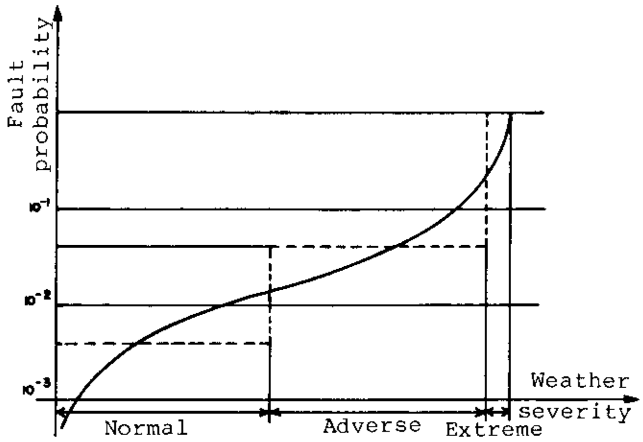


Figure I.1 - Representation of weather severity by discrete weather states

A compromise must be achieved between a large number of states, which introduces problems of modeling complexity and lacks sufficient data to specify each state, and a small number of states (perhaps even one), which may not have the required accuracy to adequately represent the relationship between fault probability and weather severity.

In order to model the weather adequately with respect to the likelihood of line outages, the results of surveys (such as those reported in Table I.2) are of great help. They indicate two types of weather effect, in fact: one seasonal, the other due to the concentration in time and space of the occurrence of adverse-weather phenomena.

The seasonal effect is due to the different types and occurrence rates of the stresses to which overhead lines are subjected, which depend on the meteorological phenomena characterizing each season. The result is that the failure and repair characteristics vary. In Europe and North America, for instance, the worst stresses in winter are those caused by ice formation on conductors, whereas in summer overvoltage type stresses induced by lightning predominate, or mechanical stresses caused by the wind. Research conducted by CEGB in the United Kingdom and MAPP in the United States on operational data indicates that this seasonal effect is responsible for differences in the failure rates per unit for exposure time, as well as in the repair time values.

As for the second effect, namely the concentration in space and time of phenomena such as gales, snow, ice or thunderstorms, the surveys revealed that their occurrence is random in nature and usually of brief duration (a few hours) while the size of the area depends on climatic and geographical characteristics.

Processed field data show a very substantial increase in the failure rate during adverse weather and some reduction (3 to 5 times) in service restoration time for faults occurring during such brief periods compared with restoration times for faults occurring in normal weather.

Based on these findings, a fairly accurate model of the weather can be achieved using one or other of the approaches described in the pages that follow.

Table I.1 - Main characteristics of the networks examined

| | CEGB | ENEL | MAPP |
|---|---|---|---|
| Network examined | National and regional supergrids (275 kV and 400 kV) | Regional supergrids (230 kV and 400 kV) | Multi-regional supergrid (230 kV and 345 kV) |
| Exposure time (years) | 5 and 13 for national and regional grids respectively | 7 | 6 |
| Seasonal subdivision (summer - winter) | Yes | No | Yes |
| Method for adverse-weather identification | Failure bunches, together with proximity criterion | Failure bunches, including 130-kV network | Snowfall levels (winter)<br>Keraunic levels (summer) |
| Adverse-weather frequency and duration analysis | Yes | Yes | No |
| Number of weather conditions considered | 2 | 2 | Severity levels:<br>. 2 in winter<br>. 3 in summer |
| Outage classification | Transient sustained | Transient:<br>. temporary ( >3 h long)<br>. permanent ( <3 h long) | Not specified |
| Common-mode failure analysis | Yes | No | No |
| Outage parameters | . Failure rate and restoration time | . Failure rate and restoration time | Failure rate only |
| Statistical distribution analysis | Yes | No | Yes |

- A deterministic alternation of average conditions, to take into account seasonal variations in the failure rate, as illustrated below.

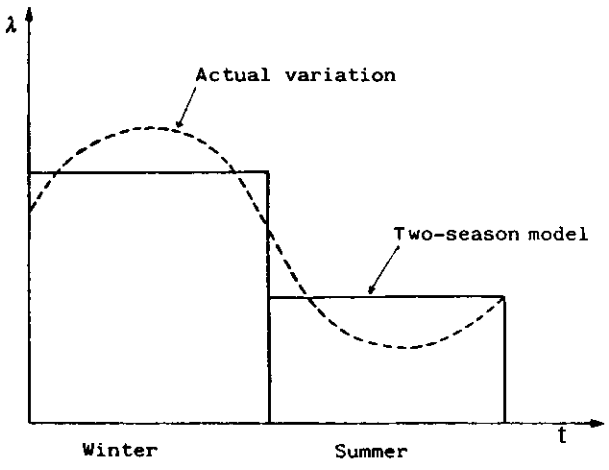


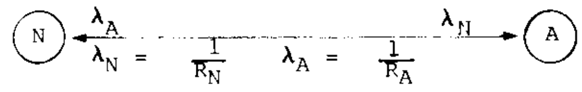
Figure I.2 - Modeling of seasonal forced-outage rate variation

A two-season (winter and summer) model is usually sufficient, the duration of each season depending, of course, on the geographical area where the network under study is located. In north and central Europe and in North America, for example, winter is usually assumed to last from November to March, with the other months considered as summertime.

- A random alternation of normal- and adverse-weather conditions superimposed on the previous deterministic one to model severe stress on lines during brief periods.

According to the results of a CEGB survey showing that transition times from normal (N) to adverse (A) weather are exponentially distributed, this random alternation can be represented by a Markov model [4]. The relevant state-space diagram [6] is shown in Fig. I.3.

- A third weather state (extreme weather), required only for geographical areas where extreme conditions such as tornadoes occur, during which mechanical stresses reach such high values as to cause towers to collapse or conductors to break. With reference to Fig. I.1, this particular weather state is required for representing the range of weather severity indices where the outage probability is very close to 100%.



$R_N$ = average duration of normal-weather periods

$R_A$ = average duration of adverse-weather periods

Figure I.3 - State-space diagram for two-state weather model

Most methodologies usually employed for the evaluation of power system reliability indices include a two-state weather model, so that the occasional need to represent three weather states does not involve any insuperable difficulty. Actually, extreme weather severity is associated with meteorological phenomena that occur so infrequently that the average time interval between one event and the next is much longer than the average transition times for normal and adverse states. According to this assumption, the contribution of such rare phenomena to component failures and power system malfunctions should be calculated by separate methods (see [7] for instance), which supply the additional unavailability to that obtained using a two-state weather model (normal and adverse) associated with a deterministic season alternation.

Generally speaking, the relationship between weather severity and fault incidence could be evaluated in quantitative terms on the basis of the results of a correlation analysis requiring a wide range of detailed recordings of meteorological parameters close to overhead transmission lines.

A recent research project [8] promoted by EPRI and developed by the Commonwealth Research Corporation in the United States investigated the possible correlation between hourly weather states, recorded at a meteorological station and described by approximately 30 categories, and outages that occurred on lines within a 65-km radius of the observation point. The same report also suggests some weather models for which the transition rates into and out of adverse weather (or particular types thereof) can be derived directly from such meteorological records. In most countries, however, the statistical data required by an analysis of correlations such as between fault occurrence and meteorological conditions at the time of faults do not exist or are not available in suitable form. Some utilities have nevertheless tried to overcome such deficiencies by using processing techniques that allow them to pinpoint the dependency of fault occurrence on weather.

Two approaches in particular have been suggested and appropriate data processing techniques developed by CEGB [1,9,10], ENEL [11] and MAPP [12]. A detailed description of the techniques and the results obtained is given below, while the main characteristics of investigations based on these techniques are summarized in Table I.1.

## I.2 CEGB AND ENEL BUNCHING APPROACH

### I.2.1 Characteristics and Main Assumptions

The bunching approach is based on an outage data processing technique that takes into account the fact that line faults occur in rapid succession under adverse-weather conditions. Two weather conditions are considered: normal and adverse, whose alternation could be represented as in Fig. I.4.

The occurrence of adverse weather is traced back to failure bunches due to adverse environmental conditions, according to the following rules:

- If the time interval between two subsequent failures is less than or equal to a given limit $\Delta T$, two or more failures are considered as belonging to the same bunch.
- If at least one fault is certain to have had an environmental cause, the failure bunch is considered due to adverse weather.
- If the lines on which the faults occurred are less than L km apart (CEGB only).

The parameters $\Delta T$ and L are chosen so as to adequately represent adverse-weather occurrence in the area under investigation. The values retained are $\Delta T$ = 6 h and L = 60 km (CEGB).

The duration of the $i^{th}$ period of adverse weather ($r_A$) is defined as the interval between the first fault in the $i^{th}$ observed bunch and the start of the last fault in that bunch. An end correction equal to the mean interval between faults during adverse weather is added by CEGB.

The method adopted to identify adverse-weather periods is both empirical and pragmatic. The storms detected are given in terms of bunches of faults.

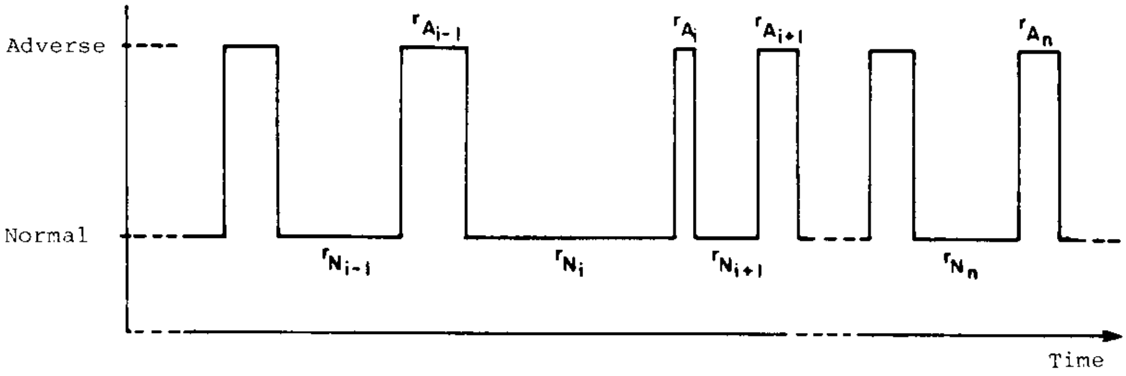


Figure I.4 - Random alternation of weather conditions (two-state model)

### I.2.2 Evaluation of Indices

If the transmission system is located in a geographical area characterized by seasonal periods in which appreciably different meteorological conditions occur, the values for the indices should be assessed separately for each season.

#### I.2.2.1 Weather indices

If two weather states are assumed (their random alternation can be represented as in Fig. I.4), the indices of interest are:

$R_N$ : average duration of normal-weather periods
$R_A$ : average duration of adverse-weather periods.

Taking

$r_{Ai}$= duration (in hours) of the $i^{th}$ adverse-weather period

$N_A$ = number of adverse-weather periods observed during the total investigation time (many years usually)

$H_u$ = duration (in hours) of a given unit time interval (e.g. one year)

$f_A$ = average number of adverse-weather occurrences in $H_u$

the indices are evaluated as follows:

$$R_A = \frac{\sum_{i=1}^{N_A} r_{Ai}}{N_A} \qquad (I.1)$$

$$R_N = \frac{H_u}{f_A} - R_A \qquad (I.2)$$

Suitable best-fitting analysis could be carried out to ascertain the probabilistic distribution law of $r_A$ and $r_N$.

#### I.2.2.2 Line unavailability indices

Assuming two meteorogical conditions, the relevant indices are

$\lambda$, $\lambda'$ = failure rates with normal and adverse weather, respectively, expressed as the number of failures per year of exposure (normal-weather or adverse-weather year)

$r$, $r'$ = mean duration of failures occurring in normal or adverse weather, respectively

Since the reliability assessment is performed in both steady-state (adequacy) and transient (security) conditions, it is advisable to calculate $\lambda$ and $\lambda'$ separately for transient and sustained outages.

The indices $\lambda$ and $\lambda'$, referred to a conventional unit length (100 km) and a given exposure time interval (1 yr = 8760 h), are evaluated as follows[1]

$$\lambda = \frac{\sum_{i=1}^{N_L} F_i}{\frac{H_N}{8760} \cdot \frac{k.y}{100}} \qquad (I.3)$$

where

$N_L$ = number of lines observed

$F_i$ = number of faults on $i^{th}$ line during normal weather

$H_N$ = number of normal-weather hours during investigation[2]

---

[1] These formulas assume the exposure time is practically identical to the duration of the investigation, which is generally the case with transmission equipment.

[2] The investigation period may refer to summer, winter or the whole year, of course.

$$\lambda' = \frac{\sum_{i=1}^{N_L} F'_i}{\frac{H_A}{8760} \cdot \frac{k.y}{100}} \qquad (I.4)$$

where

$F'_i$ = number of faults on $i^{th}$ line during adverse weather

$H_A$= number of hours of adverse weather during investigation[2]

k.y = total kilometres of overhead lines considered, times the years of relevant data.

The exponential distribution law is usually assumed for times to failure, both in normal and in adverse weather.

The indices r and r' (for sustained outages only) can be evaluated approximately as the mean values of the durations of all sustained outages that occurred within a given time interval in normal and adverse weather respectively:

$$r = \frac{\sum_{i=1}^{N_L} r_i}{\sum_{i=1}^{N_L} F_i} \qquad (I.5)$$

where

$r_i$ = total down-time of $i^{th}$ line due to faults in normal weather

$$r' = \frac{\sum_{i=1}^{N_L} r'_i}{\sum_{i=1}^{N_L} F'_i} \qquad (I.6)$$

where

$r'_i$ = total down-time of $i^{th}$ line due to faults in adverse weather

In this case, the exponential distribution law is assumed, taking the repair rates as

$$\mu = \frac{1}{r} \qquad \mu' = \frac{1}{r'} \qquad (I.7)$$

With regard to the statistical distribution law of r, a more sophisticated approach can be used: the best fitting in the available data set with various types of distribution (exponential, log-normal, Weibull) is verified by suitable techniques such as $\chi^2$ or Kolmogoroff-Smirnoff tests [13]. This analysis, which is realistic only if sufficent field data is available, provides the relevant indices.

### I.2.3 Results and Comments

The documentation made available by CEGB and ENEL [1,9-11] relates to various investigations, as seen in Table I.1, but only the most significant results, especially those regarding 400-kV lines and the origin of line-related outages, are summarized here.

#### I.2.3.1 Weather fluctuation indices

The indices for the weather fluctuation used by CEGB and ENEL in their surveys are given in Table I.2.

The CEGB investigation showed that the transition times from normal to adverse weather and vice versa ($r_{Ni}$ and $r_{Ai}$ of Fig. I.4 respectively) follow an exponential distribution law.

As noted in section I.2.1, the results were obtained using $\Delta T$ = 6 h. Subsequently, research was performed to establish how a bunching approach involved a bias of the results due to the ratio between $\Delta T$ and the actual duration of adverse-weather periods. If $\Delta T$ is halved or doubled (3 h and 12 h), the calculated value of $R_A$ (average duration of adverse-weather periods) changes very little.

Table I.2
Indices used in CEGB and ENEL surveys

| Index | CEGB | | ENEL |
|---|---|---|---|
| | Winter | Summer | |
| f : Frequency of adverse-weather periods (per month) | 0.86 | 0.51 | 2.8 |
| $R_N$ : Mean duration (h) of normal-weather periods | 833 | 1408 | 251 |
| $R_A$ : Mean duration (h) of adverse-weather periods | 3.9 | 3.5 | 6.7 |

Table I.3 - CEGB and ENEL surveys: 400-kV lines, independent sustained forced outages

| Index | | Weather | CEGB | | ENEL |
|---|---|---|---|---|---|
| | | | Winter | Summer | |
| Outage rate/100 km. yr | $\lambda$ | Normal | 0.20 | 0.21 | 0.92 |
| | $\lambda'$ | Adverse | 244 | 86 | 49 |
| Mean repair time (h) | r | Normal | 74 | 57 | 25 |
| | r' | Adverse | 21 | 10.5 | 9 |

Table I.4 - CEGB and ENEL surveys: 400-kV lines, transient forced outages

| | Outage rate (per 100 km. yr) | | |
|---|---|---|---|
| Weather | ENEL | CEGB | |
| | | Winter | Summer |
| Normal | 0.80 | 0.15 | 0.16 |
| Adverse | 80.6 | 432 | 201 |

Table I.5 - CEGB survey: 400-kV double-circuit lines, common-mode outage rate $\lambda_c$ (per 100 km. yr)

| Season | $\lambda_c$ Normal weather | $\lambda'_c$ Adverse weather |
|---|---|---|
| Winter | 0.087 | 56 |
| Summer | 0.035 | 21 |

### I.2.3.2 Line forced-unavailability indices

The results presented in Tables I.3 to I.5 show:

- Some seasonal effect, on both $\lambda$ and r, which is notable for adverse-weather periods ($\lambda'$ summer/$\lambda'$winter $\simeq 2.5$)
- A very significant effect of adverse weather on failure rates, measured by the ratio $\lambda'/\lambda$ (both the CEGB and the ENEL surveys show that this effect is greater on transient than on sustained outages)
- A significant effect of the weather on average outage durations (a sustained outage originating in normal weather has a 3-5 times longer repair time than one originating in adverse weather)
- Increase in the failure rate due to weather, which is of the same order of magnitude for common-mode as for independent outages.

## I.3 MAPP SEASONAL APPROACH

### I.3.1 Characteristics and Main Assumptions

The MAPP investigation was conducted on fault data collected between 1977 and 1982 on 230-kV and 345-kV transmission systems in Minnesota, Nebraska, Iowa, North Dakota and South Dakota [12]. The line outage data was broken down by:

- line voltage level
- season when faults occurred
- line-related and terminal-related origin of faults
- average severity of adverse-weather phenomena (storm intensity) affecting the lines considered. In particular:
  - For the summer period, three regions were identified as having 20-30, 30-40 and 40-50 thunderstorm days per year;

- For the winter period, two areas were identified as having an annual snowfall of 40-80 cm and 80-160 cm.

Since two voltage levels, two seasons and two types of fault were considered, eight main data sets were obtained (e.g. 345 kV, summer, line-related, 20-30 thunderstorm days). By also taking into account areas with different average intensities with respect to meteorological phenomena, the number of data sets was increased to 18. For each data set, it is assumed that the failure rate is constant and, therefore, that the expected number of faults within a given time interval follows Poisson's law.

The effects of the season and the storm intensity were analysed by comparing homogeneous data samples (e.g. 345 kV, summer, line-related, etc.) and by using a $\chi^2$ test to determine whether the differences in the failure rates were due to sampling errors or to actual external causes (season or severity of meteorological phenomena).

### I.3.2 Index Evaluation

The relevant index in the MAPP survey is the forced-outage rate, which is calculated for each data set according to the formulas given below.

#### I.3.2.1 Line-related outages

For outages of line-related origin, or internal faults, the index is calculated by taking

$N$ = maximum number of lines in a given data set
$M_i$ = length of the $i^{th}$ line (in miles)
$ET_i$ = exposure time of the $i^{th}$ line
$M.y$ = total mile-years of the data set
$O_i$ = number of interval outages on the $i^{th}$ line

which yields:

$$M.y = \sum_{i=1}^{N} M_i(ET_i) \qquad (I.8)$$

$$\lambda_i = \frac{\sum\limits_{i=1}^{N} O_i}{M.Y} \text{ (outages/mile-year)} \qquad (I.9)$$

#### I.3.2.2 Terminal-related outages

For terminal-related outages, or external faults, the index is calculated by taking

$N$ = maximum number of lines
$N_i$ = number of lines of (i) terminals
$NT$ = maximum number of terminals
$T_{ij}$ = number of terminals of $j^{th}$ line of (i) terminals
$ET_{ij}$ = exposure time of $j^{th}$ line of (i) terminals
$j$ = $j^{th}$ line in a group of N lines
$O_j$ = number of external outages of $j^{th}$ line

which yields

$$T.y = \sum_{i=2}^{NT} \sum_{j=1}^{N_i} T_{ij} \cdot ET_{ij} \qquad (I.10)$$

$$\lambda_e = \frac{\sum\limits_{j=1}^{N} O_j}{T.Y} \text{ (outages/terminal-year)} \qquad (I.11)$$

### I.3.3 Results

Only the results relevant to line-related outages are given here.

#### I.3.3.1 Seasonal effects

Table I.6 gives the overall results for the whole area, obtained by processing the summer and winter data separately.

The $\chi^2$ test on separate summer and winter data sets confirmed that the differences between the values obtained are not due to sampling errors.

Table I.6 - MAPP survey: seasonal variation of $\lambda$ (outages/100 km. yr)

| Season | $\lambda$ | |
|---|---|---|
| | 345 kV | 230 kV |
| Summer | 1.05 | 0.83 |
| Winter | 0.47 | 1.05 |

#### I.3.3.1 Mean weather severity effects

The results for the winter snowfall level effect presented in Table I.7 below are contradictory, despite being fairly similar. The $\chi^2$ tests indicate that for 345 kV there is a very strong probability (68%) that the differences are due to sampling errors. For 230 kV, however, this probability is very low (2%) so that the differences on $\lambda$ must be due to the differences in the average weather severity, represented by the snowfall levels.

Table I.7 - MAPP survey: snowfall-level effect on $\lambda$ (outages/100 km. yr)

| Snowfall level (in./yr) | $\lambda$ | |
|---|---|---|
| | 345 kV | 230 kV |
| 16-32 | 0.50 | 0.87 |
| 32-64 | 0.45 | 1.17 |

The results obtained for the effect of summer thunderstorms are given in Table I.8. Again, the average values calculated on the individual data sets differ only slightly. According to the $X^2$ test, there is an appreciable probability that these differences are due to sampling errors.

Table I.8 - MAPP survey: keraunic-level effect on $\lambda$ (outages/100 km. yr)

| Keraunic level (thunderstorm days/year) | $\lambda$ | |
|---|---|---|
| | 345 kV | 230 kV |
| 20-30 | - | 0.097 |
| 30-40 | 0.019 | 0.098 |
| 40-50 | 0.128 | 0.078 |

REFERENCES

[1] S.J. Argent, K.R. Jarret and A.R. Pearson, "Modelling the Effect of Weather on Electrical Power Transmission Systems," 7th Advances in Reliability Technology Symposium, NCSR/ University of Bradford, April 1982.

[2] S. Panichelli, L. Salvaderi and S. Scalcino, "Unavailability Statistical Models for Power System Reliability Studies," Generic Techniques in System Reliability Assessment, NATO Advanced Study Institute, Nordhoff International Publishers (Liverpool), 1973, p.295.

[3] R. Billinton and R.N. Allan, Reliability Evaluation of Power Systems, Longmans (London, England) Plenum Press (New York, USA), 1984.

[4] R. Billinton and Y. Kumar, "Transmission Line Reliability Models Including Common-Mode and Adverse-Weather Effects," IEEE Trans. PAS-100, No. 8, pp. 3899-3911, August 1981.

[5] J.C.R. Hunt and M.D. Rowbottom, "Meteorological Conditions Associated with the Full Span Galloping Oscillations of Overhead Transmission Lines," Proc. IEEE, Vol. 120, No.8, 1993 pp. 874-876.

[6] R. Billinton, Power System Reliability Evaluation, Gordon and Breach Science Publishers (New York), 1970.

[7] G.L. Anders, P.L. Dandeno and E.E. Neudorf, "Computation of Frequency of Right-of-Way Losses Due to Tornadoes," IEEE Trans. PAS-103, No. 9, pp. 2375-2381, September, 1984.

[8] EPRI, "Predicting Transmission Outages for System Reliability Evaluations," Report No. EL-3880 on Project RP 14682, Vol.1, May 1985 and Vol.2, October 1986.

[9] K.R. Jarret, "The Extraction of Weather-Related Features from Power Transmission Reliability Data Collection Schemes," Fourth EuReDaTa Conference, Venice, 1983.

[10] S.J. Argent and S.G. Ryan, "An Analysis of Supergrid Transmission Fault Data in a Specific Area of England and Wales," 8th Advances in Reliability Technology Symposium, NCSR/University of Bradford, 1984.

[11] A. Invernizzi and S. Massucco, "Analysis of Weather Effect on EHV Overhead Line Unavailabilities: Parameter Computation for Reliability Studies," L'Energia Elettrica, No.10, pp. 414-421, 1984.

[12] M.G. Lauby, J.H. Doudna, R.W. Polesky, P.J. Lehman and D.D. Klempel, "Effect of Pooling Weather Associated MAPP Bulk Transmission Outage Data on Calculated Forced Outage Rates," IEEE Trans. PAS-103, No. 1, pp. 213-221, 1984.

[13] A.B. Clarke and R.L. Disney, Probability and Random Processes, John Wiley & Sons, 1985.

# APPENDIX II

# SUBSTATION MODELING

## TASK FORCE

S. Scalcino (Chairman)
J. Endrenyi
R. Ringlee

Contributing members:

R. Billinton
B. MacRae
R. Naggar

## II.1 PURPOSE AND UTILIZATION

In studying the reliability of the generation and transmission system it is usually not sufficient to consider a substation simply as a network node and to disregard its details, since each substation layout has a distinct impact on line outages and, therefore, on system reliability. This is particularly true for multiple line failures, which are highly dependent on substation outages. A useful approach for reliability studies is to consider substations as system components for which the usual two-state (available/unavailable) model, satisfactory for lines and generators, cannot be used. In this approach, three classes of substation failure events can be defined:

- loss of one terminal
- loss of more than one terminal but not of the entire substation (pairs, triplets, etc. of terminals)
- loss of the entire substation.

A reliability study of the generation and transmission system can be usefully divided into two stages [7]:

- A separate study of each substation,[1] preparation of a simplified model and determination of the probabilities, frequencies and durations of all events in all three classes.
- Use of these models and the statistical data as input to study the generation and transmission system as a whole.

The first stage is dealt with in this appendix while the second belongs essentially to Chapter 3, Methodologies.

Naturally, substation reliability studies are also conducted specifically for station design, without direct account being taken of the system of which the substation will form part but this aspect will not be considered here.

## II.2 MODELS AND ASSUMPTIONS

### II.2.1 Definitions

Components of a substation model: transformers, circuit breakers, disconnecting switches and buses (generally); lightning arresters, voltage and current instrument transformers are often neglected. Components of the protection system are generally not considered explicitly but failure data may take into account the outages induced by them.

Station availability: existence of an appropriate electrical linkage between station terminals.

Failure-effect analysis: analysis of the effect of component failures solely in terms of the existence or non-existence of linkages between the various terminals.

Active failure: this involves not only the unavailability of the component concerned but also a series of switching operations aimed at isolating the component from the system.

Passive failure: unavailability is limited to the failed component. The failure is such that it does not cause the operation of protective devices.

It should be pointed out that the definitions for active and passive failures can differ according to the author.

---

[1] In practice, these studies can be reduced to a few typical cases for a few types of layout.

Stuck-closed condition: a normally-closed circuit breaker or switch that fails to open on demand.

Stuck-open condition: a normally-open circuit breaker or switch that fails to close on demand.

Maintenance: a regular activity aimed at improving the condition of a component. It can be deferred if this is required by system conditions (maintenance which cannot be deferred should be considered as a failure).

Repair and replacement: some models consider two possible developments: a failed component is either repaired or replaced by another one from stock.

### II.2.2 Events Considered

In the general case, the events listed below (up to triple contingencies) may represent system failure and should therefore be evaluated:

- single repair outage
- single switching outage
- double repair outage
- double outage: switching and repair
- double outage: maintenance and repair
- double outage: maintenance and switching
- switching outage and stuck-breaker condition
- repair outage and stuck condition of a normally-open breaker
- switching outage and stuck condition of a normally-open breaker
- triple repair outage
- double repair and switching
- maintenance, repair and switching
- double repair and stuck condition of a normally-open breaker
- maintenance, repair, stuck condition of a normally-open breaker
- maintenance and double repair.

If replacement by spares is a possibility, the following events should also be considered:

- repair outage followed by replacement
- replacement of one component in a double-repair outage, with spares available for both components
- replacement in a double repair outage, with spares available for only one component
- replacement of a component in repair, with a normally-open breaker stuck
- as above, in a double outage involving maintenance and repair
- replacement of one component in a triple repair outage, with spares available for all three components
- as above, but spares available for only two components
- as above, but spares available for only one component
- replacement of one component in a triple outage with double-repair plus maintenance, where spares are available for both components under repair
- as above, but a spare available for only one component.

### II.2.3 Effects of Component Unavailability: Success Condition

According to the simplest definition, a system with a single input node and a single output node operates successfully if at least one of the sets of components linking the two nodes operates.

In a more refined definition, the substation is considered as a multipole whose terminals are the poles and the condition of success is the existence of electrical linkages between pre-selected poles. If it is assumed that the power flow is always in the same direction, this substation will have n points of input and m of output. The generic success condition can then be defined as the condition which ensures that at least $m_j$ output points out of a total of m can be reached from at least $n_i$ input points out of a total of n.

This problem is generally solved by the so-called minimal cut-sets method. For details, the reader is referred to the literature [2,5].

### II.2.4 Determination of System Failure Probability, Frequency and Duration

#### II.2.4.1 Assumptions and constraints

- No component shall be taken out for maintenance if this may cause substation failure. This implies, for example, that if the event "component A failed and component B under maintenance" represents system failure, it can happen only if the maintenance of B is initiated before the failure of A.

- Stuck-breaker conditions (both open and closed) can occur only during switching operations (active failure) and each is characterized by the probability of such an event occurring upon repeated commands of the appropriate operation.

- A failed component is replaced by a spare only if the average failure duration is longer than the replacement time. The probability of replacement is the probability that the spare needed is available. It is a function both of the failure state probabilities (single, double, etc.), since these determine the demand for spares, and of the spares policy. This policy may differ for different systems; for example, spares may be used either in the case of system failure only or at any time when a component has failed.

- It seems reasonable to avoid replacing components under maintenance, stuck or switching conditions and to limit this option to passive failures. Obviously, if there is a choice of several replacement possibilities (a multiple failure with spares for more than one component), the fastest replacement should be chosen.

- Outages containing double or triple switching or double or triple stuck-breaker conditions can be neglected, owing to the very low probability of occurrence of such events.

- Examination of statistical data on network failures and its correlation with the weather shows that some weather conditions give rise to failure bunching (increase in component failure rate and in the rate of overlapping failures). This occurs for many types of component but is particularly marked only in the case of transmission lines and the phenomena will therefore be neglected for all substation components.

For each type of failure state, its probability, frequency and duration are computed. Usually the Markov method is adopted for this purpose (see [2,5]), which requires the following assumptions:

- Events are stochastically independent.

- All rates related to the transition from one state to another are time-independent.

- The process is in the steady state, that is, predictions are made for moments far enough in the future where state probabilities no longer change.

### II.2.4.2 Importance of spares

It should be stressed that spare components play a crucial role in system reliability, since they allow system unavailability to be curbed significantly. An adequate number of spares must therefore provided for the most critical components in terms of system availability [4].

The following study applications are typical:

- assessment of system sensitivity to variations in the number of spares for each type of component

- comparison of "more reliable" layouts without spares with "less reliable" layouts with spares.

The spares referred to here are so-called "standby" spares, i.e. spares in stock ready for installation when a component of the same type fails. The time required to replace the failed component with a spare is termed the replacement time. This is a random number which is assumed to be exponentially distributed and whose average depends on the distance from the store, the facilities and manpower available, and a number of other factors.

It should be emphasized that the availability of spares can be computed starting from the list of minimal cut-sets that the system would have without those spares.

### II.2.4.3 Switching after faults

In most applications, a typical component life history was assumed to consist of two alternating states, working and failed. Switching routines after failures introduce a degree of added complexity. When a component fails, first the system protection will isolate every component within the protection zone of the faulty device. As soon as possible after that, all but the minimal number of components to be kept out of service for isolation of the failed device will be restored to operation through appropriate switching [1,2,6]. Thus, while a component is in the failed state, the system moves through two states, that before switching and that after switching. Obviously, as far as the system is concerned, the pre-switching state is relatively severe, the one after switching being less critical.

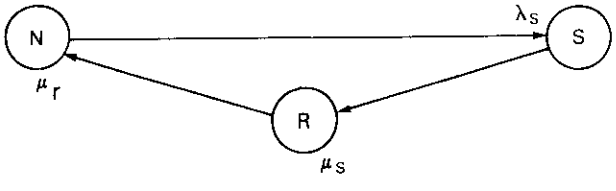


Figure II.1 - Model for repair followed by switching

The corresponding state diagram is shown in Fig. II.1, where

N = normal condition

S = switching condition

R = repair condition

$\lambda_S$ = component fault rate

$\mu_S$ = switching-to-repair transition rate

$\mu_R$ = repair rate

Obviously, since

$T_S = 1/\mu_S$ = average switching time

$T_R = 1/\mu_R$ = average repair time

the state probabilities are

$P_S = \lambda_S\, T_S\, P_N \quad P_R = \lambda_S\, T_R\, P_N$

$$P_N = \frac{1}{[1 + \lambda_S\,(T_R + T_S)]}$$

Failure effect analysis: A failure effect analysis of states R and S in Fig. II.1 may have three outcomes: first, neither represents system failure; second, only S is a system failure state; third, both R and S are system failure states. The R state by itself cannot represent system failure because S is a more severe system condition than R so that if the system is failed in R it must also be failed in S.

It should be mentioned that several publications refer to faults that require switching as "active" and to those that do not require switching as "passive".

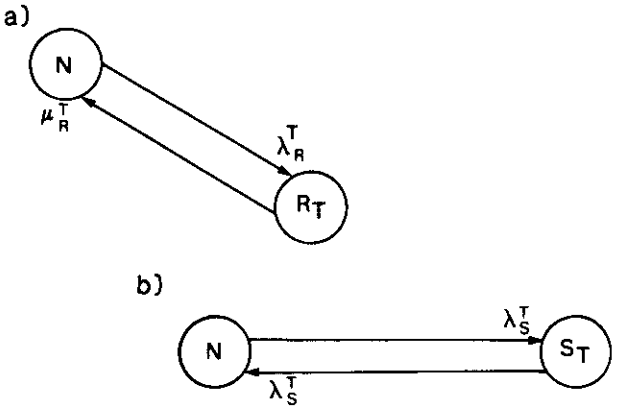


Figure II.2 - Models for false operation

False breaker operation: Not all component faults are followed by the above routine involving switching. For example, open circuits and, above all, false breaker operation can still be described by a two-state model. Figure II.2a shows one example of such an event, where

N = normal condition

$R_T$ = temporary repair condition

$\lambda^T_R$ = normal condition to temporary-repair condition rate

$\mu^T_R$ = restoration rate from temporary repair condition

The state probabilities are now given by the following equations:

$$P_N = \frac{\mu^T_R}{\mu^T_R + \lambda^T_R} \qquad P_{RT} = \frac{\lambda^T_R}{\mu^T_R + \lambda^T_R}$$

Note that temporary repair rates are generally different from those of normal repair.

Other types of false operation: Inadvertent operation does not always induce the outage of a single component but may involve (e.g. as in a protection system fault) several components and appear as temporary switching. In this case, too, the model is a two-state one, as in Fig. II.2b, where

N = normal condition

$S_T$ = temporary switching condition (this is not switching proper, because it is due to false operation)

$\lambda^T_S$ = temporary switching rate

$\mu^T_S$ = restoration rate

The associated state probabilities are:

$$P_N = \frac{\mu^T_S}{\mu^T_S + \lambda^T_S} \qquad P_{ST} = \frac{\lambda^T_S}{\mu^T_S + \lambda^T_S}$$

Events of this kind, even if rare, are very important in that they can seriously impair system stability.

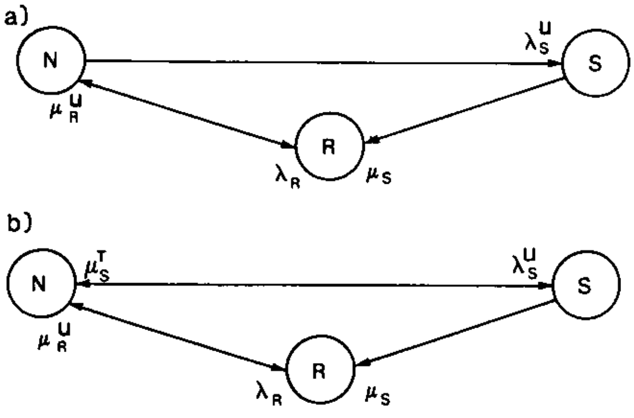


Figure II.3 - Unified models

A possible unified model is shown in Fig. II.3b, where no distinction is made between temporary repair state and repair state and, similarly, every type of switching is encompassed in state S.

Obviously,

$$\lambda_S^u = \lambda_S + \lambda_S^T$$

$$\lambda_R = \lambda_R^T$$

$$\mu_R^u = \mu_r + \mu_r^T$$

Note that if temporary switching is neglected, the well-known model in Fig. II.3a can be used. The formula for $\mu^u_R$ is also applicable in this case and reflects the fact that the mean repair times are different for normal and temporary repair. If a single value is used, an equivalent rate is necessary. The following relations apply to the model

$$P_N = \frac{1}{1 + \frac{\lambda^u}{\mu_R^u} + \frac{\lambda_S}{\mu_S}}, \quad P_S = \frac{\lambda_S}{\mu_S} P_N, \quad P_R = \frac{\lambda^u}{\mu_R^u} P_N$$

where $\lambda^u = \lambda_S + \lambda_R$ is the total fault rate of the component. The frequency of occurrence of the various states is

$f_N \approx \lambda^u$, $f_S \approx \lambda_S$, $f_R \approx \lambda^u$.

It should be observed that:

- The frequency and probability of the repair state depend on an "equivalent" rate, which is the sum of the "switching" and "repair" rates.
- The frequency of the "working" state is approximately equal to that of the repair state.

## II.3 DATA REQUIREMENTS

The required data includes:

- topological data describing the functional link between the various components
- statistical data on the unavailability of each type of component, such as:
  - passive failure rate (occ /year)
  - active failure rate (occ /year)
  - maintenance rate (occ /year)
  - stuck-condition probability (%)
  - mean switching duration (h)
  - mean repair duration (h)
  - mean maintenance duration (h)

If the effect of spares is to be studied, the mean replacement time and the number of spares available are also required.

Note that the probability of the stuck-closed condition is generally assumed to be equal to that of the stuck-open condition. However, the use of two different probability values for the two conditions does not introduce any complication.

## II.4 EXAMPLES

### II.4.1 Active and Passive Failures

It is useful at this stage to give an example of differences in the behavior of the system in the case of active and passive failures. Figures II.4 and II.5 show the effects of the two types of failure. In both cases, it is the same disconnecting switch that fails. Figure II.4 shows the effects of a false opening, resulting in a passive failure, while Fig. II.5 illustrates the effects of a failure-to-ground of the disconnecting switch, resulting in an active failure. It is clear that the active failure represents a much more severe condition for the system.

### II.4.2 Detailed Comparison of Two Substation Layouts

This example describes a reliability study that compares a substation with a one-and-half-breaker layout and a substation with a double-interconnected-ring layout. Since the reliability value of these layouts depends on the number of substation terminals, it was decided to refer to a situation where the number of terminals was sufficiently high to justify the double-ring layout. A layout with eight terminals was selected (see Figs. II.6 and II.7) where the power flow was assumed to be unidirectional, with four input and four output terminals [3].

The statistical data used is given in Table II.1, which indicates the availability of a spare breaker and a spare disconnecting switch but no spare bus. To account for possible uncertainties in the input data, the computations were repeated, varying the passive and active breaker failure rates. This helps to assess the system's sensitivity to this parametric variation.

The following cases were examined:

- one-and-a-half-breaker layout without spares
- double-interconnected-ring layout without spares
- one-and-a-half-breaker layout, with spares for breakers and disconnecting switches

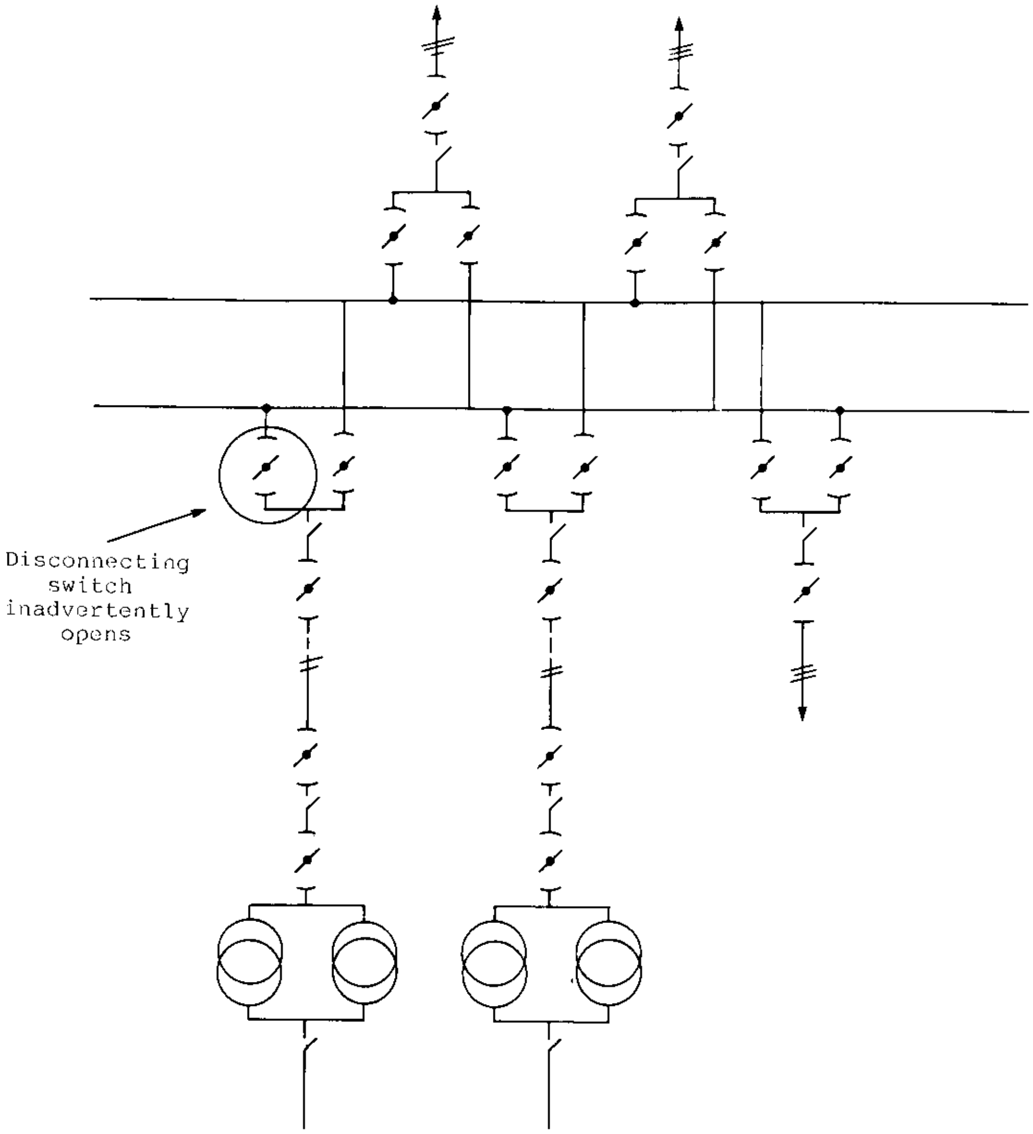


Figure II.4 - Example of passive failure

Table II.1

Statistical data used in the double-interconnected-ring and one-and-a-half-breaker layouts

| Component | Rate (occ./year) | | | Stuck-breaker probability | Mean duration (h) | | | | Number of spares |
|---|---|---|---|---|---|---|---|---|---|
| | Active failure | Passive failure | Maintenance | | Active failure | Passive failure | Maintenance | Replacement | |
| Breaker | 0.1100 | 0.1000 | 0.25 | 0.001 | 3.00 | 50.00 | 70.00 | 10.00 | 1 |
| Disconnector | 0.0010 | 0.0010 | 0 | 0 | 2.00 | 15.00 | 0 | 4.00 | 1 |
| Bus | 0.0060 | 0.0050 | 0 | 0 | 2.00 | 30.00 | 0 | 0 | 0 |

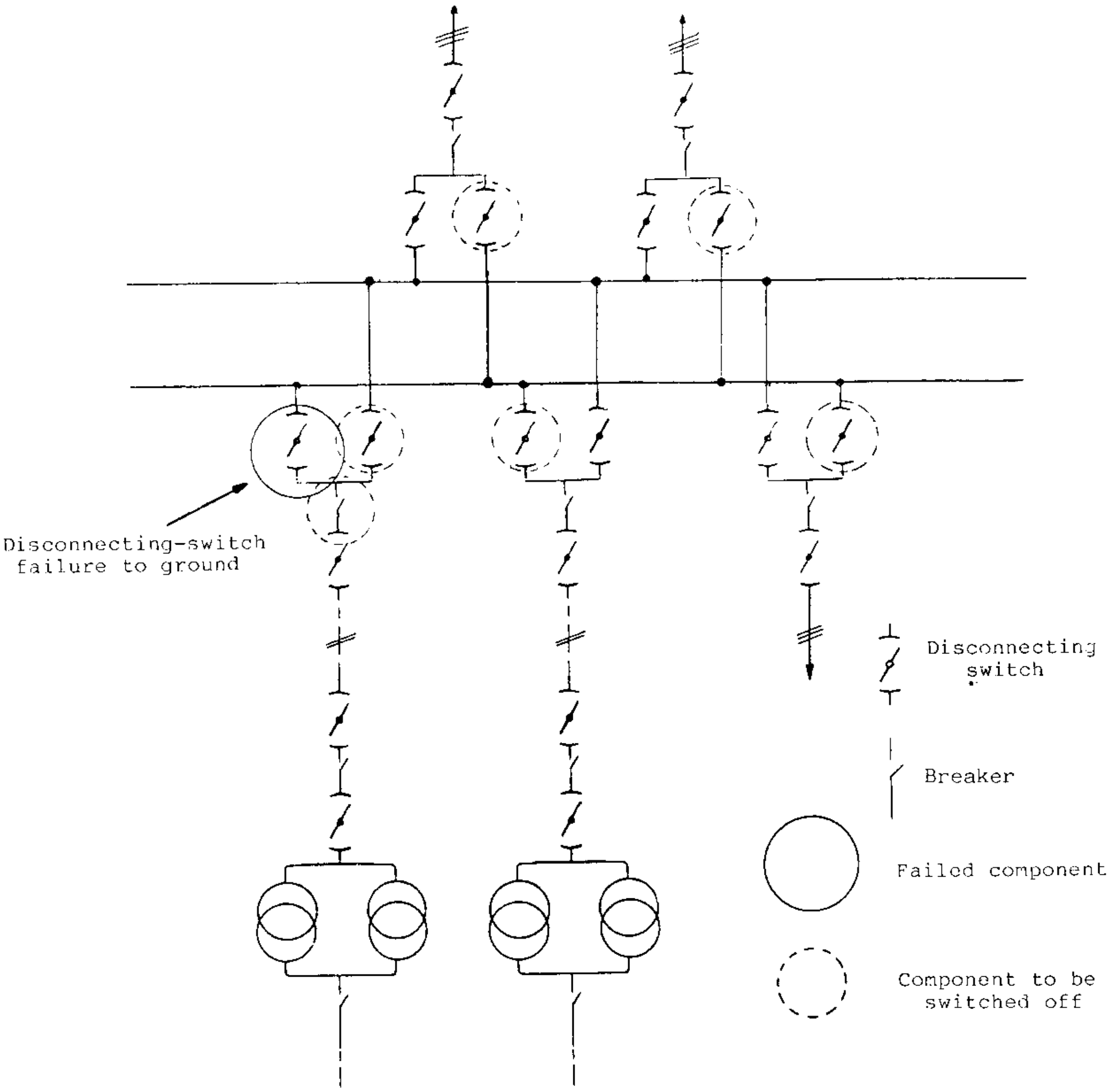


Figure II.5 - Example of active failure

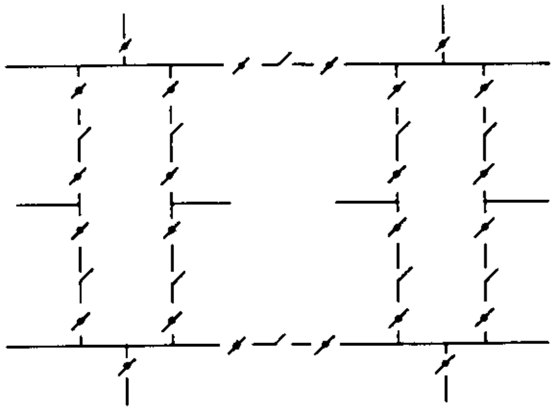


Figure II.6 - Double-interconnected-ring layout

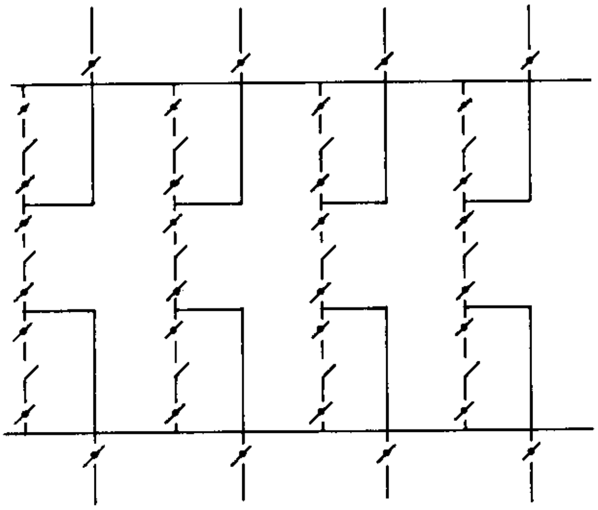


Figure II.7 - One-and-a-half-breaker layout

- double-interconnected-ring layout, with spares for breakers and disconnecting switches.

These reference cases were repeated by varying the passive and active breaker failure rates. The rates were assumed to be 20% of their initial value.

Since the substation was studied with no indication as to the system configuration for which it was intended, the probabilities of all "derated" operating conditions were computed, from the loss of one terminal to global failure with the loss of all connections between terminals. This approach required ten success conditions to be considered because only 10 of the 16 possible combinations (4 inputs x 4 outputs) had different reliability values. This is due to the symmetry of the layout, which has the same reliability if inputs and outputs are interchanged.

The results obtained were used to prepare Tables II.2 to II.6, where Table II.2 refers to the success condition that calls for all the terminals to be in operation and Table II.3 to a success condition that requires all four inputs and at least three outputs to be available; subsequent tables refer to increasingly "tolerant" success conditions.

Table II.2 - At least 4 input terminals and at least 4 output terminals to be in operation for success

| Layout | Spares | Reduced breaker failure-rates | Unavailability (h/yr) | Frequency (1/yr) | Mean duration (h) | % Contribution of components | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | Breakers | Disconnectors | Buses |
| Ring | No | No | 0.76 | 0.03862 | 19.60 | 9.67 | 11.18 | 79.24 |
| 1½ breaker | No | No | 0.33 | 0.03066 | 10.85 | 54.31 | 46.25 | 1.42 |
| Ring | Yes | No | 0.66 | 0.03862 | 17.18 | 3.53 | 6.06 | 90.44 |
| 1½ breaker | Yes | No | 0.12 | 0.03066 | 4.05 | 48.51 | 52.09 | 3.15 |
| Ring | No | Yes | 0.70 | 0.03647 | 19.11 | 1.83 | 12.13 | 86.11 |
| 1½ breaker | No | Yes | 0.19 | 0.02540 | 7.34 | 18.47 | 82.32 | 1.95 |
| Ring | Yes | Yes | 0.64 | 0.03647 | 17.66 | 0.60 | 6.24 | 93.18 |
| 1½ breaker | Yes | Yes | 0.08 | 0.02540 | 3.03 | 16.88 | 83.89 | 4.51 |

Table II.3 - At least 4 input terminals and at least 3 output terminals to be in operation for success

| Layout | Spares | Reduced breaker failure-rates | Unavailability (h/yr) | Frequency (1/yr) | Mean duration (h) | % Contribution of components | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | Breakers | Disconnectors | Buses |
| Ring | No | No | 0.70 | 0.03652 | 19.13 | 2.10 | 12.04 | 85.88 |
| 1½ breaker | No | No | 0.20 | 0.01646 | 11.95 | 61.39 | 39.25 | 1.80 |
| Ring | Yes | No | 0.64 | 0.03652 | 17.65 | 0.73 | 6.21 | 93.07 |
| 1½ breaker | Yes | No | 0.07 | 0.01648 | 4.40 | 55.90 | 44.84 | 4.04 |
| Ring | No | Yes | 0.69 | 0.03609 | 19.02 | 0.37 | 12.25 | 87.39 |
| 1½ breaker | No | Yes | 0.10 | 0.01296 | 7.66 | 23.46 | 77.56 | 2.75 |
| Ring | Yes | Yes | 0.64 | 0.03609 | 17.75 | 0.12 | 6.25 | 93.64 |
| 1½ breaker | Yes | Yes | 0.04 | 0.01296 | 3.16 | 21.92 | 79.12 | 6.35 |

Table II.4 - At least 4 input terminals and at least 2 output terminals to be in operation for success

| Layout | Spares | Reduced breaker failure-rates | Unavailability (h/yr) | Frequency (1/yr) | Mean duration (h) | % Contribution of components | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | Breakers | Disconnectors | Buses |
| Ring | No | No | 0.68 | 0.03600 | 19.00 | 0.0 | 12.28 | 87.72 |
| 1½ breaker | No | No | 0.20 | 0.01648 | 11.95 | 61.39 | 39.25 | 1.80 |
| Ring | Yes | No | 0.64 | 0.03600 | 17.78 | 0.0 | 6.25 | 93.75 |
| 1½ breaker | Yes | No | 0.07 | 0.01648 | 4.40 | 55.90 | 44.84 | 4.04 |
| Ring | No | Yes | 0.68 | 0.03600 | 19.00 | 0.0 | 12.28 | 87.72 |
| 1½ breaker | No | Yes | 0.10 | 0.01296 | 7.66 | 23.46 | 77.56 | 2.75 |
| Ring | Yes | Yes | 0.64 | 0.03600 | 17.78 | 0.0 | 6.25 | 93.75 |
| 1½ breaker | Yes | Yes | 0.04 | 0.01296 | 3.16 | 21.92 | 79.12 | 6.35 |

Table II.5 - At least 4 input terminals and at least 1 output terminal to be in operation for success

| Layout | Spares | Reduced breaker failure-rates | Unavailability (h/yr) | Frequency (1/yr) | Mean duration (h) | % Contribution of components | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | Breakers | Disconnectors | Buses |
| Ring | No | No | 0.68 | 0.03600 | 19.00 | 0.0 | 12.28 | 87.72 |
| 1½ breaker | No | No | 0.14 | 0.01421 | 9.56 | 44.05 | 56.41 | 0.87 |
| Ring | Yes | No | 0.64 | 0.03600 | 17.78 | 0.0 | 6.25 | 93.75 |
| 1½ breaker | Yes | No | 0.05 | 0.01421 | 3.64 | 38.22 | 62.30 | 1.89 |
| Ring | No | Yes | 0.68 | 0.03600 | 19.00 | 0.0 | 12.28 | 87.72 |
| 1½ breaker | No | Yes | 0.09 | 0.01246 | 7.00 | 12.84 | 87.74 | 1.04 |
| Ring | Yes | Yes | 0.64 | 0.03600 | 17.78 | 0.0 | 6.25 | 93.75 |
| 1½ breaker | Yes | Yes | 0.04 | 0.01246 | 2.89 | 11.26 | 89.34 | 2.41 |

Table II.6 - At least 3 input terminals and at least 3 output terminals to be in operation for success

| Layout | Spares | Reduced breaker failure-rates | Unavailability (h/yr) | Frequency (1/yr) | Mean duration (h) | % Contribution of components | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | Breakers | Disconnectors | Buses |
| Ring | No | No | 0.02 | 0.00062 | 25.78 | 99.86 | 1.26 | 7.56 |
| 1½ breaker | No | No | 0.0 | 0.0 | 7.34 | 0.0 | 22.52 | 85.74 |
| Ring | Yes | No | 0.01 | 0.00062 | 9.30 | 99.68 | 1.85 | 17.34 |
| 1½ breaker | Yes | No | 0.0 | 0.0 | 7.02 | 0.0 | 19.01 | 89.63 |
| Ring | No | Yes | 0.0 | 0.00016 | 21.40 | 99.38 | 4.61 | 26.31 |
| 1½ breaker | No | Yes | 0.0 | 0.0 | 7.34 | 0.0 | 22.52 | 85.74 |
| Ring | Yes | Yes | 0.0 | 0.00016 | 10.38 | 98.92 | 5.03 | 51.64 |
| 1½ breaker | Yes | Yes | 0.0 | 0.0 | 7.02 | 0.0 | 19.01 | 89.63 |

Only the first five tables are discussed since the remaining cases offer little interest, the system then being so reliable that its availability is practically 100%.

For a well-defined success condition, each table compares the performance of the ring layout and the one-and-a-half-breaker layout. It gives the annual hours of unavailability, annual failure frequency and duration (in hours) and, also, the percentage contribution to the total unavailability of each type of component.

Tables II.2 to II.6, which actually refer to the most stringent success conditions, show unavailability results that are significantly different from zero. The one-and-a-half breaker layout always has a higher reliability than the other, even if a double-ring case with spares is compared with a one-and-a-half-breaker case without spares. The same remains true for this scenario even if the breaker unavailability in the double-ring case is reduced to 20%.

Adding a spare in the double-ring alternative reduces the difference in the number of breakers between the two layouts to a single unit. The results for reduced breaker failure rates in the double-ring case reflect the fact that there is little to be gained by installing more reliable and, therefore, more expensive breakers in this case. This is explained by the relatively low contribution of the breakers to the total unavailability of the double-ring layout.

## REFERENCES

[1] J. Endrenyi, P.C. Maenhaut and L.E. Payne, "Reliability Evaluation of Transmission Systems with Switching After Faults - Approximations and Computer Program," IEEE Trans. PAS-92, No. 6, pp. 1863-1875, 1973.

[2] J. Endrenyi, Reliability Modeling in Electric Power Systems, J. Wiley & Sons (Chichester), 1978.

[3] C. Camensig, C. Freda and S. Scalcino, "Un metodo automatico per il calcolo dell'affidabilità di un impianto elettrico," L'Energia Elettrica, February 1984.

[4] C. Camensig and S. Scalcino, "Direct Probabilistic Approach to Evaluate Reliability of Complex Electric Equipment or of Parts of the Power Transmission System," PSCC Meeting, paper 276, Lisbon, 1987.

[5] R. Billinton and R.N. Allan, Reliability Evaluation of Engineering Systems: Concepts and Techniques, Longmans (London, England)/Plenum Publishing, (New York, USA), 1984.

[6] R. Billinton and R.N. Allan, Reliability Evaluation of Power Systems, Longmans (London, England)/Plenum Press (New York, USA), 1984.

[7] C. Camensig and S. Scalcino, "Effect of Selection of Substation Layout on Transmission System Reliability," Proceedings of Sixth CEPSI Meeting, Vol. 4, paper 4.12, Jakarta, 1986.

# APPENDIX III

# TERMINOLOGY

## TASK FORCE

R.J. Ringlee (Chairman)
R. Billinton
J. Endrenyi
P.T. Manning
J. Mastrocola
L. Salvaderi
W. Wellssow

Contributing members:

R.N. Allan
P. Albrecht
M.P. Bhavaraju
C.R. Heising
M. Hue
M.G. Lauby

## INTRODUCTION

The objective in selecting the terms and definitions presented in this appendix has been to form an internally consistent and sufficient set to permit the description of power system reliability and allow quantification of system reliability in terms of classes of system failures. It therefore includes the appropriate indices for the measurement and prediction of power system reliability.

It is important to present some of the arguments that were considered in the selection process:

- Reliability evaluation of generation and transmission systems addresses the second level of a hierarchy of reliability assessment in which the first level concerns the generation system; the second, generation and transmission; and the third level, generation, transmission and distribution. Most of the terms included in the present document are related to Level II, although some are generic and can also be used in Levels I and III. Specific terms pertaining to distribution and protection are given in the supplements to this appendix.
- In order to be able to describe adequately and completely the reliability of power systems, it is essential to associate reliability terminology with terms and definitions of such systems and their constituent parts. This is why some not strictly power system reliability terms are included.
- Where more than one definition was available, only one per term has been retained. Explanatory notes, diagrams and examples are added to clarify the definitions, whenever needed.
- An effort has been made to harmonize the terms and definitions with those in IEC documents, (Chapter 191 of the International Electrotechnical Vocabulary is dedicated to terminology in the fields of reliability, availability, maintainability, and quality of service).

This compilation of terms has been formed from the research of CIGRÉ TF 38.03.01 members. Sources include technical documents and standards pertaining to power system reliability.

The terms have been classified as follows :

0 - Reliability Concepts and Techniques
1 - System and Network Constituent Parts
2 - Connectivity
3 - States and Occurrences
4 - Disturbances, Faults and Failures
5 - Bulk Power System Fault Modes
6 - Bulk Power System Failure and Deficiency Attributes
7 - Rates
8 - Duration
9 - Exposure
10 - Performance Concepts
11 - Generic Performance Indices
12 - Selected Specific Performance Indices

The terms in the introductory section on reliability concepts and techniques are used to describe power system reliability in a qualitative sense only. For quantitative descriptions, readers are referred to the succeeding sections. Terms related to protective relay systems and customer reliability indices are given in supplements A and B.

## 0-0 RELIABILITY CONCEPTS AND TECHNIQUES

### 0-01 RELIABILITY

A measure of the ability of a bulk power system to deliver electricity to all points of utilization within accepted standards and in the amount desired.

Note 1: In many applications this generic concept is quantified by expressing the ability by the probability of the same.

Note 2: Bulk power system reliability may be analysed in terms of the static and dynamic aspects of bulk power system performance.

### 0-02 ADEQUACY

A measure of the ability of a bulk power system to supply the aggregate electric power and energy requirements of the customers within component ratings and voltage limits, taking into account scheduled and unscheduled outages of system components and the operating (security) constraints imposed by operations.

### 0-03 SECURITY (OF A BULK POWER SYSTEM)

A measure of the ability of a bulk power system to withstand specified sudden disturbances such as electric short circuits or unanticipated loss of system components.

### 0-04 INTEGRITY

The ability of a bulk power system to preserve interconnected operation.

### 0-05 STRATEGIC CONSTRAINTS

The social, geographical, environmental, financial and political requirements and limitations to be satisfied in the the production, transmission and delivery of electric energy.

### 0-10 RELIABILITY PREDICTION

1) The process of calculation used to obtain predicted values of reliability indices.

2) The predicted value of a reliability index.

### 0-11 RELIABILITY MODEL

A mathematical model used for prediction or estimation of reliability indices for items or systems.

### 0-12 FAULT MODES AND EFFECTS ANALYSIS

A qualitative method of reliability analysis which involves the study of the fault modes that can exist in every component and the determination of the effects of each fault mode on the functions of other components and on the required functions of the unit, substation or bulk power system.

### 0-13 FAULT MODES, EFFECTS AND CRITICALITY ANALYSIS

Fault modes and effects analysis together with a consideration of the probability of occurrence and a ranking of the seriousness of each fault.

## 1-0 SYSTEM AND NETWORK CONSTITUENT PARTS

### 1-01 SYSTEM

A group of components connected or associated in a fixed configuration to perform a specified function.

### 1-02 POWER SYSTEM

A group of one or more generating sources, substations and connecting transmission and distribution lines operated under common management or supervision to supply load.

### 1-03 BULK POWER SYSTEM

That portion of the power system comprising the generation and transmission facilities used for the production and transfer of electric energy.

Note 1: A fully equivalent term in use is BULK ELECTRICITY SYSTEM.

Note 2: The extent of the bulk power system is usually limited to the means for production and transmission of electric energy to major industrial and distribution centres.

### 1-04 TRANSMISSION SYSTEM

The aggregate of all the power transmission facilities operated under common management or supervision to transfer and/or distribute electric energy.

### 1-05 GENERATING SYSTEM

The aggregate of all the generating units operated or dispatched under common management or supervision to generate electric energy.

### 1-10 NETWORK

A grouping of lines and other electrical equipment connected for the purpose of conveying electricity from generating stations to the customer.

Note 1: The extent of the network may be restricted by factors other than the electrical grouping of lines or equipment; for instance, there may be limitations to a specified geographical area, a voltage, a type of equipment, a utility's property, or to a function of the link between the production and consumption of electricity.

Note 2: The term network may be used to indicate the transmission system or a specific area of the transmission system.

### 1-11 AREA

A term used to denote a specific portion of a bulk power system.

### 1-12 COMPONENT

An item which performs a major operating function and which is regarded as an entity for purposes of outage data analysis and reliability modeling (see Fig. III.2).

Note: Components may be divided into two general classes: major and auxiliary. For purposes of recording outage data, auxiliary components are included with the item of equipment or major component of which they are a part.

### 1-13 ITEM

A part, device, subsystem, functional unit, equipment or system that is considered as a whole in a given application.

Note 1: An item may consist of hardware, software or both, and in the case of systems may also include people.

Note 2: The term is also used to denote a number of items, population of items, or sample, wherever this use is justified.

### 1-14 UNIT

A group of components which are functionally related and regarded as an entity for purposes of recording and analysing data on outages (see Fig. III.1).

Note 1: A unit may be defined in several alternative ways, for example:

i) A group of components that constitute an operating entity bounded by automatic fault-interrupting devices that isolate it from other entities for faults on any component within the group.

ii) The components within a sensing zone of a particular system of protective relays, e.g. a transformer and associated terminal facilities switched with it.

iii) Two or more units grouped for the purpose of reporting data, one (the supplying unit) being the only path by which the remaining (supplied) units are interconnected to the system.

Note 2: The components included within a unit are often protected by a common primary protective-relay scheme. For example, a unit might consist of an overhead line and the terminal equipment switched with the line by circuit breakers during normal fault-clearing operations.

Note 3: A unit may be single-terminal, two-terminal, or multi-terminal (i.e. connected to three or more terminals).

Note 4: It should be recognized that certain components (e.g. circuit breakers) may be part of more than one unit.

Note 5: Types include transmission units (overhead or cable), transformer units, bus units, and special units consisting of equipment such as shunt capacitors or static var devices protected by separate breakers.

### 1-15 LINE

A unit or units of a transmission system extending between adjacent stations or from a station to an adjacent interconnection point.

Note: A line may consist of one or more circuits.

### 1-16 CIRCUIT

A unit of a transmission line.

Note: A circuit breaker (or fuse) is always the boundary point between two adjacent circuits and must be regarded as a constituent part of the circuits.

### 1-17 SEGMENT

A portion of a line section that has a particular type of construction or is exposed to a particular type of failure, and therefore may be regarded as a separate entity for the purpose of reporting and analysing failure and exposure data.

### 1-18 LINE SECTION

That portion of a transmission unit bounded by two terminations and/or line-taps (see Fig. III.2).

### 1-19 LINE-TAP

A point on the multi-terminal transmission unit where portions leading, directly or indirectly, to three or more terminals are joined (see Fig. III.2).

### 1-20 TERMINAL

A functional facility (substation, generating station or load centre) which includes components such as bus sections, circuit breakers and protection systems, where transmission units terminate (see Fig. III.1).

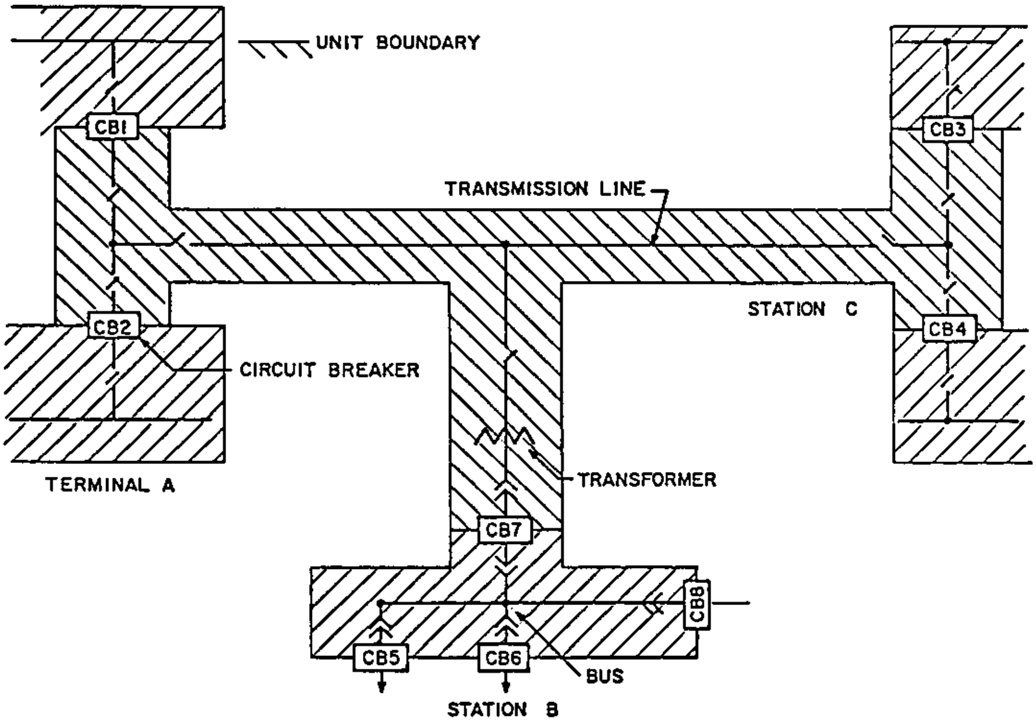


Figure III.1 - Examples of transmission units

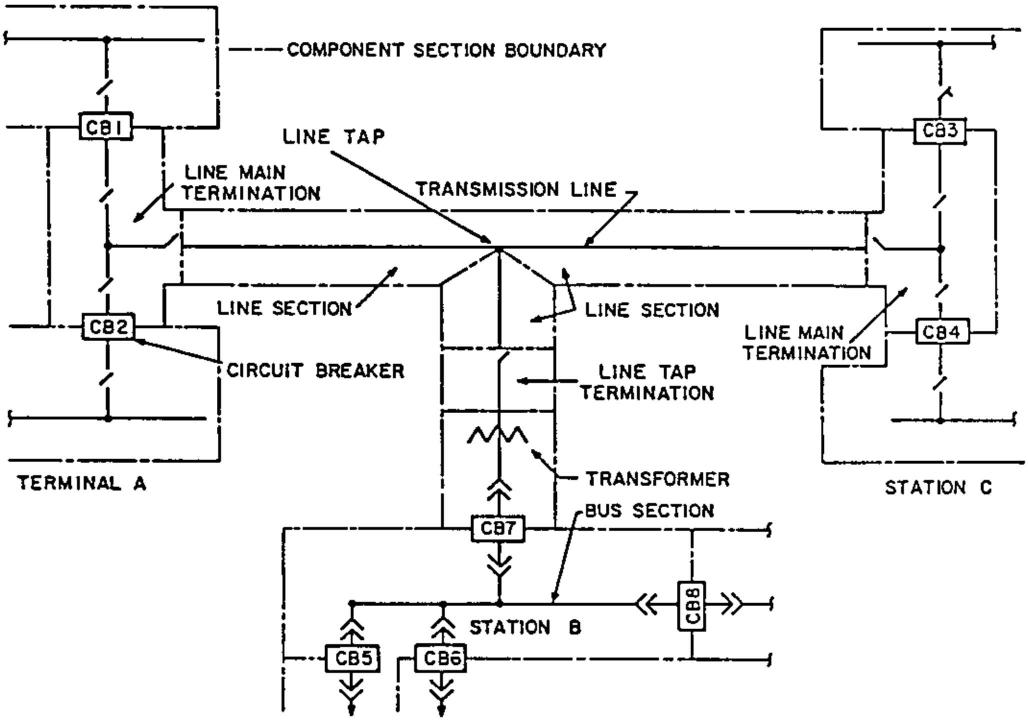


Figure III.2 - Examples of transmission components

1-21 SUBSTATION

A group of equipment containing switches, circuit breakers, buses, transformers, and voltage control equipment for switching power circuits, voltage control and transforming power from one voltage to another or from one system to another.

Note: A substation layout is a plan or sketch which illustrates the electrical connections of the substation equipment.

1-22 TERMINATION

The components within a terminal that are switched with a specific unit, such as surge protective devices, voltage transformers, potential devices, strain insulators, coupling capacitors, etc. (see Fig. III.2).

1-23 BUS

A conductor or group of conductors that serves as a common connection for two or more electric circuits within a station.

1-24 NODE

A terminal of any branch of a network or terminal common to two or more branches of a network.

1-25 SPARE (COMPONENT OR EQUIPMENT)

Component or equipment, complete or in parts, on hand for repair or replacement.

Note: To estimate the time for placing the spare component or equipment into service, consideration must be given to the time to move the spare to the site and remove the failed component as well as to the installation, conditioning and startup tests required to make the spare ready for service.

1-30 INTERCONNECTION

An interface point between two power systems.

1-31 DELIVERY POINT

An interface point between a bulk power system and a purchaser of energy.

Note 1: The purchaser may be an end user or an organization for the distribution of energy to consumers.

Note 2: For bulk electricity systems, the delivery point is the interface point between the bulk electricity system and the distribution electricity system.

1-32 LOAD POINT

A point of load aggregation in a network model of a bulk power system.

Note 1: A load point is a point within a bulk power system that is selected as an interface to limit the extent of the bulk power system model and to aggregate loads.

Note 2: Preferred interfaces for load points are points at which network power flow is directly associated with loads and independent of system dispatch. Examples of preferred interfaces would be points of first-contingency separation of load from the transmission system. These points would include substations at which radial connections are made to subtransmission or distribution systems.

2-0 CONNECTIVITY

2-01 CONNECTED NETWORK

A network in which all buses or terminals are connected by lines or transformers forming at least one tree.

Note: A tree is a set of connected branches including no meshes (elementary topology).

2-02 SEPARATION

The event of isolation of a portion of the bulk power system.

Note: A synonym is SYSTEM SPLITTING.

2-03 ISLAND

A portion of a power system, or a number of power systems, that has become disconnected from the rest of the bulk power system.

Note: Other terms often used are SPLIT SYSTEM(S) or SPLIT SUBSYSTEM(S).

2-04 TRANSMISSION INTERRUPTION

Cessation of power supply to a delivery point caused by an outage.

2-05 SUPPLY INTERRUPTION

The cessation of power supply to a customer or customers caused by an outage.

Note: Outages may or may not result in a supply interruption.

## 3-0 STATES AND OCCURRENCES

### 3-01 COMPONENT AND UNIT STATES

### 3-01-1 STATE

The way in which a set of attributes stands disposed at a particular time.

Note: The state of a component at a particular time is described by that attribute, within the set defined by a given model, which best indicates the condition of the component. The most elementary operational model would be described by two states: operational and non operational.

### 3-01-2 AVAILABLE STATE

The condition of an item, component or unit being able to perform any one of its required functions.

### 3-01-3 IN-SERVICE STATE

The component or unit is available, energized and connected to the system.

Note: Components such as circuit breakers may be in service and not transmitting power when this is the desired objective for operational purposes.

### 3-01-4 RESERVE SHUTDOWN

The condition in which the unit or component is removed from but kept ready for service.

Note: The term OPERATIONS-RELATED SHUTDOWN is fully equivalent.

### 3-01-5 PARTIAL OUTAGE

A component or unit partially energized but not fully connected to all its terminals so that it is not serving some of its functions within the power system.

Note: A unit composed of a three-terminal line would be in a partial-outage state if it is disconnected from one terminal but two line sections are connected and capable of carrying power.

### 3-01-6 DERATED STATE

A unit or component that may be placed in service and that can perform its intended functions but which is not able to sustain rated capability.

Note: The amount of derating is the measure of the shortfall between actual capability and rated capability.

### 3-01-7 OUTAGE

The state of an item, component or unit characterized by its inability to perform a required function, for any event.

Note 1: An outage may or may not cause an interruption of service to customers, depending on the system configuration.

Note 2: A unit or component may not be capable of performing its required function due to external restrictions, testing, work being performed, or some adverse condition.

Note 3: The outage state is referred to as the unavailable state.

### 3-01-8 PLANNED OUTAGE

A manual outage for the purpose of inspection, testing or overhaul.

Note: A planned outage is scheduled well in advance.

### 3-01-9 UNPLANNED OUTAGE

Any outage that is not a planned outage.

### 3-01-10 FORCED OUTAGE

An automatic outage or a manual outage that cannot be deferred.

Note: A more complete definition of "cannot be deferred" is often needed when collecting outage data in order to obtain consistency in reporting.

### 3-01-11 DEFERRABLE UNPLANNED OUTAGE

An unplanned outage that may be deferred to accommodate switching and/or transfer of load.

Note: An emergency that requires the outage of a line by manual actions would be a deferrable unplanned outage.

### 3-01-12 TRANSIENT OUTAGE

A forced outage whose cause is self-clearing so that the affected unit is restored to service automatically by a recloser or circuit breaker.

Note 1: An example of a transient outage is the outcome from a lightning flashover successfully interrupted and followed by successful automatic reclosing.

Note 2: A necessary condition for the occurrence of transient outages is that the unit be equipped with automatic reclosing.

### 3-01-13 TEMPORARY OUTAGE

A forced outage whose cause is self-clearing so that the affected unit is restored to service by manually reclosing a switch or circuit breaker.

### 3-01-14 PERMANENT OUTAGE

A forced outage whose cause must be corrected by eliminating the hazard or by repairing or replacing the affected item before the unit can be returned to service.

Note: An example of a permanent outage is the outcome from a lightning flashover which shatters an insulator and disables the item until repair or replacement can be made.

### 3-01-15 SUSTAINED OUTAGE

Any forced outage which is not a transient outage (see Fig. III.3).

Note: This is the sum of the permanent and temporary outages.

### 3-02-3 SECURE STATE

A state in which the power system is capable of withstanding one in a specific class of events.

Note 1: Successful withstand implies network accommodation of the event without violating specified voltage and longterm loading limits.

Note 2: The class of events may be a set of defined contingencies (deterministic approach) or the set of contingencies whose likelihood of occurrence is above a specific threshold (probabilistic approach).

### 3-02-4 ALERT STATE

A state in which the power system is incapable of withstanding one in a specific class of events.

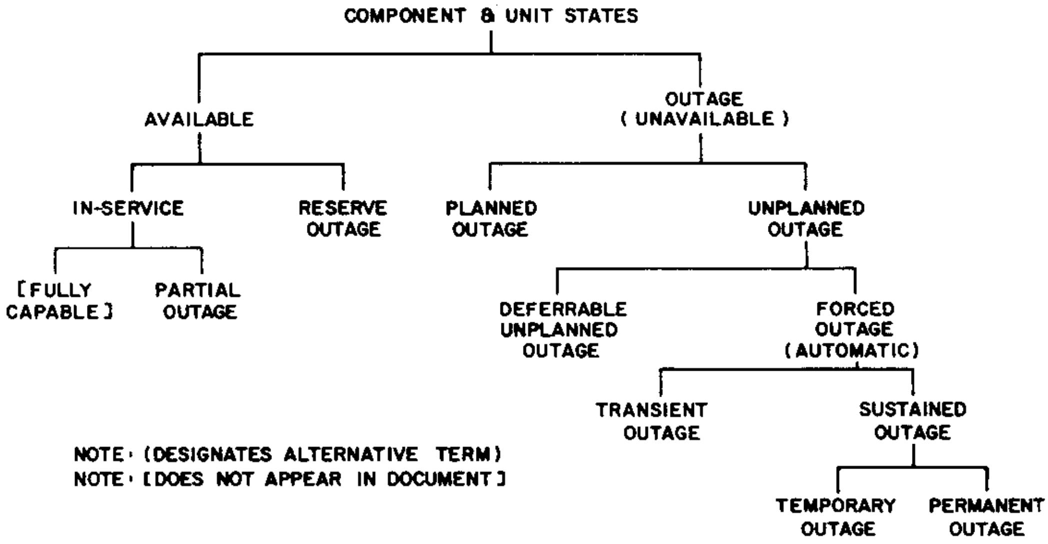


Figure III-3 - Component and unit state tree

## 3-02 POWER SYSTEM STATES

### 3-02-1 POWER SYSTEM STATE

The way in which a set of power system attributes stands disposed at a particular time.

Note 1: The power system state may, by synthesis, be described as a state compounded from the state of its constituent units and of other relevant attributes.

Note 2: The power system state may, by analysis, be described by a set of attributes which convey its operational capability and margin to failure.

### 3-02-2 CONTINGENCY STATE

A system state where, owing to failures, one or more of the system's components are not, or not fully, available.

Note 1: Unsuccessful withstand: violation of specified voltage limits or component short-term loading limits, or instability.

Note 2: The class of events may be a set of defined contingencies (deterministic approach) or the set of contingencies whose likelihood of occurrence is above a specified threshold (probabilistic approach).

### 3-02-5 EMERGENCY STATE

A state in which the system is unable to satisfy all customers with electric power of frequency and voltage within specified limits.

Note 1: An emergency is considered to exist in an area if firm load may have to be shed or reduced by voltage reduction.

### A-08 DEPENDABILITY (OF A PROTECTION SYSTEM)

The probability that a protection system will operate to successfully clear a fault or overload on the power system.

Note: The protection system can operate to successfully clear the fault or overload and may also have a backup protection system operate incorrectly.

## SUPPLEMENT B

## SELECTED CUSTOMER-INTERRUPTION INDICES

### B-01 SYSTEM AVERAGE INTERRUPTION FREQUENCY INDEX (SAIFI)

The average number of interruptions per customer served per time unit.

Note: SAIFI is determined by dividing the accumulated number of customer interruptions in a year by the number of customers served. Both momentary and sustained interruptions can be used for this purpose but utilities customarily select the latter.

### B-02 SYSTEM AVERAGE INTERRUPTION DURATION INDEX (SAIDI)

The average interruption duration for customers served during a year.

Note: SAIDI is determined by dividing the sum of all sustained-interruption durations during the year by the number of customers served.

### B-03 CUSTOMER AVERAGE INTERRUPTION FREQUENCY INDEX (CAIFI)

The average number of interruptions experienced per customer affected per time unit.

Note 1: CAIFI is determined by dividing the number of sustained interruptions observed in a year by the number of customers affected.

Note 2: Each customer affected must be counted only once, regardless of the number of interruptions that customer may have experienced during the year.

### B-04 CUSTOMER AVERAGE INTERRUPTION DURATION INDEX (CAIDI)

The interruption duration for customers interrupted during a year.

Note: CAIDI is determined by dividing the sum of all sustained-interruption durations during the specified period by the number of sustained interruptions during the year.

### B-05 AVERAGE SERVICE AVAILABILITY INDEX (ASAI)

The ratio of the total number of customer hours that service was available during a year to the total customer hours demanded.

Note 1: Customer hours demanded are determined as the 12-month average number of customers served times 8760.

Note 2: The complementary value of this index, i.e. the Average Service Unavailability Index (see B-06) may also be used sometimes.

### B-06 AVERAGE SERVICE UNAVAILABILITY INDEX (ASUI)

This is the complement of the Average Service Availability Index:
ASUI = 1.0 - ASAI.

## BIBLIOGRAPHY

[1] Central Electricity Generating Board, Electricity Supply Industry Definitions of Terms used when Predicting or Measuring Electricity Transmission and Distribution Reliability, Std. 99-3, Issue 1, London, Feb. 1981.

[2] ———, CEGB Fault Recording Scheme, Appendix B, London, 1983.

[3] CIGRE, "Questionnaire on Repair Time for EHV Equipment," prepared by WG 31-02, Paper No. 79/05/13, April 1980.

[4] ———, "Measuring and Reporting Overall Reliability of Bulk Electricity Systems," prepared by W.H. Winter, Paper No. 32-15, 1980.

[5] ———, "Consideration on the Reliability of Power Systems - Coordination of the Activities of CIGRE Study Committee on Reliability," August 1981.

[6] ———, "Disturbance Performance of Bulk Electricity Systems," prepared by W.H. Winter and B. Le Reverend, Paper No. 37/38/39-02, Paris , 1986.

[7] Deutsche Verbundgesellschaft, "Zuverlaessigkeit elektrischer Versorgungssysteme - Definitionen der wichtigsten Begriffe, Arbeitskreis Planungsrechnung," December 1978, Berlin.

[8] Electric Power Research Institute, "Reliability Indexes for Power Systems," Report No. EL 1773, March 1981.

[9] ———, "Bulk Transmission System Component Outage Data Base," Report No. EL 1797, April 1981.

[10] Institute of Electrical and Electronics Engineers, Std. 313-1971 (ANSI C37.90), Standard for Relays and Relay Systems Associated with Electric Power Apparatus, 1971.

### 4-03 FAULT

The inability of an item to perform a required function.

### 4-04 DEFECT

Any departure of a characteristic of an item from requirements.

Note 1: The requirements may or may not be expressed in the form of a specification.

Note 2: A defect may or may not affect the ability of an item to perform a required function.

Note 3: The sum of faults and defects is termed "troubles".

### 4-05 ACTIVE FAILURE

A failure which causes the operation of the primary protection zone around the failed component.

Note: A short circuit such as a faulted insulator or a grounded phase conductor are examples of active failures.

### 4-06 PASSIVE FAILURE

A mode of failure which does not cause operation of circuit breakers or fuses.

Note: The false trip of a circuit breaker would be a passive failure.

### 4-07 LATENT FAULT

A condition in which the occurrence of failure remains undetected until the component or subsystem is called to perform a required function.

Note: Systems that can incur latent faults include protective relaying subsystems, circuit-breaker trip mechanisms, or control systems which could incur non-functioning states.

## 5-0 BULK POWER SYSTEM FAULT MODES

### 5-01 BULK POWER SYSTEM FAULT MODE

A way in which outage of generators and transmission units can result in shutdown of bulk power systems or portions thereof and loss of load.

### 5-02 CASCADING

The sequential forced tripping of transmission units and generators caused by excessive loading of lines sharing the duty of transferring power into or out of an area.

Note: The forced tripping may be either automatic or by manual actions to protect equipment.

### 5-03 VOLTAGE COLLAPSE

Excessive drop in voltages in an area resulting from insufficient reactive supply to buses or to the transmission system.

### 5-04 INSTABILITY

Inability to maintain synchronism or to maintain alternator rotor relative angular positions in a stable condition.

Note 1: Transient instability is the loss of synchronism, due to a large disturbance, of one or more generating units, singly or as a group, with the remainder of the system.

Note 2: Dynamic instability is the lack of damping which results in build-up of repeated power and voltage oscillations in the system, and may or may not lead to loss of synchronism. Under this condition, the derivative of electric power with respect to rotor speed is negative for at least one machine.

Note 3: Steady-state instability is the loss of synchronism between two or more generators or groups of generators resulting from power transfers in excess of the synchronous capability of the transmission network. Under this condition, the derivative of electric power with respect to rotor angle is negative for at least one machine.

### 5-05 UNCONTROLLED SEPARATION

The forced partitioning of an interconnected network into islands due to automatic protection or control action as a consequence of cascading or instability or due to emergency manual action to protect equipment and load.

### 5-06 BUS ISOLATION

Outage of all transmission units connected to a bus.

## 6-0 BULK POWER SYSTEM FAILURE AND DEFICIENCY ATTRIBUTES

### 6-01 LOAD NOT SERVED

The amount of load that was not served due to specified generation and transmission outages.

Note: This is an umbrella term encompassing the interruption of load and curtailment of load through actions of load shedding or reduction.

### 6-02 LOAD INTERRUPTED

The amount of load disconnected as a result of bus isolation or bulk power system shutdown.

### 6-03 LOAD SHED

The amount of customer load disconnected in response to an emergency condition.

### 6-04 LOAD REDUCTION

The amount of a load reduced by voltage reduction in response to an emergency condition.

### 6-20 RESERVE DEFICIENCY

The magnitude of shortfall of reserves caused by specified generation and transmission outages.

### 6-21 CAPACITY RESERVE DEFICIENCY

The magnitude of shortfall of the generating-capacity margin in a specific area caused by generation and transmission outages.

### 6-22 REACTIVE-SUPPLY DEFICIENCY

The magnitude of reactive-supply deficiency at specified buses caused by generation and transmission outages.

### 6-23 DEFICIENCY IN TRANSMISSION TRANSFER CAPABILITY

The magnitude of power transfer deficiency on a specified cut or boundary within the bulk power system for specified generation and transmission outages.

### 6-30 COMPONENT OVERLOAD

A condition wherein in a component is carrying current (load) in excess of its applicable rating.

Note: Current rating may be limited by clearance, strength reduction, aging or thermal runaway.

### 6-40 BUS VOLTAGE LIMIT VIOLATION

Bus voltage outside specified limits or the magnitude of bus voltage change outside specified limits.

Note: Limits on bus voltage may be set in terms of operating limits, equipment limits, admissible voltage excursions.

## 7-0 RATES

### 7-01 FAILURE RATE

The expected number of failures of a given type, per unit of exposure.

Note: An example is capacitor short-circuit failures per capacitor-year.

### 7-02 OUTAGE RATE

For a particular classification of outage and type of item, the expected number of outages per unit of exposure.

Note: Outage rates may be defined for specific weather conditions and types of outage. Permanent-outage rates, for example, may be separated into adverse-weather and normal-weather permanent-outage rates.

### 7-03 TRANSIENT-OUTAGE RATE

The expected number of outages per unit of exposure, successfully restored by high-speed automatic-reclosing devices.

Note: The exposure used for determining the transient-outage rate must be on lines that have automatic reclosing.

### 7-04 TEMPORARY-OUTAGE RATE

The expected number of outages per unit of exposure, successfully restored by manual reclosing.

### 7-05 PERMANENT-OUTAGE RATE

The expected number of outages per unit of exposure, restored by replacement of or repairs to the faulted component.

### 7-06 FORCED-OUTAGE RATE

The expected number of forced outages per unit of exposure.

Note: North American definitions, IEEE/ANSI Std. 762-1987, include this term as a measure of unit generating unavailability due to forced outages. The two concepts are not equivalent.

### 7-07 PLANNED-OUTAGE RATE

The expected number of planned outages per unit of exposure.

## 8-0 DURATION

### 8-00 DURATION

The numerical difference between the time of departure from and time of entry into a state.

Note: RESIDENCE TIME is a fully equivalent term.

### 8-01 FORCED-OUTAGE DURATION

The period of time from the occurrence of a forced outage until the affected component or unit is restored to the available state.

### 8-02 TRANSIENT-OUTAGE DURATION

The period of time required to effect electrical fault clearing and reclosure by automatic means.

### 8-03 TEMPORARY-OUTAGE DURATION

The period of time required to effect electrical fault clearing and for manually operated switching to effect re-energization and restoration.

### 8-04 PERMANENT-OUTAGE DURATION

The period of time required to effect electrical fault clearing and to carry out repairs or replacement and return the unit to the available state.

### 8-20 SWITCHING DURATION

The period of time required to carry out switching operations to effect component isolation and to reconfigure a network usually to effect partial restoration of affected units.

### 8-21 REPLACEMENT DURATION

The period of time required to carry out the removal of an existing item or component and replacement with a spare item or component.

Note: The duration may be subdivided into the period of waiting for the arrival of the replacement component and the period of actual work of replacement.

### 8-30 INTERRUPTION DURATION

The period from the initiation of an interruption to a customer until service has been restored to that customer.

Note 1: Interruptions are classified by duration.

Note 2: Interruption durations may vary among customers affected by the same outages if restoration of service proceeds through a series of partial restoration steps.

### 8-31 MOMENTARY INTERRUPTION

An interruption for which restoration must be completed within a specified time.

Note: A time commonly specified by North American utilities is 5 min or less.

### 8-32 SUSTAINED INTERRUPTION

An interruption not classified as a momentary interruption.

### 8-40 SHUTDOWN DURATION

The period of time from the start of the shutdown state until restoration is completed.

### 8-50 PLANNED-OUTAGE DURATION

The period of time from initiation of the planned outage until the affected components or units are available for service.

## 9-0 EXPOSURE

### 9-01 EXPOSURE

The condition describing the working environment within which equipment or components are subject to a change of state.

Note: Both extent, i.e. time or cycles of operation, and severity, or duty, are necessary parts of the determination of exposure to failure.

### 9-02 WEATHER EXPOSURE

The duty imposed by weather on components installed outdoors.

### 9-03 NORMAL WEATHER

All weather not designated as adverse or major storm disaster.

### 9-04 ADVERSE WEATHER

A weather state which leads to an abnormally high failure rate of exposed components during the periods such conditions persist.

Note 1: Adverse-weather conditions can be defined for a particular system by selecting the proper values and combinations of conditions: thunderstorms, tornados, high winds, unusual rates of precipitation, temperature extremes, etc.

Note 2: SEVERE WEATHER is another term used.

9-05 MAJOR STORM DISASTER

A weather state which exceeds the design limits of lines and plant and which has one or more of the following consequences:

- extensive mechanical damage to plant.
- more than a specified percentage of customers out of service.
- excessive service restoration times.

Note 1: Examples of major storm disasters are hurricanes and major ice storms.

Note 2: The percentage of customers out of service and restoration times typically used by the industry are 10% and 24 h respectively. The percentage of customers out of service may be related to a utility operating area rather than to an entire utility.

Note 3: EXTREME WEATHER is another term used.

9-10 EXPOSURE TIME

The time during which an event of interest can occur.

Note 1: The event can be a failure, an outage, a repair or replacement, or other cause of transit from one state to another.

Note 2: Exposure time is expressed in unit-years.

9-11 EXPOSURE TIME (FOR OUTAGE)

Time during which a unit or component is performing its intended function and is subject to outage.

9-12 EXPOSURE TIME (FOR REPAIR)

Time during which a unit or component is unavailable and awaiting completion of corrective maintenance to return it to an operating condition.

Note: Typically, exposure time for repair is divided into waiting time, i.e. the interval following fault recognition for the arrival of crews, equipment and replacement parts, and working time, i.e. the interval required to complete corrective maintenance.

9-20 EXPOSURE LENGTH

The length of a line section, common structure or common right-of-way which influences the failure rate.

Note: Exposure lengths are expressed in hundreds of kilometres.

9-30 EXPOSURE OPERATIONS

Number of operations during which an item performing its intended function is subject to incorrect operation.

Note 1: In the case of circuit breakers, the exposure operations are expressed as the number of breaker operations for specified duty.

Note 2: In the case of protection equipment and automatic reclosing equipment, the exposure operations are expressed as the number of terminal operations.

10-0 RELIABILITY PERFORMANCE CONCEPTS, ATTRIBUTES AND MEASURES

10-01 PERFORMANCE CONCEPTS

These are the attributes and measures used to describe system performance in terms of both the occurrence of the state of failure and the degree of failure, i.e. severity of failure. Indices are a specific subset of measures used to indicate or describe performance.

10-02 PERFORMANCE ATTRIBUTES

10-02-1 SYSTEM PERFORMANCE STATE

The degree to which a system is able to meet specified criteria and support the functions of providing service to loads and carrying transfers.

Note: System capability may be categorized in terms of secure, alert, emergency, shutdown, and restoration states (see 3-02-3 to 3-02-8).

10-02-2 SYSTEM CONTINGENCY LEVEL

The contingency level that the system can withstand for specified loads and transfers.

10-02-3 SYSTEM PROBLEM

The combination of unit outage states which results in the system performance failing to meet specified criteria. Failure may be defined to include violation of loading or voltage criteria and may include events of separation and isolation of portions of the system.

10-02-4 COMPONENT-OVERLOAD PROBLEM

Violation of a specific component-loading criterion.

Note: Consideration must involve both the loading level and duration.

10-02-5 BUS ABNORMAL-VOLTAGE PROBLEM

Violation of a specific component or bus voltage criterion.

### 10-02-6 SEPARATION PROBLEM

Existence of a separation of portions of the interconnected system regardless of the load and generation affected.

### 10-02-7 BUS ISOLATION PROBLEM

Interruption of service to a bus.

Note: See 5-06.

## 10-03 PERFORMANCE MEASURES

### 10-03-1 SEVERITY OF FAILURE

A measure of the degree of system failure expressed in terms of the actions necessary to correct violations of criteria, including amount and extent of load interrupted or curtailed.

### 10-03-2 INTERRUPTION SEVERITY MEASURE

The unsupplied energy in an event, in MW-min, divided by the annual peak system load, in MW.

Note 1: Severity is expressed in system-minutes, one system-minute being equivalent, in energy, to an interruption of the total system load for 1 min at the time of the annual system peak.

Note 2: The degree of severity is indicated as follows:

D-1: incident with a severity from 1 to 9 system-minutes

D-2: incident with a severity from 10 to 99 system-minutes

D-3: incident with a severity from 100 to 999 system-minutes

### 10-03-3 SYSTEM MARGIN

A measure of system reserve capability to withstand additional fault and outage events or to carry additional load or power transfers without violating component operating limits.

### 10-03-4 SYSTEM LOAD-CARRYING CAPABILITY

A measure of system capability to support a specified generation dispatch and load distribution in the presence of specified fault and outage events and without violating component operating limits.

Note: Load conformity and dispatch basis must be stated to a define unique-load carrying capability for a specified system state.

### 10-03-5 SYSTEM LOAD CURTAILMENT

The amount of system load curtailment resulting from remedial action to relieve an emergency condition in the system.

Note: The term BUS can be used in place of SYSTEM.

### 10-03-6 SYSTEM TRANSFER CAPABILITY

The ability to transfer power between defined areas within the bulk power system under specified disturbance and outage events.

### 10-03-7 FIRST-CONTINGENCY INCREMENTAL TRANSFER CAPABILITY

The amount of power, incremental above normal base power transfers, that can be transferred over the transmission network in a reliable manner, based on the following conditions:

- With all transmission facilities in service, all facility loadings are within normal ratings and all voltages are within normal limits.
- The bulk power system is capable of absorbing dynamic power swings and remaining stable following a disturbance resulting in loss of any single generating unit, transmission circuit or transformer.
- After the dynamic power swings following a disturbance resulting in the loss of any single generating unit, transmission circuit or transformer, but before operator-directed system adjustments are made, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits.

Note 1: A facility is an item, component or unit which performs a major operating function and which is regarded as an entity for establishing ratings.

Note 2: Normal ratings specify the level of power flow that facilities can carry through a series of daily load cycles without loss of life to the facility involved.

Note 3: Emergency ratings specify the level of power flow that a facility can carry for the time sufficient for adjustment of transfer schedules or generation dispatch in an orderly manner with acceptable loss of life to the facility involved.

Note 4: Normal voltage limits define the voltage range that is acceptable on a sustained basis.

Note 5: Emergency voltage limits define the voltage range that is acceptable without serious system consequences, for the time sufficient for system adjustments to be made.

Note 6: Normal base power transfers are the power transfers considered to be a part of normal base system loadings for the condition being analysed. Other transfers, such as emergency power or opportunistic economy energy transfers, are excluded even though they may be provided for in contractual arrangements.

### 10-03-8 SYSTEM TRANSFER CURTAILMENT

A reduction in power transfer or power transfer objective caused by a deficiency in system transfer capability.

## 11.0 GENERIC PERFORMANCE INDICES

Note: Performance indices are always related to some unwanted state or occurrence such as an outage or overload. The concepts can be extended, of course, to any state or occurrence.

### 11-01 RATE

The number of occurrences per unit of exposure time.

### 11-02 FREQUENCY

The number of occurrences per item per unit of period time.

### 11-03 STEADY-STATE PROBABILITY

The proportion of time, in the long run, for which a specified state prevails.

Note : The term INTERVAL PROBABILITY is also used.

### 11-04 AVAILABILITY

Point availability: the probability of a repairable component performing its required function at any arbitrarily selected instant.

Steady-state availability: the proportion of time, in the long run, that a repairable device is in or ready for service, that is, the observed ratio of available time to period time, i.e., the limit of point availability.

### 11-05 UNAVAILABILITY

The complement of availability.

### 11-06 OPERATIONAL FAILURE PROBABILITY

The expected number of failures to operate for a given number of commands to operate.

Note 1: Recognition must be given to the type of operation commanded and the form of the resulting failure. For example, circuit-breaker failures to trip or to open on command should be distinguished from failures to close on command while breaker failures to open should be distinguished from failures to interrupt fault current.

Note 2: The term STUCK BREAKER is used to describe circuit-breaker failure to open on command.

Note 3: The term BREAKER FAILURE is reserved for circuit-breaker failure to interrupt fault current.

Note 4: See Supplement A for additional definitions.

### 11-07 MEAN DURATION

The expected length of the period for which a state prevails.

## 12-0 SELECTED SPECIFIC PERFORMANCE INDICES

### 12-01 LOSS-OF-LOAD INDICES

### 12-01-1 LOSS-OF-LOAD EXPECTATION (LOLE)

The expected number of days in a year when a loss of load occurs.

Note: This term is often used to describe daily peak load calculations.

### 12-01-2 LOSS-OF-LOAD PROBABILITY (LOLP)

At a point in time (or given hour) the probability of load loss due to generation capacity deficiency.

Note: LOLP is calculated by using a continuous load model composed of hourly load entries (and assuming that the load is constant during each hour).

### 12-01-3 LOSS-OF-LOAD FREQUENCY (LOLF)

The frequency of loss of (system, area, bus) load due to outage events in the transmission system.

### 12-02 LOAD INTERRUPTION INDICES (SYSTEM, AREA, BUS)

### 12-02-1 LOAD CURTAILMENT PROBABILITY

The probability of curtailment of (system, area, bus) load due to transmission outage events.

### 12-02-2 DELIVERY POINT MOMENTARY-INTERRUPTION FREQUENCY INDEX

The annual number of momentary interruptions experienced at a delivery point.

### 12-02-3 DELIVERY POINT SUSTAINED-INTERRUPTION FREQUENCY INDEX

The annual number of sustained interruptions experienced at a delivery point.

### 12-02-4 DELIVERY POINT SUSTAINED-INTERRUPTION DURATION INDEX

The annual number of minutes of sustained interruption experienced at a delivery point.

### 12-02-5 BULK ELECTRICITY SYSTEM SUSTAINED-INTERRUPTION DURATION INDEX

The annual number of system-minutes of sustained interruption experienced by a bulk electricity system.

### 12-02-6 BULK POWER INTERRUPTION INDEX (BPII)

The bulk power interruption index is defined as the average number of megawatts of (system, area, bus) load interrupted per megawatt of (system, area, bus) load served.

Note: The BPII is similar in concept to the system average interruption frequency used for customer service reliability analysis. This index is the ratio of total load interrupted to annual peak load.

## 12-03 ENERGY INDICES

### 12-03-1 EXPECTED ENERGY NOT SUPPLIED (EENS)

The expected (system, area, bus) energy not served as a result of bulk power system deficiencies.

Note: See Section 2.1.5, Chapter 2, Reliability Indices, for expressions to calculate EENS.

### 12-03-2 BULK POWER ENERGY CURTAILMENT INDEX (BPECI)

The ratio of annual energy not supplied to peak load:

$BPECI = EENS/L_{max}$

## SUPPLEMENT A

## PROTECTIVE RELAY SYSTEM

### A-01 OPERATIONAL STATE

Protective-relaying subsystem capable of responding properly (safely) when called upon.

### A-02 NONOPERATIONAL STATE

Protective-relaying subsystem incapable of responding when called upon.

Note: This condition would arise if the protective-relaying subsystem were left in the test mode owing to a maintenance error or if an auxiliary component fails in a nonoperation mode.

### A-03 INCORRECT OPERATION STATE

The protective-relaying subsystem responds incorrectly when called upon.

Note: This condition would arise if a communication malfunction affected transmission of the blocking information and resulted in undesired tripping of a circuit breaker.

### A-04 FALSE OPERATION

The protective-relaying subsystem responds spontaneously when not called upon.

Note: This condition may arise from a communication malfunction or relay malfunction which results in spurious initiation of trip of a circuit breaker.

### A-05 CORRECT BUT UNDESIRED OPERATION

The protective-relaying subsystem responds correctly to its input quantities but its operation causes an undesired outage of system facilities.

Note: Examples include impedance relay operation under out-of-step system conditions.

### A-06 DETECTABILITY

The probability of identifying a failure of a component or a subassembly of the system in a given period of time starting at the moment the failure occurred.

### A-07 SECURITY (OF A PROTECTION SYSTEM)

The probability that a protection system will operate correctly after a fault or overload has occurred on the power system.

Note: IEEE Std. 100 defines security of a relay or relay system (power switchgear) as follows: That facet of reliability that relates to the degree of certainty that the relay or relay system will not operate incorrectly.

A-08 DEPENDABILITY (OF A PROTECTION SYSTEM)

The probability that a protection system will operate to successfully clear a fault or overload on the power system.

Note: The protection system can operate to successfully clear the fault or overload and may also have a backup protection system operate incorrectly.

## SUPPLEMENT B

## SELECTED CUSTOMER-INTERRUPTION INDICES

### B-01 SYSTEM AVERAGE INTERRUPTION FREQUENCY INDEX (SAIFI)

The average number of interruptions per customer served per time unit.

Note: SAIFI is determined by dividing the accumulated number of customer interruptions in a year by the number of customers served. Both momentary and sustained interruptions can be used for this purpose but utilities customarily select the latter.

### B-02 SYSTEM AVERAGE INTERRUPTION DURATION INDEX (SAIDI)

The average interruption duration for customers served during a year.

Note: SAIDI is determined by dividing the sum of all sustained-interruption durations during the year by the number of customers served.

### B-03 CUSTOMER AVERAGE INTERRUPTION FREQUENCY INDEX (CAIFI)

The average number of interruptions experienced per customer affected per time unit.

Note 1: CAIFI is determined by dividing the number of sustained interruptions observed in a year by the number of customers affected.

Note 2: Each customer affected must be counted only once, regardless of the number of interruptions that customer may have experienced during the year.

### B-04 CUSTOMER AVERAGE INTERRUPTION DURATION INDEX (CAIDI)

The interruption duration for customers interrupted during a year.

Note: CAIDI is determined by dividing the sum of all sustained-interruption durations during the specified period by the number of sustained interruptions during the year.

### B-05 AVERAGE SERVICE AVAILABILITY INDEX (ASAI)

The ratio of the total number of customer hours that service was available during a year to the total customer hours demanded.

Note 1: Customer hours demanded are determined as the 12-month average number of customers served times 8760.

Note 2: The complementary value of this index, i.e. the Average Service Unavailability Index (see B-06) may also be used sometimes.

### B-06 AVERAGE SERVICE UNAVAILABILITY INDEX (ASUI)

This is the complement of the Average Service Availability Index:
ASUI = 1.0 - ASAI.

## BIBLIOGRAPHY

[1] Central Electricity Generating Board, Electricity Supply Industry Definitions of Terms used when Predicting or Measuring Electricity Transmission and Distribution Reliability, Std. 99-3, Issue 1, London, Feb. 1981.

[2] ——, CEGB Fault Recording Scheme, Appendix B, London, 1983.

[3] CIGRE, "Questionnaire on Repair Time for EHV Equipment," prepared by WG 31-02, Paper No. 79/05/13, April 1980.

[4] ——, "Measuring and Reporting Overall Reliability of Bulk Electricity Systems," prepared by W.H. Winter, Paper No. 32-15, 1980.

[5] ——, "Consideration on the Reliability of Power Systems - Coordination of the Activities of CIGRE Study Committee on Reliability," August 1981.

[6] ——, "Disturbance Performance of Bulk Electricity Systems," prepared by W.H. Winter and B. Le Reverend, Paper No. 37/38/39-02, Paris , 1986.

[7] Deutsche Verbundgesellschaft, "Zuverlaessigkeit elektrischer Versorgungssysteme - Definitionen der wichtigsten Begriffe, Arbeitskreis Planungsrechnung," December 1978, Berlin.

[8] Electric Power Research Institute, "Reliability Indexes for Power Systems," Report No. EL 1773, March 1981.

[9] ——, "Bulk Transmission System Component Outage Data Base," Report No. EL 1797, April 1981.

[10] Institute of Electrical and Electronics Engineers, Std. 313-1971 (ANSI C37.90), Standard for Relays and Relay Systems Associated with Electric Power Apparatus, 1971.

[11] ______, Std. 346-1973, IEEE Standard Definitions in Power Operations Terminology Including Terms for Reporting and Analyzing Outages of Electrical Transmission and Distribution Facilities and Interruptions to Customer Service, 1973.

[12] ______, "Definitions of Customer and Load Reliability Indices for Evaluating Electric Power System Performance," presented by the Working Group on Reliability Performance Records for Optimizing System Design, PES Summer Power Meeting, Paper No. A75 588-4, 1975.

[13] ______, ANSI/IEEE Std. 762-1987, IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity, February 1986.

[14] ______, Terms of Reporting and Analyzing Outages of Electrical Transmission and Distribution Facilities, prepared by T&D Outage and Interruption Definitions Task Force, Standards Draft P859/D1, March 1986.

[15] International Electrotechnical Commission, International Electrotechnical Vocabulary: Chapter 603 - Generation, Transmission and Distribution of Electricity, (Draft) IEC 1 (CO)1170, Sept. 1981.

[16] ______, International Electrotechnical Vocabulary: Chapter 191 - Reliability and Maintainability, prepared by TC 56, December 1983.

[17] Northeast Power Coordinating Council, Glossary of Standard Operating Terms, Revision April 7, 1982, New York (not published).

[18] L. Salvaderi, ENEL Operations Department Definitions, unofficial English translation, Rome, 1984.

[19] UNIPEDE (International Union of Producers and Distributors of Electrical Energy) Statistical Terminology Employed in the Electricity Supply Industry, Third Edition, June 1975.

[20] ______, "Unavailability of Transmission", UNIPEDE Congress, Paper No. 80/D.1, Warsaw, June 11-15, 1979.

# INDEX

# APPENDIX IV

## BIBLIOGRAPHY ON POWER SYSTEM RELIABILITY

Compiled by

J. Endrenyi

This appendix presents a list of books published world-wide on electric power system reliability. Despite the effort to establish as complete a list as possible, a strong possibility exists that some publications which should have been included were omitted simply because no references to them could be found. Unavoidable as they are, such omissions are much regretted.

The entries are all publications whose main subject is power system reliability. Books on reliability in general or on power system analysis with just a short chapter on reliability evaluation are not included. Neither are conference proceedings.

The listing is chronological, with books published the same year listed alphabetically by the first author's name.

V.I. Nitu and H. Albert, "Metode statistico-probabilistice in energetica" (Statistical and probabilistic methods in power system studies), Editure Tehnica, Bucharest, 1968.

R. Billinton, "Power System Reliability Evaluation," Gordon and Breach, New York, 1970.

Yu.B. Gook, N.A. Kazak and A.V. Myashikov, "Theory and calculation of power system reliability" (in Russian), Energija, Moscow, 1970.

R. Billinton, R.J. Ringlee and A.J. Wood, "Power System Reliability Calculations," MIT Press, Cambridge, Mass., 1973.

V.I. Nitu, "Fiabilitatea installatiilor energetice" (Power system reliability), Editura Academiei RSR, Bucharest, 1973.

D. Mukhedkar, F. Bretault and G. Sevestre, "Aspects modernes de la fiabilité" (Modern aspects of reliability theory), Presses de l'Université de Montréal, Montréal, Québec, 1974.

M.N. Rozanov, "Reliability of electric power systems" (in Russian), Energija, Moscow, 1974, Second edition, Energoizdat, Moscow, 1984.

Yu.N. Rudenko and M.B. Cheltzov, "Reliability and the provision of reserves in electric power systems" (in Russian), Nauka, Novosibirsk, 1974.

J. Endrenyi, "Reliability Modeling in Electric Power Systems," J. Wiley & Sons, Chichester, 1978, published in Russian, Energoatomizdat, Moscow, 1983, and translated into Chinese (Xi'an, 1982).

H. Khatib, "Economics of Reliability in Electrical Power Systems," Technicopy Ltd., Stonehouse, Glos., England, 1978.

W. Koenne and P. Zinterhof, "Zuverlässigkeits theoretische Analyse von Elektrizitätsversorgungssystemen" (Reliability analysis of electric supply systems), Springer-Verlag, Vienna, 1978.

V.I. Nitu and C. Ionescu, "Fiabilitate in energetica" (Reliability of power systems), Editura Didactica si Pedagogica, Bucharest, 1980.

C.C.B. Camargo, "Confiabilidade aplicada a sistemas de potencia eletrica" (Reliability applied to electric power systems), Livros Tecnicos e Cientificos Editoria, Rio de Janeiro, 1981.

J. Vardi and B. Avi-Itzhak, "Electric Energy Generation: Economics, Reliability and Rates," MIT Press, Cambridge, Mass., 1981.

R. Billinton and R.N. Allan, "Reliability Evaluation of Power Systems," Pitman Publishing Ltd. (London, England)/Plenum Press (New York, USA) 1984, Published in Chinese (People's Republic of China), 1987 and in Russian (USSR), 1988.

Yu. N. Rudenko and I.A. Ushakov, "Power system reliability" (in Russian), Nauka, Moscow, 1986.

R. Billinton and R.N. Allan, "Reliability Assessment of Large Electric Power Systems," Kluwer Academic Publishers, 1988.

LOUIS-JEAN
avenue d'Embrun, 05003 GAP cedex
Tél. : 92.53.17.00
Dépôt légal : 105 — Février 1992
Imprimé en France

# CIGRE WG 38-03

## LIST OF MEMBERS

Donald T. McGillis - Chairman
Hydro-Québec, Canada

Ronald N. Allan
UMIST
United Kingdom

Osvaldo Bertoldi
ENEL
Italy

Murty P. Bhavaraju
Public Service Electric
and Gas Co.
USA

Roy Billinton*
University of Saskatchewan
Canada

Julio H. Di Salvo
Agua y Energía Eléctrica
Argentina

John Endrenyi*
Ontario Hydro
Canada

William Fairney
CEGB
United Kingdom

Juan Kariger
Hidroeléctrica Espanola S.A.
Spain

Mark Lauby
EPRI
USA

Joseph Mastrocola
Hydro-Québec
Canada

George Mijne
ESCOM
South Africa

John B. Prince Jr.
Wisconsin Electric Power Co.
USA

Robert J. Ringlee*
Power Technologies Inc.
USA

Luigi Salvaderi
ENEL
Italy

Sergio Scalcino
ENEL
Italy

David Thorne
New Brunswick Electric Power
Commission
Canada

Wolfram Wellssow
FGH
Germany

Wally Winter (representing
SC 39)
Ontario Hydro
Canada

* Members of the Editorial Committee

The members acknowledge contributions from:

Paul Albrecht, General Electric, USA
Steve J. Argent, CEGB, United Kingdom
Peter Baxter, CEGB, United Kingdom
Anthony Harpur, Electricity Supply Board, Eire
Charles Heising, Consultant, USA
Michelle Hue, EDF, France
Alfred Inesi, ENEL, Italy
Brian MacRae, The Electricity Commission, New South Wales, Australia
Peter T. Manning, CEGB, United Kingdom
Raouf Naggar, Hydro-Québec, Canada
Alexander Schneider, Commonwealth Edison, USA
Françoise Talandier, EDF, France
Wayne G. Thomson, Baltimore Gas & Electric, USA
Peter O. Wright, Queensland Electricity Commission, Australia

Le CIGRÉ a apporté le plus grand soin à la réalisation de cette brochure thématique numérique afin de vous fournir une information complète et fiable.

Cependant, le CIGRÉ ne pourra en aucun cas être tenu responsable des préjudices ou dommages de quelque nature que ce soit pouvant résulter d'une mauvaise utilisation des informations contenues dans cette brochure.

Publié par le CIGRÉ
21, rue d'Artois
FR-75 008 PARIS
Tél. : +33 1 53 89 12 90
Fax : +33 1 53 89 12 99

**Copyright © 2000**

Tous droits de diffusion, de traduction et de reproduction réservés pour tous pays.

Toute reproduction, même partielle, par quelque procédé que ce soit, est interdite sans autorisation préalable. Cette interdiction ne peut s'appliquer à l'utilisateur personne physique ayant acheté ce document pour l'impression dudit document à des fins strictement personnelles.
Pour toute utilisation collective, prière de nous contacter à sales-meetings@cigre.org

*The greatest care has been taken by CIGRE to produce this digital technical brochure so as to provide you with full and reliable information.*

*However, CIGRE could in any case be held responsible for any damage resulting from any misuse of the information contained therein.*

*Published by CIGRE*
*21, rue d'Artois*
*FR-75 008 PARIS*
*Tel : +33 1 53 89 12 90*
*Fax : +33 1 53 89 12 99*

***Copyright © 2000***

*All rights of circulation, translation and reproduction reserved for all countries.*

*No part of this publication may be produced or transmitted, in any form or by any means, without prior permission of the publisher. This measure will not apply in the case of printing off of this document by any individual having purchased it for personal purposes.*
*For any collective use, please contact us at sales-meetings@cigre.org*